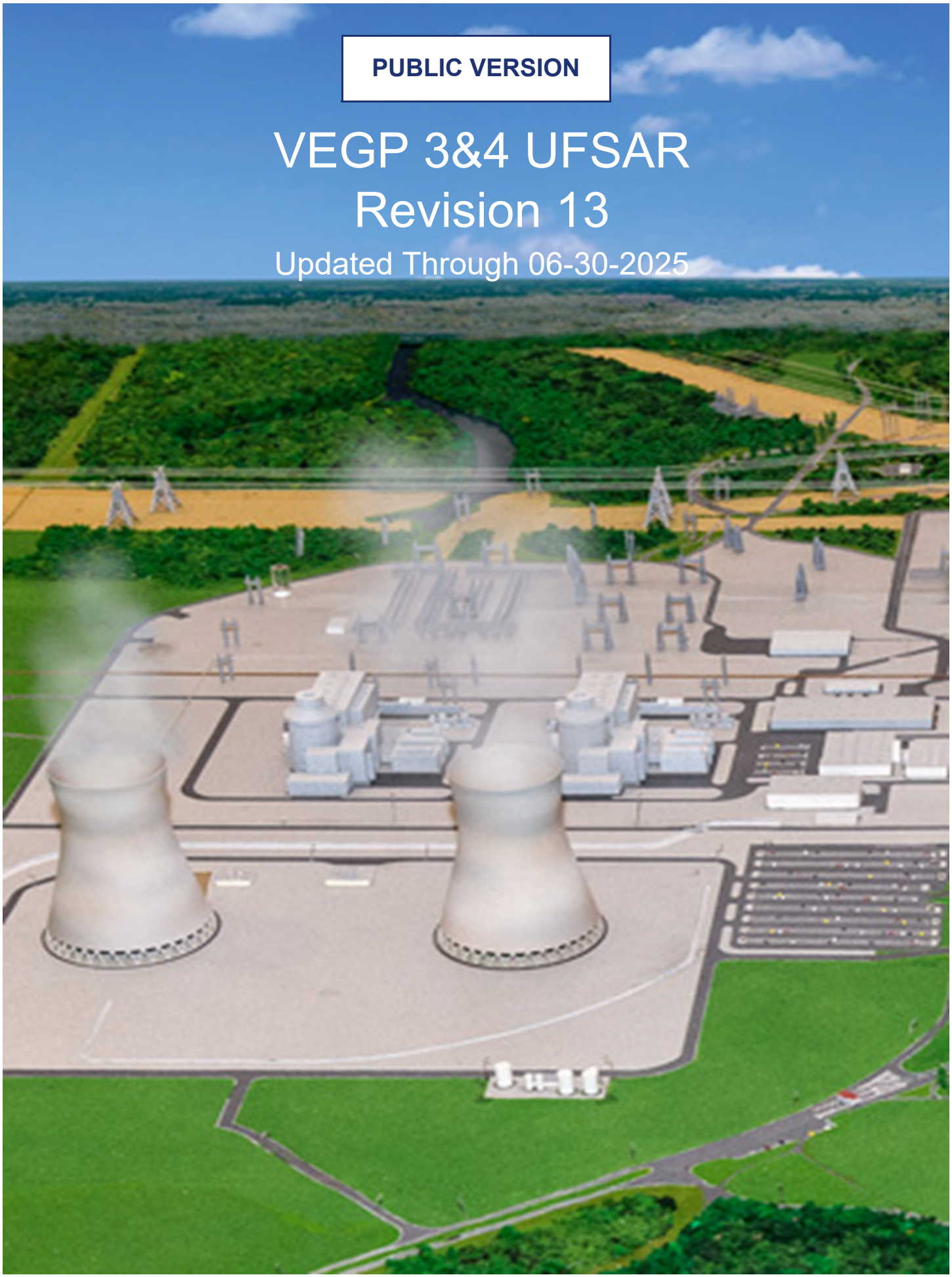
PUBLIC VERSION

VEGP 3&4 UFSAR
Revision 13

Updated Through 06-30-2025



List of Effective Sections

Section	R7[(a)]	R8	R9	R10	R11	R12	R13
1.1	5	6	7	8	9	9	10
1.2	7	8	9	10	10	10	11
1.3	1	2	3	3	3	3	3
1.4	4	4	4	5	5	5	5
1.5	1	1	1	1	1	1	1
1.6	7	8	9	10	11	12	13
1.7	5	6	7	7	7	7	7
1.8	4	5	6	7	8	8	8
1.9	7	8	9	10	11	11	12
1.10	1	1	1	1	1	1	1
1A	7	8	9	10	11	12	13
1B	1	1	1	1	1	1	1
1AA	1	1	1	1	1	1	1
2.0	3	4	4	4	4	5	6
2.1	3	3	4	5	5	5	5
2.2	4	4	5	6	7	7	7
2.3	3	4	4	4	4	4	5
2.4	1	2	3	4	4	5	6
2.4A	0	0	0	0	0	0	0
2.4B	0	0	0	0	0	0	0
2.5	4	5	5	5	6	6	6
2.5A	1	1	1	1	1	1	1
2.5B	1	1	1	1	1	1	1
2.5C	1	1	1	1	1	1	1
2.5D	1	1	1	1	1	1	1
2.5E	0	1	1	2	2	2	2
3.1	3	4	5	5	6	6	6
3.2	7	8	9	10	11	11	12
3.3	4	4	5	5	5	5	5
3.4	6	7	8	8	8	9	10
3.5	6	7	8	9	9	9	9
3.6	6	7	8	9	9	9	10
3.7	6	7	8	9	10	10	11
3.8	7	8	9	10	11	11	12

List of Effective Sections

Section	R7[(a)]	R8	R9	R10	R11	R12	R13
3.9	6	7	8	9	10	10	11
3.10	3	4	5	5	5	5	5
3.11	7	8	9	10	11	11	12
3A	2	2	3	3	3	3	3
3B	2	3	3	4	5	5	5
3C	1	2	2	2	2	2	2
3D	7	8	9	10	10	10	10
3E	5	6	7	7	8	8	8
3F	2	2	3	3	3	3	3
3G	3	4	4	4	4	4	4
3GG	0	0	0	0	0	0	0
3H	7	8	9	10	10	10	11
3I	7	8	9	10	11	11	12
4.1	2	3	4	4	4	4	4
4.2	3	4	5	5	5	5	5
4.3	4	5	6	6	6	6	7
4.4	3	4	5	5	6	6	7
4.5	4	4	5	5	6	6	6
4.6	1	1	1	1	1	1	1
5.1	4	5	6	7	7	7	7
5.2	6	7	8	9	10	10	11
5.3	5	6	6	7	7	7	7
5.4	7	8	9	10	11	11	12
6.0	0	0	1	1	1	1	1
6.1	6	7	8	8	8	8	8
6.2	6	7	8	9	10	10	11
6.3	7	8	9	10	11	12	13
6.4	7	8	9	10	11	12	13
6.5	2	2	2	2	2	2	2
6.6	1	1	2	3	3	3	3
6A	2	3	3	3	3	3	3

List of Effective Sections

Section	R7[(a)]	R8	R9	R10	R11	R12	R13
7.1	5	6	7	8	8	8	9
7.2	6	7	8	9	10	10	10
7.3	5	6	7	8	9	9	9
7.4	2	2	2	2	2	2	2
7.5	4	5	6	6	6	6	6
7.6	2	2	3	4	5	5	5
7.7	4	5	6	7	7	7	8
7A	3	4	5	6	6	6	6
7B	N/A	N/A	0	1	1	1	1
8.1	4	5	6	6	7	7	7
8.2	5	6	7	8	8	8	8
8.3	6	7	8	9	10	11	12
9.1	7	8	9	9	10	10	11
9.2	7	8	9	10	11	12	13
9.3	7	8	9	10	11	12	13
9.4	6	7	8	9	10	11	12
9.5	6	7	8	9	10	11	12
9A	7	8	9	10	11	12	13
9B	0	N/A	N/A	N/A	N/A	N/A	N/A
10.1	3	3	4	5	5	5	5
10.2	4	5	6	6	7	7	7
10.3	5	6	7	8	8	9	10
10.4	7	8	9	10	11	11	12
11.1	1	2	3	3	3	3	3
11.2	5	6	7	7	8	8	9
11.3	5	6	7	8	9	9	9
11.4	5	5	5	5	5	5	6
11.5	4	5	6	7	7	7	7

List of Effective Sections

Section	R7[(a)]	R8	R9	R10	R11	R12	R13
12.1	4	4	5	6	6	6	6
12.2	6	7	8	9	9	9	10
12.3	7	8	9	10	11	11	12
12.4	3	4	5	5	5	5	5
12.5	3	3	3	4	4	4	4
12AA	2	2	3	4	4	4	4
13.1	7	8	9	10	10	10	11
13.2	5	5	5	6	6	6	7
13.2A	1	1	1	1	1	1	1
13.3	4	4	4	4	4	5	5
13.3A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13.4	4	5	5	6	7	7	7
13.5	4	4	4	5	5	6	6
13.6	2	2	3	3	3	4	4
13.7	4	5	6	6	6	6	6
13AA	7	7	7	7	8	8	9
14.1	0	0	0	0	0	0	0
14.2	7	8	9	10	11	12	13
14.3	5	6	7	8	8	8	8
14.4	2	3	3	3	3	3	3
14A	0	0	0	0	0	0	0
15.0	4	5	6	6	6	6	7
15.1	3	4	5	5	5	5	5
15.2	3	4	5	6	6	6	6
15.3	3	4	5	5	5	5	5
15.4	3	4	5	5	6	6	7
15.5	3	4	4	4	4	4	4
15.6	4	5	6	7	8	8	8
15.7	2	3	3	3	3	3	3
15.8	1	1	1	1	1	1	1
15A	3	4	5	5	6	6	6
15B	0	1	2	2	2	2	2

List of Effective Sections

Section	R7[(a)]	R8	R9	R10	R11	R12	R13
16.1	1	2	2	2	2	2	3
16.2	1	1	1	1	1	1	1
16.3	3	4	4	4	4	4	4
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17.6	2	2	3	3	3	3	4
17.7	1	1	1	1	1	1	1
17.8	1	1	2	2	2	2	3
18.1	2	3	4	4	4	4	5
18.2	5	6	7	8	8	8	8
18.3	0	0	1	1	1	1	1
18.4	1	1	2	2	2	2	2
18.5	5	6	6	6	6	6	6
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18.7	2	3	3	3	3	3	3
18.8	5	6	6	7	7	7	8
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18.11	4	5	6	6	6	6	6
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19.7	0	0	0	0	1	1	2
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List of Effective Sections

Section	R7[(a)]	R8	R9	R10	R11	R12	R13
19.9	0	0	0	0	1	1	1
19.10	0	0	0	0	1	1	2
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19.18	0	0	0	0	1	1	1
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19A	0	0	0	0	1	1	1
19B	1	1	1	1	2	2	2
19C	0	0	0	0	1	1	1
19D	5	6	6	6	7	7	8
19E	5	6	7	8	9	9	10
19F	3	4	5	5	6	6	6

(a) For revision history prior to Revision 7, please refer to the Revision 7 version of the UFSAR.

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 1	INTRODUCTION AND GENERAL DESCRIPTION OF THE PLANT	1.1-1
1.1	Introduction	1.1-1
1.1.1	Plant Location	1.1-1
1.1.1.1	Site Location	1.1-2
1.1.1.2	Site Development	1.1-2
1.1.2	Containment Type	1.1-2
1.1.3	Reactor Type	1.1-3
1.1.4	Power Output	1.1-3
1.1.5	Schedule	1.1-3
1.1.6	Format and Content	1.1-3
1.1.6.1	Regulatory Guide 1.70	1.1-3
1.1.6.2	Standard Review Plan	1.1-3
1.1.6.3	Text, Tables, and Figures	1.1-3
1.1.6.4	Numbering of Pages	1.1-4
1.1.6.5	Proprietary Information	1.1-4
1.1.6.6	Acronyms	1.1-4
1.1.7	Combined License Information	1.1-4
1.1.8	References	1.1-4
1.2	General Plant Description	1.2-1
1.2.1	Design Criteria, Operating Characteristics, and Safety Considerations	1.2-1
1.2.1.1	Overall Plant	1.2-1
1.2.1.2	Reactor Coolant System Design	1.2-4
1.2.1.3	Steam and Power Conversion System Design	1.2-6
1.2.1.4	Auxiliary Fluid Systems Design	1.2-7
1.2.1.5	Electrical and Control Systems Designs	1.2-9
1.2.1.6	Plant Arrangement and Construction	1.2-10
1.2.2	Site Description	1.2-12
1.2.3	Plant Arrangement Description	1.2-12
1.2.4	Nuclear Island	1.2-13
1.2.4.1	Containment Building	1.2-13
1.2.4.2	Shield Building	1.2-15
1.2.4.3	Auxiliary Building	1.2-17
1.2.5	Annex Building	1.2-19
1.2.6	Diesel Generator Building	1.2-20
1.2.7	Radwaste Building	1.2-20
1.2.8	Turbine Building	1.2-21
1.2.9	Combined License Information	1.2-21
1.3	Comparisons with Similar Facility Designs	1.3-1
1.4	Identification of Agents and Contractors	1.4-1
1.4.1	Applicant – Program Manager	1.4-1
1.4.2	Other Contractors and Participants	1.4-2
1.4.2.1	Bechtel North American Power Corporation	1.4-2
1.4.2.2	Southern Electric International	1.4-2
1.4.2.3	Burns & Roe Company	1.4-2
1.4.2.4	Washington Group (MK-Ferguson Company)	1.4-3
1.4.2.5	Avondale Industries, Inc.	1.4-3
1.4.2.6	Chicago Bridge & Iron Services, Inc.	1.4-3

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	1.4.2.7 Other Participants	1.4-3
	1.4.2.8 Other Contractors	1.4-3
	1.4.3 Combined License Information	1.4-5
1.5	Requirements for Further Technical Information	1.5-1
	1.5.1 AP600 Safety-Related Tests	1.5-1
	1.5.1.1 Large-Break LOCA	1.5-2
	1.5.1.2 Small-Break LOCA	1.5-2
	1.5.1.3 Containment Cooling	1.5-3
	1.5.1.4 Non-LOCA Transient Analysis	1.5-4
	1.5.1.5 Integral Systems Testing	1.5-5
	1.5.2 AP600 Component Design Tests	1.5-6
	1.5.3 Combined License Information	1.5-6
	1.5.4 References	1.5-7
1.6	Material Referenced	1.6-1
1.7	Drawings and Other Detailed Information	1.7-1
	1.7.1 Electrical and Instrumentation and Control Drawings	1.7-1
	1.7.2 Piping and Instrumentation Diagrams	1.7-1
	1.7.3 Combined License Information	1.7-1
1.8	Interfaces for Standard Design	1.8-1
1.9	Compliance with Regulatory Criteria	1.9-1
	1.9.1 Regulatory Guides	1.9-1
	1.9.1.1 Division 1 Regulatory Guides - Power Reactors	1.9-1
	1.9.1.2 Division 4 Regulatory Guides - Environmental and Siting	1.9-2
	1.9.1.3 Division 5 Regulatory Guides - Materials and Plant Protection	1.9-2
	1.9.1.4 Division 8 Regulatory Guides - Occupational Health	1.9-3
	1.9.1.5 Combined License Information	1.9-4
	1.9.2 Compliance with Standard Review Plan (NUREG-0800)	1.9-4
	1.9.3 Three Mile Island Issues	1.9-4
	1.9.4 Unresolved Safety Issues and Generic Safety Issues	1.9-22
	1.9.4.1 Review of NRC List of Unresolved Safety Issues and Generic Safety Issues	1.9-22
	1.9.4.2 AP1000 Resolution of Unresolved Safety Issues and Generic Safety Issues	1.9-23
	1.9.5 Advanced Light Water Reactor Certification Issues	1.9-61
	1.9.5.1 SECY-90-016 Issues	1.9-61
	1.9.5.2 Other Evolutionary and Passive Design Issues	1.9-75
	1.9.5.3 Passive Design Issues	1.9-81
	1.9.5.4 Additional Licensing Issue	1.9-85
	1.9.5.5 Operational Experience	1.9-86
	1.9.6 References	1.9-86
1.10	Nuclear Power Plants to be Operated on Multi-Unit Sites	1.10-1
	1.10.1 Potential Construction Activity Hazards	1.10-1
	1.10.2 Potentially Impacted SSCs and Limiting Conditions for Operation	1.10-1
	1.10.3 Managerial and Administrative Controls	1.10-2

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
Appendix 1A	Conformance With Regulatory Guides	1A-1
1A.1	References	1A-89
Appendix 1B	Not Used	1B-1
Appendix 1AA	Not Used	1AA-1

LIST OF TABLES

Table Number	Title	Page
1.1-1	AP1000 Acronyms	1.1-5
1.1-201	Post First Full Power Operation Continuing Tier 2* Matter Information	1.1-14
1.1-202	Not Used	1.1-15
1.1-203	Anticipated Schedule for Construction and Operation of Two AP1000 Units at the VEGP Site	1.1-16
1.3-1	AP1000 Plant Comparison With Similar Facilities	1.3-2
1.5-1	AP600 Design Tests and AP1000 Evaluation	1.5-9
1.6-1	Material Referenced	1.6-2
1.6-201	Additional Material Referenced	1.6-21
1.6-202	Cross Reference of ESPA SSAR Sections Incorporated by Reference into FSAR Sections—{HISTORICAL}	1.6-22
1.7-1	I&C Functional and Electrical One-Line Diagrams	1.7-2
1.7-2	AP1000 System Designators and System Diagrams	1.7-3
1.7-201	Not Used	1.7-6
1.8-1	Summary of AP1000 Plant Interfaces With Remainder of Plant	1.8-4
1.8-2	Summary of AP1000 Standard Plant Combined License Information Items	1.8-10
1.8-201	Summary of FSAR Departures from the DCD—{HISTORICAL}	1.8-24
1.8-202	COL Item Tabulation	1.8-26
1.9-1	Regulatory Guide/Section Cross-References	1.9-91
1.9-2	Listing of Unresolved Safety Issues and Generic Safety Issues	1.9-108
1.9-201	Not Used	1.9-141
1.9-202	Conformance with SRP Acceptance Criteria—{HISTORICAL}	1.9-142
1.9-203	Not Used	1.9-169
1.9-204	Generic Communications Assessment	1.9-170
1.10-201	Potential Hazards from Construction Activities	1.10-3
1.10-202	Hazards During Construction Activities	1.10-6
1.10-203	Managerial and Administrative Construction Controls	1.10-8

LIST OF FIGURES

Figure Number	Title	Page
1.1-201	Site Location Map	1.1-17
1.1-202	Site Layout	1.1-18
1.1-203	50-Mile Vicinity	1.1-19
1.1-204	Not Used	1.1-20
1.1-205	Not Used	1.1-20
1.1-206	Not Used	1.1-20
1.2-1	Reactor Coolant System	1.2-22
1.2-2	Site Plan	1.2-23
1.2-3	Functional Allocation of System Components of AP1000 Power Generation Complex	1.2-24
1.2-4	Nuclear Island General Arrangement Plan at Elevation 66'-6"	1.2-25
1.2-5	Nuclear Island General Arrangement Plan at Elevation 82'-6"	1.2-26
1.2-6	Nuclear Island General Arrangement Plan at Elevation 96'-6"	1.2-27
1.2-7	Nuclear Island General Arrangement Plan at Elevation 100'-0" & 107'-2"	1.2-28
1.2-8	Nuclear Island General Arrangement Plan at Elevation 117'-6" & 130'-0"	1.2-29
1.2-9	Nuclear Island General Arrangement Plan at Elevation 117'-6" with Equipment	1.2-30
1.2-10	Nuclear Island General Arrangement Plan at El. 135'-3"	1.2-31
1.2-11	Nuclear Island General Arrangement Plan at Elevation 153'-0" & 160'-6"	1.2-32
1.2-12	Nuclear Island General Arrangement Plan at Elevation 160'-6", 180'-0", & 329'-0"	1.2-33
1.2-13	Nuclear Island General Arrangement Section A-A	1.2-34
1.2-14	Nuclear Island General Arrangement Section A-A with Equipment	1.2-35
1.2-15	Nuclear Island General Arrangement Section B-B	1.2-36
1.2-16	Nuclear Island General Arrangement Section B-B with Equipment	1.2-37
1.2-17	Annex Building General Arrangement Section A-A	1.2-38
1.2-201	Annex Building General Arrangement Plan at Elevation 100'-0" & 107'-2"	1.2-39
1.2-19	Annex Building General Arrangement Plan at Elevation 117'-6" & 126'-3"	1.2-40
1.2-20	Annex Building General Arrangement Plan at Elevation 135'-3" through 183'-6"	1.2-41
1.2-21	Diesel Generator Building General Arrangement Plan at Elevation 100'-0" & Section A-A	1.2-42
1.2-22	Radwaste Building General Arrangement Plan at Elevation 100'-0"	1.2-43
1.2-23	Turbine Building General Arrangement Plan at Elevation 100'-0″	1.2-44
1.2-24	Turbine Building General Arrangement Plan at Elevation 120'-6"	1.2-45
1.2-25	Turbine Building General Arrangement Plan at Elevation 141'-3"	1.2-46
1.2-26	Turbine Building General Arrangement Plan at Elevation 170'-0"	1.2-47
1.2-27	Turbine Building General Arrangement Plan at Elevation 170'-0" with Equipment	1.2-48
1.2-28	Turbine Building General Arrangement Plan at Elevation 255'-3"	1.2-49
1.2-29	Turbine Building General Arrangement Section A-A	1.2-50
1.2-30	Turbine Building General Arrangement Section B-B	1.2-51
1.7-1	(Sheet 1 of 3) Legend for Electrical Power, Lighting, and Communication Drawings	1.7-7
1.7-1	(Sheet 2 of 3) Legend for Electrical Power, Lighting, and Communication Drawings	1.7-8
1.7-1	(Sheet 3 of 3) Legend for Electrical Power, Lighting, and Communication Drawings	1.7-9

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
1.7-2	(Sheet 1 of 3) Piping and Instrumentation Diagram Legend	1.7-10
1.7-2	(Sheet 2 of 3) Piping and Instrumentation Diagram Legend	1.7-11
1.7-2	(Sheet 3 of 3) Piping and Instrumentation Diagram Legend	1.7-12

Chapter 1 Introduction and General Description of the Plant

1.1 Introduction

The Design Control Document (DCD) for the Westinghouse AP1000 simplified passive advanced light water reactor plant is incorporated by reference into the Design Certification Rule for the AP1000 design (Section II.A) of Appendix D to 10 CFR Part 52. The DCD was also approved by the NRC as an amendment to the Design Certification Rule for the AP1000.

This Final Safety Analysis Report (FSAR) incorporates the Design Control Document (DCD) (as identified in Table 1.6-201) for a simplified passive advanced light water reactor plant provided by Westinghouse Electric Company, the entity originally sponsoring and obtaining the AP1000 design certification documented in 10 CFR Part 52, Appendix D. Throughout this FSAR, the "referenced DCD" is the AP1000 DCD submitted by Westinghouse as Revision 19 including any supplemental material as identified in Table 1.6-201. Unless otherwise specified, reference to the DCD refers to Tier 2 information, including references to the sensitive unclassified non-safeguards information (including proprietary information) and safeguards information, contained in the AP1000 DCD. Such DCD information was included in the combined license application in the same manner as it is included in the AP1000 DCD and the appropriate material has been included in the FSAR, i.e., references in the DCD are included as references in the FSAR, and material incorporated by reference into the DCD is incorporated by reference into the FSAR. Appropriate agreements are in place to provide for the licensee's rights to possession (including constructive possession) and use of the withheld sensitive unclassified non-safeguards information (including proprietary information) and safeguards information referenced in the AP1000 DCD for the life of the project.

A limited set of DCD Tier 2 information was further designated as Tier 2* matter information. As provided in 10 CFR Part 52, Appendix D, Section VIII.B.6.c, much of the Tier 2* matter information reverts to Tier 2 information for the unit once the unit first achieves full power operation. Tier 2* matter information that continues to be designated as Tier 2* for the unit beyond the unit's first full power operation is identified in Table 1.1-201. Changes to Tier 2* matter information may require prior NRC approval pursuant to License Condition 2.D.(13) in accordance with the departure evaluation process specified therein.

Appendix D to 10 CFR Part 52 is hereby incorporated by reference into the COL application.

This Final Safety Analysis Report (FSAR) was submitted under Section 103 of the Atomic Energy Act by the Southern Nuclear Operating Company, Inc. (SNC) to the NRC as part of the application for two Class 103 combined licenses (COLs) to construct and operate two nuclear power plants under the provisions of 10 CFR Part 52 Subpart C.

1.1.1 Plant Location

VEGP Units 3 and 4 are located on a 3,169-acre coastal plain bluff on the southwest side of the Savannah River in eastern Burke County, Georgia. The site is approximately 30 river miles above the U.S. 301 bridge and directly across the river from the Department of Energy's Savannah River Site (Barnwell County, South Carolina). The VEGP site is approximately 15 miles east-northeast of Waynesboro, Georgia and 26 miles southeast of Augusta, Georgia. It is also about 100 miles from Savannah, Georgia and 150 river miles from the mouth of the Savannah River.

Figure 1.1-201 identifies the site location. Figure 1.1-202 shows the plant arrangement within the site.

The AP1000 is a standardized plant that is to be placed on a site with parameters described in Chapter 2, "Site Characteristics." The site parameters relate to the seismology, hydrology, meteorology, geology, heat sink, and other site-related aspects.

1.1.1.1 Site Location

The 3,169-acre VEGP site is located on a coastal plain bluff on the southwest side of the Savannah River in eastern Burke County. The site exclusion area boundary (EAB) is bounded by River Road, Hancock Landing Road and 1.7 miles of the Savannah River (River Miles 150.0 to 151.7). The property boundary entirely encompasses the EAB and extends beyond River Road in some areas. The site is approximately 30 river miles above the U.S. 301 bridge and directly across the river from the Department of Energy's Savannah River Site (Barnwell County, South Carolina). The VEGP site is approximately 15 miles east-northeast of Waynesboro, Georgia and 26 miles southeast of Augusta, Georgia, the nearest population center (i.e., having more than 25,000 residents). It is also about 100 miles from Savannah, Georgia and 150 river miles from the mouth of the Savannah River. Numerous small towns exist within 50 miles of the site. A major Interstate highway, I-20, crosses the northern portion of the 50-mile radius. Access to the site is via US Route 25; Georgia Routes 56, 80, 24, 23; and New River Road. A navigation channel is authorized on the Savannah River from the Port of Savannah to Augusta, Georgia. A railroad spur connects the site to the Norfolk Southern Savannah-to-Augusta track.

Figures 1.1-201 and 1.1-203 show the site location and a 6-mile and 50-mile radius, respectively.

1.1.1.2 Site Development

The VEGP site currently has two Westinghouse pressurized water reactors (PWRs), rated at 3,625.6 MWt, and their supporting structures. These structures include two natural-draft cooling towers (one per unit), associated pumping and discharge structures, water treatment building, switchyard, and training center. Plant Wilson, a six-unit oil-fueled combustion turbine facility, is also located on the VEGP site. Figure 1.1-202 shows the VEGP site layout.

The new plant footprint selected for the ESP is adjacent to the west side of the VEGP Units 1 and 2, and is generally the area that was originally designated for VEGP Units 3 and 4 when the plant was first proposed for construction.

SNC has selected the Westinghouse AP1000 certified reactor design for the ESP application. Section 1.3 identifies the design parameters, site characteristics, and site interface values that form the permit basis for NRC's issuance of an ESP. The design parameters are based on the addition of two Westinghouse AP1000 units, to be designated Vogtle Units 3 and 4. Each unit represents a portion of the total generation capacity to be added and will consist of one reactor with a thermal power rating of 3,400 MWt and a net electrical output of 1,117 MWe (Reference 201). The layout and arrangement of the proposed new units are shown in Figure 1.1-202.

1.1.2 Containment Type

The containment building is a freestanding, cylindrical, steel containment vessel with elliptical upper and lower heads. It is surrounded by a seismic Category I shield building constructed of reinforced concrete and steel concrete composite modules. The containment vessel is an integral part of the passive containment cooling system. The vessel provides the safety-related interface with the ultimate heat sink, which is the surrounding atmosphere. Westinghouse is responsible, along with their contractor team members, for the design of the containment.

1.1.3 Reactor Type

The nuclear steam supply system (NSSS) for the AP1000 is a Westinghouse-designed pressurized water reactor.

1.1.4 Power Output

The plant's net producible electrical power to the grid is at least 1000 MWe, with a core power rating of 3400 MWt. In some safety evaluations a power level higher than the rated power level is employed.

1.1.5 Schedule

The scheduled completion date and estimated commercial operation date of nuclear power plants referencing the AP1000 design certification are provided as discussed in Subsection 1.1.7.

Table 1.1-203 displays the anticipated schedule for construction and operation of two AP1000 units at the VEGP site. A site-specific construction plan and startup schedule will be provided to the NRC after issuance of the COL.

1.1.6 Format and Content

1.1.6.1 Regulatory Guide 1.70

To the extent practical, the AP1000 DCD has used as a guide the format and content recommendations of Regulatory Guide 1.70, Revision 3, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants - LWR Edition," November 1978.

The DCD generally uses the same chapter, section, subsection, and paragraph headings used in the standard format. Where appropriate, the DCD is subdivided beyond the extent of the standard format to provide additional information specifically required for that area. Similarly, some of the passive features of the AP1000 require modification of the standard format and content either in terms of placement or type of material presented.

This FSAR generally follows the AP1000 DCD organization and numbering. Some organization and numbering differences are adopted where necessary to include additional material, such as additional content identified in Regulatory Guide 1.206.

1.1.6.2 Standard Review Plan

The technical guidance provided in NUREG-0800, is followed in the preparation of the AP1000 DCD. Standard Review Plan conformance is also determined in accordance with 10 CFR 50.34 to identify the deviations of the AP1000 DCD from the Standard Review Plan. See Subsection 1.9.2 for additional details on Standard Review Plan conformance.

1.1.6.3 Text, Tables, and Figures

AP1000 DCD tables of data are identified by the section or subsection number followed by a sequential number (for example, Table 3.2-3 is the third table of Section 3.2). Tables are located at the end of the section immediately following the text. Drawings, pictures, sketches, curves, graphs, plots, and engineering diagrams are identified as figures and are numbered sequentially by section or subsection similar to tables, and follow at the end of the applicable section or subsection.

FSAR tables, figures, and references are numbered in the same manner as the DCD, but the first new FSAR item is numbered as 201, the second 202, the third 203, and consecutively thereafter.

New appendices are included in the FSAR with double letter designations following the pertinent chapter (e.g., 12AA).

When it provides greater contextual clarity, an existing DCD table or figure is revised by adding new information to the table or figure and replacing the DCD table or figure with a new one in the FSAR. In this instance, the revised table or figure clearly identifies the information being added, and retains the same numbering as in the DCD, but the table or figure number is revised to end with the designation "R" to indicate that the table or figure has been revised and replaced. For example, revised "Table 4.2-1" would become "Table 4.2-1R."

1.1.6.4 Numbering of Pages

Text pages are numbered sequentially within each section or subsection.

1.1.6.5 Proprietary Information

The AP1000 DCD contains no proprietary information.

Some portions of this FSAR may be considered as proprietary, personal, or sensitive and withheld from public disclosure pursuant to 10 CFR 2.390 and Regulatory Issue Summary (RIS) 2005-026. Such material is clearly marked and the withheld material is separately provided for NRC review.

1.1.6.6 Acronyms

Table 1.1-1 provides a list of acronyms used in the AP1000 DCD and VEGP Units 3 and 4 FSAR. Acronyms for systems are defined in the section in which they are used. Other acronyms may be defined in the section in which they are used. Table 1.7-2 provides a list of AP1000 and VEGP Units 3 and 4 system designators.

1.1.7 Combined License Information

The construction and startup schedule information is addressed in Subsection 1.1.5.

1.1.8 References

201. **(Westinghouse 2011)** *AP1000 Design Control Document*, AP1000 Document No. APP-GW-GL-700, Revision 19, Westinghouse Electric Company, 2011.

Table 1.1-1 (Sheet 1 of 9)
AP1000 Acronyms

ac	Alternating Current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	Aluminum Conductor Steel Reinforced
AD	Air Diffuser
ADAMS	Agencywide Documents Access and Management System
ADS	Automatic Depressurization System
AE	Architect Engineer
AFW	Auxiliary Feedwater
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
ALARA	As-Low-As-Reasonably Achievable
ALOHA	Areal Location of Hazardous Atmosphere
ALWR	Advanced Light Water Reactor
AMCA	Air Movement and Control Association
ANL	Argonne National Laboratory
ANS	American Nuclear Society
ANSI	American National Standards Institute
API	American Petroleum Institute
AR	Air Removal
ARI	Air Conditioning and Refrigeration Institute
ASCE	American Society of Civil Engineers
ASHRAE	American Society of Heating, Refrigeration and Air-Conditioning Engineers
ASME	American Society of Mechanical Engineers
ASS	Auxiliary Steam System
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transient Without Scram
AWS	American Welding Society
AWWA	American Water Works Association
BD	Bay Door
BDS	Blowdown System
BEACON	Best Estimate Analyzer for Core Operations - Nuclear
BOL	Beginning of Life
BOP	Balance of Plant
BP	Blowout Panel
BPO	Bulk Power Operations
B&PVC	Boiler and Pressure Vessel Code
BR	Breathing Rate
BTP	Branch Technical Position
BWR	Boiling Water Reactor
CAM	Continuous Air Monitor

Table 1.1-1 (Sheet 2 of 9)
AP1000 Acronyms

CAPCO	Corrective Action Program Coordinator
CDI	Conceptual Design Information
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFR	Code of Federal Regulations
CFS	Chemical Feed System
CHF	Critical Heat Flux
CMAA	Crane Manufacturers Association of America
CMT	Core Makeup Tank
CN	Curve Number
CNO	Chief Nuclear Officer
COL	Combined Operating License/Combined License
COLA	Combined License Application
CP	Construction Phase
CR	Control Room
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
CS	Containment Shell
CSA	Control Support Area
CVS	Chemical and Volume Control System
DAC	Derived Air Concentration
DAC	Design Acceptance Criteria
DAW	Dry Active Waste
dc	Direct Current
DBA	Design Basis Accident
DBE	Design Basis Event
DCD	Design Control Document
D-EHC	Digital Electrohydraulic Control
DEMA	Diesel Engine Manufacturers Association
DG	Diesel Generator
DNB	Departure from Nucleate Boiling
DNBR	Departure from Nucleate Boiling Ratio
DOE	Department of Energy
DPU	Distributed Processing Unit
DRAP	Design Reliability Assurance Program
DVI	Direct Vessel Injection
EAB	Exclusion Area Boundary
EAL	Emergency Action Level
EBR	Experimental Breeder Reactor
ECCS	Emergency Core Cooling System
EFPD	Effective Full Power Days

Table 1.1-1 (Sheet 3 of 9)
AP1000 Acronyms

EIS	Environmental Impact Statement
EMI	Electromagnetic Interference
ENS	Emergency Notification System
EOF	Emergency Offsite Facility
EOF	Emergency Operations Facility
EOP	Emergency Operating Procedures
EP	Emergency Planning
EPA	Environmental Protection Agency
EPC	Engineering, Procurement & Construction
EP-ITAAC	Emergency Planning ITAAC
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQMEL	EQ Master Equipment List
ER	Environmental Report
ERF	Emergency Response Facility
ERO	Emergency Response Organization
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation System
ESP	Early Site Permit
ESPA SSAR	Early Site Permit Application Site Safety Analysis Report
EVP	Executive Vice President
FAC	Flow Accelerated Corrosion
FERC	Federal Energy Regulatory Commission
FFD	Fitness For Duty
FHA	Fire Hazards Analysis
FID	Fixed Incore Detector
FM	Factory Mutual Engineering and Research Corporation
FMEA	Failure Modes and Effects Analysis
FMEA	Failure Mode Effects Analysis
FNP	Farley Nuclear Plant
FPS	Fire Protection System
FSAR	Final Safety Analysis Report
FSER	Final Safety Evaluation Report
FWPCA	Federal Water Pollution Control Act
FWS	Feedwater System
GCC	Georgia Transmission Control Center
GDC	General Design Criteria
GI-LLI	Gastrointestinal Tract–Lower Large Intestine
GMRS	Ground Motion Response Spectrum
GPC	Georgia Power Company
GRCA	Gray Rod Cluster Assembly

Table 1.1-1 (Sheet 4 of 9)
AP1000 Acronyms

GSI	Generic Safety Issues
GSU	Generator Step-up (Transformer)
HCLPF	High Confidence, Low Probability of Failure
HEPA	High Efficiency Particulate Air
HFE	Human Factors Engineering
HP	Health Physics
HNP	Hatch Nuclear Plant
HRHF	Hard Rock High Frequency
HV	High Voltage
HVAC	Heating, Ventilation and Air Conditioning
I&C	Instrumentation and Control
IBC	International Building Code
ICEA	Insulated Cable Engineers Association
IDCOR	Industry Degraded Core Rulemaking
IDLH	Immediately Dangerous to Life and Health
IEEE	Institute of Electrical and Electronics Engineers
IES	Illumination Engineering Society
IIS	Incore Instrumentation System
ILRT	Integrated Leak Rate Test
INEL	Idaho National Engineering Laboratory
INPO	Institute of Nuclear Plant Operations
I/O	Input/Output
IRWST	In-containment Refueling Water Storage Tank
ISA	Instrument Society of America
ISFSI	Independent Spent Fuel Storage Installation
ISI	Inservice Inspection
IST	Inservice Testing
ITA	Inspections, Tests, Analyses
ITAAC	Inspections, Tests, Analyses and Acceptance Criteria
ITP	Initial Test Program
IVR	In-Vessel Retention
JOG	Joint Owners Group
JPM	Job Performance Measure
JTWG	Joint Test Working Group
LBB	Leak-Before-Break
LCO	Limiting Condition for Operation
LFL	Lower Flammability Limit
LHX	Letdown Heat Exchanger
LLC	Limited Liability Corporation
LLW	Low Level Waste
LOCA	Loss of Coolant Accident

Table 1.1-1 (Sheet 5 of 9)
AP1000 Acronyms

LOF	Loss-of-Flow with Failure to Scram
LOFT	Loss of Flow Test
LOOP	Loss of Offsite Power
LOSP	Loss of System Pressure with Degraded ECCS Operation
LPZ	Low Population Zone
LSB	Last Stage Blade
LTOP	Low Temperature Overpressure Protection
LWR	Light Water Reactor
MAAP	Modular Accident Analysis Programs
MCC	Motor Control Center
MCR	Main Control Room
MCRHS	Main Control Room Habitability System
MFCV	Main Feedwater Control Valve
MFIV	Main Feedwater Isolation Valve
M-MIS	Man-Machine Interface System
MOV	Motor-Operated Valve
MPC	Maximum Permissible Concentration
MSIV	Main Steam Isolation Valve
MSL	Mean Sea Level
MSLB	Main Steam Line Break
MSPI	Mitigating Systems Performance Indicator
MTBE(F)	Mean Time Between Event (Failure)
MW	Megawatt
MWe	Megawatt, electric
MWt	Megawatt, thermal
NAE	National Academy of Engineering
NAS	National Academy of Sciences
NBS	National Bureau of Standards
ND	Nuclear Development
NDCT	Natural Draft Cooling Tower
NDE	Non-destructive Examination
NDQA	Nuclear Development Quality Assurance
NE	North East
NEC	National Electrical Code
NEI	Nuclear Energy Institute
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
NFPA	National Fire Protection Association
NLO	Non-Licensed Operator
NPDES	National Pollutant Discharge Elimination System

Table 1.1-1 (Sheet 6 of 9)
AP1000 Acronyms

NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
NUMARC	Nuclear Management and Resources Council (Superseded by NEI)
NUREG	Report designator for NRC reports
NUS	Nuclear Utility Services
OBE	Operating Basis Earthquake
ODCM	Offsite Dose Calculation Manual
OE	Operating Experience
OJT	On-the-Job Training
OM	Operations and Maintenance
ORE	Occupation Radiation Exposure
OSC	Operations Support Center
PC	Permit Condition
PCC	Power Coordination Center
PCCWST	Passive Containment Cooling Water Storage Tank
PCCAWST	Passive Containment Cooling Ancillary Water Storage Tank
PCP	Process Control Program
PCS	Passive Containment Cooling System
PGS	Plant Gas System
P&ID	Piping and Instrumentation Diagram
PM	Project Manager
PMF	Probable Maximum Flood
PMP	Probable Maximum Precipitation
PMWP	Probable Maximum Winter Precipitation
PNNL	Pacific Northwest National Laboratory
PORV	Power Operated Relief Valve
PR	Proposed Revision
PRA	Probabilistic Risk Assessment
PRHR	Passive Residual Heat Removal
PRHR HX	Passive Residual Heat Removal Heat Exchanger
PS-ITAAC	Physical Security ITAAC
PT&O	Plant Test and Operations
PV	Plant Vent
PVC	Polyvinyl Chloride
PWR	Pressurized Water Reactor
PWS	Potable Water System
PXS	Passive Core Cooling System
PZR	Pressurizer
QA	Quality Assurance
QAPD	Quality Assurance Program Description

Table 1.1-1 (Sheet 7 of 9)
AP1000 Acronyms

QMS	Quality Management System
RAM	Reliability, Availability, Maintainability
RAP	Reliability Assurance Program
RAT	Reserve Auxiliary Transformer
RCA	Radiological Controlled Area
RCDT	Reactor Coolant Drain Tank
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RFI	Radio Frequency Interference
R.G.	Regulatory Guide
RHR	Residual Heat Removal
RHX	Regenerative Heat Exchanger
RIS	Regulatory Issue Summary
RNS	Normal Residual Heat Removal
RO	Reactor Operator
RP	Radiation Protection
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RS	Review Standard
RSW	Remote Shutdown Workstation
RT	Radiography Techniques
RTDP	Revised Thermal Design Procedure
RV	Reactor Vessel
SAMDA	Severe Accident Mitigation Design Alternatives
SAMG	Severe Accident Management Guidance
SAR	Safety Analysis Report
SAT	Systematic Approach to Training
SBAA	Southern Balancing Authority Area
SC	South Carolina
SCBA	Self Contained Breathing Apparatus
SCEG	South Carolina Electric and Gas
SCS	Southern Company Services
SCT	Southern Company Transmission
SDP	Significance Determination Process
SDS	Sanitary Drains System
SECY	Secretary of the Commission Letter
SER	Safety Evaluation Report
SERC	South Eastern Reliability Corporation
SGMP	Steam Generator Management Program
SGS	Steam Generation System

Table 1.1-1 (Sheet 8 of 9)
AP1000 Acronyms

SGTR	Steam Generator Tube Rupture
SGW/L	Steam Generator Water Leg
Shaw	Shaw Stone & Webster Nuclear Services
SMACNA	Sheet Metal and Air Conditioning Contractors National Association
SNC	Southern Nuclear Operating Company
SNM	Special Nuclear Material
SRO	Senior Reactor Operator
SRP	Standard Review Plan
SSAR	Standard Safety Analysis Report
SSC	Seismic Source Characterization
SSC(s)	Structure(s), System(s), and Component(s)
SSD	System Specification Document
SSE	Safe Shutdown Earthquake
SSI	Soil Structure Interaction
SS-ITAAC	Site-Specific ITAAC
STA	Shift Technical Advisor
SUFCV	Startup Feedwater Control Valve
SUFIV	Startup Feedwater Isolation Valve
SV	Steam Vent
SVP	Senior Vice President
TBD	To Be Determined
TEDE	Total Effective Dose Equivalent
TID	Total Integrated Dose
TLD	Thermoluminescent Dosimeter
TMD	Transient Mass Distribution
TMI	Three Mile Island
TNT	Trinitrotoluene
TS	Technical Specification(s)
TSC	Technical Support Center
TSO	Transmission System Operator
TSP	Trisodium Phosphate
TtNUS	Tetra Tech NUS, Inc.
UAT	Unit Auxiliary Transformer
UBC	Uniform Building Code
UFL	Upper Flammability Limit
UFSAR	Updated Final Safety Analysis Report
UL	Underwriters Laboratories
UPS	Uninterruptible Power Supply
URD	Utility Requirements Document
USI	Unresolved Safety Issue
USPHS	United States Public Health Service

Table 1.1-1 (Sheet 9 of 9)
AP1000 Acronyms

UT	Ultrasonic Techniques
V & V	Verification and Validation
VEGP	Vogtle Electric Generating Plant
VP	Vice President
WAC	Waste Acceptance Criteria
WBGT	Wet Bulb Globe Temperature
WCAP	Westinghouse report designator, originally Westinghouse Commercial Atomic Power
WEC	Westinghouse Electric Company
WMA	Wildlife Management Area

Table 1.1-201
Post First Full Power Operation Continuing Tier 2* Matter Information

Tier 2* Matter	UFSAR Information Location(s)
Fuel principal design requirements.	4.1.1
Fuel criteria evaluation process. WCAP-12488-P-A, “Fuel Criteria Evaluation Process,” October 1994 WCAP-14204-A, “Fuel Criteria Evaluation Process,” October 1994	Table 1.6-1 (4.1 - WCAP-12488-P-A) Table 1.6-1 (4.2 - WCAP-12488-P-A) Table 1.6-1 (4.3 - WCAP-12488-P-A) Table 1.6-1 (4.4 - WCAP-12488-P-A) 4.1.3 4.2 4.2.1 4.2.1.1.2 4.2.1.1.3 4.2.1.5 4.2.1.6 4.2.3 4.2.6 4.3.1 4.3.1.1.1 4.3.5 4.4.8
Maximum fuel rod average burn-up.	4.3.1.1.1
Reactor coolant pump type.	5.4.1.2.1
Heat sink data for containment peak pressure analysis.	Table 6.2.1.1-10
Screen design criteria.	6.3.2.2.7.1
Small-break loss-of-coolant accident (LOCA) analysis methodology.	15.6.5.4B.2.2 15.6.5.4B.2.3

Table 1.1-202
Not Used

Table 1.1-203
Anticipated Schedule for Construction and Operation of Two AP1000 Units at the VEGP Site

Activity	Start(1)	Finish(1)	Duration
	UNIT 3		
Early Procurement Activities	2nd Q 2008	--	--
Site Preparation	3rd Q 2008	3rd Q 2011	36 Months
Commence Construction (Safety-related activities)	1st Q 2010 (LWA)		--
Fuel Load, Commence Start-Up	4th Q 2015	2nd Q 2016	6 Months
Commercial Operation	April 2016		
	UNIT 4		
Early Procurement Activities	2nd Q 2008	--	--
Site Preparation	3rd Q 2008	3rd Q 2012	48 Months
Commence Construction (Safety-related activities)	1st Q 2010 (LWA)		--
Fuel Load, Commence Start-Up	4th Q 2016	2nd Q 2017	6 Months
Commercial Operation	April 2017		

Notes:
(1) Activities that do not indicate a start or finish date are milestones, and represent the anticipated commencement (start) or completion (finish) of the activity.

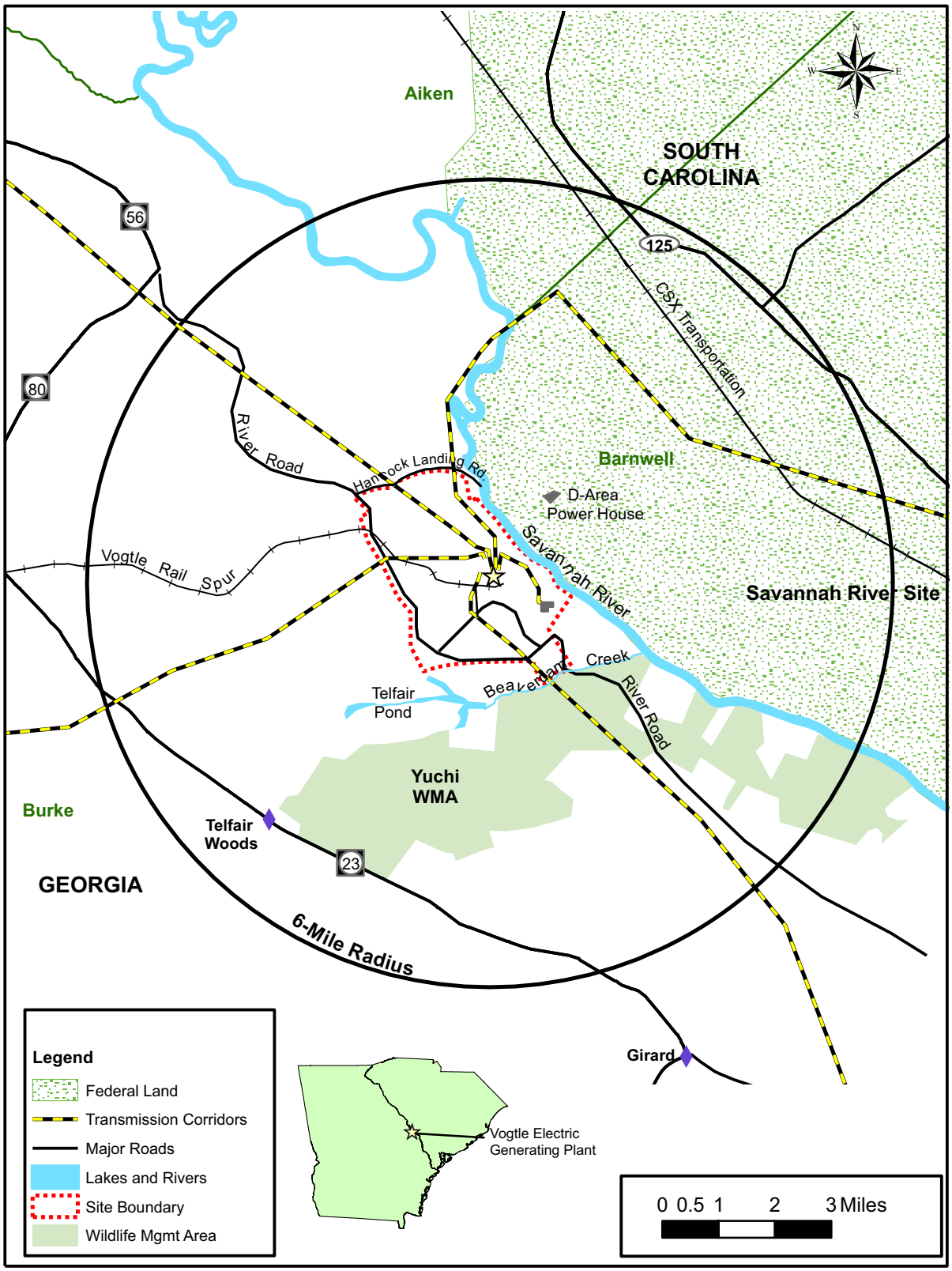

Figure 1.1-201
Site Location Map

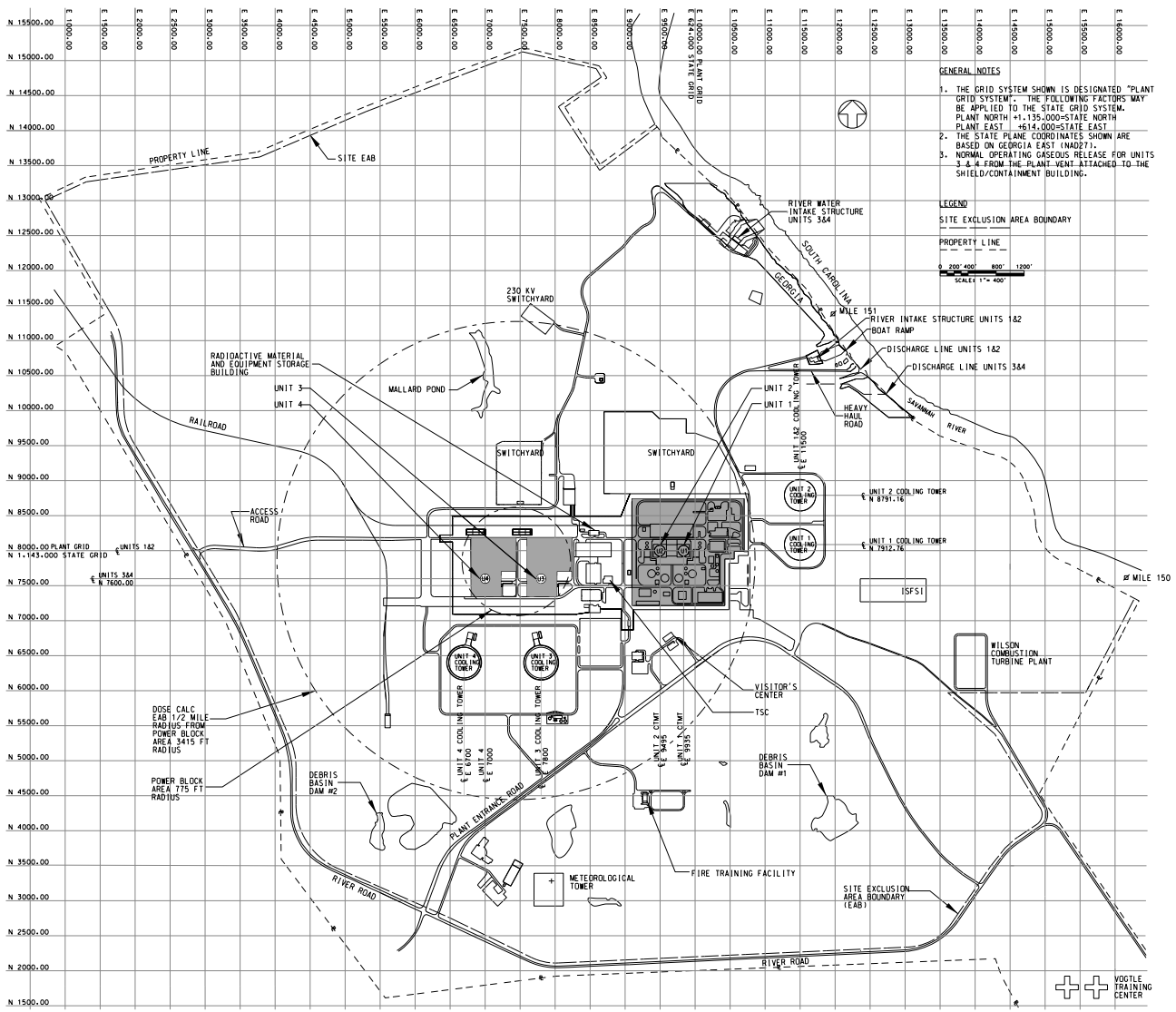

Figure 1.1-202
Site Layout

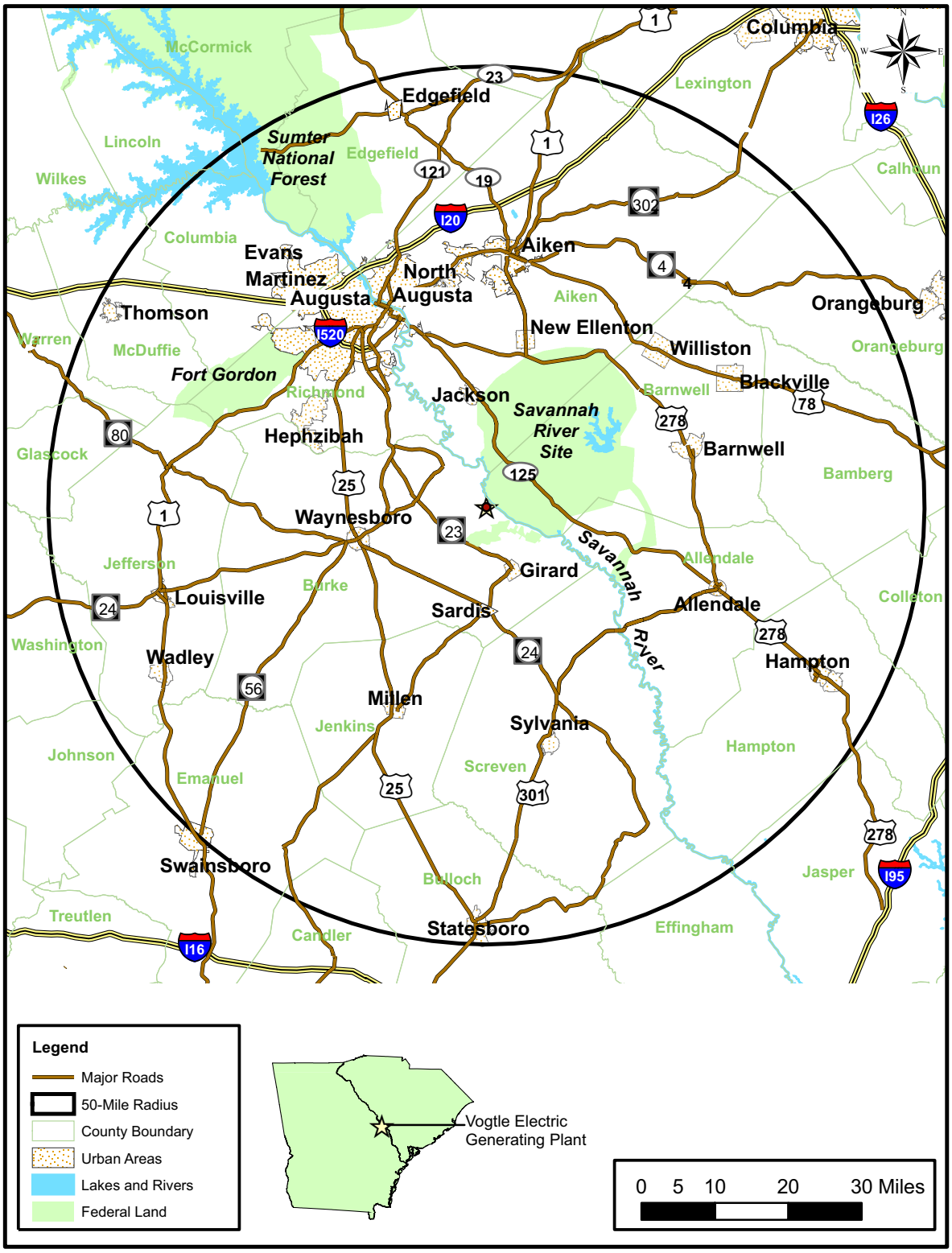

Figure 1.1-203
50-Mile Vicinity

Figure 1.1-204
Not Used

Figure 1.1-205
Not Used

Figure 1.1-206
Not Used

1.2 General Plant Description

This section includes a general discussion of the objectives, design criteria, operating characteristics and safety considerations for the AP1000 and provides a general description of the plant site, the site criteria, the general plant arrangement, the plant arrangement criteria and key features of each of the individual buildings that are collectively defined as the power generation complex.

Design Certification is sought for the power generation complex, excluding those elements and features considered site-specific. The AP1000 design extends beyond those structures, systems, and equipment which are safety-related. All safety-related structures, systems, and components are located on the nuclear island and are to be included in the design certification. To provide a better understanding of the safety-related features of the AP1000, nonsafety-related features are also described in this DCD. In addition, some plant design features which are outside the boundary of the AP1000, and considered to be site-specific, are described for completeness and to provide a basis for quantification of the required interfaces, as required by 10 CFR 52.47 (a)(25). The site-specific structures located off the nuclear island are neither safety-related nor seismic Category I. A more complete description of interfaces for the standard design is contained in Section 1.8.

1.2.1 Design Criteria, Operating Characteristics, and Safety Considerations

This section provides an overview of the AP1000 design objectives, design criteria, operating characteristics and safety considerations.

1.2.1.1 Overall Plant

The primary objective of the AP1000 design is to meet applicable safety requirements and goals defined for advanced light water pressurized water reactors with passive safety features. Since the AP600 has already received a Design Certification, it is also a design objective for AP1000 to be as similar as possible to the AP600.

Westinghouse was a principal participant in the development of the EPRI sponsored Utility Requirements Document (URD) and continues to be involved with EPRI on changes to that document. Therefore, an objective of the AP1000 design is to remain as consistent as possible with the EPRI URD. Additional design objectives for the AP1000 are to provide a greatly simplified plant with respect to design, licensing, construction, operation, inspection and maintenance. Specific design objectives follow.

1.2.1.1.1 Power Capability Objectives

- The plant's net electrical power to the grid is at least 1000 MWe with a nuclear steam supply system power rating (core plus reactor coolant pump heat) of about 3415 MWt.

- The plant is designed for rated performance with up to 10 percent of the steam generator tubes plugged and with a maximum hot leg temperature of 610°F.

- The plant is designed to accept a step load increase or decrease of 10 percent between 25 and 100 percent power without reactor trip or steam dump system actuation provided the rated power level is not exceeded.

- The plant is designed to accept a 100 percent load rejection from full power to house loads without reactor trip or operation of the pressurizer or steam generator safety valves. The design provides for a turbine capable of continued stable operation at house loads.

- The plant is designed to accept ramp load changes of 5 percent per minute while operating in the range of 25 to 100 percent of full power without reactor trip or steam dump actuation subject to core power distribution limits and provided the rated power level is not exceeded.

- The plant is designed to permit a design basis daily load follow cycle for at least 90 percent of the fuel cycle length. The design basis daily load follow cycle is defined as the daily (24 hour period) cycle of operation at 100 percent power, followed by a 2-hour linear ramp to 50 percent power, operation at 50 percent power and a 2-hour linear ramp back to 100 percent power. The duration of time at 50 percent power can vary between 2 and 10 hours. This load follow capability is achievable during 90 percent of each fuel cycle.

- During load follow the plant is designed to routinely make load changes of ≤ 10 percent at ± 2 percent per minute between 50 and 100 percent power without exceeding the core power distribution limits for the purpose of responding to grid frequency changes. No change to the reactor coolant boron concentration is required during these load follow maneuvers.

1.2.1.1.2 Reliability and Availability Objectives

- The overall plant availability goal is greater than 90 percent considering all forced and planned outages.

- The rate of unplanned reactor trips goal is less than one per year.

- The plant is designed with significantly fewer components and significantly fewer safety-related components than a current pressurized water reactor of a comparable size.

- The plant design objective is 60 years without the planned replacement of the reactor vessel which itself has a 60 year design objective based on conservative assumptions. The design provides for the replaceability of other major components, including the steam generators.

- The design of the major components required for power generation such as the steam generators, reactor coolant pumps, fuel, internals, turbine and generator is based on equipment that has successfully operated in power plants. Modifications to these proven designs were based on similar equipment that had successful operating experience in similar or more severe conditions.

1.2.1.1.3 Safety Design Criteria

- The plant design conforms to applicable regulations as discussed in Sections 1.9 and 3.1.

- The plant is designed to be fabricated, erected, and operated in such a manner that the release of radioactive materials to the environment does not exceed the limits and guideline values of applicable government regulations pertaining to the release of radioactive materials for normal operations and for design basis transients and accidents.

- Gaseous and liquid waste disposal facilities are designed so that the discharge of radioactive effluents can be made in accordance with applicable regulations.

- The design provides means by which plant operators are alerted when limits on the release of radioactive effluent are approached.

- The reactor core is designed so its nuclear characteristics do not contribute to a divergent power transient.

- The reactor is designed so that there is no tendency for divergent oscillation of any operating characteristic, considering the interaction of the reactor with other appropriate plant systems.

- Sufficient indications are provided to allow determination that the reactor is operating within the envelope of conditions considered by plant safety analysis.

- Essential safety actions are provided by equipment of sufficient redundancy and independence so that no single failure of active components can prevent the required actions.

- Provisions are made for control of active components of nuclear safety systems and engineered safety features from the control room.

- Those portions of the nuclear steam supply system that form part of the reactor coolant pressure boundary are designed to retain integrity as a radioactive material containment barrier following design basis operational transients and accidents.

- Nuclear safety systems and engineered safety features functions are designed so that no damage to the reactor coolant pressure boundary results from internal pressures caused by design basis operational transients and accidents.

- Nuclear safety systems and engineered safety features are designed to permit demonstrations of their functional performance requirements.

- The design of nuclear safety systems and engineered safety features includes allowances for natural environmental disturbances such as earthquakes, floods, and storms at the station site.

- Standby electrical power sources have sufficient capacity to power the nuclear safety systems and engineered safety features requiring electrical power. Safety-related electrical power requirements needed during a loss of all ac power are supplied via Class 1E dc power.

- Standby electrical power sources are provided to allow prompt reactor shutdown and removal of decay heat under circumstances where normal auxiliary power is not available.

- A containment is provided which completely encloses the reactor system.

- The containment is designed to allow periodic integrity and leak tightness testing.

- The containment, in conjunction with other engineered safety features, limits the release of radioactivity from inside the containment, in the event of a design basis accident. This has the effect of limiting radiological consequences of a design basis accident to within an appropriate fraction of regulatory guidelines.

- Piping that penetrates the containment and could serve as a path for the uncontrolled release of radioactive material to the environs is automatically isolated whenever such uncontrolled radioactive material release is threatened. Such isolation is effected in time to limit radiological effects to less than the specified acceptable limits.

- Provisions are made for passively removing energy from the containment to maintain the integrity of the containment system following accidents that release energy to the containment.

- Passive core cooling systems are provided to limit fuel cladding temperature to less than the limits established by 10 CFR 50.46 in the event of a loss-of-coolant accident.

- The passive core cooling system provides for core cooling over the complete range of postulated break sizes in the reactor coolant pressure boundary.

- Actuation of the passive core cooling system occurs automatically when required, regardless of the availability of offsite power supplies and the normal generating system.

- The control room is shielded against radiation so that continued occupancy under accident conditions is possible.

- In the event that the control room becomes uninhabitable, it is possible to bring the reactor from power range operation to safe shutdown conditions by utilizing the remote shutdown workstation located outside the control room.

- Backup reactor shutdown capability is provided independent of normal reactivity control provisions. This backup system has the capability to shutdown the reactor from any normal operating conditions and subsequently to maintain the shutdown condition.

- The fuel handling and storage facility is designed to prevent inadvertent criticality and to maintain shielding and cooling of spent fuel.

1.2.1.1.4 Site Objectives

- The plant is designed for location at a site with the parameters set forth in Chapter 2, Site Characteristics.

1.2.1.1.5 Other Objectives

- The radiation exposure goal for plant personnel resulting from normal operation, inspection and maintenance is less than 100 man-Rem/year. Radiation shielding is provided and access control patterns are established to allow a properly trained operating staff to control radiation doses within the limits of applicable regulations in any mode of normal plant operations.

- The total low level radioactive waste volume goal is less than 1,970 cubic feet per year after de-watering. This waste includes items such as spent resins, spent filter elements, tank sludge, chemical wastes, and clothing. Spent condensate polishing resins are not included. The total wet radioactive waste volume produced from spent resin and filter elements, tank sludge and chemical waste is designed not to exceed 550 cubic feet per year (de-watered).

1.2.1.2 Reactor Coolant System Design

The AP1000 reactor coolant system (Figure 5.1-2) is designed to remove or to enable removal of heat from the reactor during all modes of operation, including shutdown and accident conditions.

The system consists of two heat transfer circuits, each with a steam generator, two reactor coolant pumps, a single hot leg and two cold legs, for circulating reactor coolant. In addition the system includes a pressurizer, interconnecting piping, valves and instrumentation necessary for operational control and safeguards actuation. All system equipment is located in the reactor containment.

During operation, the reactor coolant pumps circulate pressurized water through the reactor vessel and the steam generators. The water, which serves as coolant, moderator and solvent for boric acid (chemical shim control), is heated as it passes through the core to the steam generators where the

heat is transferred to the steam system. The water is then is returned to the reactor (core) by the pumps to repeat the process.

The reactor coolant system pressure is controlled by operation of the pressurizer, where water and steam are maintained in equilibrium by the activation of electrical heaters and/or a water spray. Steam is formed by the heaters or condensed by the water spray to control pressure variations due to expansion and contraction of the reactor coolant.

Overpressure protection for the reactor coolant system is provided by the spring loaded safety valves installed on the pressurizer. These valves discharge to the containment atmosphere. The valves for the first three stages of automatic depressurization are also mounted on the pressurizer. These valves discharge steam through spargers to the in-containment refueling water storage tank. The discharged steam is condensed and cooled by mixing with water in the tank.

The reactor coolant system is also served by a number of auxiliary systems, including the chemical and volume control system, the passive core cooling system, the spent fuel pool cooling system, the steam generator system, the primary sampling system, the liquid radwaste system and the component cooling water system.

1.2.1.2.1 Reactor Design

- The core is designed for an 18-month fuel cycle.
- There are no reactor vessel penetrations below the top of the core.
- The core is designed for a moderator temperature coefficient that is non-positive over the entire fuel cycle at any power level with the reactor coolant at the normal operating temperature.
- A core design is maintained for projected fuel cycles.
- The core design provides adequate margin so that departure from nucleate boiling will not occur with a 95 percent probability and 95 percent confidence basis for all Condition I and II events.
- The core is located low in the vessel to minimize core temperature during loss-of-coolant accidents.
- The vessel and internals are designed so coolant at approximately the average of T_{cold} and T_{hot} is maintained in the head and control rod drive mechanism regions.
- The lower internals are designed to prevent flow jetting into the core.
- Bottom mounted incore instrumentation is not used. No vessel penetrations exist below the top of the core.
- An integrated head package which contains a forced air cooling system, radial arm hoist system, control rod drive mechanism, seismic support system, integrated head package lifting rig, radiation shielding, integrated cable support system, integrated head package service structures, and shroud that provides housing for the control rod drive mechanisms is employed.
- A welded permanent cavity seal ring is used to provide the seal between the vessel flange and the refueling cavity floor.

1.2.1.2.2 Steam Generator Design

- The Model Delta 125 steam generator of proven design is employed. The steam generator employs thermally treated nickel-chromium-iron Alloy 690 tubes and a steam separator area sludge trap with clean out provisions.
- The channel head is designed for the direct attachment of two reactor coolant pumps.
- The channel head is designed for both manual and robotic accessibility for inspection, plugging, sleeving and nozzle dam placement operations.

1.2.1.2.3 Reactor Coolant Pump Design

- Sealless pumps of proven design are used.
- Two reactor coolant pumps are attached directly to each steam generator channel head with the motor located below the channel head to simplify the loop piping and minimize fuel uncovery during small loss-of-coolant accidents.
- Each reactor coolant pump includes sufficient internal rotating inertia to provide a flow coastdown to avoid departure from nucleate boiling following a loss of reactor coolant flow accident.
- The reactor coolant pump motors are designed with appropriate lifting and handling attachments (lugs and trunnions) to facilitate maintenance.
- The reactor coolant pumps are designed such that they are not damaged due to a loss of all cooling water until a reactor coolant pump trip occurs on High-2 bearing water temperature. This automatic protection is provided to protect the reactor coolant pumps from an extended loss of coolant water.

1.2.1.2.4 Pressurizer and Loop Arrangement

- The piping layout is designed for adequate thermal expansion flexibility assuming a fixed vessel and a free floating steam generator/reactor coolant pump support system.
- The reactor coolant loop and surge line piping are designed to leak-before-break criteria.
- The pressurizer is designed such that, with design spray flow rates, the power-operated relief valve function is not required nor provided.

1.2.1.3 Steam and Power Conversion System Design

1.2.1.3.1 Turbine Design

- The turbine is a power conversion system designed to change the thermal energy of the steam flowing through the turbine into rotational mechanical work which rotates a generator to provide electrical power. It consists of a double flow high pressure cylinder (high pressure turbine) and three double flow low pressure cylinders (low pressure turbines) which exhaust to the condenser. It is a six flow tandem compound, 1800 rpm machine. The turbine system includes stop, control and intercept valves attached to the turbine and in the steam flow path, crossover and crossunder piping between the turbine cylinders and the moisture separator reheater.

- The high pressure turbine has connections for two stages of feedwater heating. The high pressure turbine exhaust steam provides steam for one stage of feedwater heating in the deaerator. The low pressure turbines have extraction connections for four stages of feedwater heating.

- The moisture separator reheaters are an integral component of the turbine system which extracts moisture from the steam and reheats the steam to improve the turbine system performance. There are two moisture separator reheaters located between the high pressure turbine exhaust and the low pressure turbine inlet. The reheater has two stages of reheat.

- The turbine orientation minimizes potential interaction between turbine missiles and safety-related structures and components.

1.2.1.3.2 Main Steam System Design

- The main steam system is designed to supply steam from the steam generators to the high pressure turbine over a range of flows and pressures for the entire plant operating range, i.e., from system warmup to valves-wide-open turbine conditions.

- The main steam system is also designed to dissipate heat generated by the nuclear steam supply system to the condenser through steam dump valves or to the atmosphere through power-operated atmospheric relief valves or spring-loaded main steam safety valves when either the turbine-generator or the condenser is not available.

- Six steam generator safety valves are utilized per steam header. There are two steam headers.

1.2.1.3.3 Main Feedwater and Condensate System Design

- The main feedwater system is designed to supply the steam generators with adequate feedwater during all modes of plant operation including transient conditions. The condensate system is designed to condense and collect steam from the low-pressure turbines and turbine steam bypass systems and then, transfer this condensate from the main condenser to the deaerator.

- The main feedwater and condensate systems are designed for increased availability and improved dissolved oxygen control.

- A deaerating heater is employed.

1.2.1.4 Auxiliary Fluid Systems Design

1.2.1.4.1 Engineered Safeguards Systems Design

- The safety systems are designed to mitigate design basis accidents with a single failure, as defined in Chapter 15.

- The safety systems are designed to maximize the use of natural driving forces such as pressurized nitrogen, gravity flow and natural circulation flow. They do not use active components such as pumps, fans or diesel generators. A minimum number of valves are used for the purpose of initially aligning the safety systems.

- The safety systems are designed to function without safety-related support systems such as alternating current, component cooling water, service water, heating, ventilation and air conditioning.

- The number and complexity of operator actions required to control the safety systems are minimized. In meeting this objective, the approach was to eliminate the required action and not to automate them.

- An automatic reactor coolant system depressurization feature is included in the design and meets the following criteria:

  – The reliability (redundancy and diversity) of the automatic depressurization system valves and controls satisfies single failure criteria as well as the failure tolerance required by the low core melt frequency goals.

  – The design provides for both real demands (such as reactor coolant system leaks and failure of the chemical and volume control system makeup pumps) and spurious instrumentation signals. The probability of significant flooding of the containment due to the use of the automatic depressurization system is less than once in 600 years.

- The passive safety-related systems can operate for at least 1 hour following anticipated transients without release of contaminants that require significant plant cleanup. The automatic depressurization system is designed not to activate for anticipated transients.

- The passive safety-related systems are designed to cool the reactor coolant system from normal operating temperatures to safe shutdown conditions.

- The passive containment cooling system maintains the containment pressure and temperature within the appropriate design limits for both design basis and severe accident scenarios.

1.2.1.4.2 Nonsafety-Related Systems Designs

- The nonsafety-related systems designs are simplified; the number of systems and components and the complexity of operation and maintenance are reduced from current operating plants.

- The nonsafety-related systems are not relied upon to provide safety functions required to mitigate design basis accidents.

- Nonsafety-related systems that are required for normal plant operation provide high plant availability. These systems have appropriate redundancy, are powered by onsite standby power supplies and have sufficient capacity to prevent automatic passive safety system actuation following anticipated Condition II events.

  – The reactor coolant system makeup capability design is sufficient for reactor coolant leaks up to 3/8 inch.

  – Steam generator feedwater capability from the startup feedwater system is designed to provide sufficient flow for a loss of main feedwater event.

  – The normal containment sump pumps (part of the liquid radwaste system) are designed to assist in recovery from leakage to the containment sump.

- Boric acid solutions are designed to be stored at concentrations that do not require heat tracing or room temperatures above normal values.

1.2.1.5 Electrical and Control Systems Designs

1.2.1.5.1 Control and Protection Systems Designs

- The design provides that during normal operation, a single failure in the protection and safety monitoring system does not result in a reactor trip, with the exception of a limited number of PMS component failures, e.g., certain CIMs. This is true even with a channel under maintenance or test.

- The potential for reactor trip and for safeguards actuation due to failures in the plant control system is reduced relative to current operating plants.

- The number of measured plant variables used for reactor trip and for safeguards actuation is minimized relative to current operating plants.

- The margin between the normal operating conditions and the protection system setpoints is increased relative to current operating plants.

- The potential for interaction between the protection and safety monitoring system and the plant control system is reduced relative to current operating plants by incorporating a signal selector function that selects signals for control and for protection.

1.2.1.5.2 Alternating Current and Direct Current Power Design

- Safety-related direct current (dc) power is provided to support reactor trip and engineered safeguards actuation. Batteries are sized to provide the necessary dc power and uninterruptible ac power for items such as the protection and safety monitoring system actuation, the control room functions including habitability, dc-powered valves in the passive safety-related systems and containment isolation.

- All safety-related electrical power is provided from the Class 1E dc power system. No separate safety-related ac power system is required.

1.2.1.5.3 Control Room Design

- A main control room is provided that is able to control the plant during normal and anticipated transients and design basis accidents. The main control room includes indications and controls capable of monitoring and controlling the plant safety systems as well as the nonsafety-related control systems.

- A remote shutdown capability is provided. The remote shutdown workstation contains the indications and controls that allow an operator to achieve and maintain safe shutdown of the plant following an event when the main control room is unavailable. Additional nonsafety-related indications and controls are provided as described in Chapter 7.

- The remote shutdown workstation contains indications and controls consistent with its intended use; i.e., the remote shutdown workstation is to be used in the unlikely event that the main control room is not available.

- Access to the remote shutdown workstation transfer mechanism is under strict administrative control.

- The main control room is serviced by reliable and redundant nonsafety-related power sources and heating, ventilation and air conditioning systems during normal operation.

- In the unlikely event that the normal power source or the heating, ventilating and air conditioning system becomes unavailable, there are passive systems (batteries, compressed air) to support the main control room for up to 3 days.

- The main control room contains the safety-related instrumentation and controls to allow the operator to achieve and maintain safe shutdown following any design basis accident.

- The safety-related power sources and passive cooling system are designed to provide a habitable environment for the operating staff assuming that no ac power is available. Installed equipment provides for at least 3 days of operation, as stated above. After 3 days, it is possible to continue operation with the control room cooled and ventilated with circulation of outside air.

- A mechanism is provided to allow the operating staff to transfer control from the main control room to the remote shutdown workstation.

- The system prevents spurious signals caused by fire damage from being issued to components once transfer to the remote shutdown workstation has been effected.

- The transfer of the control of components to the remote shutdown workstation is alarmed in the main control room.

- Both the main control room and the remote shutdown workstation are designed in accordance with human factors engineering principles and practices.

- Human factors considerations are utilized so that the indications and controls for the remote shutdown workstation are similar to those provided in the main control room.

- The safety-related instrumentation (equipment racks) is maintained at acceptable ambient conditions for 3 days following a loss of all ac power by using a passive cooling system. After 3 days, it is possible to continue operation with the instrumentation and control rooms cooled by circulation of outside air.

- A technical support center is provided.

1.2.1.6 Plant Arrangement and Construction

1.2.1.6.1 Plant Arrangement

- The plant arrangement is comprised of five principal building structures; the nuclear island, the turbine building, the annex building, the diesel generator building, and the radwaste building (see Figure 1.2-3).

- The nuclear island is structurally designed to meet seismic Category I requirements as defined in Regulatory Guide 1.29. The nuclear island consists of a free-standing steel containment building, a concrete shield building, and an auxiliary building. The foundation for the nuclear island is an integral basemat which supports these buildings.

- The nuclear island structures are designed to withstand the effects of natural phenomena such as hurricanes, floods, tornados, tsunamis, and earthquakes without loss of capability to perform safety functions. Design for natural phenomena is based on the industry standards as described in Chapters 2 and 3.

- The nuclear island is designed to withstand the effects of postulated internal events such as fires and flooding without loss of capability to perform safety functions.

- The main area of the turbine building structure is designed to International Building Code requirements. The first bay of the turbine building is designed to seismic Category II requirements. The turbine building is supported on a single basemat foundation.

- The annex building area outlined by Column lines E – I.1 and 2 – 13 is designed to seismic Category II requirements. The rest of the annex building area is designed to International Building Code requirements. The annex building includes functions such as the health physics area, the control support area, access control, and personnel facilities (shower and locker rooms).

- The diesel generator building houses two diesel generators and their associated heating, ventilation and air conditioning equipment. The building is a nonseismic structure designed for wind and seismic loads in accordance with the Uniform Building Code.

- The radwaste building contains facilities for the handling and storage of plant wastes. It is a nonseismic structure designed for wind and seismic loads in accordance with the Uniform Building Code. The foundation for the building is a reinforced concrete mat on grade.

- Radioactive equipment and piping in all buildings are arranged and shielded to minimize radiation exposure.

- The overall plant arrangement utilizes building configurations and structural designs to minimize the building volumes and quantities of bulk materials (concrete, structural steel, rebar) consistent with safety, operational, maintenance, and structural needs.

- The plant arrangement provides separation between safety-related and nonsafety-related systems to preclude adverse interaction between safety-related and nonsafety-related equipment. Separation between redundant safety-related equipment and systems provides confidence that the safety design functions can be performed. In general this separation is provided by partitioning an area with concrete walls.

- The plant arrangement provides separation for radioactive and non-radioactive equipment and provides separate pathways to these areas for personnel access.

- Pathways through the plant are designed to accommodate equipment maintenance and equipment removal from within the plant. The size of the pathways is dictated by the largest appropriate piece of equipment that may have to be removed or installed after initial installation. Where required, laydown space is provided for disassembling large pieces of equipment to accommodate the removal or installation process.

- Adequate space is provided for equipment maintenance, laydown, removal and inspection. Hatches, monorails, hoists, and removable shield walls are provided to facilitate maintenance.

1.2.2 Site Description

Site Characteristics

The AP1000 is a standard plant that is to be placed on a site with parameters bounded by those used as a basis for design certification as described in Chapter 2, Site Characteristics. The site parameters relate to the seismology, hydrology, meteorology, geology, heat sink and other site-related aspects. The allowable site interface parameters bound a large percentage of potential sites.

The AP1000 is designed on the basis that the equipment, modules, structures, and bulk material can be shipped to the site by commercial rail or truck. This does not preclude the shipment of large equipment or structures by barges should a specific site be accessible by water.

Site Plan

The site layout and the site plan are shown in Figure 1.1-202 and Figure 1.2-2, respectively. Principal structures, facilities, and roads are illustrated. Orientation of the two AP1000 units is such that “plant north” corresponds with true north. Plant elevation in the DCD is 100 feet, whereas the plant elevation for VEGP is 220 feet; therefore DCD elevations are to be increased by 120 feet to be actual site elevations.

The river intake for VEGP Units 3 and 4 withdraw makeup water from the Savannah River. The intake system is located upstream of the river intake of VEGP Units 1 and 2. Makeup water is pumped directly to the cooling tower basin. Cooling tower circulating water pump complexes are located south of the reactors. The intake structure is located at the end of a canal, and is situated northeast of the reactors.

The transformer area is located north of the turbine building. The unit auxiliary transformers (UAT), the reserve auxiliary transformers (RAT), and the generator step-up transformers (GSU) are located in this area. The main switchyard area is located adjacent to the transformer area.

An administrative building is located east of the cooling tower basins. The building houses management, administration, and support functions for the site. The training and simulator building is located southeast of the reactor complex, but within the site boundary.

1.2.3 Plant Arrangement Description

Building Definition

A set of the general arrangement drawings for the AP1000 is provided in Figures 1.2-4 through 1.2-30.

Figure 1.2-201 replaces Figure 1.2-18 to reflect the relocation of the Operations Support Center.

The AP1000 consists of the following five principal structures. Each of these buildings is constructed on an individual basemat:

- Nuclear island
- Turbine building
- Annex building
- Diesel generator building
- Radwaste building

The structures that make up the nuclear island are:

- Containment building
- Shield building
- Auxiliary building

These nuclear island buildings are depicted on the site plan. The safety-related equipment designed to perform accident mitigation functions is located in the nuclear island.

1.2.4 Nuclear Island

1.2.4.1 Containment Building

Building Function

The containment building is the containment vessel and the structures contained within the containment vessel. The containment building is an integral part of the overall containment system with the functions of containing the release of airborne radioactivity following postulated design basis accidents and providing shielding for the reactor core and the reactor coolant system during normal operations.

The containment vessel is an integral part of the passive containment cooling system. The containment vessel and the passive containment cooling system are designed to remove sufficient energy from the containment to prevent the containment from exceeding its design pressure following postulated design basis accidents.

The containment building is designed to house the reactor coolant system and other related systems and provides a high degree of leak tightness.

Civil/Structural Features

The containment building, a seismic Category I structure, is a freestanding cylindrical steel containment vessel with elliptical upper and lower heads. It is surrounded by a seismic Category I shield building.

Figures 1.2-13 through 1.2-16 provide sectional views through the containment that show the configuration of the containment vessel and the internal structures of the containment.

There are two floor elevations (grade access maintenance floor and operating deck) and four lower equipment compartments within the containment building. Removable hatches are provided for access to equipment at other elevations.

Figures 1.2-7, 1.2-8, 1.2-9, 1.2-15, and 1.2-16 depict the configuration of the refueling water storage tank. This tank is located below the operating deck. The capacity of the refueling water storage tank exceeds the quantity of water required to accomplish safety functions or to fill the refueling cavity during refueling operations. The refueling cavity has two floor elevations. The upper and lower reactor internals storage area is at the lower elevation as is the fuel transfer tube.

Equipment Arrangement

The principal system located within the containment building is the reactor coolant system that consists of two main coolant loops, a reactor vessel, two steam generators, four sealless reactor coolant pumps, and a pressurizer. Figures 1.2-9, 1.2-14 and 1.2-16 depict the reactor coolant system component locations in the containment.

The main steam and feedwater lines are routed from the steam generators to a horizontal run below the operating deck. The steam and feedwater lines penetrate the north side of the containment vessel and are routed through the main steam isolation valve area in the auxiliary building to the turbine island.

The passive core cooling system is also located in the containment building. The primary components of the passive core cooling system are two core makeup tanks, two accumulators, the refueling water storage tank, the passive residual heat removal heat exchanger, and two spargers. The first three stages of the automatic depressurization valves are located above the pressurizer and consist of a two-tier valve module.

The passive residual heat removal heat exchanger and the spargers are located within the refueling water storage tank (Figures 1.2-7 and 1.2-9). The core makeup tanks are located on floor elevation 107′2″ level (Figures 1.2-7 and 1.2-9).

The chemical and volume control system equipment module is located in the containment below the maintenance floor level. This module represents the high pressure purification loop of the chemical and volume control system (Figure 1.2-14).

The reactor coolant drain tank, the reactor coolant drain tank heat exchanger and the containment sump pumps are located in the compartment adjacent to the reactor vessel cavity. Access to the reactor vessel cavity is via a stairwell that descends from the maintenance floor (Figure 1.2-14).

Four containment recirculation fan coil unit assemblies are located adjacent to the steam generator compartments. Each consists of a vaneaxial fan, cooling coils, and the associated exit ducts and inlet plenum. The four fan coil unit assemblies are connected to the common exit plenum (ring header). Several vertical ducts branch off from the ring header to provide cooling flow to the lower compartments in the containment while other vertical ducts are directed up to provide cooling flow to the upper regions of the containment vessel.

Equipment and Material Handling

A seismic Category I polar crane is provided in the containment and its bridge is sized for lifting the steam generator during a steam generator removal operation. A temporary construction trolley is required for this operation. The polar crane support is attached to the steel cylindrical shell of the containment as shown in Figures 1.2-14 and 1.2-16.

The layout of the containment is designed to permit the removal of either steam generator through a temporary opening cut through the top of containment, then through the center of the passive containment cooling air diffuser. During a steam generator removal operation, the steam generator is lifted from the steam generator compartment by a temporary construction trolley and then through containment by a large mobile crane.

The polar crane trolley is designed for normal refueling operations such as lifting the integrated head package, the lower internals package and the upper internals package.

An auxiliary hook is provided with the polar crane for easier movement of smaller equipment. The polar crane is used for lifting reactor coolant pump motor/impeller assemblies from the steam generator/loop compartments to the operating deck in the event that the reactor coolant pump motor/impeller assemblies have to be removed from the containment for major maintenance.

A reactor coolant pump maintenance cart is provided for use in either of the two steam generator/loop compartments for removing the reactor coolant pump motor/impeller assemblies from the bottom head of the steam generators. This maintenance cart transports the reactor coolant pump motor/impeller assemblies to a designated area in each of the steam generator/loop compartments

where the assemblies are lifted from the compartment to the operating deck by the polar crane. Removable sections of grating at all platform levels in the steam generator/loop compartments permit direct access to the pumps. From the operating deck level, the reactor coolant pump motor/impeller assemblies are removed from the containment via the main equipment hatch into the annex building maintenance area.

A refueling machine is provided to move fuel between the fuel transfer system and the reactor core (Figure 1.2-14). The refueling machine consists of a rectilinear bridge and a trolley crane with a vertical mast extending down into the refueling cavity. The bridge spans the refueling cavity and runs on rails set into the edge of the refueling cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly. In addition, the refueling machine is equipped with an auxiliary hoist which provides additional capability for other refueling operations.

A fuel transfer system is provided to transfer nuclear fuel assemblies between the refueling cavity in the containment building and the fuel transfer canal/spent fuel pool located in the fuel handling area of the auxiliary building. The fuel transfer system also has the capability to transfer control rod clusters.

Building Access and Exit

Access to the containment is provided through a personnel airlock and the main equipment hatch located at the operating deck level and a personnel airlock and a maintenance hatch at the maintenance floor level. Access to the containment can be controlled by the health physics office in the annex building.

In the event that large numbers of temporary personnel require access to the containment during a major outage, temporary personnel facilities can be provided immediately adjacent to the health physics area in the annex building.

1.2.4.2 Shield Building

Building Function

The shield building is the structure that surrounds the containment vessel. During normal operations, a primary function of the shield building is to provide shielding for the containment vessel and the radioactive systems and components located in the containment building. The shield building, in conjunction with the internal structures of the containment building, provides the required shielding for the reactor coolant system and the other radioactive systems and components housed in the containment.

Another function of the shield building is to protect the containment building from external events. The shield building protects the containment vessel and the reactor coolant system from the effects of tornadoes and tornado produced missiles.

During accident conditions, the shield building provides the required shielding for radioactive airborne materials that may be dispersed in the containment as well as radioactive particles in the water distributed throughout the containment.

The shield building is an integral part of the passive containment cooling system.

Civil/Structural Features

The shield building is a seismic Category I structure. It shares a common basemat with the containment building and the auxiliary building.

Figures 1.2-13 through 1.2-16 provide sectional views of the shield building which show the basic configuration of the shield building and the annulus area between the containment vessel and the shield building.

The following items represent the significant features of the shield building and the annulus area:

- Shield building cylindrical structure
- Shield building roof structure
- Connections between reinforced concrete and steel concrete composite modules
- Tension ring at the interface between the roof and shield building cylinder
- Knuckle Region at interface of roof and outer wall of passive containment cooling system water storage tank
- Compression ring below the inner wall of the passive containment cooling system water storage tank
- Lower annulus area
- Middle annulus area
- Upper annulus area
- Passive containment cooling system air inlets at the top of the shield building cylinder
- Passive containment cooling system air inlet plenum
- Passive containment cooling system water storage tank
- Passive containment cooling system air diffuser
- Passive containment cooling system air baffle

The cylindrical section of the shield building serves as shielding and a missile barrier and is a key component of the passive containment cooling system. It structurally supports the roof and is a major structural member for the entire nuclear island. Floor slabs and structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building.

A watertight seal is provided between the upper and middle annulus areas to provide an environmental barrier. The middle annulus area contains the majority of containment penetrations and radioactive piping. This environmental barrier is provided to protect against the following:

- In the event of an accident or spurious actuation, the passive containment cooling system drains the system water storage tank. The water, which runs down the outside of the containment vessel, is prevented from draining into the middle annulus area by the watertight seal. Drains are provided to direct the passive containment cooling system runoff water out of the shield building.

- The passive containment cooling system is designed to perform with the upper annulus permanently open to the environment to permit sufficient air flow through the shield building in the event of an accident. The watertight seal protects the middle annulus area from ambient environmental conditions.

The shield building roof is a reinforced concrete conical shell supporting the passive containment cooling system water storage tank and air diffuser. Air intakes are located at the top of the cylindrical portion of the shield building. The conical roof supports the passive containment cooling system water storage tank which is constructed with a stainless steel liner attached to reinforced concrete walls. The air diffuser in the center of the roof discharges containment cooling air directly upwards.

The passive containment cooling system air baffle is located in the upper annulus area. It is attached to the cylindrical section of the containment vessel. The function of the passive containment cooling system air baffle is to provide a pathway for natural circulation of cooling air in the event that a design basis accident results in a large release of energy into the containment. In this event the outer surface of the containment vessel transfers heat to the air between the baffle and the containment

shell. This heated and thus, lower density air flows up through the air baffle to the air diffuser and cooler and higher density air is drawn into the shield building through the air inlets at the top cylindrical portion of the shield building.

Equipment and Material Handling

A monorail is provided in the upper annulus area of the shield building to facilitate the initial installation of the passive containment cooling system air baffle panels and to permit the removal of these air baffle panels when an inspection or repainting of the containment vessel is required.

Two personnel workstation platforms are provided for transporting staff and equipment from the operating deck floor level of the upper annulus area to the top of the shield building. The work station platforms are powered from their respective monorail sections and are able to be positioned at any circumferential position or height beneath the monorail sections. Figures 1.2-14 and 1.2-16 depict the monorail system and the personnel work station platforms.

1.2.4.3 Auxiliary Building

Building Function

The primary function of the auxiliary building is to provide protection and separation for the seismic Category I mechanical and electrical equipment located outside the containment building.

The auxiliary building provides protection for the safety-related equipment against the consequences of either a postulated internal or external event. The auxiliary building also provides shielding for the radioactive equipment and piping that is housed within the building.

The most significant equipment, systems, and functions contained within the auxiliary building are the following:

- Main control room
- Class 1E instrumentation and control systems
- Class 1E electrical system
- Fuel handling area
- Mechanical equipment areas
- Containment penetration areas
- Main steam and feedwater isolation valve compartment

Main control room: The main control room provides the human system interfaces required to operate the plant safely under normal conditions and to maintain it in a safe condition under accident conditions. The main control room includes the main control area, the operations work area, the operations break area, and an office for the shift manager.

Instrumentation and control systems: The protection and safety monitoring system and the plant control system provide monitoring and control of the plant during startup, ascent to power, powered operation, and shutdown. The instrumentation and control systems include the protection and safety monitoring system, the plant control system, and the data display and processing system.

Class 1E electrical system: The Class 1E system provides 250 volts dc power for safety-related and vital control instrumentation loads including monitoring and control room emergency lighting. It is required for safe shutdown of the plant during a loss of ac power and during a design basis accident with or without concurrent loss of offsite power.

Fuel handling area: The primary function of the fuel handling area is to provide for the handling and storage of new and spent fuel. The fuel handling area in conjunction with the annex building provides

the means for receiving, inspecting and storing the new fuel assemblies. It also provides for safe storage of spent fuel as described in Section 9.1, Fuel Storage and Handling.

The fuel handling area provides for transferring new fuel assemblies from the auxiliary building rail car bay to and from the new fuel storage area to the containment building and for transferring spent fuel assemblies from the containment building to the spent fuel storage pit within the auxiliary building.

The fuel handling area provides the means for removing the spent fuel assemblies from the spent fuel storage pit and loading the assemblies into a shipping cask for transfer from the facility.

The fuel handling area is protected from external events such as tornadoes and tornado produced missiles. Protection is provided for the spent fuel assemblies, the new fuel assemblies and the associated radioactive systems from external events.

The fuel handling area is constructed so that the release of airborne radiation following any postulated design basis accident that could result in damage to the fuel assemblies or associated radioactive systems does not result in unacceptable site boundary radiation levels.

Mechanical equipment areas: The mechanical equipment located in radiological control areas of the auxiliary building are the normal residual heat removal pumps and heat exchangers, the spent fuel cooling system pumps and heat exchangers, the solid, liquid, and gaseous radwaste pumps, tanks, demineralizers and filters, the chemical and volume control pumps, and the heating, ventilating and air conditioning exhaust fans.

The mechanical equipment located in the clean areas of the auxiliary building are the heating, ventilating and air conditioning air handling units, associated equipment that service the main control room, instrumentation and control cabinet rooms, the battery rooms, the passive containment cooling system recirculation pumps and heating unit and the equipment associated with the air cooled chillers that are an integral part of the chilled water system.

Containment penetration areas: The auxiliary building contains all of the containment penetration areas for mechanical, electrical, and instrumentation and control penetrations. The auxiliary building provides separation of the radioactive piping penetration areas from the non-radioactive penetration areas and separation of the electrical and instrumentation and control penetration areas from the mechanical penetration areas. Also provided is separation of redundant divisions of instrumentation and control and electrical equipment.

Main steam and feedwater isolation valve compartment: The main steam and feedwater isolation valve compartment is contained within the auxiliary building. The auxiliary building provides an adequate venting area for the main steam and feedwater isolation valve compartment in the event of a postulated leak in either a main steam line or feedwater line.

Civil/Structural Features

The auxiliary building is a seismic Category I reinforced concrete structure. It shares a common basemat with the containment building and the shield building.

The auxiliary building wraps around approximately 70 percent of the circumference of the shield building. Floor slabs and the structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building.

Equipment and Material Handling

A cask handling crane is located in the fuel handling area of the auxiliary building. The cask handling crane is designed to transport the spent fuel cask between the rail car bay, the cask loading pit, and the cask washdown pit. The crane rail length and rail stop limits the crane travel and thus precludes the movement of this crane in the near vicinity of the spent fuel pool. A fuel handling machine is provided to transfer new fuel from the rail car bay to the new fuel rack to the new fuel elevator. A bridge crane is provided in the rail car bay for handling the spent resin waste container fill station cover, the spent resin waste container, and the high activity filter transfer casks.

The major components of the fuel transfer system are located in the fuel transfer canal. The fuel transfer system is designed to transfer fuel assemblies between the fuel transfer canal located in the fuel handling area and the refueling cavity located in the containment building. The fuel transfer system consists of a transfer car/fuel container, a drive car, a traverse drive mechanism, an upending mechanism, the transfer tube, a quick opening hatch/blind flange on the containment side of the transfer tube and a valve on the fuel handling area side of the transfer tube.

A fuel handling machine is provided to move the spent fuel assemblies between the fuel transfer canal, the spent fuel pool and the cask loading pit. The fuel handling machine is a gantry crane, which has an extension to the south wall to reach the new fuel racks.

The high bay area is designed for a trailer to enter the building through a slide-up door. When used to transport a spent fuel cask to the fuel handling area, the trailer is positioned in the high bay area and the cask lifting rig is attached to the cask handling crane. When the cask is in the vertical position, it is disconnected from the trunnion and lifted to the operating deck through the equipment hatch and placed in the cask loading pit.

1.2.5 Annex Building

Building Function

The annex building (Figures 1.2-17 through 1.2-20) provides the main personnel entrance to the power generation complex. It includes accessways for personnel and equipment to the clean areas of the nuclear island in the auxiliary building and to the radiological control area. The building includes the health physics facilities for the control of entry to and exit from the radiological control area as well as personnel support facilities such as locker rooms. The annex building also includes office areas, a fire brigade locker room, and a radiation protection calibration lab. The building also contains the non-1E ac and dc electric power systems, the ancillary diesel generators and their fuel supply, other electrical equipment, the control support area, and various heating, ventilating and air conditioning systems. No safety-related equipment is located in the annex building.

The annex building includes the health physics facilities and provides personnel and equipment accessways to and from the containment building and the rest of the radiological control area via the auxiliary building. Provided are large, direct accessways to the upper and lower equipment hatches of the containment building for personnel access during outages and for large equipment entry and exit. The building includes a hot machine shop for servicing radiological control area equipment. The hot machine shop includes decontamination facilities including a portable decontamination system that may be used for decontamination operations throughout the nuclear island.

Civil/Structural Features

The seismic classification of the annex building can be found in Table 3.2-2. No protection against missile penetration is required. However, certain areas of the building, such as the hot machine shop, radiation protection calibration lab, and the control support area, are provided with shielding for protection against low level radiation from either internal sources or external sources under accident conditions. This is accomplished by either reinforced concrete walls, reinforced masonry walls, or

lead-lined fire rated plywood/gypsum wall boards on metal studs. The control support area is designed so that it may be used as a technical support center (TSC) if desired.

The annex building is a combination of reinforced concrete structure and steel framed structure with insulated metal siding. Floor slabs are reinforced concrete supported by metal decking. Roof slabs are either reinforced concrete or rigid insulation supported on metal decking. Floors are designed to act as diaphragms to transmit horizontal loads to side wall bracing and to concrete shear walls. The building foundation is a reinforced concrete mat.

1.2.6 Diesel Generator Building

Building Function

The diesel generator building (Figure 1.2-21) houses two identical slide along diesel generators separated by a three hour fire wall. These generators provide backup power for plant operation in the event of disruption of normal power sources. No safety-related equipment is located in the diesel generator building.

Civil/Structural Features

The diesel generator building houses the two diesel generators and their associated heating, ventilating and air conditioning equipment, none of which are required for the safe shutdown of the plant. The seismic classification of the diesel generator building can be found in Table 3.2-2. The building is designed as a structure subject to wind loads in accordance with the Uniform Building Code.

The building is a single story steel framed structure with insulated metal siding. The roof is composed of a metal deck supporting a concrete slab and serves as a horizontal diaphragm to transmit lateral loads to sidewall bracing and thereby to the foundation.

The foundation consists of a reinforced concrete mat. The diesel generators are skid-mounted and rest on vibration isolators supported directly from the mat.

1.2.7 Radwaste Building

Building Function

The radwaste building includes facilities for segregated storage of various categories of waste prior to processing, for processing by mobile systems, and for storing processed waste in shipping and disposal containers. No safety-related equipment is located in the radwaste building. Dedicated floor areas and trailer parking space for mobile processing systems is provided for the following:

- Contaminated laundry shipping for offsite processing
- Dry waste processing and packaging
- Hazardous/mixed waste shipping for offsite processing
- Chemical waste treatment
- Empty waste container receiving and storage
- Storage and loading packaged wastes for shipment

The radwaste building also provides for temporary storage of other categories of plant wastes.

Three liquid waste monitor tanks are located within the radwaste building. These tanks contain processed effluents which are ready for release to the environment.

Civil/Structural Features

The radwaste building general arrangement is shown on Figure 1.2-22. The seismic design of the radwaste building can be found in Table 3.2-2. The liquid radwaste processing areas are designed to contain any liquid spills. These provisions include a raised perimeter and floor drains that lead to the liquid radwaste system waste holdup tanks. The foundation for the entire building is a reinforced concrete mat on grade.

1.2.8 Turbine Building

Building Function

The turbine building houses the main turbine, generator, and associated fluid and electrical systems. It provides weather protection for the laydown and maintenance of major turbine/generator components. The turbine building also houses the makeup water purification system. No safety-related equipment is located in the turbine building.

Civil/Structure Features

The turbine building, shown in Figures 1.2-23 through 1.2-30, consists of two sections, the first bay and the main area which houses the turbine. The first bay is immediately adjacent to the auxiliary building, and it consists of reinforced concrete walls and steel framing with reinforced concrete and steel grated floors. The main area is a steel framed building with reinforced concrete and steel grated floors. The first bay and the main area are two independent structures. The turbine building ground floor (structural mat) is a reinforced concrete slab shared by the first bay and main area structure. The seismic design of the turbine building can be found in Table 3.2-2.

The turbine-generator is low-tuned by means of spring supports. The design consists of a reinforced concrete deck mounted on springs. The springs are supported on a structural steel framework that forms an integral part of the turbine building structural system. Lateral bracing serves to provide lateral support for the building as well as the turbine-generator support. The spring-supported concept isolates dynamically the turbine-generator deck from the remainder of the structure for operating frequencies, thus allowing for an integrated structure below the deck. This includes an integrated reinforced concrete foundation mat that supports both the turbine generator and the building. The condenser is attached rigidly to the low pressure turbine exhaust and is supported on springs. The foundation for the entire building is a reinforced concrete mat.

1.2.9 Combined License Information

This section contained no requirement for additional information.

Figure 1.2-1
Not used

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-2
Site Plan

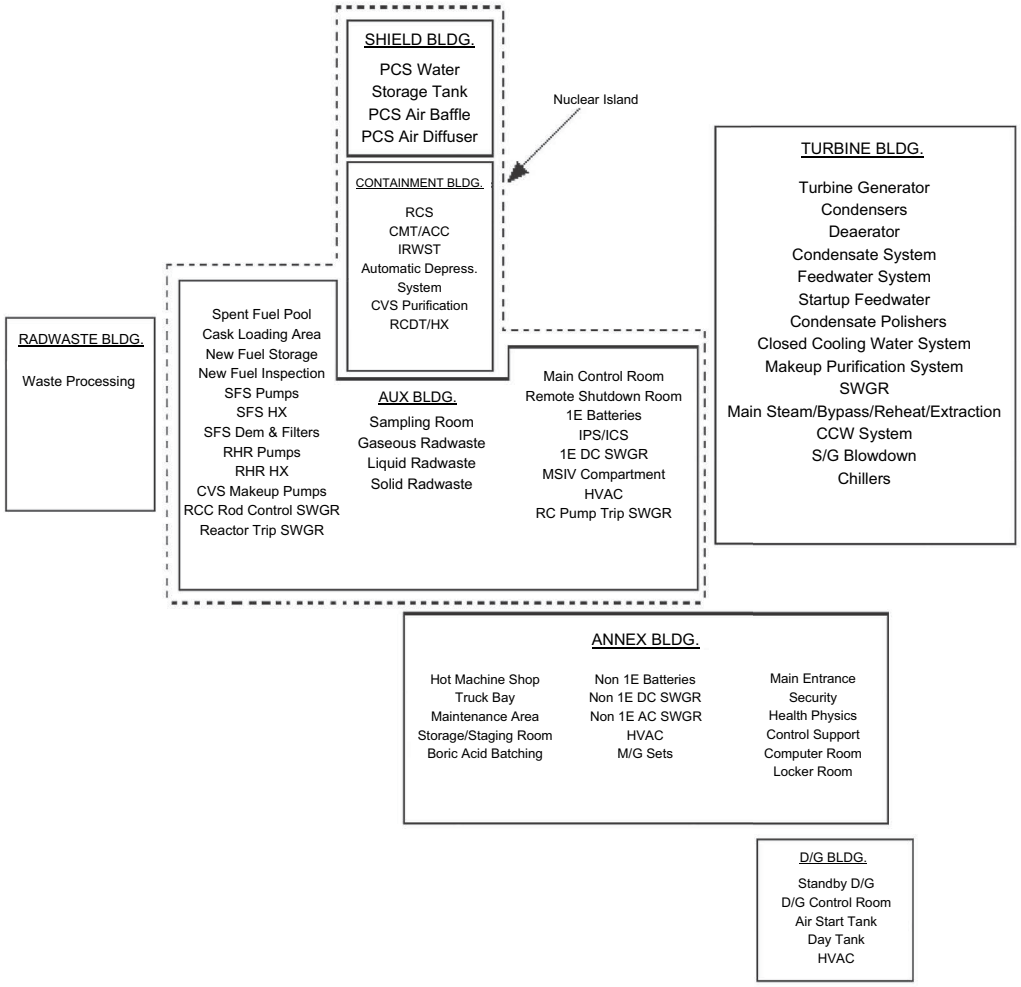

Figure 1.2-3
Functional Allocation of System Components of AP1000 Power Generation Complex

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-4
Nuclear Island General Arrangement
Plan at Elevation 66'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-5
Nuclear Island General Arrangement
Plan at Elevation 82'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-6
Nuclear Island General Arrangement
Plan at Elevation 96'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-7
Nuclear Island General Arrangement Plan at Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-8
Nuclear Island General Arrangement
Plan at Elevation 117'-6" & 130'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-9
Nuclear Island General Arrangement
Plan at Elevation 117'-6" with Equipment

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-10
Nuclear Island General Arrangement Plan at El. 135'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-11
Nuclear Island General Arrangement
Plan at Elevation 153'-0" & 160'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-12
Nuclear Island General Arrangement
Plan at Elevation 160'-6", 180'-0", & 329'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-13
Nuclear Island General Arrangement
Section A-A

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-14
Nuclear Island General Arrangement
Section A-A with Equipment

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-15
Nuclear Island General Arrangement
Section B-B

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-16
Nuclear Island General Arrangement
Section B-B with Equipment

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-17
Annex Building General Arrangement
Section A-A

Security-Related Information, Withheld Under 10 CFR 2.390d

(Note: This figure replaces Figure 1.2-18.)

Figure 1.2-201
Annex Building General Arrangement
Plan at Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-19
Annex Building General Arrangement
Plan at Elevation 117'-6" & 126'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-20
Annex Building General Arrangement
Plan at Elevation 135'-3" through 183'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-21
Diesel Generator Building General Arrangement
Plan at Elevation 100'-0" & Section A-A

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-22
Radwaste Building General Arrangement Plan at Elevation 100'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-23
Turbine Building General Arrangement
Plan at Elevation 100'-0″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-24
Turbine Building General Arrangement
Plan at Elevation 120'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-25
Turbine Building General Arrangement
Plan at Elevation 141'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-26
Turbine Building General Arrangement
Plan at Elevation 170'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-27
Turbine Building General Arrangement
Plan at Elevation 170'-0" with Equipment

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-28
Turbine Building General Arrangement
Plan at Elevation 255'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-29
Turbine Building General Arrangement
Section A-A

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 1.2-30
Turbine Building General Arrangement
Section B-B

1.3 Comparisons with Similar Facility Designs

A comparison of the major AP1000 design features and nominal parameters with the certified AP600 and a typical two-loop Westinghouse plant is provided in Table 1.3-1. The values provided for AP1000 are nominal and provided for comparison. Design parameter values for design certification are delineated in the sections referenced. The values provided in Table 1.3-1 for the reference AP600 and two-loop plants are typical. The two-loop plant parameters are represented by Waterford Unit 3.

Table 1.3-1 (Sheet 1 of 6)
AP1000 Plant Comparison With Similar Facilities

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Plant design objective	1.2	60 yrs	60 yrs	40 yrs
NSSS power	4.0	3,415 MWt	1,940 MWt	3,410 MWt
Core power	4.0	3,400 MWt	1,933 MWt	3,390 MWt
Net electrical output	1.2	≥ 1,000 MWe	600 MWe	1,075 MWe
Reactor operating pressure	5.1	2,250 psia	2,250 psia	2,250 psia
Hot leg temp	5.1	610°F	600°F	611°F (Cycle 1) 603°F (current)
Steam generator design pressure	5.4	1200 psia	1200 psia	1100 psia
Main feedwater temp	10.3	440°F	435°F	445°F
Core	4.0			
Number fuel assem.		157	145	217
Active fuel length		168 in	144 in	150 in
Fuel assembly array		17 x 17	17 x 17	16 x 16
Fuel rod OD		0.374 in	0.374 in	0.382 in
Number control assem.		53	45	83
– Absorber material		Ag-In-Cd	Ag-In-Cd	B_4C/Ag-In-Cd
Number gray rod assem.		16	16	8 (part length)
– Absorber material		Tungsten	SS-304/Ag-In-Cd	Inconel 625/ B_4C
Avg linear power		5.72 kW/ft	4.11 kW/ft	5.34 kW/ft
Heat flux hot channel factor, FQ		2.60	2.60	2.35

Table 1.3-1 (Sheet 2 of 6)
AP1000 Plant Comparison With Similar Facilities

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Reactor Vessel	5.3			
Vessel ID		159 in	157 in	172 in
Construction		forged rings	forged rings	welded plate
Number hot leg nozzles		2	2	2
– ID		31.0 in	31.0 in	42 in
Number cold leg nozzles		4	4	4
– ID		22.0 in	22.0 in	30 in
Number safety injection nozzles		2	2	0
Steam Generators	5.4.2			
Type		Vertical U-tube Recirc. design	Vertical U-tube Recirc. design	Vertical U-tube Recirc. design
Model		Delta-125	Delta-75	–
Number		2	2	2
Heat transfer area/SG		123,538 ft^2	75,180 ft^2	103,574 ft^2
Number tubes/SG		10,025	6,307	9,300
Tube material		I 690 TT	I 690 TT	I 600 TT
Separate startup feedwater nozzle		Yes	Yes	No
Reactor Coolant Pumps	5.4.1			
Type		canned	canned	shaft seal
Number		4	4	4
Rated HP		7,300 hp/pump	≤3,500 hp/pump	9,700 hp/pump
Estimated flow/loop		150,000 gpm	102,000 gpm	198,000 gpm

Table 1.3-1 (Sheet 3 of 6)
AP1000 Plant Comparison With Similar Facilities

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Pressurizer	5.4.5			
Total volume		2,100 ft^3	1,600 ft^3	1,500 ft^3
Volume/MWt		0.618 ft^3/MWt	0.825 ft^3/MWt	0.440 ft^3/MWt
Safety valves #/size		2 – 6"x8"	2 – 6"x6"	3 – 6"
PORV #/size		no	no	no
PRT volume		no	no	2,400 ft^3
Auto depressurization		yes	yes	no
Turbine Island	10.2			
Turbine – # HP cylinder		1	1	1
# LP cylinders		3	2	3
Max blade length		52 in	47 in	40 in
Number reheat stages		2	1	1
Feedwater heating stages				
– # LP stages		4	4	5
– # HP stages		2	2	1
Deaerator		yes	yes	no
Main feedwater pumps		3 motor driven	2 motor driven	2 turbine driven
Condensate pumps		3	3	3
Condenser tube material		Ti	Ti	SS
Condensate polishing		0–33%	33%	0–100%

Table 1.3-1 (Sheet 4 of 6)
AP1000 Plant Comparison With Similar Facilities

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Containment	6.2			
Type		Steel	Steel	Steel
Inside dia.		130 ft	130 ft	140 ft
Volume		2.06 E+06 ft^3	1.76 E+06 ft^3	2.677 E+06 ft^3
Volume/MWt		606 ft^3/MWt	910 ft^3/MWt	785 ft^3/MWt
Post accident cooling		Air and water on outside of steel containment vessel	Air and water on outside of steel containment vessel	Component cooling water cooled fan coolers
Safety Injection	6.3			
Accumulator – #/volume		2/2,020 ft^3	2/2,000 ft^3	4/2,250 ft^3
Core makeup tank – #/volume		2/2,500 ft^3	2/2,000 ft^3	no
High head pumps – #		none	none	3
– runout flow		–	–	380 gpm
– shutoff head		–	–	1,365 psi
Low head pumps – #		none	none	See RHR pumps
Refuel water storage tank – #		1	1	1
– location		in containment	in containment	ex-containment
– volume		590,000 gal	530,000 gal	475,000 gal
Boron inject tank #/vol		no	no	1/630 gal (batching) 2/11,800 gal (makeup)
Normal Residual Heat Removal (NRHR)	5.4.7			
Design pressure		900 psig	900 psig	650 psig
Normal RHR pumps – #/design flow		2/1,500 gpm per pump	2/1,000 gpm per pump	2/4,050 gpm per pump

Table 1.3-1 (Sheet 5 of 6)
AP1000 Plant Comparison With Similar Facilities

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Cooling Water Systems	9.2			
Safety-related		no	no	yes
Component cooling water pumps		2	2	3
Service water pumps		2	2	none
Heat sink		Separate mechanical draft cooling towers	Separate mechanical draft cooling towers	Separate mechanical draft cooling towers
Startup/Auxiliary Feedwater	10.4			
Motor pumps – #/flow per pump/ safety-related		2/520 gpm/no	2/380 gpm/no	2/350 gpm/yes 1/900 gpm/no
Turbine pumps – #/flow		none/–	none/–	1/700 gpm
Passive RHR HX – #/heat removal/ safety-related		1/60 MW/Yes	1/42 MW/Yes	None/–/–
Chemical and Volume Control	9.3.6			
Purification/Letdown flow				
– normal		100 gpm	100 gpm	38 gpm
– max		100 gpm	100 gpm	126 gpm
Purification location		IRC	IRC	ORC
RCP seal injection/pump		none	none	5 – 8 gpm
Charging pumps		2 @ 100 gpm	2 @ 100 gpm	3 @ 44 gpm
– SI use		no	no	no
– safe shutdown use		no	no	yes
– continuous oper.		no	no	yes
Boron thermal regeneration		no	no	no
Boron recycle evaporator		no	no	no

Table 1.3-1 (Sheet 6 of 6)
AP1000 Plant Comparison With Similar Facilities

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Instrumentation and Control	7.7			
Type I&C system		digital	digital	analog
Type control room		work station	work station	control boards
Electrical				
Diesels – #	8.3.1	2	2	2
– safety-related		no	no	yes
– capacity		4,000 kW	4,000 kW	4,400 kW
1E batteries – total capacity	8.3.2	14,400 amp-hr	28,800 amp-hr	3 x 2,320 amp-hr (@ 8 hour rate)

1.4 Identification of Agents and Contractors

1.4.1 Applicant – Program Manager

The Southern Nuclear Operating Company, Inc. (SNC) is the non-owner applicant for a Combined License for the VEGP and will be the constructor and licensed operator of Units 3 and 4. The owner licensees are as follows: Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia[1], and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners (Dalton Utilities). SNC is a wholly-owned subsidiary of Southern Company.

SNC was formed for the purpose of operating nuclear facilities owned by other Southern Company subsidiaries. SNC operates the Edwin I. Hatch Nuclear Plant, Units 1 and 2, the Vogtle Electric Generating Plant, Units 1 and 2, and the Joseph M. Farley Nuclear Plant Units 1 and 2. The combined electric generation of the three plants is in excess of 5,900 MWe.

{HISTORICAL—On April 8, 2008, the owner licensees for VEGP Units 3 and 4 executed a contract for Engineering, Procurement, and Construction (EPC) of the facilities with a Consortium comprised of Westinghouse and Stone & Webster, Inc. (also referred to herein as Shaw Stone & Webster or simply Shaw). The Consortium will act as the AP1000 provider and architect-engineer for VEGP Units 3 and 4. Southern Nuclear, as the constructor of VEGP Units 3 and 4, has delegated responsibility for physical construction activities to the Consortium.—HISTORICAL}

{HISTORICAL—Westinghouse Electric Company, LLC (Westinghouse), is responsible for the overall design and design certification of the AP1000 nuclear power plant. A significant portion of the AP1000 design is the same as the design of AP600. Westinghouse Electric Company was also responsible for the overall design and design certification of AP600.

Westinghouse has designed, developed, and manufactured nuclear facilities since the 1950s, beginning with the world's first large central station nuclear plant (Shippingport), which produced power from 1957.

Westinghouse has designed and delivered more than 100 commercial nuclear power plants with a combined electrical generating capacity in excess of 90,000 MW. The company's manufacturing facilities include the commercial nuclear fuel fabrication facility at Columbia, South Carolina; and nuclear component manufacturing facilities at Blairsville, Pennsylvania; and Newington, New Hampshire.

Westinghouse has been involved with advanced light water reactor plant design efforts for over fifteen years. Included is the development of the advanced, passive pressurized water reactors known as the AP600 and AP1000.

Westinghouse has substantial, proven experience, knowledge, and capability to design, manufacture and furnish technical assistance for the installation, startup and service of nuclear power plants. —HISTORICAL}

{HISTORICAL—Shaw is a Fortune 500 company which has been an active participant in the nuclear industry for nearly 60 years, from providing engineering and design services for Shippingsport, the nation’s first commercial nuclear power plant, to the restart of Tennessee Valley Authority’s Browns Ferry Unit 1, which at the time was the largest nuclear construction project in the western hemisphere. Shaw continues to prove its leadership role in the nuclear industry by being part of the

1. On June 24, 2015, Municipal Electric Authority of Georgia (MEAG) transferred its ownership interest to its wholly owned subsidiaries: MEAG Power SPVM, LLC; MEAG Power SPVJ, LLC; and MEAG Power SPVP, LLC.

AP1000 Consortium. Shaw is part of a vertically integrated company, Shaw Group, Inc., which has nearly 180 offices worldwide and over 21,000 employees, of which approximately 3,100 are nuclear professionals offering nuclear services on four continents.—HISTORICAL}

Westinghouse is responsible for the overall plant design, AP1000 Design Certification revisions, procurement of primary NSSS equipment, power block major components and plant training simulator. Westinghouse is also responsible for site specific design related work, secondary equipment procurement, module procurement, procurement of ASME III materials, and procurement of Highly Engineered Materials. Fuel supply will be provided by Westinghouse under a separate contract. SNC is responsible for site development, construction, testing, and start-up. SNC will be responsible for all other procurement not provided by Westinghouse.

1.4.2 Other Contractors and Participants

{HISTORICAL—Under the direction of Westinghouse, a number of highly qualified organizations provide design and analysis in support of the AP600 and AP1000. Each has a specific responsibility to Westinghouse as defined by various contracts and agreements. Where design features are the same between AP600 and AP1000, the design and analysis performed for AP600 by organizations other than Westinghouse are applied directly to AP1000. The major contributors are identified in this section. They are included here if they have contributed to the base AP600 design or if they have contributed specifically to the AP1000 design.

Throughout the design process, lines of communication have been established among all participants. Design information is generated using common formats, electronic tools and software. Common requirement and compliance documentation has been established and followed. This has allowed design to progress in a complete and consistent manner with interfaces explicitly managed.—HISTORICAL}

1.4.2.1 Bechtel North American Power Corporation

{HISTORICAL—Bechtel North American Power Corporation (Bechtel) is one of the foremost architect-engineering firms in the United States, with the design and construction of 150 nuclear power projects in 25 countries to its credit. In addition to new construction, Bechtel has first-hand experience in operating plant retrofit design and construction, as well as maintenance and management.—HISTORICAL}

1.4.2.2 Southern Electric International

{HISTORICAL—Southern Electric International (SEI) is a wholly owned subsidiary of The Southern Company. The Southern Company is comprised of Southern Company Services, Inc. (an engineering technical services company), six operating utility companies, and Southern Electric International (a commercial engineering consulting services company).

Southern Electric International has benefited from over 99 years of engineering and consulting services experience with the Southern electric utility system. This expertise is derived from experience in designing, constructing, operating, maintaining, and modernizing the 251 generating units of the Southern electric system and those of Southern Electric International's clients. Southern Electric International provides a unique perspective and expertise of an operating electric utility. —HISTORICAL}

1.4.2.3 Burns & Roe Company

{HISTORICAL—Burns & Roe Company is an architect-engineering firm with considerable nuclear expertise. Burns & Roe has provided design, construction management and modernization services

to a wide variety of domestic and foreign operating utilities. Burns & Roe contributed to the design and installation of a number of commercial nuclear power plants. Burns & Roe has also been involved with the development of advanced light water reactors since their inception.—HISTORICAL}

1.4.2.4 Washington Group (MK-Ferguson Company)

{HISTORICAL—MK-Ferguson Company is one of the larger construction firms in the world. Their planning and construction management work extends to commercial and industrial projects as well as power generation units. They are a DOE-approved subcontractor on the defense waste processing facility at Savannah River and have worked on such diverse nuclear plant challenges as the replacement of the steam generator at the D.C. Cook Nuclear Plant, decommissioning of the Shippingport Plant and nuclear reactor modifications at Bettis Atomic Power Laboratory. —HISTORICAL}

1.4.2.5 Avondale Industries, Inc.

{HISTORICAL—Avondale Industries, Inc. is the United States pioneer and leader in modular construction. Their modern shipyards prove ideally suited for the modular construction of industrial and commercial facilities. They have the sophisticated infrastructure in engineering, program management, materials and cost control needed to support large, complex projects.—HISTORICAL}

1.4.2.6 Chicago Bridge & Iron Services, Inc.

{HISTORICAL—Chicago Bridge & Iron Services (CBI) is the leading designer and maker of nuclear reactor containment vessels and liners. They have successfully erected 107 containment structures, 70 percent of all containments built in the United States. Chicago Bridge & Iron Services also specializes in operating plant modification and maintenance upgrades; their service expertise includes planning, development, scheduling and implementation of work procedures, ALARA, and decontamination.—HISTORICAL}

1.4.2.7 Other Participants

{HISTORICAL—Westinghouse has also received support from a variety of engineering and testing firms on a subcontract basis. The organizations providing important design or testing services include: SOPREN/ANSALDO of Italy, University of Western Ontario of Canada, ENEL of Italy, BATAN of Indonesia, ENEA of Italy, BPPT of Indonesia, FIAT of Italy, INITEC of Spain, UNESA of Spain, UTE of Spain, PLN/BPPT of Indonesia, Oregon State University, EdF of France, SNERDI of China, MHI of Japan, UAK of Switzerland, DTN of Spain, Fortum of Finland, IBF of Italy, Tioga of the United States, Pennsylvania State University, Ishikawajima-Harima Heavy Industries Co., Ltd. of Japan, SPX/Copes Vulcan of the United States, Doosan of the Republic of Korea, KOPEC of the Republic of Korea, KSB of Germany, EMD of the United States, Toshiba of Japan, Obayashi of Japan, and Shaw Stone & Webster of the United States.—HISTORICAL}

1.4.2.8 Other Contractors

The following contractors also assisted in the preparation of the COL application.

{HISTORICAL—SNC has selected Bechtel Power Corporation (Bechtel) as its principal contractor to assist with preparing the SSAR portion of the ESP application and Tetra Tech NUS, Inc. (TtNUS), to assist with preparing the Environmental Report portion. A Consortium composed of Westinghouse Electric Company, LLC and Shaw Stone & Webster Nuclear Services (Shaw) will act as the engineering and procurement construction contractor for proposed VEGP Units 3 and 4, with Shaw providing the bulk of the construction services for the LWA activities. Bechtel, Westinghouse, Shaw,

and TtNUS have supplied personnel, systems, project management, and resources to work on an integrated team with SNC.—HISTORICAL}

1.4.2.8.1 Bechtel Corporation

{HISTORICAL—Bechtel is the nation's largest power contractor and is headquartered in San Francisco. Bechtel has a history of supporting the nuclear power industry, beginning with the construction in 1950 of the EBR-1 reactor. Since then, Bechtel has engineered and constructed more than 60,000 MWe of nuclear power capacity worldwide. Bechtel currently has approximately 40,000 employees working on 400 projects in 47 different countries around the globe.—HISTORICAL}

1.4.2.8.2 Tetra Tech NUS, Inc.

{HISTORICAL—TtNUS is an environmental and engineering consulting company with a history of service to the nuclear power industry since the inception of its predecessor company, Nuclear Utility Services (NUS) Corporation in 1960. TtNUS currently has 20 offices and approximately 700 employees throughout the country. TtNUS is a wholly owned subsidiary of Tetra Tech, Inc., which has approximately 9,000 employees worldwide.—HISTORICAL}

1.4.2.8.3 Shaw Stone & Webster Nuclear Services (Shaw)

{HISTORICAL—Shaw is a Fortune 500 company which has been an active participant in the nuclear industry for nearly 60 years, from providing engineering and design services for Shippingport, the nation's first commercial nuclear power plant, to the restart of Tennessee Valley Authority's Browns Ferry Unit 1, which at the time was the largest nuclear construction project in the western hemisphere. Shaw continues to prove its leadership role in the nuclear industry by being part of the AP1000 Consortium. Shaw is part of a vertically integrated company, Shaw Group, Inc., which has nearly 180 offices worldwide and over 21,000 employees, of which approximately 3,100 are nuclear professionals offering nuclear services on four continents.—HISTORICAL}

1.4.2.8.4 Westinghouse Electric Company, LLC (Westinghouse)

{HISTORICAL—Westinghouse offers a wide range of nuclear plant products and services to utilities throughout the world, including fuel, service and maintenance, instrumentation and control, and advanced nuclear plant designs, including the AP1000 certified reactor design. With headquarters in Monroeville, Pennsylvania, Westinghouse now has operations in twelve states and fourteen countries. After designing the world's first commercial pressurized water reactor nuclear power plant at Shippingport in 1957, Westinghouse and its licensees provided more than 40 percent of the world's 434 operating commercial nuclear plants. By the end of 2003, reactors based on Westinghouse technology had amassed over 2500 reactor-years of power generation. —HISTORICAL}

1.4.2.8.5 Other Contractors

{HISTORICAL—In addition to Bechtel, Westinghouse, Shaw, and TtNUS, contractual relationships were established with several specialized consultants to assist in developing the ESP application.—HISTORICAL}

1.4.2.8.5.1 MACTEC Engineering and Consulting, Inc.

{HISTORICAL—MACTEC Engineering and Consulting, Inc., performed geotechnical field investigations and laboratory testing in support of Section 2.5, Geology, Seismology, and Geotechnical Engineering. That effort included performing standard penetration tests; obtaining core samples and rock cores; performing cone penetrometer tests, downhole geophysical logging, and

laboratory tests of soil and rock samples; installing groundwater observation wells; and preparing a data report.—HISTORICAL}

1.4.2.8.5.2 William Lettis & Associates, Inc.

{HISTORICAL—William Lettis & Associates, Inc., performed geologic mapping and characterized seismic sources in support of Section 2.5, including literature review, geologic field reconnaissance, review and evaluation of existing seismic source characterization models, identification and characterization of any new or different sources, and preparation of the related sections. —HISTORICAL}

1.4.2.8.5.3 Risk Engineering, Inc.

{HISTORICAL—Risk Engineering, Inc., performed probabilistic seismic hazard assessments and related sensitivity analyses in support of Section 2.5. These assignments included sensitivity analyses of seismic source parameters and updated ground motion attenuation relationships, development of updated Safe Shutdown Earthquake ground motion values, and preparation of the related sections.—HISTORICAL}

1.4.3 Combined License Information

This section contained no requirement for additional information.

1.5 Requirements for Further Technical Information

Introduction

Tests were conducted during the AP600 Conceptual Design Program (1986 through 1989) to provide input for plant design and to demonstrate the feasibility of unique design features. Tests for the AP600 design certification and design program were devised to provide input for the final safety analyses, to verify the safety analysis models (computer codes), and to provide data for final design and verification of plant components. An AP1000 specific Phenomena Identification and Ranking Table (PIRT) and scaling analysis (Reference 25) and a review of safety analysis evaluations of AP1000 (Chapter 15 of this DCD) show that AP600 and AP1000 exhibit a similar range of conditions for the events analyzed. This provides justification that the database of test information generated during the AP600 Conceptual Design Program is sufficient to meet the requirements of 10 CFR Part 52 for AP1000. Table 1.5-1is a list of the AP600 tests and AP1000 evaluations with references to test and evaluation documentation. Note that Reference 25 reviews each of the AP600 tests described and assesses their applicability to AP1000. The evaluations of Reference 25 show that the AP600 tests are sufficient to support AP1000 safety analysis.

The AP600 tests related to the plant safety functions were selected based on the plant features that are different from current PWRs and where directly applicable experimental data are not available. The tests simulate plant features as required to demonstrate the phenomena being examined. To validate the computer models, these experiments are modeled using the same computer codes used for plant analyses.

Testing of some plant component designs is required to verify their reliability and manufacturability. Other component tests provide data for design optimization. The completed component design tests are described below.

No technical information development programs remain to be performed to support this application.

1.5.1 AP600 Safety-Related Tests

The AP600 safety-related experiments are designed to meet several goals:

- Provide input for safety analysis
- Provide data on the passive safeguards systems to validate the safety analysis methods and computer codes
- Assess the design margin in the passive safety system performance

To accomplish these goals, the AP600 test program utilizes the available data from the NRC and industry light water reactor safety research programs as well as specific tests which address the uniqueness of the AP600. The AP600 safety-related test program utilizes component experiments and integral tests to determine the transient behavior of the AP600 safety system components such that computer models can be developed and verified.

The range of plant conditions for design basis accidents and transients, and the new features of the AP600 design were evaluated against current Westinghouse designs and safety-related data available in the literature (NUREG-1230). The results of this assessment were used to determine the data needs, and to define the experiments to support the AP600 safety analysis. Based upon the experiments performed for AP600 and the AP1000 range of plant conditions for design basis accidents and transients, the tests were shown to be sufficient to support AP1000 safety analysis as well.

1.5.1.1 Large-Break LOCA

For large-break LOCA safety analysis, the relevant new features of the AP600 were the core makeup tanks (CMTs), which drain by gravity, and the use of hermetically sealed, high inertia centrifugal canned-motor reactor coolant pumps (RCPs). Two-phase pump flow data exists for Westinghouse designed pumps and others (NUREG-1230) that can be used to characterize the AP600 pumps. The core makeup tank is unique to the AP600 and AP1000 design. A specific AP600 test was conducted for this component. In addition, a test of passive safety injection system check valve flow vs. ΔP with low differential pressure has been completed. The evaluation of Reference 25 shows that these tests are applicable to AP1000.

Core Makeup Tank Performance Test

The purpose of this experiment is to verify the natural circulation and draining behavior of the core makeup tank over a full range of flowrates, pressures and temperatures, and to provide data to support the design and operation of the tank level indication which acts as a control for the automatic depressurization system (ADS). When actuated, the CMT adds water mass to the reactor coolant system (RCS) by natural circulation when the cold leg contains hot water. The water in the core makeup tank drains by gravity head into the RCS when steam is provided from the cold leg to the top of the core makeup tank. This steam replaces the water drained from the core makeup tank. Some of the steam condenses upon entry into the core makeup tank and can affect the tank draining performance. The objective of the test is to verify that the tank will drain as predicted.

A one-eighth diameter and one-half height scale core makeup tank was constructed and instrumented to obtain the condensation rates within the tank to verify the computer model. The core makeup tank water delivery was examined.

Passive Safety Injection System Check Valve Tests

The AP1000 uses check valves to isolate passive systems from the reactor coolant system. Tests have been performed in the AP600 test program on these check valves to demonstrate their operability.

Tests were conducted to measure check valve pressure drop from very low flow to full flow conditions. Detailed data on initial valve opening, valve disk behavior and flow versus differential pressure were obtained for individual check valves as well as for valves installed in series.

Initial check valve low differential opening tests have determined the characteristic valve flow under the expected gravity drain conditions. A review of existing utility information has been conducted to assess check valve performance under conditions similar to those which would be experienced by the gravity drain check valves.

1.5.1.2 Small-Break LOCA

For small-break LOCA safety analysis, the relevant new features of the AP600 and the AP1000 designs are the core makeup tank, and the automatic depressurization system which depressurizes the primary system to near containment pressure.

The core makeup tank provides injection flow to the reactor vessel at any reactor coolant system pressure. The core makeup tank tests described above duplicated small-break conditions as well as the large-break conditions. The automatic depressurization system provides controlled venting of the reactor coolant system to reduce pressure to allow transition to gravity driven injection from the IRWST. Full-scale tests were conducted in the AP600 test program to obtain data on the performance of the automatic depressurization system. As shown by the AP1000 evaluations, these tests also support AP1000 safety analysis.

Automatic Depressurization System Hydraulic Tests

The purpose of these tests is to simulate the automatic depressurization system, to confirm the capacity of the automatic depressurization system valves and spargers, and to determine the dynamic effects on the IRWST structure.

A pressurized, heated water/steam source was used to simulate the water/steam flow rate from the AP600 reactor coolant system during various stages of the automatic depressurization system blowdown. Two test phases were conducted. Phase A consisted of steam only blowdowns at bounding volumetric flowrates. The flow is piped to a full sized sparger submerged in a quench tank simulating the IRWST. The Phase B1 portion of the test included steam/water blowdowns at bounding mass flowrates through a simulation of one of the two ADS stage 1,2,3 flowpaths. Instrumentation to measure water and steam flow rate, and IRWST dynamic loads was installed. Sparger behavior was obtained from ambient to fully saturated IRWST water temperatures.

1.5.1.3 Containment Cooling

Tests to characterize the heat removal capabilities of the AP600 containment design were performed to provide the database for the containment cooling models. These include the following:

- Study of water film behavior and wetting of a steel plate simulating the containment exterior surface
- Heated plate tests to examine the evaporating heat transfer of water from the steel surface of the containment and heat transfer with only air cooling
- Containment external cooling air flow path pressure drop tests to characterize the hydraulic losses
- Steam condensation heat transfer experiments on a flat cool surface at different angles of inclination to simulate the condensation on the inside of the containment in the presence of noncondensible gases

In addition, tests were performed to examine the integrated behavior of the steam condensation on the inside, and the evaporative film cooling and air cooling on the outside of a pressure vessel. The cylindrical vessel used for this integral test was 3 feet wide and 24 feet high. These experiments included transient and steady-state tests which have been used as the basis for the containment analyses. The limits of coolability and the effect of cold weather conditions were also examined.

As shown by the AP1000 evaluations, these tests also support AP1000 safety analysis.

Integral Containment Cooling Tests

This test examines the combined effect of natural convection and condensation on the interior of the containment while the exterior is cooled by film evaporation and air flow. This test demonstrated the operation of the passive containment cooling system over a range of operating conditions, including operation at low environmental temperatures. This test, in conjunction with completed conceptual design phase testing and the large scale containment test described below, characterize the passive containment cooling system design and performance.

Passive Containment Cooling System Heat Transfer Test

A one-eighth scale steel containment structure with external water film and natural circulation air cooling and modeled containment internal compartments was constructed.

This test accurately models both the containment dome and side wall heat transfer areas. It complements the integral containment experiment which simulates the side wall condensation and evaporating film heat transfer. This test was used to verify the containment analysis analytical methods.

Instrumentation measured the condensation heat flux distribution, the resulting heat transfer coefficients, the air/steam mass ratios, and the resulting liquid film evaporation rates. Both the current integral containment cooling test and this larger scale containment test have been modeled to verify the Chapter 15 analysis computer code and to demonstrate the scalability of the results.

Passive Containment Cooling System Water Distribution Test

A passive containment cooling system water distribution experiment was performed to examine and finalize the AP600 containment water distribution. The results provide input into the containment safety analysis computer codes for water coverage of the containment shell.

The test was performed on a full-scale 1/8th sector of the containment dome. The AP600 water supply/distribution arrangement was modeled. Tests were conducted to demonstrate and measure the water spreading from the top center of the dome to the outer edges. Tests have been conducted to verify the performance of the water distribution system design. Tests were conducted with the surface coated with the prototypic AP600 containment coating. Measurements of water film velocities and film thickness variation as a function of flow rate and radial distance on the dome were obtained.

Passive Containment Cooling System Wind Tunnel Tests

Containment cooling relies on natural circulation of air to enhance evaporative cooling of the containment shell during a design basis event. Wind tunnel tests were performed to demonstrate that wind does not adversely affect natural circulation air cooling through the shield building and around the containment shell.

An approximately 1/100-scale model of the AP600 plant, including the adjacent buildings and cooling tower structure, was constructed and instrumented with pressure taps. The model was placed in a boundary layer wind tunnel and tested at different wind directions. The results were used to design the shield building air inlet and exhaust arrangement and to determine the loads on the air baffle. Variations in site layout and topography have been addressed using an approximately 1/800-scale model of the site buildings and local topography.

Tests were also conducted in a larger, higher speed wind tunnel on an approximately 1/30-scale model. These tests were conducted to confirm that the early test results conservatively represented those expected at full scale Reynolds numbers and to obtain better estimates of the baffle loads in the presence of a cooling tower.

1.5.1.4 Non-LOCA Transient Analysis

The non-LOCA accidents are evaluated using the same transient analysis methods used on existing Westinghouse PWR designs. Passive core cooling system computer models have been developed and added to the transient analysis codes. These models consist of a core makeup tank model and a passive residual heat removal (PRHR) heat exchanger model. As shown by the AP1000 evaluations, these tests also support AP1000 safety analysis.

Passive Residual Heat Removal Heat Exchanger Performance Test

The PRHR heat exchanger is located in the IRWST. This heat exchanger, which is connected directly to the reactor coolant system, transfers core decay heat and sensible heat energy to the IRWST water and depends only on natural circulation driving forces.

The passive residual heat removal heat exchanger test determined the heat transfer characteristics of the PRHR heat exchanger and the mixing characteristics in the IRWST. These results confirm the heat exchanger size and configuration.

The test facility consisted of three full-length heat exchanger tubes placed vertically in a cylindrical tank filled with water and baffled to simulate the AP600 IRWST. Water at prototypic natural circulation and forced flow rates was run through the heat exchanger tubes at prototypic system pressure and temperatures. Data was taken with IRWST water cold to saturation temperature to define the PRHR heat transfer correlation. Tests were also conducted using a baffle to simulate the effect of other rows of tubes have on heat exchanger thermal performance and tank mixing.

Departure from Nucleate Boiling Test

Due to the shorter coastdown of the AP600 canned motor reactor coolant pumps, the flow rates at the time of minimum DNBR are somewhat below previously correlated flow rates. DNB testing was performed to extend the DNB correlation to these lower flows.

These critical heat flux tests were conducted using a 5x5, full length heated rod bundle with non-uniform radial and axial heating distributions.

1.5.1.5 Integral Systems Testing

In the AP600, the water injected into the reactor coolant system comes from the CMTs, accumulators, and the IRWST. Two integral systems tests were conducted in the AP600 test program, a low-pressure scaled test and a full-height, full-pressure test. In addition, the NRC conducted tests in the low-pressure scaled test facility (Reference 27). As shown in the AP1000 evaluations (Reference 25), these three test programs are sufficient to support AP1000 safety analysis.

Low-Pressure Integral Systems Test

The primary purpose of this experiment was to examine the operation of the long-term makeup path from the in-containment refueling water storage tank. In addition, analysis of this experiment demonstrates water flow through the core to limit the long-term concentration of boric acid. The facility is capable of simulating high-pressure system responses.

The test models the reactor vessel, steam generators, reactor coolant pumps, in-containment refueling water storage tank, the automatic depressurization system vent paths, the lower containment, and the connecting piping. The hot legs and cold legs are modeled as are the core makeup tanks, PRHR heat exchangers, accumulators, and pressurizer.

Water is the working fluid and the core is simulated with electric heater rods scaled to match the core power levels consistent with the test scaling approach. Tests were performed to simulate various small-break LOCAs with different break locations, break sizes, with and without nonsafety systems operating. The analysis methods in Chapter 15 were compared to the test.

Full-Height, Full-Pressure Integral Systems Test

A test was performed to provide data on system performance at high pressure. This test facility is configured as a full-height, full-pressure integral test with AP600 features including two loops with one hot leg and two cold legs per loop, two core makeup tanks, two accumulators, a PRHR heat exchanger and an automatic depressurization system. The facility includes a scaled reactor vessel, steam generators, pressurizer and reactor coolant pumps. Water is the working fluid and the core is simulated with electric heater rods.

Tests were performed simulating small break LOCAs, steam generator tube ruptures and a steam line break transient. The analysis methods in Chapter 15 were compared to the test results.

1.5.2 AP600 Component Design Tests

The component design tests will provide a larger database for design optimization during the detailed design of the plant. Tests on selected plant components were performed to confirm their reliability or that materials and fabrication methods meet ASME requirements. These tests are also applicable to the AP1000 design and analysis.

Incore Instrumentation System Tests

Systems similar to the AP600 and AP1000 top mounted fixed incore detector (FID) instrumentation have been demonstrated in operating plants. A test was performed to demonstrate that the system will not be susceptible to electro-magnetic interference (EMI) from the nearby control rod drive mechanisms.

The electro-magnetic interference test was performed by mocking up instrument cables, bringing them into close proximity with an operating control rod drive mechanism, and measuring the resulting noise induced on simulated flux signals.

Reactor Coolant Pump/Steam Generator Airflow Test

The airflow test was performed to identify effects on the pump performance due to non-uniform channel head flow distribution, pressure losses of the channel head nozzle dams and pump suction nozzle, and possible vortices in the channel head induced by the pump impeller rotation.

The air test facility was constructed as an approximate one-half scale mockup of the outlet half of the channel head, the two pump suction nozzles, and two pump impellers and diffusers. The channel head tube sheet was constructed from clear plastic to allow smoke flow stream patterns to be seen.

The results of the test showed no flow anomalies or vortices in the channel head were induced by the dual impellers.

Reactor Coolant Pump High Inertia Rotor/Bearing Tests

In the AP600 a rotor, manufactured of depleted uranium clad with stainless steel, was incorporated into the hermetically sealed, high inertia centrifugal canned motor reactor coolant pump to provide the required flow coastdown performance for loss of flow transients.

Tests have been performed to verify manufacturability of the rotor, to determine friction and drag losses, to verify the operating performance of the pivoted-pad bearings, and to develop a detailed quantitative knowledge of the factors influencing bearing design and performance.

Tests were performed to verify the drag losses of the rotor with the journal bearing located on the pump shaft. Approximately 1000 cycles of starts and stops were also performed as a life test to demonstrate that the rotor will maintain its dimensional stability. These tests were performed on the specially-constructed, full-scale rotor/bearing test rig.

The results of these tests were used to check analytical methods used in the design of the AP1000 reactor coolant pump.

1.5.3 Combined License Information

This section contained no requirement for additional information.

1.5.4 References

1. WCAP-14217, “Core Makeup Tank Final Data Report,” (Proprietary), WCAP-14218 (Nonproprietary), November 1994.

2. WCAP-13286, “AP600 Passive Core Cooling System Check Valve Test Final Report,” (Proprietary), WCAP-13287 (Nonproprietary), April 1992.

3. WCAP-13891, “AP600 Automatic Depressurization System Phase A Test Data Report,” (Proprietary), WCAP-14095 (Nonproprietary), May 1994.

4. WCAP-14324, “Final Data Report for ADS Phase B1 Tests,” (Proprietary), WCAP-14325 (Nonproprietary), April 1995.

5. WCAP-14134, “AP600 Passive Containment Cooling System Integral Small-Scale Tests Final Report,” (Proprietary), WCAP-14137 (Nonproprietary), August 1994.

6. WCAP-13566, “AP600 1/8th Large Scale Passive Containment Cooling System Heat Transfer Baseline Data Report,” (Proprietary), Revision 1, WCAP-13567 (Nonproprietary), Revision 0, December 1992.

7. WCAP-14135, “Final Test Report for PCS Large Scale Phase 2 and Phase 3 Tests,” (Proprietary), WCAP-14138 (Nonproprietary), Revision 3, September 1998.

8. WCAP-13353, “Passive Containment Cooling System Water Distribution Phase 1 Test Data Report,” (Proprietary), WCAP-13354 (Nonproprietary), April 1992.

9. WCAP-13296, “PCS Water Distribution Test Phase II Test Data Report,” (Proprietary), WCAP-13297 (Nonproprietary), March 1992.

10. WCAP-13960, “PCS Water Distribution Phase 3 Test Data Report,” (Proprietary), WCAP-13961 (Nonproprietary), December 1993.

11. WCAP-13294, “Phase I Wind Tunnel Testing for the Westinghouse AP600 Reactor,” (Proprietary), WCAP-13295 (Nonproprietary), April 1992.

12. WCAP-13323, “Phase II Wind Tunnel Testing for the Westinghouse AP600 Reactor,” (Proprietary), WCAP-13324 (Nonproprietary), August 1992.

13. WCAP-14068, “Phase IVa Wind Tunnel Testing for the Westinghouse AP600 Reactor,” (Proprietary), WCAP-14084 (Nonproprietary), May 1994.

14. WCAP-14169, “Phase IVa Wind Tunnel Testing for the Westinghouse AP600 Reactor, Supplemental Report,” (Proprietary), WCAP-14170 (Nonproprietary), September 1994.

15. WCAP-14091, “Phase IVb Wind Tunnel Testing for the Westinghouse AP600 Reactor,” (Proprietary), WCAP-14092 (Nonproprietary), July 1994.

16. WCAP-12980, “AP600 Passive Residual Heat Removal Heat Exchanger Test Final Report,” (Proprietary), WCAP-13573 (Nonproprietary), Revision 3, April 1997.

17. WCAP-14371, “AP600 Low Flow Critical Heat Flux (CHF) Test Data Analysis,” (Proprietary), WCAP-14372 (Nonproprietary), May 1995.

18. WCAP-14252, “AP600 Low Pressure 1/4 Height Integral Systems Tests - Final Data Report,” (Proprietary), WCAP-14253 (Nonproprietary), Revision 1, November 1998.

19. WCAP-14309, “AP600 Design Certification Program, SPES-2 Tests Final Data Report,” (Proprietary), WCAP-14310 (Nonproprietary), Revision 2, May 1997.

20. WCAP-12648, “AP600 Incore Instrumentation System Electromagnetic Interference Test Report,” (Proprietary), WCAP-13322 (Nonproprietary), Revision 1, April 1992.

21. WCAP-13298, “RCP Air Model Test Report,” (Proprietary), WCAP-13299 (Nonproprietary), August 1991.

22. WCAP-12668, “AP600 High Inertia Rotor Testing - Phase I, Test Report,” (Proprietary), WCAP-13321 (Nonproprietary), March 1990.

23. WCAP-13319, “AP600 High Inertia Rotor Testing - Phase 2 Report,” (Proprietary), WCAP-13320 (Nonproprietary), August 1991.

24. WCAP-13758, “High Inertia Rotor Test Phase 3 Report,” (Proprietary), WCAP-13759 (Nonproprietary), June 1993.

25. WCAP-15613, “AP1000 PIRT and Scaling Assessment,” (Proprietary), WCAP-15706 (Nonproprietary), March 2001.

26. Not used.

27. NUREG/CR-6641, “Final Report of NRC Research Conducted at Oregon State University,” August 1999.

Table 1.5-1
AP600 Design Tests and AP1000 Evaluation

Test	Reference
LOCA Mitigation	
Core Makeup Tank Performance Test	(1)
Passive Safety Injection System Check Valve Test	(2)
Automatic Depressurization System Hydraulic Test	(3), (4)
Containment Cooling	
Integral Containment Cooling Test	(5)
Passive Containment Cooling System Heat Transfer Test	(6), (7)
Passive Containment Cooling System Water Distribution Test	(8), (9), (10)
Passive Containment Cooling System Wind Tunnel Test	(11), (12), (13), (14), (15)
Non-LOCA Transients	
Passive Residual Heat Removal Heat Exchanger Performance Test	(16)
Departure from Nucleate Boiling Test	(17)
Integral Systems Tests	
Low Pressure Integral Systems Test	(18)
Full Height Full Pressure Integral Systems Test	(19)
NRC Low Pressure Integral Systems Test	(27)
Component Design Tests	
Incore Instrumentation System Test	(20)
Reactor Coolant Pump/Steam Generator Airflow Test	(21)
Reactor Coolant Pump High Inertia Rotor/Bearing Test	(22), (23), (24)
AP1000 Evaluation	
AP1000 PIRT and Scaling Assessment	(25)

1.6 Material Referenced

The AP1000 Design Control Document references various Westinghouse technical support documents; these documents are listed by DCD section in Table 1.6-1.

Table 1.6-201 provides a list of the various technical documents incorporated by reference in the FSAR in addition to those technical documents incorporated by reference in the AP1000 DCD. Note that the incorporation by reference may be all, or only a portion, of the identified document. The material incorporated by reference is specifically identified in the text of the section in which the document is referenced.

{HISTORICAL—The Vogtle Early Site Permit Application (ESPA) Site Safety Analysis Report (SSAR) is incorporated by reference into this Combined License Application (COLA) Final Safety Analysis Report (FSAR) with variances and/or supplements as noted. Table 1.6-202, Cross Reference of SSAR Sections Incorporated by Reference into FSAR Sections, provides information regarding incorporation of SSAR information into the FSAR.

Reference to the ESPA SSAR is understood to mean Revision 5, as submitted by Southern Nuclear Operating Company (SNC) on December 23, 2008, and as approved by the NRC in the Vogtle Early Site Permit and Limited Work Authorization (ESP-004), dated August 26, 2009 (ADAMS Accession Numbers ML092290130 and ML092290157) including the following three Amendments as identified below:

- Amendment 1 to Early Site Permit No. ESP-004, dated May 21, 2010 (ADAMS Accession Number ML101400509)
- Amendment 2 to Early Site Permit No. ESP-004, dated June 25, 2010 (ADAMS Accession Number ML101760370)
- Amendment 3 to Early Site Permit No. ESP-004, dated July 9, 2010 (ADAMS Accession Number ML101870522)—HISTORICAL}

Table 1.6-203 provides a list of documents which include a methodology that is required by the Technical Specifications. Changes to these methodologies require a license amendment to change the Technical Specification reference.

Table 1.6-1 (Sheet 1 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[2]	Title
1.9	WCAP-15993	Evaluation of the AP1000 Conformance to Inter-System Loss-of-Coolant Accident Acceptance Criteria, Revision 2, June 2017
	{HISTORICAL — WCAP-15799	AP1000 Compliance with SRP Acceptance Criteria, Revision 1, August 2003 — HISTORICAL}
	WCAP-15800	Operational Assessment for AP1000, Revision 3, July 2004
	WCAP-15992	AP1000 Adverse Systems Interactions Evaluation Report, Revision 1, February 2003
	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems, Revision 1, July 2019
1A	WCAP-8577	The Application of Pre-Heat Temperature After Welding of Pressure Vessel Steels, September 1975
	WCAP-16650-P (P) WCAP-16650-NP	Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines, Revision 0, February 2007
3.3	WCAP-13323 (P) WCAP-13324	Phase II Wind Tunnel Testing for the Westinghouse AP600 Reactor, August 1992
	WCAP-14068 (P) WCAP-14084	Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor, May 1994
	WCAP-14169 (P) WCAP-14170	Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor, Supplemental Report, September 1994
	WCAP-13294-P (P) WCAP-13295-NP	Phase I Wind Tunnel Testing for the Westinghouse AP600 Reactor, April 1992
3.6	WCAP-8077 (P) WCAP-8078	Ice Condenser Containment Pressure Transient Analysis Methods, March 1973
	WCAP-8708 (P) WCAP-8709-A	MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics, February 1976
	WCAP-8252	Documentation of Selected Westinghouse Structural Analysis Computer Codes, Revision 1, May 1977
3.7	WCAP-7921-AR	Damping Values of Nuclear Power Plant Components, May 1974
	WCAP-9903 (P)	Justification of the Westinghouse Equivalent Static Analysis Method for Seismic Qualification of Nuclear Power Plant Auxiliary Mechanical Equipment, August 1980

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Table 1.6-1 (Sheet 2 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number(2)	Title
3.8	[*APP-GW-GLR-602*	*AP1000 Shield Building Design Details for Select Wall and RC/SC Connections, Revision 5, October 2014, Westinghouse Electric Company LLC*]*
3.9	WCAP-8708-P-A (P) Volumes 1 and 2 WCAP-8709-A Volumes 1 and 2	MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics, February 1976
	WCAP-17983-P (P) WCAP-17983-NP	Comprehensive Vibration Assessment Program (CVAP) Measurement and Inspection Programs for the AP1000 Plant, March 2015
	WCAP-17984-P (P) WCAP-17984-NP	Comprehensive Vibration Assessment Program (CVAP) Vibration Analysis Program for the AP1000 Plant, July 2015

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*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 1.6-1 (Sheet 3 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number(2)	Title
3H	[*APP-GW-GLR-602*	*AP1000 Shield Building Design Details for Select Wall and RC/SC Connections, Revision 5, October 2014, Westinghouse Electric Company LLC*]*
4.1	WCAP-10444-P-A (P) WCAP-10445-NP-A	Reference Core Report VANTAGE 5 Fuel Assembly, September 1985, and VANTAGE 5H Fuel Assembly, Addendum 2A, February 1989
	WCAP-12610-P-A (P) WCAP-14342-A	VANTAGE+ Fuel Assembly Reference Core Report, April 1995
	[*WCAP-12488-A (P)* [*WCAP-14204-A*]*	*Fuel Criteria Evaluation Process, October 1994*]*
4.2	[*WCAP-12488-A (P)* [*WCAP-14204-A*]*	*Fuel Criteria Evaluation Process, October 1994*]*
	WCAP-10125-P-A (P) WCAP-10126-NP-A	Extended Burnup Evaluation of Westinghouse Fuel, December 1985
	WCAP-9179 (P) WCAP-9224	Properties of Fuel and Core Component Materials, July 1978
	WCAP-12610-P-A (P) WCAP-14342-A	VANTAGE+ Fuel Assembly Reference Core Report, June 1990/ April 1995
	WCAP-10851-P-A (P) WCAP-11873-A	Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations, August 1988
	WCAP-13589-A (P) WCAP-14297-A	Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel, March 1995
	WCAP-10021-P-A (P) WCAP-10377-NP-A	Westinghouse Wet Annular Burnable Absorber Evaluation Report, Revision 1, October 1983
	WCAP-10444-P-A (P) WCAP-10445-NP-A	Reference Core Report VANTAGE 5 Fuel Assembly, September 1985
	WCAP-8691 (P) WCAP-8692	Fuel Rod Bow Evaluation, Revision 1, July 1979
	WCAP-8236 (P) WCAP-8288	Safety Analysis of the 17x17 Fuel Assembly for Combined Seismic and Loss-of-Coolant Accident, December 1973

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*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 1.6-1 (Sheet 4 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number(2)	Title
4.2	WCAP-9401-P-A (P) WCAP-9402-A	Verification, Testing, and Analysis of the 17x17 Optimized Fuel Assembly, August 1981
	WCAP-9283	Integrity of Primary Piping Systems of Westinghouse Nuclear Power Plants During Postulated Seismic Events, March 1978
	WCAP-15063-P-A (P) WCAP-15064-NP-A	Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), Revision 1, July 2000
	WCAP-8377 (P)	Revised Clad Flattening Model, July 1974
	WCAP-16652-NP	AP1000 Core & Fuel Design Technical Report, Revision 0, October 2006
	WCAP-16943-P-A (P) WCAP-16943-NP-A	Enhanced GRCA Rodlet Design, September 2012
4.3	WCAP-9272-P-A (P) WCAP-9273-NP-A	Westinghouse Reload Safety Evaluation Methodology, July 1985
	[*WCAP-12488-P-A (P)* *[WCAP-14204-A*]*	*Fuel Criteria Evaluation Process, October 1994*]*
	WCAP-12472-P-A (P) WCAP-12473-A	BEACON: Core Monitoring and Operations Support System, August 1994; Addendum 1, May 1996; Addendum 2, March 2001
	WCAP-12472-P-A (P) WCAP-12472-NP-A	BEACON: Core Monitoring and Operations Support System, Addendum 4, September 2012
	WCAP-8218-P-A (P) WCAP-8219-A	Fuel Densification Experimental Results and Model for Reactor Application, March 1975
	WCAP-8359	Effects of Fuel Densification Power Spikes on Clad Thermal Transients, July 1974
	WCAP-7811	Power Distribution Control of Westinghouse Pressurized Water Reactors, December 1971
	WCAP-8385 (P) WCAP-8403	Power Distribution Control and Load Following Procedures, September 1974
	WCAP-17661-P-A (P) WCAP-17661-NP-A	Improved RAOC and CAOC F_Q Surveillance Technical Specifications, Revision 1, February 2019
	WCAP-10216-P-A (P) WCAP-10217-A	Relaxation of Constant Axial Offset Control, F_Q Surveillance Technical Specification, Revision 1A, February 1994
	WCAP-7912-P-A (P) WCAP-7912-A	Power Peaking Factors, January 1975
	WCAP-7048-P-A (P) WCAP-7757-A	The PANDA Code, February 1975
	WCAP-7213-A (P) WCAP-7758-A	The TURTLE 24.0 Diffusion Depletion Code, February 1975

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*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 1.6-1 (Sheet 5 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[2]	Title
4.3	WCAP-6073 (P)	LASER – A Depletion Program for Lattice Calculations Based on MUFT and THERMOS, April 1966
	WCAP-2048 (P)	The Doppler Effect for a Non-Uniform Temperature Distribution in Reactor Fuel Elements, July 1962
	WCAP-11596-P-A (P) WCAP-11597-A	Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, June 1988
	WCAP-10841 (P) WCAP-10842	Qualification of the PHOENIX/POLCA Nuclear Design and Analysis Program for Boiling Water Reactors, June 1985
	WCAP-10965-P-A (P) WCAP-10966-A	ANC: A Westinghouse Advanced Nodal Computer Code, September 1986
	WCAP-13589-A (P) WCAP-14297-A	Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel, March 1995
	WCAP-13524-P-A (P) WCAP-14952-NP-A	APOLLO - A One Dimensional Neutron Theory Program, Revision 1-A, September 1997
	WCAP-16652-NP	AP1000 Core & Fuel Design Technical Report, Revision 0, October 2006

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Table 1.6-1 (Sheet 6 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[(2)]	Title
4.3	WCAP-16045-P-A (P) WCAP-16045-NP-A	Qualification of the Two-Dimensional Transport Code PARAGON, August 2004
	WCAP-16943-P-A (P) WCAP-16943-NP-A	Enhanced GRCA Rodlet Design, September 2012
	WCAP-16045-P-A Addendum 1-A (P) WCAP-16045-NP-A Addendum 1-A	Qualification of the NEXUS Nuclear Data Methodology, August 2007
	WCAP-10965-P-A Addendum 2-A (P) WCAP-10966-A Addendum 2-A	Qualification of the New Pin Power Recovery Methodology, September 2010
4.4	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-10444-P-A (P) WCAP-10445-NP-A	Reference Core Report VANTAGE 5 Fuel Assembly, September 1985
	[*WCAP-12488-A (P)*	*Westinghouse Fuel Criteria Evaluation Process, October 1994*]*
	WCAP-8691 (P) WCAP-8692	Fuel Rod Bow Evaluation, Revision 1, July 1979
	WCAP-2923	In-Pile Measurement of UO_2 Thermal Conductivity, March 1966
	WCAP-10851-P-A (P) WCAP-11873-A	Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations, August 1988
	WCAP-7912-P-A (P) WCAP-7912-A	Power Peaking Factors, January 1975
	WCAP-15025-P-A (P) WCAP-15026-NP-A	Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids, April 1999
	WCAP-14565-P-A (P) WCAP-15306-NP-A	VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999
	WCAP-15063-P-A (P) WCAP-15064-NP-A	Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), Revision 1, July 2000
	WCAP-16652-NP	AP1000 Core & Fuel Design Technical Report, Revision 0, October 2006
	WCAP-14565-P-A, Addendum 1-A (P)	Addendum 1 to WCAP-14565-P-A Qualification of ABB Critical Heat Flux Correlations with VIPRE-01 Code, August 2004
	WCAP-14565-P-A, Addendum 2-P-A (P)	Addendum 2 to WCAP-14565-P-A Extended Application of ABB-NV Correlation and Modified ABB-NV Correlation WLOP for PWR Low Pressure Applications, Revision 0, April 2008
5.2	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984

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Table 1.6-1 (Sheet 7 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[2]	Title
5.3	WCAP-15557	Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology, August 2000
	WCAP-14040-NP-A	Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves, Revision 4, May 2004
6.2	WCAP-8077 (P) WCAP-8078	Ice Condenser Containment Pressure Transient Analysis Methods, March 1973
	WCAP-10325-P-A (P) WCAP-10326-A	Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version, May 1983
	WCAP-8822 (P) WCAP-8860 WCAP-8822-P-S1 (P) WCAP-8822-S2-P-A (P)	Mass and Energy Releases Following A Steam Line Rupture, September 1976 Supplement 1 - Calculations of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture, January 1985 Supplement 2 - Impact of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture for Dry and Subatmospheric Containment Designs, September 1986
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-15846 (P) WCAP-15862	WGOTHIC Application to AP600 and AP1000, Revision 5, September 2016
	WCAP-15846-P Addendum 1 WCAP-15846-NP Addendum 1	Effective Thermal Conductivity Model of Inorganic Zinc Coating for Application to AP1000, Revision 0, October 2013
	WCAP-14234 (P) WCAP-14235	LOFTRAN and LOFTTR2 AP600 Code Applicability Document, Revision 1, August 1997

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Table 1.6-1 (Sheet 8 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[2]	Title
6.2	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
6.3	WCAP-13594 (P) WCAP-13662 (NP)	FMEA of Advanced Passive Plant Protection System, Revision 1, June 1998
7.1	WCAP-15775	AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report, Revision 8, May 2017
	[*WCAP-16096-P-A* *WCAP-16096-NP-A*	*Software Program Manual for Common Q™ Systems, Revision 4, February 2013*[1] *(as modified by the SPM alternatives in WCAP-15927, Revision 8)*]*
	[*WCAP-16097-P-A* *WCAP-16097-NP-A*	*Common Qualified Platform Topical Report, Revision 3, February 2013 (as modified by the Topical Report alternatives in WCAP-15927, Revision 8)*]*
	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems, Revision 1, July 2019
	WCAP-16674-P WCAP-16674-NP	AP1000 I&C Data Communication and Manual Control of Safety Systems and Components, Revision 9, June 2019
	WCAP-16675-P WCAP-16675-NP	AP1000 Protection and Safety Monitoring System Architecture Technical Report, Revision 10, September 2020

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*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 1.6-1 (Sheet 9 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number(2)	Title
7.1	[*WCAP-15927-P* *WCAP-15927-NP*	*Design Process for AP1000 Common Q Safety Systems, Revision 8, September 2020*]*
		Westinghouse Electric Company Quality Management System (QMS), (Non-Proprietary), Revision 7, October 2013
	APP-GW-J0R-012	AP1000 Protection and Safety Monitoring System Computer Security Plan, Revision 5, September 2020
7.2	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems, Revision 1, July 2019
7.3	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems, Revision 1, July 2019
7.7	WCAP-17184-P	AP1000™ Diverse Actuation System Planning and Functional Design Summary Technical Report, Revision 13, May 2019
	WCAP-15775	AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report, Revision 8, May 2017
	WCAP-17179-P WCAP-17179-NP	AP1000 Component Interface Module Technical Report, Revision 6, April 2016
10.2	WCAP-16650-P (P) WCAP-16650-NP	Analysis of the Probability of the Generation of Missiles for AP1000 Fully Integral Low Pressure Turbines, Revision 0, February 2007
	WCAP-16651-P (P) WCAP-16651-NP	Probabilistic Evaluation of Turbine Valve Test Frequency, Revision 1, May 2009

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*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 1.6-1 (Sheet 10 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[2]	Title
15.0	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-10054-P-A (P) WCAP-10081	Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code, August 1985
	WCAP-12945-P-A (P) WCAP-14747	Code Qualification Document for Best Estimate LOCA Analysis, Revision 1, March 1998
	WCAP-7908-A	FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-7979-P-A (P) WCAP-8028-A	TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code, January 1975
	WCAP-10698-P-A (P) WCAP-10750-A	SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill, August 1987
	WCAP-14234 (P) WCAP-14235	LOFTRAN and LOFTTR2 AP600 Code Applicability Document, Revision 1, August 1997
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
	WCAP-16009-P-A (P) WCAP-16009-NP-A	Realistic Large Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM), January 2005
15.1	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-9226-P-A (P) WCAP-9227-A	Reactor Core Response to Excessive Secondary Steam Releases, Revision 1, February 1998
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
	WCAP-14565-P-A (P) WCAP-15306-NP-A	VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal Hydraulic Safety Analysis, October 1999

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Table 1.6-1 (Sheet 11 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[2]	Title
15.2	WCAP-7769	Overpressure Protection for Westinghouse Pressurized Water Reactors, Revision 1, June 1972
	WCAP-16779-NP	Overpressure Protection Report for AP1000 Nuclear Power Plant, April 2007
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
	WCAP-7908-A	FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
	WCAP-14565-P-A (P) WCAP-15306-NP-A	VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal Hydraulic Safety Analysis, October 1999
15.3	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-7908-A	FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
	WCAP-8424	An Evaluation of Loss of Flow Accidents Caused by Power System Frequency Transients in Westinghouse PWRs, Revision 1, May 1975
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-14565-P-A (P) WCAP-15306-NP-A	VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal Hydraulic Safety Analysis, October 1999
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
15.4	WCAP-7979-P-A (P) WCAP-8028-A	TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code, January 1975
	WCAP-7908-A	FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984

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Table 1.6-1 (Sheet 12 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number(2)	Title
15.4	WCAP-15806-P-A (P) WCAP-15807-NP-A	Westinghouse Control Rod Ejection Accident Analysis Methodology Using Multi-Dimensional Kinetics, November 2003
	WCAP-10965-P-A (P) WCAP-10966-A	ANC: A Westinghouse Advanced Nodal Computer Code, September 1986
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
	WCAP-11596-P-A (P) WCAP-11597-A	Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, June 1988
	WCAP-16045-P-A (P) WCAP-16045-NP-A	Qualification of the Two-Dimensional Transport Code PARAGON, August 2004
	WCAP-10965-P-A, Addendum 1 (P) WCAP-10966-A Addendum 1	ANC – A Westinghouse Advanced Nodal Computer Code; Enhancements to ANC Rod Power Recovery, April 1989
	WCAP-14565-P-A (P) WCAP-15306-NP-A	VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999
	WCAP-15063-P-A, Revision 1 with Errata (P) WCAP-15064-NP-A	Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), July 2000
	WCAP-16045-P-A Addendum 1-A (P) WCAP-16045-NP-A Addendum 1-A	Qualification of the NEXUS Nuclear Data Methodology, August, 2007
	WCAP-10965-P-A, Addendum 2-A (P)	Qualification of the New Pin Power Recovery Methodology, September, 2010
15.5	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
15.6	WCAP-12945-P-A (P) WCAP-14747	Code Qualification Document for Best Estimate Analysis, Revision 2, March 1998
	WCAP-10079-P-A (P) WCAP-10080-A	NOTRUMP – A Nodal Transient Small Break and General Network Code, August 1985

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Table 1.6-1 (Sheet 13 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[(2)]	Title
15.6	WCAP-10054-P-A (P) WCAP-10081-A	Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code, August 1985
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-10698-P-A (P) WCAP-10750-A	SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill, August 1987
	WCAP-14601 (P) WCAP-15062	AP600 Accident Analyses – Evaluation Models, Revision 2, May 1998
	WCAP-14234 (P) WCAP-14235	LOFTRAN and LOFTTR2 AP600 Code Applicability Document, Revision 1, August 1997
	WCAP-14171 (P) WCAP-14172	WCOBRA/TRAC Applicability to AP600 Large-Break Loss-of-Coolant Accident, Revision 2, March 1998
	WCAP-14807 (P) WCAP-14808	NOTRUMP Final Validation Report for AP600, Revision 5, August 1998
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
	WCAP-16009-P-A (P) WCAP-16009-NP-A	Realistic Large Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM), January 2005
	WCAP-14449-P-A (P) WCAP-14450	Application of Best Estimate Large Break LOCA Methodology to Westinghouse PWRs with Upper Plenum Injection, Revision 1, October 1999
16.1	WCAP-17661-P-A (P) WCAP-17661-NP-A	Improved RAOC and CAOC F_Q Surveillance Technical Specifications, Revision 1, February 2019

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Table 1.6-1 (Sheet 14 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number[(2)]	Title
18.2	WCAP-14644	AP600/AP1000 Functional Requirements Analysis and Function Allocation, Revision 1, October 2008
18.3	WCAP-14645	Human Factors Engineering Operating Experience Review Report for the AP1000 Nuclear Power Plant, Revision 3, May 2006
18.4	WCAP-14644	AP600/AP1000 Functional Requirements Analysis and Function Allocation, Revision 1, October 2008

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 1.6-1 (Sheet 15 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number(2)	Title
18.5	[*WCAP-14695*	*Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology, July 1996*]*
	[*WCAP-14651*	*Integration of Human Reliability Analysis and Human Factors Engineering Design Implementation Plan, Revision 2, May 1997*]*
18.7	[*WCAP-14651*	*Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan, Revision 2, May 1997*]*
18.7	WCAP-16555	AP1000 Identification of Critical Human Actions and Risk Important Tasks, Revision 0, March 2006
18.8	[*WCAP-14651*	*Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan, Revision 2, May 1997*]*
	[*WCAP-15860*	*Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan, Revision 2, October 2003*]*
	[*WCAP-14695*	*Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology, July 1996*]*
	WCAP-14655	Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel, Revision 1, August 1996
	WCAP-14694	Designer's Input to Determination of the AP600 Main Control Room Staffing Level, July 1996
	[*WCAP-14396*	*Man-in-the-Loop Test Plan Description, Revision 3, November 2002*]*
18.10	WCAP-14655	Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel, Revision 1, August 1996

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 1.6-1 (Sheet 16 of 16)
Material Referenced

DCD Section Number	Westinghouse Topical Report Number(2)	Title
18.11	[*WCAP-15860*	*Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan, Revision 2, October 2003*]*
	[*APP-OCS-GEH-120*	*AP1000 Human Factors Engineering Design Verification Plan,*]* Revision 3, December 2014, Westinghouse Electric Company LLC
	[*APP-OCS-GEH-220*	*AP1000 Human Factors Engineering Task Support Verification Plan,*]* Revision 6, February 2018, Westinghouse Electric Company LLC
	[*APP-OCS-GEH-320*	*AP1000 Human Factors Engineering Integrated System Validation Plan,*]* Revision 7, February 2018, Westinghouse Electric Company LLC [*(as modified by changes provided in UFSAR Appendix 18A)*]*
	[*APP-OCS-GEH-420*	*AP1000 Human Factors Engineering Discrepancy Resolution Process,*]* Revision 2, December 2014, Westinghouse Electric Company LLC
	[*APP-OCS-GEH-520*	*AP1000 Plant Startup Human Factors Engineering Design Verification Plan,*]* Revision 4, December 2014, Westinghouse Electric Company LLC
18.12	WCAP-13793	The AP600 System/Event Matrix, June 1994
19E	WCAP-10698-P-A (P) WCAP-10750-A	SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill, August 1987
	WCAP-14171 (P) WCAP-14172	WCOBRA/TRAC Applicability to AP600 Large-Break Loss-of-Coolant Accident, Revision 2, March 1998

(P) Denotes Document is Proprietary
(NT)Denotes Document is Non-Topical Westinghouse Report

Notes:

1. [*Section 12, "Secure Development and Operational Environment Plan," of WCAP-16096, "Software Program Manual for Common Q™ Systems," Revision 4, is not applicable to the AP1000.*]*
2. Any reference to the AP1000 Design Control Document in Incorporated By Reference documents should be viewed as referring the reader to the associated updated information in the UFSAR.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 1.6-201
Additional Material Referenced

Author/ Report Number[(a)]	Title	Revision	Section	Document Transmittal	ADAMS Accession Number
10 CFR Part 52 Appendix D	Design Certification Rule for the AP1000 Design	–	1.1	–	–
QAPD	SNC Nuclear Development Quality Assurance Manual	–	17.5	–	–
VEGP ESPA SSAR	Vogtle Early Site Permit Application Site Safety Analysis Report as approved by the NRC in the Vogtle Early Site Permit and Limited Work Authorization (ESP-004), dated August 26, 2009, including Amendments 1, 2 and 3.	5	Table 1.6-202	December 2008	ML090280033
Westinghouse/ APP-GW-GL-700	AP1000 Design Control Document	19	All	June 2011	ML11171A500
NEI 07-08A	Generic FSAR Template Guidance for Ensuring That Occupational Radiation Exposures Are As Low As Is Reasonably Achievable (ALARA)	0	12.1	October 2009	ML093220164
NEI 07-03A	Generic FSAR Template Guidance for Radiation Protection Program Description	0	Appendix 12AA	May 2009	ML091490684
NEI 06-13A	Template for an Industry Training Program Description	2	13.2	March 2009	ML090910554
NEI 07-02A	Generic FSAR Template Guidance for Maintenance Rule Program Description for Plants Licensed Under 10 CFR Part 52	0	17.6	March 2008	ML080910149

(a) The NRC-accepted NEI documents identified by the A in the document number include the accepted template, the NRC safety evaluation, and corresponding responses to the NRC Requests for Additional Information. Only the accepted template is incorporated by reference. The remainder of the document is referenced but not incorporated into the FSAR.

(A) Denotes NRC approved document.

Historical
Historical

Table 1.6-202 (Sheet 1 of 4)
Cross Reference of ESPA SSAR Sections Incorporated by Reference into FSAR Sections—{HISTORICAL}

Historical

SSAR Section	SSAR Section Title	Corresponding FSAR Section
1.1	Introduction	SSAR Section 1.1 provides general information related to the ESP proceeding, and is not applicable to any particular FSAR section.
1.2	General Site Description	Section 1.1.1 Plant Location. This ESPA SSAR Section is Incorporated by Reference into FSAR Subsection 1.1.1 with the exception of Figures 1-4 and 1-5. COLA Part 7 requests a variance for this ESPA section.
1.3	Site Characteristics, Design Parameters, and Site Interface Values	Section 2.0, Site Characteristics. This ESPA SSAR Section is Incorporated by Reference into FSAR Section 2.0 with the exception of Table 1-1 values for Maximum Normal Dry- and Wet-Bulb temperatures and Minimum Dry Bulb temperature. COLA Part 7 requests a variance for this ESPA table.
1.4	Identification of Agents and Contractors	Section 1.4, Identification of Agents and Contractors
1.5	Requirements for Further Technical Information	Section 1.5, Requirements for Further Technical Information
1.6	Material Incorporated by Reference	This ESPA SSAR section is not Incorporated by Reference into the FSAR. This section of the ESPA SSAR includes a reference to Revision 15 of the AP1000 DCD. COLA Part 7 requests a variance for this ESPA section.
1.7	Drawings and Other Detailed Information	Section 1.7, Drawings and Other Detailed Information

Historical

Table 1.6-202 (Sheet 2 of 4)
Cross Reference of ESPA SSAR Sections Incorporated by Reference into FSAR Sections—{HISTORICAL}

Historical

SSAR Section	SSAR Section Title	Corresponding FSAR Section
1.8	Conformance to NRC Regulations and Regulatory Guidance	Section 1.9, Compliance With Regulatory Criteria.
2.1	Geography and Demography	Section 2.1, Geography and Demography
2.2	Identification of Potential Hazards in Site Vicinity	Section 2.2, Nearby Industrial, Transportation, and Military Facilities. This ESPA SSAR Section is Incorporated by Reference into FSAR Section 2.2 with the exception of the last paragraph of ESPA SSAR 2.2.3.2.3, and ESPA SSAR Table 2.2-6. This information has been superseded by information contained in Sections 2.2 and 6.4. COLA Part 7 requests a variance for this ESPA subsection and table.
2.3	Meteorology	Section 2.3, Meteorology. The third from last and second from last paragraphs of ESPA SSAR Subsection 2.3.1.5 are replaced by information contained in the replacement paragraph, which is shown in Subsection 2.3.1.5. COLA Part 7 requests a variance for this ESPA subsection.
2.4	Hydrologic Engineering	Section 2.4, Hydrologic Engineering
2.5	Geology, Seismology, and Geotechnical Engineering	Section 2.5, Geology, Seismology, and Geotechnical Information
3.5.1.6	Aircraft Hazards	Section 3.5.1.6, Aircraft Hazards

Historical

Table 1.6-202 (Sheet 3 of 4)
Cross Reference of ESPA SSAR Sections Incorporated by Reference into FSAR Sections—{HISTORICAL}

Historical

SSAR Section	SSAR Section Title	Corresponding FSAR Section
3.8.5	Foundations	This ESPA SSAR subsection is Incorporated by Reference into FSAR Subsection 3.8.5.1 with the exception of the first paragraph. This paragraph includes a reference to Revision 15 of the AP1000 DCD. Additionally, the first paragraph in ESPA SSAR Subsection 3.8.5.1.1 is not incorporated by reference. COLA Part 7 requests a variance for this ESPA section.
11.2.3	Liquid Radioactive Releases	Section 11.2.3.5, Estimated Doses
11.3.3	Gaseous Radioactive Releases	Section 11.3.3.4, Estimated Doses
13.3	Emergency Planning	Section 13.3, Emergency Planning. This ESPA SSAR section is Incorporated by Reference into FSAR Section 13.3 with the exception of Figure 13.3-2. COLA Part 7 requests a variance for this ESPA section.
13.6	Industrial Security	Section 13.6, Security
13.7	Fitness for Duty	Section 13.7, Fitness for Duty
15	Accident Analyses	This ESPA SSAR chapter is not Incorporated by Reference into the FSAR. This chapter of the ESPA SSAR provides accident release information that has been superseded by the referenced DCD. COLA Part 7 requests a variance for this ESPA section.

Historical

Table 1.6-202 (Sheet 4 of 4)
Cross Reference of ESPA SSAR Sections Incorporated by Reference into FSAR Sections—{HISTORICAL}

Historical

SSAR Section	SSAR Section Title	Corresponding FSAR Section
17	Quality Assurance	This ESPA SSAR chapter is not Incorporated by Reference into the FSAR. The SNC Nuclear Development Quality Assurance Manual, provided as Appendix 17.1A of the ESPA SSAR, is now provided in COLA Part 11.

Historical

Table 1.6-203 Methodologies Required By Technical Specifications

Technical Specification	Methodology Document Number	Methodology Document Title
5.5.14	WCAP-16361-P	Westinghouse Setpoint Methodology for Protection Systems – AP1000, February 2011
5.6.3 – 1	WCAP-9272-P-A (P) WCAP-9273-NP-A	Westinghouse Reload Safety Evaluation Methodology, July 1985
5.6.3 – 2a	WCAP-8385 (P) WCAP-8403	Power Distribution Control and Load Following Procedures, September 1974
5.6.3 – 2b	January 31, 1980 Memo Attachment	T. M. Anderson to K. Kniel (Chief of Core Performance Branch, NRC) January 31, 1980 - Attachment: Operation and Safety Analysis Aspects of an Improved Load Follow Package
5.6.3 – 2c	BTP CPB 4.3-1	NUREG-0800, Standard Review Plan, U.S. Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981. Branch Technical Position CPB 4.3-1, Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981
5.6.3 – 3	WCAP-10216-P-A (P) WCAP-10217-A	Relaxation of Constant Axial Offset Control FQ Surveillance Technical Specification, Revision 1A, February 1994
5.6.3 – 4a	WCAP-16009-P-A (P) WCAP-16009-NP-A	Realistic Large Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM), Revision 0, January 2005
5.6.3 – 4b	APP-GW-GLE-026 (P) APP-GW-GLE-026-NP	Application of ASTRUM Methodology for Best-Estimate Large-Break Loss-of-Coolant Accident Analysis for AP1000, Revision 1, January 2009
5.6.3 – 5	WCAP-12472-P-A (P) WCAP-12473-A	BEACON Core Monitoring and Operations Support System, August 1994; Addendum 1, May 1996; and Addendum 2, March 2001
5.6.3 – 5	WCAP-12472-P-A (P) WCAP-12472-NP-A	BEACON Core Monitoring and Operations Support System, Addendum 4, September 2012
5.6.3 – 6	APP-GW-GLR-137	Bases of Digital Overpower and Overtemperature Delta-T (OPΔT/ OTΔT) Reactor Trips, Revision 1
5.6.3 – 7a	WCAP-16045-P-A WCAP-16045-NP-A	Qualification of the Two-Dimensional Transport Code PARAGON, August 2004
5.6.3 – 7b	WCAP-16045-P-A WCAP-16045-NP-A	Qualification of the NEXUS Nuclear Data Methodology, Addendum 1-A, August 2007
5.6.3 – 7c	WCAP-13749-P-A	Safety Evaluation Supporting the Conditional Exemption of the Most Negative EOL Moderator Temperature Coefficient Measurement, March 1997
5.6.4	WCAP-14040-NP-A	Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves, Revision 4, May 2004

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

1.7 Drawings and Other Detailed Information

The figures referenced in Subsections 1.7.1 and 1.7.2 may represent a functional diagram, general structural representation, or another general illustration. For instrumentation and control (I&C) systems, figures may also represent aspects of the relevant logic of the system or part of the system. Unless specified explicitly, the figures are not indicative of the scale, location, dimensions, shape, or spatial relationships of as-built structures, systems, and components. In particular, the as-built attributes of structures, systems, and components may vary from the attributes depicted on the figures, provided that those safety functions discussed in the design description pertaining to the figure are not adversely affected.

1.7.1 Electrical and Instrumentation and Control Drawings

Instrument and control functional diagrams, electrical one-line diagrams, and onsite standby diesel generator loading sequence and initiating circuit logic diagrams are listed in Table 1.7-1.

The legend for electrical power, control, lighting, and communication drawings is provided in Figure 1.7-1, sheets 1, 2, and 3. The index, notes, and symbols for instrument and control functional diagrams are provided in Figure 7.2-1.

1.7.2 Piping and Instrumentation Diagrams

Table 1.7-2 contains a list of piping and instrumentation diagrams (P&IDs) and the corresponding figure numbers. The three letter system names are provided in Table 1.7-2. Figures appear at the end of the respective text section. The P&ID legend, Figure 1.7-2, sheets 1, 2, and 3, provides an explanation of AP1000 symbols and characters used in these figures.

1.7.3 Combined License Information

This section contained no requirement for additional information.

Table 1.7-1
I&C Functional and Electrical One-Line Diagrams

DCD Figure Number	Title
7.2-1 (Sheet 1)	Index and Symbols
7.2-1 (Sheet 2)	Reactor Trip Function
7.2-1 (Sheet 3)	Nuclear Startup Protection
7.2-1 (Sheet 4)	Nuclear Overpower Protection
7.2-1 (Sheet 5)	Core Heat Removal Protection and Reactor Coolant Pump Trip
7.2-1 (Sheet 6)	Primary Overpressure & Loss of Heat Sink Protection
7.2-1 (Sheet 7)	Loss of Heat Sink Protection
7.2-1 (Sheet 8)	Loss of Heat Sink Protection
7.2-1 (Sheet 9)	Steam Line Isolation
7.2-1 (Sheet 10)	Feedwater Isolation
7.2-1 (Sheet 11)	Safeguards Actuation
7.2-1 (Sheet 12)	Core Makeup Tank Actuation
7.2-1 (Sheet 13)	Containment and Other Protection
7.2-1 (Sheet 14)	Turbine Trip and Refueling Cavity and SFS Isolation
7.2-1 (Sheet 15)	Automatic RCS Overpressurization Valve Sequencing
7.2-1 (Sheet 16)	Incontainment Refueling Water Storage Tank Actuations
7.2-1 (Sheet 17)	Passive Residual Heat Removal and Core Makeup Tank Isolation Valve Interlocks
7.2-1 (Sheet 18)	Normal Residual Heat Removal System Isolation Valve Interlocks
7.2-1 (Sheet 19)	Containment Vacuum Relief Protection
7.2-1 (Sheet 20)	Diverse Actuation System Logic, Automatic Actuations
7.2-1 (Sheet 21)	Diverse Actuation System Logic, Manual Actuations
8.3.1-1	AC Power System - Station One-Line Diagram (Sheets 1 & 2)
8.3.1-2	On-site Standby Diesel Generator Initiation Circuit Logic Diagram
8.3.1-3	Ancillary Diesel Generator One Line Diagram
8.3.2-1	Class 1E DC System One-Line Diagrams (Sheets 1 & 2)
8.3.2-2	Class 1E 208Y/120V UPS One-Line Diagram
8.3.2-3	Non-Class 1E DC & UPS System One-Line Diagrams (Sheets 1, 2 & 3)

Table 1.7-2 (Sheet 1 of 3)
AP1000 System Designators and System Diagrams

Designator	System (Note 1)	Section	Figure (Note 2)
ASS	Auxiliary Steam Supply System	10.4.10	None
BDS	Steam Generator Blowdown System	10.4.8	10.4.8-1
CAS	Compressed and Instrument Air Systems	9.3.1	9.3.1-1
CCS	Component Cooling Water System	9.2.2	9.2.2-2
CDS	Condensate System	10.4.7	10.4.7-1
CES	Condenser Tube Cleaning System	10.4.1.2.1, 10.4.5.2.3	None
CFS	Turbine Island Chemical Feed System	10.4.11	None
CMS	Condenser Air Removal System	10.4.2	None
CNS	Containment System	6.2.3	None
CPS	Condensate Polishing System	10.4.6	10.4.6-1
CVS	Chemical and Volume Control System	9.3.6	9.3.6-1
CWS	Circulating Water System	10.4.5	10.4-201
DAS	Diverse Actuation System	7.7	7.2-1 (Sh. 19 & 20)
DDS	Data Display and Processing System	7.1 & 7.7	7.1-1
DOS	Standby Diesel Fuel Oil System	9.5.4	9.5.4-1
DRS	Storm Drain System (Wholly out of scope)	None	None
DTS	Demineralized Water Treatment System	9.2.3	None
DWS	Demineralized Water Transfer and Storage System	9.2.4	9.2.4-1
ECS	Main ac Power System	8.3.1	8.3.1-1
EDS	Non Class 1E dc and UPS System	8.3.2	8.3.2-3
EFS	Communication Systems	9.5.2	None
EGS	Grounding and Lightning Protection System	8.3.1.1	None
EHS	Special Process Heat Tracing System	8.3.1.1	None
ELS	Plant Lighting System	9.5.3	None
EQS	Cathodic Protection System (Partially out of scope)	None	None
FHS	Fuel Handling and Refueling System	9.1.1, 9.1.2, 9.1.4	9.1 - various
FPS	Fire Protection System	9.5.1, 6.5.2	9.5.1-1
FWS	Main and Startup Feedwater System	10.4.7, 10.4.9	10.4.7-1
GSS	Gland Seal System	10.4.3	10.4.3-1
HCS	Generator Hydrogen and CO_2 Systems	10.2	None
HDS	Heater Drain System	10.4.7	None
HSS	Hydrogen Seal Oil System	10.2	None
IDS	Class 1E dc and UPS System	8.3.2	8.3.2-1
IIS	In-core Instrumentation System	4.4.6	None

Table 1.7-2 (Sheet 2 of 3)
AP1000 System Designators and System Diagrams

Designator	System (Note 1)	Section	Figure (Note 2)
LOS	Main Turbine and Generator Lube Oil System	10.2	None
MES	Meteorological and Environmental Monitoring System (Wholly out of scope)	2.3.3	None
MHS	Mechanical Handling System	9.1	None
MSS	Main Steam System	10.3	10.3.2-2
MTS	Main Turbine System	10.2	10.2-1
OCS	Operation and Control Centers System	7.1, Ch. 18	7.1-1
PCS	Passive Containment Cooling System	6.2.2	6.2.2-1
PGS	Plant Gas Systems	9.3.2	None
PLS	Plant Control System	7.1 & 7.7	7.1-1
PMS	Protection and Safety Monitoring System	Ch. 7	7.2-1
PSS	Primary Sampling System	9.3.3	9.3.3-1
PWS	Potable Water System (Partially out of scope)	9.2.5	9.2.5-1 (Note 4)
PXS	Passive Core Cooling System	6.3	6.3-1
RCS	Reactor Coolant System	5.1	5.1-5
RDS	Gravity and Roof Drain Collection System (Partially out of scope)	None	None
RMS	Radiation Monitoring System	11.5	None
RNS	Normal Residual Heat Removal System	5.4.7	5.4-7
RWS	Raw Water System	9.2.1.2.2, 9.2.1.2.3.1, 9.2.3, 9.2.5, 9.2.11	9.2-201
RXS	Reactor System	3.9.4, 3.9.5, 4.2.2.2, 4.2.2.3.1, 5.3	5.3-1
SDS	Sanitary Drainage System (Partially out of scope)	9.2.6	None
SES	Plant Security System (Partially out of scope)	13.6	None
SFS	Spent Fuel Pool Cooling System	9.1.3	9.1-6
SGS	Steam Generator System	10.3, 10.4.7, 10.4.9	10.3.2-1
SJS	Seismic Monitoring System	3.7.4	None
SMS	Special Monitoring System	4.4.6.4	None
SSS	Secondary Sampling System	9.3.4	None
SWS	Service Water System	9.2.1	9.2.1-1
TCS	Turbine Building Closed Cooling Water System	9.2.8	None

Table 1.7-2 (Sheet 3 of 3)
AP1000 System Designators and System Diagrams

Designator	System (Note 1)	Section	Figure (Note 2)
TDS	Turbine Island Vents, Drains and Relief System	9.2.9.2.2, 10.4.2.2.1, 10.4.3.1.2, 10.4.3.2.2, 10.4.6.3	None
TOS	Main Turbine Control and Diagnostics System	10.2.2.4	None
TVS	Closed Circuit TV System (Wholly out of scope)	None	None
VAS	Radiologically Controlled Area Ventilation System	9.4.3	9.4.3-1
VBS	Nuclear Island Nonradioactive Ventilation System	9.4.1	9.4.1-1
VCS	Containment Recirculation Cooling System	9.4.6	9.4.6-1
VES	Main Control Room Emergency Habitability System	6.4	6.4-2
VFS	Containment Air Filtration System	9.4.7	9.4.7-1
VHS	Health Physics and Hot Machine Shop HVAC System	9.4.11	9.4.11-1
VLS	Containment Hydrogen Control System	6.2.4	6.2.4 - various
VRS	Radwaste Building HVAC System	9.4.8	9.4.8-1
VTS	Turbine Building Ventilation System	9.4.9	9.4.9-1
VUS	Containment Leak Rate Test System	6.2.5	6.2.5-1
VWS	Central Chilled Water System	9.2.7	9.2.7-1
VXS	Annex/Auxiliary Non-Radioactive Ventilation System	9.4.2	9.4.2-1
VYS	Hot Water Heating System	9.2.10	None
VZS	Diesel Generator Building Ventilation System	9.4.10	9.4.10-1
WGS	Gaseous Radwaste System	11.3	11.3-2
WLS	Liquid Radwaste System	11.2	11.2-2
WRS	Radioactive Waste Drain System	9.3.5, 11.2	9.3.5-1
WSS	Solid Radwaste System	11.4	11.4-1
WWS	Waste Water System (Partially out of scope)	9.2.9	None
YFS	Yard Fire Water System (Wholly out of scope)	None	None
ZAS	Main Generation System (Note 3)	8.1	None
ZBS	Offsite Power System One-Line Diagram	8.2	8.2-201
ZBS	Switchyard General Arrangement	8.2	8.2-202
ZOS	Onsite Standby Power System	8.2.1, 8.3.1	8.3.1-4, 8.3.1-5
ZRS	Offsite Retail Power System (Wholly out of scope)	None	None
ZVS	Excitation and Voltage Regulation System	10.2.2.3	None

Notes:

1. For the System names:
   a) An entry with the system name only means the system is wholly in the scope of the AP1000 design certification.
   b) An entry with the system name followed by (Partially out of scope) means the system is partially in the scope of the AP1000 design certification.
   c) An entry with the system name followed by (Wholly out of scope) means the system is not in the scope of the AP1000 design certification.
2. For the DCD Figures:
   In the AP1000 design documentation system, Piping and Instrumentation Diagrams are numbered xxx-M6-yyy, where xxx is the system designator and yyy is the sheet number. Electrical One-Line Diagrams are numbered xxx-E3-yyy, where xxx is the system designator and yyy is the sheet number. I&C Functional Logic Diagrams are numbered xxx-J1-yyy, where xxx is the I&C system designator and yyy is the sheet number.
3. For the Main Generation System:
   The high side voltage of the main step-up transformer and the reserve auxiliary transformer is site specific.
4. Figure 9.2.5-1 is a partial Piping and Instrumentation Diagram entitled, “Main Control Room Potable Water System Isolation.”

Table 1.7-201
Not Used

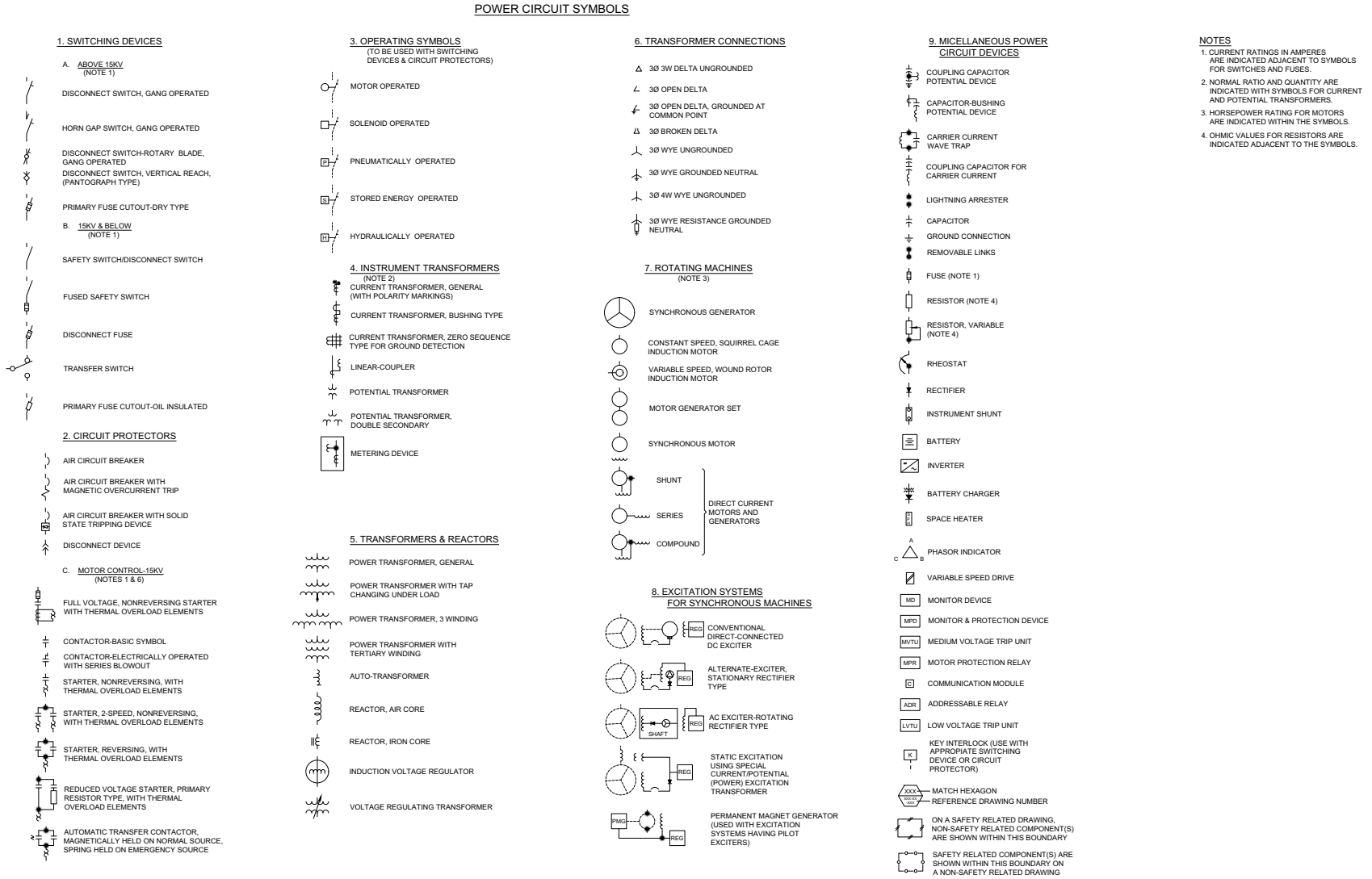


Figure 1.7-1 (Sheet 1 of 3)
Legend for Electrical Power, Lighting, and Communication Drawings

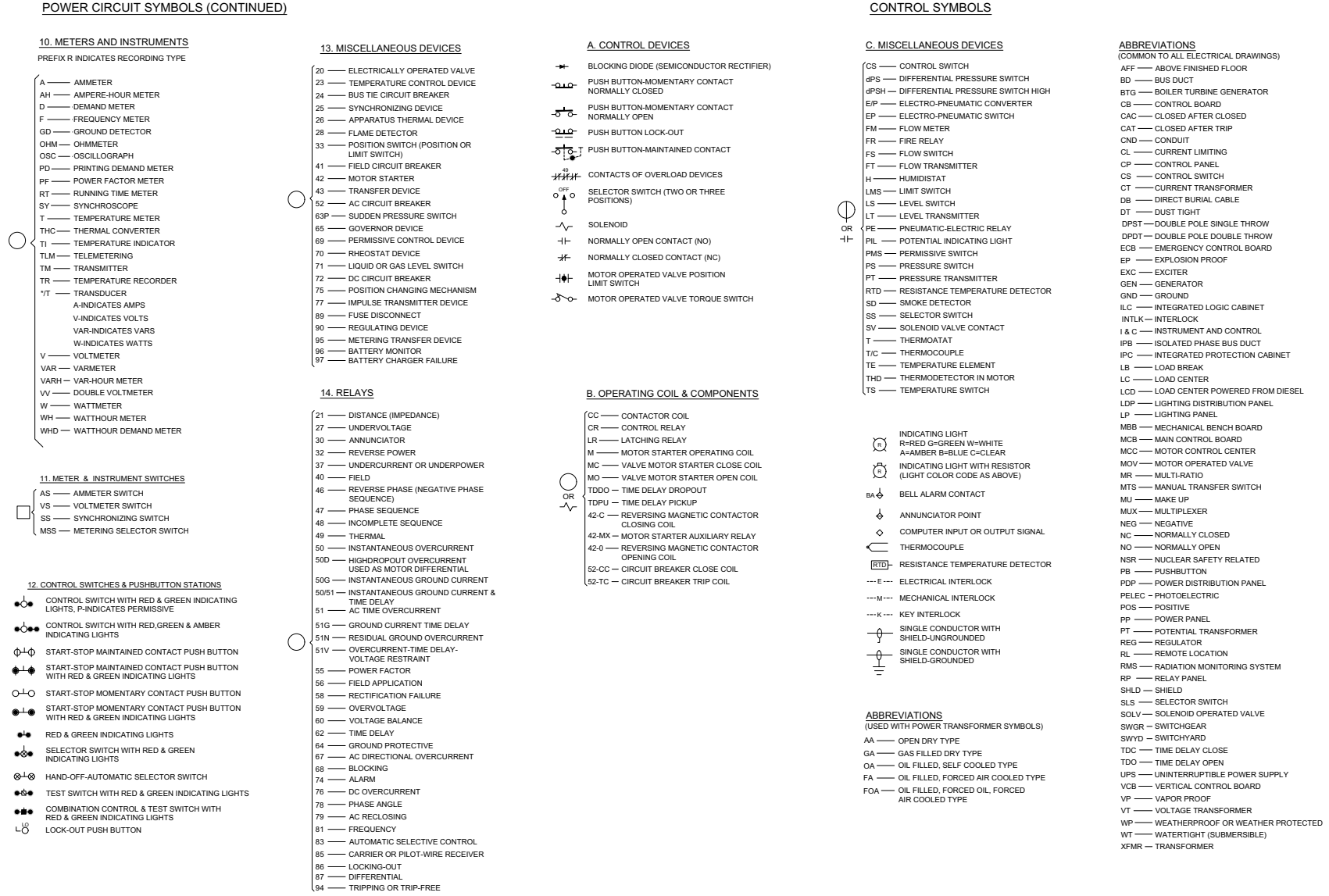


Figure 1.7-1 (Sheet 2 of 3)
Legend for Electrical Power, Lighting, and Communication Drawings

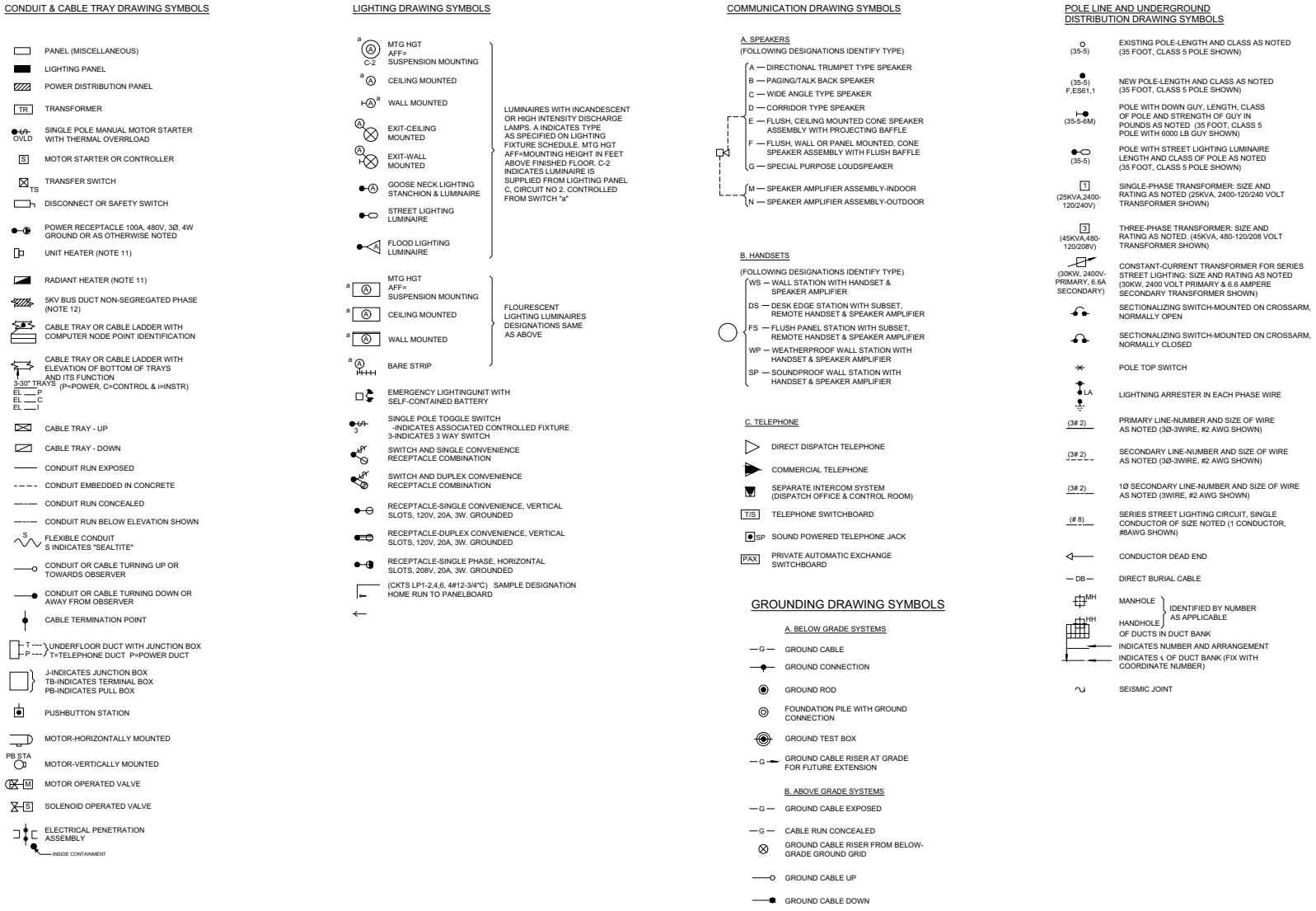


Figure 1.7-1 (Sheet 3 of 3)
Legend for Electrical Power, Lighting, and Communication Drawings

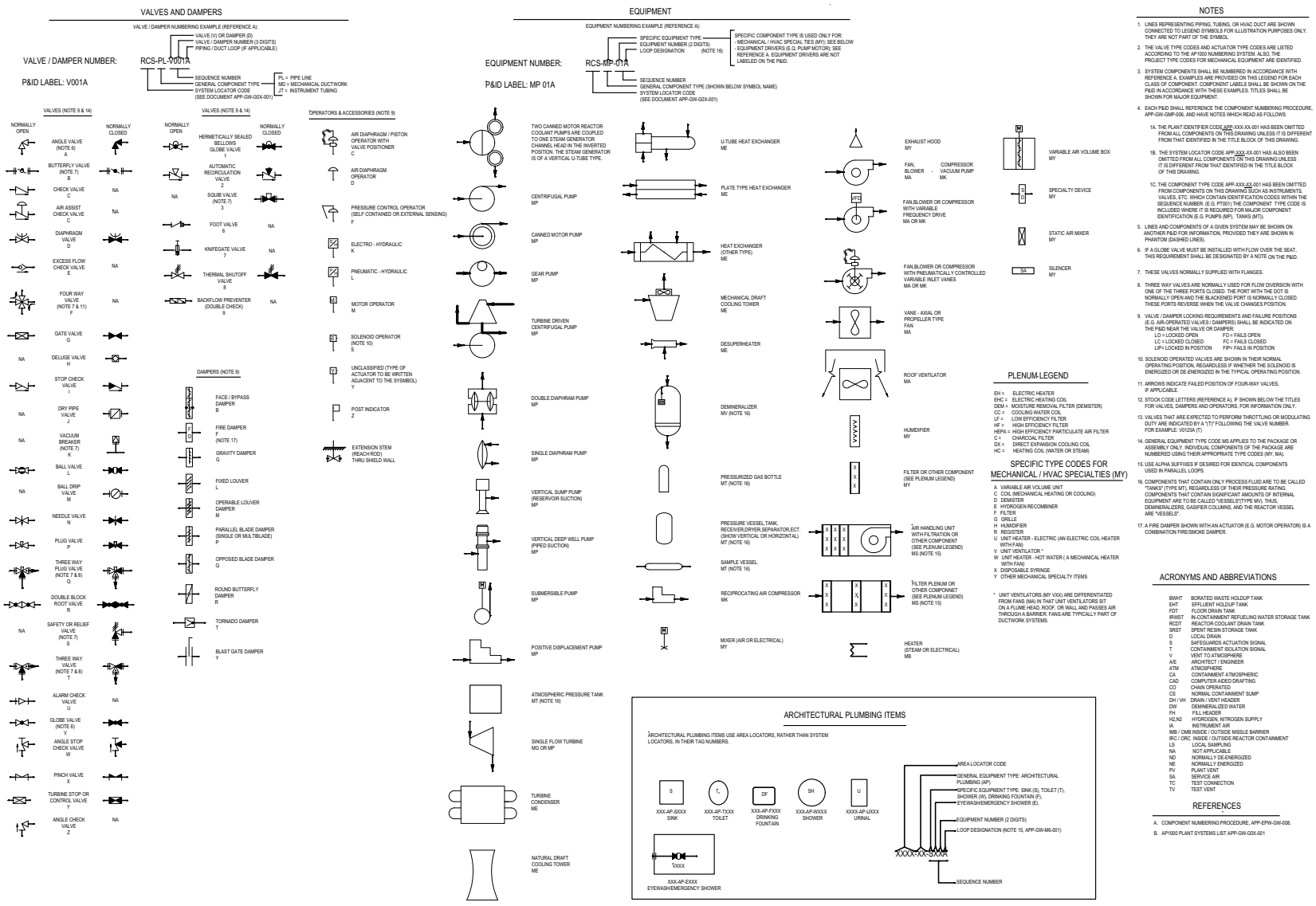
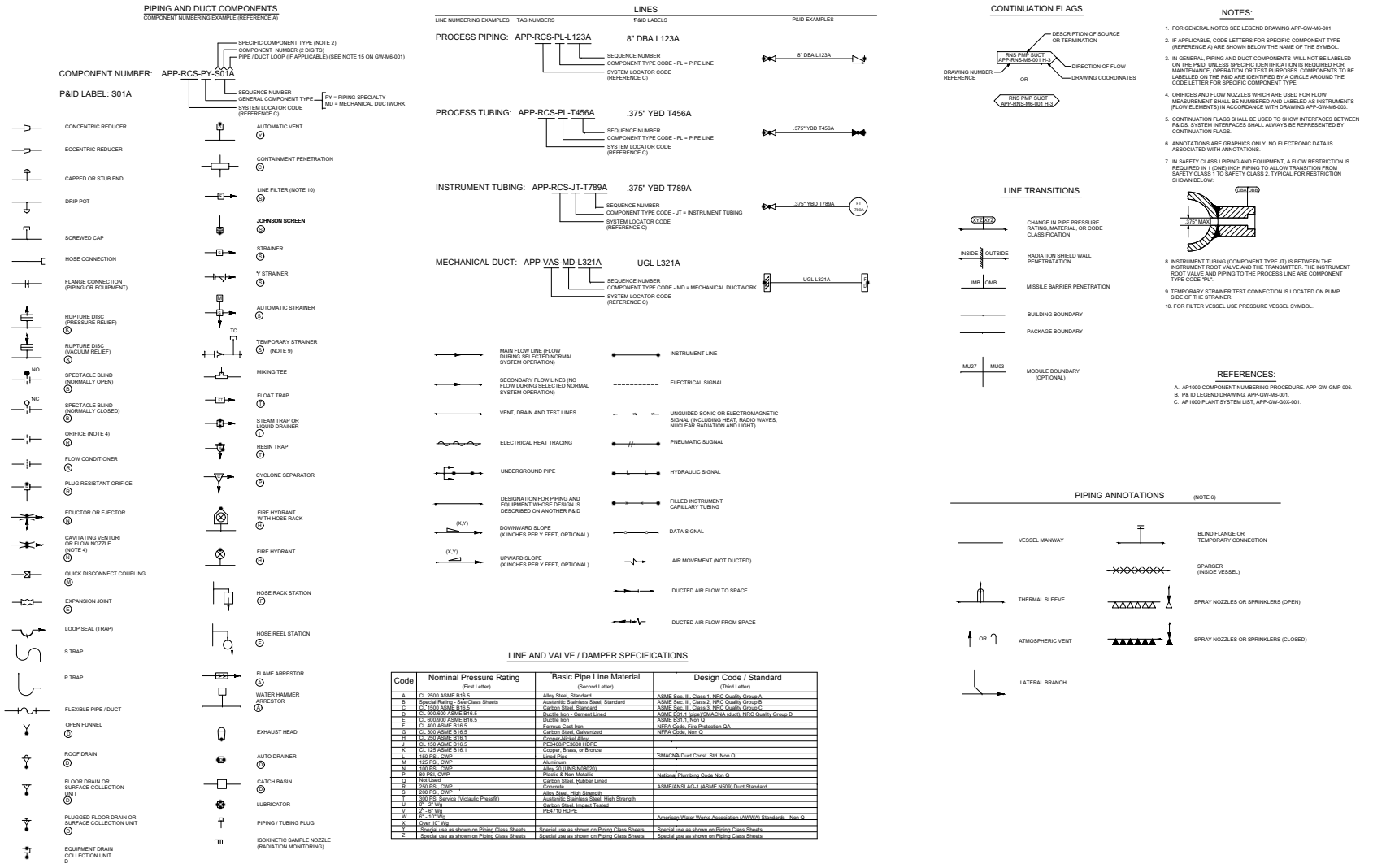
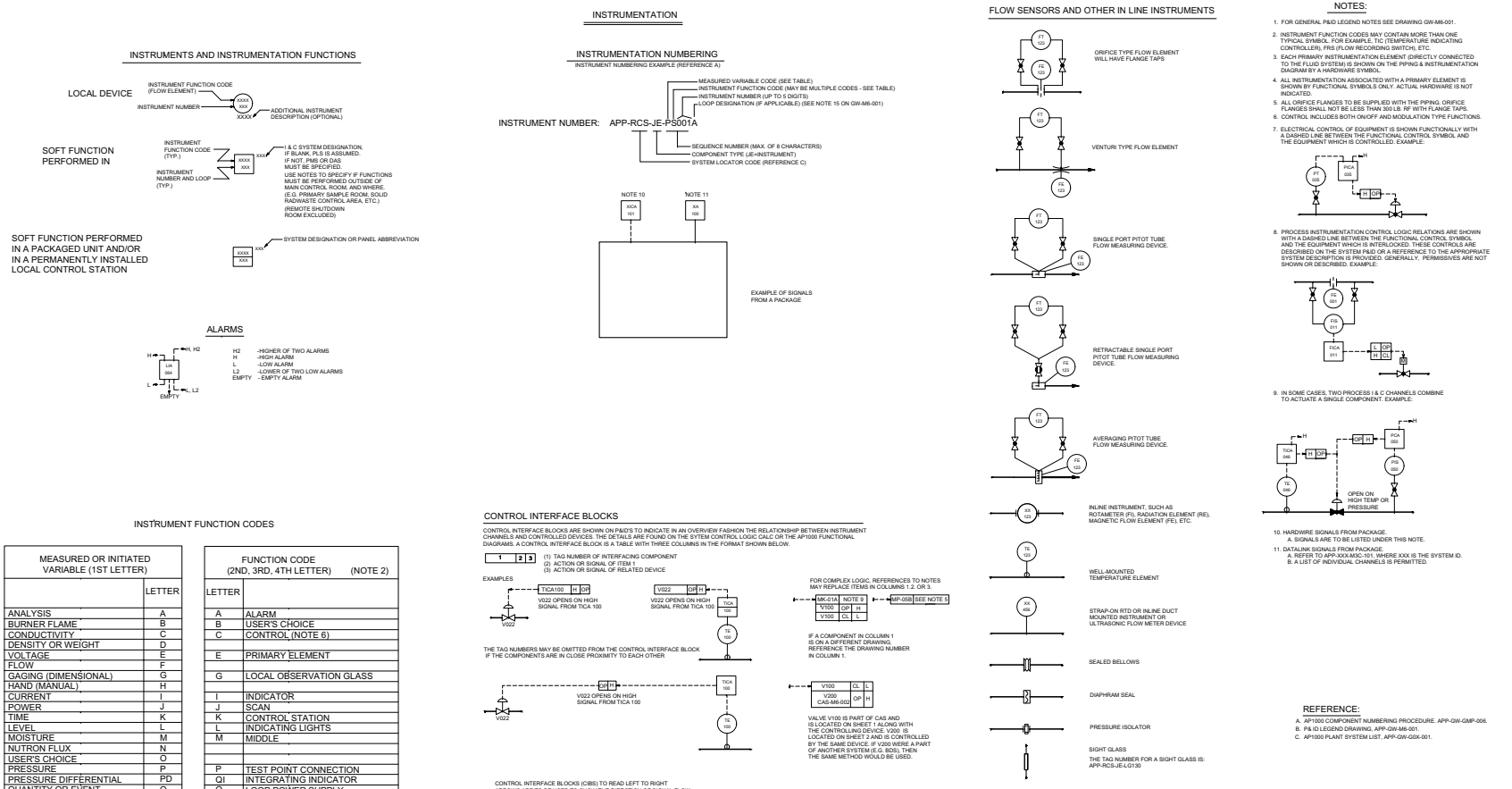


Figure 1.7-2 (Sheet 1 of 3)
Piping and Instrumentation Diagram Legend



Code	Nominal Pressure Rating (First Letter)	Basic Pipe Line Material (Second Letter)	Design Code / Standard (Third Letter)
A	CL 2500 ASME B16.5	Alloy Steel, Standard	ASME Sec. III, Class 1, NRC Quality Group A
B	Special Rating - See Class Sheets	Austenitic Stainless Steel, Standard	ASME Sec. III, Class 2, NRC Quality Group B
C	CL 1500 ASME B16.5	Carbon Steel, Standard	ASME Sec. III, Class 3, NRC Quality Group C
D	CL 900/600 ASME B16.5	Ductile Iron - Cement Lined	ASME B31.1 (pipe)/SMACNA (duct), NRC Quality Group D
E	CL 600/900 ASME B16.5	Ductile Iron	ASME B31.1, Non Q
F	CL 400 ASME B16.5	Ferrous Cast Iron	NFPA Code, Fire Protection QA
G	CL 300 ASME B16.5	Carbon Steel, Galvanized	NFPA Code, Non Q
H	CL 250 ASME B16.1	Copper-Nickel Alloy	-
J	CL 150 ASME B16.5	PE3408/PE3608 HDPE	-
K	CL 125 ASME B16.1	Copper, Brass, or Bronze	-
L	150 PSI, CWP	Lined Pipe	SMACNA Duct Const. Std. Non Q
M	125 PSI, CWP	Aluminum	-
N	100 PSI, CWP	Alloy 20 (UNS N08020)	-
P	80 PSI, CWP	Plastic & Non-Metallic	National Plumbing Code Non Q
Q	Not Used	Carbon Steel, Rubber Lined	-
R	250 PSI, CWP	Concrete	ASME/ANSI AG-1 (ASME N509) Duct Standard
S	200 PSI, CWP	Alloy Steel, High Strength	-
T	300 PSI Service (Victaulic Presefit)	Austenitic Stainless Steel, High Strength	-
U	0" - 2" Wg	Carbon Steel, Impact Tested	-
V	2" - 5" Wg	PE4710 HDPE	-
W	5" - 10" Wg	-	American Water Works Association (AWWA) Standards - Non Q
X	Over 10" Wg	-	-
Y	Special use as shown on Piping Class Sheets	Special use as shown on Piping Class Sheets	Special use as shown on Piping Class Sheets
Z	Special use as shown on Piping Class Sheets	Special use as shown on Piping Class Sheets	Special use as shown on Piping Class Sheets

Figure 1.7-2 (Sheet 2 of 3)
Piping and Instrumentation Diagram Legend



INSTRUMENT FUNCTION CODES

MEASURED OR INITIATED VARIABLE (1ST LETTER)	LETTER
ANALYSIS	A
BURNER FLAME	B
CONDUCTIVITY	C
DENSITY OR WEIGHT	D
VOLTAGE	E
FLOW	F
GAGING (DIMENSIONAL)	G
HAND (MANUAL)	H
CURRENT	I
POWER	J
TIME	K
LEVEL	L
MOISTURE	M
NUTRON FLUX	N
USER'S CHOICE	O
PRESSURE	P
PRESSURE DIFFERENTIAL	PD
QUANTITY OR EVENT	Q
RADIOACTIVITY	R
SPEED OR FREQUENCY	S
TEMPERATURE	T
TEMPERATURE DIFFERENTIAL	TD
MULTIVARIABLE	U
VISCOSITY	V
WEIGHT	W
UNCLASSIFIED	X
VIBRATION	Y
POSITION	Z

LETTER	FUNCTION CODE (2ND, 3RD, 4TH LETTER) (NOTE 2)
A	ALARM
B	USER'S CHOICE
C	CONTROL (NOTE 6)
E	PRIMARY ELEMENT
G	LOCAL OBSERVATION GLASS
I	INDICATOR
J	SCAN
K	CONTROL STATION
L	INDICATING LIGHTS
M	MIDDLE
P	TEST POINT CONNECTION
QI	INTEGRATING INDICATOR
Q	LOOP POWER SUPPLY
R	RECORDER
S	SWITCH
T	TRANSMITTER
U	MULTI VARIABLE
Y	RELAY OR COMPUTER FUNCTION
Z	OTHER FINAL CONTROL ELEMENT

ST	START
SP	STOP
OP	OPEN
CL	CLOSE
H2	HIGH-2
H	HIGH
L	LOW
L2	LOW-2

H,H2,H3,L,L2,L3, ETC. (MULTIPLE SETPOINTS)	MULTIPLE SETPOINTS WHERE H3 IS HIGHER THAN H2, ETC. AND L2 IS LOWER THAN L, ETC.
MOD	MODULATE
TRP	TRIP
S (PMS)	SAFEGUARD ACTUATION
T (PMS)	CONTAINMENT ISOLATION

Figure 1.7-2 (Sheet 3 of 3)
Piping and Instrumentation Diagram Legend

1.8 Interfaces for Standard Design

This section identifies the AP1000 standard plant scope, interfaces related to design certification between the AP1000 plant design and the Combined License applicant, and the site-specific items to be included in an application for a Combined License. It is submitted to satisfy the requirements of 10 CFR 52.47(a)(25).

The AP1000 is a plant incorporating six buildings, the equipment in them, and the associated yard structures and tankage. This includes the nuclear island (consisting of the containment/shield building and the auxiliary building), the annex building and associated equipment, the diesel generator building and associated equipment, the turbine building, the turbine/generator equipment, and the radwaste facilities. The physical boundary of the portion of the AP1000 included in this application is shown on the site plan, Figure 1.2-2. It includes arrangement and placement of structures within the indicated boundary. Additionally, the red zone delay barrier necessary for security is included, but the boundary fence and vehicle barrier are not included since they are site-specific. As a result, no interfaces need to be identified between or among the portions of the plant within the boundary. They are addressed in their appropriate section of this DCD. There are no safety-related interfaces to site-specific elements of the plant outside the scope of this certification application. The following site-specific elements are outside the scope of the AP1000 standard plant:

(1) The portions of the circulating water system and its heat sink outside the AP1000 buildings, the portions of the service water blowdown lines outside the AP1000 buildings, which transfer fluid to the circulating water cooling tower basins, as well as the specific design details of the main condenser. A conceptual design is presented, delineated by Double Brackets ([[ ]]), in Subsection 10.4.5, based upon a cooling tower approach.

(2) The offsite power transmission system outside the low voltage terminals of the main and reserve transformers. Location and design of the main switchyard area and the equipment located therein, as well as design details such as voltage level for the main step-up transformers. A conceptual design of this system is included, delineated by Double Brackets ([[ ]]), in Section 8.2 for reference.

(3) Raw water source and treatment outside the turbine building. An interface specification of amount and water chemistry limits is provided.

(4) Sanitary and other drain systems outside the buildings identified above. This DCD is based upon the COL applicant providing adequate overall site drain collection and processing systems

(5) Communications systems and equipment outside the buildings identified above. This DCD is based upon the COL applicant providing adequate external communications.

(6) Location and design of administrative and training structures.

(7) Landscaping features.

(8) Size and location of the waste water retention basins and the associated plant outfall piping.

A more detailed listing of the systems included in the standard AP1000 plant is included in Section 3.2.

There are a number of information interfaces between the AP1000 design and other portions of a completely licensed facility which must be addressed by parties that reference the AP1000 design. These interfaces are identified in Table 1.8-1 in the order they are presented in this DCD.

The safety-related interface requirements in Table 1.8-1 have been selected based on a review of interfaces between the AP1000 plant design and other Combined License applicant or site-specific items. Satisfying the referenced information for each of the interfaces listed will provide confidence that systems, structures and components within the AP1000 can perform their safety functions. The specific details of the interface parameters are identified in the DCD sections identified in Table 1.8-1. The interface specifications have been selected to suit a wide range of potential sites. Values identified by a Combined License applicant to be outside the range of acceptable parameters may be demonstrated to be acceptable. Such cases will be documented in the appropriate sections of the specific Combined License application.

The classification of interface types is based on the sources of interfaces listed in Appendix A of Regulatory Guide 1.70. The first four types below are directly related to the four sources of interfaces. They have been redefined slightly to reflect the fact that AP1000 is an essentially complete plant design. The classification of interface types is as follows:

- **Requirement of AP1000** – Requirements for operation of the AP1000 design that must be satisfied by the matching portion of the site, utility or Combined License applicant administration.

- **AP1000 Interface** – Interface condition used for AP1000 design which must be more precisely defined during the coordination effort between the AP1000 design team and the Combined License applicant.

- **Site Interface** – Site-related interface data upon which the AP1000 design is based.

- **Pertinent Criteria** – Criteria pertinent to the AP1000 design that may be useful for the design and staff review of the matching systems, components and structures.

- **Not an Interface** – Interface items identified in Appendix A of Regulatory Guide 1.70 which are wholly within the boundaries of the AP1000 plant. As a result, the "Matching Interface Item" in Table 1.8-1 is identified as N/A (not applicable).

- **Non-Nuclear Safety (NNS)** – Interface items identified in Appendix A of Regulatory Guide 1.70 which are non-nuclear safety-related because of the design features of AP1000.

Note that all plant interfaces listed in Appendix A of Regulatory Guide 1.70 have been listed in Table 1.8-1. As noted above and in Table 1.8-1, a number of these interfaces do not apply to the AP1000 plant as described in this DCD. In some cases, the interface listed in Appendix A of Regulatory Guide 1.70 is totally within the AP1000 plant and therefore not an interface. Other interfaces from Appendix A of Regulatory Guide 1.70 are identified as non-nuclear safety. The classification of systems, structures and components is described in Section 3.2. Only safety-related interfaces are detailed in Table 1.8-1. An example of an "NNS" (non-nuclear safety) type of interface is any of those associated with site service water. AP1000 does not rely on site service water as a safety grade ultimate heat sink. Neither the cooling tower nor the diesel-generator building is safety-related in AP1000. As such, there are no safety-related interfaces for these features.

Interfaces are listed in the order discussed in the DCD. General interfaces are listed as they relate to a particular section of this DCD. No specific system-by-system interface listings are required due to the complete nature of the AP1000 plant design. All safety-related systems are contained within the AP1000 plant design. The listing includes identification of the interface classification and the

matching interface item to be specified by the Combined License applicant. In addition, the section of this DCD which addresses the listed interface is identified. To satisfy the requirements of 10 CFR 52.47(a)(25), representative conceptual designs are included in this DCD for those portions of the plant for which Westinghouse does not seek certification to aid the NRC staff in its review of the DCD and the probabilistic risk assessment to be submitted in support of the application, and to permit assessment of the adequacy of interface requirements.

Combined License Information

Combined License applicants referencing the AP1000 certified design will be required to provide site-specific information, verification that interface criteria are satisfied, information related to operating procedures, and other information required to support the AP1000 Design Certification. The description of information to be provided by the Combined License applicant is found in the DCD sections applicable to the specific information. Table 1.8-2 is a listing of the Combined License Information Items and the DCD location of the description of the information. In some cases, the activity required by a COL Information Item requires as-built information or other conditions that are not available when the COL application is submitted. These items are noted in the applicable DCD sections and Table 1.8-2. These activities are completed prior to fuel load.

{HISTORICAL—Departures from the referenced DCD are summarized in Table 1.8-201. Table 1.8-201 lists each departure and the section or subsection impacted.—HISTORICAL}

{HISTORICAL—Variances from the referenced ESPA are identified in Table 1.6-202.—HISTORICAL}

Table 1.8-2 presents Combined License Information for the AP1000. Items requiring COL Applicant or COL Holder action are presented in Table 1.8-202. Section(s) addressing these COL items are tabulated in this table. COL Holder items listed in Table 1.8-202 are commitments of the COL Holder and these actions will be completed as specified in the appropriate section. Completion of these COL Holder items is the subject of a proposed License Condition as presented in a separate document submitted as part of the COL application.

Demonstrations that the VEGP Units 3 and 4 site characteristics, design parameters, and site interface values fall within the site-related parameters for which the AP1000 was designed are provided in Section 2.0.

Table 1.8-1 presents interface items for the AP1000, with appropriate section(s) addressing these interface items.

Table 1.8-1 (Sheet 1 of 6)
Summary of AP1000 Plant Interfaces With Remainder of Plant

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
2.1	Envelope of AP1000 plant site related parameters	Site Interface	Site specific parameters	2.0 Table 2.0-201 Table 2.0-202
2.2	External missiles from man-made hazards and accidents	Site Interface	Site specific parameters	2.2 2.2.2.6 2.2.3.1 2.2.3.2 3.5
2.3	Maximum loads from man-made hazards and accidents	Site Interface	Site specific parameters	2.2 2.2.3.1 2.2.3.2
2.4	Limiting meteorological parameters (χ/Q) for design basis accidents and for routine releases and other extreme meteorological conditions for the design of systems and components exposed to the environment.	Site Interface	Site specific parameters	2.3 Table 2.0-201 Table 2.0-202
2.5	Tornado and operating basis wind loadings	Site Interface	Site specific parameters	2.3 Table 2.0-201
2.6	External missiles generated by natural phenomena	Site Interface	Site specific parameters	2.3 Table 2.0-201
2.7	Snow, ice and rain loads	Site Interface	Site specific parameters	2.3 2.3.1.3.4
2.8	Ambient air temperatures	Site Interface	Site specific parameters	2.3 Table 2.0-201
2.9	Onsite meteorological measurement program	Requirement of AP1000	Combined License applicant program	2.3.3 2.3.3.4
2.10	Flood and ground water elevations	Site Interface	Site specific parameters	2.4 Table 2.0-201
2.11	Hydrostatic loads on systems, components and structures	Site Interface	Site specific parameters	2.4 Table 2.0-201
2.12	Seismic parameters peak ground acceleration response spectra shear wave velocity	Site Interface	Site specific parameters	 2.5 2.5 2.5 Table 2.0-201

Table 1.8-1 (Sheet 2 of 6)
Summary of AP1000 Plant Interfaces With Remainder of Plant

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
2.13	Required bearing capacity of foundation materials	Site Interface	Site specific parameters	2.5 Table 2.0-201
3.1	Deleted			N/A
3.2	Operating procedures to minimize water hammer	Requirement of AP1000	Combined License applicant procedure	3.6, 10 10.3.2.2.1 10.4.7.2.1
3.3	Site seismic sensor location and "trigger" value	Requirement of AP1000	Onsite implementation	3.7.4 3.7.4.2.1
3.4	Depth of overburden	Requirement of AP1000	Onsite implementation	3.8 2.5.4.5 3.8.5.1
3.5	Depth of embedment	Requirement of AP1000	Onsite implementation	3.8 2.5.4.5 3.8.5.1
3.6	Specific depth of waterproofing	Requirement of AP1000	Onsite implementation	3.8.5 2.5.4.5.7 3.8.5.1
3.7	Foundation Settlement Monitoring	Requirement of AP1000	Combined License applicant coordination	3.8.5 2.5.4.10.2
3.8	Lateral earth pressure loads	Not an Interface	N/A	3 N/A
3.9	Preoperational piping vibration test parameters	Not an Interface	N/A	3 N/A
3.10	Inservice Inspection requirements and locations	Requirement of AP1000	Combined License applicant program	3.9.6 5.2.4 6.6 3.9.6 5.2.4 6.6
3.11	Maintenance of preservice and reference test data for inservice testing of pumps and valves	Requirement of AP1000	Combined License applicant program	3.9.6 5.2.4 6.6 3.9.6
3.12	Earthquake response procedures	Requirement of AP1000	Combined License applicant program	3.7.4 3.7.4.4
5.1	Steam Generator Tube Surveillance Requirements	Requirement of AP1000	Combined License applicant program	5.4.2 5.4.2.5
6.1	Inservice Inspection requirements for the containment	Requirement of AP1000	Combined License applicant program	6.2.1 6.6

Table 1.8-1 (Sheet 3 of 6)
Summary of AP1000 Plant Interfaces With Remainder of Plant

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
6.2	Offsite environmental conditions assumed for Main Control Room and control support area habitability design	AP1000 Interface	Site specific parameter	6.4 2.2.3 6.4
7.1	Listing of all design criteria applied to the design of the I&C systems	Not an Interface	N/A	7 N/A
7.2	Power required for site service water instrumentation	NNS and Not an Interface	N/A	7 N/A
7.3	Other provisions for site service water instrumentation	NNS and Not an Interface	N/A	7 N/A
7.4	Post-accident monitoring system	NNS	Combined License applicant coordination	7.5.5 7.5.5
8.1	Listing of design criteria applied to the design of the offsite power system	NNS	Combined License applicant coordination	8 8.1.4.3
8.2	Offsite ac requirements Steady-state load Inrush kVA for motors Nominal voltage Allowable voltage regulation Nominal frequency Allowable frequency fluctuation Maximum frequency decay rate Limiting under frequency value for RCP	NNS	Combined License applicant coordination	8 8.2.2

Table 1.8-1 (Sheet 4 of 6)
Summary of AP1000 Plant Interfaces With Remainder of Plant

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
8.3	Offsite transmission system analysis: Loss of AP1000 or largest unit Voltage operating range Transient stability must be maintained and the RCP bus voltage must remain above the voltage required to maintain the flow assumed in Chapter 15 analyses for a minimum of three (3) seconds following a turbine trip. The protective devices controlling the switchyard breakers are set with consideration given to preserving the plant grid connection following a turbine trip.	NNS	Combined License applicant analysis	8.2 8.2.1.2.1 8.2.2 14.2.9.4.23
8.4	Listing of design criteria applied to the design of onsite ac power systems	NNS and Not an Interface	N/A	8 N/A
8.5	Onsite ac requirements	NNS and Not an Interface	N/A	8 N/A
8.6	Diesel generator room coordination	NNS and Not an Interface	N/A	8 N/A
8.7	Listing of design criteria applied to the design of onsite dc power systems	Not an Interface	N/A	8 N/A
8.8	Provisions of dc power systems to accommodate the site service water system	NNS and Not an Interface	N/A	8 N/A
9.1	Listing of design criteria applied to the design of portions of the site service water within AP1000	NNS and Not an Interface	N/A	9 N/A
9.2	Integrated heat load to site service water system	NNS and Not an Interface	N/A	9 N/A
9.3	Plant cooling water systems parameters	NNS and Not an Interface	N/A	9 N/A
9.4	Plant makeup water quality limits	NNS	Site specific parameter	9 9.2.11

Table 1.8-1 (Sheet 5 of 6)
Summary of AP1000 Plant Interfaces With Remainder of Plant

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
9.5	Requirements for location and arrangement of raw and sanitary water systems	NNS	Site implementation	9 9.2.5 9.2.6 9.2.11
9.6	Ventilation requirements for diesel-generator room	NNS and Not an Interface	N/A	9 N/A
9.7	Requirements to satisfy fire protection program	AP1000 Interface	Combined License applicant program	9.5.1 9.5.1
9.8	Requirements for location and size of waste water retention basins and associated plant outfall	NNS	Site Implementation	9 9.2.9
11.1	Expected release rates of radioactive material from the Liquid Waste System including: Location of release points Effluent temperature Effluent flow rate Size and shape of flow orifices	Site Interface	Site specific parameters	11.2 11.2
11.2	Expected release rates of radioactive materials from the Gaseous Waste System including: Location of release points Height above grade Height relative to adjacent buildings Effluent temperature Effluent flow rate Effluent velocity Size and shape of flow orifices	Site Interface	Site specific parameters	11.3 11.3
11.3	Expected release rates of radioactive material from the Solid Waste System including: Location of release points Material types Material qualities Size and shape of material containers	Site Interface	Site specific parameters	11.4 11.4.6

Table 1.8-1 (Sheet 6 of 6)
Summary of AP1000 Plant Interfaces With Remainder of Plant

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
11.4	Requirements for offsite sampling and monitoring of effluent concentrations	AP1000 Interface	Combined License applicant program	11.5 11.5.3 11.5.8
12.1	Identification of miscellaneous radioactive sources	AP1000 Interface	Combined License applicant program	12.2 12.2.1.1.10
13.1	Features that may affect plans for coping with emergencies	AP1000 Interface	Combined License applicant program	13.3 13.3
13.2	Physical Security Plan consistent with AP1000 plant	AP1000 Interface	Combined License applicant program	13.6 13.6
14.1	Identification of special features to be considered in development of the initial test program	Requirement of AP1000	Combined License applicant program	14 14
14.2	Maintenance of preoperational test data and inservice inspection baseline data	AP1000 Interface	Combined License applicant program	14 14
16.1	Administrative requirements associated with reliability information maintenance	AP1000 Interface	Combined License applicant program	16 16.3
16.2	Administrative requirements associated with the Technical Specifications	Requirement of AP1000	Combined License applicant implementation	16 16.1
16.3	Site and operator related information associated with the Reliability Assurance Program (D-RAP)	Requirement of AP1000	Combined License applicant program	16.2 16.2
18.1	Operating staff consistent with Human Factors evaluations	AP1000 Interface	Combined License applicant program	18.6 18.6
18.2	Operator training consistent with Human Factors evaluations	AP1000 Interface	Combined License applicant program	18.8 18.10 18.8 18.10
18.3	Operating Procedures consistent with Human Factors evaluations	AP1000 Interface	Combined License applicant program	18.8 18.10 18.8 18.10

Table 1.8-2 (Sheet 1 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
1.1-1	Construction and Startup Schedule	1.1.7	N/A	Yes	–
1.9-1	Regulatory Guide Conformance	1.9.1.5	APP-GW-GLN-129	Yes	–
2.1-1	Geography and Demography	2.1.1	N/A	Yes	–
2.2-1	Identification of Site-specific Potential Hazards	2.2.1	N/A	Yes	–
2.3-1	Regional Climatology	2.3.6.1	N/A	Yes	–
2.3-2	Local Meteorology	2.3.6.2	N/A	Yes	–
2.3-3	Onsite Meteorological Measurements Program	2.3.6.3	N/A	Yes	–
2.3-4	Short-Term Diffusion Estimates	2.3.6.4	N/A	Yes	–
2.3-5	Long-Term Diffusion Estimates	2.3.6.5	N/A	Yes	–
2.4-1	Hydrological Description	2.4.1.1	N/A	Yes	–
2.4-2	Floods	2.4.1.2	N/A	Yes	–
2.4-3	Cooling Water Supply	2.4.1.3	N/A	Yes	–
2.4-4	Groundwater	2.4.1.4	N/A	Yes	–
2.4-5	Accidental Release of Liquid Effluents into Ground and Surface Water	2.4.1.5	N/A	Yes	–
2.4-6	Flood Protection Emergency Operation Procedures	2.4.1.6	N/A	Yes	–

Table 1.8-2 (Sheet 2 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
2.5-1	Basic Geologic and Seismic Information	2.5.1	N/A	Yes	–
2.5-2	Site Seismic and Tectonic Characteristics Information	2.5.2.1	N/A	Yes	–
2.5-3	Geoscience Parameters	2.5.2.3	N/A	Yes	–
2.5-4	Surface Faulting	2.5.3	N/A	Yes	–
2.5-5	Site and Structures	2.5.4.6.1	N/A	Yes	–
2.5-6	Properties of Underlying Materials	2.5.4.6.2	N/A	Yes	–
2.5-7	Excavation and Backfill	2.5.4.6.3	N/A	Yes	–
2.5-8	Ground Water Conditions	2.5.4.6.4	N/A	Yes	–
2.5-9	Liquefaction Potential	2.5.4.6.5	N/A	Yes	–
2.5-10	Bearing Capacity	2.5.4.6.6	N/A	Yes	–
2.5-11	Earth Pressures	2.5.4.6.7	N/A	Yes	–
2.5-12	Static and Dynamic Stability of Facilities	2.5.4.6.9	N/A	Yes	–
2.5-13	Subsurface Instrumentation	2.5.4.6.10	N/A	Yes	–
2.5-14	Stability of Slopes	2.5.5	N/A	Yes	–
2.5-15	Embankments and Dams	2.5.6	N/A	Yes	–
2.5-16	Settlement of Nuclear Island	2.5.4.6.11	N/A	Yes	–
2.5-17	Waterproofing System	2.5.4.6.12	N/A	Yes	–

Table 1.8-2 (Sheet 3 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
3.3-1	Wind and Tornado Site Interface Criteria	3.3.3	APP-GW-GLR-020	Yes	–
3.4-1	Site-Specific Flooding Hazards Protective Measures	3.4.3	N/A	Yes	–
3.5-1	External Missile Protection Requirements	3.5.4	APP-GW-GLR-020	Yes	–
3.6-1	Pipe Break Hazards Analysis	3.6.4.1	APP-GW-GLR-021 APP-GW-GLR-074	No	Yes
3.6-2	Leak-Before-Break Evaluation of as-Designed Piping	3.6.4.2	APP-GW-GLR-022	No	No
3.6-3	Deleted Leak-Before-Break Evaluation of as-Built Piping	Deleted	APP-GW-GLR-021	N/A	N/A
3.6-4	Primary System Inspection Program for Leak-Before-Break Piping	3.6.4.4	N/A	Yes	–
3.7-1	Seismic Analysis of Dams	3.7.5.1	N/A	Yes	–
3.7-2	Post-Earthquake Procedures	3.7.5.2	N/A	Yes	–
3.7-3	Seismic Interaction Review	3.7.5.3	APP-GW-GLR-021	No	Yes
3.7-4	Reconciliation of Seismic Analyses of Nuclear Island Structures	3.7.5.4	APP-GW-GLR-021 APP-GW-S2R-010	No	Yes
3.7-5	Location of Free-Field Acceleration Sensor	3.7.5.5	N/A	Yes	–
3.8-1	Containment Vessel Design Adjacent to Large Penetrations	3.8.6.1	APP-GW-GLR-005	No	No

Table 1.8-2 (Sheet 4 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
3.8-2	Deleted Passive Containment Cooling System Water Storage Tank Examination	Deleted	APP-GW-GLR-021	N/A	N/A
3.8-3	Deleted As-Built Summary Report	Deleted	APP-GW-GLR-021	N/A	N/A
3.8-4	Deleted In-Service Inspection of Containment Vessel	Deleted	APP-GW-GLR-021	N/A	N/A
3.8-5	Structures Inspection Program	3.8.6.5	N/A	Yes	–
3.8-6	Construction Procedures Program	3.8.6.6	N/A	No	Yes
3.9-1	Reactor Internal Vibration Response	3.9.8.1	WCAP-16687-P	No	No
3.9-2	Design Specification and Reports	3.9.8.2	APP-GW-GLR-021	No	Yes
3.9-3	Snubber Operability Testing	3.9.8.3	N/A	Yes	–
3.9-4	Valve Inservice Testing	3.9.8.4	APP-GW-GLN-020	Yes	–
3.9-5	Surge Line Thermal Monitoring	3.9.8.5	N/A	Yes	–
3.9-6	Piping Benchmark Program	3.9.8.6	APP-GW-GLR-006	No	No
3.9-7	As-Designed Piping Analysis	3.9.8.7	Various	Yes	Yes
3.10-1	Deleted Experience-Based Qualification	Deleted		N/A	N/A
3.11-1	Equipment Qualification File	3.11.5	APP-GW-GLN-110	No	Yes
4.2-1	Changes to Reference Reactor Design	4.2.5	APP-GW-GLR-059	No	No
4.3-1	Changes to Reference Reactor Design	4.3.4	APP-GW-GLR-059 APP-GW-GLR-119	No	No

Table 1.8-2 (Sheet 5 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
4.4-1	Changes to Reference Reactor Design	4.4.7.1	APP-GW-GLR-059	No	No
4.4-2	Confirm Assumptions for Safety Analyses DNBR Limits	4.4.7.2	N/A	–	Yes
5.2-1	ASME Code and Addenda	5.2.6.1	N/A	Yes	–
5.2-2	Plant Specific Inspection Program	5.2.6.2	N/A	Yes	–
5.2-3	Response to Unidentified Reactor Coolant System Leakage Inside Containment	5.2.6.3	N/A	Yes	–
5.3-1	Reactor Vessel Pressure – Temperature Limit Curves	5.3.6.1	APP-GW-GLR-021	No	Yes
5.3-2	Reactor Vessel Materials Surveillance Program	5.3.6.2	N/A	Yes	–
5.3-3	Surveillance Capsule Lead Factor and Azimuthal Location Confirmation	5.3.6.3	APP-GW-GLR-023	No	No
5.3-4	Reactor Vessel Materials Properties Verification	5.3.6.4.1	N/A	No	Yes
5.3-5	Reactor Vessel Insulation	5.3.6.5	APP-GW-GLR-060	No	No
5.3-6	Analysis of Reactor Vessel Insulation and Support Structure	5.3.6.4.2	APP-GW-GLR-060	No	No
5.4-1	Steam Generator Tube Integrity	5.4.15	N/A	Yes	–
5.3-7	Quickloc Weld Buildup ISI	5.3.6.6	N/A	Yes	–
6.1-1	Procedure Review for Austenitic Stainless Steels	6.1.3.1	N/A	Yes	–

Table 1.8-2 (Sheet 6 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
6.1-2	Coating Program	6.1.3.2	N/A	Yes	–
6.2-1	Containment Leak Rate Testing	6.2.6	N/A	Yes	–
6.3-1	Containment Cleanliness Program	6.3.8.1	N/A	Yes	–
6.3-2	Verification of Containment Resident Particulate Debris Characteristics	6.3.8.2	APP-GW-GLR-079	No	No
6.4-1	Local Hazardous Gas Services and Monitoring	6.4.7	N/A	Yes	–
6.4-2	Procedures for Training for Control Room Habitability	6.4.7	N/A	Yes	–
6.4-3	Main Control Room Inleakage Test Frequency	6.4.7	APP-GW-GLR-007	No	No
6.6-1	Inspection Programs	6.6.9.1	N/A	Yes	–
6.6-2	Construction Activities	6.6.9.2	N/A	Yes	–
7.1-1	Setpoint Calculations for Protective Functions	7.1.6.1	WCAP-16361-P	Yes	Yes
7.1-2	Resolution of Generic Open Items and Plant-Specific Action Items	7.1.6.2	APP-GW-GLR-017	No	No
7.2-1	FMEA for Protection System	7.2.3	WCAP-16438-P WCAP-16592-P	No	No
7.5-1	Post-Accident Monitoring	7.5.5	N/A	Yes	No
8.2-1	Offsite Electrical Power	8.2.5	N/A	Yes	–
8.2-2	Technical Interfaces	8.2.5	N/A	Yes	–

Table 1.8-2 (Sheet 7 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
8.3-1	Grounding and Lightning Protection	8.3.3	N/A	Yes	–
8.3-2	Onsite Electrical Power Plant Procedures	8.3.3	N/A	Yes	–
9.1-1	New Fuel Rack	9.1.6.1	APP-GW-GLR-026	No	No
9.1-2	Criticality Analysis for New Fuel Rack	9.1.6.2	APP-GW-GLR-030	No	No
9.1-3	Spent Fuel Racks	9.1.6.3	APP-GW-GLR-033	No	No
9.1-4	Criticality Analysis for Spent Fuel Racks	9.1.6.4	APP-GW-GLR-029P	No	No
9.1-5	Inservice Inspection Program of Cranes	9.1.6.5	N/A	Yes	–
9.1-6	Radiation Monitor	9.1.6.6	N/A	Yes	–
9.1-7	Metamic Monitoring Program	9.1.6.7	N/A	No	Yes
9.2-1	Potable Water	9.2.11.1	N/A	Yes	–
9.2-2	Waste Water Retention Basins	9.2.11.2	N/A	Yes	–
9.3-1	Air Systems (NUREG-0933 Issue 43)	9.3.7	N/A	Yes	–
9.4-1	Ventilation Systems Operations	9.4.12	N/A	Yes	–
9.5-1	Qualification Requirements for Fire Protection Program	9.5.1.8.1	N/A	Yes	–
9.5-2	Fire Protection Analysis Information	9.5.1.8.2	N/A	Yes	–
9.5-3	Regulatory Conformance	9.5.1.8.3	N/A	Yes	–

Table 1.8-2 (Sheet 8 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
9.5-4	NFPA Exceptions	9.5.1.8.4	N/A	Yes	–
9.5-5	Operator Actions Minimizing Spurious ADS Actuation	9.5.1.8.5	APP-GW-GLR-027	No	No
9.5-6	Verification of Field Installed Fire Barriers	9.5.1.8.6	N/A	No	Yes
9.5-7	Fire Resistance Test Data	9.5.1.8.8	APP-GW-GLR-019	No	No
9.5-8	Establishment of Procedures to Minimize Risk for Fire Areas Breached During Maintenance	9.5.1.8.7	N/A	Yes	–
9.5-9	Offsite Interfaces	9.5.2.5.1	N/A	Yes	–
9.5-10	Emergency Offsite Communications	9.5.2.5.2	N/A	Yes	–
9.5-11	Security Communications	9.5.2.5.3	N/A	Yes	–
9.5-12	Cathodic Protection	9.5.4.7.1	APP-GW-GLR-120	No	No
9.5-13	Fuel Degradation Protection	9.5.4.7.2	APP-GW-GLR-120	Yes	–
10.1-1	Erosion-Corrosion Monitoring	10.1.3	N/A	No	Yes
10.2-1	Turbine Maintenance and Inspection	10.2.6	APP-GW-GLN-018	No	Yes
10.4-1	Circulating Water Supply	10.4.12.1	N/A	Yes	–
10.4-2	Condensate, Feedwater and Auxiliary Steam System Chemistry Control	10.4.12.2	N/A	Yes	–
10.4-3	Potable Water	10.4.12.3	N/A	Yes	–

Table 1.8-2 (Sheet 9 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
11.2-1	Liquid Radwaste Processing by Mobile Equipment	11.2.5.1	N/A	Yes	–
11.2-2	Cost Benefit Analysis of Population Doses	11.2.5.2	N/A	Yes	–
11.2-3	Identification of Ion Exchange and Adsorbent Media	11.2.5.3	APP-GW-GLR-008	No	No
11.2-4	Dilution and Control of Boric Acid Discharge	11.2.5.4	APP-GW-GLR-014	No	No
11.3-1	Cost Benefit Analysis of Population Doses	11.3.5.1	N/A	Yes	–
11.3-2	Identification of Adsorbent Media	11.3.5.2	APP-GW-GLR-008	No	No
11.4-1	Solid Waste Management System Process Control Program	11.4.6	N/A	Yes	–
11.5-1	Plant Offsite Dose Calculation Manual (ODCM)	11.5.8	N/A	Yes	–
11.5-2	Effluent Monitoring and Sampling	11.5.8	N/A	Yes	–
11.5-3	10 CFR 50, Appendix I	11.5.8	N/A	Yes	–
12.1-1	ALARA and Operational Policies	12.1.3	N/A	Yes	–
12.2-1	Additional Contained Radiation Sources	12.2.3	N/A	Yes	–
12.3-1	Administrative Controls for Radiological Protection	12.3.5.1	N/A	Yes	–
12.3-2	Criteria and Methods for Radiological Protection	12.3.5.2	N/A	Yes	–
12.3-3	Groundwater Monitoring Program	12.3.5.3	N/A	Yes	–

Table 1.8-2 (Sheet 10 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
12.3-4	Record of Operational Events of Interest for Decommissioning	12.3.5.4	N/A	Yes	–
12.5-1	Radiological Protection Organization and Procedures	12.5.5	N/A	Yes	–
13.1-1	Organizational Structure of Combined License Applicant	13.1.1	N/A	Yes	–
13.2-1	Training Program for Plant Personnel	13.2.1	N/A	Yes	–
13.3-1	Emergency Planning and Communications	13.3.1	N/A	Yes	–
13.3-2	Activation of Emergency Operations Facility	13.3.1	N/A	Yes	–
13.4-1	Operational Review	13.4.1	N/A	Yes	–
13.5-1	Plant Procedures	13.5.1	APP-GW-GLR-040	Yes	–
13.6-1	Security	13.6	APP-GW-GLR-062 APP-GW-GLR-066 APP-GW-GLR-068	Yes	–
13.6-2	Deleted Vital Equipment Verification	Deleted	APP-GW-GLR-062 APP-GW-GLR-066 APP-GW-GLR-068	N/A	N/A
13.6-3	Deleted Site-Specific Security System	Deleted	APP-GW-GLR-062 APP-GW-GLR-066 APP-GW-GLR-068	N/A	N/A

Table 1.8-2 (Sheet 11 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
13.6-4	Deleted Nuclear Material Control Requirements	Deleted	APP-GW-GLR-062 APP-GW-GLR-066 APP-GW-GLR-068	N/A	N/A
13.6-5	Cyber Security Program	13.6	APP-GW-GLR-104	No	Yes
14.4-1	Organization and Staffing	14.4.1	N/A	Yes	–
14.4-2	Test Specifics and Procedures	14.4.2	APP-GW-GLR-037	No	Yes
14.4-3	Conduct of Test Program	14.4.3	APP-GW-GLR-038	No	Yes
14.4-4	Review and Evaluation of Test Results	14.4.4	N/A	No	Yes
14.4-5	Testing Interface Requirements	14.4.5	N/A	Yes	–
14.4-6	First-Plant-Only and Three-Plant-Only Tests	14.4.6	APP-GW-GLR-021	Yes	Yes
15.0-1	Documentation of Plant Calorimetric Uncertainty Methodology	15.0.15.1	NA	–	Yes
15.7-1	Consequences of Tank Failure	15.7.6	N/A	Yes	–
16.1-1	Technical Specification Preliminary Information	16.1	APP-GW-GLR-064 APP-GW-GLN-075	Yes	–
16.3-1	Procedure to Control Operability of Investment Protection Systems, Structures and Components	16.3.2	N/A	Yes	–
17.5-1	Quality Assurance Design Phase	17.5.1	N/A	Yes	–

Table 1.8-2 (Sheet 12 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
17.5-2	Quality Assurance for Procurement, Fabrication, Installation, Construction and Testing	17.5.2	N/A	Yes	–
17.5-3	Design Reliability Assurance Program/Site Specific List of Systems, Structures and Components	17.5.3	APP-GW-GLR-117	No	No
17.5-4	Quality Assurance Program for Operations	17.5.4	N/A	Yes	–
17.5-5	Maintaining Reliability of Risk-Significant SSCs	17.5.5	APP-GW-GLR-117	No	No
17.5-6	Maintenance Activities Relevant to Maintenance Rule	17.5.6	APP-GW-GLR-117	No	No
17.5-7	Operational Reliability Assurance Activities	17.5.7	APP-GW-GLR-117	No	No
17.5-8	Operational Reliability Assurance Program Integration with Quality Assurance Program	17.5.8	N/A	Yes	–
18.2-1	Execution of the NRC Approved Human Factors Engineering Program	18.2.6.1	APP-GW-GLR-012	No	No
18.2-2	Design of the Emergency Operations Facility	18.2.6.2	APP-GW-GLR-136	Yes	No
18.5-1	Task Analysis	18.5.4.1	APP-GW-GLR-081 APP-GW-GLR-090	No	No
18.5-2	Main Control Room	18.5.4.2	APP-GW-GLR-090	No	No
18.6-1	Plant Staffing	18.6.1	APP-GW-GLR-090	Yes	–

Table 1.8-2 (Sheet 13 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
18.7-1	Execution and Documentation of the Human Reliability Analysis/Human Factors Engineering Integration	18.7.1	APP-GW-GLR-011 APP-GW-GLR-090	No	No
18.8-1	Execution and Documentation of the Human System Interface Design Implementation Plan	18.8.5	APP-GW-GLR-082 APP-GW-GLR-090	No	No
18.9-1	Procedure Development	18.9.1	APP-GW-GLR-040 APP-GW-GLR-090	No	No
18.10-1	Training Program Development	18.10.1	APP-GW-GLR-090	Yes	–
18.11-1	Verification and Validation of AP1000 Human Factors Engineering Program	18.11.1	APP-GW-GLR-084 APP-GW-GLR-090	No	No
18.14-1	Human Performance Monitoring	18.14	APP-GW-GLR-090	Yes	–
19.59.10-1	As-Built SSC HCLPF Comparison to Seismic Margin Evaluation	19.11	APP-GW-GLR-021	No	Yes
19.59.10-2	Evaluation of As-Built Plant Versus Design in AP1000 PRA and Site-Specific PRA External Events	19.11	APP-GW-GLR-101	Yes	Yes
19.59.10-3	Internal Fire and Internal Flood Analyses	19.11	APP-GW-GLR-021	No	Yes
19.59.10-4	Develop and Implement Severe Accident Management Guidance	19.11	APP-GW-GLR-070	Yes	–
19.59.10-5	Equipment Survivability	19.11	APP-GW-GLR-021	No	Yes

Table 1.8-2 (Sheet 14 of 14)
Summary of AP1000 Standard Plant
Combined License Information Items

Item No.	Subject	Subsection	Addressed by Westinghouse Document	Action Required by COL Applicant	Action Required by COL Holder
19.59.10-6	Confirm that the Seismic Margin Assessment analysis is applicable to the COL site.	19.11	n/a	Yes	No
	Bulletins and Generic Letters (WCAP-15800, Revision 3, July 2004)	1.9.5.5	n/a	Yes	No
	Unresolved Safety Issues and Generic Safety Issues	Table 1.9-2	APP-GW-GLN-129	Yes	No

Table 1.8-201 (Sheet 1 of 2)
Summary of FSAR Departures from the DCD—{HISTORICAL}

Historical

Departure Number	Departure Description Summary	FSAR Section or Subsection
VEGP DEP 1.1-1	An administrative departure is established to identify instances where the renumbering of FSAR sections is necessary to effectively include content consistent with Regulatory Guide 1.206, as well as NUREG-0800.	2.1.1 2.1.4 2.2.1 2.2.4 2.4.1 2.4.15 2.5 2.5.7 9.2.11 9.2.12 9.2.13 9.5.1.8 9.5.1.9 13.1 13.1.4 13.3.6 13.5 13.5.3 13.7 17.5 17.6 17.7 17.8
VEGP DEP 2.5-1	The lower and upper mudmat thickness is as presented in the ESPA SSAR.	2.5.4.1.3
VEGP DEP 3.4-1	An alternate waterproofing system for the seismic Category I structures below grade is as presented in the ESPA SSAR.	3.4.1.1.1.1
STD DEP 8.3-1	The Class 1E voltage regulating transformers do not have active components to limit current.	8.3.2.2
VEGP DEP 9.2-1	The water source to the Potable Water System does not require filtration.	9.2.5.3

Historical

Table 1.8-201 (Sheet 2 of 2)
Summary of FSAR Departures from the DCD—{HISTORICAL}

Historical

Departure Number	Departure Description Summary	FSAR Section or Subsection
VEGP DEP 18.8-1	At VEGP, the Technical Support Center (TSC) is not located in the control support area (CSA) as identified in DCD Subsection 18.8.3.5; the TSC location is as described in the Emergency Plan. Additionally, the Operations Support Center (OSC) is also being moved from the location identified in DCD Subsections 18.8.3.6 and 12.5.2.2 and as identified on DCD figures in Sections 1.2 and 12.3, and Appendix 9A; the OSC location is as described in the Emergency Plan.	1.2.3 9A 12.3 12.5.2.2 13.3.8 18.8.3.5 18.8.3.6

Historical

Table 1.8-202 (Sheet 1 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
1.1-1	Construction and Startup Schedule	1.1.7	1.1.5 1.1.7	A
1.9-1	Regulatory Guide Conformance	1.9.1.5	1.9.1 1.9.1.1 1.9.1.2 1.9.1.3 1.9.1.4 1.9.1.5 Appendix 1A Appendix 1AA	A
1.9-2[(a)]	Bulletins and Generic Letters	1.9.5.5	1.9.5.5	A
1.9-3[(a)]	Unresolved Safety Issues and Generic Safety Issues	Table 1.9-2 1.9.4.1	1.9.4.1 1.9.4.2.3	A
2.1-1	Geography and Demography	2.1.1	1.1.1 1.2.2 2.1.4	A
2.2-1	Identification of Site-specific Potential Hazards	2.2.1	2.2.3.2.3.1 2.2.3.2.3.2 2.2.3.3 2.2.3.4 2.2.4	A
2.3-1	Regional Climatology	2.3.6.1	2.3.6.1	A

Table 1.8-202 (Sheet 2 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
2.3-2	Local Meteorology	2.3.6.2	2.3.6.2	A
2.3-3	Onsite Meteorological Measurements Program	2.3.6.3	2.3.3.4 2.3.6.3	A
2.3-4	Short-Term Diffusion Estimates	2.3.6.4	2.3.4 2.3.6.4 15.6.5.3.7.3 15A.3.3	A
2.3-5	Long-Term Diffusion Estimates	2.3.6.5	2.3.5 2.3.6.5	A
2.4-1	Hydrological Description	2.4.1.1	2.4.15.1	A
2.4-2	Floods	2.4.1.2	2.4.2 2.4.10 2.4.15.2	A
2.4-3	Cooling Water Supply	2.4.1.3	2.4.15.3	A
2.4-4	Groundwater	2.4.1.4	2.4.15.4	A
2.4-5	Accidental Release of Liquid Effluents into Ground and Surface Water	2.4.1.5	2.4.15.5	A
2.4-6	Flood Protection Emergency Operation Procedures	2.4.1.6	2.4.14 2.4.15.6	A

Table 1.8-202 (Sheet 3 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
2.5-1	Basic Geologic and Seismic Information	2.5.1	2.5.7.1	A
2.5-2	Site Seismic and Tectonic Characteristics Information	2.5.2.1	2.5.7.2	A
2.5-3	Geoscience Parameters	2.5.2.3	2.5.7.3	A
2.5-4	Surface Faulting	2.5.3	2.5.7.4	A
2.5-5	Site and Structures	2.5.4.6.1	2.5.7.5	A
2.5-6	Properties of Underlying Materials	2.5.4.6.2	2.5.7.6	A
2.5-7	Excavation and Backfill	2.5.4.6.3	2.5.7.7	A
2.5-8	Ground Water Conditions	2.5.4.6.4	2.5.7.8	A
2.5-9	Liquefaction Potential	2.5.4.6.5	2.5.7.9	A
2.5-10	Bearing Capacity	2.5.4.6.6	2.5.7.10	A
2.5-11	Earth Pressures	2.5.4.6.7	2.5.7.11	A
2.5-12	Static and Dynamic Stability of Facilities	2.5.4.6.9	2.5.7.13	A
2.5-13	Subsurface Instrumentation	2.5.4.6.10	2.5.7.14	A
2.5-14	Stability of Slopes	2.5.5	2.5.7.15	A
2.5-15	Embankments and Dams	2.5.6	2.5.7.16	A

Table 1.8-202 (Sheet 4 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
2.5-16	Settlement of Nuclear Island	2.5.4.6.11	2.5.7.17	A
2.5-17	Waterproofing System	2.5.4.6.12	2.5.7.18 3.4.1.1.1.1 3.8.5.1	A
3.3-1	Wind and Tornado Site Interface Criteria	3.3.3	1.2.2 3.3.1.1 3.3.2.1 3.3.2.3 3.3.3 3.5.1.5 3.5.1.6	A
3.4-1	Site-Specific Flooding Hazards Protective Measures	3.4.3	3.4.1.3 3.4.3	A
3.5-1	External Missile Protection Requirements	3.5.4	1.2.2 3.3.1.1 3.3.2.1 3.3.2.3 3.5.1.5 3.5.1.6 3.5.4	A
3.6-1	Pipe Break Hazards Analysis	3.6.4.1	3.6.4.1 14.3.3.2	H

Table 1.8-202 (Sheet 5 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
3.6-4	Primary System Inspection Program for Leak-Before-Break Piping	3.6.4.4	3.6.4.4	A
3.7-1	Seismic Analysis of Dams	3.7.5.1	3.7.2.12 3.7.5.1	A
3.7-2	Post-Earthquake Procedures	3.7.5.2	3.7.4.4 3.7.5.2	A
3.7-3	Seismic Interaction Review	3.7.5.3	3.7.5.3	H
3.7-4	Reconciliation of Seismic Analyses of Nuclear Island Structures	3.7.5.4	3.7.5.4	H
3.7-5	Location of Free-Field Acceleration Sensor	3.7.5.5	3.7.4.2.1 3.7.5.5	A
3.8-5	Structures Inspection Program	3.8.6.5	3.8.3.7 3.8.4.7 3.8.5.7 3.8.6.5 17.6	A
3.8-6	Construction Procedures Program	3.8.6.6	3.8.6.6	H
3.9-2	Design Specification and Reports	3.9.8.2	3.9.8.2	H
3.9-3	Snubber Operability Testing	3.9.8.3	3.9.3.4.4 3.9.8.3	A

Table 1.8-202 (Sheet 6 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
3.9-4	Valve Inservice Testing	3.9.8.4	3.9.6	A
3.9-5	Surge Line Thermal Monitoring	3.9.8.5	3.9.3.1.2 3.9.8.5 14.2.9.2.22	A
3.9-7	As-Designed Piping Analysis	3.9.8.7	3.9.8.7 14.3.3.3	H
3.11-1	Equipment Qualification File	3.11.5	3.11.5	H
4.4-2	Confirm Assumptions for Safety Analyses DNBR Limits	4.4.7.2	4.4.7	H
5.2-1	ASME Code and Addenda	5.2.6.1	5.2.1.1 5.2.6.1	A

Table 1.8-202 (Sheet 7 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
5.2-2	Plant Specific Inspection Program	5.2.6.2	5.2.4 5.2.4.1 5.2.4.3.1 5.2.4.3.2 5.2.4.4 5.2.4.5 5.2.4.6 5.2.4.8 5.2.4.9 5.2.4.10 5.2.6.2	A
5.2-3	Response to Unidentified Reactor Coolant System Leakage Inside Containment	5.2.6.3	5.2.6.3 5.2.5.3.5	A
5.3-1	Reactor Vessel Pressure – Temperature Limit Curves	5.3.6.1	5.3.6.1	H
5.3-2	Reactor Vessel Materials Surveillance Program	5.3.6.2	5.3.2.6 5.3.2.6.3 5.3.6.2	A
5.3-4	Reactor Vessel Materials Properties Verification	5.3.6.4.1	5.3.6.4.1	H
5.3-7	Quickloc Weld Build-up ISI	5.3.6.6	5.2.4.1 5.3.6.6	A
5.4-1	Steam Generator Tube Integrity	5.4.15	5.4.2.5 5.4.15	A

Table 1.8-202 (Sheet 8 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
6.1-1	Procedure Review for Austenitic Stainless Steels	6.1.3.1	6.1.1.2 6.1.3.1	A
6.1-2	Coating Program	6.1.3.2	6.1.2.1.6 6.1.3.2	A
6.2-1	Containment Leak Rate Testing	6.2.6	6.2.5.1 6.2.5.2.2 6.2.6	A
6.3-1	Containment Cleanliness Program	6.3.8.1	6.3.8.1	A
6.4-1	Local Hazardous Gas Services and Monitoring	6.4.7	2.2.3.2.3.1 2.2.3.2.3.2 2.2.3.3 6.4.4.2 6.4.7	A
6.4-2	Procedures for Training for Control Room Habitability	6.4.7	6.4.3 6.4.7	A
6.6-1	Inspection Programs	6.6.9.1	6.6 6.6.1 6.6.3.1 6.6.3.2 6.6.3.3 6.6.4 6.6.6 6.6.9.1	A

Table 1.8-202 (Sheet 9 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
6.6-2	Construction Activities	6.6.9.2	6.6.2 6.6.9.2	A
7.1-1	Setpoint Calculations for Protective Functions	7.1.6.1	7.1.6.1	B
7.5-1	Post Accident Monitoring	7.5.5	7.5.2 7.5.3.5 7.5.5	A
8.2-1	Offsite Electrical Power	8.2.5	8.2.1 8.2.1.1 8.2.1.2 8.2.1.3 8.2.1.4 8.2.5	A
8.2-2	Technical Interfaces	8.2.5	8.2.1.2.1 8.2.2 8.2.5	A
8.3-1	Grounding and Lightning Protection	8.3.3	8.3.1.1.7 8.3.1.1.8 8.3.3	A
8.3-2	Onsite Electrical Power Plant Procedures	8.3.3	8.3.1.1.2.4 8.3.1.1.6 8.3.2.1.4 8.3.3	A

Table 1.8-202 (Sheet 10 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
9.1-5	Inservice Inspection Program of Cranes	9.1.6.5	9.1.4.4 9.1.5.4 9.1.6	A
9.1-6	Radiation Monitor	9.1.6.6	9.1.4.3.8 9.1.5.3 9.1.6	A
9.1-7	Metamic Monitoring Program	9.1.6.7	9.1.6	H
9.2-1	Potable Water	9.2.11.1	9.2.5.2.1 9.2.5.2.2 9.2.5.3 9.2.5.6 9.2.12.1	A
9.2-2	Waste Water Retention Basins	9.2.11.2	9.2.9.2.1 9.2.9.2.2 9.2.9.5 9.2.12.2	A
9.3-1	Air Systems (NUREG-0933 Issue 43)	9.3.7	9.3.7	A
9.4-1	Ventilation Systems Operations	9.4.12	6.4.4.2 9.4.1.4 9.4.7.4 9.4.12	A
9.5-1	Qualification Requirements for Fire Protection Program	9.5.1.8.1	9.5.1.6 9.5.1.8 9.5.1.8.1.2 9.5.1.8.2 9.5.1.8.3 9.5.1.8.4 9.5.1.8.5 9.5.1.8.6 9.5.1.8.7 9.5.1.9.1 13.1.1.2.10	A
9.5-2	Fire Protection Analysis Information	9.5.1.8.2	9.5.1.9.2 9A.3.3	A

Table 1.8-202 (Sheet 11 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
9.5-3	Regulatory Conformance	9.5.1.8.3	9.5.1.8.1.1 9.5.1.8.8 9.5.1.8.9 9.5.1.9.3 9A.3.3	A
9.5-4	NFPA Exceptions	9.5.1.8.4	9.5.1.8.1.1 9.5.1.9.4	A
9.5-6	Verification of Field Installed Fire Barriers	9.5.1.8.6	9.5.1.8.6 9.5.1.9.6	H

Table 1.8-202 (Sheet 12 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
9.5-8	Establishment of Procedures to Minimize Risk for Fire Areas Breached During Maintenance	9.5.1.8.7	9.5.1.8.1.2 9.5.1.9.7	A
9.5-9	Offsite Interfaces	9.5.2.5.1	9.5.2.5.1	A
9.5-10	Emergency Offsite Communications	9.5.2.5.2	9.5.2.5.2	A
9.5-11	Security Communications	9.5.2.5.3	9.5.2.5.3	A
9.5-13	Fuel Degradation Protection	9.5.4.7.2	9.5.4.5.2 9.5.4.7.2	A
10.1-1	Erosion-Corrosion Monitoring	10.1.3	10.1.3.1 10.1.3.2 10.1.3.3	H
10.2-1	Turbine Maintenance and Inspection	10.2.6	10.2.6	H
10.4-1	Circulating Water Supply	10.4.12.1	10.4.5.2.1 10.4.5.2.2 10.4.5.5 10.4.12.1	A
10.4-2	Condensate, Feedwater and Auxiliary Steam System Chemistry Control	10.4.12.2	10.4.7.2.1 10.4.12.2	A
10.4-3	Potable Water	10.4.12.3	9.2.5.3 10.4.12.3	A

Table 1.8-202 (Sheet 13 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
11.2-1	Liquid Radwaste Processing by Mobile Equipment	11.2.5.1	11.2.1.2.5.2 11.2.5.1	A
11.2-2	Cost Benefit Analysis of Population Doses	11.2.5.2	11.2.3.3 11.2.3.5 11.2.5.2	A
11.3-1	Cost Benefit Analysis of Population Doses	11.3.5.1	11.3.3.4 11.3.5.1	A
11.4-1	Solid Waste Management System Process Control Program	11.4.6	11.4.6	A
11.5-1	Plant Offsite Dose Calculation Manual (ODCM)	11.5.8	11.5.8	A
11.5-2	Effluent Monitoring and Sampling	11.5.8	11.5.1.2 11.5.2.4 11.5.3 11.5.4 11.5.4.1 11.5.4.2 11.5.6.5 11.5.8	A
11.5-3	10 CFR 50, Appendix I	11.5.8	11.2.3.5 11.3.3.4 11.5.8	A

Table 1.8-202 (Sheet 14 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
12.1-1	ALARA and Operational Policies	12.1.3	12.1 12.1.3 Appendix 12AA	A
12.2-1	Additional Contained Radiation Sources	12.2.3	12.2.1.1.10 12.2.3	A
12.3-1	Administrative Controls for Radiological Protection	12.3.5.1	12.3.5.1 Appendix 12AA	A
12.3-2	Criteria and Methods for Radiological Protection	12.3.5.2	12.3.4 12.3.5.2	A
12.3-3	Groundwater Monitoring Program	12.3.5.3	12.3.5.3 Appendix 12AA	A
12.3-4	Record of Operational Events of Interest for Decommissioning	12.3.5.4	12.3.5.4 Appendix 12AA	A
12.5-1	Radiological Protection Organization and Procedures	12.5.5	12.5.5 Appendix 12AA	A
13.1-1	Organizational Structure of Combined License Applicant	13.1.1	13.1.1 13.1.2 13.1.3 13.1.4 Appendix 13AA	A

Table 1.8-202 (Sheet 15 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
13.2-1	Training Program for Plant Personnel	13.2.1	13.2 13.2.1	A
13.3-1	Emergency Planning and Communications	13.3.1	13.3 13.3.1	A
13.3-2	Activation of Emergency Operations Facility	13.3.1	13.3 13.3.6	A
13.4-1	Operational Review	13.4.1	13.4 13.4.1	A
13.5-1	Plant Procedures	13.5.1	13.5 13.5.3	A
13.6-1	Security	13.6	13.6 13.6.1 14.3.2.3.2	A
13.6-5	Cyber Security Program	13.6.1	13.6 13.6.1	H
14.4-1	Organization and Staffing	14.4.1	14.2.2 14.4.1	A
14.4-2	Test Specifics and Procedures	14.4.2	14.4.2	H
14.4-3	Conduct of Test Program	14.4.3	14.4.3	H

Table 1.8-202 (Sheet 16 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
14.4-4	Review and Evaluation of Test Results	14.4.4	14.2.3.2 14.4.4	H
14.4-5	Testing Interface Requirements	14.4.5	14.2.9.4.15 14.2.9.4.22 14.2.9.4.23 14.2.9.4.24 14.2.9.4.25 14.2.9.4.26 14.2.9.4.27 14.2.10.4.30 14.4.5	A
14.4-6	First-Plant-Only and Three-Plant-Only Tests	14.4.6	14.4.6	B
15.0-1	Documentation of Plant Calorimetric Uncertainty Methodology	15.0.15.1	15.0.15 15.0.3.2	H
15.7-1	Consequences of Tank Failure	15.7.6	15.7.6	A
16.1-1	Technical Specification Preliminary Information	16.1	16.1.1	A
16.3-1	Procedure to Control Operability of Investment Protection Systems, Structures and Components	16.3.2	16.3.1 16.3.2	A
17.5-1	Quality Assurance Design Phase	17.5.1	17.1 17.5 17.7	A

Table 1.8-202 (Sheet 17 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
17.5-2	Quality Assurance for Procurement, Fabrication, Installation, Construction and Testing	17.5.2	17.5 17.7	A
17.5-4	Quality Assurance Program for Operations	17.5.4	17.5 17.7	A
17.5-8	Operational Reliability Assurance Program Integration with Quality Assurance Program	17.5.8	17.5 17.7	A
18.2-2	Design of the Emergency Operations Facility	18.2.6.2	9.5.2.2.5 18.2.1.3 18.2.6.2	A
18.6-1	Plant Staffing	18.6.1	13.1.1.4 13.1.3.1 13.1.3.2 18.6 18.6.1	A
18.10-1	Training Program Development	18.10.1	13.1.1.3.1.3.2.2 13.2 18.10 18.10.1	A
18.14-1	Human Performance Monitoring	18.14	18.14	A
19.59.10-1	As-Built SSC HCLPF Comparison to Seismic Margin Evaluation	19.59.10.5	19.11	H

Table 1.8-202 (Sheet 18 of 18)
COL Item Tabulation

COL ITEM	SUBJECT	DCD SUBSECTION	FSAR SECTION(S)	COL APPLICANT (A), HOLDER (H) OR BOTH (B)
19.59.10-2	Evaluation of As-Built Plant Versus Design in AP1000 PRA and Site-Specific PRA External Events	19.59.10.5	19.11	B
19.59.10-3	Internal Fire and Internal Flood Analyses	19.59.10.5	19.11	H
19.59.10-4	Implement Severe Accident Management Guidance	19.59.10.5	19.11	H
19.59.10-5	Equipment Survivability	19.59.10.5	19.11	H
19.59.10-6	Confirm that the Seismic Margin Assessment analysis is applicable to the COL site	19.59.10.5	19.20.6.3 19.11	A

a) COL Items 1.9-2 and 1.9-3 are un-numbered in the DCD.

1.9 Compliance with Regulatory Criteria

1.9.1 Regulatory Guides

Regulatory guides are issued by the NRC in the following 10 broad divisions:

- Division 1 - Power Reactors
- Division 2 - Research and Test Reactors
- Division 3 - Fuels and Materials Facilities
- Division 4 - Environmental and Siting
- Division 5 - Materials and Plant Protection
- Division 6 - Products
- Division 7 - Transportation
- Division 8 - Occupational Health
- Division 9 - Antitrust and Financial Review
- Division 10 - General

Divisions 2, 3, 6, 7, 9, and 10 of the regulatory guides do not apply to the design and design certification phase of AP1000. The following sections provide a summary discussion of NRC Divisions 1, 4, 5, and 8 of the regulatory guides applicable to the design and design certification phase of AP1000.

Appendix 1A provides a discussion of AP1000 regulatory guide conformance.

Divisions 2, 3, 6, 7, 9, and 10 of the regulatory guides do not apply to the construction or operational safety considerations and are not addressed.

Division 4 of the regulatory guides applies to the Environmental Report and the topics are addressed in the Environmental Report. Three Division 4 Regulatory Guides are addressed in Appendix 1A.

Division 5 of the regulatory guides applies to materials and plant protection. As appropriate, the Division 5 regulatory guide topics are addressed in the DCD and plant-specific security plans (i.e., Physical Security Plan, Training and Qualification Plan, Safeguards Contingency Plan, and Cyber Security Plan).

Applicable Division 8 Regulatory Guides are addressed in Appendix 1A.

Appendix 1A provides a discussion of plant specific regulatory guide conformance, addressing new Regulatory Guides and new revisions not addressed by the referenced DCD. Regulatory Guides that are completely addressed by the DCD are not listed.

The following subsections provide a summary discussion of Divisions 1, 4, 5 and 8 of the regulatory guides as applicable to the content of this document, or to the construction and/or operations phases.

1.9.1.1 Division 1 Regulatory Guides - Power Reactors

Currently there are approximately 190 Division 1 regulatory guides that have been issued by the NRC for implementation or for comment.

Appendix 1A provides an evaluation of the degree of AP1000 compliance with NRC Division 1 regulatory guides. The revisions of the regulatory guides against which AP1000 is evaluated are indicated. Any exceptions or alternatives to the provisions of the regulatory guides are identified and justification is provided. For those regulatory guides applicable to the AP1000 Table 1.9-1 identifies

the appropriate cross-references. The cross-referenced sections contain descriptive information applicable to the regulatory guide positions found in Appendix 1A.

The superseded or canceled regulatory guides are not considered in Appendix 1A or Table 1.9-1.

Appendix 1A provides an evaluation of the degree of compliance with Division 1 regulatory guides as applicable to the content of this document, or to the site-specific design, construction and/or operational aspects. The revisions of the regulatory guides against which the degree of compliance is evaluated are indicated. Any exceptions or alternatives to the provisions of the regulatory guides are identified and justification is provided. One such general alternative is the use of previous revisions of the Regulatory Guide for design aspects as stated in the DCD in order to preserve the finality of the certified design (see Notes at the end of Appendix 1A). Table 1.9-1 identifies the appropriate regulatory guide to cross-references. The cross-referenced sections contain descriptive information applicable to the regulatory guide positions found in Appendix 1A.

Superseded or canceled regulatory guides are not considered in Appendix 1A or Table 1.9-1.

1.9.1.2 Division 4 Regulatory Guides - Environmental and Siting

One Division 4 regulatory guide, Regulatory Guide 4.7, merits discussion.

Regulatory Guide 4.7, "General Site Suitability Criteria for Nuclear Power Stations," provides guidelines for identifying suitable candidate sites for nuclear power stations. The guidance of this regulatory guide is considered as appropriate in the establishment of the AP1000 site interface criteria, and is described in Sections 2.1 and 2.5.

Division 4 of the regulatory guides applies to the Environmental Report and the topics are addressed in the Environmental Report. Appendix 1A provides an evaluation of the degree of compliance with Division 4 regulatory guides as applicable to the content of this document, or to the site-specific design, construction and/or operational aspects. The revisions of the regulatory guides against which the plant is evaluated are indicated. Any exceptions or alternatives to the provisions of the regulatory guides are identified and justification is provided. One such general alternative is the use of previous revisions of the Regulatory Guide for design aspects as stated in the DCD in order to preserve the finality of the certified design (see Notes at the end of Appendix 1A). For those regulatory guides applicable, Table 1.9-1 identifies the appropriate cross-references. The cross-referenced sections contain descriptive information applicable to the regulatory guide positions found in Appendix 1A.

1.9.1.3 Division 5 Regulatory Guides - Materials and Plant Protection

Division 5 of the regulatory guides applies to materials and plant protection. Appendix 1A provides an evaluation of the degree of conformance with Division 5 regulatory guides as applicable to the content of the AP1000 DCD and the plant-specific Cyber Security Plan. Appendix 1A provides an evaluation of the degree of conformance with Division 5 Regulatory Guide 5.71 related to the Cyber Security Program. The plant-specific physical security plans (i.e., Physical Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan) were developed using the template in NEI 03-12, Revision 6, “Template for the Security Plan, Training and Qualification Plan, Safeguards Contingency Plan [and Independent Spent Fuel Storage Installation Security Program],” which was endorsed for use by NRC letter dated April 9, 2009. The plant-specific physical security plans include no substantive deviations from the NRC-endorsed template in NEI 03-12, Revision 6. Therefore, the degree of conformance with Division 5 regulatory guides for the plant-specific physical security plans is consistent with the degree of conformance of NEI 03-12, Revision 6.

Appendix 1A also provides an evaluation of the degree of conformance with the Division 5 Regulatory Guide 5.84 related to the construction fitness-for-duty (FFD) program. The VEGP 3 and 4

construction FFD program is described in Section 13.7. Section 13.7 states that the construction FFD program is consistent with NEI 06-06, Revision 6 (April 2013), as endorsed by Regulatory Guide 5.84, Revision 0, with exceptions.

Three Division 5 regulatory guides, Regulatory Guides 5.9, 5.12, and 5.65, merit discussion.

Regulatory Guide 5.9, "Guidelines for Germanium Spectroscopy Systems for Measurement of Special Nuclear Material," provides guidelines for data acquisition systems associated with the use of a lithium-drifted germanium gamma ray spectroscopy system. This regulatory guide is not applicable to AP1000 design certification.

Regulatory Guide 5.12, "General Use of Locks in the Protection and Control of Facilities and Special Nuclear Materials," provides guidelines for the selection and use of commercially available locks in the protection of facilities and special nuclear material. The guidance of this regulatory guide is considered as appropriate in the AP1000 design.

Regulatory Guide 5.65, "Vital Area Access Controls, Protection of Physical Security Equipment, and Key and Lock Controls," is not applicable to design certification.

1.9.1.4 Division 8 Regulatory Guides - Occupational Health

Two Division 8 regulatory guides, Regulatory Guides 8.8 and 8.19 merit discussion.

Regulatory Guide 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposure at Nuclear Power Stations will be As Low As is Reasonably Achievable (ALARA)," provides NRC guidance for meeting the requirements of 10 CFR Part 20. This regulatory guide includes guidance in the following areas for maintaining radiation exposures ALARA:

- Overall program (e.g., policy, organization, and training)
- Facility and equipment design features
- Radiation protection program
- Radiation protection facilities, instrumentation, and equipment

Regulatory Guide 8.8 is written primarily for utility applicants and licensees. However, Westinghouse has established policy, design, and operational considerations that will be applied in the AP1000 design in accordance with this regulatory guide. These considerations are discussed in Section 12.1.

Regulatory Guide 8.19, "Occupational Radiation Dose Assessment in Light-Water Reactor Power Plants" describes a method acceptable to the NRC staff for performing an assessment of collective occupational radiation dose as part of the ongoing design review process involved in designing a light-water-cooled power reactor so that occupational radiation exposures will be ALARA. This regulatory guide includes guidance for estimating occupational radiation exposures (principally during the design stage) as a result of:

- Reactor operations and surveillance
- Routine maintenance
- Waste processing
- Refueling
- Inservice inspection
- Special maintenance

Occupational radiation exposure estimates that are in accordance with Regulatory Guide 8.19 are described in Section 12.4.

Appendix 1A provides an evaluation of the degree of compliance with Division 8 regulatory guides as applicable to the content of this document, or to the site-specific design, construction and/or operational aspects. The revisions of the regulatory guides against which the plant is evaluated are indicated. Any exceptions or alternatives to the provisions of the regulatory guides are identified and justification is provided. One such general alternative is the use of previous revisions of the Regulatory Guide for design aspects as stated in the DCD in order to preserve the finality of the certified design (see Notes at the end of Appendix 1A). For those regulatory guides applicable,Table 1.9-1 identifies the appropriate cross-references. The cross-referenced sections contain descriptive information applicable to the regulatory guide positions found in Appendix 1A.

Superseded or canceled regulatory guides are not considered in Appendix 1A or Table 1.9-1.

1.9.1.5 Combined License Information

Division 1, 4, 5 and 8 Regulatory Guides applicable to the content of this document, or to the site-specific design, construction and/or operational aspects are listed in Table 1.9-1 and Appendix 1A.

1.9.2 Compliance with Standard Review Plan (NUREG-0800)

{HISTORICAL — WCAP-15799, "AP1000 Compliance with SRP Acceptance Criteria," provides the results of a review of the AP1000 compliance with the acceptance criteria for each section of the Standard Review Plan, NUREG-0800. — HISTORICAL}

WCAP-15799 (Reference 63) and Table 1.9-202 provided the required assessment of conformance of the combined license application with the applicable acceptance criteria and the associated cross-references. However, WCAP-15799 and Table 1.9-202 were provided solely to assist the NRC review of the application and are historical information and need not be updated.

1.9.3 Three Mile Island Issues

This section identifies the Three Mile Island issues of 10 CFR 50.34(f) that are addressed by AP1000 design features or program plans. The additional issues of NUREG-0660 and NUREG-0737 that apply to the AP1000 are resolved in accordance with the guidance of NUREG-0933, with specific details provided in the applicable sections of the DCD.

Some of the 10 CFR 50.34(f) issues initially identified as applicable only to Boiling Water Reactors (BWRs) or Babcock and Wilcox plants have also been addressed for the AP1000 design. For example, the AP1000 design incorporates an automatic depressurization system with some similarity to that utilized for BWRs.

10 CFR 50.34(f):

(1)(i) Plant/Site Specific TMI-Related Risk Assessment (NUREG-0660 Item II.B.8)

"Perform a plant/site specific probabilistic risk assessment, the aim of which is to seek such improvements in the reliability of core and containment heat removal systems as are significant and practical and do not impact excessively on the plant."

AP1000 Response:

A plant-specific Probabilistic Risk Assessment (PRA) performed on the AP1000 design evaluates the plant in terms of core damage frequency and containment integrity. The PRA supports the design effort and establishes the capability of the design to meet established safety goals. Level 1 (Plant) and Level 2 (Containment) PRA evaluations, and offsite dose evaluation, including internal and external events:

- Demonstrate that the plant design meets the NRC safety goals
- Identify design vulnerabilities, evaluate alternate design features and operational strategies, and modify the design to reduce risk

The PRA process has been integrated into the design process to verify that the design effort meets the targeted goals and resolves the identified vulnerabilities. As a result, specific design changes were incorporated into the plant systems to improve the reliability of the core and containment heat removal systems.

Close interaction between the plant designers and PRA analysts is maintained to consider severe accident vulnerabilities as part of the design process. The AP1000 PRA is provided to the NRC as a separate document.

(1)(ii) Auxiliary Feedwater System Evaluation (NUREG-0737 Item II.E.1)

"Perform an evaluation of the proposed auxiliary feedwater system, to include (applicable to pressurized water reactors only): (A) a simplified Auxiliary Feedwater System reliability analysis using event-tree and fault-tree logic techniques, (B) a design review of Auxiliary Feedwater System, and (C) an evaluation of Auxiliary Feedwater System flow design bases and criteria."

AP1000 Response:

The AP1000 design does not utilize an auxiliary feedwater system. A nonsafety-related startup feedwater system is provided to remove the core decay heat after the reactor trip during postulated non-LOCA event. Decay heat removal maintains core subcooling and prevents water relief from the pressurizer safety valves by preventing heatup of the reactor coolant system. The startup feedwater pumps automatically start following anticipated transients resulting in low steam generator level. However, operation of the nonsafety-related startup feedwater system is not credited to mitigate licensing design basis accidents described in Chapter 15.

The safety-related passive core cooling system provides emergency core decay heat removal during transients, accidents, or whenever the normal nonsafety-related heat removal paths are unavailable.

The safety-related passive core cooling system design basis and criteria are described in Section 6.3.

(1)(iii) Reactor Coolant Pump Seals (NUREG-0737 Items II.K.2.16 and II.K.3.25)

"Perform an evaluation of the potential for and impact of reactor coolant pump seal damage following small-break loss of coolant accident with loss of offsite power. If damage cannot be precluded, provide an analysis of the limiting small-break loss of coolant accident with subsequent reactor coolant pump seal damage."

AP1000 Response:

The AP1000 design uses sealless motor pumps for circulating primary reactor coolant through the reactor core, piping, and steam generators. In the sealless design, all rotating components are inside a pressure vessel; therefore, no seal can fail and initiate reactor coolant system leakage.

(1)(iv) Automatic Power-Operated Relief Valve Isolation System (NUREG-0737 Item II.K.3.2)

"Perform an analysis of the probability of a small-break loss of coolant accident caused by a stuck-open power-operated relief valve. If this probability is a significant contributor to the probability of small-break loss of coolant accidents from all causes, provide a description and evaluation of the

effect on small-break loss of coolant accident probability of an automatic power-operated relief valve isolation system that would operate when the reactor coolant system pressure falls after the power-operated relief valve has opened."

AP1000 Response:

The AP1000 design does not include power-operated relief valves. The pressurizer volume is about 40 percent larger than the pressurizer volume in current plants with a comparable power rating. The larger pressurizer increases transient operation margins and prevents safety valve actuation in most accident situations. The pressurizer surge line is also larger to permit a more rapid transfer of coolant between the reactor coolant system and the pressurizer, and also to accommodate the automatic depressurization system first- to third-stage flow rates. The surge line limits the pressure drop during maximum anticipated surge (Condition II loss of load transient) to prevent exceeding the maximum reactor coolant system pressure limit.

Overpressure protection is provided by two totally enclosed pop-type safety valves. These valves are spring-loaded and self-actuated and they are designed to meet the requirements of the ASME Code, Section III. If the pressurizer pressure exceeds the set pressure, the safety valves start lifting. A temperature indicator in the discharge piping for each safety valve alarms on high temperature to alert the operator to the presence of high temperature fluid from leakage or when the valves open.

The AP1000 design also includes an automatic depressurization system. The system consists of four stages of valves. Three stages are connected to the pressurizer. The fourth stage is connected to the hot legs. These valves are not actuated on a high pressure signal. Design features are included to reduce the chance of spurious automatic depressurization system actuation including appropriate interlocks, 2-out-of-4 instrument actuation, fail as is valves, redundant, closed first, second, and third stage valves in each line, and redundant series controllers for fourth stage valves. Probabilistic risk assessment is used to determine the probability of a loss of coolant accident caused by failure of the automatic depressurization system. Results of this evaluation are factored into the design process. See Chapter 5 and Section 6.3 for additional information.

(1)(v) Separation of HPCI and RCIC System Initiation Levels (NUREG-0737 Item II.K.3.13)

"Perform an evaluation of the safety effectiveness of providing for separation of high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) system initiation levels so that the RCIC system initiates at a higher water level than the HPCI system, and of providing that both systems restart on low water level. (For plants with high pressure core spray systems in lieu of high pressure coolant injection systems, substitute the words 'high pressure core spray' for 'high pressure coolant injection' and 'HPCS' for 'HPCI')."

AP1000 Response:

This issue is applicable to BWRs only and is not applicable to AP1000.

(1)(vi) Relief Valve Challenges (NUREG-0737 Item II.K.3.16)

"Perform a study to identify practicable system modifications that would reduce challenges and failures of relief valves, without compromising the performance of the valves or other systems."

AP1000 Response:

This issue is applicable to BWRs only and is not applicable to AP1000.

(1)(vii) Automatic Depressurization System Activation (NUREG-0737 Item II.K.3.18)

"Perform a feasibility and risk assessment study to determine the optimum automatic depressurization system design modifications that would eliminate the need for manual activation to ensure adequate core cooling."

AP1000 Response:

Although this issue is identified as applicable to BWRs only, the AP1000 design uses an automatic depressurization system with some similarity to that used on BWRs.

The automatic depressurization system actuates on Low-3 core makeup tank level, coincident with a core makeup tank actuation signal. Therefore manual actuation of the automatic depressurization system is not required to maintain core cooling. As discussed in Section (1)(i), PRA analysis confirms the reliability of the automatic actuation. Additional information is provided in Section 6.3.

(1)(viii) Core Spray and Low Pressure Coolant Injection Systems (NUREG-0737 Item II.K.3.21)

"Perform a study of the effect on all core-cooling modes under accident conditions of designing the core spray and low pressure coolant injection systems to ensure that the systems will automatically restart on loss of water level, after having been manually stopped, if an initiation signal is still present."

AP1000 Response:

This issue is applicable to BWRs only and is not applicable to AP1000.

(1)(ix) RCIC and HPCI Additional Space Cooling (NUREG-0737 Item II.K.3.24)

"Perform a study to determine the need for additional space cooling to ensure reliable long-term operation of the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems, following a complete loss of offsite power to the plant for at least two (2) hours. (For plants with high pressure core spray systems in lieu of high pressure coolant injection systems, substitute the words 'high pressure core spray' for 'high pressure coolant injection' and 'HPCS' for 'HPCI')."

AP1000 Response:

This issue is applicable to BWRs only and is not applicable to AP1000.

(1)(x) Automatic Depressurization System Functionality During Accidents (NUREG-0737 Item II.K.3.28)

"Perform a study to ensure that the Automatic Depressurization System, valves, accumulators, and associated equipment and instrumentation will be capable of performing their intended functions during and following an accident situation, taking no credit for non-safety related equipment or instrumentation, and accounting for normal expected air (or nitrogen) leakage through valves."

AP1000 Response:

Although this issue is identified as applicable to BWRs only, the AP1000 uses a safety-related automatic depressurization system that is different from that presently used on BWRs. The AP1000 automatic depressurization system uses safety-related dc motor-operated valves and squib valves to initiate depressurization. The motive power for these valves is safety-related dc power. There is no nonsafety-related equipment or instrumentation, including instrument air or nitrogen supply, relied on in the operation of these valves.

These valves are designed and qualified to function in the conditions of an accident. They will also be subject of pre-operational and in-service testing. They will be included in the reliability assurance program. Additional information is provided in Section 6.3 for the passive core cooling system, Subsection 3.9.3 for valve operability requirements, Chapter 14 for the initial test program, Subsection 3.9.6 for in-service testing, and Section 16.2 for the reliability assurance program.

(1)(xi) Depressurization Methods/Rapid Cooldown (NUREG-0737 Item II.K.3.45)

"Provide an evaluation of depressurization methods, other than by full actuation of the automatic depressurization system, that would reduce the possibility of exceeding vessel integrity limits during rapid cooldown."

AP1000 Response:

This issue is applicable to BWRs only.

(1)(xii) Hydrogen Control System Evaluation (NUREG-0660 Item II.B.8)

"Perform an evaluation of alternative hydrogen control systems that would satisfy the requirements of paragraph (f)(2)(ix) of this section (50.34). As a minimum include consideration of a hydrogen ignition and post-accident inerting system. The evaluation shall include: (A) a comparison of costs and benefits of the alternative systems considered, (B) for the selected system, analyses and test data to verify compliance with the requirements of (f)(2)(ix) of this section (50.34), and (C) for the selected system, preliminary design descriptions of equipment, function, and layout."

AP1000 Response:

Continuous indication of hydrogen concentration in the containment atmosphere is provided. The containment hydrogen control system maintains hydrogen concentrations below 10 percent following the reaction of 100 percent of the active zircaloy cladding.

Hydrogen igniters control rapid releases of hydrogen during and after postulated degraded core and core melt accidents to maintain concentration below 10 percent.

Sufficient vent area is provided for each subcompartment in the containment to prevent high local concentrations of hydrogen.

See Subsection 6.2.4 for additional information.

(2)(i) Simulator Capability (NUREG-0933 Item I.A.4.2)

"Provide simulator capability that correctly models the control room and includes the capability to simulate small-break loss of coolant accidents."

AP1000 Response:

Simulator capability is not included within the scope of the AP1000 design certification. Functional requirements for simulator capability are derived from Human Factors Engineering Program described in Chapter 18.

(2)(ii) Plant Procedures (NUREG-0933 Item I.C.9)

"Establish a program to begin during construction and follow into operation, for integrating and expanding current efforts to improve plant procedures. The scope of the program shall include emergency procedures, reliability analyses, human factors engineering, crisis management, operator training, and coordination with INPO and other industry efforts."

AP1000 Response:

See Chapter 13 for a discussion of plant procedures, training of operations personnel and emergency planning.

(2)(iii) Control Room Design (NUREG-0737 Item I.D.1)

"Provide, for Commission review, a control room design that reflects state-of-the-art human factor principles prior to committing to fabrication or revision of fabricated control room panels and layouts."

AP1000 Response:

The human factors engineering design process of the AP1000 has been developed to conform with NUREG-0711, "Human Factors Engineering Program Review Model." The elements of the design process provide a structured top-down system analysis using accepted human factors engineering principles. The design of the main control room and the other operation and control centers reflect state-of-the-art human factors principles. See Appendix 1A for information on conformance with applicable regulatory guides. See Chapter 18 for additional information on the AP1000 human factors engineering design process.

(2)(iv) Safety Parameter Display System (NUREG-0737 Item I.D.2)

"Provide a plant safety parameter display console that will display to operators a minimum set of parameters defining the safety status of the plant, capable of displaying a full range of important plant parameters and data trends on demand, and capable of indicating when process limits are being approached or exceeded."

AP1000 Response:

The purpose of the plant safety parameter display console (or safety parameter display system) is to display important plant variables in the main control room in order to assist in rapidly and reliably determining the safety status of the plant.

The requirements for the safety parameter display system are specified during the main control room design process, and are met by the main control room design, specifically as part of the alarms, displays, and controls. The requirements for a safety parameter display system (NUREG-0696, Reference 1) are met by grouping the alarms by plant process or purpose, as directly related to the critical safety functions.

The process data presented on the graphic displays is similarly grouped, facilitating an easy transition for the operators. The safety parameter display system requirement for presentation of plant data in an analog fashion prior to reactor trip is met by the design of the graphic CRT displays.

Displays are available at the operator workstations, the remote shutdown workstation, and at the technical support center. See Chapter 18 for additional information pertaining to the safety parameter display system design.

(2)(v) Safety System Status Indication (NUREG-0933 Item I.D.3)

"Provide for automatic indication of the bypassed and [in]operable status of safety systems."

AP1000 Response:

The AP1000 main control room meets the NRC Regulatory Guide 1.47 recommendations, including automatic indication of bypassed and inoperable status of plant safety systems, as described in Appendix 1A.

Plant safety parameters, protection system status, and plant component status signals are processed by the protection and safety monitoring system and made available to the entire instrumentation and control system via the redundant monitor bus.

Class 1E signals are provided to the qualified data processor, which is part of the protection and safety monitoring system, for accident monitoring displays. The display of this data is incorporated in the process data displays on the PMS safety displays in the AP1000 main control room.

See Chapters 7 and 18 for additional information pertaining to bypass inoperable status indication. Appendix 1A describes conformance with Regulatory Guide 1.47.

(2)(vi) Reactor Coolant System High Point Vents (NUREG-0737 Item II.B.1)

"Provide the capability of high point venting of noncondensible gases from the reactor coolant system, and other systems that may be required to maintain adequate core cooling. Systems to achieve this capability shall be capable of being operated from the control room and their operation shall not lead to an unacceptable increase in the probability of loss-of-coolant accident or an unacceptable challenge to containment integrity."

AP1000 Response:

In the AP1000 design, the capability for remotely operated high point venting of the reactor coolant system is provided by the safety-related automatic depressurization system valves and the safety-related reactor vessel head vent system. Both of these vent paths discharge to the in-containment refueling water storage tank.

During loss of cooling accident events, the automatic depressurization system automatically depressurizes the reactor coolant system so that the passive core cooling system may effectively deliver core cooling flow. Depressurization via the automatic depressurization system results in creation of a gas-steam volume in the upper region of the vessel. This vapor volume expands down to the inside of the hot leg before it begins venting through the hot leg either via the automatic depressurization system paths connected to the pressurizer or directly from the hot legs via the fourth stage automatic depressurization system paths. This process provides an open injection and steam venting flow path through the reactor vessel, maintaining required core cooling flow.

The reactor vessel head vent system can also be operated from the main control room to directly vent from the top of the reactor vessel head. Subsection 5.4.12 provides additional information pertaining to the reactor coolant system venting capabilities.

(2)(vii) Plant Radiation Shielding (NUREG-0737 Item II.B.2)

"Perform radiation and shielding design reviews of spaces around systems that may, as a result of an accident, contain TID-14844 source term radioactive materials, and design as necessary to permit adequate access to important areas and to protect safety equipment from the radiation environment."

AP1000 Response:

Post-accident radiation sources, used in the shield design and assessment of post-accident access to vital areas, are addressed in Subsection 12.2.1.3. The post-LOCA instantaneous and integrated source strengths as a function of time are also included as Tables 12.2-20 and 12.2-21, respectively. The sources are based on the core activity release model from Regulatory Guide 1.183, which supersedes the TID-14844 source term assumptions as reflected in Regulatory Guide 1.4.

Vital areas for post-accident personnel access are addressed in Section 12.3, including radiation zone maps that show projected dose rates in these areas and access routes for the various

post-accident actions in vital areas. Time estimates have been made for ingress, egress, and performance of actions at the vital area locations and have been used in demonstrating that total individual radiation doses are limited to less than 5 rem and that Item II.B.2 of NUREG-0737 and GDC-19 requirements are met.

Environmental qualification of safety-related equipment is addressed in Section 3.11. The determination of the radiation environments during postulated accident situations considers the activity release model based on NUREG-1465, which supersedes the source term definition of Parts 1 and 4 of Item II.B.2 of NUREG-0737.

Subsection 12.2.3 defines the responsibility to address any additional contained radiation sources not identified in 12.2.1. Thus, appropriate source terms have been identified and used in establishing that the requirements of Item II.B.2 of NUREG-0737 and GDC 19 are met and the issues are resolved.

(2)(viii) Post-Accident Sampling (NUREG-0737 Item II.B.3)

"Provide a capability to promptly obtain and analyze samples from the reactor coolant system and containment that may contain TID-14844 source term radioactive materials without radiation exposures to any individual exceeding 5 rem to the whole-body or 50 rem to the extremities. Materials to be analyzed and quantified include certain radionuclides that are indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and non-volatile isotopes), hydrogen in the containment atmosphere, dissolved gases, chloride, and boron concentrations."

AP1000 Response:

Recently the NRC published a model Safety Evaluation Report on eliminating post-accident sampling system requirements from technical specifications for operating plants (Federal Register Volume 65, Number 211, October 31, 2000). The AP1000 sampling design is consistent with the approach in the Model safety evaluation report and not the guidance outlined in NUREG-0737 and Regulatory Guide 1.97. The primary sampling system design is consistent with contingency plans to obtain and analyze highly radioactive post-accident samples from the reactor coolant system, the containment sump, and the containment atmosphere.

(2)(ix) Hydrogen Control (NUREG-0660 Item II.B.8)

"Provide a system for hydrogen control that can safely accommodate hydrogen generated by the equivalent of a 100 percent fuel-clad metal-water reaction. Preliminary design information on the tentatively preferred system option of those being evaluated in paragraph (1)(xii) of this section (50.34) is sufficient at the construction permit stage. The hydrogen control system and associated systems shall provide, with reasonable assurance, that:

(A) Uniformly distributed hydrogen concentrations in the containment do not exceed 10 percent during and following an accident that releases an equivalent amount of hydrogen as would be generated from a 100 percent fuel-clad metal-water reaction, or that the post-accident atmosphere will not support hydrogen combustion.

(B) Combustible concentrations of hydrogen will not collect in areas where unintended combustion or detonation could cause loss of containment integrity or loss of appropriate mitigating features.

(C) Equipment necessary for achieving and maintaining safe shutdown of the plant and maintaining containment integrity will perform its safety function during and after being exposed to the environmental conditions attendant with the release of hydrogen generated by the equivalent of a 100 percent fuel-clad metal-water reaction including the environmental conditions created by activation of the hydrogen control system.

(D) If the method chosen for hydrogen control is a post-accident inerting system, inadvertent actuation of the system can be safely accommodated during plant operation."

AP1000 Response:

See the response provided for issue (1)(xii).

(2)(x) Reactor Coolant System Valve Testing (NUREG-0737 Item II.D.1)

"Provide a test program and associated model development and conduct tests to qualify reactor coolant system relief and safety valves and, for pressurized water reactors, power-operated relief valves, block valves, for all fluid conditions expected under operating conditions, transients and accidents. Consideration of anticipated transients without scram (ATWS) conditions shall be included in the test program. Actual testing under ATWS conditions need not be carried out until subsequent phases of the test program are developed."

AP1000 Response:

The AP1000 reactor coolant system design does not include power-operated relief valves and their associated block valves. However, the safety valve and discharge piping used in the AP1000 design will be either of design similar to those items tested by EPRI and documented in EPRI Report EPRI NP-2770-LD (Reference 2) or will be tested in accordance with the guidelines of Item [II.D.1] of NUREG-0737.

The AP1000 design includes automatic depressurization system valves which are used to depressurize the plant and establish conditions for injection from the accumulators and the in-containment refueling water storage tank. The operability of the automatic depressurization system valves and spargers is confirmed by a test program. See Section 1.5 for information pertaining to the testing program.

Accident analyses for the AP1000 determine fluid conditions expected under operating conditions, transients, and accidents, and the postulated system responses to these conditions, including the operation of reactor coolant system safety valves. Anticipated transients without scram events are analyzed. Appropriate valve qualification documentation is maintained.

(2)(xi) Valve Position Indication (NUREG-0737 Item II.D.3)

"Provide direct indication of relief and safety valve position (open or closed) in the control room."

AP1000 Response:

The AP1000 design does not include power-operated relief valves and their associated block valves from the reactor coolant system.

Direct indication of relief and safety valve position (open or closed) is provided in the main control room.

(2)(xii) Auxiliary Feedwater System Initiation and Indication (NUREG-0737 Item II.E.1.2)

"Provide automatic and manual auxiliary feedwater system initiation, and provide auxiliary feedwater system flow indication in the control room."

AP1000 Response:

As previously noted in the AP1000 response to Issue (1)(ii), the AP1000 design includes a nonsafety-related startup feedwater system, but not an auxiliary feedwater system. Flow indication of the startup feedwater system is provided in the main control room.

The startup feedwater pumps automatically start following anticipated transients resulting in low steam generator level. The startup feedwater control valves automatically control feedwater flow to the steam generators during operation. They can also be operated manually from the main control room.

The safety-related passive core cooling system provides for emergency core decay heat removal during transients, accidents, or whenever the normal heat removal paths are unavailable. Automatic and manual actuation and flow rate indication are available in the main control room.

(2)(xiii) Pressurizer Heater Power Supplies (NUREG-0737 Item II.E.3.1)

"Provide pressurizer heater power supply and associated motive and control power interfaces sufficient to establish and maintain natural circulation in hot standby conditions with only onsite power available."

AP1000 Response:

The AP1000 pressurizer heaters are powered from the nonsafety-related ac power system. During loss of offsite power events, a portion of the pressurizer heaters is capable of being powered from the nonsafety-related onsite standby power system. The pressurizer heaters are capable of establishing and maintaining natural circulation in hot standby condition, with only the diesel generators supplying electrical power.

With only safety-related dc (Class 1E dc) power available, the safety-related passive core cooling system can establish and maintain natural circulation cooling using the passive residual heat removal heat exchangers, transferring the decay heat to the in-containment refueling water storage tank water and to the passive containment cooling system.

Therefore, the nonsafety-related pressurizer heaters are not required for core decay heat removal following a loss of offsite power. See Section 8.3 for additional information.

(2)(xiv) Containment Isolation System (NUREG-0737 Item II.E.4.2)

"Provide containment isolation systems that: (A) ensure all nonessential systems are isolated automatically by the containment isolation system, (B) for each non-essential penetration (except instrument lines) have two isolation barriers in series, (C) do not result in reopening of the containment isolation valves on resetting of the isolation signal, (D) utilize a containment set point pressure for initiating containment isolation as low as is compatible with normal operation, and (E) include automatic closing on a high radiation signal for all systems that provide a path to the environs."

AP1000 Response:

The AP1000 containment isolation design satisfies NRC requirements, including post-TMI requirements. In general, this means that two barriers are provided -- one inside containment and the other outside containment. Usually these barriers are valves, but in some cases they are closed, seismic Category I piping systems not connected to the reactor coolant system or to the containment atmosphere. Table 6.2.3-1 identifies containment isolation design provisions for mechanical penetrations. The isolation signal and maximum closure times are defined for each remotely

operated valve. Containment penetrations, other than equipment hatches and flanges, incorporate two isolation barriers in series.

The AP1000 design incorporates a reduction in the number of required penetrations compared to the number in previous plant designs. The majority of these penetrations are normally closed. Those few that are normally open, use automatically closed isolation valves.

Containment isolation is automatically actuated by a safeguards actuation signal, using two-out-of-four coincident logic. The containment isolation actuation is set as low as reasonable without creating potential for spurious trips during normal operations. Containment isolation can also be initiated manually from the main control room. Containment penetrations do not automatically reopen on the resetting of the isolation signal. See Subsection 6.2.3 for additional information.

(2)(xv) Containment Purging/Venting (NUREG-0933 Item II.E.4.4)

"Provide a capability for containment purging/venting designed to minimize the purging time consistent with ALARA principles for occupational exposure. Provide and demonstrate high assurance that the purge system will reliably isolate under accident conditions."

AP1000 Response:

Containment purging for the AP1000 is provided by the nonsafety-related containment air filtration system. The function of the system is to clean up the containment atmosphere to acceptable radiation levels during plant operation and prior to personnel entry. It can also be used for containment pressure equalization.

The containment air filtration system is designed to reliably isolate under accident conditions. There are two penetrations and two containment filtration subsystems for AP1000.

See Subsection 9.4.7 for additional information.

(2)(xvi) ECCS Actuation Cycles (NUREG-0933 Item II.E.5.1)

"Establish a design criterion for the allowable number of actuation cycles of the emergency core cooling system and reactor protection system consistent with the expected occurrence rates of severe overcooling events (considering both the expected transients and accidents)."

AP1000 Response:

This issue is applicable to Babcock & Wilcox designs only.

The AP1000 design uses the passive core cooling system to provide emergency reactor coolant inventory control and emergency decay heat removal. Component design criteria have been established for the number of actuation cycles for the passive core cooling system. The identified actuation cycles include inadvertent actuation, as well as the system response to expected plant trip occurrences, including overcooling events.

Automatic depressurization system operation is not expected for either design basis or best estimate overcooling events. See Subsection 3.9.1 for additional information.

(2)(xvii) Specific Accident Monitoring Instrumentation (NUREG-0737 Item II.F.1)

"Provide instrumentation to measure, record and readout in the control room: (A) containment pressure, (B) containment water level, (C) containment hydrogen concentration, (D) containment radiation intensity (high level), and (E) noble gas effluents at all potential accident release points.

Provide for continuous sampling of radioactive iodines and particulates in gaseous effluents from all potential accident release points, and for onsite capability to analyze and measure these samples."

AP1000 Response:

AP1000 post-accident monitoring is described in Chapter 7.

AP1000 post-accident monitoring provides for indication of the specified parameters as follows:

- Containment pressure
- Containment water level
- Containment radiation intensity (high level)
- Noble gas effluents - to ascertain reactor coolant system integrity

Other noble gas effluents are designated Type E variables and include information to permit the operators to:

- Monitor the habitability of the main control room
- Monitor plant areas where access may be required to service equipment necessary to monitor or mitigate the consequences of an accident
- Estimate the magnitude of release of radioactive materials through identified pathways
- Monitor radiation levels and radioactivity in the environment surrounding the plant

Subsection 11.5.5 has additional information on measurement of radioactive effluents and conformance with Regulatory Guide 1.97.

The AP1000 primary sampling system is designed to provide post accident sampling functions. See Subsection 9.3.3.1 for additional information on the post accident sampling system.

The human factors aspects of the AP1000 are discussed in Chapter 18.

(2)(xviii) Inadequate Core Cooling Instrumentation (NUREG-0737 Item II.F.2)

"Provide instruments that provide in the control room an unambiguous indication of inadequate core cooling, such as primary coolant saturation meters in PWRs, and a suitable combination of signals from indicators of coolant level in the reactor vessel and in-core thermocouples in PWRs and BWRs."

AP1000 Response:

The AP1000 reactor system includes instrumentation for detecting voids in the reactor vessel head and other reactor vessel inventory deficits that could lead to inadequate core cooling.

The available instrumentation includes core subcooling margin monitors, core exit thermocouples, pressurizer level indicators, and reactor coolant system hot leg level.

The AP1000 design uses hot leg level instrumentation to provide those functions necessary to support monitoring of the passive plant design features and to provide indication that the reactor vessel water level remains above the elevation of the fuel.

The AP1000 features that provide margin to or indication of inadequate core cooling include the following:

- A larger pressurizer than most current PWRs, with a pressurizer that is located above the reactor pressure vessel head
- No automatic power-operated relief valves
- An improved reactor vessel head venting capability
- A passive core cooling system
- A passive containment cooling system
- No dependence on ac power to maintain adequate core and containment cooling
- Reactor coolant system hot leg level instrumentation
- Improved reactor system instrumentation
- Core subcooling monitoring

See Sections 6.3 and 7.5 for additional information.

(2)(xix) Post-Accident Monitoring Instrumentation (NUREG-0933 Item II.F.3)

"Provide instrumentation adequate for monitoring plant conditions following an accident that includes core damage."

AP1000 Response:

The AP1000 post-accident monitoring system was developed by using Regulatory Guide 1.97 as a guidance document.

Data used for post-accident monitoring is displayed either by the normal control room display system or by the PMS safety display subsystem.

The normal control room display system is used for display of nonsafety-related signals which are not required to be displayed by a qualified system. The PMS safety display subsystem provides for the display of signals which must be displayed by a qualified system.

The qualified data processing system is a microprocessor-based, safety-related system that provides instrumentation to monitor the plant variables and systems during and following an accident. The system consists of two independent, electrically isolated, physically separated divisions.

Additional details pertaining to this system are provided in the AP1000 response to issue (2)(xvii) and in Chapter 7.

(2)(xx) Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators (NUREG-0737 Item II.G.1)

"Provide power supplies for pressurizer relief valves, block valves, and level indicators such that: (A) level indicators are powered from vital buses, (B) motive and control power connections to the emergency power sources are through devices qualified in accordance with requirements applicable to systems important to safety, and (C) electric power is provided from emergency power sources."

AP1000 Response:

The AP1000 design does not include power-operated relief valves and their associated block valves from the reactor coolant system.

Pressurizer level indication is provided by instrumentation powered from the Class 1E dc and UPS system. The system provides safety-related, uninterruptible power for the Class 1E plant instrumentation, control, monitoring, and other vital functions, including safety-related components that are essential for safe shutdown of the plant.

The Class 1E direct current system is designed such that these critical plant loads are powered during emergency plant conditions when both onsite and offsite ac power sources are unavailable.

See Chapter 7 and Section 8.3 for additional information.

(2)(xxi) Auxiliary Heat Removal Systems (NUREG-0933 Item II.K.1.22)

"Design auxiliary heat removal systems such that necessary automatic and manual actions can be taken to ensure proper functioning when the main feedwater system is not operable."

AP1000 Response:

Although this issue is applicable to BWRs only, there are some considerations for AP1000.

Following a loss of main feedwater for the AP1000, there are a number of plant systems that automatically actuate to provide decay heat removal. The startup feedwater system is a nonsafety-related system, that can be powered by the nonsafety-related diesel generators, and is automatically actuated and controlled by steam generator level.

For design basis events, the safety-related passive core cooling system includes a passive residual heat removal heat exchanger which automatically actuates to provide emergency core decay heat removal if the nonsafety-related systems are not available.

The AP1000 main control room meets the NRC guidelines for manual actuation of protective functions including those that are used in the event of a loss of normal feedwater.

See Sections 6.3 and 10.4 for additional information.

(2)(xxii) Failure Mode and Effects Analysis for Control Systems (NUREG-0933 Item II.K.2.9)

"Provide a failure modes and effects analysis of the integrated control system to include consideration of failures and effects of input and output signals to the integrated control system."

AP1000 Response:

This issue is applicable to Babcock & Wilcox plants only.

(2)(xxiii) Safety-Grade Anticipatory Reactor Trip (NUREG-0737 Item II.K.2.10)

"Provide, as part of the reactor protection system, an anticipatory reactor trip that would be actuated on loss of main feedwater and on turbine trip."

AP1000 Response:

This issue is applicable to Babcock & Wilcox plants only.

The AP1000 trip logic includes an anticipatory reactor trip for loss of main feedwater using low steam generator water level. See Section 7.2 for additional information.

Since the AP1000 design does not include power-operated relief valves and their associated block valves in the reactor coolant system, the anticipatory reactor trip on turbine trip is not required for AP1000.

(2)(xxiv) Central Water Level Recording (NUREG-0933 Item II.K.3.23)

"Provide the capability to record reactor vessel water level in one location on recorders that meet normal post-accident recording requirements."

AP1000 Response:

This issue is applicable to BWRs only.

(2)(xxv) Emergency Response Facilities (NUREG-0737 Item III.A.1.2)

"Provide an onsite technical support center, an onsite operational support center, and, for construction permit applications only, a nearsite emergency operations facility."

AP1000 Response:

The AP1000 provides for an onsite technical support center and an operational support center. See the figures in Sections 1.1 and 1.2 for additional information on the location. The detailed design of the workstations and the associated man-machine interface for the technical support center and the operational support center is guided by the human factors engineering design process described in Chapter 18. The offsite emergency response facility is discussed in Subsection 18.2.6.

(2)(xxvi) Leakage Control Outside Containment (NUREG-0737 Item III.D.1.1)

"Provide for leakage control and detection in the design of systems outside containment that contain (or might contain) TID-14844 source term radioactive materials following an accident. Applicants shall submit a leakage control program, including an initial test program, a schedule for retesting these systems, and the actions to be taken for minimizing leakage from such systems. The goal is to minimize potential exposures to workers and public, and to provide reasonable assurance that excessive leakage will not prevent the use of systems needed in an emergency."

AP1000 Response:

As described in issue (2)(vii), the safety-related AP1000 passive systems do not recirculate radioactive fluids outside of containment following an accident. A nonsafety-related system can be used to recirculate coolant outside of containment following an accident, but this system is not operated when high containment radiation levels exist.

(2)(xxvii) In-Plant Monitoring (NUREG-0737 Item III.D.3.3)

"Provide for monitoring of inplant radiation and airborne radioactivity as appropriate for a broad range of routine and accident conditions."

AP1000 Response:

Area radiation monitors (ARMs) are provided to supplement the personnel and area radiation survey provisions of the AP1000 health physics program described in Section 12.5 and to comply with the personnel radiation protection guidelines of 10 CFR 20, 10 CFR 50, and Regulatory Guides 1.97,

8.2, and 8.8. In addition to the installed detectors, periodic plant environmental surveillance is established.

(2)(xxviii) Control Room Habitability (NUREG-0737 Item III.D.3.4)

"Evaluate potential pathways for radioactivity and radiation that may lead to control room habitability problems under accident conditions resulting in a TID-14844 source term release, and make necessary design provisions to preclude such problems."

AP1000 Response:

Normally, a nonsafety-related HVAC system keeps the AP1000 main control room slightly pressurized to prevent infiltration of air from other plant areas. During accident conditions, a safety-related isolation of the main control room is automatically actuated.

Upon the loss of nonsafety-related ac power, the main control room environment is sufficient to protect the operators and support the man-machine interfaces necessary to establish and maintain safe shutdown conditions for the plant following postulated design basis accident conditions. The sources are based on the core activity release model from Regulatory Guide 1.183, which supersedes the TID-14844 source term assumptions as reflected in Regulatory Guide 1.4.

The main control room is sealed with safety-related connections to a safety-related compressed air breathing source. This compressed air system provides continued pressurization and a source of fresh air for operator habitability. The air supply is sized to last for 72 hours following an accident. It is expected that the onsite nonsafety-related normal HVAC system will be operational before the installed compressed air supply is exhausted.

The nonsafety-related HVAC system, equipped with a refrigeration-type air conditioning unit, normally provides main control room cooling. This equipment is powered from the onsite diesel generators. If the normal HVAC system is not available, outside air is not allowed into the main control room, and the safety-related compressed air storage system is actuated.

(3)(i) Industry Experience (NUREG-0737 Item I.C.5)

"Provide administrative procedures for evaluating operating, design, and construction experience and for ensuring that applicable important industry experiences will be provided in a timely manner to those designing and constructing the plant."

AP1000 Response:

AP1000 design engineers are continually involved in reviewing industry experiences from sources such as NRC Bulletins, Licensee Event Reports, NRC request for information letters to holders of operating licenses for nuclear power reactors, Federal Register information, and generic letters. Lessons learned experience was incorporated in the AP600 through the Westinghouse participation in developing Volume III of the ALWR Utility Requirements Document and participation in the ALWR Utility Steering Committee activities. The AP1000 design is closely based on the AP600. See Subsection 1.9.5.5 for additional information.

(3)(ii) Quality Assurance List (NUREG-0933 Item I.F.1)

"Ensure that the quality assurance list required by Criterion II, Appendix B, 10 CFR Part 50 includes all structures, systems and components important to safety."

AP1000 Response:

The AP1000 Quality Assurance Plan is described in Chapter 17. Structures, systems, and components are classified as described in Section 3.2.

(3)(iii) Quality Assurance Program (NUREG-0737 Item I.F.2)

"Establish a quality assurance program based on consideration of: (A) ensuring independence of the organization performing checking functions from the organization responsible for performing the functions; (B) performing quality assurance/quality control functions at construction sites to the maximum feasible extent; (C) including Quality Assurance personnel in the documented review of and concurrence in quality related procedures associated with design, construction and installation; (D) establishing criteria for determining Quality Assurance programmatic requirements; (E) establishing qualification requirements for Quality Assurance and Quality Control personnel; (F) sizing the Quality Assurance staff commensurate with its duties and responsibilities; (G) establishing procedures for maintenance of "as-built" documentation; and (H) providing a Quality Assurance role in design and analysis activities."

AP1000 Response:

The AP1000 Quality Assurance Plan described in Chapter 17 meets the requirements of issue 1.F.2.

(3)(iv) Dedicated Containment Penetrations (NUREG-0660 Item II.B.8)

"Provide one or more dedicated containment penetrations, equivalent in size to a single 3-foot diameter opening, in order not to preclude future installation of systems to prevent containment failure, such as a filtered vented containment system."

AP1000 Response:

The containment analysis for the AP1000, including PRA and severe accident assessments, demonstrate that the containment, with its passive heat rejection capability, does not need a filtered vent to prevent overpressurization.

The 36-inch diameter containment air filtration system penetration provided for AP1000 meets the requirement of 10 CFR 50.34(f)(3)(iv). See Figure 9.4.7-1, sheet 1, note 6, for additional information.

(3)(v) Containment Design (NUREG-0660 Item II.B.8)

"Provide preliminary design information at a level of detail consistent with that normally required at the construction permit stage of review sufficient to demonstrate that:

(A)(1) Containment integrity will be maintained (i.e., for steel containments by meeting the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subarticle NE-3220, Service Level C Limits, except that evaluation of instability is not required, considering pressure and dead load alone. For concrete containments by meeting the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division 2 Subarticle CC-3720, Factored Load Category, considering pressure and dead load alone) during an accident that releases hydrogen generated from 100 percent fuel clad metal-water reaction accompanied by either hydrogen burning or the added pressure from post-accident inerting assuming carbon dioxide is the inerting agent. As a minimum, the specific code requirements set forth above, appropriate for each type of containment, will be met for a combination of dead load and an internal pressure of 45 psig. Modest deviations from these criteria will be considered by the staff, if good cause is shown by an applicant. Systems necessary to ensure containment integrity shall also be demonstrated to perform their function under these conditions.

(2) Subarticle NE-3220, Division 1, and subarticle CC-3720, Division 2, of Section III of the July 1, 1980 ASME Boiler and Pressure Vessel Code, which are referenced in paragraph (f)(3)(v)(A)(1) and (f)(3) (v)(B)(1) of this section, were approved for incorporation by reference by the Director of the Office of the Federal Register. A notice of any changes made to the material incorporated by reference will be published in the Federal Register. . . .

(B)(1) Containment structure loadings produced by an inadvertent full actuation of a post-accident inerting hydrogen control system (assuming carbon dioxide), but not including seismic or design basis accident loadings will not produce stresses in steel containments in excess of the limits set forth in the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subarticle NE-3220, Service Level A Limits, except that evaluation of instability is not required (for concrete containments the loadings specified above will not produce strains in the containment liner in excess of the limits set forth in the ASME Boiler and Pressure Vessel Code, Section III, Division 2, Subarticle CC-3720, Service Load Category), (2) The containment has the capability to safely withstand pressure tests at 1.10 and 1.15 times (for steel and concrete containments, respectively) the pressure calculated to result from carbon dioxide inerting."

AP1000 Response:

The AP1000 containment vessel is designed to meet the requirements of the ASME Code, Section III, Division I, Subsection NE. A severe accident containment analysis is conducted to support the design effort. The results of the analysis are fission product source terms and plant thermal-hydraulic response for each of the accident sequences chosen to be representative of the plant damage states determined in level 1 PRA analysis.

Results of the analysis indicate that containment failure is not predicted for cases in which the passive containment cooling system cooling water is available. The hydrogen igniter system controls hydrogen and mitigates threats to the containment due to hydrogen.

See Section 6.2 for additional information.

(3)(vi) Hydrogen Recombiners (NUREG-0737 Item II.E.4.1)

"For plant designs with external hydrogen recombiners, provide redundant dedicated containment penetrations so that, assuming a single failure, the recombiner systems can be connected to the containment atmosphere."

AP1000 Response:

Since external hydrogen recombiners are not provided for the AP1000, this requirement is not applicable. See Section 6.2 for additional information.

(3)(vii) Management Plan (NUREG-0933 Item II.J.3.1)

"Provide a description of the management plan for design and construction activities, to include: (A) the organizational and management structure singularly responsible for direction of design and construction of the proposed plant; (B) technical resources director by the applicant; (C) details of the interaction of design and construction within the applicant's organization and the manner by which the applicant will ensure close integration of the architect engineer and the nuclear steam supply vendor; (D) proposed procedures for handling the transition to operation; (E) the degree of top level management oversight and technical control to be exercised by the applicant during design and construction, including the preparation and implementation of procedures necessary to guide the effort."

AP1000 Response:

The AP1000 design team has developed a management plan for the AP1000 project which consists of a properly structured organization with open lines of communication, clearly defined responsibilities, well-coordinated technical efforts, and appropriate control channels. The procedures to be used in the construction, startup, and operation phases of the plant are provided in accordance with the Master Plan and Procedure Development Process identified in APP-GW-GLR-040 (Reference 72).

1.9.4 Unresolved Safety Issues and Generic Safety Issues

Proposed technical resolutions of Unresolved Safety Issues and medium- and high-priority Generic Safety Issues, as identified in NUREG-0933, Reference 3 are required for new plants as part of the NRC policy on severe accidents and are required for design certification in accordance with 10 CFR 52.47(a)(21).

The current program for identifying and establishing the priority of open safety issues is summarized in NUREG-0933. This program provides for the prioritization and tracking of previously categorized Unresolved Safety Issues and Generic Safety Issues, New Generic Issues, TMI Action Plan Items Under Development, and Human Factors Program Plan Issues.

The following subsection reviews each of the NUREG-0933 safety issues and identifies the safety issues that are applicable to the AP1000. For each of these issues guidance is provided on how the issue is addressed for the AP1000.

1.9.4.1 Review of NRC List of Unresolved Safety Issues and Generic Safety Issues

Applicants for design certification are required by 10 CFR 52.47(a)(21) to identify:

"Proposed technical resolutions of those Unresolved Safety Issues and medium- and high-priority Generic Safety Issues which are identified in the version of NUREG-0933 current on the date six months prior to application and which are technically relevant to the design."

NUREG-0933, "A Prioritization of Generic Safety Issues," through Supplement 25 identifies hundreds of issues. The issues tabulated in Supplement 25 were reviewed to determine which issues are technically relevant to the AP1000 design. In this review process, the following screening criteria were applied:

a. Issue has been prioritized as **Low**, **Drop**, or has not been prioritized.

b. Issue is not an AP1000 design issue. Issue is applicable to GE, B&W, or CE designs only.

c. Issue resolved with no new requirements.

d. Issue is not a design issue (Environmental Issue, Licensing Issue, Regulatory Impact Issue, or covered in an existing NRC program).

e. Issue superseded by one or more issues.

f. Issue is not an AP1000 design certification issue. Issue is applicable to NTOL plants only, responsibility of combined license applicant, or issue is limited to current generation operating plants.

Issues meeting one or more of the preceding screening criteria were screened out of the review process as issues that are not applicable to the AP1000 design. The remaining issues fall into one of the following two categories:

g. Issue is resolved by establishment of new regulatory requirements and/or guidance.

h. Issue is unresolved pending generic resolution (e.g., prioritized as **High**, **Medium**, or possible resolution identified).

Table 1.9-2 identifies the results of the screening review. For those issues identified as relevant to the AP1000 design (i.e., issues screened as **g** or **h**), Table 1.9-2 identifies the subsection that addresses the issue.

Table 1.9-2 addresses the second un-numbered COL Information Item identified at the end of Table 1.8-2 and listed in Table 1.8-202 as COL Information Item 1.9-3, "Unresolved Safety Issues and Generic Safety Issues." As such, Table 1.9-2 lists those issues identified by Note "d," which apply to other than design issues, Note "f," which apply either to resolution of Combined License (COL) Information Items or to nuclear power plant operations issues, Note "h," which apply to issues unresolved pending generic resolution at the time of submittal of the AP1000 DCD, and any new Unresolved Safety Issues and Generic Safety Issues that have been included in NUREG-0933 (through supplement 30) since the DCD was developed. Many of these have since been resolved and incorporated into the applicable licensing regulations or guidance (e.g., the standard review plans). These resolved items (as indicated by NUREG-0933) are identified only as "Resolved per NUREG-0933." Many others are not in the list of items in NUREG-0933 Appendix B identified as applicable to new plants. These items are identified only as "Not applicable to new plants." For the remaining items, the table provides the sections that address the topic.

1.9.4.2 AP1000 Resolution of Unresolved Safety Issues and Generic Safety Issues

1.9.4.2.1 TMI Action Plan Issues

TMI Action Plan issues that were not incorporated in 10CFR50.34(f) are addressed in the following. Those issues incorporated into 10CFR50.34(f) are addressed in Subsection 1.9.3.

I.D.5(2) Plant Status and Post-Accident Monitoring Discussion:

TMI action plant item I.D.5(2) addresses the need to improve the operators' ability to prevent, diagnose and properly respond to accidents. The emphasis is on the information needs (i.e., indication of plant status) of the operator. This issue was resolved with the issuance of Revision 2 to Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Environs Conditions During and Following an Accident."

AP1000 Response:

The AP1000 conforms to and meets the intent of Regulatory Guide 1.97. Regulatory Guide 1.97 provides the requirements for post-accident monitoring of nuclear reactor safety parameters, including plant process parameters important to safety and the monitoring of effluent paths and plant environs for radioactivity. These guidelines include definition and categorization of plant variables that are available to the main control room operators for monitoring the plant safety status following a design basis event.

For the AP1000, an analysis is conducted to identify the appropriate variables and to establish the appropriate design basis and qualification criteria for instrumentation used by the operator for monitoring conditions in the reactor coolant system, the secondary heat removal system, the

containment, and the systems used for attaining a safe shutdown condition, as discussed in Section 7.5.

This instrumentation is used by the operator to monitor and maintain the safety of the plant during operating conditions, including anticipated operational occurrences and accident and post-accident conditions. A set of plant parameters identified according to the Regulatory Guide 1.97 guidelines are processed by the qualified data processing system (QDPS) and displayed by the safety displays of the PMS safety display subsystem, which is discussed in Section 18.8. The verification and validation (V&V) of the safety displays complies with the V&V process described in Section 18.11.

I.D.5(3) On-Line Reactor Surveillance System

Discussion:

TMI action plan item I.D.5(3) addresses the benefit to plant safety and operations of continuous on-line automated surveillance systems. Continuous on-line surveillance systems that automatically monitor reactors can assist plant operations by providing diagnostic information which can predict anomalous behavior.

Various methods of on-line reactor surveillance have been used, including neutron noise monitoring in boiling water reactors (BWRs) to detect internals vibration, and pressure noise surveillance at TMI-2 to monitor primary loop degasification.

AP1000 Response:

The AP1000 reactor coolant pressure boundary is monitored for leaks from the reactor coolant and associated systems by a variety of components located in multiple systems. The leak detection system provides information permitting the plant operators to take corrective action if any detected leakage exceeds technical specifications. The leak detection system is designed according to the requirements of 10 CFR 50, Appendix A, General Design Criterion 30. The system provides a means to detect and, to the extent practical, to identify the source of the reactor coolant pressure boundary leakage. Subsection 5.2.5 provides further discussion of leak detection.

A digital metal impact monitoring system (DMIMS) monitors the reactor coolant system for the presence of loose metallic parts. This system conforms with the guidance provided in Regulatory Guide 1.133, Rev. 1, May 1981. An advanced microprocessor-based system, employing digital technology, automatically actuates audible and visual alarms if a signal exceeds the preset alarm level.

I.F.1 Expand Quality Assurance List

Discussion:

Item I.F.1 addressed the issue of systems that are "important to safety" that are not on the Quality Assurance List. The suggestion was made that equipment important to safety be ranked and that ranking used to determine systems that should be added to the Quality Assurance List. This approach has not been implemented by the NRC on either a generic or cases-by case basis. In NUREG-0933 this item was classified as resolved with no additional requirements established.

AP1000 Response:

The requirements of 10 CFR Appendix B apply to safety-related systems and components. See Subsection 3.2.2 for a discussion of the AP1000 equipment classification system and the associated quality assurance requirements, including requirements for nonsafety-related systems.

I.G.1 Training Requirements

Discussion:

Item I.G.1 included the issue of natural circulation testing for use as input into operator training.

AP1000 Response:

For the AP1000, natural circulation heat removal using the steam generators is not safety-related, as in current plants. This safety-related function is performed by the passive residual heat removal system. Testing of the passive residual heat removal system meets the intent of the requirement to perform natural circulation testing and the results of this testing is factored into the operator training.

For the AP1000, the tests outlined below are contained in the AP1000 initial test plan and demonstrate the effectiveness of natural circulation cooling.

1. Not Used.

2. After fuel loading, but prior to criticality, with the reactor system at no-load operating temperature and pressure and all reactor coolant pumps operating, the depressurization rate is determined by de-energizing the heaters and pressure is further reduced through use of sprays (See Subsection 14.2.10.1.19).

3. After criticality is achieved and the plant is at ~ 3% power, the plant is placed in a natural circulation mode by tripping all reactor coolant pumps and observing the plant response using the steam generators (See Subsection 14.2.10.3.6). This test is performed for the first plant only.

4. A PRHR natural circulation test (see Subsection 14.2.10.4.29) is performed using decay heat generated following reactor operation. The plant is operated at power for a sufficient duration to generate decay heat. The reactor is then tripped, followed by the tripping of all reactor coolant pumps and placing the PRHR heat exchanger into service. The plant response is observed using the PRHR and IRWST as the primary heat sink. This test is performed for the first plant only.

5. A loss-of-offsite power test is performed with the plant at minimum power level supplying normal house loads. The turbine is tripped and the plant is placed in a stable condition using batteries and the diesel generator (See Subsection 14.2.10.4.26).

6. Data obtained from the first plant only natural circulation tests using the steam generators and PRHR is provided for operator training on a plant simulator at the earliest opportunity.

This response as modified for the AP1000 design is consistent with the response to NUREG-0737, action item I.G.1 which provided a proposal for low power testing of existing and future Westinghouse pressurized water reactors in Attachment 4 to letter NS-EPR-2465 from Westinghouse (E. P. Rahe) to the NRC (H. R. Denton) dated July 8, 1981.

I.G.2 Scope of Test Program

Discussion:

TMI Action Plan Items I.G.2 recommended additional testing during preoperational and startup programs to search for anomalies in a plants response to transients. The Standard Review Plan, Section 14 was revised to provide additional guidance for preoperational and startup test programs.

AP1000 Response:

The program plan for preoperational and startup testing of the AP1000 is in Section 14.2. This section addresses the Standard Review Plan, Section 14. The conformance with Standard Review Plan, Section 14 is outlined in AP1000 Compliance with SRP Acceptance Criteria, WCAP-15799.

II.E.1.3 Update Standard Review Plan and Develop Regulatory Guide

Discussion:

This item was a requirement to update Section 10.4.9 of the Standard Review Plan to address the requirements of Items II.E.1.1 and II.F.1.2 for auxiliary feedwater systems. Standard Review Plan 10.4.9 was revised and this issue is classified as resolved.

AP1000 Response:

The AP1000 does not have a safety-related auxiliary feedwater system. For conformance of the AP1000 with Items II.E.1.1 and II.E.1.2 see the write-up for (1)(ii) and (2)(xii) in Subsection 1.9.3. For conformance with Standard Review Plan Section 10.4.9 see WCAP-15799.

II.E.6.1 Test Adequacy Study

Discussion:

This item was intended to establish the adequacy of requirements for safety-related valve testing. Subsequent to this item, expanded requirements were written into the ASME OM Code for valve testing.

AP1000 Response:

The AP1000 is designed for an in-service test program in accordance with the ASME OM Code. See Subsection 3.9.6 for additional information on the in-service testing program plan.

II.K.1(10) Review and Modify Procedures for Removing Safety-related Systems from Service

Discussion:

This item required operating plants to review and modify (as required) their procedures for removing safety-related systems from service to assure operability status is known.

AP1000 Response:

Section 13.5 describes the AP1000 procedure development, preparation, and responsibility.

II.K.1(13) Propose Technical Specification Changes Reflecting Implementation of All Bulletin Items.

Discussion:

This item required that operating plants propose technical specification changes to address Bulletin items.

AP1000 Response:

The AP1000 Technical Specifications are based on and were reviewed against the Westinghouse Standard Technical Specifications, which incorporated the requirements of the bulletins for the TMI Action Plan.

II.K.1(17) Trip PZR Level Bistable So That Low Pressure Will Initiate Safety Injection

Discussion:

This item required operating licensees and operating license applicants with Westinghouse designed nuclear steam supply systems to trip the pressurizer level bistable so that the pressurizer low pressure (rather than the pressurizer low pressure and pressurizer low level coincidence) would initiate safety injection.

AP1000 Response:

This issue does not apply to AP1000. The AP1000 does not rely on coincident low pressurizer pressure and low pressurizer level for actuation. See Section 6.3 for a discussion of actuation of the passive core cooling system.

II.K.1(24) Perform LOCA Analyses for a Range of Small-Break Sizes and a Range of Time Lapses Between Reactor Trip and Reactor Coolant Pump Trip

Discussion:

This item requires analyses to provide the basis for the comparison of analytical methods.

AP1000 Response:

The analyses documented in Chapter 15 cover a range of small break sizes. The AP1000 automatically trips the reactor coolant pump on an S signal. The need to look at time lapses between reactor trip and pump trip is not required.

II.K.3(5) Automatic Trip of Reactor Coolant Pumps

Discussion:

This item requires that operating plants and operating plant applicants study the need for automatic trip of reactor coolant pumps and to modify procedures of designs as appropriate.

AP1000 Response:

The AP1000 design provides for an automatic trip of the reactor coolant pumps on actuation of the passive core cooling system. This trip is provided to prevent reactor coolant pump interaction with the operation of the core makeup tank. See Section 6.3 for additional information.

II.K.3(9) Proportional Integral Derivative Controller Modification

Discussion:

TMI action plan item II.K.3(9) required all Westinghouse plants to raise the interlock bistable trip setting to preclude derivative action from opening the PORVs.

AP1000 Response:

This issue is not applicable to the AP1000. The AP1000 does not include power-operated relief valves. See Subsections 5.1.2 and 5.2.2 for additional information.

1.9.4.2.2 Task Action Plan Items

A-1 Water Hammer

Discussion:

Generic Safety Issue A-1 was raised after the occurrence of various incidents of water hammer that involved steam generator feedrings and piping, emergency core cooling systems, residual heat removal systems, containment spray, service water, feedwater, and steam lines. The incidents have been attributed to such causes as rapid condensation of steam pockets, steam-driven slugs of water, pump startup with partially empty lines, and rapid valve motion. Most of the damage has been relatively minor and involved pipe hangers and restraints. However, several incidents have resulted in piping and valve damage. This item was originally identified in NUREG-0371, (Reference 4) and was later determined to be an Unresolved Safety Issue.

AP1000 Response:

Specific sections of the Standard Review Plan (NUREG-0800) address criteria for mitigation of water hammer concerns. The applicable Standard Review Plan sections as well as information provided in NUREG-0927 (Reference 5) were reviewed. The AP1000 meets the water hammer provisions as specified. The discussion that follows provides a brief description of selected systems identified as being subject to water hammer occurrences and special design features that mitigate or prevent water hammer damage.

Design features are incorporated as appropriate to prevent water hammer damage in applicable systems including steam generator feedrings and piping, passive core cooling system, passive residual heat removal system, service water system, feedwater system, and steam lines.

Water hammer issues are considered in the design of the AP1000 passive core cooling system. The passive core cooling system design includes a number of design features specifically to prevent or mitigate water hammer.

The automatic depressurization system operation uses multiple, sequenced valve stages to provide a relatively slow, controlled depressurization of the reactor coolant system, which helps to reduce the potential for water hammer.

Once the depressurization is complete, gravity injection from the in-containment refueling water storage tank is initiated by opening squib valves and then check valves, which reposition slowly. Gravity injection flow actuates slowly, without water hammer, as the pressure differential across the gravity injection check valves equalizes, and the valves open and initiate flow.

The passive residual heat removal heat exchanger is normally aligned with an open inlet valve and closed discharge valves. This alignment keeps the system piping at reactor coolant system pressure, preventing water hammer upon initiation of flow through the heat exchanger. Instrumentation is provided at the system high point to detect a void in the system.

The core makeup tanks are normally aligned with an open inlet line from the reactor coolant cold leg to keep the tanks at reactor coolant system pressure. This alignment keeps the system piping at reactor coolant pressure, preventing water hammer upon initiation of flow through the tank. In addition, instrumentation is provided at each high point to detect voids within the system. Section 6.3 provides additional information on the passive core cooling system.

The potential for water hammer in the feedwater line is minimized by the improved design and operation of the feedwater delivery system. The steam generator features include introducing feedwater into the steam generator at an elevation above the top of the tube bundles and below the

normal water level by a top discharge spray tube feedring. The feedring is welded to the feedwater nozzle to limit the potential for inadvertent draining. The layout of the feedwater line is consistent with industry standard recommendations to reduce the potential of a steam generator water hammer.

The startup feedwater system is a nonsafety-related system that provides feedwater during normal plant startup, shutdown, and hot standby. The startup feedwater line is separate from the main feedwater line and therefore does not contribute to the potential of water hammer in the feedwater piping or steam generator feedring.

The main steam line drains are designed to remove accumulated condensate from the main steam lines and to maintain the turbine bypass header at operating temperature during plant operation. The system is designed to accommodate drain flows during startup, shutdown, transient, and normal operation to protect the turbine and the turbine bypass valves from water slug damage.

A-2 Asymmetric Blowdown Loads on Reactor Primary Coolant Systems

Discussion:

Generic Safety Issue A-2 pertains to asymmetric loadings that could act on a pressurized water reactor's primary system as the result of a postulated double-ended rupture of the piping in the primary coolant system. The magnitude of these loads is potentially large enough to damage the supports of the reactor vessel, the reactor internals, and other primary components of the system. Therefore, the NRC initiated a generic study to develop criteria for an evaluation of the response of the primary systems in pressurized water reactors to these loads.

AP1000 Response:

The use of mechanistic pipe break criteria permits elimination of the evaluation of dynamic effects of sudden circumferential and longitudinal pipe breaks in the structural analysis of structures, systems, and components. General Design Criterion 4 allows the use of analyses to eliminate from the design basis the dynamic effects of pipe ruptures postulated at locations defined in Subsection 3.6.2. Dynamic effects include jet impingement, pipe whip, jet reaction forces on other portions of the piping and components, subcompartment pressurization including reactor cavity asymmetric pressurization transients, and traveling pressure waves from the depressurization of the system.

The AP1000 reactor coolant loop and pressurizer surge line are designed in accordance with mechanistic pipe break criteria. In addition, other high energy ASME Code, Section III, Class 1 and 2 piping of 6 inches and greater nominal diameter is evaluated against leak-before-break criteria. The evaluation methodology is described in Subsection 3.6.3 and Appendix 3B.

A-3 Steam Generator Tube Integrity

Discussion:

Pressurized water reactor steam generator tube integrity is subject to various degradation mechanisms, including corrosion-induced wastage, cracking, reduction in tube diameter, denting, (which leads to primary side stress corrosion cracking), vibration-induced fatigue cracks, and wear or fretting due to loose parts in the secondary system. The primary concern is the capability of degraded tubes to maintain their integrity during normal operation and under accident conditions (LOCA or a main steam line break) with adequate safety margins.

Steam generator tube integrity concerns for the three steam generator suppliers, Westinghouse, Combustion Engineering, and Babcock and Wilcox, are addressed by an integrated NRC program for Generic Safety Issues A3, A4, and A5. This program addresses the areas of steam generator integrity, plant systems response, human factors, radiological consequences, and the response of various organizations to a steam generator tube rupture.

AP1000 Response:

The AP1000 steam generators are designed in accordance with the recommendations of Generic Letter 85-02 and NUREG-0844 (References 6 and 7). The AP1000 steam generator is equipped with a number of features to enhance steam generator tube performance and reliability. These features are described in Subsection 5.4.2.

A-9 Anticipated Transients Without Scram

Discussion:

Generic Safety Issue A-9 was resolved with the publication of 10 CFR 50.62. This regulation sets forth the requirements for reduction of risks from anticipated transients without scram.

AP1000 Response:

The AP1000 complies with the requirements of 10 CFR 50.62 except that the AP1000 does not have a safety-related auxiliary feedwater system. In lieu of the automatic initiation of the auxiliary feedwater system under conditions indicative of an ATWS as required by 10 CFR 50.62 (c)(1), the AP1000 automatically initiates the passive residual heat removal system as discussed in Section 6.3.

A discussion of the AP1000 design features used to address the probability of an ATWS is presented in Subsection 1.9.5 and Section 7.7.

A-11 Reactor Vessel Materials Toughness

Discussion:

Generic Issue A-11 addresses a concern with the reduction of reactor vessel fracture toughness as plants accumulate more and more service time. 10 CFR 50, Appendix G provides requirements for reactor vessel material toughness.

AP1000 Response:

The AP1000 reactor vessel design complies with the requirements of 10 CFR 50, Appendix G and includes numerous features to reduce neutron fluence, enhance material toughness at low temperature and eliminate weld seams in critical areas. Material requirements are provided in Subsection 5.3.2. Pressure and temperature limits are provided in Subsection 5.3.3.

A-12 Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports

Discussion:

Generic Safety Issue A-12 addresses a concern with the potential for lamellar tearing of steam generator and RCP support material. NUREG-0577 (Reference 8) categorizes operating plants relative to the adequacy of the plant's steam generator and reactor coolant pump supports with respect to fracture toughness.

AP1000 Response:

The steam generator and reactor coolant pump supports are described in Subsection 5.4.10. The supports are designed in accordance with subsection NF of Section III of the ASME Code. Design and fabrication of these supports in accordance with Subsection NF requirements provide acceptable fracture toughness of materials, and conform with NUREG-0577.

A-13 Snubber Operability Assurance

Discussion:

Generic Issue A-13 addresses snubber operability concerns. Snubbers are utilized primarily as seismic and pipe whip restraints at nuclear power plants. Their safety function is to operate as rigid supports for restraining the motion of attached systems or components under rapidly applied load conditions such as earthquakes, pipe breaks, and severe hydraulic transients.

Operating experience reports show that a substantial number of snubbers have leaked hydraulic fluid and that the rejection rate from functional testing and inspection is high. This has led to an NRC and ACRS concern regarding the effect of snubber malfunctions on plant safety.

AP1000 Response:

The use of snubbers is minimized in the AP1000. Gapped support devices, leak-before-break considerations, and state-of-the-art piping analysis methods are used to minimize the use of snubbers. Snubbers applied in safety-related applications are constructed to ASME Code, Section III, Subsection NF as discussed in Subsection 3.9.3.4.3.

A-17 Systems Interactions in Nuclear Power Plants

Discussion:

This item addresses the potential systems interactions among systems including safety-related and nonsafety-related structures, systems, and components. There can be unintended and unrecognized dependencies among structures, systems, and components. A number of specific types of interactions have been addressed in other generic safety issues and NRC staff activities. These include guidance for inclusion of internal flooding in the IPE program, requirements that address seismically-induced systems interactions, and evaluation of electric power supplies for electric power reliability. NUREG-0933 classifies this item as resolved with no new requirements.

AP1000 Response:

In addition to addressing the specific system interaction guidance mentioned above, the AP1000 was the subject of a systematic evaluation of potential adverse systems interactions documented in WCAP-15992, "AP1000 Adverse Systems Interactions Evaluation Report" (Reference 69).

A-24 Qualification of Class 1E Safety-Related Equipment

Discussion:

Generic Issue A-24 was resolved with the publication of 10 CFR 50.49, prescribing aging and testing for synergistic effects. The NRC has also issued Revision 1 to Regulatory Guide 1.89 for comment. The proposed revision describes a method acceptable to the NRC staff to demonstrate compliance with the requirements of 10 CFR 50.49.

AP1000 Response:

The AP1000 environmental qualification methodology described in Appendix 3D is based on the generic Westinghouse qualification program approved by the NRC. The Westinghouse methodology addresses the requirements of General Design Criteria 4 and 10 CFR 50.49, as well as the guidance of Regulatory Guide 1.89 and IEEE Standard 323-1974. See Appendix 1A and Reference 9.

A-25 Non-Safety Loads on Class 1E Power Sources

Discussion:

Generic Issue A-25 addresses whether nonsafety-related loads should be allowed to share Class 1E power sources with safety-related plant systems. Past regulatory practice has allowed the connection of nonsafety-related loads in addition to the required safety loads to Class 1E power sources by imposing some restrictions. The purpose of this issue is for the NRC to determine whether the reliability of the Class 1E power sources is significantly affected by the sharing of safety and nonsafety-related loads.

The NRC considers this issue as technically resolved with the issuance of Revision 2 to Regulatory Guide 1.75. This regulatory guide includes special requirements for connection of nonsafety-related loads to a Class 1E source.

AP1000 Response:

The AP1000 conforms with the criteria of Regulatory Guide 1.75 with minor exceptions (see Appendix 1A and IEEE 384-1974). The AP1000 safety-related power source is the Class 1E dc and UPS system, which supplies power to the ac inverters for the plant instrumentation and control systems. The system also provides power to dc loads associated with the four protection channels and the accident monitoring system. Non-Class 1E loads powered from Class 1E sources are limited to loads that need connection to a reliable power source. No Credible failure of non-Class 1E equipment or systems will degrade the Class 1E system below an acceptable level. Subsection 8.3.2.1.1 provides a discussion on the Class 1E power source.

A-26 Reactor Vessel Pressure Transient Protection

Discussion:

Generic Issue A-26 addresses the need to provide reactor vessel overpressure protection whenever plants are in a cold shutdown condition. Branch Technical Position RSB 5-2 establishes the current NRC criteria for a low-temperature overpressurization protection system.

AP1000 Response:

The AP1000 conforms with the criteria established in Branch Technical Position RSB 5-2. The AP1000 pressurizer is sized to accommodate most pressure transients. Overpressure protection for the reactor coolant system is provided by either the pressurizer safety valves or the normal residual heat removal relief valves, as described in Subsection 5.2.2.

A-28 Increase in Spent Fuel Pool Storage Capacity

Discussion:

Generic Issue A-28 addresses the safety significance of damage to spent fuel, primarily from a lack of adequate cooling, that could result in the release of radioactivity.

AP1000 Response:

The AP1000 incorporates the NRC criteria. The heat load is evaluated for the spent fuel storage capacity.

A-29 Nuclear Power Plant Design for the Reduction of Vulnerability to Industrial Sabotage

Description

This item addresses potential methods to reduce vulnerability to sabotage. The NRC staff concluded that existing requirements dealing with plant physical security, controlled access to vital areas, screening for reliable personnel appear to be effective. This item was resolved with no new requirements.

AP1000 Response:

The passive systems in the AP1000 provided to mitigate the effects of potential accidents may have an inherent advantage when considering potential acts of sabotage compared to the active systems in operating plants. The AP1000 includes provisions for access control to the vital area. The provisions for security are discussed in the AP1000 Security Design Report and outlined in Section 13.6.

A-31 Residual Heat Removal Requirements

Discussion:

Generic Issue A-31 addresses the desire for plants to be able to go from hot-standby to cold-shutdown conditions (when this is determined to be the safest course of action) under an accident condition. The safe shutdown of a nuclear power plant following an accident not related to a loss-of-coolant accident has been typically interpreted as achieving a hot standby condition (the reactor is shut down, but system temperature and pressure are at or near normal operating values). There are events that require eventual cooldown and long-term cooling to perform inspection and repairs.

AP1000 Response:

The AP1000 employs safety-related core decay heat removal systems that establish and maintain the plant in a safe, stable condition following design basis events. It is not necessary that these passive systems achieve cold shutdown as defined by Regulatory Guide 1.139.

The AP1000 complies with General Design Criteria 34 by using a more reliable and simplified system design. The passive core cooling system is employed for both hot-standby and long-term cooling modes. Hot-standby conditions are achieved immediately and a temperature of 420°F is reached within 36 hours as discussed in Subsection 19E.4.10.2. Reactor pressure is controlled and can be reduced to about 250 psig. The passive residual heat removal system provides a closed cooling system to maintain long-term core cooling. Passive feed and bleed cooling, using the passive injection features for the feed and the automatic depressurization system for bleed, provides safety-related cooling capability. See Section 7.4 for a discussion of safe shutdown and Section 6.3 for a description of the passive core cooling system.

Since the passive core cooling system maintains safe conditions indefinitely, cold shutdown is necessary only to gain access to the reactor coolant system for inspection or repair. On the AP1000, cold shutdown is accomplished by using non-safety-related systems. These systems are highly reliable. They have similar redundancy as current generation safety-related systems and are supplied with ac power from either onsite or offsite sources. See Subsection 5.4.7 for a description of the normal residual heat removal system and Subsection 7.4.1.3 for a discussion of cold shutdown achieved by use of non-safety-related systems.

A-35 Adequacy of Offsite Power Systems

Discussion:

Generic Issue A-35 addresses the susceptibility of safety-related electric equipment to offsite power source degradation. The NRC considers this issue as technically resolved with the issuance of the Standard Review Plan, Section 8.3.1 criteria specified in Appendix A, Branch Technical Position BTP PSB 1, "Adequacy of Station Electric Distribution System Voltages."

AP1000 Response:

The AP1000 ac power system is discussed in Sections 8.1 through 8.3. The AP1000 does not require any ac power source to achieve and maintain safe shutdown.

A-36 Control of Heavy Loads Near Spent Fuel

Discussion:

Generic Issue A-36 addresses the need to review requirements, facility designs, and Technical Specifications regarding the movement of heavy loads near spent fuel. The NRC has documented its technical position on this issue in NUREG-0612 (Reference 10) and that issued Standard Review Plan, Section 9.1.5, which includes NUREG-0612 as a part of the review plan.

AP1000 Response:

The AP1000 design conforms to NUREG-0612 and Standard Review Plan, Section 9.1.5. Light load handling systems are described in Subsection 9.1.4, and overhead heavy-load handling systems are described in Subsection 9.1.5.

A-39 Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits for BWR Containments

Discussion:

Generic Issue A-39 addresses operation of BWR primary system pressure relief valves whose operation can result in hydrodynamic loads on the suppression pool retaining structures or those structures located within the pool. These loads result from initial vent clearing of relief valve piping and steam quenching due to high local pool temperatures. This USI was resolved with the issuance of SRP Section 6.2.1.1.C and a series of NUREG reports.

Generic Issue A-39 is not directly applicable to the AP1000. However, the AP1000 in-containment refueling water storage tank (IRWST) has some functional similarity to a suppression pool when the automatic depressurization system (ADS) is actuated.

AP1000 Response:

The AP1000 in-containment refueling water storage tank design includes consideration of loads due to automatic depressurization system operation. The effect of hydrodynamic loads is addressed in Subsection 3.8.3.4.2.

A-40 Seismic Design Criteria - Short Term Program

Discussion:

Generic Issue A-40 addresses a desire to identify and quantify conservatism in the seismic design process. The Standard Review Plan, Section 3.7 provides clarification of development of site-specific spectra, justification for use of single synthetic time-history by power spectral density function, location and reductions of input ground motion for soil-structure interaction, and design of

above-ground vertical tanks. The revised provisions are used for margin studies and re-evaluations or individual plant examination for external events.

AP1000 Response:

The AP1000 conforms to the criteria outlined in the Standard Review Plan, Section 3.7. The seismic design criteria and seismic evaluation methodology are described in Section 3.7.

The AP1000 employs generic, enveloping seismic design criteria and applies established seismic evaluation methodology that complies with current regulations and regulatory guidance. For sites having specific characteristics outside the range of the selected parameters, the AP1000 is evaluated to demonstrate acceptability to the site-specific characteristics.

A-43 Containment Emergency Sump Performance

Discussion:

Generic Issue A-43 addresses technical concerns as follows:

- Pressurized water reactor sump (or boiling water reactor residual heat removal system suction intake) hydraulic performance under post-loss-of-coolant accident adverse conditions resulting from potential vortex formation, air ingestion, and subsequent pump failure

- The possible transport of large quantities of insulation debris generated by a loss-of-coolant accident resulting from a pipe break to the sump debris screen(s), and the potential for sump screen (or suction strainer) blockage to reduce net positive suction head (NPSH) margin below that required for the recirculation pumps to maintain long-term cooling

- The capability of residual heat removal and containment spray system pumps to continue pumping when subjected to possible air, debris, or other effects, such as particulate ingestion on pump seal and bearing systems

AP1000 Response:

Air ingestion, vortexing, and debris blockage are not significant concerns for the AP1000. Containment recirculation includes sump screens that conform to the criteria specified in Regulatory Guide 1.82. The recirculation screens have a large cross-sectional area to reduce the fluid flow velocity through the screen and to provide a large screening area to accommodate accumulated debris. A horizontal plate located above the recirculation screens precludes debris being deposited in the water directly adjacent to the screens. Pipes that are the subject of loss of coolant pipe breaks and in the vicinity of these breaks use reflective metallic insulation (or a suitable equivalent, as demonstrated per the criteria in Subsection 6.3.2.2.7.1) to preclude the generation of fibrous insulation debris. See Subsection 6.3.2.2.7 for additional information on the design of the screens and limits on use of fibrous insulation.

Since the AP1000 design does not use pumps to provide safety injection flow, the passive core cooling system injection flow rates are substantially lower than those for plants with pumped injection flow. This results in lower fluid flow velocities through the screens, reducing the potential to draw debris into the sump screens.

The containment recirculation sump piping inlet is located slightly above the compartment floor, which is substantially below the expected flood-up water level. This precludes air ingestion in the piping since recirculation does not initiate until the flood-up water level is well above the piping inlet.

The elimination of pumps also eliminates concerns about the effects on safety injection capability for vortexing, air ingestion, and blockage effects on pump net positive suction head.

The AP1000 includes the capability to use nonsafety-related normal residual heat removal pumps to take a suction from the containment recirculation sump to provide reactor coolant system injection. The sump screen design addresses concerns with screen debris, vortexing, and air ingestion.

Section 6.3 provides additional information on the operation of the passive core cooling system. Appendix 1A describes conformance with Regulatory Guide 1.82. Section 6.2 provides additional information on the containment recirculation sump.

A-44 Station Blackout

Discussion:

Generic Issue A-44 was resolved with the publication of 10 CFR 50.63, which provides requirements that light-water-cooled nuclear power plants be able to withstand for a specified duration and recover from a station blackout. It specifies that an alternate ac power source constitutes acceptable capability to withstand station blackout provided an analysis is performed that demonstrates that the plant has this capability from the onset of the station blackout until the alternate ac source(s) and required shutdown equipment are started and lined up to operate.

10 CFR 50.2 for the alternate ac source notes that the alternate ac power source must have sufficient capability and reliability for operation of all systems required for coping with station blackout for the time required to place and maintain the plant in safe shutdown.

AP1000 Response:

AC electrical power is not needed to establish or maintain a plant safe shutdown condition for the AP1000. The ac power system is discussed in Chapter 8. In addition, two nonsafety-related standby diesel generators are provided as alternate sources of electrical power to nonsafety-related active systems that provide a defense-in-depth function.

A-46 Seismic Qualification of Equipment in Operating Plants

Discussion:

Generic Issue A-46 addresses the variability among operating plants in the margins of safety provided in equipment to resist seismically induced loads and perform the intended safety functions. The NRC believes that the seismic qualification of equipment in operating plants must, therefore, be reassessed to confirm the ability to bring the plant to a safe shutdown condition when it is subject to a seismic event.

AP1000 Response:

This issue applies to operating plants and, as such, does not specifically apply to the AP1000, which is designed in accordance with current seismic requirements. The seismic Category I mechanical and electrical equipment utilized for the AP1000 is qualified in accordance with the AP1000 qualification methodology discussed in Section 3.10. The methodology is based on the generic Westinghouse qualification program previously approved by the NRC. This methodology addresses IEEE Standard 344-1987 (Reference 13) and Regulatory Guide 1.100. See Subsection 1.9.1 (Appendix 1A).

A-47 Safety Implications of Control Systems

Discussion:

Generic Issue A-47 addresses the safety impact of non-safety-related control systems on plant dynamics. Instrumentation and control systems used by nuclear plants comprise safety-related protection systems and nonsafety-related control systems. Safety-related systems are used to trip

the reactor when specified parameters exceed allowable limits and to protect the core from overheating by initiating emergency core cooling systems. Nonsafety-related control systems are used to maintain the plant within prescribed parameters during shutdown, startup, normal load, and varying power operation. Nonsafety-related systems are not relied on to perform any safety functions during or following postulated accidents, but are used to control plant processes.

AP1000 Response:

For the AP1000, control system failures are considered as potential initiating events. The analyses of these transients demonstrate that the consequences of such failures are bounded by ANS Condition II criteria. No design basis failure of a control system violates Condition II criteria.

The integrated control system for the AP1000 obtains certain control input signals from signals used in the integrated protection system. With the integrated control and protection system, functional independence of the control and protection systems is maintained by providing a signal selection device in the control system for those signals used in the protection system. The purpose of the signal selection device is to prevent a failed signal, caused by the failure of a protection channel, from resulting in a control action that could lead to a plant condition requiring that protective action. The signal selection device provides this capability by comparing the redundant signals and automatically eliminating an aberrant signal from use in the control system. This capability exists for bypassed sensors or for sensors whose signals diverge from the expected error tolerance.

The plant control system incorporates design features such as redundancy, automatic testing, and self-diagnostics to prevent challenges to the protection and safety monitoring system. Chapter 7 provides a discussion of the AP1000 instrumentation and controls. The surveillance requirements for the main and startup feedwater control are found in Technical Specifications 3.7.3 and 3.7.7.

A-48 Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment

Discussion:

Generic Issue A-48 addresses postulated light water reactor accidents resulting in a degraded or melted core that could result in the generation and release to the containment of large quantities of hydrogen. One source of hydrogen is from the reaction of the zirconium fuel cladding with the steam at high temperatures. The NRC requires design provisions for handling hydrogen releases associated with rapid reaction of a large portion of fuel cladding (10 CFR 50.44 and 10 CFR 50.34).

AP1000 Response:

The AP1000 design complies with the provisions of draft changes to 10 CFR 50.44 and 10 CFR 50.34 (f). The mechanisms used to monitor and control hydrogen inside containment are discussed in Subsection 6.2.4.

A-49 Pressurized Thermal Shock

Discussion:

Generic Issue A-49 addresses transients and accidents postulated to occur in pressurized water reactors that can result in severe overcooling (thermal shock) of the reactor vessel, concurrent with high pressure. In these pressurized thermal shock events, rapid cooling of the reactor vessel internal surface causes a temperature distribution across the reactor vessel wall that produces a thermal stress with maximum tensile stress at the inside surface of the vessel. The magnitude of the thermal stress varies with the rate of change of temperature and is compounded by coincident pressure stresses.

As long as the fracture resistance of the reactor vessel material is relatively high, these events are not expected to cause vessel failure. The fracture resistance of the reactor vessel material decreases with the integrated exposure to fast neutrons. The rate of decrease is dependent on the chemical composition of the vessel wall and weld materials.

AP1000 Response:

The AP1000 complies with the requirements of 10 CFR 50.61. Material requirements and pressure-temperature limits are discussed in Subsections 5.3.2 and 5.3.3.

B-5 Ductility of Two-Way Slabs and Shells and Buckling Behavior of Steel Containments

Discussion:

Part I - Ductility of Two-Way Slabs and Shells

Generic Issue B-5 involved a concern over the lack of information on the behavior of two-way reinforced concrete slabs loaded dynamically in biaxial membrane tension, flexure, and shear. The NRC Staff concluded that there is sufficient information pertaining to the design of two-way slabs subjected to dynamic loads and biaxial tension to enable a reasonably accurate analysis.

Part II - Buckling Behavior of Steel Containments

Generic Issue B-5 involves a concern over the lack of a uniform, well defined approach for design evaluation of steel containments. Of particular interest was potential instability of the shell during dynamic loadings. Based on the conclusion of the NRC Staff that existing steel containments had adequate margins against buckling and that the issue of steel containment buckling had very little safety impact, this item was classified as resolved with no new requirements.

AP1000 Response:

The design requirements and analysis methods used for two-way reinforced concrete slabs and for the steel containment are outlined in Section 3.8.

B-17 Criteria for Safety-Related Operator Actions

Discussion:

Generic Issue B-17 addresses the development of a time criterion for safety-related operator actions including a determination of whether or not automatic actuation is required. The evaluation of this issue includes Issue 27, Manual versus Automated Actions.

AP1000 Response:

The AP1000 automatically initiates the safety-related actions required to protect the plant during design basis events. The plant systems are designed to provide the required information to the operator to monitor plant conditions and to evaluate the performance of the safety-related passive systems, as well as the nonsafety-related active systems. The active systems are designed to automatically actuate and provide defense-in-depth for various plant events, to preclude unnecessary actuation of the safety-related passive systems. The plant design also provides the capability for a backup manual initiation of both the safety-related systems and the nonsafety-related defense-in-depth systems.

As described in Chapter 15, the AP1000 safety systems maintain the plant in a safe condition following design basis events. For the design basis events described in Chapter 15, this is accomplished without the need for operator action for up to 72 hours. Operator action is planned and

expected during plant events to achieve the most effective plant response consistent with event conditions and equipment availability. For events where operator action is taken, the plant design maximizes the time available to complete actions for events. For example, during a steam generator tube rupture, no operator action is required to establish safe shutdown conditions or prevent steam generator overfill. It is expected that the main control room operators take actions similar to those taken in current plants to identify and isolate the faulted steam generator and to stabilize plant conditions.

For events where operator actions are taken, the AP1000 design is based on previous experience and the guidance of ANSI 58.8-1984 (Reference 21). At least 30 minutes is available following design basis events for the operator to initiate planned actions.

B-22 LWR Fuel

Discussion:

Generic Issue B-22 addresses the reliability of fuel behavior predictions during normal operation and postulated accidents. Standard Review Plan, Section 4.2 provides detailed NRC criteria for the design of fuel and core components.

AP1000 Response:

The AP1000 reactor core design complies with the Standard Review Plan, Section 4.2. See Section 4.2 for a discussion of the fuel system design.

B-29 Effectiveness of Ultimate Heat Sinks

Discussion:

Generic Issue B-29 addresses NRC confirmation of currently used mathematical models for prediction of ultimate heat sink performance by comparing model performance with field data and development of better guidance regarding the criteria for weather record selection to define ultimate heat sink design basis meteorology.

The NRC considers this issue to be technically resolved with the publication of three reports: NUREG-0693, NUREG-0733, and NUREG-0858 (References 23, 24 and 25).

AP1000 Response:

The AP1000 passive containment cooling system complies with Standard Review Plan, Section 9.2.5 by providing passive decay heat removal that transfers heat to the atmosphere, which is the ultimate heat sink for accident conditions. The passive containment cooling system is described in Subsection 6.2.2.

B-32 Ice Effects on Safety-Related Water Supplies

Discussion:

Generic Issue B-32 addresses the potential effects of extreme cold weather and ice buildup on the reliability of various plant water supplies. Current NRC criteria are provided in Standard Review Plan, Section 2.4.7, "Ice Effects."

AP1000 Response:

Subsection 6.2.2 describes the ultimate heat sink design and discusses the features that prevent freezing in the passive containment cooling system.

B-36 Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Features Systems and for Normal Ventilation Systems

Discussion:

Generic Issue B-36 addresses the development of revisions to current guidance and technical positions regarding engineered safety features and normal ventilation system air filtration and adsorption units. The NRC considers this issue technically resolved with the issuance of Revision 2 to Regulatory Guide 1.52 and Revision 1 to Regulatory Guide 1.140.

AP1000 Response:

The AP1000 main control room emergency habitability system (VES) includes a passive filtration system that is contained entirely within the main control room envelope. Regulatory Guide 1.52 was written for active safety-related filtration systems. To the extent applicable, system design criteria are established in accordance with Regulatory Guide 1.52 Revision 3. The passive filtration portion of the AP1000 VES contains no active equipment.

B-53 Load Break Switch

Discussion:

Generic Issue B-53 addresses the use of the generator load break switch for isolating the generator from the step-up transformer following turbine trip. Plant designs that utilize generator load circuit breakers to satisfy the requirement for an immediate access circuit stated in General Design Criterion 17, "Electric Power Systems," must prototype-test the generator load circuit breaker to demonstrate functional capability.

AP1000 Response:

The AP1000 design incorporates a generator load circuit breaker to provide a reliable source of ac power to the electrical systems. Exceptions to General Design Criteria 17, as discussed in Section 3.1, are due to the AP1000 design not requiring ac power sources for a design basis accident. Subsection 8.2.2.5 provides further discussion.

B-56 Diesel Reliability

Discussion:

Generic Safety Issue B-56 addresses the reliability of emergency onsite diesel-generators. Diesel reliability is a factor in the criteria associated with the resolution of Unresolved Safety Issue A-44. The resolution of issue B-56 is the development of guidelines for an acceptable emergency diesel-generator reliability program to ensure conformance with the emergency diesel-generator target reliability (0.95 to 0.975) identified in the proposed resolution of Unresolved Safety Issue A-44.

AP1000 Response:

The AP1000 diesel-generators are not safety related. The AP1000 diesel-generator reliability is based on diesel-generator industry standards and practices. The diesel generator is discussed in Subsection 8.3.1. The diesel generator reliability is modeled in the PRA. The reliability assurance program is discussed in Section 16.2.

B-61 Allowable ECCS Equipment Outage Periods

Discussion:

Generic Safety Issue B-61 addresses surveillance test intervals and allowable equipment outage periods in the technical specifications for safety-related systems. This task involves the NRC development of analytically based criteria for use in confirming or modifying these surveillance intervals and allowable equipment outage periods.

AP1000 Response:

The AP1000 surveillance test intervals and allowable outage times help to meet plant safety goals while maximizing plant availability and operability. In determining these limits for the AP1000 technical specifications, a combination of NUREG-1431 precedent, system design, and safety-related function is considered.

B-63 Isolation of Low-Pressure Systems Connected to the Reactor Coolant Pressure Boundary

Discussion:

Generic Issue B-63 addresses the adequacy of the isolation of low-pressure systems that are connected to the reactor coolant pressure boundary. The NRC staff requires that valves forming the interface between high- and low-pressure systems associated with the reactor coolant boundary have sufficient redundancy to prevent the low-pressure systems from being subjected to pressures that exceed their design limits.

AP1000 Response:

The AP1000 includes interconnections between high- and low-pressure systems. Each of these systems interfaces contains appropriate isolation provisions. Valves at the interface between high- and low-pressure systems have redundancy to prevent low-pressure systems from being subjected to pressures that exceed their design limits. The AP1000 design meets the provisions of the Standard Review Plan, Section 3.9.6.

The normal residual heat removal system interface is addressed in Subsection 5.4.7. WCAP-15993 (Reference 56) provides an evaluation of the AP1000 conformance to intersystem loss-of-coolant accident regulatory criteria.

B-66 Control Room Infiltration Measurements

Discussion:

Generic Safety Issue B-66 addresses the adequacy of control room area ventilation systems and control building layout to ensure that plant operators are adequately protected against the effects of accidental releases of toxic and radioactive gases. The NRC considers this issue as being technically resolved, and criteria have been incorporated in Standard Review Plan, Section 6.4.

AP1000 Response:

The AP1000 main control room is essentially leak-tight. A description of the control room habitability systems is contained in Section 6.4.

Verification of design infiltration rates is as specified in Standard Review Plan, Section 6.4. The AP1000 minimizes unfiltered in-leakage by maintaining the main control room at a slightly positive pressure.

C-1 Assurance of Continuous Long-Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment

Discussion:

Generic Issue C-1 addresses the long-term capability of hermetically sealed instruments and equipment that must function in post-accident environments. The NRC considers this issue as being technically resolved with the issuance of current criteria for qualification of safety-related electrical equipment.

AP1000 Response:

The AP1000 environmental qualification program described in response to Unresolved Safety Issue A-24 addresses qualification of safety-related instrumentation and electrical equipment that must function under accident conditions. This program confirms the integrity of seals employed in the design of Class 1E equipment. See item A-24 of this subsection and Section 3.11 for AP1000 qualification methodology.

C-4 Statistical Methods for ECCS Analysis

Discussion:

Generic Issue C-4 addresses NRC development of a statistical assessment of the certainty level of the peak clad temperature limit. Appendix K, "ECCS Evaluation Models," to 10 CFR 50 specifies the requirements for ECCS analysis. These requirements call for conservatisms to be applied to certain models and assumptions used in the analysis to account for data uncertainties at the time Appendix K was written. The resulting conservatism in the calculated peak clad temperature (PCT) has not been thoroughly compared against the uncertainty in peak clad temperature obtained from a realistically calculated (best-estimate) LOCA. The staff allows voluntary use of statistical uncertainty analysis to justify relaxation of all but the required conservatisms contained in current ECCS evaluation models.

AP1000 Response:

Chapter 15 discusses the LOCA analysis for the AP1000.

C-5 Decay Heat Update

Discussion:

Generic Issue C-5 involves following the work of research groups in determining best-estimate decay heat data and associated uncertainties for use in LOCA calculations.

The staff has determined that the 1979 ANSI 5.1 is technically acceptable and has allowed the use of this data to justify relaxation of non-required conservatisms in current ECCS evaluation models. The ECCS rule change allows the use of this new data. This issue was determined to be resolved.

AP1000 Response:

The large-break LOCA analyses for the AP1000, which employ the best-estimate W COBRA/TRAC analysis methodology (Subsection 15.6.5), use the decay heat model identified in the 1979 ANSI 5.1 (Reference 26).

C-6 LOCA Heat Sources

Discussion:

Generic Issue C-6 addresses the impact on LOCA calculations of LOCA heat sources, their associated uncertainties, and the manner in which they are combined. An evaluation was made of the combined effect of power density, decay heat, stored energy, fission power decay, and their associated uncertainties with regard to calculations of LOCA heat sources.

AP1000 Response:

See Subsection 15.6.5 for a discussion of LOCA heat sources.

C-10 Effective Operation of Containment Sprays in a LOCA

Discussion:

Generic Issue C-10 addresses the effectiveness of containment sprays to remove airborne radioactive materials that could be present within the containment following a LOCA. The NRC considers this issue as being technically resolved with the issuance of ANSI 56.5-1979 (Reference 28), which is referenced in Standard Review Plan, Section 6.5.2.

AP1000 Response:

The AP1000 design does not employ a safety-related containment spray system for removal of airborne radioactive materials in containment. Subsection 15.6.5.3 provides details of source term and mitigation techniques.

C-17 Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes

Discussion:

Generic Issue C-17 addresses the development of criteria for acceptability of radwaste solidification agents. The NRC considers this issue as technically resolved with the issuance of 10 CFR 61.56.

AP1000 Response:

The AP1000 solid radwaste system transfers, stores, and prepares spent ion exchange resins for disposal. It also provides for disposal of filter elements; sorting, shredding, and compaction of compressible dry active wastes. The solid radwaste system does not provide for liquid waste concentration or solidification. These functions, if used, are provided using mobile systems. Solidification of wastes is not performed by permanently installed systems.

1.9.4.2.3 New Generic Issues

These items were identified in NUREG-0933 as New Generic Issues and surfaced after the publication of the NUREGs that included the Task Action Plan items other unresolved safety issues.

Issue 14 PWR Pipe Cracks

Discussion:

This issue addresses the occurrences of main feedwater line cracking found in operating plants. This issue was classified as resolved with no new requirements.

AP1000 Response:

The design and inspection requirements for the feedwater lines are discussed in Subsection 10.4.7.

Issue 15 Radiation Effects on Reactor Vessel Supports

Discussion:

Generic Safety Issue 15 addresses the potential problem of radiation embrittlement of reactor vessel support structures. There is a potential for radiation embrittlement of the reactor vessel support structure from long-term exposure to neutrons with an energy of 1 MeV or greater. Embrittlement due to neutron damage may increase the potential for propagation of existing flaws.

AP1000 Response:

The supports for the AP1000 reactor pressure vessel are designed for loading conditions and environmental factors including consideration of neutron fluence levels. The material requirements include fracture toughness requirements and impact testing requirements in compliance with ASME Code, Section III, Subsection NF requirements. The reactor pressure vessel supports are not in the region of high neutron fluence where neutron embrittlement of the supports would be a significant concern.

Issue 22 Inadvertent Boron Dilution Event

Discussion:

Some operating plants do not have provisions to detect boron dilution during cold shutdown. This could result in inadvertent criticality. The NRC staff concluded that existing review criteria are adequate. This issue was classified as resolved with no new requirements.

AP1000 Response:

The provisions in the design to preclude inadvertent boron dilution events are outlined in Subsection 9.3.6.

Issue 23 Reactor Coolant Pump Seal Failures

Discussion:

Generic Safety Issue 23 addresses reactor coolant pump seal failures that challenge the makeup capacity in PWRs. Such seal failures represent small-break loss-of-coolant accidents.

AP1000 Response:

The AP1000 reactor coolant pumps are sealless pumps. A sealless pump contains the motor and all rotating components inside a pressure vessel designed for full reactor coolant system pressure. The shaft for the impeller and rotor is contained within the pressure boundary; therefore, seals are not required in order to restrict leakage out of the pump into containment. Subsection 5.4.1 provides additional information on the sealless pump design for the AP1000 reactor coolant pumps. Since the reactor coolant pumps do not rely on seals as a reactor coolant pressure boundary, this issue is not applicable to the AP1000.

Issue 24 Automatic ECCS Switchover to Recirculation

Discussion:

This issue addresses the issue of switchover from safety injection to recirculation using manual valve alignment or automatic valve alignment.

AP1000 Response:

The AP1000 does not switch from injection to recirculation in the sense that injection is not isolated when recirculation is opened. The AP1000 does provide for automatic opening of the recirculation line on a low level signal from the in-containment refueling water storage tank. See Section 6.3 for additional details.

Issue 29 Bolting Degradation or Failure in Nuclear Power Plants

Discussion:

Generic Safety Issue 29 addresses a concern about pressure boundary integrity and component support reliability associated with bolt failures.

As documented in Generic Letter 91-17, the NRC has provided resolution of this issue. The resolution is documented in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," and NUREG-1445, "Regulatory Analysis for the Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants." The resolution was based on a number of industry initiatives and NRC staff actions. NRC staff actions include issuing a number of bolting-related bulletins, generic letters and information notices. Industry initiatives include the publishing of EPRI Reports NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," and NP-5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel."

EPRI Report NP-5769 establishes the characteristic that bolted connections exhibit leakage prior to failure resulting from bolt degradation. The NRC has endorsed the recommendation in NP-5769 that plant-specific bolting integrity programs be established that encompass safety-related bolting. NUREG-1339 includes recommendations and guidelines for the content of a comprehensive bolting integrity program.

AP1000 Response:

The elements of resolution pertain to the design, material selection, fabrication, and in-service inspection of the bolted connections found in the AP1000. To address this, resolutions found in NUREG-1339 are incorporated into the design, material selection, fabrication, and maintenance of the bolted connections. The maintenance practices are addressed by the maintenance program of the combined license holder. Conformance to ASME Code, Section III requirements for pressure boundary components and related supports provides safe operation in the event of bolting degradation. Because of the emphasis in the AP1000 design on access for maintenance and inspection, the recommended maintenance practices can be implemented.

Issue 43 Reliability of Air Systems

Discussion:

This issue addresses the concern that compressed air system degradation or malfunction may cause malfunction of safety-related systems and components. Of particular interest are air operated valves because of problems with the quality of the air supply or the manner in which the compressed air system fails. Generic Letter 88-14 and NUREG-1275 were issued in response to this issue.

AP1000 Response:

The compressed air systems are described in Subsection 9.3.1. Provisions are included to maintain the quality of the air supply. The AP1000 safety-related, air-operated valves do not rely on the air supply to perform their safety-related function.

Issue 45 Inoperability of Instrumentation Due to Extreme Cold Weather

Discussion:

Generic Safety Issue 45 addresses the inoperability of instrumentation due to extreme cold weather. This issue was resolved with the issuance of changes to Standard Review Plan, Section 7.1, Appendix A to Section 7.1, Section 7.5, and Section 7.7.

AP1000 Response:

The AP1000 complies with Standard Review Plan Section 7.1, Appendix A to Section 7.1, Section 7.5, and Section 7.7.

Issue 51 Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems

Discussion:

Generic Safety Issue 51 addresses the susceptibility of open cycle service water systems to fouling including the buildup of aquatic bivalves and corrosion products that can significantly degrade the performance of the system. In operating plants, the service water system is typically used to cool safety-related equipment and to transfer decay heat to the ultimate heat sink.

AP1000 Response:

The service water system in the AP1000 provides cooling water to the component cooling water system and has no safety-related functions. None of the safety-related equipment requires cooling water to effect a safe shutdown or mitigate the effects of design basis events. Heat transfer to the ultimate heat sink is accomplished by heat transfer through the containment shell to air and water flowing on the outside of the shell.

The design of the service water system and the provisions for minimizing long-tern corrosion and organic fouling are described in Subsection 9.2.1.

Issue 57 Effects of Fire Protection System Actuation

Discussion:

Generic Safety Issue 57 addresses the potential for adverse interactions from actuation of the fire protection system with safety-related equipment. Operating experience has shown that safety-related equipment subject to fire protection system water spray and other suppressant chemicals can be rendered inoperable.

AP1000 Response:

The fire protection system and fire protection program in the AP1000 minimize the potential for adverse interactions of safety-related equipment with the fire protection system. The means used to achieve this result include: isolating combustible material and limiting the spread of fire by subdividing the plant into fire areas separated by fire barriers, providing separate and redundant safe shut down components and associated electrical divisions to preserve the ability to safely shutdown the plant following a fire, and providing floor drains sized to remove expected firefighting water without flooding safety-related equipment. The design of the fire protection system is described in Subsection 9.5.1.

Issue 67.3.3 Improved Accident Monitoring

Discussion:

This issue addresses weaknesses in accident monitoring. The recommended solution is to implement Regulatory Guide 1.97.

AP1000 Response:

The guidance of Regulatory Guide 1.97 is followed to determine the appropriate parameters to monitor in the AP1000.

Issue 73 Detached Thermal Sleeves

Discussion:

This issue addresses problems with "generation 3" thermal sleeves.

AP1000 Response:

The AP1000 does not use generation 3 thermal sleeves and includes design provisions to preclude failures of thermal sleeves.

Issue 75 Generic Implications of ATWS Events at the Salem Nuclear Plant

Discussion:

This issue considers the failure of reactor trip breakers to open and issues related to design and testing of the reactor protection system. Issues to be considered include the capability to record and display reactor trip system parameters, equipment classification information, post-maintenance testing, and reliability improvements in operating plants. Generic letter 83-28 and IE Bulletins 83-01 and 83-04 were issued by the staff with specific requirements.

AP1000 Response

The design of the reactor trip breakers and the reactor protection system is outlined in Section 7.1. Information on the functional requirements for reactor trip and conformance with industry and regulatory guidance is outlined in Section 7.2.

The provisions provided to display and record parameters used by the reactor trip system are outlined in Subsections 7.1.2.6 and 7.1.2.13. Section 7.5 also provides information on requirements for safety-related display information.

Subsection 7.1.1 identifies the safety-related functions provided by the protection and safety monitoring system and the items that are included in the system including the reactor trip switchgear. Conformance of safety-related systems and components to industry and regulatory criteria is identified in Subsection 7.1.4.

The reliability and fault tolerance of the protection and safety monitoring system for test maintenance and bypass conditions are outlined in Subsection 7.1.2.10.

The changes in the design of the reactor trip breakers and associated logic to enhance reliability in operating nuclear power plants have been incorporated in the AP1000 design as appropriate. The reactor trip system includes built-in test capability.

WCAP-15800 addresses conformance with generic letters and bulletins.

Issue 79 Unanalyzed Reactor Vessel Thermal Stress During Natural Convection Cooldown

Discussion:

Generic Safety Issue 79 addresses the thermal stresses that occur in the reactor vessel head flange during a natural circulation cooldown. High stresses in the flange or studs during a natural circulation cooldown in PWRs could violate ASME code allowables. Cycling of the stresses could reduce the fatigue margin. Generic Letter 92-02 repeated the reporting requirements of 10CFR 50.73 (a)(2)(ii)(B), "Licensee event report system."

AP1000 Response:

The natural circulation cooldown transient is evaluated as part of ASME Code vessel evaluations and is discussed in Subsection 3.9.1.1.2.11. The reporting requirements to address the requirements of 10CFR 50.73 (a)(2)(ii)(B) referenced in Generic Letter 92-02 are the responsibility of the Combined License holder.

Issue 82 Beyond Design Basis Accidents in Spent Fuel Pools

Discussion:

This issue addresses the concern of a beyond design basis accident in which the spent fuel pool is drained and spent fuel stored there subsequently catches on fire releasing very large amounts of radioactive contamination. This issue is classified as resolved with no new requirements.

AP1000 Response:

The AP1000 includes design provisions that preclude draining of the spent fuel pool. Also, provisions are available to supply water to the pool in the event the water covering the spent fuel begins to boil off.

Issue 83 Control Room Habitability

Discussion:

Loss of control room habitability following an accidental release of external toxic or radioactive material or smoke can impair or cause loss of the control room operators' capability to safely control the reactor. Use of the remote shutdown workstation outside the control room following such events is unreliable since this station has no emergency habitability or radiation protection provisions.

AP1000 Response:

Habitability of the main control room is provided by the main control room/control support area HVAC subsystem of the nonsafety-related nuclear island nonradioactive ventilation system (VBS). If ac power is unavailable for more than 10 minutes or if main control room differential pressure is below the “Low” setpoint for more than 10 minutes or if “High-2” particulate or iodine radioactivity is detected in the main control room supply air duct, which may lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The safety-related main control room emergency habitability system supplies breathable quality air for the main control room operators while the main control room is isolated.

In the event of external smoke or radiation release, the nonsafety-related nuclear island nonradioactive ventilation system provides for a supplemental filtration mode of operation, as discussed in Section 9.4. In the unlikely event of a toxic chemical release, the safety-related main control room emergency habitability system has the capability to be manually actuated by the

operators. Further, a 6-hour supply of self-contained portable breathing equipment is stored inside the main control room pressure boundary.

Issue 87 Failure of HPCI Steam Line Without Isolation

Discussion:

Generic Safety Issue 87 addresses the uncertainty regarding the operability of the motor-operated isolation valves for the steam supply lines of the high-pressure coolant injection (HPCI) system in boiling water reactors following a postulated break in the supply line. A break in the line could lead to high flow or high differential pressure that may inhibit closure of the isolation valve. These valves typically cannot be tested in-situ for the design flow rates and pressures. Although the AP1000 does not have a high-pressure coolant injection system, it does have isolation valves designed to close against high flow or high pressure differential in the event of a postulated pipe break.

The issue of the operability of motor-operated valves has received considerable attention since Generic Safety Issue 87 was initiated. The NRC provided guidance for inservice testing of motor-operated, safety-related valves in Generic Letter 89-10. SECY-93-087 identifies the proposed position on inservice testing of safety-related valves for advance light water reactors. The guidance in these documents recommends that safety-related valves be tested under full flow under actual plant conditions where practical. EPRI has a program to demonstrate operation of motor-operated valves.

AP1000 Response:

Safety-related valves must meet the requirements of ASME Code, Section III to provide pressure boundary integrity. Valves and valve operators are sized to provide operation under a full range of design basis flow and pressure drop conditions. For the AP1000, safety-related motor-operated valve designs are subject to qualification testing to demonstrate the capability of the valve to open, close, and seat against maximum pressure differential and flow. The requirements for this testing are based on ASME QME-1-2007, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants.” See Subsection 5.4.8 for an outline of AP1000 valve requirements.

The in-service testing program for safety-related valves is discussed in Subsection 3.9.6. Subsection 3.9.6 includes a discussion of the factors to be considered to determine which valves and test conditions are to be used for operability testing of power-operated valves. Sufficient flow is provided to fully open check valves during testing unless the maximum accident flows are not sufficient to fully open the check valve. The valves built to ASME Code, Section III are tested in compliance with the requirements found in the ASME code, "Code for Operation and Maintenance of Nuclear Power Plants." For additional information on inservice testing of safety-related valves, see Subsection 3.9.6.

Issue 93 Steam Binding of Auxiliary Feedwater Pumps

Discussion:

Generic Safety Issue 93 addresses the potential for a common mode failure of the pumps in an auxiliary or emergency feedwater system. Hot water leaking through one or more isolation valves can flash to steam at the auxiliary feedwater pump potentially resulting in the failure of the pump to operate if required because of steam binding. The NRC addressed this issue in Bulletin 85-01, and reinforced it in Generic Letter 88-03, by requesting that the fluid conditions in the auxiliary feedwater system be monitored and procedures be developed to recognize steam binding and restore the auxiliary feedwater system to operable status if steam binding should occur.

AP1000 Response:

The AP1000 does not have a safety-related auxiliary feedwater system. The passive core cooling system provides the safety-related function of cooling the reactor coolant system in the event of loss of feedwater. The startup feedwater system provides the steam generators with feedwater during plant conditions of startup, hot standby, and cooldown and when the main feedwater pumps are unavailable. The startup feedwater system has no safety-related function.

The startup feedwater system includes temperature instrumentation in the pump discharge for monitoring of the temperature of the startup feedwater system. The system also includes a normally closed isolation valve and a normally closed check valve for each pump limiting potential back leakage.

Issue 94 Additional Low-Temperature Overpressure Protection for Light Water Reactors

Discussion:

Generic Safety Issue 94 addresses the establishment of additional guidance for reactor coolant system low-temperature overpressure protection to ensure reactor vessel and reactor coolant system integrity beyond that identified in the resolution to Generic Safety Issue (GSI) A-26. Low-pressure overpressurization events that occurred subsequent to the implementation of the guidelines for resolution of GSI A-26 indicated a need for additional low-temperature overpressure protection. To resolve this issue, the NRC issued Generic Letter 90-06 which required a revision to plant technical specifications for operability of the low-temperature overpressure protection system. Other possible solutions identified in GL 90-06 included hardware modifications including use of residual heat removal system relief valves and requiring the low temperature overpressure protection system to be fully safety related.

AP1000 Response:

The reactor vessel for the AP1000 is designed to be less susceptible to brittle fracture during low temperature overpressure events. The material requirements and welding processes are developed to enhance resistance to embrittlement. See Subsection 5.3.2 for additional information on the requirements to address fracture toughness of the reactor vessel.

The normal residual heat removal system is designed to provide the safety-related function of low temperature overpressure protection for the reactor coolant system during refueling, startup, and shutdown operations. The system is designed to limit the reactor coolant system pressure within the limits specified in 10 CFR 50, Appendix G. The relief valves in the normal residual heat removal system are used to provide the overpressure protection. See Subsection 5.4.7 for additional information on the design of the normal residual heat removal system and the overpressure protection function.

Issue 103 Design for Probable Maximum Precipitation

Discussion:

Generic Safety Issue 103 addresses the methodology used for determining the design flood level for a particular reactor site. This issue was resolved by incorporating the methodology into the Standard Review Plan.

AP1000 Response:

This is a site-related parameter. The AP1000 is designed for air temperatures, humidity, precipitation, snow, wind, and tornado conditions as specified in Table 2.0-201. The site is acceptable if the site characteristics fall within the AP1000 plant site design parameters in Table 2.0-201. For cases where a site characteristic exceeds the envelope parameter, see Chapter 2.

Issue 105 Interfacing System LOCA at BWRs

Discussion:

Generic Safety Issue 105 addresses concerns over the adequacy of isolation valves between the reactor coolant system and low-pressure interfacing systems in BWRs. This issue, which is limited to pressure isolation valves in BWRs, is related to Generic Safety Issue 96, which considers the failure of the pressure isolation valves between the reactor coolant system and the RHR system in PWRs. Overpressurization of low-pressure piping systems due to reactor coolant system boundary isolation failure could result in rupture of the low-pressure piping outside containment. This may result in a core melt accident with an energetic release outside the containment building that could cause a significant offsite radiation release. Designing interfacing systems to withstand full reactor pressure is an acceptable means of resolving this issue.

AP1000 Response:

For information on this issue, see Subsection 1.9.5.1 SECY-90-016 Issues. See Subsection 5.4.7 for additional information on the normal residual heat removal system design.

Issue 106 Piping and Use of Highly Combustible Gases in Vital Areas

Discussion:

Generic Safety Issue 106 addresses the normal process system use of relatively small amounts of combustible gases on site and also addresses leaks or breaks in the hydrogen piping and supply system that could result in the accumulation of a combustible or an explosive mixture of air and hydrogen within the auxiliary systems building. The accumulation of combustible or explosive mixtures of gas in the auxiliary systems building could represent a threat to safety-related equipment if the combustible gases are inadvertently ignited.

AP1000 Response:

The AP1000 uses small amounts of combustible gases for normal plant operation. Most of these gases are used in limited quantities and are associated with plant functions or activities that do not jeopardize any safety-related equipment. These gases are found in areas of the plant that are removed from the Nuclear Island (see Subsection 9.3.2 for a description of the plant gas system). The exception to this is the hydrogen supply line to the chemical and volume control system (CVS).

The chemical and volume control system is the only system on the nuclear island that uses hydrogen gas. Hydrogen is supplied to the AP1000 CVS inside containment from a hydrogen injection package supplied from high pressure hydrogen bottles. The release of the contents of high pressure hydrogen bottles in the limiting building volumes (both inside containment and in the auxiliary building) would not result in a volume percent of hydrogen large enough to reach a detonable level.

The chemical and volume control system hydrogen supply piping is routed through the turbine building and into the auxiliary building and then into containment. The H_2 supply line is routed through the piping/valve room on elevation 100′-0″ of the auxiliary building. The piping/valve penetration room in the auxiliary building on elevation 100′-0″ is designed as a 3-hour fire zone. A fire in this area would not inhibit the safe shutdown of the plant. More information is contained in Appendix 9A.

The turbine building does not house any safety-related systems or equipment. The release of hydrogen into an area of the turbine building does not represent a threat to the safety of the plant.

The AP1000 containment has hydrogen sensors that would detect hydrogen leaks. The containment hydrogen concentration monitoring subsystem is described in Subsection 6.2.4.1.

Issue 113 Dynamic Qualification Testing of Large-Bore Hydraulic Snubbers

Discussion:

Generic Safety Issue 113 addresses the requirements for qualification and periodic operability testing of large bore hydraulic snubber for operating plants. Large-bore hydraulic snubbers are used to a limited extent on the AP1000 to provide support, particularly for seismic events, of piping systems and components while allowing for movement due to thermal expansion. The NRC, in a draft regulatory guide (SC-708-4, "Qualification and Acceptance Test for Snubbers Used in Systems Important to Safety"), has established recommendations for testing of hydraulic snubbers on a forward-fit basis; that is, units without a license at the time the recommendations were established.

AP1000 Response:

The AP1000 plant uses significantly fewer hydraulic snubbers than do currently operating plants. In addition to the recommendations in the draft regulatory guide, testing requirements have been established in ASME OM Code, "Code for Operation and Maintenance of Nuclear Power Plants," as implemented in the Inservice Testing Program Plan. Subsection 3.9.3.4.3 discusses requirements for production and qualification testing. The design of the hydraulic snubbers permits required preoperational and inservice testing.

Subsection 3.9.8.3 defines the responsibility to provide information on snubber operability testing.

Issue 120 On-Line Testability of Protection System

Discussion:

This issue is related to the protection system of some older plants that do not provide for as complete a degree of on-line protection system testing surveillance capability as is now required. Testing requirements and guidance are found in GDC 21, Regulatory Guides 1.22 and 1.118 and IEEE Standard 338. This item is classified as resolved with no additional requirements.

AP1000 Response:

This item does not apply to the AP1000. The provision for testing of the protection system in conformance with the regulatory guidance is found in Section 7.1.

Issue 121 Hydrogen Control for Large, Dry PWR Containments

Discussion:

Generic Safety Issue 121 concerns ongoing NRC experimental and analytical programs addressing the likelihood of safe shutdown equipment surviving a hydrogen burn. The staff also intends to explore the possibility and probable consequences of the formation of local detonable concentrations in large, dry PWRs. The concerns are prediction of conditions in realistic configurations, and containment and equipment survivability.

AP1000 Response:

The AP1000 includes provisions for hydrogen control for the unlikely severe accident cases in which large amounts of hydrogen could be generated because of degraded core events. Analyses were performed to examine the consequences of hydrogen burn and to evaluate the likelihood of deflagration to detonable transitions (see Appendix 19D).

For severe accident cases, the containment hydrogen control system prevents hydrogen burn initiation at high hydrogen concentration levels. Hydrogen igniters promote burning when the lower

flammability limit is reached and limits the containment hydrogen concentration to less than 10 volume percent during and following a degraded core or core melt.

Thus, for severe accident cases, the AP1000 is designed to prevent the occurrence of hydrogen detonation, thereby preventing the possibility of the resultant large pressure spikes in containment, which is the source of concern for containment integrity and equipment survival. Details of the hydrogen ignition subsystem are provided in Subsection 6.2.4.2.3. Placement of the hydrogen igniters is discussed in Subsection 6.2.4.

A hydrogen burn analysis shows that the AP1000 hydrogen igniter system is effective in maintaining the hydrogen concentration throughout the containment close to the lower flammability limit, and that the peak pressure in the containment during and following hydrogen burn remains well below ASME service level C stress intensity limits. The hydrogen concentration is similar in all compartments analyzed, indicating that the hydrogen released mixes well in the AP1000 containment. The analyses predict conditions in realistic configurations. Peak gas temperatures and pressures in each compartment for each case analyzed are provided, thus providing the hydrogen burn thermal environment that containment equipment will experience. Details are provided in Chapter 14 of the AP1000 PRA report.

The challenge to the AP1000 containment integrity from hydrogen deflagrations and detonations during core damage events is examined in the hydrogen deflagration and detonation analyses. This bounding evaluation assumes that an amount of hydrogen equivalent to 100-percent active cladding oxidation burns all at once in the AP1000 containment, with no credit taken for the hydrogen igniters. The evaluation concludes that a hydrogen deflagration is unlikely to cause containment failure. Other analyses show that a deflagration to detonation transition in any part of the AP1000 containment is unlikely. Containment failure from a detonation is not considered a credible event for the AP1000 because of the lack of conditions supporting a deflagration to detonation transition, the provision and placement of hydrogen igniters, and the containment design features resulting in a well-mixed atmosphere. Details are provided in subsection 10.2.5 of the AP1000 PRA evaluation report.

The hydrogen igniters and the containment electrical and mechanical penetrations are designed to operate in the most limiting severe accident environment, including a hydrogen burn. (See subsection 10.2.5 of the AP1000 PRA evaluation report.) The approach of using controlled burning to prevent accidental hydrogen burn initiation provides confidence that safety-related equipment will continue to operate during and after hydrogen burns. (See Subsection 6.2.4.)

Issue 124 Auxiliary Feedwater System Reliability

Discussion:

Generic Safety Issue 124 addresses the use of probabilistic risk assessment to evaluate the reliability of the auxiliary feedwater system. The issue was resolved by the NRC's issuing plant-specific requirements for a few plants that did not initially have a reliability higher than a minimum criteria.

AP1000 Response:

This issue is not applicable to the AP1000. The AP1000 does not have a safety-related auxiliary feedwater system. The passive core cooling system provides the safety-related function of cooling of the reactor coolant system in the event of loss of feedwater. The startup feedwater system provides the steam generators with feedwater during plant conditions of startup, hot standby, and cooldown and when the main feedwater pumps are unavailable. The startup feedwater system has no safety-related function beyond containment isolation.

Issue 128 Electrical Power Reliability

Discussion:

Generic Safety Issue 128 addresses the reliability of onsite electrical systems and encompasses GSI 48, GSI 49, and GSI A-30.

AP1000 Response:

The design basis and design criteria for the Class 1E dc and UPS system is provided in Subsections 8.1.4.2.1 and 8.1.4.3. The class 1E dc and UPS system design is described in Subsection 8.3.2.1.1. Specifically, this design addresses IEEE Standards 603 and 308. This includes the following generic issues:

- Generic Safety Issue 48, LCO for Class 1E vital instrument buses in operating reactors. The AP1000 Technical Specifications provide the limiting conditions for operation in the event of a loss of one or more Class 1E 120-vac vital instrument buses and the associated inverters. The AP1000 Class 1E buses have no tie breakers

- Generic Safety Issue 49, interlocks and LCOs for Class 1E tie breakers. Based on the historical background, this issue is not applicable to the AP1000 design. There are no tie breakers between the four class 1E divisions.

- Generic Safety Issue A-30, adequacy of safety-related dc power supplies. The AP1000 incorporates the following recommended enhancements:

  – The Class 1E dc distribution system design is in accordance with the guidelines of IEEE Standard 384 and Regulatory Guide 1.75.

  – Four separate divisions of Class 1E dc power are provided.

The AP1000 design provides additional testing capability through the installed spare battery bank with one installed battery charger. The spare battery bank permits frequent full-component testing, as described in Subsection 8.3.2.1.1, without compromising plant availability. Battery equalization can be performed off-line. The battery and battery charger can be tested and maintained separately.

Issue 130 Essential Service Water Pump Failure at Multiple Plant Sites

Discussion:

Generic Safety Issue 130 addresses the use of shared or cross-connected essential service water systems at sites with two or more reactor plants. During some situations the crosstied pumps may not be available for accident mitigation operations.

AP1000 Response:

The AP1000 is a single, independent plant that does not share or cross-tie systems or components with another plant. See Section 1.2 for a general description of the plant. This issue is not applicable to the AP1000.

Issue 135 Integrated Steam Generator Issues

Discussion:

Generic Safety Issue 135 was initiated to provide an integrated work plan for the resolution of steam generator issues including steam generator overfill consequences, water hammer, and eddy current testing. The issue was divided into the following four tasks:

1. Assessing current capabilities of eddy current testing and developing recommendations.

2. Reviewing SGTR results and conclusions to develop regulatory analysis supporting Standard Review Plan changes.

3. Reassessing SGTR associated issues including radiological, design basis, tube integrity, procedures, and RCS pressure control.

4. Reviewing the effects of water hammer, overfill and water carryover.

The results of the tasks will provide the staff with a basis to develop a position on offsite dose, operator action, tube integrity, water hammer, and valve operability.

AP1000 Response:

The AP1000 design features are discussed below.

TASK 1: Appendix 1A identifies the level of conformance with Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes." As detailed in Appendix 1A, the AP1000 conforms with the regulatory guidance except where state-of-the-art advances have enhanced inservice inspection techniques. Further, as specified in Subsection 5.4.2.5, the steam generators permit access to tubes for inspection and/or repair or plugging, if necessary, per the guidelines described in Regulatory Guide 1.83. The AP1000 steam generator includes features to enhance robotics inspection of steam generator tubes.

TASK 2: Subsection 15.6.3.1.4 discusses anticipated operator recovery actions and the effects of those actions in the mitigation of a steam generator tube rupture (SGTR). As discussed in Subsection 15.6.3.2, the AP1000 incorporates automatic steam generator overfill protection. The details of the design are provided in Subsection 15.6.3.2, with the control logic provided in Section 7.2.

TASK 3: The following sections provide pertinent details on SGTR issues.

- Reassessment of radiological consequences: Subsection 15.6.3 provides details of the scenario, analysis assumptions, and results.

- Re-evaluation of design basis SGTR: The design basis SGTR evaluated on the AP1000 is discussed in Subsection 15.6.3, providing details of the scenario, analysis assumptions and results.

- Supplemental Tube Inspections: See Subsection 5.4.2.5, Appendix 1A, Regulatory Guide 1.83.

- Denting criteria: Subsection 5.4.2.4.3 provides a discussion of steam generator design and tubing compatibility with secondary coolants.

- Improved accident monitoring and reactor vessel inventory measurement: Section 7.5 discusses the safety related display information.

- Reactor coolant pump trip: Subsection 7.3.1.2.5 discusses reactor coolant pump trip.

- Control room design: Sections 7.5 and 18.8 discuss the control room design and design process.

- Emergency operating procedures: Section 18.9 addresses the development of emergency operating procedures.
- Organizational responses: Chapter 13 identifies the requirements for organizational responses.
- Reactor coolant pressure control: Subsection 7.7.1.6 addresses primary system pressure control.

TASK 4: Steam generator overfill, water carryover and water hammer are addressed as discussed in Subsection 15.6.3.2, with the control logic provided in Section 7.2.

Issue 142 Leakage Through Electrical Isolators in Instrumentation Circuits

Discussion:

Generic Issue 142 addresses the susceptibility to leakage of isolation devices between safety- and nonsafety-related electrical systems. The NRC requires that licensees identify isolation devices in instrumentation circuits that are potentially susceptible to electrical leakage, define and perform an inspection and test program, replace failed or unacceptable isolators, and implement an annual program to inspect and test all electronic isolators between Class 1E and non-Class 1E systems.

AP1000 Response:

The use of isolation devices in the AP1000 Instrumentation and Control Architecture is described in Subsections 7.1.2.10, "Isolation Devices," 7.7.1.11, "Diverse Actuation System," and WCAP-15776 (Reference 70), Section 3.9, “Conformance to the Requirements to Maintain Independence Between Safety Systems and Other Interconnected Equipment (Paragraph 5.6.3.1 of IEEE 603-1991).” As stated in WCAP-15776, Section 3.9, the isolation devices are tested to conform to requirements. This testing meets the requirement for an inspection and test program and identifies those devices that are potentially susceptible to electrical leakage. Implementation of an annual program to inspect and test all electronic isolators between Class 1E and non-Class 1E systems is the responsibility of the Combined License holder. The use of fiber-optic data links eliminates electrically conductive paths between receiving and transmitting terminals, and eliminates the potential for electrically generated noise caused by leakage through an isolator. These communication links also use extensive testing and error checking to minimize erroneous transmissions. These data links are described in Subsection 7.1.2.8, "Communication Functions." In addition, electromagnetic design, testing, and qualification is performed as described in WCAP-15776, Section 2.6, "Design Basis: Range of Conditions for Safety System Performance (Paragraph 4.7 of IEEE 603-1991.)"

Issue 143 Availability of Chilled Water System and Room Cooling

Discussion:

This issue relates to the need to maintain air cooling systems in some rooms containing safety-related system components.

AP1000 Response:

This issue does not apply to the AP1000. The AP1000 does not rely on active safety systems to provide safe shutdown of the plant. A total loss of HVAC systems will not prevent a safe shutdown.

Issue 153 Loss of Essential Service Water in LWRs

Discussion:

This issue is related to the reliability of essential service water and the failure of such systems due to fouling mechanisms, ice effects, design deficiencies, flooding, multiple equipment failures, and personnel errors. This issue has been the subject of a number of generic communications from the NRC staff.

AP1000 Response:

This issue is not applicable to the AP1000. The AP1000 does not rely on the service water and component cooling water systems to provide safety-related safe shutdown.

Issue 163 Multiple Steam Generator Tube Leakage

Discussion:

This issue identifies a safety concern associated with potential multiple steam generator tube leaks triggered by a main steam line break outside containment that cannot be isolated. This sequence of events could lead to core damage due to the loss of all primary system coolant and safety injection fluid in the refueling water storage tank.

AP1000 Response:

The AP1000 plant response to a main steam line break (MSLB) scrams the reactor automatically and removes decay heat via the intact generator or the PRHR heat exchanger. If the MSLB is not isolated, the RCS will continue to lose coolant after shutdown through leaking steam generator tubes; the plant responds to the scenario as a small LOCA. The core makeup tanks drain and produce a low level signal. The plant protection and monitoring system depressurizes the RCS via the automatic depressurization system (ADS). The core remains covered throughout the scenario. Once the RCS is depressurized, the much lower reactor coolant system pressure stops the water loss through the leaking steam generator tubes. Therefore, no long-term core uncovery is expected.

Issue 168 Environmental Qualification of Electrical Equipment

Discussion:

This issue is related to the effects of cable aging and whether the licensing basis for older plants should be reassessed or enhanced in connection with license renewal, or whether they should be reassessed for the current license term.

AP1000 Position:

This issue applies to operating plants and does not apply to the AP1000.

Issue 185 Control of Recriticality Following Small-Break LOCAs in PWRs

Discussion:

This issue is related to the potential for large reactivity transients, including prompt criticality, and significant heat generation resulting from natural circulation flow of unborated water formed in steam generators following small-break LOCAs.

AP1000 Position:

This scenario is not a safety concern for the AP1000 because of the passive safety systems designed to mitigate the consequences of a LOCA. Specifically, the automatic depressurization

system operates to reduce primary system pressure and, thus, prevents significant heat transfer in the steam generators. Consequently, the steam generators should not generate any significant amount of boron-free condensate via reflux condensation over an extended period during a LOCA event. In the AP1000 design, the steam generator functions as a "heat source" as the RCS depressurizes, rather than a "heat sink" as it does in conventional PWR designs. Therefore, the differential temperature across the primary and secondary side of the generators is such that steam from the reactor will not condense on the tubes.

Another important design feature of the AP1000 that reduces the significance of this event is the elimination of the loop seal in the inlet to the reactor coolant pump. By elimination of the crossover leg piping, a large volume of boron-free condensate cannot collect in the loop piping. Thus, restart of the reactor coolant pumps following a LOCA will not result in a large slug of unborated water entering the core.

Post-LOCA, the PRHR heat exchanger can act as a heat sink and potentially could be a source of unborated water post-LOCA. However, condensate from the PRHR heat exchanger outlet mixes with the borated injection from the core makeup tanks and accumulators, and adequately mixes in the reactor vessel downcomer to prevent post-LOCA boron dilution. Long-term boration of the core is provided by the injection from the borated IRWST.

Issue 186 Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants

Discussion:

This issue concerns licensees operating within the regulatory guidelines of Generic Letter 85-11 that may not have taken adequate measures to assess and mitigate the consequences of dropped heavy loads.

FSAR Position:

There are no planned heavy load lifts outside those already described in the DCD. However, over the plant life there may be occasions when heavy loads not presently addressed need to be lifted (i.e. in support of special maintenance/ repairs). For these occasions, special procedures are generated that address the activity. Further discussion is provided in Subsection 9.1.5.3.

Issue 189 Susceptibility of Ice Condenser and Mark III Containments to Early Failure From Hydrogen Combustion During a Severe Accident Description

Discussion:

This issue concerns the early containment failure probability for ice condenser and BWR MARK III containments given the relatively low containment free volume and low containment strength in these designs.

FSAR Position:

The AP1000 design does not have an ice condenser containment or a Mark III containment. Therefore, this issue is not addressed here.

Issue 191 Assessment of Debris Accumulation on PWR Sump Performance

Discussion:

This issue addresses new contributors to debris and possible blockage of PWR sumps. Generic Letter (GL) 2004-02 (Reference 2), issued in September 2004, identified actions that utilities must take to address the sump blockage issue. The NRC position is that plants must be able to demonstrate that debris transported to the sump screen after a LOCA will not lead to unacceptable

head loss for the recirculating flow. For the AP1000, this requirement is interpreted as demonstrating that debris transported to recirculating screens will not significantly impede flow through the PXS and will not adversely affect the long-term operation of the PXS.

AP1000 Position:

The AP1000 Nuclear Power Plant uses natural recirculation for cooling the core following a loss of coolant accident (LOCA).

Screens are provided in strategic areas of the plant to remove debris that might migrate with the water in containment and adversely affect core cooling. Accordingly, it must be assured that the screens themselves are not susceptible to plugging.

Technical report APP-GW-GLR-079 (Reference 71) evaluates the potential for debris to plug the AP1000 screens consistent with Regulatory Guide 1.82 Revision 3 and subsequently issued Nuclear Regulatory Commission guidance. The evaluation considers the various potential contributors to screen plugging. It considers debris that could be produced by a LOCA as well as resident fibers and particles that could be present in containment prior to the LOCA. It considers the AP1000 containment design, equipment locations, and containment cleanliness program. The evaluation uses debris characteristics based on sample measurements from operating plants and evaluates the generation of chemical precipitants considering materials used inside the AP1000 containment, the post-accident water chemistry, and applicable research and testing. The AP1000 screen designs are acceptable.

Issue 191 Assessment of Debris Accumulation on PWR Sump Performance (REV. 1)

Discussion:

Results of research on BWR ECCS suction strainer blockage identified new phenomena and failure modes that were not considered in the resolution of Issue A-43. In addition, operating experience identified new contributors to debris and possible blockage of PWR sumps, such as degraded or failed containment paint coatings.

FSAR Position:

The design aspects of this issue are addressed by the DCD. The protective coatings program controls the procurement, application, inspection, and monitoring of Service Level I and Service Level III coatings with the quality assurance features discussed above. The protective coatings program complies with Regulatory Guide 1.54, and is controlled and implemented by administrative procedures. The program is discussed in Subsection 6.1.2.1.6.

Administrative procedures implement the containment cleanliness program. Implementation of the program minimizes the amount of debris that might be left in containment following refueling and maintenance outages. The program is consistent with the containment cleanliness program used in the evaluation discussed in Subsection 6.3.8.2. The program is discussed in Subsection 6.3.8.1.

Issue 196 Boral Degradation

Discussion:

The issue specifically addresses the use of Boral in long-term dry storage casks for spent reactor fuel.

FSAR Position:

Long-term dry storage casks for spent reactor fuel are not used and therefore this issue is not addressed here.

1.9.4.2.4 Human Factors Issues

These issues were outlined in the Human Factors Program Plan and are documented in NUREG-0985, Revision 1. The Human Factors Program Plan includes the human factors tasks required to address NUREG-0660.

HF4.4 Guidelines for Upgrading Other Procedures

Discussion:

The need was evaluated to develop technical guidance for use in upgrading normal operating procedures and abnormal operating procedures, similar to what the NRC staff completed for emergency operating procedures. NUREG-0933 classified this item as resolved with no new requirements.

AP1000 Response:

The process to manage the development, review and approval of AP1000 Normal Operating, Abnormal Operating, Emergency Operating, Refueling and outage planning, Alarm response, Administrative, Maintenance, Inspection, Test and Surveillance Procedures as well as the procedures which address the operation of post-72 hour equipment is delineated in APP-GW-GLR-040 (Reference 72).

Writer's Guidelines have been developed which control the preparation of Normal Operating Procedures and Two-Column Format Procedures. The Writer's Guidelines establish programmatic guidelines. The criteria and methodology for procedure development is described in this technical report and in Westinghouse Writer's Guidelines, and Human Factors-related procedures have been developed in accordance with these criteria/guidelines.

HF5.1 Local Control Stations

Discussion:

Human Factors Issue 5.1 addresses the need to develop additional guidance for the design of local control stations.

AP1000 Response:

The AP1000 local control stations are designed using the same human factors engineering (HFE) design process as is used for the main control room (MCR). The human factors engineering design process is described in Chapter 18. Section 18.8 provides a description of the human system interface (HSI) design element of the overall design process. As part of the human system interface design process, design guidelines for each interface, such as workstation displays, are generated. These guidelines are used when designing the respective interface and control stations. This provides consistency of human system interface design, including local control stations, with the main control room.

HF5.2 Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation

Discussion:

Human Factors Issue 5.2 addresses review criteria for human factors aspects of advanced controls and instrumentation.

AP1000 Response:

Chapter 18 describes the human factors engineering (HFE) program for the AP1000. Section 18.4 includes a description of the Functional Requirements Analysis and Allocation (element 3) for the AP1000. The objective of this allocation process is to define the AP1000 safety function requirements and allocate functions between the human and the machine appropriately. Section 18.8 also presents the implementation plan for the human system interface (HSI) design. This description of the human system interface design process includes the development of design guidelines, the execution of man-in-the-loop concept testing, review of human system interface design, and the use of a full-scale mockup.

The AP1000 human system interface (HSI)/man-machine interface (MMI) includes the following resources:

- Alarm system (also identified as alarm presentation system)
- Computerized Procedure System
- Plant Information System
- PMS Safety Display Subsystem
- Controls (dedicated and soft)
- Wall Panel Information System (WPIS)

The implementation plan for the design of each of these human system interfaces (HSI design) is described in Section 18.8. The mission statements and high-level information for each of these resources is also provided in Section 18.8. The plant information system provides display at the operators workstation. The protection and safety monitoring system provides qualified (Class 1E) displays to the operator, located at the dedicated safety panel. The alarm system provides alarm overviews which are integrated into the wall panel information system and it provides alarm system displays at the operator's workstation. Alarms are integrated into the workstation displays. There is a navigational link from an alarm system display for a specific alarm to its associated alarm response procedure as presented to the operator by the alarm presentation system. Design guidelines for each human system interface is developed as part of the human system interface design (as described in Section 18.8). These design guidelines are developed from existing industry guidelines and considerations specific to the technology planned for the human system interface. Human factors engineering specialists are part of the human factors engineering/ man-machine interphase design team (Section 18.2) and were involved in the development of the design guidelines.

1.9.5 Advanced Light Water Reactor Certification Issues

This subsection addresses the advanced light water reactor issues identified by the NRC in SECY-90-016 (Reference 29), in the February 27, 1992 NRC letter from D. M. Crutchfield to E. E. Kintner (Reference 30).

1.9.5.1 SECY-90-016 Issues

The following issues were outlined in SECY-90-016 (Reference 29).

1.9.5.1.1 Advanced Light Water Reactor Public Safety Goal

NRC Position:

Based on current regulatory guidance, including the NRC Severe Accident Policy Statement, Standardization Policy Statement, and Safety Goal Policy Statement, it is expected that any new standard plant design will result in a higher level of severe accident safety than current plant designs. This is achieved by improving safety and by striking a balance between accident prevention and mitigation.

The overall objective of the public safety goal is to significantly reduce or eliminate the likelihood of known major safety issues.

The safety goals approved by the NRC in the Staff Requirements Memorandum to SECY-90-016 (Reference 31) are as follows:

- The mean core damage frequency target for each design should be less than $1.0x10^{-4}$ per reactor year.

- The overall mean frequency of a large release of radioactive materials to the environment from a reactor accident should be less than 1 in 1,000,000 per year of reactor operation, where a large release is defined as one that has a potential for causing an early offsite fatality.

AP1000 Response:

The AP1000 level 1, 2, and 3 PRA evaluations for both internal and external events (excluding seismic events) demonstrate conformance with the NRC safety goals. The AP1000 PRA evaluates shutdown events and provides additional information and specific results.

1.9.5.1.2 Use of Physically-Based Source Term

NRC Position:

As noted in SECY-95-172 (Reference 57), the NRC plans to use the accident source term model from NUREG-1465 (Reference 58). This source term model provides a physically based approach to modelling of activity releases from the reactor core to the containment in the event of a core degradation accident. As discussed in SECY-94-302 (Reference 59), for the design basis accident, release of activity from the core will not be assumed to extend beyond the in-vessel release phase.

In calculating the radiological consequences of accidents, as stated in Reference 57, the NRC intends to use the model presented in SECY-94-194 (Reference 60) which identifies the proposed changes to 10 CFR Parts 50 and 100. The pertinent features that will be applied to the determination of accident radiological consequences are:

- In place of thyroid and whole body dose limits, dose limits are specified as total effective dose equivalent (TEDE). The offsite dose limits of 25 rem whole body and 300 rem thyroid are replaced by a limit of 25 rem TEDE. The dose limit for the control room operators (currently identified in SRP Section 6.4 as 5 rem whole body, 30 rem thyroid, and 30 rem beta skin) is replaced by 5 rem TEDE which is consistent with GDC 19.

- Instead of calculating the site boundary dose over the first two hours of the accident, the dose is to be calculated for the two hour interval over which the highest dose would be calculated.

AP1000 Response:

The AP1000 radiological consequence analysis utilizes the accident source term provided in Regulatory Guide 1.183.

1.9.5.1.3 Anticipated Transients Without Scram (ATWS)

NRC Position:

This former unresolved safety issue was resolved with the issuance of Rule 10 CFR 50.62. Requirements for currently operating pressurized water reactors include diverse reactor trip (except for Westinghouse plants) and diverse actuation of auxiliary feedwater and turbine trips.

The Staff Requirements Memorandum to SECY-90-016 (Reference 31) approved the requirement for diverse reactor trip systems for evolutionary advanced light water reactors. However, it added that if the applicant can demonstrate that the consequences of an anticipated transient without reactor trip are acceptable, the NRC should accept the demonstration as an alternative to the diverse reactor trip system.

AP1000 Response:

The AP1000 complies with the current rules on an anticipated transient without reactor trip as specified in 10 CFR 50.62.

The AP1000 design includes the following design features aimed at minimizing the probability of occurrence of an anticipated transient without reactor trip and at mitigating the consequences if it occurs.

- The design of the protection and safety monitoring system is highly reliable, using a two out of four coincidence logic and featuring continuous diagnostic testing. The system incorporates fail-safe features to the extent practical. It is designed to generate a reactor trip signal and to generate an actuation signal for most engineered safety features components when protection system failures occur.

- For a reactor trip, the switchgear consists of eight circuit breakers arranged in a two out of four matrix located in two separate cabinets. The trip is implemented by undervoltage trip attachments and diverse shunt trip devices on the circuit breakers. To initiate a reactor trip, power is interrupted to the undervoltage trip attachment, while the shunt trip attachment is energized. Either device trips the breaker. The eight-breaker configuration permits testing of the reactor trip breakers without the use of auxiliary bypass breakers.

- The reactor trip switchgear can be actuated manually from the main control room by reactor trip switches. The reactor trip switches are connected to the undervoltage trip attachment via the protection and safety monitoring system reactor trip matrix termination units and interposing relays. The reactor trip switches are also connected to the shunt trip attachment via the reactor trip matrix termination units. This manual trip signal does not pass through any software-based portion of the protection and safety monitoring system. In addition, it is possible to manually initiate a reactor trip from the main control room by turning off the motor-generators that provide power for control rod operation.

- A nonsafety-related diverse actuation system is included in the AP1000 design. The diverse actuation system inserts control rods by de-energizing the field windings of the control rod motor-generators.

- The diverse actuation system trips the turbine and diversely actuates selected other engineered safeguards functions. Additional details of the diverse actuation system are included in Section 7.7.

Section 15.8 describes the evaluation of an anticipated transient without reactor trip.

1.9.5.1.4 Midloop Operation

NRC Position:

Loss of decay heat removal function has occurred on a number of occasions in operating plants. In response to these events, the NRC issued Generic Letter 87-12 requesting that operating plants provide information regarding mid-loop operation. Generic Letter 88-17 requested additional

information and provided guidance to operating utilities. Subsequent NRC evaluations have indicated that loss of decay heat removal during midloop operation may contribute significantly to public risk.

It is the NRC position that for future plants, conformance with Generic Letter 88-17 is insufficient, and additional hardware features should be incorporated into the design.

The Staff Requirements Memorandum to SECY-90-016 (Reference 31) approved the proposed NRC position, with the following four additional recommendations made by the ACRS:

- Design provisions to help ensure continuity of flow through the core and residual heat removal system with low liquid levels at the junction of the decay heat removal system suction lines and the reactor coolant system
- Provisions to ensure availability of reliable systems for decay heat removal
- Instrumentation for reliable measurements of liquid levels in the reactor vessel and at the junction of the decay heat removal system suction lines and the reactor coolant system
- Provisions for maintaining containment closure or for rapid closure of containment openings.

AP1000 Response:

The following features are incorporated into the design of the reactor coolant system and the normal residual heat removal system for continued performance of the residual heat removal function during midloop operation:

- The layout of the reactor coolant system hot leg piping and the steam generator channel head is such that installation of the nozzle dams can be performed with an 80 percent level in the hot leg piping. This is about 9 inches above the actual hot leg piping midplane elevation. (The hot leg piping has a 31-inch inside diameter.)
- A specially designed vortex breaker is used for the normal residual heat removal system suction nozzle. This vortex breaker connects vertically to the bottom of the hot leg piping. The normal residual heat removal system suction piping is connected to the bottom of this vortex breaker. With the vortex breaker, the amount of air entrainment remains below 10 percent unless the hot leg is essentially drained. Therefore, the potential for a loss of normal residual heat removal system flow and damage to the normal residual heat removal pump is substantially reduced.
- The normal residual heat removal pump suction piping is designed to be self-venting to a condition acceptable for RNS pump operation such that no manual venting is required to start the pumps if stopped on cavitation due to excessive air entrainment. This is achieved by sloping most of the RNS pump suction piping upward from the RNS pump suction to the reactor coolant system hot leg. In the level portions of piping, there are no local high points. If the pump should stop during midloop operation, any air bubbles present in the pump or suction piping are vented back up through the suction line to the water surface in the hot leg. This feature allows the operator to rapidly restart the pump with no additional action required.
- The normal residual heat removal pumps are designed to minimize susceptibility to cavitation and other adverse conditions. The plant piping layout configuration (such as piping elevations and routing) and the available and required net positive suction head characteristics are designed such that the normal residual heat removal pumps normally operate without the need for throttling a residual heat removal control valve when the level in the reactor coolant system is reduced to a midloop level. If the reactor coolant system is at saturated conditions

and midloop level, some throttling of a residual heat removal flow control valve is necessary to maintain adequate net positive suction head. The normal residual heat removal system is readily restored after a temporary loss of decay heat removal.

- The core makeup tanks, accumulators, and the in-containment refueling water storage tank are isolated, but can be manually actuated during midloop operations. In addition, the in-containment refueling water storage tank is automatically actuated on a sustained loss of shutdown decay heat removal. This arrangement provides a reliable water source for maintaining the reactor coolant system inventory that is either automatically or manually actuated.

- Redundant narrow-range level instrumentation indicates the reactor coolant system water level between the bottom of the hot leg and the top of the steam generator inlet elbow. Indication and low level alarms are provided in the main control room. In addition, this instrumentation actuates the in-containment refueling water storage tank makeup.

- Wide-range pressurizer level instrumentation used during cold plant operations is expanded to the bottom of the hot legs. This provides a continuous level indication in the main control room, from the normal level in the pressurizer to the range of the two narrow-range hot leg level instrumentation.

- Normal residual heat removal system heat exchanger discharge flow instrumentation provides main control room indication of return flow to the reactor vessel. A low-flow alarm alerts the operator to a decrease in normal residual heat removal system return flow from either heat exchanger.

- The drain-down of the reactor coolant system to the midloop operating level and the subsequent reactor coolant system inventory control during midloop operation are performed by the operator from the main control room.

The plant design precludes the need to locally coordinate actions in the containment with the main control room operators to control the reactor coolant system drain-down rate and level.

- The normal residual heat removal temperature instruments upstream of the heat exchangers indicate reactor coolant system hot leg temperature when in reduced inventory conditions. In addition, at least two incore thermocouple channels are available to directly measure the core exit temperature during midloop residual heat removal operation. These two thermocouple channels are associated with separate electrical divisions.

- The automatic depressurization system first-, second-, and third-stage valves, connected to the top of the pressurizer, are open whenever the core makeup tanks are blocked during shutdown conditions while the reactor vessel upper internals are in place. This provides a vent flow path that, when combined with actuation of the automatic depressurization system fourth-stage valves, sufficient steam venting area is provided to reduce reactor coolant system pressure. Actuation of ADS stage 4, either automatically or manually (as described in Subsection 19E.4.8.3) allows the in-containment water storage tank to provide injection flow following a loss of decay heat removal.

Administrative controls require containment closure capability in modes 5 and 6, during reduced inventory operations, and when the upper internals are in place. Containment closure capability is defined as the capability to close the containment prior to core uncovery following a loss of the normal decay heat removal system (that is, normal residual heat removal system). The containment design also includes penetrations for temporary cables and hoses needed for shutdown operations. These penetrations are isolated in an emergency.

In addition to these design features, appropriate procedures are defined to guide and direct the operator in the proper conduct of midloop operation and to aid in identifying and correcting abnormal conditions that might occur during shutdown operations.

1.9.5.1.5 Station Blackout

NRC Position:

The NRC has issued NUREG-0649 (Reference 34), NUREG-1032 (Reference 35), and NUREG-1109 (Reference 36) to address the unresolved safety issue of station blackout (USI-44). See Subsection 1.9.4 for a discussion of USI-44.

To resolve this issue, the NRC published 10 CFR 50.63 and Regulatory Guide 1.155, which establish new requirements so that an operating plant can safely shut down following a loss of all ac power. SECY-94-084 (Reference 67), discusses station blackout for passive plants.

AP1000 Response:

The AP1000 is in conformance with the NRC guidelines for station blackout.

The AP1000 design minimizes the potential risk contribution of station blackout by not requiring ac power sources for design basis events. Safety-related systems do not need nonsafety-related ac power sources to perform safety-related functions.

The AP1000 safety-related passive systems automatically establish and maintain safe, stable conditions for the plant following design basis events, including an extended loss of ac power sources. The passive systems can maintain these safe, stable conditions after design basis events for at least 72 hours, without operator action, following a loss of both onsite and offsite ac power sources. Subsection 1.9.5.4 provides additional information on long-term actions following an extended station blackout beyond 72 hours.

The AP1000 also includes redundant nonsafety-related onsite ac power sources (diesel-generators) to provide electrical power for the nonsafety-related active systems which provide defense in depth.

AP1000 design features that mitigate the consequences of a station blackout are as follows:

- A full-load rejection capability to reduce the probability of loss of onsite power
- Safety-related passive residual heat removal heat exchanger
- Safety-related passive containment cooling
- Bleed and feed capability, using the safety-related automatic depressurization system in conjunction with the water available from the core makeup tanks, the accumulators, and the in-containment refueling water storage tank
- Class 1E batteries sized for 72 hours of operation under station blackout conditions
- Nonsafety-related reserve auxiliary transformers to provide power to selected ac power systems
- A nonsafety-related ac power system that includes two diesel-generators that automatically start on loss of normal ac power and offsite power

- An automatic nonsafety-related load-sequencing circuit that starts the following redundant nonsafety-related equipment after a loss of normal ac power and offsite power, once the associated diesel-generator is started:
  - Startup feedwater pump
  - Component cooling water pump
  - Service water pump
- Reactor coolant pumps without shaft seals
- Passive cooling for the rooms containing equipment assumed to operate during station blackout conditions (the protection and safety monitoring system cabinet rooms and the main control room) so that this equipment continues to operate. (Section 6.4 provides additional information.)

Training and procedures to mitigate a 10 CFR 50.63 “loss of all alternating current power” (or station blackout (SBO)) event are implemented in accordance with Sections 13.2 and 13.5, respectively. As recommended by NUMARC 87-00 (Reference 201), the SBO event mitigation procedures address response (e.g., restoration of onsite power sources), ac power restoration (e.g., coordination with transmission system load dispatcher), and severe weather guidance (e.g., identification of actions to prepare for the onset of severe weather such as an impending tornado), as applicable. The AP1000 is a passive design and does not rely on offsite or onsite ac sources of power for at least 72 hours after an SBO event, as described above.

Restoration from an SBO event will be contingent upon ac power being made available from any one of the transmission lines described in Section 8.2 or any one of the standby diesel generators.

1.9.5.1.6 Fire Protection

NRC Position:

Current fire protection criteria are contained in GDC 3 and 10 CFR 50.48, guidelines for compliance with these criteria are provided in the Standard Review Plan, Section 9.5.1, including Branch Technical Position CMEB 9.5-1. Reference 37 identifies the following enhancements:

- Alternative, dedicated shutdown capability for main control room fires.
- Safe shutdown capability required for a fire in any other fire area, without reliance on any equipment in that area or re-entry into that area for repairs or for performance of operator actions.
- Fire protection for redundant shutdown systems in the reactor containment building must be provided to ensure, to the extent practicable, that on shutdown the division will be free of fire damage.
- Migration of smoke, hot gases, or fire-suppressant chemicals into other applicable fire areas must be minimized by design to prevent any adverse impact on safe shutdown capability, including operator actions.

SECY-98-161 (Reference 66) presents the results of the NRC review of the AP1000 Fire Protection System.

AP1000 Response:

Enhanced fire protection has been one of the goals of the AP1000 design. The following physical separation philosophy is used:

Outside Containment:

- Within the nuclear island, redundant divisions of safety-related equipment outside containment are located in safety-related areas separated from each other and from other areas in the plant by fire barriers with a minimum fire resistance rating of 3-hours to provide that safe shutdown can be achieved. Since most safety-related mechanical equipment is located inside containment, this applies primarily to the protection and safety monitoring system and the Class 1E dc and UPS system.

- Each safety-related area is provided with ventilation isolation provisions at the fire barrier boundaries to minimize the migration of smoke, hot gasses, or fire suppressant chemicals into other safety-related areas. Fiber-optic cables are used to provide communication between redundant protection and safety monitoring divisions.

- Exceptions to the use of three-hour fire barriers outside containment are made only in cases where physical separation conflicts with other requirements or where the equipment is not clearly division oriented, such as the main control room, the remote shutdown room, the main steam tunnel, and the passive containment cooling system valve room.

Inside Containment:

- The containment is a single fire area. Separation by three-hour fire barriers inside containment is not practical due to issues of hydrogen venting, compartment pressure equalization, and during high-energy line breaks and for system functionality. To the extent practical, separation is provided between redundant safety-related equipment.

- Separation between redundant safety-related equipment is accomplished by using existing structural walls. Where this is not possible, other methods are used, such as physical separation with no intervening combustibles.

- To the extent practical, the containment is split into two different fire zones for the purpose of routing of protection and safety monitoring system cabling and electrical power cabling. Divisions A and C cabling is routed below the operating deck, while Divisions B and D cabling is routed above the operating deck. Additional separation is provided by existing floors and walls and by the physical separation of cabling runs. Protection for the primary input sensors and the final actuation devices is accomplished by the physical separation of the various sensors and components using existing containment walls as barriers.

- The in-containment fire area contains reduced combustible material due to the use of sealless reactor coolant pump motors that do not use oil lubrication and due to strict combustible material limitations.

Main Control Room:

- Functionality requirements dictate that the main control room be a single fire zone. Features are included in the main control room to:

  – Reduce the probability of fire initiation
  – Reduce the likelihood of fire spreading
  – Increase the probability of fire detection
  – Effectively mitigate the effects of a fire

- In the event of main control room evacuation, safe shutdown conditions are established and maintained using the remote shutdown workstation.

See Appendix 9A.3 for information on the main steam tunnel and the passive containment cooling system valve room. See Subsection 9.5.1 and Appendix 9A for additional information.

1.9.5.1.7 Intersystem LOCA

NRC Position:

Overpressurization of low-pressure piping systems due to reactor coolant system boundary isolation failure could result in rupture of the low-pressure piping outside containment. This may result in a core melt accident with an energetic release outside the containment building that could cause a significant offsite radiation release.

It is the NRC position that designing interfacing systems to withstand full reactor pressure is an acceptable means of resolving this issue. The Staff Requirements Memorandum to SECY-90-016 (Reference 31) added that consideration should be given to all elements of the low-pressure system (such as instrument lines, pump seals, heat exchanger tubes, and valve bonnets). For interfacing systems not designed to withstand full reactor coolant system pressure, it is necessary to provide leak testing capability for the pressure isolation valves, main control room position indication for de-energized reactor coolant system isolation valves, and high pressure alarms to alert control room operators when increasing reactor coolant system pressure approaches the design pressure of attached low-pressure systems and both isolation valves are not closed.

AP1000 Response:

The AP1000 has incorporated various design features to address intersystem loss-of-coolant accident challenges. These design features result in very low AP1000 core damage frequency for intersystem loss-of-coolant accidents compared with operating nuclear power plants. The design features are primarily associated with the normal residual heat removal system and are discussed in Section 3 of WCAP-15993 (Reference 56) as well as Subsection 5.4.7. WCAP-15993 was prepared to document the evaluation of the AP1000 for conformance to the intersystem loss-of-coolant accident regulatory criteria identified in various NRC documents. See that document for additional information on conformance to intersystem loss-of-coolant accident regulatory criteria.

1.9.5.1.8 Hydrogen Generation and Control

NRC Position:

It is the NRC position that the likelihood of early containment failure from hydrogen combustion should be reduced. Because of the uncertainties in the phenomenological knowledge of hydrogen generation and combustion, advanced light water reactors should be designed to:

- Accommodate hydrogen equivalent to 100 percent metal-water reaction of the fuel cladding
- Limit containment hydrogen concentration to no greater than 10 percent

Further, because hydrogen control is necessary to preclude local concentrations of hydrogen below detonable limits, and given uncertainties in present analytical capabilities, advanced light water reactors should provide containment-wide hydrogen control (such as igniters or inerting) for severe accidents. Additional advantages of providing hydrogen control mitigation features (rather than reliance on random ignition of richer mixtures) includes the lessening of pressure and temperature loadings on the containment and essential equipment.

AP1000 Response:

The AP1000 design includes mechanisms for monitoring and controlling hydrogen inside the containment. The containment hydrogen control system maintains hydrogen concentrations below 10 percent following the reaction of 100 percent of the zircaloy cladding.

Passive autocatalytic hydrogen recombiners control hydrogen concentration following design basis events. Nonsafety-related hydrogen igniters control rapid releases of hydrogen during and after postulated events with degraded core conditions or with core melt.

Sufficient vent area is provided for each subcompartment in the containment to prevent high local concentrations of hydrogen.

The containment air filtration system provides a capability to purge the containment atmosphere.

See Subsection 6.2.4 for additional information.

1.9.5.1.9 Core-Concrete Interaction - Ability to Cool Core Debris

NRC Position:

Containment integrity could be breached in the event of a severe accident in which the core melts through the reactor vessel, resulting in interaction between core debris and concrete, which can generate large quantities of hydrogen and other gases. It is the NRC position that sufficient reactor cavity floor space be provided to enhance debris spreading, and that a method for quenching debris in the reactor cavity be incorporated. The NRC staff has not formulated specific criteria for debris bed coolability and reviews each vendor's design to determine how they address the general criteria for debris spreading and quenching.

AP1000 Response:

The AP1000 design provides superior protection against core-concrete interaction by reliably depressurizing the reactor vessel and flooding the reactor cavity to cool the vessel and prevent debris from relocating from the vessel into the containment. Based on the DOE/ARSAP analysis of the thermal-hydraulics of in-vessel debris retention (see Section 19.16 and Appendix 19B as supported by Theofanous, T. G., et al., Reference 62) performed using the Risk Oriented Accident Analysis Methodology, the AP1000 has a large margin to reactor vessel failure in the depressurized, flooded cavity condition. This strategy eliminates the large uncertainties associated with ex-vessel debris relocation that could result in containment failure even while meeting the NRC criteria for debris coolability in the cavity.

In the event that cavity flooding fails, the floor area under the vessel provides debris spreading area to enhance the coolability of the debris. The AP1000 containment design drains the water from the reactor coolant system, core makeup tanks and accumulators to the reactor cavity to provide enough water to quench ex-vessel debris. The heat is ultimately removed from the containment via the passive containment cooling system, and the condensate is returned to the cavity to continue to provide cooling water to the debris bed.

1.9.5.1.10 High Pressure Core Melt Ejection

NRC Position:

Direct containment heating associated with the ejection of molten core debris, under high pressure, from the reactor vessel can result in a rapid addition of energy to the containment atmosphere. It is the NRC position that, pending completion of ongoing research, it is prudent to provide protection against this potential failure mode. This protection should include the following two aspects:

- Providing a rate of reactor coolant system depressurization to preclude molten core ejection and creep rupture of steam generator tubes

- Arranging the reactor cavity so that high-pressure core debris ejection resulting from reactor vessel failure does not impinge on the containment boundary

AP1000 Response:

The AP1000 design includes an automatic depressurization system that is redundant, diverse, independent of ac power sources, and automatically actuated. The automatic depressurization system can also be manually actuated. Any of the automatic depressurization system lines can sufficiently reduce the reactor coolant system pressure to help preclude direct containment heating. Subsection 5.4.6 and Section 6.3 provide additional information on the automatic depressurization system.

In addition, the reactor cavity region and lower containment of the AP1000 are designed to preclude transport of significant core debris to the upper containment in the unlikely event of a high pressure melt ejection scenario from the reactor vessel. This is a passive feature involving the geometric configuration of the reactor cavity lower containment. There is no direct pathway from the cavity to the upper compartment.

1.9.5.1.11 Containment Performance

NRC Position:

The NRC opinion is that because there are substantial uncertainties in core damage predictions, and because it is very important to maintain defense in depth, it is necessary that the containment boundary serve as a reliable barrier against fission product release for credible severe accident challenges. Hence, a containment performance criterion has been proposed by the NRC.

The objective of the containment performance criterion is to provide a leaktight barrier against radioactive releases for two distinct categories of severe accident challenges:

- Rapid energy release, hydrogen combustion, and initial release of stored reactor coolant system energy

- Slow energy release, including decay heat and noncondensible gas generation, due to core-concrete interaction

The NRC position is that the reactor containment boundary should serve as a reliable barrier against fission product release for credible severe accident challenges. A conditional containment failure probability of 0.1 should be used unless a deterministic containment performance goal can offer comparable protection.

An alternate deterministic criterion proposed in SECY-90-016 (Reference 29) states that "...The containment should maintain its role as a reliable leak tight barrier by ensuring that containment stresses do not exceed ASME service level C limits for a minimum period of 24 hours following the onset of core damage..."

This capability should, to the extent practical, be provided by the passive capability of the containment and any related passive design features. The NRC further believes that following this 24-hour period, the containment should continue to provide a barrier against the uncontrolled release of fission products.

AP1000 Response:

The AP1000 design includes several features to minimize the potential for large fission product releases in the event of a severe accident. These features are aimed at both the prevention and the mitigation of severe accident phenomena that can threaten containment integrity. An adequate margin to containment performance is maintained.

The AP1000 containment is continuously cooled by natural air circulation outside the steel shell. During accident conditions, water drains on the outside of the containment vessel to increase heat transfer. The containment design best-estimate performance analysis alone shows that the maximum containment pressure reached maintains the containment shell stresses below the ASME Code Service Level C stress intensity limits, using a factor of safety of 1.5 for buckling of the top head.

Additionally, the probability of containment bypass scenarios is reduced by improved containment isolation, by designing to protect against interfacing system LOCAs, thereby reducing the associated core melt frequency, and by reducing the steam generator tube rupture core melt frequency.

The interfacing system LOCA core melt frequency is reduced by the use of several features, including effective leak testing of the normal residual heat removal system motor-operated isolation valves. A third valve is provided to the normal residual heat removal system suction line. It is a motor-operated valve located outside containment. This prevents inadvertently aligning the reactor coolant system to the normal residual heat removal system. The normal residual heat removal system design pressure is 900 psig. Therefore the ultimate rupture strength of the system prevents it from failing when exposed to the normal reactor coolant system operating pressure (2250 psia). See the position on intersystem LOCA for additional information on the normal residual heat removal system design against overpressurization.

Steam generator tube rupture core melt frequency is reduced by incorporating multiple levels of defense that are both redundant and diverse. The first level of defense relies on the use of nonsafety-related active systems and operator action. The second level of defense uses safety-related passive systems and equipment, such as the core makeup tanks and passive residual heat removal heat exchangers, without the safety-related automatic depressurization of the reactor coolant system. The third level of defense uses the redundant and diverse safety-related automatic depressurization system valves to depressurize the reactor coolant system and initiate low-pressure passive injection. Any of these levels of defense can prevent core damage during a steam generator tube rupture event.

Finally, containment isolation capabilities are substantially improved by reducing the number of penetrations and the number of open paths. Most of the open containment penetration lines use fail-closed valves for automatic isolation.

1.9.5.1.12 ABWR Containment Vent Design

This issue is specific to BWRs and PWRs with ice condenser containments. Therefore this issue does not apply to the AP1000 design.

1.9.5.1.13 Equipment Survivability

NRC Position:

Safety-related equipment used to mitigate design basis events is subject to a comprehensive set of criteria such as redundancy, diversity, environmental qualification, and quality assurance to provide reasonable assurance that they perform their intended functions, if needed. However, equipment used to mitigate the effects of severe accidents should not be treated in the same manner because of large differences in the likelihood of occurrence. There should be reasonable assurance that the

equipment will operate in the severe accident environment for which they are intended and over the time span for which they are needed. However, equipment provided only for severe accident protection need not be subject to the 10 CFR 50.49, environmental qualification requirements, 10 CFR 50, Appendix B quality assurance requirements, and 10 CFR 50 Appendix A, redundancy and diversity requirements.

AP1000 Response:

The equipment used to mitigate severe accidents is identified in the AP1000 PRA evaluation report. Because of the nature of the passive safety features of the AP1000, there is very little equipment in this category. Equipment used to mitigate severe accidents is designed to survive the environmental conditions identified in the AP1000 PRA evaluation (see Appendix 19D).

1.9.5.1.14 Operating Basis Earthquake (OBE)/Safe Shutdown Earthquake (SSE)

NRC Position:

Currently, 10 CFR 100 requires that the magnitude of the operating basis earthquake be at least one-half that of the safe shutdown earthquake. This forces the safety-related system design at some plants to be controlled by the operating basis earthquake, but the NRC agrees that the operating basis earthquake should not control the safety-related system design. Therefore, the NRC recommends eliminating the operating basis earthquake from the design of systems, structures, and components. Until final rulemaking is approved for 10 CFR 100, Appendix A, the elimination of the operating basis earthquake from the design of passive plants will require an exemption from current regulations, with acceptable supporting justification from the designer. The details of this process will be resolved with the NRC through the appropriate code-related activities or supplemental regulatory guidance.

AP1000 Response:

The operating basis earthquake is not used as a design basis for AP1000 safety-related structures, systems, and components. For safety-related equipment, the safe shutdown earthquake is used as the design basis. In specifying design criteria for this earthquake, consideration is given to lower magnitude earthquakes having a greater probability of occurrence, as well as to larger magnitude earthquakes having a lower probability.

Cyclic stresses due to earthquakes are included in the design of those components sensitive to fatigue. Analysis methods and allowable stresses provide margin for the design requirements for the safe shutdown earthquake. Sections 3.7 and 3.10 provide additional information.

1.9.5.1.15 In-Service Testing of Pumps and Valves

NRC Position:

Periodic testing according to ASME Code, Section XI is required to confirm operability of safety-related pumps and valves. The NRC believes that these testing requirements do not necessarily verify the capability of the components to perform their intended safety function. To address this concern, the NRC has issued Generic Letters 89-04 (Reference 38) and 89-10 (Reference 39), and has proposed rulemaking to extend in-service testing beyond code components and to demonstrate capability to perform safety functions. Reference 29 includes the following provisions to be applied to safety-related pumps and valves (not limited to only ASME Code Class 1, 2, or 3):

- Piping design should incorporate provisions for full-flow testing (maximum design flow) of pumps and check valves.

- Designs should incorporate provisions to test motor-operated valves under design basis differential pressure.

- Check valve testing should incorporate the use of advanced, nonintrusive techniques to address degradation and performance characteristics.

- A program should be established to determine the frequency necessary for disassembly and inspection of pumps and valves to detect unacceptable degradation that cannot be detected through the use of advanced, nonintrusive techniques.

In June 1990, the NRC position was approved, additionally noting that due consideration should be given to the practicality of designing testing capability, particularly for large pumps and valves.

The NRC concluded that this was an issue for passive plant designs in SECY-94-084 (Reference 67), because the safety-related passive systems rely on the proper operation of equipment such as check valves and depressurization valves to mitigate the effects of transients.

AP1000 Response:

The AP1000 safety-related passive systems include the following design features:

- The AP1000 does not include any active ASME Section III safety-related pumps.

- The motor-operated valve design is simplified by extending opening and closing times and by using simplified, conservative valve designs.

- Safety-related motor-operated valves are designed to be cycled with the plant at power.

- Features are included in the design to provide proper operational testing of the appropriate check valves, motor-operated valves, and air-operated valves, including flow and differential pressure testing during shutdown conditions.

Subsection 3.9.8.4 defines the responsibility for the in-service testing program for ASME Code Class 1, 2, and 3 valves.

Subsection 3.9.6 summarizes the requirements for the in-service testing program, including industry standards and NRC recommendations. The AP1000 system and valve designs generally allow implementation of the NRC recommendations in Generic Letters 89-04 and 89-10. Requirements for nonsafety-related pumps and valves that support the operation of systems that preclude unnecessary operation of the safety-related passive systems are outlined in Subsection 3.9.6.

The AP1000 in-service testing program provides for periodic testing of the safety-related passive system components. The safety-related passive system components and systems are designed to meet the intent of the ASME Code, Section XI, for in-service inspection.

The AP1000 is designed for the following basic types of in-service testing of safety-related components:

- Periodic functional testing of active components during power operation (such as cycling of specific valves)

- Periodic flow/differential pressure operability testing of active components

- Periodic leak testing of the containment isolation valves.

- Periodic system flow or heat transfer rate testing of passive safety-related injection or cooling features during plant shutdown

The passive system design includes specific features to support in-service test performance:

- Remotely operated valves can be exercised during plant operation.
- Level, pressure, flow, and valve position instrumentation is provided for monitoring passive system equipment during plant operation and testing.
- Permanently installed test lines and connections are provided for performance of the containment isolation valve leakage testing.

1.9.5.2 Other Evolutionary and Passive Design Issues

Other evolutionary and passive design issues were identified in Reference 30.

1.9.5.2.1 Industry Codes and Standards

NRC Position:

SECY-91-273 (Reference 40) discusses NRC concerns with the use of recently developed or modified design codes and industry standards that the ALWR vendors are using in applications, but that have not yet been reviewed by the NRC for acceptability. The NRC recommends using the newest codes and standards endorsed by the NRC in the review of passive design applications. Unapproved revisions to codes and standards will be reviewed on a case-by-case basis.

AP1000 Response:

When the AP1000 design is based on revisions of industry codes and standards later than those required by NRC regulation, such use is explicitly discussed in the appropriate section. Use of codes and standards later than those recommended in NRC guidance documents is also discussed in the appropriate section.

Appendix 1A discusses regulatory guide conformance. For those standards endorsed by regulatory guides and subsequently superseded by a more recent revision, when the later revision is used its use is discussed or indicated in Appendix 1A.

1.9.5.2.2 Electrical Distribution

NRC Position:

The Commission approved the recommendations in SECY-91-078 (Reference 41) for evolutionary plant designs to include the following:

1. An alternate power source for nonsafety-related loads unless design margins for loss of nonsafety-related loads are no more severe than turbine-trip-only events in current plants
2. At least one offsite circuit to each redundant safety division supplied directly from offsite power sources with no intervening nonsafety-related buses

The applicability of this issue to passive designs is discussed in SECY-94-084 (Reference 67).

AP1000 Response:

See the response to station blackout in Subsection 1.9.5.1.

1.9.5.2.3 Seismic Hazard Curves and Design Parameters

NRC Position:

To assess the seismic risk associated with an ALWR design, EPRI proposed the use of generic bounding seismic hazard curves for sites in the central and eastern United States. EPRI proposes that these curves be used in the seismic PRA. NRC regulations do not require performance of a seismic PRA to determine site acceptability.

The NRC has compared the proposed EPRI ALWR seismic hazard bounding curve for rock sites to hazard curves derived by Lawrence Livermore National Laboratories (LLNL) using historical earthquake methodology in NUREG/CR-4885 and to hazard curves generated by EPRI for the Seabrook site. The LLNL hazard curves are generally higher than the EPRI results for the same sites.

The proposed EPRI bounding curve is exceeded for accelerations below 0.1g and the NRC questions the adequacy of the proposed EPRI bounding curve at higher peak accelerations. The NRC concludes that the EPRI bounding hazards curve is nonconservative and also that its use in a seismic PRA assessment would underpredict the core damage frequency. Therefore, the EPRI curves are not sufficiently conservative for ALWR designer use.

The Combined License applicant must demonstrate that site-specific seismic parameters meet the certified design parameters, or a site-specific analysis will be required to confirm site acceptability.

AP1000 Response:

The AP1000 includes a seismic margin assessment performed in lieu of a seismic PRA. The seismic margin assessment follows the guidelines established in NUREG-1407 (Reference 42). This assessment demonstrates that the AP1000, located at a site having the most severe seismic inputs meeting the AP1000 site interface requirements, has a seismic risk comparable to that at existing nuclear power plants.

1.9.5.2.4 Leak-Before-Break

NRC Position:

GDC 4 provides the basis for the leak-before-break (LBB) analysis that has been approved for PWR primary piping, and the pressurizer surge, accumulator, and residual heat removal piping. In addition, it has been used for primary piping inside containment and for piping at least 6 inches nominal diameter and for both austenitic and carbon steel (clad with stainless) materials.

The NRC will evaluate the acceptability in ALWR designs, based on the justification provided by a deterministic fracture mechanics analysis submitted as part of the design. The NRC concluded that the analyses should be based on specific data, such as piping geometry, materials, and piping loads. However, the analyses may incorporate an initial set of bounding values and preliminary stress analysis results during the design certification phase. Subsequent verification of the preliminary analysis will be required.

The LBB approach has established certain limitations for excluding piping susceptible to failure from degradation mechanisms. In addition, the LBB introduced acknowledged inconsistency in the design basis, but the NRC published clarifications for the intended treatment of the containment, emergency core cooling systems, and environmental qualification in the LBB application.

The NRC position on LBB for the AP1000 is presented in SECY-95-172 (Reference 68).

AP1000 Response:

The AP1000 incorporates the leak-before-break approach for most high-energy lines inside containment that are 6 inches in diameter or larger. Detailed methodology and criteria are defined in Subsection 3.6.3 and are consistent with those accepted by the NRC on existing nuclear power plants.

1.9.5.2.5 Classification of Main Steam Line of Boiling Water Reactors (BWRs)

This issue is specific to BWRs and therefore does not apply to the AP1000 design.

1.9.5.2.6 Tornado Design Basis

NRC Position:

WASH-1300 (Reference 43) and Regulatory Guide 1.76 contain the current NRC regulatory position for design basis tornados. Based on a contractor review of Regulatory Guide 1.76, the NRC recommends a maximum tornado speed of 300 mph be used for design basis tornado for passive ALWR designs.

The tornado design basis requirements have been used in establishing structural requirements against effects not covered explicitly in review guidance such as Regulatory Guides or the SRP. The Combined License applicant will have to demonstrate that the design will also be sufficient to withstand other site hazards such as aviation crashes, nearby explosions, and explosion debris and missiles.

AP1000 Response:

The AP1000 is designed in accordance with the NRC recommendations for a maximum tornado wind speed of 300 mph, as described in Section 3.3. The AP1000 site interface defined in Chapter 2 provides information to evaluate other site hazards if appropriate.

1.9.5.2.7 Containment Bypass

NRC Position:

Reasonable efforts should be made to minimize the possibility of containment bypass leakage, and ALWR designs should allow for a certain amount of leakage in the containment design. The NRC is evaluating the need for containment spray for all ALWRs. The containment spray provides containment temperature and pressure suppression effects and scrubs the containment atmosphere of fission products, mitigating the effects on the fission product bypass distribution.

AP1000 Response:

Although the phenomenon described for this item is primarily applicable to BWRs, the AP1000 has a variety of design features that help to reduce the potential for containment bypass leakage.

The response to the containment performance issue in Subsection 1.9.5 provides additional information pertaining to various improvements that help to reduce containment bypass.

The safety-related passive containment cooling system design also contributes to the containment performance. The system includes multiple flow paths to provide cooling water for containment during severe accident conditions. The containment is also capable of successfully removing core decay heat with air-cooling alone.

The containment has a significantly reduced number of penetrations. The number of normally open containment penetrations is also reduced. The result is a low containment leak rate and a low probability of bypass.

The response to intersystem LOCA in Subsection 1.9.5.1 provides additional information pertaining to applicable AP1000 design features that reduce the potential for intersystem LOCA and the potential for containment bypass.

Improvements are made to the steam generator design, such as the use of improved tube materials and tube supports. These improvements reduce the potential for tube leakage, which contributes to a reduction in containment bypass. Subsection 5.4.2 provides additional information on the steam generator design.

During a steam generator tube rupture event, the safety-related passive core cooling system automatically mitigates the effects of the event, including automatic safety-related protection against steam generator overfill.

The safety-related passive core cooling system provides long-term pH control for the containment sump, which helps to reduce the levels of airborne radioactivity, thereby reducing the consequences of leakage from the containment. Section 6.3 includes additional information on the passive core cooling system.

The diverse actuation system includes containment isolation features to provide isolation for the most risk-significant containment penetrations. AP1000 PRA Chapter 24 discusses the provisions for isolating risk significant containment penetrations.

The performance of the passive fission product removal process and minimal potential for containment bypass precludes the need for a safety-related containment spray system on AP1000.

1.9.5.2.8 Containment Leak Rate Testing

NRC Position:

SECY-91-348 (Reference 44) proposes changes to 10 CFR 50, Appendix J to allow an increased interval from 24 months to 30 months for Type C containment leakage rate tests, until rule change proceedings are completed.

AP1000 Response:

10 CFR 50 Appendix J has been revised since SECY-91-348 was issued. AP1000 type C testing and compliance with 10 CFR 50 Appendix J is discussed in Subsection 6.2.5.

1.9.5.2.9 Post-Accident Sampling System

NRC Position:

Regulatory Guide 1.97 and NUREG-0737 (Reference 45) provide guidance regarding the design of the post-accident sampling system. 10 CFR 50.34 required the capability to obtain and analyze samples from containment and the reactor coolant system that may contain TID-14844 source term radioactive materials, without exceeding specified radiation exposures. The analysis and quantification are required for certain specified radionuclides that are indicators of the degree of core damage, containment hydrogen, dissolved gases, chloride, and boron concentrations.

The NRC concluded that adequate capability for monitoring post-accident hydrogen is provided by the safety-grade containment hydrogen monitoring instrumentation.

The NRC requires sampling the reactor coolant system for dissolved hydrogen, chloride, and oxygen. The time for taking these samples can be extended to 24 hours after the accident.

The NRC requires sampling the reactor coolant system for boron and for activity measurements. The time for taking these samples can be extended to 8 hours after power operation for boron and 24 hours after power operation for activity measurements.

AP1000 Response:

The post-accident sampling system is a subsystem of the primary sampling system, described in Subsection 9.3.3.

The primary sampling system is designed to conform to the guidelines of the model Safety Evaluation Report on eliminating post-accident sampling system requirements from technical specifications for operating plants (Federal Register Volume 65, Number 211, October 31, 2000). The primary sampling system conforms with the most recent NRC position.

1.9.5.2.10 Level of Detail

NRC Position:

The Staff Requirements Memorandum for SECY-90-377 (Reference 47) provided guidance on the level of detail to be provided for a design certification application under 10 CFR 52. The guidance was that the application should include the information traditionally provided in a final safety analysis report, less the site-specific and as-procured information. This information should be supplemented by design inspections, tests, analysis, and acceptance criteria for those areas where the NRC is unable to make a final safety decision because of not having the site-specific information or the as-procured information, or because the technology is evolving so rapidly that it would be inappropriate to lock in the design.

AP1000 Response:

The AP1000 submittals are consistent with the requirements of 10 CFR 52 and the position in Reference 47.

1.9.5.2.11 Prototyping

NRC Position:

10 CFR 52.47 requires that sufficient data exist on the safety features of the design to assess the analytical tools used for safety analysis over a sufficient range of normal operating conditions, transient conditions, and specified accident conditions. Further, the interdependent effects among the safety features of the design must be found acceptable by analysis, appropriate test programs, experience, or a combination thereof. SECY-91-057 (Reference 48) informed the Commission of the steps the NRC was taking to identify the research needs for the AP600. SECY-91-074 (Reference 49) outlined the process the NRC would use to determine the need for a prototype or other demonstration facility for advanced reactor designs. SECY-91-273 (Reference 40) presented to the Commission the staff's recommendations for reviewing, monitoring and approving the Westinghouse test program to support the AP600 design certification application. SECY-92-030 (Reference 50) presented the Commission with the NRC opinion that there was a need for a full-height, full-pressure integral systems test to support the issuance of a final design approval.

AP1000 Response:

The Westinghouse testing program to assess the analytical methodologies used for the AP1000 safety analysis is described in Section 1.5 and is in conformance with the NRC position.

1.9.5.2.12 Inspections, Test, Analyses, and Acceptance Criteria (ITAAC)

NRC Position:

10 CFR 52 requires that the design certification application include the proposed tests, inspections, analyses, and the associated acceptance criteria. For certified standard designs, these tests, inspections, and analyses must apply to those portions of the facility covered by the design certification.

The Staff Requirements Memorandum for SECY-91-178 (Reference 51) provided guidance regarding development of ITAAC for final design approval and design certification applications.

AP1000 Response:

The AP1000 design certification application includes ITAACs.

1.9.5.2.13 Reliability Assurance Program

NRC Position:

SECY-89-013 (Reference 52) requires a reliability assurance program for design certification. The program would ensure that the design reliability of safety significant systems, structures, and components is maintained over the life of a plant.

The NRC is working on the development of a detailed guidance document consisting of two levels. The vendor submittal is the first level, consisting of a top-level program that identifies the scope, conceptual framework, and essential elements of an effective program. The Combined License applicant fully develops and implements the program based on the plant-specific design information.

AP1000 Response:

Section 16.2 includes a description of the reliability assurance program. The program description identifies the scope, conceptual framework, and essential elements of the program. The reliability assurance program confirms that the performance of the safety-related systems, structures, and components is consistent with the assumptions made for the design basis analysis.

In addition, the reliability assurance program monitors the long-term performance of important nonsafety-related structures, systems, and components that provide defense-in-depth against unnecessary actuation of the passive safety-related systems.

1.9.5.2.14 Site-Specific Probabilistic Risk Assessments (PRAs)

NRC Position:

10 CFR 52.47 requires all applicants for standard design certification to provide a PRA with enveloping analyses for seismic events and tornadoes. The Combined License applicant is responsible for the site-specific PRA information that addresses site-specific events such as river flooding, storm surge, tsunami, volcanism, and hurricanes.

AP1000 Response:

The AP1000 PRA submitted as a part of the design certification application is based on a site that bounds a large percentage of plant sites in the United States and is described in Chapter 2. APP-GW-GLR-101 (Reference 73) identifies the potential external events that may impact the AP1000 risk on a site-specific basis. This technical report considers a wide range of site-specific external events as long as a site can show that the external events listed in this report bound those

applicable to the site. The report also discusses impact of site selection on PRA Offsite Dose Evaluation requirements.

1.9.5.2.15 Severe Accident Mitigation Design Alternatives

NRC Position:

The National Environmental Policy Act (NEPA) requires that alternatives be investigated for actions that may significantly affect the quality of the human environment. The timing of the NEPA hearing is at the Early Site Permit or Combined License stage. One objective of the 10 CFR 52 design certification rulemaking is to preclude changes to a certified standard plant design. The U.S. Court of Appeals has required the NRC to include consideration of severe accident mitigation design alternatives (SAMDAs) as a part of their environmental impact review for operating license applications. If this same process is followed for a plant design that had been certified, it may be necessary to reopen issues that had been resolved in the design certification rulemaking. To avoid this situation, the NRC issued SECY-91-229 (Reference 53) which recommended that SAMDAs be specifically addressed during the design certification rulemaking.

AP1000 Response:

The severe accident mitigation design alternatives (SAMDA) evaluation for AP1000 is contained in Appendix 1B.

FSAR Position:

The severe accident mitigation design alternatives (SAMDA) evaluation for AP1000 contained in DCD Appendix 1B is not incorporated into this FSAR, but is addressed in the ESPA Environmental Report.

1.9.5.2.16 Generic Rulemaking Related to Design Certification

NRC Position:

SECY-91-262 (Reference 54) provides the NRC recommendations to proceed with design-specific rulemaking where appropriate for passive designs, as information becomes available from ongoing efforts on those issues, independent of the design review and certification processes. In SECY-93-087 the NRC staff concludes that the design of passive plants is not sufficiently developed to determine whether generic rulemaking should be initiated for passive plant designs.

Generic rulemaking activities for source terms during severe accidents are ongoing, and the results may be used during design certification of the passive plants, focusing on updating 10 CFR 100 siting criteria, and planning to incorporate the revised source criteria in 10 CFR 50.

AP1000 Response:

No response necessary. See Subsection 1.9.5.1.2 for a discussion of the use of a physically based source term.

1.9.5.3 Passive Design Issues

Issues related to the passive design were outlined in Reference 30.

1.9.5.3.1 Regulatory Treatment of Non-Safety Systems

NRC Position:

The NRC believes that its review of passive designs requires not only a review of the passive safety-related systems, but also a review of the functional capability and availability of the active nonsafety-related systems to provide significant defense-in-depth and accident and core damage prevention capability. The NRC issued a commission policy paper SECY-94-084 (Reference 67), on the regulatory treatment of non-safety systems (RTNSS), that outlines the process for resolving the RTNSS issue. This process includes a combination of probabilistic and deterministic criteria to identify risk-significant nonsafety-related systems.

AP1000 Response:

The AP1000 nonsafety-related active systems are designed to provide reliable support for normal plant operations and to provide defense-in-depth to minimize unnecessary challenges to the safety-related passive systems. These active systems are designed for more probable component and system failures. The systems include reliable, proven equipment and component designs. These active systems are capable of being powered by the nonsafety-related diesel-generators. The systems have nonsafety-related automatic actuation and controls that are separate from those of the safety-related systems.

These systems are designed to provide highly reliable performance. The design standards and operability provisions for these systems are discussed in Subsection 3.2.2.6. Availability controls were developed for nonsafety related structures, systems, and components found to be important via the RTNSS process. The availability controls for the AP1000 are documented in Section 16.3 and are the same as those for the AP600.

1.9.5.3.2 Definition of Passive Failure

NRC Position:

The NRC considered redefining failure of check valves in passive safety systems, where the valve fails to provide the mechanical movement to complete its intended safety function, to that of an active failure, as defined in Appendix A to 10 CFR 50. The NRC was concerned, since safety-related check valves in passive designs operate under different conditions (low flow and pressure without pump pressure to open valves) than current generation reactors and evolutionary designs. The check valves have increased safety significance to the operation of the passive safety-related systems, and operating experience has shown that they have a lower reliability than originally anticipated. The Staff position is described in SECY-94-084 (Reference 67).

AP1000 Response:

AP1000 is designed to tolerate the single failure of a check valve to change position to perform a safety-related function. Valve redundancy is provided for the core makeup tank discharge check valves (to close), the in-containment refueling water storage tank gravity injection check valves (to open), the containment recirculation gravity injection check valves (to open), and containment isolation line check valves (to close). The redundancy in the design for each of these safety-related flow paths is sufficient to accommodate the single failure of a check valve to reposition as required to perform its safeguards function.

Section 6.3 provides additional information on the failures assumed for the passive core cooling system including exceptions to the single failure criteria.

1.9.5.3.3 SBWR Stability

This issue is applicable to BWRs only.

1.9.5.3.4 Safe Shutdown Requirements

NRC Position:

GDC 34 requires that a residual heat removal system be provided to remove residual heat from the reactor core so that specified, acceptable fuel design limits are not exceeded. Regulatory Guide 1.139 and Branch Technical Position 5-1 implement this requirement and set forth conditions to cold shutdown (200°F for a PWR) using only safety-related systems within 36 hours.

The NRC evaluated the alternate means of addressing GDC 34 using passive safety-related systems to achieve a safe shutdown condition of 420°F. Additionally, the NRC reviewed the acceptability of using active, nonsafety-related systems to take a plant to cold shutdown conditions. The results of this review are presented in SECY-94-084 (Reference 67).

AP1000 Response:

The AP1000 includes safety-related passive systems and equipment that are designed to automatically establish and indefinitely maintain safe shutdown conditions for the plant following design basis events.

Sections 6.3 and 7.4 provide additional information pertaining to safe shutdown, using the safety-related passive systems.

1.9.5.3.5 Control Room Habitability

NRC Position:

10 CFR 50, Appendix A, GDC 19 requires adequate radiation protection to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of five rem whole body, or its equivalent, to any part of the body, for the duration of the accident. Section 6.4 of the Standard Review Plan defines this dose criterion in terms of specific whole-body and organ doses (5 rem to whole body, and 30 rem each to thyroid and skin). The NRC requires that the analyses of main control room habitability be based on the dose criterion defined in GDC 19 of Appendix A to 10 CFR 50 and Section 6.4 of the Standard Review Plan (5 rem to whole body, and 30 rem each to thyroid and skin). In addition, the analyses of control room habitability should be based on the duration of the accident according to GDC 19 of Appendix A to 10 CFR 50.

AP1000 Response:

The AP1000 design includes a passive, safety-related main control room habitability system to meet the requirements of GDC 19. Section 6.4 provides additional information.

As described in Subsection 15.6.5.3, the main control room operator doses following a design basis loss of coolant accident are within the dose criterion of GDC 19 (5 rem TEDE as applied to the AP1000 design).

1.9.5.3.6 Radionuclide Attenuation

NRC Position:

The NRC is concerned that use of the auxiliary building for holdup may require additional restrictions to be placed on the auxiliary building during normal operation. In addition, the NRC is continuing its evaluation of the need for a containment spray system for passive plant designs.

AP1000 Response:

The AP1000 design does not have a safety-related containment spray or take credit for auxiliary building holdup for mitigation of the design basis loss of coolant accident. The design includes a low-leakage-rate containment (0.10 percent per day) together with credit for aerosol removal by naturally occurring processes and pool scrubbing in containment. The low-leakage containment and natural aerosol removal are adequate to meet 10 CFR 50.34 dose limits, consistent with the physically-based source term.

1.9.5.3.7 Simplification of Off-Site Emergency Planning

NRC Position:

The NRC states that changes to emergency planning regulatory requirements may be appropriate, but that an NRC determination on this issue will require detailed design evaluation. Summaries of specific NRC conclusions are as follows:

- Unique characteristics of the designs should be considered in determining the extent of emergency planning, including the ability to prevent significant release of radioactive material or to provide delay times for all but the most unlikely events.

- A very low likelihood of all containment bypass sequences will be required before relaxing emergency planning requirements.

- Lack of information on source term and risk precludes further NRC evaluation of emergency preparedness for the passive plants at this time.

- Emergency planning requirements following the TMI-2 accident were not premised on specific assumptions regarding severe accident probability. So, as a policy matter, even very low calculated probabilities may not be a sufficient basis for changes to emergency planning requirements.

The industry and the NRC are working to determine a process, including developing technical criteria and methods, that would justify simplification of offsite emergency planning. The results of this process would be used as input to a generic rulemaking proposal to be initiated by nuclear industry organizations.

AP1000 Response:

The AP1000 PRA evaluation risk assessment includes calculations of the AP1000 response to severe accidents. This response includes the release of radionuclides following a severe accident. This analysis supports the technical basis for simplification of offsite emergency planning. The offsite emergency planning is discussed in Section 13.3.

1.9.5.4 Additional Licensing Issue

Post-72 Hour Support Actions

The AP1000 includes safety-related passive systems and equipment that are sufficient to automatically establish and maintain safe shutdown conditions for the plant following design basis events, assuming that the most limiting single failure occurs. The safety-related passive systems maintain safe shutdown conditions after an event -- without operator action, without onsite and offsite ac power sources.

The AP1000 includes nonsafety-related active systems and equipment designed to provide multiple levels of defense for a wide range of events. For the more probable events, these nonsafety-related systems automatically actuate to provide a first level of defense to reduce the likelihood of unnecessary actuation and operation of the safety-related passive systems. These nonsafety-related systems establish and maintain safe shutdown conditions for the plant following design basis events, provided that at least one of the standby nonsafety-related ac power sources is available.

Although event scenarios that result in an extended loss of the nonsafety-related systems or both offsite and onsite ac power sources for more than 72 hours are very unlikely, this potential is considered in the AP1000 design.

The actions described below are required following an extended loss of these nonsafety-related systems.

The safety functions required include the following:

- Core cooling, inventory, and reactivity control
- Containment cooling and ultimate heat sink
- Main control room habitability and post-accident monitoring
- Spent fuel pool cooling

The AP1000 design includes the capability to:

- Provide electrical power to supply the post-accident and spent fuel pool monitoring instrumentation using the ancillary diesel generators to feed the safety-related voltage regulating transformer. A connection is also available for use with a portable generator. See Section 8.3 for additional information.

- Provide makeup water to the passive containment cooling water storage tank to maintain external containment cooling water flow using one of the two PCS recirculation pumps powered by an ancillary diesel generator. A safety-related connection is also available for use with a portable pump. See Subsection 6.2.2 for additional information.

- Ventilation and cooling of the main control room, the instrumentation and control rooms, and the dc equipment rooms is provided by open doors and ancillary fans or portable fans which receive power via the safety-related voltage regulating transformer. See Subsections 6.4.2.2 and 9.4.1 for additional information.

- Provide makeup water to the spent fuel pool from the passive containment cooling water storage tank, passive containment cooling ancillary water storage tank, and from the long term makeup connection. See Subsection 6.2.2.2.4 for a discussion of the operation of the passive containment cooling system and Subsection 9.1.3.4.3 and 9.1.3.5 for discussion of makeup to the spent fuel pool.

- Provide a vent path between the fuel handling area and outside environment to vent water vapor generated by elevated spent fuel pool water temperature. See Subsection 9.1.3.4.3.4 for additional information.

These actions are accomplished by the site support personnel, in coordination with the main control room operators. These actions are performed separate from, but in parallel with, other actions taken by the plant operators to directly mitigate the consequences of an event.

1.9.5.5 Operational Experience

Operational experience highlighted in NRC bulletins, generic letters, and information notices has been incorporated into the AP1000 design. Generic letters and bulletins are identified in WCAP-15800 (Reference 65). The applicability of each generic letter and bulletin to the AP1000 is assessed in WCAP-15800. If required, additional information for applicable issues is provided in the referenced sections of the DCD.

Table 1.9-204 lists the Bulletins and Generic Letters addressed by topical discussion in this FSAR. Table 1.9-204 also lists Bulletins and Generic Letters categorized as part of the first un-numbered COL Information Item identified at the end of Table 1.8-2 and listed in Table 1.8-202 as COL Information Item 1.9-2. Table 1.9-204 provides the appropriate cross-references for the discussion of the topics addressed by those Bulletins and Generic Letters. Bulletins or Generic Letters issued after those listed in the DCD are also included in Table 1.9-204. Issues identified as “procurement” or “maintenance” or “surveillance” in WCAP-15800 are addressed as part of the scope of the certified design and are not specifically identified in Table 1.9-204. Issues identified as “procedural” in WCAP-15800 are addressed by the procedures discussed in Section 13.5 and are not specifically identified in Table 1.9-204. Other items in WCAP-15800, including the Circulars and Information Notices, are considered to have been adequately addressed based on the guidance identified in Regulatory Guide 1.206 and the NRC Standard Review Plans.

1.9.6 References

1. NUREG-0696, "Functional Criteria for Emergency Response Facilities," 1981.

2. Report NP-2770-LD, "EPRI PWR Safety Valve Test Report," December 1982.

3. NUREG-0933, "A Prioritization of Generic Safety Issues," June 2001.

4. NUREG-0371, "Task Action Plans for Generic Activities (Category A)," U.S. Nuclear Regulatory Commission, November 1978.

5. NUREG-0927, Revision 1, "Evaluation of Water Hammer Occurrences in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, March 1984.

6. NRC letter to all PWR Licensees of Operating Reactors, Applicants for Operating Licensees and Holders of Construction Permits, and Ft. St. Vrain, "Staff Recommended Actions Stemming from NRC Integrated Program for the Resolution of Unresolved Safety Issues Regarding Steam Generator Tube Integrity," (Generic Letter 85-02) April 17, 1985.

7. NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, A-5 Regarding Steam Generator Tube Integrity," U.S. Nuclear Regulatory Commission, September 1988.

8. NUREG-0577, Revision 1, "Potential for Low Fracture Toughness and Lamellar Tearing in PWR Steam Generator and Reactor Coolant Pump Supports," U.S. Nuclear Regulatory Commission, October 1983.

9. IEEE 323-1974, "Qualifying Class 1E Equipment for Nuclear Power Generating Stations," Institute of Electrical and Electronics Engineers.

10. NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," U.S. Nuclear Regulatory Commission, July 1980.

11. NUREG-0510, "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants," U.S. Nuclear Regulatory Commission, January 1979.

12. NUREG-0705, "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plant Stations," U.S. Nuclear Regulatory Commission, February 1981.

13. IEEE 344-1987, "Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," Institute of Electrical and Electronics Engineers.

14. NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants."

15. NUREG-0660, "NRC Action Plan Developed as a result of the TMI-2 accident," May 1980.

16. NUREG-0985, "Nuclear Regulatory Commission Human Factors Program Plan Revision 2," April 1986.

17. IEEE 384-1981, "IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits," Institute of Electrical and Electronics Engineers.

18. NUREG-0471, "Generic Task Problem Descriptions (Category B, C, and D Tasks)" and NUREG-0933, "A Prioritization of Generic Safety Issues," June 1978.

19. NUREG-0484, Revision 1, "Methodology for Combining Dynamic Responses," May 1980.

20. IEEE 317-1983, "Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations," Institute of Electrical and Electronics Engineers.

21. ANSI/ANS-58.8-1984. "Time Response Design Criteria for Nuclear Safety Related Operator Actions."

22. NUREG/CR-2425, "Sediment and Radionuclide Transport in Rivers," December 1982.

23. NUREG-0693, "Analysis of Ultimate-Heat-Sink Cooling Ponds," November 1980.

24. NUREG-0733, "Analysis of Ultimate Heat-Sink Spray Ponds," August 1981.

25. NUREG-0858, "Comparison Between Field Data and Ultimate Heat Sink Cooling-Pond and Spray-Pond Models," September 1980.

26. ANSI 5.1, "Decay Heat Power in Light Water Reactors," American National Standards Institute, 1979.

27. NUREG-0691, "Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," September 1980.

28. ANSI 56.5-1979, "PWR and BWR Containment Spray System Design Criteria."

29. USNRC, SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues And Their Relationship to Current Regulatory Requirements," January 12, 1990.

30. NRC letter, Subject: Identification of Issues Concerning the Evolutionary and Passive Plant Designs, Dennis M. Crutchfield, USNRC Director, Division of Advanced Reactors and Special Projects, to E. E. Kintner, Chairman ALWR Steering Committee, February 27, 1992.

31. Staff Requirements Memorandum, Subject: SECY-90-016 - Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements, Samuel J. Chilk, USNRC Secretary, to James M. Taylor, USNRC Executive Director for Operations, June 26, 1990.

32. NUREG-1150, "Severe Accident Risk: An Assessment for Five U.S. Nuclear Power Plants," June 1989.

33. "Passive ALWR Source Term," D. E. Leaver, et al., DOE/ID-10321, February 1991.

34. NUREG-0649, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants," Revision 1, September 1984.

35. NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants, Technical Findings Related to Unresolved Safety Issue A-44," June 1988.

36. NUREG-1109, "Regulatory/Backfit Analysis for the Resolution of Unresolved Safety Issue A-44, Station Blackout," June 1988.

37. NUREG-0800, U.S. Nuclear Regulatory Commission Standard Review Plan, Section 9.5.1, “Fire Protection Program,” Revision 3, July 1981, including Branch Technical Position (BTP) CMEB 9.5-1, “Guidelines for Fire Protection for Nuclear Power Plants,” Revision 2, July 1981.

38. Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," April 3, 1989.

39. Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," June 28, 1989.

40. SECY-91-273, "Review of Vendors' Test Programs to Support the Design Certification of Passive Light Water Reactors," August 27, 1991.

41. SECY-91-078, "Chapter 11 of EPRI's Requirements Document and Additional Evolutionary Light Water Reactor Certification Issues," March 25, 1991.

42. NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991.

43. WASH-1300, “Technical Basis for Interim Regional Tornado Criteria,” May 1974.

44. SECY-91-348, preliminary untitled SECY related to containment leakrate testing, issued to the Commission for review, and not yet released by the NRC.

45. NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

46. NUREG-4330, "Review of Light Water Reactor Regulatory Requirements, Volume 1, Identification of Regulatory Requirements That May Have Marginal Importance to Risk," April 1986.

47. SECY-90-377, "Requirements for Design Certification Under 10 CFR Part 52," November 8, 1990.

48. SECY-91-057, "Early Review of AP600 and SBWR Research Needs," March 1, 1991.

49. SECY-91-074, "Prototype Decisions for Advanced Reactor Designs," March 19, 1991.

50. SECY-92-030, "Integral System Testing Requirements for Westinghouse's AP600 Plant," January 27, 1992.

51. SECY-91-178, "Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC) for Design Certifications and Combined Licenses," June 12, 1991.

52. SECY-89-013, "Design Requirements Related to the Evolutionary Advanced Light Water Reactors (ALWRs)," January 19, 1989.

53. SECY-91-229, "Severe Accident Mitigation Design Alternatives for Certified Standard Designs," July 31, 1991.

54. SECY-91-262, "Resolution of Selected Technical and Severe Accident Issues for Evolutionary Light Water Reactor (LWR) Designs," August 16, 1991.

55. Not used.

56. WCAP-15993, “Evaluation of the AP1000 Conformance to Inter-System Loss-of-Coolant Accident Acceptance Criteria,” Revision 2, June 2017.

57. SECY-95-172, "Key Technical Issues Pertaining to the Westinghouse AP600 Standardized Passive Reactor Design," June 30, 1995.

58. NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants," L. Soffer, et al., February 1995.

59. SECY-94-302, "Source Term-Related Technical and Licensing Issues Pertaining to Evolutionary and Passive Light-Water-Reactor Designs," December 19, 1994.

60. SECY-94-194, "Proposed Revisions to 10 CFR Part 100 and 10 CFR Part 50, and New Appendix S to 10 CFR Part 50," July 27, 1994.

61. Not used.

62. Theofanous, T. G., et al., "In-Vessel Coolability and Retention of a Core Melt," DOE/ID-10460, July 1995.

63. WCAP-15799, "AP1000 Compliance with SRP Acceptance Criteria," Revision 1, August 2003.

64. NCRP Report No. 116, Limitation of Exposure to Ionizing Radiation, March 31, 1993.

65. WCAP-15800, "Operational Assessment for AP1000," Revision 3, July 2004.

66. SECY-98-161, "The Westinghouse AP1000 Standard Design as it Relates to the Fire Protection and the Spent Fuel Pool Cooling Systems," July 1, 1998.

67. SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," March 28, 1994.

68. SECY-95-172, "Key Technical Issues Pertaining to the Westinghouse AP1000 Standardized Passive Reactor Design," June 30, 1995.

69. WCAP-15992, "AP1000 Adverse Systems Interactions Evaluation Report," Revision 1, February 2003.

70. WCAP-15776, “Safety Criteria for the AP1000 Instrumentation and Control Systems,” Revision 1, July 2019.

71. APP-GW-GLR-079, "AP1000 Verification of Water Sources for Long-Term Recirculation Cooling Following a LOCA," Westinghouse Electric Company LLC.

72. APP-GW-GLR-040, "Plant Operations, Surveillance, and Maintenance Procedures," Westinghouse Electric Company LLC.

73. APP-GW-GLR-101, "AP1000 Probabilistic Risk Assessment Site-Specific Considerations," Westinghouse Electric Company LLC.

201. NUMARC 87-00, Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, Revision 1, August 1991.

Table 1.9-1 (Sheet 1 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.1	Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps (Rev. 0, November 2, 1970)	This regulatory guide is not applicable to AP1000.
1.2	Withdrawn	
1.3	Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-coolant Accident for Boiling Water Reactors (Rev. 2, June 1974)	This regulatory guide is not applicable to AP1000.
1.4	Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors (Rev. 2, June 1974)	The guidance of Reg. Guide 1.183, “Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors” will be followed instead of Reg. Guide 1.4.
1.5	Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break Accident for Boiling Water Reactors (Rev. 0, March 10, 1971)	This regulatory guide is not applicable to AP1000.
1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Rev. 0, March 10, 1971)	8.1 8.3.1 8.3.2 16.1 Bases 16 (TS Bases 3.8.1)
1.7	Control of Combustible Gas Concentration in Containment Following a Loss-of-Coolant Accident (Rev. 2, November 1978)	6.1.1 6.2.4 15.6.3 Appendix 15A
1.7	Control of Combustible Gas Concentrations in Containment (Rev. 3, March 2007)	DCD discussion only
1.8	Qualification and Training of Personnel for Nuclear Power Plants (Rev. 3, 1 May 2000)	This regulatory guide is not applicable to AP1000 design certification. 12.1 (NEI 07-08A) 12.1.1.3 Appendix 12AA Appendix 12AA (NEI 07-03A) 13.1.1.4 13.1.2.1.1 13.1.2.1.1.1.1 13.1.3.1 13.2 (NEI 06-13A) 16 (TS 5.3.1) 17.5 (QAPD, IV)
1.9	Selection, Design, and Qualification of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants (Proposed Rev. 3, November 1988)	This regulatory guide is not applicable to AP1000.
1.10	Withdrawn	
1.11	Instrument Lines Penetrating Primary Reactor Containment (Rev. 0, March 10, 1971)	3.6.2 6.2.3
1.11	Instrument Lines Penetrating Primary Reactor Containment (Rev. 1, March 2010)	DCD discussion only
1.12	Instrumentation for Earthquakes (Rev. 2, March 1997)	3.7.4 3.7.4.1

Table 1.9-1 (Sheet 2 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.13	Spent Fuel Storage Facility Design Basis (Proposed Rev. 2, December 1981)	9.1.2 9.1.3 9.1.4 16.1 Bases
1.13	Spent Fuel Storage Facility Design Basis (Rev. 2, March 2007)	16 (TS Bases 3.7.11) 16 (TS Bases 3.7.12)
1.14	Reactor Coolant Pump Flywheel Integrity (Rev. 1, August 1975)	5.4.1
1.15	Withdrawn	
1.16	Reporting of Operating Information - Appendix A Technical Specifications (Rev. 4, August 1975).	This regulatory guide is not applicable to AP1000 design certification.
1.17	Withdrawn	
1.18	Withdrawn	
1.19	Withdrawn	
1.20	Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing (Rev. 2, May 1976)	3.9.2 14
1.20	Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing (Rev. 3, March 2007)	DCD discussion only
1.21	Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents From Light-Water-Cooled Nuclear Power Plants (Rev. 1, June 1974)	11.5 11.5.1.2 11.5.4.1 12.3.4
1.22	Periodic Testing of Protection System Actuation Functions (Rev. 0, February 17, 1972)	7.1 7.2 7.4
1.23	Onsite Meteorological Program (Second Proposed Rev. 1, April 1986)	2.3
1.23	Meteorological Monitoring Programs for Nuclear Power Plants (Pr-1, September 1980)	2.3.2 2.3.3
1.24	Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure (Rev. 0, March 23, 1972)	This regulatory guide is not applicable to AP1000.
1.25	Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors (Rev. 0, March 23, 1972)	The guidance of Reg. Guide 1.183, “Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors” will be followed instead of Reg. Guide 1.25.
1.26	Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants (Rev. 3, February 1976)	3.2.2
1.26	Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants (Rev. 4, March 2007)	5.2.4.1 17.5 (QAPD IV)
1.27	Ultimate Heat Sink for Nuclear Power Plants (Rev. 2, January 1976)	6.2.2

Table 1.9-1 (Sheet 3 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.28	Quality Assurance Program Requirements (Design and Construction) (Rev. 3, August 1985)	2.5 17 14.2.2.2 17.5 (QAPD, II, 17.1) 17.5 (QAPD, IV)
1.29	Seismic Design Classification (Rev. 3, September 1978)	3.2.1
1.29	Seismic Design Classification (Rev. 4, March 2007)	17.5 (QAPD IV)
1.30	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Rev. 0, August 11, 1972)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.31	Control of Ferrite Content in Stainless Steel Weld Metal (Rev. 3, April 1978)	4.5.1 4.5.2 5.2.3 5.3.2 6.1.1 6.1.1.2
1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants (Rev. 2, February 1977)	8.1 8.2 8.3.1 8.3.2 16.1 Bases
1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants and Rev. 3, March 2004	16 (TS Bases 3.8.1)
1.33	Quality Assurance Program Requirements (Operation) (Rev. 2, February 1978)	3.11.2.1 3D.4.1.2 3D.6.4 16 (TS 5.4.1) 17.5 (QAPD, IV)
1.34	Control of Electroslag Weld Properties (Rev. 0, December 28, 1972)	4.5.2 5.2.3 5.3.2
1.35	Inservice Inspection of Ungrouted Tendons in Pre-stressed Concrete Containments (Rev. 3, July 1990)	This regulatory guide is not applicable to AP1000.
1.35.1	Determining Prestressing Forces for Inspection of Prestressed Concrete Containments (Rev. 0, July 1990)	This regulatory guide is not applicable to AP1000.
1.36	Nonmetallic Thermal Insulation for Austenitic Stainless Steel (Rev. 0, February 23, 1973)	5.2.3 6.1.1
1.37	Quality Assurance Requirements for cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (Rev. 0, March 1973)	17
1.37	Quality Assurance Requirements for cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (Rev. 1, March 2007)	17.5 (QAPD, II, 13.2) 17.5 (QAPD IV)
1.38	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2, May 1977)	17

Table 1.9-1 (Sheet 4 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.39	Housekeeping Requirements for Water-Cooled Nuclear Power Plants (Rev. 2, September 1977)	17
1.40	Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants (Rev. 0, March 16, 1973)	This regulatory guide is not applicable to AP1000.
1.41	Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments (Rev. 0, March 16, 1973)	14
1.42	Withdrawn	
1.43	Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components (Rev. 0, May 1973)	5.2.3 5.3.2
1.44	Control of the Use of Sensitized Stainless Steel (Rev. 0, May 1973)	4.5.1 4.5.2 5.2.3 5.3.2 6.1.1 10.3 6.1.1.2
1.45	Reactor Coolant Pressure Boundary Leakage Detection Systems (Rev. 0, May 1973)	5.2.5 16.1 Bases 16 (TS Bases 3.4.7) 16 (TS Bases 3.4.9)
1.46	Withdrawn	
1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems (Rev. 0, May 1973)	6.3 7.2 7.3 7.4 7.5 8.3.2
1.48	Withdrawn	
1.49	Withdrawn	
1.50	Control of Preheat Temperature for Welding of Low-Alloy Steel (Rev. 0, May 1973)	5.2.3 5.3.2 6.1.1
1.51	Withdrawn	
1.52	Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants (Rev. 3, June 2001)	6.4 16 (TS 3.7.6) 16 (TS Bases B 3.7.6) 1.9.4.2.2
1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems (Rev. 0, June 1973)	7.1 7.2 7.4 15.2 15.3 15.4 15.5 15.6
1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems (Rev. 2, November 2003)	DCD discussion only

Table 1.9-1 (Sheet 5 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.54	Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants (Rev. 1, July 2000 and Rev. 2, October 2010)	6.1.2 1.9.4.2.3 6.1.2.1.6
1.55	Withdrawn	
1.56	Maintenance of Water Purity in Boiling Water Reactors (Rev. 1, July 1978)	This regulatory guide is not applicable to AP1000.
1.57	Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components (Rev. 0, June 1973)	3.8.2 3.8.3
1.57	Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components (Rev. 1, March 2007)	DCD discussion only
1.58	Withdrawn	
1.59	Design Basis Floods for Nuclear Power Plants (Rev. 2, August 1977)	2.4.2 2.4.3 2.4.5 3.4 3.4.1.1.1
1.60	Design Response Spectra for Seismic Design of Nuclear Power Plants (Rev. 1, December 1973)	2.5 2.5.2 3.7.1 Table 2.0-201 Appendix 2.5E
1.61	Damping Values for Seismic Design of Nuclear Power Plants (Rev. 0, October 1973)	3.7.1 3.9.23.10 Appendix 3D
1.61	Damping Values for Seismic Design of Nuclear Power Plants (Rev. 1, March 2007)	DCD discussion only
1.62	Manual Initiation of Protective Actions (Rev. 0, October 1973)	7.1 7.2
1.63	Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants (Task EE 405-4) (Rev. 3, February 1987)	8.3.1 Appendix 3D
1.64	Withdrawn	
1.65	Materials and Inspections for Reactor Vessel Closure Studs (Rev. 0, October 1973)	5.3.2
1.66	Withdrawn	
1.67	Withdrawn	
1.68	Initial Test Programs for Water-Cooled Nuclear Power Plants (Rev. 2, August 1978)	14 16.1 Bases
1.68	Initial Test Programs for Water-Cooled Nuclear Power Plants (Rev. 3, March 2007)	14.2.1 14.2.3 14.2.8 14.2.5.2 16 (TS Bases 3.1.8)
1.68.1	Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants (Rev. 1, January 1977)	This regulatory guide is not applicable to AP1000.
1.68.2	Initial Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants (Rev. 1, July 1978)	14
1.68.3	Preoperational Testing of Instrument and Air Control Systems (Task RS 709-4) (Rev. 0, April 1982)	9.3.1 14

Table 1.9-1 (Sheet 6 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.69	Concrete Radiation Shields for Nuclear Power Plants (Rev. 0, December 1973)	3.8.4 12.3
1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants (Rev. 3, November 1978)	1.1 1.1.6.1 2.5.1
1.71	Welder Qualification for Areas of Limited Accessibility (Rev. 0, December 1973)	5.2.3.4.6
1.71	Welder Qualification for Areas of Limited Accessibility (Rev. 1, March 2007)	DCD discussion only
1.72	Spray Pond Piping Made From Fiberglass-Reinforced Thermosetting Resin (Rev. 2, November 1978)	This regulatory guide is not applicable to AP1000.
1.73	Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants (Rev. 0, January 1974)	3.11 Appendix 3D
1.74	Withdrawn	
1.75	Physical Independence of Electric Systems (Rev. 2, September 1978)	7.1 7.2 7.3 7.4 7.5 8.1 8.3.1 8.3.2 9.5.1
1.75	Criteria for Independence of Electrical Safety Systems (Rev 3, February 2005)	DCD discussion only
1.76	Design Basis Tornado for Nuclear Power Plants (Rev. 0, April 1974)	2.3 3.3
1.76	Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants (PR-1, January 2006)	2.3.1
1.76	Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants (Rev. 1, March 2007)	Table 2.0-201
1.77	Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors (Rev. 0, May 1974)	The interim acceptance criteria specified in Appendix B to NUREG-0800 Section 4.2, Revision 3, is followed for the analysis of the RCCA ejection accident instead of Regulatory Guide 1.77. The guidance of Regulatory Guide 1.183, “Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors” is also followed instead of Regulatory Guide 1.77. See Subsection 15.4.8.1.2.

Table 1.9-1 (Sheet 7 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.78	Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release (Rev. 1, December 2001)	2.2 6.4 9.4.1 9.5.1 16.1 Bases 2.2.3.2 6.4.3 6.4.4.2 16 (TS Bases 3.7.6)
1.79	Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors (Rev. 1, September 1975)	14
1.80	Withdrawn	
1.81	Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plant (Rev. 1, January 1975)	This regulatory guide is not applicable to AP1000.
1.82	Water Sources for Long Term Recirculation Cooling Following a Loss-of-Coolant Accident (Task 203-4) (Rev. 3, November 2003)	6.3
1.83	Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes (Rev. 1, July 1975)	5.4.2
1.84	Design and Fabrication Code Case Acceptability ASME Section III Division 1 (Rev. 32, June 2003)	4.5.1 4.5.2 5.2.1 5.2.3 10.3
1.84	Design, Fabrication, and Materials Code Case Acceptability, ASME Section III (Rev. 33, August 2005)	DCD discussion only
1.85	Withdrawn	
1.86	Termination of Operating Licenses for Nuclear Reactors (Rev. 0, June 1974)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.87	Guidance for Construction of Class 1 Components in Elevated-Temperature Reactors (Rev. 1, June 1975)	This regulatory guide is not applicable to AP1000.
1.88	Withdrawn	
1.89	Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants (Task EE 042-2) (Rev. 1, June 1984)	3.11 Appendix 3D 1.9.4 8.1.4 8.3.2 11.5.2 11.5.6
1.90	Inservice Inspection of Prestressed Concrete Containment Structures With Grouted Tendons (Rev. 1, August 1977)	This regulatory guide is not applicable to AP1000.
1.91	Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plant Sites (Rev. 1, February 1978)	2.2.3.1 2.2.3.2 3.5.1.5
1.92	Combining Modal Responses and Spatial Components in Seismic Response Analysis (Rev. 1, February 1976; Rev. 2, July 2006)	3.7 Appendix 3D
1.92	Combining Modal Responses and Spatial Components in Seismic Response Analysis (Rev. 2, July 2006)	DCD discussion only

Table 1.9-1 (Sheet 8 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.93	Availability of Electric Power Sources (Rev. 0, December 1974)	8.1 8.3 16.1 Bases 16 (TS Bases 3.8.1) 16 (TS Bases 3.8.5)
1.94	Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (Rev. 1, April 1976)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.95	Withdrawn	
1.96	Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants (Rev. 1, June 1976)	This regulatory guide is not applicable to AP1000.
1.97	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident (Rev. 3, May 1983)	7.5 18.8 16.1 Bases Appendix 3D Table 7.5-201 Appendix 12AA 16 (TS Bases 3.3.17)
1.97	Criteria For Accident Monitoring Instrumentation For Nuclear Power Plants (Rev. 4, June 2006)	Not referenced; See Appendix 1A
1.98	Assumptions Used for Evaluating the Potential Radiological Consequences of a Radioactive Offgas System Failure in a Boiling Water Reactor (Rev. 0, March 1976)	This regulatory guide is not applicable to AP1000.
1.99	Radiation Embrittlement of Reactor Vessel Materials (Task ME 305-4) (Rev. 2, May 1988)	5.3.2 5.3.3 16.1 Bases
1.99	Radiation Embrittlement of Reactor Vessel Materials (Rev. 2, May 1988)	16 (TS Bases 3.4.3)
1.100	Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants (Task EE 108-5) (Rev. 2, June 1988)	3.10 Appendix 3D 1.9.4 3.11.2 8.1.4 8.3.2 11.5.2 11.5.6
1.101	Emergency Planning and Preparedness for Nuclear Power Reactors (Rev. 3, August 1992)	This regulatory guide is not applicable to AP1000 design certification.
1.101	Emergency Planning and Preparedness for Nuclear Power Reactors (Rev. 4, July 2003)	13.3 (EP) 9.5.1.8.2.2 Table 9.5-201
1.101	Emergency Planning and Preparedness for Nuclear Power Reactors (Rev. 5, June 2005)	Not referenced; see Appendix 1A
1.102	Flood Protection for Nuclear Power Plants (Rev. 1, September 1976)	3.4 2.4
1.103	Withdrawn	
1.104	Withdrawn	

Table 1.9-1 (Sheet 9 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.105	Instrument Setpoints for Safety-Related Systems (Task 1C 010-5) (Rev. 3, December 1999)	7.1 16
1.106	Thermal Overload Protection for Electric Motors on Motor-Operated Valves (Rev. 1, March 1977)	8.1
1.107	Qualifications for Cement Grouting Tendons for Prestressing Tendons in Containment Structures (Rev. 1, February 1977)	This regulatory guide is not applicable to AP1000.
1.108	Withdrawn	
1.109	Calculation of Annual Doses to Man From Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance With 10 CFR Part 50 Appendix I (Rev. 1, October 1977)	11.2.3 11.3.3
1.110	Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors (Rev. 1, March 1976)	11.2.3.5.1 11.3.3.4.1
1.110	Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors (Draft Rev. 0, March 1976)	11.2.3.5.1 11.3.3.4.1
1.111	Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases From Light-Water-Cooled Reactors (Rev. 1, July 1977)	2.3 2.3.4.1 2.3.5.1 11.3.3.1
1.112	Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Light-Water-Cooled Power Reactors (Rev. 0-R, May 1977)	11.2.3 11.3.3
1.112	Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Light-Water-Cooled Power Reactors (Rev. 1, March 2007)	DCD discussion only
1.113	Estimating Aquatic Dispersion of Effluents From Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I (Rev. 1, April 1977)	This regulatory guide is not applicable to AP1000 design certification.
1.114	Guidance to Operators at the Controls and to Senior Operators in the Control Room of a Nuclear Power Unit (Rev. 2, May 1989)	This regulatory guide is not applicable to AP1000 design certification. 13.1.2.1.4
1.115	Protection Against Low-Trajectory Turbine Missiles (Rev 1, July 1977)	3.5 3.8.4 3.5.1.3
1.116	Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (Rev. 0-R, May 1977)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.117	Tornado Design Classification (Rev. 1, April 1978)	3.5 9.1.2
1.118	Periodic Testing of Electric Power and Protection Systems (Rev. 3, April 1995)	7.1 8.1 8.3
1.119	Withdrawn	
1.120	Fire Protection Guidelines for Nuclear Power Plants (Rev. 1, November 1977)	9.5.1
1.121	Bases for Plugging Degraded PWR Steam Generator Tubes (Rev. 0, August 1976)	5.4.2 16.1 Bases 16 (TS Bases 3.4.17)

Table 1.9-1 (Sheet 10 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.122	Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components (Rev. 1, February 1978)	3.7 Appendix 3D
1.123	Withdrawn	
1.124	Service Limits and Loading Combinations for Class 1 Linear-Type Component Supports (Rev. 1, January 1978)	3.9.3, 9.1.2.1, 9.1.1.1
1.124	Service Limits and Loading Combinations for Class 1 Linear-Type Supports (Rev. 2, February 2007)	DCD discussion only
1.125	Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants (Rev. 1, October 1978)	2.4
1.126	An Acceptable Model and Related Statistical Methods for the Analysis of Fuel Densification (Rev. 1, March 1978)	4.2
1.127	Inspection of Water-Control Structures Associated With Nuclear Power Plants (Rev. 1, March 1978)	This regulatory guide is not applicable to AP1000.
1.128	Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants (Rev. 1, October 1978)	8.3.2
1.128	Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants (Rev. 2, February 2007)	DCD discussion only
1.129	Maintenance, Testing, and Replacement of Vented Lead-Acid Storage Batteries for Nuclear Power Plants (Rev. 2, February 2007)	Table 8.1-1
1.130	Service Limits and Loading Combinations for Class 1 Plate-and-Shell-Type Component Supports (Rev. 1, October 1978)	3.9.3
1.130	Service Limits and Loading Combinations for Class 1 Plate-And-Shell-Type Supports (Rev. 2, March 2007)	DCD discussion only
1.131	Qualification Tests of Electric Cables, Field Splices and Connections for Light-Water-Cooled Nuclear Power Plants (Rev. 0, August 1977)	3.11 Appendix 3D
1.132	Site Investigations for Foundations of Nuclear Power Plants (Rev. 1, March 1979)	This regulatory guide is not applicable to AP1000 design certification.
1.132	Site Investigations for Foundations of Nuclear Power Plants (Rev. 2, October 2003)	2.5.4.3
1.133	Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors (Rev. 1, May 1981)	4.4.6.4 Not referenced; see Appendix 1A
1.134	Medical Evaluation of Nuclear Power Plant Personnel Requiring Operator Licenses (Rev. 3, March 1998)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.135	Normal Water Level and Discharge at Nuclear Power Plants (Rev. 0, September 1977)	2.4
1.136	Material for Concrete Containments (Rev. 2, June 1981)	This regulatory guide is not applicable to AP1000.
1.137	Fuel-Oil Systems for Standby Diesel Generators (Rev. 1, October 1979)	9.5.4
1.138	Laboratory Investigation of Soils for Engineering Analysis and Design of Nuclear Power Plants (Rev. 0, April 1978)	This regulatory guide is not applicable to AP1000 design certification.
1.138	Laboratory Investigations of Soils and Rocks for Engineering Analysis and Design of Nuclear Power Plants (Rev. 2, December 2003)	2.5.4.2.4

Table 1.9-1 (Sheet 11 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.139	Guidance for Residual Heat Removal (Rev. 0, May 1978)	6.3 7.4
1.140	Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants (Rev. 2, June 2001)	9.4.1 9.4.4 9.4.5 9.4.7 9.4.9 9.4.1.4 9.4.7.4 16.3 (TRM Bases 3.9.2)
1.141	Containment Isolation Provisions for Fluid Systems (Rev. 0, April 1978)	6.2.4
1.142	Safety-Related Concrete Structures for Nuclear Power Plants (Other Than Reactor Vessels and Containments) (Rev. 2, November 2001)	3.8.3 3.8.4 3.8.5
1.143	Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants (Rev. 2, November 2001)	3.8.4 10.4.8 11.2 11.3 11.4 11.5 11.2.1.2.5.2 11.2.3.6 11.3.3.6 11.4.5 11.4.6.2
1.144	Withdrawn	
1.145	Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants (Rev. 1, November 1982)	This regulatory guide is not applicable to AP1000 design certification. 2.3.4.1 2.3.4.2
1.146	Withdrawn	
1.147	Inservice Inspection Code Case Acceptability ASME Section XI Division 1 (See PSI and ISI Programs)	5.2.4 6.6
1.148	Withdrawn	
1.149	Nuclear Power Plant Simulation Facilities for Use in Operator License Examinations (Rev. 2, April 1996)	This regulatory guide is not applicable to AP1000 design certification.
1.149	Nuclear Power Plant Simulation Facilities for Use in Operator Training, License Examinations, and Applicant Experience Requirements (Rev. 4, April 2011)	13.2 (NEI 06-13A)
1.150	Ultrasonic Testing of Reactor Pressure Vessel Welds During Preservice and Inservice Examinations (Rev. 1, February 1983)	5.2.4 5.3.2 5.3.4 DCD discussion only
1.151	Instrument Sensing Lines (Task 1C 126-5) (Rev. 0, July 1983)	7.1 7.5 7.6 7.7
1.152	Criteria for Digital Computers in Safety Systems of Nuclear Power Plants (Rev. 1, January 1996)	7

Table 1.9-1 (Sheet 12 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.152	Criteria for Use of Computers in Safety Systems of Nuclear Power Plants (Rev. 2, January 2006)	Not referenced; see Appendix 1A
1.153	Criteria for Power, Instrumentation, and Control Portions of Safety Systems (Task 1C 609-5) (Rev. 1, June 1996)	7.1 7.2 7.3 7.4 7.5 7.6
1.154	Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors (Rev. 0, January 1987)	5.3
1.155	Station Blackout (Task SI 501-4) (Rev. 0, August 1988)	8.2 8.3.1
1.155	Station Blackout (Rev. 0, August 1998)	Table 8.1-201
1.156	Environmental Qualification of Connection Assemblies for Nuclear Power Plants (Task EE 404-4) (Rev. 0, November 1987)	Appendix 3D
1.157	Best-Estimate Calculations of Emergency Core Cooling System Performance (Task RS 701-4) (Rev. 0, May 1989)	6.3
1.158	Qualification of Safety-Related Lead Storage Batteries for Nuclear Power Plants (Task EE 006-5) (Rev. 0, February 1989)	Appendix 3D 8.3.2
1.159	Assuring the Availability of Funds for Decommissioning Nuclear Reactors (Rev. 0, August 1990)	This regulatory guide is not applicable to AP1000 design certification.
1.159	Assuring the Availability of Funds for Decommissioning Nuclear Reactors (Rev. 1, October 2003)	Not referenced; see Appendix 1A
1.160	Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Rev. 4, August 2018)	3.8.3.7 3.8.4.7 3.8.5.7 17.6 (NEI 07-02A)
1.161	Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb (Rev. 0, June 1995)	This regulatory guide is not applicable to AP1000 design certification.
1.162	Format and Content of Report for Thermal Annealing of Reactor Pressure Vessels (Rev. 0, February 1996)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.163	Performance Based Containment Leak-Test Program (Rev. 0, September 1995)	6.2 16.1 Bases 6.2.5.1 6.2.5.2.2 16 (TS 5.5.8)
1.165	Identification and Characterization of Seismic Sources and Determination Safe Shutdown Earthquake Ground Motion (Rev. 0, March 1997)	2.5 2.5.1 2.5.2 2.5.3
1.166	Pre-Earthquake Planning and Immediate Nuclear Power Plant Operator Postearthquake Actions (Rev. 0, March 1997)	This regulatory guide is not applicable to AP1000 design certification. 3.7.4.4

Table 1.9-1 (Sheet 13 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.167	Restart of a Nuclear Power Plant Shut Down by a Seismic Event (Rev. 0, March 1997)	This regulatory guide is not applicable to AP1000 design certification. 3.7.4.4
1.168	Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	7 (Common Q discussions)
1.168	Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 1, February 2004)	7 (Component Interface Module discussions)
1.168	Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 1, February 2004)	DCD discussion only
1.169	Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	7
1.170	Software Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	7
1.171	Software Unit Testing for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	7
1.172	Software Requirements Specifications for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	7
1.173	Developing Software Life Cycle Processes for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	7
1.174	An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis (Rev. 0, July 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.174	An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis (Rev. 1, November 2002)	Not referenced; see Appendix 1A
1.175	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing (Rev. 0, July 1998)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.176	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Graded Quality Assurance (Rev. 0, August 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.177	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications (Rev. 0, August 1998)	Not referenced; see Appendix 1A
1.178	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Inspection of Piping (Rev. 0, September 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.178	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Inspection of Piping (Rev. 1, September 2003)	Not referenced; see Appendix 1A
1.179	Standard Format and Content of License Termination Plans for Nuclear Power Reactors (Rev. 0, January 1999)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.180	Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems (Rev. 1, October 2003)	Appendix 3D 7.1.4.2

Table 1.9-1 (Sheet 14 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.181	Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e) (Rev. 0, September 1999)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.182	Withdrawn	
1.183	Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors (Rev. 0, July 2000)	2.3 Appendix 3D 4.2 6.5.1 15.4 15.6.3 15.7 16.1 Bases 16 (TS Bases 3.7.5) 16 (TS Bases 3.9.4) 16 (TS Bases 3.9.5)
1.184	Decommissioning of Nuclear Power Reactors (Rev. 0, August 2000)	This regulatory guide is not applicable to AP1000 design certification.
1.184	Decommissioning of Nuclear Power Reactors (Rev. 0, July 2000)	Not referenced; see Appendix 1A
1.185	Standard Format and Content for Post-shutdown Decommissioning Activities Report (Rev. 0, August 2000)	This regulatory guide is not applicable to AP1000 design certification.
1.185	Standard Format and Content for Post- shutdown Decommissioning Activities Report (Rev. 0, July 2000)	Not referenced; see Appendix 1A
1.186	Guidance and Examples of Identifying 10 CFR 50.2 Design Bases (Rev. 0, December 2000)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.187	Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments (Rev. 0, November 2000)	This regulatory guide is not applicable to AP1000 design certification. Not referenced; see Appendix 1A
1.188	Standard Format and Content for Applications To Renew Nuclear Power Plant Operating Licenses (Rev. 1, September 2005)	Not referenced; see Appendix 1A
1.189	Fire Protection for Operating Nuclear Power Plants (Rev. 0, April 2001)	This regulatory guide is not applicable to AP1000 design certification.
1.189	Fire Protection for Nuclear Power Plants (Rev. 1, March 2007)	9.5.1.8.1.1 9.5.1.8.2.2 Table 9.5.1-1 Appendix 9A 17.5 (QAPD III.2)
1.190	Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence (Rev. 0, March 2001)	5.3.2.6 5.3.3.1
1.191	Fire Protection Program for Nuclear Power Plants During Decommissioning and Permanent Shutdown (Rev. 0, May 2001)	Not referenced; see Appendix 1A

Table 1.9-1 (Sheet 15 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
1.192	Operation and Maintenance Code Case Acceptability, ASME OM Code (Rev. 3, October 2019)	Not referenced; See Appendix 1A
1.193	ASME Code Cases Not Approved for Use (Rev. 1, August 2005)	Not referenced; see Appendix 1A
1.194	Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants (Rev. 0, June 2003)	2.3.4.3.1 15A.3.3
1.195	Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-Water Nuclear Power Reactors (Rev. 0, May 2003)	Not referenced; see Appendix 1A
1.196	Control Room Habitability at Light-Water Nuclear Power Reactors (Rev. 1, January 2007)	6.4.3 16 (TS Bases 3.7.6)
1.197	Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors (Rev. 0, May 2003)	9.4.1 6.4.5
1.198	Procedures and Criteria for Assessing Seismic Soil Liquefaction at Nuclear Power Plant Sites (Rev. 0, November 2003)	2.5.4
1.199	Anchoring Components and Structural Supports in Concrete (Rev. 0, November 2003)	3.8.3.5 3.8.4.5.1 3.8.5.5
1.200	An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities (Rev. 2, March 2009)	19
1.201	Guidelines for Categorizing Structures, Systems, and Components in Nuclear Power Plants According to Their Safety Significance (Rev. 1, May 2006)	Not referenced; see Appendix 1A
1.202	Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors (Rev. 0, February 2005)	Not referenced; see Appendix 1A
1.203	Transient and Accident Analysis Methods (Rev. 0, December 2005)	Not referenced; see Appendix 1A
1.204	Guidelines for Lightning Protection of Nuclear Power Plants (Rev. 0, November 2005)	Table 8.1-1
1.205	Risk-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants (Rev. 0, May 2006)	Not referenced; see Appendix 1A
1.206	Combined License Applications for Nuclear Power Plants (LWR Edition) (Rev. 0, June 2007)	1.1.6.1 Table 1.8-201 1.9.5.5 See Appendix 1A Table 8.1-1 12.1.1.3 12AA.5 14.2.1 Appendix 14A
1.207	Guidelines for Evaluating Fatigue Analyses Incorporating the Life Reduction of Metal Components Due to the Effects of the Light-Water Reactor Environment for New Reactors (Rev. 0, March 2007)	Not referenced; see Appendix 1A
1.208	A Performance-Based Approach to Define the Site-Specific Earthquake Ground Motion (Rev. 0, March 2007)	Not referenced; see Appendix 1A
1.209	Guidelines for Environmental Qualification of Safety-Related Computer-Based Instrumentation and Control Systems in Nuclear Power Plants (Rev. 0, March 2007)	Not referenced; see Appendix 1A

Table 1.9-1 (Sheet 16 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
Division 4 Regulatory Guides		
4.15	Quality Assurance for Radiological Monitoring Programs (Inception through Normal Operations to License Termination) — Effluent Streams and the Environment (Rev. 1, February 1979)	11.5.1.2 11.5.3 11.5.4 11.5.6.5
4.15	Quality Assurance for Radiological Monitoring Programs (Inception through Normal Operations to License Termination) — Effluent Streams and the Environment (Rev. 2, July 2007)	11.5.3
Division 5 Regulatory Guides		Note c
5.71	Cyber Security Programs for Nuclear Facilities (Rev. 0, January 2010)	13.6
5.84	Fitness-For-Duty Programs at New Reactor Construction Sites (Rev. 0, July 2015)	13.7
Division 8 Regulatory Guides		
8.2	Guide for Administrative Practices in Radiation Monitoring (Rev. 0, February 1973)	12.1 (NEI 07-08A) 12.3.4 Appendix 12AA (NEI 07-03A)
8.4	Direct-Reading and Indirect-Reading Pocket Dosimeters (Rev. 0, February 1973)	Appendix 12AA (NEI 07-03A)
8.5	Withdrawn	
8.6	Standard Test Procedure for Geiger-Muller Counters (Rev. 0, May 1973)	Appendix 12AA (NEI 07-03A)
8.7	Instructions for Recording and Reporting Occupational Radiation Dose Data (Rev. 2, November 2005)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.8	Information Relevant to Ensuring That Occupational Radiation Exposures at Nuclear Power Stations Will Be as Low as Is Reasonably Achievable (Rev. 3, June 1978)	12.1 (NEI 07-08A) 12.3.4 Appendix 12AA Appendix 12AA (NEI 07-03A)
8.9	Acceptable Concepts, Models, Equations, and Assumptions for a Bioassay Program (Rev. 1, July 1993)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.10	Operating Philosophy for Maintaining Occupational Radiation Exposures as Low as Is Reasonably Achievable (Rev. 1-R, May 1977)	12.1 (NEI 07-08A) 12.3.4 Appendix 12AA Appendix 12AA (NEI 07-03A)
8.13	Instruction Concerning Prenatal Radiation Exposure (Rev. 3, June 1999)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.15	Acceptable Programs for Respiratory Protection (Rev. 1, October 1999)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.27	Radiation Protection Training for Personnel at Light-Water-Cooled Nuclear Power Plants (Rev. 0, March 1981)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.28	Audible-Alarm Dosimeters (Rev. 0, August 1981)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.29	Instruction Concerning Risks from Occupational Radiation Exposure (Rev. 1, February 1996)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.34	Monitoring Criteria and Methods To Calculate Occupational Radiation Doses (Rev. 0, July 1992)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.35	Planned Special Exposures (Rev. 0, June 1992)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)
8.36	Radiation Dose to the Embryo/Fetus (Rev. 0, July 1992)	12.1 (NEI 07-08A) Appendix 12AA (NEI 07-03A)

Table 1.9-1 (Sheet 17 of 17)
Regulatory Guide/Section Cross-References

Division 1 Regulatory Guide		Chapter, Section or Subsection
8.38	Control of Access to High and Very High Radiation Areas of Nuclear Plants (Rev. 1, May 2006)	12.1 (NEI 07-08A) Appendix 12AA Table 12AA-201 Appendix 12AA (NEI 07-03A)

{HISTORICAL—a. NEI templates are incorporated by reference. See Table 1.6-201.—HISTORICAL}

b. Not used.

c. Division 5 of the regulatory guides applies to materials and plant protection. As appropriate, the Division 5 regulatory guide topics are addressed in the DCD and plant-specific security plans (i.e., Physical Security Plan, Training and Qualification Plan, Safeguards Contingency Plan, and Cyber Security Plan).

Table 1.9-2 (Sheet 1 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
TMI Action Plan Items			
I.A.1.1	Shift Technical Advisor	f	Resolved per NUREG-0933
I.A.1.2	Shift Supervisor Administrative Duties	f	Resolved per NUREG-0933
I.A.1.3	Shift Manning	f	Resolved per NUREG-0933
I.A.1.4	Long-Term Upgrading	f	See Subsection 13.1.1 Resolved per NUREG-0933
I.A.2.1(1)	Qualifications - Experience	f	Resolved per NUREG-0933
I.A.2.1(2)	Training	f	
I.A.2.1(2)	Immediate Upgrading of RO & SRO Training and Qualifications, Training	f	Resolved per NUREG-0933
I.A.2.1(3)	Facility Certification of Competence and Fitness of Applicants for Operator and Senior Operator Licenses	f	Resolved per NUREG-0933
I.A.2.2	Training and Qualifications of Operations Personnel	c	
I.A.2.3	Administration of Training Programs	f	Resolved per NUREG-0933
I.A.2.4	NRR Participation in Inspector Training	d	Not applicable to new plants
I.A.2.5	Plant Drills	c	
I.A.2.6(1)	Revise Regulatory Guide 1.8	f	Resolved per NUREG-0933
I.A.2.6(2)	Staff Review of NRR 80-117	c	
I.A.2.6(3)	Revise 10 CFR 55	e	
I.A.2.6(4)	Operator Workshops	c	
I.A.2.6(5)	Develop Inspection Procedures for Training Programs	c	
I.A.2.6(6)	Nuclear Power Fundamentals	a	
I.A.2.7	Accreditation of Training Institutions	c	
I.A.3.1	Revise Scope of Criteria for Licensing Examinations	f	Resolved per NUREG-0933
I.A.3.2	Operator Licensing Program Changes	c	
I.A.3.3	Requirements for Operator Fitness	c	
I.A.3.4	Licensing of Additional Operations Personnel	c	
I.A.3.5	Establish Statement of Understanding with INPO and DOE	d	Not applicable to new plants

Table 1.9-2 (Sheet 2 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
I.A.4.1(1)	Short-Term Study of Training Simulators	c	
I.A.4.1(2)	Interim Changes in Training Simulators	f	Resolved per NUREG-0933
I.A.4.2(1)	Research on Training Simulators	f	Resolved per NUREG-0933
I.A.4.2(2)	Upgrade Training Simulator Standards	f	Resolved per NUREG-0933
I.A.4.2(3)	Regulatory Guide on Training Simulators	f	See Subsection 1.9.3, item (2)(i) Resolved per NUREG-0933
I.A.4.2(4)	Review Simulators for Conformance to Criteria	f	Resolved per NUREG-0933
I.A.4.3	Feasibility Study of Procurement of NRC Training Simulator	d	Not applicable to new plants
I.A.4.4	Feasibility Study of NRC Engineering Computer	d	Not applicable to new plants
I.B.1.1(1)	Prepare Draft Criteria	c	
I.B.1.1(2)	Prepare Commission Paper	c	
I.B.1.1(3)	Issue Requirements for the Upgrading of Management and Technical Resources	c	
I.B.1.1(4)	Review Responses to Determine Acceptability	c	
I.B.1.1(5)	Review Implementation of the Upgrading Activities	c	
I.B.1.1(6)	Prepare Revisions to Regulatory Guides 1.33 and 1.8	e	
I.B.1.1(7)	Issue Regulatory Guides 1.33 and 1.8	e	
I.B.1.2(1)	Prepare Draft Criteria	c	
I.B.1.2(2)	Review Near-Term Operating License Facilities	c	
I.B.1.2(3)	Include Findings in the SER for Each Near-Term Operating License Facility	c	
I.B.1.3(1)	Require Licensees to Place Plant in Safest Shutdown Cooling Following a Loss of Safety Function Due to Personnel Error	d	Not applicable to new plants
I.B.1.3(2)	Use Existing Enforcement Options to Accomplish Safest Shutdown Cooling	d	Not applicable to new plants
I.B.1.3(3)	Use Non-Fiscal Approaches to Accomplish Safest Shutdown Cooling	d	Not applicable to new plants
I.B.2.1(1)	Verify the Adequacy of Management and Procedural Controls and Staff Discipline	d	Not applicable to new plants

Table 1.9-2 (Sheet 3 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
I.B.2.1(2)	Verify that Systems Required to Be Operable Are Properly Aligned	d	Not applicable to new plants
I.B.2.1(3)	Follow-up on Completed Maintenance Work Orders to Ensure Proper Testing and Return to Service	d	Not applicable to new plants
I.B.2.1(4)	Observe Surveillance Tests to Determine Whether Test Instruments Are Properly Calibrated	d	Not applicable to new plants
I.B.2.1(5)	Verify that Licensees Are Complying with Technical Specifications	d	Not applicable to new plants
I.B.2.1(6)	Observe Routine Maintenance	d	Not applicable to new plants
I.B.2.1(7)	Inspect Terminal Boards, Panels, and Instrument Racks for Unauthorized Jumpers and Bypasses	d	Not applicable to new plants
I.B.2.2	Resident Inspector at Operating Reactors	d	Not applicable to new plants
I.B.2.3	Regional Evaluations	d	Not applicable to new plants
I.B.2.4	Overview of Licensee Performance	d	Not applicable to new plants
I.C.1(1)	Small Break LOCAs	f	Resolved per NUREG-0933
I.C.1(2)	Inadequate Core Cooling	f	Resolved per NUREG-0933
I.C.1(3)	Transients and Accidents	f	Resolved per NUREG-0933
I.C.1(4)	Confirmatory Analyses of Selected Transients	c	
I.C.2	Shift and Relief Turnover Procedures	f	Resolved per NUREG-0933
I.C.3	Shift Supervisor Responsibilities	f	Resolved per NUREG-0933
I.C.4	Control Room Access	f	Resolved per NUREG-0933
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	g	See Subsection 1.9.3, item (3)(i)
I.C.6	Procedures for Verification of Correct Performance of Operating Activities	f	Resolved per NUREG-0933
I.C.7	NSSS Vendor Review of Procedures	f	Resolved per NUREG-0933
I.C.8	Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants	f	Resolved per NUREG-0933

Table 1.9-2 (Sheet 4 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
I.C.9	Long-Term Program Plan for Upgrading of Procedures	c	See Subsections 13.5.1 and 1.9.3, item (2)(ii)
I.D.1	Control Room Design Reviews	g	See Subsection 1.9.3, item (2)(iii)
I.D.2	Plant Safety Parameter Display Console	g	See Subsection 1.9.3, item (2)(iv)
I.D.3	Safety System Status Monitoring	c	See Subsection 1.9.3, item (2)(v)
I.D.4	Control Room Design Standard	c	
I.D.5(1)	Operator-Process Communication	c	
I.D.5(2)	Plant Status and Post-Accident Monitoring	g	See Subsection 1.9.4, item I.D.5(2)
I.D.5(3)	On-Line Reactor Surveillance System	c	See Subsection 1.9.4, item I.D.5(3)
I.D.5(4)	Process Monitoring Instrumentation	c	
I.D.5(5)	Disturbance Analysis Systems	d	Not applicable to new plants
I.D.6	Technology Transfer Conference	d	Not applicable to new plants
I.E.1	Office for Analysis and Evaluation of Operational Data	d	Not applicable to new plants
I.E.2	Program Office Operational Data Evaluation	d	Not applicable to new plants
I.E.3	Operational Safety Data Analysis	d	Not applicable to new plants
I.E.4	Coordination of Licensee, Industry, and Regulatory Programs	d	Not applicable to new plants
I.E.5	Nuclear Plant Reliability Data Systems	d	Not applicable to new plants
I.E.6	Reporting Requirements	d	Not applicable to new plants
I.E.7	Foreign Sources	d	Not applicable to new plants
I.E.8	Human Error Rate Analysis	d	Not applicable to new plants
I.F.1	Expand QA List	c, j	See Subsections 1.9.4.2.1, item I.F.1 and 1.9.3, item (3)(ii)
I.F.2(1)	Assure the Independence of the Organization Performing the Checking Function	a	See Section 17.5
I.F.2(2)	Include QA Personnel in Review and Approval of Plant Procedures	g	See Subsection 1.9.3, item (3)(iii)
I.F.2(3)	Include QA Personnel in All Design, Construction, Installation, Testing, and Operation Activities	g	See Subsection 1.9.3, item (3)(iii)

Table 1.9-2 (Sheet 5 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
I.F.2(4)	Establish Criteria for Determining QA Requirements for Specific Classes of Equipment	a	See Section 17.5
I.F.2(5)	Establish Qualification Requirements for QA and QC Personnel	a	See Section 17.5
I.F.2(6)	Increase the Size of Licensees' QA Staff	f	Resolved per NUREG-0933
I.F.2(7)	Clarify that the QA Program Is a Condition of the Construction Permit and Operating License	a	See Section 17.5
I.F.2(8)	Compare NRC QA Requirements with Those of Other Agencies	a	See Section 17.5
I.F.2(9)	Clarify Organizational Reporting Levels for the QA Organization	f	Resolved per NUREG-0933
I.F.2(10)	Clarify Requirements for Maintenance of "As-Built" Documentation	a	See Section 17.5
I.F.2(11)	Define Role of QA in Design and Analysis Activities	a	See Section 17.5
I.G.1	Training Requirements	f, j	See Subsection 1.9.4.2.1, item I.G.1 Resolved per NUREG-0933
I.G.2	Scope of Test Program	f, j	See Subsection 1.9.4.2.1, item I.G.2 Resolved per NUREG-0933
II.A.1	Siting Policy Reformulation	c	
II.A.2	Site Evaluation of Existing Facilities	e	
II.B.1	Reactor Coolant System Vents	g	See Subsection 1.9.3, item (2)(vi)
II.B.2	Plant Shielding to Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	g	See Subsection 1.9.3, item (2)(vii)
II.B.3	Post-Accident Sampling	g	See Subsection 1.9.3, item (2)(viii)
II.B.4	Training for Mitigating Core Damage	f	Resolved per NUREG-0933
II.B.5(1)	Behavior of Severely Damaged Fuel	d	Not applicable to new plants
II.B.5(2)	Behavior of Core Melt	d	Not applicable to new plants
II.B.5(3)	Effect of Hydrogen Burning and Explosions on Containment Structures	d	Not applicable to new plants
II.B.6	Risk Reduction for Operating Reactors at Sites with High Population Densities	f	Resolved per NUREG-0933
II.B.7	Analysis of Hydrogen Control	e	
II.B.8	Rulemaking Proceedings on Degraded Core Accidents	g	See Subsection 1.9.3, items (1)(i), (1)(xii), (2)(ix), (3)(iv), and (3)(v)
II.C.1	Interim Reliability Evaluation Program	c	

Table 1.9-2 (Sheet 6 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.C.2	Continuation of Interim Reliability Evaluation Program	c	
II.C.3	Systems Interaction	e	
II.C.4	Reliability Engineering	c	
II.D.1	Testing Requirements	g	See Subsection 1.9.3, item (2)(x)
II.D.2	Research on Relief and Safety Valve Test Requirements	a	
II.D.3	Relief and Safety Valve Position Indication	g	See Subsection 1.9.3, item (2)(xi)
II.E.1.1	Auxiliary Feedwater System Evaluation	g	See Subsection 1.9.3, item (1)(ii)
II.E.1.2	Auxiliary Feedwater System Automatic Initiation and Flow Indication	g	See Subsection 1.9.3, items (1)(ii) and (2)(xii)
II.E.1.3	Update Standard Review Plan and Develop Regulatory Guide	d, j	See Subsection 1.9.4.2.1, item II.E.1.3 Resolved per NUREG-0933
II.E.2.1	Reliance on ECCS	e	
II.E.2.2	Research on Small Break LOCAs and Anomalous Transients	c	
II.E.2.3	Uncertainties in Performance Predictions	a	
II.E.3.1	Reliability of Power Supplies for Natural Circulation	g	See Subsection 1.9.3, item (2)(xiii)
II.E.3.2	Systems Reliability	e	
II.E.3.3	Coordinated Study of Shutdown Heat Removal Requirements	e	
II.E.3.4	Alternate Concepts Research	c	
II.E.3.5	Regulatory Guide	e	
II.E.4.1	Dedicated Penetrations	g	See Subsection 1.9.3, item (3)(vi)
II.E.4.2	Isolation Dependability	g	See Subsection 1.9.3, item (2)(xiv)
II.E.4.3	Integrity Check	c	
II.E.4.4	Purging	g	See Subsection 1.9.3, item (2)(xv)
II.E.5.1	Design Evaluation	b	
II.E.5.2	B&W Reactor Transient Response Task Force	b	
II.E.6.1	Test Adequacy Study	d, j	See Subsection 1.9.4.2.1, item II.E.6.1 Resolved per NUREG-0933
II.F.1	Additional Accident Monitoring Instrumentation	g	See Subsection 1.9.3, item (2)(xvii)
II.F.2	Identification of and Recovery from Conditions Leading to Inadequate Core Cooling	g	See Subsection 1.9.3, item (2)(xviii)

Table 1.9-2 (Sheet 7 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.F.3	Instruments for Monitoring Accident Conditions	g	See Subsection 1.9.3, item (2)(xix)
II.F.4	Study of Control and Protective Action Design Requirements	a	
II.F.5	Classification of Instrumentation, Control, and Electrical Equipment	d	Not applicable to new plants
II.G.1	Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators	g	See Subsection 1.9.3, item (2)(xx)
II.H.1	Maintain Safety of TMI-2 and Minimize Environmental Impact	c	
II.H.2	Obtain Technical Data on the Conditions Inside the TMI-2 Containment Structure	b	
II.H.3	Evaluate and Feed Back Information Obtained from TMI	e	
II.H.4	Determine Impact of TMI on Socioeconomic and Real Property Values	d	Not applicable to new plants
II.J.1.1	Establish a Priority System for Conducting Vendor Inspections	d	Not applicable to new plants
II.J.1.2	Modify Existing Vendor Inspection Program	d	Not applicable to new plants
II.J.1.3	Increase Regulatory Control Over Present Non-Licensees	d	Not applicable to new plants
II.J.1.4	Assign Resident Inspectors to Reactor Vendors and Architect-Engineers	d	Not applicable to new plants
II.J.2.1	Reorient Construction Inspection Program	d	Not applicable to new plants
II.J.2.2	Increase Emphasis on Independent Measurement in Construction Inspection Program	d	Not applicable to new plants
II.J.2.3	Assign Resident Inspectors to All Construction Sites	d	Not applicable to new plants
II.J.3.1	Organization and Staffing to Oversee Design and Construction	f	See Subsection 1.9.3, item (3)(vii) Not applicable to new plants
II.J.3.2	Issue Regulatory Guide	e	
II.J.4.1	Revise Deficiency Reporting Requirements	f	Resolved per NUREG-0933
II.K.1(1)	Review TMI-2 PNs and Detailed Chronology of the TMI-2 Accident	f	Resolved per NUREG-0933
II.K.1(2)	Review Transients Similar to TMI-2 That Have Occurred at Other Facilities and NRC Evaluation of Davis-Besse Event	b	
II.K.1(3)	Review Operating Procedures for Recognizing, Preventing, and Mitigating Void Formation in Transients and Accidents	f	Resolved per NUREG-0933
II.K.1(4)	Review Operating Procedures and Training Instructions	f	Resolved per NUREG-0933
II.K.1(5)	Safety-Related Valve Position Description	f	Resolved per NUREG-0933

Table 1.9-2 (Sheet 8 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.1(6)	Review Containment Isolation Initiation Design and Procedures	f	Resolved per NUREG-0933
II.K.1(7)	Implement Positive Position Controls on Valves That Could Compromise or Defeat AFW Flow	b	
II.K.1(8)	Implement Procedures That Assure Two Independent 100% AFW Flow Paths	b	
II.K.1(9)	Review Procedures to Assure That Radioactive Liquids and Gases Are Not Transferred out of Containment Inadvertently	f	Resolved per NUREG-0933
II.K.1(10)	Review and Modify Procedures for Removing Safety-Related Systems from Service	f, j	See Subsection 1.9.4.2.1, item II.K.1(10) Resolved per NUREG-0933
II.K.1(11)	Make All Operating and Maintenance Personnel Aware of the Seriousness and Consequences of the Erroneous Actions Leading up to, and in Early Phases of, the TMI-2 Accident	f	Resolved per NUREG-0933
II.K.1(12)	One Hour Notification Requirement and Continuous Communications Channels	f	Resolved per NUREG-0933
II.K.1(13)	Propose Technical Specification Changes Reflecting Implementation of All Bulletin Items	f, j	See Subsection 1.9.4.2.1, item II.K.1(13) Resolved per NUREG-0933
II.K.1(14)	Review Operating Modes and Procedures to Deal with Significant Amounts of Hydrogen	f	Resolved per NUREG-0933
II.K.1(15)	For Facilities with Non-Automatic AFW Initiation, Provide Dedicated Operator in Continuous Communication with CR to Operate AFW	f	Resolved per NUREG-0933
II.K.1(16)	Implement Procedures That Identify PZR PORV "Open" Indications and That Direct Operator to Close Manually at "Reset" Setpoint	f	Resolved per NUREG-0933
II.K.1(17)	Trip PZR Level Bistable so That PZR Low Pressure Will Initiate Safety Injection	f, j	See Subsection 1.9.4.2.1, item II.K.1(17) Resolved per NUREG-0933
II.K.1(18)	Develop Procedures and Train Operators on Methods of Establishing and Maintaining Natural Circulation	b	
II.K.1(19)	Describe Design and Procedure Modifications to Reduce Likelihood of Automatic PZR PORV Actuation in Transients	b	
II.K.1(20)	Provide Procedures and Training to Operators for Prompt Manual Reactor Trip for LOFW, TT, MSIV Closure, LOOP, LOSG Level, and LO PZR Level	b	
II.K.1(21)	Provide Automatic Safety-Grade Anticipatory Reactor Trip for LOFW, TT, or Significant Decrease in SG Level	b	

Table 1.9-2 (Sheet 9 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.1(22)	Describe Automatic and Manual Actions for Proper Functioning of Auxiliary Heat Removal Systems When FW System Not Operable	g	See Subsection 1.9.3, item (2)(xxi)
II.K.1(23)	Describe Uses and Types of RV Level Indication for Automatic and Manual Initiation Safety Systems	b	
II.K.1(24)	Perform LOCA Analyses for a Range of Small-Break Sizes and a Range of Time Lapses Between Reactor Trip and RCP Trip	e, j	See Subsection 1.9.4.2.1, item II.K.1(24)
II.K.1(25)	Develop Operator Action Guidelines	e	
II.K.1(26)	Revise Emergency Procedures and Train ROs and SROs	f	Resolved per NUREG-0933
II.K.1(27)	Provide Analyses and Develop Guidelines and Procedures for Inadequate Core Cooling Conditions	e	
II.K.1(28)	Provide Design That Will Assure Automatic RCP Trip for All Circumstances Where Required	e	
II.K.2(1)	Upgrade Timeliness and Reliability of AFW System	b	
II.K.2(2)	Procedures and Training to Initiate and Control AFW Independent of Integrated Control System	b	
II.K.2(3)	Hard-Wired Control-Grade Anticipatory Reactor Trips	b	
II.K.2(4)	Small-Break LOCA Analysis, Procedures and Operator Training	b	
II.K.2(5)	Complete TMI-2 Simulator Training for All Operators	b	
II.K.2(6)	Reevaluate Analysis of Dual-Level Setpoint Control	b	
II.K.2(7)	Reevaluate Transient of September 24, 1977	b	
II.K.2(8)	Continued Upgrading of AFW System	e	
II.K.2(9)	Analysis and Upgrading of Integrated Control System	e	
II.K.2(10)	Hard-Wired Safety-Grade Anticipatory Reactor Trips	b	See Subsection 1.9.3, item (2)(xxiii)
II.K.2(11)	Operator Training and Drilling	b	
II.K.2(12)	Transient Analysis and Procedures for Management of Small Breaks	e	
II.K.2(13)	Thermal-Mechanical Report on Effect of HPI on Vessel Integrity for Small-Break LOCA With No AFW	b	
II.K.2(14)	Demonstrate That Predicted Lift Frequency of PORVs and SVs Is Acceptable	b	
II.K.2(15)	Analysis of Effects of Slug Flow on Once-Through Steam Generator Tubes After Primary System Voiding	b	
II.K.2(16)	Impact of RCP Seal Damage Following Small-Break LOCA With Loss of Offsite Power	g	See Subsection 1.9.3, item (1)(iii)
II.K.2(17)	Analysis of Potential Voiding in RCS During Anticipated Transients	b	
II.K.2(18)	Analysis of Loss of Feedwater and Other Anticipated Transients	e	
II.K.2(19)	Benchmark Analysis of Sequential AFW Flow to Once-Through Steam Generator	b	

Table 1.9-2 (Sheet 10 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.2(20)	Analysis of Steam Response to Small-Break LOCA	b	
II.K.2(21)	LOFT L3-1 Predictions	b	
II.K.3(1)	Install Automatic PORV Isolation System and Perform Operational Test	g	See Subsection 1.9.3, item (1)(iv)
II.K.3(2)	Report on Overall Safety Effect of PORV Isolation System	g	See Subsection 1.9.3, item (1)(iv)
II.K.3(3)	Report Safety and Relief Valve Failures Promptly and Challenges Annually	f	Resolved per NUREG-0933
II.K.3(4)	Review and Upgrade Reliability and Redundancy of Non-Safety Equipment for Small-Break LOCA Mitigation	e	
II.K.3(5)	Automatic Trip of Reactor Coolant Pumps	f, j	See Subsection 1.9.4.2.1, item II.K.3(5) Resolved per NUREG-0933
II.K.3(6)	Instrumentation to Verify Natural Circulation	e	
II.K.3(7)	Evaluation of PORV Opening Probability During Overpressure Transient	b	
II.K.3(8)	Further Staff Consideration of Need for Diverse Decay Heat Removal Method Independent of SGs	e	
II.K.3(9)	Proportional Integral Derivative Controller Modification	g	See Subsection 1.9.4, item II.K.3(9)
II.K.3(10)	Anticipatory Trip Modification Proposed by Some Licensees to Confine Range of Use to High Power Levels	f	Resolved per NUREG-0933
II.K.3(11)	Control Use of PORV Supplied by Control Components, Inc. Until Further Review Complete	f	Resolved per NUREG-0933
II.K.3(12)	Confirm Existence of Anticipatory Trip Upon Turbine Trip	f	Resolved per NUREG-0933
II.K.3(13)	Separation of HPCI and RCIC System Initiation Levels	b	
II.K.3(14)	Isolation of Isolation Condensers on High Radiation	b	
II.K.3(15)	Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems	b	
II.K.3(16)	Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification	b	
II.K.3(17)	Report on Outage of ECC Systems - Licensee Report and Technical Specification Changes	b	
II.K.3(18)	Modification of ADS Logic - Feasibility Study and Modification for Increased Diversity for Some Event Sequences	g	See Subsection 1.9.3, item (1)(vii)
II.K.3(19)	Interlock on Recirculation Pump Loops	b	
II.K.3(20)	Loss of Service Water for Big Rock Point	b	
II.K.3(21)	Restart of Core Spray and LPCI Systems on Low Level - Design and Modification	b	
II.K.3(22)	Automatic Switchover of RCIC System Suction - Verify Procedures and Modify Design	b	

Table 1.9-2 (Sheet 11 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.3(23)	Central Water Level Recording	e	
II.K.3(24)	Confirm Adequacy of Space Cooling for HPCI and RCIC Systems	b	
II.K.3(25)	Effect of Loss of AC Power on Pump Seals	g	See Subsection 1.9.3, item (1)(iii)
II.K.3(26)	Study Effect on RHR Reliability of Its Use for Fuel Pool Cooling	e	
II.K.3(27)	Provide Common Reference Level for Vessel Level Instrumentation	b	
II.K.3(28)	Study and Verify Qualification of Accumulators on ADS Valves	g	See Subsection 1.9.3, item (1)(x)
II.K.3(29)	Study to Demonstrate Performance of Isolation Condensers with Non-Condensibles	b	
II.K.3(30)	Revised Small-Break LOCA Methods to Show Compliance with 10 CFR 50, Appendix K	f	Resolved per NUREG-0933
II.K.3(31)	Plant-Specific Calculations to Show Compliance with 10 CFR 50.46	f	Resolved per NUREG-0933
II.K.3(32)	Provide Experimental Verification of Two-Phase Natural Circulation Models	e	
II.K.3(33)	Evaluate Elimination of PORV Function	e	
II.K.3(34)	Relap-4 Model Development	e	
II.K.3(35)	Evaluation of Effects of Core Flood Tank Injection on Small-Break LOCAs	e	
II.K.3(36)	Additional Staff Audit Calculations of B&W Small-Break LOCA Analyses	e	
II.K.3(37)	Analysis of B&W Response to Isolated Small-Break LOCA	e	
II.K.3(38)	Analysis of Plant Response to a Small-Break LOCA in the Pressurizer Spray Line	e	
II.K.3(39)	Evaluation of Effects of Water Slugs in Piping Caused by HPI and CFT Flows	e	
II.K.3(40)	Evaluation of RCP Seal Damage and Leakage During a Small-Break LOCA	e	
II.K.3(41)	Submit Predictions for LOFT Test L3-6 with RCPs Running	e	
II.K.3(42)	Submit Requested Information on the Effects of Non Condensible Gases	e	
II.K.3(43)	Evaluation of Mechanical Effects of Slug Flow on Steam Generator Tubes	e	
II.K.3(44)	Evaluation of Anticipated Transients with Single Failure to Verify No Significant Fuel Failure	b	
II.K.3(45)	Evaluate Depressurization with Other Than Full ADS	b	
II.K.3(46)	Response to List of Concerns from ACRS Consultant	b	
II.K.3(47)	Test Program for Small-Break LOCA Model Verification Pretest Prediction, Test Program, and Model Verification	e	
II.K.3(48)	Assess Change in Safety Reliability as a Result of Implementing B&OTF Recommendations	e	

Table 1.9-2 (Sheet 12 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.3(49)	Review of Procedures (NRC)	e	
II.K.3(50)	Review of Procedures (NSSS Vendors)	e	
II.K.3(51)	Symptom-Based Emergency Procedures	e	
II.K.3(52)	Operator Awareness of Revised Emergency Procedures	e	
II.K.3(53)	Two Operators in Control Room	e	
II.K.3(54)	Simulator Upgrade for Small-Break LOCAs	e	
II.K.3(55)	Operator Monitoring of Control Board	e	
II.K.3(56)	Simulator Training Requirements	e	
II.K.3(57)	Identify Water Sources Prior to Manual Activation of ADS	b	
III.A.1.1(1)	Implement Action Plan Requirements for Promptly Improving Licensee Emergency Preparedness	f	Resolved per NUREG-0933
III.A.1.1(2)	Perform an Integrated Assessment of the Implementation	f	Not applicable to new plants
III.A.1.2	Upgrade Licensee Emergency Support Facilities	g	See Subsection 1.9.3, item (2)(xxv)
III.A.1.3(1)	Maintain Supplies of Thyroid-Blocking Agent - Workers	c	
III.A.1.3(2)	Maintain Supplies of Thyroid-Blocking Agent - Public	c	
III.A.2.1(1)	Publish Proposed Amendments to the Rules	d	Resolved per NUREG-0933
III.A.2.1(2)	Conduct Public Regional Meetings	d	Not applicable to new plants
III.A.2.1(3)	Prepare Final Commission Paper Recommending Adoption of Rules	d	Not applicable to new plants
III.A.2.1(4)	Revise Inspection Program to Cover Upgraded Requirements	d	Resolved per NUREG-0933
III.A.2.2	Development of Guidance and Criteria	d	Resolved per NUREG-0933
III.A.3.1(1)	Define NRC Role in Emergency Situations	c	
III.A.3.1(2)	Revise and Upgrade Plans and Procedures for the NRC Emergency Operations Center	c	
III.A.3.1(3)	Revise Manual Chapter 0502, Other Agency Procedures, and NUREG-0610	c	
III.A.3.1(4)	Prepare Commission Paper	c	
III.A.3.1(5)	Revise Implementing Procedures and Instructions for Regional Offices	c	
III.A.3.2	Improve Operations Centers	c	
III.A.3.3	Communications	d	See Subsection 9.5.2.5.2 Resolved per NUREG-0933
III.A.3.4	Nuclear Data Link	c	
III.A.3.5	Training, Drills, and Tests	c	
III.A.3.6(1)	Interaction of NRC and Other Agencies - International	c	

Table 1.9-2 (Sheet 13 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
III.A.3.6(2)	Federal	c	
III.A.3.6(3)	State and Local	c	
III.B.1	Transfer of Responsibilities to FEMA	c	
III.B.2(1)	The Licensing Process	c	
III.B.2(2)	Federal Guidance	c	
III.C.1(1)	Review Publicly Available Documents	d	Not applicable to new plants
III.C.1(2)	Recommend Publication of Additional Information	d	Not applicable to new plants
III.C.1(3)	Program of Seminars for News Media Personnel	d	Not applicable to new plants
III.C.2(1)	Develop Policy and Procedures for Dealing With Briefing Requests	d	Not applicable to new plants
III.C.2(2)	Provide Training for Members of the Technical Staff	d	Not applicable to new plants
III.D.1.1(1)	Review Information Submitted by Licensees Pertaining to Reducing Leakage from Operating Systems	g	See Subsection 1.9.3, item (2)(xxvi)
III.D.1.1(2)	Review Information on Provisions for Leak Detection	a	
III.D.1.1(3)	Develop Proposed System Acceptance Criteria	a	
III.D.1.2	Radioactive Gas Management	a	
III.D.1.3(1)	Decide Whether Licensees Should Perform Studies and Make Modifications	a	
III.D.1.3(2)	Review and Revise SRP	a	
III.D.1.3(3)	Require Licensees to Upgrade Filtration Systems	a	
III.D.1.3(4)	Sponsor Studies to Evaluate Charcoal Adsorber	c	
III.D.1.4	Radwaste System Design Features to Aid in Accident Recovery and Decontamination	a	
III.D.2.1(1)	Evaluate the Feasibility and Perform a Value-Impact Analysis of Modifying Effluent-Monitoring Design Criteria	a	
III.D.2.1(2)	Study the Feasibility of Requiring the Development of Effective Means for Monitoring and Sampling Noble Gases and Radioiodine Released to the Atmosphere	a	
III.D.2.1(3)	Revise Regulatory Guides	a	
III.D.2.2(1)	Perform Study of Radioiodine, Carbon-14, and Tritium Behavior	c	
III.D.2.2(2)	Evaluate Data Collected at Quad Cities	e	
III.D.2.2(3)	Determine the Distribution of the Chemical Species of Radioiodine in Air-Water-Steam Mixtures	e	
III.D.2.2(4)	Revise SRP and Regulatory Guides	e	
III.D.2.3(1)	Develop Procedures to Discriminate Between Sites/Plants	c	
III.D.2.3(2)	Discriminate Between Sites and Plants That Require Consideration of Liquid Pathway Interdiction Techniques	c	
III.D.2.3(3)	Establish Feasible Method of Pathway Interdiction	c	

Table 1.9-2 (Sheet 14 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
III.D.2.3(4)	Prepare a Summary Assessment	c	
III.D.2.4(1)	Study Feasibility of Environmental Monitors	c	
III.D.2.4(2)	Place 50 TLDs Around Each Site	d	Not applicable to new plants
III.D.2.5	Offsite Dose Calculation Manual	c	
III.D.2.6	Independent Radiological Measurements	d	Not applicable to new plants
III.D.3.1	Radiation Protection Plans	c	
III.D.3.2(1)	Amend 10 CFR 20	d	Not applicable to new plants
III.D.3.2(2)	Issue a Regulatory Guide	d	Not applicable to new plants
III.D.3.2(3)	Develop Standard Performance Criteria	d	Not applicable to new plants
III.D.3.2(4)	Develop Method for Testing and Certifying Air-Purifying Respirators	d	Not applicable to new plants
III.D.3.3	In-plant Radiation Monitoring	g COL Item 12.3-2	See Subsection 1.9.3, item (2)(xxvii) 12.3.4, Appendix 12AA
III.D.3.4	Control Room Habitability	g	See Subsection 1.9.3, item (2)(xxviii)
III.D.3.5(1)	Develop Format for Data To Be Collected by Utilities Regarding Total Radiation Exposure to Workers	d	Not applicable to new plants
III.D.3.5(2)	Investigate Methods of Obtaining Employee Health Data by Nonlegislative Means	d	Not applicable to new plants
III.D.3.5(3)	Revise 10 CFR 20	d	Not applicable to new plants
IV.A.1	Seek Legislative Authority	d	Not applicable to new plants
IV.A.2	Revise Enforcement Policy	d	Not applicable to new plants
IV.B.1	Revise Practices for Issuance of Instructions and Information to Licensees	d	Not applicable to new plants
IV.C.1	Extend Lessons Learned from TMI to Other NRC Programs	c	
IV.D.1	NRC Staff Training	d	Not applicable to new plants
IV.E.1	Expand Research on Quantification of Safety Decision-Making	d	Not applicable to new plants
IV.E.2	Plan for Early Resolution of Safety Issues	d	Not applicable to new plants
IV.E.3	Plan for Resolving Issues at the CP Stage	d	Not applicable to new plants

Table 1.9-2 (Sheet 15 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
IV. E.4	Resolve Generic Issues by Rulemaking	d	Not applicable to new plants
IV.E.5	Assess Currently Operating Reactors	c	
IV.F.1	Increased OIE Scrutiny of the Power-Ascension Test Program	c	
IV.F.2	Evaluate the Impacts of Financial Disincentives to the Safety of Nuclear Power Plants	c	
IV.G.1	Develop a Public Agenda for Rulemaking	d	Not applicable to new plants
IV.G.2	Periodic and Systematic Reevaluation of Existing Rules	d	Not applicable to new plants
IV.G.3	Improve Rulemaking Procedures	d	Not applicable to new plants
IV.G.4	Study Alternatives for Improved Rulemaking Process	d	Not applicable to new plants
IV.H.1	NRC Participation in the Radiation Policy Council	d	Not applicable to new plants
V.A.1	Develop NRC Policy Statement on Safety	d	Not applicable to new plants
V.B.1	Study and Recommend, as Appropriate, Elimination of Nonsafety Responsibilities	d	Not applicable to new plants
V.C.1	Strengthen the Role of Advisory Committee on Reactor Safeguards	d	Not applicable to new plants
V.C.2	Study Need for Additional Advisory Committees	d	Not applicable to new plants
V.C.3	Study the Need to Establish an Independent Nuclear Safety Board	d	Not applicable to new plants
V.D.1	Improve Public and Intervenor Participation in the Hearing Process	d	Not applicable to new plants
V.D.2	Study Construction-During-Adjudication Rules	d	Not applicable to new plants
V.D.3	Reexamine Commission Role in Adjudication	d	Not applicable to new plants
V.D.4	Study the Reform of the Licensing Process	d	Not applicable to new plants
V.E.1	Study the Need for TMI-Related Legislation	d	Not applicable to new plants
V.F.1	Study NRC Top Management Structure and Process	d	Not applicable to new plants
V.F.2	Reexamine Organization and Functions of the NRC Offices	d	Not applicable to new plants
V.F.3	Revise Delegations of Authority to Staff	d	Not applicable to new plants
V.F.4	Clarify and Strengthen the Respective Roles of Chairman, Commission, and Executive Director for Operations	d	Not applicable to new plants

Table 1.9-2 (Sheet 16 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
V.F.5	Authority to Delegate Emergency Response Functions to a Single Commissioner	d	Not applicable to new plants
V.G.1	Achieve Single Location, Long-Term	d	Not applicable to new plants
V.G.2	Achieve Single Location, Interim	d	Not applicable to new plants
Task Action Plan Items			
A-1	Water Hammer (former USI)	g	See Subsection 1.9.4, item A-1
A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant Systems (former USI)	g	See Subsection 1.9.4, item A-2
A-3	Westinghouse Steam Generator Tube Integrity (former USI)	g COL Item 5.4-1	See Subsection 1.9.4, item A-3 5.4.2.5
A-4	CE Steam Generator Tube Integrity (former USI)	b	
A-5	B&W Steam Generator Tube Integrity (former USI)	b	
A-6	Mark I Short-Term Program (former USI)	b	
A-7	Mark I Long-Term Program (former USI)	b	
A-8	Mark II Containment Pool Dynamic Loads Long-Term Program (former USI)	b	
A-9	ATWS (former USI)	g	See Subsection 1.9.4, item A-9
A-10	BWR Feedwater Nozzle Cracking (former USI)	b	
A-11	Reactor Vessel Materials Toughness (former USI)	g	See Subsection 1.9.4, item A-11
A-12	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports (former USI)	g	See Subsection 1.9.4, item A-12
A-13	Snubber Operability Assurance	g	See Subsection 1.9.4, item A-13
A-14	Flaw Detection	a	
A-15	Primary Coolant System Decontamination and Steam Generator Chemical Cleaning	c	
A-16	Steam Effects on BWR Core Spray Distribution	b	
A-17	Systems Interactions in Nuclear Power Plants (former USI)	c, j	See Subsection 1.9.4.2.2, item A-17
A-18	Pipe Rupture Design Criteria	a	
A-19	Digital Computer Protection System	d	Not applicable to new plants
A-20	Impacts of the Coal Fuel Cycle	d	Not applicable to new plants
A-21	Main Steam Line Break Inside Containment - Evaluation of Environmental Conditions for Equipment Qualification	a	
A-22	PWR Main Steam Line Break - Core, Reactor Vessel and Containment Building Response	a	

Table 1.9-2 (Sheet 17 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
A-23	Containment Leak Testing	d COL Item 6.2-1	6.2.5.1
A-24	Qualification of Class 1E Safety-Related Equipment (former USI)	g	See Subsection 1.9.4, item A-24
A-25	Non-Safety Loads on Class 1E Power Sources	g	See Subsection 1.9.4, item A-25
A-26	Reactor Vessel Pressure Transient Protection (former USI)	g	See Subsection 1.9.4, item A-26
A-27	Reload Applications	d	Not applicable to new plants
A-28	Increase in Spent Fuel Pool Storage Capacity	g	See Subsection 1.9.4, item A-28
A-29	Nuclear Power Plant Design for the Reduction of Vulnerability to Industrial Sabotage	c, j	See Subsection 1.9.4.2.2, item A-29
A-30	Adequacy of Safety-Related DC Power Supplies	e	
A-31	RHR Shutdown Requirements (former USI)	g	See Subsection 1.9.4, item A-31
A-32	Missile Effects	e	
A-33	NEPA Review of Accident Risks	i	
A-34	Instruments for Monitoring Radiation and Process Variables During Accidents	e	
A-35	Adequacy of Offsite Power Systems	g	See Subsection 1.9.4, item A-35
A-36	Control of Heavy Loads Near Spent Fuel (former USI)	g	See Subsection 1.9.4, item A-36
A-37	Turbine Missiles	a	
A-38	Tornado Missiles	a	
A-39	Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits (former USI)	b	See Subsection 1.9.4, item A-39
A-40	Seismic Design Criteria - Short Term Program (former USI)	g	See Subsection 1.9.4, item A-40
A-41	Long Term Seismic Program	c	
A-42	Pipe Cracks in Boiling Water Reactors (former USI)	b	
A-43	Containment Emergency Sump Performance (former USI)	g	See Subsection 1.9.4, item A-43
A-44	Station Blackout (former USI)	g	See Subsection 1.9.4, item A-44
A-45	Shutdown Decay Heat Removal Requirements (former USI)	c	
A-46	Seismic Qualification of Equipment in Operating Plants (former USI)	g	See Subsection 1.9.4, item A-46
A-47	Safety Implications of Control Systems (former USI)	g	See Subsection 1.9.4, item A-47

Table 1.9-2 (Sheet 18 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment	g	See Subsection 1.9.4, item A-48
A-49	Pressurized Thermal Shock (former USI)	g	See Subsection 1.9.4, item A-49
B-1	Environmental Technical Specifications	d	Not applicable to new plants
B-2	Forecasting Electricity Demand	d	Not applicable to new plants
B-3	Event Categorization	a	
B-4	ECCS Reliability	e	
B-5	Ductility of Two-Way Slabs and Shells and Buckling Behavior of Steel Containments	c, j	See Subsection 1.9.4.2.2, item B-5
B-6	Loads, Load Combinations, Stress Limits	e	
B-7	Secondary Accident Consequence Modeling	a	
B-8	Locking Out of ECCS Power Operated Valves	a	
B-9	Electrical Cable Penetrations of Containment	c	
B-10	Behavior of BWR Mark III Containments	b	
B-11	Subcompartment Standard Problems	d	Not applicable to new plants
B-12	Containment Cooling Requirements (Non-LOCA)	c	
B-13	Marviken Test Data Evaluation	d	Not applicable to new plants
B-14	Study of Hydrogen Mixing Capability in Containment Post-LOCA	e	
B-15	CONTEMPT Computer Code Maintenance	a	
B-16	Protection Against Postulated Piping Failures in Fluid Systems Outside Containment	e	
B-17	Criteria for Safety-Related Operator Actions	c	See Subsection 1.9.4, item B-17
B-18	Vortex Suppression Requirements for Containment Sumps	e	
B-19	Thermal-Hydraulic Stability	c	
B-20	Standard Problem Analysis	d	Not applicable to new plants
B-21	Core Physics	a	
B-22	LWR Fuel	a	See Subsection 1.9.4, item B-22
B-23	LMFBR Fuel	a	
B-24	Seismic Qualification of Electrical and Mechanical Components	e	
B-25	Piping Benchmark Problems	d	Not applicable to new plants
B-26	Structural Integrity of Containment Penetrations	c	
B-27	Implementation and Use of Subsection NF	d	Not applicable to new plants

Table 1.9-2 (Sheet 19 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
B-28	Radionuclide/Sediment Transport Program	d	Not applicable to new plants
B-29	Effectiveness of Ultimate Heat Sinks	d	See Subsection 1.9.4, item B-29 Not applicable to new plants
B-30	Design Basis Floods and Probability	d	Not applicable to new plants
B-31	Dam Failure Model	a	
B-32	Ice Effects on Safety-Related Water Supplies	e	See Subsection 1.9.4, item B-32
B-33	Dose Assessment Methodology	d	Not applicable to new plants
B-34	Occupational Radiation Exposure Reduction	e	
B-35	Confirmation of Appendix I Models for Calculations of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Cooled Power Reactors	d	Not applicable to new plants
B-36	Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Feature Systems and for Normal Ventilation Systems	g	See Subsection 1.9.4, item B-36
B-37	Chemical Discharges to Receiving Waters	d	Not applicable to new plants
B-38	Reconnaissance Level Investigations	a	
B-39	Transmission Lines	a	
B-40	Effects of Power Plant Entrainment on Plankton	a	
B-41	Impacts on Fisheries	a	
B-42	Socioeconomic Environmental Impacts	d	Not applicable to new plants
B-43	Value of Aerial Photographs for Site Evaluation	d	Not applicable to new plants
B-44	Forecasts of Generating Costs of Coal and Nuclear Plants	d	Not applicable to new plants
B-45	Need for Power - Energy Conservation	e	
B-46	Cost of Alternatives in Environmental Design	a	
B-47	Inservice Inspection of Supports - Classes 1, 2, 3, and MC Components	a	
B-48	BWR CRD Mechanical Failure (Collet Housing)	b	
B-49	Inservice Inspection Criteria and Corrosion Prevention Criteria for Containments	d	Not applicable to new plants
B-50	Post-Operating Basis Earthquake Inspections	a	
B-51	Assessment of Inelastic Analysis Techniques for Equipment and Components	e	
B-52	Fuel Assembly Seismic and LOCA Responses	e	

Table 1.9-2 (Sheet 20 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
B-53	Load Break Switch	g	See Subsection 1.9.4, item B-53
B-54	Ice Condenser Containments	c	
B-55	Improved Reliability of Target Rock Safety Relief Valves	b	
B-56	Diesel Reliability	g	See Subsection 1.9.4, item B-56
B-57	Station Blackout	e	
B-58	Passive Mechanical Failures	c	
B-59	(N-1) Loop Operation in BWRs and PWRs	d	Not applicable to new plants
B-60	Loose Parts Monitoring System	c	
B-61	Allowable ECCS Equipment Outage Periods	g	See Subsection 1.9.4, item B-61
B-62	Reexamination of Technical Bases for Establishing SLs, LSSSs, and Reactor Protection System Trip Functions	a	
B-63	Isolation of Low Pressure Systems Connected to the Reactor Coolant Pressure Boundary	g	See Subsection 1.9.4, item B-63
B-64	Decommissioning of Reactors	f	Resolved per NUREG-0933
B-65	Iodine Spiking	a	
B-66	Control Room Infiltration Measurements	g	See Subsection 1.9.4, item B-66
B-67	Effluent and Process Monitoring Instrumentation	e	
B-68	Pump Overspeed During LOCA	a	
B-69	ECCS Leakage Ex-Containment	e	
B-70	Power Grid Frequency Degradation and Effect on Primary Coolant Pumps	c	
B-71	Incident Response	e	
B-72	Health Effects and Life Shortening from Uranium and Coal Fuel Cycles	d	Not applicable to new plants
B-73	Monitoring for Excessive Vibration Inside the Reactor Pressure Vessel	e	
C-1	Assurance of Continuous Long Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment	g	See Subsection 1.9.4, item C-1
C-2	Study of Containment Depressurization by Inadvertent Spray Operation to Determine Adequacy of Containment External Design Pressure	c	
C-3	Insulation Usage Within Containment	e	
C-4	Statistical Methods for ECCS Analysis	d	See Subsection 1.9.4, item C-4 Not applicable to new plants

Table 1.9-2 (Sheet 21 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
C-5	Decay Heat Update	d	See Subsection 1.9.4, item C-5 Not applicable to new plants
C-6	LOCA Heat Sources	d	See Subsection 1.9.4, item C-6 Not applicable to new plants
C-7	PWR System Piping	c	
C-8	Main Steam Line Leakage Control Systems	b	
C-9	RHR Heat Exchanger Tube Failures	a	
C-10	Effective Operation of Containment Sprays in a LOCA	g	See Subsection 1.9.4, item C-10
C-11	Assessment of Failure and Reliability of Pumps and Valves	c	
C-12	Primary System Vibration Assessment	c	
C-13	Non-Random Failures	e	
C-14	Storm Surge Model for Coastal Sites	a	
C-15	NUREG Report for Liquids Tank Failure Analysis	a	
C-16	Assessment of Agricultural Land in Relation to Power Plant Siting and Cooling System Selection	a	
C-17	Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes	g	See Subsection 1.9.4, item C-17
D-1	Advisability of a Seismic Scram	a	
D-2	Emergency Core Cooling System Capability for Future Plants	a	
D-3	Control Rod Drop Accident	c	
New Generic Issues			
1.	Failures in Air-Monitoring, Air-Cleaning, and Ventilating Systems	a	
2.	Failure of Protective Devices on Essential Equipment	a	
3.	Set Point Drift in Instrumentation	c	
4.	End-of-Life and Maintenance Criteria	c	
5.	Design Check and Audit of Balance-of-Plant Equipment	e	
6.	Separation of Control Rod from Its Drive and BWR High Rod Worth Events	c	
7.	Failures Due to Flow-Induced Vibrations	a	
8.	Inadvertent Actuation of Safety Injection in PWRs	e	
9.	Reevaluation of Reactor Coolant Pump Trip Criteria	e	
10.	Surveillance and Maintenance of TIP Isolation Valves and Squib Charges	a	
11.	Turbine Disc Cracking	e	
12.	BWR Jet Pump Integrity	b	
13.	Small Break LOCA from Extended Overheating of Pressurizer Heaters	a	

Table 1.9-2 (Sheet 22 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
14.	PWR Pipe Cracks	c, j	See Subsection 1.9.4.2.3, item 14
15.	Radiation Effects on Reactor Vessel Supports	c	See Subsection 1.9.4, item 15
16.	BWR Main Steam Isolation Valve Leakage Control Systems	e	
17.	Loss of Offsite Power Subsequent to LOCA	a	
18.	Steam Line Break with Consequential Small LOCA	e	
19.	Safety Implications of Nonsafety Instrument and Control Power Supply Bus	e	
20.	Effects of Electromagnetic Pulse on Nuclear Power Plants	c	
21.	Vibration Qualification of Equipment	a	
22.	Inadvertent Boron Dilution Events	c, j	See Subsection 1.9.4.2.3, item 22
23.	Reactor Coolant Pump Seal Failures	c	See Subsection 1.9.4, item 23
24.	Automatic Emergency Core Cooling System Switch to Recirculation	a, j	See Subsection 1.9.4.2.3, item 24
25.	Automatic Air Header Dump on BWR Scram System	b	
26.	Diesel Generator Loading Problems Related to SIS Reset on Loss of Offsite Power	e	
27.	Manual vs. Automated Actions	e	
28.	Pressurized Thermal Shock	e	
29.	Bolting Degradation or Failure in Nuclear Power Plants	c	See Subsection 1.9.4, item 29
30.	Potential Generator Missiles - Generator Rotor Retaining Rings	a	
31.	Natural Circulation Cooldown	e	
32.	Flow Blockage in Essential Equipment Caused by Corbicula	e	
33.	Correcting Atmospheric Dump Valve Opening Upon Loss of Integrated Control System Power	e	
34.	RCS Leak	a	
35.	Degradation of Internal Appurtenances in LWRs	a	
36.	Loss of Service Water	c	
37.	Steam Generator Overfill and Combined Primary and Secondary Blowdown	e	
38.	Potential Recirculation System Failure as a Consequence of Injection of Containment Paint Flakes or Other Fine Debris	a	
39.	Potential for Unacceptable Interaction Between the CRD System and Non-Essential Control Air System	e	
40.	Safety Concerns Associated with Pipe Breaks in the BWR Scram System	b	
41.	BWR Scram Discharge Volume Systems	b	
42.	Combination Primary/Secondary System LOCA	e	

Table 1.9-2 (Sheet 23 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
43.	Reliability of Air Systems	f, j	See Subsection 1.9.4.2.3, item 43 Resolved per NUREG-0933
44.	Failure of Saltwater Cooling System	e	
45.	Inoperability of Instrumentation Due to Extreme Cold Weather	g	See Subsection 1.9.4, item 45
46.	Loss of 125 Volt DC Bus	e	
47.	Loss of Off-Site Power	c	
48.	LCO for Class e Vital Instrument Buses in Operating Reactors	e	
49.	Interlocks and LCOs for Redundant Class e Tie Breakers	e	
50.	Reactor Vessel Level Instrumentation in BWRs	c	
51.	Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems	g	See Subsection 1.9.4, item 51
52.	SSW Flow Blockage by Blue Mussels	e	
53.	Consequences of a Postulated Flow Blockage Incident in a BWR	a	
54.	Valve Operator-Related Events Occurring During 1978, 1979, and 1980	e	
55.	Failure of Class e Safety-Related Switchgear Circuit Breakers to Close on Demand	a	
56.	Abnormal Transient Operating Guidelines as Applied to a Steam Generator Overfill Event	e	
57.	Effects of Fire Protection System Actuation	c	See Subsection 1.9.4, item 57
58.	Inadvertent Containment Flooding	a	
59.	Technical Specification Requirements for Plant Shutdown when Equipment for Safe Shutdown is Degraded or Inoperable	d	Not applicable to new plants
60.	Lamellar Tearing of Reactor Systems Structural Supports	e	
61.	SRV Line Break Inside the BWR Wetwell Airspace of Mark I and II Containments	c	
62.	Reactor Systems Bolting Applications	e	
63.	Use of Equipment Not Classified as Essential to Safety in BWR Transient Analysis	a	
64.	Identification of Protection System Instrument Sensing Lines	c	
65.	Probability of Core-Melt Due to Component Cooling Water System Failures	e	
66.	Steam Generator Requirements	c	
67.2.1	Integrity of Steam Generator Tube Sleeves	d	Not applicable to new plants
67.3.1	Steam Generator Overfill	e	
67.3.2	Pressurized Thermal Shock	e	

Table 1.9-2 (Sheet 24 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
67.3.3	Improved Accident Monitoring	e, j	See Subsection 1.9.4.2.3, item 67.3.3
67.3.4	Reactor Vessel Inventory Measurements	e	
67.4.1	RCP Trip	e	
67.4.2	Control Room Design Review	e	
67.4.3	Emergency Operating Procedures	e	
67.5.1	Reassessment of SGTR Design Basis	d	
67.5.1	Reassessment of Radiological Consequences	d	Not applicable to new plants
67.5.2	Reevaluation of SGTR Design Basis	d	Not applicable to new plants
67.5.3	Secondary System Isolation	a	
67.6.0	Organizational Responses	e	
67.7.0	Improved Eddy Current Tests	e	
67.8.0	Denting Criteria	e	
67.9.0	Reactor Coolant System Pressure Control	e	
67.10.0	Supplement Tube Inspections	d	Not applicable to new plants
68.	Postulated Loss of Auxiliary Feedwater System Resulting from Turbine-Driven Auxiliary Feedwater Pumps Steam Supply Line Rupture	e	
69.	Make-up Nozzle Cracking in B&W Plants	c	
70.	PORV and Block Valve Reliability	g	See Subsection 1.9.3, item (1)(iv)
71.	Failure of Resin Demineralizer Systems and Their Effects on Nuclear Power Plant Safety	a	
72.	Control Rod Drive Guide Tube Support Pin Failures	a	
73.	Detached Thermal Sleeves	a, j	See Subsection 1.9.4.2.3, item 73
74.	Reactor Coolant Activity Limits for Operating Reactors	a	
75.	Generic Implications of ATWS Events at the Salem Nuclear Plant	g, j	See Subsection 1.9.4.2.3, item 75
76.	Instrumentation and Control Power Interactions	a	
77.	Flooding of Safety Equipment Compartments by Back-flow Through Floor Drains	e	
78.	Monitoring of Fatigue Transient Limits for Reactor Coolant System	c	
79.	Unanalyzed Reactor Vessel Thermal Stress During Natural Circulation Cooldown	c	See Subsection 1.9.4.2.3, item 79
80.	Pipe Break Effects on Control Rod Drive Hydraulic Lines in the Drywells of BWR Mark I and II Containments	a	
81.	Impact of Locked Doors and Barriers on Plant and Personnel Safety	a	

Table 1.9-2 (Sheet 25 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
82.	Beyond Design Basis Accidents in Spent Fuel Pools	c, j	See Subsection 1.9.4.2.3, item 82
83.	Control Room Habitability	c	See Subsection 1.9.4.2.3, item 83
84.	CE PORVs	c	
85.	Reliability of Vacuum Breakers Connected to Steam Discharge Lines Inside BWR Containments	a	
86.	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	b	
87.	Failure of HPCI Steam Line Without Isolation	g	See Subsection 1.9.4, item 87
88.	Earthquakes and Emergency Planning	c	
89.	Stiff Pipe Clamps	h (Medium)	
90.	Technical Specifications for Anticipatory Trips	a	
91.	Main Crankshaft Failures in Transamerica DeLaval Emergency Diesel Generators	c	
92.	Fuel Crumbling During LOCA	a	
93.	Steam Binding of Auxiliary Feedwater Pumps	g	See Subsection 1.9.4, item 93
94.	Additional Low Temperature Overpressure Protection for Light Water Reactors	g	See Subsection 1.9.4, item 94
95.	Loss of Effective Volume for Containment Recirculation Spray	c	
96.	RHR Suction Valve Testing	e	
97.	PWR Reactor Cavity Uncontrolled Exposures	e	
98.	CRD Accumulator Check Valve Leakage	a	
99.	RCS/RHR Suction Line Valve Interlock on PWRs	f	Resolved per NUREG-0933
100.	OTSG Level	b	
101.	BWR Water Level Redundancy	c	
102.	Human Error in Events Involving Wrong Unit or Wrong Train	c	
103.	Design for Probable Maximum Precipitation	g	See Subsection 1.9.4, item 103
104.	Reduction of Boron Dilution Requirements	a	
105.	Interfacing Systems LOCA at BWRs	c	See Subsection 1.9.4, item 105
106.	Piping and Use of Highly Combustible Gases in Vital Areas	c	See Subsection 1.9.4, item 106
107.	Main Transformer Failures	a	
108.	BWR Suppression Pool Temperature Limits	a	
109.	Reactor Vessel Closure Failure	a	
110.	Equipment Protective Devices on Engineered Safety Features	a	

Table 1.9-2 (Sheet 26 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
111.	Stress Corrosion Cracking of Pressure Boundary Ferritic Steels in Selected Environments	d	Not applicable to new plants
112.	Westinghouse RPS Surveillance Frequencies and Out-of-Service Times	d	Not applicable to new plants
113.	Dynamic Qualification Testing of Large Bore Hydraulic Snubbers	c	See Subsection 1.9.4, item 113
114.	Seismic-Induced Relay Chatter	e	
115.	Enhancement of the Reliability of Westinghouse Solid State Protection System	c	
116.	Accident Management	a	
117.	Allowable Time for Diverse Simultaneous Equipment Outages	a	
118.	Tendon Anchorage Failure	f	Resolved per NUREG-0933.
119.1	Piping Rupture Requirements and Decoupling of Seismic and LOCA Loads	d	Not applicable to new plants
119.2	Piping Damping Values	a	
119.3	Decoupling the OBE from the SSE	d	Not applicable to new plants
119.4	BWR Piping Materials	d	Not applicable to new plants
119.5	Leak Detection Requirements	d	Not applicable to new plants
120.	On-Line Testability of Protection Systems	c, j	See Subsection 1.9.4.2.3, item 120
121.	Hydrogen Control for Large, Dry PWR Containments	c	See Subsection 1.9.4, item 121
122.1.a	Failure of Isolation Valves in Closed Position	e	
122.1.b	Recovery of Auxiliary Feedwater	e	
122.1.c	Interruption of Auxiliary Feedwater Flow	e	
122.2	Initiating Feed-and-Bleed	c	
122.3	Physical Security System Constraints	a	
123.	Deficiencies in the Regulations Governing DBA and Single-Failure Criteria Suggested by the Davis-Besse Event of June 9, 1985	a	
124.	Auxiliary Feedwater System Reliability	g	See Subsection 1.9.4, item 124
125.I.1	Availability of the STA	a	
125.I.2.a	Need for a Test Program to Establish Reliability of the PORV	e	
125.I.2.b	Need for PORV Surveillance Tests to Confirm Operational Readiness	e	
125.I.2.c	Need for Additional Protection Against PORV Failure	a	

Table 1.9-2 (Sheet 27 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
125.I.2.d	Capability of the PORV to Support Feed-and-Bleed	e	
125.I.3	SPDS Availability	c	
125.I.4	Plant-Specific Simulator	a	
125.I.5	Safety Systems Tested in All Conditions Required by Design Basis Analysis	a	
125.I.6	Valve Torque Limit and Bypass Switch Settings	a	
125.I.7.a	Recover Failed Equipment	a	
125.I.7.b	Realistic Hands-On Training	a	
125.I.8	Procedures and Staffing for Reporting to NRC Emergency Response Center	a	
125.II.1.a	Two-Train AFW unavailability	a	
125.II.1.b	Review Existing AFW Systems for Single Failure	e	
125.II.1.c	NUREG-0737 Reliability Improvements	a	
125.II.1.d	AFW/Steam and Feedwater Rupture Control System/ICS Interactions in B&W Plants	a	
125.II.2	Adequacy of Existing Maintenance Requirements for Safety-Related Systems	a	
125.II.3	Review Steam/Feedline Break Mitigation Systems for Single Failure	a	
125.II.4	Thermal Stress of OTSG Components	a	
125.II.5	Thermal-Hydraulic Effects of Loss and Restoration of Feedwater on Primary System Components	a	
125.II.6	Reexamine PRA-Based Estimates of the Likelihood of a Severe Core Damage Accident Based on Loss of All Feedwater	a	
125.II.7	Reevaluate Provisions to Automatically Isolate Feedwater from Steam Generator During a Line Break	c	
125.II.8	Reassess Criteria for Feed-and-Bleed Initiation	a	
125.II.9	Enhanced Feed-and-Bleed Capability	a	
125.II.10	Hierarchy of Impromptu Operator Actions	a	
125.II.11	Recovery of Main Feedwater as Alternative to AFW	a	
125.II.12	Adequacy of Training Regarding PORV Operation	a	
125.II.13	Operator Job Aids	a	
125.II.14	Remote Operation of Equipment Which Must Now Be Operated Locally	a	
126.	Reliability of PWR Main Steam Safety Valves	d	
127.	Testing and Maintenance of Manual Valves in Safety-Related Systems	a	
128.	Electrical Power Reliability	h (High)	See Subsection 1.9.4, item 128 Resolved per NUREG-0933.

Table 1.9-2 (Sheet 28 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
129.	Valve Interlocks to Prevent Vessel Drainage During Shutdown Cooling	a	
130.	Essential Service Water Pump Failures at Multiplant Sites	f	See Subsection 1.9.4, item 130 See Subsection 1.9.4, item 130
131.	Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System in Westinghouse Plants	e	
132.	RHR Pumps Inside Containment	a	
133.	Update Policy Statement on Nuclear Plant Staff Working Hours	d	Not applicable to new plants
134.	Rule on Degree and Experience Requirements	c	
135.	Steam Generator and Steam Line Overfill	c	See Subsection 1.9.4, item 135
136.	Storage and Use of Large Quantities of Cryogenic Combustibles On Site	d	Not applicable to new plants
137.	Refueling Cavity Seal Failure	a	
138.	Deinerting Upon Discovery of RCS Leakage	a	
139.	Thinning of Carbon Steel Piping in LWRs	d	Not applicable to new plants
140.	Fission Product Removal Systems	a	
141.	LBLOCA With Consequential SGTR	a	
142.	Leakage Through Electrical Isolators in Instrumentation Circuits	c	See Subsection 1.9.4, item 142
143.	Availability of Chilled Water Systems	c, j	See Subsection 1.9.4.2.3, item 143
144.	Scram Without a Turbine/Generator Trip	a	
145.	Actions to Reduce Common Cause Failures	c	
146.	Support Flexibility of Equipment and Components	d	Not applicable to new plants
147.	Fire-Induced Alternate Shutdown Control Room Panel Interactions	d	Not applicable to new plants
148.	Smoke Control and Manual Fire-Fighting Effectiveness	d	Not applicable to new plants
149.	Adequacy of Fire Barriers	a	
150.	Overpressurization of Containment Penetrations	a	
151.	Reliability of Recirculation Pump Trip During an ATWS	c	

Table 1.9-2 (Sheet 29 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
152.	Design Basis for Valves That Might Be Subjected to Significant Blowdown Loads	a	
153.	Loss of Essential Service Water in LWRs	c, j	See Subsection 1.9.4.2.3, item 153
154.	Adequacy of Emergency and Essential Lighting	a	
155.1	More Realistic Source Term Assumptions	g	
155.2	Establish Licensing Requirements For Non-Operating Facilities	d	Not applicable to new plants
155.3	Improve Design Requirements For Nuclear Facilities	a	
155.4	Improve Criticality Calculations	a	
155.5	More Realistic Severe Reactor Accident Scenario	a	
155.6	Improve Decontamination Regulations	a	
155.7	Improve Decommissioning Regulations	a	
156	Systematic Evaluation Program	f	Not applicable to new plants
156.6.1	Pipe Break Effects on Systems and Components	High	The AP1000 is a new plant that takes the effects of a pipe break into account and therefore issue 156.6.1 is not applicable.
157	Containment Performance	c	
158	Performance Of Safety-Related Power-Operated Valves Under Design Basis Conditions	c	
159	Qualification Of Safety-Related Pumps While Running On Minimum Flow	a	
160	Spurious Actuations Of Instrumentation Upon Restoration Of Power	a	
161	Use Of Non-Safety-Related Power Supplies In Safety-Related Circuits	a	
162	Inadequate Technical Specifications For Shared Systems At Multiplant Sites When One Unit Is Shut Down	a	
163	Multiple Steam Generator Tube Leakage	h (Medium) h (High)	See Subsection 1.9.4.2.3, item 163 See Subsection 1.9.4.2.3, item 163
164	Neutron Fluence In Reactor Vessel	a	
165	Spring-Actuated Safety And Relief Valve Reliability	c	
166	Adequacy Of Fatigue Life Of Metal Components	c	
167	Hydrogen Storage Facility Separation	a	

Table 1.9-2 (Sheet 30 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
168	Environmental Qualification Of Electrical Equipment	f	See Subsection 1.9.4.2.3, item 168 Not applicable to new plants
169	BWR MSIV Common Mode Failure Due To Loss Of Accumulator Pressure	a	
170	Fuel Damage Criteria For High Burnup Fuel	c	
171	ESF Failure From LOOP Subsequent To A LOCA	c	
172	Multiple System Responses Program	e	
173.A	Spent Fuel Storage Pool Operating Facilities	c	
173.B	Spent Fuel Storage Pool Permanently Shutdown Facilities	c	
174	Fastener Gaging Practices	c	
175	Nuclear Power Plant Shift Staffing	c	
176	Loss Of Fill-Oil In Rosemount Transmitters	c	
177	Vehicle Intrusion At TMI	g	
178	Effect Of Hurricane Andrew On Turkey Point	d	Not applicable to new plants
179	Core Performance	c	
180	Notice Of Enforcement Discretion	d	Not applicable to new plants
181	Fire Protection	d	Not applicable to new plants
182	General Electric Extended Power Uprate	b	
183	Cycle-Specific Parameter Limits In Technical Specifications	d	Not applicable to new plants
184	Endangered Species	d	Not applicable to new plants
185	Control of Recriticality following Small-Break LOCA in PWRs	h (High)	See Subsection 1.9.4.2.3, item 185 Not applicable to new plants
186	Potential Risk and Consequences of Heavy Load Drops	a	
186	Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants	Continue	1.9.4.2.3 9.1.5.3
187	The Potential impact of Postulated Cesium Concentration on Equipment Qualification in the Containment Sump in Nuclear Power Plants.	a	
188	Steam Generator Tube Leaks/Ruptures Concurrent with Containment Bypass	a	
189	Susceptibility of Ice Condenser Containments to Early Failure from Hydrogen Concentration during a Severe Accident	a	
189	Susceptibility of Ice Condenser and Mark III Containments to Early Failure from Hydrogen Combustion During a Severe Accident Description	Continue	Not applicable to the AP1000.

Table 1.9-2 (Sheet 31 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
190	Fatigue Evaluation Of Metal Components For 60-Year Plant Life	c	
191	Assessment Of Debris Accumulation On PWR Sump Performance	h (High)	See Subsections 6.3.2.2.7 and 1.9.4.2.3, item 191 See Subsections 6.3.2.2.7 and 1.9.4.2.3, item 191
199	Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States	Issue to be Prioritized by NRC in the Future	2.5
Human Factors Issues			
HF1.1	Shift Staffing	f	13.1.2.1.5 18.6
HF1.2	Engineering Expertise on Shift	c	
HF1.3	Guidance on Limits and Conditions of Shift Work	c	
HF2.1	Evaluate Industry Training	d	Not applicable to new plants
HF2.2	Evaluate INPO Accreditation	d	Not applicable to new plants
HF2.3	Revise SRP Section 13.2	d	Not applicable to new plants
HF3.1	Develop Job Knowledge Catalog	d	Not applicable to new plants
HF3.2	Develop License Examination Handbook	d	Not applicable to new plants
HF3.3	Develop Criteria for Nuclear Power Plant Simulators	e	
HF3.4	Examination Requirements	e	
HF3.5	Develop Computerized Exam System	d	Not applicable to new plants
HF4.1	Inspection Procedure for Upgraded Emergency Operating Procedures	c, i	
HF4.2	Procedures Generation Package Effectiveness Evaluation	d	Not applicable to new plants
HF4.3	Criteria for Safety-Related Operator Actions	e	
HF4.4	Guidelines for Upgrading Other Procedures	c, j	See Subsection 1.9.4.2.4, item HF4.4
HF4.5	Application of Automation and Artificial Intelligence	e	

Table 1.9-2 (Sheet 32 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
HF5.1	Local Control Stations	c	See Subsection 1.9.4, item HF5.1
HF5.2	Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation	g	See Subsection 1.9.4, item HF5.2
HF5.3	Evaluation of Operational Aid Systems	e	
HF5.4	Computers and Computer Displays	e	
HF6.1	Develop Regulatory Position on Management and Organization	e	
HF6.2	Regulatory Position on Management and Organization at Operating Reactors	e	
HF7.1	Human Error Data Acquisition	d	Not applicable to new plants
HF7.2	Human Error Data Storage and Retrieval	d	Not applicable to new plants
HF7.3	Reliability Evaluation Specialist Aids	d	Not applicable to new plants
HF7.4	Safety Event Analysis Results Applications	d	Not applicable to new plants
HF8	Maintenance and Surveillance Program	c	
Chernobyl Issues			
CH1.1A	Symptom-Based EOPs	d	Not applicable to new plants
CH1.1B	Procedure Violations	d	Not applicable to new plants
CH1.2A	Test, Change, and Experiment Review Guidelines	d	Not applicable to new plants
CH1.2B	NRC Testing Requirements	d	Not applicable to new plants
CH1.3A	Revise Regulatory Guide 1.47	d	Not applicable to new plants
CH1.4A	Engineered Safety Feature Availability	d	Not applicable to new plants
CH1.4B	Technical Specification Bases	d	Not applicable to new plants
CH1.4C	Low Power and Shutdown	d	Not applicable to new plants
CH1.5	Operating Staff Attitudes Toward Safety	d	Not applicable to new plants
CH1.6A	Assessment of NRC Requirements on Management	d	Not applicable to new plants
CH1.7A	Accident Management	d	Not applicable to new plants
CH2.1A	Reactivity Transients	d	Not applicable to new plants
CH2.2	Accidents at Low Power and at Zero Power	e	

Table 1.9-2 (Sheet 33 of 33)
Listing of Unresolved Safety Issues and Generic Safety Issues

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
CH2.3A	Control Room Habitability	e	
CH2.3B	Contamination Outside Control Room	d	Not applicable to new plants
CH2.3C	Smoke Control	d	Not applicable to new plants
CH2.3D	Shared Shutdown Systems	d	Not applicable to new plants
CH2.4A	Firefighting With Radiation Present	d	Not applicable to new plants
CH3.1A	Containment Performance	d	Not applicable to new plants
CH3.2A	Filtered Venting	d	Not applicable to new plants
CH4.1	Size of the Emergency Planning Zones	a	
CH4.2	Medical Services	a	
CH4.3A	Ingestion Pathway Protective Measures	d	Not applicable to new plants
CH4.4A	Decontamination	d	Not applicable to new plants
CH4.4B	Relocation	d	Not applicable to new plants
CH5.1A	Mechanical Dispersal in Fission Product Release	d	Not applicable to new plants
CH5.1B	Stripping in Fission Product Release	d	Not applicable to new plants
CH5.2A	Steam Explosions	d	Not applicable to new plants
CH5.3	Combustible Gas	a	
CH6.1A	The Fort St. Vrain Reactor and the Modular HTGR	a	
CH6.1B	Structural Graphite Experiments	d	Not applicable to new plants
CH6.2	Assessment	d	Not applicable to new plants

Notes:

a. Issue has been prioritized as **Low, Drop** or has not been prioritized.
b. Issue is not an AP1000 design issue. Issue is applicable to GE, B&W, or CE designs only.
c. Issue resolved with no new requirements.
d. Issue is not a design issue (Environmental, Licensing, or Regulatory Impact Issue; or covered in an existing NRC program).
e. Issue superseded by one or more issues.
f. Issue is not an AP1000 design certification issue. Issue is applicable to current operating plants or is programmatic in nature.
g. Issue is resolved by establishment of new regulatory requirements and/or guidance.
h. Issue is unresolved pending generic resolution (for example, prioritized as **High, Medium**, or possible resolution identified).
i. The AP600 DSER (Draft NUREG-01512) identified this item as not being required to be addressed by 10 CFR 52.47.
j. The AP600 DSER (Draft NUREG-01512) identified this item as required to be discussed.

Table 1.9-201
Not Used

Table 1.9-202 (Sheet 1 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
1	Introduction and Interfaces, Initial Issuance, 03/2007		N/A	No specific acceptance criteria associated with these general requirements.
2.0	Site Characteristics and Site Parameters, Initial Issuance, 03/2007			See Note h.
2.1.1	Site Location and Description			See Note h.
2.1.2	Exclusion Area Authority and Control			See Note h.
2.1.3	Population Distribution			See Note h.
2.2.1 – 2.2.2	Identification of Potential Hazards in Site Vicinity			See Note h.
2.2.3	Evaluation of Potential Accidents			See Note h.
2.3.1	Regional Climatology			See Note h.
2.3.2	Local Meteorology			See Note h.
2.3.3	Onsite Meteorological Measurements Programs			See Note h.
2.3.4	Short-Term Atmospheric Dispersion Estimates for Accident Releases			See Note h.
2.3.5	Long-Term Atmospheric Dispersion Estimates for Routine Releases			See Note h.

Historical
Historical

Table 1.9-202 (Sheet 2 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
2.4.1	Hydrologic Description			See Note h.
2.4.2	Floods, Rev. 4, 03/2007			See Note h.
2.4.3	Probable Maximum Flood (PMF) on Streams and Rivers, Rev. 4, 03/2007			See Note h.
2.4.4	Potential Dam Failures			See Note h.
2.4.5	Probable Maximum Surge and Seiche Flooding			See Note h.
2.4.6	Probable Maximum Tsunami Hazards			See Note h.
2.4.7	Ice Effects			See Note h.
2.4.8	Cooling Water Canals and Reservoirs			See Note h.
2.4.9	Channel Diversions			See Note h.
2.4.10	Flooding Protection Requirements			See Note h.
2.4.11	Low Water Considerations			See Note h.
2.4.12	Groundwater			See Note h.
2.4.13	Accidental Releases of Radioactive Liquid Effluents in Ground and Surface Waters			See Note h.
2.4.14	Technical Specifications and Emergency Operation Requirements			Acceptable.

Historical
Historical

Table 1.9-202 (Sheet 3 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
2.5.1	Basic Geologic and Seismic Information, Rev.4, 03/2007			See Note h.
2.5.2	Vibratory Ground Motion, Rev. 4, 03/2007			See Note h.
2.5.3	Surface Faulting, Rev. 4, 03/2007			See Note h.
2.5.4	Stability of Subsurface Materials and Foundations			See Note h.
2.5.5	Stability of Slopes			See Note h.
3.2.1	Seismic Classification, Rev. 2, 03/2007			See Notes d and e.
3.2.2	System Quality Group Classification, Rev. 2, 03/2007			See Notes d and e.
3.3.1	Wind Loadings		Acceptable	See Notes d, e, and f.
3.3.2	Tornado Loadings		Acceptable	See Notes d, e, and f.
3.4.1	Internal Flood Protection for Onsite Equipment Failures		Acceptable	See Notes d, e, and f.
3.4.2	Analysis Procedures			See Notes d and e.
3.5.1.1	Internally Generated Missiles (Outside Containment)			See Notes d and e.
3.5.1.2	Internally Generated Missiles (Inside Containment)			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 4 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
3.5.1.3	Turbine Missiles		Acceptable	See Notes d, e, and f.
3.5.1.4	Missiles Generated by Tornadoes and Extreme Winds			See Notes d and e.
3.5.1.5	Site Proximity Missiles (Except Aircraft), Rev.4, 03/2007		Acceptable	See Notes d, e, and f.
3.5.1.6	Aircraft Hazards			See Note h
3.5.2	Structures, Systems, and Components to be Protected from Externally-Generated Missiles			See Notes d and e.
3.5.3	Barrier Design Procedures			See Notes d and e.
3.6.1	Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment			See Notes d and e.
3.6.2	Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
3.6.3	Leak-Before-Break Evaluation Procedures, Rev. 1, 03/2007		Acceptable	See Notes d, e, and f.
3.7.1	Seismic Design Parameters			See Notes d and e.
3.7.2	Seismic System Analysis		Acceptable	See Notes d, e, and f.
3.7.3	Seismic Subsystem Analysis			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 5 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
3.7.4	Seismic Instrumentation, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
3.8.1	Concrete Containment, Rev. 2, 03/2007			See Notes d and e.
3.8.2	Steel Containment, Rev. 2, 03/2007			See Notes d and e.
3.8.3	Concrete and Steel Internal Structures of Steel or Concrete Containments, Rev. 2, 03/2007			See Notes d and e.
3.8.4	Other Seismic Category I Structures, Rev. 2, 03/2007			See Notes d and e.
3.8.5	Foundations, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
3.9.1	Special Topics for Mechanical Components			See Notes d and e.
3.9.2	Dynamic Testing and Analysis of Systems, Structures, and Components			See Notes d and e.
3.9.3	ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
3.9.4	Control Rod Drive Systems			See Notes d and e.
3.9.5	Reactor Pressure Vessel Internals			See Notes d and e.
3.9.6	Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints		Acceptable	See Notes d, e, and f.

Historical
Historical

Table 1.9-202 (Sheet 6 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
3.9.7	Risk-Informed Inservice Testing, Rev. 0, 08/1998		N/A	
3.9.8	Risk-Informed Inservice Inspection of Piping, Rev. 0, 09/2003		N/A	
3.10	Seismic and Dynamic Qualification of Mechanical and Electrical Equipment			See Notes d and e.
3.11	Environmental Qualification of Mechanical and Electrical Equipment		Acceptable	See Notes d, e, and f.
3.12	ASME Code Class 1, 2, and 3 Piping Systems, Piping Components and their Associated Supports, Initial Issuance, 03/2007			See Note g.
3.13	Threaded Fasteners - ASME Code Class 1, 2, and 3, Initial Issuance, 03/2007			See Note g.
4.2	Fuel System Design			See Notes d and e.
4.3	Nuclear Design			See Notes d and e.
4.4	Thermal and Hydraulic Design, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
4.5.1	Control Rod Drive Structural Materials			See Notes d and e.
4.5.2	Reactor Internal and Core Support Structure Materials			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 7 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
4.6	Functional Design of Control Rod Drive System, Rev. 2, 03/2007			See Notes d and e.
5.2.1.1	Compliance with the Codes and Standards Rule, 10 CFR 50.55a		Acceptable	See Notes d, e, and f.
5.2.1.2	Applicable Code Cases			See Notes d and e.
5.2.2	Overpressure Protection			See Notes d and e.
5.2.3	Reactor Coolant Pressure Boundary Materials		Acceptable	See Notes d, e, and f.
5.2.4	Reactor Coolant Pressure Boundary Inservice Inspection and Testing, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
5.2.5	Reactor Coolant Pressure Boundary Leakage Detection, Rev. 2, 03/2007			See Notes d and e.
5.3.1	Reactor Vessel Materials, Rev. 2, 03/2007			See Notes d and e.
5.3.2	Pressure-Temperature Limits Upper-Shelf Energy and Pressurized Thermal Shock, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
5.3.3	Reactor Vessel Integrity, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
5.4	Reactor Coolant System Component and Subsystem Design, Rev. 2, 03/2007		N/A	No specific acceptance criteria associated with these general requirements.
5.4.1.1	Pump Flywheel Integrity (PWR), Rev. 2, 03/2007			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 8 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
5.4.2.1	Steam Generator Materials			See Notes d and e.
5.4.2.2	Steam Generator Program, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
5.4.6	Reactor Core Isolation Cooling System (BWR), Rev. 4, 03/2007		N/A	
5.4.7	Residual Heat Removal (RHR) System, Rev. 4, 03/2007			See Notes d and e.
5.4.8	Reactor Water Cleanup System (BWR)		N/A	
5.4.11	Pressurizer Relief Tank			See Notes d and e.
5.4.12	Reactor Coolant System High Point Vents, Rev. 1, 03/2007			See Notes d and e.
5.4.13	Isolation Condenser System (BWR), Initial Issuance, 03/2007		N/A	
6.1.1	Engineered Safety Features Materials, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
6.1.2	Protective Coating Systems (Paints) – Organic Materials		Acceptable	See Notes d, e, and f.
6.2.1	Containment Functional Design			See Notes d and e.
6.2.1.1.A	PWR Dry Containments, Including Subatmospheric Containments			See Notes d and e.
6.2.1.1.B	Ice Condenser Containments, Rev. 2, 07/1981		N/A	

Historical
Historical

Table 1.9-202 (Sheet 9 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
6.2.1.1.C	Pressure-Suppression Type BWR Containments, Rev. 7, 03/2007		N/A	
6.2.1.2	Subcompartment Analysis			See Notes d and e.
6.2.1.3	Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accidents (LOCAs)			See Notes d and e.
6.2.1.4	Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures, Rev. 2, 03/2007			See Notes d and e.
6.2.1.5	Minimum Containment Pressure Analysis for Emergency Core Cooling System Performance Capability Studies			See Notes d and e.
6.2.2	Containment Heat Removal Systems, Rev. 5, 03/2007			See Notes d and e.
6.2.3	Secondary Containment Functional Design			See Notes d and e.
6.2.4	Containment Isolation System			See Notes d and e.
6.2.5	Combustible Gas Control in Containment		Acceptable	See Notes d, e, and f.
6.2.6	Containment Leakage Testing		Acceptable	See Notes d, e, and f.
6.2.7	Fracture Prevention of Containment Pressure Boundary, Rev. 1, 03/2007			See Notes d and e.
6.3	Emergency Core Cooling System		Acceptable	See Notes d, e, and f.

Historical
Historical

Table 1.9-202 (Sheet 10 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
6.4	Control Room Habitability System		Acceptable	See Notes d, e, and f.
6.5.1	ESF Atmosphere Cleanup Systems			See Notes d and e.
6.5.2	Containment Spray as a Fission Product Cleanup System, Rev. 4, 03/2007			See Notes d and e.
6.5.3	Fission Product Control Systems and Structures			See Notes d and e.
6.5.4	Ice Condenser as a Fission Product Cleanup System, Rev. 3, 12/1988		N/A	
6.5.5	Pressure Suppression Pool as a Fission Product Cleanup System, Rev. 1, 03/2007		N/A	
6.6	Inservice Inspection and Testing of Class 2 and 3 Components, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
6.7	Main Steam Isolation Valve Leakage Control System (BWR), Rev. 2, 07/1981		N/A	
7	Instrumentation and Controls –Overview of Review Process, Rev. 5, 03/2007			See Notes d and e.
Appendix 7.0-A	Review Process for Digital Instrumentation and Control Systems, Rev. 5, 03/2007			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 11 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
7.1	Instrumentation and Controls –Introduction, Rev. 5, 03/2007			See Notes d and e.
7.1-T Table 7-1	Regulatory Requirements, Acceptance Criteria, and Guidelines for Instrumentation and Control Systems Important to Safety, Rev. 5, 03/2007			See Notes d and e.
Appendix 7.1-A	Acceptance Criteria and Guidelines for Instrumentation and Controls Systems Important to Safety, Rev. 5, 03/2007			See Notes d and e.
Appendix 7.1-B	Guidance for Evaluation of Conformance to IEEE Std 279, Rev. 5, 03/2007			See Notes d and e.
Appendix 7.1-C	Guidance for Evaluation of Conformance to IEEE Std 603, Rev. 5, 03/2007			See Notes d and e.
Appendix 7.1-D	Guidance for Evaluation of the Application of IEEE Std 7-4.3.2 Initial Issuance 03/2007			See Notes d and e.
7.2	Reactor Trip System, Rev. 5, 03/2007			See Notes d and e.
7.3	Engineered Safety Features Systems, Rev. 5, 03/2007			See Notes d and e.
7.4	Safe Shutdown Systems, Rev. 5, 03/2007			See Notes d and e.
7.5	Information Systems Important to Safety, Rev. 5, 03/2007			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 12 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
7.6	Interlock Systems Important to Safety, Rev. 5, 03/2007			See Notes d and e.
7.7	Control Systems, Rev. 5, 03/2007			See Notes d and e.
7.8	Diverse Instrumentation and Control Systems, Rev. 5, 03/2007			See Notes d and e.
7.9	Data Communication Systems, Rev. 5, 03/2007			See Notes d and e.
8.1	Electric Power – Introduction		N/A	No specific acceptance criteria associated with these general requirements.
8.2	Offsite Power System, Rev. 4, 03/2007		Acceptable	See Notes d, e, and f
8.3.1	A-C Power Systems (Onsite)		Acceptable	See Notes d, e, and f.
8.3.2	D-C Power Systems (Onsite)		Acceptable	See Notes d, e, and f.
8.4	Station Blackout, Initial Issuance, 03/2007			See Note g.
9.1.1	Criticality Safety of Fresh and Spent Fuel Storage and Handling			See Notes d and e.
9.1.2	New and Spent Fuel Storage, Rev. 4, 03/2007			See Notes d and e.
9.1.3	Spent Fuel Pool Cooling and Cleanup System, Rev. 2, 03/2007			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 13 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
9.1.4	Light Load Handling System (Related to Refueling)		Acceptable	See Notes d, e, and f.
9.1.5	Overhead Heavy Load Handling Systems, Rev. 1, 03/2007		Acceptable	See Notes d, e, and f.
9.2.1	Station Service Water System, Rev. 5, 03/2007		Acceptable	See Notes d, e, and f.
9.2.2	Reactor Auxiliary Cooling Water Systems, Rev. 4, 03/2007			See Notes d and e.
9.2.4	Potable and Sanitary Water Systems			See Notes d and e.
9.2.5	Ultimate Heat Sink		Acceptable	See Notes d, e, and f.
9.2.6	Condensate Storage Facilities		Acceptable	See Notes d, e, and f.
9.3.1	Compressed Air System, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
9.3.2	Process and Post-accident Sampling Systems			See Notes d and e.
9.3.3	Equipment and Floor Drainage System			See Notes d and e.
9.3.4	Chemical and Volume Control System (PWR) (Including Boron Recovery System)			See Notes d and e.
9.3.5	Standby Liquid Control System (BWR)		N/A	
9.4.1	Control Room Area Ventilation System		Acceptable	See Notes d, e, and f.
9.4.2	Spent Fuel Pool Area Ventilation System			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 14 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
9.4.3	Auxiliary and Radwaste Area Ventilation System			See Notes d and e.
9.4.4	Turbine Area Ventilation System			See Notes d and e.
9.4.5	Engineered Safety Feature Ventilation System			See Notes d and e.
9.5.1	Fire Protection Program, Rev. 5, 03/2007		Acceptable	See Notes d, e, and f.
9.5.2	Communications Systems		Acceptable	See Notes d, e, and f.
9.5.3	Lighting Systems			See Notes d and e.
9.5.4	Emergency Diesel Engine Fuel Oil Storage and Transfer System		Acceptable	See Notes d, e, and f.
9.5.5	Emergency Diesel Engine Cooling Water System			See Notes d and e.
9.5.6	Emergency Diesel Engine Starting System			See Notes d and e.
9.5.7	Emergency Diesel Engine Lubrication System			See Notes d and e.
9.5.8	Emergency Diesel Engine Combustion Air Intake and Exhaust System			See Notes d and e.
10.2	Turbine Generator		Acceptable	See Notes d, e, and f.
10.2.3	Turbine Rotor Integrity, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
10.3	Main Steam Supply System, Rev. 4, 03/2007		Acceptable	See Notes d, e, and f.

Historical
Historical

Table 1.9-202 (Sheet 15 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
10.3.6	Steam and Feedwater System Materials		Acceptable	See Notes d, e, and f.
10.4.1	Main Condensers			See Notes d and e.
10.4.2	Main Condenser Evacuation System		Acceptable	See Notes d, e, and f.
10.4.3	Turbine Gland Sealing System			See Notes d and e.
10.4.4	Turbine Bypass System			See Notes d and e.
10.4.5	Circulating Water System		Acceptable	See Notes d, e, and f.
10.4.6	Condensate Cleanup System			See Notes d and e.
10.4.7	Condensate and Feedwater System, Rev. 4, 03/2007		Acceptable	See Notes d, e, and f.
10.4.8	Steam Generator Blowdown System (PWR)			See Notes d and e.
10.4.9	Auxiliary Feedwater System (PWR)			See Notes d and e.
11.1	Source Terms			See Notes d and e.
11.2	Liquid Waste Management System		Acceptable	See Notes d, e, f, and h.
11.3	Gaseous Waste Management System			See Notes d, e, f, and h.
11.4	Solid Waste Management System		Acceptable	See Notes d, e, and f.
11.5	Process and Effluent Radiological Monitoring Instrumentation and Sampling Systems, Rev. 4, 03/2007		Acceptable	See Notes d, e, and f.

Historical
Historical

Table 1.9-202 (Sheet 16 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
12.1	Assuring that Occupational Radiation Exposures Are As Low As Is Reasonably Achievable		Exception	See Notes d, e, and f. An exception is taken to following the guidance of RG 1.206 to address RG 8.20, 8.25, and RG 8.26. NUREG-1736, Final Report (published 2001) lists RG 8.20 and RG 8.26 as “outdated” and recommends the methods of RG 8.9 R1. RG 8.25 states it is not applicable to nuclear facilities licensed under 10 CFR Part 50, and, by extension, to 10 CFR Part 52. An exception is taken to RG 8.8 C.3.b. RG 1.16 C.1.b (3) data is no longer reported. Reporting per C.1.b (2) is also no longer required.
12.2	Radiation Sources		Exception	See Notes d, e, and f. A general description of miscellaneous sealed sources related to radiography is provided in FSAR text. Other requested details are maintained on-site for NRC review and audit upon their procurement.
12.3 – 12.4	Radiation Protection Design Features		Acceptable	See Notes d, e, and f.

Historical
Historical

Table 1.9-202 (Sheet 17 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
12.5	Operational Radiation Protection Program		Acceptable	See Notes d, e, and f.
13.1.1	Management and Technical Support Organization, Rev. 5, 03/2007		Exception	See Notes d, e, and f. Design and construction responsibilities are not defined in numbers. The experience requirements of corporate staff are set by corporate policy and not provided here in detail, however the experience level of the corporate staff, as discussed Subsections 13.1.1, 13.1.1.1, and Appendix 13AA, in the area of nuclear plant development, construction, and management establishes that the applicant has the necessary capability and staff to ensure that design and construction of the facility will be performed in an acceptable manner.

Historical
Historical

Table 1.9-202 (Sheet 18 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
				Resumes and/or other documentation of qualification and experience of initial appointees to appropriate management and supervisory positions are available for NRC after position vacancies are filled.
13.1.2 –13.1.3	Operating Organization, Rev. 6, 03/2007		Exception	See Notes d, e, and f. The SRP requires resumes of personnel holding plant managerial and supervisory positions to be included in the FSAR. Current industry practice is to have the resumes available for review by the regulator when requested but not be kept in the FSAR. Additionally, at time of COLA, most positions are unfilled.

Historical
Historical

Table 1.9-202 (Sheet 19 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

	Criteria Section[b]	Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
13.2.1	Reactor Operator Requalification Program; Reactor Operator Training		Exception	See Notes d, e, and f. SRP requires meeting the guidance of NUREG-0711. NEI 06-13A, Template for an Industry Training Program Description, which is incorporated by reference in FSAR 13.2, does not address meeting the guidance of NUREG-0711. NEI 06-13A, is approved by NRC to meet the regulatory requirements for the FSAR description of the Training Program. SRP requires meeting the guidance of Regulatory Guide 1.149, “Nuclear Power Plant Simulation Facilities for Use in Operator Training and License Examinations” RG 1.149 is not addressed in NEI 06-13A. Level of detail is consistent with NEI 06-13A.
13.2.2	Non-Licensed Plant Staff Training		Exception	See Notes d, e, and f. Level of detail is consistent with NEI 06-13A.
13.3	Emergency Planning			See Notes d, e, f, and h.
13.4	Operational Programs		Acceptable	See Notes d, e, and f.

Historical
Historical

Table 1.9-202 (Sheet 20 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
13.5.1.1	Administrative Procedures – General, Initial Issuance, 03/2007		Exception	The procedure development schedule is addressed in the COL application (not in the SAR as requested by this SRP).
13.5.2.1	Operating and Emergency Operating Procedures, Rev. 2, 03/2007		Exception	See Notes d, e, and f. Procedures are generally identified in this section by topic, type, or classification in lieu of the specific title and represent general areas of procedural coverage.
13.6	Physical Security		Acceptable	See Security Plan developed in accordance with NEI 03-12.
13.6.1	Physical Security - Combined License Review Responsibilities, Initial Issuance, 03/2007		Acceptable	See Security Plan developed in accordance with NEI 03-12
13.6.2	Physical Security - Design Certification, Initial Issuance, 03/2007			See notes d and e.
13.6.3	Physical Security - Early Site Permit, Initial Issuance, 03/2007			See Note h.
14.2	Initial Plant Test Program - Design Certification and New License Applicants		Exception	See Notes d, e, and f. The level of detail is consistent with DCD section content addressing nonsafety-related systems.

Historical
Historical

Table 1.9-202 (Sheet 21 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
14.2.1	Generic Guidelines for Extended Power Uprate Testing Programs, Initial Issuance, 08/2006		N/A	No power uprate is sought.
14.3	Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007		Acceptable	
14.3.1	[Reserved]			
14.3.2	Structural and Systems Engineering - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007			See Notes d and e.
14.3.3	Piping Systems and Components - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007			See Notes d and e.
14.3.4	Reactor Systems - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007			See Notes d and e.
14.3.5	Instrumentation and Controls - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007			See Notes d and e.
14.3.6	Electrical Systems - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007			See Notes d and e.
14.3.7	Plant Systems - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007		Acceptable	See Notes d, e, and f.

Historical
Historical

Table 1.9-202 (Sheet 22 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
14.3.8	Radiation Protection - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007			See Notes d and e.
14.3.9	Human Factors Engineering - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007			See Notes d and e.
14.3.10	Emergency Planning - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007		Exception	See Subsection 14.3.2.3.1.
14.3.11	Containment Systems - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007			See Notes d and e.
14.3.12	Physical Security Hardware - Inspections, Tests, Analyses, and Acceptance Criteria, Initial Issuance, 03/2007		Acceptable	See Notes d, e, and f.
15	Introduction —Transient and Accident Analysis			See Notes d and e.
15.0.1	Radiological Consequence Analyses Using Alternative Source Terms, Rev. 0, 07/2000			See Notes d and e.
15.0.2	Review of Transient and Accident Analysis Method, Rev. 0, 12/2005			See Notes d and e.
15.0.3	Design Basis Accident Radiological Consequences of Analyses for Advanced Light Water Reactors, Initial Issuance, 03/2007			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 23 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
15.1.1 – 15.1.4	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve, Rev. 2, 03/2007			See Notes d and e.
15.1.5	Steam System Piping Failures Inside and Outside of Containment (PWR)			See Notes d and e.
15.2.1 – 15.2.5	Loss of External Load; Turbine Trip; Loss of Condenser Vacuum; Closure of Main Steam Isolation Valve (BWR); and Steam Pressure Regulator Failure (Closed), Rev. 2, 03/2007			See Notes d and e.
15.2.6	Loss of Nonemergency AC Power to the Station Auxiliaries, Rev. 2, 03/2007			See Notes d and e.
15.2.7	Loss of Normal Feedwater Flow, Rev. 2, 03/2007			See Notes d and e.
15.2.8	Feedwater System Pipe Breaks Inside and Outside Containment (PWR), Rev. 2, 03/2007			See Notes d and e.
15.3.1 – 15.3.2	Loss of Forced Reactor Coolant Flow Including Trip of Pump Motor and Flow Controller Malfunctions, Rev. 2, 03/2007			See Notes d and e.
15.3.3 – 15.3.4	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 24 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
15.4.1	Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition			See Notes d and e.
15.4.2	Uncontrolled Control Rod Assembly Withdrawal at Power			See Notes d and e.
15.4.3	Control Rod Misoperation (System Malfunction or Operator Error)			See Notes d and e.
15.4.4 –15.4.5	Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate, Rev. 2, 03/2007			See Notes d and e.
15.4.6	Inadvertent Decrease in Boron Concentration in the Reactor Coolant System (PWR), Rev. 2, 03/2007			See Notes d and e.
15.4.7	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position, Rev. 2, 03/2007			See Notes d and e.
15.4.8	Spectrum of Rod Ejection Accidents (PWR)			See Notes d and e.
15.4.8.A	Radiological Consequences of a Control Rod Ejection Accident (PWR) , Rev. 1, 07/1981			See Notes d and e.
15.4.9	Spectrum of Rod Drop Accidents (BWR)		N/A	

Historical
Historical

Table 1.9-202 (Sheet 25 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
15.5.1 – 15.5.2	Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory, Rev. 2, 03/2007			See Notes d and e.
15.6.1	Inadvertent Opening of a PWR Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve, Rev. 2, 03/2007			See Notes d and e.
15.6.5	Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary			See Notes d and e.
15.8	Anticipated Transients Without Scram, Rev. 2, 03/2007			See Notes d and e.
15.9	Boiling Water Reactor Stability, Initial Issuance, 03/2007		N/A	
16	Technical Specifications, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
16.1	Risk-informed Decision Making: Technical Specifications, Rev. 1, 03/2007		N/A	This SRP applies to the Technical Specifications change process.
17.1	Quality Assurance During the Design and Construction Phases, Rev. 2, 07/1981		Acceptable	See Notes d, e, and f.
17.2	Quality Assurance During the Operations Phase, Rev. 2, 07/1981			See Notes d and e.

Historical
Historical

Table 1.9-202 (Sheet 26 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
17.3	Quality Assurance Program Description, Rev. 0, 08/1990			See Notes d and e.
17.4	Reliability Assurance Program (RAP), Initial Issuance, 03/2007			See Notes d and e.
17.5	Quality Assurance Program Description - Design Certification, Early Site Permit and New License Applicants, Initial Issuance, 03/2007		Acceptable	See Notes d, e, and f. This section covers the requirements of SRP Section 17.5 through reference to Quality Assurance Program Description which is maintained separately and developed in accordance with NEI 06-14A.
17.6	Maintenance Rule, Rev 1, 08/2007		Acceptable	Content developed in accordance with NEI 07-02A
18.0	Human Factors Engineering, Rev. 2, 03/2007		Acceptable	See Notes d, e, and f.
19.0	Probabilistic Risk Assessment and Severe Accident Evaluation for New Reactors, Rev. 2, 06/2007		Acceptable	See Notes d, e, and f.
19.1	Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities, Rev. 2, 06/2007		Acceptable	See Notes d, e, and f.

Historical
Historical

Table 1.9-202 (Sheet 27 of 27)[a]
Conformance with SRP Acceptance Criteria—{HISTORICAL}

Criteria Section[b]		Reference Criteria	FSAR Position[c]	Comments/Summary of Exceptions
19.2	Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance, Initial Issuance, 06/2007			See Note g.

a) This table is provided as a one-time aid to facilitate NRC review. This table becomes historical information and need not be updated

b) If no revision or date is specified, it is Rev. 3, 03/2007.

c) Consult the AP1000 Design Control Document (DCD) Appendix 1A and Appendix 1AA to determine extent of conformance with Regulatory Guides (except Regulatory Guide 1.206).

d) Conformance with a previous revision of this SRP is documented in AP1000 Design Control Document (Section 1.9.2 and WCAP-15799)

e) Conformance with the design aspects of this SRP is as stated in the AP1000 DCD.

f) Conformance with the plant or site-specific aspects of this SRP is as stated under “FSAR Position.”

g) This SRP is not applicable to the AP1000 certified design.

h) Conformance with RS-002 and NUREG-0800 criteria contained in referenced ESPA. Refer to ESPA SSAR Table 1-2.

Historical
Historical

Table 1.9-203
Not Used

Table 1.9-204 (Sheet 1 of 6)
Generic Communications Assessment

Number	Title	Comment
BULLETIN		
80-06	Engineered Safety Feature (ESF) Reset Controls (3/80)	See Note a.
80-10	Contamination of Nonradioactive System and Resulting Potential for Unmonitored, Uncontrolled Release of Radioactivity to Environment (5/80)	Appendix 12AA
80-15	Possible Loss of Emergency Notification System (ENS) with Loss of Offsite Power (6/80)	9.5.2.2.5 9.5.2.5.1
88-11	Pressurizer Surge Line Thermal Stratification	3.9.3.1.2
02-01	Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity	5.2.4 See Note a.
02-02	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs	5.2.4 See Note a.
03-01	Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors	6.3 See Note a.
03-02	Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity	5.2.4.3 See Note a.
03-03	Potentially Defective 1-inch Valves for Uranium Hexafluoride Cylinders	N/A
03-04	Rebaselining of Data in the Nuclear Materials Management and Safeguards System	N/A One time report.

Table 1.9-204 (Sheet 2 of 6)
Generic Communications Assessment

Number	Title	Comment
04-01	Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors	See Note a.
05-01	Material Control and Accounting at Reactors and Wet Spent Fuel Storage Facilities	13.5.2.2.9
05-02	Emergency Preparedness and Response Actions for Security-Based Events	13.3
GENERIC LETTERS		
80-22	Transmittal of NUREG-0654 “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans” (3/80)	13.3
80-26	Qualifications of Reactor Operators (3/80)	13.2 18.10
80-51	On-Site Storage Of Low-Level Waste (6/90)	11.4.6
80-55	Possible Loss of Hotline With Loss Of Off-Site Power	See Bulletin 80-15
80-77	Refueling Water Level (8/80)	16.1 See Note a.
80-094	Emergency Plan (11/80)	13.3
80-099	Technical Specification Revisions for Snubber Surveillance (11/80)	Snubbers no longer in generic Tech Specs See Note a.
80-108	Emergency Planning (12/80)	13.3
81-02	Analysis, Conclusions and Recommendations Concerning Operator Licensing (1/81)	13.2

Table 1.9-204 (Sheet 3 of 6)
Generic Communications Assessment

Number	Title	Comment
81-10	Post-TMI Requirements for the Emergency Operations Facility (2/81)	13.3
81-38	Storage of Low-Level Radioactive Waste at Power Reactor Sites (11/81)	11.4.6
81-40	Qualifications of Reactor Operators (12/81)	13.1 13.2
82-02	Commission Policy on Overtime (2/82)	16.1
82-04	Use of INPO See-in Program (3/82)	13.1 13.5
82-12	Nuclear Power Plant Staff Working Hours (6/82)	13.1.2.1.5
82-13	Reactor Operator and Senior Reactor Operator Examinations (6/82)	For information only.
82-18	Reactor Operator and Senior Reactor Operator Requalification Examinations (10/82)	13.2
83-06	Certificates and Revised Format For Reactor Operator and Senior Reactor Operator Licenses (1/83)	13.2
83-11	Licensee Qualification for Performing Safety Analyses in Support of Licensing Actions (2/83)	13.1 See Note a.
83-12	Issuance of NRC FORM 398 - Personal Qualifications Statement - Licensee (2/83)	13.2
83-17	Integrity of the Requalification Examinations for Renewal of Reactor Operator and Senior Reactor Operator Licenses (4/83)	13.1
83-22	Safety Evaluation of "Emergency Response Guidelines" (6/83)	18.9

Table 1.9-204 (Sheet 4 of 6)
Generic Communications Assessment

Number	Title	Comment
83-40	Operator Licensing Examination (12/83)	13.2
84-10	Administration of Operating Tests Prior to Initial Criticality (10 CFR 55.25) (4/84)	13.2
84-14	Replacement and Requalification Training Program (5/84)	13.2
84-17	Annual Meeting to Discuss Recent Developments Regarding Operator Training, Qualifications, and Examinations (7/84)	Administrative
84-20	Scheduling Guidance for Licensee Submittals of Reloads That Involve Unreviewed Safety Questions (8/84)	13.5
85-04	Operating Licensing Examinations (1/85)	Administrative
85-05	Inadvertent Boron Dilution Events (1/85)	13.5
85-14	Commercial Storage At Power Reactor Sites Of Low Level Radioactive Waste Not Generated By The Utility (8/85)	Administrative
85-18	Operator Licensing Examinations (9/85)	Administrative
85-19	Reporting Requirements On Primary Coolant Iodine Spikes (9/85)	16.1
86-14	Operator Licensing Examinations (8/86)	Administrative
87-14	Operator Licensing Examinations (8/87)	Administrative
88-05	Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants (3/88)	5.2.4 See Note a.
88-14	Instrument Air Supply System Problems Affecting Safety-Related Equipment (8/88)	9.3.7
88-18	Plant Record Storage on Optical Disk (10/88)	17

Table 1.9-204 (Sheet 5 of 6)
Generic Communications Assessment

Number	Title	Comment
89-07	Power Reactors Safeguards Contingency Planning for Surface Vehicle Bombs (4/89)	13.6
89-07 S1	Power Reactor Safeguards Contingency Planning for Surface Vehicle Bombs	13.6
89-08	Erosion/Corrosion-Induced Pipe Wall Thinning	10.1.3.1
89-12	Operator Licensing Examination (7/89)	13.2
89-15	Emergency Response Data System (8/89)	9.5.2 13.3
89-17	Planned Administrative Changes to the NRC Operator Licensing Written Examination Process (9/89)	N/A
91-14	Emergency Telecommunications (9/91)	9.5.2 13.3
91-16	Licensed Operators and Other Nuclear Facility Personnel Fitness for Duty (10/91)	13.7
92-01	Reactor Vessel Structural Integrity (1/92)	5.3.2.6.3
93-01	Emergency Response Data System Test Program	13.3
93-03	Verification of Plant Records	17
96-02	Reconsideration of Nuclear Power Plant Security Requirements Associated with an Internal Threat (2/96)	13.6
03-01	Control Room Habitability	6.4 See Note a.
04-01	Requirements for Steam Generator Tube Inspections	5.4.2.5 16.1 See Note a.

Table 1.9-204 (Sheet 6 of 6)
Generic Communications Assessment

Number	Title	Comment
04-02	Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors	6.3.8.1 See Note a.
06-01	Steam Generator Tube Integrity and Associated Technical Specifications	5.4.2.5 16.1 See Note a.
06-02	Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power	8.2.1.1 8.2.2 See Note a.
06-03	Potentially Nonconforming Hemyc and MT Fire Barrier Configurations	9.5.1.8 See Note a.
07-01	Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients.	17.6 See Note a.

(a) The design aspects of this topic are as stated in the AP1000 DCD.

1.10 Nuclear Power Plants to be Operated on Multi-Unit Sites

The certification for the AP1000 is for a single unit. Dual siting of AP1000 is achievable, provided that the centerlines of the units are sufficiently separated. The primary consideration in setting this separation distance is the space needed to support plant construction via the use of a heavy-lift crane.

Security controls during construction and operation are addressed in the Physical Security Plan.

Management and administrative controls are established to identify potential hazards to structures, systems, and components (SSCs) of an operating unit as a result of construction activities at a unit under construction. Controls within this section are not required unless there is an operating unit on the site, i.e., a unit with fuel loaded into the reactor vessel. Advance notification, scheduling and planning allow site management to implement interim controls to reduce the potential for impact to SSCs.

This section presents an assessment of the potential impacts of construction of one unit on SSCs important to safety for an operating unit, in accordance with 10 CFR 52.79(a)(31). This assessment includes:

- Identification of potential construction activity hazards
- Identification of SSCs important to safety and limiting conditions for operation (LCOs) for the operating unit
- Identification of potentially impacted SSCs and LCOs
- Identification of applicable managerial and administrative controls

1.10.1 Potential Construction Activity Hazards

The power blocks for Units 3 and 4 have a minimum separation of at least 800 feet between plant centerlines.

Construction activities may include site exploration, grading, clearing, and installation of drainage and erosion-control measures; boring, drilling, dredging, pile driving and excavating; transportation, storage and warehousing of equipment; and construction, erection, and fabrication of new facilities.

Construction activities and their representative hazards to an operating unit are shown in Table 1.10-201.

1.10.2 Potentially Impacted SSCs and Limiting Conditions for Operation

The construction activities described above were reviewed for possible impact to operating unit SSCs important to safety.

- VEGP Unit 1 and Unit 2 SSCs important to safety are described in Chapter 3 of the Updated Final Safety Analysis Report (UFSAR).
- VEGP Unit 1 and Unit 2 LCOs are located in Appendix A of the Unit 1 and Unit 2 Operating Licenses (Technical Specifications).
- Unit 3 and Unit 4 SSCs important to safety are described in Chapter 3.

- As indicated in Chapter 16, the LCOs for Units 3 and 4 are located in Part 4 of the COL Application.

The initial assessment consisted of a review of individual SSCs and LCOs to determine whether an item is applicable, or may be eliminated due to either examination or being internal and specific to an operating unit. The assessment identified the SSCs that could reasonably be expected to be impacted by construction activities unless administrative and managerial controls are established. The results of the assessment are presented in Table 1.10-202.

Periodic assessment during construction is addressed in Appendix 13AA, Subsection 13AA.1.1.1.1.8.

1.10.3 Managerial and Administrative Controls

To eliminate or mitigate construction hazards that could potentially impact operating unit SSCs important to safety, specific managerial and administrative controls have been identified as shown in Table 1.10-203.

Although not all of the managerial and administrative construction controls are necessary to protect the operating unit, the identified controls are applied to any operating unit as a conservative measure. This conservative approach provides reasonable assurance of protecting the identified SSCs from potential construction hazards and preventing the associated LCOs specified in the operating unit Technical Specifications from being exceeded as a result of construction activities, as discussed below.

The majority of the operating unit SSCs important to safety are contained and protected within safety-related structures. The managerial controls protect these internal SSCs from postulated construction hazards by maintaining the integrity and design basis of the safety-related structures and foundations. Heavy load drop controls, crane boom failure standoff requirements, ground vibration controls and construction generated missile(s) control are examples of managerial controls that provide this protection.

Other managerial controls support maintaining offsite power, control of hazardous materials and gases, and protection of cooling water supplies and safety system instrumentation. These managerial controls prevent or mitigate external construction impacts that could affect SSCs important to safety. These controls also prevent or mitigate unnecessary challenges to safety systems caused by plant construction hazards, such as disruption of offsite transmission lines or impact to plant cooling water supplies.

The above discussed controls to eliminate or mitigate construction hazards that could potentially impact operating unit SSCs important to safety are in place when there is an operating nuclear unit on the site. Additional controls may be established during construction as addressed in Appendix 13AA, Subsection 13AA.1.1.1.1.8.

Table 1.10-201 (Sheet 1 of 3)
Potential Hazards from Construction Activities

CONSTRUCTION ACTIVITY HAZARD	POTENTIAL IMPACT
Site Exploration, Grading, Clearing, Installation of Drainage and Erosion Control Measures	• Overhead Power Lines • Transmission Towers • Underground Conduits, Piping, Tunnels, etc. • Site Access and Egress • Drainage Facilities and Structures • Onsite Transportation Routes • Slope Stability • Soil Erosion and Local Flooding • Construction-Generated Dust and Equipment Exhausts • Encroachment on Plant Control Boundaries • Encroachment on Structures and Facilities
Boring, Drilling, Pile Driving, Dredging, Demolition, Excavation	• Underground Conduits, Piping, Tunnels, etc. • Foundation Integrity • Structural Integrity • Slope Stability • Erosion and Turbidity Control • Groundwater and Groundwater Monitoring Facilities • Dewatering Structures, Systems and Components • Nearby Structures, Systems and Components • Vibratory Ground Motion

Table 1.10-201 (Sheet 2 of 3)
Potential Hazards from Construction Activities

CONSTRUCTION ACTIVITY HAZARD	POTENTIAL IMPACT
Equipment Movement, Material Delivery, Vehicle Traffic	• Overhead Power Lines • Transmission Towers • Underground Conduits, Piping, Tunnels • Crane Load Drops • Crane or Crane Boom Failures • Vehicle Accidents • Rail Car Derailments
Equipment and Material Laydown, Storage, Warehousing	• Releases of Flammable, Hazardous or Toxic Materials • Wind-Generated, Construction-Related Debris and Missiles
General Construction, Erection, Fabrication	• Physical Integrity of Structures, Systems and Components • Adjacent or Nearby Structures, Systems and Components • Instrumentation and Control Systems and Components • Electrical Systems and Components·Cooling Water Systems and Components • Waste Heat Environmental Controls and Parameters • Radioactive Waste Release Points and Parameters • Abandonment of Structures, Systems or Components • Relocation of Structures, Systems or Components • Removal of Structures, Systems or Components

Table 1.10-201 (Sheet 3 of 3)
Potential Hazards from Construction Activities

CONSTRUCTION ACTIVITY HAZARD	POTENTIAL IMPACT
Connection, Integration, Testing	• Instrumentation and Control Systems and Components • Electrical and Power Systems and Components • Cooling Water Systems and Components

Table 1.10-202 (Sheet 1 of 2)
Hazards During Construction Activities

CONSTRUCTION HAZARD	IMPACTED SSCs
Impact on Overhead Power Lines	• Offsite Power System
Impact on Transmission Towers	• Offsite Power Systems
Impact on Utilities, Underground Conduits, Piping, Tunnels, Tanks	• Fire Protection System • Service Water System[1]
Impact of Construction-Generated Dust and Equipment Exhausts	• Control Room Emergency HVAC Systems[1] • Diesel Generators
Impact of Vibratory Ground Motion	• Offsite Power System • Onsite Power Systems • Instrumentation and Seismic Monitors
Impact of Crane or Crane Boom Failures	• Safety-Related Structures
Impact of Releases of Flammable, Hazardous or Toxic Materials	• Control Room Emergency HVAC Systems[1]
Impact of Wind-Generated, Construction-Related Debris and Missiles	• Safety-Related Structures • Control Room Emergency HVAC Systems[1]
Impact on Electrical Systems and Components	• Offsite Power System • Onsite Power Systems
Impact on Cooling Water Systems and Components	• Service Water System[1] • Ultimate Heat Sink[1]
Impact on Radioactive Waste Release Points and Parameters	• Gaseous and Liquid Radioactive Waste Management Systems

Table 1.10-202 (Sheet 2 of 2)
Hazards During Construction Activities

CONSTRUCTION HAZARD	IMPACTED SSCs
Impact of Relocation of Structures, Systems or Components	• Fire Protection System • Service Water System[1]
Impact of Site Groundwater Depression and Dewatering	• Safety-Related Structures and Foundations
Impact of Equipment Delivery and Heavy Equipment Delivery	• Safety-Related Structures and Foundations
Impact of Local Flooding	• Safety-related structures, systems, and components (SSCs)

1 Not applicable to AP1000 operating units.

Table 1.10-203 (Sheet 1 of 3)
Managerial and Administrative Construction Controls

CONSTRUCTION HAZARDS TO SSCs	MANAGERIAL CONTROL
Impact on Transmission Power Lines and Offsite Power Lines	• Safe standoff clearance distances are established for transmission power lines, including verification of standoff distance for modules, the reactor vessel and other equipment to be transported beneath energized electric lines to meet minimum standoff clearance requirements. • Physical warning or caution barriers and signage are erected along transport routes.
Impact on Transmission Towers	• Establish controls or physical barriers to avoid equipment collisions with electric transmission support towers.
Impact on Utilities, Underground Conduits, Piping, Tunnels, Tanks	• Grading, excavation, and pile driving require location and identification of equipment or underground structures that must be relocated, removed, or left in place and protected prior to the work activity.
Impact of Construction-Generated Dust and Equipment Exhausts	• Fugitive dust and dust generation is controlled. Potentially affected system air intakes and filters are periodically monitored.
Impact of Vibratory Ground Motion	• Construction administrative procedures, methods, and controls are implemented to prevent exceeding ground vibration and instrumentation limit settings.
Impact of Crane or Crane Boom Failures	• Construction standoff distance controls prevent heavy load impacts from crane boom failures and crane load drops. Drop analyses may be substituted if minimum standoff distances are not practical.

Table 1.10-203 (Sheet 2 of 3)
Managerial and Administrative Construction Controls

CONSTRUCTION HAZARDS TO SSCs	MANAGERIAL CONTROL
Impact of Releases of Flammable, Hazardous or Toxic Materials and Missile Generation	• Environmental, safety and health controls limit transport, storage, quantities, type and use of flammable, hazardous, toxic materials and compressed gasses. Construction safety and storage controls maintain potential missile generation events from compressed gasses within the operating unit design basis.
Impact of Wind-Generated, Construction-Related Debris and Missiles	• Administrative controls address equipment, material storage and transport during high winds or high wind warnings. • Plant procedures are followed during severe weather conditions which may call for power reduction or shut down.
Impact on Electrical Systems and Components	• Affected operating unit electrical systems and components within the construction area are identified and isolated or relocated or otherwise protected.
Impact on Cooling Water Systems and Components	• Transport of heavy load equipment over buried cooling water piping is prohibited without evaluation.
Impact on Radioactive Waste Release Points and Parameters	• Engineering evaluation and managerial controls are implemented, as necessary, to prevent radioactive releases beyond the established limits due to construction activity.
Impact of Relocation of Structures, Systems or Components	• Administrative controls identify SSCs that require relocation. Temporary or permanent design changes are implemented if necessary.
Impact of Equipment Delivery and Heavy Equipment Delivery	• Rail transport speed limits and maximum rail loading weights onsite are established. • General equipment and heavy equipment movement controls and limitations are established.

Table 1.10-203 (Sheet 3 of 3)
Managerial and Administrative Construction Controls

CONSTRUCTION HAZARDS TO SSCs	MANAGERIAL CONTROL
Impact of Local Flooding	• Site grading and drainage provisions consider potential flooding impacts from local intense precipitation
Impact of Site Groundwater Dewatering	• Administrative controls address groundwater level monitoring

Appendix 1A Conformance With Regulatory Guides

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
DIVISION 1 – Power Reactors			
Reg. Guide 1.1, Rev. 0, 11/70 – Net Positive Suction Head For Emergency Core Cooling and Containment Heat Removal System Pumps			
General		N/A	The AP1000 passive safety systems make maximum use of natural phenomena (gravity, natural circulation, and gas driven injection) and fail-safe position valves, and thus require no active pumps, diesel-generators, or fans. The AP1000 normal residual heat removal system is designed to take suction from the cask loading pit, the in-containment refueling water storage tank, and from containment, however it is not a safety-related system, and does not control or mitigate the consequences of an accident in the licensing basis accident analyses.
Reg. Guide 1.2 – Withdrawn			
Reg. Guide 1.3, Rev. 2, 6/74 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors			
General		N/A	Applies to boiling water reactors only.
Reg. Guide 1.4, Rev. 2, 6/74 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors			
General		Exception	The guidance of Reg. Guide 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents at Nuclear Power Reactors" will be followed instead of Reg. Guide 1.4.
Reg. Guide 1.5, Rev. 0, 3/71 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break Accident for Boiling Water Reactors			
General		N/A	Applies to boiling water reactors only.
Reg. Guide 1.6, Rev. 0, 3/71 – Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems			
General		Exception	The AP1000 main ac power system is a nonsafety-related system. This regulatory guide is applicable only to the Class 1E dc and UPS system.
D.1		Conforms	Guidance applies only to the Class 1E dc and UPS system, since the AP1000 ac power system is a nonsafety-related system.
D.2		N/A	The main ac power system is a nonsafety-related system. Therefore, this regulatory position is not applicable. However, the AP1000 design includes connections to a preferred (offsite) power source and two nonsafety-related onsite standby diesel generators.
D.3		Conforms	
D.4		N/A	See comment on Criteria Section D.2.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
D.5		N/A	See comment on Criteria Section D.2.
Reg. Guide 1.7, Rev. 2, 11/78 and Rev. 3, 03/07 – Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident			
Conformance of the design aspects with Revision 2 of the Regulatory Guide is as stated below in the DCD.			
C.1		Conforms	Mixing of the containment atmosphere is accomplished through natural passive processes (natural circulation), not with an active system.
C.2		Conforms	
C.3	Regulatory Guide 1.29 Regulatory Guide 1.26	Conforms	The hydrogen recombiners are passive autocatalytic recombiners and nonsafety-related. They do not require and are not supplied with power.
C.4		Conforms	
C.5		Conforms	
C.6		Conforms	
Conformance with Revision 3 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
C.2		Conforms	
C.4		Conforms	
Reg. Guide 1.8, Rev. 3, 5/00 – Qualification and Training of Personnel for Nuclear Power Plants			
Conformance of the design aspects of the Regulatory Guide is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 13.2.1 defines the responsibility for the training program for plant personnel.
Conformance for programmatic and/or operational aspects is documented below.			
C.1		Conforms	
C.2	Section 4 of ANSI/ ANS-3.1-1993	Exception	Not able to meet Regulatory Guide 1.8, Rev. 3 qualification requirements for licensed personnel prior to operations. In lieu of the minimum experience requirements specified in ANSI/ANS-3.1-1993, paragraphs 4.5.3.1 (chemistry), 4.5.3.2 (radiation protection) and 4.5.3.3 (instrumentation and control) technicians, and in paragraphs 4.5.7.1 (electrical) and 4.5.7.2 (mechanical) maintenance personnel, the minimum experience requirements specified in ANSI/ANS-3.1-2014 paragraphs 4.5.3.1, 4.5.3.2, 4.5.3.3, 4.5.7.1 and 4.5.7.2, as endorsed by and clarified in RG 1.8, Rev. 4 apply. When fuel is initially loaded in the reactor, and thereafter, whenever fuel is in the reactor, at least one (1) radiation protection technician meeting the minimum qualifications of RG 1.8, Rev. 3, will be on-site and on duty, for compliance with TS 5.3.1. Additional radiation protection technicians on-site when fuel is in the reactor may be qualified to RG 1.8, Rev. 4.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.9, Rev. 2, 12/79 – Selection, Design, and Qualification of Diesel Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants			
General		N/A	Guidelines apply to Class 1E diesel-generators. They are not applicable to the AP1000.
C.1-14		N/A	Guidelines apply to Class 1E diesel-generators. They are not applicable to the AP1000.
Reg. Guide 1.10 – Withdrawn			
Reg. Guide 1.11, Rev.1, 3/10 – Instrument Lines Penetrating Primary Reactor Containment			
General		Conforms	
C.1		Conforms	
C.2.a-c		Conforms	
C.2.d	10 CFR 100	Conforms	
C.3.a-c		N/A	Design features described are not applicable to AP1000 Design.
C.4		Conforms	Regulatory position describes the AP1000 implementation.
C.5		Conforms	
C.6		Conforms	
C.7.a-b		N/A	There are no instrument lines penetrating containment that are not associated with protection or safety system instrumentation.
Reg. Guide 1.12, Rev. 2, 3/97 – Instrumentation for Earthquakes			
Conformance of the design aspects is as stated below in the DCD.			
C.1		Exception	Two elevations (excluding the foundation) on a structure internal to the containment are specified in the draft regulatory guide. A second sensor internal to the containment is not provided because access to a sensor at a lower elevation is inconsistent with maintaining occupational radiation exposures as low as reasonably achievable (ALARA) and the containment seismic analyses show such a location to be unnecessary. The response of the containment internal structures is well represented by the response obtained at elevation 138′-0″. Two independent Category I structure foundations where the response is different from that of the containment structure are also specified. Since all seismic Category I structures are part of the nuclear island, which has a common basemat, no additional foundation sensors are required.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.2		Conforms	Should the seismic response at multiple units at the same site be evaluated as not essentially the same, multiple seismic monitoring systems will be installed at the units. If the seismic response is essentially the same at the other units, the system will be installed at only one unit; however annunciation will be provided in the main control room of each unit.
C.3		Conforms	
C.4		Conforms	The system power panel provides timing signals to components of the entire system. The triaxial acceleration sensor input signals exceeding a preset value are used as the actuation signal for system recording and analysis.
C.5		Conforms	
C.6		Conforms	The triaxial acceleration sensor input signals exceeding a preset value are used as the actuation signal for system recording and analysis.
C.7		Conforms	See Criteria Section C.2.
C.8		N/A	Not applicable to AP1000 design certification. Section 13.5 defines the responsibility for development of procedures.
Conformance for programmatic and/or operational aspects is documented below.			
C.3		Conforms	
C.8		Conforms	
Reg. Guide 1.13, Rev. 1, 12/75 and Rev. 2, 03/07 – Spent Fuel Storage Facility Design Basis			
Conformance of the design aspects with Revision 1 of the Regulatory Guide is as stated below in the DCD.			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
C.4	Regulatory Guide 1.25	Exception	The ventilation system is not designed to mitigate the consequences of a fuel handling accident.
C.5		Conforms	
C.6		Conforms	
C.7		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.8		Exception	Normal makeup supply (demineralized water) is not seismic Category I. Long-term post-accident supply piping is seismic Category I.
Conformance with Revision 2 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
C.7		Conforms	
Reg. Guide 1.14, Rev. 1, 8/75 – Reactor Coolant Pump Flywheel Integrity			
1.a	ASTM A.20	Exception	The flywheel is made of a bi-metallic design. Heavy alloy segments are fitted to a stainless steel hub and held in place by a retaining ring. Therefore, the specific guidelines in this section are not directly applicable to the AP1000.
1.b		Exception	Fracture toughness and tensile properties are checked for components that are required for structural integrity of the bi-metallic flywheel.
1.c		N/A	This guideline is not applicable to the flywheel assembly. Therefore, the guideline is not applicable to the AP1000 reactor coolant pump.
1.d		Conforms	The components of the flywheel that are relied upon for structural integrity require no welding.
2.a-b		Conforms	
2.c-e	ASME Code, Section III	Exception	The limits and methods of ASME Code, Section III, Paragraph F-1331.1(b), (replacement for Paragraph F-1323.1) are not directly applicable to the flywheel assembly. The calculated stress levels in the flywheel are evaluated against the ASME Code, Section III, Subsection NG stress limits used as guidelines and the recommended stress limits in Positions 4.a and 4.c of the Standard Review Plan 5.4.1.1. The stress evaluated is the maximum primary stress.
2.f		Exception	The calculated stress levels in the flywheel satisfy the ASME Code, Section III, Subsection NG stress limits used as guidelines and the recommended stress limits in Position 4.a of the Standard Review Plan 5.4.1.1. The stress evaluated is the maximum primary stress.
2.g		Conforms	
3		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
4.a	ASME Code, Section III, NB-2545 or NB-2546,NB-2540, NB-2530	Exception	The inspections and guidelines referenced in the regulatory guide were developed for steel flywheels in shaft seal pumps. The paragraphs of Subsection NB referenced in the regulatory guide apply only to forged and plate steel components. The bi-metallic flywheel design will be manufactured using multiple processes and materials. In accordance with the regulatory guide, each structural component of the bi-metallic flywheel will be inspected prior to final assembly according to its fabrication and the procedures outlined in Section III, NB-2500 of the ASME Code. Inspection of the flywheel assembly inside the sealed enclosure following a spin test is not practical.
4.b	ASME Code, Section XI	Exception	Inservice inspection of the flywheel assembly is not required to support safe operation of the reactor coolant pump. Planned, routine inspections of the flywheel assembly require considerable occupational radiation exposure and are not recommended. Inservice inspection of the flywheel assemblies requires extensive disassembly. Postulated missiles from the failure of the flywheel are contained within the stator shell and the pressure boundary is not breached. Vibration of the shaft due to a small flywheel fracture or leak in the enclosure does not result in stresses in the pressure boundary of sufficient magnitude to result in a break in the primary pressure boundary.
Reg. Guide 1.15 – Withdrawn			
Reg. Guide 1.16, Rev. 4, 8/75 – Reporting of Operating Information – Appendix A Technical Specifications			
General		N/A	Not applicable to AP1000 design certification. Reporting requirements associated with the technical specifications are identified in Tech Spec. Section 5.6. Subsection 1.1.1 defines the responsibility for finalizing the technical specification.
Reg. Guide 1.17 – Withdrawn			
Reg. Guide 1.18 – Withdrawn			
Reg. Guide 1.19 – Withdrawn			
Reg. Guide 1.20, Rev. 2, 5/76 and Rev. 3, 3/07 – Comprehensive Vibration Assessment Program For Reactor Internals During Preoperational and Initial Startup Testing			
Conformance with Revision 2 of the Regulatory Guide is as stated below in the DCD. This guidance is completely within the scope of the DCD.			
General		Conforms	The AP1000 internals are similar to those for a three-loop XL Westinghouse 17 x 17 robust fuel assembly core internals, a core shroud and the new incore instrumentation system. The upper internals are not significantly changed from standard designs. An internals vibration measurement program is conducted during hot functional testing. The results are evaluated based on pre-established allowable levels.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			During hot functional testing the AP1000 internals are subjected to operational system flow conditions that are similar to those imposed on previous 3XL three-loop designs. The duration of the hot functional flow testing is sufficient to subject each critical reactor internals component to at least 10^6 cycles of vibration. Pre- and post-test inspections are conducted to confirm that the AP1000 internals experience no excessive motion or wear.
C.1		Conforms	Although the AP1000 internals do not represent a first of a kind or unique design on the basis of the arrangement, design, size, or operating conditions, for the purposes of the reactor internals preoperational test program, the first operational AP1000 reactor vessel internals are classified as a prototype. Subsequent plants will be classified as the appropriate Non-prototype Category based on the designation of the first AP1000 as a Valid Prototype. See Subsections 3.9.2.3 and 3.9.2.4 for additional information on the vibration assessment of the reactor vessel internals.
C.2		Conforms	A comprehensive vibration assessment program will be developed for the first AP1000 reactor vessel internals. With regard to transients, data are acquired only during the hot functional test. Additionally, data are calculated over the ranges of hot functional test temperatures and during startup, shutdown, and steady-state operation of various combinations of reactor coolant pumps. Subsection 3.9.8 addresses information provided about the vibration assessment program.
C.3		Conforms	Subsequent to completion of the vibration assessment program for the first AP1000 reactor vessel internals, the vibration analysis program will address the criteria for the appropriate Non-prototype Category internals.
Reg. Guide 1.21, Rev. 1, 6/74 – Measuring Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents From Light-Water-Cooled Nuclear Power Plants			
Conformance of the design aspects is as stated below in the DCD.			
General		Conforms	The design guidance of this regulatory guide for the selection of locations and type of effluent measurements to cover major or potentially significant pathways of release of radioactive materials during normal reactor operation, including anticipated operational occurrences, are incorporated in the plant design and in the requirements of the radiological effluent technical specifications. The calibration of effluent monitoring systems is performed according to written plant procedures. Subsection 11.5.8 defines the responsibility for the radiation monitoring program. Subsection 13.5.1 defines the responsibility for the plant procedure preparation.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.1		N/A	Not applicable to AP1000 design certification. Subsection 11.5.8 defines the responsibility for the radiation monitoring program.
C.2		Conforms	
C.3-5		N/A	Not applicable to AP1000 design certification. Subsection 11.5.8 defines the responsibility for the radiation monitoring program.
C.6	ANSI N13.1-1969	Exception	ANSI N13.1-1969 prescribes the use of isokinetic sampling systems along with the use of multipoint sample nozzles for sampling from large ducts or vents. The use of alternate non-isokinetic sampling systems with a single point shrouded nozzle is also an acceptable method for obtaining representative samples from ducts or vents provided the flow is well mixed at the sample extraction point in the flow stream.
C.7-14		N/A	Not applicable to AP1000 design certification. Subsection 11.5.8 defines the responsibility for the radiation monitoring program.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
C.1		Conforms	
C.3-C.5		Conforms	
C.6	ANSI N13.1-1969	Exception	ANS N13.1-1969 prescribes the use of isokinetic sampling systems along with the use of multipoint sample nozzles for sampling from large ducts and vents. The use of alternate sampling systems such as a single point shrouded nozzle is also an acceptable method for obtaining representative samples from ducts and vents provided the flow is well mixed as the extraction point in the flow stream.
C.7-C.14		Conforms	
Reg. Guide 1.22, Rev. 0, 2/72 – Periodic Testing of Protection System Actuation Functions			
General		Conforms	Safety actuation circuitry is provided with a capability for testing with the reactor at power. The protection system, including the engineered safety features test cabinet design, conforms to this regulatory guide. The protection functions are tested at power to the greatest extent practical. Only the device function and/or system level function is not universally tested. The logic associated with the devices has the capability for testing at power, at the subsystem and/or component level.
D.1		Conforms	The AP1000 protection system is designed to permit periodic testing.
D.2-4		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.23, Second Proposed Rev. 1, 4/86 and Rev. 1, 3/2007 – Meteorological Monitoring Programs for Nuclear Power Plants			
Conformance of the DCD scope of second proposed Rev. 1 aspects is as stated below in the DCD.			
General		Conforms	The onsite meteorological measurement program is site-specific and will be defined as indicated in Subsection 2.3.6. The number and location of meteorological instrument towers are determined by actual site parameters. Subsection 2.3.6 defines the responsibility for the onsite meteorological program. The data display and processing system has the capability to record the data from the meteorological instruments and display the information in the main control room.
Conformance with Revision 1 of this Regulatory Guide for site-specific aspects is documented below.			
General		Conforms	
Reg. Guide 1.24, Rev. 0, 3/72 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure			
General		N/A	This regulatory guide applies to the evaluation of a waste gas storage tank failure. The AP1000 design does not include waste gas storage tanks. Therefore, it is not applicable to the AP1000.
Reg. Guide 1.25, Rev. 0, 3/72 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors			
General		Exception	The guidance of Reg. Guide 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors" will be followed instead of Reg. Guide 1.25.
Reg. Guide 1.26, Rev. 3, 2/76 and Rev. 4, 3/07 – Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containment Components of Nuclear Power Plants			
Conformance with Revision 3 of the Regulatory Guide for DCD scope of work is as stated below in the DCD.			
C.1		Exception	A portion of the chemical and volume control system that is defined as reactor coolant pressure boundary uses an alternate classification in conformance with the requirements of 10 CFR 50.55a(z). The alternate classification is discussed in Section 5.2.
C.1.a		Exception	For the AP1000 plant design, Quality Group B is reserved for the containment boundary including any extensions such as containment isolation valves and associated piping. Quality Group C is essentially equivalent quality except that it has less stringent ISI. For equipment such as passive safety system accumulators, minor leakage is not a problem for the following reasons: a. It is located inside containment so activity releases are contained.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			b. Minor leakage does not affect its functional performance, especially considering the limited duration of post-accident operation. c. There is continuous water level and gas pressure monitoring of the passive safety system accumulators that detects leaks. This approach results in the change of quality group (from Quality Group B to Quality Group C) for various components such as the IRWST. Portions of systems that provide emergency core cooling system functions and are constructed using ASME Code, Section III, Class 3 criteria have the additional requirement that radiography will be conducted on a random sample of welds during construction, see Subsection 3.2.2.5.
C.1.b		Exception	The AP1000 residual heat removal system is a nonsafety-related system, but it is classified as Quality Group C. The passive core cooling system provides the safety-related function that the residual heat removal system provides in current plants with active safety-related systems.
C.1.c		N/A	Applies to boiling water reactors only.
C.1.d		Conforms	Portions of the feedwater and steam systems are Quality Group B, up to the isolation valves.
C.1.e		Conforms	
C.2.a		Conforms	The component cooling water and the service water systems are Quality Group D since they perform no safety-related functions.
C.2.b		Conforms	Component cooling water is not required for safe shutdown of the AP1000. The reactor cooling pumps do not have seals and do not require seal water supply.
C.2.c		Conforms	
C.2.d		N/A	Regulatory Guide 1.143 supersedes this guideline.
C.2.e		N/A	Regulatory Guide 1.143 supersedes this guideline.
C.3		Exception	Systems that are normally radioactive are classified as Quality Group D. AP1000 also classifies as Quality Group D, nonsafety-related systems and components which have functions that have been identified as important as part of the implementation of the regulatory treatment of nonsafety-related systems or as defense-in-depth systems. Some structures, systems, and components that have the potential to be contaminated with radioactive fluids but normally do not contain radioactive fluids are not classified as Quality Group D.
Conformance with Revision 4 of this Regulatory Guide for remaining scope is documented below.			
General		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.27, Rev. 2, 1/76 – Ultimate Heat Sink for Nuclear Power Plants			
C.1		Conforms	The passive containment cooling system water storage tank is sized to provide water cooling to the containment vessel and provide heat removal to meet the requirements of General Design Criterion 38 to reduce and maintain the containment temperature and pressure following a postulated loss-of-coolant accident for 3 days following passive containment cooling system actuation. This water delivery is done in conjunction with the flow of air over the containment shell to provide the containment cooling. After 3 days of water delivery from the PCCWST, the PCS cooling water supply is continued through either: • simple operator action via installed safety-related piping and connection utilizing offsite or available onsite supplies of water and an offsite pump to resupply water to the tank; or, • simple operator action utilizing onsite seismically analyzed pumps, piping and 4 days of water inventory within the passive containment cooling ancillary water storage tank to resupply the PCCWST. Supplemental supplies would then be available from either onsite storage facilities or an offsite source. Since the passive containment cooling system can function with replenished water supplies from either onsite or offsite, the system meets the guideline of providing an ultimate heat sink for more than 30 days.
C.2		Conforms	The AP1000 design conforms to this regulatory position, provided that the definition of a single failure of a man-made structure does not include the safety-related, seismically-designed containment structure assembly. The AP1000 uses the atmosphere as the ultimate heat sink. A baffle located between the containment shell and the shield building sustains the natural circulation that provides for air flow over the containment shell to carry heat away. The baffle is composed of a large number of panels and will continue to function if damaged by an external missile.
C.3		Conforms	The seismically-designed passive containment cooling system water storage, integral to the containment structure meets this regulatory position.
C.4		Conforms	Technical Specifications exist for the passive containment cooling system and air inlet and air baffle.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.28, Rev. 3, 8/85 – Quality Assurance Program Requirements (Design and Construction)			
Conformance for DCD scope of work is as stated below in the DCD.			
General	ANSI/ASME N45.2-1977 ANSI/ASME NQA-1-1983 through NQA-1a-1983 Addenda	Exception	The Westinghouse quality assurance program is described in Chapter 17. Refer to "Westinghouse Electric Company Quality Management System" (QMS) referenced therein for Westinghouse positions on regulatory guides within the scope of the quality assurance program. In some cases current industry consensus standards have replaced the standards specifically referenced by certain regulatory guides. In particular, the N45.2 series standards have been replaced by ASME NQA-1. Therefore, the "Quality Management System" may reference ASME NQA-1 rather than the N45.2 series standards when describing the Westinghouse position. Work performed under QMS, Rev. 5 and Rev. 6, is based on application of Regulatory Guide 1.28, Revision 3, and ASME NQA-1-1994. Work performed under QMS, Rev. 7, is based on application of Regulatory Guide 1.28, Revision 4, and ASME NQA-1-2008 and NQA-1a-2009. Application of Regulatory Guide 1.28, Revision 4, is addressed in Appendix A of the Westinghouse QMS, Revision 6.
2.	Criteria 17 10 CFR 50 Appendix B	Conforms	
Conformance for remaining scope is documented below.			
General		Exception	Quality assurance requirements utilize the more recently NRC endorsed NQA-1 in lieu of the identified outdated standards.
Reg. Guide 1.29, Rev. 3, 9/78 and Rev. 4 3/07 – Seismic Design Classification			
Conformance with Revision 3 of the Regulatory Guide for DCD scope of work is as stated below in the DCD.			
C.1.a		Conforms	
C.1.b		Conforms	
C.1.c		Conforms	
C.1.d		Exception	The AP1000 normal residual heat removal system is nonsafety-related. The safety-related function of decay heat removal is provided by the safety-related passive residual heat removal heat exchanger of the passive core cooling system that is seismic Category I. The spent fuel pool cooling system does not have active components that are required for the safety-related decay heat removal function. This function is provided passively through a large heat sink of water in the pool. The spent fuel pool is sized to keep the fuel covered for at least 72 hours without active cooling or makeup following a loss of ac power sources.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			The 72-hour sizing calculation accounts for the maximum loss of water due to the rupture of non-seismic piping. seismic Category I components within the spent fuel pool cooling system include the containment penetration, the connections for makeup, and the spent fuel pool.
C.1.e		N/A	Applies to boiling water reactors only.
C.1.f		Conforms	
C.1.g		Exception	The AP1000 does not have a safety-related auxiliary feedwater system. The safety-related decay heat removal function is provided by the passive residual heat removal heat exchanger. The safety-related functions of the essential service water system are provided by the passive residual heat removal heat exchangers and the passive containment cooling system. The component cooling system is a nonsafety-related system, since it performs no safety-related functions.
C.1.h		Conforms	
C.1.i		N/A	The diesel-generators are nonsafety-related. Therefore, this section is not applicable to the AP1000.
C.1.j		Conforms	
C.1.k		Conforms	
C.1.l		Conforms	
C.1.m		Conforms	
C.1.n		Exception	Structures or equipment whose failure results in incapacitating injury to the occupants of the main control room are classified as seismic Category II and covered under Position 2 of this regulatory guide.
C.1.o		Conforms	
C.1.p		Conforms	
C.1.q		Conforms	
C.2		Conforms	
C.3		Conforms	
C.4		Conforms	
Conformance with Revision 3 of this Regulatory Guide for the site-specific scope is documented below.			
General		Conforms	
Conformance with Revision 4 of this Regulatory Guide for remaining scope is documented below.			
C.4		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.30, Rev. 0, 8/72 – Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment			
Conformance for DCD scope of work is as stated below in the DCD.			
General	ANSI/ASME N45.2.4-1972	N/A	Not applicable to AP1000 design certification. Section 17.5 defines the responsibility for the Quality Assurance program.
Conformance for remaining scope is documented below.			
General		Exception	Quality assurance requirements utilize the more recently NRC endorsed NQA-1 in lieu of the identified outdated standards.
Reg. Guide 1.31, Rev. 3, 4/78 – Control of Ferrite Content in Stainless Steel Weld Metal			
General		Conforms	
C.1-5		Conforms	
Reg. Guide 1.32, Rev. 2, 2/77 – Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants			
Regulatory Guide 1.32, Rev. 3, 03/04 – Criteria for Power Systems for Nuclear Power Plants			
Conformance of the design aspects with Revision 2 of the Regulatory Guide is as stated below in the DCD.			
1.	IEEE Std. 308-1974	Exception	Regulatory Guide 1.32 endorses IEEE Std. 308-1974 (Reference 5) which has been superseded by IEEE Std. 308-1991(Reference 6). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.32. The guidelines are applicable to the Class 1E dc and UPS system only. There are no safety-related ac power systems in the AP1000.
1.a	Regulatory Guide 1.93	N/A	The AP1000 has no safety-related ac power system. Therefore, the guidelines specified in this criterion section recommending the availability of offsite power "within a few seconds" are not applicable.
1.b	IEEE Std. 308-1974, Section 5.3.4	Exception	See comment on Criterion Section 1.
1.c	IEEE Std. 450-1975	Exception	Battery performance discharge test is per IEEE-Std 450-1995 as described in Bases for Technical Specification, Surveillance Requirement 3.8.7.6. The AP1000 has adopted a testing interval of 24 months that aligns with industry practice.
1.d	Regulatory Guide 1.6 Regulatory Guide 1.75	Exception	The guidelines are applicable to the Class 1E dc and UPS system only. There are no safety-related ac power systems in the AP1000.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
1.e	Regulatory Guide 1.75	Exception	The guidelines are applicable to the Class 1E dc and UPS system only. There are no safety-related ac power systems in the AP1000.
1.f	Regulatory Guide 1.9	N/A	Guidelines apply to Class 1E diesel generators. Therefore, they are not applicable to the AP1000.
2.a	IEEE Std. 308-1974, Section 8.2, 8.3.1; Regulatory Guide 1.81	N/A	The AP1000 is a single-unit plant. This criterion is not applicable to the AP1000. When two or more AP1000s are located adjacent, electrical systems are not shared.
2.b.	Regulatory Guide 1.93	Exception	The guidelines are applicable to the Class 1E dc and UPS system only. There are no safety-related ac power systems in the AP1000. See comments on Regulatory Guide 1.93.
Conformance with Revision 3 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.33, Rev. 2, 2/78 – Quality Assurance Program Requirements (Operation)			
Conformance for DCD scope of work is as stated below in the DCD.			
General	ANSI N18.7-1976 ANS-3.2	N/A	Not applicable to AP1000 design certification. Section 17.5 defines the responsibility for the Quality Assurance program. Regulatory Guide 1.33 is used in a specific manner for determining documentation adequacy in regard to the ongoing qualification method based on the assumption the utility programs are in conformance with Regulatory Guide 1.33.
Conformance for remaining scope is documented below.			
General	ANSI N18.7-1976 ANS-3.2	N/A	QA program requirements based on NEI 06-14A, Rev 7 as noted in Section 17.5.
Reg. Guide 1.34, Rev. 0, 12/72 – Control of Electroslag Weld Properties			
General	ASME Code, Sections III and IX	Conforms	The AP1000 prohibits the use of electroslag welding on reactor coolant pressure boundary components. AP1000 safety-related components that use electroslag welding conform to the provisions of the ASME Code and this regulatory guide.
C.1-5		Conforms	
Reg. Guide 1.35, Rev. 3, 7/90 – Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments			
General		N/A	The AP1000 does not have a concrete containment and does not use a prestressing tendon in the containment structure. Therefore, this regulatory guide is not applicable to the AP1000.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.35.1, Rev. 0, 7/90 – Determining Prestressing Forces for Inspection of Prestressed Concrete Containments			
General		N/A	The AP1000 does not have a concrete containment and does not use a prestressing tendon in the containment structure. Therefore, this regulatory guide is not applicable to the AP1000.
Reg. Guide 1.36, Rev. 0, 2/73 – Nonmetallic Thermal Insulation for Austenitic Stainless Steel			
General		Conforms	
C.1		Conforms	
C.2.a	ASTM C692-71 RDT M12-1T	Conforms	
C.2.b		Conforms	
C.3-4		Conforms	
Reg. Guide 1.37, Rev. 0, 3/73 and Rev. 1, 3/07 – Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water Cooled Nuclear Power Plants			
Conformance of the design aspects with Revision 0 of the Regulatory Guide is as stated below in the DCD.			
General	ANSI N45.2.1-1973	Exception	The ANSI N45.2 series of standards that are referenced by the current revisions of the Quality Assurance regulatory guides have been replaced by ASME NQA-1. ANSI N45.2.1, which is referenced in Regulatory Guide 1.37, has been incorporated into NQA-1 Subpart 2.1. The technical requirements specified in ANSI N45.2.1 and NQA-1 Part II, Subpart 2.1 are compatible. Therefore, compliance with NQA-1 Part II, Subpart 2.1 satisfies Regulatory Guide 1.37. Section 17.5 defines the responsibility for the Quality Assurance program.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.38, Rev. 2, 5/77 – Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants			
Conformance for DCD scope of work is as stated below in the DCD.			
General	ANSI N45.2.2-1972	Exception	The ANSI N45.2 series of standards that are referenced by the current revisions of the Quality Assurance regulatory guides have been replaced by ASME NQA-1. Refer to the Regulatory Guide 1.28 position. Section 17.5 defines the responsibility for the Quality Assurance program.
Conformance for remaining scope is documented below.			
General		Exception	Quality assurance requirements utilize the more recently NRC endorsed NQA-1 in lieu of the identified outdated standards.
Reg. Guide 1.39, Rev. 2, 9/77 – Housekeeping Requirements for Water-Cooled Nuclear Power Plants			
Conformance for DCD scope of work is as stated below in the DCD.			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
General	ANSI N45.2.3-1973	Exception	The ANSI N45.2 series of standards that are referenced by the current revisions of the Quality Assurance regulatory guides have been replaced by ASME NQA-1. Refer to the Regulatory Guide 1.28 position. Section 17.5 defines the responsibility for the Quality Assurance program.
Conformance for remaining scope is documented below.			
General		Exception	Quality assurance requirements utilize the more recently NRC endorsed NQA-1 in lieu of the identified outdated standards.
Reg. Guide 1.40, Rev. 0, 3/73 – Qualification Tests of Continuous-Duty, Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants			
General	IEEE Std. 334-1971	N/A	The AP1000 does not have continuous-duty safety-related motors installed inside the containment. Therefore, the regulatory guide is not applicable to the AP1000.
Reg. Guide 1.41, Rev. 0, 3/73 – Preoperational Testing of Redundant On-Site Electric Power Systems to Verify Proper Load Group Assignments			
General		Exception	The guidelines are followed for Class 1E dc power systems during the preoperational testing of AP1000 redundant onsite electric power systems to verify proper load group assignments, except as follows. Complete preoperational testing of the startup, sequence loading, and functional performance of the load groups is performed where practical. In those cases where it is not practical to perform complete functional performance testing, an evaluation is used to supplement the testing.
Reg. Guide 1.42 – Withdrawn			
Reg. Guide 1.43, Rev. 0, 5/73 – Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components			
General		Conforms	The guidelines of this regulatory guide are followed during the welding process used for cladding ferritic steel components of the AP1000 with austenitic stainless steel. No qualifications are provided for by this regulatory guide for ASME SA-533 material and equivalent chemistry for forging grade ASME SA-508, Class 3, material. The reactor vessel, steam generator channel heads, accumulators, and core makeup tanks design specification restricts the low alloy steel forging material to ASME SA-508, Class 3, which is made to a fine grain practice only. Cladding of ASME SA-508, Class 2 is not applicable to the AP1000 design. The fabricator monitors and records the weld parameters to verify agreement with the parameters established by the procedure qualification as stated in Regulatory Position C.3.
C.1-3		N/A	The AP1000 material, specifically ASME SA-533 and SA-508 Class 3 made to a fine grain practice, is not subjected to the controls in this regulatory guide.
Reg. Guide 1.44, Rev. 0, 5/73 – Control of the Use of Sensitized Stainless Steel			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance with Revision 0 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
C.4		Exception	Material exposed to reactor coolant has a controlled concentration of less than 0.10 ppm dissolved oxygen at all temperatures above 250°F during normal operation.
C.5		Conforms	
C.6		Conforms	
Reg. Guide 1.45, Rev. 0, 5/73 – Reactor Coolant Pressure Boundary Leakage Detection Systems			
Conformance of the design aspects is as stated below in the DCD.			
C.1		Conforms	
C.2		Conforms	
C.3		Exception	The AP1000 uses two methods for leak detection, including sump level and flow monitoring, and airborne particulate radioactivity monitoring.
C.4		Conforms	
C.5		Conforms	
C.6		Exception	Seismically qualified tubing from containment to the containment atmosphere particulate monitor is not provided. Leak detection is provided by the seismic Category I containment sump level monitor leakage detection system.
C.7		Conforms	
C.8		Conforms	
C.9		Conforms	
Conformance with programmatic and/or operational aspects is documented below.			
C.7		Conforms	
Reg. Guide 1.46 – Withdrawn			
Reg. Guide 1.47, Rev. 0, 5/73 – Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems			
General	IEEE Std. 279-1971, Section 4.13; and 10 CFR 50 App. B, Criterion XIV	Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.1-4		Conforms	
Reg. Guide 1.48 – Withdrawn			
Reg. Guide 1.49 – Withdrawn			
Reg. Guide 1.50, Rev. 0, 5/73 – Control of Preheat Temperature for Welding of Low-Alloy Steel			
General	ASME Code, Sections III and IX	N/A	The guidelines of this regulatory guide are followed during the initial fabrication of low-alloy steel components of the AP1000. This regulatory guide is considered as applicable to ASME Code, Section III, Class 1 components. The AP1000 practice for Class 1 components is in agreement with the guidance of this regulatory guide except for Regulatory Positions C.1(b) and 2. For AP1000 Class 2 and 3 components, the guidelines provided by this regulatory guide are not applied, however all requirements of the ASME Boiler and Pressure Vessel Code are imposed.
C.1(b)		Exception	The welding procedures are qualified within the preheat temperature ranges required by ASME Code, Section IX. Experience has shown excellent quality of welds using the ASME qualification procedures.
C.2		Exception	The AP1000 position is that the guidance specified in this regulatory guide is both unnecessary and impractical. Code acceptable low-alloy steel welds have been and are being made under present procedures. It is not necessary to maintain the preheat temperature until a post-weld heat treatment has been performed in accordance with the guidance provided by this regulatory guide, in the case of large components. In some cases of reactor vessel main structural welds, the practice of maintaining preheat until the intermediate or final post-weld heat treatment has been followed. In other cases, an extended preheat practice has been utilized in accordance with the reactor vessel design specification. In this practice, the weld temperature is maintained at 400°F to 750°F for 4 hours after welding. The weld temperature may then be lowered to ambient without performing an intermediate or final post-weld heat treatment at 1100°F. The welds have shown high integrity. Westinghouse practices are documented in WCAP-8577 (Reference 9) which has been accepted by the Nuclear Regulatory Commission.
Reg. Guide 1.51 – Withdrawn			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Regulatory Guide 1.52, Rev. 3, 6/01 – Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants			
Conformance with the design and operational aspects is as stated below in the DCD.			
General		Conforms	The AP1000 main control room emergency habitability system (VES) includes a passive filtration system that is contained entirely within the main control room envelope. The passive filtration portion of the AP1000 VES contains no active equipment. This regulatory guide is followed where appropriate for the AP1000 MCR passive filtration system.
C.1		Conforms	The performance, design, construction, acceptance testing, and QA of the AP1000 MCR passive filtration system will be in accordance with ASME AG-1-1997 where appropriate. Also, it will be designed to ASME N509-1989 and tested to ASME N510-1989.
C.2		Conforms	The AP1000 MCR passive filtration is designed to operate under the environmental conditions specified by the guidelines in this regulatory position.
C.3.1 – 3.2		Exception	Redundant filtration trains are not needed in the AP1000 passive filtration system. The passive filtration system contains no active components or moving parts. Adequate margin is provided in the design to prevent the likelihood of a passive failure.
C.3.3		Conforms	The maximum pressure surge is experienced during the highly unlikely failure of the upstream pressure regulator valve in the VES. The passive filtration system is designed to operate under this pressure surge.
C.3.4		Conforms	All components in the MCR passive filtration system are designed to be seismic Category I.
C.3.5		Conforms	The mechanical design of the MCR passive filtration system is such that it can withstand the buildup of postulated radioactivity levels and maintain functionality.
C.3.6		Conforms	The AP1000 passive filtration system volumetric air-flow rate is below 30,000 CFM.
C.3.7		Exception	Temporary differential pressure gauges are provided to perform the initial and the in-service testing in compliance with the Ventilation Filter Testing Program of Technical Specification 5.5.13. During system operation, air flow through the passive filtration line, in lieu of pressure drop across the filters, provides indication of satisfactory flow through the filtration unit.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			The flow instrumentation is not required to be safety related. The instrumentation does not perform a safety function. The instrumentation monitoring flow from the VES emergency air storage tanks indicates whether there is sufficient flow coming from the compressed air tanks to induce the passive filtration.
C.3.8		Exception	The AP1000 passive filtration system does not rely upon, use, or need a power supply and/or electrical distribution.
C.3.9		Conforms	The AP1000 passive filtration system is designed to operate for 72 hours following a DBA.
C.3.10		Conforms	
C.3.11		Exception	There are no outdoor air intakes for the AP1000 passive filtration system. The system uses breathable compressed air that is stored in compressed air tanks during the post-72-hour operation time.
C.3.12		Exception	The AP1000 passive filtration system is located completely within the CRE. Leakages as explained in this regulatory position are not applicable to this system.
C.4.1 – 4.2		Exception	There are no moisture separators and/or heaters in the AP1000 passive filtration line.
C.4.3		Exception	ASME AG-1, 1997 Section FB requires filters be certified to UL 900, Class 1, 5th Edition 1987. As of May 2012 UL no longer classifies UL 900 filters with a Class 1 or Class 2 rating. The Class 1 requirements per UL 900, “Air Filter Units” 8th Edition, are obsolete and deleted, as UL 900 no longer distinguishes between Class 1 and Class 2 filters.
C.4.4		Exception	ASME AG-1, 1997 Section FC require HEPA Filters be listed to UL 586, 7th Edition. Manufacturers only list components per the latest Edition of the UL Standard. Previous UL Standard Editions/Revisions cannot be invoked.
C.4.5 - 4.7		Conforms	
C.4.8		Exception	There are no water drains in the AP1000 passive filtration line.
C.4.9		Conforms	The credited adsorber efficiencies are 90% for elemental iodine and 90% for organic iodine. These efficiencies assume no humidity control.
C.4.10		Conforms	Type II adsorbers are used in this application
C.4.11		Conforms	The AP1000 passive filtration line uses impregnated activated carbon as the absorbent. The absorber is designed for a minimum average atmosphere residence time of 0.25 seconds per 2 inches of absorbent bed.
C.4.12		Conforms	
C.4.13		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.4.14		Exception	The passive filtration line requires no fans.
C.5.1		N/A	Only one bank of filters is used.
C5.2		Exception	This system is not used for normal HVAC, and the filters should not build up unusual levels of particulate once installed.
C.6.1		Conforms	
C.6.2 – 6.5		Conforms	
C.7		Conforms	
Table 1		Conforms	The Technical Specification methyl iodide penetration acceptance limit for the AP1000 activated carbon adsorber is 5%, which correlates to 90% removal efficiency of both organic and elemental iodine. The calculated design basis for the AP1000 passive filtration adsorbers assumes a 90% organic iodine removal efficiency and a 90% elemental iodine efficiency. A 1% bypass leakage is accounted for by testing to increased organic iodine removal efficiency.

Reg. Guide 1.53, Rev. 0, 6/73 – Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems

Regulatory Guide 1.53, Rev. 2, 11/03 – Application of the Single-Failure Criterion to Safety Systems

Conformance of the design aspects with Revision 0 of the Regulatory Guide is as stated below in the DCD.This guidance is completely within the scope of the DCD.

General	IEEE Std. 379-1972	Exception	Regulatory Guide 1.53 endorses IEEE Std. 379-72 (Reference 10), which has been superseded by IEEE Std. 379-2000 (Reference 11). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.53. IEEE Std. 379-2000 is endorsed by DG-1118 (Proposed Revision of Regulatory Guide 1.53). The guidelines are applicable to safety-related dc power systems. There are no safety-related ac power sources in the AP1000.

Reg. Guide 1.54, Rev. 1, 7/00 and Rev. 2, 10/10 – Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants

Conformance with Revision 1 of this regulatory guide is as stated below.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
General	ASTM D 3843-00, ASTM D 3911-95, ASTM D 5144-00	Exception	Some coatings inside containment are nonsafety-related and satisfy appropriate ASTM Standards. See Subsection 6.1.2 for additional information, e.g., delamination of Service Level II coatings during design basis accident testing is acceptable if the Service Level II coating meets the criteria identified in Subsection 6.1.2.1.1. Application is controlled by procedures using qualified personnel to provide a high quality product. The paint materials for coatings inside the containment are subject to 10 CFR Part 50 Appendix B Quality Assurance requirements. The quality assurance features of the AP1000 coatings systems are outlined in Subsection 6.1.2.1.6. Subsection 6.1.3 defines the responsibility for the coating program.
General		Exception	Revision 2 of the regulatory guide is applied to use for protective coatings on the containment vessel shell and attachments to the containment vessel shell.
C.4	ASTM D 5962-96	Exception	Unqualified coatings inside containment are managed consistent with the guidance of ASTM D 7491-08, “Standard Guide for Management of Non-Conforming Coatings in Coating Service Level I Areas of Nuclear Power Plants.” Regulatory Guide 1.54 Revision 2 endorses this standard.
Conformance with Revision 2 of this regulatory guide is as stated below.			
General	ASTM D 3843-00, ASTM D 3911-08, ASTM D 5144-08	Exception	Some coatings inside containment are nonsafety-related and satisfy appropriate ASTM Standards. See Subsection 6.1.2 for additional information. Application is controlled by procedures using qualified personnel to provide a high quality product. The paint materials for coatings inside the containment are subject to 10 CFR Part 50 Appendix B Quality Assurance requirements. The quality assurance features of the AP1000 coatings systems are outlined in Subsection 6.1.2.1.6. Subsection 6.1.3 defines the responsibility for the coating program.
General		Exception	Revision 2 of this regulatory guide is applied to use only for management of nonconforming coatings within Service Level I areas and protective coatings on the containment vessel shell and attachments to the containment vessel shell. Other protective coatings use Revision 1 of the regulatory guide.
General	ASTM D 3911-08	Exception	Regulatory Guide 1.54 provides additional acceptance criteria for Service Level I coatings when tested per ASTM D 3911-08. Of the additional acceptance criteria, a) Peeling and delamination shall not be permitted and b) Cracking is not considered a failure unless it is accompanied by delamination or loss of adhesion. These are not applicable to a Service Level I epoxy top coat applied over inorganic zinc. This is because delamination and/or detachment of epoxy coatings does not impact plant safety and does not adversely affect underlying inorganic zinc coating or the ability of the inorganic zinc coating to perform its safety functions.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance with programmatic and/or operational aspects of Revision 1 is documented below. Revision 2 is not utilized for the programmatic and/or operational aspects except as noted below for management of unqualified coatings.			
C.4	ASTM D 5962-96	Exception	Programmatic and/or operational aspects regarding management of nonconforming coatings in Service Level I areas comply with ASTM D 7491-08 endorsed in Revision 2 of this regulatory guide.
Reg. Guide 1.55 – Withdrawn			
Reg. Guide 1.56, Rev. 1, 7/78 – Maintenance of Water Purity in Boiling Water Reactors			
General		N/A	Applies to boiling water reactors only.
Reg. Guide 1.57, Rev. 0, 6/73 and Rev. 1, 03/07 – Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components			
Conformance with Revision 0 of the Regulatory Guide is as stated below in the DCD. This guidance is completely within the scope of the DCD.			
General	ASME Code, Section III	Exception	The regulatory guide was issued in 1973. It refers to the ASME Code through the Summer 1973 Addenda. The acceptance criteria have been defined in greater detail in SRP 3.8.2. The AP1000 complies with the SRP acceptance criteria with the exception that the operating basis earthquake is excluded.
Reg. Guide 1.58 – Withdrawn			
Reg. Guide 1.59, Rev. 2, 8/77 – Design Basis Floods for Nuclear Power Plants			
Conformance with the design aspects is as stated below in the DCD.			
C.1-4	Regulatory Guide 1.29	N/A	The maximum water level due to the probable maximum flood is established as a site interface in Chapter 2 and is used in the design of the AP1000.
Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms	Section 2.4 and Section 3.4 provide the site-specific information on historical flooding and potential flooding factors.
Reg. Guide 1.60, Rev. 1, 12/73 – Design Response Spectra for Seismic Design of Nuclear Power Plants			
Conformance of the design aspects is as stated below in the DCD.			
C.1		Conforms	
C.2		Conforms	
Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms with Clarification	Site-specific response spectra is derived in accordance with 10 CFR Part 100 Subpart B 100.23. The standard spectral shape of Regulatory Guide is not used.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.61, Rev. 0, 10/73 and Rev. 1, 3/07 – Damping Values for Seismic Design of Nuclear Power Plants			
Conformance with Revision 0 of the Regulatory Guide is as stated below in the DCD. This guidance is completely within the scope of the DCD.			
General		Conforms	Damping values used in the AP1000 safe shutdown earthquake analyses are shown in Table 3.7.1-1. These values are based on Regulatory Guide 1.61, on the recommendations of ASCE 4-86 (Reference 12), and on values used and accepted on past projects (Reference 13). The values are conservative relative to realistic damping values reported in the literature (Reference 14) A site interface is established to verify that the site is within the range considered in the design.
Reg. Guide 1.62, Rev. 0, 10/73 – Manual Initiation of Protective Actions			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
C.4		Conforms	
C.5		Conforms	
C.6	IEEE Std. 279-1971, Section 4.16	Conforms	
Reg. Guide 1.63, Rev. 3, 2/87 – Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants			
General	IEEE Std. 317-1983 IEEE Std. 741-1986, Section 5.4	Exception	Regulatory Guide 1.63 endorses IEEE Std. 741-1986 (Reference 15), which has been superseded by IEEE Std. 741-1997 (Reference 16). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.63. Electric penetration assemblies are in conformance with IEEE Std. 317-1983 (Reference 17), Reference 16, and this regulatory guide with the clarification discussed below. The majority of low voltage control circuits are self-limiting in that circuit resistance limits the fault current to a level that does not damage the penetration. Where, on a case-by-case basis, a circuit is found not to be self-limiting, primary and backup breaker or fuse coordination or the addition of a subfeed over current protection as in the case of motor control centers, provide for safe operation. The energy levels in the instrument systems are such that damage cannot occur to the containment penetration.
Reg. Guide 1.64 – Withdrawn			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.65, Rev. 0, 10/73 – Materials and Inspections for Reactor Vessel Closure Studs			
Conformance of the design aspects is as stated below in the DCD.			
C.1.a	ASME Code, Section III, Subsection NB	Conforms	The reactor vessel closure stud bolting material is pro-cured to a minimum yield strength of 130,000 psi and a minimum tensile strength of 145,000 psi. The material meets the criteria of Appendix G to 10 CFR 50. The reactor vessel design specification requires the maximum tensile strength of 170,000 psi for the closure stud material.
C.1.b		Conforms	
C.2	ASME Code, Section III, NB-2580	Conforms	The guidelines of this regulatory guide are followed during the fabrication of the stud bolts and nuts.
C.3		Conforms	The guidance of this regulatory guide is followed during the venting and filling of the AP1000 pressure vessel.
C.4	ASME Code, Section XI; ASME Code, Section III, NB-2545 or NB-2546	Conforms	The guidelines of this regulatory guide are followed during the inservice examination of the AP1000 pressure vessel stud bolting.
Conformance with programmatic and/or operational aspects is documented below.			
C.3		Conforms	
C.4		Exception	ASME XI ISI criteria for reactor vessel closure stud examinations are applied in lieu of the ASME III NB 2545 and NB 2546 surface examinations. The volumetric examinations currently required by ASME XI provide improved (since 1973) detection of bolting degradation.
Reg. Guide 1.66 – Withdrawn			
Reg. Guide 1.67 – Withdrawn			
Reg. Guide 1.68, Rev. 2, 8/78 and Rev. 3, 3/07 – Initial Test Program for Water-Cooled Nuclear Power Plants			
Conformance with Revision 2 of the Regulatory Guide is documented below in the DCD. Conformance of the design aspects is as stated below in the DCD.			
C.1	App. A.1.a	Conforms	Applies to AP1000 reactor coolant system components. (Pressurizer power-operated relief valves and reactor vessel internal vent valves are not design features of the AP1000. Jet pumps are applicable to boiling water reactors only.)
	App. A.1.b	Conforms	Applies to the AP1000 reactivity control system, except the systems for boiling water reactors such as rod worth minimizers. Standby liquid control system is not a design feature of the AP1000.
	App. A.1.c	Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
	App. A.1.d	Conforms	The functions of these systems are replaced by the passive residual heat removal heat exchanger of the passive core cooling system. Reactor core isolation cooling system is not a design feature of the AP1000.
	App. A.1.e	Conforms	
	App. A.1.f	Conforms	
	App. A.1.g	Conforms	
	App. A.1.h	Conforms	The characteristics of the AP1000 passive safety systems allow the support systems such as the cooling water systems, the heating, ventilating, and air conditioning and the ac power sources to be nonsafety-related and simplified. The capability of these systems is established by testing. Air flow resistance of the passive containment cooling system is verified by scale testing and analysis. Cold water interlocks are not a design feature of the AP1000.
	App. A.1.i	Conforms	The AP1000 has no secondary containment. Therefore, this guideline applies only to primary containment. The following systems or functions are not design features of the AP1000 and are therefore not tested: • Containment supplementary leak collection • Standby gas treatment • Secondary containment system • Containment annulus and cleanup • Bypass leakage tests on pressure suppression • Ice condenser systems • Containment penetration cooling
	App. A.1.j	Conforms	Recirculation flow control, traversing incore probes, automatic dispatching control systems and hotwell level control are not design features of the AP1000.
	App. A.1.k	Conforms	
	App. A.1.l	Conforms	Condenser off gas systems are not a design feature of the AP1000.
	App. A.1.m	Conforms	
	App. A.1.n	Conforms	Seal water, boron recovery, shield cooling, refueling water storage tank heating, and equipment for establishing and maintaining subatmospheric pressures are not design features of the AP1000.
	App. A.1.o	Conforms	
	App. A.2	Conforms	As applicable for pressurized water reactor.
	App. A.3	Conforms	As applicable for pressurized water reactor.
	App. A.4	Conforms	As applicable for pressurized water reactor.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			Compliance with A.4.t is met for the AP1000 with the provisions to perform the pre-operational tests of the passive RHR heat exchanger, as well as the tests described in DCD test abstracts 14.2.10.3.6, “Natural Circulation (First Plant Only)” and 14.2.10.4.29, “Passive Residual Heat Removal Heat Exchanger (First Plant Only).”
			Natural circulation testing of the reactor coolant system will be performed using the steam generators and the PRHR for the first plant only, in conformance with the AP1000 position on TMI item I.G.1 as outlined in Subsection 1.9.4.2.1.
	App. A.5	Conforms	
C.2 through C.9		N/A	Section 14.2 describes the AP1000 plant initial test program. Section 14.4 describes the responsibilities required to perform the AP1000 plant initial test program.
General	Appendix B	N/A	Section 14.2 describes the AP1000 plant initial test program. Section 14.4 describes the responsibilities required to perform the AP1000 plant initial test program.
General	Appendix C	N/A	Section 14.2 describes the AP1000 plant initial test program. Section 14.4 describes the responsibilities required to perform the AP1000 plant initial test program.
Conformance with Revision 3 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
C.2-C.9 Appendix B Appendix C		Conforms	
		Exception	Exception to the statement in C.9 regarding "...the startup report, as discussed in RG 1.16." This statement is interpreted to mean the report is submitted to NRC on the docket as discussed in (Withdrawn) RG 1.16. The startup report will be completed on the schedule and include the content information as described in RG 1.68 Item C.9 (a) - (e), however the report will be retained onsite rather than submitted to NRC on the docket as discussed in (Withdrawn) RG 1.16.
Reg. Guide 1.68.1, Rev. 1, 1/77 – Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants			
General		N/A	Applies to boiling water reactors only.
Reg. Guide 1.68.2, Rev. 1, 7/78 – Initial Test Program to Demonstrate Remote Shutdown Capability for Water Cooled Nuclear Power Plants			
General		Conforms	
Reg. Guide 1.68.3, (Task RS 709-4), 4/82 – Preoperational Testing of Instrument and Control Air Systems			
General	Regulatory Guide 1.68	Exception	
C.6		Exception	Regulatory Guide 1.68.3 endorses ANSI/ISA Standard S7.3-1975. The AP1000 references ANSI/ISA S7.3-1981.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.7		N/A	The instrument and control air systems (CAS instrument air and service air subsystems) does not include redundant components or air supplies to meet the single failure criterion for any safety functions except for the containment isolation function which is tested outside the scope of this regulatory guide.
C.8		Exception	Testing for complete loss of system pressure, both sudden and gradual, and to partial reductions in system pressure is only performed on safety related air operated valves. Testing is performed on a component level, not by branches.
C.9		N/A	Service air is specifically designed as a backup for Instrument Air. The compressors, dryers, filters, receivers and interconnecting piping are designed to meet the same air quality standards as the instrument air system.
C.11		N/A	There is no credible failure affecting the performance of safety-related valves to perform their safety-function due to over pressurization of the CAS air supply as by design, the air operated valves required to perform a safety-related function either • have a pressure regulator (to protect the end-user valve) designed to withstand an input pressure greater than the CAS safety valve set point or • when a pressure regulator is not used to regulate the CAS air pressure to the air operated valve, the air operated valve itself is designed to withstand an input pressure greater than the CAS safety valve set point.
C.1-C.5, C.10		Conforms	
Reg. Guide 1.69, Rev. 0, 12/73 – Concrete Radiation Shields for Nuclear Power Plants			
General	ANSI N101.6-1972	Exception	Regulatory Guide 1.69 endorses ANSI N101.6-1972 (Reference 18), which has been superseded by ANSI/ANS 6.4 1997 (Reference 19) and ACI 349-R01 (Reference 44). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.69.
Reg. Guide 1.70, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants (LWR Edition), Rev. 3, 11/78			
Conformance of the design aspects is as stated below in the DCD.			
General		Conforms	
Conformance with programmatic and/or operational aspects is documented below.			
General		Exception	The format and content of the FSAR follow Regulatory Guide 1.206 and AP 1000 Design Control Document as required by Appendix D of 10 CFR Part 52.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			Regulatory Guide 1.70 requires the security plan to be submitted as a separate document. The security plan will be submitted with the COL. The ESP application followed the guidance described in RS-002, Attachment 2, Note 2.
Reg. Guide 1.71, Rev. 0, 12/73 and Rev. 1, 3/07 – Welder Qualification for Areas of Limited Accessibility			
Conformance of the design aspects with Revision 0 of the Regulatory Guide is as stated below in the DCD.			
General		Exception	Current practice does not require qualification or requalification of welders for areas of limited accessibility as described by this regulatory guide. The performance of required nondestructive evaluations helps to confirm weld quality. Limited accessibility qualification or requalification in excess of ASME Code, Section III or IX requirements is considered an unduly restrictive requirement for component fabrication, where the welders' physical position relative to the welds is controlled and does not present significant problems. In addition, shop welds of limited accessibility are repetitive due to multiple production of similar components, and such welding is closely supervised. For field application, the type of qualification is considered on a case-by-case basis due to the great variety of circumstances encountered.
Conformance with Revision 1 of the Regulatory Guide during the operational phase (i.e., after the construction phase is completed per the DCD) is documented below.			
General		Exception	Current SNC practice does not require qualification or requalification of welders for areas of limited accessibility as described by this regulatory guide. The performance of required nondestructive evaluations helps to confirm weld quality. Limited accessibility qualification or requalification in excess of ASME Code, Section III or IX requirements is considered an unduly restrictive requirement for component fabrication, where the welders' physical position relative to the welds is controlled and does not present significant problems. In addition, shop welds of limited accessibility are repetitive due to multiple production of similar components, and such welding is closely supervised. For field application, the type of qualification is considered on a case-by-case basis due to the great variety of circumstances encountered.
Reg. Guide 1.72, Rev. 2, 11/78 – Spray Pond Piping Made From Fiberglass-Reinforced Thermosetting Resin			
General	ASME Code CCN-155-1 (1792-1)	N/A	The AP1000 does not have safety-related spray pond piping components. Therefore, this regulatory guide is not applicable to the AP1000.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.73, Rev. 0, 1/74 – Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants			
General	IEEE Std. 382-1972	Exception	Qualification of valve appurtenances, such as motor operators, solenoid valves, and limit switches, is in accordance with this regulatory guide. For safety-related motor-operated valves located inside containment, environmental qualification is performed in accordance with IEEE Standards 382-1996 (Reference 21) and 323-1974 (Reference 22).
C.1-6		Conforms	
Reg. Guide 1.74 – Withdrawn			
Reg. Guide 1.75, Rev. 2, 9/78 – Physical Independence of Electric Systems			
Conformance with Revision 2 of the Regulatory Guide is as stated below in the DCD. This guidance is completely within the scope of the DCD.			
General	IEEE Std. 384-1974	Exception	Regulatory Guide 1.75 endorses IEEE Std. 384-74 (Reference 23) which has been superseded by a later revision, IEEE Std. 384-81 (Reference 24). It is the later version that is used for the referenced purposes. This version has not yet been endorsed by a regulatory guide. The differences between the two revisions are not expected to contribute to conflicting design configurations because the jurisdiction of Regulatory Guide 1.75 with regard to the onsite ac power sources is limited. Specifically, since the AP1000 does not use safety-related ac power sources, the guidelines of Regulatory Guide 1.75 are applicable on a very limited basis to provide guidance on the Class 1E/non-Class 1E electrical separation and isolation for the following ac components that employ safety-related and nonsafety-related circuits: a) Class 1E dc battery chargers b) Reactor coolant pump switchgear c) Class 1E dc and UPS system regulating transformers. See Subsection 8.3.2.4.2 for exceptions related to spacial separation between separation groups. Two fuses in series may be used as an isolation device for Class 1E and non-Class 1E isolation. Fiber optic cable may be used as an isolation device for Class 1E to non-Class 1E isolation as well as Class 1E inter-divisional isolation. IEEE 384-2008 exempts fiber optic cables from the need to undergo qualification testing to demonstrate their isolation capability due to their inherent electrical isolation characteristics. This provision has been adopted for the AP1000. Fiber optic cables are not capable of generating a fire due to an internally generated fault. Therefore, separation is not required for fiber optic cables when the cable normally considered as a potential fire source is a fiber optic cable.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.76, Rev. 0, 4/74 and Rev. 1, 3/07 – Design Basis Tornado for Nuclear Power Plants			
Regulatory Guide 1.76, Rev. 1, 3/07 – Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants			
Conformance with Revision 0 of the Regulatory Guide is as stated below in the DCD. This guide is completely within the scope of the DCD.			
C.1		Exception	The design basis tornado for the AP1000 is defined by the following parameters: Maximum wind speed: 300 mph Maximum rotational speed: 240 mph Translational speed: 60 mph (maximum) 5 mph (minimum) Radius to maximum wind from center of tornado: 150 feet Atmospheric pressure drop: 2.0 psi Rate of pressure drop: 1.2 psi/sec. Chapter 2 provides design basis tornado interface parameters.
C.2		Conforms	
Reg. Guide 1.77, Rev. 0, 5/74 – Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors			
General		N/A	The interim acceptance criteria specified in Appendix B to NUREG-0800 Section 4.2, Revision 3, is followed for the analysis of the RCCA ejection accident instead of Regulatory Guide 1.77. The guidance of Regulatory Guide 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors" is also followed instead of Regulatory Guide 1.77.
Reg. Guide 1.78, Rev. 1, 12/01 – Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release			
Conformance with the design aspects is as stated below in the DCD.			
C.1		N/A	This criterion is site-specific. It is not applicable to AP1000 design certification. Subsection 2.2.1defines the responsibility for addressing site-specific information on identification of site-specific potential hazards.
C.2		N/A	This criterion is site-specific. Therefore, this is not applicable to AP1000 design certification. Subsection 2.1.1 defines the responsibility for addressing site-specific information on identification of site-specific potential hazards. Subsection 6.4.7 defines the responsibility for addressing site-specific information amount and location of possible sources of toxic chemicals in or near the plant relative to control room habitability.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.3.1		N/A	This criterion is site-specific. It is not applicable to AP1000 design certification. Subsection 2.2.1 defines the responsibility for addressing site-specific information on identification of site-specific potential hazards. Subsection 6.4.7 defines the responsibility for addressing site-specific information amount and location of possible sources of toxic chemicals in or near the plant relative to control room habitability.
C.3.2		Conforms	
C.3.3		Exception	For AP1000 design certification, the atmospheric dispersion factors are not calculated (since there are no specific site data), but are selected so as to bound the majority of existing sites. Section 2.3 provides additional information.
C.3.4		Conforms	
C.4.1		N/A	This criterion is site-specific. It is not applicable to AP1000 design certification. Subsection 2.2.1 defines the responsibility for addressing site-specific information on identification of site-specific potential hazards. Subsection 6.4.7 defines the responsibility for addressing site-specific information amount and location of possible sources of toxic chemicals in or near the plant relative to control room habitability.
C.4.2		Conforms	
C.4.3		Conforms	
C.5		N/A	Not applicable to AP1000 design certification. Subsection 2.1.1 defines the responsibility for addressing site-specific information on identification of site location and description, exclusion area authority and control, and population distribution. Subsection 2.2.1 defines the responsibility for addressing site-specific information on identification of site-specific potential hazards. Section 13.3 defines the responsibility for addressing emergency planning.
Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.79, Rev. 1, 9/75 – Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors			
General		Conforms	Preoperational testing is performed to test the functioning of the accumulators, core makeup tanks, passive residual heat removal heat exchanger, and automatic depressurization system, in a manner consistent with this regulatory guide. However, the AP1000 does not have high-head or low-head active safety-injection pumps. Therefore, many of the specific guidelines of this regulatory guide do not apply.
Reg. Guide 1.80 – Withdrawn			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.81, Rev. 1, 1/75 – Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plant			
General		N/A	The AP1000 is a single unit plant. When two or more AP1000s are located adjacent, electrical systems are not shared.
Reg. Guide 1.82, Rev. 3, 11/03 – Water Sources for Long Term Recirculation Cooling Following a Loss-of-Coolant Accident			
Conformance with the design aspects is as stated below in the DCD.			
General		Conforms	The AP1000 does not have high-head or low-head safety-injection pumps that need to take suction from the containment. The AP1000 does have a gravity-driven recirculation path that employs a containment recirculation arrangement. This containment recirculation can also be used to feed the normal residual heat removal pumps if they are available. The containment recirculation design conforms with the guidelines of this regulatory guide.
Conformance with programmatic and/or operational aspects is documented below.			
C.1.1.2		Conforms	
C.1.1.5		Conforms	
Reg. Guide 1.83, Rev. 1, 7/75 – Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes			
Conformance of the design aspects is as stated below in the DCD. The programmatic and/or operational aspects are not applicable since this guidance was withdrawn by NRC (74 FR 58324, 11/12/2009).			
General		Conforms	A program for in-service inspection of AP1000 steam generator tubing is established and performed in accordance with the guidelines of this regulatory guide. The baseline inspection will be performed in accordance with Regulatory Position C.3.a. Should the Combined License applicant request a baseline examination at the manufacturing facility, it will be performed in accordance with Regulatory Position C.3.a.
C.1		Conforms	
C.2		Exception	The specification of equipment in Regulatory Position C.2.c does not represent state-of-the-art equipment for gathering and storing eddy current information. When an eddy current inspection of an AP1000 steam generator is done in the manufacturing facility, more capable equipment than that specified in the regulatory guide is used. The steam generator design is compatible with robotic eddy current inspection equipment.
C.3		Exception	As noted in the comment on Criteria Section C.2, any eddy current inspection done in the manufacturing facility uses equipment of more current technology than that specified in Criteria Section C.2.
C.4-7		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.8		Exception	The only corrective action recognized by the regulatory guide is plugging of the tube to remove it from service. Sleeving of tubes is in many cases an acceptable repair method. The AP1000 steam generator design provides increased access to tubes to implement the sleeving repair method or other repair methods which may be developed.
Reg. Guide 1.84, Rev. 32, 6/03 and Rev. 33, 8/05 – Design and Fabrication Code Case Acceptability ASME Section III Division 1			
Regulatory Guide 1.84, Rev. 33, 8/05 – Design, Fabrication, and Materials Code Case Acceptability, ASME Section III			
Conformance with Revision 32 of the Regulatory Guide is as stated below in the DCD. This guidance is completely within the scope of the DCD.			
General		Conforms	The ASME Code Cases required for design certification are listed in Table 5.2-3. These cases are included in Regulatory Guide 1.84 or have been accepted by the US Nuclear Regulatory Commission staff as part of the review of AP1000.
C.1	ASME Code, Section III, Code Cases	Conforms	As applicable for pressurized water reactor.
C.2-5		Conforms	
Reg. Guide 1.85, Rev. 31, 5/99 – Materials Code Case Acceptability - ASME Code, Section III, Division 1			
General		Conforms	Refer to the discussion on Regulatory Guide 1.84. Subsequent to Revision 31 Reg. Guide 1.85 was combined with Reg. Guide 1.84. The guidance and conditions included in the previous revisions of Reg. Guide 1.85 remains valid.
C.1	ASME Code, Section III, Code Cases	Conforms	As applicable for pressurized water reactor.
C.2-5		Conforms	
Reg. Guide 1.86, Rev. 0, 6/74 – Termination of Operating Licenses for Nuclear Reactors			
General		N/A	Not applicable to AP1000 design certification. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Reg. Guide 1.87, Rev. 1, 6/75 – Guidance for Construction of Class 1 Components in Elevated Temperature Reactors			
General		N/A	The AP1000 is not an elevated temperature reactor. See Section 1.2 for a general description of the plant and plant parameters. This regulatory guide is not applicable to the AP1000.
Reg. Guide 1.88 – Withdrawn			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.89, (Task EE 042-2), Rev. 1, 6/84 – Environmental Qualification of Certain Electric Equipment Important to Safety For Nuclear Power Plants			
General	IEEE Std. 323-1974	Conforms	Conformance of AP1000 Class 1E equipment with 10 CFR 50.49, Reference 26 and this regulatory guide is demonstrated by an appropriate combination of the following: type testing, operating experience, qualification by analysis and ongoing qualification.
C.1	App. A	Conforms	As applicable for pressurized water reactor.
	App. B	Conforms	As applicable for pressurized water reactor.
	Regulatory Guide 1.97	Conforms	As applicable for pressurized water reactor.
C.2		Conforms	
C.2.a	App. C	Conforms	As applicable for pressurized water reactor.
C.2.b		Conforms	
C.2.c	App. D	Conforms	
C.2.c.1		Exception	Source term definition is discussed in the exceptions to Regulatory Guide 1.4, Positions C.1.a and C.1.b.
C.2.c.2		Exception	The fission product inventories in the fuel are discussed in the exception to Regulatory Guide 1.25, Position C.1.d.
C.2.c.3-8		Conforms	
C.2.d		Conforms	
C.3-6		Conforms	
C.7	App. E	Conforms	
Reg. Guide 1.90, Rev. 1, 8/77 – Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons			
General		N/A	The AP1000 does not have a concrete containment and does not use a prestressing tendon in the containment structures. Therefore, this regulatory guide is not applicable to the AP1000.
Reg. Guide 1.91, Rev. 1, 2/78 – Evaluation of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plant Sites			
Conformance of the design aspects is as stated below.			
General		Conforms	Offsite explosive materials are site-specific. See Subsection 2.2.1 for information for identification of site-specific potential hazards. See Subsection 2.2.3 for site-specific hazards evaluation.
General		Exception	Onsite explosive materials conform to the guidelines of Reg. Guide 1.91, Rev. 2. See Subsection 2.2.1 for information on potential hazards.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.92, Rev. 1, 2/76 and Rev. 2, 07/06 – Combining Modal Responses and Spatial Components in Seismic Response Analysis			
Conformance with Revision 1 of the Regulatory Guide is as stated below in the DCD. This guidance is completely within the scope of the DCD.			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
Reg. Guide 1.93, Rev. 0, 12/74 – Availability of Electric Power Sources			
C.1-2		N/A	The ac power sources are nonsafety-related. Therefore, these guidelines do not apply to the AP1000.
C.3		N/A	The function of the nonsafety-related diesel-generators for the AP1000 is to provide ac power for equipment and lighting during loss of offsite power but is not required for safe shutdown. Therefore, these guidelines do not apply to the AP1000.
C.4		N/A	See discussion on Criteria Section C.3.
C.5		Exception	AP1000 does not follow the guidance of C.5 for a 2-hour completion time for the limiting conditions of operation associated with the loss of one dc power subsystem. If one of the Class 1E dc electrical power subsystems is inoperable, the remaining Class 1E dc electrical power subsystems have the capacity to support a safe shutdown and to mitigate all design basis accidents, based on conservative analysis. Because of the passive system design and the use of fail-safe components, the remaining Class 1E dc electrical power subsystems have the capacity to support a safe shutdown and to mitigate most design basis accidents following a subsequent worst-case single failure. Also, with passive/fail-safe design, the risk associated with the loss of one Class 1E dc subsystem is similar to the loss of one ac supply for a conventional unit. AP1000 uses a 6-hour completion time for the limiting conditions of operation associated with the loss of one dc power subsystem to be consistent with the guidance in C.1 for a conventional plant with the loss of one ac source. The 6-hour completion time is reasonable based on engineering judgement balancing the risks of operation without one dc subsystem against the risks of a forced shutdown. Additionally, the completion time reflects a reasonable time to assess plant status; attempt to repair or replace, thus avoiding an unnecessary shutdown, and if necessary, prepare and effect an orderly and safe shutdown.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.94, Rev. 1, 4/76 – Quality Assurance Requirements for Installation, Inspection and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants			
Conformance for DCD scope of work is as stated below in the DCD.			
General	ANSI N45.2.5-1974	N/A	Not applicable to AP1000 design certification. Section 17.5 defines the responsibility for the quality assurance program.
Conformance for remaining scope is documented below.			
General		Exception	Quality assurance requirements utilize the more recently NRC endorsed NQA-1 in lieu of the identified outdated standards.
Reg. Guide 1.95 – Withdrawn			
Reg. Guide 1.96, Rev. 1, 6/76 – Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants			
General		N/A	Applies to boiling water reactors only.
Reg. Guide 1.97, Rev. 3, 5/83 and Rev. 4, 6/06 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident			
Regulatory Guide 1.97, Rev. 4, 6/06 – Criteria For Accident Monitoring Instrumentation For Nuclear Power Plants			
Conformance with Revision 3 of the Regulatory Guide is as stated below in the DCD.			
General	ANS-4.5-1980	Conforms	The variables to be monitored are selected according to usage and need in the plant Emergency Response Guidelines. They are assigned design and qualification Category 1, 2, or 3 and classified as Type A, B, C, D, or E. Due to AP1000 specific design features, the selection of some plant-specific variables and their classifications and categories are different from those of this regulatory guide. For example, the use of the passive residual heat removal system as the safety grade heat sink allows steam generator wide range level to be category 2, not category 1 as specified in Regulatory Guide 1.97. The AP1000 has no Type A variables. See Section 7.5 for additional information. Since Category 3 instrumentation is not part of a safety-related system, it is not qualified to provide information when exposed to a post-accident adverse environment. Category 3 instrumentation is subject to servicing, testing, and calibration programs that are specified to maintain their capability. However, these programs are not in accordance with Regulatory Guide 1.118, which applies to safety-related systems.
C.1-2		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Exception	Portable equipment outside the DCD scope conforms to Revision 3 of this Regulatory Guide for consistency with DCD scope since Revision 4 indicates that partial implementation is not advised.
Reg. Guide 1.98, Rev. 0, 3/76 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Radioactive Offgas System Failure in a Boiling Water Reactor			
General		N/A	Applies to boiling water reactors only.
Reg. Guide 1.99, (Task ME 305-4), Rev. 2, 5/88 – Radiation Embrittlement of Reactor Vessel Materials			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
Reg. Guide 1.100, (Task EE 108-5), Rev. 2, 6/88 – Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants			
General	IEEE Std. 344-1987	Conforms	
Reg. Guide 1.101, Rev. 3, 8/92 and Rev. 5, 6/05 – Emergency Planning and Preparedness for Nuclear Power Reactors			
Conformance of the design aspects of Rev. 3 is as stated below in the DCD.			
General	NUREG-0654, FEMA-REP-1 NUMARC/NESP-007	Conforms	Section 13.3 defines the responsibility for addressing emergency planning. RG 1.101 (Revision 2) references NUREG-0654/ FEMA-REP-1 and item II.H, "Emergency Facilities and Equipment" of NUREG-0654/FEMA-REP-1, is applicable to the technical support center (TSC), operations support center (OSC), and the emergency operations facility (EOF) in the AP1000 design. Subsection 18.2.6 defines the responsibility for designing the EOF in accordance with the AP1000 human factors engineering program, including specification of its location. The AP1000 design conforms with the design criteria of item II.H that pertain to the TSC and the OSC.
Conformance with Rev. 5 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.102, Rev. 1, 9/76 – Flood Protection for Nuclear Power Plants			
Conformance of the design aspects is as stated below in the DCD.			
C.1		Conforms	
C.2	Regulatory Guide 1.59, C.2	Conforms	
C.3		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.103 – Withdrawn			
Reg. Guide 1.104 – Withdrawn			
Reg. Guide 1.105, Rev. 3, 12/99 – Instrument Setpoints for Safety-Related Systems			
General	ISA-S67.04-1994	Conforms	The technical specifications setpoints provide the margin from the nominal setpoint to the safety-analysis limit to account for drift when measured at the rack during periodic testing. The allowances between the technical specification limit and the safety limit include the following items: a) the inaccuracy of the instrument; b) process measurement accuracy; c) uncertainties in the calibration; and d) environmental effects on equipment accuracy caused by postulated or limiting postulated events (only for those systems required to mitigate consequences of an accident). The setpoints are chosen such that the accuracy of the instrument is adequate to meet the assumptions of the safety analysis. The instrumentation range is based on the span necessary for the associated function. Narrow range instruments are used where necessary. Instruments are selected based on expected environmental and accident conditions. The need for qualification testing is evaluated and justified on a channel-by-channel basis. Administrative procedures coupled with the present cabinet alarms and/or locks provide sufficient control over the setpoint adjustment mechanism such that no integral setpoint securing device is required. Integral setpoint locking devices are not supplied. A plant-specific setpoint analysis must be performed to provide technical specification setpoints prior to plant startup. AP1000 conforms to the documentation requirements of the 1994 criteria.
Reg. Guide 1.106, Rev. 1, 3/77 – Thermal Overload Protection for Electric Motors on Motor-Operated Valves			
C.1	IEEE 279-1971, Sections 4.1, 4.2, 4.3, 4.4, 4.5, 4.10, and 4.13	Exception	Regulatory Guide 1.106 endorses IEEE Std. 279-1971 Reference 27, which has been replaced by IEEE STD 603-1991, (Reference 51). The AP1000 uses IEEE Std. 603-1991. This standard is endorsed by Regulatory Guide 1.153. The only safety-related electric motor-operated valves are dc.
C.2		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.107, Rev. 1, 2/77 – Qualifications for Cement Grouting for Prestressing Tendons in Containment Structures			
General		N/A	The AP1000 does not have a concrete containment and does not use a prestressing tendon in the containment structure. Therefore, these guidelines are not applicable to the AP1000.
Reg. Guide 1.108 – Withdrawn			
Reg. Guide 1.109, Rev. 1, 10/77 – Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I			
Conformance of the design aspects is as stated below in the DCD.			
General		Conforms	This is applicable to the evaluation of specific sites. AP1000 design certification application evaluates how the AP1000 design is expected to compare with existing plants. This comparison is made based on the calculation of anticipated annual releases for the AP1000.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.110, Rev. 0, 3/76 – Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors			
Conformance of the design aspects is as stated below in the DCD.			
General	10 CFR 50, App. I, Section II.D	Exception	The disposal of effluents for the AP1000 is within the limits of Appendix I of 10 CFR 50, and the radwaste treatment systems have sufficient capacity to control effluents. The AP1000 approach to the design of radwaste systems is the result of a nuclear industry-sponsored program to optimize the radwaste systems design. A site-specific cost-benefit analysis is not required for sites that meet the site interface criteria.
Conformance with Revision 0 this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.111, Rev. 1, 7/77 – Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors			
Conformance of the design aspects of the Regulatory Guide is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. This is applicable to the evaluation of specific sites. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to design certification.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.112, Rev. 0-R, 5/77 and Rev. 1, 3/07 – Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water-Cooled Power Reactors			
Conformance of the design aspects with Revision 0-R of the Regulatory Guide is as stated below in the DCD.			
C.1	10 CFR 20.1(c); 10 CFR 50.34a; 10 CFR 50.36a; 10 CFR 50, App. I	Exception	The reference to 10 CFR 20.1(c) is no longer valid in the current version of 10 CFR Part 20.
C.2	NUREG-0016; NUREG-0017	Exception	Revision 1 of NUREG-0017 is used. Plant-specific values for charcoal adsorption coefficients are used to calculate delay times in-place of the generic values given in NUREG-0017.
C.3		Conforms	
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General	ANSI 18.1-1999	Conforms	
Reg. Guide 1.113, Rev. 1, 4/77 – Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I			
Conformance of the design aspects of the Regulatory Guide is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. This is applicable to the evaluation of specific sites. Interface data are provided. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to design certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.114, Rev. 2, 5/89 – Guidance to Operators at the Controls and to Senior Operators in the Control Room of a Nuclear Power Unit			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Section 13.2 defines the responsibility for training and Section 13.5 defines the responsibility for procedures.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.115, Rev. 1, 1/77 – Protection Against Low-Trajectory Turbine Missiles			
Conformance of the design aspects is as stated below in the DCD.			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
General		Conforms	The SRP 3.5.1.3 issued in 1981 and Regulatory Guide 1.115, issued in 1977, provide criteria for protection against the effects of potential turbine missiles. Reference 28 issued in 1984 states that "the Nuclear Regulatory Commission staff has shifted emphasis in the reviews of the turbine missile issue from the strike and damage probability (P_2xP_3) to the missile generation probability (P_1) and, in the process, has attempted to integrate the various aspects of the issue into a single coherent evaluation." The AP1000 turbine is arranged in a radial orientation. The three low pressure turbines incorporate fully integral rotors. The turbine conforms with the criteria given in Reference 28 and WCAP-16650 (Reference 52).
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.116, Rev. O-R, 5/77 – Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems			
Conformance for DCD scope of work is as stated below in the DCD.			
General	ANSI N45.2.8-1975	N/A	Not applicable to AP1000 design certification. Section 17.5 defines the responsibility for the Quality Assurance program.
Conformance for remaining scope is documented below.			
General		Exception	Quality assurance requirements utilize the more recently NRC endorsed NQA-1 in lieu of the identified outdated standards.
Reg. Guide 1.117, Rev. 1, 4/78 – Tornado Design Classification			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
APPENDIX			
General		Conforms	For the AP1000, the leaktight integrity of the primary containment is maintained.
Reg. Guide 1.118, Rev. 3, 4/95 – Periodic Testing of Electric Power and Protection Systems			
General	IEEE Std. 338-1987	Conforms	Guidelines apply to safety-related dc power systems. Since the AP1000 has no safety-related ac power sources, the guidelines do not apply to the AP1000 ac power sources. The types of tests described in IEEE 338 Section 6.3 are not all applicable to the protection and safety monitoring system. In certain instances, the self-diagnostics included within the protection and safety monitoring system are used to verify that the safety system is capable of meeting its designed safety function in lieu of manual testing as part of the surveillance program.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			Specifically, logic system function tests, response time tests, and in certain instances, channel checks are not manually performed on the protection and safety monitoring system equipment as part of the AP1000 surveillance program. In these cases, self-diagnostic test features continuously monitor the system. Functional tests are only performed on the PMS equipment that do not have complete self-diagnostic coverage. The Technical Specifications provide the necessary manual functional testing requirements in these instances (e.g., ALT, TADOT, channel checks). Channel calibration verification tests are included in the AP1000 surveillance program.
Reg. Guide 1.119 – Withdrawn			
Reg. Guide 1.120, Rev. 1, 11/77 – Fire Protection Guidelines for Nuclear Power Plants			
General		Exception	The AP1000 design conforms with the Branch Technical Position CMEB 9.5-1 (Reference 32), which is attached to Section 9.5.1 of the Standard Review Plan, NUREG-0800 (Reference 33), as described in Section 9.5.1. Therefore, these guidelines are not applicable to the AP1000.
Reg. Guide 1.121, Rev. 0, 8/76 – Bases for Plugging Degraded Pressurizer Water Reactor Steam Generator Tubes			
General		Conforms	The only corrective action recognized by this regulatory guide is plugging of the tube to remove it from service. Sleeving of tubes is in many cases an acceptable repair method. The AP1000 steam generator design provides increased access to tubes to implement the sleeving repair method or other repair methods which may be developed.
C.1		Exception	Westinghouse interprets the term "unacceptable defects" to apply to those imperfections resulting from service induced mechanical or corrosion degradation of the tube walls which have penetrated to a depth or a length or a combination of both in excess of the plugging limit.
C.2.a.(1)		Exception	Westinghouse interprets this criterion to exclude the local region of the crack tip for Inconel tubing.
C.2.a.(2)		Exception	Tube minimum wall requirements are calculated in accordance with the following criteria. For normal plant operation, allowable membrane stress, Pm, is limited to a margin of three against exceeding the ultimate tensile strength of the material. As this regulatory guide constitutes an operating criterion, the allowable stress limits are based on expected lower bound material properties rather than ASME Code minimum values. Expected strength properties are obtained from statistical analysis of tensile test data of actual production tubing.
C.2.a(3)		Conforms	
C.2.a(4)		Exception	Refer to the discussion on Criteria Section C.2.a(2).

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.2.a.(5)-(6)		Conforms	
C.2..b.		Exception	In cases where sufficient inspection data exist to establish degradation allowance, the rate used is an average time-rate determined from the mean of the test data. Where requirements for minimum wall are markedly different for various areas of the tube bundle, such as the U-bend area versus straight length in Westinghouse designs, separate plugging limits are established to address the varying requirements in a manner which does not require unnecessary plugging of tubes.
C.3.a - c		Conforms	
C.3.d.(1)-(3)		Conforms	
C.3.e.(1)-(5)		Conforms	
C.3.e.(6)		Exception	Computer code names and references are supplied rather than actual codes.
C.3.e.(7)-(10)		Conforms	
C.3.f.(1)-(3)		Conforms	
Reg. Guide 1.122, Rev. 1, 2/78 – Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components			
C.1-3		Conforms	
Reg. Guide 1.123 – Withdrawn			
Reg. Guide 1.124, Rev. 1, 1/78 and Rev. 2, 02/07 – Service Limits and Loading Combinations for Class 1 Linear-Type Component Supports			
Regulatory Guide 1.124, Rev. 2, 02/07 – Service Limits and Loading Combinations for Class 1 Linear-Type Supports			
Conformance with Revision 1 of the Regulatory Guide is as stated below in the DCD.			
General	ASME Code, Section III Subsection NF	Conforms	Many of the items addressed in this regulatory guide have since been incorporated into later ASME Code, Section III Editions and Addenda. The design conforms to this regulatory guide with the following interpretations to maintain consistency with the ASME Code: 1. References to ASME Code, Section III, Subsection NF and Appendix XVII paragraphs are interpreted to be references to the corresponding paragraph in Subsection NF of the ASME Code. 2. References to ASME Code Case 1644 are interpreted to be references to the accepted versions of ASME Code Cases N-249 and N-71.
C.1		Conforms	
C.2	Code Case 1644	Conforms	Values of Su at these elevated temperatures are determined by test rather than via the method 2 as given by this regulatory position.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.3	ASME Code, Section III, Appendix XVII	Conforms	
C.4	ASME Code, Section III, Appendix XVII-2110(b)	Exception	Paragraph B.1(b) of this regulatory guide states that "Allowable service limits for bolted connections are derived from tensile and shear stress limits and their nonlinear interaction. They also change with the size of the bolt. For this reason, the increases permitted by ASME Code, Section III, Subsections NF-3231.1, XVII-2110(a), and F-1370(a) are not directly applicable to allowable shear stresses and allowable stresses for bolts and bolted connections." This regulatory position also states that "This increase of level A or B service limits does not apply to limits for bolted connections and shear stresses." As stated above, the increase in bolt allowable stress under emergency and faulted conditions is not permitted because the interaction between the allowable tension and shear stress in bolts is nonlinear, and the allowable tension and shear stress vary with the bolt size. The ASME Code, NF-3225, allows small increases in allowable stresses for Level B, Level C (previously termed "emergency"), Level D (previously termed "faulted"), and test conditions. The ASME Code rules are adequate since they satisfy the two objectives raised in the above quoted paragraph and will be used without further restrictions or justifications. This position is based on the following. 1. The interaction curve between the shear and tension stress in bolts is more closely represented by an ellipse and not a line. 2. The ASME Code specifies stress limits for bolts and represents this tension/shear relationship as a non-linear interaction equation (ellipse). This interaction equation has a built-in safety factor that ranges between two and three (depending on whether the bolt load is predominately tension or shear) based on the actual strength of the bolt as determined by test. See Reference 34.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			3. This regulatory position states that "Any increases of limits for shear stresses above 1.5 times the ASME Code, Level A service limits should be justified." Concerning allowable shear stresses, the AP1000 uses the ASME Code, Subsection NF requirements. The ASME Code shear stress limits (NF-3300 and Tables NF-3523.2 and NF-3623.2-1) generally meet the guidance provided by this regulatory position that shear stresses be maintained within 1.5 times Level A service limits. This limit may be exceeded slightly in some limited cases such as Level D limits for SA-36 material, in which case the NF shear stress limit of .42 Su is 13 percent greater than this regulatory guide limit of 1.5 x .4 Fy. Su and Fy are the material tensile and yield strengths, respectively.
C.5.a	ASME Code, Section III,	Exception	The AP1000 evaluates supports to current Level B stress limits for the upset load combination. Effects of constraint of free-end displacements are included in the upset loading condition while no further increase in allowable stresses over and above the Level B limits is permitted. The operating basis earthquake has been eliminated from the AP1000 design basis.
C.5.b-c	ASME Code, Section III, Subsection NF-3262.3, Appendix XVII-4200, Appendix XVII-4110(a)	Conforms	The operating basis earthquake has been eliminated from the AP1000 design basis.
C.6	ASME Code, Section III, Appendix XVII-2000, 2110(a) Subsection NF 2362.3, Appendix XVII-4200, 4110(a), II-1400	Conforms	
C.7.a	ASME Code, Section III, Appendix XVII-2000, and F-1370(a)	Conforms	
C.7.b		Exception	The AP1000 uses the provisions of the ASME Code, Section III, Appendix F to determine faulted condition allowable loads for supports designed by the load rating method. The method described in this regulatory position is conservative and inconsistent with the remainder of the faulted stress limits.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.7.c	ASME Code, Section III Appendix XVII-4200, and F-1370(b)	Conforms	
C.7.d	ASME Code, Section III, II-1400, and F-1370(b)	Conforms	
C.8		Exception	The reduction of allowable stresses to no greater than Level B limits for support structures in those systems with normal safety-related functions occurring during emergency or faulted plant conditions is overly conservative for components which are not required to mechanically function (inactive components). For service Level C and D loading conditions, Level C limits are used for the support of active components.

Conformance with Revision 2 for programmatic and/or operational aspects of the Regulatory Guide is as stated below. This guidance is completely within the scope of the DCD.

Reg. Guide 1.125, Rev. 1, 10/78 – Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants

Conformance of the design aspects of the Regulatory Guide is as stated below in the DCD.

General	Conforms	
C.1-6	Conforms	

Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

General	Conforms	

Reg. Guide 1.126, Rev. 1, 3/78 – An Acceptable Model and Related Statistical Methods for the Analysis of Fuel Densification

C.1-2	Exception	Westinghouse uses the densification model described in the Nuclear Regulatory Commission-approved topical reports WCAP-10851-A and WCAP-13589-A. Westinghouse conforms to the methodology of this regulatory guide when implementation of the methodology is required.
C.3-4	Conforms	
C.5	Conforms	

Reg. Guide 1.127, Rev. 1, 3/78 – Inspection of Water-Control Structures Associated With Nuclear Power Plants

General	N/A	The AP1000 does not have water-control structures. Therefore, this guideline is not applicable to the AP1000. Subsection 2.5.6 defines the responsibility for embankments and dams.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.128, Rev. 1, 10/78 and Rev. 2, 2/07– Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants			
Regulatory Guide 1.128, Rev. 2, 2/07 – Installation Design and Installation of Vented Lead-Acid Storage Batteries for Nuclear Power Plants			
Conformance with Revision 1 of the Regulatory Guide is as stated below in the DCD.			
General	IEEE Std. 484-1975	Exception	Regulatory Guide 1.128 endorses IEEE Std. 484-75 (Reference 36) which has been superseded by IEEE Std. 484-1996 (Reference 37). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.128.
Regulatory Guide 1.129, Rev. 2, 2/07 – Maintenance, Testing, and Replacement of Vented Lead-Acid Storage Batteries for Nuclear Power Plants			
General	IEEE Std. 450-2002	Exception	Battery maintenance, testing, and replacement is in accordance with approved Technical Specifications which are based on IEEE Std. 450-1995.
Reg. Guide 1.130, Rev. 1, 10/78 – Service Limits and Loading Combinations for Class 1 Plate-And-Shell-Type Component Supports			
Regulatory Guide 1.130, Rev. 2, 3/07 - Service Limits and Loading Combinations for Class 1 Plate-And-Shell-Type Supports			
Conformance with Revision 1 of the Regulatory Guide is as stated below in the DCD.This guidance is completely within the scope of the DCD.			
General	ASME Code, Section III Subsection NF	Exception	Many of the items addressed in this regulatory guide have since been incorporated into later ASME Code, Section III, Editions and Addenda. The plant design conforms to this regulatory guide with the following interpretations to maintain consistency with the ASME Code: 1. Regulatory guide references to ASME Code, Section III, Subsection NF and Appendix XVII paragraphs are interpreted to be references to the corresponding paragraph in the ASME Code, Subsection NF. 2. Regulatory guide references to ASME Code Case 1644 are interpreted to be references to the latest acceptable versions of the ASME Code Case N-249 and N-71. Paragraph B.1 of this regulatory guide states that "Allowable stress limits for bolted connections are derived on a different basis that varies with the size of the bolt. For this reason, the increases permitted by NF-3222.3 and F-1323.1(a) of ASME Code, Section III are not directly applicable to bolts and bolted connections." The ASME Code rules are adequate for bolt design without further restriction or justification.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			The maximum stress increase factor allowed is 25 percent for the Service Level D condition, and the stress allowables do not vary with bolt size. The AP1000 takes exception to the guideline stated in Paragraph B.5 of this regulatory guide, that systems whose safety-related function occurs during emergency or faulted plant conditions should meet Level A limits. The reduction of allowable stresses to no greater than Level A limits for support structures in those systems with normal safety-related functions occurring during emergency or faulted plant conditions is overly conservative for components which are not required to mechanically function (inactive components). For service, Level C and D loading conditions, Level C limits are used for the support of active components.
C.1		Conforms	
C.2	Code Case 1644	Conforms	
C.3		Exception	Design margins of two for flat plates and three for shells are unnecessarily restrictive for normal, upset, and emergency conditions, as well as inconsistent with ASME Code requirements. For these loading conditions, the AP1000 limits the allowable buckling strength to 1/2 of the critical buckling strength.
C.4	ASME Code, Section III, NF-3221.1, NF-3221.2, NF-3222, NF-3262.2, II-1400	Exception	This regulatory position recommends that design stress limits be used in conjunction with a loading combination that includes operating basis earthquake. The ASME Code rules (in which Level B stress limits are typically used for the upset load combination) provide a conservative design basis. The AP1000 uses the latest rules (as of 4/2001) without further restriction or justification. The operating basis earthquake has been eliminated from the AP1000 design basis. Refer also to the discussion on Criteria Section C.3.
C.5.a	ASME Code, Section III, NF-3224	Exception	Refer to the discussion on Criteria Section C.3.
C.5.b-c	ASME Code, Section III, NF-3262.2, II-1400	Conforms	
C.6.a	ASME Code, Section III, F-1323.1(a), F-1370(c)	Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.6.b	ASME Code, Section III, NF-3262.1	Exception	The limit based on the test load given in this regulatory position is overly conservative and is inconsistent with ASME Code requirements. The AP1000 uses the provisions of the ASME Code, Section III, Appendix F to determine faulted condition allowable loads for supports designed by the load rating method.
C.6.c		Conforms	
C.6.d	ASME Code Section III, F-1324, F-1370(c)	Conforms	
C.7		Conforms	
Reg. Guide 1.131, Rev. 0, 8/77 – Qualification Tests of Electric Cables, Field Splices and Connections for Light-Water-Cooled Nuclear Power Plants			
General	IEEE Std. 383-1974	Exception	The insulating and jacketing material for electrical cables are selected to meet the fire and flame test requirements of IEEE Standard 1202, IEEE Standard 383, or the standards for the corresponding test types as listed in Tables K-1 and K-2 in NEI 04-02, Rev 3 excluding the option to use the alternate flame source, oil or burlap.
C.1-14		Conforms	
Reg. Guide 1.132, Rev. 1, 3/79 and Rev. 2, 10/03 – Site Investigations for Foundations of Nuclear Power Plants			
Conformance of the design aspects for Revision 1 of this Regulatory Guide is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Section 2.5 defines the responsibility for site investigations and the site specific information related to basic geological, seismological, and geotechnical engineering of the site.
Conformance with Revision 2 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.133, Rev. 1, 5/81 – Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors			
Conformance of the design aspects is as stated below in the DCD.			
General		Conforms	A digital metal impact monitoring system (DMIMS) monitors the reactor coolant system for the presence of loose metallic parts. The system actuates audible and visual alarms if a signal exceeds the preset alarm level. The digital metal impact monitoring system is not a Class 1E system. It serves as a diagnostic aid to detect loose parts in the reactor coolant system before damage occurs. Database calibration is made prior to plant startup and the capability for periodic online channel checks and channel functional tests are incorporated in the digital metal impact monitoring system design.
C.1.a-i		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.2		Conforms	
C.3.a		N/A	Not applicable to AP1000 design certification. Section 13.5 defines the responsibility for development of procedures.
C.3.b		Conforms	
C.4		Conforms	
C.5		Exception	Not applicable to AP1000 design certification. A loose parts detection system is excluded from technical specification requirements per the NRC screening selection criteria in 10 CFR 50.36(c)(2)(ii).
C.6		N/A	Not applicable to AP1000 design certification. Section 13.5 defines the responsibility for development of procedures.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
C.2b		Conforms	Procedures are addressed in Section 13.5
C.3a		Conforms	Procedures are addressed in Section 13.5
C.4g		Conforms	Procedures are addressed in Section 13.5
C.4h		Conforms	Procedures are addressed in Section 13.5
C.4i		Conforms	ALARA is addressed in Chapter 12 and Section 13.5
C.4j		Conforms	Training is addressed in Section 13.2
C.6		Exception	Regulatory Guide 1.16 has been withdrawn. Event reporting is performed in accordance with 10 CFR 50.72 and 50.73 utilizing the guidance of NUREG-1022
Reg. Guide 1.134, Rev. 3, 3/98 – Medical Evaluation of Nuclear Power Plant Personnel Requiring Operator Licenses			
Regulatory Guide 1.134, Rev. 3, 3/98 – Medical Evaluation of Licensed Personnel at Nuclear Power Plants			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 plant design certification. Section 13.5 defines the responsibility for administrative procedures.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.135, Rev. 0, 9/77 – Normal Water Level and Discharge at Nuclear Power Plants			
Conformance of the design aspects is as stated below in the DCD. The programmatic and/or operational aspects are not applicable since this guidance was withdrawn by NRC (74 FR 39349, 08/06/2009).			
General		Conforms	The normal ground and surface water levels and surface water discharges for the AP1000 are determined using the postulated site parameters. Chapter 2 provides additional information.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.136, Rev. 2, 6/81 – Materials, Construction, and Testing of Concrete Containments			
General		N/A	The AP1000 does not have a concrete containment. Therefore, this guideline is not applicable to the AP1000.
Reg. Guide 1.137, Rev. 1, 10/79 – Fuel-Oil Systems for Standby Diesel Generators			
General		N/A	The AP1000 diesel-generators and the associated fuel-oil systems are nonsafety-related. Therefore, this guideline is not applicable to the AP1000.
Reg. Guide 1.138, Rev. 0, 4/78 and Rev. 2, 12/03 – Laboratory Investigations of Soils for Engineering Analysis and Design of Nuclear Power Plants			
Conformance of the design aspects of the Regulatory Guide is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 2.5.4.6.2 defines the responsibility to establish the properties of the foundation soils including laboratory investigations of underlying materials.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.139, Rev. 0, 5/78 – Guidance for Residual Heat Removal			
Conformance with the design aspects is as stated below in the DCD. The programmatic and/or operational aspects are not applicable since this guidance was withdrawn by NRC (73 FR 32750, 06/10/2008).			
C.1.a		Exception	The AP1000 employs a full pressure/temperature passive residual heat removal heat exchanger that is automatically actuated. The heat exchanger does not rely on ac or dc power. Fail-safe valves are used to manually isolate the heat exchanger. When these valves are open, the reactor coolant pumps (if available) or natural circulation produces flow through the heat exchangers. The heat exchanger is safety-related, seismically designed, and can tolerate single active failure. Continued operation of the heat exchanger brings the reactor coolant system pressure and temperature down to the point where the stress in the reactor coolant system pressure boundary is low. This temperature is about 400°F which allows an reactor coolant system pressure of 1/10 of design (250 psia).
C.1.b		Conforms	
C.1.c		Exception	See the comment on Criteria Section C.1.a. The passive residual heat removal heat exchanger does not rely on pumps, ac power sources, air systems, or water cooling systems.
C.2		Conforms	
C.3		Conforms	
C.4		N/A	The passive residual heat removal heat exchanger does not have pumps. Therefore, this guideline is not applicable to the AP1000.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.5	IEEE Std. 338; Regulatory Guide 1.22; Regulatory Guide 1.68	Conforms	IEEE Std. 338-1987 (Reference 31) is current standard.
C.6		N/A	The passive residual heat removal heat exchanger provides this function. As a result, the auxiliary feedwater system has been replaced by a nonsafety-related startup feedwater system. Therefore, this guideline is not applicable to the AP1000.
C.7	Regulatory Guide 1.33	N/A	Not applicable to AP1000 design certification. Section 17.5 defines the responsibility for the quality assurance program.
Reg. Guide 1.140, Rev. 2, 06/01 – Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmosphere Cleanup System in Light-Water-Cooled Nuclear Power Plants			
C.1		Conforms	Regulatory Guide 1.140 endorses ASME Standard N509-1989 (Reference 39), ASME Standard N510-1989 (Reference 40), and ASME AG-1-1997 (Reference 38). The AP1000 uses the latest version of the industry standards (as of 3/2002).
C.2.1-2.4		Conforms	
C.3.1-3.2		Conforms	
C.3.3	ERDA 76-21, Section 5.6; ASME N509-1989 Section 4.9	Conforms	
C.3.4	Regulatory Guide 8.8	Conforms	
C.3.5		Conforms	
C.3.6	ASME AG-1-1997Article SA-4500	Exception	Exhaust ductwork upstream of the containment air filtration system exhaust filters that has a negative operating pressure is designed to meet at least SMACNA design standards.
	ASME AG-1-1997,Section TA	Conforms	
C.4.1	ASME AG-1-1997,Section FB	Exception	ASME AG-1, 1997 Section FB requires filters be certified to UL 900, Class 1, 5th Edition 1987. As of May 2012 UL no longer classifies UL 900 filters with a Class 1 or Class 2 rating. The Class 1 requirements per UL 900, “Air Filter Units” 8th Edition, are obsolete and deleted, as UL 900 no longer distinguishes between Class 1 and Class 2 filters.
C.4.2	ASME AG-1-1997, Section CA	Exception	ASME AG-1, 1997 Section CA require heaters be listed to UL 1996, 2nd Edition. Manufacturers only list components per the latest Edition of the UL Standard. Previous UL Standard Editions/Revisions cannot be invoked.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.4.3	ASME AG-1-1997, Section FC, and Section TA	Exception	ASME AG-1, 1997 Section FC require HEPA Filters be listed to UL 586, 7th Edition. Manufacturers only list components per the latest Edition of the UL Standard. Previous UL Standard Editions/Revisions cannot be invoked.
C.4.4	ASME AG-1-1997, Section FG	Conforms	
C.4.5	ERDA 76-21, Section 4.4; ASME AG-1a-2000, Section HA	Conforms	
C.4.6	ASME N509-1989, Section 5.6; ASME AG-1a-2000, Section HA	Conforms	
C.4.7	ASME AG-1-1997, Section CA	Conforms	
C.4.8	ASME AG-1-1997, Section FD or FE	Conforms	
C.4.9	ASME AG-1-1997, Section FD and FE or, Section FF	Conforms	
C.4.10	ASME AG-1-1997 Section SA	Exception	Exhaust ductwork upstream of the containment air filtration system exhaust filters that has a negative operating pressure is designed to meet at least SMACNA design standards.
C.4.11		Conforms	
C.4.12	ASME AG-1-1997 Section DA	Conforms	
C.4.13	ASME AG-1-1997, Section BA and SA	Conforms	
C.5.1	ERDA 76-21, Section 2.3.8; ASME AG-1a-2000, Section HA	Conforms	
C.5.2		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.6	ASME N510-1989	Conforms	ASME N510-1989 Section 13.1 states that the system bypass test requirements can be considered satisfied if it can be shown that all potential external bypass pathways (bypass dampers, ducts, conduits, floor drains, pipe penetrations, etc.) are challenged by the HEPA and adsorber filter in-place bank tests. Both the VBS and VFS filtration units employ a blow through design which pressurizes the entire filtration units limiting potential bypass pathways internal to the filtration units which are assessed by the HEPA and adsorber filter in-place bank tests.
C.6	ASME AG-1-1997 ASME N510-1989	Exception	The structural capability and leak tightness of outside air intake isolation dampers VBS-MD-D201 and VBS-MD-D202 is affirmed by satisfactory performance of seat leakage testing performed by the damper manufacturer, per Paragraph DA-5740 of ASME AG-1-1997, supplemented by inleakage testing of the main control room pressure boundary during system startup testing, per ASTM E741.
C.7	ANSI N509-1989	Conforms	
Reg. Guide 1.141, Rev. 0, 4/78 – Containment Isolation Provisions for Fluid Systems			
General	ANSI N271-1976	Exception	Regulatory Guide 1.141 endorses ANSI N271-1976 (Reference 41) that has been superseded by ANS 56.2-1984 (Reference 42). The AP1000 uses the latest version of industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviations from the design philosophy otherwise stated in Regulatory Guide 1.141. Containment isolation for AP1000 fluid systems conforms to Reference 42 with the following exceptions and/or clarifications. ANS 56.2-1984, Section 3.6.3 states that "remote manual closure of isolation valves on engineered safeguards features or engineered safeguards features-related systems is acceptable when provisions are made to detect possible failure of the fluid lines inside and outside containment." The AP1000 engineered safeguards features are designed to avoid the need for transport of post-accident fluids outside of containment and thus avoid the concern associated with remote manual isolation of engineered safety feature lines. Non-engineered safety feature lines capable of providing engineered safety feature functions are provided with the capability for remote manual isolation. The nonsafety-related normal residual heat removal system has provisions to isolate on High-2 containment radiation. Radiation monitors are provided inside containment to assess continuation of the functions.
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.4	ANSI N271-1976, Section 4.4.8, Section 3.5 or 3.6.7	Conforms	
C.5	Regulatory Guide 1.7 & 1.89	Conforms	
C.6	ANSI N271-1976, Section 3.5 or 3.7	Conforms	
Reg. Guide 1.142, Rev. 2, 11/01 – Safety-Related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments)			
General	ACI 349-97	Exception	Regulatory Guide 1.142 endorses ACI 349-97 (Reference 43) that has been superseded by ACI 349-01 (Reference 44). The AP1000 uses the latest version of industry standards (as of October 2001). This version is not endorsed by a regulatory guide but its use should not result in deviations from the design philosophy otherwise stated in Regulatory Guide 1.142. In the following evaluation of conformance, the design is shown as conforming since the requirements of ACI 349-01 are similar to those of ACI 349-97.
		Clarification	ACI 349-01 (Reference 44) Section 1.2.1 requires that "Copies of structural drawings, typical details, and specifications for all reinforced concrete construction shall be signed by a licensed engineer." The signature of the licensed engineer shall be confirmable by documentation to be that of a licensed professional engineer.
C.1		N/A	The compartments within the containment are not designed to be leaktight since they must communicate with one another to preclude subcompartment pressurization. Therefore, this guideline is not applicable to the AP1000.
C.2	ANS 6.4-1997	Conforms	
C.3	ANSI/ACI 349-97	Conforms	
C.4		Conforms	
C.5		Conforms	
C.6	ACI 349-97, Section 9.2.1	Conforms	
C.7		Conforms	
C.8		Conforms	
C.9		N/A	The AP1000 does not include a pressure-suppression containment. Therefore, this guideline is not applicable to the AP1000.
C.10	ACI 349-97, App. C	Conforms	
C.11		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.12	ACI 349-97, App. A	Conforms	
C.13		Conforms	
C.14		N/A	The AP1000 containment vessel is steel.
C.15		Conforms	The provisions in Section 11.6 of ACI 349-01 are the same as those in ACI 318-99 (Reference 46).
Reg. Guide 1.143, Rev. 2, 11/01 - Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light Water Cooled Nuclear Power Plants			
Conformance of the design aspects is as stated below in the DCD.			
General			The AP1000 Radwaste Building provides space to store dry active waste and space for mobile waste processing systems and equipment and three liquid waste monitor tanks which contain liquid effluents which have been processed and are acceptable for release to the environment (within the requirements of classification RW-IIC of Regulatory Guide 1.143). It does not contain installed systems and components used to process, store, or handle gaseous or liquid waste.
C.1.1.1	Regulatory Guide 1.143, Table 1	Exception	Components in the liquid radwaste systems are designed and tested to the requirements set forth in the codes and standards listed in Table 1 of Regulatory Guide 1.143 with the exception of the use of the 2013 Edition of ASME, Section VIII, Div. 1, instead of the 1998 Edition (with 1999 Addenda) that is referenced in Appendix A of Regulatory Guide 1.143. This version is not endorsed by a regulatory guide, but its use should not result in deviations from the design philosophy otherwise stated in Regulatory Guide 1.143. Equipment classifications and design codes are listed in Table 3.2-3. Pressure vessels are designed and built according to ASME, Section VIII, Div. 1. Atmospheric tanks are per API 650 or ASME, Section III and heat exchangers to ASME Section VIII, Div. 1 and TEMA (for shell and tube). Piping and valves are per ASME B31.1 except the containment penetrations and isolation valves are per ASME, Section III, Class 2. Pumps are according to manufacturer's standards. Steam generator blowdown system (BDS) electrodeionization (EDI) modules within the EDI packages are designed and constructed in accordance with the manufacturer's standards and may be fabricated from non-metallic materials that differ from those identified in Table 1. Flexible hose is used in the BDS—flexible metal hoses connect the EDI reject radiation monitor package to external piping and flexible plastic hoses within the EDI packages connect EDI modules to adjacent piping.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.1.1.2	ASME Code, Section II	Conforms	Materials, except elastomers for gaskets, seals, seats, diaphragms, and packing, are provided in accordance with the ASME Code, Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ASME B31.1. Pump materials are provided according to manufacturer's standards.
C.1.1.3		Conforms	The auxiliary building that contains the liquid radwaste system with the exception of three monitor tanks is designed to seismic Category I criteria. The seismic Category I structure will retain the maximum liquid inventory of the system. The lowest level of the auxiliary building, elevation 66'-6", contains the liquid radwaste system effluent holdup tanks, a monitor tank, and chemical waste tank within a common flood zone. This flood zone has watertight floors and walls. The enclosed volume within this flood zone is sufficient to contain the contents of the system. The effluent holdup tank rooms, the monitor tank room, and chemical waste tank room each have one or two floor drains that lead to the sump. Tank overflows or spills will be collected in the auxiliary building sump. The sump is automatically pumped to a waste holdup tank. The waste holdup tank rooms each have two normally isolated floor drains that are connected to a sump pump. The waste holdup tank overflows or spills will be manually pumped to a waste holdup tank. Two liquid radwaste system monitor tanks are above at elevations 92′-6" and 107′-2". Overflows or spills from these monitor tanks drain by gravity down through the drain system to a waste holdup tank. The seismic Category I criteria exceed the operating basis earthquake required by regulatory position C.6 of Regulatory Guide 1.143. The radwaste building that contains three liquid radwaste monitor tanks is designed to the Uniform Building Code. The basemat and curbed structure will retain the maximum liquid inventory of any of the three monitor tanks. Tank overflows or spills will be collected by the radioactive waste drain system and routed to the auxiliary building sump. The sump is automatically pumped to a waste holdup tank. The Uniform Building Code design of the radwaste building meets the requirements of regulatory position C.6 of Regulatory Guide 1.143 for structures classified as RW-IIC.
		Exception	The turbine building first bay, which houses the BDS, is seismic Category II. The BDS components are not designed for protection against natural phenomena or internal/ external hazards.
C.1.2.1		Conforms	Atmospheric tanks in the liquid radwaste system have level sensors, transmitters, and alarms. Local alarm is not provided because the tanks are located in shielded areas that are not normally occupied by people.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.1.2.2		Conforms	Tank overflows, drains and sample lines that may contain radioactive water are routed to the liquid radwaste system for processing.
C.1.2.3		Conforms	Please refer to the discussion of conformance to C.1.1.3, which addresses the provisions in the buildings that contain radioactive waste to contain any spills.
C.1.2.4		Conforms	Please refer to the discussion of conformance to C.1.1.3, which addresses the provisions in the building that contain radioactive waste to contain any spills. The design includes the following provisions to prevent contaminated leakage from entering unmonitored and nonradioactive systems and ductwork in the area: the HVAC subsystems serving radiologically controlled areas (RCAs) normally maintain the served building areas at a slightly negative pressure to prevent the uncontrolled release of airborne radioactivity to the atmosphere or adjacent clean plant areas. Additionally, ductwork passing through RCAs is Class R and is designed, constructed, and tested in accordance with ASME AG-1 Section SA to prevent the infiltration of airborne radiation to unmonitored and nonradioactive systems. Interfaces with the adjacent buildings are limited to doorways, airlocks, and ductwork. Ductwork connecting the annex building and adjacent areas consists entirely of supply air ductwork handling outside air for the fuel handling area, health physics area, containment purge supply, and main control room. The main control room supplemental air filtration unit is in the HVAC equipment room; however, this unit has no radioactive material during normal plant operation.
		Exception	There are no provisions to prevent BDS leakage from entering the nonradioactive waste water system (WWS). WWS water is monitored for radioactivity prior to discharge and can be manually diverted to the liquid radwaste system (WLS) if necessary. There is no means to prevent BDS leakage from entering nonradioactive ductwork.
C.1.2.5		Conforms	This guideline does not apply because the liquid radwaste treatment system has no outdoor tanks. No other outside tanks store radioactive fluids.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.2.1	Regulatory Guide 1.143, Table 1	Exception	Components in the gaseous radwaste systems are designed and tested to the requirements set forth in the codes and standards listed in Table 1 of Regulatory Guide 1.143 with the exception of the use of the 2013 Edition of ASME, Section VIII, Div. 1, instead of the 1998 Edition (with 1999 Addenda) that is referenced in Appendix A of Regulatory Guide 1.143. This version is not endorsed by a regulatory guide, but its use should not result in deviations from the design philosophy otherwise stated in Regulatory Guide 1.143. Heat exchangers are designed and built according to ASME, Section VIII, Div. 1 and TEMA (for shell and tube). Piping and valves are per ASME B31.1. Pumps are according to manufacturer's standards.
C.2.2	ASME Code, Section II	Conforms	Materials, except elastomers for gaskets, seals, seats, diaphragms, and packing, are provided in accordance with the ASME Code Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ASME B31.1. Pump materials are provided according to manufacturer's standards.
C.2.3		Conforms	The guard bed and the delay beds, including supports, in the gaseous radwaste system are designed for seismic loads according to the requirements of Regulatory Guide 1.143. These are the only AP1000 components used to store or delay the release of gaseous radioactive waste. The beds are located in the seismic Category I auxiliary building at elevation 66′-6″. Seismic loads for this equipment will be established using one-half of the safe shutdown earthquake (SSE) floor response spectra. The loads due to this seismic response spectra are equivalent or greater than those due to an operating basis earthquake (OBE). Other equipment and supports will be designed in accordance with the codes indicated in Table 3.2-3.
C.3		Conforms	The regulatory guidance applies to the AP1000 solid waste processing system except for components and subsystems used to solidify or concentrate liquid waste. The AP1000 solid waste processing system does not have these components/subsystems. These functions are provided by contractors who process these wastes using mobile systems.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.3.1	Regulatory Guide 1.143, Table 1, Reg. Pos. 3.2 and 3.3	Exception	The solid radwaste system is designed and tested to the requirements set forth in the codes and standards listed in Table 1 of Regulatory Guide 1.143 with the exception of the use of the 2013 Edition of ASME, Section VIII, Div. 1, instead of the 1998 Edition (with 1999 Addenda) that is referenced in Appendix A of Regulatory Guide 1.143. This version is not endorsed by a regulatory guide, but its use should not result in deviations from the design philosophy otherwise stated in Regulatory Guide 1.143. The spent resin tanks are designed and tested in accordance with ASME Code, Section VIII, Div. 1. Piping and valves are designed and tested according to ASME B31.1. The pumps are designed to manufacturers' standards and tested in accordance with the Hydraulic Institute standards.
C.3.2	ASME Code, Section II	Conforms	Materials, except elastomers for gaskets, seals, seats, diaphragms, and packing, are provided in accordance with the ASME Code, Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ASME B31.1. Pump materials are provided according to manufacturer's standards.
C.3.3		Conforms	The seismic Category I auxiliary building will retain the maximum liquid and spent resin inventory of the spent resin tanks. The seismic Category I criteria exceed the operating basis earthquake required by regulatory position C.6 of Regulatory Guide 1.143.
C.3.4		Conforms	The equipment and components used to collect, process, and store solid radwaste are nonseismic as permitted by this paragraph.
C.4.1	Regulatory Guide 8.8	Conforms	Chapter 12, "Radiation Protection," discusses the measures taken to maintain the radiation exposure to personnel as low as reasonably achievable.
C.4.2		Conforms	The quality assurance program for design, fabrication, procurement, and installation of radwaste systems is in accordance with the overall quality assurance program described in Chapter 17, which meets the requirements of Regulatory Guide 1.143, position C.7.
C.4.3	ASME Code, Section IX	Conforms	Pressure-containing components in the radwaste systems are of welded construction to the maximum practical extent. Flanged joints and quick connect fittings are used only where maintenance or operational requirements indicate that they are preferable. Screwed connections are not used except for some instrumentation and vents and drains where welded construction is not suitable. Process lines are 1 in. or larger. Butt welds are used in process lines, which contain radioactive fluids. Nonconsumable backing rings are not used in process piping welds. Process pipe welding is performed as required by ASME B31.1. Component welding is performed as required by the applicable construction code.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
		Exception	The EDI modules within the EDI packages have threaded inlet and outlet connections. There is also process piping less than 3/4" nominal diameter inside the EDI packages.
C.4.4		Conforms	Hydrostatic testing is performed as required by the applicable construction codes.
C.4.5		Conforms	In-service testing of the containment penetrations and isolation valves is performed as described in Subsection 3.9.6. Other tests, on nonsafety equipment, are performed on an item-by-item basis as judged necessary to confirm proper operation of the systems.
C.5	10 CFR Part 20		
C.5.1		Conforms	Systems containing enough activity to be possibly classified as RW-IIa are located in the Auxiliary Building. The Auxiliary Building is seismic Category I.
C.5.2		Conforms	
C.5.3	10 CFR Part 71 Appendix A	Conforms	AP1000 systems and components that store or process radioactive waste are located in the Auxiliary Building.
C.5.4	10 CFR Part 71 Appendix A	Conforms	AP1000 systems and components that store or process radioactive waste are located in the Auxiliary Building and radwaste building.
C.6.1.1	Table 2	Exception	Refer to the discussion on Criteria Section C.1.1.3 for the exception on the BDS piping and components.
C.6.1.2	Table 3	Exception	Refer to the discussion on Criteria Section C.1.1.3 for the exception on the BDS piping and components.
C.6.1.3	Table 4	Exception	Refer to the discussion on Criteria Section C.1.1.3 for the exception on the BDS piping and components.
C.6.1.4	Table 1 & 4	Exception	Refer to the discussion on Criteria Section C.1.1.3 for the exception on the BDS piping and components.
C.6.2.1	UBC 1997, ASCE 7-95	Conforms	The Radwaste Building is designed to UBC-1997 and ASCE 7-98.
C.6.2.2		Conforms	Shield structures, if used, will comply with Regulatory Guide 1.143, position C.6.2.
C.7	ANSI/ANS55.6-1993	Conforms	The quality assurance program for design, fabrication, procurement, and installation of radwaste systems is in accordance with the overall quality assurance program described in Chapter 17, which meets the requirements of Regulatory Guide 1.143, position C.6.
Conformance with Revision 2 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	

Reg. Guide 1.144 – Withdrawn

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.145, Rev. 1, 11/82 (Revised 2/83 to correct page 1.145-7) – Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants			
Conformance of the design aspects of the Regulatory Guide is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. The atmospheric dispersion factors for use in determining potential accident consequences are selected to be representative of existing nuclear power plant sites and to bound the majority of them. Chapter 2 provides the interface criteria.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.146 – Withdrawn			
Reg. Guide 1.147, Rev. 12, 5/99 and Applicable Revision – Inservice Inspection Code Case Acceptability ASME Section XI Division 1			
Conformance with Revision 12 of the Regulatory Guide is documented below in the DCD. Conformance of the design aspects is as stated in the DCD.			
General	ASME Code, Section XI	Conforms	
Conformance with the applicable revision of this Regulatory Guide for programmatic and/or operational aspects is documented in the Preservice and Inservice Inspection (PSI and ISI) Programs in accordance with 10 CFR 50.55a.			
Reg. Guide 1.148 – Withdrawn			
Reg. Guide 1.149, Rev. 2, 4/96 – Nuclear Power Plant Simulation Facilities for Use in Operator License Examinations			
Regulatory Guide 1.149, Rev. 4, 4/11 – Nuclear Power Plant Simulation Facilities for Use in Operator Training, License Examinations, and Applicant Experience Requirements			
Conformance with Revision 2 of the Regulatory Guide is documented below in the DCD. Conformance of the design aspects is as stated in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 13.2.1 defines the responsibility to develop and implement training programs for plant personnel. These training programs will address the scope of licensing examinations.
Conformance with Revision 4 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
C.1		Conforms	
C.2		Conforms	During cold licensing, training and Operator Licensing exams are conducted using a Commission-approved simulation facility (CAS) approved under 10 CFR 55.46(b) and in accordance with Appendix D of ANSI/ANS-3.5-2009. The approval to administer tests on the CAS will expire upon availability of a plant-referenced simulator meeting the requirements of 10 CFR 55.46(c).
C.3		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.4		N/A	The simulation facility for VEGP 3&4 was originally implemented under ANSI/ANS-3.5-1998. This standard was revised to incorporate Scenario Based Training (SBT) guidance contained in NEI 09-09 and to clarify previous guidance for ease of use. These changes were incorporated into ANSI/ANS-3.5-2009. During implementation of the VEGP 3&4 CAS, the facility incorporated guidance contained in NEI 09-09. This addition allowed the VEGP simulation facilities to meet requirements in both ANSI/ANS-3.5-1998 and ANSI/ANS-3.5-2009. As such, the incorporation of ANSI/ANS-3.5-2009 does not require changes to operational or programmatic aspects of the VEGP simulation facilities.
C.5		Conforms	The simulation facility for VEGP 3&4 comprises two AP1000 full scope simulators which are referenced to VEGP Unit 3. Given that Unit 3 serves as the reference plant, differences between Unit 3 and Unit 4 will be evaluated for their potential to create negative training.
C.6		Conforms	
Reg. Guide 1.150, Rev. 1, 2/83 – Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations			
Conformance with the design aspects is as stated below in the DCD. The programmatic and/or operational aspects are not applicable since this guidance was withdrawn by NRC (73 FR 7766, 02/11/2008).			
General		Conforms	The reactor vessel design includes features that permit conformance to the pre-service and in-service inspection of this regulatory guide. Guidelines for such features as positioning of welds, vessel contour, and weld surface preparation are included.
Reg. Guide 1.151, (Task 1C 126-5), Rev. 0, 7/83 – Instrument Sensing Lines			
General	ISA-S67.02	Conforms	This regulatory guide addresses the use of ISA-S67.02, “Nuclear-Safety-Related Instrument Sensing Line Piping and Tubing Standards for Use in Nuclear Power Plants,” 1980, to provide a basis for the design and installation of instrument sensing lines. It establishes the applicable ASME code requirements and boundaries for the design and installation of instrument sensing line in accordance with the appropriate parts of ASME Code, Section III. Where there is a conflict between the ISA standard and the ASME Code, Section III, the ASME Code requirements are followed. Because this instrument configuration (permanently sealed, fluid-filled tubing) is excluded from the scope of Section III, the tubing is designed and fabricated to ASME B31.1. Industry standard ISA-S67.02 reiterates and clarifies the practice of controlling documents such as interface requirements and regulations. The AP1000 uses the Piping and Instrumentation Diagram as the approved document to designate the safety classification system boundaries.
C.1		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.2	ASME Code, Class 2 SC I	Conforms	Safety-related instrumentation has safety class pressure boundaries, including the sensing line, valves, and instrumentation sensors. The pressure boundary is the same safety class as the equipment to which it is connected. The AP1000 credits design features such as flow restrictors and diaphragms as class separation. For that portion of a sensing line from the ASME Code, Class 1 piping or vessel out to the class separation device, ISA-S67.02 includes the ASME Code, Class 1 requirement. For that portion of the sensing line from the class separation device to the sensor is designated as ASME Code, Class 2 requirement. The AP1000 has no sensing lines penetrating the containment barrier.
C.3	ASME Code, Class 3 SC I	Exception	The guidelines apply to the AP1000 sensing lines, except the sensing lines that are connected to some ASME Code, Class 3 components that do not have a seismic design requirement. Sensing lines from these components are not ASME Code, seismic Category I.
C.4-6		Conforms	

Reg. Guide 1.152, Rev. 1, 1/96 – Criteria for Digital Computers in Safety Systems of Nuclear Power Plants

Regulatory Guide 1.152, Rev. 2, 1/06 – Criteria for Use of Computers in Safety Systems of Nuclear Power Plants

Conformance of the design aspects with Revision 1 of the Regulatory Guide is as stated below in the DCD.

General	ANSI/ IEEE-ANS-7-4.3.2 -1993	Exception	The Common Q portion of the protection and safety monitoring system is developed using the Common Q Software Program Manual (SPM) (as modified by the SPM alternatives in WCAP-15927) and Common Q Topical Report (as modified by the Topical Report alternatives in WCAP-15927). The Common Q SPM and Topical Report were reviewed and approved by the NRC. The Common Q SPM and Topical Report meet IEEE Std. 7-4.3.2-2003, as endorsed by Regulatory Guide 1.152, Revision 3.

Conformance with Revision 2 of this Regulatory Guide for programmatic and/or operational aspects is documented below.

General		Exception	The Cyber Security Program is based on March 2009 revisions of the 10 CFR 73.54 regulations in lieu of Revision 2 of this Regulatory Guide.

Reg. Guide 1.153, Rev. 1, 6/96 – Criteria for Power, Instrumentation, and Control Portions of Safety Systems

General	IEEE Std. 603-1991 including January 30, 1995 Correction sheet	Conforms

Reg. Guide 1.154, Rev. 0, 1/87 – Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors

Conformance of the design aspects with the Regulatory Guide is as stated below in the DCD.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
General		N/A	See Section 5.3 for additional information on pressurized thermal shock. Subsection 5.3.6 defines the responsibility to document reactor vessel materials and material evaluation.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.155, (Task SI 501-4), Rev. 0, 8/88 – Station Blackout			
General	10 CFR 50.63	N/A	There are no safety-related ac power sources. Therefore, this regulatory guide is not applicable to the AP1000.
Reg. Guide 1.156, (Task EE 404-4), Rev. 0, 11/87 – Environmental Qualification of Connection Assemblies for Nuclear Power Plants			
General	IEEE Std. 572-1985	Conforms	
Reg. Guide 1.157, (Task RS 701-4), Rev. 0, 5/89 – Best-Estimate Calculations of Emergency Core Cooling System Performance			
C.1		Conforms	
C.2		Conforms	
C.3.1	10 CFR 50, App. A	Conforms	
C.3.2-12		Conforms	
C.3.13-14		N/A	Applies to boiling water reactors only.
C.3.15-16		Conforms	
C.4.1	10 CFR 50.46(a)(1)(i)	Conforms	
C.4.2-4		Conforms	
C.4.5		Conforms	
Reg. Guide 1.158, (Task EE 006-5), Rev. 0, 2/89 – Qualification of Safety-Related Lead Storage Batteries for Nuclear Power Plants			
General	IEEE Std. 535-1986	Conforms	
Reg. Guide 1.159, Rev. 0, 8/90 and Rev. 1, 10/03 – Assuring the Availability of Funds for Decommissioning Nuclear Reactors			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		N/A	This Regulatory Guide is outside the scope of the FSAR.
Reg. Guide 1.160, Rev. 4, 8/18 – Monitoring the Effectiveness of Maintenance at Nuclear Power Plants			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.161, Rev. 0, 6/95 – Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb			
General		N/A	The design and material specification for the reactor vessel do not permit a Charpy value less than 50 ft.-lb. Subsection 5.3.6.4 defines the responsibility for reactor vessel materials properties verification.
Reg. Guide 1.162, Rev. 0, 2/96 – Format and Content of Report for Thermal Annealing of Reactor Pressure Vessels			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Reg. Guide 1.163, Rev. 0, 9/95 – Performance Based Containment Leak-Test Program			
Conformance of the design aspects is as stated below in the DCD.			
1	NEI94-01 ANSI/ ANS 56.8-1994	Conforms	Schedular exceptions as identified in TS 5.5.8
2	NEI Section 11.3.2	Conforms	
3	NEI 94-01 Section 9.2.1 NEI 94-01 Section 10.2.3.3	Conforms	
Conformance with Revision 0 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.165, Rev. 0, 3/97 – Identification and Characterization of Seismic Sources and Determination Safe Shutdown Earthquake Ground Motion			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Subsection 2.5.2.1 defines the responsibility to address site-specific information related to the vibratory ground motion aspects.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
		Conforms with Clarification	Regulatory Guide 1.165 is used to (1) conduct geological, seismological, and geophysical investigations of the site and region around the site, (2) identify and characterize seismic sources, and (3) perform PSHA. The procedure to determine the SSE for the site departs from the Regulatory Guide 1.165 procedure. Site-specific SSE spectra following the procedures of ASCE 43-05 for defining the Design Response Spectra (DRS) using a Target Performance Goal (Pf) of a mean annual probability of exceedance of 1E- 05 is used to define the ESP SSE design ground motion.
Reg. Guide 1.166, Rev. 0, 3/97 – Pre-Earthquake Planning and Immediate Nuclear Power Plant Operator Postearthquake Actions			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 13.5.1 defines the responsibility for the plant procedure preparation.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.167, Rev. 0, 3/97 – Restart of a Nuclear Power Plant Shut Down by a Seismic Event			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 13.5.1 defines the responsibility for the plant procedure preparation.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.168, Rev. 0, 9/97 and Rev. 1, 2/04 – Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
Conformance of the design aspects with Revision 0 of the Regulatory Guide is as stated below in the DCD.			
General		Exception	See Chapter 7 for a discussion of the instrumentation and control software program related to Common Qualified Platform (Common Q). The Common Q portion of the protection and safety monitoring system is developed using the Common Q SPM (as modified by the SPM alternatives in WCAP-15927). The Common Q SPM was reviewed and approved by the NRC using the criteria of IEEE Std. 1012-1998 and IEEE Std. 1028-1997 as endorsed by Regulatory Guide 1.168, Revision 1.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance of the design aspects with Revision 1 of the Regulatory Guide is as stated below.			
General		Exception	See Chapter 7 for a discussion of the instrumentation and control software program related to the Component Interface Module (CIM) subsystem. Exceptions to the standards endorsed by Regulatory Guide 1.168, Revision 1 (i.e., IEEE 1012-1998 and IEEE 1028-1997) related to the CIM subsystem are noted below.
General	IEEE 1012-1998	Exception	The CIM subsystem takes exception to the requirement in Section 7.6 that states each Independent Verification and Validation (IV&V) Anomaly Report shall contain "recommendations." The IV&V Anomaly Reports do not require recommendations so that the independence of IV&V is maintained.
General	IEEE 1028-1997	Exception	The CIM subsystem takes exception to the requirement in Section 4.5.4 that requires team members to review the relevant materials prior to the management review. The project manager is required to distribute review materials before the meeting, and the material is reviewed during the meeting. The CIM subsystem takes exception to Section 4.6, which requires a management review to be considered complete when specific criteria are met. There is no requirement to officially declare the management review complete. The management review is considered complete at the discretion of the program manager in conjunction with the management review team. However, the CIM subsystem management reviews adhere to the meeting goals and outputs as defined by IEEE 1028, Sections 4.6 and 4.7 (with the exceptions noted in this appendix). The CIM subsystem takes exception to the guidance in Section 4.7, which requires specific criteria for documenting and tracking action item statuses, anomalies, and review team member participation as management review outputs. Contrary to IEEE 1028: • Only significant action items are formally documented and tracked in management meeting minutes. • Anomalies are formally tracked using issue tracking databases. • Members of the review teams are not formally captured as a management review output.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			The CIM subsystem takes exception to the guidance in Section 8.5.5.1, which requires auditors to perform activities outside the scope of the audit plan, if the activities are required to define the full extent of an issue. Contrary to IEEE 1028, auditors are not directed to perform or document reviews outside of the assigned audit scope or to take actions beyond that required by the audit plan. Issues found during an audit are entered into a corrective action tracking system. The corrective action program formally evaluates the issues and determines if an "extent of condition" investigation is required.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.169, Rev. 0, 9/97 – Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		Exception	Westinghouse uses the Common Q SPM (as modified by the SPM alternatives in WCAP-15927) to develop and maintain the Common Q portion of the protection and safety monitoring system. The Common Q SPM was reviewed and approved by the NRC using the criteria of Regulatory Guide 1.169, Revision 0 and IEEE 828-2005. The CIM subsystem complies with Regulatory Guide 1.169, Revision 0 with the exception(s) identified below:
General	IEEE 828-1990	Exception	The CIM subsystem takes exception to the requirement in Section 2.3.4 to perform a configuration audit on a configuration item prior to its release. Configuration audits occur after the release of a configuration item document instead of prior to its release. Configuration audits are complete prior to installation of the Configuration Item in the plant. See Chapter 7 for a discussion of the instrumentation and control software program.
Reg. Guide 1.170, Rev. 0, 9/97 – Software Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		Exception	The Common Q portion of the protection and safety monitoring system is developed using the Common Q SPM (as modified by the SPM alternatives in WCAP-15927). The Common Q SPM was reviewed and approved by the NRC using the criteria of Regulatory Guide 1.170, Revision 0 and IEEE 829-1998. The CIM subsystem complies with Regulatory Guide 1.170, Revision 0 with the exception(s) identified below:

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
General	IEEE 829-1983	Exception	The CIM subsystem takes exception to the requirement in Section 3 to specify the version/revision level of the test items within the test plan. The CIM Test Plan is authored to be independent of the specific versions/revisions of the test items to be tested and requires the latest approved test plan version to be used.
General	IEEE 829-1983	Exception	The CIM subsystem takes exception to the required structure/format specified for Test-Design Specification (Section 4), Test-Case Specification (Section 5), Test-Procedure Specification (Section 6), Test-Item Transmittal Report (Section 7), Test Log (Section 8), Test-Incident Report (Section 9), and Test-Summary Report (Section 10). The CIM subsystem documents corresponding to the documents referred to in Sections 4 through 10 contain the content required by IEEE 829.
General	IEEE 829-1983	Exception	The CIM subsystem takes exception to the requirements in Sections 7.2.2 and 7.2.4 to include a reference to the test plan and deviations from the test plan when transmitting test items. The version/revision of the test item is recorded in the test record. There will be no deviations from the identified software documentation at the time of the software release.
General	IEEE 829-1983	Exception	The CIM subsystem takes exception to the requirement in Section 8 to record the start and end times of a test event. The date of the event is recorded, not the specific start and end times.
General	IEEE 829-1983	Exception	The CIM subsystem takes exception to the requirement in Section 10 to summarize resource consumption data in the test report. Resource consumption data is addressed in project schedules and budget data.
			See Chapter 7 for a discussion of the instrumentation and control software program.
Reg. Guide 1.171, Rev. 0, 9/97 – Software Unit Testing for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		Conforms	See Chapter 7 for a discussion of the instrumentation and control software program.
Reg. Guide 1.172, Rev. 0, 9/97 – Software Requirements Specifications for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		Exception	The Common Q portion of the protection and safety monitoring system is developed using the Common Q SPM (as modified by the SPM alternatives in WCAP-15927). The Common Q SPM was reviewed and approved by the NRC using the criteria of Regulatory Guide 1.172, Revision 0 and IEEE 830-1998.
			See Chapter 7 for a discussion of the instrumentation and control software program.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.173, Rev. 0, 9/97 – Developing Software Life Cycle Processes for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		Exception	Westinghouse uses the Common Q SPM (as modified by the SPM alternatives in WCAP-15927) to develop and maintain the Common Q portion of the protection and safety monitoring system. The Common Q SPM was reviewed and approved by the NRC using the criteria of IEEE 1074-1995 as endorsed by Regulatory Guide 1.173, Revision 0. The CIM subsystem complies with Regulatory Guide 1.173, Revision 0 with the exception(s) identified below.
General	IEEE 1074-1995	Exception	The CIM subsystem takes exception to the requirements in Sections 4.1.4, 4.1.5, and 4.1.7, respectively, to perform the "Formulate Potential Approaches" and "Constraints and Benefits" activity; the "Conduct Feasibility Study" activity; and the "Refine and Finalize Idea or Need" activity. Using information from previous projects, the basic CIM subsystem design approach was already formulated at the time the project was initiated.
General	IEEE 1074-1995	Exception	The CIM subsystem takes exception to the requirement in Section 7.4.3 to consider the software requirements as an input to the development of the training program. The training plan was written to be independent of the software requirements developed later in the project. See Chapter 7 for a discussion of the instrumentation and control software program.
Reg. Guide 1.174, Rev. 0, 7/98 and Rev. 1, 11/02 – An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis			
Conformance of the design aspects for Revision 0 of this Regulatory Guide is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. The AP1000 is a standardized design. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
This Regulatory Guide is outside the scope of the FSAR.			
Reg. Guide 1.175, Rev. 0, 7/98 – An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing			
Regulatory Guide 1.175, Rev. 0, 8/98 – An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. The AP1000 is a standardized design. Inservice testing of ASME Section III components is discussed in Subsection 3.9.6.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Risk-informed inservice testing is not being utilized for this plant.			
Reg. Guide 1.176, Rev. 0, 8/98 – An Approach for Plant-Specific, Risk-Informed Decisionmaking: Graded Quality Assurance			
General		N/A	Not applicable to AP1000 design certification. The AP1000 is a standardized design. Quality assurance is discussed in Chapter 17.
Reg. Guide 1.177, Rev. 0, 8/98 – An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. The AP1000 is a standardized design. The standard AP1000 Technical Specifications are provided in DCD Chapter 16. Vogtle 3&4 Technical Specifications are provided in COL Appendix A.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
This Regulatory Guide is outside the scope of the FSAR.			
Reg. Guide 1.178, Rev. 0, 9/98 and Rev. 1, 9/03 – An Approach for Plant-Specific Risk-informed Decisionmaking Inservice Inspection of Piping			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. The AP1000 is a standardized design. Inservice inspection is discussed in Subsection 5.2.4 and Section 6.6.
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
Risk-informed inservice inspection is not being utilized for this plant.			
Reg. Guide 1.179, Rev. 0, 1/99 – Standard Format and Content of License Termination Plans for Nuclear Power Reactors			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. The AP1000 is a standardized design. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Reg. Guide 1.180, Rev. 1, 10/03 – Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems			
Conformance of the design aspects is as stated below in the DCD.			
General		Conforms	See Appendix 3D for a discussion of the EMI/RFI qualification.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	Exclusion zones are established through administrative controls to prohibit the activation of portable EMI/RFI emitters (e.g., welders and transceivers) in areas where safety-related I&C systems are installed.
Reg. Guide 1.181, Rev. 0, 9/99 – Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e)			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.182 – Withdrawn			
Reg. Guide 1.183, Rev. 0, 7/00 – Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors			
Conformance of the design aspects is as stated below in the DCD.			
General		Conforms	
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.184, Rev. 0, 7/00 – Decommissioning of Nuclear Power Reactors			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Reg. Guide 1.185, Rev. 0, 8/00 – Standard Format and Content for Post-shutdown Decommissioning Activities Report			
Regulatory Guide 1.185, Rev. 0, 7/00 – Standard Format and Content for Post-shutdown Decommissioning Activities Report			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Reg. Guide 1.186, Rev. 0, 12/00 – Guidance and Examples of Identifying 10 CFR 50.2 Design Bases			
Conformance of the design aspects is as stated below in the DCD.			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
General		N/A	Not applicable to AP1000 design certification. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Reg. Guide 1.187, Rev. 0, 11/00 – Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Regulatory Guide 1.188, Rev. 1, 9/05 – Standard Format and Content for Applications To Renew Nuclear Power Plant Operating Licenses			
Conformance of the design aspects is as stated in the DCD. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Regulatory Guide 1.189, Rev. 1, 3/07 – Fire Protection for Operating Nuclear Power Plants			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Subsection 9.5.1 describes the AP1000 Fire Protection System. Subsection 9A.3.3 describes the plant-specific design of the Radioactive Material and Equipment Building.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	Subsection 9.5.1.8 defines the protection program.
Reg. Guide 1.190, Rev. 0, 3/01 – Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence			
General		Exception	Subsection 5.3.2.6 describes the calculational and dosimetry methods for determining pressure vessel neutron fluence for the AP1000. Subsections 5.3.2.6.3 and 5.3.3.1 describe the reporting of the test results. Subsection 5.3.6.4 describes the reactor vessel materials properties verification.
Regulatory Guide 1.191, Rev. 0, 5/01 – Fire Protection Program for Nuclear Power Plants During Decommissioning and Permanent Shutdown			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Regulatory Guide 1.192, Rev. 3, 10/19 – Operation and Maintenance Code Case Acceptability, ASME OM Code			
General		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Regulatory Guide 1.193, Rev. 1, 8/05– ASME Code Cases Not Approved for Use			
This Regulatory Guide is not applicable to the AP1000 certified design. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Regulatory Guide 1.194, Rev. 0, 6/03 – Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants			
Conformance with Revision 0 of the Regulatory Guide is documented in the DCD. Conformance of the design aspects is as stated in the DCD. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Regulatory Guide 1.195, Rev. 0, 5/03 – Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-Water Nuclear Power Reactors			
This Regulatory Guide is not applicable to the AP1000 certified design.			
Regulatory Guide 1.196, Rev. 1, 1/07 – Control Room Habitability at Light-Water Nuclear Power Reactors			
This Regulatory Guide is not applicable to the AP1000 certified design. Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.197, Rev. 0, 5/03 – Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors			
Conformance with the design aspects is as stated in the DCD.			
General		Conforms	The design of the AP1000 control room and associated HVAC systems facilitates testing to demonstrate control room envelope integrity.
C.1.1-2.6		N/A	Not applicable to AP1000 design certification. Section 13.5 defines the responsibility for procedures. Section 14.4 describes the responsibilities required to perform the AP1000 plant initial test program.
Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms	
Regulatory Guide 1.198, Rev. 0, 11/03 – Procedures and Criteria for Assessing Seismic Soil Liquefaction at Nuclear Power Plant Sites			
Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 1.199, Rev. 0, 11/03 – Anchoring Components and Structural Supports in Concrete			
Conformance with Revision 0 of the Regulatory Guide is as stated below in the DCD. This guidance is completely within the scope of the DCD.			
C.1 – C.7		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Regulatory Guide 1.200, Rev. 2, 3/09 – An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities			
This Regulatory Guide is not applicable to the AP1000 certified design. Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms	
Regulatory Guide 1.201, Rev. 1, 5/06 – Guidelines for Categorizing Structures, Systems, and Components in Nuclear Power Plants According to Their Safety Significance			
This Regulatory Guide is not applicable to the AP1000 certified design.			
Regulatory Guide 1.202, Rev. 0, 2/05 – Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors			
This Regulatory Guide is outside the scope of the FSAR.			
Regulatory Guide 1.203, Rev. 0, 12/05 – Transient and Accident Analysis Methods			
This Regulatory Guide is not applicable to the AP1000 certified design.			
Regulatory Guide 1.204, Rev. 0, 11/05 – Guidelines for Lightning Protection of Nuclear Power Plants			
This Regulatory Guide is not applicable to the AP1000 certified design. Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms	
Regulatory Guide 1.205, Rev. 0, 5/06 – Risk-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants			
This Regulatory Guide is not applicable to the AP1000 certified design.			
Regulatory Guide 1.206, Rev. 0, 6/07 – Combined License Applications for Nuclear Power Plants (LWR Edition)			
Conformance with the design aspects is as stated in the DCD. Conformance with programmatic and/or operational aspects is documented below.			
General	Format	Conforms	
General	Content	Exception	Exceptions to content are identified in the application and were reviewed and approved by the NRC staff. Applicable for Combined License Application phase. This position statement is not being updated after the COL is issued.
Regulatory Guide 1.207, Rev. 0, 3/07 – Guidelines for Evaluating Fatigue Analyses Incorporating the Life Reduction of Metal Components Due to the Effects of the Light-Water Reactor Environment for New Reactors			
This Regulatory Guide is not applicable to the AP1000 certified design.			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions

Regulatory Guide 1.208, Rev. 0, 3/07 – A Performance-Based Approach to Define the Site-Specific Earthquake Ground Motion

This Regulatory Guide is not applicable to the AP1000 certified design.

	N/A	Performance-based analysis per RG 1.165 and ASCE 43-05.

Regulatory Guide 1.209, Rev. 0, 3/07 – Guidelines for Environmental Qualification of Safety-Related Computer-Based Instrumentation and Control Systems in Nuclear Power Plants

This Regulatory Guide is not applicable to the AP1000 certified design.

DIVISION 4 – Environmental and Siting

Regulatory Guide 4.2 & Supp. 1, Rev. 2, 7/76, S-1, 9/00 – Preparation of Environmental Reports for Nuclear Power Stations

Conformance with programmatic and/or operational aspects is documented below.

General	Conforms	

Reg. Guide 4.7 Rev. 2, 4/98 – General Site Suitability Criteria for Nuclear Power Stations

Conformance with the design aspects is as stated below in the DCD.

General	N/A	Chapter 2 defines the site-related parameters for which the AP1000 plant is designed. These interface parameters envelop most potential sites in the United States. The guidelines in this regulatory guide are site-specific. Chapter 2 defines the responsibility for determining general site suitability.

Conformance with programmatic and/or operational aspects is documented below.

General	Conforms	

Regulatory Guide 4.15 Rev. 2, 7/07 – Quality Assurance for Radiological Monitoring Programs (Inception through Normal Operations to License Termination) – Effluent Streams and the Environment

	Exception	The Guidance of Rev. 1, February 1979 will be followed as per the justification provided in Subsection 11.5.3.

DIVISION 5 – Materials and Plant Protection

The plant-specific physical security plans include no substantive deviations from the NRC-endorsed template in NEI 03-12, Rev. 6. Therefore, the degree of conformance with Division 5 regulatory guides for the Physical Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan is consistent with the degree of conformance of NEI 03-12, Rev. 6.

Reg. Guide 5.9 Rev. 2, 12/83 – Specifications for Ge (Li) Spectroscopy Systems for Material Protection Measurements Part 1: Data Acquisition Systems

Regulatory Guide 5.9, Rev. 2, 12/83 – Guidelines for Germanium Spectroscopy Systems for Measurement of Special Nuclear Material

Conformance of the design aspects is as stated below in the DCD.

General	N/A	Not applicable to AP1000 design certification. Laboratory Equipment is not included in the AP1000 design. Subsection 1.9.1.5 defines the responsibility for Regulatory Guides not applicable to Design Certification.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Conformance with programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Reg. Guide 5.12, Rev. 0, 11/73 – General Use of Locks in the Protection and Controls of Facilities and Special Nuclear Materials			
Conformance of the design aspects is as stated below in the DCD.			
C.1	UL-768	Conforms	
C.2	FF-P-110F	Conforms	
C.3	UL-437	Conforms	
C.4	FF-P-001480 (GSA FSS)	Conforms	
C.5-8		Conforms	
Conformance with programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Reg. Guide 5.65, Rev. 0, 9/86 – Vital Area Access Controls, Protection of Physical Security Equipment, and Key and Lock Controls			
Conformance of the design aspects is as stated below in the DCD.			
General		Conforms	The AP1000 provides for physical protection of the vital area. Identification of the protected and vital areas and an outline of the physical protection system are presented in the AP1000 Security Design Report.
Conformance with programmatic and/or operational aspects is documented below.			
		N/A	This Regulatory Guide is outside the scope of the FSAR.
Regulatory Guide 5.71, Rev. 0, 1/10 – Cyber Security Programs for Nuclear Facilities			
Conformance with regulatory positions C.1 through C.5 of Regulatory Guide 5.71, Rev. 0 is as stated in the Fleet Cyber Security Plan (CSP-1), implemented in accordance with “NEI 08-09, Rev. 6, Addendum 1 - Cyber Security Plan for Nuclear Power Reactors,” with exceptions included within the CSP and within Attachment A of the CSP.			
Regulatory Guide 5.84, Rev. 0, 7/15 - Fitness-For-Duty Programs at New Reactor Construction Sites			
Conformance with programmatic and/or operational aspects is documented below:			

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
General	10 CFR Part 26 NEI 06-06, Rev. 6 (April 2013)	Exception	Exceptions to guidance provided in NEI 06-06 Rev. 6 (April 2013) are as described below: The third paragraph of Section 2.1, Construction, is revised to read: The FFD program for construction applies to individuals specified in 10 CFR 26.4(f) who are constructing or directing the construction of safety- or security-related SSCs, unless the construction site entity chooses to subject these individuals to a full FFD program that meets all of the requirements in 10 CFR Part 26, except Subparts I and K, or are escorted by a qualified individual subject to the construction FFD program. Thus, the FFD program for construction applies to individuals who perform the following types of activities: A definition is added to define a limited FFD authorization as follows: Limited Fitness-for-Duty (FFD) Authorization (FFDA) - An authorization granted for a limited period of time to potential 10 CFR 26.4(f) workers that have not completed all elements for FFDA for individuals subject to 10 CFR Part 26 Subpart K. Workers granted a Limited FFDA shall be administratively prevented from constructing or directing construction of safety- or security-related structures, systems, and components (SSCs). A definition is added to define a construction escort as follows: Construction Escort — An individual subject to the construction FFD program assigned to escort and observe a construction worker engaged in constructing or directing the construction of a safety- or security-related SSC and is not subject to the construction FFD program. A definition is added to define a construction visitor as follows: Construction Visitor — An individual determined by the construction entity to have expertise needed to support or direct the construction of a safety- or security-related SSC for thirty days or less in a sixty day period and authorized by a first line supervisor or greater, but who is not subject to the construction FFD program.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			Insert additional required procedures to Section 5.2, *Procedures* as follows: 14. Procedures for processing, escorting, and controlling construction visitors to include: a. Confirmation of identity b. Checking against industry databases for denied access c. Maintenance of a visitor control register d. Requirement that all construction visitors be escorted within the construction site 15. Procedures for training and controlling construction escorts to include: a. Requiring escorts to hold a FFDA for the construction site b. Requiring understanding of responsibilities to perform escort duties c. Requirement to be generally knowledgeable of the construction activities to be performed by the construction visitor Section 6.2.1, *Pre-Assignment*, is clarified to allow an individual to have limited access to the construction site under the conditions specified in Section 9.3. An individual may be eligible for limited access to the construction site under the conditions specified in Section 9.3 [of NEI 06-06 Revision 6 (April 2013)]. Section 8, *Reviewing Official*, the first sentence of the first paragraph is revised to read: The construction site entity or as applicable, approved contractors/vendors (C/V), is required to designate in writing one or more individuals as a reviewing official to make FFDA (including Limited FFDA) determinations relative to a potential construction site workforce member's trustworthiness and reliability and fitness for duty. Section 8, *Reviewing Official*, last paragraph, is revised to read: If an individual who has FFDA status is not subject to an FFD program that meets the requirements of this document for more than 30 continuous days, then the reviewing official shall terminate the individual's FFDA status and the individual shall meet the requirements in order to reestablish FFDA. In the case of a Pandemic Response where a portion of Subpart K workers could potentially be offsite for a period longer than 30 days, the 30 continuous day requirement can be suspended without terminating the individuals' FFDA status.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
			Section 9.2, *Types of FFDA*, is revised to add a fourth type – Limited FFDA Section 9.3, *Granting FFDA and FFDA Elements*, is revised to add an introductory paragraph that reads: A construction site entity may grant a Limited FFDA for a period of up to five business days upon successful completion and documentation of the elements specified within Section 9.1, as appropriate, except the requirement for documentation of a passed drug test. Section 9.3, *Granting FFDA and FFDA Elements*, last paragraph, is revised to read: If an individual who has FFDA status is not subject to a FFDA program that meets the requirements as defined in this section for more than 30 continuous days, then the licensee shall terminate the individual's FFDA status. In the case of a Pandemic Response where a portion of Subpart K workers could potentially be offsite for a period longer than 30 days, the 30 continuous day requirement can be suspended without terminating the individuals' FFDA status.
DIVISION 8 – Occupational Health			
Reg. Guide 8.2, Rev. 0, 2/73 – Guide for Administrative Practices in Radiation Monitoring			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Section 13.5 defines the responsibility for administrative procedures. Subsection 12.1.3 defines the responsibility for operational considerations of ALARA.
Conformance with programmatic and/or operational aspects is documented below.			
General	10 CFR Part 20; ANSI 13.2-1969	Exception	The reference to 10 CFR 20.401 is no longer valid in the current version of 10 CFR Part 20. ANSI N13.2-1969 was reaffirmed in 1988.
Regulatory Guide 8.4, Rev. 0, 2/73 - Direct-Reading and Indirect-Reading Pocket Dosimeters			
Conformance with the design aspects is as stated in the DCD. Conformance with programmatic and/or operational aspects is documented below.			
General	10 CFR Part 20 ANSI N13.5-1972	Exception	The reference to 10 CFR 20.202 (a) and 20.401 is no longer valid in the current version of 10 CFR Part 20. ANSI N13.5-1972 was reaffirmed in 1989. The two performance criteria specified in Regulatory Guide 8.4 (accuracy and leakage) for these devices are met using acceptance standards in ANSI N322-1997 "American National Standard Inspection, Test, Construction, and Performance Requirements for Direct Reading Electrostatic/Electroscope Type Dosimeters".

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Regulatory Guide 8.5, Rev. 1, 3/81 - Withdrawn			
Regulatory Guide 8.6, Rev. 0, 5/73 - Standard Test Procedure for Geiger-Muller Counters			
Conformance with the design aspects is as stated in the DCD. Conformance with programmatic and/or operational aspects is documented below.			
General		Exception	Instrument calibration program is based upon criteria in ANSI N323A-1997 (with 2004 Correction Sheet) "Radiation Protection Instrumentation Test and Calibration, Portable Survey Instruments." The ANSI 42.3-1969 Standard is no longer recognized as sufficient for calibration of modern instruments.
Regulatory Guide 8.7, Rev. 2, 11/05 - Instructions for Recording and Reporting Occupational Radiation Dose Data			
Conformance with the design aspects is as stated in the DCD. Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 8.8, Rev. 3, 6/78 – Information Relevant to Ensuring That Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable			
Conformance of the design aspects is as stated below in the DCD.			
1		N/A	Not applicable to AP1000 design certification. Subsection 12.1.3 defines the responsibility for operational considerations of ALARA.
1.a-c	Regulatory Guide 1.8	N/A	Not applicable to AP1000 design certification. Subsection 12.1.3 defines the responsibility for operational considerations of ALARA.
1.d		Conforms	
2	ANSI N237-1976	Exception	Regulatory Guide 8.8 endorses ANSI-N237-1976 (Reference 49), which has been superseded by ANSI 18.1-1999 (Reference 50). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 8.8.
2.a	10 CFR 20-203	Conforms	
2.b-d		Conforms	
2.e		Conforms	See Subsection 12.3.1.1.1, "Materials," and corresponding Table 12.3-1.
2.f-g		Conforms	
2.h	ANS N197 ANS 55.1 ANS N19	Conforms	ANS-55.1-1992-R2000 is Current Version
2.i		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
3		N/A	Not applicable to AP1000 design certification. Subsection 12.1.3 defines the responsibility for operational considerations of ALARA.
4.a		Conforms	
4.b-d		N/A	Not applicable to AP1000 design certification. Subsection 12.1.3 defines the responsibility for operational considerations of ALARA.
4.e		Conforms	
Conformance with Revision 3 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
C.1		Conforms	
C.3.a		Conforms	
C.3.b		Exception	Regulatory Guide 1.16 C.1.b.(3) data is no longer reported. Reporting per C.1.b(2) is also no longer required.
C.3.c		Conforms	
C.4.b-C.4.d	ANSI Z-88.2, Regulatory Guide 8.15, NUREG-0041	Conforms	Conformance is with the latest revision of NUREG-0041.
Regulatory Guide 8.9, Rev. 1, 7/93 – Acceptable Concepts, Models, Equations, and Assumptions for a Bioassay Program			
Conformance with the design aspects is as stated in the DCD. Conformance with programmatic and/or operational aspects is documented below.			
General		Conforms	
Reg. Guide 8.10, Rev. 1-R, 5/77 – Operating Philosophy For Maintaining Occupational Radiation Exposures as Low as is Reasonably Achievable			
Conformance of the design aspects is as stated below in the DCD.			
General		N/A	Not applicable to AP1000 design certification. Subsection 12.1.3 defines the responsibility for operational considerations of ALARA.
Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	
C.1.a - C.1.c		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.1.d		Exceptions	Reg. Guide 8.10 states that radiation workers should understand how radiation protection relates to his job and should be tested on this understanding at least once per year. VEGP 3&4 takes exception to the annual testing of radiation workers understanding of radiation protection as stated in Reg. Guide 8.10 Subsection C.1.d. VEGP 3&4 follows the retraining frequency of 48 months nominal, not to exceed 51 months as evaluated in a Systematic Approach to Training analysis. The retraining frequency for ALARA requirements is defined in Subsection 12.1.1.2.
C.1.e - C.1.f		Conforms	
C.2		Conforms	

Reg. Guide 8.12 – Withdrawn

Reg. Guide 8.13, Rev. 3, 6/99 – Instruction Concerning Prenatal Radiation Exposure

Conformance of the design aspects is as stated below in the DCD.

General	10 CFR 19.12	N/A	Not applicable to AP1000 design certification. Subsection 12.1.3 defines the responsibility for operational considerations of ALARA. Section 13.5 defines the responsibility for administrative procedures.

Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

General		Conforms	

Reg. Guide 8.14 – Withdrawn

Reg. Guide 8.15, Rev. 1, 10/99 – Acceptable Programs for Respiratory Protection

Conformance of the design aspects is as stated below in the DCD.

General	10 CFR 20.103	N/A	Not applicable to AP1000 design certification. Subsection 12.1.3 defines the responsibility for operational considerations of ALARA. See Section 12.3 for information on radiation protection design features. See Section 12.5 for information on health physics facilities. Section 13.5 defines the responsibility for administrative procedures.

Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

General		Conforms	

Reg. Guide 8.19, Rev. 1, 6/79 – Occupational Radiation Dose Assessment in Light-Water Reactor Power Plants Design Stage Man-Rem Estimates

General		Conforms	

Regulatory Guide 8.27, Rev. 0, 3/81 – Radiation Protection Training for Personnel at Light-Water-Cooled Nuclear Power Plants

Conformance of the design aspects is as stated in the DCD. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

General		Conforms	

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
C.2.2		Exception	Reg. Guide 8.27 requires annual radiation protection refresher training, which includes ALARA training. However, VEGP 3&4 follows the retraining frequency 48 months nominal, not to exceed 51 months as evaluated in a Systematic Approach to Training analysis. The retraining frequency for ALARA requirements is defined in Subsection 12.1.1.2.

Regulatory Guide 8.28, Rev. 0, 8/81 – Audible-Alarm Dosimeters

Conformance of the design aspects is as stated in the DCD. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

General	ANSI N13.27-1981	Conforms	

Regulatory Guide 8.29, Rev. 1, 2/96 – Instruction Concerning Risks from Occupational Radiation Exposure

Conformance of the design aspects is as stated in the DCD. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

General		Exception	Reg. Guide 8.29 requires instruction to workers performed in compliance with 10 CFR 19.12 be given prior to occupational exposure and annually thereafter. However, VEGP 3&4 follows the retraining frequency of 48 months nominal, not to exceed 51 months as evaluated in a Systematic Approach to Training analysis. The retraining frequency for ALARA requirements is defined in Subsection 12.1.1.2.

Regulatory Guide 8.34, Rev. 0, 7/92 – Monitoring Criteria and Methods To Calculate Occupational Radiation Doses

Conformance of the design aspects is as stated in the DCD. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

General		Conforms	

Regulatory Guide 8.35, Rev. 0, 6/92 – Planned Special Exposures

Conformance of the design aspects is as stated in the DCD. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

General		Conforms	

Regulatory Guide 8.36, Rev. 0, 7/92 – Radiation Dose to the Embryo/Fetus

Conformance of the design aspects is as stated in the DCD. Conformance with this Regulatory Guide for programmatic and/or operational aspects is documented below.

Criteria Section	Referenced Criteria	AP1000/ FSAR Position	Clarification/Summary Description of Exceptions
Reg. Guide 8.38, Rev. 0, 6/93 and Rev. 1, 5/06 – Control of Access to High and Very High Radiation Areas of Nuclear Plants			
Conformance of the design aspects for Revision 0 of this Regulatory Guide is as stated below in the DCD.			
General		Conforms	
Conformance with Revision 1 of this Regulatory Guide for programmatic and/or operational aspects is documented below.			
General		Conforms	

Note a. Not used.

Note b. Above stated general alternatives regarding the use of previous revisions of the Regulatory Guide for design aspects as stated in the DCD is provided to preserve the finality of the certified design. Further, each stated conformance with the programmatic and/or operational aspects is only to the extent that a design change or departure from the approved DCD is not required to implement those programmatic and/or operational aspects. As the operational and programmatic aspects become more fully defined (for example, during the preparation, approval, or initial implementation of plant procedures), there exists a potential that a conflict could be identified between the design as certified in the DCD and the programmatic and/or operational aspects of the guidance. In such cases, the design certification (rule) becomes the controlling factor, and the design conformance to the Regulatory Guide is per the revision stated in the DCD.

Note c. A “Criteria Section” entry of “General” indicates a scope for the conformance statement of “all regulatory guide positions related to programmatic and/or operational aspects.” Thus, an associated conformance statement of “Conforms” indicates that the applicant “complies with all regulatory guide positions related to programmatic and/or operational aspects.”

1A.1 References

1. Sofer, et al., "Accident Source Terms for Light Water Nuclear Power Plants." NUREG-1465, February 1995.

2. Not used.

3. Not used.

4. Not used.

5. IEEE Std. 308-1974, IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations, 1974.

6. IEEE Std. 308-1991, IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations, 1991.

7. Not used.

8. Not used.

9. WCAP-8577, "The Application of Pre-Heat Temperature After Welding of Pressure Vessel Steels," September 1975.

10. IEEE 379-72, IEEE Trial-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems, 1972.

11. IEEE 379-2000, IEEE Standard Application of the Single-Failure Criterion to Nuclear Power Generating Station Safety Systems, 2000.

12. ASCE 4-86, Seismic Analysis of Safety-Related Nuclear Structures, September 1986.

13. RESAR/SP90, Westinghouse Advanced Pressurized Water Reactor, Paragraph 3.7.1.3, Damping Values, January 1989.

14. Design & Evaluation Guideline for Department of Energy Facilities Subjected to Natural Phenomena Hazards, Lawrence Livermore National Laboratory, UCRL-15910, R. P. Kennedy et al., May 1989.

15. IEEE 741-1986, IEEE Standard Criteria for Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations, 1986.

16. IEEE Std. 741-1997, IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations, 1997.

17. IEEE 317-1983, IEEE Standard for Electric Penetrations Assemblies in Containment Structures for Nuclear Power Generating Stations, 1983.

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19. ANSI/ANS 6.4 1997, Guidelines on the Nuclear Analysis and Design of Concrete Radiation Shielding for Nuclear Power Plants.

20. Not used.

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22. IEEE 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations, 1974.

23. IEEE 384-74, IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits, 1974.

24. IEEE 384-81, IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits, 1981.

25. ANS 5.4-1982, American National Standard Method for Calculating the Fractional Release of Volatile Fission Products From Oxide Fuel, 1982.

26. Title 10 Code of Federal Regulations Part 50, 50.49, Environmental qualification of electric equipment important to safety for nuclear power plants.

27. IEEE Std. 279-1971, IEEE Standard Criteria for Protection Systems for Nuclear Power Generating Stations, 1971.

28. NRC Safety Evaluation Report, letter from B. D. Liaw to J. A. Martin, December 27, 1984.

29. IEEE 384-2008, IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits, 2008.

30. Not used.

31. IEEE Std. 338-1987, IEEE Standard Criteria for the Periodic Surveillance Testing of Nuclear Power Generating Stations Safety Systems, 1987.

32. NUREG-0800, U.S. Nuclear Regulatory Commission Standard Review Plan, Section 9.5.1, “Fire Protection Program,” Revision 3, July 1981, including Branch Technical Position (BTP) CMEB 9.5-1, “Guidelines for Fire Protection for Nuclear Power Plants,” Revision 2, July 1981.

33. SRP (NUREG-0800) Section 9.5.1 "Fire Protection Program," Revision 3, July 1986.

34. Guide to Design Criteria for Bolted and Riveted Joints, Fisher and Struik, copyright 1974, John Wiley and Sons.

35. Not used.

36. IEEE 484-75, IEEE Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations, 1975.

37. IEEE 484-1996, IEEE Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations, 1996.

38. ASME AG-1-1997, "Code on Nuclear Air and Gas Treatment," 1997.

39. ASME Code N509-1989, "Nuclear Power Plant Air Cleaning Units and Components," 1989.

40. ASME Code N510-1989, "Testing of Nuclear Air Cleaning Systems," 1989.

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44. ACI 349-01, "Code Requirements for Nuclear Safety Related Concrete Structures," 2001.

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48. Not used.

49. ANSI N237-1976, Source Term Specification, 1976.

50. ANSI/ANS 18.1-1999, Radioactive Source Term for Normal Operation of Light Water Reactors, 1999.

51. IEEE Std. 603-1991, IEEE Standard Criteria for Power Generating Stations, 1991.

52. WCAP-16650-P (Proprietary) and WCAP-16650-NP (Non-Proprietary), "Analysis of the Probability of Generation of Missiles for Fully Integral Low Pressure Turbines," Revision 0, February 2007.

Appendix 1B Not Used

DCD Appendix 1B is not incorporated into this document. Rather, the severe accident mitigation design alternatives are addressed in the Environmental Report. As indicated in 10 CFR Part 52, Appendix D, Section III.B, "...the evaluation of severe accident mitigation design alternatives in appendix 1B of the generic DCD are not part of this appendix."

The applicable Environmental Report was provided in the Early Site Permit (ESP) application and evaluated in the Environmental Impact Statement for an ESP at the Vogtle Electric Generating Plant Site.

Appendix 1AA Not Used

FSAR Appendix 1AA is merged with DCD Appendix 1A and therefore Appendix 1AA is not used.

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
2.0	Site Characteristics	2.0-1
2.1	Geography and Demography	2.1-1
2.1.1	Site Location and Description	2.1-1
2.1.1.1	Site Location	2.1-1
2.1.1.2	Site Description	2.1-1
2.1.1.3	Boundary for Establishing Effluent Release Limits	2.1-2
2.1.2	Exclusion Area Authority and Control	2.1-2
2.1.2.1	Authority	2.1-2
2.1.2.2	Control of Activities Unrelated to Plant Operation	2.1-2
2.1.2.3	Arrangements for Traffic Control	2.1-3
2.1.3	Population Distribution	2.1-3
2.1.3.1	Resident Population Within 10 Mi	2.1-3
2.1.3.2	Resident Population Between 10 and 50 Mi	2.1-4
2.1.3.3	Transient Population	2.1-4
2.1.3.4	Low Population Zone	2.1-4
2.1.3.5	Population Center	2.1-5
2.1.3.6	Population Density	2.1-5
2.1.4	Combined License Information for Geography and Demography	2.1-5
2.1.5	References	2.1-5
2.2	Identification of Potential Hazards in Site Vicinity	2.2-1
2.2.1	Location of Nearby Industrial, Transportation, and Military Facilities	2.2-1
2.2.2	Descriptions	2.2-1
2.2.2.1	Industrial Facilities	2.2-1
2.2.2.2	Mining Activities	2.2-3
2.2.2.3	Roads	2.2-3
2.2.2.4	Railroads	2.2-4
2.2.2.5	Waterways	2.2-4
2.2.2.6	Airports, Airways, and Military Training Routes	2.2-4
2.2.2.7	Natural Gas or Petroleum Pipelines	2.2-6
2.2.2.8	Military Facilities	2.2-6
2.2.2.9	VEGP Units 1 and 2 Storage Tanks/Chemicals	2.2-6
2.2.3	Evaluation of Potential Accidents	2.2-6
2.2.3.1	Explosion and Flammable Vapor Clouds	2.2-8
2.2.3.2	Hazardous Chemicals	2.2-12
2.2.3.3	Fires	2.2-19
2.2.3.4	Radiological Hazards	2.2-21
2.2.4	Combined License Information for Identification of Site-Specific Potential Hazards	2.2-22
2.2.5	References	2.2-22
2.3	Meteorology	2.3-1
2.3.1	Regional Climatology	2.3-1
2.3.1.1	Data Sources	2.3-1
2.3.1.2	General Climate	2.3-3
2.3.1.3	Severe Weather	2.3-4
2.3.1.4	Meteorological Data for Evaluating the Ultimate Heat Sink	2.3-11

TABLE OF CONTENTS (CONTINUED)

Section		Title	Page
	2.3.1.5	Design Basis Dry- and Wet-Bulb Temperatures	2.3-11
	2.3.1.6	Restrictive Dispersion Conditions	2.3-14
	2.3.1.7	Climate Changes	2.3-15
2.3.2		Local Meteorology	2.3-17
	2.3.2.1	Data Sources	2.3-17
	2.3.2.2	Normal, Mean, and Extreme Values of Meteorological Parameters	2.3-17
	2.3.2.3	Potential Influence of the Plant and Related Facilities on Meteorology	2.3-21
	2.3.2.4	Current and Projected Site Air Quality	2.3-22
	2.3.2.5	Topographic Description	2.3-22
2.3.3		Onsite Meteorological Measurements Program	2.3-23
	2.3.3.1	Onsite Meteorological Measurements Program	2.3-23
	2.3.3.2	General Program Description	2.3-23
	2.3.3.3	Location, Elevation, and Exposure of Instruments	2.3-24
	2.3.3.4	VEGP Meteorological Monitoring Program Compliance	2.3-24
2.3.4		Short-Term (Accident) Diffusion Estimates	2.3-25
	2.3.4.1	Basis	2.3-26
	2.3.4.2	PAVAN Modeling Results	2.3-28
	2.3.4.3	Radiological Accident Dispersion Estimates at the Control Room	2.3-28
	2.3.4.4	Dispersion Estimates Associated with Accidental Onsite and Offsite Hazardous Material Releases	2.3-31
2.3.5		Long-Term (Routine) Diffusion Estimates	2.3-31
	2.3.5.1	Basis	2.3-32
	2.3.5.2	XOQDOQ Modeling Results	2.3-33
2.3.6		Combined License Information	2.3-33
	2.3.6.1	Regional Climatology	2.3-33
	2.3.6.2	Local Meteorology	2.3-34
	2.3.6.3	Onsite Meteorological Measurements Program	2.3-34
	2.3.6.4	Short-Term Diffusion Estimates	2.3-34
	2.3.6.5	Long-Term Diffusion Estimates	2.3-34
2.3.7		References	2.3-34
2.4		Hydrologic Engineering	2.4-1
2.4.1		Hydrologic Description	2.4-1
	2.4.1.1	Site and Facilities	2.4-1
	2.4.1.2	Hydrosphere	2.4-2
2.4.2		Floods	2.4-7
	2.4.2.1	Flood History	2.4-7
	2.4.2.2	Flood Design Considerations	2.4-9
	2.4.2.3	Effects of Local Intense Precipitation	2.4-10
2.4.3		Probable Maximum Flood	2.4-13
	2.4.3.1	Review of Studies for Units 1 and 2	2.4-14
	2.4.3.2	Estimation of PMF by Approximate Methods	2.4-15
	2.4.3.3	Estimation of Flood Stage at VEGP Site for PMF	2.4-15
	2.4.3.4	Conclusions	2.4-16

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
2.4.4	Potential Dam Failures	2.4-17
2.4.4.1	Dam Failure Permutations	2.4-17
2.4.4.2	Unsteady Flow Analysis of Potential Dam Failures	2.4-18
2.4.4.3	Water Level at the Plant Site	2.4-23
2.4.5	Probable Maximum Surge and Seiche Flooding	2.4-24
2.4.6	Probable Maximum Tsunami Flooding	2.4-24
2.4.7	Ice Effects	2.4-25
2.4.7.1	Ice Conditions and Historical Ice Formation	2.4-25
2.4.7.2	Ice Jam Events	2.4-25
2.4.7.3	Description of the Cooling Water System	2.4-25
2.4.8	Cooling Water Canals and Reservoirs	2.4-26
2.4.8.1	Cooling Water Canals	2.4-26
2.4.8.2	Reservoirs	2.4-27
2.4.9	Channel Diversions	2.4-27
2.4.10	Flood Protection Requirements	2.4-28
2.4.11	Low Water Considerations	2.4-29
2.4.11.1	Low Flow in Streams	2.4-29
2.4.11.2	Low Water Resulting from Surges, Seiches, Tsunamis, or Ice Effects	2.4-33
2.4.11.3	Historical Low Water	2.4-33
2.4.11.4	Future Controls	2.4-34
2.4.11.5	Plant Requirements	2.4-34
2.4.11.6	Heat Sink Dependability Requirements	2.4-34
2.4.12	Groundwater	2.4-34
2.4.12.1	Regional and Local Groundwater Aquifers and Conceptual Model Description	2.4-35
2.4.12.2	Regional and Local Groundwater Use	2.4-51
2.4.12.3	Monitoring or Safeguard Requirements	2.4-52
2.4.12.4	Design Basis for Subsurface Hydrostatic Loading	2.4-53
2.4.13	Accidental Releases of Liquid Effluents in Ground and Surface Waters	2.4-53
2.4.13.1	Groundwater	2.4-53
2.4.13.2	Surface Water	2.4-60
2.4.14	Technical Specifications and Emergency Operation Requirements	2.4-60
2.4.15	Combined License Information	2.4-60
2.4.15.1	Hydrological Description	2.4-60
2.4.15.2	Floods	2.4-60
2.4.15.3	Cooling Water Supply	2.4-61
2.4.15.4	Groundwater	2.4-61
2.4.15.5	Accidental Release of Liquid Effluents in Ground and Surface Water	2.4-61
2.4.15.6	Emergency Operation Requirement	2.4-61
2.4.16	References	2.4-61
APPENDIX 2.4A	—OBSERVATION WELL INSTALLATION AND DEVELOPMENT REPORT	2.4A-1
APPENDIX 2.4B	—GROUNDWATER MODEL DEVELOPMENT & ANALYSIS	2.4B-1
2.5	Geology, Seismology, and Geotechnical Engineering	2.5-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
2.5.1	Basic Geologic and Seismic Information	2.5-2
2.5.1.1	Regional Geology (200 mi radius)	2.5-2
2.5.1.2	Site Area Geology	2.5-44
2.5.2	Vibratory Ground Motion	2.5-62
2.5.2.1	Seismicity	2.5-63
2.5.2.2	Geologic Structures and EPRI Seismic Source Model for the Site Region	2.5-65
2.5.2.3	Correlation of Seismicity with Geologic Structures and EPRI Sources	2.5-87
2.5.2.4	Probabilistic Seismic Hazard Analysis and Controlling Earthquakes	2.5-87
2.5.2.5	Seismic Wave Transmission Characteristics of the Site	2.5-93
2.5.2.6	Horizontal Ground Motion	2.5-100
2.5.2.7	Vertical GMRS Spectrum	2.5-102
2.5.2.8	Operating Basis Earthquake Ground Motion	2.5-106
2.5.2.9	Sensitivity Studies	2.5-106
2.5.3	Surface Faulting	2.5-112
2.5.3.1	Geological, Seismological, and Geophysical Investigations	2.5-112
2.5.3.2	Geological Evidence, or Absence of Evidence, for Surface Deformation	2.5-117
2.5.3.3	Correlation of Earthquakes With Capable Tectonic Sources	2.5-119
2.5.3.4	Ages of Most Recent Deformations	2.5-121
2.5.3.5	Relationships of Tectonic Structures in the Site Area to Regional Tectonic Structures	2.5-121
2.5.3.6	Characterization of Capable Tectonic Sources	2.5-122
2.5.3.7	Designation of Zones of Quaternary Deformation Requiring Detailed Fault Investigation	2.5-123
2.5.3.8	Potential for Tectonic or Non-Tectonic Deformation at the Site	2.5-123
2.5.4	Stability of Subsurface Materials and Foundations	2.5-127
2.5.4.1	Geologic Features	2.5-127
2.5.4.2	Properties of Subsurface Materials	2.5-127
2.5.4.3	Exploration	2.5-142
2.5.4.4	Geophysical Surveys	2.5-148
2.5.4.5	Excavation and Backfill	2.5-152
2.5.4.6	Groundwater Conditions	2.5-159
2.5.4.7	Response of Soil and Rock to Dynamic Loading	2.5-160
2.5.4.8	Liquefaction Potential	2.5-167
2.5.4.9	Earthquake Design Basis	2.5-171
2.5.4.10	Static Stability	2.5-171
2.5.4.11	Design Criteria	2.5-176
2.5.4.12	Techniques to Improve Subsurface Conditions	2.5-177
2.5.4.13	Heavy Lift Derrick Counterweight and Ring Foundation	2.5-178
2.5.5	Stability of Slopes	2.5-179

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
2.5.5.1	Review of Existing Slopes	2.5-179
2.5.5.2	New Slopes	2.5-179
2.5.6	Embankments and Dams	2.5-180
2.5.6.1	Review of Existing Embankments and Dams	2.5-180
2.5.6.2	New Embankments and Dams	2.5-180
2.5.7	Combined License Information	2.5-181
2.5.7.1	Basic Geologic and Seismic Information	2.5-181
2.5.7.2	Seismic and Tectonic Characteristics Information	2.5-181
2.5.7.3	Geoscience Parameters	2.5-181
2.5.7.4	Surface Faulting	2.5-181
2.5.7.5	Site and Structures	2.5-181
2.5.7.6	Properties of Underlying Materials	2.5-181
2.5.7.7	Excavation and Backfill	2.5-181
2.5.7.8	Ground Water Conditions	2.5-181
2.5.7.9	Liquefaction Potential	2.5-181
2.5.7.10	Bearing Capacity	2.5-181
2.5.7.11	Earth Pressures	2.5-181
2.5.7.12	Soil Properties for Seismic Analysis of Buried Pipes	2.5-182
2.5.7.13	Static and Dynamic Stability of Facilities	2.5-182
2.5.7.14	Subsurface Instrumentation	2.5-182
2.5.7.15	Stability of Slopes	2.5-182
2.5.7.16	Embankments and Dams	2.5-182
2.5.7.17	Settlement of Nuclear Island	2.5-182
2.5.7.18	Waterproofing System	2.5-182
2.5.8	References	2.5-183
APPENDIX 2.5A	—GEOTECHNICAL INVESTIGATION AND LABORATORY TESTING DATA REPORT – ESP	2.5A-1
APPENDIX 2.5B	—HIGH RESOLUTION COMPRESSIONAL SEISMIC SURVEY FIELD REPORT	2.5B-1
APPENDIX 2.5C	—GEOTECHNICAL INVESTIGATION AND LABORATORY TESTING DATA REPORT – COL	2.5C-1
APPENDIX 2.5D	—ENGINEERED FILL BELOW GRADE TEST PAD, PHASE 1	2.5D-1
APPENDIX 2.5E	—AP1000 VOGTLE SITE SPECIFIC SEISMIC EVALUATION REPORT	2.5E-1

LIST OF TABLES

Table Number	Title	Page
2-1	Not Used	2.0-2
2.0-201	Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics	2.0-3
2.0-202	Comparison of Control Room Atmospheric Dispersion Factors for Accident Analysis for AP1000 DCD and VEGP Units 3 & 4	2.0-12
2.0-203	Site Characteristics, Design Parameters, and Site Interface Values	2.0-14
2.2-1	AP1000 OnSite Explosion Safe Distances	2.2-25
2.2-201	Nearby Largest Employers	2.2-26
2.2-202	Description of Products and Materials: Chem-Nuclear Systems, Inc.	2.2-26
2.2-203	Burke County, Georgia, Transportation Accident Data Within 5 Miles of the VEGP Site	2.2-26
2.2-204	Bush Field (Augusta) Terminal Area Forecast Fiscal Years 1990–2025 Total Flights	2.2-27
2.2-205	VEGP Units 1 and 2 Onsite Chemical Storage	2.2-28
2.2-206	Not Used	2.2-29
2.3-201	ARCON96 X/Q Values at the Control Room HVAC Intake	2.3-38
2.3-202	ARCON96 X/Q Values at the Annex Building Access Door	2.3-39
2.3-203	NWS and Cooperative Observing Stations Near the VEGP Site	2.3-40
2.3-204	Local Climatological Data Summary for Augusta, Georgia	2.3-41
2.3-205	Climatological Extremes at Selected NWS and Cooperative Observing Stations in the VEGP Site Area	2.3-42
2.3-206	Mean Seasonal and Annual Morning and Afternoon Mixing Heights and Wind Speeds for Athens, Georgia	2.3-43
2.3-207	Climatological Normals (Means) at Selected NWS and Cooperative Observing Stations in the VEGP Site Area	2.3-44
2.3-208	Seasonal and Annual Mean Wind Speeds for the VEGP Site (1998–2002) and the Augusta, Georgia, NWS Station (1971–2000, Normals)	2.3-45
2.3-209	Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 10-m Level	2.3-46
2.3-210	Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 60-m Level	2.3-52
2.3-211	Seasonal and Annual Vertical Stability Class and Mean 10-Meter Level Wind Speed Distributions for the VEGP Site (1998–2002)	2.3-58
2.3-212	Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)	2.3-59
2.3-213	Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)	2.3-67
2.3-214	VEGP Onsite Weather Instruments	2.3-75
2.3-215	Annual Data Recovery Statistics - VEGP 60-Meter Meteorological Tower (1998-2002)	2.3-76
2.3-216	PAVAN Output – χ/Q Values at the Dose Calculation EAB	2.3-77
2.3-217	PAVAN Output – χ/Q Values at the LPZ	2.3-78
2.3-218	Shortest Distances Between the VEGP Units 3 and 4 Power Block Area and Receptors of Interest by Downwind Direction Sector	2.3-79
2.3-219	XOQDOQ-Predicted Maximum χ/Q and D/Q Values at Receptors of Interest	2.3-80

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
2.3-220	XOQDOQ-Predicted Annual Average χ/Q and D/Q Values at the Standard Radial Distances and Distance-Segment Boundaries	2.3-81
2.4-201	Rainfall Depths Used as Input for Frequency Storm HEC-HMS Module	2.4-69
2.4-202	Subbasin Parameters for Entry in Unit 3 & 4 Drainage System HEC-HMS Model	2.4-70
2.4-203	Deleted	2.4-72
2.4-204	Summary Results of HEC-HMS Model of Unit 3 & 4 PMP Drainage System	2.4-73
2.4-205	HEC-RAS Flow Hydrograph Input Location	2.4-75
2.4-206	Deleted	2.4-77
2.4-207	Summary of HEC-RAS output for PMP Profile	2.4-78
2.4-208	Savannah River Subbasins and Drainage Areas above VEGP Site	2.4-83
2.4-209	River Miles for Key Landmarks Along the Savannah River	2.4-84
2.4-210	USGS Gage Data for the Savannah River	2.4-85
2.4-211	Daily Mean Flow Data for the Savannah River at Calhoun Falls, South Carolina (USGS Gage 2189000)	2.4-86
2.4-212	Daily Mean Flow Data for the Savannah River at Augusta, Georgia (USGS Gage 2197000)	2.4-87
2.4-213	Daily Mean Flow Data for the Savannah River at Jackson, South Carolina (USGS Gage 2197320)	2.4-88
2.4-214	Approximate Lengths and Slopes of Local Streams	2.4-89
2.4-215	Inventory of Savannah River Watershed Water Control Structures	2.4-90
2.4-216	Surface Water Users on the Savannah River Near or Downstream of Proposed Units	2.4-91
2.4-217	Plant Water Use	2.4-92
2.4-218	Annual Peak Discharge for USGS Gage 2197000 on the Savannah River at Augusta, Georgia	2.4-94
2.4-219	Comparison of Annual Peak Discharges on the Savannah River at Augusta, Georgia and Jackson, South Carolina for 1972 to 2002	2.4-95
2.4-220	Probable Maximum Precipitation Values for Point Rainfall at VEGP Site	2.4-96
2.4-221	Results of Previous PMF Modeling Efforts	2.4-96
2.4-222	PMF Values for an Area-PMF Relationship at the VEGP Site	2.4-96
2.4-223	PMF Flood Stages for Cross-Section Nearest VEGP Site	2.4-97
2.4-224	Estimated Probable Maximum Flood Stage at VEGP Site	2.4-97
2.4-225	Normal Pool Storage Volumes	2.4-97
2.4-226	Breach Parameter Estimation Formulas	2.4-98
2.4-227	J. Strom Thurmond Dam Input Variables	2.4-99
2.4-228	J. Strom Thurmond Dam Breach Parameters	2.4-99
2.4-229	Richard B. Russell Dam Input Variables	2.4-100
2.4-230	Richard B. Russell Dam Breach Parameters	2.4-100
2.4-231	Estimated Probable Maximum Surge at the Savannah River Mouth	2.4-101
2.4-232	Variation in Lowest Average Daily Temperatures and Number of Days with Average Daily Temperature Below Freezing	2.4-102
2.4-233	Variation in the Minimum Water Temperatures at Five Locations on the Savannah River	2.4-103
2.4-234	Summary of Action Levels for Drought Management in the Savannah River Basin	2.4-104

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
2.4-235	Locations, Catchment Areas, and Data Availability of the USGS Gage Stations	2.4-105
2.4-236	Variation of Annual Minimum Daily-mean Flow in the Savannah River at Augusta, Jackson, and Burtons Ferry Gages	2.4-106
2.4-237	Summary of Statistical Parameters for Different Probability Density Functions Calculated with Annual Minimum Daily-mean Streamflow Values at Augusta for the Water Years 1884–1952	2.4-110
2.4-238	Summary of Low Flow Statistics for Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean and 7-Day Moving-average Streamflow Values at Augusta and Jackson for Different Water Years	2.4-111
2.4-239	Summary of Streamflow Measurement at USGS Station No. 021973269 Savannah River Near Waynesboro	2.4-112
2.4-240	Summary of Proposed Modifications in Action Levels for Drought Management in the Savannah River Basin	2.4-113
2.4-241	Monthly Groundwater Level Elevations in the Water Table Aquifer (ft msl)	2.4-114
2.4-242	Monthly Groundwater Level Elevations in the Tertiary Aquifer (ft msl)	2.4-115
2.4-243	Hydraulic Conductivity Values	2.4-116
2.4-244	Summary of Laboratory Test Results on Grain Size, Moisture Content and Specific Gravity for the Barnwell Formation	2.4-118
2.4-245	Summary of Laboratory Test Results on Grain Size, Moisture Content, and Porosity for the Lisbon Formation	2.4-120
2.4-246	Summary of Laboratory Test Results on Grain Size, Moisture Content, and Specific Gravity for the Still Branch and Congaree Formations	2.4-121
2.4-247	Georgia EPD Permitted Municipal and Industrial Groundwater Users within 25 miles of the VEGP Site	2.4-123
2.4-248	Georgia EPD Permitted Agricultural Groundwater Users within 25 miles of the VEGP Site	2.4-124
2.4-249	SDWIS Listed Public Water Systems Supplied From Groundwater Within 25 Miles of the VEGP Site in Georgia	2.4-126
2.4-250	Water-Supply Wells for the Existing VEGP Plant	2.4-127
2.4-251	Groundwater Use of the existing VEGP Plant from January 1, 2005, to December 31, 2005, gpm (Thousands of Gallons)	2.4-128
2.4-252	Projected Groundwater Use for Two AP1000 Units	2.4-129
2.4-253	Presence of Utley Limestone in the VEGP ESP and COL Site Borings	2.4-130
2.4-254	Summary of Holes Drilled at the Site for the Installation of Observation Wells	2.4-136
2.4-255	Historical Groundwater Levels for the Water Table Aquifer	2.4-137
2.4-256	Minimum and Maximum Water Levels Recorded at Observation Wells 802A, 805A, 808, LT-7A, LT-12, and LT-13	2.4-145
2.4-257	Radionuclide Concentrations in the AP1000 Effluent Holdup Tanks	2.4-146
2.4-258	Water Table Aquifer Results of Transport Analysis Considering Radioactive Decay Only	2.4-148
2.4-259	Results of kd Analysis	2.4-150
2.4-260	Water Table Aquifer Results of Transport Analysis Considering Radioactive Decay and Adsorption	2.4-151

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
2.4-261	Results of Transport Analysis Considering Radioactive Decay, Adsorption, and Dilution	2.4-152
2.4-262	Tertiary Aquifer Results of Transport Analysis Considering Radioactive Decay Only	2.4-153
2.4-263	Water Table Aquifer Compliance with 10 CFR Part 20	2.4-155
2.4-264	Tertiary Aquifer Compliance with 10 CFR Part 20	2.4-157
2.5-1	Limits of Acceptable Settlement Without Additional Evaluation	2.5-216
2.5-201	Definitions of Classes Used in the Compilation of Quaternary Faults, Liquefaction Features, and Deformation in the Central and Eastern United States	2.5-217
2.5-202	Earthquakes 1985–2005, Update to the EPRI (NP-4726-A 1988) Seismicity Catalog with $Em_b \geq 3.0$, Within a 30° to 37° N, 78° to 86° W Latitude-Longitude Window, Incorporating the 200 mi (320 km) Radius Site Region	2.5-218
2.5-203	Summary of Bechtel Seismic Sources	2.5-220
2.5-204	Summary of Dames & Moore Seismic Sources	2.5-222
2.5-205	Summary of Law Engineering Seismic Sources	2.5-224
2.5-206	Summary of Rondout Seismic Sources	2.5-226
2.5-207	Summary of Weston Seismic Sources	2.5-228
2.5-208	Summary of Woodward-Clyde Seismic Sources	2.5-231
2.5-209	Summary of USGS Seismic Sources (Frankel et al. 2002)	2.5-233
2.5-210	Chapman and Talwani (2002) Seismic Source Zone Parameters	2.5-234
2.5-211	Local Charleston-Area Tectonic Features	2.5-235
2.5-212	Geographic Coordinates (Latitude and Longitude) of Corner Points of Updated Charleston Seismic Source (UCSS) Geometries	2.5-236
2.5-213	Comparison of Post-EPRI NP-6395-D 1989 Magnitude Estimates for the 1886 Charleston Earthquake	2.5-237
2.5-214	Comparison of Talwani and Schaeffer (2001) and UCSS Age Constraints on Charleston-Area Paleoliquefaction Events	2.5-238
2.5-215	Seismic Sources Used for Each 1986 EPRI Team	2.5-239
2.5-216	Comparison of Seismic Hazard at VEGP ESP	2.5-240
2.5-217	Hard Rock Mean UHS Results (in g) for VEGP ESP	2.5-241
2.5-218	Computed and Recommended Mbar and Dbar Values Used for Development of High and Low Frequency Target Spectra	2.5-241
2.5-219	Candidate High-Frequency (M5.6, R = 12km) Time Histories for Spectral Matching	2.5-242
2.5-220	Candidate Low-Frequency (M7.2, R = 130 km) Time Histories for Spectral Matching	2.5-243
2.5-221	Site Response Analyses Performed	2.5-243
2.5-222	Amplification Factors as a Function of Input Hard Rock Motion at Top of Blue Bluff Marl (depth 86 feet), as Developed from Site Response Analysis using SRS and EPRI Soil Degradation Models, for High-frequency Rock Motions	2.5-244
2.5-223	Amplification Factors as a Function of Input Hard Rock Motion at Top of Blue Bluff Marl (depth 86 feet), as Developed from Site Response Analysis using SRS and EPRI Soil Degradation Models, for Low-frequency Rock Motions	2.5-245

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
2.5-224	Amplification Factors as a Function of Input Hard Rock Motion at 40-ft Depth Horizon (FIRS), as Developed from Site Response Analysis using SRS and EPRI Soil Degradation Models, for High-Frequency Rock Motions	2.5-246
2.5-225	Amplification Factors as a Function of Input Hard Rock Motion at 40-ft Depth Horizon (FIRS), as Developed from Site Response Analysis Using SRS and EPRI Soil Degradation Models, for Low-Frequency Rock Motions	2.5-247
2.5-226	Amplification Factors as a Function of Input Hard Rock Motion at Ground Surface (GMRS), as Developed from Site Response Analysis Using SRS and EPRI Soil Degradation Models, for High-Frequency Rock Motions	2.5-248
2.5-227	Amplification Factors as a Function of Input Hard Rock Motion at Ground Surface (GMRS), as Developed from Site Response Analysis Using SRS and EPRI Soil Degradation Models, for Low-Frequency Rock Motions	2.5-249
2.5-228	Spectral Accelerations (SA, in g) for Hard Rock Conditions and for Hypothetical Outcrop of Highest Competent In Situ Layer (Top of Blue Bluff Marl)	2.5-250
2.5-229	Spectral Accelerations (SA, in g) for Hard Rock Conditions and for Hypothetical Outcrop at 40-ft Depth Horizon (FIRS)	2.5-251
2.5-230	Spectral Accelerations (SA, in g) for Hard Rock Conditions and for Ground Surface Motions (GMRS)	2.5-252
2.5-231	Amplitudes (g) for the Hypothetical Outcrop of Highest Competent In Situ Layer (Top of Blue Bluff Marl)	2.5-253
2.5-232	FIRS Amplitudes (g) for the Hypothetical Outcrop at 40-ft Depth Horizon	2.5-254
2.5-233	SSE Amplitudes (g) for the Ground Surface (GMRS)	2.5-255
2.5-234	Coversion Between Body-Wave (m_b) and Moment (M) Magnitudes	2.5-256
2.5-235	Summary of Bedrock Faults Mapped Within the 5-Mile VEGP Site Radius	2.5-257
2.5-236	Static Engineering Properties of Subsurface Materials (ESP)	2.5-258
2.5-237	Static Engineering Properties of Subsurface Materials (COL)	2.5-259
2.5-238	Design Dynamic Shear Modulus (ESP)	2.5-260
2.5-239	Types and Numbers of Laboratory Tests Completed for the ESP Application	2.5-261
2.5-240	Types and Numbers of Completed Laboratory Tests in the Powerblock Footprint for the COL Investigation	2.5-261
2.5-241	Summary of Laboratory Tests Performed on Selected Soils Samples from ESP Borings	2.5-262
2.5-242	Summary of SPT N-Values Measured at the ESP Borings	2.5-266
2.5-243	Typical Shear Wave Velocity Values for Existing Strata (ESP)	2.5-267
2.5-244	Summary of ESP Borings and CPTs	2.5-268
2.5-245	Summary of COL Borings, CPTs, and Test Pits	2.5-269
2.5-246	Summary of Undisturbed Samples of the Blue Bluff Marl (ESP)	2.5-275
2.5-247	Summary of SPT Hammer Energy Transfer Efficiency from ESP Investigation	2.5-276

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
2.5-248	Summary of SPT Hammer Energy Transfer Efficiency from COL Investigation	2.5-276
2.5-249	Estimated Shear Wave Velocity and Dynamic Shear Modulus Values for the Compacted Backfill (ESP)	2.5-277
2.5-250	Shear Wave Velocity Values for the Compacted Backfill (COL)	2.5-277
2.5-251	Shear Wave Velocity Values for Site Amplification Analysis Part A: Soil Shear-Wave Velocities (ESP)	2.5-278
2.5-252	Shear Wave Velocity Values for Site Amplification Analysis Part B: Rock Shear-Wave Velocities - Six Alternate Profiles	2.5-279
2.5-253	Shear Wave Velocity Values for Site Amplification Analysis Part A: Soil Shear-Wave Velocities (COL Soil Column)	2.5-280
2.5-254	Summary of Modulus Reduction and Damping Ratio Values – EPRI-Base	2.5-281
2.5-255	Summary of Modulus Reduction and Damping Ratio Values – Site Specific	2.5-282
2.5-256	Summary of Modulus Reduction and Damping Ratio Values – SRS-Based	2.5-283
2.5-257	Acceptable Gradation Envelope for Compacted Backfill	2.5-284
2.5-258	Criteria for Evaluation of Borrow Material from Outside of the Three Designated Category 1 and 2 Borrow Areas	2.5-284

LIST OF FIGURES

Figure Number	Title	Page
2.1-201	10-Mile Surrounding Area	2.1-7
2.1-202	50-Mile Surrounding Area	2.1-8
2.1-203	10-Mile Resident and Transient Population Distribution – 2000	2.1-9
2.1-204	10-Mile Resident and Transient Population Distribution – 2010	2.1-10
2.1-205	10-Mile Resident and Transient Population Distribution – 2020	2.1-11
2.1-206	10-Mile Resident and Transient Population Distribution – 2030	2.1-12
2.1-207	10-Mile Resident and Transient Population Distribution – 2040	2.1-13
2.1-208	10-Mile Resident and Transient Population Distribution – 2070	2.1-14
2.1-209	Population Grid Out to 50 Miles	2.1-15
2.1-210	10 to 50-Mile Resident Population Distribution 2000	2.1-16
2.1-211	10 to 50-Mile Resident Population Distribution 2010	2.1-17
2.1-212	10 to 50-Mile Resident Population Distribution 2020	2.1-18
2.1-213	10 to 50-Mile Resident Population Distribution 2030	2.1-19
2.1-214	10 to 50-Mile Resident Population Distribution 2040	2.1-20
2.1-215	10 to 50-Mile Resident Population Distribution 2070	2.1-21
2.1-216	Population Compared to NRC Siting Criteria	2.1-22
2.1-217	Low Population Zone	2.1-23
2.2-201	Site Vicinity Map	2.2-30
2.2-202	Airports Within 30 Miles of VEGP	2.2-31
2.2-203	Industrial Facilities Within 25 Miles of VEGP	2.2-32
2.2-204	Corridor Analysis	2.2-33
2.3-201	Climatological Observing Stations Near the VEGP Site	2.3-85
2.3-202	VEGP 10-m Level Annual Wind Rose (1998-2002)	2.3-86
2.3-203	VEGP 10-m Level Winter Wind Rose (1998-2002)	2.3-87
2.3-204	VEGP 10-m Level Spring Wind Rose (1998-2002)	2.3-88
2.3-205	VEGP 10-m Level Summer Wind Rose (1998-2002)	2.3-89
2.3-206	VEGP 10-m Level Autumn Wind Rose (1998-2002)	2.3-90
2.3-207	(Sheet 1 of 12) VEGP 10-m Level January Wind Rose (1998–2002)	2.3-91
2.3-208	VEGP 60-m Level Annual Wind Rose (1998-2002)	2.3-103
2.3-209	VEGP 60-m Level Winter Wind Rose (1998-2002)	2.3-104
2.3-210	VEGP 60-m Level Spring Wind Rose (1998-2002)	2.3-105
2.3-211	VEGP 60-m Level Summer Wind Rose (1998-2002)	2.3-106
2.3-212	VEGP 60-m Level Autumn Wind Rose (1998-2002)	2.3-107
2.3-213	(Sheet 1 of 12) VEGP 60-m Level January Wind Rose (1998–2002)	2.3-108
2.3-214	Topographic Features Within a 5-Mile Radius of the VEGP Site	2.3-120
2.3-215	(Sheet 1 of 4) Terrain Elevation Profiles Within 50 Miles of the VEGP Site	2.3-121
2.4-201	Site Plan with PMP Drainage Boundaries and Flow Paths	2.4-159
2.4-201a	Cross-Section Location Map for HEC-RAS Model of Local PMF for Units 3 and 4	2.4-160
2.4-202	PMP Hyetograph Determined in Frequency Storm Module of HEC-HMS	2.4-161
2.4-203	Sample HEC-HMS PMP Runoff Hydrographs	2.4-162
2.4-204	Savannah River Watershed and HUCs (No Scale)	2.4-163
2.4-205	Mean Daily Discharge for the Year – Selected Gages of the Savannah River	2.4-164
2.4-206	Site Drainage	2.4-165
2.4-207	Unregulated and Regulated Peak Discharge Frequency Curves for the Savannah River at Augusta, Georgia (02197000)	2.4-166

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.4-208	Correlation of Annual Peak Discharges on the Savannah River at Augusta, Georgia (02197000), and Jackson, South Carolina (2197320), for Years with Annual Peak Derived from Same Storm Event	2.4-167
2.4-209	Unregulated and Regulated Annual Peak Discharge Frequency Curves for the Savannah River at Augusta, Georgia	2.4-168
2.4-210	Probable Maximum Precipitation Values as a Function of Duration for Point Rainfall at VEGP Site	2.4-169
2.4-211	Area-PMF Plot for VEGP Site per Approximate Method from RG 1.59	2.4-170
2.4-212	Longitudinal Profiles of the Savannah River from Steady-State HEC-RAS Model Run	2.4-171
2.4-213	HEC-RAS Model Section at VEGP Site (Looking Downstream)	2.4-172
2.4-214	Savannah River Basin Dam Locations	2.4-173
2.4-215	J. Strom Thurmond Area Capacity Curve	2.4-174
2.4-216	Richard B. Russell Area Capacity Curve	2.4-175
2.4-217	Hartwell Dam and Reservoir Area Capacity	2.4-176
2.4-218	Keowee Area Capacity Curve	2.4-177
2.4-219	Jocassee Area Capacity Curve	2.4-178
2.4-220	J. Strom Thurmond Dam Cross Section	2.4-179
2.4-221	Richard B. Russell Dam Cross Section	2.4-180
2.4-222	Dam Breach Flood Flow and Stage Hydrograph at the VEGP Site	2.4-181
2.4-223	Savannah River SPF Water Surface Profile	2.4-182
2.4-224	Savannah River Dam Breach Flood Maximum Water Surface Profile	2.4-183
2.4-225	Savannah River Dam Breach Flood Water Surface Profile for Peak Discharge at VEGP Site	2.4-184
2.4-226	Maximum Fetch Length	2.4-185
2.4-227	Lowest Temperature Observed at the VEGP Site in 1985	2.4-186
2.4-228	Variation in Daily Mean Streamflow Rates at Augusta, Georgia, on the Savannah River (USGS Stream Gauging Station 02197000, Savannah River at Augusta, Georgia), Showing Streamflow Modulation After the Construction of the Dams	2.4-187
2.4-229	Variation in Annual Minimum Daily-mean Stream Flow in the Savannah River at Augusta, Jackson, and Burtons Ferry Gages	2.4-188
2.4-230	Change in Annual Minimum Daily-mean Flow at Jackson and Burtons Ferry Corresponding to that at Augusta for the Period of 1940-2003	2.4-189
2.4-231	Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean Flow Data from Augusta for the Water Years 1884–1952	2.4-190
2.4-232	Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean Flow Data from Augusta for the Water Years 1953–2003	2.4-191
2.4-233	Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean Flow Data from Augusta for the Water Years 1985–2003	2.4-192
2.4-234	Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean Streamflow from Jackson for the Water Years 1985–2002	2.4-193
2.4-235	River Stage-Discharge Rating Relationship at USGS Waynesboro Gage Station Near the VEGP Site Using Data for the Years 2005, 1988, 1987 and 1986	2.4-194
2.4-236	Comparison of Estimated River Stage Corresponding to Zero Discharge (H_0) with Measured River Thalweg Levels Near the Intake Location	2.4-195
2.4-237	Schematic Hydrostratigraphic Classification for VEGP Site	2.4-196

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.4-238	Hydrogeologic Cross-Section of the Water Table Aquifer at the VEGP Site	2.4-197
2.4-239	Hydrogeologic Cross-Section of the Tertiary Aquifer at the VEGP Site	2.4-198
2.4-240	Observation Well Locations	2.4-199
2.4-241	Water Table Aquifer: Piezometric Contour Map for June 2005	2.4-200
2.4-242	Water Table Aquifer: Piezometric Contour Map for October 2005	2.4-201
2.4-243	Water Table Aquifer: Piezometric Contour Map for December 2005	2.4-202
2.4-244	Water Table Aquifer: Piezometric Contour Map for March 2006	2.4-203
2.4-245	Water Table Aquifer: Piezometric Contour Map for June 2006	2.4-204
2.4-246	Tertiary Aquifer: 1971–1985 Hydrographs	2.4-205
2.4-247	Tertiary Aquifer: Piezometric Contour Map for June 2005	2.4-206
2.4-248	Tertiary Aquifer: Piezometric Contour Map for October 2005	2.4-207
2.4-249	Tertiary Aquifer: Piezometric Contour Map for December 2005	2.4-208
2.4-250	Tertiary Aquifer: Piezometric Contour Map for March 2006	2.4-209
2.4-251	Tertiary Aquifer: Piezometric Contour Map for June 2006	2.4-210
2.4-252	Locations of Agricultural, Industrial, Municipal, and Public Water Supply Wells Within 25 Miles of the VEGP Site	2.4-211
2.4-253	Locations of Existing Supply Wells at the VEGP Site	2.4-212
2.4-254	Water Table Aquifer: 1979–2007 Hydrographs	2.4-213
2.4-255	Average Annual PDSI and PHDI for Georgia and Total Annual Precipitation for the Period 1979–2006	2.4-214
2.4-256	Water Table Aquifer: June 2005 – July 2007 Hydrographs	2.4-215
2.4-257	Water Table Aquifer: Piezometric Contour Map for November 2006	2.4-216
2.4-258	Tertiary Aquifer: June 2005 – July 2007 Hydrographs	2.4-217
2.4-259	Tertiary Aquifer: Piezometric Contour Map for November 2006	2.4-218
2.4-260	Proposed Locations of VEGP Units 3 and 4 Water Supply Wells	2.4-219
2.4-261	Water Table Aquifer — Piezometric Contour Map for March 2007	2.4-220
2.4-262	Water Table Aquifer — Piezometric Contour Map for June 2007	2.4-221
2.4-263	Tertiary Aquifer — Piezometric Contour Map for March 2007	2.4-222
2.4-264	Tertiary Aquifer — Piezometric Contour Map for June 2007	2.4-223
2.4-265	Conceptual Model for Evaluating Radionuclide Transport in the Water Table Aquifer	2.4-224
2.4-266	Conceptual Model for Evaluating Radionuclide Transport in the Tertiary Aquifer	2.4-224
2.5-201	Vogtle Site-Specific At-Rest Lateral Earth Pressure Diagrams for Rigid Below Grade Nuclear Island (NI) Walls	2.5-285
2.5-202	Comparison of Vogtle Site-Specific Total At-Rest Lateral Earth Pressure Diagrams and AP1000 Maximum Design Envelopes	2.5-286
2.5-203	Heavy Lift Derrick Foundation Location	2.5-287
2.5-204	Physiographic Provinces of the Southeastern United States	2.5-288
2.5-205	Conceptual Section Linking Dunbarton Basin with South Georgia Basin Complex	2.5-289
2.5-206	Regional Geologic Map (200-Mile Radius)	2.5-290
2.5-207	Regional Geologic Map (200-Mile Radius) Explanation	2.5-291
2.5-208	Simplified Geologic Map of Western Piedmont Terrane in Relation to Blue Ridge and Carolina Terranes	2.5-292
2.5-209	Map of Carolina Terrane and Modoc Zone	2.5-293
2.5-210	Triassic Basins in the Eastern United States	2.5-294

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.5-211	Stratigraphic Correlation Chart	2.5-295
2.5-212	Location Map Showing SRS Boundary and VEGP Site	2.5-296
2.5-213	Evolution of the Appalachian Orogen	2.5-297
2.5-214	Regional Cross Section – DNAG E-5	2.5-298
2.5-215	Tectonic Features of the Southeastern United States	2.5-299
2.5-216	Regional Tectonic Features Map (200-Mile Radius)	2.5-300
2.5-217	Terrains and Physiographic Provinces of Site Region	2.5-301
2.5-218	Seismic Source Zones and Seismicity in Central and Eastern North America	2.5-302
2.5-219	Site Vicinity Tectonic Features and Seismicity	2.5-303
2.5-220	Potential Quaternary Features Map	2.5-304
2.5-221	Regional Charleston Tectonic Features	2.5-305
2.5-222	Local Charleston Tectonic Features	2.5-306
2.5-223	Local Charleston Seismicity	2.5-307
2.5-224	SRS Faults from Stieve and Stephenson (1995)	2.5-308
2.5-225	SRS Faults from Cumbest et al. (1998)	2.5-309
2.5-226	SRS Faults—First-Order Faults of Cumbest et al. (2000)	2.5-310
2.5-227	Gravity Field in the Vicinity of the VEGP Site	2.5-311
2.5-228	Northwest–Southeast Gravity Profile Through the VEGP Site	2.5-312
2.5-229	Magnetic Field in the Vicinity of the VEGP Site	2.5-313
2.5-230	Northwest–Southeast Profile of Magnetic Intensity Through the VEGP Site	2.5-314
2.5-231	Site Vicinity Geologic Map (25-Mile Radius)	2.5-315
2.5-232	Site Area Geologic Map (5-Mile Radius)	2.5-316
2.5-233	Site Area Topographic Map (5-Mile Radius)	2.5-317
2.5-234	Site Geologic Map (0.6-Mile Radius)	2.5-318
2.5-235	Site Topographic Map (0.6-Mile Radius)	2.5-319
2.5-236	Site Borings Location Map	2.5-320
2.5-237	Location of Pen Branch Fault	2.5-321
2.5-238	Seismic Reflection Array	2.5-322
2.5-239	Seismic Refraction Array	2.5-323
2.5-240	(A) Seismic Reflection Line 4 (Time Section; Display Velocity = 12,000 fps) (B) Interpretation (Blue Line Represents Top of Basement)	2.5-324
2.5-241	Site Stratigraphic Column	2.5-325
2.5-242	Location of the Pen Branch Fault at Top of Basement Beneath the Overlying Monocline in the Blue Bluff Marl	2.5-326
2.5-243	Northwest–Southeast Cross Section Showing Pen Branch Fault Beneath VEGP Site	2.5-327
2.5-244	East–West Cross Section Showing Pen Branch Fault Beneath VEGP Site	2.5-328
2.5-245	VEGP Site Plant Layout	2.5-329
2.5-246	Geologic Map of Qte Terrace Study Area	2.5-330
2.5-247	Geomorphic Map Showing Best-Preserved Remnants of Qte Terrace Surface (Red Shading) in Study Area at the SRS. Yellow Ds Indicate Dissolution Collapse-Related Depressions. Base Image is 1943 Aerial Photograph.	2.5-331

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.5-248	Longitudinal Profile A-A' from SRS Qte Terrace Surface. Points Interpreted as Representing the Best-Preserved Remnant of the Qte Surface are Shown in Red, all Other Points that Do Not Represent the Terrace Surface are Shown in Gray.	2.5-332
2.5-249	Transect and Borehole Location Map	2.5-333
2.5-250	Stratigraphic Structure Contour Map: Top of Blue Bluff Marl	2.5-334
2.5-251	Geologic Cross section of Transect A-A'	2.5-335
2.5-252	Geologic Cross Section of Transect B-B'	2.5-336
2.5-253	Geologic Cross Section of Transect C-C'	2.5-337
2.5-254	Isopach Map: Thickness of the Blue Bluff Marl	2.5-338
2.5-255	Stratigraphic Structure Contour Map: Top of the Utley Limestone	2.5-339
2.5-256	Isopach Map: Thickness of the Utley Limestone	2.5-340
2.5-257	Bechtel EPRI Zones	2.5-341
2.5-258	Dames and Moore EPRI Zones	2.5-342
2.5-259	Law EPRI Zones	2.5-343
2.5-260	Rondout EPRI Zones	2.5-344
2.5-261	Woodward-Clyde EPRI Zones	2.5-345
2.5-262	Weston EPRI Zones	2.5-346
2.5-263	USGS Model	2.5-347
2.5-264	SCDOT Model	2.5-348
2.5-265	UCSS Map	2.5-349
2.5-266	EPRI All Charleston Map	2.5-350
2.5-267	Updated Charleston Seismic Source (USGS) Logic Tree with Weights for each Branch Shown in Italics	2.5-351
2.5-268	Map of ZRA-S from Marple and Talwani (2000)	2.5-352
2.5-269	Geographic Distribution of Liquefaction Features Associated with Charleston Earthquakes	2.5-353
2.5-270	PGA Mean Seismic Hazard Curves for Current (2005) Calculation and for EPRI-SOG	2.5-354
2.5-271	PGA Median Seismic Hazard Curves for Current (2005) Calculation and for EPRI-SOG	2.5-354
2.5-272	PGA 85 Percent Seismic Hazard Curves for Current (2005) Calculation and for EPRI-SOG	2.5-355
2.5-273	Map Showing Two Areas Used To Examine Effect of New Seismicity Information	2.5-356
2.5-274	Comparison of Recurrence Rates for Rectangular Charleston Source	2.5-357
2.5-275	Comparison of Recurrence Rates for Triangular South Carolina Source	2.5-357
2.5-276	Geometry of Four New Charleston Sources	2.5-358
2.5-277	Original Rondout Source 26	2.5-358
2.5-278	New Rondout Source 26-A that Surrounds Charleston Source A	2.5-359
2.5-279	New Rondout Source 26-B that Surrounds Charleston Source B	2.5-359
2.5-280	New Rondout Source 26-B´ that Surrounds Charleston Source B	2.5-360
2.5-281	New Rondout Source 26-C that Surrounds Charleston Source C	2.5-360
2.5-282	Mean Uniform Hazard Spectra, Hard Rock Conditions, for VEGP ESP	2.5-361
2.5-283	Hard Rock Magnitude-Distance Deaggregation for High Frequencies, 10^{-4} Mean Annual Frequency of Exceedance	2.5-362
2.5-284	Hard Rock Magnitude-Distance Deaggregation for Low Frequencies, 10^{-4} Mean Annual Frequency of Exceedance	2.5-363

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.5-285	Hard Rock Magnitude-Distance Deaggregation for High Frequencies, 10^{-5} Mean Annual Frequency of Exceedance	2.5-364
2.5-286	Hard Rock Magnitude-Distance Deaggregation For Low Frequencies, 10^{-5} Mean Annual Frequency of Exceedance	2.5-365
2.5-287	Hard Rock Magnitude-Distance Deaggregation for High Frequencies, 10^{-6} Mean Annual Frequency of Exceedance	2.5-366
2.5-288	Hard Rock Magnitude-Distance Deaggregation for Low Frequencies, 10^{-6} Mean Annual Frequency of Exceedance	2.5-367
2.5-289	Magnitude Deaggregation for High Frequencies for Three Mean Annual Frequencies of Exceedance	2.5-368
2.5-290	Magnitude Deaggregation for Low Frequencies for Three Mean Annual Frequencies of Exceedance	2.5-368
2.5-291	Hard Rock Distance Deaggregation for High Frequencies for Three Mean Annual Frequencies of Exceedance	2.5-369
2.5-292	Hard Rock Magnitude Deaggregation for Low Frequencies for Three Mean Annual Frequencies of Exceedance	2.5-369
2.5-293	10 Hz Hard Rock Seismic Hazard Curves by Seismic Source for Rondout Team	2.5-370
2.5-294	1 Hz Hard Rock Seismic Hazard Curves by Seismic Source for the Rondout Team	2.5-371
2.5-295	Summary Statistics Calculated from the 60 Shear-Wave Velocity Profiles	2.5-372
2.5-296	ESP and COL plus ESP Soil Models	2.5-373
2.5-297	High Frequency Hard Rock Target Spectra for the Three Annual Probability Levels of 10^{-4}, 10^{-5}, and 10^{-6}	2.5-374
2.5-298	Low Frequency Hard Rock Target Spectra for the Three Annual Probability Levels of 10^{-4}, 10^{-5}, and 10^{-6}	2.5-375
2.5-299	High Frequency (10^{-6}) Match for the 30 Time Histories	2.5-376
2.5-300	Low Frequency (10^{-6}) Match for the 30 Time Histories	2.5-377
2.5-301	High Frequency (10^{-5}) Match for the 30 Time Histories	2.5-378
2.5-302	Low Frequency (10^{-5}) Match for the 30 Time Histories	2.5-379
2.5-303	High Frequency (10^{-4}) Match for the 30 Time Histories	2.5-380
2.5-304	Low Frequency (10^{-4}) Match for the 30 Time Histories	2.5-381
2.5-305	Typical Results of Spectral Amplification at 86-ft Depth (Top of Blue Bluff Marl) Using EPRI Degradation Curves for High Frequency Time Histories of 10^{-4} MAFE Input Motion Level	2.5-382
2.5-306	Typical Results of Spectral Amplification at 40-ft Horizon Outcrop Motion Using EPRI Degradation Curves for High-Frequency Time Histories of 10^{-4} MAFE Input Motion Level	2.5-383
2.5-307	Typical Results of Spectral Amplification Ground Surface using EPRI Degradation Curves for High Frequency Time Histories of 10^{-4} MAFE Input Motion Level	2.5-384
2.5-308	Horizontal Raw and Smoothed, Top of Blue Bluff Marl	2.5-385
2.5-309	Horizontal Raw and Smoothed FIRS, 40-ft Depth Horizon	2.5-386
2.5-310	Horizontal Raw and Smoothed GMRS, Ground Surface	2.5-387
2.5-311	Plots of V/HWUS,Soil,Empirical Term of Equation 2.5.2-6 for “Near” [M5.6 at a Distance of 12 km] and “Far” [M7.2 at a Distance of 130 km] Events Using the Attenuation Relation of Abrahamson and Silva (1997)	2.5-388

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.5-312	Plots of [V/HCEUS,Soil,Model / V/HWUS,Soil,Model] Term of Equation 2.5.2-6 for M6.5 and Distances of 10, 20, and 40 km, as Available in NUREG/CR-6728 (McGuire et al 2001)	2.5-389
2.5-313	Plots of Recommended V/HCEUS,Soil from Equation 2.5.2-6 for “Near” and “Far” Events Using Results from NUREG/CR-6728 (McGuire et al 2001)	2.5-390
2.5-314	Plots of Recommended V/HCEUS,Soil from Equation 2.5.2-6 for “Near” and “Far” Events Using Results from Lee (2001)	2.5-391
2.5-315	Plots of V/HCEUS,Soil (Blue Patterned) Derived from Results from NUREG/CR-6728 (McGuire et al 2001) and Lee (2001)	2.5-392
2.5-316	VEGP ESP Horizontal and Vertical Top of Blue Bluff Marl (5% Damping)	2.5-393
2.5-317	VEGP ESP Horizontal and Vertical FIRS Spectra, at the 40-ft Depth Horizon	2.5-394
2.5-318	VEGP ESP Horizontal and Vertical GMRS Spectra (5% Damping)	2.5-395
2.5-319	Example of Initial Seed Input Time Acceleration, Velocity, and Displacement Time Histories (One of Thirty) for High Frequency Target Spectrum	2.5-396
2.5-320	Final Modified Spectrum-Compatible Acceleration, Velocity, and Displacement Time Histories (One of Thirty) for 10^{-6} High Frequency Target Spectrum	2.5-397
2.5-321	Comparison of 10^{-6} High Frequency Target Spectrum (Thick Grey Line), Response Spectrum from Initial Seed Input Acceleration Time History Scaled to Target PGA (Thin Blue Line), and Acceleration Response Spectrum for Final Modified Spectrum Compatible Time History (Thin Red Line)	2.5-398
2.5-322	Comparison of Normalized Arias Intensity from Initial Seed Input Time History (Thick Grey Line) and Final Modified Spectrum Compatible (10^{-6} High Frequency Target Spectrum) Time History (Thin Red Line) for an Example Case	2.5-399
2.5-323	Horizontal Component 1 Modified Spectrum Compatible Time Acceleration, Velocity, and Displacement Time Histories for FIRS Horizontal Target Spectrum Prior to Application of 1.01 Scale Factor	2.5-400
2.5-324	Comparison of Horizontal FIRS Target Spectrum (Thick Grey Line), 1.3*FIRS Target Spectrum (Dashed Black Line), 0.9*FIRS Target Spectrum (Dashed Green Line), and Acceleration Response Spectrum for Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Horizontal Component 1	2.5-401
2.5-325	Comparison of Normalized Arias Intensity from Initial Seed Input Time History (Thick Grey Line) and Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Horizontal Component 1	2.5-402
2.5-326	Horizontal Component 2 Modified Spectrum Compatible Time Acceleration, Velocity, and Displacement Time Histories for FIRS Horizontal Target Spectrum Prior to Application of 1.01 Scale Factor	2.5-403

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.5-327	Comparison of Horizontal FIRS Target Spectrum (Thick Grey Line), 1.3*FIRS Target Spectrum (Dashed Black Line), 0.9*FIRS Target Spectrum (Dashed Green Line), and Acceleration Response Spectrum for Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Horizontal Component 2	2.5-404
2.5-328	Comparison of Normalized Arias Intensity from Initial Seed Input Time History (Thick Grey Line) and Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Horizontal Component 2	2.5-405
2.5-329	Vertical Component Modified Spectrum Compatible Time Acceleration, Velocity, and Displacement Time Histories for FIRS Vertical Target Spectrum Prior to Application of 1.01 Scale Factor	2.5-406
2.5-330	Comparison of Vertical FIRS Target Spectrum (Thick Grey Line), 1.3*FIRS Target Spectrum (Dashed Black Line), 0.9*FIRS Target Spectrum (Dashed Green Line), and Acceleration Response Spectrum for Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Vertical Component	2.5-407
2.5-331	Comparison of Normalized Arias Intensity from Initial Seed Input Time History (Thick Grey Line) and Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Vertical Component	2.5-408
2.5-332	Low Strain Backfill Shear Wave Velocity (ft/sec)	2.5-409
2.5-333	Plant Layout	2.5-410
2.5-334	Cross Section A	2.5-411
2.5-335	SASSI 2D-Model	2.5-412
2.5-336	Amplification at 0 ft (GMRS Horizon)	2.5-413
2.5-337	Transfer Functions at 0 ft (GMRS Horizon)	2.5-414
2.5-338	Amplification at 40 ft depth (FIRS horizon)	2.5-415
2.5-339	Transfer Functions at 40 ft (FIRS Horizon)	2.5-416
2.5-340	Amplification at 86 ft depth (Top of Blue Bluff Marl)	2.5-417
2.5-341	2D SASSI Backfill Model	2.5-418
2.5-342	Node 4041 — EL 99.00 NI at Reactor Vessel Support Elevation	2.5-419
2.5-343	Node 4061 — EL 116.5 Auxiliary Shield Building at Control Room Floor	2.5-420
2.5-344	Node 4120 — EL 179.56 ASB Auxiliary Building Roof Area	2.5-421
2.5-345	Node 4310 — EL 327.41 ASB Shield Building Roof Area	2.5-422
2.5-346	Node 4412 — EL 224 Steel Containment Vessel Near Polar Crane	2.5-423
2.5-347	Node 4335 — EL 135.25 Containment Internal Structure at Operating Deck	2.5-424
2.5-348	Amplification at 40-ft Outcrop Depth (FIRS Horizon)	2.5-425
2.5-349	Vogtle Strain Compatible Profiles (S-Wave Velocity)	2.5-426
2.5-350	Vogtle Strain Compatible Profiles (S-Wave Damping)	2.5-427
2.5-351	Envelope at 40 ft Depth (FIRS Horizon)	2.5-428
2.5-352	Low Strain Shear Wave Velocity Profile Cases (LB, BE, UB) - Study for Material Over Excavation Slopes	2.5-429
2.5-353	Strain Compatible BE Shear Wave Velocity Profiles Cases-for Material Over Excavation Slopes (2D SASSI SSI Bathtub Analyses)	2.5-430

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.5-354	Comparison of SASSI 2D Bathtub Model Site Response: Amplification at 0 ft (GMRS horizon)	2.5-431
2.5-355	Comparison of SASSI 2D Bathtub Model Site Response: Amplification at 40 ft depth (FIRS horizon)	2.5-432
2.5-356	Comparison of SASSI 2D Bathtub Model Site Response: Amplification at 86 ft depth (Top of Blue Bluff Marl)	2.5-433
2.5-357	Comparison of SASSI 2D Bathtub NI Model SSI Responses: Node 4041-EL 99 NI at Reactor Vessel Support Elevation	2.5-434
2.5-358	Comparison of SASSI 2D Bathtub NI Model SSI Responses: Node 4061-EL 116.5 Auxiliary Shield Building at Control Room Floor	2.5-435
2.5-359	Comparison of SASSI 2D Bathtub NI Model SSI Responses: Node 4120-EL 179.56 ASB Auxiliary Building Roof Area	2.5-436
2.5-360	Comparison of SASSI 2D Bathtub NI Model SSI Responses: Node 4310-EL 327.41 ASB Shield Building Roof Area	2.5-437
2.5-361	Comparison of SASSI 2D Bathtub NI Model SSI Responses: Node 4412-EL 224 Steel Containment Vessel Near Polar Crane	2.5-438
2.5-362	Comparison of SASSI 2D Bathtub NI Model SSI Responses: Node 4535-EL 135.25 Containment Internal Structure at Operating Deck	2.5-439
2.5-363	Contorted Bedding in Garbage Trench at VEGP Site	2.5-440
2.5-364	West Wall of Garbage Trench Showing Small Offsets (1–24 inches) (Upper) and Arcuate Fractures and Clastic Dikes Over Center of Depression (Lower)	2.5-441
2.5-365	Surface Geometry of Unit F Illustrating Localized Nature of Deformation	2.5-442
2.5-366	ESP Study Boring Location Plan	2.5-443
2.5-367	COL Site Boring Location Plan	2.5-444
2.5-368	COL Power Block — Cooling Tower Boring Location	2.5-445
2.5-369	Subsurface Profile Legend	2.5-446
2.5-370	Subsurface Profile A–A’	2.5-447
2.5-371	Subsurface Profile D–D’	2.5-448
2.5-372	Subsurface Profile B–B’	2.5-449
2.5-373	Subsurface Profile C–C’	2.5-450
2.5-374	Subsurface Profile E–E’	2.5-451
2.5-375	Subsurface Profile F–F’	2.5-452
2.5-376	Shear Wave Velocity Measurements	2.5-453
2.5-377	Shear Wave Velocity Measurements in the Upper Sand Stratum as Measured by COL SCPT	2.5-454
2.5-378	Shear Wave Velocity Profile for SHAKE Analysis	2.5-455
2.5-379	Shear Wave Velocity Profile — ESP and COL Soil Columns	2.5-456
2.5-380	Rock shear-wave velocities for three SRS sites [DRB] (SRS 2005) and B-1003 [Figure 2.5.4-6]. The DRB data has been shifted in depth so that the depth to top of rock is consistent with B-1003.	2.5-457
2.5-381	Shear Modulus Reduction Curves for SHAKE Analysis – EPRI Curves	2.5-458
2.5-382	Site-Specific Shear Modulus Reduction Curves	2.5-459
2.5-383	Shear Modulus Reduction Curves for SHAKE Analysis – SRS Curves	2.5-460
2.5-384	Damping Ratio Curves for SHAKE Analysis – EPRI Curves	2.5-461
2.5-385	Site-Specific Damping Ratio Curves	2.5-462
2.5-386	Damping Ratio Curves for SHAKE Analysis – SRS Curves	2.5-463
2.5-387	Allowable Bearing Capacity of Typical Foundation	2.5-464

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
2.5-388	Power Block Excavation and Switchyard Borrow Area	2.5-465
2.5-389	Power Block Excavation Sections	2.5-466
2.5-390	Nuclear Island Temporary Retaining Wall	2.5-467
2.5-391	Distribution of SPT N60–Value with Elevation (COL)	2.5-468
2.5-392	Comparison of Shear Modulus Reduction Curves - Backfill Soils	2.5-469
2.5-393	Comparison of Shear Modulus Reduction Curves - Blue Bluff Marl	2.5-470
2.5-394	Comparison of Shear Modulus Reduction Curves - Lower Sands	2.5-471
2.5-395	Comparison of Damping Ratio Curves - Backfill Soils	2.5-472
2.5-396	Comparison of Damping Ratio Curves - Blue Bluff Marl	2.5-473
2.5-397	Comparison of Damping Ratio Curves - Lower Sands	2.5-474

2.0 Site Characteristics

Chapter 2 describes the characteristics and site-related design parameters of the Vogtle Electric Generating Plant (VEGP), Units 3 and 4. The site location, characteristics and parameters, as described in the following five sections are provided in sufficient detail to support a safety assessment:

- Geography and Demography (Section 2.1)
- Nearby industrial, Transportation, and Military Facilities (Section 2.2)
- Meteorology (Section 2.3)
- Hydrologic Engineering (Section 2.4)
- Geology, Seismology, and Geotechnical Engineering (Section 2.5)

Table 2.0-201 provides a comparison of site-related design parameters for which the AP1000 plant is designed and site characteristics specific to VEGP in support of this safety assessment. The first two columns of Table 2.0-201 are a compilation of the site parameters. The third column of Table 2.0-201 is the corresponding site characteristic for the VEGP. The fourth column denotes the place where this data is presented. The last column indicates whether or not the site characteristic falls within the AP1000 site parameters. “Yes” indicates the site characteristic falls within the parameter. Control room atmospheric dispersion factors (χ/Q) for accident dose analysis are presented in Table 2.0-202. All of the control room χ/Q values fall within the AP1000 parameters.

Table 2.0-203 provides a summary list of the limiting site characteristic values that have been established by analyses presented throughout this document. This list also provides a summary of important site characteristics necessary to establish the findings required by 10 CFR Parts 52 and 100 on the suitability of the site.

Table 2-1
Not Used

Table 2.0-201 (Sheet 1 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

	AP1000 DCD Site Parameter[a]	VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
Air Temperature				
Maximum Safety[b]	115°F dry bulb/86.1°F coincident wet bulb[h]	115°F dry bulb/77.7°F coincident wet bulb	Table 2.0-203	Yes
	86.1°F wet bulb (noncoincident)	83.9°F wet bulb (noncoincident)	Table 2.0-203	Yes
Minimum Safety[b]	-40°F	-8°F	Table 2.0-203	Yes
Maximum Normal[c]	101°F dry bulb/80.1°F coincident wet bulb	97°F dry bulb/76°F coincident wet bulb	Subsection 2.3.1.5	Yes
	80.1°F wet bulb (noncoincident)[d]	79°F wet bulb (noncoincident)	Subsection 2.3.1.5	Yes
Minimum Normal[c]	-10°F	21°F dry bulb	Subsection 2.3.1.5	Yes
Wind Speed				
Operating Basis	145 mph (3 second gust); importance factor 1.15 (safety), 1.0 (nonsafety); exposure C; topographic factor 1.0	104 mph (3 second gust); exposure C; topographic factor 1.0. (Importance factor is not a property of the wind speed.)	Table 2.0-203 Figure 2.5-235	Yes
Tornado	300 mph	300 mph	Table 2.0-203	Yes
	Maximum pressure differential of 2.0 lb/in^2	2.0 lb/in^2	Table 2.0-203	Yes

Table 2.0-201 (Sheet 2 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

	AP1000 DCD Site Parameter[a]	VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
Seismic				
CSDRS	CSDRS free field peak ground acceleration of 0.30 g with modified Regulatory Guide 1.60 response spectra (See Figures 5.0-1 and 5.0-2.). The SSE is now referred to as CSDRS. Seismic input is defined at finished grade except for sites where the nuclear island is founded on hard rock. If the site-specific spectra exceed the response spectra in Figures 5.0-1 and 5.0-2 at any frequency, or if soil conditions are outside the range evaluated for AP1000 design certification, a site-specific evaluation can be performed. This evaluation will consist of a site-specific dynamic analysis and generation of in-structure response spectra at key locations to be compared with the floor response spectra of the certified design at 5-percent damping. The site is acceptable if the floor response spectra from the site-specific evaluation do not exceed the AP1000 spectra for each of the locations or the exceedances are justified.	Site-specific GMRS values specified and illustrated in Subsection 2.5.2. The seismic design of AP-1000 nuclear island is discussed in Subsection 3.7.1.1.1 Site-specific evaluation performed in Appendix 2.5E	Table 2.0-203 Subsection 3.7.1.1.1 Appendix 2.5E	Yes

Table 2.0-201 (Sheet 3 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

	AP1000 DCD Site Parameter[a]	VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
	The hard rock high frequency (HRHF) envelope response spectra are shown in Figure 5.0-3 and Figure 5.0-4 defined at the foundation level for 5% damping. The HRHF envelope response spectra provide an alternative set of spectra for evaluation of site specific GMRS. A site is acceptable if its site specific GMRS fall within the AP1000 HRHF envelope response spectra. Evaluation of a site for application of the HRHF envelope response spectra includes consideration of the limitation on shear wave velocity identified for use of the HRHF envelope response spectra. This limitation is defined by a shear wave velocity at the bottom of the basemat equal to or higher than 7,500 fps, while maintaining a shear wave velocity equal to or above 8,000 fps at the lower depths.			
Fault Displacement Potential	No potential fault displacement considered beneath the seismic Category I and seismic Category II structures and immediate surrounding area. The immediate surrounding area includes the effective soil supporting media associated with the seismic Category I and seismic Category II structures.	No fault displacement potential within the investigative area.	Table 2.0-203	Yes

Table 2.0-201 (Sheet 4 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

	AP1000 DCD Site Parameter[(a)]	VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
Soil				
Average Allowable Static Bearing Capacity	The allowable bearing capacity, including a factor of safety appropriate for the design load combination, shall be greater than or equal to the average bearing demand of 8,900 lb/ft² over the footprint of the nuclear island at its excavation depth	34,000 lb/ft^2	Table 2.0-203	Yes
Dynamic Bearing Capacity for Normal Plus Safe Shutdown Earthquake (SSE)	The allowable bearing capacity, including a factor of safety appropriate for the design load combination, shall be greater than or equal to the maximum bearing demand of 35,000 lb/ft² at the edge of the nuclear island at its excavation depth, or Site-specific analyses demonstrate factor of safety appropriate for normal plus safe shutdown earthquake loads.	42,000 lb/ft^2	Table 2.0-203	Yes
Shear Wave Velocity	Greater than or equal to 1,000 ft/sec based on minimum low-strain soil properties over the footprint of the nuclear island at its excavation depth	Greater than 1000 ft/sec	Table 2.0-203	Yes
Lateral Variability	Soils supporting the nuclear island should not have extreme variations in subgrade stiffness. This may demonstrated by one of the following:			

Table 2.0-201 (Sheet 5 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

		AP1000 DCD Site Parameter[(a)]	VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
Lateral Variability (Continued)	1	Soils supporting the nuclear island are uniform in accordance with Regulatory Guide 1.132 if the geologic and stratigraphic features at depths less than 120 feet below grade can be correlated from one boring or sounding location to the next with relatively smooth variations in thickness or properties of the geologic units, or	Site is uniform based on boring data and placement of engineered backfill	Subsection 2.5.4.4 and Subsection 2.5.4.5	Yes
	2	Site specific assessment of subsurface conditions demonstrates that the bearing pressures below the footprint of the nuclear island do not exceed 120% of those from the generic analyses of the nuclear island at a uniform site, or	N/A		
	3	Site specific analysis of the nuclear island basemat demonstrates that the site specific demand is within the capacity of the basemat.	N/A		
		As an example of sites that are considered uniform, the variation of shear wave velocity in the material below the foundation to a depth of 120 feet below finished grade within the nuclear island footprint and 40 feet beyond the boundaries of the nuclear island footprint meets the criteria in the case outlined below:			

Table 2.0-201 (Sheet 6 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

	AP1000 DCD Site Parameter[a]		VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
Lateral Variability (Continued)	Case 1: For a layer with a low strain shear wave velocity greater than or equal to 2500 feet per second, the layer should have approximately uniform thickness, should have a dip not greater than 20 degrees, and should have less than 20 percent variation in the shear wave velocity from the average velocity than any layer.		N/A		
Limits of Acceptable Settlement Without Additional Evaluation[i]	Differential Across Nuclear Island Foundation Mat	1/2 inch in 50 ft	~15/32 inch in 50 ft (projected)	Subsection 2.5.4.10.2	Yes (projected)
	Total for Nuclear Island Foundation Mat	6 inches	4–5 inches (projected)		
	Differential Between Nuclear Island and Turbine Building[j]	3 inches	<2 inch (projected)		
	Differential Between Nuclear Island and Other Buildings[j]	3 inches	<3 inch (projected)		

Table 2.0-201 (Sheet 7 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

	AP1000 DCD Site Parameter[a]	VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
Liquefaction Potential	No liquefaction considered beneath the seismic Category I and seismic Category II structures and immediate surrounding area. The immediate surrounding area includes the effective soil supporting media associated with the seismic Category I and seismic Category II structures.	None at the site-specific SSE.	Table 2.0-203	Yes
Minimum Soil Angle of Internal Friction	Minimum soil angle of internal friction is greater than or equal to 35 degrees below the footprint of nuclear island at its excavation depth. If the minimum soil angle of internal friction is below 35 degrees, a site specific analysis shall be performed using the site specific soil properties to demonstrate stability.	36 degrees	Table 2.0-203	**Yes**
Missiles				
Tornado	4000-lb automobile at 105 mph horizontal, 74 mph vertical 275-lb, 8-in. shell at 105 mph horizontal, 74 mph vertical 1-inch-diameter steel ball at 105 mph in the most damaging direction	4000-lb automobile at 105 mph horizontal, 74 mph vertical 275-lb, 8-in. shell at 105 mph horizontal, 74 mph vertical 1-inch-diameter steel ball at 105 mph in the most damaging direction	Subsection 3.5.1.5 Subsection 3.5.1.4 APP-GW-GLR-020, “Wind and Tornado Site Interface Criteria,” Westinghouse Electric Company LLC.[e]	Yes
Flood Level	Less than plant elevation 100 feet	The design basis river flood level is El. 178.10 ft MSL, which is 41.9 feet below plant elevation (220 ft MSL). Maximum local PMP flood elevation is 219.1 ft MSL, which is 0.9 feet below plant elevation (220 ft MSL).	Table 2.0-203 Subsection 2.4.2	Yes

Table 2.0-201 (Sheet 8 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

	AP1000 DCD Site Parameter[a]	VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
Ground Water Level	Less than plant elevation 98 feet	The maximum groundwater level is 165 ft MSL which is 55 feet below plant elevation (220 ft MSL).	Table 2.0-203	Yes
Plant Grade Elevation	Less than plant elevation 100 feet, except for portion at a higher elevation adjacent to the annex building	The standard plant-floor elevation of the safety-related facilities is established at plant elevation 220 ft MSL; the finished plant grade elevation slopes away from plant structures	Subsection 2.4.2.3	Yes
Precipitation				
Rain	20.7 in/hr [1-hr 1-mi^2 PMP]	19.2 in/hr	Table 2.0-203	Yes
Snow/Ice	75 pounds per square foot on ground with exposure factor of 1.0 and importance factors of 1.2 (safety) and 1.0 (non-safety)	10.0 pounds per square foot	Table 2.0-203	Yes
Atmospheric Dispersion Values - χ/Q[f]				
Site Boundary (annual average)	$\leq 2.0 \times 10^{-5}$ sec/m^3	0.55×10^{-5} sec/m^3	Table 2.0-203	Yes
Site Boundary (0-2 hr)	$\leq 5.1 \times 10^{-4}$ sec/m^3 [g]	3.49×10^{-4} sec/m^3	Table 2.0-203	Yes
Low population zone boundary[g]				
0–8 hr	$\leq 2.2 \times 10^{-4}$ sec/m^3	7.04×10^{-5} sec/m^3	Table 2.0-203	Yes
8–24 hr	$\leq 1.6 \times 10^{-4}$ sec/m^3	5.25×10^{-5} sec/m^3	Table 2.0-203	Yes
24–96 hr	$\leq 1.0 \times 10^{-4}$ sec/m^3	2.77×10^{-5} sec/m^3	Table 2.0-203	Yes
96–720 hr	$\leq 8.0 \times 10^{-5}$ sec/m^3	1.11×10^{-5} sec/m^3	Table 2.0-203	Yes
Control Room	Table 2.0-202	Table 2.0-202	Table 2.0-202	Yes

Table 2.0-201 (Sheet 9 of 9)
Comparison of AP1000 DCD Site Parameters and Vogtle Electric Generating Plant Units 3 & 4 Site Characteristics

	AP1000 DCD Site Parameter[a]	VEGP Site Characteristic	VEGP Reference	VEGP Within Site Parameter
Population Distribution[g]				
Exclusion area (site)	0.5 mi.	The minimum distance from the effluent release boundary to the exclusion area boundary is 0.50 mile.[f]	Table 2.0-203	Yes

(a) AP1000 DCD Site Parameters are a compilation of DCD Tier 1 Table 5.0-1 and DCD Tier 2 Table 2-1.
(b) Maximum and minimum safety values are based on historical data and exclude peaks of less than 2 hours duration.
(c) The maximum normal value is the 1-percent seasonal exceedance temperature. The minimum normal value is the 99-percent seasonal exceedance temperature. The minimum temperature is for the months of December, January, and February in the northern hemisphere. The maximum temperature is for the months of June through September in the northern hemisphere. The 1-percent seasonal exceedance is approximately equivalent to the annual 0.4-percent exceedance. The 99-percent seasonal exceedance is approximately equivalent to the annual 99.6-percent exceedance. See Subsection 2.3.1.5 for further discussion on this relationship.
(d) The noncoincident wet bulb temperature is applicable to the cooling tower only.
(e) Per APP-GW-GLR-020, the kinetic energies of the missiles discussed in Section 3.5 are greater than the kinetic energies of the missiles discussed in Regulatory Guide 1.76 and result in a more conservative design.
(f) For AP1000, the term “site boundary” and “exclusion area boundary” are used interchangeably. Thus, the χ/Q specified for the site boundary applies whenever a discussion refers to the exclusion area boundary. At VEGP the “site boundary” and ”exclusion area boundary” are not interchangeable. See Figure 1.1-202.
(g) Site Interface Values for Post-Accident Dose Consequences and Minimum Distance to Site Boundary are reported per Table 2.0-203. Cooling Tower Make-up Flow Rate, which is not an AP1000 DCD Site Parameter, is 61,145 gpm (2 units) per Table 2.0-203.
(h) The containment pressure response analysis is based on a conservative set of dry-bulb and wet-bulb temperatures. These results envelope any conditions where the dry-bulb temperature is 115°F or less and wet-bulb temperature is less than or equal to 86.1°F.
(i) Additional evaluation may include evaluation of the impact of the elevated estimated settlement values on the critical components of the AP1000, determining a construction sequence to control the predicted settlement behavior, or developing an active settlement monitoring system throughout the entire construction sequence as well as a long-term (plant operation) plan.
(j) Differential settlement is measured at center of Nuclear Island and center of adjacent structures.

Table 2.0-202 (Sheet 1 of 2)
Comparison of Control Room Atmospheric Dispersion Factors for Accident Analysis for AP1000 DCD and VEGP Units 3 & 4

X/Q (sec/m^3) at HVAC Intake for the Identified Release Points[a]

	Plant Vent or PCS Air Diffuser[b]	Plant Vent	PCS Air Diffuser	**Ground Level Containment Release Points[c]**	Ground Level Containment Release Points	**PORV and Safety Valve Releases[d]**	PORV and Safety Valve Releases	**Condenser Air Removal Stack[g]**	Condenser Air Removal Stack	**Steam Line Break Releases**	**Steam Line Break Releases**	**Fuel Handling Area[e]**	Fuel Handling Area Blowout Panel	Fuel Handling Area Truck Bay Door
Release Time	**DCD**	VEGP	VEGP	**DCD**	VEGP	**DCD**	VEGP	**DCD**	VEGP	**DCD**	VEGP	**DCD**	VEGP	VEGP
0 – 2 hours	**2.53E-03**	2.27E-03	1.71E-03	**4.00E-03**	2.93E-03	**1.92E-02**	1.77E-02	**6.0E-3**	6.60E-04	**2.13E-02**	1.87E-02	**6.0E-3**	1.57E-03	1.30E-03
2 – 8 hours	**1.98E-03**	1.86E-03	1.32E-03	**2.28E-03**	1.75E-03	**1.60E-02**	1.41E-02	**4.0E-3**	4.83E-04	**1.76E-02**	1.51E-02	**4.0E-3**	1.15E-03	9.36E-04
8 – 24 hours	**7.96E-04**	7.36E-04	5.56E-04	**1.03E-03**	7.78E-04	**6.90E-03**	6.25E-03	**2.0E-3**	2.17E-04	**7.50E-03**	6.79E-03	**2.0E-3**	4.62E-04	3.78E-04
1 – 4 days	**6.40E-04**	5.99E-04	4.63E-04	**9.03E-04**	6.81E-04	**4.96E-03**	4.61E-03	**1.5E-3**	1.57E-04	**5.43E-03**	4.94E-03	**1.5E-3**	3.72E-04	2.98E-04
4 – 30 days	**4.78E-04**	4.31E-04	3.43E-04	**7.13E-04**	5.30E-04	**4.16E-03**	3.87E-03	**1.0E-3**	1.17E-04	**4.55E-03**	4.14E-03	**1.0E-3**	2.68E-04	2.09E-04

X/Q (sec/m^3) at Annex Building Door for the Identified Release Points[f]

	Plant Vent or PCS Air Diffuser[b]	Plant Vent	PCS Air Diffuser	**Ground Level Containment Release Points[c]**	Ground Level Containment Release Points	**PORV and Safety Valve Releases[d]**	PORV and Safety Valve Releases	**Condenser Air Removal Stack[g]**	Condenser Air Removal Stack	**Steam Line Break Releases**	**Steam Line Break Releases**	**Fuel Handling Area[e]**	Fuel Handling Area Blowout Panel	Fuel Handling Area Truck Bay Door
Release Time	**DCD**	VEGP	VEGP	**DCD**	VEGP	**DCD**	VEGP	**DCD**	VEGP	**DCD**	VEGP	**DCD**	VEGP	VEGP
0 – 2 hours	**1.0E-3**	5.02E-04	4.62E-04	**1.0E-3**	3.97E-04	**4.0E-3**	1.13E-03	**2.0E-2**	1.72E-03	**4.0E-3**	1.00E-03	**6.0E-3**	3.99E-04	3.83E-04
2 – 8 hours	**7.5E-4**	3.94E-04	3.55E-04	**7.5E-4**	3.26E-04	**3.2E-3**	8.98E-04	**1.8E-2**	1.12E-03	**3.2E-3**	7.97E-04	**4.0E-3**	3.00E-04	2.88E-04
8 – 24 hours	**3.5E-4**	1.61E-04	1.49E-04	**3.5E-4**	1.34E-04	**1.2E-3**	3.69E-04	**7.0E-3**	4.50E-04	**1.2E-3**	3.25E-04	**2.0E-3**	1.22E-04	1.21E-04
1 – 4 days	**2.8E-4**	1.29E-04	1.23E-04	**2.8E-4**	1.10E-04	**1.0E-3**	2.92E-04	**5.0E-3**	3.17E-04	**1.0E-3**	2.58E-04	**1.5E-3**	1.00E-04	9.58E-05
4 – 30 days	**2.5E-4**	9.63E-05	9.12E-05	**2.5E-4**	8.32E-05	**8.0E-4**	2.19E-04	**4.5E-3**	2.60E-04	**8.0E-4**	1.91E-04	**1.0E-3**	7.23E-05	6.78E-05

Table 2.0-202 (Sheet 2 of 2)
Comparison of Control Room Atmospheric Dispersion Factors for Accident Analysis for AP1000 DCD and VEGP Units 3 & 4

a. These dispersion factors are to be used 1) for the time period preceding the isolation of the main control room and actuation of the emergency habitability system, 2) for the time after 72 hours when the compressed air supply in the emergency habitability system would be exhausted and outside air would be drawn into the main control room, and 3) for the determination of control room doses when the non-safety ventilation system is assumed to remain operable such that the emergency habitability system is not actuated.

b. These dispersion factors are used for analysis of the doses due to a postulated small line break outside of containment. The plant vent and PCS air diffuser are potential release paths for other postulated events (loss of-coolant accident, rod ejection accident, and fuel handling accident inside the containment); however, the values are bounded by the dispersion factors for ground level releases.

c. The listed values represent modeling the containment shell as a diffuse area source, and are used for evaluating the doses in the main control room for a loss-of-coolant accident, for the containment leakage of activity following a rod ejection accident, and for a fuel handling accident occurring inside the containment.

d. The listed values bound the dispersion factors for releases from the steam line safety & power-operated relief valves. These dispersion factors would be used for evaluating the doses in the main control room for a steam generator tube rupture, a main steam line break, a locked reactor coolant pump rotor, and for the secondary side release from a rod ejection accident.

e. The listed values bound the dispersion factors for releases from the fuel storage and handling area. The listed values also bound the dispersion factors for releases from the fuel storage area in the event that spent fuel boiling occurs and the fuel handling area relief panel opens on high temperature. These dispersion factors are used for the fuel handling accident occurring outside containment and for evaluating the impact of releases associated with spent fuel pool boiling.

f. These dispersion factors are to be used when the emergency habitability system is in operation and the only path for outside air to enter the main control room is that due to ingress/egress.

g. This release point is included for information only as a potential activity release point. None of the design basis accident radiological consequences analyses model release from this point.

Table 2.0-203 (Sheet 1 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part I Site Characteristics		
Item	**Value**	**Description and Reference**
Precipitation		
Maximum Rainfall Rate	19.2 inches in 1 hr 6.2 inches in 5 min	PMP for 1-hr and 5-min duration of precipitation at the site. Refer to Table 2.4-220 and Figure 2.4-210
100-Year Snow Pack 48-Hour Winter Probable Maximum Precipitation (PMP)	10 lb/sq ft 28.3 in.	Weight, per unit area, of the 100-year return period snowpack at the site Maximum probable winter rainfall in 48-hour period. Refer to Subsection 2.3.1.3.4
Seismic		
Design Response Spectra	Site-specific GMRS values specified and illustrated in Subsection 2.5.2	Site-specific response spectra. Refer to Subsection 2.5.2 and Figures 2.5-316, 2.5-317, and 2.5-318.
Capable Tectonic Structures or Sources	No fault displacement potential within the investigative area	Conclusion on the presence of capable faults or earthquake sources in the vicinity of the plant site. Refer to Subsections 2.5.1.1.4, 2.5.1.2.4, and 2.5.3; Table 2.5-235
Water		
Maximum Flood (or Tsunami)	178.10 ft msl	Water level at the site due to dam breach. Refer to Subsections 2.4.2.2, 2.4.3.4, 2.4.4.3, and 2.4.10
Maximum Groundwater	165 ft msl	Site basis for subsurface hydrostatic loading due to difference in elevation between the site grade elevation in the power block area and the maximum site groundwater level. Refer to Subsections 2.4.12.4 and 2.5.4.6.1

Table 2.0-203 (Sheet 2 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part I Site Characteristics		
Item	**Value**	**Description and Reference**
Subsurface Material Properties		
Liquefaction	None at site-specific SSE. Compacted structural fill will provide an adequate safety factor against liquefaction (min >1.1).	Liquefaction potential for subsurface material at the site. Refer to Subsection 2.5.4.8.4
Minimum Bearing Capacity (Static and Dynamic)	34,000 lb/sq ft (Static) 42,000 lb/sq ft (Dynamic)	Allowable load-bearing capacity of the layer supporting plant structures. Refer to Subsection 2.5.4.10.1
Minimum Shear Wave Velocity	Values in Tables 2.5-251 and 2.5-253	Propagation velocity of shear waves through the foundation materials. Refer to Subsection 2.5.4.7.1; Tables 2.5-251 and 2.5-253; Figures 2.5-376, 2.5-378, 2.5-379, and 2.5-380
Tornado		
Maximum Pressure Drop	2.0 psi	Decrease in ambient pressure from normal atmospheric pressure at the site due to passage of a tornado having a probability of occurrence of 10^{-7} per year. Refer to Subsection 2.3.1.3.2
Maximum Rotational Speed	240 mph	Rotation component of maximum wind speed at the site due to passage of a tornado having a probability of occurrence of 10^{-7} per year. Refer to Subsection 2.3.1.3.2
Maximum Translational Speed	60 mph	Translation component of maximum wind speed at the site due to the movement across ground of a tornado having a probability of occurrence of 10^{-7} per year. Refer to Subsection 2.3.1.3.2

Table 2.0-203 (Sheet 3 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part I Site Characteristics		
Item	**Value**	**Description and Reference**
Maximum Wind Speed	300 mph	Sum of the maximum rotational and maximum translational wind speed components at the site due to passage of a tornado having a probability of occurrence of 10^{-7} per year. Refer to Subsection 2.3.1.3.2
Radius of Maximum Rotational Speed	150 ft	Distance from the center of the tornado at which the maximum rotational wind speed occurs at the site due to passage of a tornado having a probability of occurrence of 10^{-7} per year. Refer to Subsection 2.3.1.3.2
Maximum Rate of Pressure Drop	1.2 psi/sec	Maximum rate of pressure drop at the site due to passage of a tornado having a probability of occurrence of 10^{-7} per year. Refer to Subsection 2.3.1.3.2
Wind		
Basic Wind Speed	104 mph	Three-second gust wind velocity, associated with a 100-year return period, at 33 ft (10 m) above ground level in the site area. Refer to Subsection 2.3.1.3.2
Selected Site Characteristic Ambient Air Temperatures		*(Site characteristic wet bulb and dry bulb temperatures associated with listed exceedance values and 100-year return period)*
Maximum Dry Bulb • 2% annual exceedance • 0.4% annual exceedance • 100-year return period	 92°F 97°F 115°F	Refer to Subsection 2.3.1.5

Table 2.0-203 (Sheet 4 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part I Site Characteristics		
Item	**Value**	**Description and Reference**
Minimum Dry Bulb • 1% annual exceedance • 0.4% annual exceedance • 100-year return period	 25°F 21°F -8°	Refer to Subsection 2.3.1.5
Maximum Wet Bulb • 0.4% annual exceedance • 100-year return period	 79°F 88°F	Refer to Subsection 2.3.1.5
Site Temperature Basis for AP1000 • Maximum Safety Dry Bulb and Coincident Wet Bulb • Maximum Safety Wet Bulb (Non-coincident) • Maximum Normal Dry Bulb and Coincident Wet Bulb • Maximum Normal Wet Bulb (Non-coincident)	 115°F dry bulb/77.7°F wet bulb 83.9°F 97°F dry bulb/76°F wet bulb 79°F	Refer to Subsection 2.3.1.5
Airborne Effluent Release Point		
Atmospheric Dispersion (χ/Q) (Accident)		
0-2 hr @ Exclusion Area Boundary (EAB) 0-8 hr @ Low Population Zone (LPZ) 8-24 hr @ LPZ 1-4 day @ LPZ 4-30 day @ LPZ	3.49E-04 sec/m^3 7.04E-05 sec/m^3 5.25E-05 sec/m^3 2.77E-05 sec/m^3 1.11E-05 sec/m^3	The atmospheric dispersion coefficients used in the design safety analysis to estimate dose consequences of accident airborne releases. Refer to Subsection 2.3.4.2.

Table 2.0-203 (Sheet 5 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part I Site Characteristics		
Item	**Value**	**Description and Reference**
Atmospheric Dispersion (χ/Q) (Routine Release)		
Annual Average Undepleted/No Decay χ/Q Value @ EAB	5.5E-06 sec/m^3	The maximum annual average EAB undepleted/no decay atmospheric dispersion factor (χ/Q) value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Subsection 2.3.5.2; Table 2.3-219
Annual Average Undepleted/ 2.26-Day Decay χ/Q Value @ EAB	5.5E-06 sec/m^3	The maximum annual average EAB undepleted/2.26-day decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average Depleted/ 8.00-Day Decay χ/Q Value @ EAB	5.0E-06 sec/m^3	The maximum annual average EAB depleted/8.00-day decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average D/Q Value @ EAB	1.7E-08 1/m^2	The maximum annual average EAB relative deposition factor (D/Q) value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average Undepleted/No Decay χ/Q Value @ Nearest Resident	3.4E-06 sec/m^3	The maximum annual average resident undepleted/no decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Subsection 2.3.5.2; Table 2.3-219

Table 2.0-203 (Sheet 6 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part I Site Characteristics		
Item	**Value**	**Description and Reference**
Annual Average Undepleted/ 2.26-Day Decay χ/Q Value @ Nearest Resident	3.4E-06 sec/m^3	The maximum annual average resident undepleted/2.26-day decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average Depleted/ 8.00-Day Decay χ/Q Value @ Nearest Resident	3.0E-06 sec/m^3	The maximum annual average resident depleted/8.00-day decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average D/Q Value @ Nearest Resident	1.0E-08 $1/m^2$	The maximum annual average resident D/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average Undepleted/No Decay χ/Q Value @ Nearest Meat Animal	3.4E-06 sec/m^3	The maximum annual average meat animal undepleted/no decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Subsection 2.3.5.2; Table 2.3-219
Annual Average Undepleted/ 2.26-Day Decay χ/Q Value @ Nearest Meat Animal	3.4E-06 sec/m^3	The maximum annual average meat animal undepleted/2.26-day decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average Depleted/ 8.00-Day Decay χ/Q Value @ Nearest Meat Animal	3.0E-06 sec/m^3	The maximum annual average meat animal depleted/8.00-day decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219

Table 2.0-203 (Sheet 7 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part I Site Characteristics		
Item	**Value**	**Description and Reference**
Annual Average D/Q Value @ Nearest Meat Animal	1.0E-08 $1/m^2$	The maximum annual average meat animal D/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average Undepleted/No Decay χ/Q Value @ Nearest Vegetable Garden	3.4E-06 sec/m^3	The maximum annual average vegetable garden undepleted/no decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average Undepleted/ 2.26-Day Decay χ/Q Value @ Nearest Vegetable Garden	3.4E-06 sec/m^3	The maximum annual average vegetable garden undepleted/2.26-day decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average Depleted/ 8.00-Day Decay χ/Q Value @ Nearest Vegetable Garden	3.0E-06 sec/m^3	The maximum annual average vegetable garden depleted/8.00-day decay χ/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219
Annual Average D/Q Value @ Nearest Vegetable Garden	1.0E-08 $1/m^2$	The maximum annual average vegetable garden D/Q value for use in determining gaseous pathway doses to the maximally exposed individual. Refer to Table 2.3-219

Table 2.0-203 (Sheet 8 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part I Site Characteristics		
Item	**Value**	**Description and Reference**
Population Density		
Population Center Distance	Approximately 26 mi (Augusta, GA)	The minimum allowable distance from the reactor(s) to the nearest boundary of a densely populated center containing more than about 25,000 residents (not less than one and one-third times the distance from the reactor(s) to the outer boundary of the LPZ) (i.e., 2-2/3 mi for VEGP). Refer to Section 1.1, Subsections 1.2.1, 2.1.1, 2.1.3.2, and 2.1.3.5
Exclusion Area Boundary (EAB)	See Figure 1.1-202	The area surrounding the reactor(s), in which the reactor licensee has the authority to determine all activities, including exclusion or removal of personnel and property from the area. Refer to Subsections 2.1.1, 2.1.2, and 2.3.4.1; Figure 1.1-202
Low Population Zone (LPZ)	A 2-mile-radius circle from the midpoint between the containment buildings of Units 1 and 2.	The area immediately surrounding the exclusion area that contains residents. Refer to Subsections 2.1.3.4, 2.3.4.1, 2.3.4.2, and 2.3.5.1; Table 2.3-217
Dose Calculation EAB	See Figure 1.1-202	A circle extending ½ mi beyond the power block area circle (775-ft radius circle encompassing Units 3 and 4). Total radius is 3,415 ft from the centroid of the power block circle. Dose Calculation EAB is completely within the actual plant EAB and is used to conservatively determine χ/Q values and subsequent accident radiation doses. Refer to Subsections 2.3.4.1, 2.3.4.2, and 2.3.5.1; Tables 2.3-216, 2.3-218, and 2.3-219; Figure 1.1-202

Table 2.0-203 (Sheet 9 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part II Design Parameters		
Item	**Single Unit [Two Unit] Value**	**Description and Reference**
Structures		
Building Height	234 ft 0 in.	The height from finished grade to the top of the tallest power blocks structure, excluding cooling towers (i.e., Containment Building). Refer to Subsection 2.3.3.3
Building Foundation Embedment	39 ft 6 in. to bottom of basemat from plant grade	The depth from finished grade to the bottom of the basemat for the most deeply embedded power block structure (i.e., Containment/Auxiliary Building). Refer to Subsections 2.4.12 and 2.5.4.10.1
Cooling Tower Height	600 ft	The height is from the finished grade to the top of the cooling tower Refer to Subsection 2.3.3.3
Cooling Tower Base Diameter	550 ft	The bottom of the cooling tower where it connects to the basin Refer to Subsection 2.3.3.3
Cooling Tower Diameter at the Top	330 ft	The cooling tower diameter at its highest elevation Refer to Subsection 2.3.3.3
Airborne Effluent Release Point		
Release Point Elevation (Post-Accident)	Ground level	The elevation above finished grade of the release point for accident sequence releases. Refer to Subsections 2.3.4.1 and 2.3.5.1; Tables 2.3-216 and 2.3-217

Table 2.0-203 (Sheet 10 of 10)
Site Characteristics, Design Parameters, and Site Interface Values

Part II Design Parameters		
Item	**Single Unit [Two Unit] Value**	**Description and Reference**
Plant Characteristics		
Megawatts Thermal	3,400 MWt [6,800 MWt]	The thermal power generated by one unit. Refer to Section 1.1, Subsections 1.2.2 and 1.3.2

Part III Site Interface Values		
Item	**Single Unit [Two Unit] Value**	**Description and Reference**
Normal Plant Heat Sink		
Cooling Tower Make-up Flow Rate	30,572 gpm [61,145 gpm]	The maximum rate of removal of water from the Savannah River to replace water losses from the circulating watersystem. The bounding Makeup Flow Rate is a calculated value based on the sum of the expected evaporation rate at design ambient conditions plus the bounding blowdown flow rate and drift. Refer to Subsections 2.4.1.2.6, 2.4.8, and 2.4.11.5; Table 2.4-217
Airborne Effluent Release Point		
Minimum Distance to Site Boundary	3,420 ft	The minimum lateral distance from the release point (power block area circle) to the site boundary. Refer to Figure 1.1-202

2.1 Geography and Demography

2.1.1 Site Location and Description

2.1.1.1 Site Location

Units 3 and 4 are on the existing VEGP site. The 3,169-acre VEGP site is located on a coastal plain bluff on the southwest side of the Savannah River in eastern Burke County. The site exclusion area boundary (EAB) is bounded by River Road, Hancock Landing Road, and 1.7 miles of the Savannah River (River Miles 150.0 to 151.7). The property boundary entirely encompasses the EAB and extends beyond River Road in some areas. The site is approximately 30 river miles above the US 301 bridge and directly across the river from the Department of Energy's (DOE's) Savannah River Site (SRS) (Barnwell County, South Carolina). The VEGP site is approximately 15 mi east-northeast of Waynesboro, Georgia, and 26 mi southeast of Augusta, Georgia, the nearest population center (i.e., having more than 25,000 residents). It is also about 100 mi from Savannah, Georgia, and 150 river miles from the mouth of the Savannah River.

The VEGP site is situated within three major resource areas: the Southern Piedmont, the Carolina and Georgia Sand Hills, and the Coastal Plain. These characteristics are typical of land forms that resulted from historical marine sediment deposits in central and eastern Georgia. There are no mountains in the general area.

Burke County includes five incorporated towns: Waynesboro, Girard, Keysville, Midville, and Sardis. Of these five towns, only the town of Girard is within 10 mi of the VEGP site. According to the 2000 Census survey, Girard, which has a population of 227, is the largest community within 10 mi of the VEGP site (Reference 207). Figure 2.1-201 shows Girard and its location with respect to the VEGP site. Access to the site is by River Road via US Route 25, Georgia Routes 56, 80, 24, and 23. A railroad spur connects the site to the Norfolk Southern Savannah-to-Augusta track.

Figure 2.1-202 shows highways, railways and airports located in the 50 mi surrounding area. The nearest highway, Interstate 20 (I-20), passing through Augusta and connecting Columbia, South Carolina, with Atlanta, Georgia, is located approximately 29 mi north of the VEGP site.

2.1.1.2 Site Description

VEGP Units 3 and 4 (Westinghouse Electric Company, LLC [Westinghouse] AP1000 certified reactor design plants) is located in the power block area shown in Figure 1.1-202. The centerline of VEGP Unit 3 is located approximately 1,700 ft west and 400 ft south of the center of the existing VEGP Unit 2 containment building. VEGP Unit 4 is approximately 800 ft west of VEGP Unit 3. The coordinates of the center of the containment building for VEGP Units 3 and 4 are as follows:

Unit	Georgia East Coordinates (NAD27) 1001 – Georgia East (US ft)		UTM Coordinates (NAD83) Zone 17 – 84W to 78W (m)		Latitude/Longitude (NAD83)(Deg/Min/Sec)	
3	N	1,142,600	N	3,667,170	N	33 08 27
	E	621,800	E	428,320	W	81 46 07
4	N	1,142,600	N	3,667,170	N	33 08 27
	E	621,000	E	428,070	W	81 46 16

No commercial, industrial, institutional, recreational, or residential structures are located within the site area, with the exception of Plant Wilson, the Georgia Power Company (GPC) combustion turbine plant. The nearest point to the exclusion area boundary (EAB) is located approximately 3,400 ft southwest of the VEGP Units 3 and 4 power block area.

2.1.1.3 Boundary for Establishing Effluent Release Limits

VEGP Units 3 and 4 are located within the power block area, which is the perimeter of a 775-ft-radius circle with the centroid at a point between the two AP1000 units. The EAB as described previously, is the same as the exclusion area boundary for the existing VEGP units. There are no residents in this exclusion area. No unrestricted areas within the site boundary are accessible to members of the public. Access within the property boundary is controlled as discussed in Subsection 2.1.2. Detailed discussion of effluent release points is provided in Subsection 2.3.5.

All areas outside the exclusion areas are unrestricted areas in the context of 10 CFR 20. Additionally, the guidelines provided in 10 CFR 50, Appendix I, for radiation exposures to meet the criterion “as low as is reasonably achievable” would be applied at the EAB.

2.1.2 Exclusion Area Authority and Control

The EAB is bounded by River Road, Hancock Landing Road, and 1.7 miles of the Savannah River (River Miles 150.0 to 151.7) as shown in Figure 1.1-202.

2.1.2.1 Authority

The co-owners own the entire plant exclusion area in fee simple including mineral rights. Pursuant to the VEGP owner’s agreement, GPC, for itself and as agent for the co-owners, has delegated to Southern Nuclear Operating Company, Inc. (SNC) complete authority to regulate any and all access and activity within the entire plant exclusion area.

The perimeter of the VEGP EAB is adequately posted with “No Trespassing” signs on land and with signs along the Savannah River, and indicate the actions to be taken in the event of emergency conditions at the plant.

2.1.2.2 Control of Activities Unrelated to Plant Operation

There are only two facilities within the EAB that have authorized activities unrelated to nuclear plant operations, the visitor’s center and the GPC combustion turbine plant, Plant Wilson.

The exclusion area outside the controlled area fence is posted and is closed to persons who have not received permission to enter the property.

The access route to the visitor's center is from River Road along the main plant access road to the road leading to the visitor’s center. Normally, only a few administrative personnel are located at the visitor’s center. Because of the remote location of the site, the number of visitors at the center is minimal. However, approved persons visiting the center will occupy the center and the area and parking lot immediately adjacent to the center. In the event of emergency conditions at the plant, the emergency plan provides for notification of visitors to the center concerning the proper actions to be taken and evacuation instructions. Plant Wilson is controlled and operated by VEGP staff. Access to the facility from New River Road is limited by locked gates. The emergency plan also provides for notification and evacuation of VEGP personnel at Plant Wilson.

SNC normally will not control passage or use of the Savannah River along the exclusion area boundary. “No trespassing” signs are posted near the river indicating the actions to be taken in the event of emergency conditions at the plant.

2.1.2.3 Arrangements for Traffic Control

No state or county roads, railways, or waterways traverse the VEGP exclusion area.

SNC has made arrangements with the Burke County Sheriff for control of traffic nearby in the event of an emergency. Evacuation of the EAB including the Visitors Center and Plant Wilson is addressed in the Emergency Plan.

2.1.3 Population Distribution

The population distribution surrounding the VEGP site, up to a 50-mi (80 km) radius, was estimated based on the year 2000 US Census Bureau decennial census data (Reference 202). The population distribution is estimated in 10 concentric bands at 0 to 1 mi, 1 to 2 mi, 2 to 3 mi, 3 to 4 mi, 4 to 5 mi, 5 to 10 mi, 10 to 20 mi, 20 to 30 mi, 30 to 40 mi, and 40 to 50 mi from the center of the power block area (generating facilities and switchyard), shown in Figure 1.1-202 and 16 directional sectors, each direction consisting of 22.5 degrees. The population projections for 2010, 2020, 2030, 2040, and 2070 have been estimated by calculating an annualized growth rate using the 1980 and 2000 census data (by county) as the base (Reference 204, Reference 206).

2.1.3.1 Resident Population Within 10 Mi

Figure 2.1-201 shows the general locations of the municipalities and other features within 10 mi (16 km) of the VEGP site. According to the 2000 Census, Girard, with a population of 227, is the largest community within 10 mi of the site (Reference 207). The population of Girard showed an increase of 16.4 percent in the last decade from a population of 195 in 1990 to a population of 227 in 2000 (Reference 205).

The population distribution within 10 mi of the site was computed by overlaying the 2000 Census block points data (the smallest unit of census data) on the grid shown in Figure 2.1-201 and summing the population of the census block points within each sector. SNC used SECPOP 2000, a code developed for the NRC by Sandia National Laboratories, to calculate population by emergency planning zone sectors (Reference 202). SECPOP uses 2000 block data from the US Census Bureau and overlays it into the sectors in the annuli prescribed by the user. The 1980 and 2000 population distributions for each county considered in Georgia and South Carolina were obtained from the U.S Census Bureau and used to calculate a growth rate over 20 years (Reference 204, Reference 206). Each county growth rate was annualized and used to project future populations within each sector, taking into account the percentage of each sector that each county occupied.

The population distributions and related information were collected and the results tabulated for all distances of interest in all 16 directions. All the north-northeast to east sectors in South Carolina are occupied by the SRS, which has no residents. SRS transients are accounted for in the SRS Emergency Plan and, therefore, are not included in the Emergency Plan. The SRS will remain a government-controlled facility in perpetuity. The SECPOP 2000 results show that in 2000, the combined resident and transient populations within 5 mi and 10 mi of the VEGP site were 687 and 3,560 persons, respectively. The resident and transient 10-mi population for 2000 and projections for 2010 through 2070 are shown in Figures 2.1-203 through 2.1-208 and are summarized in the table below.

Year	2000	2010	2020	2030	2040	2070
Population 0–10 miles	3,560	3,822	4,108	4,406	4,737	5,877

2.1.3.2 Resident Population Between 10 and 50 Mi

The 50-mi (80-km) radius centered at the VEGP site includes all, or parts of, 16 counties in Georgia, and 12 counties in South Carolina (Figure 2.1-209). Augusta, Georgia, approximately 26 mi northwest of the VEGP site, had a population of 195,182 in year 2000. Estimates of the year 2000

resident population between 10 and 50 mi from the VEGP site were computed using the same methodology used to develop the 10-mi population distribution.

The population grid to 50 mi is shown in Figure 2.1-209. The 10–50-mi population for 2000 and projections for 2010 through 2070 are shown in Figures 2.1-210 through 2.1-215. The total 0–50 mile population and projections are summarized in the table below.

Year	2000	2010	2020	2030	2040	2070
Population 0–50 miles	674,101	770,243	893,950	1,056,017	1,272,093	2,530,357

2.1.3.3 Transient Population

2.1.3.3.1 Transient Population Within 10 Miles

Information concerning transient population for the 10-mi radius was obtained from the Emergency Plan. The transient population includes hunters and fishermen at recreational areas along the Savannah River. Up to 200 hunters and fishermen may be located along the Savannah River on any weekend day during the hunting season (Reference 203). Although most hunters and fishermen likely reside in the area, this information is not definitive. Therefore, all hunters and fishermen were included as transient population. The construction workforce for VEGP Units 3 and 4 and the existing staff at VEGP were not included as transient population within 10 mi of the plant because they are counted as residents within the 10–50 mi radius area.

Portions of the SRS fall within 10 mi of the VEGP site. However, SRS workers are not counted as transient population in the Emergency Plan because SRS is responsible for its own evacuation plan. (Reference 203)

2.1.3.3.2 Transient Population Between 10 and 50 Miles

Colleges, schools, hospitals, a military base, and the SRS are between 10 and 50 mi from the VEGP site. In addition, thousands of people visit Augusta and the surrounding area out to the 50-mi limit annually during the week of the Masters Tournament and for other annual events within a 50-mi radius. However, compared to the resident population within a 50-mi radius, the transient population is expected to be very small.

2.1.3.4 Low Population Zone

The low population zone (LPZ) for VEGP Units 3 and 4 is the same as the LPZ for the existing VEGP units and consists of the area falling within a 2-mi radius of the midpoint between the VEGP Unit 1 and Unit 2 containment buildings. The resident and transient population distribution within the LPZ is indicated in Figures 2.1-203 through 2.1-208, based on the 2000 Census and projections through 2070. The LPZ population projections are also shown in the table below.

Year	2000	2010	2020	2030	2040	2070
Population	93	100	109	116	126	157

There are no schools in the LPZ. One private school is located approximately 9 mi west of the site, Lord's House of Praise Christian School, with an enrollment of approximately 50 students. S.G.A. Elementary School is the nearest public school and is located in the town of Sardis approximately 11 mi from the VEGP site (Reference 201). As stated in the previous section, the only significant transient population within 10 mi is hunters and fishermen along the banks of the Savannah River.

Approximately 50 hunters and fishermen could be considered transient population within the LPZ. River Road is the only road within the LPZ. No towns, recreational facilities, hospitals, schools, prisons, or beaches are within the LPZ (Reference 203). Design basis accidents are evaluated in Chapter 15 to demonstrate that doses at the LPZ will be within the dose limits of 10 CFR 100.21(c) and 10 CFR 50.34(a)(1)(ii). Evacuation of the LPZ is addressed in the referenced Emergency Plan.

2.1.3.5 Population Center

The nearest population center to the VEGP site with more than 25,000 residents is the City of Augusta, Georgia, with a 2000 population of 195,182 (Reference 207). Augusta is approximately 26 miles north-northwest of the VEGP site.

2.1.3.6 Population Density

Regulatory Position C.4 of Regulatory Guide 4.7, *General Site Suitability Criteria for Nuclear Power Plants*, Revision 2, April 1998 (RG 4.7) and NRC Review Standard RS-002, *Processing Applications for Early Site Permits*, May 3, 2004 (RS-002) provide guidance on suitable population densities. Given an ESP approval date of 2010, a conservative startup date of 2030 (at the end of an ESP approval period of 20 years), and an operational period of 40 years, operations could extend until 2070. Figure 2.1-216 is a plot of population density to radial distance from the plant. Three VEGP site curves, one actual and two projected, were plotted to illustrate that the VEGP site vicinity population density is well below the regulatory guidance for population density. The three VEGP curves show the cumulative population in 2000 within 20 mi of the site and projected cumulative populations in 2040 and 2070. On the same figure, spanning the same radial distances, regulatory guidance population curves are plotted for hypothetical densities of 500 persons per square mile and 1,000 persons per square mile. Based on these projections, population densities, averaged over any radial distance out to 20 mi, are expected to be less than 500 persons per square mile over the lifetime of the new units. Figure 2.1-217 provides a representation of the LPZ that includes topographic features, as well as transportation routes (i.e., highways, railways, and waterways).

2.1.4 Combined License Information for Geography and Demography

Site-specific geography and demography information is addressed in Subsections 1.1.1, 1.2.2, and in Section 2.1.

2.1.5 References

201. **(BCS 2006)** *Burke County Schools,* BCS, 2006, available online at: http://www.burke.k12.ga.us, accessed April 5, 2006.

202. **(NRC 2003)** *SECPOP 2000: Sector Population, Land Fraction, and Economic Estimation Program*, Office of Nuclear Regulatory Research, US Nuclear Regulatory Commission, Washington, D.C., August 2003.

203. **(SNC 2004)** *Vogtle Electric Generating Plant Emergency Plan*, Revision 29, Southern Nuclear Operating Company, Inc., 2004.

204. **(USCB 1990a)** CPH-2-1. *1990 Census of Population and Housing, Population and Housing Unit Counts, United States, Table 30: Population and Housing Units: 1940 to 1990*, US Census Bureau, available online at: http://www.census.gov/population/www/censusdata/hiscendata.html, accessed June 1, 2005.

205. **(USCB 1990b)** *DP-1. General Population and Housing Characteristics*: 1990, US Census Bureau, Available online at http://factfinder.census.gov/, accessed June 3, 2005.

206. **(USCB 2000a)** *Census 2000 PHC-T-4. Ranking Tables for Counties;* 1990 and 2000, US Census Bureau, available online at http://www.census.gov, accessed June 2, 2005.

207. **(USCB 2000b)** *GCT-PH1. Population, Housing Units, Area, and Density*: 2000, US Census Bureau, available online at http://factfinder.census.gov, accessed June 3, 2005.

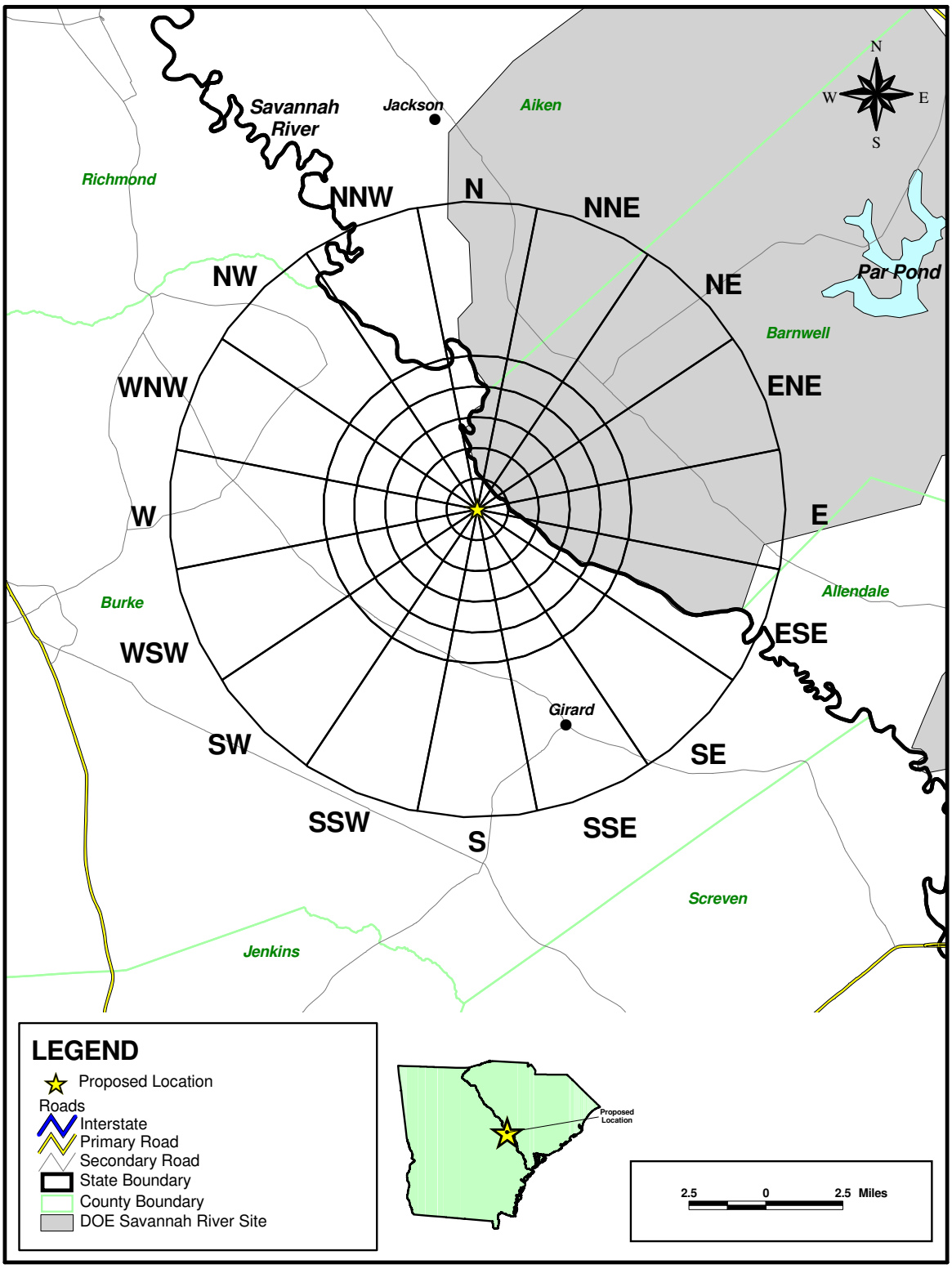


Figure 2.1-201
10-Mile Surrounding Area

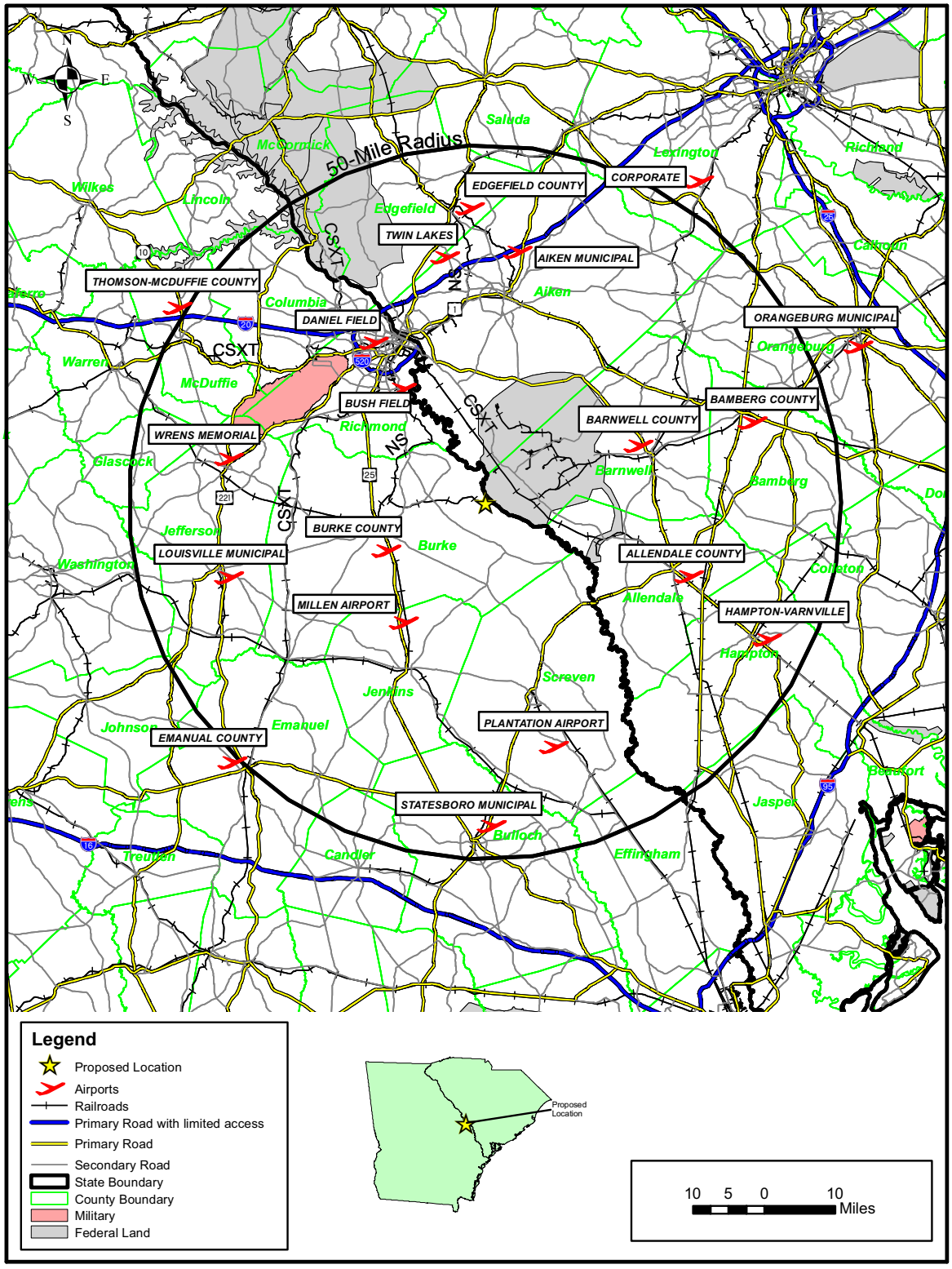
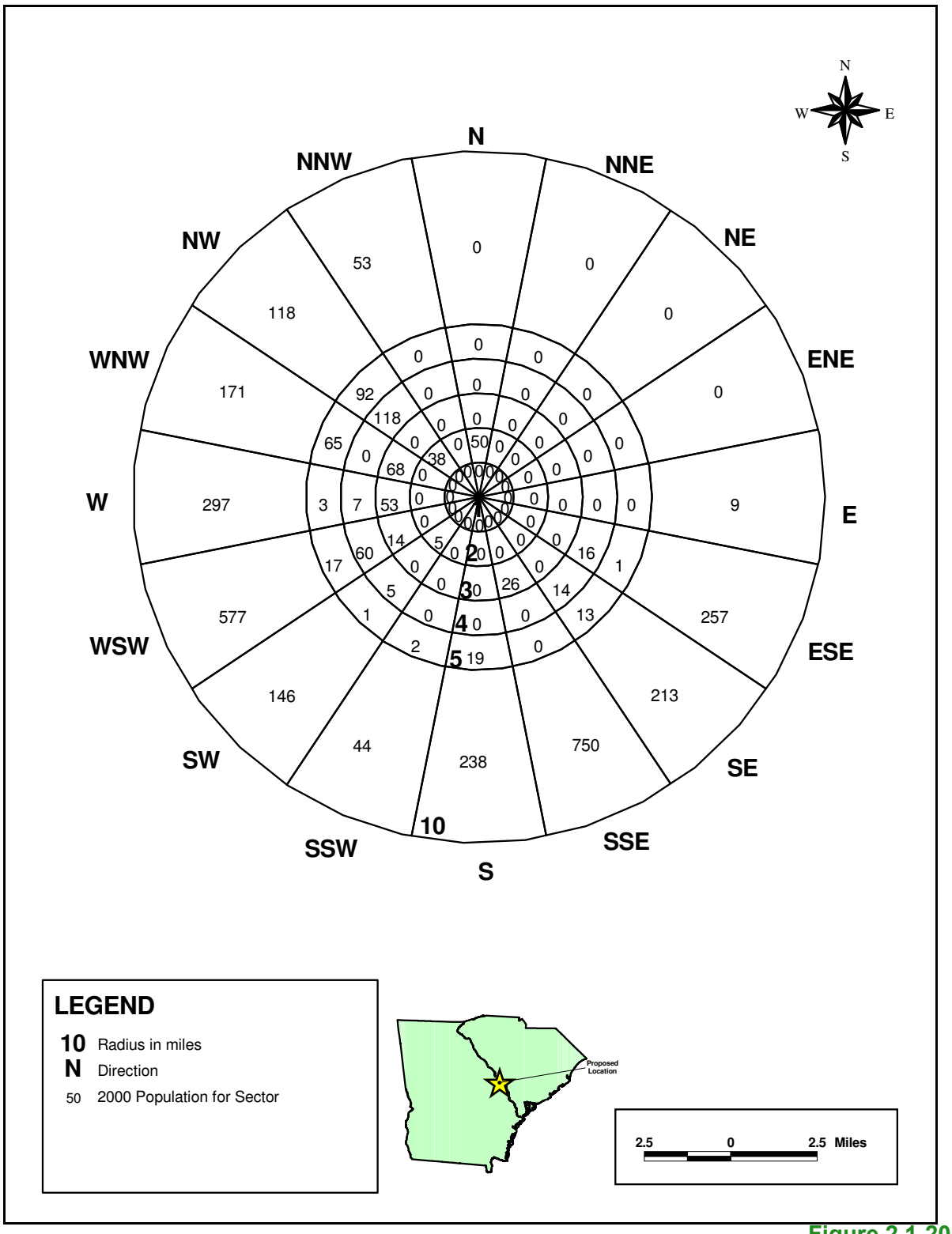


Figure 2.1-202
50-Mile Surrounding Area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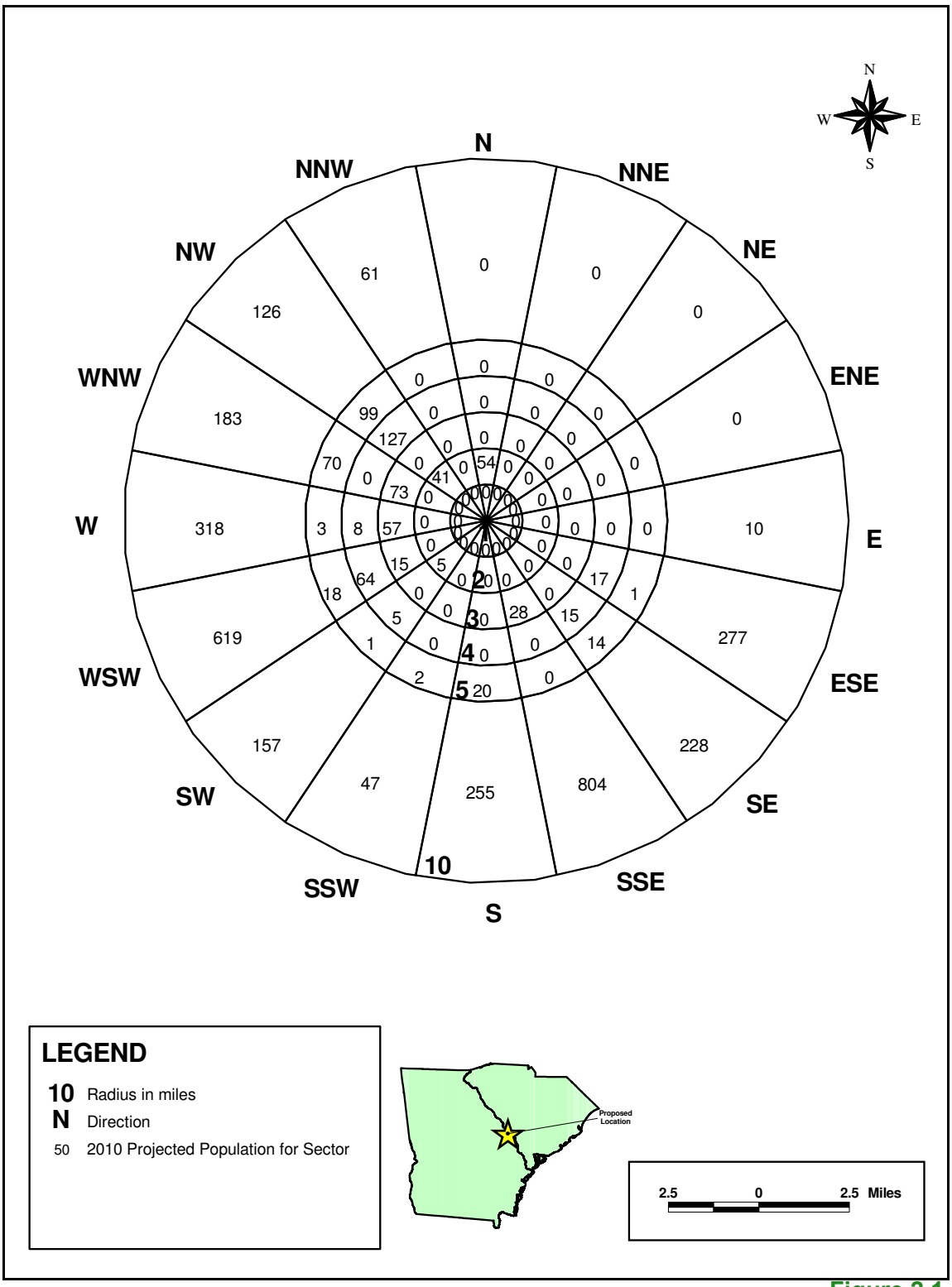
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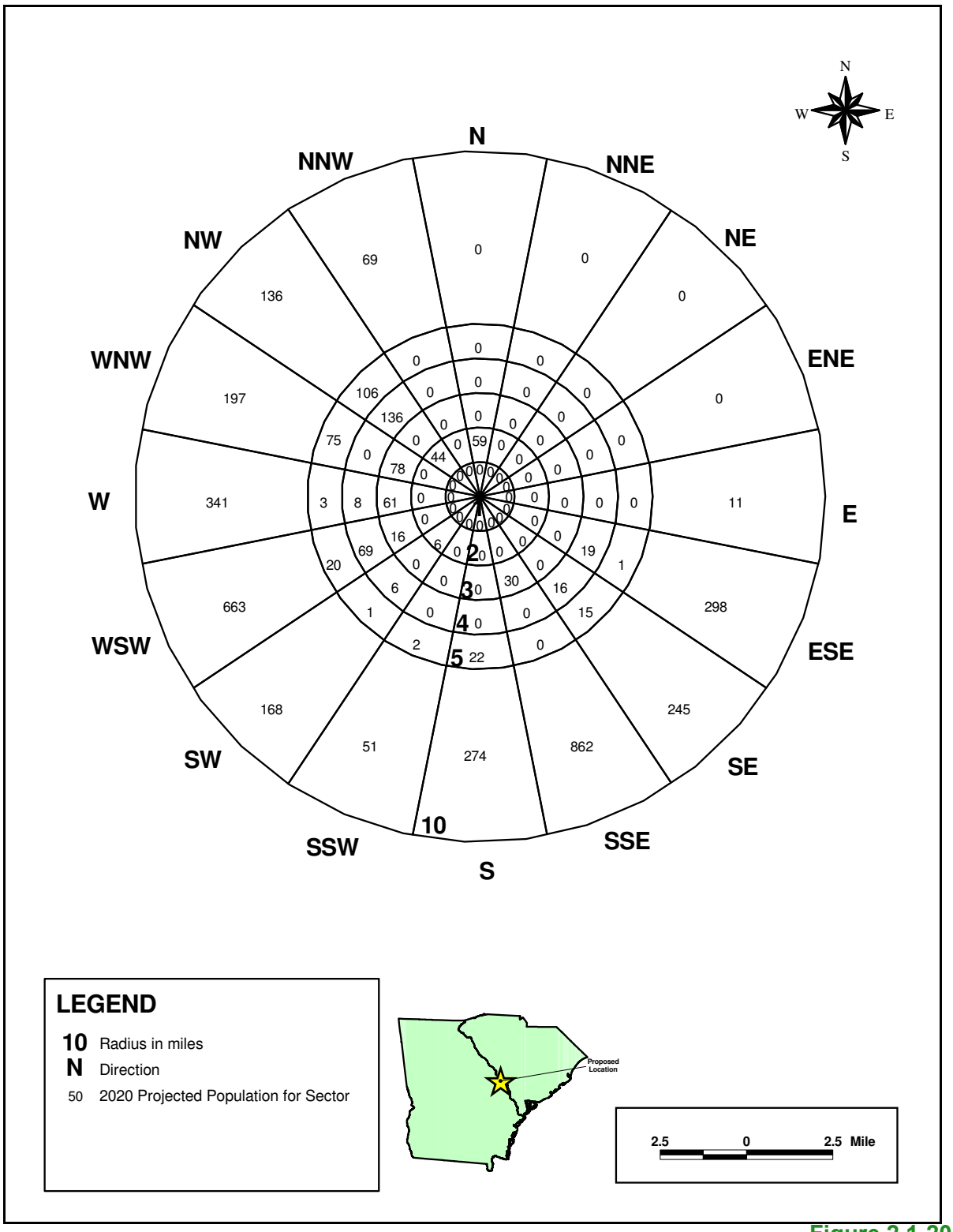
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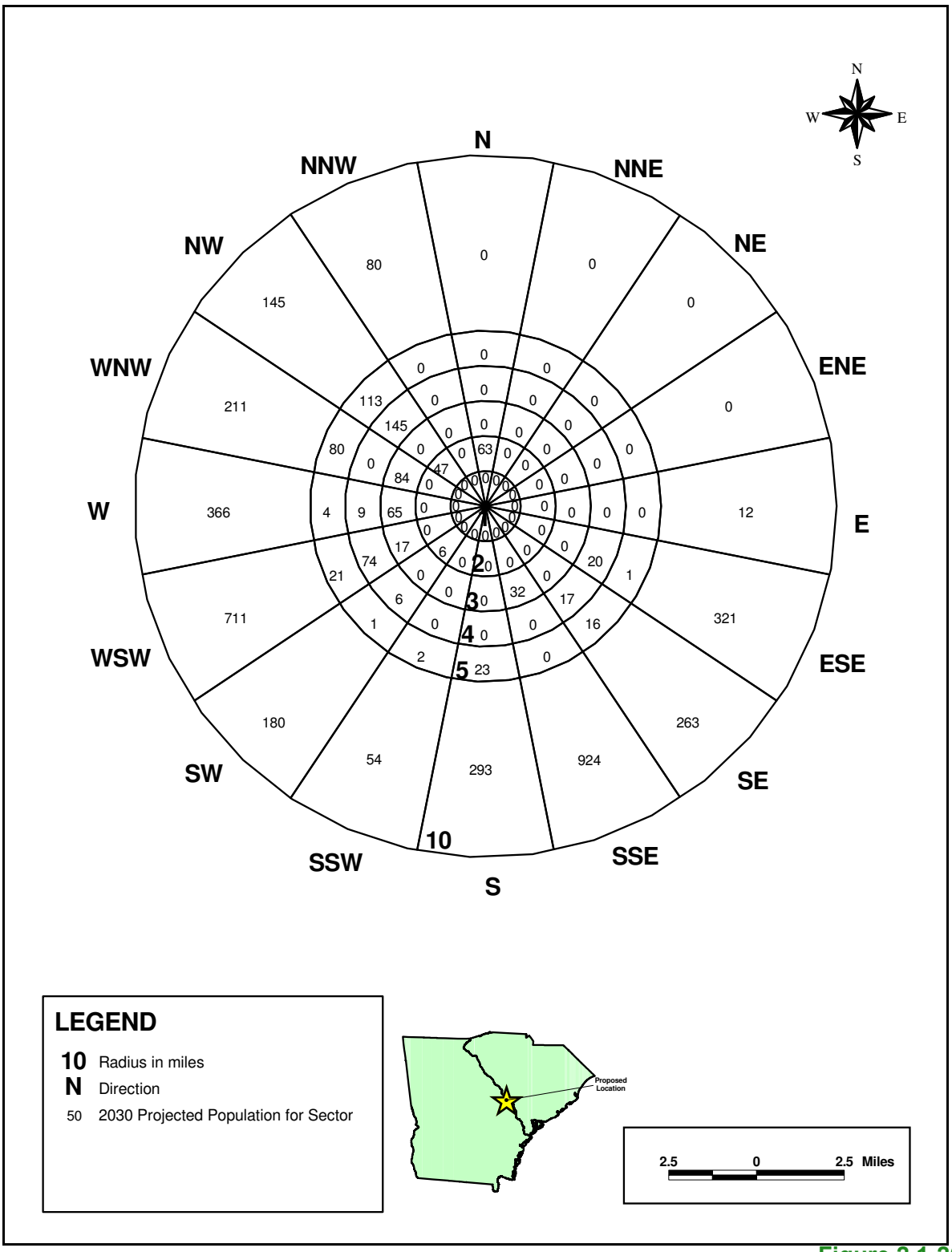
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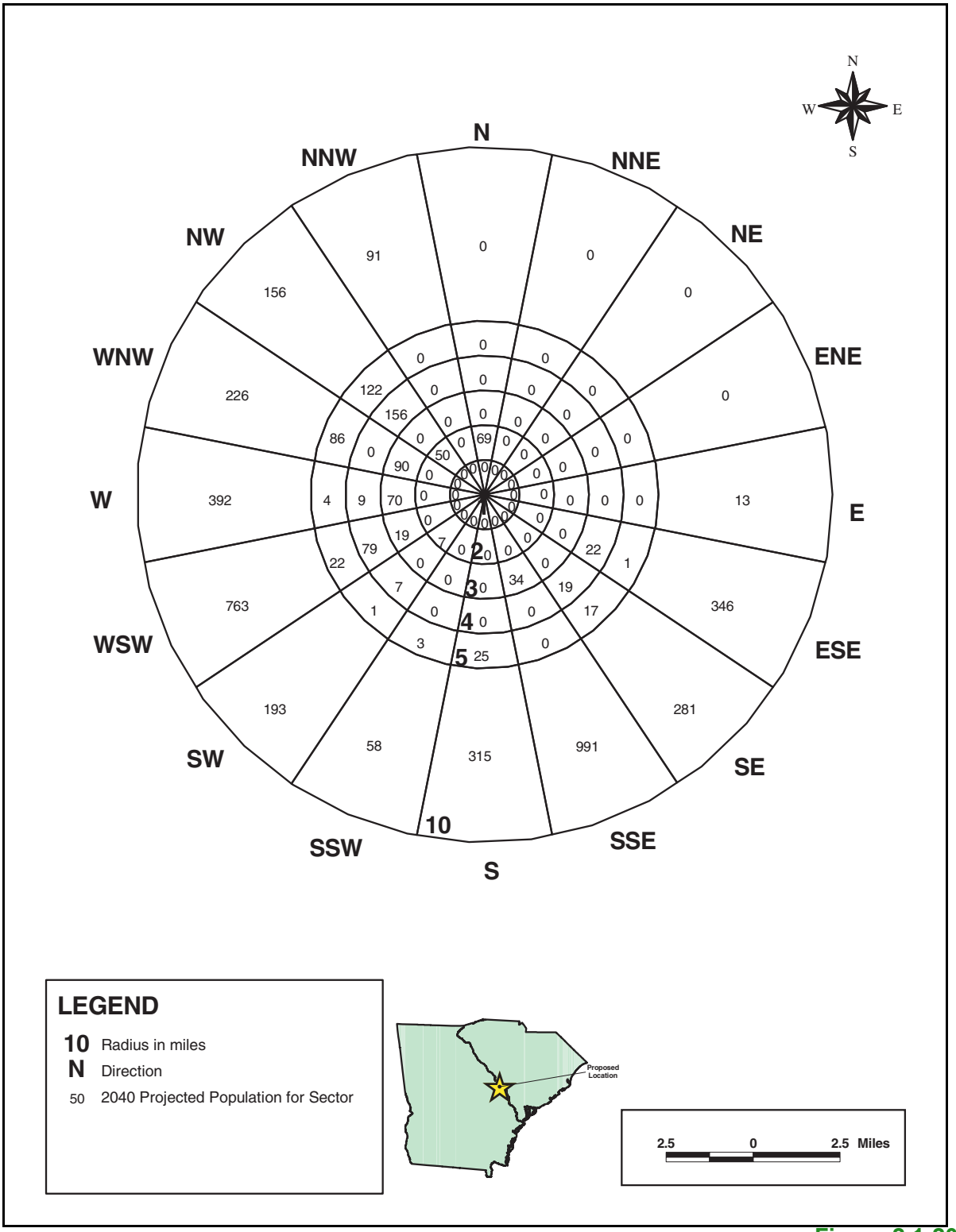
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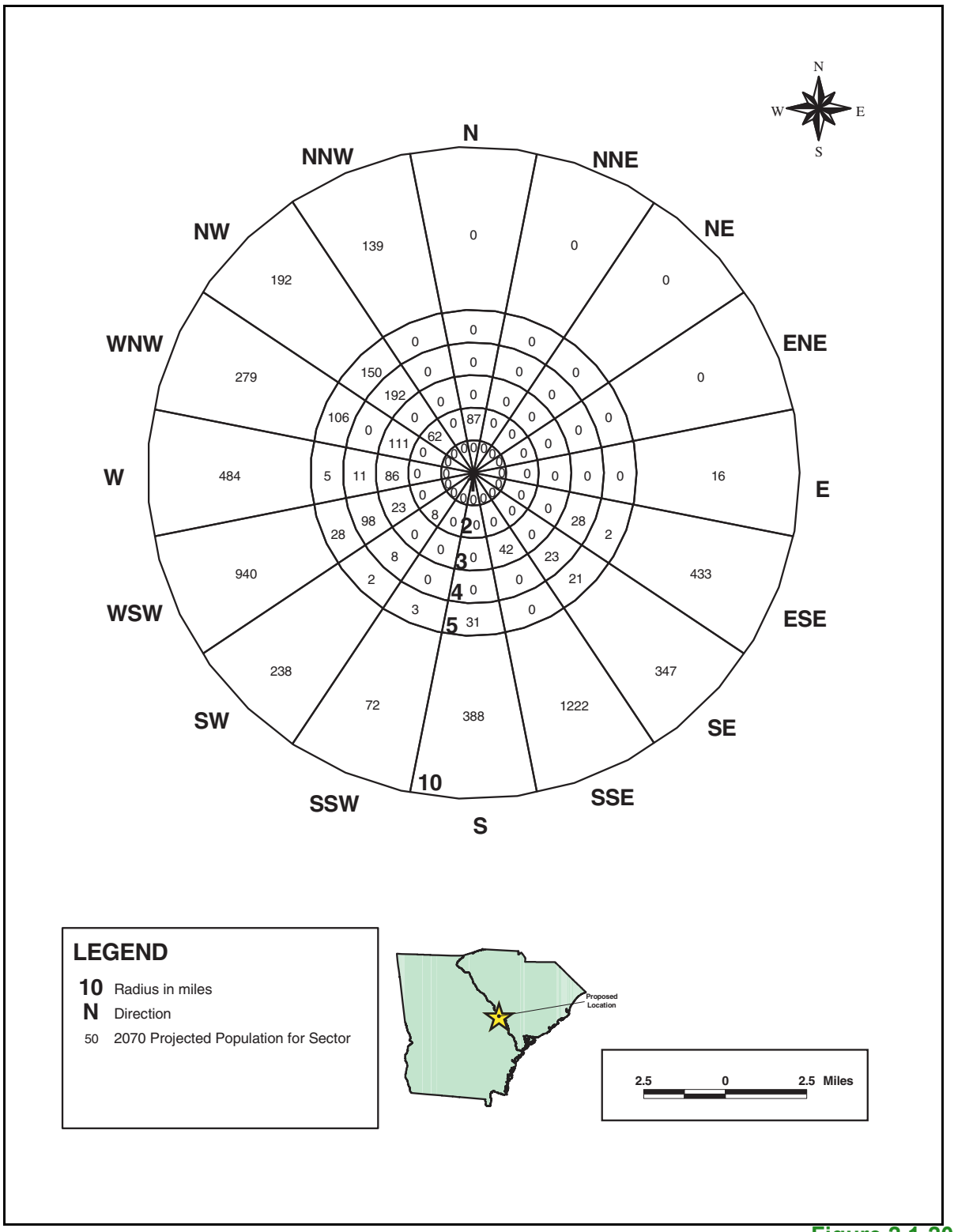


Figure 2.1-208
10-Mile Resident and Transient Population Distribution – 2070

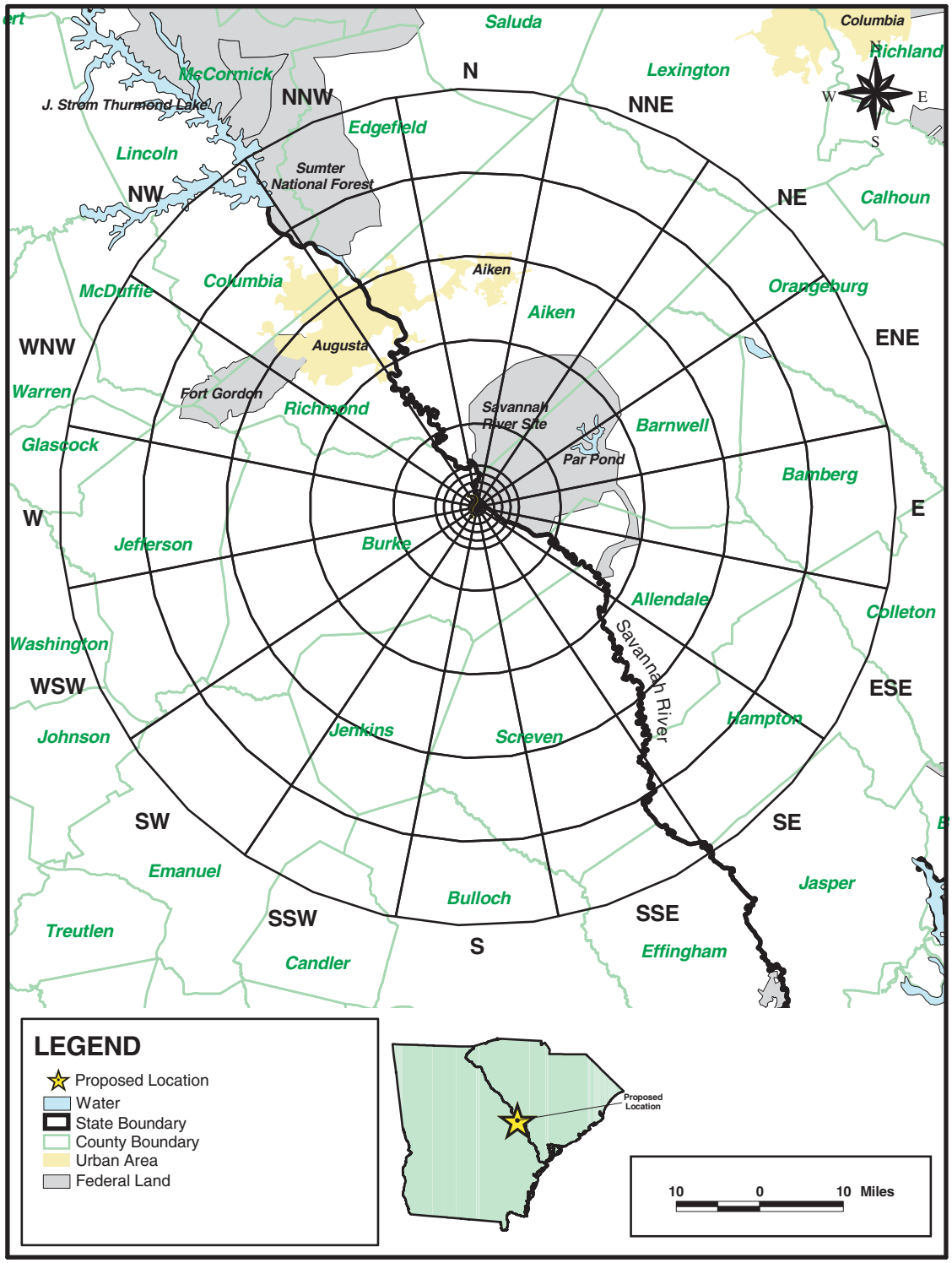


Figure 2.1-209
Population Grid Out to 50 Miles

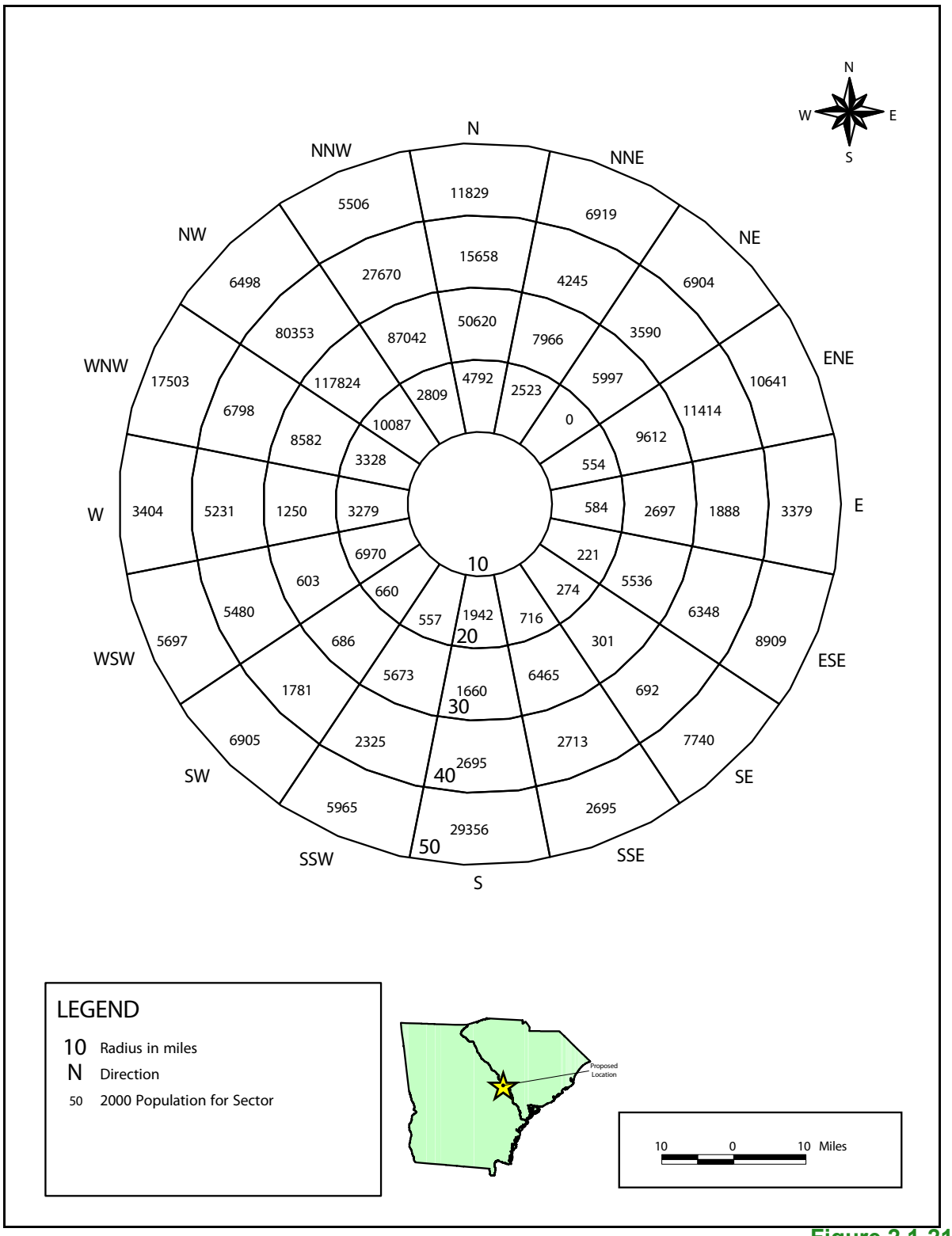


Figure 2.1-210
10 to 50-Mile Resident Population Distribution 2000

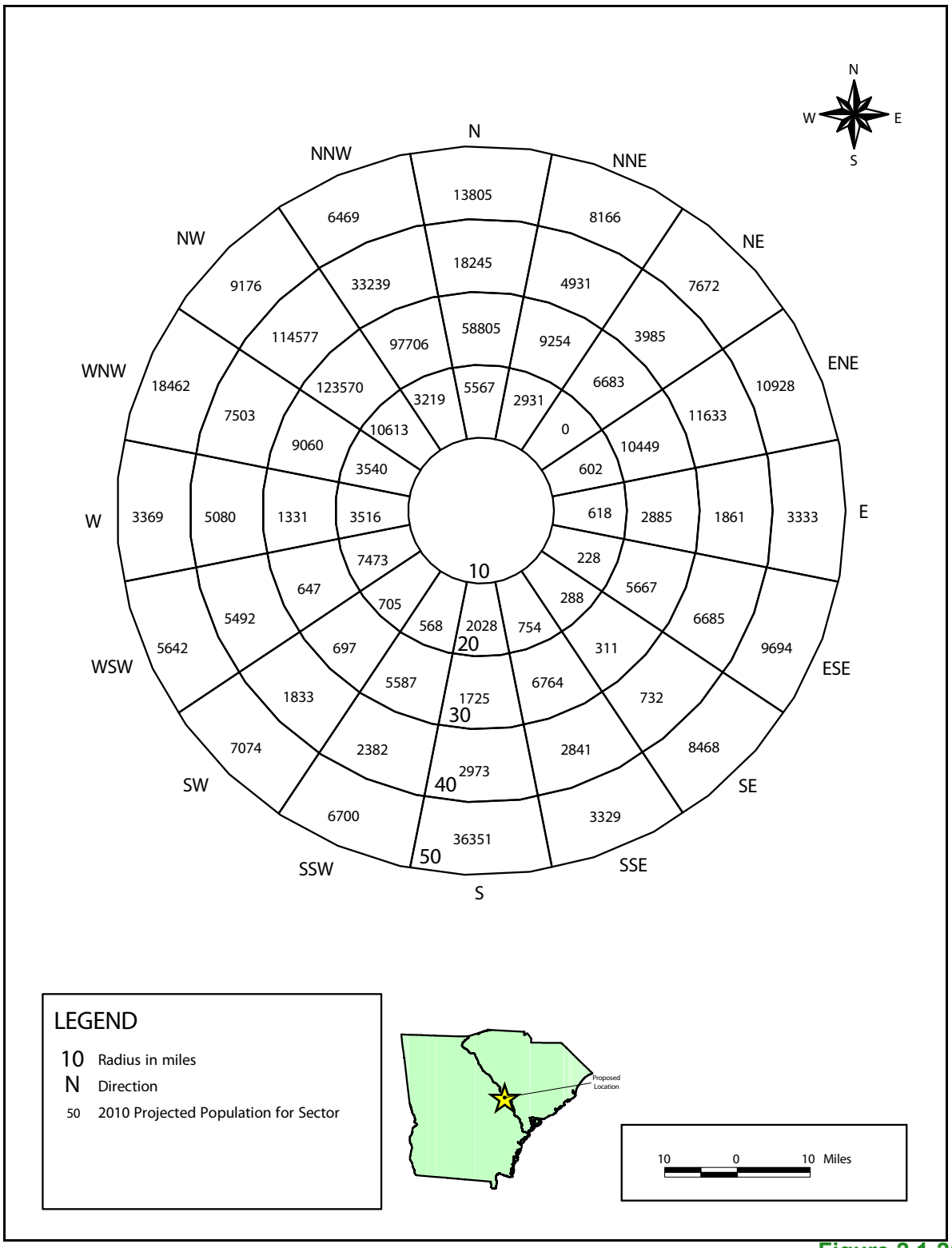


Figure 2.1-211
10 to 50-Mile Resident Population Distribution 2010

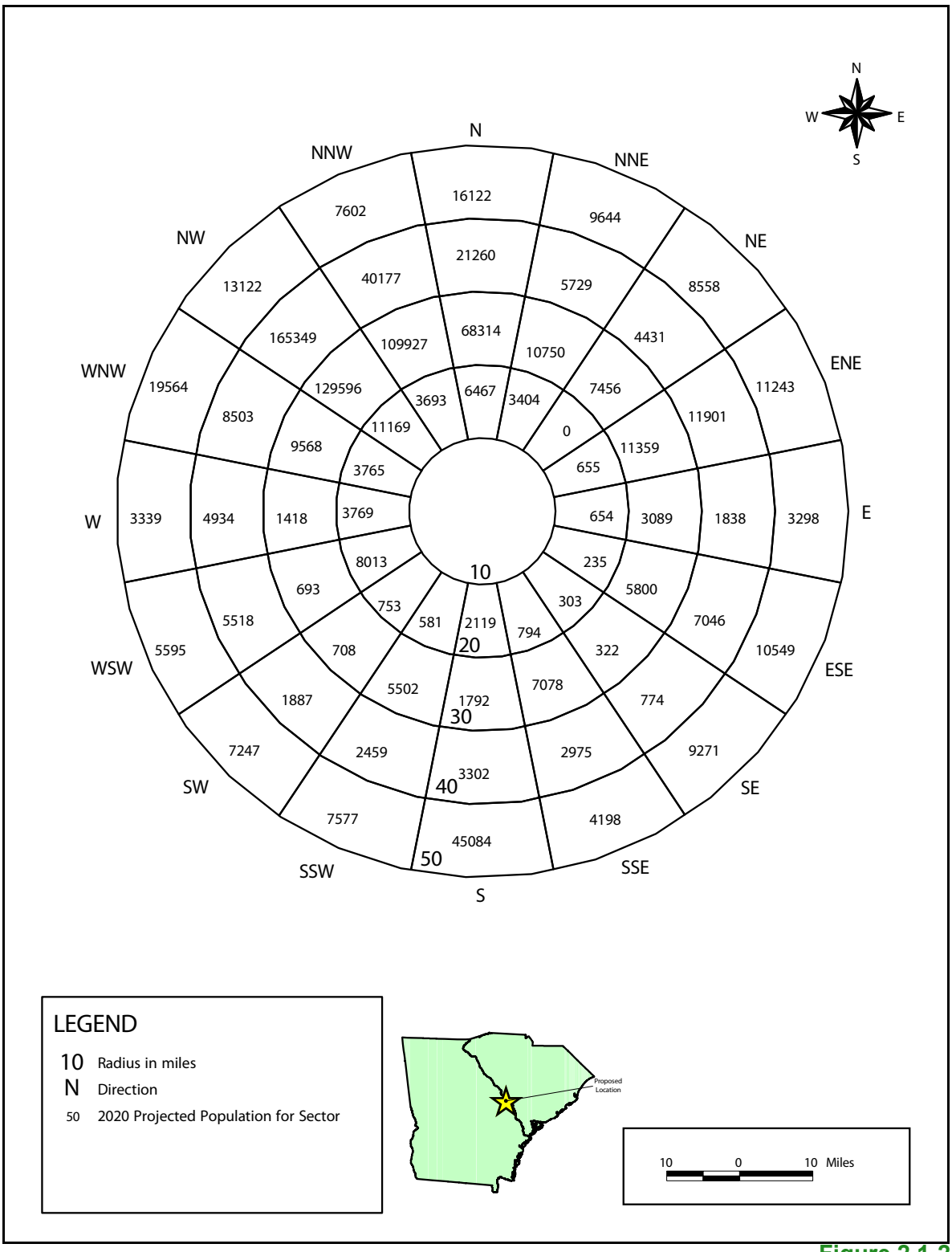


Figure 2.1-212
10 to 50-Mile Resident Population Distribution 2020

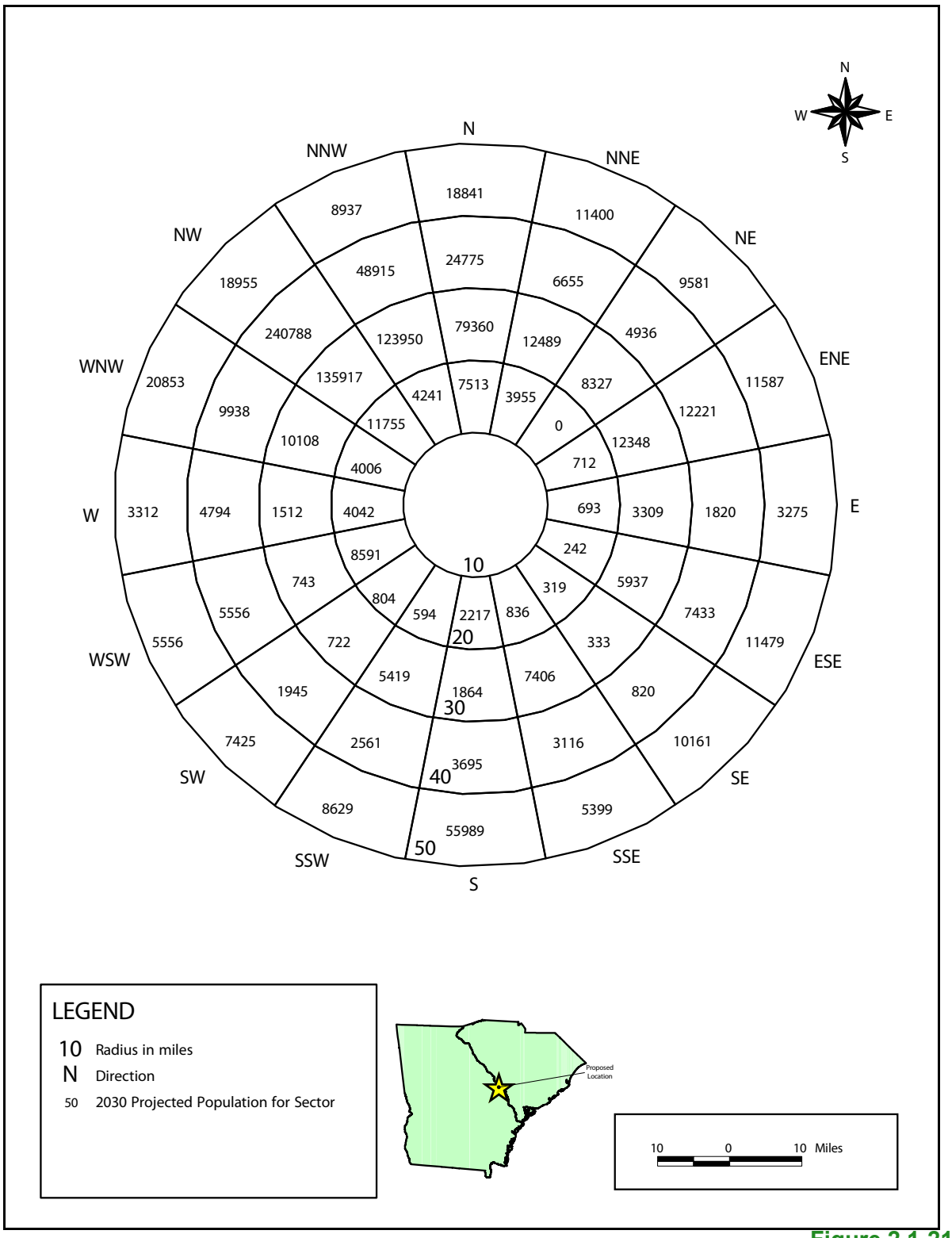


Figure 2.1-213
10 to 50-Mile Resident Population Distribution 2030

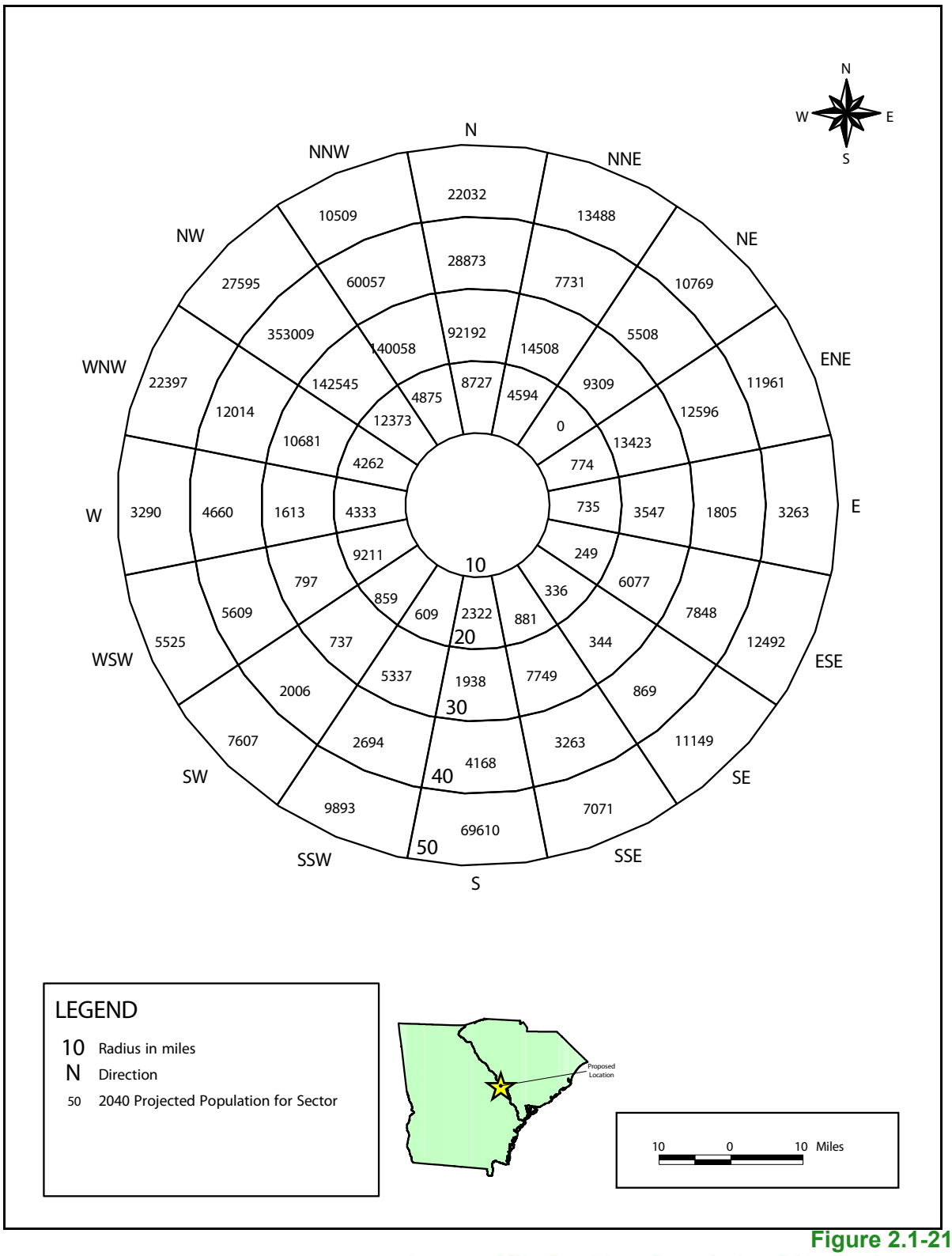


Figure 2.1-214
10 to 50-Mile Resident Population Distribution 2040

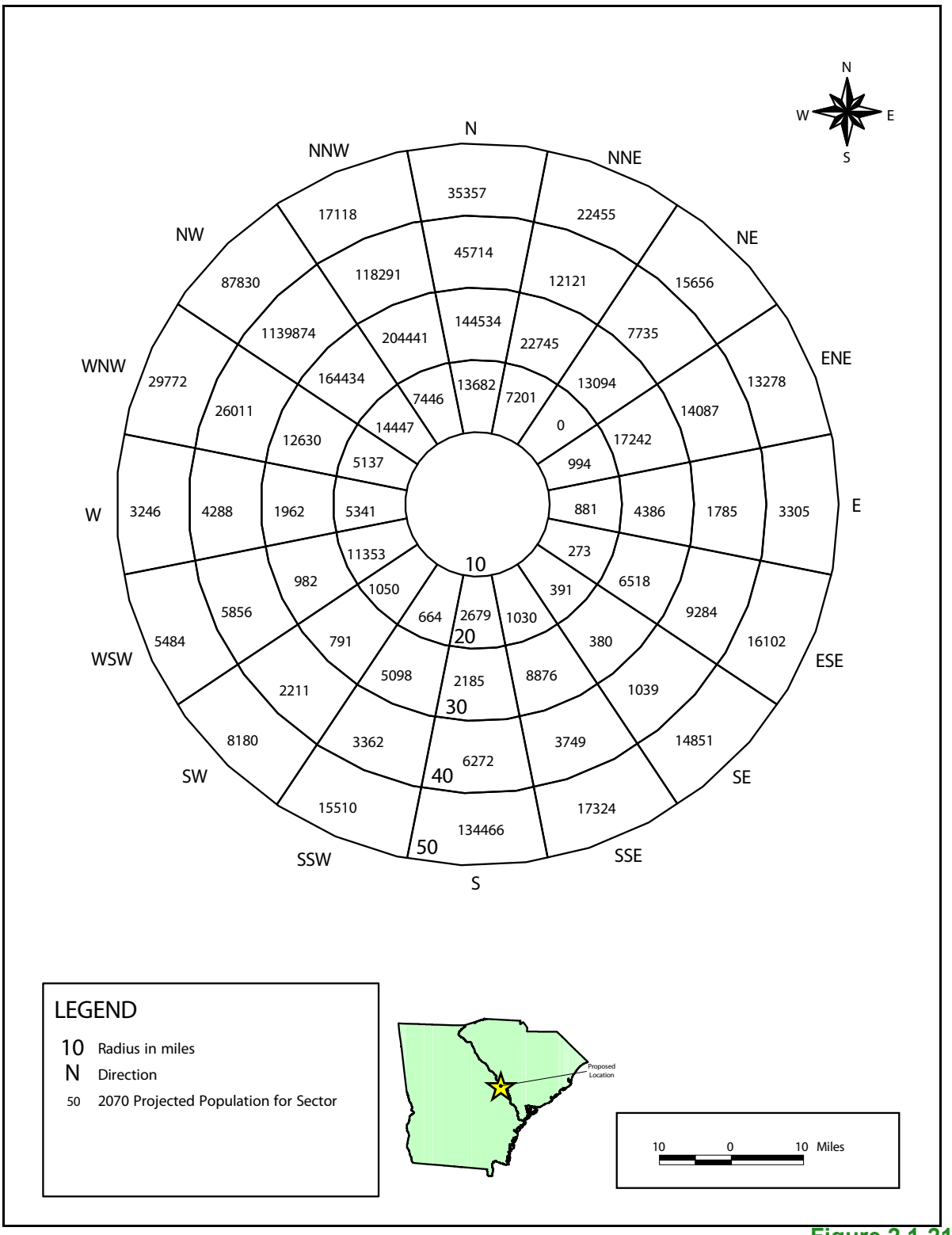


Figure 2.1-215
10 to 50-Mile Resident Population Distribution 2070

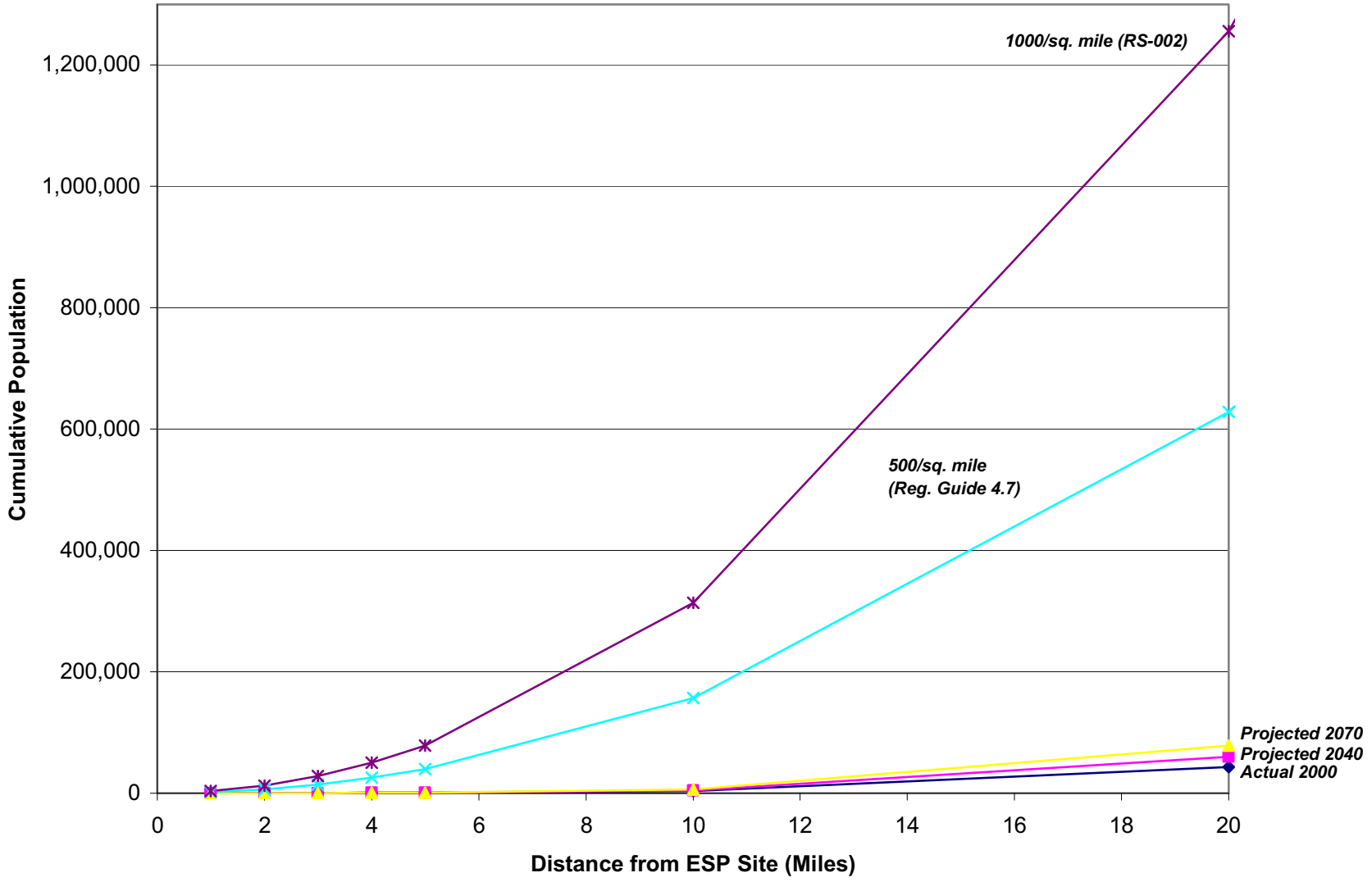
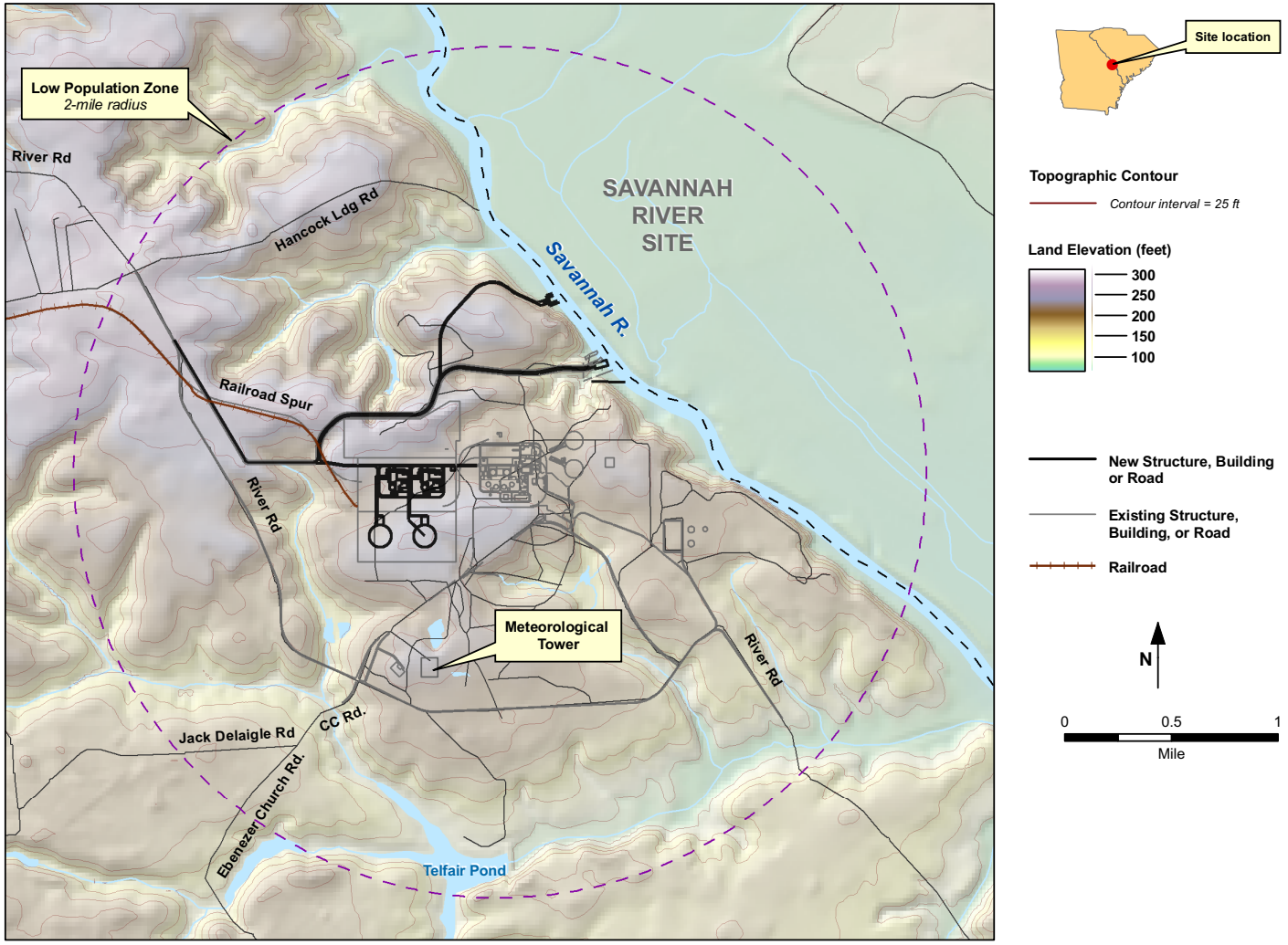


Figure 2.1-216
Population Compared to NRC Siting Criteria



Source data: ESRI, Data & Maps and StreetMap USA, 2005. USGS, seamless data distribution, NED shaded relief.
Vogtle Project Drawing No. 0-C2-00 10-00001.

Figure 2.1-217
Low Population Zone

2.2 Identification of Potential Hazards in Site Vicinity

2.2.1 Location of Nearby Industrial, Transportation, and Military Facilities

Within a 5-mile vicinity of the VEGP site, there are several major industrial facilities, one railroad, and one highway with commercial traffic. Specifically, the following transportation routes and facilities are shown on the indicated figures:

- Plant Wilson (see Figure 2.2-201)
- Savannah River Site (see Figure 2.2-202)
- Georgia State Highway 23 (see Figure 2.2-203)
- CSX Railroad (see Figure 2.2-201)
- A coal-fired steam plant operated by Washington Savannah River Company in D-Area of the SRS
- VEGP Unit 1 and Unit 2

Figures 2.2-202 and 2.2-203 show the location of major industrial facilities, military bases, highway transportation routes, airports, railroads, and pipelines within a 25-mile radius of the site. In addition, Figure 2.2-202 shows nearby airways and military operation areas.

Items illustrated on the maps are described in Subsection 2.2.3. The only military facility within a 50-mile radius is Fort Gordon. The Fort Gordon U.S. Army Signal Corps training facility is barely within 25 miles of the VEGP site. The only major storage facility within 25 miles of the VEGP site, other than those at the SRS and at Chem-Nuclear Systems, is a group of oil storage tanks associated with the existing combustion turbine generators for Plant Wilson on the VEGP site.

2.2.2 Descriptions

2.2.2.1 Industrial Facilities

The Burke County Comprehensive Plan: 2010, Part 1 (Reference 207) shows a relatively slow, stable population growth pattern for the county. This is indicative that the nearby industries have not experienced much growth.

The Comprehensive Plan also reveals that services and manufacturing industries dominate the top 10 employers in the county. Southern Nuclear and Samson Manufacturing Company (curtains and draperies) are the largest Burke County employers. Nearby industries also include the Chem-Nuclear Systems radioactive waste disposal site (18 miles away in South Carolina) operated by Duratek; Unitech Services Group nuclear laundry facility (21 miles away in South Carolina); and the facilities of the SRS (also in South Carolina). Table 2.2-201 lists the largest employers for the three-county region, based on recent data obtained for Burke County (Reference 208) in Georgia, and nearby Aiken and Barnwell counties in South Carolina (Reference 203; Reference 206).

There currently are no projected major increases to industrial, military, or transportation facilities within a 25-mile radius of the VEGP site except for the development of the site for VEGP Units 3 and 4.

2.2.2.1.1 Savannah River Site

The SRS borders the Savannah River for approximately 17 miles opposite the VEGP site. It occupies an approximately circular area of 310 square miles (198,344 acres) encompassing parts of Aiken, Barnwell, and Allendale counties in South Carolina (Reference 230). The SRS is owned by the DOE and operated by an integrated team led by Washington Savannah River Company (WSRC). The site is a closed government reservation except for through traffic on South Carolina Highway 125 (Savannah River Site Road A) and the CSX Railroad.

The SRS processes and stores nuclear materials in support of the national defense and U. S. non-proliferation efforts. The site also develops and deploys technologies to improve the environment and treat nuclear and hazardous wastes left from the Cold War. (Reference 230)

The following is a list of current and near-term operating facilities at the SRS and the activities conducted at these facilities (Reference 230; Reference 213):

- Separations facilities for processing irradiated materials (H Area).
- Waste management facilities that process, dispose or ship solid radioactive waste, hazardous waste, mixed waste, transuranic waste, and sanitary waste (E Area).
- The Defense Waste Processing Facility is processing high-level radioactive waste into stable borosilicate glass for disposal (S Area).
- The Savannah River National Laboratory (a process development laboratory to support production operations and containing two test reactors) and administrative facilities (A Area).
- The L Area Disassembly Basin which provides receipt and interim storage of research reactor fuel (L Area).
- Tritium Extraction Facility to extract tritium from fuel rods irradiated at TVA's reactors and to load the extracted tritium into canisters for shipment to the Department of Defense. Expected to begin operation in fiscal year 2007.
- Replenishment of tritium – recycling, purifying, and reloading nuclear weapons reservoirs.
- MOX Fuel Fabrication Facility (to be constructed) to manage and convert excess weapons-grade plutonium to a form that can be used in commercial nuclear power plants.
- Stabilization, management, and storage of plutonium materials (K Area).
- Salt Waste Processing Facility to remove radioactive constituents from high-level waste (under construction).
- A variety of non-nuclear facilities necessary for plant operations.

Five nuclear production reactors and several small test reactors are deactivated and are awaiting decommissioning and decontamination.

The major waste storage areas for high-level waste are adjacent to the two separations areas and consist of two tank farms linked to the separations areas and to each other by pipelines with secondary containment. In addition, the SRS uses engineered concrete vaults and engineered trenches for the permanent disposal of solid low-level radioactive waste (Reference 230). The

deactivated reactors, separations areas, and waste storage areas are at least 4 miles from the nearest VEGP site boundary.

2.2.2.1.2 Unitech Services Nuclear Laundry Facility

Although not located within 5 miles of the VEGP site, the Unitech Services Nuclear Laundry Facility, located in the Barnwell County Industrial Park, is described due to its relative proximity to and association with the SRS (Figure 2.2-203). It was constructed by Unitech Service Group to provide radiological laundry, decontamination and respirator services. The facility has about 50 employees as of May 2006 (Reference 225).

2.2.2.1.3 Chem-Nuclear Systems

Chem-Nuclear Systems developed, constructed, and operates the largest radioactive waste disposal site in the country near Barnwell, South Carolina (Figure 2.2-203). This site contains 308 acres, of which 235 have been deeded to the State of South Carolina as a designated exclusion area. Waste receipts are in the form of solids only; no liquids are accepted. Since the disposal facility began operation in 1971, about 28 million cubic feet, or 90 percent of the available disposal volume, have been used (Reference 210). The facility handles approximately 400 shipments of low-level spent fuel per year. The products and materials associated with Chem-Nuclear Systems are described in Table 2.2-202 (Reference 224).

2.2.2.1.4 Georgia Power Company's Plant Wilson

Plant Wilson is located approximately 6,000 feet east-southeast from the proposed VEGP Units 3 & 4 footprint. The existing combustion turbine plant is an electrical peaking power station of Georgia Power Company. The plant consists of six combustion turbines with a total rated capacity of 351.6 MW. The storage capacity of the fuel storage tanks is 9,000,000 gallons.

2.2.2.1.5 VEGP Units 1 and 2

The existing VEGP Units 1 and 2 reactors are located about 3,600 ft and 3,900 ft, respectively, west of the Savannah River. For these units, the exclusion area is the same as that for the proposed units and it is defined as an irregular shaped area which generally conforms to the site's boundary lines. There are no residents within the exclusion area, and there are no highways, railways, or waterways crossing the area. Besides the activities at Plant Wilson, the only other activities that may occur within the exclusion area that are unrelated to plant operations are those associated with the operation of the Visitor's Center. VEGP has made arrangements to control and, if necessary, evacuate the exclusion area in the event of an emergency.

2.2.2.2 Mining Activities

There are no mining activities within 5 miles of the VEGP site.

2.2.2.3 Roads

The nearest highway with commercial traffic is Georgia State Highway 23 (Figure 2.2-203). Segments of Georgia State Highways 23, 80, and 56 Spur are located within a 5-mile radius of the site. Other than traffic volumes, the Georgia Department of Transportation does not maintain data on the products and materials carried over these roads. However, major commercial traffic occurs only on State Highway 23, which serves as a major link between Augusta and Savannah. The heaviest truck traffic along State Highway 23 near the site consists primarily of timber and wood products and materials. State Highways 80 and 56 Spur serve primarily as minor transportation routes for local

traffic. Available statistical data on personal injury accidents on these roads between 1999 and 2003 are presented in Table 2.2-203 (Reference 218).

2.2.2.4 Railroads

CSX is the nearest railroad with commercial traffic and is approximately 4.5 miles northeast of the VEGP site. CSX runs through and services the SRS. Major chemical substances identified as being carried by the CSX Railroad include cyclohexane, anhydrous ammonia, carbon monoxide, and elevated temperature material liquids (ETML). (Reference 220)

Burke County has two local Norfolk Southern rail lines, one through Waynesboro and one through Midville. These are approximately 12 miles west of the VEGP site.

2.2.2.5 Waterways

The Savannah River above the VEGP site (River Mile 151) is primarily used for recreational purposes since 1979, with the closing of the New Savannah Bluff Lock and Dam (River Mile 187) to commercial traffic (Reference 226). No commercial facilities or barge slips/docks are visible on satellite imagery between the VEGP site and the New Savannah Bluff Lock and Dam. This section of the river is primarily forested and otherwise undeveloped land to the river's edge.

Downstream of the VEGP site, barge traffic may be present closer to the Port of Savannah (River Mile 21). In 2005, no barge traffic was reported to the Army Corp of Engineers Waterborne Commerce Statistics Center in New Orleans, Louisiana (Reference 227). In 2004, only 13 commercial vessels were recorded (Reference 219). These vessels were reported to contain a total of less than 500 tons of non-explosive residual fuel oil (less than a full barge load).

Therefore, the current use of the river and the lack of commercial facilities and barge slips/docks upstream of the plant indicate that there is no current or projected barge traffic on the Savannah River past the VEGP site. Based on the above information, SNC has determined that evaluation of hazardous shipments by barge is not necessary for VEGP Units 3 and 4.

2.2.2.6 Airports, Airways, and Military Training Routes

2.2.2.6.1 Airports

There are no airports within 10 miles of the VEGP site. The closest airport, Burke County Airport, is approximately 16 miles west-southwest of the VEGP site. It has a 4,035-foot asphalt runway oriented 250° WSW – 70° ENE. The airport, which has a non-directional radio beacon for runway approach, is used by single-engine private aircraft and by crop-dusting operations. There are only two multi-engine and five single-engine aircraft based at the field. The average number of operations (landings and takeoffs are counted separately) is about 57 per week. Most operations are transient general aviation; only about 33 percent are local general aviation (Reference 209).

The closest commercial airport is Augusta Regional Airport at Bush Field, which is located approximately 17 miles north-northwest of the VEGP site. It has an 8,000-foot primary runway oriented 170° SSE – 350° NNW and a 6,000-foot crosswind runway oriented 80° ENE – 260° WSW. FAA information effective April 13, 2006, indicates that 17 aircraft are based on the field. Ten of these are single-engine airplanes, four are multi-engines airplanes, and three are jet-engine airplanes. The average number of operations is about 91 per day. Most (40 percent) are general transient aviation, 24 percent are air taxi, 12 percent are local general aviation, 14 percent are commercial, and 10 percent are military (Reference 205). Based on the historical flight data recorded prior to 2005, projections for air traffic at Bush Field up to fiscal year 2025 are given in Table 2.2-204

(Reference 204). Approach and departure paths at Bush Field are not aligned with the VEGP site; and no regular air traffic patterns for Bush Field extend into airspace over the VEGP site.

A small un-improved grass airstrip is located immediately north of the VEGP site (north of Hancock Landing Road and west of the Savannah River). At its closest point, the airstrip is more than 1.4 mile from the power block of the new units. This privately owned and operated airstrip has a 1,650-foot turf runway oriented 80° East – 260° West. Thus take-offs and landings are tangential to the site property and oriented away from the plant. While no FAA traffic information is available for this airstrip, informal communication with the owner/operator revealed that the airstrip is for personal use and the associated traffic consists only of small single-engine aircraft (Reference 222). In addition, there is a small helicopter landing pad on the VEGP site. This facility exists for corporate use and for use in case of emergency. The traffic associated with either of these facilities may be characterized as sporadic. Therefore, due to the small amount and the nature of the traffic, these facilities do not present a safety hazard to the VEGP site.

2.2.2.6.2 Airways

The centerline of Airway V185 is approximately 1.5 miles west of the VEGP site (Figure 2.2-202). Additionally, Airway V417 is about 12 miles northeast of the VEGP site, and Airway V70 is approximately 20 miles south of the VEGP site (Figure 2.2-202) (Reference 217). Due to its close proximity to the VEGP site, an evaluation of hazards from air traffic along the V185 airway is presented in Subsection 3.5.1.6. That evaluation shows that the presence of Airway V185 is not a safety concern for the VEGP site.

2.2.2.6.3 Military Training Routes

In August 2005, Shaw Air Force Base (AFB), South Carolina, issued a draft Environmental Impact Statement (EIS) (Reference 223) regarding implementing airspace modifications to the Gamecock and Poinsett Military Operation Areas (MOAs) in South Carolina and the Bulldog MOAs in Georgia. The west edge of the Poinsett MOA is about 75 miles east-northeast of the VEGP site. The Gamecock MOAs are east of the Poinsett MOA. The proposed Gamecock E MOA would be created to form a “bridge,” allowing maneuvering and training between the Gamecock MOAs and the Poinsett MOA. The east edge of the Bulldog MOAs is about 11 miles west of the VEGP site (see Figure 2.2-202). Because of the relatively long distances between the VEGP site and these MOAs, and their related training routes, no aircraft accident analysis is required for flight activities associated with these MOAs and their related training routes.

Under the proposed action, the airspace structure at Bulldog A MOA would be expanded to the east under the Bulldog B “shelf” to match the boundary of the existing Bulldog B. Mainly, the current 500-foot msl floor as allowed at Bulldog A would be laterally expanded into Bulldog B. Because the current Bulldog B floor is 10,000 feet msl, this lateral expansion would increase the airspace volume in the Bulldog MOAs. The overall distance from the MOA boundary to the VEGP site is unchanged.

Military aircraft in the Bulldog MOAs are expected to come mainly from Shaw AFB (about 32 miles east of Columbia, South Carolina) and McEntire Air National Guard Station (about 13 miles east-southeast of Columbia). Among the military training routes, VR97-1059 is located closest to the VEGP site. The distance between the centerline of VR97-1059 and the VEGP site is about 18 miles (Figure 2.2-202). The maximum route width of VR97-1059 is 20 nautical miles (NM); therefore, the width on either side of the route centerline is assumed to be 10 NM (11.5 miles). The VEGP site is located more than 6 miles from the edge of this training route. Additionally, the total number of military aircraft using route VR97-1059 is approximately 833 per year (Reference 223).

According to RS-002, *Processing Applications for Early Site Permits*, May 2004 (RS-002), the aircraft accident probability for military training routes is considered to be less than 10^{-7} per year if the

distance from the site is at least 5 statute miles from the edge of military training routes, including low-level training routes, except for those associated with a usage greater than 1,000 flights per year, or where activities may create an unusual stress situation.

In summary, the MOA use is projected to remain relatively unchanged and no modifications are proposed to the military routes. The VEGP site is located more than 5 statute miles from the edge of VR97-1059, and the total military flights using the same route is less than 1,000 per year; therefore, no aircraft accident analysis is required for flights using VR97-1059 (Reference 223).

2.2.2.7 Natural Gas or Petroleum Pipelines

Three pipelines are within 25 miles of the VEGP site (Figure 2.2-203); however, none are located within 10 miles of the VEGP site.

Pipeline 1, located approximately 21 miles northeast of the VEGP site, is an 8-inch-diameter line constructed in 1959. It operates at a maximum pressure of 750 psi; is buried 3 feet deep; has 8-inch Rockwell isolation valves at 25-mile intervals; and carries natural gas. It is not used for storage.

Pipeline 2, located approximately 19 miles southwest of the VEGP site, has a 14-inch-diameter line constructed in 1954 and a 20-inch-diameter line constructed in 1977. Both lines are buried 3-feet deep; operate at a maximum pressure of 1,250 psi; have buried Rockwell isolation valves every 8 to 9 miles; and carry natural gas. They are not used for storage.

Pipeline 3, located approximately 20 miles northwest of the VEGP site, has two 16-inch-diameter lines constructed in 1953 and 1957. Both operate at a maximum pressure of 1,250 psi; are buried 3 feet deep; have buried Rockwell isolation valves every 8 to 9 miles; and carry natural gas.

Because the pipelines identified are well over 10 miles from the VEGP site, there is no need to identify the locations of individual pipeline valves.

2.2.2.8 Military Facilities

There are no military facilities within 5 miles of the VEGP site.

2.2.2.9 VEGP Units 1 and 2 Storage Tanks/Chemicals

Chemicals currently stored at the VEGP site are presented in Table 2.2-205.

2.2.3 Evaluation of Potential Accidents

The plant has inherent capability to withstand certain types of external accidents due to the specified design conditions associated with earthquakes, wind loading, and radiation shielding. Acceptability for external accidents associated with VEGP Units 3 and 4 is covered in this subsection.

The determination of the probability of occurrence of potential accidents which could have severe consequences is based on analyses of available statistical data on the occurrence of the accident together with analyses of the effects of the accident on the plant's safety-related structures and components. If an accident is identified for which the probability of severe consequences is unacceptable, specific changes to the AP1000 are identified. The criteria for not requiring changes to the AP1000 design is that the total annual frequency of occurrence is less than 10^{-6} per year for an external accident leading to severe consequences. The following accident categories are considered in determining the frequency of occurrence, as appropriate:

Explosions – Accidents involving detonations of high explosives, munitions, chemicals, or liquid and gaseous fuels will be considered for facilities and activities in the vicinity of the plant where such materials are processed, stored, used, or transported in quantity.

The AP1000 includes onsite storage facilities for compressed and liquid hydrogen. Accidents involving accidental detonations of hydrogen from these storage facilities are evaluated as part of the AP1000 certified design. It is not required to provide analyses of accidents involving these storage facilities provided that the locations and size of the storage facilities are consistent with the safe distances defined by the AP1000 certified design. The bulk gas storage area for the plant gas system (PGS) is located sufficiently far from the nuclear island that an explosion would not result in damage to safety-related structures, systems, and components.

Evaluation of potential explosions due to exposure of chemical storage tanks to exterior fires has determined that all of these postulated accidents are safe distances away from safety-related items.

The AP1000 certified design does not include liquid oxygen or propane storage facilities. The three 2000 gallon capacity above-ground liquid propane tanks installed at the Vogtle Fire Training Facility (building 695) are addressed in Subsection 2.2.3.2.3.

Flammable Vapor Clouds (Delayed Ignition) – Accidental releases of flammable liquids or vapors that result in the formation of unconfined vapor clouds in the vicinity of the plant.

A flammable vapor cloud (delayed ignition) due to the accidental release of hydrogen from the PGS bulk gas storage area is evaluated as part of the AP1000 certified design. A detonation of such a hydrogen vapor cloud would not result in damage to safety-related structures, systems, and components. No other chemical has the possibility of developing unconfined flammable vapor clouds.

Toxic Chemicals – Accidents involving the release of toxic chemicals from nearby mobile and stationary sources.

Fires – Accidents leading to high heat fluxes or smoke, and to nonflammable gas or chemical-bearing clouds from the release of materials as the consequence of fires in the vicinity of the plant.

Airplane Crashes – Accidents involving aircraft crashes leading to missile impact or fire in the vicinity of the plant.

The safe distance for material in onsite storage facilities for explosions, flammable vapor clouds, and fires is tabulated in Table 2.2-1.

Analyses were performed in order to evaluate the impact on the VEGP Units 3 & 4 following potential accidents resulting in an explosion or flammable cloud or toxic chemical releases within a 5-mile radius of the VEGP site. The postulated accidents that would result in an explosion or chemical release were analyzed at the following locations:

- Nearby transportation routes (Savannah River, Highway 23, and CSX Railroad)
- Nearby chemical and fuel storage facilities (Savannah River Site, Plant Wilson)
- Onsite chemical storage tanks
- Other nearby fire sources

The existing analysis of potential hazards to the Units 1 and 2 was reviewed for applicability to the Units 3 and 4. That analysis evaluated postulated releases of flammable materials and toxic gases transported or stored at industrial facilities within a 5-mile radius of the VEGP site. In addition, new chemicals, which have been identified as being associated with Units 1 and 2, were subsequently evaluated or analyzed to determine their impact to Units 3 and 4. As described below, in each case, these analyses concluded that the potential for hazard is minimal and will not affect safe operation of Units 3 and 4.

2.2.3.1 Explosion and Flammable Vapor Clouds

The effects of explosion and formation of flammable vapor clouds from the nearby sources are evaluated below.

2.2.3.1.1 Truck Traffic

Segments of Georgia State Highways 23, 80, and 56 Spur are located within a 5-mile radius of the VEGP site. Major commercial traffic occurs only on State Highway 23, which serves as a major link between Augusta and Savannah, Georgia.

An analysis of truck-borne hazards that was performed for Units 1 and 2 identified that chlorine (1 ton), anhydrous ammonia (6 tons), liquid nitrogen (6,500 gallons), phosphoric acid (200 lb), nitric acid (5,000 gallons), and diesel oil (6,000 gallons) were transported on nearby Highway 23. At its nearest point, Highway 23 passes about 4.7 miles from the center point of the Units 1 and 2 control rooms. The allowable and actual distances of hazardous chemicals transported on highways were evaluated according to NRC Regulatory Guide 1.91, Revision 1, *Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants*. Regulatory Guide 1.91 cites 1 psi as a conservative value of peak positive incident overpressure, below which no significant damage would be expected. The analysis demonstrated that truck-borne substances transported within a 5-mile radius of the VEGP Units 1 and 2, as well as explosions and flammable vapor clouds induced by these chemicals, would not adversely affect safe operation of the units.

The six chemicals identified above in the analysis of truck traffic were obtained from the original design basis analysis for Units 1 and 2 and were based on a 1975 study performed by the Georgia Institute of Technology for Georgia Power Company. The original study is no longer available, and these chemicals have been re-evaluated as described below.

SNC has obtained the EPA Tier II reports for Burke and Richmond Counties in Georgia, identifying those facilities in the vicinity of the plant that have permits for storing hazardous materials (Reference 216). These reports, along with the EPA Landview 6 database, were used to confirm and/or update the list of chemicals for analysis. (Reference 215) The sites identified from these sources containing chemicals within a 20-mile radius of the VEGP site are depicted on Figure 2.2-204.

A traffic corridor evaluation has been performed to determine whether there are any new or additional chemicals transported by truck within 5 miles of the site related to the facilities described above. The evaluation shows that even fewer chemicals pass by the site now than assumed in the previous analysis performed for the existing units.

Only two EPA regulated sites exist that would likely use State Route 23 to transport materials and equipment. These sites are construction-related sites and are located 7 to 10 miles south of the VEGP site. Neither of these sites currently uses any of the previously identified chemicals, nor have they been identified to use or cause the transport of any hazardous chemicals other than fuel oil or gasoline. The remaining sites are all outside the 5-mile corridor and are likely to transport their materials and equipment via other, more direct, routes, rather than along State Route 23. These remaining sites, therefore, do not warrant further analysis.

The use of bulk anhydrous ammonia has been discontinued at the plant site. Since there are no other users of this chemical in the vicinity of this site, the issue of transportation of this chemical along the roadways or to the site does not require further analysis. (Anhydrous ammonia is still being transported by rail car, and is evaluated in Subsection 2.2.3.1.4).

SNC's re-evaluation concluded that the only remaining hazardous chemicals transported by truck in the vicinity of the site are gasoline and diesel/fuel oil.

For an 8,500 gallon truck on State Road 23 at the closest approach distance of approximately 4.2 miles (22,000 ft), the following calculations were performed in accordance with Regulatory Guide 1.91:

- TNT equivalent safe distance for an explosion of a gasoline vapor cloud
- TNT equivalent safe distance for an explosion of gasoline vapor in a truck

The gasoline truck analysis for the vapor cloud explosion used the industry standard program DEGADIS to calculate the distance from the site of the spill to the boundaries of the upper and lower flammability limits and to obtain the flammable mass within the vapor plume. The concentrations were compared to the lower flammability limits for the respective chemical to determine the maximum distance for the flammable vapor cloud. The input parameters were:

- Quantity of gasoline in the truck = 50,000 lb (56,165 lb TNT equivalent)
- Physical property data:
  - Molecular weight = 95 g/mole
  - Diffusion coefficient = 0.05 cm^2/sec
  - Vapor pressure = 305 mm Hg
  - Boiling point temperature = 130°C
  - Specific gravity = 0.732
- The meteorological conditions assumed were:
  - Stability class = F (stable)
  - Wind speeds = 1 m/s up to 2.5 m/s

For an explosion from an 8,500 gallon truck, the TNT equivalent safe distance beyond which the blast pressure would be less than 1 psi was calculated to be 1,723 feet.

For an explosion from a flammable vapor cloud, the TNT equivalent safe distance beyond which the blast pressure would be less than 1 psi was calculated to be 1,279 feet. The outer edge of the lower flammability limit (LFL) of the flammable portion of the gasoline vapor cloud is 1200 ft downwind from the road. If the blast occurs at the outer edge of the vapor cloud, which is a conservative assumption, then the maximum distance for which a peak incident of 1 psi would occur is the sum of the two distances, or 2,479 ft from the road.

The distance between State Road 23 and Units 3 and 4 is approximately 4.2 miles. This distance is far greater than either of the above calculated critical distances. Therefore, there will not be any impact on Unit 3 or 4 from an explosion of gasoline from a truck or vapor cloud.

The size of gasoline delivery trucks on State Road 23 ranges from 4,000 to 8,500 gallons, so the assumption of an 8,500-gallon truck in the analysis is conservative and bounding.

In addition to road transit, gasoline is delivered to the site by a tank wagon (10-wheel truck) containing a maximum volume of 4,000 gallons. The closest distance from the site delivery route to the power block circle is approximately 2,000 feet.

For an explosion from a 4,000 gallon truck, the TNT equivalent safe distance beyond which the blast pressure would be less than 1 psi was calculated to be 1,340 feet.

For an explosion from a flammable vapor cloud, the TNT equivalent safe distance beyond which the blast pressure would be less than 1 psi was calculated to be 920 feet. The outer edge of the lower flammability limit (LFL) of the flammable portion of the gasoline vapor cloud is 738 ft downwind from the road. If the blast occurs at the outer edge of the vapor cloud, which is a conservative assumption, then the maximum distance for which a peak incident of 1 psi would occur is the sum of the two distances, or 1,658 ft from the road.

As discussed above, since the closest distance from the site delivery route to the power block circle is approximately 2,000 feet, and the 1 psi blast pressure distances for the truck explosion and the vapor cloud explosion are 1,340 ft and 1,658 ft from the road, respectively, there will not be any impact on Unit 3 or 4 from an accident involving the 4,000 gallon gasoline tank wagon.

Since transported diesel/fuel oil is not flammable and is much less volatile than gasoline, the gasoline truck analysis becomes bounding in the evaluation of truck-borne hazards.

The quantity of chemical (diesel and gasoline), distance to Units 3 and 4, the TNT equivalent safe distance (beyond which the blast pressure would be less than 1 psi), the distance from the point of the spill to the point where the vapor concentration is equal to the lower flammability limit, and the lower flammability limit concentrations are shown below:

Chemical	Quantity	Distance to Units 3 and 4	TNT Equivalent Distance	Distance to Lower Flammability Limit	LFL
#2 Diesel	6,000 gal.	~4.2 mi (22,693 ft)	Not applicable	Not applicable	13,000 ppm
#2 Diesel	4,000 gal.	2,000 ft	Not applicable	Not applicable	13,000 ppm
Gasoline	50,000 lb 8,500 gal.	~4.2 mi (22,693 ft)	1,723 ft	1,200 ft	14,000 ppm
Gasoline	23,530 lb 4,000 gal.	2,000 ft	1,340 ft	738 ft	14,000 ppm

2.2.3.1.2 Pipelines and Mining Facilities

No natural gas pipeline or mining facilities are located within 10 miles of the VEGP site. No pipelines carrying potentially hazardous materials are located within 5 miles of the VEGP site. Therefore, the potential for hazards from these sources are minimal and will not adversely affect safe operation of the plant.

2.2.3.1.3 Waterway Traffic

As discussed in Subsection 2.2.2.5, there is no barge traffic past the VEGP site. Therefore, there are no chemicals transported by barge that require evaluation.

2.2.3.1.4 Railroad Traffic

The only railroad within a 5-mile radius of the VEGP site is the CSX Railroad (approximately 4.5 miles northeast of the center point between Units 1 and 2), which runs through, and services, the SRS. A hazards analysis performed for VEGP Units 1 and 2 showed that explosions and flammable vapor clouds induced by chemicals carried by this rail line will not adversely affect safe operation of Units 1 and 2. The critical distance (given by $kW^{1/3}$ in Regulatory Guide 1.91) that could cause overpressures of 1 psi to safety-related structures is approximately 2,291 feet. This scenario is caused by the explosion of a 26-ton ammonia railroad tank car (assumed to contain 132,000 pounds TNT equivalent). Because of the relatively long distance (approximately 4.5 miles) between the railroad and the VEGP site, if an explosion occurred due to an accident involving an ammonia railroad tank car, it would occur at a distance great enough not to pose an overpressure hazard to the safety-related structures. Since the proposed VEGP Units 3 and 4 will be located farther away from the railroad line than Units 1 and 2, the possibility of adverse effects from explosions and flammable vapor clouds is even smaller for the new units.

More recent information obtained from CSX (Director of Infrastructure Security) (Reference 220) indicates that the top four substances carried by CSX during 2005, which qualified as DOT hazardous chemicals, are cyclohexane (64%), anhydrous ammonia (9%), carbon monoxide (3%), elevated temperature material liquids (ETMLs) (3%).

Evaluations were made for each of the above chemicals. Some of these chemicals were already analyzed in a previous analysis for effect on Units 1 and 2, and some were evaluated specifically for their potential effect on Units 3 and 4. In each case, the evaluations concluded that the potential hazard from the chemicals is minimal and will not affect the safe operation of the new units.

Accidental spills of carbon monoxide or ETMLs are not expected to create an explosion or vapor hazard for the site. Carbon monoxide, which can cause asphyxiation, will quickly vaporize and dissipate before coming close to the VEGP plant limits. ETMLs, also referred to as elevated temperature goods, are not necessarily flammable. ETMLs are DOT Class 9 materials, and the main hazard they present is the potential to cause contact burns due to the elevated temperature of the substance. Because of the long distance separation between the CSX Railroad and the new units, no direct contact with these substances is expected. Therefore, no adverse impact is expected from the accidental releases of the ETML substances.

Cyclohexane (used in the manufacture of nylon, paint, resin, etc.) is a hazardous chemical that was not previously considered in the Unit 1 and 2 analyses, so a new analysis has been performed for Units 3 and 4.

For a 67-ton rail car at the closest approach distance of approximately 4.5 miles (23,760 ft), the following calculations were performed in accordance with Regulatory Guide 1.91:

- TNT equivalent safe distance for an explosion of cyclohexane vapor in a rail tank car
- TNT equivalent safe distance for an explosion of a cyclohexane vapor cloud

The cyclohexane rail car analysis for the vapor cloud explosion used the industry standard program DEGADIS to calculate the distance from the site of the spill to the boundaries of the upper and lower flammability limits and to obtain the flammable mass within the vapor plume. The concentrations

were compared to the lower flammability limits for the respective chemical to determine the maximum distance for the flammable vapor cloud. The input parameters were:

- Quantity of cyclohexane vapor in the rail car = 48.8 lb (117.5 lb TNT equivalent)
- Physical property data:
  - Molecular weight = 84.16 g/mole
  - Diffusion coefficient = 0.076 cm^2/sec
  - Molecular volume = 133.2
  - Boiling point temperature = 80.7°C
  - Specific gravity = 0.779
- The meteorological conditions assumed were:
  - Stability class = F (stable)
  - Wind speeds = 1 m/s up to 2.5 m/s

For the explosion from a rail car, the TNT equivalent safe distance beyond which the blast pressure would be less than 1 psi was calculated to be 220 feet.

For an explosion from a flammable vapor cloud, the TNT equivalent safe distance beyond which the blast pressure would be less than 1 psi was calculated to be 451 feet. The outer edge of the lower flammability limit (LFL) of the flammable portion of the cyclohexane vapor cloud is 575 ft downwind from the railroad line. If the blast occurs at the outer edge of the vapor cloud, which is a conservative assumption, then the maximum distance for which a peak incident of 1 psi would occur is the sum of the two distances, or 1,026 ft from the rail car.

The distance between the closest point of the rail line and Units 3 and 4 is approximately 4.5 miles. This distance is far greater than either of the above calculated critical distances. Therefore, there will not be any impact on Unit 3 or 4 from an explosion of cyclohexane from a rail car or vapor cloud.

2.2.3.2 Hazardous Chemicals

Regulatory Guide 1.78 requires evaluation of control room habitability for a postulated release of chemicals stored within 5 miles of the control room. As described in Subsection 2.2.2, no manufacturing plants, chemical plants, storage facilities, or oil or gas pipelines are located within 5 miles of the VEGP site. Therefore, three scenarios were evaluated:

1. Potential hazards from chemicals transported on routes within a 5-mile radius of the site, at a frequency of 10 or more per year, and with weights outlined in Regulatory Guide 1.78
2. Potential hazards from major depots or storage areas
3. Potential hazards from onsite storage tanks

Each hazard is discussed and evaluated below. The VEGP Units 1 and 2 analysis was reviewed for applicability to Units 3 and 4 for the effects from each of these hazards. The review determined that

the impact to the new units for each of these postulated events is bounded by the impact to Units 1 and 2.

2.2.3.2.1 Release of Hazardous Chemicals Due to a Transportation Accident

As previously discussed, three routes (Georgia State Highways 23, 80, and 56) pass within 5 miles of the VEGP site. Of these three routes, major commercial traffic occurs only on State Highway 23, which serves as a major link between Augusta and Savannah. In addition, rail traffic exists within the 5-mile radius of the plant.

As discussed in Subsection 2.2.2.5, there is no barge traffic past the VEGP site. Therefore, there are no chemicals transported by barge that require evaluation.

The hazardous chemical sources due to a transportation accident were analyzed. The results of the analysis indicated that control rooms of VEGP Units 3 and 4 would remain habitable for all transported chemicals as discussed below.

In the analysis for truck traffic, methods specified in NUREG-0570 were used to estimate vapor emission rates and their dispersion. As discussed in Subsection 2.2.3.1.1, the only hazardous chemicals transported by truck in the vicinity of the VEGP site are gasoline and diesel/fuel oil.

The table below shows, for each chemical transported by truck, the key input parameters and the results of the evaluation using the methodology of NUREG-0570.

Chemical	Quantity	Distance to Control Room	Wind Speed	Stability	Control Room Concentration	Toxicity Limit
#2 Diesel	6,000 gal.	~4.2 mi (22,693 ft)	0.5 m/s	G	0.057 ppm	300 ppm
#2 Diesel	4,000 gal.	2,000 ft	1 m/s	F	Bounded by gasoline	300 ppm
Gasoline	50,000 lb 8,500 gal.	~4.2 mi (22,693 ft)	1 m/s	F	34.9 ppm	300 ppm
Gasoline	23,530 lb 4,000 gal.	2,000 ft	1 m/s	F	95.1 ppm	300 ppm

Therefore, no adverse impact to VEGP Units 3 and 4 is expected from the accidental release of gasoline or diesel/fuel oil.

For a postulated accident on a rail line, cyclohexane and ammonia were evaluated. The potential adverse impact caused by accidental release of cyclohexane was analyzed for the ESP because it was not previously evaluated, it is flammable, and it has an established toxic threshold limit value (TLV). Using approaches specified in NUREG-0570, the analysis has concluded that the accidental release of cyclohexane from a railcar will not have adverse effects to the control room operators. The meteorological conditions used in the ESP analysis were based on guidance provided in Regulatory Guide 1.78. Regulatory Guide 1.78 describes a simplified procedure for calculating weights of hazardous chemicals for control room evaluations. In that simplified procedure, stable atmospheric stability (F stability) is used because it represents the worst 5% meteorology observed at the majority of nuclear plant sites per Regulatory Guide 1.78. Therefore, in the ESP analysis, stable atmospheric meteorological conditions (F stability with a wind speed of 1 m/s) were assumed.

The assumed railcar capacity (67 tons) is similar to that described in Regulatory Guide 1.91. With a control room air intake height about 60 ft above grade, the control room outside concentration was estimated to be 0.12 g/m^3 (34.3 ppm). The immediate danger to life and health (IDLH) value of cyclohexane is 1,300 ppm (Reference 211). Since the control room outside concentration was

estimated to be only 34.3 ppm, the accidental release of the cyclohexane tank car will not cause adverse effects to the control room operators.

The evaluation of ammonia was originally performed for Units 1 and 2, and it has been extended to Units 3 and 4. Assuming the release from a rail car containing 26 tons of anhydrous ammonia, the evaluation showed that the Units 1 and 2 control room concentration at 2 minutes after odor detection is 112 ppm, without taking credit for control room isolation. This concentration is much lower than the IDLH value of 300 ppm. In accordance with Regulatory Guide 1.78, the evaluation assumed 2 minutes is sufficient time for a trained operator to put a self-contained breathing apparatus into operation, if they are to be used.

For ammonia and cyclohexane, the factors for estimating the concentration of each chemical at the control room air intake are:

Compound	Quantity	Distance from Railroad to Control Room	Wind Speed	Stability Class	Concentration of Compound at Control Room Air Intake, ppm	IDLH Toxicity Limit, ppm
Ammonia	26 tons	4.5 miles	1 m/s	G	112 @ 2 min	300
Cyclohexane	67 tons	4.5 miles	1 m/s	F	34.3	1,300

In addition the AP1000 design provides manual actuation to initiate the emergency habitability system. Protective measures (including manual actuation of the main control room habitability system) required to be taken by the control room operators are evaluated in accordance with Subsection 6.4.7.

Therefore, no adverse impact to VEGP Units 3 and 4 is expected from the accidental release of ammonia or cyclohexane.

2.2.3.2.2 Potential Hazard from Major Depots or Storage Areas

There are no major depots within 5 miles of the VEGP site. The only chemical storage areas within 5 miles of the VEGP site exist at the SRS and the Wilson combustion turbine plant.

The original analysis (performed for Units 1 and 2) had determined that SRS had the potential to use chlorine and ammonia at the D-Area, which is approximately 4.5 miles distant from Units 1 and 2. However, the 2004 Tier II EPA report for this site (Reference 216), and recent communications with SRS management, have indicated that ammonia and chlorine are no longer in use at D-Area (Reference 228), (Reference 214). The area has been remediated, and nearly all of the facilities have been removed. The only chemicals used at the site, according to the recent Tier II report, are chlorine softener chemicals and biocide, which are used in the waste treatment process to eliminate the bacteria in the water. There were no chemicals identified that would be hazardous to the VEGP site or would require further evaluation.

The chemicals stored at the Plant Wilson combustion turbine plant (6,000 feet from the new AP1000 units' power block), consist of fuel oil, sulfuric acid, and several other chemicals kept in small quantities. These chemicals have low volatility and toxicity, and there would be no potential hazard to the new AP1000 unit control rooms habitability from these substances. The three No. 2 fuel oil tanks located at east of the Service Building for the combustion turbine plant have a capacity of 3,000,000 gallons each (Reference 221). The tanks are surrounded by a dike, which would prevent a fuel leak from spreading into a large spill area. An analysis, based on the methodology of NUREG-0570, has

shown that a postulated release of fuel oil from an accidental spill at Plant Wilson will result in a concentration of less than 50 ppm at the air intake for the control room for Unit 3 or 4.

	Quantity	Wind Speed	Stability	Distance to Control Room	Concentration of Vapor at Control Room Air Intake	Toxicity Limit
Fuel Oil	3,000,000 gallons	1 m/s	F	Approximately 5,500 ft	< 50 ppm	300 ppm

Therefore, the Plant Wilson fuel oil storage tanks do not pose a hazard to VEGP Units 3 and 4.

2.2.3.2.3 Potential Hazard from Onsite Storage Tanks

The storage facilities for VEGP Units 1 and 2 are listed in Table 2.2-205. Many of the chemicals listed in that table are excluded from further consideration due to their properties (e.g., low volatility or low toxicity) or due to the relatively small quantities that are stored. The guidelines and methodologies of NUREG-0570 were used to determine the release rates and concentrations of toxic gases at the control room air intake for existing VEGP Units 1 and 2. This analysis shows that the control room would remain habitable for most release scenarios without any operator action and that there would be sufficient time for control room operators to take emergency action (donning emergency breathing apparatus) for the remaining release scenarios. For all releases except hydrazine, the average concentration over an 8-hour period would never exceed the long-term toxicity limit. Where the long-term limit would be exceeded, it has been shown by calculation for VEGP Units 1 and 2 that at least 2 minutes would be available between detection and the time the short-term toxicity limit (as defined in Regulatory Guide 1.78) would be reached. Since hydrazine is stored northeast of the VEGP Unit 1 reactor, this chemical would be separated by a minimum of about 1,800-feet from Units 3 and 4. Therefore, the impact on the new Units 3 and 4 due to an accidental hydrazine release will be expected to be smaller than that for existing Units 1 and 2, and will be evaluated at the time of the COL in accordance with DCD COL Information Item 6.4-1.

The impact on the new Units 3 and 4 due to an accidental hydrazine release is evaluated in Subsection 2.2.3.2.3.1 below.

Additionally, there are three 2000 gallon capacity above-ground liquid propane tanks installed at the Vogtle Fire Training Facility (building 695). These tanks provide fuel to fire training aids installed at the facility. The distance from the tanks to the nearest safety-related structure (the Unit 3 auxiliary building) is approximately 3300 feet and the distance to the control room air intake is approximately 3400 feet. The tanks are designed and installed in accordance with ASME Section VIII (Division 1, 1998 Edition, 2000 Addenda), and the relevant NFPA and insurance standards. The potential hazards considered to be associated with these tanks are:

A. The shockwave from an explosion of the tanks' contents or a flammable vapor cloud emanating from a tank rupture.

B. A dangerous thermal environment resulting from a tank or flammable vapor cloud fire.

C. A potentially lethal concentration of toxic gases in the control room resulting from a tank fire.

D. Diesel generator overspeed, starvation or prevention of a diesel generator start due to a propane tank rupture.

The tanks have been evaluated consistent with the methods described in Regulatory Guide 1.91. Based upon an evaluation, the fire training facility propane tanks are located beyond the distance where an exploding tank or an exploding flammable vapor cloud would yield an overpressure of 1 psi

on any safety-related structure. As noted in Regulatory Guide 1.91, the effects of blast-generated missiles will be less than those associated with blast overpressure.

The fire training facility propane tanks have also been evaluated for thermal effects of a fire using the methodology described in NUREG/CR-1748. The calculated temperature rise is less than the maximum allowable temperature rise.

Control room habitability following a propane fire at the fire training facility is bounded by the analysis of Plant Wilson discussed in Subsection 2.2.3.3.2.

The fire training facility propane tank evaluation also determined that the tanks are located beyond the distance where a propane gas cloud could starve or prevent the start of a diesel generator.

Based on the evaluation, the propane tanks at the fire training facility are located at a safe distance from the control room air intake and any safety-related structures. Therefore, the propane tanks are not considered to be a credible hazard.

2.2.3.2.3.1 Hydrazine Hazard from Onsite Storage Tanks

Impact on safety related structures and control room habitability for Units 3 and 4 due to accidental releases from or explosion in the 6,644 gallon Units 1 and 2 hydrazine tank is evaluated below.

The Areal Locations of Hazardous Atmospheres (ALOHA) code (Reference 202) and the TNT equivalency method is used to determine the minimum safe distances for hydrazine that is stored onsite at VEGP. These minimum safe distances for Unit 3 control room are then compared to the distances from where hydrazine is stored to Unit 3. Since the Unit 4 control room is further west of Unit 3, the evaluation is based on Unit 3 only and then the results are applied to Unit 4. The four scenarios evaluated are: toxicity of a vapor cloud, flammability of a vapor cloud, explosive vapor cloud, and a tank explosion.

The assumptions for the three vapor cloud scenarios include the following:

- Hydrazine is a 35% hydrazine solution.
- Atmospheric air flow is turbulent in only one direction (no cross flow) such that the released gases spread downstream in a Gaussian manner.
- Total quantity of hydrazine is released and forms an evaporating puddle with a depth of 1 cm (NUREG-0570). This provides a significant surface area to maximize evaporation and the formation of a vapor cloud.
- Ambient temperature is 95.1°F for daytime releases and 70.1°F for nighttime releases, the relative humidity is 50%, and the atmospheric pressure is 1 atmosphere (40 CFR 68.22).
- A sensitivity study was performed to determine the worst-case meteorological conditions (wind speed and stability class). The worst-case scenario is a wind speed of 2 m/s and stability class “F”.
- Ground roughness is “Urban or Forest” which most accurately represents site conditions.
- Cloud cover selected is based on the appropriate stability class and wind speed (Reference 202).

- Time of accidental release is 12:00 pm on July 21, 2008 for daytime releases and 5:00 a.m. on July 21, 2008 for nighttime releases. The date was selected because it coincides with the highest daily maximum temperature, and 12:00 p.m. was selected because solar radiation is highest during midday. Higher solar radiation leads to a higher evaporation rate and thus a larger vapor cloud. Five o'clock (5:00) a.m. on July 21, 2008 was selected to provide a realistic meteorological condition for the more stable stability classes. ALOHA requires manual override if 12:00 p.m. is used with stability classes "E" and "F", or "D" with a wind speed of 3 m/s (Reference 202).

- Wind input height is 10 meters. ALOHA calculates a wind profile based on where the meteorological data is taken. ALOHA assumes that the MET station is at a height of 10 meters. The National Weather Service usually reports wind speeds from the height of 10 meters.

- There is no temperature inversion.

- It is not known how long after a release ignition occurs for vapor cloud explosions. Therefore, the "unknown" time of vapor cloud ignition option was selected for this case. ALOHA will run explosion scenarios for a range of ignition times that encompass all of the possible ignition times for a scenario. ALOHA takes the results from all of these scenarios and combines them on a single Threat Zone plot.

- Type of vapor cloud ignition is "ignited by detonation." This is the worst case scenario for an accidental explosion.

The assumptions for the tank explosion (TNT mass equivalency) scenario include the following:

- Vapor space is assumed to be the tank volume at the upper flammability limit of hydrazine.

- Air temperature is 32.2°F, the lowest mean daily minimum temperature, which corresponds to an air density of 0.081 lb/ft3.

- Detonation occurs inside the tank.

- Vapor explosion is treated as if it is completely confined. Thus, a yield factor of 100% is used for the confined vapor explosion (NUREG-1805).

Toxicity of a Hydrazine Vapor Cloud

For assessing the toxicity of a vapor cloud from hydrazine release, it is necessary to determine the maximum distance at which the Immediately Dangerous to Life or Health (IDLH) value exists (Regulatory Guide 1.78). This distance represents the minimum safe distance from the hydrazine storage area that a nuclear power plant can operate. The distance depends on the prevailing meteorological conditions, wind speed, relative humidity, atmospheric pressure, ambient temperature, toxicity and the quantity of hydrazine released. It is also necessary to determine the resulting concentration of hydrazine inside the control room to ascertain the effects of a toxic vapor on the operators. ALOHA calculated both the inside and outside concentrations of the control room over time (0 to 1 hour). For this evaluation, a release of 6,644 gallons of 35% hydrazine solution is assumed.

The hydrazine tank is located east of the Unit 1 Turbine Building, 2,200 feet from the Unit 3 control room. The evaluation considers a control room air exchange rate of 0.95 exchanges per hour, and an IDLH for hydrazine of 50 ppm. The maximum vapor cloud distance to the IDLH is calculated to be 927 feet (the resulting maximum concentration at the control room air intake is 15.4 ppm). The

maximum concentration of hydrazine inside the control room is calculated to be 7.76 ppm. The resulting hydrazine concentrations inside the Units 3 and 4 control rooms are within the IDLH limit value of 50 ppm.

Results indicate that operators in the Units 3 and 4 control rooms are not impacted by the potential toxicity from a hydrazine vapor cloud.

Flammability of a Hydrazine Vapor Cloud

For assessing the flammability of a vapor cloud from a hydrazine release, the ALOHA air dispersion model is used to determine the distances where the vapor cloud may exist between the upper flammability limit (UFL) and lower flammability limit (LFL) (40 CFR 68.22). Once the concentration of the hydrazine vapor cloud is above the UFL or below the LFL, the vapor is no longer flammable.

For this evaluation, a release of 6,644 gallons of 35% hydrazine solution is analyzed for potential flammable hydrazine vapor threats.

Hydrazine has an LFL of 4.7% and a UFL of 99.9%. The distance from the leak source to the LFL is 54 feet. Though ALOHA does report a distance to the LFL, the vapor cloud does not ever exceed the LFL for any scenario. The distance that is reported is the same for every situation due to near field patchiness. It is further shown that the LFL is never exceeded because, as shown below, no explosions occur, even though a detonation was chosen in every instance.

The distance from the hydrazine storage tank to where the hydrazine vapor cloud exists between the UFL and the LFL is less than the distance from the storage tank to the Units 3 and 4 control rooms. Therefore, results indicate that there is no potential flammable, hydrazine vapor cloud reaching safety related structures or the operators in the Units 3 and 4 control rooms.

Explosive Hydrazine Vapor Cloud

For assessing the explosion from a vapor cloud due to hydrazine release, it is necessary to determine the “safe distance”, the minimum distance required for an explosion to have less than or equal to 1 psi peak incident pressure (Regulatory Guide 1.91). This is the minimum safe distance for no impacts from an explosion of a hydrazine vapor cloud. A peak overpressure of 1 psi will shatter glass but not significantly cause structural damage to buildings (Regulatory Guide 1.91). The peak overpressure to the Unit 3 control room is also established. For this evaluation, a release of 6,644 gallons of 35% hydrazine solution is analyzed for potential explosive vapor threats.

The ALOHA analysis indicates that the vapor cloud does not reach the LFL and, therefore, does not explode. Since there is no explosion, the safety related structures and operators working in the Units 3 and 4 control rooms are not impacted.

Hazard from a Tank Explosion

The methodology presented below is for a confined explosion occurring within some form of a storage container (i.e. tank). Since only vapor will burn or explode, the methodology employed considers the maximum vapor within the hydrazine storage tank as explosive (equivalent TNT). For atmospheric liquid storage, this maximum vapor would involve the container to be completely empty of liquid and filled only with air and chemical vapor at UFL conditions (NUREG-1805). Due to complete confinement and the use of only the UFL vapor mass, a 100% yield factor is attributed to the explosion (NUREG-1805). The equivalent mass of TNT is calculated by taking into account the product of the vapor mass (within the flammable range), heat of combustion, and the explosion yield factor. Once the equivalent mass of TNT is calculated, a radial distance generating a 1 psi peak

incident pressure (“safe distance”) is calculated by taking the product of the factor 45 and the cube root of the equivalent mass of TNT (Regulatory Guide 1.91).

The evaluation is based on a vapor-filled 6,644 gallon hydrazine tank. For the assumed atmospheric conditions, a heat of combustion of 8,345 Btu/lb, and a vapor specific gravity of 1.1, the mass of flammable hydrazine in the tank is 79 pounds. The resulting equivalent mass of TNT is calculated to be 330 pounds, and the resulting “safe distance” is 311 feet.

Results from the TNT equivalency method indicate that there are no potential explosive vapor threats from hydrazine storage tanks to safety related structures or operators in the Units 3 and 4 control rooms.

As shown in Table 2.2-205, some chemicals previously used for Units 1 and 2 have recently been replaced. Phosphoric acid (Nalco 3DT177) is one of the new chemicals used for the existing Units 1 and 2 that was identified to be toxic. This material is stored in a 5050-gallon tank located between the two existing cooling towers at a distance of approximately 3,200 feet from the air intake for the Unit 3 control room (the closest of the new control rooms to the chemical source). An analysis has shown that under stable atmospheric conditions (F stability) the phosphoric acid concentration outside the new control room air intake would be 94 $\mu g/m^3$, which is much lower than the 8-hour TLV of 1 mg/m^3 and the short term exposure limit of 3 mg/m^3 (Reference 211) following an accidental release. Since this material is not flammable, the explosion effect was not evaluated. Another chemical shown in Table 2.2-205, that was evaluated for Units 1 and 2 is methoxypropylamine (MPA). This chemical is stored in a tank outside the turbine building and in a smaller tank inside the turbine building. The evaluation for Units 1 and 2 considered the failure of the smaller tank, inside the turbine building, due to its proximity to the control room air intake. For that evaluation, the failure assumed a 400 gallon release, 59 meters away from the control room air intake. For a wind speed of 2.5 m/s and a G stability class, the concentration outside the control room intake was calculated to be 1.5 ppm. The STEL for this chemical is 15 ppm. Due to the distance between the new Units 3 and 4 and the existing Units 1 and 2, the effects of accidental MPA release at Units 1 and 2 will be expected to be less than that for the existing Units 1 and 2.

2.2.3.2.3.2 Other Chemical Hazards from Onsite Storage Tanks

Table 6.4-201 provides specific information about the chemicals described in Table 6.4-1. This includes chemical names or limiting types and quantities. Except as noted, these chemicals have been suggested by Westinghouse for use in the AP1000 and have been evaluated in conjunction with AP1000 standard design and found not to present a hazard to the control room operators or to safety-related systems, structures, or components. In some instances, alternative chemicals to those proposed by Westinghouse have been suggested. These chemicals are comparable in function to those proposed by Westinghouse and are the same as those already in use for similar applications in VEGP Units 1 and 2. These chemicals also have been evaluated and found not to present a hazard to the control room operators or to safety-related systems, structures, or components. Therefore, no further analysis is required.

2.2.3.3 Fires

In the vicinity of the VEGP site, the following potential fire hazards exist:

a. Fire due to a transportation accident

b. Forest fire

c. Fire due to an accident at offsite industrial storage facilities

d. Fire due to an onsite storage tank spill

An analysis was performed for VEGP Units 1 and 2 which evaluated the potential fire hazards identified above. Items a, c and d above have been addressed in previous sections. For each event, the analysis concluded that combustion products would not reach concentrations in the VEGP Unit 1 and 2 control room that approached toxicity limits.

An analysis of a postulated forest fire indicates that toxic chemicals (such as CO, NO_2 and CH_4) emitted from the forest fire, located approximately 1,800 feet from the Units 1 and 2 control room, produce negligible concentrations outside the Units 1 and 2 control room air intakes due to the relatively high buoyancy of the plume. In addition, due to the long distance separating the tree line from the control room, the analysis indicates that there would not be any adverse heat impact in the form of heat flux from the forest fire. The temperature rise for each event was calculated to be insignificant when compared with fuel oil fires for causing thermal damage to any safety-related structures at VEGP Units 1 and 2. For all of the fire events evaluated, the location of the new AP1000 units on the VEGP site is the same distance from the source of the fire as the existing VEGP Units 1 and 2, or is further removed, and therefore the same conclusions concerning impact may be made**. I**n addition the design of the control room HVAC for the AP1000 includes smoke detectors. Any smoke detected from an onsite or offsite fire would initiate isolation of the control room HVAC prior to toxicity limits being exceeded.

The specific application to Units 3 and 4 of these forest and industrial fire evaluations is further described below.

2.2.3.3.1 Forest Fires

The surrounding plant terrain is characterized by gently rolling hills and is approximately 30-percent farmland, with the remainder primarily wooded areas. The nearest forest to the Units 1 and 2 control room is the Sandhill-Upland hardwood pine forest with an assumed total area of approximately 3,169 acres and an assumed distance of 1,836 feet away. Based on historical data on forest fires from the state of Georgia, the average size of a forest fire typically is approximately 11.4 acres. The rate of spread is conservatively assumed to be 8 feet per minute with a duration of 4 hours.

The toxic chemicals emitted from a forest fire are CO, NO_2, and CH_4. The emission concentrations in the control room air intake were calculated using the infinite line source diffusion equation with the wind direction perpendicular to the line source and blowing directly toward the control room intake, and the Briggs plume rise equation, which accounts for the buoyancy effect from the heat of the fire. For Units 1 and 2, calculations were performed to demonstrate that the pollutant concentrations outside the control room air intake for a variety of wind speeds (from 0.25 to 10 m/sec) and the Pasquill stability category G are effectively zero. Therefore, the release of toxic combustion products from the onsite forest fire did not pose a hazard to the Units 1 and 2 control room operators.

Using the methodology described in NUREG/CR-1748, the heat flux and resultant temperature rise on plant structures due to a forest fire were also evaluated for Units 1 and 2. The calculated temperature rise (~46.5°C) is less than the allowable temperature rise (bulk 194°C and local 361°C). Therefore, a forest fire will not cause thermal damage to VEGP safety-related structures, based on the distance from the forest.

The centerline of VEGP Units 3 and 4 is approximately 2,100 feet west and 400 feet south of the center of the Unit 2 containment building. The Unit 4 containment is approximately 800 feet west of the Unit 3 containment. It is assumed that the distance from the nearest forest to VEGP Units 3 and 4 is the same as that from the forest to VEGP Units 1 and 2. Since Units 3 and 4 are approximately adjacent to Units 1 and 2 and the vegetation in the vicinity remains the same even after revegetation of the Units 3 and 4 construction site, the toxic chemicals emitted from a forest fire and the emission

concentrations in the control room would have the same effect for Units 3 and 4. Therefore, the release of toxic combustion products from the onsite forest fire does not pose a hazard to the Units 3 and 4 control room operators.

2.2.3.3.2 Fire Due to an Accident at Offsite Industrial Storage Facility

Georgia Power Company's combustion turbine plant (Plant Wilson) is located approximately 1,350 meters from the VEGP Units 1 and 2 control room. Of the chemicals and toxic substances stored at this location, diesel fuel oil and miscellaneous oils are flammable. Based on a previous evaluation, a diesel fuel oil fire at Plant Wilson bounds the impacts from any fires of miscellaneous oils stored at Plant Wilson. One of the three tanks containing no. 2 diesel fuel oil is assumed to burn. The entire tank volume of 3×10^6 gallons is spilled into a dike area of 8,756 m^2.

The primary products of combustion emitted from a diesel fuel oil fire at Plant Wilson are CO, CO_2, CH_4, NO_2, SO_2, and SO_3. The toxicity limits in ppm for these constituents are 50 (CO), 5,000 (CO_2), 1.43×10^5 (CH_4), 2 (SO_2 and SO_3), and 3 (NO_2). Using the Briggs plume rise equations and by assuming the maximum burning rate of 0.12 inches/min, the maximum emission rate, duration of fire (8 hours), class A stability, and wind speeds (0.25-10 m/s), it was determined that the resulting concentrations of the primary products of combustion outside the Units 1 and 2 control room air intakes would not approach the above listed toxicity limits.

Using the methodology described in NUREG/CR-1748, the heat flux and resultant temperature rise on the VEGP structures due to a diesel fuel oil fire at Plant Wilson were also evaluated for the Units 1 and 2 control rooms. The calculated temperature rise (115°C) is less than the maximum allowable temperature rise (bulk 194°C and local 361°C). Since a fire at Plant Wilson is limiting (the largest source at the closest distance to the VEGP site), it is concluded that source fires and vapor cloud fires resulting from a delayed ignition at nearby industrial facilities will not cause thermal damage to safety-related structures at VEGP Units 1 and 2.

Units 3 and 4 are located at a farther distance from Plant Wilson than Units 1 and 2. Drawing from the conclusion based on the previous evaluation of Units 1 and 2, any industrial fire due to diesel oil or miscellaneous oils stored at Plant Wilson would not have an impact on control room habitability or cause thermal damage to safety-related structures at Units 3 and 4.

2.2.3.4 Radiological Hazards

The hazard due to the release of radioactive material from either VEGP Units 1 and 2 or the facilities at SRS, as a result of normal operations or an unanticipated event, would not threaten safety of the new units. Smoke detectors, radiation detectors, and associated control equipment are installed at various plant locations as necessary to provide the appropriate operation of the systems. Radiation monitoring of the main control room environment is provided by the radiation monitoring system (RMS). The habitability systems for the AP1000 are capable of maintaining the main control room environment suitable for prolong occupancy throughout the duration of the postulated accidents that require protection from external fire, smoke and airborne radioactivity. Automatic actuation of the individual systems that perform a habitability systems function is provided. In addition, safety related structures, systems, and components for the AP1000 have been designed to withstand the effects of radiological events and the consequential releases which would bound the contamination from a release from either of these potential sources. (Reference 229)

The effect on the control rooms of VEGP Unit 3 and 4 of a postulated design basis accident (DBA) in Unit 1 or 2 was evaluated based on a LOCA in Unit 1 or 2, at uprated conditions, using the releases produced from the alternate source term (AST) methodology. The dose at the Unit 3 and 4 control rooms were determined considering the time-dependent source terms, the atmospheric dispersion factors (χ/Q values), the assumed occupancy rates, the volume of the control room, the HVAC

filtration and flow rates, and the operator breathing rates. The χ/Q values from the containment of Unit 2 to the Units 3 and 4 control room air intakes were conservatively calculated using the same methodology and meteorology as was used to calculate the control room χ/Q values presented in Subsection 2.3.4. Breathing rates were assumed to be constant for the control room operators for the duration of the period evaluated. The occupancy rate in the control room was assumed to be 100 percent for the first 24 hours and then decreasing to 60 percent for the next 3 days and then to 40 percent over the remainder of the 30 day period. The resultant dose from this analysis is comparable to the dose reported in Table 15.6.5-3 for a postulated LOCA in the AP1000 and is less than the GDC 19 limits.

2.2.4 Combined License Information for Identification of Site-Specific Potential Hazards

Site-specific information related to the identification of potential hazards within the site vicinity is addressed in Subsections 2.2.3.2.3.1, 2.2.3.2.3.2, 2.2.3.3, and 2.2.3.4.

2.2.5 References

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Table 2.2-1
AP1000 OnSite Explosion Safe Distances

Material	Explosion Minimum Safe Distance(1) (feet)	Flammable Vapor Cloud Safe Distance(1) (feet)	AP1000 Distance to SSC (feet)
Liquid Hydrogen, H_2	577	175	635
Pressurized Gaseous Hydrogen, H_2 (PGS Hydrogen Switchover Station)	10.5	Not Applicable	24
Pressurized Gaseous Hydrogen, H_2 (Spare Cylinders)	6	Not Applicable	10
Hydrazine, N_2H_4	45	Not Applicable	123
Ethanolamine, C_2H_7NO Methoxypropylamine, (MOPA), $C_4H_{11}NO$ Morpholine, $O(CH_2CH_2)_2NH$	75	Not Applicable	123
No. 2 Diesel Fuel Oil (DOS-MT-01A/B)	119	Not Applicable	313
No. 2 Diesel Fuel Oil (DOS-MT-02A/B)	34	Not Applicable	182
No. 2 Diesel Fuel Oil (DOS-MT-03)	23	Not Applicable	53
No. 2 Diesel Fuel Oil (FPS-MT-02)	20	Not Applicable	368
No. 2 Diesel Fuel Oil (ASS-EP-006 Temporary Auxiliary Boiler Diesel Tank)	34	Not Applicable	250
Waste Oil	102	Not Applicable	201
Liquid Propane	1440	565	3280

Note:
1. Safe distance is to nearest point of nuclear island SSC.

Table 2.2-201
Nearby Largest Employers

Burke County, GA	Aiken County, SC	Barnwell County, SC
Burke County Hospital	Westinghouse Savannah River	Dixie Narco Inc.
Kwikset Corporation	Aiken County Board of Education	Barnwell School District #45
Management Analysis & Utilization Inc.	Bechtel Savannah River Company	Ness Motley Loadholt Richardson
Samson Manufacturing Inc.	Avondale Mills Inc.	Sara Lee Sock Company Inc.
Southern Nuclear Operating Co. Inc.	Kimberly-Clark Corporation	Excel Comfort Systems Inc.

Table 2.2-202
Description of Products and Materials: Chem-Nuclear Systems, Inc.

Products or Materials	Status	Annual Amounts	Shipment
Isotopes – Including Co-60 (by far largest quantity), Fe-55, and Ni-63	Stored	0.50 x 10^6 ft^3 (7/1/04-6/30/05) 0.45 x 10^6 ft^3 (7/1/05-6/30/06) 0.40 x 10^6 ft^3 (7/1/06-6/30/07) 0.35 x 10^6 ft^3 (7/1/07-7/30/08)	400/year; average volume - 150 ft^3; largest volume for a single shipment - 8,000 ft^3

Note: The above materials are transported via highway.

Table 2.2-203
Burke County, Georgia, Transportation Accident Data Within 5 Miles of the VEGP Site

	1999	2000	2001	2002	2003
State Route 80					
Accidents					
Injuries	5	0	10	3	3
Fatalities	0	0	0	0	0
State Route 23					
Accidents					
Injuries	14	3	9	15	12
Fatalities	3	0	0	0	0
State Route 56C					
Accidents					
Injuries	0	0	0	0	0
Fatalities	0	0	0	0	0

Table 2.2-204
Bush Field (Augusta) Terminal Area Forecast Fiscal Years 1990–2025 Total Flights

Year	Total[a]
1990	47981
1991	38455
1992	37682
1993	36246
1994	33057
1995	34008
1996	33346
1997	34459
1998	34428
1999	37631
2000	36961
2001	35222
2002	34617
2003	33916
2004	35561
2005	27917
2006	28330
2007	28753
2008	29184
2009	29625
2010	30074
2011	30532
2012	31001
2013	31479
2014	31967
2015	32305
2016	32647
2017	32995
2018	33347
2019	33703
2020	34065
2021	34430
2022	34801
2023	35178
2024	35558
2025	35945

[a] Itinerant Operations (air taxi + commercial air carrier + general aviation + military)

Table 2.2-205
VEGP Units 1 and 2 Onsite Chemical Storage

Material	Quantity	Location
Kitchen Grease	550 gallons	Underground tank east of service building
No. 2 Diesel Fuel	1,500 gallons	South of PESB
No. 2 Diesel Fuel	160,000 gallons*	East of U1 diesel generator building
No. 2 Diesel Fuel	160,000 gallons*	West of U2 diesel generator building
Hydrazine	6,000 gallons	East of turbine building
Methoxypropylamine	400 gallons	Turbine building
Methoxypropylamine	12,780 gallons	East of turbine building
Clean Lube Oil	30,000 gallons	East of turbine building
Dirty Lube Oil	30,000 gallons	East of turbine building
No. 2 Diesel Fuel	100,000 gallons	East of turbine building
No. 2 Diesel Fuel	560 gallons	Fire protection pumphouse
No. 2 Diesel Fuel	560 gallons	Fire protection pumphouse
Main Turbine Lube Oil	12,800 gallons	Turbine building
Main Turbine Lube Oil	12,800 gallons	Turbine building
SGFP Lube Oil	2,800 gallons	Turbine building
SGFP Lube Oil	2,800 gallons	Turbine building
EHC Fluid	1,600 gallons	Turbine building
EHC Fluid	1,600 gallons	Turbine building
No. 2 Diesel Fuel	1,250 gallons	U1 diesel generator building
No. 2 Diesel Fuel	1,250 gallons	U1 diesel generator building
No. 2 Diesel Fuel	1,250 gallons	U2 diesel generator building
No. 2 Diesel Fuel	1,250 gallons	U2 diesel generator building
Unleaded Gasoline	6,000 gallons	East of receiving warehouse
No. 2 Diesel Fuel	3,000 gallons	East of receiving warehouse
Sodium Hypochlorite	6,700 gallons	Main Cooling towers
Dispersant**	4,400 gallons	Main Cooling towers
MS Corrosion Inhibitor***	5,050 gallons	Main Cooling towers
Copper Corrosion Inhibitor****	2,200 gallons	Main Cooling towers
Kerosene	7,000 gallons	Fire training area
Sodium Hypochlorite	250 gallons	East of plant potable water storage tank
Boric Acid	46,000 gallons	U1 aux building
Boric Acid	46,000 gallons	U2 aux building
Used Oil	4,000 gallons	NW of admin support building
Used Oil	5,000 gallons	NW of admin support building
Sodium Bromide	4,000 gallons	Main Cooling towers
Nalco STABREX	6,700 gallons	Main Cooling towers
Sodium Hypochlorite	200 gallons	Plant potable water building
Sodium Phosphate, Tribasic	200 gallons	Plant potable water building
Copper Corrosion Inhibitor****	200 gallons	U1 NSCW tower chemical addition building
Copper Corrosion Inhibitor****	200 gallons	U2 NSCW tower chemical addition building
Ammonium Bisulfite	200 gallons	Circulating water dechlorination building
Liquid Propane	2000 gallons	Fire Training Facility
Liquid Propane	2000 gallons	Fire Training Facility
Liquid Propane	2000 gallons	Fire Training Facility

* Actually two 80,000 gallon tanks that are interconnected and function as one tank.
** Currently using Nalco 3DT102, swapping to Nalco 3DT190 during summer 2006.
*** Currently using Nalco 73297, swapping to Nalco 3DT177 during summer 2006.
**** Currently using Nalco 1336.

Table 2.2-206
Not Used

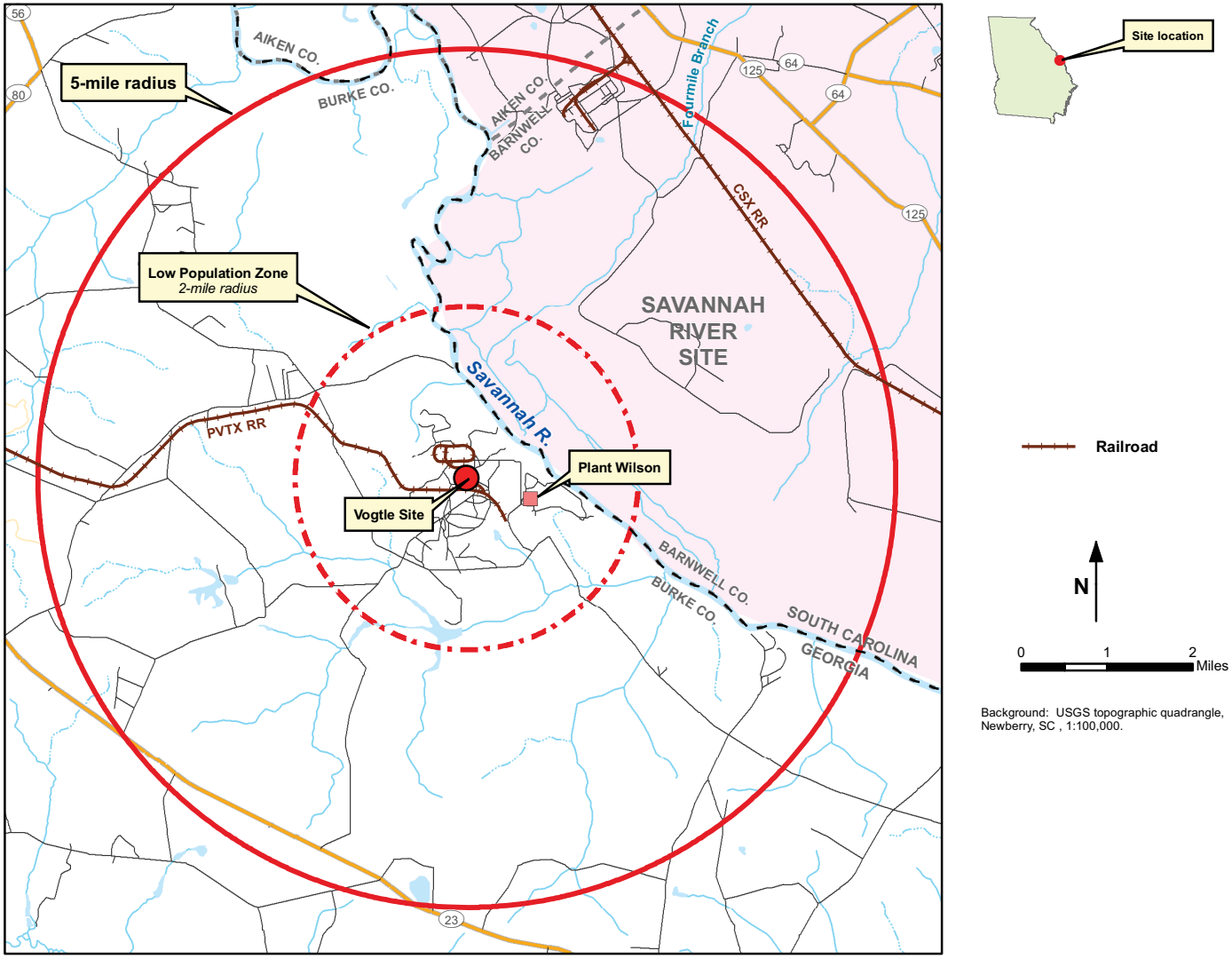

Figure 2.2-201
Site Vicinity Map

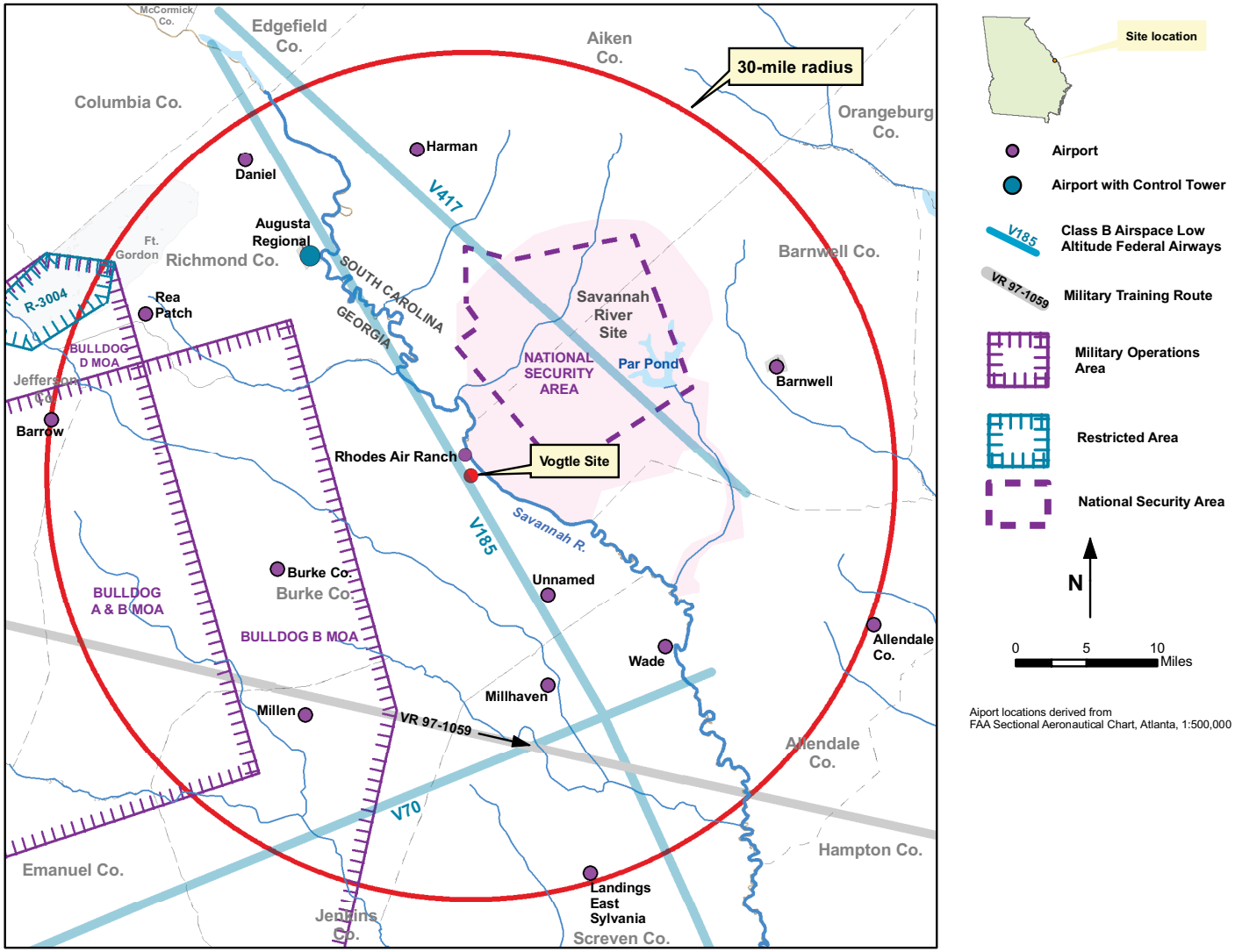

Figure 2.2-202
Airports Within 30 Miles of VEGP

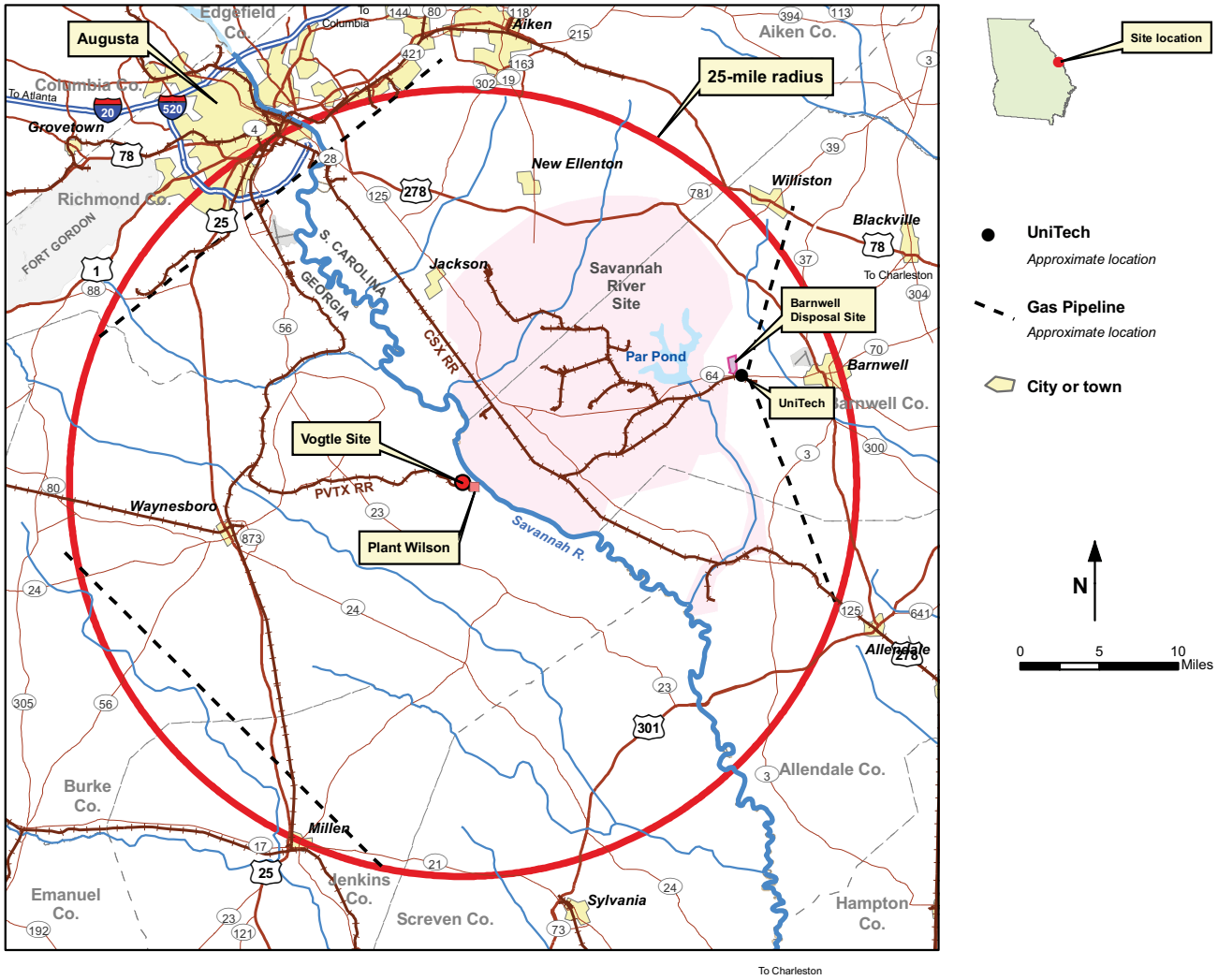

Figure 2.2-203
Industrial Facilities Within 25 Miles of VEGP

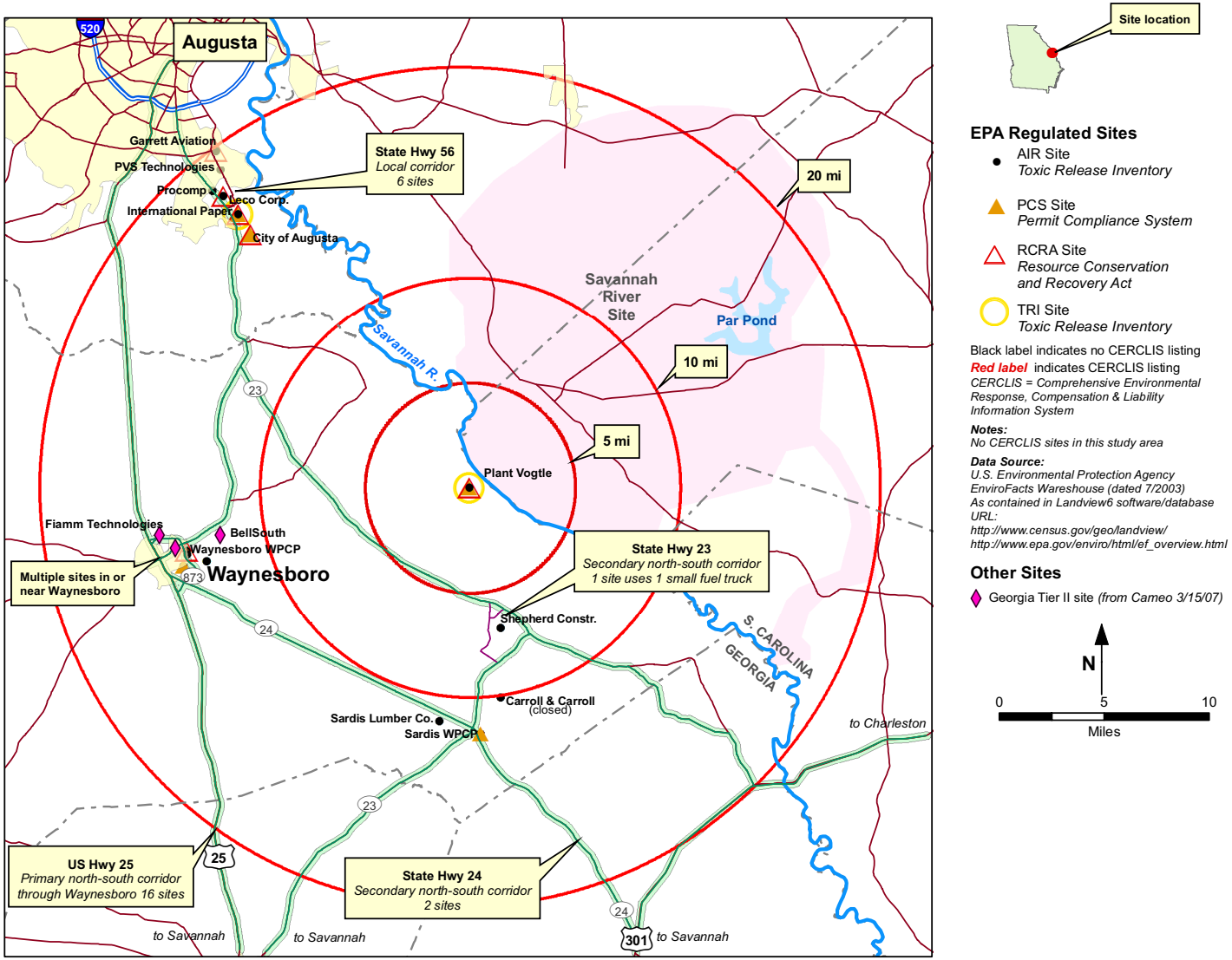

Figure 2.2-204
Corridor Analysis

2.3 Meteorology

The AP1000 is designed for air temperatures, humidity, precipitation, snow, wind, and tornado conditions as specified in Table 2.0-201. The design wind is specified as a basic wind speed of 145 mph with an annual probability of occurrence of 0.02. Wind loads are calculated for exposure C, which is applicable to shorelines in hurricane prone areas. The VEGP site parameters for the design wind are demonstrated to be acceptable by comparison of the wind loads on the structures. Refer to Subsection 2.3.1.3.

This section describes the regional and local climatological and meteorological characteristics applicable to the VEGP site for consideration in the design and operating bases of safety- and/or non-safety related structures, systems and components for proposed VEGP Units 3 and 4. This section also provides site-specific meteorological information for use in evaluating construction-related, routine operational, and hypothetical accidental releases to the atmosphere.

2.3.1 Regional Climatology

The VEGP site is located in the region known as the Upper Coastal Plain, lying between the Appalachian Mountains and the Atlantic Ocean, just south of the Fall Line that separates the Piedmont from the Coastal Plain. Elevation is generally 150 to 250 ft above sea level in this region, which is cut by the valley of the Savannah River. The river valley ranges from 2 to 5 mi wide near the VEGP site.

2.3.1.1 Data Sources

SNC used several sources of data to characterize regional climatological conditions pertinent to the VEGP site. The National Climatic Data Center (NCDC) compiled data from the first-order National Weather Service (NWS) station in Augusta, Georgia, and from nine other nearby locations in its network of cooperative observer stations.

These climatological observing stations are located in Burke, Richmond, Jenkins, Screven, and Jefferson Counties, Georgia, and in Aiken, Barnwell, Orangeburg, and Bamberg Counties, South Carolina. Table 2.3-203 identifies the specific stations and lists their approximate distance and direction from the existing reactors at the VEGP site. Figure 2.3-201 illustrates these station locations relative to the VEGP site.

The objective of selecting nearby, off-site climatological monitoring stations is to demonstrate that the mean and extreme values measured at those locations are reasonably representative of conditions that might be expected to be observed at the VEGP site. The 50-mi radius circle shown in Figure 2.3-201 provides a relative indication of the distance between the climate observing stations and the VEGP site.

However, a 50-km (about 31-mi) grid spacing is considered to be a reasonable fine mesh grid in current regional climate modeling, and this distance was used as a nominal radius for the station selection process. The identification of stations to be included was based on the following considerations:

- Proximity to the site (i.e., within the nominal 50-km radius indicated above, to the extent practicable)
- Coverage in all directions surrounding the site (to the extent possible)

- Where more than one station exists for a given direction relative to the site, a station was chosen if it contributed one or more extreme conditions (e.g., rainfall, snowfall, maximum and/or minimum temperatures) for that general direction.

Nevertheless, if an overall extreme precipitation or temperature condition was identified for a station located within a reasonable distance beyond the nominal 50-km radius and that event was considered to be reasonably representative for the site area, such stations were also included, regardless of directional coverage.

Normals (i.e., 30-year averages), means, and extremes of temperature, rainfall, and snowfall are based on the:

- *2004 Local Climatological Data, Annual Summary with Comparative Data for Augusta, Georgia* (Reference 221)
- *Climatography of the United States, No. 20, 1971-2000, Monthly Station Climate Summaries* (Reference 222)
- *Climatography of the United States, No. 81, 1971-2000, U.S. Monthly Climate Normals* (Reference 211)
- Southeast Regional Climate Center (SERCC), *Historical Climate Summaries and Normals for the Southeast* (Reference 230).
- *Cooperative Summary of the Day, TD3200, Period of Record Through 2001, for the Eastern United States, Puerto Rico and the Virgin Islands* (Reference 213).

First-order NWS stations also record measurements, typically on an hourly basis, of other weather elements, including winds, several indicators of atmospheric moisture content (i.e., relative humidity, dew point, and wet-bulb temperatures), and barometric pressure, as well as other observations when those conditions occur (e.g., fog, thunderstorms). Table 2.3-204, excerpted from the 2004 local climatological data (LCD) summary for the Augusta NWS Station, presents the long-term characteristics of these parameters.

The following data sources were also used in describing climatological characteristics of the VEGP site area and region:

- *Solar and Meteorological Surface Observation Network, 1961-1990, Volume 1, Eastern U.S.* (Reference 227)
- *Hourly United States Weather Observations, 1990-1995* (Reference 210)
- *Integrated Surface Hourly Observations*, 1995-1999 (Reference 215), 2000 (Reference 216), 2001 (Reference 217), 2002 (Reference 218), 2003 (Reference 220), 2004 (Reference 223), 2005 (Reference 226)
- *International Station Meteorological Climate Summary* (Reference 232)
- *Engineering Weather Data, 2000 Interactive Edition, Version 1.0* (Reference 202)
- *Minimum Design Loads for Buildings and Other Structures* (Reference 204)

- *Seasonal Variation of 10-Square-Mile Probable Maximum Precipitation Estimates, United States East of the 105th Meridian,* Hydrometeorological Report No. 53, June 1980 **(NUREG/CR-1486)**
- *Storm Events for Georgia and South Carolina*, Tornado Event Summaries, accessed July 2005 and January 2006 (Reference 224)
- *Historical Hurricane Tracks Storm Query*, 1851 through 2004 (Reference 228)
- *The Climate Atlas of the United States* (Reference 212)
- *Storm Events for Georgia and South Carolina*, Hail Event and Snow and Ice Event Summaries for Burke, Jenkins, Richmond, and Screven Counties in Georgia, and Aiken, Allendale, and Barnwell Counties in South Carolina (Reference 225)
- *Storm Data (and Unusual Weather Phenomena with Late Reports and Corrections)*, January 1959 (Volume 1, Number 1) to January 2004 (Volume 42, Number 1) (Reference 219)
- *Air Stagnation Climatology for the United States (1948-1998)* (Reference 233)
- *Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States* (Reference 209)
- *Climatography of the United States, No. 85, Divisional Normals and Standard Deviations of Temperature, Precipitation, and Heating and Cooling Degree Days 1971-2000 (and previous normals periods)* (Reference 214)

2.3.1.2 General Climate

The general climate in this region is characterized by mild, short winters; long periods of mild sunny weather in the autumn; somewhat more windy but mild weather in spring; and long, hot summers.

The regional climate is predominately influenced by the Azores high-pressure system. Due to the clockwise circulation around the western extent of the Azores High, maritime tropical air mass characteristics prevail much of the year, especially during the summer with the establishment of the Bermuda High and the Gulf High. Together, these systems govern Georgia's summertime temperature and precipitation patterns. This macro-circulation feature also has an effect on the frequency of high air pollution potential in the VEGP site region. These characteristics and their relationship to the Bermuda High, especially in the late summer and autumn, are addressed in Subsection 2.3.1.6.

This macro-scale circulation feature continues during the transitional seasons and winter months; however, it is regularly disrupted by the passage of synoptic- and meso-scale weather systems. During winter, cold air masses may briefly intrude into the region with the cyclonic (i.e., counter-clockwise) northerly flow that follows the passage of low-pressure systems. These systems frequently originate in the continental interior around Colorado, pick up moisture-laden air due to southwesterly through southeasterly airflow in advance of the system, and result in a variety of precipitation events that include rain, snow, sleet, and freezing rain or mixtures, depending on the temperature characteristics of the weather system itself and the temperature of the underlying air (see Subsection 2.3.1.3.5). Similar cold air intrusion and precipitation patterns may also be associated with secondary low-pressure systems that form in the eastern Gulf of Mexico or along the Atlantic Coast and move northeastward along the coast (also referred to as "nor'easters").

Larger and relatively more persistent outbreaks of very cold, dry air associated with massive high-pressure systems that move southeastward out of Canada also periodically affect the VEGP site region. These weather conditions are moderated by the Appalachian Mountains to the northwest, which shelter the region in winter from these cold air masses that sweep down through the continental interior. In general, the cold air that does reach the VEGP site area is warmed by its descent to the relatively lower elevations of the region, as well as by modification due to heating as it passes over the land.

Monthly precipitation exhibits a cyclical pattern, with one maximum during the winter into early spring and a second maximum during late spring into summer (see Table 2.3-204). The winter and early spring maximum is associated with low-pressure systems moving eastward and northward through the Gulf States and up the Atlantic Coast, drawing in warm, moist air from the Gulf of Mexico and the Atlantic Ocean. These air masses receive little modification as they move into the region. The late spring and summer maximum is due to thunderstorm activity. Heavy precipitation associated with late summer and early autumn tropical cyclones, as discussed in Subsection 2.3.1.3.3, is not uncommon. The VEGP site is located far enough inland that the strong winds associated with tropical cyclones are much reduced by the time that such systems affect the site area.

2.3.1.3 Severe Weather

2.3.1.3.1 Extreme Winds

Estimating the wind loading on plant structures for design and operating bases considers the “basic” wind speed, which is the “3-second gust speed at 33 ft (10 m) above the ground in Exposure Category C,” as defined in Sections 6.2 and 6.3 of the ASCE-SEI design standard, *Minimum Design Loads for Buildings and Other Structures* (Reference 204).

The basic wind speed for the VEGP site is about 97 mph, as estimated by linear interpolation from the plot of basic wind speeds in Figure 6-1 of ASCE (2002) for that portion of the U.S. that includes the VEGP site (Reference 204). This interpolated value is about 7.5 percent higher than the basic wind speed reported in the Engineering Weather Data summary for the Augusta (Bush Field) NWS Station (i.e., 90 mph) (Reference 202), which is located about 20 mi northwest of the VEGP site. The former value is, therefore, considered to be a reasonably conservative indicator of the basic wind speed.

From a probabilistic standpoint, these values are associated with a mean recurrence interval of 50 years. Section C6.0 of the ASCE-SEI design standard provides conversion factors for estimating 3-second-gust wind speeds for other recurrence intervals (Reference 204). Based on this guidance, the 100-year return period value is determined by multiplying the 50-year return period value by a scaling factor of 1.07, which yields a 100-year return period 3-second-gust wind speed for the VEGP site of about 104 mph.

2.3.1.3.2 Tornadoes

The design-basis tornado (DBT) characteristics applicable to structures, systems, and components important to safety at the proposed VEGP site include the following parameters as identified in Draft Regulatory Guide DG-1143, *Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants, Proposed Revision 1 of NRC Regulatory Guide 1.76 (dated April 1974)*, January 2006 (DG-1143) and the predecessor US Atomic Energy Commission (USAEC) guidance document WASH-1300, *Technical Basis for Interim Regional Tornado Criteria* (Reference 231), on which the original version of Regulatory Guide 1.76 is based:

- Tornado strike probability

- Maximum wind speed
- Translational speed
- Maximum rotational wind speed
- Radius of maximum rotational speed
- Pressure drop
- Rate of pressure drop

The tornado strike probability is determined by evaluating certain characteristics of tornadoes that have been observed within a 2-degree latitude and longitude square centered on the VEGP site. These characteristics include the Fujita-scale wind speed classification (or “F-scale”) and the Pearson-scale path length and path width classification (or “P-scale”). As tornado intensity increases, so does the magnitude or the dimensions of these parameters along with the assigned numerical classification, which ranges from 0 to 5.

The 2-degree square area was assumed to be centered on the VEGP Unit 1 reactor, adjacent to the new unit footprint, and located at the following coordinates:

Latitude = 33° 08’ 30” N; Longitude = 81° 45’ 44” W

A searchable database of tornado occurrences by location, date, and time; starting and ending coordinates; F-scale classification; P-scale dimensions; and damage statistics has been compiled by the NCDC beginning with January 1950 (Reference 224). The 2-degree square area for this evaluation includes all or portions of 30 counties in Georgia and all or portions of 18 counties in South Carolina.

Through the nearly 55-year period ending April 30, 2005, the records in the database indicate that a total of 348 tornadoes or portions of a tornado path passed within the 2-degree square area centered on the VEGP site. Tornado F-scale classifications (with corresponding wind speed range) and respective frequencies of occurrence are as follows:

- F5 (wind speed > 117 m/sec) = 0
- F4 (wind speed 93 to 116 m/sec) = 1
- F3 (wind speed 70 to 92 m/sec) = 18
- F2 (wind speed 50 to 69 m/sec) = 62
- F1 (wind speed 33 to 49 m/sec) = 151
- F0 (wind speed 18 to 32 m/sec) = 116

Following the WASH-1300 methodology, the probability that a tornado will strike a particular location during any one year is given as:

PS = n (a / A)

where:

P_S = mean tornado strike probability per year
n = average number of tornadoes per year in the area being considered
a = average individual tornado area
A = total area being considered (i.e., the 2-degree square area)

Based on an average occurrence of 6.29 tornadoes per year (i.e., 348 tornadoes over a 55.33-year period of record), an average individual tornado area of 0.197 sq mi (i.e., an average tornado path length of 3.3 mi and an average tornado path width of 105.3 yds), and a total area of 16,010 sq mi for the 2-degree square under consideration, the tornado strike probability (P_S) for the VEGP site area is estimated to be about 774 x 10^{-7} (about 0.0000774 per year), or a recurrence interval of once every 12,920 years.

WASH-1300 indicates that determination of the DBT characteristics is based on the premise that the probability of occurrence of a tornado that exceeds the DBT should be on the order of 10^{-7} per year per nuclear power plant. DG-1143 retains that threshold criterion.

The estimated recurrence interval for the VEGP site area exceeds this threshold; therefore, it is necessary to determine the DBT parameters listed at the beginning of this section. These parameters are able to be calculated from the area-specific database used to determine PS. However, DG-1143 also provides DBT characteristics for three tornado intensity regions, each with a 10^{-7} probability of occurrence, that are acceptable to the agency.

As indicated in DG-1143, Figure 1, the VEGP site is adjacent to Tornado Intensity Regions I and II. The more conservative DBT parameters for Region I will be used for the design of structures, systems, and components that are important to safety that must take DBT characteristics into account. DG-1143, Table 1, provides the following DBT parameter values for Tornado Intensity Region I:

- Maximum wind speed = 300 mph
- Translational speed = 60 mph
- Maximum rotational wind speed = 240 mph
- Radius of maximum rotational speed = 150 ft
- Pressure drop = 2.0 psi
- Rate of pressure drop = 1.2 psi/sec

2.3.1.3.3 Tropical Cyclones

Tropical cyclones include not only hurricanes and tropical storms, but systems classified as tropical depressions, sub-tropical depressions, and extra-tropical storms, among others. This characterization considers all “tropical cyclones” (rather than systems classified only as hurricanes and tropical storms) because storm classifications are generally downgraded once landfall occurs and the systems weaken, although they may still result in significant rainfall events as they travel through the site region.

NOAA’s Coastal Services Center (NOAA-CSC) provides a comprehensive historical database, extending from 1851 through 2004, of tropical cyclone tracks based on information compiled by the National Hurricane Center. This database indicates that a total of 102 tropical cyclone centers or

storm tracks have passed within a 100-nautical mile radius of the VEGP site during this historical period (Reference 228). Storm classifications and respective frequencies of occurrence over this 154-year period of record are as follows:

- Hurricanes – Category 3 (5), Category 2 (4), Category 1 (16)
- Tropical storms – 46
- Tropical depressions – 23
- Sub-tropical storms – 1
- Sub-tropical depressions – 2
- Extra-tropical storms – 5

Tropical cyclones within this 100-nautical-mile radius have occurred as early as May and as late as November, with the highest frequency (36 out of 102 events) recorded during September, including all classifications except sub-tropical depressions. August and October account for 21 and 20 events, respectively, indicating that 75 percent of the tropical cyclones that affect the VEGP site area occur from mid-summer to early autumn. Three of the five Category 3 hurricanes occurred in September, and the other two occurred in August.

Tropical cyclones are responsible for at least 12 separate rainfall records at 8 NWS cooperative observer network stations in the VEGP site area – eight 24-hour (daily) rainfall totals and 3 monthly rainfall totals (see Table 2.3-205). In October 1990, rainfall associated with Tropical Depression Marco (along with a slow-moving cold frontal system) resulted in historical daily maximum totals of 8.60 in. at the Louisville 1E Station, 8.19 in. at the Midville Experiment Station, and 5.50 in. at the Newington 2NE Station, all located in Georgia. Two daily records were established due to Hurricane Gracie in September 1959, at the Blackville 3W (7.53 in.) and Springfield (7.10 in.) stations in South Carolina. In August 1964, a 24-hour rainfall total of 8.02 in. was recorded at the Millen 4N Station (in Georgia) due to Tropical Storm Cleo; and in September 2000, Tropical Depression Helene produced 8.02 in. of rain in a 24-hour period at the Bamberg, South Carolina, observing station. A daily maximum total of 7.30 in. was measured at the Augusta Weather Service Office (WSO) (also in Georgia) in September 1998 during the passage of Tropical Storm Earl **(**Reference 219**,** Reference 225**;** Reference 230**)**.

Monthly station records were established due to contributions from the following tropical cyclones: Tropical Depression Marco in October 1990 (14.82 in. at Augusta WSO and 14.67 in. at Blackville 3W); Tropical Storm Cleo in August 1964 (13.45 in. at Millen 4N); and to some extent, Tropical Depression Jerry in August 1995 (15.26 in. at Bamberg) **(**Reference 215**,** Reference 219**,** Reference 225**)**.

2.3.1.3.4 Precipitation Extremes

Because precipitation is a point measurement, mean and extreme statistics, such as individual storm event, or daily or cumulative monthly totals typically vary from station to station. Assessing the variability of precipitation extremes over the VEGP site area, in an effort to evaluate whether the available long-term data are representative of conditions at the site, is largely dependent on station coverage.

Historical precipitation extremes (rainfall and snowfall) are presented in Table 2.3-205 for the ten nearby climatological observing stations listed in Table 2.3-203. Based on the similarity of the maximum recorded 24-hour and monthly totals among these stations and the areal distribution of

these stations around the VEGP site, the data suggest that these statistics are reasonably representative of precipitation extremes that might be expected to be observed at the site.

As indicated in Subsection 2.3.1.3.3, most of the individual station 24-hour rainfall records (and to a lesser extent the monthly record totals) were established as a result of precipitation associated with tropical cyclones that passed within a 100-nautical-mile radius of the VEGP site.

However, the overall highest 24-hour rainfall total in the VEGP site area — 9.68 in. on April 16, 1969, at the Aiken 4NE Station in South Carolina (Reference 222), about 25 mi north-northeast of the VEGP site—was not associated with a low-pressure system or other well-defined synoptic-scale feature. Rather, this appears to have been an embedded, localized event in an otherwise widespread area of disturbed weather that brought precipitation to the entire East Coast (Reference 208).

Similarly, the overall highest monthly rainfall total recorded in the VEGP site area —17.32 in. during June 1973 at the cooperative observing station in Springfield, South Carolina **(**Reference 230**;** Reference 213**)**, 37 mi northeast of the VEGP site — represents the accumulation of 21 days of measurable precipitation during that month (Reference 213) due to both synoptic-scale weather features (e.g., stationary frontal boundaries and stalled low-pressure areas off the Carolina coast) and more regional- to local-scale events (i.e., thunderstorms).

For the most part, when daily or monthly rainfall records were established at a given station, regardless of their cause(s), significant amounts of precipitation were usually measured at the other stations in the VEGP site area (Reference 213).

Although the disruptive effects of any winter storm accompanied by frozen precipitation can be significant in the Upper Coastal Plain of Georgia and South Carolina, storms that produce large measurable amounts of snow occur infrequently. With one exception, all of the 24-hour and monthly record snowfall totals listed in Table 2.3-205 were established during the storm of early February 1973, the highest 24-hour and monthly totals (19.0 and 22.0 in., respectively) being recorded at the Bamberg Station in South Carolina, about 44 mi east-northeast of the VEGP site. Similar amounts, ranging from 14.0 to 17.0 in., were recorded at most of the other stations **(**Reference 222**;** Reference 230**)**.

The stations with lower maximum 24-hour snowfall totals — 8.0 in. at the Augusta WSO on February 9 and 5.0 in. at Newington 2NE on February 10 (both in Georgia) **(**Reference 222**;** Reference 230**)**, and 8.0 in. at Springfield, South Carolina, on February 11 (Reference 230**;**Reference 213) — recorded a comparable amount of snowfall on the preceding or following day, making the 2-day totals for these stations similar to the single-day records at the other stations (except at the Newington 2NE station, the lowest of all the station records).

The record monthly snowfall total at the Millen 4N Station (15.0 in. in February 1968) represents the cumulative amount from two smaller snow events that occurred around February 8 and from February 22 to 24. A review of the daily records for the other stations indicates that except for the Augusta (Georgia) and Blackville 3W (South Carolina) stations, the data are missing for these time periods. (Reference 213)

Estimating the design basis snow load on the roofs of safety-related structures considers two climate-related components: the weight of the 100-year return period ground-level snowpack, and the weight of the 48-hour probable maximum winter precipitation (PMWP). From a probabilistic standpoint, the estimated weight of the 100-year return period ground-level snowpack for the VEGP site area is about 10 lb/ft^2, as determined in accordance with the guidance in Section C7.0 of the ASCE-SEI design standard, *Minimum Design Loads for Buildings and Other Structures* (Reference 204).

The 48-hour PMWP component is derived from plots of 24- and 72-hour, 10-sq mi area, monthly probable maximum precipitation (PMP) as presented in NUREG/CR-1486, *Seasonal Variation of 10-Square-Mile Probable Maximum Precipitation Extremes, United States East of the 105th Meridian,* NOAA Hydrometeorological Report No. 53, June 1980 (NUREG/CR-1486). The highest winter season (i.e., December through February) PMP values for the VEGP site area occur in December. The 48-hour PMWP value is determined by linear interpolation between the 24- and 72-hour PMP values for that month (Figures 35 and 45 of NUREG/CR-1486) and result in a value of 28.3 in. One inch of liquid water is equivalent to 5.2 lb/ft^2; therefore, the estimated weight of the 48-hour PMWP is about 147 lb/ft^2.

The AP1000 safety-related roofs are sloped and designed to handle winter snowpack with margin to handle rainfall on top of the snowpack. The AP1000 design basis snow load of 75 psf (ground) and 63 psf (roof) has sufficient margin to include the weight of rain water adding to a pre-existing snow pack. Using ASCE 7-98 the design snow load 50 psf (ground) converts to 42 psf (roof). Therefore, the AP1000 design includes a 21 psf (63 - 42) margin above the design ASCE 7-98 requirement. This margin could accommodate the equivalent weight of 4" of water within the snow on the roof.

Winter PMP loads in excess of this loading are not considered credible based on the design of the roof. The safety related roofs are constructed of 15" thick reinforced concrete supported by steel beams. The roofs will not deflect enough to hold water under the snow load; therefore, ponding of rain water with pre-existing snow pack conditions will not occur. The physical arrangement of the AP1000 sloped roof is designed such that the 100-year snow pack will not prevent the winter PMP water from draining off the sloped roof system.

In addition the AP1000 roof includes R10 insulation that assures uniform temperatures on the roof surface. This minimizes the potential for ice dams that are typically formed across roofs with a temperature differential.

For the VEGP site, the 100 year snow load is 10 psf which is well within the 63 psf design basis snow load of the AP1000. Thus, for the VEGP site, a 53 psf margin is available to accommodate winter PMP water that may be impounded in the 100-year snow pack as the water flows off of the roof.

2.3.1.3.5 Hail, Snowstorms, and Ice Storms

Frozen precipitation typically occurs in the form of hail, snow, sleet, and freezing rain. The frequency of occurrence of these types of weather events in the VEGP site area is based on the latest version of *The Climate Atlas of the United States* (Reference 212), which has been developed from observations made over the 30-year period of record from 1961 to 1990.

Though hail can occur at any time of the year and is associated with well-developed thunderstorms, it has been observed primarily during the spring and early summer months and least often during the late summer and autumn months. The Climate Atlas indicates that Burke County, Georgia, and adjacent Barnwell County, South Carolina, can expect, on average, hail with diameters 0.75 in. or greater about 1 day per year. The occurrence of hailstorms with hail greater than or equal to 1.0 in. in diameter averages less than 1 day per year in Burke County.

However, the annual mean number of days with hail 0.75 in. and 1.0 in. or greater is slightly higher in nearby Richmond and Columbia Counties, Georgia (just to the northwest of the VEGP site), and in Aiken and Edgefield Counties, South Carolina (just to the north and north-northwest of the VEGP site), ranging from 1 to 2 days per year (0.75 in. diameter or greater) and up to 1 day per year (1.0 in. diameter or greater).

NCDC cautions that hailstorm events are point observations and somewhat dependent on population density. While no hailstorms of note have been recorded in some years, multiple events have been

observed in other years, including 16 events on 9 separate dates in 1998 and 8 events on 8 separate dates during 1999 in Aiken County, and 8 events on 6 separate dates during 1998 in Richmond County (Reference 225). Therefore, the slightly higher annual mean number of hail days may be a more representative indicator of frequency for the relatively less-populated VEGP site area.

Despite these long-term statistics, golfball-size hail (about 1.75 in. in diameter) is not a rare occurrence (Reference 219, Reference 225**)**. However, in terms of extreme hailstorm events, the NCDC publication *Storm Data* indicates that baseball-size hail (about 2.75 in. in diameter) was observed at one location in the general VEGP site area (Reference 219) on May 21, 1964, at Hampton, South Carolina, about 43 mi southeast of the VEGP site.

Snow is infrequent in the Upper Coastal Plain of Georgia and South Carolina, where the VEGP site is located, but can occur when a source of moist air from the Atlantic Ocean or the Gulf of Mexico interacts with a very cold air mass that penetrates across the otherwise protective Appalachian mountain range in northern Georgia and northwestern South Carolina. The Climate Atlas (Reference 212) indicates that the occurrence of snowfalls 1 in. or greater in the VEGP site area averages less than 1 day per year.

Heavy snow is a rarity. The greatest snowfall on record in the VEGP site area occurred between February 9 and 11, 1973, depending on the cooperative observing station records. Snowfall totals for the overall event typically ranged between 14 and 22 in., the highest single-day total recorded at the Bamberg Station (19.0 in.) on February 10, which contributed to the highest cumulative monthly total for that station and for the site area. Single-day and cumulative monthly record snowfall totals were also set at nearly all of the other nearby cooperative observing stations as a result of this event. Additional details were given previously in Subsection 2.3.1.3.4 and Table 2.3-205.

Depending on the temperature characteristics of the air mass, snow events are often accompanied by or alternate between sleet and freezing rain as the weather system traverses the VEGP region. The Climate Atlas (Reference 212) indicates that, on average, freezing precipitation occurs only about 1 or 2 days per year in the VEGP site area.

However, the site area appears to be in a transition zone for frequency of occurrence, with the eastern two-thirds of Aiken and Barnwell Counties and all of Allendale County (immediately to the northeast, east, and southeast in South Carolina) and the northeastern quadrant of Screven County, Georgia (just to the southeast of the VEGP site in northeastern Burke County), showing an average frequency of 3 to 5 days of freezing precipitation per year (Reference 212). Therefore, it is not unreasonable to expect a slightly higher annual frequency of occurrence of freezing precipitation events at the VEGP site.

Storm event records from the winters of 2000 through 2005 for the seven-county area surrounding the VEGP site note that ice accumulations of up to 1 in. have occurred, although it is typically less than this thickness (Reference 225).

2.3.1.3.6 Thunderstorms

Thunderstorms can occur in the VEGP site area at any time during the year. Based on a 54-year period of record, Augusta, Georgia, averages about 52 thunderstorm-days (i.e., days on which thunder is heard at an observing station) per year. On average, July has the highest monthly frequency of occurrence — about 12 days. On an annual basis, nearly 60 percent of thunderstorm-days are recorded between late spring and mid-summer (i.e., from June through August). From October through January, a thunderstorm might be expected to occur about 1 day per month. (Reference 221)

The mean frequency of lightning strikes to earth can be estimated using a method attributed to the Electric Power Research Institute, as reported by the US Department of Agriculture Rural Utilities Service in the publication entitled Summary of Items of Engineering Interest Reference 206. This methodology assumes a relationship between the average number of thunderstorm-days per year (T) and the number of lightning strikes to earth per square mile per year (N), where:

$$N = 0.31T$$

Based on the average number of thunderstorm-days per year at Augusta, Georgia (i.e., 52; see Table 2.3-204), the frequency of lightning strokes to earth per square mile is about 16 per year for the VEGP site area. This frequency is essentially equivalent to the mean of the 5-year (1996 to 2000) flash density for the area that includes the VEGP site, as reported by the NWS—4 to 8 flashes per square kilometer per year Reference 229—and, therefore, a reasonable indicator.

The potential reactor area for VEGP Units 3 and 4 is represented in Figure 1.1-202 as an area bounded by a 775-ft-radius circle (or approximately 0.068 mi^2). Given the estimated annual average frequency of lightning strokes to earth in the VEGP site area, the frequency of lightning strokes in the reactor area can be calculated as follows:

(16 lightning strokes/mi^2/year) X (0.068 mi^2) = 1.09 lightning strokes/year
or about once each year in the reactor area.

2.3.1.4 Meteorological Data for Evaluating the Ultimate Heat Sink

Unlike the Vogtle 1 and 2 design, the AP1000 design does not use a cooling tower to release heat to the atmosphere following a Loss-of-Coolant Accident (LOCA). Instead, the AP1000 design uses a passive containment cooling system (PCS) to provide the safety-related ultimate heat sink (UHS) for the plant (Reference 234). The PCS uses a high-strength steel containment vessel inside a concrete shield building. The steel containment vessel provides the heat transfer surface that removes heat from inside the containment and transfers it to the atmosphere.

Heat is removed from the containment vessel by continuous, natural circulation of air. In the event of a LOCA, a high-pressure signal activates valves, allowing water to drain by gravity from a storage tank installed on top of the shield building. An air flow path is formed between the shield building and the containment vessel to aid in the evaporation and is exhausted through a chimney at the top of the shield building (Reference 205).

The use of the PCS in the AP1000 design is not significantly influenced by local weather conditions. Therefore, the identification of meteorological conditions that are associated with maximum evaporation and drift loss of water, as well as minimum cooling by the UHS (i.e., periods of maximum wet-bulb temperatures) is not necessary.

A reactor design has been chosen as specified in Section 1.1 that does not use an ultimate heat sink cooling tower to release heat to the atmosphere following a loss of coolant accident; therefore, evaluation of meteorological site characteristics such as maximum evaporation and drift loss and minimum water cooling conditions used to evaluate this design is not necessary.

2.3.1.5 Design Basis Dry- and Wet-Bulb Temperatures

Long-term, engineering-related climatological data summaries, prepared by the AFCCC and the NCDC for the nearby Augusta NWS Station (Reference 202) are used to characterize typical design basis dry- and wet-bulb temperatures for the VEGP site. These characteristics include:

- Maximum ambient threshold dry-bulb (DB) temperatures at annual exceedance probabilities of 2.0 and 0.4 percent, along with the mean coincident wet-bulb (MCWB) temperatures at those values.

- Minimum ambient threshold DB temperatures at annual exceedance probabilities of 1.0 and 0.4 percent.

- Maximum ambient threshold wet-bulb temperature with an annual exceedance probability of 0.4 percent.

Based on the 24-year period of record from 1973 to 1996 for Augusta, Georgia, the maximum DB temperature with a 2.0 percent annual exceedance probability is 92°F, with a MCWB temperature of 75°F. The maximum DB temperature with a 0.4 percent annual exceedance probability is 97°F with a corresponding MCWB temperature value of 76°F. (Reference 202)

For the same period of record, the minimum DB temperatures with 1.0 and 0.4 percent annual exceedance probabilities are 25°F and 21°F, respectively. The maximum wet-bulb temperature with a 0.4 percent annual exceedance probability is 79°F. (Reference 202)

The AFCCC-NCDC data summaries, from which the dry-bulb and mean coincident wet-bulb temperatures, presented above, were obtained, do not include values that represent return intervals of 100 years. Maximum dry-bulb, minimum dry-bulb, and maximum wet-bulb temperatures corresponding to a 100-year return period were derived through linear regression using individual daily maximum and minimum dry-bulb temperatures and maximum daily wet-bulb temperatures for each year over a 30-year period of record from 1966 through 1995 at the Augusta, Georgia, NWS station (Reference 227; Reference 210).

Based on the linear regression analyses of these data sets for a 100-year return period, the maximum dry-bulb temperature is estimated to be about 115°F, the minimum dry-bulb temperature is estimated to be about -8°F, and the maximum wet-bulb temperature is estimated to be about 88°F.

The Westinghouse basis for the determination of maximum design-basis dry- and wet-bulb (WB) temperature values reflected in the AP1000 design (Reference 234, Reference 235) is summarized below:

- Maximum Safety Dry-Bulb and Coincident Wet-Bulb Temperatures. These site parameter values represent a maximum DB temperature that exists for 2 hours or more, combined with the maximum WB temperature that exists in that population of dry-bulb temperatures. Note that this coincident WB temperature is not defined in the same way as the MCWB values presented previously.

- Maximum Safety Wet-Bulb Temperature (Non-Coincident). This site parameter value represents a maximum WB temperature that exists within a set of hourly data for a duration of 2 hours or more.

- Maximum Normal Dry-Bulb and Coincident Wet-Bulb Temperatures. The DB temperature component of this site parameter pair is represented by a maximum DB temperature that exists for 2 hours or more, excluding the highest 1 percent of the values in an hourly data set. The WB temperature component is similarly represented by the highest WB temperature excluding the highest 1 percent of the data, although there is no minimum 2-hour persistence criterion associated with this WB temperature. The coincident WB temperature is not defined in the same way as the MCWB values presented previously.

- Maximum Normal Wet-Bulb Temperature (Non-Coincident). This site parameter value represents a maximum WB temperature, excluding the highest 1 percent of the values in an hourly data set (i.e., a 1 percent exceedance), that exists for 2 hours or more.

Site characteristic values for the Maximum Safety Dry-Bulb and Coincident Wet-Bulb Temperatures, and the Maximum Safety Wet-Bulb Temperature (Non-Coincident) were estimated, as discussed below, using a conservative approach that reflects 100-year return intervals for these values.

The dry-bulb temperature component of the Maximum Safety Dry-Bulb and Coincident Wet-Bulb Temperature site characteristic pair is represented by the 100-year return period maximum dry-bulb value (i.e., 115°F) reported earlier. Because this 100-year return period dry-bulb value is extrapolated from a regression curve on a single parameter, there is no corresponding MCWB temperature. As a result, the coincident wet-bulb temperature component had to be derived based on a characteristic relationship between concurrent dry- and wet-bulb temperatures—that is, as dry-bulb temperature continues to increase, there is a point at which the concurrent wet-bulb temperature reaches a maximum and thereafter changes little or even decreases. This characteristic is not unique to this location or climatological setting.

This relationship is exhibited by the annual percent frequency distribution of wet-bulb temperature depression for the Augusta, Georgia, NWS station, as reported in the International Station Meteorological Climate Summary (Reference 232), over the 47-year period from 1949 through 1995. This type of summary is a bivariate distribution of dry-bulb temperatures in 2-degree ranges by wet-bulb depression (i.e., the difference between concurrent dry- and wet-bulb observations), also in 2-degree ranges.

For the Augusta NWS station, this threshold dry-bulb temperature occurs at about 85°F. A cubic polynomial curve was fit to the concurrent maximum dry-bulb and maximum wet-bulb temperature pairs extracted from this bivariate distribution at and above this threshold dry-bulb value. The equation of the curve is an estimation of the trend where the maximum coincident wet-bulb temperature can then be determined as a function of the maximum dry-bulb temperature in this upper range of dry-bulb values. Based on a 100-year return period maximum dry-bulb temperature of 115°F, the corresponding wet-bulb temperature is estimated to be 77.7°F. Therefore, this pair of values is used to represent the Maximum Safety Dry-Bulb and Coincident Wet-Bulb Temperature site characteristic values, respectively, for the VEGP Units 3 & 4 site.

The Maximum Safety Wet-Bulb Temperature (Non-Coincident) site characteristic value was developed in a manner similar to the previously reported 100-year return period maximum and minimum dry-bulb temperatures and the maximum wet-bulb temperature in that a regression equation was used to extrapolate the available data to that return interval. However, the wet-bulb temperature data were filtered to include only observed periods of persistence of two hours or more, consistent with the Westinghouse basis.

This persistence criterion introduced the constraint of only being able to analyze data sets with sequential hourly wet-bulb observations. As a result, the period of record utilized to estimate the Maximum Safety Wet-Bulb Temperature (Non-Coincident) associated with a 100-year return period was different than the 100-year return period maximum wet-bulb temperature reported above. A 30-year period of record from 1975 through 2005 (except 1980) for the Augusta NWS station was used to identify the maximum wet-bulb temperature for each year (References 215, 216, 217, 218, 220, 223, and 226).

When applied to the equation of the curve defined by these maximum yearly values, the wet-bulb temperature associated with a return period of 100 years was estimated to be 83.9°F. Therefore, this value is used to represent the Maximum Safety Wet-Bulb Temperature (Non-Coincident) site characteristic for the VEGP Units 3 & 4 site.

The AP1000 DCD maximum and minimum normal temperature site characteristics are 1-percent (99-percent) seasonal exceedance values. According to the ASHRAE 2001 Fundamentals Handbook, these are approximately equivalent to the annual 0.4-percent (99.6-percent) annual exceedance values. Thus, the maximum normal dry bulb temperature (1% seasonal exceedance) is 97° F with a coincident maximum normal wet bulb temperature of 76°F. The maximum normal non-coincident wet bulb temperature is 79°F. Additionally, the minimum normal dry bulb temperature (99% seasonal exceedance) is 21°F.

These values are summarized in Table 2.0-203, *Site Characteristics, Design Parameters, and Site Interface Values*.

2.3.1.6 Restrictive Dispersion Conditions

Atmospheric dispersion can be described as the horizontal and vertical transport and diffusion of pollutants released into the atmosphere. Horizontal and along-wind dispersion is controlled primarily by wind direction variation and wind speed. Subsection 2.3.2.2.1 addresses wind characteristics for the VEGP site vicinity based on measurements from the existing meteorological monitoring program at the VEGP site. The persistence of those wind conditions is also discussed in Subsection 2.3.2.2.1.

In general, lower wind speeds represent less turbulent air flow, which is restrictive to horizontal and vertical dispersion. And, although wind direction tends to be more variable under lower wind speed conditions (which increases horizontal transport), air parcels containing pollutants often re-circulate within a limited area, thereby increasing cumulative exposure.

Major air pollution episodes are usually related to the presence of stagnating high-pressure weather systems (or anti-cyclones) that influence a region with light and variable wind conditions for 4 days or more. An updated air stagnation climatology is available for the continental US based on over 50 years of observations from 1948 through 1998. Although inter-annual frequency varies, the data in Figures 1 and 2 of that report indicate that, on average, the VEGP site area can expect about 20 days per year with stagnation conditions, or about 4 cases per year with the mean duration of each case lasting about 5 days. (Reference 233)

Air stagnation conditions primarily occur during an “extended” summer season that runs from May through October. This is a result of the weaker pressure and temperature gradients, and therefore weaker wind circulations, during this period (as opposed to the winter season). Based on the *Air Stagnation Climatology for the United States (1948-1998)*, Figures 17 to 67, the highest incidence is recorded in the latter half of that period between August and October, typically reaching its peak in September. As the LCD summary for Augusta, Georgia, in Table 2.3-204 indicates, this 3-month period coincides with the lowest monthly mean wind speeds during the year. Within this “extended” summer season, air stagnation is at a relative minimum during July due to the influence of the Bermuda High pressure system. (Reference 233)

The mixing height (or depth) is defined as the height above the surface through which relatively vigorous vertical mixing takes place. Lower mixing heights (and wind speeds), therefore, are a relative indicator of more restrictive dispersion conditions. Holzworth (1972) reports mean seasonal and annual morning and afternoon mixing heights and wind speeds for the contiguous US based on observations over the 5-year period from 1960 to 1964. Out of the network of 62 NWS stations in the 48 contiguous US at which daily surface and upper air sounding measurements were routinely made, one station was located in Athens, Georgia, about 105 mi northwest of the VEGP site. The information in that report indicates that the results from that station should be reasonably representative of conditions at the VEGP site.

Table 2.3-206 summarizes the mean seasonal and annual morning and afternoon mixing heights and wind speeds for Athens, Georgia (Reference 209). From a climatological standpoint, considering all

weather conditions, the lowest morning mixing heights occur in the autumn and are highest during the winter although, on average, morning mixing heights are only slightly lower in the spring and summer months than during the winter. Conversely, afternoon mixing heights reach a seasonal minimum in the winter and a maximum during the summer, as might be expected due to more intense summertime heating.

The wind speeds listed in Table 2.3-206 for Athens, Georgia, are consistent with the LCD summary for Augusta, Georgia, in Table 2.3-204 in that the lowest mean wind speeds are shown to occur during summer and autumn. This period of minimum wind speeds likewise coincides with the "extended" summer season described by Wang and Angell (1999) that is characterized by relatively higher air stagnation conditions.

2.3.1.7 Climate Changes

It is a given that climatic conditions change over time and that such changes are cyclical in nature on various time and spatial scales. The timing, magnitude, relative contributions to, and implications of these changes are generally more speculative, even more so for specific areas or locations.

With regard to the expected 40-year operating life for proposed VEGP Units 3 and 4, which could extend until the year 2070 based on a start-up year of 2030 (see Subsection 2.3.1.6), it is reasonable to evaluate the record of readily-available and well-documented climatological observations of temperature and rainfall (normals, means, and extremes) as they have varied over time (i.e., the last 60 to 70 years or so), and the occurrences of severe weather events, in the context of the plant's design bases.

Trends of temperature and rainfall normals and standard deviations are identified over a 70-year period for successive 30-year intervals, updated every 10 years, beginning in 1931 (e.g., 1931–1960, 1941–1970, etc.) through the most recent normal period (i.e., 1971–2000) in the NCDC publication Climatography of the United States, No. 85 (Reference 214). The report summarizes these observations for the 344 climate divisions in the 48 contiguous states.

A climate division represents a region within a state that is as climatically homogeneous as possible. Division boundaries generally coincide with county boundaries except in the Western US. In Georgia, the VEGP site is located within Climate Division GA-06 (East Central). In South Carolina, Climate Division SC-05 (West Central), whose southern extent includes Aiken County, is nearly adjacent to the VEGP site.

Summaries of successive annual temperature and rainfall normals as well as the composite 70-year average are provided below for these climate divisions (Reference 214).

	Temperature (°F)		Rainfall (inches)	
Period	**GA-06**	**SC-05**	**GA-06**	**SC-05**
1931-2000	64.3	62.2	45.60	46.99
1931-1960	65.0	62.9	43.42	44.88
1941-1970	64.3	62.3	45.35	46.46
1951-1980	63.8	61.8	45.95	47.53
1961-1990	63.6	61.6	46.61	48.46
1971-2000	63.9	61.8	47.06	48.36

These data indicate a slight cooling trend over most of the 70-year period, with a slight increase of about 0.2 to 0.3°F during the most recent normal period. In general, total annual rainfall has

increased slightly in these divisions over the period by about 1.5 inches. Similar trends are observable for all of the other climate divisions in Georgia and South Carolina (Reference 214).

The preceding values represent variations of “average” temperature and rainfall conditions over time. The occurrence of extreme temperature and precipitation (rainfall and snowfall) events does not necessarily follow the same trends. However, characteristics about the occurrence of such events over time are indicated by the summaries for observed extremes of temperature and rainfall and snowfall totals recorded in the VEGP site area (see Table 2.3-205).

The data summarized in Table 2.3-205 show that individual station records for maximum temperature have been set between 1952 (including the overall highest value for the site area) and 1999, i.e., there is no discernible trend for these extremes in the site area. Similarly, record-setting 24-hour rainfall totals were established between 1959 and 2000, with station records for total monthly rainfall between 1964 and 1995 – again, no clear trend. Cold air outbreaks that result in overall extreme low temperature records occur infrequently; record-setting snowfalls are even more rare events. The almost singular dates of their occurrence (in 1985 and 1973, respectively) are indicative of this characteristic. Nevertheless, records of these types for individual calendar days span a range of years similar to the maximum temperature, and the maximum 24-hour and monthly total rainfall records (Reference 230).

Characteristics and/or effects of other types of severe weather phenomena have been discussed previously, including tornadoes (see Subsection 2.3.1.3.2 and tropical cyclones (see Subsection 2.3.1.3.3).

The number of recorded tornado events has increased, in general, since detailed records were routinely documented beginning around 1950. However, some of this increase is attributable to a growing population, greater public awareness and interest, and technological advances in detection. These changes are superimposed on normal year-to-year variations. Consequently, the number of observations recorded within a 2-degree latitude and longitude square centered on the VEGP site reflect these effects.

As the frequency distribution in Subsection 2.3.1.3.2 indicates, the most intense tornado recorded in this study area was classified as an “F4” storm. The event occurred in 1973 and is the only tornado classified as such based on the nearly 55-year period of record evaluated. All of the tornadoes classified as “F3” storms (a total of 18) were recorded since 1972. Tornadoes with lower intensity classifications are much more numerous and have been identified throughout the available period of record (Reference 224).

The occurrence of all tropical cyclones within a 100-nautical mile radius of the VEGP site has been fairly steady since about 1950 when considered on a decadal (i.e., 10-year) basis or in terms of 30-year intervals similar to the “normal” periods used to evaluate temperature and rainfall data. Both the frequency and intensity of hurricanes passing within 100 nautical miles of the site have generally decreased over the available 154-year period of record, reaching a peak more than a hundred years ago around the turn of the last century. The frequency of tropical depressions has shown some increase in the last 30 years – storms of this classification have been associated with many of the 24-hour and monthly total rainfall records identified in Table 2.3-205 and discussed in Subsection 2.3.1.3.3 (Reference 228).

Nevertheless, the regulatory guidance for evaluating the climatological characteristics of a site from a design basis standpoint is not event specific, but rather is statistically based and for several parameters includes expected return periods of 100 years or more and probable maximum event concepts. These return periods exceed the design life of the proposed units. The design-basis characteristics determined previously under Subsection 2.3.1.3 are developed consistent with the intent of that guidance and incorporate the readily-available, historical data records for locations

considered to be representative of the site for VEGP Units 3 and 4. These site characteristic values are summarized and compared in Table 2.0-203, *Site Characteristics, Design Parameters, and Site Interface Values*.

2.3.2 Local Meteorology

The potential influence of the construction and operation of VEGP Units 3 and 4 are evaluated using meteorological data representative of local conditions as described below.

2.3.2.1 Data Sources

The primary sources of data used to characterize local meteorological and climatological conditions representative of the VEGP site include summaries for the first-order NWS station at Augusta, Georgia (Bush Field) and nine other nearby cooperative network observing stations, and measurements from the existing VEGP onsite meteorological monitoring program. Table 2.3-203 identifies the offsite observing stations and provides the approximate distance and relative direction of each station to the VEGP site; their locations are shown in Figure 2.3-201. The onsite meteorological tower is located about 1 mi south-southwest of the Units 1 and 2 Containment Buildings and about 0.9 mi south of VEGP Units 3 and 4 as shown on Figure 1.1-202.

The NWS and cooperative observing station summaries were used to characterize climatological normals, period-of-record means, and extremes of temperature, rainfall, and snowfall in the vicinity of the VEGP site. In addition, first-order NWS stations also record measurements, typically on an hourly basis, of other weather elements, including winds, relative humidity, dew point, and wet-bulb temperatures, as well as other observations (e.g., fog, thunderstorms). This information was based on the following resources:

- *2004 Local Climatological Data, Annual Summary with Comparative Data for Augusta, Georgia* (Reference 221)
- *Climatography of the United States, No. 20, 1971-2000, Monthly Station Climate Summaries* (Reference 222)
- *Climatography of the United States, No. 81, 1971-2000, U.S. Monthly Climate Normals* (Reference 211)
- *SERCC, Historical Climate Summaries and Normals for the Southeast* (Reference 230)
- *Cooperative Summary of the Day, TD3200, Period of Record through 2001 for the Eastern United States, Puerto Rico and the Virgin Islands* (Reference 213)

Wind speed, wind direction, and atmospheric stability data based on the VEGP meteorological monitoring program form the basis for determining and characterizing atmospheric dispersion conditions in the vicinity of the site. These data include measurements taken over the 5-year period of record from 1998 through 2002.

2.3.2.2 Normal, Mean, and Extreme Values of Meteorological Parameters

Historical extremes of temperature, rainfall, and snowfall are listed in Table 2.3-205 for the 10 NWS and cooperative observing stations in the VEGP site area. The normals, means, and extremes of the more extensive set of measurements and observations made at the Augusta NWS Station are summarized in Table 2.3-204. Finally, Table 2.3-207 compares the annual normal (i.e., 30-year average) daily maximum, minimum, and mean temperatures, as well as the normal annual rainfall and snowfall totals for these stations.

2.3.2.2.1 Wind

Average Wind Direction and Wind Speed Conditions

The distribution of wind direction and wind speed is an important consideration when characterizing the dispersion climatology of a site. Long-term average wind motions at the macro- and synoptic scales (i.e., on the order of several thousand down to several hundred kilometers) are influenced by the general circulation patterns of the atmosphere at the macro-scale and by large-scale topographic features (e.g., mountain ranges, land-water interfaces such as coastal areas). These characteristics are addressed in Subsection 2.3.1.2.

Site-specific or micro-scale (i.e., on the order of 2 km or less) wind conditions, while reflecting these larger-scale circulation effects, are influenced primarily by local and, to a lesser extent (generally), by meso- or regional-scale (i.e., up to about 200 km) topographic features. Wind measurements at these smaller scales are available from the existing meteorological monitoring program at the VEGP site and from data recorded at the nearby Augusta NWS Station.

Subsection 2.3.3 provides a summary description of the onsite meteorological monitoring program at the VEGP site. In its current configuration, wind direction and wind speed measurements are made at two levels on an instrumented 60-m tower (i.e., the lower level at 10 m and the upper level at 60 m).

Figures 2.3-202 through 2.3-206 present annual and seasonal wind rose plots (i.e., graphical distributions of the direction from which the wind is blowing and wind speeds for each of sixteen 22.5-degree compass sectors centered on north, north-northeast, northeast, etc.) for the 10-m level based on measurements at the VEGP site over the composite 5-year period from 1998 through 2002.

For the VEGP site, the wind direction distribution at the 10-m level generally follows a southwest-northeast orientation on an annual basis (see Figure 2.3-202). The prevailing wind (i.e., defined as the direction from which the wind blows most often) is from the southwest, with nearly 25 percent of the winds blowing from the southwest through west sectors. Conversely, winds from the northeast through east sectors occur about 20 percent of the time. On a seasonal basis, winds from the southwest quadrant predominate during the spring and summer months (see Figures 2.3-204 and 2.3-205). This is also the case during the winter, although westerly winds prevail and the relative frequency of west-northwest winds during this season is greater (see Figure 2.3-203) due to increased cold frontal passages. Winds from the northeast quadrant predominate during the autumn months (see Figure 2.3-206). Plots of individual monthly wind roses at the 10-m measurement level are presented in Figure 2.3-207 (Sheets 1 to 12).

Wind rose plots based on measurements at the 60-m level are shown in Figures 2.3-208 through 2.3-213. By comparison, wind direction distributions for the 60-m level are fairly similar to the 10-m level wind roses on a composite annual (see Figure 2.3-208) and seasonal basis (see Figures 2.3-209 through 2.3-212). Plots of individual monthly wind roses at the 60-m measurement level are presented in Figure 2.3-213 (Sheets 1 to 12).

Wind information summarized in the LCD for the Augusta NWS Station (see Table 2.3-204) indicates a prevailing west-southwesterly wind direction (Reference 221) that appears to be similar to the 10-m level wind flow at the VEGP site, at least on an annual basis (see Figure 2.3-202).

Table 2.3-208 summarizes seasonal and annual mean wind speeds based on measurements from the upper and lower levels of the existing VEGP site meteorological tower (1998–2002) and from wind instrumentation at the Augusta NWS Station (1971–2000 station normals) (Reference 221). The elevation of the wind instruments at the Augusta NWS Station is nominally 20 ft (about 6.1 m) (Reference 221), comparable to the lower (10-m) level measurements at the VEGP site.

On an annual basis, mean wind speeds at the 10- and 60-m levels are 2.5 m/sec and 4.6 m/sec, respectively, at the VEGP site. The annual mean wind speed at Augusta (i.e., 2.7 m/sec) is similar to the 10-m level at the VEGP site, differing by only 0.2 m/sec; seasonal average wind speeds at Augusta are likewise slightly higher. Seasonal mean wind speeds for both measurement levels at the VEGP site follow the same pattern discussed in Subsection 2.3.1.6 for Augusta and Athens, Georgia, and their relationship to the seasonal variation of relatively higher air stagnation and restrictive dispersion conditions in the site region.

Based on the joint frequency distributions of wind speed and wind direction by atmospheric stability class (see Subsection 2.3.2.2.2), the annual frequencies of calm wind conditions are 0.35 and 0.05 percent of the time for the 10-m and 60-m tower levels, respectively, at the VEGP site.

Wind Direction Persistence

Wind direction persistence is a relative indicator of the duration of atmospheric transport from a specific sector-width to a corresponding downwind sector-width that is 180 degrees opposite. Atmospheric dilution is directly proportional to the wind speed (other factors remaining constant). When combined with wind speed, a wind direction persistence/wind speed distribution further indicates the downwind sectors with relatively more or less dilution potential (i.e., higher or lower wind speeds, respectively) associated with a given transport wind direction.

Tables 2.3-207 and 2.3-208 present wind direction persistence/wind speed distributions based on measurements at the VEGP site for the 5-year period of record from 1998 through 2002. The distributions account for durations ranging from 1 to 48 hours for wind directions from 22.5-degree and 67.5-degree upwind sectors centered on each of the 16 standard compass radials (i.e., north, north-northeast, northeast, etc.). Further, the distributions are provided for wind measurements made at the lower (10-m) and the upper (60-m) tower levels, respectively.

2.3.2.2.2 Atmospheric Stability

Atmospheric stability is a relative indicator for the potential diffusion of pollutants released into the ambient air. Atmospheric stability, as discussed in this SSAR, is determined by the delta-temperature ($\Delta\mathbf{T}$) method as defined in Table 1 of Proposed Revision 1 to Regulatory Guide 1.23, *Meteorological Programs in Support of Nuclear Power Plants,* September 1980.

The approach classifies stability based on the temperature change with height (i.e., the difference in °C per 100 m). Stability classifications are assigned according to the following criteria:

- Extremely Unstable (Class A) —$\Delta\mathbf{T}/\Delta\mathbf{Z} \leq$ -1.9°C
- Moderately Unstable (Class B) — -1.9°C < $\Delta\mathbf{T}/\Delta\mathbf{Z} \leq$ -1.7°C
- Slightly Unstable (Class C) — -1.7°C < $\Delta\mathbf{T}/\Delta\mathbf{Z} \leq$ -1.5°C
- Neutral Stability (Class D) — -1.5°C < $\Delta\mathbf{T}/\Delta\mathbf{Z} \leq$ -0.5°C
- Slightly Stable (Class E) — -0.5°C < $\Delta\mathbf{T}/\Delta\mathbf{Z} \leq$ +1.5°C
- Moderately Stable (Class F) — +1.5°C < $\Delta\mathbf{T}/\Delta\mathbf{Z} \leq$ +4.0°C
- Extremely Stable (Class G) — +4.0°C < $\Delta\mathbf{T}/\Delta\mathbf{Z}$

The diffusion capacity is greatest for extremely unstable conditions and decreases progressively through the remaining unstable, neutral stability, and stable classifications.

During the 1998 through 2002 time period at the VEGP site, $\Delta\mathbf{T}$ was determined from the difference between temperature measurements made at the 10-m and 60-m tower levels. Seasonal and annual frequencies of atmospheric stability class and associated 10-m level mean wind speeds for this period of record are presented in Table 2.3-211.

The data indicate a predominance of slightly stable (Class E) and neutral stability (Class D) conditions, ranging from about 50 to 60 percent of the time on a seasonal and annual basis. Extremely unstable conditions (Class A) are more frequent during the spring and summer months due to greater solar insolation. Extremely stable conditions (Class G) are most frequent during the fall and winter months, owing in part to increased radiational cooling at night.

Joint frequency distributions (JFDs) of wind speed and wind direction by atmospheric stability class and for all stability classes combined for the 10-m and 60-m wind measurement levels at the VEGP site are presented in Tables 2.3-210 and 2.3-211, respectively, for the 5-year period of record from 1998 through 2002. The 10-m level JFDs are used to evaluate short-term dispersion estimates for accidental atmospheric releases (see Subsection 2.3.4) and long-term diffusion estimates of routine releases (see Subsection 2.3.5).

2.3.2.2.3 Temperature

Extreme maximum temperatures recorded in the vicinity of the VEGP site have ranged from 105°F to 112°F, with the highest reading observed at the Louisville 1E Station on July 24, 1952. The station record high temperature for the Midville Experiment Station (i.e., 105°F) has been reached on four separate occasions. As Table 2.3-205 shows, individual station extreme maximum temperature records were set at multiple locations on the same or adjacent dates (i.e., Waynesboro 2NE, Louisville 1E, and Millen 4N; Augusta, Midville Experiment Station, and Aiken 4NE; and Waynesboro 2NE, Midville Experiment Station, and Newington 2NE) (Reference 222; Reference 230).

Extreme minimum temperatures in the vicinity of the VEGP site have ranged from 2°F to -4°F, with the lowest reading on record observed at the Aiken 4NE Station on January 21, 1985, the same date on which the record low temperature was set at the nine other nearby stations (Reference 222; Reference 230).

The extreme maximum and minimum temperature data indicate that synoptic-scale conditions responsible for periods of record-setting excessive heat as well as significant cold air outbreaks tend to affect the overall VEGP site area. The similarity of the respective extremes suggests that these statistics are reasonably representative of the temperature extremes that might be expected to be observed at the VEGP site.

Daily mean temperatures (which are based on the average of the daily mean maximum and minimum temperature values) for these stations are similar, ranging from 63.1°F at Waynesboro 2NE to 65.0°F at the Midville Experiment Station (Reference 211). Likewise, the diurnal (day-to-night) temperature ranges, as indicated by the differences between the daily mean maximum and minimum temperatures, are fairly comparable, ranging from 21.9°F at Bamberg to 26.3°F at Aiken 4NE (Reference 211).

2.3.2.2.4 Water Vapor

Based on a 49-year period of record, the LCD summary for the Augusta, Georgia NWS Station (see Table 2.3-204) indicates that the mean annual wet-bulb temperature is 56.7°F, with a seasonal maximum during the summer months (June through August) and a seasonal minimum during the winter months (December through February). The highest monthly mean wet-bulb temperature is 72.7°F in July (only slightly less during August); the lowest monthly mean value (40.3°F) occurs

during January. (Reference 221) Wet-bulb temperature characteristics are addressed in Subsection 2.3.1.5 from a design-basis standpoint.

The LCD summary shows a mean annual dew point temperature of 51.9°F, also reaching its seasonal maximum and minimum during the summer and winter, respectively. The highest monthly mean dew point temperature is 69.7°F in July; again, only slightly less during August. The lowest monthly mean dew point temperature (34.4°F) occurs during January. (Reference 221)

The 30-year normal daily relative humidity averages 72 percent on an annual basis, typically reaching its diurnal maximum in the early morning (around 0700 hours) and its diurnal minimum during the early afternoon (around 1300 hours). There is less variability in this day-to-night pattern with the passage of weather systems, persistent cloud cover, and precipitation. Nevertheless, this diurnal pattern is evident throughout the year. The LCD summary shows that average early morning relative humidity levels exceed 90 percent during August, September, and October. (Reference 221)

2.3.2.2.5 Precipitation

With the exception of the Aiken 4NE Station, normal annual rainfall totals are similar for the nine other nearby observing stations listed in Table 2.3-207, differing by only about 4.7 in. (or about 10 percent) and ranging from 43.85 to 48.57 in. The current 30-year average for the Aiken 4NE Station is somewhat higher at 52.43 in. Snowfall is an infrequent occurrence, as discussed in Subsection 2.3.1, with normal annual totals of only 0.1 to 1.4 in. (References 211, 222; 230).

2.3.2.2.6 Fog

The closest station to the VEGP site at which observations of fog are made and routinely recorded is the Augusta NWS Station about 20 mi to the northwest. The 2004 LCD summary for this station (Table 2.3-204) indicates an average of 35.1 days per year of heavy fog conditions based on a 54-year period of record. The NWS defines heavy fog as fog that reduces visibility to 1/4 mi or less.

The frequency of fog conditions at the VEGP site would be expected to be similar to that of Augusta because of their proximity to one another and because of the similarity of topographic features at both locations (i.e., gently rolling terrain, adjacent to the Savannah River, and location within that broad river valley).

2.3.2.3 Potential Influence of the Plant and Related Facilities on Meteorology

The dimensions and operating characteristics of VEGP Units 3 and 4 and existing VEGP Units 1 and 2 facilities and the associated paved, concrete, or other improved surfaces are considered to be insufficient to generate discernible, long-term effects to local- or micro-scale meteorological conditions.

Wind flow may be altered in areas immediately adjacent to and downwind of larger site structures. However, these effects will likely dissipate within ten structure heights downwind of the intervening structure(s). Similarly, while ambient temperatures immediately above any improved surfaces could increase, these temperature effects will be too limited in their vertical profile and horizontal extent to alter local- or regional-scale ambient temperature patterns.

Units 1 and 2 at the VEGP site use two 550-ft-high natural-draft cooling towers as a means of heat dissipation. Depending on local meteorological conditions, plume rise ranges from 500 to 1,000 ft above those 550-ft-high towers. Because of the elevated release point and plume rise, there is minimal effect on local meteorology or the plant.

Two 600-ft-high natural-draft cooling towers provide cooling for VEGP Units 3 and 4. Because the release height of the thermal/water vapor plumes from these cooling towers is even higher than that of the VEGP Units 1 and 2 cooling towers, minimal effect on local meteorology or the plant is expected.

While there is excavation, landscaping, site leveling, and clearing associated with the construction of the new units, these alterations to the site terrain would be localized and would not represent a significant alteration to the flat-to-gently-rolling topographic character of the area and region around the site. Therefore, the overall meteorological characteristics of the site will not be affected.

2.3.2.4 Current and Projected Site Air Quality

The VEGP site is located within the Augusta (Georgia) – Aiken (South Carolina) Interstate Air Quality Control Region (40 CFR 81.114). The counties within this region are designated as being in attainment or unclassified for all criteria air pollutants (40 CFR 81.311; 40 CFR 81.341). Attainment areas are areas where the ambient air quality levels are better than the EPA-promulgated National Ambient Air Quality Standards (NAAQS). Criteria pollutants are those for which NAAQS have been established: sulfur dioxide, particulate matter (i.e., PM_{10} and $PM_{2.5}$ – particles with nominal aerodynamic diameters less than or equal to 10.0 and 2.5 micons, respectively), carbon monoxide, nitrogen dioxide, ozone, and lead (40 CFR Part 50).

Four pristine areas in the States of Georgia and South Carolina are designated as “Mandatory Class I Federal Areas Where Visibility is an Important Value.” They include the Cohutta Wilderness Area, the Okefenokee Wilderness Area, and the Wolf Island Wilderness Area in Georgia (40 CFR 81.408), and the Cape Romain Wilderness Area in South Carolina (40 CFR 81.426). The two closest of these Class I areas are both about 130 mi away from the VEGP site—the Wolf Island Wilderness Area to the south-southeast and the Cape Romain Wilderness Area to the east-southeast.

The nuclear steam supply system and other related radiological systems are not sources of criteria pollutants or other air toxics. Supporting equipment (e.g., diesel generators, fire pump engines) and other non-radiological emission-generating sources (e.g., storage tanks and related equipment) or activities are not a significant source of criteria pollutant emissions.

Emergency equipment is only operated on an intermittent test or emergency-use basis. Therefore, these emission sources are not expected to significantly impact ambient air quality levels in the vicinity of the VEGP site, nor be a significant factor in the design and operating bases of VEGP Units 3 and 4. Likewise, because of the relatively long distance of separation from the VEGP site, visibility at any of these Class I Federal Areas are not significantly impacted by project construction and facility operations.

Nevertheless, these non-radiological emission sources are regulated by the Georgia Department of Natural Resources (DNR) under the Georgia Rules for Air Quality Control (Chapter 391-3-1) and permitted under the State’s Title V Operating Permit Program implemented by the Georgia DNR pursuant to 40 CFR Part 70 either as a separate facility or via a revision to the then current Title V Operating Permit for the existing VEGP site.

2.3.2.5 Topographic Description

The VEGP site (approximately 3,169 acres) is located in Burke County, Georgia, along (west of) the Savannah River. Topographic features within a 5-mi radius of the VEGP site are shown in Figure 2.3-214. Terrain elevation profiles along each of the 16 standard 22.5-degree compass radials out to a distance of 50 mi from the VEGP site are illustrated in Figure 2.3-215 (Sheets 1 through 4).

These profiles indicate that the terrain in the VEGP site area is flat to gently rolling. The only other nearby topographic feature of note is the Savannah River, located adjacent to the VEGP site; the broad river valley represents a depression running northwest to southeast.

2.3.3 Onsite Meteorological Measurements Program

2.3.3.1 Onsite Meteorological Measurements Program

SNC uses measurement data from the VEGP onsite meteorological monitoring program to support operation of VEGP Units 3 and 4.

2.3.3.2 General Program Description

The VEGP onsite meteorological measurements program commenced operation in April 1972. Instruments for measuring pertinent meteorological parameters were installed on a 45-m tower located in a cleared area at site coordinates N 3260 and E 8040. This location is about 3,840 ft (1,170 m) south of the 775-ft-radius circle that encloses the VEGP Units 3 and 4 power block area (see Figure 1.1-202 for general location). The base of the tower is at approximately plant grade.

The onsite meteorological measurements program and equipment were updated in the first quarter of 1984 to meet the intent of NUREG-0654 (*Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,* FEMA-REP-1, Revision 1, November 1980). A new meteorological data collection center (MDCC) included a 60-m tower located at site coordinates N 3100 and E 7940 with permanent instrumentation at the 10- and 60-m elevations. The 60-m tower is located about 3,960 ft (1,207 m) south of the 775-ft-radius circle that encloses the VEGP Units 3 and 4 power block area (see Figure 1.1-202 for general location). A 2-kVA uninterruptible power supply was also installed to prevent the loss of meteorological data collection in the event that offsite power is interrupted.

The onsite meteorological measurements program and equipment were upgraded in the second quarter of 2015 to replace obsolete equipment and to improve data recovery values. The upgrade replaced the 60-m tower's existing 10-m and 60-m instruments with redundant instruments providing primary and secondary (backup) data. The use of the backup 45-m tower and its instruments was discontinued. Table 2.3-214 presents instrument descriptions and accuracies for the meteorological monitoring systems. Measurement system accuracies are in conformance with Regulatory Guide 1.23.

The instruments are monitored at least once a week by SNC personnel. Preventive maintenance is performed by SNC personnel in accordance with the instrument manuals and is intended to maintain 90 percent data recovery.

Data collection for the MDCC consists of redundant data loggers and workstations, both located in the meteorological tower equipment building. These data are transmitted via redundant fiber optic cables. The fiber optic cables provide instrument data to the Control Rooms for Units 1, 2, 3 and 4, Technical Support Center, and Emergency Operations Facility. The collected data are compiled in accordance with Regulatory Guide 1.23 and are summarized and edited to provide averages representative of each hour of measurements.

The annual and/or seasonal summaries of onsite meteorological data presented in this section are based on hourly-averaged measurements from instrumentation mounted on the 60-m tower taken over the 5-year period of record from 1998 through 2002. These data were used to determine the wind roses and joint frequency distributions of wind speed and wind direction by atmospheric stability class presented and discussed in Subsection 2.3.2.

A year-by-year summary of the percent data recoveries for each parameter is shown in Table 2.3-215. Composite data recoveries of 94 percent or greater were achieved in each of those 5 years for the dispersion modeling-related parameters of wind speed and wind direction from the 10-m and 60-m levels, and vertical stability based on the delta-temperature between the 60-m and 10-m levels. The only parameters with annual data recoveries less than the 90 percent target recovery level are dew point temperature (i.e., 89.6 percent) and rainfall (i.e., 78.8 percent) during 2002.

2.3.3.3 Location, Elevation, and Exposure of Instruments

The general location of the meteorological tower is shown in Figure 1.1-202.

The nearest major structures are VEGP Units 3 and 4 reactors and their associated natural-draft cooling towers located, respectively, about 4,525 ft (mid-point between the two units) and about 3,025 ft (closest point on the Unit 3 cooling tower) to the north of the meteorological tower. Regulatory Guide 1.23 indicates that a meteorological tower located at 10-building-heights horizontal distance downwind will not have adverse building wake effects exerted by the structure. Since the height of the AP1000 units is about 234 ft above grade, the zone of turbulent flow created by the reactor buildings is limited to about 2,340 ft (or 10 building heights) downwind. Thus, the reactors do not adversely affect the measurements taken at the meteorological tower.

The 10-building-height distance of separation guidance is usually applied to square- or rectangular-shaped structures or objects. A round structure will produce a downwind wake zone that is shorter than a square or rectangular structure or object. The downwind region of adverse influence of a hyperbolically-shaped, natural-draft cooling tower is estimated to be about five times the width of the tower at the top of the structure (Reference 207).

The natural-draft cooling towers are about 600 ft high, with a base diameter of 550 ft, and a diameter of 330 ft at the top. Based on the EPA guidance for this type of structure and the diameter at its top, the outermost boundary of influence that is exerted by the cooling towers is estimated to be about 1,650 ft. This distance is much shorter than the physical separation of the cooling towers from the meteorological tower (i.e., about 3,025 ft). Therefore, the natural-draft cooling towers do not adversely affect measurements made at the meteorological tower. Similarly, minor structures in the vicinity of the meteorological tower have been evaluated as having no adverse effect on the measurements taken at that tower.

2.3.3.4 VEGP Meteorological Monitoring Program Compliance

The meteorological monitoring program operated in support of VEGP Units 1 and 2 will also support the operation of VEGP Units 3 and 4. Characteristics of this monitoring program, include:

- siting of the meteorological tower with respect to potential obstructions to air flow (e.g., containment structures, cooling towers, tree lines),
- descriptions of the meteorological instrumentation (e.g., performance specifications, methods and equipment for recording sensor output, QA program for sensors and recorders, and data acquisition and reduction procedures), and
- operation, maintenance, and calibration procedures.

The NRC evaluated the meteorological monitoring program as part of the ESPA SSAR safety evaluation site audit on December 6, 2006 and through their review of Subsection 2.3.3.

The current monitoring program and its implementation were determined to meet the guidance in Proposed Revision 1 to Regulatory Guide 1.23 and found to provide an acceptable basis for

estimating atmospheric dispersion conditions for accidental and routine releases of radioactive material to the atmosphere.

2.3.4 Short-Term (Accident) Diffusion Estimates

In the absence of a specific site for use in determining values for short-term diffusion, a study was performed to determine the atmospheric dispersion factors (χ/Q values) that would envelope most current plant sites and that could be used to calculate the radiological consequences of design basis accidents. The χ/Q values thus derived for offsite are provided in Table 2.0-201.

This set of offsite χ/Q values is representative of potential sites for construction of the AP1000. The values are appropriate for analyses to determine the radiological consequences of accidents. These values were selected to bound 70 to 80 percent of U.S. sites.

The χ/Q values for the control room air intake or the door leading to the control room are dependent not only on the site meteorology but also on the plant design and layout. These χ/Q values are addressed in Appendix 15A. Separate sets of χ/Q values are identified for each combination of activity release location and receptor location.

This subsection addresses the determination of conservative, short-term atmospheric dispersion estimates due to postulated design-basis, accidental releases of radioactive material to the ambient air for receptors located:

- on the Exclusion Area Boundary (EAB) and the outer boundary of the Low Population Zone (LPZ) (Subsections 2.3.4.1 and 2.3.4.2) to support the evaluation of offsite radiological consequences; and

- at air intake points to the control room (Subsection 2.3.4.3) to support the evaluation of personnel exposures inside the control room and the design of the control room habitability system.

This subsection also briefly addresses the determination of accident-related concentrations at the control room due to onsite and/or offsite airborne releases of hazardous materials such as flammable vapor clouds, toxic chemicals, and smoke from fires (Subsection 2.3.4.4).

In the AP1000 reactor DCD, the terms “site boundary” and “exclusion area boundary” are used interchangeably. Thus, the χ/Q value specified for the site boundary applies whenever a discussion in the DCD refers to the exclusion area boundary. In the Subsections 2.3.4.1 and 2.3.4.2 site specific χ/Q calculations, the term “Dose Calculation EAB” is equivalent to the DCD term “EAB”.

Short-term, dispersion-related site parameters at the site boundary and the LPZ boundary, on which the AP1000 design is based, are identified in DCD Tier 1, Table 5.0-1, Table 2.0-201, and Table 15A-5. As indicated above, site-specific dispersion characteristics that correspond to these site parameters are presented in Subsections 2.3.4.1 and 2.3.4.2.

Short-term, dispersion-related site parameters at the control room, also incorporated in the AP1000 design, are identified in DCD Tier 1, Table 5.0-1, Table 2.0-201, and Table 15A-6. Site-specific dispersion characteristics that correspond to these site parameters are presented in Subsection 2.3.4.3.

Tables 2.0-201 and 2.0-202 compare the applicable site parameters and corresponding site-specific characteristic values.

2.3.4.1 Basis

To evaluate potential health effects for Westinghouse AP1000 design-basis accidents, a hypothetical accident is postulated to predict upper-limit concentrations and doses that might occur in the event of a containment release to the atmosphere.

Regulatory Guide 4.7, *General Site Suitability Criteria for Nuclear Power Stations*, Revision 2, April 1998, states that for site approval, each applicant should collect at least 1 year of meteorological information that is representative of the site conditions for calculating radiation doses resulting from the release of fission products as a consequence of a postulated accident. Site-specific meteorological data covering the 5-year period of record from 1998 through 2002 (see Subsection 2.3.2.2.2) have been used to quantitatively evaluate such a hypothetical accident at the VEGP site. Onsite data provide representative measurements of local dispersion conditions appropriate to the VEGP site and a 5-year period is considered to be reasonably representative of long-term conditions.

According to 10 CFR Part 100, it is necessary to consider the doses for various time periods immediately following the onset of a postulated containment release at the exclusion distance and for the duration of exposure for the low population zone and population center distances. The relative air concentrations (χ/Qs) are estimated for various time periods ranging from 2 hours to 30 days.

Meteorological data have been used to determine various postulated accident conditions as specified in Regulatory Guide 1.145, *Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants*, Revision 1, November 1982 (Re-issued February 1983). Compared to an elevated release, a ground-level release usually results in higher ground-level concentrations at downwind receptors due to less dilution from shorter traveling distances. Since the ground-level release scenario provides a bounding case, elevated releases are not considered in this ESP application.

The NRC-sponsored PAVAN computer code (NUREG/CR-2858, *PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations*, PNL-4413, November 1982 [NUREG/CR-2858]) has been used to estimate ground-level χ/Qs at the Exclusion Area Boundary (EAB) and Low Population Zone (LPZ) for potential accidental releases of radioactive material to the atmosphere. Such an assessment is required by 10 CFR Part 100.

As discussed in Subsection 2.1.1.3, the EAB for VEGP Units 3 and 4 is the same as the exclusion area for the existing VEGP units. For the purposes of determining χ/Qs and subsequent radiation dose analyses, an effective EAB, hereafter referred to as the Dose Calculation EAB, was developed for the proposed units. The AP1000 units will be located within the power block area, shown in Figure 1.1-202, which is the perimeter of a 775-ft-radius circle with the centroid at a point between the two AP1000 units. The Dose Calculation EAB is a circle that extends 1/2 mi beyond the power block area (i.e., a circle with a 3,415-ft radius with its centroid at the centroid of the power block circle). The Dose Calculation EAB is completely within the actual plant EAB and, thus, the χ/Qs and the subsequent radiation doses are conservatively higher.

The PAVAN program implements the guidance provided in Regulatory Guide 1.145. Mainly, the code computes χ/Qs at the EAB and LPZ for each combination of wind speed and atmospheric stability class for each of 16 downwind direction sectors (i.e., north, north-northeast, northeast, etc.). The χ/Q values calculated for each direction sector are then ranked in descending order, and an associated cumulative frequency distribution is derived based on the frequency distribution of wind speeds and stabilities for the complementary upwind direction sector. The χ/Q value that is equaled or exceeded 0.5 percent of the total time becomes the maximum sector-dependent χ/Q value.

The χ/Q values calculated above are also ranked independently of wind direction into a cumulative frequency distribution for the entire site. The PAVAN program then selects the χ/Qs that are equaled or exceeded 5 percent of the total time.

The larger of the two values (i.e., the maximum sector-dependent 0.5 percent χ/Q or the overall site 5 percent χ/Q value) is used to represent the χ/Q value for a 0- to 2-hour time period. To determine χ/Qs for longer time periods, the program calculates an annual average χ/Q value using the procedure described in Regulatory Guide 1.111, *Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors*, Revision 1, July 1977. The program then uses logarithmic interpolation between the 0- to 2-hour χ/Qs for each sector and the corresponding annual average χ/Qs to calculate the values for intermediate time periods (i.e., 8 hours, 16 hours, 72 hours, and 624 hours). As suggested in NUREG/CR-2858, each of the sector-specific 0- to 2-hour χ/Qs provided in the PAVAN output file has been examined for "reasonability" by comparing them with the ordered χ/Qs also presented in the model output.

The PAVAN model has been configured to calculate offsite χ/Q values assuming both wake-credit allowed and wake-credit not allowed. The entire Dose Calculation EAB is located beyond the wake influence zone induced by the Reactor Building. And, because the LPZ is located farther away from the plant site than the Dose Calculation EAB (i.e., a 2-mi-radius [3,218 m] circle centered at the midpoint of the existing reactors bounds the LPZ), the "wake-credit not allowed" scenario of the PAVAN results has been used for the χ/Q analyses at both the Dose Calculation EAB and the LPZ.

The PAVAN model input data are presented below:

- Meteorological data: 5-year (January 1, 1998 to December 31, 2002) composite onsite JFD of wind speed, wind direction, and atmospheric stability.
- Type of release: Ground-level.
- Wind sensor height: 10 m.
- Vertical temperature difference: (10 m-60 m).
- Number of wind speed categories: 11.
- Release height: 10 m (default height).
- Distances from release point to Dose Calculation EAB: 800 m, for all downwind sectors.
- Distances from release point to LPZ: 2,304 m, for all downwind sectors.

The PAVAN model uses building cross-sectional area and containment height to estimate wake-related χ/Q values. Since the Dose Calculation EAB and the LPZ are both located beyond the building wake influence zone, these two input parameters have no effect in calculating the non-wake χ/Q values.

To be conservative, the 1/2 mi (or approximately 800 m) distance between the VEGP Units 3 and 4 power block area circle and the Dose Calculation EAB has been entered as input for each downwind sector to calculate the χ/Q values at the Dose Calculation EAB. Similarly, the shortest distance from the power block area circle to the LPZ has been input for all direction sectors to calculate the χ/Q values at the LPZ. The distance from the center-point of the existing units to the western perimeter of the power block area is about 914 m. Therefore, the minimum distance from the power block area circle to the LPZ is about 2,304 m (or about 1.4 mi).

2.3.4.2 PAVAN Modeling Results

As presented in Table 2.3-216, the maximum 0- to 2-hour, 0.5 percentile, direction-dependent χ/Q value (3.14×10^{-4} sec/m^3) is less than the corresponding 5 percentile overall site χ/Q value (3.49×10^{-4} sec/m^3) at the Dose Calculation EAB. Therefore, the 5 percentile overall site χ/Qs should be used as the proper χ/Qs at the Dose Calculation EAB.

Similarly, Table 2.3-217 shows that the maximum 0- to 2-hour, 0.5 percentile, direction-dependent χ/Q value (1.17×10^{-4} sec/m^3) is less than the corresponding 5 percentile overall site χ/Q value (1.27×10^{-4} sec/m^3) at the LPZ. Therefore, the 5 percentile overall site χ/Qs should be used as the proper χ/Qs at the LPZ.

The maximum χ/Qs presented in Tables 2.3-214 and 2.3-215 for the Dose Calculation EAB and the LPZ, respectively, are summarized below for the 0- to 2-hour time period, the annual average time period, and other intermediate time intervals evaluated by the PAVAN model.

Summary of PAVAN χ/Q Results (5% Limiting Case), 1998–2002 Meteorological Data

Source Location	Receptor Location	0-2 hr (Dir, Dist)	0-8 hr (Dir, Dist)	8-24 hr (Dir, Dist)	1-4 days (Dir, Dist)	4-30 days (Dir, Dist)	Annual (Dir, Dist)
ESP PBAC[(a)]	Dose Calculation EAB	3.49E-04	2.41E-04	2.00E-04	1.34E-04	7.56E-05	3.74E-05
ESP PBAC[a]	LPZ	1.27E-04 [(b)]	7.04E-05	5.25E-05	2.77E-05	1.11E-05	3.63E-06

(a) PBAC = Power Block Area Circle
(b) The 0-2 hour χ/Q values are reported here for reference only (not required based on Regulatory Guide 1.145).

Using the same assumptions and methodology as described in Subsection 2.3.4.1 (which relied on DCD Revision 15), the short-term (accidental release) dispersion estimates at the EAB and the LPZ boundary were evaluated using the revised building dimensions provided in DCD Revision 17. That evaluation confirmed that the χ/Q values for the EAB and LPZ remain the same. This result is reasonable given that the designated receptor points at the EAB and the LPZ boundary are beyond the distance that would be influenced by building wake.

2.3.4.3 Radiological Accident Dispersion Estimates at the Control Room

Subsection 2.3.4.3.1 describes the dispersion modeling analysis used to determine short-term, relative concentration estimates associated with a postulated design-basis, accidental release of radioactive material to the atmosphere. The results of this dispersion analysis for receptors at air intake points to the control room are summarized in Subsection 2.3.4.3.2.

2.3.4.3.1 Regulatory Basis and Technical Approach

General Design Criterion 19 (*Control Room*) under 10 CFR Part 50, Appendix A, requires that the control room remain functional so that actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain the plant in a safe state under accident conditions.

Regulatory Guide 1.194, *Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants*, June 2003, provides guidance on utilizing the ARCON96 dispersion model to characterize atmospheric dispersion conditions (χ/Q values) that are input to the evaluation of the consequences of accidental airborne radiological releases on control room habitability. The ARCON96 dispersion model is described in NUREG/CR-6331 (*Atmospheric Relative Concentrations in Building Wakes*, PNNL-10521, Revision 1, May 1997). [Reference 201]

Five consecutive calendar years (from 1998 through 2002) of sequential hourly meteorological data, from the onsite monitoring program operated in support of VEGP Units 1 & 2, were input to ARCON96 in model-required format. As such, the estimated χ/Q values represent the composite 5-year period of record. Wind data from both the 10- and 60-m measurement levels were included. Wind speed units of measure were in meters per second.

Joint data recovery of atmospheric stability class and 10-m level wind speed and wind direction was greater than 94 percent for each of the five years. Data recoveries for 60-m level wind data exceeded 95 percent for wind speed during each year, and ranged from about 93 to 97 percent for wind direction for all years except 1998 (at slightly more than 88 percent). Subsections 2.3.2 and 2.3.3 establish that these data are representative of site dispersion characteristics.

χ/Q values were estimated at two air intake points leading to the control room—at the Heating Ventilation and Air Conditioning (HVAC) system intake and at the annex building access door (i.e., the pathway for outside air to the control room is that due to building ingress/egress). These two air intake points, designated as Receptors 1 and 2, respectively, are illustrated in Figure 15A-1.

These receptors may be contaminated by accidental radiological releases from any of eight potential sources (the two- or four-letter Source Indicator is included in the ARCON96 model):

- plant vent (Source Indicator - PV);
- passive containment cooling system (PCS) air diffuser (Source Indicator - AD);
- auxiliary building fuel handling area blowout panel (Source Indicator - BP);
- radwaste building truck staging area door (Source Indicator - BD);
- a steam vent (or line) break (Source Indicator - SV);
- Power Operated Relief Valves (PORV) and safety valves (Source Indicator - PORV);
- condenser air removal stack (Source Indicator - AR); and
- the containment shell (Source Indicator - CS).

These potential release points, designated as Sources 1 to 8, respectively, are also illustrated in Figure 15A-1. Note that Source 4, the fuel building rail bay door in the list above, is referred to as the “Radwaste Building Truck Staging Area Door” in Figure 15A-1.

The receptor locations are also reflected in the ARCON96 model and may be distinguished by the respective two-letter indicators “CR” (i.e., control room HVAC intake) and “AN” (annex building access door).

The release types used in the ARCON96 modeling analyses follow those specified in Chapter 15, Appendix 15A. Figure 15A-1 shows that among the potential release sources, the containment shell is considered to be a diffuse area source. All other releases are considered to be point sources.

The Regulatory Position in Section 3.2.2 of Regulatory Guide 1.194 specifies that the stack release mode in ARCON96 is appropriate for releases from a freestanding, vertical, uncapped stack that is outside the directionally dependent zone of influence of adjacent structures. Furthermore, Regulatory Guide 1.194 states that such a stack should be more than 2-1/2 times the height of adjacent structures. From Table 15A-7, the height of the plant vent is 55.7 m above grade; the condenser air removal stack only 49.5 m above grade. Given that the PCS air diffuser sits atop the containment

shield building at an elevation of 69.8 m above grade, the vertical criterion for stack releases is not met. Therefore, modeling these sources in stack release mode was not considered.

The Regulatory Position in Section 3.2.3 of Regulatory Guide 1.194 states that modeling sources using the vent release mode "may not be sufficiently conservative for accident evaluations" and so "should not be used in design basis assessments". As neither a release from the condenser air removal stack nor the plant vent can be represented as stack releases, both potential sources were considered to be ground-level releases in the ARCON96 modeling analyses.

Different building cross-sectional areas were input to the model depending on the receptor being evaluated. For the annex building access door, a building cross-sectional area of 2,636 m^2 was used. This receptor, at an assumed elevation of 1.5 m, is located in a region where the air flow is under the influence of the combined structural wakes generated by the entire containment shield building, the auxiliary building, and the annex building. However, for this modeling analysis, the wake effects induced by the auxiliary building and the annex building were not considered. By excluding these two structures, the total building cross-sectional area is reduced, which is a relatively conservative assumption in that a smaller cross-sectional area results in higher χ/Q values.

The 2,636 m^2 cross-sectional area is based on an assumed diameter of the containment shield building of 43.3 m and an effective structural height of 60.9 m. The assumed diameter of the containment is slightly smaller than the actual diameter and is conservative since the smaller diameter results in a higher χ/Q. The effective structural height takes into account the fact that the containment shield building is a tapered structure beginning at elevation 170.84 ft above grade. The overall height of this building is 228.75 ft above grade. The effective structural height is taken, then, as the mid-point between the start of the taper and the overall building height—that is, 199.8 ft or 60.9 m.

For the receptor at the control room HVAC system intake, a cross-sectional area of 1,805 m^2 was assumed. This receptor, at an elevation of 19.7 m above grade, is located within the wake generated by that portion of the containment shield building that extends above the roof of the auxiliary building where this receptor is situated. The difference between the effective structural height of the containment shield building (i.e., 60.9 m, as discussed above) and the roof height of this part of the auxiliary building (i.e., 19.2 m above grade) is multiplied by the diameter of the containment shield building (i.e., 43.3 m) to yield the cross-sectional area input to the ARCON96 model for estimating χ/Q values at this receptor.

Specification of initial diffusion coefficients is only applicable to a hypothetical release from the containment shell which was modeled as a diffuse area source, as indicated previously. The Regulatory Positions in Sections 3.2.4.4 and 3.2.4.5 of Regulatory Guide 1.194 indicate that in the absence of site-specific empirical data, as is the case here, the initial horizontal and vertical diffusion coefficients may be estimated as follows:

- Sigma-y_o = Area Source Width ÷ 6; and
- Sigma-z_o = Area Source Height ÷ 6.

Consistent with those regulatory positions, the area source width and height are based on the horizontal and vertical dimensions used to determine the building cross-sectional areas input to the ARCON96 modeling analyses. For the receptor at the annex building access door, Sigma-y_o and Sigma-z_o are estimated to be 7.2 m (i.e., 43.3 m ÷ 6) and 10.2 m (i.e., 60.9 m ÷ 6), respectively. For the receptor at the control room HVAC intake, Sigma-y_o and Sigma-z_o are estimated to be 7.2 m (i.e., 43.3 m ÷ 6) and 7.0 m (i.e., 41.7 m ÷ 6), respectively.

Other parameters input to ARCON96 that are based on the recommendations in Regulatory Guide 1.194, Table A-2 (which are different, in some cases, than the default values in the model user's guidance, Reference 201) include:

- Surface Roughness Length = 0.2 (rather than the model default value of 0.1);
- Averaging Sector Width Constant = 4.3 (rather than the model default value of 4.0);
- Vertical Velocity, Stack Radius, and Stack Flow = 0 (all sources are assumed to be ground-level releases and so vertical velocity and stack radius are not used; stack flow during the course of an accident cannot be demonstrated with reasonable assurance);
- Release Height Elevation Difference = 0 (differences in grade elevations between all sources and receptors are only a few feet or less); and
- Wind Direction Window = 90 (default value in both Regulatory Guide 1.194 and Reference 201).

Finally, Table 15A-7 lists the heights of the two modeled receptors and the eight potential sources of radioactive releases, the straight-line distances between these sources and the respective receptors.

2.3.4.3.2 ARCON96 Modeling Results

The χ/Qs determined by the ARCON96 dispersion model represent 95th-percentile values based on all of the hourly relative concentrations calculated using the 5-year meteorological data set input to the model. χ/Q values at the control room HVAC intake and at the annex building access door for time averaging intervals of 0-2 hours, 2-8 hours, 8-24 hours, 1-4 days, and 4-30 days are summarized in Tables 2.3-201 and 2.3-202, respectively.

2.3.4.4 Dispersion Estimates Associated with Accidental Onsite and Offsite Hazardous Material Releases

Potential control room habitability effects and personnel exposures at VEGP Units 3 & 4 due to:

- postulated accidental releases of chemicals and other hazardous materials stored onsite, and at offsite locations within 5 miles of the units;
- for toxic or flammable materials carried over nearby transportation routes (e.g., roadways, railways, and waterways); and
- explosions

were addressed in Subsection 2.2.3 and in Section 2.2.

Concentrations at the control room HVAC intake and at the annex building access door due to accidental hazardous chemical releases were determined and evaluated in consideration of the guidance in Regulatory Guide 1.78, *Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release*, Revision 1, December 2001.

2.3.5 Long-Term (Routine) Diffusion Estimates

The long-term diffusion estimates are site specific. The site boundary annual average χ/Q shown in Table 2.0-201 is used to calculate release concentrations at the site boundary for comparison with the activity release limits defined in 10 CFR 20. The value specified is expected to bound

atmospheric conditions at most U.S. sites. If a selected site has a χ/Q value that exceeds this reference site value, the release concentrations reported in Section 11.3 would be adjusted proportionate to the change in χ/Q.

2.3.5.1 Basis

The NRC-sponsored XOQDOQ computer program (NUREG/CR-2919, *XOQDOQ: Computer Program for the Meteorological Evaluation of Routine Effluent Releases at Nuclear Power Stations*, PNL-4380, September 1982 [NUREG/CR-2919]) was used to estimate χ/Q values due to routine releases of gaseous effluents to the atmosphere. The XOQDOQ computer code has the primary function of calculating annual average χ/Q values and annual average relative deposition (D/Q) values at receptors of interest (e.g., the Dose Calculation EAB and the LPZ boundaries, the nearest milk cow, residence, garden, meat animal). χ/Q and D/Q values due to intermittent releases, which occur during routine operation, may also be evaluated using the XOQDOQ model.

The XOQDOQ dispersion model implements the assumptions outlined in Regulatory Guide 1.111. The program assumes that the material released to the atmosphere follows a Gaussian distribution around the plume centerline. In estimating concentrations for longer time periods, the Gaussian distribution is assumed to be evenly distributed within a given directional sector. A straight-line trajectory is assumed between the release point and all receptors.

The following input data and assumptions have been used in the XOQDOQ modeling analysis:

- Meteorological Data: 5-year (January 1, 1998 to December 31, 2002) composite onsite JFD of wind speed, wind direction, and atmospheric stability.
- Type of release: Ground-level.
- Wind sensor height: 10 m.
- Vertical temperature difference: (10 m – 60 m).
- Number of wind speed categories: 11.
- Release height: 10 m (default height).
- Minimum building cross-sectional area: 2,926 m^2.
- Containment structure equivalent height: 65.6 m.
- Distances from the release point to the nearest residence, nearest site boundary, vegetable garden, and meat animal.

The AP1000 reactor design has been used to calculate the minimum building cross-sectional area as called for in NUREG/CR-2919 for evaluating building downwash effects on dispersion. The containment building minimum cross-sectional area contains two parts: the reactor enclosure building plus a PCS water storage tank on the top of that structure. The height of the entire contiguous building is assumed to be 234.4 ft (71.4 m), while the bottom (W_B) and the top (W_T) widths of the building are 146.3 ft (44.6 m) and 89 ft (27.1 m), respectively. The height of the PCS is 39.1 ft (11.9 m).

The total calculated cross-sectional area of the structure (A_T) is 31,498 ft^2 (2,926 m^2). Using this total area, and dividing by the actual width of the bottom of the reactor enclosure building (i.e., 146.3 ft),

the equivalent structural height is calculated ($H_e = A_T / W_B$) to be 215.2 ft (65.6 m), which assumes that the structure width is uniform in the vertical direction.

These calculated values were input into the XOQDOQ model to predict the required annual average χ/Q and D/Q values.

Distances from the midpoint between the VEGP Unit 1 and Unit 2 reactors to various receptors of interest (i.e., nearest residence, meat animal, site boundary, and vegetable garden) for each directional sector are provided in AREOR (2004). The distance to the nearest residence (i.e., 0.67 mi) was conservatively used in all the directional sectors for all types of sensitive receptors (meat animal, vegetable garden, and residence). The results are presented in Table 2.3-218.

2.3.5.2 XOQDOQ Modeling Results

Table 2.3-219 summarizes the maximum relative concentration and relative deposition (i.e., χ/Q and D/Q values predicted by the XOQDOQ model for identified sensitive receptors in the vicinity of the VEGP site due to routine releases of gaseous effluents. The listed maximum χ/Q values reflect several plume depletion scenarios that account for radioactive decay (i.e., no decay, and the default half-life decay periods of 2.26 and 8 days).

The overall maximum annual average χ/Q value (with no decay) is 5.5×10^{-6} sec/m^3 and occurs at the Dose Calculation EAB at a distance of 0.5 mi to the northeast of the VEGP site. The maximum annual average χ/Q values (along with the direction and distance of the receptor locations relative to the VEGP site) for the other sensitive receptor types are:

- 3.4×10^{-6} sec/m^3 for the nearest residence occurring in the northeast sector at a distance of 0.67 mi.

- Because the same shortest distance (0.67 mi) was used to estimate χ/Q values for the nearest vegetable garden and meat animal, the same χ/Q value (3.4×10^{-6} sec/m^3) was obtained at these receptors.

Finally, Table 2.3-220 summarizes annual average χ/Q values (for no decay) and D/Q values at the XOQDOQ model's 22 standard radial distances between 0.25 and 50 mi and for the model's 10 distance-segment boundaries between 0.5 and 50 mi downwind along each of the 16 standard direction radials (i.e., separated by 22.5 degrees).

In the AP1000 reactor DCD, the terms "site boundary" and "exclusion area boundary" (EAB) are used interchangeably. Thus, the χ/Q specified for the site boundary applies whenever a discussion in the DCD refers to the exclusion area boundary. In Subsection 2.3.5 site specific χ/Q calculations, the term "Dose Calculation EAB" is equivalent to the DCD term "EAB".

Using the same assumptions and methodology as described earlier in this subsection (which relied on DCD Revision 15), along with the building dimensions provided in DCD Revision 17, the long-term (routine release) dispersion and deposition estimates were evaluated at the Dose Calculation EAB and at the various receptor locations. This evaluation confirmed that the χ/Q values for the EAB and the various receptor locations are within approximately 3.3% of those previously calculated. This result is reasonable given that the designated receptor points at the EAB and the various receptor locations are beyond the distance that would be appreciably influenced by building wake.

2.3.6 Combined License Information

2.3.6.1 Regional Climatology

Site-specific information related to regional climatology is addressed in Subsection 2.3.1.

2.3.6.2 Local Meteorology

Site-specific local meteorology information is addressed in Subsection 2.3.2.

2.3.6.3 Onsite Meteorological Measurements Program

The site-specific onsite meteorological measurements program is addressed in Subsections 2.3.3.4 and 2.3.3.

2.3.6.4 Short-Term Diffusion Estimates

Site-specific χ/Q values are addressed in Subsections 2.3.4, 15.6.5.3.7.3, and Appendix 15A.3.3.

2.3.6.5 Long-Term Diffusion Estimates

Long-term diffusion estimates and χ/Q values are addressed in Subsection 2.3.5.

2.3.7 References

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Table 2.3-201
ARCON96 X/Q Values at the Control Room HVAC Intake

Release Point	0 – 2 hours	2 – 8 hours	8 – 24 hours	1 – 4 days	4 – 30 days
Plant Vent	2.27E-03	1.86E-03	7.36E-04	5.99E-04	4.31E-04
PCS Air Diffuser	1.71E-03	1.32E-03	5.56E-04	4.63E-04	3.43E-04
Auxiliary Building Fuel Handling Area Blowout Panel	1.57E-03	1.15E-03	4.62E-04	3.72E-04	2.68E-04
Radwaste Building Truck Staging Area Door	1.30E-03	9.36E-04	3.78E-04	2.98E-04	2.09E-04
Steam Line Break	1.87E-02	1.51E-02	6.79E-03	4.94E-03	4.14E-03
PORV & Safety Valves	1.77E-02	1.41E-02	6.25E-03	4.61E-03	3.87E-03
Condenser Air Removal Stack	6.60E-04	4.83E-04	2.17E-04	1.57E-04	1.17E-04
Containment Shell (As Diffuse Area Source)	2.93E-03	1.75E-03	7.78E-04	6.81E-04	5.30E-04

Table 2.3-202
ARCON96 X/Q Values at the Annex Building Access Door

Release Point	0 – 2 hours	2 – 8 hours	8 – 24 hours	1 – 4 days	4 – 30 days
Plant Vent	**5.02E-04**	**3.94E-04**	**1.61E-04**	**1.29E-04**	**9.63E-05**
PCS Air Diffuser	**4.62E-04**	**3.55E-04**	**1.49E-04**	**1.23E-04**	**9.12E-05**
Auxiliary Building Fuel Handling Area Blowout Panel	**3.99E-04**	**3.00E-04**	**1.22E-04**	**1.00E-04**	**7.23E-05**
Radwaste Building Truck Staging Area Door	**3.83E-04**	**2.88E-04**	**1.21E-04**	**9.58E-05**	**6.78E-05**
Steam Line Break	**1.00E-03**	**7.97E-04**	**3.25E-04**	**2.58E-04**	**1.91E-04**
PORV & Safety Valves	**1.13E-03**	**8.98E-04**	**3.69E-04**	**2.92E-04**	**2.19E-04**
Condenser Air Removal Stack	**1.72E-03**	**1.12E-03**	**4.50E-04**	**3.17E-04**	**2.60E-04**
Containment Shell (As Diffuse Area Source)	**3.97E-04**	**3.26E-04**	**1.34E-04**	**1.10E-04**	**8.32E-05**

Table 2.3-203
NWS and Cooperative Observing Stations Near the VEGP Site

Station[a]	State	County	Approximate Distance (miles)	Direction Relative to Site	Elevation (feet)
Waynesboro 2NE	GA	Burke	16	WSW	270
Augusta WSO (Bush Field)	GA	Richmond	20	NW	132
Millen 4N	GA	Jenkins	22	SSW	195
Midville Experiment Station	GA	Burke	32	SW	280
Louisville 1E	GA	Jefferson	37	WSW	322
Newington 2NE	GA	Screven	41	SSE	209
Aiken 4NE	SC	Aiken	25	NNE	502
Blackville 3W	SC	Barnwell	29	ENE	324
Springfield	SC	Orangeburg	37	NE	300
Bamberg	SC	Bamberg	44	ENE	165

Notes:

a – Numeric and letter designators following a station name (e.g., Waynesboro 2NE) indicate the station's approximate distance in miles (e.g., 2) and direction (e.g., northeast) relative to the place name (e.g., Waynesboro)

Table 2.3-204
Local Climatological Data Summary for Augusta, Georgia
NORMALS, MEANS, AND EXTREMES
AUGUSTA, GA (AGS)

LATITUDE: 33° 22' 11" N | LONGITUDE: 81° 57' 53" W | ELEVATION (FT): GRND: 160 BARO: 163 | TIME ZONE: EASTERN (UTC +5) | WBAN: 03820

	ELEMENT	POR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
TEMPERATURE °F	NORMAL DAILY MAXIMUM	30	56.5	61.3	69.2	76.7	83.9	89.6	92.0	90.2	85.3	76.5	67.8	59.1	75.7
	MEAN DAILY MAXIMUM	48	56.4	60.6	68.3	76.8	84.0	89.4	91.9	90.6	85.6	76.9	68.3	59.1	75.7
	HIGHEST DAILY MAXIMUM	54	82	86	89	96	99	105	107	108	101	97	90	82	108
	YEAR OF OCCURRENCE		2002	1962	1995	1986	2000	1952	1980	1983	1999	1954	1961	1998	AUG 1983
	MEAN OF EXTREME MAXS.	56	74.4	76.0	80.7	88.8	93.4	98.1	99.0	97.9	94.5	88.3	81.5	76.1	87.4
	NORMAL DAILY MINIMUM	30	33.1	35.5	42.5	48.1	57.2	65.4	69.6	68.4	62.4	49.6	40.9	34.7	50.6
	MEAN DAILY MINIMUM	48	32.7	34.7	40.4	48.9	58.0	66.0	70.1	69.1	63.3	50.7	41.5	34.3	50.8
	LOWEST DAILY MINIMUM	54	-1	0	0	26	35	47	55	52	36	22	15	5	-1
	YEAR OF OCCURRENCE		1985	1998	1998	1982	1971	1984	1951	2004	1967	1952	1970	1981	JAN 1985
	MEAN OF EXTREME MINS.	56	16.6	19.0	25.0	33.4	43.5	54.7	62.5	60.4	49.7	34.4	24.9	18.5	36.9
	NORMAL DRY BULB	30	44.8	48.4	55.9	62.4	70.5	77.5	80.8	79.3	73.8	63.1	54.4	46.9	63.1
	MEAN DRY BULB	56	45.2	48.4	55.3	63.0	71.2	77.9	81.0	80.1	74.6	64.1	54.5	46.9	63.5
	MEAN WET BULB	49	40.3	42.8	48.4	55.5	63.4	69.8	72.7	72.3	67.4	57.4	48.5	41.7	56.7
	MEAN DEW POINT	49	34.4	36.0	41.5	49.4	58.9	66.0	69.7	69.4	64.3	53.4	43.2	36.1	51.9
	NORMAL NO. DAYS WITH:														
	MAXIMUM ≥ 90°	30	0.0	0.0	0.0	0.6	5.9	16.0	23.5	19.4	9.4	0.6	0.0	0.0	75.4
	MAXIMUM ≤ 32°	30	0.4	0.2	*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.7
	MINIMUM ≤ 32°	30	15.0	11.5	4.6	0.9	0.0	0.0	0.0	0.0	0.0	0.6	6.5	13.1	52.2
	MINIMUM ≤ 0°	30	*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H/C	NORMAL HEATING DEG. DAYS	30	617	469	301	129	21	1	0	0	5	118	317	547	2525
	NORMAL COLLING DEG. DAYS	30	1	2	15	52	191	385	506	459	285	74	15	1	1986
RH	NORMAL (PERCENT)	30	70	67	66	66	70	72	74	77	77	75	74	72	72
	HOUR 01 LST	30	80	77	77	80	86	87	88	91	90	89	86	82	84
	HOUR 07 LST	30	84	84	85	86	87	87	89	92	92	91	89	85	88
	HOUR 13 LST	30	55	50	48	45	48	52	54	56	55	50	51	54	52
	HOUR 19 LST	30	68	61	57	55	60	63	67	72	77	78	74	71	67
S	PERCENT POSSIBLE SUNSHINE														
W/O	MEAN NO. DAYS WITH:														
	HEAVY FOG (VISBY ≤ 1/4 MI)	54	3.5	2.7	2.1	2.5	2.5	1.4	1.6	3.1	3.8	3.9	4.0	4.0	35.1
	THUNDERSTORMS	54	0.9	1.8	2.7	3.6	6.0	9.4	11.9	9.3	3.4	1.3	0.8	0.7	51.8
CLOUDINESS	MEAN:														
	SUNRISE-SUNSET (OKTAS)	1			7.2		3.2	4.0	5.6	4.8		5.6		4.0	
	MIDNIGHT-MIDNIGHT (OKTAS)	1			6.4		4.0	4.0	4.8	4.0					
	MEAN NO. DAYS WITH:														
	CLEAR	1	2.0	2.0	9.0		14.0	7.0	2.0	6.0	3.0	7.0	5.0	10.0	
	PARTLY CLOUDY	1		2.0	1.0		2.0	8.0	2.0	2.0	2.0	4.0	1.0	1.0	
	CLOUDY	1	2.5	3.0	12.0		3.0	4.0		6.0	7.0	3.0	1.0	7.0	
PR	MEAN STATION PRESSURE (IN)	31	29.97	29.93	29.89	29.86	29.83	29.84	29.87	29.88	29.89	29.93	29.96	29.98	29.90
	MEAN SEA-LEVEL PRES. (IN)	47	30.14	30.09	30.04	30.02	30.00	29.99	30.03	30.01	30.04	30.08	30.11	30.15	30.06
WINDS	MEAN SPEED (MPH)	28	6.7	7.1	7.4	6.9	6.1	5.7	5.6	5.0	5.3	5.2	5.5	6.2	6.1
	PREVAIL. DIR (TENS OF DEGS)	29	27	29	29	18	14	14	24	14	04	04	29	29	24
	MAXIMUM 2-MINUTE:														
	SPEED (MPH)	10	40	37	40	37	49	45	36	38	36	38	38	35	49
	DIR. (TENS OF DEGREES)		26	30	29	28	23	34	21	01	02	34	18	28	23
	YEAR OF OCCURRENCE		1997	2003	1999	2001	2004	1998	1995	2002	1997	1995	2001	2000	MAY 2004
	MAXIMUM 5-SECOND:														
	SPEED (MPH)	10	54	45	51	55	74	53	47	49	45	52	49	43	74
	DIR. (TENS OF DEGREES)		25	31	29	34	23	33	21	01	01	33	03	28	23
	YEAR OF OCCURRENCE		1997	2003	1999	1997	2004	1998	1998	2002	1997	1995	1995	2000	MAY 2004
PRECIPITATION	NORMAL (IN)	30	4.50	4.11	4.61	2.94	3.07	4.19	4.07	4.48	3.59	3.20	2.68	3.14	44.58
	MAXIMUM MONTHLY (IN)	54	8.91	7.67	11.92	8.43	9.61	10.57	11.43	11.34	9.51	14.82	7.76	8.65	14.82
	YEAR OF OCCURRENCE		1987	1961	1980	1961	1979	2004	1967	1986	1975	1990	1985	1981	OCT 1990
	MINIMUM MONTHLY (IN)	54	0.75	0.69	0.88	0.60	0.36	0.68	1.02	0.65	0.31	T	0.09	0.32	T
	YEAR OF OCCURRENCE		1981	1968	1968	1970	2000	1984	1987	1980	1984	1953	1960	1955	OCT 1953
	MAXIMUM IN 24 HOURS (IN)	54	3.61	3.69	5.31	3.96	4.44	5.08	3.71	5.98	7.30	8.57	3.82	3.12	8.57
	YEAR OF OCCURRENCE		1960	1985	1967	1955	1981	1981	1979	1964	1998	1990	1985	1970	OCT 1990
	NORMAL NO. DAYS WITH:														
	PRECIPITATION ≥ 0.01	30	11.0	8.7	9.8	7.4	9.0	10.1	11.2	10.9	7.8	6.2	7.2	9.5	108.8
	PRECIPITATION ≥ 1.00	30	1.2	1.2	1.3	0.8	0.8	1.4	1.1	1.4	0.9	1.0	0.8	0.7	12.6
SNOWFALL	NORMAL (IN)	30	0.3	1.0	0.*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.4
	MAXIMUM MONTHLY (IN)	50	2.6	14.0	1.1	T	0.0	T	0.0	0.0	0.0	0.0	T	1.0	14.0
	YEAR OF OCCURRENCE		1992	1973	1980	1992		1994					1968	1993	FEB 1973
	MAXIMUM IN 24 HOURS (IN)	50	2.6	13.7	1.1	T	0.0	T	0.0	0.0	0.0	0.0	T	1.0	13.7
	YEAR OF OCCURRENCE		1992	1973	1980	1992		1994					1968	1993	FEB 1973
	MAXIMUM SNOW DEPTH (IN)	48	2	13	1	0	0	0	0	0	0	0	0	1	13
	YEAR OF OCCURRENCE		1988	1973	1980									1958	FEB 1973
	NORMAL NO. DAYS WITH:														
	SNOWFALL ≥ 1.0	30	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3

Note: Source: NCDC, 2005a

Table 2.3-205
Climatological Extremes at Selected NWS and Cooperative Observing Stations in the VEGP Site Area

Parameter	Waynesboro 2NE	Augusta WSO	Millen 4N	Midville Exp Station	Louisville 1E	Newington 2NE	Aiken 4NE	Blackville 3W	Springfield	Bamberg
Maximum Temperature	108 °F [a, b] (7/25/52); (7/14/80)	108 °F [a] (8/21/83)	109 °F [b] (7/24/52)	105 °F [a, b] (7/13/80); (8/21/83) (7/19/86); (7/21/86)	112 °F [a] (7/24/52)	110 °F [a] (7/13/80)	109 °F [a] (8/22/83)	108 °F [a] (8/1/99)	NA [d]	109 °F [a] (7/24/52)
Minimum Temperature	-1 °F [a, b] (1/20/85); (1/21/85)	-1 °F [a] (1/21/85)	0 °F [b] (1/21/85)	-1 °F [a] (1/21/85)	-2 °F [a] (1/21/85)	-1 °F [a] (1/21/85)	-4 °F [a] (1/21/85)	-1 °F [a] (1/21/85)	NA [d]	2 °F [a] (1/21/85)
Maximum 24-hr Rainfall	7.40 in. [a] (10/3/94)	7.30 in. [a] (9/3/98)	8.02 in. [b] (8/29/64)	8.19 in. [a] (10/12/90)	8.60 in. [a] (10/12/90)	5.50 in. [a] (10/10/90)	9.68 in. [a] (4/16/69)	7.53 in. [a] (9/30/59)	7.10 in. [b, c] (9/30/59)	8.02 in. [a, c] (9/23/00)
Maximum Monthly Rainfall	16.99 in. [a, b] (10/94)	14.82 in. [a, b] (10/90)	13.45 in. [b] (8/64)	15.97 in. [b, c] (8/70)	14.76 in. [b, c] (8/91)	15.29 in. [a, b] (7/89)	14.45 in. [a, b] (3/80)	14.67 in. [a, b] (10/90)	17.32 in. [b, c] (6/73)	15.26 in. [a, b] (8/95)
Maximum 24-hr Snowfall	16.0 in. [a, b] (2/10/73)	8.0 in. [a, b] (2/9/73)	14.0 in. [b] (2/10/73)	14.0 in. [b, c] (2/10/73)	14.8 in. [a, b] (2/10/73)	5.0 in. [a, b] (2/10/73)	15.0 in. [a, b] (2/10/73)	17.0 in. [b, c] (2/10/73)	8.0 in. [b, c] (2/11/73)	19.0 in. [a, b] (2/10/73)
Maximum Monthly Snowfall	16.0 in. [a, b] (2/73)	14.0 in. [a, b] (2/73)	15.0 in. [b] (2/68)	14.0 in. [b, c] (2/73)	14.8 in. [a, b] (2/73)	8.0 in. [a, b] (2/73)	15.0 in. [a, b] (2/73)	17.0 in. [b, c] (2/73)	15.0 in. [b, c] (2/73)	22.0 in. [a, b] (2/73)

Sources:
a – NCDC 2005b
b – SERCC 2006
c – NCDC 2002c
d – NA = Measurements not made at this station

Table 2.3-206
Mean Seasonal and Annual Morning and Afternoon Mixing Heights and Wind Speeds for Athens, Georgia

Parameter	Winter	Spring	Summer	Autumn	Annual
Mixing Height – AM (m)	407	383	390	314	374
Wind Speed – AM (m/sec)	6.0	5.3	3.8	4.4	4.9
Mixing Height – PM (m)	1042	1754	1918	1455	1542
Wind Speed – PM (m/sec)	7.0	7.2	4.9	5.7	6.2

Note: Mean wind speed values represent the arithmetic average of speeds observed at the surface and aloft within the mixed layer.
Source: Reference 209

Table 2.3-207
Climatological Normals (Means) at Selected NWS and Cooperative Observing Stations in the VEGP Site Area

Station	Normal Annual Temperatures (°F)[a]			Normal Annual Precipitation	
	Daily Maximum	Daily Minimum	Daily Mean	Rainfall[a] (inches)	Snowfall (inches)
Waynesboro 2NE	75.2	51.0	63.1	47.20	1.0 [a]
Augusta	75.7	50.6	63.2	44.58	1.4 [b]
Millen 4N	76.1	50.6	63.4	43.85	0.5 [c]
Midville Exp Station	76.9	52.9	65.0	44.90	0.1 [b]
Louisville 1E	75.6	51.7	63.7	45.92	0.9 [b]
Newington 2NE	76.2	52.5	64.4	47.81	0.8 [b]
Aiken 4NE	77.2	50.9	64.1	52.43	1.4 [b]
Blackville 3W	77.6	51.6	64.6	47.23	0.7 [b]
Springfield	NA [e]	NA [e]	NA [e]	46.28	0.7 [d]
Bamberg	75.0	53.1	64.1	48.57	1.3 [b]

Sources:
a – Reference 211
b – Reference 212
c – Reference 230, based on available Period of Record (1930-1998)
d – Reference 230, based on available Period of Record (1948-2005)
e – NA = Measurements not made at this station

Table 2.3-208
Seasonal and Annual Mean Wind Speeds for the VEGP Site (1998–2002) and the Augusta, Georgia, NWS Station (1971–2000, Normals)

60-Meter Tower Tower Elevation	Location	Winter	Spring	Summer	Autumn	Annual
Upper Level (60 m) (m/sec)	Plant Vogtle	5.0	5.0	4.1	4.4	4.6
Lower Level (10 m) (m/sec)	Plant Vogtle	2.6	2.8	2.4	2.3	2.5
Single Level (6.1 m) (m/sec)	Augusta WSO [a]	3.0	3.0	2.4	2.4	2.7

Notes:
Winter = December, January, February
Spring = March, April, May
Summer = June, July, August
Autumn = September, October, November

Source: a - Reference 221

Table 2.3-209 (Sheet 1 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 10-m Level

1998 TO 2002 WIND PERSISTENCE
VEGP METEOROLOGICAL TOWER – 10-M LEVEL
22.5° SECTOR WIDTH
START AND END OF PERIOD 98010101 - 02123124

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 5.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	1180	1133	1919	2028	1392	822	948	863	906	1298	1541	1478	1804	1444	856	894
2	439	376	919	983	538	231	353	294	305	493	621	526	830	639	266	310
4	99	75	343	326	139	27	88	58	56	102	164	105	246	197	51	52
8	6	4	97	65	13	4	5	2	3	4	14	4	28	30	3	0
12	0	0	36	10	0	0	0	0	0	0	0	0	2	9	0	0
18	0	0	9	0	0	0	0	0	0	0	0	0	0	3	0	0
24	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 10.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	136	126	323	415	149	58	116	85	74	167	246	250	362	361	150	59
2	42	51	129	197	39	16	37	27	24	57	106	91	156	167	46	22
4	7	9	40	63	5	3	8	5	3	9	25	21	47	45	11	6
8	0	0	11	7	0	0	0	0	0	0	0	1	4	5	0	0
12	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-209 (Sheet 2 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 10-m Level

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 15.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	3	9	13	25	8	1	6	3	4	14	21	17	40	43	19	2
2	0	3	2	10	0	0	0	0	0	4	6	5	13	14	5	1
4	0	0	0	5	0	0	0	0	0	0	3	0	0	2	0	0
8	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 20.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	1	0	0	4	0	0	0	0	0	2	0	1	3	5	0	0
2	0	0	0	3	0	0	0	0	0	0	0	0	0	1	0	0
4	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-209 (Sheet 3 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 10-m Level

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 25.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-209 (Sheet 4 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 10-m Level

1998 TO 2002 WIND PERSISTENCE
VEGP METEOROLOGICAL TOWER - 10-M LEVEL
67.5° SECTOR WIDTH

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 5.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	3207	4232	5080	5339	4242	3162	2633	2717	3067	3745	4317	4823	4726	4104	3194	2930
2	1885	2649	3569	3875	2751	1762	1438	1539	1694	2224	2686	3187	3226	2738	1881	1630
4	901	1461	2358	2587	1495	830	666	740	733	1031	1363	1765	1941	1635	908	738
8	310	653	1331	1443	570	271	219	248	208	250	455	623	824	749	297	216
12	129	358	828	880	237	96	78	116	68	73	168	209	361	376	119	80
18	54	187	466	471	87	23	19	29	4	15	57	64	134	148	41	20
24	32	107	283	287	32	0	3	6	0	3	20	15	52	67	17	2
30	17	69	164	178	2	0	0	0	0	0	6	2	22	33	2	0
36	11	48	96	117	0	0	0	0	0	0	0	0	4	20	0	0
48	0	27	33	38	0	0	0	0	0	0	0	0	0	8	0	0

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 10.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	321	585	864	887	622	323	259	275	326	487	663	858	973	873	570	345
2	160	271	484	515	328	114	115	127	143	243	354	489	592	549	332	143
4	74	115	212	243	128	26	42	49	40	71	135	218	299	313	168	59
8	33	44	69	74	24	0	12	15	0	2	15	36	81	115	55	16
12	19	21	26	20	4	0	2	3	0	0	0	2	30	43	18	4
18	5	6	3	1	0	0	0	0	0	0	0	0	6	13	4	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-209 (Sheet 5 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 10-m Level

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 15.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	14	25	47	46	34	15	10	13	21	39	52	78	100	102	64	24
2	5	6	20	17	10	0	0	0	4	14	23	29	49	56	29	7
4	0	0	7	7	5	0	0	0	0	5	5	6	16	21	9	0
8	0	0	1	1	1	0	0	0	0	0	0	0	3	3	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 20.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	1	1	4	4	4	0	0	0	2	2	3	4	9	8	5	1
2	0	0	3	3	3	0	0	0	0	0	0	0	3	3	1	0
4	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-209 (Sheet 6 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 10-m Level

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 25.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-210 (Sheet 1 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 60-m Level

1998 TO 2002 WIND PERSISTENCE
VEGP METEOROLOGICAL TOWER - 60-M LEVEL
22.5° SECTOR WIDTH

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 5.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	1610	1940	3083	2713	2037	1558	1645	2015	2294	2694	3397	3268	3052	2001	1615	1488
2	641	889	1687	1343	946	666	734	986	1057	1266	1739	1594	1576	910	663	575
4	168	245	736	446	273	167	218	319	290	346	569	492	586	293	146	131
8	20	33	192	70	43	19	20	56	35	27	73	51	122	67	6	3
12	4	7	67	7	15	1	4	15	0	0	5	13	17	16	0	0
18	0	0	20	0	5	0	0	0	0	0	0	0	0	0	0	0
24	0	0	13	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 10.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	616	954	1922	1457	984	747	802	713	1006	1597	2138	2098	2036	1247	775	615
2	240	435	1107	710	442	303	339	305	433	750	1106	1066	1106	619	322	231
4	68	116	515	219	114	77	100	82	118	207	366	359	444	233	73	59
8	14	16	161	33	23	10	13	6	12	13	43	44	101	60	4	2
12	4	6	63	5	12	0	1	0	0	0	3	13	13	15	0	0
18	0	0	20	0	2	0	0	0	0	0	0	0	0	0	0	0
24	0	0	13	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-210 (Sheet 2 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 60-m Level

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 15.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	131	211	522	254	106	66	112	75	171	364	628	721	732	436	147	123
2	53	87	264	94	31	11	33	15	52	123	277	314	362	211	49	39
4	23	27	117	29	6	0	10	2	8	26	81	94	140	89	15	9
8	12	10	44	8	0	0	3	0	0	0	3	9	34	21	2	1
12	4	6	24	4	0	0	0	0	0	0	0	3	1	2	0	0
18	0	0	17	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	11	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 20.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	24	21	44	25	12	8	16	4	19	48	97	135	183	118	36	12
2	13	6	20	10	4	0	5	0	3	14	21	48	87	54	16	4
4	7	1	7	5	0	0	3	0	0	2	0	12	30	19	7	2
8	3	0	0	1	0	0	0	0	0	0	0	0	6	1	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-210 (Sheet 3 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 60-m Level

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 22.5 DEGREES)

Speed Greater than or Equal to 25.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	2	0	5	5	1	0	0	0	2	6	15	26	37	21	5	3
2	0	0	1	3	0	0	0	0	0	2	2	12	16	7	1	2
4	0	0	0	1	0	0	0	0	0	0	0	6	6	2	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-210 (Sheet 4 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 60-m Level

1998 TO 2002 WIND PERSISTENCE
VEGP METEOROLOGICAL TOWER - 60-M LEVEL
67.5° SECTOR WIDTH

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 5.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	5038	6633	7736	7833	6308	5240	5218	5954	7003	8385	9359	9717	8321	6668	5104	4713
2	3401	4871	6139	6199	4565	3663	3670	4240	5098	6291	7318	7740	6402	4858	3475	3173
4	1887	3216	4448	4396	2827	2165	2126	2561	3130	4099	5024	5525	4399	3100	1942	1745
8	842	1778	2685	2516	1215	905	847	1122	1331	1939	2694	3133	2539	1549	726	666
12	459	1095	1746	1561	527	398	376	556	576	953	1523	1874	1606	876	295	286
18	225	581	1046	836	152	127	134	198	184	370	671	934	842	425	112	121
24	123	355	665	449	61	52	44	77	69	151	331	511	460	223	51	71
30	82	241	417	251	19	28	14	46	24	57	146	308	217	110	17	49
36	52	162	253	145	11	16	4	28	5	13	58	186	84	54	3	38
48	18	66	95	49	0	0	0	1	0	0	4	80	9	11	0	26

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 10.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	2185	3492	4333	4363	3188	2533	2262	2521	3316	4741	5833	6272	5381	4058	2637	2006
2	1281	2389	3217	3156	2011	1548	1344	1406	2029	3291	4248	4711	4052	2884	1663	1170
4	627	1465	2159	1982	998	757	620	620	959	1932	2698	3182	2793	1848	876	557
8	245	751	1218	993	313	228	183	188	223	775	1306	1701	1607	984	325	207
12	139	460	754	570	119	74	69	76	50	330	700	985	1007	555	125	109
18	84	230	449	296	26	8	14	21	0	118	275	496	503	264	24	52
24	45	131	285	165	5	0	1	4	0	48	104	273	252	130	2	32
30	26	76	176	97	0	0	0	0	0	19	30	170	108	56	0	20
36	12	45	108	62	0	0	0	0	0	1	6	106	35	29	0	14
48	0	13	44	19	0	0	0	0	0	0	0	41	0	10	0	2

Table 2.3-210 (Sheet 5 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 60-m Level

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 15.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	465	864	987	882	426	284	253	358	610	1163	1713	2081	1889	1315	706	401
2	223	470	549	462	163	104	90	126	243	606	1005	1322	1217	814	369	189
4	100	233	276	207	46	32	29	32	63	239	482	731	711	456	173	92
8	51	106	121	79	11	5	8	8	1	41	111	257	304	206	59	48
12	37	59	75	47	7	0	0	0	0	8	31	97	145	95	8	33
18	19	24	44	29	1	0	0	0	0	0	5	12	37	40	0	21
24	10	11	26	19	0	0	0	0	0	0	0	0	18	25	0	10
30	4	5	14	13	0	0	0	0	0	0	0	0	11	18	0	4
36	0	0	6	7	0	0	0	0	0	0	0	0	5	12	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 20.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	57	89	90	81	45	36	28	39	71	164	280	415	436	337	166	72
2	26	43	44	38	15	10	5	9	21	55	122	210	240	194	88	38
4	14	16	17	15	5	3	3	3	3	12	38	82	107	92	41	23
8	5	3	1	1	1	0	0	0	0	1	2	16	18	19	7	10
12	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	2
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-210 (Sheet 6 of 6)
Wind Direction Persistence/Wind Speed Distributions for the VEGP Site – 60-m Level

PERSISTENCIES FROM 98010101 TO 02123124 (SECTOR WIDTH = 67.5 DEGREES)

Speed Greater than or Equal to 25.0 mph

Hours	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	5	7	10	11	6	1	0	2	8	23	47	78	84	63	29	10
2	2	1	5	5	3	0	0	0	2	6	21	36	40	30	12	3
4	0	0	1	1	1	0	0	0	0	1	9	16	17	12	3	0
8	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.3-211
Seasonal and Annual Vertical Stability Class and Mean 10-Meter Level Wind Speed Distributions for the VEGP Site (1998–2002)

Period	Vertical Stability Categories[a]						
	A	B	C	D	E	F	G
Winter							
Frequency (%)	2.23	2.94	6.40	31.25	28.96	14.06	14.14
Wind Speed (m/sec)	3.4	3.9	3.6	3.1	2.6	1.7	1.4
Spring							
Frequency (%)	11.49	5.29	7.04	25.18	27.10	13.94	9.95
Wind Speed (m/sec)	3.6	3.7	3.6	3.3	2.5	1.8	1.4
Summer							
Frequency (%)	8.27	6.12	7.60	24.73	33.00	14.22	6.04
Wind Speed (m/sec)	3.4	3.1	2.9	2.7	2.1	1.5	1.4
Autumn							
Frequency (%)	3.76	3.79	8.36	28.90	26.92	13.65	14.62
Wind Speed (m/sec)	3.2	3.3	3.2	2.8	2.2	1.7	1.2
Annual							
Frequency (%)	6.48	4.54	7.34	27.50	28.99	13.97	11.17
Wind Speed (m/sec)	3.5	3.5	3.3	3.0	2.4	1.7	1.3

Note: a – Vertical stability based on temperature difference (DT) between 10-m and 60-m measurement levels.

Table 2.3-212 (Sheet 1 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP10M **Direction:** DI10M **Lapse:** DT60M

Stability Class: A Delta Temperature Extremely Unstable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	0	0	0	3	7	38	63	4	0	0	0	0	115
NNE	0	0	2	3	17	48	33	13	0	0	0	0	116
NE	0	0	0	7	6	36	79	17	0	0	0	0	145
ENE	0	0	1	3	13	75	127	30	0	0	0	0	249
E	0	0	0	5	15	77	133	10	0	0	0	0	240
ESE	0	0	1	4	17	66	55	0	0	0	0	0	143
SE	0	1	1	4	11	41	49	5	0	0	0	0	112
SSE	0	0	1	9	2	32	36	2	1	0	0	0	83
S	0	1	0	10	22	42	51	5	0	0	0	0	131
SSW	0	0	2	6	19	59	97	12	0	0	0	0	195
SW	0	0	2	8	18	71	117	20	3	0	0	0	239
WSW	0	0	2	6	23	74	167	26	3	0	0	0	301
W	0	2	0	4	17	79	156	26	2	0	0	0	286
WNW	0	0	0	5	9	39	88	16	3	0	0	0	160
NW	0	0	0	6	9	28	57	14	3	0	0	0	117
NNW	1	0	1	2	6	23	59	1	0	0	0	0	93
Totals	1	4	13	85	211	828	1367	201	15	0	0	0	2725

Number of Calm Hours for this Table	0
Number of Variable Direction Hours for this Table	11
Number of Invalid Hours	1633
Number of Valid Hours for this Table	2725
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-212 (Sheet 2 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP10M **Direction:** DI10M **Lapse:** DT60M

Stability Class: B Delta Temperature Moderately Unstable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	0	0	1	3	9	39	64	5	0	1	0	0	122
NNE	0	0	0	5	13	38	36	8	2	0	0	0	102
NE	0	1	0	4	7	40	48	7	0	0	0	0	107
ENE	1	0	0	1	11	54	69	23	0	0	0	0	159
E	0	0	0	5	4	44	65	8	0	0	0	0	126
ESE	0	0	1	6	6	31	22	3	0	0	0	0	69
SE	0	0	4	7	8	23	22	1	0	0	0	0	65
SSE	0	0	0	7	14	21	18	1	0	0	0	0	61
S	0	1	0	2	12	30	27	4	0	0	0	0	76
SSW	0	0	0	3	17	53	51	5	2	0	0	0	131
SW	0	0	1	9	18	51	75	19	2	0	0	0	175
WSW	0	0	0	4	7	58	64	18	1	0	0	0	152
W	0	0	0	2	8	60	96	22	3	0	0	0	191
WNW	0	0	0	2	7	37	75	28	4	1	0	0	154
NW	0	0	0	3	5	33	42	12	2	0	0	0	97
NNW	0	0	0	1	11	37	70	4	0	0	0	0	123
Totals	1	2	7	64	157	649	844	168	16	2	0	0	1910

Number of Calm Hours for this Table	1
Number of Variable Direction Hours for this Table	44
Number of Invalid Hours	1633
Number of Valid Hours for this Table	1910
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-212 (Sheet 3 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP10M **Direction:** DI10M **Lapse:** DT60M

Stability Class: C Delta Temperature Slightly Unstable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	0	1	1	8	24	81	84	5	1	0	0	0	205
NNE	0	0	4	6	17	72	72	3	0	0	0	0	174
NE	0	0	0	5	15	60	72	13	0	0	0	0	165
ENE	0	0	3	6	19	74	115	17	0	0	0	0	234
E	0	0	1	9	21	58	105	1	1	0	0	0	196
ESE	0	0	2	9	15	52	44	1	0	0	0	0	123
SE	0	1	2	11	19	43	35	5	1	0	0	0	117
SSE	0	0	2	10	9	28	45	10	1	0	0	0	105
S	0	0	3	8	29	70	47	4	0	0	0	0	161
SSW	0	1	0	7	26	70	84	8	1	0	0	0	197
SW	0	0	0	11	22	74	127	21	3	0	0	0	258
WSW	0	1	0	11	24	94	101	23	1	0	0	0	255
W	0	0	3	10	27	110	138	41	5	0	0	0	334
WNW	0	0	0	8	22	53	71	43	7	0	0	0	204
NW	0	2	1	3	24	68	66	14	4	0	0	0	182
NNW	2	1	2	4	20	81	67	1	0	0	0	0	178
Totals	2	7	24	126	333	1088	1273	210	25	0	0	0	3088

Number of Calm Hours for this Table	1
Number of Variable Direction Hours for this Table	114
Number of Invalid Hours	1633
Number of Valid Hours for this Table	3088
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-212 (Sheet 4 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP10M **Direction:** DI10M **Lapse:** DT60M

Stability Class: D Delta Temperature Neutral

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	0	7	13	78	137	345	215	29	0	0	0	0	824
NNE	2	6	8	72	106	278	209	32	2	0	0	0	715
NE	3	4	15	57	99	342	507	75	1	0	0	0	1103
ENE	1	2	12	61	95	303	454	87	4	1	0	0	1020
E	1	10	18	67	114	268	215	21	3	0	0	0	717
ESE	3	5	14	49	71	165	124	9	0	0	0	0	440
SE	1	16	9	48	80	138	149	39	2	0	0	0	482
SSE	4	9	17	65	96	186	152	18	0	0	0	0	547
S	2	9	14	78	114	240	125	10	0	0	0	0	592
SSW	1	9	21	47	96	229	219	38	3	0	0	0	663
SW	3	3	14	83	117	269	238	40	7	0	0	0	774
WSW	1	8	18	68	141	294	246	53	2	1	0	0	832
W	1	4	11	72	123	269	334	81	16	0	0	0	911
WNW	6	3	19	59	109	222	287	83	14	0	0	0	802
NW	2	4	11	69	97	212	123	31	4	0	0	0	553
NNW	0	3	12	60	98	244	154	17	0	0	0	0	588
Totals	31	102	226	1033	1693	4004	3751	663	58	2	0	0	11563

Number of Calm Hours for this Table	4
Number of Variable Direction Hours for this Table	543
Number of Invalid Hours	1633
Number of Valid Hours for this Table	11563
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-212 (Sheet 5 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP10M **Direction:** DI10M **Lapse:** DT60M

Stability Class: E Delta Temperature Slightly Stable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	9	16	26	87	94	154	108	12	1	0	0	0	507
NNE	9	11	37	89	93	224	112	13	1	0	0	0	589
NE	9	20	26	88	124	338	272	23	3	0	0	0	903
ENE	12	14	33	94	149	327	206	29	6	1	0	0	871
E	7	23	38	95	164	330	114	19	2	0	0	0	792
ESE	12	8	50	123	184	246	86	14	0	0	0	0	723
SE	13	21	45	110	184	293	160	9	0	0	0	0	835
SSE	13	25	47	167	250	322	101	8	0	0	0	0	933
S	10	21	60	239	233	271	76	9	1	0	0	0	920
SSW	3	21	43	151	200	272	135	17	1	0	0	0	843
SW	8	18	53	167	245	335	170	13	1	0	0	0	1010
WSW	9	18	40	191	223	266	82	10	1	0	0	0	840
W	5	13	59	127	156	281	169	15	0	0	0	0	825
WNW	9	11	22	113	122	216	185	29	1	0	0	0	708
NW	8	14	27	102	107	147	84	9	1	0	0	0	499
NNW	7	8	21	57	85	128	75	6	2	0	0	0	389
Totals	143	262	627	2000	2613	4150	2135	235	21	1	0	0	12187

Number of Calm Hours for this Table	35
Number of Variable Direction Hours for this Table	396
Number of Invalid Hours	1633
Number of Valid Hours for this Table	12187
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-212 (Sheet 6 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP10M **Direction:** DI10M **Lapse:** DT60M

Stability Class: F Delta Temperature Moderately Stable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	11	20	20	56	61	65	15	0	0	0	0	0	248
NNE	16	21	30	62	44	61	25	0	0	0	0	0	259
NE	22	15	24	70	71	97	19	0	0	0	0	0	318
ENE	17	29	27	77	86	162	24	1	0	0	0	0	423
E	16	28	45	103	128	117	5	0	0	0	0	0	442
ESE	16	25	37	94	112	69	2	0	0	0	0	0	355
SE	21	17	35	85	112	52	6	0	0	0	0	0	328
SSE	15	28	30	88	106	65	7	0	0	0	0	0	339
S	12	22	47	143	111	55	0	1	0	0	0	0	391
SSW	20	14	36	138	135	88	10	0	0	0	0	0	441
SW	19	24	36	148	224	99	7	0	0	0	0	0	557
WSW	12	19	47	183	228	110	1	0	0	0	0	0	600
W	10	18	50	169	129	64	9	1	0	0	0	0	450
WNW	10	24	30	103	110	45	11	3	0	0	0	0	336
NW	6	16	21	66	57	34	3	0	0	0	0	0	203
NNW	12	14	18	44	49	38	7	0	0	0	0	0	182
Totals	235	334	533	1629	1763	1221	151	6	0	0	0	0	5872

Number of Calm Hours for this Table	39
Number of Variable Direction Hours for this Table	230
Number of Invalid Hours	1633
Number of Valid Hours for this Table	5872
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-212 (Sheet 7 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP10M **Direction:** DI10M **Lapse:** DT60M

Stability Class: G Delta Temperature Extremely Stable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	26	31	49	75	46	18	5	0	0	0	0	0	250
NNE	25	26	34	33	13	16	1	0	1	0	0	0	149
NE	45	30	35	58	24	16	0	0	0	0	0	0	208
ENE	29	26	42	73	61	36	2	0	0	0	0	0	269
E	28	33	55	101	78	30	3	0	0	0	0	0	328
ESE	28	33	56	110	40	17	1	0	0	0	0	0	285
SE	21	31	39	48	48	20	3	0	0	0	0	0	210
SSE	20	34	43	46	36	14	2	0	0	0	0	0	195
S	15	20	41	58	47	22	1	0	1	0	0	0	205
SSW	24	22	56	104	111	49	5	0	0	0	0	0	371
SW	32	34	56	150	203	68	2	0	0	0	0	0	545
WSW	19	38	61	207	170	50	2	0	0	0	0	0	547
W	25	36	78	178	133	42	0	0	0	0	0	0	492
WNW	26	34	43	83	56	14	2	1	0	0	0	0	259
NW	35	32	32	41	21	6	0	0	0	0	0	0	167
NNW	22	25	45	81	28	16	1	0	0	0	0	0	218
Totals	420	486	765	1446	1115	434	30	1	2	0	0	0	4698

Number of Calm Hours for this Table	67
Number of Variable Direction Hours for this Table	432
Number of Invalid Hours	1633
Number of Valid Hours for this Table	4698
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-212 (Sheet 8 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (10-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP10M **Direction:** DI10M **Lapse:** DT60M

Summary of All Stability Classes Delta Temperature

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	46	75	110	310	378	740	554	55	2	1	0	0	2271
NNE	52	64	115	270	303	737	488	69	6	0	0	0	2104
NE	79	70	100	289	346	929	997	135	4	0	0	0	2949
ENE	60	71	118	315	434	1031	997	187	10	2	0	0	3225
E	52	94	157	385	524	924	640	59	6	0	0	0	2841
ESE	59	71	161	395	445	646	334	27	0	0	0	0	2138
SE	56	87	135	313	462	610	424	59	3	0	0	0	2149
SSE	52	96	140	392	513	668	361	39	2	0	0	0	2263
S	39	74	165	538	568	730	327	33	2	0	0	0	2476
SSW	48	67	158	456	604	820	601	80	7	0	0	0	2841
SW	62	79	162	576	847	967	736	113	16	0	0	0	3558
WSW	41	84	168	670	816	946	663	130	8	1	0	0	3527
W	41	73	201	562	593	905	902	186	26	0	0	0	3489
WNW	51	72	114	373	435	626	719	203	29	1	0	0	2623
NW	51	68	92	290	320	528	375	80	14	0	0	0	1818
NNW	44	51	99	249	297	567	433	29	2	0	0	0	1771
Totals	833	1196	2195	6383	7885	12374	9551	1484	137	5	0	0	42043

Number of Calm Hours for this Table	147
Number of Variable Direction Hours for this Table	1770
Number of Invalid Hours	1633
Number of Valid Hours for this Table	42043
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-213 (Sheet 1 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP60M **Direction:** DI60M **Lapse:** DT60M

Stability Class: A Delta Temperature Extremely Unstable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	0	0	0	4	5	22	36	33	6	0	0	0	106
NNE	0	0	0	1	6	24	34	21	9	1	0	0	96
NE	0	0	0	0	4	23	84	88	28	0	0	0	227
ENE	0	0	1	3	7	35	141	71	15	1	0	0	274
E	0	0	0	1	2	31	86	26	2	0	0	0	148
ESE	1	0	0	4	3	19	52	21	1	0	0	0	101
SE	0	0	0	2	2	10	31	7	0	0	0	0	52
SSE	0	0	1	2	4	27	49	14	1	0	0	0	98
S	0	0	2	4	6	15	51	32	8	0	0	0	118
SSW	0	0	0	2	11	27	80	51	23	3	0	0	197
SW	0	0	0	3	14	33	98	110	60	13	0	0	331
WSW	0	1	1	2	9	26	96	104	76	15	5	9	335
W	0	1	0	2	9	34	57	48	46	5	0	0	202
WNW	0	0	1	2	1	12	37	37	12	7	0	0	109
NW	0	0	0	2	10	19	46	30	4	1	2	0	114
NNW	0	0	1	0	5	22	47	33	2	0	0	0	110
Totals	1	2	7	34	98	379	1025	726	293	46	7	0	2618

Number of Calm Hours for this Table	0
Number of Variable Direction Hours for this Table	6
Number of Invalid Hours	3217
Number of Valid Hours for this Table	2618
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-213 (Sheet 2 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP60M **Direction:** DI60M **Lapse:** DT60M

Stability Class: B Delta Temperature Moderately Unstable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	0	0	1	4	4	17	48	20	8	0	0	0	102
NNE	0	0	0	1	5	15	33	22	5	0	0	0	81
NE	0	1	0	4	1	20	60	46	12	0	0	0	144
ENE	0	0	0	2	3	23	67	35	4	0	0	0	134
E	0	0	0	2	3	18	43	21	1	0	0	0	88
ESE	0	0	0	1	2	18	27	10	0	0	0	0	58
SE	0	0	1	0	3	12	20	10	0	0	0	0	46
SSE	0	0	0	3	1	15	19	5	0	0	0	0	43
S	0	0	0	1	4	15	29	11	8	0	0	0	68
SSW	0	0	1	1	1	17	48	22	18	1	1	0	110
SW	0	0	0	0	8	28	80	46	35	4	1	0	202
WSW	0	0	0	1	6	26	73	49	35	7	1	0	198
W	0	0	0	1	6	17	67	48	29	12	0	0	180
WNW	0	0	0	0	3	14	45	26	17	7	2	0	115
NW	0	0	0	2	4	17	52	27	8	1	0	0	111
NNW	0	0	0	0	5	18	53	28	2	0	0	0	106
Totals	0	1	3	23	59	290	765	426	182	32	5	0	1786

Number of Calm Hours for this Table	0
Number of Variable Direction Hours for this Table	26
Number of Invalid Hours	3217
Number of Valid Hours for this Table	1786
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-213 (Sheet 3 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP60M **Direction:** DI60M **Lapse:** DT60M

Stability Class: C Delta Temperature Slightly Unstable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	0	0	0	2	12	54	80	27	4	0	0	0	179
NNE	1	1	1	3	10	34	62	24	8	0	0	0	144
NE	0	2	0	6	7	36	99	48	6	0	0	0	204
ENE	0	0	2	5	8	45	97	49	8	0	0	0	214
E	0	0	0	6	11	44	100	16	2	1	0	0	180
ESE	0	0	1	6	5	18	34	11	0	1	0	0	76
SE	0	0	1	1	7	19	41	14	2	0	0	0	85
SSE	0	0	0	6	5	26	51	13	6	1	0	0	108
S	0	0	0	4	13	38	63	21	10	0	0	0	149
SSW	0	0	0	4	9	37	85	38	13	3	0	0	189
SW	0	0	2	3	4	49	102	73	34	7	0	0	274
WSW	0	1	0	5	9	52	122	60	41	6	1	0	297
W	0	1	1	1	12	47	111	54	44	11	1	0	283
WNW	0	0	0	4	5	34	69	43	26	12	2	0	195
NW	0	0	1	5	12	40	92	30	5	2	0	0	187
NNW	0	1	3	5	4	46	89	22	5	0	0	0	175
Totals	1	6	12	66	133	619	1297	543	214	44	4	0	2939

Number of Calm Hours for this Table	0
Number of Variable Direction Hours for this Table	60
Number of Invalid Hours	3217
Number of Valid Hours for this Table	2939
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-213 (Sheet 4 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP60M **Direction:** DI60M **Lapse:** DT60M

Stability Class: D Delta Temperature Neutral

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	2	2	1	24	47	152	291	114	39	2	0	0	674
NNE	0	4	9	24	49	129	319	182	62	2	0	0	780
NE	0	3	5	25	42	147	425	382	125	1	0	0	1155
ENE	1	1	8	27	59	158	352	199	47	3	2	0	857
E	1	4	6	24	40	115	237	91	27	1	0	0	546
ESE	2	0	6	21	32	76	134	50	12	2	0	0	335
SE	2	2	9	20	38	72	170	100	41	1	0	0	455
SSE	1	5	7	23	43	114	210	109	22	0	0	0	534
S	1	4	4	29	59	148	233	100	22	3	0	0	603
SSW	2	3	7	19	36	102	231	138	57	12	1	0	608
SW	1	3	6	22	48	135	307	186	111	13	1	0	833
WSW	2	3	6	23	37	149	299	253	155	22	2	0	951
W	0	4	9	24	45	143	286	212	166	46	8	0	943
WNW	0	5	6	26	33	93	189	139	93	21	0	0	605
NW	0	2	11	18	34	122	206	109	31	5	0	0	538
NNW	2	2	5	22	42	158	258	109	45	1	0	0	644
Totals	17	47	105	371	684	2013	4147	2473	1055	135	14	0	11061

Number of Calm Hours for this Table	0
Number of Variable Direction Hours for this Table	257
Number of Invalid Hours	3217
Number of Valid Hours for this Table	11061
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-213 (Sheet 5 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP60M **Direction:** DI60M **Lapse:** DT60M

Stability Class: E Delta Temperature Slightly Stable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	3	2	7	18	17	91	205	107	21	8	0	0	479
NNE	0	0	3	20	25	93	248	212	58	0	0	0	659
NE	2	1	4	12	32	87	331	373	122	4	0	0	968
ENE	1	1	4	19	31	89	347	277	50	4	3	0	826
E	1	2	4	15	21	82	312	204	27	3	0	0	671
ESE	1	2	6	16	24	71	289	221	24	1	0	0	655
SE	0	1	6	9	16	81	345	215	18	0	0	0	691
SSE	0	4	6	31	48	196	513	163	11	1	0	0	973
S	0	3	5	25	41	179	421	222	29	2	1	0	928
SSW	1	3	6	13	21	90	371	336	57	3	0	0	901
SW	1	4	3	18	27	71	419	368	98	7	0	0	1016
WSW	2	2	2	11	25	64	310	288	106	9	0	0	819
W	3	3	5	13	26	48	253	364	146	10	1	0	872
WNW	5	1	6	11	15	61	170	204	112	9	0	0	591
NW	1	3	3	16	14	60	169	147	41	2	0	0	456
NNW	1	0	8	15	25	61	131	91	17	3	1	0	353
Totals	19	32	78	262	408	1424	4834	3792	937	66	6	0	11858

Number of Calm Hours for this Table	8
Number of Variable Direction Hours for this Table	83
Number of Invalid Hours	3217
Number of Valid Hours for this Table	11858
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-213 (Sheet 6 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP60M **Direction:** DI60M **Lapse:** DT60M

Stability Class: F Delta Temperature Moderately Stable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	1	3	1	8	9	39	78	43	8	0	0	0	190
NNE	0	0	1	3	13	39	117	68	15	0	0	0	256
NE	1	2	0	8	9	39	100	156	33	0	0	0	348
ENE	2	1	1	8	16	27	150	174	26	0	0	0	405
E	1	1	2	8	7	30	163	142	2	0	0	0	356
ESE	3	2	1	13	14	44	157	89	3	0	0	0	326
SE	1	1	3	6	15	41	157	85	6	0	0	0	315
SSE	1	2	4	18	27	94	142	94	5	0	0	0	387
S	1	1	11	25	30	80	156	149	8	0	0	0	461
SSW	1	5	3	4	8	47	187	212	28	0	0	0	495
SW	3	1	5	10	15	40	156	280	44	0	0	0	554
WSW	0	0	3	8	11	26	150	242	37	1	0	0	478
W	2	1	4	6	14	29	133	216	49	0	0	0	454
WNW	1	0	2	7	13	31	89	142	31	0	0	0	316
NW	0	0	3	5	8	30	87	80	5	0	0	0	218
NNW	2	2	2	4	9	27	75	51	7	0	0	0	179
Totals	20	22	46	141	218	663	2097	2223	307	1	0	0	5738

Number of Calm Hours for this Table	4
Number of Variable Direction Hours for this Table	14
Number of Invalid Hours	3217
Number of Valid Hours for this Table	5738
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-213 (Sheet 7 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP60M **Direction:** DI60M **Lapse:** DT60M

Stability Class: G Delta Temperature Extremely Stable

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	2	2	4	10	16	32	69	17	0	0	1	0	153
NNE	2	2	2	12	15	56	86	17	1	0	0	0	193
NE	1	1	7	15	22	37	90	55	7	0	0	0	235
ENE	0	3	8	13	12	40	118	88	20	0	0	0	302
E	0	4	3	9	13	24	123	97	10	0	0	0	283
ESE	2	2	5	7	8	28	111	72	1	0	0	0	236
SE	1	1	4	9	20	38	90	43	2	0	0	0	208
SSE	1	2	7	17	29	76	82	39	4	0	0	0	257
S	1	1	7	18	33	70	113	94	27	0	0	0	364
SSW	1	3	5	13	12	34	135	172	45	0	0	0	420
SW	1	0	2	9	13	43	147	171	58	0	0	0	444
WSW	4	1	2	7	15	41	103	216	37	0	0	0	426
W	4	5	3	12	15	47	126	159	33	0	0	0	404
WNW	1	3	3	8	10	41	102	90	11	0	0	0	269
NW	1	1	6	11	12	47	98	50	4	0	0	0	230
NNW	0	0	3	8	16	44	57	31	2	0	0	0	161
Totals	22	31	71	178	261	698	1650	1411	262	0	1	0	4585

Number of Calm Hours for this Table	9
Number of Variable Direction Hours for this Table	42
Number of Invalid Hours	3217
Number of Valid Hours for this Table	4585
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-213 (Sheet 8 of 8)
Joint Frequency Distribution of Wind Speed and Wind Direction (60-m Level) by Atmospheric Stability Class for the VEGP Site (1998–2002)

Hours at Each Wind Speed and Direction

Period of Record: 01/01/98 1:00 - 12/31/02 23:00 Total Period

Elevation: **Speed:** SP60M **Direction:** DI60M **Lapse:** DT60M

Summary of All Stability Classes Delta Temperature

Wind Speed (m/s)

Wind Direction (from)	0.23 - 0.50	0.51 - 0.75	0.76 - 1.0	1.1 - 1.5	1.6 - 2.0	2.1 - 3.0	3.1 - 5.0	5.1 - 7.0	7.1 - 10.0	10.1 - 13.0	13.1 - 18.0	> 18.0	Total
N	8	9	14	70	110	407	807	361	86	10	1	0	1883
NNE	3	7	16	64	123	390	899	546	158	3	0	0	2209
NE	4	10	16	70	117	389	1189	1148	333	5	0	0	3281
ENE	4	6	24	77	136	417	1272	893	170	8	5	0	3012
E	3	11	15	65	97	344	1064	597	71	5	0	0	2272
ESE	9	6	19	68	88	274	804	474	41	4	0	0	1787
SE	4	5	24	47	101	273	854	474	69	1	0	0	1852
SSE	3	13	25	100	157	548	1066	437	49	2	0	0	2400
S	3	9	29	106	186	545	1066	629	112	5	1	0	2691
SSW	5	14	22	56	98	354	1137	969	241	22	2	0	2920
SW	6	8	18	65	129	399	1309	1234	440	44	2	0	3654
WSW	8	8	14	57	112	384	1153	1212	487	60	9	0	3504
W	9	15	22	59	127	365	1033	1101	513	84	10	0	3338
WNW	4	9	18	58	80	286	702	681	302	56	4	0	2200
NW	2	6	24	59	94	335	750	473	98	11	2	0	1854
NNW	5	5	22	54	106	376	710	365	80	4	1	0	1728
Totals	80	141	322	1075	1861	6086	15815	11594	3250	324	37	0	40585

Number of Calm Hours for this Table	21
Number of Variable Direction Hours for this Table	488
Number of Invalid Hours	3217
Number of Valid Hours for this Table	40585
Total Hours for the Period	43823

Note: Stability class based on temperature difference (ΔT or lapse) between 10-m and 60-m measurement levels.

Table 2.3-214
VEGP Onsite Weather Instruments

60-m Tower Instruments						
Sensed Parameter	**Range**	**System Accuracy**	**Starting Threshold**	**Distance Constant**	**Damping Ratio**	**Elevation**
Wind Speed	0-112 mph (0-50 m/sec)	≤ ±5%	1.0 mph (0.45 m/sec)	2 m	-----	10 m; 60 m
Wind Direction	0°-360°	≤ ±5°	1.0 mph (0.45 m/sec)	-----	0.4-0.6 with deflection of 10° and delay distance of ≤ 2 m	10 m; 60 m
Ambient Temperature	-58°F to +122°F (-50°C to +50°C)	≤ ±0.9°F (±0.5°C)	-----	-----	-----	10 m; 60 m
Differential Temperature	-10°F to +20°F (-23.3°C to -6.6°C)	≤ ±0.18°F (±0.1°C)	-----	-----	-----	10 m – 60 m
Relative Humidity	0-100%	≤ ±4%	-----	-----	-----	10 m
Dew Point	40°F to 120°F (40°C to 49°C)	≤ ±2.7°F (±1.5°C)	-----	-----	-----	10 m
Precipitation	0-100 in. reset daily	±10% of the total accumulated catch	Resolution of 0.01 in. (0.25 mm)	-----	-----	Tower base
Sigma-Theta	0°-100°	-----	-----	-----	See wind direction	10 m; 60 m

Note: Redundant primary and secondary instruments are installed for each sensed parameter.

Table 2.3-215
Annual Data Recovery Statistics - VEGP 60-Meter Meteorological Tower (1998-2002)

Parameter	1998	1999	2000	2001	2002
Wind Speed (10m)	99.0	99.0	97.8	95.1	97.1
Wind Speed (60 m)	98.4	98.1	97.7	95.2	96.7
Wind Direction (10 m)	99.1	98.9	98.4	95.2	96.4
Wind Direction (60 m)	88.2	93.3	96.6	95.3	97.6
Δ -Temperature (60m – 10m)[a]	96.6	98.6	97.2	94.9	99.3 [b]
Temperature (10 m)	99.2	98.9	97.8	95.0	97.6 [b]
Dewpoint (10 m)	99.0	98.3	85.5	95.1	89.6
Rainfall	99.5	99.3	99.1	96.3	78.8
Composite Parameters					
WS/WD (10m), ΔT (60m-10m) [a]	96.4	98.3	96.5	94.9	95.3
WS/WD (60m), ΔT (60m-10m) [a]	85.6	91.9	94.8	94.9	96.1

Notes:
a – Temperature difference (ΔT) between 10-m and 60-m levels.
b – Data recovery for Δ-Temperature is greater than the 10-m temperature parameter recovery rate due to data substitution by SNC in the 2002 data set for the ΔT parameter only.

Table 2.3-216
PAVAN Output – χ/Q Values at the Dose Calculation EAB

/ PLANT NAME: Vogtle COL
DATA PERIOD: 1998–2002 JFD
TYPE OF RELEASE: Ground-Level Release
SOURCE OF DATA: Onsite
COMMENTS: Accidental Releases
PROGRAM: PAVAN, 10/76, 8/79 REVISION, IMPLEMENTATION OF REGULATORY GUIDE 1.145

METEOROLOGICAL INSTRUMENTATION
WIND SENSORS HEIGHT: 10 m
DELTA-T HEIGHTS: 10 m – 60 m

0 RELATIVE CONCENTRATION (X/Q) VALUES (SEC/CUBIC METER) VERSUS AVERAGING TIME

DOWNWIND SECTOR	DISTANCE (METERS)	0–2 HOURS	0–8 HOURS	8–24 HOURS	1–4 DAYS	4–30 DAYS	ANNUAL AVERAGE IN SECTOR	HOURS PER YEAR MAX 0–2 HR X/Q IS EXCEEDED	DOWNWIND SECTOR
S	800.	2.53E–04	1.69E–04	1.38E–04	8.89E–05	4.73E–05	2.19E–05	29.9	S
SSW	800.	2.22E–04	1.49E–04	1.21E–04	7.84E–05	4.18E–05	1.94E–05	530.6	SSW
SW	800.	2.59E–04	1.77E–04	1.46E–04	9.61E–05	5.29E–05	2.54E–05	34.4	SW
WSW	800.	2.67E–04	1.82E–04	1.50E–04	9.95E–05	5.49E–05	2.65E–05	32.5	WSW
W	800.	2.88E–04	1.97E–04	1.63E–04	1.08E–04	5.94E–05	2.88E–05	36.9	W
WNW	800.	2.85E–04	1.92E–04	1.57E–04	1.02E–04	5.52E–05	2.59E–05	36.4	WNW
NW	800.	2.47E–04	1.67E–04	1.37E–04	8.97E–05	4.87E–05	2.30E–05	30.0	NW
NNW	800.	2.45E–04	1.67E–04	1.38E–04	9.16E–05	5.06E–05	2.45E–05	29.3	NNW
N	800.	2.42E–04	1.67E–04	1.39E–04	9.26E–05	5.20E–05	2.57E–05	25.6	N
NNE	800.	2.78E–04	1.92E–04	1.59E–04	1.06E–04	5.92E–05	2.91E–05	34.1	NNE
NE	800.	3.14E–04	2.21E–04	1.85E–04	1.26E–04	7.30E–05	3.73E–05	43.7	NE
ENE	800.	2.95E–04	2.10E–04	1.77E–04	1.22E–04	7.18E–05	3.74E–05	36.7	ENE
E	800.	3.03E–04	2.11E–04	1.77E–04	1.19E–04	6.82E–05	3.43E–05	40.1	E
ESE	800.	2.59E–04	1.75E–04	1.44E–04	9.45E–05	5.14E–05	2.44E–05	31.2	ESE
SE	800.	2.11E–04	1.42E–04	1.16E–04	7.51E–05	4.03E–05	1.88E–05	26.5	SE
SSE	800.	2.39E–04	1.56E–04	1.26E–04	7.91E–05	4.07E–05	1.80E–05	26.6	SSE
MAX X/Q		3.14E–04				TOTAL HOURS AROUND SITE:		*****	
SRP 2.3.4	800.	1.86E–03	9.75E–04	7.06E–04	3.50E–04	1.28E–04	3.74E–05		
SITE LIMIT		3.49E–04	2.41E–04	2.00E–04	1.34E–04	7.56E–05	3.74E–05		

0THE FIVE-PERCENT-FOR-THE-ENTIRE-SITE X/Q IS LIMITING.

Table 2.3-217
PAVAN Output – χ/Q Values at the LPZ

/ PLANT NAME: Vogtle COL
DATA PERIOD: 1998–2002 JFD
TYPE OF RELEASE: Ground-Level Release
SOURCE OF DATA: Onsite
COMMENTS: Accidental Release
PROGRAM: PAVAN, 10/76, 8/79 REVISION, IMPLEMENTATION OF REGULATORY GUIDE 1.145

METEOROLOGICAL INSTRUMENTATION
WIND SENSORS HEIGHT: 10 m
DELTA-T HEIGHTS: 10 m – 60 m

0 RELATIVE CONCENTRATION (X/Q) VALUES (SEC/CUBIC METER) VERSUS AVERAGING TIME

DOWNWIND SECTOR	DISTANCE (METERS)	0–2 HOURS	0–8 HOURS	8–24 HOURS	1–4 DAYS	4–30 DAYS	ANNUAL AVERAGE	HOURS PER YEAR MAX 0–2 HR X/Q IS EXCEEDED IN SECTOR	DOWNWIND SECTOR
S	2304.	8.95E–05	4.82E–05	3.54E–05	1.81E–05	6.89E–06	2.12E–06	29.6	S
SSW	2304.	7.42E–05	4.04E–05	2.98E–05	1.54E–05	5.97E–06	1.87E–06	502.4	SSW
SW	2304.	8.94E–05	4.94E–05	3.67E–05	1.93E–05	7.64E–06	2.47E–06	32.2	SW
WSW	2304.	9.17E–05	5.08E–05	3.78E–05	1.99E–05	7.92E–06	2.57E–06	29.5	WSW
W	2304.	1.02E–04	5.61E–05	4.17E–05	2.19E–05	8.66E–06	2.79E–06	34.5	W
WNW	2304.	1.03E–04	5.56E–05	4.09E–05	2.10E–05	8.10E–06	2.52E–06	34.9	WNW
NW	2304.	8.52E–05	4.67E–05	3.45E–05	1.80E–05	7.04E–06	2.24E–06	28.3	NW
NNW	2304.	8.53E–05	4.72E–05	3.51E–05	1.85E–05	7.36E–06	2.38E–06	28.5	NNW
N	2304.	8.32E–05	4.66E–05	3.48E–05	1.86E–05	7.52E–06	2.49E–06	24.1	N
NNE	2304.	1.00E–04	5.55E–05	4.13E–05	2.18E–05	8.68E–06	2.82E–06	32.8	NNE
NE	2304.	1.11E–04	6.28E–05	4.73E–05	2.56E–05	1.06E–05	3.61E–06	39.5	NE
ENE	2304.	1.17E–04	6.59E–05	4.95E–05	2.65E–05	1.08E–05	3.63E–06	43.7	ENE
E	2304.	1.15E–04	6.40E–05	4.78E–05	2.53E–05	1.01E–05	3.32E–06	42.3	E
ESE	2304.	9.13E–05	4.99E–05	3.69E–05	1.92E–05	7.48E–06	2.36E–06	29.4	ESE
SE	2304.	7.34E–05	3.98E–05	2.94E–05	1.51E–05	5.83E–06	1.82E–06	25.8	SE
SSE	2304.	8.49E–05	4.47E–05	3.24E–05	1.61E–05	5.92E–06	1.74E–06	26.6	SSE
MAX X/Q		1.17E–04				TOTAL HOURS AROUND SITE:		984.3	
SRP 2.3.4	2304.	3.47E–04	1.63E–04	1.12E–04	4.94E–05	1.53E–05	3.63E–06		
SITE LIMIT		1.27E–04	7.04E–05	5.25E–05	2.77E–05	1.11E–05	3.63E–06		

0THE FIVE-PERCENT-FOR-THE-ENTIRE-SITE X/Q IS LIMITING.

Table 2.3-218
Shortest Distances Between the VEGP Units 3 and 4 Power Block Area and Receptors of Interest by Downwind Direction Sector[a]

Direction	Meat Animal	Residence	Vegetable Garden	EAB[b]
N	1,071	1,071	1,071	800
NNE	1,071	1,071	1,071	800
NE	1,071	1,071	1,071	800
ENE	1,071	1,071	1,071	800
E	1,071	1,071	1,071	800
ESE	1,071	1,071	1,071	800
SE	1,071	1,071	1,071	800
SSE	1,071	1,071	1,071	800
S	1,071	1,071	1,071	800
SSW	1,071	1,071	1,071	800
SW	1,071	1,071	1,071	800
WSW	1,071	1,071	1,071	800
W	1,071	1,071	1,071	800
WNW	1,071	1,071	1,071	800
NW	1,071	1,071	1,071	800
NNW	1,071	1,071	1,071	800

Notes:
a – Distances shown are in meters
b – EAB = Exclusion Area Boundary
c – There are no milk-giving animals (i.e., cows, goats) within a 5-mile radius of the VEGP Units 3 and 4 Site.

Table 2.3-219
XOQDOQ-Predicted Maximum χ/Q and D/Q Values at Receptors of Interest

Type of Location	Direction from Site	Distance meters/ (miles)	χ/Q (sec/m^3) (No Decay) (Undepleted)	χ/Q (sec/m^3) (2.26 Day Decay) (Undepleted)	χ/Q (sec/m^3) (8 Day Decay) (Depleted)	D/Q (1/m^2)
Residence	NE	1,071 (0.67)	3.4E-06	3.4E-06	3.0E-06	1.0E-08[a]
Dose Calculation EAB	NE	800 (0.5)	5.5E-06	5.5E-06	5.0E-06	1.7E-08[b]
Meat Animal	NE	1,071 (0.67)	3.4E-06	3.4E-06	3.0E-06	1.0E-08[a]
Vegetable Garden	NE	1,071 (0.67)	3.4E-06	3.4E-06	3.0E-06	1.0E-08[a]

Notes:
a – NE, ENE, and E
b – NE and ENE

Table 2.3-220 (Sheet 1 of 4)
XOQDOQ-Predicted Annual Average χ/Q and D/Q Values at the Standard Radial Distances and Distance-Segment Boundaries

No Decay X/Qs at Various Distances

EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
NO DECAY, UNDEPLETED

ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) — DISTANCE IN MILES FROM THE SITE

SECTOR	0.250	0.500	0.750	1.000	1.500	2.000	2.500	3.000	3.500	4.000	4.500
S	1.097E-05	3.306E-06	1.697E-06	1.088E-06	6.032E-07	3.998E-07	2.971E-07	2.339E-07	1.912E-07	1.606E-07	1.377E-07
SSW	9.903E-06	2.986E-06	1.546E-06	9.958E-07	5.570E-07	3.707E-07	2.750E-07	2.160E-07	1.762E-07	1.478E-07	1.265E-07
SW	1.326E-05	3.993E-06	2.063E-06	1.328E-06	7.408E-07	4.926E-07	3.660E-07	2.881E-07	2.353E-07	1.976E-07	1.694E-07
WSW	1.342E-05	4.026E-06	2.076E-06	1.336E-06	7.479E-07	4.982E-07	3.702E-07	2.912E-07	2.378E-07	1.996E-07	1.711E-07
W	1.421E-05	4.237E-06	2.168E-06	1.392E-06	7.796E-07	5.201E-07	3.877E-07	3.059E-07	2.504E-07	2.106E-07	1.808E-07
WNW	1.282E-05	3.803E-06	1.947E-06	1.251E-06	7.014E-07	4.684E-07	3.498E-07	2.764E-07	2.266E-07	1.908E-07	1.639E-07
NW	1.157E-05	3.450E-06	1.790E-06	1.156E-06	6.516E-07	4.357E-07	3.241E-07	2.552E-07	2.086E-07	1.751E-07	1.502E-07
NNW	1.210E-05	3.626E-06	1.899E-06	1.231E-06	6.940E-07	4.637E-07	3.443E-07	2.706E-07	2.208E-07	1.852E-07	1.586E-07
N	1.239E-05	3.719E-06	1.951E-06	1.266E-06	7.147E-07	4.779E-07	3.543E-07	2.781E-07	2.266E-07	1.898E-07	1.624E-07
NNE	1.424E-05	4.240E-06	2.171E-06	1.395E-06	7.821E-07	5.221E-07	3.892E-07	3.071E-07	2.515E-07	2.115E-07	1.816E-07
NE	1.832E-05	5.438E-06	2.773E-06	1.778E-06	9.945E-07	6.633E-07	4.952E-07	3.914E-07	3.208E-07	2.702E-07	2.322E-07
ENE	1.781E-05	5.295E-06	2.696E-06	1.728E-06	9.670E-07	6.451E-07	4.816E-07	3.805E-07	3.119E-07	2.626E-07	2.257E-07
E	1.645E-05	4.895E-06	2.488E-06	1.591E-06	8.856E-07	5.890E-07	4.395E-07	3.473E-07	2.847E-07	2.397E-07	2.060E-07
ESE	1.211E-05	3.630E-06	1.865E-06	1.198E-06	6.685E-07	4.449E-07	3.310E-07	2.607E-07	2.132E-07	1.791E-07	1.537E-07
SE	9.657E-06	2.893E-06	1.486E-06	9.531E-07	5.289E-07	3.509E-07	2.611E-07	2.058E-07	1.684E-07	1.415E-07	1.215E-07
SSE	9.037E-06	2.711E-06	1.382E-06	8.836E-07	4.892E-07	3.242E-07	2.413E-07	1.903E-07	1.558E-07	1.310E-07	1.125E-07

ANNUAL AVERAGE CHI/Q (SEC/METER CUBED) — DISTANCE IN MILES FROM THE SITE

SECTOR	5.000	7.500	10.000	15.000	20.000	25.000	30.000	35.000	40.000	45.000	50.000
S	1.201E-07	7.112E-08	4.917E-08	2.936E-08	2.045E-08	1.546E-08	1.232E-08	1.018E-08	8.626E-09	7.459E-09	6.552E-09
SSW	1.102E-07	6.491E-08	4.471E-08	2.655E-08	1.841E-08	1.388E-08	1.103E-08	9.093E-09	7.694E-09	6.642E-09	5.826E-09
SW	1.477E-07	8.727E-08	6.025E-08	3.589E-08	2.493E-08	1.883E-08	1.498E-08	1.236E-08	1.046E-08	9.039E-09	7.932E-09
WSW	1.492E-07	8.812E-08	6.081E-08	3.621E-08	2.515E-08	1.899E-08	1.511E-08	1.246E-08	1.055E-08	9.113E-09	7.996E-09
W	1.579E-07	9.376E-08	6.494E-08	3.885E-08	2.707E-08	2.048E-08	1.632E-08	1.348E-08	1.143E-08	9.884E-09	8.682E-09
WNW	1.432E-07	8.529E-08	5.918E-08	3.548E-08	2.475E-08	1.875E-08	1.495E-08	1.236E-08	1.048E-08	9.067E-09	7.967E-09
NW	1.309E-07	7.737E-08	5.339E-08	3.178E-08	2.206E-08	1.664E-08	1.323E-08	1.091E-08	9.232E-09	7.971E-09	6.992E-09
NNW	1.381E-07	8.131E-08	5.597E-08	3.318E-08	2.297E-08	1.730E-08	1.373E-08	1.130E-08	9.553E-09	8.239E-09	7.221E-09
N	1.413E-07	8.295E-08	5.697E-08	3.369E-08	2.328E-08	1.751E-08	1.388E-08	1.142E-08	9.644E-09	8.313E-09	7.281E-09
NNE	1.585E-07	9.419E-08	6.524E-08	3.904E-08	2.720E-08	2.058E-08	1.640E-08	1.355E-08	1.149E-08	9.932E-09	8.724E-09
NE	2.029E-07	1.209E-07	8.394E-08	5.038E-08	3.517E-08	2.666E-08	2.127E-08	1.759E-08	1.492E-08	1.291E-08	1.135E-08
ENE	1.971E-07	1.174E-07	8.150E-08	4.889E-08	3.413E-08	2.586E-08	2.064E-08	1.706E-08	1.447E-08	1.253E-08	1.101E-08
E	1.800E-07	1.073E-07	7.453E-08	4.477E-08	3.129E-08	2.373E-08	1.895E-08	1.568E-08	1.331E-08	1.152E-08	1.013E-08
ESE	1.341E-07	7.943E-08	5.492E-08	3.279E-08	2.282E-08	1.725E-08	1.374E-08	1.134E-08	9.613E-09	8.310E-09	7.297E-09
SE	1.060E-07	6.292E-08	4.357E-08	2.607E-08	1.818E-08	1.376E-08	1.097E-08	9.066E-09	7.689E-09	6.652E-09	5.845E-09
SSE	9.818E-08	5.836E-08	4.046E-08	2.425E-08	1.693E-08	1.283E-08	1.024E-08	8.467E-09	7.186E-09	6.220E-09	5.468E-09

Table 2.3-220 (Sheet 2 of 4)
XOQDOQ-Predicted Annual Average χ/Q and D/Q Values at the Standard Radial Distances and Distance-Segment Boundaries

No Decay X/Qs at Various Segments

EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES
NO DECAY, UNDEPLETED
CHI/Q (SEC/METER CUBED) FOR EACH SEGMENT

	SEGMENT BOUNDARIES IN MILES FROM THE SITE									
DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	1.784E-06	6.205E-07	2.992E-07	1.917E-07	1.380E-07	7.225E-08	2.980E-08	1.554E-08	1.020E-08	7.469E-09
SSW	1.621E-06	5.717E-07	2.769E-07	1.767E-07	1.268E-07	6.600E-08	2.697E-08	1.395E-08	9.115E-09	6.651E-09
SW	2.165E-06	7.609E-07	3.686E-07	2.360E-07	1.697E-07	8.868E-08	3.643E-08	1.892E-08	1.238E-08	9.051E-09
WSW	2.181E-06	7.677E-07	3.727E-07	2.385E-07	1.714E-07	8.955E-08	3.676E-08	1.908E-08	1.249E-08	9.125E-09
W	2.283E-06	8.003E-07	3.903E-07	2.511E-07	1.812E-07	9.519E-08	3.941E-08	2.057E-08	1.351E-08	9.897E-09
WNW	2.050E-06	7.200E-07	3.521E-07	2.272E-07	1.642E-07	8.656E-08	3.598E-08	1.883E-08	1.238E-08	9.079E-09
NW	1.877E-06	6.678E-07	3.263E-07	2.092E-07	1.504E-07	7.861E-08	3.226E-08	1.672E-08	1.093E-08	7.982E-09
NNW	1.986E-06	7.111E-07	3.467E-07	2.215E-07	1.589E-07	8.267E-08	3.371E-08	1.738E-08	1.133E-08	8.251E-09
N	2.039E-06	7.319E-07	3.568E-07	2.273E-07	1.627E-07	8.438E-08	3.424E-08	1.760E-08	1.145E-08	8.325E-09
NNE	2.286E-06	8.027E-07	3.918E-07	2.521E-07	1.819E-07	9.562E-08	3.960E-08	2.068E-08	1.358E-08	9.945E-09
NE	2.923E-06	1.021E-06	4.985E-07	3.217E-07	2.326E-07	1.227E-07	5.108E-08	2.677E-08	1.763E-08	1.293E-08
ENE	2.843E-06	9.930E-07	4.847E-07	3.127E-07	2.260E-07	1.192E-07	4.958E-08	2.598E-08	1.710E-08	1.254E-08
E	2.624E-06	9.106E-07	4.425E-07	2.854E-07	2.064E-07	1.089E-07	4.539E-08	2.383E-08	1.571E-08	1.154E-08
ESE	1.961E-06	6.867E-07	3.333E-07	2.138E-07	1.540E-07	8.068E-08	3.328E-08	1.733E-08	1.137E-08	8.321E-09
SE	1.562E-06	5.440E-07	2.629E-07	1.688E-07	1.217E-07	6.390E-08	2.645E-08	1.382E-08	9.086E-09	6.660E-09
SSE	1.456E-06	5.035E-07	2.430E-07	1.562E-07	1.127E-07	5.925E-08	2.460E-08	1.289E-08	8.486E-09	6.228E-09

Table 2.3-220 (Sheet 3 of 4)
XOQDOQ-Predicted Annual Average χ/Q and D/Q Values at the Standard Radial Distances and Distance-Segment Boundaries

D/Qs at Various Distances

EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES

********** RELATIVE DEPOSITION PER UNIT AREA (M**-2) AT FIXED POINTS BY DOWNWIND SECTORS **********

DIRECTION	DISTANCES IN MILES										
FROM SITE	0.25	0.50	0.75	1.00	1.50	2.00	2.50	3.00	3.50	4.00	4.50
S	3.128E-08	1.058E-08	5.431E-09	3.335E-09	1.663E-09	1.008E-09	6.817E-10	4.940E-10	3.756E-10	2.959E-10	2.396E-10
SSW	2.900E-08	9.807E-09	5.035E-09	3.092E-09	1.541E-09	9.348E-10	6.321E-10	4.580E-10	3.483E-10	2.744E-10	2.221E-10
SW	4.066E-08	1.375E-08	7.059E-09	4.334E-09	2.161E-09	1.311E-09	8.861E-10	6.421E-10	4.882E-10	3.847E-10	3.114E-10
WSW	4.440E-08	1.502E-08	7.710E-09	4.734E-09	2.360E-09	1.431E-09	9.678E-10	7.013E-10	5.333E-10	4.201E-10	3.401E-10
W	3.911E-08	1.323E-08	6.791E-09	4.170E-09	2.079E-09	1.261E-09	8.525E-10	6.177E-10	4.697E-10	3.701E-10	2.996E-10
WNW	2.948E-08	9.971E-09	5.119E-09	3.143E-09	1.567E-09	9.505E-10	6.426E-10	4.657E-10	3.541E-10	2.790E-10	2.258E-10
NW	2.963E-08	1.002E-08	5.145E-09	3.159E-09	1.575E-09	9.552E-10	6.458E-10	4.680E-10	3.559E-10	2.804E-10	2.270E-10
NNW	3.119E-08	1.055E-08	5.415E-09	3.325E-09	1.658E-09	1.005E-09	6.797E-10	4.925E-10	3.745E-10	2.951E-10	2.389E-10
N	3.408E-08	1.152E-08	5.917E-09	3.633E-09	1.811E-09	1.099E-09	7.427E-10	5.382E-10	4.092E-10	3.224E-10	2.610E-10
NNE	3.910E-08	1.322E-08	6.789E-09	4.169E-09	2.078E-09	1.260E-09	8.522E-10	6.175E-10	4.696E-10	3.699E-10	2.995E-10
NE	4.897E-08	1.656E-08	8.503E-09	5.221E-09	2.603E-09	1.579E-09	1.067E-09	7.735E-10	5.882E-10	4.634E-10	3.751E-10
ENE	4.850E-08	1.640E-08	8.422E-09	5.171E-09	2.578E-09	1.564E-09	1.057E-09	7.661E-10	5.825E-10	4.589E-10	3.715E-10
E	4.798E-08	1.622E-08	8.330E-09	5.115E-09	2.550E-09	1.547E-09	1.046E-09	7.578E-10	5.762E-10	4.539E-10	3.675E-10
ESE	3.612E-08	1.221E-08	6.271E-09	3.851E-09	1.920E-09	1.164E-09	7.872E-10	5.704E-10	4.338E-10	3.417E-10	2.766E-10
SE	2.507E-08	8.478E-09	4.353E-09	2.673E-09	1.333E-09	8.082E-10	5.464E-10	3.960E-10	3.011E-10	2.372E-10	1.920E-10
SSE	2.440E-08	8.252E-09	4.237E-09	2.602E-09	1.297E-09	7.867E-10	5.319E-10	3.854E-10	2.931E-10	2.309E-10	1.869E-10

DIRECTION	DISTANCES IN MILES										
FROM SITE	5.00	7.50	10.00	15.00	20.00	25.00	30.00	35.00	40.00	45.00	50.00
S	1.982E-10	9.712E-11	6.094E-11	3.080E-11	1.864E-11	1.250E-11	8.956E-12	6.725E-12	5.229E-12	4.177E-12	3.409E-12
SSW	1.837E-10	9.004E-11	5.650E-11	2.856E-11	1.728E-11	1.159E-11	8.304E-12	6.235E-12	4.848E-12	3.873E-12	3.161E-12
SW	2.576E-10	1.262E-10	7.920E-11	4.003E-11	2.423E-11	1.625E-11	1.164E-11	8.741E-12	6.796E-12	5.429E-12	4.431E-12
WSW	2.813E-10	1.379E-10	8.651E-11	4.372E-11	2.646E-11	1.774E-11	1.271E-11	9.547E-12	7.423E-12	5.930E-12	4.840E-12
W	2.478E-10	1.214E-10	7.620E-11	3.851E-11	2.331E-11	1.563E-11	1.120E-11	8.409E-12	6.538E-12	5.223E-12	4.263E-12
WNW	1.868E-10	9.155E-11	5.744E-11	2.903E-11	1.757E-11	1.178E-11	8.442E-12	6.339E-12	4.929E-12	3.937E-12	3.214E-12
NW	1.877E-10	9.200E-11	5.773E-11	2.918E-11	1.766E-11	1.184E-11	8.484E-12	6.371E-12	4.954E-12	3.957E-12	3.230E-12
NNW	1.976E-10	9.683E-11	6.075E-11	3.071E-11	1.859E-11	1.246E-11	8.929E-12	6.705E-12	5.213E-12	4.164E-12	3.399E-12
N	2.159E-10	1.058E-10	6.639E-11	3.356E-11	2.031E-11	1.362E-11	9.757E-12	7.327E-12	5.697E-12	4.551E-12	3.714E-12
NNE	2.477E-10	1.214E-10	7.617E-11	3.850E-11	2.330E-11	1.562E-11	1.120E-11	8.406E-12	6.536E-12	5.221E-12	4.262E-12
NE	3.103E-10	1.521E-10	9.541E-11	4.823E-11	2.919E-11	1.957E-11	1.402E-11	1.053E-11	8.187E-12	6.540E-12	5.338E-12
ENE	3.073E-10	1.506E-10	9.450E-11	4.776E-11	2.891E-11	1.938E-11	1.389E-11	1.043E-11	8.109E-12	6.477E-12	5.287E-12
E	3.040E-10	1.490E-10	9.347E-11	4.724E-11	2.859E-11	1.917E-11	1.374E-11	1.032E-11	8.021E-12	6.407E-12	5.229E-12
ESE	2.288E-10	1.121E-10	7.036E-11	3.557E-11	2.153E-11	1.443E-11	1.034E-11	7.766E-12	6.038E-12	4.823E-12	3.937E-12
SE	1.588E-10	7.784E-11	4.884E-11	2.469E-11	1.494E-11	1.002E-11	7.178E-12	5.390E-12	4.191E-12	3.348E-12	2.733E-12
SSE	1.546E-10	7.577E-11	4.754E-11	2.403E-11	1.454E-11	9.752E-12	6.988E-12	5.247E-12	4.080E-12	3.259E-12	2.660E-12

Table 2.3-220 (Sheet 4 of 4)
XOQDOQ-Predicted Annual Average χ/Q and D/Q Values at the Standard Radial Distances and Distance-Segment Boundaries

D/Qs at Various Segments

EXIT ONE - GROUND LEVEL RELEASE - NO PURGE RELEASES

********** RELATIVE DEPOSITION PER UNIT AREA (M**-2) BY DOWNWIND SECTORS **********

SEGMENT BOUNDARIES IN MILES

DIRECTION FROM SITE	.5-1	1-2	2-3	3-4	4-5	5-10	10-20	20-30	30-40	40-50
S	5.643E-09	1.743E-09	6.937E-10	3.791E-10	2.409E-10	1.035E-10	3.209E-11	1.272E-11	6.793E-12	4.204E-12
SSW	5.232E-09	1.616E-09	6.432E-10	3.515E-10	2.234E-10	9.595E-11	2.975E-11	1.179E-11	6.298E-12	3.898E-12
SW	7.335E-09	2.266E-09	9.017E-10	4.927E-10	3.132E-10	1.345E-10	4.171E-11	1.653E-11	8.829E-12	5.465E-12
WSW	8.011E-09	2.475E-09	9.848E-10	5.382E-10	3.420E-10	1.469E-10	4.556E-11	1.806E-11	9.643E-12	5.968E-12
W	7.056E-09	2.180E-09	8.675E-10	4.740E-10	3.013E-10	1.294E-10	4.013E-11	1.591E-11	8.494E-12	5.257E-12
WNW	5.319E-09	1.643E-09	6.539E-10	3.574E-10	2.271E-10	9.756E-11	3.025E-11	1.199E-11	6.403E-12	3.963E-12
NW	5.346E-09	1.652E-09	6.572E-10	3.591E-10	2.283E-10	9.804E-11	3.040E-11	1.205E-11	6.435E-12	3.983E-12
NNW	5.626E-09	1.738E-09	6.917E-10	3.780E-10	2.402E-10	1.032E-10	3.200E-11	1.268E-11	6.772E-12	4.192E-12
N	6.148E-09	1.899E-09	7.558E-10	4.130E-10	2.625E-10	1.128E-10	3.496E-11	1.386E-11	7.400E-12	4.580E-12
NNE	7.054E-09	2.179E-09	8.672E-10	4.739E-10	3.012E-10	1.294E-10	4.012E-11	1.590E-11	8.491E-12	5.255E-12
NE	8.835E-09	2.730E-09	1.086E-09	5.936E-10	3.773E-10	1.620E-10	5.025E-11	1.992E-11	1.064E-11	6.583E-12
ENE	8.751E-09	2.703E-09	1.076E-09	5.879E-10	3.736E-10	1.605E-10	4.977E-11	1.972E-11	1.053E-11	6.520E-12
E	8.656E-09	2.674E-09	1.064E-09	5.815E-10	3.696E-10	1.587E-10	4.923E-11	1.951E-11	1.042E-11	6.449E-12
ESE	6.516E-09	2.013E-09	8.011E-10	4.377E-10	2.782E-10	1.195E-10	3.706E-11	1.469E-11	7.843E-12	4.855E-12
SE	4.523E-09	1.397E-09	5.560E-10	3.039E-10	1.931E-10	8.295E-11	2.572E-11	1.020E-11	5.444E-12	3.370E-12
SSE	4.403E-09	1.360E-09	5.413E-10	2.958E-10	1.880E-10	8.075E-11	2.504E-11	9.924E-12	5.300E-12	3.280E-12

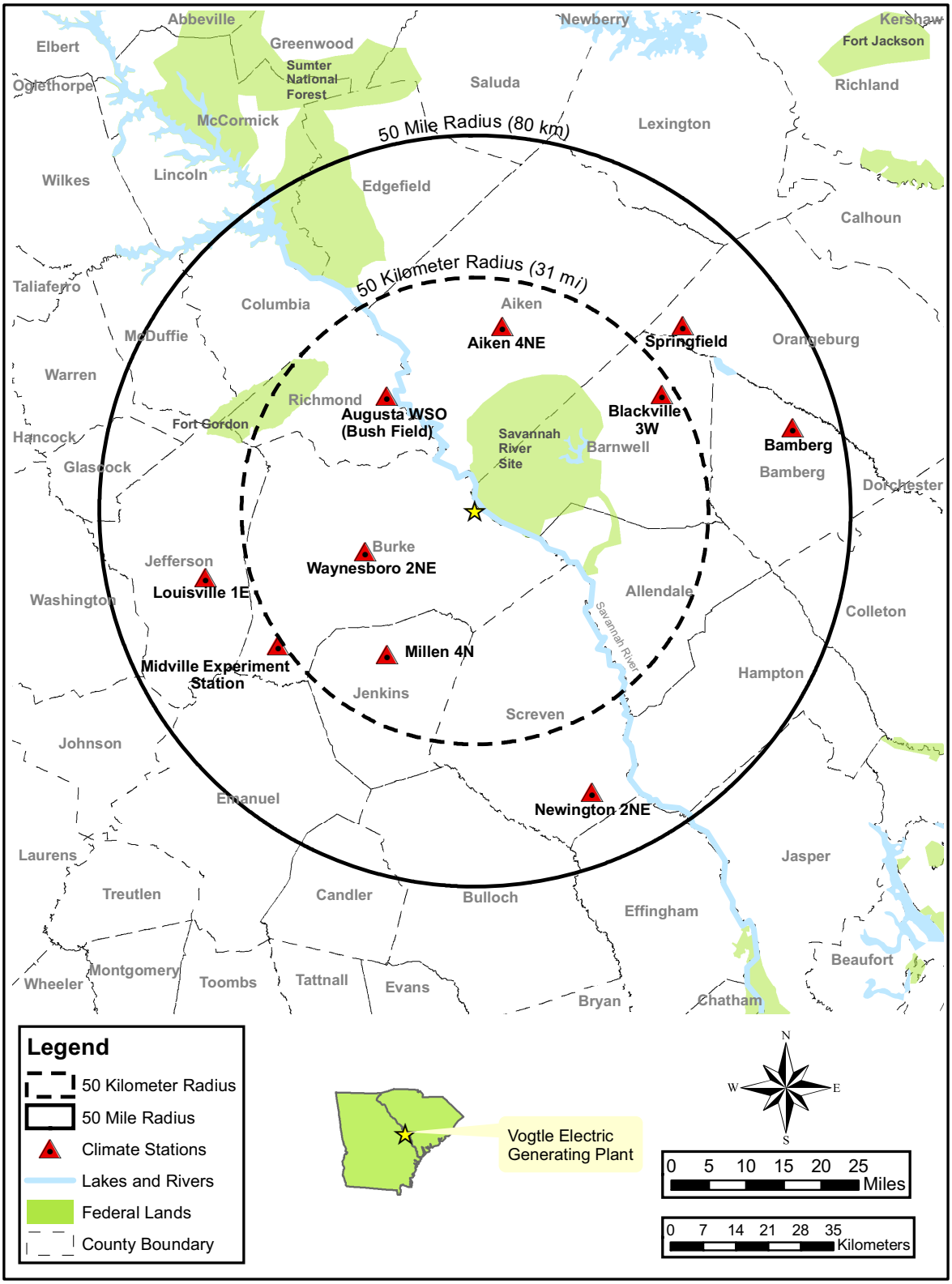

Figure 2.3-201
Climatological Observing Stations Near the VEGP Site

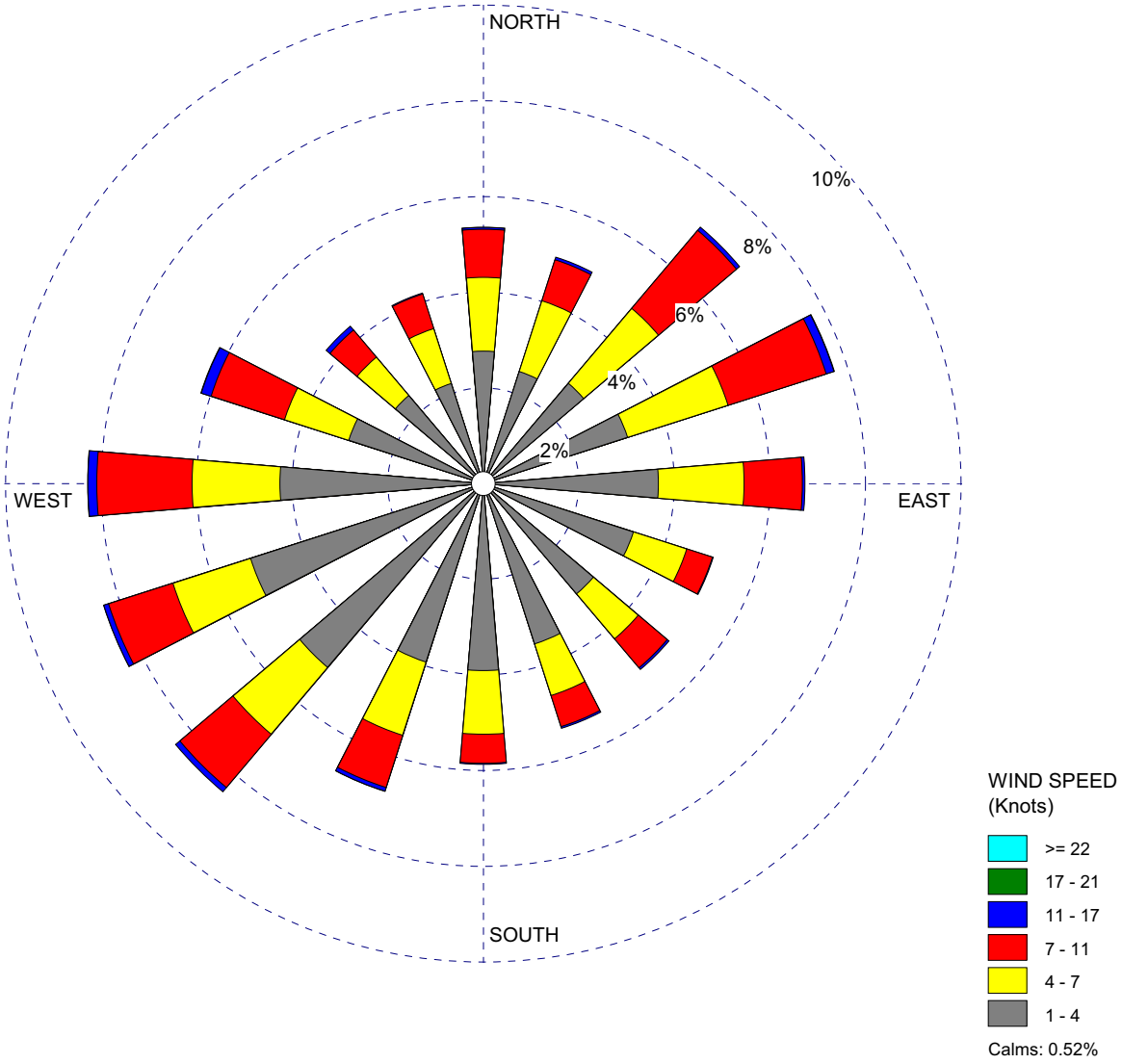

Figure 2.3-202
VEGP 10-m Level Annual Wind Rose (1998-2002)

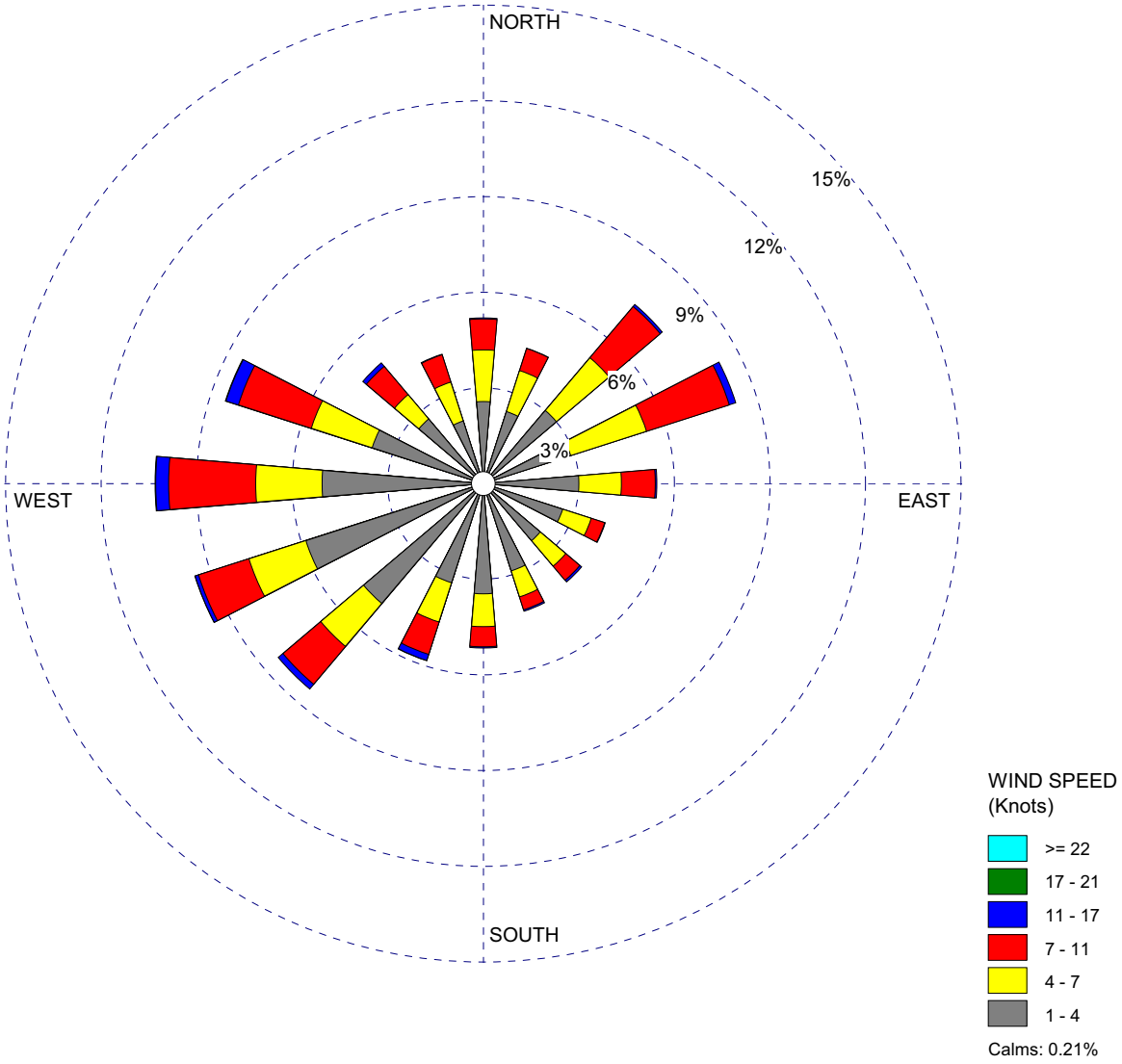

Figure 2.3-203
VEGP 10-m Level Winter Wind Rose (1998-2002)

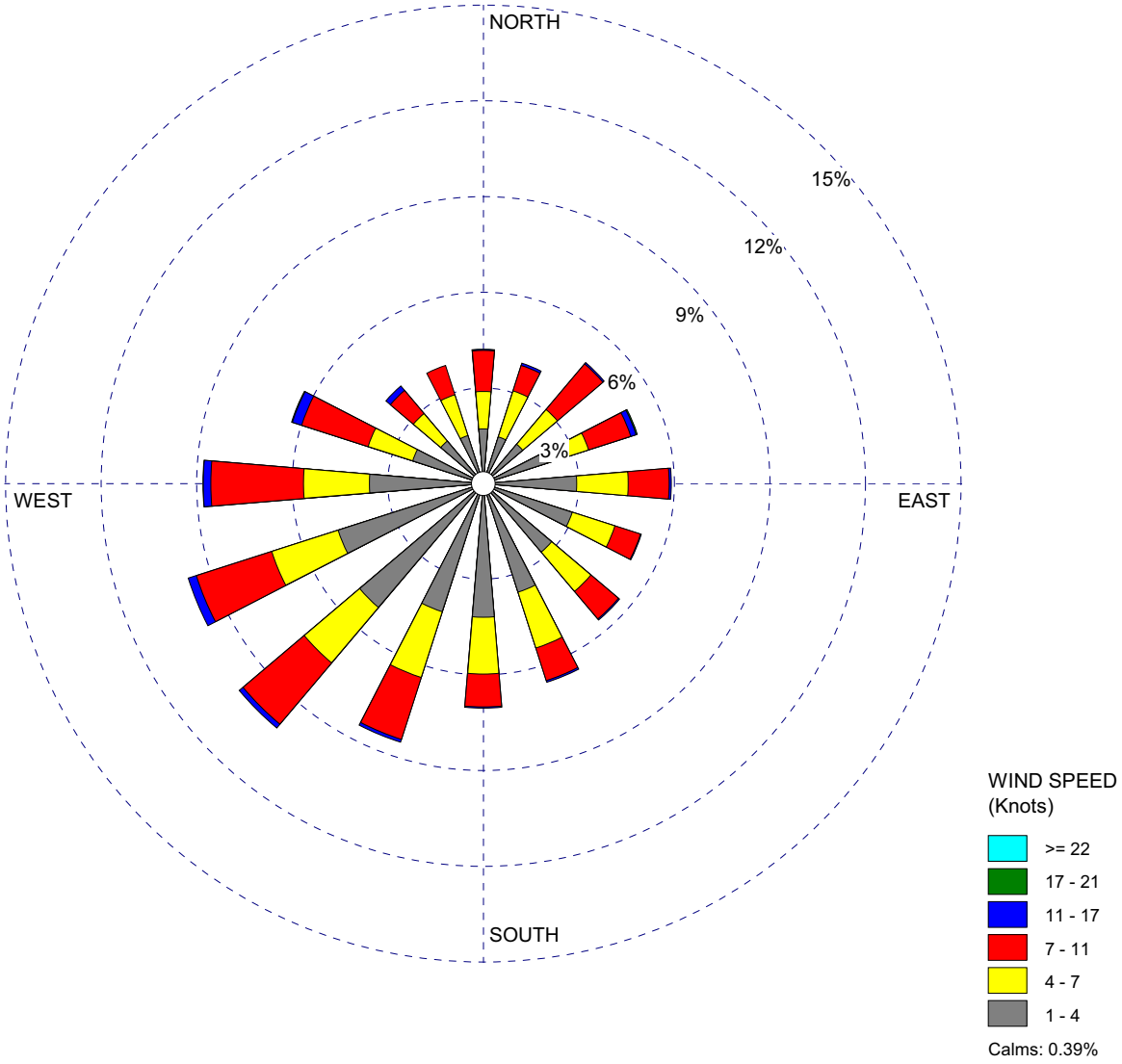

Figure 2.3-204
VEGP 10-m Level Spring Wind Rose (1998-2002)

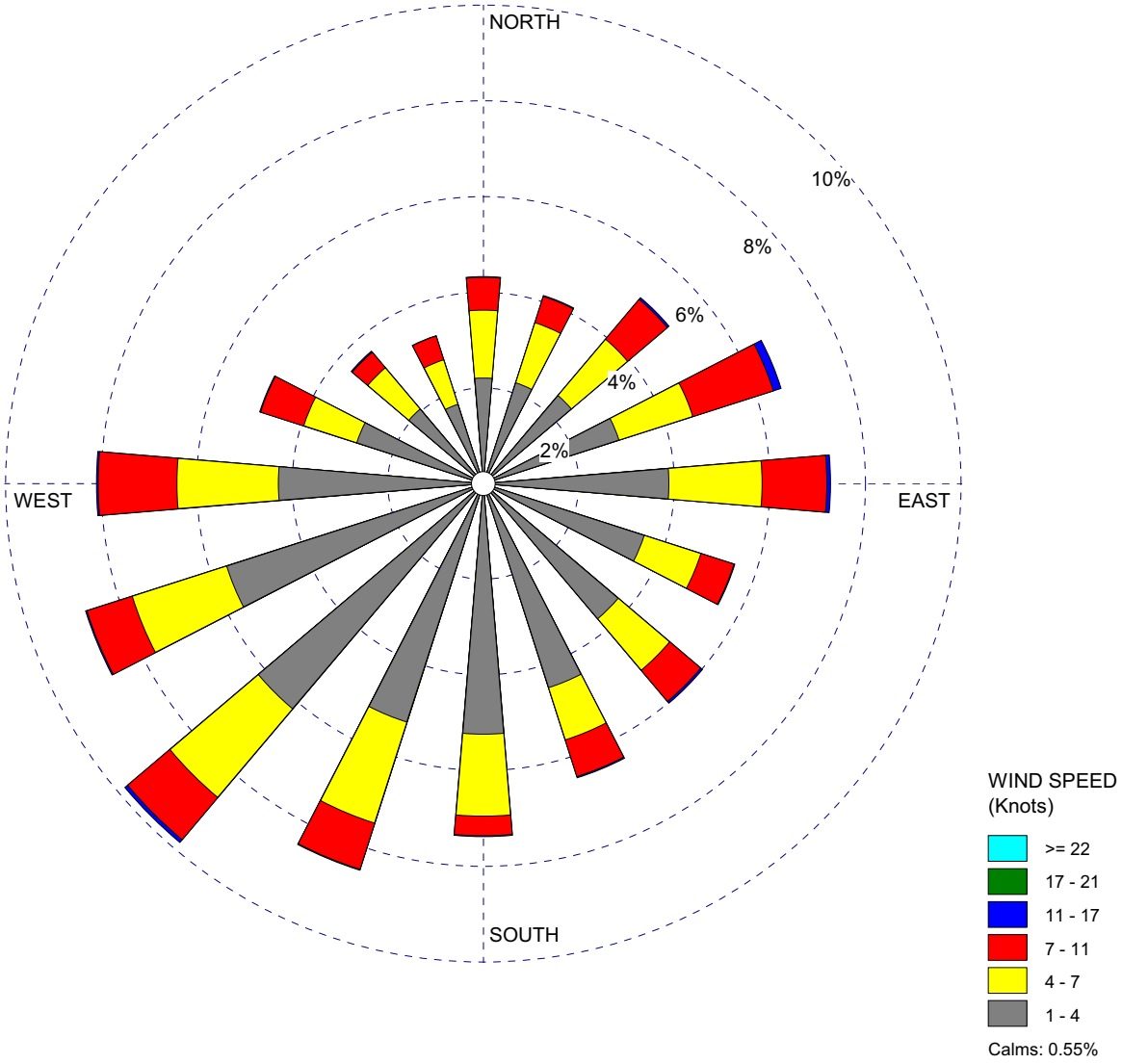

Figure 2.3-205
VEGP 10-m Level Summer Wind Rose (1998-2002)

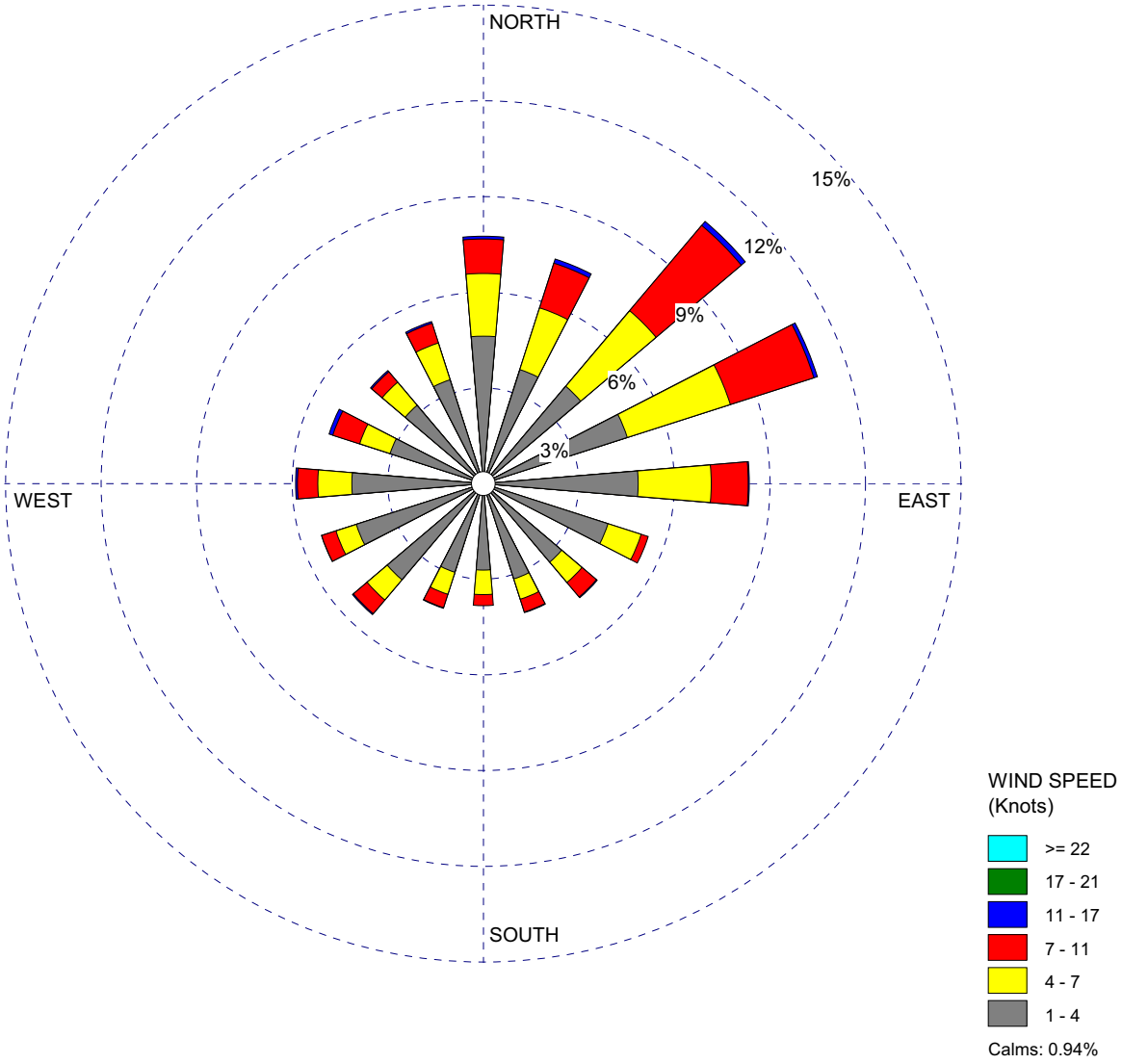

Figure 2.3-206
VEGP 10-m Level Autumn Wind Rose (1998-2002)

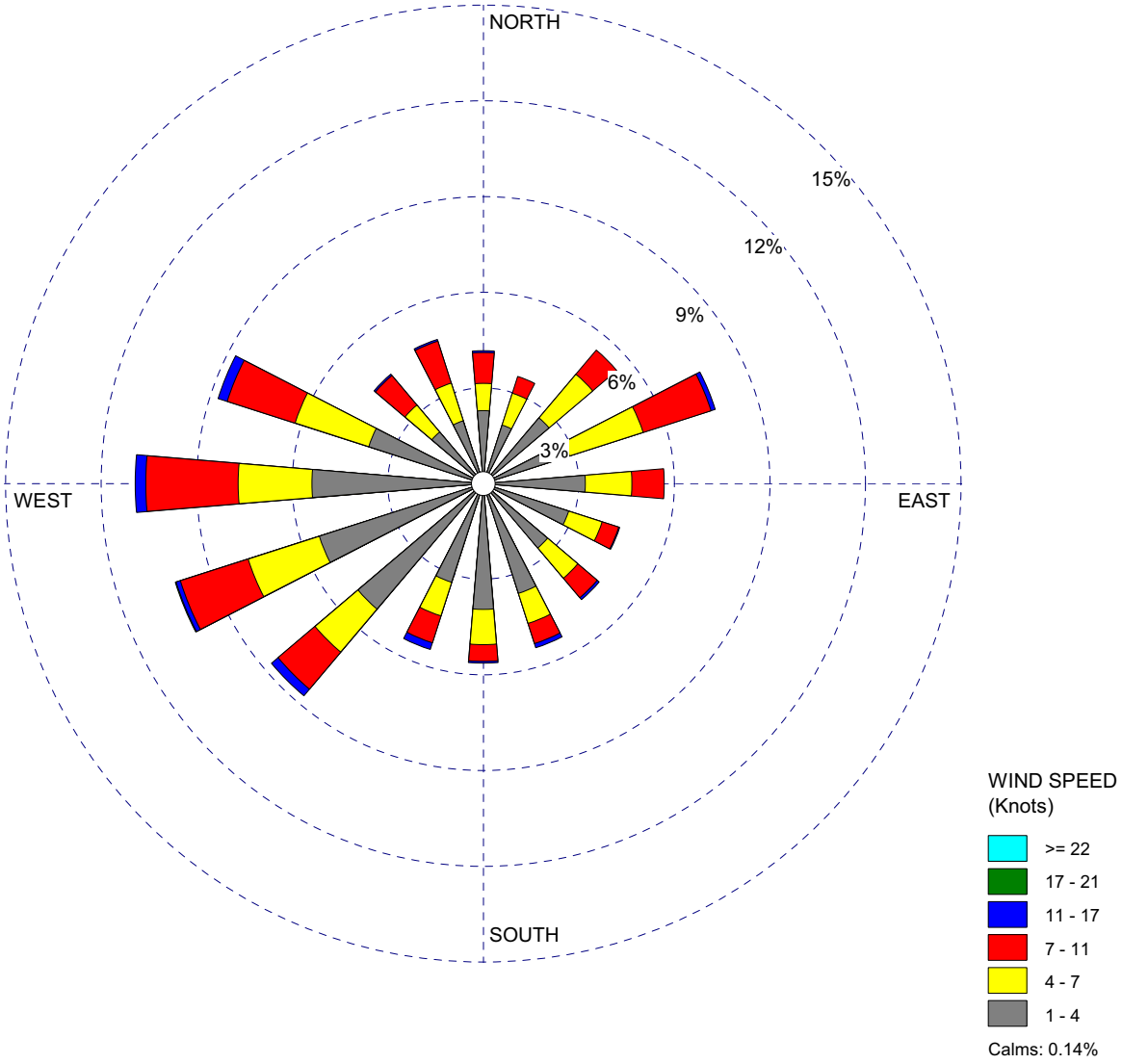

Figure 2.3-207 (Sheet 1 of 12)
VEGP 10-m Level January Wind Rose (1998–2002)

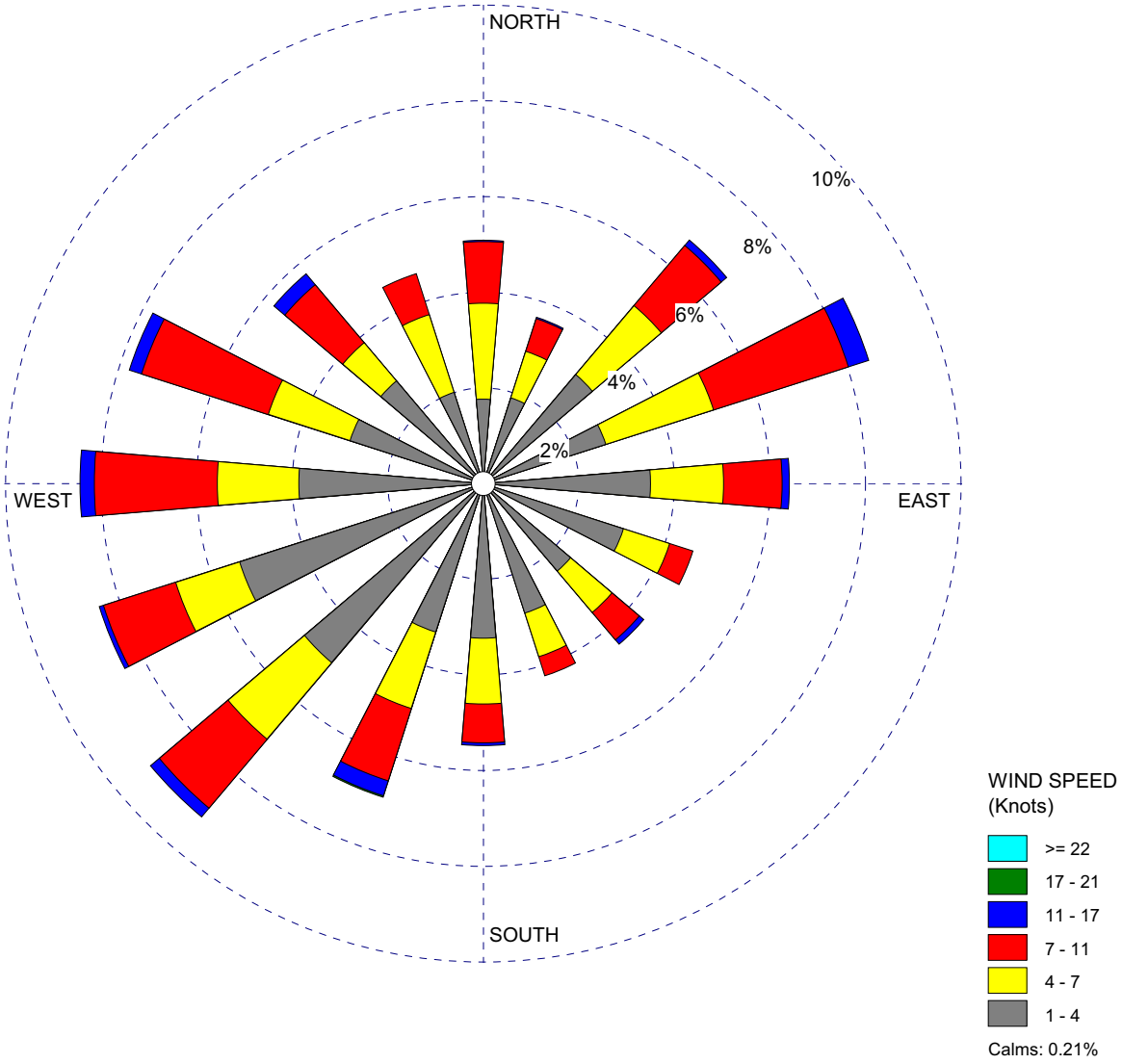

Figure 2.3-207 (Sheet 2 of 12)
VEGP 10-m Level February Wind Rose (1998–2002)

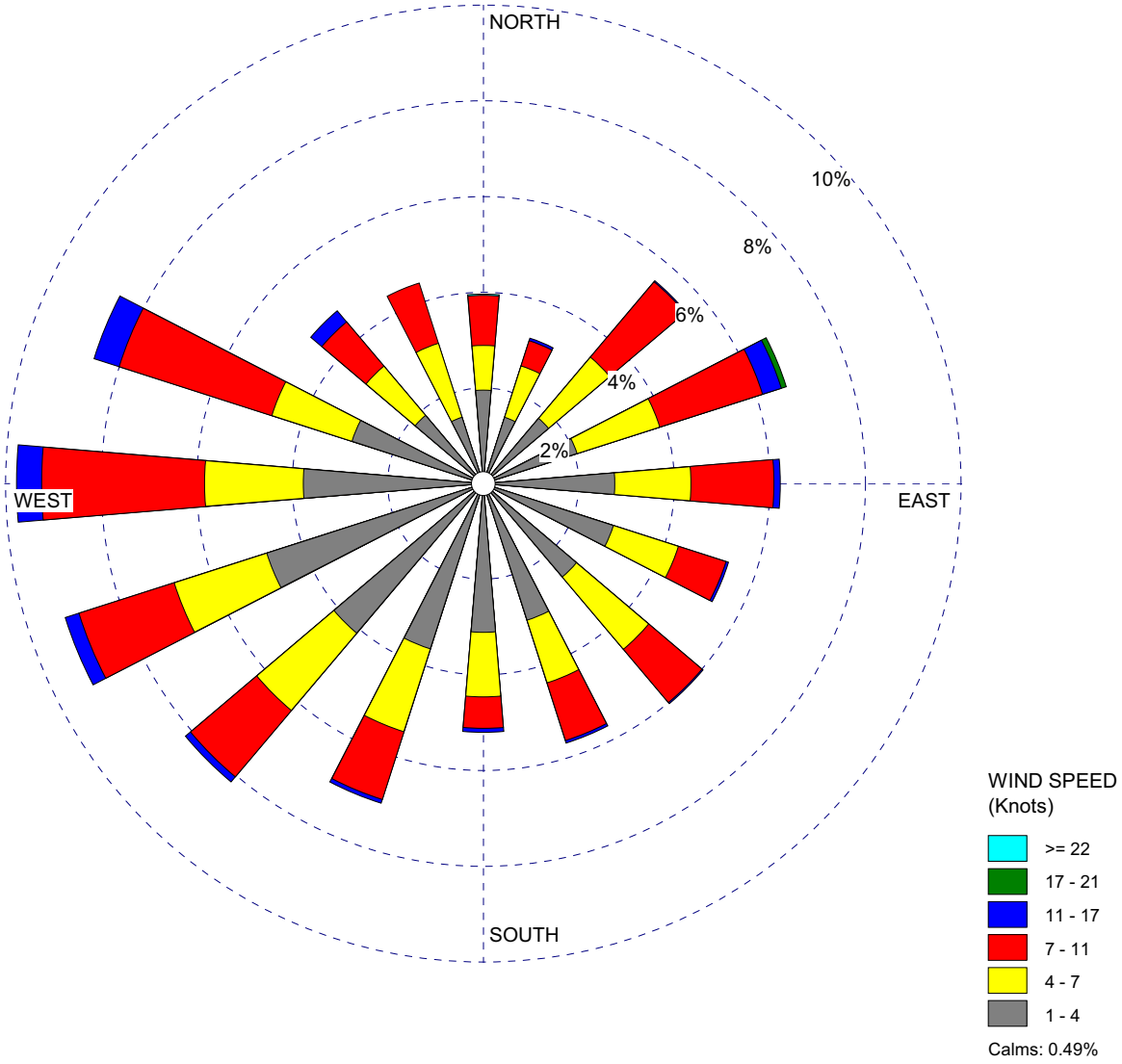

Figure 2.3-207 (Sheet 3 of 12)
VEGP 10-m Level March Wind Rose (1998–2002)

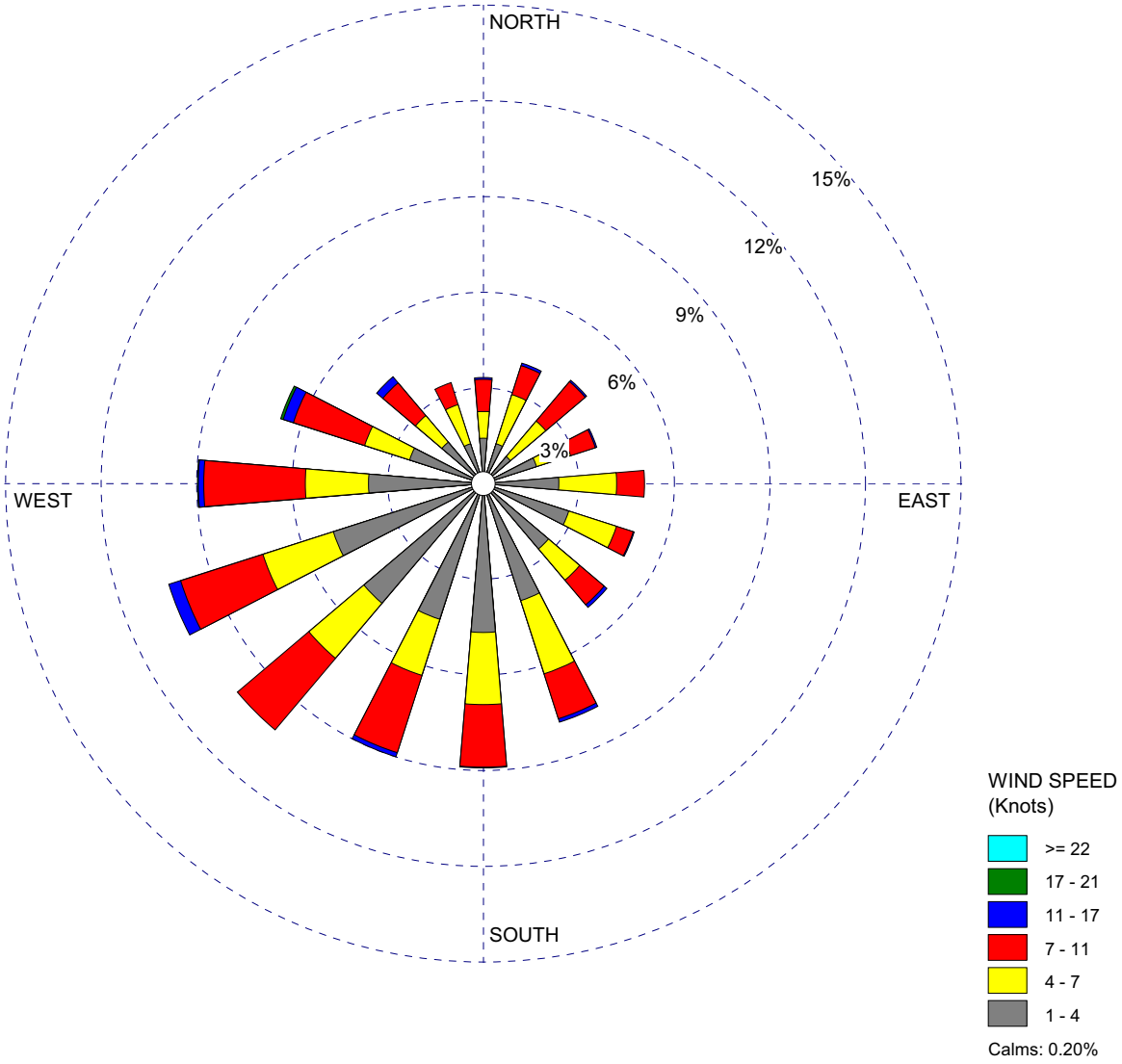

Figure 2.3-207 (Sheet 4 of 12)
VEGP 10-m Level April Wind Rose (1998–2002)

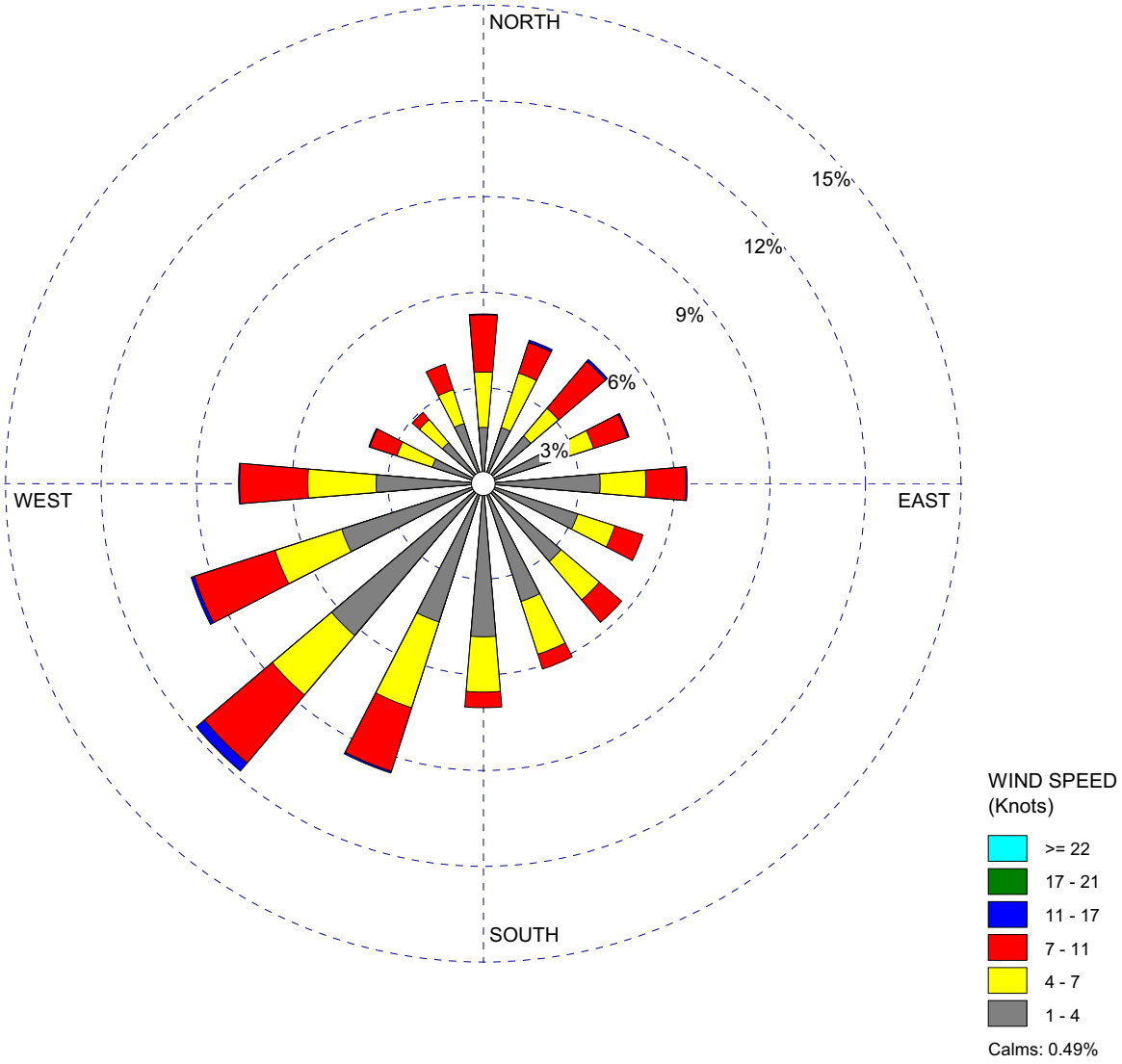

Figure 2.3-207 (Sheet 5 of 12)
VEGP 10-m Level May Wind Rose (1998–2002)

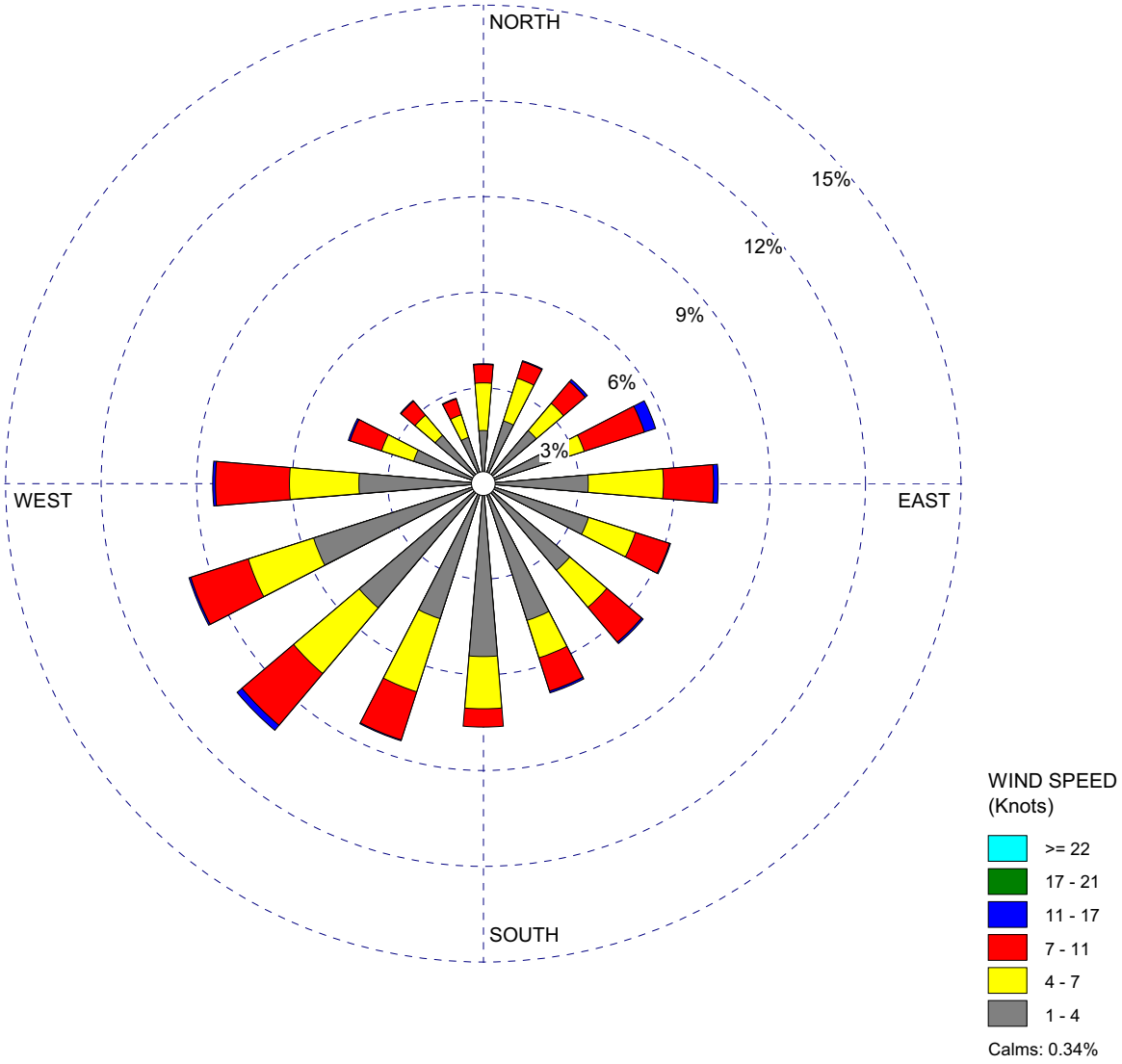

Figure 2.3-207 (Sheet 6 of 12)
VEGP 10-m Level June Wind Rose (1998–2002)

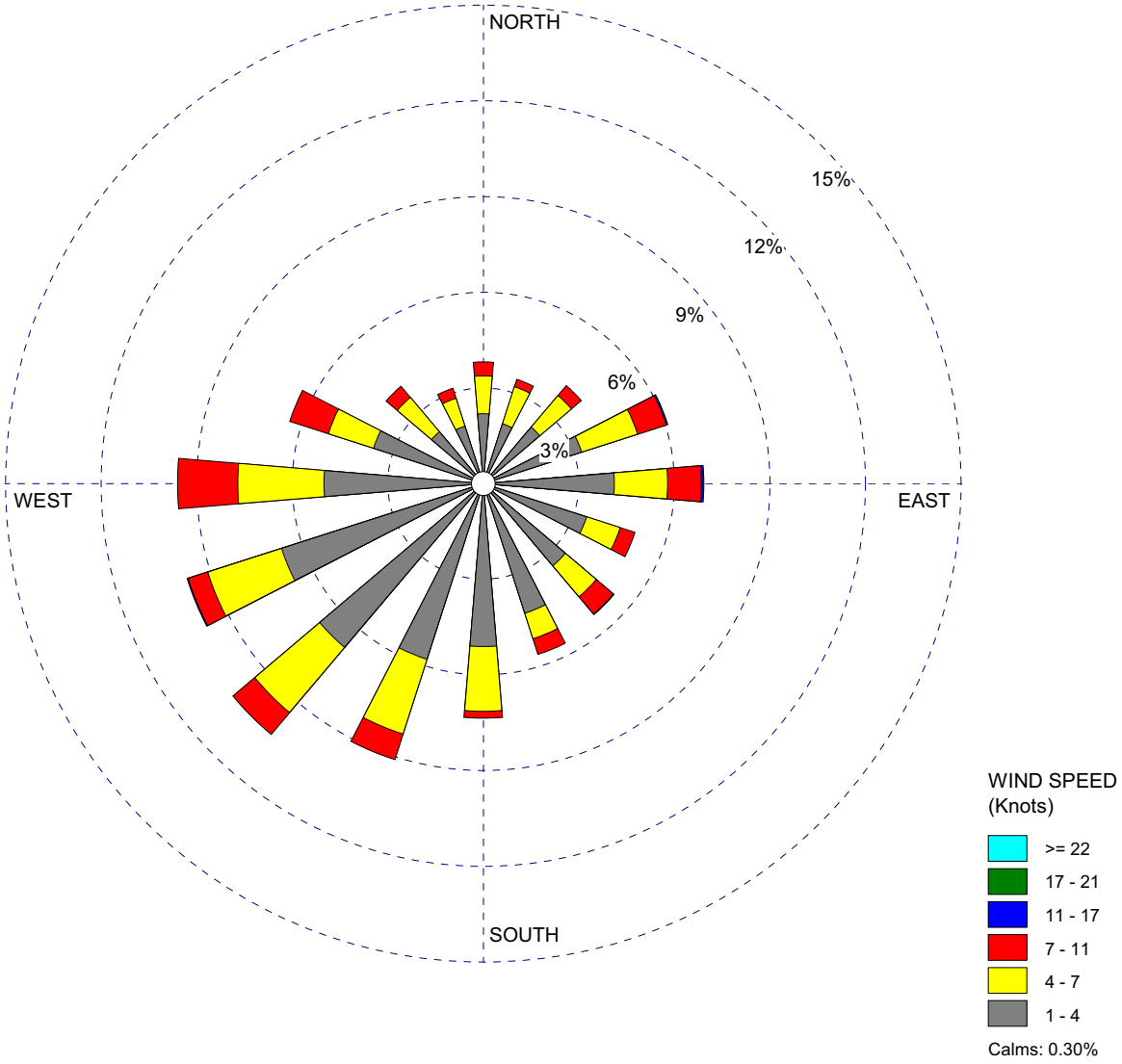

Figure 2.3-207 (Sheet 7 of 12)
VEGP 10-m Level July Wind Rose (1998–2002)

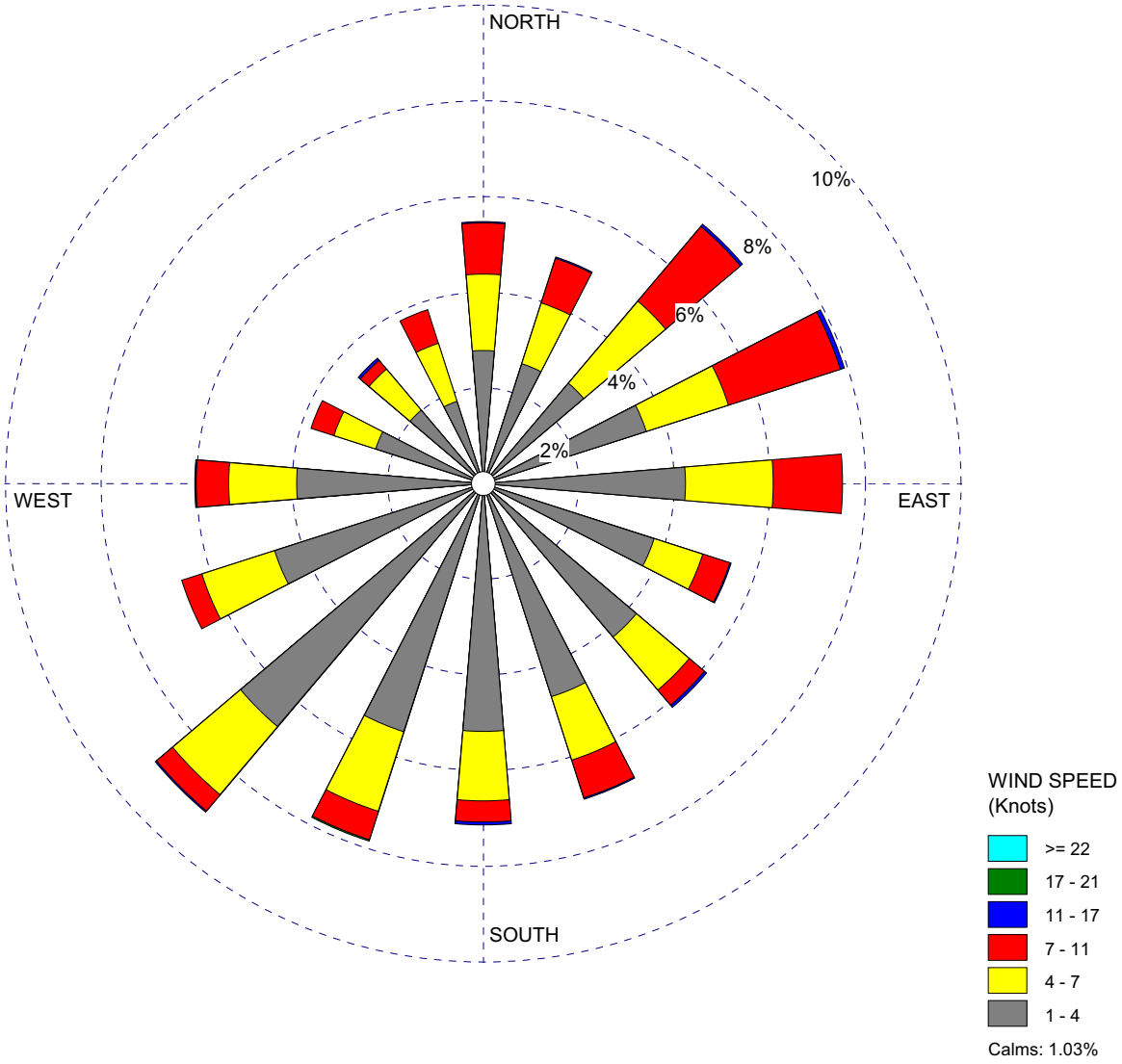

Figure 2.3-207 (Sheet 8 of 12)
VEGP 10-m Level August Wind Rose (1998–2002)

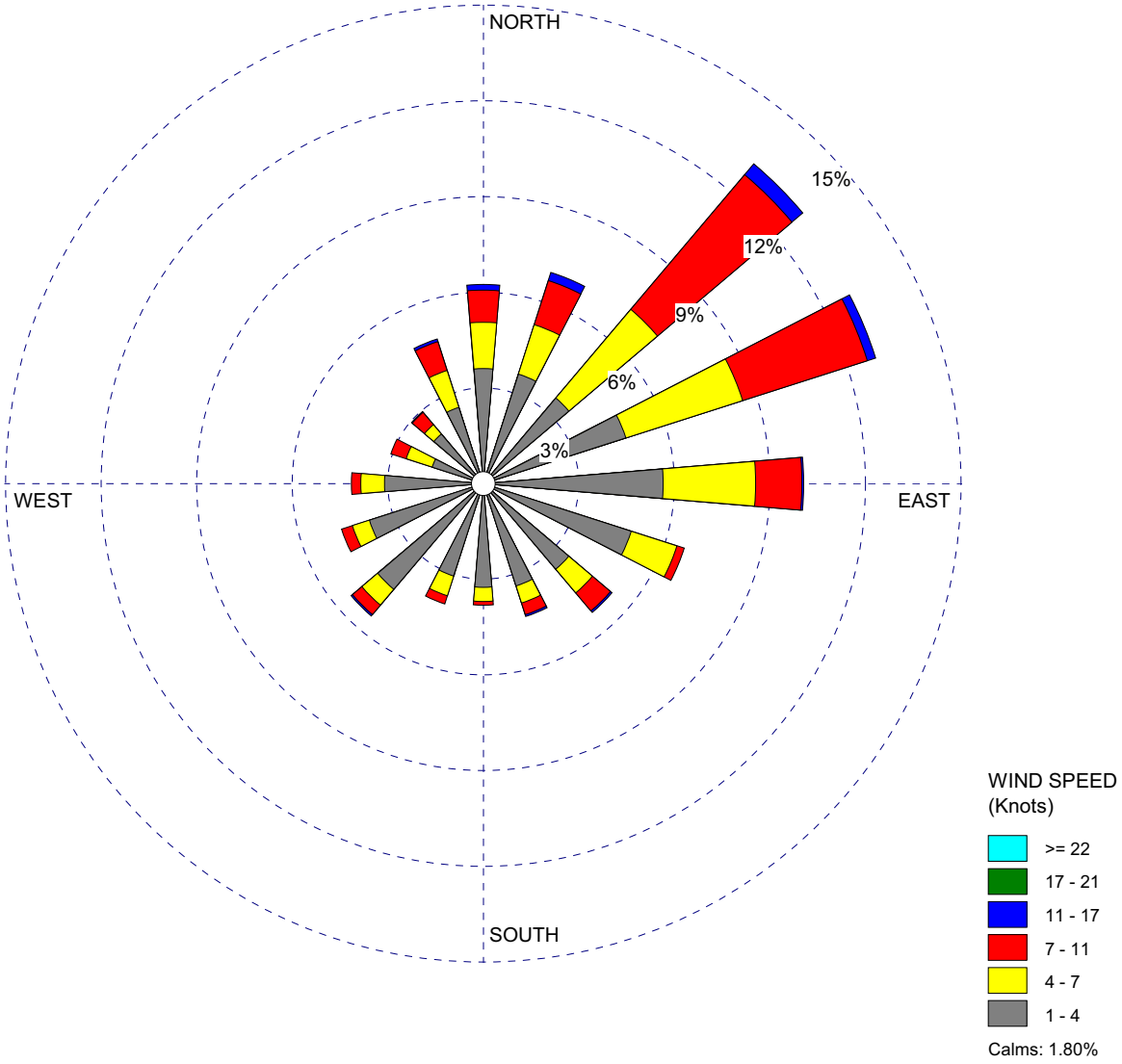

Figure 2.3-207 (Sheet 9 of 12)
VEGP 10-m Level September Wind Rose (1998–2002)

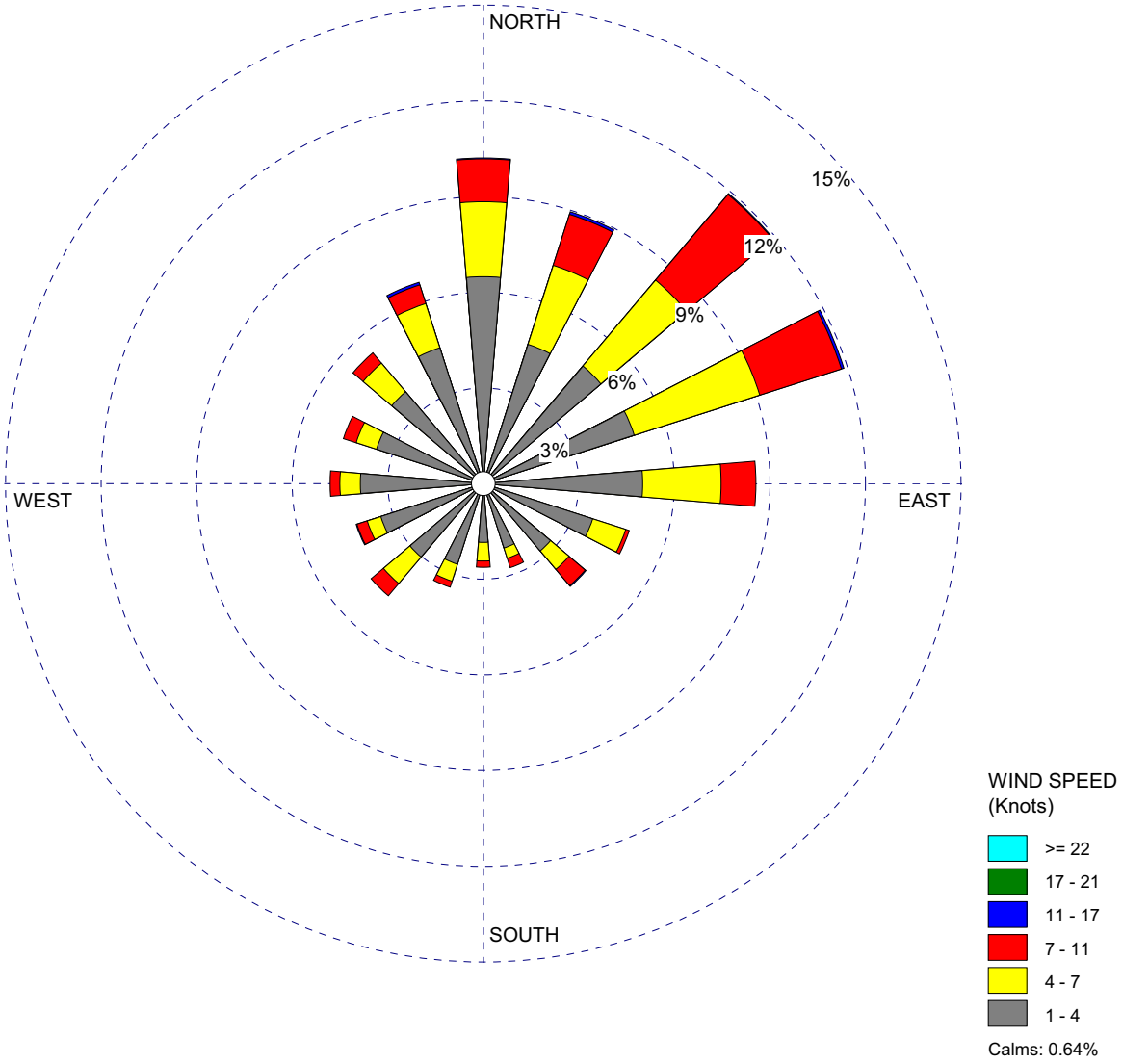

Figure 2.3-207 (Sheet 10 of 12)
VEGP 10-m Level October Wind Rose (1998–2002)

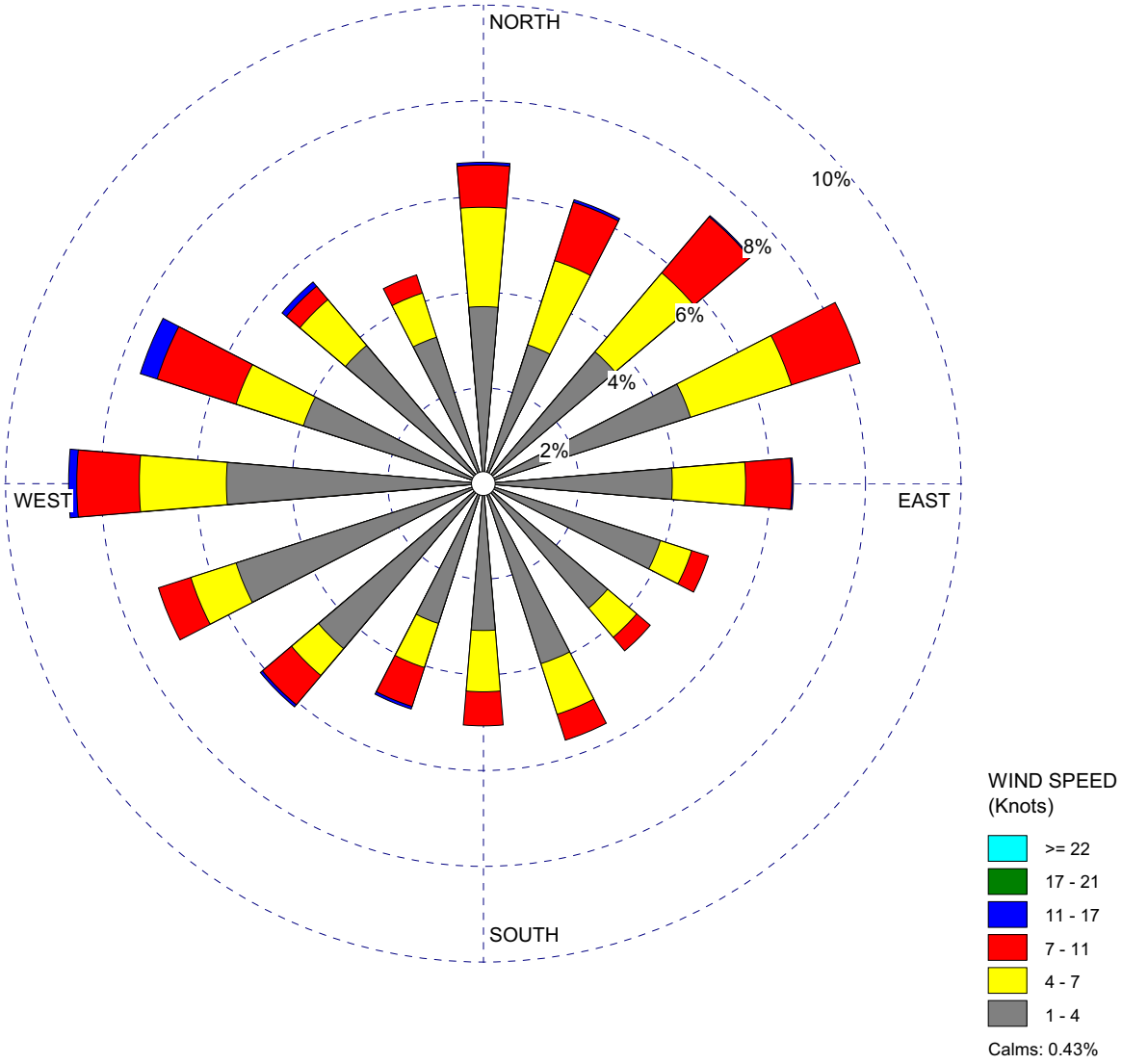

Figure 2.3-207 (Sheet 11 of 12)
VEGP 10-m Level November Wind Rose (1998–2002)

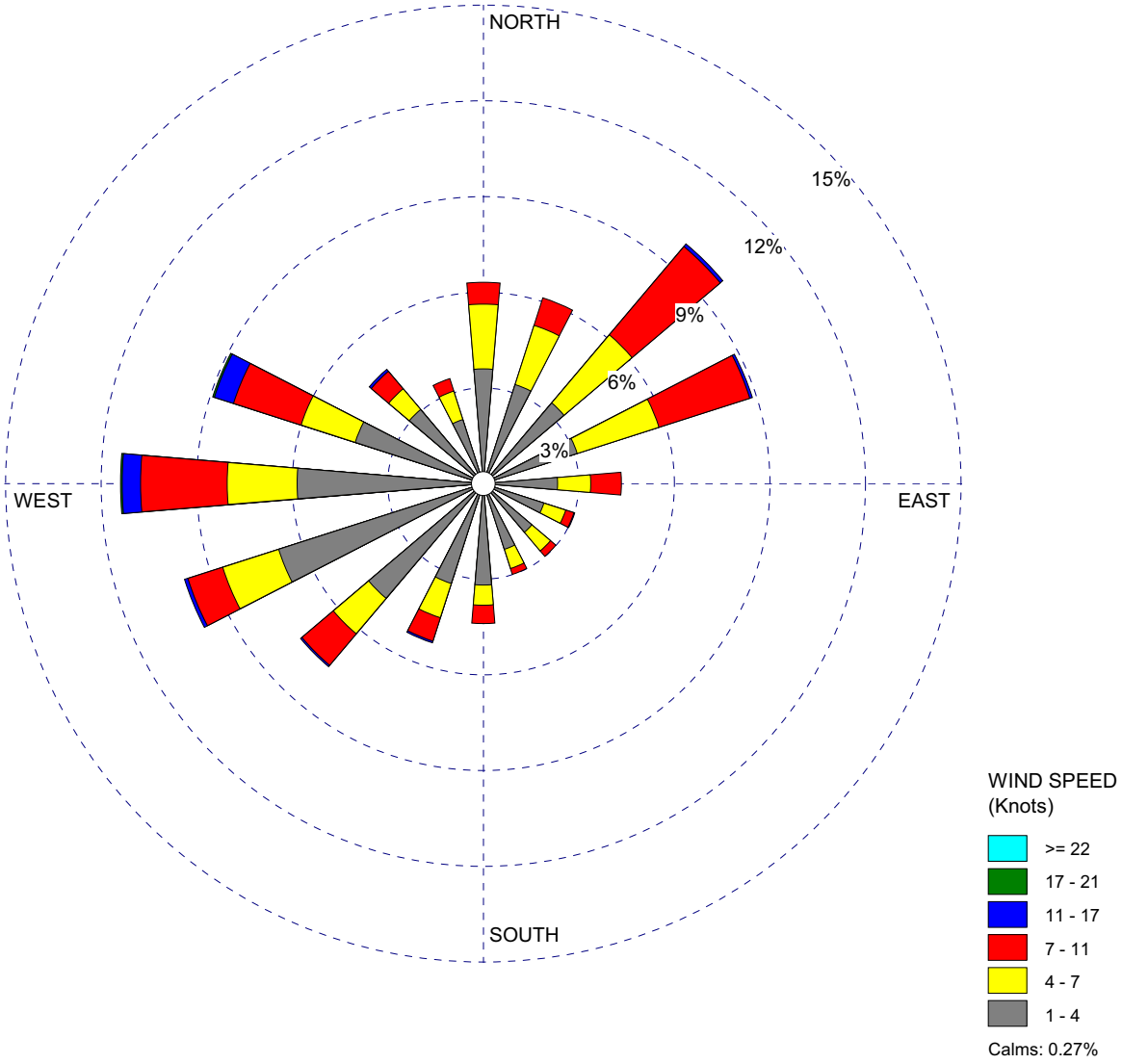

Figure 2.3-207 (Sheet 12 of 12)
VEGP 10-m Level December Wind Rose (1998–2002)

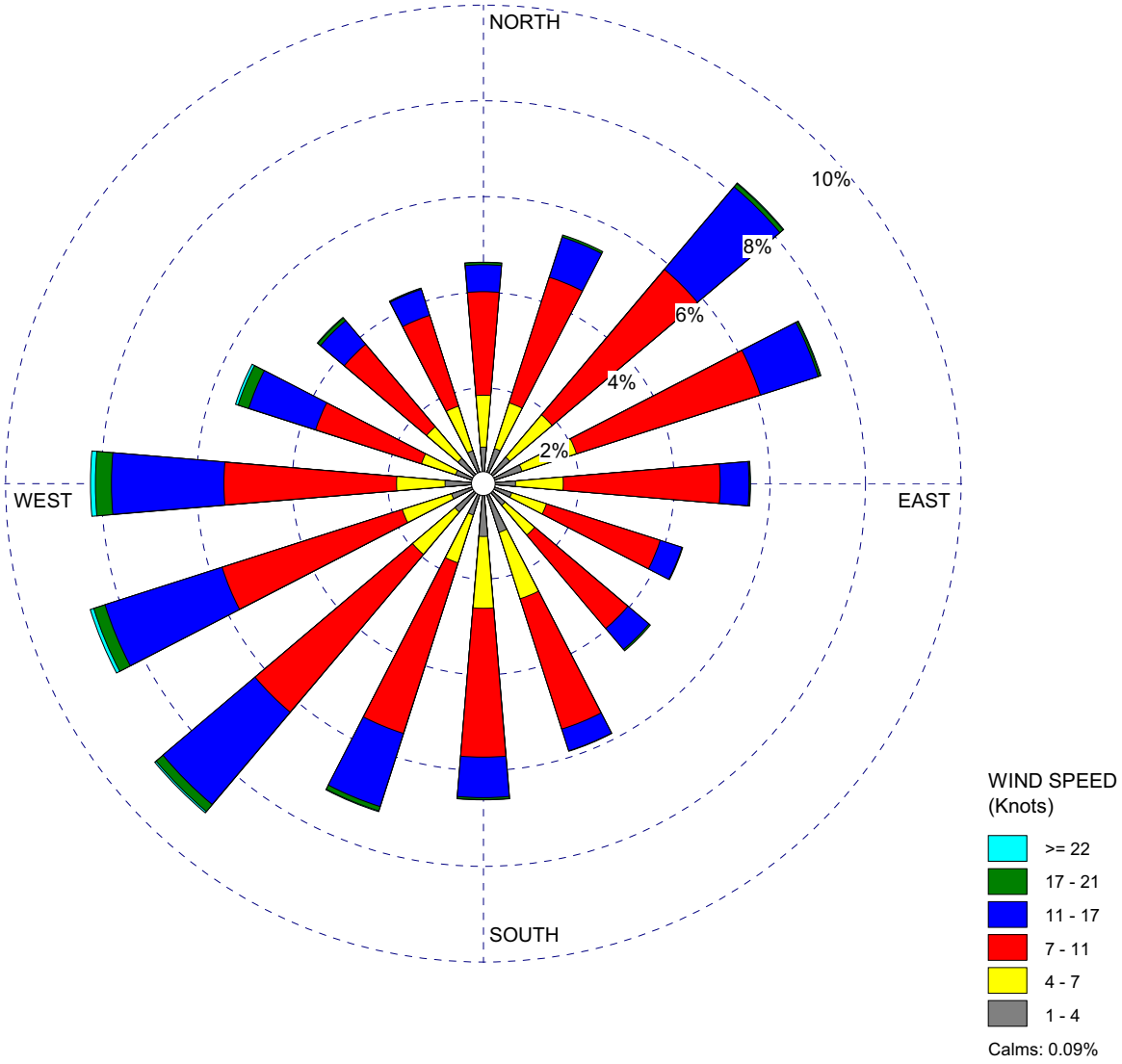

Figure 2.3-208
VEGP 60-m Level Annual Wind Rose (1998-2002)

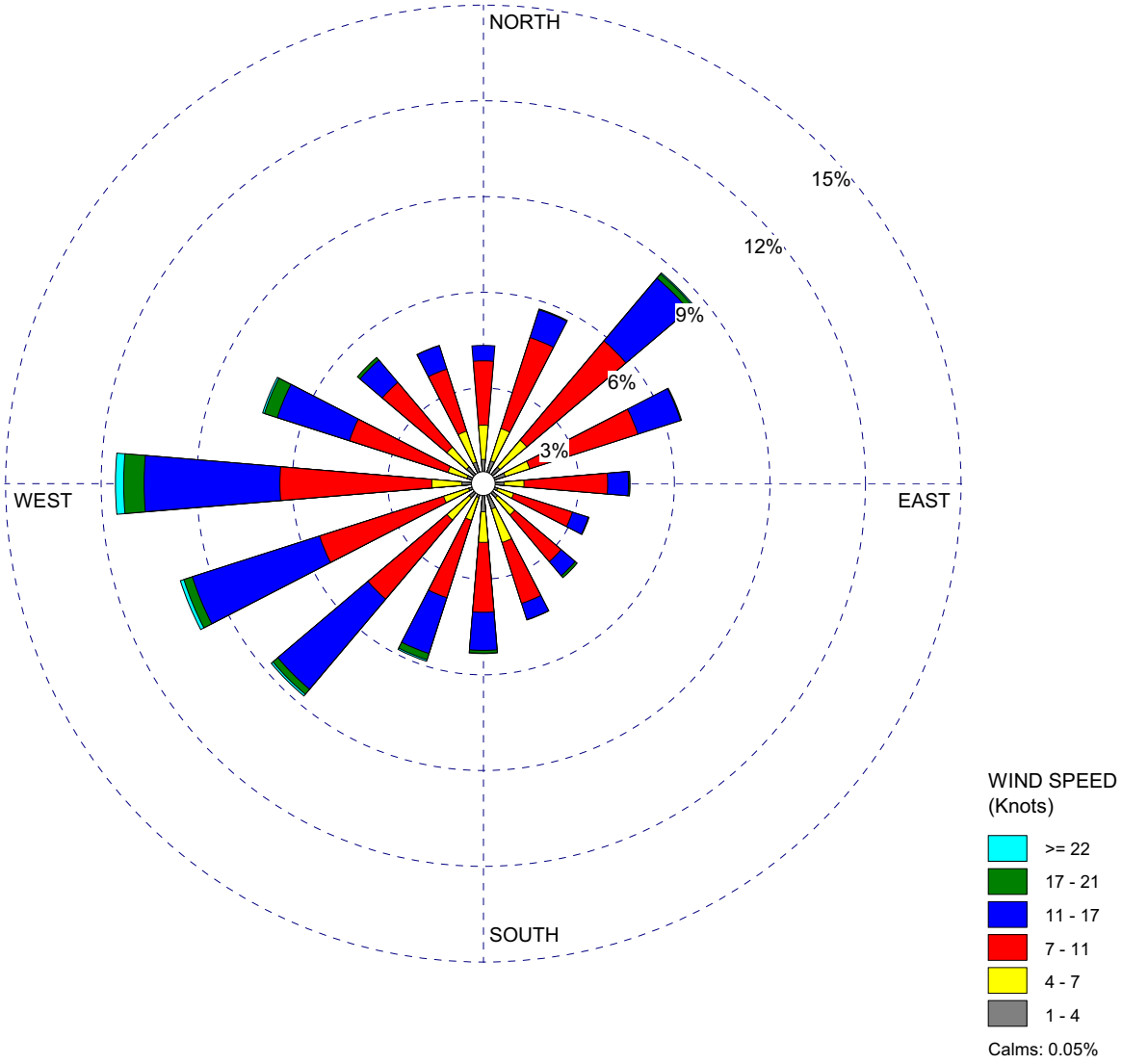

Figure 2.3-209
VEGP 60-m Level Winter Wind Rose (1998-2002)

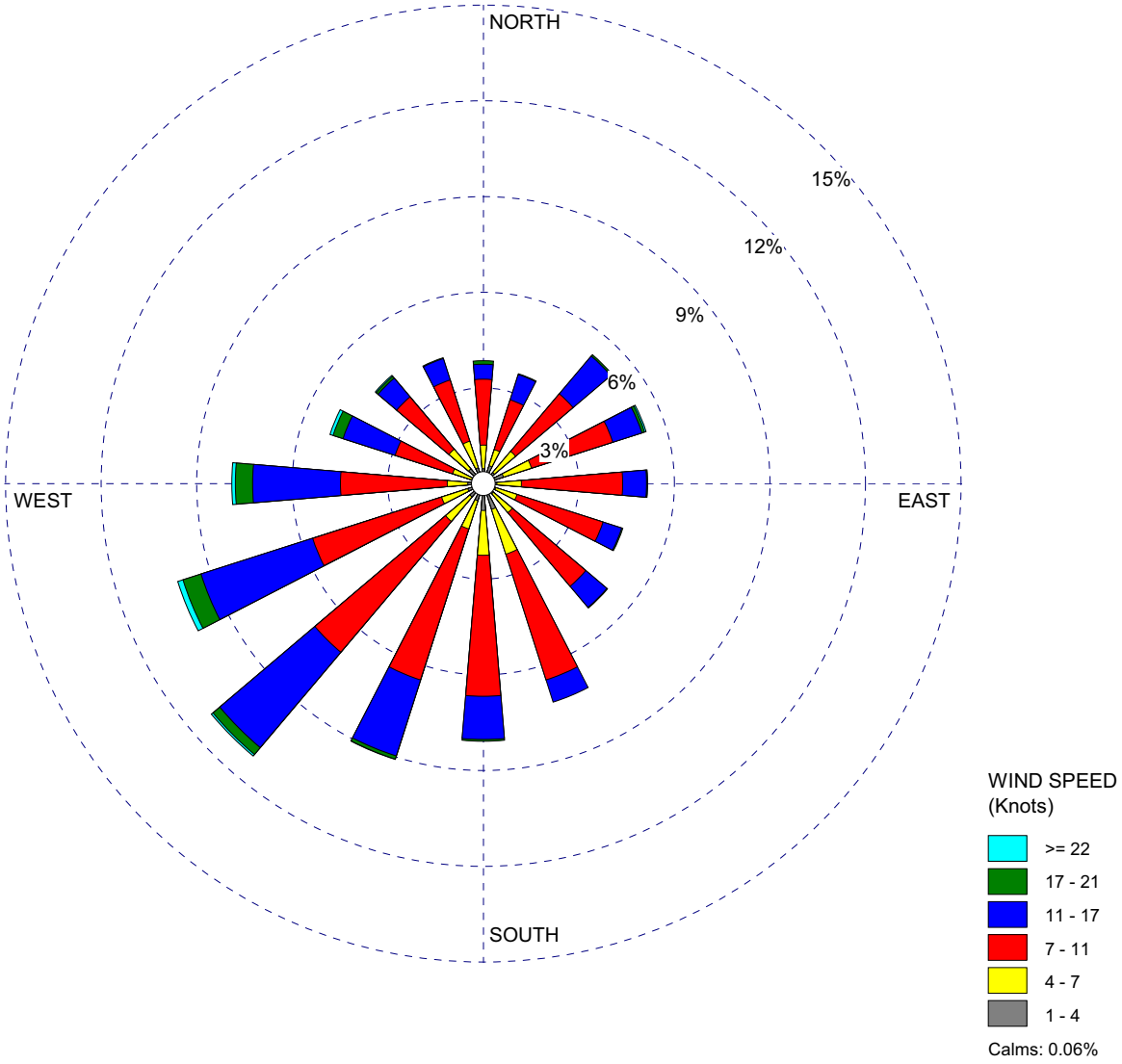

Figure 2.3-210
VEGP 60-m Level Spring Wind Rose (1998-2002)

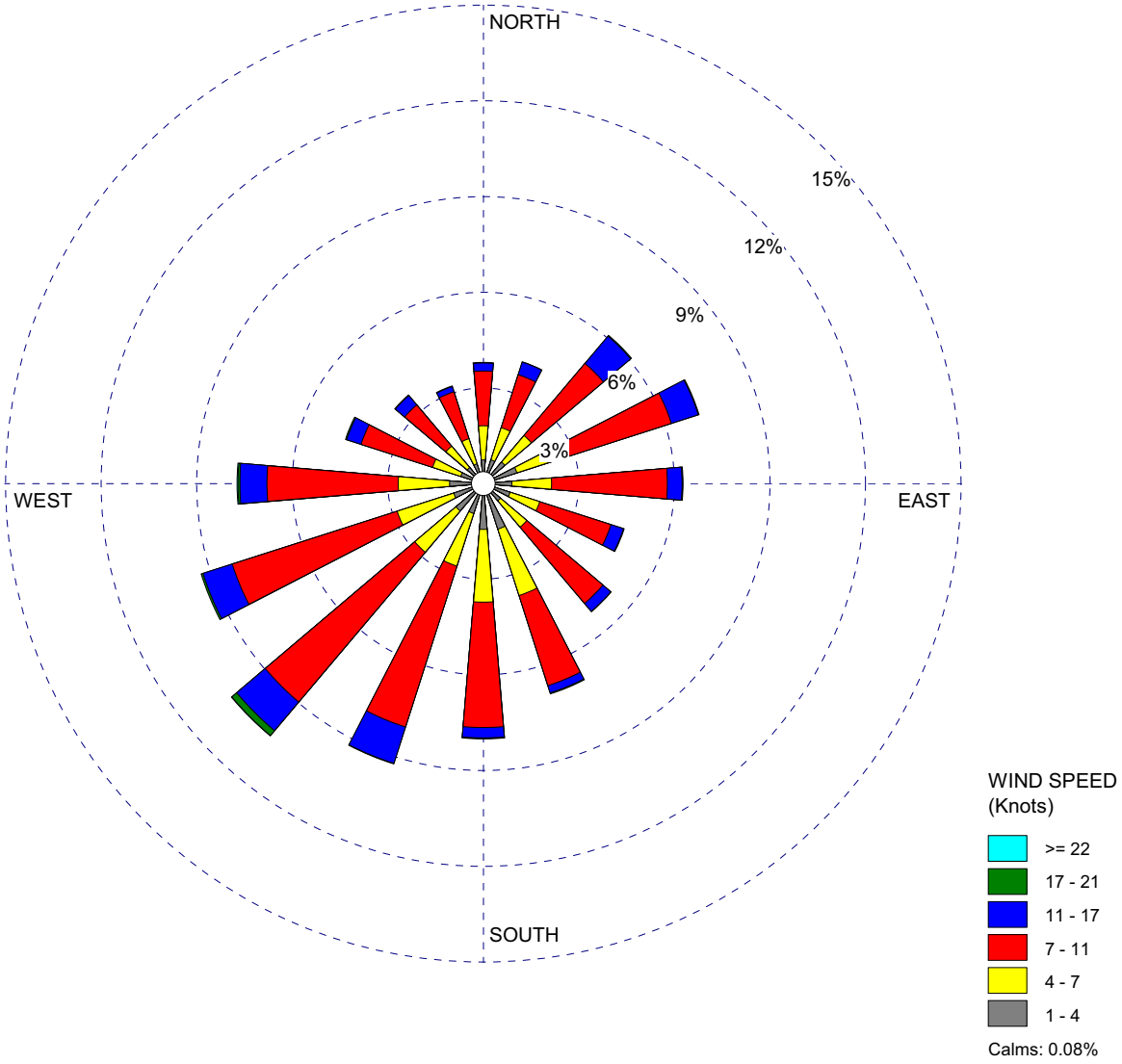

Figure 2.3-211
VEGP 60-m Level Summer Wind Rose (1998-2002)

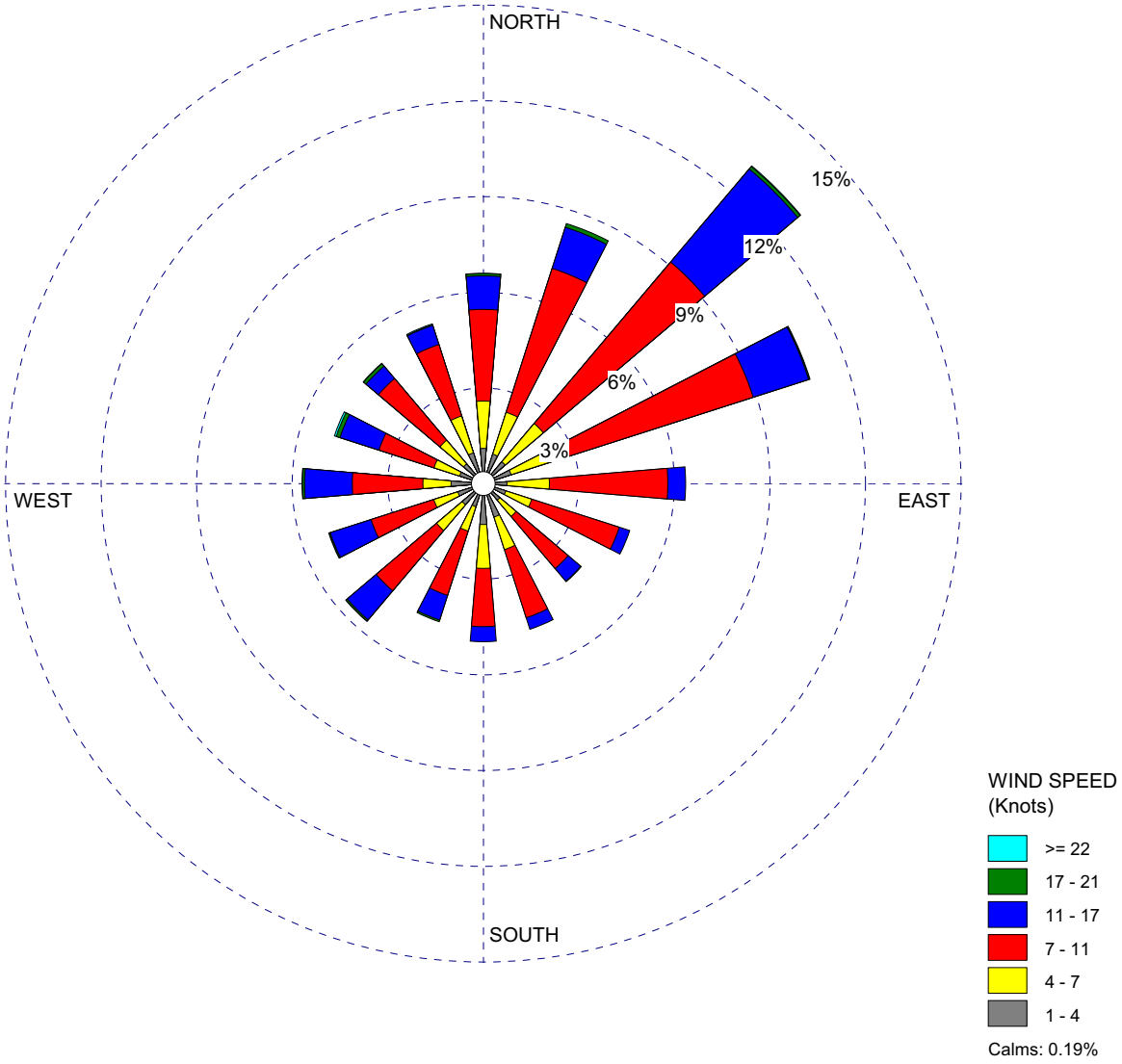

Figure 2.3-212
VEGP 60-m Level Autumn Wind Rose (1998-2002)

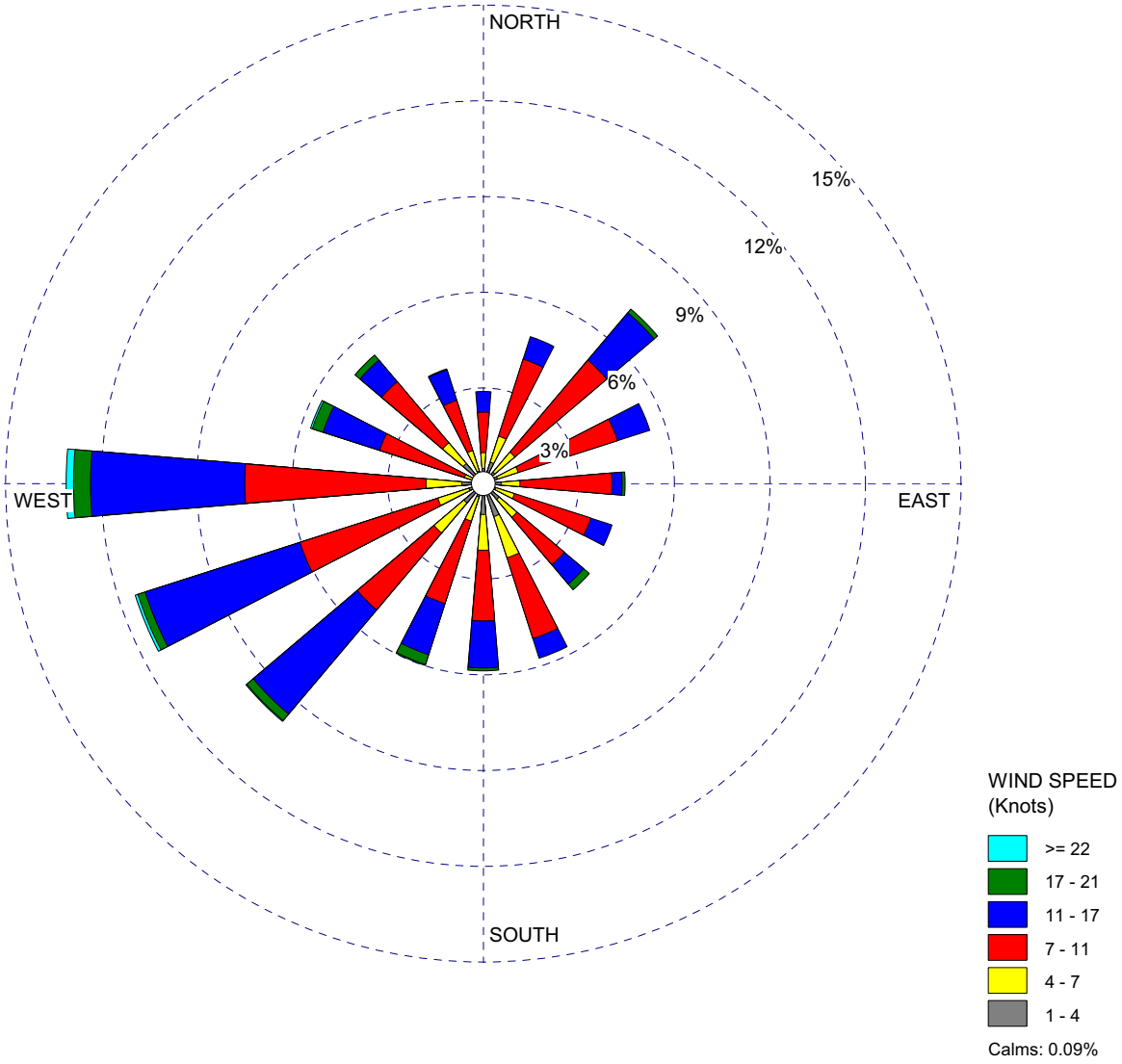

Figure 2.3-213 (Sheet 1 of 12)
VEGP 60-m Level January Wind Rose (1998–2002)

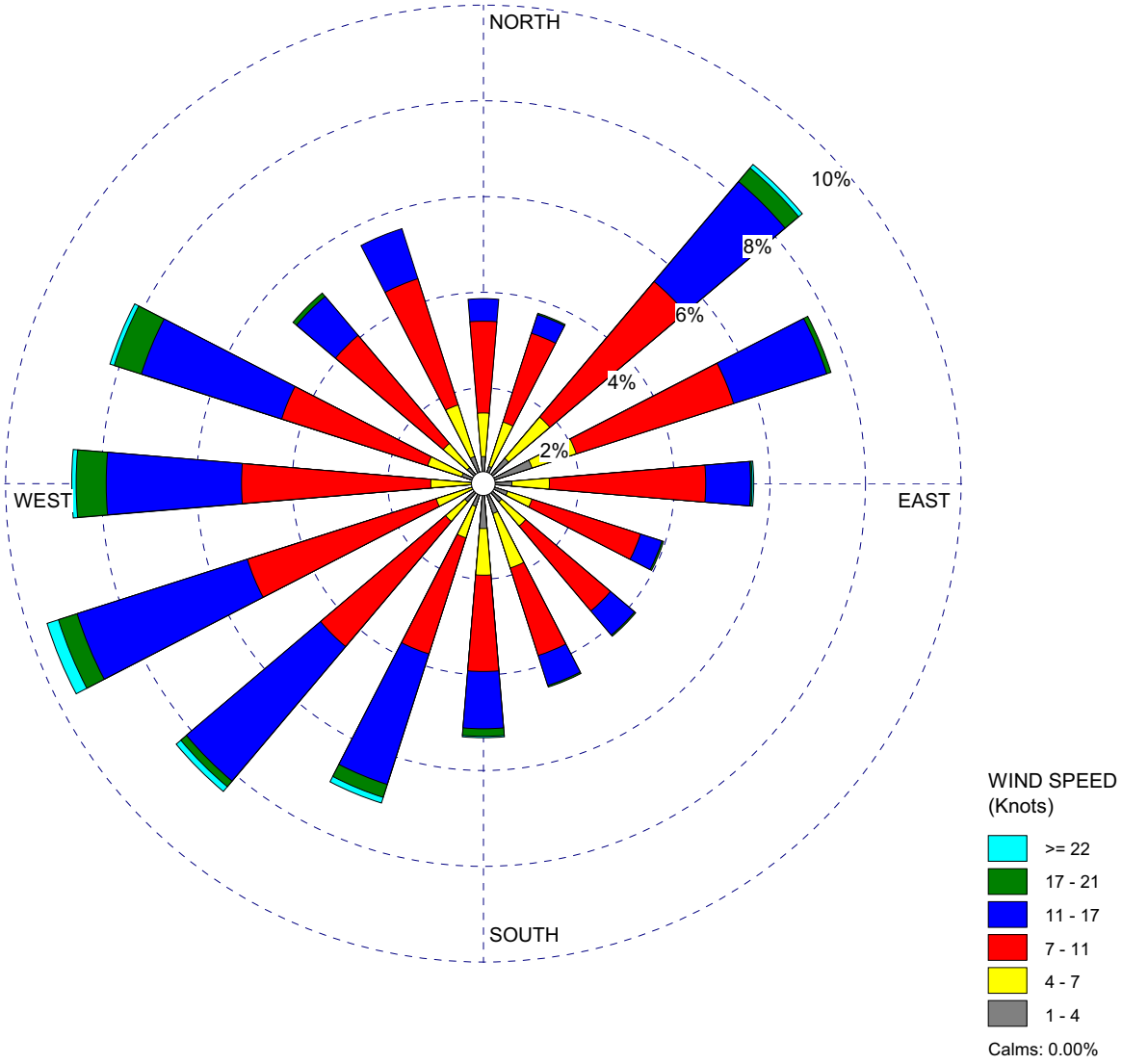

Figure 2.3-213 (Sheet 2 of 12)
VEGP 60-m Level February Wind Rose (1998–2002)

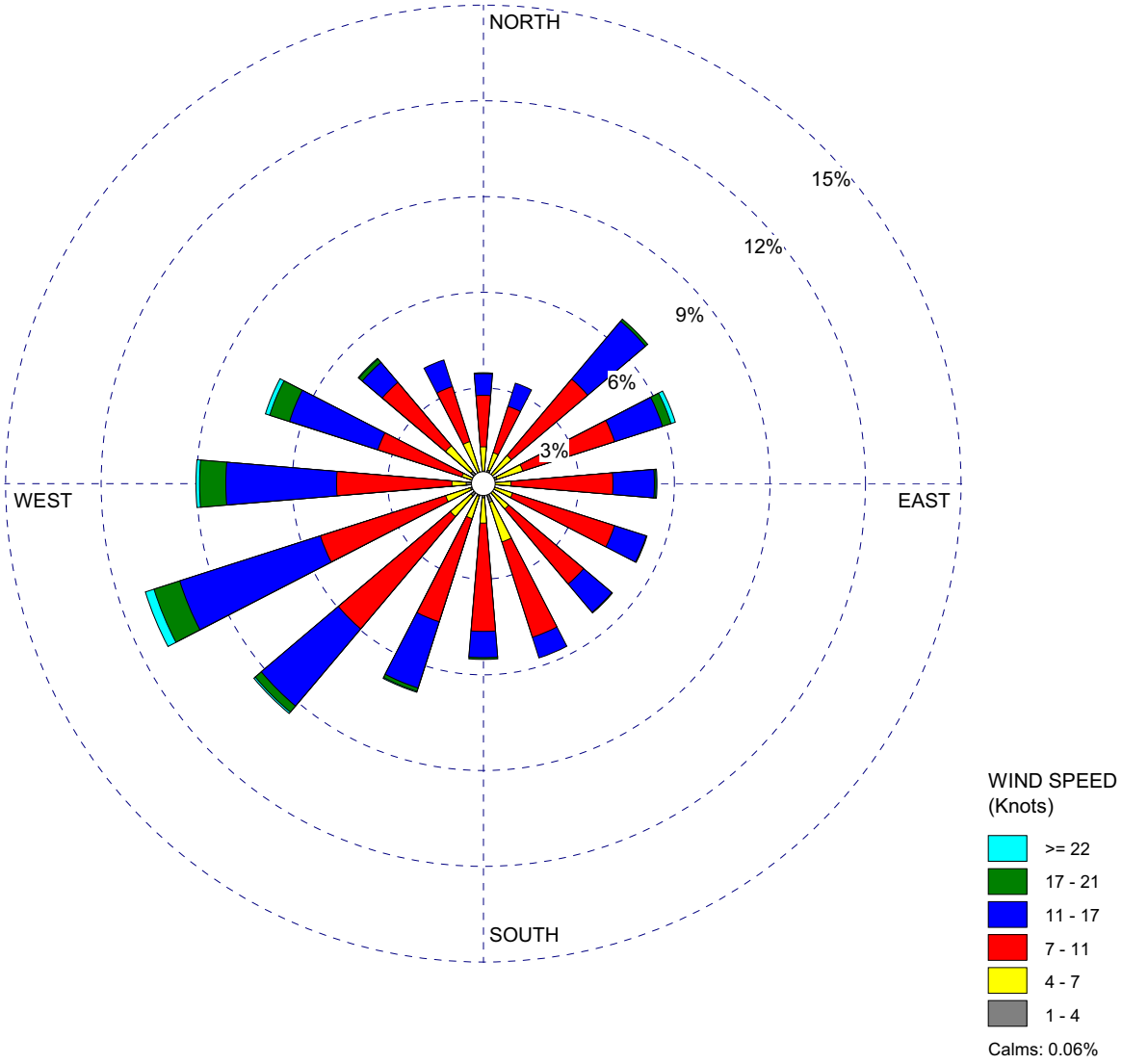

Figure 2.3-213 (Sheet 3 of 12)
VEGP 60-m Level March Wind Rose (1998–2002)

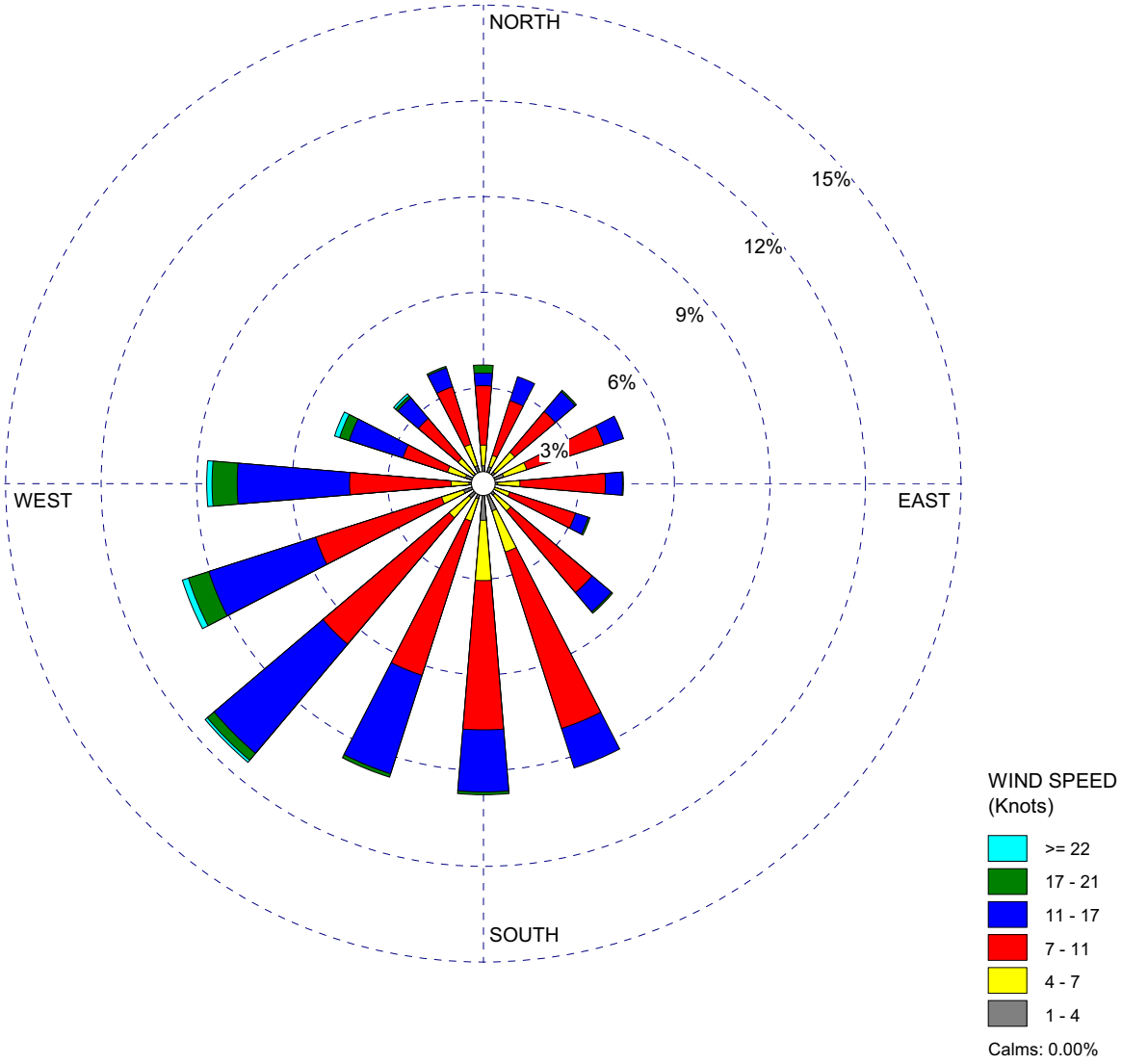

Figure 2.3-213 (Sheet 4 of 12)
VEGP 60-m Level April Wind Rose (1998–2002)

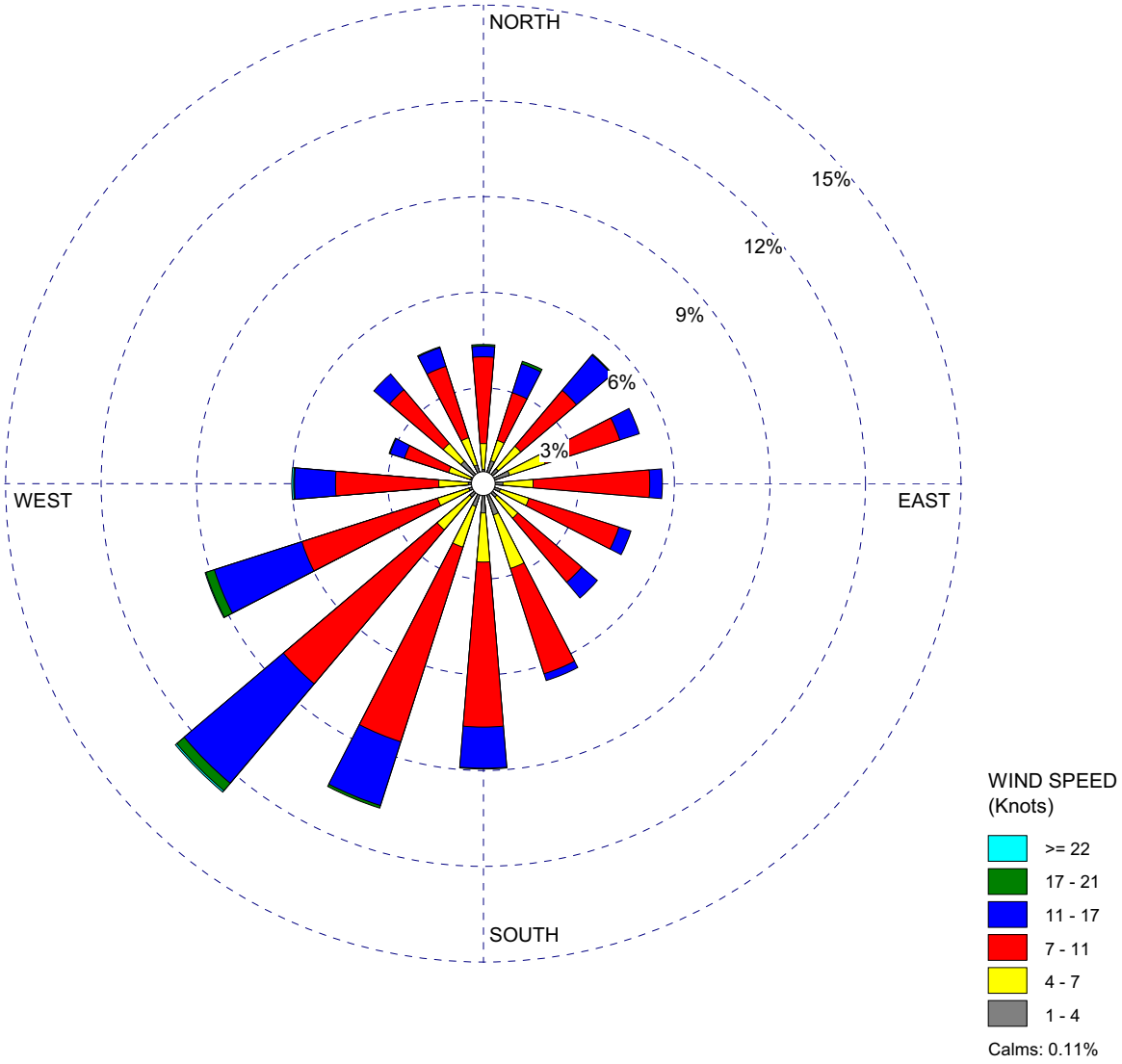

Figure 2.3-213 (Sheet 5 of 12)
VEGP 60-m Level May Wind Rose (1998–2002)

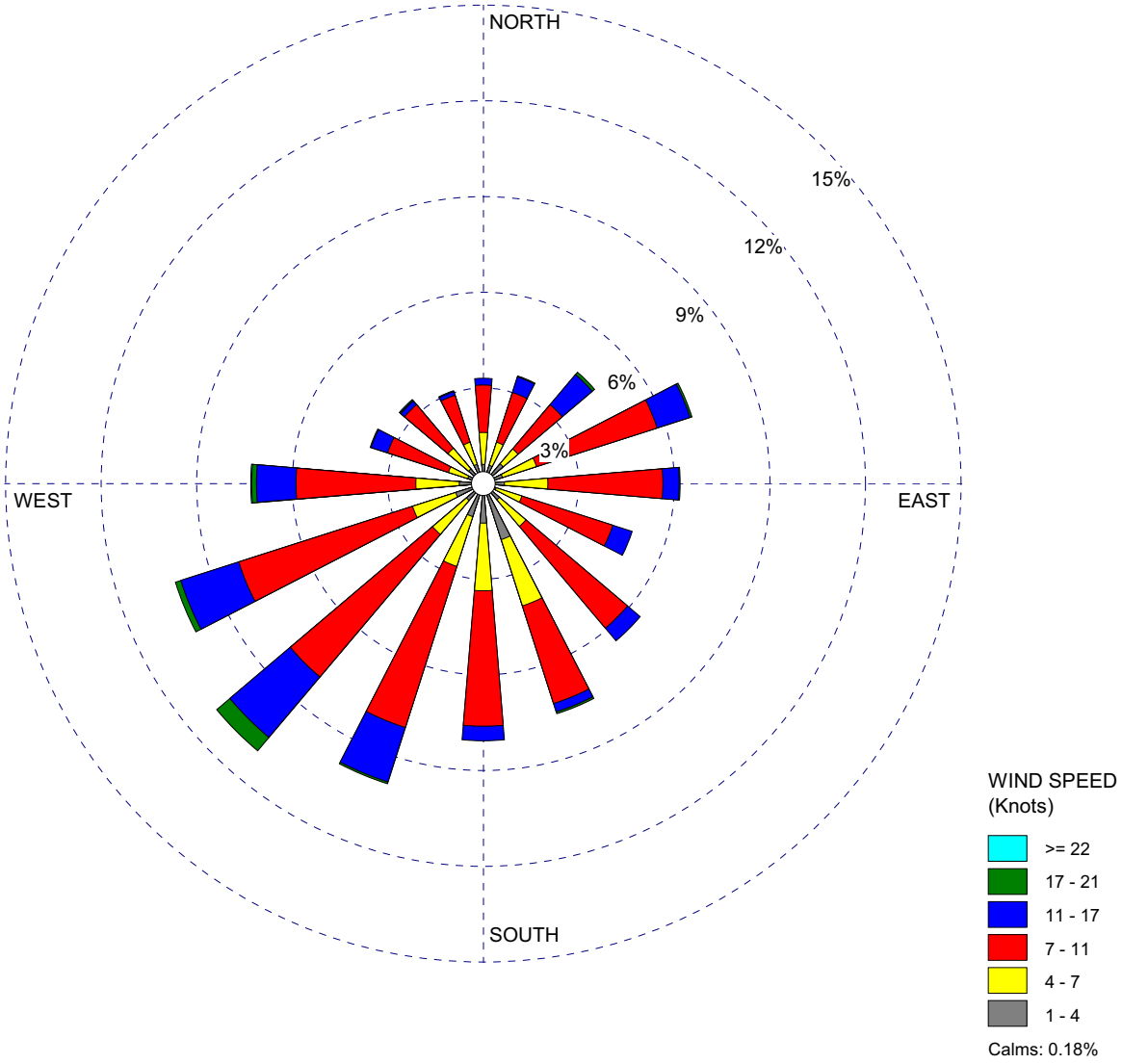

Figure 2.3-213 (Sheet 6 of 12)
VEGP 60-m Level June Wind Rose (1998–2002)

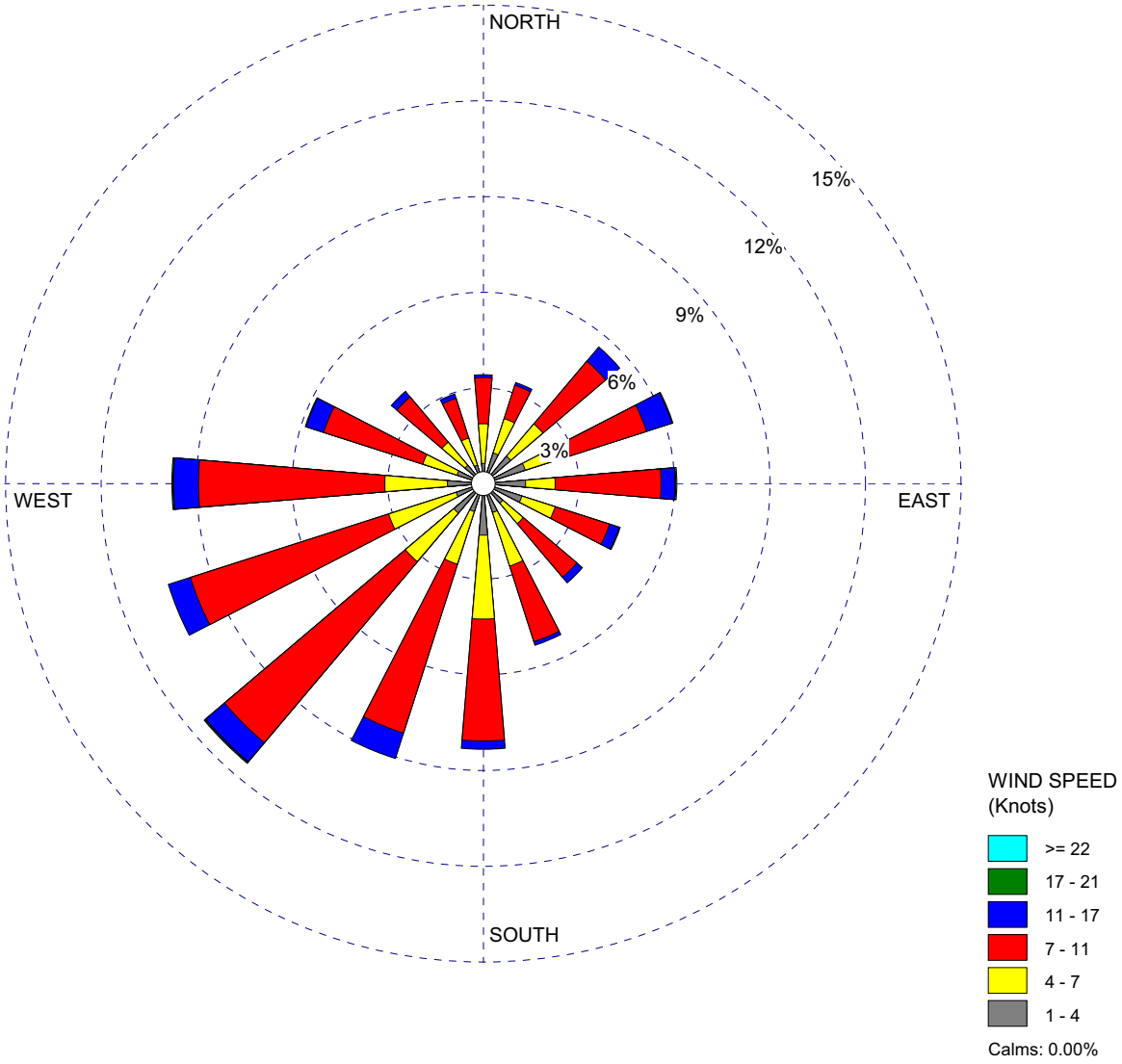

Figure 2.3-213 (Sheet 7 of 12)
VEGP 60-m Level July Wind Rose (1998–2002)

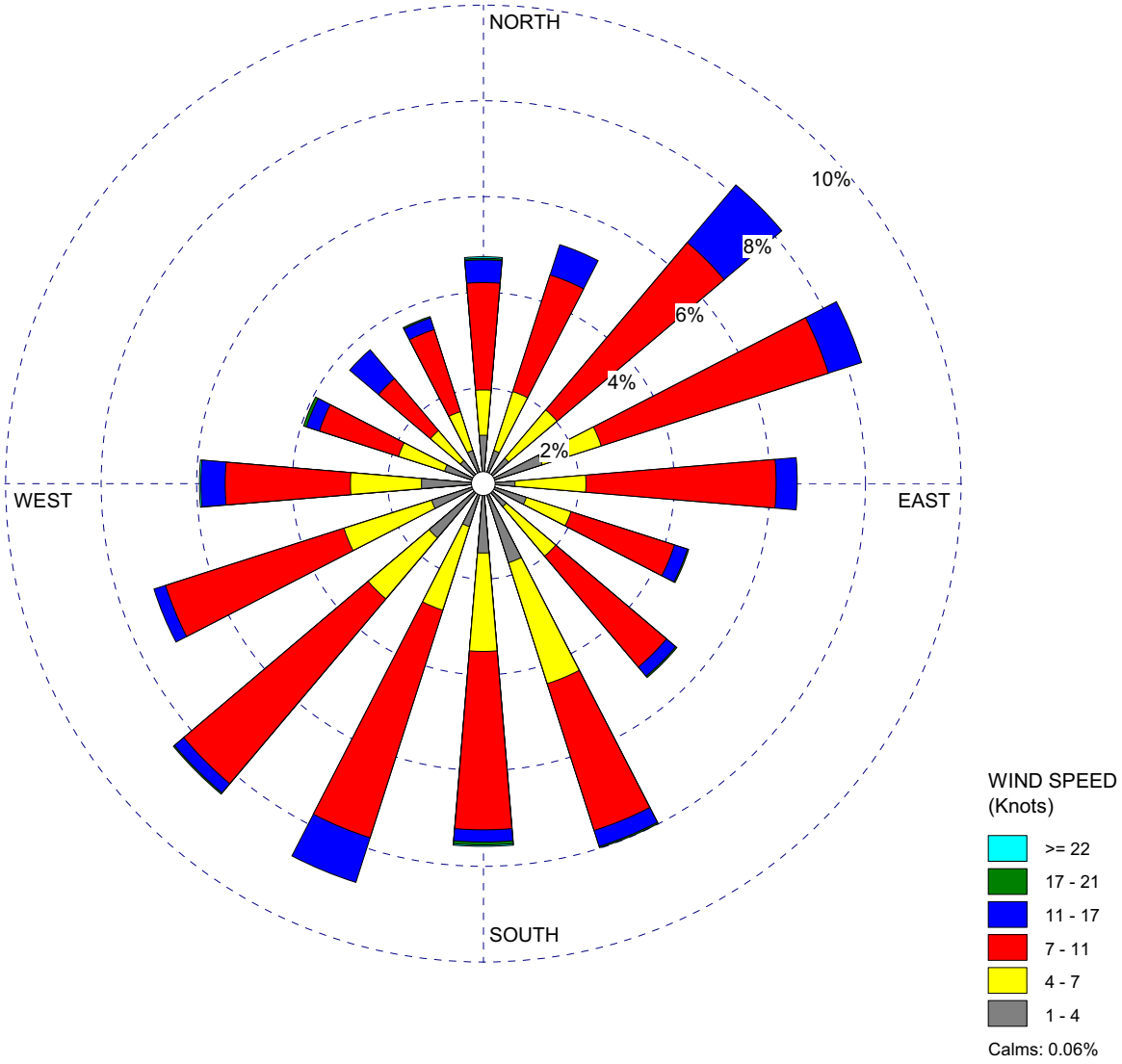

Figure 2.3-213 (Sheet 8 of 12)
VEGP 60-m Level August Wind Rose (1998–2002)

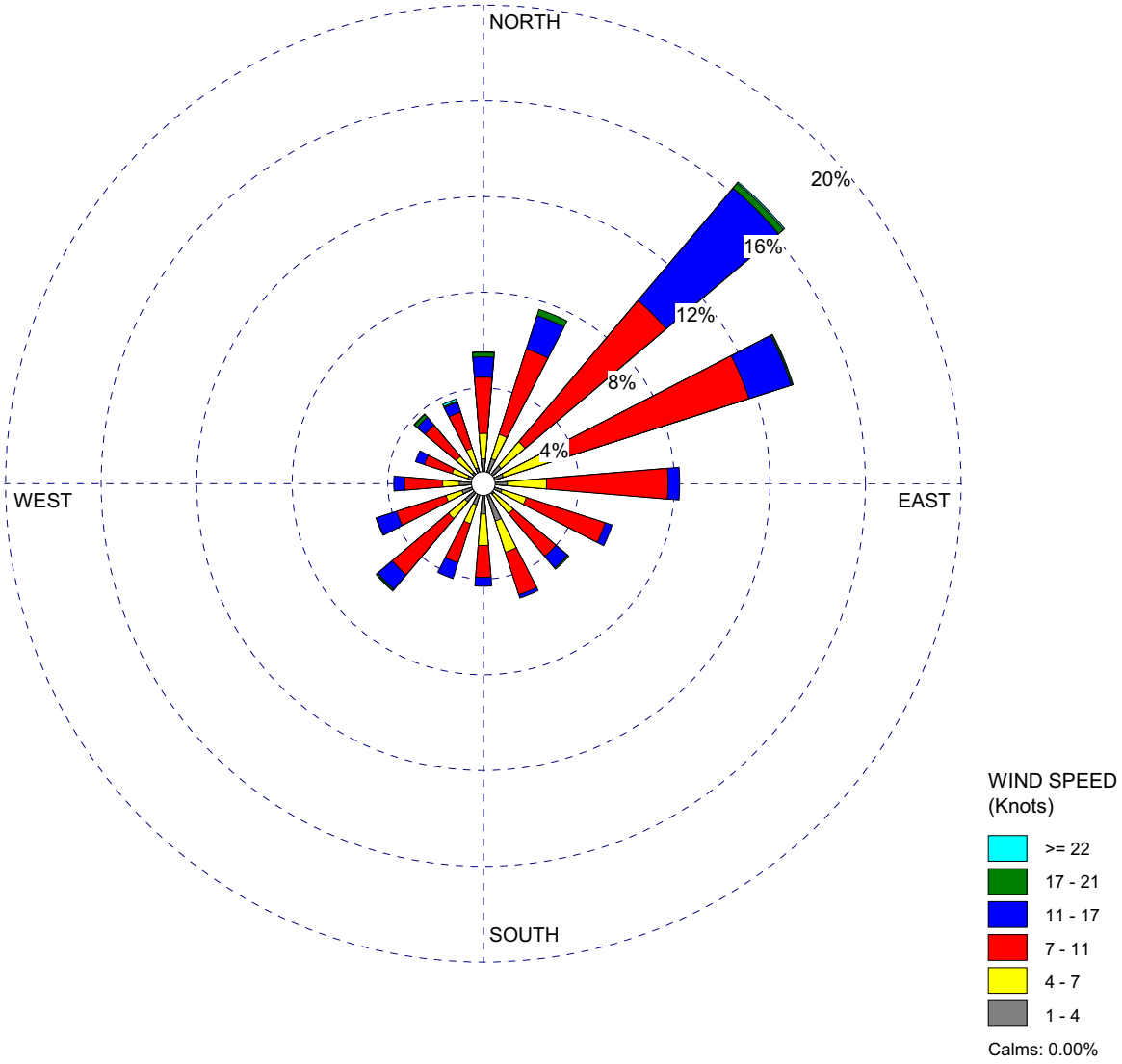

Figure 2.3-213 (Sheet 9 of 12)
VEGP 60-m Level September Wind Rose (1998–2002)

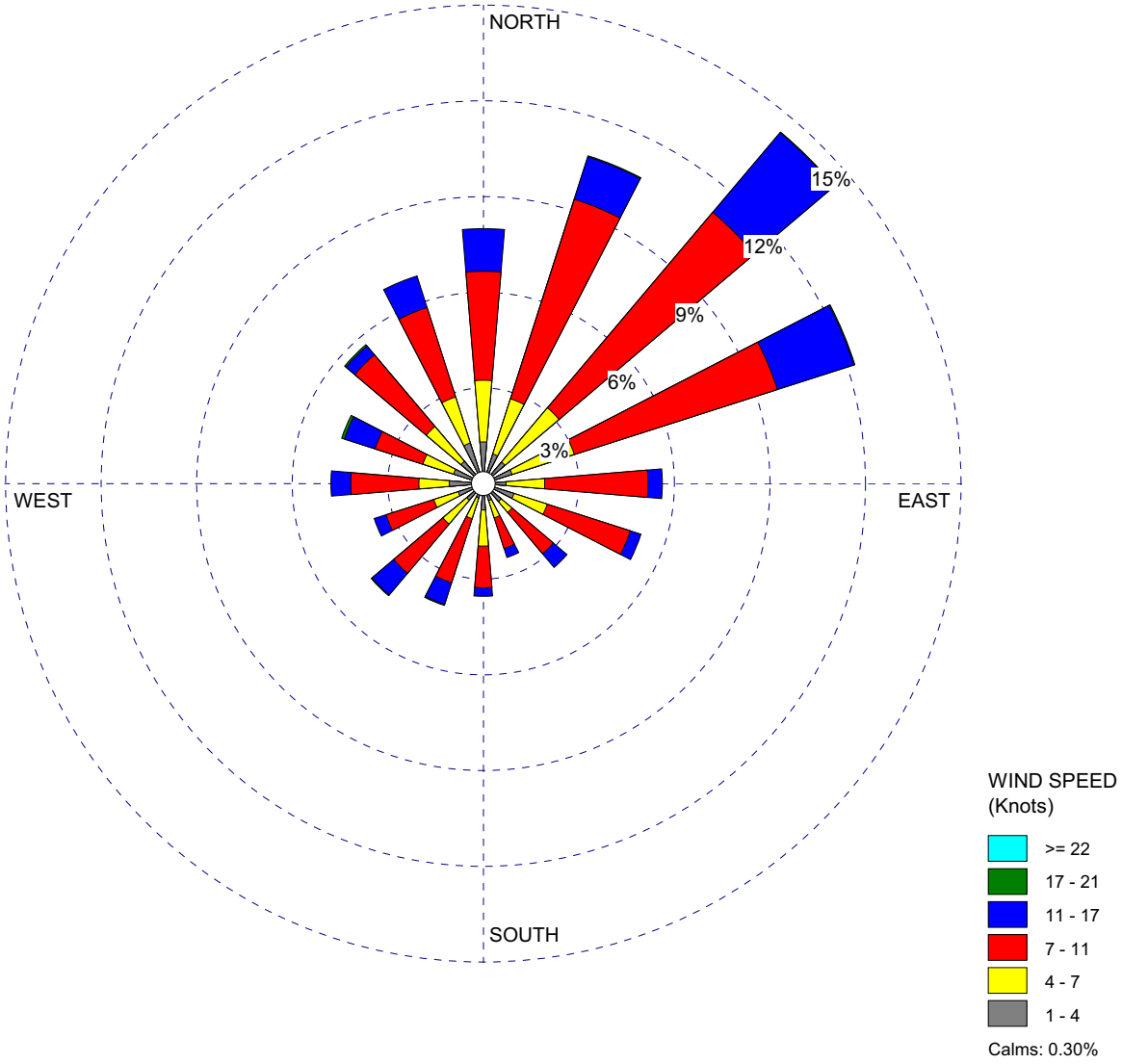

Figure 2.3-213 (Sheet 10 of 12)
VEGP 60-m Level October Wind Rose (1998–2002)

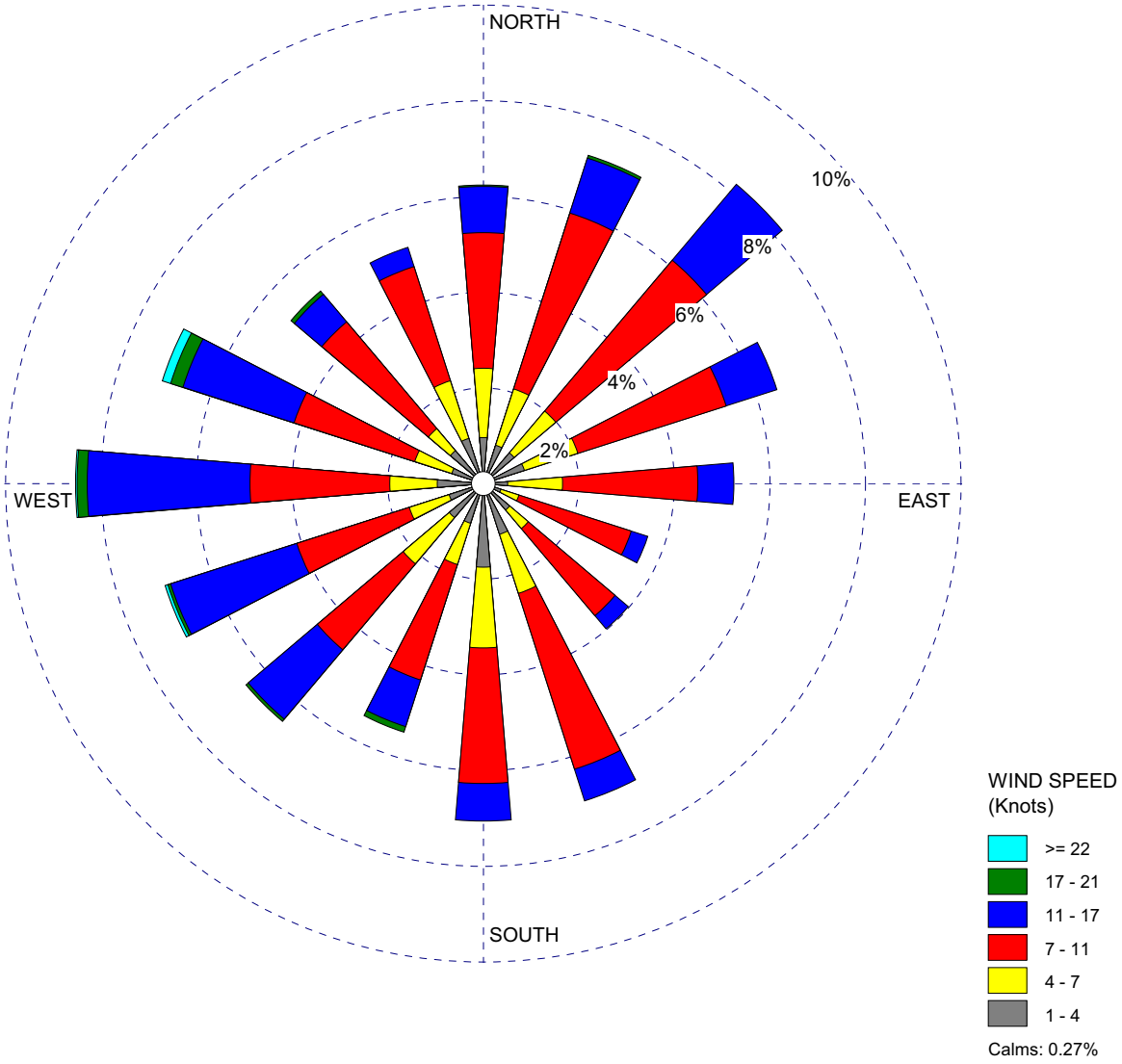

Figure 2.3-213 (Sheet 11 of 12)
VEGP 60-m Level November Wind Rose (1998–2002)

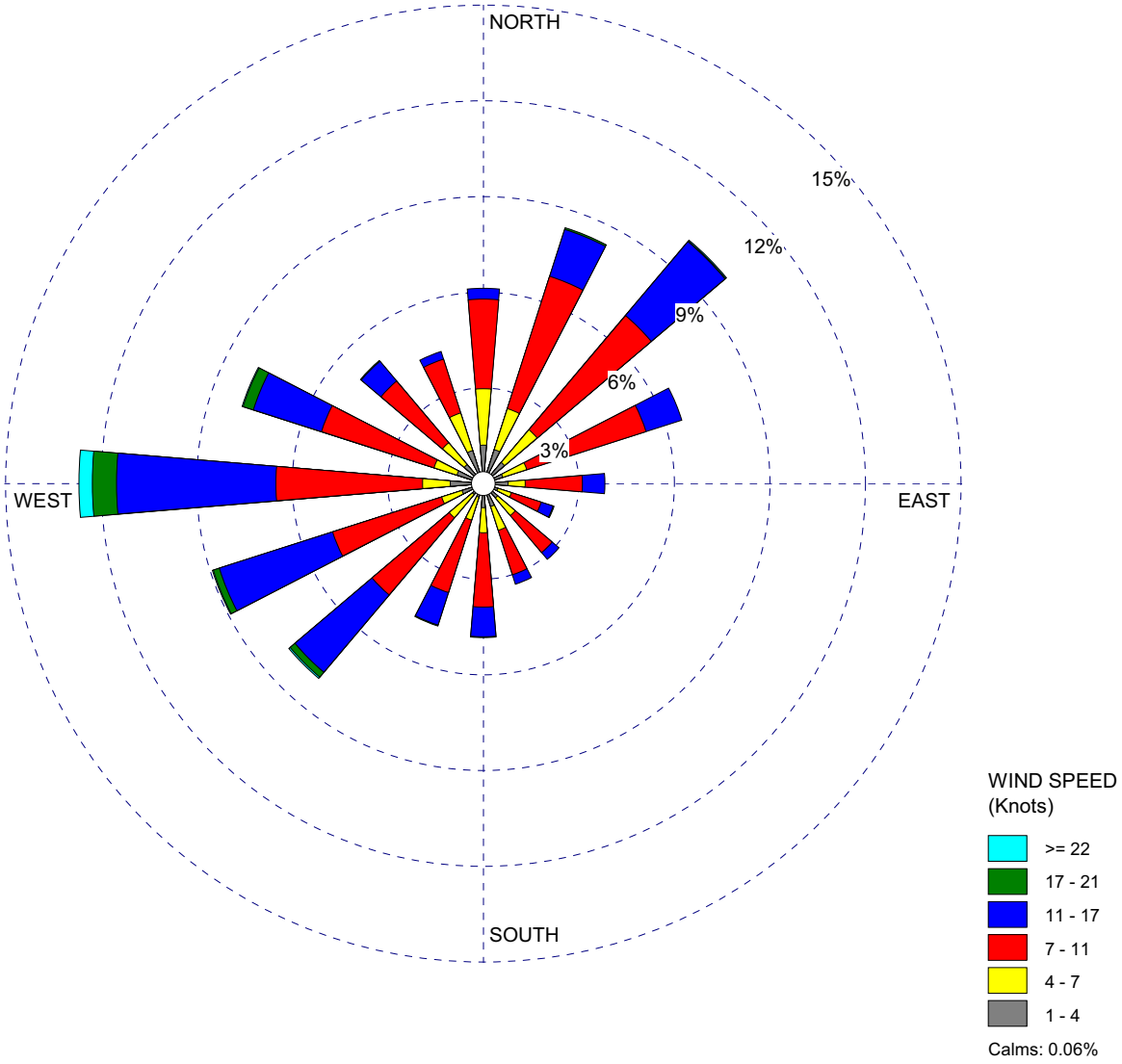

Figure 2.3-213 (Sheet 12 of 12)
VEGP 60-m Level December Wind Rose (1998–2002)

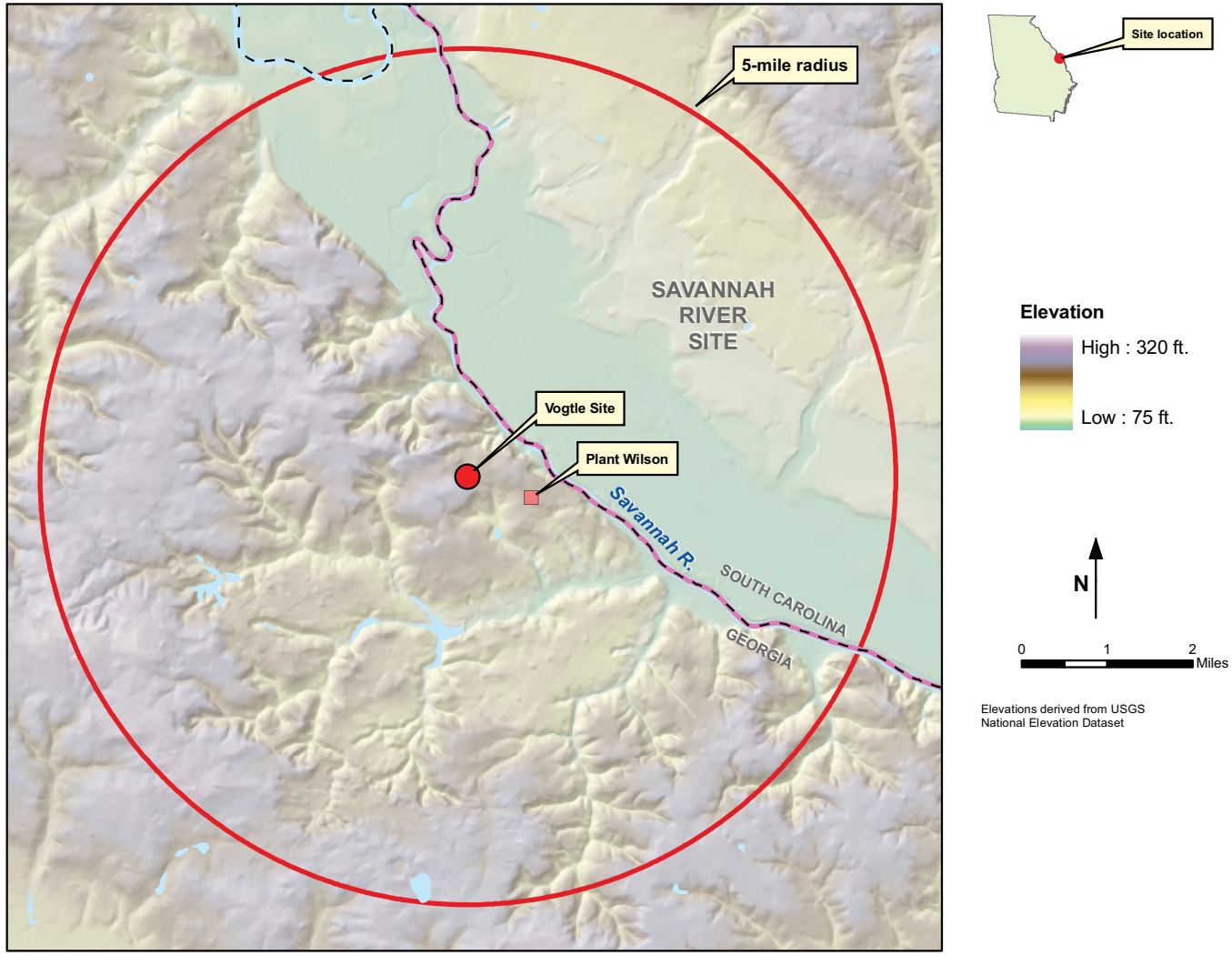

Figure 2.3-214
Topographic Features Within a 5-Mile Radius of the VEGP Site

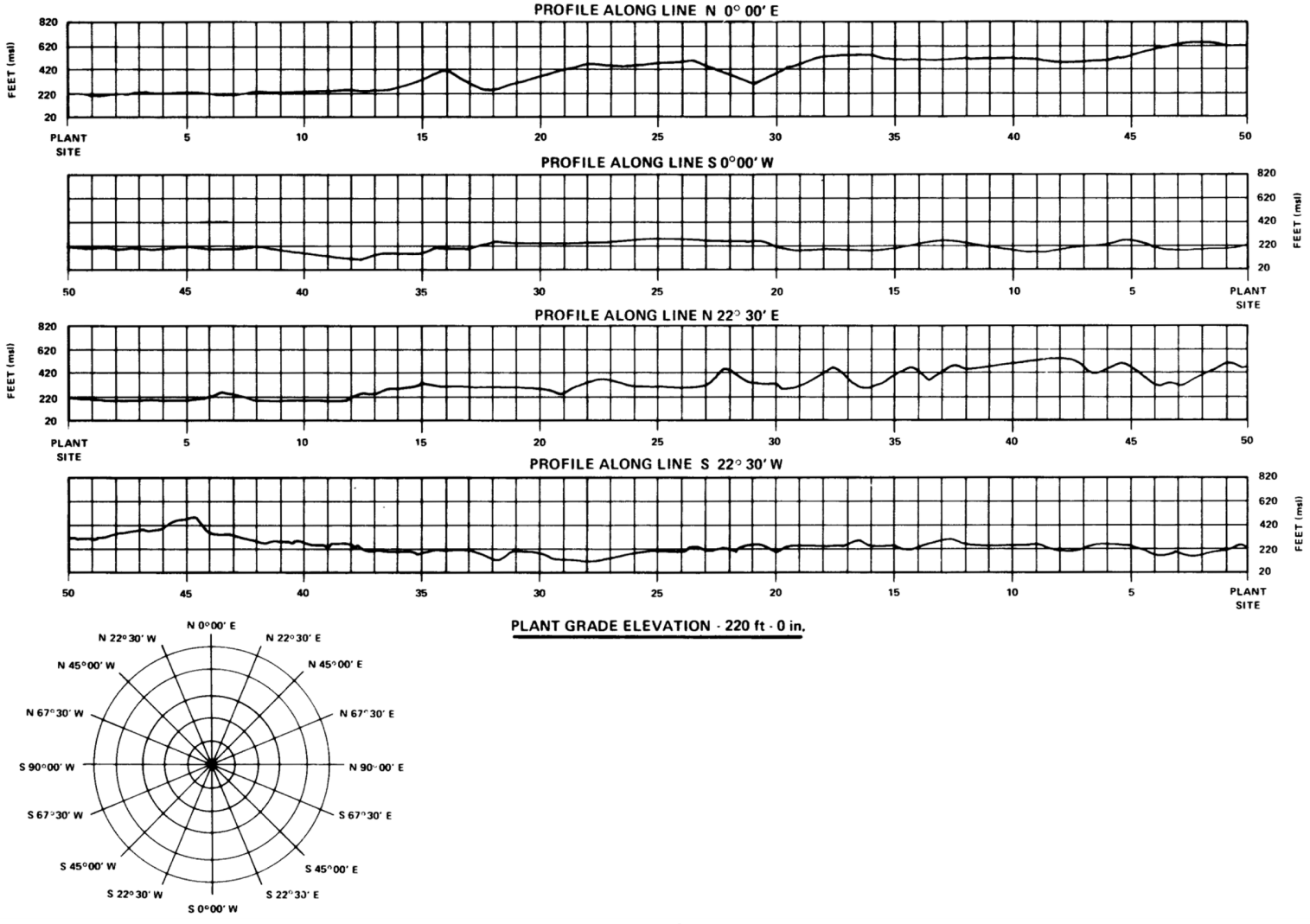

Figure 2.3-215 (Sheet 1 of 4)
Terrain Elevation Profiles Within 50 Miles of the VEGP Site

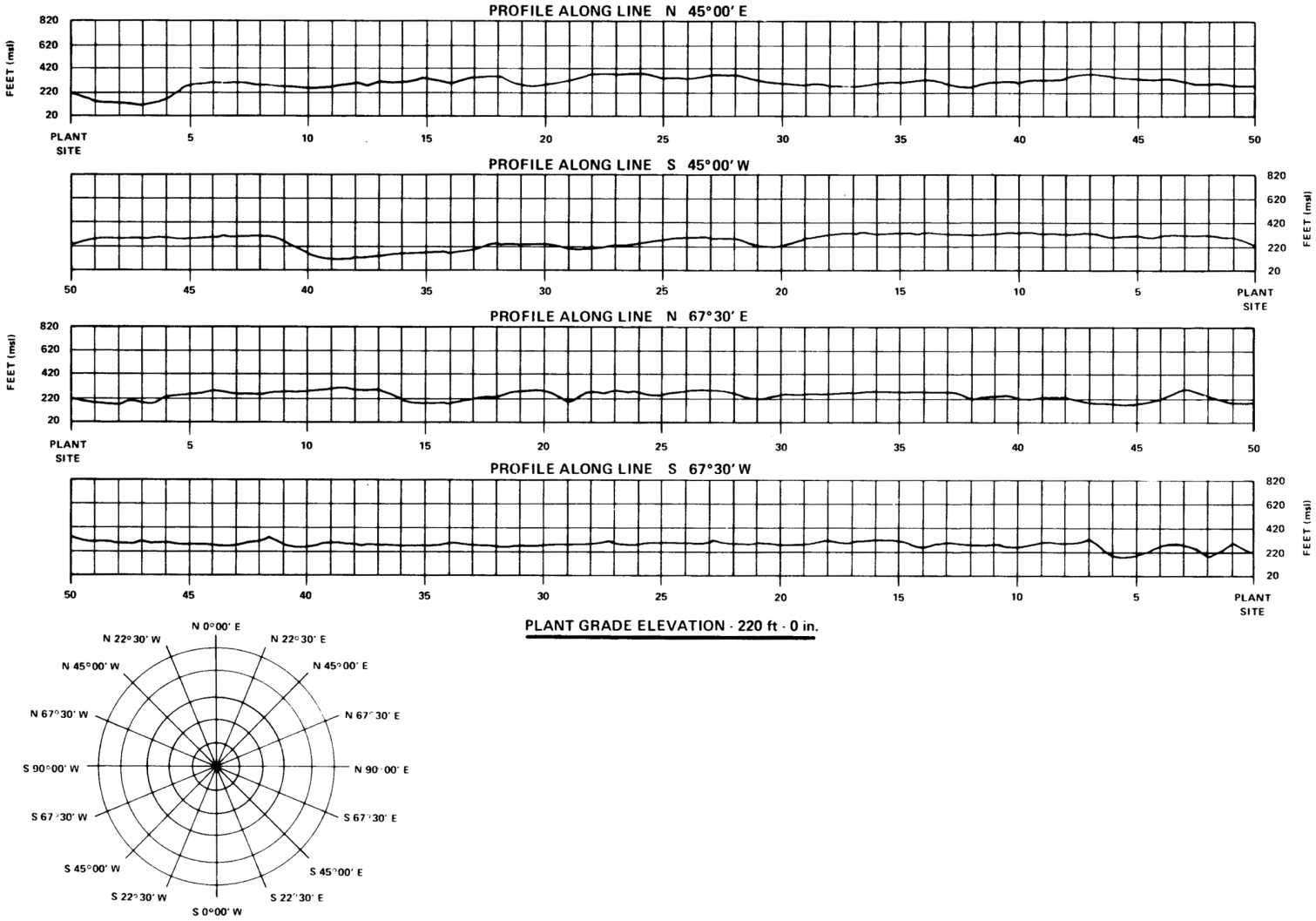

Figure 2.3-215 (Sheet 2 of 4)
Terrain Elevation Profiles Within 50 Miles of the VEGP Site

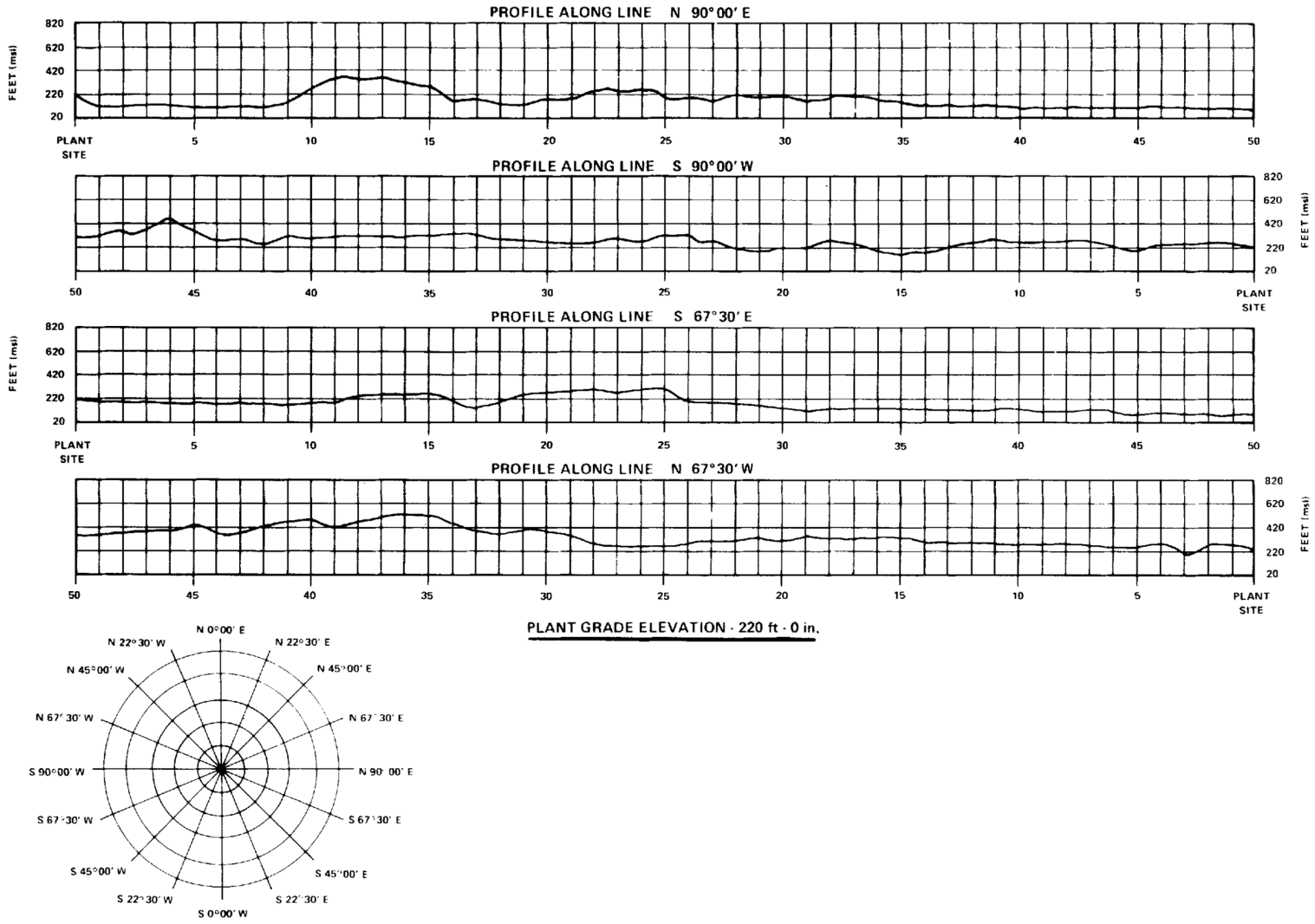

Figure 2.3-215 (Sheet 3 of 4)
Terrain Elevation Profiles Within 50 Miles of the VEGP Site

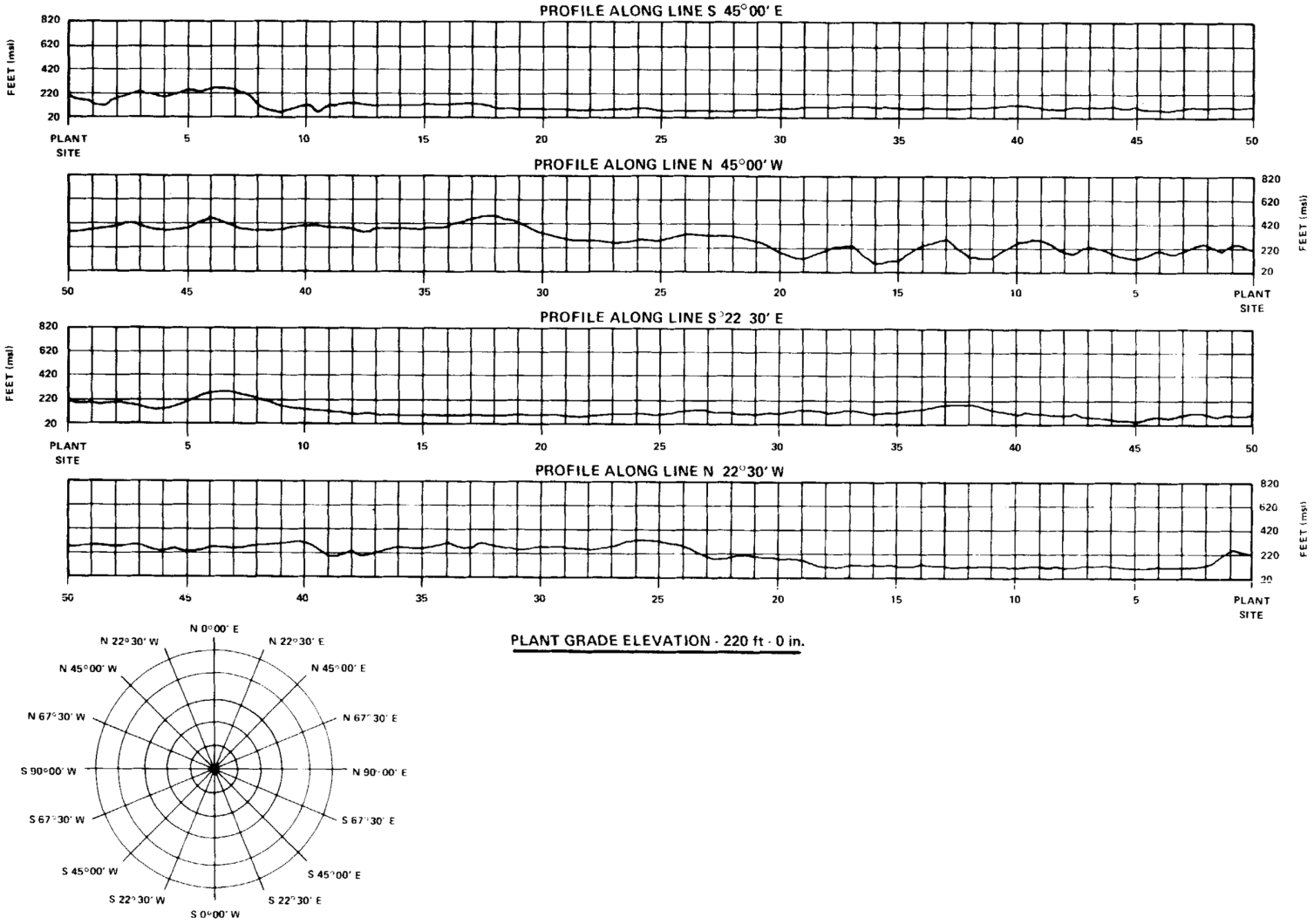

Figure 2.3-215 (Sheet 4 of 4)
Terrain Elevation Profiles Within 50 Miles of the VEGP Site

2.4 Hydrologic Engineering

Section 2.4 describes the hydrological characteristics of the VEGP site. The site location and description are provided in sufficient detail to support the safety analysis. This section addresses characteristics and natural phenomena that have the potential to affect the design basis for the proposed AP1000 units. The Section is divided into thirteen sections:

- Hydrologic Description (Subsection 2.4.1)
- Floods (Subsection 2.4.2)
- Probable Maximum Flood on Streams and Rivers (Subsection 2.4.3)
- Potential Dam Failures (Subsection 2.4.4)
- Probable Maximum Surge and Seiche Flooding (Subsection 2.4.5)
- Probable Maximum Tsunami Flooding (Subsection 2.4.6)
- Ice Effects (Subsection 2.4.7)
- Cooling Water Canals and Reservoirs (Subsection 2.4.8)
- Channel Diversions (Subsection 2.4.9)
- Flood Protection Requirements (Subsection 2.4.10)
- Low Water Considerations (Subsection 2.4.11)
- Groundwater (Subsection 2.4.12)
- Accidental Releases of Liquid Effluents in Ground and Surface Waters (Subsection 2.4.13)

2.4.1 Hydrologic Description

2.4.1.1 Site and Facilities

The 3,169-acre VEGP site is located on a coastal plain bluff on the southwest side of the Savannah River in eastern Burke County. The site is approximately 30 river miles above the U.S. Highway 301 bridge and directly across the river from the Department of Energy's Savannah River Site (Barnwell County, South Carolina). The VEGP site is approximately 15 miles east-northeast of Waynesboro, Georgia and 26 miles southeast of Augusta, Georgia, the nearest population center (i.e., having more than 25,000 residents). It is also about 100 miles north-northwest of Savannah, Georgia and 150 river miles from the mouth of the Savannah River. The contributing drainage area of the Savannah River at the site is 8,304 square miles, as estimated from digital mapping.

The Savannah River Basin and its subbasins, as delineated by the National Weather Service (Reference 208), and further subdivided into USGS Hydrologic Unit Code (HUC-12) subbasins (Reference 219), are shown in Figure 2.4-204. The drainage areas of the NWS subbasins are given in Table 2.4-208.

Two Westinghouse pressurized water reactors (PWRs), rated at 3,625.6 MWt each, are currently in operation at the VEGP site. Unit 1 began commercial operation in May 1987; Unit 2 began commercial operation in May 1989. All structures, including the containment structures, two natural

draft cooling towers (one per unit), associated pumping and discharge structures, water treatment building, switchyard, and training center, are located at or above El. 220 ft mean sea level (msl).

SNC has selected the Westinghouse AP1000 certified plant design **(NRC 2006).** The AP1000 units, referred to as Units 3 and 4, are located west of and adjacent to existing Units 1 and 2 as shown in Figure 1.1-202. The AP1000 is rated at 3,400 MWt, with a net electrical output of 1,117 megawatts electrical (MWe). The new units will use natural draft towers for circulating water system cooling, with make-up water coming from the Savannah River, and mechanical draft towers for service water system cooling, with make-up water coming from site wells. The Units 3 and 4 grade elevation is 220 feet msl. An extensive site storm water drainage system was developed during construction of Units 1 and 2 and is used for Units 3 and 4 with some modifications.

2.4.1.2 Hydrosphere

The Savannah River is the main hydrologic feature that may affect or be affected by power plants constructed at the VEGP site.

The watershed of the Savannah River extends into the mountains of North Carolina, South Carolina, and Georgia near Ellicott Rock, the point where the borders of those three states meet. The river system drains a basin of 10,577 sq mi, divided between the three states as follows (Reference 209):

- 4,581 sq mi in South Carolina
- 5,821 sq mi in Georgia
- 175 sq mi in North Carolina

Within the three states, the basin includes portions of 44 counties and borders two major metropolitan centers, Augusta and Savannah. The lower 50 mi is tidally influenced (Reference 211).

The Savannah River basin, which is described as long and relatively narrow, crosses through three distinct physiographic provinces: Mountain, Piedmont, and Coastal Plain. The Mountain and Piedmont provinces are within the Appalachian Mountain range, with the border between them extending from northeast to southwest, crossing the Tallulah River at Tallulah Falls. The Fall Line, or division between the Piedmont province and the Coastal Plain, also crosses the basin in a generally northeast to southwest direction, near Augusta, Georgia (Reference 211).

Watershed elevations range from 5,030 ft msl at Little Bald Peak in North Carolina to sea level at Savannah. The approximate range of elevations for each physiographic region is (Reference 211):

- 5,030 to 1,800 ft msl within the Mountain Province
- 1,800 to 500 ft msl within the Piedmont Province
- 500 to 0 ft msl within the Coastal Plain

The Savannah River, together with certain of its tributaries, forms the border between the states of Georgia and South Carolina. The confluence of the Seneca and Tugaloo Rivers, formerly known as "The Forks," but now inundated by Hartwell Lake, marks the upstream end of the Savannah River. The length of the Savannah River from “The Forks” to the mouth is approximately 312 mi (Reference 211).

The following principal streams make up the Savannah River stream system (Reference 211):

- The Tallulah and Chatooga rivers combine to form the Tugaloo River at River Mile 358.1.
- Twelve Mile Creek and the Keowee River join to form the Seneca River at River Mile 338.5.
- The Tugaloo and Seneca rivers join to form the Savannah River proper at River Mile 312.1, at the point known as “The Forks.”

The entire 312-mi length of the Savannah River is regulated by three adjoining US Army Corps of Engineers (USACE) multipurpose projects, forming a chain along the Georgia–South Carolina border 120 mi long. The three reservoirs, each with appreciable storage, are, from upstream to downstream:

- Hartwell Lake and Dam
- Richard B. Russell Lake and Dam
- J. Strom Thurmond Lake and Dam (also known as Clarks Hill Lake and Dam)

Of the 6,144 sq mi drainage basin above Thurmond Dam, 3,244 sq mi (53 percent) are between Thurmond and Russell Dams, 802 sq mi (13 percent) are between Russell and Hartwell Dams, and 2,088 sq mi (34 percent) are above the Hartwell Dam (Reference 211). Table 2.4-209 lists the River Miles of key landmarks along the Savannah River.

The climate in the upper Savannah River watershed is classified as temperate, with generally mild winters and long summers. The basin is protected from the extremes of winter continental weather experienced in the nearby Tennessee Valley by the Blue Ridge Mountains. The annual mean temperature for the basin is 60ºF. January, which is usually the coldest month of the year, frequently has night temperatures of 20ºF or lower. July and August, the hottest months of the year, have many days with temperatures over 90ºF. In the lower section of the basin, the winters are milder and the summer temperatures higher (Reference 211).

There are generally two periods of maximum rainfall in the upper basin: February–March and July–August, although heavy rainfall has occurred in practically every calendar month. The mean annual precipitation decreases from 83.5 in. in Highlands, North Carolina, to 49.2 in. at Savannah, Georgia (Reference 211).

2.4.1.2.1 Hydrologic Characteristics

Average daily and annual peak flow series data have been tabulated by the USGS for nine stream gages that have been maintained along the Savannah River between River Miles 288.9 and 60.9. Table 2.4-210 identifies location, gage elevation, upstream drainage area, and start and stop date and number of records for the annual and daily time series for each gage. Annual peak discharge data for these gages are used in Subsection 2.4.2; daily discharge data for these gages are used in Subsection 2.4.11.3. Summary statistics characterizing the seasonal flow variability are discussed below.

As indicated in Table 2.4-209, the USGS gage at Jackson, South Carolina, is approximately 6 river miles upstream of the VEGP site. Based on the mean daily flow series for this gage, presented in Table 2.4-213, the average daily discharge at the site is 8,913 cfs, calculated as the mean of the average daily flows for each day of the 31-year record. For this gage, the monthly mean daily flow varies from a minimum of 7,216 cfs in September to a maximum of 11,347 cfs in March. A plot of the monthly variation in mean daily flow on the Savannah River recorded at the Jackson, South Carolina,

stream gage (with plots for the Calhoun Falls and Augusta, Georgia, gages included for comparison) is provided in Figure 2.4-205, based on USGS records for the years of record of each gage, without accounting for the impact of changes in upstream regulation. Tables 2.4-211 through 2.4-213 show the mean daily discharge for the years of record for each of the three gages presented in Figure 2.4-205.

2.4.1.2.2 Local Site Drainage

Local drainage is shown in Figure 2.4-206, which was developed from the Shell Bluff Landing, Girard NW, Alexander, and Girard USGS quadrangle sheets. The site is on a high, steep bluff on the west bank of the Savannah River, overlooking the extensive floodplain on the east bank. Georgia State Highway 23 runs roughly parallel to the river, about 4 mi from the VEGP site. It runs along the ridge line that separates local drainage running northeast to the river from runoff draining generally to the southwest.

An unnamed, highly incised creek drains the northern area of the site, including Mallard Pond, into the Savannah River just upstream of the site, near the point identified as Hancock Landing in Figure 2.4-206.

To the west, the site is drained by the Red Branch and Daniels Branch, which combine and drain along with Beaverdam Creek and High Head Branch into Telfair Pond, south of the site. Beaverdam Creek intercepts three streams draining runoff from north of State Road 23 before they reach the site.

The names, estimated channel lengths, and slopes of the natural channels draining the site area are provided in Table 2.4-214.

2.4.1.2.3 Dams and Reservoirs

There are a number of water control structures on the Savannah River and its major tributaries (Reference 213, Reference 210, and Reference 211). Table 2.4-215 presents a list of these structures with hydraulic design information for each project and identification of its location with respect to the VEGP site.

Three major projects run by the USACE upstream of the VEGP site have a significant influence on the discharge of the Savannah River due to their large storage volume. These are:

- Hartwell Lake and Dam,
- Richard Russell Lake and Dam, and
- J. Strom Thurmond Lake and Dam (also known as Clarks Hill Lake and Dam on the Georgia side)

The authorized water management goals of the three-dam multi-use project are specified for normal operation, flood operation, and drought condition operation as follows (Reference 211):

For normal conditions, the operation policy is designed to maximize the public benefits of hydroelectric power, flood damage reduction, recreation, fish and wildlife, water supply, and water quality.

Under flood conditions, the water management objective of the multipurpose projects is to operate the reservoir system to minimize flooding downstream by timing turbine discharges, gate openings, and spillway discharges as required.

For drought conditions, the water management objectives of the projects are:

- To prevent draw-down of lake levels below the bottom of the conservation pool,
- To make use of most of the available storage in the lake during the drought-of-record,
- To maintain hydroelectric plant capacity throughout the drought, and
- To minimize adverse impacts to recreation during the recreation season (generally considered to be from May 1 through Labor Day)

The USACE also operates the New Savannah Bluff Lock and Dam upstream of the VEGP site, but this project has very little impact on flows at the site, due to its small run-of-river storage volume (Reference 211).

Each project is described briefly in the following paragraphs (Reference 211).

The Hartwell Lake and Dam is at River Mile 288.9, 7 mi east of Hartwell, Georgia. The top of the conservation pool is set at El. 660 ft msl. At this level, the reservoir extends 49 mi up the Tugaloo River in Georgia and 45 mi up the Seneca and Keowee Rivers in South Carolina. The shoreline at El. 660 ft msl is approximately 962 mi long, excluding island areas. Operation of the project began in 1965.

The reservoir has a total storage capacity of 2,550,000 acre-feet below El. 660 ft msl. The dam consists of a concrete gravity section 1,900 ft in length and rising about 204 ft above the streambed, and two earth embankment sections extending to high ground on the Georgia and South Carolina shores of the river, for a total length of 17,880 ft.

The Richard B. Russell Lake and Dam is at River Mile 259.1 in Elbert County, Georgia, and Abbeville County, South Carolina. The dam is 18 mi southwest of Elberton, Georgia; 4 mi southwest of Calhoun Falls, South Carolina; and 40 mi northeast of Athens, Georgia. Operation of the project began in January 1985.

The top of the conservation pool is set at El. 475 ft msl. The reservoir has a total storage capacity of 1,026,200 acre-feet at this level, and 1,166,166 acre-feet of total storage at the top of the flood control pool (El. 480 ft msl).

The dam consists of a concrete gravity section 1,883.5 ft in length and two earth embankment sections, 2,180 ft in length in Georgia and 460 ft in length in South Carolina. A concrete overflow spillway section is located in what was formerly the stream channel. It has an ogee-shaped crest controlled by 10 tainter gates.

A flip bucket for dissipating the energy of spillway discharges is located at the bottom of the spillway. The spillway tainter gates are designed for a maximum discharge of 800,000 cfs at pool El. 490 ft msl.

The J. Strom Thurmond Lake and Dam is at River Mile 221.6 on the Savannah River, 22 mi upstream of Augusta, Georgia. The reservoir at the top of the flood control pool (El. 335 ft msl) has an area of 78,500 acres. At El. 330 ft msl, the top of the conservation pool, the reservoir extends about 40 mi up the Savannah River and about 30 mi up the Little River in Georgia and has approximately 1,050 mi of shoreline, excluding island areas. The reservoir has a total storage capacity of 2,510,000 acre-feet below El. 330 ft msl. Operation of the project began in 1952.

The dam consists of a concrete gravity section 2,282 ft in length and two earth embankment sections with a total length of 5,680 ft, extending to high ground on the Georgia and South Carolina shores.

The spillway is a concrete gravity ogee section extending across the west floodplain and river channel. A bucket anchored to solid rock and constructed at four levels ranging from El. 163.0 ft msl to El. 179.0 ft msl, is provided at the toe of the spillway. The spillway discharges are controlled by 23 tainter gates separated by concrete piers 8 ft thick.

The embankments and earth dam are of rolled fill construction. An impervious core, graded from coarse and medium sand to fine silt and clay, extends to rock and is contained by a more pervious shell, consisting of well-graded coarse and medium sand to silt. The embankments are covered with rip-rap from the top down to El. 295 ft msl on the upstream side, and from the toe up to an elevation above maximum tailwater on the downstream side. U.S. Highway 221 crosses the dam.

The New Savannah Bluff Lock and Dam is located at River Mile 187.7. The function of the lock was originally to provide adequate draft depths for navigation, but there is currently very little commercial navigation above Savannah Harbor. Today the structure's main function is to maintain an adequate river stage for upstream water supply intake structures.

The structure crosses the Savannah River about 13 mi below Augusta. It is a concrete dam 360 ft long containing five vertical-lift crest control gates. The lock chamber, located on the Georgia side of the river, is 56 ft by 360 ft and is closed by mitering lock gates. The lift is 15 ft, the depth over the lower miter sill being about 10 ft at low water and over the upper miter sill being 14 ft at normal pool level. Elevation of the normal pool is about 115.0 ft msl, and low water at the downstream entrance to the lock is at El. 101.8 ft msl, based on a flow of 6,300 cfs.

2.4.1.2.4 Proposed Water Management Changes

The USACE, working in response to US Environmental Protection Agency (EPA) recommendations, is currently reviewing operating rules for the dams under its jurisdiction in the Savannah River watershed. The study goal is to determine if changes are warranted to meet current and future water resource management goals, including flood control, water supply, fish and wildlife enhancement, drought control, water quality, recreation, and aquatic plant control. The study is scheduled for completion in 2009 (Reference 212).

Pending the results of the watershed study, current USACE operations along the river are limited to the maintenance of existing structures and minor flood control improvements with no significant impact on the VEGP site.

It has been reported (Reference 209) that the Ports Authority of Georgia is considering deepening the harbor in Savannah to accommodate the new very large container ships that will be visiting ports on the East coast. The possibility that dredging would force the salinity gradient further upstream with possible adverse impact on the Savannah National Wildlife Refuge has been the subject of some study, but the possible change in policy would have no impact on safety issues at the VEGP site.

2.4.1.2.5 Surface Water Users

Historically, the Savannah River was an important transportation corridor, but today it serves primarily as a source of water for industry and municipalities, a receiving body for the subsequent discharge of effluent, and an avenue for power generation and recreational activities (Reference 209).

Agencies with important roles in the watershed include the USACE, which is responsible for maintaining reservoirs on the main stem of the Savannah River, and the EPA in cooperation with the

Georgia Environmental Protection Division and the South Carolina, which are responsible for maintaining water quality in the basin.

Current in-stream use of Savannah River water includes minimum stream flow requirements for navigation and environmental maintenance, and diversions for industrial use, including once-through cooling. Consumptive use of Savannah River water is predominantly for industrial withdrawals for cooling water towers and processing and diversions to water treatment plants for municipal water use.

Table 2.4-216 presents a summary of data on surface-water users adjacent to or downstream from VEGP whose intakes could be adversely impacted by an accidental release of contaminants from the site; the summary includes information on the owner, facility type, estimated distance from the VEGP site, and average daily withdrawal rate.

Information about groundwater users is presented in Subsection 2.4.12, while Subsection 2.4.13 discusses the consequences of liquid effluent releases to surface waters.

2.4.1.2.6 Water Consumption

The AP1000 units require water for both plant cooling and operational uses. The Savannah River provides makeup water for the circulating water system (CWS) to replace the water lost to evaporation, drift, and blowdown. Onsite wells provide groundwater makeup for the service water system (SWS). The wells also provide water for other plant systems, including the fire protection system, the plant demineralized water supply system, and the potable water system. Surface water consumptive use for the two AP1000 units' normal operation is 29,125 gpm, with a maximum of 30,585 gpm. Groundwater consumptive use is 752 gpm on average, with a maximum of 2,797 gpm. During normal operation, approximately 305 gpm of groundwater is returned as surface water to the Savannah River. Table 2.4-217 identifies the normal and maximum water demand and effluent streams for the AP1000 units.

The CWS and SWS cooling towers lose water from evaporation and drift. Evaporation and drift from the CWS cooling towers is estimated at 29,125 gpm during normal operations. Evaporation and drift for the SWS cooling tower is estimated at 403 gpm. These values are based on site characteristics and AP1000 design parameters for cooling.

Table 2.4-217 also provides the water release estimates for wastewater and blowdown discharged to the Savannah River. These include estimates for all wastewater flows from the site, including radiological effluent releases, sanitary waste, miscellaneous drains, and demineralizer discharges. The normal values listed are the expected values for normal plant operation with two new units in operation. The maximum values are those expected for upset or abnormal conditions with two new units in operation.

2.4.2 Floods

2.4.2.1 Flood History

Potential causes of flooding at the site are limited to local runoff events due to intense point-rainfall near the site and flooding from the Savannah River. There is no historical record of flooding due to storm surges or tsunamis at the site, which is consistent with its location approximately 150 River Miles inland from the ocean. Because there are no large bodies of water near the site, flooding due to seiche motion was not considered (see Subsections 2.4.5 and 2.4.6).

Table 2.4-218 (Reference 214) provides the date, stage elevation, and annual peak discharge for the entire period of record of USGS stream gage 02197000 on the Savannah River at Augusta, Georgia,

approximately 48.7 River Miles upstream of the VEGP site. The annual peak floods include estimated values from historic floods reported in 1796, 1840, 1852, 1864, 1865, and 1876.

The maximum annual peak flood discharge for the period of record is 350,000 cfs from the storm of October 2, 1929. The storm of January 17, 1796, estimated from reported stages using slope-conveyance methods, is the oldest event used to extend the record length. The estimated value of the peak flow for this storm ranges from 280,000 cfs for a reported stage of 38 ft (Reference 214) to 360,000 cfs for a reported maximum flood stage of 40 ft (Reference 213). This puts the maximum flood elevation of the Savannah River at Augusta, Georgia, for the historic period between 134.6 and 136.6 ft msl, based on an elevation of 96.58 ft msl for the Augusta, Georgia, stream gage datum (see Table 2.4-218).

Since 1952, annual peaks on the Savannah River at Augusta, Georgia, have been impacted by regulation from upstream reservoirs: J. Strom Thurmond (also known as Clarks Hill) Lake and Dam in 1952, Hartwell Lake and Dam in 1961, and Richard B. Russell Lake and Dam in 1984 (Reference 211). In Figure 2.4-207 (Reference 213), which is based on the historical record from 1796 to 1985, this impact is shown by the pronounced reduction of peak flows after 1952. The addition of annual peak stream gage data from 1986 to 2002 would not significantly affect this graph, as indicated by the following averages:

Average annual peak discharge 1796–1950:	232,696 cfs
Average annual peak discharge 1876–1950:	113,086 cfs
Average annual peak discharge 1951–2004:	34,343 cfs
Average annual peak discharge 1951–1985:	37,569 cfs
Average annual peak discharge 1986–2004:	28,734 cfs

The USGS stream gage at Jackson, South Carolina, which is approximately 5.9 River Miles upstream of the VEGP site (see Table 2.4-209), has a record length significantly shorter than that of the Augusta gage and contains no observations before upstream dams were closed. Table 2.4-219 compares the annual peak discharges on the Savannah River at Augusta, Georgia, and Jackson, South Carolina, for the 29 coincident years of record. During this period, the peak annual discharge at the two sites was not associated with the same storm event in seven instances. These cases are indicated by the grayed-out rows of Table 2.4-219, for which the dates of the peaks differ by a significant number of days. There is a 1-to-2-day lag in the occurrence of annual maximum peaks at the two gages derived from the same flood event. A very strong linear correlation exists between flood stages at the two sites for the annual peak floods derived from the same event, as shown in Figure 2.4-208, making it feasible to extend the historical record at Jackson, South Carolina. The annual peak flood stage at the VEGP site could then be estimated from the stages at Jackson, with a level of confidence dependent on the ability to establish a reliable estimate of the stage at the VEGP site from the river stage at Jackson, South Carolina, based on hydraulic considerations.

Annual peak flood frequency curves for regulated and unregulated conditions for the Savannah River at Augusta, Georgia, were developed for the period between 1796 and 1985 and are presented in Figure 2.4-209 (Reference 213). Unregulated annual peak discharge values for the period after 1952 and regulated annual peak discharge values for the years before 1952 were generated by modeling reservoir operation based on the stage-storage-discharge characteristics reported for the three projects, using the 1990 operating rule set for the entire period (Reference 213).

Figure 2.4-209 clearly shows the convergence of the regulated and unregulated annual flood frequency plots with increasing flood size. On the left side of the graph, for the 80 percent chance-of-exceedence event (a 1.25-year return period), the unregulated peak discharge exceeds the regulated peak by more than 100 percent; on the right side, for the 0.2 percent chance-of-

exceedence event (500-year return period), the unregulated peak discharge exceeds the regulated peak by about 30 percent. Based on this trend, regulation would not be expected to significantly affect the probable maximum flood on the Savannah River downstream of Augusta, provided that the regulating structures do not fail. Flooding due to dam-breaks is discussed in Subsection 2.4.4.

2.4.2.2 Flood Design Considerations

The AP1000 is designed for a normal groundwater elevation up to plant elevation 98′ and for a flood level up to plant elevation 100′. For structural analysis purposes, grade elevation is also established as plant elevation 100′. Actual grade will be a few inches lower to prevent surface water from entering doorways.

For a portion of the annex building the site grade will be 107 feet to permit truck access at the elevation of the floor in the annex building and inside containment. Subsection 3.4.1 describes design provisions for groundwater and flooding.

The location of VEGP Units 3 and 4 would be adjacent to and generally to the west of existing VEGP Units 1 and 2, as illustrated in Figure 1.1-202. The site is located on a high bluff on the west bank of the Savannah River. The site grade for the new units is El. 220 ft msl, similar to the existing VEGP units, well above the probable maximum flood stage of the Savannah River, as discussed in Subsection 2.4.3.

The annual maximum flood at the VEGP site can occur in any month of the year and is not associated specifically with icing, which does not normally occur to any significant degree, as indicated in Subsection 2.4.7. For this reason, the effect of ice accumulation on runoff was not taken into account in selecting the design flood.

The design basis flood for the VEGP site was determined by selecting the maximum flood elevation on the Savannah River obtained by considering all flooding scenarios applicable to the location, including an approximate estimate of the probable maximum flood (PMF), flooding due to probable maximum precipitation (PMP) over local drainage courses, and potential dam failures coincident with wind set-up and wave run-up. Flood surge from ocean storms and tsunami-caused flooding were not considered because the VEGP site is approximately 151 river miles inland.

Each applicable flooding scenario was evaluated following guidelines provided in Regulatory Guide 1.59, *Design Basis Floods for Nuclear Power Plants*, 1977 (RG 1.59) and ANSI/ANS-2.8, *Determining Design Basis Flooding at Power Reactor Sites* (Reference 220), as detailed in Subsections 2.4.3 through 2.4.7.

Adverse effects of flooding due to high water or ice effects do not have to be considered for site-specific nonsafety-related structures and water sources outside the scope of the certified design. Flooding of water intake structures, cooling canals, or reservoirs or channel diversions would not prevent safe operation of the plant.

The controlling event for the VEGP site was determined to be from the breach of the upstream dams, estimated as described in Subsection 2.4.4, using the Standard Project Flood discharge as a starting condition, including wind set-up and wave run-up. The design basis flooding level derived from this event, including wave setup, is El. 178.10 ft msl, which is 41.9 ft below the site grade elevation of 220.0 ft msl.

Elevations for safety-related components and structures are not yet established for the proposed units. However, the grade elevation in the power block area of the VEGP site would be approximately the same as the existing units, elevation 220 ft msl, providing over 41 ft of freeboard

above the design basis flooding level. Freeboard for all above-grade, safety-related structures, systems, and components of the new units will be equal to or greater than this value.

2.4.2.3 Effects of Local Intense Precipitation

The design basis for local intense precipitation at the site is the PMP, which is defined as the "greatest depth of precipitation for a given duration that is physically possible over a given size storm area at a particular geographical location at a certain time of year" (Reference 222). Maps of the PMP are published for durations ranging from 6 to 72 hours and for watershed areas ranging from 10 to 20,000 sq mi (Reference 221).

As can be seen in Figure 2.4-206, the VEGP site is situated on high ground in such a manner that the areas to be drained by each conveyance system serving the site will be on the order of 1 sq mi, with times of concentration considerably less than 6 hours. The 1-sq-mi PMP for the VEGP site is calculated for a range of durations between 5 and 60 minutes from the 10-sq-mi, 6-hour, all-season average PMP depth, using multipliers following accepted engineering practice (Reference 222). These values of depth are used to develop a relation between rainfall intensity and durations for the PMP, which will be used for storm drain designs at the VEGP site. The point values used for developing the relation are listed in Table 2.4-220 and the estimated curve is plotted in Figure 2.4-210.

The existing storm water system provides positive drainage away from the site for the runoff generated by the PMP: surface runoff flows away from the high ground on which the Unit 1 and 2 structures are located and is collected in four principal drainage channels aligned in concert with access roads and railroad facilities to outfall to the north, south, east, and west.

In general, the storm water management system developed for Units 3 and 4 has been integrated with the existing facilities as possible; runoff from Units 3 and 4 is directed away from Unit 1 and 2 structures, to outfall to the north, west and south of the VEGP site.

The storm drain system has been designed in accordance with good engineering practice, following all applicable federal, state, and local storm water management regulations. In addition, site grading has been sufficiently sloped to convey runoff overland from the PMP event, away from all buildings and safety-related equipment, without flooding, even if all catch basins and roof drains are plugged. The storm drain system is visually inspected to verify the flow path is unobstructed. The system is observed under simulated or actual precipitation events to verify that the runoff from roof drains and the plant site and adjacent areas does not result in unacceptable soil erosion adjacent to, or flooding of, Seismic Category I structures.

The design elements of the VEGP Units 3 and 4 storm water management system pertaining to the local PMP flood event are described below.

The VEGP Units 3 and 4 power block is graded to direct runoff east and west to three north-south ditches which will outfall to the concrete-lined main ditch, running east and west for 2,000 feet along the south side of the power block. The ditch cross section consists of one vertical side wall and the other a 2.5:1 sloping side wall with a 13 to 15 foot bottom width. At the southwest corner of the power block, the main ditch turns due south, and the existing ditch is used. From the west, it intercepts runoff from the construction laydown area; from the east it intercepts discharge from two ditches draining the cooling tower block.

The main ditch has a mild slope (0.22%) for its first 4,600 feet, at which point the slope increases to over 5% before outfalling about 5,100 feet from its upstream end into Debris Basin No. 2, which drains to an unnamed tributary of Daniels Branch, about 2,500 feet upstream of Telfair Pond.

The main ditch drains runoff from a total area of about 350 acres during the PMP event. The northeast drainage ditch is located between the Units 1&2 power block and the Units 3&4 power block, flowing north and eventually discharging to the Savannah River northeast of both sites. The ditch is a concrete lined trapezoidal ditch.

The local PMP event was modeled in HEC-HMS, which is an industry standard program for this application. For inputs of rainfall and drainage basin characteristics, the program outputs stream flow hydrographs at selected locations within the drainage basin (Reference 203).

The design rainfall hyetograph was developed in HEC-HMS utilizing the frequency storm option in the Meteorologic Models module (Reference 205). This option requires the input of PMP point depths for durations of 5, 15, 60, 120, 180, and 360 minutes.

Based on the logarithmic fit to the data shown in Table 2.4-220, a PMP total depth was estimated for the missing durations, as indicated in Table 2.4-201. An intensity position of 50 percent was selected for the HEC-HMS calculation, consistent with the alternating block pattern used in standard analysis (Reference 201) The rainfall hyetograph developed from the data is shown in Figure 2.4-202.

Elements within the HEC-HMS basin model include subbasins, reaches, and junctions. Runoff hydrographs were developed for subbasins and were routed through the channel system along reaches connected by junctions (Reference 205).

This calculation utilized the SCS Hydrograph Methodology (Reference 205), which requires the following parameters for each subbasin:

- Drainage Area, in square miles
- Runoff Curve Number and Initial Abstractions
- Lag Time, in minutes
- Base flow, in cfs

Drainage areas were delineated and measured for each subbasin.

The runoff curve number (CN) was selected as 98 for all types of cover to provide a conservative estimate of runoff volume and peak discharges and to account for nonlinear basin response to extreme rainfall events. Under normal flood conditions, the area-weighted average for each subbasin could be expected to vary between 50 and 75, while a CN value of 98 is typically used for impervious areas.

The lag time was estimated as 60 percent of the time of concentration, which is the time required for all areas of the drainage basin to be contributing to outflow. It was calculated for each subbasin as the sum of the overland, shallow concentrated, and channel flow times along the critical flow path through the basin using standardized equations (Reference 205). The minimum time of concentration is taken as 5 minutes, which results in slightly higher peak runoff discharges.

An assumption of the PMP design storm is that a 40-percent PMP storm has occurred 3 to 5 days prior to the start of the rainfall associated with the actual PMP event, so some flow in the drainage ditches would be expected as the result of interflow draining from the pervious areas of the upstream watershed, although it would not be a significant quantity for this site, considering the limited drainage area. For this site, base flow is taken as zero for subbasins that are completely paved. Base flow is estimated on a 100 cfs per square mile basis for subbasins with uncovered ground.

The SCS unit hydrograph parameters calculated for each of the subbasins in the HEC-HMS models are provided in Table 2.4-202.

The subbasin hydrographs are added at junctions and routed through channel reaches.

Peak discharges from all subbasins resulting from modeling the PMP rainfall event in HEC-HMS are summarized in Table 2.4-204. The hydrographs simulated for a sample of subbasins are shown in Figure 2.4-203.

The backwater analysis for the PMP drainage network was developed in HEC-RAS (Reference 205). Cross sections were developed for the main drainage ditch and feeder channels with topographic data for the overbank area, using the proposed geometric configuration for the channels.

The assumptions made and the data utilized in the development of the hydraulic model are as follows:

- All channels are concrete lined, so no local scoured-out cross sections are utilized in the model.
- All culverts in the model are assumed to be 100% blocked by debris collected from the catchment.
- The blocked culverts within the power block area are modeled as in-line weirs in HEC-RAS following common hydraulic engineering practice (Reference 205). The effect of the blocked culvert in Feeder Ditch 4 is accounted for by adjusting cross section geometry to indicate the ditch is filled in at the culvert location.
- The unsteady flow option in the HEC-RAS hydraulic model uses the actual channel geometry from the cross-section data in the model to calculate storage and flow attenuation. The method in HEC-RAS is a more accurate representation of the flow attenuation that occurs.

The Manning's n roughness values used in the model were selected for standard conservative assumptions (Reference 202) as follows:

- concrete feeder ditches (assumed to be well maintained) with n = .014 and overbank areas assumed to be gravel bottom and concrete curbs with n = .020
- overbank areas assumed to be short grass with n = .030
- narrow overbank areas along some sections of 100-year Ditch, Feeder Ditch 6, and the Northeast Drainage Ditch with n = .050 and left overbank areas of 100-year Ditch at downstream end with n = .10

The results of the mixed-flow regime back water calculation for PMP discharges in the drainage network are presented in Table 2.4-207.

The feeder ditches draining the power block area are subject to high tailwater conditions in the main ditch for the PMP runoff event. The HEC-RAS output indicates that the maximum floodwater surface elevation would be between 218.4 ft msl and 219.1 ft at the location of safety-related facilities. As all safety-related facilities have entry elevations at or above 220 ft msl, it has been determined that the maximum local PMP flood elevation is at least 0.9 ft below any entry to any safety related facility, and the flooding of safety-related facilities due to this PMP event does not occur. Configuration control of the plant layout, as assumed in the hydraulic model described above, is governed by applicable plant procedures.

In summary, the main ditch system has been designed to convey the peak discharge of the PMP flood event safely offsite. In addition, site grading is sufficiently sloped to convey runoff overland from the local PMP event away from all buildings and safety-related equipment, without flooding.

The required maintenance for the drainage ditches and overbank areas will be determined during the quarterly walk-through inspections of the drainage features (main drainage and feeder ditches and their overbank areas) in the Units 3 and 4 portion of the protected area and from the protected area fence through the Units 3 and 4 cooling tower area.

2.4.2.3.1 Effect of Temporary Configuration: Unit 3 in Operation and Unit 4 in Construction

After Unit 3 fuel load, but prior to Unit 4 fuel load, there is a period where the site layout differs from that reflected in the foregoing discussion. The temporary site layout includes a temporary barrier between Unit 3 and Unit 4, temporary construction structures and laydown area, missing Feeder Ditch 5, and a different Feeder Ditch 3 geometry. Hydrologic runoff analysis and hydraulic flood routing and water level determination analysis were performed to determine the flood levels for the local PMP event in a worst-case temporary configuration. The analyses were done with industry standard codes (HEC-HMS and HEC-RAS) using accepted engineering practices. The results of the analysis were compared to Maximum Flood Level (standard plant design elevation 100 ft/site-specific plant elevation 220 ft msl). The analysis determined that the maximum local PMP water level in the VEGP Units 3&4 power block is at a maximum elevation of 219.6 ft msl at the upstream end of Feeder Ditch 1. This elevation is lower than the slab grade for the Unit 3 safety-related SSCs at elevation 220.0 ft msl.

2.4.3 Probable Maximum Flood

In this section, the hydrometeorological design basis of any necessary flood protection measures is presented for those structures, systems, and components necessary to ensure the capability to shut down the proposed VEGP Units 3 and 4 and maintain them in a safe shutdown condition. One of the scenarios investigated to determine the design basis flood for ensuring the safety of nuclear power plants is the Probable Maximum Flood (PMF). PMF flows and stages at a site can be the result of local flooding, as discussed in Subsection 2.4.2, or riverine flooding, as described below.

The location of VEGP Units 3 and 4 is adjacent to and generally to the west of the existing VEGP units, as illustrated in Figure 1.1-202. The site is located on a high bluff on the west bank of the Savannah River. The site grade for the new units is established as Elevation 220 ft msl, similar to the existing VEGP units, which is well above the probable maximum flood stage of the Savannah River.

Based on calculations, site visits, an assessment of site conditions, and a review of previous studies, it was determined that the maximum water surface elevation resulting from the PMF on the Savannah River at the VEGP site and the additional combined action of wind setup and wave run-up would be substantially below El. 220 ft msl.

Considering this assessment, the VEGP site can be characterized as a “flood-dry site,” as described in Section 5.1.3 of the American National Standard Report, *Determining Design Basis Flooding at Power Reactor Sites*, because the safety-related structures of both the existing VEGP and proposed AP1000 units are or will be so high above the Savannah River that safety from flooding is “obvious or can be documented with minimum analysis” (Reference 220).

A review of studies and analysis performed for the existing units was carried out to confirm that the conclusions continue to be valid for Units 3 and 4. This characterization of the VEGP site is reported in Subsection 2.4.3.1.

A calculation of the PMF discharge using approximate methods was developed for the ESP application from Regulatory Guide 1.59, *Design Basis Floods for Nuclear Power Plants*, Revision 2, August 1977, reported in Subsection 2.4.3.2, and the calculation of the associated flood stage using a steady-state hydraulic model and wave run-up, reported in Subsection 2.4.3.3. These calculations indicate that the maximum flood stage associated with Savannah River flooding is approximately 70 ft below the base slab elevation of the proposed units, confirming the assessment of the VEGP site as "flood dry."

2.4.3.1 Review of Studies for Units 1 and 2

As part of the hydrologic study carried out for Units 1 and 2, the PMF values for the Savannah River at the site were first estimated using a hydrologic model of the entire upstream watershed and then were checked with a dynamic hydraulic model of the reach of the Savannah River between the last storage reservoir and the VEGP site, as summarized below:

1. The HEC-1 Flood Hydrograph Computer Program, developed by the USACE, was used to develop the PMF hydrograph of the Savannah River near the VEGP site, using the unit hydrographs of the 10 subbasins developed by the National Weather Service (NWS) together with Probable Maximum Precipitation (PMP) estimates derived from methodology outlined in National Weather Service Hydrometeorological Reports (NWS HMR 51 and HMR 52). Valley storage was accounted for by separately modeling the Strom Thurmond Dam HEC-1 outflow hydrograph with the NWS DAMBRK program.

2. The HEC-1 model was independently verified by routing the USACE-derived PMF outflow hydrograph from the Strom Thurmond Dam down to the VEGP site and combining it with the PMF hydrographs from the intervening drainage areas developed from HEC-1.

The results of these previous modeling efforts are summarized in Table 2.4-221 and are described in more detail below.

2.4.3.1.1 Savannah River Watershed Hydrologic Model

In the HEC-1 hydrologic model, the watershed for the Savannah River at the VEGP site was subdivided into 10 subbasins with a total drainage area estimated at that time as 8,015 sq mi (the subwatershed areas used by the NWS for the current flood forecasting model of the Savannah River basin are different from the values used in previous modeling; the updated watershed areas are presented in Table 2.4-208 and are used for the PMF approximation described in Subsection 2.4.3.2). The PMF hydrograph for each subbasin was developed using the unit hydrograph obtained from NWS for the respective subbasins and the corresponding PMP estimates pertaining to the subbasin in question.

Starting from the most upstream subbasin, the PMF hydrograph was then routed and combined in succession in the downstream direction to the VEGP site, including reservoir routing through the upstream Burton, Hartwell, Strom Thurmond, and Stevens Creek dams.

Below Augusta, Georgia, significant floodplain storage exists that could significantly reduce the flood peak. Two PMF values at the VEGP site are presented in the study for licensing Units 1 and 2: a value of 540,000 cfs, with valley storage effects considered, and a value of 895,000 cfs without storage. Without the wind wave activities included, the maximum Savannah River PMF water levels at the VEGP site were estimated to be at El. 126 ft msl and 136 ft msl, respectively, for these two cases.

2.4.3.1.2 Dynamic Hydraulic Model Check on Hydrologic Model Results

An independent check of the reliability of the HEC-1-based estimate of the PMF at the VEGP site was carried out by routing the USACE-derived PMF outflow hydrograph from the Strom Thurmond Dam down to the VEGP site using the NWS dynamic hydraulic model DAMBRK and combining it with the HEC-1-derived PMF hydrographs from the intervening drainage areas between the Strom Thurmond Dam and the site.

The PMF outflow hydrograph at the Strom Thurmond Dam was obtained from the 1962 USACE *Reservoir Regulation Manual* (revised in 1968) developed by the Savannah District before the HMR 51 and 52 PMP guidelines were published and before the closure of the upstream dams.

The PMF peak discharge at the VEGP site was found to be 710,000 cfs, with a corresponding maximum water level at EL 138 ft msl.

It appears that a PMF value of 710,000 cfs was adopted in the study for Units 1 and 2 because it gave a higher water level than the 540,000 cfs value derived from the HEC-1/NWS modeling effort, when valley storage effects were considered.

2.4.3.2 Estimation of PMF by Approximate Methods

An alternative method for estimating the PMF is described in the NRC Regulatory Guide 1.59 for flood dry sites. The method consists of obtaining a relationship for the PMF discharge as a function of drainage area, based on PMF iso-line maps developed for regions of the United States east of the 105th Meridian, and utilizing the drainage area at a given site, obtain the PMF from the relation determined for that region. No PMP is required for this method. Calculations for the estimated PMF at the VEGP site are presented in Table 2.4-222.

The PMF values determined from the 100-, 500-, 1,000-, 5,000-, 10,000-, and 20,000 sq mi contributing area maps at the location of the Savannah River watershed upstream of the VEGP site are tabulated in Table 2.4-222.

A logarithmic plot of the power curve fit to these values is presented in Figure 2.4-211. Based on the curve fit to the data and the currently estimated drainage area of 8,304 sq mi (as discussed in Subsection 2.4.1), the estimated PMF for the VEGP site is about 920,000 cfs. This point is located on the curve in Figure 2.4-211, along with a data point for VEGP (reported as Alvin W. Vogtle), presented on page 4 of 17 in Table B.1 of Regulatory Guide 1.59 as 1,001,000 cfs for a drainage area of 6,144 sq mi. Considering current and previously reported measurements, the drainage area reported for the VEGP site in Table B.1 appears to be incorrect and inconsistent with the Regulatory Guide 1.59 method, which was used to derive the value. However, it is presented as a published reference value.

2.4.3.3 Estimation of Flood Stage at VEGP Site for PMF

A stage-discharge relationship or “rating curve” is required to estimate the water surface elevation of the Savannah River near the VEGP site associated with the PMF discharge. This relationship was obtained from a steady-state hydraulic backwater analysis of the Savannah River run in HEC-RAS, a computer model developed by the USACE (Reference 224).

The steady-state model was adapted from the dynamic model used for the analysis of the dam-break scenario described in Subsection 2.4.4, using the same channel roughness (Manning’s n) values as in that model. All bridges were removed from the dynamic model; they were not put back into the steady-state model, which is equivalent to assuming that any downstream bridges are either swept away or have a negligible impact on water surface elevations at the VEGP site during the PMF event.

Changes in the HEC-RAS model used to estimate stages at the VEGP site included:

- The reaches of the model upstream of the Augusta City Dam (River Mile 199.667) were removed.
- The model was converted from dynamic to steady-state mode with the downstream boundary condition at River Mile 99.406 determined by normal depth using an estimated energy slope of 0.0005 (the downstream water surface elevation will have a negligible impact on water surface elevations some 90 mi upstream near the VEGP site).
- The PMF and reference discharges were input for the entire model reach.
- The cross-section nearest the VEGP site (River Mile 150.906) was extended to the proposed top-of-slab elevation using 1:24,000-scale topography from 7.5-minute USGS quadrangles (Reference 225).

The results for the cross-section nearest to the VEGP site (River Mile 150.906 in the model) are shown in Table 2.4-223.

The longitudinal profile output for the Savannah River for this model is reproduced as Figure 2.4-212. The cross section developed for the VEGP site is shown in Figure 2.4-213.

The estimated maximum stages at the VEGP site for the PMF estimated per the approximate method outlined in Regulatory Guide 1.59 are shown in Table 2.4-224.

Based on the fact that the estimated maximum stage reached by the Savannah River at the site for the approximate PMF flood is over 69 feet below the minimum top-of-slab elevation of any safety-related systems, structures, or components at the VEGP site, the characterization of a flood-dry site should be established.

2.4.3.4 Conclusions

The PMF discharge on the Savannah River at the VEGP site estimated using the approximate methodology recommended for flood-dry sites is approximately 920,000 cfs, which corresponds to an approximate flood stage of about El. 139 ft msl. Accounting for wave run-up and wind setup, the probable maximum water surface elevation on the Savannah River at the VEGP site would be less than elevation 151 ft msl.

The peak flood discharge associated with the dam-break analysis presented in Subsection 2.4.4 is about 2,332,000 cfs – significantly higher than the estimated PMF, which is consistent with the very significant volume of storage in the reservoirs upstream of the site. The maximum water surface elevation of the Savannah River at the VEGP site associated with the dam-break scenario is El. 166.79 ft msl at a discharge of 2,233,000 cfs (occurring several hours after the wave front associated with peak discharge, at which time the water surface is lower). Including 11.31 feet of wave run-up and wind set-up, the estimated maximum water stage at the VEGP site is El. 178.1 ft msl, significantly higher than the stage resulting from the PMF event with no dam failure.

In either case, the probable maximum flood stage is so far below the grade elevation for the new units that the site can be classified as flood dry without reservation, and it can be concluded that the site is not susceptible to flooding from the Savannah River.

2.4.4 Potential Dam Failures

The VEGP site is located on the west bank of the Savannah River about 50 River Miles downstream of the City of Augusta, Georgia. There are 14 dams in the Savannah River Basin upstream of the VEGP site. These dams are owned and operated by either the U.S. Army Corps of Engineers (USACE) or one of several electric power generation companies located in Georgia and South Carolina. Table 2.4-216 lists the dams, their owners, and other pertinent data. The dams owned and operated by electric power generators fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC); the other dams fall under the jurisdiction of the USACE.

Both FERC and USACE regulations require that dams for which failures pose a risk to human life be designed to survive very large earthquakes without risk of failure. Thus, it is unlikely that failure of any of the upstream dams would occur during a Safe Shutdown Earthquake (SSE). However, to demonstrate that the VEGP site will not be subject to flooding due to potential dam failures, a domino-type failure of the upstream dams is assumed, and this section analyzes the resulting flood wave and corresponding flood elevations at the VEGP site.

2.4.4.1 Dam Failure Permutations

Figure 2.4-214 shows the locations of the Savannah River Basin dams. Two of these dams, Stevens Creek Dam and New Savannah Bluff Lock and Dam, are relatively small weir structures used for flow diversion and small hydropower generation and do not have significant storage volumes. Both of these dams are located downstream of J. Strom Thurmond (also known as Clark's Hill) Dam and would be completely inundated by a breach of the upstream dams. Therefore, they are not included in the dam breach analysis presented in this subsection.

Table 2.4-216 lists each dam, its location, and size. Note that Little River Lake and Dam and Keowee Lake and Dam are hydraulically connected and share a common reservoir. All discharge from the common reservoir is through the Keowee Dam. Little River Dam has no outlet works.

Three large hydroelectric and storage dams on the Savannah River are operated by the USACE. They are J. Strom Thurmond Lake and Dam, Richard B. Russell Lake and Dam, and Hartwell Lake and Dam. Each dam comprises an earth embankment with a concrete gravity section in the center where the hydroelectric generation facilities and spillway gates are located. Upstream of Hartwell Dam, the remaining dams are located on tributaries to the Savannah River. Keowee/Little River Dam and Jocassee Dam are located on the Keowee River. Yonah Dam and Tugaloo Dam are located on the Tugaloo River. Tallulah Falls Dam, Mathis Dam, Nacoochee Dam, and Burton Dam are located on the Tallulah River, which is a tributary to the Tugaloo River.

For the dam breach analysis, conservatism of coincident flow rates in the Savannah River and water levels in the dams are assumed. The dam failure is assumed to be coincident with the standard project flood (SPF) water levels in the reservoirs behind the dams and the USACE-defined SPF discharge in the Savannah River.

Upstream of Thurmond Dam, there are essentially no free-flowing reaches of the Savannah River or the Keowee River. Each dam discharges into the reservoir pool of the next downstream dam. The failure mode that produces the largest flood wave and flood elevations at the VEGP site would produce the highest water level and largest volume of water at Thurmond Dam (the dam closest to the site) just before the assumed breach of Thurmond Dam. Based on the configuration of the dams upstream of Thurmond Dam, two breach scenarios are possible.

The first scenario consists of breaching all dams simultaneously. In this scenario, the water level at Thurmond Dam would be the SPF flood level in the lake, El. 342.1 ft msl (Reference 211). Initially, the stored water behind the reservoir would be the storage volume associated with the SPF water level.

The inflow into Thurmond Lake would be equal to the flow through the breach at Russell Dam, which would be based on the SPF water level at Russell Dam, and so on upstream for all dams.

The second scenario consists of initially breaching only the most upstream dam in one of the stream reaches upstream of Hartwell Dam and allowing it to fill the next downstream reservoir, overtopping the downstream dam and breaching it. This scenario would continue breaching dams downstream by overtopping until Thurmond Dam is breached. In this scenario, when the breach occurs at Thurmond Dam, the water level would be at the top of the dam, El. 351.0 ft msl (Reference 211). Since the water level would be higher than the SPF level, the storage volume would also be larger. Additionally, the flow from Russell Dam into Thurmond Lake would have already started before Thurmond Dam was breached and would also be based on a higher water level in Russell Lake, resulting in a larger discharge into Thurmond Lake. Thus, with higher water levels and larger storage volumes and with the discharges from the upstream breaches already established before Thurmond Dam is breached, the second alternative would produce the higher flood wave downstream.

In the second scenario, there are two possible failure modes. The first mode (Mode 1) consists of Jocassee Dam breaching and progressing downstream through Keowee Dam to Lake Hartwell. The second mode (Mode 2) consists of Burton Dam breaching and progressing downstream through Nacoochee Dam, Mathis Dam, Tallulah Falls Dam, Tugaloo Dam, and Yonah Dam to Lake Hartwell. By comparing the normal pool storage volumes for the upstream dams listed in Table 2.4-216, the most severe failure mode is estimated. The combined normal pool storage volumes behind the dams in each mode are shown in Table 2.4-225.

Table 2.4-225 indicates that the normal pool storage volume in Mode 1 is 10 times the volume in Mode 2. Thus, an assumed dam failure scenario following Mode 1 with the Jocassee Dam failing is analyzed.

2.4.4.2 Unsteady Flow Analysis of Potential Dam Failures

The dam breach option of the USACE River Analysis System computer program (HEC-RAS) (Reference 224) was used to develop the dam breach flood wave. The unsteady flow option of HEC-RAS was then used to route the flood wave downstream to the VEGP site. Multiple dams were breached in the analysis to determine the maximum flood elevation at the site. Although HEC-RAS is capable of routing several dam breaches in succession, this analysis used an alternative modeling approach for simplicity and conservatism. In this analysis, only two dams (Russell Dam and Thurmond Dam) were breached in succession. The storage volume behind the upstream dam (Russell Dam) was assumed to be equivalent to the SPF storage volume of all the upstream reservoirs (Lake Jocassee, Lake Keowee, Hartwell Lake, and Lake Russell). This approach conservatively models the successive failure of the three upstream dams and the simultaneous arrival of their combined storage volumes at Russell Dam. Russell Dam is breached by overtopping, which then causes the overtopping breach of Thurmond Dam and a subsequent flood wave down the Savannah River.

The *Savannah River Basin Water Control Manual* (Reference 211) contains the SPF water levels, SPF discharges, and storage volumes from the Thurmond, Russell, and Hartwell dams, as well as storage data for the Jocassee and Keowee dams. Jocassee and Keowee dam SPF peak discharges and water levels are not available. However, probable maximum flood (PMF) water levels and discharges, which are greater than SPF values, are available and were used instead of the SPF values in the analysis. The PMF water levels and peak discharges for these two dams were obtained from LBC&W Associates of South Carolina (Reference 228). Area-capacity curves for each of the five reservoirs are shown on Figures 2.4-215 through 2.4-219, respectively.

For the purposes of this analysis, the Russell and Thurmond dams were assumed to fail by overtopping. The HEC-RAS computer program dam breach option requires the input of several

breach parameters. These include the final bottom width (B) and the bottom elevation of the breach along with the side slopes (Z) of the breach. The time (tf) to reach the final breach dimensions is also required input. Several methodologies are available to estimate these parameters. The Bureau of Reclamation has summarized many of these methodologies in a single document, Prediction of Embankment Dam Breach Parameters (Reference 231). These methodologies give various results. The breach parameters for the Thurmond and Russell Dams are estimated using many of the procedures described in USBR 1998 and the results compared.

The formulas used for each of the breach parameter estimation methods are shown in Table 2.4-226. The input and output variables for each of these formulas are meters, cubic meters, and hours. Several variables for each of these methods are required. The required variables are listed below:

h_w = Depth of water at dam at failure, above the breach bottom (m)

h_b = Height of breach (m)

h_d = Height of dam (m)

S = Storage volume at breach elevation (m^3)

S* = Dimensionless storage (S/h_b^3)

W_c = Width of dam crest (m)

W_b = Width of dam bottom (m)

W* = Dimensionless average dam width ($(W_c + W_d)/2h_b$)

V_{er} = Volume of material eroded, estimated by ($0.0261(S^*h_w)^{0.769}$) (m^3)

K_o = Overtopping correction factor (1.4 if failure mode is overtopping)

K_c = Core wall correction factor (0.6 if dam has a core wall, 1.0 if not)

The breach for each dam will consist of an overtopping breach. The breach depth for each dam is also assumed to reach to the upstream reservoir invert. This is a conservative assumption for both the Russell and Thurmond Dams because the majority of the portions of each dam that reach the upstream inverts are the portions constructed of concrete where the tainter gate spillways and hydroelectric turbines are located. In order for the earth sections to breach to the invert depths for the widths calculated in the following discussion, native material will have to be eroded. However, for the purpose of this analysis, it will be assumed that the embankment and native material will erode to the upstream invert elevation.

The input variables along with the estimated breach parameters, by the various methodologies, for each dam are shown in Tables 2.4-227 through 2.4-230.

For the Thurmond Dam, the FERC (1987) equation from Table 2.4-226, as well as other sources in the literature, indicates that the breach width should be 2 to 5 times the height of the dam. This guidance is confirmed by the USBR report (Reference 231), which shows the 84 data points for observed breach widths used in their analysis of dam breach parameters. The Froehlich (1995b) relationships in the Table 2.4-226 were developed using a regression analysis of the data, which is biased by the fact that the majority of the data points are for breach widths less than 50 m (164 ft). In fact, the USBR report (Reference 231) states that the Froehlich relationships are apparently the best fit for cases with observed breach widths less than 50 m (164 ft). Extrapolation of the Froehlich

relations to the anticipated breach width on the order of 5 times the height of the dam (230 m [755 ft]) indicates that the Froehlich relations are not in agreement with the observed data for breach widths greater than 150 m (492 ft). Because all of the other methods shown in Table 2.4-228 are of the same order of magnitude, and are also within the range of accepted engineering practice for FERC-mandated dambreak analyses, a breach width of 755 ft was selected for this study. The value of 755 ft also is the maximum of the values obtained by all other methods, and is therefore conservative. The following considerations of the dam layout and river cross-section at the dam show that the use of a 755-ft breach width is also conservative in light of the physical layout of J. Strom Thurmond Dam and appurtenances:

- The HEC-RAS dam breach model and the equations used to determine discharges from the breach assume a “flat” bottom breach with a constant elevation. This means that bottom elevation of the entire 755-ft breach width is assumed to be at El. 200 ft msl, which is the minimum elevation of the original streambed on the upstream side of J. Strom Thurmond Dam.

- As shown on Figure 2.4-220, the total dam width at the top of the dam is about 5,700 ft (Reference 211). The width of the dam at the upstream invert elevation (El. 200 ft msl) is about 2,840 ft. Located within the portion of the dam that extends to El. 200 ft is a concrete embankment section 2,282 ft wide where the tainter gate spillways and powerhouse are located (Reference 211). The failure mode assumes that only the earth section of the dam will erode during the breach. Consequently, the 755-ft bottom width of the breach extends beyond the area in which the actual ground elevation is at the minimum ground elevation of El. 200 ft msl.

- Superposing the 755-ft bottom width at El. 200 ft msl on the cross-section of the valley on the upstream side of the dam shows that more than 200 ft of the breach would be above El. 200 ft msl. Therefore, the entire bottom of the breach was taken as El. 200 ft msl to be conservative. The cross section shown in Figure 2.4-220 has been artificially widened at El. 200 ft msl to accommodate the 755-ft-wide breach.

Based on a review of data and analyses for 84 dam failure cases, and the physical layout of J. Strom Thurmond Dam, a breach width of 755 ft, with 2 to 1 side slopes was selected for this analysis. Additionally, most of the breach time predictions are close to 1.0 hour. Thus, a breach time of 1.0 hour was selected for this analysis.

The breach width for the Richard B. Russell dam is also much larger than 50 m and thus, the Froehlich equations predict values much greater than the observed data. Since all of the other methods shown in Table 2.4-230 are of the same order of magnitude, and are also within the range of accepted engineering practice for FERC-mandated dambreak analyses, a breach width of 750 ft was selected for this study. The value of 750 ft also is the maximum of the values obtained by all other methods, and is therefore conservative. The following considerations of the dam layout and river cross-section at the dam show that the use of a 750-ft breach width is also conservative in light of the physical layout of Richard B. Russell Dam and appurtenances:

- The HEC-RAS dam breach model and the equations used to determine discharges from the breach assume a “flat” bottom breach with a constant elevation. This means that the bottom elevation of the entire 750-ft breach width is assumed to be at El. 345 ft msl, which is the minimum elevation of the original streambed on the upstream side of Richard B. Russell Dam.

- As shown on Figure 2.4-221, the total dam width at the top of the dam is about 4,500 ft. (Reference 211). The width of the dam at the upstream invert elevation (El 345 ft msl) is about 2,200 ft. Located within the portion of the dam that extends to El. 345 ft msl is a

concrete embankment section 2,180 ft wide where the tainter gate spillways and powerhouse are located (Reference 211). Only 1,000 ft of the concrete section extends to El. 345 ft msl, the remaining portion extends up the embankment. The failure mode assumes that only the earth section of the dam will erode during the breach. Consequently, the 750-ft bottom width of the breach extends beyond the area in which the actual ground elevation is at the minimum ground elevation of El. 345 ft msl.

- Superposing the 750-ft bottom width at El. 345 ft msl on the cross-section of the valley on the upstream side of the dam shows that more than 150 ft of the breach would be above El. 345 ft msl. Therefore, the entire bottom of the breach was taken as El. 345 ft msl to be conservative. The cross section shown in Figure 2.4-221 has been artificially widened at El. 345 ft mls to accommodate the 750-ft-wide breach.

Based on a review of data and analyses for 84 dam failure cases, and the physical layout of Richard B. Russell Dam, a breach width of 750 ft, with 2 to 1 side slopes was selected for this analysis. Additionally, most of the breach time predictions are close to 1.0 hour. Thus, a breach time of 1.0 hour was selected for this analysis.

Once the dam breach occurred, the HEC-RAS computer program determined the flood wave discharge from the dam based on the breach dimensions, water level in the reservoir behind the dam, and the water level downstream of the dam. The program then used an unsteady flow option to model the progression of the flood wave downstream to the VEGP site. Additionally, HEC-RAS continued to model the flows through the dam breaches until the stored water in the reservoirs was evacuated. Since the combined volume of all five reservoirs is more than 10 million acre-feet, the flood wave from the dam breaches would last for several days at the VEGP site.

Cross-section data for the Savannah River used in the HEC-RAS computer model were obtained directly from the USACE, Savannah District (Reference 229). The data were supplied in HEC-RAS format and assembled from various floodplain studies on the Savannah River. To ensure that the cross-section data were accurate, several representative cross-sections near the site, in the City of Augusta, and near Thurmond Dam, were compared with cross-sections developed independently from USGS topographic maps (Reference 232). In each instance, the cross-section data supplied provided a good match with those developed from USGS topographic maps.

The USACE elevation data for most of the cross-sections did not extend to the computed water surface elevation for the dam breach analysis. Therefore, HEC-RAS extended the left-most and right-most cross-section elevations vertically to meet the computed water surface. Usually, this approach is conservative in that it produces a cross-sectional area less than the actual cross-section. However, downstream of the breached dam, a constricted cross-section could produce water levels high enough to restrict the flow from the breach due to tail water submergence. Thus, four cross-sections downstream of the dam were sufficiently extended horizontally, based on USGS topographic information, to cover the range of the computed water levels.

A sensitivity analysis was performed to assess the effect of extending the remaining cross-sections to higher elevations. The results of this analysis indicated that extending the cross-sections lowered the water level and peak discharge at the VEGP site by less than 0.5 ft. Thus, for the most part, these cross-sections were not modified. However, the cross-section data through the City of Augusta extend only to the top of the levee on the right (west) bank of the Savannah River. Flood elevations for the dam breach event would overtop the levee and extend out into the City of Augusta. Thus, cross-section data through the City of Augusta were extended horizontally using topographic maps (Reference 232) to include additional area to these cross-sections and account for overtopping of the levee.

At least two sets of River Mile stationing have appeared in different USACE publications for the Savannah River. There is an approximately 16-mi discrepancy between the two stationing sets. The River Mile stationing set used in this analysis matches the stationing set used in the VEGP UFSAR and most of the *Savannah River Basin Water Control Manual* (Reference 211). The VEGP site is located at River Mile 150.9 in the HEC-RAS model. The other River Mile stationing reference would have the site at approximately River Mile 167.

Several bridges cross the Savannah River downstream of Thurmond Dam and through the City of Augusta. The last of these bridges is about 40 river miles upstream of the VEGP site. Modeling the dam breach flood wave through the City of Augusta with the bridges intact would produce results that impede the travel of the flood wave and reduce the computed flood levels at the VEGP site. However, during a dam breach event, all bridges would be significantly overtopped and it is likely that most, if not all, would be washed out. Thus, to provide more reasonable results, which allow the flood wave to progress unimpeded downstream (a conservative assumption for modeling the flood elevations at the VEGP site), the bridge structures were removed from the HEC-RAS model.

The Savannah River cross-section data supplied by the USACE stopped just downstream of Thurmond Dam. Cross-sections upstream and downstream of Thurmond and Russell dams were obtained from USGS topographic maps (Reference 232). The below-water portions of the cross-section data were obtained from fishing maps with depth contours (Reference 226; Reference 227).

Roughness coefficients (Manning's n) were estimated using procedures developed by the US Geological Survey (Reference 233). Additionally, roughness coefficients were estimated for the flood studies performed for the existing VEGP Units 1 and 2 by calibrating water surface profile models with known flood elevations. The USGS estimation procedures produce roughness coefficients that are higher, and more conservative, than those presented in the UFSAR. Thus, the USGS-estimated roughness coefficients were used in the HEC-RAS dam breach model. The use of higher roughness coefficients is consistent with observations of dam-break floods that show that roughness coefficients for exceptionally high flow depths associated with dam-break floods are higher than those associated with lower flood flows in a river.

The starting water levels at three locations were required in the HEC-RAS dam breach model—in each of the two reservoirs and at the downstream end of the model. The cross-section farthest downstream in the HEC-RAS model is located at the River Mile 99.41, 51.5 mi downstream of the VEGP site. The normal depth option in HEC-RAS was used to determine the starting water surface elevation at this location. Given the distance from the site, any changes in the downstream boundary condition water level will not affect the computed flood elevations at the VEGP site.

The starting water level in Thurmond Lake was set at the SPF water level (i.e., El. 344.7 ft msl). Additionally, at this point an initial inflow was added equal to the SPF discharge of 560,000 cfs from Thurmond Dam. Once Russell Dam breaches, the overtopping breach of Thurmond Dam is triggered when the water level reaches El. 351.1 ft msl, 0.1 ft above the top of the dam (Reference 211), due to inflows from the breach of Russell dam.

The starting water level at Russell Dam was treated slightly differently. The model was set up as if the breaches of the Jocasse, Keowee, and Hartwell dams have already occurred and the combined SPF storage volume from these reservoirs is already at Russell Dam. Any upstream breaches would have already raised the water level to the top of Russell Dam. Therefore, the starting water level at Russell Dam was set at the top of the dam at El. 495.0 ft msl (Reference 211). The overtopping breach of Russell Dam was triggered 2 hours after the start of the HEC-RAS simulation. This 2-hour time delay allowed the SPF flood flow in the Savannah River downstream of Thurmond Dam to stabilize in the HEC-RAS model prior to initiating the Russell Dam breach.

2.4.4.3 Water Level at the Plant Site

The results of the HEC-RAS dam breach and unsteady flow routing analysis indicate that the peak water level at the VEGP site due to dam failure is El. 166.79 ft msl, which is 53.21 ft below the site grade at El. 220.0 ft msl. The computed discharge at the time of the peak water level is 2,232,605 cfs.

The computed peak discharge rate, however, occurs 5 hours before the peak water level. The peak discharge is 2,331,582 cfs, with a corresponding water level at El. 164.71 ft msl. The delay in the peak water level at the site is due to backwater effects caused by the peak flood wave moving downstream of the site. The results are quoted to more significant figures than is physically possible to measure so that, if necessary, a direct correlation between the numerical results presented here and the computer output in supporting calculations can be obtained easily.

A plot of the Savannah River discharge and stage hydrograph at the VEGP site location is shown in Figure 2.4-222. Plots of the SPF water surface profile, maximum water surface profile, and water surface profile at the time of the maximum water level at the VEGP site are shown on Figures 2.4-223 through 2.4-225, respectively.

The flood elevations determined for this section have been determined to demonstrate that a postulated dam-break flood wave cannot adversely impact the VEGP site. The analysis to determine these elevations is based on very conservative assumptions, and the computed flood elevations should not be used for any other purposes or locations.

In accordance with ANSI/ANS-2.8 (1992), the maximum wave height and wave run-up at the shoreline generated by a 2-year wind speed must be estimated in conjunction with the dam breach flood level at the site. The fastest mile 2-year wind speed at the site is 50 mph (Reference 220). The *Coastal Engineering Manual* (Reference 230) is used to estimate the wave height and run-up elevations at the VEGP site. The procedures outlined in the *Coastal Engineering Manual* use the wind speed, wind speed duration, water depth, and over-water fetch length to determine wave heights and run-up. The maximum fetch length during the dam breach flood is from the northeast and is about 11.14 miles long. The maximum fetch length is shown on Figure 2.4-226.

Various wind speed durations were analyzed to determine the maximum wave height and run-up elevation at the site. The wave run-up was determined based on the steep embankment condition that will exist during a dam breach flood event at the VEGP site. The estimated slope of the embankment is 2H:1V for the wave run-up determination.

The estimated wave height and run-up values at the VEGP site during the dam breach flooding event are as follows:

- Maximum Wave Height, HMAX = 7.46 ft
- Spectral Peak Period, TP(MAX) = 4.09 s
- Maximum Wave Length, L0 = 85.73 ft
- Maximum Wave Run-up, R = 11.31 ft

The calculated wave run-up also includes wave setup effects. To obtain the maximum flood elevation due to wind-induced waves at the VEGP site, the maximum wave run-up elevation was added to the still water elevation due to dam breach flooding. Adding these two numbers gives a maximum flood level of El. 178.10 ft msl, which is 41.9 ft below the site grade of El. 220.0 ft msl. Therefore, the VEGP site is precluded from flooding due to potential dam failures and coincident wind-generated waves.

2.4.5 Probable Maximum Surge and Seiche Flooding

The VEGP site is located on a coastal plain bluff on the west bank of the Savannah River approximately 151 River Miles inland from the Atlantic Ocean at grade El. 220 ft msl. Since the site is not located on an open or large body of water, surge or seiche flooding will not produce the maximum water levels at the site.

The Savannah River estuary region is occasionally exposed to extreme mid-Atlantic hurricanes. Between 1841 and 2004, only three major hurricanes, Category 3 or over (measured using the Saffir/Simpson Hurricane Scale), hit the coast of Georgia (Reference 234). The most devastating hurricane on record with a landfall within approximately 100 miles of the Savannah River estuary was Hurricane Hugo, which hit the coast of South Carolina near Charleston in 1989. This Category 4 hurricane produced a 20-foot-high storm surge in the Cape Romain-Bulls Bay area in South Carolina (Reference 235).

Regulatory Guide 1.59, *Design Basis Floods for Nuclear Power Plant*, Revision 2, August 1977 (RG 1.59), Appendix C provides the distribution of probable maximum surge levels from hurricanes along the Atlantic coast. It shows maximum surge heights of 28.2 ft mean low water (mlw) at Folly Island, South Carolina, and 33.9 ft mlw at Jekyll Island, Georgia, located northeast and southwest of the Savannah River estuary, respectively. The probable maximum storm surge height at the mouth of the Savannah River can be estimated from these values following the procedure described in RG 1.59 Appendix C, as shown in Table 2.4-231.

The high tide at the estuary with a 10 percent exceedance level is defined as 9.0 ft mlw, and the mlw at the entrance to Savannah River, Georgia is 1.2 ft below msl (Reference 220). Considering the coincidence of the probable maximum surge with a 10-percent-exceedence high tide at the river mouth, a probable maximum surge height of 32.3 ft mlw or 31.1 ft msl may be obtained for the Savannah River estuary, as shown in Table 2.4-231.

If it is assumed that a storm surge of such a magnitude is generated in the Savannah River estuary moving inland, the surge height would dissipate before reaching the VEGP site (151 River Miles inland and at grade El. 220 ft msl), and the site would be free from any resultant flood. Also, because the VEGP site is not located on a large enclosed body of water, flooding due to seiche is precluded.

The probable maximum surge data from RG 1.59 have not included those from the hurricanes after 1975. The inclusion of the data from recent hurricanes, including Hurricane Hugo, may have changed the probable maximum surge data from RG 1.59 somewhat. However, because the VEGP site is 151 River Miles inland and at grade El. 220 ft msl, the effects of probable maximum surge at the estuary of Savannah River would be insignificant at the site, and would not cause flooding of the site.

2.4.6 Probable Maximum Tsunami Flooding

Since the VEGP site is not located on an open ocean coast or large body of water, tsunami-induced flooding will not produce the maximum water level at the site.

The Atlantic Ocean region is characterized by infrequent seismic and volcanic activities, resulting in few recorded tsunamis. The majority of tsunamis in the Atlantic Ocean and Caribbean Sea have been either triggered by seismic (earthquake) activity or the result of volcanic eruption. The most notable Atlantic tsunami was generated by the Great Lisbon Earthquake of 1755. The tsunami hit the coasts of Portugal, Spain, and northern Africa and traveled across the Atlantic Ocean with a 10-to-15-ft wave reportedly reaching the Caribbean coasts (Reference 236). Computer models suggested a wave height of 10 ft along the east coast of the US (Reference 237) from this tsunami.

The effects of any tsunami with similar height approaching the Savannah River estuary would be dissipated before reaching the VEGP site (151 River Miles inland and at grade El. 220 ft msl), and the site would be free from any resultant flood.

2.4.7 Ice Effects

2.4.7.1 Ice Conditions and Historical Ice Formation

Long-term air temperature records available at the National Weather Service (NWS) weather station at Augusta, Georgia (Bush Field), and seven other cooperative observation stations around the VEGP site are used to analyze historical extreme air temperature variations at the VEGP site. The analysis was also supported by onsite temperature data measured at the VEGP site. A detailed description of station locations and data availability is presented in Subsection 2.3.2.

The climate at the VEGP site is characterized by short, mild winters and long, humid summers. Local climatology data at Augusta, Georgia, for a period of 129 years show an average annual air temperature of 64.2°F (17.9°C) (Reference 239). January is the coldest month, with an average temperature of 46.8°F (8.2°C). July is the warmest, with an average temperature of 81.3°F (27.4°C). Based on temperature records at Augusta and seven surrounding stations, the lowest air temperature on record was observed to be -4.0°F (-20.0°C) at Aiken in January 1985 (Table 2.3-205). The January 1985 event produced a minimum air temperature of -0.1°F (-17.8°C) at the VEGP site, with the air temperature remaining below freezing (32°F [0°C]) for only about 50 hours (Figure 2.4-227). VEGP temperature data from 1984 through 2002 show that the average daily air temperature has remained below freezing for a maximum of 3 consecutive days (Table 2.4-232). In three instances, the average daily air temperature remained above freezing the entire year.

Historical water temperatures recorded at five USGS stations located on the Savannah River (Reference 238) are presented in Table 2.4-233. These USGS stations include: No. 02187500 near Iva, South Carolina, at River Mile 280.4; No. 02189000 near Calhoun Falls, South Carolina, at River Mile 263.6; No. 02197000 at Augusta, Georgia, at River Mile 187.4; No. 02197500 at Burtons Ferry near Milhaven, Georgia, at River Mile 118.7; and No. 02198500 near Clyo, Georgia, at River Mile 60.9. The data cover a river reach that includes the VEGP site. Within this river reach, the minimum water temperature is observed in February, which shows a variation between 39.2°F (4.0°C) and 42.8°F (6.0°C).

Based on the record of air and water temperatures, it is very unlikely that surface or frazil ice formation would occur in the Savannah River in the vicinity of the proposed VEGP Units 3 and 4 river intake location.

2.4.7.2 Ice Jam Events

There are no recorded ice jam events in the lower reach of the Savannah River based on a search of the *Ice Jam Database* of the US Army Corps of Engineers (Reference 240).

The large dams and reservoirs on the Savannah River located upstream of the VEGP site reduce the possibility of any surface ice or ice floes moving downstream. Since the water temperatures in the lower reach of the Savannah River remain consistently above freezing, as seen in Table 2.4-233, the formation of frazil ice or ice jams would be very unlikely at the proposed VEGP Units 3 and 4 intake location.

2.4.7.3 Description of the Cooling Water System

The VEGP Units 3 and 4 are Westinghouse AP1000 reactors and use a closed cycle cooling system with wet, natural-draft cooling towers for circulating water system cooling. The river intake system,

comprising an intake canal and a pump intake structure, are located upstream from the existing river intake structure for the VEGP Units 1 and 2. Makeup water from the Savannah River are required to replace evaporative water losses, drift losses, and blowdown discharge from the circulating water system cooling towers.

For safety-related cooling, AP1000 reactors use passive ultimate heat sink (UHS) systems with in-plant storage water. These reactor plants do not require an external safety-related UHS system to reach safe shutdown. Also, the AP1000 design have a non-safety-related heat removal auxiliary heat sink–service water system (SWS) used for shutdown, normal operations, and anticipated operational events. Make-up water to the SWS is supplied from site groundwater wells or a site water storage tank. Consequently, no water is necessary from the Savannah River or from any other open surface water sources for the AP1000 UHS and SWS. Therefore, even a very unlikely ice event on the Savannah River does not have any impact on safety-related UHS or non-safety-related SWS of the proposed AP1000 units.

2.4.8 Cooling Water Canals and Reservoirs

2.4.8.1 Cooling Water Canals

The VEGP Units 3 and 4 use a closed cycle cooling system for condenser heat rejection and use wet, natural-draft, cooling towers for circulating water system cooling. Makeup water from the Savannah River is required to replace evaporative water losses, drift losses, and blowdown discharge. The river intake for VEGP Units 3 and 4 withdraws makeup water from the Savannah River at a maximum rate of approximately 61,145 gpm (136.2 cfs). The intake system is located upstream of the river intake of the existing VEGP units. The makeup water is pumped directly to the cooling tower basin.

For safety related cooling, AP1000 reactor plants use passive ultimate heat sink (UHS) systems with sufficient in-plant storage water for safety-related water cooling. These reactor plants do not require an external safety-related UHS system to reach safe shutdown. Therefore, the river intake system is not part of the safety-related facilities for VEGP Units 3 and 4, and the river intake canal and structure have no safety-related functions. These reactor plants also have a non-safety-related heat removal auxiliary heat sink–service water system (SWS) used for shutdown, normal operations, and anticipated operational events. Make-up water to the SWS is supplied from site groundwater wells; therefore, the SWS does not depend on the river intake system.

The river intake system for VEGP Units 3 and 4 consists of an intake canal and an intake structure. The design details of the river intake system have been established. An overview of the conceptual design is provided below.

The river intake canal is approximately 320 ft long and 120 ft wide at the intake structure entrance and approximately 170 ft wide at the entrance to the river, with a bottom elevation of about El. 70 ft msl. The canal upstream of the intake structure apron is unpaved. The river intake canal acts as a siltation basin and incorporates a sill to reduce sediment inflow into the canal. At the minimum river operating level (78 ft msl), the flow velocity in the new canal is about 0.1 fps, calculated based on a maximum makeup water demand of 136.2 cfs. Because the river intake canal also acts as the siltation basin, maintenance dredging may be necessary to maintain the canal invert elevation. Also, the canal embankment slopes and benches are protected by earthen berms armored with rip-rap of appropriate design specifications on the exterior (river-side) slopes of the berms.

The intake structure, located at the end of the river intake canal, houses multiple makeup water pumps, traveling band screens, and trash racks with raking mechanisms. For each of the two new units, three 50-percent-capacity, vertical wet-pit pumps are installed in the intake structure, with one

makeup water pump at each pump bay, along with one dedicated traveling band screen and a trash rack.

Because VEGP Units 3 and 4 do not rely on the Savannah River for safe shutdown, a minimum river water level is not necessary for safety-related cooling water supply.

2.4.8.2 Reservoirs

VEGP Units 3 and 4 do not have any cooling water reservoirs.

2.4.9 Channel Diversions

The VEGP site area lies in the Upper Coastal Plain of the Atlantic Coastal Plain physiographic province and is bordered by the Savannah River to the east. The surrounding topography consists of gently rolling hills with surface topography elevation ranges from about 200 to nearly 300 ft msl. Local site drainage consists of a principally dendritic drainage pattern where all major streams are tributary to the Savannah River. The VEGP site and surrounding areas are shown in Figure 2.4-206.

Near the site area, incision of the Savannah River has produced a deep valley with topographic relief of nearly 150 ft from the river surface and a valley width of over 4 mi. The present-day river course is located at the western side of the valley, forming steep bluffs near the VEGP site. The river floodplain consists of a broad alluvial surface extended on the eastern side at heights of 5–10 ft above the riverbank.

Rivers in the Upper Coastal Plain are typically underlain by sands, clays, limestones, and gravels and exhibit gentle to moderate bed slopes, wide floodplain development, and increased sinuosity. Consequently, diversion of the river channel in this region cannot be completely discounted.

Historical development of the river plan-form, which is the shape on map of river bank-line, near the VEGP site is well-represented in the USGS 7.5-minute series (topographic) maps. Oxbow lakes, meander cutoffs, abandoned meanders, low-lying swamps, and forested wetlands provide considerable evidence of historical channel plan-form development. Although meander river plan-form is present upstream and downstream of the site, the Savannah River near the site has a relatively straight and stable reach extending approximately from River Mile 143 to River Mile 152. A comparison of river bank-lines between 1965 and 1989, obtained from USGS topographic maps (Reference 241; Reference 242; Reference 243) and topographic maps used for VEGP Units 1 and 2, shows a nearly unchanged river plan-form within the reach during this period.

Since 1952, the Savannah River flow has been regulated by large federal multipurpose projects: Hartwell Dam, Richard B. Russell Dam, and J. Strom Thurmond (also known as Clarks Hill) Dam. A major impact of dam operation on river flow downstream of the J. Strom Thurmond Dam is the modulation of the outflow hydrograph, with reduced peaks and increased low-flow rates, as can be seen from Figure 2.4-228. Such flow modulation results in much-reduced river morphological activity, and a sudden river plan-form change is unlikely.

It is, therefore, unlikely that the river at the VEGP site will be diverted from the river intake by natural causes. Furthermore, analysis for existing VEGP Units 1 and 2 indicate that any possible effect on water supply to the intake from river channel diversion should come from extremely slow changes, which can be remedied as they occur.

While it is unlikely that a diversion of the main river channel will occur, such a diversion, either upstream or downstream of the proposed river intake, cannot be discounted. The river upstream and downstream from the proposed river intake has bluffs and steep slopes along the west bank. If it is assumed that a bluff slid into the river bed just upstream from the river intake structure, it may

obstruct the flow of the main river channel, and river flow would divert over the floodplain on the eastern side of the river and away from the river intake. This could result in loss of the river intake due to river water starvation. Likewise, if a bluff slid into the river bed just downstream of the river intake structure, it again may obstruct the flow of the main river channel, but could possibly flood the river intake structure before diverting river water over the floodplain on the eastern side of the river. In this case, the river intake structure would be lost due to flooding. However, all the safety-related cooling water systems for the AP1000 reactor plants do not use water from the river intake. Hence, the river intake is not classified as a safety-related structure and loss of the river intake for either of these described scenarios would have no adverse affect on plant safety.

2.4.10 Flood Protection Requirements

The maximum design basis flood elevation, including wind setup and wave run-up, at the VEGP site is El. 178.10 ft msl, as discussed in Subsection 2.4.4. This elevation is well below the VEGP site grade at El. 220.0 ft msl. Entrances and openings to all safety-related structures for the proposed VEGP Units 3 and 4 are located at or above the site grade. Since the site grade is well above the maximum design basis flood elevation, the possibility is precluded of flooding VEGP Units 3 and 4 safety-related structures, systems, and components.

The effects of intense local precipitation on the safety-related structures, systems, and components of VEGP Units 3 and 4 has been considered in the design of site drainage facilities. The VEGP Units 3 and 4 site is on locally high ground, and natural drainage flow-paths slope away from the site, as shown in Figure 2.4-206. Thus, the topography of the proposed site facilitates drainage of intense rainfall events. Drainage facilities for the VEGP Units 3 and 4 site have been designed so that the peak discharge from the local probable maximum precipitation (PMP) do not produce flood elevations that could cause a flooding hazard to any safety-related structure, system, or component at the VEGP Units 3 and 4 site. The design also assumes that all drainage structures (e.g., culverts, storm drains, and bridges) are blocked during the PMP event. The safety-related structures, systems, and components are still safe from resulting flood hazards.

Additionally, the design of the drainage facilities and the development of construction and operation plans incorporates measures to ensure that existing VEGP Units 1 and 2 safety-related facilities are not subject to flooding during construction and operation of VEGP Units 3 and 4. Drainage from the VEGP Units 3 and 4 site during construction and operation of the new VEGP units is directed away from the existing drainage facilities of VEGP Units 1 and 2. Hence, drainage from the VEGP Units 3 and 4 site does not interfere with the safety-related structures, systems, and components of VEGP Units 1 and 2.

The roofs of all safety-related structures have been designed to prevent flooding of, or leakage into, safety-related structures, systems, and components as a result of PMP on the roofs. The design basis combination of a 100-year return period ground-level snowpack and 48-hour probable maximum winter precipitation, as applied to safety-related roofs, is discussed in Subsection 2.3.1.3.4.

Although the river intake is not a safety-related facility, rip-rap protection of embankment slopes has been provided at the river intake location on the west bank of the Savannah River to prevent intake canal bank erosion.

Applicable NRC, federal, state, and local stormwater management regulations have been followed in the design of the drainage facilities.

The maximum flood elevation in the Savannah River at the VEGP site is El. 178.10 ft msl, resulting from the cascading failure of upstream dams including wind setup and wave run-up, as discussed in Subsection 2.4.4. This elevation is well below the VEGP site grade at El. 220 ft msl.

Subsection 2.4.2 subsequently considered the flooding effects of local intense precipitation (also termed as the local probable maximum precipitation or local PMP) on the Units 3 and 4 safety-related structures at the VEGP site. A local PMP drainage analysis was performed by conservatively assuming that all underground storm drains and culverts were clogged. Details of the local PMP analysis and the resulting flood levels are presented in Subsection 2.4.2. As indicated in Subsection 2.4.2, the maximum water level in the Units 3 and 4 power block area due to the local PMP flood event is calculated to be at El. 219.1 ft msl. The entrances and openings for all safety-related facilities are located at or above the VEGP site grade of EL. 220 ft msl.

Thus, none of the VEGP Units 3 and 4 safety-related structures will be adversely affected by any flood event. Consequently, no flood protection measures are required for VEGP Units 3 and 4. Additionally, no technical specifications or emergency procedures to implement flood protection activities are required.

Furthermore, the design of VEGP Units 3 and 4 drainage facilities incorporates measures to ensure that VEGP Units 1 and 2 safety-related facilities are not subject to flooding during construction and operation of VEGP Units 3 and 4. Drainage from the VEGP Units 3 and 4 portion of the site during construction and operation of Units 3 and 4 is directed away from the drainage facilities of Units 1 and 2. Hence, drainage from the VEGP Units 3 and 4 site area do not affect the safety-related structures, systems, and components of VEGP Units 1 and 2.

As discussed in Subsection 3.4.1.1, the roofs of all safety-related structures are designed to prevent flooding of, or leakage into, safety-related structures, systems, and components as a result of the PMP on the roofs. The design basis combination of a 100-year return period ground-level snowpack and 48-hour probable maximum winter precipitation, as applied to safety-related roofs, is discussed in Subsection 2.3.1.3.4.

2.4.11 Low Water Considerations

This section identifies the natural events that may reduce or limit the available cooling water supply and demonstrates that an adequate water supply will exist to operate or shut down the plant under normal operations, anticipated operations, and emergency conditions.

2.4.11.1 Low Flow in Streams

VEGP Units 3 and 4 are Westinghouse AP1000 reactors that do not require a conventional ultimate heat sink to provide safety-related cooling during emergency shutdown. Consequently, river water is not necessary to achieve safe shutdown of the units. The only use of water from the Savannah River for the reactor units is for the circulating water system/turbine plant cooling water system makeup, where river water is required to replace evaporative water losses, drift losses, and blowdown discharge.

2.4.11.1.1 Observed Low Flow Data

The Savannah River flow near the VEGP site is regulated by the operation of three large federal multipurpose projects located upstream: Hartwell Dam, Richard B. Russell Dam (Russell Dam), and J. Strom Thurmond (also known as Clarks Hill) Dam. The operation of the dams during low flow periods is controlled by the drought contingency plan for the Savannah River basin (Reference 249). The contingency plan was developed in 1989 during one of the most severe droughts in the region in recent history. The objectives (Reference 249) of the plan are to:

- Maintain reservoir levels at or above the bottom of the conservation pools for the three reservoirs

- Maintain a minimum release no less than 3,600 cfs at J. Strom Thurmond Dam (Thurmond Dam) for downstream use
- Use most of the available storage in the reservoirs during the drought-of-record while maintaining reservoir levels above the bottom of the conservation pools as a contingency against a drought that exceeds the drought-of-record
- Maintain project capacity throughout the drought
- Maintain releases required to meet state water quality standards from J. Strom Thurmond Dam for as long as possible without jeopardizing water supplies
- Minimize impact to recreation during the recreational season, from the first of May through Labor Day

Depending on the pool elevations at Hartwell and Thurmond reservoirs, four levels of actions are defined in the drought contingency plan, as summarized in Table 2.4-234. Actions for Level 3, which corresponds to the severe drought of 1988–89 (drought-of-record), will maintain a minimum of 3,600 cfs of water released through Thurmond Dam. Thurmond Dam Level 4 actions require maintaining the minimum flow of 3,600 cfs for as long as possible and, thereafter, allow the same outflow as the reservoir inflow. Consequently, the drought contingency plan for the Savannah River basin will impact water availability at the VEGP site during low flow periods.

Low water conditions in the Savannah River in the vicinity of the VEGP site are analyzed using flow records at three USGS stream gage stations. These are USGS Station No. 02197000 at Augusta, Georgia, at River Mile 187.4; 02197320 at Jackson, South Carolina, at River Mile 156.8; and 02197500 at Burtons Ferry near Milhaven, Georgia, at River Mile 118.7. The VEGP site, located at River Mile 150.9, is nearest to the Jackson gage and nearly halfway between the gages at Augusta and Burtons Ferry.

Daily-mean stream flow data are available at these three stations from the USGS Web site (Reference 223). USGS maintains stream flow records covering a water year, which starts on October 1 of the preceding year and ends on September 30 of the current year. The longest daily-mean flow record is available at Augusta, with a period of record from the water years 1884–1891, 1896–1906, and 1925–2003. At Burtons Ferry, the flow period of record is available between the water years 1940 and 2003, with missing data periods from 1971 to 1982. The Jackson gage presents the shortest period of record of daily stream flow data, with data available between the water years 1972 and 2002. Data from the Jackson gage also include numerous periods of missing flow values. However, these periods with missing data are generally during peak flow discharges with the low flow data remained mostly unaffected.

Streamflow gage and water level measurement data are also available near the VEGP site at USGS Station No. 021973269 – Savannah River near Waynesboro at approximate River Mile 150.6. However, flow records at this gage are only available since January 2005. The short duration of the record for this gage makes it unsuitable for the calculation of low flow statistics. These data are used instead for developing a stage-discharge relationship near the site as discussed in Subsection 2.4.11.1.4. Details of gage locations and data availability are shown in Table 2.4-235.

Annual minimum daily-mean stream flow data from the three gages are shown in Figure 2.4-229 and Table 2.4-236. The data show that the annual minimum daily-mean flow within the river reach between Augusta and Burtons Ferry increased considerably after the construction of the Thurmond and Hartwell dams. The annual minimum daily-mean flow decreased during the drought-of-record (1986–1989) and has remained lower, since the implementation of the drought contingency plan in 1989, than prior to the onset of the drought. Russell Dam, the last of the three major projects, was

commissioned in 1985. Because of increased catchment area downstream from Augusta, the flow at Jackson and Burtons Ferry generally is higher than the flow at Augusta. However, occasionally, the annual minimum daily-mean flow at Augusta remains higher than that at Jackson or Burtons Ferry.

Figure 2.4-230 shows the variation of annual minimum daily-mean flow at Jackson and Burtons Ferry corresponding to that at Augusta for the period of available data. As indicated before, the annual minimum daily-mean flow at Jackson and Burtons Ferry remains higher than that at Augusta most of the time, except a few occasions when flow at Jackson or Burtons Ferry becomes similar to or less than that at Augusta. This may indicate that although the daily-mean flow generally increases at Jackson and Burtons Ferry compared to that at Augusta because of the increase in catchment area, during certain years the additional catchment area may not contribute additional flow to the low-flow available at Augusta.

Within the period from 1985 to 2003, after the completion of Richard B. Russell Dam and representing present-day river regulation, the lowest daily-mean flow at Augusta was observed as 3,460 cfs on May 16, 1996; at Jackson it was 3,960 cfs on September 13, 2002; and at Burtons Ferry a minimum flow of 3,920 cfs was observed on September 14, 2002 (Table 2.4-236). The low flow measured at Augusta is also the lowest observed after the completion of all three dams within the river reach that includes the VEGP site. This data period of record also includes two of the most severe droughts in recent history in the region, 1986–1989 (Reference 249) and 1998–2003 (Reference 250; Reference 244).

American National Standard ANSI/ANS-2.13-1979, *Evaluation of Surface-Water Supplies for Nuclear Power Sites* (Reference 245), recommends that for ungaged sites that have gage stations located upstream and downstream, the flow at the site may be estimated by interpolation between the gaged records based on catchment areas at the site and at the gage stations. An analysis was performed following the procedure of ANSI/ANS-2.13 (1979), which showed that the data from the Augusta gage would be the most suitable for the analysis of low flow statistics at the VEGP site. Consequently, only data from the Augusta gage is used to obtain the low flow statistics at the VEGP site. Also, because the low flow data at Augusta are generally lower than the low flow data at Jackson or Burtons Ferry, it is more conservative to use the Augusta gage data to calculate low flow statistics at the VEGP site.

2.4.11.1.2 Low Flow Statistics

Analyses for low flow statistics were performed based on historical flow data at Augusta for daily-mean annual minimum flow conditions. Because of the regulation of the Savannah River due to the construction of the dams, the complete flow record at Augusta could not be used for the analyses. Instead, flow statistics were computed within discrete segments of homogenous data periods of record. Historical annual minimum daily-mean flow data from the water years 1884 to 1952 were first analyzed using six different probability density functions: normal, log-normal, exponential, generalized extreme value – type 1 (Gumbel), Pearson – type 3 (P3), and log-Pearson – type 3 (LP3) distributions. The parameters for the distributions were estimated using the method of moments. Goodness-of-fit of the distributions was evaluated using standard ^{2} – and Kolmogorov-Smirnov tests. A distribution is considered acceptable when the test value is lower than a standard test value for a certain confidence interval. Also, further consideration is given to distributions with a smaller standard error and that fit the observed data near the desired return period.

The results of the analyses are summarized in Table 2.4-237. It shows that five distributions—normal, log-normal, Gumbel, P3, and LP3—are acceptable when both goodness-of-fit tests are considered for 95 percent confidence interval. Considering the goodness-of-fit, standard error magnitude, and comparison with observed data, the LP3 distribution was found to be the most suitable. The LP3 distribution with data from 1884 to 1952 is presented in Figure 2.4-231. Weibull plotting position formula was used for observed data, and the frequencies of the distributions were

modified to reflect low flow conditions following the methodology proposed by Riggs (1972). LP3 distribution was then used to obtain flow statistics for annual minimum daily-mean flow values for the water years 1985–2003, the period representative of present-day river regulation. A similar goodness-of-fit analysis with annual minimum daily-mean flow data for water years 1985 to 2003 also showed a best fit for the LP3 distribution with observed data.

Figure 2.4-232 shows the LP3 distribution of the data for the water years 1953–2003. This period of record corresponds to the first regulation of the Savannah River by J. Strom Thurmond Dam. However, additional regulation of the river was added in 1965 and 1985 when Hartwell Dam and Richard B. Russell Dam, respectively—the last two of the three major projects—were constructed. The effect of this additional river regulation can be observed in the figure with a reduced fit of the distribution with observed data. The distribution is also found to be unacceptable according to the ^{2} goodness-of-fit test (Table 2.4-238).

Table 2.4-238 also shows the summary of low flow statistics for water years 1985–2003 for annual minimum daily-mean flow at Augusta. Although the period of record for this data is small, it represents the present-day full regulation of the river flow and shows acceptable goodness-of-fit for annual minimum daily-mean flows. The low flow volume thus estimated for a 100-year return period is 3,298 cfs, as shown in Table 2.4-238. A 7-day average 10 year return period minimum discharge (7Q10) of 3,829 cfs was calculated for the flow at Augusta, as shown in Table 2.4-238.

The corresponding low flow for a 100-year return period at Jackson (3,746 cfs) is also presented in Table 2.4-238 to facilitate a comparison. Figure 2.4-233 is a plot of the low flow frequency curve derived using the minimum daily-mean flow data observed at the Augusta gage for the period of 1985-2003. A similar frequency curve for the Jackson gage is presented in Figure 2.4-234.

2.4.11.1.3 Probable Minimum Flow

Because the river water is not used for any safety-related activities for VEGP Units 3 and 4, probable minimum flow at the VEGP site has not been determined.

2.4.11.1.4 River Water Level for the 100-year Drought Condition

The flow rate for a 100-year drought event is estimated as 3,298 cfs in Table 2.4-238. The river stage corresponding to this flow rate was estimated from the stage-discharge relationship developed at USGS stream gage station 021973269 at Waynesboro, Georgia on the Savannah River near the VEGP site. Details of the stream measurements at this gaging location are presented in Table 2.4-235.

Streamflow measurements by the USGS at this gage were established very recently, and only eight records of measured data are available from the USGS Web site (Reference 251). Details of these flow measurements and corresponding river stages are shown in Table 2.4-239. The data show five measurement events in 2005 and one each in 1986, 1987, and 1988. Flow measurements in 2005 were performed using an acoustic Doppler current profiler (ADCP). Measurements in the previous years were performed using current meters from boats.

The gage datum at this station is given on the USGS Web site as El. 90 ft above sea level NGVD29, which is equivalent to El. 90 ft msl. Using this datum, the converted water surface elevation for the measurements in 1988, 1987, and 1986 becomes close to El. 170 ft msl, which clearly is not correct. Based on the stage-discharge relationship presented in a VEGP Unit 1 and 2 analysis, it is assumed that these levels, which are shown as gage heights on the USGS Web site (also in Table 2.4-239), likely represent the river stage in feet msl after datum conversion.

Uncertainties also remain with the gage datum in converting the measured water surface gage heights from 2005, where the water levels become too high after conversion; for example, a flow of 8,120 cfs show a river stage of over El. 100 ft msl. This uncertainty in defining the gage datum for the Waynesboro gage was also identified at the site, where a gage datum of 70.75 ft msl was established based on a discussion with USGS and onsite geodetic marker of Georgia Power Company (GPC). Accordingly, a gage datum of 70.75 ft msl is used in this analysis.

The stage-discharge rating relationship at the site was developed using the measured flow discharges and river stages, as shown in Figure 2.4-235. The following approach was used to develop the rating relationship. First, the measured water levels for the years 1988, 1987, and 1986 were assumed to be the river stages in feet msl. Second, using data from all the measurement points, a best fit of the rating relation was investigated. A river stage corresponding to a no flow condition in the river at the station (H_0) was assumed, and all river stage data were converted to H-H_0 values. H-H_0 was then plotted against corresponding measured streamflow values. Last, an optimization of the best-fit rating relation was performed by modifying the assumed H_0 to maximize the root-mean-square value (R^2) of the best-fit equation. The final estimated relationship is shown in Figure 2.4-235. The optimization provided a zero flow level (H_0) of El. 67.56 ft msl, and an R^2 value of nearly 100 percent. The H_0 magnitude of El. 67.56 ft msl also lies within the range of river bottom elevations measured near the VEGP Units 3 and 4 river intake location during a bathymetric survey conducted in January 2006, as shown in Figure 2.4-236.

Using the stage-discharge relationship developed in Figure 2.4-235, a river stage of El. 76.26 ft msl was estimated at the VEGP site for the drought event with 100-year return period (3,298 cfs).

2.4.11.2 Low Water Resulting from Surges, Seiches, Tsunamis, or Ice Effects

Since the VEGP site is not located on a large body of water or in a coastal region, low water conditions resulting from storm surges, seiches, or tsunamis do not apply. Since there is no evidence of ice jam events near the VEGP site (see Subsection 2.4.7), low water conditions due to ice effects are also precluded. There are no dams downstream from the VEGP site; therefore, downstream dam failure is not a factor that could cause low flow condition at the site. Furthermore, no VEGP Unit 3 and 4 safety-related facilities will be dependent on water supply from the Savannah River.

2.4.11.3 Historical Low Water

Table 2.4-236 shows the annual minimum daily-mean flow recorded at the three USGS stations: Augusta, Jackson, and Burtons Ferry. Within the period of data availability, the lowest recorded daily-mean flow at Augusta was 1,040 cfs on October 2, 1927. At Jackson the record lowest flow of 3,220 cfs was observed on December 9, 1981, and at Burtons Ferry it was 2,120 cfs on September 9, 1951. The lowest flow on record at Augusta and Burtons Ferry occurred prior to construction of the dams on the Savannah River. However, because of the short length of flow records, the lowest flow at Jackson occurred after the J. Strom Thurmond and Hartwell dams were completed. The corresponding low flow at Augusta was 2,810 cfs, observed on December 7, 1981. Burtons Ferry data for this water year are not available.

Low water conditions in the river reach between Augusta and Burtons Ferry after completion of all three dams are discussed in Subsection 2.4.11.1.1. Since construction of the dams, the lowest flow measurement of 3,460 cfs was observed at Augusta on May 16, 1996. The corresponding flow at Jackson and Burtons Ferry, however, was considerably higher, with 5,730 cfs at Jackson on May 17, 1996, and 5,590 cfs at Burtons Ferry on May 18, 1996.

The lowest ever-recorded instantaneous flow at Augusta was 648 cfs on September 24, 1939, which was caused by the operation of the gates at the New Savannah Bluff Lock and Dam. The low flow stage-discharge rating curve at the Augusta gage was established based on the lowest measured

flow magnitude of 1,400 cfs. The instantaneous low flow magnitude in 1939 was estimated by extrapolating the stage-discharge relationship at the gage station below the lowest measured discharge value of 1,400 cfs. The daily-mean flow for that day, however, was higher, at 2,940 cfs.

2.4.11.4 Future Controls

Present consumptive use of water from the Savannah River includes public supply, industrial and commercial use, power generation, and irrigation. A compilation of water use data for Georgia indicates that surface water use within the state remained nearly unchanged between 1980 and 2000 (Reference 246). For South Carolina, while surface water use between 1990 and 2000 remained nearly the same, an increase of approximately 50 percent in surface water use is projected for the year 2045 (Reference 248). The projected increase also includes water demand for power generation.

The US Army Corps of Engineers, Savannah District, along with the states of Georgia and South Carolina, are developing an updated comprehensive water resources management plan for the Savannah River basin. As part of the comprehensive water management scenarios, a revised drought management plan is now being actively considered. Under the proposed plan and for proposed alternative (Alternative 2), flow through Thurmond Dam would be increased (from 3,600 cfs) to 3,800 cfs for a Level 3 drought (USACE 2006c). This would also increase the low water flow available in the Savannah River near the VEGP site. The proposed drought triggers for this alternative are shown in Table 2.4-240.

2.4.11.5 Plant Requirements

VEGP Units 3 and 4 are Westinghouse AP1000 reactor designs with a closed-cycle wet cooling system for condenser heat rejection. The only use of water from the Savannah River for the reactor units is for the circulating water system/turbine plant cooling water system makeup, where river water is required to replace evaporative water losses, drift losses, and blowdown discharge. Under normal operating conditions and design ambient conditions, river water demand for two-unit operation is 82.9 cfs (37,212 gpm). The maximum water requirement for plant operation is 136.2 cfs (61,145 gpm).

2.4.11.6 Heat Sink Dependability Requirements

The AP1000 reactor plants selected for VEGP Units 3 and 4 do not require a conventional ultimate heat sink to provide safety-related cooling during emergency shutdown. The AP1000 reactors make use of a passive cooling system and use water stored in onsite tanks. Consequently, river water is not necessary to achieve safe shutdown of the units.

2.4.12 Groundwater

This section describes the groundwater resources as it relates to the design bases for the Westinghouse AP1000 reactor design. The hydrogeology of the VEGP regional and local area including the site and the interface with the new AP1000 units are discussed in this section. Current and projected groundwater uses in the VEGP region are also discussed.

The 3,169 acre VEGP site is located on a bluff on the southwest side of the Savannah River in eastern Burke County, Georgia, within the Coastal Plain Physiographic Province (Figure 2.5-204). The proposed AP1000 units referred to as VEGP Units 3 and 4 have a finished grade level elevation of 220 ft msl. The bottom of the foundation slab for the safety related AP1000 containment structure is 39.5 ft (180.5 ft msl) below grade level. The Westinghouse AP1000 reactor design has no safety-related ultimate heat sink that relies on surface water or groundwater supplies. On-site wells provide make-up water for the service water system (SWS). The wells also supply water for power plant systems, including the fire protection system, the plant demineralized water supply system, and the

potable water system. Groundwater withdrawn for the proposed two new units is 752 gpm on average, with a maximum of 3,140 gpm. During normal operation, approximately 305 gpm of the withdrawn groundwater is returned as surface water to the Savannah River (Reference 292).

In constructing the new units, the site was excavated approximately 80 to 90 ft below existing grade to remove the in situ soil down to the principal bearing strata, the Blue Bluff Marl. The in situ soil was replaced with Seismic Category 1 and 2 fill material as described in Subsection 2.5.4. Foundations for the new units are poured on this new backfill material and the fill material is placed around the structures and continues up to the finished grade elevation of 220 ft msl. Seismic analysis of the geological formations under the proposed new units including the seismically designed backfill are discussed in Section 2.5.

2.4.12.1 Regional and Local Groundwater Aquifers and Conceptual Model Description

The following primary sources of information were used to develop the regional and local hydrogeological description and the conceptual model description presented in this section:

- Vogtle ALWR ESP Project Final Data Report, ES1374, Southern Company Services Inc., November 2005. (Appendix 2.4A)
- Data Report of Geotechnical Investigation and Laboratory Testing MACTEC Engineering and Consulting Inc., January 2005. (Appendix 2.5A)
- Data Report of Geotechnical Investigation and Laboratory Testing MACTEC Engineering and Consulting Inc., November 2007. (Appendix 2.5C)
- Groundwater Atlas of the United States, Segment 6, Alabama, Florida, Georgia, and South Carolina, U.S. Geological Survey, Hydrologic Investigations Atlas 730-G, J.A. Miller, 1990. (Reference 282)
- The Lithostratigraphic Framework of the Upper Cretaceous and Lower Tertiary of Eastern Burke County, Georgia, Bulletin 127, Georgia Department of Natural Resources, Huddlestun, P.F., and J.H. Summerour, 1996. (Reference 276)
- Final Safety Analysis Report for Vogtle Electric Generating Plant (VEGP) Units 1 and 2.
- An Investigation of Tritium in the Gordon and Other Aquifers in Burke County, Georgia, Phase II: Georgia Geologic Survey Information Circular 102, J.H., Summerour, E.A. Shapiro, and P.F. Huddlestun, 1998. (Reference 289)
- Ground-Water Levels, Predevelopment Ground-Water Flow, and Stream-Aquifer Relations in the Vicinity of Savannah River Site, Georgia and South Carolina: U.S. Geological Survey Water-Resources Investigations Report 97-4197, 1997. J.S. Clarke, and C.T. West. (Reference 262)
- Simulation of Ground-Water Flow and Stream-Aquifer Relations in the Vicinity of the Savannah River Site, Georgia and South Carolina: U.S Geological Survey Water-Resources Investigations Report 98-4062, 134 p. J.S. Clarke, and C.T. West, 1998. (Reference 263)
- Simulation and Particle-Tracking Analysis of Ground-Water Flow Near the Savannah River Site, Georgia and South Carolina, 2002, and for Selected Water-Management Scenarios, 2002 and 2020: U.S. Geological Survey Scientific Investigations Report 2006-5195, G.S. Cherry, 2006. (Reference 261)

2.4.12.1.1 Regional Hydrogeology

The region within a 200-mi radius around the VEGP site encompasses parts of four physiographic provinces. These include, from northwest to southeast, the Valley and Ridge, Blue Ridge, Piedmont, and Coastal Plain Physiographic Provinces. Figure 2.5-204 shows the physiographic provinces and indicates a 200-mi radius from the VEGP site. Several major aquifers or aquifer systems are present with these physiographic provinces. The VEGP site and associated groundwater are located within the Coastal Plain province (Reference 282). However, groundwater within the other provinces is discussed below to provide a complete picture of regional hydrogeologic conditions.

The Valley and Ridge Physiographic Province lies about 180 mi northwest of the VEGP site. Aquifers underlying the Valley and Ridge province occur within Paleozoic-age folded and faulted sedimentary rock. The sedimentary strata consist predominantly of sandstone, shale, and limestone, with minor amounts of dolomite, conglomerate, chert, and coal. The carbonate and sandstone layers form the principal aquifers in the province. Typical well yields are from 10 gpm in sandstone formations to 10 to 50 gpm within the limestone units. Locally high yields, equal to 100 gpm or greater, are possible within highly fractured strata or solution cavities. Localized weathered rock and alluvium can provide lesser, but adequate, groundwater yields for domestic use. (Reference 282)

The Piedmont and Blue Ridge Physiographic Provinces are hydrologically similar in nature. Both provinces are composed primarily of metamorphic and igneous rocks. Surface materials in the Blue Ridge Province consist mainly of thin residual soils, alluvium and colluvium. Surface materials in the Piedmont Province consist generally of more deeply weathered residual soils (saprolite) and alluvium. Groundwater occurs both in the fractured portions of bedrock and within the saprolite and alluvium material. Well yields generally depend on the local fracture density and fracture connectivity of the bedrock and range from a few to 30 gpm. Localized groundwater well yields of 100 gpm or greater are possible. (Reference 282)

The majority of Georgia's groundwater use occurs in the Coastal Plain Physiographic Province. The Coastal Plain sediments are thin, less than 200 ft thick, along the western boundary of the province (where they terminate at the contact with the Piedmont province, the Fall Line) and thicken to over 4,000 ft in an eastern-to-southeastern direction. The sediments range in age from Holocene to Cretaceous and overlie crystalline igneous and metamorphic bedrock, which is an eastward extension of the Piedmont province (Reference 282).

Groundwater in the Coastal Plain is withdrawn from both unconfined, shallow aquifer systems and deeper, confined aquifer systems. These aquifers are recharged principally in their outcrop area along the western boundary of the province near the Fall Line and from localized infiltration of precipitation within the province. Precipitation migrates downward and laterally through the unconsolidated surficial materials and discharges to nearby streams and low areas or percolates downward into the deeper unconsolidated and consolidated material. The thickness and areal extent of the Coastal Plain sediments result in higher groundwater storage than for any other physiographic provinces in Georgia (Reference 282).

Coastal Plain sediments comprise three aquifer systems consisting of seven aquifers that are separated hydraulically by confining units. As presented by (Reference 262), the aquifer systems are, in descending order: (1) the Floridan aquifer system, which consists of the Upper Three Runs and Gordon aquifers in sediments of Eocene age; (2) the Dublin aquifer system, consisting of the Millers Pond, upper Dublin, and lower Dublin of Paleocene-Late Cretaceous age; and (3) the Midville aquifer system, consisting of the upper Midville and lower Midville aquifers in sediments of Late Cretaceous age. It is important to note that nomenclature used by the U.S. Geological Survey (Reference 262) for geologic and hydrogeologic units differs from the (Reference 276) nomenclature used in Subsection 2.4.12.1.2 to describe the local hydrogeologic units. In this document, the Water Table aquifer comprises the Upper Three Runs aquifer, the Tertiary sand aquifer comprises the Gordon

aquifer, and the Cretaceous aquifer comprises the Dublin and Midville aquifers. Figure 2.4-237 and Figure 4 of Clarke and West (1997) provide additional details.

The Upper Three Runs aquifer is the shallowest aquifer and is unconfined to semi-confined throughout most of the area. Groundwater levels in the Upper Three Runs aquifer respond to a local flow system and are affected mostly by topography and climate. Groundwater flow in the deeper Gordon aquifer and Dublin and Midville aquifer systems is characterized by local flow to the northwest near outcrop areas, changing to intermediate flow and then regional flow downdip (southeastward) as the aquifers become more deeply buried. Water levels in these deeper aquifers show a pronounced response to topography and climate in the vicinity of outcrops that diminishes southeastward where the aquifer is more deeply buried. Stream stage and pumpage affect groundwater levels in these deeper aquifers to varying degrees throughout the area. (Reference 262)

The geologic characteristics of the Savannah River alluvial valley substantially control the configuration of potentiometric surfaces, groundwater flow directions, and stream-aquifer relations. Data from 18 shallow borings (Reference 278) indicate incision into each aquifer by the paleo Savannah River, and subsequent infill by permeable alluvium has resulted in direct hydraulic connection between the aquifers and the Savannah River along various parts of its reach. This hydraulic connection may be the cause of large groundwater discharge to the river near Jackson, South Carolina, as evidenced by stream baseflow and potentiometric measurements, where the Gordon aquifer is in contact with Savannah River alluvium, and also the cause of lows or depressions in potentiometric surfaces of confined aquifers that are in contact with the alluvium. Groundwater in these aquifers flows toward the depressions. The influence of the river diminishes downstream where the aquifers become deeply buried beneath the river channel, and where upstream and downstream groundwater flow is possibly separated by a groundwater flow divide or “saddle.” Water-level data indicate that saddle features probably exist in the Gordon aquifer and Dublin aquifer system, with the groundwater divide occurring just downstream of the VEGP site, and also might be present in the Midville aquifer system. (Reference 262)

Basin-wide potentiometric-surface maps for the unconfined Upper Three Runs aquifer and confined Gordon, Dublin, and Midville aquifer systems have been prepared using historical data (Reference 262) and numerical simulation (Reference 261). Detailed discussions of these maps are provided in the cited references. Data from observation wells installed and monitored for an 18-month period at the VEGP site have also been used to develop potentiometric-surface maps on a more highly resolved, site-specific basis. These maps are discussed in detail in Subsection 2.4.12.1.3. The groundwater flow directions inferred from these maps are generally consistent with the larger-scale maps produced by Clarke and West (1997) and Cherry (2006), i.e., groundwater flow in the Upper Three Runs (Water Table) aquifer generally conforms with surface topography, while that in the confined Gordon (Tertiary) aquifer is towards the Savannah River.

Recharge to the Upper Three Runs (Water Table) aquifer is almost exclusively by precipitation, while discharge is primarily to local drainages. Recharge to the confined Gordon (Tertiary) and Dublin and Midville (Cretaceous) aquifers occurs primarily by direct infiltration of rainfall in their outcrop areas northwest of the VEGP site that are generally parallel to the Fall Line. Because the permeable alluvium of the Savannah River valley allows for direct hydraulic connection between aquifers and the Savannah River, the river serves as the major discharge area for the confined aquifers in hydraulic connection with the river valley alluvium. Potentiometric maps presented by Clarke and West (1997) indicate groundwater discharge from the confined Gordon, Dublin, and Midville aquifers to the Savannah River. For the shallower Gordon confined aquifer, groundwater flow directions are generally perpendicular to the river reach. In the case of the deeper Dublin and Midville aquifers, there are upriver components to the groundwater flow directions that depend on where the paleo river channel has breached confining units. Clarke and West (1997) provide a detailed discussion of this phenomenon.

Although a water budget for the VEGP site has not been quantified, recharge and discharge rates have been estimated on a basin-wide basis by other investigators. Clarke and West (1997) estimated groundwater discharge to the Savannah River based on the net gain in stream discharge for local, intermediate, and regional groundwater flow systems and for different hydrologic conditions. Groundwater discharge ranged from 910 ft^3/s during a drought year (1941), to 1,670 ft^3/s during a wet year (1949), and averaged 1,220 ft^3/s. Of the average discharge, the local flow system contributed an estimated 560 ft^3/s and the intermediate and regional flow systems contributed an estimated 660 ft^3/s. Clarke and West (1997) approximated the long-term average recharge by weighting these values according to drainage area, and estimated the average groundwater recharge in the Savannah River basin to be 14.5 inches, of which 6.8 inches is to the local flow system, 5.8 inches is to the intermediate flow system, and 1.9 inches is to the regional flow system. Mean-annual precipitation in the basin ranges from 44 to 48 inches. Cherry (2006) presents simulated water budgets for different hydrologic conditions using a numerical model for groundwater flow in Georgia and South Carolina near the Savannah River Site. The numerical model contains estimates of inflow or outflow across lateral boundaries, recharge, discharge, groundwater pumpage, and vertical flow upward and downward across confining units.

A two-dimensional, site specific, single layer numerical groundwater model has been developed to predict the effects of VEGP Units 3 and 4 construction on the Water Table aquifer flow regime (Appendix 2.4B). Aquifer recharge was varied across the model domain to account for variations and post-construction changes in surficial geology, vegetative cover, and local land use patterns. Net recharge and hydraulic conductivity values are varied across the model domain based on observed hydrogeologic conditions in order to calibrate the model to observed Water Table aquifer groundwater levels. The results of this modeling yield a recharge rate ranging from 0.0 to 10.0 inches per year depending on surficial conditions (Appendix 2.4B, Table 8). These values are in general agreement with the recharge rates of Clarke and West (1997).

The potential for trans-river flow in the vicinity of the Savannah River Site and VEGP site has been discussed by Clarke and West (1997). Trans-river flow is a term that describes a condition under which groundwater originating on one side of a river migrates beneath the river floodplain to the other side of the river. Although some groundwater could discharge into the river floodplain on the opposite side of the river from its point of origin, such flow would likely be discharged to the river because flow in the alluvium is toward the river. Potentiometric-surface maps developed by Clarke and West (1997) for the Upper Three Runs aquifer and Gordon aquifers do not indicate the possible occurrence of trans-river flow. However, flow lines on potentiometric-surface maps of the confined Dublin and Midville aquifer systems do suggest the possible occurrence of trans-river flow for a short distance into the Savannah River alluvial valley. The possible occurrence of trans-river flow in the Dublin aquifer system also is suggested by the chemical and isotopic composition of water from the Brighams Landing well-cluster site in Georgia. Clarke and West (1997) suggest that the potential for trans-river flow may be facilitated by groundwater withdrawal, particularly at pumping centers located near the Savannah River. Pumped wells on one side of the river could intercept groundwater that originates on the other side. For this to occur, pumping would need to be sufficient to reverse the hydraulic gradient away from the river and towards the pumping center.

Numerical simulation techniques have been used to further evaluate areas of previously documented trans-river flow on the Georgia side of the Savannah River (Reference 263; Reference 261). At such areas, local head gradients might allow the migration of contaminants from the Savannah River Site into the underlying aquifers and beneath the Savannah River into Georgia. Cherry (2006) identified the area near Flowery Gap Landing (covering about 1 mi^2) as an area of potential trans-river discharge. Backward particle tracking analysis was conducted to better quantify trans-river flow. Between 29 and 37 percent of the particles released in this area backtracked to recharge areas on the Savannah River Site (trans-river flow), depending on the scenario being evaluated. Of the particles exhibiting trans-river flow, the median time-of-travel ranged from 366 to 507 years. For the

worst-case scenario evaluated (deactivation of Savannah River Site production wells), the median time-of-travel decreased to about 370 years, with a shortest time-of-travel period of about 80 years.

While the potential for trans-river flow exists, it is likely that such flow would be quickly discharged to the river because flow in the river alluvium is toward the river. Also, any tritiated water originating from the Savannah River Site and participating in trans-river flow would undergo significant radioactive decay, considering its 12.35-year half-life, relative to even the worst-case 80-year time-of-travel. Furthermore, pumping of the current make-up water wells for VEGP Units 1 and 2 does not appear to have intercepted groundwater originating from the other side of the river, based on the particle tracking results presented by Cherry (2006). It is also unlikely that pumping the additional water needed to supply VEGP Units 3 and 4 would be sufficient to reverse that hydraulic gradient and cause groundwater originating from South Carolina to be drawn any further into Georgia, given the high transmissivities of the confined Tertiary and Cretaceous aquifers. Therefore, trans-river flow does not appear to be a mechanism that would contribute to the contamination of aquifers underlying the VEGP site.

There is no evidence to suggest that the potential for groundwater leakage between the Upper Three Runs (Water Table) aquifer and Gordon (Tertiary sand) aquifer in the vicinity of the Pen Branch fault exists at the VEGP site. Subsection 2.5.1.2.4 describes previous investigations of the Pen Branch fault and the site subsurface investigation of the fault that was conducted for the ESP application. Results of this investigation, which included seismic reflection and refraction surveys, clearly document that the Pen Branch fault strikes northeast and dips southeast beneath the VEGP site. Figure 2.5-245 shows the vertical projection of the Pen Branch fault from the top of basement rock in relation to VEGP Units 3 and 4. The plan projection of the intersection of the Pen Branch fault with the top of basement rock is located beneath or slightly southeast of the antiformal hinge at the top of the monocline in the Blue Bluff Marl (Figure 2.5-242). Because of its spatial association with the Pen Branch fault, it is likely that this monocline feature is the result of reverse or reverse-oblique slip on the Pen Branch fault. The seismic survey data indicate that the fault terminates in the Cretaceous Coastal Plain deposits and that the overlying Tertiary deposits, including those comprising the Gordon (Tertiary sand) aquifer, Gordon aquitard (Blue Bluff Marl), and Upper Three Runs (Water Table) aquifer, are not considered to be affected by the Pen Branch fault. This result is consistent with that of Summerour et al. (1998) who reported that none of the faults identified in their seismic surveys appear to have disturbed the Gordon aquitard (Blue Bluff Marl), which isolates the unconfined from the underlying confined aquifers.

Based on the results and discussion presented above, the Pen Branch fault has not affected the Tertiary age deposits at the VEGP site and would be neither a barrier nor conduit for groundwater transport in these deposits. Insufficient data are available to determine if the fault would be a barrier or conduit in the deeper, Cretaceous deposits that have been affected by the fault.

2.4.12.1.2 Local Hydrogeology

The VEGP site is located approximately 40 mi southeast of the Fall Line, the northwestern boundary of the Coastal Plain physiographic province, and is adjacent to the Savannah River. Geologic conditions beneath the VEGP site generally consist of about 1000 ft of Coastal Plain sediments with underlying Triassic Basin rock southeast of the Pen Branch fault and Paleozoic crystalline rock northwest of this fault (Subsection 2.5.1). The Savannah River lies along the northeast border of the VEGP site and influences the local hydrogeologic conditions within the site area. This local hydrogeology discussion is restricted to the VEGP site vicinity (approximate radius of 5 mi) south of the Savannah River.

Geotechnical and hydrogeological investigations performed provide information on the VEGP site from the Triassic Basin rock to the ground surface. The geotechnical logs are provided in Appendices 2.5A and 2.5C and further discussed in Subsection 2.5.4. The boring logs from the observation well

installation are presented in Appendix 2.4A. In addition, reviews of the original site investigations for VEGP Units 1 and 2, existing unit well monitoring programs, and published literature were included in the analysis. Results from these investigations indicate that there are three aquifers underlying the VEGP site, the Cretaceous, Tertiary, and Water Table (or Upper Three Runs), all being part of the Southeastern Coastal Plain aquifer system. Although present regionally, the Surficial aquifer system, consisting of Miocene (Hawthorne Formation) through Quaternary deposits, is not continuous over Burke County or the VEGP site (Reference 282) and was not encountered in the investigations performed.

The lower aquifer at the VEGP site overlies the bedrock and is comprised of Cretaceous-age sediments. Locally, this aquifer system is known as the Cretaceous aquifer. The sediments include sands, gravels, and clays of the Cape Fear Formation, Pio-Nono Formation and associated unnamed sands, Gaillard Formation, Black Creek Formation, and Steel Creek Formation. The middle aquifer system is made up of Tertiary-age sediments occurring over the Cretaceous-age sediments described above. The middle aquifer is known locally as the Tertiary aquifer system. It consists primarily of the permeable sands of the Still Branch and Congaree Formations. The relatively impermeable clays and silts of the Snapp and Black Mingo Formations overlie and confine the Cretaceous aquifer, while the clays and clayey sands of the Lisbon Formation overlie and confine the Tertiary aquifer**.** The upper aquifer is unconfined and is comprised of Tertiary-age sands, clays, and silts of the Barnwell Formation, which overlie the relatively impermeable Lisbon Formation. This aquifer is known locally as the Water Table aquifer or Upper Three Runs aquifer. Figure 2.4-237 illustrates the hydrostratigraphic column for the VEGP site and surrounding area, identifying geologic units, confining units, and aquifers. Figures 2.4-238 and 2.4-239 present hydrogeologic cross sections for the VEGP site. The aquifers underlying the VEGP site and surrounding area are discussed below.

Cretaceous Aquifer

The Cretaceous aquifer locally comprises the Cape Fear Formation, Pio-Nono Formation/unnamed sands, Gaillard Formation/Black Creek Formation, and Steel Creek Formation. These formations generally consist of fluvial and estuarine deposits of cross-bedded quartzitic sand and gravel interbedded with silt and clay. The coarse-grained sediments are mostly unconsolidated and are generally permeable, while the fine-grained sediments are partially consolidated and are generally impermeable. In addition to the varying lithology, the formation also exhibits lateral facies changes, on-lap and off-lap relationships, and discontinuous lenses (Reference 276). The elevations, thicknesses, and descriptions of these geologic formations, as determined from VEGP geotechnical boring B-1003 (Appendix 2.5A), are summarized below:

- The basal Cape Fear Formation overlies the Triassic Dunbarton Basin bedrock, which consists of alternating mudstone, sandstone, and breccia. Boring B-1003 encountered top of bedrock at an elevation of approximately -826 ft msl. The Cape Fear Formation consists of interbedded sands, silts, clays, and gravels. The formation is approximately 191 ft thick, with the top of the formation being at El. -635 ft msl.

- The Pio-Nono Formation and other unnamed sands overlie the Cape Fear Formation. This formation consists of sand, silt, and clay. The formation is approximately 60 ft thick, while the top of the formation is at approximately El. -575 ft msl.

- The undifferentiated Gaillard Formation and Black Creek Formation overlie the Pio-Nono Formation and unnamed sands. Most of the formation consists of sand with silt and clay, and layers of gravel. The deposit is approximately 211 ft thick, with the top of the formation being at approximately El. -364 ft msl.

- The Steel Creek Formation overlies the undifferentiated Gaillard Formation and Black Creek Formation. It consists mainly of sand with clay and silt. The formation is approximately 110 ft thick; the top of the formation is at approximately El. -254 ft msl.

The Cretaceous aquifer system has not been extensively developed, primarily because the shallower Tertiary system is adequate for most groundwater needs and is available for use throughout the region. Quantitative data from the limited number of test and production wells in the Cretaceous strata, and inferred data from geologic and stratigraphic studies, indicate clearly that the Cretaceous aquifer system is highly transmissive and is capable of providing good quality groundwater.

Recharge to the Cretaceous aquifer system is primarily by direct infiltration of rainfall in its outcrop area, located north of the VEGP site in a 10- to 30-mile-wide belt extending from Augusta, Georgia, northeastward across South Carolina to near the state line separating North and South Carolina. In the outcrop areas, precipitation penetrates the Cretaceous sediments. Groundwater in the outcrop areas is under water table conditions, but as it moves progressively downdip, it becomes confined beneath the overlying Snapp and Black Mingo Formations in the vicinity of the VEGP site. Hence, the Cretaceous aquifer system is under confined conditions for most of its areal extent. Discharge of the Cretaceous aquifer system is primarily from subaqueous exposures of the aquifer that are presumed to occur along the Continental Shelf. Other discharge sources are to the Savannah River and by pumping.

Tertiary Aquifer

The most productive aquifer at the VEGP site consists of the Congaree and Still Branch Formations, which are hydraulically connected and are referred to as the Tertiary aquifer. The overlying Lisbon Formation, containing the Blue Bluff Marl, acts as a confining layer. The elevations, thicknesses, and descriptions of geologic formations comprising the Tertiary aquifer, as encountered in boring B-1003 (Appendix 2.5A), are described below:

- The Black Mingo and Snapp Formations constitute a semi-confining hydrogeologic unit under the VEGP site that separates the underlying Cretaceous aquifer from the overlying Tertiary sand aquifer as they dip to the southeast. The Paleocene-age Black Mingo Formation is approximately 39 ft thick and consists of sand, clay, and silt. The top of the formation is at approximately El. -215 ft msl. The Snapp Formation overlies the Black Mingo Formation and consists of sand, clay and silt, and includes a basal gravel layer. The stratum is also Paleocene in age. The formation is approximately 107 ft thick. The top of the formation is at approximately El. -108 ft msl.

- Above the Snapp is the Eocene-age Congaree Formation. The Congaree Formation has a thickness of about 115 ft and consists primarily of sand with clay and silt, and a basal gravel layer. The top of the formation is at an elevation of approximately 7.3 ft msl. The overlying Still Branch and Bennock Millpond Sands Formation consist of sand, clay, and silt and has a weak carbonate component. The formation thickness is approximately 54 ft, with the top of the formation being approximately El. 50 ft msl.

- The Lisbon Formation overlies the Tertiary sediments. The Lisbon Formation is Eocene in age and is comprised of sand, clay, and silt with interbedded layers of fossiliferous limestone. The Lisbon Formation contains a marl known as the Blue Bluff Member (Blue Bluff Marl). The Lisbon Formation also contains the McBean Limestone Member, a fossiliferous limestone layer not encountered in borings at the VEGP Units 3 and 4 site. The formation has a thickness of approximately 63 ft, and the top of the formation is at approximately El. 130 feet msl. This formation separates the confined and unconfined aquifer systems beneath the VEGP site.

In addition, the VEGP Units 1 and 2 UFSAR Section 2.5.1.2.2.2.1.1 indicates that the Blue Bluff Marl is a distinct unit that is relatively constant in thickness over many square miles, although variable in lithology. Contours of the upper and lower surfaces as well as an isopach map of the marl in the vicinity of the plant are shown on drawings AX6DD352, AX6DD371, and AX6DD372 of the UFSAR. These drawings indicate the Blue Bluff Marl to be continuous over the entire VEGP site. VEGP geotechnical and hydrogeological boring data have been incorporated into the Blue Bluff Marl dataset. These data indicate that the base of the Blue Bluff Marl ranges in elevation between 21 ft msl and 83 ft msl. Where fully penetrated, the marl thickness ranges from a minimum of 5.0 feet where it has been scoured by the Savannah River to a maximum of approximately 95 feet. Where the marl is fully intact, its mean thickness is approximately 63 feet. Blue Bluff Marl structure contour and isopach maps have been prepared to include this new data. These are included as Figures 2.5-250 and 2.5-254, respectively.

Recharge to the Tertiary aquifer is primarily by infiltration of rainfall in its outcrop area, which is a belt 20 to 60 miles wide extending northeastward across central Georgia and into portions of Alabama to the west and South Carolina to the east. Discharge from the Tertiary aquifer occurs from pumping, from natural springs in areas where topography is lower than the piezometric level of the aquifer, and from subaqueous outcrops that are presumed to occur offshore. Discharge also occurs to the Savannah River where the river has completed eroded the Blue Bluff Marl confining layer allowing discharge from the aquifer to the river bed.

Water Table Aquifer

The uppermost aquifer at the VEGP site is unconfined and consists of the Barnwell Group, including the discontinuous deposits of the Utley limestone. The saturated interval within the Barnwell Group is commonly referred to as the Water Table aquifer (also known as the Upper Three Runs aquifer) and is the first water-bearing zone encountered beneath the VEGP site. The elevations, thicknesses, and descriptions of geologic formations comprising the Barnwell Group were determined from VEGP geotechnical and hydrogeological borings and are described below (Appendices 2.4A, 2.5A, and 2.5C).

- The Utley Limestone Member of the Barnwell Group consists of sand, clay, and silt with carbonate-rich layers. The stratum is discontinuous across the VEGP site and was not encountered in many of the borings. To assess its degree of discontinuity, borings logged for the hydrogeological and geotechnical investigations have been examined for the presence/absence of the Utley limestone. Logs for these borings are included in Appendices 2.4A, 2.5A, and 2.5C. In completing this assessment, effort was made to eliminate spatial bias. Therefore, only one boring log was considered when there were adjacent borings from OW-series well pairs, or adjacent B- and OW-series borings. The results are summarized in Table 2.4-253.

  The data presented in Table 2.4-253 indicate that 27 of 189 borings were terminated above the elevation where the Utley limestone would be expected to be encountered. An additional 10 borings were advanced at locations where the ground surface is below the elevation where the Utley limestone would be expected to be encountered. Of the remaining 152 soil borings, the Utley Limestone is absent in 54 borings, or 36 percent of the borings. Spatial trends in the presence/absence of the Utley limestone indicate that the unit tends to be present in the power block area for VEGP Units 3 and 4 and the area to the north towards Mallard Pond and south towards the VEGP Units 3 and 4 cooling towers. Where present, the base of the Utley Limestone ranges in elevation from approximately 96 ft msl to 152 ft msl. The Utley Limestone isopach map presented in Figure 2.5-255 indicates that the limestone is a linear feature in its areal extent with the axis of maximum thickness roughly extending north-northeast from the VEGP Units 3 and 4 cooling towers to a location approximately 1200 feet east of Mallard Pond. The limestone is absent along the flanks of this feature and increases in thickness to a maximum of approximately

25 ft to 38 ft along its axis. Total thickness varies considerably, and the Utley Limestone is absent in some places within its general area of extent.

- Overlying the Utley limestone are undifferentiated sands, clays, and silts of the Barnwell Group. The thickness of this group is variable and ranges from approximately 26 to 162 ft in borings where the undifferentiated sediments of the Barnwell Group are fully penetrated. The top of the group extends to the ground surface and ranges from approximately El. 164 ft msl to 280 ft msl.

Recharge to the Water Table aquifer is almost exclusively by infiltration of direct precipitation. The presence of porous surface sands and the moderate topographic relief in the VEGP site area suggest that a significant fraction of the precipitation infiltrates the ground or is lost to the atmosphere by evapotranspiration. Discharge is to localized drainages and wells.

2.4.12.1.3 Observation Well Data

Data from a combination of new wells installed and existing VEGP site wells were used to develop groundwater elevation contour maps and present groundwater elevation trends. The new wells, designated OW-1001 through OW-1015, were installed in May and June 2005. Ten of the new wells are screened in the Water Table aquifer and five are screened in the confined Tertiary aquifer system below the Blue Bluff Marl. No wells were installed into the deeper Cretaceous aquifer. Existing wells 142 and 179, remaining from the pre-construction monitoring network for VEGP Units 1 and 2, are screened in the Water Table aquifer. Existing wells with identifications beginning with the number 8 were installed between 1979 and 1985 to monitor construction dewatering of VEGP Units 1 and 2. These wells are screened in either the Water Table or Tertiary aquifers. Existing wells with an LT designation were installed in 1985 as part of post-construction monitoring activities and are screened in the Water Table aquifer.

Observation well OW-1001A was installed at the site in October 2005 to replace OW-1001. Observation well OW-1001A was the only new “A” well installed at the site for the ESP application. Observation well OW-1001A may be confused with the borings or drill logs contained in Appendix 2.4A which also use the suffix “A” to indicate abandoned wells. OW-1001A was installed during the geotechnical subsurface investigation performed at the site and is not discussed in Appendix 2.4A report. A summary of borings or holes drilled at the site to accommodate installation of the new observation wells is provided in Table 2.4-254.

Groundwater level elevations in OW-1001 measured between the period June 2005 and July 2007 (groundwater level data continues to be collected in wells OW-1001 and OW-1001A for observation purposes) range from about 114 to 118 ft msl with a seasonal fluctuation of about 4.4 ft. These groundwater levels and seasonal fluctuations are not consistent with the groundwater levels and seasonal fluctuations of groundwater levels in the Water Table aquifer and suggest that the screened portion of the well is not in good hydraulic communication with the Water Table aquifer. Review of the boring log, daily field log, well development log and in situ hydraulic conductivity test results for the well indicate that either the formation material adjacent to the well was adversely impacted by well construction or that the well was inadvertently installed in the confining unit underlying the formation material. Observation well OW-1001A was installed to replace well OW-1001, as discussed above. The construction log for OW-1001A contained in Appendix 2.5A (report Appendix D) indicates that the screened portion of the well ranges in elevation from 146.13 to 136.13 ft msl. Groundwater level elevations for the 18-month monitoring period range from 135.91 to 135.99 ft msl. Based on these groundwater level data, it is evident that the groundwater level in the well is close to or below the bottom of the screened interval of the well, indicating no hydraulic communication with the Water Table aquifer. Groundwater data obtained from OW-1001 and OW-1001A are considered invalid and are not used in the following groundwater evaluations.

Monthly water levels in the observation wells were measured to characterize seasonal trends in groundwater levels and flow directions for the VEGP site. Monthly monitoring of these wells began in June 2005 and is continuing. A 26-month data set representing June 2005 through July 2007 is utilized for the ESP application. In addition, some long-term data are available for certain existing wells completed in the Water Table and Tertiary aquifers and are used to characterize historic trends.

The locations of VEGP site observation wells that are being monitored are shown in Figure 2.4-240. Table 2.4-241 lists the observation wells currently being used to monitor the Water Table aquifer, while Table 2.4-242 lists the observation wells currently being used to monitor the Tertiary aquifer.

The following groundwater piezometric surface discussion is based on the information presented in Tables 2.4-241 and 2.4-242, Figures 2.4-241 through 2.4-245, Figures 2.4-247 through 2.4-251, Figures 2.4-254 through 2.4-259, and Figures 2.4-261 through 2.4-264.

Water Table Aquifer

Groundwater level data for the Water Table aquifer available for the 1979 through 2007 period are provided in Figure 2.4-254. Table 2.4-255 summarizes the historical groundwater levels for the Water Table aquifer. Also shown on this figure is annual precipitation measured at three climate stations close to the VEGP site, which includes the Augusta WSO Airport, Waynesboro 2 NE, and Millen 4N climate stations. Precipitation data were obtained from the South Carolina Department of Natural Resources website (Reference 286). In addition, the Palmer Drought Severity Index (PDSI) and Palmer Hydrological Drought Index (PHDI) are plotted on Figure 2.4-255 for the same period. The PDSI attempts to measure the duration and intensity of the long-term cumulative meteorological drought and wet conditions. The PDHI is another long-term drought index intended to measure the hydrological impacts of drought (e.g., reservoir levels, groundwater levels, etc.). PDSI and PHDI data were obtained from the National Climatic Data Center (NCDC) website (Reference 283). These indices provide an indication of the severity of a wet or dry spell. The indices generally range from +6 to -6 with negative values denoting dry spells and positive values denoting wet spells. Values of +0.5 to -0.5 indicate normal conditions.

Figure 2.4-254 shows that during the period 1979 to 1984, groundwater level elevations in the Water Table aquifer were impacted (lowered) by construction dewatering of the power block excavation for VEGP Units 1 and 2 that was in effect from June 1976 to March 1983. Groundwater levels for subsequent years exhibit variability in response to meteorological conditions. The magnitude of the variability can be estimated using data from the wells having the longest period of record, which include wells 802A, 805A, 808, LT-7A, LT-12, and LT-13. Table 2.4-256 summarizes the minimum and maximum water levels recorded at each of these wells. These results indicate a 5-to 8-ft range in water levels over the 17-year period of record for these wells. Inspection of the long-term hydrographs for these wells in conjunction with the drought severity indices for the same period indicates that groundwater levels in the Water Table aquifer generally correlate with the PDSI and PDHI. Water levels tend to remain unchanged when the drought severity indices remain near normal (±1). During drought periods when the PDSI or PDHI index falls to -2 or below, groundwater levels tend to decline. Conversely, during wet periods when the PDSI or PDHI increases to +2 or more, groundwater levels tend to rise. Increases or decreases in the drought indices would be associated with the increases or decreases in the rate of recharge of the Water Table aquifer. Because of the relatively large depth to the water table (at least 60 ft), prolonged wet or dry periods on the order of a year in duration are apparently required to affect the recharge to the water table at these depths.

Recent groundwater data from June 2005 to July 2007 for the Water Table aquifer are summarized in Table 2.4-241 and shown in Figure 2.4-256. During the 26-month monitoring period, groundwater elevations ranged from about 132 to 165.5 ft msl with seasonal fluctuations averaging about 1.7 feet. These data exhibit very little variability because the recharge during this period was evidently relatively constant. Comparison of historical groundwater level elevations to precipitation events and other meteorological indices over a longer period of time suggest that persistent and significant wet

weather is required to elicit any significant water table response, as discussed above. The annual precipitation, the PDSI, and the PDHI for the 2004 to 2006 period have been relatively stable and near normal values. Due to the absence of any upward or downward trends in these indices, it is therefore expected that groundwater elevations in the Water Table aquifer would be relatively steady over this period.

The groundwater elevation data summarized in Table 2.4-241 were used to develop groundwater surface elevation contour maps for the Water Table aquifer on a quarterly basis. These maps are presented in Figures 2.4-241 through 2.4-245 for June 2005 through June 2006, Figure 2.4-257 for November 2006, and Figures 2.4-261 to 2.4-262 for March and June 2007. Note that a contour map for November 2006 was not developed as no groundwater level data are available for September and October 2006. For each quarter, the spatial trend in the piezometric surface is similar, with elevations ranging from a high of approximately El. 165.5 ft msl in the vicinity of well OW-1013 to a low of approximately El. 132 ft msl at well OW-1005. The groundwater surface contour maps indicate that horizontal groundwater flow across the VEGP site is in a north-northwest direction toward Mallard Pond (also known as Mathes Pond). This surface water feature is a local discharge point for the shallow groundwater flowing beneath the VEGP site. The observed horizontal hydraulic gradient across the site for the Water Table aquifer is relatively consistent between the seven figures and is approximately 0.014 ft/ft.

Tertiary Aquifer

Historical groundwater elevations from 1971 through 1985 for Tertiary aquifer wells 27 and 29 are provided in Figure 2.4-246.

Recent groundwater elevation data from June 2005 to July 2007 for the Tertiary aquifer are summarized in Table 2.4-242 and shown in Figure 2.4-258. Groundwater elevations for this 26-month monitoring period range from about 81 to 128 ft msl. Elevations are relatively constant from June to August 2005. In most cases, the piezometric head of the aquifer declines from August 2005 through November 2005. The elevations begin to rebound in December 2006, continuing through February 2006. A decline in piezometric head is observed from February 2006 through November 2006 followed by rising levels through February 2007. Groundwater elevations decreased from March 2007 through July 2007, reaching the lowest levels seen during the 26-month observation period. The lowering of the piezometric surface is likely in response to a decrease in precipitation. October and November are the months with the lowest precipitation during the year for this area. Well 27 shows a higher degree of variability than the others and is likely influenced by its proximity to the Savannah River.

The groundwater elevation data summarized in Table 2.4-242 were used to develop piezometric surface maps for the Tertiary aquifer. The Tertiary aquifer piezometric surface is presented in Figures 2.4-247 through 2.4-251 for June 2005 through June 2006, Figure 2.4-259 for November 2006, and Figures 2.4-263 to 2.4-264 for March and June 2007. The piezometric surfaces for the Tertiary aquifer show a relatively consistent flow pattern. In general, the groundwater in this aquifer unit shows an east-to-northeast flow pattern, toward the Savannah River. Head elevations range from approximately El. 125 ft msl in the western portion of the VEGP site to less than El. 100 ft msl in the vicinity of the bluff next to the Savannah River flood plain. The elevation of the piezometric head at the bluff and that of the Savannah River flood plain suggest groundwater is discharging to the Savannah River. The piezometric elevations in the Tertiary aquifer decreased by an average of approximately 8.7 ft across the VEGP site during the 26-month observation period.

The horizontal hydraulic gradient across the site for the Tertiary aquifer is relatively consistent among the seven figures and is approximately 0.005 ft/ft. In the center of the VEGP site, there is a downward head difference of approximately 50 ft between the Water Table aquifer and the Tertiary aquifer, suggesting hydraulic separation of the two aquifers. The Blue Bluff Marl confining unit that separates the aquifer systems has an average thickness of about 63 ft at the VEGP site.

Cretaceous Aquifer

At the VEGP site, both the Cretaceous and the Tertiary aquifers are considered confined beneath the Blue Bluff Marl but are in apparent hydraulic connection with each other. At some distance downdip of the VEGP site, the Cretaceous aquifer becomes hydraulically separated from the Tertiary aquifer. This separation is believed to be due to facies changes in the intervening clays and silts of the Snapp and Black Mingo formations becoming relatively impermeable. The point at which this occurs is not well defined but it is believed to be a few miles downdip (south) of the site.

The regional direction of the groundwater flow in the Cretaceous (and the Tertiary) aquifer system is south-by-southeast at a hydraulic gradient of approximately 6 to 20 ft/mi (0.001 to 0.004 ft/ft) (Reference 285). From the vicinity of the Fall Line to a point expected to be a few miles south of the site, the Savannah River has downcut through the Blue Bluff Marl confining layer and into the underlying strata. The Savannah River channel cut allows both the Cretaceous and the Tertiary aquifers to discharge to the riverbed, resulting in a localized hydraulic (groundwater) sink. The aquifer flow directions in the vicinity of the river cut are affected by the hydraulic sink and do not follow regional trends.

2.4.12.1.4 Hydrogeologic Properties

Slug tests were performed in the new groundwater observation wells installed to determine in situ hydraulic conductivity values for the Water Table and Tertiary aquifers. Table 2.4-243 summarizes the test results. Soil samples collected from selected geotechnical and hydrogeological borings were submitted for laboratory tests to determine grain size, moisture content, and specific gravity, results from which are included in Tables 2.4-244 through 2.4-246. Similar data are available for the adjacent VEGP Units 1 and 2 site. The hydrogeological properties of the Water Table aquifer, Lisbon Formation (Blue Bluff Marl) confining unit, Tertiary aquifer, and Cretaceous aquifer at the VEGP site are discussed below.

Water Table Aquifer

In the vicinity of the VEGP site, the basal unit of the Barnwell Group, the Utley limestone member, is capable of transmitting groundwater but is of limited areal and vertical extent. In addition, the horizontal and vertical hydraulic conductivity of the saturated clays, silts, and sands within the Barnwell Group varies considerably, due to variable clay content.

The hydraulic conductivity of the Water Table aquifer within the vicinity of the VEGP site was previously measured by both in situ and laboratory testing methods during site characterization investigations for VEGP Units 1 and 2. In situ hydraulic conductivity values for the Barnwell Group sands, silts, and clays were found to range between 200 and 267 ft/yr (0.5 to 0.7 ft/day). Laboratory values varied beyond the range of the in situ tests from 9.8 to 302 ft/yr (0.03 to 0.8 ft/day). Well pumping tests conducted in the Utley limestone member of the Barnwell Group resulted in hydraulic conductivities ranging from 3,250 to 125,400 ft/yr (9 to 343 ft/day), while falling and constant head tests suggested lower values, ranging from 96 to 5,800 ft/yr (0.3 to 16 ft/day). These results indicate the possibility of localized, highly permeable zones in the Utley limestone.

Hydraulic conductivities were reported from the site characterization investigations for VEGP Units 3 and 4. Slug test results for the Water Table aquifer range from 0.12 to 2.65 ft/day, with a geometric mean of 0.5 ft/day (Table 2.4-243). A two-dimensional, site specific, single layer numerical groundwater model has been developed to predict the effects of VEGP Units 3 and 4 construction on the Water Table aquifer flow regime (Appendix 2.4B). Hydraulic conductivity was varied across the model domain to account for lateral variations in surficial geology and locations of construction fill materials. Horizontal hydraulic conductivity values were varied across the model domain based on observed hydrogeologic conditions in order to calibrate the model to recently observed Water Table aquifer groundwater levels. The results of this modeling yield horizontal hydraulic conductivity values

ranging from 8.0 to 32 ft/day for the areas outside of the immediate VEGP Units 3 and 4 Power Block area. These values lie within the range of Barnwell Group hydraulic conductivity values cited above and are considered representative of the horizontal hydraulic conductivity for the Water Table aquifer.

VEGP Units 1 and 2 laboratory porosity values for the Barnwell Group sands, silts, and clays were found to range from 34 to 61 percent, with a mean value of 44 percent. Table 2.4-244 summarizes the laboratory test results for geotechnical samples collected below the capillary fringe in the Barnwell Formation, which were at depths ranging from El. 108 to 160 ft msl. Sand and clay make up the majority of samples. Measured moisture contents, by weight percent, range from 19.7 to 47.0 percent and have a median value of 27.6 percent. Specific gravity analysis was performed only for the samples collected from the observation well borings. Values range between 2.59 to 2.75 and have a median value of 2.66. Using the median moisture content of 27.6 percent and a value of 2.66 for the specific gravity, the void ratio is estimated to be about 0.73. A total porosity of 42 percent is calculated from this void ratio (Reference 264), and an effective porosity of about 34 percent is estimated based on 80 percent of the total porosity (Reference 280). The specific yield for the Water Table aquifer was not determined; however, an estimate of this value taken from published literature for similar aquifer materials indicates that it may be in the range of 0.20 to 0.33 (Reference 281). The effective porosity of the backfill is assumed to be 0.34 as established during site characterization investigations for VEGP Units 1 and 2.

Post-Construction Groundwater Model

A two-dimensional single layer groundwater model was developed to simulate post-construction groundwater flow in the Water Table aquifer at the VEGP site (Appendix 2.4B). A conceptual representation of the groundwater model developed for the VEGP site is shown on Appendix 2.4B, Figure 18. Appendix 2.4B, Figure 19 shows the numerical representation of the groundwater model including the horizontal grid formulation. The grid spacing surrounding the existing (Units 1 and 2) and proposed (Units 3 and 4) plant areas is set at 100 ft by 100 ft, whereas for the remaining area, the grid spacing is set at 200 ft by 200 ft.

Topographic and surficial geology maps were used to delineate the vertical extent of the Water Table aquifer in this single layer groundwater model. The top elevation of the groundwater model is the ground surface elevation. The ground surface elevation data were obtained from USGS 1:24,000 quadrangle maps. The base elevation of the groundwater model (i.e. top of Blue Bluff Marl) is defined by geotechnical and hydrogeological boring data. The base layer of the model is the low permeability Blue Bluff Marl which hydraulically isolates the Water Table aquifer from the underlying Tertiary aquifer (Appendix 2.4B, Figure 5). The model domain covers approximately six square miles.

The boundaries of the model domain were selected to coincide with key physical features of the model area that are shown in Appendix 2.4B, Figure 18. These key physical features are numerically represented as drain boundaries and no flow boundaries.

Hydraulic conductivity and net recharge values were allowed to vary in order to calibrate the model to the observed groundwater levels (March 2006). The model calibration suggested that a much higher hydraulic conductivity value should be used for the area surrounding Mallard Pond (100 ft/day) in order to match the observed water table elevations in the area near Mallard Pond. Hydraulic conductivities for the Barnwell Group in the primary model domain area were varied to account for the presence/absence of the more permeable Utley Limestone member. During construction, fill material will be used around and beneath the power block and auxiliary buildings. It is necessary to account for this fill material in the post-construction model. The hydraulic conductivity of the fill material for the construction of Units 3 & 4 is assumed to be the same as that of the fill material used for Units 1 & 2. As discussed in Appendix 2.4B, Section 2.7, the geometric mean of four slug tests conducted in the structural fill material for Units 1 & 2 was 2.3 ft/day. The hydraulic conductivity values from these tests ranged from1.3 to 3.3 ft/day. As a conservative assumption it is assumed that

the hydraulic conductivity of the fill material is equal to the maximum measured value, i.e. 3.3 ft/day (Appendix 2.4B, Table 4). The aquifer recharge rate was varied across the model domain to account for variations in surficial geology, vegetative cover, and local land use patterns. For paved areas, the net recharge rate in the model was set equal to zero.

By executing a series of seven model runs with different combinations of hydraulic conductivity and recharge values, the best performing model run was identified as Model 7. These seven model runs represent alternative conceptual models, i.e. different sets of assumptions, for the site. The key input parameters used for these model runs are described in Appendix 2.4B, Section 4.4 and summarized in Appendix 2.4B, Table 8. Simulated post-construction groundwater levels generated using Model 7 are presented in Appendix 2.4B, Figure 74. The post-construction groundwater levels at observation well OW-1003 (Unit 3 location) are approximately 0.5 feet higher than the calibrated pre-construction groundwater levels.

Post-construction release points, groundwater pathways and discharge points were evaluated using particle tracking for the selected model run (Model 7). In each case, particles are released from the perimeter of the 775-ft radius circle defining the area surrounding the nuclear island auxiliary buildings of Units 3 & 4 and tracked to their potential discharge points. As seen from Appendix 2.4B, Figure 77, the potential particle tracking path line from the various discharge points is always directed towards Mallard Pond. This implies that all releases from any point inside the 1200-ft diameter circle around the power block area will also discharge to Mallard Pond. The particle tracking path line from the specific release point in the Unit 4 Auxiliary Building is shown in Appendix 2.4B, Figure 78.

Groundwater Travel Time

The groundwater travel time has been estimated by considering the locations of the effluent holdup tanks (the initial release location), observed hydraulic conductivities of the backfill, and estimates of the hydraulic gradients, and hydraulic conductivities, and travel path lengths through the native materials comprising the Water Table aquifer based on the results of the post-construction groundwater modeling. The total saturated zone travel time is the sum of three components: (1) travel time in the backfill; (2) travel time in the Water Table aquifer in the area between the backfill and the area near OW-1005; and (3) travel time between OW-1005 and Mallard Pond. The travel time in each is a function of the travel distance, hydraulic conductivity, effective porosity, and hydraulic gradient. The basis for estimating the travel time in each of these three segments is described below.

The travel distance in the backfill represents the curvilinear distance along the predicted particle flow track between the release point in the northwestern portion of the Unit 4 auxiliary building potentially flooded by a tank rupture and the southwestern extent of the power block excavation at an elevation of approximately 158 ft msl, where groundwater would flow from backfill to native material (Appendix 2.4B, Figure 78). As indicated previously, a hydraulic conductivity of 3.3 ft/day was assigned to the backfill. The effective porosity of the backfill was taken to be 0.34 as established during site characterization investigations for VEGP Units 1 and 2. Because the backfill for Units 3 and 4 will be obtained from the borrow areas used for Units 1 and 2 and compacted to the same criteria, the hydraulic conductivity and porosity values observed for Units 1 and 2 should be representative of Units 3 and 4. Based on the aforementioned parameters, the groundwater travel time in the backfill was calculated to be 2.4 years (Appendix 2.4B, Table 15) (Reference 275).

The travel distance through the native material between the power block area and well OW-1005 lies along the predicted particle flow track between the location on southwestern side of the power block excavation where groundwater flow enters native material and the area near observation well OW-1005 where higher permeability alluvial material is modeled to be encountered (Appendix 2.4B, Figure 78). A hydraulic conductivity of 32 ft/day, based on the groundwater model calibration results, is used in this analysis. The effective porosity of the Water Table aquifer has been estimated to be

0.34 based on site-specific investigation measurements. Using the parameters described above, a groundwater travel time of 3.2 years is estimated for this segment (Appendix 2.4B, Table 15).

The predicted groundwater travel time along the particle flow track between the modeled boundary of the alluvial materials near observation well OW-1005 and Mallard Pond (Appendix 2.4B, Figure 78) is approximately 1.1 years (Appendix 2.4B, Table 15). A hydraulic conductivity of 100 ft/day, based on the groundwater model calibration results, and the same effective porosity cited above for the native materials (0.34) is used in this analysis.

Summing the above travel times, the total travel time for this analysis is 6.7 years (Appendix 2.4B, Table 15).

The geotechnical boring logs contained in Appendix 2.4A, which report some occurrence of water loss during drilling through the Utley limestone, and high hydraulic conductivity test results for the Utley limestone obtained during site investigations for VEGP Units 1 and 2 indicate the possibility of localized highly permeable zones in the Utley limestone. These zones could act as preferential pathways for groundwater flow if there was an accidental liquid release of effluents to the groundwater at the VEGP site.

As described in Subsection 2.5.4.5, construction of the new VEGP Units 3 and 4 required a substantial amount of excavation and backfill. The excavation was necessary to completely remove the sands, silt, clays, and Utley limestone of the Barnwell Group. Total excavation depth to the Blue Bluff Marl bearing stratum ranged from approximately 80 to 90 ft below existing grade. Backfilling was performed from the top of the Blue Bluff Marl to the bottom of the containment and auxiliary buildings at a depth of about 40 ft below final grade. Filling continued up around these structures to final grade. The fill primarily consisted of granular materials, selected from portions of the excavated sands and from other available borrow sources. Following the guidelines used during construction of VEGP Units 1 and 2, structural fill was a sandy or silty sand material with no more than 25 percent of the particle sizes smaller than the No. 200 sieve. This structural fill was compacted to a minimum of 97 percent of the maximum dry density.

Excavating existing soils and replacing these soils with structural fill altered the hydrogeologic characteristics of the subsurface materials within the footprint of VEGP Units 3 and 4. Compared to the hydraulic conductivities for the Water Table aquifer, as described above, it can be seen that the hydraulic conductivity of the fill is lower than that of the in situ soils.

Development of VEGP Units 3 and 4 also increased the impervious area across the VEGP site where power generation and associated facilities are constructed. Storm-water management facilities (e.g., catch basins, storm sewers) are used to convey runoff from precipitation offsite. The increased impervious area and use of storm-water management facilities tend to reduce the recharge to the Water Table aquifer in areas affected by Unit 3 and 4 construction.

Construction of VEGP Units 3 and 4 entails the placement of relatively large and impermeable structures below grade. The base elevations of the major structures (containment and auxiliary buildings) are at about El. 186.5 ft msl. This elevation is at least 25 to 35 ft above the water table. Because these structures do not extend below the water table, they do not affect the hydrogeologic characteristics of the underlying saturated zone.

Lisbon Formation (Blue Bluff Marl) Confining Unit

The hydraulic conductivity of the marl layer is very low, and it effectively confines the aquifer underlying it. It is considered a vertical barrier to groundwater movement. In situ permeability tests (packer tests) were performed in the marl during site characterization investigations for VEGP Units 1 and 2. In 90 percent of the intervals tested, no measurable water inflow occurred. Laboratory permeability tests were also conducted on core samples collected from the marl. Laboratory

measurements ranged from 0.0052 to 8.8 ft/yr (1.4×10^{-5} to 2.4×10^{-2} ft/day) with a geometric mean of 1.3×10^{-3} ft/day, indicating the marl is nearly impermeable. Porosity values ranged from 24 to 62 percent, with a mean value of 48 percent.

Geotechnical laboratory results for the Lisbon Formation (Blue Bluff Marl) confining unit are summarized in Table 2.4-245 for the VEGP site. Soil samples were collected between El. 51 and 135 ft msl. The samples consist of gravel, sand, and clay. Moisture contents range from 13.5 to 67 percent, with porosities of 25 to 59 percent. Using the median moisture content of 29 percent from geotechnical laboratory results and an assumed specific gravity of 2.65, the void ratio of the confining unit is estimated to be 77 percent. Based on the void ratio value, total porosity is calculated to be 44 percent. The effective porosity of the Blue Bluff Marl was estimated using de Marsily (1986) Figure 2.17. This figure plots total and effective porosity as a function of grain size. To estimate the effective porosity for the marl, the ratio of effective to total porosity determined from Figure 2.17 was applied to the site-specific total porosity value for the VEGP site. Using the median D50 value of 0.24 mm as a representative grain size (Table 2.4-245), a ratio of effective to total porosity of about 0.8 was determined. Multiplying the median total porosity of 0.44 by this ratio yields an effective porosity of 0.35.

The effective porosity was also estimated as the difference between the total porosity and the residual water content, as given by Yu et al. (1993) Equation 4.4. Grain size distribution data indicate that most of the Blue Bluff Marl samples can be classified as a silty sand (SM) or clayey sand (SC). The residual water content for SM or SC soils obtained from Carsel and Parrish (1988) using equivalent USDA-SCS soil textural classifications ranges from 0.07 to 0.10. The effective porosity would then range from 0.34 to 0.37. This result indicates that the 0.35 value for effective porosity is representative of the Blue Bluff Marl.

Tertiary Aquifer

Hydraulic conductivities determined from Tertiary aquifer slug tests range from 0.35 to 2.1 ft/day, with a geometric mean of 0.83 ft/day (Table 2.4-243). These results are consistent with those for the VEGP Units 1 and 2 site for which the geometric mean was determined to be 0.51 ft/day. The laboratory results from the geotechnical samples collected in the Tertiary aquifer are presented in Table 2.4-246. Sample elevations range from El. -273 ft msl to 75 ft msl, with the samples consisting mainly of sand and fine particles, with some gravel. Moisture content ranges from 16.5 to 40.7 percent, with specific gravity values varying from 2.62 to 2.69. Using the median moisture content of 23.6 percent and a value of 2.67 for the specific gravity, the void ratio of the Tertiary aquifer is estimated to be about 0.63. A total porosity of 38.7 percent is calculated from this void ratio (Reference 264), and an effective porosity of about 30.9 percent is estimated based on 80 percent of the total porosity (Reference 280). The storage coefficient for the Tertiary aquifer alone has not been determined; however, previous tests of wells completed in the combined Cretaceous/Tertiary aquifers suggest that a value on the order of 10^{-4} would be a reasonable estimate (see below).

The horizontal hydraulic gradient of the Tertiary aquifer is approximately 0.005 ft/ft, based on the maximum water level observed at well OW-1008 (127.99 ft msl), the minimum water level observed at well 27 (81.01 ft msl), and the distance between the two observation wells of about 8,700 ft. The average horizontal groundwater velocity was calculated at 0.013 ft/day using a hydraulic conductivity of 0.83 ft/day, a hydraulic gradient of 0.005 ft/ft, and an effective porosity of 30.9 percent (Reference 275). Using a distance of 5,600 ft from the center of the power block area for the new AP1000 units to the closest point of the Savannah River, the groundwater travel time from the power block area to the Savannah River in the Tertiary aquifer is estimated to be about 1142 years.

Cretaceous Aquifer

Two makeup water wells (designated as MU-1 and MU-2A) for VEGP Units 1 and 2 were reported to be capable of supplying water at 2,000 gal./min and 1,000 gal./min, respectively. The water is

withdrawn from the combined Cretaceous/Tertiary aquifers. Pumping tests were conducted at these wells in 1977. Transmissivity values ranged between 110,400 to 130,900 gallons per day per foot (gpd/ft). A storage coefficient was calculated at 1.07×10^{-4}.

A pumping test was also conducted in a Cretaceous aquifer test well identified as TW-1 during site characterization activities for VEGP Units 1 and 2. A transmissivity value of 158,000 gpd/ft was calculated as an average value for the aquifer. The storage coefficient ranged between 3.3×10^{-4} and 2.1×10^{-4}, indicating the aquifer is effectively under confined conditions.

Vertical hydraulic conductivities were estimated assuming that the anisotropy ratio between the vertical and horizontal directions is 1:3, based on measured horizontal and vertical hydraulic conductivities for sandstone deposits (Reference 268). The vertical hydraulic conductivities for the Water Table aquifer, Lisbon Formation confining unit, and Tertiary aquifer are estimated to be 0.14, 0.00045, and 0.28 ft/day, respectively.

2.4.12.2 Regional and Local Groundwater Use

Present groundwater uses within 25 mi of the VEGP site are primarily municipal, industrial, and agricultural. Most of the groundwater wells withdraw water from the Cretaceous aquifer. Apart from water withdrawals for VEGP Units 1 and 2, the immediate area near the VEGP site has mainly domestic users, with no other nearby large groundwater users. The nearest domestic well is located west of the VEGP site across River Road.

The Georgia Environmental Protection Division (EPD) issues permits for wells having average daily withdrawals that exceed 100,000 gpd during any single month. Table 2.4-247 lists the permitted groundwater users, aquifer and withdrawal rates, and annual average withdrawal rates for municipal and industrial wells within 25 mi of the VEGP site and permitted by the Georgia EDP. Table 2.4-248 lists similar data for agricultural wells for the counties within 25 mi of the VEGP site and permitted by the Georgia EPD. The Safe Drinking Water Information System (SDWIS) maintained by the US EPA lists community, non-transient non-community, and transient non-community water systems serving the public. Community water systems are defined as those that serve the same people year-round (e.g., in homes or businesses). Non-transient non-community water systems are those that serve the same people, but not year-round (e.g., schools that have their own water system). Transient non-community water systems are those that do not consistently serve the same people (e.g., rest stops, campground, gas stations). Table 2.4-249 lists the community, non-transient non-community, and transient non-community water systems using groundwater as their primary water source within 25 mi of the VEGP site.

The locations of the agricultural, industrial, and municipal wells permitted by the Georgia EPD along with the public water system wells listed in the SDWIS database within 25 mi of the VEGP site are shown in Figure 2.4-252. These data indicate the nearest permitted agricultural well (William Hatcher, A-28) to be about 3.4 mi northwest of the VEGP site, while the nearest permitted industrial well (International Paper, I-1) is about 8.5 mi northwest of the site. The nearest municipal well (City of Waynesboro, M-1) is seen to be about 14.5 mi west-southwest of the VEGP site. The nearest SDWIS-listed well (Dealigle Mobile Home Park, C-6) is about 4.9 mi southwest of the VEGP site These wells are sufficiently distant from the VEGP site such that pumping these wells would have no effect on groundwater levels at the VEGP site. The recharge areas for the source aquifers for the nearest Georgia EPD-permitted wells are in their outcrop areas located up-gradient of the VEGP site and beyond the influence of the new units.

Regionally, projected overall water use is expected to increase through 2035 for Burke County. Surface water usage is increasing; however, it is increasing at a much slower rate than groundwater usage, approximately 5 percent versus 17 percent. Burke County's water usage, including both surface and groundwater, is projected as 100 to 120 mgpd for 2035 (Reference 267). Projections for

Burke County total water use in 2050 are provided in the Comprehensive Water Supply Management Plan for Burke County and its Municipalities (Reference 284). Assuming the same water usage patterns, groundwater demand with the population increasing to 43,420 people is projected to be 10.94 mgpd for domestic use, 14.73 mgpd for industrial use, and 40.96 mgpd for agricultural use, which totals 66.63 mgpd (Reference 284).

Local groundwater use includes domestic wells and wells supplying water to existing VEGP Units 1 and 2. Operating plant uses include makeup process water, utility water, potable water, and supply for the fire protection system. Table 2.4-250 lists these wells, while Figure 2.4-253 identifies their location. Current permitted withdrawal rates are a monthly average of 6 mgpd and an annual average of 5.5 mgpd, as permitted by the Georgia EPD. Three of the wells are in the Cretaceous aquifer at depths varying from 851 to 884 ft, with design yields of 1,000 to 2,000 gpm. These wells provide makeup water for the plant processes. The remaining six wells extend into the Tertiary aquifer, range in depth from 200 to 370 ft, and have design yields of 20 to 150 gpm. Average annual usage levels for 1999 to 2004 from all wells excluding SEC are from 0.79 to 1.44 mgpd (Reference 287). The SEC well was added in 2005 and will be included on water usage data from 2006. Recent groundwater usage from June 2005 to December 2005 is in Table 2.4-251.

Table 2.4-252 shows projected groundwater use for two AP1000 units with normal and maximum usage values. Service water system make-up, potable water system, demineralized water system, fire protection system, and miscellaneous users are the intended uses. Groundwater needed to supply VEGP Units 3 and 4 will be obtained from two 1,500 gpm wells installed in the Cretaceous aquifer. The maximum case water demand is conservatively based on several plant operating modes, which are not expected to operate concurrently. Based on the wells that currently supply makeup water for plant processes for the existing Units 1 and 2 (MU-1 and MU-2A) the proposed wells will extend to a depth of approximately 850 ft below the ground surface and will be open to selected aquifer zones within the Cretaceous aquifer. The proposed locations of the new wells are shown on Figure 2.4-260. SNC's groundwater use permit (Reference 287) will be modified accordingly.

2.4.12.3 Monitoring or Safeguard Requirements

Groundwater monitoring for the VEGP site takes place through programs implemented both for the existing units and VEGP Units 3 and 4 COL. Current groundwater monitoring programs for the existing units are addressed in VEGP Procedure Number 30140-C, Revision 22 (Reference 290). The results of these programs are reported semiannually.

As part of detailed engineering, the existing SNC groundwater monitoring programs were evaluated with respect to placement of the new units to determine if any additional monitoring of existing or construction of new observation wells would be required to adequately monitor impacts on groundwater. This evaluation included a review of the observation wells installed for the ESP application to determine if they could be used as part of any longer-term groundwater monitoring program.

The existing SNC groundwater monitoring programs are evaluated with respect to placement of the new units in Subsection 2.4.12.3.1 below.

2.4.12.3.1 Long Term Groundwater Level Monitoring

Subsection 2.4.12.3 indicates that the existing groundwater monitoring programs would be evaluated to determine if any additional monitoring of existing observation wells or construction of new observation wells would be required to adequately monitor the impact on groundwater. The results of the evaluation indicate that the long term collection of Units 3 and 4 water table level data is

appropriate to confirm the direction of groundwater flow in the vicinity of the power blocks of Units 3 and 4.

Groundwater level data will be collected from a network of observation wells similar to that utilized for the ESP phase (June 2005 through July 2007) to ensure the data is comparable to that of the ESP phase. Most of the active Units 1 and 2 observation wells that were included in the ESPA data will not be impacted by the earth moving activities for Units 3 and 4. However, most of the remainder of the ESPA observation wells will be impacted by these earthwork activities. The number and location of the replacement wells to be installed for long term monitoring will be determined after the earthwork activities are complete and heavy construction is well underway. Some of these observation wells will be installed in the Units 3 and 4 power block areas.

Groundwater level monitoring will be initiated prior to commercial operation of Unit 3 and revised as needed based upon the review and evaluation of the observed data.

Safeguards will be used to minimize the potential for adverse impacts to the groundwater by construction and operation of the new units. These safeguards could include the use of lined containment structures around storage tanks and hazardous materials storage areas, emergency cleanup procedures to capture and remove surface containments, and other measures deemed necessary to prevent or minimize adverse impacts to the groundwater beneath the VEGP site.

2.4.12.4 Design Basis for Subsurface Hydrostatic Loading

The design basis for subsurface hydrostatic loading for existing VEGP Units 1 and 2 is El. 165 ft msl. For new VEGP Units 3 and 4, the design basis for groundwater-induced loadings on subsurface portions of safety-related structures, systems, and components is also El. 165 ft msl as discussed in Subsection 2.5.4.6. Note that the lowest elevation of a safety-related structure, system, or component is El. 180.5 ft msl (bottom elevation of the containment building slab). This elevation is about 20 to 30 ft above the highest water table elevation recorded in the power block area based on the contours plotted in Figures 2.4-241 through 2.4-245, Figure 2.4-257, and Figures 2.4-261 and 2.4-262.

A two-dimensional, site specific, single layer numerical groundwater model was developed to predict the effects of VEGP Units 3 and 4 construction on the Water Table aquifer flow regime. To predict post-construction groundwater flow conditions, the model accounts for the different hydraulic conductivity value of the fill material associated with the excavated areas for Units 3 & 4, as well as changes in groundwater recharge due to building and parking lot construction, regrading, and assumed changes in vegetative cover patterns. The results of this model indicate that the post-construction Water Table aquifer elevation in the power block area at OW-1003 is approximately 0.5 feet higher than calibrated pre-construction levels, or approximately 157.9 ft msl. This elevation is approximately 22 ft below the bottom elevation of the containment building slab. Because the subsurface portions of all safety-related structures, systems, and components are well above the highest recorded water table elevations, there will be no groundwater-induced loadings. No permanent dewatering system will be required to lower the design basis groundwater level. No wells will be used for safety-related purposes.

2.4.13 Accidental Releases of Liquid Effluents in Ground and Surface Waters

2.4.13.1 Groundwater

This section provides a conservative analysis of a postulated, accidental liquid release of effluents to the groundwater at the VEGP site. The accident scenario is described. The conceptual model used to evaluate radionuclide transport is presented, along with potential pathways of contamination to water users. The radionuclide transport analysis is described, and the results are summarized. The

radionuclide concentrations to which a water user might be exposed are compared against the regulatory limits.

Results are considered acceptable if the concentrations are less than the effluent concentration limits (ECLs) included in 10 CFR Part 20, Appendix B, Table 2, Column 2. Because the identity and concentration of each radionuclide in the mixture are known, the ratio present in the mixture and the concentration otherwise established in 10 CFR Part 20, Appendix B, for the specific radionuclide not in a mixture must also be determined. The sum of such ratios for all of the radionuclides in the mixture may not exceed “1” (i.e., “unity”). These criteria apply to the nearest potable water supply in an unrestricted area.

2.4.13.1.1 Accident Scenario

The accident scenario has been selected based on information developed by Westinghouse to assist AP1000 COL applicants in evaluating the accidental liquid release of effluents (Reference 301). The accident scenario assumes an instantaneous release from one of the two effluent holdup tanks located in the lowest level of the AP1000 auxiliary building.

There are two effluent holdup tanks, each with a capacity of 28,000 gal., for each AP1000 unit. These tanks have both the highest potential radionuclide concentrations and the largest volume. Therefore, they have been selected by Westinghouse as the limiting tanks for evaluating an accidental release of liquid effluents that could lead to the most adverse contamination of groundwater or surface water, via the groundwater pathway.

Westinghouse estimated the radionuclide concentrations of the effluent holdup tanks to be 101 percent of the reactor coolant. Westinghouse determined the radionuclide concentrations in reactor coolant itself to be as follows:

- For tritium (H-3), a coolant concentration of 1.0 µCi/g should be used.
- Corrosion products (Cr-51, Mn-54, Mn-56, Fe-55, Fe-59, Co-58 and Co-60) should be taken directly from the AP1000 DCD, Table 11.1-2, *Design Basis Reactor Coolant Activity*.
- Other radionuclides should be based on the AP1000 DCD, Table 11.1-2 multiplied by 0.12/0.25 to adjust the failed fuel rate from the design basis to a conservatively bounding value for this analysis.

Based on these recommendations, the expected radionuclide concentrations in the effluent holdup tanks have been calculated, and the results are summarized in Table 2.4-257.

2.4.13.1.2 Conceptual Model

Figures 2.4-265 and 2.4-266 illustrate the conceptual models used to evaluate an accidental liquid release of effluent to groundwater, or to surface water via the groundwater pathway. The key elements and assumptions embodied in the conceptual model are described and discussed below.

2.4.13.1.2.1 Water Table Aquifer

As indicated in Subsection 2.4.13.1.1, the effluent holdup tanks are assumed to be the source of the release, with each tank having a volume of 28,000 gal. and the radionuclide concentrations as summarized in Table 2.4-257. These tanks are located at the lowest level of the auxiliary building, which has a floor elevation of approximately 186.5 ft msl and is approximately 25 to 35 ft above the water table, based on water table contour plots presented on Figures 2.4-241 through 2.4-245, Figure 2.4-257, and Figures 2.4-261 to 2.4-262. One of these tanks is postulated to rupture, and 80

percent of the liquid volume (22,400 gal.) is assumed to be released in accordance with Branch Technical Position 11-6 of NUREG-0800. Flow from a tank rupture would initially flood the tank room and begin to flow to the auxiliary building radiologically controlled area sump via floor drains as described in Subsection 3.4.1.2.2.2 of the AP1000 DCD. It is assumed that sump pumps are inoperable. According to the AP1000 DCD, this would result in the 22,400 gal. release flooding the balance of level 1 of the auxiliary building via the interconnecting floor drains. Once level 1 is flooded, it is assumed that a pathway is created that would allow the entire 22,400 gal. to enter the groundwater (Water Table aquifer) instantaneously. This assumption is very conservative because it requires failure of the floor drain system, plus it ignores the barriers presented by the 6-ft-thick basemat and the sealed, 3-ft-thick exterior walls of the AP1000 auxiliary building. Furthermore, there is a minimum of 20 ft of unsaturated zone beneath the basemat. Radionuclide concentrations would be attenuated during unsaturated zone transport as a consequence of adsorption, dispersion, and radioactive decay, which is not considered in this conservative analysis.

With the postulated instantaneous release of the contents of an effluent holdup tank to groundwater, radionuclides would enter the Water Table aquifer and migrate with the groundwater in the direction of decreasing hydraulic head. Hydraulic head contour maps for the Water Table aquifer presented in Figures 2.4-241 through 2.4-245, Figure 2.4-257, and Figures 2.4-261 to 2.4-262 indicate that the pre-construction groundwater pathway from a point of release in either of the AP1000 auxiliary buildings would be northward to Mallard Pond, a groundwater discharge area, as discussed in Subsection 2.4.12.1.3. Because the underlying Blue Bluff Marl has a very low vertical permeability, as is described in Subsection 2.4.12, groundwater flow in the Water Table aquifer is predominantly horizontal. Since VEGP Unit 4 is closer to Mallard Pond, it is selected as the release location for this evaluation. Post-construction groundwater modeling described in Appendix 2.4B was conducted to reflect the hydrologic alterations associated with the construction of VEGP Units 3 and 4. Modeling results indicate that the groundwater pathway will still be northward toward Mallard Pond after construction of the new units. Particle tracking results show the flow path to be curvilinear between the VEGP Unit 4 auxiliary building and the south side of Mallard Pond. During saturated zone transport, radionuclide concentrations of the liquid released to the water table would be reduced by the processes of adsorption, hydrodynamic dispersion, and radioactive decay. There are no existing water-supply wells between the postulated release points and Mallard Pond that withdraw water from the Water Table aquifer. Based on the data in Table 2.4-250, all water-supply wells for the existing VEGP plant withdraw their water from the deeper, confined Tertiary and Cretaceous aquifers. Figure 2.4-237 illustrates the conceptual model for evaluating radionuclide transport in the Water Table aquifer.

Mallard Pond serves as a groundwater discharge area for the Water Table aquifer. The radionuclides associated with a liquid release would enter the surface water system via Mallard Pond. Radionuclide concentrations would be diluted in the pond and in the stream running from the pond to the Savannah River. Groundwater flow into Mallard Pond is continuous, and the pond level is controlled by a spillway. Measurements of stream flow discharge from Mallard Pond and at points downstream indicate that flow increases progressively in magnitude before discharging to the Savannah River (Reference 294). Upon discharge to the Savannah River, the stream flow would mix with the Savannah River flow, resulting in significantly further dilution prior to withdrawal by the nearest surface water user. As noted in Subsection 2.4.1, the nearest downstream industrial surface water users include the Fort James Operating Company and the Georgia Power Company. Both companies operate river intakes that withdraw water from the Savannah River near River Mile 45, which is about 106 miles downstream of the VEGP site. The City of Savannah Municipal and Industrial Plant, and the Beaufort-Jasper County Water and Sewer Authority are the nearest downstream municipal water users. The City of Savannah obtains water from Abercorn Creek where it enters the Savannah River near River Mile 29, which is about 122 miles downstream from the VEGP site. Beaufort-Jasper County withdraws water from the Savannah River via an 18-mile canal.

2.4.13.1.2.2 Tertiary Aquifer

An alternative, less likely, conceptual model is also considered in this analysis. This model considers groundwater flow in the deeper Tertiary aquifer with eventual direct discharge to the Savannah River (Figure 2.4-266). Based on Table 2.4-250 and Figure 2.4-253, there are no existing VEGP plant Tertiary aquifer potable water-supply wells located downgradient of the postulated accidental release or any potable wells potentially impacted by such a release. The release mechanism is the same as that described in Subsection 2.4.13.1.2.1 for the Water Table aquifer with the exception that the accidental release is assumed to enter the Tertiary aquifer instantaneously. This conceptual model is conservative because the low permeability Blue Bluff Marl hydraulically isolates the overlying Water Table aquifer from the underlying Tertiary aquifer. The flow path is assumed to be a straight line between the center of the power block area for the new AP1000 units downgradient to the closest point of the Savannah River, a distance of approximately 5600 ft. Upon discharge to the Savannah River, contaminated groundwater would mix with the Savannah River flow, resulting in significant dilution prior to withdrawal by the nearest surface water user described in Subsection 2.4.13.1.2.1. Figure 2.4-266 illustrates the conceptual model for evaluating radionuclide transport in the Tertiary aquifer.

2.4.13.1.3 Radionuclide Transport Analysis

A radionuclide transport analysis has been conducted to estimate the radionuclide concentrations that might expose existing and future water users based on an instantaneous release of the radioactive liquid of an AP1000 effluent holdup tank. Analysis of liquid effluent release commenced with the simplest of models, using demonstratively conservative assumptions and coefficients. Radionuclide concentrations resulting from the preliminary analysis were then compared against the ECLs identified in 10 CFR Part 20, Appendix B, Table 2, Column 2, to determine acceptability. Further analysis, using progressively more realistic and less conservative assumptions and modeling techniques, was conducted when the preliminary results do not meet 10 CFR Part 20 requirements.

Radionuclide transport along a groundwater path line is governed by the advection-dispersion-reaction equation (Reference 295), which is given as

$$R\frac{\partial C}{\partial t} = D\frac{\partial^2 C}{\partial x^2} - v\frac{\partial C}{\partial x} - \lambda RC \qquad \text{(Equation 2.4.13-1)}$$

where: C = radionuclide concentration; R = retardation factor; D = coefficient of longitudinal hydrodynamic dispersion; v = average linear velocity; and λ = radioactive decay constant. The retardation factor is defined from the relationship

$$R = 1 + \frac{\rho_b K_d}{n_e} \qquad \text{(Equation 2.4.13-2)}$$

where: ρ_b = bulk density; K_d = distribution coefficient; and n_e = effective porosity. The average linear velocity is determined using Darcy's law, which is

$$v = -\frac{K}{n_e}\frac{dh}{dx} \qquad \text{(Equation 2.4.13-3)}$$

where: K = hydraulic conductivity; and dh/dx = hydraulic gradient. The radioactive decay constant can be written as

$$\lambda = \frac{\ln 2}{t_{1/2}} \qquad \text{(Equation 2.4.13-4)}$$

where $t_{1/2}$ = radionuclide half-life. Conservatively neglecting hydrodynamic dispersion, Equation 2.4.13-1 can be integrated to yield

$$C = C_0 \exp(-\lambda t) \qquad \text{(Equation 2.4.13-5)}$$

where: C = radionuclide concentration; C_0 = initial radionuclide concentration; $t = LR/v$ = radionuclide travel time; and L = groundwater path line length.

To estimate the radionuclide concentrations in the Water Table aquifer, groundwater discharging to Mallard Pond, Equation 2.4.13-5 was applied along the groundwater path line that would originate at the liquid effluent release points beneath the AP1000 auxiliary building at VEGP Unit 4 and terminate at Mallard Pond. For the Tertiary aquifer, Equation 2.4.13-5 was similarly applied along the groundwater path line from the center of the power block area for the new AP1000 units downgradient to the discharge point in the Savannah River. These analyses were performed sequentially as described below.

2.4.13.1.3.1 Water Table Aquifer

Transport Considering Radioactive Decay Only

An initial screening analysis was performed considering radioactive decay only. This analysis assumed that all radionuclides migrate at the same rate as groundwater and considered no adsorption and retardation, which would otherwise result in a longer travel time and more radioactive decay. The concentrations of the radionuclides appearing in Table 2.4-257 were decayed for a period equal to the groundwater travel time from the point of release to Mallard Pond, using Equation 2.4.13-5 with R = 1. Radionuclides having concentrations less than 1 percent of their respective ECLs were eliminated from consideration because their concentrations would be well below their regulatory limits. Any radionuclides having a concentration greater than or equal to 1 percent of their ECL were retained for further evaluation. Evaluating transport considering radioactive decay only requires an estimate of the groundwater travel time.

The groundwater travel time from the VEGP Unit 4 Auxiliary Building to Mallard Pond has been estimated using a two-dimensional groundwater flow model (Appendix 2.4B) considering the locations of the effluent holdup tanks, and modeled estimates of hydraulic gradients and hydraulic conductivities of the Water Table aquifer and construction backfill material. The total saturated zone travel time was determined to be 6.7 years. The travel times in the various hydrogeologic units encountered along the groundwater pathway are as follows: 2.4 years in the backfill; 3.2 years in the Water Table aquifer in the area between the backfill and a point near OW-1005 where more permeable sediments are present; and 1.1 years in the more permeable sediments present between OW-1005 and Mallard Pond.

Using Equation 2.4.13-5, the initial concentrations given in Table 2.4-257 were decayed for a period of 6.7 years. Table 2.4-258 summarizes the results considering only radioactive decay and identifies those radionuclides that would exceed 1 percent of their ECL. These include H-3, Mn-54, Fe-55, Co-60, Sr-90, Ag-110m, I-129, Cs-134, Cs-137, and Ce-144.

Transport Considering Radioactive Decay and Adsorption

The H-3, Mn-54, Fe-55, Co-60, Sr-90, Ag-110m, I-129, Cs-134, Cs-137, and Ce-144 retained from the radioactive decay screening analysis were further evaluated considering adsorption and retardation in addition to radioactive decay. Distribution coefficient values for Co, Sr, and Cs were determined based on laboratory analyses of soil samples obtained from the VEGP site (Reference 296; Reference 298) and are shown in Table 2.4-259. Sixteen soil samples were taken from shallow test pits located in potential borrow source areas for backfill that will be required for the

new AP1000 units. Laboratory testing of these backfill samples yielded distribution coefficients that range from 1.4 to 15.3 mL/g for Co, 6.0 to 51.7 mL/g for Sr, and 3.5 to 56.2 mL/g for Cs. Three additional soil samples were obtained from a vibratory boring located near B-1003. The samples acquired from the vibratory boring represent the Barnwell Group sediments based on the boring log for B-1003. Testing of the Barnwell Group sediment samples resulted in distribution coefficients that range from 3.9 to 21.3 mL/g for Co, 14.4 to 17.4 mL/g for Sr, and 22.7 to 33.2 mL/g for Cs.

Distribution coefficients for Co, Sr, and Cs in the backfill were conservatively assigned the minimum value determined from the 16 samples (1.4 mL/g for Co, 6.0 mL/g for Sr, and 3.5 mL/g for Cs). Distribution coefficients for Co, Sr, and Cs in the Barnwell Group sediments were conservatively assigned the minimum value observed for the three vibratory boring samples (3.9 mL/g for Co, 14.4 mL/g for Sr, and 22.7 mL/g for Cs). Distribution coefficients for H-3 and I-129, which have no or little tendency for adsorption, were taken to be zero for both the backfill and Barnwell Group sediments. Distribution coefficients for Mn-54, Fe-55, Ag-110m, and Ce-144 were conservatively assumed to be zero in both the backfill and the native Barnwell Group sediments. Distribution coefficients for the more permeable material near Mallard Pond were taken to be the same as those used for the native material in the Barnwell Group.

Retardation factors were calculated using Equation 2.4.13-2 with the distribution coefficients as stated above, effective porosities of 0.34 for the backfill, Barnwell Group sediments, and the permeable Mallard Pond materials, and a bulk density of 1.54 g/cm^3 for all materials. The bulk density was calculated using a total porosity value of 0.42 and a specific gravity of 2.66 as provided in Subsection 2.4.12.1.4. Total radionuclide travel times were calculated by summing the radionuclide travel times in the backfill, Barnwell Group, and permeable Mallard Pond materials described above. Radionuclide concentrations were then determined at the point of discharge to Mallard Pond using Equation 2.4.13-5 and the appropriate initial concentration, decay rate, and total travel time. Results are summarized in Table 2.4-260 and indicate that H-3, Mn-54, Fe-55, Sr-90, Ag-110m, I-129, Cs-137, and Ce-144 would exceed 1 percent of their respective ECL.

Transport Considering Radioactive Decay, Adsorption, and Dilution

The radionuclides retained after screening for the effects of radioactive decay and adsorption in groundwater would discharge to surface water (Mallard Pond) and mix with other, uncontaminated surface water. A dilution factor was estimated to account for the mixing and dilution of contaminated groundwater with uncontaminated surface waters. For the Water Table aquifer, the dilution factor is the ratio of the rate at which the postulated release would discharge to surface water (Mallard Pond) as contaminated groundwater to the total rate of groundwater discharge to Mallard Pond, which would include both uncontaminated and contaminated groundwater. The magnitude of the dilution factor was estimated as described below.

The rate at which a release from an effluent holdup tank discharges to surface water (Mallard Pond) is determined by the transport characteristics of the Water Table aquifer. A release from an effluent holdup tank would undergo unsaturated zone transport beneath the auxiliary building, followed by saturated zone transport first through the backfill and then through the Barnwell Group and more permeable Mallard Pond materials, and would finally discharge to Mallard Pond from the permeable Mallard Pond materials. The discharge rate itself is a function of the Darcy velocity, and the assumed volume and dimensions of the resulting contaminant slug. The mean Darcy velocity in the backfill was determined to be 0.043 ft/day based on a hydraulic conductivity of 3.3 ft/day and a hydraulic gradient of 0.013 ft/ft estimated from Appendix 2.4B, Figure 78. The volume of the liquid release has been assumed to be 22,400 gal. (2995 ft^3), which represents 80 percent of the 28,000 gal. capacity of one effluent holdup tank (NUREG-0800, Branch Technical Position 11-6 recommends that 80 percent of the liquid volume be considered in this analysis). Considering the effective porosity of the backfill (0.34), the release would occupy about 8810 ft^3 of the saturated backfill. The shape of the resulting contaminant slug is assumed to be square in plan view and extend vertically throughout the entire saturated thickness of the backfill. Using 20 ft as a representative saturated thickness (water

table to top of Blue Bluff Marl), the slug would have an area of about 440 ft^2 in plan view and a width of about 21 ft. The cross-sectional area of the contaminant slug normal to the groundwater flow direction would therefore be 20 ft by 21 ft or about 420 ft^2. The discharge rate of the contaminant slug is then the product of the Darcy velocity (0.043 ft/day) and the cross-sectional area (420 ft^2) or 18 ft^3/day (0.094 gpm). The rate of total groundwater discharge to surface water has been estimated as 1125 gpm at a point just downstream of the confluence of the stream discharging from Mallard Pond and its west branch. This value is the result of stream flow measurements that were taken in the months of June and July to support the licensing of VEGP Units 1 and 2 (Reference 294). Because the stream discharging from Mallard Pond and its west branch are both perennial streams, the stream flow measurements would represent the groundwater discharge. The resulting dilution factor at this location is calculated as the ratio of 0.094 gpm to 1125 gpm, or 8.3E-5.

This dilution factor is applied to the H-3, Mn-54, Fe-55, Sr-90, Ag-110m, I-129, Cs-137, and Ce-144 concentrations reported in Table 2.4-260 to account for dilution in addition to radioactive decay and adsorption. Table 2.4-261 summarizes the resulting concentrations, which would represent the concentrations in the surface water at a point just downstream of the confluence of the stream discharging from Mallard Pond and its west branch. It is seen that the concentrations of each of these radionuclides are below their respective ECLs.

2.4.13.1.3.2 Tertiary Aquifer

Transport Considering Radioactive Decay Only

As indicated in Subsection 2.4.12.1.4, the horizontal hydraulic gradient of the Tertiary aquifer is approximately 0.005 ft/ft, based on the water levels observed at well OW-1008 and Well 27, and the distance between the two observation wells. Tertiary aquifer travel time was calculated using a hydraulic conductivity of 0.83 ft/day as reported in Subsection 2.4.12.1.4 and Table 2.4-243, a hydraulic gradient of 0.005 ft/ft, and an effective porosity of 0.309 based on the site-specific investigation measurements presented in Subsections 2.4.12.1.3 and 2.4.12.1.4. Using a distance of 5600 ft from the center of the power block area for the new AP1000 units to the closest point of the Savannah River, the groundwater travel time from the power block area to the Savannah River in the Tertiary aquifer is estimated to be about 1142 years. Using Equation 2.4.12-5, the initial concentrations given in Table 2.4-257 were decayed for a period of 1142 years. Table 2.4-262 summarizes the results and identifies those radionuclides that would exceed 1 percent of their ECL. The only radionuclide exceeding 1 percent of its ECL is I-129. As with the Water Table aquifer, the distribution coefficient of I-129 is taken to be zero because it has little to no tendency for adsorption. Therefore, no credit is taken for I-129 adsorption, and the I-129 concentration discharging to the Savannah River from the Tertiary aquifer remains unchanged from that calculated in the radioactive decay screening analysis. As seen in Table 2.4-262, the calculated concentration is well below the ECL.

2.4.13.1.4 Compliance with 10 CFR Part 20

The radionuclide transport analysis presented in Subsection 2.4.13.1.3 demonstrates that all of the radionuclides that could be accidentally released to groundwater would be individually below their ECLs. However, 10 CFR Part 20, Appendix B, Table 2, imposes additional requirements when the identity and concentration of each radionuclide in a mixture are known. In this case, the ratio present in the mixture and the concentration otherwise established in 10 CFR Part 20 Appendix B for the specific radionuclide not in a mixture must be determined. The sum of such ratios for all of the radionuclides in the mixture may not exceed “1” (i.e., “unity”) as indicated by Note 4 in Appendix B, 10 CFR Part 20.

This sum of fractions approach was applied to the radionuclide concentrations conservatively estimated in Subsection 2.4.13.1.3. Results are summarized in Table 2.4-263 for the Water Table aquifer and Table 2.4-264 for the Tertiary aquifer. The ratios for the mixture sum to 0.058 for the

Water Table aquifer, which demonstrates that an accidental liquid release of effluents in groundwater would not exceed 10 CFR Part 20 limits in the Mallard Pond stream before reaching the VEGP site property (EAB). Compliance with 10 CFR Part 20 is further assured considering that the point at which compliance has been demonstrated is within the restricted area and not a potable water source. The stream discharging from Mallard Pond is a gaining stream that discharges to, and mixes with, the Savannah River. Nearly the entire reach of this stream, about 1.0 mi. in length, is within the restricted area and not a potable water supply. Downstream of the point where compliance has been demonstrated, the stream appears to enter the adjacent Hancock Landing property for a short distance before re-entering the VEGP site property and discharging into the Savannah River. The nearest potable water supply in an unrestricted area to which the 10 CFR Part 20 requirements would apply is the Savannah River. Mixing of the tributary stream flow with the Savannah River flow would dilute radionuclide concentrations further. The magnitude of this additional dilution can be estimated from the ratio of the tributary stream flow rate (1125 gpm) to the Savannah River flow rate. Using the 100-year drought flow, given as 3298 ft^3/sec (1,480,000 gpm) in Subsection 2.4.11, to conservatively represent the Savannah River flow rate, a dilution factor of 7.6E-04 is calculated. Accounting for this additional dilution would further reduce radionuclide concentrations by a factor of about 1,000. Consequently, the ratios for the mixture would sum to a value much less than unity and well below the compliance limit.

Considering radioactive decay only, the ratios for the mixture sum to 0.036 for the Tertiary aquifer prior to discharge in the Savannah River indicating compliance with 10 CFR Part 20 limits (Table 2.4-264). Mixing of the Tertiary aquifer discharge with the Savannah River flow would significantly dilute radionuclide concentrations further.

2.4.13.2 Surface Water

No outdoor tanks contain radioactivity in the Westinghouse AP1000 design (Reference 301). In particular, the AP1000 design does not require boron changes for load follow and does not recycle boric acid or reactor coolant water, so the boric acid tank is not radioactive. Because no outdoor tanks contain radioactivity, no accident scenario could result in the release of liquid effluent directly to the surface water.

2.4.14 Technical Specifications and Emergency Operation Requirements

The plant elevation (220 ft MSL) of the VEGP is above the design basis river flood elevation and the probable maximum precipitation flood elevation; therefore, due to design there are no requirements for emergency protective measures designed to minimize the impact of hydrology-related events on safety-related facilities, and none are incorporated into the technical specifications or emergency procedures.

2.4.15 Combined License Information

2.4.15.1 Hydrological Description

Major hydrologic features on or in the vicinity of the site are addressed in Subsection 2.4.1.

2.4.15.2 Floods

Site-specific information on historical flooding and potential flooding factors is addressed in Subsections 2.4.2, 2.4.3, 2.4.4, 2.4.5, 2.4.6, and 2.4.10.

2.4.15.3 Cooling Water Supply

The water supply sources to provide makeup water to the service water system cooling tower are addressed in Subsection 2.4.12.

2.4.15.4 Groundwater

Site-specific information on groundwater is addressed in Subsection 2.4.12.

2.4.15.5 Accidental Release of Liquid Effluents in Ground and Surface Water

Site-specific information on the ability of the ground and surface water to disperse, dilute, or concentrate accidental releases of liquid effluents, and the effects of these releases on existing and known future use of surface water resources are addressed in Subsection 2.4.13.

2.4.15.6 Emergency Operation Requirement

Flood protection emergency procedures required to meet the site parameter for flood level are addressed in Subsection 2.4.14.

2.4.16 References

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Table 2.4-201
Rainfall Depths Used as Input for Frequency Storm HEC-HMS Module

Duration, Minutes	Depth, Inches
5	6.20[a]
15	9.80[a]
30	14.10[a]
60	19.20[a]
120	23.52[b]
180	25.95[b]
360	31.00[a]

a) Calculated with HMR 51/52
b) Calculated by curve fitting

Table 2.4-202 (Sheet 1 of 2)
Subbasin Parameters for Entry in Unit 3 & 4 Drainage System HEC-HMS Model

Sub-Basin	Sub-Basin Area		Runoff Curve No.	Base Flow	Base Flow	T_c	Lag
	Acres	Sq. mi.		0:no, 1:yes	Cfs	Min	Min
Units 1&2 Sub-Basin HEC-HMS Input Parameters							
S2A	2.36	0.00368	98	0	0.0	5.0	3.0
S2B	2.36	0.00368	98	0	0.0	5.0	3.0
S3	5.96	0.00931	98	0	0.0	5.0	3.0
SW	7.49	0.0117	98	0	0.0	5.0	3.0
WF1-2	1.03	0.00162	98	0	0.0	5.0	3.0
WF2-2	2.61	0.00408	98	0	0.0	5.0	3.0
W1	3.04	0.00474	98	0	0.0	5.0	3.0
W2	5.83	0.00911	98	0	0.0	5.0	3.0
W3	6.13	0.00958	98	0	0.0	5.0	3.0
W4	8.15	0.01274	98	0	0.0	5.0	3.0
NW	1.76	0.00275	98	0	0.0	5.0	3.0
NE-1	2.21	0.00345	98	0	0.0	5.0	3.0
NE-2	13.36	0.02088	98	0	0.0	7.2	4.3
NE-3	22.43	0.03505	98	0	0.0	10.3	6.2
NE-4	19.31	0.03017	98	0	0.0	11.5	6.9
Totals	104.03	0.16254			0.0		
Units 3&4 Sub-Basin HEC-HMS Input Parameters							
M1S	6.05	0.00945	98	0	0.0	5.0	3.0
M1W	11.45	0.01789	98	0	0.0	5.0	3.0
FD1WA	8.32	0.01300	98	0	0.0	5.0	3.0
FD1WB	5.90	0.00922	98	0	0.0	5.0	3.0
M2E	4.79	0.00748	98	0	0.0	5.0	3.0
M2S	16.79	0.02623	98	0	0.0	16.1	9.7
M2W	5.89	0.00920	98	0	0.0	5.0	3.0
FD2E	6.62	0.01034	98	0	0.0	5.0	3.0
FD2W	9.61	0.01502	98	0	0.0	5.0	3.0
M3E	8.96	0.01400	98	0	0.0	5.0	3.0
M3S	19.78	0.03091	98	0	0.0	12.0	7.2
M3W	13.56	0.02119	98	1	2.1	9.0	5.4
FD3E	14.32	0.02238	98	0	0.0	5.0	3.0
FD3W	20.27	0.03167	98	1	3.2	13.8	8.3
LD2	8.17	0.01277	98	1	1.3	5.0	3.0
LD3	2.47	0.00386	98	1	0.4	5.0	3.0
M4W	2.11	0.00330	98	1	0.3	5.0	3.0

Table 2.4-202 (Sheet 2 of 2)
Subbasin Parameters for Entry in Unit 3 & 4 Drainage System HEC-HMS Model

Sub-Basin	Sub-Basin Area		Runoff Curve No.	Base Flow	Base Flow	T_c	Lag
	Acres	Sq. mi.		0:no, 1:yes	Cfs	Min	Min
Units 3&4 Sub-Basin HEC-HMS Input Parameters (continued)							
M5W	7.62	0.01191	98	1	1.2	5.0	3.0
FD5aN	13.26	0.02072	98	0	0.0	5.0	3.0
M6E	17.73	0.02770	98	0	0.0	7.8	4.7
M6W	9.38	0.01466	98	1	1.5	5.0	3.0
LD4	2.45	0.00383	98	1	0.4	5.0	3.0
FD6bE	13.88	0.02169	98	1	2.2	16.9	10.2
FD6aE	9.80	0.01531	98	1	1.5	13.0	7.8
M7E	13.11	0.02048	98	1	2.0	13.0	7.8
M7W	6.94	0.01084	98	1	1.1	5.0	3.0
LD5	1.32	0.00206	98	1	0.2	5.0	3.0
M8Cat	34.45	0.05383	98	1	5.4	13.1	7.9
M8W	7.90	0.01234	98	1	1.2	5.0	3.0
Totals	302.90	0.47328			24.0		

Table 2.4-203
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Table 2.4-204 (Sheet 1 of 2)
Summary of Results of HEC-HMS Model of Unit 3 & 4 PMP Drainage System

Element	Area, mi^2	Q_{peak}, cfs	Time of peak*	Runoff	
				inches	ac-ft
Units 1&2 HEC-HMS Summary Output					
W1	0.00474	196.3	21Jun2017, 03:05	30.68	7.76
WF2-2	0.00408	169	21Jun2017, 03:05	30.68	6.68
WF1-2	0.00162	67.1	21Jun2017, 03:05	30.68	2.65
W1WF12	0.01044	432.4	21Jun2017, 03:05	30.68	17.08
W2	0.00911	377.3	21Jun2017, 03:05	30.68	14.91
W12WF12	0.01955	809.6	21Jun2017, 03:05	30.68	31.99
W3	0.00958	396.7	21Jun2017, 03:05	30.68	15.67
W123	0.02913	1206.4	21Jun2017, 03:05	30.68	47.66
W4	0.01274	527.6	21Jun2017, 03:05	30.68	20.84
W1234WF12	0.04187	1734	21Jun2017, 03:05	30.68	68.51
NW	0.00275	113.9	21Jun2017, 03:05	30.68	4.5
W1234&NW	0.04462	1847.9	21Jun2017, 03:05	30.68	73.01
WN-NE5	0.04462	1847.9	21Jun2017, 03:05	30.68	73.01
NE-4	0.03017	910.4	21Jun2017, 03:09	30.68	49.36
WN-NE45	0.07479	2542.5	21Jun2017, 03:05	30.68	122.37
NE-3	0.03505	1114.1	21Jun2017, 03:08	30.68	57.35
WN-NE345	0.10984	3553.3	21Jun2017, 03:06	30.68	179.72
NE-2	0.02088	772.4	21Jun2017, 03:06	30.68	34.16
WN-NE2345	0.13072	4325.7	21Jun2017, 03:06	30.68	213.88
NE-1	0.00345	142.9	21Jun2017, 03:05	30.68	5.64
WN-NE12345	0.13417	4461.3	21Jun2017, 03:06	30.68	219.52
S3	0.00931	385.6	21Jun2017, 03:05	30.68	15.23
S2B	0.003685	152.6	21Jun2017, 03:05	30.68	6.03
S2A	0.003685	152.6	21Jun2017, 03:05	30.68	6.03
S1B2	0.00737	305.2	21Jun2017, 03:05	30.68	12.06
S1B23	0.01668	690.8	21Jun2017, 03:05	30.68	27.29
SW	0.0117	484.5	21Jun2017, 03:05	30.68	19.14
S1B23SW	0.02838	1175.3	21Jun2017, 03:05	30.68	46.43
Units 3&4 HEC-HMS Summary Output					
M0	0.009453	391.5	21Jun2017, 03:05	30.68	15.47
FD2W	0.015016	621.9	21Jun2017, 03:05	30.68	24.57
FD1WB	0.009219	381.8	21Jun2017, 03:05	30.68	15.08
M1	0.049563	2052.6	21Jun2017, 03:05	30.68	81.09
M2	0.117844	4222.7	21Jun2017, 03:05	30.68	192.82
M3	0.237985	7665.8	21Jun2017, 03:06	30.92	392.46
FD1WA	0.013	538.4	21Jun2017, 03:05	30.68	21.27
M4	0.254047	8305.5	21Jun2017, 03:05	30.97	419.66
FDW1-AB	0.022219	920.2	21Jun2017, 03:05	30.68	36.35
M5	0.273641	9119	21Jun2017, 03:05	31.03	452.88
M6	0.288297	9727.5	21Jun2017, 03:05	31.07	477.73

* for an assumed start of storm time of 21 Jun 2017, 0:00 hours

Table 2.4-204 (Sheet 2 of 2)
Summary of Results of HEC-HMS Model of Unit 3 & 4 PMP Drainage System

Element	Area, mi^2	Q_{peak}, cfs	Time of peak*	Runoff	
				inches	ac-ft
Units 3&4 HEC-HMS Summary Output (continued)					
M3S	0.030906	916.1	21Jun2017, 03:09	30.68	50.57
FD6bE	0.021688	544.5	21Jun2017, 03:12	31.78	36.76
FD6aE	0.015313	436.8	21Jun2017, 03:10	31.74	25.92
FD6b	0.042406	1197.8	21Jun2017, 03:05	31.24	70.66
FD5aN	0.020719	858	21Jun2017, 03:05	30.68	33.9
FD6a	0.057719	1551.8	21Jun2017, 03:06	31.37	96.58
M7E	0.020484	584.3	21Jun2017, 03:10	31.74	34.67
M6E	0.027703	983.8	21Jun2017, 03:07	30.68	45.33
FD6_ab7E	0.105906	3030.4	21Jun2017, 03:07	31.26	176.58
M7W	0.010844	450.2	21Jun2017, 03:05	31.78	18.38
FD3_M3E	0.068047	2120.5	21Jun2017, 03:06	31.19	113.19
M1S	0.009453	391.5	21Jun2017, 03:05	30.68	15.47
M5W	0.011906	494.3	21Jun2017, 03:05	31.77	20.18
FD3E	0.022375	926.6	21Jun2017, 03:05	30.68	36.61
M3W	0.021188	717.2	21Jun2017, 03:07	31.75	35.88
M1W	0.017891	740.9	21Jun2017, 03:05	30.68	29.27
RROF2	0.016063	666.8	21Jun2017, 03:05	31.76	27.21
RROF4	0.014656	608.5	21Jun2017, 03:05	31.79	24.85
RROF3	0.019594	813.5	21Jun2017, 03:05	31.79	33.22
RROF5	0.012906	535.8	21Jun2017, 03:05	31.77	21.87
M2E	0.007484	310	21Jun2017, 03:05	30.68	12.25
FD3W	0.031672	879.8	21Jun2017, 03:10	31.77	53.67
M2S	0.026234	671.7	21Jun2017, 03:11	30.68	42.92
M6W	0.014656	608.5	21Jun2017, 03:05	31.79	24.85
FD2E	0.010344	428.4	21Jun2017, 03:05	30.68	16.92
M4W	0.003297	136.8	21Jun2017, 03:05	31.67	5.57
FD1	0.013	538.4	21Jun2017, 03:05	30.68	21.27
M2W	0.009203	381.1	21Jun2017, 03:05	30.68	15.06
FD3	0.054047	1570.2	21Jun2017, 03:06	31.32	90.28
FD2	0.025359	1050.2	21Jun2017, 03:05	30.68	41.49
LD3	0.003859	160.2	21Jun2017, 03:05	31.8	6.55
LD2	0.012766	530	21Jun2017, 03:05	31.78	21.64
LD5	0.002063	85.6	21Jun2017, 03:05	31.73	3.49
LD4	0.003828	158.9	21Jun2017, 03:05	31.81	6.49
M3E	0.014	579.8	21Jun2017, 03:05	30.68	22.91
M7	0.40711	13164.6	21Jun2017, 03:06	31.14	676.18
M8	0.473282	14885.7	21Jun2017, 03:06	31.23	788.27
M8Cat	0.053828	1528.1	21Jun2017, 03:10	31.77	91.2
M8W	0.012344	512.4	21Jun2017, 03:05	31.73	20.89

* for an assumed start of storm time of 21 Jun 2017, 0:00 hours

Table 2.4-205 (Sheet 1 of 2)
HEC-RAS Flow Hydrograph Input Location

Ditch	Reach	Cross Section River Station	HEC-HMS Flow Hydrograph	HEC-HMS Model
Units 3&4 HEC-RAS Model				
100-Year	Main Reach-0	73.00	S2A	Units 1&2
100-Year	Main Reach-0	69.00	S2B	Units 1&2
100-Year	Main Reach-0	62.00	S3	Units 1&2
100-Year	Main Reach-0	59.00	SW	Units 1&2
100-Year	Main Reach-0	52.80*	M1S	Units 3&4
100-Year	Main Reach-1	44.00	M1W	Units 3&4
100-Year	Main Reach-1	39.00	M2S	Units 3&4
100-Year	Main Reach-2	37.00	M3S	Units 3&4
100-Year	Main Reach-3	24.89	M3W	Units 3&4
100-Year	Main Reach-3	22.00	RROF2	Units 3&4
100-Year	Main Reach-3	18.00	RROF3	Units 3&4
100-Year	Main Reach-3	14.00	M6W	Units 3&4
100-Year	Main Reach-5	10.00	LD5	Units 3&4
100-Year	Main Reach-5	9.00	M7W	Units 3&4
100-Year	Main Reach-6	6.00	M8W	Units 3&4
100-Year	Main Reach-6	3.00	M8Cat	Units 3&4
Feeder Ditch-1	Feeder Reach-1	12.00	FD1WA	Units 3&4
Feeder Ditch-1	Feeder Reach-1	11.50	FD1WB	Units 3&4
Feeder Ditch-2	Feeder Reach-2	8.00	FD2	Units 3&4
Feeder Ditch-2	Feeder Reach-2	1.80	M2W	Units 3&4
Feeder Ditch-2	Feeder Reach-2	1.70	M2E	Units 3&4
Feeder Ditch-3	Feeder Reach-3	11.00	FD3E	Units 3&4
Feeder Ditch-3	Feeder Reach-3	5.00	FD3W	Units 3&4
Feeder Ditch-3	Feeder Reach-3	1.00	M3E	Units 3&4
Feeder Ditch-6	Feeder Reach-6	21.00	FD6bE	Units 3&4
Feeder Ditch-6	Feeder Reach-6	20.00	FD5aN	Units 3&4
Feeder Ditch-6	Feeder Reach-6	19.00	FD6aE	Units 3&4
Feeder Ditch-6	Feeder Reach-6	10.00	M7E	Units 3&4
Feeder Ditch-6	Feeder Reach-6	9.00	M6E	Units 3&4

* Interpolated cross section

Table 2.4-205 (Sheet 2 of 2)
HEC-RAS Flow Hydrograph Input Location

Ditch	Reach	Cross Section River Station	HEC-HMS Flow Hydrograph	HEC-HMS Model
Units 1&2 HEC-RAS Model				
Northeast Ditch	1	33.00	WF2-2	Units 1&2
Northeast Ditch	1	32.00	W1	Units 1&2
Northeast Ditch	1	30.00	WF1-2	Units 1&2
Northeast Ditch	1	29.00	W2	Units 1&2
Northeast Ditch	1	24.50	W3	Units 1&2
Northeast Ditch	1	17.00	W4	Units 1&2
Northeast Ditch	1	16.50	NW	Units 1&2
Northeast Ditch	1	9.00	NE-4	Units 1&2
Northeast Ditch	1	6.00	NE-3	Units 1&2
Northeast Ditch	1	3.00	NE-2	Units 1&2
Northeast Ditch	1	1.45454*	NE-1	Units 1&2

* Interpolated cross section

Table 2.4-206
Deleted

Table 2.4-207 (Sheet 1 of 5)
Summary of HEC-RAS output for PMP Profile

Reach	River Sta	Profile	Q Total	Min Ch El	W.S. Elev	Crit W.S.	E.G. Elev	E.G. Slope	Vel Chnl	Flow Area	Top Width	Froude # Chl
			(cfs)	(ft)	(ft)	(ft)	(ft)	(ft/ft)	(ft/s)	(sq ft)	(ft)	
Units 3&4 100-Year Ditch Main Reach 0 Cross Section 57 to 73 (Units 1&2 South Reach)												
Main Reach-0	73	Max WS	120	216	219.6		219.6	0.000057	0.7	230	171.5	0.07
Main Reach-0	72	Max WS	119.1	216	219.6		219.6	0.000073	0.7	211.5	169.8	0.08
Main Reach-0	71	Max WS	117.4	216	219.6		219.6	0.000212	0.9	159.9	166.7	0.13
Main Reach-0	70	Max WS	115.2	216	219.5		219.5	0.000262	1	146.2	160.7	0.14
Main Reach-0	69	Max WS	113.7	216	219.5		219.5	0.000313	1.1	135.9	157	0.15
Main Reach-0	68	Max WS	221.6	216	219.5		219.5	0.000439	1.3	267	415.8	0.19
Main Reach-0	67	Max WS	217.1	216	219.4		219.4	0.00091	1.7	186.1	317.9	0.27
Main Reach-0	66	Max WS	215.5	216	219.3		219.4	0.001359	2	144.6	214.4	0.31
Main Reach-0	65	Max WS	213.9	216	219.3		219.3	0.001048	1.7	164.5	236.9	0.27
Main Reach-0	64	Max WS	204.8	216	219.2		219.2	0.001324	1.8	149.4	237.9	0.3
Main Reach-0	63	Max WS	203.3	216	219.2		219.2	0.000701	1.3	227.9	428	0.22
Main Reach-0	62	Max WS	179.3	216	219.1		219.1	0.000177	0.6	305.3	358.9	0.11
Main Reach-0	61	Max WS	504.5	216	218.9		218.9	0.002365	1.8	260.7	358.9	0.39
Main Reach-0	60	Max WS	463.4	216	218.5		218.6	0.003402	1.6	213.3	326.4	0.43
Main Reach-0	59	Max WS	444.9	216	218.5		218.5	0.000016	0.2	1107.3	750.6	0.04
Main Reach-0	58	Max WS	679.6	216	218.5		218.5	0.000082	0.5	772.7	551	0.08
Main Reach-0	57	Max WS	660.3	213	218.5		218.5	0.000257	1.1	571.2	370.7	0.15
Northeast Drainage Ditch												
1	33	Max WS	100.6	213	219.1		219.1	0.000001	0.3	914.8	475	0.03
1	32	Max WS	98.4	211	219.1		219.1	0.000001	0.3	811	445.5	0.02
1	31	Max WS	213.4	211	219.1		219.1	0.000004	0.7	856.4	584.5	0.05
1	30	Max WS	209.9	211	219.1		219.1	0.000002	0.6	1191.4	635	0.04
1	29	Max WS	247.3	210	219.1		219.1	0.000004	0.7	1003.6	416.4	0.05
1	28	Max WS	465.7	210	219.1		219.1	0.000008	0.9	1089.8	454.3	0.07
1	27	Max WS	464.6	210	219.1	213	219.1	0.000005	0.7	1088.6	510.3	0.06
1	26		Inl Stru									
1	25	Max WS	464.6	210	219.1		219.1	0.000005	0.8	1537.1	682.5	0.06
1	24.5	Max WS	463.8	210	219.1		219.1	0.000004	0.6	1521.8	682.5	0.05
1	24	Max WS	698.8	210	219.1		219.1	0.000031	1.6	1071.8	664.3	0.13
1	22.5	Max WS	697.7	210	219.1		219.1	0.000023	1.6	909.6	581.5	0.12
1	22	Max WS	697.4	210	219.1	213.6	219.1	0.000025	1.4	966.8	636.6	0.12
1	21.5		Inl Stru									
1	21	Max WS	684.4	210	219		219	0.000014	1.4	1373.9	644.6	0.09
1	20	Max WS	678.8	216	219		219	0.000643	0.9	854.4	530.2	0.1
1	19	Max WS	677.4	216	219		219	0.000776	1	788.6	530.5	0.11
1	18	Max WS	676.5	216	219		219	0.000853	1.1	755.3	525.8	0.11
1	17	Max WS	676	216	218.9		219	0.000115	1.1	749.5	527.9	0.11
1	16.7	Max WS	1024.5	215	218.9		218.9	0.001279	1.5	803.1	513.1	0.14
1	16.5	Max WS	1023.1	209	218.9		218.9	0.000048	1.9	1070.2	518.7	0.12
1	16	Max WS	1095.2	209	218.8	214.5	218.9	0.000124	3	884.4	280.7	0.19
1	15		Inl Stru									
1	14	Max WS	733.5	208.4	214.9		215.2	0.000634	4.3	169.5	44	0.39
1	13	Max WS	778.8	208	215		215.1	0.000151	2.5	871.5	526.3	0.2
1	12	Max WS	772.2	208	215		215.1	0.000219	2.9	586.1	431	0.24
1	11	Max WS	768.6	207	215		215	0.000112	2.1	938.7	681.5	0.17
1	10	Max WS	767.2	207	215		215	0.000111	2.1	928.1	680.9	0.17
1	9	Max WS	766.5	207	215		215	0.000031	1.1	1271.7	794.2	0.09
1	8	Max WS	1279.7	207	214.9		215.1	0.000433	4.1	777.5	678.6	0.34
1	7	Max WS	1191.3	206	214.7		214.9	0.000341	3.8	532	436	0.31
1	6	Max WS	891.7	205	214.4		214.7	0.000256	3.7	251.4	73.8	0.27
1	5	Max WS	1917.6	204	211.8	211.6	213.8	0.003587	11.3	169.3	38.3	0.95

Table 2.4-207 (Sheet 2 of 5)
Summary of HEC-RAS output for PMP Profile

Reach	River Sta	Profile	Q Total	Min Ch El	W.S. Elev	Crit W.S.	E.G. Elev	E.G. Slope	Vel Chnl	Flow Area	Top Width	Froude # Chl
			(cfs)	(ft)	(ft)	(ft)	(ft)	(ft/ft)	(ft/s)	(sq ft)	(ft)	
Northeast Drainage Ditch (continued)												
1	4	Max WS	1917.2	204	210.4	210.8	213	0.005398	13	147.7	37.7	1.16
1	3	Max WS	1554.5	201	208.3		209.8	0.00294	9.9	157.4	37.9	0.85
1	2	Max WS	2300.8	200.5	205.4	208.3	216.3	0.031901	26.4	87.1	29.1	2.69
1	1	Max WS	2415.1	194	199.1	202.2	210.8	0.032014	27.4	88	27.5	2.7
Units 3&4 100-year Ditch												
Main Reach-0	53	Max WS	404.2	211.3	218.3		218.4	0.000238	3	156.6	135.5	0.33
Main Reach-0	52	Max WS	504.6	209.7	218.3		218.4	0.000068	2.4	239.2	75.7	0.17
Main Reach-0	51	Max WS	504.3	208.9	218.3		218.4	0.000053	2.2	274.7	82.9	0.15
Main Reach-0	50	Max WS	504	208.7	218.3		218.4	0.000049	2.2	249.1	102.1	0.15
Main Reach-0	49	Max WS	503.9	208.6	218.3		218.4	0.000049	2.2	234.2	44.6	0.15
Main Reach-0	48.5	Max WS	503.9	208.4	218.3		218.4	0.000043	2.1	245	42	0.14
Main Reach-0	48.35	Max WS	503.9	208.3	218.3	211.6	218.4	0.000036	2.1	238	41.9	0.13
Main Reach-0	48.25		Bridge									
Main Reach-0	48.15	Max WS	503.9	208.3	218.3		218.4	0.000038	2.1	234.5	41.5	0.14
Main Reach-0	48	Max WS	594.8	208.1	218.3		218.4	0.000054	2.4	252.8	41.4	0.16
Main Reach-0	47	Max WS	594.7	208.1	218.3		218.4	0.000059	2.3	257	42.1	0.17
Main Reach-0	46	Max WS	593.6	208	218.3		218.4	0.000039	2.1	447.4	203.8	0.14
Main Reach-1	45	Max WS	898.2	208	218.3		218.4	0.00003	2.1	1248.1	499.5	0.12
Main Reach-1	44	Max WS	896.2	208	218.4		218.4	0.000021	1.8	1690.2	760	0.1
Main Reach-1	43	Max WS	1294.3	208	218.3		218.4	0.00004	2.5	1449.3	464.6	0.14
Main Reach-1	42	Max WS	1292.5	207	218.3		218.4	0.000036	2.4	1354.5	370	0.13
Main Reach-1	41	Max WS	1291.1	207	218.3		218.4	0.000029	2.2	1308.6	247	0.12
Main Reach-1	40.5	Max WS	1290.4	207	218.3		218.4	0.000027	2.2	1323.7	244.9	0.12
Main Reach-1	40	Max WS	1290.2	207	218.3		218.4	0.000027	2.1	1339.4	249.1	0.12
Main Reach-1	39	Max WS	1289	207	218.3		218.4	0.000025	2.1	1393.8	260	0.11
Main Reach-1	38.5	Max WS	1891.1	206.2	218.3		218.3	0.00004	2.7	1761.2	510	0.14
Main Reach-2	38.25	Max WS	2485.3	206.1	218.3		218.3	0.000057	3.2	2129.5	510	0.17
Main Reach-2	38.2	Max WS	2485.1	206.1	218.3		218.3	0.000057	3.2	2129.5	510	0.17
Main Reach-2	38	Max WS	2480.7	206	218.3		218.3	0.000053	3.1	2534.8	760	0.16
Main Reach-2	37.5		Lat Struct									
Main Reach-2	37	Max WS	2246.6	205.7	218.3		218.3	0.000046	2.8	2198.3	660	0.15
Main Reach-2	36.5		Lat Struct									
Main Reach-2	36	Max WS	2306.6	205.5	218.3		218.3	0.000048	2.9	2188	660	0.15
Main Reach-2	35.5		Lat Struct									
Main Reach-2	35	Max WS	2396.3	205.4	218.3		218.3	0.000044	2.8	2620.1	760	0.14
Main Reach-2	34.5		Lat Struct									
Main Reach-2	34.1	Max WS	1870.5	205.1	218.3		218.3	0.000056	3.2	1651	760	0.16
Main Reach-2	34	Max WS	1869.8	205.1	218.3		218.3	0.000056	3.2	1650.5	760	0.16
Main Reach-2	33.5	Max WS	1869.1	205	218.3		218.3	0.000039	2.7	1614.8	510	0.14
Main Reach-2	33	Max WS	1869	205	218.3		218.3	0.00004	2.8	1538.8	486.1	0.14
Main Reach-2	32.75	Max WS	1868.9	205	218.3		218.3	0.000045	2.6	1482.8	265	0.13
Main Reach-2	32.5	Max WS	1868.8	205	218.3		218.3	0.000042	2.8	1461.3	264.7	0.14
Main Reach-2	32	Max WS	1868.8	205	218.3		218.3	0.000042	2.8	1458.8	263.8	0.14
Main Reach-2	31	Max WS	1868.6	205	218.3		218.3	0.000042	2.9	1413.4	248	0.15
Main Reach-2	30	Max WS	2097	205	218.3		218.3	0.000048	3.1	1642.6	398.1	0.16
Main Reach-2	29.9	Max WS	2096.7	205	218.3		218.3	0.000048	3.1	1642.6	398.1	0.16
Main Reach-3	25	Max WS	3229.7	204.4	218.2		218.3	0.000043	3.3	2171.2	461	0.17
Main Reach-3	24.89	Max WS	3222	204.1	218.2		218.3	0.000047	3.4	2093.4	457.7	0.18
Main Reach-3	24.78	Max WS	3560.5	204.1	218.2		218.3	0.000064	3.9	2008.9	452.1	0.21
Main Reach-3	24.67	Max WS	3551.2	204	218.2		218.3	0.00007	4.1	1931.7	447.6	0.22
Main Reach-3	24	Max WS	3542	204	218.1		218.4	0.000131	5.3	1502.6	424.7	0.29
Main Reach-3	23	Max WS	3519.4	203.8	218.1		218.4	0.000156	5.5	1413.5	487.2	0.32

Table 2.4-207 (Sheet 3 of 5)
Summary of HEC-RAS output for PMP Profile

Reach	River Sta	Profile	Q Total	Min Ch El	W.S. Elev	Crit W.S.	E.G. Elev	E.G. Slope	Vel Chnl	Flow Area	Top Width	Froude # Chl
			(cfs)	(ft)	(ft)	(ft)	(ft)	(ft/ft)	(ft/s)	(sq ft)	(ft)	
Units 3&4 100-year Ditch (continued)												
Main Reach-3	22	Max WS	3497.4	203.6	218		218.4	0.000186	6	1091.6	425.5	0.34
Main Reach-3	21	Max WS	3687.5	203.4	217.7		218.4	0.000272	7.1	693.2	287.4	0.41
Main Reach-3	20.2	Max WS	3678.8	203.2	217.4	213.4	218.3	0.002664	7.6	488.5	206.1	0.47
Main Reach-3	20.1		Bridge									
Main Reach-3	20	Max WS	3678.8	203.2	216.9		217.9	0.003205	8	458.1	60.8	0.52
Main Reach-3	19	Max WS	3678.4	203	216.9		217.7	0.001718	6.9	534	73.3	0.42
Main Reach-3	18	Max WS	2988.4	202.8	216.6		217.2	0.0016	6.1	493.2	70.8	0.38
Main Reach-3	17	Max WS	3925.3	202.6	215.8		217	0.003429	8.7	448.8	60.5	0.57
Main Reach-3	16	Max WS	3923.9	202.4	215.3		216.6	0.004415	9.2	426	59.6	0.61
Main Reach-3	15	Max WS	3922.9	202.2	214.5		216.1	0.00558	10.1	387.3	57.3	0.69
Main Reach-3	14	Max WS	3596.1	202	213.6		215.3	0.005544	10.6	340.1	51.3	0.72
Main Reach-3	13	Max WS	4107.5	201.8	212.4	212.2	215.3	0.008897	13.6	301.9	49.2	0.97
Main Reach-3	12	Max WS	4106.8	201.5	211.7		213.7	0.004456	11.5	357.2	50.4	0.76
Main Reach-3	11	Max WS	4068.2	201	211.4		213.4	0.004512	11.5	354.2	50.7	0.77
Main Reach-3	10	Max WS	4066.5	200.5	210.7	210.7	213.7	0.009628	14	290.1	48.5	1.01
Main Reach-3	9	Max WS	4133	200	209.5	210.5	213.9	0.014672	16.8	245.7	44.9	1.27
Main Reach-3	8	Max WS	4282.5	199.5	207.1	210.3	217.7	0.029961	26.1	163.9	37.1	2.19
Main Reach-6	7	Max WS	7490.6	198.7	207.1	210.7	234.2	0.041962	41.9	195	477.7	3.03
Main Reach-6	6	Max WS	6195.2	197.9	205.1		205.1	0.000012	0.8	3327.5	529.6	0.06
Main Reach-6	5	Max WS	7200.1	197.1	205.1		205.1	0.000051	1	10160.3	618.6	0.08
Main Reach-6	4	Max WS	7192	195.5	205.1		205.1	0.000094	1.6	7455.9	523.4	0.11
Main Reach-6	3	Max WS	7189.6	190.1	205		205.1	0.000067	3.6	6727.4	392	0.18
Main Reach-6	2	Max WS	2656.4	180.6	205		205	0.000004	1.7	6753.8	354.5	0.06
Main Reach-6	1	Max WS	2669.7	168	205	175.3	205	0.000001	1	10991.7	556.2	0.03
Units 3&4 Feeder Ditch 1												
FeederReach-1	12	Max WS	526	218.6	220	220	220.6	0.007253	6.7	80.9	66	1.06
FeederReach-1	11.5	Max WS	511	218	219.8		220.3	0.004485	5.7	91.5	66	0.84
FeederReach-1	11	Max WS	872.2	218	219.6	219.8	220.6	0.006377	8	108.6	418	1.19
FeederReach-1	10.25	Max WS	867.4	218	219.3	219.4	220	0.003906	6.9	129.8	290.4	1.05
FeederReach-1	10	Max WS	863.1	217.2	219	219.1	219.7	0.009736	6.3	133.1	272.1	0.92
FeederReach-1	9	Max WS	850.2	217	218.5	218.5	219.1	0.006792	5.3	155.9	494	0.77
FeederReach-1	8	Max WS	745.6	217	218.5		218.7	0.001755	3.3	218.3	483.4	0.5
FeederReach-1	7	Max WS	741.2	216.8	218.5		218.6	0.000572	3.1	303.2	252.4	0.44
FeederReach-1	6	Max WS	737.7	216	218.5		218.5	0.000246	2.4	388.8	258.2	0.29
FeederReach-1	5	Max WS	680.1	216	218.5		218.5	0.000192	1.7	427	309	0.2
FeederReach-1	4.5	Max WS	616.2	216.4	218.5		218.5	0.000247	2	360.4	282.9	0.25
FeederReach-1	4.35	Max WS	358.9	216.6	218.4		218.5	0.000108	1.5	278	226.2	0.21
FeederReach-1	4.27	Max WS	358.6	216.6	218.4		218.5	0.000108	1.5	278.2	226.3	0.21
FeederReach-1	4.25	Max WS	358.5	216.9	218.4		218.5	0.000126	1.5	273.2	334.9	0.22
FeederReach-1	4	Max WS	460.7	216.1	218.5		218.5	0.000069	1.3	486.3	476.8	0.16
FeederReach-1	3.5	Max WS	602.3	215.8	218.5		218.5	0.000093	0.9	533.6	523.4	0.1
FeederReach-1	3.25	Max WS	460.5	216.1	218.5		218.5	0.000137	1.5	431.7	358	0.18
FeederReach-1	3	Max WS	360.4	216.6	218.4		218.5	0.000238	1.1	368.8	378.7	0.15
FeederReach-1	2	Max WS	360	215.8	218.4		218.5	0.000146	1	457.8	419	0.12
FeederReach-1	1	Max WS	359.3	216.1	218.4		218.5	0.000128	0.9	513.6	563	0.11
FeederReach-1	0.5	Max WS	354.7	208	218.4		218.4	0.000657	0.8	611.2	479.2	0.08
FeederReach-1	0	Max WS	342.8	208	218.4		218.4	0.000148	0.8	502.3	763	0.11
Units 3&4 Feeder Ditch 2												
FeederReach-2	8	Max WS	996.8	217.6	219.3		219.8	0.005811	5.4	188.5	253.1	0.79
FeederReach-2	7.5	Max WS	992.5	217	219.2		219.5	0.005395	4.8	206.2	298	0.69
FeederReach-2	7	Max WS	918	217	219.2		219.4	0.002361	3.8	253.2	367	0.47
FeederReach-2	6	Max WS	915.5	217	219.2		219.3	0.001699	3.1	284.9	593.4	0.4

Table 2.4-207 (Sheet 4 of 5)
Summary of HEC-RAS output for PMP Profile

Reach	River Sta	Profile	Q Total	Min Ch El	W.S. Elev	Crit W.S.	E.G. Elev	E.G. Slope	Vel Chnl	Flow Area	Top Width	Froude # Chl
			(cfs)	(ft)	(ft)	(ft)	(ft)	(ft/ft)	(ft/s)	(sq ft)	(ft)	
Units 3&4 Feeder Ditch 2 (continued)												
FeederReach-2	5.5	Max WS	911.2	217	219.2		219.3	0.001094	2.5	368.8	410.6	0.32
FeederReach-2	5	Max WS	907.7	217	219.2		219.2	0.000883	2.2	427.1	426.5	0.29
FeederReach-2	4.5	Max WS	903.9	217	219.1		219.2	0.000748	2.1	422	486	0.27
FeederReach-2	4	Max WS	900.9	217	219.1		219.2	0.000681	2	434.7	382.2	0.25
FeederReach-2	3	Max WS	892.3	217	219.1		219.1	0.000731	2.4	366.6	409	0.33
FeederReach-2	2.5	Max WS	887.9	217	219		219.1	0.000715	2.3	382.1	363.1	0.3
FeederReach-2	2	Max WS	885.9	217	219		219.1	0.000751	2.4	371.8	196	0.31
FeederReach-2	1.9	Max WS	885.7	217	219		219.1	0.000761	2.4	370.2	195.9	0.31
FeederReach-2	1.85	Max WS	841.2	217	219		219	0.000626	2.1	402.8	308.3	0.28
FeederReach-2	1.8	Max WS	819.8	217	219		219	0.000324	1.4	571.7	528.2	0.19
FeederReach-2	1.7	Max WS	1169.8	217	218.7		218.9	0.000839	3.7	324.3	303.1	0.57
FeederReach-2	1.67	Max WS	1497.6	217	218.6	218.6	219.1	0.002197	5.6	280.5	292.3	0.9
FeederReach-2	1.63	Max WS	1489.3	217	218.5		218.8	0.004058	4.9	374.6	423.9	0.72
FeederReach-2	1.6	Max WS	1479.1	217	218.5		218.6	0.001603	2.8	540.4	487.7	0.4
FeederReach-2	1.5	Max WS	1475.8	217	218.4		218.6	0.003178	3.7	432.9	478.7	0.58
FeederReach-2	1.45	Max WS	609.4	216.9	218.4		218.4	0.000336	1.1	511.4	488.3	0.17
FeederReach-2	1.4	Max WS	602.5	215.8	218.3		218.4	0.00008	0.8	1029.7	814	0.09
FeederReach-2	1.3	Max WS	601.9	215.7	218.3		218.4	0.000069	0.8	1072	814	0.08
FeederReach-2	1.25	Max WS	598.2	215.4	218.3		218.3	0.000077	0.3	2012.3	814	0.03
FeederReach-2	1.15	Max WS	597.4	215.3	218.3		218.3	0.000067	0.3	2095.4	814	0.03
FeederReach-2	1	Max WS	594.2	215	218.3		218.3	0.000005	0.3	2460	814	0.02
Units 3&4 Feeder Ditch 3												
FeederReach-3	11	Max WS	300	207.8	218.4		218.4	0.000013	1.2	559	408.8	0.07
FeederReach-3	10	Max WS	299.6	207.7	218.4		218.4	0.000008	1	677.3	358.4	0.06
FeederReach-3	9	Max WS	299.5	207.5	218.4		218.4	0.00001	1.1	579.3	298.8	0.07
FeederReach-3	8.5	Max WS	259.5	207.2	218.4		218.4	0.000009	1	582.7	377.5	0.06
FeederReach-3	8	Max WS	255.3	207	218.4		218.4	0.000006	0.8	680.6	416	0.05
FeederReach-3	7	Max WS	231.7	206.8	218.4		218.4	0.000005	0.8	627.4	415	0.05
FeederReach-3	6	Max WS	210.4	206.4	218.4		218.4	0.000004	0.7	690.6	371.7	0.04
FeederReach-3	5	Max WS	190.1	206	218.4		218.4	0.000002	0.6	755.7	407	0.03
FeederReach-3	4	Max WS	868.2	205.6	218.3		218.4	0.000046	2.5	798.3	444.6	0.14
FeederReach-3	3	Max WS	859.5	205.2	218.3		218.4	0.00009	3.1	479.9	445.6	0.19
FeederReach-3	2	Max WS	854.8	205	218.3		218.4	0.000072	2.9	437.7	606.6	0.18
FeederReach-3	1	Max WS	844.2	205	218.3		218.4	0.000058	2.5	896.5	750.8	0.15
FeederReach-3	0	Max WS	1133	205	218.3		218.3	0.000036	2.2	2061.2	677.4	0.13
Units 3&4 Feeder Ditch 6												
FeederReach-6	21	Max WS	457.8	211	214.4		214.4	0.000045	1.4	558	325.6	0.15
FeederReach-6	20	Max WS	439.1	210.5	214.4		214.4	0.000049	1.6	517.3	315	0.16
FeederReach-6	19	Max WS	850.9	210	214.1		214.4	0.000761	5.8	516.6	388.1	0.6
FeederReach-6	18	Max WS	1239.5	209.5	213.8		214.4	0.000995	7.5	451.5	254	0.71
FeederReach-6	17	Max WS	1192.7	209	213.6	212.8	214.5	0.001079	9	392.9	253.6	0.78
FeederReach-6	16	Max WS	1144.4	208.5	213.6		214.3	0.000717	7.8	385.4	220.3	0.64
FeederReach-6	15	Max WS	1120.5	208	213.6		214.2	0.000535	7.1	438.7	238.3	0.56
FeederReach-6	14	Max WS	1276.9	207.5	213.1	212.9	214.3	0.000956	9.4	293.3	204.2	0.73
FeederReach-6	13	Max WS	1451.4	207	212.8	212.9	214.5	0.001284	10.7	225.9	156.4	0.85
FeederReach-6	12	Max WS	1612.4	205.7	212.9		213.3	0.000229	5.6	649.7	228.1	0.38
FeederReach-6	11	Max WS	1770.9	205.1	212.4	212.2	213.7	0.001023	9.8	378.5	187.6	0.75
FeederReach-6	10	Max WS	1764	205	212.5		213.3	0.000454	7.6	393	148.6	0.53
FeederReach-6	9	Max WS	2816.1	204.7	211.5	212.4	215.1	0.002111	15.8	272.8	82.9	1.13
FeederReach-6	8	Max WS	3227.1	204.3	211.3	213	215.9	0.002865	17.9	266	95.1	1.32
FeederReach-6	7	Max WS	3224.8	204	210.9	213.3	218.4	0.005149	22.9	200.7	54.5	1.71
FeederReach-6	6	Max WS	3221.8	203.7	210.4	212.6	216.6	0.004368	21.2	231.3	59.3	1.58

Table 2.4-207 (Sheet 5 of 5)
Summary of HEC-RAS output for PMP Profile

Reach	River Sta	Profile	Q Total	Min Ch El	W.S. Elev	Crit W.S.	E.G. Elev	E.G. Slope	Vel Chnl	Flow Area	Top Width	Froude # Chl
			(cfs)	(ft)	(ft)	(ft)	(ft)	(ft/ft)	(ft/s)	(sq ft)	(ft)	
Units 3&4 Feeder Ditch 6 (continued)												
FeederReach-6	5	Max WS	3218.3	203.3	210	211.1	214	0.003586	17.8	311.5	87.7	1.4
FeederReach-6	4	Max WS	3214.5	203	209.6	211.1	214.8	0.004101	19.8	272.8	80.7	1.51
FeederReach-6	3	Max WS	3211.1	202.7	209.1	210.9	215.1	0.004717	20.5	225.3	67.2	1.61
FeederReach-6	2	Max WS	3208.7	202.3	208.3	210.9	217.8	0.011285	24.7	129.9	37.6	2.34
FeederReach-6	1	Max WS	3208.2	202	207.1	211.9	235.1	0.032766	42.6	81.1	28.9	3.94

Table 2.4-208
Savannah River Subbasins and Drainage Areas above VEGP Site

NWS Subbasin			Drainage Area, mi^2	
No.	I.D.	NWS Subbasin Name	upstream of site (1)	downstream of site (2)
1	TIGG1	Burton Dam, GA	122.3	0.0
2	JCSS1	Jocassee Dam, SC	157.7	0.0
3	KEOS1	Keowee Dam, SC	288.0	0.0
4	HRTG1	Hartwell Dam, GA	1544.7	0.0
5	RBRS1	R.B. Russell Dam	738.2	0.0
6	CARG1	Carlton Bridge, GA	760.6	0.0
7	CHDS1UP	Clark Hill - Thurmon Dam (upstream)	665.9	0.0
8	CHDS1	Clark Hill Dam	1847.7	0.0
9	MODS1	Modoc, S.C.	539.9	0.0
10	AGTG1	Steven Creek Dam, GA	454.8	0.0
11	AGSG1	Augusta 5th Street	77.1	0.0
12	AUGG1	Augusta/Butler Creek	273.6	0.0
13	JACS1	Jackson, S.C.	651.2	0.0
14	BFYG1	Burton's Ferry, GA	182.5	293.4
15	BRIG1	Millhaven, GA	0.0	646.2
16	CLYG1	Clyo, GA	0.0	634.7
Estimated Savannah River drainage area at site			**8304.2**	

1) Based on data from Southeast River Flood Forecasting Center, Atlanta, GA. (NWS 2005)

2) As estimated from HUC-12 shapefiles

Table 2.4-209
River Miles for Key Landmarks Along the Savannah River

Land Mark	River Mile *
Confluence of White Water & Toxaway Rivers	368.6
Confluence of Tallulah & Chatooga (forming the Tugaloo)	358.1
Confluence of the Keowee & Twelve Mile Creek (forming Seneca River)	338.5
Confluence of the Senaca & Tugaloo Rivers (forming the Savannah)	312.1
Hartwell Dam (USGS gage 02187250)	288.9
Iva gage (USGS gage 02187500)	280.4
Confluence of Broad River	269.6
Calhoun Falls (USGS gage 02189000)	263.6
Richard B. Russell Dam (USGS gage 02189004)	259.1
Confluence of Little River	223.4
J. Strom Thurmond Dam (USGS gage 02194500)	221.6
Confluence of Stevens Creek	208.1
Augusta City Dam	207.0
Augusta, GA at Fifth Street gage site (02197000)	199.6
Horse Creek at mouth	197.4
New Savannah Bluff Lock and Dam	187.7
Shell Bluff Landing, Georgia	161.9
Jackson, SC gage (02197320)	156.8
Vogtle Electric Generating Plant	150.9
Burtons Ferry gage (02197500)	118.7
Confluence of Brier Creek	102.5
Clyo gage (02198500)	60.9
Ebenezer Landing, Georgia	48.1
Houlihan Bridge (U.S. Highway 17)	21.6
City of Savannah, GA at Bull Street	14.4
Mouth of the Savannah River	0.0

* River miles measured from the mouth of Savannah Harbor, as reported by USACE 1996.

Table 2.4-210
USGS Gage Data for the Savannah River

USGS Gage ID	Location on Savannah River	River Mile*	Coordinates		Altitude, feet MSL**	Area drained, mi^2	Average Daily Flow Series			Annual Peak Flow Series		
							Start	End	No.	Qp Start	Qp End	No.
2187252	below Hartwell Lake nr Hartwell, GA	288.9	34°21'15" N,	82°48'55" W	470.00	2,090	10/1/1984	9/30/1999	4,502	1/21/1985	8/24/1999	15
2187500	near Iva, SC	280.4	34°15'20" N,	82°44'42" W	432.26	2,231	10/1/1950	9/30/1981	11,323	10/8/1949	7/24/1981	32
2189000	near Calhoun Falls, SC	263.6	34°04'15" N,	82°38'30" W	363.53	2,876	10/1/1896	9/30/1979	17,044	4/5/1897	3/28/1980	82
2195000	near Clarks Hill, SC	NR	33°38'40" N,	82°12'05" W	182.69	6,150	5/14/1940	6/30/1954	5,161	--	--	0
2196484	near North Augusta, SC	207.0	33°33'06" N,	82°02'19" W	150.00	7,150	10/1/1988	9/30/2002	5,113	9/21/1989	3/4/2002	13
2197000	at Augusta, GA	199.6	33°22'25" N,	81°56'35" W	96.58	7,508	10/1/1883	9/30/2003	35,793	1/17/1796	6/14/2004	133
2197320	near Jackson, SC	156.8	33°13'01" N,	81°46'04" W	77.00	8,110	10/1/1971	9/30/2002	10,733	1/21/1972	3/5/2002	30
2197500	at Burtons Ferry Bridge nr Millhaven, GA	118.7	32°56'20" N,	81°30'10" W	52.42	8,650	10/1/1939	9/30/2003	18,993	10/1/1929	3/21/2003	53
2198500	near Clyo, GA	60.9	32°31'41" N,	81°16'08" W	13.39	9,850	10/1/1929	9/30/2003	25,567	1/24/1925	3/3/2004	80

* River miles measured from the mouth of Savannah Harbor, as reported by USACE 1996.
** NGVD 1929
Source: Adapted from USGS 2006a

Table 2.4-211
Daily Mean Flow Data for the Savannah River at Calhoun Falls, South Carolina (USGS Gage 2189000)

Day of month	Mean of daily mean values for this day for 49 years of record[1], in ft^3/s											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	5,364	5,898	6,560	8,923	6,925	5,443	4,455	3,872	4,237	3,286	3,630	4,632
2	5,084	6,221	6,427	8,229	6,832	5,161	4,482	4,081	3,904	3,078	3,827	4,534
3	5,719	5,796	6,734	7,558	6,824	4,698	4,020	4,167	3,718	2,960	3,821	4,435
4	5,632	6,219	7,497	7,158	6,529	5,023	3,008	4,237	3,547	3,205	4,180	5,338
5	5,596	5,686	6,972	8,424	5,786	5,796	3,114	4,531	3,558	3,488	4,082	6,139
6	6,324	5,925	6,452	8,819	5,454	5,555	3,935	4,285	3,642	3,323	4,048	5,638
7	7,437	7,683	7,408	8,529	5,380	5,587	4,638	4,310	4,473	3,224	3,810	5,778
8	6,593	6,761	7,349	8,164	5,243	6,334	4,592	4,356	4,503	3,887	3,820	5,563
9	5,991	6,038	6,340	8,194	5,215	5,651	4,681	4,450	4,410	3,780	3,864	4,983
10	6,304	6,226	5,744	6,916	5,039	4,783	4,567	4,226	3,976	3,412	3,780	5,151
11	6,274	6,374	6,054	6,539	5,265	4,809	4,260	3,953	3,885	3,451	3,932	4,961
12	5,577	6,749	6,824	7,098	5,606	4,912	4,617	3,676	3,593	3,463	3,866	5,437
13	5,061	8,015	7,053	7,949	5,521	5,155	5,113	5,354	3,819	3,246	4,227	5,333
14	5,664	8,108	7,193	8,068	5,405	5,225	4,718	5,460	3,958	3,128	3,872	5,486
15	5,451	6,564	6,791	7,346	5,621	4,838	4,503	4,829	4,023	3,178	4,062	6,332
16	5,840	6,167	7,183	7,791	5,561	4,552	4,880	4,299	3,899	3,248	4,064	5,910
17	6,253	6,370	6,959	7,460	5,493	4,819	4,899	4,407	3,956	3,186	4,004	5,658
18	6,401	6,974	6,071	6,864	5,345	5,148	4,658	4,863	3,937	3,299	4,532	5,487
19	6,468	6,621	6,076	6,996	5,339	4,973	5,127	4,654	3,711	3,282	4,809	5,520
20	7,141	6,584	6,982	7,193	5,422	5,021	4,759	4,114	3,667	3,340	4,662	5,688
21	7,074	7,106	7,352	6,842	5,789	5,171	4,663	4,012	3,741	3,639	4,303	6,548
22	6,061	7,211	8,108	6,423	5,717	5,128	4,353	4,114	3,478	3,333	4,507	6,862
23	5,743	6,675	8,035	6,193	5,491	4,999	4,414	4,290	3,301	3,131	4,308	6,130
24	5,919	6,069	8,340	6,133	5,611	5,239	4,326	4,160	3,375	3,287	4,284	5,631
25	6,107	5,968	7,747	6,176	5,157	5,323	4,268	4,246	3,428	3,189	4,317	4,358
26	5,687	6,205	7,591	6,311	4,968	5,114	4,391	3,963	3,705	3,524	4,400	4,748
27	5,432	6,620	7,547	6,261	4,722	4,701	4,367	3,760	3,852	3,427	4,870	6,071
28	5,945	6,525	7,624	6,064	4,845	4,901	4,231	4,016	3,731	3,201	5,000	5,934
29	5,903	5,381	7,737	6,111	5,369	5,269	4,003	4,081	3,386	3,481	5,503	6,425
30	5,555		8,100	6,932	5,325	4,942	4,129	4,709	3,125	3,492	5,053	6,429
31	6,005		8,063		5,419		4,098	5,175		3,446		5,769
Average:	5,987	6,508	7,126	7,255	5,555	5,142	4,396	4,344	3,785	3,342	4,248	5,578

1 – Available period of record may be less than value shown for certain days of the year.

Table 2.4-212
Daily Mean Flow Data for the Savannah River at Augusta, Georgia (USGS Gage 2197000)

Day of Month	Mean of Daily Mean Values for this Day for 98 Years of Record[1], in ft^3/s											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	10,790	11,320	17,390	16,289	10,680	8,129	7,708	8,359	8,281	7,717	5,987	8,172
2	11,380	11,860	15,900	16,230	10,950	8,078	8,381	8,139	8,205	10,460	6,316	7,694
3	11,360	11,960	14,110	17,210	10,570	8,107	7,871	8,541	7,546	10,080	6,574	7,651
4	12,460	12,860	13,420	15,820	10,130	7,917	7,126	8,446	7,586	8,478	6,847	8,232
5	13,170	13,380	14,440	14,099	9,711	7,943	7,085	7,901	7,451	7,249	6,990	8,680
6	12,130	13,339	14,920	15,170	9,621	8,233	7,356	8,065	7,634	7,143	6,782	8,617
7	11,860	13,850	15,029	15,920	9,875	8,760	7,357	8,125	7,709	6,793	6,303	8,444
8	12,600	15,250	15,910	15,740	10,160	8,985	7,993	7,921	7,986	6,526	6,310	8,281
9	12,650	15,590	16,410	15,490	10,140	8,532	8,653	8,440	7,689	6,696	6,763	8,289
10	12,080	15,459	16,070	15,120	10,110	8,316	8,541	8,329	8,819	7,243	6,846	8,670
11	11,550	15,330	14,549	14,560	9,318	8,103	7,732	7,352	9,687	7,243	6,650	8,512
12	11,790	15,190	13,940	13,650	8,830	8,026	7,387	7,287	7,867	7,047	6,635	8,372
13	12,240	14,620	14,520	12,780	8,648	8,111	7,342	7,680	6,671	7,058	6,901	8,580
14	11,610	14,330	14,940	12,730	8,600	8,570	7,788	8,807	6,223	6,582	7,357	8,793
15	11,200	14,090	14,690	13,110	8,388	8,829	7,669	9,442	6,372	6,121	7,344	9,559
16	10,860	13,469	15,490	13,619	8,393	9,036	7,872	9,381	6,331	5,916	7,227	10,260
17	11,570	13,880	15,880	13,450	8,369	8,825	7,699	9,570	6,543	6,188	7,475	9,995
18	12,350	15,020	14,779	12,270	7,988	8,540	7,635	9,034	7,583	6,975	7,398	9,486
19	13,900	15,020	13,869	11,650	7,629	8,056	7,612	8,447	7,598	6,931	7,311	9,025
20	15,450	14,170	14,490	11,670	8,318	7,589	7,735	8,776	6,913	6,854	7,297	8,854
21	14,820	14,130	15,780	11,620	9,137	7,369	7,393	8,078	6,540	7,215	6,879	9,797
22	12,730	15,110	16,450	11,370	9,283	7,657	7,171	7,790	6,591	7,233	6,834	9,845
23	11,580	14,790	16,189	10,830	9,216	7,228	6,961	7,473	6,438	7,373	6,792	9,854
24	11,800	14,010	16,550	10,380	8,788	7,318	6,879	7,321	6,270	7,584	7,131	9,289
25	11,990	13,780	15,960	10,060	8,499	8,373	7,196	7,213	6,418	7,035	7,296	9,232
26	12,190	13,880	15,079	10,500	7,805	8,399	7,623	7,367	6,989	6,491	7,352	9,595
27	11,760	14,160	15,370	10,500	7,795	7,699	7,499	7,301	8,905	6,709	7,551	10,100
28	11,260	16,089	15,380	10,190	7,904	7,406	7,428	7,615	8,902	6,778	7,584	10,090
29	11,310	11,980	15,300	9,767	7,866	7,209	7,655	8,207	7,516	6,342	7,950	10,160
30	11,450		16,800	10,480	7,794	7,598	8,445	8,447	7,140	6,319	8,448	11,020
31	11,250		16,920		7,823		8,962	8,352		6,173		11,100
Average:	12,101	14,066	15,372	13,076	8,979	8,098	7,669	8,168	7,413	7,115	7,038	9,169

1 – Available period of record may be less than value shown for certain days of the year.

Table 2.4-213
Daily Mean Flow Data for the Savannah River at Jackson, South Carolina (USGS Gage 2197320)

Day of month	Mean of daily mean values for this day for 31 years of record[1], in ft^3/s											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	8,843	10,990	10,650	11,520	9,351	8,778	8,337	7,511	7,725	7,052	7,188	8,115
2	9,091	11,140	11,050	10,540	8,757	8,383	7,974	7,581	7,334	7,079	7,167	8,850
3	9,807	11,920	11,320	10,560	8,860	7,941	7,691	7,778	7,141	7,541	7,088	8,730
4	9,931	11,990	11,470	10,660	8,858	8,393	7,922	7,877	7,433	7,708	7,193	8,524
5	9,759	11,430	12,559	10,900	9,146	8,316	7,743	7,420	7,791	7,885	7,261	8,674
6	9,677	11,560	12,140	11,150	8,650	8,323	8,097	7,441	7,891	7,779	7,233	8,840
7	9,407	11,650	12,040	10,630	8,578	8,328	8,102	7,409	7,778	7,589	7,218	8,908
8	9,032	11,730	12,160	10,290	7,630	8,169	7,924	7,463	7,395	7,581	7,141	9,053
9	9,086	11,620	12,240	10,180	7,377	8,247	7,316	7,566	7,322	7,791	7,225	9,121
10	9,402	11,830	12,020	10,470	8,088	7,944	7,700	7,752	7,428	7,937	7,354	8,978
11	9,922	11,430	11,100	10,920	7,937	8,374	7,524	7,465	7,247	7,994	7,435	9,219
12	10,540	11,980	11,480	10,510	8,381	8,175	7,107	7,766	7,042	7,991	7,510	9,271
13	10,800	12,060	11,790	10,360	8,695	8,682	7,079	7,695	7,059	7,850	7,542	9,356
14	10,870	11,850	11,920	9,937	8,551	8,554	7,042	7,798	7,047	7,693	7,745	9,084
15	10,640	11,930	11,740	9,614	8,096	8,441	7,183	7,859	7,299	7,367	8,222	9,007
16	10,430	11,840	11,510	10,490	8,221	8,061	7,270	7,835	7,208	7,330	8,354	9,235
17	10,510	10,920	11,570	10,510	8,368	7,730	7,478	7,945	7,015	7,739	7,940	9,326
18	10,770	10,540	11,340	10,150	8,784	7,774	7,583	8,110	6,855	7,308	7,681	9,248
19	11,290	11,110	10,750	9,529	9,375	7,715	7,551	8,038	6,841	7,717	7,734	9,064
20	11,480	10,840	10,560	9,320	8,814	7,670	7,688	7,437	6,826	7,695	7,644	9,841
21	11,260	10,200	10,800	9,484	8,461	8,276	7,558	7,482	6,702	7,905	7,584	9,628
22	11,430	10,260	10,990	9,388	8,173	8,800	7,393	7,431	7,010	7,758	7,739	9,536
23	11,580	10,760	10,220	9,379	8,739	8,878	7,469	7,361	7,161	7,848	8,381	9,469
24	11,300	11,080	9,758	9,780	9,255	8,404	7,360	7,312	7,366	8,257	8,387	9,350
25	11,240	11,250	10,010	9,456	9,503	8,230	7,209	7,335	7,141	8,340	8,529	9,362
26	10,980	11,090	11,160	9,380	9,236	8,154	7,234	7,284	7,216	8,108	8,117	9,653
27	10,900	11,380	11,150	9,780	9,021	8,113	7,057	7,332	7,115	7,974	7,992	9,524
28	11,230	10,990	10,860	9,542	8,956	8,240	6,866	7,430	6,977	8,022	7,863	9,155
29	10,720	10,540	11,550	9,237	9,177	8,481	6,835	8,035	7,106	7,759	8,077	8,781
30	10,850		11,950	9,728	9,396	8,469	7,195	7,984	7,017	7,360	8,527	8,777
31	10,870		11,900		9,236		7,465	7,957		7,160		8,816
Average:	10,440	11,307	11,347	10,113	8,699	8,268	7,482	7,635	7,216	7,713	7,702	9,113

1 -- Available period of record may be less than value shown for certain days of the year.
Source: Adapted from USGS 2006d

Table 2.4-214
Approximate Lengths and Slopes of Local Streams

Map ID	Stream Identification	Approximate length, ft **	Upstream Elevation	Outfall Elevation	Approximate Slope
1	Unnamed creek at Hancock Landing to the Savannah River	7,000	163	85	0.0111
2	Unnamed tributary to Daniels Branch	6,000	190	105	0.0142
3	Red Branch to Daniels Branch	10,500	235	115	0.0114
4	Daniels Branch D/S of embankment dam to confluence with Red Br.	5,500	140	115	0.0045
5	Unnamed tributary to Beaverdam Creek	8,500	235	87	0.0174
6	Beaverdam Creek to Telfair Pond	13,500	100	85	0.0011
7	Beaverdam Creek, D/S of Telfair Pond to Savannah River	21,000	190	105	0.0040

* Identifier for streams shown in Figure 2.4-206
** from outfall to end of longest tributary

Table 2.4-215
Inventory of Savannah River Watershed Water Control Structures

Name of Dam or Reservoir	Owner or Operator	Stream	Savannah River Mile	Distance U/S of Vogtle Site	Drainage Area above dam (sq. mi.)	Total Storage, in 1000's of acre-feet	Normal Pool Elev, ft MSL	Spillway Crest Elevation, ft. MSL	Top of Dam Elevation, ft. MSL	Generator Capacity, MW
New Savannah Bluff Lock & Dam	USACE	Savannah River	187.7	36.8	7,508	RoR	115.0	n/a	n/a	n/a
Stevens Creek	SC Electric & Gas	Savannah River	208.1	57.2	7,173	11	n/a	n/a	n/a	19.2
J. Strom Thurmond Lake & Dam	USACE	Savannah River	221.6	70.7	6,144	2,510	335.0	300	351	280
Richard B. Russell Lake & Dam	USACE	Savannah River	259.1	108.2	2,900	1,026	475.0	436	495	300
Hartwell Lake & Dam	USACE	Savannah River	288.9	138.0	2,088	2,550	660.0	630	679	330
Yonah Dam	GA Power Company	Tugaloo-Chatooga	340.0	189.1	470	10.2	744.2	742	757	22.5
Keowee Lake & Dam	Duke Power Company	Senaca-Keowee	341.0	190.1	439	940	800.0	765	815	157.5
Tugaloo Lake & Dam	GA Power Company	Tugaloo	343.1	192.2	464	43.2	891.5	885	905	45
Tallulah Falls Dam	GA Power Company	Tallulah River	346.7	195.8	186	2.46	1,500.0	1493	1514	72
Mathis Lake & Dam	GA Power Company	Tallulah River	353.4	202.5	151	31.4	1,689.6	1681	1704	16
Jocassee Lake & Dam	Duke Power Company	Senaca-Keowee	357.0	206.1	148	1,100	1,110.0	1077	1125	612
Nacoochee Dam	GA Power Company	Tallulah River	362.1	211.2	136	8.2	1,752.5	1753	1765	4.8
Little River Lake & Dam	Duke Power Company	Senaca-Keowee	366.0	215.1	439	940	800.0	765	815	n/a
Burton Lake & Dam	GA Power Company	Tallulah River	366.4	215.5	118	108	1,866.6	1860	1873	6.1

Source: Compiled from USACE 1996

Table 2.4-216
Surface Water Users on the Savannah River Near or Downstream of Proposed Units

Owner	Facility Type and Description	Source Water	River mile	Distance from VEGP	Average Daily Withdrawal	Reference
Savannah River Site, US DOE	Tritium Extraction Facility	Savannah River	151.0	-0.1	2.9 MGD (1)	DOE/EIS 1997
Georgia Power Company	Vogtle Electric Generating Plant	Savannah River	150.9	0.0	171.3 MGD (1)	DOE/EIS 1997
SCE&G	Coal-fired plant cooling water at SRS	Savannah River	151.0	-0.1	44.2 MGD (1)	DOE/EIS 1997
City of Savannah	Cherokee Hill Water Treatment Plant in Port Wentworth for treatment of industrial & domestic water	Savannah River	29.0	121.9	50.0 MGD	DOE/EIS 1997
Beaufort/Jaspar Water & Sewer Authority	W.T.P. Intake for WTP facility serving 75% of Beaufort Co. & 1% of Jasper Co.	Savannah River	39.2	111.7	16.0 MGD	DOE/EIS 1997
City of Waynesboro, Burke Co.	Water Treatment Plant intake for municipal water supply (12 miles overland from site)	Brier Creek	102.5	48.4	1.5 MGD (2)	Georgia DNR 2006
International Paper Corporation in Chatham Co., GA	Water treatment plant intake for industrial water supply (approximate river mile)	Savannah River	18.5 (3)	132.4	50.0 MGD (2)	Georgia DNR 2006
Kerr-McGee Chemical, LLC in Chatham Co., GA	Water treatment plant intake for industrial water supply (approximate river mile)	Savannah River	18.5 (3)	132.4	20.0 MGD (2)	Georgia DNR 2006
Georgia Power Company Riverside, GA	Water treatment plant intake for industrial water supply	Savannah River	18.5 (3)	132.4	174.0 MGD (2)	Georgia DNR 2006
Savannah Electric & Power Co-Pt Wentworth, GA	Water treatment plant intake for industrial water supply (approximate river mile)	Savannah River	18.5 (3)	132.4	267.0 MGD (2)	Georgia DNR 2006
Weyerheauser Company, Chatham Co., GA	Water treatment plant intake for industrial water supply (approximate river mile)	Savannah River	18.5 (3)	132.4	27.5 MGD (2)	Georgia DNR 2006
Weyerheauser Company, Chatham Co., GA	Water treatment plant intake for industrial water supply (approximate river mile)	Savannah River	18.5 (3)	132.4	30.0 MGD (2)	Georgia DNR 2006
Fort James Operating Company, Effingham, GA	Water Treatment Plant intake for municipal water supply	Savannah River	45	105.9	35.0 MGD (2)	Georgia DNR 2006
Savannah Electric & Power Co, McIntosh, GA	Water treatment plant intake for industrial water supply	Savannah River	45	105.9	130.0 MGD (2)	Georgia DNR 2006
Savannah Industrial & Domestic Water, Effingham Co., GA	Combined municipal and industrial water supply (near confluence with Savannah R.)	Abercorn Creek	29	121.9	55.0 MGD (2)	Georgia DNR 2006
J M Huber Corp-Brier Creek, in Warren Co., GA	Water treatment plant intake for industrial water supply (near confluence with Savannah R.)	Brier Creek	102.5	48.4	4.0 MGD (2)	Georgia DNR 2006

1) Average water use, 1998 interpolated to 2006 using 2010 projected value
2) Average water use, Georgia DNR 2006
3) Midpoint of the reach identified in Georgia DNR 2006

Table 2.4-217 (Sheet 1 of 2)
Plant Water Use

Stream Description	Normal Case[a] gpm	Maximum Case[a,b] gpm	Comments
Groundwater (Well) Streams:			
Plant Well Water Demand	752	2,797	
Well Water for Service Water System Makeup	537	1,600	
• Service Water System Consumptive Use	403	1,100	
– Service Water System Evaporation	402	1,099	
– Service Water System Drift	1	1	c
• Service Water System Blowdown	134	500	d
Well Water for Power Plant Makeup/Use	215	1,197	
• Demineralized Water System Feed	150	1,080	
– Plant System Makeup/Processes	109	999	
– Misc. Consumptive Use	41	81	
• Potable Water Feed	42	70	
• Fire Water System	10	12	
• Misc. Well Water Users	13	35	
Surface Water (Savannah River) Streams			
River Water for Circulating Water/Turbine Plant Cooling Water System Makeup	38,825	61,145	
• Circulating Water/Turbine Plant Cooling Water System Consumptive Use	29,125	30,585	
Circulating Water/Turbine Plant Cooling Water System Evaporation	29,100	30,560	
Circulating Water/Turbine Plant Cooling Water System Drift	25	25	c
• Circulating Water/Turbine Plant Cooling Water System Blowdown	9,700	30,560	d

Table 2.4-217 (Sheet 2 of 2)
Plant Water Use

Stream Description	Normal Case[a] gpm	Maximum Case[a,b] gpm	Comments
Plant Effluent Streams			
Final Effluent Discharge to River	9,608	30,761	
• Blowdown Sump Discharge	9,605	30,561	
Wastewater Retention Basin Discharge	171	505	
• Miscellaneous Low Volume Waste	129	365	
• Treated Sanitary Waste	42	140	
• Service Water System Blowdown	134	1,176	d
Circulating Water/Turbine Plant Cooling Water System Blowdown	9,300	28,880	d
Start-up Pond Discharge	0	0	e
• Treated Liquid Radwaste	3	200	f

Notes:

a The flow rate values are for two AP1000 units.

b These flows are not necessarily concurrent.

c The cooling tower drifts are 0.002% of the tower circulating water flow.

d For the normal case, the cooling towers are assumed operating at four cycles of concentration. For the service water cooling tower (maximum case), both unit towers are assumed operating at two cycles of concentration. For the main condenser / turbine auxiliary cooling water tower (maximum case), both towers are assumed operating at two cycles of concentration. Flows are determined by weather conditions, water chemistry, river conditions (circulating water / turbine plant cooling water system only) and operator discretion.

e Start-up flushes and start-up pond discharge would occur only during the initial plant start-up phase and potentially after unit outages when system flushes are required.

f The short-term liquid waste discharge flow rate may be up to 200 gpm. However, given the waste liquid activity level, the discharge rate must be controlled to be compatible with the available dilution (cooling tower blowdown) flow.

Table 2.4-218
Annual Peak Discharge for USGS Gage 2197000 on the Savannah River at Augusta, Georgia

Water Year	Date	Gage Height (feet)	Stream-Flow (cfs)	Water Year	Date	Gage Height (feet)	Stream-Flow (cfs)
1796	Jan. 17, 1796	38	280,000 (2)	1937	Jan. 04, 1937	30.1	91,400
1840	May 28, 1840	37.5	260,000 (2)	1938	Oct. 21, 1937	30.1	91,400
1852	Aug. 29, 1852	36.8	230,000 (2)	1939	Mar. 02, 1939	24.1	90,900
1864	Jan. 01, 1864	34	160,000 (2)	1940	Aug. 15, 1940	29.4	239,000
1865	Jan. 11, 1865	36.4	220,000 (2)	1941	Jul. 08, 1941	22.89	53,300
1876	Dec. 30, 1875	28.6	86,400	1942	Mar. 23, 1942	24.56	105,000
1877	Apr. 14, 1877	31.4	119,000	1943	Jan. 20, 1943	25.1	117,000
1878	Nov. 23, 1877	23.5	51,500	1944	Mar. 22, 1944	25.53	128,000
1879	Aug. 03, 1879	22	44,000	1945	Apr. 27, 1945	23.16	64,000
1880	Dec. 16, 1879	30.1	102,000	1946	Jan. 09, 1946	24.43	97,200
1881	Mar. 18, 1881	32.2	130,000	1947	Jan. 22, 1947	23.97	86,000
1882	Sep. 12, 1882	29.3	93,300	1948	Feb. 10, 1948	23.9	83,200
1883	Jan. 22, 1883	30.8	111,000	1949	Nov. 30, 1948	26.61	154,000
1884	Apr. 16, 1884	28	81,000	1950	Oct. 09, 1949	20.1	32,500
1885	Jan. 26, 1885	27.5	77,000	1951	Oct. 22, 1950	22.32	46,300
1886	May 21, 1886	32.5	135,000	1952	Mar. 06, 1952	21.53	39,300 (5)
1887	Jul. 31, 1887	34.5	173,000	1953	May 8, 1953	20.8	35,200 (6)
1888	Sep. 11, 1888	38.7	303,000	1954	Mar. 30, 1954	17.39	25,500 (6)
1889	Feb. 19, 1889	33.3	149,000	1955	Apr. 15, 1955	16.77	23,900 (6)
1890	Feb. 27, 1890	22.9	48,500	1956	Apr. 12, 1956	14.7	18,600 (6)
1891	Mar. 10, 1891	35.5	197,000	1957	May 7, 1957	14.08	18,000 (6)
1892	Jan. 20, 1892	32.8	140,000	1958	Apr. 18, 1958	22.91	66,300 (6)
1893	Feb. 14, 1893	25	60,000	1959	Jun. 08, 1959	18.65	28,500 (6)
1894	Aug. 07, 1894	24	54,000	1960	Feb. 14, 1960	20.58	34,900 (6)
1895	Jan. 11, 1895	30.4	106,000	1961	Apr. 02, 1961	20.56	34,800 (6)
1896	Jul. 10, 1896	30.5	107,000	1962	Jan. 09, 1962	20.09	32,500 (6)
1897	Apr. 06, 1897	29.3	93,300	1963	Mar. 23, 1963	19.52	31,300 (6)
1898	Sep. 02, 1898	31.3	117,000	1964	Apr. 09, 1964	24.16	87,100 (6)
1899	Feb. 08, 1899	31	113,000	1965	Dec. 27, 1964	20.62	34,600 (6)
1900	Feb. 15, 1900	32.7	138,000	1966	Mar. 06, 1966	21.5	39,300 (6)
1901	Apr. 04, 1901	31.8	124,000	1967	Aug. 25, 1967	18.1	26,500 (6)
1902	Mar. 01, 1902	34.6	175,000	1968	Jan. 12, 1968	20.94	35,900 (6)
1903	Feb. 09, 1903	33.2	147,000	1969	Apr. 21, 1969	22.24	45,600 (6)
1904	Aug. 10, 1904	25.5	63,000	1970	Apr. 01, 1970	17.68	25,200 (6)
1905	Feb. 14, 1905	25.8	64,800	1971	Mar. 05, 1971	23.3	63,900 (6)
1906	Jan. 05, 1906	29.6	96,600	1972	Jan. 20, 1972	20.36	33,700 (6)
1907	Oct. 05, 1906	23.6	52,000	1973	Apr. 08, 1973	21.63	40,200 (6)
1908	Aug. 27, 1908	38.8	307,000	1974	Feb. 23, 1974	20.13	32,900 (6)
1909	Jun. 05, 1909	28.7	87,300	1975	Mar. 25, 1975	22.24	45,600 (6)
1910	Mar. 02, 1910	26.4	69,800	1976	Jun. 05, 1976	20.27	33,300 (6)
1911	Apr. 14, 1911	19.1	32,800	1977	Apr. 07, 1977	20.5	34,200 (6)
1912	Mar. 17, 1912	36.8	234,000	1978	Jan. 26, 1978	21.98	43,100 (6)
1913	Mar. 16, 1913	35.1	156,000	1979	Feb. 27, 1979	21.13	37,300 (6)
1914	Dec. 31, 1913	24.3	48,000	1980	Mar. 31, 1980	22.33	47,200 (6)
1915	Jan. 20, 1915	28.2	61,000	1981	Feb. 12, 1981	14.7	17,700 (6)
1916	Feb. 03, 1916	31	82,400	1982	Jan. 02, 1982	19.39	30,700 (6)
1917	Mar. 06, 1917	29.2	68,000	1983	Apr. 10, 1983	23.21	66,100 (6)
1918	Jan. 30, 1918	25.5	45,500	1984	5-May-84	20.35	34,000 (6)
1919	Dec. 24, 1918	35	128,000	1985	Feb. 07, 1985	17.89	25,700 (6)
1920	Dec. 11, 1919	35.4	133,000	1986	Oct. 03, 1985	15.74	21,000 (6)
1921	Feb. 11, 1921	35.1	129,000	1987	Mar. 06, 1987	18.98	29,200 (6)
1922	Feb. 16, 1922	32	92,000	1988	Feb. 05, 1988	10.61	13,600 (6)
1923	Feb. 28, 1923	28	59,700	1989	Sep. 22, 1989	15.33	20,200 (6)
1924	Sep. 22, 1924	28	59,700	1990	Feb. 27, 1990	20.69	35,300 (6)
1925	Jan. 20, 1925	36.5	150,000	1991	Oct. 13, 1990	22.8	59,200 (6)
1926	Jan. 20, 1926	27.3	55,300	1992	Mar. 27, 1992	16.29	22,100 (6)
1927	Dec. 30, 1926	24	39,000	1993	Jan. 14, 1993	21.81	45,100 (6)
1928	Aug. 17, 1928	40.4	226,000	1994	Jul. 01, 1994	21.4	40,700 (6)
1929	Sep. 27, 1929	46.3	343,000	1995	Feb. 19, 1995	20.28	33,600 (6)
1930	Oct. 02, 1929	45.1	350,000	1996	Feb. 05, 1996	20.48	34,400 (6)
1931	Nov. 17, 1930	19.9	26,100	1997	Mar. 10, 1997	18.11	26,300 (6)
1932	Jan. 09, 1932	30.4	93,800	1998	Feb. 07, 1998	21.63	43,000 (6)
1933	Oct. 18, 1932	30.3	92,600	1999	Feb. 02, 1999	14.72	19,000 (6)
1934	Mar. 05, 1934	28.5	73,200	2000	Jan. 25, 2000	13.25	16,800 (6)
1935	Mar. 14, 1935	27.4	63,700	2002	Mar. 04, 2002	7.14	8,510 (6)
1936	Apr. 08, 1936	41.2	258,000	2003	24-May-03	20.42	31,600 (6)
				2004	Jun. 14, 2004	13.82	17,600 (6)

2 -- Discharge is an Estimate
5 -- Discharge affected to unknown degree by Regulation or Diversion
6 -- Discharge affected by Regulation or Diversion
Source: USGS 2006c

Table 2.4-219
Comparison of Annual Peak Discharges on the Savannah River at Augusta, Georgia and Jackson, South Carolina for 1972 to 2002

	Savannah River at Augusta, GA			Savannah River at Jackson, SC		
Water Year (Oct–Sept)	Date of Annual Peak Discharge	Gage Height (feet)	Stream-Flow (cfs)	Date of Annual Peak Discharge	Gage Height (feet)	Stream-Flow (cfs)
1972	Jan. 20, 1972	20.36	33,700	Jan. 21, 1972	19.02	n/r
1973	Apr. 08, 1973	21.63	40,200	Apr. 09, 1973	19.71	n/r
1974	Feb. 23, 1974	20.13	32,900	Feb. 24, 1974	18.64	n/r
1975	Mar. 25, 1975	22.24	45,600	Sep. 16, 1975	20.22	n/r
1976	Jun. 05, 1976	20.27	33,300	Jul. 06, 1976	18.84	n/r
1977	Apr. 07, 1977	20.5	34,200	Apr. 08, 1977	18.85	n/r
1978	Jan. 26, 1978	21.98	43,100	Jan. 28, 1978	19.65	n/r
1979	Feb. 27, 1979	21.13	37,300	Apr. 28, 1979	19.12	n/r
1980	Mar. 31, 1980	22.33	47,200	Apr. 01, 1980	20.72	n/r
1981	Feb. 12, 1981	14.7	17,700	Feb. 13, 1981	15.16	17300
1982	Jan. 02, 1982	19.39	30,700	Feb. 20, 1982	17.12	20500
1983	Apr. 10, 1983	23.21	66,100	Apr. 11, 1983	21.57	n/r
1984	May 5, 1984	20.35	34,000	Mar. 09, 1984	19.3	n/r
1985	Feb. 07, 1985	17.89	25,700	Feb. 08, 1985	17.21	20600
1986	Oct. 03, 1985	15.74	21,000	Nov. 24, 1985	14.29	15900
1987	Mar. 06, 1987	18.98	29,200	Mar. 07, 1987	18.35	n/r
1988	Feb. 05, 1988	10.61	13,600	Feb. 06, 1988	12.42	13200
1989	Sep. 22, 1989	15.33	20,200	Sep. 23, 1989	14.9	16800
1990	Feb. 27, 1990	20.69	35,300	Feb. 28, 1990	19.61	n/r
1991	Oct. 13, 1990	22.8	59,200	Oct. 14, 1990	20.05	n/r
1992	Mar. 27, 1992	16.29	22,100	Mar. 27, 1992	16.26	18800
1994	Jul. 01, 1994	21.4	40,700	Jul. 03, 1994	19.19	n/r
1995	Feb. 19, 1995	20.28	33,600	Feb. 20, 1995	18.91	n/r
1996	Feb. 05, 1996	20.48	34,400	Mar. 16, 1996	18.86	n/r
1997	Mar. 10, 1997	18.11	26,300	Mar. 11, 1997	18.41	n/r
1998	Feb. 07, 1998	21.63	43,000	Feb. 09, 1998	19.83	n/r
1999	Feb. 02, 1999	14.72	19,000	Oct. 28, 1998	15.23	17300
2000	Jan. 25, 2000	13.25	16,800	Jan. 26, 2000	14.86	16500
2002	Mar. 04, 2002	7.14	8,510	Mar. 05, 2002	8.77	8870

Source: Based on data from USGS 2006c and 2006d

Table 2.4-220
Probable Maximum Precipitation Values for Point Rainfall at VEGP Site

Duration	Watershed Area, mi^2	Multiplier	Applied to	Source	PMP depth (inches)
6-hour	10	n/a	n/a	HMR-51, Fig 18	31.0
1-hour	1	0.620	6-hr 10 mi^2 value	HMR-52, Fig 23	19.2
30-minutes	1	0.736	1-hr 1 mi^2 value	HMR-52, Fig 38	14.1
15-minutes	1	0.509	1-hr 1 mi^2 value	HMR-52, Fig 37	9.8
5-minutes	1	0.323	1-hr 1 mi^2 value	HMR-52, Fig 36	6.2

Table 2.4-221
Results of Previous PMF Modeling Efforts

Model	Description	PMF and Flood Elevation Results	PMF Stage Including Wave Action	Freeboard wrt El. 220 ft msl
HEC-1 Model with HMR 51 and 52 PMP	Ignoring Valley Storage	895,000 cfs, 136 ft msl	163 ft msl	57 ft
	Valley Storage Modeled in NWS DAMBRK	540,000 cfs, 126 ft msl	153 ft msl	67 ft
USACE PMF with NWS DAMBRK Model		710,000 cfs, 138 ft msl	165 ft msl	55 ft

Table 2.4-222
PMF Values for an Area-PMF Relationship at the VEGP Site

Watershed Area, sq. mi.	PMF in cfs from isolines	Supporting Figure (RG 1.59)
100	110,000	B-2
500	250,000	B-3
1,000	330,000	B-4
5,000	750,000	B-5
10,000	1,050,000	B-6
20,000	1,300,000	B-7

Table 2.4-223
PMF Flood Stages for Cross-Section Nearest VEGP Site

Profile	Q Total, cfs	W.S. Elev, ft	E.G. Elev, ft	E.G. Slope	Vel Chnl, fps	Flow Area, sf	Top Width, ft	Froude # Chl
Avg Daily Max	13,669	88.22	88.25	0.000056	1.50	31,765	8,238	0.07
Avg Annual Peak	28,734	92.37	92.39	0.000056	1.64	66,743	8,551	0.07
Historic Max	360,000	118.55	118.63	0.000093	4.12	384,032	14,534	0.11
PMF	917,965	138.82	138.95	0.000102	5.66	680,627	14,681	0.13
2 x PMF	1,835,930	160.50	160.71	0.000120	7.50	999,754	14,784	0.14

Table 2.4-224
Estimated Probable Maximum Flood Stage at VEGP Site

PMF Stage:	138.82 ft msl –HEC-RAS WSL at River Mile 150.906
Wave run-up & wind set-up	11.31 ft – result for 2h:1v slope w/ 50 mph wind from NE over an 11-mile fetch resulting from dam-break
Total PMF Stage:	150.13 ft msl
Minimum Slab elevation	220.00 ft msl
Estimated Freeboard	69.87 feet

Table 2.4-225
Normal Pool Storage Volumes

Dam	Mode 1 Reservoir Storage Volume (1,000 ac-ft)	Mode 2 Reservoir Storage Volume (1,000 ac-ft)
Jocassee	1,100	
Keowee	940	
Burton		108
Nacoochee		8.2
Mathis		31.4
Tallulah Falls		2.46
Tugalo		43.2
Yonah		10.2
Total	2,040	203

Table 2.4-226
Breach Parameter Estimation Formulas

Reference	Number of Case Studies	Relations Proposed (S.I. units, meters, m^3/s, hours)
Johnson & Illes (1976)		$0.5h_d \leq B \leq 3h_d$ for earthfill dams
Singh & Snorrason (1982, 1984)	20	$2h_d \leq B \leq 5h_d$ 0.15 m $\leq d_{ovtop}$ 0.61 m 0.25 hr $\leq t_f \leq$ 1.0 hr
MacDonald & Langridge-Monopolis (1984)	42	Earthfill dams: $V_{er} = 0.0261\ (V_{out} * h_w)^{0.769}$ [best-fit] $T_f = 0.0179(V_{er})^{0.364}$ [upper envelope] Non-earthfill dams: $V_{er} = 0.00348(V_{out} * h_w)^{0.852}$ [best-fit]
FERC (1987)		B is normally 2-4 times h_d B can range from 1-5 times h_d Z = 0.25 – 1.0 [engineered, compacted dams] Z = 1 – 2 [non-engineered, slag or refuse dams] t_f = 0.1 - 1 hr [engineered, compacted earth dams] t_f = 0.1 - 0.5 hr [non-engineered, poorly compacted earth dams]
Froehlich (1987)	43	$\overline{B}^* = 0.47K_0\ (S^*)^{0.25}$ K_0 = 1.4 overtopping; 1.0 otherwise $Z = 0.75\ K_c(h^*_w)^{1.57}(\overline{W}^*)^{0.73}$ K_c = 0.6 with corewall; 1.0 without corewall $t_f = 79(S^*)^{0.47}$
Reclamation (1988)	52	$B = 3h_w$ $t_f = 0.011B$
Von Thun & Gillette (1990)	57	B, Z, t_f see guidance in USBR 1998
Froehlich (1995b)	63	$\overline{B} = 0.1803K_0V_w^{0.32}h_b^{0.19}$ $t_f = 0.00254V_w^{0.53}h_b^{(-0.90)}$ K_0 = 1.4 for overtopping; 1.0 otherwise

Source: USBR 1998

Table 2.4-227
J. Strom Thurmond Dam Input Variables

Input Variable	English Units	SI Units
h_w	151.1 ft	46.1 m
h_b	151.0 ft	46.0 m
h_d	151.0 ft	46.0 m
S	4360000 ac-ft	5378009947 m^3
S*		55162.75
W_c	40 ft	12.2 m
W_b	740 ft	225.6 m
W*		2.58
V_{er}		15085176.57 m^3
K_o		1.4
K_c		0.6

Table 2.4-228
J. Strom Thurmond Dam Breach Parameters

Reference	B (m)	B (ft)	Z	tf (hrs)
Johnson and Illes	138.1	453		
Singh and Snorrason (1982, 1984)	230.1	755		0.25 to 1.0
MacDonald and Langridge-Monopolis (1984)				7.34
FERC (1987)	230.1	755	1 to 2	0.1 to 1.0
Froehlich (1987)	422.7	1387	0.9	
Bureau of Reclamation (1988)	138.2	453		1.52
Von Thun and Gillette	170.0	558		1.17
Froehlich (1995b)	679.0	2228		11.62

Table 2.4-229
Richard B. Russell Dam Input Variables

Input Variable	English Units	SI Units
Hw	150.1 ft	45.8 m
Hb	150.0 ft	45.7 m
Hd	150.0 ft	45.7 m
Storage	1700000 ac-ft	2096930484 m^3
S*		21941.45
W_c	20 ft	6.1 m
W_b	865 ft	263.7 m
W*		2.95
V_{er}		7274160.639 m^3
K_o		1.4
K_c		0.6

Table 2.4-230
Richard B. Russell Dam Breach Parameters

Reference	B (m)	B (ft)	Z	tf(hrs)
Johnson and Illes	137.2	450		
Singh and Snorrason (1982, 1984)	228.6	750		0.25 to 1.0
MacDonald and Langridge-Monopolis (1984)				5.63
FERC (1987)	228.6	750	1 to 2	0.1 to 1.0
Froehlich (1987)	320.8	1053	1.0	
Bureau of Reclamation (1988)	137.3	450		1.51
Von Thun and Gillette	169.3	555		1.17
Froehlich (1995b)	501.7	1646		7.10

Table 2.4-231
Estimated Probable Maximum Surge at the Savannah River Mouth

Components	Unit	Folly Island[a]	Jekyll Island[b]	Savannah Estuary[c]	Comments
Wind Setup	ft mlw[d]	17.15	20.63	18.89	Taken as average of wind set-up from Folly Island and Jekyll Island
Pressure Set-up	ft mlw	3.23	3.34	3.29	Taken as average of pressure set-up from Folly Island and Jekyll Island
Initial Water Level	ft mlw	1.00	1.20	1.10	Taken as average of initial water level from Folly Island and Jekyll Island
10% Exceedence High Tide	ft mlw	6.80	8.70	9.00	Magnitude at the Savannah River estuary taken from ANSI/ANS-2.8-1992; others from NRC RG 1.59 1977
Total Surge Height	ft mlw	28.2	33.9	32.3	Sum of wind and pressure set-up, initial water level, and 10% exceedence high tide
mlw to msl conversion[e]	ft			-1.2	Magnitude at the Savannah estuary obtained from ANSI/ANS-2.8-1992
Sea Surface Anomaly	ft			0.0	Magnitude at the Savannah estuary obtained from ANSI/ANS-2.8-1992
Total Surge Height	ft msl			31.1	

a NRC RG 1.59 1977
b NRC RG 1.59 1977
c Wind and pressure set-up, and initial water level averaged from Folly Island and Jekyll Island, tidal data was obtained from ANSI/ANS-2.8-1992
d Mean low water (mlw)
e Mean sea level (msl) = (mlw +1.2) ft at the Savannah estuary (ANSI/ANS-2.8 1992)

Table 2.4-232
Variation in Lowest Average Daily Temperatures and Number of Days with Average Daily Temperature Below Freezing

Year	Lowest Average Daily Temp °F (°C)		Date Lowest Average Daily Temp Occurred	Maximum No. of Consecutive Freezing Days	Total No. of Freezing Days
1984	25.7	-(3.5)	12/7/1984	1	3
1985	11.9	-(11.2)	1/21/1985	3	5
1986	20.7	-(6.3)	1/28/1986	2	3
1987	31.2	-(0.4)	1/27/1987	1	1
1988	25.2	-(3.8)	1/8/1988	3	6
1989	19.0	-(7.2)	12/23/1989	3	6
1990	37.3	(2.9)	12/25/1990	0	0
1991	26.0	-(3.3)	2/16/1991	1	1
1992	33.4	(0.8)	1/16/1992	0	0
1993	30.4	-(0.9)	3/14/1993	1	1
1994	21.3	-(5.9)	1/19/1994	2	4
1995	29.2	-(1.6)	2/9/1995	2	4
1996	20.8	-(6.2)	1/8/1996	3	8
1997	28.9	-(1.7)	1/18/1997	2	2
1998	34.8	(1.6)	12/26/1998	0	0
1999	25.2	-(3.8)	1/14/1999	3	3
2000	26.5	-(3.1)	12/20/2000	2	4
2001	30.9	-(0.6)	1/3/2001	2	2
2002	29.7	-(1.3)	1/4/2002	2	2
Average days				1.7	2.9

Table 2.4-233
Variation in the Minimum Water Temperatures at Five Locations on the Savannah River

USGS Station No.	Location	River Mile	Data Period	Observed Minimum Temperature, °F (°C)											
				Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.
02187500	Savannah River near Iva, SC	280.4	1958-1984	62.6 (17.0)	55.4 (13.0)	46.4 (8.0)	44.6 (7.0)	39.2 (4.0)	42.8 (6.0)	48.2 (9.0)	48.2 (9.0)	57.2 (14.0)	55.4 (13.0)	53.6 (12.0)	57.2 (14.0)
02189000	Savannah River near Calhoun Falls, SC	263.6	1957-1974	65.3 (18.5)	59 (15.0)	46.4 (8.0)	46.4 (8.0)	42.8 (6.0)	51.8 (11.0)	53.6 (12.0)	59.9 (15.5)	64.4 (18.0)	66.2 (19.0)	68 (20.0)	71.6 (22.0)
02197000	Savannah River at Augusta, GA	207.0	1958-1973	64.4 (18.0)	59 (15.0)	51.8 (11.0)	42.8 (6.0)	42.8 (6.0)	50 (10.0)	57.2 (14.0)	59.9 (15.5)	66.2 (19.0)	66.2 (19.0)	64.4 (18.0)	69.8 (21.0)
02197500	Savannah River at Burtons Ferry near Milhaven, GA	118.7	1957-1979	63.5 (17.5)	58.1 (14.5)	46.4 (8.0)	43.7 (6.5)	39.2 (4.0)	44.6 (7.0)	55.4 (13.0)	59 (15.0)	66.2 (19.0)	73.4 (23.0)	71.6 (22.0)	71.6 (22.0)
02198500	Savannah River near Clyo, GA	60.9	1938-1984	59.9 (15.5)	46.4 (8.0)	44.6 (7.0)	41 (5.0)	40.1 (4.5)	44.6 (7.0)	57.2 (14.0)	57.2 (14.0)	68 (20.0)	73.4 (23.0)	71.6 (22.0)	67.1 (19.5)

Source: Dyer and Alhadeff 1997

Table 2.4-234
Summary of Action Levels for Drought Management in the Savannah River Basin

Level	Reservoir Pool Levels				Action
	Hartwell Dam		J. S. Thurmond Dam[a]		
	Apr 18 – Oct 15 ft msl[b]	Dec 1 – Jan 1 ft msl	May 1 – Oct 15 ft msl	Dec 15 – Jan 1 ft msl	
1	656	655	326	325	Public Safety Information
2	654	652	324	322	Reduce Thurmond discharge to 4,500 cfs; reduce Hartwell discharge as appropriate to maintain balanced pool
3	646	646	316	316	Reduce Thurmond discharge to 3,600 cfs; reduce Hartwell discharge as appropriate to maintain balanced pool
4	625	625	312	312	Continue Level 3 discharge as long as possible; thereafter Inflow = Outflow

[a] J. Strom Thurmond Dam
[b] mean sea level
Source: USACE 1989

Table 2.4-235
Locations, Catchment Areas, and Data Availability of the USGS Gage Stations

Station Name	County/Town	USGS Station ID	Location			River Mile[a]	Catch-ment Area (mi^2)	Daily Streamflow Data Availability		
			Latitude	Longitude	HU[b]			Start Date	End Date	Count
Savannah River at Augusta	Richmond, GA	02197000	33°22'25"	81°56'35"	03060106	187.4	7,508	10/1/1883	9/30/2003	35,793
Savannah River near Jackson	Aiken, SC	02197320	33°13'01"	81°46'04"	03060106	156.8	8,110	10/1/1971	9/30/2002	10,733
Savannah River at Burtons Ferry near Millhaven	Millhaven, GA	02197500	32°56'20"	81°30'10"	03060106	118.7	8,650	10/1/1939	9/30/2003	18,993
Savannah River near Waynesboro	Burke, GA	021973269	33°08'59"	81°45'18"	03060106	150.6[c]	8,300	1/22/2005	9/30/2005	252

[a] USACE 1996
[b] Hydrological Unit
[c] Approximate River Mile
Source: USGS 2006g

Table 2.4-236 (Sheet 1 of 4)
Variation of Annual Minimum Daily-mean Flow in the Savannah River at Augusta, Jackson, and Burtons Ferry Gages

	Flow (ft^3/sec) at Locations			
	Augusta	Jackson	Burtons Ferry	
River Mile	187.7	156.8	118.7	Comments
1884	2,060			
1885	1,980			
1886	3,500			
1887	2,780			
1888	3,300			
1889	4,340			
1890	2,700			
1891	4,480			
1896	2,230			
1897	1,990			
1898	2,080			
1899	2,350			
1900	3,000			
1901	3,940			
1902	3,920			
1903	3,740			
1904	2,060			
1905	1,450			
1906	2,650			
1925	1,100			
1926	1,380			
1927	1,160			
1928	1,040			Historical low flow at Augusta on Oct. 2, 1927
1929	3,580			
1930	1,970			
1931	1,420			
1932	1,230			
1933	2,280			
1934	1,950			

Table 2.4-236 (Sheet 2 of 4)
Variation of Annual Minimum Daily-mean Flow in the Savannah River at Augusta, Jackson, and Burtons Ferry Gages

	Flow (ft^3/sec) at Locations			
	Augusta	Jackson	Burtons Ferry	
River Mile	187.7	156.8	118.7	Comments
1935	2,090			
1936	1,590			
1937	2,970			
1938	1,860			
1939	1,770			
1940	1,340		2,400	
1941	1,510		2,320	
1942	1,390		2,240	
1943	2,700		3,600	
1944	2,780		3,440	
1945	2,350		3,120	
1946	2,550		3,530	
1947	1,840		2,720	
1948	1,900		3,230	
1949	2,930		4,900	
1950	2,850		4,120	
1951	1,710		2,120	Lowest flow (within available data) at Burtons Ferry on Sep. 9, 1951
1952	1,770		2,550	J. Strom Thurmond Dam
1953	3,260		3,850	
1954	5,460		5,500	
1955	4,180		4,770	
1956	3,580		4,590	
1957	5,170		5,500	
1958	5,000		5,500	
1959	5,260		5,500	
1960	5,350		6,440	
1961	4,930		6,060	
1962	4,760		5,700	
1963	5,130		6,260	
1964	6,120		6,900	

Table 2.4-236 (Sheet 3 of 4)
Variation of Annual Minimum Daily-mean Flow in the Savannah River at Augusta, Jackson, and Burtons Ferry Gages

	Flow (ft^3/sec) at Locations			
	Augusta	Jackson	Burtons Ferry	
River Mile	187.7	156.8	118.7	Comments
1965	6,300		7,600	Hartwell Dam
1966	6,160		7,110	
1967	5,740		6,780	
1968	5,890		6,950	
1969	5,800		6,900	
1970	5,870		6,710	
1971	4,460			
1972	6,220	6,330		
1973	5,460	6,390		
1974	5,450	6,330		
1975	5,830	6,760		
1976	6,750	6,770		
1977	6,000	6,420		
1978	6,110	5,800		
1979	5,940	5,770		
1980	5,970	5,930		
1981	5,120	5,190		
1982	2,810	3,220		Lowest flow (within available data) at Jackson on Dec. 9, 1981
1983	5,080	5,050	5,870	
1984	4,740	4,900	5,210	
1985	4,750	4,760	4,830	Richard B. Russell Dam
1986	4,590	4,760	4,390	
1987	3,790	4,120	3,960	
1988	3,880	4,150	4,000	
1989	3,800	4,360	4,100	
1990	4,010	4,880	4,730	
1991	4,310	4,640	4,330	
1992	4,000	4,610	4,620	
1993	4,560	5,620	5,320	
1994	4,200	5,160	4,930	

Table 2.4-236 (Sheet 4 of 4)
Variation of Annual Minimum Daily-mean Flow in the Savannah River at Augusta, Jackson, and Burtons Ferry Gages

	Flow (ft^3/sec) at Locations			
	Augusta	Jackson	Burtons Ferry	
River Mile	187.7	156.8	118.7	Comments
1995	5,110	5,590	5,410	
1996	3,460	5,730	5,360	After 1985, lowest flow at Augusta on May 16, 1996
1997	4,230	4,790	4,480	
1998	4,300	5,310	5,370	
1999	3,800	4,710	4,490	
2000	3,880	4,300	4,160	
2001	3,670	4,380	4,550	
2002	3,730	3,960	3,920	After 1985, lowest flow at Jackson on Sep. 13, 2002; at Burtons Ferry on Sep. 14, 2002
2003	3,470		4,360	
Record Low Flow	1,040	3,220	2,120	
Low Flow between 1983–2002	3,460	3,960	3,920	Period of common data availability
Low Flow after 1985	3,460	3,960	3,920	Period after the completion of three major dams (present-day regulation of the Savannah River)

Source: USGS 2006g

Table 2.4-237
Summary of Statistical Parameters for Different Probability Density Functions Calculated with Annual Minimum Daily-mean Streamflow Values at Augusta for the Water Years 1884–1952

Distribution	Mean	SD[a]	Cs[b]	Goodness-of-Fit (95% confidence level)				Comments
				Standard Test Value		Present set of Data		
				χ^2	K-S[c]	χ^2	K-S	
Normal	2331.1	881.64	0.713	21.92	0.159	11.5	0.115	Acceptable
Exponential	2331.1	881.64	0.713			23.7	0.129	Not acceptable
Gumbel[d]	2331.1	881.64	0.713			6.9	0.046	Acceptable
P3[e]	2331.1	881.64	0.713			6.4	0.044	Acceptable
Log-Normal	7.7	0.37	0.011			11.0	0.050	Acceptable
LP3[f]	7.7	0.38	0.011			7.4	0.046	Acceptable, selected

a Standard Deviation
b Coefficient of Skewness
c Kolmogorov-Smirnov
d Extreme Value Type I
e Pearson Type 3
f Log-Pearson Type 3

Table 2.4-238
Summary of Low Flow Statistics for Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean and 7-Day Moving-average Streamflow Values at Augusta and Jackson for Different Water Years

Gage Station	Water Years	Data Type	Mean Ln (cfs)	SD[a]	Cs[b]	Goodness-of-Fit[c]		Low Flow Magnitudes (cfs) for Return Periods (years)				
						χ^2	K-S[d]	5	10	20	50	100
Augusta	1953-2003	Daily-mean	8.47	0.21	-0.38	23.6	0.093	3,985	3,684	3,465	3,246	3,115
	1985-2003	Daily-mean	8.31	0.11	0.49	6.9	0.079	3,708	3,569	3,466	3,361	3,298
	1985-2003	7-Day Moving-average	8.40	0.12	0.17	11.9	0.149	4,018	3,829	3,682	3,528	3,430
Jackson	1985-2002	Daily-mean	8.46	0.11	0.26	8.7	0.083	4,316	4,130	3,988	3,839	3,746
	1985-2002	7-Day Moving-average	8.52	0.14	0.27	10.0	0.083	4,478	4,238	4,056	3,868	3,752

a Standard deviation
b Coefficient of Skewness
c For 95% confidence limit, standard χ^2 test value is 21.92; for Kolmogorov-Smirnov tests the standard values are 0.154 for water years 1953-2003, 0.231 for 1985-2003, and 0.236 for 1985-2002
d Kolmogorov-Smirnov

Table 2.4-239
Summary of Streamflow Measurement at USGS Station No. 021973269
Savannah River Near Waynesboro

Measurement No.	Date	Width ft	Area ft^2	Mean Velocity fps	Gage Height ft	Streamflow cfs	Measurement Type
8	10/14/2005	359	2740	1.89	7.81	5,180	ADCP
7	5/18/2005	369	4000	2.03	10.56	8,120	ADCP
6	3/31/2005	423	6740	3.22	19.28	21,700	ADCP
5	3/17/2005	371	5540	2.63	14.80	14,600	ADCP
4	1/19/2005				12.03	9,840	ADCP
3	8/29/1988	333	2270	1.96	77.56	4,450	Boat
2	2/4/1987	310	3300	2.32	80.60	7,640	Boat
1	9/24/1986	300	2300	1.98	77.84	4,570	Boat

Note: A detailed discussion on gage heights for different years is included in Subsection 2.4.11.1.4
Source: USGS 2006j

Table 2.4-240
Summary of Proposed Modifications in Action Levels for Drought Management in the Savannah River Basin

Level	Reservoir Pool Levels				Action
	Hartwell Dam		J.S. Thurmond Dam[a]		
	Apr 1 – Oct 15 ft msl[b]	Dec 15 – Jan 1 ft msl	Apr 1 – Oct 15 ft msl	Dec 15 – Jan 1 ft msl	
1	656	654	326	324	Reduce Thurmond discharge to 4,200 ft^3/sec
2	654	652	324	322	Reduce Thurmond discharge to 4,000 ft^3/sec
3	646	646	316	316	Reduce Thurmond discharge to 3,800 ft^3/sec
4	625	625	312	312	Inflow = Outflow

[a] J. Strom Thurmond reservoir
[b] mean sea level
Source: USACE 2006c

Table 2.4-241
Monthly Groundwater Level Elevations in the Water Table Aquifer (ft msl)

Well No.	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07
142	154.37	154.38	154.49	154.64	154.75	154.69	154.60	154.71	154.78	154.71	154.63	154.55	154.48	154.41	154.36	0.00	0.00	154.16	154.03	154.00	153.97	153.93	153.75	153.59	153.61	153.59
179	147.42	148.40	148.42	148.72	148.69	148.75	148.52	148.61	148.64	148.72	148.66	148.76	148.78	148.56	148.75	0.00	0.00	148.79	148.78	148.57	148.89	148.51	148.45	148.40	148.40	148.44
802A	157.88	157.86	158.07	158.23	158.29	158.34	158.28	158.28	158.39	158.23	158.17	158.09	157.99	157.91	157.89	0.00	0.00	157.56	157.37	157.24	157.19	157.67	156.92	156.80	156.79	156.75
803A	159.98	159.91	160.15	160.32	160.39	160.48	160.39	160.37	160.48	160.45	160.30	160.20	160.12	159.96	159.88	0.00	0.00	159.64	159.50	159.25	159.30	159.25	158.94	158.80	158.80	158.78
804	163.73	163.62	163.92	164.10	164.21	164.23	164.05	164.08	164.23	164.30	164.11	163.99	163.88	163.69	163.69	0.00	0.00	162.84	163.19	162.95	162.98	163.09	162.47	162.59	162.70	162.82
805A	158.53	158.57	158.84	158.98	159.09	159.09	159.05	158.94	158.92	158.98	158.82	158.82	158.63	158.53	158.45	0.00	0.00	158.19	158.01	158.77	157.67	157.69	157.40	157.31	157.27	157.29
806B	155.62	155.65	155.78	155.90	155.96	155.98	155.88	155.97	155.98	156.03	155.85	155.78	155.73	155.68	155.62	0.00	0.00	155.42	155.21	155.06	155.10	155.09	154.89	154.71	154.72	154.69
808	158.88	159.14	159.42	159.55	159.49	159.37	159.15	159.04	159.19	159.15	158.99	158.53	158.80	158.72	158.65	0.00	0.00	158.40	158.40	158.00	157.96	158.17	158.01	158.06	158.02	157.93
809	152.78	152.70	152.75	152.89	152.98	152.97	152.98	153.10	153.22	153.18	153.05	153.02	153.00	152.88	152.86	0.00	0.00	152.71	152.62	152.63	152.65	152.62	152.37	152.30	152.32	152.3
LT-1B	154.92	154.82	155.01	155.16	155.18	155.22	155.06	155.18	155.52	155.28	155.18	155.15	154.95	154.95	154.95	0.00	0.00	154.78	154.63	154.51	154.33	154.35	154.28	153.98	153.98	153.9
LT-7A	154.39	154.15	154.33	154.46	154.48	154.46	154.31	154.57	154.83	154.59	154.57	154.50	154.41	154.30	154.34	0.00	0.00	154.25	154.01	153.96	153.68	153.70	153.68	153.24	153.36	153.32
LT-12	158.21	157.90	158.07	158.22	158.31	158.28	158.21	158.53	158.66	158.48	158.54	158.48	158.23	158.19	158.18	0.00	0.00	158.11	157.79	157.77	157.48	157.60	157.53	156.95	157.19	157.05
LT-13	156.10	155.92	156.13	156.30	156.32	156.37	156.23	156.36	156.66	156.35	156.32	156.32	156.23	156.08	156.14	0.00	0.00	155.93	155.75	155.63	155.41	155.55	155.30	155.05	155.10	155.05
OW-1003	155.94	155.89	156.06	156.29	156.24	156.36	156.26	156.34	156.37	156.43	156.32	157.24	156.16	156.03	155.98	0.00	0.00	155.90	155.70	155.60	155.91	155.70	155.46	155.34	155.35	155.3
OW-1005	132.95	132.73	132.88	133.01	132.67	132.65	132.53	132.74	133.04	133.12	133.14	133.20	133.12	132.94	132.84	0.00	0.00	132.50	132.39	132.32	132.51	132.25	132.18	132.07	132.04	132.14
OW-1006	147.66	147.48	147.57	147.60	147.49	147.20	147.18	147.41	147.40	147.37	147.35	147.12	147.05	146.88	146.80	0.00	0.00	146.47	146.26	146.25	146.47	146.10	145.98	145.60	145.70	145.58
OW-1007	151.82	151.72	151.78	151.63	151.45	151.15	151.05	151.41	151.49	151.45	151.22	151.11	150.99	150.76	150.53	0.00	0.00	150.08	149.94	150.06	150.24	150.26	150.14	149.96	149.86	149.7
OW-1009	162.38	162.40	162.71	162.90	163.01	163.03	162.87	162.93	163.01	163.01	162.89	162.79	162.65	162.50	162.44	0.00	0.00	162.17	161.95	161.74	161.89	161.80	161.65	161.54	161.53	161.42
OW-1010	163.06	163.26	163.59	163.77	163.81	163.78	163.62	163.60	163.63	163.57	163.44	163.29	163.09	162.91	162.84	0.00	0.00	162.51	162.33	162.24	162.23	162.40	162.45	162.33	162.25	161.89
OW-1012	161.83	161.93	162.07	162.06	161.98	161.80	161.71	161.82	161.86	161.80	161.68	161.53	161.37	161.22	161.00	0.00	0.00	160.49	160.31	160.19	160.26	160.23	160.15	159.95	159.95	159.8
OW-1013	164.95	165.00	165.29	165.47	165.48	165.42	165.21	165.29	165.46	165.31	165.23	165.11	164.96	164.79	164.68	0.00	0.00	164.25	164.01	163.76	163.94	163.75	163.68	163.49	163.49	163.39
OW-1015	159.63	159.58	159.78	159.90	159.96	159.96	159.82	159.81	159.79	159.89	159.75	159.66	159.58	159.45	159.35	0.00	0.00	159.06	158.83	158.58	158.63	158.52	158.24	158.07	158.04	157.94

Note.

Groundwater level data for the period between June 2005 and February 2006 provided Request For Information (RFI) Number 25144-000-GRI-GEX-00027, SNC ALWR ESP Project. **(Bechtel Power Corporation, March 2006).**

Groundwater level data for the period between March 2006 and June 2006 provided Request For Information (RFI) Number 25144-000-GRI-GEX-00038, SNC ALWR ESP Project. **(Bechtel Power Corporation, June 2006).**

Groundwater level data for the period between July 2006 and November 2006 provided Request For Information (RFI) Number 25144-000-GRI-GEX-00039, SNC ALWR ESP Project **(Bechtel Power Corporation, November 2006).**

Groundwater level data for the period between December 2006 and July 2007 provided Request For Information (RFI) Number 25144-000-GRI-GEX-00050, SNC ALWR ESP Project. **(Bechtel Power Corporation, August 2007)**.

Table 2.4-242
Monthly Groundwater Level Elevations in the Tertiary Aquifer (ft msl)

Well No.	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07
27	91.50	89.96	91.63	83.96	82.13	88.24	82.57	84.62	85.77	84.49	83.42	83.08	83.03	84.54	84.73	0.00	0.00	81.50	81.68	85.32	83.04	82.84	83.49	82.90	81.64	81.01
29	98.88	97.80	98.33	93.17	91.86	91.89	92.59	93.97	94.19	93.63	93.05	92.16	91.76	91.86	91.44	0.00	0.00	89.97	90.35	92.84	92.53	92.54	92.24	91.49	90.69	89.50
850A	105.27	104.68	104.76	101.04	100.03	99.91	100.70	101.86	101.69	101.48	101.14	100.07	99.63	99.23	98.57	0.00	0.00	97.56	98.21	100.01	100.60	100.50	99.88	99.19	98.66	97.06
851A	114.54	114.40	114.02	111.59	111.38	110.60	112.34	112.32	112.43	112.42	112.23	111.08	110.36	109.31	108.00	0.00	0.00	107.77	108.71	110.36	111.20	111.07	110.56	109.66	108.91	106.31
852	114.71	114.49	114.00	111.88	111.09	111.21	111.88	113.06	113.51	113.14	112.82	111.74	110.38	108.78	107.20	0.00	0.00	108.35	109.14	110.96	111.40	111.44	111.14	109.55	108.44	105.79
853	108.60	108.17	107.98	104.51	103.64	103.45	104.18	105.32	105.14	104.97	104.65	103.58	103.15	102.57	101.86	0.00	0.00	101.13	101.55	103.35	104.09	103.98	103.32	102.63	102.10	100.40
854	107.06	106.88	106.65	103.37	102.38	102.23	102.38	104.13	103.85	103.73	103.45	102.31	101.86	101.31	100.57	0.00	0.00	99.87	100.35	101.88	102.85	102.72	102.05	101.44	100.90	99.30
855	102.63	101.74	102.00	97.22	96.08	96.21	96.85	98.43	98.48	98.15	97.53	96.75	95.93	95.85	94.96	0.00	0.00	94.12	94.35	97.34	96.64	96.74	96.48	95.57	94.60	92.92
856	114.07	113.94	113.49	111.37	110.57	110.63	111.31	112.52	112.46	112.39	112.07	111.21	109.94	108.36	106.75	0.00	0.00	107.75	109.44	110.43	110.86	110.95	110.57	109.04	107.94	105.32
OW-1002	120.76	120.61	120.04	118.65	117.81	117.71	118.44	119.36	119.63	119.64	119.43	118.37	117.65	116.45	114.48	0.00	0.00	114.77	115.52	117.20	117.74	117.97	117.52	116.56	115.80	112.68
OW-1004	108.27	108.14	108.01	105.06	104.05	103.75	104.51	105.56	105.38	105.28	105.12	103.88	103.54	102.81	102.06	0.00	0.00	101.26	101.79	103.32	104.35	104.22	103.67	102.95	102.49	100.87
OW-1008	126.06	127.99	125.09	124.24	123.49	123.51	124.19	125.10	125.46	125.54	125.21	124.33	123.42	122.18	119.64	0.00	0.00	120.42	121.26	122.86	123.51	123.41	123.17	122.22	121.19	117.63
OW-1011	122.50	122.38	121.49	120.37	119.59	119.73	120.46	121.41	121.64	121.70	121.48	120.47	119.37	117.67	115.35	0.00	0.00	116.59	117.51	119.20	119.82	119.85	119.54	118.16	117.04	113.77
OW-1014	111.18	111.00	110.74	108.34	107.34	107.11	107.81	108.87	108.73	108.75	108.66	107.41	106.94	105.98	104.86	0.00	0.00	104.44	105.04	106.63	107.51	107.45	107.03	106.16	105.59	103.63

Note.

Groundwater level data for the period between June 2005 and February 2006 provided Request For Information (RFI) Number 25144-000-GRI-GEX-00027, SNC ALWR ESP Project. (Bechtel Power Corporation, March 2006).

Groundwater level data for the period between March 2006 and June 2006 provided Request For Information (RFI) Number 25144-000-GRI-GEX-00038, SNC ALWR ESP Project. (Bechtel Power Corporation, June 2006).

Groundwater level data for the period between July 2006 and November 2006 provided Request For Information (RFI) Number 25144-000-GRI-GEX-00039, SNC ALWR ESP Project. (Bechtel Power Corporation, November 2006).

Groundwater level data for the period between December 2006 and July 2007 provided Request For Information (RFI) Number 25144-000-GRI-GEX-00050, SNC ALWR ESP Project. (Bechtel Power Corporation, August 2007).

Table 2.4-243 (Sheet 1 of 2)
Hydraulic Conductivity Values

Observation Well No.	Depth Test Interval	Aquifer	Material	Hydraulic Conductivity	
	(ft)			(cm/sec)	(ft/day)
OW-1003	72 - 91	Water Table	Reddish brown silty SAND (SM) with Light tan silty SAND with Tan and grey clayey COQUINA.	4.4E-05	0.12
OW-1005	143 - 169	Water Table	Pale yellow, silty SAND, calcareous (SM), fine-coarse-grained with shell pieces.	1.1E-04	0.32
OW-1006	113 - 136	Water Table	Very light tan silty SAND (SM) with light gray COQUINA, unconsolidated (OW-1006A). Tan sandy and shelly CLAY (CH), saturated with light tan, fine-coarse grained SAND with shell (SW) (OW-1006).	4.8E-04	1.4
OW-1007	99 - 120	Water Table	Tan fine-grained silty SAND (SM), saturated with very light tan silty SAND (SM) becoming shelly with light olive grey CLAY (CH).	9.3E-04	2.65
OW-1009	81 - 98	Water Table	Very light tan silty SAND (SM) with Tan limestone shell hash, very light tan silty SAND (SM) WITH "Brown silty CLAY.	4.0E-04	1.1
OW-1010	70 - 92	Water Table	Tan poorly graded SAND with silt (SP-SM) with brownish yellow clayey silty SAND (SC-SM), soft with white SHELL HASH.	6.4E-05	0.18
OW-1012	71 - 94	Water Table	Brown SAND, fine-to-medium-grained with pale yellow silt (SM) with Pale olive silt (ML) with pale yellow SILT, micaceous (ML).	1.4E-04	0.39
OW-1013	81 - 104	Water Table	Tan fine-to-medium-grained SAND (SP-SM) with tan or clay tubes or bioturbation with light olive tan calcareous silty fine grained-grained SAND (SP-SM) with light olive tan calcareous CLAY (CL), wet but not saturated.	1.3E-04	0.38
OW-1015	90 - 120	Water Table	Grayish white, fine-to-medium-grained SAND (SP) saturated with very light tan poorly graded SAND with silt (SP-SM) with tan shelly (coarse) fine to medium grained clayey SAND (SC).	1.5E-04	0.44

Table 2.4-243 (Sheet 2 of 2)
Hydraulic Conductivity Values

Observation Well No.	Depth Test Interval	Aquifer	Material	Hydraulic Conductivity	
OW-1002	216 - 237	Tertiary	Light greenish gray fine- to medium- grained silty, glauconitic SAND with gray clay layer (SM).	3.2E-04	0.9
OW-1004	150 - 187	Tertiary	Fine- to medium- grained dark gray SAND with organics, wet, poorly graded with silt (SP-SM).	1.3E-04	0.35
OW-1008	226 - 247	Tertiary	Gray, fine SAND (SW) with light gray fine sand (SM).	7.5E-04	2.1
OW-1011	197 - 218	Tertiary	Dark bluish-gray silty fine- to medium- grained SAND, very moist with gray, poorly graded sand with silt (SP-SM) with silty gravelly sand with fossils, shark teeth with gray medium- to coarse-grained SAND.	3.8E-04	1.1
OW-1014	179 - 197	Tertiary	Dark gray silty SAND (SM-SP), high organic content, saturated with light gray fine quartz SAND (SP), silty SAND (SM) and dark gray Sandy SILT (ML).	1.9E-04	0.54
			Geometric Mean Water Table Aquifer	1.75E-04	0.5
			Geometric Mean Tertiary Aquifer	2.95E-04	0.83

Note.
Hydraulic conductivity values provided in Appendix 2.5A (report Appendix D)
Material descriptions from the borings logs provided in Appendix 2.4A (report Appendix E)

Table 2.4-244 (Sheet 1 of 2)
Summary of Laboratory Test Results on Grain Size, Moisture Content and Specific Gravity for the Barnwell Formation

ESP / COL	Borehole / Well No.	Sample Elevation	Water Table Elevation1	Grain Size Distribution			Moisture Content	Specific Gravity
				Gravel	Sand	Clay/Silt		
		(ft msl)	(ft msl)	(%)	(%)	(%)	(%)	
ESP	OW-1003	144.5	156.0	0.0	65.1	34.9	ND	2.69
ESP	OW-1003	139.5	156.0	31.1	50.0	18.4	ND	2.68
ESP	OW-1005	115.9	132.0	8.9	57.0	34.1	ND	2.63
ESP	OW-1005	110.9	132.0	18.2	47.6	34.3	ND	2.61
ESP	OW-1006	113.6	146.0	7.0	61.1	31.9	ND	2.67
ESP	OW-1006	108.6	146.0	3.6	74.4	22.0	ND	2.59
ESP	OW-1007	113.4	152.0	0.0	85.0	15.0	ND	2.65
ESP	OW-1007	108.4	152.0	0.0	85.0	18.1	ND	2.66
ESP	OW-1009	135.9	162.0	2.7	74.6	22.7	ND	2.61
ESP	OW-1009	130.9	162.0	34.7	45.9	19.2	ND	2.75
ESP	OW-1010	143.4	163.0	0.0	89.3	10.7	ND	2.67
ESP	OW-1010	138.4	163.0	0.0	63.5	36.5	ND	2.63
ESP	OW-1012	131.9	162.0	0.0	76.1	23.9	ND	2.66
ESP	OW-1012	126.9	162.0	0.0	14.1	85.9	ND	2.66
ESP	OW-1013	132.9	164.0	0.0	91.1	8.9	ND	2.65
ESP	OW-1013	122.9	164.0	0.0	91.1	8.9	ND	2.65
ESP	OW-1015	126.9	160.0	0.0	97.7	2.8	ND	2.63
ESP	OW-1015	125.4	160.0	0.0	93.2	6.8	ND	2.67
ESP	B-1002	148.5	150.0	0.4	89.6	10.0	24.5	ND
ESP	B-1002	138.5	150.0	0.0	93.9	6.1	27.6	ND
ESP	B-1003	148.2	156.0	0.0	91.8	8.2	32.3	ND
ESP	B-1004	126.3	144.0	48.6	32.2	19.2	19.7	ND
ESP	B-1010	160.1	164.0	0.0	86.7	13.3	27.3	ND
COL	B-3001	159.9	159.0	0.0	93.6	6.4	ND	ND
COL	B-3002	155.4	159.0	0.0	84.3	15.7	47.0	ND
COL	B-3003	159.8	159.0	ND	ND	15.4	ND	ND
COL	B-3004	160.0	159.0	ND	ND	5.3	ND	ND
COL	B-3008	159.4	159.0	0.0	84.4	15.6	31.4	ND
COL	B-3024	156.7	155.0	ND	ND	8.4	ND	ND
COL	B-3036	149.4	159.0	0.0	76.5	23.5	ND	ND

Table 2.4-244 (Sheet 2 of 2)
Summary of Laboratory Test Results on Grain Size, Moisture Content and Specific Gravity for the Barnwell Formation

ESP / COL	Borehole / Well No.	Sample Elevation	Water Table Elevation1	Grain Size Distribution			Moisture Content	Specific Gravity
				Gravel	Sand	Clay/Silt		
		(ft msl)	(ft msl)	(%)	(%)	(%)	(%)	
COL	B-4002	145.6	155.0	ND	ND	6.2	ND	ND
COL	B-4004	155.0	157.0	10.5	70.9	18.6	31.5	ND
COL	B-4004	145.0	157.0	2.1	81.4	16.5	24.2	ND
COL	B-4007	159.4	158.0	ND	ND	12.5	ND	ND
COL	B-4009	154.4	157.0	0.0	90.2	9.8	ND	ND
						Median	27.6	2.66

Note.
[1] Elevation at time of sample collection (October 2005 for ESP samples, February 2007 for COL samples)
ND - Not Determined
OW-series data are provided in Appendix 2.4A
B-series ESP data are provided in Appendix 2.5A
B-series COL data are provided in Appendix 2.5C
Moisture content is by weight percent.

Table 2.4-245
Summary of Laboratory Test Results on Grain Size, Moisture Content, and Porosity for the Lisbon Formation

Borehole/Well	Sample	Grain Size Distribution			Moisture	D50	Porosity
No.	Elevation	Gravel	Sand	Clay/Silt	Content		
	(ft msl)	(%)	(%)	(%)	(%)	(mm)	
B-1002	130.0	49.4	21.7	28.9	52.1	3.49	0.59
B-1002	118.5	22.9	41.2	35.9	56.5	0.26	0.56
B-1002	108.5	12.8	53.4	33.8	25.5	0.21	0.36
B-1002	98.5	53.7	21.8	24.5	13.5	7.52	0.25
B-1002	88.5	26.3	49.4	24.3	28.6	0.87	0.45
B-1003	135.2	16.5	50.1	33.4	67.4	0.43	ND
B-1003	130.2	1.6	57.8	40.6	30.6	0.14	0.46
B-1003	118.5	1.2	67.1	31.7	40.6	0.27	0.52
B-1003	101.5	11.7	45.8	42.5	28.0	0.12	0.42
B-1003	81.5	7.3	58.5	34.2	25.9	0.15	0.39
B-1004	105.8	1.0	52.7	46.3	44.6	0.10	0.56
B-1004	96.3	0.7	57.6	41.7	30.1	0.15	0.45
B-1004	86.3	38.0	29.8	32.2	25.1	0.49	0.43
B-1004	72.8	20.9	37.4	41.7	20.8	0.12	0.38
B-1004	61.3	34.9	41.3	23.8	29.0	0.85	0.44
B-1004	51.3	5.2	60.3	34.5	26.2	0.18	0.39
				Median	29	0.24	0.44

Note.

ND – Not Determined
B-series data are provided in Appendix 2.5A
Moisture content is by weight percent.
Porosity calculated assuming specific gravity of 2.65.

Table 2.4-246 (Sheet 1 of 2)
Summary of Laboratory Test Results on Grain Size, Moisture Content, and Specific Gravity for the Still Branch and Congaree Formations

ESP / COL	Borehole / Well No.	Sample Elevation (ft msl)	Grain Size Distribution			Moisture Content (%)	Specific Gravity
			Gravel (%)	Sand (%)	Clay/Silt (%)		
ESP	OW-1002	8.9	0.2	79.6	20.2	ND	2.65
ESP	OW-1002	-9.6	0.0	1.4	90.6	ND	2.62
ESP	OW-1004	69.4	0.1	89.7	10.2	ND	2.69
ESP	OW-1004	64.4	0.0	93.4	6.6	ND	2.67
ESP	OW-1008	-11.9	0.0	83.2	16.8	ND	2.69
ESP	OW-1008	-21.9	2.2	67.9	20.3	ND	2.68
ESP	OW-1011	12.3	0.0	88.9	10.8	ND	2.67
ESP	OW-1011	-2.7	4.5	89.6	5.9	ND	2.66
ESP	OW-1014	37.4	0.0	87.8	12.2	ND	2.69
ESP	OW-1014	32.4	0.0	89.6	10.4	ND	2.66
ESP	B-1002	68.5	20.0	40.6	39.4	23.3	ND
ESP	B-1002	33.5	0.0	93.4	6.6	40.7	ND
ESP	B-1002	16.5	3.1	84.6	12.3	18.5	ND
ESP	B-1003	57.5	0.0	94.6	5.4	23.6	ND
ESP	B-1003	37.5	0.9	82.7	16.4	32.3	ND
ESP	B-1003	17.5	1.4	77.2	21.4	39.3	ND
ESP	B-1003	-17.5	0.0	89.1	10.9	23.2	ND
ESP	B-1003	-57.5	0.3	85.5	14.2	23.2	ND
ESP	B-1003	-92.5	70.7	26.0	3.3	32.7	ND
ESP	B-1003	-127.5	0.0	21.5	78.5	21.3	ND
ESP	B-1003	-177.5	0.3	83.9	15.8	18.9	ND
ESP	B-1003	-227.5	0.0	84.1	15.9	28.6	ND
ESP	B-1003	-273.5	0.0	86.8	13.2	26.4	ND
COL	B-3001	44.9	ND	ND	11.6	24.2	2.65
COL	B-3001	24.9	ND	ND	ND	28.1	ND
COL	B-3001	9.9	ND	ND	17.0	21.4	ND
COL	B-3003	55.3	ND	ND	20.8	20.1	ND
COL	B-3021	74.7	0.5	91.6	7.9	ND	ND
COL	B-3021	69.7	0.0	87.5	12.5	19.3	ND
COL	B-3023	74.8	ND	ND	ND	24.5	ND

Table 2.4-246 (Sheet 2 of 2)
Summary of Laboratory Test Results on Grain Size, Moisture Content, and Specific Gravity for the Still Branch and Congaree Formations

ESP / COL	Borehole / Well No.	Sample Elevation (ft msl)	Grain Size Distribution			Moisture Content (%)	Specific Gravity
			Gravel (%)	Sand (%)	Clay/Silt (%)		
COL	B-3036	64.4	9.4	81.1	9.5	20.0	ND
COL	B-4001	40.4	0.9	73.9	25.2	32.7	ND
COL	B-4001	20.4	ND	ND	19.7	ND	ND
COL	B-4001	-19.6	ND	ND	69.6	18.6	ND
COL	B-4001	-29.6	ND	ND	ND	16.5	2.65
COL	B-4001	-79.6	ND	ND	13.7	ND	ND
COL	B-4001	-89.6	ND	ND	67.4	16.7	2.68
COL	B-4002	45.6	ND	ND	5.4	17.9	ND
COL	B-4002	-14.4	ND	ND	ND	27.7	ND
COL	B-4003	18.0	ND	ND	18.3	ND	ND
COL	B-4003	-29.5	ND	ND	17.8	ND	ND
COL	B-6027	63.2	0.0	78.2	21.8	17.3	ND
COL	B-6027	58.2	0.0	93.3	6.7	23.8	ND
COL	B-6027	48.2	0.5	90.8	8.7	29.5	ND
COL	B-6027	43.2	0.0	77.5	22.5	23.8	ND
COL	B-6027	38.2	0.0	78.8	21.2	32.4	ND
COL	B-6027	33.2	0.0	91.2	8.8	24.8	ND
COL	B-6028	67.2	0.3	97.3	2.4	25.6	ND
COL	B-6028	57.2	0.0	98.4	1.6	19.8	ND
COL	B-6028	47.2	4.9	88.3	6.8	19.6	ND
COL	B-6029	46.9	0.0	89.1	10.9	23.4	ND
COL	B-6030	44.9	0.0	44.5	55.5	35.9	ND
					Median	23.6	2.67

Note.
ND – Not Determined
OW-series data are provided in Appendix 2.4A
ESP-series data are provided in Appendix 2.5A
COL-series data are provided in Appendix 2.5C
Moisture content is by weight percent.

Table 2.4-247
Georgia EPD Permitted Municipal and Industrial Groundwater Users within 25 miles of the VEGP Site

Well ID	Permit Holder	County	Aquifer	Year	Permitted Monthly Average, gpm (mgpd)	Permitted Annual Average, gpm (mgpd)	Average Annual Water Use, gpm (mgpd)
C-2	City of Sardis	Burke	Floridan	2004	278 (0.40)	278 (0.40)	63 (0.09)
				2005	278 (0.40)	278 (0.40)	NA
C-12	East Central Regional Hospital - Gracewood Campus	Richmond	Cretaceous Sand	2004	347 (0.50)	278 (0.40)	146 (0.21)
				2005	NA	NA	76 (0.11)
C-13	City of Hephzibah	Richmond	Cretaceous Sand	2004	833 (1.20)	833 (1.20)	160 (0.23)
				2005	NA	NA	236 (0.34)
C-19	Olin Corporation	Richmond	Cretaceous Sand	2004	847 (1.22)	847 (1.22)	514 (0.74)
				2005	NA	NA	486 (0.70)
C-19	Olin Corporation - Corrective Action Wells	Richmond	Cretaceous Sand	2004	632 (0.91)	632 (0.91)	229 (0.33)
				2005	NA	NA	250 (0.36)
I-1	International Paper	Burke	Cretaceous Sand	2004	660 (0.95)	660 (0.95)	181 (0.26)
				2005	660 (0.95)	660 (0.95)	35 (0.05)
I-2	Prayon, Inc	Richmond	Cretaceous Sand	2004	292 (0.42)	264 (0.38)	35 (0.05)
				2005	NA	NA	63 (0.09)
I-3	Thermal Ceramics, Inc.	Richmond	Cretaceous Sand	2004	625 (0.90)	625 (0.90)	313 (0.45)
				2005	NA	NA	208 (0.30)
I-4	Procter & Gamble Manufacturing Company	Richmond	Cretaceous Sand	2004	486 (0.70)	486 (0.70)	278 (0.40)
				2005	NA	NA	243 (0.35)
I-5	Southern Wood Piedmont Company	Richmond	Cretaceous Sand	2004	451 (0.65)	451 (0.65)	188 (0.27)
				2005	NA	NA	174 (0.25)
M-1	City of Waynesboro	Burke	Cretaceous Sand	2004	2778 (4.00)	2431 (3.50)	NA
				2005	2778 (4.00)	2431 (3.50)	NA
M-2	Augusta-Richmond Utilities Department	Richmond	Cretaceous Sand	2004	12778 (18.40)	12083 (17.40)	8285 (11.93)
				2005	NA	NA	8.40
	Southern Nuclear Operating Co.	Burke	Cretaceous Sand	2004	4167 (6.00)	3819 (5.50)	556 (0.80)
				2005	4167 (6.00)	3819 (5.50)	583 (0.84)

Notes:
NA – not available
Groundwater permit and usage data (Voudy 2006)
Groundwater aquifer description (Georgia DNR 2006)
Well locations are labeled in Figure 2.4-252 using the listed Well IDs.
Southern Nuclear Operating Co. well locations are shown on Figure 2.4-253.

Table 2.4-248 (Sheet 1 of 2)
Georgia EPD Permitted Agricultural Groundwater Users within 25 miles of the VEGP Site

Well ID	Permit Holder	County	Depth (ft)	Permit (gpm)
A-1	ANDERSON JOHN	Burke	363	1500
A-2	BLANCHARD HENRY	Burke	500	1200
A-3	BLANCHARD HENRY	Burke	450	1400
A-4	BOLLWEEVIL PLANATION	Burke	300	190
A-5	Chance Bill	Burke	500	450
A-6	CHANDLER FARM	Burke	580	1600
A-7	Chandler Michael	Burke	556	2400
A-8	Chandler Randall	Burke	579	2500
A-9	COCHRAN IRBY	Burke	420	1350
A-10	COLLINS ROBERT	Burke	430	1350
A-11	COLLINS ROBERT	Burke	530	1200
A-12	COLLINS ROBERT	Burke	480	1100
A-13	COLLINS ROBERT	Burke	440	1100
A-14	Collins Robert	Burke	490	1700
A-15	DIXON CARL	Burke	600	2000
A-16	DIXON JAMES	Burke	210	400
A-17	DIXON JAMES	Burke	200	200
A-18	DIXON JOANNE	Burke	640	1150
A-19	DIXON PERCY	Screven	560	2000
A-20	DIXON PERCY	Burke	560	2000
A-21	DIXON PERCY	Burke	350	115
A-22	DIXON PERCY	Burke	350	115
A-23	DIXON PERCY	Burke	550	3400
A-24	DIXON PERCY	Burke	350	200
A-25	DIXON PERCY	Burke	575	2500
A-26	DIXON PERCY	Burke	550	2500
A-27	GWR Partnership LLP	Burke	360	200
A-28	Hatcher William	Burke	300	500
A-29	HEATH CLAXTON	Burke	300	150
A-30	HEATH CLAXTON	Burke	400	250
A-31	HEATWOLE BYARD	Burke	325	200
A-32	HOPKINS HENRY	Burke	363	350
A-33	Horst Isaac	Burke	260	250
A-34	MALLARD CLYDE	Burke	320	400
A-35	MALLARD CLYDE MALLARD FARMS	Burke	210	250
A-36	MALLARD J.	Burke	200	150
A-37	McGregor Charles	Burke	430	350
A-38	MOBLEY DANNY	Burke	396	350
A-39	Mobley Danny	Burke	424	650
A-40	MOBLEY HERBERT	Burke	465	1100
A-41	MOBLEY HERBERT	Burke	500	1250
A-42	MOBLEY JAMES F.	Burke	572	2000
A-43	PENNINGTON FARMS- INC.	Burke	240	250

Table 2.4-248 (Sheet 2 of 2)
Georgia EPD Permitted Agricultural Groundwater Users within 25 miles of the VEGP Site

Well ID	Permit Holder	County	Depth (ft)	Permit (gpm)
A-44	RAYMOND NEIL	Burke	430	1350
A-45	Shepherd Joseph	Burke	421	1500
A-46	SMART DARRELL	Burke	300	350
A-47	SMART DARRELL	Burke	300	350
A-48	SMART DARRELL	Burke	300	350
A-49	SMART DARRELL	Burke	300	400
A-50	MIMS JOHN	Jenkins	445	1500
A-51	MIMS JOHN	Jenkins	460	1500
A-52	MULKEY A.	Jenkins	300	1000
A-53	MULKEY A.	Jenkins	400	500
A-54	PARKER GEORGE	Jenkins	450	700
A-55	PARKER GEORGE	Jenkins	300	450
A-56	PARKER GEORGE	Jenkins	300	450
A-57	Parker George	Jenkins	450	450
A-58	POINTE SOUTH GOLF CLUB- INC.	Richmond	311	400
A-59	BRAGG SOL	Screven	380	240
A-60	BRIAR CREEK COUNTRY CLUB	Screven	180	300
A-61	CAIN BRIAN	Screven	390	600
A-62	Cain Brian	Screven	493	1100
A-63	CLEMENT INVESTMENTS	Screven	282	1250
A-64	FOREHAND FARMS	Screven	160	250
A-65	Lee Mike	Screven	480	1800
A-66	Mill Haven Company Inc.	Screven	600	1200
A-67	MILLHAVEN CO.- INC.	Screven	553	1900
A-68	MILLHAVEN CO.- INC.	Screven	565	1400
A-69	NEWTON JAMES	Screven	350	400
A-70	SOWELL CAROLYN	Screven	275	300
A-71	STEPONGZI FRANK & PEARL	Screven	225	300
A-72	THOMPSON JAMES	Screven	475	750
A-73	THOMPSON ROGER	Screven	500	1000
A-74	WADE PLANTATION	Screven	215	200
A-75	WADE PLANTATION	Screven	250	190
A-76	WADE PLANTATION	Screven	460	1200
A-77	WADE PLANTATION	Screven	119	1000
A-78	WADE PLANTATION	Screven	750	1800
A-79	WADE PLANTATION	Screven	494	900
A-80	WADE PLANTATION	Screven	475	1200
A-81	WADE PLANTATION	Screven	672	1100
A-82	WADE PLANTATION	Screven	475	1100
A-83	WADE PLANTATION	Screven	525	1400
A-84	Wade Plantation	Screven	467	1100

Notes: Groundwater permit data (Lewis 2006)
Well locations are labeled in Figure 2.4-252 using the listed Well IDs.

Table 2.4-249
SDWIS Listed Public Water Systems Supplied From Groundwater Within 25 Miles of the VEGP Site in Georgia

Well ID	Water System ID	Water System Name	County Served	Type	System Status
C-1	GA0330000	Girard	Burke	Community	Active
C-2	GA0330002	Sardis	Burke	Community	Active
C-3	GA0330013	Mamie Joe Rhodes Harrison Subdivision	Burke	Community	Closed
C-4	GA0330006	Burke Academy	Burke	Non-Transient Non-Community	Active
C-5	GA0330022	Burke County Training Center	Burke	Non-Transient Non-Community	Active
C-6	GA0330020	Delaigle Mobile Home Park	Burke	Transient Non-Community	Closed
C-7	GA1650000	Millen	Jenkins	Community	Active
C-8	GA1650001	Perkins Water Authority	Jenkins	Community	Active
C-9	GA1650006	Jockey International, Inc.	Jenkins	Non-Transient Non-Community	Active
C-10	GA1650005	DNR - Magnolia Springs State Pk.	Jenkins	Transient Non-Community	Active
C-11	GA1650008	National Fish Hatchery	Jenkins	Transient Non-Community	Closed
C-12	GA2450023	East Central Regional Hospital	Richmond	Community	Active
C-13	GA2450002	Hephzibah	Richmond	Community	Active
C-14	GA2450017	Hephzibah - Oakridge	Richmond	Community	Active
C-15	GA2450014	Mars Trailer Park	Richmond	Community	Active
C-16	GA2450016	Mobile Home Country Club MHP	Richmond	Community	Active
C-17	GA2450004	Richmond County	Richmond	Community	Closed
C-18	GA2450159	Albion Kaolin Company	Richmond	Non-Transient Non-Community	Closed
C-19	GA2450152	Olin Chemicals	Richmond	Non-Transient Non-Community	Closed
C-20	GA2510000	Hiltonia	Screven	Community	Active
C-21	GA2510015	Buck Creek M.H.P.	Screven	Community	Closed
C-22	GA2510052	Millhaven Plantation	Screven	Community	Closed
C-23	GA2510011	DOT - Georgia Welcome Center	Screven	Transient Non-Community	Active
C-24	GA2510057	Savannah River Challenge Program	Screven	Transient Non-Community	Active
	GA0330035	Southern Nuclear - Simulator Bld	Burke	Non-Transient Non-Community	Active
	GA0330017	Southern Nuclear - Vogtle Makeup	Burke	Non-Transient Non-Community	Active
	GA0330036	Southern Nuclear - Vogtle Rec	Burke	Transient Non-Community	Active

Notes: US EPA SDWIS Database (EPA 2006b)
Well locations are labeled in Figure 2.4-252 using the listed Well IDs.
Southern Nuclear Operating Co. well locations are shown on Figure 2.4-253.

Table 2.4-250
Water-Supply Wells for the Existing VEGP Plant

Water Supply Well No.	Well Depth (ft)	Aquifer	Design Yield (gpm)	Water Use
MU-1	851	Cretaceous	2000	Make-up water for plant use (nuclear service water system; make-up to the water treatment plant demineralizer, and potable water source).
MU-2A	884	Cretaceous	1000	Make-up water for plant use (nuclear service water system; make-up to the water treatment plant demineralizer, and potable water source).
TW-1	860	Cretaceous	1000	Back-up water for the production make-up well system.
SW-5	200	Tertiary	20	Water supply for old security tactical training area.
IW-4	370	Tertiary	120	Irrigation water for ornamental vegetation.
CW-3	220	Tertiary	NA	Water supply for nuclear operations garage.
REC	265	Tertiary	150	Potable water supply for recreation area.
SB	340	Tertiary	50	Potable water supply for simulator training building.
SEC	320	Tertiary	10	Non-potable water for lavatory use at a new plant entrance security building

Notes: NA – not available
Water supply well data (excluding SEC well) (SNC 2005b)
SEC well data (SNC 2005a)
Well locations, excluding Well REC, are shown on Figure 2.4-253. Well REC is located approximately 9300 ft southwest from Well IW-4.

Table 2.4-251
Groundwater Use of the existing VEGP Plant from January 1, 2005, to December 31, 2005, gpm (Thousands of Gallons)

Month	Well MU-1	Well MU-2A	Well TW-1	Well SW-5	Well IW-4	Well CW-3	Well REC	Well SB
January	445 (19,209)	0	0	0	0	0.07 (3)	0.88 (38)	0.05 (2)
February	403 (17,416)	0	0	0	0	0.05 (2)	1.16 (50)	1.34 (58)
March	500 (21,601)	0	0	0	0	0.05 (2)	0.95 (41)	1.25 (54)
April	607 (26,211)	0	0	0	0	0.02 (1)	1.09 (47)	1.5 (65)
May	686 (29,648)	0	0	0	0	0.05 (2)	1.55 (67)	1.74 (75)
June	825 (35,625)	0	0	0	0.32 (14)	0.05 (2)	0.97 (42)	1.92 (83)
July	552 (23,846)	0	0	0	1.27 (55)	0.05 (2)	2.89 (125)	2.73 (118)
August	569 (24,560)	0	0	0	2.92 (126)	0.14 (6)	2.41 (104)	1.53 (66)
September	649 (28,020)	0	0	0	3.1 (134)	0.09 (4)	1.94 (84)	1.6 (69)
October	701 (30,290)	0	0	0	0	0.07 (3)	1.83 (79)	1.13 (49)
November	469 (20,282)	67 (2,880)	0	0	0	0.05 (2)	1.67 (72)	2.41 (104)
December	610 (26,363)	0	0	0	0	0.05 (2)	0.95 (41)	3.7 (160)
Total	7016 (303,071)	67 (2,880)	0	0	7.62 (329)	0.72 (31)	18.26 (789)	22.55 (974)
Monthly Average	585 (252,56)	6 (240)	0	0	0.625 (27)	0.07 (3)	1.53 (66)	1.88 (81)

Notes: Groundwater use data from Southern Nuclear Operating Company
SEC well is active in 2006

Table 2.4-252
Projected Groundwater Use for Two AP1000 Units

Water Use	Normal Case (gpm)	Maximum Case (gpm)
Service Water System Make-up	537	2353
Potable Water System	42	140
Demineralized Water System	150	600
Fire Protection System	10	12
Miscellaneous Users	13	35
Total	752	3140

Table 2.4-253 (Sheet 1 of 6)
Presence of Utley Limestone in the VEGP ESP and COL Site Borings

Boring No.	Coordinates (NAD 27)		Utley Limestone
	Northing	Easting	
COL Boring Data			
B-1105	1144168.4	620002.8	Absent
B-1107	1144153.8	620916.1	Present
B-1108	1144214.1	621273.0	Present
B-1109	1144180.5	621580.6	Present
B-1110	1144170.9	622011.3	Present
B-1111	1144212.6	622333.8	Present
B-1112A	1144219.4	622561.5	Absent
B-1113	1143901.4	620217.2	Present
B-1116	1143894.1	621264.7	Present
B-1117	1143890.8	621628.4	Absent
B-1118	1143885.9	622008.0	Absent
B-1119	1143888.3	622333.8	Present
B-1120	1143893.1	622558.5	Present
B-1121	1143575.6	620216.3	Present
B-1123	1143575.4	620922.0	Present
B-1124	1143627.6	621421.6	Absent
B-1125	1143586.8	621628.2	Present
B-1126	1143567.7	621980.4	Absent
B-1127	1143573.3	622332.3	Absent
B-1128	1143572.7	622682.4	Absent
B-1129	1143278.2	621893.7	Present
B-1130	1142482.8	622250.0	Present
B-1131	1143173.0	621823.1	Present
B-1132	1142614.2	621450.1	Present
B-1133	1142968.9	621451.2	Absent
B-1134	1143282.9	621104.3	Present
B-1136	1143178.1	621023.0	Absent
B-1138	1143469.7	619192.8	NE
B-1139	1142289.9	621026.8	Present
B-1140	1142290.2	621823.6	Present
B-1142	1144416.6	620649.6	NE
B-1146	1145428.4	622272.1	Present
B-1148	1145537.8	623236.5	Absent
B-1150	1145467.3	624235.3	Absent
B-1152	1145581.7	625227.3	Absent

Table 2.4-253 (Sheet 2 of 6)
Presence of Utley Limestone in the VEGP ESP and COL Site Borings

Boring No.	Coordinates (NAD 27)		Utley Limestone
	Northing	Easting	
B-1153	1145569.0	625673.5	Absent
B-1154	1145664.2	626216.1	Absent[1]
B-1155	1147390.3	624936.4	Absent[1]
B-1156	1147302.5	624571.7	Absent[1]
B-1157	1147209.6	625062.2	Absent
B-1158	1145194.9	626669.1	Absent[1]
B-1159	1147285.8	624954.5	Absent
B-1161	1147363.4	624862.1	Absent[1]
B-1162	1147234.9	624815.0	Absent[1]
B-1163	1147170.6	624938.8	Absent
B-1164	1146994.8	624518.6	Present
B-1166	1147453.0	623961.6	Absent
B-1168	1147688.5	623467.8	Absent
B-1170	1147423.9	622953.7	NE
B-1172	1146983.4	622538.7	NE
B-1174	1146476.1	622228.1	NE
B-1176	1145876.3	622195.2	NE
B-1176A	1145878.8	622196.8	Present
B-1185	1144716.6	622232.2	Present
B-1186	1144711.9	618818.9	NE
B-1187	1144710.2	619259.6	NE
B-1189	1144459.7	618997.5	NE
B-1191	1144301.6	619490.8	NE
B-1192	1144217.4	618840.9	Absent
B-1193	1144091.5	619277.8	Absent
B-1194	1147504.7	621630.2	NE
B-1195	1147574.8	622478.4	NE
B-1196	1147286.6	622017.5	NE
B-1197	1146874.7	622003.8	NE
B-3001	1142599.5	621799.6	Present
B-3002	1142600.0	621872.5	Present
B-3003	1142599.9	621727.3	Present
B-3004	1142447.4	621867.1	Present
B-3005	1142717.6	621749.1	Present
B-3006	1142425.6	621925.0	Present
B-3007	1142718.5	621876.7	Present
B-3008	1142425.4	621773.0	Absent
B-3009	1142484.5	621956.6	Present

Table 2.4-253 (Sheet 3 of 6)
Presence of Utley Limestone in the VEGP ESP and COL Site Borings

Boring No.	Coordinates (NAD 27)		Utley Limestone
	Northing	Easting	
B-3010	1142634.9	622025.0	Present
B-3011	1142776.7	622024.9	Present
B-3012	1142772.5	621911.9	Absent
B-3013 (c)	1142842.9	621825.4	Present
B-3014	1142799.4	621748.6	Present
B-3015	1142956.9	621824.0	Present
B-3016	1142978.4	621913.4	Present
B-3017	1143034.4	621749.9	Present
B-3018	1142738.1	622115.8	Present
B-3019	1142977.4	622167.5	Present
B-3020	1142977.9	622074.8	Present
B-3021	1143070.2	622033.2	Present
B-3022	1143069.8	621873.4	Present
B-3023	1143061.1	621679.9	Present
B-3024	1142905.8	621399.7	Absent
B-3025	1142460.4	621425.3	Present
B-3026	1142290.2	621403.7	Present
B-3027	1142058.7	621423.3	Present
B-3028	1141867.3	621408.8	Present
B-3029	1141881.5	621803.9	Present
B-3030	1141699.9	621799.7	Present
B-3031	1141398.7	622042.0	Present
B-3032	1141158.2	621709.5	Present
B-3033	1141405.3	621715.2	Absent
B-3034	1141399.8	621914.7	Present
B-3035	1142729.2	621675.4	Present
B-3036	1142441.6	621676.0	Present
B-3037	1143057.4	621768.9	Present
B-3038	1141883.0	621543.2	Present
B-3039	1142917.7	621753.5	Present
B-4001(DH)	1142599.5	621000.2	Absent
B-4002(DH)	1142600.2	621072.2	Absent
B-4003(DH)	1142599.9	620927.1	Absent
B-4004	1142459.7	621046.6	Present
B-4005	1142715.0	620948.7	Absent
B-4006	1142719.6	621076.4	Absent
B-4007	1142426.2	621125.3	Present
B-4008	1142424.2	620973.8	Present

Table 2.4-253 (Sheet 4 of 6)
Presence of Utley Limestone in the VEGP ESP and COL Site Borings

Boring No.	Coordinates (NAD 27)		Utley Limestone
	Northing	Easting	
B-4009	1142486.1	621156.9	Present
B-4010	1142667.6	621249.0	Present
B-4011	1142773.1	621236.4	Absent
B-4013 (c)	1142842.7	621020.3	Absent
B-4014	1142832.0	620950.2	Present
B-4015	1142773.0	621115.2	Absent
B-4016	1142996.4	621112.9	Absent
B-4017	1143034.8	620949.9	Present
B-4018	1142735.5	621315.5	Present
B-4019	1142975.9	621371.4	Present
B-4020	1142969.4	621280.0	Present
B-4020A	1142973.7	621280.3	Present
B-4021	1143092.6	621247.4	Present
B-4022	1143081.3	621073.5	Present
B-4023	1143062.4	620879.8	Absent
B-4024	1142904.8	620601.8	Present
B-4025	1142510.0	620625.0	Present
B-4026	1142330.2	620597.7	Present
B-4027	1142180.1	620633.5	Present
B-4028	1141984.2	620587.8	Present
B-4029	1141874.9	620700.0	Absent
B-4030	1141676.7	620698.5	Absent
B-4031	1141399.8	620975.0	Absent
B-4032	1141118.5	620794.6	NE
B-4032A	1141123.7	620794.7	Present
B-4033	1141398.1	620348.8	Present
B-4034	1141375.7	620795.4	Absent
B-4035	1142729.1	620876.3	Present
B-4036	1142457.2	620876.3	Present
B-5001	1146177.1	621807.7	Absent
B-5002	1146339.8	621808.3	Absent
B-5003	1146386.6	621574.7	Absent
B-5004	1146547.8	621568.4	Present
B-6002	1144134.1	619626.9	NE
B-6003	1143925.0	619422.8	Absent
B-6004	1143718.2	619473.3	Absent
B-6005	1143718.0	619873.8	Absent
B-6006	1143069.8	620301.8	NE

Table 2.4-253 (Sheet 5 of 6)
Presence of Utley Limestone in the VEGP ESP and COL Site Borings

Boring No.	Coordinates (NAD 27)		Utley Limestone
	Northing	Easting	
B-6007	1142730.7	620301.8	NE
B-6008	1145443.8	622676.4	Absent
B-6009	1144773.7	621748.2	Present
B-6010	1143893.3	621059.2	Present
B-6011	1144557.9	621261.7	Present
B-6012	1144256.7	620480.5	Present
B-6013	1143169.5	617234.9	NE
B-6014	1143168.2	618281.5	NE
B-6015	1143166.3	619317.9	NE
B-6018	1142909.3	618366.6	NE
B-6019	1142132.7	618344.5	NE
B-6020	1142634.0	619555.9	Present
B-6021	1142185.7	619103.4	Present
B-6022	1142224.8	620040.3	Present
B-6023	1141553.1	619177.9	NE
B-6024	1141545.9	619997.7	NE
B-6025	1140518.7	619189.7	NE
B-6026	1140537.7	619900.2	NE
B-6027	1145779.4	626145.1	Absent[1]
B-6028	1145611.4	626062.4	Absent[1]
B-6029	1147771.7	623966.6	Absent[1]
B-6030	1147588.1	624222.6	Absent[1]
ESP Boring Data			
B-1001	1142661.92	620220.42	Present
B-1002	1142998.52	620985.47	Absent
B-1003	1142974.36	621889.85	Present
B-1004	1142985.41	620131.44	Present
B-1005	1143991.57	620155.35	Present
B-1006	1143810.26	621342.9	Absent
B-1007	1142662.29	621120.13	Present
B-1008	1142670.93	621996.15	Present
B-1009	1141000.54	620361.26	Absent
B-1010	1141000.12	621279.68	Absent
B-1011	1143741.13	622378.01	Present
B-1013	1140976.08	622272.5	Absent
Observation Well Data			
OW-1006	1,143,817.85	619,179.75	Present
OW-1008	1,142,347.94	619,306.69	Present

Table 2.4-253 (Sheet 6 of 6)
Presence of Utley Limestone in the VEGP ESP and COL Site Borings

Boring No.	Coordinates (NAD 27)		Utley Limestone
	Northing	Easting	
OW-1009	1,141,891.65	620,888.61	Present
OW-1012	1,139,969.50	621,045.92	Absent
OW-1013	1,140,805.40	621,715.03	Absent
OW-1015	1,140,550.58	623,086.32	Absent

Note:
[1] Surface elevation of boring is below the elevation of the Utley Limestone.
NE = Not encountered, indicating that the boring terminated in the Barnwell sands.
COL boring data are provided in Appendix 2.5C
ESP Boring data are provided in Appendix 2.5A
OW-series data are provided in Appendix 2.4A

Table 2.4-254
Summary of Holes Drilled at the Site for the Installation of Observation Wells

Boring/Drill Log No.	Drilling Method	Drill Dates		Sampled Depth		Drilled Depth Below the GS	Boring "Abandoned" or "Well" Installed
		Start	End	From (ft)	To (ft)	(ft)	
OW-1001A	3.25" HSA	25-May	25-May	No sampling		100	Abandoned
OW-1001	4.25" HSA	24-May	29-May	113.5	140	140	Well
OW-1002A	3.25" HSA	24-May	25-May	0	108.5	108.5	Abandoned
OW-1002	Rotosonic	2-Jun	6-Jun	87	237	237	Well
OW-1003A	3.25" HSA	24-May	24-May	0	90	90	Abandoned
OW-1003	4.25" HSA	25-May	25-May	No sampling		90.5	Well
OW-1004	Rotosonic	3-Jun	11-Jun	87	187	187	Well
OW-1005A	3.25" HSA	31-May	31-May	0	75	75	Abandoned
OW-1005	4.25" HSA	2-Jun	7-Jun	68.5	170	170	Well
OW-1006A	4.25" HSA	3-Jun	4-Jun	0	125	125	Abandoned
OW-1006	4.25" HSA	9-Jun	14-Jun	118.5	135	135	Well
OW-1007	4.25" HSA	4-Jun	7-Jun	98.5	122	122	Well
OW-1008A	3.25" HSA	26-May	26-May	0	107.5	105	Well OW-1008
OW-1008	Rotosonic	31 May	1-Jun	108	247	247	Well
OW-1009	4.25" HSA	24-May	27-May	0	100	100	Well
OW-1010	4.25" HSA	1-Jun	1-Jun	0	93.5	93.5	Well
OW-1011	Rotosonic	11-Jun	12-Jun	87	217	217	Well
OW-1012	4.25" HSA	31-May	1-Jun	0	93.6	93.6	Well
OW-1013	4.25" HSA	9-Jun	10-Jun	0	103.5	103.5	Well
OW-1014	Rotosonic	11-Jun	11-Jun	97	197.4	197.4	Well
OW-1015	4.25" HSA	30-May	3-Jun	0	120	120	Well

Note.

Borings OW-1001A, OW-1002A, OW-1003A, and OW-1005A were abandoned due to the use of 3.25-in hollow stem auger, which would not adequately accommodate well installation.

Boring OW-1006A was abandoned due to the of shortage hollow stem auger flights.

Boring OW-1008A is the upper portion of boring OW-1008 and was not abandoned. The “A” is designated to show that the upper portion of this boring was drilled using 3.25-in hollow-stem augers while the lower portion was drilled using the rotosonic drilling method.

Boring log OW-1003 contained in Appendix 2.4A (report Appendix E) should read OW-1003A.

The drilling method for boring OW-1006 is assumed to be 4.25" HSA (not described in Appendix 2.4A (report Appendix E)).

Table 2.4-255 (Sheet 1 of 8)
Historical Groundwater Levels for the Water Table Aquifer

Date	Observation Well and Water Level Elevations (ft msl)												
	142	179	802A	803A	804	805A	806B	808	809	LT-1A/1B	LT-7/7A	LT-12	LT-13
23-Oct-71		154.3											
2-Nov-71		156.8											
10-Nov-71		160.3											
17-Nov-71		160.8											
23-Nov-71		161.1											
1-Dec-71		162.1											
7-Dec-71		162.4											
14-Dec-71		164.3											
23-Dec-71		164.6											
29-Dec-71		165.8											
5-Jan-72		166.1											
12-Jan-72		167.3											
19-Jan-72		168.1											
26-Jan-72		168.5											
3-Feb-72		168.6											
9-Feb-72		168.9											
23-Feb-72		169.8											
2-Mar-72		170.1											
9-Mar-72		170.3											
16-Mar-72		167.9											
21-Mar-72		170.2											
18-Apr-72		171.9											
1-May-73		174.1											
30-May-73		173.6											
27-Jul-73		172.3											
13-Oct-73		170.8											
3-Nov-73		170.4											
9-Dec-73		170.1											
7-Jan-74		168.9											
10-Feb-74		166.6											
23-Mar-74		168.1											

Table 2.4-255 (Sheet 2 of 8)
Historical Groundwater Levels for the Water Table Aquifer

Date	Observation Well and Water Level Elevations (ft msl)												
	142	179	802A	803A	804	805A	806B	808	809	LT-1A/1B	LT-7/7A	LT-12	LT-13
17-Apr-74		167.4											
15-Aug-74		165.3											
11-Sep-74		165.1											
7-Jul-79		160.2		155.5	161.2	152.4							
26-Nov-79		161.8		155.1		153.0							
2-Jan-1980				155.1	161.2	152.9				137.2	141.6		
11-Jan-1980				155.1						136.8	141.7		
24-Jan-1980		161.0		154.9	161.0	138.2				136.8	141.6		
1-Feb-1980				154.9		138.5				136.5	141.1		
15-Feb-1980				155.0						136.6	141.2		
25-Mar-1980		157.9		154.7	161.0					136.2	142.1		
27-Jun-1980		162.0			161.4	137.5				137.0	140.6		
2-Sep-1980										136.4	139.0		
27-Sep-1980		161.7		154.7	161.1	153.3							
1-Dec-1980										135.6	140.2		
29-Dec-1980		161.1		154.4	160.9								
2-Mar-1981										135.8			
28-Mar-1981		159.3		154.0	160.3								
2-Apr-1981											139.7		
1-Jun-1981										135.4			
29-Jun-1981		158.0		153.6									
2-Jul-1981											139.5		
24-Dec-1981											140.2		
7-Feb-1982											139.6		
23-Mar-1982		158.8		152.6	159.1	150.8							
15-Jun-1982		158.8		152.4	159.0	151.0				135.6			
9-Jul-1982											140.7		
15-Sep-1982		159.5		152.7	158.7	151.9							
20-Sep-82										137.0			
11-Dec-82	146.1	160.1		152.6	159.0	153.7							
18-Dec-82										135.1			
8-Mar-83	146.3				158.8	153.6							

Table 2.4-255 (Sheet 3 of 8)
Historical Groundwater Levels for the Water Table Aquifer

Date	Observation Well and Water Level Elevations (ft msl)												
	142	179	802A	803A	804	805A	806B	808	809	LT-1A/1B	LT-7/7A	LT-12	LT-13
9-Mar-83		159.6		152.6									
15-Mar-83										140.9			
22-Jun-83	152.3	159.7		155.1	159.0	156.1	152.7			151.4	149.9		
15-Sep-83	153.3	159.7		156.5			154.5						
21-Sep-83					159.7	156.8							
3-Oct-83											154.2		
15-Oct-83										153.8			
12-Dec-83	154.4	160.4		157.7	160.0	157.9	155.4						
14-Dec-83										156.4	155.9		
12-Mar-84	155.1					158.5	156.2						
13-Mar-84		159.9		158.2	160.1								
22-Mar-84										156.1	156.6		
11-Jun-84				158.9	160.5	159.9							
12-Jun-84		155.8					157.1			157.4	157.4		
13-Sep-84				159.8									
16-Sep-84					161.0								
18-Sep-84	156.5	150.9				160.6	157.4				157.7		
13-Dec-84	155.9	151.1		159.9	160.2	160.1	157.1			157.0			
31-Dec-84											158.0		
4-Feb-85	155.7	148.9		159.6	160.9	159.9	157.0			157.1			
30-Jun-85	155.5	150.2		159.6	161.0	159.5	156.9			152.0	152.0		
7-Jul-85	155.3	148.5		159.5	160.8	159.3	156.6	159.2	155.5	157.0		158.5	157.6
16-Jul-85	155.3	150.0		159.4	160.8	159.3	156.7	159.2	152.7	155.2	158.0	160.2	157.5
23-Jul-85	155.2	150.3		159.5	160.8	159.3	156.7	159.3	152.8	155.2	158.1	160.0	157.6
31-Jul-85	155.3	150.6		159.5	160.9	159.3	156.8	159.8	152.8	155.2	158.0	160.0	157.5
7-Aug-85	155.4	148.6		159.4	160.9	159.3	157.0	160.0	152.8	155.3	158.1	160.2	157.7
14-Aug-85	155.3	148.6		159.4	160.8	159.2	156.2	160.3	152.7	155.3	158.0	160.2	157.7
21-Aug-85	155.4	148.6		159.4	160.8	159.3	157.1	160.4	152.8	157.2	158.1	160.4	157.8
28-Aug-85	155.6	148.8		159.5	160.9	159.4	157.2	160.5	152.5	157.3	158.2	160.5	157.7
4-Sep-85	155.5	148.8	159.0	159.6	161.0	159.6	157.2	160.4	152.8	157.4	158.3	160.8	157.8
11-Sep-85	155.5	148.8	159.0	159.5	161.0	159.6	157.2	160.6	152.9	157.4	158.4	161.1	158.1
18-Sep-85	155.4	148.8	159.0	159.5	160.8	159.5	157.2	160.5	152.8	157.3	158.4	161.1	158.0

Table 2.4-255 (Sheet 4 of 8)
Historical Groundwater Levels for the Water Table Aquifer

Date	Observation Well and Water Level Elevations (ft msl)												
	142	179	802A	803A	804	805A	806B	808	809	LT-1A/1B	LT-7/7A	LT-12	LT-13
25-Sep-85	155.6	148.8	159.0	159.3	160.9	159.6	157.3	160.4	152.9	157.5	158.5	161.4	158.1
6-Oct-85	155.6	148.8	159.1	159.6	160.9	159.7	157.3	160.3	152.9	157.5	158.5	161.5	158.1
9-Oct-85	155.5	148.8	159.0	159.6	160.9	159.6	157.2	160.2	152.9	157.3	158.3	161.3	158.0
16-Oct-85	155.5	148.8	159.2	159.7	160.8	159.6	157.4	160.3	152.9	157.6	158.7	161.5	158.2
23-Oct-85	155.5	148.8	159.1	159.7	160.7	159.7	157.3	160.2	152.9	157.5	158.8	161.5	158.3
30-Oct-85	155.7	148.8	159.2	159.8	161.1	159.9	157.5	160.2	153.0	157.7	159.0	162.0	158.5
6-Nov-85	155.5	148.7		159.5	160.8	159.7	157.2	160.1	152.9	157.4	158.5	161.6	158.4
13-Nov-85	155.5	148.8		159.5	161.0	159.8	157.2	160.1	152.9	157.3	158.5	161.5	158.0
20-Nov-85	155.6	148.9	159.2	159.8	161.0	159.7	157.3	160.2	153.1	157.4	158.5	161.5	158.1
27-Nov-85	155.6	148.8	159.1	159.6	160.6	159.8	157.4	160.1	153.0	157.6	158.7	161.6	158.1
4-Dec-85	155.7	148.8	159.1	159.7	160.8	159.6	157.4	160.1	153.0	157.5	158.5	161.3	158.4
11-Dec-85	155.8	148.8	159.2	159.9	161.1	159.9	157.6	160.3	153.0	157.8	158.8	161.6	158.3
18-Dec-85	155.8	148.8	159.2	159.7	160.9	159.9	157.6	160.4	153.0	157.7	158.9	161.5	158.3
28-Dec-85	155.9	148.8	159.3	159.8		159.9	157.7	160.5	153.0	157.8	158.6	161.6	158.6
2-Jan-86	156.0	148.9	159.4	159.8	161.0	159.8	157.7	160.5	153.1	157.8	158.6	161.6	158.4
10-Jan-86	156.1	148.9	159.6	160.0	161.4	159.7	157.9	160.5	153.3	158.2	158.8	161.8	158.3
15-Jan-86	155.7	148.7	159.4	159.8	160.7	159.8	157.7	160.6	152.9	157.9	158.8	161.9	158.7
22-Jan-86	156.0	148.8	159.4	159.8	161.0	160.0	157.2	160.5	153.1	157.8			158.7
29-Jan-86	156.0	148.8	159.5	160.0	161.2	160.2	157.7	160.5	153.1	157.9	159.2	161.8	158.8
5-Feb-86	156.0	148.7	159.5	159.9	161.1	160.1	157.6	160.6	153.0	157.9	159.2	162.0	158.6
12-Feb-86	155.9	148.8	159.4	159.9	160.9	160.0	157.6	160.5	153.0	157.7	158.8	161.5	158.8
19-Feb-86	156.0	148.8	159.6	160.0	161.2	160.2	157.7	160.4	153.1	157.9	159.1	162.0	158.8
26-Feb-86	156.0	148.9	159.8	160.3	161.2	160.5	157.9	160.3	153.1	158.2	159.6	162.4	158.7
5-Mar-86	155.8	148.7	159.4	159.9	161.0	160.1	157.5	160.3	153.0	157.7	158.9	161.7	158.7
15-Mar-86	156.1	148.8	159.7	160.2	161.5	160.1	157.8	160.3	153.3	157.7	159.0	161.8	158.6
19-Mar-86	155.8	148.8	159.4	160.0	161.1	160.1	157.5	160.2	153.1	157.6	158.9	161.5	158.4
26-Mar-86	155.8	148.8	159.4	160.1	161.4	160.3	157.5	160.1	153.0	157.7	158.9	161.6	158.5
2-Apr-86	155.9	148.7	159.6	160.3	161.4	160.4	157.6	160.1	153.2	157.8	159.0	161.7	158.5
9-Apr-86	155.9	148.8	159.6	160.1	161.3	160.2	157.6	160.2	153.1	157.9	159.2	161.9	158.7
16-Apr-86	155.7	148.7	159.8	160.3	161.1	160.3	157.4	160.1	153.1	157.5	158.7	161.4	158.1
23-Apr-86	155.9	148.8	159.5	160.2	161.4	160.0	157.5	160.2	153.2	157.7	158.9	161.5	158.7
30-Apr-86	155.8	148.8	159.4	160.1	161.4	160.2	157.4	160.1	153.1	157.7	158.8	161.5	158.5

Table 2.4-255 (Sheet 5 of 8)
Historical Groundwater Levels for the Water Table Aquifer

Date	Observation Well and Water Level Elevations (ft msl)												
	142	179	802A	803A	804	805A	806B	808	809	LT-1A/1B	LT-7/7A	LT-12	LT-13
7-May-86	155.7	148.7	159.4	160.1	161.2	160.2	157.5	160.0	153.0	157.4	158.5	161.2	158.3
14-May-86	155.7	148.8	159.3	160.1	161.3	160.1	157.3	160.0	153.1	157.6	158.8	161.3	158.9
21-May-86	155.8	148.8	159.4	160.1	161.3	160.2	157.4	159.9	153.1	157.6	158.8	161.5	158.4
28-May-86	155.7	148.8	159.4	160.1	161.4	160.2	157.3	159.9	153.1	157.5	158.7	161.3	158.2
4-Jun-86	155.7	148.7	159.3	160.0	161.2	160.0	157.2	159.9	153.1	157.3	158.4	161.0	158.3
11-Jun-86	155.7	148.8	159.4	159.9	161.3	160.0	157.2	159.8	153.0	157.4	158.6	161.4	158.2
18-Jun-86	155.9	148.8	159.3	160.0	161.1	160.0	157.3	159.8	153.1	157.5	158.7	161.1	158.2
25-Jun-86	155.8	148.8	159.4	160.0	160.9	159.6	157.3	159.7	153.1	157.5	158.6	161.2	158.2
2-Jul-86	155.8	148.8	159.3	160.0	161.4	160.0	157.3	159.7	153.1	157.5	158.6	161.1	158.2
9-Jul-86	155.7	148.7	159.2	160.0	161.4	160.0	157.2	159.7	153.0	157.4	158.5	161.0	158.1
16-Jul-86	155.7	148.7	159.2	159.9	160.9	159.9	157.2	159.7	153.0	157.3	158.4	160.9	158.2
23-Jul-86	155.6	148.7	159.0	159.9	161.2	159.9	157.1	159.6	153.0	157.2	158.3	160.7	158.2
30-Jul-86	155.7	148.7	159.0	159.9	161.2	159.9	157.2	159.6	153.0	157.2	158.3	160.9	158.2
6-Aug-86	155.7	148.8	159.3	160.0	161.3	160.0	157.2	159.6	153.1	157.3	158.3	160.8	157.9
13-Aug-86	155.6	148.8	159.0	159.9	161.2	159.9	157.1	159.5	153.0	157.3	158.4	160.8	158.0
20-Aug-86	155.6	148.8	159.1	159.9	161.1	159.9	157.1	159.5	153.0	157.2	158.2	160.6	158.1
27-Aug-86	155.6	148.8	159.1	159.9	161.2	159.8	157.0	159.4	153.0	157.2	158.3	160.7	157.9
3-Sep-86	155.6	148.8	159.1	159.9	161.2	159.9	157.1	159.6	153.0	157.3	158.3	160.7	158.0
10-Sep-86	155.6	148.7	159.1	159.9	161.2	159.8	157.1	159.6	152.9	157.3	158.3	160.7	157.9
17-Sep-86	155.5	148.7	159.0	159.9	161.0	159.8	157.0	159.7	152.9	157.4	158.5	160.5	157.8
24-Sep-86	155.5	148.7	159.0	159.8	161.0	159.8	157.0	159.9	152.9	157.6	158.2	160.5	158.0
1-Oct-86	155.7	148.8	158.9	159.9	161.0	159.9	157.0	159.9	153.0	157.6	158.3	160.7	157.8
11-Oct-86	155.6	148.8	159.0	160.0	161.1	159.9	157.0	159.8	152.9	157.1	158.1	160.5	157.9
15-Oct-86	155.5	148.8	159.1	159.9	161.1	159.9	157.1	159.9	152.9	157.0	158.2	160.5	158.0
22-Oct-86	155.6	148.8	159.1	159.9	161.2	159.9	157.1	159.8	153.0	157.0	158.2	160.5	157.7
29-Oct-86	155.5	148.8	159.0	159.8	160.9	159.8	157.1	159.9	152.9	156.9	158.2	160.6	157.9
5-Nov-86	155.6	148.8	159.1	159.6	161.2	159.9	157.2	159.8	153.0	157.2	158.2	160.7	158.0
12-Nov-86	155.6	148.8	159.1	159.6	161.1	159.8	157.2	159.7	153.0	157.2	158.3	160.6	157.9
19-Nov-86	155.5	148.8	159.2	159.7	160.9	160.0	157.3	159.8	152.8	157.5	158.6	160.9	158.0
26-Nov-86	155.6	148.8	159.2	159.6	160.9	159.9	157.2	159.6	152.9	157.3	158.3	160.7	158.2
3-Dec-86	155.6	148.8	159.0	159.7	160.9	160.0	157.2	159.6	152.8	157.1	158.0	160.5	157.9
31-Dec-86	155.9	148.8	159.0	159.8	160.9	159.8	157.5	159.4	153.0	157.6	158.6	160.8	158.1

Table 2.4-255 (Sheet 6 of 8)
Historical Groundwater Levels for the Water Table Aquifer

Date	Observation Well and Water Level Elevations (ft msl)												
	142	179	802A	803A	804	805A	806B	808	809	LT-1A/1B	LT-7/7A	LT-12	LT-13
10-Jan-87	156.0	148.9	159.1	160.1	160.9	160.1	157.8	159.3	153.1	158.0	158.9	161.2	158.1
14-Jan-87	156.0	148.8	159.2	160.1	160.8	160.0	157.6	159.1	153.1	158.1	159.1	161.3	158.3
21-Jan-87	155.9	148.7	159.3	160.1	160.8	159.9	157.5	159.2	152.8	158.2	159.1	161.4	158.4
28-Jan-87	156.2	148.8	159.4	160.1	161.2	159.9	157.9	159.5	153.0	158.1	158.9	161.1	158.3
Jan-88	156.7	148.8	160.5	161.8	161.9	161.4	158.2	159.7	153.4	158.2	159.0	160.9	158.6
Feb-88	156.7	148.9	160.7	163.0	162.1	161.6	158.4	159.7	153.3	158.3	159.2	161.1	159.0
Mar-88	156.6	148.8	160.4	161.8	162.1	161.5	158.2	159.3	153.3	158.3	159.2	161.1	158.7
Apr-88	156.7	148.8	160.4	161.6	162.2	161.4	158.1	159.3	153.4	158.3	159.3	161.2	158.9
May-88	156.3	148.7	159.9	161.3	161.7	161.0	157.8	159.0	153.2	157.9	158.8	160.6	158.3
Jun-88	156.2	148.8	159.9	161.1	161.7	161.2	157.8	159.1	153.2	157.9	158.8	160.5	158.3
16-Dec-94			158.8			160.0	156.0	159.4		156.8	155.8	158.3	156.6
14-Mar-95										157.1	156.2	158.7	157.1
13-Jun-95						161.0	156.6						
29-Jun-95			159.6					160.4		157.3	156.3	158.9	157.2
22-Sep-95										157.7	156.7	159.2	157.6
20-Dec-95			160.1							157.8	157.0	159.8	157.8
21-Dec-95						161.6	157.0	160.2					
21-Mar-96										157.6	156.7	159.7	157.6
12-Jun-96						161.6	157.3						
13-Jun-96			160.1					159.7		157.4	156.5	159.9	157.5
15-Sep-96										156.8	156.4	159.0	156.6
11-Dec-96						160.8	156.5	159.4					
30-Dec-96			159.5							157.3	156.4	159.1	157.3
13-Mar-97										157.1	157.7	159.7	157.7
19-Jun-97			159.0			160.7	156.5	159.2		156.8	156.0	158.6	156.8
29-Sep-97										156.8	156.1	158.6	156.8
31-Dec-97			158.9			160.7	156.6	159.0		156.7	155.8	158.4	156.7
24-Mar-98										157.6	156.5	159.2	157.6
23-Jun-98			158.8			160.8	156.7	159.2		157.1	156.1	159.0	157.1
28-Sep-98										157.3	156.5	159.1	157.4
21-Dec-98			158.6			160.7	156.6	159.1		157.1	156.3	158.9	157.1
23-Mar-99										158.8	157.8	160.0	158.8

Table 2.4-255 (Sheet 7 of 8)
Historical Groundwater Levels for the Water Table Aquifer

Date	Observation Well and Water Level Elevations (ft msl)												
	142	179	802A	803A	804	805A	806B	808	809	LT-1A/1B	LT-7/7A	LT-12	LT-13
8-Jun-99										158.5		160.6	
15-Jun-99							157.6						158.6
17-Jun-99			160.8			162.5		159.0			157.7		
23-Sep-99										157.5	158.4	161.1	158.1
17-Dec-99			159.7			160.9	156.9	158.6		156.9	156.1	159.6	157.6
22-Mar-00										158.5	157.3	159.0	158.1
2-Jun-00						159.7	156.0				157.0	158.3	156.5
5-Jun-00			158.6					158.3		156.8			
8-Sep-00										155.5	156.4	157.7	156.0
7-Dec-00			157.8			158.8	155.3	158.4		155.5	156.4	157.8	155.9
5-Mar-01										155.9	154.4	157.0	155.2
8-Jun-01			157.4			158.5	155.1			155.1	156.0	157.2	155.6
12-Jun-01								155.0					
14-Mar-02										155.3	156.1	157.7	155.7
5-Jun-02			157.0							154.7	155.5	156.9	155.3
7-Jun-02						157.7	154.6	158.0					
18-Sep-02										154.2	155.2	156.4	154.7
5-Dec-02			156.1			156.9	154.0	157.6		154.2	153.4	156.2	154.7
10-Mar-03										153.9	154.7	155.8	154.3
18-Jun-03			156.9			159.0	154.8	160.0		154.7	154.0	156.3	155.1
4-Sep-03										155.6	154.5	157.3	155.9
9-Dec-03			158.7			160.0	156.2	160.6		156.2	155.0	158.0	156.7
3-Mar-04										156.3	155.2	158.4	156.9
3-Sep-04										156.1	157.0	158.4	156.7
17-Dec-04			158.5			159.5	155.9	158.6		156.0	155.2	158.2	156.6
15-Jun-05	154.37	147.42	157.88	159.98	163.73	158.53	155.62	158.88	152.78	154.92	154.39	158.21	156.10
16-Jul-05	154.38	148.40	157.86	159.91	163.62	158.57	155.65	159.14	152.70	154.82	154.15	157.90	155.92
20-Aug-05	154.49	148.42	158.07	160.15	163.92	158.84	155.78	159.42	152.75	155.01	154.33	158.07	156.13
17-Sep-05	154.64	148.72	158.23	160.32	164.10	158.98	155.90	159.55	152.89	155.16	154.46	158.22	156.30
17-Oct-05	154.75	148.69	158.29	160.39	164.21	159.09	155.96	159.49	152.98	155.18	154.48	158.31	156.32
19-Nov-05	154.69	148.75	158.34	160.48	164.23	159.09	155.98	159.37	152.97	155.22	154.46	158.28	156.37
17-Dec-05	154.60	148.52	158.28	160.39	164.05	159.05	155.88	159.15	152.98	155.06	154.31	158.21	156.23

Table 2.4-255 (Sheet 8 of 8)
Historical Groundwater Levels for the Water Table Aquifer

Date	Observation Well and Water Level Elevations (ft msl)												
	142	179	802A	803A	804	805A	806B	808	809	LT-1A/1B	LT-7/7A	LT-12	LT-13
15-Jan-06	154.71	148.61	158.28	160.37	164.08	158.94	155.97	159.04	153.10	155.18	154.57	158.53	156.36
27-Feb-06	154.78	148.64	158.39	160.48	164.23	158.92	155.98	159.19	153.22	155.52	154.83	158.66	156.66
15-Mar-06	154.71	148.72	158.23	160.45	164.30	158.98	156.03	159.15	153.18	155.28	154.59	158.48	156.35
15-Apr-06	154.63	148.66	158.17	160.30	164.11	158.82	155.85	158.99	153.05	155.18	154.57	158.54	156.32
15-May-06	154.55	148.76	158.09	160.20	163.99	158.82	155.78	158.53	153.02	155.15	154.50	158.48	156.32
15-Jun-06	154.48	148.78	157.99	160.12	163.88	158.63	155.73	158.80	153.00	154.95	154.41	158.23	156.23
26-Jul-06	154.41	148.56	157.91	159.96	163.69	158.53	155.68	158.72	152.88	154.95	154.30	158.19	156.08
28-Aug-06			157.89							154.95	154.34	158.18	156.14
31-Aug-06	154.36	148.75		159.88	163.69	158.45	155.62	158.65	152.86				
15-Nov-06	154.16	148.79	157.56		162.84	158.19	155.42	158.40	152.71	154.78	154.25	158.11	155.93
16-Nov-06				159.64									
13-Dec-06	154.03	148.78	157.37	159.50	163.19	158.01	155.21	158.40	152.62	154.63	154.01	157.79	155.75
25-Jan-07	154.00	148.57	157.24	159.25	162.95	158.77	155.06	158.00	152.63	154.51	153.96	157.77	155.63
14-Feb-07	153.97	148.89	157.19	159.30	162.98	157.67	155.10	157.96	152.65	154.33	153.68	157.48	155.41
1-Mar-07	153.93	148.51	157.67	159.25	163.09	157.69	155.09	158.17	152.62	154.35	153.70	157.60	155.55
17-Apr-07	153.75	148.45	156.92	158.94	162.47	157.40	154.89	158.01	152.37	154.28	153.68	157.53	155.30
24-May-07	153.59	148.40	156.80	158.80	162.59	157.31	154.71	158.06	152.30	153.98	153.24	156.95	155.05
7-Jun-07	153.61	148.40	156.79	158.80	162.70	157.27	154.72	158.02	152.32	153.98	153.36	157.19	155.10
16-Jul-07	153.59	148.44	156.75	158.78	162.82	157.29	154.69	157.93	152.3	153.9	153.32	157.05	155.05

Note.
Water level data for 802A (168.1 ft msl) measured on 13-Nov-85 considered invalid.
Water level data for 804 (166.0 ft msl) measured on 28-Dec-85 considered invalid.
Water level data for Oct-71 to Feb-85 provided in Ground Water Supplement for VEGP Units 1 and 2 (Georgia Power March 1985).
Water level data for Jun-85 to Dec-85 provided in Observation Well Readings for VEGP Units 1 and 2, July-December 1985 (Georgia Power July 1985).
Water level data for Dec-85 to Jun-86 provided in Observation Well Readings for VEGP Units 1 and 2, January-June 1986 (Georgia Power January 1986).
Water level data for Jun-86 to Dec-86 provided in Observation Well Readings for VEGP Units 1 and 2, July-December 1986 (Georgia Power July 1986).
Water level data for Dec-86 to Jan-87 provided in Piezometer Weekly Readings Report for VEGP Units 1 and 2 (Georgia Power 1987).
Water level data for Jan-88 to Jun-88 provided in Ground-Water Monitoring July 1987 – June 1988, Vogtle Electric Generating Plant (Bechtel Civil, Inc. 1988).
Water level data for Dec-94 to Dec-04 provided in Request For Information Number 25144-000-GRI-GEX-00028, SNC ALWR ESP Project (Bechtel Power Corporation 2006).

Table 2.4-256
Minimum and Maximum Water Levels Recorded at Observation Wells 802A, 805A, 808, LT-7A, LT-12, and LT-13

Observation Well	Minimum Water Level Elevation (ft msl)	Date	Maximum Water Level Elevation (ft msl)	Date
802A	156.1	5-Dec-02	160.8	17-Jun-99
805A	156.9	5-Dec-02	162.5	17-Jun-99
808	155.0	12-Jun-01	160.6	9-Dec-03
LT7A	152.0	30-Jun-85	159.6	19-Feb-86
LT12	155.8	10-Mar-03	162.4	26-Feb-86
LT13	154.3	10-Mar-03	159.0	1-Feb-88

Note.
Water level data provided in Table 2.4-255.

Table 2.4-257 (Sheet 1 of 2)
Radionuclide Concentrations in the AP1000 Effluent Holdup Tanks

Radionuclide	Design Basis Reactor Coolant Activity[a] (μCi/g)	Reactor Coolant Concentrations[b] (μCi/cm^3)	Effluent Holdup Tank Concentrations[c] (μCi/cm^3)
H-3	-	1.00E+00	1.01E+00
Cr-51	1.30E-03	1.30E-03	1.31E-03
Mn-54	6.70E-04	6.70E-04	6.77E-04
Mn-56	1.70E-01	1.70E-01	1.72E-01
Fe-55	5.00E-04	5.00E-04	5.05E-04
Fe-59	1.30E-04	1.30E-04	1.31E-04
Co-58	1.90E-03	1.90E-03	1.92E-03
Co-60	2.20E-04	2.20E-04	2.22E-04
Br-83	3.20E-02	1.54E-02	1.55E-02
Br-84	1.70E-02	8.16E-03	8.24E-03
Br-85	2.00E-03	9.60E-04	9.70E-04
Rb-88	1.50E+00	7.20E-01	7.27E-01
Rb-89	6.90E-02	3.31E-02	3.35E-02
Sr-89	1.10E-03	5.28E-04	5.33E-04
Sr-90	4.90E-05	2.35E-05	2.38E-05
Sr-91	1.70E-03	8.16E-04	8.24E-04
Sr-92	4.10E-04	1.97E-04	1.99E-04
Y-90	1.30E-05	6.24E-06	6.30E-06
Y-91m	9.20E-04	4.42E-04	4.46E-04
Y-91	1.40E-04	6.72E-05	6.79E-05
Y-92	3.40E-04	1.63E-04	1.65E-04
Y-93	1.10E-04	5.28E-05	5.33E-05
Nb-95	1.60E-04	7.68E-05	7.76E-05
Zr-95	1.60E-04	7.68E-05	7.76E-05
Mo-99	2.10E-01	1.01E-01	1.02E-01
Tc-99m	2.00E-01	9.60E-02	9.70E-02
Ru-103	1.40E-04	6.72E-05	6.79E-05
Rh-103m	1.40E-04	6.72E-05	6.79E-05
Rh-106	4.50E-05	2.16E-05	2.18E-05
Ag-110m	4.00E-04	1.92E-04	1.94E-04
Te-127m	7.60E-04	3.65E-04	3.68E-04
Te-129m	2.60E-03	1.25E-03	1.26E-03
Te-129	3.80E-03	1.82E-03	1.84E-03
Te-131m	6.70E-03	3.22E-03	3.25E-03
Te-131	4.30E-03	2.06E-03	2.08E-03
Te-132	7.90E-02	3.79E-02	3.83E-02
Te-134	1.10E-02	5.28E-03	5.33E-03

Table 2.4-257 (Sheet 2 of 2)
Radionuclide Concentrations in the AP1000 Effluent Holdup Tanks

Radionuclide	Design Basis Reactor Coolant Activity[a] (μCi/g)	Reactor Coolant Concentrations[b] (μCi/cm^3)	Effluent Holdup Tank Concentrations[c] (μCi/cm^3)
I-129	1.50E-08	7.20E-09	7.27E-09
I-130	1.10E-02	5.28E-03	5.33E-03
I-131	7.10E-01	3.41E-01	3.44E-01
I-132	9.40E-01	4.51E-01	4.56E-01
I-133	1.30E+00	6.24E-01	6.30E-01
I-134	2.20E-01	1.06E-01	1.07E-01
I-135	7.80E-01	3.74E-01	3.78E-01
Cs-134	6.90E-01	3.31E-01	3.35E-01
Cs-136	1.00E+00	4.80E-01	4.85E-01
Cs-137	5.00E-01	2.40E-01	2.42E-01
Cs-138	3.70E-01	1.78E-01	1.79E-01
Ba-137m	4.70E-01	2.26E-01	2.28E-01
Ba-140	1.00E-03	4.80E-04	4.85E-04
La-140	3.10E-04	1.49E-04	1.50E-04
Ce-141	1.60E-04	7.68E-05	7.76E-05
Ce-143	1.40E-04	6.72E-05	6.79E-05
Pr-143	1.50E-04	7.20E-05	7.27E-05
Ce-144	1.20E-04	5.76E-05	5.82E-05
Pr-144	1.20E-04	5.76E-05	5.82E-05

[a] Values from AP1000 DCD Table 11.1-2.

[b] For tritium (H-3) a coolant concentration of 1.0 μCi/g is used; corrosion products (Cr-51, Mn-54, Mn-56, Fe-55, Fe-59, Co-58 and Co-60) are taken directly from the AP1000 DCD, Table 11.1-2; and other radionuclides are based on the AP1000 DCD, Table 11.1-2 multiplied by 0.12/0.25. The density of all liquids is assumed to be 1 g/cm^3.

[c] Values are 101% of the reactor coolant concentrations.

Table 2.4-258 (Sheet 1 of 2)
Water Table Aquifer Results of Transport Analysis Considering Radioactive Decay Only

Radionuclide	Effluent Holdup Tank Concentration[a] ($\mu Ci/cm^3$)	Half-life[b] (days)	Decay Rate[c] ($days^{-1}$)	ECL[d] ($\mu Ci/cm^3$)	Groundwater Concentration[e] ($\mu Ci/cm^3$)	Groundwater Concentration / ECL
H-3	1.01E+00	4.51E+03	1.54E-04	1.00E-03	6.93E-01	6.93E+02
Cr-51	1.31E-03	2.77E+01	2.50E-02	5.00E-04	3.33E-29	6.66E-27
Mn-54	6.77E-04	3.13E+02	2.21E-03	3.00E-05	3.00E-06	1.00E-01
Mn-56	1.72E-01	1.07E-01	6.48E+00	7.00E-05	0.00E+00	0.00E+00
Fe-55	5.05E-04	9.86E+02	7.03E-04	1.00E-04	9.04E-05	9.04E-01
Fe-59	1.31E-04	4.45E+01	1.56E-02	1.00E-05	3.65E-20	3.56E-16
Co-58	1.92E-03	7.08E+01	9.79E-03	2.00E-05	7.56E-13	3.78E-09
Co-60	2.22E-04	1.93E+03	3.59E-04	3.00E-06	9.22E-05	3.07E+01
Br-83	1.55E-02	9.96E-02	6.96E+00	9.00E-04	0.00E+00	0.00E+00
Br-84	8.24E-03	2.21E-02	3.14E+01	4.00E-04	0.00E+00	0.00E+00
Br-85	9.70E-04	2.01E-03	3.44E+02	1.00E+00	0.00E+00	0.00E+00
Rb-88	7.27E-01	1.24E-02	5.59E+01	4.00E-04	0.00E+00	0.00E+00
Rb-89	3.35E-02	1.06E-02	6.54E+01	9.00E-04	0.00E+00	0.00E+00
Sr-89	5.33E-04	5.05E+01	1.37E-02	8.00E-06	1.38E-18	1.72E-13
Sr-90	2.38E-05	1.06E+04	6.54E-05	5.00E-07	2.03E-05	4.06E+01
Sr-91	8.24E-04	3.96E-01	1.75E+00	2.00E-05	0.00E+00	0.00E+00
Sr-92	1.99E-04	1.13E-01	6.16E+00	4.00E-05	0.00E+00	0.00E+00
Y-90	6.30E-06	2.67E+00	2.60E-01	7.00E-06	7.80E-282	1.11E-276
Y-91m	4.46E-04	3.45E-02	2.01E+01	2.00E-03	0.00E+00	0.00E+00
Y-91	6.79E-05	5.85E+01	1.18E-02	8.00E-06	1.73E-17	2.17E-12
Y-92	1.65E-04	1.48E-01	4.68E+00	4.00E-05	0.00E+00	0.00E+00
Y-93	5.33E-05	4.21E-01	1.65E+00	2.00E-05	0.00E+00	0.00E+00
Nb-95	7.76E-05	3.52E+01	1.97E-02	3.00E-05	9.15E-26	3.05E-21
Zr-95	7.76E-05	6.40E+01	1.08E-02	2.00E-05	2.40E-16	1.20E-11
Mo-99	1.02E-01	2.75E+00	2.52E-01	2.00E-05	1.34E-269	6.71E-265
Tc-99m	9.70E-02	2.51E-01	2.76E+00	1.00E-03	0.00E+00	0.00E+00
Ru-103	6.79E-05	3.93E+01	1.76E-02	3.00E-05	1.22E-23	4.07E-19
Rh-103m	6.79E-05	3.90E-02	1.78E+01	6.00E-03	0.00E+00	0.00E+00
Rh-106	2.18E-05	4.63E-04	1.50E+03	NA[f]	0.00E+00	
Ag-110m	1.94E-04	2.50E+02	2.77E-03	6.00E-06	2.19E-07	3.66E-02
Te-127m	3.68E-04	1.09E+02	6.36E-03	9.00E-06	6.42E-11	7.13.E-06
Te-129m	1.26E-03	3.36E+01	2.06E-02	7.00E-06	1.506E-25	2.14E-20
Te-129	1.84E-03	4.83E-02	1.44E+01	4.00E-04	0.00E+00	0.00E+00
Te-131m	3.25E-03	1.25E+00	5.55E-01	8.00E-06	0.00E+00	0.00E+00
Te-131	2.08E-03	1.74E-02	3.98E+01	8.00E-05	0.00E+00	0.00E+00
Te-132	3.83E-02	3.26E+00	2.13E-01	9.00E-06	4.07E-228	4.53E-223
Te-134	5.33E-03	2.90E-02	2.39E+01	3.00E-04	0.00E+00	0.00E+00
I-129	7.27E-09	5.73E+09	1.21E-10	2.00E-07	7.27E-09	3.63E-02
I-130	5.33E-03	5.15E-01	1.35E+00	2.00E-05	0.00E+00	0.00E+00
I-131	3.44E-01	8.04E+00	8.62E-02	1.00E-06	8.14E-93	8.14E-87
I-132	4.56E-01	9.58E-02	7.24E+00	1.00E-04	0.00E+00	0.00E+00

Table 2.4-258 (Sheet 2 of 2)
Water Table Aquifer Results of Transport Analysis Considering Radioactive Decay Only

Radionuclide	Effluent Holdup Tank Concentration[a] ($\mu Ci/cm^3$)	Half-life[b] (days)	Decay Rate[c] ($days^{-1}$)	ECL[d] ($\mu Ci/cm^3$)	Groundwater Concentration[e] ($\mu Ci/cm^3$)	Groundwater Concentration / ECL
I-133	6.30E-01	8.67E-01	7.99E-01	7.00E-06	0.00E+00	0.00E+00
I-134	1.07E-01	3.65E-02	1.90E+01	4.00E-04	0.00E+00	0.00E+00
I-135	3.78E-01	2.75E-01	2.52E+00	3.00E-05	0.00E+00	0.00E+00
Cs-134	3.35E-01	7.53E+02	9.21E-04	9.00E-07	3.52E-02	3.91E+04
Cs-136	4.85E-01	1.31E+01	5.29E-02	6.00E-06	2.83E-57	4.71E-52
Cs-137	2.42E-01	1.10E+04	6.30E-05	1.00E-06	2.07E-01	2.07E+05
Cs-138	1.79E-01	2.24E-02	3.09E+01	4.00E-04	0.00E+00	0.00E+00
Ba-137m	2.28E-01	1.81E-03	3.84E+02	NA[6]	0.00E+00	
Ba-140	4.85E-04	1.27E+01	5.46E-02	8.00E-06	4.79E-62	5.98E-57
La-140	1.50E-04	1.68E+00	4.13E-01	9.00E-06	0.00E+00	0.00E+00
Ce-141	7.76E-05	3.25E+01	2.13E-02	3.00E-05	1.67E-27	5.57E-23
Ce-143	6.79E-05	1.38E+00	5.02E-01	2.00E-05	0.00E+00	0.00E+00
Pr-143	7.27E-05	1.36E+01	5.10E-02	2.00E-05	4.59E-59	2.74E-54
Ce-144	5.82E-05	2.84E+02	2.44E-03	3.00E-06	1.48E-07	4.94E-02
Pr-144	5.82E-05	1.20E-02	5.78E+01	6.00E-04	0.00E+00	0.00E+00

a Values from Table 2.4-257.
b Values from NUREG/CR-5512, Table E.1 (Kennedy and Strenge 1992), and U. S. Department of Health Radiological Health Handbook (USDOH 1970) for Sr-92, Rh-106, and Ba-137m.
c Values calculated from Equation 2.4.13-4.
d Values calculated from Equation 2.4.13-4.
e Values calculated from Equation 2.4.13-5 for a travel time of 6.7 years.
f ECL is not available.

Highlighted values indicate groundwater concentration/ECL ratios exceeding 0.01

Table 2.4-259
Results of kd Analysis

Soil Sample	K_d Value (mL/g)		
	Co	Sr	Cs
Samples From Potential Borrow Sources Areas			
A-10(a)	8.1	13.2	56.2
C-7	3.9	9.0	14.8
D-10	1.7	7.8	9.9
E-7	10.1	25.7	19.9
E-12	15.3	51.7	10.7
G-9	7.9	9.8	> 25.5
J-11	13.5	9.2	> 47.4
K-10	15.2	10.0	19.3
L-7	1.7	11.4	18.8
M-5	7.3	9.3	16.8
N-3	5.8	10.7	7.8
P-8	6.5	7.0	5.3
Q-7	3.2	9.3	14.6
H-6	1.4	6.0	3.5
S-9	3.0	8.6	19.3
R-8	2.1	10.5	13.5
Samples From Barnwell Formation			
B-1003V-55-65	10.9	17.4	> 30.1
B-1003V-65-75	3.9	15.0	22.7
B-1003V-75-82	21.3	14.4	33.2

Source: Kaplan and Millings 2006

Table 2.4-260
Water Table Aquifer Results of Transport Analysis Considering Radioactive Decay and Adsorption

Radionuclide	Effluent Holdup Tank Conc[1] (mCi/cm^3)	Half-life[2] (days)	Decay Rate[3] ($years^{-1}$)	ECL[4] ($\mu Ci/cm^3$)	Backfill			Barnwell Group			Mallard Pond Material			Total Travel Time[7] (years)	Ground Water Conc[8] ($\mu Ci/cm^3$)	Ground Water Conc/ECL
					Distribution Coefficient (cm^3/g)	Retard Factor[5]	Travel Time[6] (years)	Distribution Coefficient (cm^3/g)	Retard Factor[5]	Travel Time[6] (years)	Distribution Coefficient (cm^3/g)	Retard Factor[5]	Travel Time[6] (years)			
H-3	1.01E+00	4.51E+03	5.61E-02	1.00E-03	0.0	1.0	2.40	0.0	1.0	3.20	0.0	1.0	1.10	6.70	6.93E-01	6.93E+02
Mn-54	6.77E-04	3.13E+02	8.09E-01	3.00E-05	0.0	1.0	2.40	0.0	1.0	3.20	0.0	1.0	1.10	6.70	3.00E-06	1.00E-01
Fe-55	5.05E-04	9.86E+02	2.57E-01	1.00E-04	0.0	1.0	2.40	0.0	1.0	3.20	0.0	1.0	1.10	6.70	9.04E-05	9.04E-01
Co-60	2.22E-04	1.93E+03	1.31E-01	3.00E-06	1.4	7.3	17.62	3.9	18.8	60.06	3.9	18.8	20.65	98.33	5.56E-10	1.85E-04
Sr-90	2.38E-05	1.06E+04	2.39E-02	5.00E-07	6.0	28.2	67.62	14.4	66.6	213.15	14.4	66.6	73.27	354.04	5.06E-09	1.01E-02
Ag-110m	1.94E-04	2.50E+02	1.01E+00	6.00E-06	0.0	1.0	2.40	0.0	1.0	3.20	0.0	1.0	1.10	6.70	2.19E-07	3.66E-02
I-129	7.27E-09	5.73E+09	4.42E-08	2.00E-07	0.0	1.0	2.40	0.0	1.0	3.20	0.0	1.0	1.10	6.70	7.27E-09	3.63E-02
Cs-134	3.35E-01	7.53E+02	3.36E-01	9.00E-07	3.5	16.9	40.45	22.7	104.4	334.16	22.7	104.4	114.87	489.48	1.13E-72	1.25E-66
Cs-137	2.42E-01	1.10E+04	2.30E-02	1.00E-06	3.5	16.9	40.45	22.7	104.4	334.16	22.7	104.4	114.87	489.48	3.10E-06	3.10E+00
Ce-144	5.82E-05	2.84E+02	8.91E-01	3.00E-06	0.0	1.0	2.40	0.0	1.0	3.20	0.0	1.0	1.10	6.70	1.48E-07	4.94E+02

1 Values from Table 2.4-257.
2 Values from NUREG/CR-5512, Table E.1 (Kennedy and Strenge 1992).
3 Values calculated from Equation 2.4.13-4.
4 Values from 10 CFR Part 20, Appendix B, Table 2, Column 2.
5 Values calculated from Equation 2.4.13-2.
6 Radionuclide travel time = retardation factor x groundwater travel time.
7 Total travel time = backfill travel time + Barnwell Group travel time + permeable Mallard Pond material travel time.
8 Values calculated from Equation 2.4.13-5.
Highlighted values indicate groundwater concentration/ECL ratios exceed 0.01.

Table 2.4-261
Results of Transport Analysis Considering Radioactive Decay, Adsorption, and Dilution

Water Table Aquifer

Radionuclide	ECL[1]	Groundwater Concentration[2] ($\mu Ci/cm^3$)	Surface Water Concentration[3] ($\mu Ci/cm^3$)	Surface Water Concentration / ECL
H-3	1.00E-03	6.93E-01	5.76E-05	5.76E-02
Mn-54	3.00E-05	3.00E-06	2.49E-10	8.31E-06
Fe-55	1.00E-04	9.04E-05	7.52E-09	7.52E-05
Sr-90	4.00E-05	5.06E-09	4.21E-13	1.05E-08
Ag-110m	6.00E-06	2.19E-07	1.82E-11	3.04E-06
I-129	2.00E-07	7.27E-09	6.04E-13	3.02E-06
Cs-137	1.00E-06	3.10E-06	2.58E-10	2.58E-04
Ce-144	3.00E-06	1.48E-07	1.23E-11	4.11E-06

1 Values from 10 CFR Part 20, Appendix B, Table 2, Column 2.
2 Values from Table 2.4-260 for Water Table Aquifer.
3 Surface water concentration = groundwater concentration x dilution factor. Dilution factor = 8.3E-05 for Water Table aquifer.

Table 2.4-262 (Sheet 1 of 2)
Tertiary Aquifer Results of Transport Analysis Considering Radioactive Decay Only

Radionuclide	Effluent Holdup Tank Concentration[a] ($\mu Ci/cm^3$)	Half-life[b] (days)	Decay Rate[c] ($days^{-1}$)	ECL[d] ($\mu Ci/cm^3$)	Groundwater Concentration[e] ($\mu Ci/cm^3$)	Groundwater Concentration / ECL
H-3	1.01E+00	4.51E+03	1.54E-04	1.00E-03	1.49E-28	1.49E-25
Cr-51	1.31E-03	2.77E+01	2.50E-02	5.00E-04	0.00E+00	0.00E+00
Mn-54	6.77E-04	3.13E+02	2.21E-03	3.00E-05	0.00E+00	0.00E+00
Mn-56	1.72E-01	1.07E-01	6.48E+00	7.00E-05	0.00E+00	0.00E+00
Fe-55	5.05E-04	9.86E+02	7.03E-04	1.00E-04	2.53E-131	2.53E-127
Fe-59	1.31E-04	4.45E+01	1.56E-02	1.00E-05	0.00E+00	0.00E+00
Co-58	1.92E-03	7.08E+01	9.79E-03	2.00E-05	0.00E+00	0.00E+00
Co-60	2.22E-04	1.93E+03	3.59E-04	3.00E-06	2.05E-69	6.82E-64
Br-83	1.55E-02	9.96E-02	6.96E+00	9.00E-04	0.00E+00	0.00E+00
Br-84	8.24E-03	2.21E-02	3.14E+01	4.00E-04	0.00E+00	0.00E+00
Br-85	9.70E-04	2.01E-03	3.44E+02	1.00E+00	0.00E+00	0.00E+00
Rb-88	7.27E-01	1.24E-02	5.59E+01	4.00E-04	0.00E+00	0.00E+00
Rb-89	3.35E-02	1.06E-02	6.54E+01	9.00E-04	0.00E+00	0.00E+00
Sr-89	5.33E-04	5.05E+01	1.37E-02	8.00E-06	0.00E+00	0.00E+00
Sr-90	2.38E-05	1.06E+04	6.54E-05	5.00E-07	3.43E-17	6.86E-11
Sr-91	8.24E-04	3.96E-01	1.75E+00	2.00E-05	0.00E+00	0.00E+00
Sr-92	1.99E-04	1.13E-01	6.16E+00	4.00E-05	0.00E+00	0.00E+00
Y-90	6.30E-06	2.67E+00	2.60E-01	7.00E-06	0.00E+00	0.00E+00
Y-91m	4.46E-04	3.45E-02	2.01E+01	2.00E-03	0.00E+00	0.00E+00
Y-91	6.79E-05	5.85E+01	1.18E-02	8.00E-06	0.00E+00	0.00E+00
Y-92	1.65E-04	1.48E-01	4.68E+00	4.00E-05	0.00E+00	0.00E+00
Y-93	5.33E-05	4.21E-01	1.65E+00	2.00E-05	0.00E+00	0.00E+00
Nb-95	7.76E-05	3.52E+01	1.97E-02	3.00E-05	0.00E+00	0.00E+00
Zr-95	7.76E-05	6.40E+01	1.08E-02	2.00E-05	0.00E+00	0.00E+00
Mo-99	1.02E-01	2.75E+00	2.52E-01	2.00E-05	0.00E+00	0.00E+00
Tc-99m	9.70E-02	2.51E-01	2.76E+00	1.00E-03	0.00E+00	0.00E+00
Ru-103	6.79E-05	3.93E+01	1.76E-02	3.00E-05	0.00E+00	0.00E+00
Rh-103m	6.79E-05	3.90E-02	1.78E+01	6.00E-03	0.00E+00	0.00E+00
Rh-106	2.18E-05	4.63E-04	1.50E+03	NA[f]	0.00E+00	
Ag-110m	1.94E-04	2.50E+02	2.77E-03	6.00E-06	0.00E+00	0.00E+00
Te-127m	3.68E-04	1.09E+02	6.36E-03	9.00E-06	0.00E+00	0.00E+00
Te-129m	1.26E-03	3.36E+01	2.06E-02	7.00E-06	0.00E+00	0.00E+00
Te-129	1.84E-03	4.83E-02	1.44E+01	4.00E-04	0.00E+00	0.00E+00

Table 2.4-262 (Sheet 2 of 2)
Tertiary Aquifer Results of Transport Analysis Considering Radioactive Decay Only

Radionuclide	Effluent Holdup Tank Concentration[a] ($\mu Ci/cm^3$)	Half-life[b] (days)	Decay Rate[c] ($days^{-1}$)	ECL[d] ($\mu Ci/cm^3$)	Groundwater Concentration[e] ($\mu Ci/cm^3$)	Groundwater Concentration / ECL
Te-131m	3.25E-03	1.25E+00	5.55E-01	8.00E-06	0.00E+00	0.00E+00
Te-131	2.08E-03	1.74E-02	3.98E+01	8.00E-05	0.00E+00	0.00E+00
Te-132	3.83E-02	3.26E+00	2.13E-01	9.00E-06	0.00E+00	0.00E+00
Te-134	5.33E-03	2.90E-02	2.39E+01	3.00E-04	0.00E+00	0.00E+00
I-129	7.27E-09	5.73E+09	1.21E-10	2.00E-07	7.27E-09	3.63E-02
I-130	5.33E-03	5.15E-01	1.35E+00	2.00E-05	0.00E+00	0.00E+00
I-131	3.44E-01	8.04E+00	8.62E-02	1.00E-06	0.00E+00	0.00E+00
I-132	4.56E-01	9.58E-02	7.24E+00	1.00E-04	0.00E+00	0.00E+00
I-133	6.30E-01	8.67E-01	7.99E-01	7.00E-06	0.00E+00	0.00E+00
I-134	1.07E-01	3.65E-02	1.90E+01	4.00E-04	0.00E+00	0.00E+00
I-135	3.78E-01	2.75E-01	2.52E+00	3.00E-05	0.00E+00	0.00E+00
Cs-134	3.35E-01	7.53E+02	9.21E-04	9.00E-07	6.82E-168	7.58E-162
Cs-136	4.85E-01	1.31E+01	5.29E-02	6.00E-06	0.00E+00	0.00E+00
Cs-137	2.42E-01	1.10E+04	6.30E-05	1.00E-06	9.40E-13	9.40E-07
Cs-138	1.79E-01	2.24E-02	3.09E+01	4.00E-04	0.00E+00	0.00E+00
Ba-137m	2.28E-01	1.81E-03	3.84E+02	NA[f]	0.00E+00	
Ba-140	4.85E-04	1.27E+01	5.46E-02	8.00E-06	0.00E+00	0.00E+00
La-140	1.50E-04	1.68E+00	4.13E-01	9.00E-06	0.00E+00	0.00E+00
Ce-141	7.76E-05	3.25E+01	2.13E-02	3.00E-05	0.00E+00	0.00E+00
Ce-143	6.79E-05	1.38E+00	5.02E-01	2.00E-05	0.00E+00	0.00E+00
Pr-143	7.27E-05	1.36E+01	5.10E-02	2.00E-05	0.00E+00	0.00E+00
Ce-144	5.82E-05	2.84E+02	2.44E-03	3.00E-06	0.00E+00	0.00E+00
Pr-144	5.82E-05	1.20E-02	5.78E+01	6.00E-04	0.00E+00	0.00E+00

[a] Values from Table 2.4-257.
[b] Values from NUREG/CR-5512, Table E.1 (Kennedy and Strenge 1992), and U. S. Department of Health Radiological Health Handbook (USDOH 1970) for Sr-92, Rh-106, and Ba-137m.
[c] Values calculated from Equation 2.4.13-4.
[d] Effluent Concentration Limit (ECLs) from 10 CFR Part 20, Appendix B, Table 2, Column 2
[e] Values calculated from Equation 2.4.13-5 for a travel time of 1142 years.
[f] ECL is not available.

Highlighted values indicate groundwater concentration/ECL ratios exceeding 0.01

Table 2.4-263 (Sheet 1 of 2)
Water Table Aquifer Compliance with 10 CFR Part 20

Radionuclide	Water Table Aquifer Concentration / ECL			
	Decay[a]	Decay and Adsorption[b]	Decay, Adsorption, and Dilution[c]	Minimum
H-3	6.93E+02	6.93E+02	5.76E-02	5.76E-02
Cr-51	6.66E-26			6.66E-27
Mn-54	1.00E-01	1.00E-01	8.31E-06	8.31E-06
Mn-56	0.00E+00			0.00E+00
Fe-55	9.04E-01	9.04E-01	7.52E-05	7.52E-05
Fe-59	3.65E-16			3.65E-16
Co-58	3.78E-09			3.78E-09
Co-60	3.07E+01	1.85E-04		1.85E-04
Br-83	0.00E+00			0.00E+00
Br-84	0.00E+00			0.00E+00
Br-85	0.00E+00			0.00E+00
Rb-88	0.00E+00			0.00E+00
Rb-89	0.00E+00			0.00E+00
Sr-89	1.72E-13			1.72E-13
Sr-90	4.06E+01	1.01E-02	1.05E-08	1.05E-08
Sr-91	0.00E+00			0.00E+00
Sr-92	0.00E+00			0.00E+00
Y-90	1.11E-276			1.11E-276
Y-91m	0.00E+00			0.00E-00
Y-91	2.17E-12			2.17E-12
Y-92	0.00E+00			0.00E+00
Y-93	0.00E+00			0.00E+00
Nb-95	3.05E-21			3.05E-21
Zr-95	1.20E-11			1.20E-11
Mo-99	6.71E-265			6.71E-265
Tc-99m	0.00E+00			0.00E+00
Ru-103	4.07E-19			4.07E-19
Rh-103m	0.00E+00			0.00E+00
Rh-106[4]	0.00E+00			0.00E+00
Ag-110m	3.66E-02	3.66E-02	3.04E-06	3.04E-06
Te-127m	7.13E-06			7.13E-05
Te-129m	2.14E-20			2.14E-20
Te-129	0.00E+00			0.00E+00
Te-131m	0.00E+00			0.00E+00
Te-131	0.00E+00			0.00E+00
Te-132	4.53E-223			4.53E-223

Table 2.4-263 (Sheet 2 of 2)
Water Table Aquifer Compliance with 10 CFR Part 20

Radionuclide	Water Table Aquifer Concentration / ECL			
	Decay[a]	Decay and Adsorption[b]	Decay, Adsorption, and Dilution[c]	Minimum
Te-134	0.00E+00			0.00E+00
I-129	3.63E-02	3.63E-02	3.02E-06	3.02E-06
I-130	0.00E+00			0.00E+00
I-131	8.14E-87			8.14E-87
I-132	0.00E+00			0.00E+00
I-133	0.00E+00			0.00E+00
I-134	0.00E+00			0.00E+00
I-135	0.00E+00			0.00E+00
Cs-134	3.91E+04	1.25E-66		1.25E-66
Cs-136	4.71E-52			4.71E-52
Cs-137	2.07E+05	3.10E+00	2.58E-04	2.58E-04
Cs-138	0.00E+00			0.00E+00
Ba-137m[d]	0.00E+00			0.00E+00
Ba-140	5.98E-57			5.98E-57
La-140	0.00E+00			0.00E+00
Ce-141	5.57E-23			5.57E-23
Ce-143	0.00E+00			0.00E+00
Pr-143	2.47E-54			2.47E-54
Ce-144	4.94E-02	4.94E-02	4.11E-06	4.11E-06
Pr-144	0.00E+00			0.00E+00

Sum of Fractions = 0.058

a Table 2.4-258.
b Table 2.4-260.
c Table 2.4-261.
d No ECLs are published for Rh-106 and Ba-137m. However, the half-lives for these radionuclides are short (less than 1 day) and they decay to near zero values. Their ratios have been taken as zero.

Table 2.4-264 (Sheet 1 of 2)
Tertiary Aquifer Compliance with 10 CFR Part 20

Radionuclide	Tertiary Aquifer Concentration / ECL Decay[a]	Minimum
H-3	1.49E-25	1.49E-25
Cr-51	0.00E+00	0.00E+00
Mn-54	0.00E+00	0.00E+00
Mn-56	0.00E+00	0.00E+00
Fe-55	2.53E-127	2.53E-127
Fe-59	0.00E+00	0.00E+00
Co-58	0.00E+00	0.00E+00
Co-60	6.82E-64	6.82E-64
Br-83	0.00E+00	0.00E+00
Br-84	0.00E+00	0.00E+00
Br-85	0.00E+00	0.00E+00
Rb-88	0.00E+00	0.00E+00
Rb-89	0.00E+00	0.00E+00
Sr-89	0.00E+00	0.00E+00
Sr-90	6.86E-11	6.86E-11
Sr-91	0.00E+00	0.00E+00
Sr-92	0.00E+00	0.00E+00
Y-90	0.00E+00	0.00E+00
Y-91m	0.00E+00	0.00E+00
Y-91	0.00E+00	0.00E+00
Y-92	0.00E+00	0.00E+00
Y-93	0.00E+00	0.00E+00
Nb-95	0.00E+00	0.00E+00
Zr-95	0.00E+00	0.00E+00
Mo-99	0.00E+00	0.00E+00
Tc-99m	0.00E+00	0.00E+00
Ru-103	0.00E+00	0.00E+00
Rh-103m	0.00E+00	0.00E+00
Rh-106[b]	0.00E+00	0.00E+00
Ag-110m	0.00E+00	0.00E+00
Te-127m	0.00E+00	0.00E+00
Te-129m	0.00E+00	0.00E+00
Te-129	0.00E+00	0.00E+00
Te-131m	0.00E+00	0.00E+00
Te-131	0.00E+00	0.00E+00
Te-132	0.00E+00	0.00E+00
Te-134	0.00E+00	0.00E+00
I-129	3.63E-02	3.63E-02
I-130	0.00E+00	0.00E+00
I-131	0.00E+00	0.00E+00
I-132	0.00E+00	0.00E+00
I-133	0.00E+00	0.00E+00
I-134	0.00E+00	0.00E+00
I-135	0.00E+00	0.00E+00

Table 2.4-264 (Sheet 2 of 2)
Tertiary Aquifer Compliance with 10 CFR Part 20

Radionuclide	Tertiary Aquifer Concentration / ECL Decay[a]	Minimum
Cs-134	7.58E-162	7.58E-162
Cs-136	0.00E+00	0.00E+00
Cs-137	9.40E-07	9.40E-07
Cs-138	0.00E+00	0.00E+00
Ba-137m[b]	0.00E+00	0.00E+00
Ba-140	0.00E+00	0.00E+00
La-140	0.00E+00	0.00E+00
Ce-141	0.00E+00	0.00E+00
Ce-143	0.00E+00	0.00E+00
Pr-143	0.00E+00	0.00E+00
Ce-144	0.00E+00	0.00E+00
Pr-144	0.00E+00	0.00E+00
	Sum of Fractions =	0.036

[a] Table 2.4-262.

[b] No ECLs are published for Rh-106 and Ba-137m. However, the half-lives for these radionuclides are short (less than 1 day) and they decay to near zero values. Their ratios have been taken as zero.

Figure 2.4-201
Not Used

Figure 2.4-201a
Not Used

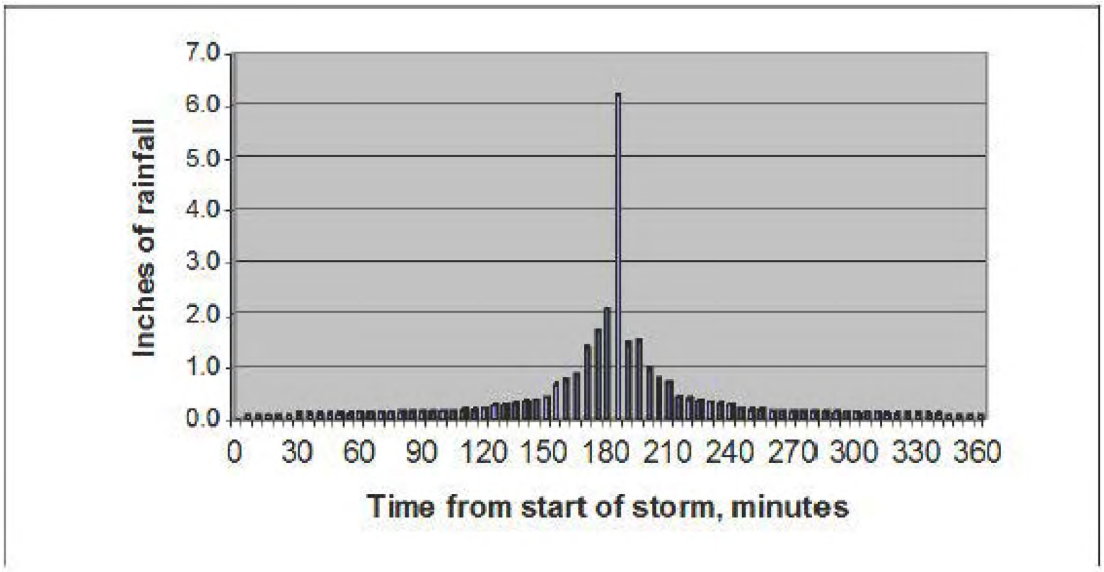


Figure 2.4-202
PMP Hyetograph Determined in Frequency Storm Module of HEC-HMS

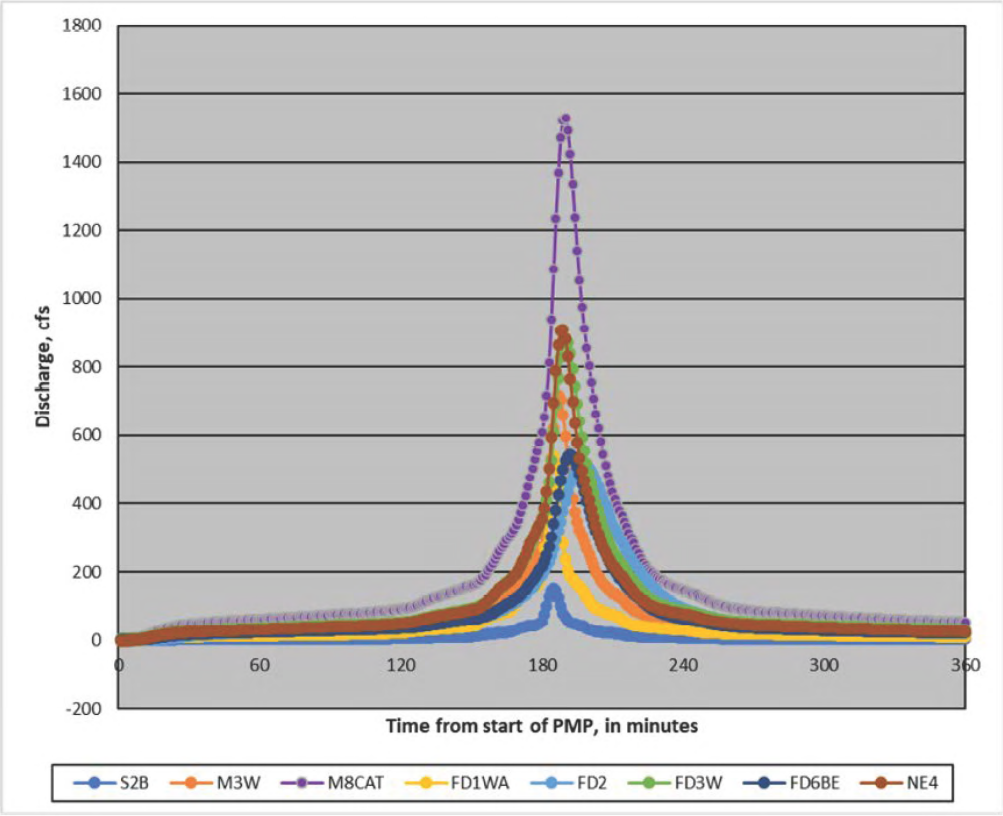
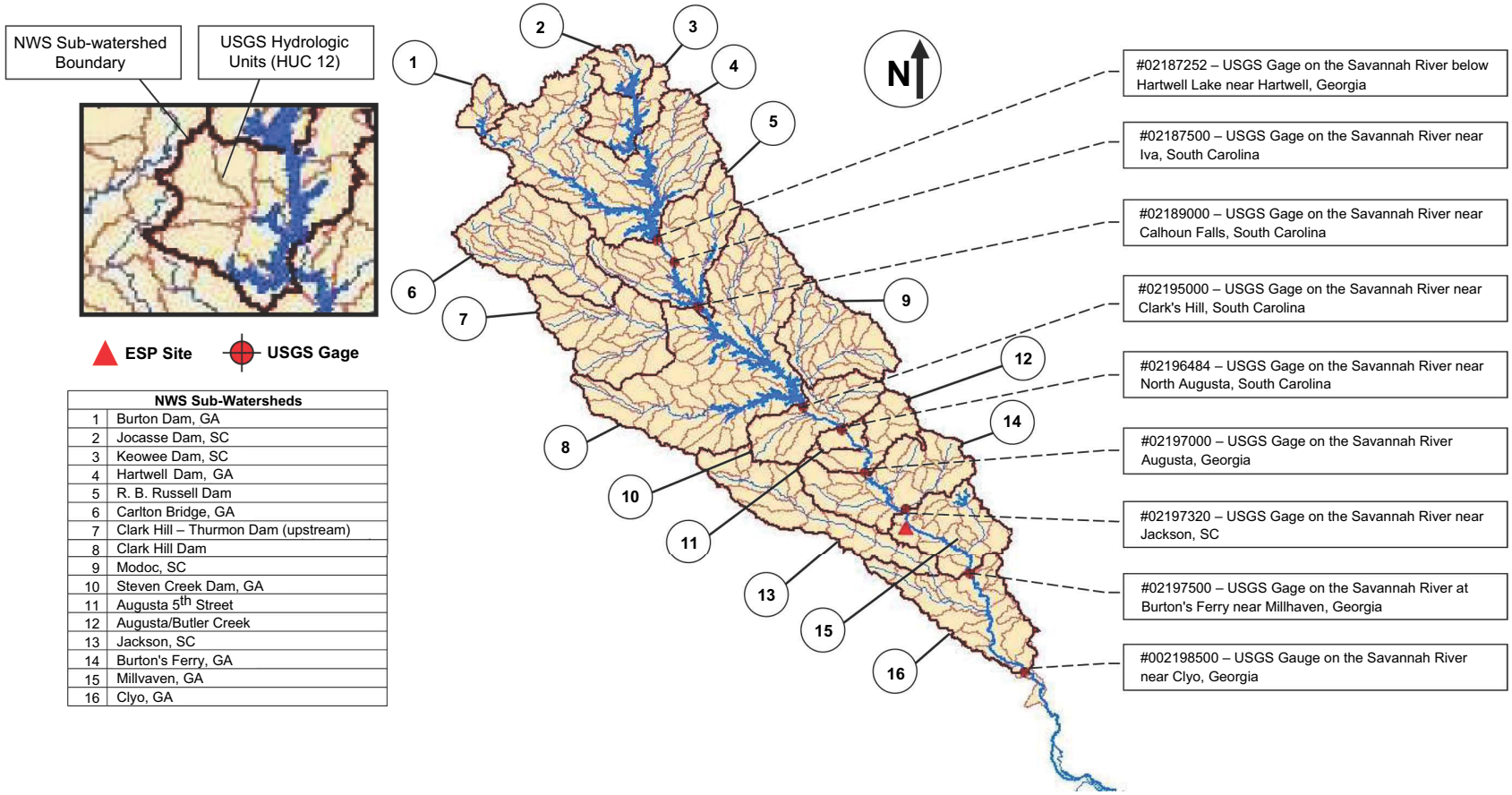


Figure 2.4-203
Sample HEC-HMS PMP Runoff Hydrographs



NWS Sub-Watersheds	
1	Burton Dam, GA
2	Jocasse Dam, SC
3	Keowee Dam, SC
4	Hartwell Dam, GA
5	R. B. Russell Dam
6	Carlton Bridge, GA
7	Clark Hill – Thurmon Dam (upstream)
8	Clark Hill Dam
9	Modoc, SC
10	Steven Creek Dam, GA
11	Augusta 5th Street
12	Augusta/Butler Creek
13	Jackson, SC
14	Burton's Ferry, GA
15	Millvaven, GA
16	Clyo, GA

Figure 2.4-204
Savannah River Watershed and HUCs (No Scale)

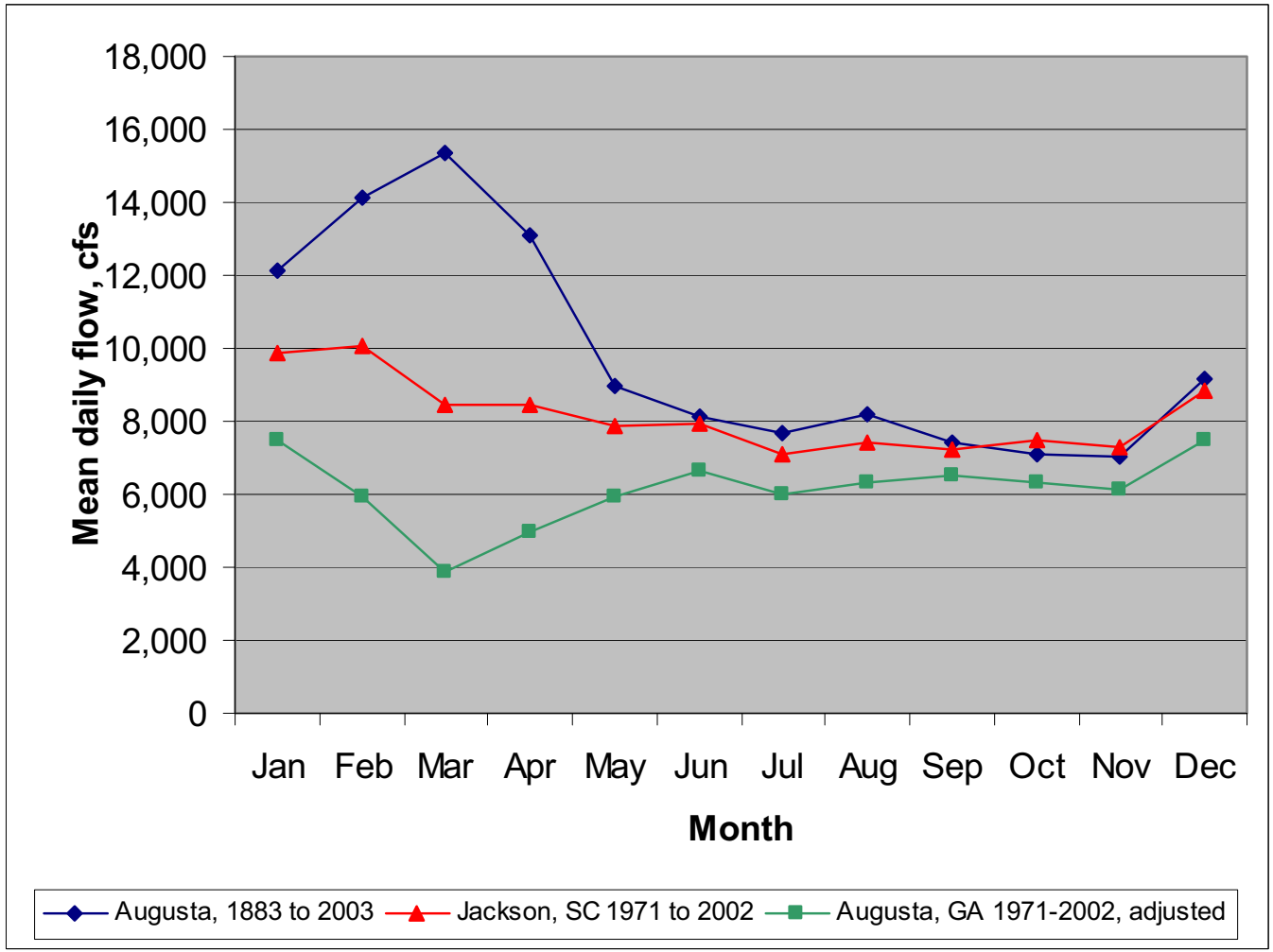
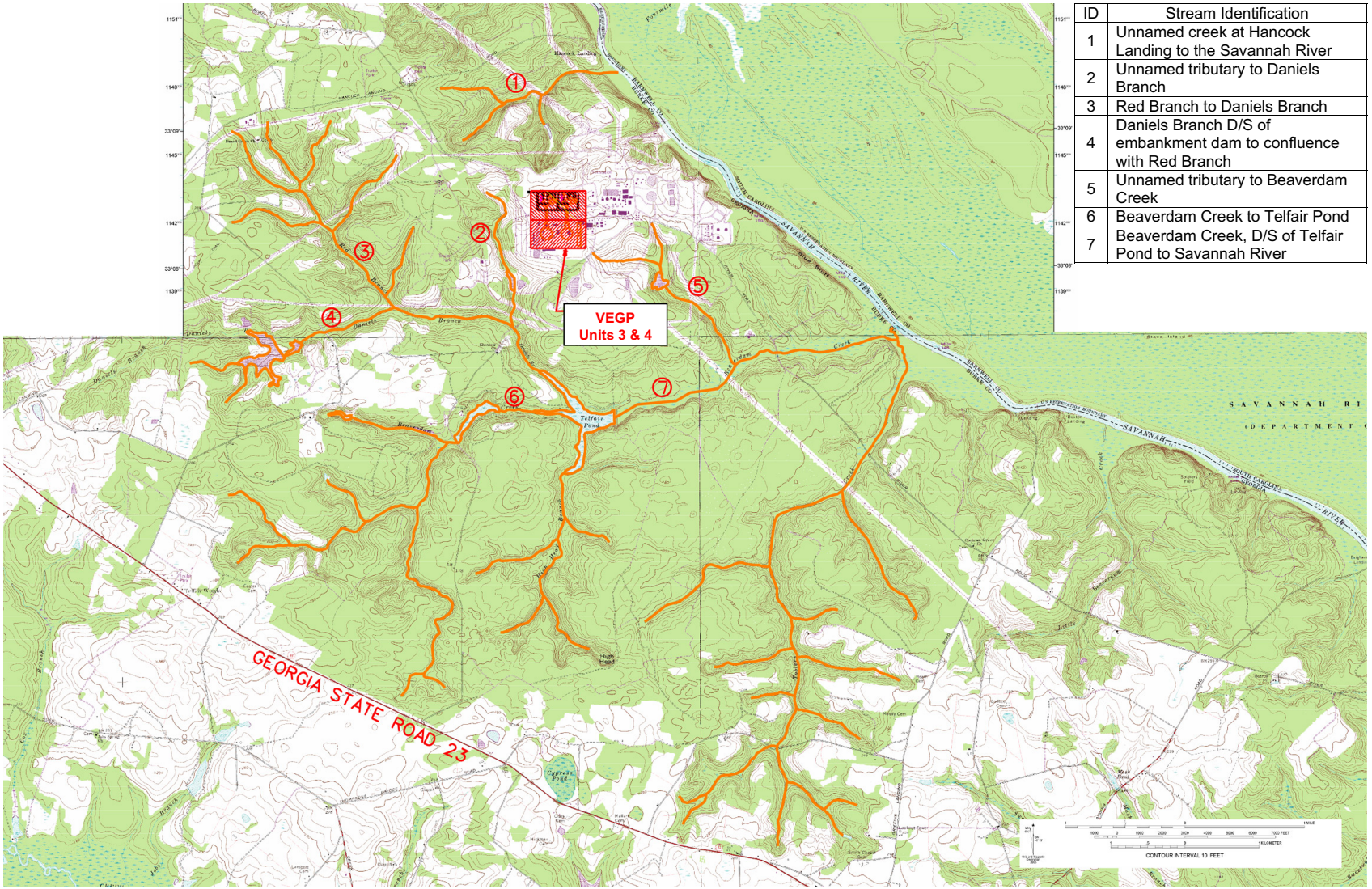
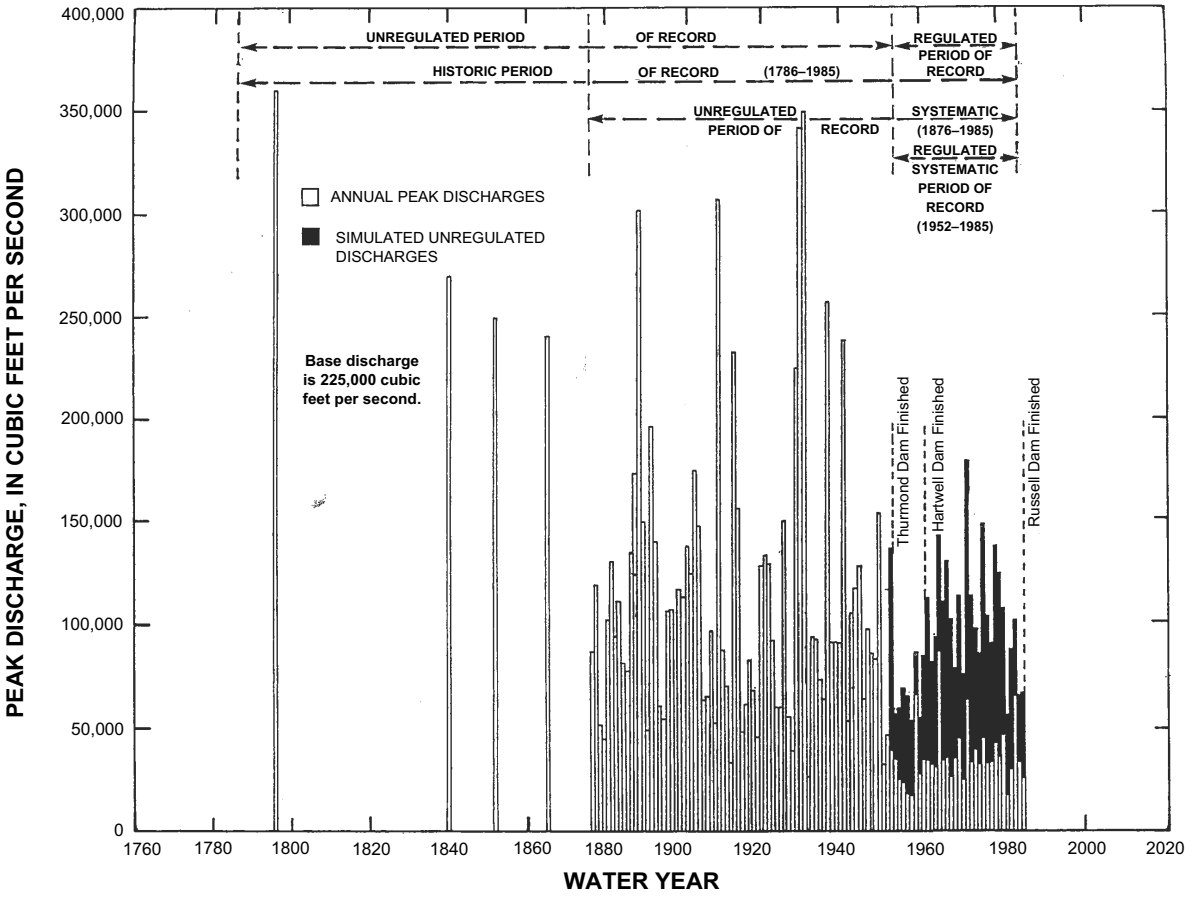


Figure 2.4-205
Mean Daily Discharge for the Year – Selected Gages of the Savannah River



ID	Stream Identification
1	Unnamed creek at Hancock Landing to the Savannah River
2	Unnamed tributary to Daniels Branch
3	Red Branch to Daniels Branch
4	Daniels Branch D/S of embankment dam to confluence with Red Branch
5	Unnamed tributary to Beaverdam Creek
6	Beaverdam Creek to Telfair Pond
7	Beaverdam Creek, D/S of Telfair Pond to Savannah River

Figure 2.4-206
Site Drainage



Source: Figure 2 from USGS 1990

Figure 2.4-207
Unregulated and Regulated Peak Discharge Frequency Curves for the Savannah River at Augusta, Georgia (02197000)

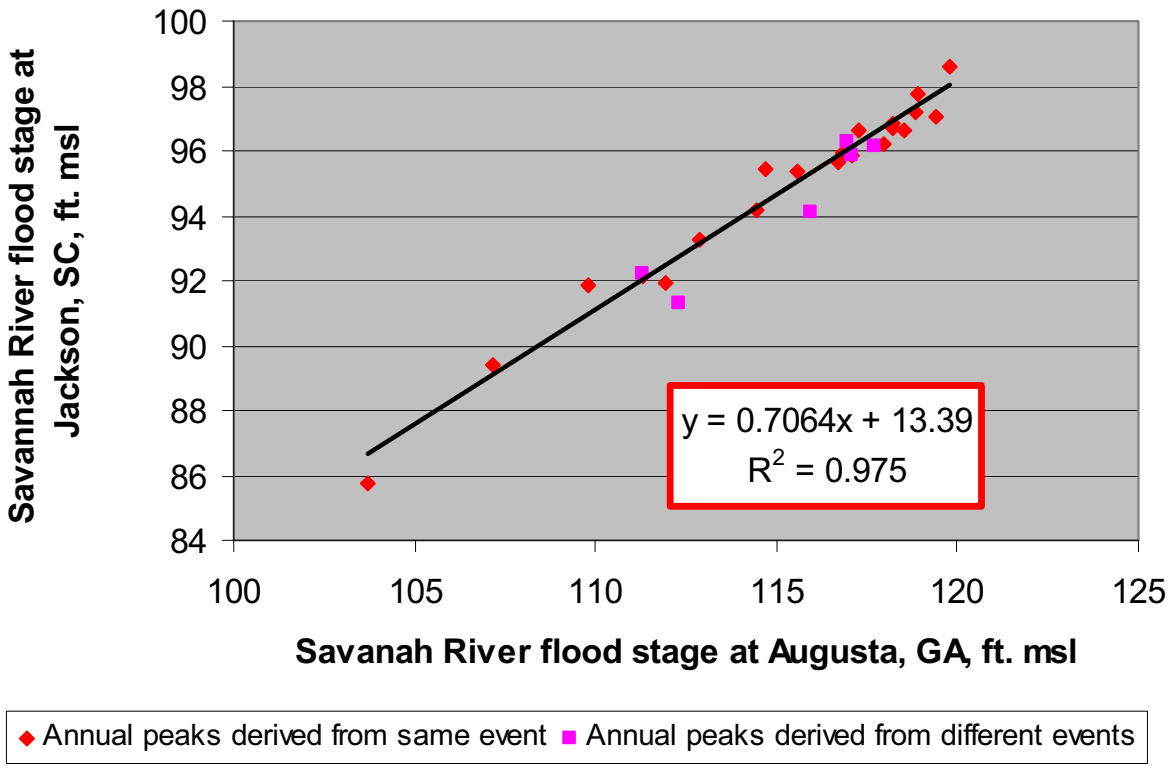
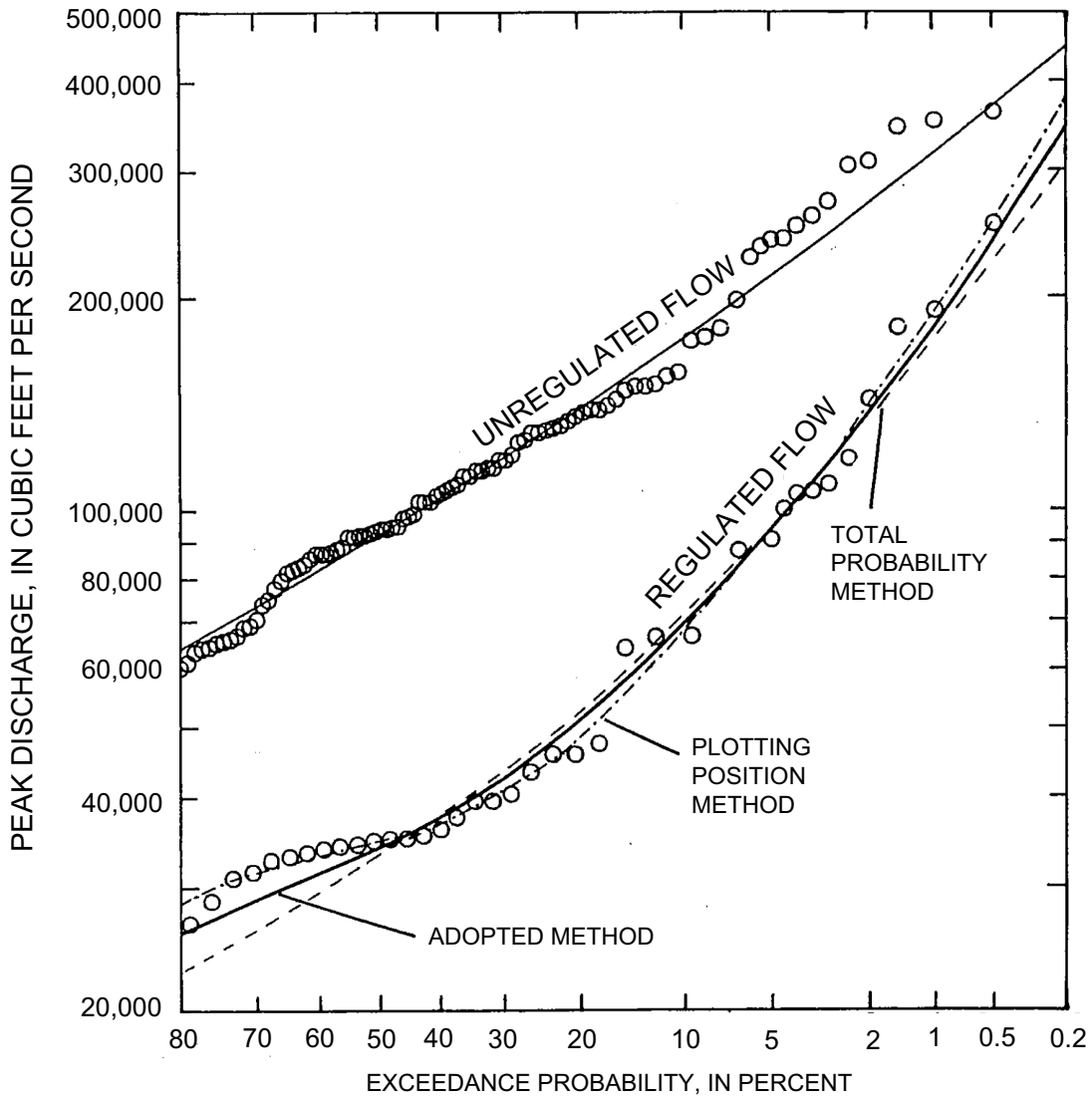


Figure 2.4-208
Correlation of Annual Peak Discharges on the Savannah River at Augusta, Georgia (02197000), and Jackson, South Carolina (2197320), for Years with Annual Peak Derived from Same Storm Event



Source: Figure 35 from USGS 1990

Figure 2.4-209
Unregulated and Regulated Annual Peak Discharge Frequency Curves for the Savannah River at Augusta, Georgia

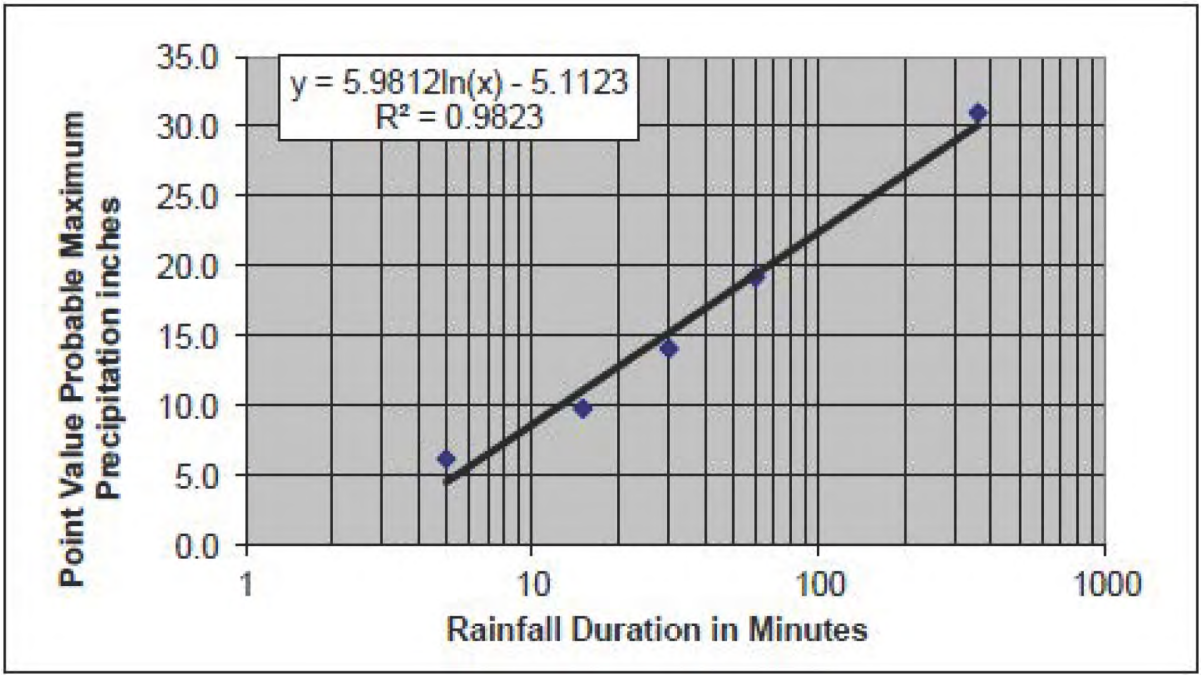


Figure 2.4-210
Probable Maximum Precipitation Values as a Function of Duration for Point Rainfall at VEGP Site

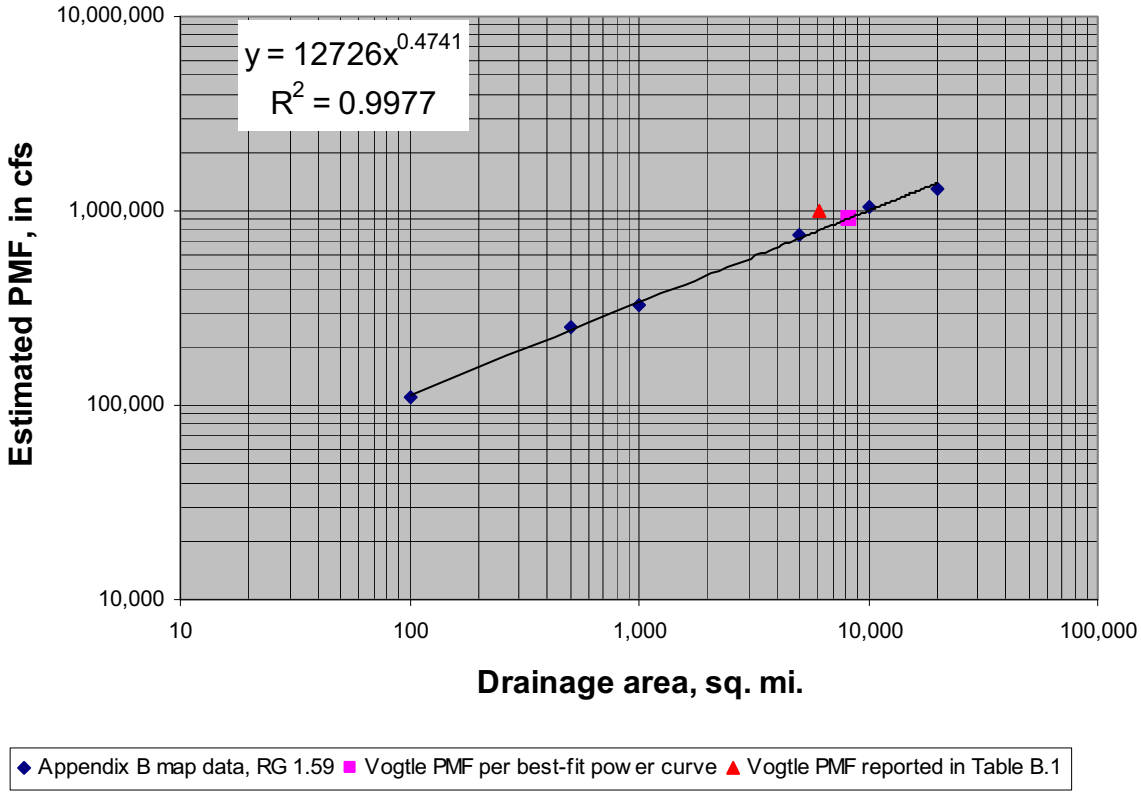


Figure 2.4-211
Area-PMF Plot for VEGP Site per Approximate Method from RG 1.59

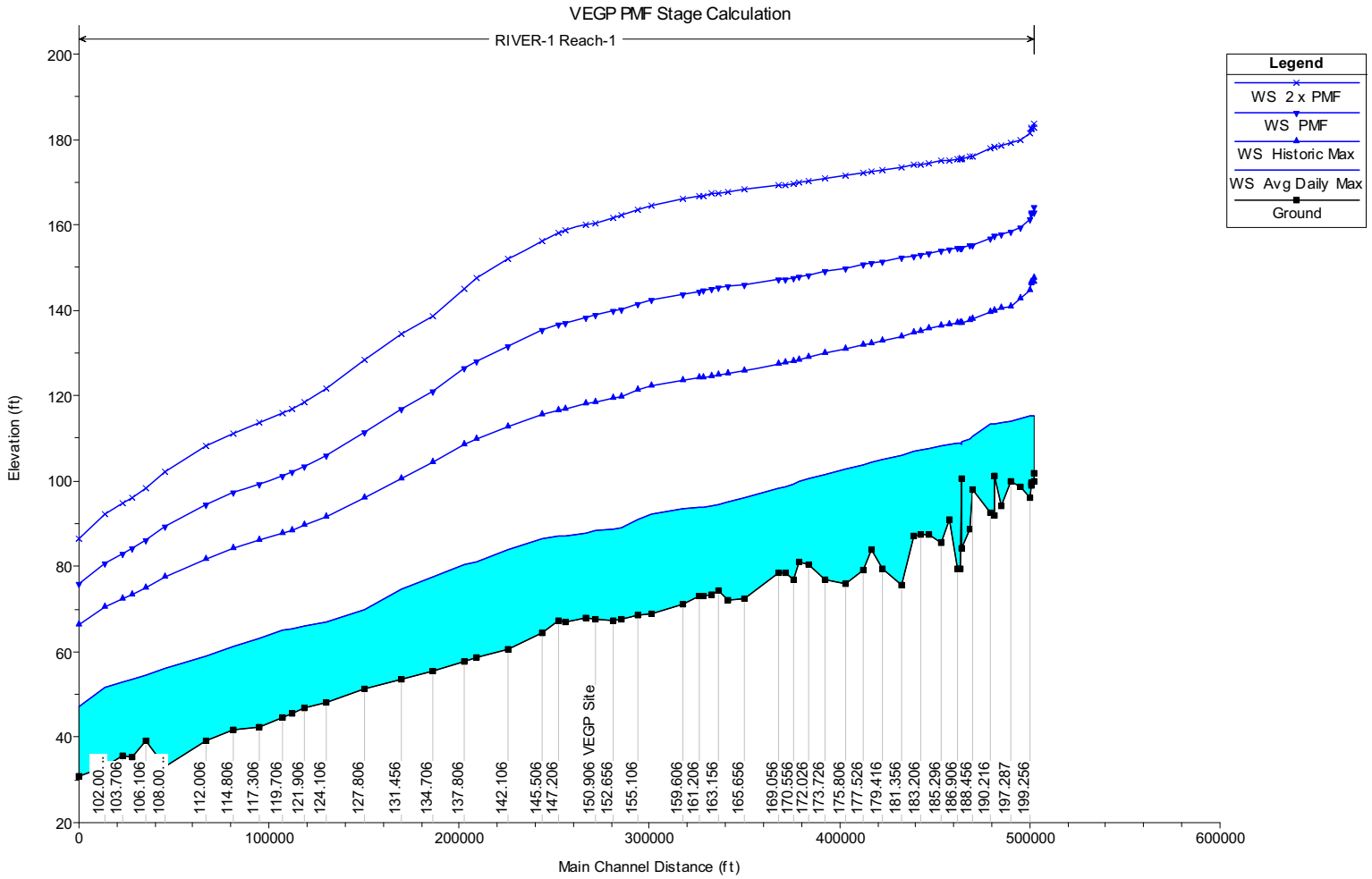


Figure 2.4-212
Longitudinal Profiles of the Savannah River from Steady-State HEC-RAS Model Run

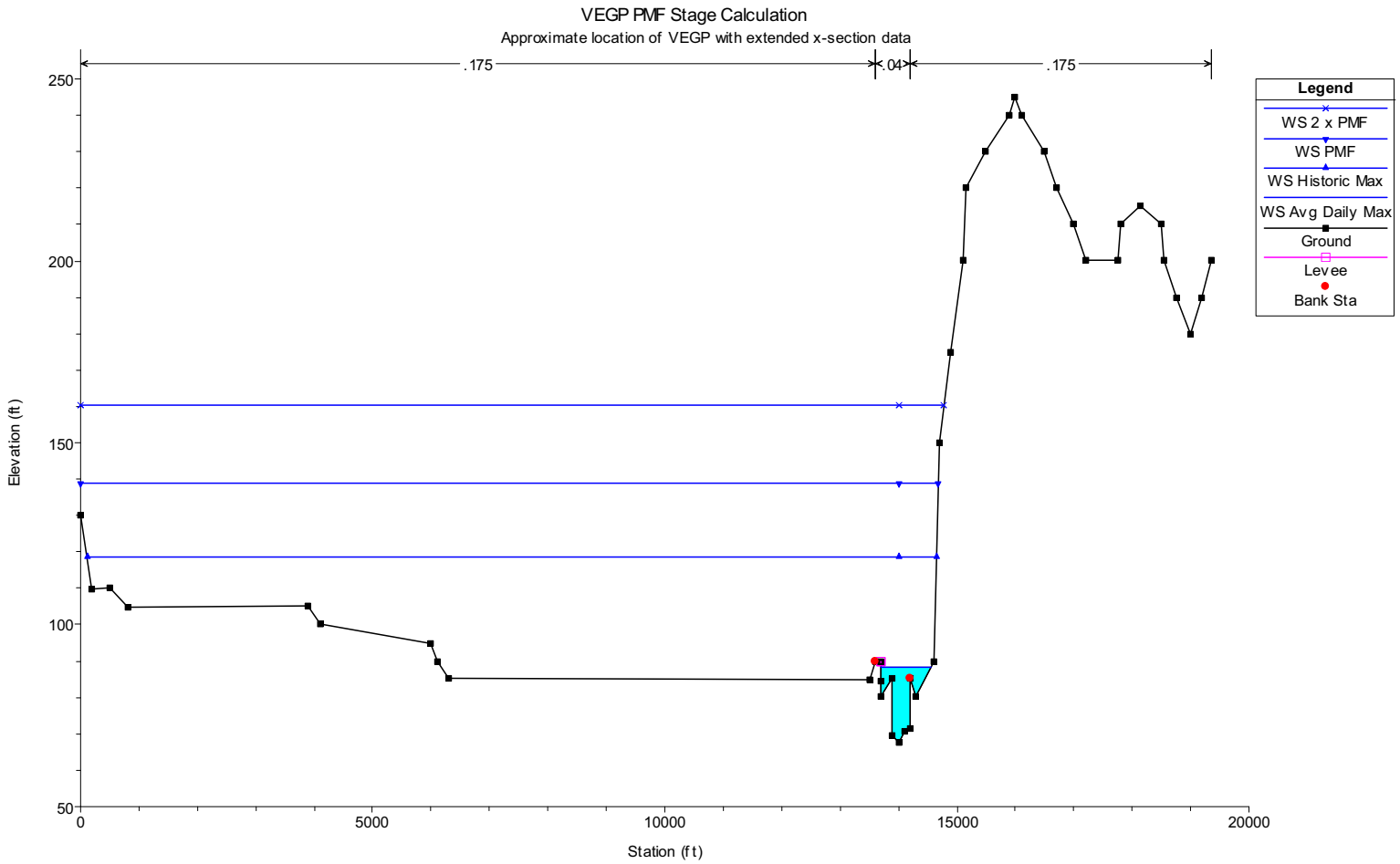


Figure 2.4-213
HEC-RAS Model Section at VEGP Site (Looking Downstream)

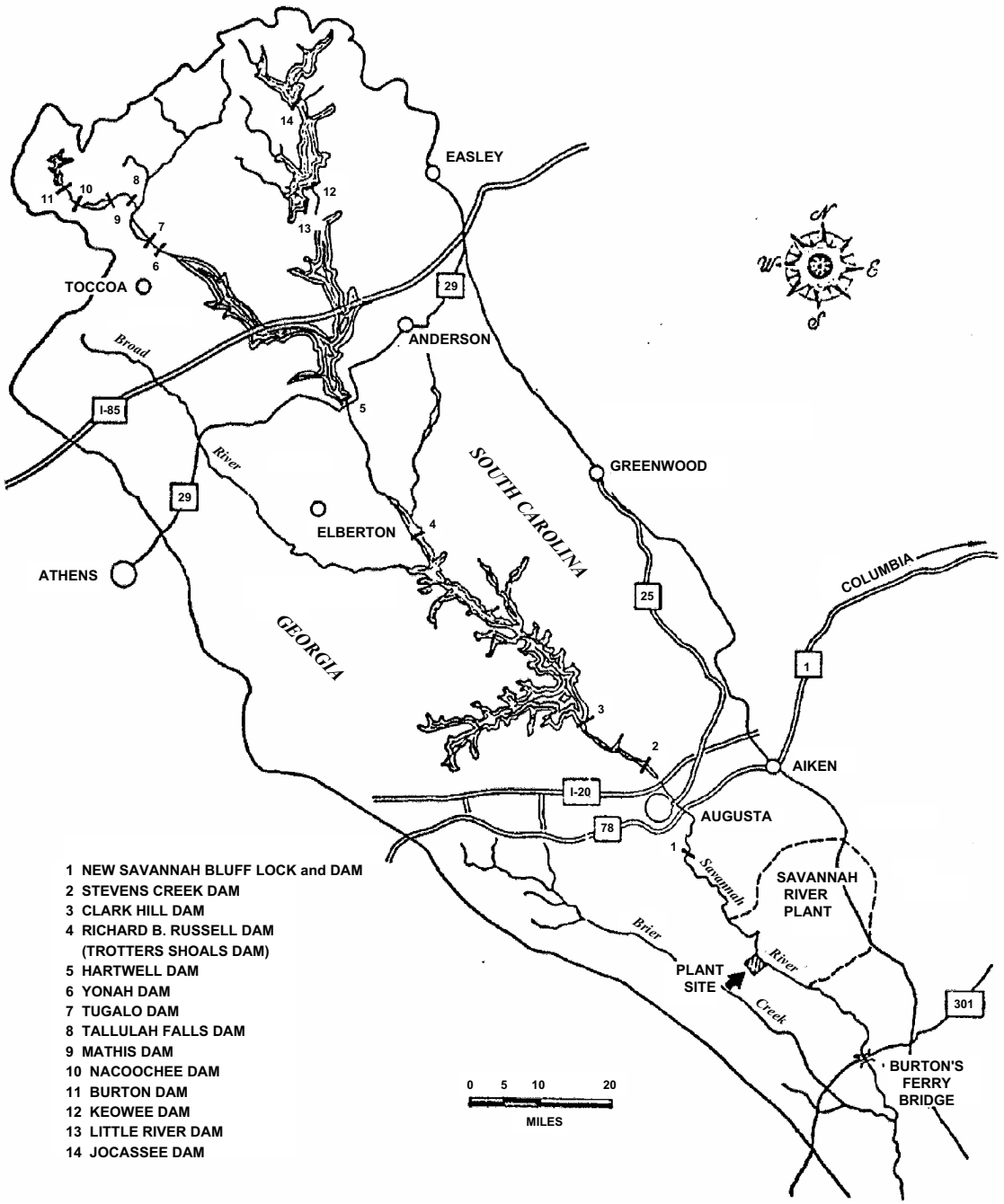
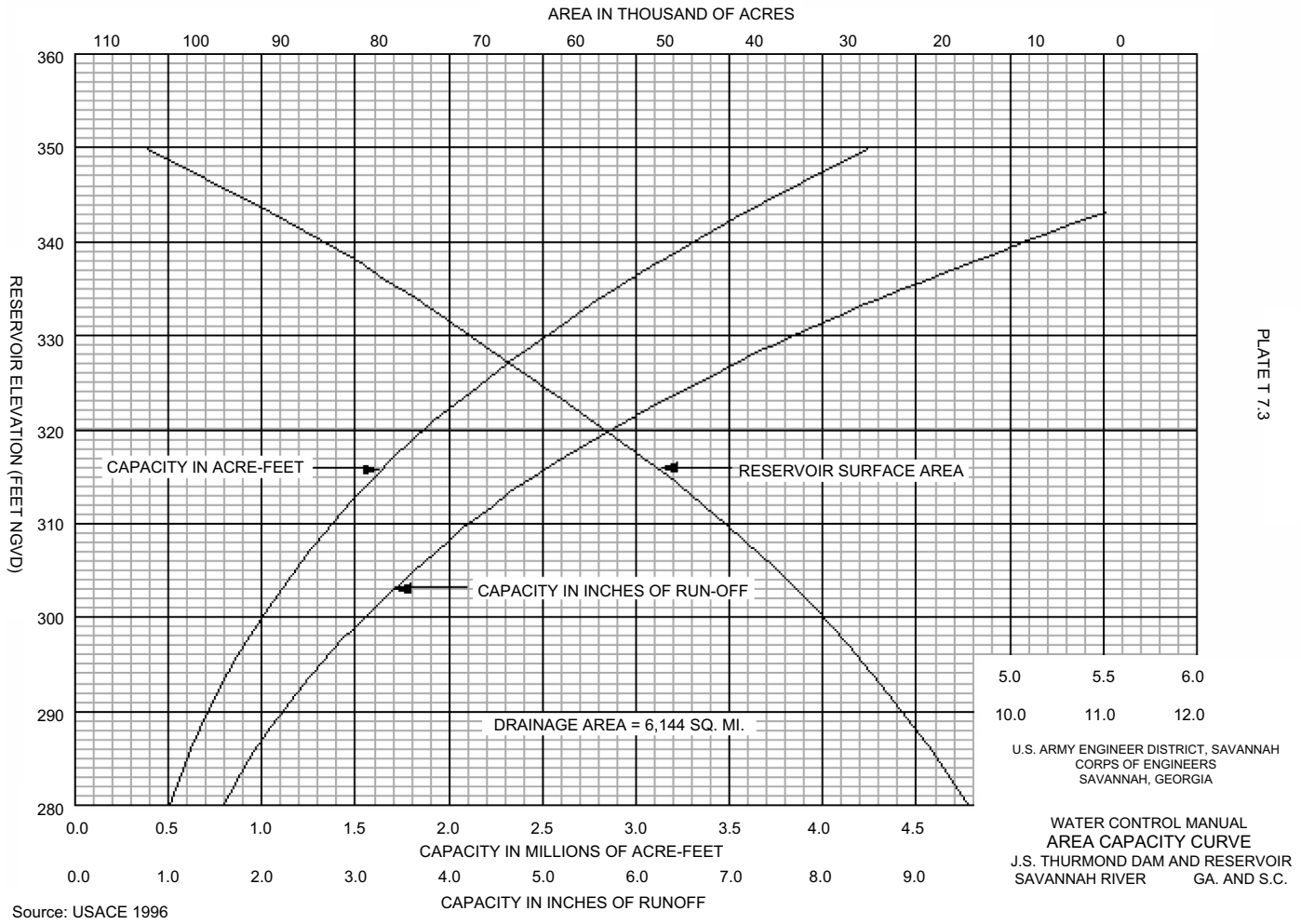
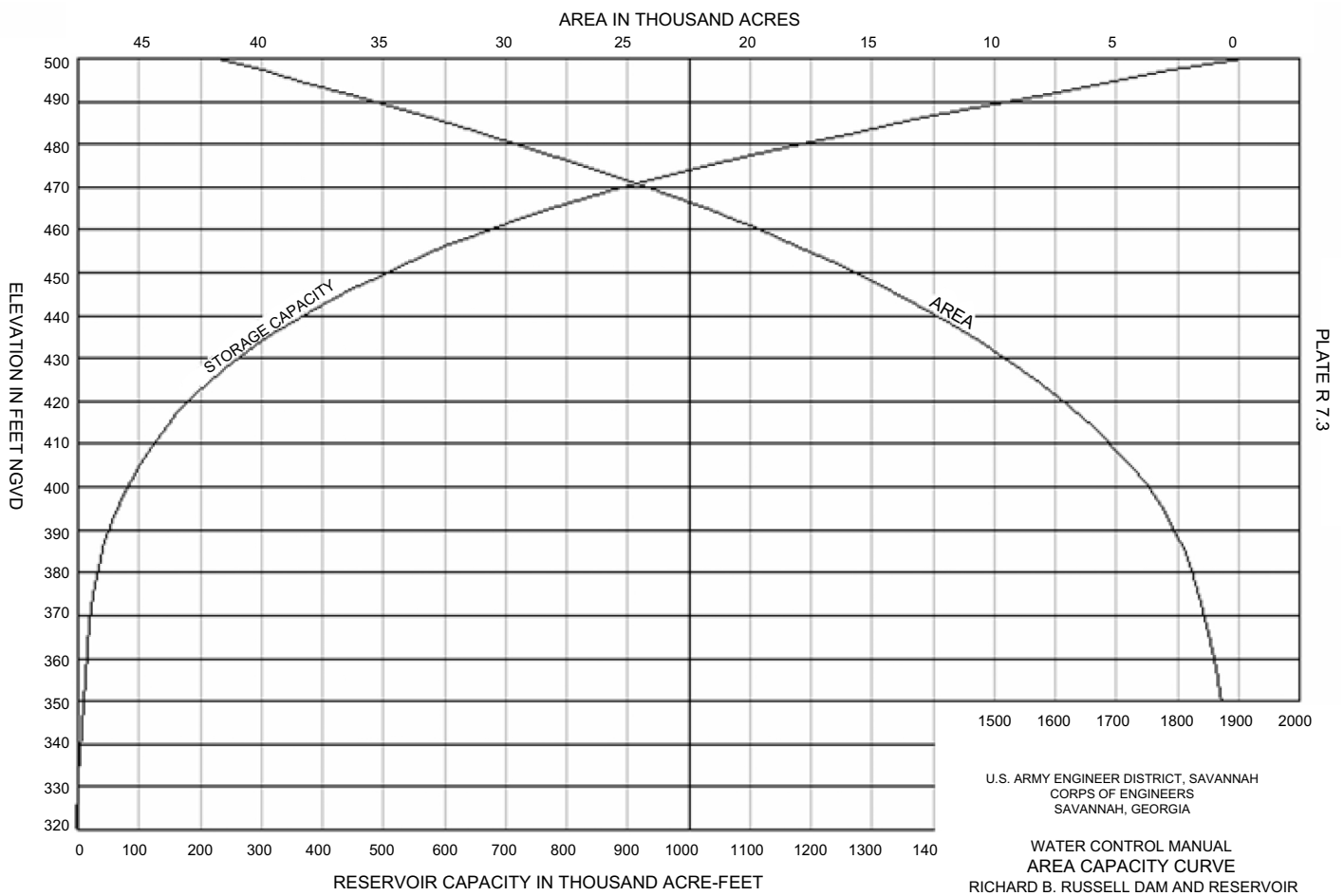


Figure 2.4-214
Savannah River Basin Dam Locations



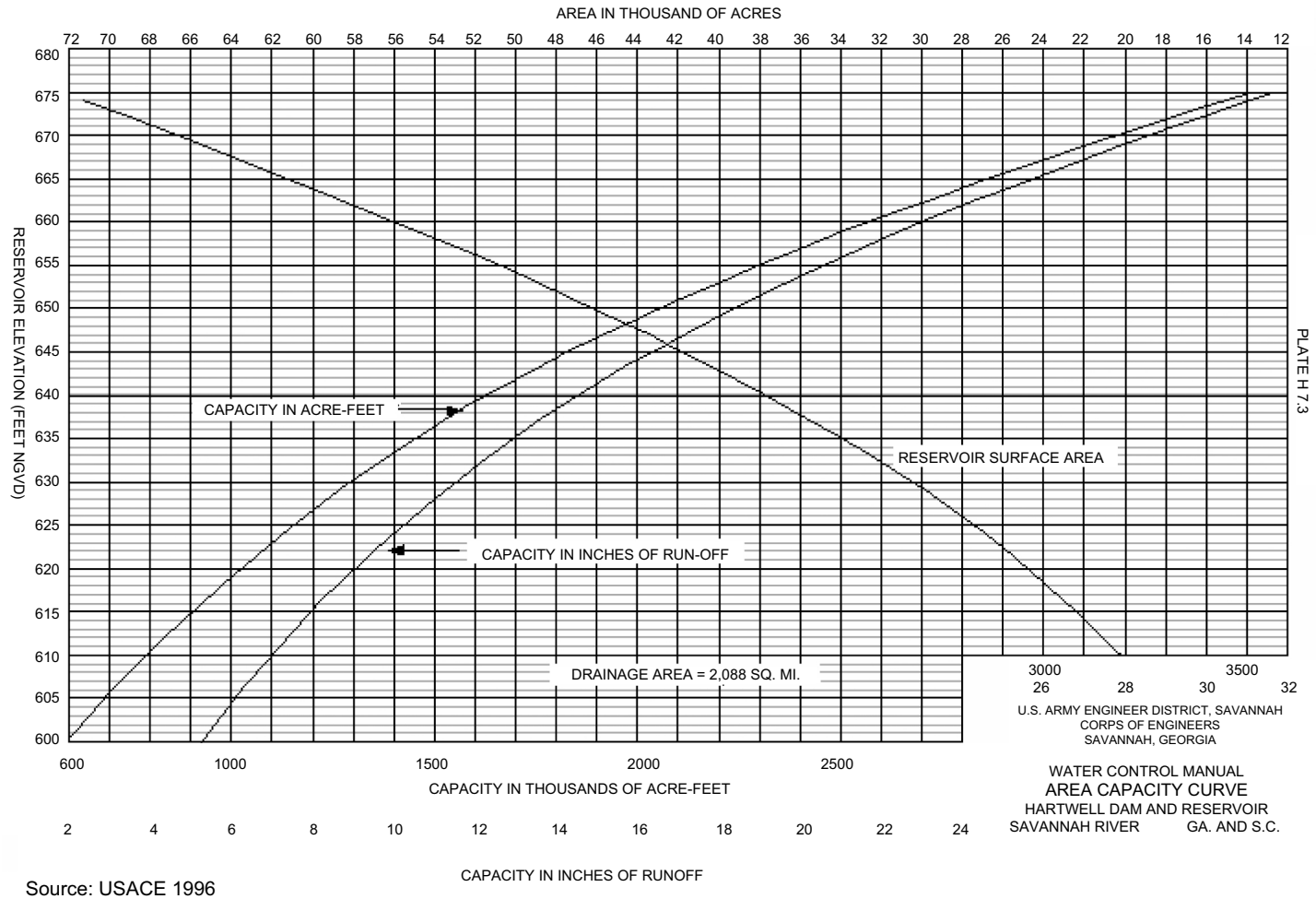
Source: USACE 1996

Figure 2.4-215
J. Strom Thurmond Area Capacity Curve



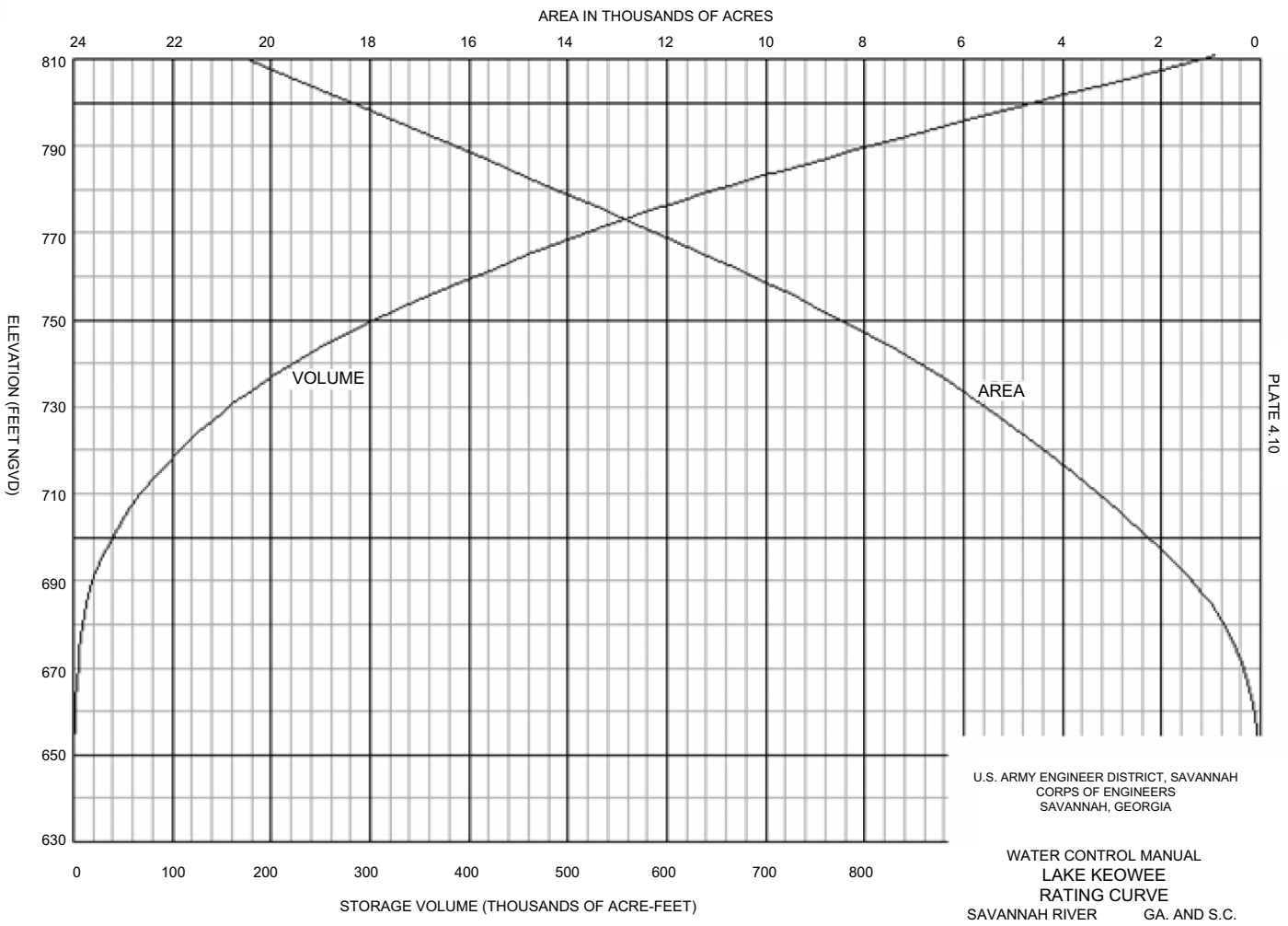
Source: USACE 1996

Figure 2.4-216
Richard B. Russell Area Capacity Curve



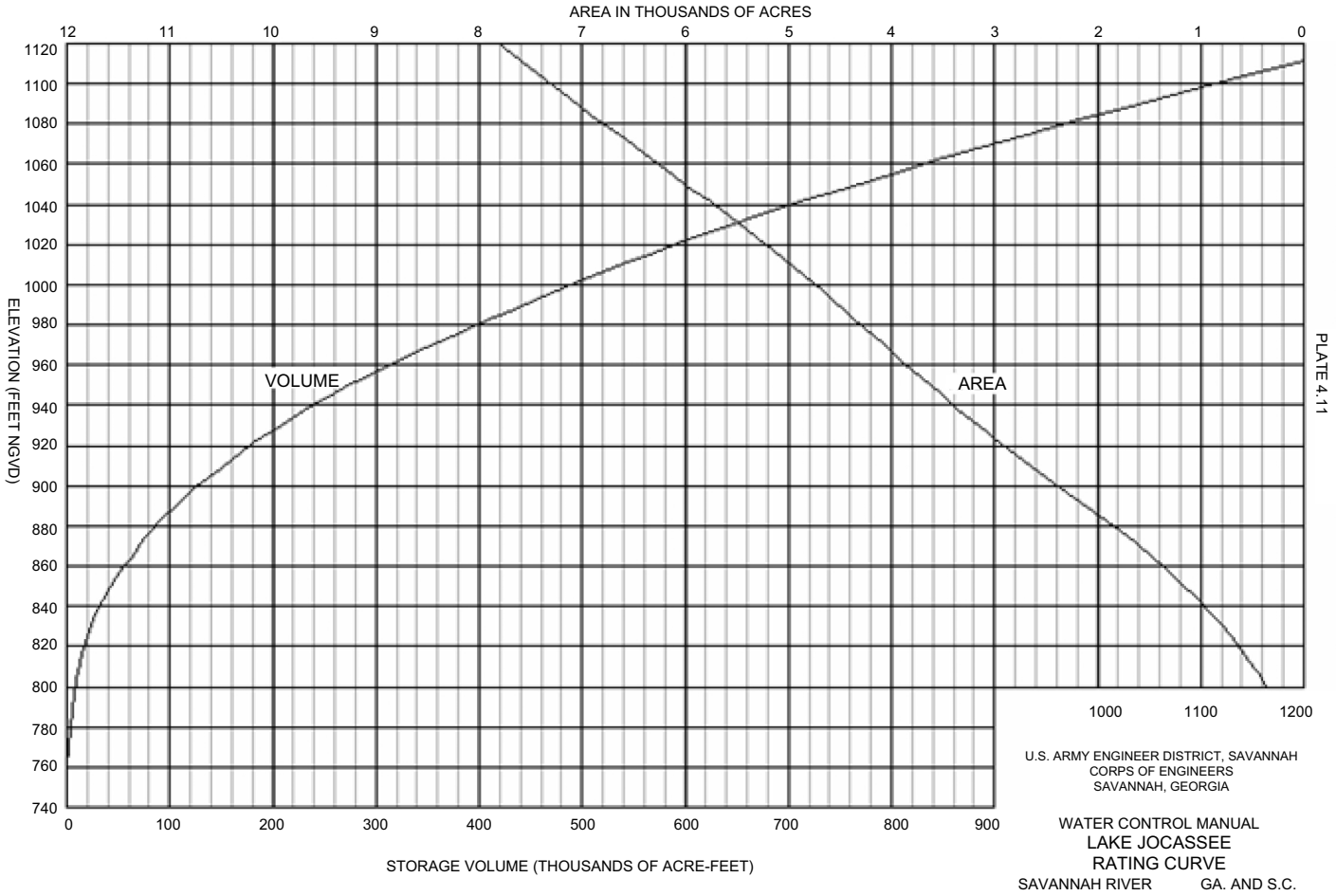
Source: USACE 1996

Figure 2.4-217
Hartwell Dam and Reservoir Area Capacity



Source: USACE 1996

Figure 2.4-218
Keowee Area Capacity Curve



Source: (USACE 1996)

Figure 2.4-219
Jocassee Area Capacity Curve

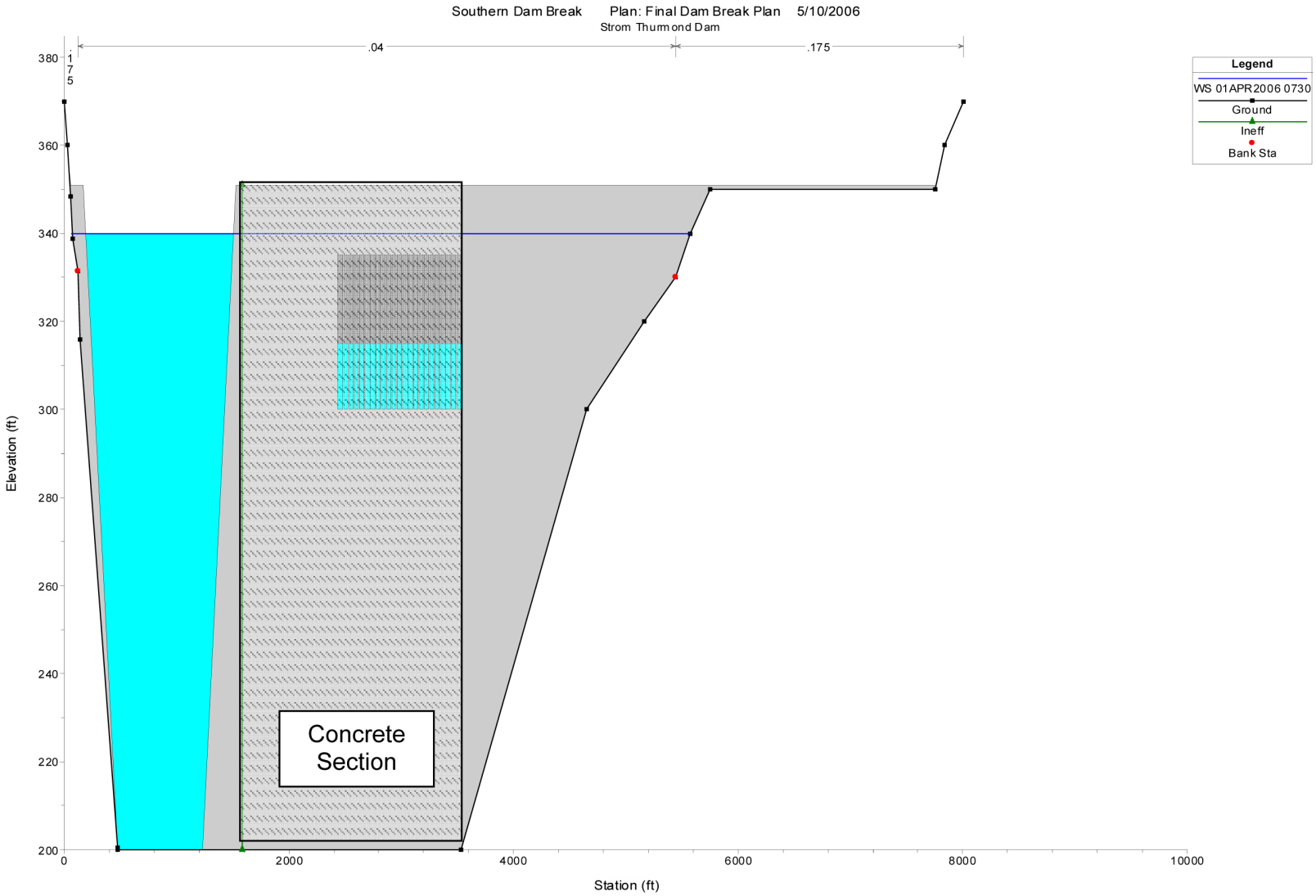


Figure 2.4-220
J. Strom Thurmond Dam Cross Section

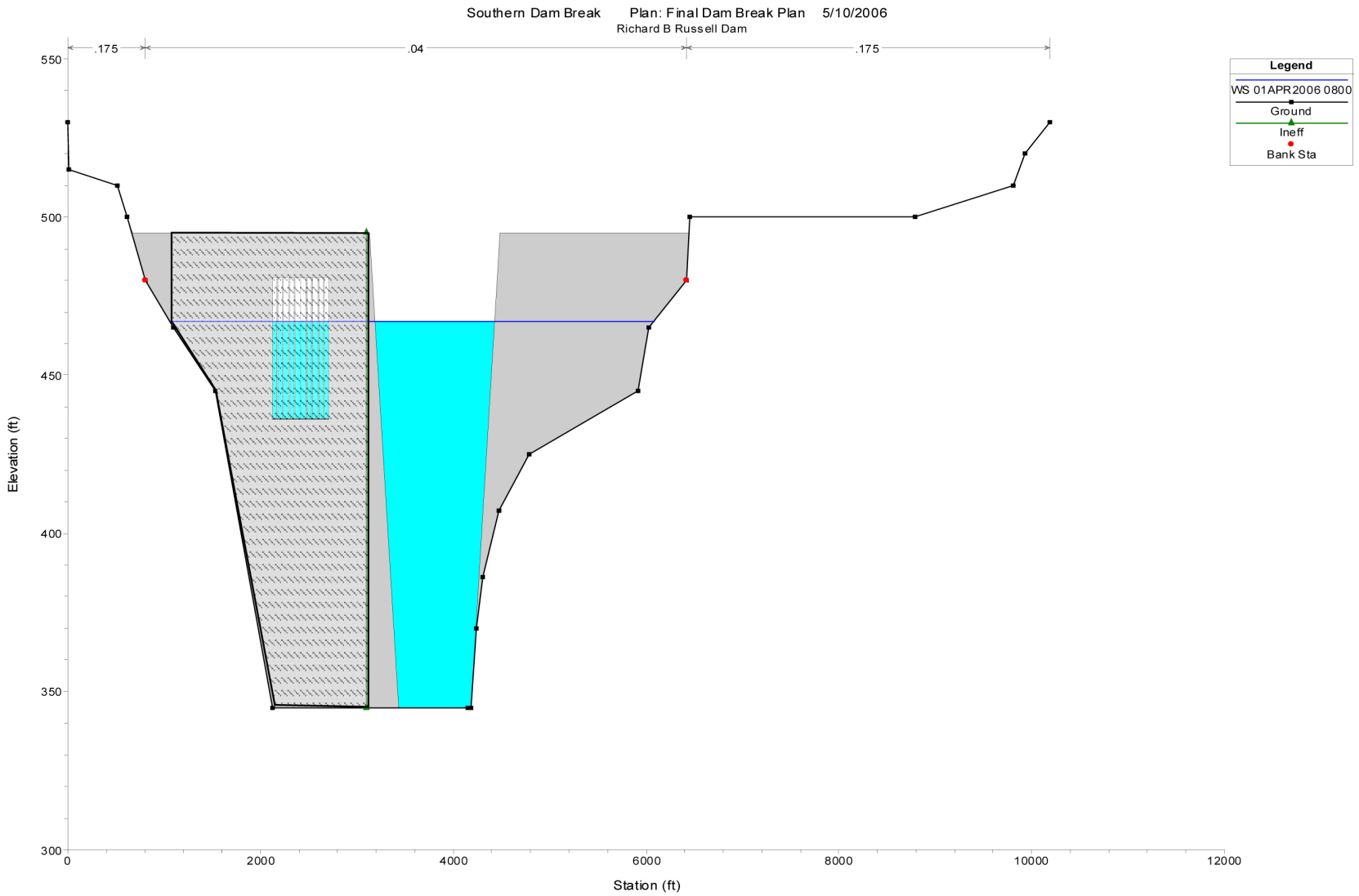


Figure 2.4-221
Richard B. Russell Dam Cross Section

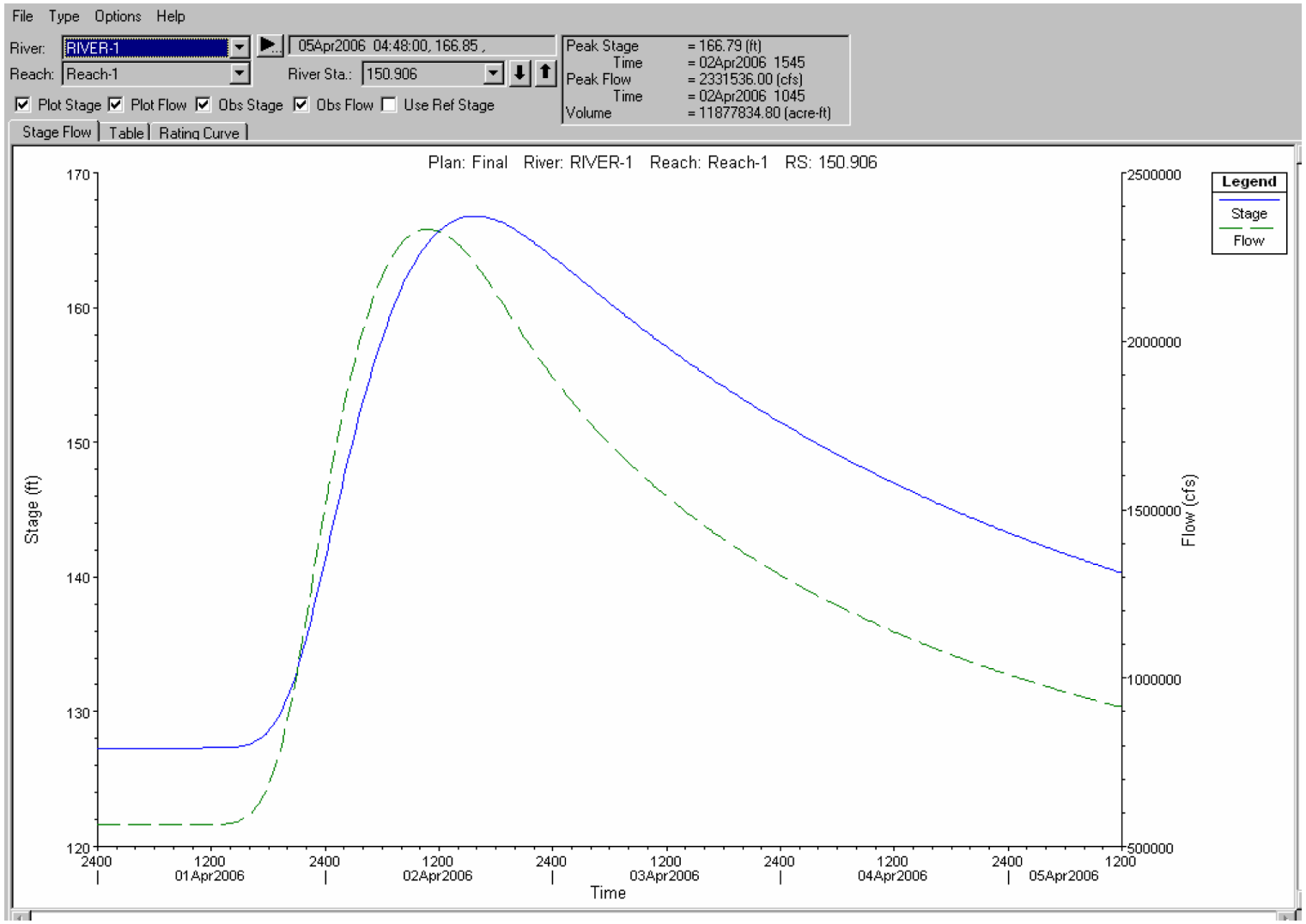


Figure 2.4-222
Dam Breach Flood Flow and Stage Hydrograph at the VEGP Site

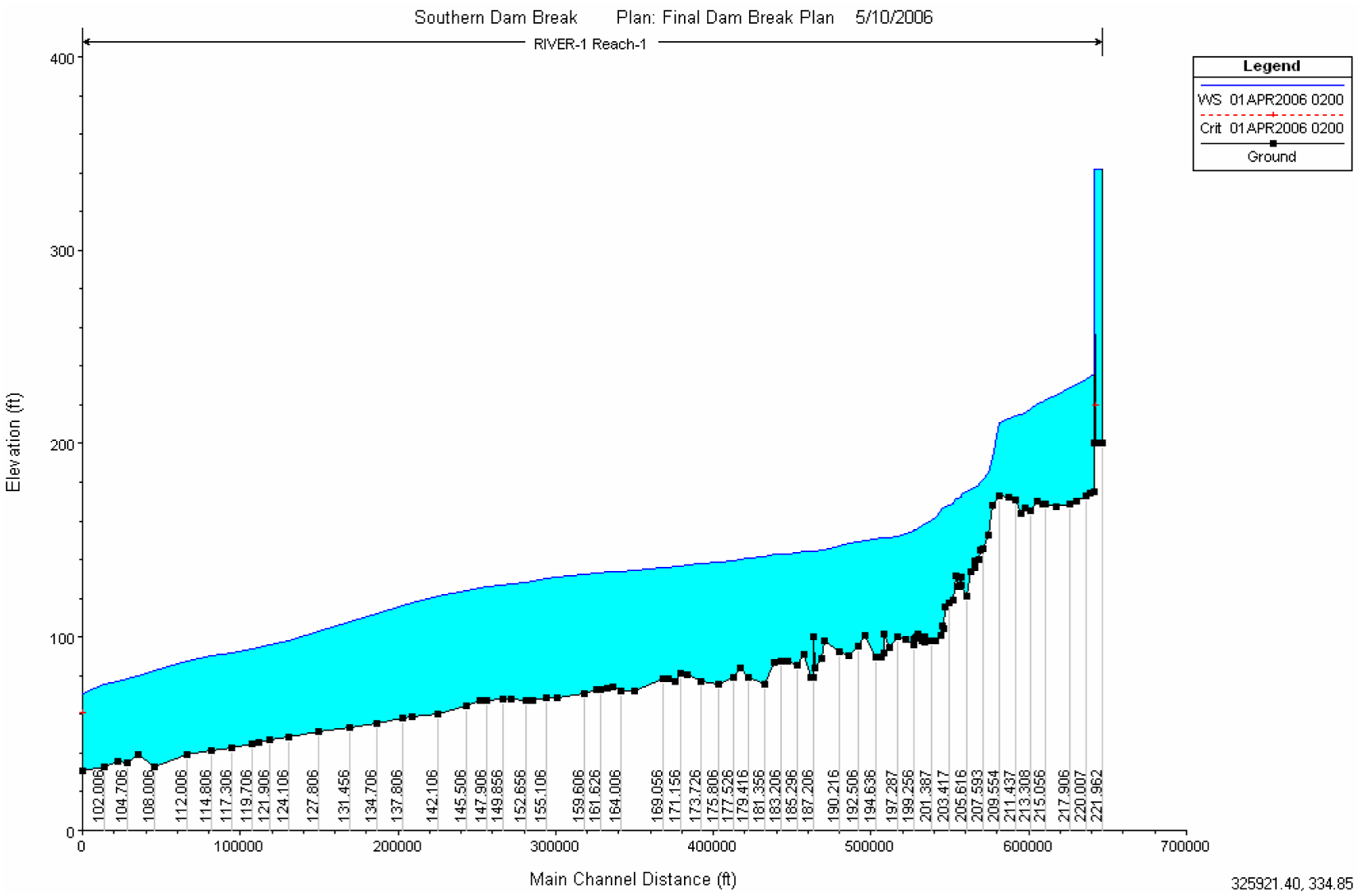


Figure 2.4-223
Savannah River SPF Water Surface Profile

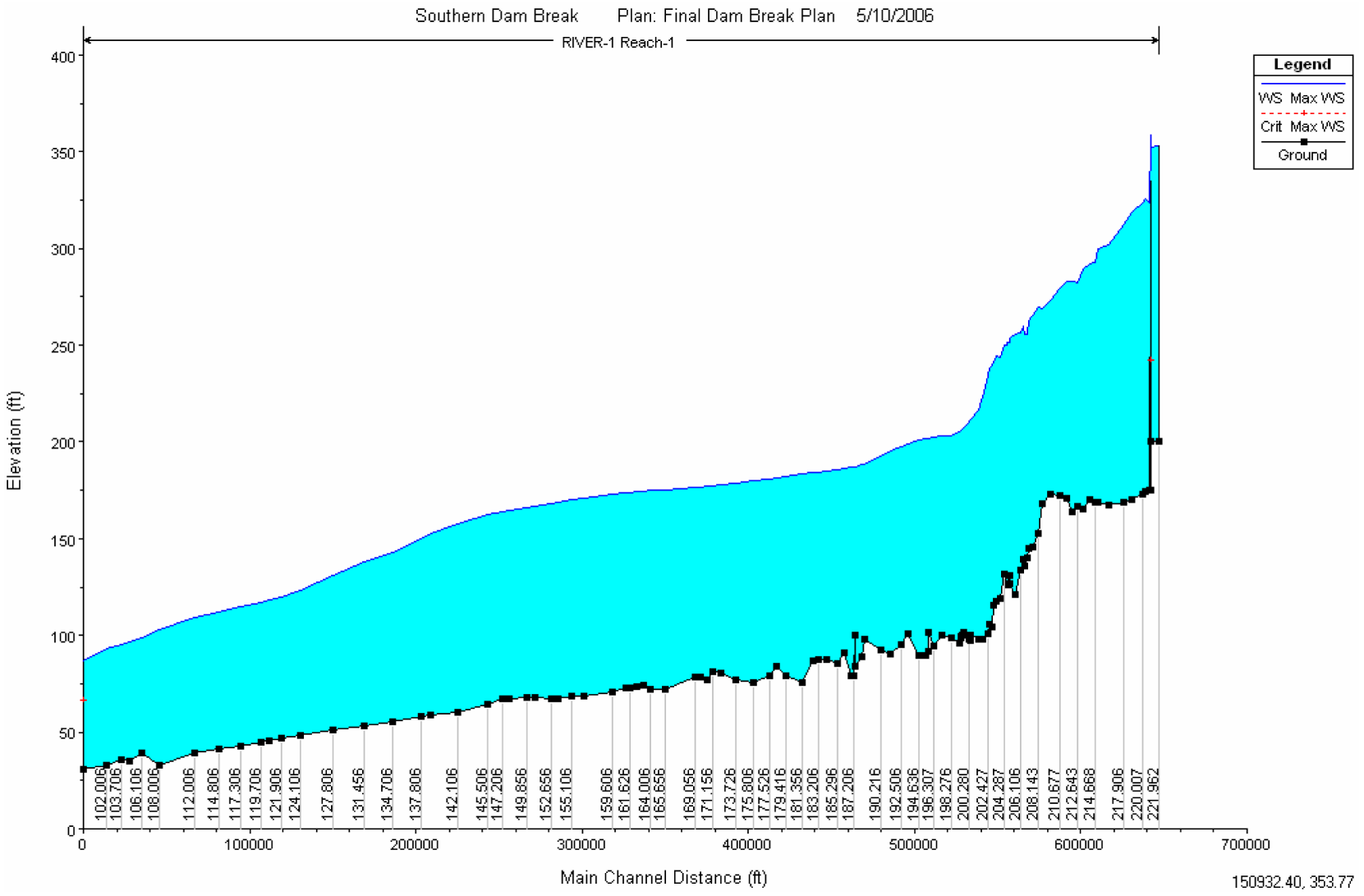


Figure 2.4-224
Savannah River Dam Breach Flood Maximum Water Surface Profile

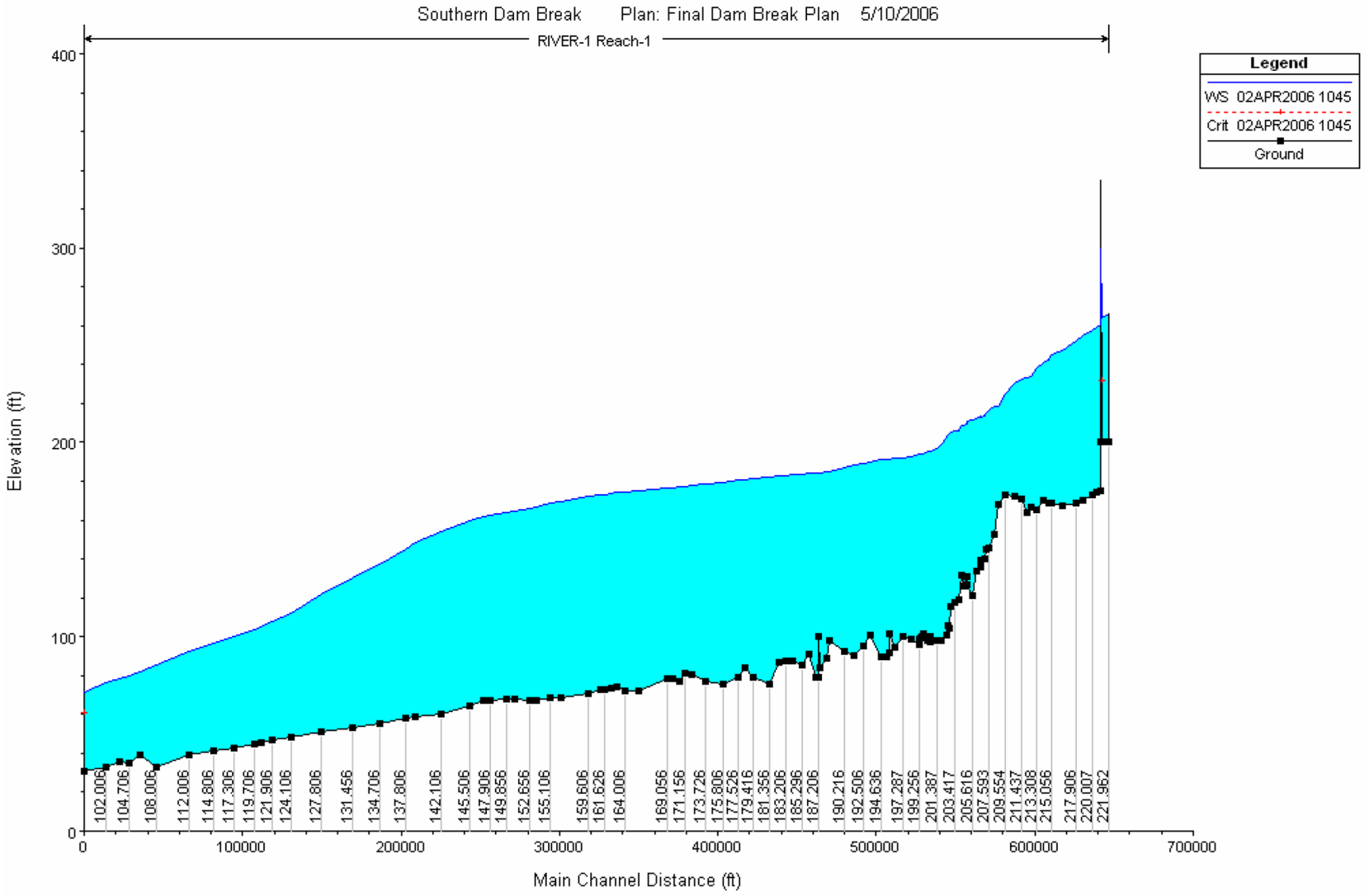


Figure 2.4-225
Savannah River Dam Breach Flood Water Surface Profile for Peak Discharge at VEGP Site

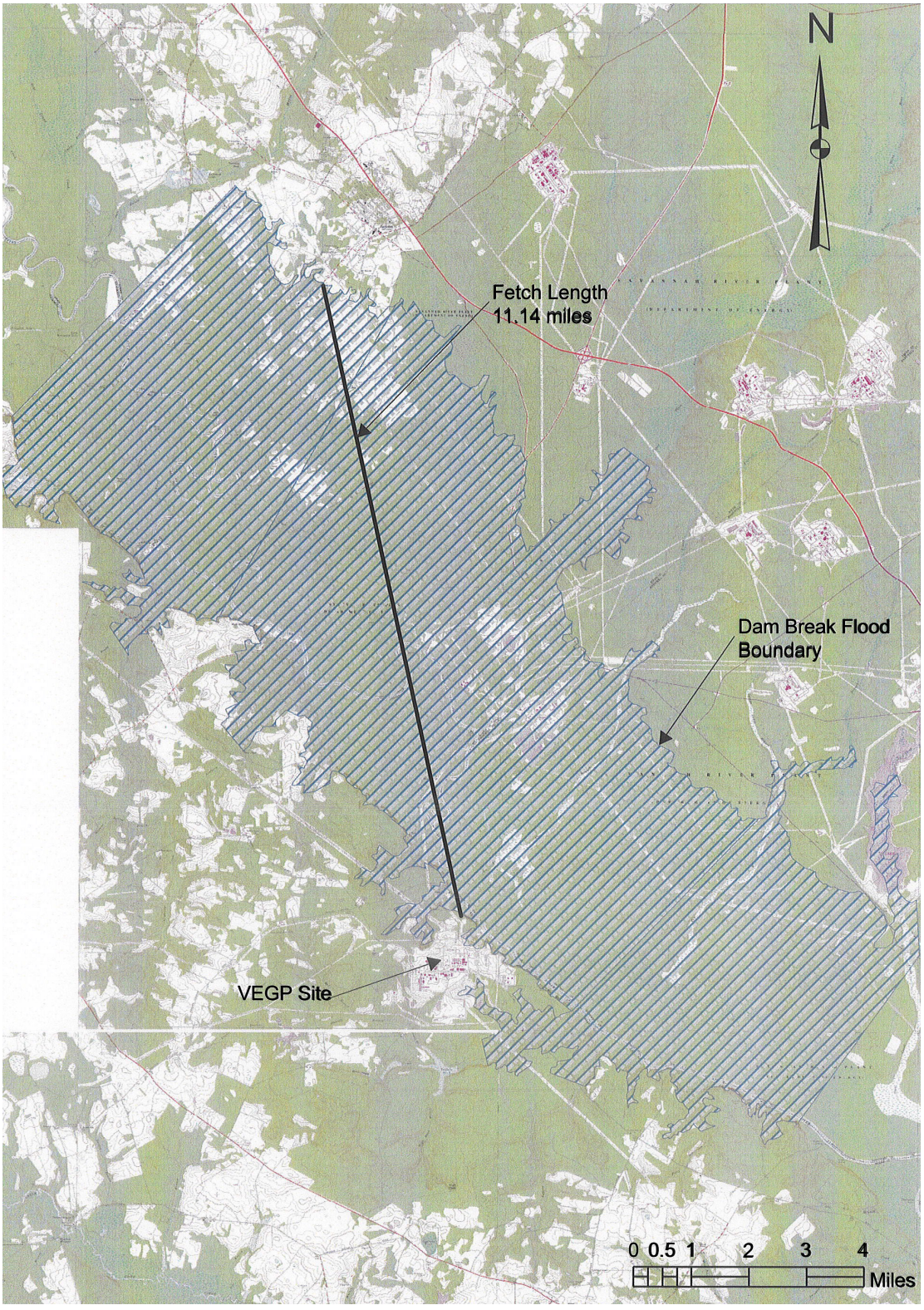
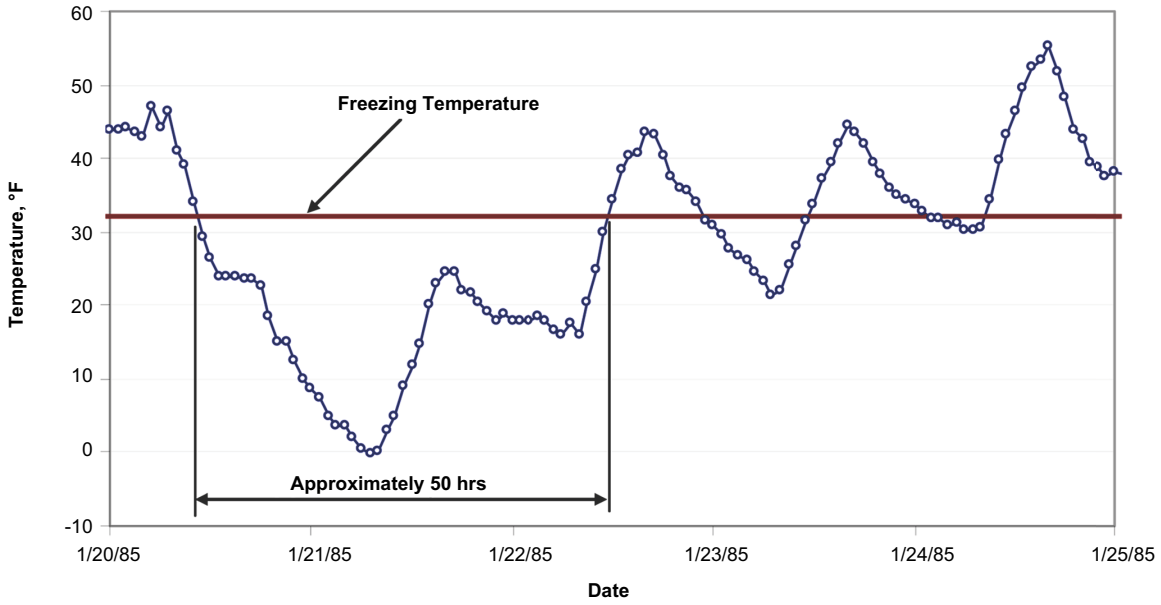
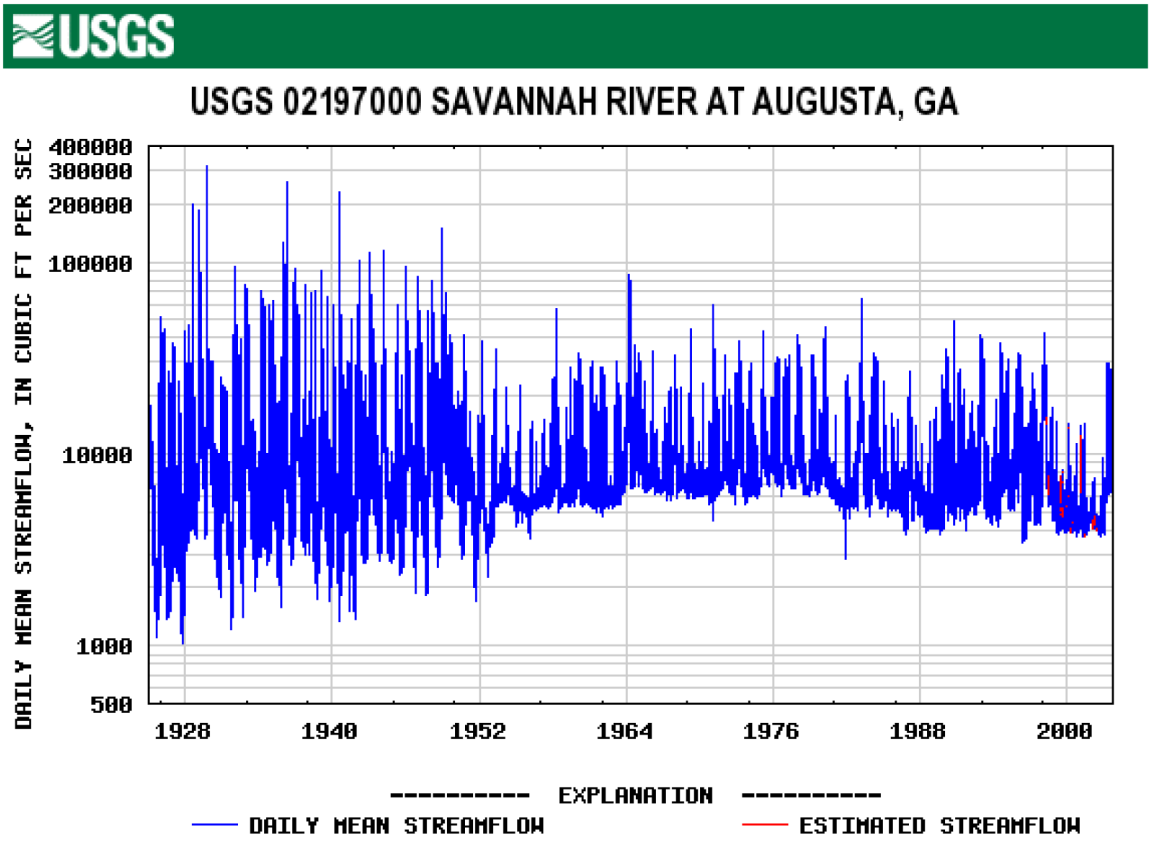


Figure 2.4-226
Maximum Fetch Length



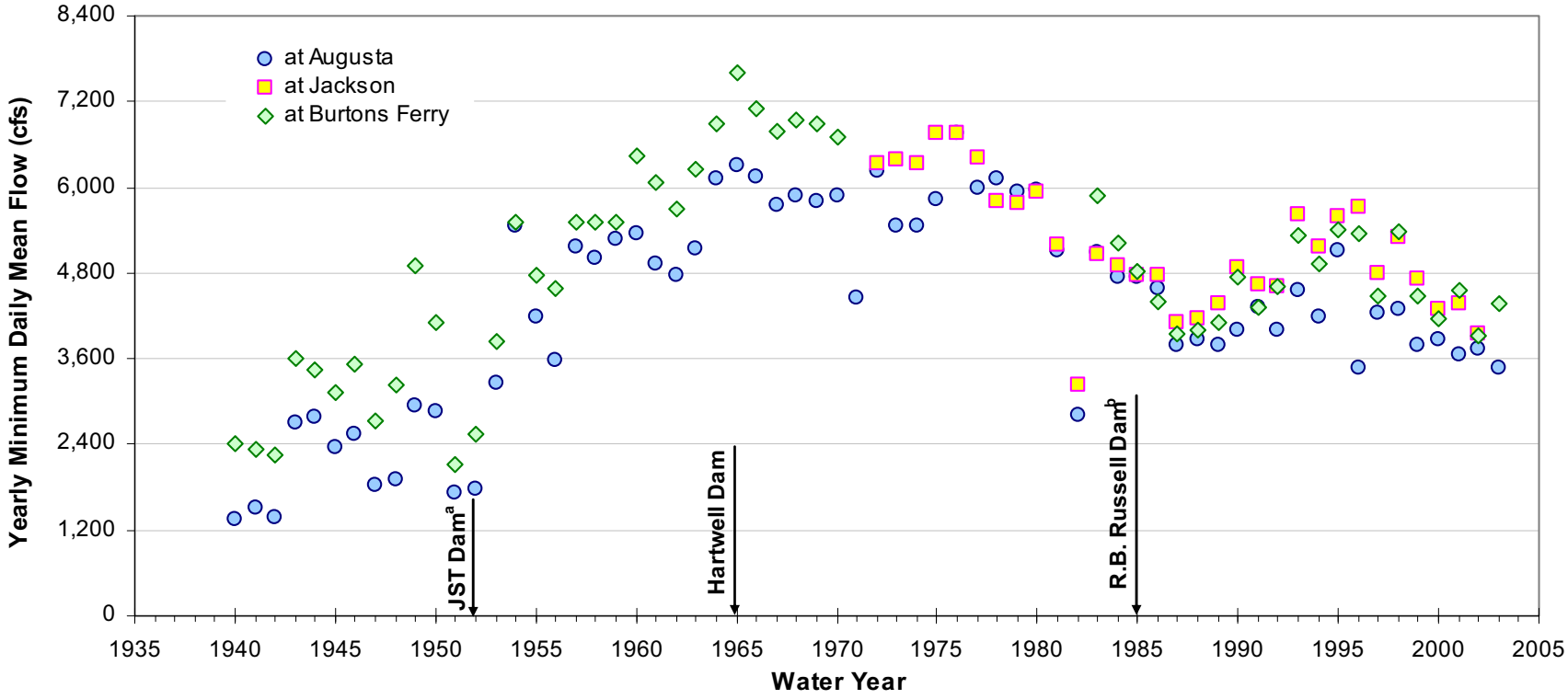
(The temperature remained below freezing for approximately 50 consecutive hours.)

Figure 2.4-227
Lowest Temperature Observed at the VEGP Site in 1985



Source: USGS 2006b

Figure 2.4-228
Variation in Daily Mean Streamflow Rates at Augusta, Georgia, on the Savannah River (USGS Stream Gauging Station 02197000, Savannah River at Augusta, Georgia), Showing Streamflow Modulation After the Construction of the Dams

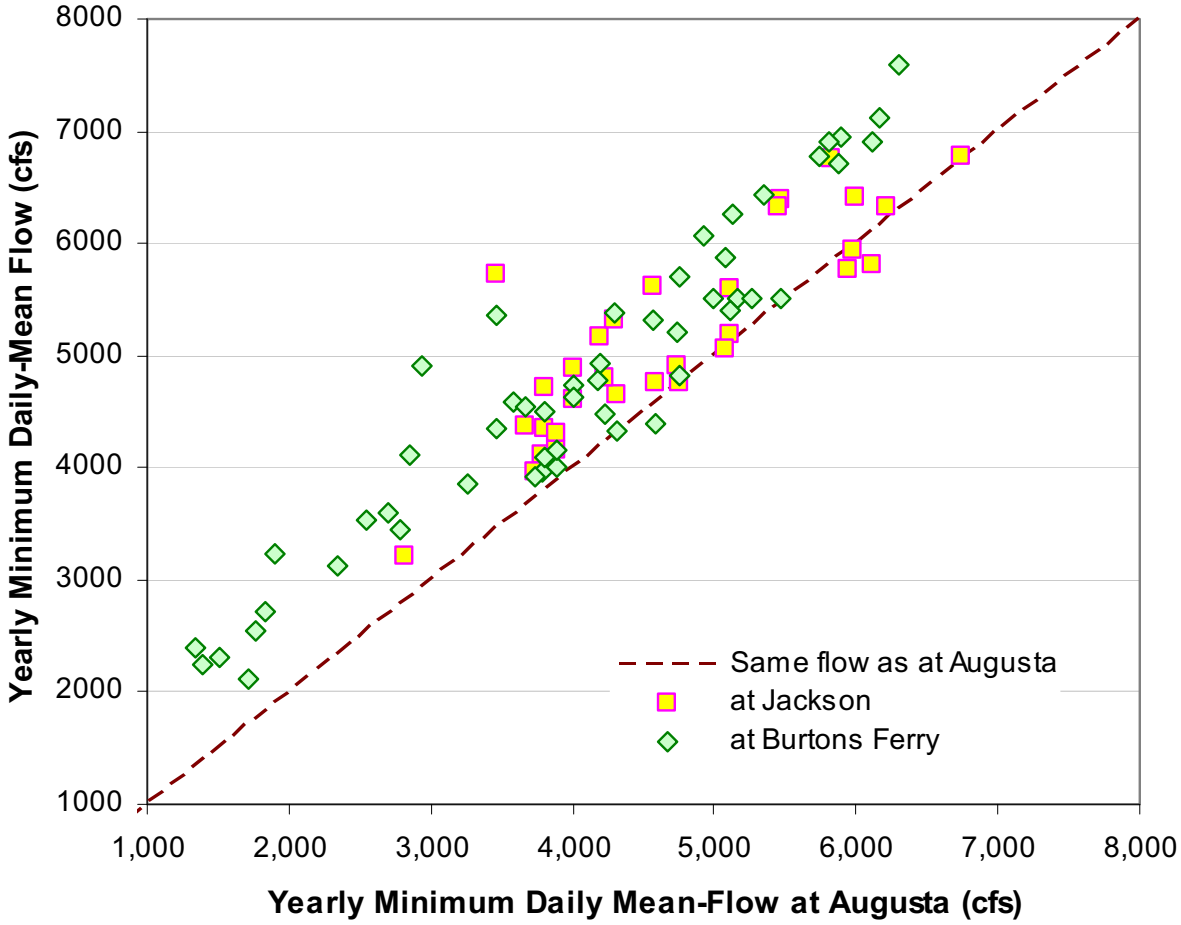


[a] J. Strom Thurmond Dam

[b] Richard B. Russell Dam

Source: USGS 2006g

Figure 2.4-229
Variation in Annual Minimum Daily-mean Stream Flow in the Savannah River at Augusta, Jackson, and Burtons Ferry Gages



Source: USGS 2006g

Figure 2.4-230
Change in Annual Minimum Daily-mean Flow at Jackson and Burtons Ferry Corresponding to that at Augusta for the Period of 1940-2003

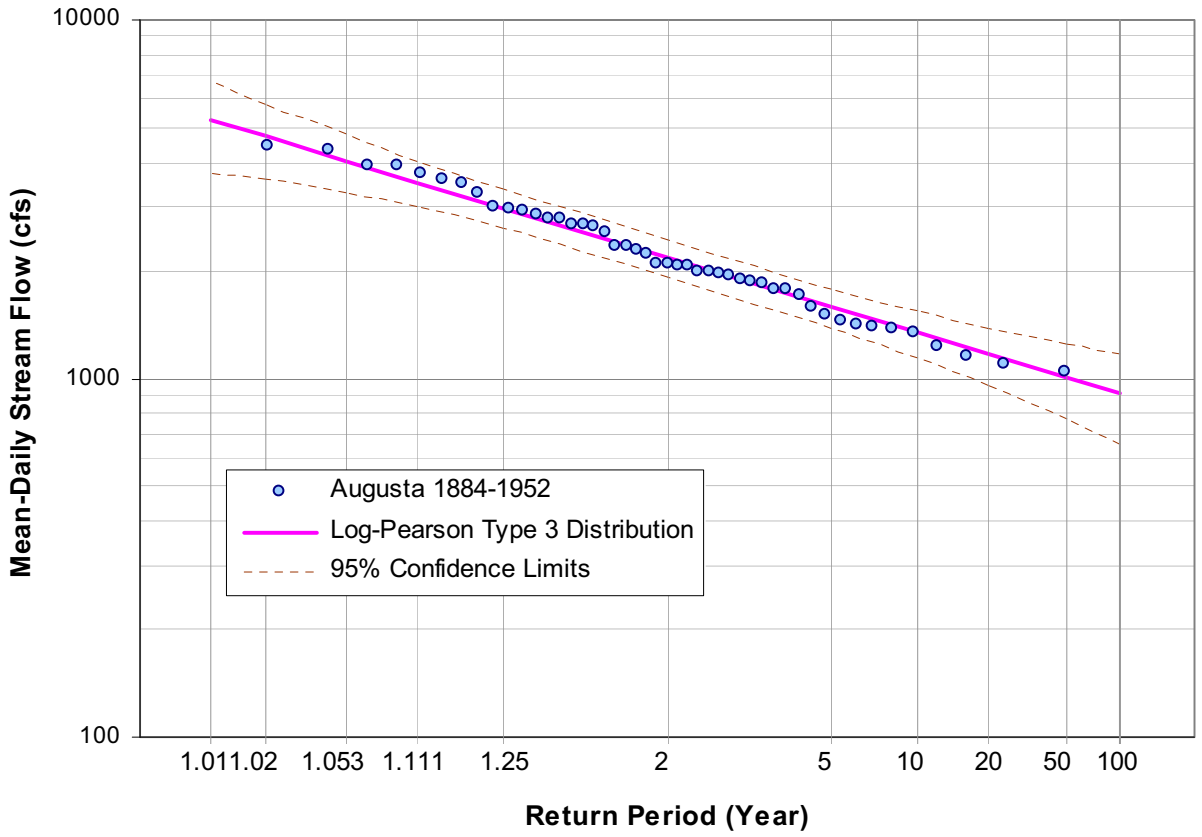


Figure 2.4-231
Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean Flow Data from Augusta for the Water Years 1884–1952

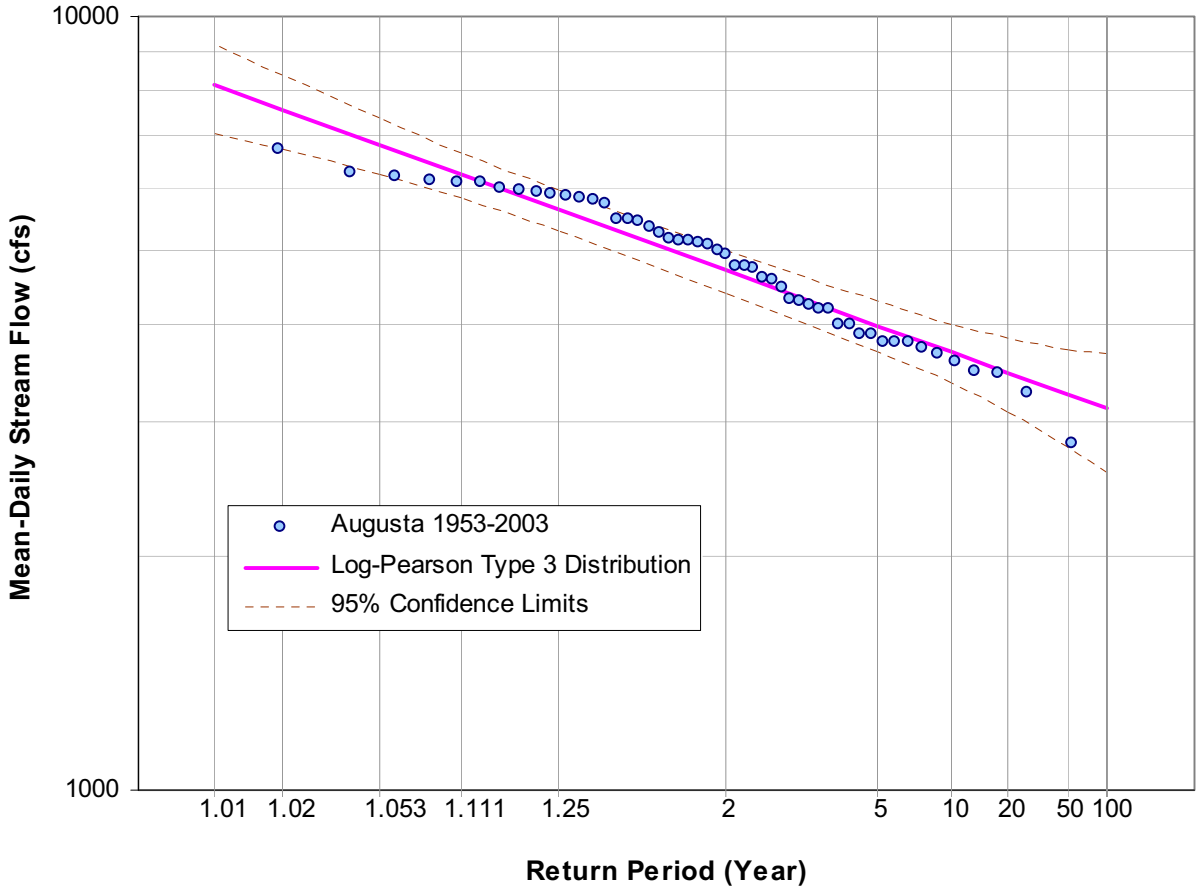


Figure 2.4-232
Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean Flow Data from Augusta for the Water Years 1953–2003

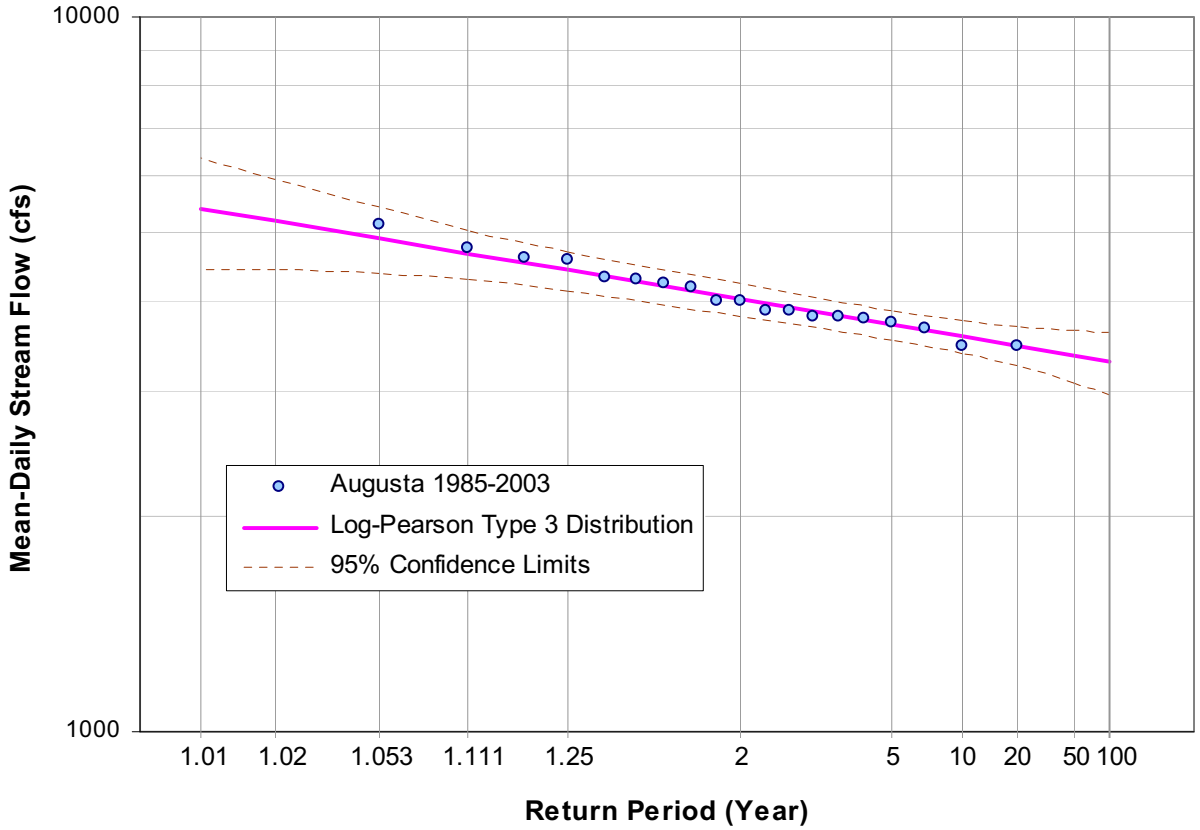


Figure 2.4-233
Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean Flow Data from Augusta for the Water Years 1985–2003

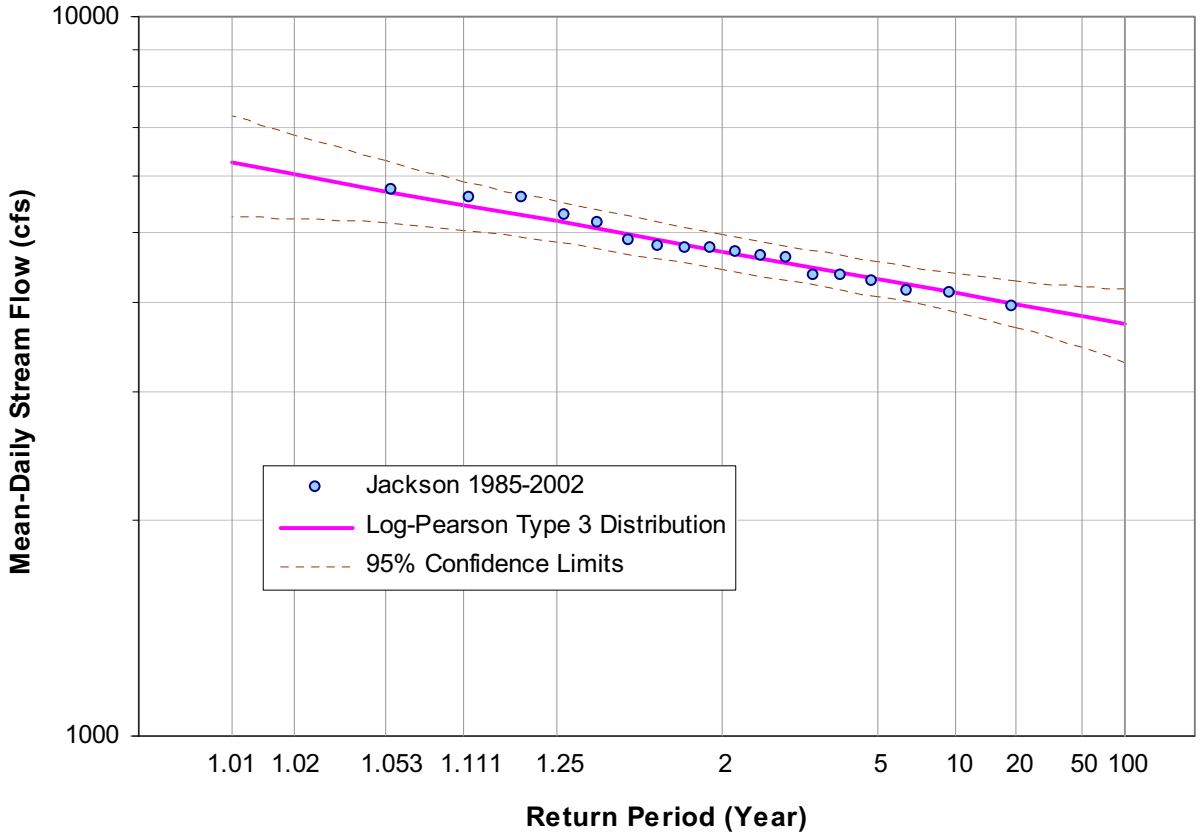
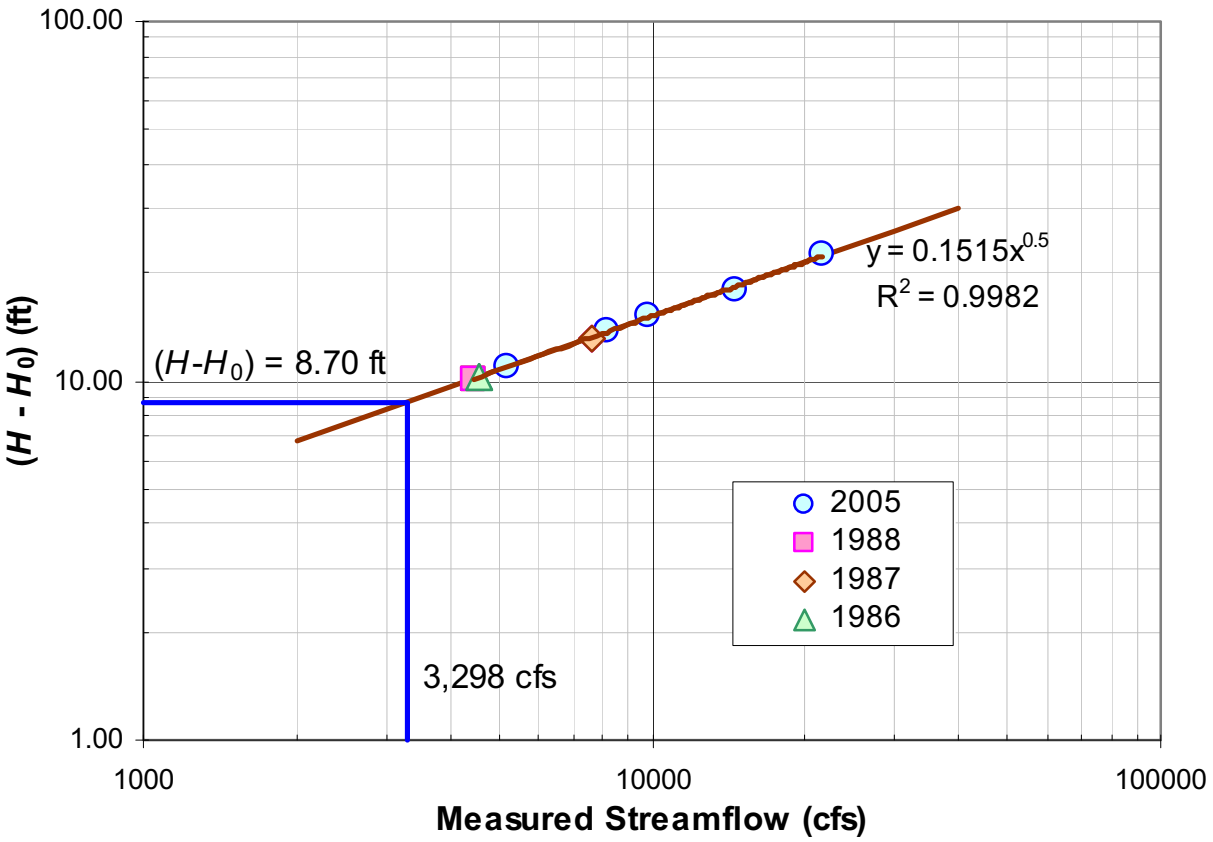


Figure 2.4-234
Log-Pearson Type 3 Distribution with Annual Minimum Daily-Mean Streamflow from Jackson for the Water Years 1985–2002



H = Water surface elevation in El. ft msl

H_0 = Elevation corresponding to zero flow = El. 67.56 ft msl

Figure 2.4-235
River Stage-Discharge Rating Relationship at USGS Waynesboro Gage Station Near the VEGP Site Using Data for the Years 2005, 1988, 1987 and 1986

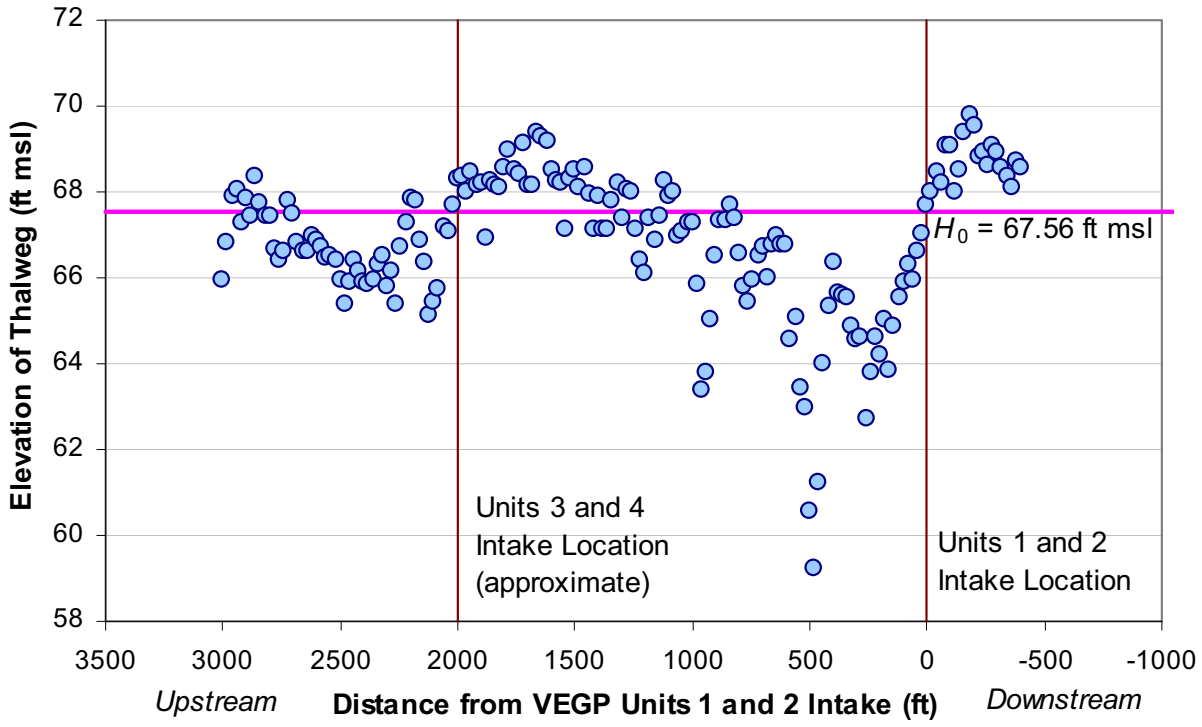


Figure 2.4-236
Comparison of Estimated River Stage Corresponding to Zero Discharge (H_0) with Measured River Thalweg Levels Near the Intake Location

GEOLOGIC TIME		SNC ESP NOMENCLATURE		
PERIOD	SERIES	GEOLOGIC UNIT	HYDROGEOLOGIC UNIT	REGIONAL HYDROGEOLOGIC UNIT
TERTIARY	Eocene	Barnwell Gr.	Water Table aquifer	Southeastern Coastal Plain Aquifer System
		Lisbon Fm. / Blue Bluff Mbr.	Confining unit	
		Still Branch Fm. Congaree Fm.	Tertiary sand aquifer	
	Paleocene	Snapp Fm. Black Mingo Fm.	Semi-confining unit	
Cretaceous		Steel Creek Fm.	Cretaceous aquifer	
		Gaillard Fm. / Black Creek Fm.		
		Pio-Nono Fm. / unnamed sands		
		Cape Fear Fm.		

Notes: Geologic unit naming convention **(Huddlestun and Summerour 1996; Falls and Prowell 2001)**
Regional hydrogeologic unit naming convention **(Miller 1990)**

Figure 2.4-237
Schematic Hydrostratigraphic Classification for VEGP Site

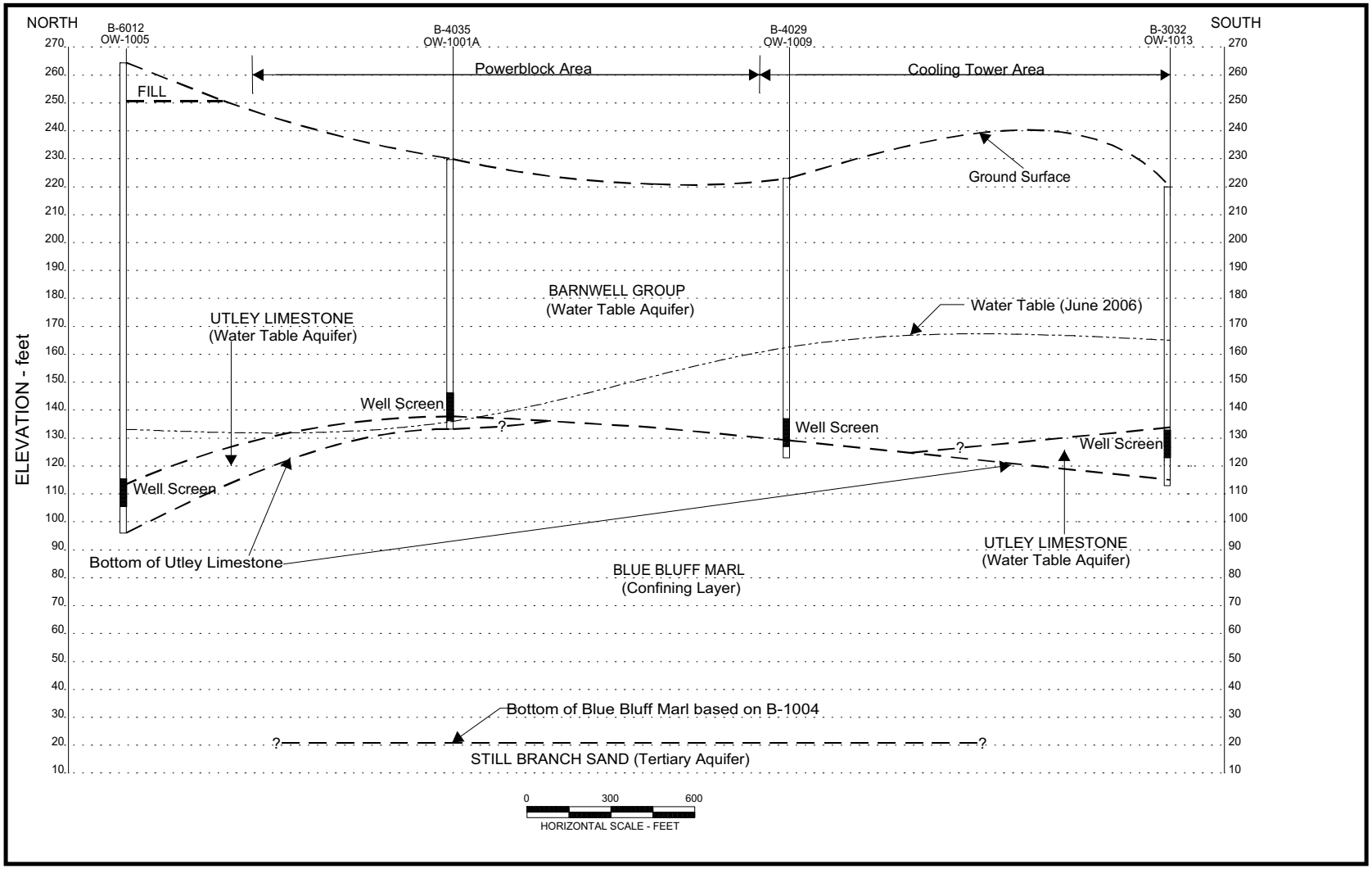


Figure 2.4-238
Hydrogeologic Cross-Section of the Water Table Aquifer at the VEGP Site

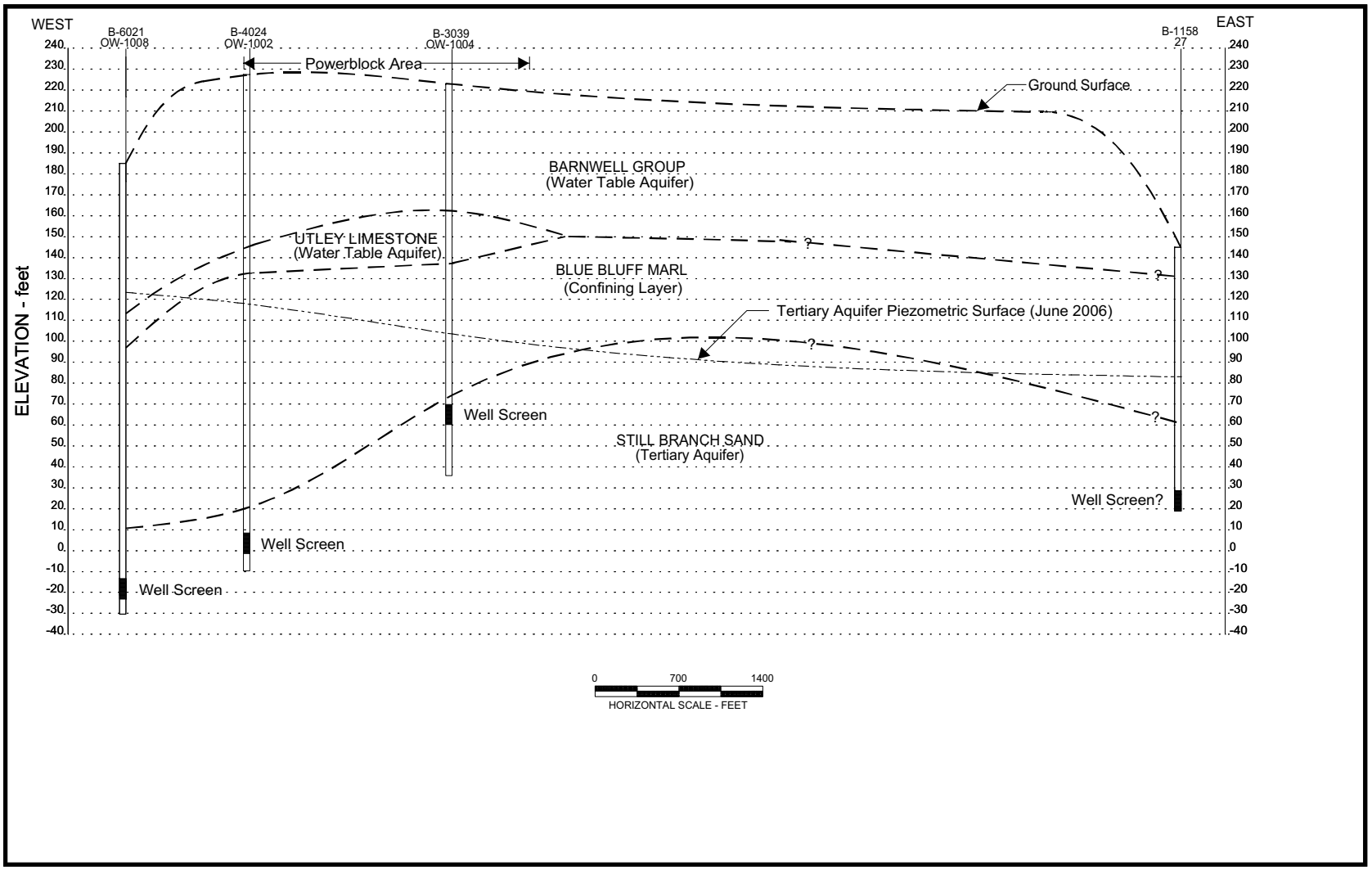


Figure 2.4-239
Hydrogeologic Cross-Section of the Tertiary Aquifer at the VEGP Site

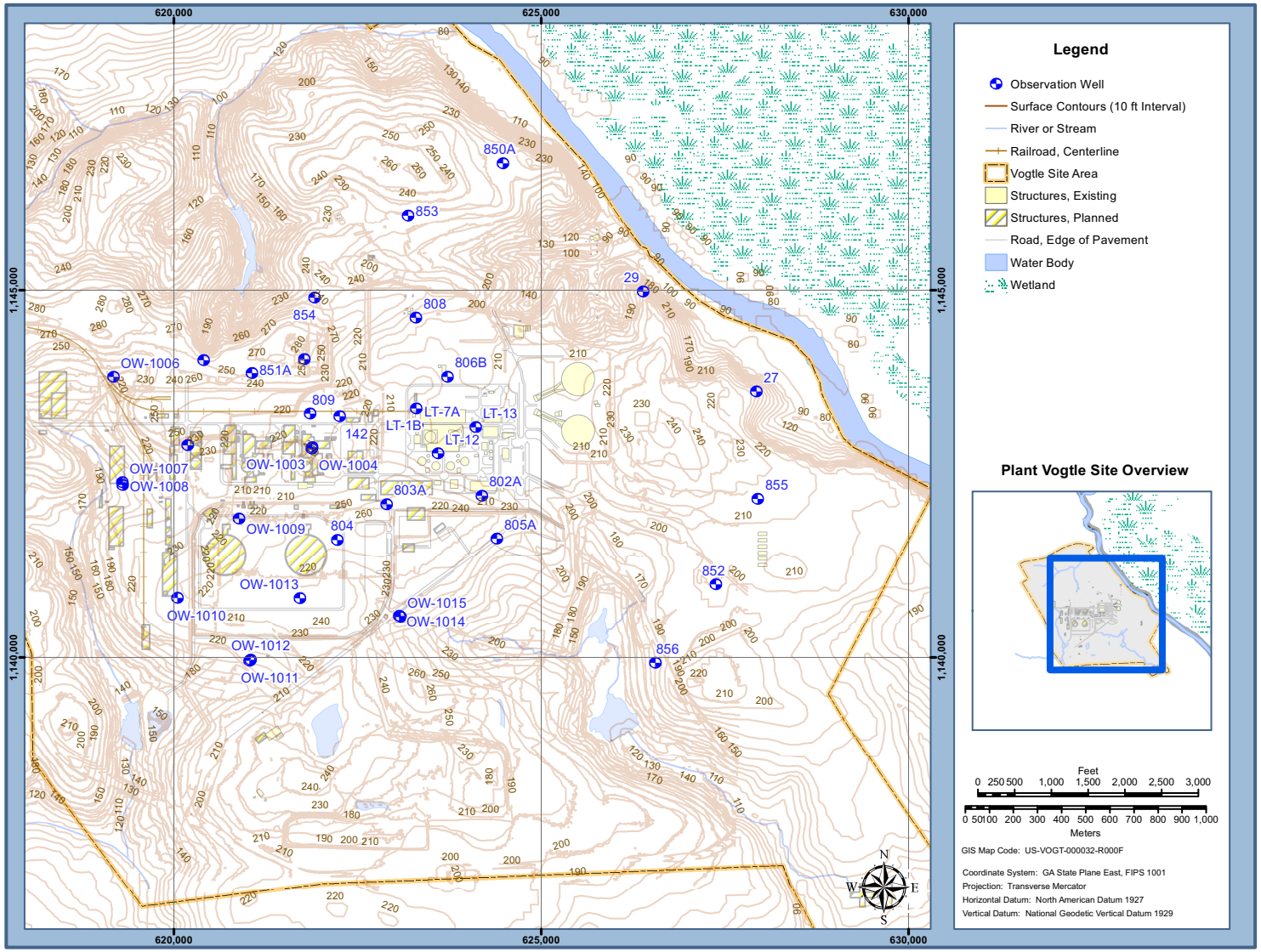


Figure 2.4-240
Observation Well Locations

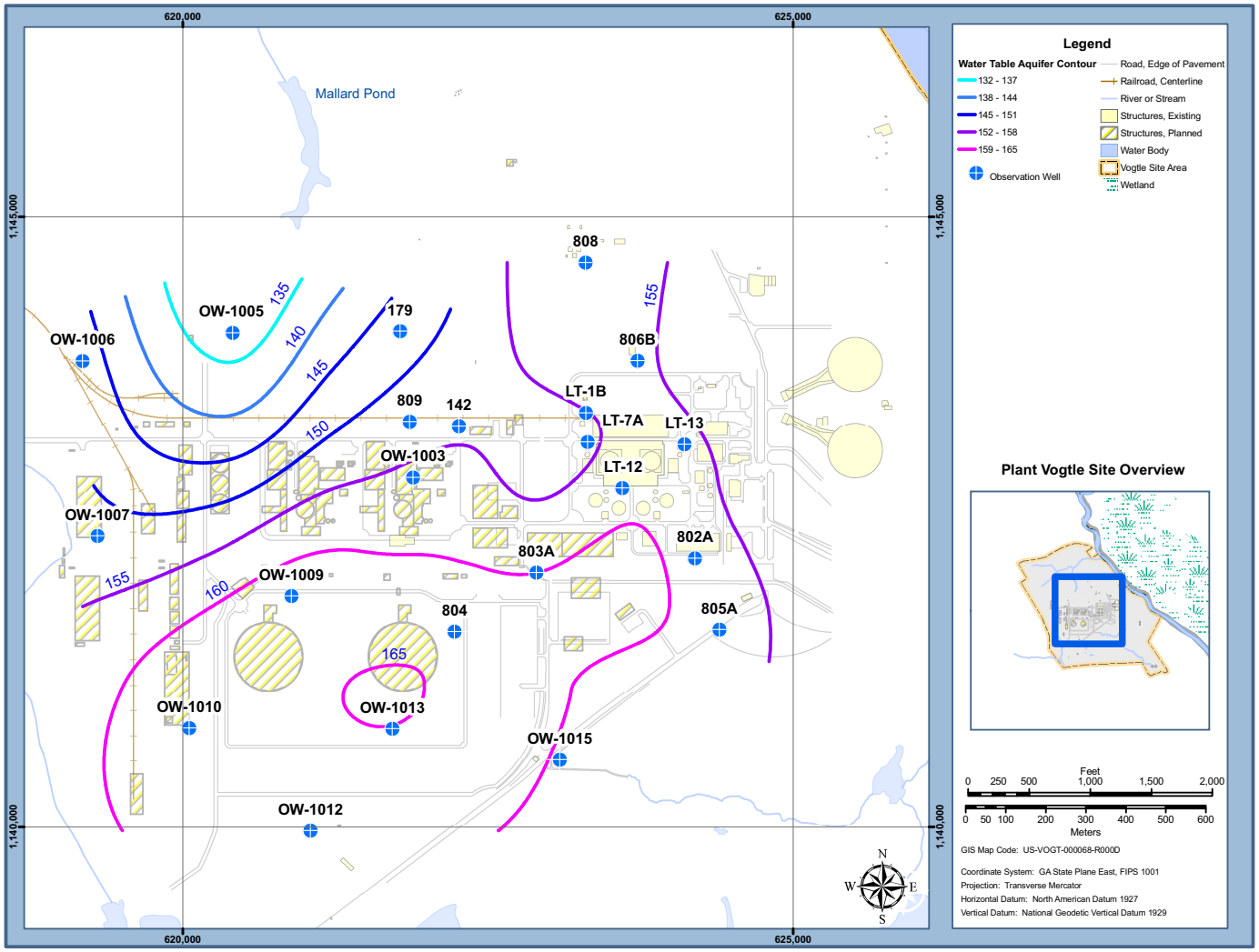


Figure 2.4-241
Water Table Aquifer: Piezometric Contour Map for June 2005

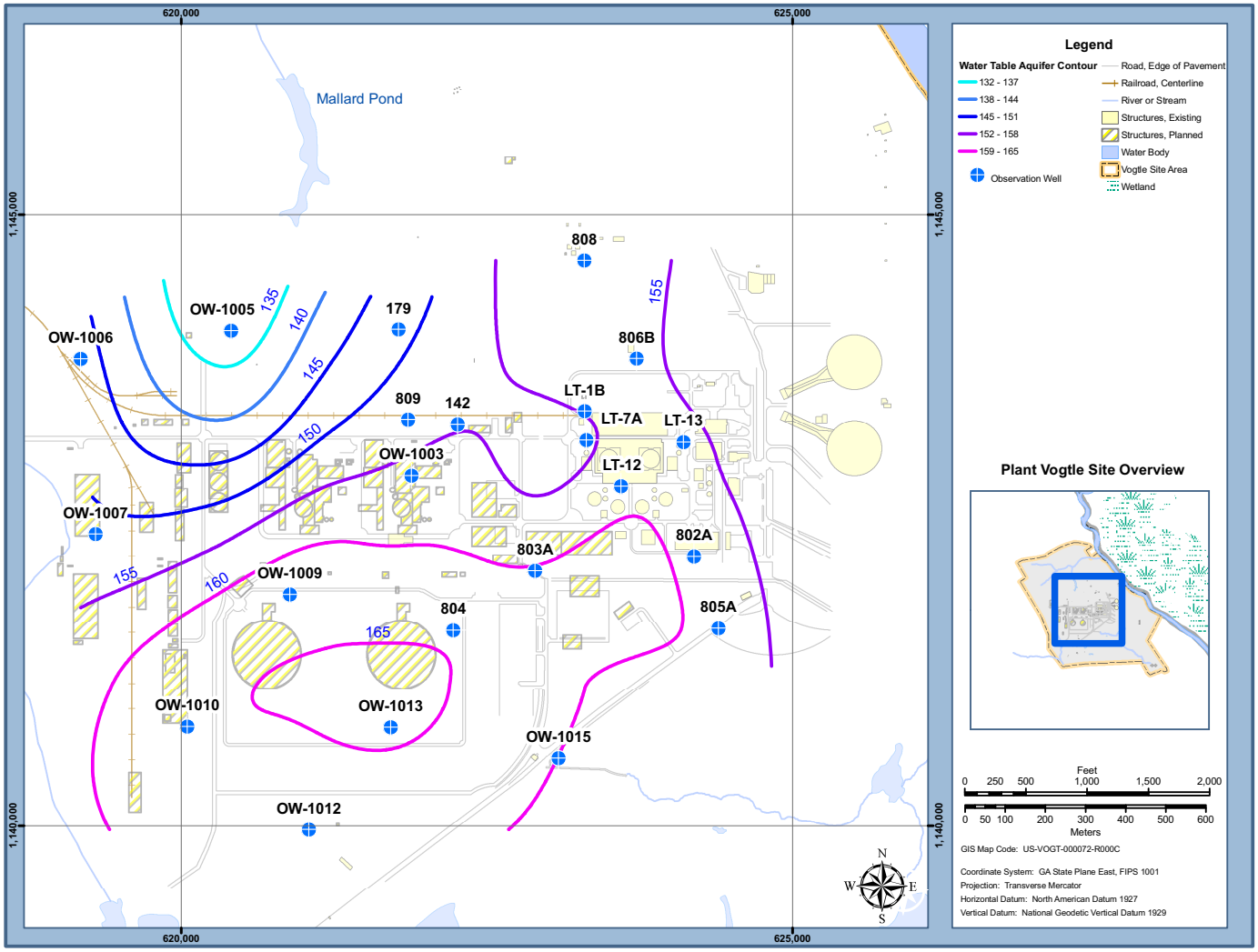


Figure 2.4-242
Water Table Aquifer: Piezometric Contour Map for October 2005

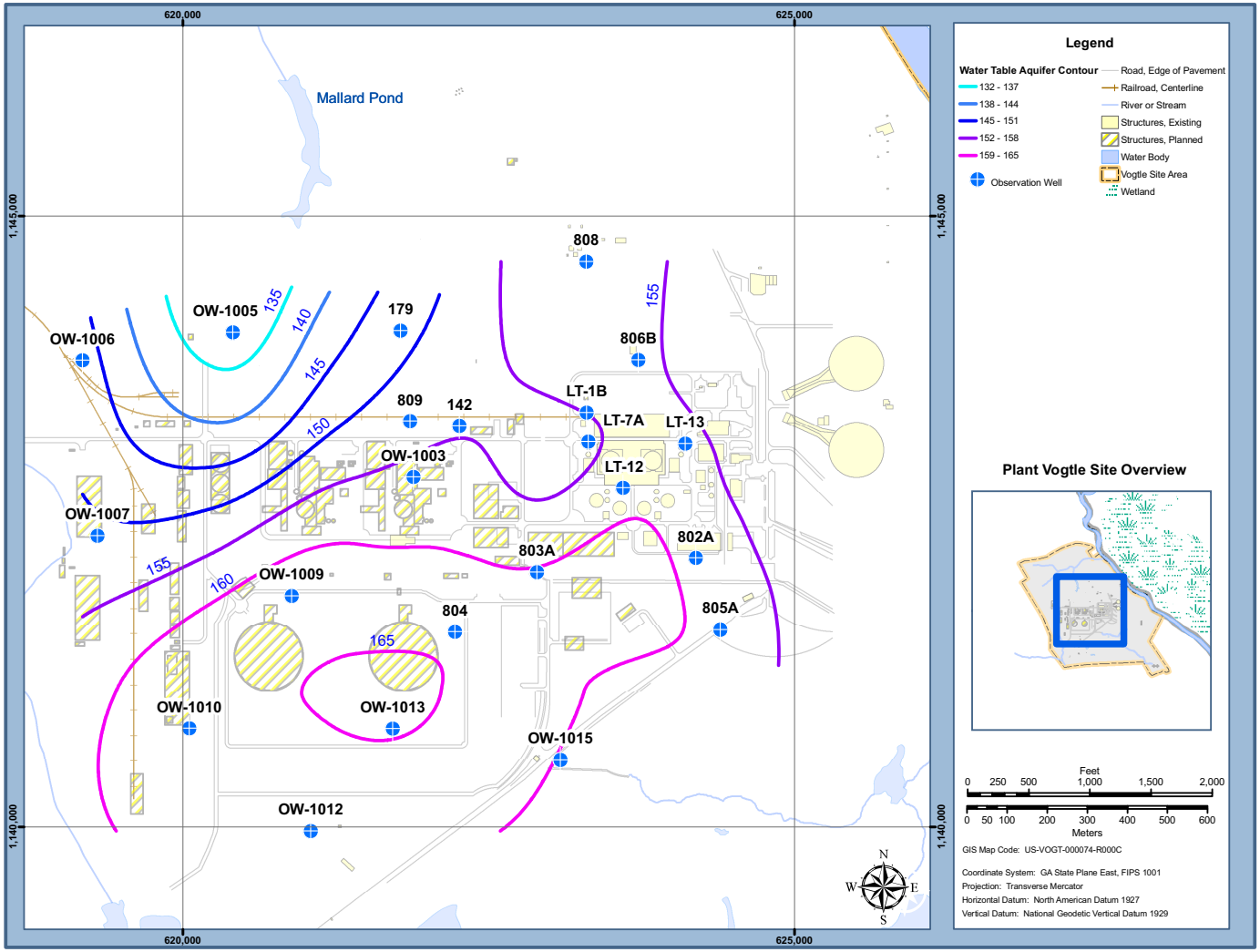


Figure 2.4-243
Water Table Aquifer: Piezometric Contour Map for December 2005

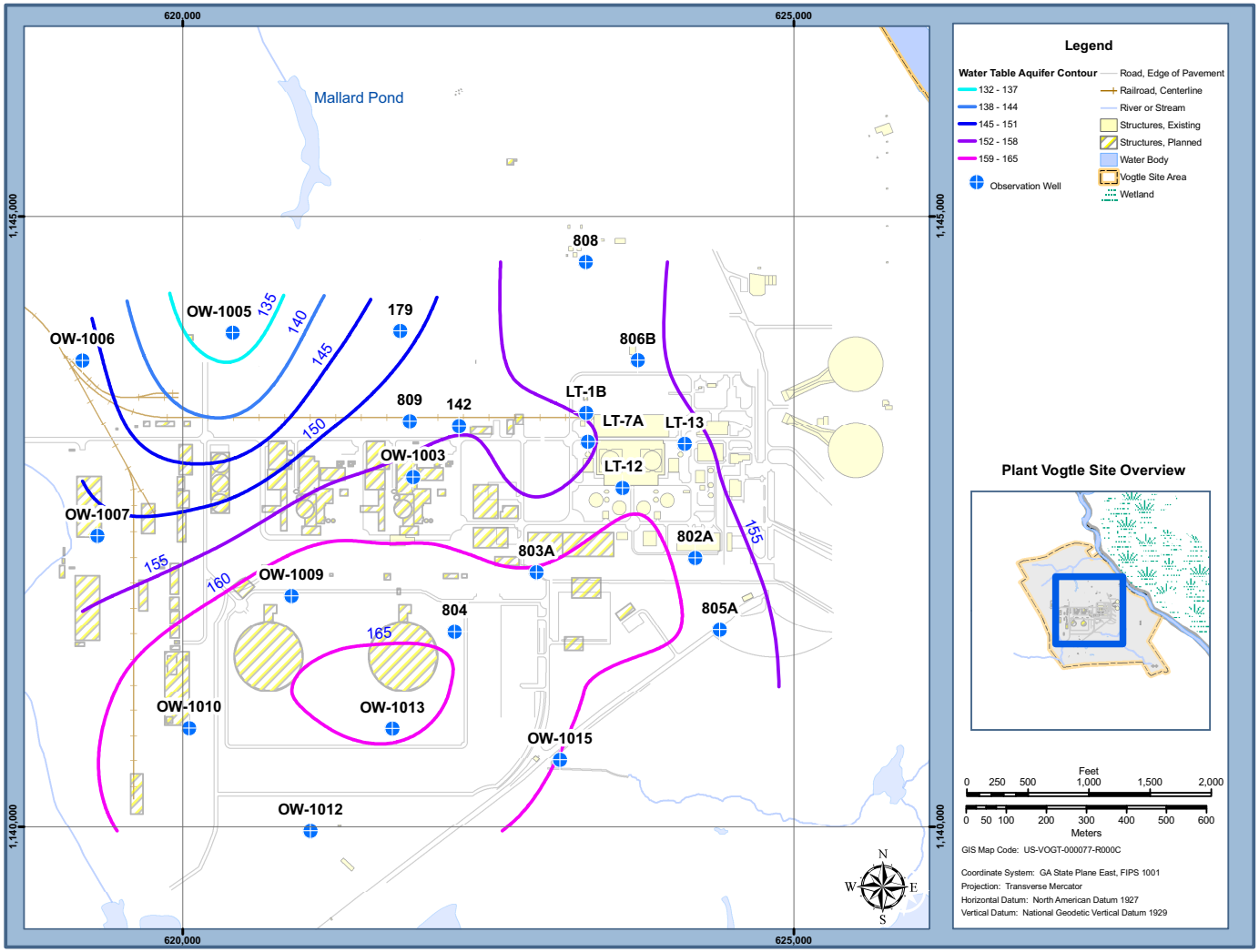


Figure 2.4-244
Water Table Aquifer: Piezometric Contour Map for March 2006

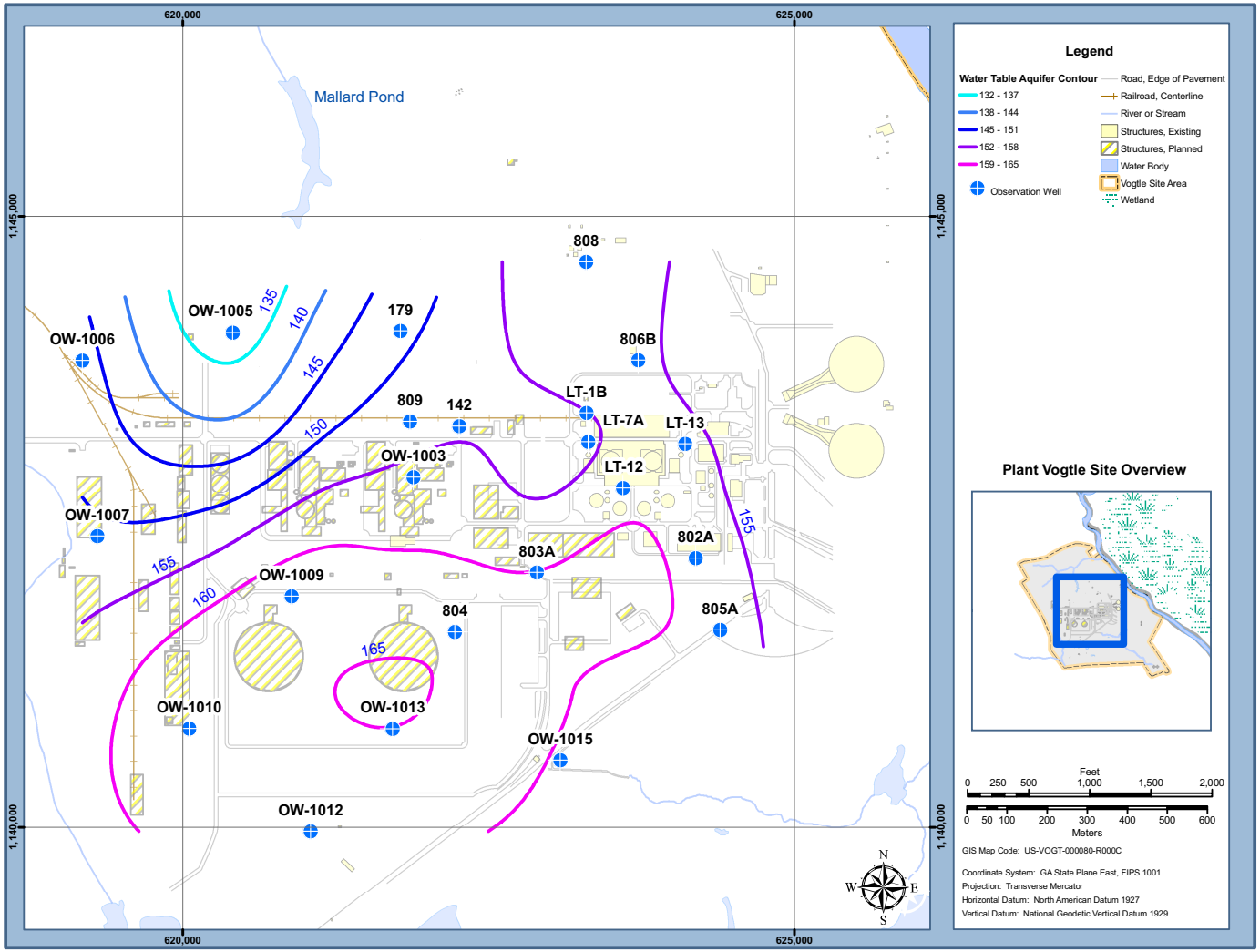


Figure 2.4-245
Water Table Aquifer: Piezometric Contour Map for June 2006

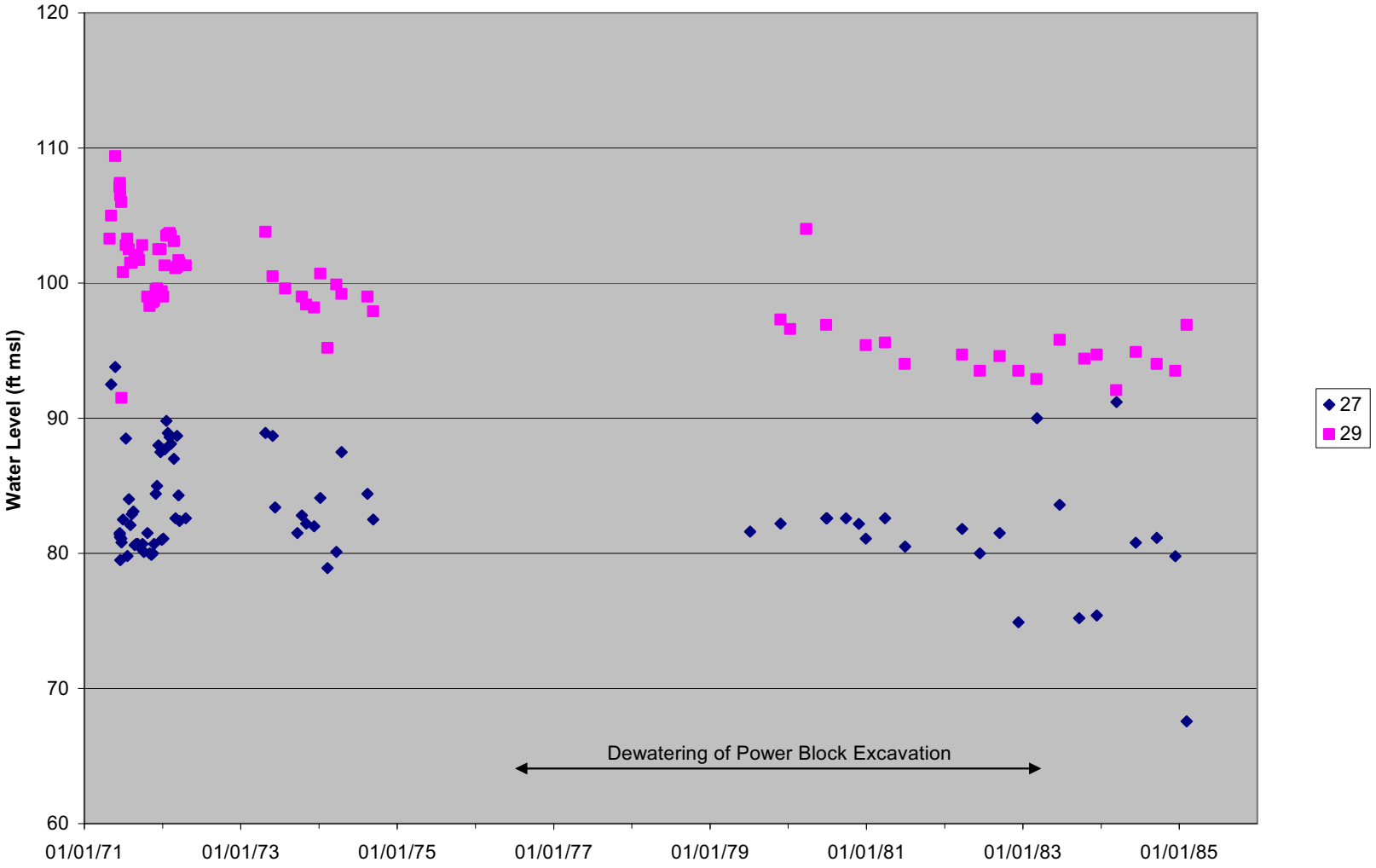


Figure 2.4-246
Tertiary Aquifer: 1971–1985 Hydrographs

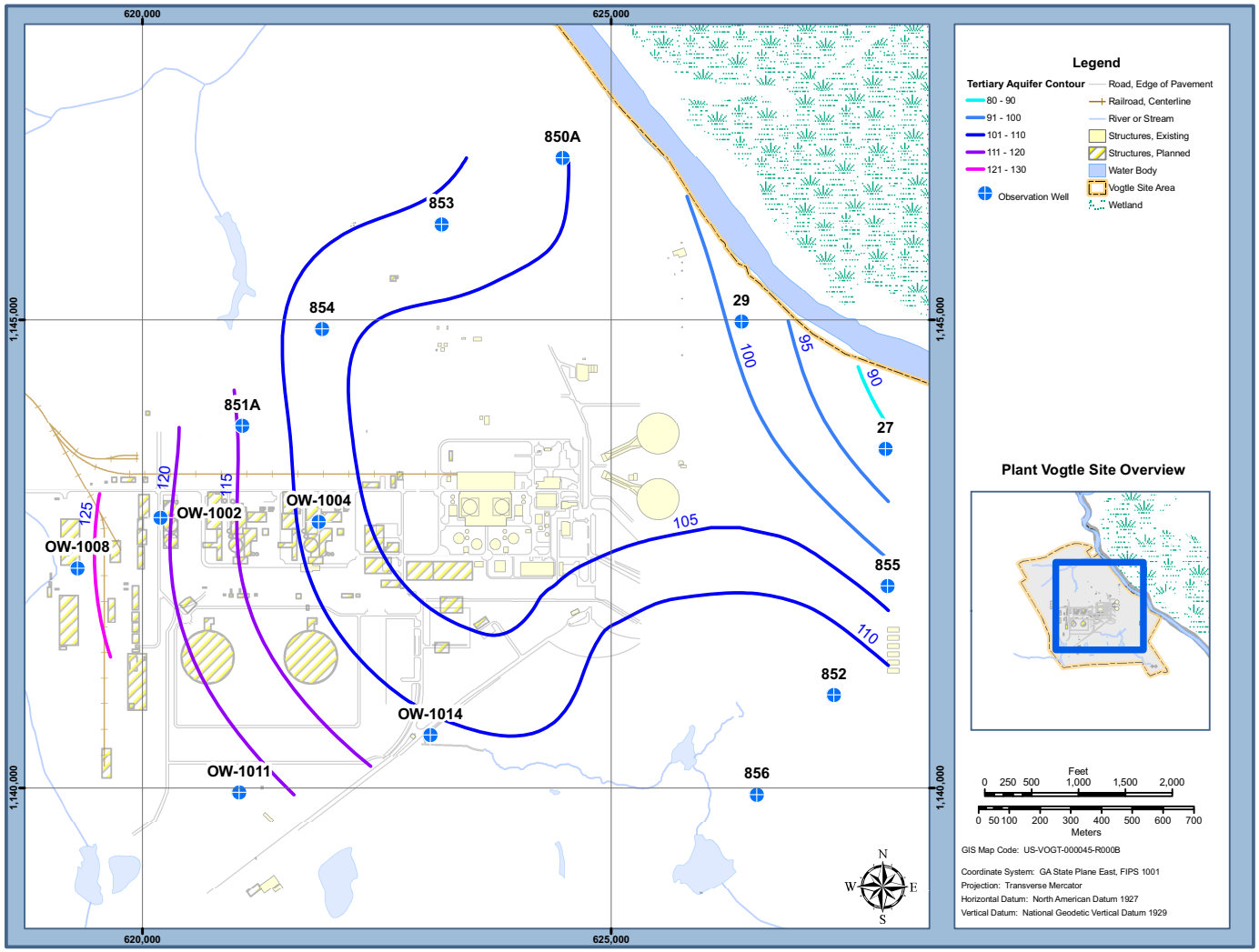


Figure 2.4-247
Tertiary Aquifer: Piezometric Contour Map for June 2005

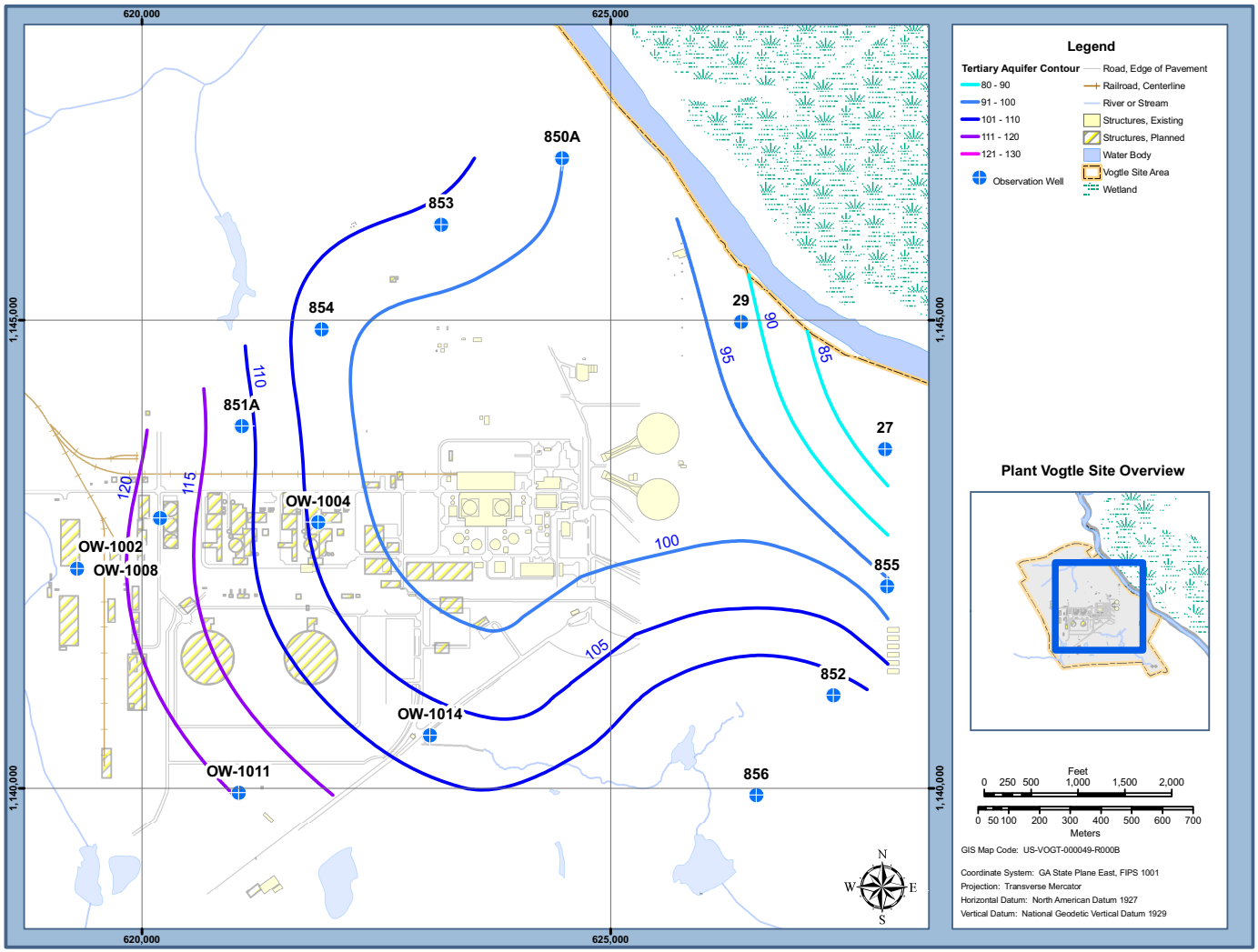


Figure 2.4-248
Tertiary Aquifer: Piezometric Contour Map for October 2005

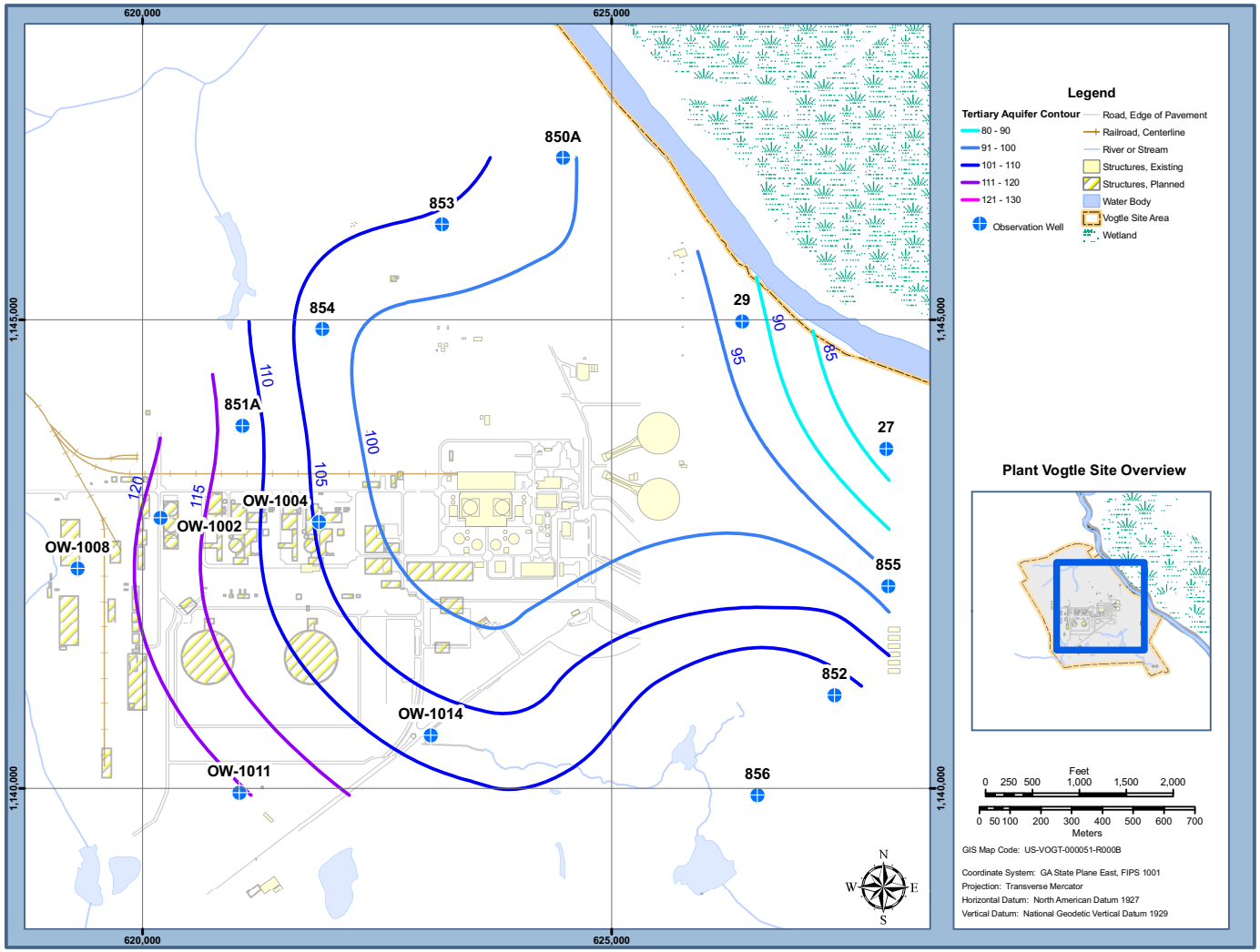


Figure 2.4-249
Tertiary Aquifer: Piezometric Contour Map for December 2005

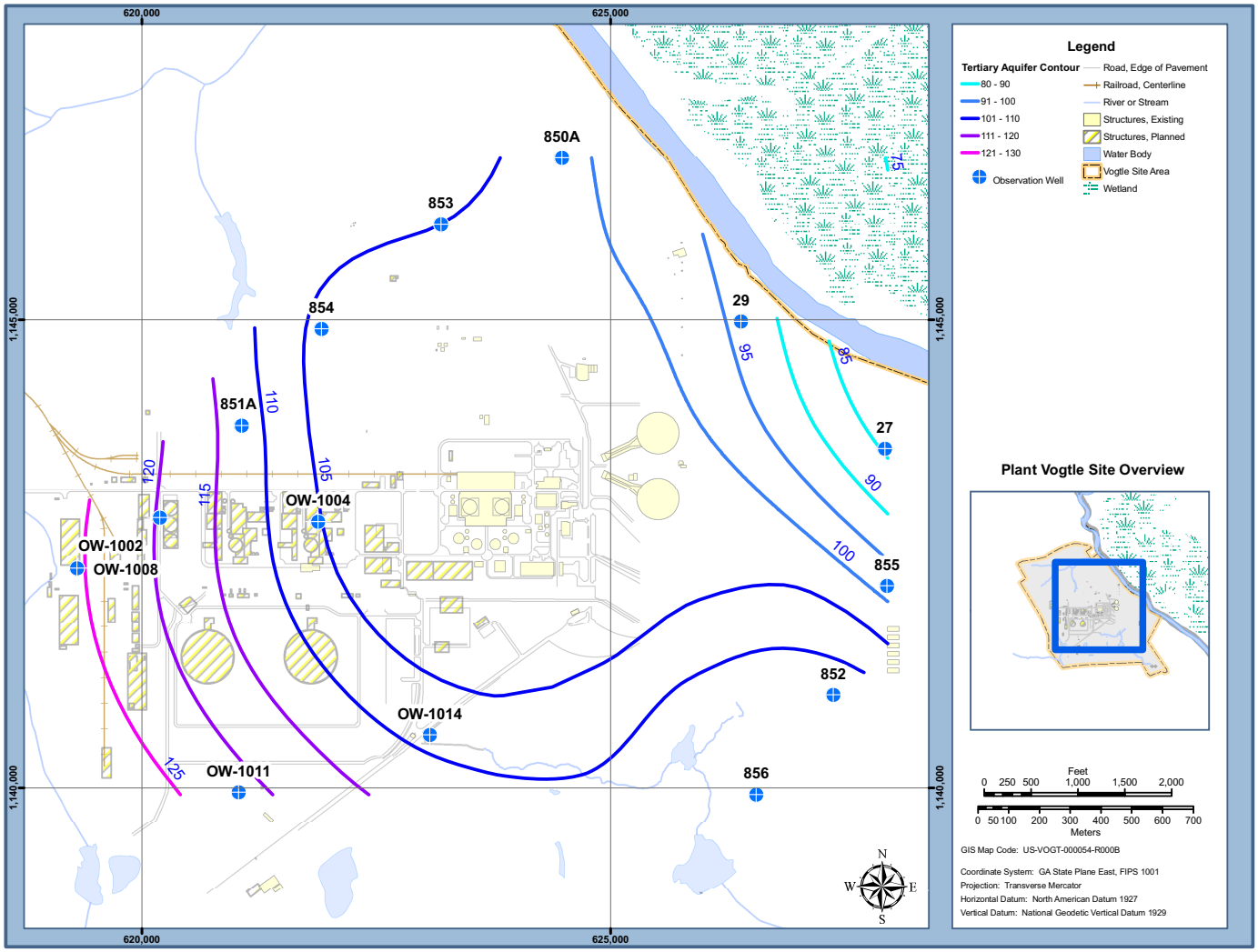


Figure 2.4-250
Tertiary Aquifer: Piezometric Contour Map for March 2006

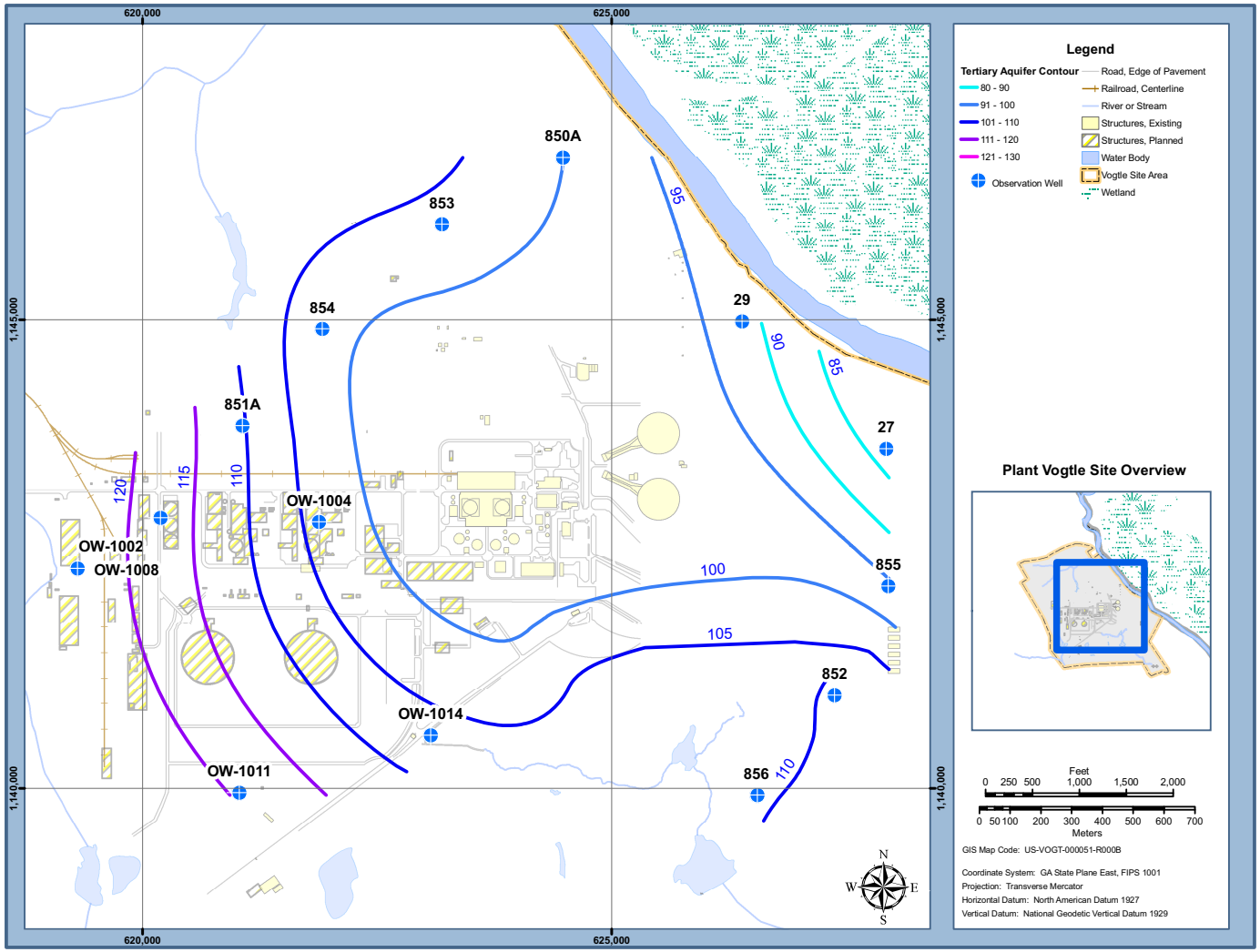


Figure 2.4-251
Tertiary Aquifer: Piezometric Contour Map for June 2006

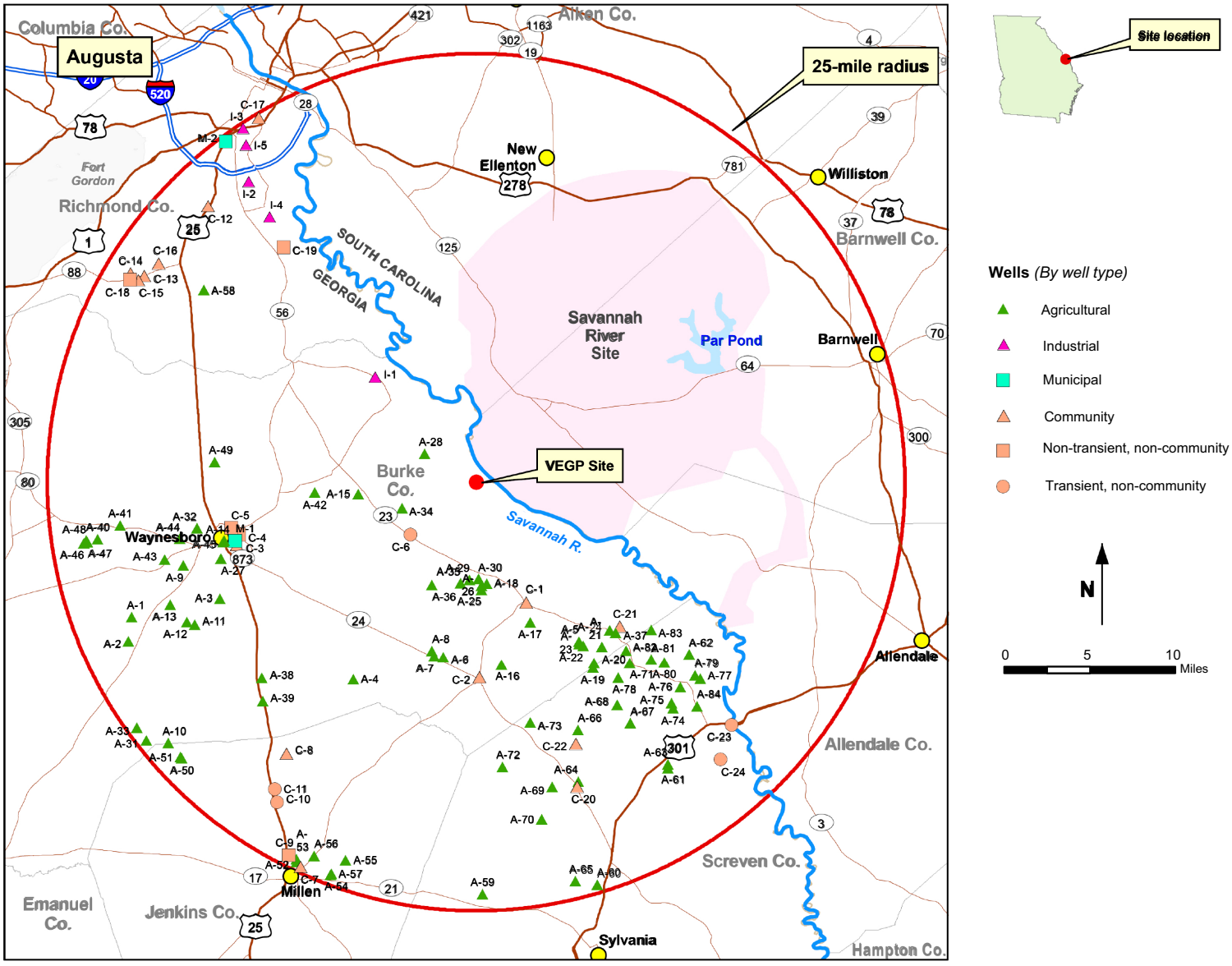


Figure 2.4-252
Locations of Agricultural, Industrial, Municipal, and Public Water Supply Wells Within 25 Miles of the VEGP Site

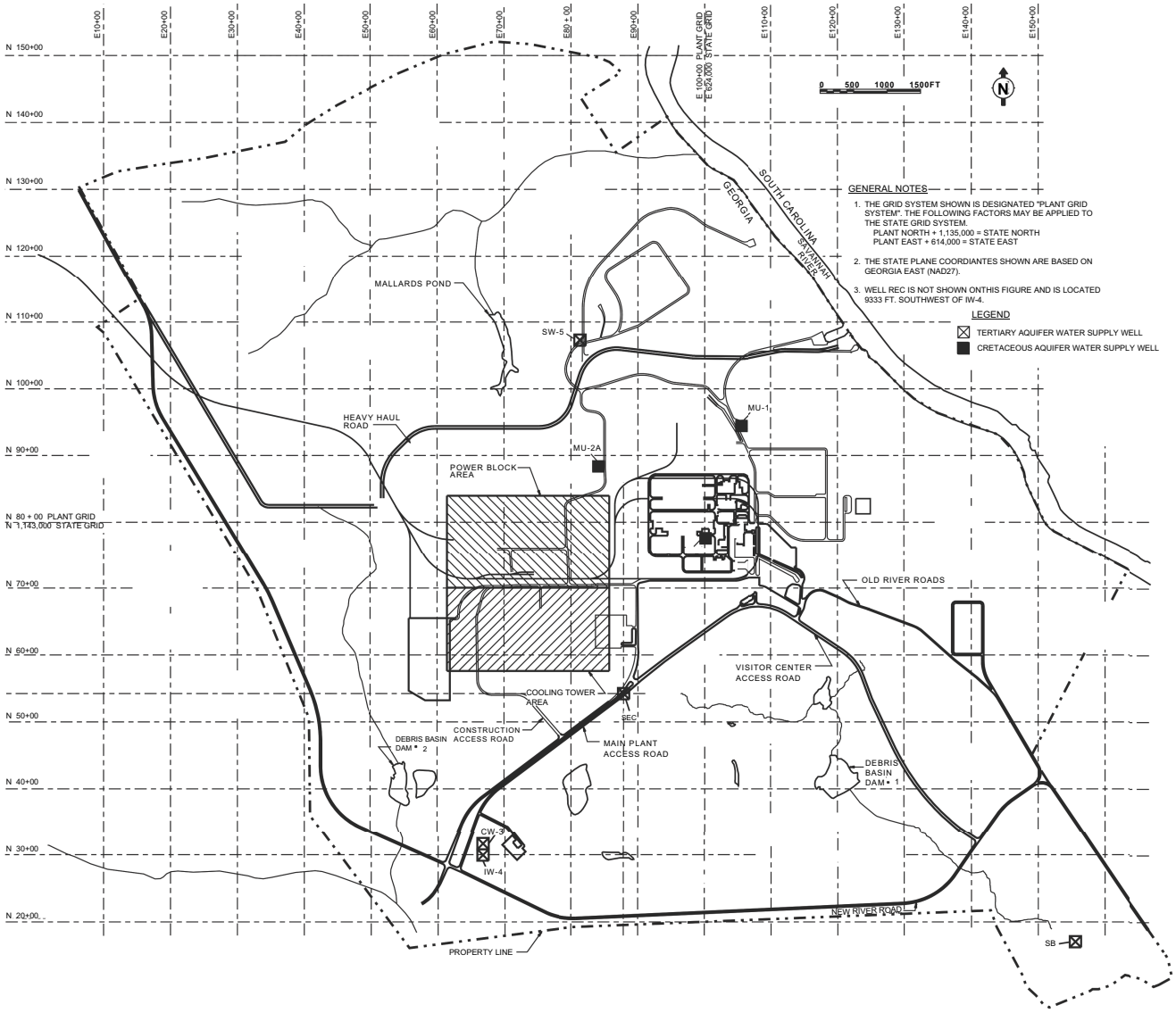


Figure 2.4-253
Locations of Existing Supply Wells at the VEGP Site

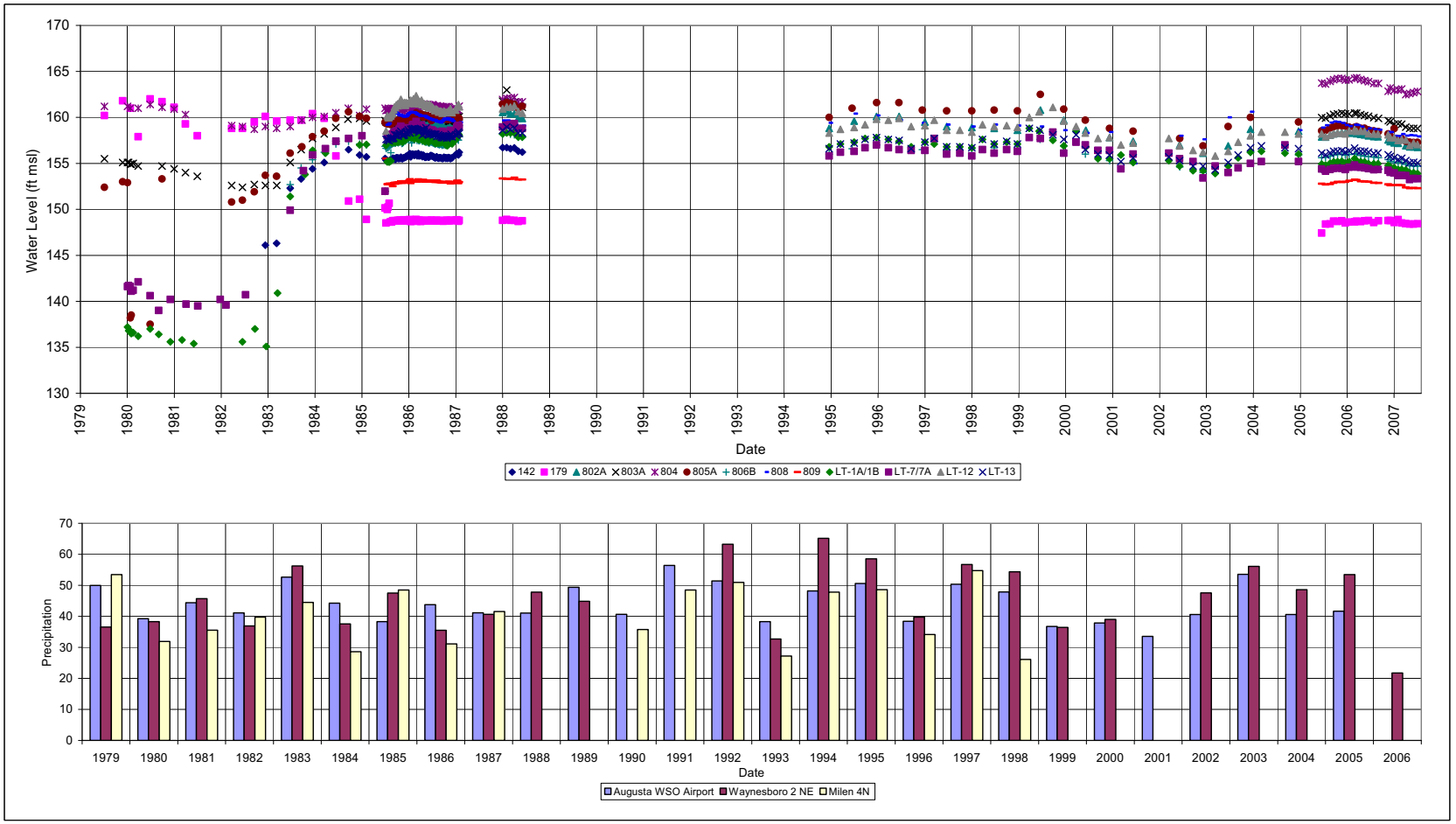


Figure 2.4-254
Water Table Aquifer: 1979–2007 Hydrographs

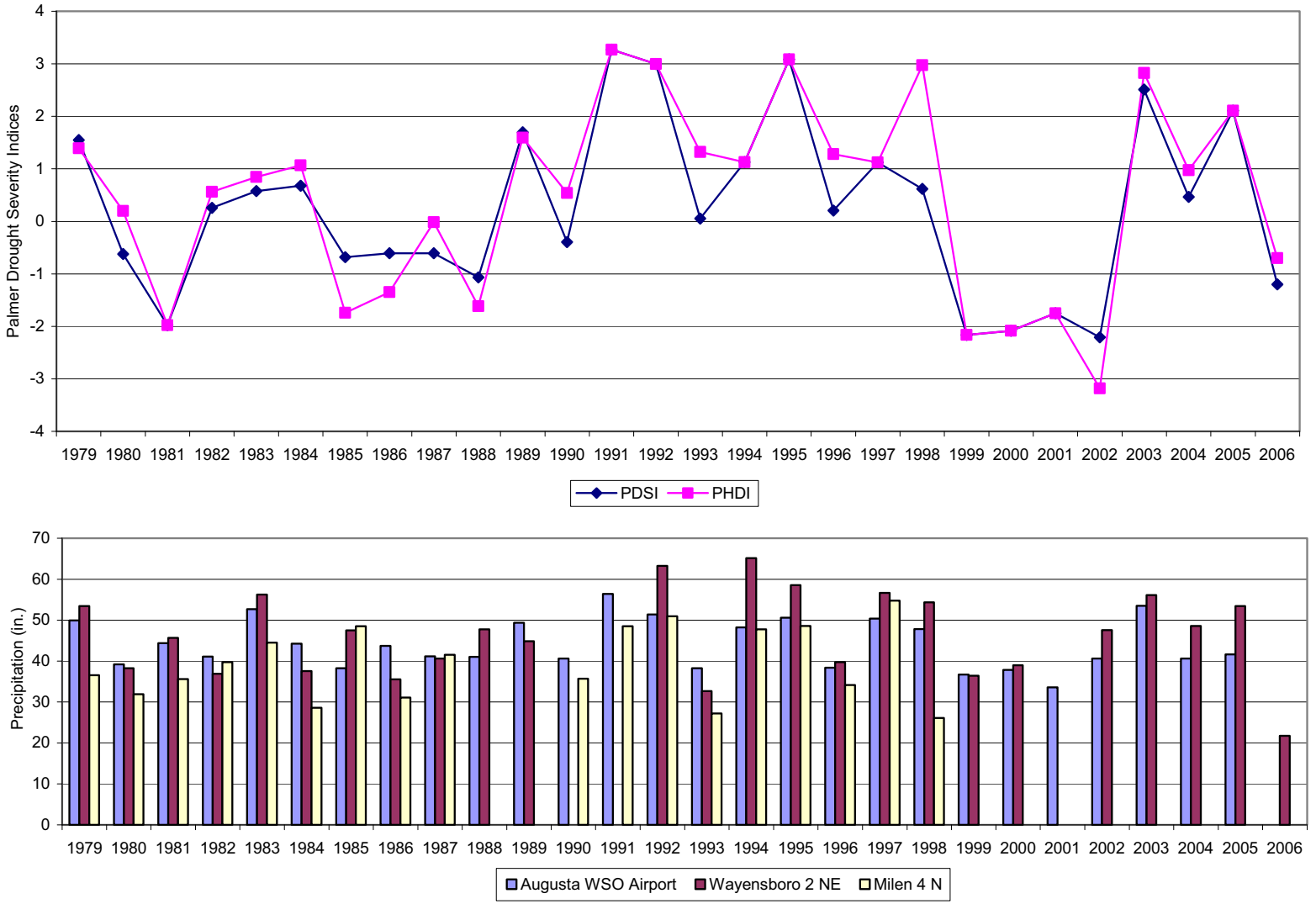


Figure 2.4-255
Average Annual PDSI and PHDI for Georgia and Total Annual Precipitation for the Period 1979–2006

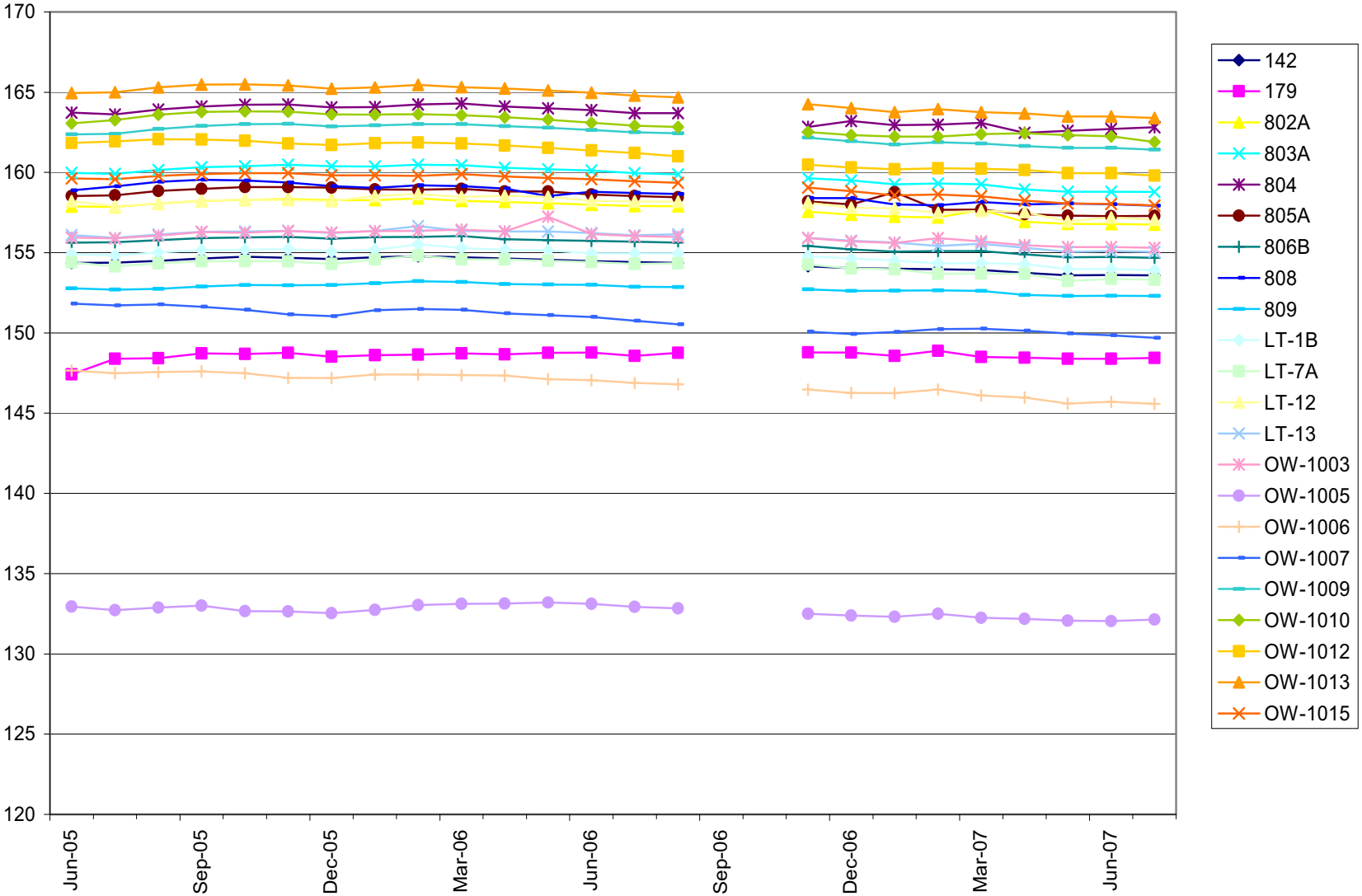


Figure 2.4-256
Water Table Aquifer: June 2005 – July 2007 Hydrographs

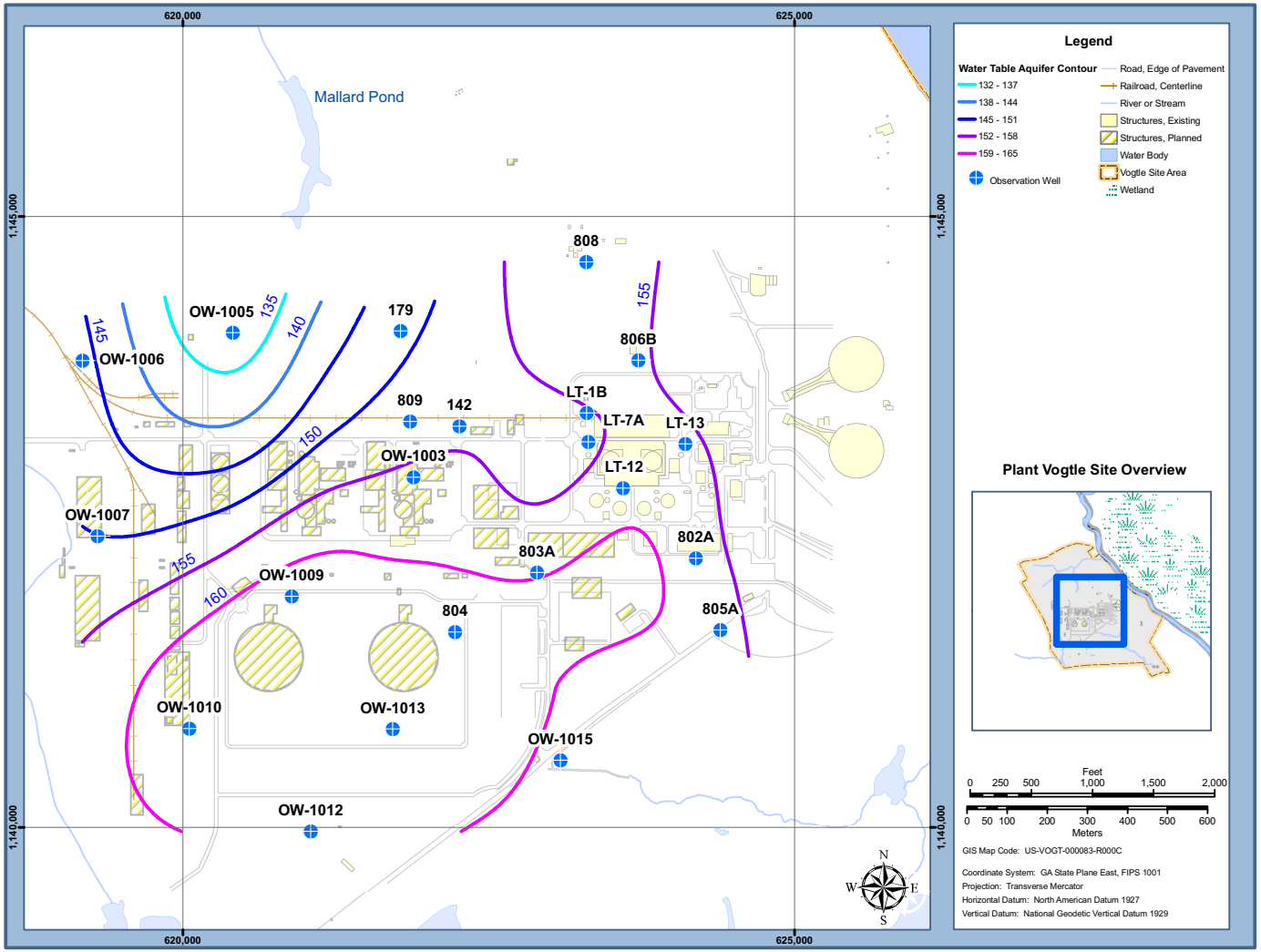


Figure 2.4-257
Water Table Aquifer: Piezometric Contour Map for November 2006

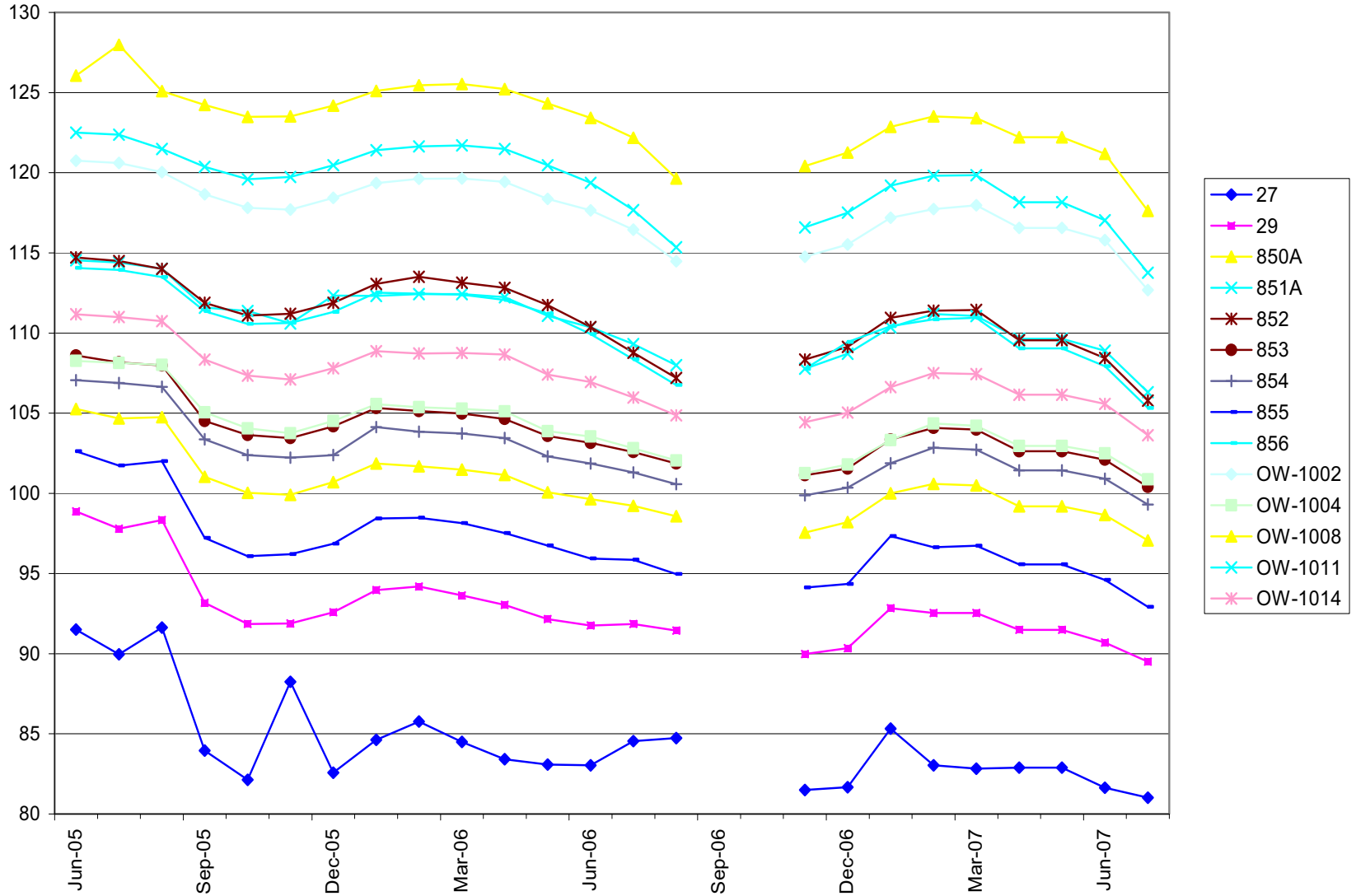


Figure 2.4-258
Tertiary Aquifer: June 2005 – July 2007 Hydrographs

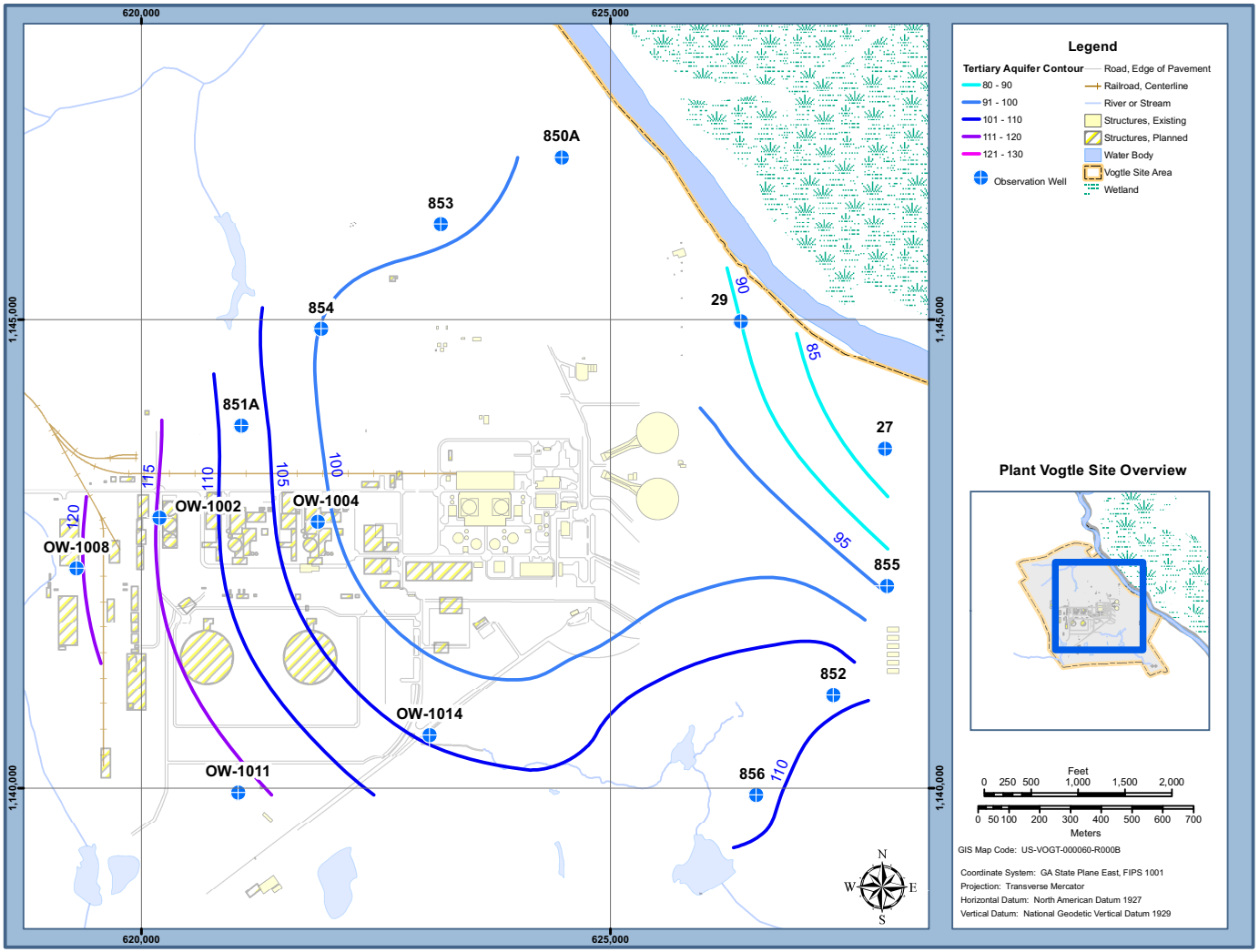


Figure 2.4-259
Tertiary Aquifer: Piezometric Contour Map for November 2006

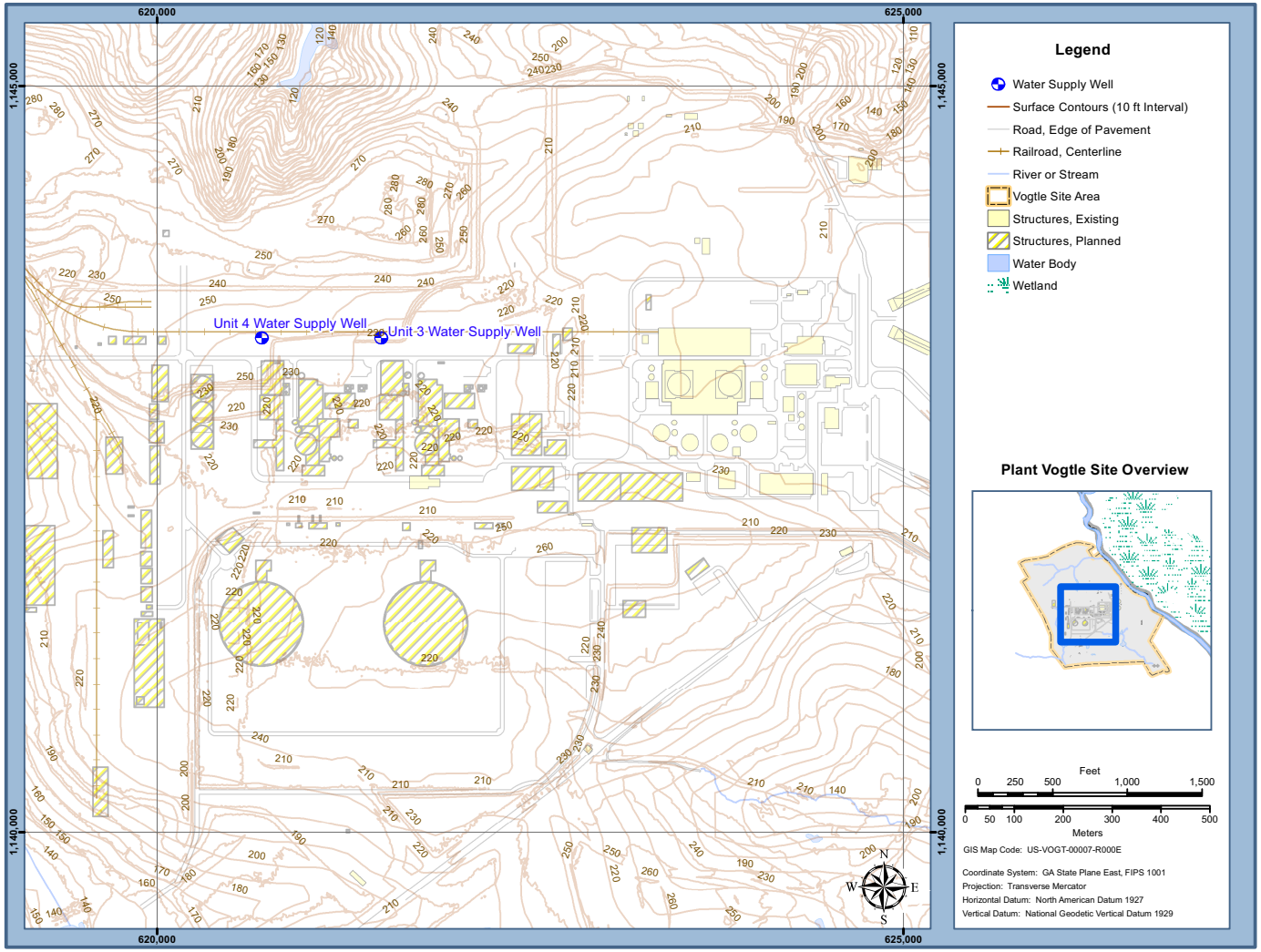


Figure 2.4-260
Proposed Locations of VEGP Units 3 and 4 Water Supply Wells

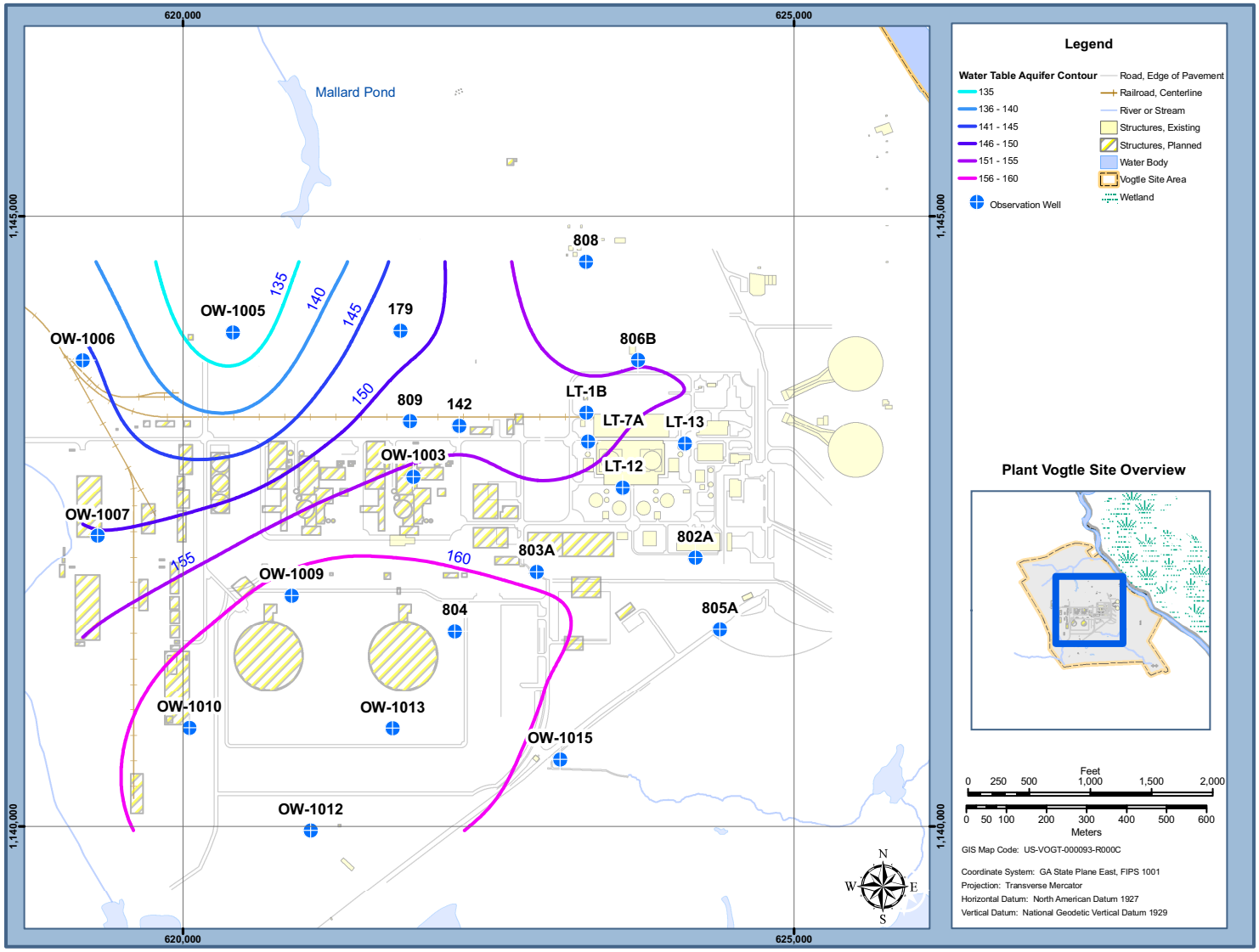


Figure 2.4-261
Water Table Aquifer — Piezometric Contour Map for March 2007

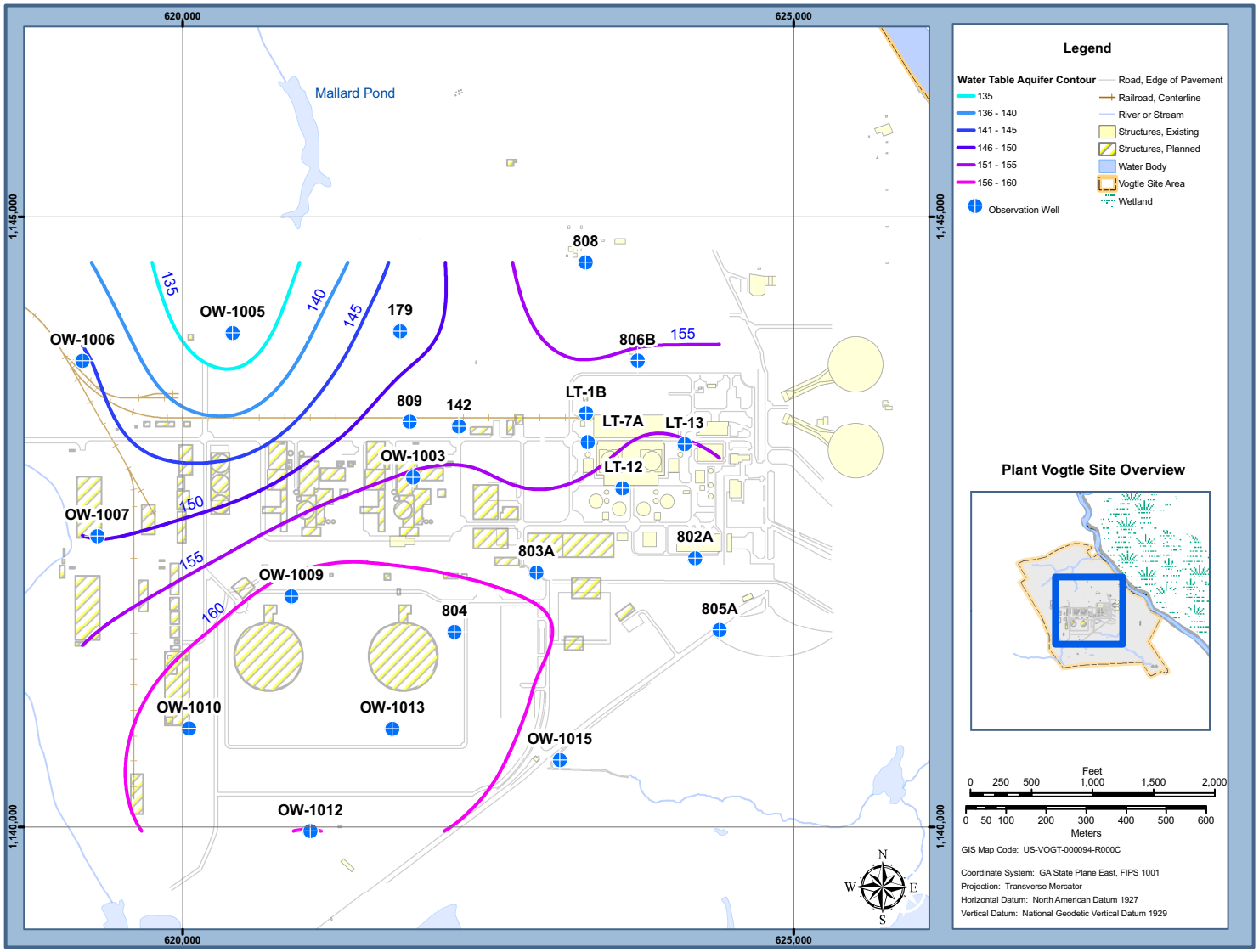


Figure 2.4-262
Water Table Aquifer — Piezometric Contour Map for June 2007

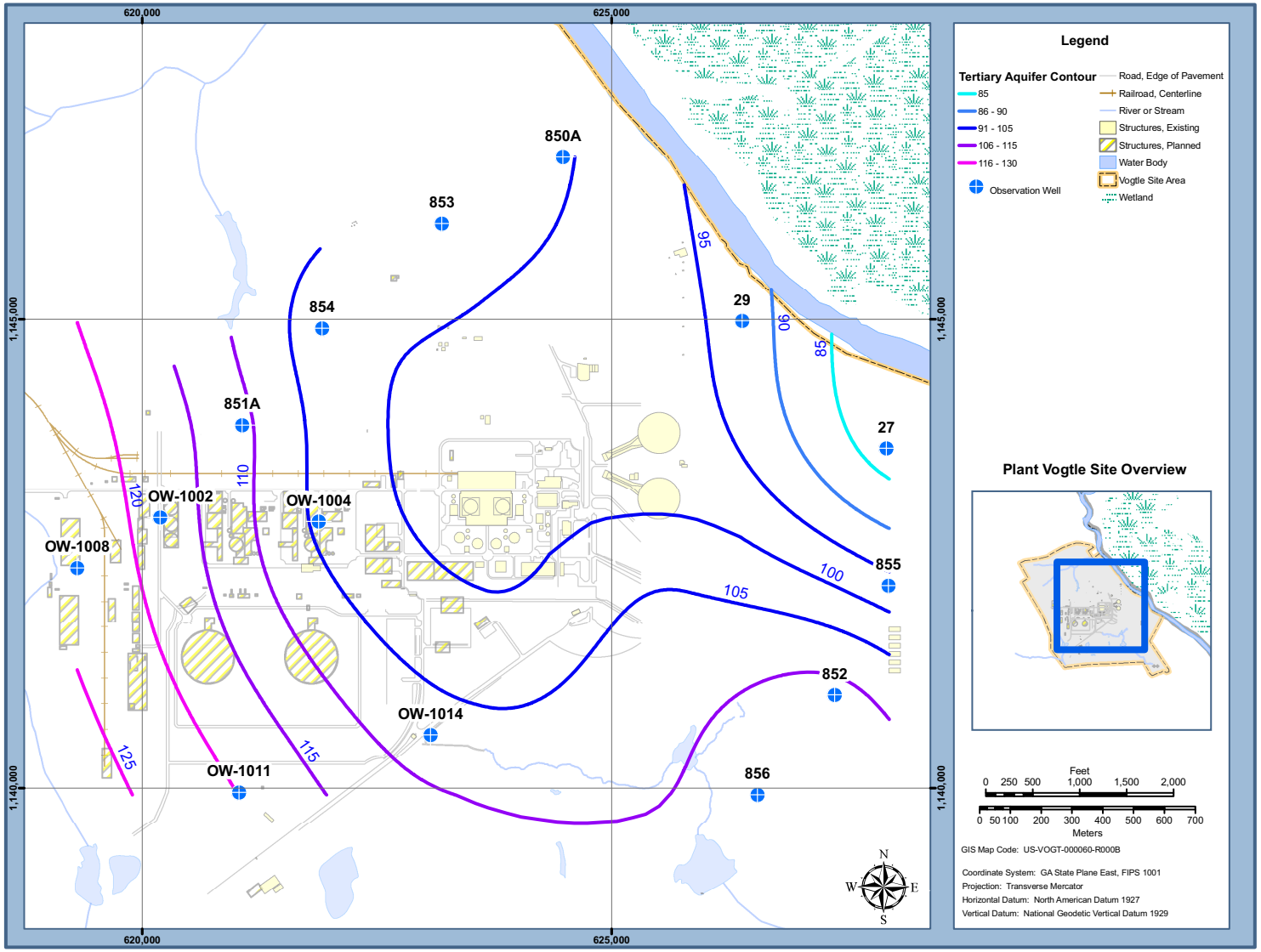


Figure 2.4-263
Tertiary Aquifer — Piezometric Contour Map for March 2007

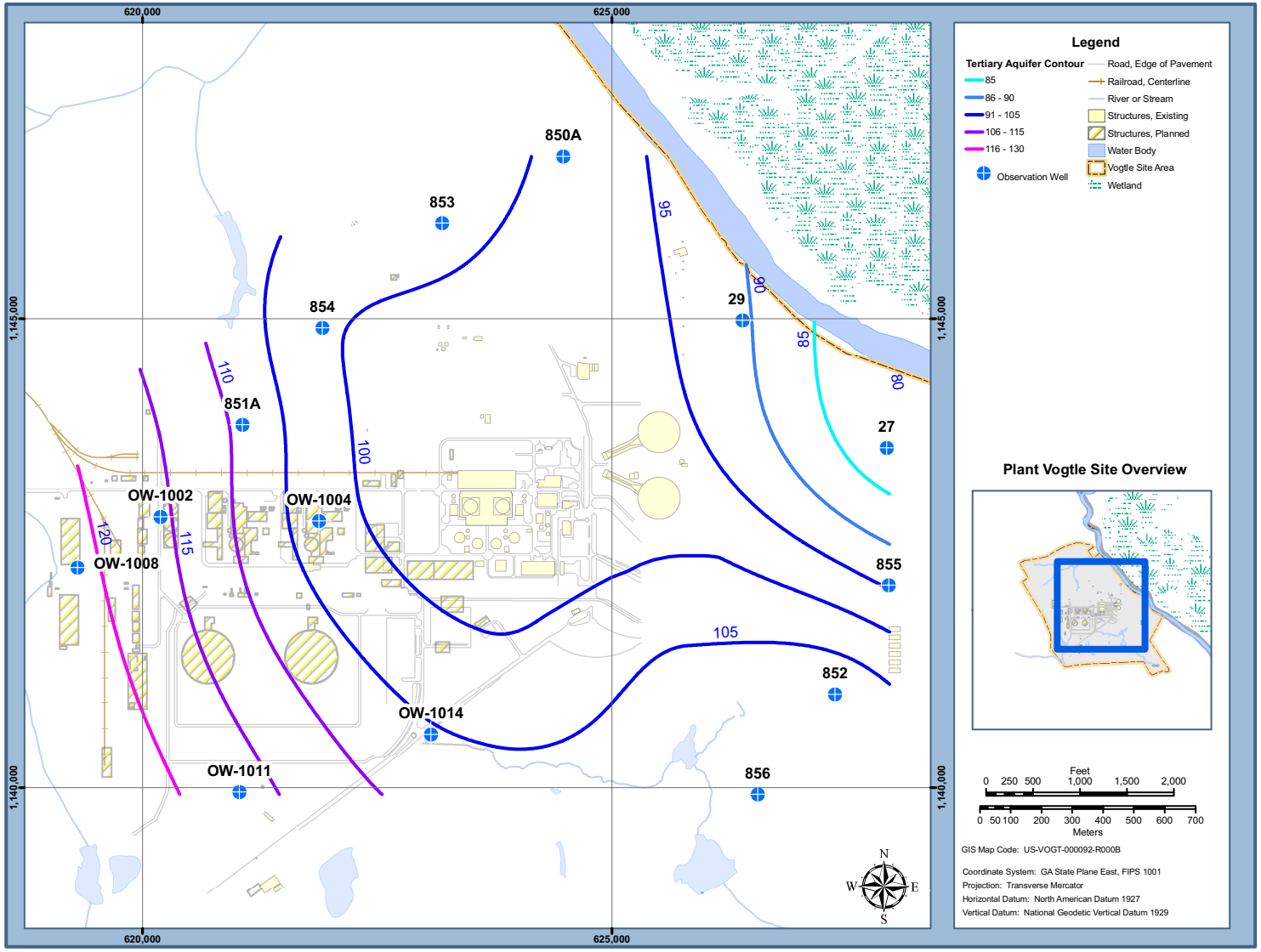


Figure 2.4-264
Tertiary Aquifer — Piezometric Contour Map for June 2007

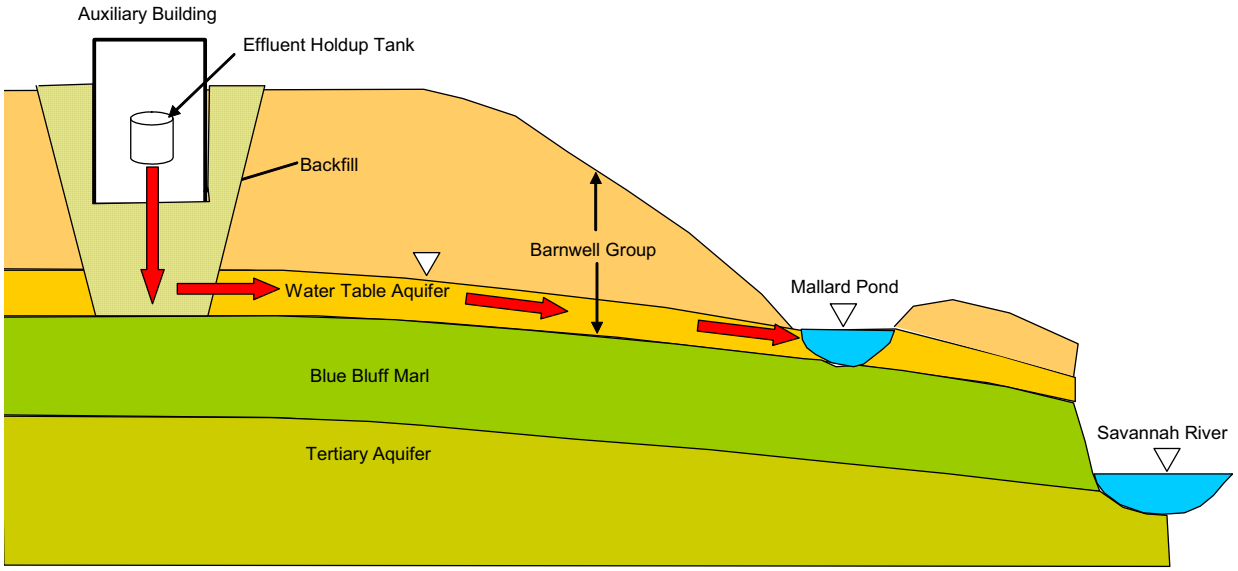


Figure 2.4-265
Conceptual Model for Evaluating Radionuclide Transport in the Water Table Aquifer

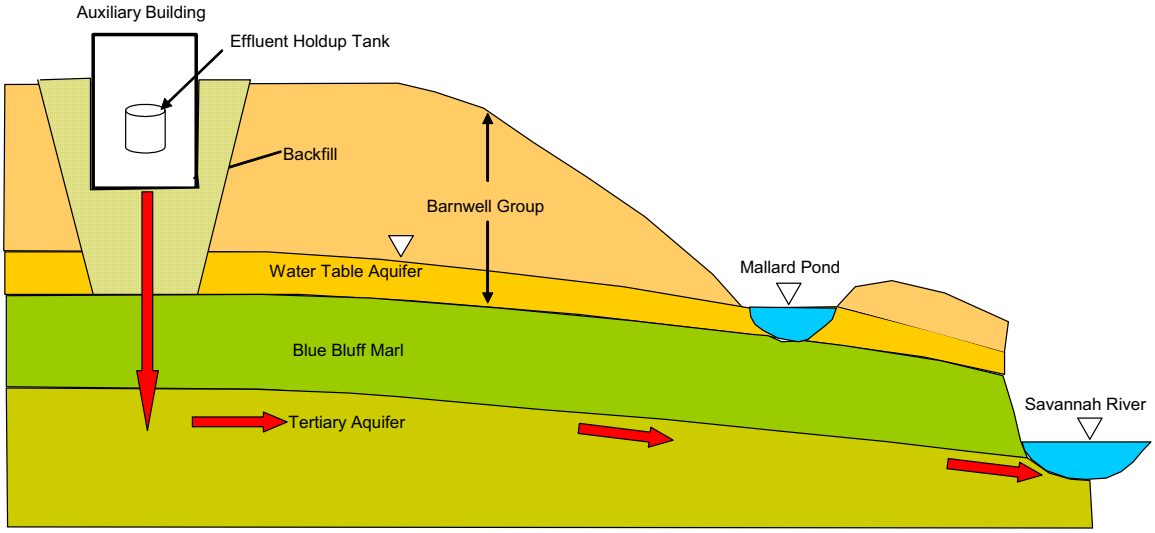


Figure 2.4-266
Conceptual Model for Evaluating Radionuclide Transport in the Tertiary Aquifer

Appendix 2.4A—Observation Well Installation and Development Report

(Excludes contents of report Appendix J)

Prepared by
Earth Sciences and Environmental Engineering,
Technical Services,
Southern Company Generation
November 2005

VOGTLE ALWR ESP PROJECT
FINAL DATA REPORT
ES1374

Prepared By

Earth Science and Environmental Engineering
Technical Services
Southern Company Generation

November 2005

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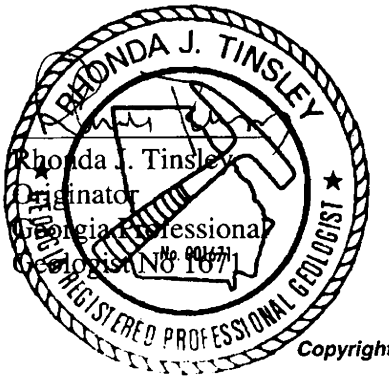
VOGTLE ALWR ESP PROJECT
FINAL DATA REPORT

Prepared By

Earth Science and Environmental Engineering
Technical Services
Southern Company Generation

November 2005



Rhonda J. Tinsley
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TABLE OF CONTENTS

1.0 INTRODUCTION

2.0 SURVEYING SERVICES

3.0 UNDERGROUND UTILITY DETECTION

4.0 DRILLING AND SAMPLING

5.0 GROUNDWATER OBSERVATION WELLS

6.0 SAMPLE STORAGE AND DISPOSAL

7.0 LABORATORY TESTING

8.0 SITE CLEAN UP

9.0 SITE PHOTOGRAPHY

APPENDICES

APPENDIX A	DAILY FIELD LOGS
APPENDIX B	WEEKLY FIELD LOGS
APPEMDIX C	SURVEY
APPENDIX D	FIELD INSTRUMENTS/EQUIPMENT
APPENDIX E	BORING LOGS
APPENDIX F	ABANDONMENT FORMS AND AS BUILT WELL CONSTRUCTION LOGS
APPENDIX G	WELL DEVELOPMENT FORMS
APPENDIX H	WELL INSPECTION FORMS
APPENDIX I	LABORATORY DATA
APPENDIX J	SITE PHOTOS

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1.0 INTRODUCTION

This report presents the information specified in the Bechtel Corporation (Bechtel) document titled *Technical Specification for Groundwater Well Installation for Southern ALWR ESP Project, Burke County, Georgia* (Bechtel Specification Number 25144-002-3PS-CY00-00002-000). This work occurred from May 24 through June 17, 2005. Southern Company Generation provided field supervision, technical consultation, and drilling subcontractors under the technical direction of Bechtel and SNC ESP Project.

Daily and weekly logs were developed during the project. These are respectively included in Appendices A and B.

2.0 SURVEYING SERVICES

The final well survey was provided by Georgia Power Land Engineering Group, Atlanta, Georgia, following the completion of the well installation program. A new survey was also performed for the existing wells to be used in the project. Qualified land surveyors performed the survey and met all survey requirements of the State of Georgia.

The horizontal survey was based on the plant grid system and converted to the State of Georgia coordinate system of northing and easting. The survey originated at a benchmark established for Plant Vogtle. Ground surface elevations were based on the 1927 National Geodetic Vertical Datum (NGVD). The horizontal survey meets the third-order accuracy (1:5000) and the elevation survey is accurate to at least the nearest one-tenth of a foot. This survey data is included in Appendix C.

The locations of the boreholes were determined by SCS and Bechtel using a hand held GPS unit. The proposed well layout coordinates are from existing distribution system layout drawings provided by Georgia Power.

3.0 UNDERGROUND UTILITY DETECTION

A survey to locate underground utilities was completed before the drilling work began at the site. The survey was completed by Mr. John Lattner, Vogtle Engineering, on May 23, 2005. All locations were clear of obstructions with the exception of OW-1009, which was offset to avoid fire protection water and electrical lines.

4.0 DRILLING AND SAMPLING

The drilling program began on May 24, 2005. Drilling was performed by: Kilman Brothers, Stone Mountain, Georgia; Greene's Water Wells, Inc., Gray, Georgia; S&ME, Inc., Blountville, Tennessee; and Prosonic Corporation, New Ellenton, S.C. A list of the equipment used on site during the investigation is included in Appendix D.

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Drilling initially used both 3-1/4" ID and 4-1/4" ID hollow-stem augers (HSA) using Central Mine Equipment (CME) drill rigs. After discovering the 3-1/4" HSAs were too small to adequately set a well, all shallow aquifer wells were drilled, sampled, and set using 4-1/4" ID HSAs. In addition to conventional drilling procedures, rotosonic drilling was provided by Prosonic. This drilling technique uses high-frequency resonant energy. This resonant energy is transferred down the drill string at various sonic frequencies to provide a continuous relatively undisturbed core sample. SCG recommended this method due to the depths necessary for deep well installation, difficult drilling conditions for the conventional equipment as well as its increased speed of drilling.

Soil samples were collected through the hollow stem augers at 5 foot intervals using standard 2' split-spoon samplers, driven 18" by a standard 140 pound hammer or approved automatic hammer. Samples were logged on the site and representative portions were placed in 8-ounce glass sample jars labeled with the sample number, boring number, date, depth, and standard penetration test (SPT) data, including *n* the number of blows over a one-foot sample interval. Bag sampling of representative portions of the continuous 4" rotosonic core samples proceeded at the same 5-foot intervals as the spoon samples. The rotosonic, grab-sample intervals are correlative to the SPT sample intervals. The rotosonic samples were double-bagged and labeled with the same information as the SPT samples, except for *n*.

The complete soil boring logs are included in Appendix E. Due to the initial use of incorrect auger size (3-1/4" ID HSA) for some of the initial wells, some holes were cement-bentonite grout abandoned and new holes were drilled, generally adjacent to the original borehole. The abandoned holes are labeled as 'A' (for example, OW-1002A). The borehole abandonment forms and well construction details are included in Appendix F.

A brief description of the drilling and sampling for each location follows.

OW-1001A

Boring OW-1001A was started and completed on May 25, 2005. The borehole was drilled to a depth of 100' with 3-1/4" ID HSAs by Greene's. It was determined that the auger size was incorrect for the installation of the pre-pack well screen. No boring log was created for this hole since OW-1002A, located adjacent to the hole, was logged from the surface to 108.5 feet below ground surface. The hole was abandoned and grouted by S&ME on June 5, 2005.

OW-1001

Shallow well OW-1001 is installed approximately 10 feet from boring OW-1001A. Drilling on this hole continued from May 24 to May 29, 2005. No log was created for the upper portion of this hole since the adjacent boring OW-1002 was logged from the surface down. This boring was completed by Greene's to a depth of 140 feet and logged by an SCS geologist from split-spoon samples. Shallow well OW-1001 is installed in this boring.

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OW-1002A
Boring OW-1002A was drilled on May 24 and 25, 2005. The borehole was drilled to a depth of 108.5' with 3-1/4" ID HSAs by Greene's. The hole was logged by an SCS geologist from split-spoon samples. It was determined that the auger size was incorrect for the installation of the pre-pack well screen. The hole was abandoned and grouted by S&ME on June 5, 2005.

OW-1002
Boring OW-1002 was started on June 2 and completed on June 6, 2005 by Prosonic. The borehole was drilled to a depth of 237 feet. The hole was logged by an SCS geologist from continuous 4" samples. Deep well OW-1002 is installed in this boring.

OW-1001 and OW-1002 are a well pair.

OW-1003A
Boring OW-1003A was started and completed on May 24, 2005. The borehole was drilled to a depth of 88.5 feet with 3-1/4" ID HSAs by S&ME, Inc. The hole was logged by an SCS geologist from split-spoon samples. It was determined that the auger size was incorrect for the installation of the pre-pack well screen. The hole was abandoned and grouted by S&ME on June 5, 2005.

OW-1003
Boring OW-1003 was started and completed on May 25, 2005. This boring was drilled approximately ten feet south of OW-1003A with 4-1/4" ID HSAs by S&ME. No log was prepared for this hole due to the proximity of OW-1003A. The hole was drilled down to 90.5' with no sampling and shallow observation well OW-1003 was installed.

OW-1004
Boring OW-1004 was started on June 3 and completed on June 11, 2005. The boring was drilled to a depth of 187 feet by Prosonic and logged by an SCS geologist from continuous 4" ID samples. Sampling in this boring began at 87' since OW-1003, the adjacent shallow well, was sampled to 88.5' feet. Prosonic had to shut down from June 4 to June 8 for training. Deep observation well OW-1004 was installed.

OW-1003 and OW-1004 are a well pair.

OW-1005A
Boring OW-1005A was started and completed on May 31, 2005. The auger boring was drilled to depth of 75 feet with 3-1/4" ID HSAs by Kilman. It was determined that the auger size was incorrect for the installation of the pre-pack well screen. This well was abandoned and grouted by S&ME on June 5, 2005. The hole was logged by an SCS geologist from samples collected in jars at the time of boring.

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OW-1005
Boring OW-1005 was started on June 2 and completed on June 7, 2005. Due to the incorrect size of the augers used at OW-1005A, this new hole was offset approximately 10' from that boring. The boring was drilled to 170' with 4-1/4" ID HSAs by S&ME. No sampling was performed in the upper portion of the hole due to the proximity of OW-1005A. The hole was logged by an SCS geologist from split spoon samples from 68.5 feet to 170.0 below ground surface. OW-1005 is installed in this boring.

OW-1006A
Boring OW-1006A was started on June 3 and completed on June 4, 2005. This boring was drilled to 125' by S&ME with 4/1/4" ID HSAs. The hole was logged by an SCS geologist from split-spoon samples. This boring was abandoned due to a shortage of augers. Additional augers necessary to reach the marl unit could not be brought onsite quickly and the potential for HAS deviation in the existing hole warranted a decision to start in a new hole when sufficient augers were available. The hole was abandoned and grouted by S&ME on June 5, 2005.

OW-1006
Boring OW-1006 was started on June 9 and completed on June 14, 2005, by S&ME. No sampling was performed in the upper 118.5' feet due to the proximity of boring OW-1006A which was taken to 125'. No standard penetration tests were obtained from this hole due to drilling problems. The split-spoon sampler was pushed to collect samples. Shallow well OW-1006 is installed in this boring.

OW-1007
Boring OW-1007 was started on June 4 and completed on June 8, 2005. The boring was drilled to 122 feet by Greene's with 4-1/4" ID HSAs. No sampling was performed in the upper 98.5' due to the proximity of boring OW-1008 which was logged down to 105' by an SCS geologist from split-spoon samples. Shallow well OW-1007 is installed in this boring.

OW-1008
Boring OW-1008 was started on May 31 and completed on June 1, 2005. The upper portion of the hole was drilled by Kilman with 3-1/4" ID HSAs to 105 feet and logged by an SCS geologist from split-spoon samples. The remainder of the hole was drilled by PROSONIC to a depth of 247 feet. The lower portion of the hole was logged from continuous 4" ID samples. Deep well OW-1008 was installed in this boring.

OW-1007 and OW-1008 are a well pair.

OW-1009
Boring OW-1009 was started on May 24 and completed on May 25, 2005. The boring was drilled by S&ME with 4-1/4" ID HSAs to 100' and logged by an SCS geologist from split-spoon samples. Shallow well OW-1009 is installed in this hole.

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OW-1010
Boring OW-1010 was started and completed on June 1, 2005. The boring was drilled by S&ME with 4-1/4" ID HSAs to 93.5 feet and logged by an SCS geologist from split-spoon samples taken to 95 feet. Shallow well OW-1010 is installed in this hole.

OW-1011
Boring OW-1011 was started on June 11 and completed on June 12, 2005. The boring was drilled by Prosonic to a depth of 217 feet and logged by an SCS geologist from continuous 4" ID samples taken from 87 feet to the bottom of the hole. Sampling of the upper 87 feet was not performed in this hole due to the proximity of OW-1012, which was sampled and logged from the surface to 93.6 feet. Deep well OW-1011 is installed in this boring.

OW-1012
Boring OW-1012 was started on May 31 and completed on June 1, 2005. The boring was drilled by S&ME with 4-1/4" ID HSAs to 93.6 feet and logged by an SCS geologist from split-spoon samples taken to 95 feet. Shallow well OW-1012 is installed in this hole.

OW-1011 and OW-1012 are a well pair.

OW-1013
Boring OW-1013 was started on June 9 and completed on June 10, 2005. The boring was drilled by S&ME with 4-1/4" ID HSAs to 103.5 feet and logged by an SCS geologist from split-spoon samples taken to 105 feet. Shallow well OW-10013 is installed in this hole.

OW-1014
Boring OW-1014 was started and finished June 11, 2005. The boring was drilled to a depth of 197.4 feet by Prosonic and logged by an SCS geologist from continuous 4" samples. Sampling in this boring began at 97 feet since OW-1015, the adjacent shallow well, was logged to 88.5 feet. Deep observation well OW-1014 was installed in this boring.

OW-1015
Boring OW-1015 was started May 30 and completed June 3, 2005. The boring was drilled to 120 feet by Greene's with 4-1/4" ID HSAs. The boring was logged by an SCS geologist from split-spoon samples. Shallow observation well OW-1015 was installed in this boring.

OW-1014 and OW-1015 are a well pair.

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5.0 GROUNDWATER OBSERVATION WELLS

Fifteen wells were installed at the site between the dates of May 26 and June 15, 2005. Twenty-two observation wells were previously installed. Details of the new wells are provided in Appendix F. Table 5-1 summarizes this data.

Table 5-1 Observation well construction details

Well ID	Date Installed	Ground Elev.	Top of Casing Elev.	Well Dia. (in)	Screen Slot Size (in)	Total Well Depth (ft)	Screen Length (ft)	Screened Interval Depth (ft)	Screened Interval El. (ft)	Unit
OW-1001	5/29/05	230.854	233.494	2	0.01	133	10	121 - 130	109.724 – 100.224	shallow
OW-1002	6/6/05	227.442	230.502	2	0.01	237	10	219 – 229	7.812 – (-)2.188	deep
OW-1003	5/26/05	223.044	226.284	2	0.01	90.5	10	75.5 – 84.8	146.914 – 137.614	shallow
OW-1004	6/10/05	222.92	225.671	2	0.01	187	10	153.25 – 163.26	69.04 – 59.04	deep
OW-1005	6/7/05	264.389	267.289	2	0.01	176.8	10	157.3 – 167.3	106,459 – 96.459	shallow
OW-1006	6/14-15/05	223.044	226.284	2	0.01	135.5	10	116 - 126	110.491 – 100.491	shallow
OW-1007	6/7/05	216.91	219.96	2	0.01	120	10	102 – 111.5	114.28 – 104.28	shallow
OW-1008	6/1/05	216.65	219.71	2	0.01	247	10	230 – 240	(-)13.98 – (-)23.98	deep
OW-1009	5/27/05	220.887	223.647	2	0.01	97.9	10	84 – 94	136.257 – 126.257	shallow
OW-1010	6/1/05	216.895	219.905	2	0.01	94.8	10	73.3 – 83.3	142.965 – 132.965	shallow
OW-1011	6/13/05	205.785	209.043	2	0.01	217.6	10	200.6 – 210.6	4.555 – (-)5.445	deep
OW-1012	6/1/05	205.355	208.684	2	0.01	93.5	10	74.0 – 83.4	130.725 – 121.325	shallow
OW-1013	6/10/05	216.869	219.809	2	0.01	103.5	10	83.5 – 93.5	132.775 – 122.775	shallow
OW-1014	6/11/05	220.867	223.856	2	0.01	197	10	182 – 192	38.237 – 28.237	deep
OW-1015	6/3/05	220.427	223.157	2	0.01	120	10	93 - 103	126.797 – 116.797	shallow

All new wells and the inactive wells were developed by S&ME, Inc. Well development forms are included in Appendix G. The existing wells were also inspected by SCS and Bechtel. Well inspection forms are included in Appendix H. Water level measurements are being performed by the Plant under its existing Quality Assurance Program.

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6.0 SAMPLE STORAGE

Soil samples collected from split-spoon and continuous sampling are stored onsite. Glass sample jars were used for split-spoon samples and zip-lock bags were labeled and double-bagged for the continuous 4" samples from the Prosonic rig. All samples, with the exception of those sent to the laboratory for analysis, are stored in a secure building within the plant site.

7.0 LABORATORY TESTING

Soil testing for selected samples was assigned by Bechtel. The samples were collected and delivered to the Southern Company Generation Construction Field Services soil laboratory in Alabaster, Alabama. Soil classification tests with hydrometer were performed. The laboratory results are presented in Appendix I.

8.0 SITE CLEAN UP

Site clean up to the plant's satisfaction was performed by the drillers.

9.0 SITE PHOTOGRAPHY

Digital photography of the site investigation is included as a courtesy, although the specifications did not require this work. The photographs (Appendix J) of the site investigation include selected soil samples, equipment, and site conditions.

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APPENDIX A

DAILY FIELD LOGS

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Daily Field Log

5/24/2005	• Started OW-1002A (Greene). • Started OW-1009 (S&ME) • Started OW-1003. Drilled to 88.5' with 3-1/4" ID HSAs.
5/25/2005	• Completed OW-1002A. This hole was abandoned due to incorrect auger size. • Drilled to 100' at OW-1001A. Abandoned this hole due to incorrect auger size. • Continuing at OW-1003 with 4/14" ID HSAs to bottom of yesterday's 3-1/4" ID HSA borehole. Restarted sampling at ~75'. Completed OW-1003. • Well at OW-1003 offset 10' due to 10' of cave-in in boring. Drilled down without sampling. OW-1003 well installation notes attempting to set pre-pack in open hole • S&ME development crew standing by for direction. • Kilman crew dropped supplies by OW-1003, OW-1002 and then heading to OW-1008. Had to standby till ~2 o'clock while well was relocated due to accessibility. Kilman did not bring enough HSA and rod to complete holes • Greene sampled OW-1002Ato 115'. Offset and drilled OW-1001A since no well materials were available to set well at the time. Wrong size augers were used. Had to pull out and re-drill with correct 4-1/4" ID HSAs. Greene not able to grout up hole since they did not have necessary equipment • Continue sampling on OW-1009 (S&ME). Equipment breakdown in coquina.
5/26/2005	• Started OW-1001 (Greene). Thin bed of hard crystalline limestone at 100' and again at 110'. • Completed OW-1003 (S&ME) • Development team completes 803A and 809
5/27/2005	• Completed OW-1009 (S&ME) • Development team pump burns out • Completed OW-1001 except grout installation
5/28/2005	OFF
5/29/2005	• Greene moves chemical grout pump to OW-1001. No grout delivered so grout taken from OW-1003 (6 bags). 2 additional bags brought in and 1 bag CETCO Super GeL X. Grouted hole up to 70'
5/30/2005	• Intermittent rain • Started OW-1015 (Greene)
5/31/2005 5/31/2005	• Kilman at OW-1005. Drilled to 78.5' and encountered flowing sand • Intermittent rain. Hard rain set in by 3:00 • Sand up in augers at OW-1015. Continuing on this hole • Prosonic onsite. Tom Moorer walked them through security. Brought only 150' drilling capability but sent helper to get additional tooling to reach 300'. • Discussed vibrations from Prosonic rig on plant equipment with Don Moore.. He did not see need for additional calcs to proceed • Green successfully cleans auger and took 98.5 to 100' sample. • Discuss number swap on well labeling with Louise Headland • Started lower portion OW-1008 (Prosonic) • Started OW-1012 (S&ME) • Showed location for OW-1006 to Kilman. They request road improvement
6/1/2005	• Started OW-1002B (Prosonic)

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	• S&ME drilling OW-1012. Well completed • S&ME drilling OW-1010. • Development completed on 804, 805A, 853, 854, 856
6/2/2005	• Prosonic continues with OW-1002 • Completion of OW-1010. Well is accidentally lifted during grouting but returned to planned depth. Bechtel approves well as is. • S&ME moves to OW-1005. Kilman drilled original OW-1005 but pulled out. Well abandoned by S&ME. Cable broke and grazed S&ME Ted's shoulder. Ted declined emergency room visit • S&ME second rig moves to OW-1006 • Development completed on 27, 850A 852, 855
6/3/2005	• OW-1002B completed (Prosonic) • Started OW-1004 (Prosonic) • OW-1005B and OW-1006A started by S&ME rigs. Out of auger on OW-1005 at ~3 pm. • OW-1015 completed (Greene) • Development completed on OW-1003, OW-1009, OW-1010, OW-1012, OW-1015
6/4/2005	• Greene encounters difficult drilling at 105'. Had to retool for mud to stabilize borehole and clean flowing sand from HAS • Surface completion by S&ME at OW-1002` • Prosonic leaves site for training • OW-1015 surface completion by S&ME • Started OW-1007 (Greene)
6/5/2005	• OW-1001A abandoned by S&ME • OW-1001 and OW-1006 surface completion by S&ME • OW-1002A abandoned by S&ME • OW-1003A abandoned by S&ME • OW-1005A abandoned by S&ME • OW-1006A abandoned by S&ME
6/6/2005	• Started 1007 (Greene) • Development completed for OW-1001 • GPS locations taken for new wells • Drillers report using 32 bags of grout in OW-1001 on top of 70 feet of grout already in hole. This shrank to about 20' bgs and additional 10 bags were used to top it off. S&ME used a total of 120 bags to abandon OW-1001A, OW-1002A, and top off OW-1001 and OW-1002
6/7/2005	• OW-1005 completed (S&ME) • OW-1007 completed (Greene) • Conversation with Bechtel to confirm using Schedule 80 PVC in holes over 100', due to inability to insert well pumps. Southern Co expresses concerns about representativeness of water table conditions at OW-1001 and multiple saturated zones in OW-1005 and OW-1006. • Attempted to rig a 'stand off' on water level meter to aid in getting reliable water level measurement down PVC. Capillary attraction making reading difficult in 1008 and other deep wells. 'Stand-off' initially worked but then held water, which continuously trickled over GeoSlope probe thus negating its usefulness. • Bechtel calls to say OW-1001 appears to be OK because of recovery and another well and boring are not required there
6/8/2005	• OW-1006 assigned to Greene • OW-013 assigned to S&ME
6/9/2005	• OW-1006 started (Greene) • Started OW-1013 (S&ME)
6/10/2005	• OW-1006 continues

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	• OW-1013 completed (S&ME)
6/11/2005	• OW-1014 started and completed (Prosonic) • OW-1011 started (Prosonic)
6/12/2005	• OW-1011 completed (Prosonic)
6/13/2005	• OW-1004 surface completion (S&ME development team) • OW-1011 surface completion (S&ME development team) • OW-1014 surface completion (S&ME development team) • OW-1006 continues
6/14/2005	• Development completed on OW-1002, OW-1004, OW-1007, OW-1008, OW-1011, OW-1014 • OW-1006 completed
6/15/2005	• Development completed on 142, 179, 27, OW-1005, OW-1013
6/16/2005	• OW-1006 surface completion and development (S&ME development team) • Inspected wells LT-1B, LT-12, and LT-7A. Made note of depth to water and bottom of wells. No redevelopment recommended

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APPENDIX B

WEEKLY FIELD LOG

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Vogtle ALWR ESP Project
Weekly Field Log

Well	Purpose	Status	Driller	Tuesday 24-May-05	Wednesday 25-May-05	Thursday 26-May-05	Friday 27-May-05	Saturday 28-May-05	Sunday 29-May-05	Monday 30-May-05	Tuesday 31-May-05	Wednesday 1-Jun-05	Thursday 2-Jun-05	Friday 3-Jun-05	Saturday 4-Jun-05	Sunday 5-Jun-05	Monday 6-Jun-05	Tuesday 7-Jun-05	Wednesday 8-Jun-05	Thursday 9-Jun-05	Friday 10-Jun-05	Saturday 11-Jun-05	Sunday 12-Jun-05	Monday 13-Jun-05	Tuesday 14-Jun-05	Wednesday 15-Jun-05	Thursday 16-Jun-05
OW-1001	Shallow	Completed	Greene																								
OW-1001A	Shallow	Abandoned	Kilman																								
OW-1002A	Shallow	Abandoned	Greene																								
OW-1002	Deep	Completed	Prosonic																								
OW-1003A	Shallow	Abandoned	S&ME Tim																								
OW-1003	Shallow	Completed	S&ME Tim																								
OW-1004	Deep	Started	Prosonic																								
OW-1005A	Shallow	Abandoned	Kilman																								
OW-1005	Shallow	Completed	S&ME Ted																								
OW-1006A	Shallow	Abandoned	S&ME Tim																								
OW-1006	Shallow	Located	Greene																								
OW-1007	Shallow	Completed	Greene																								
OW-1008	Deep	Completed	Kilman/Prosonic*																								
OW-1009	Shallow	Completed	S&ME Ted																								
OW-1010	Shallow	Completed	S&ME Tim																								
OW-1011	Deep	Completed	Prosonic																								
OW-1012	Shallow	Completed	S&ME Ted																								
OW-1013	Shallow	Completed	S&ME Ted																								
OW-1014	Deep	Completed	Prosonic																								
OW-1015	Shallow	Completed	Greene																								
Development Team						Developed 803a, 809	Surface Completion OW-1009				Helped gether supplies and assembled new pump	Developed 804, 805a, 853, 854, 858	Developed 850a, 852, 855 Surface Completion OW-1010	Surface completion OW-1003 Developed OW-1003, OW-1009, OW-1010, OW-1012, OW-1015	Surface completions OW-1002 OW-1015	Surface completions OW-1301 OW-1006			Surface completions OW-1005, OW-1007, OW-1012		Surface completion OW-1013				Developed and surface completion OW-1002, OW-1004, OW-1007, OW-1006, OW-1011, OW-1014	Developed 142, 179, 27, OW-1005, OW-1013	Surface Completion and development OW-1006

* Kilman 5/25 26 Prosonic 5/31-6/1

Drilling/well installation period - start to finish

Time offsite, no drilling (Holiday, training, week-end)

APPENDIX C

SURVEY DATA

EXISTING WELL SURVEY
NEW WELL SURVEY

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Vogtle Existing Well Survey (NAD27)

Well	Northing	Easting	El. Ground (ft.)	El. Top of Casing (TOC ft.)
	(NAD27)	(NAD27)		
142	1143282.409	622260.403	222.377	223.797
179	1144061.205	621778.747	274.668	275.068
802A	1142201.703	624195	215.558	218.258
803A	1142085.387	622896.031	218.394	219.574
804	1141599.597	622224.797	223.603	225.373
805A	1141616.153	624395.699	233.988	235.76
806B	1143821.568	623724.453	214.314	215.414
808	1144624.291	623297.746	214.871	215.771
809	1143320.36	621857.189	NA	223.671
LT-1B	1143390.484	623301.286	218.053	220.654
LT-7A	1143154.107	623314.265	217.813	218.563
LT-12	1142776.798	623597.644	218.274	219.024
LT-13	1143136.424	624108.674	218.273	220.073
27	1143622.414	627928.859	208.836	210.406
29	1144982.746	626389.789	190.83	192.61
850A	1146728.881	624482.466	225.225	227.025
851A	1143869.697	621064.25	261.685	263.325
852	1140993.937	627377.483	199.408	201.308
853	1146016.483	623191.496	226.599	229.969
854	1144900.49	621914.54	235.584	237.324
855	1142159.143	627948.361	216.767	218.668
856	1139928.479	626555.6	185.495	187.107

Vogtle New Well Survey (NAD27)

Location	Northing	Easting	El. Ground (ft.)	El. Top of Casing (TOC ft.)
1001	1142888.724	620148.556	230.224	232.864
1002	1142887.782	620189.341	226.812	229.872
1003	1142864.056	621884.337	222.414	225.654
1004	1142842.176	621880.794	222.29	225.041
1005	1144047.86	620408.765	263.759	266.659
1006	1143817.854	619179.749	226.491	229.971
1007	1142383.767	619301.009	216.28	219.33
1008	1142347.939	619306.686	216.02	219.08
1009	1141891.645	620888.608	220.257	223.017
1010	1140808.986	620051.708	216.265	219.275
1011	1139956.246	621033.045	205.155	208.413
1012	1139969.496	621045.924	204.725	208.054
1013	1140805.4	621715.032	216.239	219.179
1014	1140565.502	623070.234	220.237	223.226
1015	1140550.576	623086.318	219.797	222.527

APPENDIX D

FIELD INSTRUMENTS/EQUIPMENT

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Contractor	Tools/Rig Description
Greene Water Well, Inc.	CME 75 Auger drill with water tank; manual hammer 1-ton crew truck Chevrolet Pickup HD 4-1/4" ID hollow stem auger – 125' 3-1/4" ID hollow stem auger 90' NWJ rod
Kilman Brothers	CME 45; 4X4; no water tank, auto hammer 125' of 3 1/4" ID hollow stem auger 110' N rod 2 cutter heads
S&ME (2 rigs)	3 F-Series, ¾-ton trucks 1 personal vehicle 2 CME 55 Auger/Wash drill rigs with SPT Autohammers Grundfos pump Static water level indicator Generator Steam Junny 2 grout plants with tremie pipe 3-1/4" ID hollow stem augers – 90' 4-1/4" ID hollow stem augers – 180' NWJ rods with 4" fishtail or 6" rollercone – 180' 6 2' split spoons
PROSONIC	SR-083 drill rig w/ 6" outer drive casing and 4" sampling tube Two 1-ton crew trucks Onboard grout machine Pressure washer
SCS	Provided 60' 4 1/4" ID hollow stem augers
	Extra – 1 bundle (19) 5' AWJ rods 9 loose 5' AWJ rods 14 loose 10' NWJ rods Chemical grouting machine

Contractor	Well Development Tools
S&ME	Grunfos Rediflo2 submersible pump 200' of hose and power lead 1 Generac 5000 Watt, 10 HP 110/240V AC generator

Well Supplies
Schedule 80 PVC slotted screens - 10' length Schedule 80 PVC risers - 10' length

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Schedule 80 PVC riser - 2 1/2' length
Schedule 80 PVC riser - 5' length
Schedule 40 PVC slotted screens - 10' length
Schedule 40 PVC risers - 10' length
Schedule 40 PVC risers - 5' length
Schedule 40 PVC risers - 2 1/2' length

DSI 1A filter sand
JC50FS by Unimen filter sand
Foster Dixiana

CETCO Goldseal 3/8" bentonite chips
CETCO Puregold medium

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APPENDIX E

BORING LOGS

OW-1001
OW-1002
OW-1002A
OW-1003
OW-1004
OW-1005
OW-1005A
OW-1006
OW-1006A
OW-1007
OW-1008
OW-1008A
OW-1009
OW-1010
0W-1011
OW-1012
OW-1013
OW-1014
OW-1015

LEGEND

N	**Standard Penetration Resistance. The sum of the number of blows from a 140 pound hammer needed to drive the sampler over the sampling depth of 6 to 18 inches.**
Bpf	**Blows per foot. Unit of measure for 'N'.**
WOR	**Split spoon sampler penetrates by weight of the sampling rods alone.**
WOH	**Split spoon sampler penetrates by the weight of 140 pound hammer alone, with no blows from the hammer.**

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SOUTHERN COMPANY
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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1001
Sheet 1 of 5

SITE: Vogtle ALWR SSAR | HOLE DEPTH: 140' | SURF.ELEV.: 230.854

LOCATION: Burke County, Georgia | COORDINATES N: 1142888.724 | E: 620148.556

ANGLE: NA | BEARING: NA | CONTRACTOR: Greene | DRILL NO.: CME 75

DRILLING METHOD: 4 1/4" HSA | NO. SAMPLES: 4 | NO. U.D. SAMPLES: NA

WATER TABLE DEPT: 108.7' | ELEV.: | TIME AFTER COMP.: | DATE TAKEN: 5/24/2005

TYPE GROUT: NA | QUANTITY: NA | MIX: NA | DRILLING START DATE: 5/24/2005

DRILLER: Arthur | RECORDER: S. Bearce | APPROVED: NA | DRILLING COMP. DATE: 5/29/2005

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0	230.85						
1	229.85	OW-1001 was installed in this borehole. OW-1001 is a well pair with OW-1002					
2	228.85	Soil sampling for the upper portion was completed in OW-1002A to the top of the MARL at 105' bgs. Sampling in this hole began at 113.5 feet bgs. (Sheet 4)					
3	227.85						
4	226.85						
5	227.86	A previous borehole (OW-1001A) was made for this well but was abandoned. No log was prepared.					
6	224.85						
7	223.85						
8	222.85						
9	221.85						
10	222.86						
11	219.85						
12	218.85						
13	217.85						
14	216.85						
15	217.86						
16	214.85						
17	213.85						
18	212.85						
19	211.85						
20	210.85						
21	209.85						
22	208.85						
23	207.85						
24	206.85						

Form GS9901 7-26-20(

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1001
Sheet 2 of 5

SITE Vogtle ALWR SSAR TOTAL DEPTH 140' SURF.ELEV. 230.854

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
25	205.85	See Page 1					
26	204.85						
27	203.85						
28	202.85						
29	201.85						
30	200.85						
31	199.85						
32	198.85						
33	197.85						
34	196.85						
35	195.85						
36	194.85						
37	193.85						
38	192.85						
39	191.85						
40	190.85						
41	189.85						
42	188.85						
43	187.85						
44	186.85						
45	185.85						
46	184.85						
47	183.85						
48	182.85						
49	181.85						
50	180.85						
51	179.85						
52	178.85						
53	177.85						
54	178.86						
55	175.85						
56	174.85						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1001
Sheet 3 of 5

SITE Vogtle ALWR SSAR TAL DEPTH 140' ELEV. 230.854

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
57	173.85	See Page 1					
58	172.85						
59	171.85						
60	170.85						
61	169.85						
62	168.85						
63	167.85						
64	166.85						
65	165.85						
66	164.85						
67	163.85						
68	162.85						
69	161.85						
70	160.85						
71	159.85						
72	158.85						
73	157.85						
74	156.85						
75	155.85						
76	154.85						
77	153.85						
78	152.85						
79	151.85						
80	150.85						
81	149.85						
82	148.85						
83	147.85						
84	146.85						
85	145.85						
86							
87	143.85						
88	142.85						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1001
Sheet 4 of 5

SITE Vogtle ALWR SSAR TOTAL DEPTH 140' SURF.ELEV. 230.854

Depth FT.	Elev. FT.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To FT.	Blows	N BPF	Comments
89	141.85						
90	140.85						
91	139.85						
92	138.85						
93	137.85						
94	136.85						
95	135.85						
96	134.85						
97	133.85						
98	132.85						
99	131.85						5/29/05 ▼ 99' from ground surface
100	130.85						
101	129.85						
102	128.85						Difficult drilling at 100'
103	127.85						
104	126.85						
105	125.85						
106	124.85						
107	123.85						5/24/05 ▼ 108.7' from TOC
108	122.85						
109	121.85						Difficult drilling at 110'
110	120.85						
111	119.85						
112	118.85						
113	117.85	Sampling begins at 113.5'					
114	116.85	Dark grey LIMESTONE bed, 0.2' thick with black macro fossils, thin laminae (~0.05')of CHALK on bottom	1	113.50-115	50/3"	50/3"	
115	115.85						
116	114.85						
117	113.85						
118			2	118.5-120	50/2"	50/2"	
119		Buff sandy COQUINA					
120	110.85						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1001

Sheet 5 of 5

SITE: Vogtle ALWR SSAR | TOTAL DEPTH: 140' | SURF.ELEV.: 230.854

Depth FT.	Elev. FT.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
121	109.85	Buff sandy COQUINA					
122	108.85						
123	107.85						
124	106.85	No recovery, auger used to grind through interval		123.5-125	50/0"	50/0"	
125	105.85						
126	104.85						
127	103.85						
128	102.85						
129	101.85	Dark grey LIMESTONE 2" layer	3	128.5-130	50/2"	50/2"	
130	100.85						
131	99.85						
132	98.85						
133	97.85						
134	96.85		4	133.5-135	18-19-25	44	
135	95.85	Approximately 3" of dark greenish grey MARL in spoon					
136	94.85						
137	93.85						
138	92.85	Greenish gray MARL		136.5-138	50/2"	50/2"	
139	91.85						
140	90.85			138.5-140	50/2"	50/2"	
141	89.85	Boring Terminated at 140'					
142	88.85						1500 gallons of water lost cleaning bottom of hole. Pumped at 60 gpm.
143	87.85						
144	86.85						
145	85.85						
146	84.85						
147	83.85						
148	82.85						
149	81.85						
150	82.86						
151	79.85						
152	78.85						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002
Sheet 1 of 8

SITE	Vogtle ALWR SSAR	HOLE DEPTH	237	SURF.ELEV.	227.442
LOCATION	Burke County, Georgia	COORDINATES N	1142887.782	E	620189.341
ANGLE	NA	BEARING	NA	CONTRACTOR	Prosonic
DRILL NO.	SR-083				
DRILLING METHOD	Sonic	NC. SAMPLES	continuous	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	93.5'	ELEV.	133.312'	TIME AFTER COMP.	NA
DATE TAKEN	6/6/2005				
TYPE GROUT	NA	QUANTITY	NA	MIX	NA
DRILLING START DATE	6/2/2005				
DRILLER	Tony	RECORDER	Steve Bearce	APPROVED	NA
DRILLING COMP. DATE	6/6/2005				

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
0	227.44						
1		Sampling not started until 87' below ground surface. Because drill technology changed, the hole had to be offset approximately 20' North of original borehole.					
2	226.44						
3	225.44	Well OW-1002 is installed in this borehole.					
4	224.44						
5	223.44						
6	222.44						
7	221.44						
8	220.44						
9	219.44						
10	218.44						
11	217.44						
12	216.44						
13	215.44						
14	214.44						
15	213.44						
16	212.44						
17	211.44						
18	210.44						
19	209.44						
20	208.44						
21	207.44						
22	206.44						
23	205.44						
24	204.44						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002

SITE Vogtle ALWR SSAR TOTAL DEPTH 237 SURF.ELEV. 227.442

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
		See page 1							
25	202.44								
26	201.44								
27	200.44								
28	199.44								
29	198.44								
30	197.44								
31	196.44								
32	195.44								
33	194.44								
34	193.44								
35	192.44								
36	191.44								
37	190.44								
38	189.44								
39	188.44								
40	187.44								
41	186.44								
42	185.44								
43	184.44								
44	183.44								
45	182.44								
46	181.44								
47	180.44								
48	179.44								
49	178.44								
50	177.44								
51	176.44								
52	175.44								
53	174.44								
54									
55	172.44								
56	171.44								

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002

SITE Vogtle ALWR SSAR TOTAL DEPTH 237 SURF.ELEV. 227.442

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
57	170.44	See page 1							
58	169.44								
59	168.44								
60	167.44								
61	166.44								
62	165.44								
63	164.44								
64	163.44								
65	162.44								
66	161.44								
67	160.44								
68	159.44								
69	158.44								
70	157.44								
71	156.44								
72	155.44								
73	154.44								
74	153.44								
75	152.44								
76	151.44								
77	150.44								
78	149.44								
79	148.44								
80	147.44								
81	146.44								
82	145.44								
83	144.44								
84	143.44								
85	142.44								
86	140.81								
87	140.44								
88	139.44	Sampling started with ProSonic drill rig							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002
Sheet 4 of 8

SITE Vogtle ALWR SSAR TOTAL DEPTH 237 SURF.ELEV. 227.442

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
89	138.44				NA	NA	
90	137.44	Yellow tan, shelly, sandy CLAY (CH), interbedded w/ occasional fine-grained shelly SAND, (SW)	1	88.5 - 90			
91	136.44						
92	135.44						
93	134.44						
94	133.44		2	93.5 - 95			
95	132.44						
96	131.44						
97	130.44						
98	129.44	Sharp contact into greenish grey MARL					
99	128.44		3	98.5 - 100	NA	NA	
100	127.44						
101	126.44						
102	125.44						
103	124.44						
104	123.44		4	103.5 - 105	NA	NA	
105	122.44						
106	121.44						
107	120.44						
108	119.44						
109	118.44		5	108. - 110	NS	NS	
110	117.44						
111	116.44						
112	115.44						
113	113.81						
114	113.44		6	113.5 - 115	NA	NA	
115	112.44						
116	111.44						
117	110.44						
118	108.81						
119	108.44		7	118.5 - 120	NA	NA	
120	107.44						

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Form GS9901 7-26-2004

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002
Sheet 5 of 8

SITE: Vogtle ALWR SSAR | TOTAL DEPTH: 237 | SURF.ELEV.: 227.442

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
121	106.44	Greenish grey MARL							
122	105.44								
123	104.44								
124	103.44		8	123.5 - 125	NA	NA			
125	102.44								
126	101.44								
127	100.44								
128	99.44								
129	98.44		9	128.5 - 130	NA	NA			
130	97.44								
131	96.44								
132	95.44								
133	94.44								
134	93.44	Thin bedded, light grey, "soft" or "friable" LIMESTONE occurs in this interval	10	133.5 - 135	NA	NA			
135	92.44								
136	91.44								
137	90.44								
138	89.44	Greenish grey MARL, becoming lighter in color							
139	88.44								
140	87.44		11	138.5 - 140	NA	NA			
141	86.44								
142	85.44								
143	84.44								
144	83.44		12	143.5 - 145	NA	NA			
145									
146	81.44								
147	80.44								
148	79.44								
149	78.44		13	148.5 - 150	NA	NA			
150		2 thin LIMESTONE beds between 147' and 157'							
151	76.44								
152	75.44								

Form GS9901 7-26-2004

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002
Sheet 6 of 8

SITE: Vogtle ALWR SSAR
TOTAL DEPTH:
SURF.ELEV. 227.442

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From-To	Blows	N	Comments
153	73.44						
154	72.44		14	153.5 - 155	NA	NA	
155	71.44						
156	70.44						
157	69.44						
158	68.44	Greenish grey MARL					
159	67.44		15	158.5 - 160	NA	NA	
160	66.44						
161	65.44						
162	64.44						
163	63.44						
164	62.44		16	163.5 - 165	NA	NA	
165	61.44						
166	60.44						
167	59.44						
168	58.44						
169	57.44		17	168.5 - 170	NA	NA	
170	56.44						
171	55.44						
172	54.44						
173	53.44	Light olive grey sandy CLAY grading to -->					
174	52.44		18	173.5 - 175	NA	NA	
175	51.44						
176	50.44	Light olive grey fine- to coarse-grained SAND composed of shell fragments and CLAY					
177	49.44						
178	48.44	Greenish grey MARL					
179	47.44		19	178.5 - 180	NA	NA	
180	46.44						
181	45.44						
182	43.81						
183	43.44						
184	41.81		20	183.5 - 185	NA	NA	

Form GS9901 7-26-2004

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002
Sheet 7 of 8

SITE: Vogtle ALWR SSAR
TOTAL DEPTH: 237
SURF.ELEV.: 227.442

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Standard Penetration Test Blows	Standard Penetration Test N	Comments
185	42.44						
186	41.44						
187	40.44						
188	39.44	Greenish grey MARL					
189	38.44		21	188.5 - 190	NA	NA	
190	37.44						
191	36.44						
192	35.44						
193	34.44						
194	33.44		22	193.5 - 195	NA	NA	
195	32.44						
196	31.44						
197	30.44						
198	29.44						
199	28.44		23	198.5 - 200	NA	NA	
200	27.44						
201	26.44						
202	25.44						
203	24.44						
204	23.44		24	203.5 - 205	NA	NA	
205	22.44						
206	21.44						
207	20.44						
208	19.44						
209	18.44		25	208/5 - 210	NA	NA	
210	17.44						
211	16.44						
212	15.44						
213	14.44						
214		~ 1/2' gradation to dark grey fine- to medium-grained SAND (SP) with minor amounts of silt and organics and 3/4' thick lignite layer	26	213.5 - 215	NA	NA	
215	12.44						
216	11.44						

Form GS9901 7-26-2004

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002
Sheet 8 of 8

SITE: Vogtle ALWR SSAR
TOTAL DEPTH: 237
SURF.ELEV.: 227.442

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
217	10.44						
218	9.44	6" grey CLAY layer					
219	8.44		27	218.5 - 220	NA	NA	
220	7.44						
221	6.44	Light greenish grey fine- to medium-grained, silty glauconitic SAND (SM)					
223	4.44						
224	3.44		28	223.5 - 225	NA	NA	
225	2.44						
226	1.44						
227	0.44						
228	-0.56				NA	NA	
229	-1.56		29	228.5 - 230			
230	-2.56						
231	-3.56						
232	-4.56						
233	-5.56						
234	-6.56		30	233.5 - 235	NA	NA	
235	-7.56						
236	-8.56						
237	-9.56						
238	-10.56	Boring terminated at 237'. Well OW-1002 installed in this borehole.					
239	-11.56						
240	-12.56						
241	-13.56						
242	-14.56						
243	-15.56						
244	-16.56						
245	-17.56						
246	-18.56						
247	-20.19						
248	-20.56						
249	-21.56						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002A
Sheet 1 of 4

SITE: Vogtle ALWR SSAR | HOLE DEPTH: 108.5 | SURF.ELEV.: NA
LOCATION: Burke County, Georgia | COORDINATES N: NA | E: NA
ANGLE: NA | BEARING: NA | CONTRACTOR: Greene | DRILL NO.: CME 75
DRILLING METHOD: HSA 3 1/4" | NO. SAMPLES: 22 | NO. U.D. SAMPLES: NA
WATER TABLE DEPTH: 90' | ELEV.: NA | DATE TAKEN: 5/25/2005
TYPE GROUT: NA | QUANTITY: NA | MIX: NA | DRILLING START DATE: 5/24/2005
DRILLER: Greene/Arthur | RECORDER: Steve Bearce | APPROVED: NA | DRILLING COMP. DATE: 5/25/2005

Depth FT.	Elev. FT.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0							
1							
2							
3							
4		Red brown silty SAND (SM) to SAND (SW), fine- to coarse-grained	1A	3.5-5	11-13-15	28	
5							
6							
7							
8							
9		Yellow brown SAND (SW), fine- to medium-grained	2A	8.5-10	6-8-10	18	
10							
11							
12							
13							
14		Light brown clayey SAND (SC), fine- to medium-grained	3A	13.5-15	3-4-5	9	
15							
16							
17							
18							
19			4A	18.5-20	4-4-3	7	
20							
21							
22							
23							
24							

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002A
Sheet 2 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 108.5 SURF.ELEV.

Depth FT.	Elev. FT.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To FT.	Blows	N BPF	Comments
25		Light tan sandy Clay (CL)	5A	23.5-25	4-4-5	9	
26							
27							
28							
29							
30			6A	28.5 - 30	3-3-3	6	
31							
32							
33							
34		Buff COQUINA in layers ~=1/2 recovery of coquina	7A	33.5 - 35	50/3"	50/3"	
35							
36							
37							
38							
39		Buff colored, white shelly (<10%) clayey SAND (SC)	8A	38.5 - 40	10-9-8	17	
40							
41							
42							
43							
44		Same as above but no shells	9A	43.5 - 45	3-4-5	9	
45							
46							
47							
48							
49		Buff colored fine sandy CLAY (CL)	10A	48.5 - 50	7-2-9	11	
50							
51							
52							
53							
54		Grading to clayey fine SAND (SC)	11A	53.5 - 55	4-2-10	12	
55							
56							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002A
Sheet 3 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 108.5' SURF.ELEV.

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
57							
58							
59		Buff colored, sandy shelly (15%) CLAY (CL)	12A	58.5-60	28-26-13	39	high N due to shells
60							
61							
62							
63							
64		Buff colored fine-grained clayey SAND (SC) moist	13A	63.5-65	11-13-19	32	
65							
66							
67							
68		Tan, slightly pink fine-grained sandy CLAY (CL), with fine-grained SAND, (SC) slightly moist					
69			14A	68.5-70	8-12-50	62	
70							
71							
72							
73							
74		Buff colored slightly green shelly, clayey, SAND (SC)	15A	73.5-75	8-12-27	39	
75							
76							
77							
78							
79		Light brown, silty, fine-grained SAND (SM), moist	16A	78.5-80	5-20-25	45	
80							
81							
82							
83							
84			17A	83.5-85	11-21-25	46	
85							
86							
87							
88							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1002A
Sheet 4 of 4

SITE Vogtle ALWR SSAR — TOTAL DEPTH 108.5 — SURF.ELEV.

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
89		Tan fine-grained SAND, (SP), wet	18A	88.5-90	12-25-31	56	
90							5/24/05 ▼ 90' from ground surface
91							
92							
93							
94		Buff silty, SAND, (SM), wet	19A	93.5-95	50/4"	50/4"	
95							
96							
97							
98							
99		Saturated with shell fragments (thin, 4mm, to thick, ~1cm)	20A	98.5-100	12-50/3"	12-50/3"	
100							
101							
102							
103							
104							
105		Greenish grey, MARL, damp	21A	103.5-105	3-1-50	51	
106							
107							
108							
109		Boring Terminated @ 108.5'.	22A	108.5-110	11-50	61	
110		This borehole was abandoned due to use of 3 1/4" augers.					
111		Moved over approximately 20					
112		feet north and drilled OW-1002 with ProSonic rig. Well was installed in borehole OW-1002.					
113							
114							
115							
116							
117							
118							
119							
120							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1003
Sheet 1 of 4

SITE	Vogtle ALWR SSAR			HOLE DEPTH	90	SURF.ELEV.	NA
LOCATION	Burke County, Georgia			COORDINATES N	NA	E	NA
ANGLE	NA	BEARING	NA	CONTRACTOR	S&ME	DRILL NO.	CME 550
DRILLING METHOD	31/4" HSA			NO. SAMPLES	18	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	63.6'	ELEV.	NA	TIME AFTER COMP.	NA	DATE TAKEN	5/25/2005
TYPE GROUT	NA	QUANTITY	NA	MIX	NA	DRILLING START DATE	5/24/2005
DRILLER	TIM	RECORDER	Steve Bearce	APPROVED	NA	DRILLING COMP. DATE	5/24/2005

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0							
1		Red-brown silty-clayey SAND (SM-SC) fine- to medium-grained, moist	1	3.5-5	7-13-17	30	
2							
3							
4							
5							
6							
7							
8							
9		Light brown, silty SAND, (SM) to SAND (SW) fine- to medium-grained	2	8.5-10	9-6-6	12	
10							
11							
12							
13							
14		Red-brown silty-clayey SAND (SM-SC), fine-grained	3	13.5-15	8-11-13	24	
15							
16							
17							
18							
19		Red brown sandy SILT (ML) and Red-brown silty-clayey SAND, (SM-SC) fine-grained	4	18.5-20	9-14-15	29	
20							
21							
22							
23							
24		Yellow-brown SAND, (SW)					

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1003
Sheet 2 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 90 SURF.ELEV. NA

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
25		Fine- to medium-grained SAND, (SW) damp	5	23.5-25	8-11-17	28	
26							
27							
28							
29		Red-Brown silty SAND (SM) with laminations of clayey SAND (SM), clay and silt					
30			6	28.5-30	6-5-7	12	
31							
32							
33							
34							
35		Yellow-brown with mottled grey clayey SAND (SC) and fine-grained SAND, damp	7	33.5-35	7-5-5	10	
36							
37							
38							
39		Same as above with some sandy CLAY laminations, damp			4-4-4	8	
40			8	38.5-40			
41							
42							
43							
44		Yellow brown sandy CLAY (CL) fine-grained SAND, damp					
45			9	43.5-45	3-3-4	7	
46							
47							
48							
49		Layered yellow brown clayey SAND, (SC) and yellow brown sandy CLAY, moist					
50			10	48.5-50	3-3-4	7	
51							
52							
53							
54		very moist			2-2-5	7	
55			11	53.5-55			
56							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1003
Sheet 3 of 4

SITE: Vogtle ALWR SSAR
TOTAL DEPTH: 90
SURF.ELEV.: NA

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To FT.	Blows	N BPF	Comments
57							
58							
59		Light pinkish tan SAND (SW), fine- to medium-grained					
60			12	58.5-60	2-7-9	16	
61							
62							
63							
64		Light tan clayey SAND (SC)					5/25/05
65			13	63.5-65	WOR	WOR	▼ 63.6' from ground surface
66							
67							
68							
69		Buff colored clayey SAND, (SC) fine to medium grained SAND					Saturated
70			14	68.5-70	WOR 18"	WOR 18"	
71							
72							
73							
74		Same as above					
75			15	73.5-75	WOR 12"	WOR 12"	
76							
77							
78							
79		Reddish brown silty SAND (SM)					
80			16	78.5-80	1-1-2	3	
81							
82							
83							
84		Light tan silty SAND (SM)					
85		Tan and grey clayey COQUINA	17	83.5-85	1-1-2	3	
86							
87							
88							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1003
Sheet 4 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 90 SURF.ELEV. NA

Depth Ft.	Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
89			18	88.5-90	13-21-23	44	
90		Greenish grey MARL					
91		BORING Terminated at 90.0'					
92		This borehole was abandoned due to the use of 3 1/4" augers.					
93							
94		Shallow well OW-1003 was installed approximately 10' south of this borehole. No boring log was prepared for the hole due to the proximity of this borehole.					
95							
96							
97							
98							
99							
100							
101							
102							
103							
104							
105							
106							
107							
108							
109							
110							
111							
112							
113							
114							
115							
116							
117							
118							
119							
120							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1004
Sheet 1 of 7

SIT: Vogtle ALWR SSAR | HOLE DEPTH: 187 | SURF.ELEV.: 222.92
LOCATION: Burke County, Georgia | COORDINATES N: 1142842.176 | E: 621880.794
AN: NA | BEARING: NA | CONTRACTOR: Prosonic | DRILL NO.: SR-083
DRILLING METHOD: Sonic | NO. SAMPLES: 20 | NO. U.D. SAMPLES: NA
WATER TABLE DEP: | ELEV.: NA | TIME AFTER COMP.: NA | DATE TAKEN:
TYPE GROUT: NA | QUANTITY: NA | MIX: | DRILLING START DATE: 6/3/2005
DRILLER: Tony, Mike | RECORDER: S. Bearce | APPROVED: NA | DRILLING COMP. DATE: 6/11/2005

epth	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0	222.92						
1	221.92	This borehole was not sampled until 87'.					
2	220.92	OW-1004 is a well pair with OW-1003. The well is approximately ---feet --- of OW-1003.					
3	219.92						
4	218.92	See boring log OW-1003 for description of upper sediments.					
5	217.92						
6	216.92						
7	215.92						
8	214.92						
9	213.92						
10	212.92						
11	211.92						
12	210.92						
13	209.92						
14	208.92						
15	207.92						
16	206.92						
17	205.92						
18	204.92						
19	203.92						
20	202.92						
21	201.92						
22	200.92						
23	199.92						
24	198.92						

Form GS9901 7-26-2(

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1004

SITE Vogtle ALWR SSAR TOTAL DEPTH 187 SURF.ELEV. 222.92

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
25	196.92	See page 1							
26	195.92								
27	194.92								
28	193.92								
29	192.92								
30	191.92								
31	190.92								
32	189.92								
33	188.92								
34	187.92								
35	186.92								
36	185.92								
37	184.92								
38	183.92								
39	182.92								
40	181.92								
41	180.92								
42	179.92								
43	178.92								
44	177.92								
45	176.92								
46	175.92								
47	174.92								
48	173.92								
49	172.92								
50	171.92								
51	170.92								
52	169.92								
53	168.92								
54	163.39								
55	166.92								
56	161.39								

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1004

Sheet 3 of 7

SITE Vogtle ALWR SSAR TOTAL DEPTH 187 SURF.ELEV. 222.92

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
57	165.92	See page 1							
58	164.92								
59	163.92								
60	162.92								
61	161.92								
62	160.92								
63	159.92								
64	158.92								
65	157.92								
66	156.92								
67	155.92								
68	154.92								
69	153.92								
70	152.92								
71	151.92								
72	150.92								
73	149.92								
74	148.92								
75	147.92								
76	146.92								
77	145.92								
78	144.92								
79	143.92								
80	142.92								
81	141.92								
82	140.92								
83	139.92								
84	138.92								
85	137.92								
86	132.39								
87	135.92	Start sampling at 87'							
88	134.92	Olive-tan, wet CLAY (CL)							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1004
Sheet 4 of 7

SITE Vogtle ALWR SSAR TOTAL DEPTH 187 SURF.ELEV. 222.92

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
89	133.92		1	88.5 - 90.0	NA	NA	
90	132.92	Greenish grey MARL					
91	131.92						
92	130.92						
93	129.92						
94	128.92		2	93.5 - 95	NA	NA	
95	127.92						
96	126.92						
97	125.92						
98	124.92						
99	123.92		3	98.5 - 100	NA	NA	
100	122.92						
101	121.92						
102	120.92						
103	119.92	Greenish grey shelly MARL with white fossils					
104	118.92		4	103.5 - 105	NA	NA	
105	117.92						
106	116.92						
107	115.92						
108	114.92						
109	113.92		5	108.5 - 110	NA	NA	
110	112.92						
111	111.92						
112	110.92						
113	109.92						
114	108.92						
115	107.92		6	113.5 - 115	NA	NA	
116	106.92						
117	105.92						
118	100.39						
119	103.92			118.5 -	NA	NA	
120	102.92		7	120.			

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1004
Sheet 5 of 7

SITE: Vogtle ALWR SSAR | TOTAL DEPTH: 187 | SURF.ELEV.: 222.92

Depth Ft.	Elev. FT.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To FT.	Blows	N BPF	Comments
121	101.92						
122	100.92	Shelly greenish grey MARL					
123	99.92						
124	98.92		8	123.5 - 125	NA	NA	
125	97.92						
126	96.92						
127	95.92						
128	94.92						
129	93.92	abundant (30%) gravel					
130	92.92		9	130 - 131.5	NA	NA	
131	91.92						
132	90.92						
133	89.92						
134	88.92						
135	87.92		10	133.5 - 135	NA	NA	
136	86.92						
137	85.92						
138	84.92						
139	83.92		11	138.5 - 140	NA	NA	
140	82.92						
141	81.92						
142	80.92						
143	79.92						
144	78.92		12	143.5 - 145	NA	NA	
145	77.92						
146	76.92						
147	75.92	6" gradational contact with abundant shells (white)					
148	74.92						
149	73.92	Dark grey, fine- to coarse-grained SAND, (SW) with green sand grains (glauconite or dolomite?)	13	148.5 - 150	NA	NA	
150	68.39						
151	71.92						
152	70.92						

Form GS9901 7-26-2004

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1004
Sheet 6 of 7

SITE: Vogtle ALWR SSAR — TOTAL DEPTH: 187 — SURF.ELEV.: 222.92

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
153	69.92	grades to fine- to medium-grained dark grey SAND w/ organics, cohesive leaving core barrel, wet, poorly graded with silt (SP-SM)	14	153.5 - 155	NA	NA	
154	68.92						
155	67.92						
156	66.92						
157	65.92						
158	64.92		15	158.5 - 169	NA	NA	
159	63.92						
160	62.92						
161	61.92						
162	60.92						
163	59.92	Light grey, becomes loose coming out of core barrel fine-grained SAND (SP) with clay and silt	16	163.5 - 170	NA	NA	
164	58.92						
165	57.92						
166	56.92						
167	55.92						
168	54.92						
169	53.92		17	168.5 - 170	NA	NA	
170	52.92						
171	51.92						
172	50.92						
173	49.92						
174	48.92		18	173.5 - 175	NA	NA	
175	47.92	Dark grey organic, silty SAND (SM)					
176	46.92						
177	45.92						
178	44.92						
179	43.92		19	178.5 - 180	NA	NA	
180	42.92						
181	41.92						
182	36.39						
183	39.92						
184	34.39		20	183.5 - 185	NA	NA	

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1004
Sheet 7 of 7

SITE Vogtle ALWR SSAR
TOTAL DEPTH 187
SURF.ELEV. 222.92

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
185	37.92	Dark grey organic, silty SAND (SM)	20	188.5 - 190	NA	NA	
186	36.92						
187	35.92						
188	34.92	Boring teminated at 187'					
189	33.92	Well OW-1004 is installed in this borehole.					
190	32.92						
191	31.92						
192	30.92						
193	29.92						
194	28.92						
195	27.92						
196	26.92						
197	25.92						
198	24.92						
199	23.92						
200	22.92						
201	21.92						
202	20.92						
203	19.92						
204	18.92						
205	17.92						
206	16.92						
206	16.92						
208	14.92						
209	13.92						
210	12.92						
211	11.92						
212	10.92						
213	9.92						
214	4.39						
215	7.92						
216	6.92						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005
Sheet 1 of 6

SITE	Vogtle ALWR SSAR	HOLE DEPTH	170	SURF.ELEV.	264.389
LOCATION	Burke County, Georgia	COORDINATES N	1144047.86	E	620408.765
ANGLE	NA	BEARING	NA	CONTRACTOR	S&ME
DRILL NO.	CME B55	DRILLING METHOD	4/14" HSA	NO. SAMPLES	19
NO. U.D. SAMPLES	NA	WATER TABLE DEPTH		ELEV.	
TIME AFTER COMP.		DATE TAKEN		TYPE GROUT	NA
QUANTITY	NA	MIX	NA	DRILLING START DATE	6/2/2005
DRILLER	Ted	RECORDER	R Tinsley/SCB	APPROVED	NA
DRILLING COMP. DATE	6/7/2005				

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
0	264.39						
1	263.39	Sampling in this borehole began at 68.5'. The adjacent borehole OW-1005A was drilled to 75'. The borehole was abandoned due to the use of 3 1/4" augers, which were incorrect size for well installation. This borehole OW-1005 was located approximately 10' from feet from OW-1005A. Monitoring well OW-1005 is installed in this borehole.					
2	262.39						
3	261.39						
4	260.39						
5	259.39						
6	258.39						
7	257.39						
8	256.39						
9	255.39						
10	254.39						
11	253.39						
12	252.39						
13	251.39						
14	250.39						
15	249.39						
16	248.39						
17	247.39						
18	246.39						
19	245.39						
20	244.39						
21	243.39						
22	242.39						
23	241.39						
24	240.39						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005
Sheet 2 of 6

SITE Vogtle ALWR SSAR TOTAL DEPTH 170 SURF.ELEV. 264.389

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
25	239.39	See page 1					
26	238.39						
27	237.39						
28	236.39						
29	235.39						
30	234.39						
31	233.39						
32	232.39						
33	231.39						
34	230.39						
35	229.39						
36	228.39						
37	227.39						
38	226.39						
39	225.39						
40	224.39						
41	223.39						
42	222.39						
43	221.39						
44	220.39						
45	219.39						
46	218.39						
47	217.39						
48	216.39						
49	215.39						
50	214.39						
51	213.39						
52	212.39						
53	211.39						
54							
55	209.39						
56	208.39						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005
Sheet 3 of 6

SITE Vogtle ALWR SSAR — TOTAL DEPTH 170 — SURF.ELEV. 264.389

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
57	207.39	See page 1					
58	206.39						
59	205.39						
60	204.39						
61	203.39						
62	202.39						
63	201.39						
64	200.39						
65	199.39						
66	198.39						
67	197.39						
68	196.39	Sampling begins at 68.5'					
69	195.39		1B	68.5-70	2-36-50/1	36	
70	194.39	Light grey to white sandy SILT (ML), calcareous with large and small shell fragments, very stiff				50/1"	
71	193.39						
72	192.39						
73	191.39						
74	190.39		2B	73.5-75	9-14-36	50	
75	74.90	fewer shells, less sand					
76	188.39	Greenish grey MARL					
77	76.20 187.39	Light grey SILT, very stiff, calcareous with scattered shell fragments (ML)					
78	186.39		3B	78.5-80	15-19-24	43	
79	185.39						
80	184.39						
81	183.39						
82	182.39						
83	181.39		4B	83.5-85	50/2"	50/2"	
84	180.39						
85	179.39						
86							
87	177.39						
88	176.39						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005
Sheet 4 of 6

SITE Vogtle ALWR SSAR TOTAL DEPTH 170 SURF.ELEV. 264.389

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
89	175.39		5B	88.5-90	7-17-30	47	
90	174.39	Light brownish grey SAND, fine to medium-grained, slightly silty (SW), calcareous					
91	173.39						
92	172.39	Mottled white to yellowish orange, silty SAND, with small to large shell fragments, Dense (SM)					
93	171.39						
94	170.39		6B	93.5-95	7-9-14	23	
95	169.39						
96	168.39	Light grey SILT, very stiff (ML)					
97	167.39	Pale yellow sandy SILT (ML) and silty SAND SM)					
98	166.39						
99	165.39		7B	98.5-100	7-17-34	51	
100	164.39						
101	163.39						
102	162.39						
103	161.39						
104	160.39	Greenish grey MARL	8B	103.5-105	18-34-29	63	
105	159.39	Pale yellow sandy SILT (ML) and silty SAND (SM)					
106	158.39						
107	157.39						
108	156.39						
109	155.39	White SHELL HASH with fine-coarse-grained SAND and large shell fragments	9B	108.5-110	8-18-39	57	
110	154.39						
111	153.39						
112	152.39						
113	151.39						
114	150.39		10B	113.5-115	12-30-30	60	
115	149.39						
116	148.39						
117	147.39						
118	145.76	Same as above with increase in fines					
119	145.39		11B	118.5-120	16-20-40	60	
120	144.39						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005
Sheet 5 of 6

SITE: Vogtle ALWR SSAR — TOTAL DEPTH: 170 — SURF.ELEV.: 264.389

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
121	143.39						
122	142.39						
123	141.39	White SHELL HASH with fine-coarse-grained SAND (SW) and large shell fragments	12B	123.5-125	8-8-9	17	
124	140.39						
125	139.39						
126	138.39						
127	137.39						
128	136.39						
129	135.39		13B	128.5-130	15-48-40	88	
130	134.39						
131	133.39						
132	132.39						
133	131.39						
134	130.39	Pale yellow SAND, fine to very fine- grained, clean (SP)	14B	133.5-135	7-9-21	30	
135	129.39						
136	128.39						
137	127.39						
138	126.39						
139	125.39						
140	124.39	scattered shell pieces, dense	15B	138.5-140	10-13-30	43	
141	123.39						
142	122.39						
143	121.39						
144	120.39	increasing fines	16B	143.5-145	8-12-30	42	
145	119.39						
146	118.39						
147	117.39						
148	116.39						
149	115.39	Pale yellow, silty SAND, calcareous (SM), fine-coarse-grained with shell pieces	17B	148.5-150	49/50/3"	49/ 50/3"	
150							
151	113.39						
152	112.39						

Form GS9901 7-26-2004

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005
Sheet 6 of 6

SITE: Vogtle ALWR SSAR
TOTAL DEPTH: 170
SURF.ELEV.: 264.389

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
153	111.39						
154	110.39	Pale yellow, silty SAND, calcareous (SM), fine- to coarse-grained with shell pieces	18B	153.5-155	12-33-50/2	33/ 50/2"	
155	109.39						
156	108.39						
157	107.39						
158	106.39						
159	105.39						
160	104.39	Same as above, slightly more consolidated	19B	158.5-160	25-22-44	66	Boring paused to procure more auger 6/04/05
161	103.39						
162	102.39						
163	101.39						
164	100.39			163.5-165	25-50/2"	25/ 50/2"	
165	99.39	Dark greenish grey MARL					
166	98.39						
167	97.39						
168	96.39						
169	95.39	Boring Terminated at 168.5		168.5 - 170	NA	NA	
170	94.39						
171	93.39						
172	92.39						
173	91.39						
174	90.39						
175	89.39						
176	88.39						
177	87.39						
178	86.39						
179	85.39						
180	84.39						
181	83.39						
182	81.76						
183	81.39						
184	80.39						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005A
Sheet 1 of 3

SITE	Vogtle ALWR SSAR			HOLE DEPTH	75	SURF.ELEV.	263
LOCATION	Burke County, Georgia			COORDINATES N	NA	E	NA
ANGLE	NA	BEARING	NA	CONTRACTOR	Kilman	DRILL NO.	CME 45
DRILLING METHOD	3 1/4" HAS			NO. SAMPLES	15	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	NA	ELEV.	NA	TIME AFTER COMP.	NA	DATE TAKEN	NA
TYPE GROUT	NA	QUANTITY	NA	MIX	NA	DRILLING START DATE	5/31/2005
DRILLER	Kilman	RECORDER	Tinsley	APPROVED	NA	DRILLING COMP. DATE	5/31/2005

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
0	263.00						
1							
2	262.00	Brown to reddish yellow SAND (SP), fine- to medium-grained, loose					
3	261.00						
4	260.00		1A	3.5-5	4-12-11	23	
5	259.00						
6	258.00						
7	257.00						
8	256.00	Mottled red and yellow silty SAND, fine- medium-grained (SW) to sandy silt (ML)					
9	255.00		2A	8.5-10	2-10-14	24	
10	254.00						
11	253.00						
12	252.00						
13	251.00						
14	250.00	Red SAND, fine-grained, loose (SP)	3A	13.5-15	3-7-7	14	
15	249.00						
16	248.00						
17	247.00						
18	246.00						
19	245.00	Dark red, SAND, fine-grained (SP), loose	4A	18.5-20	7-6-6	12	
20	244.00						
21	243.00						
22	242.00						
23	241.00						
24	240.00						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005A
Sheet 2 of 3

SITE Vogtle ALWR SSAR — TOTAL DEPTH 75 — SURF.ELEV. 263.759

Depth ft.	Elev. ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments	% Rec	RQD
25	238.76	Red and yellow SAND, fine-grained (SP), loose	5A	23.5-25	11-7-8	15			
26	237.76								
27	236.76								
28	235.76								
29	234.76	Yellow SAND, fine-grained (SP), loose	6A	28.5-30	6-7-8	15			
30	233.76								
31	232.76								
32	231.76								
33	230.76								
34	229.76		7A	33.5-35	7-10-11	21			
35	228.76								
36	227.76								
37	226.76								
38	225.76								
39	224.76	Red to light red, SAND, fine-grained, (SP), loose	8A	38.5-40	8-7-8	15			
40	223.76								
41	222.76								
42	221.76								
43	220.76								
44	219.76	Strong Brown, SAND, fine-coarse grained with some fines, (SW)	9A	43.5-45	13-8-8	16			
45	218.76								
46	217.76								
47	216.76								
48	215.76								
49	214.76	Brown to grey silty SAND, fine-coarse grained (SM)	10A	48.5-50	13-7-5	12			
50	213.76								
51	212.76								
52	211.76								
53	210.76								
54	209.76		11A	53.5-55	3-3-3	6			
55	208.76	Light grey CLAY (CL)							
56	207.76								

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1005A

Sheet 3 of 3

SITE Vogtle ALWR SSAR TOTAL DEPTH 75 SURF.ELEV.

Depth ft.	Elev. Ft	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
57	-57.00						
58	-58.00						
59	-59.00	Light grey silty SAND very fine to fine grained, (SW)	12A	58.5-60	4-7-9	16	
60	-60.00						
61	-61.00						
62	-62.00						
63	-63.00						
64	-64.00	Light grey CLAY, (CL) stiff, calcareous	13A	63.5-65	4-5-25	30	
65	-65.00						
66	-66.00						
67	-67.00						
68	-68.00		14A	68.5-70	8-12-23	35	
69	-69.00						
70	-70.00						
71	-71.00						
72	-72.00						
73	-73.00						
74	-74.00		15A	73.5-75	9-11-21	32	
75							
76	-76.00	Boring terminated at 75' .					
77	-77.00	This borehole was abandoned due to the use of 3 1/4" augers, which are incorrect size for well installation.					
78	-78.00						
79	-79.00	Borehole OW-1005 was completed approximately 10 ' from this hole using 4 1/4" augers. Well OW-1005 is installed in that hole.					
80	-80.00						
81	-81.00						
82	-82.00						
83	-83.00						
84	-84.00						
85	-85.00						
86	-86.00						
87	-87.00						
88	-88.00						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006
Sheet 1 of 5

SITE: Vogtle ALWR SSAR | HOLE DEPTH: 135 | SURF.ELEV.: 227.121
LOCATION: Burke County, Georgia | COORDINATES N: 1143817.854 | E: 619179.749
ANGLE: NA | BEARING: NA | CONTRACTOR: Greene | DRILL NO.: CME 75
DRILLING METHOD: HSA | NO. SAMPLES: 4 | NO. U.D. SAMPLES: NA
WATER TABLE DEPTH: | ELEV.: | TIME AFTER COMP.: | DATE TAKEN:
TYPE GROUT: NA | QUANTITY: NA | MIX: NA | DRILLING START DATE: 6/9/2005
DRILLER: Arthur, Jarred | RECORDER: SC Bearce | APPROVED: NA | DRILLING COMP. DATE: 6/14/2005

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
0	227.12						
1	226.12	No sampling prior to 118.5. See log for 1006A for soil descriptions through 120-130' depth. OW-1006A was abandoned. Drilling was terminated due to shortage of auger.					
2	225.12						
3	224.12						
4	223.12						
5	222.12						
6	221.12						
7	220.12						
8	219.12						
9	218.12						
10	217.12						
11	216.12						
12	215.12						
13	214.12						
14	213.12						
15	212.12						
16	211.12						
17	210.12						
18	209.12						
19	208.12						
20	207.12						
21	206.12						
22	205.12						
23	204.12						
24	203.12						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006

SITE Vogtle ALWR SSAR

TOTAL DEPTH 135

SURF.ELEV. 227.121

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
25	202.12	See page 1					
26	201.12						
27	200.12						
28	199.12						
29	198.12						
30	197.12						
31	196.12						
32	195.12						
33	194.12						
34	193.12						
35	192.12						
36	191.12						
37	190.12						
38	189.12						
39	188.12						
40	187.12						
41	186.12						
42	185.12						
43	184.12						
44	183.12						
45	182.12						
46	181.12						
47	180.12						
48	179.12						
49	178.12						
50	177.12						
51	176.12						
52	175.12						
53	174.12						
54	172.49						
55	172.12						
56	171.12						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006

Sheet 3 of 5

SITE Vogtle ALWR SSAR

TOTAL DEPTH 135

SURF.ELEV. 227.121

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
57	170.12	See page 1					
58	169.12						
59	168.12						
60	167.12						
61	166.12						
62	165.12						
63	164.12						
64	163.12						
65	162.12						
66	161.12						
67	160.12						
68	159.12						
69	158.12						
70	157.12						
71	156.12						
72	155.12						
73	154.12						
74	153.12						
75	152.12						
76	151.12						
77	150.12						
78	149.12						
79	148.12						
80	147.12						
81	146.12						
82	145.12						
83	144.12						
84	143.12						
85	142.12						
86	140.49						
87	140.12						
88	139.12						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006
Sheet 4 of 5

SITE Vogtle ALWR SSAR — TOTAL DEPTH 135 — SURF.ELEV. 227.121

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
89							
90							
91							
92							
93							
94							
95							
96							
97							
98							
99							
100							
101							
102							
103							
104							
105							
106							
107							
108							
109							
110							
111							
112							
113							
114							
115							
116							
117							
118		Sampling begins at 118.5'	1	118.5-120	No SPTs		Pushed because of problems
119							
120		Tan sandy and shelly CLAY (CH), saturated					

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006
Sheet 5 of 5

SITE **Vogtle ALWR SSAR** TOTAL DEPTH **135** SURF.ELEV. 227.121

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N	Comments
121	106.12						
122	105.12						
123	104.12						
124	103.12	Tan sandy and shelly CLAY (CH), saturated	2	123.5-125	NA	NA	No SPTs
125	102.12						Pushed because of drilling problems
126	101.12						
127	100.12						
128	99.12						
129	98.12	Light tan, fine-coarse grained SAND with shell (SW)	3	128.5-130	NA	NA	
130	97.12						
131	96.12						
132	95.12						
133	94.12						
134	93.12	Greenish grey MARL	4	133.5-135	NA	NA	
135	92.12						last sample at 135.0'
136	91.12	Boring terminated at 133.5					
137	90.12						~six 150 gallon tubs of water used during drilling
138	89.12						
139	88.12						
140	87.12						
141	86.12						
142	85.12						
143	84.12						
144	83.12						
145	82.12						
146	81.12						
147	80.12						
148	79.12						
149	78.12						
150	76.49						
151	76.12						
152	75.12						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006A
Sheet 1 of 5

SITE	Vogtle ALWR SSAR	HOLE DEPTH	125	SURF.ELEV.	226.491
LOCATION	Burke County, Georgia	COORDINATES N	1143910.384	E	775393.399
ANGLE	NA	BEARING	NA	CONTRACTOR	S&ME
DRILL NO.	CME 55	DRILLING METHOD	4-1/4" HAS	NO. SAMPLES	25
NO. U.D. SAMPLES	NA	WATER TABLE DEPTH	79'	ELEV.	
TIME AFTER COMP.		DATE TAKEN	6/3/2005	TYPE GROUT	NA
QUANTITY	NA	MIX	NA	DRILLING START DATE	6/3/2005
DRILLER	Tim Hall	RECORDER	Tinsley	APPROVED	NA
DRILLING COMP. DATE	6/4/2005				

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
0	225.49						
1	224.49						
2	223.49						
3	222.49						
4	221.49	Yellowish brown SAND, fine-grained, loose (SP)	1	3.5-5	5-5-7	12	
5	220.49						
6	219.49						
7	218.49						
8	217.49						
9	216.49	Strong brown SAND, fine-grained, loose (SP)	2	8.5-10	3-3-3	6	
10	215.49						
11	214.49						
12	213.49						
13	212.49						
14	211.49	Reddish yellow SAND, fine-grained, loose (SP)	3	13.5-15	3-5-7	12	
15	210.49						
16	209.49						
17	208.49						
18	207.49						
19	206.49	Red and yellow SAND, fine-grained, loose (SP)	4	18.5-20	3-4-5	9	
20	205.49						
21	204.49						
22	203.49						
23	202.49						
24	201.49						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006A
Sheet 2 of 5

SITE Vogtle ALWR SSAR TOTAL DEPTH 125 SURF.ELEV. 226.491

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
25	201.49	Red and yellow SAND, fine-grained, loose (SP)	5	23.5-25	4-4-4	8	
26	200.49						
27	199.49						
28	198.49		6	28.5-30	3-4-6	10	
29	197.49						
30	196.49						
31	195.49						
32	194.49						
33	193.49						
34	192.49		7	33.5-35	3-5-5	10	
35	191.49						
36	190.49						
37	189.49						
38	188.49						
39	187.49	Yellowish red silty SAND, fine-grained (SM)	8	38.5-40	WOR/18"	WOR/ 18"	
40	186.49						
41	185.49						
42	184.49						
43	183.49						
44	182.49	White SAND, fine-grained, loose, with black minerals (SP)	9	43.5-45	WOR 1-1	2	
45	181.49						
46	180.49						
47	179.49						
48	178.49						
49	177.49						
50	176.49	light gray CLAY, slightly sandy, medium stiff (CL)	10	48.5-50	1-2-2	4	
51	175.49						
52	174.49						
53	173.49						
54	172.49	Reddish yellow clayey SAND (SC)	11	53.5-55	WOR/18	WOR/ 18"	
55	171.49						
56	170.49						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006A
Sheet 3 of 6

SITE Vogtle ALWR SSAR TOTAL DEPTH 125 SURF.ELEV. 226.491

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
57	169.49	Light gray and reddish yellow sandy CLAY (CL), soft					
58	168.49		12	58.5-60	1-1-1	2	
59	167.49						
60	166.49						
61	165.49						
62	164.49						
63	163.49						
64	162.49		13	63.5-65	WOH/18"	WHO/ 18"	
65	161.49	Yellow slightly sandy SILT (MH)					
66	160.49						
67	159.49						
68	158.49						
69	157.49	Mottled red to gray clayey SAND, fine- to medium-					
70	156.49	grained (SC)	14	68.5-70	WOH/12/5	17	
71	155.49						
72	154.49						
73	153.49						
74	152.49						
75	151.49		15	73.5-75	2-4-3	7	
76	150.49						
77	149.49						
78	148.49						
79	147.49						6/3/2005 ▼
80	146.49	Yellowish brown SAND, fine- to coarse-grained	16	78.5-80	3-2-2	4	79' from ground surface
81	145.49	slight fines (SW), loose					
82	144.49						
83	143.49						
84	142.49		17	83.5-85	12-16-17	33	
85	141.49	Pale yellow clayey SAND, to sandy CLAY with small to large shell fragments, stiff (SC-CL)					
86	140.49						
87	139.49						
88	138.49						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006A
Sheet 4 of 5

SITE Vogtle ALWR SSAR TOTAL DEPTH 125 SURF.ELEV. 226.491

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
89	137.49	Pale yellow sandy CLAY, stiff, calcareous (shell fragments) (CL)	18	88.5-90	7-7-9	16	
90	136.49						
91	135.49						
92	134.49						
93	133.49		19	93.5-95	8-8-9	17	
94	132.49	Pinkish white clayey SAND, fine - coarse-grained with shell fragments (SC)					
95	131.49						
96	130.49						
97	129.49						
98	128.49						
99	127.49	Light gray SAND, fine-grained (SP)	20	98.5-100	12-14-17	31	
100	126.49						
101	125.49						
102	124.49						
103	123.49						
104	122.49						
105	121.49		21	103.5-105	7-7-8	15	
106	120.49						
107	119.49						
108	118.49	Light gray SAND, fine-to medium grained, increase in fines (SW)					
109	117.49		22	108.5-110	10-10-10	20	
110	116.49						
111	115.49						
112	114.49						
113	113.49						
114	112.49	Very light tan silty SAND (SM)	23	113.5-115	10-11-14	25	
115	111.49						
116	110.49						
117	109.49						
118	108.49						
119	107.49	light gray COQUINA, unconsolidated	24	118.5-120	8-9-10	19	
120	106.49						

Form GS9901 7-26-2004

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1006A
Sheet 5 of 5

SITE: Vogtle ALWR SSAR
TOTAL DEPTH: 125
SURF.ELEV.: 226.491

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
121	105.49						
122	104.49						
123	103.49						
124	102.49						
125	101.49	light gray COQUINA, unconsolidated	25	23.5-12	9-16-16	32	
126	100.49	Boring terminated at 125' due to shortage of auger. This borehole was abandoned.					
127	99.49						
128	98.49						
129	97.49						
130	96.49						
131	95.49						
132	94.49						
133	93.49						
134	92.49						
135	91.49						
136	90.49						
137	89.49						
138	88.49						
139	87.49						
140	86.49						
141	85.49						
142	84.49						
143	83.49						
144	82.49						
145	81.49						
146	80.49						
147	79.49						
148	78.49						
149	77.49						
150	76.49						
151	75.49						
152	74.49						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1007
Sheet 1 of 5

SITE	Vogtle ALWR SSAR	HOLE DEPTH	122	SURF.ELEV.	216.91
LOCATION	Burke County, Georgia	COORDINATES N	1142383.767	E	619301.009
ANGLE	NA	BEARING	NA	CONTRACTOR	Greene
DRILL NO.	CME 75 1993				
DRILLING METHOD	4 1/4" HSA	NO. SAMPLES	6	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH		ELEV.		TIME AFTER COMP.	
DATE TAKEN					
TYPE GROUT	NA	QUANTITY	NA	MIX	NA
DRILLING START DATE	6/4/2005				
DRILLER	Arthur/Jarrell	RECORDER	SC Bearce	APPROVED	NA
DRILLING COMP. DATE	6/7/2005				

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
0	216.91						
1	215.91	Sampling in this borehole began at 98.5' (Sheet 4). OW-1007 is a well pair with OW-1008. See boring log for OW-1008 for description of upper sediments.					
2	214.91						
3	213.91						
4	212.91						
5	211.91						
6	210.91						
7	209.91						
8	208.91						
9	207.91						
10	206.91						
11	205.91						
12	204.91						
13	203.91						
14	202.91						
15	201.91						
16	200.91						
17	199.91						
18	198.91						
19	197.91						
20	196.91						
21	195.91						
22	194.91						
23	193.91						
24	192.91						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1007
Sheet 2 of 5

SITE Vogtle ALWR SSAR
TOTAL DEPTH 122
SURF.ELEV. 216.91

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
25	191.91	See page 1					
26	190.91						
27	189.91						
28	188.91						
29	187.91						
30	186.91						
31	185.91						
32	184.91						
33	183.91						
34	182.91						
35	181.91						
36	180.91						
37	179.91						
38	178.91						
39	177.91						
40	176.91						
41	175.91						
42	174.91						
43	173.91						
44	172.91						
45	171.91						
46	170.91						
47	169.91						
48	168.91						
49	167.91						
50	166.91						
51	165.91						
52	164.91						
53	163.91						
54	162.28						
55	161.91						
56	160.91						

216.28
216.28

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1007

Sheet 3 of 5

SITE Vogtle ALWR SSAR

TOTAL DEPTH 122

SURF.ELEV. 216.91

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
57	159.91	See page 1					
58	158.91						
59	157.91						
60	156.91						
61	155.91						
62	154.91						
63	153.91						
64	152.91						
65	151.91						
66	150.91						
67	149.91						
68	148.91						
69	147.91						
70	146.91						
71	145.91						
72	144.91						
73	143.91						
74	142.91						
75	141.91						
76	140.91						
77	139.91						
78	138.91						
79	137.91						
80	136.91						
81	135.91						
82	134.91						
83	133.91						
84	132.91						
85	131.91						
86	130.28						
87	129.91						
88	128.91						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1007

SITE Vogtle ALWR SSAR — TOTAL DEPTH 122 — SURF.ELEV. 216.91

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
89	127.91						
90	126.91						
91	125.91						
92	124.91						
93	123.91						
94	122.91						
95	121.91						
96	120.91						
97	119.91						
98	118.91	Drilling begins at 98.5'					
99	117.91		1	98.5-100	WOR		
100	116.91						
101	115.91						
102	114.91						
103	113.91						
104	112.91	Tan fine-grained silty SAND (SM), saturated					
105	111.91		2	103.5-105	2-4-6	10	
106	110.91						
107	109.91						
108	108.91						
109	107.91	Very light tan silty SAND (SM) becoming shelly	3	108.5-110	50/5"	50/5"	
110	106.91						
111	105.91						
112	104.91						
113	103.91						
114	102.91	light olive grey CLAY(CH)	4	113.5-115	80/3"	50/3"	
115	101.91						
116	100.91						
117	99.91						
118							
119	97.91	Greenish grey MARL	5	118.5-120	NA	NA	
120	96.91						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1007
Sheet 5 of 5

SITE Vogtle ALWR SSAR
TOTAL DEPTH 122
SURF.ELEV. 216.91

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N (BPF)	Comments
121	95.91	Greenish grey MARL	5	120-122	NA	NA	ss pushed with hydraulics because cat-head broke
122	94.91						
123	93.91	Boring terminated at 122'					
124	92.91						Estimated 3 auger volumes of light drilling fliud lost in this hole.
125	91.91						
126	90.91						
127	89.91						Approximately 100 gallons of water used in drilling and installation activities in addition to fluid.
128	88.91						
129	87.91						
130	86.91						
131	85.91						
132	84.91						
133	83.91						
134	82.91						
135	81.91						
136	80.91						
137	79.91						
138	78.91						
139	77.91						
140	76.91						
141	75.91						
142	74.91						
143	73.91						
144	72.91						
145	71.91						
146	70.91						
147	69.91						
148	68.91						
149	67.91						
150	66.28						
151	65.91						
152	64.91						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008
Sheet 1 of 8

SITE	Vogtle ALWR SSAR	IOLE DEPTH	247	SURF.ELEV.	216.65
LOCATION	Burke County, Georgia	COORDINATES N	1142347.939	E	619306.686
ANGLE	NA	BEARING	NA	CONTRACTOR	Kilman/Prosonic
DRILL NO.	CME 45/SR-083				
DRILLING METHOD	3-1/4" HSA and Rotosonic	NO. SAMPLES	47	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	89.78' TOC	ELEV.	128.24'	TIME AFTER COMP.	NA
DATE TAKEN	6/7/2005				
TYPE GROUT	NA	QUANTITY	NA	MIX	NA
DRILLING START DATE	5/25-26/2005 - Kilman				
DRILLER	Tony	RECORDER	S Bearce	APPROVED	NA
DRILLING COMP. DATE	5/31-6/1/2005 - Prosonic				

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N (bpf)	Comments
0	216.65						
1	215.65						
2	214.65						
3	213.65						
4	212.65						
5	211.02	Light red fine-gained silty SAND	1A	3.5-5	24-25-15	40	
6	210.65						
7	209.65						
8	208.65						
9	207.65						
10	206.65		2A	8.5-10	21-22-7	29	
11	205.65						
12	204.65						
13	203.65						
14	202.65						
15	201.65		3A	13.5-15	10-15-14	29	
16	200.65						
17	199.65						
18	198.65						
19	197.65						
20	196.65		4A	18.5-20	6-4-7	11	
21	195.65						
22	194.65						
23	193.65						
24	192.65						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008
Sheet 2 of 8

SITE Vogtle ALWR SSAR — TOTAL DEPTH 247 — SURF.ELEV. 216.65

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
25	191.65	Light yellow fine-grained SAND	5A	23.5-25	15-24-47	71			
26	190.65								
27	189.65								
28	188.65								
29	187.65								
30	186.65		6A	28.5-30	19-14-18	32			
31	185.65								
32	184.65								
33	183.65								
34	182.65								
35	181.65	Light yellow fine-grained silty SAND	7A	33.5-35	28-24-19	43			
36	180.65								
37	179.65								
38	178.65								
39	177.65								
40	176.65	Light red fine-grained silty SAND	8A	38.5-40	3-8-16	24			
41	175.65								
42	174.65								
43	173.65								
44	172.65								
45	171.65		9A	43.5-45	18-27-35	62			
46	170.65								
47	169.65								
48	168.65								
49	167.65								
50	166.65		10A	48.5-50	14-5-6	11			
51	165.65								
52	164.65								
53	163.65								
54	162.02								
55	161.65		11A	53.5-55	20-21-23	44			
56	160.65								

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008
Sheet 3 of 8

SITE Vogtle ALWR SSAR — TOTAL DEPTH 247 — SURF.ELEV. 216.65

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
57	159.65								
58	158.65								
59	157.65								
60	156.65	Mottled reddish yellow brown fine-grained silty SAND	12A	58.5-60	4-6-6	12			
61	155.65								
62	154.65								
63	153.65								
64	152.65								
65	151.65	Mottled light-red fine-grained silty sand	13A	63.5-65	4-4-5	9			
66	150.65								
67	149.65								
68	148.65								
69	147.65								
70	146.65	Light red fine-grained silty SAND, moist	14A	68.5-70	3-2-3	5			
71	145.65								
72	144.65								
73	143.65								
74	142.65								
75	141.65	White medium grained silty SAND - moist	15A	73.5-75	2-2-2	4			
76	140.65								
77	139.65								
78	138.65								
79	137.65						5/25.2005 ▼ 80'		
80	136.65	White silty medium-grained SAND with shell fragments	16A	78.5-80	2-3-3	6			
81	135.65								
82	134.65								
83	133.65								
84	132.65								
85	131.65	White silty sandy SHELL HASH	17A	83.5-85	2-2-2	4			
86	130.02								
87	129.65								
88	128.65								

Form GS9901 7-26-2004

SOUTHERN COMPANY
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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008
Sheet 4 of 8

SITE Vogtle ALWR SSAR — 247 — SURF.ELEV. 216.65

Depth ft.	Elev.ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N (bpf)	Comments
89	127.65						
90	126.65	White medium-grained silty SAND, moist	18A	88.5-90	3-4-4	8	6/7/05 ▼ 89.78' from TOC
91	125.65						
92	124.65						
93	123.65						
94	122.65						
95	121.65	White medium-grained silty SAND, with shell fragments and sharks teeth	19A	93.5-95	17-24-21	45	
96	120.65						
97	119.65						
98	118.65						
99	117.65						
100	116.65						
101	115.65	White silty SHELL HASH, saturated	20A	98.5-100	50/2"	50.2"	
102	114.65						
103	113.65						
104	112.65						
105	111.65	White medium-grained silty SAND, saturated	21A	102.5-105	18-20-22	44	
106	110.65						
107	109.65						Kilman drills to 105'
108	108.65						Prosonic completes hole from 107'
109	107.65	Yellowish tan, fine-medium and coarse grained SAND (SW) clay and silt present but generally less than 10%	1	108.5 - 110			
110	106.65	Coarse sand fraction composed of angular shell fragments ranging in size from 2mm to 1 cm.					
111	105.65	Occassional larger shell fragments. Abrupt change/ contact between sample intervals					
112	104.65						
113	103.65						
114	102.65		2	113.5-115	NA	NA	
115	101.65						
116	100.65						
117	99.65						
118	98.02	Medium greenish grey MARL with occassional fossils.	3	118.5-120	NA	NA	
119	97.65						
120	96.65						

Form GS9901 7-26-2004

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008
Sheet 5 of 8

SITE Vogtle ALWR SSAR
TOTAL DEPTH 247
SURF.ELEV. 216.65

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N (bpf)	Comments
121	95.65						
122	94.65						
123	93.65						
124	92.65	Medium greenish grey MARL with occassional fossils.	4	123.5-125	NA	NA	
125	91.65						
126	90.65						
127	89.65						
128	88.65		5	128.5-130	NA	NA	
129	87.65						
130	86.65						
131	85.65						
132	84.65						
133	83.65						
134	82.65		6	133.5-135	NA	NA	
135	81.65						
136	80.65						
137	79.65	Greenish grey limestone, layer ~ 3" thick, fine-grained, heavier than MARL					
138	78.65						
139	77.65		7	138.5-140	NA	NA	
140	76.65						
141	75.65						
142	74.65						
143	73.65						
144	72.65						
145	71.65						
146	70.65						
147	69.65						
148	68.65	Medium greenish grey MARL with occassional fossils.	8	148.5-150	Na	NA	
149	67.65						
150							
151	65.65						
152	64.65						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008
Sheet 6 of 8

SITE Vogtle ALWR SSAR
TOTAL DEPTH 247
SURF.ELEV. 216.65

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N (bpf)	Comments
153	63.65						
154	62.65						
155	61.65						
156	60.65						
157	59.65	Medium greenish grey MARL with occassional fossils.					
158	58.65		9	158.5-160	NA	NA	
159	57.65						
160	56.65						
161	55.65						
162	54.65						
163	53.65						
164	52.65		10	163.5-165	NA	NA	
165	51.65						
166	50.65						
167	49.65	Same MARL					
168	48.65						
169	47.65		11	168.5-170	NA	NA	
170	46.65						
171	45.65						
172	44.65						
173	43.65						
174	42.65		12	173.5-175	NA	NA	
175	41.65						
176	40.65	Grades to Shelly or fine to coarse grained SAND (SP) composed of whole and angular shell fragments in a MARL matrix (70%)					
177	39.65						
178	38.65						
179	37.65		13	178.5-180	NA	NA	
180	36.65						
181	35.65	"Sand" ranges from 10-30%					
182							
183	33.65						
184	32.65		14	183.5-185	NA	NA	

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008
Sheet 7 of 8

SITE Vogtle ALWR SSAR
TAL DEPTH 247
SURF.ELEV. 216.65

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N (bpf)	Comments
185	31.65						
186	30.65						
187	29.65	Same shelly MARL					
188	28.65						
189	27.65		15	188.5-190	NA	NA	
190	26.65						
191	25.65						
192	24.65						
193	23.65						
194	22.65		16	193.5-195	NA	NA	
195	21.65						
196	20.65						
197	19.65						
198	18.65	Same shelly MARL					
199	17.65		17	198.5-200	NA	NA	
200	16.65						
201	15.65						
202	14.65						
203	13.65						
204	12.65		18	203.5-205	NA	NA	
205	11.65						
206	10.65						
206	10.65	Dark grey silty SAND, (SM) fine grained SAND with some zones (1-2) feet of fine to coarse grained silty SAND (SM)					
208	8.65						
209	7.65		19	208.5-210	NA	NA	
210	6.65						
211	5.65						
212	4.65						
213	3.65						
214	2.02		20	213.5-215	NA	NA	
215	1.65						
216	0.65						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008

Sheet 8 of 8

SITE Vogtle ALWR SSAR

TAL DEPTH

SURF.ELEV. 216.65

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N (bpf)	Comments
217	-0.35						
218	-1.35	Dark grey silty SAND, (SM) fine-grained SAND with					
219	-2.35	some zones (1-2) feet of fine- to coarse-grained silty SAND (SM)	21	218.5-220	NA	NA	
220	-3.35						
221	-4.35						
223	-6.35						
224	-7.35		22	223.5-225	NA	NA	
225	-8.35						
226	-9.35						
227	-10.35	Gradual change to grey fine SAND (SW)					
228	-11.35	Light grey fine SAND (SW)					
229	-12.35		23	228.5-230	NA	NA	
230	-13.35						
231	-14.35						
232	-15.35						
233	-16.35						
234	-17.35		24	233.5-235	NA	NA	
235	-18.35						
236	-19.35						
237	-20.35						
238	-21.35						
239	-22.35	Grey silty SAND (SM)	25	238.5-240	NA	NA	
240	-23.35						
241	-24.35						
242	-25.35						
243	-26.35						
244	-27.35	Abrupt change to light grey siliceous clay, (CL), to weak SHALE	26	243.5-245	NA	NA	
245	-28.35						
246	-29.35						
247	-30.98						
248	-31.35	Boring terminated at 247'. Well OW-1008 installed in this borehole.					
249	-32.35						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008A
Sheet 1 of 4

SITE Vogtle ALWR SSAR - ESP — DLE DEPTH 107.5 — SURF.ELEV. NA

LOCATION Burke County, GA — COORDINATES N — E

ANGLE NA — BEARING NA — CONTRACTOR Kilman Bro. — DRILL NO. CME-55

DRILLING METHOD 3 1/4" HAS — NO. SAMPLES 21 — NO. U.D. SAMPLES 0

WATER TABLE DEPTH 80 — ELEV. 136 — TIME AFTER COMP. NA — DATE TAKEN 5/26/2005

TYPE GROUT NA — QUANTITY NA — MIX NA — DRILLING START DATE 5/26/2005

DRILLER Kilman Bro. — RECORDER RA Esposito — APPROVED NA — DRILLING COMP. DATE 5/26/2005

Depth FT.	Elev. FT.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To FT.	Blows	N (bpf)	Comments
0							
1							
2							
3							
4							
5		Light red fine-gained silty SAND	1	3.5-5	24-25-15	40	
6							
7							
8							
9							
10			2	8.5-10	21-22-7	29	
11							
12							
13							
14							
15			S-3	13.5-15	10-15-14	29	
16							
17							
18							
19							
20			S-4	18.5-20	6-4-7	11	
21							
22							
23							
24							

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008A
Sheet 2 of 4

SITE: Vogtle ALWR SSAR — TOTAL DEPTH: 107.5 — SURF.ELEV.: NA

Depth FT.	Elev. FT.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To FT.	Blows	N (bpf)	Comments
25		Light yellow fine-grained SAND	5	23.5-25	15-24-47	71	
26							
27							
28							
29							
30			6	28.5-30	19-14-18	32	
31							
32							
33							
34							
35		Light yellow fine-grained silty SAND	7	33.5-35	28-24-19	43	
36							
37							
38							
39							
40		Light red fine-grained silty SAND	8	38.5-40	3-8-16	24	
41							
42							
43							
44							
45			9	43.5-45	18-27-35	62	
46							
47							
48							
49							
50			10	48.5-50	14-5-6	11	
51							
52							
53							
54							
55			11	53.5-55	20-21-23	44	
56							

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008A
Sheet 3 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 107.5 SURF.ELEV. NA

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N (bpf)	Comments
57							
58							
59							
60		Mottled reddish yellow brown fine-grained silty SAND	12	58.5-60	4-6-6	12	
61							
62							
63							
64							
65		Mottled light-red fine-grained silty sand	13	63.5-65	4-4-5	9	
66							
67							
68							
69							
70		Light red fine-grained silty SAND, moist	14	68.5-70	3-2-3	5	
71							
72							
73							
74							
75		White medium grained silty SAND - moist	15	73.5-75	2-2-2	4	
76							
77							
78							
79							
80		White silty medium-grained SAND with shell fragments	16	78.5-80	2-3-3	6	5/26/2005 ▼ 80' from ground surface
81							
82							
83							
84							
85		White silty sandy SHELL HASH	17	83.5-85	2-2-2	4	
86							
87							
88							

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1008A
Sheet 4 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 107.5 SURF.ELEV. NA

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N (bpf)	Comments
89							
90		White medium-grained silty SAND, moist	18	88.5-90	3-4-4	8	
91							
92							
93							
94							
95		White medium-grained silty SAND, with shell fragments and sharks teeth	19	93.5-95	17-24-21	45	
96							
97							
98							
99							
100							
101		White silty SHELL HASH, saturated	20	98.5-100	50/2"	100+	
102							
103							
104							
105		White medium-grained silty SAND, saturated	21	102.5-105	18-20-22	44	
106							
107							
108		Boring terminated at 107.5'					
109		due to use of 3 1/4" augers.					
110		This borehole was abandoned.					
111		Well OW-1008 is installed in adjacent borehole OW-1008.					
112							
113							
114							
115							
116							
117							
118							
119							
120							

2-4A-87

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1009
Sheet 1 of 4

SITE	Vogtle ALWR SSAR - ESP	HOLE DEPTH	100	SURF.ELEV.	220.887
LOCATION	Burke County, Georgia	COORDINATES N	1141891.645	E	620888.608
ANGLE	NA	BEARING	NA	CONTRACTOR	S&ME	DRILL NO.	CME 55
DRILLING METHOD	4-1/4" HAS	NO. SAMPLES	21	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	70'	ELEV.	150.257'	TIME AFTER COMP.	NA	DATE TAKEN	5/24/2005
TYPE GROUT	NA	QUANTITY	NA	MIX	NA	DRILLING START DATE	5/24/2005
DRILLER	Ted	RECORDER	RA Esposito	APPROVED	NA	DRILLING COMP. DATE	5/27/2005

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0	220.89						
1	219.89						
2	218.89	White to red fine-grained SAND					
3	217.89						
			1	3.5-5	4-10-10	20	
4	216.89						
5	215.89	Dark red fine-grained silty SAND					
6	214.89						
7	213.89						
8	212.89						
9	211.89						
10	210.89		2	8.5-10	3-3-5	8	
11	209.89						
12	208.89						
13	207.89						
14	206.89						
15	205.89		3	13.5-15	2-4-4	8	
16	204.89						
17	203.89						
18	202.89						
19	201.89						
20	200.89		4	18.5-20	4-5-7	12	
21	199.89	moist					
22	198.89						
23	197.89						
24	196.89						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1009
Sheet 2 of 2

SITE Vogtle ALWR SSAR TOTAL DEPTH 100 SURF.ELEV. 220.887

Depth Ft.	Elev. Ft	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft	Blows	N BPF	Comments
25	195.89	Light yellow fine-grained SAND	5	23.5-25	5-5-6	11	
26	194.89						
27	193.89						
28	192.89						
29	191.89						
30	190.89	Light yellow fine-grained silty SAND	6	28.5-30	3-6-7	13	
31	189.89						
32	188.89						
33	187.89						
34	186.89						
35	185.89		7	33.5-35	3-4-5	9	
36	184.89						
37	183.89						
38	182.89						
39	181.89						
40	180.89	Light yellow fine-grained silty clayey SAND, moist	8	38.5-40	2-2-3	5	
41	179.89						
42	178.89						
43	177.89						
44	176.89						
45	175.89	Light yellow silty CLAY, moist-plastic	9	43.5-45	2-4-6	10	
46	174.89						
47	173.89						
48	172.89						
49	171.89						
50	170.89	Light yellow fine- to medium-grained silty SAND, moist	10	48.5-50	3-7-8	15	
51	169.89						
52	168.89						
53	167.89						
54	166.26						
55	165.89	Light yellow fine- to medium-grained silty SAND, moist	11	53.5-55	4-6-7	13	
56	164.89						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1009
Sheet 3 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 100 SURF.ELEV. 220.887

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N BPF	Comments
57	163.89						
58	162.89						
59	161.89						
60	160.89	Light yellow silty fine grained SAND - moist	12	58.5-60	4-6-6	12	
61	159.89						
62	158.89						
63	157.89						
64	156.89						
65	155.89	Light yellow silty fine grained SAND - moist	13	63.5-65	0-1-2	3	
66	154.89						
67	153.89						
68	152.89						
69	151.89						
70	150.89	White silty fine-grained SAND - saturated	14	68.5-70	1-2-2	4	5/24/2005 ▼ 70 feet from ground surface
71	149.89						
72	148.89						
73	147.89						
74	146.89						
75	145.89	White medium-to coarse-grained SAND,saturated	15	73.5-75	0-0-1	1	
76	144.89						
77	143.89						
78	142.89						
79	141.89						
80	140.89		16	78.5-80	4-5-6	11	
81	139.89						
82	138.89						
83	137.89						
84	136.89						
85	135.89	Very light tan silty SAND (SM)	17	83.5-85	6-50/4"	100+	
86	134.26						
87	133.89						
88	132.89						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1009
Sheet 4 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 100 SURF.ELEV. 220.887

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments	% Rec	RQD
89	131.89								
90	130.89	Tan LIMESTONE shell hash, very light tan silty SAND (SM)	18	88.5-90	50/1"	100+			
91	129.89								
92	128.89								
93	127.89								
94	126.89								
95	125.89	Brown silty CLAY	19	93.5-95	6-18-3	21			
96	124.89								
97	123.89								
98	122.89								
99	121.89								
100	120.89	Green MARL	20	98.5-100	13 / 50/.2	100+			
101	119.89	Boring terminated at 100' OW-1009 installed in this borehole.							
102	118.89								
103	117.89								
104	116.89								
105	115.89								
106	114.89								
107	113.89								
108	112.89								
109	111.89								
110	110.89								
111	109.89								
112	108.89								
113	107.89								
114	106.89								
115	105.89								
116	104.89								
117	103.89								
118	102.26								
119	101.89								
120	100.89								

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GEOLOGICAL SERVICES

Hole No. OW-1010
Sheet 1 of 4

SITE	Vogtle ALWR SSAR	LE DEPTH	93.5	SURF.ELEV.	216.895
LOCATION	Burke County, Georgia	COORDINATES N	1140808.986	E	620051.708
ANGLE	NA	BEARING	NA	CONTRACTOR	S&ME
DRILL NO.	CME550	DRILLING METHOD	4 1/4" HAS	NO. SAMPLES	19
NO. U.D. SAMPLES	NA	WATER TABLE DEPTH	58.5'	ELEV.	157.765'
TIME AFTER COMP.	NA	DATE TAKEN	6/1/2005	TYPE GROUT	NA
QUANTITY	NA	MIX	NA	DRILLING START DATE	6/1/2005
DRILLER	Tim Hall	RECORDER	R. Tinsley	APPROVED	NA
DRILLING COMP. DATE	6/1/2005				

Depth Ft.	Elev.Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0	216.90						
1	215.90						
2	214.90						
3	213.90						
4	212.90						
5	211.90	Reddish yellow SAND, fine- to medium-grained with coarse grains and hematite concretions, loose, (SW)	1	3.5-5	11-17-17	34	
6	210.90						
7	209.90						
8	208.90						
9	207.90						
10	206.90	Mottled weak red and brown SAND, fine-grained, Loose (SP)	2	8.5-10	7-8-11	19	
11	205.90						
12	204.90						
13	203.90						
14	202.90						
15	201.90		3	13.5-15	6-7-7	14	
16	200.90						
17	199.90						
18	198.90						
19	197.90						
20	196.90		4	18.5-20	7-7-8	15	
21	195.90						
22	194.90						
23	193.90						
24	192.90						

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GEOLOGICAL SERVICES

Hole No. OW-1010
Sheet 2 of 4

SITE Vogtle ALWR SSAR — TOTAL DEPTH 93.5 — SURF.ELEV. 216.895

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
25	191.90	Mottled weak red and brown SAND, fine- to medium-grained with some coarse grains (SW)	5	23.5-25	9-9-6	15	
26	190.90						
27	189.90						
28	188.90						
29	187.90	Reddish yellow SAND fine- to medium-grained, loose (SW)					
30	186.90		6	28.5-30	9-31-42	73	
31	185.90						
32	184.90						
33	183.90						
34	182.90						
35	181.90		7	33.5-35	7-6-5	11	
36	180.90						
37	179.90						
38	178.90						
39	177.90						
40	176.90	Same as above with some coarse grains	8	38.5-40	5-5-5	10	
41	175.90						
42	174.90						
43	173.90						
44	172.90	Brownish yellow clayey SAND, soft, (SC)					
45	171.90		9	43.5-45	5-2-2	4	
46	170.90						
47	169.90						
48	168.90						
49	167.90	Mottled yellowish red clayey SAND, medium-grained (SC) with organics					
50	166.90		10	48.5-50	2-3-3	6	
51	165.90						
52	164.90						
53	163.90						
54	162.27						
55	161.90	Strong brown sand, medium-grained with slight fines (SP)	11	53.5-55	2-4-5	9	
56	160.90						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1010
Sheet 3 of 4

SITE Vogtle ALWR SSAR — TOTAL DEPTH 93.5 — SURF.ELEV. 216.895

Depth Ft.	Elev.Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft	Blows	N BPF	Comments
57	159.90						
58	158.90						6/1/2005 ▼
59	157.90	Mottled white to brown clayey SAND, medium-grained (SP), medium dense	12	58.5-60	2-7-7	14	58.5' from ground surface
60	156.90						
61	155.90						
62	154.90						
63	153.90						
64	152.90						
65	151.90	Strong brown clayey SAND, fine- to medium-grained (SC)	13	63.5-65	WOR-2-3	5	
66	150.90						
67	149.90						
68	148.90						
69	147.90						
70	146.90	Brownish yellow silty SAND, medium-grained, (SM)	14	68.5-70	WOH/18"	WHO/ 18"	
71	145.90						
72	144.90						
73	143.90						
74	142.90						
75	141.90	Tan poorly graded SAND with silt (SP-SM)	15	73.5-75	WOR 2'	WOR/ 2'	
76	140.90						
77	139.90						
78	138.90						
79	137.90	Brownish yellow clayey, silty SAND (SC-SM), soft					
80	136.90		16	78.5-80	WOR/18"	WOR/ 18"	
81	135.90						
82	134.90						
83	133.90						
84	132.90						
85	131.90	White SHELL HASH	17	83.5-85	50/3"	50/3"	
86		Grayish green MARL					
87	129.90						
88	128.90						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1010
Sheet 4 of 4

SITE Vogtle ALWR SSAR DEPTH 93.5 SURF.ELEV. 216.895

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
89	127.90						
90	126.90	Grayish green MARL, very stiff	18	88.5-90	18-9-12	21	
91	125.90						
92	124.90						
93	123.90	Boring terminated at 93.5'					
94	122.90	Well OW-1010 installed in this boring.					
95	121.90		19	93.5-95	21-50/4"	50/4"	
96	120.90						
97	119.90						
98	118.90						
99	117.90						
100	116.90						
101	115.90						
102	114.90						
103	113.90						
104	112.90						
105	111.90						
106	110.90						
107	109.90						
108	108.90						
109	107.90						
110	106.90						
111	105.90						
112	104.90						
113	103.90						
114	102.90						
115	101.90						
116	100.90						
117	99.90						
118							
119	97.90						
120	96.90						

Form GS8901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1011
Sheet 1 of 7

SITE	Vogtle ALWR SSAR	HOLE DEPTH	217	SURF.ELEV.	205.785
LOCATION	Burke County, Georgia	COORDINATES N	1139956.246	E	621033.045
ANGLE	NA	BEARING	NA	CONTRACTOR	Prosonic
DRILL NO.	SR-083				
DRILLING METHOD	Sonic	NO. SAMPLES	continuous	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	NA	ELEV.	NA	TIME AFTER COMP.	NA
DATE TAKEN	NA				
TYPE GROUT	NA	QUANTITY	NA	MIX	NA
DRILLING START DATE	6/11/2005				
DRILLER	Tony	RECORDER	John Pugh	APPROVED	NA
DRILLING COMP. DATE	6/12/2005				

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
0	205.79								
1	204.79	Sampling in this boring started at 87'. Borehole OW-1012 was sampled from the surface to 93.6'. These two are a well pair.							
2	203.79								
3	202.79								
4	201.79								
5	200.79								
6	199.79								
7	198.79								
8	197.79								
9	196.79								
10	195.79								
11	194.79								
12	193.79								
13	192.79								
14	191.79								
15	190.79								
16	189.79								
17	188.79								
18	187.79								
19	186.79								
20	185.79								
21	184.79								
22	183.79								
23	182.79								
24	181.79								

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1011

SITE Vogtle ALWR SSAR TOTAL DEPTH 217 SURF.ELEV. 205.785

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
25	180.79	See page one.					
26	179.79						
27	178.79						
28	177.79						
29	176.79						
30	175.79						
31	174.79						
32	173.79						
33	172.79						
34	171.79						
35	170.79						
36	169.79						
37	168.79						
38	167.79						
39	166.79						
40	165.79						
41	164.79						
42	163.79						
43	162.79						
44	161.79						
45	160.79						
46	159.79						
47	158.79						
48	157.79						
49	156.79						
50	155.79						
51	154.79						
52	153.79						
53	152.79						
54							
55	150.79						
56	149.79						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1011

SITE Vogtle ALWR SSAR | TOTAL DEPTH 217 | SURF.ELEV. 205.785

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
57	148.79	See page one.					
58	147.79						
59	146.79						
60	145.79						
61	144.79						
62	143.79						
63	142.79						
64	141.79						
65	140.79						
66	139.79						
67	138.79						
68	137.79						
69	136.79						
70	135.79						
71	134.79						
72	133.79						
73	132.79						
74	131.79						
75	130.79						
76	129.79						
77	128.79						
78	127.79						
79	126.79						
80	125.79						
81	124.79						
82	123.79						
83	122.79						
84	121.79						
85	120.79						
86	119.16						
87	118.79	Begin sampling at 87' with ProSonic rig.					
88	117.79						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1011
Sheet 4 of 7

SITE Vogtle ALWR SSAR — TOTAL DEPTH 217 — SURF.ELEV. 205.785

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments
89	116.79	Greenish grey CLAY, stiff					
90	115.79		1	88.5-90	NA	NA	
91	114.79						
92	113.79						
93	112.79						
94	111.79	Dark greenish to olive-grey CLAY, moist, stiff, light gray mottling					
95	110.79		2	93.5-95	NA	NA	
96	109.79						
97	108.79						
98	107.79						
99	106.79	Greenish grey CLAY, stiff, moist, small shell fragments					
100	105.79		3	98.5-100	NA	NA	
101	104.79						
102	103.79						
103	102.79						
104	101.79	Greenish grey CLAY, stiff, small shell fragments, not moist					
105	100.79		4	103.5-105	NA	NA	
106	99.79						
107	98.79						
108	97.16						
		LIMESTONE 2"					
109	96.79	Greenish grey CLAY, slightly moist, limestone fragments					
110	95.79		5	108.5-110	NA	NA	
111	94.79						
112	93.79						
113	92.79						
114	91.79	Greenish grey CLAY, not moist, larger shell fragments					
115	90.79		6	113.5-115	NA	NA	
116	89.79						
117	88.79						
118	87.16						
119	86.16	Light greenish grey CLAY, moist, w/ Limestone chunks					
120	85.79		7	118.5-120	NA	NA	

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1011
Sheet 5 of 7

SITE Vogtle ALWR SSAR
TOTAL DEPTH 217
SURF.ELEV. 205.785

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
121	84.79						
122	83.79						
123	82.79	Light grey LIMESTONE 4"					
124	81.79	Greenish grey CLAY, slightly moist					
125	80.79		8	123.5-125	NA	NA	
126	79.79						
127	78.79						
128	77.79						
129	76.79	Light-grey CLAY, stiff					
130	75.79		9	128.5-130	NA	NA	
131	74.79						
132	73.79						
133	72.79						
134	71.79						
135	70.79		10	133.5-135	NA	NA	
136	69.79						
137	68.79						
138	67.79						
139	66.79						
140	65.79	Greenish grey CLAY, stiff	11	138.5-140	NA	NA	
141	64.79						
142	63.79						
143	62.79						
144	61.79						
145	60.79		12	143.5-145	NA	NA	
146	59.79						
147	58.79						
148	57.79	_ _ _ _ potential void					
149	56.79						
150	55.16	Greenish grey CLAY, stiff	13	148.5-150	NA	NA	
151	54.79						
152	53.79						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1011
Sheet 6 of 7

SITE **Vogtle ALWR SSAR** TOTAL DEPTH **217** SURF.ELEV. **205.785**

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N BPF	Comments
	152.50						
153	52.79						
154	51.79	Light bluish-grey, very fine sands to sandy CLAY, Loose, moist, clayey					
155	50.79		14	153.5-155	NA	NA	
156	49.79						
157	48.79						
158	47.79						
159	46.79	Light grey, slightly sandy CLAY, moist					
160	45.79		15	158.5-160	NA	NA	
161	44.79						
162	43.79						
163	42.79						
164	41.79	Light grey, silty, slightly sandy CLAY, moist					
165	40.79		16	163.5-165	NA	NA	
166	39.79						
167	38.79						
168	37.79						
169	36.79	Greenish grey sandy silty CLAY, bright green and tan nodules					
170	35.79		17	168.5-170	NA	NA	
171	34.79						
172	33.79						
173	32.79						
174	31.79						
175	30.79		18	173.5-175	NA	NA	
176	29.79						
177	28.79						
178	27.79	Dark olive grey CLAY, stiff					
179	26.79						
180	25.79		19	178.5-180	NA	NA	
181	24.79						
182							
183	22.79	Dark olive grey sandy CLAY					
184	21.79						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1011
Sheet 7 of 7

SITE **Vogtle ALWR SSAR** TOTAL DEPTH **217** SURF.ELEV. 205.785

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test			Comments
				From To ft.	Blows	N BPF	
185	20.79		20	183.5-185	NA	NA	
186	19.79						
187	18.79						
188	17.79						
189	16.79	Dark grey sandy CLAY					
190	15.79		21	188.5-190	NA	NA	
191	14.79						
192	13.79						
193	12.79						
194	11.79	Dark grey clayey fine SAND grading to					
195	10.79		22	193.5-195	NA	NA	
196	9.79	Clayey medium-grained SAND					
197	8.79						
198	7.79						
199	6.79	Dark bluish-gray silty fine- to medium-grained SAND very moist					
200	5.79		23	198.5-200	NA	NA	
201	4.79						
202	3.79						
203	2.79						
204	1.79						
205	0.78	Gray poorly graded sand with silt (SP-SM)	24	203.5-205	NA	NA	
206	-0.22						
206	-0.22						
208	-2.22						
209	-3.22						
210	-4.22	Gray poorly graded sand with silt (SP-SM)	25	208.5-210	NA	NA	
211	-5.22	Silty gravelly SAND with fossils, shark teeth					
212	-6.22						
213	-7.22						
214	-8.85	Dark bluish gray medium- to coarse-grained SAND					
215	-9.22		26	213.5	215	NA	
216	-10.22	Boring terminated at 217'					

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1012
Sheet 1 of 4

SITE	Vogtle ALWR SSAR	HOLE DEPTH	93.6	SURF.ELEV.	205.355
LOCATION	Burke County, Georgia	COORDINATES N	1139969.496	E	621045.924
ANGLE	NA	BEARING	NA	CONTRACTOR	S&ME
DRILL NO.	CME 55	DRILLING METHOD	HSA 4 1/4" ID	NO. SAMPLES	19
NO. U.D. SAMPLES	NA	WATER TABLE DEPTH	49.5'	ELEV.	155.225'
TIME AFTER COMP.	NA	DATE TAKEN	6/1/2005	TYPE GROUT	NA
QUANTITY	NA	MIX		DRILLING START DATE	5/31/2005
DRILLER	Ted/Rick	RECORDER	Tinsley	APPROVED	NA
DRILLING COMP. DATE	6/1/2005				

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0	205.36						
1	204.36						
2	203.36						
3	202.36						
4	201.36	Weak red SAND (SW), very fine - fine grained, loose, mottled					
5	200.36		1	3.5-5	2-2-3	5	
6	199.36						
7	198.36						
8	197.36						
9	196.36						
10	195.36		2	8.5-10	2-5-5	10	
11	194.36						
12	193.36						
13	192.36						
14	191.36						
15	190.36	Same as above with stronger mottling	3	13.5-15	3-5-5	10	
16	189.36						
17	188.36						
18	187.36	Brown SAND, fine to medium grained, loose, (SW)					
19	186.36						
20	185.36		4	18.5-20	5-15-26	41	
21	184.36						
22	183.36						
23	182.36						
24	181.36	Reddish yellow SAND					

Form GS9901 7-26-2004

SOUTHERN COMPANY
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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1012

SITE Vogtle ALWR SSAR | TOTAL DEPTH 93.6 | SURF.ELEV. 205.355

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N BPF	Comments
25	180.36	Reddish yellow SAND (SP), fine- to medium-grained with fines	5	23.5-25	6-16-17	33	
26	179.36						
27	178.36						
28	177.36						
29	176.36	Reddish yellow SAND (SP), fine-grained, loose					
30	175.36		6	28.5-30	3-7-7	14	
31	174.36						
32	173.36						
33	172.36						
34	171.36						
35	170.36		7	33.5-35	3-5-6	11	
36	169.36						
37	168.36						
38	167.36						
39	166.36						
40	165.36		8	38.5-40	2-5-6	11	
41	164.36						
42	163.36						
43	162.36						
44	161.36						
45	160.36		9	43.5-45	3-2-2	4	
46	159.36						
47	158.36	Reddish yellow SAND (SW), medium- to coarse-grained, loose, with fines					
48	157.36						
49	156.36						6/1/2005 ▼
50	155.36		10	48.5-50	1-1-2	3	49.5' from ground surface
51	154.36						
52	153.36	Pale yellow CLAY (CL), slightly sandy					
53	152.36						
54							
55	150.36		11	53.5-55	WHO/2/3	5	micas
56	149.36						

Form GS9901 7-26-2004

H

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GEOLOGICAL SERVICES

Hole No. OW-1012
Sheet 3 of 4

SITE Vogtle ALWR SSAR

93.6

SURF.ELEV. 205.355

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
57	148.36						
58	147.36						
59	146.36						
60	145.36	Pale yellow CLAY (CL), slightly sandy	12	58.5-60	1-1-2	3	
61	144.36						
62	143.36						
63	142.36						
64	141.36						
65	140.36		13	63.5-65	2-1-3	4	
66	139.36						
67	138.36						
68	137.36						
69	136.36	Pale yellow sandy CLAY, soft (CL)					
70	135.36		14	68.5-70	WOH/	WHO/1	
71	134.36				WOH/ 1		
72	133.36						
73	132.36	Brown SAND, fine- to medium-grained with pale yellow silt (SM)					
74	131.36						
75	130.36		15	73.5-75	WOH/		
76	129.36				WOH/ 1	WOH/ 1	
77	128.36						
78	127.36						
79	126.36						
80	125.36	Pale olive SILT (ML)	16	78.5-80	2-4-6	10	
81	124.36						
82	123.36						
83	122.36						
84	121.36	Pale yellow SILT, micaceous (ML)					
85	120.36		17	83.5-85	2-3-4	7	Black minerals
86							
87	118.36						
88	117.36						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1012
Sheet 4 of 4

SITE Vogtle ALWR SSAR — TOTAL DEPTH 93.6 — SURF.ELEV. 205.355

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
89	116.36	Grayish green MARL, very stiff					
90	115.36		18	88.5-90	18-25-50	75	
91	114.36						
92	113.36						
93	112.36						
94	111.36						
95	110.36	Boring Terminated at 93.6' Well OW-1012 installed in this borehole.	19	93.5-95	50/1"	50/1"	
96	109.36						
97	108.36						
98	107.36						
99	106.36						
100	105.36						
101	104.36						
102	103.36						
103	102.36						
104	101.36						
105	100.36						
106	99.36						
107	98.36						
108	97.36						
109	96.36						
110	95.36						
111	94.36						
112	93.36						
113	92.36						
114	91.36						
115	90.36						
116	89.36						
117	88.36						
118							
119	86.36						
120	85.36						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1013
Sheet 1 of 4

SITE	Vogtle ALWR SSAR	HOLE DEPTH	103.5	SURF.ELEV.	216.869
LOCATION	Burke County, Georgia	COORDINATES N	1140805.4	E	621715.032
ANGLE	NA	BEARING	NA	CONTRACTOR	S&ME
DRILL NO.	CME 55				
DRILLING METHOD	4 1/4" Hollow stem auger	NO. SAMPLES	20	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	49'	ELEV.	167.239'	TIME AFTER COMP.	NA
DATE TAKEN	6/9/2005				
TYPE GROUT	NA	QUANTITY	NA	MIX	NA
DRILLING START DATE	6/9/2005				
DRILLER	Ted Miller	RECORDER	S. Bearce	APPROVED	NA
DRILLING COMP. DATE	6/10/2005				

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0	216.87						
1	215.87						
2	214.87						
3	213.87						
4	212.87	Orange brown clayey SAND (SC)					
5	211.87		1	3.5-5	8-8-9	17	
6	210.87						
7	209.87						
8	208.87						
9	207.87						
10	206.87		2	8.5-10	5-10-9	19	
11	205.87						
12	204.87						
13	203.87						
14	202.87	Burgundy or hematitic clayey SAND (SC)					
15	201.87		3	13.5-15	2-2-3	5	
16	200.87						
17	199.87						
18	198.87						
19	197.87	Mottled orange, brown, and light gray sandy CLAY (CL)					
20	196.87		4	18.5-20	3-4-5	9	
21	195.87						
22	194.87						
23	193.87						
24	192.87	Burgundy hematite coated fine-grained to coarse-grained SAND (SW)					

Form GS9901 7-26-2004

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GEOLOGICAL SERVICES

Hole No. OW-1013
Sheet 2 of 4

SITE Vogtle ALWR SSAR
TOTAL DEPTH 103.5
SURF.ELEV. 216.869

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
25	191.87	Fine- to coarse-grsained SAND (SW) with minor amounts of clay, moist	5	23.5-25	4-5-6	11	
26	190.87						
27	189.87	Yellow brown fine SAND (SP) minor clay, moist					
28	188.87						
29	187.87						
30	186.87		6	28.5-30	2-3-5	8	
31	185.87						
32	184.87						
33	183.87						
34	182.87						
35	181.87		7	33.5-35	3-6-10	16	
36	180.87						
37	179.87						
38	178.87						
39	177.87						
40	176.87		8	38.5-40	3-6-9	15	
41	175.87						
42	174.87						
43	173.87						
44	172.87						
45	171.87	Same as above, wet	9	43.5-45	2-2-5	7	
46	170.87						
47	169.87						
48	168.87						
49	167.87						6/9/2005
50	166.87	Same as above - saturated	10	48.5-50	1-3-5	8	▼ 49 from ground surface
51	165.87						
52	164.87						
53	163.87	Yellow brown, wet, SAND (SC) clay content higher					
54	162.24						
55	161.87		11	53.5-55	3-2-5	7	
56	160.87						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1013
Sheet 3 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 103.5 SURF.ELEV. 216.869

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
57	159.87						
58	158.87						
59	157.87						
60	156.87	No recovery	12	58.5-60	2-2-2	4	
61	155.87						
62	154.87						
63	153.87						
64	152.87	Same as above with clay blobs, saturated					
65	151.87		13	63.5-65	1-3-5	8	
66	150.87						
67	149.87						
68	148.87						
69	147.87						
70	146.87		14	68.5-70	2-3-4	7	
71	145.87						
72	144.87						
73	143.87						
74	142.87						
75	141.87		15	73.5-75	2-4-6	10	
76	140.87						
77	139.87						
78	138.87						
79	137.87						
80	136.87	Tan fine- to coarse-grained SAND (SW) with medium to coarse-grained black organic material	16	78.5-80	5-10-10	20	
81	135.87						
82	134.87						
83	133.87						
84	132.87						
85	131.87	Tan fine- to medium-grained SAND (SP-SM) with tan or gray clay "tubes" or bioturbation	17	83.5-85	3-2-4	6	
86	130.24						
87	129.87						
88	128.87						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1013
Sheet 4 of 4

SITE **Vogtle ALWR SSAR** OTAL DEPTH **103.5** SURF.ELEV. **216.869**

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
89	127.87	Light olive tan calcareous silty fine-grained SAND (SP - SM)					
90	126.87		18	88.5-90	6-7-9	16	
91	125.87						
92	124.87						
93	123.87						
94	122.87	light olive tan calcareous CLAY (CL), wet but not saturated					
95	121.87		19	93.5-95	4-19-15	24	
96	120.87						
97	119.87						
98	118.87						
99	117.87						
100	116.87	Greenish gray MARL	20	98.5-100	13-28-50/3	28/ 50/3"	
101	115.87						
102	114.87						
103	113.87						
104	112.87	Boring terminated at 103.5'					
105	111.87	Well OW-1013 installed in this borehole.					
106	110.87						
107	109.87						
108	108.87						
109	107.87						
110	106.87						
111	105.87						
112	104.87						
113	103.87						
114	102.87						
115	101.87						
116	100.87						
117	99.87						
118							
119	97.87						
120	96.87						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1014
Sheet 1 of 7

SITE	Vogtle ALWR SSAR	HOLE DEPTH	197.4	SURF.ELEV.	220.867
LOCATION	Burke County, Georgia	COORDINATES N	1140565.502	E	623070.234
ANGLE	NA	BEARING	NA	CONTRACTOR	Prosonic
DRILL NO.	SR-083				
DRILLING METHOD	Sonic	NO. SAMPLES	continuous	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	NA	ELEV.	NA	TIME AFTER COMP.	NA
DATE TAKEN	NA				
TYPE GROUT	NA	QUANTITY	NA	MIX	NA
DRILLING START DATE	6/11/2005				
DRILLER	Michael	RECORDER	S Bearce	APPROVED	NA
DRILLING COMP. DATE	6/11/2005				

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
0	220.87								
1	219.87	This borehole was not sampled until 97'.							
2	218.87	OW-1014 is a well pair with OW-1015. See boring log OW-1015 fro description of the upper sediemnts.							
3	217.87								
4	216.87								
5	215.87								
6	214.87								
7	213.87								
8	212.87								
9	211.87								
10	210.87								
11	209.87								
12	208.87								
13	207.87								
14	206.87								
15	205.87								
16	204.87								
17	203.87								
18	202.87								
19	201.87								
20	200.87								
21	199.87								
22	198.87								
23	197.87								
24	196.87								

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1014

SITE Vogtle ALWR SSAR TOTAL DEPTH 197.4 SURF.ELEV. 220.867

Depth	Elev.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To	Blows	N	Comments	% Rec	RQD
		See page 1							
25	195.87								
26	194.87								
27	193.87								
28	192.87								
29	191.87								
30	190.87								
31	189.87								
32	188.87								
33	187.87								
34	186.87								
35	185.87								
36	184.87								
37	183.87								
38	182.87								
39	181.87								
40	180.87								
41	179.87								
42	178.87								
43	177.87								
44	176.87								
45	175.87								
46	174.87								
47	173.87								
48	172.87								
49	171.87								
50	170.87								
51	169.87								
52	168.87								
53	167.87								
54									
55	165.87								
56	164.87								

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1014
Sheet 3 of 7

SITE Vogtle ALWR SSAR TOTAL DEPTH 197.4 SURF.ELEV. 220.867

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
57	163.87	See Page 1					
58	162.87						
59	161.87						
60	160.87						
61	159.87						
62	158.87						
63	157.87						
64	156.87						
65	155.87						
66	154.87						
67	153.87						
68	152.87						
69	151.87						
70	150.87						
71	149.87						
72	148.87						
73	147.87						
74	146.87						
75	145.87						
76	144.87						
77	143.87						
78	142.87						
79	141.87						
80	140.87						
81	139.87						
82	138.87						
83	137.87						
84	136.87						
85	135.87						
86							
87	133.87						
88	132.87						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1014
Sheet 4 of 7

SITE Vogtle ALWR SSAR TOTAL DEPTH 197.4 SURF.ELEV. 220.867

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
89	131.87	See page 1					
90	130.87						
91	129.87						
92	128.87						
93	127.87						
94	126.87						
95	125.87						
96	124.87						
97	123.87	Sampling begins at 97'					
98	122.87	Red orange silty clayey SAND					
99	121.87						
100	120.87	White-tan fine- to medium-grained SAND	1	98.5-100	NA	NA	
101	119.87						
102	118.87	Brownish-yellow silty CLAY with shell fragments					
103	117.87						
104	116.87	Light greenish-brown carbonaceous stiff CLAY with Limestone pieces					
105	115.87		2	103.5-105	NA	NA	
106	114.87						
107	113.87						
108	112.87						
109	111.87	Moderately stiff greenish-grey carbonaceous clay with shell hash					
110	110.87		3	108.5-110	NA	NA	fizz
111	109.87						
112	108.87						
113	107.87						
114	106.87	Greenish grey stiff calcareous CLAY with small shell fragments					
115	105.87		4	113.5-115	NA	NA	
116	104.87						
117	103.87						
118							
119	101.87						
120	100.87		5	118.5-120	NA	NA	

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1014
Sheet 5 of 7

SITE: Vogtle ALWR SSAR | TOTAL DEPTH: 197.4 | SURF.ELEV.: 220.867

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
121	99.87						
122	98.87						
123	97.87						
124	96.87	Greenish grey stiff calcareous CLAY with small shell fragments					
125	95.87		6	123.5-125	NA	NA	
126	94.87						
127	93.87						
128	92.87						
129	91.87						
130	90.87		7	128.5-130	NA	NA	
131	89.87						
132	88.87						
133	87.87						
134	86.87						
135	85.87	Same as above with coarse shell fragments and limestone chunks	8	133.5-135	NA	NA	
136	84.87						
137	83.87						
138	82.87						
139	81.87						
140	80.87		9	138.5-140	NA	NA	
141	79.87						
142	78.87						
143	77.87						
144	76.87						
145	75.87		10	143.5-145	NA	NA	
146	74.87						
147	73.87						
148	72.87						
149	71.87						
150	70.24		11	148.5-150	NA	NA	
151	69.87						
152	68.87						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1014
Sheet 6 of 7

SITE: Vogtle ALWR SSAR
TOTAL DEPTH: 197.4
SURF.ELEV.: 220.867

Depth FT.	Elev. FT.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To FT.	Blows	N Bbpf	Comments
153	67.87						
154	66.87						
155	65.87		12	153.5-155	NA	NA	
156	64.87	Greenish grey stiff calcareous CLAY with small shell fragments					
157	63.87						
158	62.87						
159	61.87						
160	60.87		13	158.5-160	NA	NA	
161	59.87						
162	58.87						
163	57.87						
164	56.87						
165	55.87		14	163.5-165	NA	NA	
166	54.87						
167	53.87						
168	52.87						
169	51.87	Light green slightly clayey SAND, turns light grey with brief (~1 hour) exposure to air, with bioturbation					
170	50.87	saturated	15	168.5-170	NA	NA	
171	49.87						
172	48.87						
173	47.87						
174	46.87		16	173.5-175	NA	NA	
175	45.87						
176	44.87	Bottom of carbonate clay or confining layer					
177	43.87	Dark grey silty SAND, (SM - SP), high organic content, saturated					
178	42.87						
179	41.87						
180	40.87		17	178.5-180	NA	NA	
181	39.87	Light grey, fine quartz SAND (SP), saturated					
182							
183	37.87						
184	36.87						

DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1014
Sheet 7 of 7

SITE: Vogtle ALWR SSAR
TOTAL DEPTH: 197.4
SURF.ELEV.: 220.867

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
185	35.87	Light grey, silty, fine-grained SAND (SM), saturated	18	183.5-185	NA	NA	
186	34.87	Dark grey fine sandy SILT (ML)					
187	33.87						
188	32.87						
189	31.87						
190	30.87	Grey poorly graded SAND with silt (SP-SM)	19	188.5-190	NA	NA	
191	29.87						
192	28.87						
193	27.87						
194	26.87						
195	25.87		20	193.5-195	NA	NA	
196	24.87						
197	23.87		21	195-197.4	NA	NA	
198	22.87	Boring terminated at 197.4' Well OW-1014 installed in this borehole.					
199	21.87						
200	20.87						
201	19.87						
202	18.87						
203	17.87						
204	16.87						
205	15.87						
206	14.87						
206	14.87						
208	12.87						
209	11.87						
210	10.87						
211	9.87						
212	8.87						
213	7.87						
214							
215	5.87						
216	4.87						

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1015
Sheet 1 of 4

SITE	Vogtle ALWR SSAR	HOLE DEPTH	120	SURF.ELEV.	220.427
LOCATION	Burke County, Georgia	COORDINATES N	1140550.576	E	623086.318
ANGLE	NA	BEARING	NA	CONTRACTOR	Greene
DRILL NO.	CME 75				
DRILLING METHOD	4 1/4" HSA	NO. SAMPLES	24	NO. U.D. SAMPLES	NA
WATER TABLE DEPTH	73'	ELEV.		TIME AFTER COMP.	
DATE TAKEN	5/30/2005				
TYPE GROUT	NA	QUANTITY	NA	MIX	NA
DRILLING START DATE	5/30/2005				
DRILLER	Greene , Dulong	RECORDER	S Bearce	APPROVED	NA
DRILLING COMP. DATE	6/3/2005				

Depth Ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To Ft.	Blows	N BPF	Comments
0	220.43						
1	219.43						
2	218.43						
3	217.43						
4	216.43	Brown, fine- to medium -grained SAND (SW) <5% silt					
5	215.43		1	3.5-5	3-9-8	17	
6	214.43						
7	213.43						
8	212.43						
9	211.43	Red-brown, hematitic clayey SAND (SC)					
10	210.43		2	8.5-10	8-10-13	23	
11	209.43						
12	208.43						
13	207.43						
14	206.43	Red and tan mottled fine- to medium-grained SAND (SP), traces of silt (<5%)					
15	205.43		3	13.5-15	9-9-13	22	
16	204.43						
17	203.43						
18	202.43						
19	201.43	Reddish-brown, sandy CLAY (CL) sand laminae are light tan					
20	200.43		4	18.5-20	10-11-14	25	
21	199.43						
22	198.43						
23	197.43						
24	196.43						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1015
Sheet 2 of 4

SITE Vogtle ALWR SSAR TOTAL DEPTH 120 SURF.ELEV. 220.427

Depth ft.	Elev. FL	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
25	195.43	Reddish-brown, sandy CLAY (CL) sand laminae are light tan	5	23.5-25	8-11-14	25	
26	194.43						
27	193.43						
28	192.43						
29	191.43						
30	190.43	Orange-brown fine- to medium-grained SAND (SP) damp	6	28.5-30	6-7-8	15	
31	189.43						
32	188.43						
33	187.43						
34	186.43						
35	185.43		7	33.5-35	7-7-8	15	
36	184.43						
37	183.43						
38	182.43						
39	181.43						
40	180.43		8	38.5-40	6-8-14	22	
41	179.43						
42	178.43						
43	177.43						
44	176.43						
45	175.43		9	43.5-45	10-13-15	28	
46	174.43						
47	173.43						
48	172.43						
49	171.43	Yellowish brown sandy CLAY (CL-CH), moist					
50	170.43		10	48.5-50	6-7-9	16	
51	169.43						
52	168.43						
53	167.43						
54							
55	165.43		11	53.5-55	8-11-11	22	
56	164.43						

Form GS9901 7-26-2004

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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1015

SITE Vogtle ALWR SSAR

TOTAL DEPTH 120

SURF.ELEV. 220.427

Depth ft.	Elev. Ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
57	163.43						
58	162.43						
59	161.43	Yellowish brown clayey SAND (SC) fine-grained, moist					6/2/2005
60	160.43		12	58.5-60	9-12-14	26	▼ Water Table 59.5
61	159.43						
62	158.43						
63	157.43	Tan fine- to coarse-grained SAND (SP) saturated					
64	156.43						
65	155.43	Yellow brown clayey SAND (SC) saturated	13	63.5-65	1-3-5	8	
66	154.43						
67	153.43						
68	152.43						
69	151.43						
70	150.43		14	68.5-70	5-6-9	15	
71	149.43						
72	148.43						
73	147.43						▼
74	146.43						Water Table during drilling 5/30/2005
75	145.43		15	73.5-75	3-11-13	26	
76	144.43						
77	143.43						
78	142.43						
79	141.43						
80	140.43	Same as above, though orange in appearance	16	78.5-80	3-3-5	8	
81	139.43						
82	138.43						
83	137.43						
84	136.43						
85	135.43	Yellow brown clayey SAND (SC) saturated	17	83.5-85	2-3-3	6	
86							
87	133.43						
88	132.43						

SOUTHERN COMPANY
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DRILLING LOG
GEOLOGICAL SERVICES

Hole No. OW-1015
Sheet 4 of 4

SITE Vogtle ALWR SSAR — TOTAL DEPTH 120 — SURF.ELEV. 220.427

Depth ft.	Elev. ft.	Material Description, Classification and Remarks	Sample No.	Standard Penetration Test From To ft.	Blows	N BPF	Comments
89	131.43						
90	130.43	Yellow brown clayey SAND (SC) saturated	18	88.5-90	4-9-6	15	
91	129.43						
92	128.43						
93	127.43	Greyish white, fine- to medium-grained SAND (SP) saturated					
94	126.43						sand flowed up into augers. used water and SuperGel X to attempt to flush.
95	125.43		19	93.5-95	13-26-39	65	
96	124.43						
97	123.43						
98	122.43						
99	121.43						
100	120.43	Very light tan poorly graded SAND with silt (SP-SM)	20	98.5-100	10-13-6	19	
101	119.43						
102	118.43						
103	117.43						
104	116.43	Tan shelly (coarse) fine to medium grained clayey SAND (SC)					
105	115.43		21	103.5-105	8-9-16	25	
106	114.43						
107	113.43						
108	112.43						
109	111.43	Greenish Gray MARL					
110	110.43		22	108.5-110	6-12-33	45	
111	109.43						
112	108.43						Boring Terminated at 120'. Mixed fluid to clean auger and stabilize hole. Bentonite was additive. Approx. the volume of the ID of 125' of 4 1/4" ID auger was allowed to sit overnight. Cleaned hole with fresh water to remove mud. Volume of water used in hole was 200 gallons.
113	107.43						
114	106.43						
115	105.43		23	113.5-115	NA	NA	
116	104.43						
117	103.43						
118							
119	101.43						
120	100.43	Boring terminated at 120'	24	118.5-120	20-30-50/3"	30/ 50/3"	

Form GS9901 7-26-2004

APPENDIX F

ABANDONMENT FORMS

AND

AS BUILT
WELL CONSTRUCTION LOGS

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WELL ABANDONMENT DATA

PROJECT: SOUTHERN ALWR ESP PROJECT	**WELL/HOLE NO:** **DEPTH:** **HOLE DIAMETER:**	OW-1001A 100' ~7 5/8"
ABANDONMENT BY: S&ME, Inc.	**DATE ABANDONED:**	6/5/2005
REASON FOR ABANDONMENT: This hole was drilled with incorrect size augers.	**VOLUME USED:**	32 cubic feet
REMARKS: 32 bags of grout were used to abandon this hole.		

PROJECT: SOUTHERN ALWR ESP PROJECT	**WELL/HOLE NO:** OW-1002A **DEPTH:** 108.5' **HOLE DIAMETER:** ~7 5/8"
ABANDONMENT BY: S&ME, Inc.	**DATE ABANDONED:** 6/5/2005
REASON FOR ABANDONMENT: This hole was drilled with incorrect size augers.	**VOLUME USED:** 35 cubic feet
REMARKS: 35 bags of grout were used to abandon this hole.	

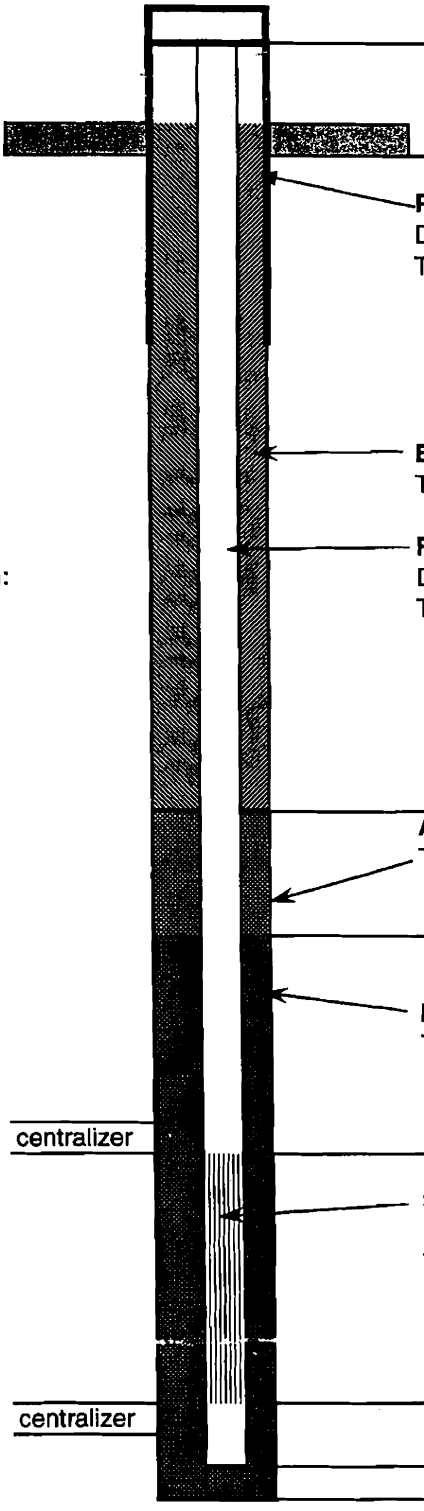
PROJECT: SOUTHERN ALWR ESP PROJECT	**WELL/HOLE NO:** **DEPTH:** **HOLE DIAMETER:**	OW-1003A 90.00' ~7 5/8"
ABANDONMENT BY: S&ME, Inc.	**DATE ABANDONED:**	5/25/2005
REASON FOR ABANDONMENT: This hole was drilled with incorrect size augers.	**VOLUME USED:**	25 cubic feet
REMARKS: 25 bags of grout were used to abandon this hole.		

PROJECT: SOUTHERN ALWR ESP PROJECT	**WELL/HOLE NO:** **DEPTH:** **HOLE DIAMETER:**	OW-1006A 125' ~7 5/8"
ABANDONMENT BY: S&ME, Inc.	**DATE ABANDONED:**	6/5/2005
REASON FOR ABANDONMENT: This hole was drilled with incorrect size augers.	**VOLUME USED:**	40 cubic feet
REMARKS: 40 bags of grout were used to abandon this hole.		

PROJECT: SOUTHERN ALWR ESP PROJECT	**WELL/HOLE NO:** **DEPTH:** **HOLE DIAMETER:**	OW-1005A 75' ~7 5/8"
ABANDONMENT BY: S&ME, Inc.	**DATE ABANDONED:**	6/5/2005
REASON FOR ABANDONMENT: This hole was drilled with incorrect size augers.	**VOLUME USED:**	25 cubic feet
REMARKS: 25 bags of grout were used to abandon this hole.		

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT	WELL NO.
CLIENT	LOCATION	
DATE INSTALLED	PREPARED	GW-1101



	DEPTH (ft.)	ELEVATION (ft.)
Top of 2" PVC Casing		233.494
3' X 3' CONCRETE PAD 4-6" THICK GROUND SURFACE	0	230.854
PROTECTIVE CASING DIA 4" x 4" x 4" TYPE Plated steel		
BACKFILL MATERIAL TYPE Cement/bentonite grout		
RISER CASING DIA 2" TYPE Sch 40 PVC		
TOP OF SEAL	113	117.854
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips		
TOP Of FILTER PACK	116	114.854
FILTER PACK TYPE: JC50FS by Unimen		
centralizer BOTTOM OF RISER/ TOP OF SCREEN	121	109.854
SCREEN DIA 2" TYPE Sch 40 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE machine slotted		
BOTTOM OF SCREEN	130	100.854
centralizer		
BOTTOM OF CASING	133	97.854
BOTTOM OF HOLE	133	97.854

STANDUP CASING:
hinge lid, welded

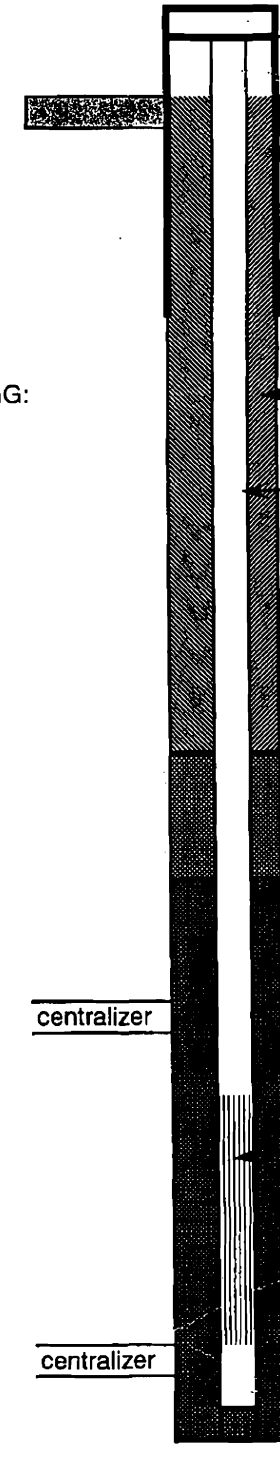
HOLE DIA: 9"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG | PROJECT: Vogtle Ash Pond | OW-109

Coords: N: 1423875.82 E: 620189.94 | LOCATION: Burke County, GA

DATE INSTALLED: 6/6/2005 | PREPARED BY: AB



		DEPTH	ELEVATION
	Top of 2" PVC casing		230.502
3' X 3' CONCRETE PAD 4-6" THICK			
	GROUND SURFACE	0	227.442
PROTECTIVE CASING			
DIA	4"x4"x4'		
TYPE	Plated steel		
STANDUP CASING: hinge lid, welded			
BACKFILL MATERIAL			
TYPE	Cement/bentonite grout		
RISER CASING			
DIA	2"		
TYPE	Sch 80 PVC		
	TOP OF SEAL	212	15.442
ANNULAR SEAL			
TYPE	Cetco Goldseal 3/8" chips		
	TOP Of FILTER PACK	216	11.442
FILTER PACK			
TYPE:	1A by DSI		
centralizer			
	BOTTOM OF RISER/ TOP OF SCREEN	219	8.442
SCREEN			
DIA	2"		
TYPE	Sch 80 PVC		
OPENING WIDTH	0.01" spaced 0.125"		
OPENING TYPE	machine slotted		
	BOTTOM OF SCREEN	229	-1.558
centralizer			
	BOTTOM OF CASING	237	-9.558
	BOTTOM OF HOLE	237	-9.558

HOLE DIA: 6"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT Vogtle ALWR SSAR	WELL NO
Coords N 142864.05 E 621884.337	LOCATION Burke County, Georgia	
DATE INSTALLED 5/26/2005	PREPARED 7/16/2005	OW-1003

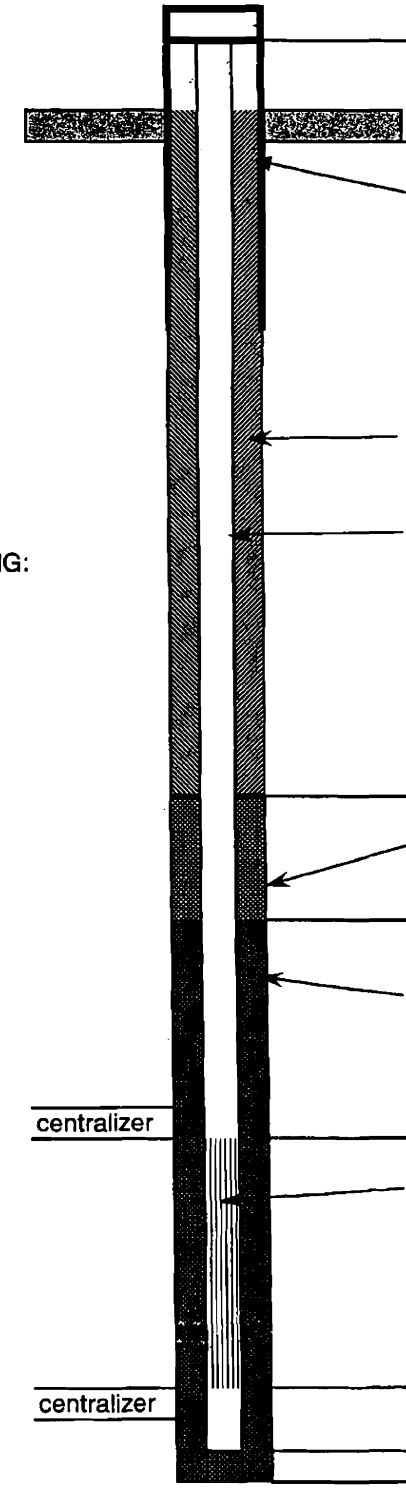


		DEPTH (ft.)	ELEVATION (ft.)
	Top of 2" PVC casing		226.284
3' X 3' CONCRETE PAD 4-6" THICK	GROUND SURFACE	0	223.044
PROTECTIVE CASING			
DIA	4"x4"x4"		
TYPE	Plated steel		
BACKFILL MATERIAL			
TYPE	Cement/bentonite grout		
RISER CASING			
DIA	2"		
TYPE	Sch 40 PVC		
STANDUP CASING: hinge lid, welded			
	TOP OF SEAL	68.5	154.544
ANNULAR SEAL			
TYPE	Cetco Goldseal 3/8" chips		
	TOP OF FILTER PACK	72	151.044
FILTER PACK			
TYPE:	1A by DSI		
	BOTTOM OF RISER/ TOP OF SCREEN	75.5	147.544
SCREEN			
DIA	2"		
TYPE	Sch 40 PVC		
OPENING WITH	0.01" spaced 0.125"		
OPENTING TYPE	machine slotted		
	BOTTOM OF SCREEN	84.8	138.244
	BOTTOM OF CASING	90.5	132.544
	BOTTOM OF HOLE	90.5	132.544

HOLE DIA: 9"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT: Vogtle ALWR SO	WELL NO.
Coords: N 1142842.17 E 621880.794	LOCATION: Burke County, Georg	
DATE INSTALLED: 6/10/2005	PREPARED: 7/18/20	OW 1004



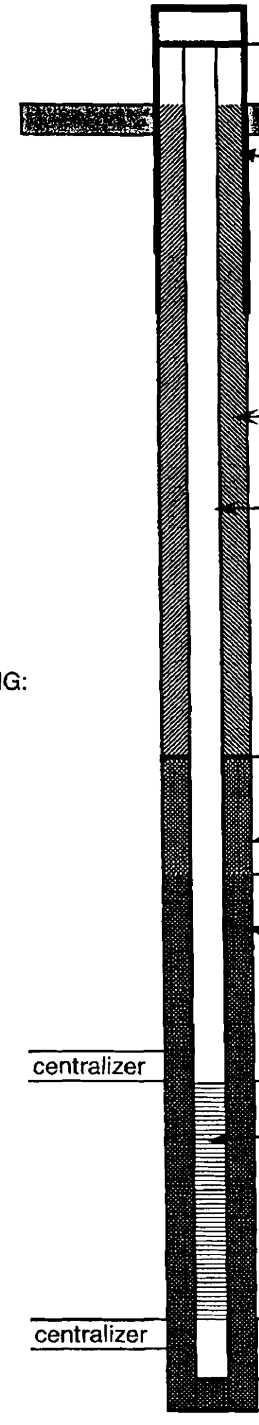
STANDUP CASING:
hinge lid, welded

HOLE DIA 6"

	DEPTH (ft.)	ELEVATION (ft.)
Top of 2" PVC CASING		225.671
3' X 3' CONCRETE PAD 4-6" THICK GROUND SURFACE	0	222.92
PROTECTIVE CASING DIA 4"X4"X4' TYPE Plated steel		
BACKFILL MATERIAL TYPE Cement/bentonite grout		
RISER CASING DIA 2" TYPE Sch 80 PVC		
TOP OF SEAL	147	75.92
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips		
TOP OF FILTER PACK	150	72.92
FILTER PACK TYPE: 1A by DSI		
BOTTOM OF RISER/ TOP OF SCREEN	153	69.92
SCREEN DIA 2" TYPE Sch 80 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted		
BOTTOM OF SCREEN	163	59.92
BOTTOM OF CASING	169	53.92
BOTTOM OF HOLE	187	35.92

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT Vogtle AFWR SSAF	WELL NO.
Coords N 1144047.86 E 620408.765	LOCATION Burke County, Georgia	
DATE INSTALLED 6/7/2005	PREPARED 7/18/2005	OW-1005



	DEPTH (ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING		267.289
3' X 3' CONCRETE PAD 4-6" THICK GROUND SURFACE	0	264.389
PROTECTIVE CASING DIA 4"X4"X4" TYPE Plated steel		
BACKFILL MATERIAL TYPE Cement/bentonite grout		
RISER CASING DIA 2" TYPE Sch 80 PVC		
STANDUP CASING: hinge lid, welded		
TOP OF SEAL	140	124.389
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips		
TOP OF FILTER PACK	143	121.389
FILTER PACK TYPE: 1A by DSI		
BOTTOM OF RISER/ TOP OF SCREEN	149	115.389
SCREEN DIA 2" TYPE Sch 80 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted		
BOTTOM OF SCREEN	159	105.389
BOTTOM OF CASING	168.5	95.889
BOTTOM OF HOLE	168.5	95.889

centralizer

centralizer

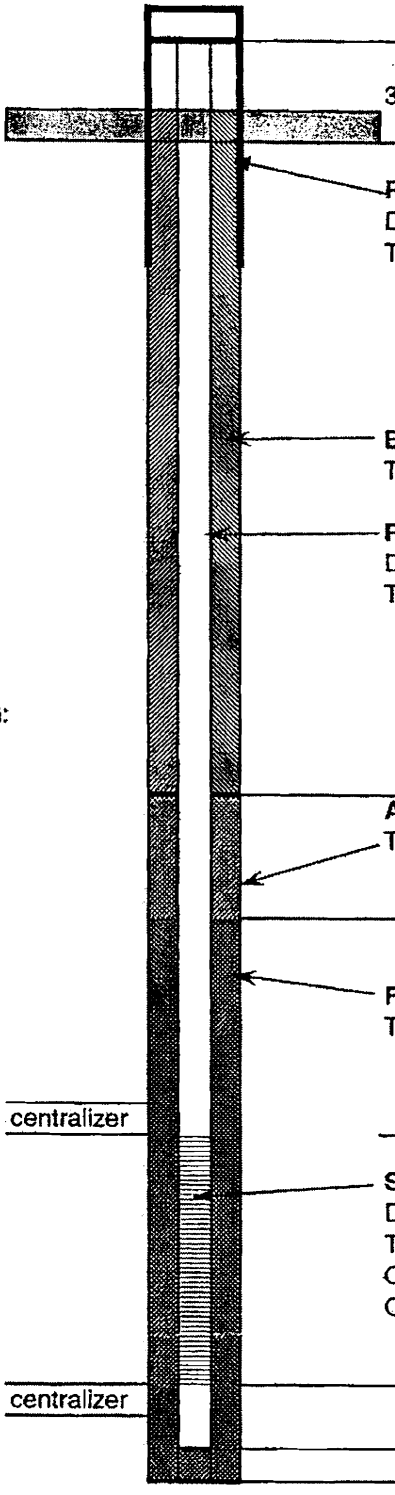
HOLE DIA: 9"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG | PROJECT: Vogtle ALWR ESA | WELL NO.

Coord's: N 1 43817.85 E 619179.749 | LOCATION: Burke County, Georgia

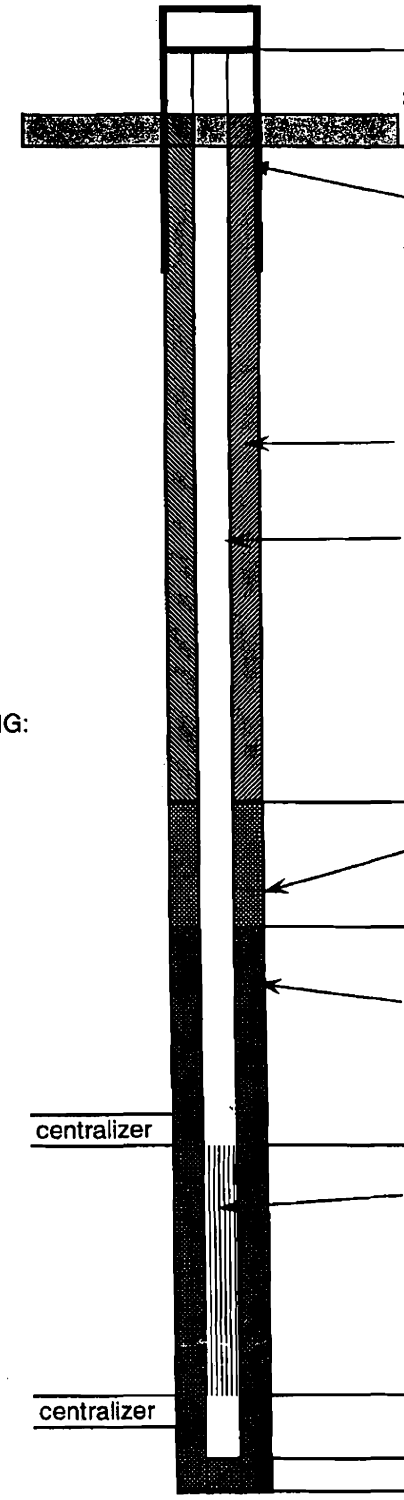
DATE INSTALLED: 6/14 - 15/07 | PREPARED: 7/18/2007 | OW-100S



	DEPTH (ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING		230.601
3' X 3' CONCRETE PAD 4-6" THICK GROUND SURFACE	0	227.121
PROTECTIVE CASING DIA 4"X4"X4" TYPE Plated steel		
BACKFILL MATERIAL TYPE Cement/bentonite grout		
RISER CASING DIA 2" TYPE Sch 80 PVC		
STANDUP CASING: hinge lid, welded		
TOP OF SEAL	110	117.121
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips		
TOP OF FILTER PACK	113	114.121
FILTER PACK TYPE: 1A by DSI		
BOTTOM OF RISER/ TOP OF SCREEN	116	111.121
SCREEN DIA 2" TYPE Sch 80 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted		
BOTTOM OF SCREEN	126	101.121
BOTTOM OF CASING	136	91.121
BOTTOM OF HOLE	136	91.121
HOLE DIA: 9"		

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT	Vogtle ALWRS SAR	WELL No.
Coords N 1142383.76 E 1930 1.009	LOCATION	Burke County, Georgia	
DATE INSTALLED 6/7/2005		PREPARED 7/18/20[illegible]	GW-1007



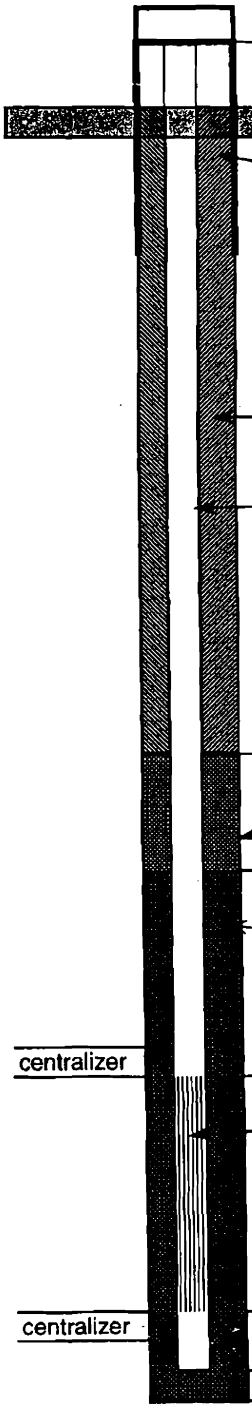
	DEPTH (Ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING		219.96
3' X 3' CONCRETE PAD 4-6" THICK GROUND SURFACE	0	216.91
PROTECTIVE CASING DIA 4"X4"X4" TYPE Plated steel **BACKFILL MATERIAL** TYPE Cement/bentonite grout **RISER CASING** DIA 2" TYPE Sch 40 PVC		
TOP OF SEAL	96	120.91
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips		
TOP OF FILTER PACK	99	117.91
FILTER PACK TYPE: 1A by DSI BOTTOM OF RISER/ TOP OF SCREEN	102	114.91
SCREEN DIA 2" TYPE Sch 40 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted		
BOTTOM OF SCREEN	112	104.91
BOTTOM OF CASING	120	96.91
BOTTOM OF HOLE	120	96.91

STANDUP CASING:
hinge lid, welded

HOLE DIA: 9"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT: Vogtle ALWR SSAR	[illegible]
Coords: N 1142347.93 E 619306.686	LOCATION: Burke County, Georgia	
DATE STARTED: 6/1/2005	PREPARED: 7/18/2[illegible]	OW-1008



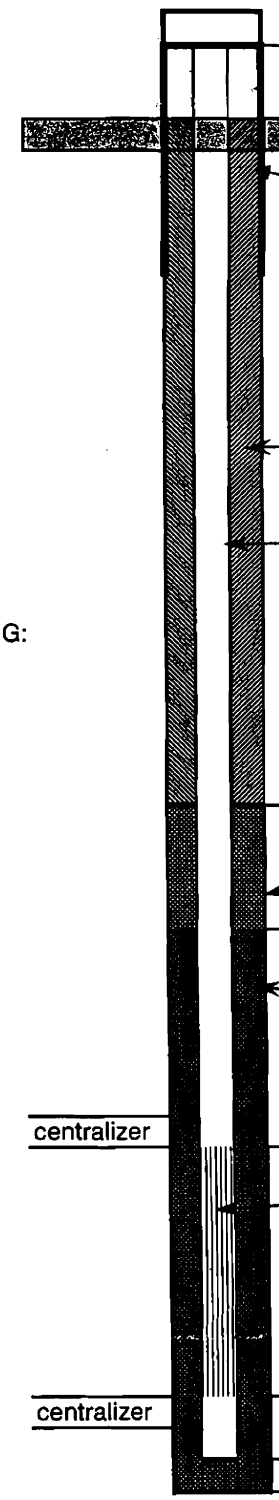
	DEPTH (ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING		219.71
3' X 3' CONCRETE PAD 4-6" THICK GROUND SURFACE	0	216.65
PROTECTIVE CASING DIA 4"X4"X4" TYPE Plated steel		
BACKFILL MATERIAL TYPE Cement/bentonite grout		
RISER CASING DIA 2" TYPE Sch 80 PVC		
TOP OF SEAL	224	-7.35
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips		
TOP OF FILTER PACK	226	-9.35
FILTER PACK TYPE: 1A by DSI		
BOTTOM OF RISER/ TOP OF SCREEN	230	-13.35
SCREEN DIA 2" TYPE Sch 80 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted		
BOTTOM OF SCREEN	240	-23.35
BOTTOM OF CASING	245	-28.35
BOTTOM OF HOLE	247	-30.35

STANDUP CASING:
hinge lid, welded

HOLE DIA: 6"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT Vogtle ALWR-5 SA	WELL NO.
Coords N 1141891.61 E 620888.608	LOCATION Burke County, Georgia	
DATE INSTALLED 5/27/2006	PREPARED 7/18/2[illegible]	OW-1009



	DEPTH (ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING		223.647
3' X 3' CONCRETE PAD 4-6" THICK GROUND SURFACE	0	220.887
PROTECTIVE CASING DIA 4"X4"X4" TYPE Plated steel		
BACKFILL MATERIAL TYPE Cement/bentonite grout		
RISER CASING DIA 2" TYPE Sch 40 PVC		
TOP OF SEAL	78	142.887
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips		
TOP OF FILTER PACK	81	139.887
FILTER PACK TYPE: 1A by DSI		
BOTTOM OF RISER/ TOP OF SCREEN	84	136.887
SCREEN DIA 2" TYPE Sch 40 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted		
BOTTOM OF SCREEN	94	126.887
BOTTOM OF CASING	98	122.887
BOTTOM OF HOLE	98	122.887

STANDUP CASING:
hinge lid, welded

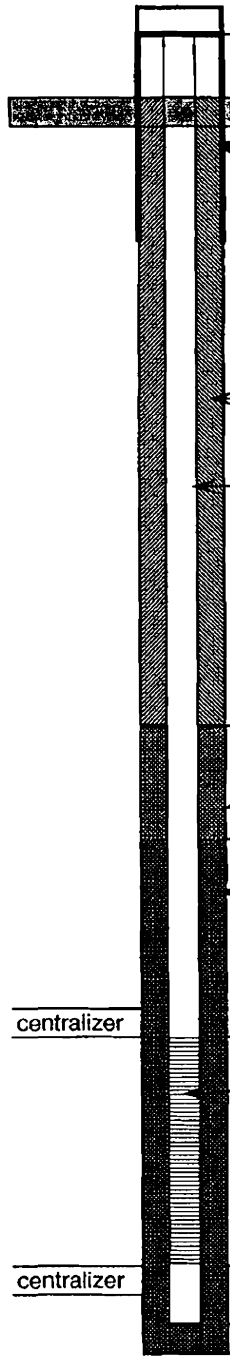
centralizer

centralizer

HOLE DIA: 9"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT: Vogtle ALWR SSAR		WELL NO.
Coords: N 1140808.98 E 620051.708	LOCATION: Burke County, Georgia		
DATE INSTALLED: 6/1/2005		PREPARED: 7/18/2005	OW 1010

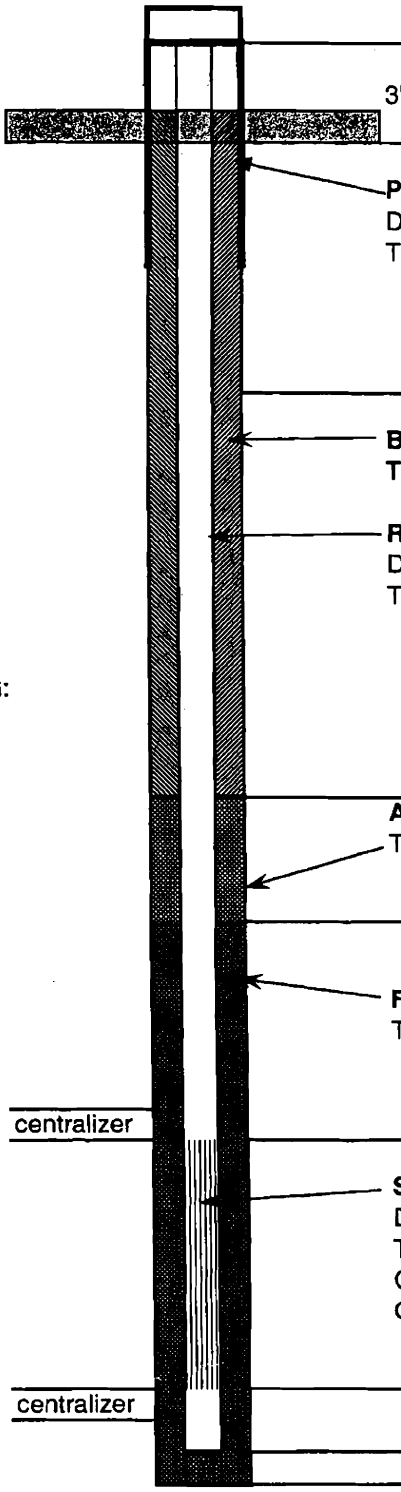


		DEPTH (ft.)	ELEVATION (ft.)
	TOP OF 2" PVC CASING		219.905
3' X 3' CONCRETE PAD 4-6" THICK	GROUND SURFACE	0	216.895
PROTECTIVE CASING DIA 4"X4"X4" TYPE Plated steel			
BACKFILL MATERIAL TYPE Cement/bentonite grout			
RISER CASING DIA 2" TYPE Sch 40 PVC			
STANDUP CASING: hinge lid, welded	TOP OF SEAL	67.0	149.895
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips	TOP OF FILTER PACK	70.1	146.795
FILTER PACK TYPE: 1A by DSI	BOTTOM OF RISER/ TOP OF SCREEN	73	143.895
centralizer			
SCREEN DIA 2" TYPE Sch 40 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted	BOTTOM OF SCREEN	83	133.895
centralizer	BOTTOM OF CASING	92	124.895
fall-in	BOTTOM OF HOLE	94	122.895

HOLE DIA: 9"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT: Vogtle ALWR SSAR	WELL NO.
Coords: N 1139956.24 E 621083.045	LOCATION: Burke County, Georgia	
DATE INSTALLED: 6/13/2005	PREPARED: 7/13/20[illegible]	OW-1011



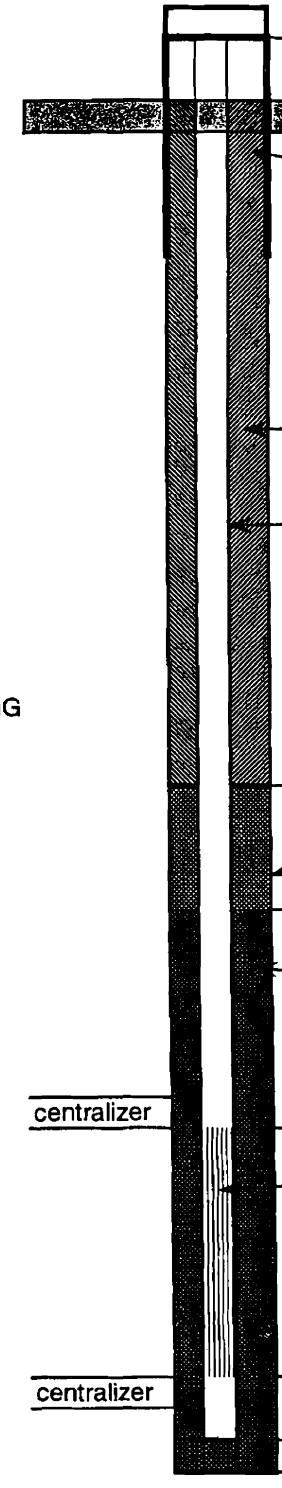
STANDUP CASING:
hinge lid, welded

HOLE DIA: 6"

		DEPTH (ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING			209.043
3' X 3' CONCRETE PAD 4-6" THICK			
GROUND SURFACE		0	205.785
PROTECTIVE CASING			
DIA	4"X4"X4"		
TYPE	Plated steel		
BACKFILL MATERIAL			
TYPE	Cement/bentonite grout		
RISER CASING			
DIA	2"		
TYPE	Sch 80 PVC		
TOP OF SEAL		193	12.785
ANNULAR SEAL			
TYPE	Cetco Puregold med chips		
TOP Of FILTER PACK		197	8.785
FILTER PACK			
TYPE:	Foster Dixiana		
BOTTOM OF RISER/ TOP OF SCREEN		200	5.785
SCREEN			
DIA	2"		
TYPE	Sch 80 PVC		
OPENING WIDTH	0.01" spaced 0.125"		
OPENING TYPE	Machine slotted		
BOTTOM OF SCREEN		210	-4.215
BOTTOM OF CASING		218	-12.215
BOTTOM OF HOLE		218	-12.215

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT: Vogtle ALWR SSAR	WELL NO.
Coords: N 1139969.49 E 621045.924	LOCATION: Burke County, Georgia	
DATE INSTALLED: 6/1/2005	PREPARED: 7/18/2005	OW 1012



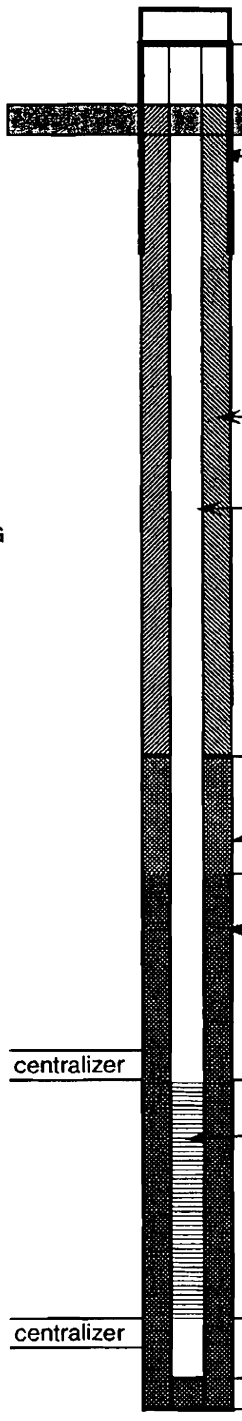
	DEPTH (ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING		208.684
3' x 3' CONCRETE PAD 4 - 6" THICK GROUND SURFACE	0	205.355
PROTECTIVE CASING DIA 4"X4"X4" TYPE Plated steel		
BACKFILL MATERIAL TYPE Cement/bentonite grout		
RISER CASING DIA 2" TYPE Sch 40 PVC		
TOP OF SEAL	67.0	138.355
ANNULAR SEAL TYPE Cetco Goldseal 3/8" chips		
TOP OF FILTER PACK	71	134.355
FILTER PACK TYPE: 1A BY DSI		
BOTTOM OF RISER/ TOP OF SCREEN	74.0	131.355
SCREEN DIA TYPE 2" TYPE Sch 40 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted		
BOTTOM OF SCREEN	83	122.355
BOTTOM OF CASING	94	111.355
BOTTOM OF HOLE	94	111.355

STANDUP CASING
hinge lid, welded

HOLE DIA: 9"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT: Vogtle AFWR SSAR	WELL NO.
Coords: N 1408054 E 621715.032	LOCATION: Burke County, Georgia	
DATE INSTALLED: 6/10/2005	PREPARED: 7/18/2005	OW-1013



		DEPTH (ft.)	ELEVATION (ft.)
	TOP OF 2" PVC CASING		219.809
3' x 3' CONCRETE PAD 4 - 6" THICK	GROUND SURFACE	0	216.869
PROTECTIVE CASING			
DIA	4"X4"X4"		
TYPE	Plated steel		
BACKFILL MATERIAL			
TYPE	Cement/bentonite grout		
RISER CASING			
DIA	2"		
TYPE	Sch 40		
	TOP OF SEAL	78	138.369
ANNULAR SEAL			
TYPE	Cetco Goldseal 3/8" chips		
	TOP OF FILTER PACK	81.0	135.869
FILTER PACK			
TYPE:	1A by DSI		
	BOTTOM OF RISER/ TOP OF SCREEN	84	132.369
SCREEN			
DIA	2"		
TYPE	Sch 40 PVC		
OPENING WIDTH	0.01" spaced 0.125"		
OPENING TYPE	Machine slotted		
	BOTTOM OF SCREEN	94	122.869
	BOTTOM OF CASING	104	112.869
	BOTTOM OF HOLE	104	112.869

STANDUP CASING
hinge lid, welded

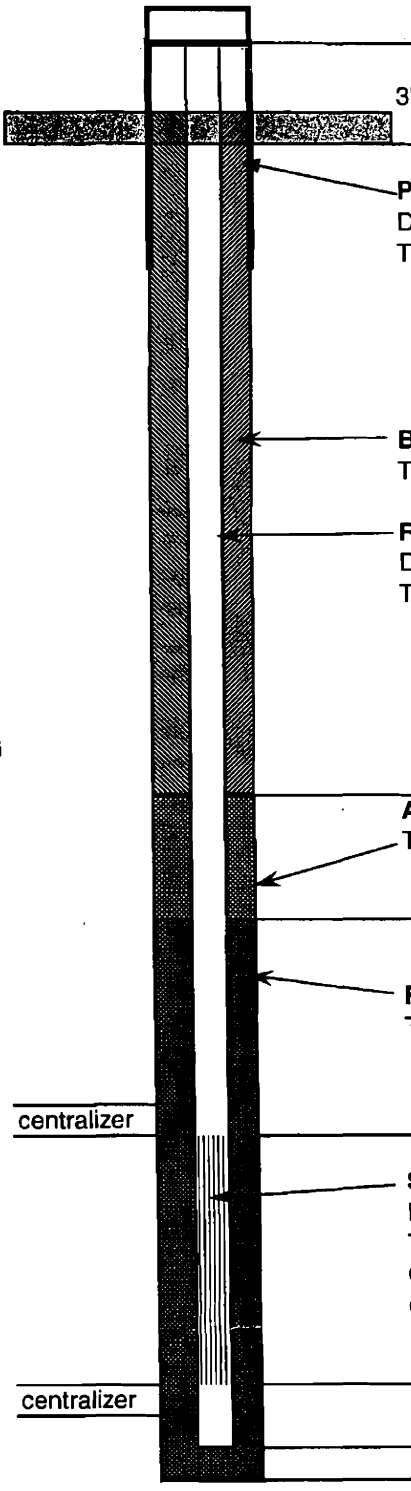
centralizer

centralizer

HOLE DIA: 9"

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT: Vogtle ALWR ISSAP	WELL NO.
Coord: N 1140565.502 E 623070.234	LOCATION: Burke County, Georgia	
DATE INSTALLED: 6/11/2006	PREPARED: 7/18/2006	OW-1014



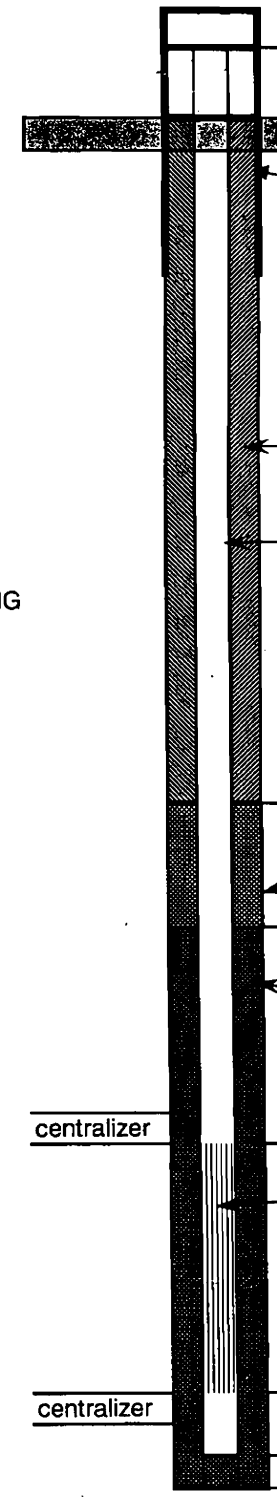
STANDUP CASING
hinge lid, welded

HOLE DIA: 6"

	DEPTH (ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING		223.856
3' x 3' CONCRETE PAD 4 - 6" THICK GROUND SURFACE	0	220.867
PROTECTIVE CASING DIA 4"X4"X4" TYPE Plated steel		
BACKFILL MATERIAL TYPE Cement/bentonite grout		
RISER CASING DIA 2" TYPE Sch 80 PVC		
TOP OF SEAL	176	44.867
ANNULAR SEAL TYPE Cetco Puregold 3/8" chips		
TOP Of FILTER PACK	179	41.867
FILTER PACK TYPE: Foster Dixiana Filter Sand		
BOTTOM OF RISER/ TOP OF SCREEN	182	38.867
SCREEN DIA 2" TYPE Sch 80 PVC OPENING WIDTH 0.01" spaced 0.125" OPENING TYPE Machine slotted		
BOTTOM OF SCREEN	192	28.867
BOTTOM OF CASING	197	23.867
BOTTOM OF HOLE	197	23.867

SOUTHERN COMPANY GENERATION

WELL CONSTRUCTION LOG	PROJECT	Vogtle ALWR SEAT	[illegible]
Coords N 1140550.57 E 623086.31	LOCATION	Burke County Georgia	
DATE INSTALLED 6/8/2005		PREPARED 7/18/2005	OW-10134



STANDUP CASING
hinge lid, welded

HOLE DIA: 9"

		DEPTH (ft.)	ELEVATION (ft.)
TOP OF 2" PVC CASING			223.157
3' x 3' CONCRETE PAD 4 - 6" THICK			
GROUND SURFACE		0	220.427
PROTECTIVE CASING			
DIA	4"X4"X4"		
TYPE	Plated steel		
BACKFILL MATERIAL			
TYPE	Cement/bentonite grout		
RISER CASING			
DIA	2"		
TYPE	Sch 40 PVC		
TOP OF SEAL		86	134.427
ANNULAR SEAL			
TYPE	Cetco Goldseal 3/8" chips		
TOP OF FILTER PACK		89.6	130.827
FILTER PACK			
TYPE:	1A BY DSI		
BOTTOM OF RISER/ TOP OF SCREEN		93	127.427
SCREEN			
DIA	2"		
TYPE	Sch 40 PVC		
OPENING WIDTH	0.01" spaced 0.125"		
OPENING TYPE	Machine slotted		
BOTTOM OF SCREEN		103	117.427
BOTTOM OF CASING		120	100.427
BOTTOM OF HOLE		120	100.427

APPENDIX G

WELL DEVELOPMENT FORMS

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MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle SSAR	Burke	27
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☐ [redacted]

3. Time spent developing well _____ min.

4. Depth of well (from top of well casing) 190.55' ft.

5. Inside diameter of well 1¾" or 1½" in.

6. Volume of water in filter pack and well casing _____ gal.

7. Volume of water removed from well _____ gal.

8. Volume of water added (if any) NONE gal.

9. Source of water added None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing)	a. 124.85' ft.	ft.
Date	b. 6-2-05	
Time	c.	
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☐ 15 (Describe)	Clear ☐ 20 Turbid ☐ 25 (Describe)
14. Total suspended solids	— mg/l	— mg/l
15. COD	— mg/l	— mg/l

Fill in if drilling fluids were used and well is at solid waste facility:

16. Well developed by: Person's Name and Firm
TIM KELLY, RICK FREDERICK } SAME

17. Additional comments on development:
WELL COULD NOT BE PURGED DUE TO DIAMETER SIZE OF PVC CASING. PUMP WOULD NOT FIT INTO CASING.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of r knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voaftle 55AR	Burke	142
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☒	20
bailed only	☐	10
pumped only		51
pumped slowly	☐	50
other	☒	[redacted]

3. Time spent developing well: 15 min.

4. Depth of well (from top of well casing): 97.0' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 4.4 gal.

7. Volume of water removed from well: Appx 13.0 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	70.10' ft.	Dry ft.
Date b.	6-15-05	6-15-05
Time c.	9:30 Am	9:45 Am
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☒ 10 Turbid ☐ 15 (Describe) WATER WAS CLEAR DURING DEVELOPMENT † WHEN DRY AFTER APPROX 1 WELL VOLUME REMOVED.	Clear ☒ 20 Turbid ☐ 25 (Describe)
14. Total suspended solids	~~—~~ mg/l	~~—~~ mg/l
15. COD	~~/~~ mg/l	~~/~~ mg/l

Fill in if drilling fluids were used and well is at solid waste facility:

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
S & MG

17. Additional comments on development:
WELL DEVELOPED USING AIR COMPRESSOR
≈ 50 PSI OF PRESSURE AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voafle SSAR	Burke	179
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☒ 20
bailed only	☐ 10
pumped only	☐ 51
pumped slowly	☐ 50
other	☐

3. Time spent developing well: 20 min.

4. Depth of well (from top of well casing): 133.62' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 1.0 gal.

7. Volume of water removed from well: Approx 3.0 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	127.17 ft.	Dry ft.
Date b.	6-15-05	6-15-05
Time c.	11:40 Am	11:55 Am
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe) Slightly turbid	Clear ☒ 20 Turbid ☐ 25 (Describe) WATER BECAME MORE CLEAR AFTER 3 WELL VOLUMES REMOVED

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
Tim Kelly
Rick Fredrick
S & ME

17. Additional comments on development:

WELL DEVELOPED USING AIR COMPRESSOR
≈ 50 PSI OF PRESSURE AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street: ~~24A 146~~

City/State/Zip:

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle 55AR	Burke	179
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well _____ min.

4. Depth of well (from top of well casing) 133.62' ft.

5. Inside diameter of well 1¾" or 1½" in.

6. Volume of water in filter pack and well casing _____ gal.

7. Volume of water removed from well _____ gal.

8. Volume of water added (if any) NONE gal.

9. Source of water added None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	127.26' ft.	ft.
Date b.	6-1-05	
Time c.		
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☐ 15 (Describe)	Clear ☐ 20 Turbid ☐ 25 (Describe)
14. Total suspended solids	— mg/l	— mg/l
15. COD	— mg/l	— mg/l

Fill in if drilling fluids were used and well is at solid waste facility:

16. Well developed by: Person's Name and Firm
Tim Kelly, Rick Frederick } S&ME

17. Additional comments on development:
WELL COULD NOT BE PURGED DUE TO DIAMETER SIZE OF PVC CASING PUMP WOULD NOT FIT INTO CASING.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle 55AR	Burke	803A
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☐	20
bailed only	☐	10
pumped only	☒	51
pumped slowly	☐	50
other _____	☒	[redacted]

3. Time spent developing well: 30 min.

4. Depth of well (from top of well casing): 89.20' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 4.7 gal.

7. Volume of water removed from well: 21 gal.

8. Volume of water added (if any): NONE gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	60.23 ft.	Dry ft.
Date b.	5/26/05	5/26/05
Time c.	2:30 pm	3:00 pm
12. Sediment in well bottom	89.20' inches	89.20 inches
13. Water clarity	Clear ☐ 10 Turbid ☐ 15 (Describe) TURBID (cloudy)	Clear ☐ 20 Turbid ☐ 25 (Describe) TURBID (CLOUDY

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY - SME
RICK FREDRICK - SME

17. Additional comments on development:
Min 3 Well Volumes Required
Max 4 Well Volumes Removed (Dry) 1st DEVELOPMENT
Noted: Pump Rate ≈ 2.0 gallon per min
Allowed well to recharge from 3:00 pm to 4:30 pm Pg 1 of 2

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____ 24A-148

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Vogtle SSAR	Burke	803 A
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☐	20
bailed only	☐	10
pumped only	☒	51
pumped slowly	☐	50
other _____	☒	[redacted]

3. Time spent developing well: 20 min.

4. Depth of well (from top of well casing): 89.20' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 4.7 gal.

7. Volume of water removed from well: 20 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	60.30' ft.	Dry ft.
Date b.	5/26/05	5/26/05
Time c.	4:30	4:50
12. Sediment in well bottom	89.20' inches	89.20 inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe)	Clear ☐ 20 Turbid ☒ 25 (Describe)
	Turbid (clay)	Turbid (clay)

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm

17. Additional comments on development:
Min of 3 well Volumes Required
Max of 4 removed (Dry) 2nd DEVELOPMENT
Note! PUMP RATE ≈ 2.0 gallon per min.

Pg 2 of 2

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voglle 55AR	Burke	804
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well: 20 min.

4. Depth of well (from top of well casing): 95.09' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in [redacted] well casing: 5.3 gal.

7. Volume of water removed from well: 16.0 gal.

8. Volume of water added (if any): NONE gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	62.31' ft.	63.10' ft.
Date b.	6-1-05	6-1-05
Time c.	4:45 pm	5:05 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 / Turbid ☑ 15 (Describe): VERY CLOUDY	Clear ☒ 20 / Turbid ☐ 25 (Describe): WATER CLEARED AFTER APPROX 1 WELL VOLUME REMOVED.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY, RICK FREDRICK } SAME

17. Additional comments on development:
3 WELL VOLUMES REMOVED
PUMP RATE ≈ 1.0 gal per min.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle SSAR	Burke	805A
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well: 55 min.

4. Depth of well (from top of well casing): 127.0' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 8.0 gal.

7. Volume of water removed from well: 24.0 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	77.69' ft.	78.20' ft.
Date b.	6-1-05	6-1-05
Time c.	6:20 pm	7:15 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☑ 15 (Describe) Gray Color Very Turbid	Clear ☒ 20 Turbid ☐ 25 (Describe) Clear after 1 well volume removed.
14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

Fill in if drilling fluids were used and well is at solid waste facility:

16. Well developed by: Person's Name and Firm
Tim Kelly, Rick Fredrick } SME

17. Additional comments on development:
3 well volumes removed
Pump rate ≈ 1.0 gal per min.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of knowledge.

Signature: _____

Print Name: _____

Firm: _____

SCS Field Form

MONITORING WELL DEVELOPMENT

Gallons per foot 0.163

Facility/Project Name	County	Well Name
Voatle SSAR	Burke	809

Facility License, Permit or Monitoring Number

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other	☒ ■

3. Time spent developing well: 20 min.

4. Depth of well (from top of well casing): 93.00 ft.

5. Inside diameter of well: 2" in.

6. Volume of water in filter pack and well casing: 3.5 gal.

7. Volume of water removed from well: 20 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: ~~None~~

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	71.50' ft.	71.66' ft.
Date b.	5/26/05	5/26/05
Time c.	1:45 pm	2:00 pm
12. Sediment in well bottom	94.35' (SEE INSP. REPORT) − 93.00' = 1.35 inches	inches
13. Water clarity	Clear ☐ 10 / Turbid ☒ 15 (Describe) SLIGHTLY TURBID	Clear ☒ 20 / Turbid ☐ 25 (Describe) CLEAR
Fill in if drilling fluids were used and well is at solid waste facility:		
14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY, RICK FREDRICK } SME, INC

17. Additional comments on development:
MIN. 3 well Volumes Required
MAX. 6 Well Volumes Removed
NOTED: Pump Rate = 2.0 gallon per min.

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voagle 55AR	Burke	850 A
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other	☒ [redacted]

3. Time spent developing well: 55 min.

4. Depth of well (from top of well casing): 193.21' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in [redacted] well casing: 11.1 gal.

7. Volume of water removed from well: 33.4 gal.

8. Volume of water added (if any): NONE gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	124.90 ft.	125.26' ft.
Date b.	6-2-05	6-2-05
Time c.	3:15 pm	4:10 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe) SLIGHTLY TURBID	Clear ☒ 20 Turbid ☐ 25 (Describe) CLEAR AFTER 2 gallons REMOVED.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
SME

17. Additional comments on development:
3 WELL VOLUMES REMOVED
PUMP RATE ≈ 1.0 gal PER MIN.

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle SSAR	Burke	852
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other	☒ [redacted]

3. Time spent developing well: 90 min.

4. Depth of well (from top of well casing): 221.63' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in [redacted] well casing: 21.7 gal.

7. Volume of water removed from well: 65 gal.

8. Volume of water added (if any): NONE gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	88.62' ft.	96.13' ft.
Date b.	6-2-05	6-2-05
Time c.	10:10 AM	11:40 AM
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☒ 10 Turbid ☐ 15 (Describe)	Clear ☒ 20 Turbid ☐ 25 (Describe)

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
Tim Kelly
Rick Fredrick
} SME

17. Additional comments on development:

3 well volumes removed

Pump rate ≈ 1.0 gal per min.

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle SSAR	Burke	853

Facility License, Permit or Monitoring Number

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well: 55 min.

4. Depth of well (from top of well casing): 224.0' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in [redacted] well casing: 16.2 gal.

7. Volume of water removed from well: 55 gal.

8. Volume of water added (if any): NONE gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	124.50' ft.	124.62' ft.
Date b.	6-1-05	6-1-05
Time c.	12:30 pm	1:25 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 / Turbid ☒ 15 (Describe) SLIGHTLY TURBID	Clear ☒ 20 / Turbid ☐ 25 (Describe) CLEAR AFTER ≈2 gallons Removed
14. Total suspended solids	~~mg/l~~	~~mg/l~~
15. COD	~~mg/l~~	~~mg/l~~

Fill in if drilling fluids were used and well is at solid waste facility:

16. Well developed by: Person's Name and Firm
TIM KELLY, RICK FREDRICK } SAME

17. Additional comments on development:

3 WELL VOLUMES REMOVED
PUMP RATE 1.0 gal per min.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voogtle SSAR	Burke	854
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? (SEE Comments) ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☐	20
bailed only	☐	10
pumped only	☒	51
pumped slowly	☐	50
other	☒	[redacted]

3. Time spent developing well: 10 min.

4. Depth of well (from top of well casing): 221.31' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~first packed~~ well casing: 14.4 gal.

7. Volume of water removed from well: 10.0 gal.

8. Volume of water added (if any): NONE gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	132.99' ft.	140.0' ft.
Date b.	6-1-05	6-1-05
Time c.	3:00 pm	3:10 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☑ 15 (Describe) SLIGHTLY TURBID	Clear ☒ 20 Turbid ☐ 25 (Describe) AFTER 10 gals REMOVED.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
} SCME

17. Additional comments on development:
THE PUMP WOULD NOT GO DEEPER THAN APPRX 140.0' SOME TYPE OF OBSTRUCTION IN WELL.
APPROX 10.0 gallons REMOVED AND THEN WENT DRY.
PUMP RATE 1.0 gal per min.

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voaftle 55AR	Burke	B55
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other	☒ [redacted]

3. Time spent developing well: 65 min.

4. Depth of well (from top of well casing): 225.50' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter packed~~ well casing: 17.2 gal.

7. Volume of water removed from well: 51.6 gal.

8. Volume of water added (if any): NONE gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	120.04' ft.	120.64' ft.
Date b.	6-2-05	6-2-05
Time c.	8:45 AM	9:50 AM
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☑ 10 Turbid ☐ 15 (Describe)	Clear ☑ 20 Turbid ☐ 25 (Describe)

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK } SAME

17. Additional comments on development:

3 WELL VOLUMES REMOVED

PUMP RATE ≈ 1.0 gal per min.

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle SSAR	Burke	856

Facility License, Permit or Monitoring Number

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well: 25 min.

4. Depth of well (from top of well casing): 120.45' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in [redacted] well casing: 7.4 gal.

7. Volume of water removed from well: 22.2 gal.

8. Volume of water added (if any): NONE gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	75.11' ft.	DRY ft.
Date b.	6-1-05	6-1-05
Time c.	5:35 pm	6:00 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☒ 10 Turbid ☐ 15 (Describe)	Clear ☒ 20 Turbid ☐ 25 (Describe)
14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

Fill in if drilling fluids were used and well is at solid waste facility:

16. Well developed by: Person's Name and Firm
TIM KELLY, RICK FREDERICK } SAME

17. Additional comments on development:
APPROX 2 WELL VOLUMES REMOVED BEFORE GOING DRY
PUMP RATE ≈ 1.0 gal per min.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voglle SSAR	Burke	1001
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well: 15 min.

4. Depth of well (from top of well casing): 137.15' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 4.44 gal.

7. Volume of water removed from well: 8.0 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	109.93 ft.	Dry ft.
Date b.	6-6-05	
Time c.	2:30pm	
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe) Gray in Color	Clear ☐ 20 Turbid ☐ 25 (Describe)
Fill in if drilling fluids were used and well is at solid waste facility:		
14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
Tim Kelly
Rick Fredrick
} S&ME

17. Additional comments on development:
WELL WHEN DRY AFTER ONLY 8 gallons REMOVED.
WATER LEVEL @ 125.49' @ 5:10pm (6-6-05) WATER LEVEL @ 124.62 (6-7-05
WATER LEVEL @ 125.39' @ 5:50pm (6-6-05)

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____ ~~2-4A-150~~

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Vogtle 55AR	Burke	1002
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☒ 20
bailed only	☐ 10
pumped only	51
pumped slowly	☐ 50
other	☒

3. Time spent developing well: 25 min.

4. Depth of well (from top of well casing): 245.60 ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack~~ and well casing: 22.3 gal.

7. Volume of water removed from well: Approx. 70 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	109.05' ft.	112.68' ft.
Date b.	6-14-05	6-14-05
Time c.	3:35	4:00
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 / Turbid ☒ 15	Clear ☒ 20 / Turbid ☐ 25
(Describe)	TURBID UNTIL WELL VOLUME REMOVED	(Describe) WATER CLEAR WHEN DEVELOPMENT COMPLETED

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	~~—~~ mg/l	~~—~~ mg/l
15. COD	~~—~~ mg/l	~~—~~ mg/l

16. Well developed by: Person's Name and Firm
Tim Kelly
Rick Fredrick
Same

17. Additional comments on development:
WELL WAS DEVELOPED USING AIR COMPRESSOR
≈ 50 PSI OF PRESSURE AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voalte SSAR	Burke	1003
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well: 65 min.

4. Depth of well (from top of well casing): 97.0' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in filter pack and well casing: 4.2 gal.

7. Volume of water removed from well: 13.0 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	71.06' ft.	Dry ft.
Date b.	6-3-05	6-3-05
Time c.	8:35 Am	9:40 Am
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe) SLIGHTLY TURBID	Clear ☒ 20 Turbid ☐ 25 (Describe) CLEAR AFTER 2ND WELL VOLUME REMOVED

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
S.I.M.G.

17. Additional comments on development:
3 WELL VOLUMES REMOVED. THE WELL WAS DRY AFTER EACH VOLUME REMOVED ALLOWED THE WELL TO RECHARGE & PURGE 3 TIMES.
PUMP RATE ≈ 1.0 gallon PER MIN.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voalle 55AR	Burke	1004
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☒	20
bailed only	☐	10
pumped only	☐	51
pumped slowly	☐	50
other	☒	[redacted]

3. Time spent developing well: 15 min.

4. Depth of well (from top of well casing): 175.0' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 9.3 gal.

7. Volume of water removed from well: APPROX 20 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	117.80' ft.	Dry ft.
Date b.	6-14-05	
Time c.	1:00	1:15
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☒ 10 / Turbid ☐ 15	Clear ☒ 20 / Turbid ☐ 25
(Describe)	WATER WAS CLEAR AT TIME OF DEVELOP.	WATER WAS CLEAR WHEN WELL WENT DRY.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
SAME

17. Additional comments on development:
WELL WAS DEVELOPED USING AIR COMPRESSOR
≈ 50 PSI OF PRESSURE USED AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle 55AR	Burke	1005
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☒	20
bailed only	☐	10
pumped only		51
pumped slowly	☐	50
other	☒	[redacted]

3. Time spent developing well: 20 min.

4. Depth of well (from top of well casing): 173.05' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 7.0 gal.

7. Volume of water removed from well: 25 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	130.07' ft.	171.33' ft.
Date b.	6-15-05	6-15-05
Time c.	8:55 AM	9:15 AM
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe): SLIGHTLY TURBID	Clear ☒ 20 Turbid ☐ 25 (Describe): CLEAR AFTER 3 WELL VOLUMES REMOVED.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
S-ME

17. Additional comments on development:
WELL DEVELOPED USING AIR COMPRESSOR
≈ 50 PSI OF PRESSURE AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Vogtle SSAR	Burke	1006
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☒ Yes ☐ No

2. Well development method:
   - surged with bailer and bailed ☐ 41
   - surged with bailer and pumped ☐ 61
   - surged with block and bailed ☐ 42
   - surged with block and pumped ☐ 62
   - surged with block, bailed, and pumped ☐ 70
   - compressed air ☒ 20
   - bailed only ☐ 10
   - pumped only ☒ 51
   - pumped slowly ☐ 50
   - other _____ ☒ [redacted]

3. Time spent developing well 25 min.

4. Depth of well (from top of well casing) 139.00' ft.

5. Inside diameter of well 2" in.

6. Volume of water in ~~filter pack and~~ well casing 9.7 gal.

7. Volume of water removed from well 30.0 gal.

8. Volume of water added (if any) gal.

9. Source of water added None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	79.81' ft.	85.14 ft.
Date b.	6-16-05	6-16-05
Time c.	7:50 Am	8:15 Am
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe) Slightly TURBID CLEARED AFTER 1 VOLUME REMOVED	Clear ☒ 20 Turbid ☐ 25 (Describe) CLEAR AT COMPLETION

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	— mg/l	— mg/l
15. COD	— mg/l	— mg/l

16. Well developed by: Person's Name and Firm
TIM. KELLY
RICK FREDRICK
S & ME

17. Additional comments on development:

WELL DEVELOPED USING AIR COMPRESSOR
≈50PSI OF PRESSURE AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle 55AR	Burke	1007
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☒ 20
bailed only	☐ 10
pumped only	51
pumped slowly	☐ 50
other	☒ [redacted]

3. Time spent developing well: 15 min.

4. Depth of well (from top of well casing): 115.0' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 7.6 gal.

7. Volume of water removed from well: APPROX 30 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	68.09 ft.	68.47' ft.
Date b.	6-14-05	6-14-05
Time c.	5:40	5:55
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 / Turbid ☒ 15	Clear ☒ 20 / Turbid ☐ 25
(Describe)	SLIGHTLY TURBID. WATER CLEAR AFTER DEVELOPMENT COMPLETED.	

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK } SAME

17. Additional comments on development:
WELL DEVELOPED USING AIR COMPRESSOR
≈ 50 PSI OF PRESSURE AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle SSAR	Burke	100B
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☒	20
bailed only	☐	10
pumped only		51
pumped slowly	☐	50
other	☒	[redacted]

3. Time spent developing well: 25 min.

4. Depth of well (from top of well casing): 252.8 ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~film pack and~~ well casing: 26.0 gal.

7. Volume of water removed from well: Appx 80 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	93.52 ft.	94.85 ft.
Date b.	6-14-05	6-14-05
Time c.	5:00 pm	5:25 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe): SLIGHTLY TURBID. CLEAR WATER WHEN DEVELOPMENT COMPLETED.	Clear ☒ 20 Turbid ☐ 25 (Describe)

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
SAME

17. Additional comments on development:
WELL DEVELOPED USING AIR COMPRESSOR
≈ 50 PSI OF PRESSURE AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voglle SSAR	Burke	1009

Facility License, Permit or Monitoring Number

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☐	20
bailed only	☐	10
pumped only	☒	51
pumped slowly	☐	50
other _____	☒	[redacted]

3. Time spent developing well 48 min.

4. Depth of well (from top of well casing) 97.0' ft.

5. Inside diameter of well 2" in.

6. Volume of water in ~~filter pack and~~ well casing 5.9 gal.

7. Volume of water removed from well 35.4 gal.

8. Volume of water added (if any) None gal.

9. Source of water added None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

11. Depth to Water (from top of well casing)	Before Development	After Development
a.	60.78' ft.	69.93' ft.
Date b.	6-3-05	6-3-05
Time c.	7:35 AM	8:23 AM
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 / Turbid ☒ 15	Clear ☒ 20 / Turbid ☐ 25
(Describe)	TAN in Color	Clear AFTER 6 well Volumes Removed.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
SAME

17. Additional comments on development:

6 - Well Volumes Removed
Pump Rate = 1.0 gallon per min.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voaftle 55AR	Burke	1010
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other	☒ [redacted]

		Before Development	After Development
11. Depth to Water (from top of well casing)	a.	55.41' ft.	90.52' ft.
Date	b.	6-3-05	6-3-05
Time	c.	11:30 ~~AM~~	12:40 pm
12. Sediment in well bottom		inches	inches
13. Water clarity		Clear ☐ 10 Turbid ☑ 15 (Describe) VERY TURBID	Clear ☐ 20 Turbid ☑ 25 (Describe) SLIGHTLY TURBID AFTER 6 WELL VOLUMES REMOVED

3. Time spent developing well	80	min.
4. Depth of well (from top of well casing)	92.0'	ft.
5. Inside diameter of well	2"	in.
6. Volume of water in ~~the pack~~ well casing	6.0	gal.
7. Volume of water removed from well	36.0	gal.
8. Volume of water added (if any)	None	gal.
9. Source of water added	None	
10. Analysis performed on water added? (If yes, attach results)	☐ Yes ☒ No	

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	~~mg/l~~	~~mg/l~~
15. COD	~~mg/l~~	~~mg/l~~

16. Well developed by: Person's Name and Firm
TIM KELLY, RICK FREDRICK } S&ME

17. Additional comments on development:

6 WELL VOLUMES REMOVED – THE WELL WAS STILL SLIGHTLY TURBID AFTER 6-WELL VOLUMES REMOVED.

PUMP RATE ≈ 1.0 gallon PER MIN.

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle SSAR	Burke	1011
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐	41
surged with bailer and pumped	☐	61
surged with block and bailed	☐	42
surged with block and pumped	☐	62
surged with block, bailed, and pumped	☐	70
compressed air	☒	20
bailed only	☐	10
pumped only		51
pumped slowly	☐	50
other	☒	[redacted]

3. Time spent developing well: 25 min.

4. Depth of well (from top of well casing): 225.0' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 22.7 gal.

7. Volume of water removed from well: Apprx 70 gal.

8. Volume of water added (if any): gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	86.12 ft.	90.10' ft.
Date b.	6-14-05	6-14-05
Time c.	2:40 pm	3:05 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe)	Clear ☒ 20 Turbid ☐ 25 (Describe)

TURBID UNTIL WATER CLEAR APPRX 1 WELL WHEN DEVELOPMEN VOLUME REMOVED COMPLETE

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
Tim Kelly
Rick Fredrick
S & ME

17. Additional comments on development:

WELL WAS DEVELOPED USING AIR COMPRESSOR
@ 50 PSI OF PRESSURE USED AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle 55AR	Burke	1012
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well: 40 min.

4. Depth of well (from top of well casing): 98.0' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack~~ well casing: 8.5 gal.

7. Volume of water removed from well: 26.0 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	45.85' ft.	52.78' ft.
Date b.	6-3-05	6-3-05
Time c.	9:55 A	10:35 A
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 / Turbid ☒ 15	Clear ☒ 20 / Turbid ☐ 25
(Describe)	VERY TURBID TAN COLOR	CLEAR AFTER 1 WELL VOLUME REMOVED.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
SAME

17. Additional comments on development:

3 WELL VOLUMES REMOVED
PUMP RATE = 1.0 gallon per min.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voaffe SSAR	Burke	1013

Facility License, Permit or Monitoring Number

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well 50 min.

4. Depth of well (from top of well casing) 108.25 ft.

5. Inside diameter of well 2" in.

6. Volume of water in fil[redacted]nd well casing 8.7 gal.

7. Volume of water removed from well 28 gal.

8. Volume of water added (if any) None gal.

9. Source of water added None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

11. Depth to Water (from top of well casing)	Before Development	After Development
a.	54.86' ft.	69.96' ft.
Date b.	6-15-05	6-15-05
Time c.	~~7:40~~ AM	8:30
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15	Clear ☒ 20 Turbid ☐ 25
(Describe)	SLIGHTLY TURBID	CLEAR AFTER 3 WELL VOLUMES REMOVED.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	~~mg/l~~	~~mg/l~~
15. COD	~~mg/l~~	~~mg/l~~

16. Well developed by: Person's Name and Firm
TIM. KELLY
RICK FREDRICK
S & ME

17. Additional comments on development:
APPROX 3 WELL VOLUMES REMOVED
PUMP RATE AT 1.0 gallon PER MIN.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of my knowledge.

Signature: _____

Print Name: _____

Firm: _____

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voglle SSAR	Burke	1014
Facility License, Permit or Monitoring Number		

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☒ 20
bailed only	☐ 10
pumped only	51
pumped slowly	☐ 50
other	☒

3. Time spent developing well: 25 min.

4. Depth of well (from top of well casing): 205' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in ~~filter pack and~~ well casing: 15.0 gal.

7. Volume of water removed from well: APPROX 95 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing) a.	113.0' ft.	119.51' ft.
Date b.	6-14-05	6-14-05
Time c.	1:50 pm	2:15 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe) WATER CLEAR AFTER 10 MIN. OF DEVELOPMENT	Clear ☒ 20 Turbid ☐ 25 (Describe)

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
TIM KELLY
RICK FREDRICK
SSME

17. Additional comments on development:
WELL WAS DEVELOPED USING AIR COMPRESSOR
~ 50 PSI OF PRESSURE USED AT BOTTOM OF WELL

Facility Address or Owner/Responsible Party Address

Name:

Firm:

Street:

City/State/Zip:

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature:

Print Name:

Firm:

MONITORING WELL DEVELOPMENT

Facility/Project Name	County	Well Name
Voatle 55AR	Burke	1015

Facility License, Permit or Monitoring Number

1. Can this well be purged dry? ☐ Yes ☒ No

2. Well development method:

surged with bailer and bailed	☐ 41
surged with bailer and pumped	☐ 61
surged with block and bailed	☐ 42
surged with block and pumped	☐ 62
surged with block, bailed, and pumped	☐ 70
compressed air	☐ 20
bailed only	☐ 10
pumped only	☒ 51
pumped slowly	☐ 50
other _____	☒ [redacted]

3. Time spent developing well: 60 min.

4. Depth of well (from top of well casing): 122.40' ft.

5. Inside diameter of well: 2" in.

6. Volume of water in [redacted] well casing: 9.6 gal.

7. Volume of water removed from well: 30.0 gal.

8. Volume of water added (if any): None gal.

9. Source of water added: None

10. Analysis performed on water added? ☐ Yes ☒ No
(If yes, attach results)

	Before Development	After Development
11. Depth to Water (from top of well casing)	a. 63.47' ft.	70.97' ft.
Date	b. 6-3-05	6-3-05
Time	c. 1:30 pm	2:30 pm
12. Sediment in well bottom	inches	inches
13. Water clarity	Clear ☐ 10 Turbid ☒ 15 (Describe) VERY MUDDY THICK BROWN IN COLOR	Clear ☒ 20 Turbid ☐ 25 (Describe) WATER BECAME CLEAR AFTER ≈ 3 WELL VOLUMES REMOVED.

Fill in if drilling fluids were used and well is at solid waste facility:

14. Total suspended solids	mg/l	mg/l
15. COD	mg/l	mg/l

16. Well developed by: Person's Name and Firm
Tim Kelly
Rick Fredrick
} SME

17. Additional comments on development:

3 Well Volumes Removed

Pump Rate ≈ 1.0 gallon per min.

Facility Address or Owner/Responsible Party Address

Name: _____

Firm: _____

Street: _____

City/State/Zip: _____

I hereby certify that the above information is true and correct to the best of m knowledge.

Signature: _____

Print Name: _____

Firm: _____

APPENDIX H

WELL INSPECTION FORMS

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SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number LT-1B Well Status active

Inspected by S.C. Bourke Date 6/16/05

Company SCS

Well Surface Description:

Stickup (ground surface to top of riser casing): 2.61'

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.55'

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity:

Remarks:

Well Description:

Depth to water (measured from top of riser casing): 66.36'

Well depth (measured from top of riser casing to bottom of well): 93.48'

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: ~ 0.2' hard mud on bottom

Recommended for Development: ____ Yes ✓ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number LT -7A Well Status active

Inspected by S.C. Boarq Date 6/16/05

Company SCS

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.74'

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.55

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity:

Remarks: no concrete surround

Well Description:

Depth to water (measured from top of riser casing): 64.80'

Well depth (measured from top of riser casing to bottom of well): 89.02

Evidence of sediment in bottom of well: ____ Yes ✓ No ____ Maybe

Remarks:

Recommended for Development: ____ Yes ✓ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number LT-12 Well Status active

Inspected by S.C. Barker Date 6/16/05

Company SCS

Well Surface Description:

Stickup (ground surface to top of riser casing): 0.18'

Riser casing diameter: 2" ND

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.55

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity:

Remarks: no concrete surround

Well Description:

Depth to water (measured from top of riser casing): 61.44'

Well depth (measured from top of riser casing to bottom of well): 88.35'

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: little sediment on end of probe after recording water level

Recommended for Development: ____ Yes ✓ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number LT-13 Well Status active

Inspected by Sc Bearce / L. Headland Date 6/16/05

Company SCS / Bechtel

Well Surface Description:

Stickup (ground surface to top of riser casing): 2.26 - 0.52

Riser casing diameter: 4" ND sch 40 4"ND sched 40 PVC

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: .55 0.55

Cap: ____ Yes ✓ No Locked: ✓ Yes ____ No

Concrete surface seal: ✓ Yes ____ No

Surface seal condition/integrity:

Remarks: difficult positioning because of sleeves level recorder. In small steel building

Well Description:

Depth to water (measured from top of riser casing): 64.60

Well depth (measured from top of riser casing to bottom of well): 90.65

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: ____

Recommended for Development: ____ Yes ✓ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 27 Well Status inactive

Inspected by John Pugh Date 5-18-05

Company Southern Company Services 12:38 EDT

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.4 ft

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.7 ft

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 126.40 ft

Well depth (measured from top of riser casing to bottom of well): 190.40 ft

Evidence of sediment in bottom of well: ____ Yes ✓ No ____ Maybe

Remarks: NO EVIDENCE OF SEDIMENT OBSERVED

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 29 Well Status Inactive

Inspected by John Pugh / L. Headland Date 5/19/05

Company SCS / Bechtel

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.9' - 0.12' = 1.78'

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.66'

Cap: ✓ Yes ____ No Locked: ____ Yes ✓ No (lock on top of well)

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 211.94'

Well depth (measured from top of riser casing to bottom of well): 99.6'

Evidence of sediment in bottom of well: ____ Yes ✓ No ____ Maybe

Remarks: tip clear.

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 142 Well Status Inactive

Inspected by J. Pugh / L. Haelland Date 5/19/05

Company SCS / Bechtel 11:55 AM

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.94' - 0.58' = 1.36'

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.66'

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No (lock cut)

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: Borehole casing diameter (steel) = 0.33'
well consists of :- protective casing, borehole casing + riser casing.

Well Description:

Depth to water (measured from top of riser casing): 70.5'

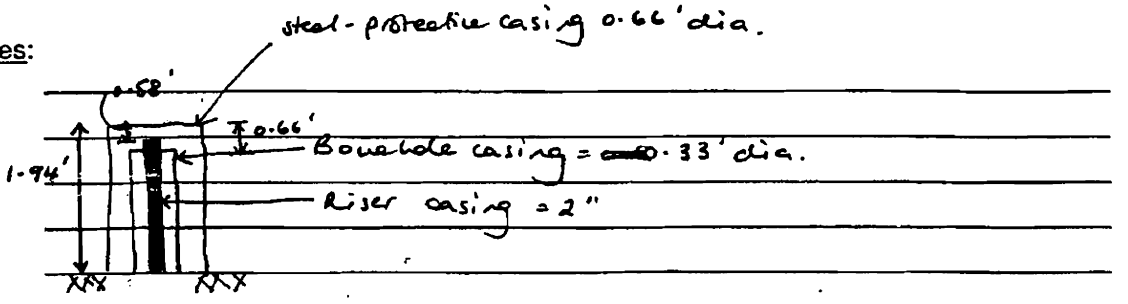
Well depth (measured from top of riser casing to bottom of well): 97.37'

Evidence of sediment in bottom of well: ____ Yes ✓ No ____ Maybe

Remarks: clean tip

Recommended for Development: ✓ Yes ____ No

Notes:



SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 179 Well Status inactive

Inspected by JOHN PUGH Date 05/18/05 16:44

Company SOUTHERN COMPANY SERVICES

Well Surface Description:

Stickup (ground surface to top of riser casing): 0.25 FT

Riser casing diameter: 2 IN.

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.71 FT

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 127.23 FT

Well depth (measured from top of riser casing to bottom of well): 132.62 FT

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: PROBE STAINED W/ VERY FINE SILT

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 802A

Well Status active

Inspected by SBearce / JHeadland

Date 6/14/05

Company SCS / Bechtel

Well Surface Description:

Stickup (ground surface to top of riser casing): 3.27 - 0.49 = 2.78'

Riser casing diameter: 4" ND sch 40 PVC

Steel surface protective casing: √ Yes — No

Protective casing diameter: 0.55'

Cap: — Yes Y No Locked: Y Yes — No

Concrete surface seal: — Yes Y No

Surface seal condition/integrity:

cover in good shape

Remarks: needs casing cap

Well Description:

Depth to water (measured from top of riser casing): 61.01

Well depth (measured from top of riser casing to bottom of well): 90.50

Evidence of sediment in bottom of well: X Yes — No — Maybe

Remarks: no sediment on probe

Recommended for Development: _____ Yes _____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 803 A Well Status Inactive

Inspected by John Pugh + Loiselleadlad Date 5-19-05

Company Southern Company 9:30 AM EST

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.53' - 0.42' = 1.11'

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.83'

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No (combination)

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A four surrounding posts

Remarks:

Well Description:

Depth to water (measured from top of riser casing): 60.25'

Well depth (measured from top of riser casing to bottom of well): 89.51'

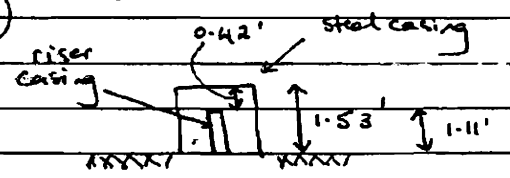
Evidence of sediment in bottom of well: ____ Yes ____ No ✓ Maybe

Remarks: Soft @ bottom, silt on tip of dipmeter

Recommended for Development: ✓ Yes ____ No

Notes:

Current riser casing / protective casing measurements (5-19-05 - 5/18/05)



SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 804 Well Status Inactive

Inspected by John Pugh / L. Heathcock Date 5/19/05

Company SCS 9.55 AM

Well Surface Description:

Stickup (ground surface to top of riser casing): 2.11' - 0.39' = 1.72'

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.83'

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A Four concrete posts surrounding well.

Remarks:

Well Description:

Depth to water (measured from top of riser casing): 62.13'

Well depth (measured from top of riser casing to bottom of well): 95.2'

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: silt on tip of dipmeter

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 805A Well Status Inactive

Inspected by J. Pugh / L. Heald Date 5/19/05

Company SCS / Bechtel

Well Surface Description:

Stickup (ground surface to top of riser casing): 2.0 - 0.42 = 1.58'

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.83'

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 77.72'

Well depth (measured from top of riser casing to bottom of well): 128.55'

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: soft ~silt on tip.

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 806B Well Status active

Inspected by S. Beard Date _____

Company SCS

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.8 − 0.65 = 1.15

Riser casing diameter: 2" ND Sch 40 PVC

Steel surface protective casing: ✓ Yes — No

Protective casing diameter: 0.95'

Cap: — Yes ✓ No Locked: ✓ Yes — No

Concrete surface seal: — Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: _____

Well Description:

Depth to water (measured from top of riser casing): 60.42

Well depth (measured from top of riser casing to bottom of well): 69.35

Evidence of sediment in bottom of well: — Yes ✓ No — Maybe

Remarks: hard bottom touch

Recommended for Development: _____ Yes ✓ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 808 Well Status active

Inspected by SBeare/LHeadland Date 6/16/05

Company SCS

Well Surface Description:

0.98 | -0.12

Stickup (ground surface to top of riser casing): .98+.98-.12= 0.98

Riser casing diameter: 4" ND Sch 40 PVC

Steel surface protective casing: ✓ Yes — No

Protective casing diameter: 0.55

Cap: — Yes ✓ No Locked: ~~—~~ Yes ✓ No

Concrete surface seal: ✓ Yes — No — SCB.

Surface seal condition/integrity: good

Remarks: In Steel building

Well Description:

Depth to water (measured from top of riser casing): 57.52

Well depth (measured from top of riser casing to bottom of well): ~75.40

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: soft bottom

Recommended for Development: ____ Yes ✓ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 809 Well Status inactive

Inspected by John Pugh Date 5-18-05

Company Southern Company Services

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.23 ft

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.56 ft

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: ____

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 71.41 ft

Well depth (measured from top of riser casing to bottom of well): 94.35 ft

Evidence of sediment in bottom of well: X Yes ____ No ____ Maybe

Remarks: brown substance on point of water level indicator when bottom was measured

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 850 A Well Status Inactive

Inspected by John Pugh Date 5-18-05 15:30 EDT

Company Southern Company Services

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.96 ft

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.56 ft

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: ____

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 126.12 ft

Well depth (measured from top of riser casing to bottom of well): 193.68

Evidence of sediment in bottom of well: ____ Yes X No ____ Maybe

Remarks: ____

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 851A Well Status inactive

Inspected by JOHN PUGH Date 05/18/05 17:00 EDT

Company SOUTHERN COMPANY SERVICES

Well Surface Description:

Stickup (ground surface to top of riser casing): 2.0 FT

Riser casing diameter: 2 IN.

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.56 FT

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 149.65 FT

Well depth (measured from top of riser casing to bottom of well): 285.18 FT

Evidence of sediment in bottom of well: ____ Yes ✓ No ____ Maybe

Remarks: ____

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 852 Well Status inactive

Inspected by John Pugh Date 5-18-05 13:19 EDT

Company Southern Company Services

Well Surface Description:

Stickup (ground surface to top of riser casing): 2.0 FT

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.52 FT

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 89.27 FT

Well depth (measured from top of riser casing to bottom of well): 222.90 FT

Evidence of sediment in bottom of well: ____ Yes ✓ No ____ Maybe

Remarks: NO EVIDENCE OF SEDIMENT OBSERVED

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 853 Well Status inactive

Inspected by JOHN BUSH Date 05/18/05

Company SOUTHERN COMPANY SERVICES 10:10 EDT

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.86 FT

Riser casing diameter: 2 IN.

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.56 FT

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 125.69 FT

Well depth (measured from top of riser casing to bottom of well): 220.86 FT

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: FINE SAND & ORGANIC MTL. ON PROBE

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 854 Well Status inactive

Inspected by JOHN PUGH Date 05/18/05

Company SOUTHERN COMPANY SERVICES ~~16:34~~ EDT 16:24

Well Surface Description:

Stickup (ground surface to top of riser casing): 1.85 FT

Riser casing diameter: 2 IN.

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.56 FT

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 134.24 FT

Well depth (measured from top of riser casing to bottom of well): 222.33

Evidence of sediment in bottom of well: ✓ Yes ____ No ____ Maybe

Remarks: SOFT BOTTOM BELOW SCREENED INTERVAL
PROBE CONTAINS ORGANIC & SILT MATERIAL TRACES

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 855 Well Status inactive

Inspected by John Pugh Date 5-18-05 12:58 EDT

Company Southern Co. Services

Well Surface Description:

Stickup (ground surface to top of riser casing): 2.0 FT.

Riser casing diameter: 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.52 FT

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 120.40FT

Well depth (measured from top of riser casing to bottom of well): 224.50FT

Evidence of sediment in bottom of well: ____ Yes ____ No ____ Maybe

Remarks: NO EVIDENCE OF SEDIMENT OBSERVED --- HOWEVER, MEASURED DEPTH OF 224.50 FT IS LESS THAN DOCUMENTED BOTTOM OF SCREENED INTERVAL.

Recommended for Development: ✓ Yes ____ No

Notes:

SNC ALWR ESP PROJECT
EXISTING OBSERVATION WELL INSPECTION REPORT

Well Number 856 Well Status inactive

Inspected by JOHN RIGN Date 05/18/05 13:47 EDT

Company SOUTHERN COMPANY SERVICES

Well Surface Description:

Stickup (ground surface to top of riser casing): 2.0 FT

Riser casing diameter: ~~0.52 FT~~ 2"

Steel surface protective casing: ✓ Yes ____ No

Protective casing diameter: 0.52 FT

Cap: ✓ Yes ____ No Locked: ✓ Yes ____ No

Concrete surface seal: ____ Yes ✓ No

Surface seal condition/integrity: N/A

Remarks: ____

Well Description:

Depth to water (measured from top of riser casing): 75.70 FT

Well depth (measured from top of riser casing to bottom of well): 182.14 FT

Evidence of sediment in bottom of well: ____ Yes ____ No ____ Maybe

Remarks: MEASURED DEPTH LESS THAN ORIGINAL BOTTOM OF SCREENED INTERVAL. NO EVIDENCE OF SEDIMENT OBSERVED ON PROBE

Recommended for Development: ✓ Yes ____ No

Notes:

APPENDIX I

LABORATORY DATA

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Intracompany Correspondence

SOUTHERN COMPANY
Energy to Serve Your World℠

Date: August 24, 2005

To: Ms. Rhonda Tinsley

From: Mr. Bobby Williams

Subject: Plant Vogtle ESP

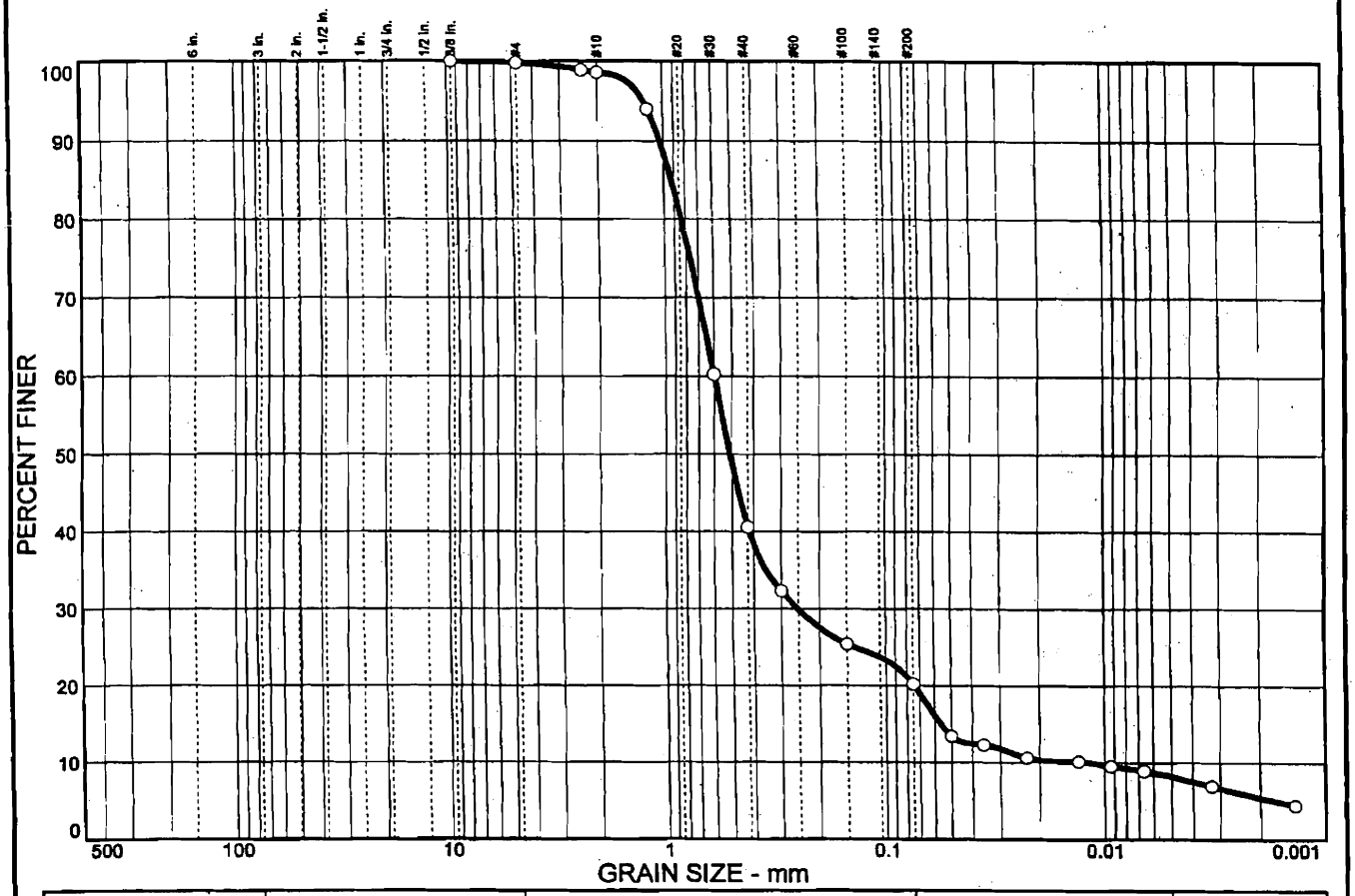
Enclosed are the test results for the Plant Vogtle ESP Project soil samples delivered to the Southern Company Central Laboratory on July 28, 2005. Tests performed include, Soil Particle Size Analysis with Hydrometer (ASTM D-422), and Specific Gravity of Soil (ASTM D-854).

We appreciate the opportunity to assist you on this project. If there are any questions, or if we can be of any further assistance, please call me at 8-255-6508 or Sam Moore at 8-255-6061.

Sincerely,

Bobby Williams, PE
Geostructural Services

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.2	79.6	12.0	8.2

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
.375 in.	100.0		
#4	99.8		
#8	98.9		
#10	98.6		
#16	94.0		
#30	60.2		
#40	40.6		
#50	32.3		
#100	25.4		
#200	20.2		

* (no specification provided)

Soil Description

Light Gray Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.925 D_{60}= 0.598 D_{50}= 0.510
D_{30}= 0.252 D_{15}= 0.0564 D_{10}= 0.0122
C_u= 49.11 C_c= 8.71

Classification

USCS= SM AASHTO=

Remarks

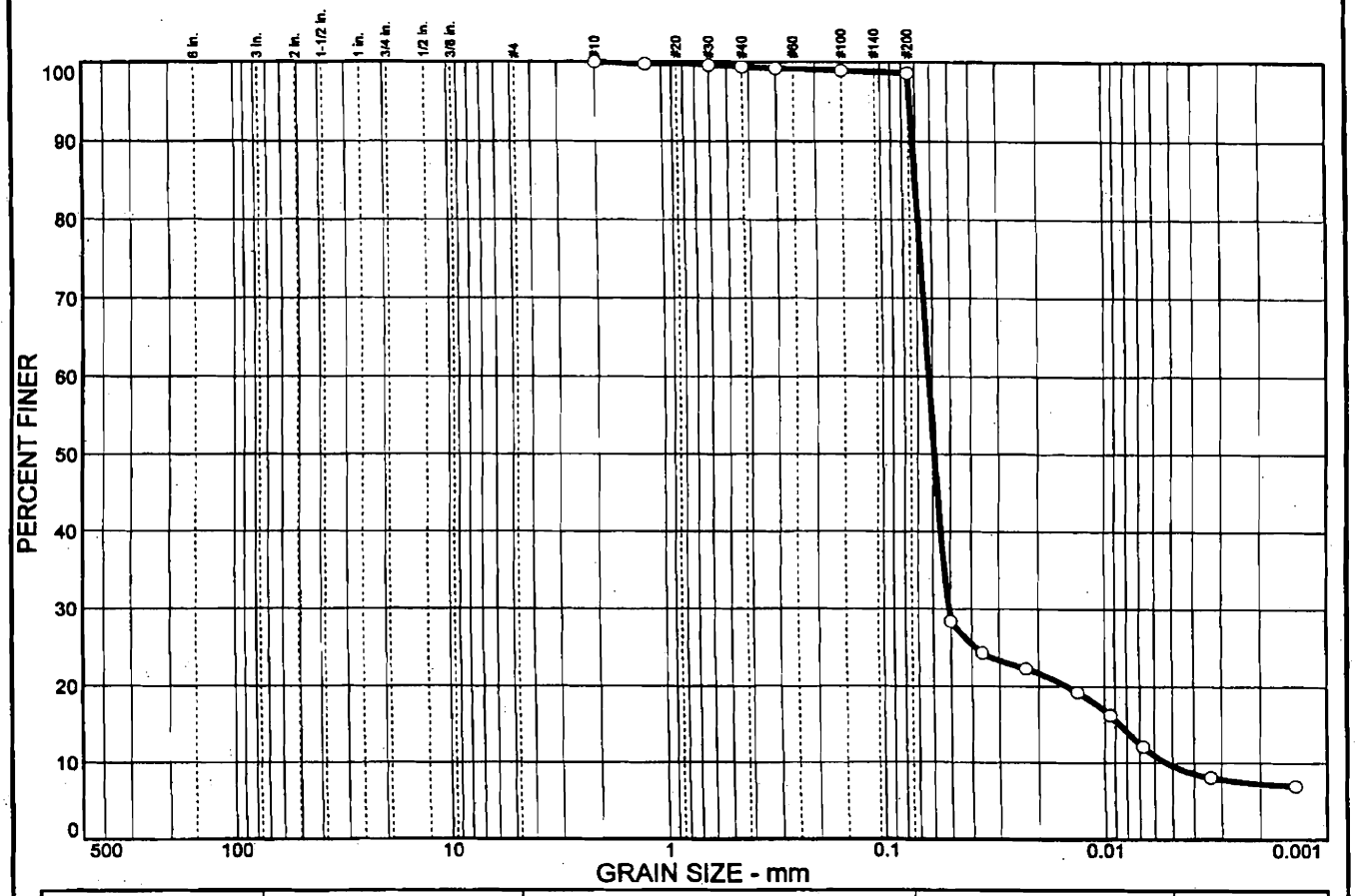
Bag Sample
Specific Gravity - 2.65

Sample No.: #27 **Source of Sample:** **Date:** 08/22/05
Location: Boring #1002 **Elev./Depth:** 218.5'-220.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 1

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	1.4	89.0	9.6

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#10	100.0		
#16	99.8		
#30	99.6		
#40	99.4		
#50	99.2		
#100	98.9		
#200	98.6		

* (no specification provided)

Soil Description

Dark Gray Silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.0705 D_{60}= 0.0624 D_{50}= 0.0590
D_{30}= 0.0509 D_{15}= 0.0086 D_{10}= 0.0053
C_u= 11.73 C_c= 7.81

Classification

USCS= ML AASHTO=

Remarks

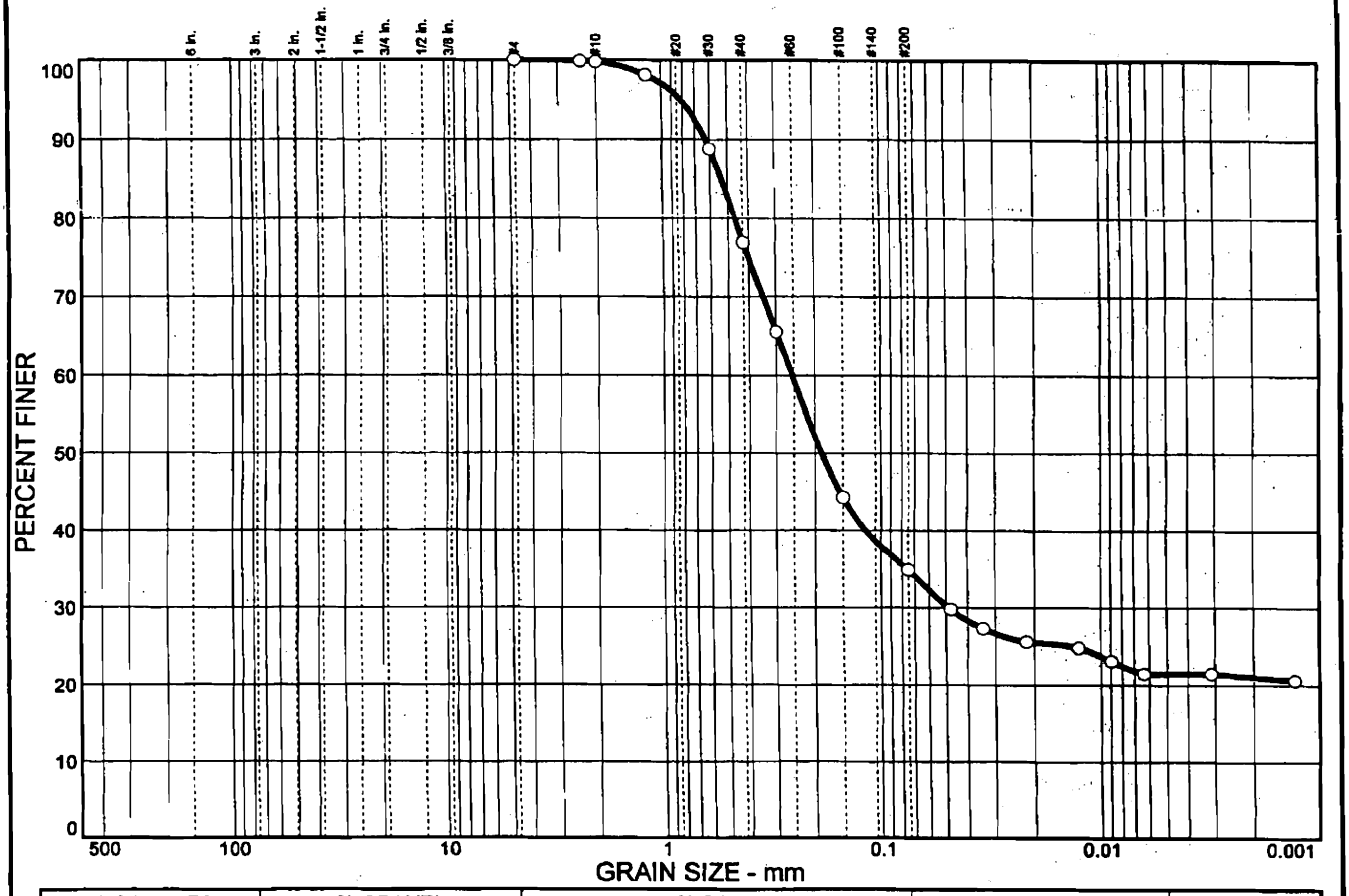
Bag Sample
Specific Gravity - 2.62

Sample No.: #29 **Source of Sample:** **Date:** 08/22/05
Location: Boring #1002 **Elev./Depth:** 237'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 2

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	65.1	13.4	21.5

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#4	100.0		
#8	99.9		
#10	99.8		
#16	98.1		
#30	88.8		
#40	76.9		
#50	65.5		
#100	44.3		
#200	34.9		

* (no specification provided)

Soil Description

Reddish Brown Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.533 D_{60}= 0.254 D_{50}= 0.186
D_{30}= 0.0487 D_{15}= D_{10}=
C_u= C_c=

Classification

USCS= SM AASHTO=

Remarks

Jar Sample
Specific Gravity - 2.69

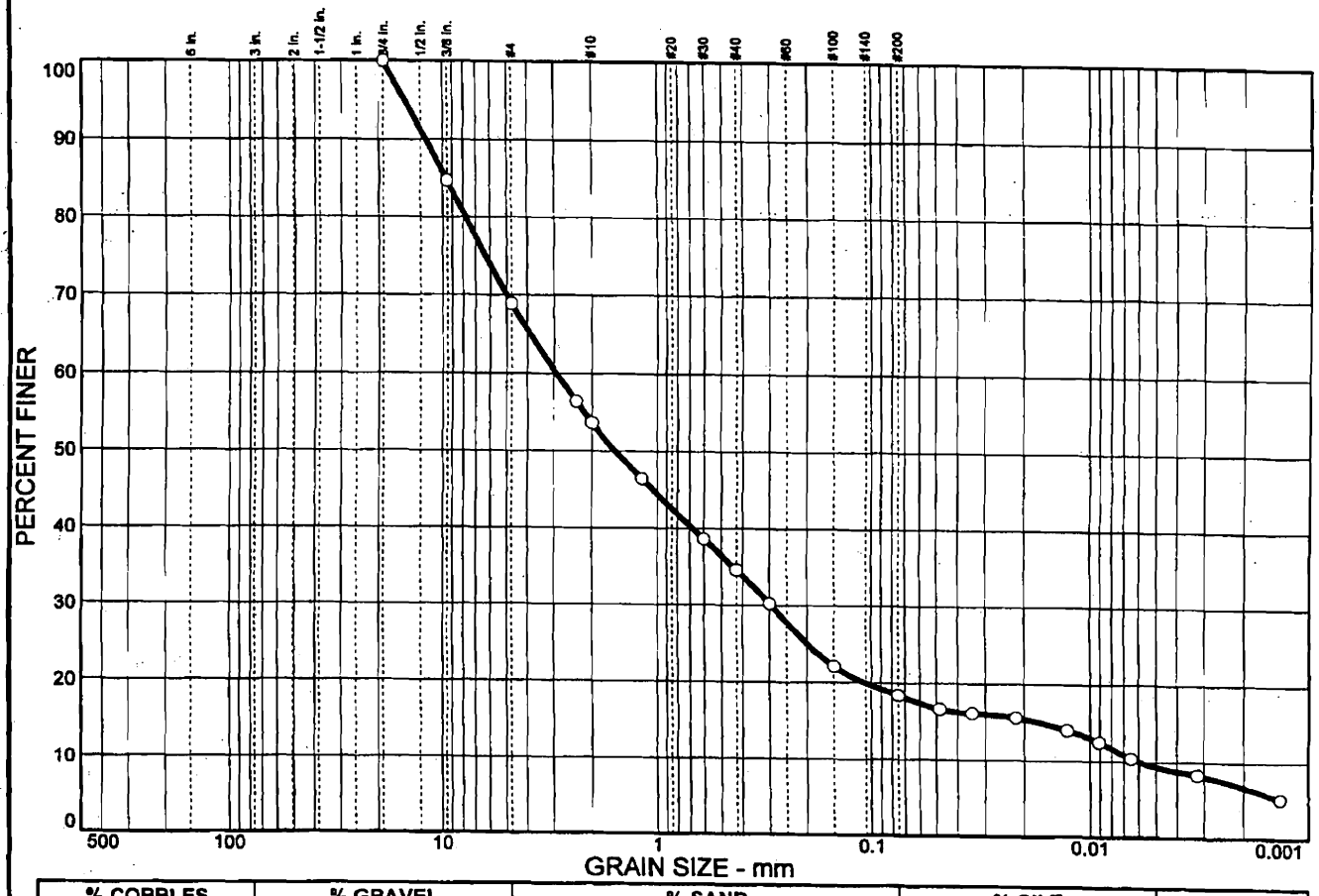
Sample No.: #16 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1003 **Elev./Depth:** 78.5'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP

Project No: V003-DE **Lab#** 3

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	31.1	50.5	9.1	9.3

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
0.75 in.	100.0		
.375 in.	84.7		
#4	68.9		
#8	56.4		
#10	53.6		
#16	46.4		
#30	38.6		
#40	34.6		
#50	30.2		
#100	22.1		
#200	18.4		

* (no specification provided)

Soil Description

Light Tan Silty sand with gravel

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 9.65 D_{60}= 2.92 D_{50}= 1.57
D_{30}= 0.295 D_{15}= 0.0171 D_{10}= 0.0060
C_u= 486.69 C_c= 4.99

Classification

USCS= SM AASHTO=

Remarks

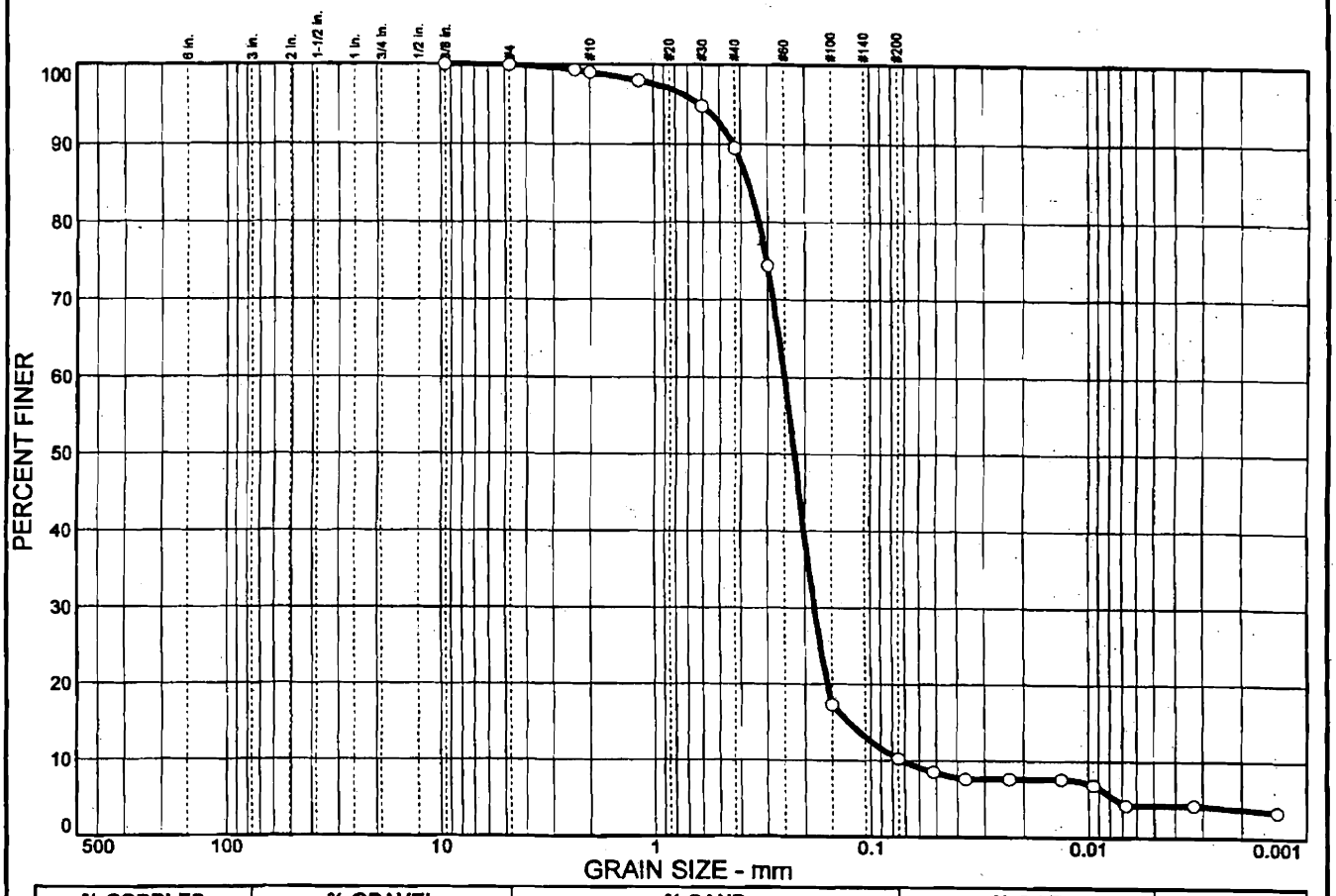
Jar Sample
Spicific Gravity - 2.68

Sample No.: #17 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1003 **Elev./Depth:** 83.5'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 4

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.1	89.7	6.0	4.2

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
.375 in.	100.0		
#4	99.9		
#8	99.3		
#10	99.0		
#16	98.0		
#30	94.8		
#40	89.5		
#50	74.4		
#100	17.3		
#200	10.2		

* (no specification provided)

Soil Description

Gray Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.368 D_{60}= 0.251 D_{50}= 0.225
D_{30}= 0.180 D_{15}= 0.126 D_{10}= 0.0725
C_u= 3.46 C_c= 1.79

Classification

USCS= SP-SM AASHTO=

Remarks

Bag Sample
Specific Gravity - 2.69

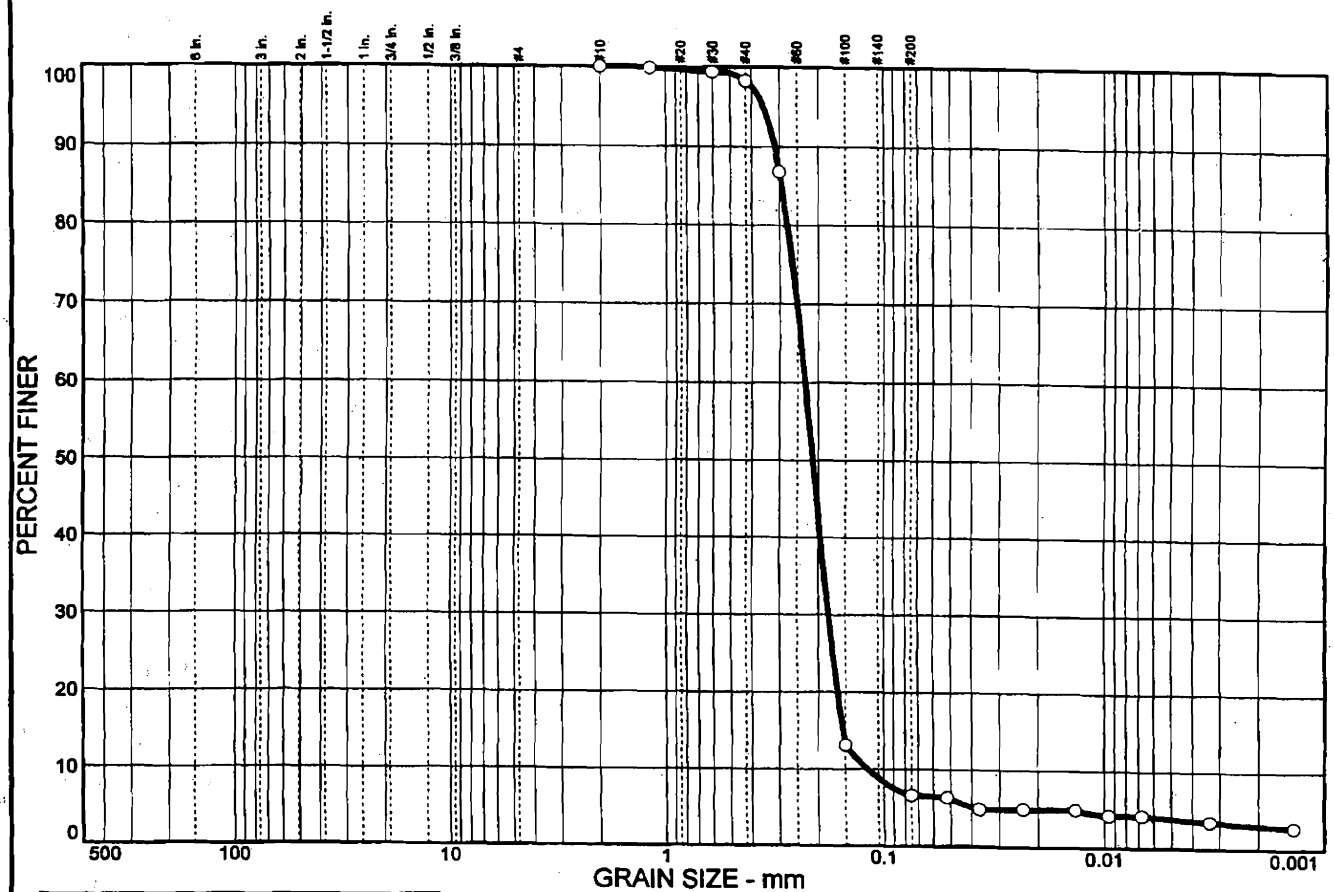
Sample No.: #14 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1004 **Elev./Depth:** 153.5'- 155.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP

Project No.: V003-DE **Lab#** 5

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	93.4	2.7	3.9

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#10	100.0		
#16	99.9		
#30	99.4		
#40	98.3		
#50	86.8		
#100	13.1		
#200	6.6		

* (no specification provided)

Soil Description

Gray Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.293 D_{60}= 0.230 D_{50}= 0.212
D_{30}= 0.180 D_{15}= 0.154 D_{10}= 0.119
C_u= 1.94 C_c= 1.18

Classification

USCS= SP-SM AASHTO=

Remarks

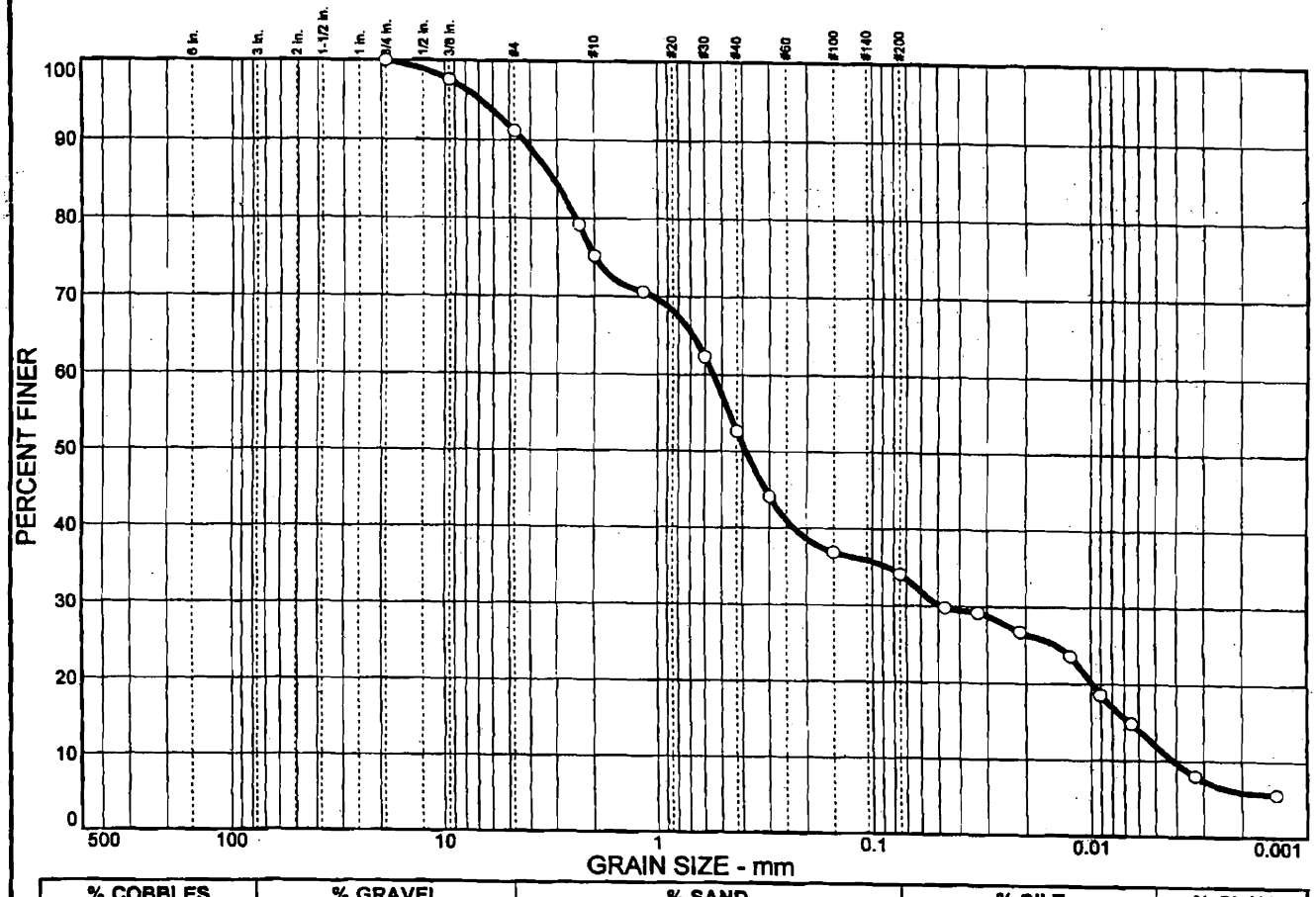
Bag Sample
Specific Gravity - 2.67

Sample No.: #15 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1004 **Elev./Depth:** 158.5'-160.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 6

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	8.9	57.0	22.1	12.0

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
0.75 in.	100.0		
.375 in.	97.6		
#4	91.1		
#8	79.2		
#10	75.2		
#16	70.6		
#30	62.3		
#40	52.6		
#50	44.1		
#100	36.9		
#200	34.1		

* (no specification provided)

Soil Description

Very Light Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 3.11 D_{60}= 0.549 D_{50}= 0.387
D_{30}= 0.0484 D_{15}= 0.0066 D_{10}= 0.0041
C_u= 132.85 C_c= 1.03

Classification

USCS= SM AASHTO=

Remarks

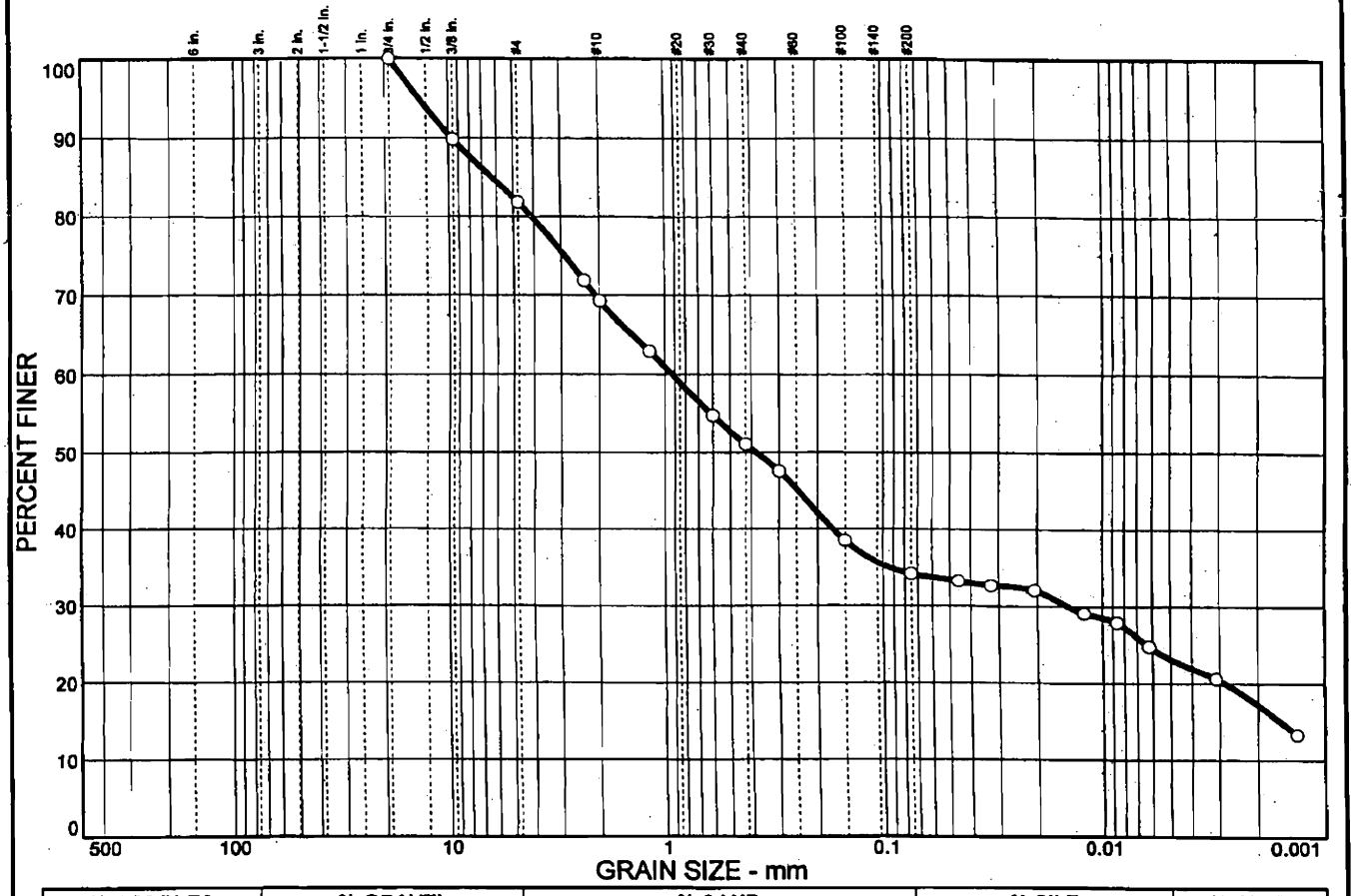
Jar Sample
Specific Gravity - 2.63

Sample No.: #17B **Source of Sample:** **Date:** 08/23/05
Location: Boring #1005 **Elev./Depth:** 148.5'-150.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 7

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	18.2	47.6	11.0	23.2

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
0.75 in.	100.0		
.375 in.	89.8		
#4	81.8		
#8	71.9		
#10	69.3		
#16	62.9		
#30	54.7		
#40	51.0		
#50	47.5		
#100	38.5		
#200	34.2		

* (no specification provided)

Soil Description

Very Light Tan Silty sand with gravel

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 6.29 D_{60}= 0.926 D_{50}= 0.383
D_{30}= 0.0144 D_{15}= 0.0016 D_{10}=
C_u= C_c=

Classification

USCS= SM AASHTO=

Remarks

Jar Sample
Specific Gravity - 2.61

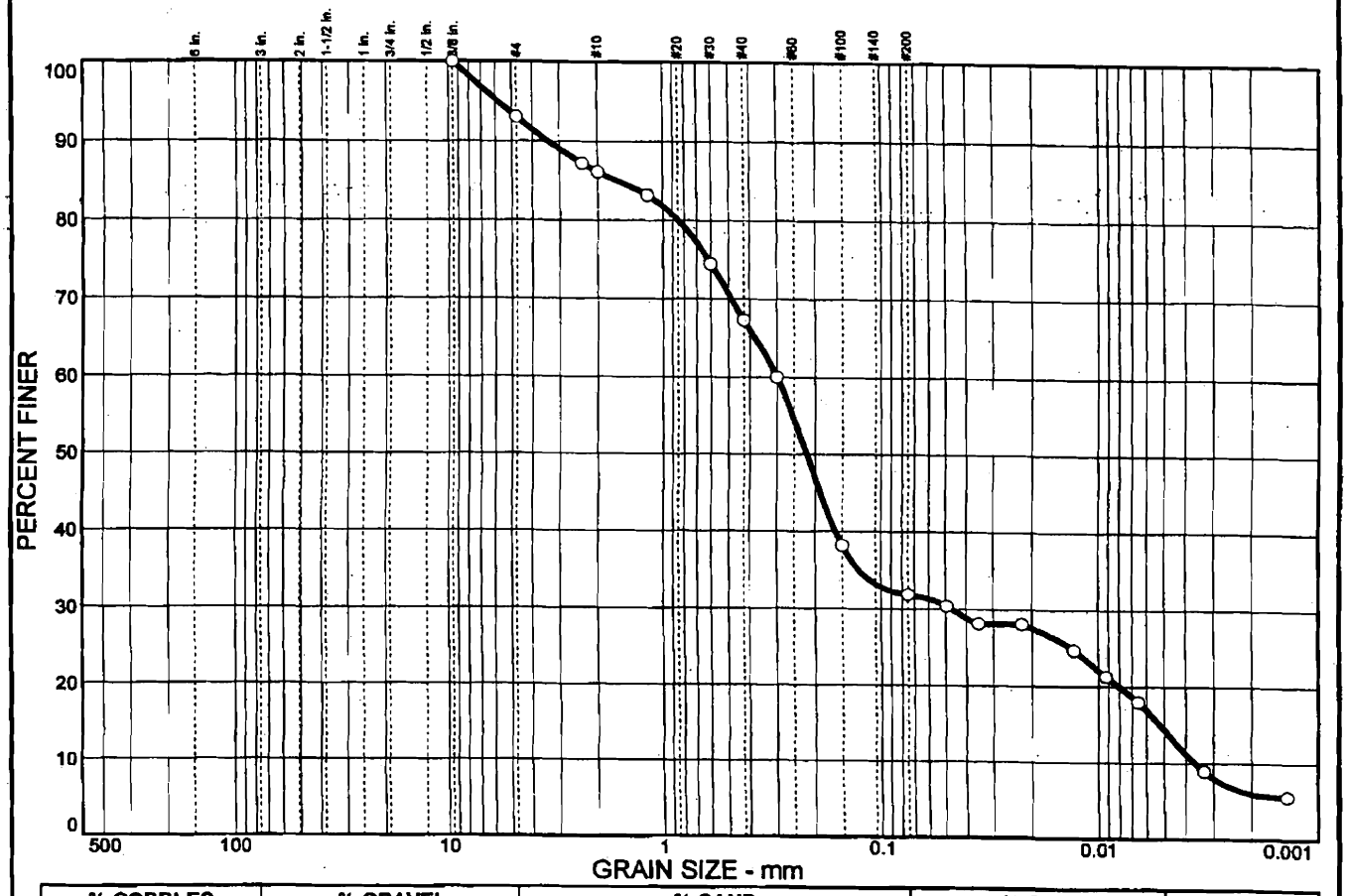
Sample No.: #18B **Source of Sample:** **Date:** 08/23/05
Location: Boring #1005 **Elev./Depth:** 153.5-155.0

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP

Project No: V003-DE **Lab#** 8

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	7.0	61.1	17.6	14.3

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
.375 in.	100.0		
#4	93.0		
#8	87.2		
#10	86.1		
#16	83.2		
#30	74.5		
#40	67.3		
#50	60.0		
#100	38.2		
#200	31.9		

* (no specification provided)

Soil Description

Very Light Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 1.62 D_{60}= 0.300 D_{50}= 0.219
D_{30}= 0.0467 D_{15}= 0.0052 D_{10}= 0.0036
C_u= 82.37 C_c= 1.99

Classification

USCS= SM AASHTO=

Remarks

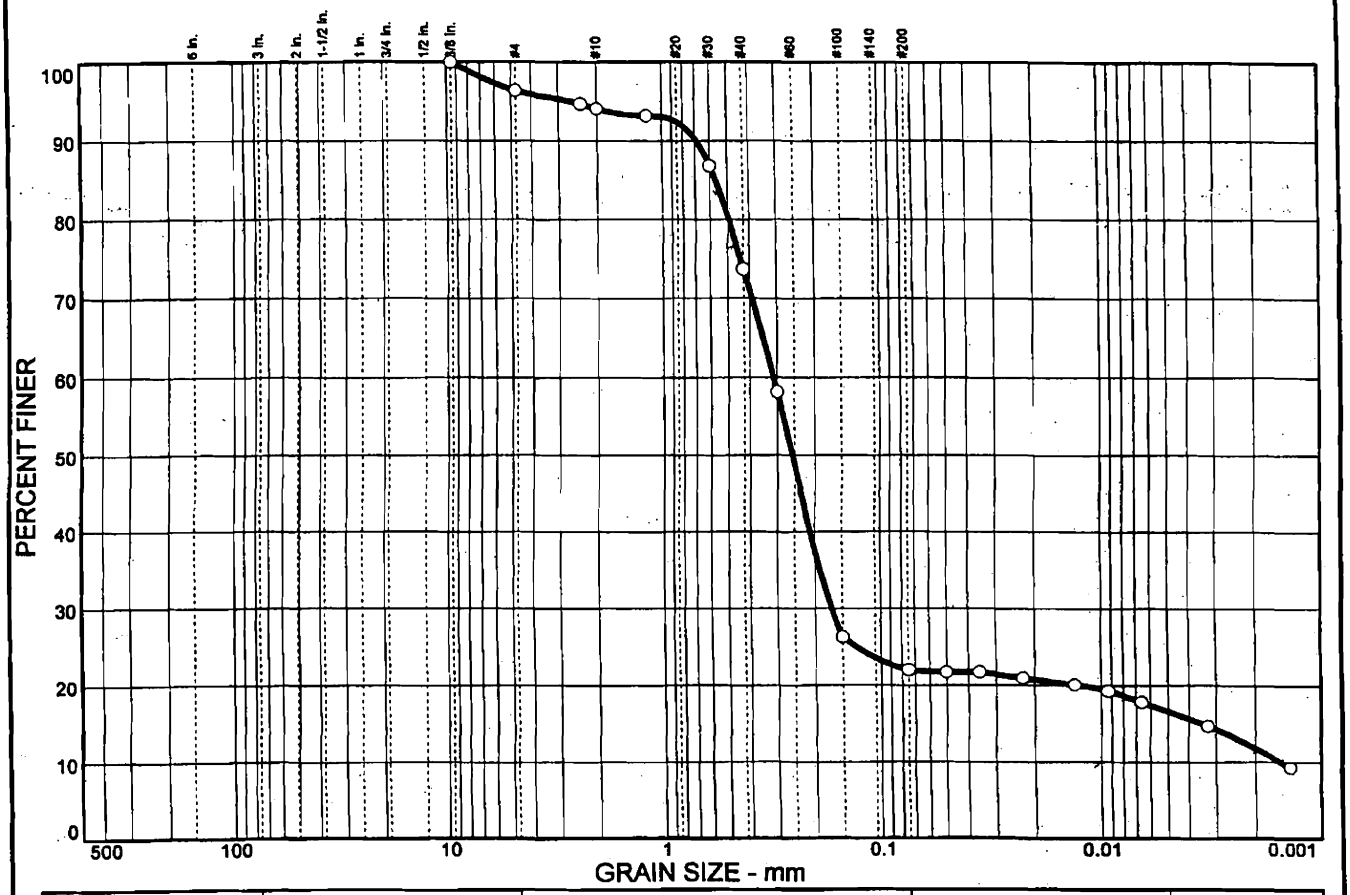
Jar Sample
Specific Gravity - 2.67

Sample No.: #23 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1006 **Elev./Depth:** 113.5'-115.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 9

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	3.6	74.4	5.4	16.6

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
.375 in.	100.0		
#4	96.4		
#8	94.7		
#10	94.1		
#16	93.2		
#30	86.8		
#40	73.7		
#50	58.1		
#100	26.3		
#200	22.0		

* (no specification provided)

Soil Description

Very Light Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.566 D_{60}= 0.312 D_{50}= 0.256
D_{30}= 0.168 D_{15}= 0.0035 D_{10}= 0.0015
C_u= 202.26 C_c= 58.75

Classification

USCS= SM AASHTO=

Remarks

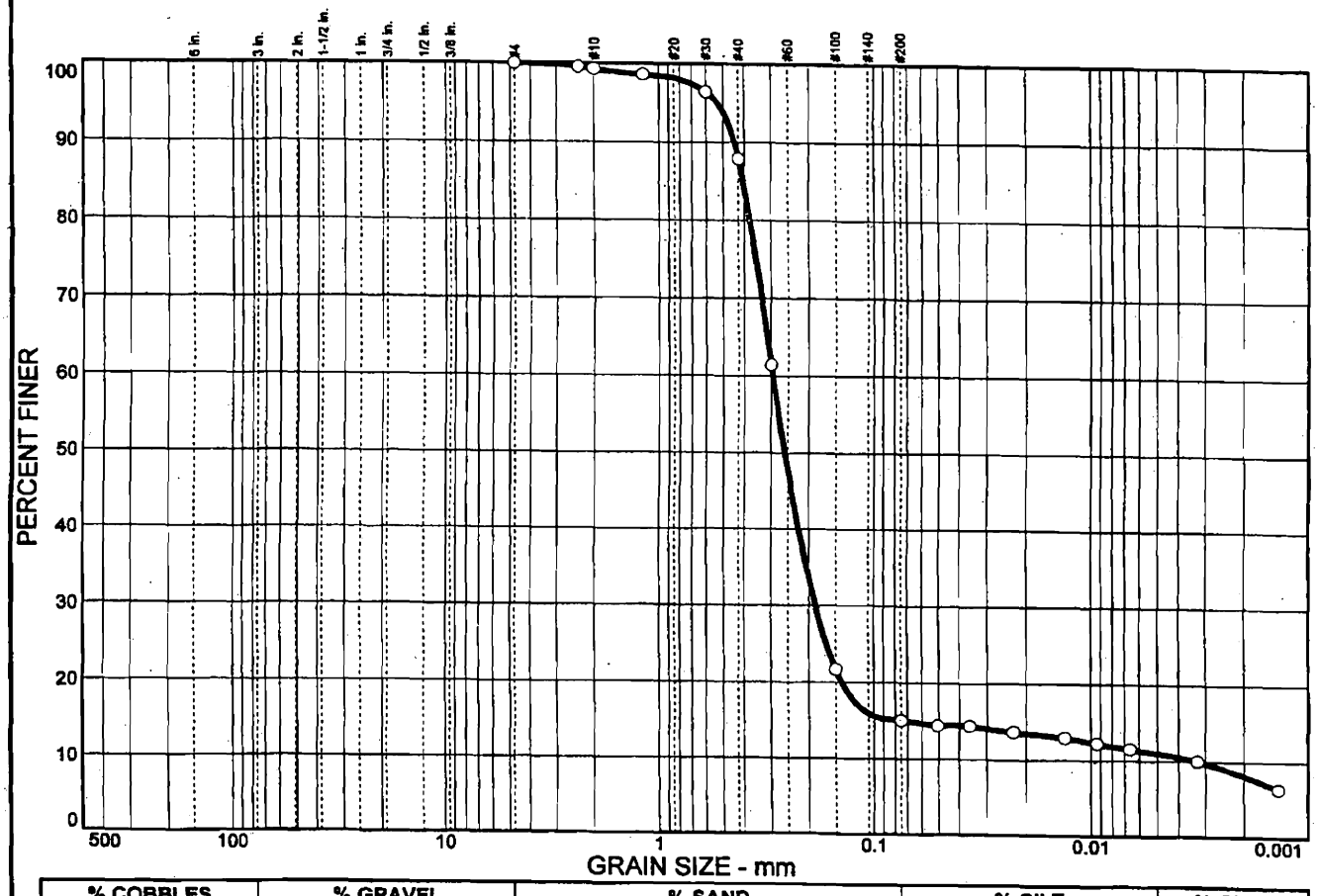
Jar Sample
Specific Gravity - 2.59

Sample No.: #24 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1006 **Elev./Depth:** 118.5'-120.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No.: V003-DE **Lab#** 10

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	85.0	4.0	11.0

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#4	100.0		
#8	99.6		
#10	99.3		
#16	98.6		
#30	96.4		
#40	87.9		
#50	61.4		
#100	21.7		
#200	15.0		

* (no specification provided)

Soil Description

Very Light Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.404 D_{60}= 0.295 D_{50}= 0.259
D_{30}= 0.186 D_{15}= 0.0750 D_{10}= 0.0033
C_u= 90.28 C_c= 35.89

Classification

USCS= SM AASHTO=

Remarks

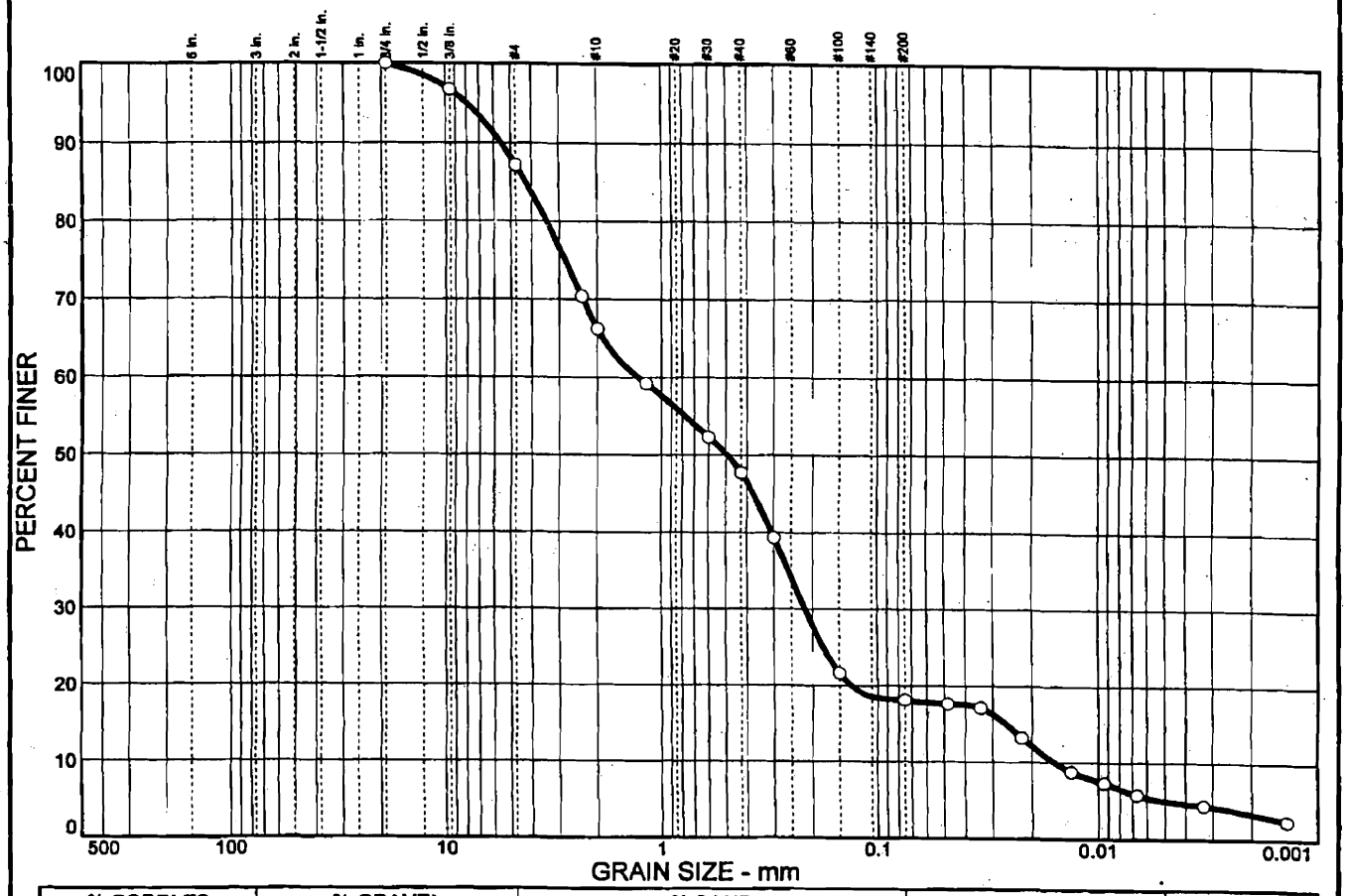
Jar Sample
Specific Gravity - 2.65

Sample No.: #2 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1007 **Elev./Depth:** 103.5'-105.0

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No.: V003-DE **Lab#** 11

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	12.8	69.1	13.1	5.0

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
0.75 in.	100.0		
.375 in.	96.7		
#4	87.2		
#8	70.4		
#10	66.2		
#16	59.2		
#30	52.3		
#40	47.7		
#50	39.3		
#100	21.6		
#200	18.1		

* (no specification provided)

Soil Description

Very Light Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 4.27 D_{60}= 1.29 D_{50}= 0.493
D_{30}= 0.217 D_{15}= 0.0263 D_{10}= 0.0157
C_u= 81.97 C_c= 2.33

Classification

USCS= SM AASHTO=

Remarks

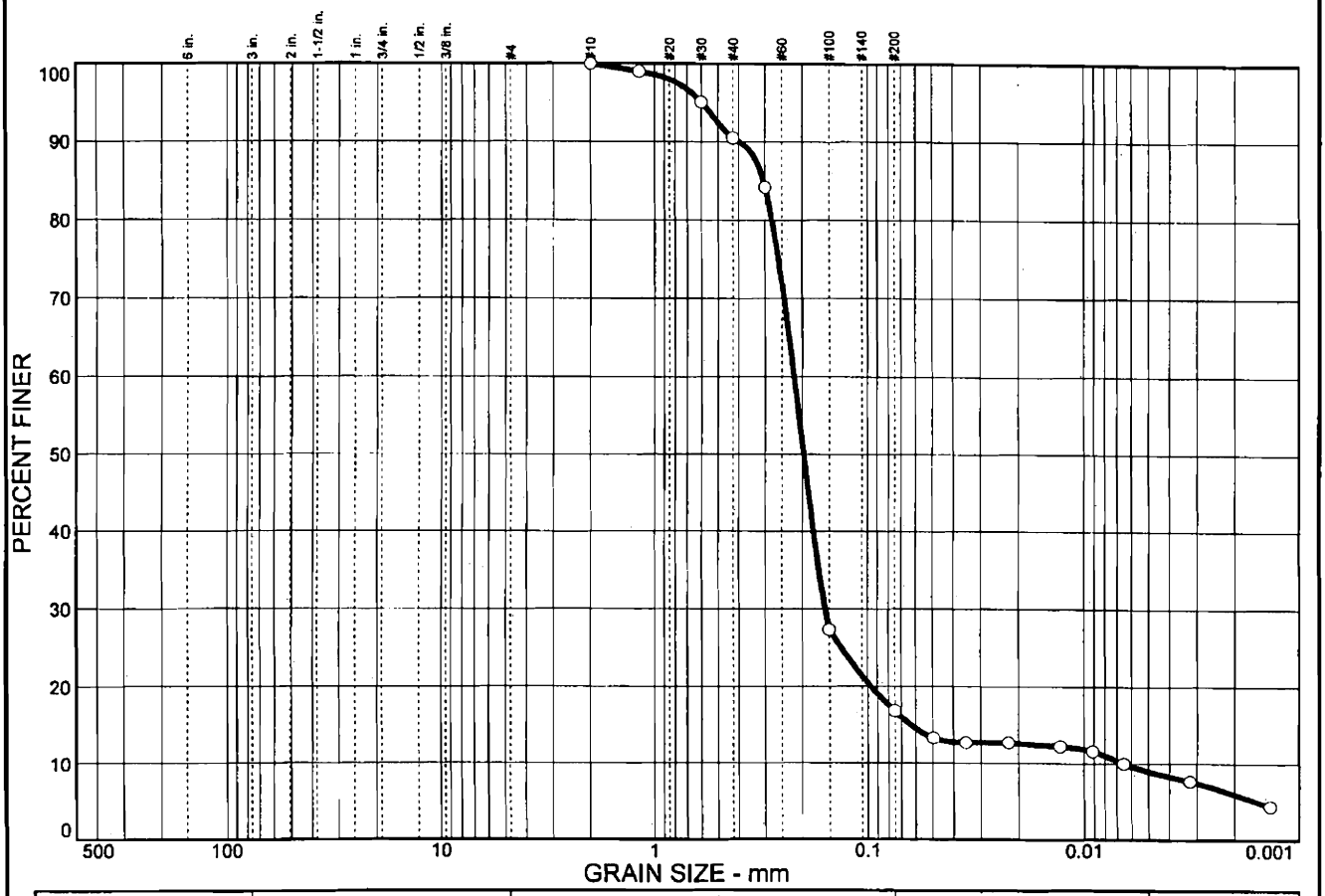
Jar Sample
Specific Gravity - 2.66

Sample No.: #3 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1007 **Elev./Depth:** 108.5'-110.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 12

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	83.2	7.8	9.0

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#10	100.0		
#16	99.0		
#30	95.1		
#40	90.5		
#50	84.2		
#100	27.3		
#200	16.8		

* (no specification provided)

Soil Description

Light Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.306 D_{60}= 0.219 D_{50}= 0.197
D_{30}= 0.156 D_{15}= 0.0632 D_{10}= 0.0065
C_u= 33.60 C_c= 17.15

Classification

USCS= SM AASHTO=

Remarks

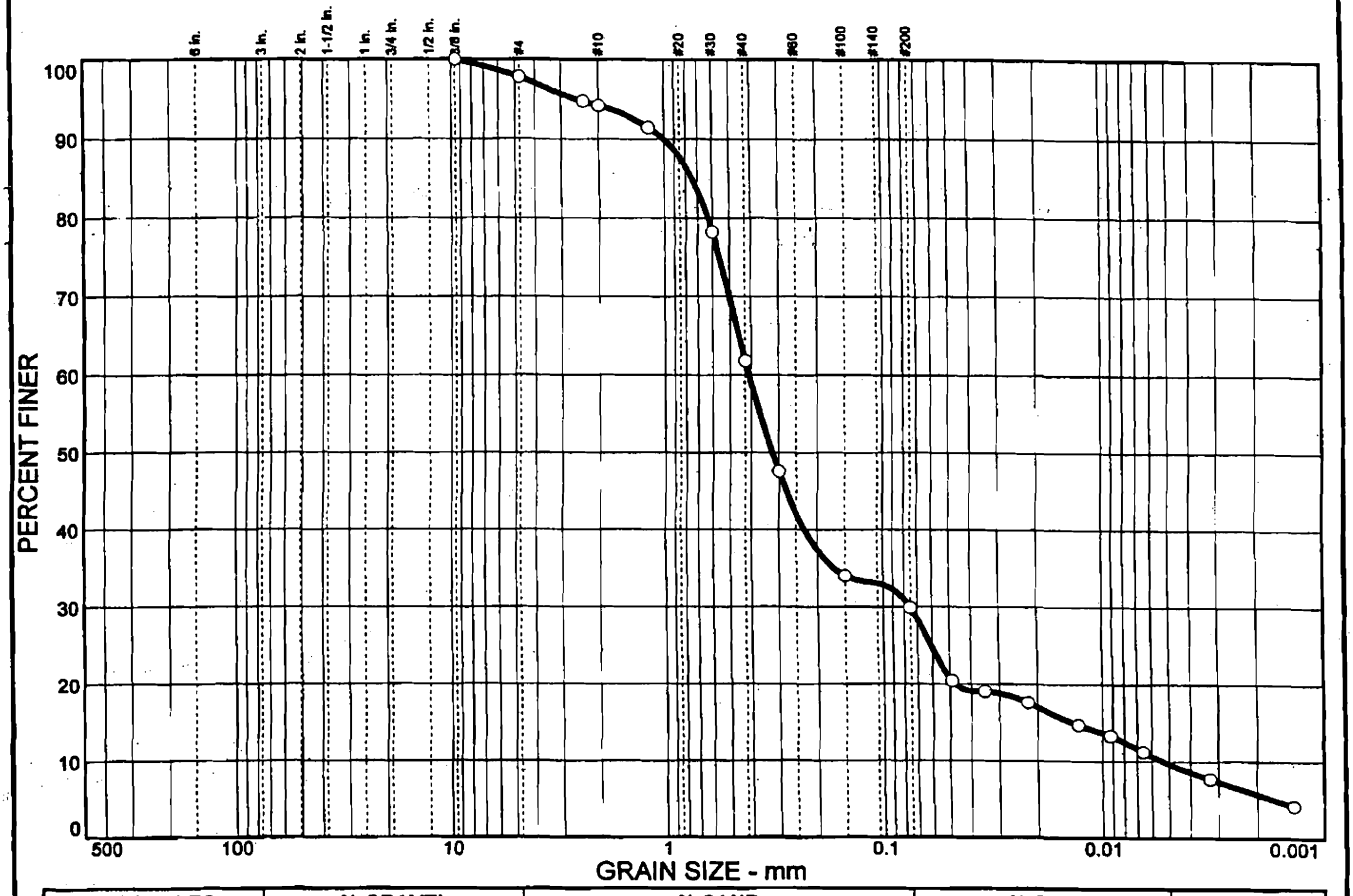
Bag Sample
Specific Gravity - 2.69

Sample No.: #24 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1008 **Elev./Depth:** 228.5'-230.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: 2121V003-DE **Lab#** 13

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	2.2	67.9	20.3	9.6

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
.375 in.	100.0		
#4	97.8		
#8	94.7		
#10	94.2		
#16	91.4		
#30	78.2		
#40	61.8		
#50	47.6		
#100	34.0		
#200	29.9		

* (no specification provided)

Soil Description

Gray Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.744 D_{60}= 0.409 D_{50}= 0.321
D_{30}= 0.0754 D_{15}= 0.0138 D_{10}= 0.0053
C_u= 76.50 C_c= 2.60

Classification

USCS= SM AASHTO=

Remarks

Bag Sample

Sample No.: #25 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1008 **Elev./Depth:** 238.5'-240.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 13

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	2.2	67.9	20.3	9.6

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
.375 in.	100.0		
#4	97.8		
#8	94.7		
#10	94.2		
#16	91.4		
#30	78.2		
#40	61.8		
#50	47.6		
#100	34.0		
#200	29.9		

* (no specification provided)

Soil Description

Gray Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.744 D_{60}= 0.409 D_{50}= 0.321
D_{30}= 0.0754 D_{15}= 0.0138 D_{10}= 0.0053
C_u= 76.50 C_c= 2.60

Classification

USCS= SM AASHTO=

Remarks

Bag Sample
Specific Gravity - 2.68

Sample No.: #25 **Source of Sample:** **Date:** 08/23/05
Location: Boring #1008 **Elev./Depth:** 238.5'-240.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 14

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	2.7	74.6	12.9	9.8

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
.375 in.	100.0		
#4	97.3		
#8	93.3		
#10	91.8		
#16	89.2		
#30	85.4		
#40	83.4		
#50	77.1		
#100	34.3		
#200	22.7		

* (no specification provided)

Soil Description

Very Light Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.558 D_{60}= 0.223 D_{50}= 0.193
D_{30}= 0.135 D_{15}= 0.0105 D_{10}= 0.0052
C_u= 42.99 C_c= 15.88

Classification

USCS= SM AASHTO=

Remarks

Jar Sample
Spicific Gravity - 2.61

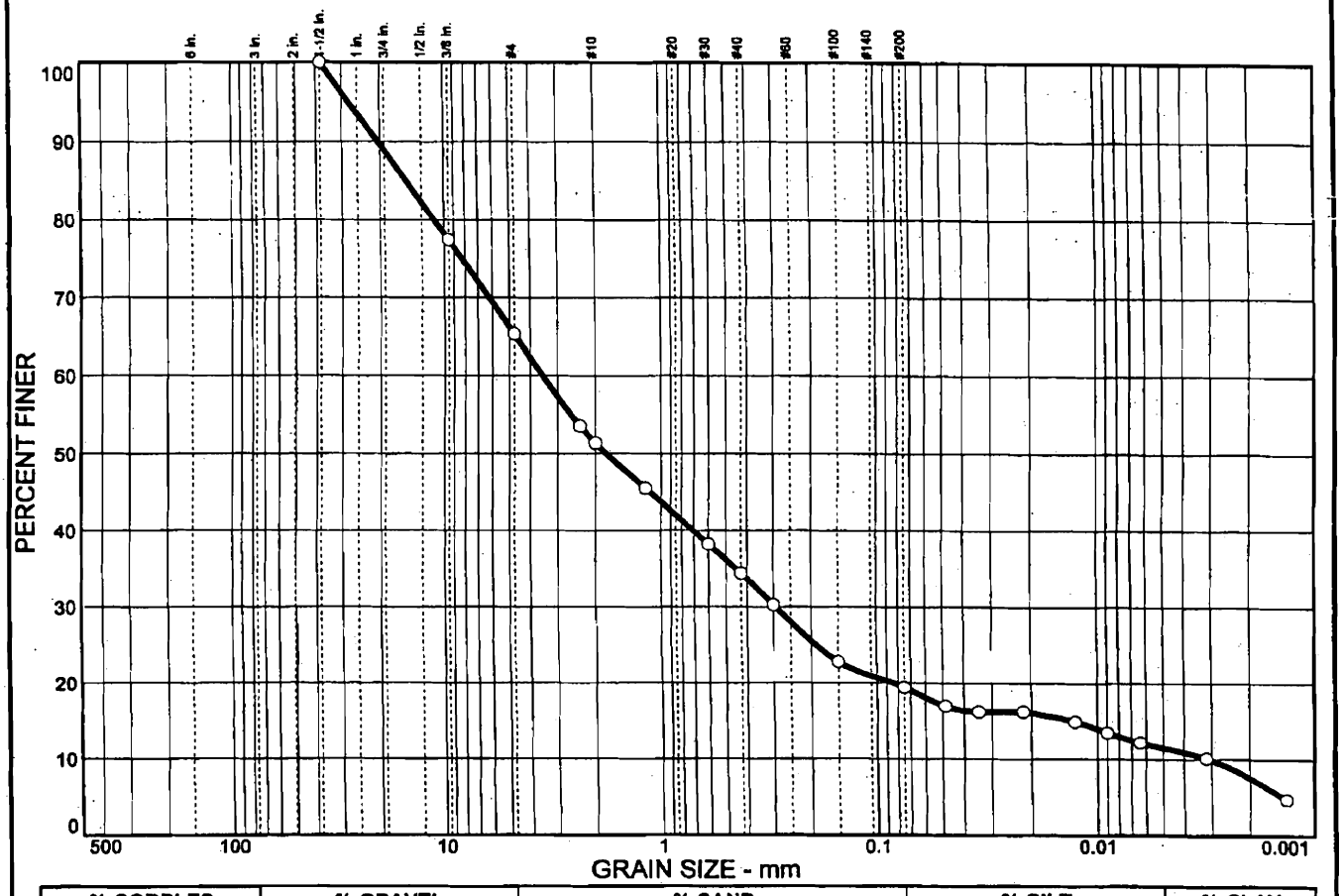
Sample No.: #17 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1009 **Elev./Depth:** 85'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP

Project No: V003-DE **Lab#** 15

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	34.7	45.9	7.9	11.5

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
1.50 in.	100.0		
.375 in.	77.4		
#4	65.3		
#8	53.5		
#10	51.3		
#16	45.5		
#30	38.2		
#40	34.4		
#50	30.3		
#100	22.8		
#200	19.4		

* (no specification provided)

Soil Description

Very Light Tan Silty sand with gravel

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 15.0 D_{60}= 3.53 D_{50}= 1.79
D_{30}= 0.293 D_{15}= 0.0130 D_{10}= 0.0031
C_u= 1142.64 C_c= 7.85

Classification

USCS= SM AASHTO=

Remarks

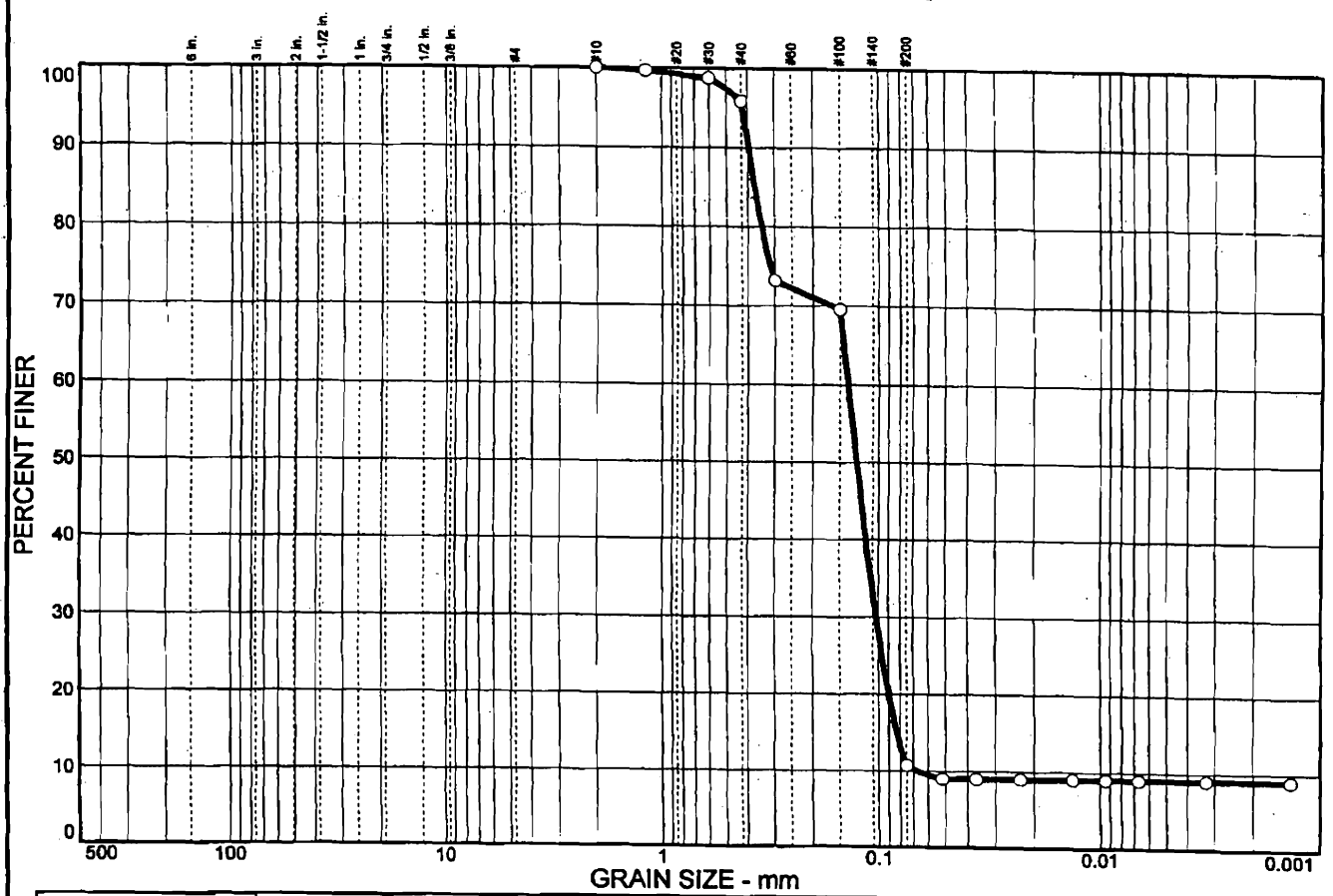
Jar Sample
Specific Gravity 2.75

Sample No.: #18 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1009 **Elev./Depth:** 90'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 16

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	89.3	1.7	9.0

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#10	100.0		
#16	99.7		
#30	98.8		
#40	95.9		
#50	73.2		
#100	69.6		
#200	10.7		

* (no specification provided)

Soil Description

Tan Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.370 D_{60}= 0.138 D_{50}= 0.126
D_{30}= 0.102 D_{15}= 0.0830 D_{10}= 0.0670
C_u= 2.05 C_c= 1.14

Classification

USCS= SP-SM AASHTO=

Remarks

Jar Sample
Specific Gravity - 2.67

Sample No.: #15 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1010 **Elev./Depth:** 73.5'-75.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 17

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	63.5	3.5	33.0

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#4	100.0		
#8	98.7		
#10	98.3		
#16	98.1		
#30	97.8		
#40	97.4		
#50	94.5		
#100	54.8		
#200	36.5		

* (no specification provided)

Soil Description

Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.257 D_{60}= 0.167 D_{50}= 0.134
D_{30}= 0.0020 D_{15}= D_{10}=
C_u= C_c=

Classification

USCS= SM AASHTO=

Remarks

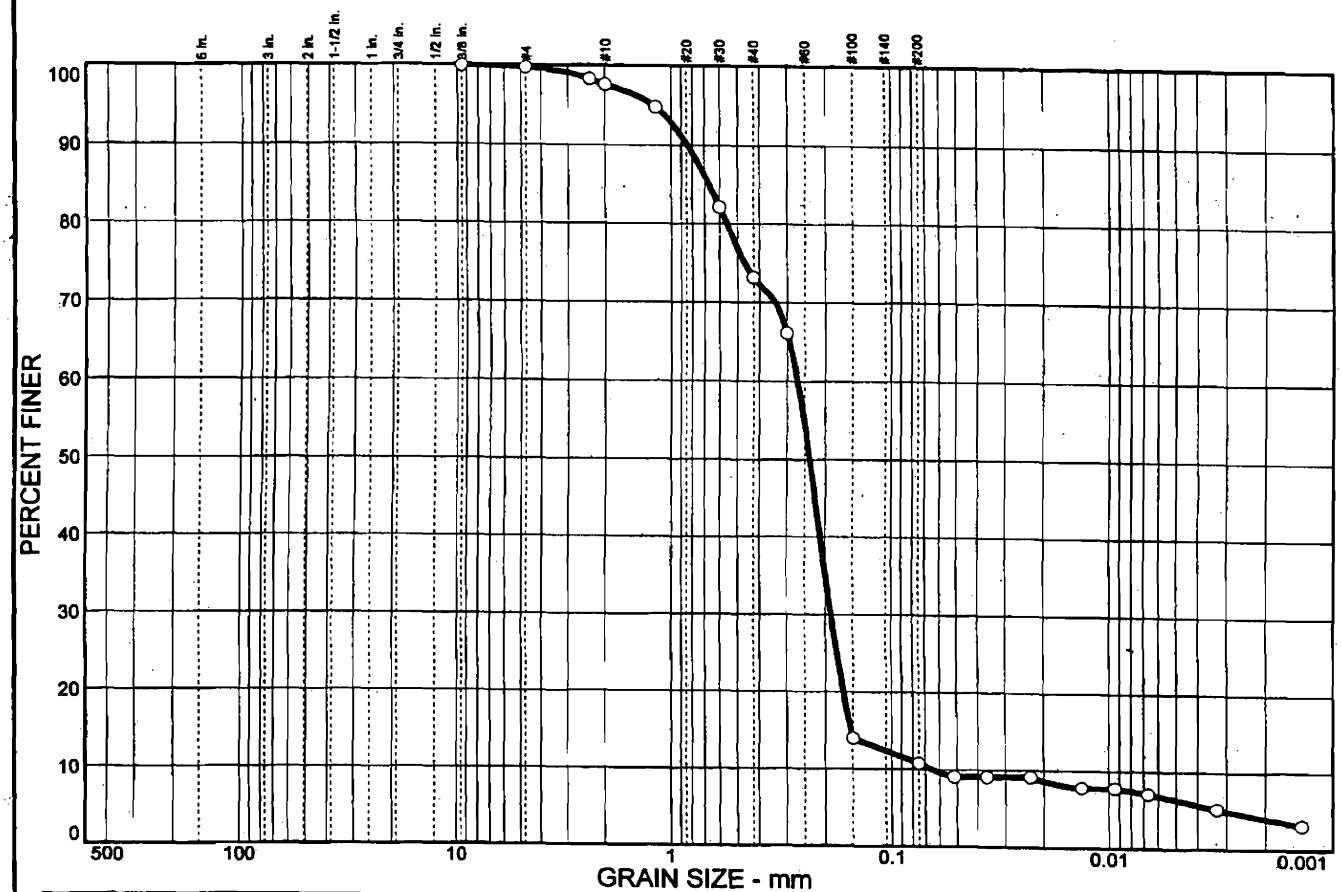
Jar Sample
Specific Gravity - 2.63

Sample No.: #16 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1010 **Elev./Depth:** 78.5'-80.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 18

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
		88.9	4.4	6.4

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
.375 in.	99.9		
#4	99.7		
#8	98.3		
#10	97.6		
#16	94.8		
#30	82.1		
#40	73.2		
#50	66.1		
#100	14.0		
#200	10.8		

* (no specification provided)

Soil Description

Gray Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.669 D_{60}= 0.269 D_{50}= 0.236
D_{30}= 0.188 D_{15}= 0.153 D_{10}= 0.0649
C_u= 4.15 C_c= 2.03

Classification

USCS= SP-SM AASHTO=

Remarks

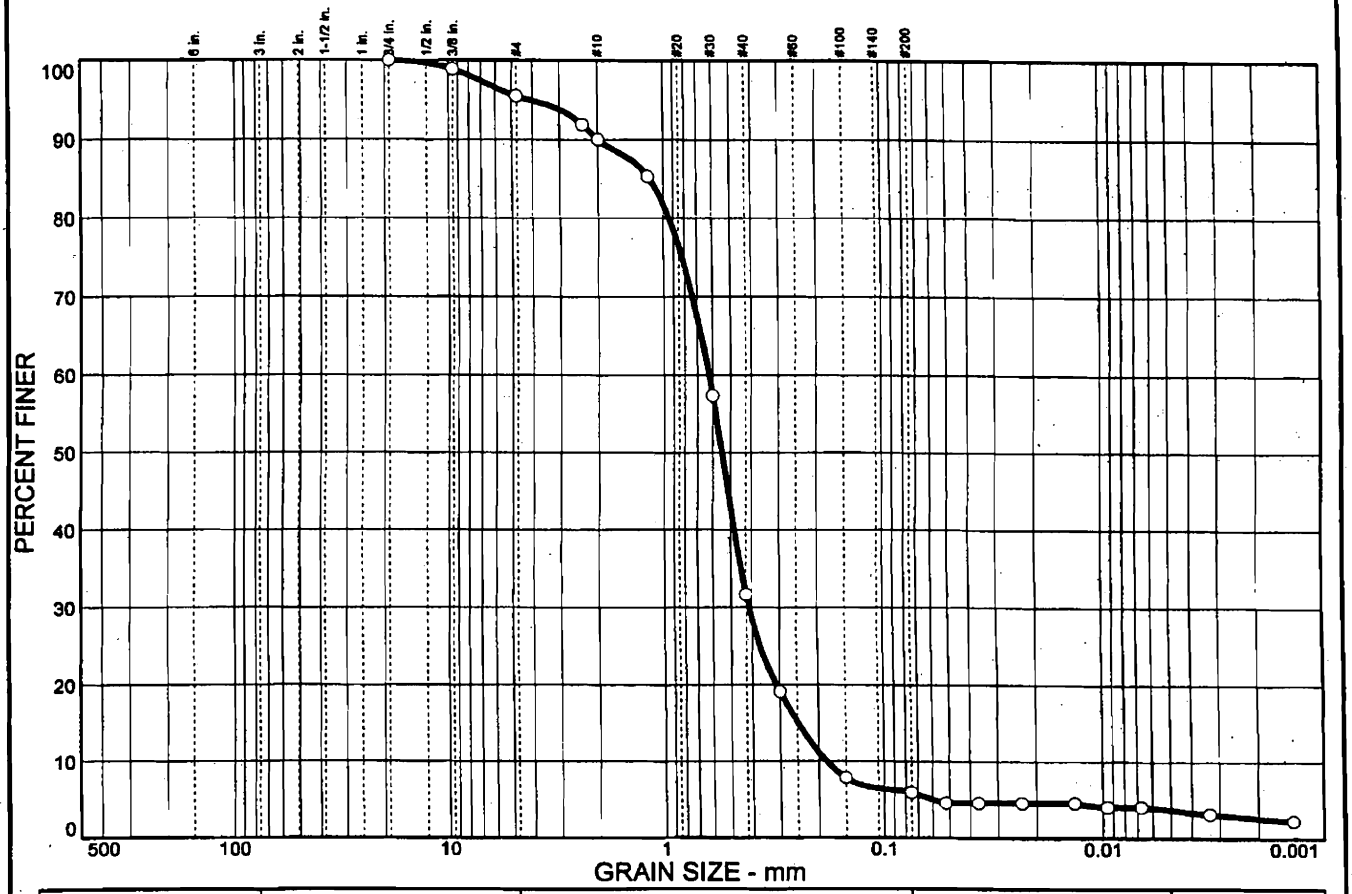
Bag Sample
Specific Gravity - 2.67

Sample No.: #24 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1011 **Elev./Depth:** 193.5'-195.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No.: 2.4A-218 V003-DE **Lab#** 19

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	4.5	89.6	2.2	3.7

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
0.75 in.	100.0		
.375 in.	98.9		
#4	95.5		
#8	91.9		
#10	90.0		
#16	85.3		
#30	57.3		
#40	31.7		
#50	19.1		
#100	7.8		
#200	5.9		

* (no specification provided)

Soil Description

Gray Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 1.16 D_{60}= 0.623 D_{50}= 0.545
D_{30}= 0.412 D_{15}= 0.249 D_{10}= 0.185
C_u= 3.38 C_c= 1.48

Classification

USCS= SP-SM AASHTO=

Remarks

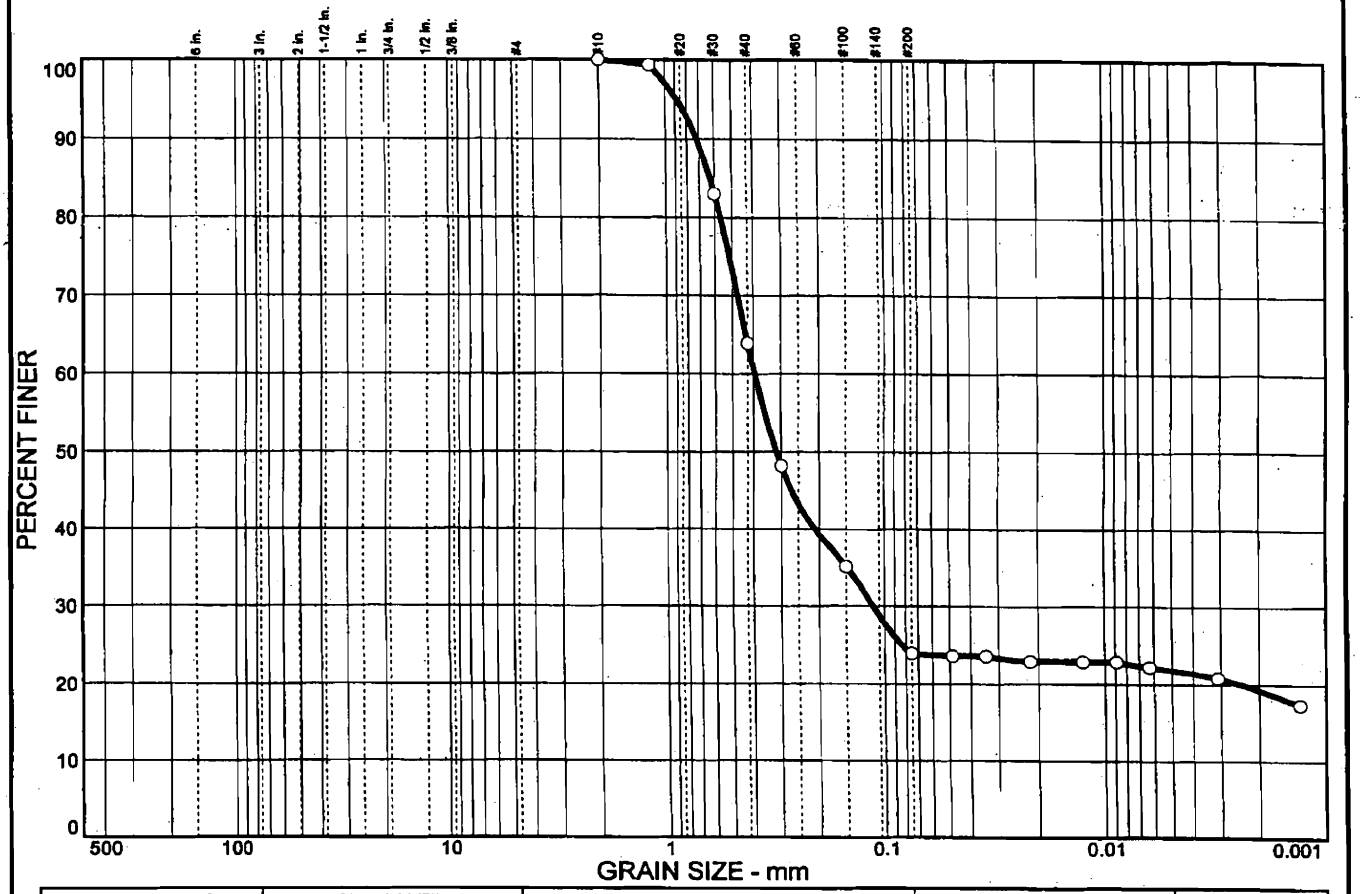
Bag Sample
Specifiv Gravity - 2.66

Sample No.: #25 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1011 **Elev./Depth:** 208.5'-210.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No.: 244-219 V003-DE **Lab#** 20

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	76.1	2.1	21.8

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#10	100.0		
#16	99.4		
#30	83.0		
#40	63.9		
#50	48.2		
#100	35.2		
#200	23.9		

* (no specification provided)

Soil Description

Tan Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.628 D_{60}= 0.395 D_{50}= 0.316
D_{30}= 0.113 D_{15}= D_{10}=
C_u= C_c=

Classification

USCS= SM AASHTO=

Remarks

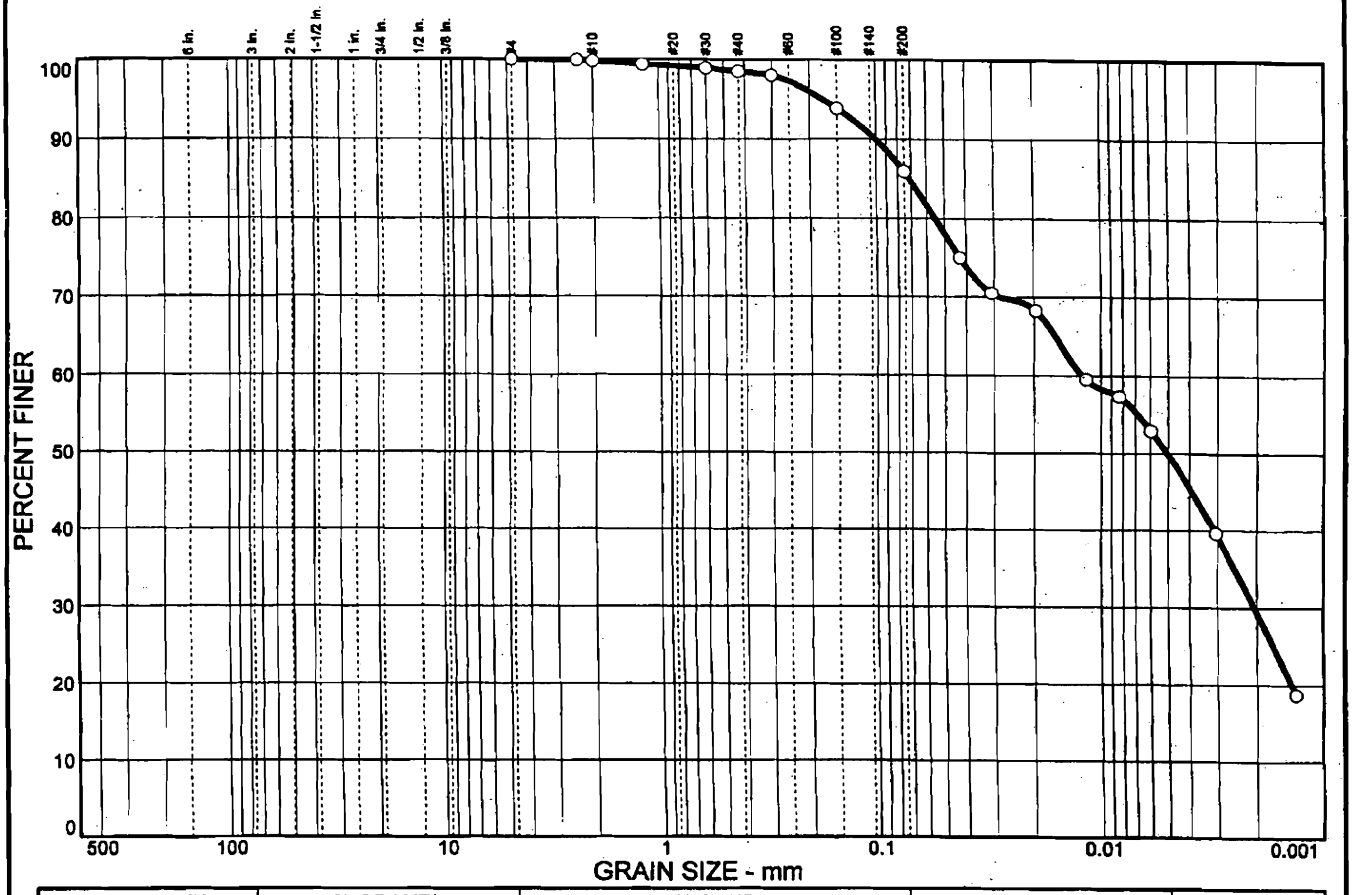
Jar Sample
Specific Gravity - 2.66

Sample No.: #15 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1012 **Elev./Depth:** 73.5'-75.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No.: 2400220 V003-DE **Lab#** 21

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	14.1	36.1	49.8

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#4	100.0		
#8	99.9		
#10	99.8		
#16	99.4		
#30	98.9		
#40	98.5		
#50	98.0		
#100	93.8		
#200	85.9		

* (no specification provided)

Soil Description

Light Tan Silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.0712 D_{60}= 0.0121 D_{50}= 0.0051
D_{30}= 0.0021 D_{15}= D_{10}=
C_u= C_c=

Classification

USCS= ML AASHTO=

Remarks

Jar Sample
Specific Gravity - 2.66

Sample No.: #16 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1012 **Elev./Depth:** 78.5'-80.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 22

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	91.1	1.6	7.3

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#4	100.0		
#8	99.6		
#10	99.4		
#16	97.2		
#30	79.4		
#40	56.1		
#50	30.1		
#100	11.7		
#200	8.9		

* (no specification provided)

Soil Description

Tan Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.676 D_{60}= 0.447 D_{50}= 0.393
D_{30}= 0.300 D_{15}= 0.200 D_{10}= 0.104
C_u= 4.28 C_c= 1.92

Classification

USCS= SP-SM AASHTO=

Remarks

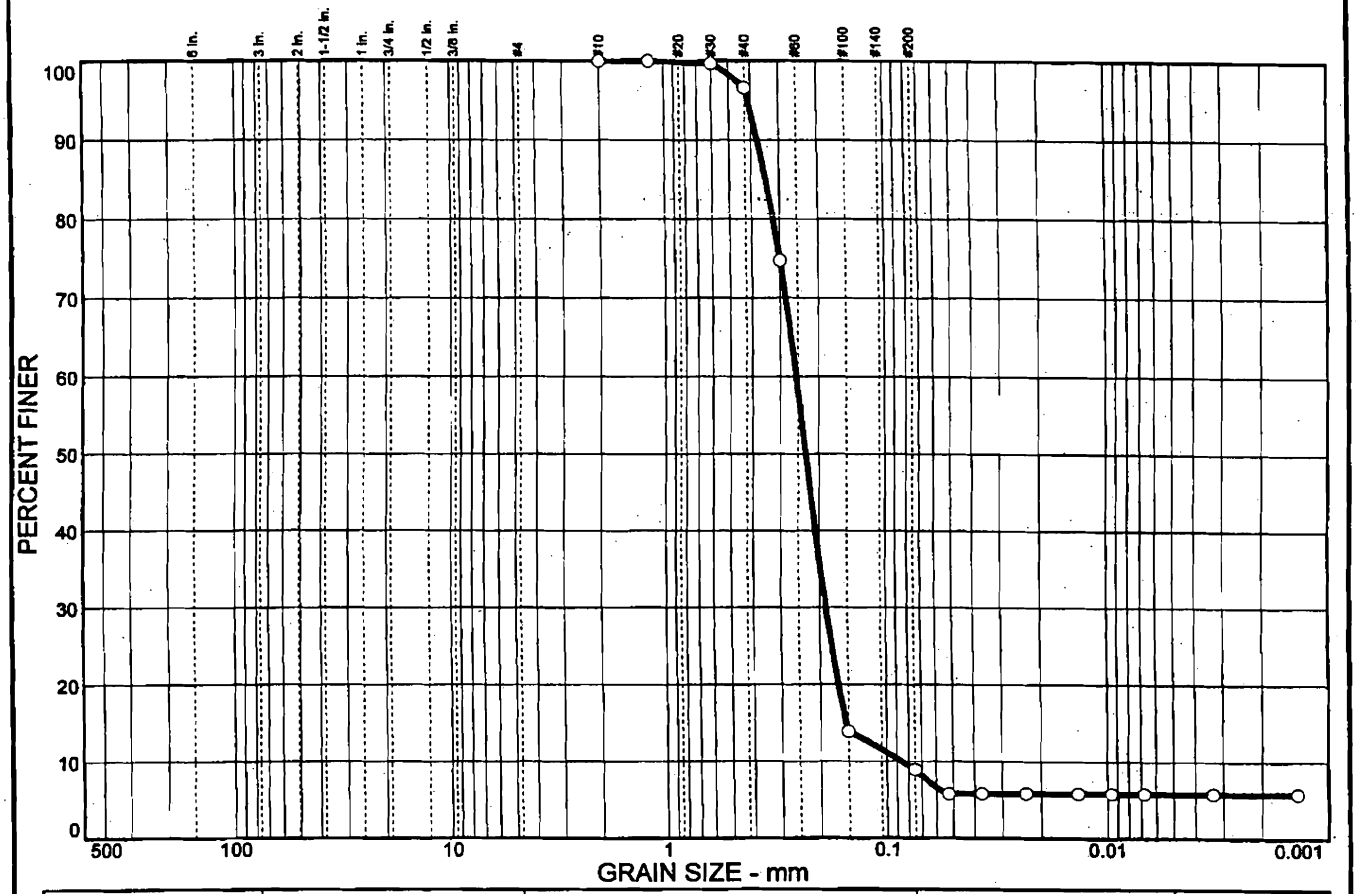
Jar Sample
Specific Gravity - 2.65

Sample No.: #17 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1013 **Elev./Depth:** 84.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 23

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	91.1	3.1	5.8

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#10	100.0		
#16	100.0		
#30	99.7		
#40	96.6		
#50	74.8		
#100	13.9		
#200	8.9		

* (no specification provided)

Soil Description

Light Tan Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.346 D_{60}= 0.255 D_{50}= 0.230
D_{30}= 0.187 D_{15}= 0.153 D_{10}= 0.0861
C_u= 2.96 C_c= 1.60

Classification

USCS= SP-SM AASHTO=

Remarks

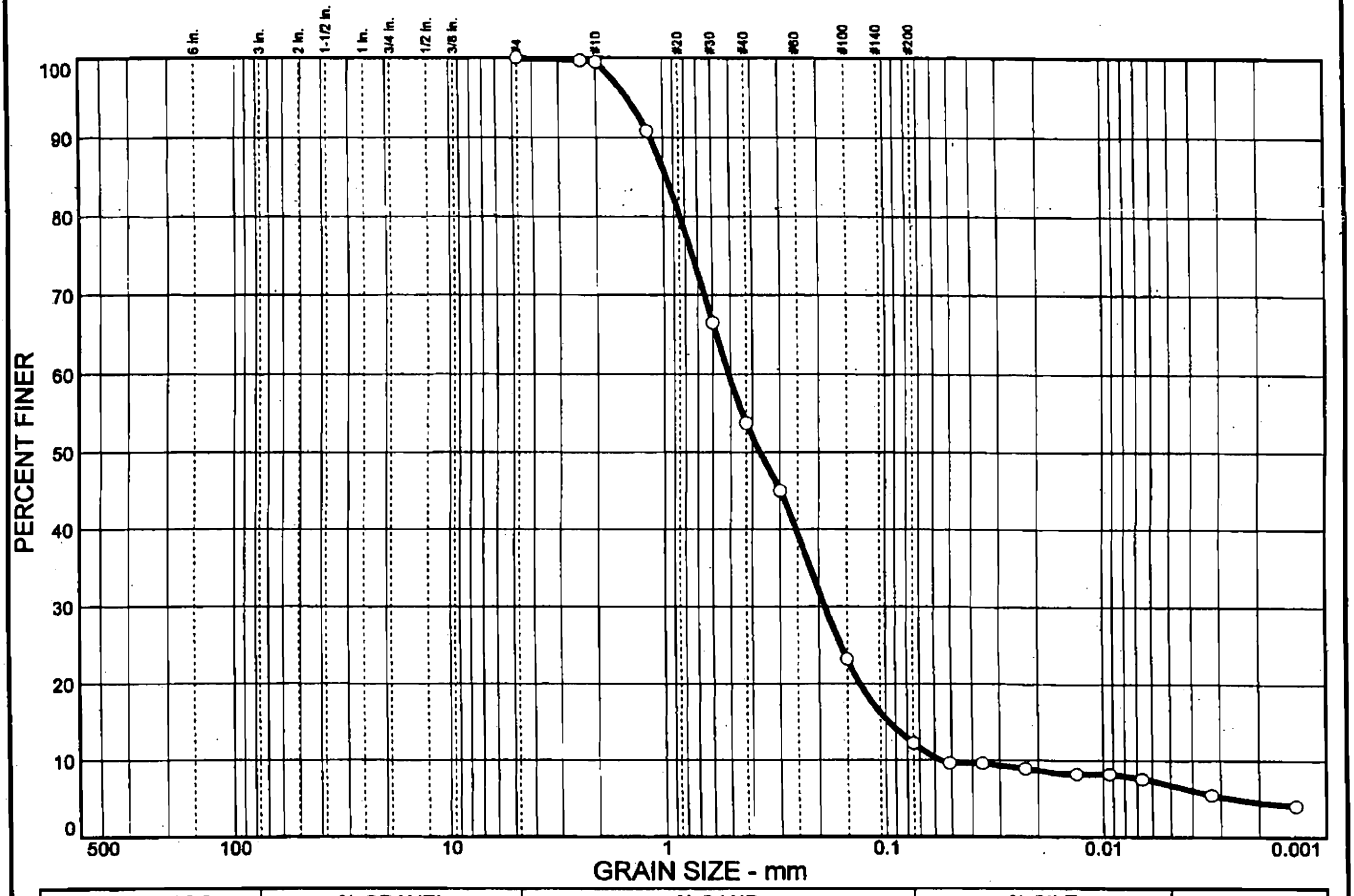
Jar Sample
Specific Gravity - 2.65

Sample No.: #18 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1013 **Elev./Depth:** 94.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: V003-DE **Lab#** 24

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	87.8	5.4	6.8

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#4	100.0		
#8	99.7		
#10	99.5		
#16	90.8		
#30	66.5		
#40	53.7		
#50	45.0		
#100	23.2		
#200	12.2		

* (no specification provided)

Soil Description

Gray Silty sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.969 D_{60}= 0.510 D_{50}= 0.369
D_{30}= 0.188 D_{15}= 0.0971 D_{10}= 0.0564
C_u= 9.04 C_c= 1.22

Classification

USCS= SM AASHTO=

Remarks

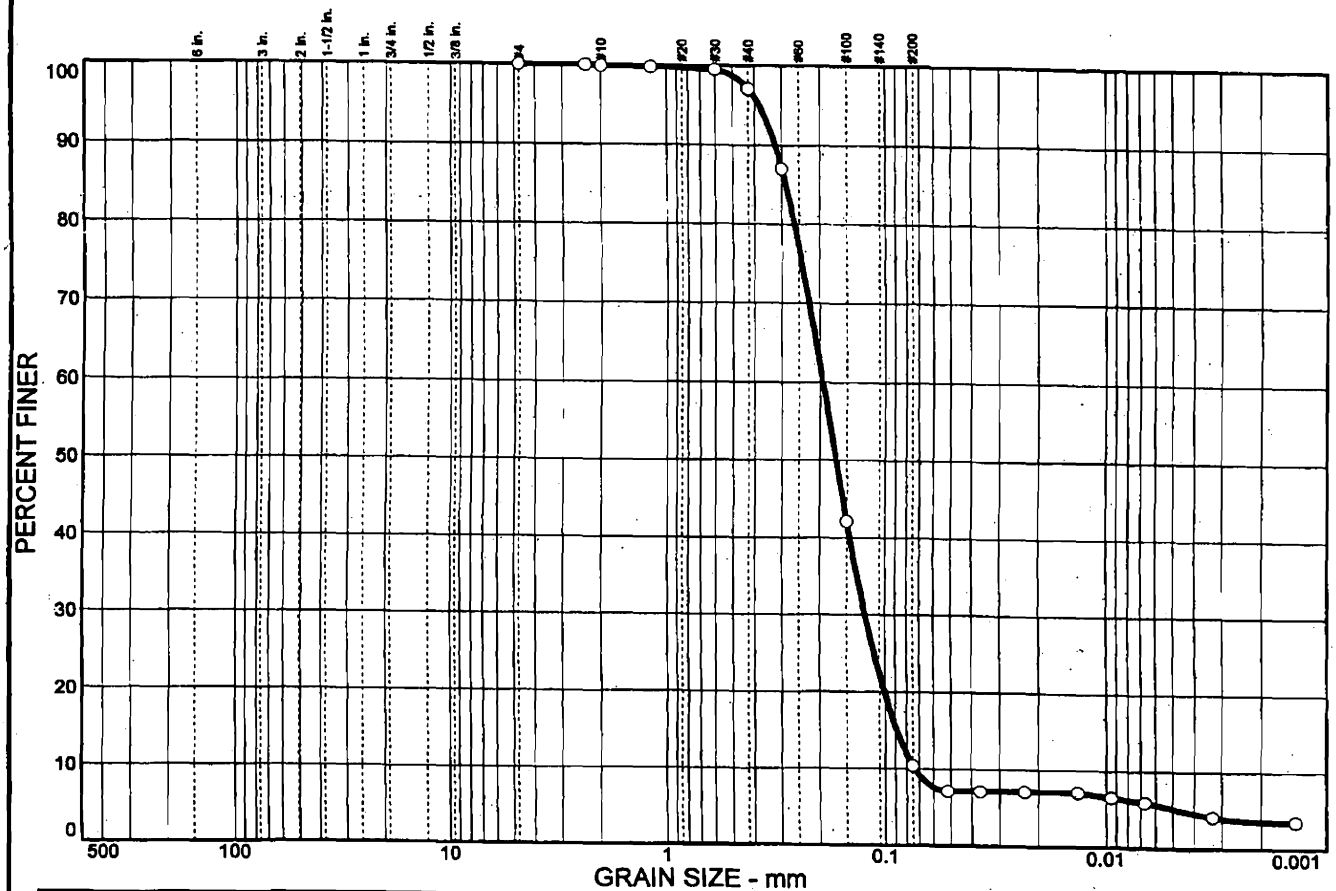
Bag Sample
Specific Gravity - 2.69

Sample No.: #18 **Source of Sample:** **Date:** 09/24/05
Location: Boring #1014 **Elev./Depth:** 183.5'-185.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No.: 244324 V003-DE **Lab#** 25

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	89.6	5.3	5.1

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#4	100.0		
#8	100.0		
#10	99.9		
#16	99.8		
#30	99.5		
#40	97.1		
#50	87.0		
#100	42.1		
#200	10.4		

* (no specification provided)

Soil Description

Gray Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.288 D_{60}= 0.194 D_{50}= 0.168
D_{30}= 0.123 D_{15}= 0.0887 D_{10}= 0.0735
C_u= 2.64 C_c= 1.07

Classification

USCS= SP-SM AASHTO=

Remarks

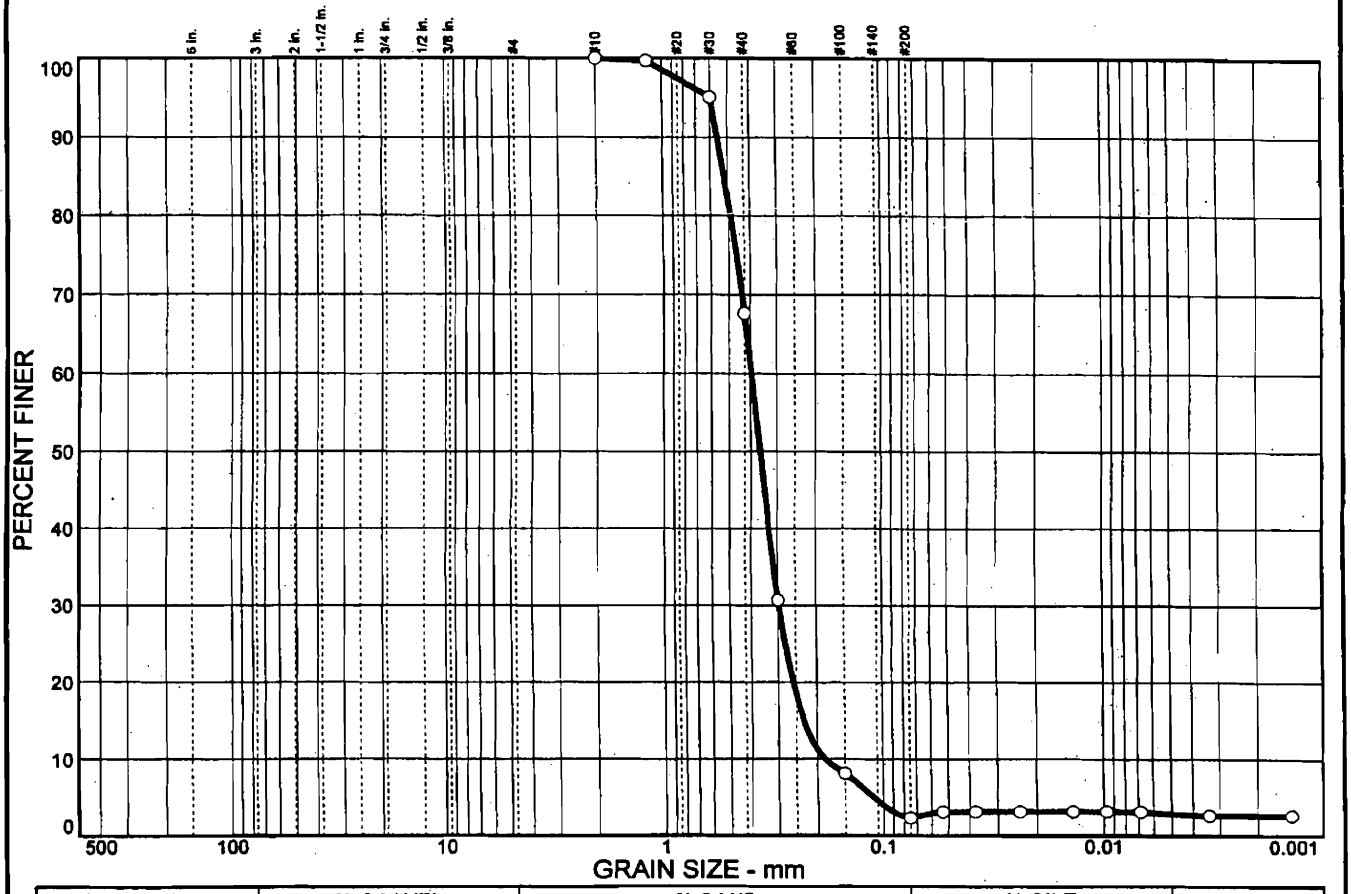
Bag Sample
Specific Gravity - 2.66

Sample No.: #19 **Source of Sample:** **Date:** 08/24/09
Location: Boring #1014 **Elev./Depth:** 188.5'-190.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project Nos V003-DE **Lab#** 26

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	97.7		2.8

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#10	100.0		
#16	99.7		
#30	95.1		
#40	67.6		
#50	30.7		
#100	8.1		
#200	2.3		

* (no specification provided)

Soil Description

Very Light Tan Poorly graded sand

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.521 D_{60}= 0.395 D_{50}= 0.362
D_{30}= 0.298 D_{15}= 0.230 D_{10}= 0.184
C_u= 2.15 C_c= 1.22

Classification

USCS= SP AASHTO=

Remarks

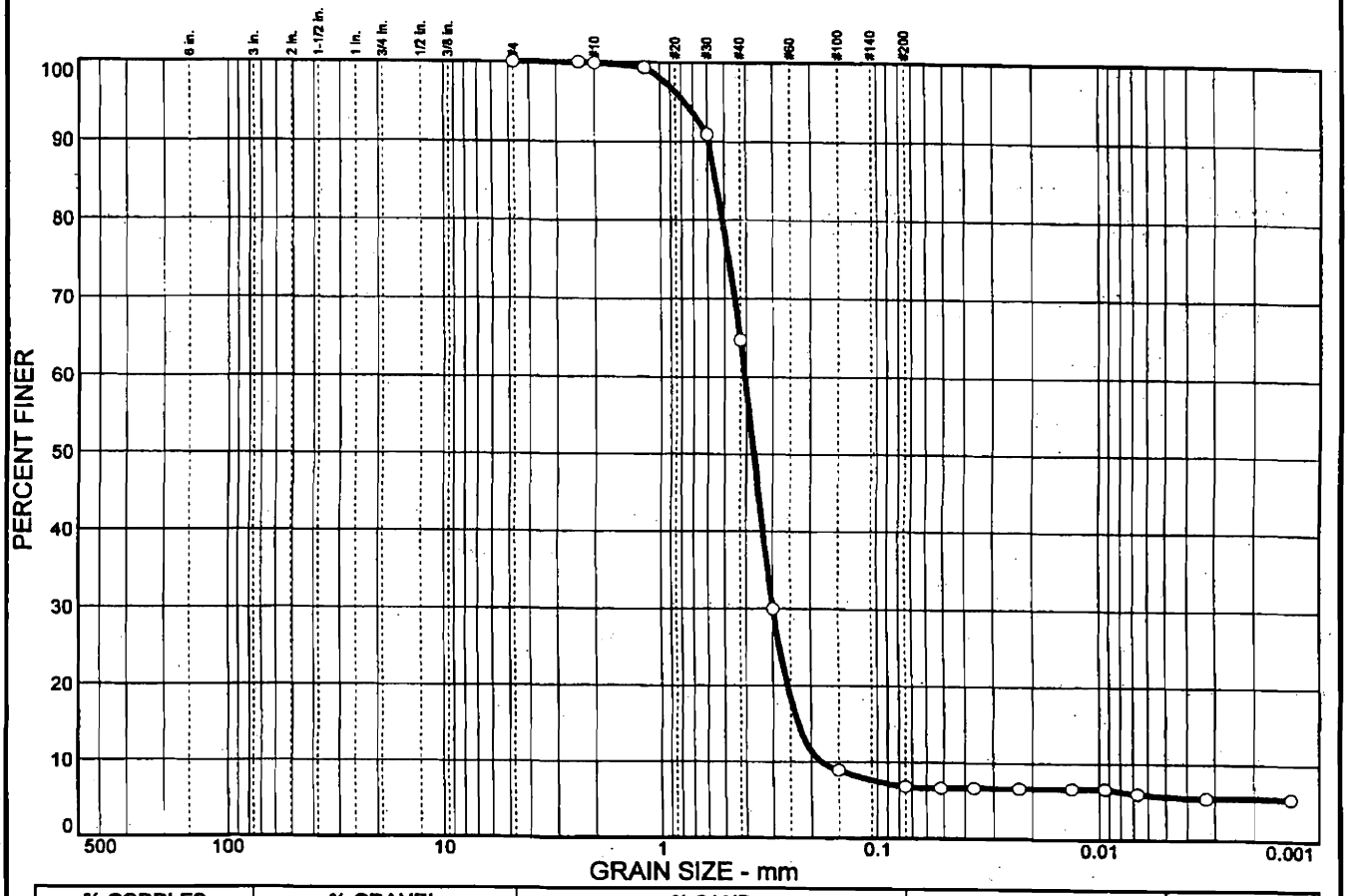
Jar Sample
Specific Gravity - 2.63

Sample No.: #19 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1015 **Elev./Depth:** 93.5'-95.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No: 6 V003-DE **Lab#** 27

Particle Size Distribution Report



% COBBLES	% GRAVEL	% SAND	% SILT	% CLAY
0.0	0.0	93.2	1.1	5.7

SIEVE SIZE	PERCENT FINER	SPEC.* PERCENT	PASS? (X=NO)
#4	100.0		
#8	100.0		
#10	99.9		
#16	99.3		
#30	90.9		
#40	64.7		
#50	30.0		
#100	8.9		
#200	6.8		

* (no specification provided)

Soil Description

Very Light Tan Poorly graded sand with silt

Atterberg Limits

PL= NA LL= NA PI= NA

Coefficients

D_{85}= 0.549 D_{60}= 0.405 D_{50}= 0.368
D_{30}= 0.300 D_{15}= 0.230 D_{10}= 0.180
C_u= 2.25 C_c= 1.23

Classification

USCS= SP-SM AASHTO=

Remarks

Jar Sample
Specific Gravity - 2.67

Sample No.: #20 **Source of Sample:** **Date:** 08/24/05
Location: Boring #1015 **Elev./Depth:** 93.5'-100.0'

SOUTHERN COMPANY

Client: SCS-Rhonda Tinsley and Steve Bearce
Project: Southern Nuclear/Plant Vogtle ESP
Project No.: V003-DE **Lab#** 28

APPENDIX J

SITE PHOTOS

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Appendix 2.4B—Groundwater Model Development & Analysis

Prepared by
Bechtel Power

June 2008

Southern Nuclear Operating Company
Vogtle Early Site Permit Application

GROUNDWATER MODEL DEVELOPMENT & ANALYSIS

Bechtel Power
June 2008



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TABLE OF CONTENTS

Executive Summary 10
1. Objective and Scope 12
2. Aquifier Description & Available Data 13
2.1 Site Overview 13
2.2 Hydrostratigraphy 13
2.3 The Water Table Aquifer 14
2.4 Groundwater Flow Conditions 15
2.5 Surface Water Features of Interest 15
2.6 Net Infiltration 17
2.7 Hydraulic Conductivity 19
3. The Groundwater Model 22
3.1 The Conceptual Hydrogeologic Model 22
3.2 The Numerical Model 22
3.2.1 The Numerical Code 22
3.2.2 The Numerical Solver 23
3.2.3 The Numerical Grid 23
3.2.4 The Vertical Extent of the Model 24
3.2.5 Types of Boundary Conditions Used in the Model 24
3.2.6 The Numerical Solver 25
3.3 Assumptions 25
3.3.1 Aquifer Materials 25
3.3.2 Flow Boundary Conditions 25
3.3.3 Groundwater Recharge 26
3.3.4 Aquifer Bottom 27
3.3.5 Hydraulic Conductivity 28
4. Model Calibration 29
4.1 Calibration Target 29
4.2 Calibration Measures and Statistics 30
4.3 Calibration Criteria 33
4.4 Model Calibration Process 33
4.4.1 Model 1: Uniform Hydraulic Conductivity and Recharge 41
4.4.2 Model 2: Uniform Hydraulic Conductivity, Variable Recharge 42
4.4.3 Model 3: Accounting for the Thickness of the Utley Limestone 42
4.4.4 Model 4: Simplified Representation of the Utley Limestone 43
4.4.5 Model 5: High Conductivity Zone Upstream of Mallard Pond 43
4.4.6 Model 6: Low Conductivity Zone in the Southwestern Part of the Model Domain 44
4.4.7 Model 7: Simplified Version of Model 6 44
4.4.8 Sensitivity Analysis 45
4.4.8.1 Hydraulic Conductivity of the Backfill Material Around Units 1 & 2 45
4.4.8.2 Rate of Recharge at the Met Tower Pond 46
4.4.8.3 Constant Head Condition at the Upper Debris Basin 2 47
4.4.8.4 Additional Areas of Zero Recharge 47
4.5 Validation of the Groundwater Model 48

4.5.1 Validation Using Stream Flow Data 48
4.5.2 Validation Using 1971 Groundwater Level Data Prior to Construction of Units 1 & 2 49
5. Post-Construction Simulations 51
5.1 Post-Construction Groundwater Simulations 51
5.1.1 Release of Particles From Circle of Radius of 775ft 52
5.1.2 Particle Release From Auxiliary Building of Unit 4 52
6. Conclusions 54
7. References 55
Attachment 1 134
Relevant Open Items 134
Attachment 2 135
NRC's Comments on the Groundwater Model 135

LIST OF TABLES

Table 1 Monthly Groundwater Level Elevations in Water Table Aquifer

Table 2 Estimated Recharge Values at Different Parts of the Savannah River Site

Table 3 Hydraulic Conductivity for Water Table Aquifer - VEGP Units 1 & 2 Site

Table 4 Hydraulic Conductivity for Fill Materials - VEGP Units 1 & 2 Site

Table 5 Hydraulic Conductivity Values for Water Table Aquifer - VEGP Units 3 & 4 Site

Table 6 Zones of Different Recharge

Table 7 March 2006 Observed Groundwater Level used in Model Calibration

Table 8 Summary of Simulated Cases During Calibration

Table 9 Sensitivity of Calibration Statistics to Units 1 & 2 Backfill

Table 10 Sensitivity of calibration statistics to the rate of recharge at the Met Tower Pond

Table 11 Sensitivity of Calibration Statistics to Constant Head Boundary Condition at Upper Debris Basin 2

Table 12 Sensitivity of Calibration Statistics to Additional Paved Areas (Parking Lot for Units 1&2 and a Number of Small Structures)

Table 13 Measured Stream Flows in the Stream of Mallard Pond in June-July 1985

Table 14 Groundwater Levels Prior to Construction of Units 1 & 2

Table 15 Travel Time for Single Particle Released from Auxiliary Building of Unit 4

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LIST OF FIGURES

Figure 1: VEGP Site Location [Figure 2.5.1-1]

Figure 2: Site Map Showing the Existing and the Proposed VEGP Units [Figure 2.4.12-3]

Figure 3: Isopachs of the Utley Limestone [Ref. 5, Figure 2.5.1-53]

Figure 4: Hydrogeologic Cross-Section of the Water Table Aquifer at the VEGP Site [Ref. 5 Figure 2.4.12-2A]

Figure 5: Outcrop and Contours of the Top of the Blue Bluff Marl at the VEGP Site

Figure 6: Site Geologic Map Showing the Outcrop of the Blue Bluff Marl [Figure 2.5.1-31]

Figure 7: Geologic Map of Barnwell Group Exposures in Eastern Burke County [from Ref. 6]

Figure 8: Water Table Aquifer: June 2005 – July 2007 Hydrographs [Ref. 5, Figure 2.4.12-23]

Figure 9: Water Table Aquifer: Piezometric Contour Map for June 2005 [Ref. 5, Figure 2.4.12-7]

Figure 10: Water Table Aquifer: Piezometric Contour Map for October 2005 [Ref. 5, Figure 2.4.12-8]

Figure 11: Water Table Aquifer: Piezometric Contour Map for December 2005 [Ref. 5, Figure 2.4.12-9]

Figure 12: Water Table Aquifer: Piezometric Contour Map for March 2006 [Ref. 5, Figure 2.4.12-10]

Figure 13: Water Table Aquifer: Piezometric Contour Map for June 2006 [Ref. 5, Figure 2.4.12-11]

Figure 14: Water Table Aquifer: Piezometric Contour Map for November 2006 [Ref. 5, Figure 2.4.12-24]

Figure 15: Ponds Near the Site of Units 3 & 4

Figure 16: Mean Annual Rainfall in the Savannah River Basin Based on Data from 1941 to 1970 [from Ref. 4]

Figure 17: Distribution of Estimated Hydraulic Conductivity Values for Units 3 & 4

Figure 18: Conceptual Groundwater Model for the VEGP Site

Figure 19: Numerical Model Grid and Boundary Conditions

Figure 20: Numerical Groundwater Model Domain with Key Physical Features and Respective Flow Boundaries

Figure 21: Bottom of the Model Domain (Top of Blue Bluff Marl) as Described in the Model

Figure 22: Groundwater Recharge Zones Used in the Model

Figure 23: Model 1 - Simulated Water Levels for Run 109 (K_1 = 27 ft/day; R_1 =7 in/yr)

Figure 24: Model 1 - Simulated Vs. Observed Water Levels for Run 109 (K_1 = 27 ft/day; R_1 =7 in/yr)

Figure 25: Model 1 - Estimated Residuals for Run 109 (K_1 = 27 ft/day; R_1 =7 in/yr)

Figure 26: Model 2 - Simulated Water Levels for Run 201 (K_1=27 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 27: Model 2 - Simulated Vs. Observed Water Levels for Run 201 (K_1=27 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 28: Model 2 - Estimated Residuals for Run 201 (K_1=27 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 29: Model 3, Run 305 - Hydraulic Conductivity Zones Accounting for the Presence of the Utley Limestone (K_1=27; K_2=20; K_3=30; K_4=60 ft/day)

Figure 30: Model 3 - Simulated water levels for Run 305 (K_1=27; K_2=20; K_3=30; K_4=60 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 31: Model 3 - Simulated Vs. Observed Water Levels for Run 305 (K_1=27; K_2=20; K_3=30; K_4=60 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 32: Model 3 - Estimated Residuals for Run 305 (K_1=27; K_2=20; K_3=30; K_4=60 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 33: Model 4, Run 403 – Simplified Hydraulic Conductivity Zones Accounting for the Presence of the Utley Limestone (K_1=20; K_2=35 ft/day)

Figure 34: Model 4- Simulated Water Levels for Run 403 (K_1=20; K_2=35 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 35: Model 4- Simulated Vs. Observed Water Levels for Run 403 (K_1=20; K_2=35 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 36: Model 4- Estimated Residuals for Run 403 (K_1=20; K_2=35 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 37: Model 5, Run 504 – Hydraulic Conductivity Zones as for Model 4 and a High Conductivity Zone Upstream of Mallard Pond (K_1=20; K_2=35; K_3=100 ft/day)

Figure 38: Model 5- Simulated Water Levels for Run 504 (K_1=20; K_2=35; K_3=100 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 39: Model 5- Simulated Vs. Observed Water Levels for Run 504 (K_1=20; K_2=35; K_3=100 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 40: Model 5- Estimated Residuals for Run 504 (K_1=20; K_2=35; K_3=100 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 41: Model 6, Run 612 – Hydraulic Conductivity Zones as for Model 5 and a Low Conductivity Zone in the Southwestern Quarter of the Model (K_1=28; K_2=33; K_3=200; K_4=8 ft/day)

Figure 42: Model 6 - Simulated Water Levels for Run 612 (K_1=28; K_2=33; K_3=200; K_4=8 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 43: Model 6 - Simulated Vs. Observed Water Levels for Run 612 (K_1=28; K_2=33; K_3=200; K_4=8 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 44: Model 6- Estimated Residuals for Run 612 (K_1=28; K_2=33; K_3=200; K_4=8 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 45: Model 7, Run 708 – Simplified Version of Model 6 (K_1=32; K_2=100; K_3=8 ft/day)

Figure 46: Model 7 - Simulated Water Levels for Run 708 (K_1=32; K_2=100; K_3=8 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 47: Model 7 - Simulated Vs. Observed Water Levels for Run 708 (K_1=23; K_2=400; K_3=6; ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 48: Model 7- Estimated Residuals for Run 708 (K_1=23; K_2=400; K_3=6; ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 49: Hydraulic Conductivity Zones Used in Model 7 to Evaluate the Sensitivity of the Model to the Hydraulic Conductivity for the Backfill Material Around Units 1 & 2

Figure 50: Simulated Water Levels with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

Figure 51: Simulated Versus Observed Water Levels with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

Figure 52: Estimated Residuals with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

Figure 53: Simulated Water Levels with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 6 in/yr

Figure 54: Simulated Versus Observed Water Levels with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 6 in/yr

Figure 55: Estimated Residuals with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 6 in/yr

Figure 56: Simulated Water Levels with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 40 in/yr

Figure 57: Simulated Versus Observed Water Levels with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 40 in/yr

Figure 58: Estimated Residuals with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 40 in/yr

Figure 59: Simulated Water Levels with Model 7 Using a Constant Head Boundary Condition at the Upper Debris Basin 2 (The constant head used was 148.5 ft msl)

Figure 60: Simulated Versus Observed Water Levels with Model 7 Using a Constant Head Boundary Condition at the Upper Debris Basin 2 (The constant head used was 148.5 ft msl)

Figure 61: Estimated Residuals with Model 7 Using a Constant Head Boundary Condition at the Upper Debris Basin 2 (The constant head used was 148.5 ft msl)

Figure 62: Simulated Water Levels with Model 7 Using Additional Paved Areas Around Units 1 & 2 and 3 & 4

Figure 63: Simulated Versus Observed Water Levels with Model 7 Using Additional Paved Areas Around Units 1 & 2 and 3 & 4

Figure 64: Estimated Residuals with Model 7 Using Additional Paved Areas Around Units 1 & 2 and 3 & 4

Figure 65: Location of Stream Flow Measurement Stations at Mallard Pond

Figure 66: Representation of Mallard Pond and Area in Groundwater Model

Figure 67: Zone Budget Representation of Mallard Pond and Area in Groundwater Model

Figure 68: Simulated Water Levels for 1971 Groundwater Model

Figure 69: Simulated Vs. Observed Water Levels for 1971 Groundwater Model

Figure 70: Estimated Residuals for 1971 Groundwater Model

Figure 71: Hydraulic Conductivity Zones Used in Model 7 to Evaluate Post-Construction Conditions

Figure 72: Excavation Plan Overlaid onto Model Grid to Show Areas of Backfill Around Units 3 & 4

Figure 73: Recharge Zones Used to Evaluate Post-Construction Conditions

Figure 74: Simulated Water Levels for Post-Construction Conditions Obtained with Model 7 (K_1=32; K_2=100; K_3=8; K_{fill}=3.3 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 75: Simulated Water Levels with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

Figure 76: Simulated Water Levels with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

Figure 77: Simulated Water Levels and Particle Tracking for Post-Construction Conditions Obtained with Model 7 (K_1=32; K_2=100; K_3=8; K_{fill}=3.3 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

Figure 78: Pathway of Particle Released from Auxiliary Building of Unit 4 (water table contour interval = 2 ft)

Abbreviations

ft	feet
ft/day	feet per day
ft/ft	feet per foot
ft^2/day	square feet per day
in/yr	inches per year
bgs	below ground surface
msl	mean sea level

Acronyms

AMG	Alebraic Multigrid
BBM	Blue Bluff Marl
ESP	Early Site Permit
GMG	Geometric Multigrid
NRC	Nuclear Regulatory Commission
PA	Protected Area
PCG	Preconditioned Conjugate-Gradient
SER	Safety Evaluation Report
SIP	Strongly Implicit Procedure
SOR	Slice-Successive Overrelaxation
SSAR	Site Safety Analysis Report
FSAR	Final Safety Analysis Report
USGS	United States Geological Survey
VEGP	Vogtle Electrical Generating Plant
WHS	Waterloo Hydrogeologic Services

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EXECUTIVE SUMMARY

A groundwater flow model of the VEGP site has been developed in support of Early Site Application for Units 3 & 4. The model is two dimensional in the horizontal plane, using a single layer to describe the Water Table aquifer. The model was developed using the code MODFLOW 2000 developed by the U.S. Geological Survey, as it is implemented in the user interface environment Visual MODFLOW developed by Schlumberger Water Services.

The computer files of an initial version of this model were submitted to the NRC in January 2008. Upon review of these files the NRC provided written comments on the model, which were further discussed in meetings between the NRC and SNC and Bechtel on April 8-9, 2008.

NRC's comments concerned the accurate representation of the top of Blue Bluff Marl (BBM), which may control the location of the groundwater divide near the site of Units 3 & 4; spatial trends in residual errors; model mass balance errors; and the inadequate documentation of the model. The present report documents the groundwater model and discusses new, not previously presented work, which addresses NRC's comments.

The top of the BBM in the model was defined based on reinterpretation of all available data, including historic data and data collected during the site investigations for the ESP/COL investigations. The mapped BBM outcrop along the bluff near the Savannah River and to the south of the VEGP site was included in the model. In addition, a walk down over the area of the groundwater model was conducted to identify areas of groundwater discharge near the outcrop of the BBM.

Spatial trends in residual errors that existed in early simulations with the model were eliminated. Spatially variable groundwater recharge based on the vegetation cover, soil conditions and ground surface slope was introduced in the model. Several plausible hydraulic conductivity zonations and values were tested.

In all simulations the mass balance discrepancy between inflow and outflow was reduced to less than one percent. This was achieved through the use of smaller head convergence criteria and by adjusting other parameters of the numerical solver used by the model.

The present report documents the calibration process in detail describing the steps towards improved agreement between computed and observed water levels and the rationale for all assumptions made along the way.

The calibrated model was used to simulate post-construction conditions, accounting for changes in the topography at the site of Units 3 & 4, the presence of backfill material in the area of the new structures, and changes in ground water recharge. Particle tracking was performed to identify the groundwater pathways of potential liquid effluent releases from the power block area.

The conclusion drawn from all simulations with several alternative plausible models was that all groundwater pathways from the power block lead to Mallard Pond north of Units 3 & 4. Under all conditions the groundwater divide remains south of the power block area.

1. OBJECTIVE AND SCOPE

The objective of this report is to document the development, calibration and use of a groundwater flow model for the Water Table aquifer at the Vogtle site. The model was developed in support of the responses to Open Items 2.4-2, 2.4-3, and 2.4-4 as identified in the NRC Safety Evaluation Report (SER) with Open Items for the Vogtle ESP application. These Open Items are listed in Attachment 1.

The model was developed in November 2007 and documented in Bechtel calculation 25144-K-003, Rev 0. A two-dimensional single layer groundwater model was used to simulate groundwater flow in the Water Table aquifer. A brief description of the model was presented in the SSAR Section 2.4.12 of the Vogtle ESP application, Revision 3, November 2007. At NRC's request the electronic files for the three simulated cases discussed in SSAR Section 2.4.12 were submitted to the NRC. These were the files included in the electronic Attachment 4 to Bechtel calculation 25144-K-003, Rev 0. However, Bechtel calculation 25144-K-003, Rev 0 itself was not reviewed by the NRC.

Upon review of the electronic computer files for the groundwater flow model, the NRC provided specific comments on the model, which are reproduced in Attachment 2. These comments were discussed in a meeting between the NRC and SNC and Bechtel at NRC's headquarters in Rockville on April 8, 2008 and in a second meeting in Bechtel's Frederick, Maryland office on April 9, 2008.

In the April 9 meeting the NRC stressed that the analysis with the model should include the plausible alternative conceptual models that do not violate the data and emphasized the need for thorough documentation of the process followed to arrive at the calibrated model used to predict future groundwater conditions and pathways of potential effluent releases. The present report was prepared in response to these comments.

2. AQUIFIER DESCRIPTION & AVAILABLE DATA

2.1 Site Overview

The 3,169 acre VEGP site is located on a bluff on the southwest side of the Savannah River in eastern Burke County, Georgia, within the Coastal Plain physiographic province (see Figure 1). The finished grade level elevation of the proposed AP1000 VEGP Units 3 & 4 will approximately 220 ft msl. The bottom of the foundation slab for the safety-related AP1000 containment structure will be at 39.5 ft below grade level, i.e. at elevation 180.5 ft msl. In constructing the new units, the site will be excavated approximately 80 ft to 90 ft below existing grade to remove the in-situ soil down to the principal bearing strata, the Blue Bluff Marl (BBM). The in-situ soil will be replaced with Category 1 and 2 structural fill material. Foundations for the new units will be poured on this new fill material and the fill material will be placed around the structures and continue up to the finished grade elevation of 220 ft msl.

Figure 2 shows the site and the location of the existing Units 1 & 2, as well as the planned Units 3 & 4, along with the observation wells monitored during the ESP groundwater investigation.

2.2 Hydrostratigraphy

The VEGP site and associated groundwater is located within the Coastal Plain physiographic province. There are three underlying aquifers at the VEGP site, the Cretaceous, the Tertiary, and the Water table (or Upper Three Runs) aquifer, all being part of the Southeastern Coastal Plain aquifer system.

- Water Table Aquifer: This is the unconfined aquifer that forms the first water-bearing zone encountered beneath the VEGP site. It consists of the Barnwell Group and includes the discontinuous deposits of the Utley limestone. The saturated interval within the Barnwell Group is commonly referred to as the Water Table aquifer which is also known as the Upper Three Runs aquifer.
- Tertiary Aquifer: The most productive aquifer at the VEGP site consists of the Congaree and Still Branch Formations, which are hydraulically connected and are referred to as the Tertiary aquifer. The overlying Lisbon Formation, containing the Blue Bluff Marl, acts as a confining layer. Recharge to the Tertiary aquifer is primarily by infiltration of rainfall in its outcrop area, which is a belt 20 to 60 miles wide extending northeastward across central Georgia and into portions of Alabama to the west and South Carolina to the east. Discharge from the Tertiary aquifer occurs from pumping, from natural springs in areas where topography is lower than the piezometric level of the aquifer, and from subaqueous outcrops that are presumed to occur offshore. Discharge also occurs to the Savannah River where the river has completely eroded the Blue Bluff Marl confining layer allowing discharge from the aquifer to the river bed.

- Cretaceous Aquifer: The Cretaceous aquifer is the lowermost aquifer at the VEGP site that overlies the impermeable bedrock. This aquifer comprises the Cape Fear Formation, Pio-Nono Formation/unnamed sands, Gaillard Formation/Black Creek Formation, and Steel Creek Formation. The Cretaceous aquifer system is under confined conditions for most of its areal extent. Recharge to the Cretaceous aquifer system is primarily by direct infiltration of rainfall in its outcrop area, located north of the VEGP site in a 10- to 30-mile-wide belt extending from Augusta, Georgia, northeastward across South Carolina to near the state line separating North and South Carolina. Discharge of the Cretaceous aquifer system is primarily from subaqueous exposures of the aquifer that are presumed to occur along the Continental Shelf. Other discharge sources are to the Savannah River and by pumping.

The ground surface contour map at the VEGP site is shown on Figure 2 (Ref. 12).

2.3 The Water Table Aquifer

The Water Table aquifer consists of the undifferentiated sands, clays, and silts of the Barnwell Group, and discontinuous deposits of the Utley limestone. The Utley limestone member of the Barnwell Group consists of sand, clay, and silt with carbonate-rich layers. The Utley limestone was found to be present in 36 percent of the borings completed for the ESP and COL subsurface investigations. It tends to be present in the power block area for VEGP Units 3 & 4 and the area to the north towards Mallard Pond and south towards the VEGP Units 3 & 4 cooling towers. Where present the base of the Utley Limestone ranges in elevation from approximately 96 ft msl to 152 ft msl. Figure 3 shows isopachs of the Utley limestone. The limestone is absent along the flanks of this feature and increases in thickness to a maximum of approximately 25 to 38 ft along its axis. Its total thickness varies considerably, and it is absent in some places within its general area of extent.

Figure 4 shows a hydrogeologic section showing the elevation, thickness, and description of subsurface materials of the Water Table aquifer at the VEGP site. This figure conceptually represents a cross-section of the single layer groundwater model developed for the VEGP site for this report (see Section 4).

The base of the aquifer is the top of the BBM. Figure 5 shows elevation contours for the top of the BBM based on the interpretation of data from 182 borings that have penetrated the top of the BBM within the VEGP site. The contour map for the top of the BBM was developed from borehole data generated from VEGP Units 1 & 2, and VEGP Units 3 & 4 ESP and COL hydrogeologic subsurface investigations. Figure 5 also shows the outcrop of the BBM based on the site geologic map presented in the ESP, reproduced in Figure 6, and the exposure of the Lisbon Formation as shown in the geologic map prepared by Huddlestun and Summerour (Ref. 8), reproduced in Figure 7. The outcrop of the BBM defines the horizontal extent of the Water Table aquifer.

2.4 Groundwater Flow Conditions

Groundwater level data from June 2005 through July 2007 for the Water Table aquifer that were used in the ESP application are summarized in Table 1. Figure 8 shows the hydrographs for all the monitoring wells. As can be seen in this figure the water level data show practically no seasonal variability.

The groundwater elevation data summarized in Table 1 were used to develop groundwater surface elevation contour maps for the Water Table aquifer on a quarterly basis. These maps are presented in Figure 9 through Figure 14 for June 2005 through November 2006. For each quarter, the spatial trend in the piezometric surface is similar, with elevations ranging from a high of approximately El. 165 ft msl in the vicinity of well OW-1013 to a low of less than El. 135 ft msl at well OW-1005. The groundwater surface contour maps indicate that horizontal groundwater flow across the VEGP site is in a north-northwest direction toward Mallard Pond (also known as Mathes Pond), which is a local discharge point for the shallow groundwater flowing beneath the VEGP site. As can be seen in Figure 9 through Figure 14 the water table contours change very little around the year. The horizontal hydraulic gradient across the site for the Water Table aquifer remains practically constant, as can be seen in the in the six water table contour maps shown in Figure 9 through Figure 14 and is approximately 0.014 ft/ft.

A feature of interest for the analysis of the pathway of potential liquid effluent releases is the location of the groundwater divide which separates the area where groundwater flow is primarily to the north from the area where groundwater flow is to the south. As can be seen in Figure 9 through Figure 14 the divide passes close to the south end of location of the cooling towers of Units 3 & 4. Its location does not seem to change around the year.

2.5 Surface Water Features of Interest

There are several small ponds in the vicinity of Units 3 & 4 (see Figure 15). To the north there is Mallard Pond with a water surface elevation of about 111 ft msl. Four relatively large ponds are located to the south of Units 3 & 4. Debris Basin 1, with a water surface elevation of about 135 ft msl, captures runoff from a drainage area of about 200 acres. The Met Tower pond, with water surface elevation of about 221 ft msl, captures runoff from a 50-acre drainage area. The Upper Debris Basin 2 receives runoff from the Units 3 & 4 power block area. It stores runoff until the water surface elevation reaches the invert elevation of 148.5 ft msl of three 36-inch diameter pipes and then discharges into the Lower Debris Basin. Finally, the Lower Debris Basin impounds water at elevation of about 138.5 ft msl. A minimal flow is maintained from the discharge pipe. The drainage area of the Lower Debris Basin is about 680 acres.

Table 1 Monthly Groundwater Level Elevations in Water Table Aquifer

Well No.	142	179	802A	803A	804	805A	806B	808	809	LT-1B	LT-7A	LT-12	LT-13	OW-1003	OW-1005	OW-1006	OW-1007	OW-1009	OW-1010	OW-1012	OW-1013	OW-1015
Jun 05	154.4	147.4	157.9	160.0	163.7	158.5	155.6	158.9	152.8	154.9	154.4	158.2	156.1	155.9	133.0	147.7	151.8	162.4	163.1	161.8	165.0	159.6
Jul 05	154.4	148.4	157.9	159.9	163.6	158.6	155.7	159.1	152.7	154.8	154.2	157.9	155.9	155.9	132.7	147.5	151.7	162.4	163.3	161.9	165.0	159.6
Aug 05	154.5	148.4	158.1	160.2	163.9	158.8	155.8	159.4	152.8	155.0	154.3	158.1	156.1	156.1	132.9	147.6	151.8	162.7	163.6	162.1	165.3	159.8
Sep 05	154.6	148.7	158.2	160.3	164.1	159.0	155.9	159.6	152.9	155.2	154.5	158.2	156.3	156.3	133.0	147.6	151.6	162.9	163.8	162.1	165.5	159.9
Oct 05	154.8	148.7	158.3	160.4	164.2	159.1	156.0	159.5	153.0	155.2	154.5	158.3	156.3	156.2	132.7	147.5	151.5	163.0	163.8	162.0	165.5	160.0
Nov 05	154.7	148.8	158.3	160.5	164.2	159.1	156.0	159.4	153.0	155.2	154.5	158.3	156.4	156.4	132.7	147.2	151.2	163.0	163.8	161.8	165.4	160.0
Dec 05	154.6	148.5	158.3	160.4	164.1	159.1	155.9	159.2	153.0	155.1	154.3	158.2	156.2	156.3	132.5	147.2	151.1	162.9	163.6	161.7	165.2	159.8
Jan 06	154.7	148.6	158.3	160.4	164.1	158.9	156.0	159.0	153.1	155.2	154.6	158.5	156.4	156.3	132.7	147.4	151.4	162.9	163.6	161.8	165.3	159.8
Feb 06	154.8	148.6	158.4	160.5	164.2	158.9	156.0	159.2	153.2	155.5	154.8	158.7	156.7	156.4	133.0	147.4	151.5	163.0	163.6	161.9	165.5	159.8
Mar 06	154.7	148.7	158.2	160.5	164.3	159.0	156.0	159.2	153.2	155.3	154.6	158.5	156.4	156.4	133.1	147.4	151.5	163.0	163.6	161.8	165.3	159.9
Apr 06	154.6	148.7	158.2	160.3	164.1	158.8	155.9	159.0	153.1	155.2	154.6	158.5	156.3	156.3	133.1	147.4	151.2	162.9	163.4	161.7	165.2	159.8
May 06	154.6	148.8	158.1	160.2	164.0	158.8	155.8	158.5	153.0	155.2	154.5	158.5	156.3	157.2	133.2	147.1	151.1	162.8	163.3	161.5	165.1	159.7
Jun 06	154.5	148.8	158.0	160.1	163.9	158.6	155.7	158.8	153.0	155.0	154.4	158.2	156.2	156.2	133.1	147.1	151.0	162.7	163.1	161.4	165.0	159.6
Jul 06	154.4	148.6	157.9	160.0	163.7	158.5	155.7	158.7	152.9	155.0	154.3	158.2	156.1	156.0	132.9	146.9	150.8	162.5	162.9	161.2	164.8	159.5
Aug 06	154.4	148.8	157.9	159.9	163.7	158.5	155.6	158.7	152.9	155.0	154.3	158.2	156.1	156.0	132.8	146.8	150.5	162.4	162.8	161.0	164.7	159.4
Nov 06	154.2	148.8	157.6	159.6	162.8	158.2	155.4	158.4	152.7	154.8	154.3	158.1	155.9	155.9	132.5	146.5	150.1	162.2	162.5	160.5	164.3	159.1
Dec 06	154.0	148.8	157.4	159.5	163.2	158.0	155.2	158.4	152.6	154.6	154.0	157.8	155.8	155.7	132.4	146.3	149.9	162.0	162.3	160.3	164.0	158.8
Jan 07	154.0	148.6	157.2	159.3	163.0	158.8	155.1	158.0	152.6	154.5	154.0	157.8	155.6	155.6	132.3	146.3	150.1	161.7	162.2	160.2	163.8	158.6
Feb 07	154.0	148.9	157.2	159.3	163.0	157.7	155.1	158.0	152.7	154.3	153.7	157.5	155.4	155.9	132.5	146.5	150.2	161.9	162.2	160.3	163.9	158.6
Mar 07	153.9	148.5	157.7	159.3	163.1	157.7	155.1	158.2	152.6	154.4	153.7	157.6	155.6	155.7	132.3	146.1	150.3	161.8	162.4	160.2	163.8	158.5
Apr 07	153.8	148.5	156.9	158.9	162.5	157.4	154.9	158.0	152.4	154.3	153.7	157.5	155.3	155.5	132.2	146.0	150.1	161.7	162.5	160.2	163.7	158.2
May 07	153.6	148.4	156.8	158.8	162.6	157.3	154.7	158.1	152.3	154.0	153.2	157.0	155.1	155.3	132.1	145.6	150.0	161.5	162.3	160.0	163.5	158.1
Jun 07	153.6	148.4	156.8	158.8	162.7	157.3	154.7	158.0	152.3	154.0	153.4	157.2	155.1	155.4	132.0	145.7	149.9	161.5	162.3	160.0	163.5	158.0
Jul 07	153.6	148.4	156.8	158.8	162.8	157.3	154.7	157.9	152.3	153.9	153.3	157.1	155.1	155.3	132.1	145.6	149.7	161.4	161.9	159.8	163.4	157.9

Groundwater level data are from SSAR Table 2.4.12-1.
No groundwater data were measured in September and October of 2006.

2.6 Net Infiltration

The net infiltration, or groundwater recharge, accounts for the rate of net gain of the groundwater system resulting from surface infiltration. The presence of porous surface sands and the moderate topographic relief in the VEGP site area suggest that a significant fraction of the precipitation infiltrates the ground.

Although a water budget for the VEGP site has not been established, recharge and discharge rates in the region have been estimated on a basin-wide basis by different investigators. For example, in 1997 Clarke and West (Ref. 4, p. 93) estimated the long-term average groundwater recharge in the nearby Savannah River basin to be 14.5 in/yr, of which 6.8 inches is to the local flow system, 5.8 inches is to the intermediate flow system, and 1.9 inches is to the regional flow system. The local flow system described by Clarke and West (Ref. 4) is characterized by relatively shallow and short flow paths. This system in the Savannah River basin is primarily the Upper Three Runs aquifer, which is equivalent to the Water Table aquifer at the VEGP site. Therefore, it is reasonable to assume that the recharge to the Water Table aquifer is about the same as that estimated for the local flow system described by Clarke and West, i.e. of the order of 6.8 in/yr.

Mean-annual precipitation in the basin ranges from 44 to 48 inches. Considering the distribution of precipitation in the Savannah River basin (see Figure 16) the rate of recharge to the Water Table aquifer at the VEGP site may be a little higher than the estimated average value (6.8 in/yr) over the entire basin. The estimate of the total rate of recharge provided in Ref. 4 (14.5 in/yr) is consistent with the groundwater recharge estimates obtained from several studies at the Savannah River Site, which are summarized in Table 2. It is also noted that the recharge at the VEGP site may be lower than that at the Savannah River Site because of greater topographic relief, which produces more runoff. The Savannah River Site is flatter than the VEGP site.

The rate of groundwater recharge within the model domain is expected to vary depending on the characteristics of the ground surface. Five different recharge zones are defined listed in approximate order of decreasing recharge:

- Open areas on mild slopes.
- Forested areas on mild slopes.
- Open areas on steep slopes (greater than 10 percent).
- Forested areas on steep slopes (greater than 10 percent).
- Buildings, paved areas and areas covered with slabs

A direct estimation of the recharge rate for each of these zones requires systematic data for the water budget in the surface layer influenced by evapotranspiration. Because such data are not available the recharge rate in each of these zones is treated as a calibration parameter.

Table 2 Estimated Recharge Values at Different Parts of the Savannah River Site

Modeled Savannah River Site Area	Global Recharge Values (in/yr)	Report Title	Report Authors	Date	Document Number
RRSB	15	Groundwater Flow and Contaminant Transport Modeling in Support of the RRSB Operable Unit (U)	INTERA	March 2003	WSRC-RP-2002-4081
CMP Pits	10 12	Groundwater Modeling for the Chemicals, Metals, and Pesticides Pits (U)	G.W. Council, GeoTrans L.M. Grogin	October 2002	WSRC-RP-2002-4195
D Area	8 15	Flow and Transport Modeling for D-Area Groundwater (U)	K.E.Brewer C.S. Sochor	October 2002	WSRC-RP-2002-4166
Southern Sector	9	Groundwater Modeling for the Southern Sector of A/M Area (U)	GeoTrans	November 2001	WSRC-RP-2001-4254
CBRP	12.5	Groundwater Modeling for the C-Area Burning/Rubble Pit (U)	GeoTrans	October 2001	WSRC-TR-2001-00298
CRGW	12.5	Groundwater Transport Modeling for Southern TCE and Tritium Plumes in the C-Area Groundwater Operable Unit (U)	T.L. Fogle K.E. Brewer	June 2001	WSRC-TR-2001-00206
CRSB/ CBRP	11.6	Hydrogeological Analysis and Groundwater Flow for C-Reactor Area with Contaminant Transport for C-Reactor Seepage Basins (CRSB) and C-Area Burning Rubble Pit (CBRP) (U)	G.P. Flach; M.K. Harris; R.A. Hiergesell; A.D. Smits	December 1999	WSRC-TR-99-00310
LBRP	12.5	Groundwater Flow and Transport Modeling for the L-Area Burning/Rubble Pit (131-L), L-Area Rubble Pile (131-3L), and L-Area Gas Cylinder Disposal Facility (131-2L) Savannah River Site, Aiken, South Carolina (U)	D.C. Noffsinger	November 1999	WSRC-RP-99-4154
MCB/MBP	15	Groundwater Flow and Transport Modeling for the Miscellaneous Chemical Basin and Metals Burning Pit (731-4A/5A) (U)	D.C. Noffsinger	March 1999	WSRC-RP-98-4167
CKLP	12.5	Hydrogeological and Groundwater Flow Model for C, K, L, and P Reactor Areas, Savannah River Site, Aiken, SC (U)	G.P. Flach; M.K. Harris; R.A. Hiergesell; A.D. Smits	September 1998	WSRC-TR-98-00285
KBRP	10 to 17	Groundwater Flow and Solute Transport Modeling Report K-Area Burning Rubble Pit and Rubble Pile	GeoTrans	June 1998	WSRC-RP-98-5052

2.7 Hydraulic Conductivity

Hydraulic conductivity tests for VEGP Units 1 & 2 performed in the Barnwell sands and the Utley limestone are described in the VEGP Final Safety Analysis Report (FSAR) for Units 1 & 2 (Ref. 5). These tests consisted of two in-situ constant head tests and three laboratory tests on undisturbed samples of the Barnwell sands. The results of the hydraulic tests are presented in FSAR (Ref. 5) Table 2.4.12-12 and are summarized in Table 3. As can be seen in Table 3, the measured hydraulic conductivity values range from 0.03 ft/day to 0.8 ft/day.

Hydraulic conductivity tests performed in the Utley limestone consisted of five pumping tests, seven falling head and four constant head tests. The results are presented in FSAR Table 2.4.12-13 and are summarized in Table 3. The pumping test yielded hydraulic conductivity values ranging from 8.9 ft/day to 343 ft/day, with a geometric mean of 60.2 ft/day. The falling head and constant head tests yielded hydraulic conductivity values ranging from 0.38 ft/day to 16 ft/day. The geometric mean of the 7 falling head tests was 1.7 ft/day. The geometric mean of 4 constant head tests was 2.8 ft/day. It is noted that the hydraulic estimates from the pumping tests are more than an order of magnitude higher than those estimated from the slug tests. Also, comparing hydraulic conductivity values obtained with the same method we find that the hydraulic conductivity of the Utley limestone (2.8 ft/day, the geometric mean of 4 constant head tests) is a little less than five times that of the Barnwell sands (0.6 ft/day, the geometric mean of 2 constant head tests).

The hydraulic conductivity of the structural fill for the VEGP Units 1 & 2 was determined from slug tests (see Table 2.4.12-15 in Ref. 5). The results of these tests are presented in Table 4, which shows that the measured hydraulic conductivity values of the fill ranged from 1.32 to 3.34 ft/day, with a geometric mean of 2.32 ft/day.

For the VEGP Units 3 & 4 sites, hydraulic conductivity values for the Water Table aquifer were determined from slug tests performed in the groundwater observation wells installed at the site. The results of these tests are presented in Table 5. Table 5 shows that the wells are screened in portions of the Barnwell sands and Utley limestone with hydraulic conductivity values ranging from 0.12 to 2.65 ft/day, and a geometric mean of 0.5 ft/day. This value is of the same order of magnitude as the geometric mean of the hydraulic conductivity estimated from the falling and constant head tests for Units 1 & 2 (1.7 and 2.8 ft/day for wells screened in the Utley limestone, and 0.6 ft day for the Barnwell sands). Figure 17 shows the spatial distribution of the hydraulic conductivity values estimated from the hydraulic tests for Units 3 & 4. As can be seen from this figure there is no distinct pattern in the distribution of the hydraulic conductivity values.

Table 3 Hydraulic Conductivity for Water Table Aquifer - VEGP Units 1 & 2 Site

Well No.	Test Interval (ft bgs)	Hydraulic Conductivity (ft/day)	Geometric Mean (ft/day)
Utley Limestone			
		Pumping Test Results	60.2
1A	56 – 78	39	
1B	68 – 78	343	
1C	56 – 80	55	
1D	56 – 80	121	
2A	62 – 85	8.9	
		Falling Head Test Results	1.7
W-1	65 – 80	16	
1A	63 – 78	1.6	
W-2	69 – 85	2.7	
2A	70 – 85	0.26	
2B	69 – 84	1	
2C	65 – 85	0.38	
2D	70 – 85	5.7	
		Constant Head Test Results	2.8
1A	56 – 78	0.44	
2A	56 – 85	8.8	
2B	56 – 84	4.9	
2D	56 – 85	3.3	
Barnwell Sands			
		Constant Head Test Results	0.6
183	50 – 60	0.5	
184	53 – 63	0.7	
		Laboratory Test Results	0.1
107A	13.8 – 14.4	0.8	
	34 – 36	0.03	
	62.5 – 63	0.08	

Source: FSAR Table 2.4.12-12 and Table 2.4.12-13.

Table 4 Hydraulic Conductivity for Fill Materials - VEGP Units 1 & 2 Site

Well ID.	Hydraulic Conductivity	
	(ft/year)	(ft/day)
LT-1B	1220	3.34
LT-7A	750	2.05
LT-12	480	1.32
LT-13	1180	3.23
Geometric Mean (ft/day)		2.32

Source: FSAR Table 2.4.12-15.

Table 5 Hydraulic Conductivity Values for Water Table Aquifer - VEGP Units 3 & 4 Site

Observation Well No.	Test Interval (ft bgs)	Hydraulic Conductivity (ft/day)
OW-1003	72 – 91	0.12
OW-1005	143 - 169	0.32
OW-1006	113 - 136	1.4
OW-1007	99 – 120	2.65
OW-1009	81 – 98	1.1
OW-1010	70 – 92	0.18
OW-1012	71 – 94	0.39
OW-1013	81 – 104	0.38
OW-1015	90 – 120	0.44
	Geometric Mean (ft/day)	0.50

Source: Vogtle ESP Application, SSAR Table 2.4.12-3

3. THE GROUNDWATER MODEL

3.1 The Conceptual Hydrogeologic Model

Based on the aquifer description presented in Section 2 the Water Table aquifer was conceptualized as a single hydrogeologic unit. No distinction is made between the Barnwell sands and the Utley limestone. The aquifer is described as a single material. Because of the low permeability of the BBM, there is negligible vertical flow from the Water Table aquifer to the underlying Tertiary aquifer. Therefore, the flow through the aquifer can be described as two-dimensional in the horizontal plane. The BBM is treated as impermeable. The top of the BBM forms the bottom of the aquifer.

The model domain was selected in such a manner as to minimize the impact of assumptions regarding boundary conditions on predictions in the area of Units 3 & 4 and their vicinity. The boundaries of the model domain were placed where reasonable assumptions regarding local conditions could be made. Figure 18 shows the selected model domain. It extends about 1 mile to the north, 2 miles to the south and about 1 mile to the west of Units 3 & 4. To the east the model extends to the outcrop of the BBM at the bluff along the Savannah River.

The northern boundary and a little more than the northern half of the western boundary of the model coincides with the surface water divide. It is assumed that in this area the groundwater divide coincides with the surface water divide. Therefore, this boundary is treated as a no-flow boundary.

The northeastern, southeastern and part of the southwestern boundary of the model is defined by the outcrop of the BBM, which represents the horizontal extent of the Water Table aquifer, and where the aquifer discharges. This interpretation is supported by observations of small springs and seeps along the bluff. The zone of groundwater discharge near the outcrop of the BBM is described in the model by a series of drains. Mallard Pond was treated as a constant head area.

3.2 The Numerical Model

3.2.1 The Numerical Code

The conceptual hydrogeologic model was implemented in a two-dimensional, single layer numerical groundwater model using the code MODFLOW 2000 (Ref. 7). MODFLOW solves the three-dimensional ground-water flow equation using a finite-difference method. It has been widely used in the industry since its development and release by the U.S. Geological Survey in 1984.

From its inception MODFLOW had a modular structure that allowed the incorporation of additional modules and packages to solve other equations that are often needed to handle specific groundwater problems (Ref. 8). Over the years several such modules and packages

have been added to the original code. MODFLOW 2000 is major revision of the code that expanded upon the modularization approach that was originally included in MODFLOW.

To facilitate the development of the present model the user interface Visual MODFLOW (Ref. 9) was used. Visual MODFLOW was developed by Waterloo Hydrogeologic Software (WHS), which is now part Schlumberger.

3.2.2 The Numerical Solver

Visual MODFLOW includes several different solvers for the numerical solution of the groundwater flow equations. They include the Preconditioned Conjugate-Gradient (PCG), the Strongly Implicit Procedure (SIP) package, the Slice-Successive Overrelaxation (SOR), the Waterloo Hydrogeologic Services (WHS), the Algebraic Multigrid Method (AMG) and the Geometric Multigrid Solver (GMG) package. After several tests it was determined the WHS solver produced converged solutions in most cases, while most of the other solvers did not. A brief description of the method used by each of the solvers is given in Ref. 9.

It was also found that for many combinations of parameters the iterative solution did not converge. To achieve convergence it was necessary to adjust the numerical parameters that affect the solver. A parameter in the WHS solver that was adjusted during several iterations was the "damping factor," which is used to reduce or "dampen" the head change calculated between successive outer iterations. As stated in Ref. 9 (page 294) for most well posed groundwater flow problems, a dampening factor of one can be used. However it was found that in this particular problem a much smaller dampening factor must be used. In some cases it was necessary to use a value as low as 0.1 or 0.05 in order to obtain a converged solution. The effect of reducing the dampening factor is to slow down the convergence speed and increase the number of required outer iterations. In some cases more than 10,000 iterations were needed for convergence.

Another numerical parameter that affects the obtained solution is the head change criterion. This is based on the maximum change between iterations at any cell. A quite small head change criterion was needed in most cases in order to obtain a mass balance discrepancy less than one percent. The default value for the head change criterion used in Visual MODFLOW is 0.01. In most simulations presented in this report a value of 0.005 was used.

3.2.3 The Numerical Grid

Figure 18 shows the rectangular area covered by the numerical grid of the model. Figure 19 shows the numerical grid and the boundary conditions used in the model. The grid spacing in the area surrounding existing Units 1 & 2 and the planned Units 3 & 4 is 100 ft by 100 ft. In areas away from these areas of interest the grid is coarser. The largest grid size used in the model is 200 ft by 200 ft. Figure 19 shows also the active cells of the model that represent the model domain described in Section 3.1. Grid cells outside this area are inactive. The model covers an

area of approximately 6 square miles. Figure 20 shows several physical features included in the model.

3.2.4 The Vertical Extent of the Model

Vertically the model is bounded by the ground surface at its top and the top of the BBM at its bottom. The topography used in the model is based on the LIDAR data for the area covered by the aerial survey conducted as part of the ESP for Units 3 & 4 (Ref. 12), and on USGS Digital Elevation Model (DEM) data for the rest of the model domain (Ref. 13). Figure 21 shows the bottom surface of the model domain as described in the model.

3.2.5 Types of Boundary Conditions Used in the Model

As explained in Section 3.1, the boundaries of the model domain were selected to coincide with key physical features that allow the definition of boundary conditions. Four different types of flow boundary conditions were used for the development of the model: drain, constant head, recharge and no flow boundaries. A brief description of these four conditions as they are defined and used in MODFLOW is provided below:

- Drain Boundary: The drain boundary condition in MODFLOW is designed to simulate the features that remove water from the aquifer at a rate equal to the product of the conductance of the drain and the difference between the head in the aquifer and a given level associated with the drain. Drain boundaries are used to simulate the effect of agricultural drains or seepage faces where groundwater discharges to the surface. The latter can happen along steep slopes or escarpments. In such cases the drain elevation corresponds to the ground surface elevation. When the water level reaches the ground surface elevation it is removed by the drain boundary. The drain has no effect if the head in the aquifer falls below the fixed elevation of the drain. The conductance of drains used to represent a seepage face is proportional to the area of the drain cells, and depends on the materials near the seepage face that may affect discharge conditions. In general the conductance of drain cells is treated as a calibration parameter.
- Constant Head Boundary: The constant head boundary condition is used to fix the head value in selected grid cells. The effect of the constant head condition is to provide a source of water entering the system, or a sink for water leaving the system, depending on the head conditions in the surrounding grid cells.
- Recharge Boundary: The recharge boundary condition is applied at the ground surface and is used to simulate the effect of groundwater recharge applied. Such recharge represents the net gain of the groundwater system as a result of deep infiltration resulting from precipitation, after the effect of evapotranspiration losses have taken into account. The recharge boundary condition can also used to describe artificial recharge or seepage from a pond.

- No Flow Boundary: This is the default boundary condition in MODFLOW when no other boundary condition is defined. It is used to describe no flow boundaries, such as the groundwater divide, or those resulting from impermeable neighboring materials.

3.2.6 The Numerical Solver

Visual MODFLOW offers the option of selecting from several built-in numerical solvers of the partial differential flow equations. Past experience with Visual MODFLOW has shown that the Waterloo Hydrogeologic Software (WHS) solver performs best in terms of numerical convergence.

The WHS solver was used for all solutions presented in this report. The WHS solver uses two convergence criteria, the head change between successive outer iterations and the residual criterion which is based on the change between successive inner iterations. The head change criterion used was 0.005 ft, and the residual change criterion was 0.001 ft.

3.3 Assumptions

The development of the model is based on the following assumptions.

3.3.1 Aquifer Materials

- Assumption: The Water Table aquifer can be described as a single hydrogeologic unit, without differentiating between the Barnwell sands and the Utley limestone.

  Rationale: The Utley limestone is very discontinuous and absent in places. Where it exists it is found at the base of the Barnwell formation. The available data do not seem to support a clear horizontal and vertical delineation of the Utley limestone as a separate unit. Because of the uncertainty in defining zones of the Utley it is deemed more defensible to describe the aquifer in a simple manner, i.e. as consisting of a single material with hydraulic conductivity close to the geometric mean of the conductivity of the Utley and the Barnwell sands.

3.3.2 Flow Boundary Conditions

- Assumption: The northeastern, southeastern and part of the southwestern boundary of the model, defined by the outcrop of the BBM can be described by the drain boundary condition. The drain elevation at drain cells along this boundary is equal to the ground surface elevation. The conductance of these drain cells along the outcrop of the BBM is 80 ft^2/day.

  Rationale: As discussed in Section 3.1, the outcrop of the BBM represents the edge of the Water Table aquifer along the bluff. Seeps and springs have been observed along the bluff. Therefore it is justified to use the drain boundary condition that allows the discharge of groundwater along a seepage face.

Setting the drain elevation equal to the ground surface is standard for the seepage faces (Ref. 9, page 244). The value of the conductance of the drain cells was determined by calibration.

- Assumption: Part of the southwest and northwest boundaries of the model can be treated as no-flow boundaries.

  Rationale: This boundary coincides with the surface water divide. In most watersheds the surface water divide coincides with the groundwater divide.

- Assumption: The bottom of the aquifer can be treated as a no-flow boundary

  Rationale: The BBM that forms the base of the Water Table aquifer has very low permeability (4.9×10^{-9} to 8.5×10^{-6} cm/s – SSAR page 2.4.12-21) and has an average thickness of 63 ft at the VEGP site (SSAR page 2.4.12-15). Therefore, it can be considered practically impermeable.

- Assumption: Mallard Pond is in hydraulic communication with the Water Table aquifer and can be represented by constant head cells. The constant head value used for Mallard Pond is El. 111 ft msl.

  Rationale: The water surface of Mallard Pond is very close to the water table. Therefore, this pond communicates with the water table. The elevation of the water surface in Mallard Pond was obtained by surveying.

- Assumption: The Met Tower pond (see Figure 20) can be treated as a recharge area.

  Rationale: The water surface elevation of Met Tower pond is at 221 ft msl, i.e. much higher than the water table in its vicinity. The maximum groundwater elevation recorded at the site of Units 3 & 4 is around 166 ft msl. The Met Tower pond is about half a mile from the site of the cooling towers of Units 3 & 4. The groundwater data collected at the site of Units 3 & 4 suggest that the groundwater divide is quite close to the south end of the cooling towers. Moving south of the divide groundwater levels should be lower. Therefore, the groundwater elevation under the Met Tower pond has to be lower than the maximum groundwater level at the site (166 ft msl). No data exist that would allow to directly estimate the recharge rate under this pond. It is assumed to be 20 in/yr, i.e. about two and a half times the average recharge area over the model domain. Because of the small area of the pond, this assumption is not deemed as having a major impact on the simulated water table at the site of Units 3 & 4. A sensitivity of the predicted water levels to the rate of recharge from this pond is presented in Subsection 4.4.8.2.

3.3.3 Groundwater Recharge

- Assumption: The distribution of groundwater recharge over the model domain can be described by the zones shown in Figure 22 and listed in Table 6:

Table 6 Zones of Different Recharge

Zone	Description	Recharge in/yr
1	Open areas on mild slopes.	8 to 12
2	Forested areas on mild slopes.	6 to 10
3	Open areas on steep slopes (> 10 percent).	6 to 10
4	Forested areas on steep slopes (> 10 percent).	4 to 8
5	Buildings, paved areas and areas covered with slabs	0

Rationale: The five zones shown in Figure 22 and listed in Table 6 were delineated based on the LIDAR topographic survey (Ref. 12), the USGS topographic map (Ref. 13), and observations during a site visit.

The recharge values shown given in Table 6 were determined through calibration. The relative magnitude of groundwater recharge is consistent with basic hydrologic principles. Areas with steep slopes have less recharge than areas on mild slopes and the same vegetation cover because of higher runoff. Forested areas have relatively lower recharge than open areas with the same ground surface slope, because of higher evapotranspiration and interception losses. Paved areas and areas covered with slabs or occupied by buildings have zero recharge. Precipitation falling on these areas runs off and is collected by the existing drainage system at the site.

On average, the aquifer recharge rate at the VEGP site is about the same as the long-term average groundwater recharge estimates provided by Clarke and West (Ref. 4) for the Savannah River basin.

3.3.4 Aquifer Bottom

- Assumption: The bottom of the Water Table aquifer is the top of the BBM, whose contours are shown in Figure 21. There is no leakage through the bottom of the aquifer.

  Rationale: The BBM is continuous across the VEGP site and hydraulically isolates the Water Table aquifer from the underlying Tertiary aquifer. Its average thickness at the VEGP site is 63 ft. (SSAR page 2.4.12-15). Laboratory permeability tests were also conducted on core samples collected from the marl. Laboratory measurements ranged from 1.4×10^{-5} to 2.4×10^{-2} ft/day ($4.9\text{x}10^{-9}$ to $8.5\text{x}10^{-6}$ cm/s) with a geometric mean of 1.3×10^{-3} ft/day ($4.6\text{x}10^{-7}$ cm/s), indicating that the marl is practically impermeable (SSAR page 2.4.12-21).

  Part of Figure 21 is based on the interpretation of data from 182 borings that penetrated the marl during the geologic and geotechnical investigations. This part is shown in Figure 5, which is reproduced from SSAR Figure 2.5.1-47.

In the part of the model domain that is beyond the area covered by Figure 5 the top of the BBM was extrapolated. For the purpose of this extrapolation it was assumed that beyond the area covered by the data from the geotechnical and geological investigations at the VEGP site, the top of the BBM gently slopes downwards.

3.3.5 Hydraulic Conductivity

- Assumption: A single value of the hydraulic conductivity can be used to characterize the part of the model domain where hydraulic tests were conducted.

  Rationale: As discussed in Section 3.1, the distribution of the estimated hydraulic conductivity values estimated from the hydraulic tests conducted at the site does not suggest a distinct pattern that would provide the basis for the delineation of different hydraulic conductivity zones (see Figure 17). The single value of the hydraulic conductivity that characterizes most of the model domain was determined in the process of the calibration of the model.

- Assumption: The fill material that will be used for the construction of Units 3 & 4 is expected to be similar to that used for Units 1 & 2. The hydraulic conductivity of this material is expected to be of the order of 2 to 3 ft/day.

  Rationale: It is expected that the construction of Units 3 & 4 will use fill materials from the same borrow areas that were used during the construction of Units 1 & 2. The geometric mean of the hydraulic conductivity values from different samples of this material reported in the FSAR for Units 1 & 2 (Ref. 5) was 2.3 ft/day. The maximum measured hydraulic conductivity was 3.3 ft/day.

- Assumption: A zone of relatively more permeable materials exists in the northern part of the model domain and especially between the site of the VEGP units and Mallard pond.

  Rationale: The hypothesis about the existence of such a zone was introduced during the calibration of the model. It is supported by the geologic and geotechnical investigation which suggest that the Utley limestone is present in this area. The isopachs of the Utley limestone (see Figure 3) were used to delineate areas of higher hydraulic conductivity. More details on the delineation of the higher conductivity zone are discussed in Subsection 4.4.3.

- Assumption: Native materials within each hydraulic conductivity zone are assumed to be homogenous and horizontally isotropic.

  Rationale: There is no evidence of anisotropy in the Water Table aquifer materials. General flow patterns are not affected much by local heterogeneities. Therefore, for the purpose of flow modeling aimed at predicting the general flow direction the effect of small scale heterogeneities can be ignored.

4. MODEL CALIBRATION

4.1 Calibration Target

The model was calibrated for the existing conditions at the VEGP site, with Units 1 & 2 in place, by comparing the model simulated groundwater head values with the observed groundwater levels. As discussed in Section 2.4 groundwater levels at the VEGP site have been monitored from June 2005 to July 2007 for this ESP application. The groundwater level data observed at 22 wells during the month of March 2006 were used as representative of the long-term to calibrate the model. Figure 12 shows the groundwater surface contour map prepared based on the March 2006 observed groundwater levels presented in Table 7.

Table 7 March 2006 Observed Groundwater Level used in Model Calibration

Well ID	Easting (ft)	Northing (ft)	Groundwater Level (ft msl)
142	622260.4	1143282.4	154.71
179	621778.7	1144061.2	148.72
802A	624195.0	1142201.7	158.23
803A	622896.0	1142085.4	160.45
804	622224.8	1141599.6	164.30
805A	624395.7	1141616.2	158.98
806B	623724.5	1143821.6	156.03
808	623297.7	1144624.3	159.15
809	621857.2	1143320.4	153.18
LT-1B	623301.3	1143390.5	155.28
LT-7A	623314.3	1143154.1	154.59
LT-12	623597.6	1142776.8	158.48
LT-13	624108.7	1143136.4	156.35
OW-1003	621884.3	1142864.1	156.43
OW-1005	620408.8	1144047.9	133.12
OW-1006	619179.7	1143817.9	147.37
OW-1007	619301.0	1142383.8	151.45
OW-1009	620888.6	1141891.6	163.01
OW-1010	620051.7	1140809.0	163.57
OW-1012	621045.9	1139969.5	161.80
OW-1013	621715.0	1140805.4	165.31
OW-1015	623086.3	1140550.6	159.89

During this monitoring period, the observed groundwater levels have exhibited little variability (see Figure 9 through Figure 14).

Even though the measured groundwater levels in March 2006 are higher than the average groundwater levels over the period of available data (June 2005 to July 2007), they are considered more representative of long-term groundwater conditions because 2007 was a very dry year.

4.2 Calibration Measures and Statistics

Several parameters providing different measures of the agreement between simulated and observed groundwater levels were used for the calibration of the model. These parameters are defined in terms of the calibration residuals of the water table level defined as the difference between calculated and observed results. The calibration residual, R_i, at a point i is defined as:

$$R_i = {}^{\mathrm{mod}\,el}X_i - {}^{obs}X_i$$

where

${}^{\mathrm{mod}\,el}X_i$ is the calculated water level at point *i*

${}^{obs}X_i$ is the observed water level at point

The residual mean, $\overline{R}$, is a measure of the average residual value and is defined by the equation:

$$\overline{R} = \frac{1}{n}\sum_{i=1}^{n} R_i$$

where n is the number of points where calculated and observed values are compared.

The absolute residual mean, $\left|\overline{R}\right|$, is a measure of the average absolute residual value and is defined as:

$$\left|\overline{R}\right| = \frac{1}{n}\sum_{i=1}^{n}\left|R_i\right|$$

The Root Mean Squared (*RMS*) residual is defined by:

$$RMS = \left[\frac{1}{n} \sum_{i=1}^{n} R_i^2 \right]^{1/2}$$

The Correlation Coefficient, $Cor\left[{}^{model}X, {}^{obs}X\right]$,is calculated as the covariance between the calculated values with the model and the observed water levels at selected points divided by the product of their standard deviations, i.e.:

$$Cor\left[{}^{model}X, {}^{obs}X\right] = \frac{Cov\left[{}^{model}X, {}^{obs}X\right]}{{}^{model}\sigma {}^{obs}\sigma}$$

where

$Cov\left[{}^{model}X, {}^{obs}X\right]$ is the covariance between the calculated and observed water levels

${}^{model}\sigma$ is the standard deviation of the calculated values with the model

${}^{obs}\sigma$ is the standard deviation of the observed values

The covariance is calculated using the following equation:

$$Cov\left[{}^{model}X, {}^{obs}X\right] = \frac{1}{n} \sum_{i=1}^{n} \left({}^{model}X_i - {}^{model}\overline{X} \right) \left({}^{obs}X_i - {}^{obs}\overline{X} \right)$$

where

${}^{model}\overline{X} = \frac{1}{n} \sum_{i=1}^{n} {}^{model}X_i$ is the mean of the water levels calculated with the model at *n* selected points

${}^{obs}\overline{X} = \frac{1}{n} \sum_{i=1}^{n} {}^{obs}X_i$ is the mean of the observed water levels at *n* selected points

The standard deviation of the water levels calculated with the model is calculated as:

$$^{model}\sigma = \left[\frac{1}{n}\sum_{i=1}^{n}\left(^{model}X_i - ^{model}\overline{X}\right)^2\right]^{1/2}$$

The standard deviation of the observed water levels is calculated as:

$$^{obs}\sigma = \left[\frac{1}{n}\sum_{i=1}^{n}\left(^{obs}X_i - ^{obs}\overline{X}\right)^2\right]^{1/2}$$

The standard error of the estimate (*SEE*) provides a measure of the variability of the residual around the expected residual value. It is given by the equation

$$SEE = \left[\frac{\frac{1}{n-1}\sum_{i=1}^{n}\left(R_i - \overline{R}\right)^2}{n}\right]^{1/2}$$

The normalized root mean squared (*NRMS*) is the *RMS* divided by the maximum difference in the observed head values. It is given by the following equation:

$$NRMS = \frac{RMS}{^{obs}X_{\max} - ^{obs}X_{\min}}$$

In addition to calculating the parameters described above for each calibration simulation, Visual MODFLOW provides also a plot of the simulated vs. the observed water level values, which provides a way of visualizing the agreement between model and measured values. An example of such a plot is given in Figure 24. The same figure shows also the range of calculated values for each observed value with 95 percent confidence that the simulation results will be acceptable for a given observed value. In a successful calibration the line representing the perfect match between modeled and observed values, i.e. the line along which the modeled values are equal to the observed values, should be within the 95% confidence interval. The plot of simulated vs. observed water levels shown in Figure 24 also shows the 95% interval, defined as the interval where 95% of the total number of data points are expected to occur.

Finally, additional measure of the adequacy of each run is the discrepancy between inflows and outflows from the model domain. To satisfy the overall mass balance, this discrepancy should be

zero. In practice though, this may not be possible. The aim in calibrating and developing the groundwater model for the VEGP site was to make the mass balance discrepancy as small as possible. The mass balance discrepancy, Md, is calculated using the following equation:

$$M_d = \frac{V_{in} - V_{out}}{\frac{1}{2}(V_{in} + V_{out})}$$

where

V_{in} is the total flow into the model domain

V_{out} is the total flow out of the model domain

Most of the calibration measures and statistics discussed above are reported for all the simulations leading to the calibration of the model presented in this report (see Table 8). In addition to these parameters, the maximum residual is also reported in this table.

4.3 Calibration Criteria

Using the calibration measures and statistics the following criteria were used for calibration of the model:

a. Root mean squared residual *RMS* < 3 ft
b. Normalized root mean squared residual *NRMS* < 10 percent
c. Absolute value of maximum residual < 6 ft
d. Mass balance discrepancy M_d < 1 percent
e. A simpler model that meets these criteria is preferable over a more complex model that also meets the same criteria.

4.4 Model Calibration Process

The primary calibration parameters were the hydraulic conductivity and the aquifer recharge rate. These two parameters were varied to achieve satisfactory agreement between simulated and observed water levels according to the calibration criteria stated in Section 4.3. The conductance of the drains, which has a smaller impact on the solution obtained with the model, was also varied. However, in the set of calibration runs presented here it was kept constant (equal to 80 ft^2/day) to better illustrate the impact of the major calibration parameters.

The calibration effort started with the simplest set of assumptions, a uniform hydraulic conductivity value over the entire model domain and a uniform recharge. Zones of different hydraulic conductivity and groundwater recharge zones were progressively introduced where their presence could be supported by local conditions and where it seemed to improve the calibration of the model. This process is described in Subsections 4.4.1 through 4.4.7, where

each conceptual configuration of different hydraulic conductivity and recharge zones is referred to as a different “model”.

The calibration was achieved through a series of simulations using different values of the key parameters involved. An attempt to use the nonlinear parameter estimation and optimization package PEST (Parameter Estimation) built into Visual MODFLOW was not successful because the code presented serious convergence problems. As a result, a decision was made to calibrate the model using the conventional approach of trying different parameter values moving progressively towards the values that best satisfy the calibration criteria. The sequence of runs documenting the sequence of the model calibration process and the key parameters used in these runs are listed in Table 8.

Table 8 Summary of Simulated Cases During Calibration

Run	Hydraulic Conductivity [1]					Recharge [2]					Calibration statistics [3]						M_d
	K_1	K_2	K_3	K_4	K_5	R_1	R_2	R_3	R_4	R_5	MR	ARM	SEE	RMS	NRMS	CC	
	Ft/d	ft/d	ft/d	Ft/d	Ft/d	in/yr	in/yr	in/yr	in/yr	in/yr	ft	ft		ft	%		%
Model 1: Uniform Hydraulic Conductivity and Recharge																	
101	12					6.8					27.215	13.306	1.06	14.165	44.004	0.761	-0.01
102	15					6.8					22.331	8.854	1.013	9.997	31.056	0.816	-0.02
103	18					6.8					18.741	5.738	0.986	7.204	22.38	0.838	-0.02
104	21					6.8					15.964	4.263	0.969	5.433	16.876	0.843	-0.02
105	24					6.8					13.724	3.539	0.96	4.544	14.116	0.841	-0.02
106	27					6.8					11.867	3.464	0.954	4.4	13.669	0.835	-0.02
107	30					6.8					10.285	3.605	0.951	4.742	14.732	0.827	-0.02
108	27					6					-9.784	3.861	0.96	5.041	15.662	0.819	-0.02
109	27					7					12.389	3.449	0.953	4.369	13.572	0.838	-0.02
110	27					8					14.901	3.815	0.951	4.928	15.308	0.85	-0.01
Model 2: Uniform Hydraulic Conductivity, Variable Recharge																	
201	27					10	6	6	4	0	10.857	3.436	0.954	4.375	13.592	0.786	-0.02
202						10	5	6	4	0	9.155	3.726	0.98	4.683	14.549	0.755	-0.01
203						10	7	6	4	0	12.47	3.513	0.938	4.427	13.752	0.814	-0.02
204						10	6	6	3	0	10.455	3.432	0.953	4.382	13.614	0.782	-0.02
205						10	6	6	2	0	10.048	3.451	0.953	4.403	13.68	0.779	-0.01
206						10	6	6	5	0	11.254	3.465	0.956	4.382	13.612	0.789	-0.02
208						9	6	6	4	0	10.678	3.438	0.954	4.428	13.755	0.797	-0.02
209						11	6	6	4	0	11.82	3.604	0.958	4.481	13.921	0.782	-0.02
211						10	6	5	4	0	11.813	3.598	0.958	4.477	13.907	0.782	-0.02
212						10	6	7	4	0	11.828	3.611	0.958	4.485	13.934	0.781	-0.02

Table 8 Summary of Simulated Cases During Calibration (cont.)

Run	Hydraulic Conductivity [1]					Recharge [2]					Calibration statistics [3]						M_d
	K_1	K_2	K_3	K_4	K_5	R_1	R_2	R_3	R_4	R_5	MR	ARM	SEE	RMS	NRMS	CC	
	Ft/d	ft/d	ft/d	Ft/d	Ft/d	in/yr	in/yr	in/yr	in/yr	in/yr	ft	ft		ft	%		%
Model 3: Accounting for the thickness of the Utley limestone																	
301	27	15	30	60		10	6	6	4	0	12.021	4.705	0.934	5.55	17.241	0.769	-0.01
302	27	15	30	45							12.026	4.755	0.932	5.639	17.519	0.77	-0.01
303	27	15	15	60							15.052	5.574	0.919	6.733	20.915	0.783	-0.01
304	27	10	30	60							13.458	7.016	1.031	8.267	25.682	0.739	-0.02
305	27	20	30	60							11.244	3.649	0.924	4.463	13.865	0.784	-0.01
306	20	20	30	60							13.742	4.193	0.924	5.115	15.894	0.806	-0.02
Model 4: Simplified representation of the Utley limestone																	
401	27	35				10	6	6	4	0	8.86	3.483	0.933	4.457	13.845	0.789	-0.02
402	27	50									-9.951	4.037	0.923	5.12	15.907	0.783	-0.02
403	20	35									10.865	3.636	0.898	4.371	13.577	0.807	-0.02
404	15	35									12.808	4.969	0.874	5.897	18.32	0.813	-0.02
405	20	25									13.781	4.424	0.923	5.317	16.518	0.809	-0.01
Model 5: High Conductivity Zone Upstream of Mallard Pond																	
501	20	35	50			10	6	6	4	0	9.053	3.454	0.876	4.144	12.873	0.81	-0.02
502	15	35	50								10.791	4.711	0.856	5.458	16.954	0.815	-0.02
503	25	35	50								-7.966	3.341	0.9	4.235	13.157	0.799	-0.02
504	20	35	100								-6.55	3.238	0.851	3.907	12.136	0.813	-0.01
505	20	35	200								-7.428	3.22	0.854	3.932	12.216	0.815	-0.01
506	20	30	100								6.706	3.366	0.841	3.961	12.306	0.818	-0.01
507	20	40	100								-7.441	3.211	0.862	3.966	12.319	0.808	-0.01

Table 8 Summary of Simulated Cases During Calibration (cont.)

Run	Hydraulic Conductivity [1]					Recharge [2]					Calibration statistics [3]						M_d
	K_1	K_2	K_3	K_4	K_5	R_1	R_2	R_3	R_4	R_5	MR	ARM	SEE	RMS	NRMS	CC	
	Ft/d	ft/d	ft/d	Ft/d	Ft/d	in/yr	in/yr	in/yr	in/yr	in/yr	ft	ft		ft	%		%
Model 6: Low Conductivity Zone in the Southwestern Part of the Model Domain																	
601	20	25	50	10							7.619	3.535	0.738	4.064	12.625	0.863	-0.02
602	15	25	200	10							6.905	3.223	0.729	3.715	11.542	0.867	-0.02
603	20	25	200	8							6.259	2.963	0.723	3.477	10.802	0.869	-0.02
604	20	25	200	6							-6.534	2.805	0.719	3.339	10.372	0.871	-0.02
605	20	25	400	6							-6.993	2.745	0.717	3.286	10.207	0.871	-0.02
606	20	25	50	10							-7.418	2.694	0.716	3.303	10.262	0.872	-0.02
607	15	25	200	10							-7.624	2.74	0.729	3.356	10.425	0.867	-0.02
608	20	25	200	8		10	6	6	4	0	-6.537	2.748	0.709	3.264	10.14	0.875	-0.02
609	20	25	200	6							6.052	2.798	0.688	3.338	10.37	0.883	-0.02
610	20	25	400	6							-6.14	2.764	0.683	3.254	10.109	0.884	-0.02
611	20	25	50	10							6.032	2.944	0.676	3.487	10.865	0.889	-0.02
612	15	25	200	10							-7.043	2.742	0.707	3.253	10.106	0.882	-0.02
613	20	25	200	8							-7.428	2.733	0.727	3.332	10.353	0.88	-0.02
614	20	25	200	6							6.687	2.781	0.681	3.34	10.377	0.885	-0.02

Table 8 Summary of Simulated Cases During Calibration (cont.)

Run	Hydraulic Conductivity [1]					Recharge [2]					Calibration statistics [3]						M_d
	K_1	K_2	K_3	K_4	K_5	R_1	R_2	R_3	R_4	R_5	MR	ARM	SEE	RMS	NRMS	CC	
	Ft/d	ft/d	ft/d	Ft/d	Ft/d	in/yr	in/yr	in/yr	in/yr	in/yr	ft	ft		ft	%		%
Model 7: Simplified Version of Model 6																	
701	28	75	8								7.449	2.98	0.659	3.607	11.205	0.894	-0.02
702	30	75	8								6.771	2.728	0.669	3.277	10.179	0.89	-0.02
703	32	75	8								-6.322	2.626	0.679	3.139	9.752	0.886	-0.02
704	34	75	8								-7.189	2.585	0.689	3.169	9.844	0.882	-0.02
705	32	80	8								-6.419	2.624	0.679	3.13	9.723	0.886	-0.02
706	32	85	8			10	6	6	4	0	-6.509	2.622	0.679	3.124	9.704	0.886	-0.02
707	32	90	8								-6.592	2.621	0.679	3.12	9.692	0.886	-0.02
708	32	100	8								-6.741	2.617	0.68	3.118	9.686	0.885	-0.02
709	32	150	8								-7.259	2.607	0.689	3.164	9.828	0.884	-0.02
710	32	100	9								-6.942	2.632	0.691	3.169	9.845	0.881	-0.02
711	32	100	7								-6.521	2.676	0.673	3.12	9.692	0.888	-0.02

Table 8 Notes

[1] Hydraulic conductivity zones 1 and 2

K_1: the entire model domain

Hydraulic conductivity zones for Model 3 (the colors next to each conductivity zone are those used in Figure 29)

K_1: Utley limestone < 10 ft thick and north of the area covered by the Utley limestone isopachs

K_2: south of the area covered by the Utley limestone isopachs

K_3: Utley limestone 10 to 20 ft thick

K_4: Utley limestone > 20 ft thick

Hydraulic conductivity zones for Model 4 (the colors next to each conductivity zone are those used in Figure 33)

K_1: area where the Utley limestone was not found to be present and area not covered by the Utley limestone isopachs

K_2: generalized area where the Utley limestone was detected

Hydraulic conductivity zones for Model 5 (the colors next to each conductivity zone are those used in Figure 37)

K_1: area where the Utley limestone was not found to be present and area not covered by the Utley limestone isopachs

K_2: generalized area where the Utley limestone was detected

K_3: high conductivity zone up gradient of Mallard Pond

Hydraulic conductivity zones for Model 6 (the colors next to each conductivity zone are those used in Figure 41)

K_1: area where the Utley limestone was not found to be present and area not covered by the Utley limestone isopachs

K_2: generalized area where the Utley limestone was detected

K_3: high conductivity zone up gradient of Mallard Pond

K_4: low conductivity zone in the southwestern part of the model domain

Hydraulic conductivity zones for Model 7 (the colors next to each conductivity zone are those used in Figure 45)

K_1: Recharge zones (the colors next to each recharge zone are those used in Figure 22) area not covered by the K_2 and K_3 zones

K_2: high conductivity zone up gradient of Mallard Pond

K_3: low conductivity zone in the southwestern part of the model domain

Table 8 Notes (cont.)

[2] Recharge zones (the colors next to each recharge zone are those used in Figure 22)

- R_1: open areas with minimal vegetation on mild slopes
- R_2: forested areas on mild slopes
- R_3: open areas with minimal vegetation on steep slopes
- R_4: forested areas on steep slopes
- R_5: buildings, paved areas and areas covered with slabs

[3] MR: maximum residual
AMR: absolute residual mean
SEE: standard error estimate
RMS: root mean squared error
NRMS: normalize root mean squared error
CC: correlation coefficient

4.4.1 Model 1: Uniform Hydraulic Conductivity and Recharge

The first step in the calibration process was to use a single value for the hydraulic conductivity over the entire model domain. This value is indicated as K1 in Table 8. To simplify the calibration of the model the fill material for the Units 1 & 2 was ignored. As stated in Section 2.7, at the time of the construction of Units 1 & 2 four slug tests were conducted to determine the hydraulic conductivity of the backfill material used. These tests resulted in values ranging from 1.32 to 3.34 ft/day, with a geometric mean of 2.32 ft/day. In general, slug tests produce lower hydraulic conductivity values than those needed to describe large scale groundwater flows, of the order of the scale of the present groundwater flow model. Pumping tests provide more representative hydraulic conductivity values of average properties over larger scales than those tested with slug tests, and therefore better estimates of hydraulic conductivity for use in models of this scale. In the absence of pumping tests in the fill material, the large-scale hydraulic conductivity of this material is essentially unknown, with the slug tests providing only a lower bound of its value. Therefore, to remove the uncertainty associated with the conductivity of the fill it was decided not to include this material in the calibration runs. It is also noted that the extent of this material is relatively small. A sensitivity analysis using different values for the fill material for Units 1 & 2 showed that its impact on the simulated water levels at the observation well that were used for the calibration of the model is very small. This sensitivity analysis is presented in Subsection 4.4.8.1.

The values of the uniform hydraulic conductivity used for the native materials were in the range of 10 to 20 ft/day. These hydraulic conductivity values are greater than the geometric mean of the hydraulic conductivity values estimated from the slug tests at the site of Units 3 & 4 (0.5 ft/day). No pumping tests were conducted at this site. It is noted that at the nearby site of Units 1 & 2 the geometric mean of the hydraulic conductivity from the pumping test was 60 ft day, while that from slug tests was 0.6 ft/day for the Barnwell Sands and 2.32 ft day for tests in the Utley limestone. Considering that the pumping test values in this case were more than an order of magnitude higher than those from the slug tests, it is reasonable to expect the same would apply to the site of Units 3 & 4 and the rest of the model domain.

Also, a single value of groundwater recharge was used over the entire model domain (indicated as R1 in Table 8). The range of values used was between 6 and 8 inches per year, i.e. between about 13 and 17 percent of the mean annual precipitation at the site). Runs for different values of these parameters are presented in Table 8. Each combination of hydraulic conductivity and recharge is described by a different “run” number. Table 8 gives the input parameters and calibration statistics for runs 101 through 110.

Figure 23 shows the simulated head for the run with the smallest RMS residual (run 109). Figure 24 shows the simulated vs. observed water levels for the same run. Figure 25 shows the

distribution of the estimated residuals for this run. As can be seen in these Figures the RMS residual and the maximum residual (at well OW-1005) are very high.

4.4.2 Model 2: Uniform Hydraulic Conductivity, Variable Recharge

The next step in the calibration process was to vary the rate of groundwater recharge by dividing the area not covered by buildings, slabs or pavements into the four different zones described in Section 2.6. Several combinations of recharge values within the following ranges were tested:

- Open areas on mild slopes: R_1 = 10 to 12 in/yr
- Forested areas on mild slopes: R_2 = 5 to 7 in/yr
- Open areas on steep slopes (greater than 10 percent): R_3 = 5 to 7 in/yr
- Forested areas on steep slopes (greater than 10 percent): R_4 = 2 to 5 in/yr

In all cases the recharge in areas covered by buildings or slabs, or that are paved was set to zero (R5 = 0).

Table 8 gives the input parameters and calibration statistics for different combinations of these recharge zones and hydraulic conductivity zones. Figure 26 shows the simulated head for one of these simulations (run 201). Figure 27 shows the simulated vs. observed water levels for the same simulation. As in the cases of uniform recharge presented in Subsection 4.4.1, the RMS residual and the maximum residual (at well OW-1005) are very high suggesting that a variable recharge distribution by itself is not enough to improve the agreement between modeled and observed water levels. Figure 28 shows the distribution of the estimated residuals for this run.

4.4.3 Model 3: Accounting for the Thickness of the Utley Limestone

The next model tested was based on a non-uniform hydraulic conductivity distribution. As stated in Section 2.7 and shown in Figure 17 there is no distinct pattern in the spatial distribution of the hydraulic conductivity values estimated from the slug tests conducted at the site of Units 3 & 4. Based on the observation that in general the Utley limestone is more permeable than the Barnwell sands (Section 2.7), different hydraulic conductivity zones were defined based on the thickness of the Utley limestone. For this purpose the contours of the thickness of the Utley limestone shown in Figure 3 were used. Four conductivity zones were defined, listed below in order of increasing hydraulic conductivity

- Areas where the thickness Utley limestone is absent (K_1)
- Areas where the thickness Utley limestone is less than 10 ft thick (K_2)
- Areas where the thickness Utley limestone is between 10 and 20 ft (K_3)
- Areas where the thickness Utley limestone is greater than 20 ft (K_4)

As can be seen in Figure 3 the isopachs of the Utley limestone based on the data from the geotechnical and geological investigations at the site is smaller than the groundwater flow model

domain. To define hydraulic conductivity zone over the entire domain, it was assumed that south of the area covered by isopachs shown in Figure 3, the Utley limestone is absent. It was also assumed that north of the area covered by isopachs shown in Figure 3, the Utley limestone is present, but it is less than 10 ft thick. The hydraulic conductivity zones defined based on the available data and the last two assumptions are shown in Figure 29. Simulations with different values for the hydraulic conductivity of each zone were made. The groundwater recharge used in all simulations was the same, based on the five recharge zones discussed in Subsection 4.4.2. The recharge values that resulted in the closest agreement with the observed water levels in Subsection 4.4.2 were used, i.e. R1=10; R2=6; R3=6; R4=4; R5=0 ft/day.

Table 8 gives the input parameters and calibration statistics for different combinations of values for the hydraulic conductivity zones defined in Model 3. Figure 30 shows the simulated head for the combination of hydraulic conductivity values that has the smallest RMS residual (run 305). Figure 31 shows the simulated vs. observed water levels for the same simulation. Figure 32 shows the distribution of the estimated residuals for this run. As can be seen in these Figures, Model 3 does not improve significantly the agreement between simulated and observed water levels. The model continues to significantly overestimate the water level at well OW-1005, and there seems to be a systematic error in the model, as suggested by all negative residuals in southern part of the area covered by data, and all positive residuals in the northern part of this area (see Figure 32).

4.4.4 Model 4: Simplified Representation of the Utley Limestone

A simplified representation of the general areas where the Utley limestone was found to be present was the basis for Model 4. The delineation of the area that was treated as a different hydraulic conductivity zone from the rest of the model is shown in Figure 33. Different combinations of the hydraulic conductivity of this zone (K2) and the rest of the model (K1) were tested. The results are shown in Table 8 which also gives the calibration statistics for these selected simulations with this model. Figure 34 shows the simulated head for the combination of hydraulic conductivity values for Model 4 that has the smallest RMS residual (run 411). Figure 35 shows the simulated vs. observed water levels for the same simulation. Figure 36 shows the distribution of the estimated residuals for this run.

As can be seen from Table 8, Figure 35 and Figure 36 the results of Model 4 are not very different for those obtained with Model 3 and they do not represent much of an improvement for the calibration of the model.

4.4.5 Model 5: High Conductivity Zone Upstream of Mallard Pond

All the simulations with four alternative models presented in Subsections 4.4.1 through 4.4.4 overestimate the water levels in the northern part of the site of Units 3 & 4 and especially at observation at observation well OW-1005. This suggests that the aquifer in this area may be

relatively more permeable. To test this hypothesis several simulations with a higher hydraulic conductivity zone between Mallard Pond and well OW-1005 were performed. Figure 37 shows the delineation of this high conductivity zone.

The calibration statistics for some of the combinations of hydraulic conductivity values tested are given in Table 8. Figure 38 shows the simulated head for the combination of hydraulic conductivity values for Model 5 that has the smallest RMS residual (run 504). Figure 39 shows the simulated vs. observed water levels for the same simulation. Figure 40 shows the distribution of the estimated residuals for this run.

As can be seen from Figure 39 and Figure 40 Model 5 improves significantly the agreement between simulated and the measured water levels at well OW-1005, but it does not improve the calibration of the model in the southern part of the model where the simulated heads for all cases are lower than what was measured.

It should also be noted that the high conductivity zone between Mallard Pond and well OW-1005 is in an area not covered by the borings drilled as part of the geological and geotechnical investigation. Therefore, there are no hydraulic test data to support the existence of such a zone.

4.4.6 Model 6: Low Conductivity Zone in the Southwestern Part of the Model Domain

Model 5 does not correctly describe groundwater levels in the southwestern part of the model domain. To address this limitation of Model 5 a low conductivity zone is defined in the southwestern quarter of the model domain. Figure 41 shows the delineation of this low conductivity zone together with the other conductivity zones used in the model. The northern boundary of this low conductivity zone coincides with the zero thickness contour of the Utley Limestone, providing evidence for the presence of a lower conductivity zone given the contrast in values between the Utley Limestone and Barnwell Sands as described in Section 2.7 and summarized in Table 3.

Different combinations of values for each of the hydraulic conductivity zones shown in Figure 41 were tested. Table 8 gives the calibration statistics for some of these combinations. Figure 42 shows the simulated head for the combination of hydraulic conductivity values for Model 6 that has the smallest RMS residual (run 612). Figure 43 shows the simulated vs. observed water levels for the same simulation. Figure 44 shows the distribution of the estimated residuals for this run.

4.4.7 Model 7: Simplified Version of Model 6

In the course of the tests with Model 6, it became apparent that satisfactory model calibration is achieved using similar hydraulic conductivity values for zones 1 and 2. Based on this observation it was decided to introduce a simpler model, where these two zones are combined into a single zone. Figure 45 shows the delineation of the three zones used in Model 7, the high

conductivity zone between Mallard Pond and well OW-1005, the low conductivity zone in the southwestern quarter of the model domain, and the rest of the model domain. Table 8 gives the calibration statistics for selected combinations of the hydraulic conductivity of these three zones.

Figure 46 shows the simulated head for the combination of hydraulic conductivity values for Model 7 that has the smallest RMS residual (run 708). Figure 47 shows the simulated vs. observed water levels for the same simulation. Figure 48 shows the distribution of the estimated residuals for this run.

The solutions obtained with Model 6 and 7 are very similar and are the closest to the measured water levels. Overall, as can be seen from Figure 46 and Figure 47 and Table 8, Model 7 gives the best match with the data. One limitation is that the hydraulic conductivity zones, whose introduction optimizes the model calibration effort, are partially outside the area covered by the geotechnical and geological borings and hydraulic testing for VEGP. As noted in 4.4.6, the northern boundary of the low conductivity zone coincides with the absence of the Utley limestone. However, there is no field data to justify the eastern boundary of the low conductivity zone.

4.4.8 Sensitivity Analysis

4.4.8.1 Hydraulic Conductivity of the Backfill Material Around Units 1 & 2

As mentioned in Subsection 4.4.1, to simplify the calibration process, the backfill material around Units 1 & 2 was ignored. To demonstrate the impact of this assumption, a sensitivity simulation was performed with Model 7, i.e. the model that has the best agreement with the water level measurements. In this simulation the fill material was treated as a separate hydraulic conductivity zone, with a hydraulic conductivity value of 3.3 ft/day, i.e. the highest estimated value from the four slug tests conducted in the fill material during construction of Units 1 & 2 (Figure 49). Figure 50 shows the simulated water levels from this simulation. A comparison of Figure 50 and Figure 46 suggests that the effect of changing the hydraulic conductivity in the backfilled area of Units 1 & 2 by an order of magnitude has very small effect on water levels. The same can be said about the basic calibration statistics. Table 9 gives the calibration statistics for the two values of the conductivity of the fill differing by an order of magnitude. Figure 51 shows the simulated vs. observed water levels for the same simulation. Figure 52 shows the distribution of the estimated residuals for this run.

Table 9 Sensitivity of Calibration Statistics to Units 1 & 2 Backfill

Hydraulic conductivity of Units 1 & 2 backfill	Calibration Statistics						
	MR	ARM	SEE	RMS	NRMS	CC	M_d
Ft/day	ft	ft		ft	%		%
3.3	-6.68	2.708	0.694	3.191	9.912	0.88	-0.02
32(1)	-6.741	2.617	0.68	3.118	9.686	0.885	-0.02

(1) This is the value for the native materials in the area of Units 1 & 2 that gave the best agreement between modeled and observed values (see Table 8).

4.4.8.2 Rate of Recharge at the Met Tower Pond

The rate of groundwater recharge from the Met Tower pond is unknown. In all calibration runs presented in Subsections 4.4.1 through 4.4.7 the rate of recharge from this pond was assumed to be 20 in/yr. Two sensitivity simulations were performed, one with a rate of recharge equal to that used in the area surrounding the pond, i.e. 6 in/yr, and another with double the rate used in most simulations, i.e. 40 in/yr.

Figure 53 shows the simulated water levels using 6 in/yr for the rate of recharge from the Met Tower pond, and Figure 54 shows the simulated vs. observed water levels for the same simulation. Figure 55 shows the distribution of the estimated residuals for this run. Figure 56 shows the simulated water levels obtained using 40 in/yr and Figure 57 shows the simulated vs. observed water levels for the same simulation. Figure 58 shows the distribution of the estimated residuals for this run. A comparison of Figure 53 (6 in/yr), Figure 46 (20 in/yr) and Figure 56 (40 in/yr) suggests that the effect of the assumed rate of groundwater recharge form the Met Tower pond is very local, with higher rates producing slightly higher water levels under this pond. The effect of the rate of recharge from this pond on the location of the groundwater divide is negligible. The effect of the recharge rate on the agreement between modeled and observed water levels is also negligible. Table 10 gives the calibration statistics for the three runs with the three different recharge rates used.

Table 10 Sensitivity of calibration statistics to the rate of recharge at the Met Tower Pond

Recharge at Met Tower pond	Calibration Statistics						
	MR	ARM	SEE	RMS	NRMS	CC	M_d
in/yr	ft	Ft		Ft	%		%
6	-6.834	2.601	0.682	3.128	9.717	0.884	-0.02
20	-6.741	2.617	0.68	3.118	9.686	0.885	-0.02
40	-6.608	2.64	0.676	3.111	9.664	0.887	-0.02

4.4.8.3 Constant Head Condition at the Upper Debris Basin 2

The Upper Debris Basin 2 was not accounted for directly in all the calibration simulations presented in Subsections 4.4.1 through 4.4.7. An alternative assumption regarding this pond is to treat it as a constant head area. A special simulation was conducted for this purpose, where the area of this pond was defined as a constant head area at 148.5 ft. msl. Figure 59 shows the simulated water levels under this assumption. As can be seen by comparing Figure 46 and Figure 59 treating the Upper Debris Basin 2 as a constant head area has practically no effect on the simulated water levels in the area of Units 3 & 4 and on the location of the groundwater divide. Table 11 gives the calibration statistics for this simulation. Figure 60 shows the simulated vs. observed water levels for the same simulation. Figure 61 shows the distribution of the estimated residuals for this run.

Table 11 Sensitivity of Calibration Statistics to Constant Head Boundary Condition at Upper Debris Basin 2

Condition at pond	Calibration Statistics						
	MR	ARM	SEE	RMS	NRMS	CC	M_d
	ft	ft		Ft	%		%
Constant head at el. 148.5 ft	-7.101	2.688	0.704	3.228	10.027	0.977	-0.02
No special condition set for the pond	-6.741	2.617	0.68	3.118	9.686	0.885	-0.02

4.4.8.4 Additional Areas of Zero Recharge

During the calibration runs, the parking lot at Units 1&2 and a number of small structures were not represented as paved areas. To assess the effect of these additional areas of zero recharge, the recharge zone map was modified and a sensitivity analysis conducted. Figure 62 shows the simulated water levels under this assumption. As can be seen by comparing Figure 46 and Figure 62, incorporating these additional paved areas has practically no effect on the simulated water levels in the area of Units 3 & 4 and on the location of the groundwater divide. Table 12 gives the calibration statistics for this simulation. Figure 63 shows the simulated vs. observed water levels for the same simulation. Figure 64 shows the distribution of the estimated residuals for this run.

Table 12 Sensitivity of Calibration Statistics to Additional Paved Areas (Parking Lot for Units 1&2 and a Number of Small Structures)

Recharge Zones	Calibration Statistics						
	MR	ARM	SEE	RMS	NRMS	CC	M_d
	ft	ft		Ft	%		%
Added parking lot at Units 1&2 and a number of small structures	-7.079	2.546	0.676	3.108	9.656	0.887	-0.02
Non-zero recharge applied to Units 1 and 2 parking lots and small structures	-6.741	2.617	0.68	3.118	9.686	0.885	-0.02

4.5 Validation of the Groundwater Model

4.5.1 Validation Using Stream Flow Data

To further establish the validity of the calibrated groundwater model, the groundwater discharge to the creek draining Mallard Pond was compared with stream flow measurements in the creek. Stream flow data had been collected in June and July 1985 in support of the construction of Units 1 & 2. The estimated flows at three points on the creek of Mallard Pond are given in Table 13. The locations of the stream flow measurements given in Table 13 are shown in Figure 65.

Table 13 Measured Stream Flows in the Stream of Mallard Pond in June-July 1985

Station	Location	Flow (gpm)	
		Measured	Estimated
2	Mallard Pond Drain	335	320
3	100 ft downstream from drain	220	346
5	300 ft downstream from drain	600	373

Model 7 was used to estimate the total groundwater discharge into Mallard Pond and the downstream reaches of the creek that are fed by Mallard Pond. Mallard Pond is represented by constant-head cells in the model, while the creek downstream of Mallard Pond is represented by drain cells (Figure 66). To estimate the groundwater discharge to different parts of the creek, the surrounding area was divided into three zones (Figure 67), which were used in a Zone Budget simulation. Zone 1 is defined by the constant-head cells representing Mallard Pond, Zone 2 is the drain cells between Stations 2 and 3 in Figure 65, and Zone 3 is the drain cells between Stations 3 and 5 in Figure 65.

The estimated cumulative groundwater discharges from the model into the creek are given in Table 13. These discharges represent the average base flow in the creek. As can be seen, the

agreement between these estimated and measured discharge is very good. With the exception of Station 3, the estimated groundwater discharges are lower than the stream flows, which should be expected because the stream flows may include some surface water runoff.

It is important to recognize the limitations of this comparison, which should be seen only as "an order of magnitude" confirmation of the predictions of the model. A detailed comparison of groundwater discharges with stream flows would require several stream flow measurements over a period of time to establish the central tendency and variability of the base flow in the stream. In addition there are limitations in the accuracy of the method used to estimate the stream flow, and it is difficult to assess what portion of the measured stream flow is attributable to groundwater discharge and what part to surface runoff.

4.5.2 Validation Using 1971 Groundwater Level Data Prior to Construction of Units 1 & 2

Another independent check was conducted by modifying the model to represent the site as it existed prior to the construction of Units 1 & 2. This model was then run to steady state and compared to groundwater levels measured in November 1971.

The main change to the setup of the model was the redistribution of recharge, particularly at the location of buildings and paved areas. These areas were changed from zero recharge zones to either that of open area on mild slopes or forested area on steep slopes, depending on the surrounding land usage. No effort was made redistribute the recharge based on pre-construction topography or landcover. It was assumed that the Met Tower pond was not present prior to Units 1 & 2, while Mallard Pond remained as a constant head boundary condition. Changes in the topography were not accounted for in this simulation. The November 1971 water levels used were obtained from Drawing No. AX6DD239 of the FSAR (Ref. 5) and are presented in Table 14.

Table 14 Groundwater Levels Prior to Construction of Units 1 & 2

Well	Plant		State		Elev (ft msl)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)	
42D	8,403	9,571	1,143,403	623,571	157
124	6,896	9,527	1,141,896	623,527	162
129	8,856	9,576	1,143,856	623,576	153
140	7,846	8,702	1,142,846	622,702	159
141	7,860	8,293	1,142,860	622,293	156
142	8,283	8,262	1,143,282	622,260	153
143	8,283	8,738	1,143,283	622,738	153
176	7,117	11,423	1,142,117	625,423	159
177	8,560	10,865	1,143,560	624,865	161
178	9,958	8,994	1,144,958	622,994	158
179	9,059	7,779	1,144,061	621,779	157

Figure 68 shows the simulated head for this model. Figure 69 shows the simulated vs. observed water levels for the same simulation. Figure 70 shows the distribution of the estimated residuals for this run. Perusal of these figures demonstrates that the model fairly represents the 1971 groundwater level data, especially considering the gross assumptions made regarding the pre-construction recharge. It is expected that a better fit of the modeled vs. observed water levels could be obtained through a more accurate representation of the pre-construction topography and spatial distribution of recharge. However, this additional validation step was not deemed necessary as there would be no effect on the post-construction simulations for Units 3 & 4.

5. POST-CONSTRUCTION SIMULATIONS

For the construction of Units 3 & 4 the existing site must be graded to create a flat pad for the planned footprint of the new units. Units 3 & 4 will have a finished grade level elevation of approximately 220 ft msl. The bottom of the foundation slab for the safety-related containment buildings will be at elevation 180.5 ft msl. During the construction of the new units the site will be excavated to remove the in-situ soil down to the principal bearing strata, the Blue Bluff Marl. The elevation of the top of the Blue Bluff Marl at the site ranges from 120 ft to 140 ft msl. The in-situ soil will be replaced with Category 1 and 2 structural fill material. Foundations for the new units will be poured on this new fill material.

5.1 Post-Construction Groundwater Simulations

Groundwater flow simulations for post-construction conditions were performed with the best calibrated model, which was simulation 708 from Model 7. For the simulation of post-construction conditions three modifications were made to this model:

a. The topography used in the model was modified to reflect the final grading of the site after the completion of the construction of Units 3 & 4.

b. A new hydraulic conductivity zone was introduced to describe the backfill material in the area around the power block of Units 3 & 4.

c. The rate of groundwater recharge in the area affected by the construction of units 3 & 4 was changed to reflect post-construction conditions.

The hydraulic conductivity of the fill material for the construction of Units 3 & 4 is assumed to be the same as that of the fill material used for Units 1 & 2. As discussed in Section 2.7, the geometric mean of four slug tests conducted in the structural fill material for Units 1 & 2 was 2.3 ft/day. The hydraulic conductivity values from these tests ranged from 1.3 to 3.3 ft/day. As a conservative assumption it is assumed that the hydraulic conductivity of the fill material is equal to the maximum measured value, i.e. 3.3 ft/day. Figure 71 shows the hydraulic conductivity zones used in the post-construction simulations. This is the same as Figure 45 with the addition of a new zone for the backfill material in the area of the power block of Units 1 & 2 and Units 3 & 4.

The hydraulic conductivity of the native materials and other parameters used in the model were kept equal to the values that produced the best agreement between computed and observed water levels (see Section 4.4). Figure 72 illustrates the model grid overlaid on the excavation plan. It can be seen from this figure that the smallest footprint of the excavation (at the base) was used to define the areas of backfill. Using this footprint enables a conservative determination of the travel time. The reason behind this is because the backfill has the lowest hydraulic conductivity of all materials between the release point and its discharge point, and hence travel through the backfill will dominate the total travel time.

Figure 73 shows the recharge zones used to simulate post-construction conditions. Over most of the model domain these zones are the same as those used for the calibration of the model under present conditions (see Figure 22), but differ at the site of Units 3 & 4, where zero recharge was defined in all paved areas or areas of buildings, and where local changes in vegetation cover and ground surface slope due to grading are expected. Figure 74 shows the simulated water levels obtained under these conditions. Figure 75 shows the simulated vs. observed water levels for the same simulation. Figure 76 shows the distribution of the estimated residuals for this run.

5.1.1 Release of Particles From Circle of Radius of 775ft

To assess the pathways of potential effluent releases particle tracking was performed with the model using 30 particles evenly distributed along the periphery of a 775-ft radius circle centered between Units and 3 & 4 and encompassing the entire power block area (see Figure 77). The 775-ft radius circle encompassing the power block used is that shown in SSAR Figure 1-4. The coordinates of the center of this circle are: Easting 621,446 and Northing 1,142,882 (in the State Plane Grid coordinate system). Results of the simulation show that all particles on the circle, which originate from the power block area, discharge to Mallard Pond as illustrated in Figure 77.

5.1.2 Particle Release From Auxiliary Building of Unit 4

To supplement the particle tracking exercise, an additional model run was conducted with the release of a single particle from underneath the auxiliary building of Unit 4. The particle was released at the location where it had the shortest pathway to travel through the fill. The purpose of this was to estimate a conservative travel time through the low hydraulic conductivity fill. The purpose of this model run was to determine the travel time of the particle through each of the subsurface materials between Unit 4 and its discharge point at Mallard Pond. The results of this model run demonstrate that the total travel time for the particle is 6.7 years, with the travel time in each material presented in Table 15. The pathway of the particle to its discharge point at Mallard Pond is illustrated in Figure 78.

Table 15 Travel Time for Single Particle Released from Auxiliary Building of Unit 4

Travel Time (years)			
Fill (3.3 ft/day)	Barnwell Sands/Utley Limestone (32 ft/day)	High Conductivity Zone above Mallard Pond (100 ft/day)	Total Pathway
2.4	3.2	1.1	6.7

6. CONCLUSIONS

A two-dimensional, horizontal plane model was developed to simulate groundwater flow under present and post-construction conditions at the VEGP site. The model was developed using all available historic data and data collected in support of the ESP/COL application.

Several alternative plausible conceptual models for the distribution of the hydraulic properties of the native materials were evaluated and tested during the calibration of the model. The calibration process is presented in seven steps, each of which is referred as a different "model." The final calibration of the model met all calibration criteria. All solutions obtained with the model and presented in this report had less than one percent mass balance discrepancy between inflow and outflow.

The calibrated model was used to simulate post-construction conditions, accounting for changes in the topography at the site of Units 3 & 4, the presence of backfill material in the area of the new structures, and changes in ground water recharge. Particle tracking was performed to identify the groundwater pathways of potential liquid effluent releases from the power block area.

Special attention was paid to the location of the groundwater divide in the vicinity of the power block. The models that produced the best agreement with the measured data have the groundwater divide south of the cooling towers.

All simulations with different alternative models suggest that the groundwater divide is to the south of the power block area of Units 3 & 4 and that any effluent releases to the groundwater from within the power block area will move northward and end up in Mallard Pond.

7. REFERENCES

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9 Waterloo Hydrogeologic Inc., Visual MODFLOW Professional v.4.2, User's Manual, 2006.

10 Countywide 7.5-min Topographic Maps (DRGs), Quadrangle Burke, scale 1:24,000, U.S. Geological Survey, published 1993, last updated 8/3/2000.

11 Drawings:
23162-000-EZ-3610-00001 00C, Units 3 & 4 - 500KV and 230KV Conceptual Transmission Lines, 11/2/2007, SV0-0000-E2-2005 V1.0
23162-000-P1-0010-00001 00E, Conceptual Plot Plan, 9/28/2007, SV0 0000 X2 2001 V5.0
23162-000-P1-0010-00002 00E, Conceptual General Arrangement, 9/28/2007, SV0 0000 X2 2001 V5.0

12 LIDAR Survey, Metro Engineering and Surveying Company. Drawing Number M-197, Dated 8/11/06.

13 Burke County, USGS Digital Elevation Map

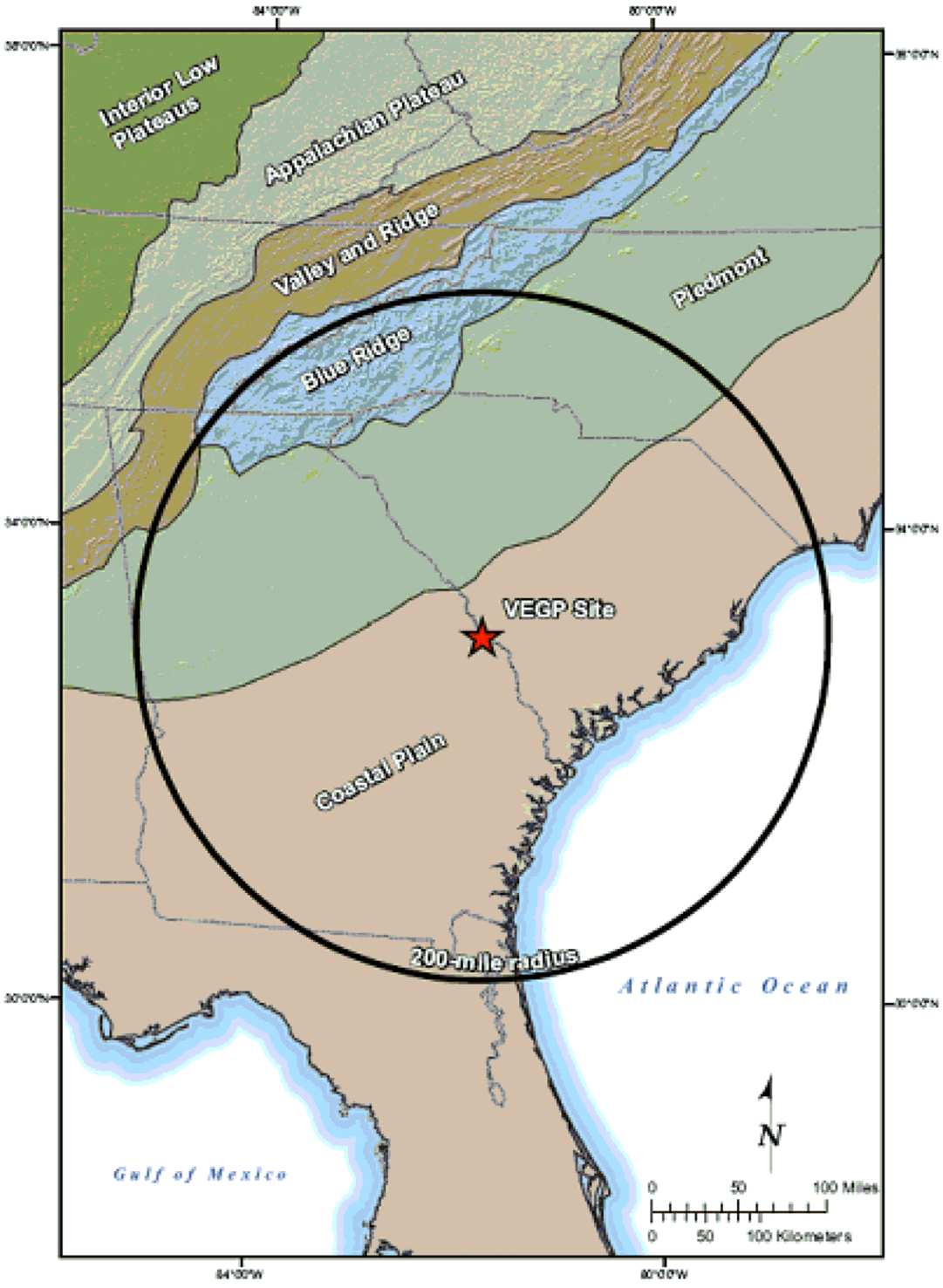


Figure 1: VEGP Site Location [Figure 2.5.1-1]

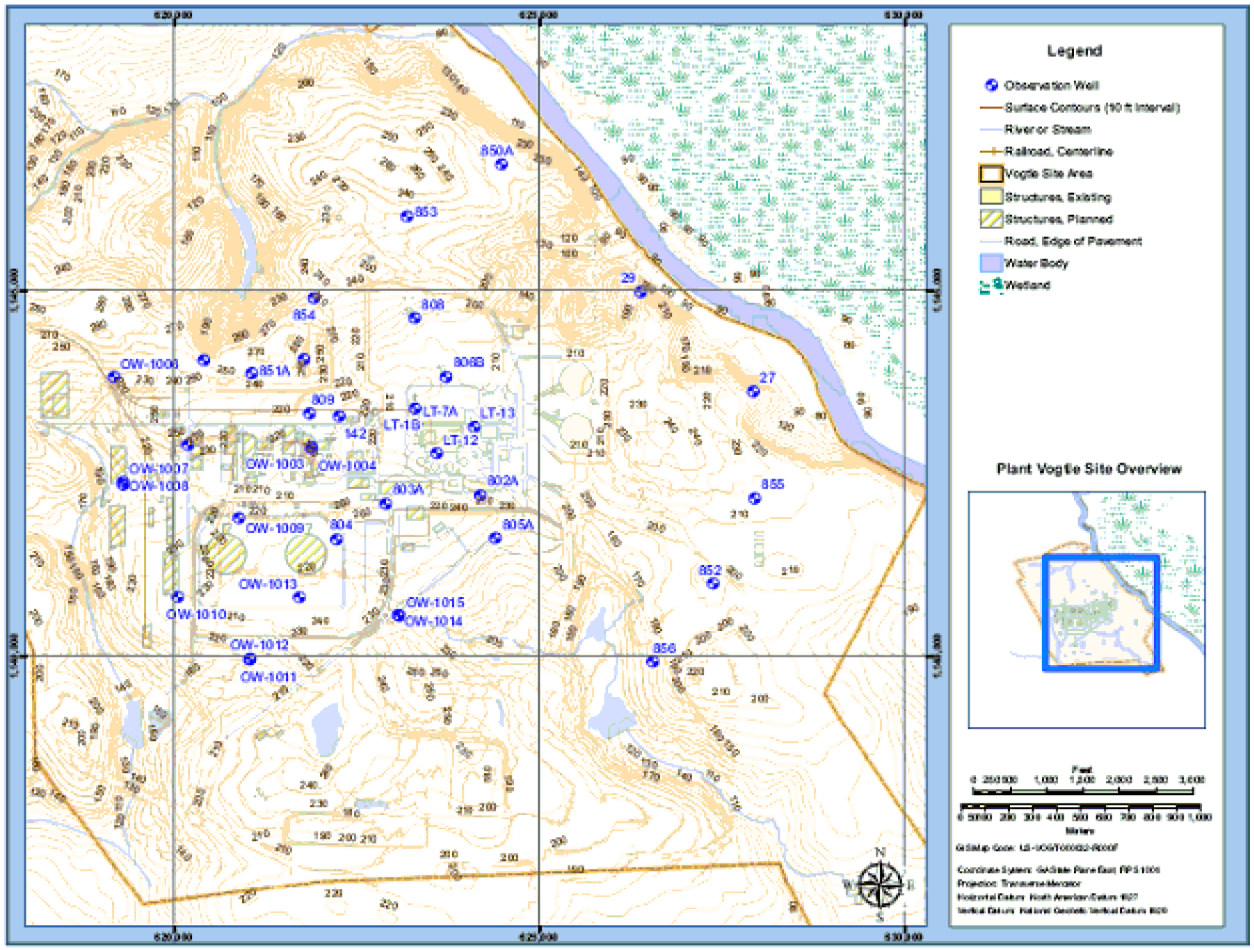


Figure 2: Site Map Showing the Existing and the Proposed VEGP Units [Figure 2.4.12-3]

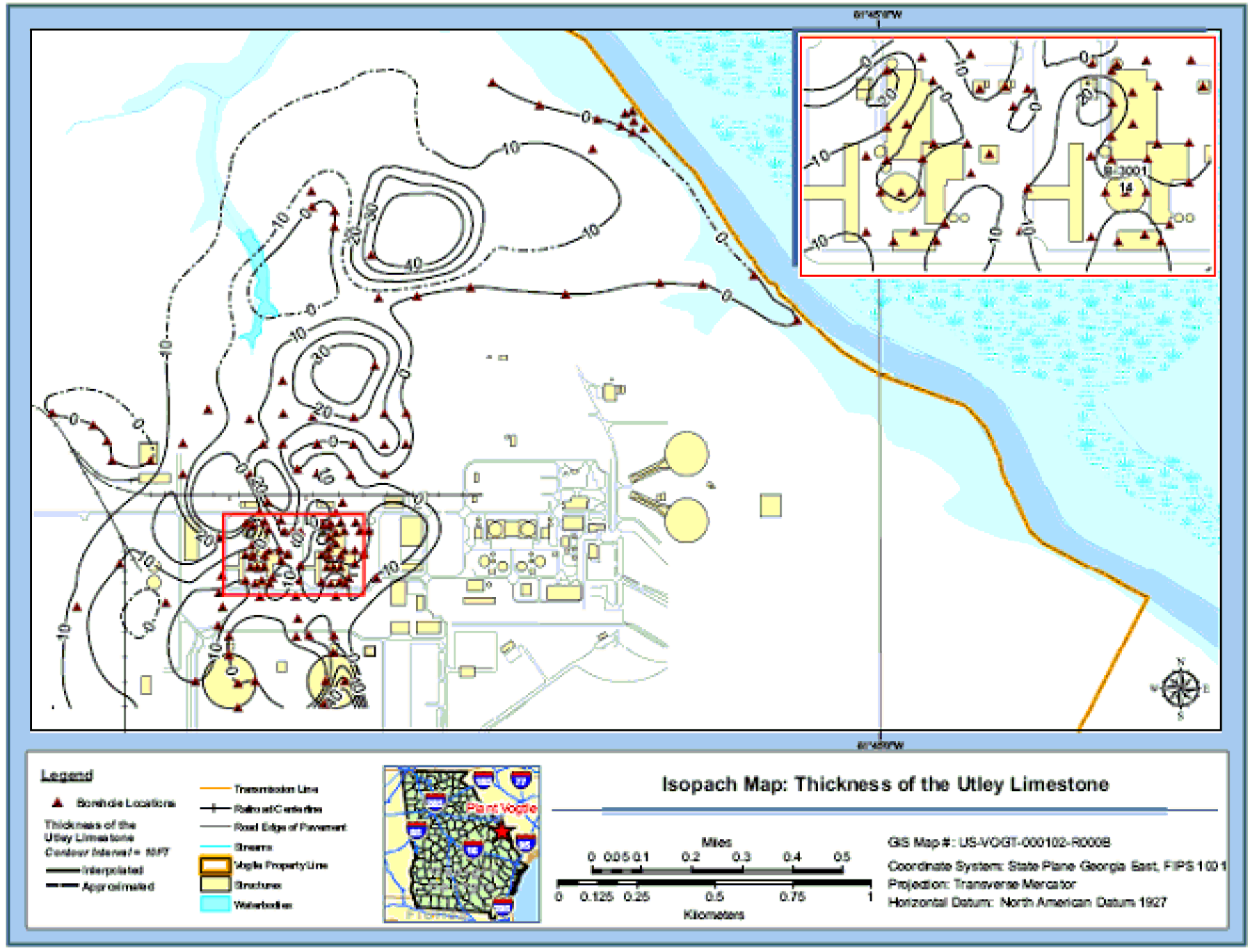


Figure 3: Isopachs of the Utley Limestone [Ref. 5, Figure 2.5.1-53]

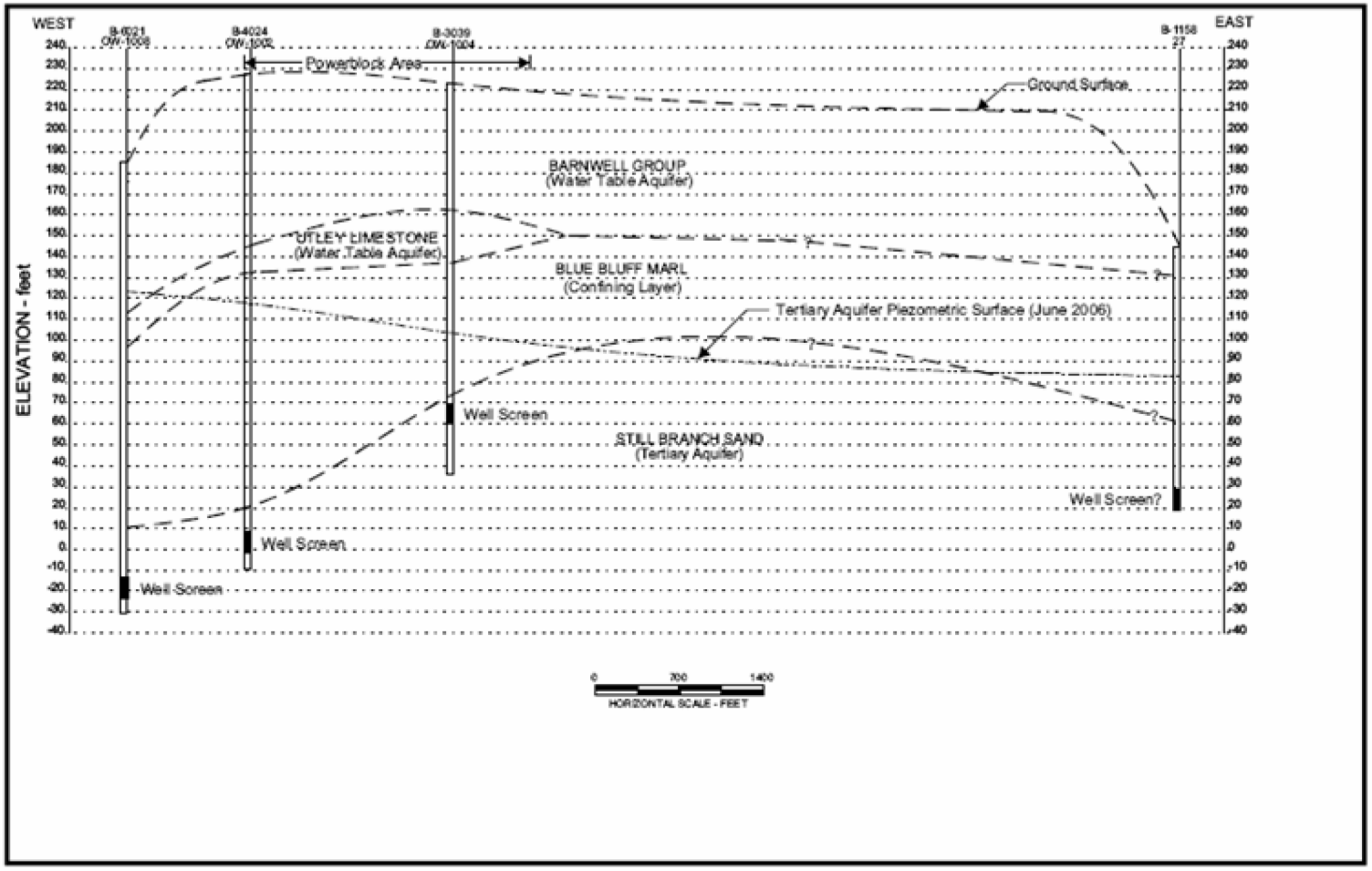


Figure 4: Hydrogeologic Cross-Section of the Water Table Aquifer at the VEGP Site [Ref. 5 Figure 2.4.12-2A]

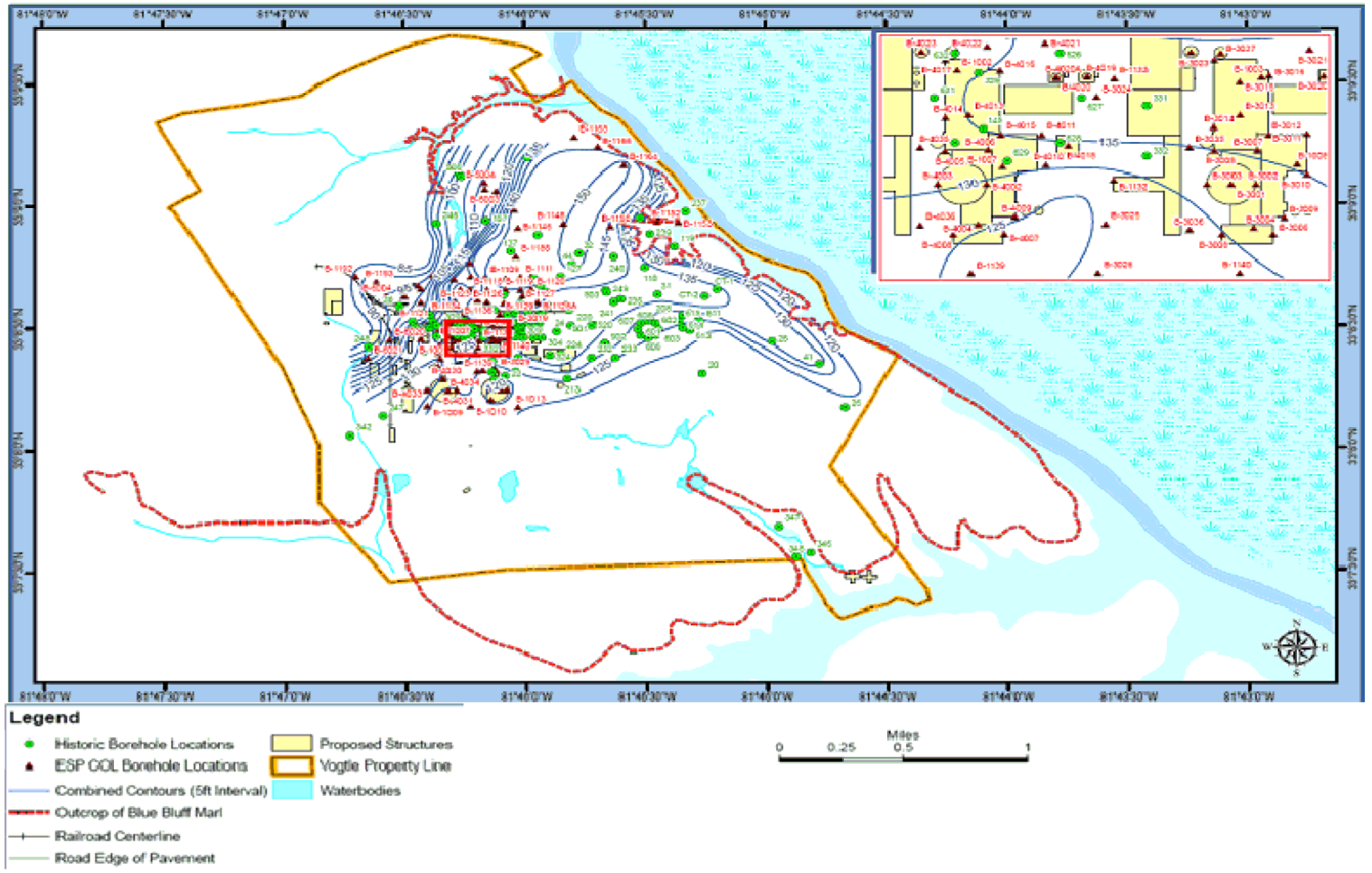


Figure 5: Outcrop and Contours of the Top of the Blue Bluff Marl at the VEGP Site

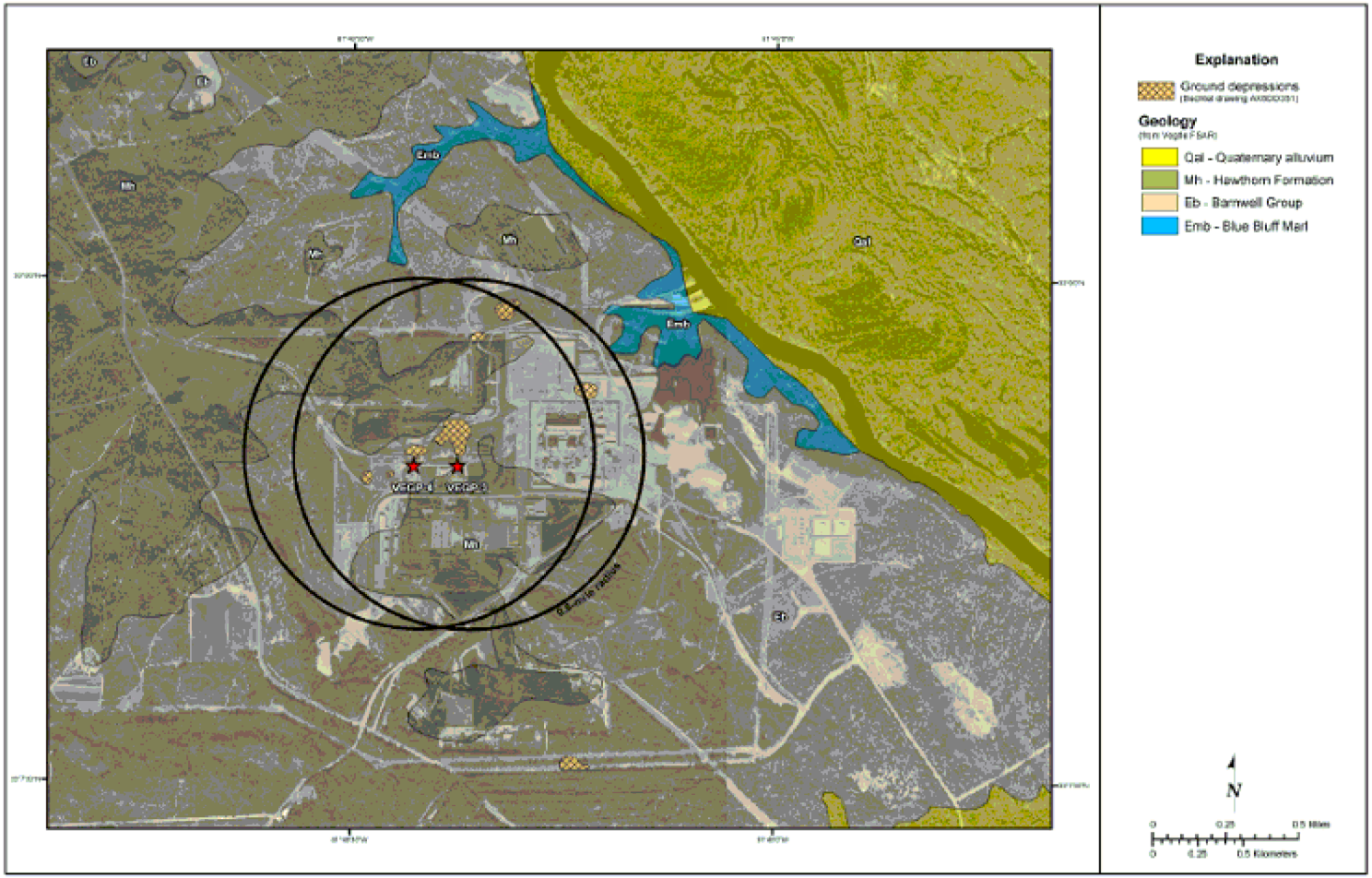


Figure 6: Site Geologic Map Showing the Outcrop of the Blue Bluff Marl [Figure 2.5.1-31]

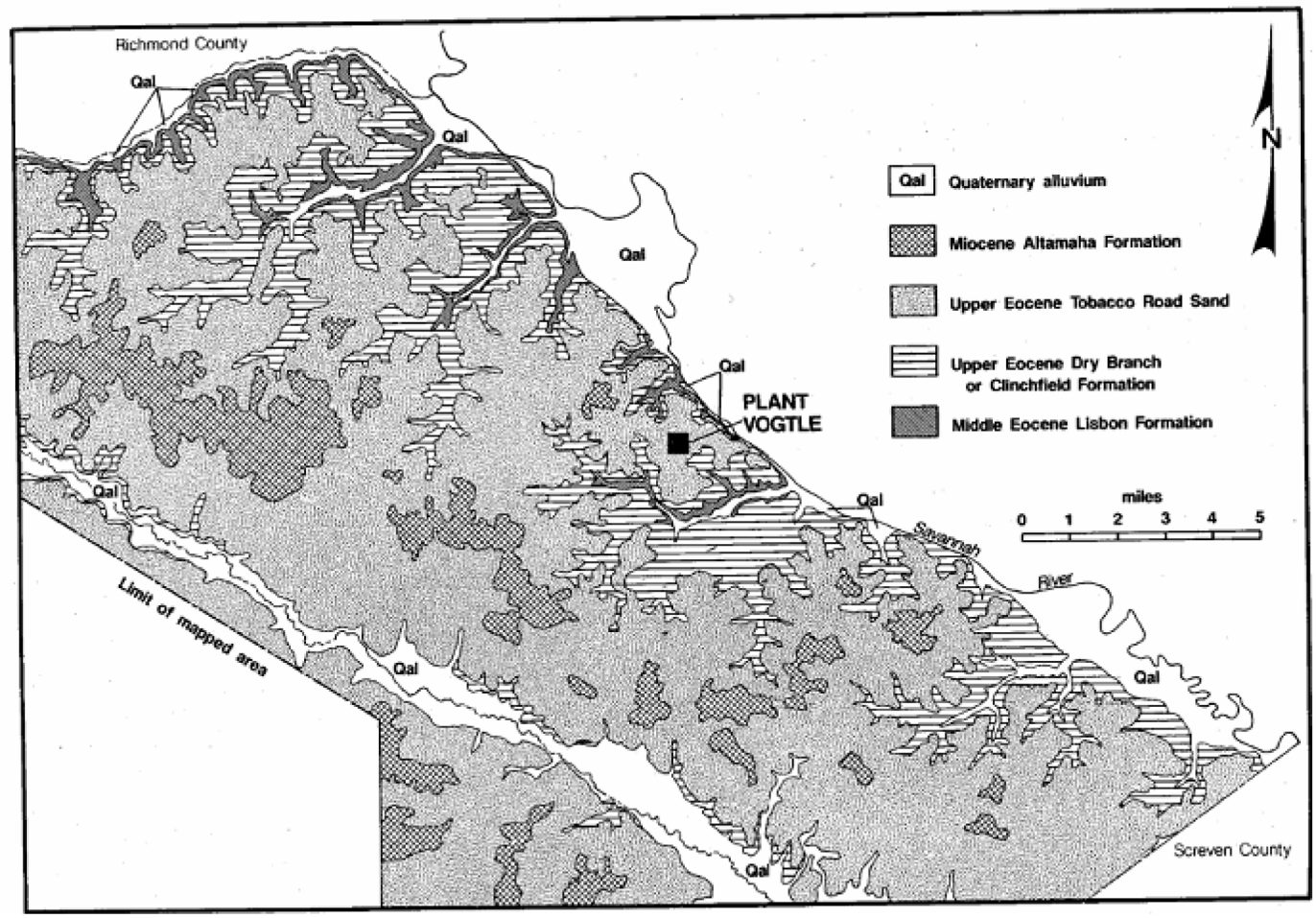


Figure 7: Geologic Map of Barnwell Group Exposures in Eastern Burke County [from Ref. 6]

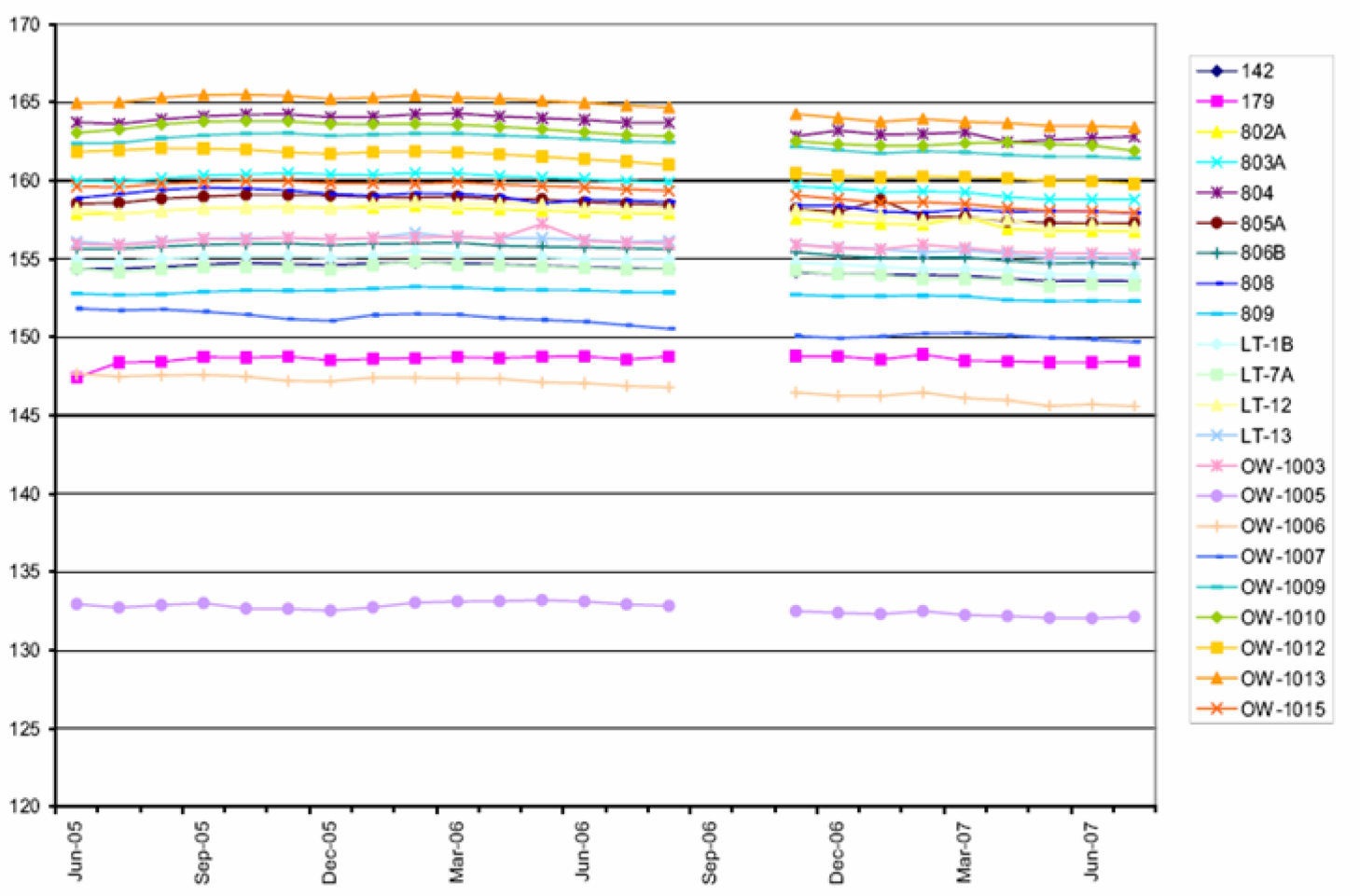


Figure 8: Water Table Aquifer: June 2005 – July 2007 Hydrographs [Ref. 5, Figure 2.4.12-23]

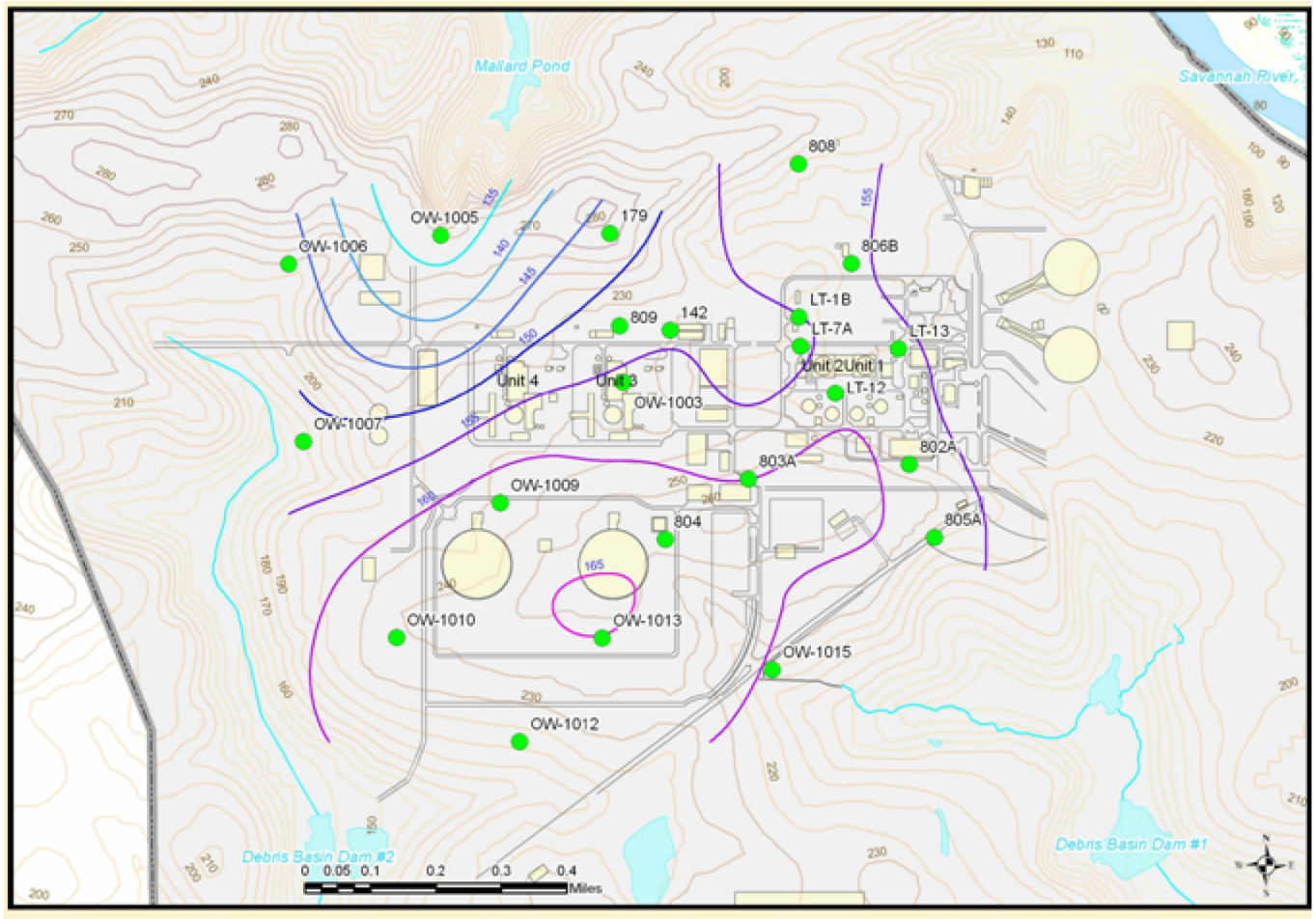


Figure 9: Water Table Aquifer: Piezometric Contour Map for June 2005 [Ref. 5, Figure 2.4.12-7]

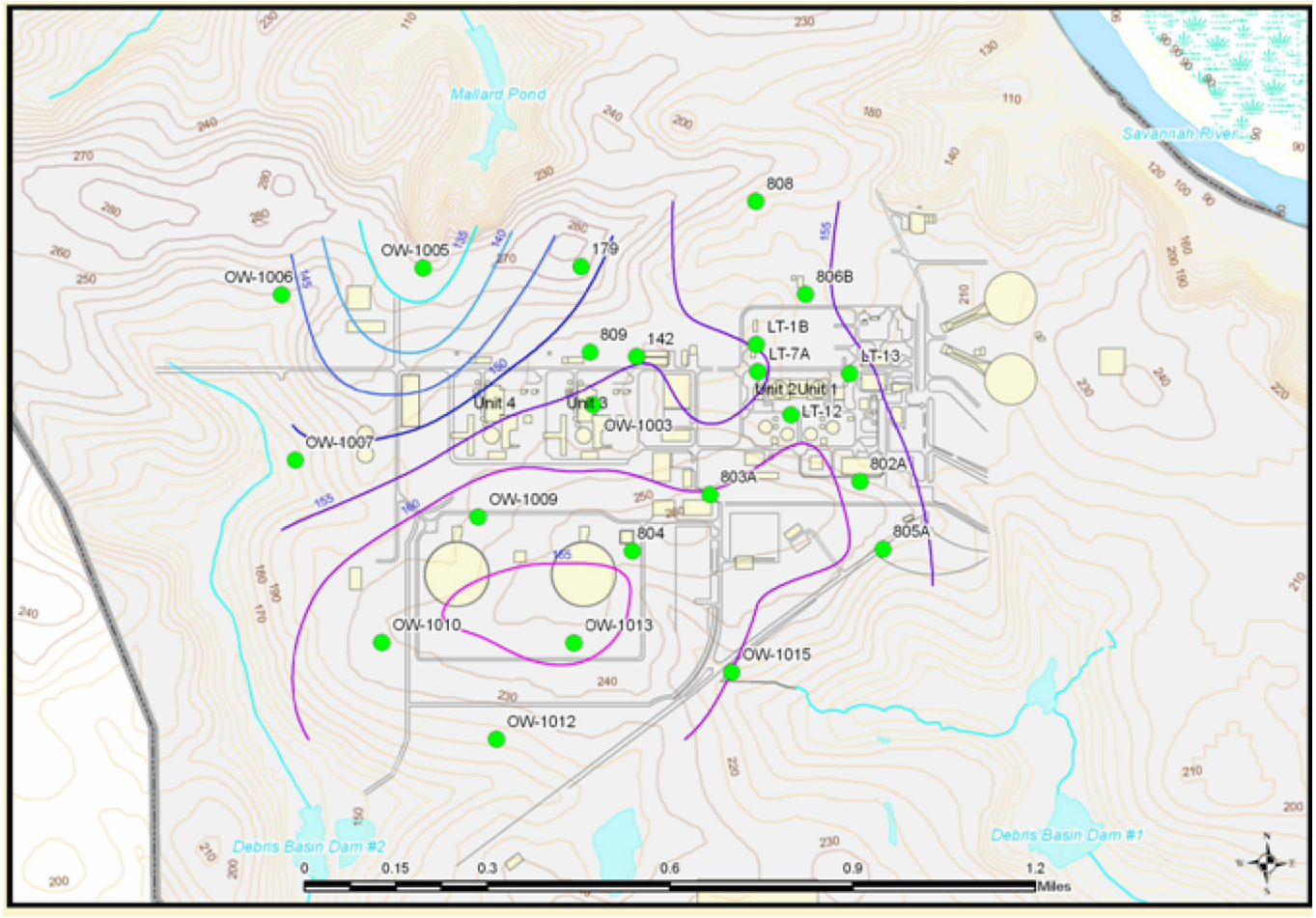


Figure 10: Water Table Aquifer: Piezometric Contour Map for October 2005 [Ref. 5, Figure 2.4.12-8]

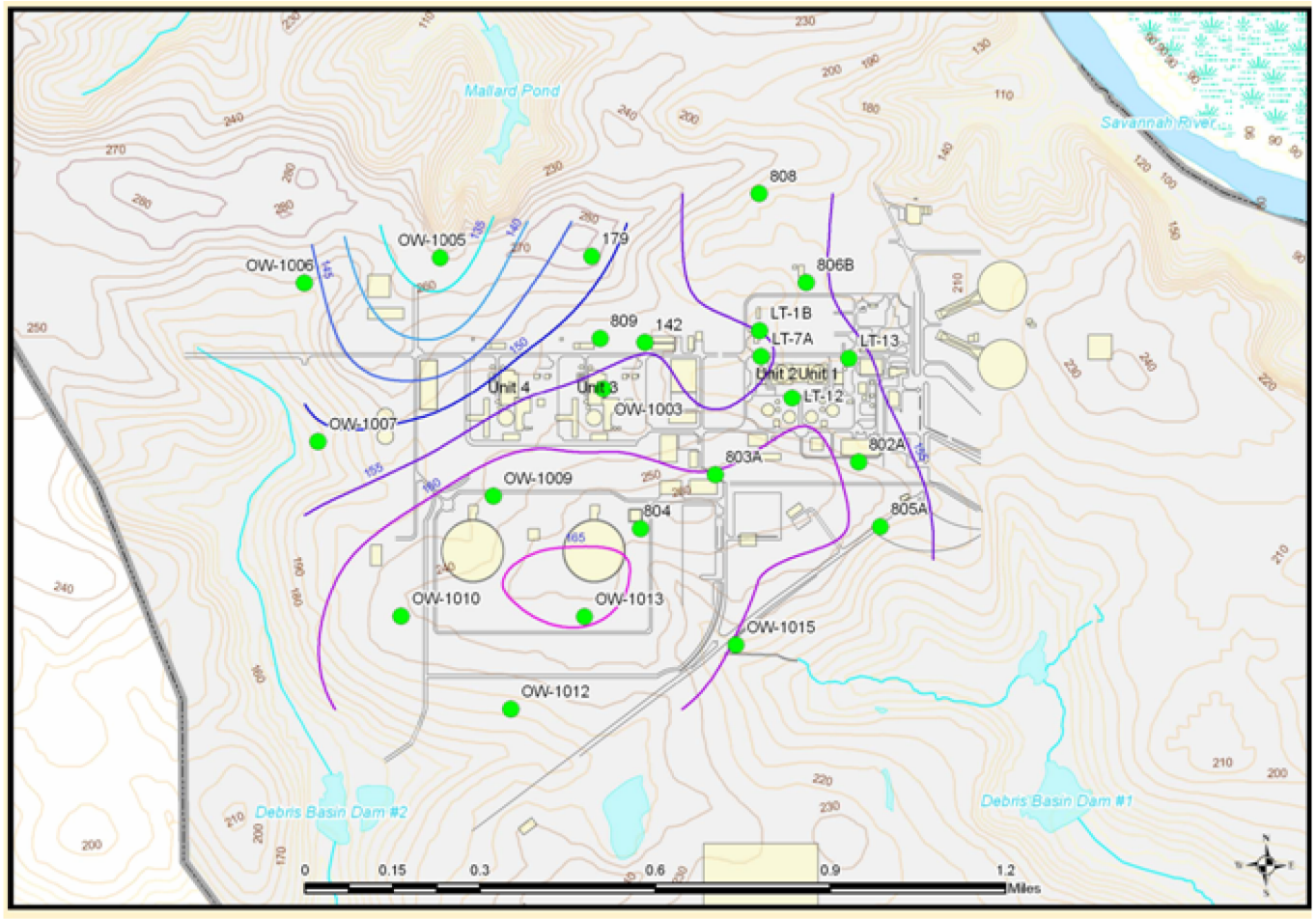


Figure 11: Water Table Aquifer: Piezometric Contour Map for December 2005 [Ref. 5, Figure 2.4.12-9]

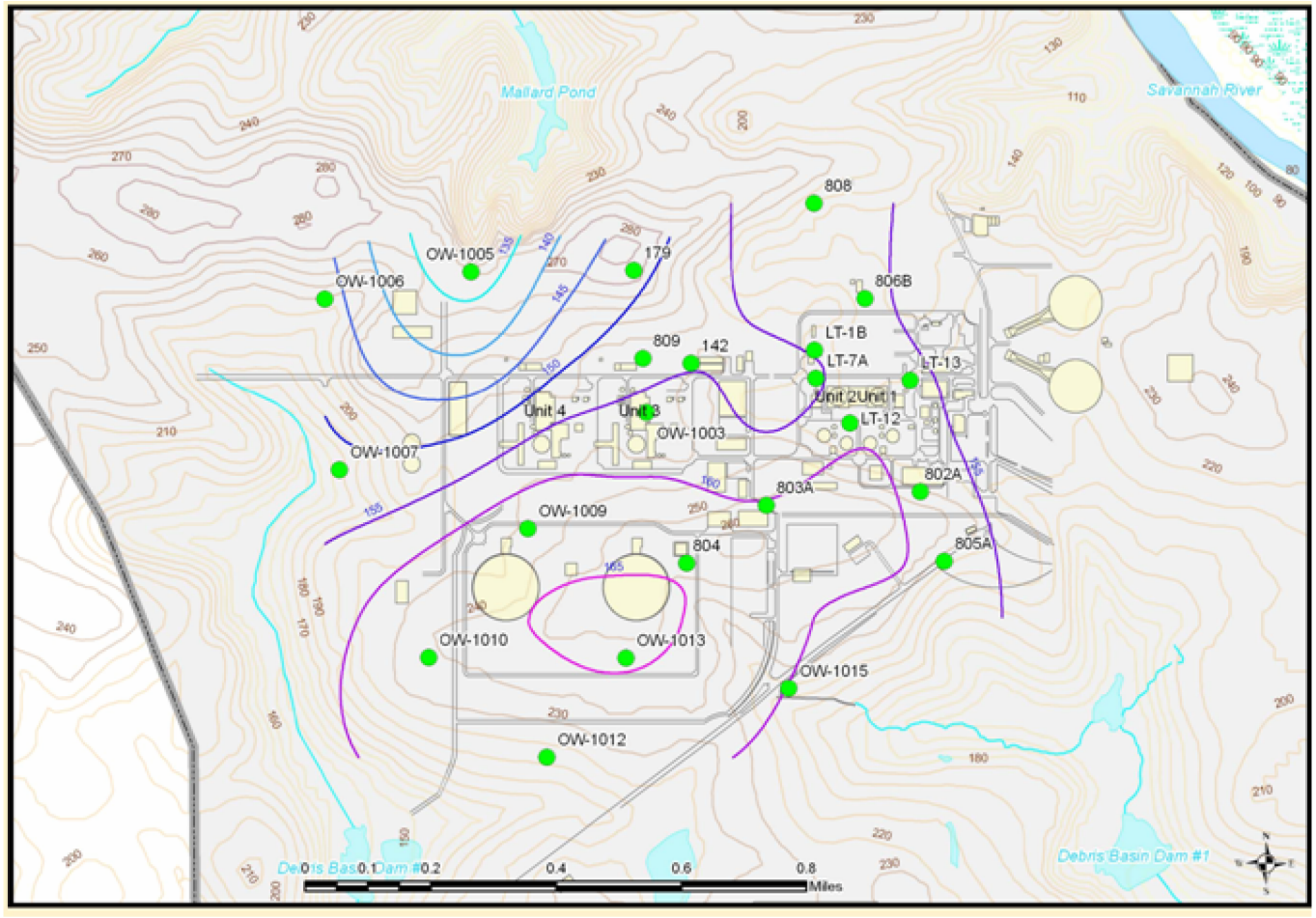


Figure 12: Water Table Aquifer: Piezometric Contour Map for March 2006 [Ref. 5, Figure 2.4.12-10]

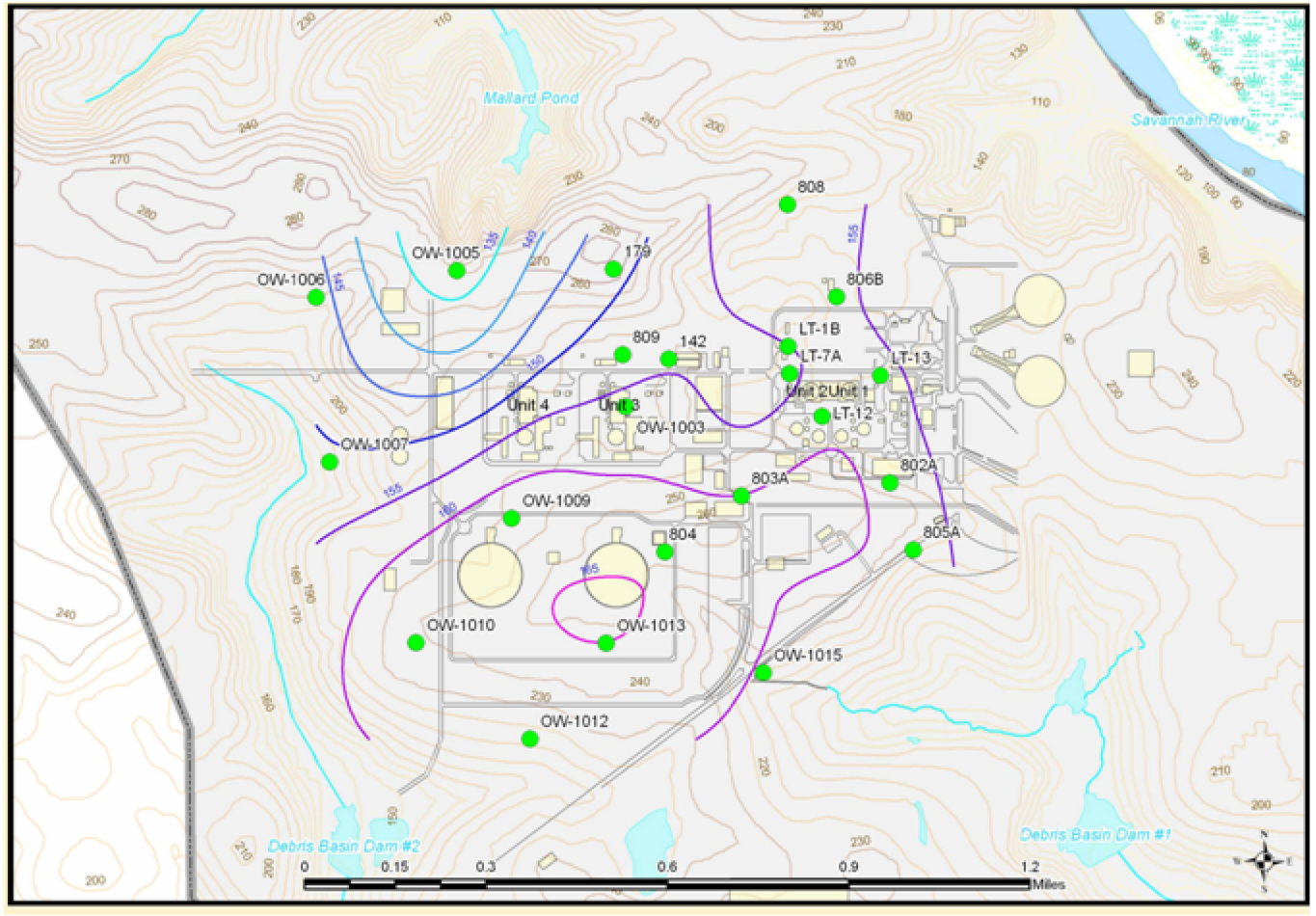


Figure 13: Water Table Aquifer: Piezometric Contour Map for June 2006 [Ref. 5, Figure 2.4.12-11]

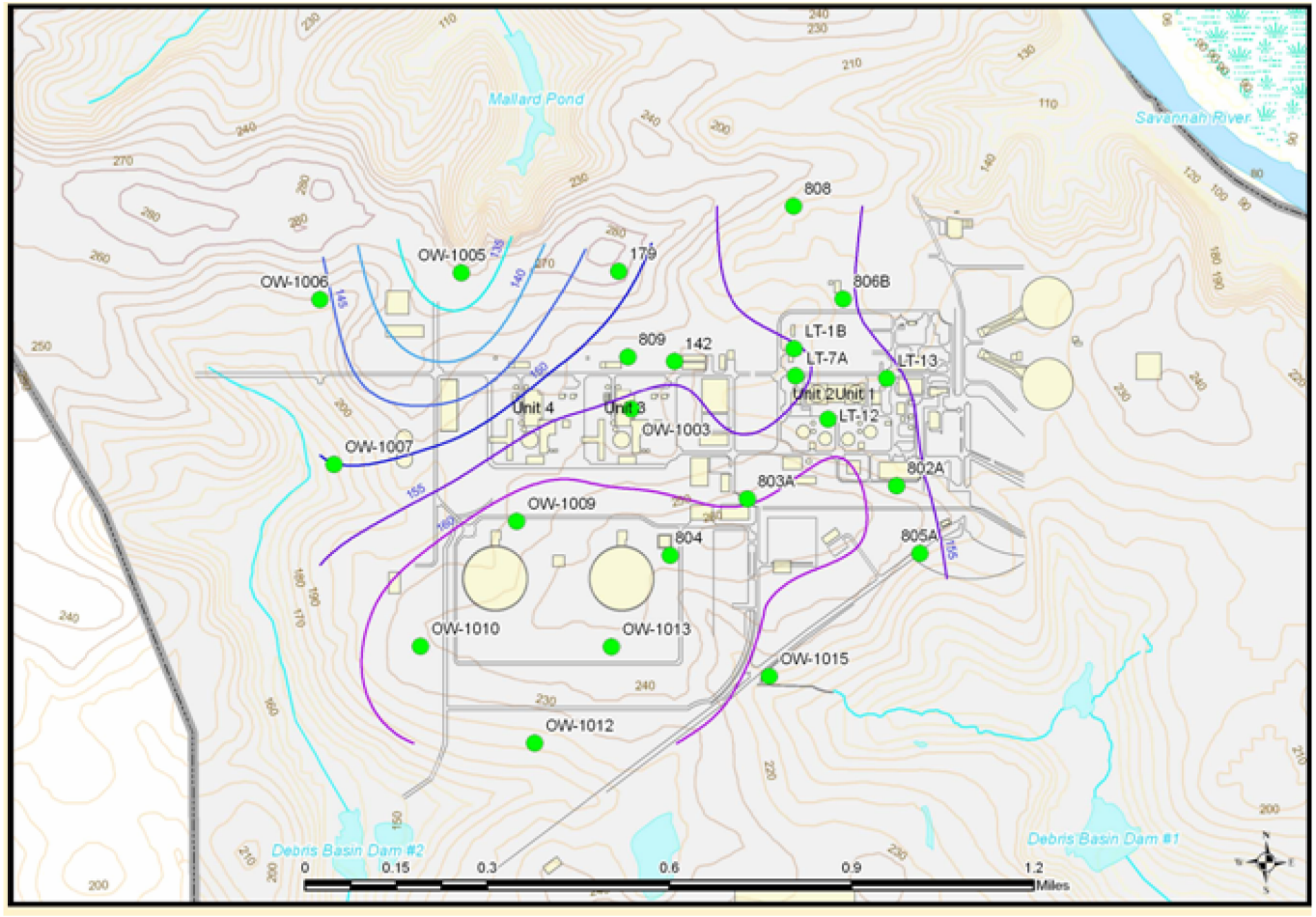


Figure 14: Water Table Aquifer: Piezometric Contour Map for November 2006 [Ref. 5, Figure 2.4.12-24]

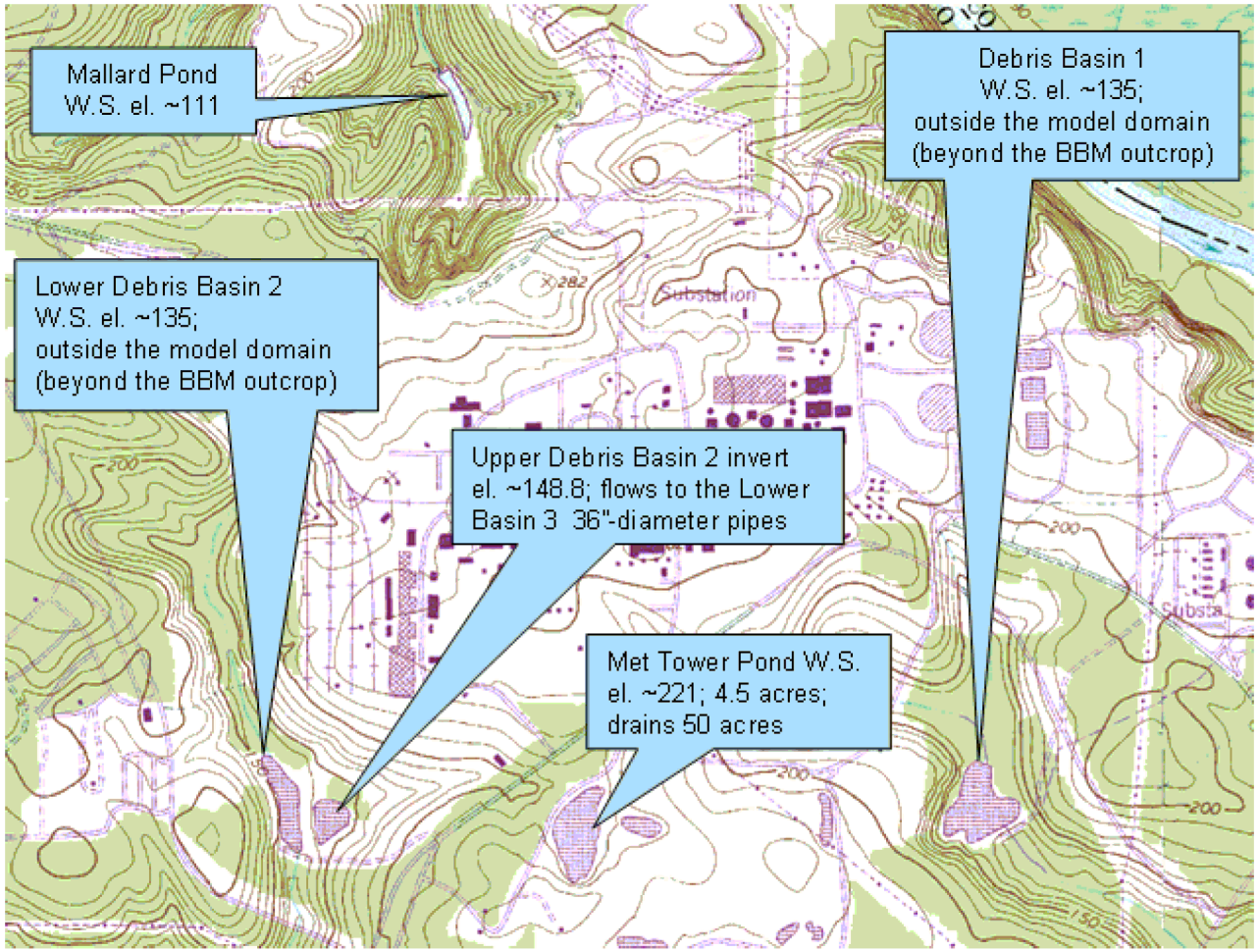


Figure 15: Ponds Near the Site of Units 3 & 4

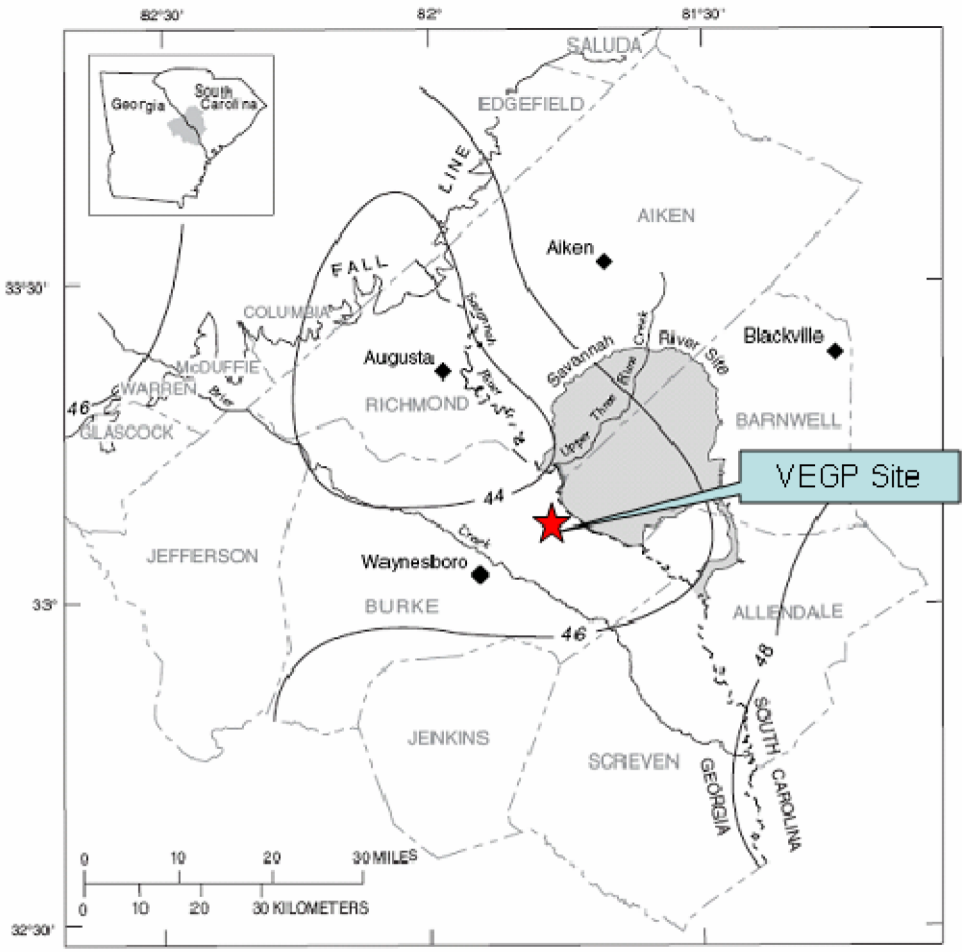


Figure 16: Mean Annual Rainfall in the Savannah River Basin Based on Data from 1941 to 1970 [from Ref. 4]

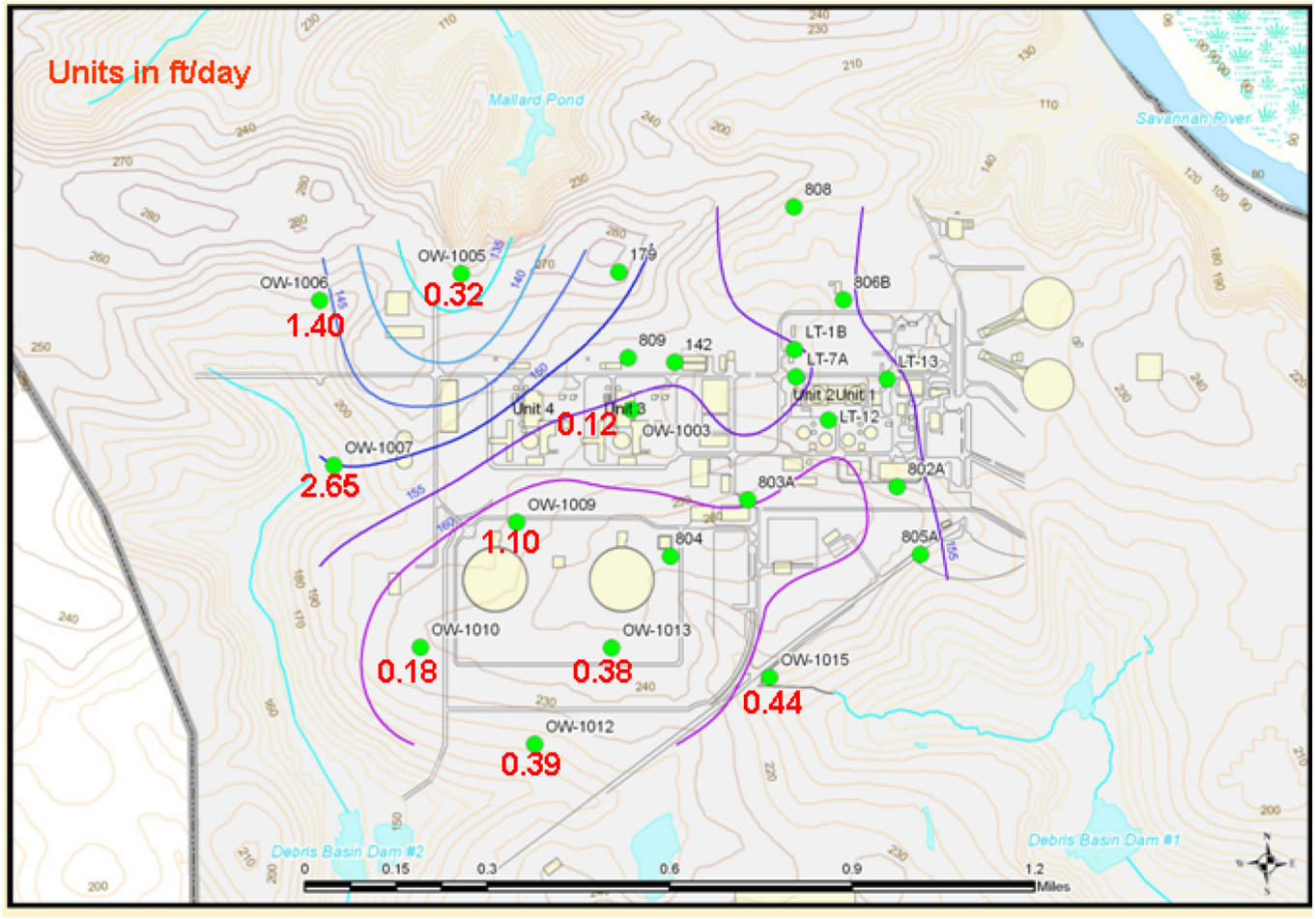


Figure 17: Distribution of Estimated Hydraulic Conductivity Values for Units 3 & 4

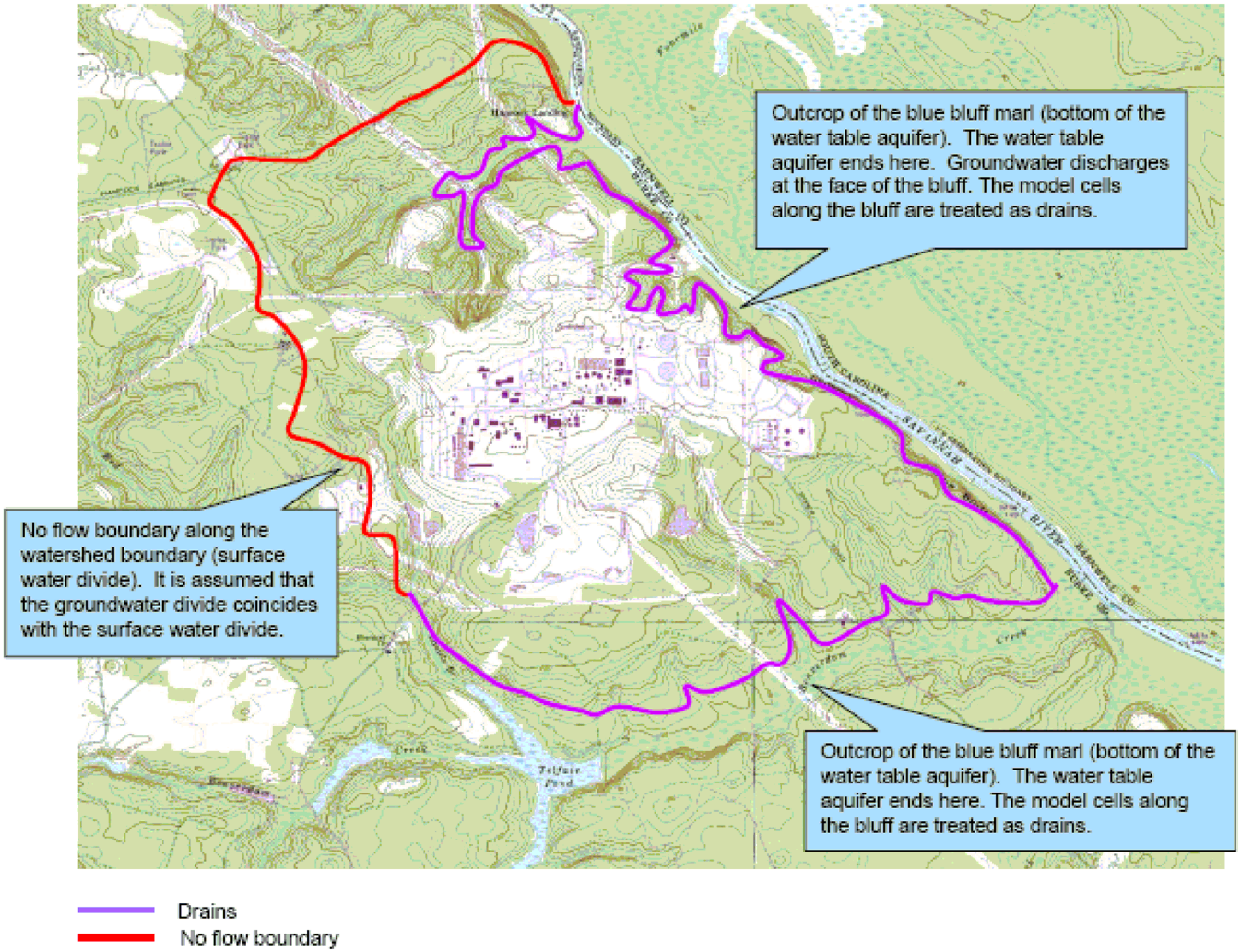


Figure 18: Conceptual Groundwater Model for the VEGP Site

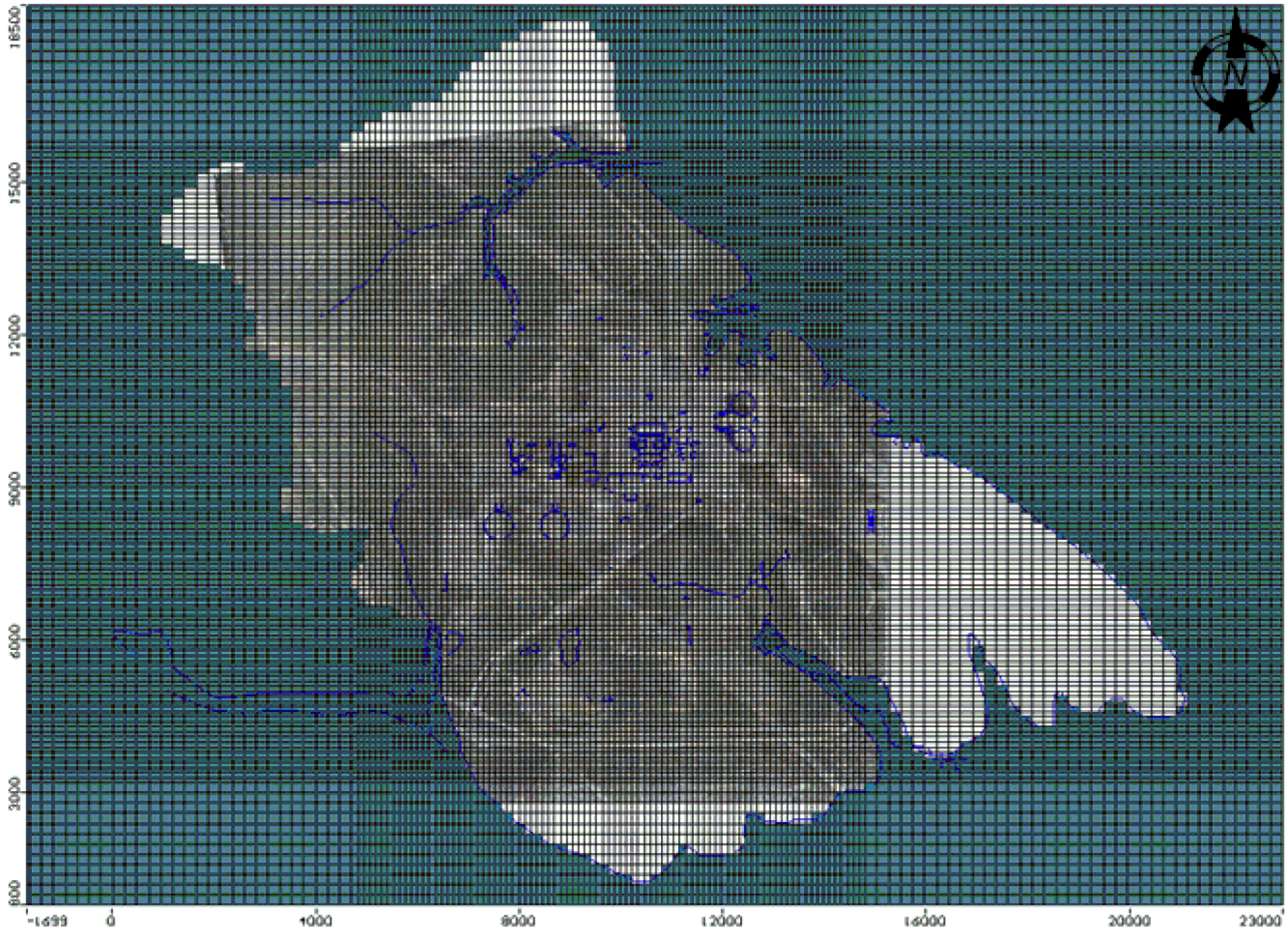


Figure 19: Numerical Model Grid and Boundary Conditions

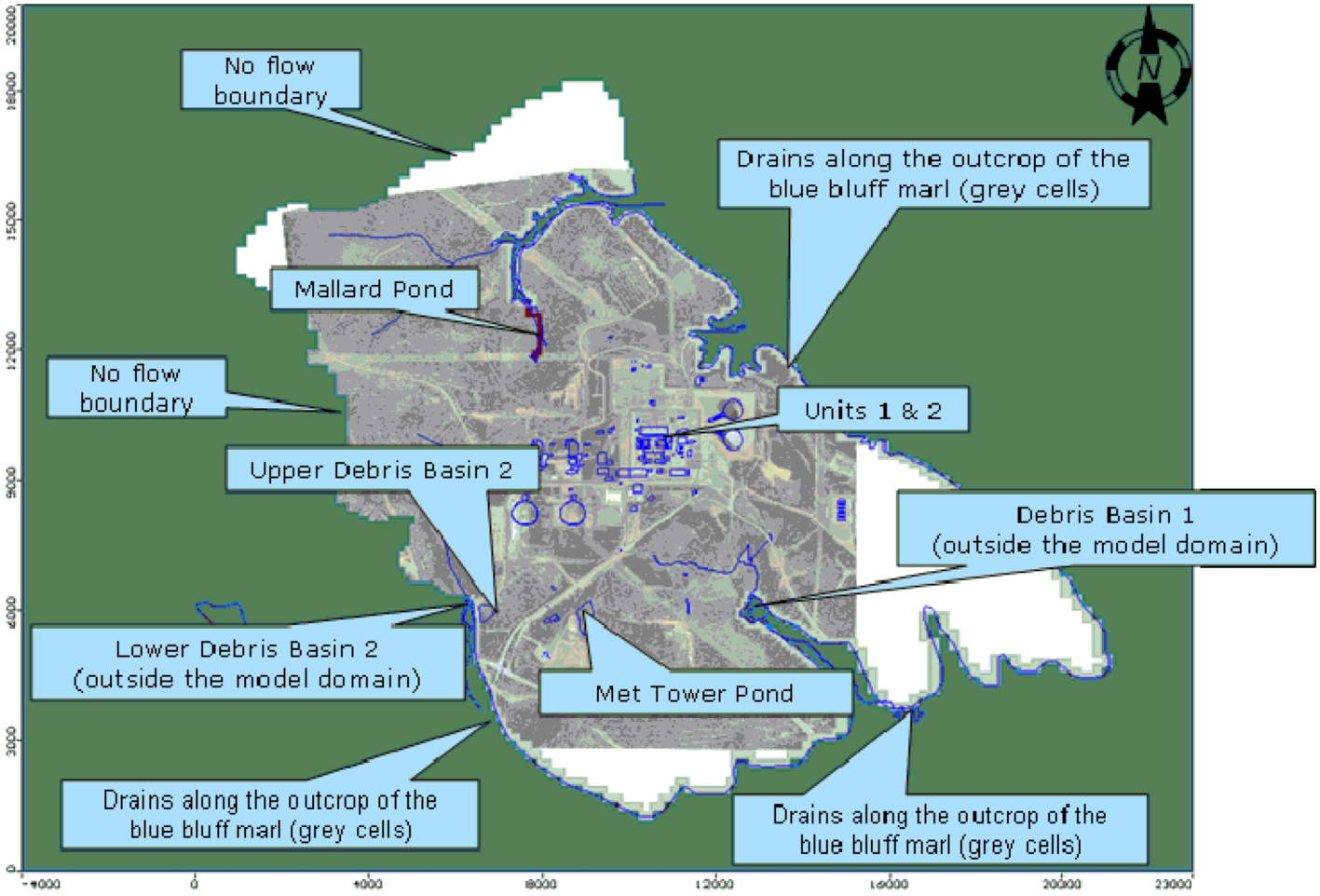


Figure 20: Numerical Groundwater Model Domain with Key Physical Features and Respective Flow Boundaries

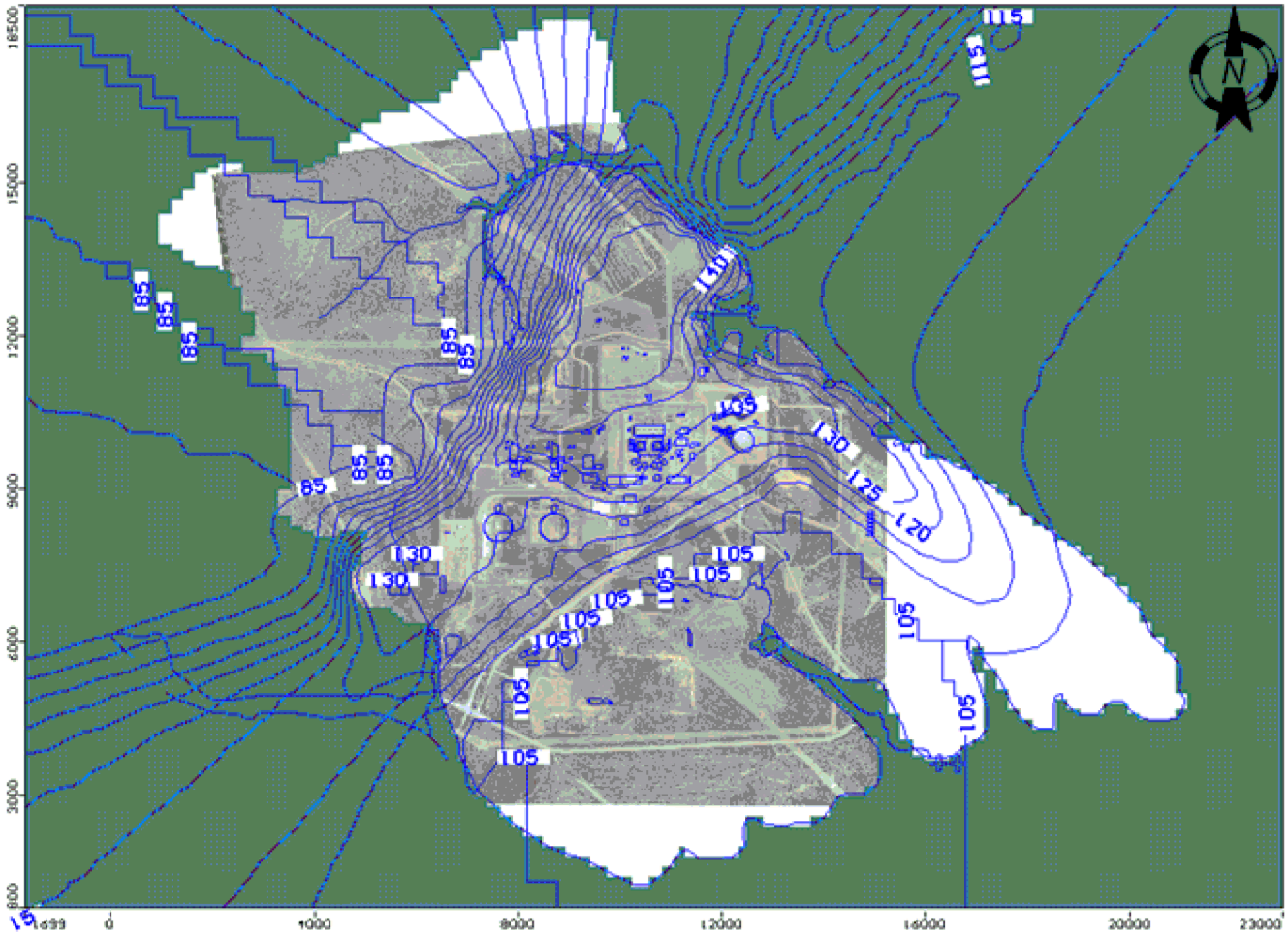


Figure 21: Bottom of the Model Domain (Top of Blue Bluff Marl) as Described in the Model

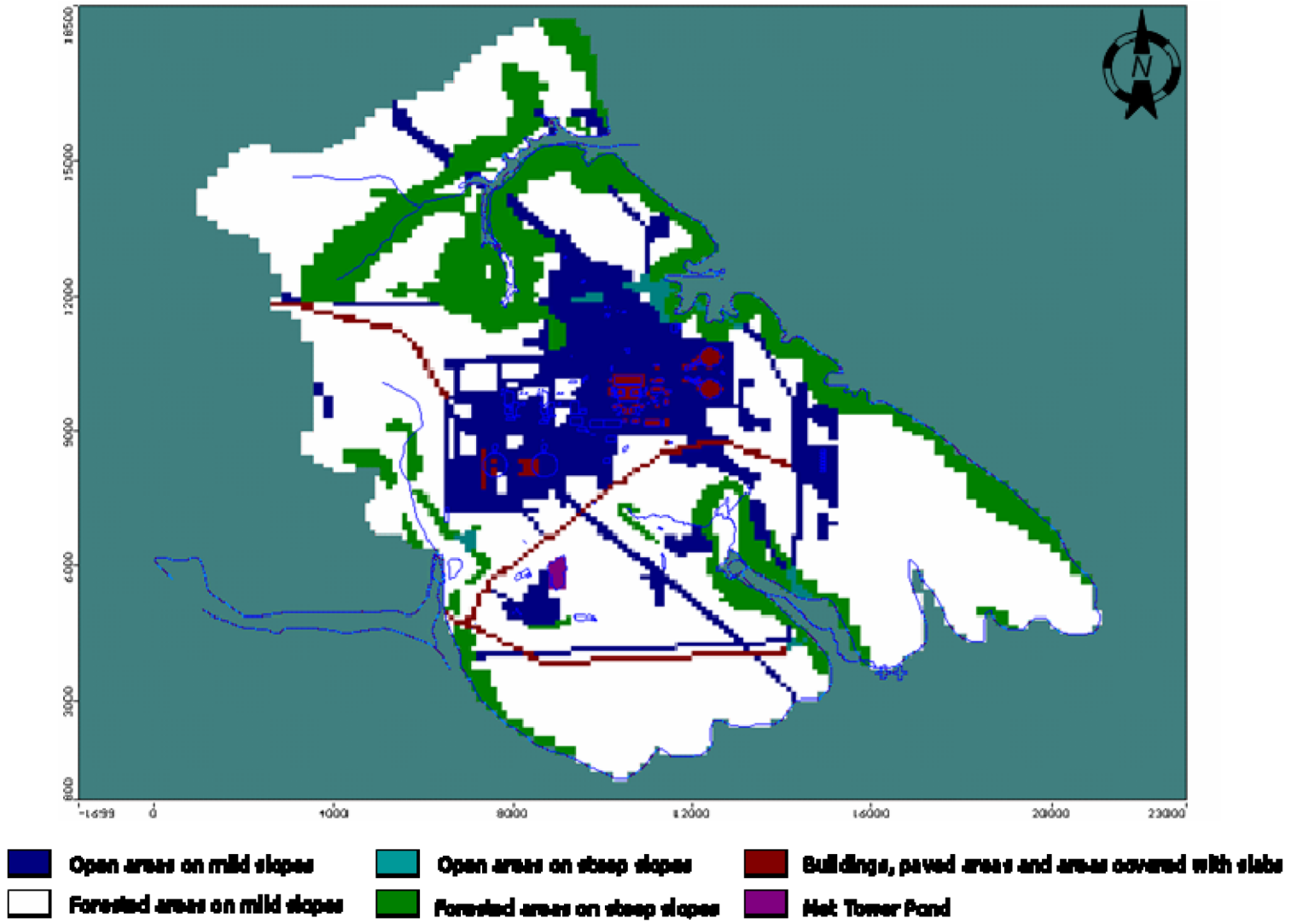


Figure 22: Groundwater Recharge Zones Used in the Model



Figure 23: Model 1 - Simulated Water Levels for Run 109 (K_1 = 27 ft/day; R_1 =7 in/yr)

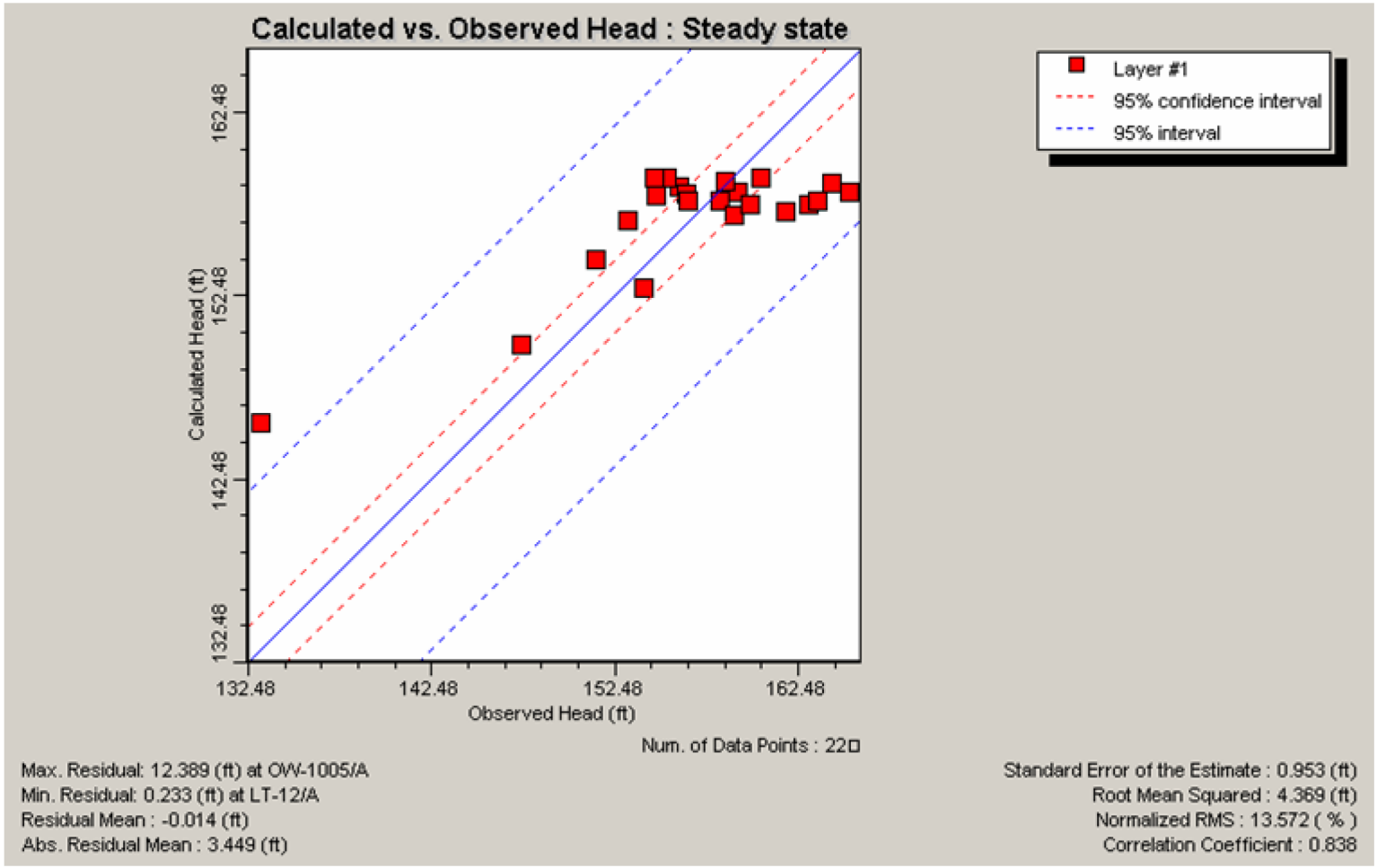


Figure 24: Model 1 - Simulated Vs. Observed Water Levels for Run 109 (K_1 = 27 ft/day; R_1 =7 in/yr)

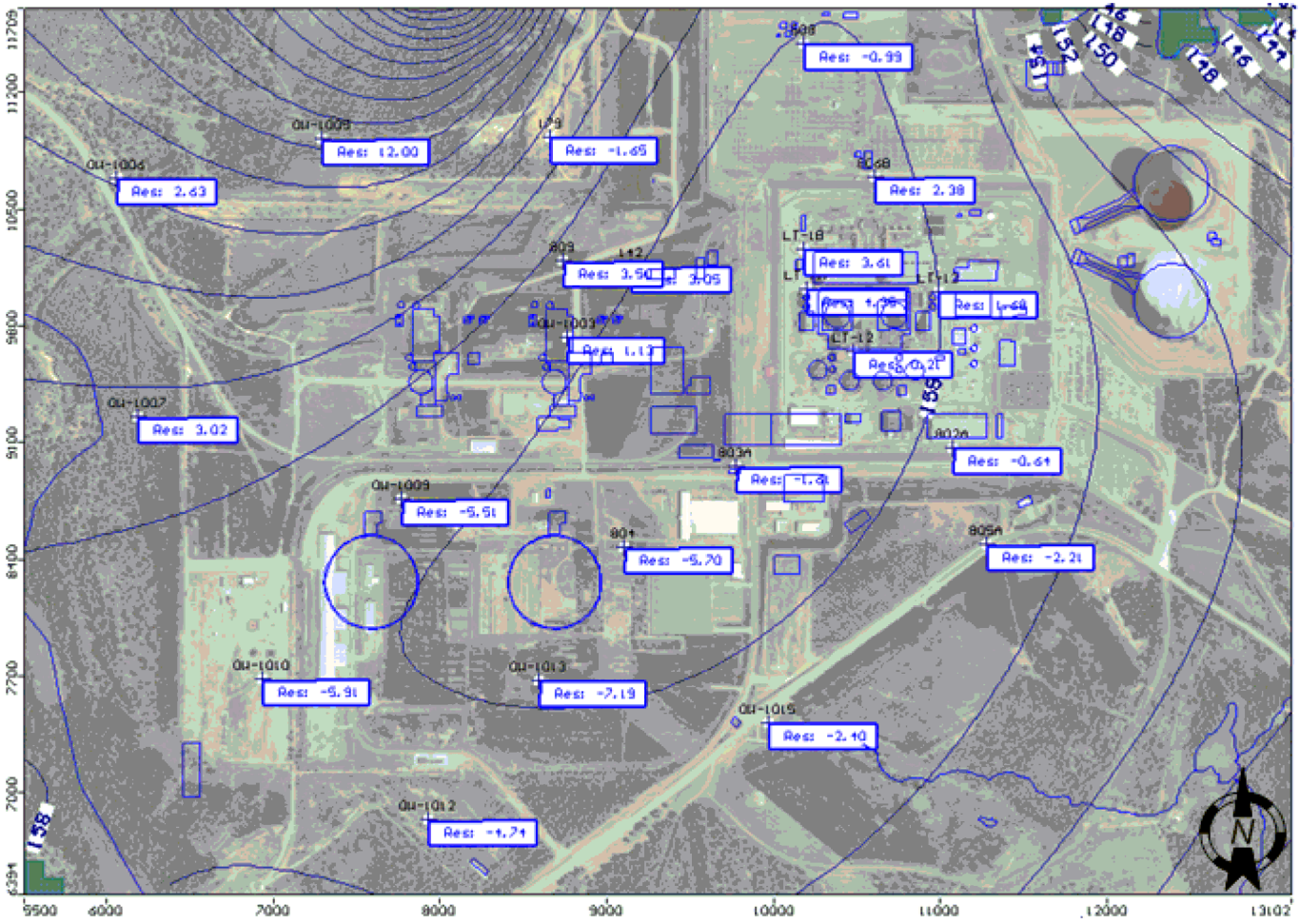


Figure 25: Model 1 - Estimated Residuals for Run 109 (K_1 = 27 ft/day; R_1 =7 in/yr)



Figure 26: Model 2 - Simulated Water Levels for Run 201 (K_1=27 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

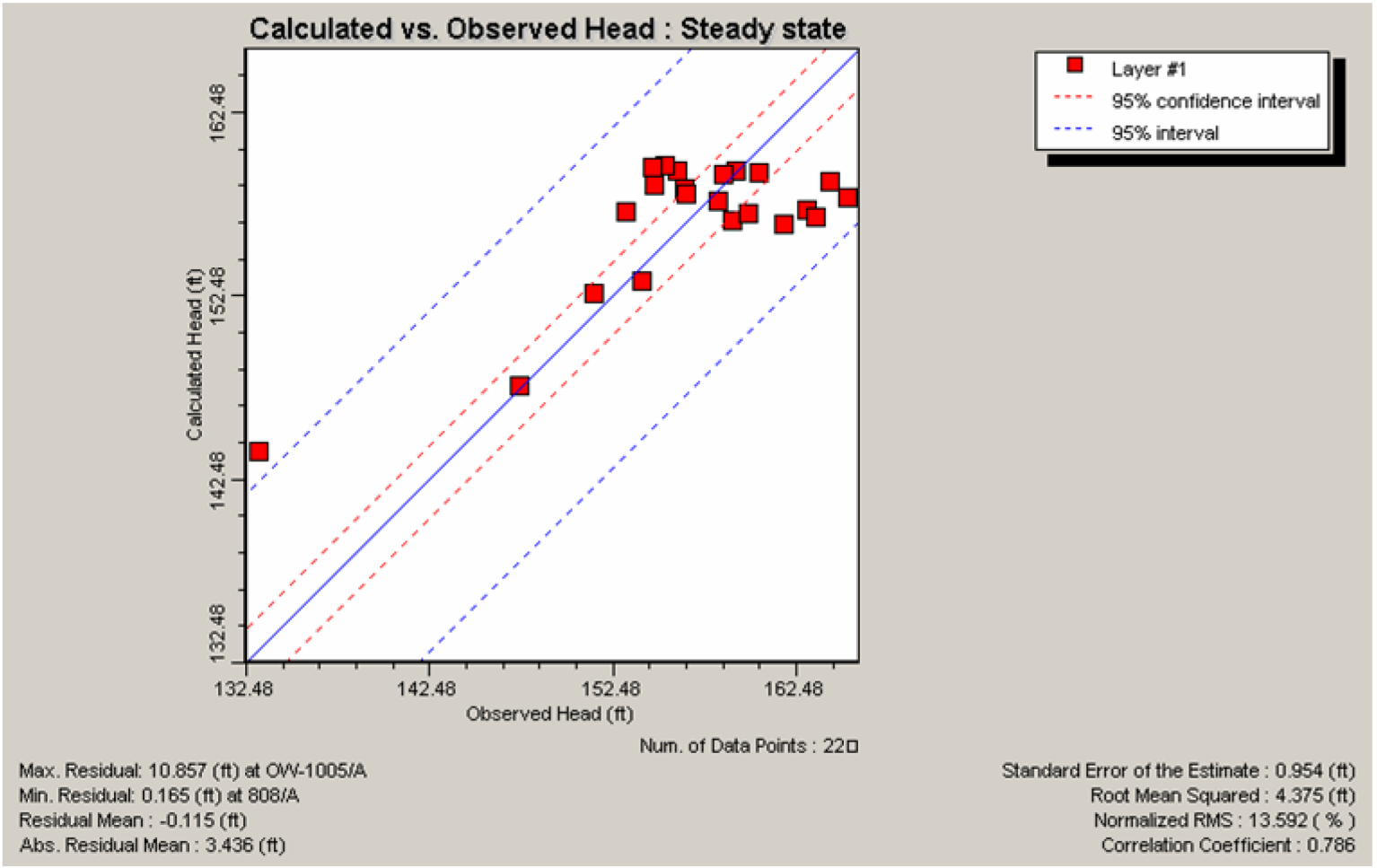


Figure 27: Model 2 - Simulated Vs. Observed Water Levels for Run 201 (K_1=27 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

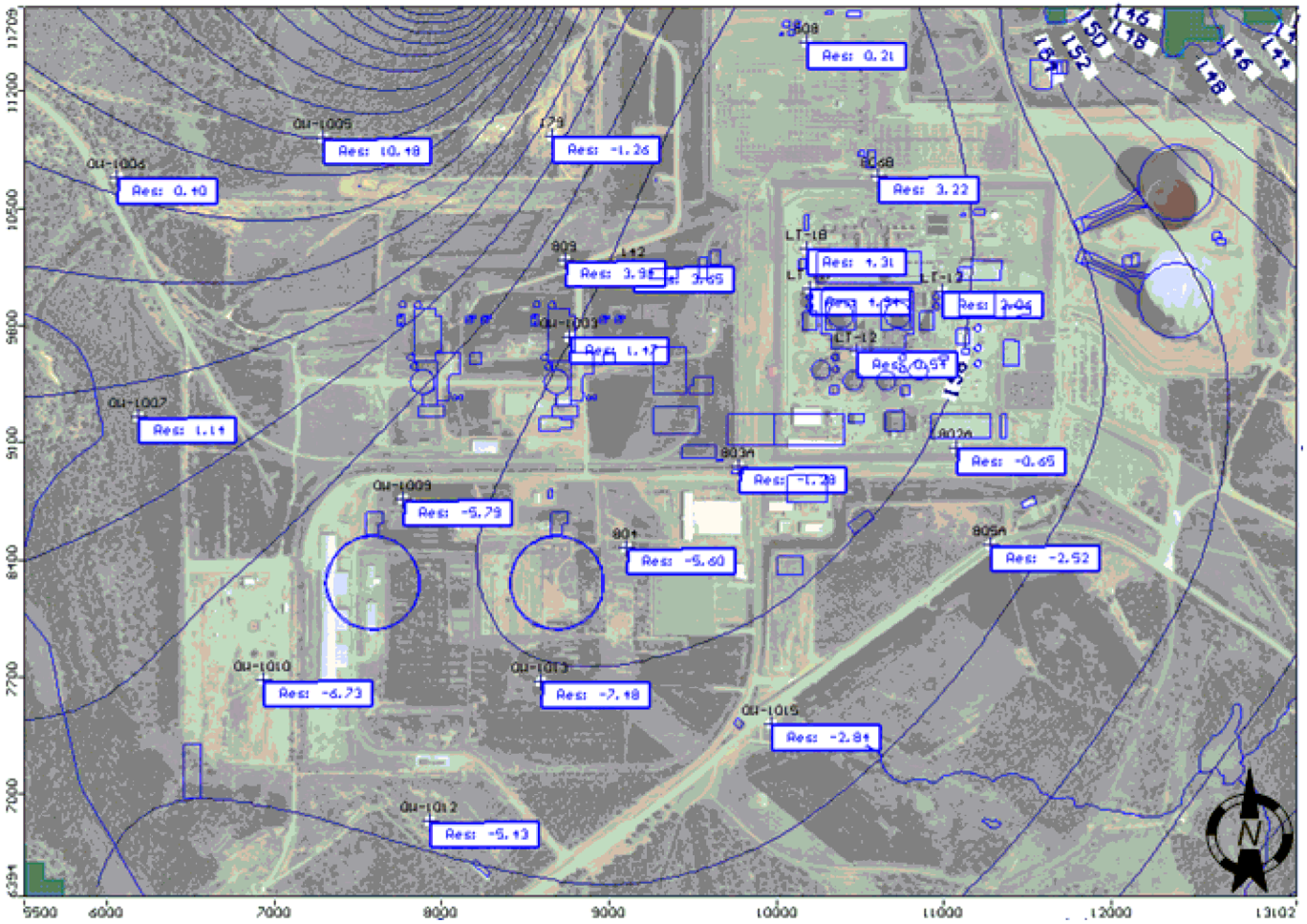


Figure 28: Model 2 - Estimated Residuals for Run 201 (K_1=27 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

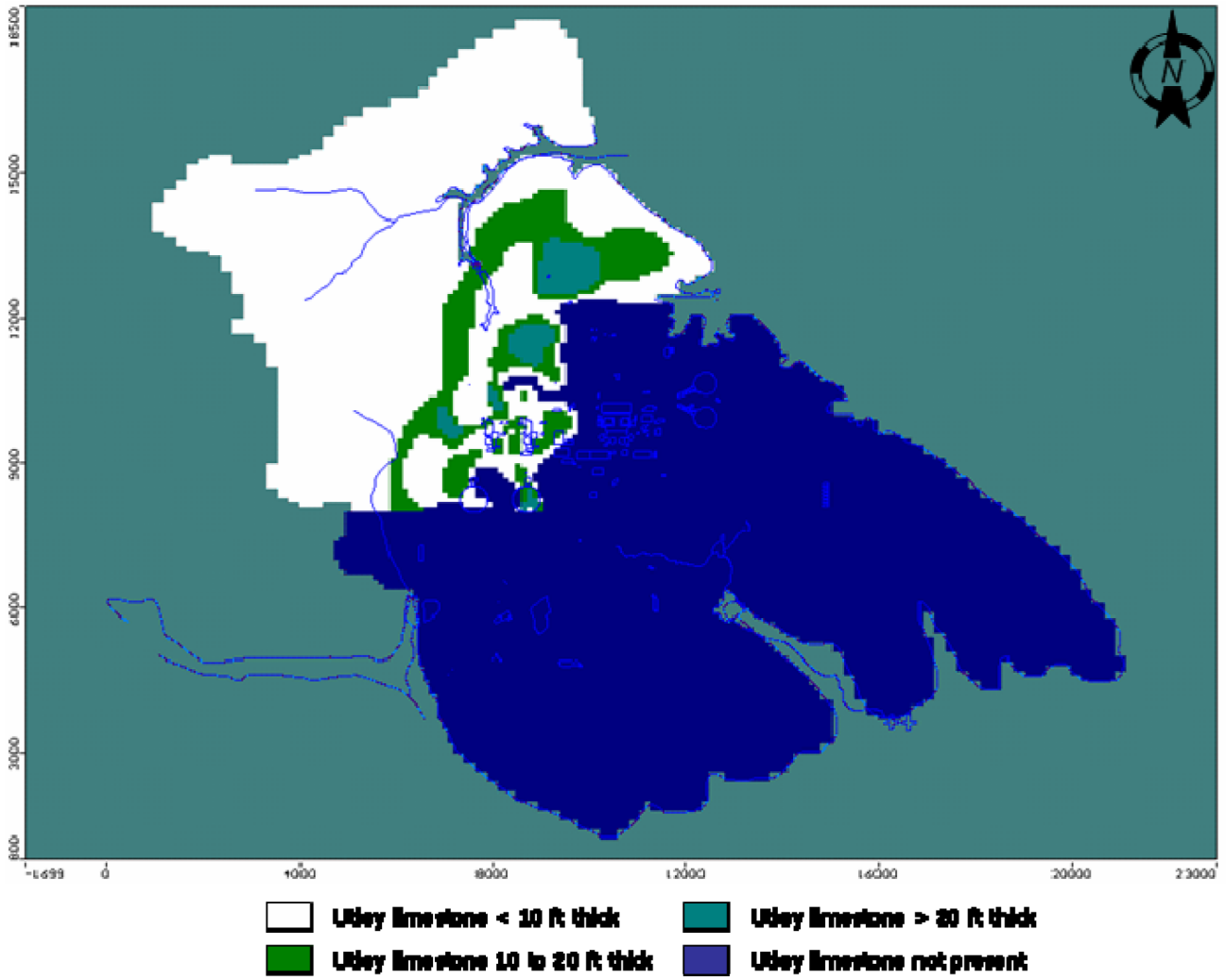


Figure 29: Model 3, Run 305 - Hydraulic Conductivity Zones Accounting for the Presence of the Utley Limestone (K_1=27; K_2=20; K_3=30; K_4=60 ft/day)

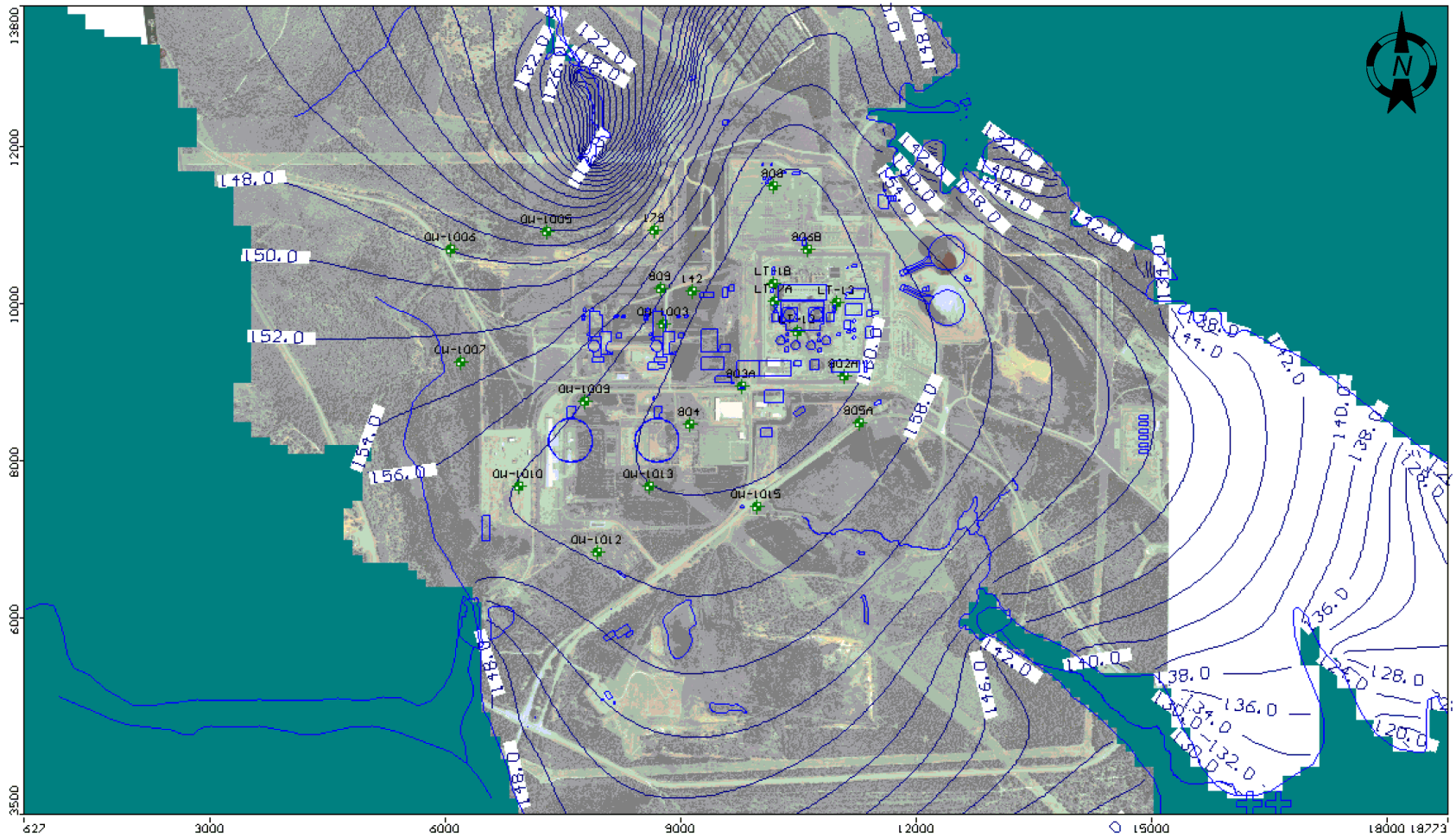


Figure 30: Model 3 - Simulated Water Levels for Run 305
(K_1=27; K_2=20; K_3=30; K_4=60 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

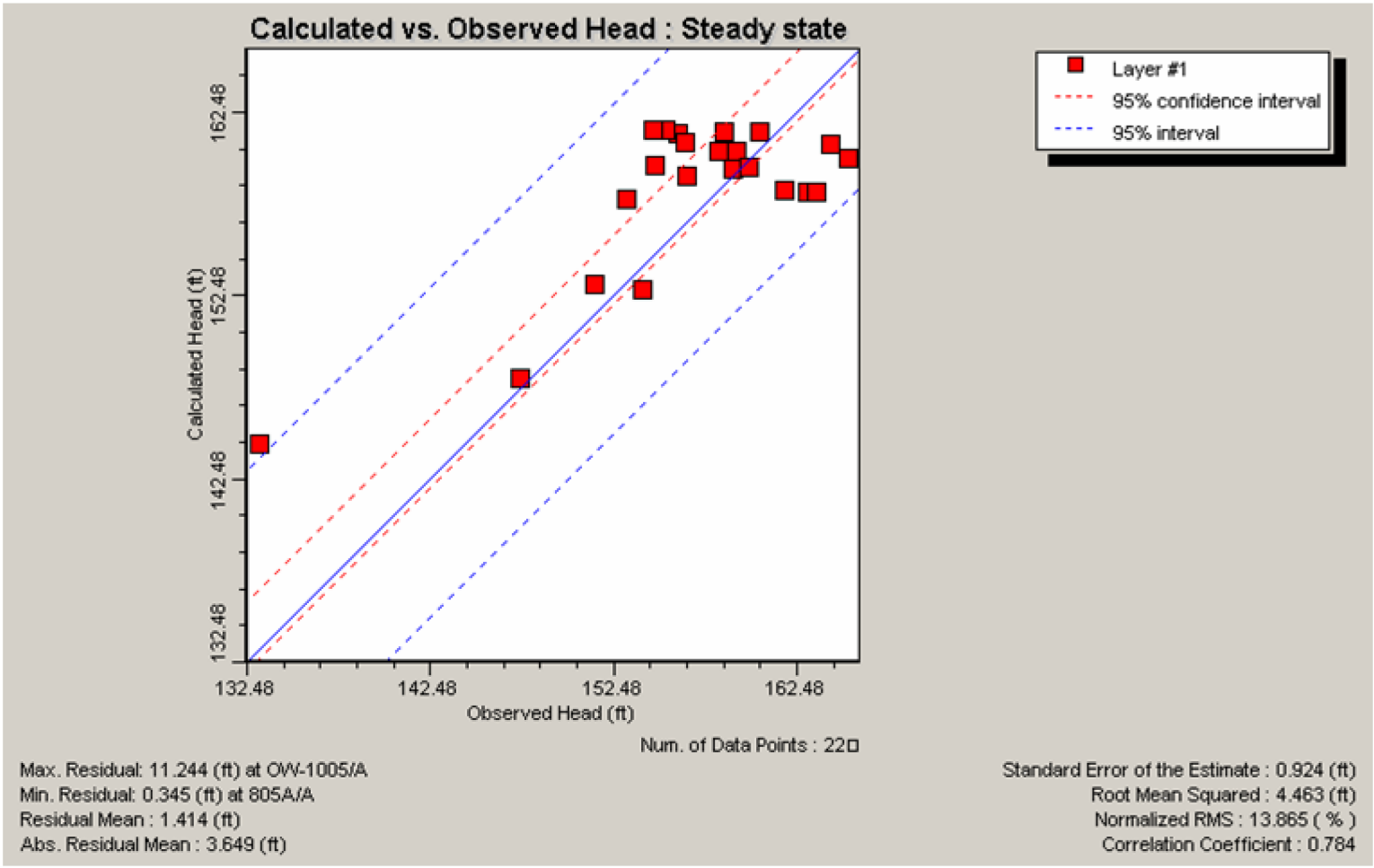


Figure 31: Model 3 - Simulated Vs. Observed Water Levels for Run 305 (K_1=27; K_2=20; K_3=30; K_4=60 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

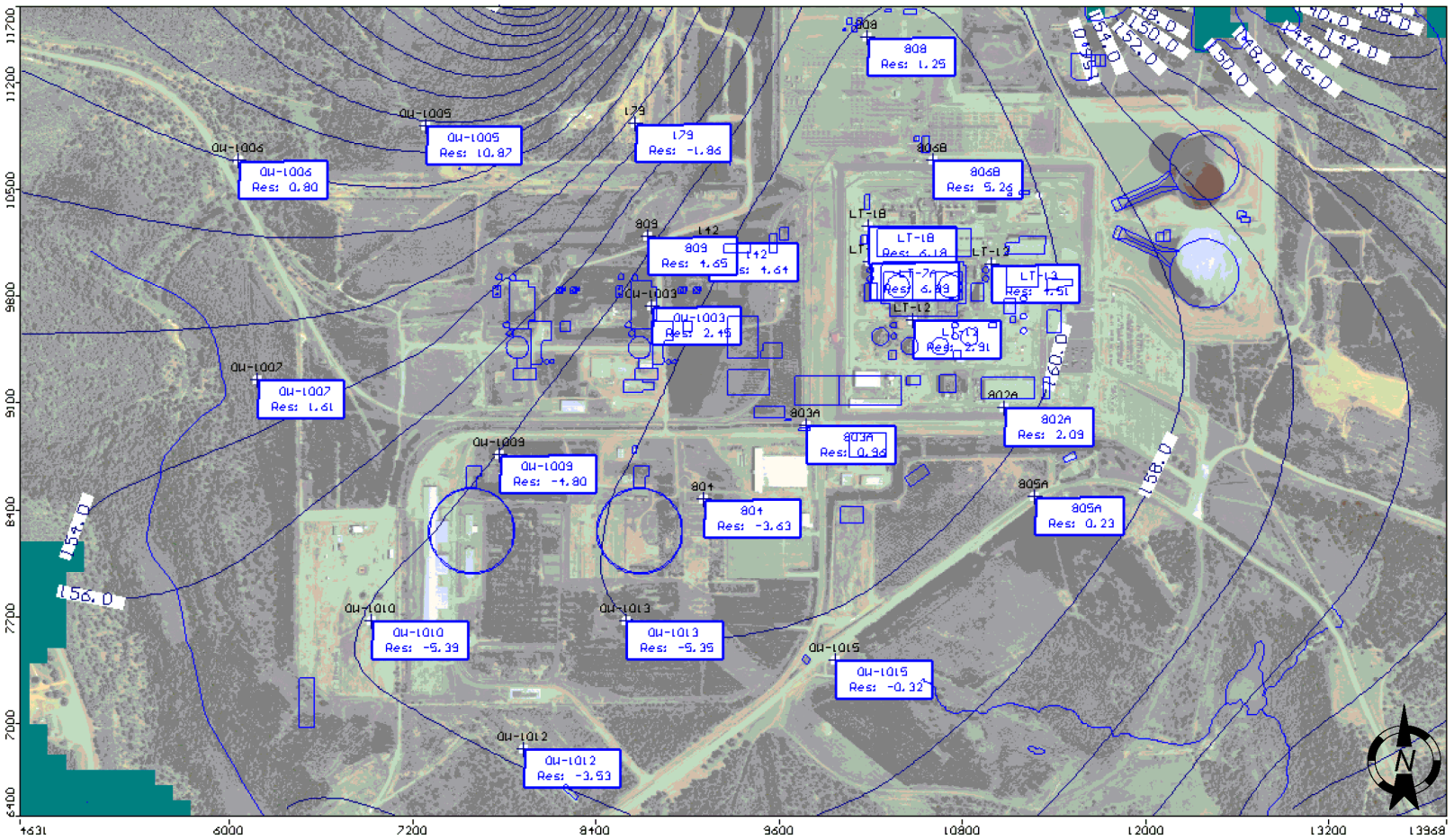


Figure 32: Model 3 - Estimated Residuals for Run 305
(K_1=27; K_2=20; K_3=30; K_4=60 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

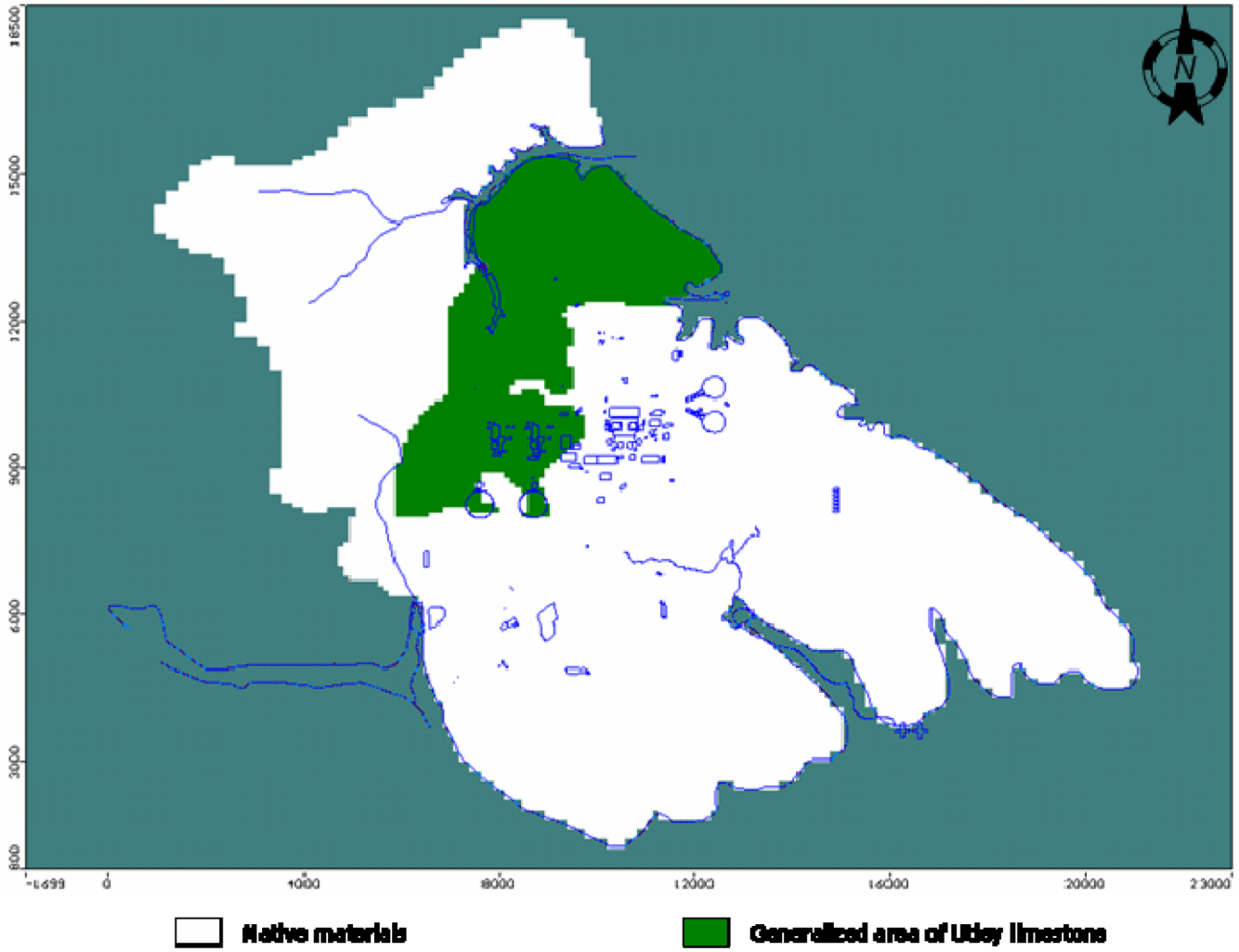


Figure 33: Model 4, Run 403 – Simplified Hydraulic Conductivity Zones Accounting for the Presence of the Utley Limestone (K_1=20; K_2=35 ft/day)

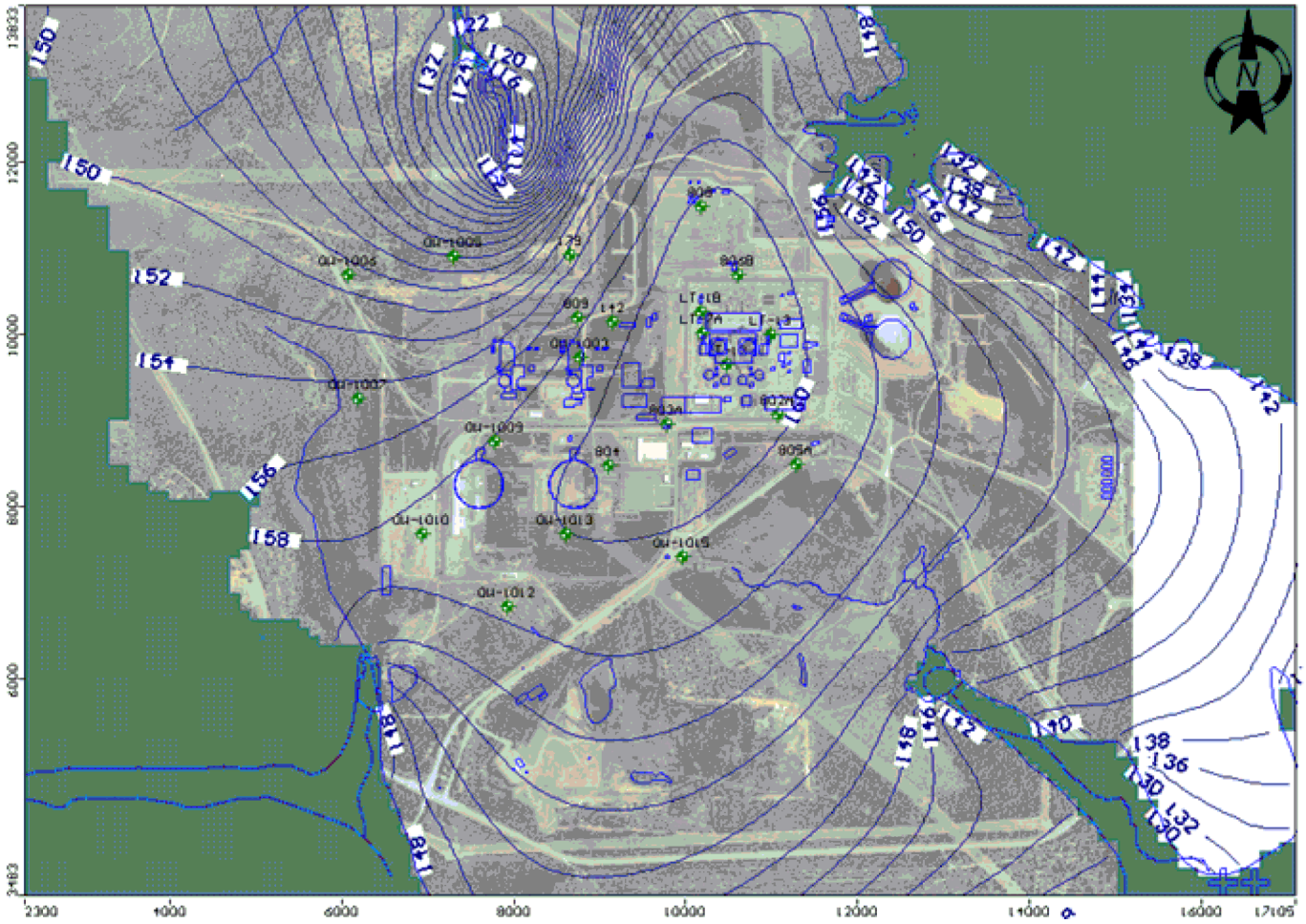


Figure 34: Model 4- Simulated Water Levels for Run 403 (K_1=20; K_2=35 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

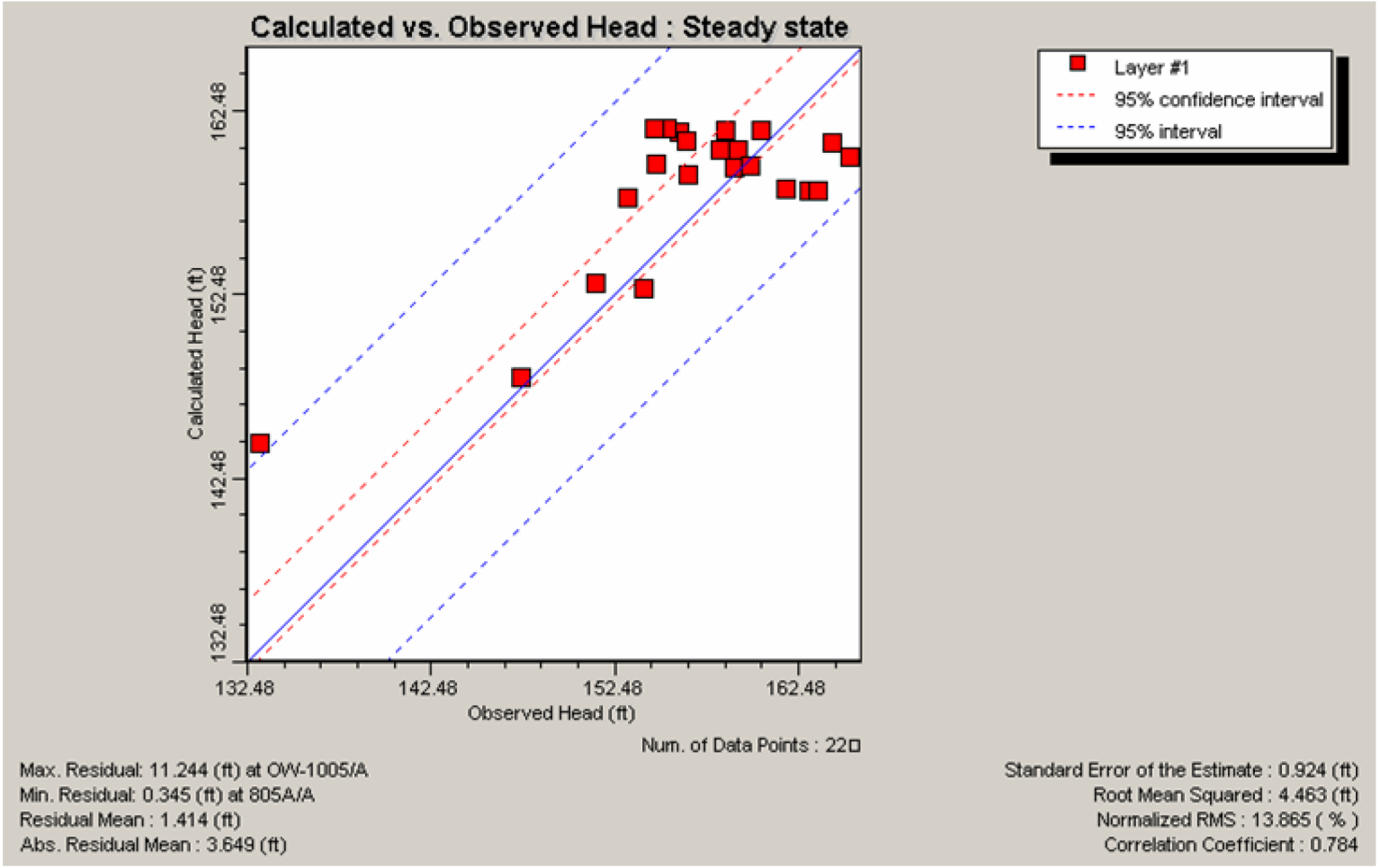


Figure 35: Model 4- Simulated Vs. Observed Water Levels for Run 403 (K_1=20; K_2=35 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

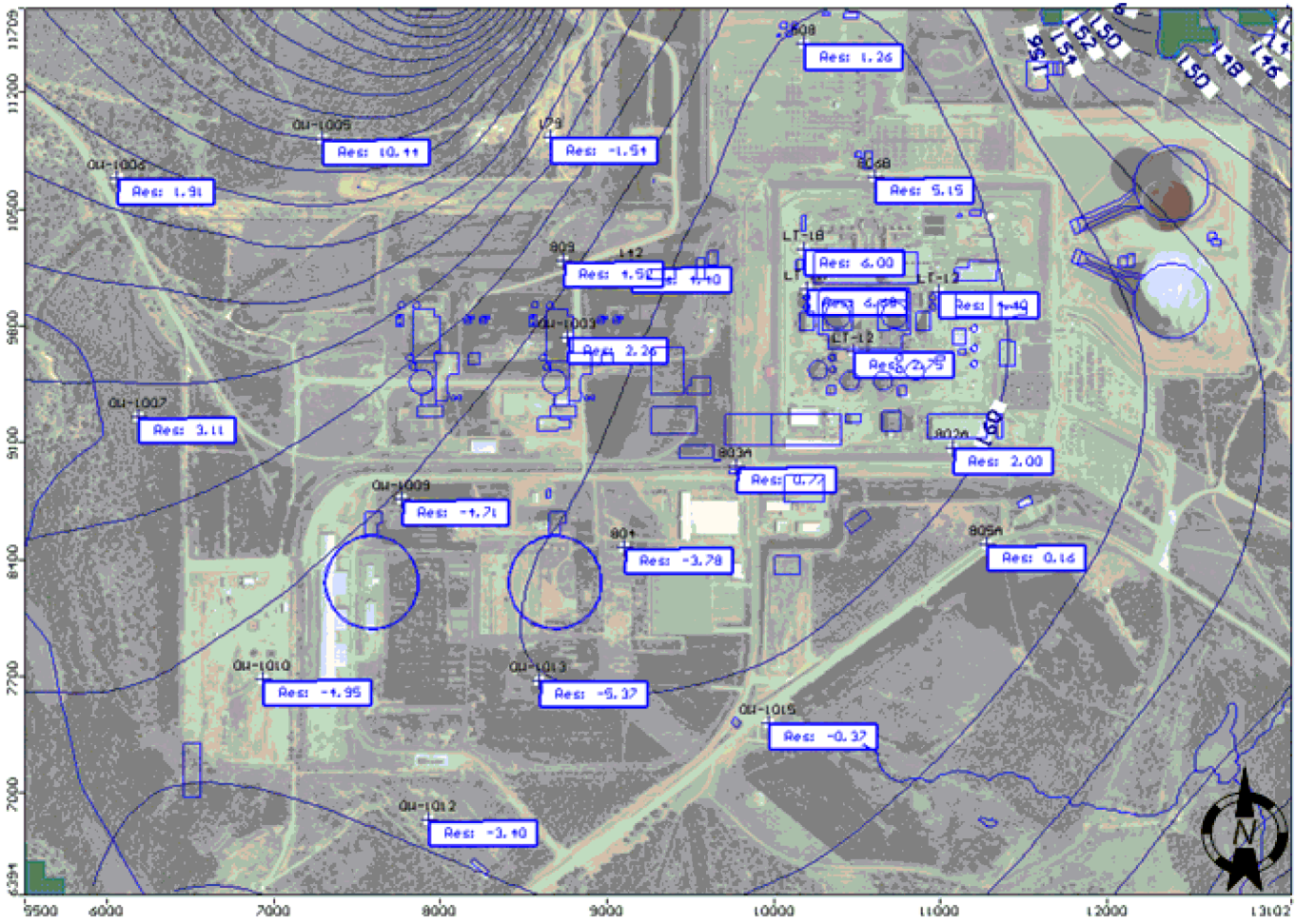


Figure 36: Model 4- Estimated Residuals for Run 403 (K_1=20; K_2=35 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

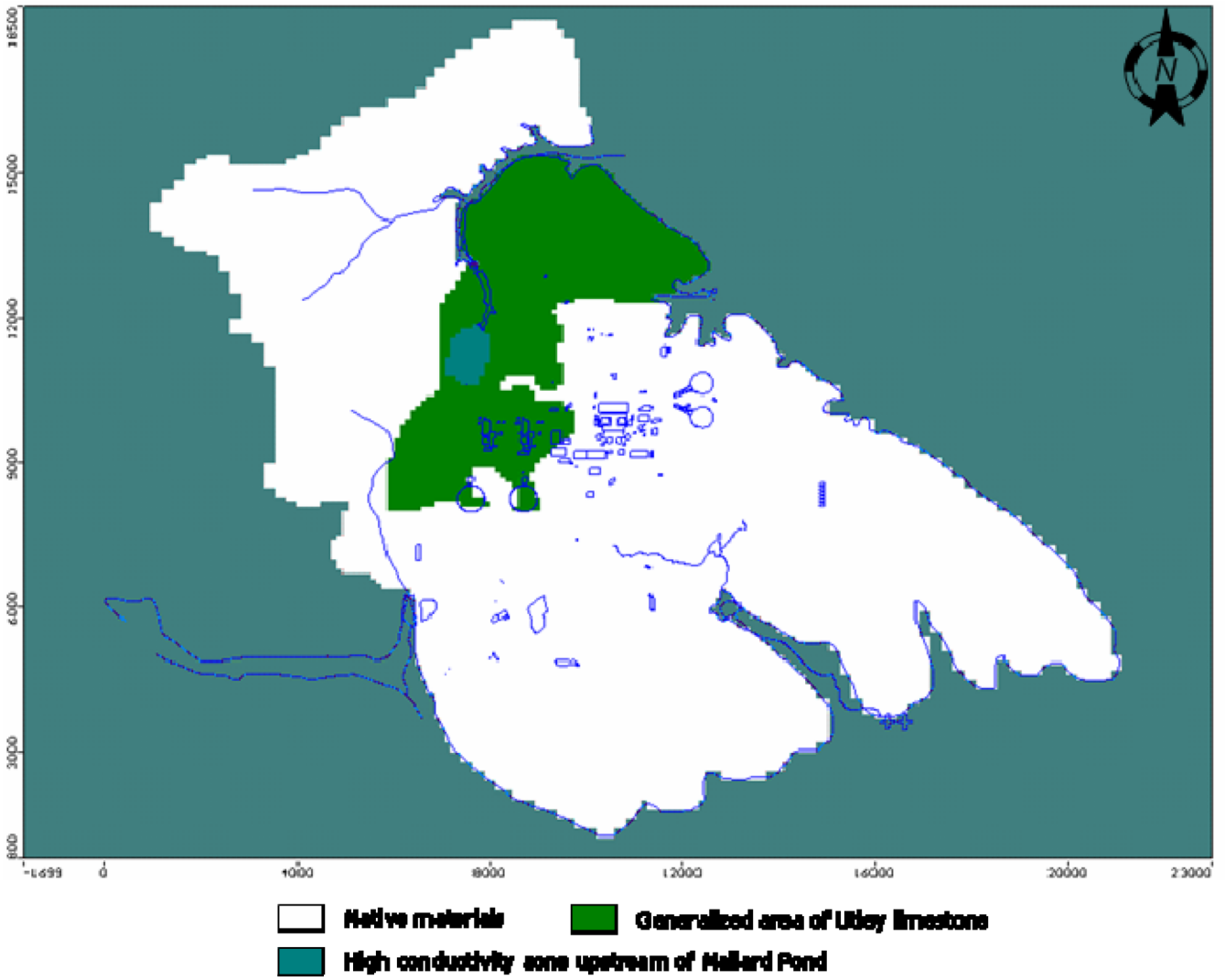


Figure 37: Model 5, Run 504 – Hydraulic Conductivity Zones as for Model 4 and a High Conductivity Zone Upstream of Mallard Pond (K_1=20; K_2=35; K_3=100 ft/day)

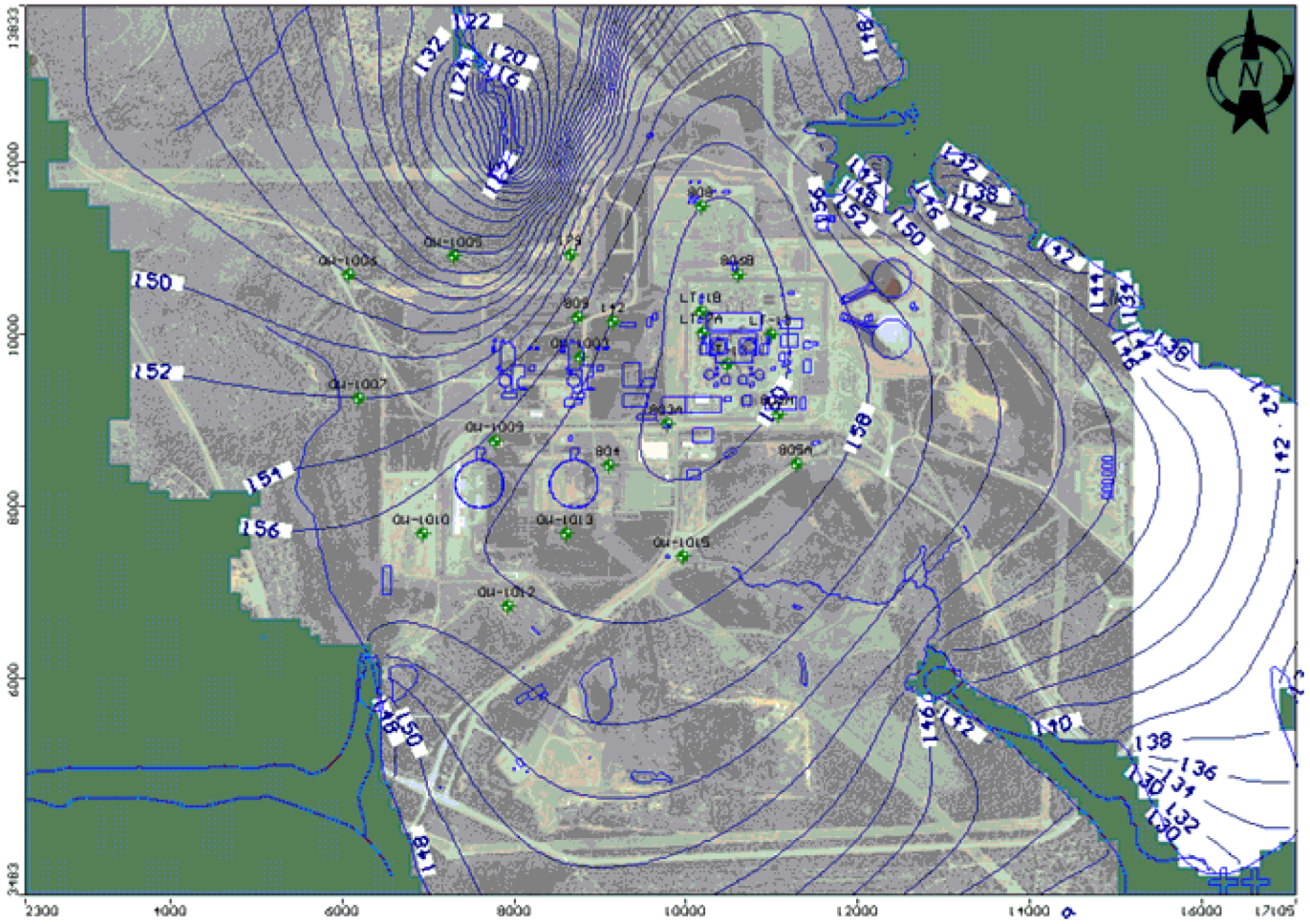


Figure 38: Model 5- Simulated Water Levels for Run 504
(K_1=20; K_2=35; K_3=100 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

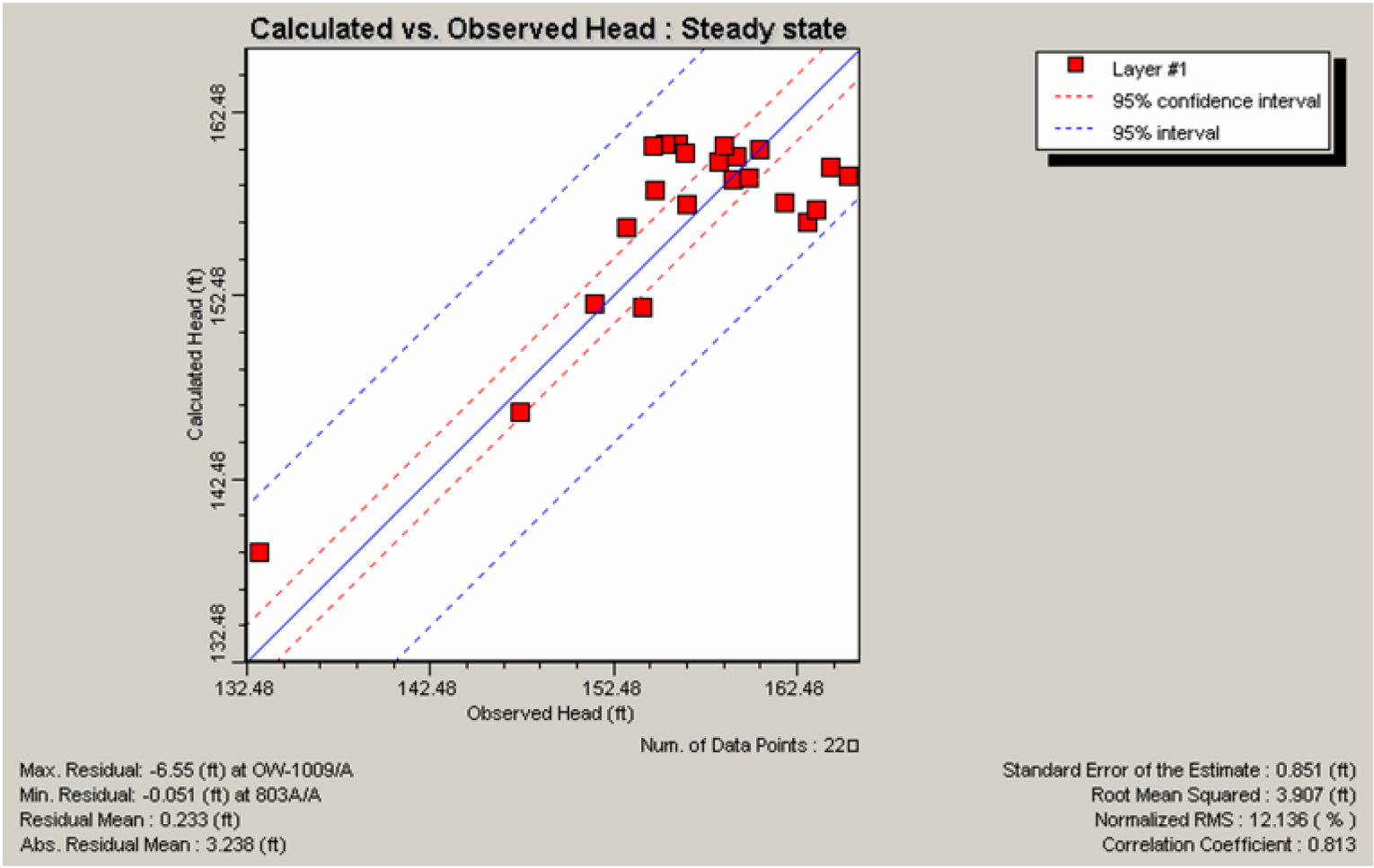


Figure 39: Model 5- Simulated Vs. Observed Water Levels for Run 504 (K_1=20; K_2=35; K_3=100 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

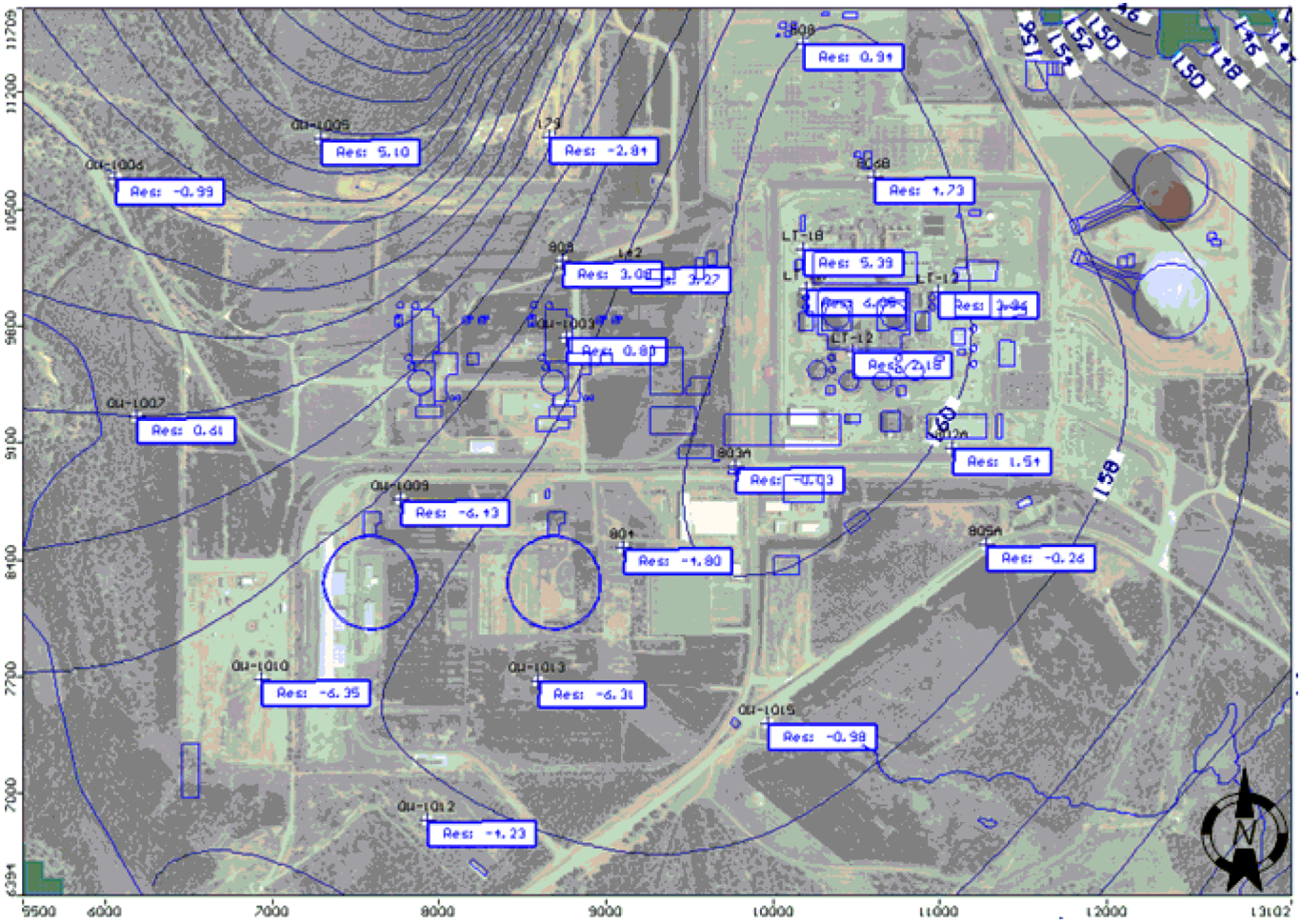


Figure 40: Model 5- Estimated Residuals for Run 504
(K_1=20; K_2=35; K_3=100 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

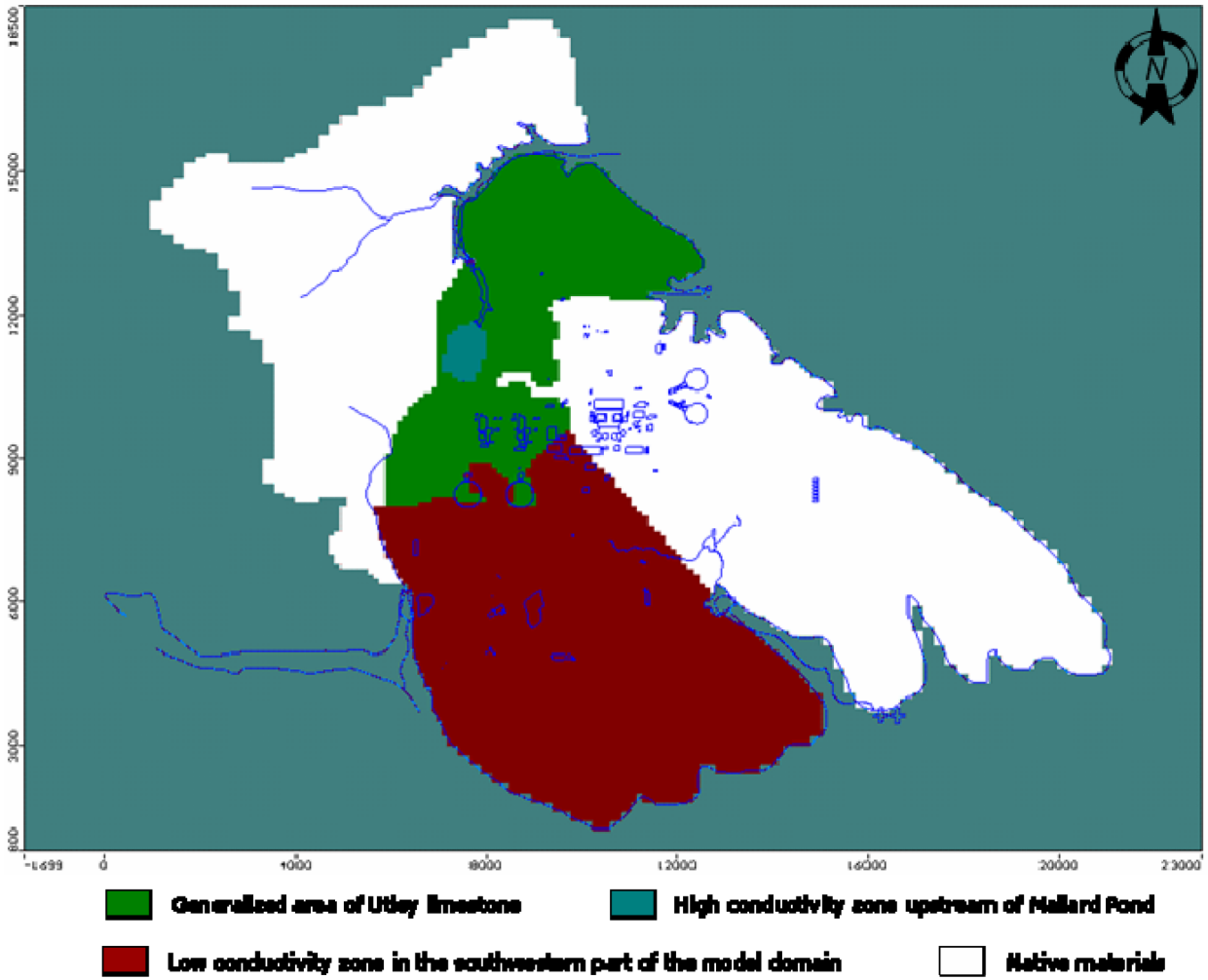


Figure 41: Model 6, Run 612 – Hydraulic Conductivity Zones as for Model 5 and a Low Conductivity Zone in the Southwestern Quarter of the Model (K_1=28; K_2=33; K_3=200; K_4=8 ft/day)

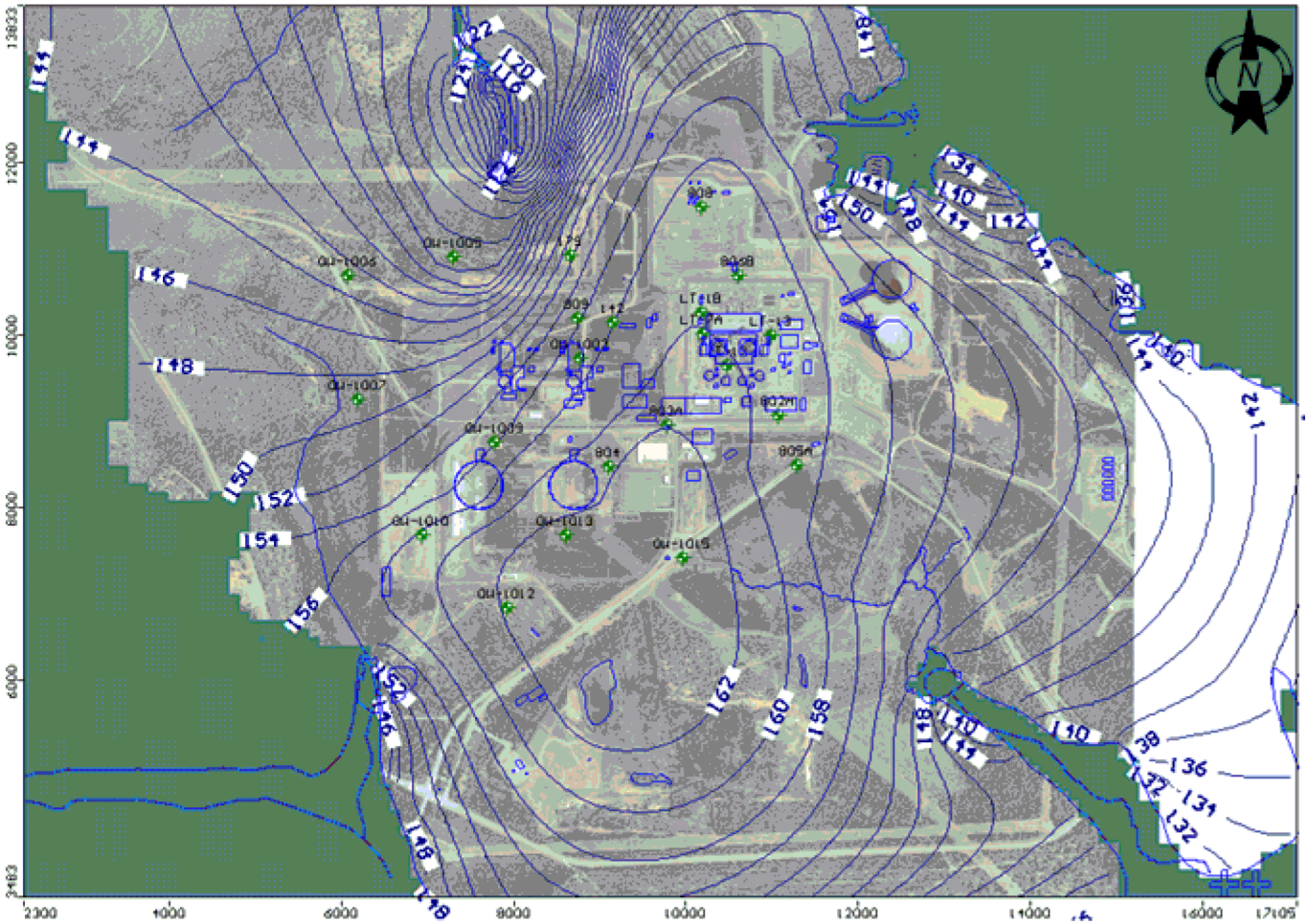


Figure 42: Model 6 - Simulated Water Levels for Run 612
(K_1=28; K_2=33; K_3=200; K_4=8 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

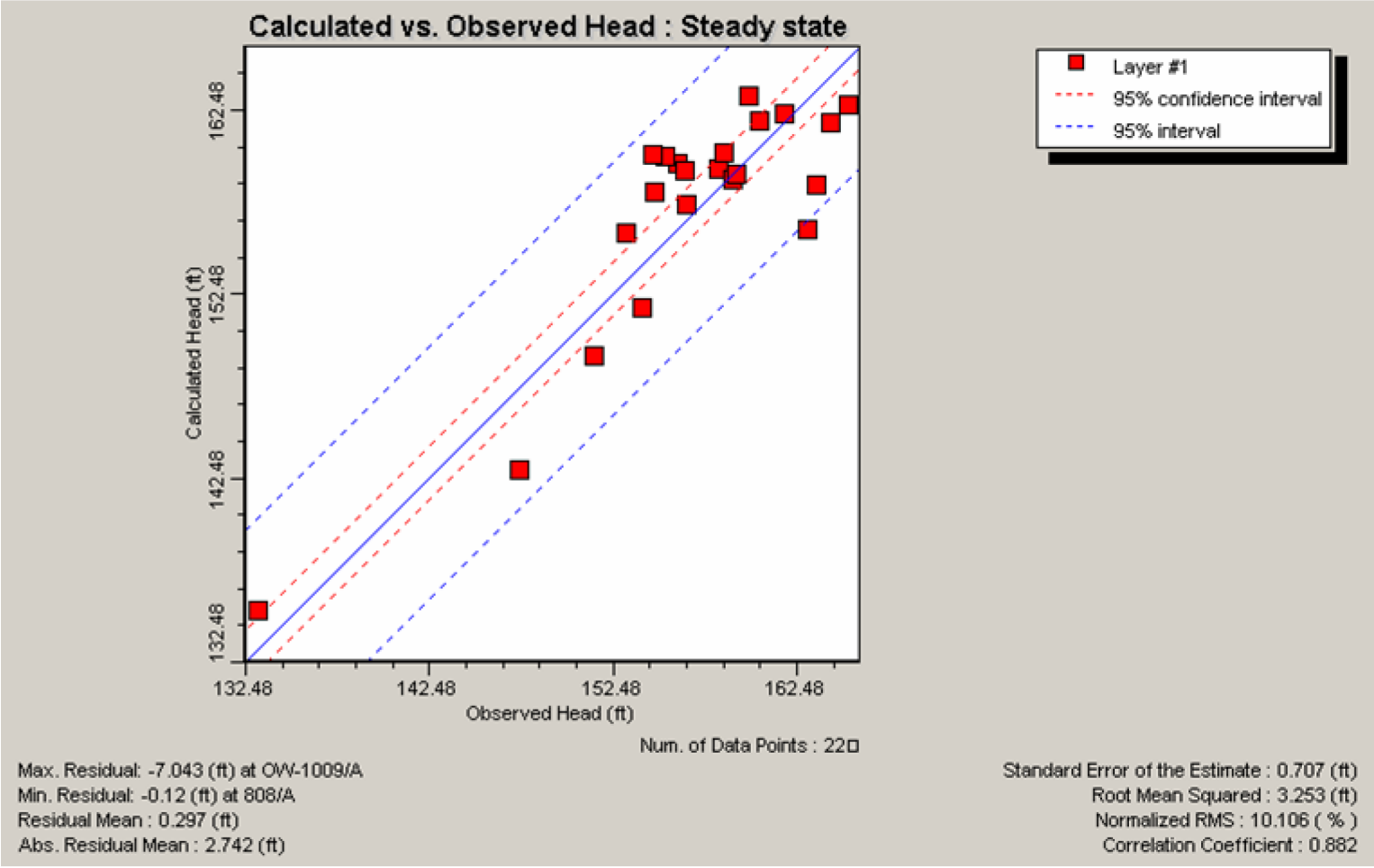


Figure 43: Model 6 - Simulated Vs. Observed Water Levels for Run 612 (K_1=28; K_2=33; K_3=200; K_4=8 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

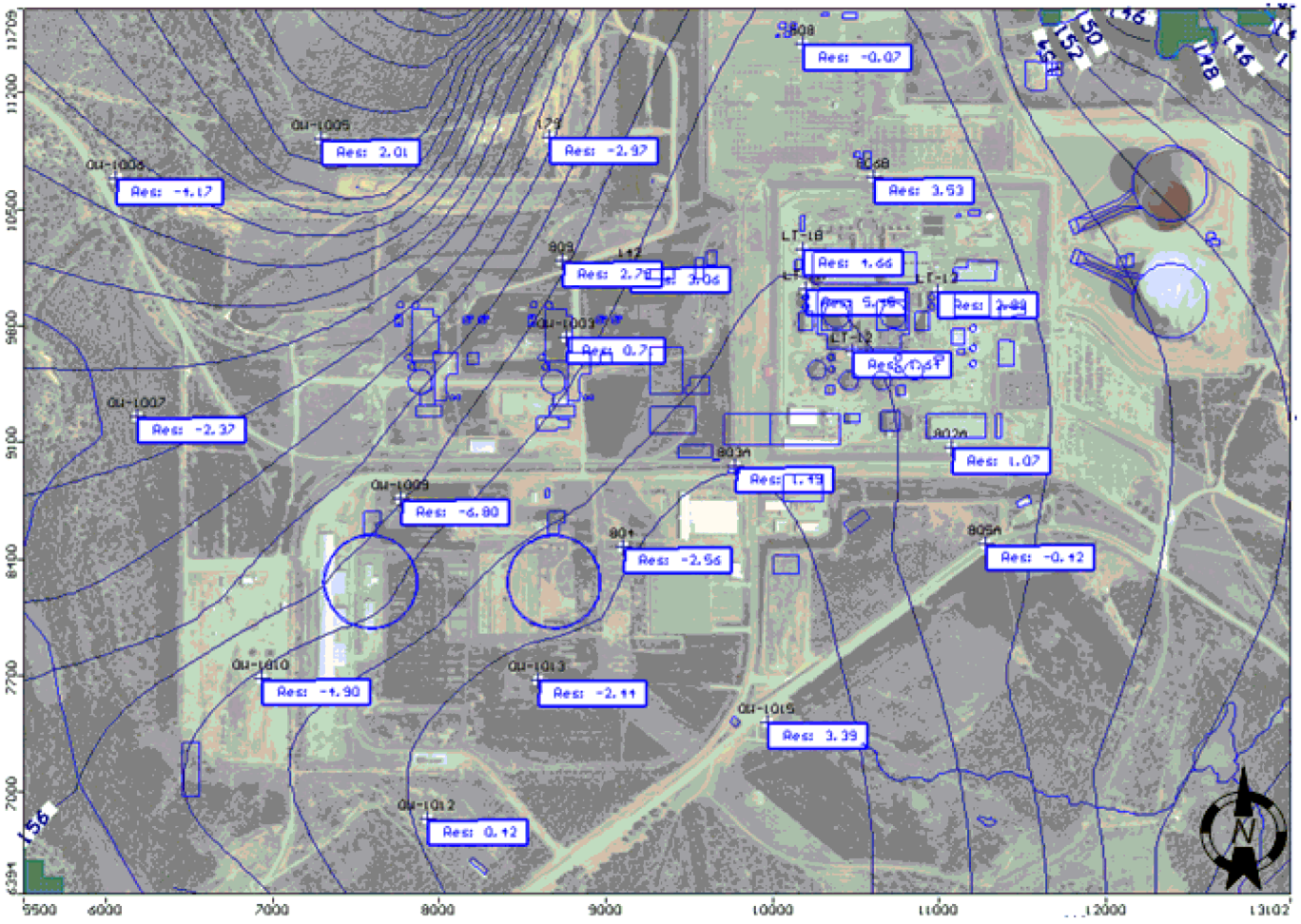


Figure 44: Model 6- Estimated Residuals for Run 612
(K_1=28; K_2=33; K_3=200; K_4=8 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

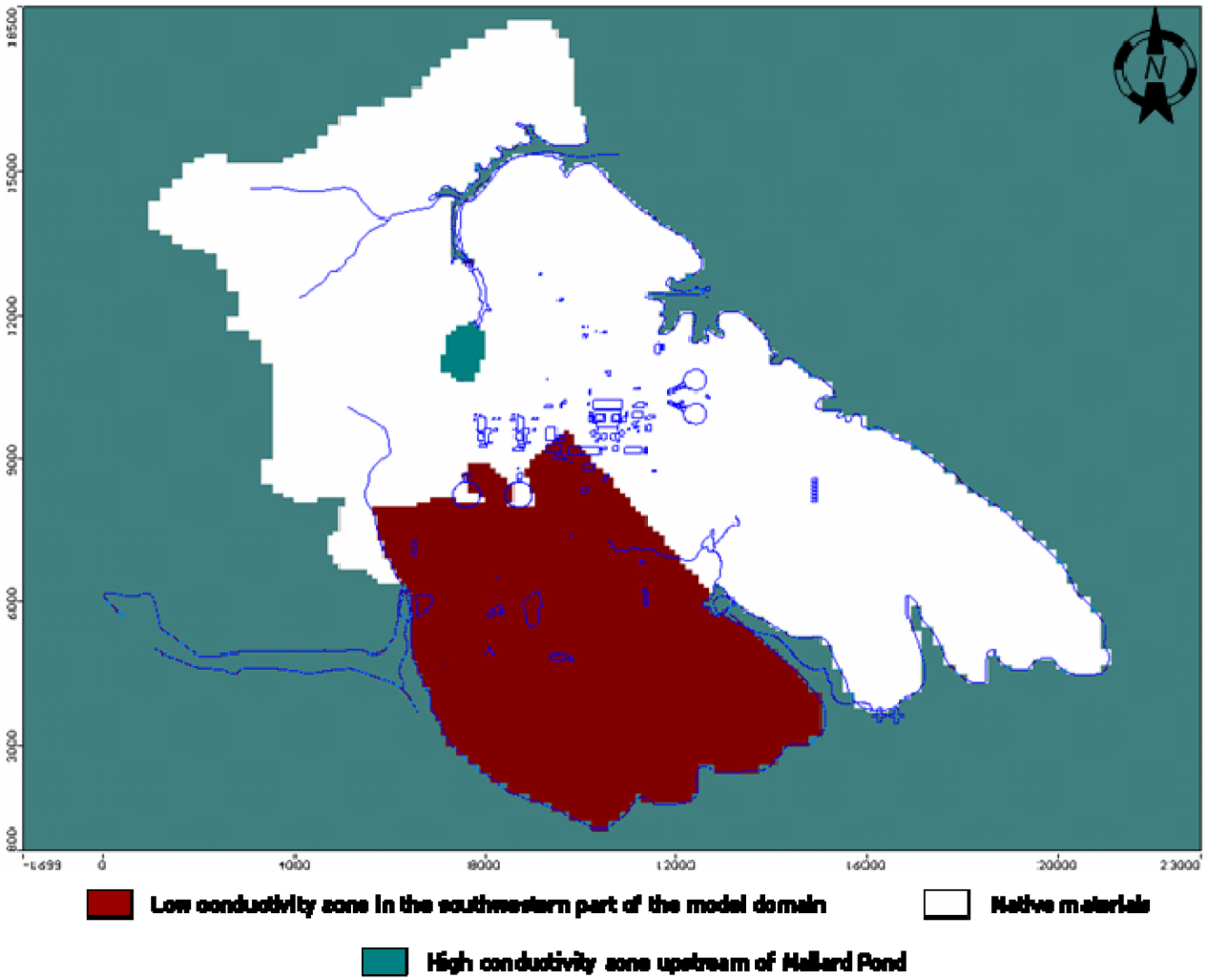


Figure 45: Model 7, Run 708 – Simplified Version of Model 6 (K_1=32; K_2=100; K_3=8 ft/day)

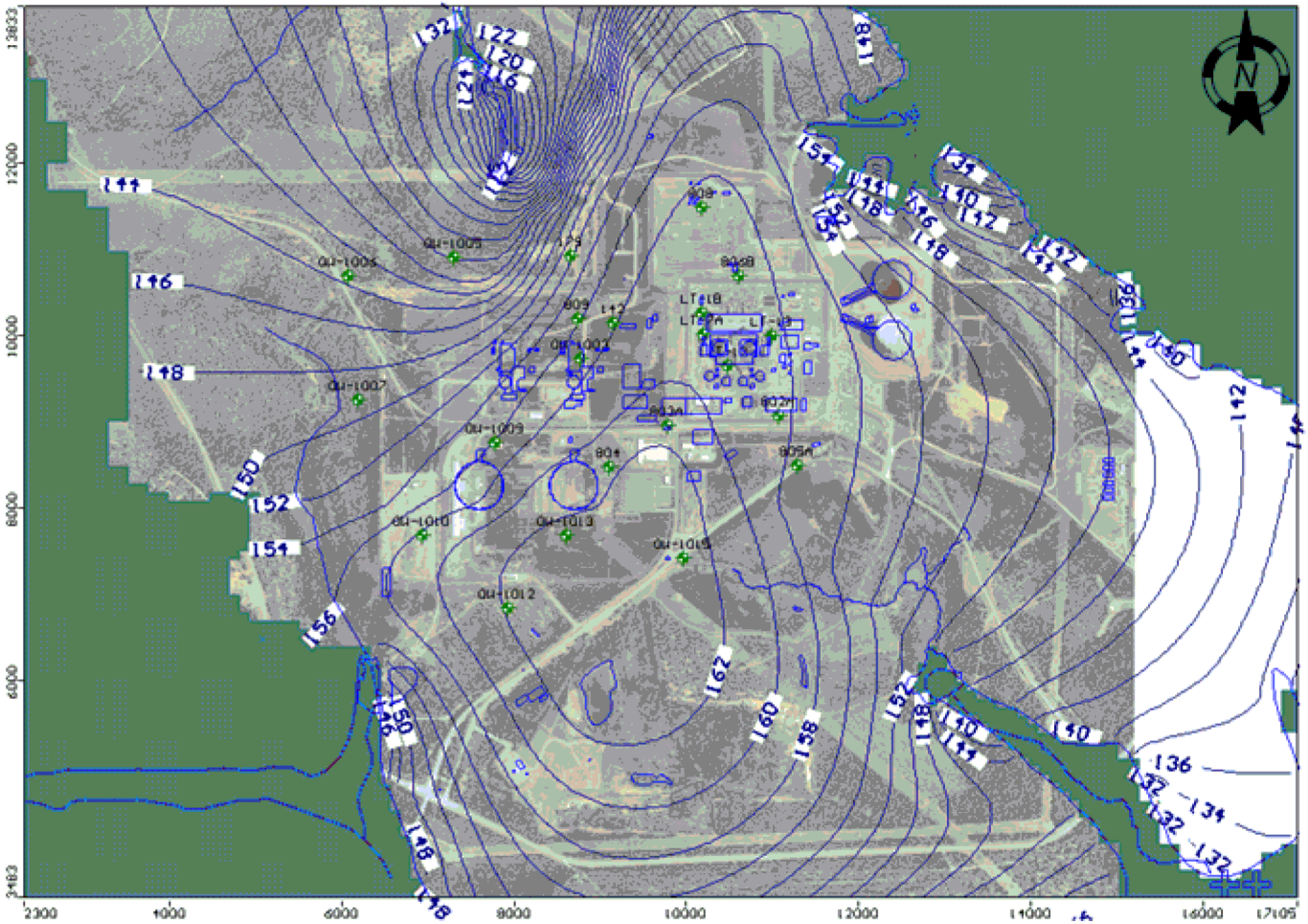


Figure 46: Model 7 - Simulated Water Levels for Run 708 (K_1=32; K_2=100; K_3=8 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

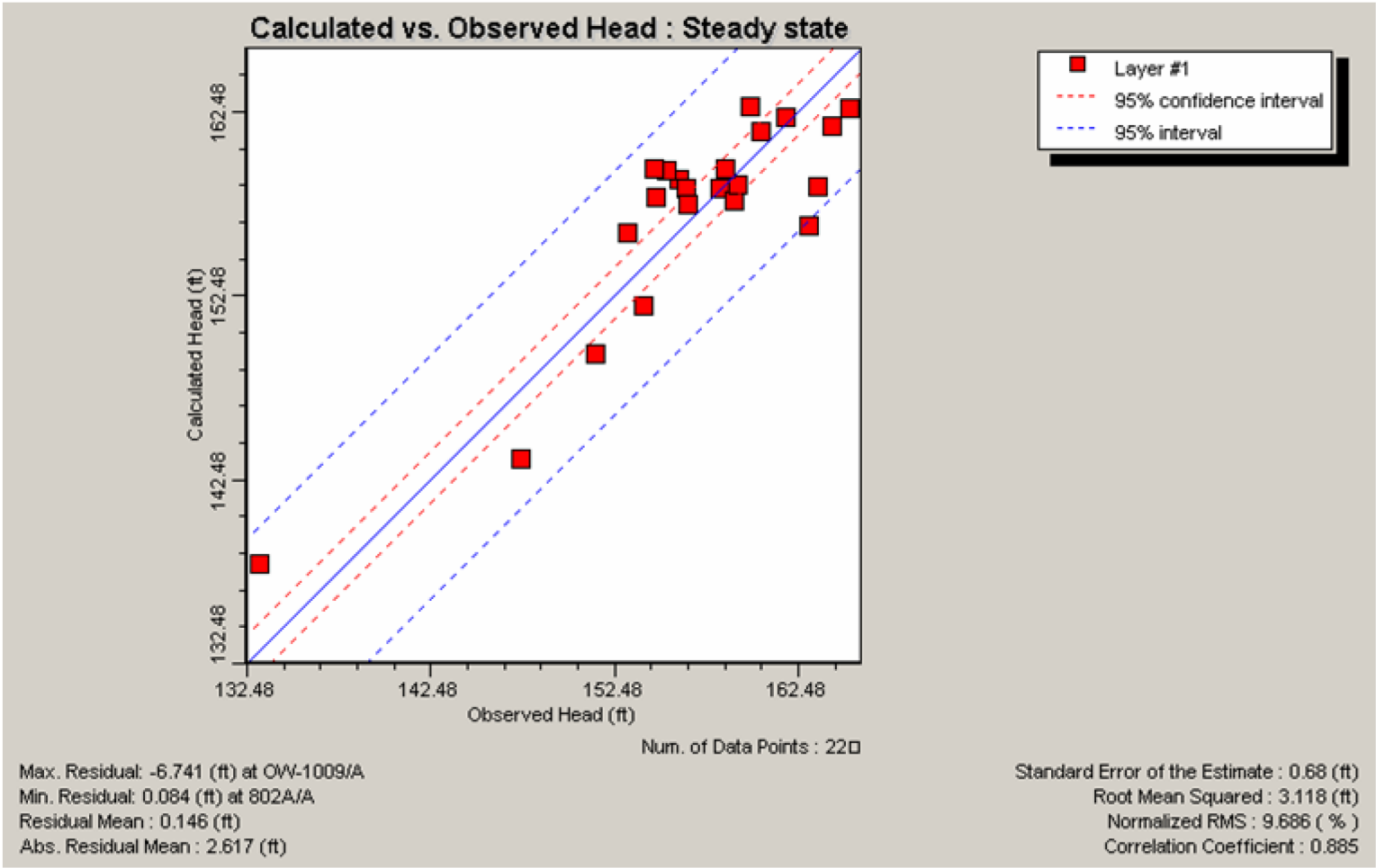


Figure 47: Model 7 - Simulated Vs. Observed Water Levels for Run 708 (K_1=32; K_2=100; K_3=8; ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

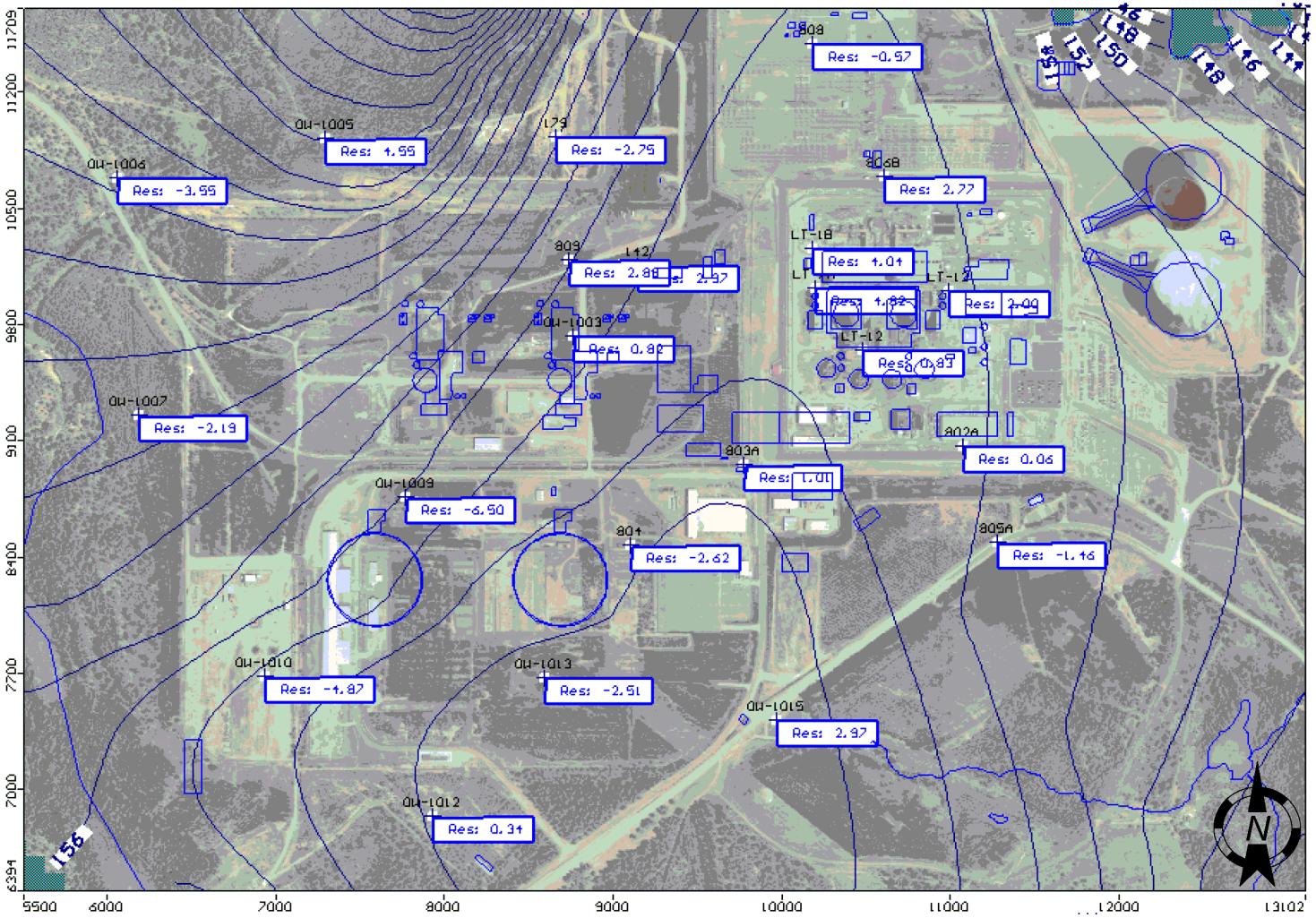


Figure 48: Model 7- Estimated Residuals for Run 708
(K_1=32; K_2=100; K_3=8; ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

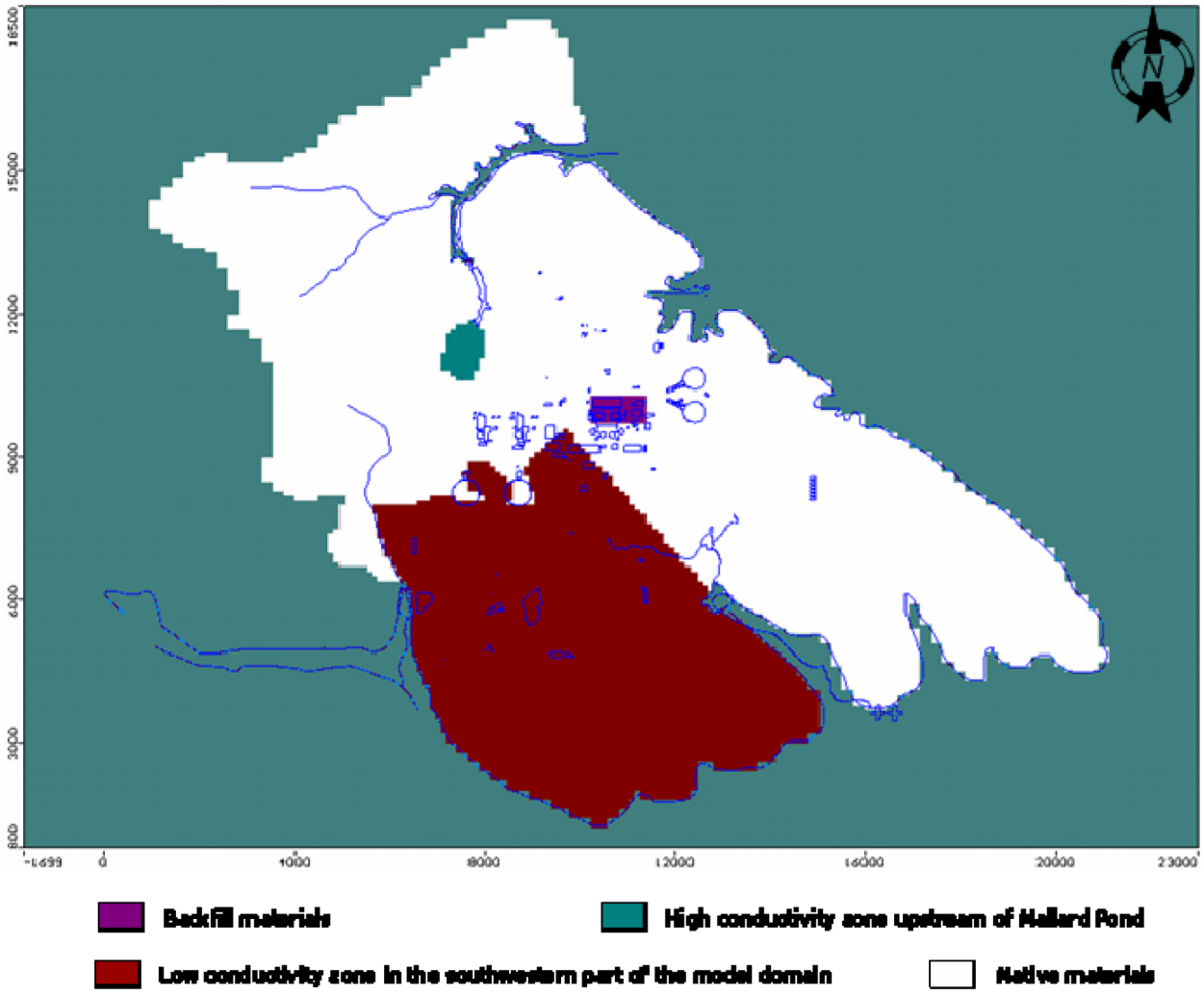


Figure 49: Hydraulic Conductivity Zones Used in Model 7 to Evaluate the Sensitivity of the Model to the Hydraulic Conductivity for the Backfill Material Around Units 1 & 2

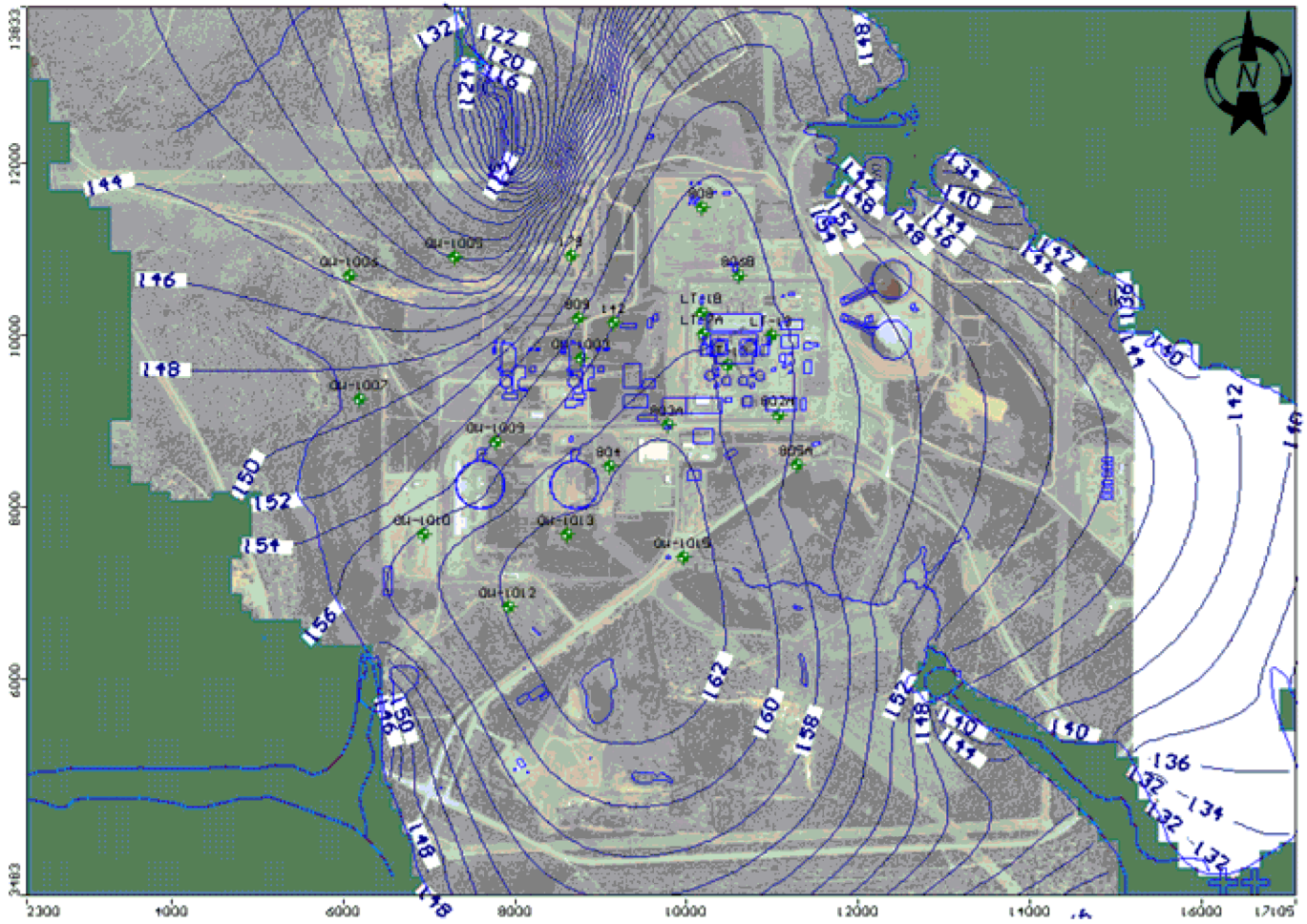


Figure 50: Simulated Water Levels with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

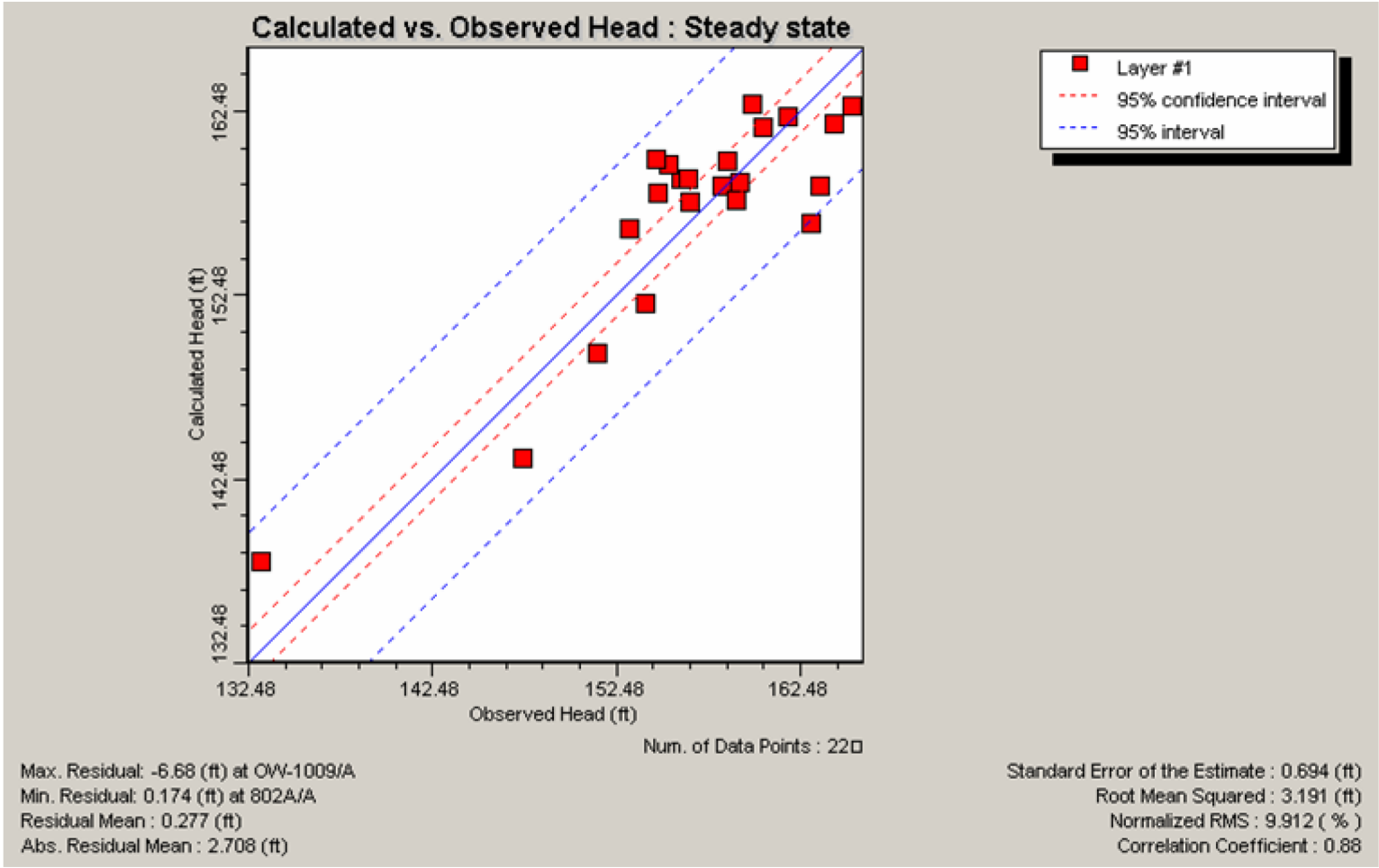


Figure 51: Simulated Versus Observed Water Levels with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

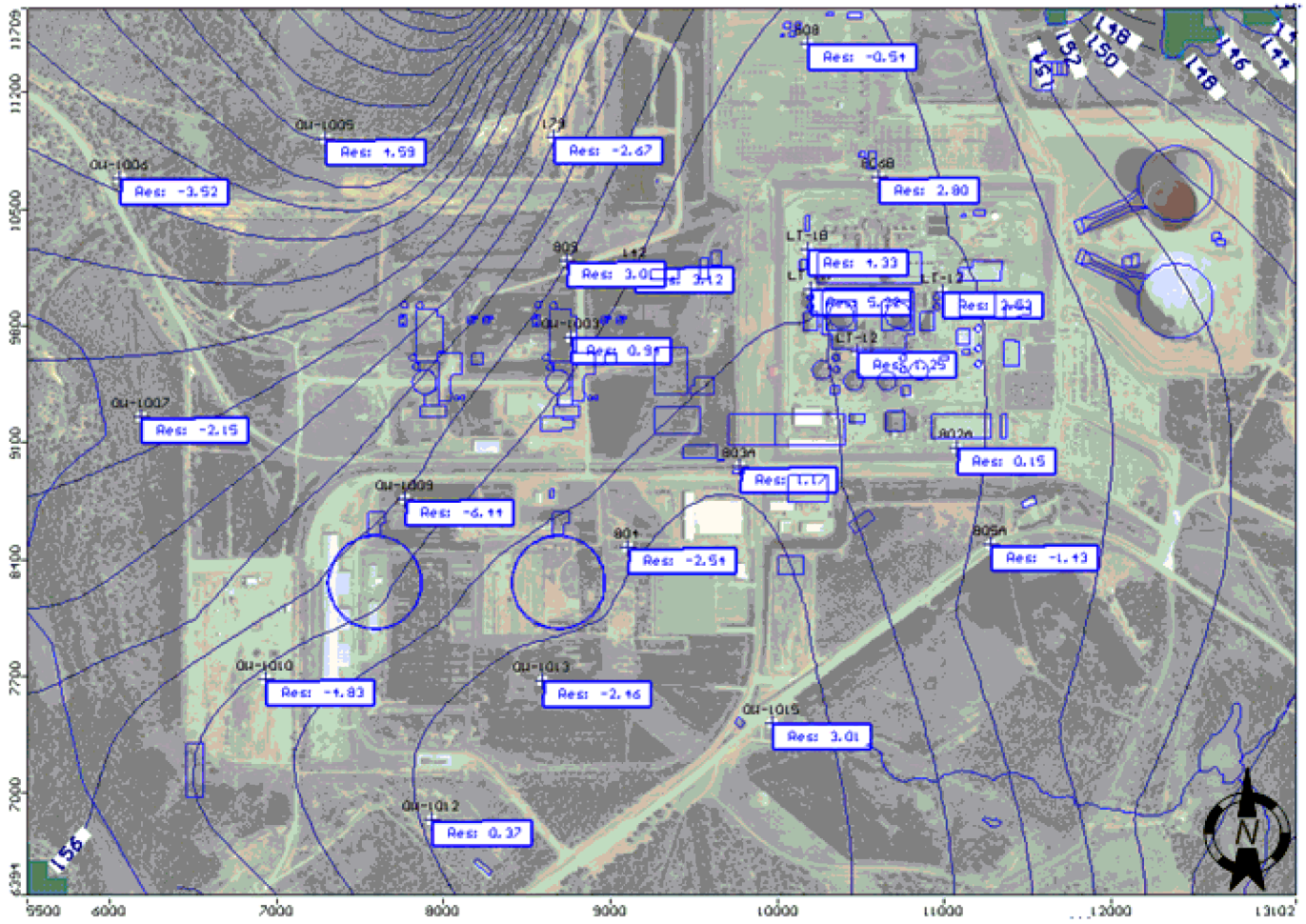


Figure 52: Estimated Residuals with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

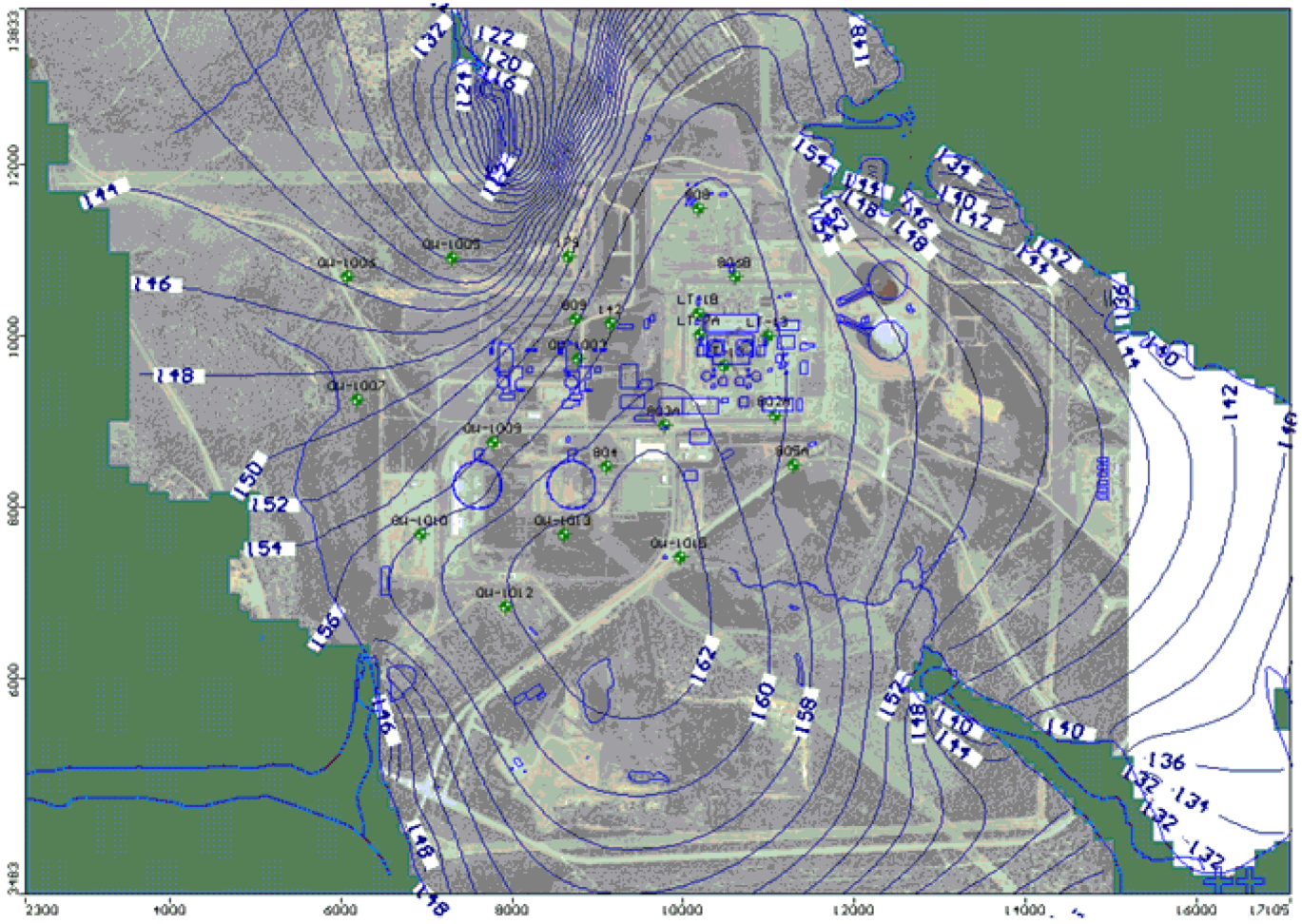


Figure 53: Simulated Water Levels with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 6 in/yr

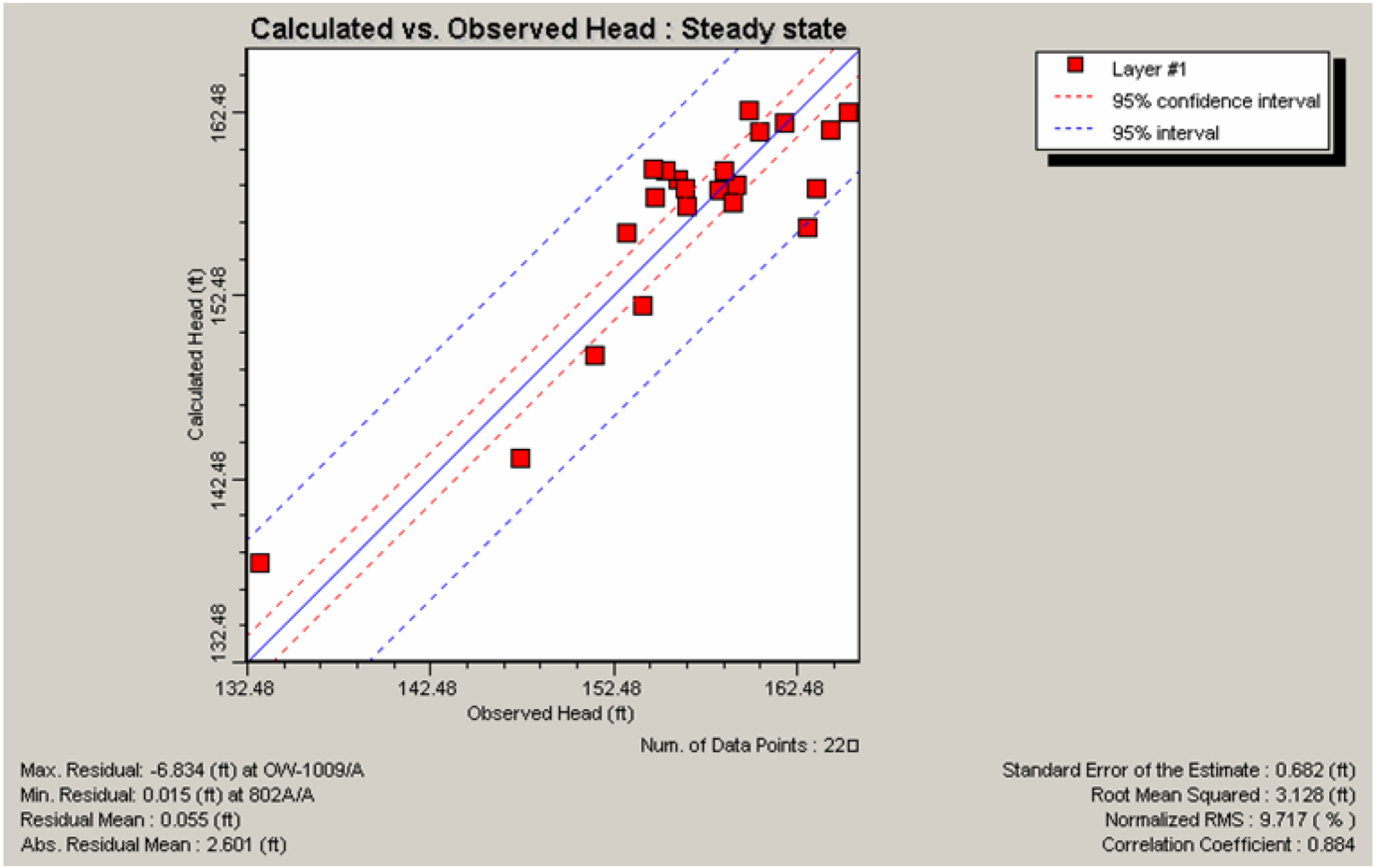


Figure 54: Simulated Versus Observed Water Levels with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 6 in/yr

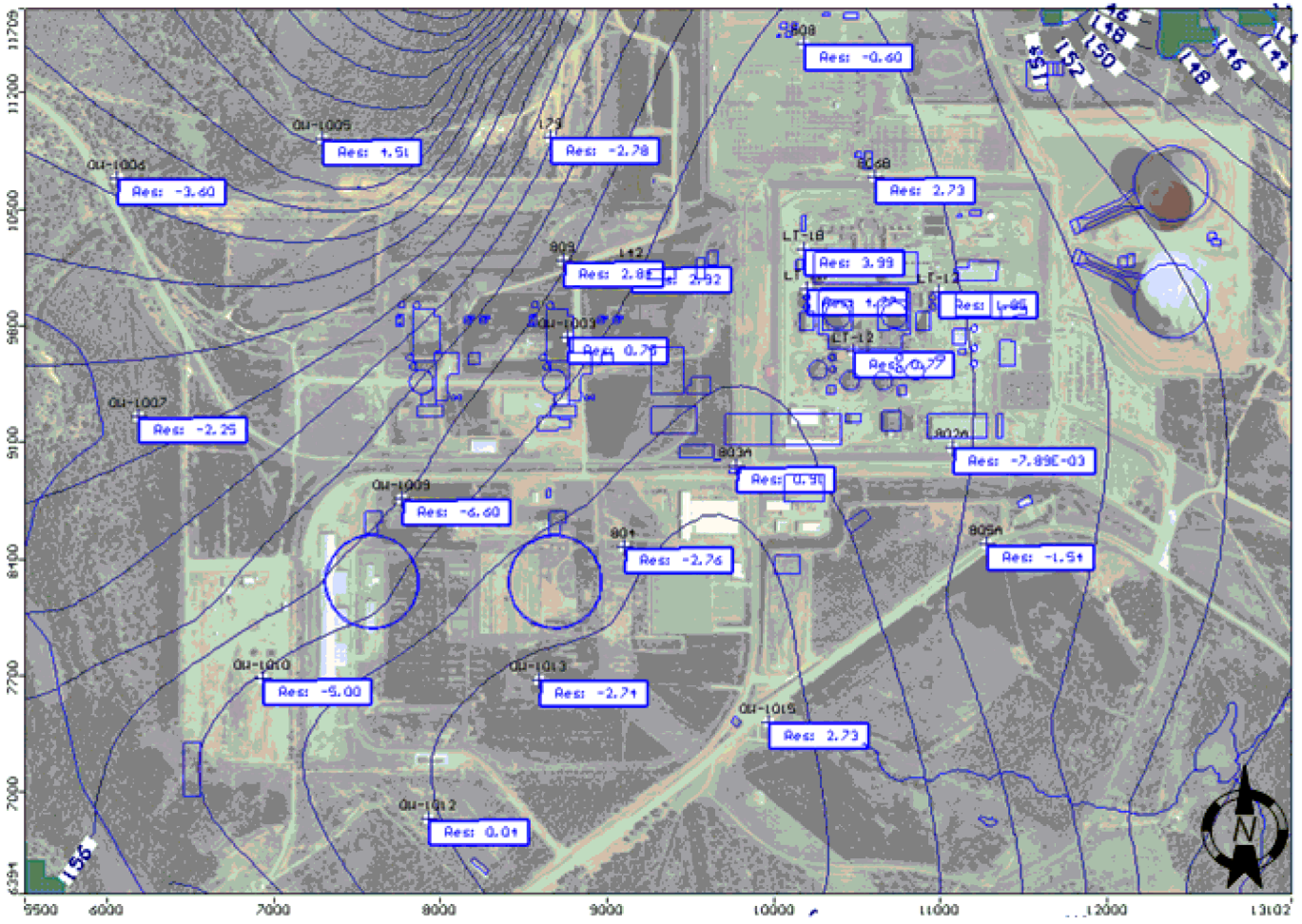


Figure 55: Estimated Residuals with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 6 in/yr

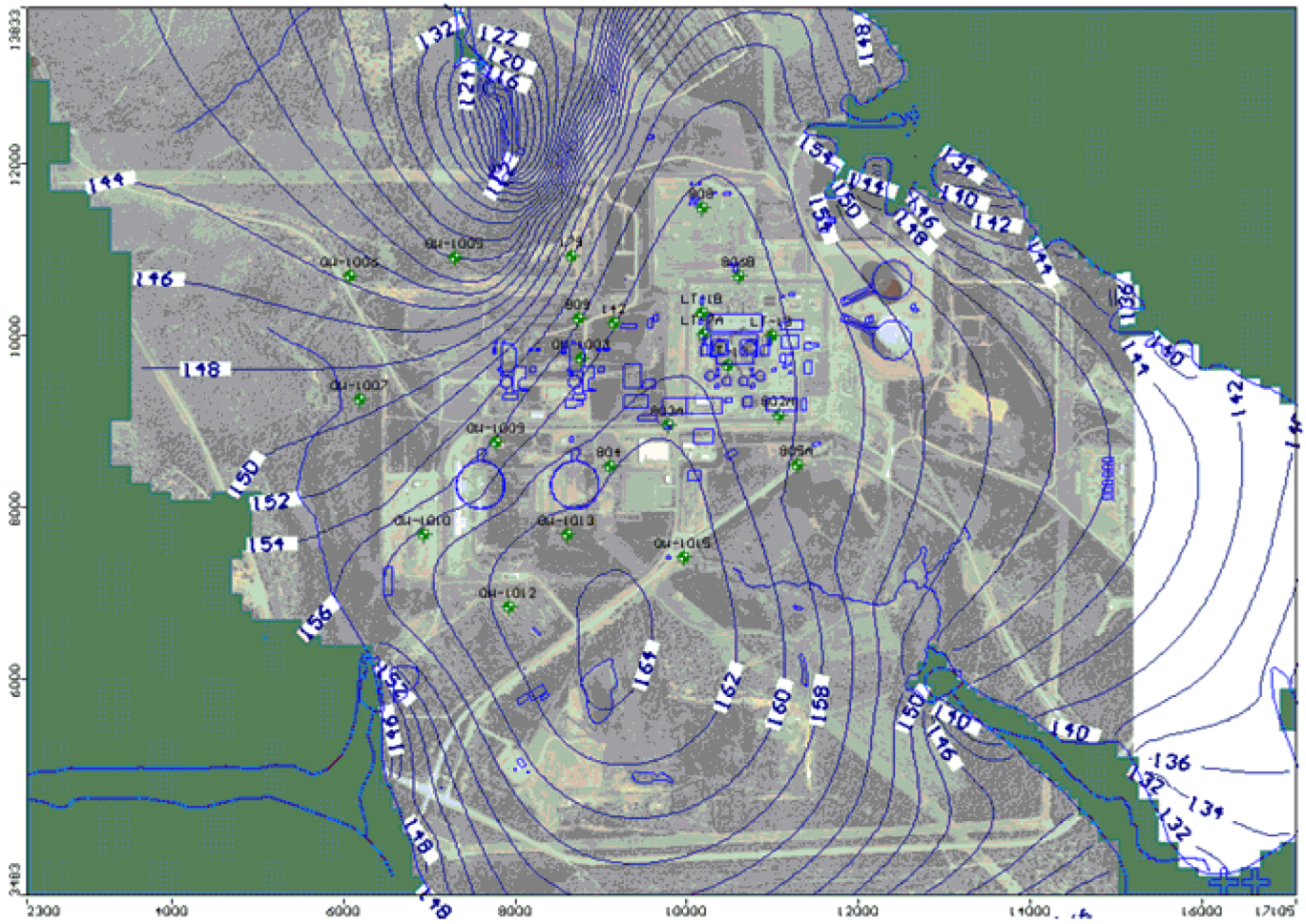


Figure 56: Simulated Water Levels with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 40 in/yr

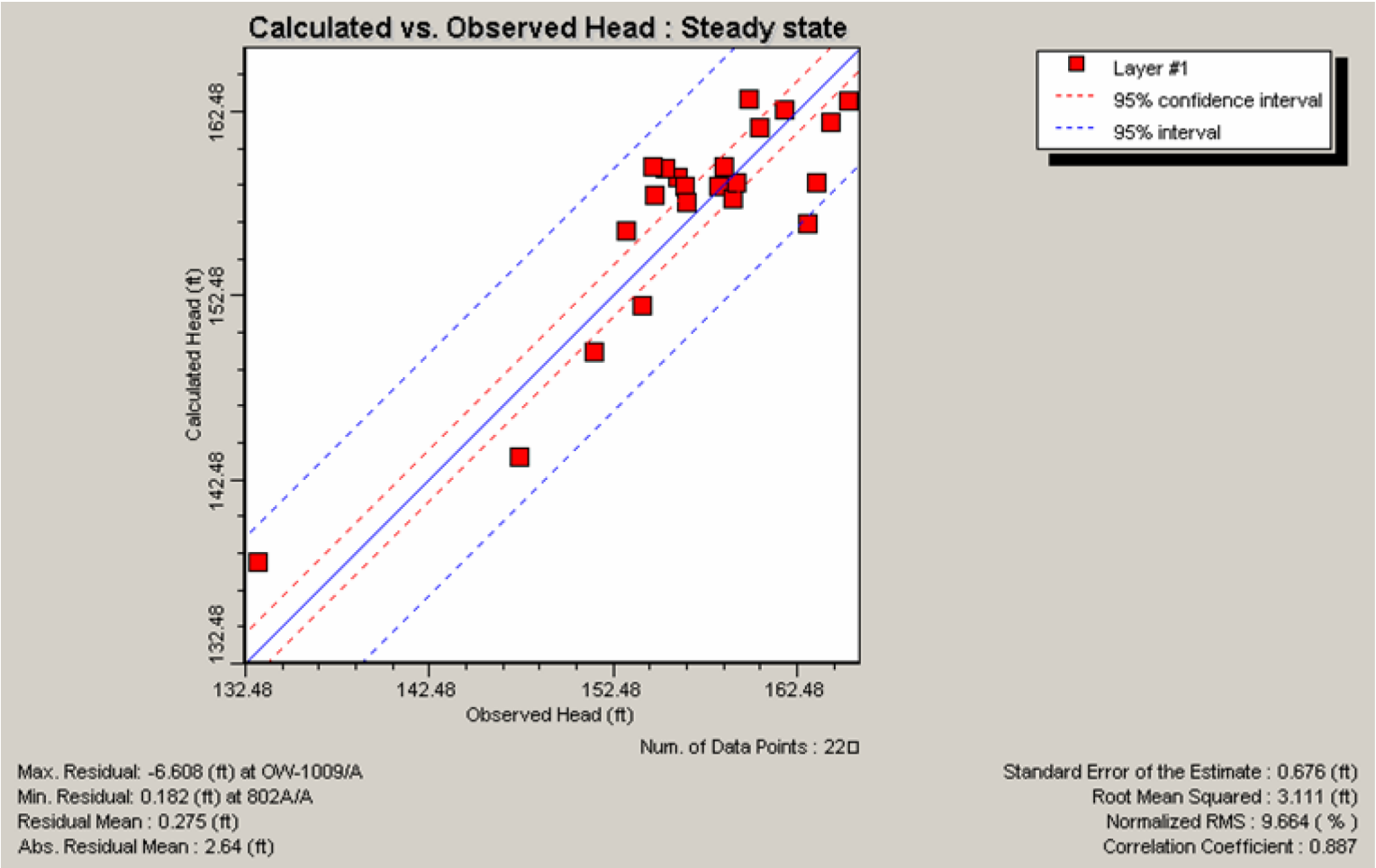


Figure 57: Simulated Versus Observed Water Levels with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 40 in/yr

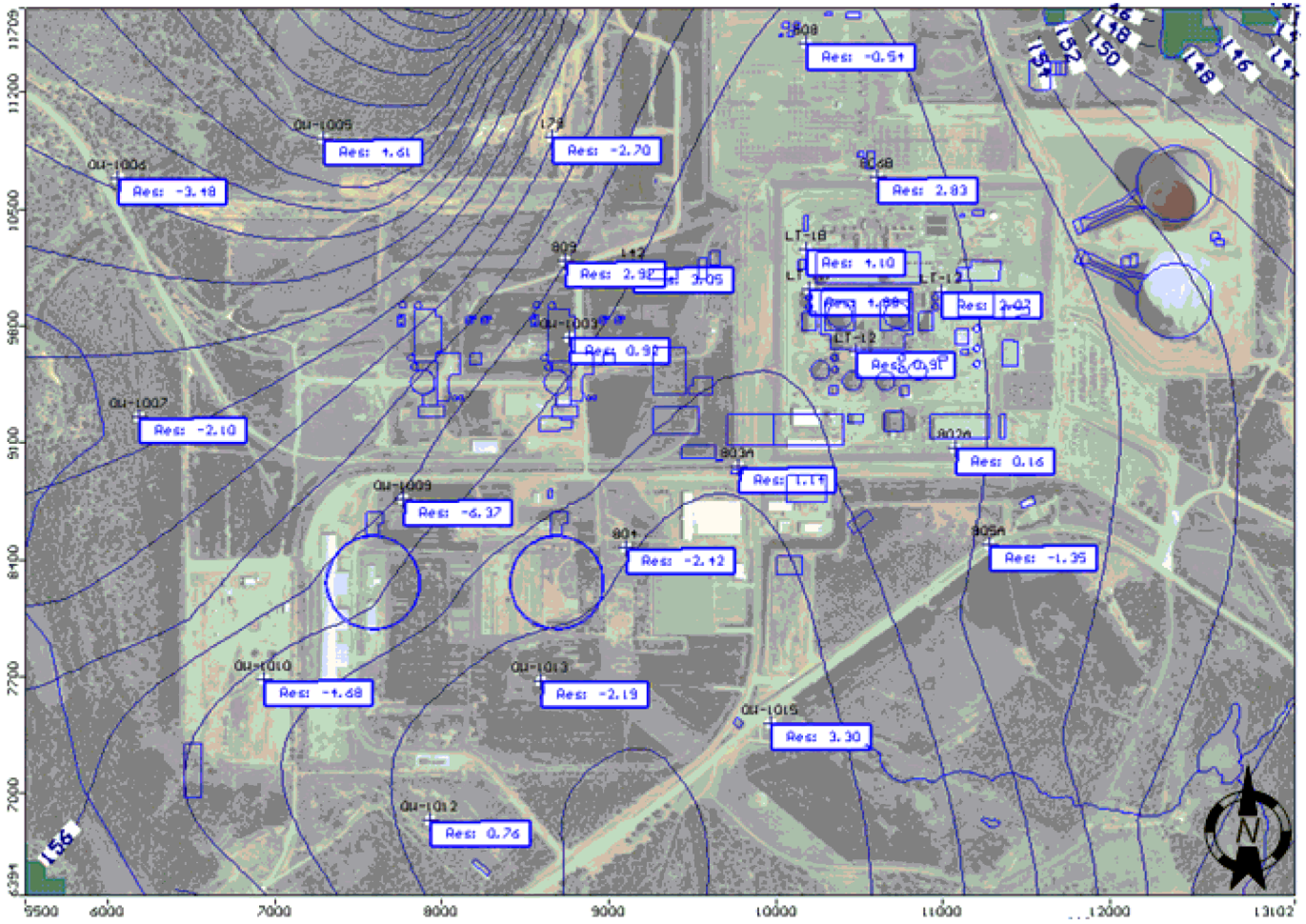


Figure 58: Estimated Residuals with Model 7 Assuming that the Rate of Groundwater Recharge at the Met Tower Pond is 40 in/yr

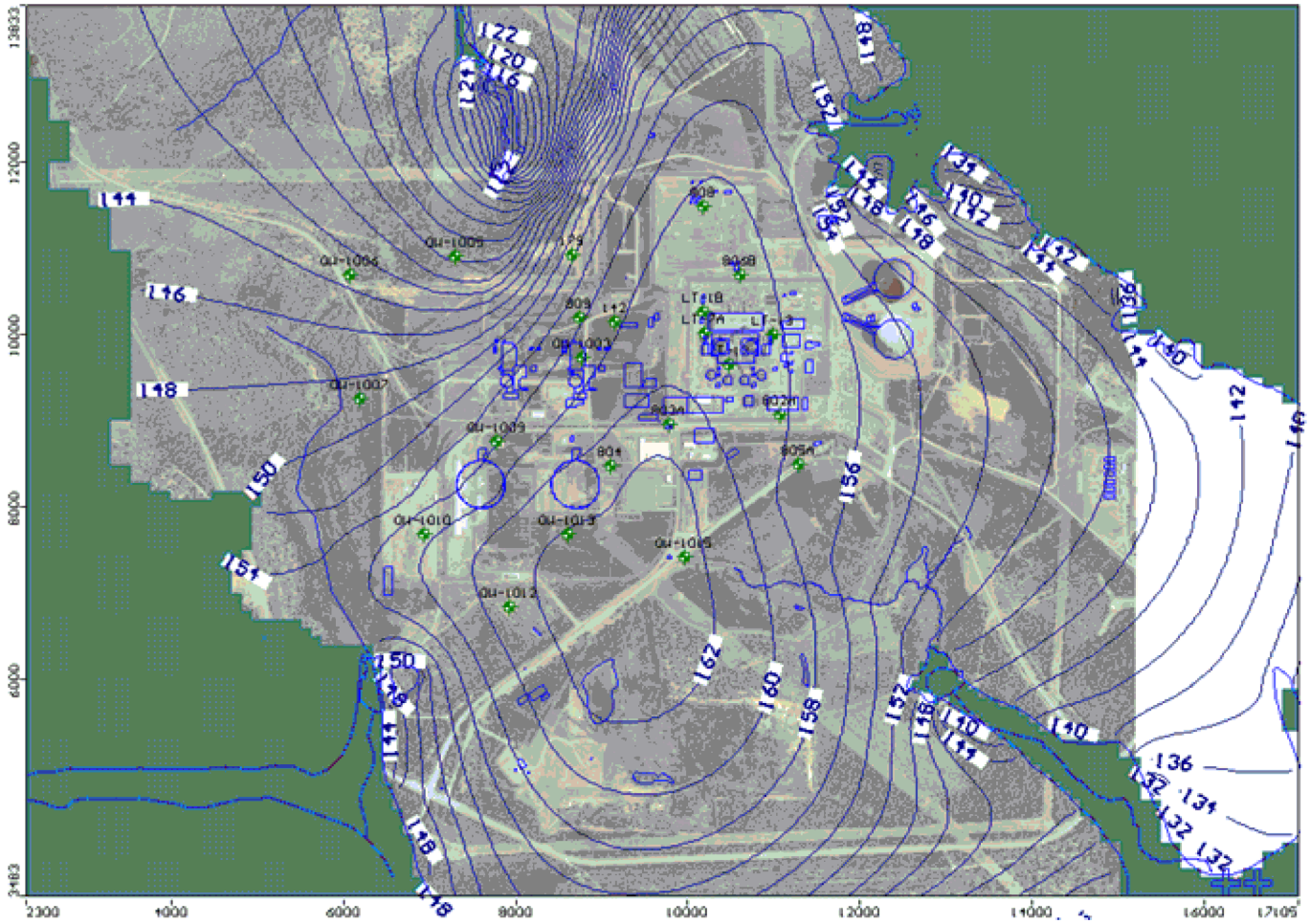


Figure 59: Simulated Water Levels with Model 7 Using a Constant Head Boundary Condition at the Upper Debris Basin 2 (The constant head used was 148.5 ft msl)

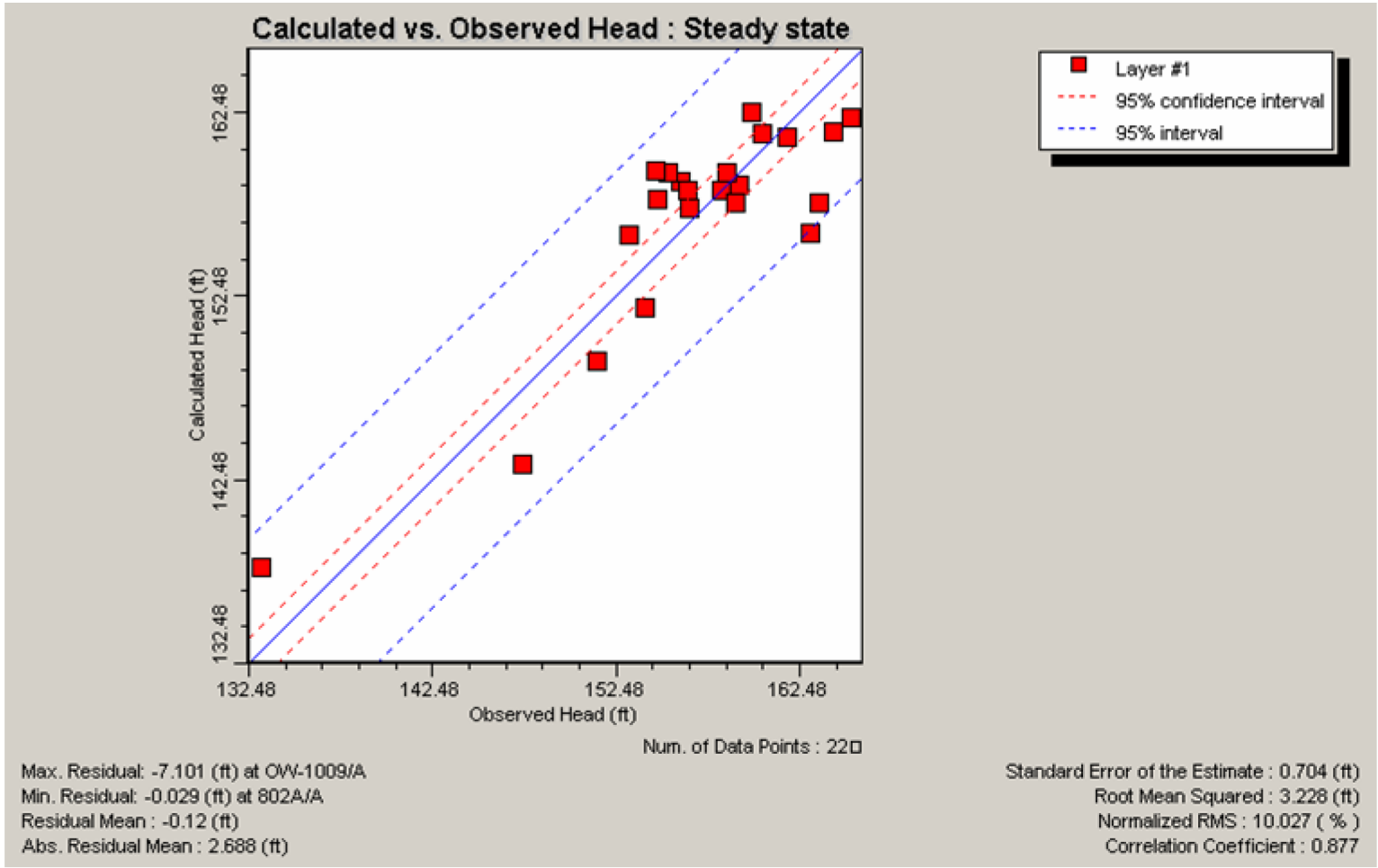


Figure 60: Simulated Versus Observed Water Levels with Model 7 Using a Constant Head Boundary Condition at the Upper Debris Basin 2 (The constant head used was 148.5 ft msl)

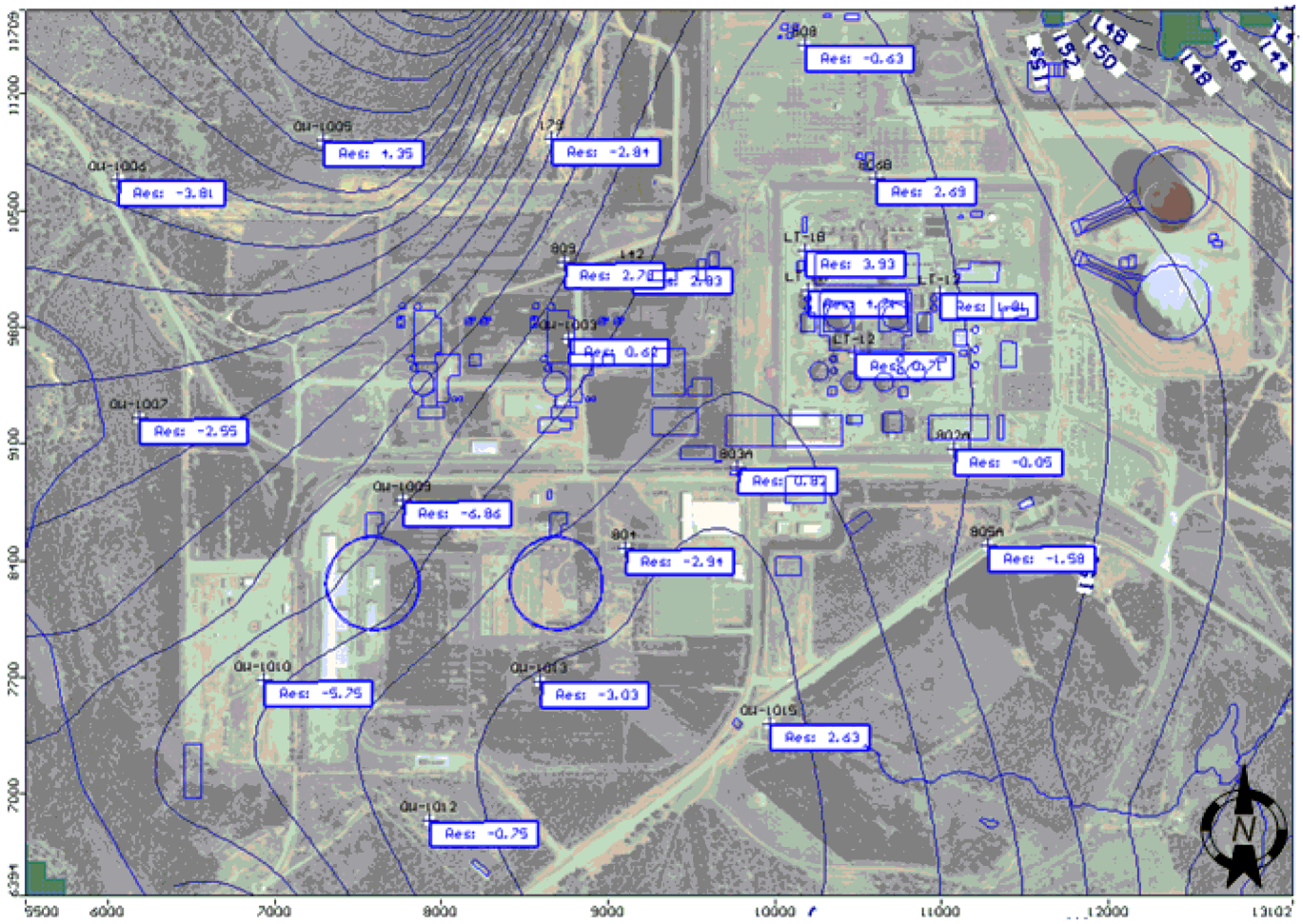
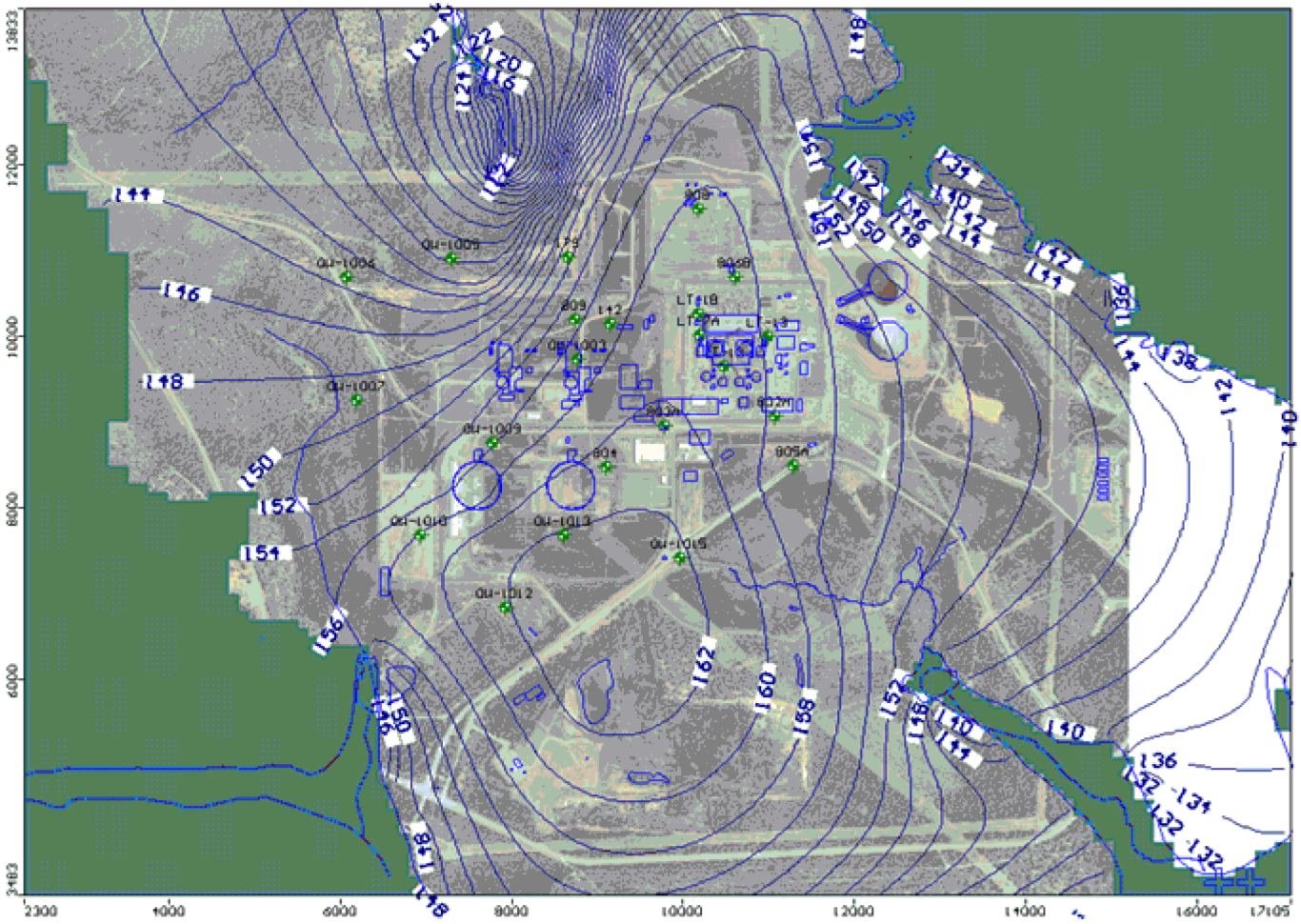


Figure 61: Estimated Residuals with Model 7 Using a Constant Head Boundary Condition at the Upper Debris Basin 2 (The constant head used was 148.5 ft msl)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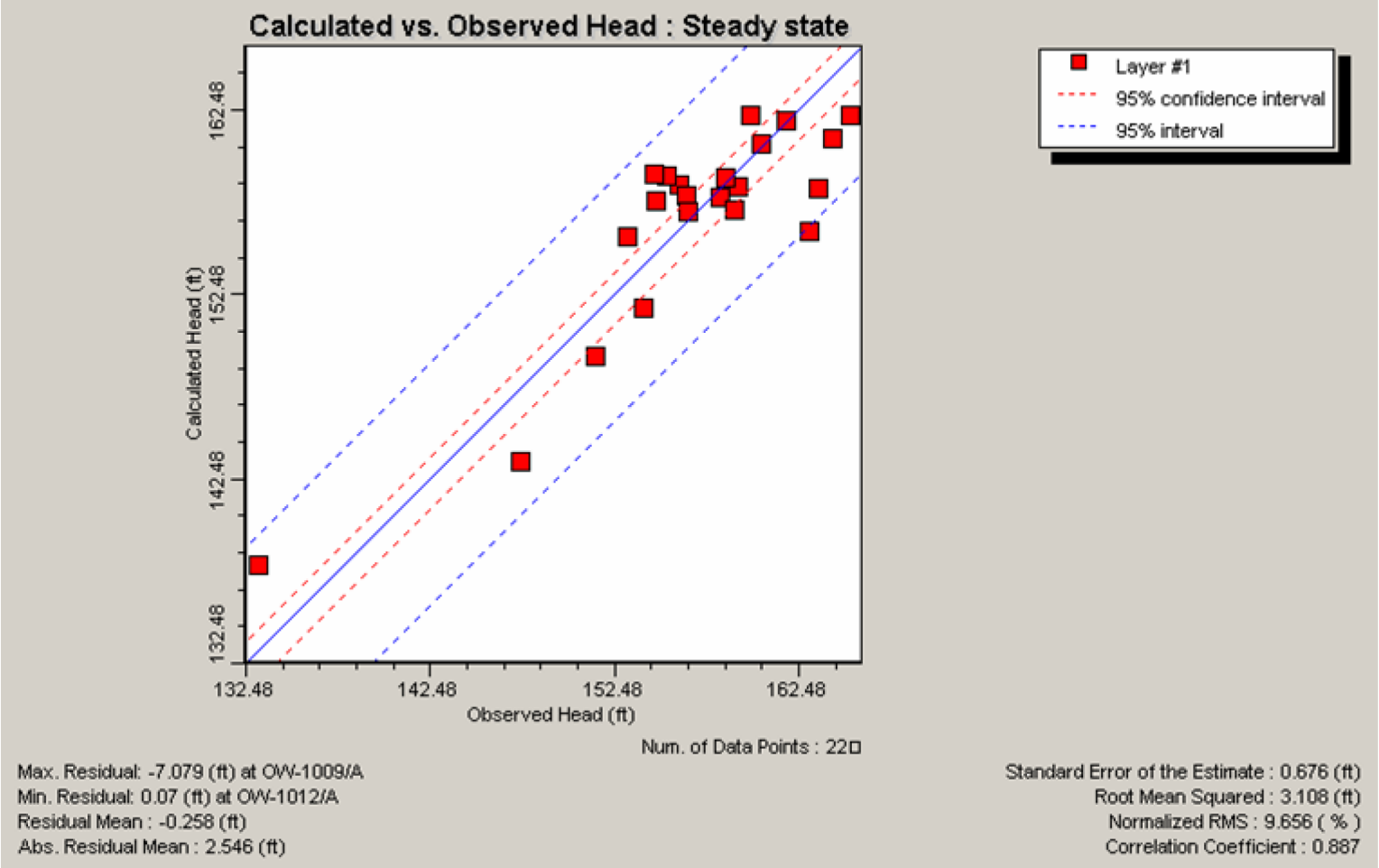


Figure 63: Simulated Versus Observed Water Levels with Model 7 Using Additional Paved Areas Around Units 1 & 2 and 3 & 4

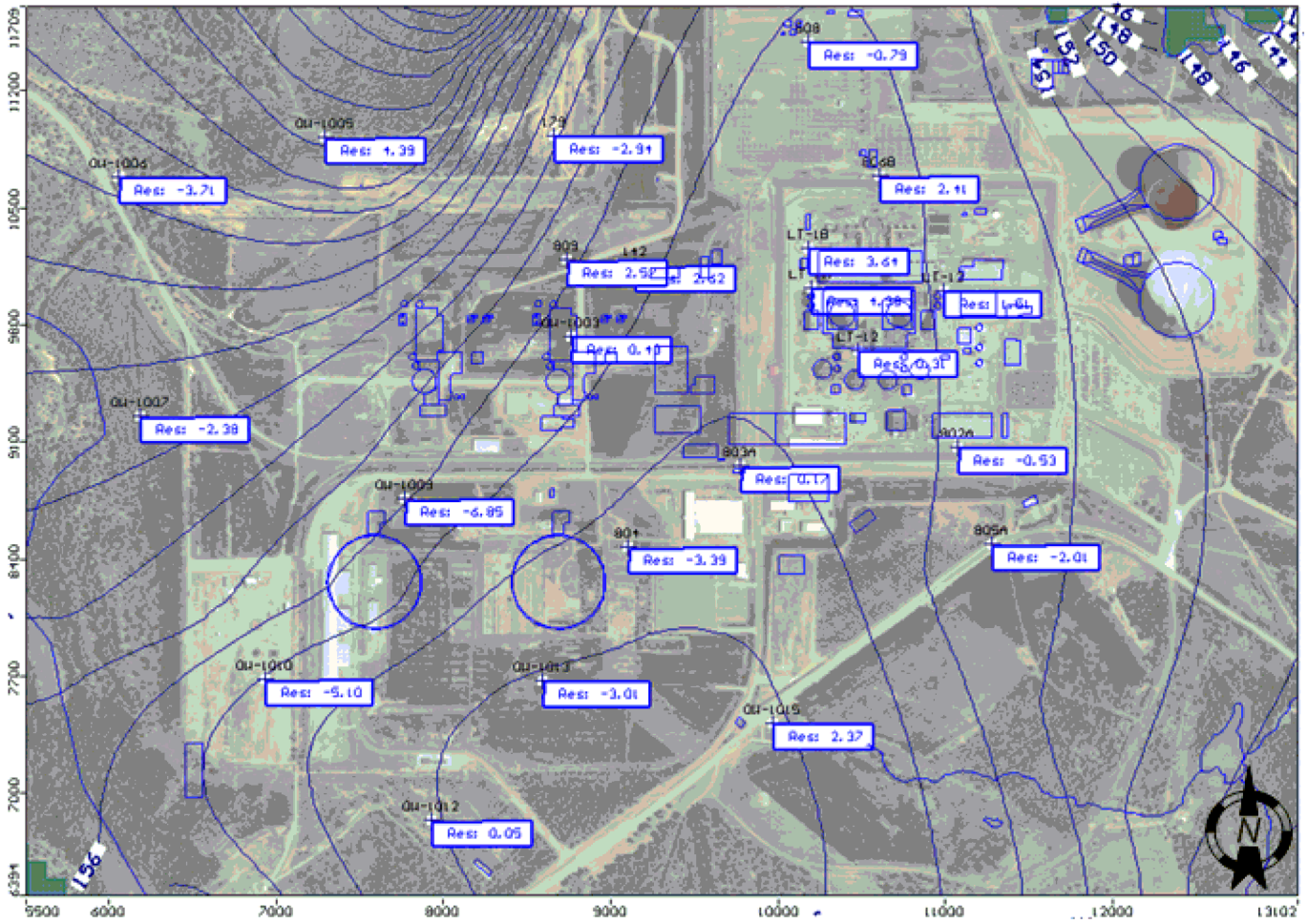
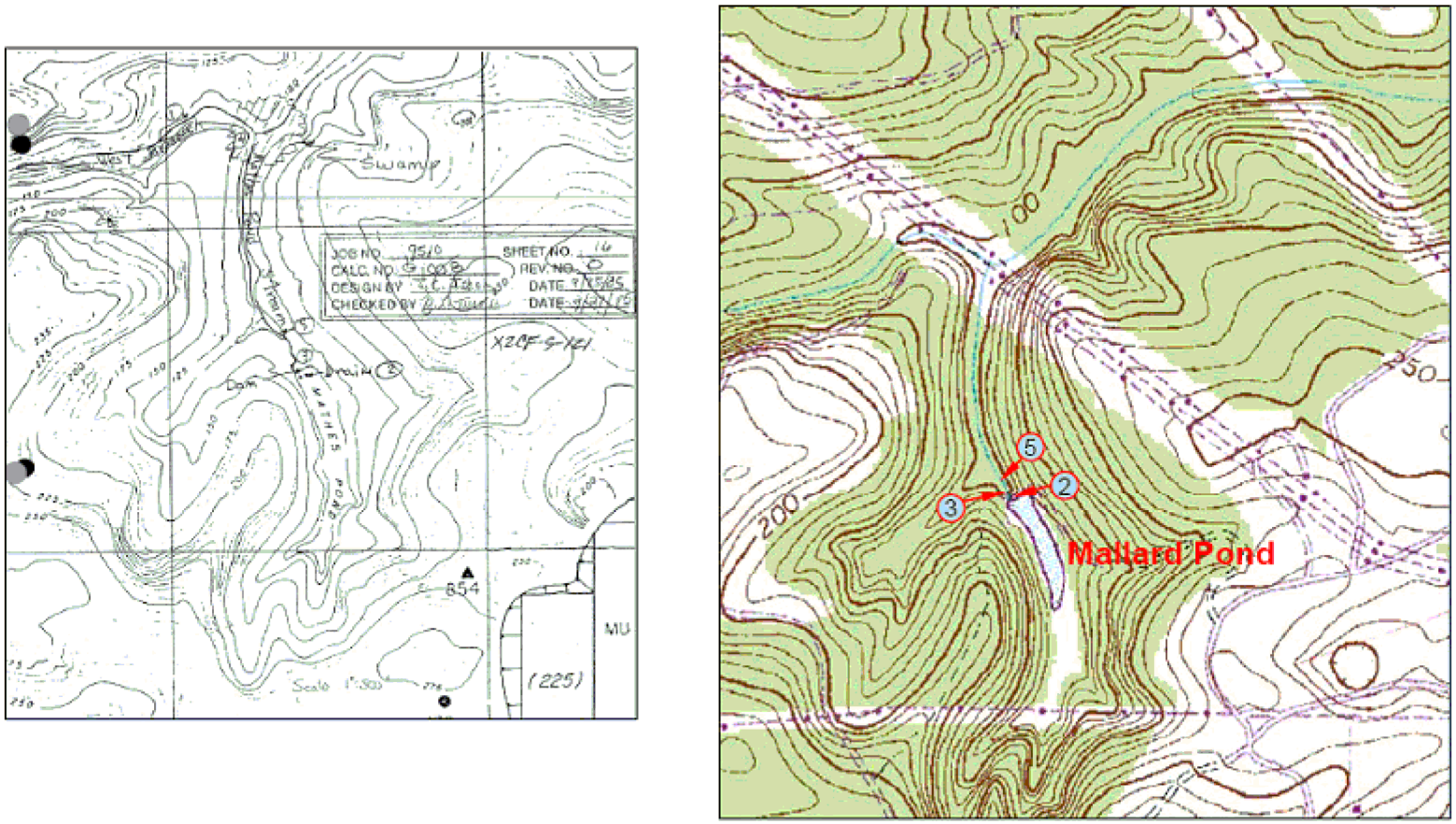


Figure 64: Estimated Residuals with Model 7 Using Additional Paved Areas Around Units 1 & 2 and 3 & 4



(a) Obtained from Ref. 11

(b) Stations from Ref. 11 Superimposed on USGS Map

Figure 65: Location of Stream Flow Measurement Stations at Mallard Pond

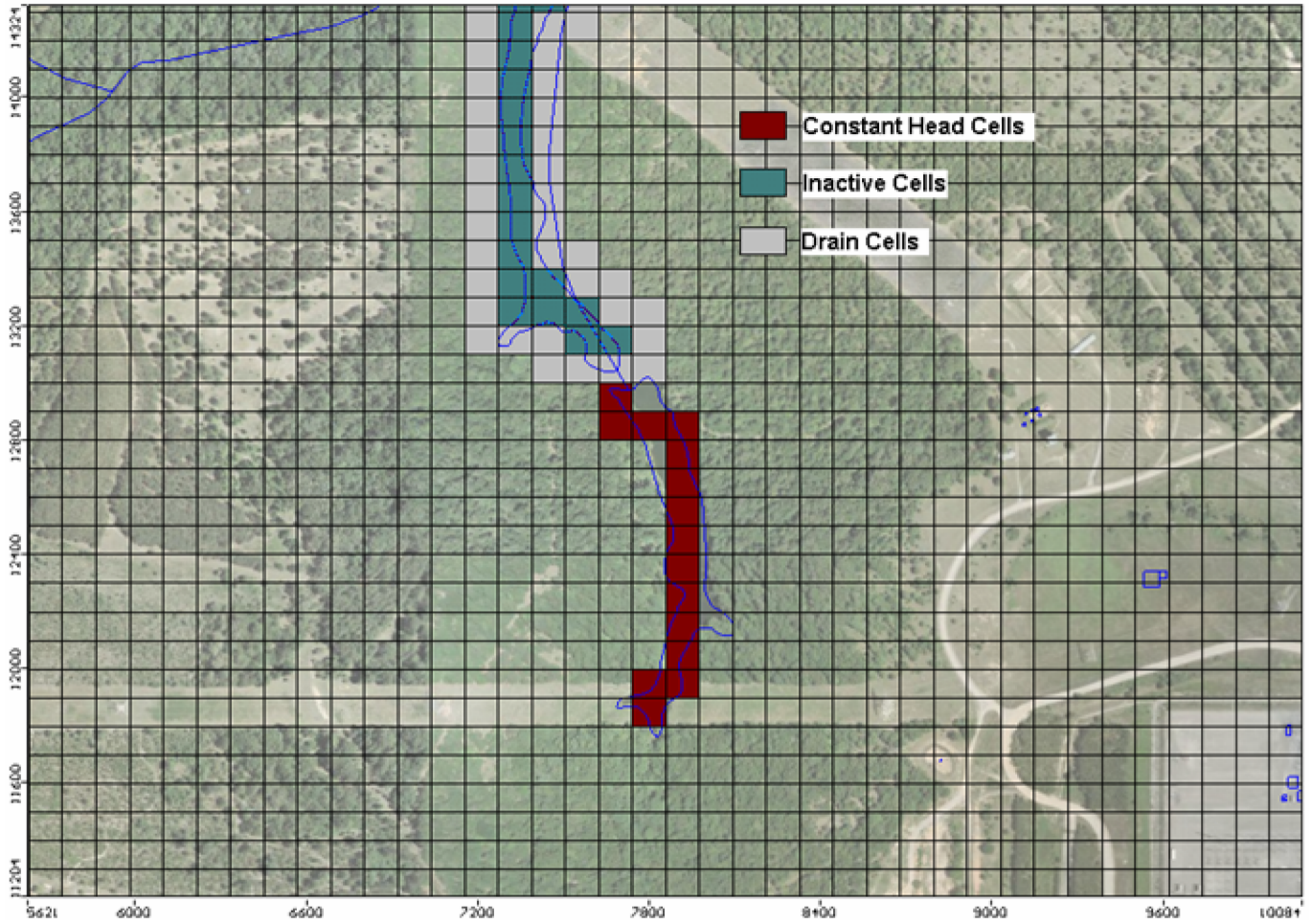


Figure 66: Representation of Mallard Pond and Area in Groundwater Model

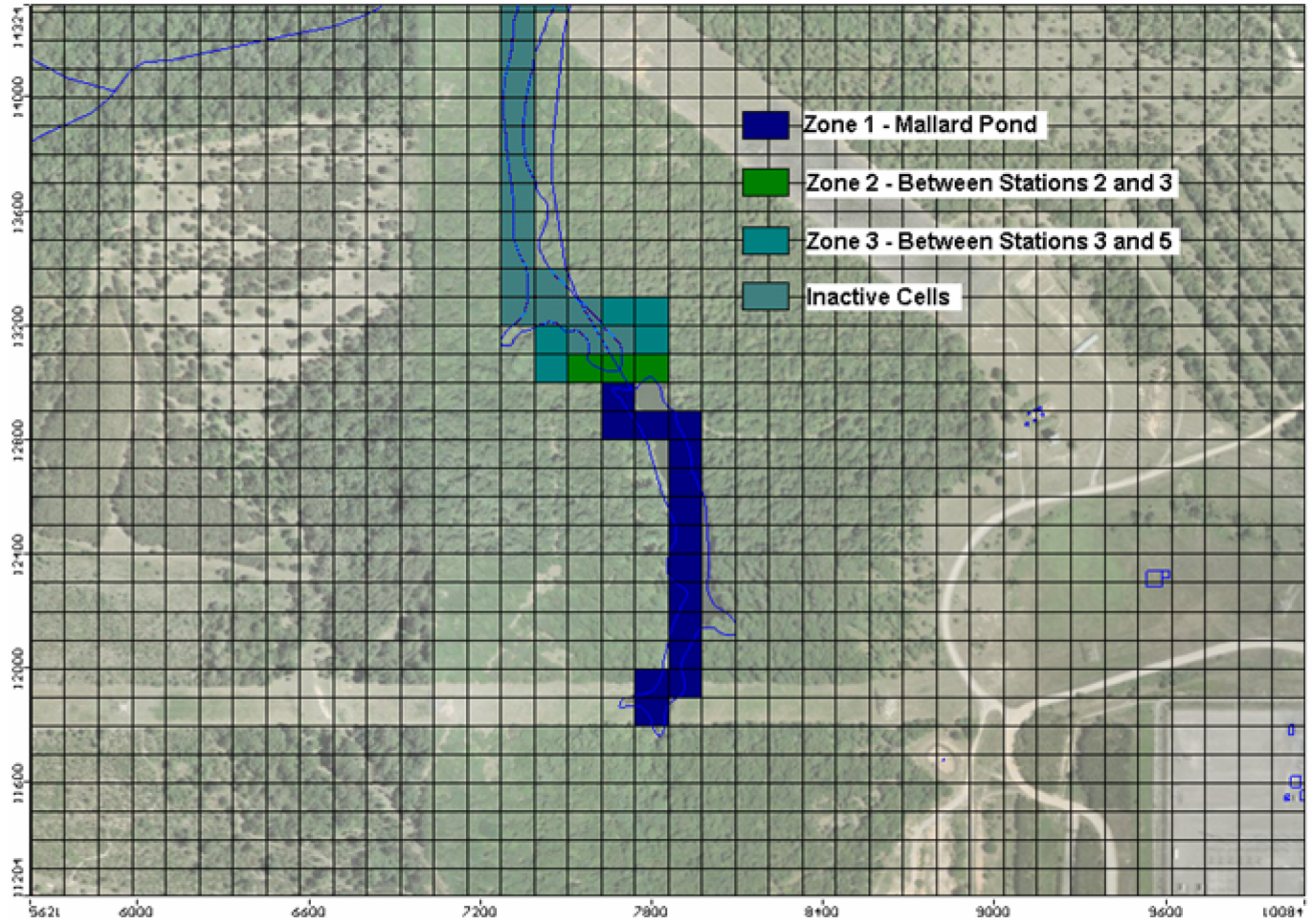


Figure 67: Zone Budget Representation of Mallard Pond and Area in Groundwater Model

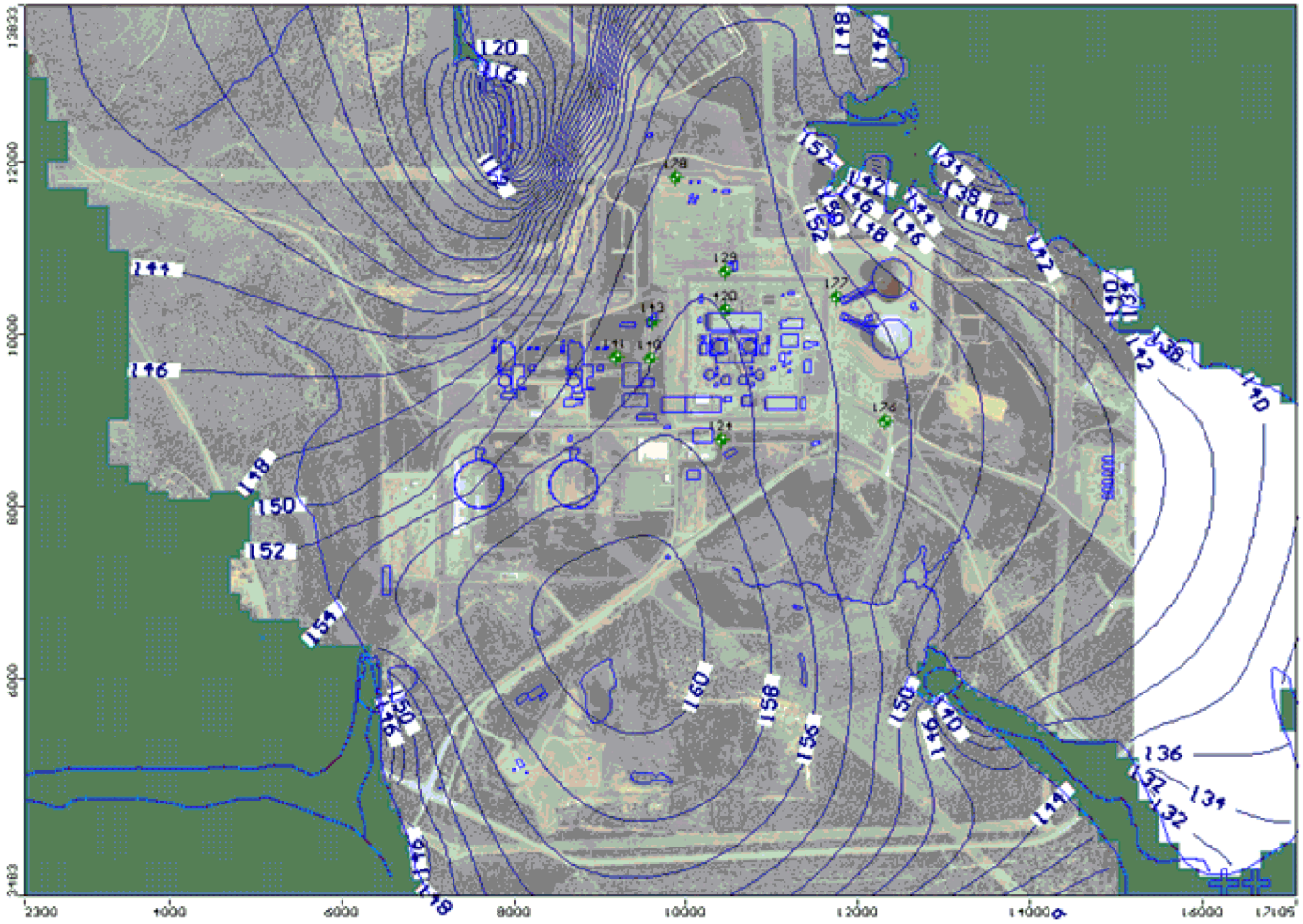


Figure 68: Simulated Water Levels for 1971 Groundwater Model

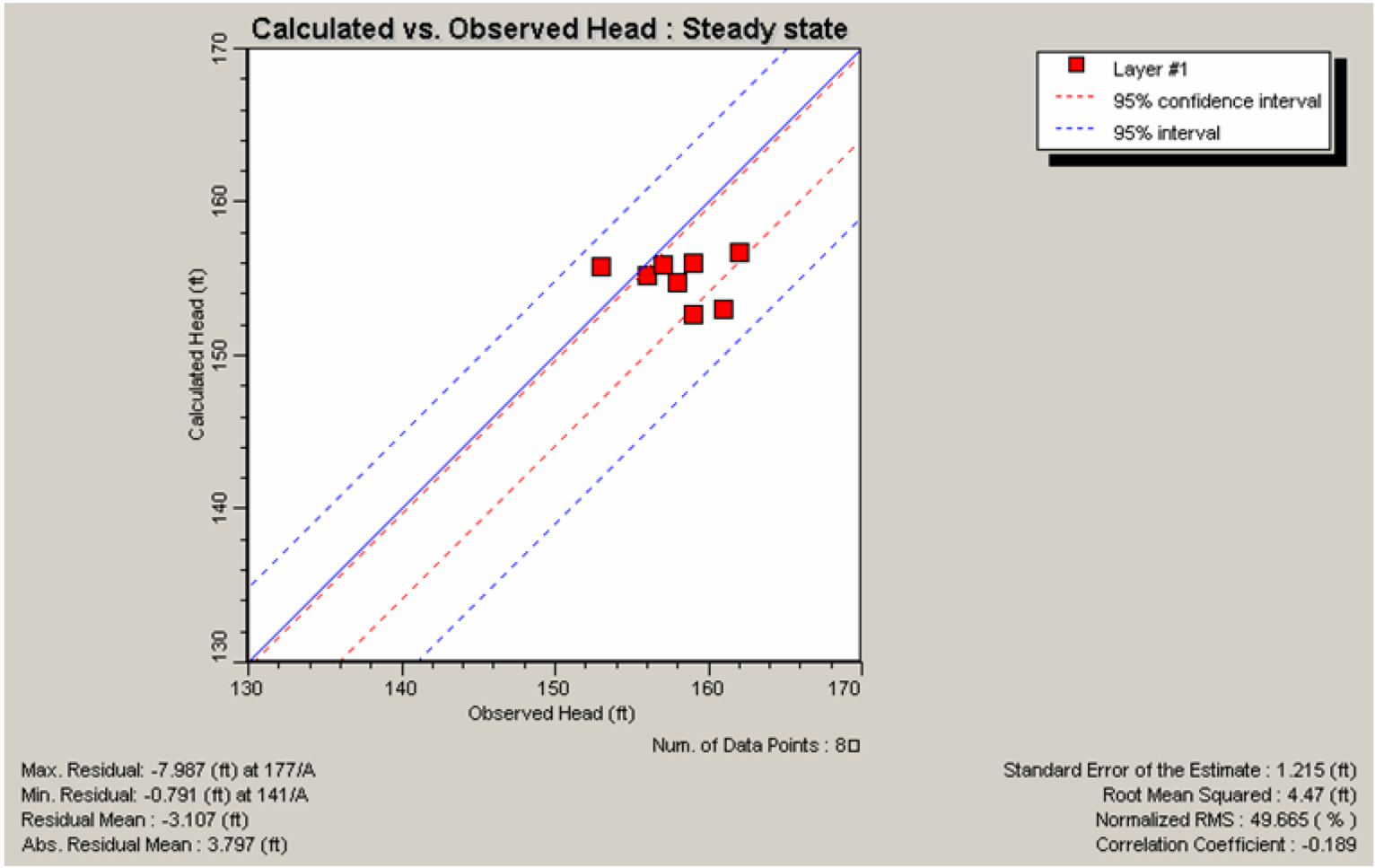


Figure 69: Simulated Vs. Observed Water Levels for 1971 Groundwater Model

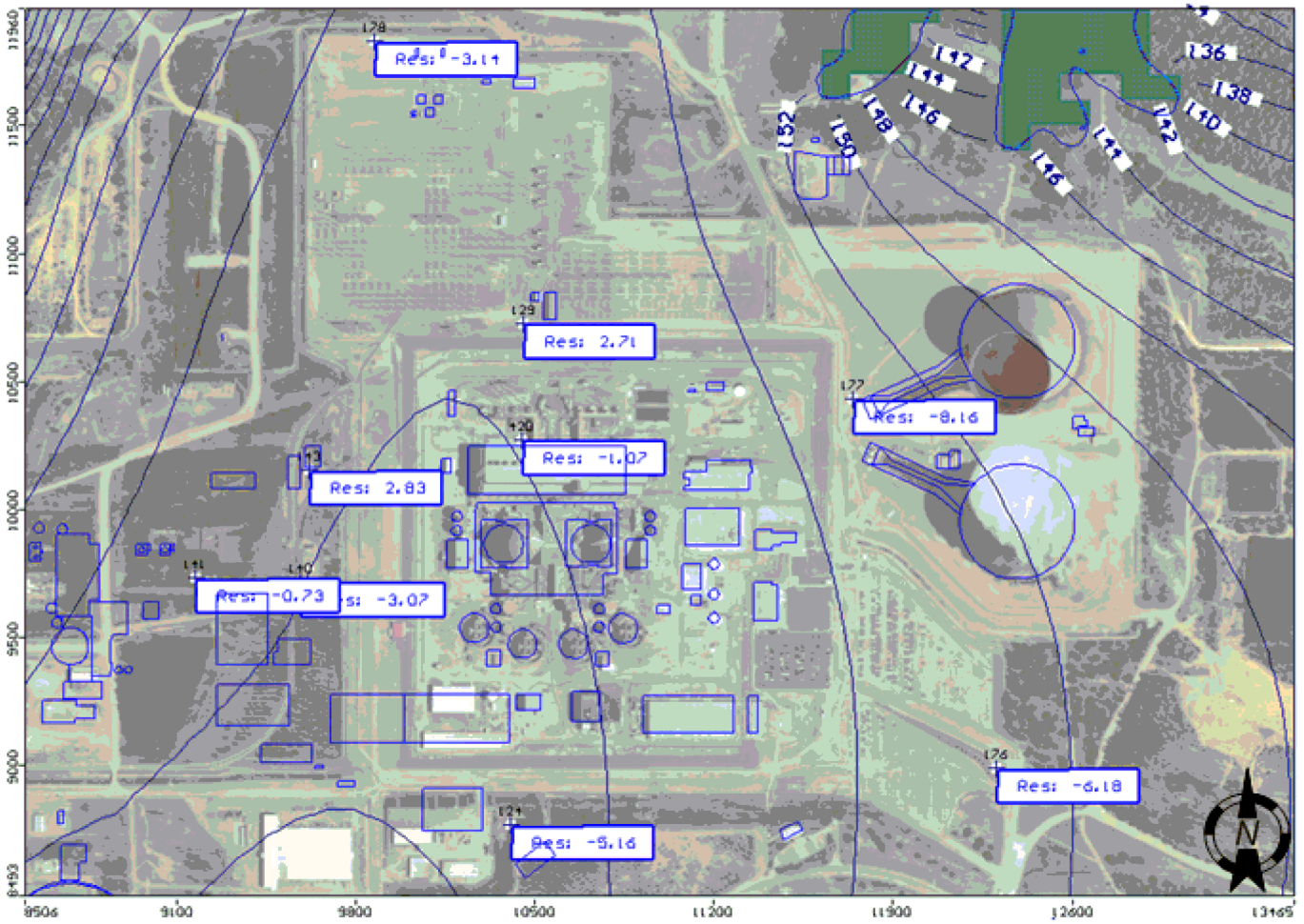


Figure 70: Estimated Residuals for 1971 Groundwater Model

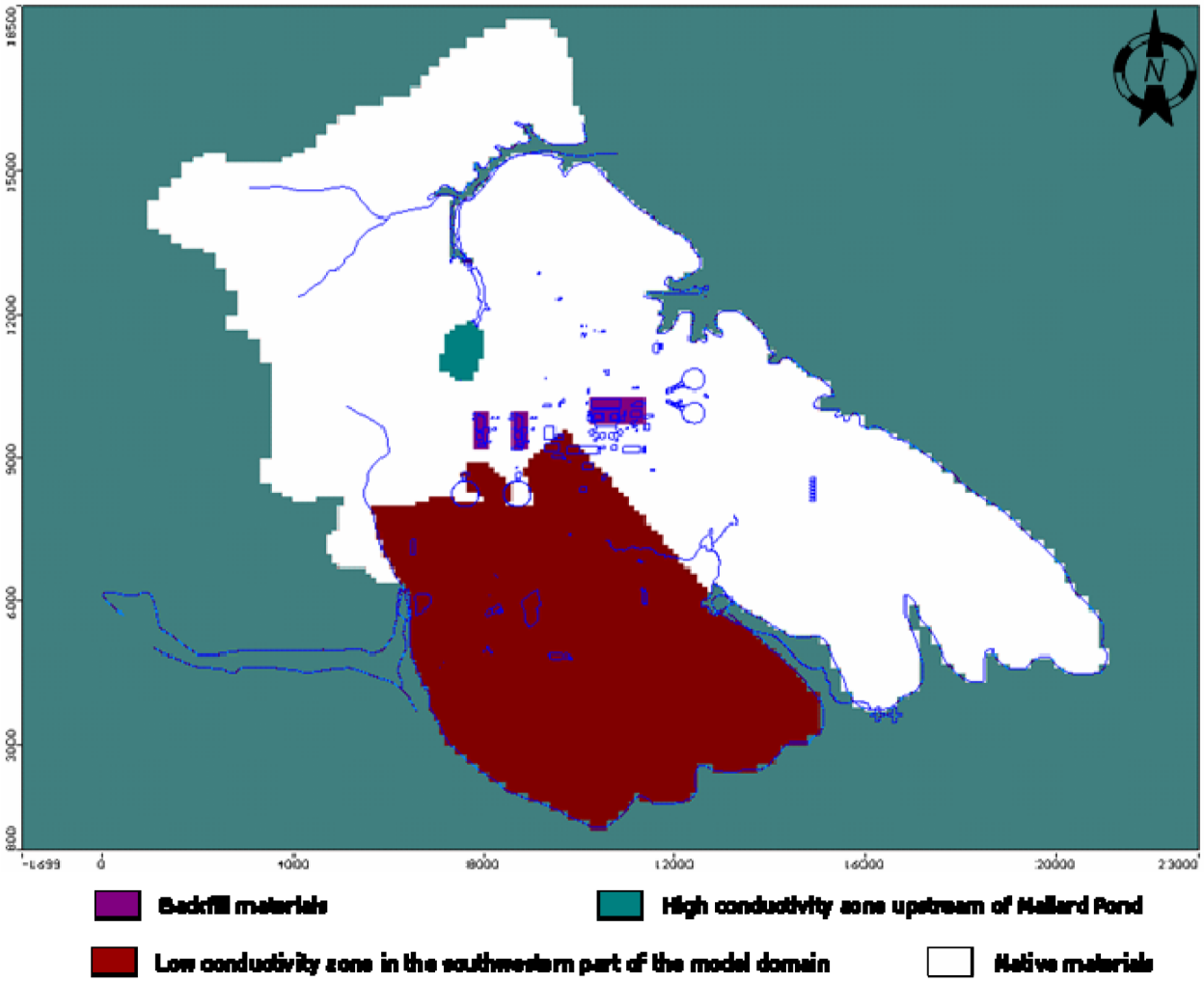


Figure 71: Hydraulic Conductivity Zones Used in Model 7 to Evaluate Post-Construction Conditions

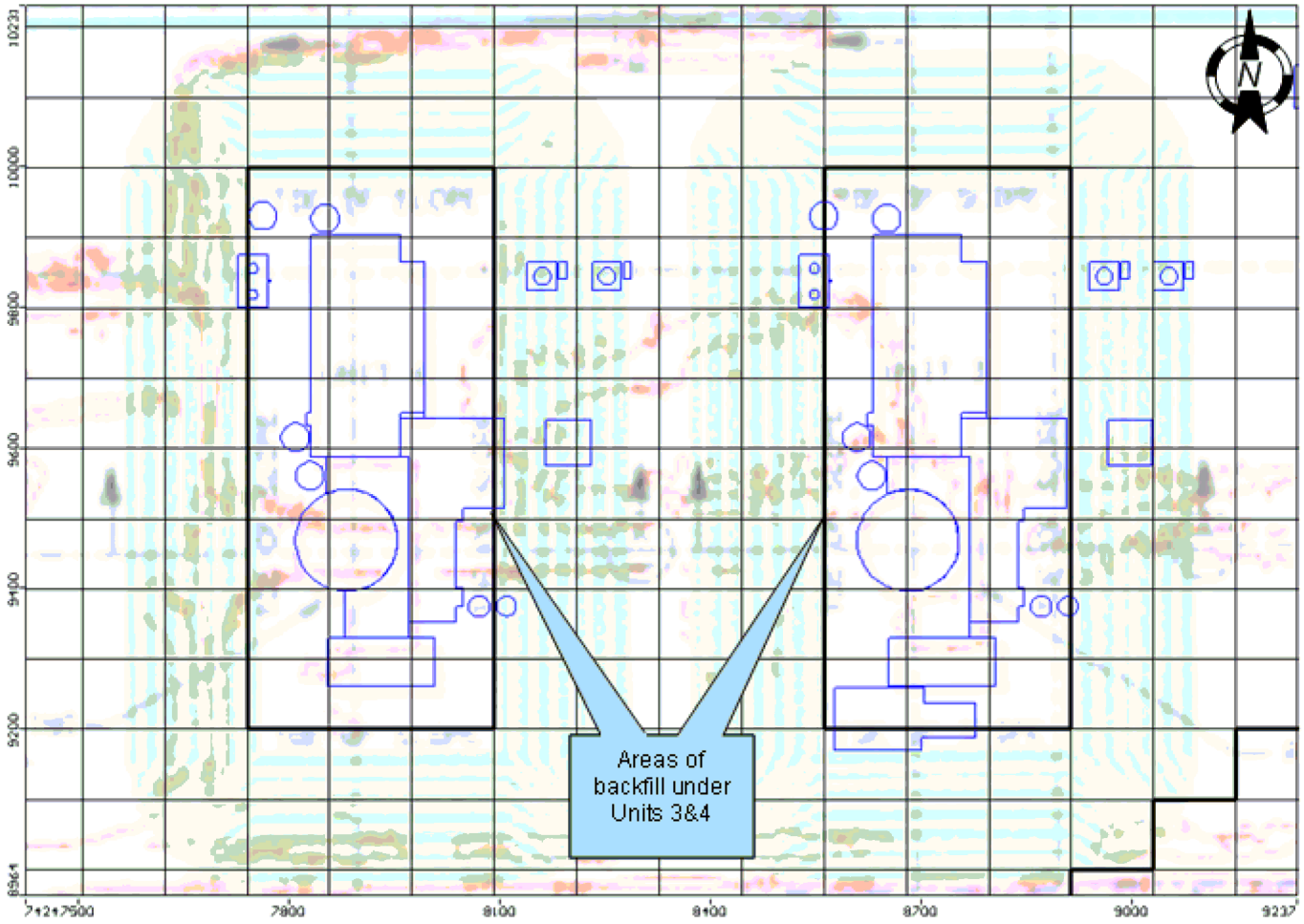


Figure 72: Excavation Plan Overlaid onto Model Grid to Show Areas of Backfill Around Units 3 & 4

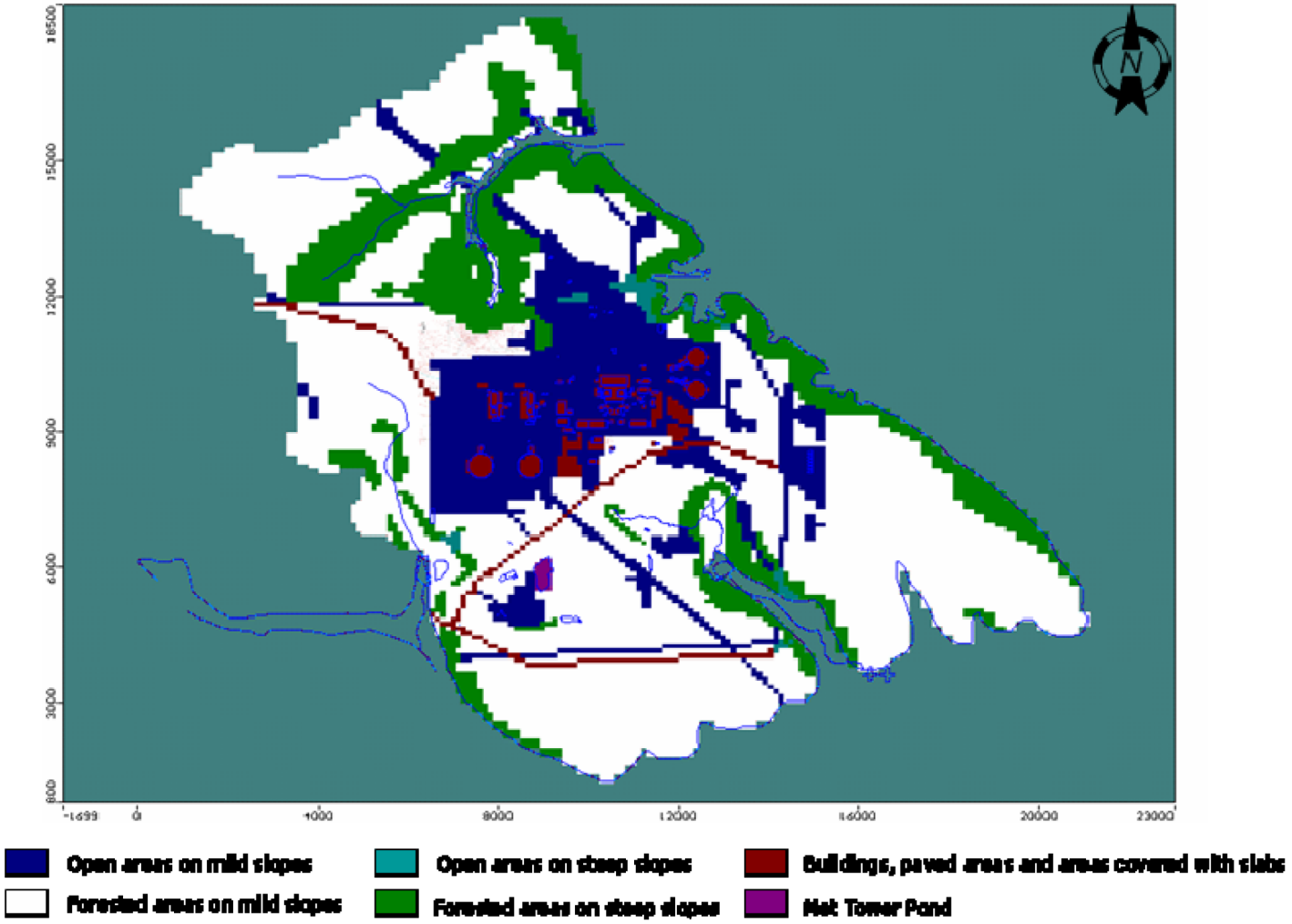


Figure 73: Recharge Zones Used to Evaluate Post-Construction Conditions

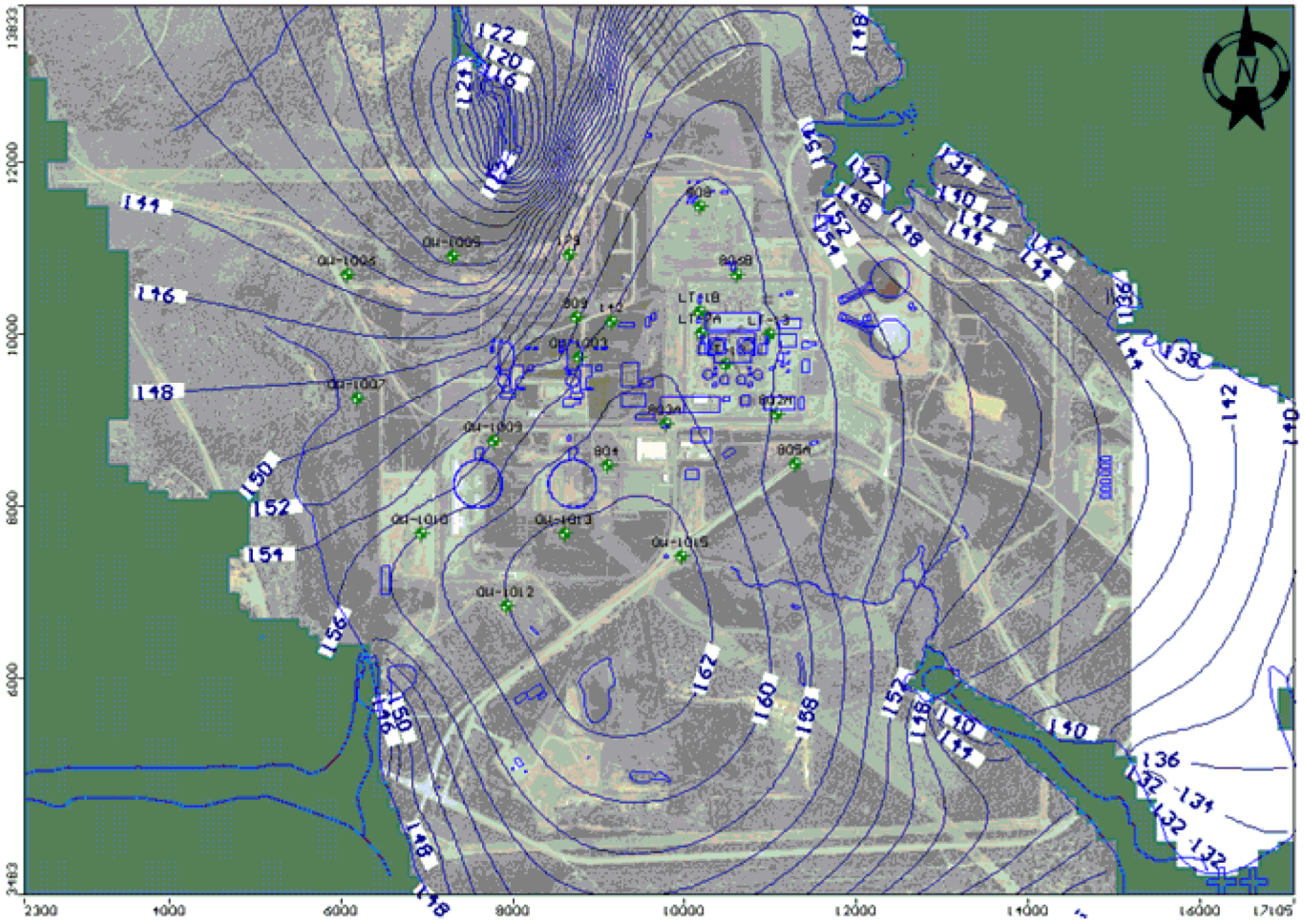


Figure 74: Simulated Water Levels for Post-Construction Conditions Obtained with Model 7 (K_1=32; K_2=100; K_3=8; K_{fill}=3.3 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

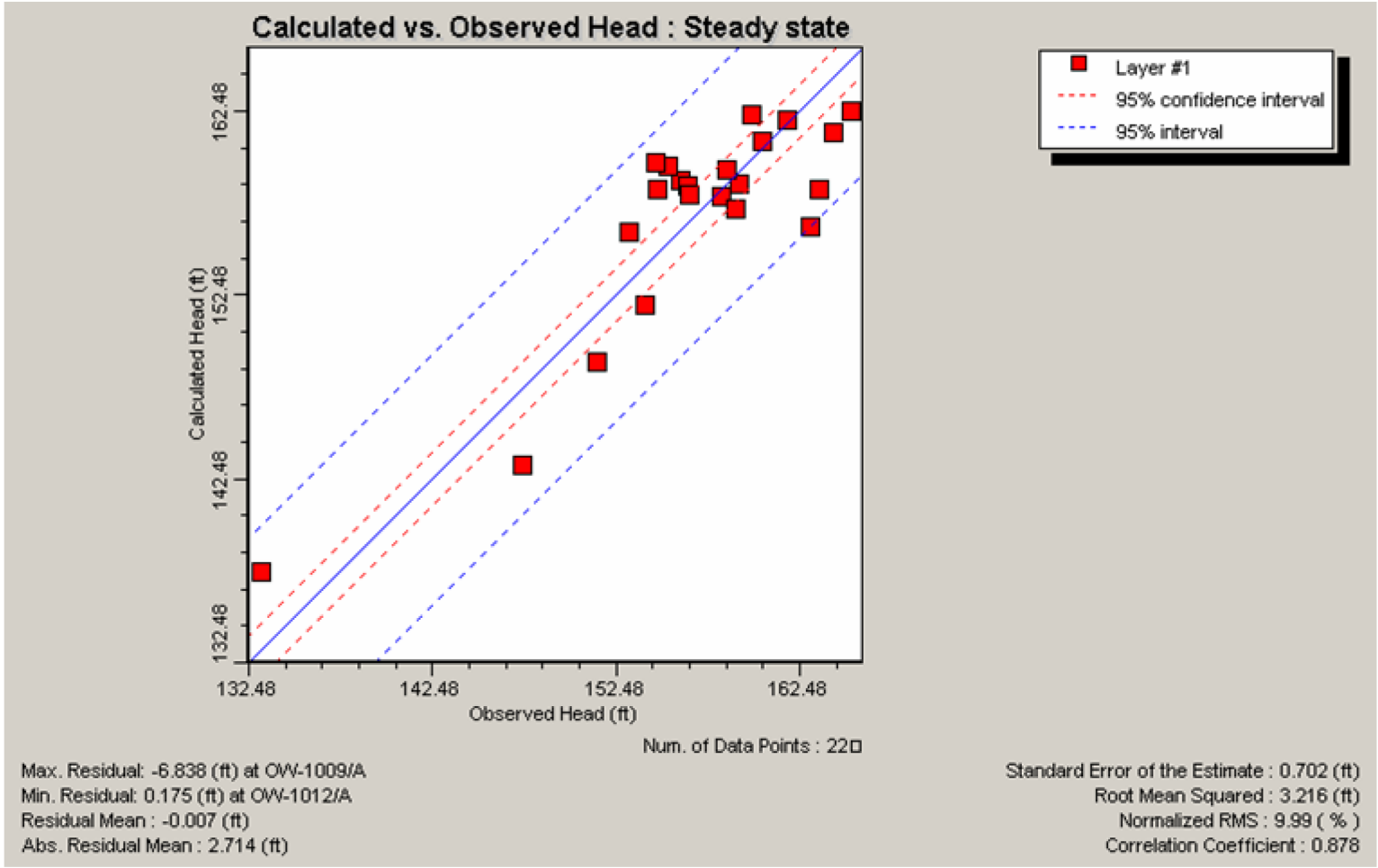


Figure 75: Simulated Water Levels with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

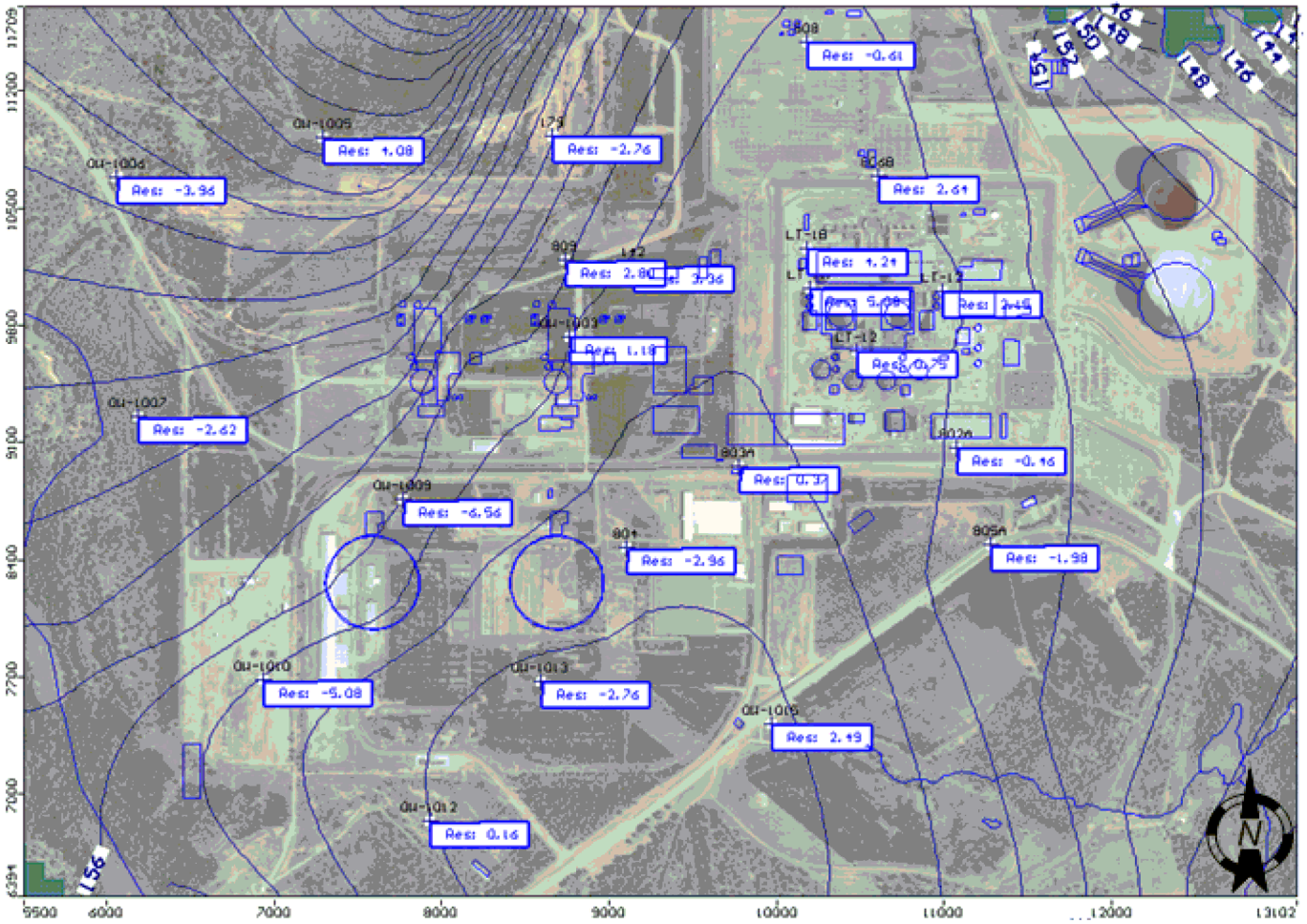


Figure 76: Simulated Water Levels with Model 7 Accounting for the Backfill Material for Units 1 & 2 as a Different Material with Hydraulic Conductivity Equal to 3.3 ft/day

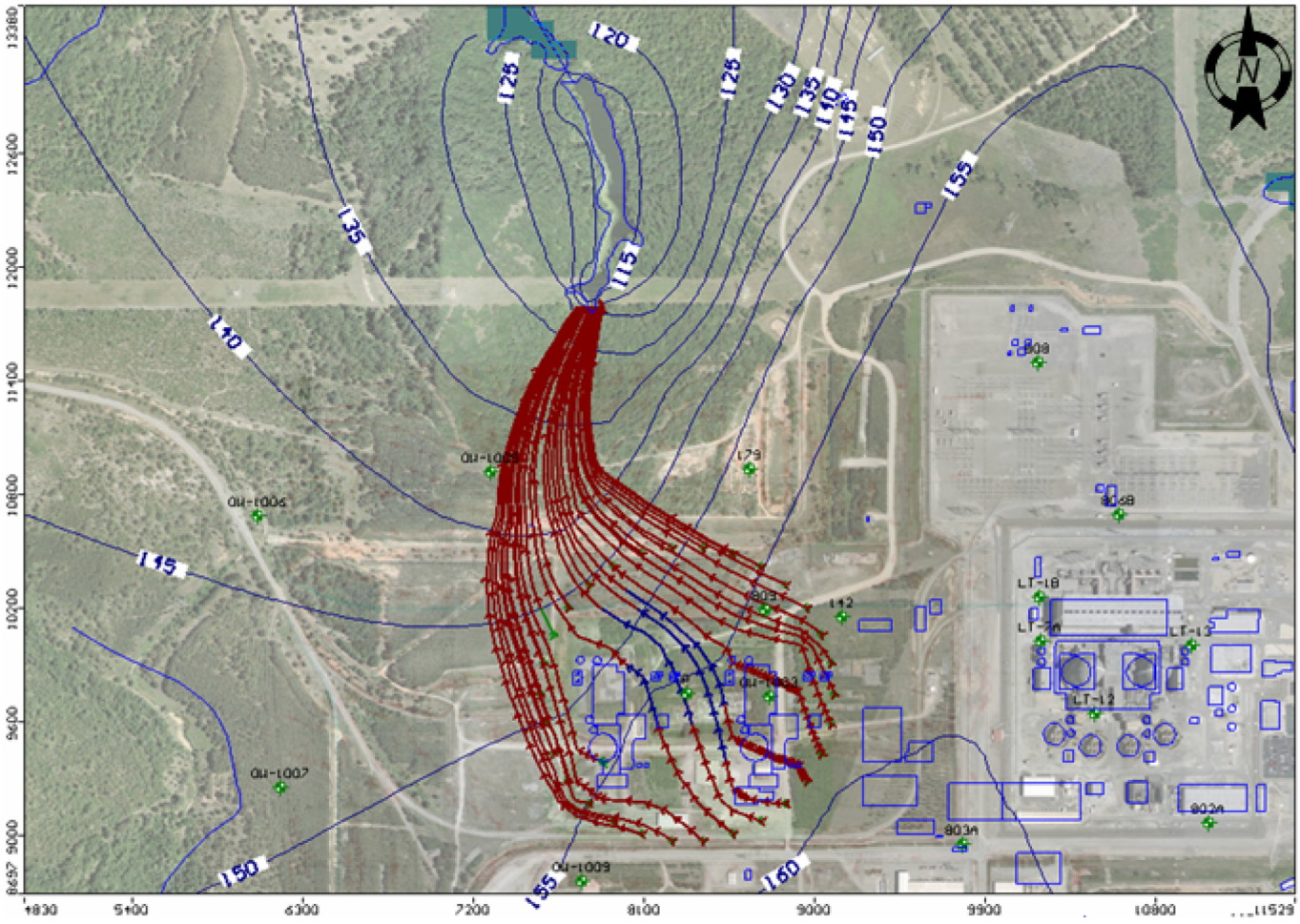


Figure 77: Simulated Water Levels and Particle Tracking for Post-Construction Conditions Obtained with Model 7 (K_1=32; K_2=100; K_3=8; K_{fill}=3.3 ft/day; R_1=10; R_2=6; R_3=6; R_4=4; R_5=0 in/yr)

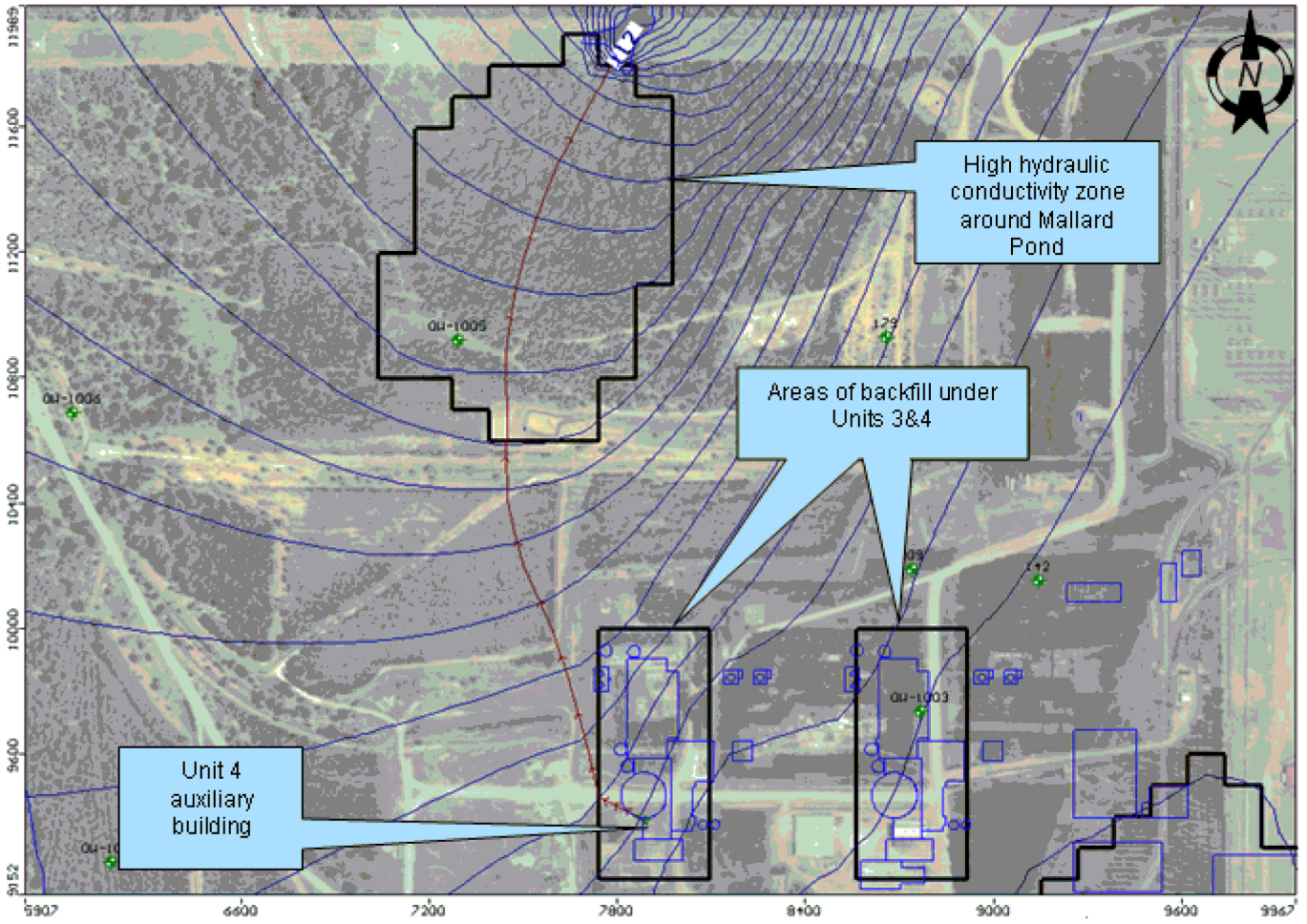


Figure 78: Pathway of Particle Released from Auxiliary Building of Unit 4

ATTACHMENT 1

Relevant Open Items

Open Item 2.4-2 in SSAR 2.4-12

The applicant should provide an improved and complete description of the current and future local hydrological conditions, including alternate conceptual models, to demonstrate that the design bases related to groundwater-induced loadings on subsurface portions of safety-related SSCs would not be exceeded. Alternatively, the applicant can provide design parameters for buoyancy evaluation of the plant structures.

Open Item 2.4-3 in SSAR 2.4-13

The NRC staff found the applicant's analysis in the SSAR to be incomplete; because it did not include consideration for the inevitable change in hydrology, and, hence, the potential changes in flow direction within the Water Table aquifer for some release locations within the protected area (PA). The applicant's analysis provided no assurance that an adequate number of combinations of release locations and feasible pathways had been considered.

Open Item 2.4-4 in SSAR 2.4-13

The NRC staff's review of the release location, migration, attenuation, and dilution of the radioactive liquid effluent inventory was incomplete because, as stated in Open Item 2.4-3, the applicant has not considered a sufficient number of alternate conceptual models to identify potential release points and pathways. Therefore, the applicant needs to specify the nearest point along each potential pathway that may be accessible to the public.

ATTACHMENT 2

NRC's Comments on the Groundwater Model

Date: 21 February 2008

To: Hosung Ahn

From: Charley Kincaid

Subject: Review of South Nuclear Company's submitted groundwater modeling of the Water Table aquifer at the VEGP Site

The following general notes and comments summarize our initial review of the modeling achieved by SNC.

General Notes and Comments:

1. Vogtle Groundwater Model installed and reviewed – per files received January 23 via e-mail message from Chris Cook, NRC. The files consist of three simulation "cases" that are described in Section 2.4.12 of the application plus two simulation variants that are not included in the document. All simulation cases have both "Existing" and "Future" variants. Thus, a total of 10 simulations were received. The cases that are not discussed in Section 2.4.12 were viewed, but not assessed in detail because of the fact that they are not described in the document. Files were generated by Visual Modflow version 4.2.0.151 (Schlumberger Water Services, Waterloo, Ontario, Canada) and were reviewed with version 4.2.0.153.
2. All simulation variants consist of a single layer model with non-uniform lateral grid spacing and a deformed grid in the vertical direction. However, based on the shapefile "map" data set for the top of Blue Bluff Marl (included in some simulation model files, such as Case 1 Existing) and the model data set representing the bottom of the Water Table aquifer, it would appear that the model does not duplicate in good fidelity the primary structural feature of the VEGP Site. It is also noted that an expected subcrop of Blue Bluff Marl above the water table to the north of VEGP Units 1 & 2 is not included in the model configuration.
3. The cases presented would appear to be a sequence of successively improved calibrations or attempts to do so. These might be described as a sequence of calibrations leading to a preferred model. However, the goal is to consider plausible alternative conceptual models that are fundamentally different than a preferred model in some way, but nonetheless consistent with the available data and observations of system behavior. The fundamental differences that should be considered are those that might influence our judgment regarding the safety of the proposed facility, (e.g., that might result in faster transport or transport in a different direction).
4. The saturated conductivity zonation represented in the cases involves a single-layer aquifer and ranges from (1) two zones (i.e., high conductivity for engineered backfill, and lower conductivity elsewhere, to (2) three zones (the third zone being one added in the immediate

vicinity of Mallard Pond), and to (3) a single layer model with the “everywhere else” zone divided in two along a line through the center of the VEGP site from southwest to northeast. Note, the latter case was provided in the files, but not used in the Rev. 3 of the application. The “Future” cases modify the hydraulic conductivity distribution by adding zones for high conductivity backfill material under reactors for Units 3 & 4. The sequence appears to be an attempt to successively improve the calibration and is not a suite of plausible alternative conceptual models.

5. The saturated conductivity assigned to the engineered fill could be conceptualized in at least two ways; (1) assigned saturated conductivity as measured and previously presented in the ER and SSAR because measurement scale and model scale (e.g., cell size) are similar, and (2) scaled saturated hydraulic conductivity to represent the hypothetical scale-up value proposed by SNC.
6. The infiltration zonation is represented in the cases with a single value for the entire model except at the post-construction areas of Units 1 & 2 (including the cooling towers), which are assigned zero recharge. However, no changes to the recharge zonation are implemented in the proposed construction zones of Units 3 & 4. Thus, the “Future” cases fail to examine alteration of recharge after construction of Units 3 & 4. One simulation variant does assign zero infiltration to areas where Units 3 & 4 reactors and cooling towers are proposed to be located, but this simulation variant is not included in the Rev 3 application. None of the alternatives examine the potential for gravel covered and essentially vegetation-free regions having substantially higher recharge than that associated with pre-construction conditions.
7. There is no discussion of model calibration in the Section 2.4.12 of the application, and there is a systematic error in each of the calibrations. All comparisons between field observations and modeled values of groundwater levels on the Mallard Pond drainage side of the model show a higher modeled value than observed value. All comparisons of groundwater levels between field observations and modeled values on the Telfair drainage side of the model show a lower modeled value than observed value. One may assess this calibration error as being conservative with respect to the direction of flow (i.e., if flow goes toward Mallard Pond even when the simulation head results in the direction of Mallard Pond are higher that the observed value, then a more correct calibration would undoubtedly flow in that direction). However, there are two problems with such an assessment. First, this systematic error in calibration is an indication that the model is not correctly conceptualized. Second, the systematic error in calibration means that the hydraulic gradient produced in the simulation is too low, and, hence, any travel time calculations will be substantially incorrect and non-conservative (i.e., the simulated travel time will be longer than the observed gradient would imply.)
8. In the three cases presented, there are model cells that go dry during the simulation. Similarly, there are cells that indicate flooding in some areas. The dry cells are in the vicinity of the expected Blue Bluff Marl outcrop above the water table, which is north of VEGP Units 1 & 2; however, the dry cells do not appear to represent the entire outcrop. Cells that go dry and those that flood are indications that the conceptual model being simulated needs to be reworked. Note also that the appearance of “dry” and “wet” cells within the simulation may indicate a misrepresentation of the structure.
9. The flow balance of the three cases is quite varied, and does not appear to represent solutions to well posed models. For example, the flow balance of Case 1 Future exhibits a

70% discrepancy, that of Case 2 Future exhibits a less than 1% discrepancy, and that of Case 3 Future exhibits a 75% discrepancy. Such information would argue against these cases being plausible alternative conceptual models of the Water Table aquifer. Note that incremental changes in starting and boundary conditions result in widely varied flow balance results, indicating an incorrect model configuration.

10. There are questions about the boundary conditions used to represent the streams in the model. The unnamed stream and Daniels Branch may be appropriately modeled by a “drain” boundary condition provided the applicant has data or knowledge of its ephemeral character. However, two other streams on the Telfair watershed side of the model appear to be spring fed (see the 1971 Water Table aquifer contour map in the FSAR of Units 1 & 2). These streams may be better represented by “river” boundary conditions, especially during a “March” or spring period of the year. Also, the location and topography of the upper reaches of the unnamed stream that feeds the Daniels Branch could be greatly improved based on local topography and would likely lead to improved calibration to nearby field observations.
11. What we want to see in plausible alternative conceptual models are models that do not violate the data, and, given the simplifications they embody, models that are arguably conservative representations of the site. The three cases presented are not plausible alternative conceptual models of the site.
12. Regarding the movement of tracer particles from the proposed VEGP Units 3 & 4, it is important to examine origins anywhere within the entire power block area. Examining start locations only in the immediate vicinity of proposed Units 3 & 4 is not adequate. The ESP assumes reactor facility locations anywhere within the power block area.
13. The model is insufficiently documented (e.g., basis for boundary conditions, calibration, sensitivity, etc.). For example, assuming calibration has been done and needs to be documented, then the accepted procedures followed to complete the calibration need to be described. This would include some quantitative assessment of the results of the calibration.
14. The model fails to consider the transient nature of the system. There needs to be a valid technical rationale for accepting a steady state model. No rationale was provided for using a steady-state model, nor for the selection of March 2006 as the appropriate observed hydraulic heads to use for calibration. Does the seasonal variation in recharge drive this aquifer system to be dynamic or transient over an annual cycle?

2.5 Geology, Seismology, and Geotechnical Engineering

The geological, seismological, and geotechnical engineering properties of the VEGP site are presented in this section. Subsection 2.5.1 describes basic geological and seismologic data. Subsection 2.5.2 describes the vibratory ground motion at the site, including an updated seismicity catalog, description of seismic sources, and development of the Safe Shutdown Earthquake (SSE) ground motion. Subsection 2.5.3 describes the potential for surface faulting in the site area, and Subsections 2.5.1, 2.5.5, and 2.5.6 describe the stability of subsurface materials and foundations at the site.

NRC Regulatory Guide 1.165, *Identification and Characterization of Seismic Sources and Determination of Safe Shutdown Earthquake Ground Motion* (RG 1.165) (1997), Appendix D, *Geological, Seismological and Geophysical Investigations to Characterize Seismic Sources*, provides guidance for the level of investigation recommended at different distances from a proposed site for a nuclear facility.

The following four terms for site map areas are designated by RG 1.165:

- Site region - area within 200 mi (320 km) of the site location.
- Site vicinity - area within 25 mi (40 km) of the site location.
- Site area - area within 5 mi (8 km) of the site location.
- Site - area within 0.6 mi (1 km) of the proposed VEGP Unit 3 and 4 locations.

These terms are used in Subsections 2.5.1 through 2.5.3 to describe these specific areas of investigation. These terms are not applicable to other sections of this ESP application.

SNC conducted field investigations and performed extensive research of relevant geologic literature to reach the conclusion that no geologic or seismic hazards have the potential to affect the VEGP site except the Charleston seismic zone and a small magnitude local earthquake occurring in the site region. These topics are discussed in greater technical detail in Subsection 2.5.2. There is only limited potential for non-tectonic surface deformation in shallow deposits within the 5-mi site area radius, and this potential can be mitigated by means of excavation.

RG 1.165 states that the vibratory design ground motion for a new nuclear power plant may be developed using either the Electric Power Research Institute (EPRI) or Lawrence Livermore National Laboratory (LLNL) probabilistic seismic hazard methodology. As described in Subsection 2.5.2, the EPRI methodology has been used to develop the SSE ground motion for the VEGP site. RG 1.165 further requires that the geological, seismological, and geophysical database be updated and any new data be evaluated to determine whether revisions to the 1986 EPRI seismic source model are required (presented in Subsection 2.5.2). This section, therefore, provides an update of the geological, seismological, and geophysical database for the VEGP site, focusing on whether any data published since the 1980s indicates a significant change to the 1986 EPRI seismic source model. In addition, the geotechnical properties of the VEGP site location are described to evaluate the ground motion site response characteristics of the site (i.e., non-tectonic geologic and man-made hazards at the site presented in Subsection 2.5.2).

2.5.1 Basic Geologic and Seismic Information

This section presents information on the geological and seismological characteristics of the VEGP site region and site area. The information is divided into two parts. Subsection 2.5.1.1 describes the geologic and tectonic setting of the site region (200 mi), and Subsection 2.5.1.2 describes the geology and structural geology of the site area (5 mi). The geological and seismological information was developed in accordance with the guidance presented in NRC Regulatory Guide 1.70, *Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, LWR Edition* (RG 1.70) (1978), Subsection 2.5.1, *Basic Geologic and Seismic Information*, and RG 1.165 and is intended to satisfy the requirements of 10 CFR 100.23(c). The geological and seismological information presented in this section is used as a basis for evaluating the detailed geologic, seismic, and man-made hazards at the site.

The geological and seismological information presented in this section was developed from a review of previous reports prepared for the existing VEGP Units 1 and 2, published geologic literature, new boreholes drilled at the VEGP Units 3 and 4 site and a seismic refraction and reflection survey. A review of published geologic literature was used to supplement and update the existing geological and seismological information. A list of the references used to compile the geological and seismological information presented in the following sections is provided at the end of each major subsection within Section 2.5.

2.5.1.1 Regional Geology (200 mi radius)

This section discusses the regional geology within a 200-mi radius of the VEGP site. The physiography and geomorphology, geologic setting and stratigraphy, and tectonic setting are discussed below. The information provided is a brief summary of this broad area, with an extensive and current bibliography. The information also provides the basis for evaluating the geologic and seismologic hazards discussed in the succeeding sections.

2.5.1.1.1 Regional Physiography and Geomorphology

From northwest to southeast the site region includes parts of the Valley and Ridge, Blue Ridge, Piedmont, and Coastal Plain provinces. The VEGP site is located on the upper Coastal Plain, about 30 mi (48 km) southeast of the Fall Line that separates the Piedmont and Coastal Plain provinces (Figure 2.5-204).

The Valley and Ridge Physiographic Province

The Valley and Ridge physiographic province extends from the 25-mi wide Hudson Valley in New York State to a wider 75-mi zone in Pennsylvania, Maryland, and Virginia and is about 50 mi wide from southern Virginia southward to Alabama. This physiographic province is underlain by a folded and faulted sequence of Paleozoic sedimentary rocks. The linear valleys and ridges typical of this province are the result of differential weathering and erosion in a humid environment of lithologies that are more or less resistant to these geomorphic processes.

The Blue Ridge Physiographic Province

The Blue Ridge physiographic province is located west of and adjacent to the Piedmont province. The Blue Ridge province extends from Pennsylvania to northern Georgia. It varies from about 10 to 75 mi (16 to 120 km) wide, north to south. Elevations are highest in North Carolina and Tennessee, with several peaks in North Carolina exceeding 5,900 ft (1,800 m) msl, including Mount Mitchell, North Carolina, the highest point (6,684 ft [2,037 m] msl) in the Appalachian Mountains. The Blue Ridge front, with a maximum elevation of about 3,950 ft (1,200 m) msl in North Carolina, is an east-facing escarpment between the Blue Ridge and Piedmont provinces in the southern Appalachians.

The Blue Ridge province is comprised primarily of relatively more resistant granites and granitic gneisses that form a broad mountainous upland area in Georgia.

The Piedmont Physiographic Province

The Piedmont physiographic province extends southwest from New York to Alabama and lies west of and adjacent to the Atlantic Coastal Plain. It is the eastern-most physiographic and structural province of the Appalachian Mountains. The Piedmont is a seaward-sloping plateau whose width varies from about 10 mi (16 km) in southeastern New York to almost 125 mi (200 km) in North Carolina; it is the least rugged of the Appalachian provinces. Elevation of the inland boundary ranges from about 200 ft (60 m) msl in New Jersey to over 1,800 ft (550 m) msl in Georgia.

The Piedmont province is divided into the Piedmont Upland section to the west and the Piedmont Lowland section to the east. The Piedmont Upland section is underlain by metamorphosed sedimentary and crystalline rocks of Precambrian to Paleozoic age. These lithologies are relatively resistant, and their erosion has resulted in a moderately irregular surface. Topographically higher terrain is underlain by Cambrian quartzites and Precambrian crystalline rocks. The Piedmont Lowland section is a less rugged terrain containing fault-bounded basins filled with sedimentary and igneous rocks of Triassic and Early Jurassic age (referred to as the Triassic Basin Rocks).

The Coastal Plain Physiographic Province

The Atlantic Coastal Plain extends southward from Cape Cod, Massachusetts, to south-central Georgia where it merges with the Gulf Coastal Plain. The surface of the Coastal Plain slopes gently seaward. The province is underlain by a seaward-dipping wedge of unconsolidated and semiconsolidated sediments that extend from the contact with the crystalline Piedmont province at the Fall Line to the edge of the continental shelf. In Georgia, the province is known as the Coastal Plain province. Sediment thickness increases from zero at the Fall Line to about 4,000 ft (1,200 m) at the Georgia - South Carolina coastline.

The VEGP site is located within a portion of the Coastal Plain in which depositional landforms have been obliterated by fluvial erosion based on studies in South Carolina (Reference 241). The lower coastal plain south of the site is dominated by primary depositional topography that has been modified slightly by fluvial erosion. In addition, the Coastal Plain contains numerous, minor geomorphic features, called Carolina bays. Since the origin of these minor geomorphic features has been controversial they are discussed in more detail in the following paragraphs. However, it is believed that these features formed as a result of erosion by predominantly southwesterly winds (Reference 448).

Carolina bays are shallow, elliptical depressions with associated sand rims that are found on the surface of the Coastal Plain sediments. These features, common throughout the Atlantic Coastal Plain, are most numerous in North and South Carolina, with major axes of the depressions up to 1.1 mi (1.8 km) long (Reference 437). The depressions are found from southern New Jersey to northern Florida, with the greatest occurrence in the Carolinas (Reference 448). One hundred ninety-four confirmed or suspected Carolina bays have been identified at the Savannah River Site (SRS), a US Department of Energy (DOE) reservation located directly east of the VEGP site area on the South Carolina side of the Savannah River. The long axes of the bays are oriented S50°E (Reference 338), and the sand rims generally are observed on the east and southeast flanks. Various authors have provided a range of hypotheses for the timing and mode of origin of these bays [e.g., (Reference 290; Reference 410; Reference 248; Reference 385; Reference 344)]. Theories regarding the origin of bays include meteorite impact, sinks, wind, and water currents [e.g., (Reference 385; Reference 410; Reference 248; Reference 464; Reference 290; Reference 344). The origin of these features remains indeterminate.

Prouty (1952), Savage (1982), and Kaczorowski (1976) provide the most likely explanation of formation: the bays formed by action of strong unidirectional wind on water ponded in surface depressions (Reference 448). The resulting waves caused the formation of the sand rims as shoreline features, and the sand rims formed perpendicular to the wind direction. The wind bays observed today formed in response to a southwesterly wind (Reference 448).

The Carolina bays are surficial features that have no effect on the subsurface sediments. Based on subsurface core data, a clay layer mapped beneath the bays and outside their rims has no greater relief beneath the bays than beyond them (Reference 290). Bryant and McCracken (1964), Preston and Brown (1964), and Thom (1970) provide additional evidence of the surficial character of Carolina bays. In these studies, certain identified strata were mapped and were found to be continuous and undeformed beneath bay and interbay areas. In Horry and Marion counties, South Carolina, there was no evidence of solution-related subsidence of the Carolina bays in spite of the presence of carbonate-rich strata in the subsurface and some localized sink holes of irregular shape with depths on the order of 20 ft. Early studies suggest that the bay-like depressions in the vicinity of the VEGP site (at SRS) probably resulted from dissolution of carbonate from the underlying geological formations (Reference 437). However, this has not been substantiated.

The age of the Carolina bays is based on Soller (1988) and Thom (1970). A minimum age has been set at middle to late Wisconsinan based on radiocarbon date (Reference 464). The maximum age can be constrained by examination of the formations on which the bays rest (Reference 448). This places bay formation between 100,000 and 200,000 years ago (ka) (Reference 448). If there is more than one generation, then the bays could be as old as the formations on which they rest.

2.5.1.1.2 Geologic History

The VEGP site is located in the Coastal Plain Physiographic province. Portions of all the major lithotectonic divisions of the Appalachian orogen (mountain belt) are found within a 200-mile (320-km) radius of the VEGP site. The structures and stratigraphic sequences within these divisions represent a complex geologic evolution that ends in the modern day passive margin of the Atlantic continental margin. Subsections 2.5.1.1.3 and 2.5.1.1.4 provide additional detail.

Within the Appalachian orogen, several lithotectonic terranes that have been extensively documented include the foreland fold belt (Valley and Ridge) and western Blue Ridge Precambrian–Paleozoic continental margin; the eastern Blue Ridge–Chauga Belt–Inner Piedmont Terrane; the volcanic-plutonic Carolina-Avalon Terrane; and the geophysically defined basement terrane beneath the Atlantic Coastal Plain [for an expanded bibliography see (Reference 315, Reference 316, Reference 318, Reference 319)]. These geological divisions contain the regional geologic record for the complete cycles of Precambrian and Paleozoic orogens and subsequent opening and closing of ocean basins (Proterozoic Iapetus Ocean and the opening of the Atlantic Ocean) (Reference 316).

The late Proterozoic rifting is recorded in rift-related sediments at the edge of the frontal Blue Ridge province and the Ocoee and Tallulah Falls basins in the western and eastern Blue Ridge, respectively. Passive margin conditions began in the middle Cambrian and persisted through early Ordovician. The Cambro–Ordovician sedimentary section in the Valley and Ridge reflects this condition. The collision-accretionary phase of the Appalachians began in the middle Ordovician and persisted with pulses through the early Permian (Penobscot/Taconic, Acadian, Alleghanian orogenies). Subsection 2.5.1.1.4 provides additional discussion.

The modern continental margin includes the Triassic basins that record the beginning of extension and continental rifting during the early to middle Mesozoic leading to the formation of the current Atlantic Ocean. One locus of major extension during early stages was in the South Georgia rift, which extends from Georgia into South Carolina. The Dunbarton Basin, underlying the VEGP site and SRS, is likely structurally related to the South Georgia rift basin (Reference 453) (Figure 2.5-205).

Subsection 2.5.1.1.3.4 provides additional discussion. During the later stage of rifting (early Jurassic), the focus of extension shifted eastward to the major marginal basins that would become the site of the Atlantic Ocean basin. The extension in the onshore, western-most basins, such as the Dunbarton, waned. Eventually, rifting of continental crust ceased as sea floor spreading began in the Atlantic spreading center sometime around 175 million years ago (Ma) (Reference 356). The oldest ocean crust in contact with the eastern continental margin is late middle Jurassic (Reference 355). The significance of the transition from rifting to sea floor spreading is that the tectonic regime of rifting is no longer acting on the continental crust along the Eastern Atlantic margin.

After the continental extension and rifting ended, a prograding shelf-slope began to form over the passive continental margin. The offshore Jurassic–Cretaceous clastic-carbonate bank sequence covered by younger Cretaceous and Tertiary marine sediments, and onshore Cenozoic sediments, represent a prograding shelf-slope Reference 316 and the final evolution to a passive margin. Cretaceous and Cenozoic sediments thicken from near zero at the Fall Line to about 1,000 ft (335 m) in the center of the VEGP area, to approximately 4,000 ft (1,219 m) at the Georgia and South Carolina coast. The fluvial-to-marine sedimentary wedge consists of alternating sand and clay with tidal and shelf carbonates common in the downdip Tertiary section. Other offshore Continental margin elements include the Florida–Hatteras shelf and slope and the unusual Blake Plateau basin and Escarpment (Reference 264; Reference 356; Reference 406).

2.5.1.1.3 Regional Stratigraphy and Geologic Setting

The regional stratigraphy within each of the physiographic provinces is presented below. The generalized geology and stratigraphy within a 200-mi radius of the VEGP site is shown on Figures 2.5-206 and 2.5-207. The stratigraphy shown on Figures 2.5-206 and 2.5-207 is from a portion of The Geologic Map of the United States (Reference 352). The regional stratigraphy of the rock units shown on Figure 2.5-206 is illustrated by the legend (Figure 2.5-207). The rock units are classified based on age and type.

2.5.1.1.3.1 Valley and Ridge Province

The Valley and Ridge lithotectonic terrane contains Paleozoic sedimentary rock consisting of conglomerate, sandstone, shale, and limestone (Figures 2.5-204, 2.5-206 and 2.5-217). This continental shelf sequence was extensively folded and thrust faulted during the Alleghanian collisional event. The physiography is expressed as a series of parallel ridges and valleys. To the east is the boundary with the Blue Ridge province, at the Blue Ridge–Piedmont fault system. This boundary is fairly distinct in most places along the strike of the Appalachians and marks the change from folded rocks that are not penetratively deformed to rocks that are penetratively deformed.

2.5.1.1.3.2 Blue Ridge Province

The Blue Ridge lithotectonic province is bounded on the southeast by the Brevard fault zone and on the northwest by a predominantly thrust fault system (Reference 310; Reference 308; Reference 349) (Figure 2.5-217). The province is a metamorphosed basement/cover sequence that has been complexly folded, faulted, penetratively deformed, and intruded. These rocks record multiple late Proterozoic to late Paleozoic deformation (extension and compression) associated with the formation of the Iapetus Ocean and the Appalachian orogen (Reference 310; Reference 324; Reference 312; Reference 390; Reference 306). The province consists of a series of westward-vergent thrust sheets, each with different tectonic histories and different lithologies, including gneisses, plutons, and metavolcanic and metasedimentary rift sequences, as well as continental and platform deposits [see (Reference 310 and Reference 316)] for an expanded bibliography). The Blue Ridge–Piedmont fault system thrust the entire Blue Ridge province northwest over Paleozoic sedimentary rock of the Valley and Ridge province during the Alleghanian orogeny (Reference 304,

Reference 305; Reference 245; Reference 249). The Blue Ridge geologic province reaches its greatest width in the southern Appalachians.

The Blue Ridge is divided into a western and an eastern belt separated by the Hayesville-Gossan Lead fault. Thrust sheets in the western Blue Ridge consist of a rift-facies sequence of clastic sedimentary rocks deposited on continental basement, whereas thrust sheets in the eastern Blue Ridge consist of slope and rise sequences deposited in part on continental basement and on oceanic crust (Reference 310; Reference 306). Western Blue Ridge stratigraphy consists of basement gneisses and metasedimentary, metaplutonic, and metavolcanic rocks, whereas Eastern Blue Ridge stratigraphy consists of fewer lithologies, more abundant mafic rocks, and minor amounts of continental basement.

Western Blue Ridge

The western Blue Ridge consists of an assemblage of Middle Proterozoic crystalline continental (Grenville) basement rock nonconformably overlain by Late Proterozoic to Early Paleozoic rift and drift facies sedimentary rock (Reference 316). The basement consists of various types of gneisses, amphibolite, gabbroic and volcanic rock, and metasedimentary rock. All basement rock is metamorphosed to granulite or uppermost amphibolite facies (Reference 316). The calculated ages of these rocks generally range from 1,000 to 1,200 million years old (Ma) [e.g., Reference 289; Reference 286; Reference 288)].

The rifting event during the Late Proterozoic through Early Paleozoic that formed the Iapetus Ocean is recorded in the rift-drift sequence of the Ocoee Supergroup and Chillhowie Group [e.g., Reference 478; Reference 418; Reference 354; Reference 392; Reference 350)]. These rocks, basement, and sedimentary cover were later affected by Taconic and possibly Acadian deformation and metamorphism. The entire composite thrust sheet was transported west as an intact package during the Alleghanian collision event on the Blue Ridge–Piedmont thrust.

Eastern Blue Ridge

The eastern Blue Ridge is located southeast of the western Blue Ridge and is separated from that province by the Hayesville-Gossen Lead fault. The Brevard fault zone forms the southeastern boundary with the Inner Piedmont. The eastern Blue Ridge is composed of metasedimentary rocks originally deposited on a continental slope and rise and ocean floor metasedimentary rocks in association with oceanic or transitional to oceanic crust [for expanded bibliography see (Reference 316; Reference 324)]. This is in contrast to the previously discussed western Blue Ridge that contains metasedimentary rocks suggesting continental rift-drift facies of a paleomargin setting. The eastern Blue Ridge is structurally complex, with several major thrust faults, multiple fold generations, and two high-grade metamorphic episodes (Reference 316). Metamorphism took place during the Taconic and possibly Acadian orogenies.

The stratigraphy within the eastern Blue Ridge includes rare Grenville (Precambrian) gneisses, metasedimentary rocks of the Tallulah Falls Formation and the Coweeta Group, metamorphosed Paleozoic granitoids, and mafic and ultramafic complexes and rocks of the Dahlonega Gold Belt. The Paleozoic granitoids are a part of a suite of similar granites found in the western Inner Piedmont, suggesting a common intrusive history. Metasedimentary rock sequences in the eastern Blue Ridge are correlated along strike as well as across some thrust fault boundaries, also suggesting a commonality in the original depositional history. Based on geochemical data, the mafic and ultramafic complexes found in particular thrust sheets in the eastern Blue Ridge have oceanic as well as continental affinities. However, their exact tectonic origin is not clear because the contacts with the host metasedimentary rock are obscure.

2.5.1.1.3.3 Piedmont Province

The Piedmont province in northwestern Georgia and South Carolina consists of variably deformed and metamorphosed igneous and sedimentary rocks ranging in age from Middle Proterozoic to Permian (1,100 to 265 Ma). The province consists of the Western (Inner) Piedmont and the Carolina-Avalon Terrane (Figure 2.5-217). This designation is made because of different tectonic origins for the western and eastern parts of the province. The province can also be subdivided into seven distinctive tectonostratigraphic belts separated by major faults, contrasts in metamorphic grade, or both. The Charlotte and Carolina Slate belts are combined and discussed as the Carolina-Avalon Terrane. The rocks of the Piedmont have been deformed into isoclinal recumbent and upright folds, which have been refolded and are contained in several thrust sheets or nappes. These metamorphic rocks extend beneath the Coastal Plain sediments in Georgia and South Carolina. The southeastern extent of the Piedmont province underneath the Coastal Plain is unknown.

Western Piedmont

The Western Piedmont encompasses the Inner Piedmont block, the Smith River Allochthon in Virginia and North Carolina, and the Sauratown Mountains Anticlinorium in north central North Carolina (Reference 327) (Figure 2.5-208). The Western (Inner) Piedmont is separated from the Blue Ridge province on the northwest by the Brevard Fault zone. It is separated from the Carolina–Avalon Terrane on the southeast by the Towaliga fault, a complex series of fault zones approximately coincident with the Central Piedmont suture (Reference 307). These faults include: Lowndesville, Kings Mountain, Eufola, Shacktown, and Chatham Fault zones (Reference 327). The province is a composite stack of thrust sheets containing a variety of gneisses, schists, amphibolite, sparse ultramafic bodies, and intrusive granitoids (Reference 391; Reference 295; Reference 308). The protoliths are immature quartzo-feldspathic sandstone, pelitic sediments, and mafic lavas.

The Sauratown Mountains anticlinorium is a complex structural window of four stacked thrust sheets that have been exposed in eroded structural domes. Each sheet contains Precambrian basement with an overlying sequence of younger Precambrian-to-Cambrian metasedimentary and metaigneous rocks (Reference 327). The Smith River Allochthon contains two predominantly metasedimentary units and a suite of plutonic rocks. It is a completely fault-bounded terrane, as is the Sauratown Mountains anticlinorium. The Inner Piedmont block is a fault-bounded, composite thrust sheet with metamorphic complexes of different tectonic affinities (Reference 327). There is some continental basement within the block (Reference 295)and scattered mafic and ultramafic bodies and complexes (Reference 386), suggesting the presence of oceanic crustal material (Reference 327). The rest of the block contains a coherent, though poorly understood, stratigraphy of metasedimentary rock, metavolcanic gneisses, and schists (Reference 327). The eastern Blue Ridge and Inner Piedmont contain some stratigraphically equivalent rocks (Reference 313).

The stratigraphy and structural geologic data in the western Piedmont reflects the effects of a complex tectonic history from the Precambrian Grenville through Late Paleozoic Alleghanian orogenies. Metamorphism affected the basement rocks of the Sauratown Mountains anticlinorium at least twice: during the Precambrian Grenville and later during the Paleozoic. The metasedimentary cover sequence as well as the Smith River allochthon and the Inner Piedmont block were affected by one metamorphic event (prograde and retrograde) in the Paleozoic (Reference 327). The Alleghanian continental collision is reflected in the thrust and dextral strike slip fault systems such as the Brevard and Bowens Creek fault zones. A few late Paleozoic granites were emplaced in the Inner Piedmont block; however, most lie further east in the Carolina Terrane. Early Mesozoic extension resulted in the formation of rift basins (Dan River and Davie County basins).

Carolina-Avalon Terrane

The Carolina Terrane is part of a late Precambrian–Cambrian composite arc terrane exotic to North America (Reference 430; Reference 425) and accreted sometime during the Ordovician to Devonian

(Reference 473; Reference 393). It consists of felsic to mafic volcanic rock and associated volcaniclastic rock. Middle Cambrian fossil fauna indicate a European or African affinity (Reference 430).

The northwestern boundary of the Carolina–Avalon Terrane is formed by a complex of faults that constitute the Central Piedmont suture (Figures 2.5-208 and 2.5-209) and separate the terrane from rocks of North American affinity [see (Reference 314; Reference 323; Reference 450; Reference 297; Reference 260; Reference 421; Reference 326; Reference 322; Reference 383)]. This structure was reactivated during the later Alleghanian collisional events as a dextral shear fault system (Reference 218). Subsequent investigators have further enhanced the geological knowledge of the complicated structure (Reference 431, Reference 432; Reference 309; Reference 323). Dennis (1991) suggested that the Central Piedmont suture is a low-angle normal fault. The Carolina-Avalon Terrane (also known as the Carolina Terrane) is bounded on the southeast by the Modoc fault zone and the Kiokee belt (Figure 2.5-209).

The Carolina–Avalon Terrane is the combination of the earlier Charlotte and Carolina slate belts. The belts were initially distinguished by metamorphic grade (Reference 349) and were later recognized as the same protolith and thus were combined (Reference 316). Metamorphic grade increases to the northwest from lower greenschist facies to upper amphibolite facies. Pre-Alleghanian structure is dominated by large northeast trending folds with steeply dipping axial surfaces. All country rock of the Carolina-Avalon Terrane has been penetratively deformed, thereby producing axial plane cleavage and foliation (Reference 316).

The Charlotte belt contains numerous intrusions and moderate- to high-grade metamorphic rock. Much of the belt was metamorphosed to amphibolite grade during the Taconic orogeny (Reference 230), but retrograde metamorphism is also widespread. The oldest rocks are amphibolite, biotite gneiss, hornblende gneiss, and schist, and probably were derived from volcanic, volcaniclastic, or sedimentary protoliths.

The Carolina Slate belt (Figure 2.5-209) is characterized by thick sequences of metasedimentary rocks derived from volcanic source areas and felsic to mafic metavolcanic rocks. The oldest rocks within the Carolina Slate belt consist of intermediate to felsic ashflow tuff and associated volcaniclastic rocks. These rocks are overlain by a sequence of mudstone, siltstone, sandstone, greywacke, and greenstone, with some interbedded volcanic tuff and flows. The belt was subjected to low- to medium-grade regional metamorphism and folding from 500 to 300 Ma and was intruded subsequently by granitic and gabbroic plutons about 300 Ma.

Kiokee Belt

The Kiokee belt is located between the Carolina-Avalon Terrane and the Belair belt in Georgia and South Carolina (Figure 2.5-209). It is referred to as the Savannah River Terrane in some of the recent literature (Reference 368). The Kiokee belt is bounded on the northwest by the Modoc fault zone and on the southeast by the Augusta fault (the Modoc fault zone and the Augusta fault are discussed in Subsection 2.5.1.1.4.3). The Kiokee belt is a medium- to high-grade metamorphic belt with associated plutonism (Reference 258). Snoke et al. (1980) concluded that the Kiokee belt was part of the Alleghanian metamorphic core. That core was deformed and metamorphosed prior to the development of the plastic shear zones bounding it (Reference 431). The bounding faults are mylonite zones that overprint the amphibolite facies infrastructure of the core of the belt (Reference 316).

The Kiokee belt is an antiformal structure that strikes northeast. The interior is a migmatitic complex of biotite amphibole paragneiss, leucocratic paragneiss, sillimanite schist, amphibolite, ultramafic schist, serpentinite, feldspathic metaquartzite, and granitic intrusions of Late Paleozoic age (Reference 429). Some of the lithologic units found in the Carolina slate belt may occur at higher metamorphic grade in the Kiokee belt (Reference 316).

From extensive field studies and geochronological dating, a complex Alleghanian history can be derived from the studies of the Kiokee belt (Reference 225; Reference 366; Reference 444; Reference 257; Reference 287; Reference 445; Reference 303; Reference 424). The pre-Alleghanian structure and stratigraphy are only partially known. The nature of the crustal rock that played a part in the metamorphism, deformation, and intrusion is still unknown. The possible role of a Precambrian basement in the Kiokee belt is a key question proposed by Hatcher et al. (1994). No rock in the Kiokee belt has been identified at this time as Precambrian basement. However, Long and Chapman (1977), suggested, based on gravity data, that a large rifted block of continental crust underlies the Kiokee belt.

Belair Belt

The Belair belt, also known as the Augusta Terrane (Reference 366, Reference 367), is locally exposed in the Savannah River valley, near Augusta, Georgia (Figure 2.5-209). It is largely concealed beneath the Atlantic Coastal Plain, but is exposed in several small erosional windows through the Coastal Plain sediments in eastern Georgia (Reference 226). The Belair belt consists of intermediate to felsic volcanic tuffs and related volcaniclastic sediments penetratively deformed and metamorphosed to greenschist facies (Reference 226; Reference 365, Reference 366, Reference 367, Reference 311; Reference 414; Reference 411; Reference 395). The Belair belt displays similar characteristics as the Carolina-Avalon Terrane (Reference 370). Geophysical and well data indicate that the Belair belt extends beneath the Atlantic Coastal Plain (Reference 258). Near Augusta, the Augusta fault and the southeast edge of the Kiokee belt appear to be offset by the north-northeast trending Cenozoic Belair fault (Figure 2.5-209) (discussed in Subsection 2.5.1.1.4.3).

2.5.1.1.3.4 Mesozoic Rift Basins

While primarily exposed in the Piedmont Province, Mesozoic-age rift basins are found along the entire eastern continental margin of North America from the Gulf Coast through Nova Scotia (Figure 2.5-210). The basins formed in response to the continental rifting episode that broke up the supercontinent, Pangea, and led to the formation of the Atlantic Ocean basin. Rift basins are exposed in the Piedmont province as well as buried beneath Cretaceous and younger Coastal Plain sediments. Many underlie offshore regions. Structurally, the basins are grabens or half grabens elongated in a northeast direction and bounded by normal faults on one or both sides (Reference 371). Several basins were localized along reactivated Paleozoic ductile or brittle fault zones (Reference 404; Reference 336; Reference 419; Reference 359; Reference 293).

The basins are located in extended or rifted continental crust, identified as the Eastern Seaboard domain (subdomain of North American stable continental crust) (Reference 345). Rifted crust is crust that has been stretched, faulted, and thinned slightly by rifting but is still recognizable as continental crust. The faulting is extensional or normal, and down-dropped blocks form rift basins. The western boundary of this zone of extended crust is defined by the western-most edge of Triassic–Jurassic onshore rift basins or the boundaries of the structural blocks in which they occur (Reference 356; Reference 346; Reference 345). The eastern boundary is the continental shelf (Reference 298).

Two belts of basins occur in the Eastern Seaboard domain, from the Carolinas to Pennsylvania **(Olsen et al. 1991)**: an eastern belt of basins buried by Atlantic Coastal Plain Sediments and a western belt exposed in the Piedmont Physiographic Province. In North and South Carolina, the Deep River, Elberbe, and Crowburg basins are in the eastern belt, and the Dan River and Davie County basins are in the western belt (Reference 402). In addition, the Dunbarton, Florence, Riddleville, and South Georgia basins are buried beneath Coastal Plain sediments in the eastern belt (Figure 2.5-210).

The basins are generally filled with lacustrine sedimentary and igneous rock. Sedimentary strata consist mainly of non-marine sandstone, conglomerate, siltstone, and shale. Carbonate rocks and coal are found locally in several basins. Igneous rocks of basaltic composition occur as flows, sills,

and stocks within the basins and as extensive dike swarms within and outside the basins (Reference 351). These basin fill strata have been described and named the Newark Supergroup (Reference 400; Reference 285; Reference 402). In general, the stratigraphy can be divided into three sections. The lower section is characteristically fluvial (Reference 440; Reference 296) and contains reddish-brown, arkosic, coarse-grained sandstone and conglomerate. The middle section mainly includes sediments of lacustrine origin (Reference 440). These sediments include gray-black fossiliferous siltstone, carbonaceous shale, and thin coal beds (Reference 402). The upper section is a complex of deltaic, fluvial, and lacustrine environments (Reference 401; Reference 428). These sediments include red-brown siltstone, arkosic sandstone, pebble sandstone, red and gray mudstone, and conglomerate (Reference 402).

In Georgia and South Carolina, the Dunbarton Triassic rift basin, a sub-basin within the South Georgia Basin, is located beneath Coastal Plain sediments below the SRS and the VEGP sites (Figure 2.5-210). The Dunbarton Basin was first identified based on aeromagnetic and well data (Reference 437). Subsequent seismic reflection surveys, potential field surveys, and additional well data have led to the current understanding of the basin (Reference 372, Reference 373; Reference 374; Reference 232; Reference 208; Reference 451; Reference 362; Reference 266). The structure is interpreted as an asymmetric graben approximately 31 mi long and 6 to 9 mi wide. The axis of the basin strikes northeast, parallel to the regional strike of crystalline basement (Reference 374) The basin extends 5 mi southwest of the Savannah River and 25 mi to the northeast of the SRS, where it terminates against a granite body interpreted from magnetic data (Reference 437; Reference 372, Reference 373; Reference 208). The primary fault controlling basin formation, the Pen Branch fault, bounds the northwest side of the basin. The fault appears to have been an earlier Paleozoic reverse fault that was reactivated as an extensional normal fault during Mesozoic continental rifting. The fault was subsequently reactivated in the Cenozoic as a reverse fault or right-oblique slip fault (Reference 409; Reference 442; Reference 453). The Pen Branch fault dips to the southeast. The master fault to the Riddleville Basin in Georgia also dips to the southeast (Reference 404). Subsections 2.5.1.1.4.3 and 2.5.1.2.4.1 provide further discussion of the Mesozoic basins and the Pen Branch fault, respectively. The southeast boundary of the Dunbarton basin is poorly constrained but is interpreted as fault bounded **(**Reference 280; Reference 443).

Fourteen wells drilled at the SRS penetrated sedimentary rocks of the Dunbarton Basin. Recovered core is Mesozoic clastic rock (Reference 403; Reference 374). Conglomerate, fanglomerate, sandstone, siltstone, and mudstone are the dominant lithologies. These rocks are similar to the clastic facies in other Newark Supergroup basins. Conglomerate and red clayey siltstone are the dominant lithologies in those cores. Parsons Brinckerhoff (1973) concluded that the lithology and stratigraphy identified in the core indicate that the proximal side of the basin is to the northwest. A larger component of coarse-grained rock types occurs to the northwest than on the southeast side of the basin. This suggests an asymmetric basin with greater cumulative separation on the northwest than to the southeast. This asymmetry led to greater local relief along the northern boundary, where high energy fluvial processes dominated, and the resulting sediments are coarser grained than farther out in the basin.

Gravity and magnetic modeling suggests that the Triassic section in the Dunbarton Basin is at least 1.2 mi (2 km) thick. Boreholes have encountered up to 899 m of Triassic fill, but the base of the Dunbarton was not encountered (Reference 374). Seismic reflection data do not unequivocally constrain the base of the basin; the transition between the Triassic rock and the crystalline terrane is unclear. However, interpreted Triassic reflectors are at least as deep as 1 to 2.3 mi (1.6 to 3.7 km) (Reference 266).

The South Georgia Basin, further east and south in Georgia and South Carolina, is a much larger, deeper, and more complex basin than the Dunbarton Basin. The basin is as wide as 62 mi and as deep as 4 mi (Reference 380). It is not a single basin, but a complex of isolated synrift grabens with

limited major crustal extension. The major border fault dips northward (Reference 380), as opposed to southeastward, for the controlling faults bounding the Dunbarton Basin.

Further to the northeast, in North Carolina, two major basins are exposed: the Dan River and Deep River basins. Both basins exhibit half-graben geometry, bounded on one side by a major normal fault zone. However, the border faults on the two basins are on opposite flanks of the basin: Dan River's Chatham fault zone dips to the southeast and Deep River's Jonesboro fault zone dips northwest (Reference 402).

2.5.1.1.3.5 Coastal Plain

In the Coastal Plain, rocks of Paleozoic and Triassic age have been beveled by erosion and are unconformably overlain by unconsolidated to poorly consolidated Coastal Plain sediments (Reference 247; Reference 437; Reference 241). The sediments of the Coastal Plain in Georgia and South Carolina are stratified sand, clay, limestone, and gravel that dip gently seaward and range in age from Late Cretaceous to Recent. The sedimentary sequence thickens from essentially zero at the Fall Line to more than 4,000 ft (1,219 m) at the coast **(Colquhoun et al. 1983)**. Regional dip is to the southeast, although beds dip and thicken locally in other directions because of locally variable depositional regimes and differential subsidence of basement features.

Many investigations have provided insight into the evolution of the southeastern United States Coastal Plain, including: Cooke (1936), Siple (1967), Huddlestun and Hetrick (1978), Colquhoun and Steele (1985), Prowell et al. (1985a, 1985b), Dennehy et al. (1988), Fallaw et al. (1990a, 1990b, 1992, 1995), Nystrom et al. (1990), Aadland and Bledsoe (1990), Huddlestun and Summerour (1996) and, most recently, Falls and Prowell (2001). The Coastal Plain section is divided into several rock-stratigraphic groups based principally on age and lithology (Figure 2.5-211).

The VEGP Units 3 and 4 site is located on the Coastal Plain. Numerous geologic studies have been conducted in the surrounding area since initial studies were conducted for the existing VEGP units. Most of these studies were conducted in the vicinity of the SRS and focused on correlating both geologic and hydrogeologic formations present in Georgia and South Carolina resulting in an updated stratigraphic nomenclature. A correlation chart showing the Vogtle FSAR, current USGS, Georgia Geological Survey, South Carolina and SRS nomenclature is provided in Figure 2.5-211. The following sections describe each geologic unit (from oldest to youngest), largely taken from the recent work of the USGS (Reference 278) and the Georgia Geological Survey (Reference 334).

Cretaceous Sediments

Five deep test holes were drilled in the Georgia Coastal Plain sediments of Burke and Screven counties by the USGS and the Georgia Geologic Survey to determine the stratigraphy of the Upper Cretaceous and Tertiary sediments in eastern Georgia near the Savannah River (Figure 2.5-212) (Reference 278). The Cretaceous sections in the cores are divided into the Cape Fear Formation, the Pio Nono/Middendorf Formation, the Gaillard/Black Creek Formation (regionally, the Black Creek Group), and the Steel Creek Formation (Figure 2.5-211). These units consist of siliciclastic sediments. Evidence for possible unconformities led the investigators to recognize two subunits in the Middendorf and three subunits in the Black Creek Group. Each contact between units is a regional unconformity and denotes considerable hiatus in sedimentation. The depositional environment for all four units is interpreted as a set of large deltaic systems that prograded across the continental shelf in east-central Georgia and western South Carolina.

Cape Fear Formation

The Cape Fear Formation consists of partially lithified to unlithified, poorly to very poorly-sorted clayey sand and sandy clay with a few beds of silty clay. The sand is fine to very coarse with granules and pebbles and is predominantly angular to subangular quartz with some feldspar. Cristobalite in

the clay matrix results in lithologies that are harder and denser than sediments in the other Cretaceous units. The cristobalitic clay matrix imparts a yellowish-green to greenish-gray color to most of the lithologies and occludes most of the intergranular porosity in the sand beds. In three out of the five test holes evaluated by the USGS, the bottom of the Cape Fear Formation was drilled through and the formation ranges in total thickness from 96 to 212 ft, thickening in the downdip direction.

The Cape Fear Formation contains multiple fining-upward cycles that range in thickness from 3 to 15 ft. Each cycle grades upward from a basal pebbly coarse sand to a clayey sand or clay. The clays are oxidized and are generally stained with reddish-brown and yellowish-brown patches of iron oxide. A root-trace pattern is present at the top of a few of the fining-upward cycles. The upper contact sediments are typically stained with iron oxides.

Most of the strata in this unit are without fossils; however, a silty clay sample from one of the cores contains low-abundance and low-diversity pollen assemblages. Palynologic analysis indicates a Coniacian microflora (Reference 284). This is consistent with the microflora of the Cape Fear Formation of South Carolina and North Carolina (Reference 237; Reference 236; Reference 446). Prowell et al. (1985a) and Fallaw and Price (1995) suggested a Santonian age for unit UK1 and the Cape Fear Formation at the SRS. Huddlestun and Summerour (1996) suggested that the Cape Fear Formation is equivalent to the Cenomanian-Turonian Tuscaloosa Formation of western Georgia.

The presence of a terrestrial microflora and the absence of dinoflagellates (marine fossils) in the Cape Fear Formation suggest deposition in a nonmarine environment. The multiple fining-upward cycles, the coarse texture of the sand layers, the iron-oxide staining, and the root-trace patterns in the clay layers suggest that most of this unit was deposited in channel and overbank environment during aggradation of a fluvially dominated, subaerially exposed part of a delta-plain environment.

Pio Nono/Middendorf Formation

The Pio Nono/Middendorf Formation unconformably overlies the Cape Fear Formation with a distinct contact. The formation is marked by an abrupt change from the moderately indurated clay and clayey sand of the underlying Cape Fear to the slightly indurated sand and lesser clayey sand of the Pio Nono/Middendorf. The Pio Nono/Middendorf sand units are moderately to poorly-sorted and are very porous and permeable in comparison to the sand units in the underlying Cape Fear. The Pio Nono/Middendorf consists predominantly of unlithified sand, which is locally fine to very coarse or fine to medium quartz. The mineral assemblage includes smoky-quartz granules and pebbles, mica, lignite, and generally very little clay matrix. The basal zone is often pebbly. The formation has a maximum known thickness of about 520 ft (158 m) in Georgia (Reference 238). Total thickness of the unit in the USGS test holes ranges from 157 to 207 ft.

The Pio Nono/Middendorf Formation contains two distinct subunits (informal, ascending Subunits 1 and 2) in the Millhaven, Girard, and Millers Pond cores (Figure 2.5-212). Each includes a basal lag deposit of poorly-sorted sand that grades upward to interbedded and interlaminated clay and sand. Micaceous and lignitic sand laminae are common in the Middendorf sections, particularly near the top of each subunit. Clay beds in some of the cores display more abundant iron-oxide staining near the top of the subunits. A root-trace pattern is observed in the clay bed at the top of Subunit 2 in the Girard core.

A Santonian age is suggested by current research (Reference 278). Lithologic and geophysical log patterns indicate the upper contact of the Pio Nono/Middendorf Formation in Georgia correlates to the UK2/UK4 boundary of Prowell et al. (1985a) and to the upper contact of the Pio Nono/Middendorf in South Carolina (Reference 273).

Dinoflagellates and other marine indicators are sparse and suggest a marginal-marine environment in the downdip cores and a nonmarine environment for this unit in the other cores.

Near Bamberg, South Carolina, the Pio Nono/Middendorf Formation consists of poorly-sorted, gray, medium to very coarse grained, angular to subangular quartz sand with quartz pebbles and sparse feldspar grains (Reference 360). Silt and fine sand are present. The angularity and large overall grain size of the quartz and the presence of feldspar indicate that deposition occurred relatively close to the source area, most likely in an upper delta plain environment. In southeastern Georgia, the Middendorf includes some shallow shelf sediments. Farther downdip, sediments of the Middendorf become finer grained. In Allendale County, South Carolina, in the vicinity of Millet, the unit consists of light gray to colorless, fine to coarse grained quartzose sand, clayey sand, and silty clay. The sand is unconsolidated and poorly to moderately-sorted. Trace amounts of heavy minerals and lignite are present. Deposition most probably occurred on a lower delta plain (Reference 360).

Gaillard /Black Creek Formation (regionally the Black Creek Group)

The Gaillard/Black Creek Formation (Black Creek Group) is distinguished from the overlying and underlying Cretaceous units by its better-sorted sand, fine grained texture, and relatively high clay content. It is generally darker, more lignitic, and more micaceous, especially in the updip part of the section, than the other Cretaceous units. The total thickness of the unit in the study area ranges from 270 to 333 ft. Falls and Prowell (2001) found that, in Georgia, the Gaillard Formation typically consists of three subunits:

- Subunit 1 - Basal, lignitic sand
- Subunit 2 - Laminated black clay and sand
- Subunit 3 - Coarsening upward sand sequence

The lag deposits observed at the bases of these subunits suggest unconformities. However, the Gaillard Formation/Black Creek Group in the Millers Pond core (updip location) is coarser and more sandy, with no recognizable subunits.

Subunit 1 is similar to the underlying Pio Nono/Middendorf Formation. The sediments consist of moderate to poorly-sorted, fine to coarse grained quartz sand. The sequence grades upward into fine and very fine sand with thin beds of clay. Sand layers contain fine lignite and mica with little clay matrix.

Subunit 2 has two sharp contacts within the subunit, observed in the downdip cores. Each contact is overlain by a basal lag of very poorly-sorted sand. Most of Subunit 2 is calcareous and contains laminae and lenses of very fine sand and sand-filled burrows. There are thick sections of silty laminated black clay. The sand layers typically contain mica, lignite, and minor glauconite.

Bioturbation features in Subunit 2 include clay-lined burrows, mottled textures, and discontinuous laminae of clay in the sands. Subunit 2 has the most abundant and diverse marine macrofaunas, microfaunas, and microfloras in the Cretaceous section in the study area, including shark teeth, pelecypods, ostracodes, benthic and planktonic foraminifers, spicules, dinoflagellates, pollen, and calcareous nannofossils.

Subunit 3 typically consists of a coarsening upward sequence with very poorly-sorted lag deposit at the base. Moderate to well-sorted, very fine to medium sand occurs above the basal lag deposit. Fine to coarse sand is found higher in the section. There are laminae and thin beds of dark gray clay, large and small lignite pieces, mica and cross-bedding.

Paleontological data from the Gaillard Formation/Black Creek Group indicate a Campanian age for the unit (Reference 284; Reference 229; Reference 294). Units UK4 and UK5 (Reference 416) and the Black Creek Group at the SRS (Reference 273) are assigned an age of Campanian to Maastrichtian. The diversity and abundance of dinoflagellates, the abundance of marine faunas, and

the presence of glauconite at Millhaven and Girard coreholes suggest a strong marine influence during the deposition of Subunit 2, probably in the distal part of a deltaic complex. Dinoflagellates in Subunit 3 suggest a marginal-marine depositional environment. The composition of the microflora and the absence of other marine indicators suggest that Subunit 1 at Millhaven and Girard, and the entire section of the Gaillard Formation/Black Creek Group at Millers Pond reflect sedimentation in a nonmarine part of the delta (Reference 284).

Steel Creek Formation

The contact between the Steel Creek Formation and the underlying Gaillard Formation/Black Creek Group is subtle in most of the test cores in the region (Reference 348; Reference 334). The contact may be conformable, paraconformable, or gradational at various locations in the region. The USGS study (Reference 278) identified the contact as unconformable and placed the boundary based on projection of the contact from a downdip test hole. The Steel Creek Formation in the study area ranges from 38 to 197 ft thick.

The Steel Creek Formation in Georgia typically consists of poorly to very poorly-sorted, fine to very coarse sand with granules and pebbles of smoky quartz. Clay matrix ranges from 5 to 15 percent. Basal lags are characteristically overlain by thick sections of oxidized clay. There are multiple fining-upward sequences in the formation. Cross-bedding is common. Lignite and mica are common accessories.

The formation is mostly barren of fossils. Some core samples yielded Cretaceous and Paleocene palynomorphs (Reference 284). Paleontology data from the Black Creek Group below and the Tertiary Black Mingo/Ellenton Formation above restrict the age to Maastrichtian.

Coarse grained sediments, fining-upward sequences, iron oxide staining, and indications of root-bearing zones indicate channel and overbank deposits in a delta-plain environment.

Tertiary Sediments

Tertiary sediments in the site area range in age from Early Paleocene to Miocene and were deposited in open marine shelf environments (downdip) to marginal-marine environments (updip) (Reference 334, Reference 278). The Tertiary sequence is divided into five units: Black Mingo/ Ellenton Formation, Snapp Formation, Congaree Formation [regionally, the Fourmile Branch/ Congaree/Warley Hill (FM/C/W) unit], Lisbon Formation (regionally, the Santee Limestone), and Barnwell Group/unit (Figure 2.5-211). The section is generally more calcareous in the downdip area than in the updip area, with greater diversity and abundance of marine microflora and fauna. The thickness of the entire Tertiary section in the study area ranges from 284 to 642 ft.

Black Mingo Formation

The Black Mingo Formation varies from a predominantly clay-rich section in the downdip area into a more sandy, clayey, and calcareous area further updip and finally to a predominantly sandy section in the most updip locations. The formation varies in total thickness from 33 to 72 ft. In the downdip core, the section contains well-sorted, fine to medium sand with large portions of well laminated clay and silty clay. The top of the section in the downdip area is calcareous and non-calcareous clay. Further updip in the Girard core, the section contains sandy carbonate, limestone, calcareous sand, and abundant glauconite, along with well laminated, non-calcareous silty clay. The sand layers are typically fine to medium grained. Several lag deposits examined have 10 to 20 percent glauconite, rounded phosphatic clasts, and shark teeth. In the updip core, the section is generally fine to very coarse sand interbedded with sandy clay. Midway in this section are interlaminated black lignitic clay and very fine to medium sand. The top of the section is clayey, fine to medium sand.

Paleontologic studies identify a diverse microflora of dinoflagellates, pollen, and calcareous nannofossils and a faunal component of ostracodes, planktonic foraminifers, pelecypods, and

gastropods in the downdip sections (Reference 270). The updip section at Millers Pond contains a low-diversity microflora of dinoflagellates and pollen (Reference 239). The marine fossils, glauconite, and carbonate in downdip sediments indicate an open-marine environment, possibly distal prodelta. The low diversity and the low abundance of dinoflagellates and the absence of other marine indicators at Millers Pond suggest a change to a more restricted marginal-marine environment.

Snapp Formation

The Snapp Formation in all test holes in the study area consists of moderate to poorly-sorted, fine to very coarse sand. The sand typically contains granules and pebbles and less than 10 percent clay matrix. The formation in the study area is from 50 to 67 ft thick. The sand section is overlain by a very light gray colored kaolin zone that is oxidized and stained red and yellow by iron oxides. Pedogenic structures are found in the clay and include root traces and desication cracks. Pyrite is disseminated in the clay and also concentrates along desication cracks. In general, there is a strong fining-upward sequence from bottom to top within the formation.

The Snapp Formation pinches out in the vicinity of the VEGP site. Snapp was not found in the Thompson Oak core. This is consistent with the described updip limit of Snapp in South Carolina, near the Upper Three Runs creek in Aiken County (Reference 273).

Paleontology samples from the downdip core hole (Millhaven) provided sparse dinoflagellates (Reference 270).

The stratigraphic position of the Snapp Formation between the Black Mingo Formation and the overlying early Eocene part of the Congaree Formation suggests that the age of the strata is either late Paleocene (Reference 416; Reference 273) or early Eocene (Reference 302).

Sedimentary characteristics suggest a fluvially dominated depositional environment in either an upper delta plain or an incised alluvial valley. The presence of dinoflagellates in the Millhaven core suggests a marginal-marine environment in the downdip part of the study area.

Congaree Formation

The Congaree Formation unit consists of mixed siliciclastic/carbonate sections in the downdip test cores and grades to siliciclastic sediments in updip holes. The total section varies from 9 to 103 ft thick.

The Congaree Formation in the downdip area of the VEGP site vicinity contains interbedded quartz sand, marl, and limestone. The sand is moderately well-sorted, very fine to fine at the bottom, grading to fine to medium grained higher in the same section. Carbonate layers, some of which are lithified, include glauconite, and have a clay matrix and fossils. Extensive burrowing is described in the sandy carbonate material.

Further updip in the Girard core, the sand layers range from fine to medium grained at the bottom of the section and grade up into medium to coarse sand interbedded with sandy carbonate, and limestone. Unlithified sandy carbonate and partially lithified calcareous sand are typical in the top portion of the section. In the most updip test hole, the unit is a 9-ft section of well-sorted, very fine to fine sand with less that 5 percent clay matrix (Reference 278). However, there are clay-lined burrows.

Dinoflagellates, pollen, and calcareous nannofossils were recovered from the core samples of the Congaree Formation unit at Millhaven and Girard. Dinoflagellates and pollen were recovered from the Thompson Oak and Millers Pond cores. Paleontologic examination of these core samples indicate that this unit is early Eocene to early middle Eocene in age and that it includes more than one biostratigraphic unit (Reference 231; Reference 283; Reference 269). Other fossils observed in the Millhaven core included bryozoans, pelecypods, and foraminifers below a depth of 462 ft, and

pelecypods and foraminifers above a depth of 462 ft. In the Girard core, pelecypods, bryozoans, and shark teeth were observed above a depth of 342 ft. Biomoldic pores indicate that gastropods also were present (Reference 278).

Sedimentary characteristics of the Still Branch Formation sections in the Girard and Thompson Oak cores suggest a nearshore-marine environment. Sedimentary characteristics of the overlying Congaree beds suggest an open-marine shelf environment for deposits in the downdip core and a fluvially dominated to marginal-marine environment for deposits in the updip cores in the vicinity of Millers Pond. However, the Warley Hill Formation at Millhaven also was deposited in an open-marine shelf environment (Reference 278).

Lisbon Formation

The Lisbon Formation is predominantly calcareous clay with limestone with a few beds of calcareous sand and clay. As discussed, the Lisbon Formation in eastern Georgia (Reference 334) includes lithologies assigned to other units (Reference 449; Reference 382; Reference 272; Reference 273, and Reference 278); the Blue Bluff Marl of the Lisbon Formation (Reference 333)**;** the Santee Limestone (Reference 438); and the McBean Limestone Formation (currently considered a Member of the Lisbon Formation) (Reference 472; Reference 334). The unit ranges between 52 and 173 ft in thickness in the VEGP site vicinity.

In the downdip Millhaven core, the Lisbon Formation can be divided into lower, middle, and upper sections. The lower section is a medium to coarse grained calcareous sand that grades into a fine to medium sandy carbonate with large oyster shells. The contact between the lower and middle sections is distinguished by a layer that is phosphatized and pyritized. The middle portion of the section is predominantly carbonate sediments that vary from marl to carbonate, with little sand in either lithology. The carbonate is well lithified with biomoldic porosity. The marl is burrow mottled to wavy laminated with minor amounts of lignite and pyrite. Fossils include foraminifers, spicules, shark teeth, pelecypods, gastropods, bryozoans, echinoids, and brachiopods. The upper section contains fine to medium sand with glauconite and marine fossils, including pelecypods, gastropods, and bryozoans.

The Lisbon Formation in the Girard test hole further updip contains a very sandy limestone with glauconite base layer. This lithology has biomoldic porosity. A marl overlies the limestone. The contact between them is pyrite rich. The marl is a fine sandy carbonate with up to 30 percent clay matrix. The sand content continues to increase to 25 percent and is very fine to fine grained. There are few macrofossils in this portion of the Lisbon.

The Lisbon Formation in the updip Millers Pond core consists of a lower sandy limestone and calcareous sand. A thin basal lag of very poorly-sorted sand separates the calcareous material from a more sandy section above. The quartz sand is fine to very coarse in calcareous sand beds and fine to medium in sandy limestone beds. The limestone below a depth of 121 ft is finely crystalline and contains glauconite and marine fossils, including pelecypods, spicules, foraminifers, and shark teeth. Marine fossils in the limestone above a depth of 100 ft include oysters and other pelecypods, foraminifers, and echinoid fragments. Biomoldic porosity also is present above a depth of 100 ft and reflects dissolution of aragonitic pelecypods and gastropods.

Calcareous nannofossils, planktonic foraminifers, dinoflagellates, and pollen from the core localities indicate a late middle Eocene (late Claibornian) age for the Lisbon sections (Reference 270). Marine fossils and carbonate suggest that this unit was deposited in an open-marine, shallow-shelf environment. The distribution of siliciclastic sediments and the diversity of marine fossils in the carbonate facies suggest that the updip Millers Pond core is more proximal to a source of siliciclastic sediments than the downdip Millhaven core.

Barnwell Unit

The Barnwell unit, as described in Falls and Prowell (2001), includes the Barnwell Groups plus post-Eocene strata in the study area. The Barnwell Group includes the Utley Limestone Member, Clinchfield and Dry Branch Formations, and the Tobacco Road Sand. The unit is 82 to 250 ft thick in the site vicinity.

In the downdip Millhaven core, the section begins with calcareous clay overlain by moderately well to well-sorted, fine to medium grained, calcareous quartz sand followed by partially lithified sandy limestone. Glauconite is a typical accessory mineral in the sand. Higher in the section, thin beds of silica-replaced limestone are common. Other lithologies in the upper section include unlithified carbonate, partially lithified limestone, and irregularly shaped phosphatized limestone clasts. The top of this unit consists of a coarsening-upward sequence of clayey sand and sandy clay.

Fossils observed in the core include pelecypods, bryozoans, echinoids, and foraminifers. Biomoldic pores are present and reflect dissolution of aragonitic pelecypods and gastropods.

The Barnwell unit in the Girard core consists of a lower portion of clay, sand, and carbonate layers. A basal calcareous clay is overlain by partially silicified, phosphatized, and glauconitic limestone; a calcareous quartz sand; a sandy limestone; a marl; and a sandy limestone that grades into an overlying quartz sand. Sand is fine to coarse near the base and grades into very fine to fine for the rest of the section. The clay matrix ranges from 20 to 40 percent. The top part of the Barnwell unit section is noncalcareous and contains clayey sand and clay. The sand ranges from fine to coarse grained.

Fossils include pelecypods and bryozoans. Biomoldic porosity ranges from 5 to 20 percent in the limestone and reflects dissolution of aragonitic pelecypods.

At the updip Millers Pond test hole, the unit contains siliciclastic sediments with essentially no limestone or carbonate. It includes thin beds of fine to medium sand and fine to very coarse sand and thin beds of well-laminated clay. The sand contains fine lignite, clay clasts, and 10 to 20 percent clay matrix. The top of the section is a coarsening-upward sequence of sand that ranges from fine to medium sand up to fine to very coarse sand with a clay matrix from 5 to 25 percent. Sedimentary structures include clay laminae and clay wisps. The Barnwell unit is mapped as the uppermost stratigraphic unit at the Millers Pond site (Reference 278), where it includes the Tobacco Road Sand and Irwinton Sand members of the Dry Branch Formation.

Paleontologic data for the Millhaven and Girard cores suggest a late Eocene to questionably early Oligocene age for the Barnwell sections (Reference 270). The Barnwell Group contains equivalent units to E6, E7, E8, and Ml (Reference 416) in addition to the Clinchfield Formation, Dry Branch Formation, and Tobacco Road Sand of the Barnwell Group at the SRS (Reference 273). Throughout the study area, the abundance of carbonate, the presence of glauconite and phosphate, and the abundance of marine macrofossils and microfossils in the calcareous part of the section indicate that the Barnwell strata were deposited in open-marine environments. The calcareous sand probably was deposited in a shallow-shelf environment, and the fossil bed at the base is a lag deposit produced by a late Eocene marine transgression. The noncalcareous sand and clay, the ovoid flattened pebbles, and the clay wisps in the upper part of the Barnwell unit suggest that these strata were deposited in nearshore-marine environments.

Quaternary Surfaces and Deposits

The Quaternary record in the VEGP area is preserved primarily in the fluvial terraces along the Savannah River and its major tributaries and in deposits of colluvium, alluvium, and eolian sediments on upland interfluvial areas.

The drainage systems within the site consist entirely of streams tributary to the Savannah River. A series of nested fluvial terraces are preserved along the east side of the Savannah River (Figure 2.5-232). Fluvial terraces are the primary geomorphic surface that can be used to evaluate Quaternary deformation within the Savannah River area. However, limited data are available for the estimation of ages of river terraces in both the Atlantic and Gulf coastal plains (Reference 376; Reference 240; Reference 387; Reference 375; Reference 447).

Along the east side of the Savannah River in the vicinity of the VEGP site, there are two prominent terraces above the modern flood plain (Qal): the Bush Field (Qtb) and the Ellenton (Qte) terraces (Figure 2.5-232) (Reference 292; Reference 301). These designations are based on morphology and relative height above local base level, which is the present elevation of the Savannah River channel. In addition, there are other minor terraces, one lower than the Bush Field and several higher older terrace remnants. Other investigators have delineated essentially the same terraces (Reference 452; Reference 227); however, there are significant differences in the estimated ages of these terraces.

The Bush Field (Qtb) and Ellenton (Qte) terraces are laterally extensive and are mapped over 15 mi both upstream and downstream from the VEGP site (Reference 292). The development of a sequence of laterally extensive fluvial terraces along the Savannah River is characteristic of other major Piedmont-draining river systems. Similar sequences of laterally extensive fluvial terraces are found along other rivers, such as the Pee Dee River in South Carolina and the Cape Fear River in North Carolina (Reference 292).

The modern flood plain is a broad alluvial surface that is 6 to 9 ft (2 to 3 m) above the channel. Local relief is about 3 ft (1 m). More extensive details are provided by Stevenson (1982). The next terrace at a structurally higher position is the Qty terrace, but that terrace is minor and not laterally continuous (Reference 292) (Figure 2.5-232).

The Bush Field terrace (Qtb), like the modern floodplain, includes a number of terrace surfaces of slightly differing heights above the modern base level (Reference 292). These surfaces range from 26 to 43 ft (8 to 13 m) above the Savannah River at SRS. This terrace is preserved primarily on the northeast side of the river. Limited subsurface data indicate the terrace is 29 to 49 ft (9 to 15 m) thick. The Ellenton terrace (Qte) is the higher of the two major terraces and includes surfaces that range from 56 to 82 ft (17 to 25 m) above the river channel. Subsurface data indicate the terrace is a minimum of 26 to 33 ft (8 to 10 m) thick (Reference 292).

Estimated ages of the terraces are based on several techniques, including radiometric Carbon-14 dates, soil chronosequences, relative position above base level, and correlation to other dated river or marine terraces (Reference 292). Alluvium within the modern floodplain ranges in age from latest Holocene to possibly latest Pleistocene (Reference 292). The Qty terrace is estimated to be 29 to 120 ka. The Qtb terrace appears to be about 90 ka based on correlation, relative position, and terrace morphology and as much as 200 ka based on soil chronosequences. Geomatrix (1993) assigned a best estimate age of the Qtb terrace of 100 to 250 ka. The Qte terrace is about 200 ka to more than 760 ka, based on regional correlation and morphology and at least 400 ka to perhaps 1 Ma based on soil chronosequences. Considering the various methods for estimating the age of the Qte terrace, Geomatrix (1993) assigned an age estimate of 350 ka to 1 Ma for the Qte terrace.

2.5.1.1.4 Regional Tectonic Setting

The regional tectonic setting of the VEGP site is presented below. This section includes discussions of regional plate tectonic evolution, regional tectonic stresses, and principal regional tectonic structures.

2.5.1.1.4.1 Plate Tectonic Evolution of the Appalachian Orogenic Belt at the Latitude of the Site Region

The VEGP site lies within the southern part of the northeast-southwest-trending Appalachian orogenic belt, which extends nearly the entire length of the eastern United States from Alabama to southern New York State. The Appalachian orogenic belt formed during the Paleozoic Era and records the opening and closing of the proto-Atlantic along the eastern margin of ancestral North America. The geologic history of the region surrounding the VEGP site is discussed in Subsection 2.5.1.1.2.

Depending on the focus of a given study, the Appalachian orogenic belt has been subdivided in a variety of ways by various researchers. These subdivisions include provinces, belts, and terranes. Provinces, which are generally more regional in extent, are defined based on both physiography (landforms) and geology. Five physiographic provinces have been defined across the Appalachian belt. From west to east, these include the Appalachian Plateaus (the “Cumberland Plateau” at the latitude of the site region) and the Valley and Ridge, Blue Ridge, Piedmont, and the Coastal Plain physiographic provinces (Figure 2.5-204). The Blue Ridge and Piedmont physiographic provinces are further divided into different lithotectonic belts of similar rock type and/or tectonic origin (Figure 2.5-217). Some geologists further divide the lithotectonic belts into individual fault-bounded terranes [e.g., (Reference 328, Reference 329; Reference 316)]. The terms “belt” and “terrane” are used interchangeably in this section to describe fault-bounded crustal blocks that share a common tectonic history.

Since the publication of EPRI (1986), geologists such as Hatcher (1987) and Horton et al. (1989, 1991) have proposed models for the development of the Appalachian orogen and its component provinces in the context of collisional tectonic events that added new fragments of crust to the eastern margin of North America and finally closed an ancestral ocean basin between ancestral North America (“Laurentia”) and ancestral Africa (“Gondwana”). The most recent synthesis of the Appalachian orogen at the latitude of the ESP study region is by Hatcher et al. (1994) and incorporates analysis of gravity, magnetic, and seismic reflection data in the interpretation. From northwest to southeast, Hatcher et al. (1994) recognized the following principal tectonic elements of the Appalachian orogen:

- The Valley and Ridge Province. This province encompasses a sequence of sedimentary rocks originally deposited on North American crust and subsequently deformed by folds and thrust faults during the Alleghanian orogeny, which resulted from the collision of Gondwana with Laurentia at the end of the Paleozoic Era.

- The Blue Ridge Province: The western part of the Blue Ridge province is a thrust-bounded sheet of crystalline rocks with overlying sedimentary strata that originally lay along the Paleozoic eastern margin of Laurentia. The eastern part of the Blue Ridge province is underlain by high-grade metamorphic rocks, some or all of which may be exotic to ancestral North America. At the latitude of the VEGP site region, the eastern and western parts of the Blue Ridge province are separated by the Hayesville fault. The eastern tectonic boundary between the Blue Ridge and Piedmont provinces is the Brevard fault.

- The Piedmont Province: The Piedmont province is subdivided into the Inner Piedmont belt on the west, and the Carolina–Avalon Terrane (Reference 316) on the east. The boundary between these two units is the Towaliga fault. Rocks of the Carolina–Avalon Terrane extend east of the Piedmont province beneath the overlying sedimentary cover of the Coastal Plain province.

- The Coastal Plain Province: This province is defined by a sequence of predominantly Cretaceous and Tertiary marine sediments overlying Paleozoic crystalline rocks and Mesozoic sedimentary rocks. The Coastal Plain strata record development of a passive continental margin along the eastern United States following Mesozoic rifting and opening of the Atlantic Ocean basin.

Modern plate tectonic reconstructions of the southern Appalachian orogenic belt published since EPRI (1986) interpret that at least some of the major regional Paleozoic deformation events (i.e., Penobscottian, Taconic, Acadian, and Alleghanian) are associated with collisions of exotic or suspect terranes with ancestral North America [e.g., (Horton et al. 1989; Hatcher et al. 1994)] (Figure 2.5-213). Most geologists generally agree that folded strata in the Valley and Ridge province and the crystalline rocks in the western Blue Ridge province are native to North America [e.g., (Horton et al. 1991; Hatcher et al. 1994)] and that these units have been transported westward from their original position along Paleozoic east-dipping, west-verging thrust faults. Key differences between plate tectonic models arise from varying interpretations of which belts and terranes represent exotic or suspect terranes and the location of primary tectonic boundaries or sutures that juxtapose such exotic terranes against North American crust and to one another. At the latitude of the VEGP site, there is general agreement among geologists regarding which belts and terranes are native to North America and which are exotic. The primary differences among models concern the precise location and downdip geometry of the major faults and sutures [e.g., alternative interpretations in (Hatcher et al. 1994)] that separate these terranes.

Development of the Appalachian orogen began in the late Precambrian with rifting of the Precambrian basement of ancestral North America, opening of an ocean basin, and formation of a passive margin (Figure 2.5-213). Sediments accumulated in local fault-bounded basins in the early phases of rifting, followed by deposition of a characteristic off-lapping, passive-margin sequence of marine carbonate and siliciclastic sediments.

The Grenville Front is the leading edge of a northeast-southwest-trending Precambrian collisional orogen that involved rocks of the pre-Appalachian basement of Laurentia (i.e., ancestral North America) (Figures 2.5-213 and 2.5-215). The following discussion is summarized from White et al. (2000). Like the younger Appalachian orogen, the Grenville orogen may have formed in part from exotic terranes that were assembled prior to 1,160 Ma, then deformed and thrust westward over the pre-Grenville Laurentian margin between 1,120 and 980 Ma. The Grenville orogen and Grenville front primarily are exposed in southeastern Canada, and can be traced in outcrop southwest to the latitude of Lake Ontario. Grenville-age rocks and structures continue on trend to the southeast into the United States, but are depositionally and structurally overlain by younger rocks, including terranes of the Appalachian orogen (Reference 217; Reference 320). Seismic reflection profiles indicate that the Grenville front and other prominent reflectors generally dip toward the east and extend to lower crustal depths (Reference 485).

The Penobscottian event is the earliest major orogeny recognized in the Appalachian belt and primarily is expressed in the northern Appalachians. Horton et al. (1989) stated that evidence for the Penobscottian orogeny has not been observed south of Virginia. The earliest Paleozoic deformation along or adjacent to the ancestral North American margin at the latitude of the VEGP site region occurred in the Middle Ordovician and is known as the Taconian event or orogeny (Figure 2.5-213). The onset of the Taconian event is marked regionally throughout much of the Appalachian belt by an unconformity in the passive-margin sequence and deposition of clastic sediments derived from an uplifted source area or areas to the east. The Taconic event at the latitude of the VEGP site region is interpreted by Horton et al. (1989) and Hatcher et al. (1994) to have resulted from the collision of one or more terranes with North America. Rocks of the eastern Blue Ridge and Inner Piedmont are interpreted to have originated east of the Laurentian passive margin in Middle Ordovician time and, thus, are candidates for Taconic collision(s).

Horton et al. (1989) included the eastern Blue Ridge at the latitude of the ESP study region in the Jefferson Terrane, a large body of sandstones, shales, basalt, and ultramafic rocks interpreted to be a metamorphosed accretionary wedge that accumulated above a subduction zone. Hatcher et al. (1994) suggested that the Hayesville thrust, which forms the western structural boundary of the eastern Blue Ridge and dips eastward beneath it, may be the "up-dip leading edge of an early Paleozoic subduction zone." If this interpretation is correct, then the Hayesville thrust fault may be a Taconic suture. The Carolina-Avalon Terrane also is interpreted by Horton et al. (1989) and Hatcher et al. (1994) to have been accreted during the Taconic orogeny. If this is correct, then the Towaliga fault between the Inner Piedmont and Carolina-Avalon Terranes also may be a Taconic structure.

According to Horton et al. (1989), evidence for the middle Paleozoic Acadian orogeny is "neither pervasive nor widespread" south of New England. The Acadian event primarily is expressed at the latitude of the ESP study region by unconformities in foreland stratigraphic succession, plutonism, and activity of several major faults (Reference 316), and possibly ductile folding elsewhere in the southern Appalachians (Reference 328). To date, geologists have not observed compelling evidence for a major accretion event at the latitude of the VEGP site region during the Acadian orogeny **(**Reference 328**;** Reference 316**)**.

The final and most significant collisional event in the formation of the Appalachian belt was the late Paleozoic Alleghanian orogeny, during which Gondwana collided with Laurentia, closing the intervening Paleozoic ocean basin (Figure 2.5-213). At the latitude of the VEGP site region, the Alleghanian collision telescoped the previously accreted Taconic terranes and drove them westward up and across the Laurentian basement, folding the passive margin sequence before them and creating the Valley and Ridge fold-and-thrust belt. The collisional process also thrust a fragment from the underlying Laurentian basement eastward over the passive margin sequence, forming the western Blue Ridge. Significant strike-slip faulting and lateral transport of terranes also are interpreted to have occurred during the Alleghanian orogeny (Reference 316).

At the latitude of the VEGP site region, the Alleghanian suture between rocks of ancestral Africa and terranes accreted to North America is buried beneath the Coastal Plain sediments and not exposed. Hatcher et al. (1994) offered alternative interpretations that the Alleghanian suture (1) coincides with the western edge of the Mesozoic Dunbarton Basin, which implies that the suture was reactivated as a normal fault during Mesozoic rifting and opening of the modern Atlantic basin or (2) is located somewhere east of the Dunbarton Basin, and its location and geometry are not known precisely. Based on detailed petrologic and geochemical analyses of basement samples from deep boreholes at the SRS, Dennis et al. (2004) concluded that the basement rocks there correlate with meta-igneous rocks of the Carolina–Avalon Terrane, which implies that the Alleghanian suture must lie east of the VEGP site.

Despite uncertainties regarding the precise origin, emplacement, and boundaries of belts and terranes, there is good agreement among tectonic models regarding first-order structural features of the southern Appalachian orogenic belt. At the latitude of the VEGP site region, the ancestral North American basement of the Paleozoic passive margin underlies the Valley and Ridge, Blue Ridge, and Inner Piedmont provinces at depths of less than 6 to 9 mi (10 to 15 km), and possibly as shallow as 3.1 mi (5 km) or less beneath the Valley and Ridge (Figure 2.5-214). A basal decollement along the top of the North American basement is the root zone for Paleozoic thrust faults in the Valley and Ridge, Blue Ridge, and Inner Piedmont provinces. Although potential seismogenic sources may be present within the North American basement below the decollement (Reference 480), the locations, dimensions, and geometries of these deeper potential sources are not necessarily expressed in the exposed fold-thrust structures above the detachment.

Wheeler (1995) suggests that many earthquakes in the eastern part of the Piedmont province and beneath the Coastal Plain province may be associated spatially with buried normal faults related to rifting that occurred during the Mesozoic Era (Figure 2.5-213). Normal faults in this region that bound

Triassic basins may be listric into the Paleozoic detachment faults [e.g., (Reference 263)] or may penetrate through the crust as high-angle faults. However, no definitive correlation of seismicity with Mesozoic normal faults has been conclusively demonstrated.

2.5.1.1.4.2 Tectonic Stress in the Mid-Continent Region

Earth science teams (ESTs) that participated in the EPRI (1986) evaluation of intra-plate stress found that tectonic stress in the Central and Eastern United States (CEUS) region primarily is characterized by northeast-southwest-directed horizontal compression. In general, the ESTs concluded that the most likely source of tectonic stress in the mid-continent region was ridge-push force associated with the Mid-Atlantic ridge, transmitted to the interior of the North American plate by the elastic strength of the lithosphere. Other potential forces acting on the North American plate were judged to be less significant in contributing to the magnitude and orientation of the maximum compressive principal stress. Some of the ESTs noted that the regional northeast-southwest trend of principal stress may vary in places along the east coast of North America and in the New Madrid region. They assessed the quality of stress indicator data and discussed various hypotheses to account for what were interpreted as variations in the regional stress trajectories.

During the 1980s, an international effort to collate and evaluate stress indicator data culminated in the publication of a new World Stress Map (Reference 491). Data for this map are ranked in terms of quality. Plate-scale trends in the orientations of principal stresses are assessed qualitatively based on analysis of high-quality data (Reference 490). Subsequent statistical analyses of stress indicators confirmed that the trajectory of the maximum compressive principal stress is uniform across broad continental regions at a high level of statistical confidence. In particular, the northeast-southwest orientation of principal stress in the CEUS inferred by the EPRI ESTs is statistically robust and is consistent with the theoretical trend of compressive forces acting on the North American plate from the mid-Atlantic ridge (Reference 490).

The more recent assessments of lithospheric stress do not support inferences by some EPRI ESTs that the orientation of the principal stress may be locally perturbed in the New England area, along the east coast of the United States, or in the New Madrid region. Zoback and Zoback (1989) summarized a variety of data, including well-bore breakouts, results of hydraulic fracturing studies, and newly calculated focal mechanisms, which indicate that the New England and eastern seaboard regions of the US are characterized by uniform horizontal northeast-southwest to east-west compression. Similar trends are present in the expanded set of stress indicators for the New Madrid region. Zoback and Zoback (1989) grouped all of these regions, along with a large area of eastern Canada, with the CEUS in an expanded "Mid-Plate" stress province characterized by northeast-southwest-directed horizontal compression.

A detailed study by Moos and Zoback (2001) evaluated the orientations and magnitudes of the principal stresses at the Savannah River Site, north of the VEGP site, to a depth of about 4,000 ft (1,220 m) using data and observations from the New Production Reactor (NPR) borehole. They inferred that the maximum horizontal compressive stress is oriented N50°E to N70°E in the upper 2,100 ft (640 m) depth range, similar to regional trends in the eastern United States reported by Zoback (1992). Moos and Zoback (2001) estimated that the magnitude of the differential stress in the upper 2,100 ft (640 m) is close to the limit of the frictional strength on NW-striking reverse faults. In the depth range of about 3,000 ft to 3,700 ft (915 to 1130 m), Moos and Zoback (2001) found that the maximum horizontal compressive stress was directed about N33°E, more toward the north and counterclockwise of regional trends, and that the magnitude of the differential stress would likely favor strike-slip displacement rather than reverse faulting. In the 4,000 ft (1,220 m) depth range near the bottom of the hole, breakouts and other stress indicators suggest that the maximum horizontal compressive stress is directed toward N55°E, subparallel to regional trends.

The observations from the NPR borehole at the Savannah River Site thus appear to document a counterclockwise rotation of the maximum horizontal compressive stress restricted to a narrow depth range in the upper 4,000 ft (1,220 m) of the crust. Stress indicators from depth intervals above and below this excursion suggest that the NE-SW orientation of the maximum horizontal compressive stress is consistent with regional trends documented in the eastern United States (Reference 490).

The significance of these results for tectonic stress and fault activity in the vicinity of the VEGP site are equivocal. The clockwise excursion in the orientation of the maximum horizontal compressive stress in the NPR borehole is limited to a narrow depth range, and may be similarly limited in horizontal extent. The specific cause of the stress rotation in the NPR borehole is not known. Moos and Zoback (2001) discuss several physical reasons why it is “not reasonable” to linearly extrapolate estimates of stress magnitudes at shallow depths to mid-crustal depths where moderate to large magnitudes typically nucleate. Thus, the data from the NPR borehole only provide information on the state of stress in the shallow crust directly adjacent to the borehole. The data suggest that while there may be local perturbations in the stress field near the borehole, the average state of crustal stress is probably characterized by horizontal NE-SW compression, similar to regional trends.

In addition to better documenting the orientation of stress, research conducted since 1986 has addressed quantitatively the relative contributions of various forces that may be acting on the North American plate to the total stress within the plate. Richardson and Reding (1991) performed numerical modeling of stress in the continental US interior and considered the contribution to total tectonic stress to be from three classes of forces:

- Horizontal stresses that arise from gravitational body forces acting on lateral variations in lithospheric density. These forces commonly are called buoyancy forces. Richardson and Reding (1991) emphasized that what is commonly called ridge-push force is an example of this class of force. Rather than a line-force that acts outwardly from the axis of a spreading ridge, ridge-push arises from the pressure exerted by positively buoyant, young oceanic lithosphere near the ridge against older, cooler, denser, less buoyant lithosphere in the deeper ocean basins (Reference 465). The force is an integrated effect over oceanic lithosphere ranging in age from about 0 to about 100 Ma (Reference 256). The ridge-push force is transmitted as stress to the interior of continents by the elastic strength of the lithosphere.

- Shear and compressive stresses transmitted across major plate boundaries (strike-slip faults and subduction zones).

- Shear tractions acting on the base of the lithosphere from relative flow of the underlying asthenospheric mantle.

Richardson and Reding (1991) concluded that the observed northeast-southwest trend of principal stress in the CEUS dominantly reflects ridge-push body forces. They estimated the magnitude of these forces to be about 2 to 3 x 10^{12} N/m (i.e., the total vertically integrated force acting on a column of lithosphere 3.28 ft [1 m] wide), which corresponds to average equivalent stresses of about 40 to 60 MPa distributed across a 30-mi-thick elastic plate. Richardson and Reding (1991) found that the fit of the model stress trajectories to data was improved by adding compressive stress (about 5 to 10 MPa) acting on the San Andreas fault and Caribbean plate boundary structures. The fit of the model stresses to data further indicates that shear stresses acting on these plate boundary structures must also be in the range of 5 to 10 MPa. Humphreys and Coblentz (in review) also found that the fit of numerical stress models for the North American plate was improved by imposing large compressive stresses on the San Andreas fault and Caribbean plate boundary structures.

Richardson and Reding (1991) noted that the general northeast-southwest orientation of principal stress in the CEUS also could be reproduced in numerical models that assume horizontal shear

tractions acting on the base of the North American plate. Richardson and Reding (1991) did not favor this as a significant contributor to total stress in the mid-continent region, however, because their model would require an order-of-magnitude increase in the horizontal compressive stress from the eastern seaboard to the Great Plains. Using numerical models, Humphreys and Coblentz (in review) also evaluated the contribution of shear tractions on the base of the North American lithosphere to intra-continental stress, and concluded that (1) there is a viscous drag or resisting force acting on the cratonic root of North America as it moves relative to the asthenospheric mantle and that this drag supports part of the ridge-push force acting from the east and creates a stress shadow for the western US and (2) shear tractions on the base of North America from flow of the underlying asthenospheric mantle are a minor contribution, if any, to stress in the mid-continental lithosphere. Humphreys and Coblenz (in review) concluded that the dominant control on the northeast-southwest orientation of the maximum compressive principal stress in the CEUS is ridge-push force from the Atlantic basin.

To summarize, analyses of regional tectonic stress in the CEUS since EPRI (1986) have not significantly altered the characterization of the northeast-southwest orientation of the maximum compressive principal stress. The orientation of a planar tectonic structure relative to the principal stress direction determines the magnitude of shear stress resolved onto the structure. Given that the current interpretation of the orientation of principal stress is similar to that adopted in EPRI (1986), a new evaluation of the seismic potential of tectonic features based on a favorable or unfavorable orientation to the stress field would yield similar results. Thus, there is no significant change in the understanding of the static stress in the CEUS since the publication of the EPRI source models in 1986, and there are no significant implications for existing characterizations of potential activity of tectonic structures.

2.5.1.1.4.3 Principal Regional Tectonic Structures

Principal tectonic structures and features in the southeastern United States and within the 200-mi VEGP site region can be divided into four categories based on their age of formation or reactivation, and are shown in Figures 2.5-215 and 2.5-216. These categories include structures that were most active during Paleozoic, Mesozoic, Tertiary, or Quaternary time. Most of the Paleozoic and Mesozoic structures are regional in scale and geologically and geophysically recognizable. The Mesozoic rift basins and bounding faults show a high degree of parallelism with the structural grain of the Paleozoic Appalachian orogenic belt, which generally reflects reactivation of pre-existing Paleozoic structures. Tertiary and Quaternary structures are generally more localized and may be related to reactivation of portions of older bedrock structures.

Regional Paleozoic Tectonic Structures

The VEGP site region encompasses portions of the Coastal Plain, Piedmont, Blue Ridge, and Valley and Ridge physiographic provinces (Figure 2.5-204). Rocks and structures within these provinces are associated with thrust sheets that formed during convergent Appalachian orogenic events of the Paleozoic Era. Tectonic structures of this affinity also exist beneath the sedimentary cover of the Coastal Plain province. These types of structures include the following: (1) sutures juxtaposing allochthonous (tectonically transported) rocks with North American crust, (2) regionally extensive Appalachian thrust faults and oblique-slip shear zones, and (3) a multitude of smaller structures that accommodated Paleozoic deformation within individual belts or terranes (Figure 2.5-14). The majority of these structures dip eastward and shallow into a low-angle, basal Appalachian decollement. The Appalachian orogenic crust is relatively thin across the Valley and Ridge province, Blue Ridge province, and western part of the Piedmont province and thickens eastward beneath the eastern part of the Piedmont province and the Coastal Plain province (Figure 2.5-11). Below the decollement are rocks that form the North American basement complex. The basement rocks contain northeast-striking, Late Precambrian to Cambrian normal faults that formed during the rifting that preceded the deposition of Paleozoic sediments (See Subsection 2.5.1.1.4.1).

Researchers have observed that much of the sparse seismicity in eastern North America occurs within the North American basement below the basal decollement. Therefore, seismicity within the Appalachians may be unrelated to the abundant, shallow thrust sheets mapped at the surface (Reference 480). For example, seismicity in the Giles County seismic zone (Figure 2.5-218), located in the Valley and Ridge province, is occurring at depths ranging from 3 to 16 mi (5 to 25 km) (Reference 233) which is generally below the Appalachian thrust sheets and basal decollement (Reference 222).

Paleozoic faults within 200 mi of the site are shown on Figure 2.5-216, and are described as follows:

- Augusta Fault: The Augusta fault zone is located near Augusta, Georgia, about 30 mi north of the VEGP site and separates amphibolite facies gneisses and schists of the Kiokee belt to the northwest from greenschist facies volcanic and volcaniclastic rocks of the Belair belt to the southeast (Reference 431; Reference 367; Reference 429) (Figures 2.5-209 and 2.5-219). The Augusta fault trends east-northeast and dips moderately to the southeast. The Augusta fault zone is characterized as a zone of quartzofeldspathic mylonites, ultramylonites, and blastomylonites with minor amphibolites, schists, and a variety of light-colored granitic veins (Reference 367). The fault contains two distinct deformation fabrics: a mylonite about 800 ft thick is overprinted by a brittle fabric. Until Maher (1987) performed a detailed structural analysis of the fault zone rocks, the Augusta fault had been characterized variably as a thrust fault, a dextral strike-slip fault, a strain gradient with little displacement, and a possible listric normal fault within the early Mesozoic (Reference 445; Reference 246; Reference 218). The sense of movement of the fault zone is now constrained by regional context, mesoscopic structures, and microscopic textures. Maher (1987) notes five observations that indicate a hanging-wall-down, oblique sense of slip: (1) geometry and orientation of folded discordant granitic veins, (2) a sporadically developed lineation, (3) composite planar fabric (S and C surfaces), (4) “mica fish”, and (5) regional geologic relations. The significant normal component of slip during the Alleghanian collisional orogeny is seemingly contradictory, but extension on the Augusta fault (and others within the region) is consistent with a model involving gravitational collapse of a thickened crust, similar to examples from the Himalaya (Reference 370). Geologic relations and the 40Ar/39Ar cooling ages of Maher et al. (1994) suggest that extensional movement on the Augusta fault zone initiated about 274 Ma. Maher et al. (1994) constrains Augusta fault extension as occurring late in the Alleghanian phase and well after initiation of Alleghanian crustal shortening in the Valley and Ridge and Blue Ridge. Some discontinuous silicified breccias occur along the Augusta fault zone, and minor brittle faults utilizing the mylonitic fabric have striae subparallel to the mylonitic lineation (Reference 367). The brittle striae and faults record the same sense and direction of shear as the mylonitic fabric, indicating Alleghanian movement on the Augusta fault occurred during transition from ductile to brittle conditions **(**Reference 367**;** Reference 370**)**. Alleghanian extensional events have been interpreted for not only the Augusta fault, but also other faults within the Eastern Piedmont fault system, suggesting that extension played a significant role in the development of the Appalachians. Maher et al. (1994) suggest that the new geochronology indicates Piedmont normal faulting is not solely Mesozoic, but includes late Alleghanian episodes. No seismicity is attributed to the Augusta fault.

- Modoc Fault Zone: The Modoc zone, located in South Carolina and Georgia about 40 mi north of the VEGP site, is a region of high ductile strain separating the Carolina Terrane (Carolina Slate and Charlotte belts) from the amphibolite facies migmatitic and gneissic rocks of the Kiokee belt (Reference 226; Reference 429) (Figures 2.5-209 and 2.5-219). The northeast-trending Modoc zone dips steeply to the northwest and can be traced from central Georgia to central South Carolina based on geological and geophysical data. Mylonitic rocks are common within the zone, although the intensity of mylonitization varies widely (Reference 226). Regional relationships and structures within the zone reflect predominantly dextral motion with a northwest-side-down normal component, related to early Alleghanian

extension (Reference 423). Geochronologic data from Dallmeyer et al. (1986) indicate movement occurred between 315 and 290 Ma, during the Alleghanian Lake Murray deformation, D2. Recent exposures created for the construction of Saluda Dam on Lake Murray exposed a portion of the Modoc fault zone where four Paleozoic ductile deformational events are recognized. The D4 deformation is recognized as an east-northeast-striking zone at least 20 km wide, and it shows a transition from ductile to brittle behavior, which correlates with retrograde mineral assemblages in D4 faults in the Modoc zone (Reference 331). Brittle features observed in the Saluda Dam foundation are interpreted to be the result of a readjustment from differential loading and unloading, as well as tectonic movement associated with latest Alleghanian deformation and initial Triassic rifting (Reference 381). No seismicity is attributed to the Modoc fault zone.

- Eastern Piedmont Fault System: Hatcher et al. (1977) suggested that the Modoc shear zone, the Irmo shear zone, and the Augusta fault are part of the proposed Eastern Piedmont Fault System, an extensive series of faults and splays extending from Alabama to Virginia (Figure 2.5-216). Aeromagnetic, gravity, and seismic reflection data indicate that the Augusta fault zone continues in the crystalline basement beneath the Coastal Plain province sediments.

- Other Paleozoic Faults: Other Paleozoic faults within the site region include the Brevard fault, the Hayesville fault, the Towliga fault, the Central Piedmont suture, and the Eastern Piedmont fault system (Figures 2.5-216 and 2.5-217). No seismicity is attributed to these Paleozoic faults, and published literature does not indicate that any of these faults offset late Cenozoic deposits or exhibit geomorphic expression indicative of Quaternary deformation. In addition, Crone and Wheeler (2000) and Wheeler (2005) do not show any of these faults to be potentially active Quaternary faults. Therefore, these Paleozoic structures in the site region are not considered to be capable tectonic sources, as defined in Appendix A of RG 1.165.

No new information has been published since 1986 on any Paleozoic fault in the site region that would cause a significant change in the EPRI seismic source model.

Regional Mesozoic Tectonic Structures

Wheeler (1995) suggested that many earthquakes in the eastern part of the Piedmont province and beneath the Coastal Plain province may be associated spatially with buried normal faults related to rifting that occurred during the Mesozoic Era. However, no definitive correlation of seismicity with Mesozoic normal faults has been conclusively demonstrated. Normal faults in this region that bound Triassic basins may be listric into the Paleozoic detachment faults [e.g., or may penetrate through the crust as high-angle faults (e.g., Reference 427). Within regions of stable continental cratons, areas of extended crust potentially contain the largest earthquakes (Reference 343). Mesozoic basins have long been considered potential sources for earthquakes along the eastern seaboard (Reference 479) and were considered by most EPRI teams in their definition of seismic sources (Reference 271). Mesozoic basins and faults in the site region include:

- Mesozoic Rift Basins - A broad zone of fault-bounded, elongate depositional basins associated with crustal extension and rifting formed during the opening of the Atlantic Ocean in early Mesozoic time. These rift basins are common features along the eastern coast of North America from Florida to Newfoundland (Figures 2.5-210 and 2.5-216). The VEGP site is located within the Dunbarton Basin. This basin is discussed in detail below (Figure 2.5-216).

- Dunbarton Basin - The Dunbarton Basin is a roughly east-northeast-trending Mesozoic rift basin located beneath the VEGP site and the SRS (Figure 2.5-219). The basin is approximately 31 mi long and 6 to 9 mi wide. Siple (1967) and Marine and Siple (1974) originally identified the general extent and shape of the Dunbarton Basin on the basis of Coastal Plain sediment cores and a limited amount of seismic data from the SRS, as well as

aeromagnetic data from Petty et al. (1965). The Dunbarton Basin coincides with both gravity and magnetic lows and is bounded on the north by the Pen Branch fault (Reference 374; Reference 232; Reference 451; Reference 253, Reference 254, Reference 255; Reference 265). The Pen Branch fault has had a long and varied history. The Pen Branch fault likely formed in the Paleozoic Era, and was reactivated as a normal fault during the Triassic Period. The Pen Branch fault was most recently reactivated as an oblique-reverse fault in the Cenozoic Era **(**Reference 253**,** Reference 254**,** Reference 255**)** and is discussed in greater detail in Subsection 2.5.1.2.4. It has been suggested that the Martin fault (discussed in Subsection 2.5.1.1.4.5) is the southeastern bounding fault of the Dunbarton Basin (Reference 442), although Domoracki et al. (1999b) suggested that the Dunbarton Basin is instead a half-graben bounded only by the Pen Branch fault to the north.

Regional Tertiary Tectonic Structures

Within 200 mi of the VEGP site, only a few tectonic features, including arches, domes, and embayments, were active during the Tertiary Period. A series of topographic highs and lows in the crust (arches and embayments, respectively) oriented perpendicular to the hinge zone have exerted control over Coastal Plain sedimentation from late Cretaceous through Pleistocene time and are indicative of episodic, differential tectonic movement. The arches are broad anticlinal upwarps, whereas the embayments are broad, sediment-filled basement flexures.

The most prominent arches in the VEGP site region include the Cape Fear Arch on the South Carolina–North Carolina border and the Yamacraw Arch on the Georgia–South Carolina border. The Cape Fear Arch is bordered by the Salisbury embayment to the northeast and the Georgia embayment to the southeast. There is no evidence that these structures are active, and Crone and Wheeler (2000) classified the Cape Fear Arch as a Class C feature, based on lack of evidence for Quaternary faulting (Figure 2.5-220).

Regional Quaternary Tectonic Structures

In an effort to provide a comprehensive database of Quaternary tectonic features, Crone and Wheeler (2000) and Wheeler (2005) compiled geological information on Quaternary faults, liquefaction features, and possible tectonic features in the CEUS. They evaluated and classified these features into one of four categories (Classes A, B, C, and D; see Table 2.5-201 for definitions) based on strength of evidence for Quaternary activity.

Within a 200-mi radius of the VEGP site, Crone and Wheeler (2000) and Wheeler (2005) identified 11 potential Quaternary features (Table 2.5-201 and Figure 2.5-220). These include: the Charleston, Georgetown, and Bluffton paleoliquefaction features (Class A), the East Coast fault system (Class C), the Cooke fault (Class C), the Helena Banks fault zone (Class C), the Pen Branch fault (Class C), the Belair fault (Class C), the fall lines of Weems (1998) (Class C), the Cape Fear Arch (Class C), and the Eastern Tennessee seismic zone (Class C).

The Charleston features (including the East Coast fault system; the Cooke fault, the Helena Banks fault zone; and the Charleston, Georgetown, and Bluffton paleoliquefaction features) are discussed in detail in Subsection 2.5.1.1.4.4. The Pen Branch fault is discussed in detail Subsection 2.5.1.2.4.1, and the Eastern Tennessee Seismic Zone is discussed in detail in Subsection 2.5.1.1.4.6. The Belair fault zone and the fall lines of Weems (1998) are discussed in detail below:

- Belair Fault Zone - The Belair fault zone has been mapped for at least 15 mi (24 km) as a series of northeast-trending, southeast-dipping, oblique-reverse slip faults near Augusta, Georgia, that generally parallel the structural grain of the Piedmont (Figures 2.5-219 and 2.5-220). The Belair fault juxtaposes Paleozoic phyllite over Late Cretaceous sands of the Coastal Plain province (Reference 414). No geomorphic expression of the fault has been reported (Reference 251). Shallow trenches excavated across the Belair fault near Fort

Gordon in Augusta, Georgia, were initially interpreted as revealing evidence for Holocene movement (Reference 415), but the apparent youthfulness of movement was probably the result of contaminated radiocarbon samples (Reference 413). (Reference 414) demonstrated that the Belair fault cuts beds of Late Cretaceous and Eocene age. Overlying, undeformed strata provide a minimum constraint on the last episode of faulting, which is constrained to sometime between post-late Eocene and pre-26,000 years ago (Reference 413). There is no evidence of historic or recent seismicity associated with the Belair fault. Crone and Wheeler (2000) classified the Belair fault zone as a Class C feature, since the most recent faulting is not demonstrably of Quaternary age. Quaternary slip on the Belair fault zone is allowed, but not demonstrated, by the available data.

Mapping and structural analysis by Bramlett et al. (1982) indicate that the Belair fault likely formed as a lateral ramp or tear associated with the Augusta fault when displacement on these faults initiated during the Paleozoic Alleghanian orogeny. The timing and sense-of-slip for the most-recent movements on the Belair and Augusta faults, however, demonstrate that these two structures have not reactivated as a single tectonic element in Cenozoic or younger time. Prowell et al. (1975) and Prowell and O'Connor (1978) document Cenozoic, brittle, reverse slip on the Belair fault. In contrast, the latest movement on the Augusta fault, as demonstrated by brittle overprinting of ductile fabrics, exhibits a normal sense-of-slip and is constrained to have occurred in late Alleghanian time during the transition from ductile to brittle conditions (Reference 367; Reference 370). The brittle overprinting on the Augusta fault is consistent with the ductile normal sense of slip. In contrast, the Belair fault exhibits a reverse sense-of-slip during its Cenozoic reactivation. Therefore, different slip histories and opposite senses of dip-slip for the Belair and Augusta faults demonstrate that these two faults have not been reactivated as a single structure during the Cenozoic.

- Fall Lines of Weems (1998) - In his examination of longitudinal profiles of large streams flowing across the Piedmont and Blue Ridge provinces of North Carolina, Virginia and Tennessee, Weems (1998) identified numerous anomalously steep stream segments (Figure 2.5-220). These "fall zones" are aligned from stream to stream along curvilinear paths, and these paths are generally subparallel to the regional structural grain. Weems (1998) presented three hypotheses to explain these phenomena, including climatic factors, rock hardness, and neotectonics. Although some fall zones are spatially coincident with changes in rock hardness, Weems (1998) favored a neotectonic origin for the fall lines. Wheeler (2005) classified the fall lines as a Class C feature, since the fall zones are not demonstrably reproducible and tectonic faulting is not demonstrated by available data.

- The Cape Fear Arch - The Cape Fear Arch is previously discussed in this section (under Regional Tertiary Tectonic Structures). Crone and Wheeler (2000) classified the Cape Fear Arch as a Class C feature based on lack of evidence for Quaternary faulting.

Regional Geophysical Anomalies and Major Tectonic Features

In addition to the tectonic structures described above, a number of regional geophysical anomalies, lineaments, and major tectonic features are located within about 300 mi of the VEGP site (Figure 2.5-215). From southeast to northwest, these include the East Coast Magnetic Anomaly, Appalachian gravity gradient, the southeast boundary of Iapetan normal faulting, Clingman lineament, Ocoee lineament, New York-Alabama lineament, the Appalachian gravity gradient. the northwest boundary of Iapetan normal faulting, Appalachian thrust front, and the Grenville front. These features are described below with more detail provided for those features within the 200-mi site region.

- East Coast Magnetic Anomaly - The East Coast Magnetic Anomaly (ECMA) is a broad, 200 to 300 nT magnetic high that is located approximately 30 to 120 mi (50 to 200 km) off the coast of North America, and which is continuously expressed for about 1,200 mi (1,900 km)

from the latitude of Georgia to Nova Scotia (Reference 356; Reference 487) (Figure 2.5-215). The ECMA is subparallel to the Atlantic coastline, and is spatially associated with the eastern limit of North American continental crust (Reference 356). The ECMA has been variously interpreted to be a discrete, relatively magnetic body such as a dike or ridge, or an "edge effect" due to the juxtaposition of continental crust on the west with higher susceptibility oceanic crust on the east (see summary and additional references in Austin et al. 1990). In the vicinity of the ECMA, deep seismic reflection profiling in the Atlantic basin has imaged packages of east-dipping reflectors that underlie the sequence of Mesozoic-Tertiary passive-margin marine strata (Reference 435). The rocks associated with the east-dipping reflectors are interpreted to be an eastward-thickening wedge of volcanic and volcaniclastic rocks that were deposited during the transition between rifting of the continental crust and opening of the Atlantic basin during the Mesozoic (Reference 487). Models of the magnetic data show that the presence of this volcanic "wedge" can account for the wavelength and amplitude of the ECMA (Reference 356).

To summarize, the ECMA is a relict of the Mesozoic opening of the Atlantic basin, and probably arises from the presence of a west-tapering wedge of relatively magnetic volcanic rocks deposited along the eastern margin of the continental crust as the Atlantic basin was opening, rather than juxtaposition of rocks with differing magnetic susceptibilities across a fault. The ECMA is not directly associated with a fault or tectonic feature, and thus is not a potential seismic source.

- Appalachian Gravity Gradient – This regional gravity gradient extends the length of the Appalachian orogen and exhibits a southeastward rise in Bouguer gravity values as much as 50 to 80 mGal (Reference 222; Reference 481). The Appalachian gravity gradient represents the southeastern thinning of relatively intact Precambrian continental crust, and the early opening of the Iapetan Ocean (e.g., Reference 222).

- Southeast and northwest boundaries of Iapetan normal faults - The southeast and northwest boundaries of Iapetan normal faults shown in Figure 2.5-215 define the extent of the Iapetan margin of the craton containing normal faults that accommodated extension during the late Proterozoic to early Paleozoic rifting that formed the Iapetan Ocean basin. Wheeler (1996) defined the southeast boundary as the southeastern limit of the intact Iapetan margin, which is nearly coincident with the Appalachian gravity gradient in the southeastern United States. The Iapetan normal faults are concealed beneath Appalachian thrust sheets that overrode the margin of the craton during the Paleozoic. A few of these Iapetan faults are thought to be reactivated and responsible for producing earthquakes in areas such as eastern Tennessee; Giles County, Virginia; and Charlevoix, Quebec (Reference 222; Reference 481).

  The southeast margin of the Iapetan normal faults shown on Figure 2.5-215 does not represent a potential seismic source since it does not represent a discrete crustal discontinuity or tectonic structure. The linear feature shown in the figure represents the southeastern extent of the intact Iapetan margin (with a location uncertainty of 30 to 35 km), and therefore, the southeastern limit of potentially seismogenic Iapetan faults (Reference 481).

- The New York-Alabama, Clingman, and Ocoee Lineaments - King and Zietz (1978) identified a 1,000-mi- (1,600-km-) long lineament in aeromagnetic maps of the eastern United States that they referred to as the "New York-Alabama lineament" (NYAL) (Figure 2.5-215). The NYAL primarily is defined by a series of northeast-southwest-trending linear magnetic gradients in the Valley and Ridge province of the Appalachian fold belt that systematically intersect and truncate other magnetic anomalies. The NYAL also is present as complementary but less-well-defined lineament on regional gravity maps (Reference 353).

The Clingman lineament is an approximately 750-mi- (1,200-km-) long, northeast-trending aeromagnetic lineament that passes through parts of the Blue Ridge and eastern Valley and Ridge provinces from Alabama to Pennsylvania (Reference 389). The Ocoee lineament is a described as a splay that branches southwest from the Clingman lineament at about latitude 36°N (see summary in Johnston et al. 1985). The Clingman-Ocoee lineaments are sub-parallel to and located about 30 to 60 mi (50 to 100 km) east of the NYAL.

King and Zeitz (1978) interpreted the NYAL to be a major strike-slip fault in the Precambrian basement beneath the thin-skinned fold-and-thrust structures of the Valley and Ridge, and suggested that it may separate rocks on the northwest that acted as a mechanical buttress from the intensely deformed Appalachian fold belt to the southeast. Shumaker (2000) interpreted the NYAL to be a right-lateral wrench fault that formed during an initial phase of late Proterozoic continental rifting that eventually led to the opening of the Iapetan Ocean. The Clingman lineament also is interpreted to arise from a source or sources in the Precambrian basement beneath the accreted and transported Appalachian terranes (Reference 389).

Johnston et al. (1985) observed that the “preponderance of southern Appalachian seismicity” occurs within the “Ocoee block”, a Precambrian basement block bounded by the NYAL and Clingman-Ocoee lineaments [the Ocoee block was previously defined by (Reference 340)]. The proximity of these lineaments to current seismicity in the Eastern Tennessee seismic zone therefore suggests the possibility that they are potential seismic sources. Based on the orientations of nodal planes from focal mechanisms of small earthquakes, Johnston et al. (1985) noted that most events within the Ocoee block occurred by strike-slip displacement on north-south and east-west striking faults, and thus these geologists did not favor the interpretation of seismicity occurring on a single, through-going NE-SW-trending structure parallel to the Ocoee block boundaries.

The Ocoee block lies within a zone defined by Wheeler (1995, 1996) as the cratonward limit of normal faulting along the ancestral rifted margin of North America that occurred during the opening of the Iapetan Ocean in late Precambrian to Cambrian time. Synthesizing geologic and geophysical data, Wheeler (1995, 1996) mapped the northwest extent of the Iapetan faults in the subsurface below the Appalachian detachment, and proposed that earthquakes within the region defined by Johnston and Reinbold (1985) as the Ocoee block may be the result of reactivation of Iapetan normal faults as reverse or strike-slip faults in the modern tectonic setting.

- Appalachian Thrust Front – The northwestern limit of allochthonous crystalline Appalachian crust was termed the Appalachian thrust front by Seeber and Armbruster (1988). This front, which lies beyond the 200-mi site region, is a sharply defined boundary interpreted as a major splay of the master Appalachian detachment.

- Grenville Front – The Grenville front, which is located beyond the 200-mi site region, is defined by geophysical, seismic reflection, and scattered drill hole data in the southeastern United States. This feature lies within the continental basement and is interpreted to separate the relatively undeformed granite-rhyolite province on the northwest from the more highly deformed rocks of the Grenville province on the southeast (Reference 471).

2.5.1.1.4.4 Charleston Tectonic Features

The August 31, 1886, Charleston, South Carolina, earthquake is one of the largest historical earthquakes in the eastern United States. The event produced Modified Mercalli Intensity (MMI) X shaking in the epicentral area and was felt strongly as far away as Chicago (MMI V) (Reference 339). As a result of this earthquake, considerable effort has gone into identifying the source of the earthquake and recurrence history of large magnitude events in the region. In spite of this effort, the

source of the 1886 earthquake has not been definitively attributed to any particular fault shown in Figures 2.5-221 and 2.5-222.

The 1886 Charleston earthquake produced no identifiable primary tectonic surface deformation; therefore, the source of the earthquake has been inferred based on the geology, geomorphology, and instrumental seismicity of the region (Figures 2.5-221 and 2.5-222). Talwani (1982) infers that the 1886 event was produced by the north-northeast-striking Woodstock fault (inferred from seismicity) near its intersection with the northwest-striking Ashley River fault (also inferred from seismicity). Marple and Talwani (2000) have more recently suggested that a northeast-trending zone of river anomalies, referred to as the East Coast fault system, represents the causative fault for the 1886 Charleston event. The southern segment of the East Coast fault system coincides with a linear zone of micro-seismicity that defines the northeast-trending Woodstock fault of Talwani (1982) and the isoseismal zone from the 1886 earthquake.

Johnston (1996) estimated a moment magnitude of (**M)** 7.3±0.26 for the 1886 Charleston event. More recently, Bakun and Hopper (2004) estimated a smaller magnitude of **M** 6.9 with a 95 percent confidence level corresponding to a range of **M** 6.4 to 7.1. Both of these more recent estimates of maximum magnitude (Mmax) are similar to the upper-bound maximum range of Mmax values used in EPRI (1986) (body wave magnitude [m_b] 6.8 to 7.5). However, significant new information regarding the source geometry and earthquake recurrence of the Charleston seismic source warrants an update of the EPRI (1986) source models in the PSHA. The updated Charleston seismic source parameters are presented in Subsection 2.5.2.2.2.4.

Potential Charleston Source Faults

Since the EPRI (1986) source models were developed, a number of faults have been identified or described in the literature as possible sources related to the 1886 Charleston earthquake. These include numerous faults localized in the Charleston meizoseismal area approximately 85 mi from the site (Figure 2.5-221).

There is evidence, in the form of paleoliquefaction features in the South Carolina Coastal Plain, that the source of the 1886 Charleston earthquake has repeatedly generated vibratory ground motion. Paleoliquefaction evidence is lacking for prehistoric earthquakes elsewhere along much of the eastern seaboard [e.g., (Reference 205; Reference 207, Reference 206)]. At a minimum, the Charleston seismic source is defined as a seismogenic source according to RG 1.165. Whereas the 1886 Charleston earthquake almost certainly was produced by a capable tectonic source, that specific tectonic structure has yet to be identified. Various studies have proposed potential causative faults for the 1886 event; however, a positive linkage between a discrete structure and the Charleston earthquake has yet to be determined.

These potential causative faults are shown in Figures 2.5-221 and 2.5-222 and described below:

- East Coast Fault System - The inferred East Coast fault system (ECFS, the southern section of which is also known as the “zone of river anomalies” or ZRA based on the alignment of river bends) is a northeast-trending, approximately 373-mi-long (600-km-long) fault system extending from west of Charleston, South Carolina, to southeastern Virginia (Reference 378). The ECFS comprises three, approximately 124-mi-long (200-km-long), right-stepping sections (southern, central, and northern; Figure 2.5-221). Evidence for the southern section is strongest, with evidence becoming successively weaker northward (Reference 482). Marple and Talwani (1993) identified a series of geomorphic anomalies (i.e., ZRA) located along and northeast of the Woodstock fault and attributed these to a buried fault much longer than the Woodstock fault. Marple and Talwani (1993, 2000) suggested that this structure, the ECFS, may have been the source of the 1886 Charleston earthquake. Marple and Talwani (2000) provided additional evidence for the existence of the southern section of the ECFS, including seismic reflection data, linear aeromagnetic anomalies, exposed Plio-Pleistocene

faults, local breccias, and upwarped strata. Since most of the geomorphic anomalies associated with the southern section of the ECFS are in late Pleistocene sediments, Marple and Talwani (2000) speculated that the fault has been active in the past 130–10 ka, and perhaps remains active. Wildermuth and Talwani (2001) used gravity and topographic data to postulate the existence of a pull-apart basin between the southern and central sections of the ECFS, which would imply a component of right-lateral slip on the fault. Wheeler (2005) classified the ECFS as a Class C feature based on the lack of demonstrable evidence that the ECFS has or can generate strong ground motion and the lack of any demonstrable evidence for any sudden uplift anywhere along the proposed fault.

- Adams Run Fault - Weems and Lewis (2002) postulated the existence of the Adams Run fault (Figure 2.5-222) on the basis of microseismicity and borehole data. Their interpretation of borehole data suggests the presence of areas of uplift and subsidence separated by the inferred fault. However, review of these data shows that the pattern of uplift and subsidence does not appear to persist through time (i.e., successive stratigraphic layers) in the same locations and that the intervening structural lows between the proposed uplifts are highly suggestive of erosion along ancient river channels. In addition, there is no geomorphic evidence for the existence of the Adams Run fault, and analysis of microseismicity in the vicinity of the proposed Adams Run fault does not clearly define a discrete structure (Figure 2.5-223).

- Ashley River Fault - The Ashley River fault was identified by Talwani (1982) on the basis of a northwest-oriented, linear zone of seismicity located about 6 mi west of Woodstock, South Carolina, in the meizoseismal area of the 1886 Charleston earthquake (Figure 2.5-222). The postulated Ashley River fault, a southwest-side-up reverse fault, is thought to offset the north-northeast-striking Woodstock fault about 3 to 4 miles to the northwest near Summerville (Reference 457; Reference 459; Reference 476).

- Charleston Fault - Lennon (1986) proposed the Charleston fault on the basis of geologic map relations and subsurface borehole data (Figure 2.5-222). Weems and Lewis (2002) suggested that the Charleston fault is a major, high-angle reverse fault that has been active at least intermittently in Holocene to modern times. The Charleston has no clear geomorphic expression, nor is it clearly defined by microseismicity (Figure 2.5-223).

- Cooke Fault - Behrendt et al. (1981) and Hamilton et al. (1983) identified the Cooke fault based on seismic reflection profiles in the meizoseismal area of the 1886 Charleston earthquake (Figure 2.5-222). This east-northeast-striking, steeply northwest-dipping fault has a total length of about 6.2 mi (10 km) (Reference 214; Reference 300). Marple and Talwani (1993, 2000) reinterpreted these data to suggest that the Cooke fault may be part of a longer, more northerly striking fault (i.e., the ZRA of Marple and Talwani [1993] and the ECFS of Marple and Talwani [2000]). Crone and Wheeler (2000) classified the Cooke fault as a Class C feature based on lack of evidence for faulting younger than Eocene.

- Drayton Fault – The Drayton fault is imaged on onshore seismic reflection lines and was known to the six EPRI ESTs at the time of EPRI (1986). The Drayton fault is mapped as a 5.5-mi-long, apparently northeast-trending, high-angle, reverse fault in the meizoseismal area of the 1886 Charleston earthquake (Reference 300) (Figures 2.5-222 and 2.5-223). The Drayton fault terminates upward at approximately 2,500 ft below the ground surface within a Jurassic-age basalt layer (Reference 300), precluding significant Cenozoic slip on this fault.

- Gants Fault – The Gants fault is imaged on onshore seismic reflection lines and was known to the six EPRI ESTs at the time of EPRI (1986) as a possible Cenozoic-active fault. The Gants fault is mapped as a 5.5-mi-long, apparently northeast-trending, high-angle, reverse fault in the meizoseismal area of the 1886 Charleston earthquake (Reference 214;

Reference 300) (Figures 2.5-222 and 2.5-223). The Gants fault displaces vertically a Jurassic-age basalt layer by about 150 ft at approximately 2,500 ft below the ground surface (Reference 300). Overlying Cretaceous and Cenozoic beds show apparent decreasing displacement with decreasing depth (Reference 300), indicating likely Cenozoic activity, but with decreasing displacement on the Gants fault during the Cenozoic.

- Helena Banks Fault Zone - The Helena Banks fault zone is clearly imaged on seismic reflection lines offshore of South Carolina **(**Reference 215; Reference 213) and was known to the six EPRI ESTs at the time of EPRI (1986) as a possible Cenozoic-active fault zone (Figure 2.5-222). Some ESTs recognized the offshore fault zone as a candidate tectonic feature for producing the 1886 event and included it in their Charleston seismic source zones. However, since 1986, three additional sources of information have become available:

  – In 2002, two magnitude m_b3.5 earthquakes (m_b 3.5 and 4.4) occurred offshore of South Carolina in the vicinity of the Helena Banks fault zone in an area previously devoid of seismicity (Figure 2.5-222).

  – Bakun and Hopper (2004) reinterpreted intensity data from the 1886 Charleston earthquake and show that the calculated intensity center is located about 100 mi offshore from Charleston (although they ultimately concluded that the epicentral location most likely lies onshore near the Middleton Place-Summerville seismic zone; Figure 2.5-222).

  – Crone and Wheeler (2000) described the Helena Banks fault zone as a potential Quaternary tectonic feature (although it was classified as a Class C feature that lacks sufficient evidence to demonstrate Quaternary activity). The occurrence of the 2002 earthquakes and the location of the Bakun and Hopper (2004) intensity center offshore suggest, at a low probability, that the fault zone could be considered a potentially active fault. If the Helena Banks fault zone is an active source, its length and orientation could possibly explain the distribution of paleoliquefaction features along the South Carolina coast.

- Sawmill Branch Fault - Talwani and Katuna (2004) postulated the existence of the Sawmill Branch fault on the basis of microseismicity and further speculated that this feature experienced surface rupture in the 1886 earthquake. According to Talwani and Katuna (2004), this approximately 3-mi-long (5-km-long), northwest-trending fault, which is a segment of the larger Ashley River fault, offsets the Woodstock fault in a left-lateral sense (Figure 2.5-222). Earthquake damage at three localities was used to infer that surface rupture occurred in 1886. These localities were reviewed in the field as part of this ESP project. Features along the banks of the Ashley River (small, discontinuous cracks in a tomb that dates to 1671 AD and displacements [less than 10 cm] in the walls of colonial Fort Dorchester) are almost certainly the product of shaking effects as opposed to fault rupture. Moreover, assessment of microseismicity in the vicinity of the proposed Sawmill Branch fault does not clearly define a discrete structure distinct or separate from the larger Ashley River fault, which was defined based on seismicity (Figure 2.5-223).

- Summerville Fault - Weems et al. (1997) postulated the existence of the Summerville fault near Summerville, South Carolina, on the basis of previously located microseismicity (Figure 2.5-222). However, there is no geomorphic or borehole evidence for the existence of the Summerville fault, and analysis of microseismicity in the vicinity of the proposed Summerville fault does not clearly define a discrete structure (Figure 2.5-223).

- Woodstock Fault - The Woodstock fault, a postulated north-northeast-trending, dextral strike-slip fault, was identified by Talwani (1982) on the basis of a linear zone of seismicity located approximately 6 mi west of Woodstock, South Carolina, in the meizoseismal area of the 1886

Charleston earthquake (Figure 2.5-222). Madabhushi and Talwani (1990, 1993) used a revised velocity model to relocate Middleton Place–Summerville seismic zone earthquakes, and the results of this analysis were used to further refine the location of the postulated Woodstock fault. Talwani (1999, 2000) subdivided the Woodstock fault into two segments that are offset in a left-lateral sense across the northwest-trending Ashley River fault. Marple and Talwani include the Woodstock fault as part of their larger ZRA (1993) and ECFS (2000).

Charleston Area Seismic Zones

Three zones of microseismic activity have been identified in the greater Charleston area. These include the Middleton Place–Summerville, Bowman, and Adams Run seismic zones. Each of these features is described in detail below, and the specifics of the seismicity catalog are discussed in Subsection 2.5.2.1.

- Middleton Place–Summerville Seismic Zone. The Middleton Place–Summerville seismic zone is an area of elevated microseismic activity located about 12 mi northwest of Charleston (Reference 462; Reference 223; Reference 364; Reference 460) (Figure 2.5-222). Between 1980 and 1991, 58 events with mb 0.8 to 3.3 were recorded in an 11-by-14-km area, with hypocentral depths ranging from about 1 to 7 mi (2 to 11 km) (Reference 364). The elevated seismic activity of the Middleton Place–Summerville seismic zone has been attributed to stress concentrations associated with the intersection of the Ashley River and Woodstock faults (Reference 457; Reference 364; Reference 460; Reference 291). Persistent foreshock activity was reported in the Middleton Place–Summerville seismic zone area (Reference 268), and it has been speculated that the 1886 Charleston earthquake occurred within this zone [e.g., (Reference 457; Reference 462; Reference 210)].

- Bowman Seismic Zone. The Bowman seismic zone is located about 50 mi northwest of Charleston, South Carolina, outside of the meizoseismal area of the 1886 Charleston earthquake and about 60 mi east-northeast of the VEGP site (Figures 2.5-221 and 2.5-222). The Bowman seismic zone was identified on the basis of a series of $3<M_L<4$ earthquakes that occurred between 1971 and 1974 (Reference 463; Reference 223).

- Adams Run Seismic Zone. The Adams Run seismic zone, located within the meizoseismal area of the 1886 Charleston earthquake, was identified on the basis of four **M**<2.5 earthquakes, three of which occurred in a 2-day period in December 1977 (Reference 462). The Adams Run seismic zone is located about 75 mi east-southeast of the VEGP site. Bollinger et al. (1991) downplayed the significance of the Adams Run seismic zone, noting that, in spite of increased instrumentation, no additional events were detected after October 1979.

Charleston Area Seismically Induced Liquefaction Features

The presence of liquefaction features in the geologic record may be indicative of past earthquake activity in a region (e.g., Reference 397). Liquefaction features have been recognized throughout coastal South Carolina and have been attributed to both the 1886 Charleston and earlier moderate to large earthquakes in the region.

- 1886 Charleston Earthquake Liquefaction Features - Liquefaction features produced by the 1886 Charleston earthquake are most heavily concentrated in the meizoseismal area (Reference 268; Reference 434; Reference 205), but have been reported as far away as Columbia, Allendale, Georgetown (Reference 434) and Bluffton, South Carolina (Reference 461) (Figure 2.5-221).

- Paleoliquefaction Features in Coastal South Carolina - Liquefaction features predating the 1886 Charleston earthquake are found throughout coastal South Carolina (Figures 2.5-221 and 2.5-222). The spatial distribution and ages of paleoliquefaction features in coastal South Carolina constrain possible locations and recurrence rates for large earthquakes [e.g., (Reference 398, Reference 399; Reference 205; Reference 207, Reference 206)]. Talwani and Schaeffer (2001) combined previously published data with their own studies of liquefaction features in the South Carolina coastal region to derive possible earthquake recurrence histories for the region. Talwani and Schaeffer's (2001) Scenario 1 allows for the possibility that some events in the paleoliquefaction record are smaller in magnitude (approximately **M** 6+), and that these more moderate events occurred to the northeast (Georgetown) and southwest (Bluffton) of Charleston. In Talwani and Schaeffer's (2001) Scenario 2, all earthquakes in the record are large events (approximately **M** 7+) located near Charleston. Talwani and Schaeffer (2001) estimated recurrence intervals of about 550 years and approximately 900 to 1,000 years from their two scenarios. Subsection 2.5.2.2.2.4.3 provides discussion of the interpretation of the paleoliquefaction record used to define earthquake recurrence for the Charleston earthquake source.

  Because there is no surface expression of faults within the Charleston seismic zone, earthquake recurrence estimates are based largely on dates of paleoliquefaction events. The most recent summary of paleoliquefaction data (Reference 461) suggests a mean recurrence time of 550 years for Charleston, which was used in the 2002 USGS model (Reference 282). This recurrence interval is less than the 650-year recurrence interval used in the USGS hazard model (Reference 281) and is roughly an order of magnitude less than the seismicity-based recurrence estimates used in EPRI (1986). Refinements of the estimate of Charleston area earthquake recurrence are presented in detail in Subsection 2.5.2.2.2.4.

2.5.1.1.4.5 Savannah River Site Tectonic Features

A number of faults have been identified on the Savannah River Site (SRS), located in South Carolina directly across the Savannah River from the VEGP site (Figures 2.5-224, 2.5-225, and 2.5-226). Fault locations are based on a combination of seismic reflection and refraction studies, borehole studies, and groundwater investigations [e.g., (Reference 442; Reference 265; Reference 453; Reference 254, Reference 255)]. There are a greater number of faults recognized east of the Savannah River because the Savannah River Site has been the focus of several decades of subsurface exploration and research over a much larger area than the VEGP site. However, the availability of high quality, high resolution seismic reflection data collected as part of the Vogtle ESP project make the existence of any unrecognized faults at the VEGP site unlikely.

The interpreted locations of the SRS faults have changed through time among different researchers and with the availability of additional data. Because most SRS faults are defined in the subsurface primarily from interpretation of seismic reflection profiles, there is considerable uncertainty regarding the strike, extent, and continuity of some features. Mapping of these subsurface structures between limited data points on seismic profiles has evolved to where some faults defined by name in earlier studies are no longer identified in more recent compilations. For example, the Ellenton fault was initially mapped by Domoracki (1994) as northerly striking fault between the Pen Branch and Crackerneck faults (Figure 2.5-224). The Ellenton fault, however, does not appear in the most recent SRS fault maps (Reference 254, Reference 255) (Figure 2.5-226).

The most significant perturbations in subsurface basement topography are associated with the Pen Branch, Steel Creek, ATTA, Crackerneck, Martin, and Tinker Creek faults (these are the so-called "first order SRS faults" of Cumbest et al. [2000]; Figure 2.5-226). Other faults that have been identified or postulated to exist on the SRS include the Ellenton, Lost Lake, Millett, and Upper Three Runs faults (Figures 2.5-224 and 2.5-225). Four of the Savannah River faults are located within the

VEGP site area (i.e., the Pen Branch, Steel Creek, Ellenton, and Upper Three Runs faults). Each SRS fault is discussed below, beginning with the four faults that lie within the VEGP site area:

- Pen Branch Fault - Because it extends under the VEGP site, the Pen Branch fault is discussed in detail in Subsections 2.5.1.2.4 and 2.5.3.

- Steel Creek Fault - The Steel Creek fault is located in the southwest portion of the SRS, about 2.5 mi (4 km) from the VEGP site (Reference 453; Reference 255) (Figure 2.5-224). The Steel Creek fault is an approximately 10-mi-long, steeply northwest-dipping, southeast-side-down reverse fault that terminates to the northeast on the Savannah River Site (Reference 265). The Steel Creek fault is subparallel to, and southeast of, the Pen Branch fault. Together the Pen Branch and Steel Creek faults form the boundaries of an uplifted block of Triassic basement, indicating that the Steel Creek fault is genetically associated with, and probably an antithetic feature to, the Pen Branch fault. The Steel Creek fault extends upward into Cretaceous units, but the uppermost extent of faulting remains unresolved (Reference 453). The orientation of the Steel Creek fault is similar to that of the southeast-dipping Pen Branch fault relative to the maximum horizontal compressive stress field (Reference 388), thereby making both the Steel Creek and Pen Branch faults unfavorably oriented to be reactivated in a reverse or strike-slip sense. Geomatrix (1993) addressed the potential capability of the Steel Creek fault in conjunction with the Pen Branch fault and concluded that there is no discernible warping or faulting of Quaternary fluvial terraces across both faults within a resolution of 7 to 10 ft.

- Ellenton Fault - The Ellenton fault is located in the southeastern portion of the SRS, about 5 mi from the VEGP site (Figure 2.5-224). The Ellenton fault strikes north-northwest and is near vertical to steeply east-dipping (Reference 453; Reference 254). The Ellenton fault appears to have an east-side-down sense of slip, but data quality are poor (Reference 453), and the latest mapping does not show this fault (Reference 254, Reference 255).

- Upper Three Runs Fault - The Upper Three Runs fault is located in the northwest portion of the SRS, about 5 mi from the VEGP site (Reference 255) (Figure 2.5-224). The northeast-trending Upper Three Runs fault is restricted to crystalline basement; seismic reflection profiling revealed no evidence for this fault offsetting Coastal Plain sediments (Reference 232; Reference 453). The Upper Three Runs fault has been interpreted as an older (initially Paleozoic) fault that soles into the Augusta fault at depth, possibly reactivated as a Mesozoic normal fault (Reference 252; Reference 265; Reference 453).

- ATTA Fault - The ATTA fault is located in the northeast portion of the SRS, about 16 mi from the VEGP site (Figure 2.5-226). The near-vertical ATTA fault strikes approximately N36°E. Based on geometrical analysis of seismic reflection data, the maximum east-side-up vertical separation of basement rocks by the ATTA fault is about 82 ft (25 m) (Reference 255). Upward penetration of the ATTA fault is uncertain because of the lack of good reflectors overlying the fault in the shallow section (Reference 453).

- Crackerneck Fault - The Crackerneck fault is located in the northwestern portion of the SRS, about 10 mi from the VEGP site (Figure 2.5-226). The Crackerneck fault strikes N22°E and dips steeply to the east (Reference 254). Based on geometrical analysis of seismic reflection data, the maximum vertical separation of basement rocks by the Crackerneck fault is about 98 ft (30 m) (Reference 255). Offset decreases upward within the Coastal Plain section to 23 ft (7 m) at the top of the Upper Eocene Dry Branch formation (approximately 38.8 Ma) (Reference 255).

- Martin Fault - The Martin fault is located just south of the SRS, about 9 mi from the VEGP site (Reference 255) (Figures 2.5-225 and 2.5-226). There is little subsurface control constraining the location and extent of the Martin fault, but aeromagnetic data anomalies associated with this fault trend N55°E for a distance of about 25 mi (Reference 255). The dip direction of the Martin fault is unknown (Reference 255). Based on data from two boreholes, Snipes et al. (1993a) estimated about 60 to 100 ft of vertical separation of the basement surface associated with the Martin fault. It has been suggested that the Martin fault is the southeastern bounding fault of the Dunbarton Basin (Reference 442), although Domoracki et al. (1999b) suggested that the Dunbarton Basin is instead a half-graben bounded only by the Pen Branch fault to the north.

- Tinker Creek Fault - The Tinker Creek fault is located in the northern portion of the SRS, about 12 mi from the VEGP site (Reference 255) (Figure 2.5-226). The Tinker Creek fault strikes approximately N36°E and dips steeply to the southeast. Based on geometrical analysis of seismic reflection data, the vertical separation of basement rocks by the Tinker Creek fault increases to the northeast to a maximum of about 79 ft (24 m) (Reference 255). Cumbest et al. (1998) suggested that the Tinker Creek fault may be of regional importance, but the southeastern extent of the fault remains unresolved.

- Lost Lake Fault -. The Lost Lake fault is located in the northwestern portion of the SRS, about 12 mi from the VEGP site (Reference 252) (Figure 2.5-225). The Lost Lake fault has been mapped based on its apparent control on contaminant flow paths. Seismic reflection and borehole data constraining the location, geometry, sense of slip, and recency of movement on the Lost Lake fault are lacking (Reference 254).

- Millett Fault - A USGS Open File Report by Faye and Prowell (1982) postulated the existence of the Millett and Statesboro faults. Based on the interpretation of (1) lithic fragments in cuttings from two water wells, (2) groundwater data, and (3) changes in Savannah River sinuosity, Faye and Prowell (1982) proposed a 40-mi-long, northeast-striking Millett fault that vertically separates the buried Triassic/Cretaceous contact by 600 ft in a southeast-side-up sense.

  A detailed multidisciplinary study was undertaken by Georgia Power Company (GPC) to investigate the postulated Millett and Statesboro faults (Reference 211). This study included:

  – Geologic mapping

  – Analysis of aerial and Landsat imagery

  – Core drilling along two transects

  – Petrographic, X-ray, and heavy minerals analysis of core samples

  – Downhole geophysical surveys

  – Seismic reflection profiling

  – Water level monitoring

  – Groundwater modeling

  – Analysis of surface water flow

The Bechtel (1982) study concludes that there is no evidence for a capable fault or any fault as young as the undeformed Blue Bluff Marl of mid-Eocene age (40 Ma). This study also demonstrated that the original interpretation of a 600-ft (183-m) vertical separation of the base of the Coastal Plain sediments was incorrect. Core VSC-4, located 200 ft (61 m) from the original well (AL66) where Triassic rock was interpreted in the cuttings, demonstrated the presence of Cretaceous Coastal Plain sediments 400 ft (122 m) below where Triassic rock had originally been interpreted by Faye and Prowell (1982).

Upon review of the Bechtel (1982) study, the NRC staff concluded that the Millett fault is not a capable fault as defined in Appendix A to 10 CFR Part 100 in the vicinity of the VEGP site. (Reference 357).

2.5.1.1.4.6 Seismic Sources Defined by Regional Seismicity

Within 200 mi of the VEGP site, there are four areas of concentrated seismicity. Three of these (the Middleton Place-Summerville, Bowman, and Adams Run seismic zones) are located in the Charleston, South Carolina area and are discussed in Subsection 2.5.1.1.4.4. The fourth area of concentrated seismicity in the site region is the Eastern Tennessee seismic zone, a northeast-trending concentration of small-to-moderate earthquakes (Figure 2.5-218).

Eastern Tennessee Seismic Zone

The Eastern Tennessee seismic zone (ETSZ) is a pronounced seismic source in the central and southeastern United States (Figure 2.5-218). Most of the seismicity associated with the Eastern Tennessee seismic zone is located more than 200 mi from the VEGP site, but diffuse seismicity associated with the southeastern margin of the Eastern Tennessee seismic zone is located just within 200 mi of the VEGP site. The zone, located in the Valley and Ridge province of eastern Tennessee, is about 185 mi (300 km) long and 30 mi (50 km) wide and has not produced a damaging earthquake in historical time (Reference 407). However, this zone is the second most active seismic area in the United States east of the Rocky Mountains, after the New Madrid seismic zone (Reference 223), and produced the second highest release of seismic strain energy in the CEUS during the 1980s, when normalized by crustal area (Reference 407).

Earthquakes in the Eastern Tennessee seismic zone are occurring at depths from 3 to 16 mi (5 to 26 km) within Precambrian crystalline basement rocks buried beneath the exposed thrust sheets of Paleozoic rocks. None of the Eastern Tennessee seismic zone earthquakes has exceeded a moment magnitude (**M**) of 4.6 (Reference 234). The mean focal depth within the seismic zone is 9 mi (15 km), which is well below the Appalachian basal decollement's maximum depth of 3 mi (5 km) (Reference 407). The lack of seismicity in the shallow Appalachian thrust sheets implies that the seismogenic structures in the Eastern Tennessee zone are unrelated to the surface geology of the Appalachian orogen (Reference 342). The majority of earthquake focal mechanisms show right-lateral slip on northerly-trending planes or left-lateral slip on easterly-trending planes (Reference 234). A smaller number of focal plane solutions show right-lateral motion on northeasterly trending planes that parallel the overall trend of seismicity (Reference 235). Statistical analyses of focal mechanisms and epicenter locations suggest that seismicity is occurring on a series of northeast-trending en-echelon basement faults intersected by several east-west-trending faults (Reference 234). Potential structures most likely responsible for the seismicity in Eastern Tennessee are reactivated Cambrian or Precambrian normal faults formed during rifting that led to the Iapetan Ocean and presently located beneath the Appalachian thrust sheets (Reference 222; Reference 480).

Earthquakes within the Eastern Tennessee seismic zone cannot be attributed to known faults (Reference 407), and no capable tectonic sources have been identified within the seismic zone. However, the seismicity is spatially associated with major geophysical lineaments. The western margin of the Eastern Tennessee seismic zone is sharply defined and is coincident with the

prominent gradient in the magnetic field defined by the New York-Alabama magnetic lineament (Reference 235). Most seismicity lies between the New York–Alabama lineament on the west and the Clingman and Ococee lineaments on the east (Reference 342).

In spite of the observations of small to moderate earthquakes in the Eastern Tennessee seismic zone, no geological evidence has demonstrated the occurrence of prehistoric earthquakes larger than any historical shocks within the seismic zone (Reference 235; Reference 482). Some researchers have suggested secondary evidence for possible large, prehistoric earthquakes in the region [e.g., (Reference 317)], but none of this work is conclusive. As a result, Wheeler (2005) classifies the Eastern Tennessee seismic zone as a Class C feature for lack of geological evidence of large earthquakes.

The EPRI source model (Reference 271) includes various source geometries and parameters to represent the seismicity of the Eastern Tennessee seismic zone. Subsequent hazard studies have used Mmax values within the range of maximum magnitudes used by the six EPRI models. Collectively, upper-bound maximum values of Mmax used by the EPRI teams ranged from m_b 6.6 to 7.4. Using three different methods specific to the Eastern Tennessee seismic source, Bollinger (1992) estimated a Mmax of m_b 6.45. Chapman and Krimgold (1994) used a Mmax of m_b 7.25 for the Eastern Tennessee zone and most other sources in their seismic hazard analysis of Virginia. Both of these more recent estimates of Mmax are similar to the range of Mmax values used in EPRI (1986). (Equivalencies between m_b and **M** as used in this SSAR are discussed in Subsection 2.5.2.2.1 and listed in Table 2.5-209). Therefore, it is concluded that no new information has been developed since 1986 that would require a significant revision to the EPRI seismic source model. Additional discussion of the significance of the ETSZ on the Vogtle ESP seismic hazard is provided in Subsection 2.5.2.2.2.5

Selected Seismogenic and Capable Tectonic Sources Beyond the Site Region

Because of the potential for distant, large earthquakes in the CEUS contributing to the long period ground motion hazard at the VEGP site, a discussion of three additional seismic sources located beyond 200 mi from the site is warranted. These sources are the Central Virginia, New Madrid, and Giles County seismic zones.

Central Virginia Seismic Zone

The Central Virginia seismic zone is an area of persistent, low-level seismicity in the Piedmont province, located more than 350 mi from the VEGP site (Figure 2.5-218). The zone extends about 75 mi in a north-south direction and about 90 mi in an east-west direction from Richmond to Lynchburg (Reference 221). The largest historical earthquake to occur in the Central Virginia seismic zone was the body-wave magnitude (m_b) 5.0 Goochland County event on December 23, 1875 (Reference 221). The maximum intensity estimated for this event was MMI VII in the epicentral region.

Seismicity in the Central Virginia seismic zone ranges in depth from about 2 to 8 mi (4 to 13 km) (Reference 484). Coruh et al. (1988) suggested that seismicity in the central and western parts of the zone may be associated with west-dipping reflectors that form the roof of a detached antiform, while seismicity in the eastern part of the zone near Richmond may be related to a near-vertical diabase dike swarm of Mesozoic age. However, given the depth distribution of 2 to 8 mi (4 to 13 km) (Reference 484) and broad spatial distribution, it is difficult to uniquely attribute the seismicity to any known geologic structure, and it appears that the seismicity extends both above and below the Appalachian detachment.

No capable tectonic sources have been identified within the Central Virginia seismic zone, but two paleoliquefaction sites have been identified within the seismic zone (Reference 251; Reference 396).

The paleoliquefaction sites reflect prehistoric occurrences of seismicity within the Central Virginia seismic zone and do not indicate the presence of a capable tectonic source.

The 1986 EPRI source model includes various source geometries and parameters to capture the seismicity of the Central Virginia seismic zone (Reference 271). Subsequent hazard studies have used Mmax values that are within the range of maximum magnitudes used by the six EPRI models. Collectively, upper-bound maximum values of Mmax used by the EPRI ESTs range from m_b 6.6 to 7.2 (discussed in Subsection 2.5.2.2). More recently, Bollinger (1992) has estimated a Mmax of m_b 6.4 for the Central Virginia seismic source. Chapman and Krimgold (1994) have used a Mmax of m_b 7.25 for the Central Virginia seismic source and most other sources in their seismic hazard analysis of Virginia. This more recent estimate of Mmax is similar to the Mmax values used in EPRI (1986). Similarly, the distribution and rate of seismicity in the Central Virginia seismic source have not changed since the 1986 EPRI study (discussed in Section 2.5.2.2.8). Thus, there is no change to the source geometry or rate of seismicity. Therefore, the conclusion is that no new information has been developed since 1986 that would require a significant revision to the EPRI seismic source model.

New Madrid Seismic Zone

The New Madrid seismic zone extends from southeastern Missouri to southwestern Tennessee and is located more than 400 mi west of the VEGP site (Figure 2.5-218). The New Madrid seismic zone lies within the Reelfoot rift and is defined by post-Eocene to Quaternary faulting and historical seismicity. Given the significant distance between the site and the seismic zone, the New Madrid seismic zone did not contribute to 99 percent of the hazard at the VEGP site in EPRI (1986). However, it is described in this section because several recent studies provide significant new information regarding magnitude and recurrence interval for the seismic zone.

The New Madrid seismic zone is approximately 125 mi (220 km) long and 25 mi (40 km) wide. Research conducted since 1986 has identified three distinct fault segments embedded within the seismic zone. These three fault segments include a southern northeast-trending dextral slip fault, a middle northwest-trending reverse fault, and a northern northeast-trending dextral strike-slip fault (Reference 483). In the current east-northeast to west-southwest directed regional stress field, Precambrian and Late Cretaceous age extensional structures of the Reelfoot rift appear to have been reactivated as right-lateral strike-slip and reverse faults.

The New Madrid seismic zone produced three historical, large magnitude earthquakes between December 1811 and February 1812 (Reference 330). The December 16, 1811, earthquake is associated with strike-slip fault displacement along the southern portion of the New Madrid seismic zone. Johnston (1996) estimated a magnitude of **M** 8.1±0.31 for the December 16, 1811, event. However, Hough et al. (2000) re-evaluated the isoseismal data for the region and concluded that the December 16 event had a magnitude of **M** 7.2 to 7.3. Bakun and Hopper (2004) similarly concluded this event had a magnitude of **M** 7.2.

The February 7, 1812, New Madrid earthquake is associated with reverse fault displacement along the middle part of the New Madrid seismic zone (Reference 341). This earthquake most likely occurred along the northwest-trending Reelfoot fault that extends approximately 43 mi from northwestern Tennessee to southeastern Missouri. The Reelfoot fault is a northwest-trending, southwest-vergent reverse fault. The Reelfoot fault forms a topographic scarp developed as a result of fault-propagation folding (Reference 470; Reference 347; Reference 469). Johnston (1996) estimated a magnitude of **M** 8.0±0.33 for the February 7, 1812, event. However, Hough et al. (2000) re-evaluated the isoseismal data for the region and concluded that the February 7 event had a magnitude of **M** 7.4 to 7.5. More recently, Bakun and Hopper (2004) estimated a similar magnitude of **M** 7.4.

The January 23, 1812, earthquake is associated with strike-slip fault displacement on the East Prairie fault along the northern portion of the New Madrid seismic zone. Johnston (1996) estimated a

magnitude of **M** 7.8±0.33 for the January 23, 1812, event. Hough et al. (2000), however, re-evaluated the isoseismal data for the region and concluded that the January 23 event had a magnitude of **M** 7.1. More recently, Bakun and Hopper (2004) estimated a similar magnitude of **M** 7.1.

Because there is very little surface expression of faults within the New Madrid seismic zone, earthquake recurrence estimates are based largely on dates of paleoliquefaction and offset geological features. The most recent summaries of paleoseismologic data (Reference 466, Reference 467; Reference 299) suggest a mean recurrence time of 500 years, which was used in the 2002 USGS model (Reference 282). This recurrence interval is half of the 1,000-year recurrence interval used in the 1996 USGS hazard model (Reference 281), and an order of magnitude less than the seismicity-based recurrence estimates used in EPRI (1986).

The upper-bound maximum values of Mmax used in EPRI (1986) range from m_b 7.2 to 7.9. Since the EPRI study, estimates of Mmax have generally been within the range of maximum magnitudes used by the six EPRI models. The most significant update of source parameters in the New Madrid seismic zone since the 1986 EPRI study is the reduction of the recurrence interval to 500 years.

Giles County Seismic Zone

The Giles County seismic zone is located in Giles County, southwestern Virginia, near the border with West Virginia and more than 250 mi from the VEGP site (Figure 2.5-218). The largest known earthquake to occur in Virginia and the second largest earthquake in the entire southeastern United States is the 1897 M 5.9 (Reference 343) Giles County event, which likely produced an MMI VIII in the epicentral area.

Earthquakes in the Giles County seismic zone occur within Precambrian crystalline basement rocks beneath the Appalachian thrust sheets at depths from 3 to 16 mi (5 to 25 km) (Reference 222). Earthquake foci define a 25-mi-long (40-km-long), northeasterly striking, tabular zone that dips steeply to the southeast beneath the Valley and Ridge thrust sheets (Reference 222; Reference 233). The lack of seismicity in the shallow Appalachian thrust sheets, estimated to be about 2 to 3.5 mi (4 to 6 km) thick, implies that the seismogenic structures in the Giles County seismic zone, similar to those inferred for the Eastern Tennessee seismic zone, are unrelated to the surface geology of the Appalachian orogen (Reference 222). The spatial distribution of earthquake hypocenters, together with considerations of the regional tectonic evolution of eastern North America, suggests that the earthquake activity is related to contractional reactivation of late Precambrian or Cambrian normal faults that initially formed during rifting associated with opening of the Iapetan Ocean (Reference 222; Reference 223).

No capable tectonic sources have been identified within the Giles County seismic zone, nor does the seismic zone have recognizable geomorphic expression (Reference 482). Thus, in spite of the occurrence of small to moderate earthquakes, no geological evidence has demonstrated the occurrence of prehistoric earthquakes larger than any historical shocks within the zone (Reference 482). As a result, Wheeler (2005) classifies the Giles County seismic zone as a Class C feature for lack of geological evidence of large earthquakes.

A zone of small Late Pliocene to Early Quaternary age faults has been identified within the Giles County seismic zone, near Pembroke, Virginia (Reference 251). The Pembroke zone is a set of extensional faults exposed in terrace deposits overlying limestone bedrock along the New River. Crone and Wheeler (2000) rated these faults as Class B features because it has not yet been determined whether these faults are tectonic or the result of solution collapse in underlying limestone units. The shallow Pembroke faults do not appear to be related to the seismicity within the Giles County seismic zone, which is occurring beneath the Appalachian basal decollement in the North American basement.

The EPRI source model includes various source geometries and parameters to represent the seismicity of the Giles County seismic zone (Reference 271). Subsequent hazard studies have used Mmax values that were within the range of maximum magnitudes used by the six EPRI models. Collectively, upper-bound maximum values of Mmax used by the EPRI teams ranged from m_b 6.6 to 7.2 (discussed in Subsection 2.5.2.2). More recently, Bollinger (1992) estimated a Mmax of m_b 6.3 for the Giles County seismic source using three different methods. Chapman and Krimgold (1994) used a Mmax of m_b 7.25 for the Giles County zone and most other sources in their seismic hazard analysis of Virginia. Both of these more recent estimates of Mmax are similar to the range of Mmax values used in EPRI (1986). Therefore, no new information has been developed since 1986 that would require a significant revision to the EPRI seismic source model.

2.5.1.1.5 Regional Gravity and Magnetic Data

Regional maps of the gravity and magnetic fields in North America were published by the Geological Society of America in 1987 as part of the Society's Decade of North American Geology (DNAG) project. The maps present the potential field data at 1:5,000,000-scale and thus are useful for identifying and assessing regional gravity and magnetic anomalies with wavelengths on the order of about 6 mi (10 km) or greater. Gravity and magnetic data also have been incorporated in the E-5 DNAG crustal transect, which traverses the Appalachian orogen from eastern Tennessee to the offshore Atlantic basin (Reference 316), and encompasses the VEGP site region. At a local scale, Cumbest et al. (1992) developed models of gravity and magnetic data to evaluate the geometry and structure of the Mesozoic Dunbarton basin beneath the SRS northeast of the VEGP site. These models in particular provide important insights for the interpretation of potential field data in the VEGP site region.

2.5.1.1.5.1 Regional Gravity Data

The 1987 DNAG gravity map and the gravity profile along the E-5 DNAG crustal transect document low gravity values beneath the Valley and Ridge and Blue Ridge provinces relative to the Cumberland Plateau province to the west (Figure 2.5-214). The approximately 40 to 60 mGal eastward decrease in gravity along the western margin of the Valley and Ridge province is likely due to eastward thickening of the relatively less dense carbonate and siliciclastic rocks above the Grenville metamorphic basement in the Valley and Ridge province relative to the Cumberland Plateau.

Bouguer gravity values increase by about 80 mGal across an approximately 62 mi (100 km) distance from the eastern Blue Ridge to the Inner Piedmont Terrane (Reference 244; Reference 316). As documented by the DNAG gravity map, this gradient is present across the Piedmont physiographic province along much of the length of the Appalachian belt. At the latitude of Virginia, north of the VEGP site region, this gradient has been interpreted to reflect the eastward thinning of the North American continental crust and associated positive relief on the Moho with proximity to the Atlantic margin. Inspection of the crustal structure interpreted by Hatcher et al. (1994) along the E-5 transect (Figure 2.5-214) indicates that the eastward increase in gravity across the Inner Piedmont at the latitude of the ESP study region also is associated with obducted metavolcanic rocks of the Carolina–Avalon Terrane that have been overthrust onto the Grenvillian basement. A gravity model by Iverson and Smithson (1983) along the southern Appalachian COCORP seismic reflection profile suggests that the gradient probably arises from both eastward thinning of continental crust and the obduction of the Inner Piedmont and Carolina Terranes, which have higher average densities than the underlying Grenvillian crust.

The gravity profile along the DNAG E-5 crustal transect indicates that the gravity field east of the Inner Piedmont is relatively uniform (Figure 2.5-214), and the 1987 DNAG gravity map shows that the Coastal Plain is characterized by relatively low amplitude anomalies with wavelengths on the order of about 12 to 25 mi (20 to 40 km) superimposed on this uniform field. Detailed modeling of the

gravity field in this region by Cumbest et al. (1992) indicates that the most prominent anomalies are associated with monzogranite plutons, which are relatively less dense than the intruded country rock and thus give rise to local gravity lows, and mafic intrusions, which are relatively more dense and give rise to local gravity highs. From modeling of gravity data, Cumbest et al. (1992) found that the predicted anomaly associated with the Mesozoic Dunbarton Basin is a subordinate feature of the gravity field compared to the anomalies associated with the plutons and mafic intrusions.

The relationship between gravity anomalies in the VEGP site vicinity and bedrock geology inferred by Dennis et al. (2004) to underlie the Coastal Plain sediments from borehole and other subsurface data is illustrated in Figure 2.5-227. The extremes in the local gravity field are highs associated with Triassic-Jurassic mafic intrusive complexes southeast of the VEGP site and lows associated with granitic plutons mapped to the north-northeast and east-northeast of the site. The lateral extent of the gravity lows associated with the Graniteville and Springfield plutons suggest that these bodies may be larger than inferred by Dennis et al. (2004). The Dunbarton Basin is spatially associated with an approximately 5-mi-wide (8-km-wide), northeast-southwest-trending gravity low northwest of the mafic intrusive complexes and associated gravity high southeast of the VEGP site. A northwest-southeast profile of the gravity data through the VEGP site (Figure 2.5-228) illustrates in detail that the gravity low associated with the Dunbarton Basin is a very modest second-order feature superimposed on the 25-mi-long (40-km-long) west-to-east increase in gravity between the granitic plutons and mafic intrusive complexes, consistent with the findings of Cumbest et al. (1992).

The gravity profile also shows that the Belair fault, which separates the Kiokee belt on the northwest from the Belair belt to the southeast, is adjacent to an approximately 35 mGal gravity difference (Figure 2.5-228). This eastward decrease in gravity shows that the high-grade metamorphic rocks of the Kiokee belt are generally denser than the relatively lower-grade rocks of the Belair belt. However, the magnitude of the gradient also could be affected by the presence of the relatively lower density granitic plutons to the east and southeast of the Belair fault.

To summarize, gravity data published since the mid-1980s document that long-wavelength anomalies along the E-5 DNAG crustal transect through the VEGP site region are characteristic of large parts of the Appalachian belt and reflect first-order features of the various provinces and accreted Paleozoic terranes and west-to-east thinning of the ancestral North American (Grenvillian) continental crust during the Mesozoic. The dominant short-wavelength characteristics of the gravity field in the vicinity of the VEGP site are gravity highs and lows associated with Mesozoic mafic and Paleozoic granitic intrusions, respectively. Detailed gravity modeling by Cumbest et al. (1992) shows that the gravity low associated with the Triassic Dunbarton Basin is a subordinate feature in the regional field. The gravity data acquisition and modeling studies performed to date do not show any evidence for Cenozoic tectonic activity or specific Cenozoic structures. There are no large, unexplained anomalies in the gravity data.

2.5.1.1.5.2 Regional Magnetic Data

Data compiled for the DNAG magnetic map reveal numerous northeast-southwest-trending magnetic anomalies that are generally parallel to the structural grain of the Paleozoic Appalachian orogenic belt (Reference 244). For example, a magnetic profile along the DNAG E-5 crustal transect (Reference 316) reveals an approximately 800 nT southeastward decrease in magnetic intensity between the Cumberland Plateau and western Valley and Ridge provinces, and the western Blue Ridge province (Figure 2.5-214). The DNAG magnetic map indicates that this difference is present to the southwest and northeast along the western Appalachian belt in adjacent parts of Alabama and Kentucky and is spatially associated with the contact between Precambrian metamorphic basement and overlying Paleozoic accreted terranes. In general, the western Valley and Ridge province and eastern Blue Ridge along the E-5 crustal transect are characterized by relatively low magnetic intensities, and the western Blue Ridge and Inner Piedmont are relative magnetic highs, probably

indicating a greater abundance of mafic rocks in the accreted Taconic units east of the Hayesville thrust.

The accreted Carolina–Avalon Terrane is characterized by short-wavelength, high-amplitude anomalies (approximately 200 nT over distances of about 6.2 mi [10 km]). Detailed modeling of magnetic data from the SRS northeast of the VEGP site indicates that these anomalies may be associated with mafic intrusions that are vertically elongated and have east-dipping boundaries (Reference 253). Felsic plutons in this region, which are inferred to exist from borehole data and gravity modeling, have modest susceptibility contrasts with the country rock they intrude and thus do not generate high-amplitude magnetic anomalies (Reference 253). Similarly, Mesozoic basin sediments are inferred to have relatively low susceptibility contrasts with the pre-intrusive basement rock, and modeling by Cumbest et al. (1992) suggests that the anomaly associated with the sediments and margins of the Dunbarton Basin is a second-order feature of the magnetic field relative to the amplitudes of the anomalies produced by the intrusive mafic rocks. The Towaliga fault along the western margin of the Carolina–Avalon Terrane is associated with alternating low and high short wavelength magnetic anomalies (Reference 316) characteristic of those produced by a susceptibility contrast across a dipping structural contact.

Comparison of aeromagnetic data from the VEGP site region (Reference 259) with bedrock geology inferred by Dennis et al. (2004) to underlie the Coastal Plain sediments from borehole and other subsurface data illustrates the relationships described by Cumbest et al. (1992). The Dunbarton Basin is associated with a northeast-southwest-trending magnetic low and is bounded on the south by pronounced magnetic highs associated with Triassic–Jurassic mafic intrusive complexes (Figure 2.5-229). A northwest-southeast-trending profile of the magnetic intensities that passes through the VEGP site shows that the magnetic low associated with the Dunbarton Basin is similar to a magnetic low approximately 12 mi to the southeast that is not associated with a known Triassic basin (Figure 2.5-230); also, the figure shows that the high magnetic anomalies associated with the mafic intrusive complexes extend northward into the basin (Figure 2.5-229). These relations are consistent with the conclusion of Cumbest et al. (1992) that the magnetic signature of the Dunbarton Basin is very modest relative to that of the mafic intrusive complexes.

The magnetic map and profile (Reference 259) also include the Kiokee and Belair belts of the Carolina arc terrane northwest of the VEGP site. Both of these belts are characterized by closely spaced, short-wavelength anomalies with amplitudes of about 100 to 200 gammas (Figure 2.5-230). In general, the magnetic intensities in the Belair belt are slightly higher than those of the Kiokee belt. Daniels (1974) noted that the bulk composition of the Kiokee belt is probably more felsic than that of the Belair belt and thus has a lower magnetic susceptibility.

To summarize, magnetic data published since the mid-1980s provide additional characterization of the magnetic field in the VEGP site region. Detailed modeling of magnetic data from the SRS provides insights into the origins of magnetic anomalies that extend southwest into the vicinity of the VEGP site. The first-order magnetic anomalies in the VEGP site region are associated primarily with northeast-southwest-trending Paleozoic and Mesozoic intrusive rock bodies. The magnetic data do not show evidence for any Cenozoic structures in the site region and do not have sufficient resolution to identify or map discrete faults, such as border faults along the Dunbarton Basin. No large, unexplained anomalies are found in the magnetic data.

2.5.1.2 Site Area Geology

This section describes the geology and structural geology of the site area (within a 5-mi radius of the VEGP site).

2.5.1.2.1 Site Area Physiography and Geomorphology

The site area lies in the Upper Coastal Plain of the Coastal Plain Physiographic Province and is bordered by the Savannah River to the east (Figures 2.5-204 and 2.5-231). The surrounding topography consists of gently rolling hills with a principally dendritic drainage pattern. Surficial soils are typically well drained. All major streams are tributary to the Savannah River.

The site area lies at the northern extent of a broad westward migrating meander in the Savannah River where the sinuosity decreases from about 1.8 to 1.3 (Reference 292). Incision of the river has formed steep bluffs and topographic relief of nearly 150 ft from the river surface to the plant site. The river level adjacent to the plant site is at an elevation of approximately 80 ft msl, with a gradient of less than 1 ft/mi (Reference 292). The flood plain is a broad alluvial surface that is 4 to 10 ft above the channel. The youngest alluvium lies along the western side of the river, while older terraces are preserved on the east side of the flood plain (Figures 2.5-232 and 2.5-234). Stream valleys are predominantly symmetrical, with slopes ranging from 0.2 to 0.6 percent. The surface topography ranges from an elevation of about 90 to nearly 300 ft msl across the VEGP site (Figures 2.5-233 and 2.5-235).

Several surface depressions were noted during the initial site investigation and were extensively studied. The topography and surface drainage within the site has been modified during and after construction of the existing VEGP units, making evaluation of these features impractical. In the Coastal Plain, surface depressions can be categorized as eolian features known as Carolina bays, whereas others may result from solution of underlying calcareous sediment (Reference 437; Reference 468; Reference 439).

Carolina bays, which are shallow, elliptical depressions with associated sand rims, are common throughout the Atlantic Coastal Plain and are most numerous in North and South Carolina. They are surficial features that have no effect on the subsurface sediments. Distinguishing features of Carolina bays are the elliptical shape, preferential orientation of the long axis at S50°E, and sand rims along the east and southeast flanks (Reference 338). A discussion of various hypotheses for the timing and mode of origin of these bays is provided in Subsection 2.5.1.1.1.

Surface depressions that do not meet the criteria of Carolina bays are typically irregularly shaped, localized features resulting most likely from the dissolution of calcareous stratum at depth. Initial site studies conducted for the existing VEGP Units 1 and 2 concluded that these features resulted principally from dissolution of a limestone unit and that lower-lying carbonate-bearing units were not involved. Subsection 2.5.3.8.2.1 contains a discussion of the significance of these features.

2.5.1.2.2 Site Area Geologic History

The Upper Coastal Plain is essentially a flat-lying section of unconsolidated fluvial and marine sediments overlying a basement complex of Paleozoic crystalline metamorphic and igneous rock as well as Triassic–Jurassic basin sediments. Evolution of the basement complex and the effect on the Coastal Plain section is regional in nature and is discussed in Subsections 2.5.1.1.2 and 2.5.1.1.4.

The Paleozoic rocks and the Triassic sediments were beveled by erosion, forming the base for Coastal Plain sediment deposition. The erosional surface dips southeast approximately 50 ft/mi (Reference 273). The Coastal Plain section consists of stratified sand, clay, limestone, and gravel that dip gently seaward. The oldest Coastal Plain sediments beneath the site area are Late Cretaceous and consist of predominantly siliciclastics deposited in an upper deltaic, fluvial setting that continued throughout the Late Cretaceous. Paleocene sedimentation continued, with a strong fluvial influence changing to more marginal marine to shallow shelf deposition well into the Middle Eocene, marked by deposition of mixed clastic-carbonate sediments. Upper Eocene sedimentation occurred in more marginal and inner-tidal settings. Miocene (or younger) high energy fluvial deposits

are present at higher topographic locations and in some areas incised deeply into the underlying Eocene section. A thin veneer of late Miocene to early Pliocene eolian sands overlies some of the higher topographic areas. The youngest sediments consist of Quaternary alluvium present within the stream and river valleys.

2.5.1.2.3 Site Area Stratigraphy

The site area stratigraphy is based on site-specific data obtained during the ESP and COL site investigations as well as regional geologic studies and includes the following sources of information:

- Regional geologic maps and studies
- Site area studies performed for VEGP Units 1 and 2 and for the ESP investigation
- Borehole data, including core and geophysical logs acquired during the ESP and COL investigations (Figures 2.5-236 and 2.5-249)
- Surface geophysical surveys performed as part of the ESP investigation, including seismic reflection and refraction (Figures 2.5-237, 2.5-238, 2.5-239, and 2.5-240).

Numerous geologic studies have been conducted in the surrounding area since initial studies were conducted for VEGP Units 1 and 2. Most of these studies were focused in the vicinity of the SRS. Many of these studies focused on correlating both geologic and hydrogeologic formations present in South Carolina and Georgia, resulting in an updated stratigraphic nomenclature. The most current stratigraphic nomenclature from Huddlestun and Summerour (1996) and Falls and Prowell (2001) is used below. A correlation chart showing current USGS, Georgia Geological Survey, South Carolina, and SRS and VEGP Units 1 and 2 FSAR nomenclature is provided as Figure 2.5-211. A site stratigraphic column based mainly on data from borehole B-1003, supplemented by data from other ESP and COL investigation borings, is shown on Figure 2.5-241.

2.5.1.2.3.1 Basement Rock

The regional basement surface has been leveled by erosion and dips to the southeast approximately 50 ft/mi (Reference 273). Basement rock lithology within the site area consists of Paleozoic crystalline rock as well as Triassic–Jurassic sedimentary rock of the Dunbarton Basin. Basement rock lithology has been determined directly from core data from boring B-1003 and inferred from seismic reflection and refraction surveys performed as part of the ESP investigation. These data are corroborated regionally with other core data and geophysical surveys, as discussed in Subsection 2.5.1.1.3.5.

Boring B-1003 was drilled within the VEGP site to acquire detailed stratigraphic, lithologic, geophysical (including natural gamma, electrical resistivity, compressional velocity, and shear wave velocity) and depth-to-basement data. Data from B-1003 identifies Triassic–Jurassic basement rock at a depth of 1,049 ft (-826 ft msl). Data from four seismic reflection and refraction lines described in Subsection 2.5.1.2.4.2, as well as borehole and seismic reflection data from other regional studies including the SRS (Reference 253; Reference 442), determine the northern boundary of the Dunbarton Basin to strike northeast-southwest across the site area, defining the approximate boundary between the Triassic–Jurassic sedimentary rock underlying the southeastern portion and Paleozoic crystalline rock underlying the northwestern portion of the site area (Figure 2.5-242).

Although no borehole data confirm the lithology of the Paleozoic crystalline rock within the site area, data from regional studies, as well as regional gravity and magnetic surveys, suggest a complex of metavolcanics (Reference 253; Reference 442). The Triassic-Jurassic sedimentary rocks of the

Dunbarton Basin consist of mudstones, sandstones, and conglomerates of varying degrees of lithification, as determined from borehole B-1003.

2.5.1.2.3.2 Site Area Coastal Plain Stratigraphy

The Paleozoic and Triassic basement complex is unconformably overlain by poorly consolidated to unconsolidated Coastal Plain sediments that dip and thicken to the southeast. These sediments range in age from Upper Cretaceous to Miocene except where the Miocene Hawthorne Formation has been removed by excavation and are approximately 1,049 ft thick in the site area, based on boring B-1003 that was drilled as part of the ESP investigation.

The stratigraphy defined for the site area adopts the nomenclature of Huddlestun and Summerour (1996), as shown on Figures 2.5-211, and 2.5-241, and was based primarily on lithology except where carbonate fossils provided more definitive stratigraphic correlation. Cretaceous sediments that had been assigned to the Tuscaloosa Formation were assigned to the Cape Fear, Pio Nono, Gaillard/ Black Creek and Steel Creek formations. Tertiary sediments were further subdivided based on both lithology and carbonate fossils where present. The youngest sediments of Quaternary age consisted of alluvial deposits within stream and river valleys.

More recent investigations in the VEGP site vicinity have included detailed lithological and paleontological studies to correlate stratigraphic units between Georgia and South Carolina (Reference 278). Over the last two decades, detailed work that focused on the SRS (Figure 2.5-211), has resulted in a more detailed lithostratigraphic column. Cross-well correlation using lithologic data from both the core and downhole geophysical logs provides a means to correlate many of the same geologic units present at the site area with those mapped in the VEGP site vicinity.

The following sub-sections describe each geologic unit, from oldest to youngest, and are based primarily on lithologic descriptions of the core log from boring B-1003 drilled and logged as part of the ESP site investigation (Appendix 2.5A) (Figure 2.5-241). The most recent stratigraphic column published by the USGS (Reference 278) is cited where those studies provide confirmatory information that is directly applicable to the site area. In addition, geologic studies and correlation with SRS stratigraphic units are cited where they provide confirmatory information directly applicable to the site area.

Cretaceous Stratigraphy

Upper Cretaceous age sediments unconformably overlie both crystalline and Triassic–Jurassic basement rock in the site area. The initial site stratigraphy for the VEGP Units 1 and 2 assigned all Cretaceous sediments to the Tuscaloosa Formation. More recent investigations have identified four geologic formations within the Cretaceous section. The following discussions rely primarily on core log data from boring B-1003 (Appendix 2.5A). Contacts, as interpreted from geophysical well logs might vary from the depths identified on the boring logs. The following sections describe these units from oldest to youngest.

Cape Fear Formation

In boring B-1003, the base of the Cape Fear Formation was determined to be at a 1,049 ft depth (-826 ft msl) and the top at a depth of 858 ft (-635 msl). This results in a thickness of 191 ft. The base of the Cape Fear Formation in Boring B-1003 consists of sandy silt overlain by well-sorted quartz gravel with subrounded to angular grains. This is overlain by generally well-sorted gray sandy silt with layers of subrounded gravels, pebbles and silty sand. The silty sand is overlain by sandy silt that in turn is overlain by a clayey sand grading up into a sandy elastic clay. The top portion of the Cape Fear formation is logged as a gray to dark gray, well-sorted, subrounded to subangular fine to coarse clayey sand with a weak cementation zone near the top and arkosic layers.

In boreholes in the site vicinity, the Cape Fear Formation consists of poorly-sorted, silty to clayey quartz, occasionally arkosic, sands with interbedded clays. Grains tend to be subangular to angular. The sands are medium to coarse, with occasional pebble zones. Lithification ranges from moderate to high due to the presence of cristobalite in the clay matrix, which can also yield a greenish blue hue to the sediments. Numerous stacked fining-upward sequences, lack of marine fossils, and the presence of terrestrial microflora and root clasts suggest deposition within a fluvial dominated delta plain (Reference 278).

Pio Nono Formation

In boring B-1003 the base of the Pio Nono Formation is logged at a depth of 858 ft (-635 msl) and the top is logged at a depth of 798 ft (-575 msl). The base consists of a light gray, well-sorted clayey sand. This is overlain primarily by well-sorted sand with silt that grades upward from a gray-tan fine to medium grained unit into a white-gray fine to coarse unit with some gravel. This formation consists primarily of moderately to well-sorted quartz sands with little silt and clayey sands. Traces of manganese staining and mica are present. Grains tend to be rounded to subangular, medium to coarse, with some gravel lags. The sands are typically non-lithified, with a few slightly cemented zones. The top of the formation is logged as a tan-white poorly-sorted fine to medium sand with silt. A fining-up sequence was logged between depths of 808 and 803 ft.

Both fining and coarsening upward sequences are noted in nearby boreholes. The top of the formation may be marked by a thick bed of oxidized clay. In borehole B-1003, this clay was logged as marking the base of the overlying Galliard/Black Creek formations. The lack of marine fossils, presence of oxidized zones, and gravel lags suggest a deltaic environment.

Upper Gaillard Formation/Black Creek Formation

The Upper Gaillard/Black Creek Formation consists of thick alternating sequences of moderately to well-sorted silty, clayey sands and silty clay beds. The sands tend to be medium to coarse grained, rounded to subrounded, and contain trace amounts of mica and glauconite. Fining-upward sequences are present, as well as gravel lag deposits. The more clayey beds tend to be dark and oxidized, with trace amounts of lignite and root clasts. The presence of marine fauna and glauconite suggests a marine influence, while oxidation in the clay beds and the presence of root clasts suggest a more lagoonal setting, which together indicate a prograding delta sequence.

The base of the Upper Gaillard/Black Creek Formation in boring B-1003 was noted at a 798-ft depth (-575 ft msl) and the top at a 587-ft depth (-364 ft msl), resulting in an overall thickness of 211 ft. As noted above, the base is logged as a 12-ft layer of black to dark gray clay. The clay is overlain by poorly graded silty sands to sandy silts. A 24-ft layer of gray sandy silt with clayey sand layers occurs between depths of 603 ft to 627 ft. The top of the Gaillard/Black Creek Formation consists of well-sorted gray fine to coarse sand with silt.

Steel Creek Formation

The basal contact of the Steel Creek Formation with the underlying upper Gaillard/Black Creek Formation is at a depth of 587 ft (-364 ft msl). The top of the Steel Creek Formation is noted at a depth of 477 ft (-254 ft msl), resulting in a total thickness of 110 ft.

Sediments of the Steel Creek Formation are predominantly sands and silty sands. These sands are well to poorly-sorted, with trace amounts of mica, kaolin, and lignite. Sand grains are subrounded to subangular. Multiple fining-upward sequences, the presence of lignite, and the oxidation of clays indicate a more fluvial, delta plain depositional setting. The top of the Steel Creek Formation in boring B-1003 is marked by a transition from gray poorly-sorted fine to coarse sand with a kaolinitic clay matrix to a clayey sand of the overlying Black Mingo Formation.

Tertiary Stratigraphy

Tertiary sediments ranging from Paleocene to Miocene age unconformably overlie the Cretaceous section in the site area. The site stratigraphy defined for the VEGP UFSAR divided the Tertiary section into the Ellenton Formation, Huber Formation, Lisbon Formation, Barnwell Group, Suwanee Limestone (not recognized at the ESP project site), and Hawthorne Formation. Further subdivisions were made for the Lisbon and Barnwell Group because these units are more easily mapped due to exposure within incised valleys as well as to more available borehole data units due to the relative shallow depth of these units. The Tertiary section also contains considerably more calcareous sediments, thus providing more biostratigraphic constraint.

More recent investigations, including detailed palynologic and paleontologic studies, have refined the Tertiary stratigraphy in the vicinity of the site area (Reference 273; Reference 278). Huddlestun and Summerour (1996) divide the Tertiary units, from oldest to youngest, into the Black Mingo, Snapp and Congaree formations, the Bennock Millpond/Still Branch Sand, the Lisbon Formation and the Barnwell Group. As with the Cretaceous section, core log data from boring B-1003 are used to describe the site stratigraphy. The following sections describe these units from oldest to youngest.

Black Mingo Formation

In boring B-1003, the base of the Black Mingo Formation was noted at a depth of 477 ft (-254 ft msl) and the top at a depth of 438 ft (-215 ft msl), giving an overall thickness of 39 ft. The base of the unit is marked by the occurrence of a gray, poorly-sorted fine to coarse sand and is overlain by a 15-ft thick layer of gray sandy clay with some coarse subangular quartz sand and lignite fragments. This, in turn is overlain by light gray well-sorted fine to medium clayey sand and sand with silt. The top of the Black Mingo Formation is logged as a 7-ft thick layer of dark gray sandy clay.

Snapp Formation

The base of the Snapp Formation in boring B-1003 is logged at a depth of 438 ft (-215 ft msl) and the top at a depth of 331 ft (-108 ft msl), resulting in an overall thickness of 107 ft. The base is marked by well-sorted sand with quartz gravel that appears to be a channel lag deposit. This grades upward into a tan-gray well-sorted silty fine to medium sand that is overlain by 18 ft of gray-red silty clay containing some 4- to 6-inch layers of white and gray fine to coarse silty quartz sand. The clay is overlain by well-sorted clayey sand that is overlain by a sandy to silty gray to red-brown clay. This 12-ft clay layer is overlain by a silty to clayey sand sequence overlain by about 5 ft of gray-reddish brown clay. The top of the Snapp Formation is a light grayish white poorly-sorted medium to coarse grained clayey sand.

Congaree Formation

The base of the Congaree Formation is logged at a depth of 331 ft (-108 ft msl) and the top at a depth of 216 ft (7 ft msl), resulting in a thickness of 115 ft. Although the core was not recovered in one 5-ft run, the base of the Congaree Formation appears to be marked by a 14-ft thick dark grayish black clay. This clay is overlain by black, well-sorted silty sand overlain by a 1-ft thick black clay layer. This clay layer is overlain by gray, well-sorted clayey sand that grades upward into a light gray, well-sorted silty sand overlain by a sandy silt. The top of the Congaree Formation consists of gray, well-sorted silty sands.

Still Branch Sand

Based on ESP and COL borings, the base of the Still Branch Sand is noted at a depth of 216 ft (7 ft msl) and the top at a depth of 173 ft (50 ft msl), resulting in a thickness of 43 ft. The base of the Still Branch is marked by the occurrence of dark greenish gray sandy silt containing 1- to 3-inch thick sand layers. This silt is overlain by light gray well-sorted medium to coarse sand that is overlain by dark gray, well-sorted clayey sand. This is overlain by dark, greenish gray calcareous silty sand

overlain by calcareous clayey sand. An overlying silty to clayey sand sequence is overlain by a gray well-sorted fine to medium sand at the top of the unit.

Lisbon Formation

The middle Eocene Lisbon Formation includes members that have been extensively mapped in the upper Coastal Plain of Georgia and South Carolina. These include the Blue Bluff Marl, McBean Limestone, and, in South Carolina, the Tinker Formation. These units commonly interfinger. In general, the Lisbon Formation is more fossiliferous and ranges from calcareous sands to coquina, while the Tinker Formation in South Carolina is the clastic equivalent consisting predominantly of well-sorted quartz sands. The Blue Bluff Marl Member tends to be more micritic, with shell fragments suspended in a micrite matrix with occasional shell-rich zones. Lithologies, fossil assemblage, and the interfingered nature suggest shallow shelf to neritic environment. In the VEGP site area, the Blue Bluff Marl is noted as the dominant facies and is exposed in the western bluffs along the site boundary with the Savannah River. In Burke County, the Blue Bluff Member disconformably overlies the Still Branch Sand. In general, the Blue Bluff Member disconformably underlies the Utley Limestone Member of the Clinchfield Formation, but locally, where the Utley Limestone is absent, the Blue Bluff Member is overlain disconformably by the Dry Branch Formation of the Barnwell Group (Reference 334). The Blue Bluff Member was extensively studied and mapped as the foundation bearing unit for VEGP Units 1 and 2 and as part of the subsurface investigation for VEGP Units 3 and 4. The regional occurrence of the Blue Bluff Marl is discussed in Subsection 2.5.1.2.6. The Lisbon Formation also contains a carbonate unit called the McBean Limestone Member (Figures 2.5-231 and 2.5-241) that occurs in an area limited to the north and northwest of the VEGP site vicinity (Reference 334). The McBean Member has not been recognized in borings at the VEGP site. At the Georgia Geological Survey reference locality, near McBean, Georgia, the McBean Member is disconformably overlain by the Utley Limestone and rests paraconformably on the Still Branch Sand (Reference 334).

A total of 186 borings were drilled as part of the ESP and COL subsurface investigations for VEGP Units 3 and 4. The boring locations are shown on Figure 2.5-249. The boring logs drilled during the VEGP Units 1 and 2 and the recent Units 3 and 4 subsurface investigations describe the Blue Bluff Member (referred to as the Blue Bluff Marl on boring logs and geotechnical data report tables [Appendices 2.5A, and 2.5C]) as a fine-grained, calcareous silty clay that directly underlies the Utley Limestone. The Blue Bluff Marl is defined as very stiff to hard carbonate-rich clayey silt to silty clay with trace amounts of very fine to fine grained sand (Appendix 2.5C). Distinguishing features in the field are the marl's greenish gray color, the presence of shell and phosphatic fragments in localized horizons, and the abundance of partially cemented, well-indurated layers consisting of very fine grained to fine grained quartz sand with carbonate mud cement. Breakage of the well-indurated (limestone) zones by the split spoon sampler often resulted in forming gravel-sized particles (Appendix 2.5C).

A total of 182 borings have penetrated the top of the Blue Bluff Marl within the VEGP site and indicate that the Utley Limestone/Blue Bluff Marl contact ranges in elevation between 96.1 ft msl and 151.6 ft msl. A structure contour map of the top of the Blue Bluff Marl, incorporating these data, is shown on Figure 2.5-250. The top of the Blue Bluff Marl is at elevations ranging from 126.2 ft msl to 136.8 ft msl in the vicinity of Unit 3 and from 121.9 to 138.2 ft msl in the vicinity of Unit 4 (Figure 2.5-250). In general, the top of the Blue Bluff Marl is located at elevations above 130 ft msl east of a monoclinal fold that downwarps the Blue Bluff Marl toward the northwest to elevations lower than 100 ft msl. This feature is shown on the structure contour map (Figure 2.5-250) and on the geologic cross sections A-A' and B-B' (Figures 2.5-249, 2.5-251, and 2.5-252) and was formed by reverse faulting along the Pen Branch fault (Subsection 2.5.1.2.4.1). The cross sections illustrate the geology beneath the nuclear islands and the monocline appears as a subtle downwarp at the top of the Blue Bluff Marl. Cross section C-C' trends to the northeast from Unit 3 (Figure 2.5-253); east of and generally parallel to the monocline.

Where fully penetrated by 85 borings, the marl thickness ranges from a minimum of 5 feet where it has been scoured by the Savannah River and overlain with alluvium (Boring B-1159) to a maximum of approximately 95 ft (Boring B-1004). The mean thickness of the marl is approximately 63 ft. An isopach map of the Blue Bluff Marl indicates that it is more than 60 ft thick at the locations of Units 3 and 4 (Figure 2.5-254).

In boring B-1003, the base of the Lisbon Formation is noted at a depth of 149 ft (74 ft msl) and the top at a depth of 86 ft (137 ft msl), with an overall thickness of 63 ft (Figure 2.5-241). The base of the Lisbon Formation is marked by the occurrence of a 12 ft-thick greenish gray, sandy non-plastic silt with fossil fragments and 1- to 3-in thick layers of fossiliferous limestone. This is overlain by a 23-ft thick layer of greenish gray highly plastic sandy silt with fossil fragments and 1- to 3-inch layers of hard fossiliferous limestone. This in turn is overlain by greenish gray well-sorted, strongly cemented sand with 1- to 2-inch layers of hard fossiliferous limestone. This is overlain by a light greenish gray fossiliferous limestone. The top of the Lisbon Formation is marked by the occurrence of dark green-gray non-plastic calcareous sandy silt (Blue Bluff Marl). The marl contains 2- to 4-in-thick layers of hard fossiliferous limestone.

Barnwell Group

The Barnwell Group overlying the Blue Bluff Marl member includes three subdivisions, from oldest to youngest, the Clinchfield Formation (including the Utley Limestone member), Dry Branch Formation, and the Tobacco Road Sand. Due to the location and surface elevation of boring B-1003, the portion of the Barnwell Group penetrated by boring B-1003 includes only the Clinchfield Formation and lower portion of the Dry Branch Formation. However, most of these units are exposed along the bluffs of the Savannah River or within stream valleys, or lie on topographically higher areas within the site and site vicinity (Figures 2.5-231 and 2.5-234). The Formations described below are logged as undifferentiated sands, clays, and silts of the Barnwell Group in the ESP and COL borings (Appendices 2.5A and 2.5C). The thickness of this group is variable and ranges from approximately 26 to 162 ft in borings where the undifferentiated sediments of the Barnwell Group are fully penetrated.

Clinchfield Formation

In Boring B-1003 the base of the Clinchfield Formation (Utley Limestone member) occurs at a depth of 88 ft (130 ft msl) and the top at a depth of 74 ft (144 ft msl), with an overall thickness of 14 ft (Figure 2.5-241). The thickness of this unit was noted as variable within the VEGP Units 1 and 2 excavation, which is consistent with dissolution of carbonate material. Based on observations during the COL subsurface investigation, identification of the Utley Limestone member in ESP drill holes was re-evaluated on the basis of descriptions in Huddlestun and Summerour (1996), additional samples obtained during the COL investigation and on field observations of outcrops along the Savannah River. Where observed in the excavations for VEGP Units 1 and 2, the Utley Limestone Member of the Clinchfield Formation is recognized as fossiliferous limestone that grades into coquina. The Utley Limestone contains minor amounts of silt and clay. Larger fossils visible in outcrop include oyster shells, unidentified shell fragments and phosphatic mineral fragments. Well-cemented zones consist of quartz sand and/or shell fragments with a carbonate cement matrix. Based on the ESP and COL data set, where well-indurated, as indicated by high blow counts during split-barrel sampling and generally low recovery, the indurated Utley breaks down into gravel-size particles with varying amounts of silt and clay. This unit contains softer zones and areas in which drilling fluid circulation was lost (Appendices 2.5A and 2.5C).

As discussed in Subsection 2.4.12.1.2, the Utley Limestone is disconintuous across the site. It is absent in 54 of the 152 borings drilled through the stratigraphic interval where this unit was expected to occur (Table 2.4-253). This variation in thickness is shown on the geologic cross sections (Figures 2.5-251, 2.5-252, and 2.5-253) and on the structure contour and isopach maps (Figures 2.5-255 and 2.5-256). As discussed in Subsection 2.5.1, all geologic units overlying the Blue

Bluff Marl will be excavated from the nuclear island foundation. The isopach map indicates that the Utley Limestone is irregularly present in the area of Units 3 and 4 (Figure 2.5-256) where it ranges in thickness from 0 to 25 ft (Boring B-3039) at Unit 3 and 0 to 15 ft (Boring 4020) at Unit 4. Based on the borings that fully penetrated the Utley Limestone, its mean thickness is 10.5 ft. The Utley Limestone also tends to be present to the north of the nuclear islands and south towards the Units 3 and 4 cooling towers. The structure contour map indicates that the limestone is a linear feature in its areal extent with the axis of maximum thickness extending approximately north-northeast from the Units 3 and 4 cooling towers to approximately 1200 feet east of Mallard Pond (Subsection 2.4.12).

The average elevation of the top of the Utley Limestone is 142.4 ft msl at Units 3 and 4 (Figure 2.5-255). This is the approximate elevation of the base of the overlying undifferentiated Barnwell Group. The Clinchfield Formation consists predominantly of calcareous sands and biomoldic limestones. Some silty and clayey sands are also present, with varying amounts of carbonate material and silicified zones.

Exposures of the Clinchfield Formation along the Savannah River and within excavations for VEGP Units 1 and 2 noted varying degrees of weathering and evidence of solution cavities, indicating that the process of carbonate removal is ongoing. This process could be a primary contributing factor to the development of surface depressions noted in the site area.

Dry Branch Formation

In boring B-1003, the Dry Branch Formation overlying the Clinchfield Formation contains more clayey, laminated sands and silty sands. The base was logged at a depth of 74 ft (144 ft msl) and this unit occurs at the ground surface. The Dry Branch Formation consists primarily of silty, clayey quartz sands. Varying amounts of carbonate material are sometimes present, often in the form of bioherms. The sands are generally moderately to well-sorted and subrounded to subangular. Lignite and manganese staining is often present, with a notable lack of glauconite. Portions of the Dry Branch Formation become significantly more clayey, with finely laminated beds reaching thicknesses of several to tens of feet. The lithology, absence of glauconite, and inclusion of bioherms indicate a back barrier depositional setting.

Tobacco Road Sand

The Tobacco Road Sand consists of moderately to poorly-sorted sands and clayey sands with varying amounts of kaolin. Sands tend to be subrounded to rounded, with coarse rounded pebbly zones present as a basal lag in some areas. Where this unit is exposed, the sediments are oxidized and, in many cases, Ophiomorpha burrows are present, as well as cross-beds and convoluted bedding indicative of an open bay, tidal flat setting.

Boring B-1003 did not penetrate this unit due to the surface elevation surrounding the boring location; however, the unit is exposed in stream valleys and road cuts within the site area and vicinity. The thickness of the Tobacco Road Sand varies due to incision by the overlying Hawthorne Formation but can be in excess of 50 ft. Where present at the VEGP site, the top of the Tobacco Road Sand generally occurs at the ground surface.

Hawthorne Formation

The Hawthorne Formation consists of poorly-sorted sands and clayey sands. Sands range from fine to coarse and are well rounded. Clay is present in the form of laminae to cobble-size clasts. This unit was not identified in any of the borings drilled as part of the ESP subsurface investigation program. It was likely removed during excavation for the existing units and, therefore, is no longer present in the developed portions of the VEGP site. However, it is present in higher elevations of the site area. Obvious incision and cross-cutting channels are noted in exposures, with channel sequences often indicated by coarse channel lags indicative of a high energy fluvial setting. The age of the Hawthorne

Formation is problematic due to the lack of fossils. However, Falls and Prowell (2001) indicate a Miocene age for this formation.

Pinehurst Formation

The Pinehurst Formation was not mapped by the USGS, nor is it considered to be a significant stratigraphic unit regionally. The Pinehurst Formation is encountered sporadically within the site area and at the VEGP site. Where preserved, the Pinehurst Formation is less than a few meters thick, and therefore does not appear on geologic maps of the VEGP site. The unit is typically clean, well-sorted fine sand. Although bedding is often absent, cross-bedding and remnant dune morphology have been noted in a few exposures, indicative of an eolian deposit (Reference 412).

Although the age of the these sediments is not definitive, the unconformable position above the Hawthorne and lack of these sediments overlying Late Pliocene marine sediments downdip of the site area place the relative age as lower Pliocene (Reference 412).

Quaternary Stratigraphy

Alluvium exists within the surrounding stream and river valleys and forms terraces that can be locally delineated and mapped. As noted on Figures 2.5-232 and 2.5-234, in the vicinity of the site area, a modern alluvial flood plain and several alluvial terraces are present on the east side of the Savannah River. The higher terraces show distinctive oxidation and weathering, and the relative position above the Holocene flood plain indicates a Pleistocene age (Reference 412). Quaternary deposits are discussed in Subsections 2.5.1.1.3.5 and 2.5.1.2.4.3.

2.5.1.2.4 Site Area Structural Geology

In the site vicinity, the basement rock beneath the Coastal Plain consists of Paleozoic crystalline rock as well as Triassic–Jurassic sedimentary rock of the Dunbarton Basin. The VEGP site lies near the buried northwest margin of the approximately 9-mi-wide (15-km-wide) Dunbarton Basin, which formed during Mesozoic rifting and opening of the Atlantic Ocean. Deep boreholes within and adjacent to the SRS that penetrate basement indicate that the Paleozoic crystalline rock northwest of the Dunbarton basement has been overprinted with a foliation that dips about 40 to 60 degrees. Based on regional correlations, the foliation strikes northeast and dips to the southeast (Reference 263).

The upper surface of the basement has been leveled by erosion and dips to the southeast between 48 ft/mi (Reference 442) and 37 ft/mi (Reference 488). In the site area, the regional basement surface is unconformably overlain by loosely consolidated, fluvial, deltaic, and shallow marine Coastal Plain sediments. The depth to the Triassic–Jurassic basement rock beneath the site is 1,049 ft (-826 ft msl), based on borehole B-1003.

Within the 5-mi site area radius, a total of four basement-involved faults have been identified, namely the Pen Branch, Ellenton, Steel Creek, and Upper Three Runs faults (Figure 2.5-224). The Ellenton fault does not appear in the most recent SRS fault maps (Reference 254, Reference 255) and, if it exists, is not considered a capable structure. The Upper Three Runs fault is restricted to basement rocks, with no evidence that it offsets Coastal Plain sediments (Reference 232; Reference 453). Similarly, the Steel Creek fault is not considered a capable tectonic source. The Pen Branch fault is thought to have been the northern bounding (normal) fault of the Mesozoic Dunbarton extensional basin, subsequently reactivated as a reverse or reverse-dextral slip fault, as documented by post-extension, reverse offsets of Late Cretaceous and younger horizons (Reference 442; Reference 254, Reference 255). The Pen Branch fault is discussed in detail below.

Only one fold potentially of tectonic origin has been identified in the site area. Bechtel site drawings AX6DD377 (“Top of the bearing horizon”) and AX6DD378 (“Bottom of the bearing horizon”) show an

apparent monoclinal flexure of the Blue Bluff Marl, with a hingeline that trends approximately northeast-southwest (Figure 2.5-242). Because of its spatial association with the Pen Branch fault, it is likely that this feature is the result of reverse or reverse-oblique slip on the Pen Branch fault. In previous studies [e.g., (Reference 212)], this monocline has been referred to as a 3° dip reversal and interpreted to be of sedimentary origin.

2.5.1.2.4.1 Pen Branch Fault

The Pen Branch fault is neither exposed nor expressed at the surface at the SRS, but its location at the SRS is constrained by dense subsurface well control, as well as seismic-reflection geophysical data [e.g., (Reference 442; Reference 453; Reference 321; Reference 254, Reference 255)]. The Pen Branch exceeds 25 mi in length and is interpreted to comprise several subparallel segments that strike N46-66°E and dip 60-75°SE (Reference 255) and is projected southwestward from SRS to beneath the VEGP site. Crone and Wheeler (2000) assigned the Pen Branch fault to Class C because of the lack of evidence for post-Eocene slip. Due to its proximity to the VEGP site, however, the Pen Branch fault is examined in detail in this SSAR.

The Pen Branch fault was first discovered in the subsurface of the SRS in 1989 from the interpretation of earlier seismic reflection surveys and other geologic studies (Reference 374; Reference 232; Reference 442; Reference 454). A brief history of the Pen Branch fault and issues concerning the VEGP site and the NRC are as follows:

- January 8, 1989: Draft report on newly discovered Pen Branch fault issued by David Snipes (Clemson University), Wallace Fallaw (Furman University), and Van Price, Jr. (SRS). This report (Reference 441) was provided to the NRC, which received it on January 12, 1989. The authors presented evidence of late Eocene movement, but emphasized “compelling evidence for absence of recent movement” and that the fault should not be assumed to be capable. The nearest seismic line data were located about 7 mi east of the VEGP site. This draft report also projected the fault toward the VEGP site based on an interpreted offset of Utley Limestone outcrop located near the existing VEGP intake structure and the dip reversal in the Blue Bluff Marl (Figure 2.5-237).

- January 18, 1989: The NRC formally requested the Georgia Power Company to assess capability and impact of the proposed Pen Branch fault on the VEGP site. Southern Company assembled a field review team to review field conditions within and nearby the VEGP site.

- January 29, 1989: Bechtel submitted a response to the NRC.

- February 1989: The NRC issued Supplement No. 8 to the VEGP Units 1 and 2 SER. The NRC concluded that the Pen Branch fault is not capable and that there was no evidence that suggested Tertiary offset on the Pen Branch fault within 6 mi northeast of the VEGP site.

- September 1989: Bechtel issued the Pen Branch fault report (Reference 212) that summarized work performed for the January 29, 1989, response to the NRC.

- 1991: A high-resolution shallow seismic reflection survey focused on the uppermost 300 ft of Coastal Plain strata at the SRS conducted by Berkman (1991) was designed to investigate the capability of the Pen Branch fault (Figure 2.5-237). Deformation associated with the Pen Branch fault was observed in the Cretaceous Cape Fear Formation but no higher in the stratigraphic section, confirming the non-capable status of the Pen Branch fault.

- October 1993: Snipes et al. (1993a) concluded that the Pen Branch fault must lie more than 2 mi upstream from the VEGP site, based on SRS borehole PBF-6 (which encountered sheared Triassic basin sediments) (Figure 2.5-237).

- 1993: Savannah River fluvial terrace study (Reference 292) concluded that the Pen Branch fault has no geomorphic expression, no tectonic deformation is observed within a resolution of approximately 7 to 10 ft, and the Pen Branch fault is not capable.

- 1994: The Confirmatory Drilling Project was designed to investigate the capability of the Pen Branch fault at the SRS (Reference 454). This report combined previous data with 18 borings to conclude that deformation associated with the Pen Branch fault likely pre-dates the Williamsburg Unconformity (about 50 Ma) and that the Pen Branch fault is therefore not capable.

- 1995: As part of a groundwater contamination study in Burke County, Georgia, Henry (1995) collected and interpreted a total of 70 mi of high-resolution seismic reflection data from the Savannah River between the Richmond/Burke county line and the Burke/Screven county line. In addition, a medium-resolution seismic survey was conducted in the Savannah River between Hancock Landing and the VEGP boat ramp (Figure 2.5-237). Henry (1995) concluded that the Pen Branch fault appears as a high-angle, southeast-side-up reverse fault located about 1,000 ft downstream from Hancock Landing. Henry (1995) interpreted the Pen Branch fault as extending upward through the Paleocene Ellenton Formation and into strata dated as possible Eocene that lie below the unconformity at the base of Savannah River alluvium.

- 1998: As part of an investigation of tritium in the Gordon Aquifer and other aquifers in Burke County, Georgia, Summerour et al. (1998) reported seismic reflection data collected and interpreted by Waddell et al. (1995). This land-based seismic reflection survey was located on an unimproved road about 0.5 mi west of River Road (Figure 2.5-237). Numerous, minor faults were interpreted to cut reflectors within the Coastal Plain section. The basement reflector, however, is not clearly faulted and, therefore, the interpretation that the Pen Branch fault is imaged in this profile (Reference 455) is questionable. Based in part on the Waddell et al. (1995) seismic reflection data, Summerour et al. (1998) reported that the Gordon Aquifer is not affected by Pen Branch fault.

- 1998: Cumbest et al. (1998) integrated more than 60 basement borings and 100 mi of seismic reflection profiling to refine the location of the Pen Branch fault at the SRS. Based on their review of existing data, Cumbest et al. (1998) concluded that no faults on the SRS, including the Pen Branch fault, are capable.

- 2000: Based on geometrical analysis of seismic reflection data, the maximum vertical separation of the contact between basement rocks and overlying Coastal Plain sediments by the Pen Branch fault (segment 4) is estimated to be about 92 ft (Reference 255). The offset decreases upward within the Coastal Plain section to 30 ft at the top of the Upper Cretaceous/Lower Paleocene Pee Dee/Ellenton formation (approximately 66.4 Ma) (Reference 255).

2.5.1.2.4.2 Site Subsurface Investigation of the Pen Branch Fault

The Pen Branch fault, which juxtaposes Paleozoic crystalline rock against Triassic (Dunbarton) Basin sedimentary rock at the SRS, has been interpreted to project southwestward into Georgia near the VEGP site. Past interpretations have projected the fault and basin boundary at VEGP site (Reference 441), north of the VEGP site (Reference 442), and south of VEGP (Reference 254; Reference 255). These and all other available data on the location of the fault were compiled and assessed for this ESP investigation. The study concluded that the Pen Branch fault is located in proximity to the VEGP site.

The seismic acquisition program was designed to image the subsurface structure and characterize the basement lithology and velocities beneath the VEGP site as input to the development of the Safe Shutdown Earthquake (SSE). An additional, specific goal of this study was to image the northeast-striking, non-capable Pen Branch fault, which has been imaged and mapped on the SRS northeast of the VEGP site [e.g., (Reference 255)], and determine its precise location, strike, and dip beneath the VEGP site.

Seismic reflection and refraction data were collected within the VEGP site area in January and February 2006. The seismic data were acquired by Bay Geophysical under contract to Southern Nuclear Operating Company (SNC); details of the acquisition and preliminary processing of the data are fully documented in the final technical report (Appendix 2.5B). The survey included four seismic reflection and three seismic refraction lines (Figures 2.5-238 and 2.5-239, respectively). The seismic array was designed to: (1) image the Pen Branch fault, with the assumption that it continues on strike to the southwest from the SRS into the VEGP site area and (2) assess the depth and character of the basement rocks beneath the Atlantic Coastal Plain deposits.

As noted in the report by Bay Geophysical (Appendix 2.5B), vibrations from the existing VEGP generated coherent noise that significantly compromised the quality of the seismic data for lines 1, 2, and 3. The noise masked the first arrivals along most or substantial parts of these three lines, which made it impossible to apply refraction static corrections to the reflection data. Consequently, these lines have anomalies in the reflector geometries that arise from the lack of a proper static solution rather than real earth structure, making detailed geologic interpretation of these lines problematic. Similarly, masking of refractor first breaks by noise from the existing VEGP on lines 1 and 3 made it impossible to confidently and accurately pick the first arrivals for use in 2-D P-wave velocity inversions (Appendix 2.5B). Based on a field assessment of the quality of the refraction data for lines 1 and 3 by Dr. Cumbest, SNC decided not to collect refraction data along line 2, as initially planned.

Reflection and refraction data from line 4 were not affected by noise problems from the existing VEGP. Consequently, line 4 has greater detail than the other three lines in the seismic survey (Figure 2.5-240).

Strike of the Pen Branch Fault

The seismic reflection data acquired for this ESP study clearly document that the Pen Branch fault strikes northeast and dips southeast beneath the VEGP site. When the intersections of the Pen Branch fault with the top of basement interpreted from reflection data are plotted on a map, it is apparent that the strike of the fault through the VEGP site is not uniform. The fault-basement intersections on lines 1, 2, and 3 fall along a common trend of about N34°E. In contrast, the fault-basement intersections on lines 4 and 1 define a more westerly trend of about N45°E (Figures 2.5-242 and 2.5-245). Although it is possible that uncertainty in picking the fault-basement intersection on the eastern three lines (especially lines 1 and 2) may account for some of the difference in strike across the plant site, the different strike east and west of line 2 is likely real for the following reasons:

- The fault and basement offset are best imaged and most confidently interpreted on lines 1 and 4. Thus, the N45°E strike of the fault determined between these two lines is likely accurate.

- The trends of the structure contours on the monoclinally folded Blue Bluff Marl beneath the VEGP site range from about N25°E to N40°E and are similar to the N34°E strike of the fault measured between lines 1, 2, and 3 (Figure 2.5-242). Most kinematic models of fault-related folding assume that the axes of fault-propagation folds and monoclines are parallel to the strike of an underlying thrust or reverse fault [e.g., (Reference 456; Reference 384)]. If these assumptions are correct, then the strike of the fault beneath the monocline is closer to N32°E, as inferred from seismic lines 1, 2, and 3, than to N45°E.

- Cumbest et al. (2000) have documented that the strike of the Pen Branch fault is not constant beneath the SRS northeast of the VEGP site. They found that the fault consists of several discrete reaches or segments variously separated by small offsets and changes in strike. The range in strike of the fault northeast of Savannah River is about N46°E to N66°E (Reference 255).

The change in strike of the Pen Branch fault across the VEGP site may be part of a regional trend. On the SRS northeast of VEGP, the Pen Branch fault includes a distinct reach that strikes about N58°E between seismic lines SRL-7 and PBF-2A and another distinct reach that strike about N53°E between seismic line PBF-2A and point in the Savannah River channel where the fault was imaged by Henry (1995), representing a counterclockwise rotation in strike from northeast to southwest. Southwest of the Savannah River, the fault strike rotates counterclockwise again to about N34°E beneath the VEGP site. The strike of the fault rotates clockwise to about N45°E between seismic lines 1 and 4. The overall trend is a bend or left jog in the strike of the fault. It is possible that the changes in strike between individual reaches of the fault also include small offsets of the fault plane, as inferred for the fault on the SRS to the north (Reference 255).

Dip of the Pen Branch Fault

The dip of the Pen Branch fault is estimated primarily from its expression in the version of seismic line 4 displayed at a constant velocity of 12,000 ft/s (Figure 2.5-240). Based on measurements of P-wave velocities for Triassic basin rocks in boreholes throughout the region (Reference 232), 12,000 ft/s probably best characterizes the average velocity of the Triassic rocks in the hanging wall of the Pen Branch fault along line 4. The dip of the Pen Branch fault reflector in the version of line 4 displayed at a velocity of 12,000 ft/s is about 40° (Figure 2.5-240).

The geometry of the fault in line 4 reflects an apparent dip because the seismic line is not perpendicular to the fault. The general trend of the section of line 4 corresponding to the well-imaged fault plane (i.e., between shotpoints 225 and 310) intersects the N45°E strike of the fault at an angle of about 55°. Using the apparent dip relation [(Reference 379), equation 3-7] to account for the obliquity of the seismic line relative to fault strike, a true dip of about 45° to the southeast is derived for the fault plane imaged on line 4 in Figure 2.5-243.

Fault-Fold Relationships

The plan projection of the intersection of the Pen Branch fault with the top of basement on lines in the seismic reflection array is located beneath or slightly to the southeast of the antiformal hinge at the top of the monocline in the Blue Bluff Marl (Figure 2.5-242). This relationship is shown more directly by two geologic cross sections that pass through borehole B-1003 (Figures 2.5-243 and 2.5-244).

The northwest-southeast cross section (Figure 2.5-243) is oriented perpendicular to the local strike of the Pen Branch fault and displays the fault and its relationship to the monoclinal fold in the Blue Bluff Marl with a minimum of geometric distortion. The plan projection of the offset of the basement surface is located about 100 ft northwest of the upper axial hinge of the monocline (Figure 2.5-242). The projection of the fault beyond its termination in the Cretaceous Coastal Plain deposits approximately intersects the synformal hinge at the base of the monocline in the marl (Figure 2.5-243). The east-west cross section (Figure 2.5-244) is oriented to pass through the locations of boreholes B-1002, B-1003, and B-1004; because the section is oblique rather than perpendicular to the fault and monocline, the geometry of the structures is slightly distorted. In particular, the apparent dip of the fault in the east-west section (35°; Figure 2.5-244) is lower than the true dip (about 45°) in the northwest-southeast section (Figure 2.5-243). Although the base of the monocline in the marl is poorly constrained by available borehole data at the west end of the east-west cross section, the Pen Branch fault appears to project toward the base of the fold (Figure 2.5-243).

2.5.1.2.4.3 Evaluation of Quaternary River Terrace Overlying Pen Branch Fault

The seismic reflection profiles and deep borehole (B-1003) performed at the VEGP site as part of the ESP study helped refine the location of the Pen Branch fault in Georgia and in the westernmost portion of the SRS in South Carolina. These new data combined with reflection profiles in the Savannah River (Reference 321) and earlier SRS studies were integrated to develop a more accurate representation of the fault's location and geometry beneath the VEGP site and Quaternary terraces flanking the Savannah River on the SRS (Figure 2.5-237). Previous geomorphic study of the fluvial terraces by Geomatrix (1993) concluded that the Pen Branch fault is not a capable tectonic source and that there is no observable deformation within a resolution of 7 to 10 ft, in the overlying Ellenton Terrace (Qte) surface estimated to be 350 ka to 1 Ma. The 10-ft contour interval of the USGS 7.5-minute topographic maps limited the resolution of this previous study.

Given the higher degree of confidence in the location of the Pen Branch fault beneath the Savannah River fluvial terraces, which represent the only significant Quaternary deposits and surfaces that straddle the Pen Branch fault, a focused study was undertaken to survey and interpret remnants of the Ellenton Terrace (Qte) surface located approximately 4 miles east-northeast of the VEGP site (Figure 2.5-212 and Figure 2.5-246). The purpose of this effort was to improve the resolution of the terrace surface elevation and independently assess the presence or absence of Quaternary tectonic deformation on the Pen Branch fault, which has been classified by Crone and Wheeler (2000) as a potential Quaternary fault having insufficient geologic evidence to demonstrate Quaternary slip or deformation (Class C in Table 2.5-201).

The scope of this investigation included a review of previous studies, as well as geomorphic mapping, analysis of aerial photographs, surveying the portion of the Qte terrace surface at the SRS that overlies the Pen Branch fault, and the construction and analysis of longitudinal terrace profiles.

Geomorphic mapping and field reconnaissance

Prior to surveying the study area to acquire elevation data, a geomorphic map of the Qte terrace surface at the SRS in the vicinity of the Pen Branch fault was prepared in order to establish geologic context, to ground-truth and refine the mapping of Geomatrix (1993), and to investigate the degree of erosion and/or anthropogenic disturbance of the terrace surface. The primary focus of the geomorphic mapping was to define the portions of the Qte surface that appear best preserved (minimal deflation and modification) (Figure 2.5-247). Preparation of this map included inspection of aerial photographs dating from 1943 to 2004, field reconnaissance, and hand-auger soil borings. A review of multiple sets of aerial photography reveals the presence of several closed depressions (of variable size), marshy areas, and tributary drainages in the study area (Figure 2.5-247). The aerial photographs also show that the study area was farmland at least as early as 1943. Today the study area is crossed by an SRS power line right-of-way and several dirt roads, and timber has been sporadically logged from portions of the study area over the past few decades.

Survey data acquisition

A total of approximately 2,600 elevation data points were collected by a Georgia Power Company survey team using a combination of differential Global Positioning System (DGPS) and total station survey techniques. Survey data were collected in UTM zone 17N coordinates, using NAD 27 geographic datum and NAVD 88 elevation datum.

The preponderance of survey data was collected from, and adjacent to, dirt roads and the power line right-of-way (Figures 2.5-246 and 2.5-247). The Qte terrace surface in the vicinity of the Pen Branch fault on the SRS is largely covered by trees and dense undergrowth. This dense vegetative cover hinders the acquisition of survey data. Fortunately, a power line right-of-way oriented approximately normal to the local strike of the Pen Branch fault and approximately parallel to the long-axis of the Qte terrace deposits extends through the study area. As much as possible, survey data were

collected away from obviously disturbed, eroded, and/or modified areas as identified by geologic reconnaissance and aerial photograph interpretation.

Terrace surface longitudinal profiles

A longitudinal profile of the Qte terrace surface was constructed by projecting elevation data onto a profile line oriented approximately N35°W (approximately normal to the local strike of the Pen Branch fault and approximately parallel to the long-axis of the Qte terrace and paleo-Savannah River valley in the study area) (Figures 2.5-246 and 2.5-247). Data points interpreted as representing the best-preserved remnants of the Qte terrace surface (as determined from field reconnaissance and aerial photograph inspection) are shown on the longitudinal profile in red (Figure 2.5-248). Data points interpreted as representing more modified or eroded portions of Qte terrace surface and those points collected away from the Qte terrace surface are shown on the longitudinal profile in gray.

Sources of error/uncertainty

There are three main sources of uncertainty and error that contribute to the overall uncertainty in the original elevation and variability of the Qte terrace surface. Each of these is discussed below:

Geologic context – The largest contributor to the overall uncertainty in characterizing the Qte terrace surface elevation is due to ambiguities regarding geologic and geomorphic context. The Qte terrace surface was initially deposited as a planar feature with some inherent variability. Since the river abandoned this surface 350 ka to 1 Ma, however, the Qte surface has been modified by geologic and anthropogenic processes. Geologic processes of deposition, erosion, and settlement resulting from dissolution of the underlying carbonate sands have all contributed to the modification the original surface. Significant deflation of the surface has occurred as a result of dissolution collapse as evidenced from the abundant closed depressions across the Qte and younger Qtb terrace surfaces (Figures 2.5-232 and 2.5-248). Incision of tributary drainages into the terrace have locally removed the deposits and surface as well as the deflated adjacent portions of the surface. Deposition of alluvial and colluvial material onto the eastern margin of the Qte terrace near the mouth of Fourmile Branch and along the base of the southwest-facing slopes has locally increased the ground surface elevation. Anthropogenic processes that have modified the original terrace surface, to a much lesser extent, include agricultural land use practices (logging and farming) and other human activities related to development of the SRS. A primary focus of this study was to define those portions of the Qte terrace surface that best preserved remnants of the original terrace (least modified) and to resolve the magnitude of the scatter in elevation data. Any remaining perturbations, if any, in the overall Qte terrace surface that cannot be explained by erosion, settlement, deposition, and/or anthropogenic modification can be considered to be of possible tectonic origin.

Survey error – The uncertainty due to both systematic and random errors associated with the collection and processing of survey data is estimated to be about 3 cm (about 1.2 inches) in the horizontal dimension and about 5 cm (about 2 inches) in the vertical dimension. The contribution of survey error to overall uncertainty is considered to be negligible.

Profile construction error – The projection of elevation data onto profile line A-A' (Figure 2.5-248) introduces a minimal amount of error into the analysis. The magnitude of the positional error resulting from profile construction is minimized by minimizing the distance over which points are projected, and by constructing the profile approximately parallel to the long-axis of the Qte terrace surface in the study area and approximately normal to the local strike of the Pen Branch fault. The amount of error introduced into this analysis from the construction of the longitudinal profile is minimal.

Results

The geomorphic map presented in Figure 2.5-247 shows the best-preserved remnants of the Qte terrace surface in the study area (red shaded areas). The influence of dissolution collapse-related depressions on the terrace surface is most clearly seen in the vicinity of depressions D1 and D2, as

short-wavelength variations in the topographic surface. In addition, portions of the Qte terrace surface have been sites for the local deposition of alluvium and colluvium. These two areas are located at the northwestern-most extent of the survey and southeast of depression D2 (Figure 2.5-248).

Taken together, the overall uncertainty in the elevation of the best-preserved remnants of the Qte terrace surface is estimated to be about 3 ft. As shown in Figure 2.5-248, the elevation data for the terrace remnant range between elevations of 153 and 156 ft.

Longitudinal profile A-A' (Figure 2.5-248) indicates about 25 ft of variability in the present topography of the Qte terrace deposit in the study area. Most of this variability is the result of erosion and deflation of the terrace surface.

A longitudinal profile of the Qte fluvial terrace surface in the study area provides evidence demonstrating the absence of discernible tectonic deformation due to the underlying Pen Branch fault within the limit of resolution of the terrace elevation data (Figure 2.5-248). The results of this study demonstrate a lack of tectonic deformation in the 350 ka to 1 Ma year old fluvial terrace surface within a resolution of about 3 ft. This observation is consistent with previous studies at both the VEGP site and the SRS that have concluded the Pen Branch fault is not a capable tectonic source.

2.5.1.2.5 Site Area Geologic Hazard Evaluation

No geologic hazards have been identified within the VEGP site area. Surface depressions associated with dissolution of carbonate bearing stratum of the Utley member of the Clinchfield Formation are discussed in Subsections 2.5.1.2.3.2 and 2.5.3.8.2.1 and do not affect the foundation-bearing layer (Blue Bluff Marl). However, structures founded above the Blue Bluff Marl will require subsurface exploration to identify low-bearing-strength layers associated with dissolution processes noted in the site area.

2.5.1.2.6 Site Engineering Geology Evaluation

2.5.1.2.6.1 Engineering Soil Properties and Behavior of Foundation Materials

Engineering soil properties, including index properties, static and dynamic strength, and compressibility are discussed in Subsection 2.5.1. Variability and distribution of properties for the foundation bearing layer will be evaluated and mapped as the excavation is completed.

Heave monitor installation will be required prior to excavation, and settlement monitoring will be required during and post construction. Heave measurements will be used to quantify recompression during reloading to measure actual net settlements.

2.5.1.2.6.2 Zones of Alteration, Weathering, and Structural Weakness

The Blue Bluff Marl will form the foundation-bearing layer and consists of unweathered, slightly lithified, micritic limestone. Some desiccation is expected; however, visual examination of the exposure will be required, and long-term exposure may require a thin application of shotcrete for protection. Any noted desiccation, weathered zones, joints, or fractures will be mapped and evaluated.

2.5.1.2.6.3 Deformational Zones

No deformational zones within the Blue Bluff Marl were reported from the detailed excavation mapping for VEGP. However, proximity of the Pen Branch fault to the VEGP site (Figures 2.5-237 and 2.5-245) may have produced deformational features during development of the anticlinal

structure described in Subsection 2.5.1.2.4.1. However, these features, if present, are not expected to compromise the foundation-bearing capacity. Excavation mapping will be required during construction, and any noted deformational zones will be evaluated.

2.5.1.2.6.4 Prior Earthquake Effects

Extensive studies of outcrops and alluvial terrace and flood plain deposits have not indicated any evidence for post-Miocene earthquake activity, as discussed in Subsection 2.5.1.2.4.

2.5.1.2.6.5 Effects of Human Activities

No mining operations (other than borrow of surficial soils), excessive extraction or injection of groundwater, or impoundment of water has occurred within the site area that can affect geologic conditions.

2.5.1.2.7 Site Groundwater Conditions

A detailed discussion of groundwater conditions is provided in Subsection 2.4.12.

2.5.2 Vibratory Ground Motion

The AP1000 is designed for an earthquake defined by a peak ground acceleration (PGA) of 0.30g and the design response spectra specified in Subsection 3.7.1.1, and Figures 3.7.1-1 and 3.7.1-2. The AP1000 design earthquake is referred to as the AP1000 Certified Seismic Design Response Spectra (CSDRS). The AP1000 CSDRS was developed using the Regulatory Guide 1.60 response spectra as the base and modified to include additional high frequency amplification at a control point at 25 Hz. The peak ground accelerations in the two horizontal and the vertical directions are equal. The CSDRS also represents the AP1000 Foundation Input Response Spectra (FIRS) at a hard rock site.

The AP1000 is evaluated for high frequency input using the response spectra specified in Appendix 3I, Figures 3I.1-1 and 3I.1-2. The seismic response spectra given in Figures 3I.1-1 and 3I.1-2 are envelope response spectra with high frequency content.

2D Analyses

Where features of the site are not within the parameters specified for the AP1000, site-specific soil structure interaction analyses may be performed using the 2D SASSI models described in Appendix 3G for variations in site conditions that can be represented in these models. Results should be compared to the results of the 2D SASSI analyses described in Appendix 3G. Such analyses may be used to demonstrate that local features, such as soil degradation properties or backfill, are well within the bounds established by the design cases. If the results are not clearly enveloped at the significant frequencies of response at the six key locations compared with the floor response spectra of the certified design at 5-percent damping, then a 3D SASSI analysis may be required.

3D Analyses

If required, a 3D evaluation will consist of a site-specific dynamic analysis and generation of in-structure response spectra at six key locations to be compared with the floor response spectra of the certified design at 5-percent damping. The certified seismic site design response spectra at the foundation level in the free-field given in Figures 3.7.1-1 and 3.7.1-2 were used to develop the floor response spectra. They were applied at foundation level for the hard rock site and at finished grade level for the soil sites. The site is acceptable if the floor response spectra from the site-specific evaluation do not exceed the AP1000 spectra for each of the locations identified below or the exceedances are justified:

Containment internal structures at elevation of reactor vessel support	Figure 3G.4-5X to 3G.4-5Z
Containment operating floor	Figure 3G.4-6X to 3G.4-6Z
Auxiliary building NE corner at elevation 116'-6"	Figure 3G.4-7X to 3G.4-7Z
Shield building at fuel building roof	Figure 3G.4-8X to 3G.4-8Z
Shield building roof	Figure 3G.4-9X to 3G.4-9Z
Steel containment vessel at polar crane support	Figure 3G.4-10X to 3G.4-10Z

Site-specific soil structure interaction analyses are performed using the 3D SASSI models described in Appendix 3G. The site-specific soil structure interaction analyses use the site-specific soil conditions (including variation in soil properties in accordance with Standard Review Plan 3.7.2 and site-specific soil degradation models). The three components of the site-specific ground motion time history must satisfy the regulatory requirements for statistical independence and enveloping of the site design spectra at 5% damping. Floor response spectra determined from the site-specific analyses should be compared against the design basis of the AP1000 described above.

If the site-specific spectra at foundation level at a rock site exceed the response spectra in Figures 3I.1-1 and 3I.1-2 at any frequency, a site-specific evaluation can be performed similar to that described in Appendix 3I.

This section provides a detailed description of the vibratory ground motion assessment that was carried out for the VEGP ESP site resulting in the development of the VEGP ESP site Ground Motion Response Spectrum (GMRS). This assessment was performed to address seismic hazard update guidance in Regulatory Guide 1.165, Identification and Characterization of Seismic Sources and Determination of Safe Shutdown Earthquake Ground Motion, Rev. 0, March 1997 (RG 1.165), and meet the SSE requirements in paragraph (d) of 10CFR 100.23. The starting point for this site assessment is the EPRI-SOG probabilistic seismic hazard analysis (PSHA) evaluation (Reference 514).

Subsection 2.5.1.2 through Subsection 2.5.2.4 document the review and update of the available EPRI seismicity, seismic source, and ground motion models. Subsection 2.5.2.5 summarizes information about the seismic wave transmission characteristics of the ESP site with reference to more detailed discussion of all engineering aspects of the subsurface in Subsection 2.5.1.

Subsection 2.5.2.6 describes the development of the horizontal GMRS for the VEGP ESP site. The selected ground motion is based on the risk-consistent/performance-based approach from NUREG/CR-6728 (Reference 525) and ASCE 43-05 (Reference 494). Site-specific horizontal ground motion amplification factors are developed using site-specific estimates of near-surface rock, soil, and engineered backfill properties. These amplification factors are then used to scale the hard rock spectra to develop Uniform Hazard Spectra (UHS) accounting for site-specific conditions using Approach 2A of NUREG/CR-6769. Horizontal GMRS spectra are developed from these ground surface Uniform Hazard Spectra (UHS) using the performance-based approach of ASCE 43-05. Companion outcrop motions are defined in Subsection 2.5.2.6 for the highest competent in situ layer and at the depth of the bottom of the Nuclear Island basemat. The highest competent in situ layer is at the top of the Blue Bluff Marl, at a depth of 86 ft. The bottom of the Nuclear Island basemat is at a depth of 40 ft. See Subsections 2.5.1 and 2.5.2.5 for further discussion of the subsurface conditions.

Ratios of vertical to horizontal motions appropriate to the site area are developed in Subsection 2.5.2.7 and applied to the horizontal spectra to derive recommended vertical spectra.

The GMRS described in this section are considered performance goal-based (risk-informed) site-specific response spectra. The spectra at the top of the Blue Bluff Marl reflect the seismic hazard in terms of a PSHA and **in situ** geologic characteristics of the site. The spectra at the bottom of the Nuclear Island basemat are used to define the Foundation Input Response Spectra (FIRS) used to help confirm the adequacy of the Certified Seismic Design Response Spectra (CSDRS) design basis of the Nuclear Island.

The site-specific SSE motion of Section 3.7.1 of the COLA is consistent with the description of the free-field ground motion at the site provided in this Subsection 2.5.2. The OBE is discussed in Subsection 2.5.2.8.

Finally, two complementary sensitivity studies, incorporating information from supplemental site-specific subsurface investigations, are discussed in Subsection 2.5.2.9.

2.5.2.1 Seismicity

The seismic hazard analysis conducted by EPRI (NP-6395-D 1989) relied on an analysis of historical seismicity in the Central and Eastern United States (CEUS) to estimate seismicity parameters (rates of activity and Richter b-values) for individual seismic sources. The historical earthquake catalog

used in the EPRI analysis was complete through 1984. The earthquake data for the site region occurring since 1984 was reviewed and used to update the EPRI catalog.

2.5.2.1.1 Regional Seismicity Catalog Used for 1989 EPRI Seismic Hazard Analysis Study

Many seismic networks record earthquakes in the CEUS. A large effort was made during the EPRI seismic hazard analysis study to combine available data on historical earthquakes and to develop a homogeneous earthquake catalog that contained all recorded earthquakes for the region. "Homogeneous" means that estimates of body-wave magnitude, m_b, for all earthquakes are consistent, that duplicate earthquakes have been eliminated, that non-earthquakes (e.g., mine blasts and sonic booms) have been eliminated, and that significant events in the historical record have not been missed. Thus, the EPRI catalog (Reference 512) forms a strong basis on which to estimate seismicity parameters.

2.5.2.1.2 Updated Seismicity Data

NRC Regulatory Guide 1.165, Identification and Characterization of Seismic Sources and Determination of Safe Shutdown Earthquake Ground Motion, Revision 0, March 1997 (RG 1.165) specifies that earthquakes of Modified Mercalli Intensity (MMI) greater than or equal to IV or magnitude greater than or equal to 3.0 should be listed for seismic sources "any part of which is within a radius of 200 mile (320 km) of the site (the site region)." In updating the EPRI catalog a latitude-longitude window of 30° to 37° N, 78° to 86° W was used. This window incorporates the 200 mi (320 km) radius "site region" and all seismic sources contributing significantly to VEGP ESP site earthquake hazard Figure 2.5-204 shows the VEGP ESP site and its associated site region. Figures 2.5-257 through 2.5-262 show this site region and the defined latitude-longitude window.

The updated catalog was compiled from the following sub-catalogs:

EPRI Catalog. The various data fields of the EPRI catalog are described in EPRI NP-4726-A 1988.

SEUSSN Catalog. The SEUSSN catalog is available from the Virginia Tech Seismological Observatory FTP site (Reference 535). On the June 3, 2005 date of the catalog update, the SEUSSN catalog had 2,483 records dating from March 1698 to December 2003 within the site region latitude-longitude window. Of these, 1,355 records occurred in 1985 or later.

ANSS Catalog. The ANSS catalog (Reference 493) was searched on June 3, 2005, for all records within the site region latitude-longitude window, resulting in 1,710 records from 1928 to April 14, 2005. Of these, 1,375 records occurred in 1985 or later.

The Southeastern US Seismic Network (SEUSSN) and Advanced National Seismic System (ANSS) catalogs were used for the temporal update (1985 to present) of the EPRI seismicity catalog. The SEUSSN has coverage over the entire site region (defined above) and is the primary catalog used to compile the national ANSS seismicity catalog. While the SEUSSN catalog is taken as the preferred catalog, some additional events listed only in the ANSS catalog are also included in the update.

The magnitudes given in both catalogs were converted to best or expected estimate of m_b magnitude ($E[m_b]$, also called Emb), using the conversion factors given as equation 4-1 and Table 4-1 in EPRI NP-4726-A 1988:

$$Emb = 0.253 + 0.907 \cdot Md \qquad \text{(Equation 2.5.2-1)}$$

$$Emb = 0.655 + 0.812 \cdot ML \qquad \text{(Equation 2.5.2-2)}$$

where Md is duration or coda magnitude and ML is "local" magnitude.

Equation 4-2 of EPRI (NP-4726-A 1988) indicates that the equation from which mb* or Rmb is estimated from the best estimate of magnitude $E[m_b]$ or Emb and the variance of m_b, σ^2_{mb}, or Smb^2 is :

$$m_b^* = E[m_b] + (1/2)\cdot ln(10)\cdot b\cdot \sigma^2_{mb} \qquad \text{(Equation 2.5.2-3)}$$

where b = 1.0.

Values for σ^2_{mb} or Smb were estimated for the two catalogs, and m_b [Rmb] was assigned to each event added to the updated catalog.

The result of the above process was a catalog of 61 earthquakes shown in Table 2.5-202 as the update of the EPRI NP-4726-A seismicity catalog recommended for the site region. For the purpose of recurrence analysis, these should be considered independent events.

The 61 events in the 30° to 37° N, 78° to 86° W latitude-longitude window, incorporating the 200 mi (320 km) radius site region, from 1985 to April 2005 with Emb magnitude 3.0 or greater have been incorporated into a number of figures, including tectonic features discussed in Subsection 2.5.1 and EPRI Earth Science Team source maps in this section.

2.5.2.2 Geologic Structures and EPRI Seismic Source Model for the Site Region

As described in Subsection 2.5.1, a comprehensive review of available geological, seismological, and geophysical data has been performed for the VEGP ESP site region and adjoining areas. The following sections summarize seismic source interpretations from the 1989 EPRI probabilistic seismic hazard analysis (PSHA) study (EPRI NP-6395-D 1989) and from relevant post-EPRI seismic source characterization studies and the updated interpretations of new and existing sources based on more recent data.

Since publication of the EPRI seismic source model, significant new information has been developed for assessing the earthquake source that produced the 1886 Charleston earthquake. This new information shows that the Charleston seismic source should be updated according to RG 1.165. Paleoliquefaction features and other new information published since the 1986 EPRI project (Reference 511) have significant implications regarding the geometry, M_{max}, and recurrence of M_{max} in the Charleston seismic source. Results from the 1989 EPRI study also show that the Charleston seismic source is the most significant contributor to seismic hazard at the VEGP ESP site (Reference 514). Thus, an update of the Charleston seismic source has been developed as part of the work performed for this ESP application. Details of the Updated Charleston Seismic Source (UCSS) model are presented in Subsection 2.5.2.2.2.4 and in a separate Engineering Study Report (Reference 498).

Sensitivity studies were performed to evaluate the potential significance of the UCSS model to seismic hazard at the VEGP ESP site, as described in detail in Subsection 2.5.2.4. Based on this analysis, it is found that the UCSS interpretations for the Charleston area show that the Charleston seismic source still dominates the seismic hazard at the VEGP ESP site. These new interpretations of the possible locations, sizes, and recurrence intervals of large earthquakes in the Charleston area form a strong basis with which to calculate the seismic ground motion hazard for the site.

2.5.2.2.1 Summary of EPRI Seismic Sources

This section summarizes the seismic sources and parameters used in the 1986 EPRI project (Reference 511). The description of seismic sources is limited to those sources within 200 mi of the VEGP ESP site (i.e., the site region) and those at distances greater than 200 mi that may affect the hazard at the VEGP ESP site.

In the 1986 EPRI project, six independent Earth Science Teams (ESTs) evaluated geological, geophysical, and seismological data to develop a model of seismic sources in the CEUS. These sources were used to model the occurrence of future earthquakes and evaluate earthquake hazards at nuclear power plant sites across the CEUS.

The six ESTs involved in the 1986 EPRI project were Bechtel Group, Dames & Moore, Law Engineering, Rondout Associates, Weston Geophysical Corporation, and Woodward-Clyde Consultants. Each team produced a report (volumes 5 through 10 of EPRI NP-4726) providing detailed descriptions of how they identified and defined seismic sources. The results were implemented into a PSHA study (Reference 514). For the computation of hazard in the 1989 study, a few seismic source parameters were modified or simplified from the original parameters determined by the six ESTs. EPRI NP-6452-D (1989) summarized the parameters used in the final PSHA calculations, and this reference is the primary source for the seismicity parameters used in this current ESP application. Each EST provides more detailed descriptions of the rationale and methodology used in evaluating tectonic features and establishing the seismic sources (refer to volumes 5 through 10 of EPRI NP-4726).

The most significant seismic sources (Reference 514) developed by each EST are shown in Figures 2.5-257 through 2.5-262. For the 1989 EPRI seismic hazard calculations, a screening criterion was implemented to identify those sources whose combined hazard exceeded 99 percent of the total hazard from all sources, for two ground motions measures (Reference 514). These sources are identified in the descriptions below as “primary” seismic sources. Other sources, which together contributed less than one percent of the total hazard from all sources for the two ground motion measures, are identified in the descriptions below as “additional” seismic sources. Earthquakes with body-wave magnitude m_b 3.0 are also shown in Figures 2.5-257 through 2.5-262 to show the spatial relationships between seismicity and seismic sources. Earthquake epicenters include both events from the EPRI earthquake catalog and for the period between 1985 and April 2005 as described in Subsection 2.5.2.1.2.

The maximum magnitude, interdependencies, and probability of activity for each EPRI EST’s seismic sources are presented in Tables 2.5-203 through 2.5-208. These tables present the parameters assigned to each source within 200 mi of the VEGP ESP site and include primary and additional seismic sources as defined above. The tables also indicate whether new information has been identified that would lead to a revision of the source’s geometry, maximum magnitude, or recurrence parameters. The seismicity recurrence parameters (a- and b-values) used in the seismic hazard studies were computed for each 1° latitude and longitude cell that intersects any portion of a seismic source.

The nomenclature used by each EST to describe the various seismic sources in the CEUS varies from team to team. In other words, a number of different names may have been used by the EPRI teams to describe the same or similar tectonic features or sources, or one team may describe seismic sources that another team does not. For example**,** the Charleston seismic source was modeled by each team but was called the Charleston Area and Charleston Faults by the Bechtel Group team; the Charleston Seismic Zone by the Dames & Moore, Law, and Weston teams; and Charleston by the Rondout and Woodward-Clyde teams. Each team’s source names, data, and rationale are included in its team-specific documentation (volumes 5 through 10 of EPRI NP-4726).

The EPRI PSHA study expressed maximum magnitude (M_{max}) values in terms of body-wave magnitude (m_b), whereas most modern seismic hazard analyses describe M_{max} in terms of moment magnitude (**M**). To provide a consistent comparison between magnitude scales, this study relates body-wave magnitude to moment magnitude using the arithmetic average of three equations, or their inversions, presented in Atkinson and Boore (1995), Frankel et al (1996), and EPRI TR-102293 (1993). The conversion relations are very consistent for magnitudes 4.5 and greater and begin to show divergence at lower magnitudes. (Table 2.5-209 lists m_b and **M** equivalences developed from

these relations over the range of interest for this study.) Throughout this section, the largest assigned values of M_{max} distributions assigned by the ESTs to seismic sources are presented for both magnitude scales (m_b and **M**) to give perspective on the maximum earthquakes that were considered possible in each seismic source. For example, EPRI m_b values of M_{max} are followed by the equivalent **M** value.

The following sections describe the most significant EPRI sources (both primary and additional seismic sources) for each EST with respect to the VEGP ESP site. Assessment of these and other EPRI sources within the site region shows that the EPRI source parameters (M_{max}, geometry, and recurrence) are sufficient to capture the current understanding of the seismic hazard in the site region.

Except for the Charleston seismic source, no new geological, geophysical, or seismological information in the literature published since the EPRI NP-6395-D source model suggests that these sources should be modified. Each EST's characterization of the Charleston seismic source was replaced by four alternative source geometries. For each geometry, large earthquake occurrences (**M** 6.7 to 7.5) were modeled with a range of mean recurrence rates, and smaller earthquakes (m_b 5 to 6.7) were modeled with an exponential magnitude distribution, with rates and b-values determined from historical seismicity. Also, all surrounding sources for each team were redrawn so that the new Charleston source geometries were accurately represented as a "hole" in the surrounding source, and seismic activity rates and b-values were recalculated for the modified surrounding sources, based on historical seismicity. Further details and the results of sensitivity analyses performed on the modified seismic sources are presented in Subsection 2.5.2.4.

2.5.2.2.1.1 Sources Used for EPRI PSHA – Bechtel Group

Bechtel Group identified and characterized six primary seismic sources. All six of these primary seismic sources are located within the site region (200 mi); they are:

- Charleston Area (H)
- Charleston Faults (N3)
- Atlantic Coastal Region (BZ4)
- S Appalachians (BZ5)
- SE Appalachians (F)
- NW South Carolina (G)

Bechtel Group also characterized four additional seismic sources. These additional seismic sources are:

- Eastern Mesozoic Basins (13)
- Bristol Trends (24)
- Rosman Fault (15)
- Belair Fault (16)

Primary and additional seismic sources characterized by the Bechtel Group team within the site region are listed in Table 2.5-203. A map showing the locations and geometries of the Bechtel

primary seismic sources is provided in Figure 2.5-257. Following is a brief discussion of each of the primary seismic sources characterized by the Bechtel Group team.

Charleston Area (H). The Charleston Area source (H) is located about 60 mi from the VEGP ESP site. This oblong combination source area is defined based on the historic earthquake pattern (including the Middleton Place-Summerville and Bowman seismic zones), is elongated northwest-southeast, and encompasses all of source zone N3 (described below). Sources H and N3 are interdependent; if N3 is active, it is unlikely that H is active, and vice versa. The largest M_{max} assigned by Bechtel Group to this zone is m_b 7.4 (**M** 7.9), reflecting its assumption that Charleston-type earthquakes are produced within this zone.

Charleston Faults (N3). The Charleston Faults (N3) source zone is a small area set within the Charleston Area (H) source zone and encompassing a number of identified and postulated faults in the Charleston, South Carolina, area, including the Ashley River, Charleston, and Woodstock faults. Source N3 is located approximately 85 mi from the VEGP ESP site. Sources H and N3 are interdependent; if N3 is active, it is unlikely that H is active, and vice versa. According to EPRI NP-4726, this combination was created for computational simplicity. The largest M_{max} assigned by the Bechtel Group team to this zone is m_b 7.4 (**M** 7.9), reflecting its assumption that Charleston-type earthquakes are produced within this zone.

Atlantic Coastal Region (BZ4). The VEGP ESP site is located within the Atlantic Coastal Region background source (BZ4). Source BZ4 is a large background zone that extends from offshore New England to Alabama and encompasses portions of the Coastal Plain from Georgia to southern Virginia. The largest M_{max} assigned by the Bechtel Group team to this zone is m_b 7.4 (**M** 7.9), reflecting its assumption that there is a small probability that a Charleston-type earthquake could occur within this region.

S Appalachians (BZ5). The Southern Appalachians background source (BZ5) is located about 10 mi from the VEGP ESP site. This source is a large background region that extends from New York to Alabama, including portions of the Southern Appalachians, Piedmont, and Coastal Plain. The largest M_{max} assigned by the Bechtel Group team to this zone is m_b 6.6 (**M** 6.5).

SE Appalachians (F). The VEGP ESP site is located about 10 mi from the Southeastern Appalachians source (F), a combination source zone that includes parts of Georgia and the Carolinas and flanks the southwest and northeast borders of Zone G (described below). Source Zone F is mutually exclusive with Zone G; if F is active, G is inactive, and vice versa. The largest M_{max} assigned by the Bechtel Group team to this zone is m_b 6.6 (**M** 6.5).

NW South Carolina (G). The VEGP ESP site is located about 10 mi from the Northwestern South Carolina combination source (G). Source Zone G is mutually exclusive with Zone F; if G is active, F is inactive, and vice versa. The largest M_{max} assigned by the Bechtel Group team to this zone is m_b 6.6 (**M** 6.5).

2.5.2.2.1.2 Sources Used for EPRI PSHA – Dames & Moore

Dames & Moore identified and characterized five primary seismic sources. All five of these seismic sources are located within the site region; they are:

- Charleston Seismic Zone (54)
- Charleston Mesozoic Rift (52)
- S Appalachian Mobile Belt (Default Zone) (53)

- S Cratonic Margin (Default Zone) (41)
- S Coastal Margin (20)

Dames & Moore also identified seven additional seismic sources within the site region. These sources are:

- Appalachian Fold Belts (4)
- Kink in Fold Belt (4A)
- Jonesboro Basin (49)
- Buried Triassic Basins (50)
- Florence Basin (51)
- Dunbarton Triassic Basin (65)
- Combination Zone 4A-4B-4C-4D (C01)

Primary and additional seismic sources characterized by the Dames & Moore team within the site region are listed in Table 2.5-204. A map showing the locations and geometries of the Dames & Moore primary seismic sources is provided in Figure 2.5-258. Following is a brief discussion of these primary seismic sources.

Charleston Seismic Zone (54). The Charleston Seismic Zone (54) is a northwest-southeast oriented polygon located about 45 mi from the VEGP ESP site. This source includes the Ashley River, Woodstock, Helena Banks, and Cooke faults, as well as the Bowman and Middleton Place-Summerville seismic zones and was designed to capture the occurrence of Charleston-type earthquakes. The largest M_{max} assigned by the Dames & Moore team to this zone is m_b 7.2 (**M** 7.5).

Charleston Mesozoic Rift (52). The Charleston Mesozoic Rift source (52) is a large polygon located less than 5 mi from the VEGP ESP site. This source extends from offshore South Carolina to Gulf Shore Florida, including portions of the South Carolina and Georgia Coastal Plain. The largest M_{max} assigned by the Dames & Moore team to this zone is m_b 7.2 (**M** 7.5).

S Appalachian Mobile Belt (Default Zone) (53). The VEGP ESP site is located within the Southern Appalachian Mobile Belt (Default Zone) source (53). This default zone comprises crustal rocks that have undergone several periods of divergence and convergence. The source is bounded on the east by the East Coast magnetic anomaly and on the west by the westernmost boundary of the Appalachian gravity gradient. The largest M_{max} assigned by the Dames & Moore team to this zone is m_b 7.2 (**M** 7.5).

S Cratonic Margin (Default Zone) (41). The Southern Cratonic Margin (Default Zone) source is located about 65 mi from the VEGP ESP site. This large default zone is located between the Appalachian Fold Belt (4) and the Southern Appalachian Mobile Belt (53) and includes the region of continental margin deformed during Mesozoic rifting. Located within this default zone are many Triassic basins and border faults. The largest M_{max} assigned by the Dames & Moore team to this zone is m_b 7.2 (**M** 7.5).

S Coastal Margin (20). The Southern Coastal Margin regional source (20) is located approximately 90 mi from the VEGP ESP site. This zone is roughly parallel to the rifted continental margin from Texas to Alabama and incorporates a region of diffuse seismicity. Located within this source is a

down-warped wedge of miogeosynclinal sediments of Cretaceous age and younger. The largest M_{max} assigned by the Dames & Moore team to this zone is m_b 7.2 (**M** 7.5).

2.5.2.2.1.3 Sources Used for EPRI PSHA – Law Engineering

Law Engineering identified and characterized 15 primary seismic sources all within the site region; They are:

- Charleston Seismic Zone (35)
- Eastern Basement (17)
- Reactivated E Seaboard Normal (22)
- Brunswick, NC Background (108)
- Mesozoic Basins (8 – Bridged) (C09)
- 8 – 35 (C10)
- 22 – 35 (C11)
- Eight mafic pluton sources (M33 and M36 through M42)

Law Engineering also characterized five additional seismic sources within the site region that do not contribute to 99 percent of the hazard at the VEGP ESP site. These are:

- Eastern Basement Background (217)
- Eastern Piedmont (107)
- 22 – 24 – 35 (GC13)
- 22 – 24 (GC12)
- Mesozoic Basins (8)

Primary and additional seismic sources characterized by the Law Engineering team within the site region are listed in Table 2.5-205. A map showing the locations and geometries of the Law Engineering primary seismic sources is provided in Figure 2.5-259. Following is a brief discussion of Law's primary seismic sources

Charleston Seismic Zone (35). The Charleston Seismic Zone source (35) is a northeast-southwest elongated polygon that includes the Charleston, Ashley River, and Woodstock faults, as well as parts of the offshore Helena Banks fault and most of the more recently discovered liquefaction features identified by Amick (1990). This source was designed to capture the occurrence of Charleston-type earthquakes. This source is located about 75 mi from the VEGP ESP site and overlaps with the Reactivated E Seaboard Normal (22; described below) and Buried Mesozoic Basins (8; not a 99 percent contributor) sources. The largest M_{max} assigned by the Law Engineering team to this zone is m_b 6.8 (**M** 6.8).

Eastern Basement (17). The VEGP ESP site is located 90 mi from the Eastern Basement (17) source. This source was defined as an area containing pre-Cambrian and Cambrian normal faults, developed during the opening of the proto-Atlantic Ocean, in the basement rocks beneath the

Appalachian decollement. The Giles County and eastern Tennessee zones of seismicity are included in this source. The largest M_{max} assigned by the Law Engineering team to this zone is m_b 6.8 (**M** 6.8).

Reactivated E Seaboard Normal (22). The VEGP ESP site is located within the Reactivated Eastern Seaboard Normal (22) source. This source was characterized as a region along the eastern seaboard in which Mesozoic normal faults are reactivated as high-angle reverse faults. The Law Engineering team assigned a single M_{max} of m_b 6.8 (**M** 6.8) to this zone.

Brunswick, NC Background (108). The VEGP ESP site is located within the Brunswick NC Background source zone (108). The source 108 site represents a zone defined by a low-amplitude, long-wavelength magnetic anomaly pattern. The Law Engineering team interpreted this pattern as possibly indicating a zone of Mesozoic extended crust. The largest M_{max} assigned by the Law Engineering team to this zone is m_b 6.8 (**M** 6.8).

Mesozoic Basins (8 – Bridged) (C09). The VEGP ESP site is located within the Mesozoic Basins (C09) source, which comprises eight bridged basins. This source was defined based on northeast-trending sediment-filled troughs in basement rock bounded by normal faults. The largest M_{max} assigned by the Law Engineering team to this zone is m_b 6.8 (**M** 6.8).

8 – 35 (C10). The VEGP ESP site is located within the 8 – 35 combination source (C10). The largest M_{max} assigned by the Law Engineering team to this zone is m_b 6.8 (**M** 6.8).

22 – 35 (C11). The VEGP ESP site is located within the 22 – 35 combination source (C11). The largest M_{max} assigned by the Law Engineering team to this zone is m_b 6.8 (**M** 6.8).

Eight Mafic Pluton Sources (M33 and M36 through M42). The Law Engineering team identified a number of mafic pluton sources, eight of which are located within about 130 mi of the VEGP ESP site. The Law Engineering team considered pre- and post-metamorphic plutons in the Appalachians to be stress concentrators and, thus, earthquake sources. Law Engineering assigned a single M_{max} of m_b 6.8 (**M** 6.8) to all mafic pluton sources.

2.5.2.2.1.4 Sources Used for EPRI PSHA – Rondout Associates

Rondout Associates characterized two primary seismic sources both within the site region; they are:

- Charleston (24)
- South Carolina (26)

Rondout Associates also identified eight additional seismic sources within the site region. These are:

- Appalachian (49)
- Background 49 (C01)
- 49 + 32 (C09)
- Grenville (50)
- Background 50 (C02)
- 50 (02) + 12 (C07)
- Southern Appalachians (25)

- Tennessee-VA Border Zone (27)

Primary and additional seismic sources characterized by the Rondout Associates team within the site region are listed in Table 2.5-206. A map showing the locations and geometries of the Rondout Associates primary seismic sources is provided in Figure 2.5-260. Following is a brief discussion of both of these primary seismic sources.

Charleston (24). The Charleston source is a northwest-southeast-oriented area set within the larger South Carolina (26) source and located about 35 mi from the VEGP ESP site. Source 24 includes the Helena Banks, Charleston, Ashley River, and Woodstock faults, as well as the Bowman and Middleton Place-Summerville seismic zones, and was designed to capture the occurrence of Charleston-type earthquakes. The largest M_{max} assigned by the Rondout Associates team to this zone is m_b 7.0 (**M** 7.2).

South Carolina (26). The VEGP ESP site is located within the South Carolina source (26). The South Carolina source (26) is a northwest-southeast elongated area that surrounds, but does not include, Source 24 (described above). Source 26 includes most of South Carolina except the Charleston area. The largest M_{max} assigned by the Rondout Associates team to this zone is m_b 6.8 (**M** 6.8).

2.5.2.2.1.5 Sources Used for EPRI PSHA – Weston Geophysical

Weston Geophysical identified and characterized 12 primary seismic sources, all within the site region; they are:

- Charleston Seismic Zone (25)
- South Carolina (26)
- Southern Coastal Plain (104)
- 103 – 23 – 24 (C19)
- 104 – 22 (C20)
- 104 – 25 (C21)
- 104 – 22 – 26 (C23)
- 104 – 22 – 25 (C24)
- 104 – 28BCDE – 22 (C26)
- 104 – 28BCDE – 22 – 25 (C27)
- 26 – 25 (C33)
- 104 – 28BE – 25 (C35)

Weston Geophysical also characterized 13 additional seismic sources within the site region. These sources are:

- 104 – 26 (C22)

- 104 – 28BE – 26 (C34)
- 104 – 28BCDE (C25)
- 104 – 28BCDE – 22 – 26 (C28)
- Zone of Mesozoic Basin (28B)
- 28A through E (C01)
- Southern Appalachians (103)
- 103 – 23 (C17)
- 103 – 24 (C18)
- Zone of Mesozoic Basin (28D)
- Zone of Mesozoic Basin (28E)
- Appalachian Plateau (102)
- New York-Alabama-Clingman (24)

Primary and additional seismic sources characterized by the Weston Geophysical team are listed in Table 2.5-207. A map showing the locations and geometries of the Weston Geophysical primary seismic sources is provided in Figure 2.5-262. Following is a brief discussion of each of the Weston Geophysical team's primary seismic sources.

Charleston Seismic Zone (25). The Charleston Seismic Zone source is an irregularly shaped hexagon centered just northeast of Charleston, South Carolina, and located about 60 mi from the VEGP ESP site. This source includes the Helena Banks, Charleston, Ashley River, and Woodstock faults, but does not include the Bowman seismic zone. This source was designed to capture the occurrence of Charleston-type earthquakes. The largest M_{max} assigned by the Weston Geophysical team to this zone is m_b 7.2 (**M** 7.5).

South Carolina (26). The South Carolina source (26) is a large area covering most of South Carolina and the VEGP ESP site. The largest M_{max} assigned by the Weston Geophysical team to this zone is m_b 7.2 (**M** 7.5).

Southern Coastal Plain (104). The Southern Coastal Plain source (104) extends from New York to Alabama and from the Towaliga-Lowdenville-Kings Mountain fault trends on the west to the offshore East Coast magnetic anomaly on the east. Source 104 was designed to include the Central Virginia seismic zone, the Charleston seismic zone, and a number of Mesozoic basins. The largest M_{max} assigned by the Weston Geophysical team to this zone is m_b 6.6 (**M** 6.5).

Nine Combination Zones: (103 – 23 – 24 (C19); 104 – 22 (C20); 104 – 25 (C21); 104 – 22 – 26 (C23); 104 – 22 – 25 (C24); 104 – 28BCDE – 22 (C26); 104 – 28BCDE – 22 – 25 (C27); 26 – 25 (C33); and 104 – 28BE – 25 (C35)). Weston Geophysical specified a number of combination seismic source zones, nine of which are primary sources for the VEGP ESP site. The largest M_{max} assigned by the Weston Geophysical team to these combination zones is m_b 6.6 (**M** 6.5).

2.5.2.2.1.6 Sources Used for EPRI PSHA – Woodward-Clyde Consultants

Woodward-Clyde Consultants identified and characterized five primary seismic sources, all five located within the site region; they are:

- Charleston (includes “none of the above,” NOTA) (30)
- S Carolina Gravity Saddle (Extended) (29)
- SC Gravity Saddle No. 2 (Combo C3) (29A)
- SC Gravity Saddle No. 3 (NW Portion) (29B)
- Vogtle Background

Woodward-Clyde Consultants also identified two additional seismic sources within the site region. These sources are:

- Blue Ridge Combo (31)
- Blue Ridge Combination – Alternate Configuration (31A)

Primary and additional seismic sources characterized by the Woodward-Clyde team within the site region are listed in Table 2.5-208. A map showing the locations and geometries of the Woodward-Clyde primary seismic sources is provided in Figure 2.5-261. Following is a brief discussion of each of the primary seismic sources identified by the Woodward-Clyde team.

Charleston (includes NOTA) (30). The Charleston seismic source (30) is a northeast-southwest-oriented rectangle that includes most of the Charleston earthquake MMI IX and X area and the Charleston Ashley River and Woodstock faults. Source 30 is located about 70 mi from the VEGP ESP site and was designed to capture the occurrence of Charleston-type earthquakes. The Charleston source (30) is mutually exclusive with Sources 29, 29A, and 29B; if 30 is active, the other three are inactive, and vice versa. The largest M_{max} assigned by the Woodward-Clyde Consultants team to this zone is m_b 7.5 (**M** 8.0).

S Carolina Gravity Saddle (Extended) (29). The South Carolina Gravity Saddle (Extended) source (29) covers most of South Carolina and parts of Georgia, including the VEGP ESP site. The South Carolina Gravity Saddle source (29) is mutually exclusive with Sources 29A, 29B, and 30; if 29 is active, the other three are inactive, and vice versa. The largest M_{max} assigned by the Woodward-Clyde Consultants team to this zone is m_b 7.4 (**M** 7.9), reflecting its assumption that Charleston-type earthquakes can occur in this zone.

SC Gravity Saddle No. 2 (Combo C3) (29A). The South Carolina Gravity Saddle No. 2 source (29A) is an irregularly shaped polygon set within the larger area of Source 29. The SC Gravity Saddle No. 2 source (29A) is mutually exclusive with Sources 29, 29B, and 30; if 29A is active, the other three are inactive, and vice versa. The largest M_{max} assigned by the Woodward-Clyde Consultants team to this zone is m_b 7.4 (**M** 7.9), reflecting its assumption that Charleston-type earthquakes can occur in this zone.

SC Gravity Saddle No. 3 (NW Portion) (29B). The South Carolina Gravity Saddle No. 3 source (29B) is an irregularly shaped polygon set within the larger area of Source 29 and includes the VEGP ESP site. The SC Gravity Saddle No. 3 source (29B) is mutually exclusive with Sources 29, 29A, and 30; if 29B is active, the other three are inactive, and vice versa. The largest M_{max} assigned by the Woodward-Clyde Consultants team to this zone is m_b 7.0 (**M** 7.2).

Vogtle Background. The VEGP ESP Background source is a large box containing the VEGP ESP site and covering most of South Carolina and Georgia as well as parts of adjoining states and extending offshore. This source is a background zone defined as a rectangular area surrounding the VEGP ESP site and is not based on any geological, geophysical, or seismological features. The largest M_{max} assigned by the Woodward-Clyde Consultants team to this zone is m_b 6.6 (**M** 6.5).

2.5.2.2.2 Post-EPRI Seismic Source Characterization Studies

Since the EPRI (NP-4726 1986, NP-6395-D 1989) seismic hazard project, three recent studies have been performed to characterize seismic sources within the VEGP ESP site region for PSHAs. These studies include the US Geological Survey's (USGS) National Seismic Hazard Mapping Project (Reference 281, Reference 282), the South Carolina Department of Transportation's seismic hazard mapping project (Reference 504), and the Nuclear Regulatory Commission's Trial Implementation Project (TIP) study (Reference 533). These three studies are described below (i.e., Subsections 2.5.2.2.2.1 through 2.5.2.2.2.3). Based on review of recent studies it was determined that an update of the Charleston seismic source for the EPRI (NP-4726 1986, NP-6395-D 1989) seismic hazard project was required. This update is presented in Subsection 2.5.2.2.2.4. In addition, at the perimeter of the VEGP ESP site region is what is now identified as the Eastern Tennessee Seismic Zone (ETSZ). The significance of the ETSZ on the VEGP ESP seismic hazard is discussed in Subsection 2.5.2.2.2.5.

2.5.2.2.2.1 US Geological Survey Model (Frankel et al. 2002)

In 2002, the USGS produced updated seismic hazard maps for the conterminous United States based on new seismological, geophysical, and geological information (Reference 282). The 2002 maps reflect changes to the source model used to construct the previous version of the national seismic hazard maps (Reference 281). The most significant modifications to the CEUS portion of the source model include changes in the recurrence, M_{max}, and geometry of the Charleston and New Madrid sources.

Unlike the EPRI models that incorporate many local sources, the USGS source model in the CEUS includes only five sources: the Extended Margin background, Stable Craton background, Charleston, Eastern Tennessee, and New Madrid (Table 2.5-209). Except for the Charleston and New Madrid zones, where earthquake recurrence is modeled by paleoliquefaction data, the hazard for the large background or "maximum magnitude" zones is largely based on historical seismicity and the variation of that seismicity. The USGS source model defines the M_{max} distribution for the Extended Margin background source zone as a single magnitude of **M** 7.5 with a weight of 1.0. The EPRI model, however, includes multiple source zones for each of the six ESTs for this region containing the eastern seaboard and the Appalachians. The EPRI M_{max} distributions for these sources capture a wide range of magnitudes and weights, reflecting considerable uncertainty in the assessment of M_{max} for the CEUS. An **M** 7.5 M_{max} is captured in most of the EPRI source zones, although at a lower weight than assigned by the USGS model.

As part of the 2002 update of the National Seismic Hazard Maps, the USGS developed a model of the Charleston source that incorporates available data regarding recurrence, M_{max}, and geometry of the source zone. The USGS model uses two equally weighted source geometries, one an areal source enveloping most of the tectonic features and liquefaction data in the greater Charleston area and the second a north-northeast-trending elongated areal source enveloping the southern half of the southern segment of the East Coast fault system (ECFS) (Table 2.5-209 and Figure 2.5-263). The Frankel et al. (2002) report does not specify why the entire southern segment of the ECFS is not contained in the source geometry. For M_{max}, the study defines a distribution of magnitudes and weights of **M** 6.8 [.20], 7.1 [.20], 7.3 [.45], 7.5 [.15]. For recurrence, Frankel et al. (2002) adopt a mean paleoliquefaction-based recurrence interval of 550 years and represent the uncertainty with a continuous lognormal distribution.

2.5.2.2.2.2 South Carolina Department of Transportation Model (Chapman and Talwani 2002)

Chapman and Talwani (2002) created probabilistic seismic hazard maps for the South Carolina Department of Transportation (SCDOT). In the SCDOT model, treatment of the 1886 Charleston, South Carolina, earthquake and similar events dominates estimates of hazard statewide.

The SCDOT model employs a combination of line and area sources to characterize Charleston-type earthquakes in three separate geometries and uses a slightly different M_{max} range (**M** 7.1 to 7.5) than the USGS 2002 model (Table 2.5-210and Figure 2.5-264). Three equally-weighted source zones defined for this study include (1) a source capturing the intersection of the Woodstock and Ashley River faults, (2) a larger Coastal South Carolina zone that includes most of the paleoliquefaction sites, and (3) a southern ECFS source zone. The respective magnitude distributions and weights used for M_{max} are **M** 7.1 [.20], 7.3 [.60], 7.5 [.20]. The mean recurrence interval used in the SCDOT study is 550 years, based on the paleoliquefaction record.

2.5.2.2.2.3 The Trial Implementation Project Study (Savy et al. 2002)

The purpose of the Lawrence Livermore National Laboratory Trial Implementation Project (TIP) study is to "test and implement the guidelines developed by the Senior Seismic Hazard Analysis Committee (SSHAC) developed under FIN L2503 (NRC 1997)" (Reference 533, p. 1). To test the SSHAC PSHA methodology, the TIP study focuses on seismic zonation and earthquake recurrence models for the Watts Bar site in Tennessee and the VEGP site. The TIP study uses an expert elicitation process to characterize the Charleston seismic source, considering published data through 1996. The TIP study identifies multiple alternative zones for the Charleston source and for the South Carolina–Georgia seismic zone, as well as alternative background seismicity zones for the Charleston region. However, the TIP study focuses primarily on implementing the Senior Seismic Hazard Advisory Committee (SSHAC) PSHA methodology (Reference 538) and was designed to be as much of a test of the methodology as a real estimate of seismic hazard. As a result, its findings are not included explicitly in this report.

2.5.2.2.2.4 Updated Charleston Seismic Source (UCSS) Model (Bechtel 2006d)

It has been nearly 20 years since the six EPRI ESTs evaluated hypotheses for earthquake causes and tectonic features and assessed seismic sources in the CEUS (Reference 511). The EPRI Charleston source zones developed by each EST are shown in Figure 2.5-266 and summarized in Table 2.5-211. Several studies that post-date the 1986 EPRI EST assessments have demonstrated that the source parameters for geometry, M_{max}, and recurrence of M_{max} in the Charleston seismic source need to be updated to capture a more current understanding for both the 1886 Charleston earthquake and the seismic source that produced this earthquake. In addition, recent PSHA studies of the South Carolina region (Reference 533; Reference 504) and the southeastern United States (Reference 282) have developed models of the Charleston seismic source that differ significantly from the earlier EPRI characterizations. Therefore, the Charleston seismic source was updated as part of this ESP application.

The UCSS model is summarized below and presented in detail in Bechtel (2006d). Methods used to update the Charleston seismic source follow guidelines provided in RG 1.165. An SSHAC Level 2 study was performed to incorporate current literature and data and the understanding of experts into an update of the Charleston seismic source model. This level of effort is outlined in the SSHAC (1997) report, which provides guidance on incorporating uncertainty and the use of experts in PSHA studies.

The UCSS model incorporates new information to re-characterize geometry, M_{max}, and recurrence for the Charleston seismic source. These components are discussed in the following sections.

Paleoliquefaction data imply that the Charleston earthquake process is defined by repeated, relatively frequent, large earthquakes located in the vicinity of Charleston, indicating that the Charleston source is different from the rest of the eastern seaboard.

2.5.2.2.2.4.1 UCSS Geometry

The UCSS model includes four mutually exclusive source zone geometries (A, B, B', and C; Figure 2.5-265). The latitude and longitude coordinates that define these four source zones are presented in Table 2.5-212. Details for each source geometry are given below. The four geometries of the UCSS are defined based on current understanding of geologic and tectonic features in the 1886 Charleston earthquake epicentral region; the 1886 Charleston earthquake shaking intensity; distribution of seismicity; and geographic distribution, age, and density of liquefaction features associated with both the 1886 and prehistoric earthquakes. These features, shown in Figures 2.5-221 and 2.5-222, strongly suggest that the majority of evidence for the Charleston source is concentrated in the Charleston area and is not widely distributed throughout South Carolina. Table 2.5-211 provides a subset of the Charleston tectonic features differentiated by pre- and post-EPRI (Reference 511) information. In addition, pre- and post-1986 instrumental seismicity, $m_b \geq 3$, are shown on Figures 2.5-221 and 2.5-222. Seismicity continues to be concentrated in the Charleston region in the Middleton Place–Summerville seismic zone (MPSSZ), which has been used to define the intersection of the Woodstock and Ashley River faults (Reference 463; Reference 364). Notably, two earthquakes in 2002 (m_b 3.5 and 4.4) are located offshore of South Carolina along the Helena Banks fault zone in an area previously devoid of seismicity of $m_b > 3$. A compilation of the EPRI EST Charleston source zones is provided in Figure 2.5-266 as a comparison to the UCSS geometries shown in Figure 2.5-265.

Geometry A - Charleston

Geometry A is an approximately 100 x 50 km, northeast-oriented area centered on the 1886 Charleston meizoseismal area (Figure 2.5-265). Geometry A is intended to represent a localized source area that generally confines the Charleston source to the 1886 meizoseismal area (i.e., a stationary source in time and space). Geometry A completely incorporates the 1886 earthquake MMI X isoseismal (Reference 219), the majority of identified Charleston-area tectonic features and inferred fault intersections, and the majority of reported 1886 liquefaction features. Geometry A excludes the northern extension of the southern segment of the East Coast fault system because this system extends well north of the meizoseismal zone and is included in its own source geometry (Geometry C). Geometry A also excludes outlying liquefaction features, because liquefaction occurs as a result of strong ground shaking that may extend well beyond the areal extend of the tectonic source. Geometry A also envelopes instrumentally located earthquakes spatially associated with the MPSSZ (Reference 463; Reference 462; Reference 364).

The preponderance of evidence strongly supports the conclusion that the seismic source for the 1886 Charleston earthquake is located in a relatively restricted area defined by Geometry A. Geometry A envelopes (1) the meizoseismal area of the 1886 earthquake, (2) the area containing the majority of local tectonic features (although many have large uncertainties associated with their existence and activity, as described earlier), (3) the area of ongoing concentrated seismicity, and (4) the area of greatest density of 1886 liquefaction and prehistoric liquefaction. These observations show that future earthquakes having magnitudes comparable to the Charleston earthquake of 1886 most likely will occur within the area defined by Geometry A. A weight of 0.70 is assigned to Geometry A (Figure 2.5-267). To confine the rupture dimension to within the source area and to maintain a preferred northeast fault orientation, Geometry A is represented in the model by a series of closely spaced, northeast-trending faults parallel to the long axis of the zone.

Geometries B, B', and C

While the preponderance of evidence supports the assessment that the 1886 Charleston meizoseismal area and Geometry A define the area where future events will most likely be centered, it is possible that the tectonic feature responsible for the 1886 earthquake either extends beyond or lies outside Geometry A. Therefore, the remaining three geometries (B, B', and C) are assessed to capture the uncertainty that future events may not be restricted to Geometry A. The distribution of liquefaction features along the entire coast of South Carolina and observations from the paleoliquefaction record that a few events were localized (moderate earthquakes to the northeast and southwest of Charleston), suggest that the Charleston source could extend well beyond Charleston proper. Geometries B and B' are assessed to represent a larger source zone, while Geometry C represents the southern segment of the East Coast fault system as a possible source zone. The combined geometries of B and B' are assigned a weight of 0.20, and Geometry C is assigned a weight of 0.10. Geometry B' a subset of B, formally defines the onshore coastal area as a source (similar to the SCDOT coastal source zone) that would restrict earthquakes to the onshore region. Geometry B, which includes the onshore and offshore regions, and Geometry B' are mutually exclusive and given equal weight in the UCSS model. Therefore, the resulting weights are 0.10 for Geometries B and B'.

Geometry B - Coastal and Offshore Zone

Geometry B is a coast-parallel, approximately 260 x 100 km source area that (1) incorporates all of Geometry A, (2) is elongated to the northeast and southwest to capture other, more distant liquefaction features in coastal South Carolina (Reference 205; Reference 207, Reference 206; Reference 461), and (3) extends to the southeast to include the offshore Helena Banks fault zone (Reference 213; Figure 2.5-265). The elongation and orientation of Geometry B is roughly parallel to the regional structural grain as well as roughly parallel to the elongation of 1886 isoseismals. The northeastern and southwestern extents of Geometry B are controlled by the mapped extent of paleoliquefaction features [e.g., (Reference 205; Reference 207, Reference 206**;** Reference 461)].

The location and timing of paleoliquefaction features in the Georgetown and Bluffton areas to the northeast and southwest of Charleston have suggested to some researchers that the earthquake source may not be restricted to the Charleston area (Reference 530; Reference 207; Reference 461). A primary reason for defining Geometry B is to account for the possibility that there may be an elongated source or multiple sources along the South Carolina coast. Paleoliquefaction features in the Georgetown and Bluffton areas may be explained by an earthquake source both northeast and southwest of Charleston, as well as possibly offshore.

Geometry B extends southeast to include an offshore area and the Helena Banks fault zone. The Helena Banks fault zone is clearly shown by multiple seismic reflection profiles and has demonstrable late Miocene offset (Reference 213). Offshore earthquakes in 2002 (m_b 3.5 and 4.4) suggest a possible spatial association of seismicity with the mapped trace of the Helena Banks fault system (Figures 2.5-265 and 2.5-222). Whereas these two events in the vicinity of the Helena Banks fault system do not provide a positive correlation with seismicity or demonstrate recent fault activity, these small earthquakes are considered new data since the EPRI studies. The EPRI earthquake catalog (Reference 512) was devoid of any events ($m_b \geq 3.0$) offshore from Charleston. The recent offshore seismicity also post-dates the development of the USGS and SCDOT source models that exclude any offshore Charleston source geometries.

A low weight of 0.10 is assigned to Geometry B (Figure 2.5-267), because the preponderance of evidence indicates that the seismic source that produced the 1886 earthquake lies onshore in the Charleston meizoseismal area and not in the offshore region. To confine the rupture dimension to within the source area and to maintain a preferred northeast fault orientation, Geometry B is represented in the model by a series of closely spaced, northeast-trending faults parallel to the long axis of the zone.

Geometry B' - Coastal Zone

Geometry B' is a coast-parallel, approximately 260 x 50 km source area that incorporates all of Geometry A, as well as the majority of reported paleoliquefaction features (Reference 205**; Amick et al. 1990a,** Reference 206**;** Reference 461). Unlike Geometry B, however, Geometry B' does not include the offshore Helena Banks fault zone (Figure 2.5-265).

The Helena Banks fault system is excluded from Geometry B' to recognize that the preponderance of the data and evaluations support the assessment that the fault system is not active and because most evidence strongly suggests that the 1886 Charleston earthquake occurred onshore in the 1886 meizoseismal area and not on an offshore fault. Whereas there is little uncertainty regarding the existence of the Helena Banks fault, there is a lack of evidence that this feature is still active. Isoseismal maps documenting shaking intensity in 1886 indicate an onshore meizoseismal area (the closed bull's eye centered onshore north of downtown Charleston, Figure 2.5-222). An onshore source for the 1886 earthquake as well as the prehistoric events is supported by the instrumentally recorded seismicity in the MPSSZ and the corresponding high density cluster of 1886 and prehistoric liquefaction features.

Similar to Geometry B above, a weight of 0.10 is assigned to Geometry B' and reflects the assessment that Geometry B' has a much lower probability of being the source zone for Charleston-type earthquakes than Geometry A (Figure 2.5-267). To confine the rupture dimension to within the source area and to maintain a preferred northeast fault orientation, Geometry B' is represented in the model by a series of closely spaced, northeast-trending faults parallel to the long axis of the zone.

Geometry C - East Coast Fault System - South (ECFS-s)

Geometry C is an approximately 200 x 30 km, north-northeast-oriented source area enveloping the southern segment of the proposed East Coast fault system (ECFS-s) shown in Figure 3 of Marple and Talwani (2000) (Figures 2.5-265 and 2.5-268). The USGS hazard model (Reference 282) (Figure 2.5-263) incorporates the ECFS-s as a distinct source geometry (also known as the zone of river anomalies [ZRA]); however, as described earlier, the USGS model truncates the northeastern extent of the proposed fault segment. The South Carolina Department of Transportation hazard model (Reference 504) also incorporates the ECFS-s as a distinct source geometry; however, this model extends the southern segment of the proposed East Coast fault system farther to the south than originally postulated by Marple and Talwani (2000) to include, in part, the distribution of liquefaction in southeastern South Carolina (Reference 503) (Figure 2.5-265).

In this ESP evaluation the area of Geometry C is restricted to envelope the original depiction of the ECFS-s by Marple and Talwani (2000). Truncation of the zone to the northeast as shown by the 2002 USGS model is not supported by available data, and the presence of liquefaction in southeastern South Carolina is best captured in Geometries B and B', rather than extending the ECFS-s farther to the south than defined by the data of Marple and Talwani (2000).

A low weight of 0.10 is assigned to Geometry C to reflect the assessment that Geometries B, B', and C all have equal, but relatively low, likelihood of producing Charleston-type earthquakes (Figure 2.5-267). As with the other UCSS geometries, Geometry C is represented as a series of parallel, vertical faults oriented northeast-southwest and parallel to the long axis of the narrow rectangular zone. The faults and extent of earthquake ruptures are confined within the rectangle depicting Geometry C.

UCSS Model Parameters

Based on studies by Bollinger et al. (1985, 1991) and Bollinger (1992), a 20-km-thick seismogenic crust is assumed for the UCSS. To model the occurrence of earthquakes in the characteristic part of the Charleston distribution (**M** > 6.7), the model uses a series of closely-spaced, vertical faults parallel to the long axis of each of the four source zones (A, B, B', and C). Faults and earthquake

ruptures are limited to within each respective source zone and are not allowed to extend beyond the zone boundaries, and ruptures are constrained to occur within the depth range of 0 to 20 km. Modeled fault rupture areas are assumed to have a width-to-length aspect ratio of 0.5, conditional on the assumed maximum fault width of 20 km. To obtain M_{max} earthquake rupture lengths from magnitude, the Wells and Coppersmith (1994) empirical relationship between surface rupture length and **M** for earthquakes of all slip types is used.

To maintain as much similarity as possible with the original EPRI model, the UCSS model treats earthquakes in the exponential part of the distribution (**M** < 6.7) as point sources uniformly distributed within the source area (full smoothing), with a constant depth fixed at 10 km.

2.5.2.2.2.4.2 UCSS Maximum Magnitude

The six EPRI ESTs developed a distribution of weighted M_{max} values and weights to characterize the largest earthquakes that could occur on Charleston seismic sources. On the low end, the Law Engineering team assessed a single M_{max} of m_b 6.8 to seismic sources it considered capable of producing earthquakes comparable in magnitude to the 1886 Charleston earthquake. On the high end, four teams defined M_{max} upper bounds ranging between m_b 7.2 and 7.5. For this ESP application, the m_b magnitude values have been converted to moment magnitude (**M**) as described previously. The m_b value and converted moment magnitude value for each team are shown below. The range in **M** for the six ESTs is 6.5 to 8.0.

Team	Charleston M_{max} range
Bechtel Group	m_b 6.8 to 7.4 (**M** 6.8 to 7.9)
Dames & Moore	m_b 6.6 to 7.2 (**M** 6.5 to 7.5)
Law Engineering	m_b 6.8 (**M** 6.8)
Rondout	m_b 6.6 to 7.0 (**M** 6.5 to 7.2)
Weston Geophysical	m_b 6.6 to 7.2 (**M** 6.5 to 7.5)
Woodward-Clyde Consultants	m_b 6.7 to 7.5 (**M** 6.7 to 8.0)

The **M** equivalents of EPRI m_b estimates for Charleston M_{max} earthquakes show that the upper bound values are similar to, and in two cases exceed, the largest modern estimate of **M** 7.3 ± 0.26 (Reference 339) for the 1886 earthquake. The upper bound values for five of the six ESTs also exceed the preferred estimate of **M** 6.9 by Bakun and Hopper (2004) for the Charleston event. The EPRI M_{max} estimates are more heavily weighted toward the lower magnitudes, with the upper bound magnitudes given relatively low weights by several ESTs (Tables 2.5-203 through 2.5-208). Therefore, updating the M_{max} range and weights to reflect the current range of technical interpretations is warranted for the UCSS.

Based on assessment of the currently available data and interpretations regarding the range of modern M_{max} estimates (Table 2.5-213), the UCSS model modifies the USGS magnitude distribution (Reference 282) to include a total of five discrete magnitude values, each separated by 0.2 **M** units (Figure 2.5-267). The UCSS M_{max} distribution includes a discrete value of **M** 6.9 to represent the Bakun and Hopper (2004) best estimate of the 1886 Charleston earthquake magnitude, as well as a lower value of **M** 6.7 to capture a low probability that the 1886 earthquake was smaller than the Bakun and Hopper (2004) mean estimate of **M** 6.9. Bakun and Hopper (2004) do not explicitly report a 1-sigma range in magnitude estimate of the 1886 earthquake, but do provide a 2-sigma range of **M** 6.4 to **M** 7.2.

The UCSS magnitudes and weights are as follows:

M	Weight	
6.7	0.10	
6.9	0.25	Bakun and Hopper (2004) mean
7.1	0.30	
7.3	0.25	Johnston (1996) mean
7.5	0.10	

This results in a weighted M_{max} mean magnitude of **M** 7.1 for the UCSS, which is slightly lower than the mean magnitude of **M** 7.2 in the USGS model (Reference 282).

2.5.2.2.2.4.3 UCSS Recurrence Model

In the 1989 EPRI study (Reference 514), the six EPRI ESTs used an exponential magnitude distribution to represent earthquake sizes for their Charleston sources. Parameters of the exponential magnitude distribution were estimated from historical seismicity in the respective source areas. This resulted in recurrence intervals for M_{max} earthquakes (at the upper end of the exponential distribution) of several thousand years.

The current model for earthquake recurrence is a composite model consisting of two distributions. The first is an exponential magnitude distribution used to estimate recurrence between the lower-bound magnitude used for hazard calculations and m_b 6.7. The parameters of this distribution are estimated from the earthquake catalog, as they were for the 1989 EPRI study. This is the standard procedure for smaller magnitudes and is the model used, for example, by the USGS 2002 national hazard maps (Reference 282). In the second distribution, M_{max} earthquakes (**M** $\geq$ 6.7) are treated according to a characteristic model, with discrete magnitudes and mean recurrence intervals estimated through analysis of geologic data, including paleoliquefaction studies. In this document, M_{max} is used to describe the range of largest earthquakes in both the characteristic portion of the UCSS recurrence model and the EPRI exponential recurrence model.

This composite model achieves consistency between the occurrence of earthquakes with **M** < 6.7 and the earthquake catalog and between the occurrence of large earthquakes (**M** $\geq$ 6.7) with paleoliquefaction evidence. It is a type of “characteristic earthquake” model, in which the recurrence rate of large events is higher than what would be estimated from an exponential distribution inferred from the historical seismic record.

M_{max} Recurrence

This section describes how the UCSS model determines mean recurrence intervals for M_{max} earthquakes. The UCSS model incorporates geologic data to characterize the recurrence intervals for M_{max} earthquakes. As described earlier, identifying and dating paleoliquefaction features provides a basis for estimating the recurrence of large Charleston area earthquakes. Most of the available geologic data pertaining to the recurrence of large earthquakes in the Charleston area were published after 1990 and therefore were not available to the six EPRI ESTs. In the absence of geologic data, the six EPRI EST estimates of recurrence for large, Charleston-type earthquakes were based on a truncated exponential model using historical seismicity (Reference 511; Reference 514). The truncated exponential model also provided the relative frequency of all earthquakes greater than m_b 5.0 up to M_{max} in the EPRI PSHA. The recurrence of M_{max} earthquakes in the EPRI models was on the order of several thousand years, which is significantly greater than more recently published estimates of about 500 to 600 years, based on paleoliquefaction data (Reference 461).

Paleoliquefaction Data

Strong ground shaking during the 1886 Charleston earthquake produced extensive liquefaction, and liquefaction features from the 1886 event are preserved in geologic deposits at numerous locations in the region. Documentation of older liquefaction-related features in geologic deposits provides evidence for prior strong ground motions during prehistoric large earthquakes. Estimates of the recurrence of large earthquakes in the UCSS are based on dating paleoliquefaction features. Many potential sources of ambiguity and/or error are associated with dating and interpreting paleoliquefaction features. This assessment does not reevaluate field interpretations and data; rather, it reevaluates criteria used to define individual paleoearthquakes in the published literature. In particular, the UCSS reevaluates the paleoearthquake record interpreted by Talwani and Schaeffer (2001) based on that study's compilation of sites with paleoliquefaction features.

Talwani and Schaeffer (2001) compiled radiocarbon ages from paleoliquefaction features along the coast of South Carolina. These data include ages that provide contemporary, minimum, and maximum limiting ages for liquefaction events. Radiocarbon ages were corrected for past variability in atmospheric ^{14}C using well established calibration curves and converted to "calibrated" (approximately calendric) ages. From their compilation of calibrated radiocarbon ages from various geographic locations, Talwani and Schaeffer (2001) correlated individual earthquake episodes. They identified an individual earthquake episode based on samples with a "contemporary" age constraint that had overlapping calibrated radiocarbon ages at approximately 1-sigma confidence interval. The estimated age of each earthquake was "calculated from the weighted averages of overlapping contemporary ages" (Reference 461) (p. 6,632). They defined as many as eight events (named 1886, A, B, C, D, E, F, and G in order of increasing age) from the paleoliquefaction record, and offered two scenarios to explain the distribution and timing of paleoliquefaction features (Table 2.5-214).

The two scenario paleoearthquake records proposed by Talwani and Schaeffer (2001) have different interpretations for the size and location of prehistoric events (Table 2.5-214). In their Scenario 1, the four prehistoric events that produced widespread liquefaction features similar to the large 1886 Charleston earthquake (A, B, E, and G) are interpreted to be large, Charleston-type events. Three events, C, D, and F, are defined by paleoliquefaction features that are more limited in geographic extent than other events and are interpreted to be smaller, moderate-magnitude events (approximately **M** 6). Events C and F are defined by features found north of Charleston in the Georgetown region, and Event D is defined by sites south of Charleston in the Bluffton area. In their Scenario 2, all events are interpreted as large, Charleston-type events. Furthermore, Events C and D are combined into a large Event C'. Talwani and Schaeffer (2001) justify the grouping of the two events based on the observation that the calibrated radiocarbon ages that constrain the timing of Events C and D are indistinguishable at the 95 percent (2-sigma) confidence interval.

The length and completeness of the paleoearthquake record based on paleoliquefaction features is a source of epistemic uncertainty in the UCSS. The paleoliquefaction record along the South Carolina coast extends from 1886 to the mid-Holocene (Reference 461). The consensus of the scientists who have evaluated these data (Reference 461; Reference 540; Reference 529) is that the paleoliquefaction record of earthquakes is complete only for the most recent about 2,000 years and that it is possible that liquefaction events are missing from the older portions of the record. The suggested incompleteness of the paleoseismic record is based on the argument that past fluctuations in sea level have produced time intervals of low water table conditions (and thus low liquefaction susceptibility), during which large earthquake events may not have been recorded in the paleoliquefaction record (Reference 461). While this assertion may be true, it cannot be ruled out that the paleoliquefaction record may be complete back to the mid-Holocene.

2-Sigma Analysis of Event Ages

Analysis of the coastal South Carolina paleoliquefaction record performed for the VEGP ESP application is based on the Talwani and Schaeffer (2001) data compilation. As described above, Talwani and Schaeffer (2001) use calibrated radiocarbon ages with 1-sigma error bands to define the timing of past liquefaction episodes in coastal South Carolina. The standard in paleoseismology, however, is to use calibrated ages with 2-sigma (95.4 percent confidence interval) error bands [e.g., (Reference 536; Reference 518)]. Likewise, in paleoliquefaction studies, to more accurately reflect the uncertainties in radiocarbon dating, the use of calibrated radiocarbon dates with 2-sigma error bands (as opposed to narrower 1-sigma error bands) is advisable (Reference 544). The Talwani and Schaeffer (2001) use of 1-sigma error bands may lead to over-interpretation of the paleoliquefaction record such that more episodes are interpreted than actually occurred. In recognition of this possibility, the conventional radiocarbon ages presented in Talwani and Schaeffer (2001) have been recalibrated and reported with 2-sigma error bands. The recalibration of individual radiocarbon samples and estimation of age ranges for paleoliquefaction events show broader age ranges with 2-sigma error bands which are used to obtain broader age ranges for paleoliquefaction events in the Charleston area.

Event ages based on overlapping 2-sigma ages of paleoliquefaction features are presented in Table 2.5-214. Paleoearthquakes have been distinguished based on grouping paleoliquefaction features that have contemporary radiocarbon samples with overlapping calibrated ages. Event ages have then been defined by selecting the age range common to each of the samples. For example, an event defined by overlapping 2-sigma sample ages of 100 to 200 cal yr BP and 50 to 150 cal yr BP would have an event age of 100 to 150 cal yr BP. The UCSS study considers the “trimmed” ages to represent the approximately 95 percent confidence interval, with a “best estimate” event age as the midpoint of the approximately 95 percent age range.

The 2-sigma analysis identified six distinct paleoearthquakes in the data presented by Talwani and Schaeffer (2001). As noted by that study, Events C and D are indistinguishable at the 95 percent confidence interval, and in the UCSS, those samples define Event C' (Table 2.5-214). Additionally, the UCSS 2-sigma analysis suggests that Talwani and Schaeffer (2001) Events F and G may have been a single, large event, defined in the UCSS as F’. One important difference between the UCSS result and that of Talwani and Schaeffer (2001) is that the three Events C, D, and F in their Scenario 1, which are inferred to be smaller, moderate-magnitude events, are grouped into more regionally extensive Events C’ and F’ (Table 2.5-214). Therefore, in the UCSS, all earthquakes in the 2-sigma analysis have been interpreted to represent large, Charleston-type events. The incorporation of large Events C’ and F’ into the UCSS model is, in effect, a conservative approach. In the effort to estimate the recurrence of M_{max} events (**M** 6.7 to 7.5), moderate-magnitude (about **M** 6) earthquakes C and D would be eliminated from the record of large (M_{max}) earthquakes in the UCSS model, thereby increasing the calculated M_{max} recurrence interval and lowering the hazard without sufficient justification. For these reasons the UCSS model uses a single, large Event C’ (instead of separate, smaller Events C and D) and a single, large Event F’ (instead of separate, smaller Events F and G). Analysis suggests that there have been four large earthquakes in the most-recent, about 2,000-year portion of the record (1886 and Events A, B, and C’). In the entire about 5,000-year paleoliquefaction record, there is evidence for six large, Charleston-type earthquakes (1886, A, B, C’, E, F’; Table 2.5-214). Figure 2.5-269 shows the geographic distribution of liquefaction features associated with each event in the UCSS model. The distributions of paleoliquefaction sites for Events A, B, C’, E, and F’ are all very similar to the coastal extent of the liquefaction features from the 1886 earthquake.

Recurrence intervals developed from the earthquakes recorded by paleoliquefaction features assume that these features were produced by large M_{max} events and that both the about 2,000-year and about 5,000-year records are complete. However, the UCSS mentions at least two concerns regarding the use of the paleoliquefaction record to characterize the recurrence of past M_{max} events. First, it is possible that the paleoliquefaction features associated with one or more of these pre-1886 events were produced by multiple moderate-sized events closely spaced in time. If this were the

case, then the calculated recurrence interval would yield artificially short recurrence for M_{max}, since it was calculated using repeat times of both large (M_{max}) events and smaller earthquakes. Limitations of radiocarbon dating and limitations in the stratigraphic record often preclude identifying individual events in the paleoseismologic record that are closely spaced in time (i.e., separated by only a few years to a few decades). Several seismic sources have demonstrated tightly clustered earthquake activity in space and time that are indistinguishable in the radiocarbon and paleoseismic record:

- New Madrid (1811, 1811, 1812)
- North Anatolian Fault (1999 and 1999)
- San Andreas Fault (1812 and 1857)

Therefore the UCSS acknowledges the distinct possibility that M_{max} occurs less frequently than what is calculated from the paleoliquefaction record.

A second concern is that the recurrence behavior of the M_{max} event may be highly variable through time. For example, the UCSS considers it unlikely that **M** 6.7 to **M** 7.5 events have occurred on a Charleston source at an average repeat time of about 500 to 600 years (Reference 461) throughout the Holocene Epoch. Such a moment release rate would likely produce tectonic landforms with clear geomorphic expression, such as are present in regions of the world with comparably high rates of moderate to large earthquakes (for example, faults in the Eastern California shear zone with sub-millimeter per year slip rates and recurrence intervals on the order of about 5,000 years have clear geomorphic expression (Reference 531). Perhaps it is more likely that the Charleston source has a recurrence behavior that is highly variable through time, such that a sequence of events spaced about 500 years apart is followed by quiescent intervals of thousands of years or longer. This sort of variability in inter-event time may be represented by the entire mid-Holocene record, in which both short inter-event times (e.g., about 400 years between Events A and B) are included in a record with long inter-event times (e.g., about 1,900 years between Events C' and E).

Recurrence Rates

The UCSS model calculates two average recurrence intervals covering two different time intervals, which are used as two recurrence branches on the logic tree (Figure 2.5-267). The first average recurrence interval is based on the four events that occurred within the past about 2,000 years. This time period is considered to represent a complete portion of the paleoseismic record based on published literature [e.g., (Reference 461)] and feedback from those researchers questioned (Reference 540; Reference 529). These events include 1886, A, B, and C' (Table 2.5-214). The average recurrence interval calculated for the most recent portion of the paleoliquefaction record (four events over the past about 2,000 years) is given 0.80 weight on the logic tree (Figure 2.5-267).

The second average recurrence interval is based on events that occurred within the past about 5,000 years. This time period represents the entire paleoseismic record based on paleoliquefaction data (Reference 461). These events include 1886, A, B, C', E, and F' as listed in Table 2.5-214. As mentioned previously, published papers and researchers questioned suggest that the older part of the record (older than about 2,000 years ago) may be incomplete. Whereas this assertion may be true, it is also possible that the older record, which exhibits longer inter-event times, is complete. The average recurrence interval calculated for the 5,000-year record (six events) is given 0.20 weight on the logic tree (Figure 2.5-267). The 0.80 and 0.20 weighting of the 2,000-year and 5,000-year paleoliquefaction records, respectively, reflect incomplete knowledge of both the current short-term recurrence behavior and the long-term recurrence behavior of the Charleston source.

The mean recurrence intervals for the most-recent 2,000-year and past 5,000-year records represent the average time interval between earthquakes attributed to the Charleston seismic source. The mean recurrence intervals and their parametric uncertainties were calculated according to the

methods outlined by Savage (1991) and Cramer (2001). The methods provide a description of mean recurrence interval, with a best estimate mean T_{ave} and an uncertainty described as a lognormal distribution with median $T_{0.5}$ and parametric lognormal shape factor $\sigma_{0.5}$.

The lognormal distribution is one of several distributions, including the Weibull, Double Exponential, and Gaussian, among others, used to characterize earthquake recurrence (Reference 510). Ellsworth et al. (1999a) and Matthews et al. (2002) propose a Brownian-passage time model to represent earthquake recurrence, arguing that it more closely simulates the physical process of strain build-up and release. This Brownian-passage time model is currently used to calculate earthquake probabilities in the greater San Francisco Bay region (Reference 547). Analyses show that the lognormal distribution is very similar to the Brownian-passage time model of earthquake recurrence for cases where the time elapsed since the most recent earthquake is less than the mean recurrence interval (Reference 508; Reference 510). This is the case for Charleston, where 120 years have elapsed since the 1886 earthquake and the mean recurrence interval determined over the past 2,000 years is about 548 years. The UCSS study has chosen to calculate average recurrence interval using a lognormal distribution because its statistics are well known (Reference 527) and it has been used in numerous studies [e.g.,(Reference 532; Reference 546; Reference 509)].

The average interval between earthquakes is expressed as two continuous lognormal distributions. The average recurrence interval for the 2,000-year record, based on the three most recent inter-event times (1886-A, A-B, B-C'), has a best estimate mean value of 548 years and an uncertainty distribution described by a median value of 531 years and a lognormal shape factor of 0.25. The average recurrence interval for the 5,000-year record, based on five inter-event times (1886-A, A-B, B-C', C'-E, E-F'), has a best estimate mean value of 958 years and an uncertainty distribution described by a median value of 841 years and a lognormal shape factor of 0.51. At one standard deviation, the average recurrence interval for the 2,000-year record is between 409 and 690 years; for the 5,000-year record, it is between 452 and 1,564 years. Combining these mean values of 548 and 958 years with their respective logic tree weights of 0.8 and 0.2 results in a weighted mean of 630 years for Charleston M_{max} recurrence.

The mean recurrence interval values used in the UCSS model are similar to those determined by earlier studies. Talwani and Schaeffer (2001) consider two possible scenarios to explain the distribution in time and space of paleoliquefaction features. In their Scenario 1, large earthquakes have occurred with an average recurrence of 454 ±21 years over about the past 2,000 years; in their Scenario 2, large earthquakes have occurred with an average recurrence of 523 ±100 years over the past 2,000 years. Talwani and Schaeffer (2001) state that, "In anticipation of additional data we suggest a recurrence rate between 500 and 600 years for **M** 7+ earthquakes at Charleston". For the 2,000-year record, the 1-standard-deviation range of 409 to 690 years completely encompasses the range of average recurrence interval reported by Talwani and Schaeffer (2001). The best-estimate mean recurrence interval value of 548 years is comarable to the midpoint of the Talwani and Schaeffer (2001) best-estimate range of 500 to 600 years. The best estimate mean recurrence interval value from the 5,000-year paleoseismic record of 958 years is outside the age ranges reported by Talwani and Schaeffer (2001), although they did not determine an average recurrence interval based on the longer record.

In the updated seismic hazard maps for the conterminous United States, Frankel et al. (2002) use a mean recurrence value of 550 years for characteristic earthquakes in the Charleston region. This value is based on the above-quoted 500 to 600 year estimate from Talwani and Schaeffer (2001). Frankel et al. (2002) do not incorporate uncertainty in mean recurrence interval in their calculations.

For computation of seismic hazard, discrete values of activity rate (inverse of recurrence interval) are required as input to the PSHA code (Cornell 1968). To evaluate PSHA based on mean hazard, the mean recurrence interval and its uncertainty distribution should be converted to mean activity rate with associated uncertainty. The final discretized activity rates used to model the UCSS in the PSHA

reflect a mean recurrence of 548 years and 958 years for the 2,000-year and 5,000-year branches of the logic tree, respectively. Lognormal uncertainty distributions in activity rate are obtained by the following steps: (1) invert the mean recurrence intervals to get mean activity rates; (2) calculate median activity rates using the mean rates and lognormal shape factors of 0.25 and 0.51 established for the 2,000-year and 5,000-year records, respectively; and (3) determine the lognormal distributions based on the calculated median rate and shape factors. The lognormal distributions of activity rate can then be discretized to obtain individual activity rates with corresponding weights.

2.5.2.2.2.5 Eastern Tennessee Seismic Zone

The Eastern Tennessee Seismic Zone (ETSZ) is one of the most active seismic zones in Eastern North America. This region of seismicity in the southern Appalachians is described in Subsection 2.5.1.1.4.6. Despite its high rate of activity, the largest known earthquake was magnitude 4.6 (Reference 505). No evidence for larger prehistoric earthquakes, such as paleoliquefaction features, has been discovered (Reference 505; Reference 482). While the lack of large earthquakes in the relatively short historical record cannot preclude the future occurrence of large events, there is a much higher degree of uncertainty associated with the assignment of Mmax for the ETSZ than other CEUS seismic source zones, such as New Madrid and Charleston, where large historical earthquakes are known to have occurred.

The EPRI source model (Reference 511) includes various source geometries and parameters to represent the seismicity of the ETSZ. All but one of the EPRI Earth Science Teams (ESTs) modeled local source zones to capture this area of seismicity and some ESTs included more than one zone. The Law team did not include a specific, local source for the ETSZ, however the ETSZ and Giles County seismic zones were included in a larger seismic source zone called the Eastern Basement (17). A wide range of Mmax values and associated probabilities were assigned to these sources to reflect the uncertainty of multiple experts from each EST. The moment magnitude (**M**) equivalents of body-wave magnitude (m_b) Mmax values assigned by the ESTs range from **M** 4.8 to 7.5. The Dames & Moore sources for the ETSZ included the largest upper-bound Mmax value of **M** 7.5. Sources from the Woodward-Clyde and Rondout teams were also assigned large upper-bound Mmax values of **M** 7.2.

Subsequent hazard studies have used Mmax values within the range of maximum magnitudes used by the six EPRI models. Collectively, upper-bound maximum values of Mmax used by the EPRI teams ranged from **M** 6.3 to 7.5. Using three different methods specific to the Eastern Tennessee seismic source, Bollinger (1992) estimated an M_{max} of **M** 6.3. The Bollinger (1992) model also included the possibility that the ETSZ was capable of generating a larger magnitude event and included an **M** 7.8 (m_b 7.37) with a low probability of 5% in the M_{max} distribution. The 5% weighted **M** 7.8 by Bollinger (1992) slightly exceeds the ERPI range, but the **M** 6.3 value was given nearly the entire weight (95%) in his characterization of the ETSZ. This smaller magnitude is much closer to the mean magnitude (about **M** 6.2) of the EPRI study. The Trial Implementation Project (TIP) (Reference 533) also provided a broad M_{max} distribution for the ETSZ. This study developed magnitude distributions for all ETSZ source zone representations that ranged from as low as **M** 4.5 to as high as **M** 7.5, with a mode of about **M** 6.5 for almost each distribution (Reference 533, pages F-12 to F-19 of Appendix F). The broad distribution of the TIP study magnitude distribution for the ETSZ source zones is very similar to the EPRI distribution of **M** 4.8 to **M** 7.5. The USGS source model assigns a single M_{max} value of **M** 7.5 for the ETSZ (Reference 282). The most recent characterizations of the ETSZ M_{max} by the USGS and TIP study consider **M** 7.5 as the largest magnitude in the distribution, and this magnitude is captured by the range of M_{max} values used in EPRI (NP-4726 1986). Therefore, it is concluded that no new information has been developed since 1986 that would require a significant revision to the EPRI seismic source model.

For the VEGP ESP site, the contribution to hazard from the ETSZ sources in the EPRI study was minimal. With the exception of the Law source 17 (Eastern Basement), none of the ETSZ sources

contributed more than one percent of the site hazard, and thus were excluded from the final hazard calculations (Reference 513). The ground motion hazard at the VEGP ESP site is dominated by the Charleston seismic source, and the inclusion of new recurrence values for Charleston based on paleoliquefaction serves to increase the relative contribution of Charleston with respect to any distant source, such as the ETSZ. No modifications to the EPRI parameters for ETSZ source zones were made as part of this ESP study.

2.5.2.3 Correlation of Seismicity with Geologic Structures and EPRI Sources

The final part of the review and update of the 1989 EPRI seismic source model was a correlation of updated seismicity with the 1989 model source. The EPRI seismicity catalog covers earthquakes in the CEUS through 1984, as described in Subsection 2.5.2.1. Figures 2.5-257 through 2.5-262 shows the distribution of earthquake epicenters from both the EPRI (pre-1985) and updated (post-1984 through April 2005) earthquake catalogs in comparison to the seismic sources identified by each of the EPRI ESTs.

Comparison of the additional events of the updated earthquake catalog to the EPRI earthquake catalog shows:

- There are no new earthquakes within the site region that can be associated with a known geologic structure.
- There are no unique clusters of seismicity that would suggest a new seismic source not captured by the EPRI seismic source model.
- The updated catalog does not show a pattern of seismicity that would require significant revision to the geometry of any of the EPRI seismic sources.
- The updated catalog neither shows nor suggests any increase in M_{max} for any of the EPRI seismic sources.
- The updated catalog does not imply a significant change in seismicity parameters (rate of activity, b-value) for any of the EPRI seismic sources (see also Subsection 2.5.2.4.2).

2.5.2.4 Probabilistic Seismic Hazard Analysis and Controlling Earthquakes

PSHA is an accepted method for determining seismic design levels (RG 1.165). The PSHA developed here relies on seismic source inputs from the EPRI-SOG study (Reference 514) which is accepted by the NRC (RG 1.165), on updates to those sources as described in Subsection 2.5.2.2, and on ground motion models (Reference 516) that have been accepted under other ESP applications.

The final GMRS ground motion for the VEGP ESP site is developed using a performance-based approach, which has as its foundation a well-justified PSHA for the VEGP ESP site. Ground motion levels corresponding to mean annual frequencies of exceedance (MAFEs) of 10^{-4} to 10^{-6} are developed, because this range encompasses the range of motions necessary to establish the GMRS ground motion under several criteria.

The seismic hazard at the VEGP ESP was first calculated using the assumptions of the EPRI (NP-6395-D 1989) study. This was to confirm that the 1989 results could be replicated. Then the seismic sources were updated with the UCSS models, including sources surrounding the Charleston source for each team, as described in Subsection 2.5.2.2.2 Also, the EPRI (1009684 2004) ground motion model was adopted for calculations of seismic hazard at seven structural frequencies. Sensitivity studies were conducted to determine the effects of these changes.

The seismic hazard was calculated for hard rock conditions for a range of ground motions corresponding to a range of annual frequencies of exceedance. This hard rock hazard formed the basis with which to integrate the effects of surficial materials on ground motion, to calculate the seismic hazard at a horizon appropriate for seismic design. The ASCE 43-05 2005 procedure was used to recommend an appropriate GMRS seismic spectrum. This procedure requires ground motion amplitudes and slopes of seismic hazard curves in the range of 10^{-4} to 10^{-5} mean annual frequency of exceedance. To obtain a full design spectrum from structural frequencies of 0.1 to 100 Hz, a smooth site-specific spectral shape was fit to the seven structural frequencies for which specific seismic hazard calculations were made.

2.5.2.4.1 Replication of 1989 EPRI Probabilistic Seismic Hazard Results

PSHA calculations were initially made using the original 1989 EPRI-SOG seismic sources and ground motion assumptions (Reference 514). The purpose of these calculations was to validate Risk Engineering Inc.'s (REI) proprietary FRISK88 seismic hazard code, the EPRI-SOG seismic sources, the EPRI-SOG source combinations, and the EPRI-SOG attenuation equations, as modeled by the FRISK88 code. The results used in this replication were the peak ground acceleration (PGA) results available for VEGP site (see Appendix E, Table 3-103 of Reference 514).

Seismic sources used to represent the seismic hazard for each of the six teams in the EPRI-SOG study are shown in Table 2.5-215. These are the primary sources used for the VEGP site in the original EPRI-SOG study, as documented in the EQHAZARD input files transmitted by EPRI.

The ground motion attenuation relations and their relative weights used in this analysis are those specified in the EPRI-SOG study (see Table 4-1 of Reference 514). Following Table 4-1 of EPRI NP-6395-D, a standard deviation of (log) amplitude of 0.5 was assumed for each ground motion equation. These equations were used to calculate hard rock hazard.

The VEGP site is classified in EPRI NP-6395-D 1989 as a "Soil V" site (see Table 2-2 of Reference 514). The site amplification factor versus PGA for this site class is shown in Figure 2-6 of EPRI NP-6395-D. To avoid having to apply site amplification factors to the rock curves, the results calculated here were compared to original EPRI-SOG hard rock results received from EPRI.

Results of this seismic hazard calculation are compared to the EPRI-SOG results in Table 2.5-216.

Agreement is excellent, generally within 5.1 percent in hazard for amplitudes up to 1g. For the 85 percent, replication is slightly less accurate, with a difference of -11.5 percent and -11.7 percent at 0.05g and 0.1g, respectively. This slight difference is of less concern, because the mean hazard curve is used to develop the GMRS ground motions. Comparison plots of the mean, median, and 85 percent PGA hazard curves are shown in Figures 2.5-270 through 2.5-272.

This comparison validates the FRISK88 code, the EPRI-SOG seismic sources, the EPRI-SOG source combinations, and the EPRI-SOG attenuation equations.

2.5.2.4.2 Effects of New Regional Earthquake Catalog

The effects of the new regional earthquake catalog were examined by comparing seismicity rates in two regions critical to seismic hazard at the VEGP ESP site: the Charleston, South Carolina, region and the local region in South Carolina and into Georgia around the VEGP ESP site. The importance of these regions to seismic hazard is addressed in Subsection 2.5.2.4.6. The effects of two seismicity catalogs were compared: (1) the EPRI-SOG (Reference 512) earthquake catalog (through 1984) and (2) the EPRI-SOG catalog updated to include more recent seismicity (Subsection 2.5.2.1). The fundamental question to be addressed is whether or not the seismicity recorded since 1984 indicates

that the seismic activity rates used in the EPRI-SOG study (Reference 514) are inadequate or insufficiently conservative for assessment of the seismic hazard at the VEGP ESP site.

Seismicity rates were assessed for two sources in the site region, as follows: (1) a small rectangular source around the Charleston seismicity and (2) a triangular-shaped source representing seismicity in South Carolina and a strip of Georgia incorporating the VEGP ESP site. Figure 2.5-273 shows a map of these two sources, along with the earthquakes from the EPRI-SOG catalog and from the updated catalog.

The seismicity in these two sources was investigated by running program EQPARAM (from the EPRI EQHAZARD package), first for the original EPRI catalog and then using the updated EPRI catalog (through April 2005). Full smoothing of a- and b-values was selected for the comparison because this was a common choice of many of the ESTs in the EPRI-SOG study. Further, if comparisons were made on an individual degree-cell basis, the rates in some cells might increase and in others might decrease; furthermore, for a source such as the triangular South Carolina source, a composite rate would have to be used to compare seismic rates using the earthquake catalog through 1984 to those using the earthquake catalog through April 2005. The choice of full smoothing achieves this composite rate directly and automatically, since it is a composite rate for the entire source.

From the a- and b-values calculated with EQPARAM, recurrence rates were calculated for different magnitudes. Figures 2.5-274 and 2.5-275 compare the annual recurrence rates for the Charleston source and for the triangular South Carolina source, respectively. For the rectangular Charleston source, the updated catalog indicates that seismicity rates are about the same. For the triangular South Carolina source, the updated catalog indicates that seismicity rates have decreased when the seismicity from 1985 to April 2005 is added.

The conclusion is that the seismicity recorded since 1984 does not indicate that seismic activity rates have increased in those sources contributing most to the hazard at the VEGP ESP site under the assumptions of the EPRI-SOG study. Therefore, for original sources of the EPRI-SOG teams and the original seismicity rates from the EPRI-SOG (Reference 512) earthquake catalog (through 1984) were used here for calculations of seismic hazard. These rates give an accurate estimate of seismicity for Charleston sources, and are slightly conservative for local sources, when compared to rates from the updated (through April 2005) catalog. Where the geometries of EPRI-SOG sources were modified to account for new information on the Charleston earthquake source (see Subsection 2.5.2.4.4 below), new seismicity rates were calculated using the updated earthquake catalog (through April 2005) in order to use the most recent information available.

2.5.2.4.3 New Maximum Magnitude Information

Geological and seismological data published since the 1986 EPRI seismic source model are presented in Subsection 2.5.1. Based on a review of these data, there are no significant changes in the EPRI M_{max} parameters, with the exception of the Charleston seismic source. A summary of M_{max} values for each EPRI EST is provided in Tables 2.5-203 through 2.5-208.

Changes to M_{max} for the Charleston seismic source are discussed in Subsection 2.5.2.2.2 and in a separate Engineering Study Report (Reference 498).

2.5.2.4.4 New Seismic Source Characterizations

The effect of new geoscience information is to modify the interpretations for the Charleston seismic source. The EPRI-SOG teams used an exponential model to represent earthquakes for sources in the Charleston area, and some teams adopted interpretations that included (with a low weight) the possibility that a specific Charleston source did not exist (i.e., that large earthquakes could occur in a large region in the eastern US). The new interpretation of the Charleston source (see

Subsection 2.5.2.2.2) indicates that a unique source of large earthquakes exists with weight 1.0 and that large magnitudes occur with a rate of occurrence unrelated to the rate of smaller magnitudes. Typical recurrence intervals for large Charleston earthquakes for the EPRI-SOG teams were on the order of 2,000 years, whereas the new information indicates recurrence intervals of 500 to 1,000 years.

In addition, the geometry of the Charleston sources has changed. Some EPRI-SOG teams drew relatively broad zones within which a Charleston-size earthquake could occur or specified (under some interpretations) that Charleston-size earthquakes were not restricted to southeast South Carolina but could occur over broad areas. The new geologic and tectonic information presented in Subsection 2.5.2.2.2 describes a relatively restricted zone within which Charleston-size earthquakes are modeled.

These changes in rate of occurrence and location of Charleston sources generally have the effect of increasing seismic hazard at the VEGP ESP site, compared to the EPRI-SOG study. It is not possible to determine the specific effect of one change, because (for example) changing the geometry of the Charleston source affects the geometries and seismicity rates of local sources and background sources for each EPRI-SOG team. The total effect of the new geoscience information is taken into account in the revised PSHA results presented in Subsection 2.5.2.4.6.

Figure 2.5-276 (reproducing Figure 2.5-265 content relevant to this discussion) shows the geometry of the four sources used to characterize the Charleston seismic source (Subsection 2.5.2.2.2).

To update the EPRI-SOG model, these four geometries of the Charleston source were overlaid onto each of the six EPRI-SOG team sources, and new geometries were created for all EPRI-SOG team sources surrounding the Charleston source. Figure 2.5-277 shows an example of the original geometry, and Figures 2.5-278 through 2.5-281 show the new geometries created for the Rondout team, source 26. The purpose in creating the new geometries was to ensure that, in incorporating the new Charleston sources, no area was left without seismicity. Seismicity parameters for the new EPRI-SOG team source geometries were calculated using the same methodology and same smoothing assumptions as in the EPRI-SOG project and using the updated seismicity catalog (through April 2005). This procedure ensured that the principles underlying the seismicity representations for each EPRI-SOG team source surrounding Charleston were maintained.

The four geometries used to represent the Charleston source were modeled, for seismic hazard calculations, with parallel faults striking northeast-southwest and spaced at 10 km intervals. This spacing was narrow enough not to affect the calculated hazard (i.e., a spacing of 5 km would not have produced significantly different results). Activity rates for the faults were equally divided among the faults, and they were represented as vertical faults from the surface to a depth of 20 km. A rupture length equation (given magnitude) was used to represent a finite rupture length, and an aspect ratio (width-to-length) of 0.5 was assumed. The specific equation selected was for surface rupture length for all rupture types from Wells and Coppersmith (1994).

A characteristic earthquake was modeled for the new Charleston source geometries, with the following magnitudes and weights (Figure 2.5-267):

M	Weight
6.7	0.1
6.9	0.25
7.1	0.3
7.3	0.25
7.5	0.1

The magnitudes and weights were discussed in Subsection 2.5.2.2.2.4.2 The rate of occurrence of the characteristic earthquake was modeled with two 5-point discrete distributions representing (respectively) the 2,000-year and 5,000-year paleoliquefaction intervals described in Subsection 2.5.2.2.2.4.3. These distributions are as follows:

2,000-Year Interval		5,000-Year Interval	
Activity Rate	Weight	Activity Rate	Weight
1.22×10^{-3}	0.101	3.65×10^{-4}	0.101
1.45×10^{-3}	0.244	6.12×10^{-4}	0.244
1.77×10^{-3}	0.310	9.20×10^{-4}	0.310
2.16×10^{-3}	0.244	1.38×10^{-3}	0.244
2.78×10^{-3}	0.101	2.32×10^{-3}	0.101

These distributions give mean activity rates of 1.823×10^{-3} and 1.044×10^{-3}, respectively, which correspond to recurrence intervals of 548 years and 958 years, and have logarithmic shape factors of 0.25 and 0.51, as described in Subsection 2.5.2.2.2.4.3.

In addition to the characteristic earthquake, smaller earthquakes were modeled for each of the four source geometries for magnitudes between the lower-bound magnitude ($m_b = 5.0$) and M_{max} value of $m_b = 6.7$, with an exponential magnitude distribution. The activity rate and b-value for this distribution were determined using the EPRI-SOG catalog, EQPARAM software, and full smoothing of seismicity parameters across the source. For this exponential model, the rectangular geometries of the Charleston sources were assumed (see Figure 2.5-276), with earthquakes uniformly distributed within the source.

The source combinations of the EPRI-SOG teams were reviewed and modified to accurately incorporate the four new Charleston seismic sources into each team's model. This generally resulted in four times as many source combinations, because a single Charleston source was being replaced by four alternative Charleston sources. As an example, the Rondout team originally had one source combination applicable to the VEGP ESP site:

Source Combination	Weight	Sources
1	1.0	26, 24

The revised model for the Rondout team had four source combinations applicable to the VEGP ESP site:

Source Combination	Weight	Sources
1	0.7	Charleston-A, 26-A
2	0.1	Charleston-B, 26-B
3	0.1	Charleston-B´, 26-B´
4	0.1	Charleston-C, 26-C

where, for example, "26-A" indicates Rondout source 26 with new Charleston source geometry A removed. See Figures 2.5-278 through 2.5-281 for maps of these source geometries.

Incorporating this new geoscience information into the PSHA for the VEGP ESP site ensures that the PSHA results reflect the most recent information and interpretations of seismicity in the southeastern US. This provides a strong basis for the GMRS ground motions.

2.5.2.4.5 New Ground Motion Models

The ground motion models developed by the 2004 EPRI-sponsored study (Reference 516) were used to examine the effects on seismic hazard of current estimates of seismic shaking as a function of earthquake magnitude and distance. For general area sources, nine estimates of median ground motion are combined with four estimates of aleatory uncertainty, giving 36 combinations. For fault sources in rifted regions, which applies to the ECFS fault segments, 12 estimates of median ground motion are combined with four estimates of aleatory uncertainty, giving 48 combinations. When both area sources and faults are active, a specific correlation of area source models and fault source models is used to represent ground motion models that might apply together. These families of models (36 for area sources, 48 for fault sources) represent the epistemic uncertainty in ground motion, and contribute to the epistemic uncertainty in seismic hazard.

Conclusions regarding a comparison of the EPRI NP-6395-D (1989) ground motion models with the EPRI 1009684 (2004) ground motion models depend on the specific magnitude, distance, and structural frequency being compared. Some comparison plots are shown in EPRI 1009684. In general, median ground motion amplitudes are similar at high frequencies. At low frequencies, the EPRI 1009684 models show lower median ground motions, because these models incorporate the possibility of a two-corner seismic source. Seismic hazard is affected by the median ground motion and also by the standard deviation. The EPRI 1009684 standard deviations are universally higher than those of EPRI NP-6395-D, which leads to higher seismic hazards.

2.5.2.4.6 Updated EPRI Probabilistic Seismic Hazard Analysis, Deaggregation, and 1 Hz, 2.5 Hz, 5 Hz, and 10 Hz Spectral Accelerations Incorporating Significant Increases Based on the Above Sensitivity Studies

Sensitivity studies were conducted to determine which magnitudes and distances contribute most to the seismic hazard at the VEGP ESP site. This was done following the guidelines of RG 1.165, modified for use in calculating GMRS spectra using a performance-based procedure. Specifically, the seismic hazard was deaggregated at mean annual frequencies of exceedance (MAFEs) of 10^{-4}, 10^{-5}, and 10^{-6}. Deaggregations were conducted for two sets of spectral frequencies: a “high-frequency” (HF) set consisting of 10 Hz and 5 Hz and a “low-frequency” (LF) set consisting of 2.5 Hz and 1 Hz. Figure 2.5-282 shows a mean uniform hazard spectrum (UHS) for hard rock conditions at the VEGP ESP site for several MAFEs from 10^{-4} to 10^{-6}, and Table 2.5-217 lists the values of the mean UHS for hard rock conditions for these MAFEs for frequencies of 100 Hz (PGA), 25 Hz, 10 Hz, 5 Hz, 2.5 Hz, 1 Hz, and 0.5 Hz.

Figures 2.5-283 through 2.5-288 show the hard rock magnitude-distance deaggregations for three MAFEs and for the high- and low-frequency sets. For the low frequencies, earthquakes from the Charleston sources dominate the hazard at all MAFEs considered. For the high frequencies, local earthquakes contribute substantially to the hazard at 10^{-5} and dominate the contribution to hazard at the 10^{-6} MAFE level.

Figures 2.5-289 and 2.5-290 show marginal magnitude distributions for hard rock PSHA from the deaggregations for high- and low-frequencies, respectively, for the three MAFEs. For the low frequencies, the large earthquakes from the Charleston dominate the hazard at all three MAFEs. For the high frequencies, large earthquakes dominate 10^{-4} but the smaller earthquakes dominate 10^{-6}.

Figures 2.5-291 and 2.5-292 show marginal distance distributions for hard rock PSHA from the deaggregations for high- and low-frequencies, respectively, for the three MAFEs. These deaggregations are consistent with those for magnitude, in terms of the contribution of large earthquakes from the Charleston sources.

The contribution of the Charleston sources to hazard can be understood by plotting and comparing hazard curves from individual sources. Figure 2.5-293 shows such a comparison, using as an example the sources from the Rondout team (which is the simplest interpretation). Figure 2.5-293, for 10 Hz spectral acceleration, shows that the main Charleston source (geometry A, marked “C-A” in Figure 2.5-293, with a weight of 0.7) dominates for MAFEs of 10^{-3} to 10^{-4} but that the local source “RND-26-A” dominates for lower MAFEs (below about 3 x 10^{-5}). At the 10^{-6} MAFE, most of the contribution to total hazard is from the local source. Figure 2.5-294, showing hazard curves for the Rondout team for 1 Hz spectral acceleration, indicates that the Charleston sources dominate the total hazard at all MAFEs (at least above 10^{-7}). Note that in both Figures 2.5-293 and 2.5-294, the mean hazard curve for each source includes the probability that source is active. Thus, the hazard curves for Charleston sources B, B´, and C (labeled C-B, C-B´, and C-C) are lower than the hazard curve for Charleston source A (labeled C-A), primarily because the former three have much lower probabilities of activity than does source A.

These results indicate that seismic sources representing earthquakes in the Charleston region have a large contribution to seismic hazard for hard rock conditions at the VEGP ESP site. The local seismic source representing seismicity in South Carolina also can have an important contribution to hazard for high frequency ground motion, particularly for MAFEs around 10^{-5} and lower.

2.5.2.5 Seismic Wave Transmission Characteristics of the Site

The uniform hazard spectra described in the preceding section are defined on hard rock (shear-wave velocity of 9,200 ft/sec), which is located more than 1,000 ft below the current ground surface at the VEGP ESP site. The subsurface materials at the VEGP ESP site are described in detail in Subsection 2.5.1. The material characterization is summarized in the following groups:

I. Upper Sand Stratum (Barnwell Group) – predominantly sands, silty sands, and clayey sands, with occasional clay seams. A Shelly Limestone (Utley Limestone) layer was encountered at the base of the Upper Sand Stratum or the top of the Blue Bluff Marl. The limestone contains solution channels, cracks, and discontinuities, and was the cause of severe fluid loss observed during drilling for the VEGP ESP site subsurface investigation.

II. Marl Bearing Stratum (Blue Bluff Marl or Lisbon Formation) – slightly sandy, cemented, calcareous clay.

III. Lower Sand Stratum (comprises several formations from the Still Branch just beneath the Blue Bluff Marl to the Cape Fear just above the Dunbarton Triassic Basin rock) – fine to coarse sand with interbedded silty clay and clayey silt.

IV. Dunbarton Triassic Basin Rock – red sandstone, breccia, and mudstone, weathered along the upper 120 ft.

V. Paleozoic Crystalline Rock – a competent rock with high shear-wave velocity that underlies the Triassic Basin rock. The non-capable Pen Branch fault forms the boundary between the Triassic Basin and Paleozoic basement rocks (see Subsection 2.5.1.2.4 for a detailed discussion of the Pen Branch fault).

The Upper Sand Stratum (Barnwell Group) will be removed because it is not considered competent material. It is susceptible to liquefaction (Subsection 2.5.4.8) and dissolution-related ground deformation (Subsection 2.5.3.8.2); also the shear-wave velocity of the Upper Sand Stratum is generally below 1000 ft/sec, see Table 2.5-218.

All safety-related structures will be founded on structural backfill that will be placed on top of the Blue Bluff Marl after complete removal of the Upper Sand Stratum. The structural fill will be a sandy or silty

sand material following the guidelines used during construction of VEGP Units 1 and 2. The properties of this structural backfill are described in Subsection 2.5.4.2.

The GMRS is defined at the free ground surface of this site-specific rock, soil, fill column. The FIRS is defined as hypothetical outcrop motion at the 40-ft depth horizon within this column. The highest in situ competent material for the VEGP ESP site is the Blue Bluff marl at 86-ft depth.

To determine the GMRS, FIRS, and 86-ft depth horizon ground motions, it is necessary to adjust the uniform hazard hard rock spectra (presented in Subsection 2.5.2.4) for amplification or deamplification as vibratory ground motion is propagated through the subsurface materials above the 9,200 ft/s shear-wave velocity horizon. This section describes the analyses performed to develop site amplification functions associated with the different hard rock ground motions presented in Subsection 2.5.2.4. These site amplification factors are used in Subsection 2.5.2.6 (GMRS, FIRS, and top of Blue Bluff Marl) along with the hard rock ground motions to develop site-specific ground motions at these three horizons.

2.5.2.5.1 Development of Site Amplification Factors

2.5.2.5.1.1 Methodology

The method adopted here to account for the effects of surficial soils on seismic hazard follows the procedure in NUREG/CR-6728 and NUREG/CR-6769 (Reference 525**,** Reference 526), described as “Approach 2A.” This procedure requires 6 steps:

1. The seismic hazard is calculated for hard rock conditions for the seven structural frequencies, over a range of ground motion amplitudes, resulting in a range of annual frequencies of exceedance.

2. For ground motion amplitudes corresponding to annual frequencies of 10^{-4}, 10^{-5}, and 10^{-6}, the seismic hazard is deaggregated for high frequencies (HF) and low frequencies (LF), as described in Subsection 2.5.2.4.6, to determine the dominant magnitudes and distances for those amplitudes and frequencies.

3. HF hard rock spectra are developed to represent earthquakes dominating the 5-10 Hz ground motions, and LF hard rock spectra are developed to represent earthquakes dominating the 1-2.5 Hz ground motions. These hard rock spectra represent the mean magnitude and distance of earthquakes that dominate the seismic hazard for those structural frequencies.

4. The rock and soil column is modeled, and soil amplitudes are calculated for input hard rock motions corresponding to frequencies of exceedance of 10^{-4}, 10^{-5}, and 10^{-6}. These calculations are made separately for ground motions dominating the HF hard rock motion and the LF hard rock motion, and the input motions have a spectrum determined by the HF or LF hard rock spectral shape, as appropriate. Multiple hard rock motions are used, and multiple soil column properties are used, so that the mean soil amplitudes can be determined accurately.

5. The soil amplification factors (AFs) are developed at 300 frequencies using analyses described in this section based on the HF and LF hard rock spectral shapes. The AFs for a given horizon represent the mean spectral acceleration (SA) at that horizon, divided by input SA at hard rock, at each frequency. At each frequency, the envelope motion is determined. This is the motion (HF or LF) that gives the higher mean soil motion, for that structural

frequency and MAFE. At frequencies above 8 Hz, this is always the HF motion. At frequencies below 2 Hz, this is always the LF motion. At intermediate frequencies, the envelope motion depends on the frequency and the MAFE.

6. The uniform hazard response spectra at MAFEs of 10^{-4} and 10^{-5} at each horizon are calculated as follows. Starting from the 10^{-4} and 10^{-5} SA hard rock values (from the hazard calculations described in Subsection 2.5.2.4) at the seven structural frequencies, interpolation is performed between those SA values to obtain 10^{-4} and 10^{-5} SA values at the 300 structural frequencies using the HF and LF spectral shapes for hard rock. The choice of HF or LF is based on the envelope motion determined in the previous step. The UHS for 10^{-4} at each horizon is calculated by multiplying the hard rock 10^{-4} SA values at the 300 frequencies by the mean AFs for 10^{-4} from step 5, again using the HF or LF mean AF corresponding to the envelope motion. (At some intermediate frequencies between 2 and 8 Hz, the HF and LF AFs are weighted in order to achieve a smooth transition between HF and LF spectra.) The UHS for 10^{-5} is calculated in a similar way, using the 10^{-5} rock SA values and the 10^{-5} AFs.

This gives an accurate calculation of the soil hazard at each horizon. In step 3, it is sufficiently accurate to use the mean magnitude to generate spectral shapes for the HF and LF spectra (Approach 2A of NUREG/CR-6728 and NUREG/CR-6769 (Reference 525, Reference 526). Using multiple magnitudes (Approach 2B of NUREG/CR-6728 and NUREG/CR-6769) does not materially affect the calculated soil spectra, as documented in NUREG/CR-6769 (Reference 526).

From the 10^{-4} and 10^{-5} SA values at each horizon, spectra are calculated using the procedure recommended by ASCE 43-05 2005. This procedure is used to establish the spectral amplitudes at the 300 structural frequencies. To obtain final horizontal spectra smoothing of the raw spectral shape is performed as described in Subsection 2.5.2.6.3.

2.5.2.5.1.2 Base Case Soil/Rock/Fill Column and Uncertainties

Development of a base case rock/soil/fill column, is described in Subsection 2.5.1. Summaries of the low strain shear wave velocity, material damping, and strain-dependency properties of the base case materials, as these parameters are used in the site response analyses, are provided below in Subsection 2.5.2.5.1.2.1. Subsection 2.5.2.5.1.2.2 describes the methodology and results of randomization to address the uncertainties in rock/soil/fill column parameters. Additional subsurface data in the power block has been collected for the COL site investigation. These data are presented in Subsection 2.5.1. The COL information includes RCTS testing and measurements of dynamic properties of the proposed backfill. Subsection 2.5.2.9.3 presents an evaluation of the effects of the combined COL and ESP geotechnical data on site response to determine its significance on site response.

2.5.2.5.1.2.1 Base Case Rock/Soil/Fill Column

2.5.2.5.1.2.1.1 Soil Column

The base case shear-wave velocity model for the soil column is provided in Figure 2.5-378, and the corresponding values are listed in Table 2.5-251. Additional shear-wave velocity data have been collected for the COL site investigation of the in-situ material. Figure 2.5-379 shows the base case shear-wave velocity model for the combined COL and ESP data. The COL plus ESP data shear-wave velocity model is not used to develop the ESP site amplification factors. This is discussed further below. The base case assumes that the uppermost 86 feet of native material will be excavated and replaced with structural fill. Shear-wave velocity was not measured for the compacted backfill during the ESP subsurface investigation (Appendix 2.5A). Interpolated values based on measurements made on fill for existing Units 1 and 2 **(Bechtel 1984)** are used instead. The backfill

shear-wave velocity values are summarized in Table 2.5-249 (these values are also included in Table 2.5-251).

The variation with strain of shear modulus and damping of the soil were developed for two sets of degradation relationships:

- Based on relationships developed for EPRI (Reference 515) and
- Based on relationships developed for SRS (Reference 519).

Site-specific soil degradation and damping ratio curves were developed as part of the COL site investigation. These curves are presented in Figures 2.5-382 and 2.5-385, respectively.

The EPRI relationships are widely used and accepted in the industry and, while the SRS curves were developed for the adjacent SRS site, the Blue Bluff Marl soil unit at the ESP site has higher velocities than the corresponding soil unit at the SRS site. Analyses are performed for both sets of degradation curves and equally weighted in developing the final spectral amplification factors. Details of the derivation and extension of the degradation curves are presented in Subsection 2.5.4.7.2.

The base case degradation curves for shear modulus and damping for the EPRI-based assumption are presented in Figures 2.5-381 and 2.5-384, respectively. The base case degradation curves for shear modulus and damping for the SRS-based assumption are presented in Figures 2.5-383 and 2.5-386, respectively. The corresponding tables of values are presented in Tables 2.5-254 and 2.5-256, for the EPRI-based and SRS-based relationships, respectively.

Unit weights, derived from the ESP laboratory testing program (Appendix 2.5A) for the shallow soils and calculation (Reference 548) for the deep sands, are provided in Table 2.5-241.

2.5.2.5.1.2.1.2 Rock Column

Due to the geometry of the Pen Branch fault, the shear-wave velocity character of the Triassic Basin and Paleozoic crystalline rocks below the Coastal Plain sediments, and the possible presence of a low velocity zone between the Triassic Basin and the Paleozoic crystalline rocks, a set of six (6) rock column models were used in combination with the base case soil column, described above, to adequately model uncertainty in the rock/soil column for site response analysis.

As discussed in Subsection 2.5.4.2.5, a rock density of 2.75 gm/cc (172 pcf) is used for the crystalline rock, and 2.53 gm/cc (158 pcf) for the Triassic rock. Based on inspection of Figures 2.5-384 and 2.5-386, the low strain damping of soils is on the order of 0.5 percent, which generally increases to 0.6 percent to 2 percent for strain compatible conditions. Rock, which would be expected to have lower damping than soil, was therefore assumed to behave as a linearly elastic material with one percent damping for all rock types.

The above-described shear-wave velocity profile, degradation relationships, and material densities were then used to develop randomized soil/rock profiles described in the following section.

2.5.2.5.1.2.2 Randomization of Site Profiles

To account for variations in shear-wave velocity across the site, sixty artificial profiles were generated using the stochastic model described in EPRI (Reference 515) and extended in Toro (1996), with some modifications to account for the conditions at the VEGP ESP site. These artificial profiles represent the soil/rock/fill column from the top of the Paleozoic crystalline rock (with a shear-wave velocity of 9,200 feet/s) to the ground surface. This model uses as inputs the following quantities: (1) the median shear-wave velocity profile, which is equal to the base-case soil and rock profiles defined

in Subsections 2.5.2.5.1.2.1.1 and 2.5.2.5.1.2.1.2; (2) the logarithmic standard deviation of shear-wave velocity as a function of depth, which is set to 10 percent for the structural backfill, is set to values obtained from soil-randomization studies performed at the SRS site (Reference 542; Reference 543) for the soil strata, and is set to values consistent with the six rock-column models described in Subsection 2.5.2.5.1.2.1.2; (3) the correlation coefficient between velocities in adjacent layers, which is taken from the second SRS soil-randomization study referenced above; (4) the probabilistic characterization of layer thickness as a function of depth, which is taken from the second SRS soil-randomization study referenced above, modified to allow for sharp changes in the base-case velocity profile; and (5) the depth to bedrock, which is randomized to account for the range of depths associated with the Pen Branch fault described in Subsection 2.5.2.5.1.2.1.2.

Figure 2.5-295 depicts the summary statistics for the 60 shear-wave velocity profiles. It is worth noting that the depth to the Blue Bluff Marl and to the Triassic Basin rock vary little between the profiles, and that the logarithmic standard deviation in shear-wave velocity is lower than typical values (e.g., Reference 541). These features are a consequence of the availability of shear-wave velocity data from the VEGP ESP site and from the nearby SRS, and of the uniformity exhibited by these data. As a consequence of this uniformity, the average amplification factors computed from site-response calculations using these profiles may not be as smooth as those obtained using artificial profiles with more variability.

Figure 2.5-296 shows the upper part of the soil column shear wave velocity profile. The ESP base case shear-wave model is shown in red, each of the 60 individual randomizations used in the site amplification factor analysis are shown in light gray lines, and the statistical characterization of the randomization is shown in black lines. In addition, the COL plus ESP shear-wave velocity base case model is shown in turquoise. The COL plus ESP shear-wave velocity model falls well within the range of randomized ESP base case velocity models. Pending additional COL data on site-specific soil degradation and damping ratio curves and measured dynamic properties for the proposed backfill, the differences in the ESP to ESP plus COL soil column shear wave velocity do not warrant at this time recalculation of site amplification factors and the GMRS.

The degradation curves for shear modulus and damping were also randomized to account for the epistemic and aleatory uncertainty in these properties. These randomizations used as input the following quantities: (1) the median degradation curves, which are equal to the base-case degradation curves in Subsections 2.5.2.5.1.2.1.1 and 2.5.2.5.1.2.1.2; (2) the uncertainties in the degradation properties of soil, which are taken from Costantino (1996), except for the engineered backfill, for which they are reduced by 1/3; and (3) the uncertainty in the damping ratio for the Triassic Basin rock, which is represented by a 5-95 percentile range of 0.7-1.5, which corresponds to a logarithmic standard deviation of 0.41. For each randomized velocity profile, one set of randomized degradation curves was generated for the EPRI curves and another set was generated for the SRS curves.

2.5.2.5.1.3 Development of Low-Frequency and High-Frequency Hard Rock Target Spectra

Hard rock target spectra were developed for the two different frequency ranges: HF (5-10 Hz) and LF (1-2.5 Hz), as defined in Reg. Guide 1.165, at each of three annual probability levels (10^{-4}, 10^{-5}, and 10^{-6}). The target spectra are based on the computed mean magnitude (Mbar) and distance (Dbar) values from the deaggregation of the hazard curves. For the HF cases (5-10 Hz), only those sources less than 105 km were used to compute the Mbar and Dbar values. For the LF cases (1-2.5 Hz), only those sources at distances greater than 105 km from the site were used to compute the Mbar and Dbar values. This distinction was made based on the noted dominance of the Charleston source for low frequencies and long return periods. The computed Mbar and Dbar results were based on the average of the 5 – 10 Hz values for the HF cases and the average of the 1 – 2.5 Hz for the LF cases. These computed values are given in Table 2.5-218. Based on the similar Mbar and Dbar values for

each of the three probability levels for the HF and LF cases, a single recommended Mbar and Dbar pair was selected to represent the computed values for each of the HF and LF cases. For the LF case, the recommended distance was set at 130 km to model the Charleston source. For the HF case, the recommended distance is approximately equal to the log-average of the three computed values rounded to the nearest km. The recommended magnitude value is approximately equal to the linear average of the three computed magnitude values. The recommended magnitude values for both the high- and low-frequency cases are equal to the linear average of the three magnitude values rounded to the nearest tenth of a magnitude unit.

Given the Mbar and Dbar values, the Central and Eastern United States spectral shape (log-average of the single and double corner source models) from NUREG/CR-6728 (Reference 525) were computed for both the HF and LF cases. These spectral shapes were scaled to the corresponding uniform hazard spectral (UHS) values (see Table 2.5-217) at 7.5 Hz and 1.75 Hz for the HF and LF cases, respectively. An additional requirement that the envelop spectrum of the scaled target spectra for a given annual probability level be no less than 90 percent of the UHS was applied. In any case for which this requirement was not met, either the scaled HF or LF target spectrum was increased to meet this requirement at the seven frequencies at which the hard rock UHS is computed. For the HF case, this requirement caused an increase of the 25 Hz spectral acceleration value at the 10^{-6} probability level. For the LF case at all three probability levels, the scaled LF spectra fall below the 90 percent UHS limit at 1 and 0.5 Hz. Thus, the scaled LF spectra were increased to 90 percent of the UHS value for the 1 and 0.5 Hz values, and for frequencies less than 0.5 Hz, the spectral shape of the LF spectrum scaled to the 90 percent of the 0.5 Hz UHS value was used.

The scaled hard rock target spectra were interpolated (log-log) to the recommended sampling rate of 100 equally log spaced values per frequency decade. The HF and LF target spectra for the three annual probability levels used to develop the spectrum-compatible time histories are shown in Figures 2.5-297 and 2.5-298.

2.5.2.5.1.4 Selection of Seed Time Histories

The selection of the seed input time histories used in the spectral matching procedure was guided by the deaggregation results described in the previous section. For the HF case, the recommended Mbar and Dbar values are 5.6 and 12 km. For the low frequency case, the recommended Mbar and Dbar values are 7.2 and 130 km. These values were considered appropriate for all three MAFEs. Based on these recommended magnitude and distance values, a total of 30 seed time histories were selected for both the HF and LF cases.

Because of the limited number of strong ground motion acceleration time histories from stations located in the Eastern North America, 58 of the 60 selected seed input time histories were recorded at stations located in other regions than the Eastern North America. The additional two seed time histories that are used for the HF case were recorded in Eastern Canada. Time histories were selected based on the database of recorded strong ground motion records, recommended magnitude and distance values, and shear-wave velocities in the top 30 meters at recording sites of greater than 600 m/sec (about 1,970 ft/sec). The selected seed time histories are listed in Table 2.5-219 and Table 2.5-220, for the HF and LF cases, respectively.

The spectral matching was performed based on a given horizontal target spectra with a spectral damping of 5 percent. The spectral matching procedure is a time domain spectral matching procedure and emphasis was placed on maintaining the phasing characteristics of the initial time history in the final modified spectrum-compatible time history. In addition, emphasis was placed on maintaining the characteristic of the normalized Arias intensities (the integral of the square of the acceleration-time history, a ground motion parameter that captures the potential destructiveness of an earthquake) of the initial and final modified spectrum-compatible time histories. The spectral matching criteria given in NUREG/CR-6728 (Reference 525) that are applicable with the use of

multiple time histories were used to check the average spectrum from the 30 time histories for a given frequency range (high- or low-frequency) and annual probability level. This is the recommended procedure in NUREG/CR-6728 (Reference 525) when multiple time histories are being generated and used.

The selected 60 seed time histories were first matched to their respective 10^{-6} high and low frequency target spectra. As an example, the acceleration, velocity, and displacement time histories for one of the thirty 10-6 HF target spectrum seed time histories are shown in Figure 2.5-319. The final modified spectrum-compatible acceleration, velocity, and displacement time histories (matched to the 10-6 HF target spectrum) are plotted in Figure 2.5-320. Figure 2.5-321 shows the 10-6 HF target spectrum (thick grey line), the response spectrum from the initial acceleration time history scaled to the target PGA value (thin blue line), and the response spectrum from the final modified spectrum-compatible time history (thin red line). The initial and final modified spectrum-compatible normalized Arias intensities for this example are plotted in Figure 2.5-322. These results are representative of the goodness of fit for all spectrum-compatible time histories. For the 10^{-5} probability level, the final modified spectrum-compatible time histories from the 10^{-6} probability level were used as the input time histories for the spectral matching. In a similar fashion, the final modified spectrum-compatible time histories for the 10^{-5} probability level were used as the input time histories for the spectral matching at the 10^{-4} probability level. The results of the spectral matching for the high and low frequency cases at each of the three annual probability levels are shown in Figures 2.5-299 through 2.5-304. These spectrum-compatible time histories were used in the site response analysis presented in the next section.

2.5.2.5.1.5 Site Response Analyses

The site response analyses were conducted using the randomized shear-wave velocity profiles and soil modulus and damping relationships discussed in Subsection 2.5.2.5.1.2.1.1 to account for variation in the dynamic soil properties across the VEGP ESP Site. Two separate sets of degradation relationships for shear modulus and damping were applied in the site response analyses: EPRI-based curves and SRS-based curves (see Subsection 2.5.2.5.1.2). The depth to hard rock (V_s > 9200 fps) was also randomized to reflect its uncertainty. All site response analyses assumed that the sedimentary rock below 1049 ft (depth to bottom of Coastal Plain sediments) remains linear during earthquake shaking with one percent damping for all rock types. This randomization process resulted in 60 randomized rock/soil/fill profiles (that included combinations of depths to hard rock and degradation relationships) for each family of degradation curves (i.e., EPRI or SRS). Additional details about the generation of profiles for the site response analyses are included in Subsection 2.5.2.5.1.2.

Each of the 60 randomized soil profiles was paired with 30 seed time histories (each time history was applied to two of the randomized soil profiles) for each of the hard rock input motions (i.e., 30 time histories for the HF spectra and 30 time histories for the low frequency spectra). Three different mean annual frequency of exceedance events (10^{-4}, 10^{-5}, and 10^{-6}, see Subsection 2.5.2.5.1.3) were analyzed for each profile—seed time history pairing in order to calculate the amplification factors, defined as the ratios of five percent damped spectral accelerations for rock input motion at the 9,200 ft/s shear-wave velocity horizon to the five percent damped spectral accelerations motions computed at a hypothetical outcrop at the top of the Blue Bluff Marl (86-ft depth) at a hypothetical outcrop at the 40-ft depth horizon, and at the ground surface.

The computer program SHAKE (Reference 497) was used to perform these analyses and amplification factors were extracted from each analysis resulting in 720 spectral amplifications (see Table 2.5-221) for each horizon.

The mean of the site amplification functions based on the suite of multiple input spectrum-compatible time histories for each group of 60 randomized soil profiles was used to develop site amplification factors for the VEGP ESP Site, as described in NUREG/ CR-6728 (Reference 525).

Figure 2.5-307 depicts the mean spectral amplification results of a typical analysis for HF content of a 10^{-4} MAFE seismic event using EPRI degradation curves for the ground surface. Similar plots of the computed amplification results for the 40-ft and 86-ft horizons are shown in Figures 2.5-306 and 2.5-305, respectively. The curves shown were determined by averaging the logarithms of amplification values for each frequency. As described in Subsection 2.5.2.5.1.2.1.1, analyses are performed for both sets of degradation curves and equally weighted in the subsequent development of the final spectral amplification factors.

In order to implement site response analysis Approach 2A, as discussed in Subsection 2.5.2.5.1.1, the amplification factors are prepared as a function of hard rock input motion. Tables 2.5-226 and 2.5-227 present the amplification factors at the ground surface for input hard rock motions corresponding to 10^{-4}, 10^{-5}, and 10^{-6} HF and LF MAFE target spectra, respectively (see Figures 2.5-297 and 2.5-298). Similar results for the 40-ft horizon outcrop motion and the top of the Blue Bluff Marl are given in Tables 2.5-224 and 2.5-225 and Tables 2.5-222 and 2.5-223, respectively. These results are presented for 30 structural frequencies, including the seven structural frequencies at which seismic hazards were calculated.

2.5.2.6 Horizontal Ground Motion

2.5.2.6.1 Criterion for GMRS

The criterion used to calculate the recommended design spectrum comes from ASCE 43-05 (Reference 494)**.** This criterion is based on the mean seismic hazard curves for multiple structural frequencies at the ground surface, taking into account the effect of rock, soil, and fill above the hard rock horizon. The spectral amplitudes at this horizon corresponding to a mean annual frequency of exceedance (MAFE) of 10^{-4} are scaled so that structures and components designed to the scaled spectral amplitudes will achieve a target performance goal corresponding to a mean annual frequency of onset of significant inelastic deformation (FOSID) of 10^{-5} per year. The soil hazard values that form the basis for this calculation were developed following Approach 2A as described in Subsection 2.5.2.5.1.1.

2.5.2.6.2 Discrete Frequency Horizontal GMRS Amplitudes

Table 2.5-230 shows ground motion amplitudes corresponding to MAFEs of 10^{-4}, 10^{-5}, and (for information purposes only) 10^{-6} for hard rock conditions. Thirty structural frequencies are tabulated, including the seven frequencies developed in Subsection 2.5.2.4and an additional twenty three frequencies from the 300 frequency values per step 6 of Subsection 2.5.2.5.1.1. Table 2.5-230 also shows ground motion amplitudes for the free ground surface of the site-specific rock/soil/fill column that were calculated from the hard rock motions and the amplification factors of Subsection 2.5.2.5.

The horizontal GMRS (the design response spectrum (DRS) in the nomenclature of the ASCE 43-05 Reference 494) is derived from the amplitudes for MAFEs of 10^{-4} and 10^{-5} in Table 2.5-230. That is, the Amplitude Ratio, AR, of 10^{-5} to 10^{-4} amplitudes is determined for spectral accelerations (SA) at each structural frequency:

$$A_R = SA(10^{-5})/SA(10^{-4}) \qquad \text{(Equation 2.5.2-4)}$$

and the horizontal GMRS is calculated as:

$$GMRS = SA(10^{-4}) \times \max(1.0, 0.6\, A_R^{0.8}) \qquad \text{(Equation 2.5.2-5)}$$

Table 2.5-233 shows thirty of the GMRS values calculated from Equation 2.5.2-5, at the free ground surface. In Table 2.5-233, the last term in Equation 2.5.2-5, 0.6 $A_R^{0.8}$, is indicated as “DF2” in the table.

2.5.2.6.3 Full GMRS Horizontal Spectrum

The horizontal GMRS values at the 300 structural frequencies, thirty of which are provided in Table 2.5-233, are used to define the raw horizontal GMRS. This spectrum is then smoothed by a running average filter for the 100-points-per-decade spectral amplitudes above 1 Hz, but is constrained to go through the seven structural frequencies at which hazard calculations were made. (An exception was made for 5 Hz, where the site amplification analysis indicated a trough, so the 5 Hz GMRS value was smoothed based on amplitudes at adjacent frequencies, which raised the 5 Hz GMRS value slightly and improved the shape of the spectrum.) This step smooths out the spectral peaks and troughs above 1 Hz, which are not statistically significant, but maintains the low-frequency peaks and troughs representing lower-mode soil column response for this site.

Figure 2.5-310 shows the raw spectrum and the smoothed VEGP ESP horizontal GMRS.

2.5.2.6.4 Foundation Input Response Spectrum (FIRS) and Top of In Situ Competent Material (top of Blue Bluff Marl) Ground Motions

2.5.2.6.4.1 Development of FIRS and Top of In Situ Competent Material Spectra

The criterion used to calculate the recommended outcrop FIRS and top of Blue Bluff Marl spectra (at the 40-ft and 86-ft depth horizons, respectively) are the same as was used to develop the ground surface GMRS motion. That is, as described above the methodology of ASCE 43-05 (Reference 494) was used**.** And, as for the GMRS, the soil hazard values that form the basis for this calculation were developed following Approach 2A and the characterization of subsurface materials as described in Subsection 2.5.2.5.1.1.

Table 2.5-229 shows ground motion amplitudes corresponding to MAFEs of 10^{-4}, 10^{-5}, and (for information purposes only) 10-6 for hard rock conditions (thirty structural frequencies are tabulated including, the seven frequencies developed in Subsection 2.5.2.4 and an additional twenty three frequencies from the 300 frequency values per step 6 of Subsection 2.5.2.5.1.1). Table 2.5-229 also shows ground motion amplitudes for an outcrop at the 40-ft depth horizon; these were calculated from the hard rock motions and the amplification factors of Subsection 2.5.2.5.

Table 2.5-228 shows similar values for the top of Blue Bluff Marl horizon.

The FIRS and top of Blue Bluff Marl horizons outcrop spectra are derived from the amplitudes for MAFEs of 10^{-4} and 10^{-5} in Tables 2.5-229 and 2.4.2-21, respectively. That is, the Amplitude Ratio, AR, of 10^{-5} to 10^{-4} amplitudes are determined for spectral accelerations (SA) at each structural frequency using the ASCE 43-05 formula given above in the development of the GMRS spectra.

Tables 2.5-232 and 2.5-231 shows thirty of the FIRS and top of Blue Bluff Marl values calculated at the hypothetical outcrops at the 40-ft and 86-ft horizons, respectively.

The FIRS and top of Blue Bluff Marl values at the 300 structural frequencies, thirty of which are provided in Tables 2.5-232 and 2.5-231, are used to define the raw ground motion response spectra. These spectra are then smoothed, as were the GMRS spectra, by a running average filter for the 100-points-per-decade spectral amplitudes above 1 Hz, but is constrained to go through the seven structural frequencies at which hazard calculations were made.

Figures 2.5-309 and Figure 2.5-308 show the raw and smoothed spectrum.

The vertical FIRS and top of Blue Bluff Marl spectra were computed by applying the V/H spectral ratio presented in Subsection 2.5.2.7.1.3 to the smoothed FIRS and top of Blue Bluff Marl horizontal spectra plotted in Figure 2.5-309 and Figure 2.5-308. The resulting VEGP ESP vertical and horizontal FIRS and top of Blue Bluff Marl spectra are plotted in Figures 2.5-317 and 2.5-316.

2.5.2.6.4.2 Selection of Time Histories and Spectral Matching to the FIRS

Time histories matching the FIRS are used in several sensitivity analyses summarized in Subsection 2.5.2.9. Therefore, these time histories are developed here. Given the FIRS horizontal and vertical spectra presented in Subsection 2.5.2.7.1 and plotted in Figure 2.5-317, one set of three component time histories was developed to be spectrum compatible to the FIRS target spectra. The single three component set was selected based on the deaggregation of the low frequency (LF) results. For the low frequency case, the recommended Mbar and Dbar values are 7.2 and 130 km. These values were considered appropriate for all three MAFEs. For this analysis, the three component time histories from the 1999 Hector Mine earthquake (Mw=7.13) recorded at the Heart Bar State Park station (R=61.21 km) were selected. This was one of the 30 sets of time histories selected for the site response analysis (see Table 2.5-220).

The spectral matching procedure is a time domain procedure and emphasis was placed on maintaining the phase characteristics of the initial time history in the final modified spectrum-compatible time history. In addition, emphasis was placed on maintaining the characteristic of the normalized Arias intensities (the integral of the square of the acceleration-time history, a ground motion parameter that captures the potential destructiveness of an earthquake) of the initial and final modified spectrum-compatible time histories. The spectral matching criteria given in NUREG/CR-6728 (Reference 525) that are applicable were used to check the acceptability of the modified spectrum compatible time history. In most cases, an additional scale factor which is applied after the spectral matching process is used to assure that the final modified time history satisfies the spectral matching criteria given in NUREG/CR-6728. A common scale factor of 1% (i.e., 1.01) was used for each of the three components. The modified acceleration, velocity, and displacement time history prior to the application of this 1.01 scale factor is shown in Figure 2.5-323 for the first horizontal component. Figure 2.5-324 shows target FIRS horizontal spectrum, 1.3*FIRS target spectrum, 0.9*FIRS target spectrum and the modified time history response spectrum including the 1.01 scale factor. The normalized Arias intensities for this first horizontal component are shown in Figure 2.5-325. The results for the second horizontal component are shown in Figures 2.5-326 through 2.5-328. The vertical component results are presented in Figures 2.5-329 through 2.5-331.

2.5.2.7 Vertical GMRS Spectrum

The method to develop the vertical GMRS is to develop a vertical-to-horizontal scaling factor [V/H], which is then applied to the horizontal GMRS at the 3 horizons (GMRS, FIRS, and top of Blue Bluff Marl), presented above.

2.5.2.7.1 Development of V/H

Reg. Guide 1.60 presents acceptable standard response spectral shapes as a function of frequency that may be considered for the seismic design of nuclear power plants. These shapes are given for both horizontal and vertical ground motions as a function of damping. The shapes are independent of peak ground acceleration (PGA), which is used as a scaling factor. The ratio of the vertical to horizontal spectral shapes results in a V/H scaling function that is a value of 2/3 for frequencies less than 0.25 Hz, 1.0 for frequencies higher than 3.5 Hz, and varies between 2/3 and 1 for frequencies between 0.25 and 3.5 Hz.

A significant increase in the number of strong ground motion observations and advances in earthquake ground motion modeling since the publication of Reg. Guide 1.60 suggest that the V/H

ratios implied in Reg. Guide 1.60 may not be appropriate for a given site (Reference 515; Reference 525). The horizontal and vertical ground motions and the V/H ratios are observed to depend on magnitude, distance, site conditions, and regional tectonic setting (e.g. western US [WUS] vs. central and eastern US [CEUS]), which presents distinctive characteristics of earthquake source, attenuation along regional path, and shallow crust).

NUREG/CR-6728 (Reference 525) presents V/H ratios for soft rock WUS sites and hard rock CEUS sites as a function of horizontal peak acceleration, as a proxy for the combined dependence on magnitude and distance. While the WUS rock V/H ratios are based on the significant empirical database of WUS strong ground motion, there are too few CEUS recordings to develop empirically-based CEUS V/H relations. NUREG/CR-6728 follows up on a technique presented in EPRI TR-102293 of using earthquake ground motion modeling to develop CEUS rock V/H. Due to assumptions and the estimation of various required parameters, the explicit results of the CEUS modeling are not considered robust, but can be used as guidelines for the difference between V/H ratios for WUS and CEUS rock sites. For the rock CEUS V/H ratios NUREG/CR-6728 uses the WUS ratios and modifies them based on the difference in trends obtained between WUS and CEUS rock sites from their modeling studies. For example, a peak in the V/H ratio is expected to occur at higher frequencies for CEUS than for WUS sites because site kappa values in the CEUS are typically lower than in the WUS.

The VEGP ESP site, however, is a deep soil site, not a hard rock site. V/H relations for soil sites are not given in NUREG/CR-6728 (Reference 525), and, again, an insufficient number of ground motion observations have been made to develop empirical CEUS relationships for soil sites. Appendix J of NUREG/CR-6728, however, does discuss the use of modeling by which V/H ratios can be developed for CEUS soil sites. The method mirrors that used in NUREG/CR-6728 in developing the CEUS rock V/H relations, and can be represented by the following formula:

$$V/H_{CEUS,Soil} = V/H_{WUS,Soil,Empirical} * [V/H_{CEUS,Soil,Model} / V/H_{WUS,Soil,Model}] \quad \text{(Equation 2.5.2-6)}$$

The first term of Equation 2.5.2-6 can be a readily available WUS relationship, such as Abrahamson and Silva (1997), which presents both vertical and horizontal ground motion attenuation relations for deep soil sites. Magnitude and distance is specified, which allows hazard contribution-appropriate specification for a given location.

The second term is a WUS-to-CEUS “transfer function” to modify the WUS ratios from the first term to give the required $V/H_{CEUS,Soil}$. The development of this second term entails ground motion modeling of both CEUS [numerator] and WUS [denominator] ground motions appropriate for the given site (e.g., the major contributing or controlling earthquake by magnitude and distance) and considers the site-specific conditions. The model for developing $V/H_{WUS,Soil,Model}$ considers generic site soil conditions, as implicitly considered in the $V/H_{WUS,Soil,Empirical}$ term. The model for developing $V/H_{CEUS,Soil,Model}$ model can consider as site-specific soil conditions as possible.

Upon developing V/HCEUS,Soil from Eq. 2.5.2-6, the vertical GMRS response spectrum is then defined by

$$Sa_{GMRD,Vertical} = Sa_{GMRS,Horizontal} * V/H_{CEUS,Soil} \quad \text{(Equation 2.5.2-7)}$$

As discussed above, the first term on the right-hand side of Equation 2.5.2-6 can be implemented using the ground motion attenuation relationship of Abrahamson and Silva (1997). The development of the WUS-to-CEUS transfer function (the second right-had side term of Equation 2.5.2-6) needs significant analytical effort, contains potentially significant uncertainties, and requires a number of assumptions. Two studies guide the development of a best estimate of $V/H_{CEUS,Soil}$ and, through Equation 2.5.2-7, the definition of the vertical GMRS response spectrum.

2.5.2.7.1.1 Estimate of V/H from NUREG/CR-6728

Appendix J of NUREG/CR-6728 (Reference 525) discusses various characteristics of vertical strong motions and, building upon the work presented in EPRI TR-102293, presents the methodology to estimate V/H for CEUS rock and soil sites. This method is that represented by Equation 2.5.2-6, above. A generic CEUS soil column is considered in their presentation of the method. In the appendix, plots of the numerator and denominator of the WUS-to-CEUS transfer function are shown, Figures J-32 and J-31, respectively, for **M**6.5 and a suite of distances [1, 5, 10, 20, and 40km]. An estimate of the WUS-to-CEUS transfer function can be made for **M**6.5 at the given distances using these results shown in these figures.

As discussed above, the GMRS response spectrum is based on slopes of the 10-4 and 10-5 ground motion hazard curves and the scaling of the 10-4 ground motions. The resulting horizontal GMRS ground motions at the seven spectral control points are generally only slightly higher than the 10-4 ground motion levels. That is, the horizontal GMRS is dominated by the 10-4 ground motion.

In reviewing the high-frequency distance deaggregation at the 10^{-4} hazard level (Figure 2.5-291), about one-quarter of the hazard is coming from “near” events, or about distances less than 20 km, while about three-quarters of the hazard is coming from “far” events, or distances centered at about 130 km. In reviewing the corresponding distance deaggregation at the 10^{-5} hazard level in the same figure, the bimodal nature of the deaggregation is yet apparent, but the relative contribution of the near and far events is about the same.

In reviewing the low-frequency magnitude-distance deaggregations at both the 10^{-4} and 10^{-5} hazard levels (Figure 2.5-292), hazard contribution is clearly dominated by the distant event centered on about 130 km.

The magnitudes and distances that can be attributed to the near and far events are taken as those used in the development of the high-frequency and low-frequency target spectra for the site response analysis: **M**5.6 at a distance of 12 km and **M**7.2 at a distance of 130 km, respectively.

Figure 2.5-311 is a plot of the first term of Equation 2.5.2-6 for both near and far events using the attenuation relationship of Abrahamson and Silva (1997).

Figure 2.5-312 is a plot of estimates of the second term of Equation 2.5.2-6 (ratio of V/H ratios) developed as the quotient of the curves in NUREG/CR-6728 (Reference 525) Figure J-32 and J-31 for highest available distances of 10, 20, and 40 km. The Appendix J figures are given only for **M**6.5. Therefore, an estimate of an equivalent ground motion proxy magnitude and distance must be made to estimate the second term of Equation 2.5.2-6. The **M**6.5, 20 km curve may be considered a reasonable proxy for the “near” event of **M**5.6 at 12 km. The greatest distance given in the two figures of Appendix J is 40 km, so this has to be used as the proxy, along with the associated **M**6.5, for the “far” event of **M**7.2 at 130 km. Given the trend of the V/H values (decreasing with distance for a given magnitude), it is expected that the “far” event proxy may be conservative (high in value), as compared to the value expect if equivalent ratio of ratio curves had been explicitly available for **M**7.2 at 130 km. Figure 2.5-312 shows the recommended “near” and “far” versions of the second term of Equation 2.5.2-6. Some smoothing has been applied that may be reflecting certain aspects (peaks, valleys) of the response reflecting the generic soil models used.

Figure 2.5-313 is a plot of $V/H_{CEUS,Soil}$ of Equation 2.5.2-6 considering both “near” and “far” events. Given the observations made earlier with regard to the relative contributions of the deaggregation “near” and “far” events to the 10^{-4} and 10^{-5} hazards, and the relative contribution of these two hazard levels to the horizontal GMRS design response spectrum, the “near” and “far” estimates of $V/H_{CEUS,Soil}$ are weighted approximately 1:3, resulting in the final $V/H_{CEUS,Soil}$ shown in Figure 2.5-313, as derived from the available results in NUREG/CR-6728.

2.5.2.7.1.2 Estimate of V/H from Lee (2001)

As a second estimate of the required V/H ratio, the results of the study for the MOX Fuel Fabrication Facility [MFFF] at the Savannah River Site are considered (Reference 520). The methodology used in that study followed the same approach as presented in NUREG/CR-6728 and EPRI TR-102293, and used in the section above, with the primary exception that the function $V/H_{CEUS,Soil,Model}$ of Equation 2.5.2-6 is developed using a site-specific model of the soil conditions. Lee (2001) notes that the following vertical and horizontal modeling assumptions are made based on validations:

Vertical motions are modeled as a combination of pure SV-waves and SV-P converted waves arriving at the base of the soil/alluvium materials at inclined angles of incidence computed using ray tracing methods;

Horizontal component spectra are computed assuming pure S-waves arriving at vertical incidence;

Linear elastic analysis is assumed for computing the vertical motions;

Low strain behavior (i.e., no wave induced dynamic strain degradation) compressional and shear-wave site velocity profiles are used in computing vertical spectra;

Damping for computing vertical spectra is the low strain level damping used to compute horizontal spectra;

For computing horizontal motions, wave induced dynamic strain degradation of the shear-wave velocity and increased damping of the profile is permitted (in an equivalent linear analysis).

The consequence of these assumptions is that the model-derived V/H ratios (particularly for the MFFF site) may be conservatively high over some range of spectral frequencies and at high loading levels.

Lee (2001) directly presents final V/H ratios (i.e., the resulting $V/H_{CEUS,Soil}$ of Equation 2.5.2-6) for several magnitudes and distances. V/H ratios for **M**5.5 at 10 and 20 km and **M**6.0 at 10 and 20 km were interpolated to estimate the “near” V/H ratio for **M**5.6 at 12 km. V/H ratios for **M**7.0 at 100 km and **M**7.5 at 100 km were interpolated to estimate a “far” V/H ratio for **M**7.2 at 100 km. The distance of 100 km was the greatest considered in Lee (2001), but is considered adequate, if not slightly conservative, for a proxy of the 130 km desired for the “far” event.

Figure 2.5-314 is a plot of $V/H_{CEUS,Soil}$ of Equation 2.5.2-6 considering both “near” and “far” events. As before, given the observations made earlier with regard to the relative contributions of the deaggregation “near” and “far” events to the 10^{-4} and 10^{-5} hazards, and the relative contribution of these two hazard levels to the horizontal GMRS response spectrum, the “near” and “far” estimates of $V/H_{CEUS,Soil}$ are weighted approximately 1:3, resulting in the final $V/H_{CEUS,Soil}$ shown in Figure 2.5-314, as derived from the available results in Lee (2001).

2.5.2.7.1.3 Recommended V/H

The results of two studies have been used to guide in the development of best estimates of $V/H_{CEUS,Soil}$, as discussed above and summarized in Figure 2.5-315. The $V/H_{CEUS,Soil}$ developed from Lee (2001) gives a higher value V/H ratio than that developed from the available NUREG/CR-6728 results for frequencies greater than about 0.7 Hz. Both results give minimum V/H values, particularly in the lower frequencies, which appear lower than engineering judgment may suggest acceptable in the current state-of-knowledge.

Given the site specific nature of the Lee (2001) estimate, which would argue against considering an average of the two results, an approximate envelope of the results is recommended, wherein some smoothing is considered and a minimum V/H value of 0.5 is considered. The recommended final V/H ratio is shown in Figure 2.5-315. This V/H ratio is described as follows:

Frequencies	V/H ratio
≤ 1 Hz	0.5
1 to 15 Hz	log-log interpolate between 0.5 and 0.9
≥ 15 Hz	0.9

In Figure 2.5-315 the V/H ratio from RG 1.60 is shown for comparison. The recommended V/H ratio is marginally less than the Reg. Guide ratio at all frequencies.

2.5.2.7.1.4 Recommended Vertical GMRS Spectrum

To develop the vertical spectra, the horizontal spectra is scaled by the recommended V/H ratios provided in Subsection 2.5.2.7.1.3. Figures 2.5-318, 2.5-317, and 2.5-316 show the resulting vertical and horizontal GMRS, FIRS, and top of Blue Bluff Marl spectra, respecitively.

2.5.2.8 Operating Basis Earthquake Ground Motion

The Operating Basis Earthquake (OBE) ground motion spectra was not determined as part of the Vogtle ESP submittal. Requirements related to the OBE are provided in paragraph IV (a) (2) of Appendix S to 10 CFR Part 50, “Earthquake Engineering Criteria for Nuclear Power Plants.” Under General Information in this appendix, the following statement is made: “This appendix applies to applications for the design certification or combined license pursuant to part 52 of this chapter or a construction permit…” Since OBE requirements are related to the design and performance of safety related systems, the OBE ground motion spectra have been determined during the COL stage as required under Appendix S.

2.5.2.9 Sensitivity Studies

2.5.2.9.1 Sensitivity for Backfill Vs

During the COL investigation and prior to conducting the Phase I test pad program, a study was conducted to evaluate the sensitivity of the AP1000 responses to the change in backfill shear wave velocity. The shear wave velocity used for the backfill sensitivity analysis (sensitivity study) is compared with the backfill velocity used for GMRS and FIRS computation (ESP profile) in Figure 2.5-332. The analyses included randomization of the entire soil column with the new backfill properties and development of the new outcrop motion at the foundation level of the AP1000 Nuclear Island. The new time history and associated strain-compatible soil properties were used in the SSI analysis of the AP1000.

The study confirmed that, even with a large variation of the backfill property, the AP1000 design is applicable to the Vogtle site with a large margin. Appendix 2.5E, Vogtle Site Specific Seismic Evaluation Report provides the results of this sensitivity analysis.

2.5.2.9.2 Study of the Effects of Backfill Geometry

Due to the large volume of excavation and the lateral extent of the backfill at the Vogtle site, the backfill layers were modeled as free-field soil layers in the modeling of the soil profile for both the soil amplification for development of the ground motion (GMRS and FIRS) and the site-specific seismic SSI analysis of the AP1000.

To verify the validity of this assumption, a two-dimensional site response analysis followed by a two-dimensional SSI analysis of the AP1000 model were used to evaluate the effect of the extent of backfill on the site response and on the SSI response of the NI. The plant layout is shown in Figure 2.5-333. For the 2D analysis, the cross section shown in the East-West direction shown in Figure 2.5-334 was used. The analysis consists of two parts.

In part I, 2D site response analysis was performed. The 2D SASSI model of the site is based on Section A shown in Figure 2.5-334 that represent a "bathtub" model of the site with backfill modeled with plane strain elements. The 2D SASSI model for site response analysis is shown in Figure 2.5-335. An axis of symmetry was used to consider the backfill geometry for both units. The in-situ upper sand layers are modeled using the site-specific dynamic properties measured at the site. The properties of the backfill, blue bluff marl, the lower sand layers and layers extending to the rock at the base were the same as those used in the site response analysis to develop GMRS and FIRS. However, since computation of GMRS and FIRS were based a wide range of soil columns and input motions (60 randomized profiles, 30 time histories for HF and 30 time histories for LF rock motion), only a subset of the properties and input motion were considered. The analysis in part I included the upper, mean and lower bound soil profiles and only 3 time histories for each of HF and LF rock input motion. The results of the site amplification for the 2D site response analysis was compared with the site amplification factors from the1D SHAKE results for the same set of input motion and soil properties. The differences in site amplification factors are shown in Figures 2.5-336, 2.5-338, and 2.5-340. The results from SHAKE are represented in terms “in-column” motions to be comparable with the 2D SASSI nodal response motions at the three locations at centerline of the backfill (Figure 2.5-335), As shown in these figures, the differences are very small confirming that geometry of the backfill has insignificant effect on GMRS and FIRS. Additionally in Figure 2.5-336 the mean amplification used to develop the GMRS motion is plotted as a red dotted line; the close fit of the curves confirms the adequacy of the selection of limited number of soil columns and time histories for this study. In addition, transfer functions are obtained from the same set of calculations that provided the spectral amplifications. Transfer functions represent the harmonic amplification of the input motion used as input to soil column analysis to the “in-column” motion at the two horizons (0 ft and 40 ft depth). Transfer functions for the mean (Best Estimate) soil profile subjected to one HF input motion are compared for the 1D SHAKE and 2D SASSI analysis at two horizons, 0 ft and 40 ft depth, in Figure 2.5-337 and Figure 2.5-339, respectively. The comparison of transfer function also confirms that 1D SHAKE analysis isadequate for the development of the ground motion given the geometry of the backfill at the site.

In part II, a new Vogtle 2D SASSI model of the NI was created to include the backfill as part of the structural model as shown in Figure 2.5-341. This model is similar to the "bathtub" model shown in Figure 2.5-335 except the AP1000 NI model is included. For this model the strain-compatible soil properties for the in-situ upper sand layer were used as part of the free-field SASSI model. The analysis in Part II was limited to the mean soil profile and for one time history from the analysis performed in Part I. The input motions for the two SSI analyses are obtained from the respective 1D SHAKE analysis in part I consistent with the free-field model used in each SASSI model. The SSI responses for the Vogtle "bathtub" 2D SASSI NI model (Bathtub Model-d5) at key locations in the NI are compared with the SSI results of the Vogtle 2D SASSI NI model (2D-AP-d5) that assumes backfill extends to infinity in lateral directions. The results of the analysis are compared at the following key locations in the NI.

Nodes	Elevation (ft)	Description
4041	99.000	NI at Reactor Vessel Support Elevation
4061	116.5	Auxiliary Shield Building at Control Room Floor
4120	179.560	ASB Auxiliary Building Roof Area
4310	327.41	ASB Shield Building Roof Area
4412	224	Steel Containment Vessel near Polar Crane
4535	134.250	Containment Internal Structure at Operating Deck

These comparisons are shown in Figures 2.5-342 through 2.5-347. The response spectra are similar and the differences are considered negligible. For information the generic AP1000 standard design response spectra are plotted for comparison purposes which confirms significant margin between the AP1000 generic response and the Vogtle 2D results. A more detailed discussion of the Vogtle "bathtub" 2D SASSI NI model and a comparison of transfer functions are documented in Appendix A of Appendix 2.5E.

The comparison of the results confirms that the extent and geometry of the backfill has negligible effects on GMRS and FIRS and has small effects on the structural responses which are well within the range of the margin of the design.

2.5.2.9.3 Updated Site Response Analyses

As discussed in Subsection 2.5.4.7, additional geotechnical data was collected as part of COL investigation and the ESP data was supplemented with the new data. The completed data set is referred to as “COL” data. Subsection 2.5.4.7.1 presents a discussion of the shear wave velocity profile of the ESP and COL data sets and Subsection 2.5.4.7.2 presents a discussion of the strain-dependent soil properties of the two data sets. Site specific (COL) strain-dependant soil properties are presented in Figures 2.5-382 and 2.5-385 and in Table 2.5-255. Subsection 2.5.4.7.5 presents the comparison of the data in terms of the shear wave velocity profile (Figure 2.5-379) and strain-dependent soil properties (Figures 2.5-392 through 2.5-397). Soil amplification analysis and development of FIRS described in Subsection 2.5.2.5.1 are based on the ESP data. In this section, the effect of COL data on the soil amplification at the depth of 40 ft (FIRS) is presented. The FIRS at 40 ft depth has been used as input for the site specific evaluation of the AP1000 design.

As described in Subsection 2.5.2.5.1, development of soil amplification using ESP data is based on 60 randomized velocity profiles and associated EPRI and SRS strain-dependent soil properties incorporating 30 time histories for the HF and LF motions at each MAFE of 10^{-4}, 10^{-5}, and 10^{-6} levels. However for the purpose of sensitivity analysis and evaluation of the effects of COL data, a limited number of soil column analysis have been performed as described below.

Using the best estimate COL velocity profile (Figure 2.5-379), the upper bound and lower bound profiles were developed using a variation of the data set. The three COL velocity profiles and the associated COL strain-dependent soil properties were analyzed using three HF and three LF time histories corresponding to MAFE of 10^{-4}. All analyses were performed twice to consider the low and high PI strain-dependent soil properties for BBM (Figures 2.5-393 and 2.5-396). Several iterations were performed in each run to converge on the soil properties. The strain-compatible velocity profiles and damping profiles obtained from the analysis are shown in Figures 2.5-349 and 2.5-350 labeled as COL. From each run, the response motion in terms of 5% acceleration response spectrum at the depth of 40 ft as SHAKE “outcrop” motion was computed. The results of HF input motion were averaged over the three time histories and over the three soil profiles as well as the low and high PI cases of the BBM. The same averaging method was used for the LF input motions. The averaged results were divided by the corresponding HF and LF input response spectrum at MAFE of 10^{-4} to

compute the spectral amplification at the 40 ft horizon. The resultant two amplifications curves were enveloped. The enveloped amplification values are shown in Figure 2.5-351 labeled as COL.

To provide a consistent soil amplification for comparison with the results using COL data, from the ESP set of runs described in Subsection 2.5.2.5.1 the strain-compatible velocity and damping profiles were used to obtain the median and upper and lower bound profiles (using one standard deviation as the variation). The velocity and damping profiles are compared with the corresponding profiles from the analysis of the COL data in Figures 2.5-349 and 2.5-350, respectively. Except for the damping profile at shallow depths, the two sets of data are consistent. The three profiles selected from the analysis of the ESP data were subsequently analyzed using the same three HF and LF time histories used in the analysis of the COL data. Since the soil properties are already compatible with shear strains, no further iteration on soil properties was performed. The results in terms of acceleration response spectrum at 5% damping at 40 ft depth as outcrop motion were obtained. The spectra for each HF and LF motions were averaged over the three time histories and over the three profiles. The averaged responses were divided by the respective HF and LF response spectra at MAFE of 10^{-4} and the resultant amplifications were enveloped. Figure 2.5-351 shows the amplification labeled as ESP.

To confirm the adequacy of the limited number of profiles and time histories for the purpose of this evaluation, the amplification corresponding to the analyses of the fully randomized ESP soil profiles (Subsection 2.5.2.) is also shown in Figure 2.5-351 labeled as “ESP-all”. The comparison of the two sets of results based on ESP data shows the selection of limited number of profiles and time histories are adequate for the purpose of the evaluation of the impact of the COL data. Furthermore, the comparison of the amplification between ESP and COL data is considered small and is expected to be reduced to be negligible if the fully randomized soil profiles were used in the COL set of analyses.

In addition, an assessment of the small differences in the amplification of the FIRS motion on the structural response of the AP1000 has been made. The AP1000 has significant margin when compared to Vogtle site specific seismic floor response spectra associated with the ESP and sensitivity soil profiles. Based on this evaluation, it has been determined that the AP1000 certified Design remains acceptable for the Vogtle site.

2.5.2.9.4 Study of Engineered Granular Backfill Placed Over the Slopes of the Excavation

Backfill within the defined excavation permits using an engineered granular backfill (EGB) material over the slopes of the excavation as shown in Figure 2.5-389. This is an alternate backfill geometry to that considered in Subsection 2.5.2.9.2. This section discusses the significance of backfill material, other than Category 1 and 2, placed over the slopes and demonstrates that the results and conclusions provided in Subsection 2.5.2.9.2 remain valid.

As described in Subsection 2.5.1 the removal of the Upper Sands is required since this in-situ material is variable, contains dissolution features, is susceptible to liquefaction, and is not a competent bearing stratum. Directly below the approximately 90 feet of Upper Sands is the first competent in-situ stratum called the Blue Bluff marl (BBM). Figures 2.5-388 and 2.5-389 show the defined width and length of the exposed BBM surface for each excavation, which is approximately 347 ft by 812 ft, respectively, producing a bearing surface area of approximately 282,000 sq ft per unit. This width and length is based on a zone of influence forming from the bottom of the foundations of the power block structures extending down to the BBM at approximately 45 degrees. Directly above this bearing surface area of the BBM, Category 1 and 2 backfill is placed to provide:

- A uniform bearing subsurface for the foundations of the major power block structures.
- Adequate static and dynamic bearing capacities (2.5.4.10.1).

- Acceptable total settlement and minimum differential settlement (2.5.4.10.2).
- No potential for liquefaction due to earthquake ground motion (2.5.4.8).

Figures 2.5-388 and 2.5-389 show that the actual amount of excavation of the upper sands is significantly larger than required to simply expose the BBM surface to provide an adequate bearing surface for the power block structure foundations. This is due to the need for a safe excavation of the upper sands, which dictate 2-horizontal to 1-vertical slopes. The slopes of the excavation are for construction purposes only and not a foundation design requirement nor needed to assure the safety performance of the Nuclear Island (NI).

For analytical purposes it was assumed the lateral extent of backfill can be considered infinite for site response and seismic SSI analyses. To demonstrate the reasonableness of this assumption a sensitivity study of the backfill geometry is provided in Subsection 2.5.2.9.2. In this sensitivity analyses, 2D SASSI bathtub models are used to represent the ESP defined excavation cross section including the slopes. The Best Estimate ESP Category 1 and 2 backfill properties were used for this sensitivity study.

Since Category 1 and 2 backfill over the defined slopes is not a foundation design requirement, this section evaluates the importance of backfill placed directly over the slopes with regard to the study of backfill geometry provided in Subsection 2.5.2.9.2. This is accomplished by comparing the 2D SASSI bathtub model results of Subsection 2.5.2.9.2 to results of the same 2D SASSI bathtub models and inputs while varying the backfill properties, primarily stiffness, directly over the slopes of the excavation. Figure 2.5-335 and Figure 2.5-341 from Subsection 2.5.2.9.2 show the 2D SASSI bathtub models for site response (Part I) and the site seismic SSI analysis (Part II) respectively. These same models are used for this study herein except the backfill properties over the slopes are varied. A range of material properties for backfill over the slopes was considered while maintaining the Best Estimate ESP backfill properties directly above the BBM. A comparison that shows no significant differences between the 2D SASSI bathtub model results for different cases of backfill over the slopes with the 2D SASSI bathtub model results of Subsection 2.5.2.9.2 will demonstrate that the results and conclusions in Subsection 2.5.2.9.2 are still valid and therefore will support the use of backfill other than Category 1 and 2 backfill over the slopes.

For this evaluation three cases are considered for material other than Category 1 and 2 backfill placed over the excavation slopes:

Case 1 is a hypothetical case of no excavation slopes (a vertical cut) with the full depth of the Upper Sands brought up to the bottom toe of the exposed BBM. This is considered an extreme contrast to the Best Estimate Category 1 and 2 backfill modeled above the BBM and would represent the most limiting lateral extent of the backfill possible.

Case 2 is a hypothetical lower bound of well-compacted engineered granular backfill. It is considered an extreme lower bound for engineered backfill, with shear wave velocities less than 1000 fps at the NI foundation elevation.

Case 3 is a hypothetical upper bound of well-compacted engineered granular backfill. It is considered an extreme upper bound for engineered granular backfill, with shear wave velocities well over 1000 fps at the NI foundation elevation.

The well-compacted engineered granular backfill would have a similar parabolic shear wave velocity profile as the ESP Category 1 and 2 backfill, but with possibly a larger potential range of values.

The three cases provide a significant range of shear wave velocity over the slopes, which create various contrasting boundaries to the adjacent best estimate ESP backfill shear wave velocity

modeled directly above the BBM. Therefore, the comparison of the 2D SASSI bathtub model results for these different cases of material over the slopes to the 2D SASSI bathtub model results of Subsection 2.5.2.9.2 is sufficient to demonstrate that engineered backfill other than Category 1 and 2 backfill placed over the slopes would not invalidate the results and conclusions provided in Subsection 2.5.2.9.2.

Figure 2.5-352 is a plot of the Lower Bound (LB), Best Estimate (BE), and Upper Bound (UB) low strain profiles for the ESP Category 1 and 2 backfill, Case 1, Case 2, and Case 3. This figure demonstrates the breadth of the variation of the shear wave velocity profiles considered for backfill material over the slopes of the excavation in order to assess the significance of material placed over the slopes on the results and conclusions provided in Subsection 2.5.2.9.2. Figure 2.5-353 is a comparison of the strain compatible BE shear wave velocity profiles for ESP Category 1 and 2 backfill used in the sensitivity analysis of Subsection 2.5.2.9.2 (identified as Base Case in the figure) along with Cases 1, 2, and 3 used in the 2D SASSI SSI bathtub models.

Part I of Subsection 2.5.2.9.2 provides the sensitivity study for seismic site response. The same 2D SASSI bathtub model shown in Figure 2.5-335 was used, except the material over the slopes was changed. Three cases described above were considered, the results of Cases 1, 2, and 3 are compared to the 2D SASSI bathtub results of Subsection 2.5.2.9.2 identified as “SASSI-BF-IS.” The results in the form of spectral amplification factors versus frequency are shown in Figures 2.5-354, 2.5-355, and 2.5-356 at three horizons: at a depth of 0 ft (GMRS Horizon), at 40 ft depth (FIRS horizon), and at 86 ft depth (top of Blue Bluff Marl), respectively. As shown in these figures the differences are very small confirming that backfill with shear wave velocities lower and higher than Category 1 and 2 backfill can be placed over the slopes without invalidating the results and conclusions provided in Subsection 2.5.2.9.2.

Part II of Subsection 2.5.2.9.2 provides the sensitivity study for site seismic SSI analyses. The same 2D SASSI SSI bathtub model shown in Figure 2.5-341 was used here except the material over the slopes was changed Three cases described above were considered, the results of cases 1, 2, and 3 are compared to the 2D SASSI SSI bathtub results of Subsection 2.5.2.9.2. These results are the horizontal in-structure response spectra at the six key locations in the NI and are shown on Figures 2.5-357 through 2.5-362. The 2D SASSI SSI bathtub results of Subsection 2.5.2.9.2 with the Best Estimate Category 1 and 2 backfill properties used throughout the excavation are identified as “Bathtub Model-d5.” The generic AP1000 standard 2D design response spectra are plotted for comparison purposes as was done in Subsection 2.5.2.9.2. As shown in these figures the differences are very small confirming that backfill with shear wave velocities lower and higher than Category 1 and 2 backfill can be placed over the slopes without invalidating the results and conclusions provided in Subsection 2.5.2.9.2.

In summary, the seismic models for VEGP 3 and 4 are based on an assumption of infinite lateral extent of backfill. The sensitivity study described in Subsection 2.5.2.9.2 demonstrated that the ESP-defined lateral extent of the excavation is adequate to support the infinite backfill assumptions of the seismic models. The results from the sensitivity studies described above show that this conclusion remains valid when the Category 1 and 2 backfill over the slopes is replaced with backfill with conservatively low shear wave velocities, backfill with conservatively higher shear wave velocities, and no backfill at all (in situ material). Thus it can be concluded that an engineered fill other than Category 1 and 2 backfill can be used over the slopes of the excavation without invalidating the results and conclusions of Subsection 2.5.2.9.2.

2.5.3 Surface Faulting

NRC Regulatory Guide 1.165, *Identification and Characterization of Seismic Sources and Determination of Safe Shutdown Earthquake Ground* Motion (RG 1.165), defines a capable tectonic source as a tectonic structure that can generate both vibratory ground motion and tectonic surface deformation, such as faulting or folding at or near the earth's surface in the present seismotectonic regime. This section evaluates the potential for tectonic surface deformation and non-tectonic surface deformation at the site. Information contained in Subsection 2.5.3 was developed in accordance with RG 1.165 and is intended to satisfy 10 CFR 100.23, *Geologic and Seismic Siting Criteria*.

There are no capable tectonic sources within the 5-mi VEGP site area radius, and there is a negligible potential for tectonic fault rupture. There is only limited potential for non-tectonic surface deformation in shallow deposits within the 5-mi site area radius, and this potential can be mitigated by means of excavation. The following sections provide the data, observations, and references to support these conclusions.

2.5.3.1 Geological, Seismological, and Geophysical Investigations

The following investigations were performed to assess the potential for tectonic and non-tectonic deformation at and within a 5-mi radius of the VEGP site:

- Compilation and review of existing data and literature
- Interpretation of aerial photography
- Field reconnaissance
- Aerial reconnaissance
- Review of historical and recorded seismicity
- Collection and interpretation of seismic reflection data at the VEGP site
- Discussions with current researchers in the area
- Collection and interpretation of survey data collected from a Quaternary fluvial terrace located at the SRS overlying the surface projection of the Pen Branch fault.

An extensive body of information is available for the VEGP site. This information is contained in five main sources:

- Work performed for the existing VEGP Units 1 and 2.
- Published geologic mapping performed by the US Geological Survey (USGS), the South Carolina Department of Natural Resources, and other researchers.
- Numerous, detailed investigations of the nearby Savannah River Site (SRS), perhaps the most extensively studied portion of the US Atlantic Coastal Plain.
- Seismicity data compiled and analyzed in published journal articles, EPRI (1986a), and the updated EPRI catalog, performed as part of this study.

- Seismic reflection data collected near the site within the Savannah River channel (Reference 321).

This existing information was supplemented by aerial and field reconnaissance performed within and beyond the 25-mi site vicinity radius, and by interpretation of aerial photography within the 5-mi site area radius. Given the extensive geologic and geomorphic studies performed previously at the SRS, the interpretation of aerial photography performed for the ESP study focused on the area southeast of the SRS. These studies were performed to document, where possible, the presence or absence of geomorphic features indicative of potential Quaternary fault activity within the Coastal Plain sediments or underlying bedrock.

2.5.3.1.1 Previous VEGP Site Investigations

This section summarizes previous site investigations performed for existing VEGP Units 1 and 2. Previous investigations for VEGP Units 1 and 2 did not identify the existence of tectonic faulting (Reference 551, Reference 552, Reference 553, Reference 554, Reference 212). Detailed geologic mapping and inspection of excavations during VEGP construction revealed no evidence of geologically recent or active faulting. However, minor, non-tectonic dissolution-induced collapse features (including minor folds and small joints and faults confined to the near-surface) were recognized and logged in detail on site Reference 555.

Bechtel (1974a) identified, discussed in Subsection 2.5.1.2.3, a northwest-dipping monoclinal flexure beneath the site in the Blue Bluff Marl. This feature, referred to as a dip reversal because the strata locally dip gently northwest against the regional southeast dip of the Coastal Plain sediments, was interpreted as a syndepositional, sedimentary feature (Reference 552). Later investigations by Bechtel (1978, 1981) describe “stratigraphic irregularities” recognized in site excavations associated with the Blue Bluff Marl. Because these stratigraphic irregularities were observed to be underlain by flat-lying, laterally continuous strata, Bechtel (1978, 1981) concluded that these irregularities were produced by syn-depositional processes.

Alterman (1984) reported observing a number of “clastic dikes” at the VEGP site and in the site vicinity during an NRC visit. Alterman’s report does not, however, interpret the origin of these features. Bechtel (1984) identified the presence of a variety of small-scale deformation structures in the walls of a garbage trench on the VEGP site within Tertiary Coastal Plain sediments. These structural features, including warped bedding, fractures, joints, minor offsets, and injected sand dikes, were interpreted as local phenomena related to dissolution of the underlying Utley Limestone and resultant plastic and brittle collapse of overlying Tertiary sediments. These features and their potential for non-tectonic surface deformation at the site are further discussed in Subsection 2.5.3.8.2.1 below. Bechtel (1984) also noted the presence of “clastic dikes” in the garbage trench and interpreted these features to be the result of near-surface pedogenic processes.

As described in Subsection 2.5.1.2.4.1, the Pen Branch fault was first discovered at the SRS in 1989, which initiated investigations at the VEGP site and a series of studies at the SRS. Investigations at the VEGP site concluded that the fault was not onsite or in close proximity to Units 1 and 2 (Reference 212). Studies of the Pen Branch fault at the SRS continued through the 1990s, but had still not definitively located the southwestward projection of the fault to the Georgia side of the Savannah River. As shown in Figures 2.5-224, 2.5-225, 2.5-227 and 2.5-237, projections of the fault into Georgia included locations northwest of the VEGP site (Reference 442) and directly southeast of the VEGP site (Reference 255).

In light of the data gathered from studies of the Pen Branch fault at the SRS during the 1990s and recent investigations at the VEGP site, some conclusions of the previous studies regarding the location of the Pen Branch fault in site studies and the FSAR should be revised. Because the Pen Branch fault has been located adjacent to the VEGP site and beneath the monocline in the Blue Bluff

Marl, it is now clear that the Pen Branch fault is associated with the monocline (or dip reversal) and that there is a Tertiary fault within 5 mi of the VEGP site. However, the new information only alters the past location of the Pen Branch fault. After considerable study, no new information gathered on the Pen Branch fault has changed the original conclusions of Snipes et al. (1989) that the youngest strata deformed by the fault are late Eocene and that the fault is not a capable tectonic source. In fact, recent studies, for this ESP study, have provided additional lines of evidence to support the non-capable status of the Pen Branch fault, a conclusion that has been supported in multiple NRC and DOE reviews (NUREG-1137, NUREG-1137-8, NUREG-1821).

2.5.3.1.2 Published Geologic Mapping

Geologic mapping of the site vicinity (25-mi radius) and site area (5-mi radius) in the past two decades has been largely focused on the SRS and surrounding regions of South Carolina (Figure 2.5-231). The USGS has published 1:100,000 scale and 1:48,000 scale geologic maps of the SRS area (Reference 558, Reference 412). In addition, the South Carolina Department of Natural Resources has published numerous 1:24,000 scale geologic maps within the site vicinity. Significantly fewer and less detailed geologic maps have been published for the Georgia portion of the VEGP site vicinity (Figure 2.5-231).

Additional studies focused on mapping and assessing specific geologic and/or tectonic features in the site vicinity. These include mapping and interpreting small-scale deformation structures (Reference 556; Reference 550) and possible Quaternary tectonic features (Reference 251; Reference 482).

McDowell and Houser (1983) mapped the distribution of small-scale deformation structures in the Upper Coastal Plain in the greater Columbia, South Carolina, to Augusta, Georgia, area. They identified small-scale folds, brittle faults, and convoluted bedding features exposed in roadcuts, excavations, and stream cuts. McDowell and Houser noted that some of these features appear to be non-tectonic in origin, whereas others are less clear and may be related to strong ground shaking.

Bartholomew et al. (2002) described exposures of “clastic dikes” in the VEGP site vicinity. One of these exposures is located in the upper Eocene Tobacco Road sand near Hancock landing (north of existing VEGP Units 1 and 2 within the VEGP site area). They interpret these clastic dikes as evidence for "strong paleoearthquakes, probably associated with late Eocene to late Miocene oblique-slip".

In addition, the USGS has published a compilation of all known Quaternary faults, liquefaction features, and possible tectonic features in the central and eastern United States (Reference 251), updated in (Reference 482) (Figure 2.5-220). The only feature within the 5-mi VEGP site area radius identified by this compilation is the Pen Branch fault (discussed in detail in Subsection 2.5.1.2.4.1). Crone and Wheeler (2000) classified the Pen Branch fault as a Class C feature (Table 2.5-201) because of its demonstrated early Cenozoic activity but absence of evidence for post-Eocene slip.

2.5.3.1.3 Previous Savannah River Site Investigations

SRS studies include numerous geological, geophysical, seismologic, and hydrologic investigations. These studies identified a number of basement faults that are mapped at the SRS based on interpretation of seismic reflection data, borehole data, gravity and magnetic data, and/or groundwater anomalies. Several of these faults are located within the 5-mi radius of the VEGP site (Figures 2.5-224, 2.5-225, and 2.5-226).

The SRS is one of the most extensively studied portions of the Coastal Plain in terms of geology. Accordingly, an exhaustive description of all SRS geologic studies is not given here. Instead, the key studies that locate and characterize tectonic features of the SRS are summarized in this section.

These studies include Chapman and DiStefano (1989), Snipes et al. (1993), Stieve et al. (1991), Stephenson and Stieve (1992), Geomatrix (1993), Domoracki (1994), Stieve and Stephenson (1995), and Cumbest et al. (1998, 2000). As described in Subsection 2.5.1.1.4.5, the majority of evidence for the presence of faults at the SRS is based on the interpretation of seismic reflection surveys; therefore, the depiction of buried fault locations differs between researchers and has also evolved through time with the successive availability of additional data.

Chapman and DiStefano (1989) conducted a vibroseis seismic reflection survey to refine existing knowledge of the basement structure beneath the SRS. This survey identifies first-order features of the basement surface, including the northern boundary fault of the Mesozoic Dunbarton Basin, later named the Pen Branch fault.

Based on core logs and supplemented by seismic reflection data from Chapman and DiStefano (1989), Snipes et al. (1993) mapped the location of the Pen Branch fault across the SRS. Snipes et al. (1993) recognized up-to-the-southeast movement for the Pen Branch fault and suggested that the fault formed originally as a Mesozoic normal fault bordering the northwestern Dunbarton Basin that was later reactivated in the Tertiary as a reverse fault.

Stieve et al. (1991) presented the results of a drilling program designed to further characterize the displacement history of the Pen Branch fault on the SRS. This study concludes that the base of the late Miocene Upland Formation is not deformed across the projected trace of the fault and thus provides direct stratigraphic evidence for the absence of activity on the Pen Branch fault within the past 5 Ma (million years ago).

Stephenson and Stieve (1992) and Stieve and Stephenson (1995) combined seismic data, borehole data, and potential field data to construct a subsurface structure model for the SRS. Their subsurface fault map identifies six basement-involved faults, including the Pen Branch, Steel Creek, ATTA, Ellenton, Crackerneck, and Upper Three Runs faults (Figure 2.5-224). These faults are described in Subsection 2.5.1.1.4.5 and Subsection 2.5.3.2.

Geomatrix (1993) performed a Quaternary and neotectonic study to assess geologic and geomorphic evidence for active tectonic deformation at the SRS. No evidence for active tectonic deformation was observed. Longitudinal profiles on Savannah River fluvial terraces show no evidence for warping or faulting of terrace surfaces associated with the surface projections of the Pen Branch and Steel Creek faults within a resolution of 7 to 10 ft (2 to 3 m).

Domoracki (1994) used 170 mi of reprocessed seismic reflection lines to map the geometry of the Dunbarton Basin and to refine the subsurface locations of SRS basement-involved faults. The report identified the Dunbarton Basin as a half-graben bounded solely by the Pen Branch fault and suggested that the Pen Branch fault possibly soles into the Augusta fault at depth (see Subsection 2.5.1.1.4.3 for discussion of the Augusta fault).

Cumbest et al. (1998, 2000) integrated data from more than 60 boreholes and more than 100 mi of seismic reflection profiles to provide the most-recent mapping of subsurface structure and basement-involved faults at the SRS. Cumbest et al. (1998) found no evidence for capability on any faults at the SRS. These data were used in combination with geometrical fault models to constrain slip histories for the Pen Branch and Crackerneck faults (Reference 255).

Cumbest et al. (2000) also compared the SRS faults with other Atlantic Coastal Plain faults and concluded that both sets of faults exhibit the same general characteristics and are closely associated. These characteristics include:

- Maximum offset less than 80 m (260 ft) at the base of the Coastal Plain sediments

- Regional-scale features that strike approximately northeast-southwest
- Predominantly reverse sense of slip
- Movement beginning in the Cretaceous Period and decreasing with time

Based on the strength of this association, and based on the fact that many of the other Coastal Plain faults are known to be non-capable, Cumbest et al. (2000) concluded by association that the SRS faults are also non-capable.

In situ stress measurements in basement rocks have been made in deep boreholes at the SRS. As part of a study of seismic hazards, magnitudes and orientations of in situ stresses were determined in five boreholes in 1998 and a 4,000-ft-deep borehole in 1992 (Reference 388). Results from the 4,000-ft-deep well (NPR hole) and previous borehole measurements at the SRS are consistent with a northeast-southwest direction of maximum compressive stress in the Altantic Coastal Plain province (Reference 388). While the orientation of maximum horizontal stress was observed to range from N75ºE to N33ºE in the NPR hole, the majority of other orientations are closer to approximately N60ºE. Thus, the maximum horizontal stress is oriented roughly parallel to the Pen Branch fault (about N55ºE), indicating that it is unlikely to accommodate reverse or strike-slip faulting earthquakes in the present stress regime (Reference 388).

2.5.3.1.4 Previous Seismicity Data

The EPRI catalog of historical seismicity has demonstrated that no known earthquake greater than body wave magnitude (m_b) 3 has occurred within the VEGP site vicinity (25-mi radius) prior to 1984 (Figure 2.5-219). Considering micro-seismicity (m_b<3) recorded since 1976 by the SRS seismic recording network, there has been no recent earthquake activity within the site area (5-mi radius) (Figure 2.5-219). The nearest micro-earthquake to the VEGP site is about 7 mi (about 11 km) to the northeast and located on the SRS (Reference 561).

The local SRS seismic network recorded three small earthquakes in 1985 (magnitude 2.6), 1988 (magnitude 2.0), and 1997 (magnitude 2.5), and a small earthquake sequence in 2001–2002 within the boundaries of the SRS (Reference 561). These small SRS earthquakes, as well as a 1993 event located north of the SRS in Aiken, South Carolina, have been studied by researchers in an effort to evaluate possible correlations to tectonic features. As described in Subsection 2.5.3.3, this minor activity is not correlated with any known faults.

2.5.3.1.5 Previous Seismic Reflection Data

In addition to the numerous seismic reflection surveys conducted at the SRS, several other seismic reflection studies have been performed in the VEGP site area. These include two surveys conducted within the Savannah River (Reference 211; Reference 321) and one conducted in a land-based survey located about 1.5 mi west of VEGP Units 1 and 2 (Reference 455).

As part of its investigation of the postulated Millett fault, Bechtel (1982) collected seismic reflection data along the Savannah River. Nelson (1989) reprocessed and re-interpreted these data from Utley Point southeastward to about 1 mi northwest of Griffins Landing to evaluate whether the Pen Branch fault extends southwest across the Savannah River beneath the VEGP site (Figure 2.5-237). Nelson (1989) concluded that there is no evidence of faulting and concluded that if the Pen Branch fault does occur in the SRS area in South Carolina, its upward termination is below the limit of survey penetration at approximately 750 ft (beneath at least the upper part of the Late Cretaceous Tuscalloosa Formation).

As part of a groundwater contamination study in Burke County, Georgia, Henry (1995) collected and interpreted seismic reflection data from two lines located in the Savannah River between Hancock Landing and the VEGP boat ramp (Figure 2.5-237). Henry (1995) concluded that the Pen Branch fault appears as a high-angle, southeast-side-up reverse fault located approximately 1,000 ft downstream from Hancock Landing (Figure 2.5-237). Henry (1995) interpreted the Pen Branch fault as a growth fault extending upward through the Paleocene Black Mingo Formation and into Eocene strata that lie below the unconformity at the base of Savannah River alluvium.

A land-based seismic reflection survey was performed along an unimproved road about 0.5 mi west of River Road (about 1.5 mi west of VEGP Units 1 and 2) and included in a report by Summerour et al.(1998) (Figure 2.5-237). Similar to Henry (1995), this research was also part of a groundwater contamination study in Burke County, Georgia. The seismic line was roughly situated across the westward projection of the Pen Branch fault within the site area and southwest of the VEGP site. Numerous, minor faults belonging to the Pen Branch fault were interpreted to cut reflectors within the Coastal Plain section. The basement reflector, however, is not clearly faulted and, therefore, these data suggesting the location of the Pen Branch fault are questionable.

2.5.3.1.6 Current Seismic Reflection Studies

Seismic reflection and refraction data were collected on the VEGP site in January and February 2006 as part of this ESP study. The seismic array was designed to: (1) image the Pen Branch fault, with the assumption that it continues on strike to the southwest from the SRS into the VEGP site area, and (2) assess the depth and character of the basement rocks beneath the Coastal Plain deposits. The survey included four seismic reflection and three seismic refraction lines (Figures 2.5-238 and 2.5-239, respectively). The results of this seismic reflection profiling clearly document that the Pen Branch fault is imaged in the basement beneath the VEGP site (see discussion in Subsection 2.5.1.2.4.2, and Figures 2.5-237 and 2.5-240). These data indicate that the Pen Branch fault strikes between N34ºE and N45ºE across the VEGP site, and dips 45º to the southeast.

2.5.3.1.7 Current Aerial and Field Reconnaissance

Field and aerial reconnaissance inspections reveal no evidence for surface rupture, surface warping, or the offset of geomorphic features indicative of active faulting. Likewise, interpretation of aerial and satellite photography and topographic maps reveals no evidence of geomorphic features indicative of potential for tectonic surface deformation (faulting or warping).

As part of the field reconnaissance performed for the ESP study, many of the features previously mapped within the site vicinity (25-mi radius) as evidence for possible tectonic activity have been observed [including those mapped by (Reference 556) and (Reference 550)]. Based on field observations and similar characteristics to features studied in a large excavation at the VEGP site (Reference 555), these features are assessed to be of non-tectonic origin. Even if the Bartholomew et al. (2002) “clastic dikes” are of tectonic origin, they interpret these features to be evidence for earthquakes that occurred during or prior to the late Miocene. “Clastic dikes” are discussed in detail in Subsection 2.5.3.8.2.2.

2.5.3.2 Geological Evidence, or Absence of Evidence, for Surface Deformation

As shown in Figure 2.5-224, four bedrock faults are mapped within 5 mi of the VEGP site (Reference 254, Reference 255; Reference 453). These four faults are:

- Pen Branch fault
- Ellenton fault

- Steel Creek fault
- Upper Three Runs fault

These faults were first identified on the SRS based on the interpretation of seismic reflection, borehole, gravity and magnetic, and/or groundwater data (Reference 232; Reference 562; Reference 451; Reference 442; Reference 265; Reference 453; and Reference 253, Reference 254, Reference 255). Each of these faults appears to terminate upward beneath the near surface. The youngest deposits deformed are Eocene in age. No deformation or geomorphic features indicative of potential Quaternary activity have been reported in the literature for these faults. Aerial and field reconnaissance and air photo interpretation performed for the current ESP study show that no geomorphic features indicative of Quaternary activity exist along any of the mapped fault traces. These four faults are summarized in Table 2.5-235 and described below.

2.5.3.2.1 Pen Branch Fault

The more than 20-mi-long (more than 30-km-long) Pen Branch fault is the northwest bounding fault of the Mesozoic Dunbarton Basin, strikes northeast, traverses the central portion of the SRS, and trends southwestward into Georgia near the VEGP site (Reference 441, Reference 442). Seismic reflection profiling performed as part of this ESP study has imaged the southeast-dipping Pen Branch fault beneath the VEGP site (see discussion in Subsection 2.5.1.2.4.2, Figure 2.5-243). The Pen Branch fault was reactivated in the Tertiary as an up-to-the-southeast reverse fault (Reference 442), and possibly soles into the Augusta fault (described in Subsection 2.5.1.1.4.3) at depth (Reference 265; Reference 453).

The Pen Branch fault is not exposed or expressed at the surface (Reference 442; Reference 453; Reference 255). Borehole and seismic reflection data collected from the SRS show no evidence for post-Eocene slip on the Pen Branch fault (Reference 255). SRS studies have been specifically designed to assess the youngest deformed strata overlying the fault through shallow, high-resolution reflection profiles, drilling of boreholes, and geomorphic analyses and have consistently concluded that late Eocene is the youngest strata deformed as described in Subsection 2.5.1.2.4.1.

The Pen Branch fault is not expressed geomorphically, nor is microseismicity associated with this fault. Therefore, it is concluded that the Pen Branch fault is not a capable fault within the site area. Within a resolution of 7 to 10 ft (2 to 3 m), longitudinal profiles along Quaternary fluvial terraces overlying the surface projection of the Pen Branch fault show no evidence of warping or faulting of the 350 ka to 1 Ma Ellenton (Qte) fluvial terrace (Reference 292).

Additional work performed for the ESP study has more accurately located the Pen Branch fault beneath a remnant of this terrace (Figure 2.5-246). The geomorphic evaluation of the Quaternary Ellenton terrace (Qte) surface overlying the Pen Branch fault is described in Subsection 2.5.1.2.4.3. The results of this study demonstrate a lack of tectonic deformation in the 350 ka to 1 Ma fluvial terrace surface within a resolution of about 3 ft. This observation is consistent with previous studies at both the VEGP site and the SRS that have concluded the Pen Branch fault is not a capable tectonic source.

2.5.3.2.2 Ellenton Fault

The Ellenton fault had been located in the southeastern portion of the SRS, about 4.6 mi from the VEGP site (Figure 2.5-224), but the Ellenton fault does not appear on the most recent SRS fault maps (Reference 254, Reference 255). The approximately 4-mi-long Ellenton fault had been interpreted to strike north-northwest, with near vertical to steeply east dip and east-side-down sense of slip (Reference 265; Reference 453). No clear relationship exists between the previously located Ellenton fault and regional structural features.

Because the data originally used to identify this fault are of poor quality according to Stieve and Stephenson (1995), the fault is not expressed geomorphically, and microseismicity is not associated with this fault; the current assessment is that this fault likely does not exist. Therefore, it is concluded that the Ellenton fault is not a capable tectonic source within the site area. Neither the Crone and Wheeler (2000) compilation of Quaternary faults and tectonic features in the central and eastern United States, nor the Wheeler (2005) compilation update, identifies the Ellenton fault as a potential Quaternary feature.

2.5.3.2.3 Steel Creek Fault

The Steel Creek fault is located in the northwest portion of the SRS, about 3 mi from the VEGP site (Reference 453; Reference 255) (Figures 2.5-224 and 2.5-226). This greater than 11-mi-long, northeast-trending, northwest-dipping, up-to-the-northwest reverse fault is located within the Dunbarton Basin and, along with the Pen Branch fault, forms a horst structure within the basin (Reference 453). The Steel Creek fault extends upward into Cretaceous units, but the uppermost extent of faulting remains unresolved (Reference 453).

Within a resolution of 7 to 10 ft (2 to 3 m), longitudinal profiles along Quaternary fluvial terraces overlying the surface projection of the Steel Creek fault show no evidence of warping or faulting of the fluvial terraces (Reference 292). The Steel Creek fault is not expressed geomorphically, nor is microseismicity associated with this fault. Therefore, it is concluded that this fault is not a capable tectonic source within the site area. Neither the Crone and Wheeler (2000) compilation of Quaternary faults and tectonic features in the central and eastern United States, nor the Wheeler (2005) compilation update, identifies the Steel Creek fault as a potential Quaternary feature.

2.5.3.2.4 Upper Three Runs Fault

The Upper Three Runs fault is located in the northwest portion of the SRS, about 5 mi from the VEGP site (Reference 453) (Figure 2.5-224). The location of the Upper Three Runs fault is mapped based on potential field data and interpretation of seismic reflection profiles (Reference 453). The Upper Three Runs fault has been interpreted as an older (initially Paleozoic) fault that soles into the Augusta fault at depth, possibly reactivated as a Mesozoic normal fault (Reference 252; Reference 265; Reference 453). The Augusta fault is discussed in Subsection 2.5.1.1.4.3.

The greater than 20-mi-long, northeast-trending Upper Three Runs fault is restricted to basement rocks. Seismic reflection profiling shows that the Coastal Plain sediments are not offset or deformed by this fault (Reference 232; Reference 453). The Upper Three Runs fault is not expressed geomorphically, nor is microseismicity associated with this fault. Therefore, it is concluded that this fault is not a capable tectonic source within the site area. Neither the Crone and Wheeler (2000) compilation of Quaternary faults and tectonic features in the central and eastern United States, nor the Wheeler (2005) compilation update, identifies the Upper Three Runs fault as a potential Quaternary feature.

2.5.3.3 Correlation of Earthquakes With Capable Tectonic Sources

Seismicity within the VEGP site vicinity (25-mi radius) is shown in Figure 2.5-219. As shown on this figure, there is no spatial correlation of earthquake epicenters with known or postulated faults. No faults or geomorphic features within the site vicinity (25 mi radius) can be correlated with earthquakes. Based on review of existing literature, no reported historical earthquake epicenters have been associated with bedrock faults within a 25 mi radius of the VEGP site (Figure 2.5-219). None of these faults within 25 mi of the VEGP site are classified as capable tectonic sources.

In general, the South Carolina and Georgia portions of the Coastal Plain and Piedmont provinces exhibit a higher rate of seismicity than elsewhere in these provinces (Figure 2.5-221). This diffuse

earthquake activity is not concentrated or aligned with any mapped faults, nor is it associated with any known tectonic structures. Figure 2.5-219 shows that no earthquakes of magnitude 3.0 or larger are known to have occurred within 25 mi of the site. However, several small events (m_b<3.0) have occurred within the site vicinity.

The SRS seismic recording network, which consists of nine instruments located within and adjacent to the SRS, has been recording microseismicity in the VEGP site vicinity since it was installed in 1976. This local network recorded three small earthquakes (in 1985 [magnitude 2.6], 1988 [magnitude 2.0], and 1997 [magnitude 2.5]) and a small earthquake sequence in 2001–2002 within the boundaries of the SRS (Reference 561). These small SRS earthquakes, and also a 1993 event located north of the SRS in Aiken, have been studied in an effort to evaluate possible correlations with tectonic features (Figure 2.5-219).

The June 9, 1985, earthquake of local duration magnitude (M_D) 2.6 was located about 5 mi north of the northwest margin of the Dunbarton Basin (Figure 2.5-219). The depth of this event was initially determined to be approximately 0.6 mi (1 km) (Reference 563), and was later listed at a depth of 3.5 mi (5.8 km) (Reference 561). This earthquake had a focal plane solution that suggests either a sinistral component of slip on a northeast-striking plane or a dextral component of slip on a northwest-striking plane (Reference 563). The close location of the event to the northwest margin of the Dunbarton Basin and northeast strike of the sinistral nodal plane led Talwani et al. (1985) to associate this event with the northeast-striking basin border fault (later named the Pen Branch fault). However, Crone and Wheeler (2000) point out that the sinistral sense of slip from the fault plane solution is inconsistent for the Pen Branch fault given the northeast-southwest orientation of principal horizontal stress. Therefore, it is highly unlikely that this event is associated with the Pen Branch fault.

The August 5, 1988, earthquake of magnitude 2.0 was centered southeast of the Pen Branch fault within the Dunbarton Basin (Figure 2.5-219*)*. The hypocenter of this event was located at a depth of about 1.5 mi (2.5 km) (Reference 561)and no focal mechanism solution could be obtained (Reference 267). Domoracki et al. (1999) suggested that this earthquake was associated with the Pen Branch fault. However, Stevenson and Talwani's (2004) more recent hypocenter location for this event suggests no spatial association with a known fault.

The August 8, 1993, Aiken, South Carolina, earthquake with a body wave magnitude estimated from Rayleigh surface waves (m_{blg}) of 3.2 was studied in detail by Stevenson and Talwani (1996), who determined that the event was located within a steep gravity gradient that they interpret to be the edge of a granitic pluton (Figure 2.5-219*)*. The hypocenter of this event was located at a depth of about 6 mi (about 10 km) (Reference 561). The event is not spatially associated with a known fault.

The May 17, 1997, earthquake of magnitude 2.5 was located about 0.5 to 1 mi northwest of the Pen Branch fault (Figure 2.5-219). Given that this event had a depth of about 3 mi (5 km) (Reference 561), it is located in excess of 3 mi from the southeast-dipping Pen Branch fault.

The most recent activity, termed the Upper Three Runs earthquake sequence, included an October 8, 2001, main event of m_{blg} 2.6 centered near Upper Three Runs Creek and a series of seven very small aftershocks occurring through March 6, 2002, in a small area of 6.0 to 6.5 square km (Reference 561) (Figure 2.5-219). All events within this earthquake sequence occurred within depths of approximately 1.8 to 3 mi (3 to 5 km), with a positional uncertainty of about 1600 ft (about 500 m) due to the proximity of the local SRS seismic stations. Single event and composite focal mechanisms indicate a predominantly reverse motion on a fault plane oriented N25ºW, 41ºSW. A 3-D plot of hypocenters defined a fault plane of similar orientation (Reference 561).

Stevenson and Talwani (2004) examined gravity data and found a northeast-trending grain to the Bouguer gravity map. Upon further processing to derive a map of the first horizontal derivative of

gravity, they defined a small local northwest-trending ridge of gravity that they interpreted as the causative structure. The shallowness and small areal extent of the Upper Three Runs earthquake sequence, combined with the apparent association of a very small basement feature running counter to the regional structural trend, suggest that this earthquake activity is extremely localized and is not attributable to any regional features (Reference 561).

2.5.3.4 Ages of Most Recent Deformations

As presented in Subsection 2.5.3.2, none of the four faults within 5 mi of the VEGP site exhibit evidence of Quaternary activity. The Pen Branch fault represents the northern bounding normal fault of the Mesozoic Dunbarton Basin, and this structure was reactivated as a Tertiary oblique-reverse fault. Borehole and seismic data provide no evidence for post-Eocene slip on the Pen Branch fault (Reference 255). Geomatrix (1993) concluded that the Pen Branch fault does not deform Quaternary fluvial terraces of the Savannah River within a resolution of 7 to 10 ft (2 to 3 m). The geomorphic evaluation of this same 350 ka to 1 Ma fluvial terrace surface performed as part of this ESP study demonstrates a lack of tectonic deformation within a resolution of about 3 ft (about 1 m) (described in Subsection 2.5.1.2.4.3).

The Ellenton fault was previously interpreted as a north-northeast-striking fault (Reference 453), but it does not appear in the most recent maps of subsurface SRS faults (Reference 254, Reference 255) and likely does not exist.

The Steel Creek fault extends upward into Cretaceous units, but the uppermost extent of faulting remains unresolved (Reference 453). Geomatrix (1993) concluded that the Steel Creek fault does not deform Quaternary fluvial terraces of the Savannah River within a resolution of 7 to 10 ft (2 to 3 m).

The Upper Three Runs fault is restricted to basement rocks. Seismic reflection profiling revealed no evidence for this fault deforming overlying Coastal Plain sediments (Reference 232; Reference 453).

2.5.3.5 Relationships of Tectonic Structures in the Site Area to Regional Tectonic Structures

The four faults identified within the site area (i.e., the Pen Branch, Ellenton, Steel Creek, and Upper Three Runs faults) are located on the SRS. Only one of these faults (the Pen Branch) is observed west of the Savannah River in Georgia. As described in Subsection 2.5.3.6, none of the four faults within the site area is considered a capable tectonic feature.

2.5.3.5.1 Pen Branch Fault

The Pen Branch fault likely is the northern boundary fault of the Mesozoic Dunbarton Basin. During the Mesozoic, the fault accommodated crustal extension and thinning with a southeast-side-down normal sense of slip (Reference 442; Reference 265; Reference 453). Snipes et al. (1993) suggested that the southeastern margin of the Dunbarton Basin may also be bounded by a fault (the Martin fault), although Domoracki et al. (1999) suggested that the Dunbarton Basin is instead a half-graben bounded only by the Pen Branch fault to the north.

The Pen Branch fault was reactivated as a reverse or reverse-oblique fault during Cretaceous and into Tertiary time, with an up-to-the-southeast sense of slip (Reference 559; Reference 442; Reference 255). Stephenson and Stieve (1992) and Stieve and Stephenson (1995) suggested that the Pen Branch fault may sole into the shallow dipping Augusta fault (described in Subsection 2.5.1.1.4.3) or a Paleozoic/Mesozoic regional decollement at depth (Figure 2.5-205).

2.5.3.5.2 Ellenton Fault

The Ellenton fault as mapped by Stieve and Stephenson (1995) is a north-northwest striking fault located within the Dunbarton Basin between the Upper Three Runs and Pen Branch faults. The Ellenton fault orientation is roughly normal to the regional structural grain and to the other SRS faults and bears no clear relationship to regional structures. The Ellenton fault does not appear on the most recent SRS fault maps (Reference 254, Reference 255) and likely does not exist.

2.5.3.5.3 Steel Creek Fault

This northeast-trending Steel Creek fault is roughly parallel to the regional structural grain and is located within the Dunbarton Basin. The Steel Creek fault is an up-to-the-northwest, secondary structure associated with the Pen Branch fault, with which it forms a horst structure within the basin (Reference 453).

2.5.3.5.4 Upper Three Runs Fault

The northeast-trending Upper Three Runs fault is roughly parallel to the regional structural grain and is restricted to basement rocks; seismic reflection profiles show that the fault does not offset Coastal Plain sediments (Reference 232; Reference 453). The Upper Three Runs fault has been interpreted as an older (initially Paleozoic) fault, possibly reactivated as a Mesozoic normal fault (Reference 252; Reference 265; Reference 453). The Upper Three Runs fault possibly soles into the Augusta fault (described in Subsection 2.5.1.1.4.3) or a Paleozoic/Mesozoic regional decollement at depth (Reference 453) (Figure 2.5-205).

2.5.3.6 Characterization of Capable Tectonic Sources

Based on studies evaluated in the preceding sections, SNC concluded that there are no capable tectonic sources within 5 mi of the VEGP site. The Pen Branch fault, the nearest fault to the VEGP site, has undergone extensive study and multiple reviews by the NRC. All of these studies, including investigations as part of this ESP study, support the non-capable status of the Pen Branch fault as outlined below:

- NUREG-1137-8 concludes that the Pen Branch fault is not a capable fault and does not represent a hazard to the VEGP site. Similarly, other NRC reviews of the Pen Branch fault for facilities such as the Mixed Oxide Fuel (MOX) Fabrication Facility at SRS have also concluded that the Pen Branch fault is not a capable fault (NURERG-1821).

- The “association clause” of Appendix A 10 CFR 100.23 applies to this discussion as follows: Cumbest et al. (2000) noted that the Pen Branch fault shares characteristics with other Atlantic Coastal Plain faults that are considered non-capable. These characteristics include northeast-southwest strikes, small total offsets of Cenozoic strata in relation to fault age, slip histories that began in the Cretaceous, and offsets that decrease with decreasing age. Cumbest et al. (2000) argued that the abundance of shared characteristics between these faults implies that these faults are genetically related. Several of these faults have been shown to be non-capable. Therefore, Cumbest et al. (2000) concluded that the Pen Branch fault is likely non-capable as well.

- The Pen Branch fault is not exposed or expressed at the surface **(**Reference 442; Reference 453; Reference 255). Reconnaissance work and aerial photograph interpretation performed for the ESP study confirm that there is no exposure of the fault or geomorphic expression of potential Quaternary activity.

- Snipes et al. (1993) investigated a 10- to 20-ft-thick (3- to 6-m-thick) Quaternary light tan soil horizon in railroad cuts overlying the projected trend of the Pen Branch fault at the SRS. They observed no detectable offset of this unit. According to Snipes et al. (1993), the youngest horizon known from borehole studies to be faulted is the top of the Dry Branch Formation of Late Eocene age.

- Regional principal stress orientations based on stress-induced wellbore breakouts and hydraulically induced fracturing show that the maximum horizontal stress is parallel to the regional orientation of the Pen Branch fault, which makes “strike-slip faulting unlikely” and “reverse faulting essentially impossible” (Reference 388). The most-recent deformation observed for this fault in Tertiary sediments is reverse faulting.

- Geomatrix (1993) evaluated longitudinal profiles along Quaternary fluvial terraces of the Savannah River and concluded that no evidence of terrace surface warping or faulting exists within a resolution of 7 to 10 ft (2 to 3 m). Additionally, as part of the ESP study, local longitudinal terrace profiles across the now well-located Pen Branch fault support the earlier conclusion that no deformation is observed in the terrace remnant of the Ellenton terrace (estimated as 350 ka to 1 Ma) overlying the Pen Branch fault.

- As part of this ESP study, geomorphic analysis of the 350 ka to 1 Ma fluvial terrace overlying the surface projection of the Pen Branch fault at the SRS demonstrates the lack of tectonic deformation of this Quaternary geomorphic surface within a resolution of about 3 ft. The resolution of this study compared with the previous studies makes it by far the most definitive evidence for the non-capability of the Pen Branch fault both at the Savannah River Site and the VEGP site. Results are described in more detail in Subsection 2.5.1.2.4.3.

2.5.3.7 Designation of Zones of Quaternary Deformation Requiring Detailed Fault Investigation

No zones of quaternary deformation require detailed investigation within the site area.

2.5.3.8 Potential for Tectonic or Non-Tectonic Deformation at the Site

The potential for tectonic deformation at the site is negligible. There is, however, the evidence for past, and the potential for future, non-tectonic deformation at the site in the form of dissolution-induced collapse features. These conclusions are discussed in the following sections.

2.5.3.8.1 Potential for Tectonic Deformation at the Site

The potential for tectonic deformation at the site is negligible. The presence of the Pen Branch fault adjacent to the VEGP Units 3 and 4 footprint and beneath the monocline in the Blue Bluff Marl (Figures 2.5-242 and 2.5-245) suggests that past deformation of the Eocene strata has occurred in the form of non-brittle folding. However, this type of deformation associated with the non-capable Pen Branch fault is no longer active and will not impact the ground surface in the future. Since the original site studies in the early 1970s, no new information has been reported to suggest the existence of any Quaternary surface faults or capable tectonic sources within the site area.

2.5.3.8.2 Potential for Non-Tectonic Deformation at the Site

Several non-tectonic features are present in the site area. These include dissolution-induced collapse structures and clastic dikes. As described below, permanent ground deformation at the site may be produced by dissolution within the Utley Limestone, whereas clastic dikes are not potential sources of permanent ground deformation. Dissolution-related permanent ground deformation would

be mitigated at the site by the excavation and removal of the Utley Limestone during construction of the site.

Clastic dikes have been reported at the site and in the site vicinity (Reference 437; Reference 549; Reference 555; Reference 550). The origin of these features has been subject to considerable debate, but those on-site features described as “clastic dikes” likely were formed by soil weathering processes, as described in Subsection 2.5.3.8.2.2. NUREG-1137 concludes that no evidence exists that these features represent a safety issue for the plant, whatever their origin.

2.5.3.8.2.1 Dissolution Collapse Features

The potential for non-tectonic deformation at the site resulting from near-surface dissolution-induced collapse has long been recognized as a possibility and has been the subject of several studies e.g., (Reference 554, Reference 555). Bechtel (1984b) identified the presence of a variety of small-scale deformation structures in the walls of a garbage trench on the VEGP site within Tertiary Coastal Plain sediments (Figure 2.5-237). These structural features, including warped bedding, fractures, joints, minor offsets, and injected sand dikes, were interpreted as local phenomena related to dissolution of the underlying Utley Limestone and resultant plastic and brittle collapse of overlying Tertiary sediments (Reference 555) (Figures 2.5-363 and 2.5-364).

The dissolution origin for the warped bedding, fractures, small-scale faults, “clastic dikes,” and sand-injected dikes is interpreted largely from the observations and detailed documentation of these features in a large trench exposure that was over 900 ft long, 30 to 45 ft deep, and 25 to 40 ft across (Reference 555). The high concentration of these features within the trench and the spatial and kinematic relationships between different types of deformation features provide some of the best information regarding their origin. Field mapping efforts performed as part of the VEGP ESP application also identified “clastic dikes” within the VEGP site and surrounding site area, and similarly concluded these features are of a non-tectonic origin based on field observations.

The three-dimensional nature of the warped bedding, combined with the spatial and kinematic relationships of the small-scale faults and fractures along the margins of the more strongly warped depressions, clearly demonstrates a dissolution or sediment collapse origin. The highly irregular, discontinuous nature of folding is consistent with a non-tectonic dissolution origin and inconsistent with a tectonic origin, since there are no laterally persistent fold axes. For example, the upper contact of Unit F, a 1-to-2-ft-thick, moderately consolidated, laminated, red and yellow, silty fine sand, is folded into a highly irregular surface (Reference 555)(Figure 2.5-365). If this minor fold deformation was associated with the underlying Pen Branch fault, fold axes should be laterally persistent and parallel to the fault. The discontinuous nature of domes and depressions in an “egg carton” or “dimpled” pattern reflects the more random, non-tectonic process of dissolution (Figure 2.5-365).

Most of the small-scale faults have normal displacement toward or into the depressions, and a few exhibit minor reverse slip near the crests of some arches (Reference 555). These features are of limited dimensions and cannot be traced laterally across the width of the trench. The orientations of fractures and small faults are locally consistent with the limbs of the individual arches and depressions, but vary strongly from fold to fold. In some cases, such as shown in Figure 2.5-364, the small faults actually arc over the centers of some of the depressions. These field relationships all support an origin related to very localized settlement of the depressions resulting from dissolution and collapse of underlying strata.

The age of these dissolution features is poorly constrained; however, they are younger than the Eocene and Miocene host sediment and older than the overlying late Pleistocene or eolian sand of the Pinehurst Formation (Reference 555). No late Pleistocene or Holocene dissolution features have been identified at the site.

Anecdotal accounts provide additional evidence for the potential for dissolution-induced collapse at the site. The presence of a cave located near Mathes Pond, currently under water, and accounts of "soft zones" encountered in boreholes above the Blue Bluff Marl suggest the possibility of dissolution at the VEGP site.

Dissolution-induced collapse structures are not tectonic features, nor do they indicate regionally significant seismicity (Reference 555). NUREG-1137 concludes that no evidence exists that these features represent a safety issue for the plant. Dissolution collapse, however, represents a potential minor, non-tectonic surface deformation hazard in areas underlain by the Utley Limestone at the site. This hazard could be mitigated during construction through excavation and removal of the Utley Limestone to establish the foundation grade of the plant.

Not all depressions in the VEGP site area are the result of dissolution collapse. Carolina bays are non-tectonic, surficial geomorphic depressions that may resemble surface expression of dissolution collapse features. Carolina bays are commonly found throughout the VEGP site area and discussed in greater detail in Subsection 2.5.1.1.1. Unlike Carolina bays, surface depressions resulting from dissolution collapse are irregularly shaped and randomly oriented.

Pre-construction topographic maps of the VEGP site show several closed depressions at the site. Site reconnaissance performed for the ESP study shows that these depressions no longer exist and that they were likely destroyed by site excavations and activities. No present-day surface depressions were identified at the VEGP site as part of the ESP study.

2.5.3.8.2.2 Clastic Dikes

Clastic dikes are relatively planar, clay-filled features that typically flare out upward and are on the order of centimeters-to-decimeters wide and decimeters-to-meters long. Clastic dikes are widespread in the Coastal Plain of Georgia and South Carolina in the upper Miocene Barnwell and Hawthorne Formations. Despite the widespread occurrence of clastic dikes, however, their origin or origins are poorly understood. They have been variously attributed to seismic shaking or tectonic activity, to solution of underlying carbonate horizons and sediment collapse, and to weathering and soil-forming hypotheses [e.g., (Reference 437; (Reference 555); Reference 550)].

Clastic dikes on the VEGP site, in the site area, and on the SRS were described in detail by Alterman (1984), who noted feature dimensions, composition, grain size, and color, but did not propose a favored formation mechanism.

In describing clastic dikes exposed in the walls of a garbage trench more than 900 ft long located on the VEGP site, Bechtel (1984) differentiated two distinct classes of dikes: (1) "sand dikes" that resulted from plastic or liquid injection of loosely consolidated fine sand into overlying, fractured, relatively consolidated sediment, and (2) "clastic dikes" that resulted primarily from weathering and soil-forming processes preferentially enhanced along pre-existing fractures that formed during dissolution collapse. According to Bechtel (1984), the present geographic distribution of clastic dikes is controlled by the depth of weathering and paleosol development in the Coastal Plain sediments and by subsequent erosion of the land surface. Bechtel (1984) concluded that the dikes are primarily a weathering phenomenon that formed at least 10 ka to 100 ka. As part of the field reconnaissance performed for the ESP study, abundant "clastic dikes" have been observed in the site area that have characteristics consistent with a pedogenic or weathering origin, but no features were observed that can reasonably be interpreted to have formed as a result of injected sand. The field reconnaissance of "clastic dikes" exhibited the following primary characteristics, which were summarized by the Bechtel (1984) study of these features within a large trench exposure on the VEGP site:

1. The dikes are widely distributed through the region in deeply weathered clayey and silty sands of the Eocene Hawthorne and Barnwell Formations.

2. The dikes occur in nearly all exposures of the weathered profile but are rare in exposures of stratigraphically lower, less weathered sediment.

3. The dikes contain a central zone of bleached host rock bounded by a cemented zone of iron oxide. Some dikes contain a clay core.

4. Grain size analyses on samples indicate that the dike interval contains the same grain distribution as the host sediment with slightly more silt and clay (excluding clay core).

5. The dikes and associated mottling decrease downward in density and size. In most cases, the dikes taper downward and pinch out over a 5-to-15-ft distance.

NUREG-1137 concluded that no evidence exists that the clastic dikes represent a safety issue for the VEGP site. The SER suggests that the clastic dikes on the VEGP site may be non-tectonic, soft-sediment deformation features that formed 20 to 25 Ma.

In contrast to non-tectonic “clastic dikes,” Bartholomew et al. (2002) interpreted sand dike features found in the upper Eocene Tobacco Road Sand near Hancock Landing, Georgia, less than five mi north of the VEGP site, as evidence for strong paleoearthquakes probably associated with late Eocene to late Miocene earthquake activity possibly associated with the Pen Branch and/or Crackerneck faults. Bartholomew et al. (2002) describe sand dikes that cut across poorly bedded clay-rich strata and are filled with massive, medium to coarse sand.

However, the sand dikes identified by Bartholomew et al. (2002) are syndepositional due to the presence of marine animal burrows that cross cut the dikes. The formation of these dikes occurred during the late Eocene while the sediments were in a subaqueous marine environment (Reference 550). Whether these dikes of Bartholomew et al. (2002) formed as a result of seismic shaking or some other process related to soft sediment deformation (e.g., compaction and de-watering), these features are significantly older than Quaternary and, therefore, do not reflect geologically recent seismic activity.

2.5.4 Stability of Subsurface Materials and Foundations

This section presents information on the stability of subsurface materials and foundations at the VEGP site that may affect the proposed new unit's seismic Category 1 facilities. This geological, geophysical, geotechnical, and seismological information is developed and used as a basis to evaluate the stability of subsurface materials and foundations at the site. Field and laboratory test data was initially gathered during the ESP phase site investigation and subsequently augmented with field and laboratory data from a COL level investigation in support of the ESP limited work authorization (LWA) request.

Information presented in this section was developed from onsite geotechnical and geophysical investigations, a review of analysis and reports prepared for the existing VEGP units, and a review of geotechnical literature. Site specific reports prepared by Bechtel Power Corporation were included in this review; these reports addressed foundation investigation (Reference 552), backfill material investigations (Reference 577, Reference 578 and Reference 581), dynamic properties of the backfill (Reference 579), and the test fill program (Reference 580).

The ESP geotechnical field and laboratory investigation performed by MACTEC Engineering and Consulting, Inc. for the application was intended to enhance the understanding of the VEGP site and complement the existing geotechnical data developed for VEGP Units 1 and 2. The ESP geotechnical investigation data report is included as Appendix 2.5A. Portions of this geotechnical data report were revised by MACTEC. A discussion of these revisions is provided in Subsection 2.5.4.3.2.4. These revisions are reflected in Appendix 2.5A. The ESP seismic reflection/refraction data report is included as Appendix 2.5B.

A comprehensive site geotechnical field and laboratory investigation was performed by MACTEC to support the COL application. This investigation was conducted to augment the existing ESP geotechnical data and to further develop geotechnical data at specific proposed VEGP Units 3 and 4 structure locations and backfill borrow source locations. The COL investigation field work was substantially completed on April 20, 2007. The MACTEC geotechnical data report is included in Appendix 2.5C. A test pad program was conducted in late 2007. A report on this effort is provided in Appendix 2.5D.

2.5.4.1 Geologic Features

Subsection 2.5.1.1 describes the regional geology, including regional physiography and geomorphology, regional geologic history, regional stratigraphy, and the regional tectonic setting. Subsection 2.5.1.2 addresses site-specific geology and structural geology, including site physiography and geomorphology, site geologic history, site stratigraphy, site structural geology, and a site geologic hazard evaluation.

2.5.4.2 Properties of Subsurface Materials

Subsurface Uniformity

Soil structure interaction and foundation design are a function of the uniformity of the soil or rock below foundation. Although the design and analysis of the AP1000 is based on soil or rock conditions with uniform properties within horizontal layers, it includes provisions and design margins to accommodate many non-uniform sites. This subsection identifies the requirements for site investigation that may be used to demonstrate that:

- A site is “uniform” based on the criteria outlined in Site Foundation Material Evaluation Criteria below. If the site can be demonstrated to be “uniform,” no further site specific analysis is required to qualify the site for the AP1000.

- A “non-uniform” site is acceptable to locate the AP1000 based on the criteria for acceptability outlined in Site Foundation Material Evaluation Criteria below. Non-uniform sites may be shown to be acceptable as described in subsection 2.5.4.5.3.1 using site-specific evaluation as part of the Combined License application.

Considerations with respect to the materials underlying the nuclear island are the type of site, such as rock or soil, and whether the site can be considered uniform. If the site is non-uniform, the non-uniform soil characteristics, such as the location and profiles of soft and hard spots, should be considered. These considerations can be assessed with the information developed in response to Regulatory Guides 1.132 and 1.138. The geological investigations of Subsections 2.5.1 and 2.5.7.5 provide information on the uniformity of the site, whether it may be geologically impacted, and whether the bedrock may be sloping or undulatory.

Site Foundation Material Evaluation Criteria

The AP1000 is designed for application at a site where the foundation conditions do not have extreme variation within the nuclear island footprint. This subsection provides criteria for evaluation of soil variability. The subsurface may consist of layers and these layers may dip with respect to the horizontal. If the dip is less than 20 degrees, the generic analysis using horizontal layers is applicable as described in NUREG/CR-0693 (Reference 2). The physical properties of the foundation medium may or may not vary systematically across a horizontal plane. The recommended methodology for checking uniformity is to calculate from the boring logs a series of “best-estimate” planes beneath the nuclear island footprint that define the top (and bottom) of each layer. The planes could represent stratigraphic boundaries, lithologic changes, and unconformities, but most important, they should represent boundaries between layers having different shear wave velocities. Shear wave velocity is the primary property used for defining uniformity of a site.

The distribution of bearing reactions under the basemat is a function of the subgrade modulus, which in turn is a function of the soil properties. The Combined License applicant shall demonstrate that the variation of subgrade modulus across the footprint is within the range considered for design of the nuclear island basemat. The farther that the non-uniform layer is located below the foundation, the less influence it has on the bearing pressures at the basemat. Lateral variability of the shear wave velocity at depths greater than 120 feet below grade (80 feet below the foundation) do not significantly affect the subgrade modulus.

Subsurface conditions should be evaluated by the Combined License applicant based on the geologic investigation in accordance with Regulatory Guide 1.132. Subsurface conditions should be evaluated within the nuclear island footprint and 40 feet beyond the boundaries of the nuclear island footprint at depths less than 120 feet below grade. Subsurface conditions may be considered uniform if the geologic and stratigraphic features can be correlated from one boring or sounding location to the next with relatively smooth variations in thicknesses or properties of the geologic units. An occasional anomaly or a limited number of unexpected lateral variations may occur. If a site can be classified as uniform, it qualifies for the AP1000 based on analyses and evaluations performed to support design certification without additional site-specific analyses.

As an example of sites that are considered uniform, the variation of soil properties in the material below the foundation to a depth of 120 feet below finished grade within the nuclear island footprint and 40 feet beyond the boundaries of the nuclear island footprint meets the criteria outlined below:

- The depth to a given layer indicated on each boring log may not fall precisely on the postulated “best-estimate” plane. The deviation of the observed layers from the “best-estimate” planes should not exceed 5 percent of the observed depths from the ground surface to the plane. If the deviation is greater than 5 percent, additional planes may be appropriate or additional borings may be required. This thereby diminishes the spacing.

- For a layer with a low strain shear wave velocity greater than or equal to 2500 feet per second, the layer should have approximately uniform thickness and should have a dip no greater than 20 degrees, and the shear wave velocity at any location within any layer should not vary from the average velocity within the layer by more than 20 percent.

Site-Specific Subsurface Uniformity Design Basis

Many sites that do not meet the above criteria for a uniform site are acceptable for the AP1000. The key attribute for acceptability of the site for an AP1000 is the bearing pressure on the underside of the basemat. A site having local soft or hard spots within a layer or layers does not meet the criteria for a uniform site. Non-uniform soil conditions may also require evaluation of the AP1000 seismic response as described in Subsection 2.5.2.

As described in Subsection 3.8.5, the nuclear island foundation is designed specifically for bearing pressures of 120 percent of those of the uniform soil properties case. Evaluation criteria are defined to evaluate sites that do not satisfy the site parameters directly. The design basis provided below is included to provide a clear specification of the design commitment and evaluation criteria required to demonstrate that a site-specific application satisfies AP1000 requirements. Application of the AP1000 to sites using this site-specific evaluation is not approved as part of the AP1000 design certification and the evaluation should be provided and reviewed as part of the Combined License application.

Rigid Basemat Evaluation

A site with nonuniform soil properties may be demonstrated to be acceptable by evaluation of the bearing pressures on the underside of a rigid rectangular basemat equivalent to the nuclear island. The soils identified in the site investigation may be included in a finite element model of the soil to analyze the effect of the lateral variability. When the variability identified at the site can be modeled in two dimensions (there is not significant variability in one horizontal direction), 2D analyses may be used. Where the variability occurs in both horizontal directions, a 3D analysis should be performed. Bearing pressures are calculated in a linear analysis for unit vertical load and overturning moments. For the site to be acceptable, the bearing pressures from this analysis need to be less than or equal to 120 percent of the bearing pressures calculated in similar analyses for a site having uniform soil properties.

Alternatively, the safe shutdown earthquake loads may be determined from a site-specific seismic analysis of the nuclear island using site-specific inputs as described in Subsection 2.5.2. For the site to be acceptable, the bearing pressures from the site-specific analyses (with site-specific response and site-specific soil properties) need to be less than or equal to 120 percent of the bearing pressures calculated in similar rigid basemat analyses using the AP1000 design ground motion at a site having uniform soil properties.

Flexible Basemat Evaluation

For sites having bedrock close to the foundation level, the assumption of a rigid basemat may be overly conservative because local deformation of the basemat will reduce the effect of local soil variability. For such sites, a site-specific analysis may be performed using the AP1000 basemat model and methodology described in Subsection 3.8.5. The soils may be represented by soil springs or by a finite element model of the soil depending on the type of variability identified at the site. The safe shutdown earthquake loads are those from the AP1000 design soil case representative of the site-specific soil. Alternatively, bearing pressures may be determined from a site-specific soil structure interaction analysis using site-specific inputs as described in Subsection 2.5.2. For the site to be acceptable, the bearing pressures from the site-specific analyses, including static and dynamic loads, need to be less than the design bearing strength of each portion of the basemat.

2.5.4.2.1 Introduction

This section describes the static and dynamic engineering properties of the VEGP site subsurface materials. An overview of the subsurface profile and materials is given in Subsection 2.5.4.2.2. The field investigations, described in Subsection 2.5.4.3, are summarized in Subsection 2.5.4.2.3. The descriptions of the subsurface materials provided in the following sections are based primarily on two recent field investigations, ESP and COL, and review of previous investigations. Within each section the ESP basis description is followed by the COL-basis description. The soils encountered during the ESP and COL subsurface investigations constitute alluvial and Coastal Plain deposits and can be placed in three groups for stability of subsurface materials and foundation purposes (i.e., for geotechnical purposes). These soils include, from top to bottom, sands with silt and clay (Group 1), clay marl (Group 2), and coarse-to-fine sand with interbedded thin seams of silt and/or clay (Group 3). The Upper Sand Stratum (Group 1 soils) will be completely removed and replaced with compacted structural fill prior to the construction of VEGP Units 3 and 4. The static and dynamic engineering properties of the three principal soil groups, along with the compacted structural fill, were determined by field investigation and laboratory testing. The laboratory tests and their results are summarized in Subsection 2.5.4.2.4. The engineering properties of the subsurface materials are presented in Subsection 2.5.4.2.5.

2.5.4.2.2 Description of Subsurface Materials

The site soils and bedrock are divided into five strata (Upper Sand Stratum, Marl Bearing Stratum, Lower Sand Stratum, Dunbarton Triassic Basin bedrock, and Paleozoic Crystalline bedrock), which correspond to the three soil groups mentioned in Subsection 2.5.4.2.1 plus the two bedrock units:

I. Upper Sand Stratum (Barnwell Group) – predominantly sands, silty sands, and clayey sands with occasional clay seams, soft zones, and shell zones. A shelly limestone (Utley Limestone) layer was encountered at the base of the Upper Sand Stratum or the top of the Blue Bluff Marl. The limestone contains shell zones, solution channels, cracks, and discontinuities. Severe fluid loss was observed in this layer during drilling for the ESP and COL subsurface investigations.

II. Marl Bearing Stratum (Blue Bluff Marl or Lisbon Formation) - slightly sandy, cemented, overconsolidated, calcareous silt and clay with some shells and partially cemented, well indurated layers.

III. Lower Sand Stratum (comprises several formations from the Still Branch just beneath the Blue Bluff Marl to the Cape Fear just above the Dunbarton Triassic Basin rock) – fine-to-coarse sand with interbedded silty clay and clayey silt.

IV. Dunbarton Triassic Basin Rock – red sandstone, breccia, and mudstone, weathered through the upper 120 ft.

V. Paleozoic Crystalline Rock – a competent rock with high shear wave velocities that underlies the non-capable Pen Branch Fault, which underlies the site.

These strata have been previously used as a means for classifying the soils and rock with regard to engineering properties, and are also used in this ESP SSAR.

The following sections provide brief descriptions of the subsurface materials, giving the soil and rock constituents, and their range of thickness encountered at the site. The information has been taken from the 14 borings and 10 cone penetrometer tests (CPT) performed during the ESP subsurface investigation. The locations of the ESP borings and CPTs are shown on Figure 2.5-366. Reference is made, as appropriate, to borings performed for VEGP Units 1 and 2. For reference, the VEGP site

elevations in the areas explored range from about El. 219 to 256 ft msl, with a median of about El. 222 ft msl. It is noted that most of the VEGP ESP site is flat at about El. 220 ft msl with surrounding areas at higher elevations of about 250 ft msl. A finished plant grade of El. 220 ft msl is used for the new unit ESP analysis. The engineering properties are provided in Subsection 2.5.4.2.5. Figures 2.5-370, 2.5-372, and 2.5-373 provide illustrations of the subsurface conditions across the VEGP site observed in the ESP borings. A profile legend is provided as Figure 2.5-369.

Information produced from 70 borings and 8 CPTs, located in the immediate area of the nuclear islands, from the COL subsurface investigation has also been used to develop the following descriptions of the subsurface materials. The locations of the explorations performed for the COL investigation are shown on Figures 2.5-367 and 2.5-368. Figures 2.5-371, 2.5-374, and 2.5-375 provide illustrations of the subsurface conditions across the Nuclear Islands (NIs) for Units 3 and 4, observed in the COL borings.

2.5.4.2.2.1 Upper Sand Stratum (Barnwell Group)

The ESP subsurface investigation (Appendix 2.5A) determined that the Upper Sand Stratum ranged in thickness from 78 to 157 ft beneath the ground surface at the completed boring locations. The wide range of thickness was due to two factors. First, three borings (B-1004, B-1005, and B-1006) were drilled from elevations about 30 ft higher than the remaining borings. Second, the top of the Blue Bluff Marl dips down toward the west and northwest portions of the VEGP site. The average thickness of the Upper Sand Stratum was 102 ft, and the median thickness was 94 ft at the ESP boring locations.

Field Standard Penetration Test (SPT) N-values obtained according to ASTM D 1586 (Reference 568) within the Upper Sand Stratum during the ESP subsurface investigation ranged from weight of rod (WOR) to 50 blows for 0-in. penetration (50/0”). The very high blow count values are indicative of zones containing the shelly limestone and shell hash. The average field SPT N-value was 25 blows per foot (bpf), and the median N-value was 21 bpf. These field values are un-corrected for hammer efficiency of the respective drill rig hammers used. Measurements of hammer energy were performed in borings B-1006 and B-1013. The measured energy transfer efficiency ranged from 65 to 87 percent, with an average value of 76 percent and a median value of 75 percent.

Selected samples recovered within the Upper Sand Stratum were submitted for laboratory testing, including percent fines, moisture content, and Atterberg Limits. The percent fines ranged from 3 to 60 percent, with an average value of 21 percent and a median value of 19 percent. The Plastic Limit ranged from 19 to 30, with an average value of 25 and a median value of 26. The Liquid Limit ranged from 43 to 97, with an average value of 62 and a median value of 53. The Plasticity Index ranged from 21 to 67, with an average value of 37 and a median value of 29. The natural moisture content of samples tested for Atterberg Limits ranged from 20 to 93 percent, with an average value of 63 percent and a median value of 70 percent.

Site geotechnical investigations for the existing units determined that the Upper Sand Stratum (Barnwell Group) is approximately 90 ft thick. A shelly limestone (Utley Limestone) is encountered at the base of this stratum and/or the top of the Blue Bluff Marl. The Upper Sand Stratum was determined to be susceptible to liquefaction during a seismic event equivalent to the safe shutdown earthquake (SSE) developed for VEGP Units 1 and 2. In addition, the underlying Utley limestone layer was determined to contain significant channeling, cracking, and other discontinuities. Therefore, it was considered necessary to remove both the Upper Sand Stratum and limestone layers before constructing VEGP Units 1 and 2. The standard penetration test data from previous studies indicate that the relative density of the Upper Sand Stratum is highly variable with a range from very loose to dense. Clay lenses encountered within the stratum ranged in consistency from soft to medium stiff.

Existing Units 1 and 2 unconsolidated undrained (UU) triaxial test results of samples within the Upper Sand Stratum indicate that the Mohr strength envelope of total stresses ranges from c=2,100 pounds per square foot (psf), ϕ=6° to c=440 psf, ϕ=32°, depending on the clay and sand content within the sample. Likewise, previous consolidated undrained (CU) triaxial test results for samples within the Upper Sand Stratum indicate that the Mohr strength envelope ranges from c=1,650 psf, ϕ=17° to c=4,000 psf, ϕ=25° for total stress and ϕ'=33° to ϕ'=34.5° for effective stresses. Because of the large number of UU and CU triaxial tests previously performed on Upper Sand Stratum samples, and the fact that this stratum would be completely removed before constructing the ESP units, no new strength tests were performed during the ESP subsurface investigation.

The COL subsurface investigation, Appendix 2.5C, with 70 borings located in the immediate area of the excavations for Units 3 and 4, was used to verify the characterization of the Upper Sand Stratum. From these data, the Upper Sand Stratum ranged in thickness from 81 to 97 feet with an average of 88 feet and a median thickness of 87 feet. One thousand four hundred and fourteen field SPT N-values were measured and ranged from WOR to 50/0" with a median of 18 bpf. Measurements of hammer energy were performed on each of the 12 drill rigs used for the COL investigation as presented in Appendix 2.5C. One hundred and sixty-eight sieve analyses disclosed a range of 5 percent to 96 percent fines with an average value of 22 percent and a median value of 20 percent. Seventeen Atterberg Limits test results on samples from the clay lenses disclosed an average liquid limit of 72, an average plastic limit of 33, and an average calculated plasticity index of 39. The moist unit weight of 15 samples was calculated and ranged from 94 pcf to 124 pcf with an average of 113 pcf and a median value of 113 pcf. The specific gravity of two samples was calculated as 2.69 and 2.75. Results of CU triaxial tests indicate average shear strength values of c=980 psf, ϕ=18° for total stress and c'=260 psf, ϕ=30° for effective stress.

The design properties of the Upper Sand Stratum are provided in Table 2.5-236 and were developed from laboratory and field test results from the ESP and COL investigations as previously described, and published engineering correlations.

2.5.4.2.2.2 Blue Bluff Marl (Lisbon Formation)

The ESP subsurface investigation (Appendix 2.5A) determined that the Blue Bluff Marl was found to range in thickness from 63 to 95 ft at three locations where the stratum was fully penetrated, with an average thickness of 76 ft and a median thickness of 69 ft. The typical thickness of the Blue Bluff Marl is illustrated on the subsurface profiles on Figures 2.5-370, 2.5-372, and 2.5-373. The profiles on Figures 2.5-370 and 2.5-372 also illustrate the downward dip of the top of the Blue Bluff Marl toward the west side of the VEGP site.

The data and laboratory test results from penetrations taken in the immediate area of the excavations for Units 3 and 4 for the COL subsurface investigation (Appendix 2.5C) were found to validate the ESP characterization of the Blue Bluff Marl except as noted in the following paragraphs. In the area of the excavations, the Blue Bluff Marl was penetrated at 42 of the 70 boring locations. The top of stratum elevation ranged from 122 ft to 140 ft with an average elevation of 132 ft. The thickness of the Blue Bluff Marl ranged from 60 ft to 77 ft with an average thickness of 67 ft and a median thickness of 68 ft. The representative thickness of the Blue Bluff Marl as determined by the COL borings is illustrated on the subsurface profile in Figure 2.5-371.

Field SPT N-values obtained within the Blue Bluff Marl during the ESP subsurface investigation ranged from 26 bpf to 50 blows for 1-in. penetration (50/1"). The average field SPT N-value was 83 bpf, and the median N-value was 100+bpf. As noted in the revised MACTEC ESP Data Report (Appendix 2.5A) fossiliferous limestone, cemented layers, and cemented nodules were encountered in the Blue Bluff Marl. The high blow counts are attributed to the presence of these cemented layers as evidenced by the angular, gravel-sized, carbonate particles recovered in the split barrel samples. SPT blow counts corresponding to less than 12 in. of sampler penetration were linearly extrapolated

to the 12 in. standard penetration. SPT blow counts that were linearly extrapolated to more than 100 bpf were truncated at 100 bpf when calculating SPT averages. The field values are uncorrected for hammer efficiency of the respective drill rig hammers used. It is noted that the 26 bpf value was measured near the bottom of the stratum in boring B-1002, and most measured values were above 50 bpf. Also, the SPT N-values did not suggest the presence of a likely weathered portion at the top of the stratum.

During the COL investigation, 742 SPT samples were taken in the Blue Bluff Marl. Field SPT N-values ranged from 13 bpf to 50/0" with a median value of 71 bpf. The field values are uncorrected for hammer efficiency of the respective drill rig hammers used. Many SPTs did not achieve the full sampler penetration (e.g., 50 blows/3"). These high blow counts were attributed to the presence of abundant, partially cemented, well indurated layers as described in the MACTEC COL Data Report (Appendix 2.5C). Most of the measured N-values were greater than 30 bpf indicating hard to very hard consistencies. In addition, SPT N-values appear to behave as expected, increasing with depth. None of the 742 measured SPT N-values was less than 10 bpf, which is twice as much as one of the criterion used to identify soft zones at the nearby Savannah River Site (SRS) site (N<5bpf). A review of the borings logs did not reveal any layers below the Upper Sand stratum similar to the soft zones found at SRS. A summary of the SPT blow counts, corrected for hammer efficiency, collected from the borings within the power block is presented in Figure 2.5-391.

Selected samples recovered within the Blue Bluff Marl during the ESP subsurface investigation were submitted for laboratory testing, including percent fines, moisture content, and Atterberg Limits. The percent fines ranged from 17.8 to 97.8 percent, with an average value of 48 percent and a median value of 41 percent. The plastic limit ranged from non-plastic (NP) to 51 percent, with an average value of 29 percent and a median value of 27 percent. The liquid limit ranged from NP to 99 percent, with an average value of 51 percent and a median value of 43 percent. The plasticity index ranged from NP to 58 percent, with an average value of 22 percent and a median value of 16 percent. The natural moisture content of samples tested for Atterberg Limits ranged from 14 to 67 percent, with an average value of 35 percent and a median value of 29 percent. In addition, 15 UU tests were performed on Blue Bluff Marl samples. The laboratory measured undrained shear strength ranged from 150 to 4,300 psf. The low end of measured values (150 psf) is lower than previously reported (260 psf) for VEGP Units 1 and 2, and the high end of measured values (4,300 psf) is significantly lower than previously reported (500,000 psf) for VEGP Units 1 and 2. The SPT N-values measured during the ESP and values previously measured in the laboratory for VEGP Units 1 and 2 support the use of a 10,000-psf design value. The reason for the sharp disagreement between the ESP laboratory values and previously reported undrained shear strength for the Blue Bluff Marl is severe sample disturbance due to sampling technique (pitcher sampler) and preparation of testing specimen. The SPT N-values measured during the ESP and values previously measured in the laboratory for VEGP Units 1 and 2 support the use of a 10,000-psf design value.

Selected samples of the Blue Bluff Marl collected during the COL investigation subsurface investigation were submitted for laboratory testing and included percent fines, moisture content, and Atterberg Limits. Sieve analyses tests were conducted on 90 representative samples that disclosed a range of fines from 29 percent to 98 percent, with an average value of 74 percent and a median value of 75 percent. Atterberg Limit tests were conducted on 92 representative samples and disclosed a liquid limit range from 34 to 112 percent, with an average value of 67 percent and a median value of 63 percent. The plastic limit ranged from 20 to 64 percent, with an average value of 34 percent and a median value of 33 percent. The calculated plasticity index ranged from 11 to 62 percent, with an average value of 33 percent and a median value of 30 percent. The natural moisture content of samples tested ranged from 14 to 62 percent, with an average value of 33 percent and a median value of 32 percent. The moist unit weight of 69 samples ranged from 95 pcf to 133 pcf with an average of 115 pcf and a median value of 115 pcf. The specific gravity of 8 samples was calculated and ranged from 2.61 to 2.66 with an average value of 2.64.

Site investigations for the existing units determined that the marl stratum (Blue Bluff Marl or Lisbon Formation) consists of hard, slightly sandy, cemented, overconsolidated, calcareous clay and ranges in thickness from approximately 60 ft to 100 ft. The comparative consistency of the Blue Bluff Marl ranges from hard to very hard. The materials are moderately brittle and resemble a calcareous claystone or siltstone. Previous seismic exploration within this stratum indicates a velocity interface approximately 15 ft beneath the top of the stratum. The upper 15 ft, a likely weathered portion, of the stratum recorded a compressive wave velocity of approximately 5,000 ft per second (fps), while the underlying material recorded a compressive wave velocity of approximately 7,000 fps. The static engineering properties of the Blue Bluff Marl stratum are summarized in Table 2.5-236.

Previous laboratory results indicate the Blue Bluff Marl to be highly overconsolidated. Plasticity index values ranged from 2 to 70 with an average value of 25. Based on work by Skempton **(1957)**, using the average PI value yields an s_u/p ratio of approximately 0.2, where s_u is undrained shear strength and p is the effective overburden pressure for a normally consolidated clay. An undrained shear strength of 16,000 psf was determined using the average value of shear strength test results which failed at less than 50,000 psf. However, given a shear strength (s_u) one can use the same relationship and compute p (in the case of an overconsolidated deposit, p would be equivalent to the preconsolidation pressure). Therefore, using the 16,000 psf value for undrained shear strength and a s_u/p ratio of 0.2, the preconsolidation pressure of the Blue Bluff Marl stratum was estimated to be 80,000 psf (an OCR of about 8). Settlements due to loadings from new structures would be small due to this high preconsolidation pressure, demonstrated by the settlement measurement for Units 1 and 2 as discuss in Subsection 2.5.4.10.2.

The undrained shear strength of the Blue Bluff Marl was verified during the excavation for VEGP Units 1 and 2. Core samples of the Blue Bluff Marl were obtained and tested. The design value of c = 10,000 psf, $\phi = 0°$ was found to be appropriately conservative. The average undrained shear strength of the core samples was 20,000 psf, and the lowest value obtained was 11,700 psf.

The heave of the Blue Bluff Marl stratum was monitored during the excavation for VEGP Units 1 and 2. Measurements were taken at nine locations at regular intervals. After excavation completion, an average heave of 1.25 in. was observed. Based on the heave measurements, the undrained Young's modulus, E, of the Blue Bluff Marl stratum was calculated to be 10,000 kips/ ft^2, similar to values of E estimated from Menard pressuremeter and seismic velocity measurements during previous field investigations.

Strength tests were conducted in the laboratory during the COL investigation (Appendix 2.5C) on relatively undisturbed (intact) samples of the Blue Bluff Marl. Strength testing included 27 unconfined compression tests, 11 UU triaxial tests, and 27 CU triaxial tests. Eighteen consolidation tests were conducted. The UU and CU triaxial tests were conducted at various confining pressures. Test results disclosed that the shear strength of the BBM increased with increasing confining pressure, as expected. The Blue Bluff Marl is approximately located from a depth of 90 to 165 ft with a design ground water level at a depth of 55 feet. Based on this overburden condition, the range of confining pressures in the Blue Bluff Marl is between 6.5 ksf and 9.7 ksf. UU test results at a confining pressure of 8.1 ksf disclosed a minimum undrained shear strength of 1.7 ksf and a maximum of 11.7 ksf with an average value of 6.5 ksf. The CU test results disclosed a minimum undrained shear strength of 2.8 ksf and a maximum value of 32.2 ksf with an average value of 9.3 ksf in this range of confining pressure. Given that the Blue Blue Marl is characterized as an overconsolidated, calcareous clay, the undrained shear strength can be represented by considering the preconsolidaton pressure. At a confining pressure of 16 ksf (the upper limit of the UU and CU test program) which represents approximately twice the in-situ confining pressure, UU test results disclosed an average undrained shear strength of 8.6 ksf and CU test results disclosed an average value of 14.9 ksf. The averaged undrained shear strength from the UU and CU tests is 11.8 ksf, which supports the design value of 10,000 psf used for VEGP Units 1 and 2.

Consolidation tests were conducted in the laboratory during the COL investigation (Appendix 2.5C) on 18 relatively undisturbed samples of the Blue Bluff Marl. The compression and recompression ratios were determined from the compression and recompression indices provided in the test results. Compression ratios ranged from 0.034 to 0.156 with an average value of 0.094. Recompression ratios ranged from 0.004 to 0.017 with an average of 0.010.

The static design properties of the Blue Bluff Marl stratum for VEGP Units 3 and 4 are provided in Table 2.5-236 and were developed from laboratory and field test results from ESP and COL subsurface investigations, available data from VEGP Units 1 and 2, as well as published engineering correlations.

A summary of the design dynamic shear modulus at strain levels of 10^{-4} percent, or lower, for the Blue Bluff Marl stratum, based on ESP investigation, is given in Table 2.5-238. Dynamic shear modulus values were computed from the in situ shear wave velocity measurements shown in Table 2.5-243. Additional in situ shear wave velocity measurements were taken during the COL investigation. These data, combined with ESP data as described in Subsection 2.5.4.7.1, are shown in Table 2.5-253.

2.5.4.2.2.3 Lower Sand Stratum

The ESP subsurface investigation (Appendix 2.5A) determined that the Lower Sand Stratum encompassed a number of geologic formations, including, listed in top to bottom order, the Still Branch, Congaree, Snapp, Black Mingo, Steel Creek, Gaillard/Black Creek, Pio Nono/Unnamed, and Cape Fear formations. The Lower Sand Stratum was fully penetrated at boring B-1003 and found to have a thickness of 900 ft at this location. Boring B-1003 also disclosed that the Lower Sand Stratum rests upon Dunbarton Triassic Basin rock. Typical depths are illustrated on the subsurface profile in Figure 2.5-372.

Field SPT N-values obtained to depths of about 300 ft within the Lower Sand Stratum during the ESP subsurface investigation ranged from 9 bpf to 50 blows for 4-in. penetration (50/4”). The average field SPT N-value was 59 bpf, and the median N-value was 47 bpf. These field values are uncorrected for hammer efficiency of the respective drill rig hammers used and comprise values measured mostly in the Still Branch Formation directly beneath the Blue Bluff Marl.

During the COL investigation, the Lower Sand Stratum was encountered in 42 of the COL borings with 36 nominal penetrations (one to 7 feet) and 6 substantial penetrations (84 to 263 feet) into this stratum. The maximum depth of penetration into the stratum was 263 ft in B-3001. One hundred and eleven field SPT N-values obtained in this stratum ranged from weight of hammer (WOH) to 50/1". The median field SPT N-value was 70 bpf. These field values are uncorrected for hammer efficiency of the respective drill rig hammers used and comprise values measured mostly in the Still Branch Formation directly beneath the Blue Bluff Marl. Nearly all of the N-values taken in the Lower Sand stratum are greater than 30 bpf indicating dense to very dense material. In addition, SPT N-values appear to behave as expected, increasing with depth. One N-value (B-4001, SS-38: WOH/18) taken in this stratum indicated very loose material. This sample was taken in the Still Branch Formation of the Lower Sand strata at an elevation of -41.5 to -43 feet. No recovery was obtained in the split barrel sample. An undisturbed sample (UD-11) was attempted prior to SS-38 from elevation -39.5 to -41.5 feet and no recovery was obtained in this sample. The material above this elevation was identified as light gray SAND (SP). The difficulty in sampling this material along with the weight of hammer reading in SS-38 is considered an anomaly and can be attributed to disturbed soil conditions at the bottom of the borehole. These conditions are likely the result of a hydrostatic pressure imbalance between the borehole and the in situ hydrostatic pressure. The resulting imbalance likely caused a quick condition to develop in the poorly graded sands at the sampling depth. Such quick conditions are difficult to sample, as evidenced by the lack of sample recovery in SS-38 and UD-11, as the now

disturbed poorly graded sand will flow out of the sampler. Besides this anomalous condition, no other evidence of soft zones or loose material was encountered in Lower Sand stratum.

ESP subsurface investigation selected samples recovered within the Lower Sand Stratum were submitted for laboratory testing, including percent fines, moisture content, and Atterberg Limits. The percent fines ranged from 3 to 80 percent, with an average value of 23.6 percent and a median value of 15 percent. The plastic limit ranged from NP to 38 percent, with average and median values of 30 percent. The liquid limit ranged from NP to 53 percent, with average and median values of 47 percent. The plasticity index ranged from NP to 19 percent, with average and median values of 17 percent. The natural moisture content for samples tested for Atterberg Limits ranged from 21 to 41 percent, with an average value of 30 percent and a median value of 28 percent. Samples with the higher percent fines and plasticity were from the silty clay and clayey silt layers in the Congaree and Snapp Formations within the Lower Sand Sratum.

Representative samples of the Lower Sand Stratum collected during the COL subsurface investigation were submitted for laboratory testing. Sieve analyses were conducted on 14 samples with a range from 5 to 70 percent fines, an average value of 23 percent, and a median value of 17 percent. The moist unit weight of 16 samples was calculated ranged from 113 pcf to 136 pcf with an average of 123 pcf and a median value of 122 pcf. The average specific gravity of four samples was calculated as 2.67. Results of CU triaxial tests indicate average shear strength values of c=4,725 psf, ϕ=26° for total stress and c'=215 psf, ϕ'=36° for effective stress.

During the COL investigation, alternating layers of fine-grained and coarse-grained soils were identified in the upper and lower portions of the Congaree Formation and in the upper portion of the Snapp Formation. These fine-grained soils were characterized as silts and clays and, where encountered, were on the order of 20 to 40 feet thick. The coarse-grained soils were characterized as silty to clayey, and poorly-graded sands. In boring B-3001, the fine-grained materials in the lower portion of the Congaree and the upper portion of the Snapp were on the order of 70 feet thick.

Site geotechnical investigations for the existing units determined that the Lower Sand Stratum consists of sands with interbedded silty clay or clayey silt. The thickness of this stratum was estimated to be 900 to 1,000 ft. SPT N-values obtained to depths of about 300 to 400 ft below grade during previous field investigations within the Lower Sand Stratum ranged from 70 to 100 bpf, indicative of a very dense material.

The static design properties of the Lower Sand Stratum for VEGP Units 3 and 4 are provided in Table 2.5-236 and were developed from laboratory and field test results from ESP subsurface investigations, available data from VEGP Units 1 and 2, as well as published engineering correlations.

A summary of the design dynamic shear modulus at strain levels of 10^{-4} percent, or lower, for the Lower Sand Stratum, based on the ESP investigation, is given in Table 2.5-238. Dynamic shear modulus values were computed from the in situ shear wave velocity measurements shown in Table 2.5-243. Additional in situ shear wave velocity measurements were taken during the COL investigation. These data, combined with ESP data as described in Subsection 2.5.4.7.1, are shown in Table 2.5-228.

2.5.4.2.2.4 Dunbarton Triassic Basin Rock

The Dunbarton Triassic Basin Rock was cored at ESP borehole B-1003 only, and consisted of red sandstone, breccia, and mudstone, weathered through the upper 120 ft. The deepest COL borehole was advanced to a depth of 263 ft into the Lower Sand Stratum for a total depth of 420 ft and did not reach bedrock. Further details are provided in Subsection 2.5.1. Because the rock

was too deep to be of any interest to foundation design, no laboratory tests were performed on the rock cores. Shear wave velocity was measured in the upper 274 ft of the rock profile, and these results were used to develop the shear wave velocity profile for site amplification that are presented in Subsection 2.5.4.7.1.

2.5.4.2.2.5 Paleozoic Crystalline Rock

As indicated in Figure 2.5-372, the VEGP site sits on over 1,000 feet of Coastal Plain sediments underlain by Triassic Basin sedimentary rock. Borehole B-1003 encountered the bottom of the Coastal Plain sediments and the start of a weathered section of the Triassic Basin at a depth of 1,049 feet. Under the part of Savannah River Site adjacent to the VEGP site, the southeast dipping Pen Branch fault separates the Triassic Basin rock from Paleozoic crystalline rock to the northwest (**Lee et al. 1997**). A seismic reflection survey in and around the VEGP site (shown in Appendix 2.5B and discussed in Subsection 2.5.1.2.4.2), has been interpreted to show the southwest continuation of the Pen Branch fault beneath the site and to indicate that the depth to the bottom of the Coastal Plain sediments is about 1,000 feet (Figure 2.5-243). This and interpretation of flexures within the older Coastal Plain sediments suggest that the Pen Branch fault lies below the area of the new containment units. Therefore, the information available implies that at some depth below the VEGP site the Paleozoic crystalline rock underlies the Triassic Basin rock.

2.5.4.2.2.6 Subsurface Profiles

Figures 2.5-370, 2.5-372, and 2.5-373 illustrate typical subsurface profiles across the power block area proposed for the proposed VEGP Units 3 and 4 based on ESP borings. A profile legend is provided as Figure 2.5-369. The locations of the borings used to develop profiles are shown in Figure 2.5-366. Figures 2.5-371, 2.5-374, and 2.5-375 illustrate typical subsurface profiles across the limited power block area proposed for VEGP Units 3 and 4 based on COL borings. The locations of the borings used to develop profiles are shown in Figure 2.5-368. These profiles are discussed in Subsection 2.5.4.5 with respect to excavation for the new units and in Subsection 2.5.4.10.1 for bearing capacity considerations.

2.5.4.2.3 Field Investigations

The exploration programs performed previously for VEGP Units 1 and 2 are referenced, as warranted. The ESP and COL subsurface investigations are described in Subsection 2.5.4.3. The boring logs from previous explorations are not included here; however, the locations of referenced borings from VEGP Units 1 and 2 are provided on Figure 2.5-368. The borings and cone penetrometer tests from the ESP subsurface investigation program are summarized in Table 2.5-244. Previous geophysical surveys and new geophysical surveys for the ESP investigation are described in Subsection 2.5.4.4. Boring logs and CPT logs from the ESP field exploration are included in Appendix 2.5A.

The exploration program for the COL subsurface investigation included borings, CPTs, seismic CPTs, geophysical surveys, and test pits. The boring, CPT, and test pit locations are summarized in Table 2.5-245 and illustrated on Figures 2.5-367 and 2.5-368. Geophysical surveys for the COL investigation are described in Subsection 2.5.4.4. Boring logs, CPT logs, geophysical survey results, and test pit logs from the COL field exploration are included in Appendix 2.5C.

Field investigations also included the construction and testing of a 20-foot thick below grade test pad using proposed borrow materials. This program was conducted to aid in evaluating the static and dynamic properties of the compacted backfill. Additional details of the program are provided in Subsection 2.5.4.5.3. Results of this program are included in Appendix 2.5D.

2.5.4.2.4 Laboratory Testing

2.5.4.2.4.1 Testing Overview

Numerous laboratory tests of soil samples were performed previously for VEGP Units 1 and 2, and new tests have been performed as part of the ESP and COL subsurface investigations. Previous test results are contained within Bechtel Power Corporation's Report on Foundation Investigations (Reference 552). The types and numbers of tests completed during the ESP subsurface investigation are shown in Table 2.5-239, and the test results are contained within the MACTEC report for the ESP subsurface investigation (Appendix 2.5A). A summary of all laboratory test results performed as part of the ESP subsurface investigation is provided in Table 2.5-241. The types and numbers of tests completed during the COL subsurface investigation are shown in Table 2.5-240 and the test results are contained within the MACTEC data report for the COL subsurface investigation (Appendix 2.5C). Results of resonant column torsional shear (RCTS) tests conducted on samples from the COL investigation are included in Attachment G of Appendix 2.5C. Laboratory tests, including RCTS, were also conducted as part of the Phase I test pad program and are included in Appendix 2.5D.

2.5.4.2.4.2 Laboratory Tests for the ESP Subsurface Investigation

Laboratory testing for the ESP investigation was performed in accordance with the guidance presented in Regulatory Guide 1.138, Laboratory Investigations of Soils for Engineering Analysis and Design of Nuclear Power Plants, US Nuclear Regulatory Commission, 2003 (RG 1.138). The laboratory work was performed under an approved quality program with work procedures developed specifically for the ESP application. Soil samples were shipped under Chain-of-Custody protection from the on-site storage area (described in Subsection 2.5.4.3.2) to the testing laboratory. Laboratory testing was performed at the MACTEC laboratories in Atlanta, Georgia.

The types and numbers of laboratory tests performed on the soil samples from the ESP exploration program are included on Table 2.5-239. The ESP tests focused primarily on verifying the basic properties of the Upper Sand Stratum, Blue Bluff Marl, and the upper formations in the Lower Sand Stratum.

The details and results of the laboratory testing are included in Appendix 2.5A. This appendix includes references to the industry standard used for each specific laboratory test. The results of the tests on soil samples are shown on Table 2.5-241.

2.5.4.2.4.3 Laboratory Tests for the COL Subsurface Investigation

Laboratory testing for the COL investigation was performed in accordance with the guidance presented in RG 1.138. The laboratory work was performed under an approved quality assurance program with work procedures developed specifically for the COL application. Soil samples were shipped using Chain-of-Custody tracking procedures from the on-site storage area (described in Subsection 2.5.4.3.3) to the testing laboratory. Laboratory tests were performed at various laboratories. RCTS tests were performed at the FUGRO laboratories in Houston, Texas. The details and results of the laboratory testing are included in Appendix 2.5C. This appendix includes references to the industry standard used for each specific laboratory test.

2.5.4.2.4.4 Laboratory Test for the Phase I Test Pad Program

Laboratory testing was conducted during construction of the test pad under an approved quality assurance program with work procedures developed specifically for the test pad program. An onsite laboratory was established to conduct most of the testing. Soil samples that were shipped to offsite laboratories were done so using Chain-of-Custody procedures. RCTS testing was

conducted offsite at laboratories in Houston, Texas and Austin, Texas. Details and results of the laboratory testing are included in Appendix 2.5D.

2.5.4.2.5 Engineering Properties

The engineering properties for the Upper Sand, Blue Bluff Marl, Lower Sand Strata, and compacted structural fill, as provided in Table 2.5-236, were derived from the ESP subsurface investigation and laboratory testing program and from previous VEGP site studies. A similar table, Table 2.5-237, was derived from the COL investigation and Phase I test pad program. The COL data, used as the basis for these properties, was taken from the borings in the immediate vicinity of the combined NI (power block) excavation footprint. The engineering properties of the proposed borrow materials that were developed from the COL data are presented in Subsection 2.5.4.5.3. The engineering properties for the structural backfill were derived from the COL investigation and the Phase I test pad program. The engineering properties developed from the ESP and COL subsurface investigation and laboratory testing programs and the Phase I test pad program (Appendix 2.5A, 2.5C, and 2.5D, respectively) were similar to those obtained from the previous VEGP Units 1 and 2 field and laboratory testing programs.

Rock densities were derived from Tables 5-2 and 5-3 of (Reference 548) for crystalline and Triassic rock, respectively. Rock densities increased with depth from 2.75 gm/cc (171.6 pcf) to 3.42 gm/cc (213.4 pcf) in the crystalline rock, and from 2.53 gm/cc (157.9 pcf) to 3.42 gm/cc (213.4 pcf) in the Triassic rock.

The following sections briefly describe the sources and/or methods used to develop the selected properties shown in Table 2.5-236 and Table 2.5-237.

2.5.4.2.5.1 Rock Properties

The Recovery and Rock Quality Designations (RQD) are based on the results provided from the deep boring, B-1003. Rock coring was not performed during the previous investigations for VEGP Units 1 and 2. Geophysical testing at the deep boring, B-1003, extended for about 290 ft into the bedrock encountered at depth of 1,049 ft below the ground surface. The shear and compressional wave velocities are based on the suspension P-S velocity seismic test performed in borehole B-1003 as part of the ESP subsurface investigation (Appendix 2.5A). Laboratory strength testing of rock cores was not performed because the rock is deemed to be too deep to provide any additional useful engineering information.

2.5.4.2.5.2 Soil Properties

The properties of the soils underlying the site were developed from ESP and COL investigations, including laboratory testing programs, review of previous investigations for VEGP Units 1 and 2, and the Phase I test pad program. The following paragraphs describe the properties of the Upper Sand, Blue Bluff Marl, and Lower Sand Strata. The properties of the proposed compacted structural backfill are discussed in Subsection 2.5.4.5.3.

Sieve analyses of 29 Upper Sand Stratum samples (including 1 fill sample), 28 Blue Bluff Marl samples, and 14 Lower Sand Stratum samples were performed as part of the ESP laboratory testing program (Appendix 2.5A).

The natural moisture content and Atterberg Limits of 4 Upper Sand Stratum, 20 Blue Bluff Marl, and 4 Lower Sand Stratum samples were determined as part of the ESP laboratory testing program. Design values shown on Table 2.5-236 were taken as the average of these test results for the respective soil strata.

The COL laboratory testing program (Appendix 2.5C) included sieve analyses of 168 Upper Sand Stratum samples, 90 Blue Bluff Marl samples, and 14 Lower Sand Stratum samples. Atterberg Limits tests were conducted on 17 Upper Sand Stratum samples and 92 Blue Bluff Marl samples. Specific gravity measurements were made on two Upper Sand Stratum samples, 8 Blue Bluff Marl samples, and 4 Lower Sand Stratum samples.

The undrained shear strength of the Blue Bluff Marl bearing stratum was determined from laboratory test data, SPT N-values, and shear wave velocity measurement. Laboratory test data included unconsolidated undrained triaxial test and consolidated undrained triaxial test results from the ESP and COL investigations. Laboratory strength testing during previous investigations as well as during the construction of VEGP Units 1 and 2 were also reviewed.

The effective angle of internal friction of the Upper Sand Stratum was determined to be 34 degrees (Reference 583) from correlation with the average SPT N-value from the ESP investigation (based on N_{60} = 25 bpf). The N-value of 25 bpf represents the measured value of 20 bpf corrected to account for the higher automatic hammer efficiency measured in the field. This correction was made following the guidelines in ASTM D 6066 (1996). The median measured N-value from the COL investigation was 18 bpf, corresponding to a N_{60}-value of 25 bpf.

The effective angle of internal friction of the Lower Sand Stratum was determined to be 41 degrees (Reference 583) from correlation with the average SPT N-value from the ESP investigation (based on N_{60} = 62 bpf). The N-value of 62 bpf represents the measured value of 50 bpf corrected to account for the higher automatic hammer efficiency measured in the field. This correction was made following the guidelines in ASTM D 6066 (1996). The median measured N-value from the COL investigation was 70 bpf, corresponding to a N_{60}-value of 94 bpf.

Moist unit weights were measured in selected samples from the ESP laboratory testing program of the Blue Bluff Marl and Lower Sand Stratum. The unit weights of 15 Blue Bluff Marl samples ranged from 102 pounds per cubic foot (pcf) to 140 pcf, with an average of 120 pcf. Unit weights of three Lower Sand Stratum samples were 119.4 pcf, 121.7 pcf, and 128.3 pcf, with an average of 123 pcf.

The COL laboratory testing program included moist unit weight measurements of 15 samples in the Upper Sand Stratum, 69 in the Blue Bluff Marl, and 16 in the Lower Sand Stratum. The values in the Upper Sand Stratum ranged from 94 to 124 pcf with an average value of 113. The values in the Blue Bluff Marl ranged from 95 to 133 pcf with an average value of 115 pcf. The values in the Lower Sand Stratum ranged from 113 to 134 pcf with an average of 123 pcf.

The in situ moist unit weights of the Upper Sand Stratum, Blue Bluff Marl, and Lower Sand Stratum for VEGP Units 1 and 2 were 118 pcf, 119 pcf, and 117 pcf, respectively.

The design SPT N-value for the Upper Sand Stratum is taken as 25 bpf. This value is based on the ESP results reported in Table 2.5-242 and includes correction for hammer efficiency. The results in Table 2.5-242 show an average uncorrected field SPT N-value of 25 bpf and median value of 21 bpf. The design corrected N-value of 25 bpf corresponds to a field N-value of 20 bpf, which is lower than the average and median values. The median uncorrected field SPT N-value for the Upper Sands from the COL investigation was 18 bpf. SPT N values for VEGP Units 1 and 2 ranged from 2 to 60 bpf with an average of 30 bpf. The design value is within the range and near the average of the COL investigation and previous investigation values.

The design SPT N-value for the Blue Bluff Marl is taken as 100 bpf. This value is based on the results reported in Table 2.5-242 and includes correction for hammer efficiency. The results in Table 2.5-242 show an average uncorrected field SPT N-value of 83 bpf and median value of 100 bpf. The design corrected N-value of 100 bpf corresponds to a field N value of 80 bpf, which is lower than the average

and median values. The median uncorrected field SPT N-value for the Blue Bluff Marl from the COL investigation was 71 bpf (N_{60}=95bpf). SPT N-values for VEGP Units 1 and 2 ranged from 10 to over 100 bpf with an average of over 100 bpf. The design value is within the range and near the median of the COL investigation and previous site investigation values.

The design SPT N-value for the Lower Sand Stratum is taken as 62 bpf. This value is based on the results reported in Table 2.5-242 and includes correction for hammer efficiency. The results in Table 2.5-242 show an average uncorrected field SPT N-value of 59 bpf and median value of 47 bpf. The design corrected N-value of 62 bpf corresponds to a field N-value of 50 bpf, which is lower than the average value and slightly higher than the median value. The median uncorrected field SPT N-value for the Lower Sands from the COL investigation was 70 bpf (N_{60}=94bpf). SPT N-values for VEGP Units 1 and 2 ranged from 70 to 100+ bpf with an average of 100+ bpf. The design value is somewhat less than the previous site investigations range of values.

Shear wave velocities were measured by suspension P-S velocity tests and seismic CPTs during the ESP and COL subsurface investigations (Appendix 2.5A and Appendix 2.5C, respectively). The suspension P-S velocity tests were performed in 5 boreholes for the ESP investigation, although only three of these tests extended into the Blue Bluff Marl and Lower Sand Strata. P-S velocity tests were performed in 6 boreholes for the COL investigation. Three seismic CPTs were performed in accordance with ASTM D 5778 (2000) for the ESP investigation and 8 for the COL investigation. Due to penetration resistance, the seismic CPT tests did not extend into the very hard underlying Blue Bluff Marl stratum. Further discussion of suspension P-S velocity and seismic CPT testing is provided in Subsection 2.5.4.4.

A complete shear wave velocity profile was developed during the ESP investigation from the ground surface to about 300 ft into the Dunbarton Triassic Basin rock for a total depth of about 1,340 ft using both suspension P-S velocity and seismic CPT testing taken during the ESP investigation. Shear wave velocities within the Upper Sand Stratum ranged from about 570 fps to 3,310 fps. Shear wave velocities ranged from 1,060 fps to 4,260 fps within the Blue Bluff Marl stratum, 930 fps to 4,670 fps within the underlying Lower Sand Stratum, and 2,320 fps to 9,350 fps within the Dunbarton Triassic Basin. Shear wave velocity measurements were made to depths of up to 290 ft during previous investigations for VEGP Units 1 and 2. In addition, shear wave velocity data were reviewed from seven deep borings performed at the neighboring Savannah River Site. Typical shear wave velocity values were determined for the Upper Sand Stratum, Blue Bluff Marl, Lower Sand Stratum, and the Dunbarton Triassic Basin rock data based upon review of all the available data and are provided in Table 2.5-243. Shear wave velocity values within the Lower Sand Stratum were determined for each of the geologic formations contained within. A more detailed discussion of shear wave velocity values and establishment of the shear wave velocity profile for site amplification are presented in Subsection 2.5.4.7.1.

Shear wave velocity measurements were made during the COL investigation to a maximum depth of 420 feet. Shear wave velocities within the Upper Sand Stratum disclosed an average shear wave velocity of 940 fps. An average shear wave velocity of 2,050 fps was disclosed in the Blue Bluff Marl stratum. The shear wave velocity measurements in the Lower Sand stratum disclosed an average shear wave velocity of 1,750 fps. A more detailed discussion of shear wave velocity values and establishment of the shear wave velocity profile for site amplification are presented in Subsection 2.5.4.7.1.

The high strain (i.e., in the range of 0.25 to 0.5 percent) elastic modulus values, tabulated in Table 2.5-236, for the Upper Sand Stratum and Lower Sand Stratum have been derived using the relationship with the SPT N-value given in (Reference 584) The high strain elastic modulus for the Blue Bluff Marl stratum has been derived using the relationship with undrained shear strength given in (Reference 584). The shear modulus values have been obtained from the elastic modulus values using the relationship between elastic modulus, shear modulus, and Poisson's ratio (Reference 583).

The low strain (i.e., 10^{-4} percent) shear modulus, tabulated in Table 2.5-238, for the Upper Sand Stratum has been derived from the average shear wave velocity of 940 fps. The low strain shear modulus of the Blue Bluff Marl stratum has been derived from the average shear wave velocity of 2,050 fps. The low strain shear modulus of the Lower Sand Stratum has been derived from the average shear wave velocity of 1,750 fps. The elastic modulus values have been obtained from the shear modulus values using the relationship between elastic modulus, shear modulus, and Poisson's ratio (Reference 583). The low strain shear modulus for the compacted backfill has been derived assuming an average shear wave velocity of 1,000 fps.

The values of unit coefficient of subgrade reaction are based on values for medium dense sand (Upper Sand Stratum), replaced as compacted structural fill, very-stiff-to-hard clay (Blue Bluff Marl), and dense-to-very-dense sand (Lower Sand Stratum) provided by Terzaghi (1955).

The earth pressure coefficients are Rankine values, assuming level backfill and a zero friction angle between the soil and the wall.

2.5.4.2.5.3 Chemical Properties

Chemical tests were not included in the ESP laboratory testing program. There were no aggressive chemical subsurface conditions identified in the license renewal aging management analysis of Unit 1 and 2 buried concrete (Reference 594). Chemical property testing of proposed backfill material (Upper Sand Stratum, switchyard borrow and Borrow Area 4) was conducted as part of the COL investigation. Laboratory tests included pH, chloride, and sulfate and were conducted on five split barrel samples from Upper Sand Stratum in the powerblock area; two bulk soil samples taken from test pits excavated in the switchyard borrow area; and three from bulk soil samples from Borrow Area 4. Average pH test results disclosed values of 6.8, 5.2 and 5.4 for the Upper sand, switchyard and Borrow Area 4, respectively, indicating the soil to be mildly corrosive (Reference 565, Reference 597). Corresponding average chloride test results disclosed values of 188, 76 and 138 ppm indicating the soil is mildly corrosive (Reference 565, Reference 597). Corresponding average sulfate test results disclosed values of 21, 9.8 and 16.3 ppm indicating the soil/concrete interaction will provide a mild exposure for sulfate attack (Reference 564). Tests were performed by Severn Trent Laboratories, Inc., working as a subcontractor to MACTEC. Test results are included in Appendix 2.5C.

2.5.4.3 Exploration

Subsection 2.5.4.3.1 summarizes previous subsurface investigation programs performed at the VEGP site, while Subsection 2.5.4.3.2 describes the ESP subsurface investigation program and Subsection 2.5.4.3.3 describes the COL subsurface investigation program.

2.5.4.3.1 Previous Subsurface Investigation Programs

Field investigations for VEGP Units 1 and 2 were initiated in January 1971. Field investigations consisted of borings, geophysical methods, and groundwater studies. Additional investigation was completed during excavation for VEGP Units 1 and 2 to verify and obtain further details concerning subsurface conditions in the power block area. A total of 474 borings and 60,000 ft of drilling were completed during these investigations. An additional 111 borings were completed after the initial investigations mentioned above for the following purposes: 41 borings were drilled to define soil conditions and lateral extent of the Blue Bluff Marl in the river facilities, 38 borings were drilled in the power block to collect samples of the Blue Bluff Marl and perform confirmatory testing, and 32 borings were drilled to collect subsurface data for the natural draft cooling tower foundation design. During the previous investigations, electric logging, natural gamma, density, neutron, caliper, and 3-D velocity logs (Birdwell) were performed at selected borings. Water pressure tests and Menard

pressuremeter tests were completed to determine properties of the Blue Bluff Marl bearing stratum. Fossil, mineral, or soluble carbonate tests were performed on recovered samples as warranted.

Geophysical methods were applied to supplement the test borings. The geophysical methods are described in Subsection 2.5.4.4. For the previous investigations, a total of 28,400 ft of shallow refraction lines, 5,000 ft of deep refraction lines, and cross-hole velocities of subsurface were performed extending from the ground surface to a depth of 290 ft.

Twenty of the previously drilled borings for VEGP Units 1 and 2 fall within, or in the immediate proximity of, the proposed combined power block excavation footprint for the VEGP Units 3 and 4 site. The locations of these borings are provided in Figure 2.5-368. Results of previous investigations are referenced as needed to support the subsurface data obtained during the ESP and COL subsurface investigations.

2.5.4.3.2 ESP Subsurface Investigation Program

The ESP subsurface investigation was performed during September through December 2005 over a substantial portion of the site enveloping the area that would contain the new reactors as well as the switchyard and the cooling towers for the proposed VEGP Units 3 and 4. This investigation consisted of exploration points that were located primarily to confirm the results obtained from the previous extensive investigations. Portions of the original ESP data report were revised as discussed in Subsection 2.5.4.3.2.4.

The ESP exploration point locations are shown in Figure 2.5-366. The exploration points from the ESP investigation are combined with selected boring locations from the previous investigations in Figure 2.5-366.

The scope of work and the special methods used by the subsurface investigation contractor (MACTEC) and its subcontractors to collect data are listed below:

- Thirteen exploratory borings were drilled by MACTEC. Two of these borings (B-1002A and C-1005A) were drilled without sampling to allow suspension P-S velocity testing to be performed above zones of drilling fluid loss encountered in the Upper Sand Stratum above the Blue Bluff Marl.

- The efficiency of the automatic hammers employed by the two rotary drill rigs was determined by SPT energy measurements. These services were provided by GRL Engineers, Inc., of Cleveland, Ohio, working as a subcontractor to MACTEC.

- One continuous soil and rock coring borehole was completed at B-1003 by MACTEC.

- Ten CPTs were performed, including three down-hole seismic CPTs. These services were provided by Applied Research Associates (ARA) of South Royalton, Vermont, working as a subcontractor to MACTEC.

- In-situ hydraulic conductivity testing was performed by MACTEC (Section 8 of ASTM D 4044 2002) in 15 groundwater observation wells. Southern Company Services installed these wells and the report is in Appendix 2.4A.

- Geophysical down-hole suspension P-S velocity logging was performed in five completed boreholes (B-1002, B-1002A, B-1003, B-1004, and C-1005A). These services were provided by GEOVision Geophysical Services (GEOVision) of Corona, California, working as a

subcontractor to MACTEC. GEOVision also performed caliper, natural gamma, resistivity, and spontaneous potential measurements in boreholes B-1002, B-1003, and B-1004, and a borehole deviation survey at B-1003.

- A topographic survey of all exploration points was performed by MACTEC.
- Laboratory testing of selected borehole samples was performed by MACTEC in its Atlanta, Georgia, laboratories.

The exploration program was performed following the guidelines in Regulatory Guide 1.132, *Site Investigations for Foundations of Nuclear Power Plants*, US Nuclear Regulatory Commission, 2003 (RG 1.132). The fieldwork was performed under an audited and approved quality program and work procedures developed specifically for the ESP application. The subsurface investigation and sample/core collection were directed by the MACTEC site manager, who was on site at all times during the field operations. A Bechtel geotechnical engineer or geologist, along with an SNC representative, was also on site during these operations. MACTEC's QA/QC expert made periodic visits to the site and was on site to audit MACTEC's subcontractors. The draft boring and well logs were prepared in the field by MACTEC geologists.

An on-site storage facility for soil samples and rock cores was established before the fieldwork began. Each sample and core was logged into an inventory system. Samples removed from the facility were noted in the sample inventory logbook. A Chain-of-Custody form was also completed for all samples removed from the facility.

Complete details and results of the exploration program appear in Appendix 2.5A. The borings, CPTs, field permeability testing, and geophysical surveys are summarized below. The laboratory tests are summarized and the results discussed in Subsection 2.5.4.2. The geophysical tests are summarized and the results discussed in Subsection 2.5.4.4.

Additionally, a seismic reflection and refraction survey was performed at the site in early 2006 to collect data to help delineate the rock profile associated with the non-capable Pen Branch fault. The results of the seismic reflection and refraction survey are presented in Appendix 2.5B and interpreted results are discussed in Subsection 2.5.1.2.4.2.

2.5.4.3.2.1 Borings and Samples/Cores

Thirteen borings (excluding B-1003) were drilled to depths ranging from 90 ft (C-1005A) to 304 ft (B-1004). The borings were advanced in the soil using mud-rotary drilling techniques and polymer and/or bentonite drilling fluids. Table 2.5-244 provides a summary of the ESP boring and CPT locations and depths, and identifies geophysical testing performed in the boreholes.

The soil was sampled using an SPT sampler at continuous intervals to a 15-ft depth and at 5- or 10-ft intervals below 15 ft. The SPT was performed with automatic hammers and was conducted in accordance with ASTM D 1586 (1999). The recovered soil samples were visually described and classified by the onsite geologist in accordance with ASTM D 2488 (2000). A selected portion of the soil sample was placed in a glass sample jar with a moisture-proof lid. The sample jars were labeled, placed in boxes, and transported to the on-site storage area. Additionally, undisturbed samples of the Blue Bluff Marl (Lisbon Formation) were obtained using rotary pitcher samplers. Disturbed materials were removed from the upper and the lower ends of the tube, and both ends were trimmed square to establish an effective seal. Pocket penetrometer tests were taken on the trimmed lower end of the samples. Both ends of the sample were then sealed with hot microcrystalline wax and protected with plastic caps. Tubes were labeled and transported to the on-site storage area. Table 2.5-246 provides a summary of undisturbed samples of the Blue Bluff Marl collected during the ESP subsurface investigation.

The energy transfer efficiency of the automatic SPT hammers used by the drill rigs was obtained using a PAK model pile driving analyzer for both drill rigs. Testing was performed at borings B-1006 and B-1013 from depth ranges of 5 to 20 ft, 30 to 50 ft, and 75 to 100 ft. Resultant energy transfer efficiency measurements ranged from 65 to 87 percent. The average energy transfer efficiency was 75 percent. Table 2.5-247 provides the SPT hammer energy transfer efficiency results.

The continuous core boring, B-1003, was performed with a Christensen 94 mm wire line system. A Speedstar Quickdrill 275 drill rig was used. Casing was installed through the soil column to prevent cave-ins and to allow coring of rock at depths below 1,049 ft. Rock coring was performed using a HW-size, double-tube core barrel in accordance with ASTM D 2113 (1999). The recovered soil and rock core samples were placed in wooden core boxes, lined with plastic sheeting. The onsite geologist visually described the core, noting the presence of joints and fractures, and distinguishing natural breaks from mechanical breaks. The geologist also computed the percentage recovery and the RQD. The average core recovery was 77 percent for the entire borehole depth (Appendix 2.5A). Filled core boxes were transported to the on-site sample storage facility, where a photograph of each core was taken.

The boring logs and the photographs of the rock cores appear in Appendix 2.5A. The soil materials encountered in the ESP borings are similar to those found in the previous borings conducted at the VEGP site.

2.5.4.3.2.2 Cone Penetrometer Tests

The CPTs were advanced in accordance with ASTM D 5778 (2000) using a 30 ton self-contained truck rig. Each CPT was advanced to refusal at depths ranging from 6 to 116.7 ft. using a Type 2 piezocone (shouldered). Shallow refusal was encountered at locations C-1001 and C-1009, and offset CPT tests were performed at locations C-1001A and C-1009A. All remaining CPT locations met refusal at or near the top of the Blue Bluff Marl bearing stratum. Down-hole seismic testing was performed at 5 ft intervals in CPTs C-1003, C-1005, and C-1009A (see Subsection 2.5.4.4) to measure the shear wave velocity in the Upper Sand Stratum. Pore pressure dissipation tests were performed at 68 ft and 79 ft depths in C-1003; 66 ft depth in C-1004; 56 ft, 73 ft, and 82 ft depths in C-1005; and 60 ft, 77 ft, 90 ft, and 99 ft depths in C-1009A.

The CPT logs, shear wave velocity results, and pore pressure versus time plots, for the dissipation tests, are contained in Appendix 2.5A. CPT locations and depths are summarized in Table 2.5-244.

2.5.4.3.2.3 In Situ Hydraulic Conductivity Testing

Fifteen observation wells were installed at the ESP project limits during May and June 2005, and a replacement observation well was installed in October 2005. Observation well details are provided in Appendix 2.4A and discussed in Subsection 2.4.12.

Each well was developed by pumping. The well was considered developed when the pH and conductivity stabilized and the pumped water was reasonably free of suspended sediment. Permeability tests were then performed in each well in accordance with Section 8 of ASTM D 4044 (2002) using a procedure that is commonly termed the slug test method. Slug testing involves establishing a static water level, lowering a solid cylinder (slug) into the well to cause an increase in water level in the well, and monitoring the time rate for the well water to return to the pre-test static level. The slug is then rapidly removed to lower the water level in the well, and the time rate for the water to recover to the pre-test static level is again measured. Electronic transducers and data loggers were used to measure the water levels and times during the test.

Appendix 2.5A contains the well permeability test results and Appendix 2.4A contains the boring logs for the observation wells and the well installation records.

2.5.4.3.2.4 Sample Re-evaluation

The MACTEC ESP data report was revised on November 18, 2007, as provided in Appendix 2.5A. Revisions include changes to the elevation of the top of Utley Limestone, changes to borings logs, and additional laboratory data. Some material descriptions in the Blue Bluff Marl and Utley Limestone were revised to clarify the descriptors of the coarse grained fraction of the sample. The coarse grained fractions, previously described as gravel, upon re-examination of the samples were found to consist of angular, gravel-sized, carbonate particles and were attributed to the mechanical breakage of cemented nodules, shells, cemented limestone, and fossiliferous limestone by the split barrel sampler. The top of Utley Limestone was redefined in some of the ESP boreholes based on the identification criteria developed for the COL investigation program.

2.5.4.3.3 COL Subsurface Investigation Program

The COL subsurface investigation was performed by MACTEC from November 2006 through April 2007 over a large portion of the site, including the power block areas for VEGP Units 3 and 4, cooling towers, switchyard/borrow areas, haul road, intake structure, pumphouse, pipeline, and construction-related areas. The exploration points were located in accordance with the guidelines in RG 1.132. The following paragraphs describe the overall COL investigation program. Other portions of this document primarily address the portion of the COL investigation associated with safety-related structures, principally the combined footprint of the power block excavation.

The COL exploration point locations are shown on Figures 2.5-367 and 2.5-368. The scope of work and the methods used by the subsurface investigation contractor (MACTEC) and its subcontractors to collect data are listed below:

- A total of 174 exploratory borings were drilled across the site.
- Seventy-seven exploratory borings were drilled in the power block and cooling tower areas with the 3000 series conducted on the east side, Unit 3, and the 4000 series conducted on the west side, Unit 4. Continuous sampling was conducted in two of these borings, B-3013(C) and B-4013(C), to depths of 155 feet and 165 feet, respectively.
- Sixty-six borings in the 1100 series were drilled in the proposed switchyard, borrow, roadway, batch plant, intake, pumphouse, and other areas across the site.
- Thirty-one borings in the 5000 and 6000 series were drilled in the laydown, roadway, and other areas across the site.
- The efficiency of the automatic hammers employed by the 12 rotary drill rigs was determined by SPT energy measurements.
- Twenty-one CPTs utilizing a Type 2 piezocone were performed, including eight seismic CPTs taken in the power block areas. These services were provided by Gregg In-Situ, Inc., of Columbia, South Carolina, working as a subcontractor to MACTEC.
- Eight test pits were excavated in proposed borrow locations to obtain bulk samples for laboratory testing. The test pit excavations were logged by a MACTEC geologist.

- Geophysical down-hole suspension P-S velocity logging was performed in six completed boreholes, B-3001(DH), B-3002(DH), B-3003(DH), B-4001(DH), B-4002(DH), and B-4003(DH). These services were provided by GEOVision Geophysical Services (GEOVision) of Corona, California, working as a subcontractor to MACTEC. GEOVision also performed caliper, boring deviation, spontaneous potential, natural gamma, and resistivity measurements in these boreholes.

- Electrical resistivity testing was performed by MACTEC along 10 arrays across the site.

- Geophysical refraction microtremor (ReMi) testing was performed by MACTEC at four arrays.

- A horizontal and vertical survey of all exploration points was performed by Toole Surveying Company, Inc., working as a contractor to Southern Company Services.

- Laboratory testing of selected borehole samples was performed by MACTEC laboratories in Atlanta, Georgia and Charlotte North Carolina.

- RCTS testing was performed by FUGRO laboratories in Houston, Texas.

The exploration program was performed following the guidelines in RG 1.132. The fieldwork was performed under an audited and approved quality assurance program, along with approved work procedures developed specifically for the COL application. The subsurface investigation and sample/core collection were directed by the MACTEC site manager, who was on site at all times during the field operations. A Bechtel geotechnical engineer or geologist, along with an SNC representative, was also on site during these operations. MACTEC's QA/QC supervisor made periodic visits to the site, and additional QA/QC personnel visited the site to audit MACTEC's subcontractors. Draft boring logs were prepared in the field by MACTEC geologists and geotechnical engineers. A data report was also prepared by MACTEC as provided in Appendix 2.5C.

An on-site storage facility for soil samples was established before the fieldwork began. Each sample was logged into an inventory system. Samples removed from the facility were noted in the sample inventory logbook. A Chain-of-Custody form was also completed for all samples removed from the facility.

2.5.4.3.3.1 Borings and Samples/Cores

One hundred and seventy-four borings were drilled to depths ranging from 21.5 ft to 420 ft. The borings were advanced in the soil using mud-rotary drilling methods and polymer and/or bentonite drilling fluids. Table 2.5-245 provides a summary of the COL boring locations and depths.

The soil was sampled using an SPT sampler at intervals 2.5 ft within the upper 15 ft and thereafter at 5- or 10-ft intervals. The SPT was performed with automatic hammers and was conducted in accordance with ASTM D 1586 (1999). The recovered soil samples were visually described and classified by the onsite geologist or geotechnical engineer in accordance with ASTM D 2488 (2000). A selected portion of the soil sample was placed in a glass sample jar with a moisture-proof lid. The sample jars were labeled, placed in boxes, and transported to the on-site storage area. Additionally, relatively undisturbed samples were obtained. In the Upper Sand stratum, these samples were taken with the direct push method in accordance with ASTM D 1587. In the Blue Bluff Marl and Lower Sand strata these samples were taken using a Pitcher sampler, a double-tube core barrel sampler, due to the very hard/dense nature of the materials. Disturbed materials were removed from the upper and the lower ends of the tube, and both ends were trimmed square to establish an effective seal. Pocket penetrometer tests were taken on the

trimmed lower end of the samples. Both ends of the sample were then sealed with hot microcrystalline wax and protected with plastic caps. Tubes were labeled and transported to the on-site storage area.

Twelve drill rigs were used during the COL investigation. The energy transfer efficiency of the automatic SPT hammers was measured for each drill rig in accordance with ASTM D 4633 (2005). Resultant average energy transfer efficiency measurements ranged from 70.1 to 90.2 percent. Table 2.5-248 provides a summary of the SPT hammer energy transfer efficiency results.

The boring logs are provided in Appendix 2.5C. The soil materials encountered in the COL borings are similar to those found in the ESP borings and previous borings conducted at the VEGP site.

2.5.4.3.3.2 Cone Penetrometer Tests

Twenty-one CPTs for the COL investigation were advanced in accordance with ASTM D 5778 (2000) using a 20 ton self-contained truck rig mounted on a tracked ATV carrier. Each CPT was advanced to refusal (utilizing a Type 2 piezocone) which generally was encountered at or near the top of the Blue Bluff Marl bearing stratum. Eight of the 21 CPTs included seismic testing as discussed in Subsection 2.5.4.4.3.2. These eight SCPTs were located in the power block and cooling tower areas of Units 3 and 4. Refusal depths encountered in these soundings ranged from 65.4 to 100.4 ft. The CPT logs, shear wave velocity results, and pore pressure versus time plots for dissipation test are contained in Appendix 2.5C. CPT locations and depths are summarized in Table 2.5-245.

2.5.4.3.3.3 Test Pits

Test pits were excavated at eight locations identified in proposed borrow areas using a track-mounted backhoe (Caterpillar 315L) capable of 12-foot reach. A MACTEC geologist logged the excavation by observing the walls of the excavation and collected representative bulk samples of the various material types. Glass jar samples were also obtained and sealed for moisture retention. The geologist prepared a Geotechnical Test Pit Log based on visual description of the excavated materials according to ASTM D 2488. The backhoe was used to backfill the test excavation using the excavated materials and the completion of logging and sample collection. The Geotechnical Test Pit Logs are included in Appendix 2.5C. Test pit locations and elevations are summarized in Table 2.5-245.

2.5.4.3.3.4 Resistivity

Field electrical resistivity testing was performed along 10 arrays in the proposed switchyards, the cooling towers, and the circulating water line areas of the site. The locations and array lengths were field adjusted to accommodate obstructions. Array locations are shown on Figures 2.5-367 and 2.5-368. The Wenner four electrode method was used to perform the tests in accordance with ASTM G57 (2006). Electrode spacing ranged from 3 feet up to 300 feet in order to determine the soil resistivity at increasing depths. The resistivity data interpreted from the tests are contained Appendix 2.5C.

2.5.4.4 Geophysical Surveys

Subsection 2.5.4.4.1 summarizes previous geophysical investigations performed at the VEGP site: Subsection 2.5.4.4.2 summarizes the VEGP site geophysical program for this ESP investigation; and Subsection 2.5.4.4.3 summarizes the geophysical surveys performed for the COL

investigation program. Geophysical surveys were also performed for the Phase I test pad program and are summarized in Section 2.5.4.4.4.

2.5.4.4.1 Previous Geophysical Survey Programs

Field investigations that included geophysical methods for VEGP Units 1 and 2 were initiated in January 1971. Geophysical seismic refraction and cross-hole surveys were conducted at the site to evaluate the occurrence and characteristics of subsurface materials. The seismic refraction survey was used to determine depths to seismic discontinuities, based on measured compressive wave velocities. Shallow and deep refraction profiles were obtained throughout the site area, totaling 28,400 and 5,000 linear ft, respectively. The cross-hole seismic survey was conducted in the VEGP Units 1 and 2 power block area to determine in situ velocity data for both compressional and shear waves to a depth of 290 ft (82 ft below sea level) in bore holes 136, 146G, 148, 149, 151, and 154. In this procedure, three-component geophones were lowered into four of the bore holes to equal elevation levels. Energy was generated in a fifth bore hole, at the same elevation level, to determine cross-hole velocities. Boreholes spacing varied from a minimum of about 36 ft to a maximum of about 200 ft.

The seismic (compressional wave) velocities measured in the subsurface soils from depths of 0 to 290 ft ranged from 1,400 fps to 6,800 fps. The shear wave velocities measured in the subsurface soils from depths of 0 to 290 ft ranged from 600 to 1,800 fps. The Upper Sand Stratum, extending from a depth of 0 to 90 ft, has a compressional wave velocity range of 1,400 to 6,650 fps and a shear wave velocity range from 600 to 1,650 fps. The Blue Bluff Marl stratum (and underlying Lower Sand Stratum), extending from a depth of 90 to 290 ft, has a compressional wave velocity of 6,800 fps and shear wave velocities ranging from 1,600 to 1,800 fps. Young's Modulus and Shear Modulus were determined from these results. For the Upper Sand Stratum, Young's Modulus ranged from 0.2×10^5 to 2.0×10^5 pounds per square inch (psi), and Shear Modulus ranged from 0.8×10^4 to 6.8×10^4 psi. For the Blue Bluff Marl (and underlying Lower Sand Stratum), Young's Modulus was 2.3×10^5 psi, and Shear Modulus was 8.0×10^4 psi.

2.5.4.4.2 ESP Geophysical Surveys

Three down-hole seismic CPT tests and five suspension P-S velocity tests were performed during the VEGP site investigation, as described in Subsection 2.5.4.3.2. In addition a seismic reflection and refraction survey was performed to image the subsurface and characterize the basement lithology and velocities beneath the VEGP site. This survey provided an image of the basement rock across the VEGP ESP site. The results of this survey are presented in Appendix 2.5B and the interpreted results are discussed in Subsection 2.5.1.2.4.2. The incorporation of these results into the development of the rock shear wave velocity profile is described in Subsection 2.5.4.7.1.2.

2.5.4.4.2.1 Suspension P-S Velocity Tests in Boreholes

Suspension P-S velocity testing was conducted in ESP borings B-1002, B-1002A, B-1003, B-1004, and C-1005A. Borings B-1002A and C-1005A did not extend below the Upper Sand Stratum. Details of the equipment used to create the seismic compressional and shear waves and to measure the seismic wave velocities are described in detail by Ohya (1986) and are also provided in Appendix 2.5A. Appendix 2.5A also contains a detailed description of the results and the method used to compute the results. Because no ASTM standard is currently available for the suspension P-S velocity testing, a brief description is provided here. The suspension P-S velocity logging system uses a 23-ft (7-m) probe containing a source near the bottom, and two geophone receivers spaced 3.3 ft (1 m) apart, suspended by a cable. The probe is lowered into the borehole to a specified depth, where the source generates a pressure wave in the borehole fluid (drilling mud). The pressure wave is converted to seismic waves (P-wave and S-wave) at the borehole wall. Along the wall, at each receiver location, the P- and S-waves are converted back to pressure waves in the fluid and received

by the geophones, which send the data to the recorder on the surface. This procedure is typically repeated at every 1.65 ft (0.5 m) or 3.3 ft (1 m) as the probe is moved up the borehole. The elapsed time between arrivals of the waves at the geophone receivers is used to determine the average velocity of a 3.3-ft (1-m) high column of soil around the borehole. Source to receiver analysis is also performed for quality assurance. The results are summarized below.

The shear wave velocity was defined to the maximum explored depth of 1,338 ft (Appendix 2.5A). For the Upper Sand Stratum, shear wave velocities ranged from 590 to 3,300 fps, with an average value of 1,089 fps. For the Blue Bluff Marl, shear wave velocities ranged from 1,060 to 4,260 fps, with an average value of 2,354 fps. For the Lower Sand Stratum, shear wave velocities ranged from 930 fps to 4,670 fps, with an average value of 2,282 fps. Typical values for the shear wave velocities of each geologic formation contained within the Lower Sand Stratum are as follows: 1,700 fps for the Still Branch, 1,950 fps for the Congaree, 2,050 fps for the Snapp, 2,350 fps for the Black Mingo, 2,650 fps for the Steel Creek, 2,850 fps for the Gaillard/Black Creek, 2,870 fps for the Pio Nono, and 2,710 fps for the Cape Fear. The shear wave velocity in the portion of the Dunbarton Triassic Basin rock measured ranged from 2,320 to 9,350 fps. There was an upper weathered rock zone about 120 ft thick, where shear wave velocities increased linearly with depth at a very high rate. This high rate of linear increase with depth abated once shear wave velocities achieved values of about 5,300 fps, and shear wave velocities increased linearly with depth at a smaller rate. It is noted that sound rock with an average shear wave velocity of 9,200 fps was not encountered. However, enough data are available to linearly extrapolate to the sound rock horizon from the measurements.

The compressional wave was also defined to the maximum explored depth of 1,338 ft (Appendix 2.5A). For the Upper Sand Stratum, the compressional wave velocity ranged from 1,300 to 7,960 fps, with an average value of 2,572 fps. For the Blue Bluff Marl, compressional wave velocities ranged from 4,640 to 9,830 fps, with an average value of 6,793 fps. For the Lower Sand Stratum, compressional wave velocities ranged from 4,990 to 9,030 fps, with an average value of 6,610 fps. The compressional wave velocity in the Dunbarton Triassic Basin rock ranged from 7,300 to 18,360 fps.

Poisson's ratio was determined from the shear wave and compressional wave velocities (Appendix 2.5A). Poisson's ratio ranged from 0.09 to 0.49 within the Upper Sand Stratum, 0.33 to 0.48 within the Blue Bluff Marl, 0.32 to 0.49 within the Lower Sand Stratum, and 0.10 to 0.46 within the Dunbarton Triassic Basin.

2.5.4.4.2.2 Down-Hole Seismic Tests with Cone Penetrometer

The tests were performed at 5-ft intervals in ESP soundings C-1003, C-1005, and C-1009A. A seismic source, located on the surface, primarily generates shear waves and two geophones mounted horizontally inside near the bottom of the cone string record incoming seismic data. Measurements were only obtained at depths within the Upper Sand Stratum because all CPTs reached refusal at the top of the Blue Bluff Marl.

The shear wave speed and time of peak versus depth plots are included in Appendix 2.5A. The shear wave velocities ranged from 572 to 1,317 fps, with an average value of 930 fps. These values were lower than those measured using the suspension P-S velocity technique and may reflect site variability.

2.5.4.4.2.3 Discussion and Interpretation of Results

Shear and compressional wave velocity measurements made during the ESP subsurface investigation were used as the basis for developing the recommended design values for each stratum that are provided in Subsection 2.5.4.2. Results from seismic CPTs and suspension velocity logging were used to develop recommended values for the Barnwell Group. Because the seismic

CPTs could not penetrate into the Blue Bluff Marl, the recommended values for the Blue Bluff Marl and the Lower Sand Stratum are based on suspension velocity logging results only. No shear or compressional wave velocity measurements were made for the compacted fill during the ESP subsurface investigation. Recommended values for the compacted fill were initially based on data for existing VEGP Units 1 and 2 (Reference 496), as discussed in Subsection 2.5.4.7.1. Results from the COL investigation and Phase I test pad program were used to confirm the recommended values.

The profile of shear wave velocity versus depth for the subsurface strata is provided in Subsection 2.5.4.7.

2.5.4.4.3 COL Geophysical Surveys

Eight down-hole seismic CPT tests, six suspension P-S velocity tests, and four refraction microtremor testing (ReMi) arrays were performed during the COL site investigation. The results of these tests, with the exception of the ReMi data, are provided in Appendix 2.5C.

2.5.4.4.3.1 Suspension P-S Velocity Tests in Boreholes

Suspension P-S velocity testing was conducted in COL borings B-3001, B-3002, B-3003, B-4001, B-4002 and B-4003. Details of the equipment used to create the seismic compressional and shear waves and to measure the seismic wave velocities are described in detail by Ohya (1986) and are also provided in Appendix 2.5C. Appendix 2.5C also contains a detailed description of the results and the method used to compute the results. A summary of the results is provided in the following paragraphs.

The shear wave velocity was defined to the maximum explored depth of 420 ft. For the Blue Bluff Marl, shear wave velocities ranged from 1,267 to 2,984 fps, with an average value of 2,050 fps. For the Lower Sand Stratum, shear wave velocities ranged from 745 fps to 2,563 fps with average values for each geologic formation contained within the Lower Sand Stratum as follows: 1,621 fps for the Still Branch, 1,863 fps for the Congaree, and 1,871 fps for the Snapp.

Poisson's ratio was determined from the shear wave and compressional wave velocities and ranged from 0.40 to 0.48 with an average of 0.45.

2.5.4.4.3.2 Down-Hole Seismic Tests with Cone Penetrometer

The tests were performed at 0.6-ft intervals in COL soundings C-3001, C-3002, C-3003, C-3005, C-4001, C-4002, C-4003, and C-4005. A seismic source, located on the surface, primarily generates shear waves and two geophones mounted horizontally inside near the bottom of the cone string record incoming seismic data. Generally, the CPT soundings could not penetrate the dense/hard materials encountered in the Utley and/or Blue Buff Marl; therefore, the shear wave measurements were limited to the Upper Sand stratum. The penetration of the seismic CPT soundings ranged from 65.4 ft to 100.4 ft.

The shear wave speed and time of peak versus depth plots are included in Appendix 2.5C. The shear wave velocities measurements ranged from 435 to 3,802 fps. A summary plot of the COL average shear wave velocity profiles in the Upper Sand Strata is provided in Figure 2.5-377.

2.5.4.4.3.3 Refraction Microtremor Testing

ReMi testing was conducted at four arrays, two in the power block areas of the existing VEGP Units 1 and 2 and two in the footprint of proposed Units 3 and 4. The original intent of collecting these data was to establish the shear wave velocity characteristics of existing backfill at Units 1

and 2. During collection of the data, it was readily apparent that the frequency of the nearby operating plant equipment was interfering with the ReMi data. Unsuccessful attempts were made in the field to overcome this interference. SNC requested Dr. K Stokoe of the University of Texas-Austin to review the ReMi results. He expressed doubt that the test results truly represented the shear wave velocity profile. Therefore these data have not been considered in the COL geophysical survey and are not included in Appendix 2.5C.

2.5.4.4.3.4 Geophysical Surveys in Compacted Fill

Geophysical surveys were conducted during construction (at three different levels) and upon completion of the 20-ft test pad in the Phase I test pad program in order to evaluate the shear wave profile in compacted fill. The SASW (Spectral Analysis of Surface Waves) method was used to determine shear wave velocity during various stages of construction and upon completion of construction. A more detailed description of this method and the measurements taken is provided in Appendix 2.5D. The cross-hole method (ASTM D 4428) was also used to measure shear wave velocity through the fill. Upon completion of the test pad, 3 cased boreholes were installed through the 20-ft test pad, extending 20 feet below the test pad into native materials. Compressional and shear wave velocity measurements were made between the boreholes. Results from these geophysical tests, along with RCTS test results, were incorporated into the analysis to develop the shear wave velocity profile for the entire depth of backfill (approximately 90 feet) as discussed in Subsection 2.5.4.7.1.1.

2.5.4.5 Excavation and Backfill

This section covers the following topics:

- The extent (horizontally and vertically) of anticipated safety-related excavations, fills, and slopes.
- Excavation methods and stability.
- Backfill design
- Backfill sources
- Quality control and ITAAC
- Construction dewatering impacts
- Retaining wall

2.5.4.5.1 Extent of Excavations, Fills, and Slopes

Within the VEGP Units 3 and 4 footprint (Figure 2.5-366) that will contain all safety-related structures, existing ground elevations are about El. 220 ft msl. The subsurface profiles in Figures 2.5-370, 2.5-372, and 2.5-373 provide an impression of the grade elevation range across the VEGP ESP site. Plant grade for the proposed VEGP Units 3 and 4 will be at El. 220 ft msl. The base of the Nuclear Island foundations for the new units will be about El. 180 ft msl. This level corresponds to a depth of approximately 40 ft below final grade (below El. 220 ft msl), or approximately 50 to 60 ft above the top of the Blue Bluff Marl bearing stratum based on the borings completed during the ESP and COL subsurface investigations. Other foundations in the power block area will be placed at nominal depths near final grade.

Construction of the new units will require a substantial amount of excavation. The excavation will be necessary to completely remove the Upper Sand Stratum. Excavation total depth to the Blue Bluff Marl bearing stratum will range from approximately 80 to 90 ft below existing grade, based on the borings completed during the ESP and COL subsurface investigations. Deeper localized excavations will be required to remove shelly, porous, or weathered material that may be encountered near the top surface of the Blue Bluff Marl.

Seismic Category 1 backfill will be placed from the top of the Blue Bluff Marl to the bottom of the Nuclear Island (NI) foundation at a depth of about 40 ft below final grade. Seismic Category 2 backfill will be placed above the NI foundation level. The lateral extent of the Category 1 and 2 backfill is defined in Figure 2.5-389. A retaining wall will be constructed along the perimeter of the NI as described in Subsection 2.5.4.5.7 to facilitate backfilling and construction. Category 2 backfill will be placed behind the retaining wall to final grade or foundation elevation of non NI structures. Category 1 and 2 backfill material will meet the same criteria and consist of granular materials, selected from portions of the excavated Upper Sand Stratum and from other acceptable onsite borrow sources. Category 1 and 2 backfill material properties and source locations are described in more detail in Subsections 2.5.4.5.3 and 2.5.4.5.4.

Engineered granular backfill (EGB) will be placed above the slopes, outside the specified lateral extent of the Category 1 and 2 backfill, as defined in Figure 2.5-389. The areas where EGB will be placed will not affect the static or seismic performance of the safety-related facilities. The EGB will be well-compacted granular backfill meeting the following requirements;

- Compacted to a minimum of 95% of modified Proctor (ASTM D1557) maximum dry density value
- Consist of sands, silty sands and clayey sands (SP, SP-SM, SP-SC, SW, SW-SM, SW-SC, SC, SC-SM, or SM based on the Unified Soil Classification System (ASTM D2487)
- Has a maximum plasticity index (PI) of 25 and a maximum fines content (% passing the No. 200 sieve) of 35%.

Materials that exceed the limits for PI and fines content may be accepted on a case-by-case basis after an engineering evaluation has been performed.

2.5.4.5.2 Excavation Methods and Stability

Excavation for the nuclear island structures below grade may use either a sloping excavation or a vertical face as described in subsequent paragraphs. If sloping excavations are to be used on a soil site, the Combined License applicants must evaluate the 3D effects on the site response and perform site-specific SSI analyses using either or a combination of 2D or 3D SASSI models that reflect the sloping excavations. If backfill is to be placed adjacent to the exterior walls of the nuclear island, the Combined License applicant will provide information on the properties of backfill and its compaction requirements as described in Subsection 2.5.4 and will evaluate its properties against those used in the seismic analyses described in Subsection 3.7.2.

For the vertical face alternative, excavation in soil for the nuclear island structures below grade will establish a vertical face with lateral support of the adjoining undisturbed soil or rock. This vertical face will be covered by a waterproof membrane as described in subsection 3.8.5.1.1 and is used as the outside form for the exterior walls below grade of the nuclear island. Alternative methods include a soil nailing and mechanically stabilized earth (MSE) walls.

Excavation in the Upper Sand Stratum will be achieved with conventional excavating equipment. Excavation must adhere to OSHA regulations (Reference 589). The excavation will be open-cut,

with slopes no steeper than 2-horizontal to 1-vertical. Since the sandy soils can be highly erosive, even temporary slopes cut into the Upper Sand Stratum will be sealed and protected. Where insufficient space for open-cut slopes exists, vertical cuts will be supported with sheet pile or soldier pile and lagging walls. Dewatering will be required once the excavation progresses to depths beneath the groundwater table (approximately El. 150 to 155 ft in the excavation, based on the groundwater monitoring results contained in Subsection 2.4.12).

Temporary slopes will be graded as the excavation through the Upper Sand Stratum progresses. There are no permanent slopes in the NI area planned for the project that need to be considered for stability.

Possible weathered zones that may be encountered in the upper portion of the Blue Bluff Marl will be removed using conventional excavating equipment. These excavations will be sloped to facilitate placement of compacted structural fill, and the excavation areas will be thoroughly cleaned of loose materials before fill is placed.

2.5.4.5.2.1 Vertical Face Using Soil Nails

Soil nailing is a method of retaining earth in-situ. As the nuclear island excavation progresses vertically downward, holes are drilled horizontally into the adjoining undisturbed soil, a metal rod is inserted into the hole, and grout is pumped into each hole to fill the hole and to anchor the “nail” rod.

As each increment of the nuclear island excavation is completed, nominal eight to ten inch diameter holes are drilled horizontally through the vertical face of the excavation into adjacent undisturbed soil. These “nail” holes, spaced horizontally and vertically on five to six feet centers, are drilled slightly downward to the horizontal. A “nail”, normally a metal bar/rod, is center located for the full length of the hole. The nominal length of soil nails is 60 percent to 70 percent of the wall height, depending upon soil conditions. The hole is filled with grout to anchor the rod to the soil. A metal face plate is installed on the exposed end of the rod at the excavated wall vertical surface. Welded wire mesh is hung on the wall surface for wall reinforcement and secured to the soil nail face plates for anchorage. A 4,000 psi to 5,000 psi non-expansive pea gravel shotcrete mix is blown onto the wire mesh to form a nominal four to six inch thick soil retaining wall. Installation of the soil retaining wall closely follows the progress of the excavation and is from the top down, with each wire mesh-reinforced, shotcreted wall section being supported by the soil “nails” and the preceding elevations of soil nailed wall placements.

Soil nailing as a method of soil retention has been successfully used on excavations up to 55 feet deep on projects in the U.S. Soils have been retained for up to 90 feet in Europe. The state of California CALTRANS uses soil nailing extensively for excavations and soil retention installations. Soil nailing design and installation has a successful history of application which is evidenced by its excellent safety record.

The soil nailing method produces a vertical surface down to the bottom of the excavation and is used as the outside forms for the exterior walls below grade of the nuclear island. Concrete is placed directly against the vertical concrete surface of the excavation.

For methods of soil retention other than soil nailing, such as for excavation in rock, four to six inches of shotcrete are blown on to the vertical surface. The concrete for the exterior walls is placed against the shotcrete.

2.5.4.5.2.2 Vertical Face Using Mechanically Stabilized Earth Walls

Mechanically stabilized earth walls (MSE) are flexible retaining wall systems that use strip, grid, or sheet type of tensile reinforcements in the soil mass, and a discrete modular pre-cast concrete, which

is vertical. MSE walls function like, and are generally more economical than, conventional retaining walls. The tensile strength of the reinforcements and the slip at the interface of the reinforcement and the soil provide great internal stability to MSE walls. These walls may be used where the side soils have to be removed or the grade elevation needs to be raised. The walls and backfill are placed prior to construction of the nuclear island.

2.5.4.5.2.3 Mudmat

The mudmat provides a working surface prior to initiating the placement of reinforcement for the foundation mat structural concrete. The lower and upper mudmats are as follows:

- Lower mudmat — (6-inch layer) of un-reinforced concrete, with a minimum compressive strength of 2,500 psi. The lower mudmat will be used as the final dental concrete layer on the underlying foundation media.

- Upper mudmat — (6-inch layer) of un-reinforced concrete with a minimum compressive strength of 2,500 psi. This upper mudmat will support the chairs that, in turn, support the reinforcing steel.

The lower and upper mudmats are additionally described in Subsection 3.8.5.1.

The waterproofing system is described in Subsection 2.5.7.18 and Subsection 3.8.5.1.1.

2.5.4.5.3 Backfill Design

The design of the Category 1 and Category 2 backfill for VEGP Units 3 and 4 was established through analysis and testing of the borrow material during the COL investigation, the Phase I test pad program, and previous site investigations. Selection and compaction requirements are discussed below.

Material selected for use as Category 1 and Category 2 backfill will be sand and silty sand and will meet the gradation requirements provided in Table 2.5-257. Material that falls outside the gradation requirements in Table 2.5-257 may be accepted on a case-by-case basis after an engineering evaluation has been performed to assess the overall impact of the material on the backfill design. Borrow material that does not meet the limits on the No. 200 sieve will not be accepted. A backfill specification will be developed to implement these requirements.

All Category 1 and Category 2 backfill will be compacted to a minimum of 95 percent of the maximum dry density, as determined by ASTM D 1557 (2002). Procedures will be developed to control all aspects of backfill placement including lift thickness, moisture conditioning, compaction, and testing. These procedures will result in a high quality, uniform, homogeneous backfill meeting all the requirements for supporting the AP1000 structures at the Vogtle site. The testing frequency for field density tests and ITAAC associated with backfill density and shear wave velocity are discussed in Subsection 2.5.4.5.5.

The Phase I test pad program is complete and is documented in Appendix 2.5D. The objective of this program was to establish site-specific design properties for the backfill, including density, compaction, gradation, and shear wave velocity, and to show that the backfill will satisfy the AP1000 standard plant design. The test pad was constructed below grade, was 20 ft deep, and was 20 ft x 60 ft in plan area. The test pad was constructed in the switchyard borrow area using methods similar to those used to construct the backfill for VEGP Units 1 and 2. The placement and compaction of the backfill were monitored and tested. Results of the test pad program demonstrated that the siting criterion for shear wave velocity of 1,000 fps at the NI foundation depth was achieved with the backfill material within the 20 ft thickness of the test pad.

The backfill properties were determined by evaluating field and laboratory results. Laboratory testing was conducted to measure density, moisture content, grain size, plasticity, shear, and shear modulus reduction and damping relationships. Field testing was conducted to measure density (compaction), shear wave velocity (SASW and cross-hole testing), and standard penetration resistance. Measured SPTs in the test fill (neglecting the upper four feet due to the lack of confining pressure) disclosed a median uncorrected N-value of 32 bpf (corrected for hammer efficiency, N_{60} = 43). A shear wave velocity profile was calculated based on field measurements of velocity in the test pad and in laboratory samples. This profile is discussed in Subsection 2.5.4.7.1.1 and is presented in Table 2.5-250. An average moist unit weight of 123 pcf was calculated. A drained internal angle of friction of 36° was determined from laboratory triaxial shear tests. Gradation requirements were developed based on the results of field and laboratory testing, including shear wave and compaction testing, from the COL investigation, test pad program, and results from previous investigations. These gradation requirements are presented Table 2.5-257. Shear modulus reduction and damping relationships are presented in Subsection 2.5.4.7.2. A summary of the engineering properties for compacted structural fill is presented in Table 2.5-237.

A Phase II test pad program is scheduled for 2008. The purpose of this program will be to finalize the placement procedures and equipment. The program will use onsite material excavated from the switchyard borrow area. Test pad results will be used to finalize the details of the backfill construction program including construction methods, compaction methods and requirements, and testing protocol. These details will be incorporated into an earthwork specification and backfill placement procedures.

2.5.4.5.4 Backfill Sources

Sufficient sources of backfill have been identified on the Vogtle site through the boring and laboratory testing programs and analysis of their results as described below. Flowable fill may also be used as Category 2 backfill in small restricted areas where adequate compaction cannot be achieved or in large areas left open for relatively long periods, to minimize erosion or disturbance of underlying backfill. When flowable fill is used in large areas, it is limited to a total thickness of 1 foot or less. The flowable fill mix is designed to have similar strength characteristics as the compacted backfill.

Identified onsite sources of borrow material for the proposed backfill include acceptable materials from the Upper Sand stratum excavated from the power block and a borrow area (switchyard) north of the power block. An alternative borrow area is located about 4,000 feet north of the power block. This alternative location (Borrow Area 4) was also identified and investigated during construction of VEGP Units 1 and 2.

Approximately 3,900,000 cubic yards of material (including an allowance for ramps) will be excavated for the Units 3 and 4 power blocks. Approximately 3,600,000 cubic yards of material will be required to backfill these excavations, of which approximately 2,000,000 cubic yards of material must meet Category 1 and 2 requirements. Based on a review of the 70 SPT boring logs and laboratory test results on selected samples from the COL subsurface investigation, approximately 50 percent of the material excavated from the power block areas will qualify for reuse as Seismic Category 1 or 2 backfill. However, because a portion of the excavated material may be difficult to segregate, an estimated 30–50 percent of the excavated material is designated for borrow. This quantity accounts for approximately 1,200,000–2,000,000 cubic yards.

Additional backfill for the power blocks, approximately 1,600,000 cubic yards, is available from a borrow source located immediately north of the power blocks (Units 3 and 4 switchyard area). See Figures 2.5-388 and 2.5-389 for plan and section views, respectively. The switchyard borrow

source was explored with 15 SPT borings and five test pits during the COL investigation. The engineering properties of these materials were evaluated with laboratory tests on disturbed, undisturbed, and bulk samples. The COL laboratory testing program (Appendix 2.5C) included sieve analyses of 27 samples that disclosed an average value of 15 percent fines and a median value of 15 percent. Based on the subsurface data, suitable backfill materials at the switchyard borrow source were identified. These materials were classified according to ASTM D 2488 as silty sands (SM) and poorly graded sands (SP). Clayey sands (SC) were also encountered in some samples. Compaction tests (ASTM D 1557) were conducted on five bulk samples taken from representative soils. Test results disclosed a range of 111 pcf to 125 pcf for the maximum dry density with an average value of 116 pcf.

If additional material is needed, an alternative borrow source is located about 4,000 feet north of the power block area, designated Borrow Area 4. It was explored with four SPT borings and three test pits during the COL investigation. This area was previously explored but not utilized during the design and construction of Units 1 and 2. Sieve analyses were conducted on 31 representative samples and disclosed values ranging from 7 percent to 43 percent fines content with an average value of 16. Compaction tests (ASTM D 1557) were conducted on five bulk samples taken from representative soils. Test results disclosed a range of 113 pcf to 121 pcf for the maximum dry density with an average value of 116 pcf. Based on the subsurface data, suitable backfill materials at Borrow Area 4 are located at the surface (approximate El. 246 ft) to a depth of 36 ft (approximate El. 210 ft) and the borrow area is estimated to contain approximately 1,200,000 cubic yards.

Other localized deposits of suitable material within the Barnwell Group of the Upper Sand stratum located within the VEGP Exclusion Area Boundary (EAB) (Figure 1.1-202 outside of the above three borrow areas may be evaluated for use as borrow material. These additional borrow areas are limited to selected areas identified in NUREG 1872, Vol. 1, “Final Environmental Impact Statement for an Early Site Permit (ESP) at the Vogtle Electric Generating Plant Site,” Table 4.3, as areas impacted by Vogtle 3 and 4 construction. These selected areas are described in NUREG 1872 as follows:

- Cooling Tower
- Temporary Parking
- Temporary Warehouse, Office, and Laydown
- Spoils Areas

In addition, three additional areas have been identified as containing suitable backfill material. These areas are identified as follows:

- Western portion of North Stockpile area (NOI 3, west)
- Borrow Area 1C (NOI 25)
- Railroad Borrow Area (NOI 28)

Deposits within these areas may be identified by review of existing boring data, additional informational borings or test pits, or excavation activities incidental to construction. The evaluation to use such material would include a geologic review of the materials, a laboratory testing program, and an engineering review of soil properties. This material would be designated as suitable for use as Category 1 and 2 backfill provided the evaluation concludes that the material meets the acceptance criteria contained in Table 2.5-258. Once identified as suitable backfill, the material will be qualified and placed in accordance with all requirements for Category 1 and 2 backfill.

2.5.4.5.5 Quality Control and ITAAC

A quality assurance and quality control program for the backfill will be established to verify that the backfill has been constructed to the design requirements. A soil testing subcontractor, independent from the earthwork contractor, will be used to perform soil testing as part of the quality control program for backfill. The soil testing subcontractor will have an approved quality program.

The backfill quality control program will cover all aspects of the backfill testing program from qualification of the borrow material to confirmatory shear wave velocity testing of the as-placed backfill. Qualification of the borrow material will include soil classification tests, grain size distribution tests, and laboratory compaction (modified Proctor) tests. These tests will determine the acceptability of borrow material and optimum moisture content for compaction. Field density testing will be performed to verify compaction requirements are met as the backfill is placed. For limited earthwork, where fill is compacted with hand equipment, one density test will be conducted for every 2,000 square feet per foot of fill placed. For mass earthwork, the frequency of field density tests for both Category 1 and Category 2 backfill will be a minimum of one test per 500 cubic yards of compacted fill, with at least one test per lift. At least two density tests per lift will be located within the footprint directly beneath the Nuclear Island.

The backfill testing results, non-conformances related to backfill, and QA audits of backfill operations will be reviewed to determine if the as-built backfill meets the minimum 95% modified Proctor compaction requirement under the Seismic Category 1 structures. The results of this evaluation will be documented in a report to support the Inspection Test and Acceptance Criteria (ITAAC) identified in the Backfill ITAAC Table. Field density tests performed on backfill directly beneath the Nuclear Island will be used to demonstrate this ITAAC has been met.

Shear wave velocity testing will be performed on the completed backfill to confirm that the shear wave velocity, at the bottom of the NI foundation and below, is greater than or equal to 1,000 fps. Shear wave velocity will be measured using the SASW method. A report will be developed to document that the required shear wave velocity has been achieved to satisfy the ITAAC identified in the Backfill ITAAC Table.

Preliminary measurements of the shear wave velocity characteristics of the backfill will be made when backfill placement reaches the approximate elevation of the bottom of the NI foundation (El. 180 ft). SASW measurements will be taken within the NI footprint. In addition, representative SASW measurements will be taken at a minimum of three reference locations outside the NI footprint. SASW results for testing at this elevation will be used as supplemental information to document the backfill characteristics. The reference SASW locations will be selected so there will be minimal influence from structures that could impact the SASW testing (e.g., circulating water piping, Lampson Crane pad, MSE wall) when the backfill is at finish grade.

Upon completion of backfill to finish grade, SASW testing will be performed at the three reference locations outside of the NI footprint to determine the backfill shear wave velocity profile down to the top of the Blue Bluff Marl. The results of the SASW measurements made at finish grade will be used to document that the backfill shear wave velocity profile at the elevation of the bottom of the NI foundation and below is greater than or equal to 1,000 fps.

A second method of measuring shear wave velocity (e.g., cross-hole testing, seismic CPT) will be performed at one of the reference locations at finish grade. The results from this test will be compared to the SASW results for the same reference location to validate the SASW results. In the event that velocity measurements do not provide adequate evidence to support closure of the ITAAC, additional evaluations and testing may be performed.

The final report submitted to close the ITAAC will present the shear wave velocity profile for the completed backfill at the referenced locations and any supporting analysis or testing used to conclude that the ITAAC has been met. For each velocity profile, the shear wave velocity profile at the elevation of the bottom of the NI foundation and below will be compared to the required 1,000 fps.

Backfill ITAAC Table

Design Requirement	Inspections and Tests	Acceptance Criteria
Backfill material under Seismic Category 1 structures is installed to meet a minimum of 95 percent modified Proctor compaction.	Required testing will be performed during placement of the backfill materials.	A report exists that documents that the backfill material under Seismic Category 1 structures meets the minimum 95 percent modified Proctor compaction.
Backfill shear wave velocity is greater than or equal to 1,000 fps at the depth of the NI foundation and below.	Field shear wave velocity measurements will be performed when backfill placement is at the elevation of the bottom of the Nuclear Island foundation and at finish grade.	A report exists and documents that the as-built backfill shear wave velocity at the NI foundation depth and below is greater than or equal to 1,000 fps.

2.5.4.5.6 Control of Groundwater During Excavation

Construction dewatering is discussed in Subsection 2.5.4.6.2. Since the Upper Sand Stratum soils can be highly erosive, sumps and ditches constructed for dewatering will be lined. The tops of excavations will be sloped back to prevent runoff down the excavated slopes during heavy rainfall.

2.5.4.5.7 Retaining Wall

A retaining wall will be constructed within each power block excavation to facilitate construction of the nuclear islands. This retaining wall, planned as a mechanically stabilized earth (MSE) wall, will be constructed around the perimeter of each NI and will permit backfilling of the excavations before construction of the NI foundations and substructure walls. The MSE wall will act as the exterior form for the foundation and substructure walls. Waterproofing will be placed on the surface of the precast concrete MSE wall facing panels before placing NI foundation and substructure wall concrete. (Figure 2.5-390)

2.5.4.6 Groundwater Conditions

2.5.4.6.1 Groundwater Measurements and Elevations

Groundwater conditions at the site are discussed in detail in Subsection 2.4.12, and only a summary is presented here. Groundwater is present in unconfined conditions in the Upper Sand Stratum and in confined conditions in the Lower Sand Stratum at the VEGP site. The Blue Bluff Marl is considered to be an aquiclude that separates the unconfined water table aquifer in the Upper Sand Stratum from the confined Tertiary aquifer in the Lower Sand Stratum. In the powerblock area, the groundwater generally occurs at a depth of about 65 to 70 ft below the existing ground surface.

Fifteen observation wells were installed at the site during June and July 2005, before the start of the ESP subsurface investigation program. Ten of these wells were installed in the unconfined aquifer, and five were installed in the confined Tertiary aquifer. Additionally, 22 existing wells were used as part of the groundwater monitoring program for the ESP study. Thirteen of these wells were installed in the unconfined water table aquifer, and nine were installed in the confined aquifer. The wells installed in the unconfined water table aquifer exhibit groundwater levels ranging from about El. 132

to El. 165.5 ft, while the wells installed in the confined aquifer exhibit groundwater levels ranging from about El. 82 to El. 128 ft. The logs and details of well installation and testing are contained in Appendix 2.4A and Appendix 2.5A. Hydraulic conductivity (slug) tests were performed in the wells installed during the ESP field investigation, as described in Subsection 2.5.4.3.2.3. Hydraulic conductivity (k) values for the unconfined water table aquifer in the Upper Sand Stratum, based on the slug test results, range from 4.4×10^{-5} to 9.3×10^{-4} cm/second, with a geometric mean of 1.75×10^{-4} cm/second. The hydraulic conductivity of the confined Teritary aquifer in the Lower Sand Stratum, based on the slug test results, ranges from 1.3×10^{-4} to 7.5×10^{-4} cm/second, with a geometric mean of 2.95×10^{-4} cm/second. Detailed descriptions of current groundwater conditions, as well as post-construction groundwater conditions are provided in Subsection 2.4.12.

Groundwater levels at the site will require temporary dewatering of excavations extending below the water table during construction of new Units 3 and 4. Dewatering will be performed in a manner that will minimize drawdown effects on the surrounding environment and VEGP Units 1 and 2. Drawdown effects are expected to be limited to the VEGP site and to be negligible for VEGP Units 1 and 2. The relatively low permeability of the Upper Sand Stratum and underlying Blue Bluff Marl means that sumps and pumps should be sufficient for successful construction dewatering, as discussed in Subsection 2.5.4.6.2.

The design groundwater level for VEGP Units 3 and 4 will be taken at El. 165 ft msl based on the results of groundwater monitoring performed during a period of 10 years prior to the ESP subsurface investigation, and during the ESP subsurface investigation, as discussed in Subsection 2.4.12. This level corresponds to the design groundwater level for the existing VEGP Units 1 and 2. The static stability of the proposed structures based on this design groundwater level is discussed in Subsection 2.5.4.10.

2.5.4.6.2 Construction Dewatering

Dewatering for all major excavations could be achieved by gravity-type systems. Due to the relatively impermeable nature of the Upper Sand Stratum, sump-pumping of ditches will be adequate to dewater the soil. These ditches will be advanced below the progressing excavation grade.

During construction of VEGP Units 1 and 2, the excavation materials were dewatered by a series of ditches oriented in an east-west direction. They were connected by a north-south ditch, which drained to a sump in the southwest corner of the excavation. The sump was equipped with four pumps each with a capacity of 500 gal./min to remove inflows from groundwater. Additional capacity was provided for the removal of inflows of storm water in the excavation.

Similar dewatering procedures will be implemented during the excavation for VEGP Units 3 and 4.

2.5.4.7 Response of Soil and Rock to Dynamic Loading

All new safety-related structures will be founded on the planned structural backfill, which will completely replace the existing Upper Sand Stratum soils. The seismic acceleration at the sound bedrock level will be amplified or attenuated up through the soil and rock column. To estimate this amplification or attenuation, the following data are required.

- Shear wave velocity profile of the soils and rock
- Variation with strain of the shear modulus and damping values of the soils
- Site-specific seismic acceleration-time history

In addition, an appropriate computer program is required to perform the analysis.

2.5.4.7.1 Shear Wave Velocity Profile

2.5.4.7.1.1 Soil Shear Wave Velocity Profile

Various measurements have been made at the VEGP ESP site to obtain estimates of the shear wave velocity in the soil. Measurements were also made at the site during the COL investigation to confirm ESP estimates of shear wave velocity in the soil.

All safety-related structures will be founded on the structural backfill that will be placed on top of the Blue Bluff Marl after complete removal of the Upper Sand Stratum. Shear wave velocity was not determined for the compacted backfill during the ESP subsurface investigation. Data for existing Units 1 and 2 is used (Reference 496) and the backfill shear wave velocity values are summarized in Table 2.5-249.

During the COL investigation, shear wave velocity data for the compacted backfill was measured directly in the field during the Phase I test pad program. These data, with laboratory test data, were used to evaluate the shear wave velocity of the backfill. A summary of the Phase I test pad program, including a discussion of material properties, is included in Subsection 2.5.4.5.3. The results of the test pad program are presented in Appendix 2.5D. RCTS and other data from the COL investigation were also used to evaluate the shear wave velocity of the backfill. The RCTS data are presented in Attachment G of Appendix 2.5C. Results of the COL investigation and Phase I test pad were used to develop the shear wave velocity profile of the backfill based on COL data. This profile is presented in Table 2.5-250 and is in good agreement with the ESP backfill profile. Both of these profiles are included in the respective soil columns in Figure 2.5-379.

Figure 2.5-376 shows the shear wave velocity values measured in the subsurface soil and rock strata for the ESP subsurface exploration program using suspension P-S velocity and CPT down-hole seismic testing. Figure 2.5-377 shows the shear wave velocity values measured in the Upper Sand Stratum using CPT down-hole seismic testing from COL data. The shear wave velocity profile shown in Figure 2.5-378 is the profile interpreted from the results of the ESP data shown in Figure 2.5-376 for strata below the Upper Sand Stratum, plus the shear wave velocity values for the backfill shown on Table 2.5-249. The shear wave velocity values corresponding to the profile shown on Figure 2.5-378 for the different soil strata encountered by the borings are provided in Table 2.5-251.

The shear wave velocity profile developed from the ESP investigation and shown in Figure 2.5-378 is used in the seismic amplification/attenuation analysis. The soil profile used consists of: Compacted backfill from 0 to 86 ft, Blue Bluff Marl from 86 to 149 ft, Lower Sand Stratum from 149 to 1,049 ft, Dunbarton Triassic Basin and Paleozoic Crystalline Rock below 1,049 ft.

During the COL investigation, shear wave velocity values were measured in the Blue Bluff Marl and the upper portions of the Lower Sand Stratum as previously described inSubsection 2.5.4.4.3. These data included measurements in 6 boreholes, extending to a maximum depth of 420 feet below ground surface. Shear wave velocity values were measured in the Still Branch, Congaree, and Snapp Formations of the Lower Sand Stratum. These COL data (6 profiles) were combined with two ESP profiles (located in the powerblock area of Units 3 and 4) and averaged. The average shear wave profile for the this COL data set is shown on Figure 2.5-379. This profile also reflects the average stratigraphy within the powerblock excavation footprints based on data from the COL borings. The shear wave velocity profile includes the shear wave velocity profile of the backfill that was developed during the Phase I test pad program. The profile below the COL data (below the upper portion of the Snapp formation)

incorporates the shear wave velocity data from the ESP profile. The COL profile consists of: compacted backfill from 0 to 88 ft, Blue Bluff Marl from 88 to 156 ft, Lower Sand Stratum from 156 to 1,058 ft, and Dunbarton Triassic Basin and Paleozoic Crystallilne Rock below 1,058 ft. The ESP profile, shown on Figure 2.5-378, is also illustrated on Figure 2.5-379 for comparison purposes. Figure 2.5-379 illustrates the relationship, including the similarity, between the two data sets. In general, within specific geologic formations, the two profiles demonstrate consistent shear wave velocity characteristics. The profile of the combined data set (COL) in the middle and upper portions of the Blue Bluff Marl is in good agreement with the ESP profile. At the lower portions of the Blue Bluff and in the Lower Sand Stratum, the COL profile exhibits slightly lower shear wave values than the ESP profile.

2.5.4.7.1.2 Rock Shear Wave Velocity Profile

As discussed in Subsection 2.5.4.2.2, the VEGP ESP site sits on over 1,000 feet of Coastal Plain sediments underlain by Triassic Basin sedimentary rock, which in turn is underlain by Paleozoic crystalline rock (see Figure 2.5-243). For the purpose of subsequent site response analysis, for which input rock time histories must be inserted at a depth where the material shear-wave velocity is approximately 9,200 ft/s, it is necessary to know the shear-wave velocity profile and materials properties for the site down to the depth at which this velocity is encountered. Because the site overlies both Triassic Basin and Paleozoic crystalline rocks, it is necessary to consider effect of shear-wave velocities and material properties of both rock types and their geometries.

As indicated in Figure 2.5-376, the shear-wave velocities measured at the top of the Triassic Basin, even through the weathered portion, do not reach the velocity of 9,200 ft/s. Inspection of available deep borehole shear-wave velocity at SRS (Reference 596) along with the B-1003 data [Figure 2.5-380], however, suggests the following character of rock shear-wave in the Triassic Basin:

- A weathered zone of ~200 feet thickness occurs at the top of the Triassic Basin, characterized by a steep shear-wave velocity gradient, where the shear-wave velocity rapidly increases with depth to a point where a relatively high shear-wave velocity, but less than 9,200 ft/s is reached;

- Below the weathered zone the shear-wave velocity increases with a gentler gradient within the unweathered rock;

- Considering the SRS data as a guide for shear-wave velocity within deep portions of the Triassic Basin, there are a range of gentle gradients and a range of shear-wave velocities for the top of the unweathered Triassic Basin that could be considered as a continuation of the site-specific profile presented by B-1003.

Figure 2.5-244 indicates that the non-capable Pen Branch fault separates the Triassic Basin from the Paleozoic crystalline rocks. The structural geometry of these rock units and the fault, relative to the locations of boreholes B-1002 and B-1003 (approximate locations of the proposed nuclear units) and considering the velocity profiles shown in Figure 2.5-380, a shear-wave velocity profile through the Triassic Basin would not likely reach 9,200 ft/s before encountering the Paleozoic crystalline rock. Several observations and studies at SRS [e.g., (Reference 585, Reference 586, Reference 265)] indicate that the shear-wave velocity of the Paleozoic crystalline rock is at least 9,200 ft/s.

Therefore, to represent the variability of the depth at which the Paleozoic crystalline rock is encountered, with a shear-wave velocity of at least 9,200 ft/s, and the uncertainty of the shear-wave velocity gradient and velocity at the top of the unweathered Triassic Basin, six rock shear-wave velocity profiles were considered to comprise the base case used in the seismic amplification/ attenuation analysis. Figure 2.5-378 shows a plot of these six rock shear-wave velocity profiles and Table 2.5-252, Part B presents their tabulation.

Figure 2.5-243 and Figure 2.5-380 suggest additional geometries for the shear-wave velocity profiles of the Triassic Basin and the Paleozoic crystalline rock that could impact site response. As interpreted in Figure 2.5-244, further to the northwest of the footprint of the project site the coastal Plain sediments would be underlain immediately by the Paleozoic crystalline rock. Conversely, further to the southeast of the footprint of the project, the Paleozoic crystalline rock is at such a depth that the shear-wave velocity gradient in the Triassic Basin would result in 9,200 ft/s being reached in the shear-wave velocity profile while still within the Triassic Basin. Close inspection of the DRB-9 shear-wave velocity profile in Figure 2.5-380 suggests a low-velocity zone at the bottom of the Triassic Basin at the encountering of the Pen Branch fault. Sensitivity analyses were performed that indicated that alternate shear-wave velocity models suggested by these observations result in insignificant variations in the site response, relative to the six profiles that were explicitly considered, as discussed above.

2.5.4.7.2 Variation of Shear Modulus and Damping with Shear Strain

2.5.4.7.2.1 Shear Modulus

2.5.4.7.2.1.1 ESP Analysis

The variation of soil shear modulus values of sands, gravels, and clays with shear strain is well-documented by researchers such as Seed and Idriss (1970); Seed et al. (1984); and Sun et al. (1988). This research, along with additional work, has been summarized by EPRI (Reference 515).

Shear modulus is derived from the respective unit weight and shear wave velocity of the soil strata with the following equation:

$$G_{max} = \rho \cdot (V_s)^2 = \gamma \cdot (V_s)^2/g$$ Equation (20-27) on page 758 of Bowles (1982)

Shear wave velocity data are shown on Table 2.5-251. Unit weight data are shown on Table 2.5-236. Values for shear modulus are tabulated during analysis with the SHAKE 2000 program (Reference 497), and the low strain values are also shown on Table 2.5-238 for the existing soils and rock, and on Table 2.5-249 for the compacted backfill.

From EPRI (Reference 515), the dynamic shear modulus reduction is derived in terms of depth for granular soils (Upper and Lower Sand Strata) and in terms of Plasticity Index (PI) for cohesive soils (Blue Bluff Marl).

The EPRI curves for sands (Reference 515, Figure 7.A-18) were used to derive the shear modulus reduction factors for the granular soil strata (compacted backfill and Lower Sand Stratum). The EPRI curves for clays (Reference 515, Figure 7.A-16) were used to derive the shear modulus reduction factors for the Lisbon Formation using PI = 25 percent. The shear modulus reduction factors are provided in Table 2.5-254 and Figure 2.5-381.

The shear modulus reduction factors developed for the neighboring SRS and contained in Lee (1996) were also used in the analysis. The SRS curves were selected based on their stratigraphic relationship to the Voglte 3 and 4 site. The SRS curve labeled as Blue Bluff Marl in Table 2.5-256 and on Figure 2.5-383 is based on the Dry Branch Formation and the Santee Formation, the SRS stratigraphic equivalent to the Vogtle Blue Bluff Marl. Degradation curves for the compacted backfill were not developed for SRS. The mean site reduction site amplification factors using EPRI and SRS shear modulus degradation relationships were weighted equally as described in Subsection 2.5.2.5.1.2.1

2.5.4.7.2.1.2 COL Analysis

Site-specific dynamic shear modulus reduction curves were developed from RCTS test results on samples from the Blue Bluff Marl and Lower Sand strata as well as proposed borrow materials for the compacted backfill, taken during the COL investigation. Index testing was also conducted on these samples. Results of index and RCTS testing are included in Attachment G of Appendix 2.5C.

In the Blue Bluff Marl, four relatively undisturbed samples (Pitcher samples) were tested. Two samples disclosed low plasticity indices (PI =26 and 27) while two disclosed high PI values (46 and 69). The shear modulus reduction data was plotted against shearing strain and overlain on the EPRI curves for clay (Reference 515, Figure 7.A-16). The site specific data followed trends consistent with the EPRI relationships for PI. Site specific curves were derived for low PI material and high PI material based on the similarity of the EPRI PI curves.

In the Lower Sand Stratum, five relatively undisturbed samples (Pitcher samples) were tested. Three were identified as sand and two were identified as low plasticity clays. The shear modulus reduction data were plotted against shearing strain and overlain on the EPRI curves for depth for granular soils (Reference 515, Figure 7.A-18). Note that RCTS data for the clayey samples were evaluated against the EPRI curves for clay; however, the damping relationships disclosed in these tests (as discussed later) were not consistent with the EPRI clay relationships. The site specific data followed trends consistent with the EPRI relationships for depth for granular soils. Site specific curves were derived for the sand and the clay materials in the Lower Sand stratum based on the similarity of the EPRI depth curves.

Five bulk samples from test pits in proposed borrow sources were identified for testing. Moisture-density (ASTM D 1557) and index testing were conducted on these samples. The fines content of these samples ranged from about 8 to 25 percent. RCTS tests were conducted on each bulk sample (using the same loading schedule) at two different levels of compaction (95% and 97% or 95% and 100%). The assigned confining pressures for the RCTS testing were determined based on representative depths throughout the proposed 90-ft column of backfill. Test results disclosed little variation based on the level of compaction. The shear modulus reduction data was plotted against shearing strain and overlaid on the EPRI curves for depth for granular soils (Reference 515, Figure 7.A-18). Test results for samples at low confining pressures disclosed similar trends, as did test results for samples at higher confining pressures. The site specific data followed trends consistent with the EPRI relationships for depth for granular soils. Site specific damping curves for borrow material were developed for samples under low confining pressure (depths less than 25 ft) and for samples under higher confining pressures (greater than 25 ft) based on the similarity of the EPRI curves for depth for granular soils.

Site specific shear modulus reduction curves developed from the RCTS testing of COL samples are provided in Table 2.5-255 and Figure 2.5-382. These data were used to evaluate the site response as described in Subsection 2.5.2.9.3

2.5.4.7.2.2 Damping

2.5.4.7.2.2.1 ESP Analysis

The publications cited above address the variation of soil damping with cyclic shear strain as well as the variation of shear modulus with shear strain.

From EPRI (Reference 515), the damping ratio is derived in terms of depth for granular soils (Upper and Lower Sand Strata) and in terms of PI for cohesive soils (Blue Bluff Marl).

The EPRI curves for sands (Reference 515, Figure 7.A-19) were used to derive the damping ratios for the granular soil strata (compacted backfill and Lower Sand Stratum). The EPRI curves for clays (Reference 515, Figure 7.A-17) were used to derive the damping ratios for the Lisbon Formation using PI = 25 percent. The damping ratios are provided in Table 2.5-254 and Figure 2.5-384.

The damping ratio values developed for the neighboring SRS and contained in Lee (1996) were also used in the analysis. The SRS curves were selected based on their stratigraphic relationship to the Voglte 3 and 4 site. The SRS curve labeled as Blue Bluff Marl in Table 2.5-256 and on Figure 2.5-386 is based on the Dry Branch Formation and the Santee Formation, the SRS stratigraphic equivalent to the Vogtle Blue Bluff Marl. Degradation curves for the compacted backfill were not developed for SRS. The mean site reduction site amplification factors using EPRI and SRS shear modulus degradation relationships were weighted equally as described in Subsection 2.5.2.5.1.2.1.

2.5.4.7.2.2.2 COL Analysis

Site-specific damping curves were developed from RCTS test results on samples from the Blue Bluff Marl and Lower Sand strata as well as proposed borrow materials for the compacted backfill, as similarly described in Subsection 2.5.4.7.2.1.2.

The RCTS damping relationships for the Blue Bluff Marl samples were plotted and overlain on the EPRI curves for clay (Reference 515, Figure 7.A-17). The site specific data followed trends consistent with the EPRI damping relationships for PI. Site specific curves were derived for low PI material and high PI material based on the similarity of the EPRI PI curves.

The RCTS damping relationships for the Lower Sand Stratum samples were plotted against shearing strain and overlain on the EPRI curves for depth for granular soils (Reference 515, Figure 7.A-19). The damping relationships for the clayey samples were evaluated against EPRI curves for clay; however, these data disclosed lower damping values at lower shear strains. Instead the RCTS data were more closely aligned with the EPRI relationships with depth for granular soils. The site specific data for both sand and clay samples followed trends consistent with the EPRI relationships for depth for granular soils. Therefore, site specific damping curves were derived for the sand and the clay materials in the Lower Sand stratum based on the similarity of the EPRI curves for depth for granular soils.

The RCTS damping relationships for the proposed borrow sources were plotted against shearing strain and overlain on the EPRI curves for depth for granular soils (EPRI TR-102293 1993, Figure 7.A-19). Test results for samples at low confining pressures disclosed similar trends, as did test results for samples at higher confining pressures. The site specific data followed trends consistent with the EPRI relationships for depth for granular soils. Site specific damping curves for borrow material were developed for samples under low confining pressure (depths less than 25 ft) and for samples under higher confining pressures (greater than 25 ft) based on the similarity of the EPRI curves for depth for granular soils.

Site specific damping curves developed from the RCTS testing of COL samples are provided in Table 2.5-255 and Figure 2.5-385. These data were used to evaluate the site response as described in Subsection 2.5.2.9.3.

After randomization, the damping curves were cut off at 15 percent damping ratio per NUREG-0800, Section 3.7.2 (1996).

2.5.4.7.3 Soil/Rock Column Amplification/Attenuation Analysis

The SHAKE2000 (Reference 497) computer program was used to compute the site dynamic responses for the soil/rock profiles described in Subsection 2.5.4.7.1. The computation was performed in the frequency domain using the complex response method. Subsection 2.5.2.5 describes in detail the soil/rock column amplification/attenuation analysis based on the ESP soil column.

SHAKE2000 uses an equivalent linear procedure to account for the non-linearity of the soil by employing an iterative procedure to obtain values for shear modulus and damping that are compatible with the equivalent uniform strain induced in each sublayer. At the outset of the analysis, a set of properties (based on the values of shear modulus and damping presented in Subsection 2.5.4.7.1, and total unit weight) was assigned to each sublayer of the soil profile. The analysis was conducted using these properties, and the shear strain induced in each sublayer was calculated. The shear modulus and damping ratio for each sublayer was then modified based on the shear modulus and damping ratio versus strain relationships presented in Subsection 2.5.4.7.2. The analysis was repeated until strain-compatible modulus and damping values were achieved.

2.5.4.7.4 Two-Dimensional Effects Site Response Analysis (Bathtub Model)

The model for the site dynamic response analysis as described in Subsection 2.5.2.5 depicted the backfill above the Blue Bluff Marl as a continuum. The model did not account for the extent of the excavation and backfill and any impacts the Upper Sands have on the site response. These impacts were evaluated by considering the site response with the Upper Sands in place and with these materials replaced with backfill. The average shear wave profile of the Upper Sands as developed from the COL data, as shown on Figure 2.5-377, was used to characterize shear wave velocity of the Upper Sands. A discussion of this analysis and results are presented in Subsection 2.5.2.9.2.

2.5.4.7.5 Comparison of ESP vs. COL Soil Column

Subsurface data were collected and evaluated at the site during two distinct phases referred to as the ESP investigation and COL investigation (including the Phase 1 test pad program) as presented in Subsection 2.5.4.3. The ESP investigation was limited in scope and broad in areal coverage; whereas the COL investigation was more focused in coverage (to the power block area) and extensive in scope. Subsurface data, including shear wave velocity, from the ESP investigation were taken from widely spaced borings. One of these boreholes (B-1003) extended through the entire soil column (over 1,000 ft) and into the underlying sedimentary rock of the Triassic Basin. Subsurface data from VEGP Units 1 and 2 and other regional sources were also evaluated. Soil non-linearity curves obtained from EPRI and the nearby Savannah River Site (SRS) were assigned based on soil type and depth. The resulting ESP soil column was used in the amplification/attenuation analysis in Subsection 2.5.2.5.

The COL investigation provided numerous additional subsurface data specific to the powerblock areas of Units 3 and 4. The COL investigation was taken to exploration depths of 420 ft. ESP data taken within the powerblock areas were compiled with the COL data to develop the COL soil column. These data included averaged shear wave velocities, averaged strata thicknesses and densities. A thick clay layer (approximately 70 ft) encountered in the Lower Sands, as discussed in Subsection 2.5.4.2.2.3, was incorporated into the COL soil column as shown on Figure 2.5-379. Site specific soil non-linearity curves for the various strata, including the clay soils in the Lower Sands, were developed from RCTS testing of representative COL samples and are included in the COL soil column. These data were discussed in Subsection 2.5.4.7.2 and are presented in Figures 2.5-382 (G/Gmax curves) and 2.5-385 (damping ratio curves). Site specific dynamic properties of the

compacted backfill were developed during the COL laboratory testing program and the Phase 1 test pad program and are included in the COL soil column.

The stratification and shear wave velocity profiles for the ESP and COL soil columns are presented in Figure 2.5-379. The offset in soil stratification between the soil columns reflects refinements due to the additional data collected during the COL investigation. The stratification of the ESP soil column is based on the deep boring, B-1003. The stratification of the COL soil column is based on numerous additional borings in the power block areas. The data disclosed thicker near surface strata as compared with boring B-1003. No additional stratification or shear wave velocity data below the top of the Snapp Formation in the Lower Sands were collected during the COL investigation; therefore, the COL soil column stratification and shear wave velocity profiles between the Snapp Formation and the top of the Triassic Basin bedrock were carried over from the ESP soil column with the same strata thicknesses but slightly shifted in depth to match the thicker near surface strata. Comparison of the two shear wave velocity profiles indicates good agreement between the data sets. Trends within the strata are consistent.

Comparisons of the soil non-linearity curves used for ESP and COL are presented in the attached Figures 2.5-392 through 2.5-397. Figures 2.5-392, 2.5-393, and 2.5-394 illustrate the normalized shear modulus vs. shear strain curves for compacted backfill, Blue Bluff Marl, and Lower Sands, respectively. Figures 2.5-395, 2.5-396, and 2.5-397 illustrate the soil damping vs. shear strain curves for the same strata. The figures include both the site specific curves developed during the COL investigation and the EPRI and SRS model curves assigned during the ESP investigation. The COL site specific data for the Lower Sands includes non-linearity curves for both sand and clay materials in this stratum. Generally the figures suggest that the subsurface soils behave more linearly (provide a smaller reduction in shear modulus and less damping) than the models used for the ESP investigation.

The COL soil column, including shear wave velocity and site specific non-linearity relationships as described here, was used in the site response sensitivity analysis to evaluate the effects of the COL data with the ESP data as described in Subsection 2.5.2.9.3.

2.5.4.7.6 MSE Backfill Shear Wave Velocity Profile

As discussed in Subsection 2.5.4.5.7, an MSE wall is planned to facilitate construction of the Nuclear Island. This wall, as shown on Figure 2.5-390, will be founded at the NI foundation level and will consist of wall facing panels and tensile elements embedded in the backfill behind the wall face. During construction, the backfill immediately behind the wall face, for a distance of about 5 feet, will likely be compacted with smaller, potentially hand-operated, compactors and in thinner lifts to achieve the compaction criteria of at least 95 percent of the maximum dry density modified Proctor value (ASTM D 1557). Beyond this wall face zone, the backfill will be compacted as part of the mass earthwork operation utilizing larger self-propelled compaction equipment. Owing to the likely different compaction procedures and the presence of the MSE wall face, the shear wave velocity profile of the backfill in the 5 ft wall face zone may be reduced. To investigate the effect of this possibility, a reduced velocity profile for the full height of the wall (MSE best estimate) was used in a soil structure interaction analysis, as presented in Appendix 2.5E. The results show that there are no differences in the seismic structural responses from the potentially reduced shear wave velocity profile behind the MSE wall.

2.5.4.8 Liquefaction Potential

The AP1000 design has not been evaluated for a site where there is a liquefaction potential of the soil below the nuclear island.

Soil liquefaction is a process by which loose, saturated, granular deposits lose a significant portion of their shear strength due to pore pressure buildup resulting from cyclic loading, such as that caused by an earthquake. Soil liquefaction occurrence (or lack thereof) depends on geologic age, state of soil saturation, density, gradation, plasticity, and earthquake intensity and duration. Soil liquefaction can occur, leading to foundation bearing failures and excessive settlements, when all of the following criteria are met:

1. Design ground acceleration is high.

2. Soil is saturated (i.e., close to or below the water table).

3. Site soils are sands or silty sands in a loose or medium dense condition.

The naturally occurring Upper Sand Stratum soils at the VEGP site meet these three criteria. These soils consist of sands with varying fines content. An approximate 30-ft depth of the Upper Sand Stratum occurs beneath the groundwater table at a depth of 60 ft beneath the ground surface. The average corrected SPT N-value within the Upper Sand Stratum was 25 bpf, indicating a medium dense condition. The underlying Blue Bluff Marl soils are significantly cohesive; although some seams of coarse-grained materials are present. The Lower Sand Stratum is sufficiently dense and deep. Liquefaction is not a concern within these strata; although the liquefaction potential of the coarse-grained materials in the Blue Bluff Marl will be discussed. The liquefaction potential of the Upper Sand Stratum will also be discussed.

During construction of VEGP Units 1 and 2, the entire portion of the Upper Sand Stratum was removed and replaced with engineered fills due to susceptibility to liquefaction. A similar excavation will be executed for VEGP Units 3 and 4.

Regulatory Guide 1.198, *Procedures and Criteria for Assessing Seismic Soil Liquefaction at Nuclear Power Plant Sites*, US Nuclear Regulatory Commission, November 2003 (RG 1.198) is used as a guide for liquefaction analysis presented herein.

2.5.4.8.1 Acceptable Factor of Safety Against Liquefaction

RG 1.198 states that factors of safety (FS) $\leq$ 1.1 against liquefaction are considered low, FS $\approx$ 1.1 to 1.4 are considered moderate, and FS $\geq$ 1.4 are considered high. The Committee of Earthquake Engineering of the National Research Council (NRC/NAP 1985) states:

> *There is no general agreement on the appropriate margin (factor) of safety, primarily because the degree of conservatism thought desirable at this point depends upon the extent of the conservatism already introduced in assigning the design earthquake. If the design earthquake ground motion is regarded as reasonable, a safety factor of 1.33 to 1.35...is suggested as adequate. However, when the design ground motion is excessively conservative, engineers are content with a safety factor only slightly in excess of unity.*

2.5.4.8.2 Previous Liquefaction Analyses

The liquefaction potential of the Upper Sand Stratum was previously evaluated using the standard penetration test blow counts obtained during the investigations for VEGP Units 1 and 2 and the simplified procedure of Seed and Idriss. This evaluation indicated that the Upper Sand Stratum below the groundwater table was susceptible to liquefaction when subjected to the maximum SSE acceleration of 0.2g developed for VEGP Units 1 and 2. Based on this evaluation, the Upper Sand Stratum was removed to an approximate elevation of 130 to 135 ft in the VEGP Units 1 and 2 power block area. Select sand and silty sand compacted to 97 percent of the maximum density determined by ASTM D 1557 was placed from the top of the Blue Bluff Marl stratum to the design elevation of the

various power block structures with the exception of an area north of the turbine building. The liquefaction potential of compacted backfill in the power block area was evaluated, and the analysis indicated a factor of safety against liquefaction on the order of 1.9 to 2.0. The analysis was done utilizing cyclic strength data (PSAR data) obtained from tests on specimens of compacted backfill.

During the investigations for borrow sources for VEGP Units 1 and 2, additional dynamic data (borrow source data) were obtained to supplement the cyclic strength data for the compacted fill. Cyclic triaxial tests were performed on compacted specimens of sands obtained from stockpiles and borrow areas. The cyclic stress ratios versus the number of cycles to 2.5 percent total strain (initial liquefaction) showed that the stress ratios for the cleaner sands were substantially lower than for silty sands. In the liquefaction analysis performed using the PSAR data, stress ratios for the cleaner sands were used to obtain the safety factor against liquefaction. Therefore, the cyclic stress ratios for the cleaner sands obtained during investigations for borrow material were compared with values obtained during the PSAR investigations. A comparison of the two test data (PSAR data versus borrow source data) indicates that the PSAR data represent a lower bound of test values. If the liquefaction analysis were performed using the upper bound values (borrow source data), a factor of safety higher than 1.9 to 2.0 would have been obtained for the design SSE conditions.

From the discussion presented above for the VEGP Units 1 and 2, it is concluded that there exists an adequate factor of safety against liquefaction for the compacted backfill.

2.5.4.8.3 Liquefaction Analyses Performed for the ESP Application

2.5.4.8.3.1 Liquefaction Analyses of the Upper Sands

Based on previous investigations and excavation completed for the existing VEGP Units 1 and 2 and their proximity to proposed VEGP Units 3 and 4, the Upper Sand Stratum will be completely removed and replaced with select compacted non-liquefiable fills back to the plant grade within the footprint of the planned power block.

Because select compacted non-liquefiable fills will be used to replace the Upper Sand Stratum in the power block area of proposed VEGP Units 3 and 4, no liquefaction study was performed for this ESP investigation.

2.5.4.8.3.2 Liquefaction Analyses of the Blue Bluff Marl

The Blue Bluff Marl is identified as a cemented, overconsolidated, calcareous fine-grained material (silt and clay), and thus exhibits high factor of safety against liquefaction. However, some lenses of silty fine sand were encountered during the COL investigation. Due to the presence of these materials, a review of the liquefaction potential of the Blue Bluff Marl is presented in the following paragraphs.

The present state-of-the-art considers an evaluation of data from SPT, CPT, and shear wave velocity (Vs) measurements, with the method employing SPT measurements being the most well-developed and well-recognized. Initially, a measure of the stress imparted to the soils by the ground motion is calculated, referred to as the cyclic stress ratio (CSR). Then, a measure of the resistance of soils to the ground motion is calculated, referred to as the cyclic resistance ratio (CRR). And finally, a factor of safety (FOS) against liquefaction is calculated as the ratio of the resisting stress, CRR, to the driving stress, CSR. Details of the liquefaction methodology and the relationships for calculating CSR, CRR, FOS, and other intermediate parameters such as the stress reduction coefficient (rd), the magnitude scaling factor (MSF), the Kσ correction factor accounting for liquefaction resistance with increasing confining pressure, and a host of other correction factors, can be found in (Reference 606). A MSF of 1.11 was used in the analyses, based on the selected earthquake magnitude. A review of the results of liquefaction potential analyses

using the available SPT and Vs data (CPT data was unavailable) for the Blue Bluff Marl in the power block are of Units 3 and 4 follows.

2.5.4.8.3.2.1 Liquefaction Potential Based on SPT Data

SPT N_{60}-values versus elevation are presented on Figure 2.5-391 for the 70 borings taken in the power block area of Units 3 and 4 for the COL investigation. With the assumption of clean sand (i.e., fines content, FS = 5%), the results show that most of the coarse-grained soil samples have corrected SPT blow counts, N1 or $(N1)_{60}$, greater than 30, indicating non-liquefiable. Among eight of the soil soils that are analyzed, only three of them are potentially liquefiable, with calculated factors of safety (FS) against liquefaction 1.43, 1.75, and 2.19. In all cases, the FS against liquefaction in the Blue Bluff Marl was greater than 1.1.

2.5.4.8.3.2.2 Liquefaction Potential Based on Shear Wave Velocity Data

Shear wave velocity (Vs) data measured in the Blue Bluff Marl by P-S logging in six borings taken in the power block for the COL investigation were evaluated for liquefaction potential. The shear wave velocity values were corrected for overburden (Vs1) following recommendations in (Reference 606). The calculated Vs1 values ranged from 253 meters/second to 508 m/s. The relationship between Vs1, CRR, and liquefaction potential presented by (Reference 606). suggests that the Blue Bluff Marl is non-liquefiable based these calculated values.

2.5.4.8.3.3 Liquefaction Analyses of the Compacted Backfill

The backfill will be compacted to a minimum of 95 percent of the maximum dry density as determined by ASTM D 1557. The Phase I test pad program (Appendix 2.5D) was conducted to evaluate backfill properties. Borrow sources and quantities have been identified as summarized in Subsection 2.5.4.5.3. Field and laboratory testing was conducted on these materials. Results from the testing of borrow sources and the test pad program including measured N-values and shear wave velocities are consistent with the results from Units 1 and 2. Figure 16 of Appendix 2.5D provides a plot of $N1_{(60)}$ vs depth and demonstrates an average $N1_{(60)}$ value (below a depth of 2 feet) equal to or greater than 40 bpf. In addition, the shear wave velocity profile for the backfill, as presented in Table 2.5-250, demonstrates a shear wave velocity greater than 1,000 fps below a depth of 30 feet. Therefore, as determined for Units 1 and 2 and presented in Subsection 2.5.4.8.2 for the design basis earthquake, liquefaction is not a concern.

2.5.4.8.4 Liquefaction Conclusions

Based on the foregoing sections on the analysis of liquefaction potential, the following conclusions are made:

- Only the Upper Sand Stratum below the groundwater table falls into the gradation and relative density categories where liquefaction would be considered possible.
- The Upper Sand Stratum was completely removed and replaced with compacted structural fill before construction of the existing VEGP Units 1 and 2. The same approach will be used before construction of the proposed VEGP Units 3 and 4.
- The liquefaction potential of the compacted structural fill, consisting of materials and methods similar to VEGP Units 1 and 2 is not a concern.
- The Blue Bluff Marl is primarily cohesive but has some lenses of coarse-grained materials. These materials were found to have an adequate factor of safety against liquefaction (greater than 1.1).

2.5.4.9 Earthquake Design Basis

The site ground motion response spectra (GMRS) is derived and discussed in detail in Subsection 2.5.2.6. The Operating Basis Earthquake (OBE) is discussed in Subsection 2.5.2.8.

2.5.4.10 Static Stability

All safety-related structures will be founded on the structural backfill that will be placed on top of the Blue Bluff Marl after complete removal of the Upper Sand Stratum. The base of the Containment and Auxiliary Building foundations for VEGP Units 3 and 4 will be about El. 180 ft msl. This level corresponds to a depth of 40 ft below final grade (below El. 220 ft msl), or 50 to 60 ft above the top of the Blue Bluff Marl bearing stratum based on the borings completed during the ESP and COL subsurface investigations. Other foundations in the power block area will be placed at depths of about 4 ft below final grade. The following sections on bearing capacity and settlement focus on these two scenarios.

Based on the results of the ESP and COL investigations and the Phase I test pad program, the soils supporting the NIs do not exhibit extreme variations in subgrade stiffness and the site can be considered uniform according to (Reference 603). As presented in Subsection 2.5.4.2.2.2, the subsurface data disclosed a nearly even top of Blue Bluff Marl (varying from El. 122 ft to El. 140 ft over the length of the excavation footprints) with relatively uniform thickness and consistent engineering properties. The earthwork specification for the compacted backfill will be developed after the completion of the Phase II test pad program which is expected to finalize the placement procedures and material types. The Phase I test pad program considered materials and placement procedures consistent with Units 1 and 2. Test results disclosed consistent engineering properties including density, shear wave velocity, and N-values as presented in Subsection 2.5.4.5.3.

A coefficient of friction of 0.45 against concrete can be expected for the sand and silty sand compacted backfill material. A site-specific stability evaluation was conducted by Westinghouse. Results are presented in Appendix 2.5E.

2.5.4.10.1 Bearing Capacity

The maximum bearing reaction determined from the 3D SASSI analyses described in Appendix 3G is less than 35,000 lb/ft^2 under all combined loads, including the safe shutdown earthquake. The maximum dynamic bearing demand of 35 ksf occurs under the west edge of the shield building and is primarily due to the response to the east-west component of the earthquake. The east edge of the nuclear island lifts off the soil. The Combined License applicant will verify that the site-specific allowable soil bearing capacities for static and dynamic loads at the site will exceed the static and dynamic bearing demand given in Table 2.0-201.

The evaluation of the allowable capacity of the soil is based on the properties of the underlying materials, including appropriate laboratory test data to evaluate strength, and considering local site effects, such as fracture spacing, variability in properties, and evidence of shear zones. The allowable bearing capacity should provide a factor of safety appropriate for the design load combination, including safe shutdown earthquake loads.

If the shear wave velocity or the allowable bearing capacity is outside the range evaluated for AP1000 design certification, a site-specific evaluation can be performed using the AP1000 basemat model and methodology described in subsection 3.8.5. The safe shutdown earthquake loads are those from the AP1000 analyses described therein. Alternatively, bearing pressures may be determined from a site-specific analysis using site-specific inputs. For the site to be acceptable, the

bearing pressures from the site-specific analyses, including static and dynamic loads, need to be less than the capacity of each portion of the basemat.

All structures in the power block footprint will be founded on the structural backfill compacted to a minimum of 95% (ASTM D 1557) as presented in Subsection 2.5.4.5. The structural backfill will be about 90 ft thick in the power block area. The Nuclear Island will be founded at a depth of about 40 ft below grade (about 50 ft of structural backfill beneath the foundations). Other structures will be founded at an approximate depth of 4 ft below grade. The allowable static bearing capacity values are calculated with Terzaghi's bearing capacity equations. An internal angle of friction of 36° was used for the compacted backfill as developed from field and laboratory testing of borrow materials during the Phase I test pad program (Appendix 2.5D) and the COL investigation (Appendix 2.5C). The influence of the Blue Bluff Marl on the allowable bearing pressure was evaluated using procedures outlined by Vesic (1975). With a factor of safety of 3.0 (ASCE 1994), site conditions provide an allowable bearing pressure of 34 ksf under static loading conditions for the Nuclear Island, which is greater than the required 8.6 ksf (WEC CCC-004). An internal friction angle of 34° was used to calculate the allowable bearing capacity values for foundations placed on compacted fills at depths of about 4 ft below finished grade as provided in Figure 2.5-387.

The allowable bearing capacity of the structural backfill under the Nuclear Island for dynamic loading conditions was also evaluated using Terzaghi's bearing capacity equation for local shear (Peck et al. 1974) and Soubra's method with seismic bearing capacity factors (Reference 595) using Terzaghi's bearing capacity equation for general shear with an internal friction angle of 36°. To simulate the potential for higher edge pressures during dynamic loading, three foundation widths were considered (10, 25, and 50 ft) corresponding to 10, 25, and 50 percent of the width of the Nuclear Island basemat. The results from these two methods compared well, with Terzaghi's approach for local shear providing more conservative values. The computed average ultimate capacities of the three widths (10, 25, and 50 ft) were 89, 100, and 119 ksf, respectively. A width of 25 ft and a factor of safety of 2.25 (ASCE 1994) were used for site specific conditions providing an allowable bearing pressure greater than 42 ksf under dynamic loading conditions for the Nuclear Island. This value is greater than the required 35 ksf for dynamic bearing (WEC SC2-065) as well as the Vogtle site specific maximum dynamic demand (for the ESP soil profile as described in Appendix 2.5E) of 18 ksf.

The bearing capacity of the structural backfill was also evaluated in terms of the ratio of the ultimate bearing capacity to the structure demand. This capacity over demand (C/D) ratio provides an alternative measure of the margin of safety against bearing failure. These C/D ratios were evaluated for the static and dynamic demand conditions as provided by Westinghouse (WEC CCC-004 and WEC SCE-065), as well as the maximum dynamic demand from the Vogtle site specific seismic evaluation (Appendix 2.5E). The results are given below:

Condition	Static	Dynamic	Site-Specific Dynamic
Ultimate Capacity (C), ksf	102	100[a]	100[a]
Demand (D), ksf	8.6[b]	35[c]	18[d]
C/D	11.9	2.9	5.6

a. Based on a reduced foundation width of 25 feet to account for higher edge pressures during a seismic event.
b. APP-1000-CCC-004, Rev. 0, Nuclear Island - Stability Evaluation.
c. APP-1000-S2C-065, Rev. 0, Nuclear Island Stick Model Analysis at Soil Sites.
d. Based on analysis using ESP profile in Appendix 2.5E.

The C/D ratios are higher than those typically used for standard practice. While these results do not take into account settlement of the structures, the significant margin suggests that settlements will be minimal and within the design requirements (WEC SC2-065). A further discussion of settlement is provided in Subsection 2.5.4.10.2.

The results of settlement analyses are presented in Subsection 2.5.4.10.2.

2.5.4.10.2 Settlement Analysis

The AP1000 does not rely on structures, systems, or components located outside the nuclear island to provide safety-related functions. Differential settlement between the nuclear island foundation and the foundations of adjacent buildings does not have an adverse effect on the safety-related functions of structures, systems, and components. Differential settlement under the nuclear island foundation could cause the basemat and buildings to tilt. Much of this settlement occurs during civil construction prior to final installation of the equipment. Differential settlement of a few inches across the width of the nuclear island would not have an adverse effect on the safety-related functions of structures, systems, and components. Table 2.5-1 provides guidance to the Combined License applicant on predictions of absolute and differential settlement that are acceptable without further evaluation. The predicted settlements will cover the periods before construction begins through the construction phase, and for the subsequent plant operating period or otherwise justified. The predicted settlements will be based on conservative assumptions of soil properties. If the predicted settlements exceed the limits of Table 2.5-1, a detailed evaluation and construction plan will be described by the Combined License applicant. During construction and plant operation at a soil site, settlements would be measured and compared to the predicted settlement values and any exceedances would require additional investigation.

Alternatives for the additional evaluations are provided as follows:

1. Evaluate the impact of the elevated estimated settlement values on the critical components of the AP1000 including, but not limited to, piping spanning between the nuclear island and the adjacent structures, the equipment support pads, the construction gap between the nuclear island and adjacent buildings, and the stresses on the basemat (along with influences to the underlying soil).

2. Submit a construction sequence to control the predicted settlement behavior. A revised sequence should follow the specific schedule to distribute construction loads as necessary in order to obtain acceptable values. Depending on soil conditions, a significant amount of the settlement could occur during construction and can be controlled through the construction sequence.

3. Provide a uniform excavation and engineered backfill to manage static building rotation and differential settlement between the nuclear island and adjacent structures.

4. Implement an active settlement monitoring system throughout the entire construction sequence as well as a long-term (plant operation) plan. By monitoring the settlement throughout construction, the Combined License applicant will be able to modify the construction sequences of adjacent buildings to conform to the site's settlement characteristics and minimize differential settlement. For soil sites, the potential heave or rebound of the excavation bottom, the effect of dewatering, and the effect of foundation loading during construction should be monitored by the Combined License applicant. The monitoring system shall consist of three primary elements as follows:

- Piezometers to measure pore pressures in a soil layer prone to consolidation type settlement. Vibrating wire piezometers are preferred for this purpose because they are adequately sensitive and responsive and easily record positive and negative changes on a real time basis.

- Settlement monuments placed directly on concrete, preferably on the mudmat for early construction monitoring and on the corners of the structures at grade once the mudmat monuments have been covered by backfill to be used for long-term monitoring. Monuments at grade are to be accessible with conventional surveying equipment.

- Settlement telltales if monuments are not practical or if fills are used over consolidation type soils and it is necessary to monitor settlement of the consolidation type in-situ soils independent of the consolidation of the engineered fill soil. Most soil sites will not need this particular form of monitoring.

Develop graphs and plots of the field measurements to:

- Show movement (settlement or heave) versus time.

- Estimate construction loads versus time.

- Measure ground water levels from the dewatering activities versus time.

This data should be maintained during construction and post-construction as needed depending on the field measurement results.

For the large mat foundations that support the major power plant structures, general considerations based on previous site experience (Reference 582) indicate that the total settlement can exceed the suggested limit of 2 in. encountered in the geotechnical literature (Peck et al. 1974). Settlement monitoring of VEGP Units 1 and 2 (Reference 582) disclosed foundation settlements ranging from 2.7 to 3.2 in. for the containment buildings, versus calculated/design values of 4.0 to 4.3 in. Similar results were obtained for the control building (measured settlements ranging from 1.1 to 1.9 inches versus calculated/design values of 3.2 to 3.4 in.), auxiliary building (measured settlements ranging from 2.9 to 3.3 in. versus calculated/design values of 4.4 to 4.6 in.), and the NSCW towers (measured settlements ranging from 2.5 to 3.6 in. versus calculated/design values of 4.5 to 4.8 in.). The ratio of measured to predicted settlement for these structures ranged from less than 0.5 to about 0.75, indicating that the subsurface soils were generally stiffer than anticipated.

Similarly, the measured differential settlements between mats of Units 1 and 2 (Reference 582), which can affect pipe connections, was generally within the suggested limit of ¾ in. encountered in the geotechnical literature (Reference 590). The measured differential settlements within structures of Units 1 and 2 were smaller than the design limit of 1/670 (Reference 582).

It is noted that settlements reported for Units 1 and 2 (Reference 582) were essentially elastic, i.e., they took place during construction. This reflects the elastic nature of the compacted backfill, the heavily overconsolidated Blue Bluff Marl, and the underlying Lower Sand Stratum.

For footings that support smaller plant components, the total settlement can be limited to 1 inch, while the differential settlement between footings can be limited to ½ in. (Reference 590).

The general approach used for Units 1 and 2 consisted of estimating total and differential settlements for powerblock structures and using them as design values. A detailed settlement monitoring program was established, and measured settlements were compared with the design values. Re-analysis and/or corrective measures were employed if measured settlements exceeded design

or trigger values. An additional strategy consisted of installing pipes as late in the construction schedule as practicable and installing pipe supports only when construction of the structure that the pipe was connected to was essentially complete.

Laboratory consolidation tests were conducted on relatively undisturbed samples from the Blue Bluff Marl and the Lower Sand strata collected during the COL investigation. These results are included in Appendix 2.5C, and they confirm the elastic behavior and very stiff and dense nature of the Blue Bluff Marl and Lower Sand strata. A test fill program has been performed (Subsection 2.5.4.5.8) to assess properties of compacted backfill. The results confirm the very dense nature, similar to Units 1 and 2, of the fill and the expected performance under load.

A detailed settlement analysis was performed at the VEGP Early Site Permit Application phase for Units 3 and 4 utilizing similar elastic properties used for the analysis of Units 1 and 2. The analysis incorporated excavation, dewatering, and a timeline of construction to estimate, as much as practical, mat displacement time histories. The results showed that for the assumed loads, predicted total settlements range from about 2 to 3 inches, with a tilt of approximately ¼ inch in 50 feet, and a differential settlement between structures of less than 1 inch (Reference 599). In addition, predicted heave due to foundation excavation ranges from about 1 to 2 ½ inches (Reference 599). As expected, the results were similar to movements measured for Units 1 and 2.

A subsequent analysis was performed to address changes to the construction sequence in Subsection 3.8.5.4.2 (Reference 607). This analysis concluded that settlement is within the requirements of Table 2.5-1.

2.5.4.10.2.1 Displacement Monitoring

An instrumentation plan will be developed to monitor heave in the subsurface soils due to excavation, change in pore pressures due to excavation and dewatering, and settlement due to construction of the structures. The detailed plan to be developed will include displacement monitoring at depth in order to estimate and confirm moduli of the subsurface soils. Estimates of unloading (excavation) and loading will be made to correlate movement with load and to update the movement time histories discussed in Subsection 2.5.4.10.2.

The instrumentation will be monitored on a regular basis and will include conventional survey, electronic instrumentation, and where practical, remote telemetry. Particular emphasis will be placed on differential movement and tilt of the structures.

2.5.4.10.3 Lateral Earth Pressure

The development of lateral earth pressures, static and dynamic (seismic), against the below-grade walls of safety-related structures is expected to be minimized with the construction of the mechanically stabilized earth (MSE) walls. As described in Subsection 2.5.4.5.7, the MSE walls are constructed adjacent to the Nuclear Island (NI) to facilitate the placement of backfill in the powerblock excavation. This bottom-up construction occurs prior to construction of the NI, and the MSE walls serve as the outside form for the NI below-grade walls. Although the MSE walls are expected to relieve much of the static lateral earth pressures exerted on the below-grade walls, over time these pressures may be transferred to the below-grade structure. Thus, the evaluation of site-specific lateral earth pressures for safety-related structures does not consider any influence from the MSE walls and full at-rest lateral earth pressures are assumed.

Site-specific static lateral earth pressures, assuming frictionless vertical walls and horizontally placed backfill, are evaluated using Rankine's theory for active, at-rest, and passive conditions (Reference 201). The earth pressure coefficients, k_a = 0.26, k_o, = 0.4, and k_p = 3.9 are based on a

drained friction angle of 36 degrees for the compacted structural fill as presented in Table 2.5-237. The at-rest earth pressure coefficient, k_o, for the compacted structural fill against the NI below grade walls is conservatively taken as 0.5.

The evaluation of site-specific lateral earth pressures includes the influence from surcharges. A vertical areal surcharge of 2,500 psf is used. This pressure conservatively represents construction loading prior to construction of adjacent buildings and subsequent adjacent permanent building loads. The vertical areal surcharge of 2,500 psf equates to a lateral surcharge pressure of 1,250 psf, which exceeds the AP1000 maximum lateral static plus dynamic design surcharge pressures.

Close-in compaction (behind the MSE wall) with a heavy vibratory roller is also considered. Lateral earth pressures increase as a result of compaction. These pressures are controlled at the construction stage by limiting the size of compaction equipment and its proximity to the walls. The influence of compaction was evaluated based on the characteristics of the vibratory compactor used for the Phase 1 Test Pad program (Appendix 2.5D). Compaction induced lateral earth pressures under at-rest conditions were evaluated using procedures developed by Duncan, et. al. (Reference 203). The inclusion of compaction-induced pressures is conservative given that these pressures will be exerted on the MSE wall prior to construction of the below-grade NI walls.

Site-specific seismic lateral earth pressures are evaluated for at-rest conditions using ASCE 4-98 (Reference 202). The site-specific ground acceleration at a frequency of 100 hertz for the Vogtle 3 and 4 site is taken as 0.266g (Subsection 2.5.2.6, Table 2.5-233 and Figure 2.5-307).

Hydrostatic pressures, attributed to the groundwater level, exert lateral pressure on below-grade structures. At the VEGP Units 3 and 4 site, in the power block areas, the design groundwater elevation of 165 ft msl, as noted in Subsection 2.4.12, is about 15 feet below the NI basemat elevation of approximately 180 ft msl. The post construction water level, as identified in Appendix 2.4B, will also be well below the basemat elevation. Since the groundwater level is located well below the basemat, hydrostatic forces will not be exerted on the below-grade walls and hydrostatic pressures are not considered in the site-specific evaluation of lateral earth pressure for the NI.

In summary, Figure 2.5-201 presents the site-specific total at-rest lateral earth pressures for the below grade NI rigid walls. This diagram was developed assuming level ground surface, a post construction groundwater level below the basemat elevation (no hydrostatic pressure), an areal surcharge pressure of 2,500 psf, and compaction-induced pressure increases. Figure 2.5-202 presents the comparison of the site-specific total at-rest lateral earth pressure distribution compared to the AP1000 DCD design envelope in both the N-S and E-W directions. In both cases, the site-specific at-rest earth pressure is enveloped by the DCD design earth pressure envelopes by significant margins.

2.5.4.11 Design Criteria

Applicable geotechnical-related design criteria are discussed in various sections and are summarized below.

Subsection 2.5.4.8 specifies that the acceptable factor of safety against liquefaction of site soils should be ≥ 1.1 in accordance with Regulatory Guide 1.198.

Bearing capacity criteria are presented in Subsection 2.5.4.10. A minimum factor of safety of 3 is used when applying bearing capacity equations. This factor of safety is also applied against breakout failure due to uplift forces on buried piping. For soils, this factor of safety can be reduced to 2.25 when dynamic or transient loading conditions apply (Reference 566).

Subsection 2.5.5.2 specifies that the minimum acceptable long-term factors of safety for slope stability based on type of slopes and locations relative to the protected area boundary and safety-related structures.

Appendix 2.5E describes the site-specific analyses that have been performed to show the acceptability of the AP1000 plant at the Vogtle site.

2.5.4.12 Techniques to Improve Subsurface Conditions

For the ESP investigation, ground improvement techniques were not considered beyond the removal and replacement of the Upper Sand Stratum. Likewise, no additional ground improvement methods are being considered based on the COL investigation. The Phase I test pad program (Appendix 2.5D) presents the field and test results of the materials and methods that are currently planned for the backfill to replace the Upper Sand Stratum. For areas outside the power block excavation, surficial ground can be improved through densification with heavy vibratory rollers. Other ground improvement methods and the use of piles will be considered as warranted.

The development of lateral earth pressures, static and dynamic (seismic), against the below-grade walls of safety-related structures is expected to be minimized with the construction of the mechanically stabilized earth (MSE) walls. As described in Subsection 2.5.4.5.7, the MSE walls are constructed adjacent to the Nuclear Island (NI) to facilitate the placement of backfill in the powerblock excavation. This bottom-up construction occurs prior to construction of the NI, and the MSE walls serve as the outside form for the NI below-grade walls. Although the MSE walls are expected to relieve much of the static lateral earth pressures exerted on the below-grade walls, over time these pressures may be transferred to the below-grade structure. Thus, the evaluation of site-specific lateral earth pressures for safety-related structures does not consider any influence from the MSE walls and full at-rest lateral earth pressures are assumed.

Site-specific static lateral earth pressures, assuming frictionless vertical walls and horizontally placed backfill, are evaluated using Rankine's theory for active, at-rest, and passive conditions (Reference 201). The earth pressure coefficients, k_a = 0.26, k_o, = 0.4, and k_p = 3.9 are based on a drained friction angle of 36 degrees for the compacted structural fill as presented in Table 2.5-237. The at-rest earth pressure coefficient, k_o, for the compacted structural fill against the NI below grade walls is conservatively taken as 0.5.

The evaluation of site-specific lateral earth pressures includes the influence from surcharges. A vertical areal surcharge of 2,500 psf is used. This pressure conservatively represents construction loading prior to construction of adjacent buildings and subsequent adjacent permanent building loads. The vertical areal surcharge of 2,500 psf equates to a lateral surcharge pressure of 1,250 psf, which exceeds the AP1000 maximum lateral static plus dynamic design surcharge pressures.

Close-in compaction (behind the MSE wall) with a heavy vibratory roller is also considered. Lateral earth pressures increase as a result of compaction. These pressures are controlled at the construction stage by limiting the size of compaction equipment and its proximity to the walls. The influence of compaction was evaluated based on the characteristics of the vibratory compactor used for the Phase 1 Test Pad program (Appendix 2.5D). Compaction induced lateral earth pressures under at-rest conditions were evaluated using procedures developed by Duncan, et. al. (Reference 203). The inclusion of compaction-induced pressures is conservative given that these pressures will be exerted on the MSE wall prior to construction of the below-grade NI walls.

Site-specific seismic lateral earth pressures are evaluated for at-rest conditions using ASCE 4-98 (Reference 202). The site-specific ground acceleration at a frequency of 100 hertz for the Vogtle 3 and 4 site is taken as 0.266g (Subsection 2.5.2.6, Table 2.5-233 and Figure 2.5-310).

Hydrostatic pressures, attributed to the groundwater level, exert lateral pressure on below-grade structures. At the VEGP Units 3 and 4 site, in the power block areas, the design groundwater elevation of 165 ft msl, as noted in Subsection 2.4.12, is about 15 feet below the NI basemat elevation of approximately 180 ft msl. The post construction water level, as identified in Appendix 2.4B, will also be well below the basemat elevation. Since the groundwater level is located well below the basemat, hydrostatic forces will not be exerted on the below-grade walls and hydrostatic pressures are not considered in the site-specific evaluation of lateral earth pressure for the NI.

In summary, Figure 2.5-201 presents the site-specific total at-rest lateral earth pressures for the below grade NI rigid walls. This diagram was developed assuming level ground surface, a post construction groundwater level below the basemat elevation (no hydrostatic pressure), an areal surcharge pressure of 2,500 psf, and compaction-induced pressure increases. Figure 2.5-202 presents the comparison of the site-specific total at-rest lateral earth pressure distribution compared to the AP1000 DCD design envelope in both the N-S and E-W directions. In both cases, the site-specific at-rest earth pressure is enveloped by the DCD design earth pressure envelopes by significant margins.

2.5.4.13 Heavy Lift Derrick Counterweight and Ring Foundation

The ring foundation for the heavy lift derrick (HLD) and counterweight are abandoned in place below grade following construction of Units 3 and 4. The HLD rails are removed from the ring foundation after construction of Units 3 and 4. The (HLD) counterweight and ring foundation are shown on Figure 2.5-203.

The top of the HLD counterweight and ring foundation concrete is located at approximately elevation 215 ft MSL, which is five feet below the nominal site grade of 220 ft MSL. The HLD counterweight and ring foundation are not visible following the installation of the roads, drainage provisions, and ground surface cover.

The HLD counterweight and ring foundation are below the surface drainage system provisions and do not affect the runoff for the local PMP flood event discussed in Subsection 2.4.2.3. The HLD counterweight and ring foundation are located above the design ground water elevation of 165 ft MSL, and do not impact the hydrological analyses described in Subsections 2.4.12 and 2.4.13.

The safety-related portion of the excavations is filled with Category 1 backfill to the NI basemat and with Category 2 backfill to grade. The side slopes are filled with engineered granular backfill (EGB), which is non-safety related and does not affect the static or seismic performance of the safety-related structures.

As shown on Figure 2.5-203, the HLD counterweight and ring foundation does not extend into the safety-related backfill of either Unit 3 or Unit 4. The ring foundation does extend into the EGB backfill of the excavations for both Unit 3 and Unit 4. The counterweight overall depth is approximately 28 ft. and is below the EGB backfill of the excavation for Unit 4. Subsection 3.7.1.1.1 provides the results of the evaluation which confirms that the presence of the HLD counterweight and ring foundation has no effect on the site specific seismic analyses.

2.5.5 Stability of Slopes

2.5.5.1 Review of Existing Slopes

The location of VEGP Units 3 and 4 will be atop a bluff on the southwest bank of the Savannah River. The new units will be located to the west of the existing Units 1 and 2 as described in Section 1.2. The ground is flat to gently rolling and at approximately the same grade elevation of the existing units (220 ft msl). There are no existing slopes or embankments near the proposed location of Units 3 and 4; therefore, no dynamic slope stability analysis was performed for VEGP Units 3 and 4.

2.5.5.2 New Slopes

There is no permanent slope that would adversely affect, either directly or indirectly, any safety-related structures. Site grading of the new units resulted in nonsafety-related permanent cut and fill slopes. The limiting permanent slopes include cut slopes approximately 50 ft in height located more than 1500 ft from safety-related structures and fill slopes approximately 20 ft in height located more than 500 ft away from safety-related structures.

{HISTORICAL—Construction excavation cut slopes would be required in the new AP1000 power block area where soils above the Blue Bluff Marl would be removed and replaced with compacted structural fill. The construction excavation cut slopes would be temporary during the construction period only. Also, these excavation slopes would be sufficiently far away from the existing VEGP Unit 1 and 2 safety-related structures, and therefore, would not adversely affect, directly or indirectly, any of the existing safety-related structures.—HISTORICAL}

Permanent slopes greater than 20 ft in height and within 1000 ft of a safety-related structure are either not steeper than 3 horizontal to 1 vertical (3h:1v) and have heights less than 10 percent of the distance from the structure to the top of the slope, or are analyzed for dynamic and static conditions. The minimum acceptable factors of safety against stability failure of permanent slopes are 1.5 for long-term static conditions and 1.1 for long-term seismic conditions (Reference 601). The minimum acceptable factor of safety against stability failure of excavation slopes is 1.3, based on geotechnical data.

Analyses confirm that the permanent slopes do not pose a hazard to the workforce or the public. Failure of permanent slopes, under any of the conditions to which they would be exposed during the plant lifetime, would not adversely affect the safety of the nuclear power plant.

2.5.6 Embankments and Dams

2.5.6.1 Review of Existing Embankments and Dams

There are no earth, rock or earth and rock fill embankments required for plant flood protection or for impounding cooling water required for the operation of the plant.

Figure 1.1-202 shows the locations of three existing non-safety-related impoundments at the VEGP site. They are:

- Mallard Pond located to the north of the proposed switchyard
- Debris Basin Dam #1 located to the southeast of the proposed AP1000 cooling towers
- Debris Basin Dam #2 located to the southwest of the proposed AP1000 cooling towers

These impoundments are not used for plant flood protection or for impounding cooling water required for the operation of the plant. However, brief descriptions of these impoundments are provided here.

The proposed finished grade elevation for the new AP1000 units is approximately 220 ft msl. The pool level in Mallard Pond is below El. 125 ft msl. In the event of a dam breach at Mallard Pond, the water would drain to the north and away from the proposed new units. The pool levels in Debris Basin Dams #1 and #2 are below El. 150 ft msl, and in the event of a dam breach, the water would drain to the south and away from the proposed new units.

2.5.6.2 New Embankments and Dams

No new embankments or dams would be constructed at the site for flood protection or for impounding cooling water required to operate the new AP1000 units. The proposed finished grade elevation for the new AP1000 units is approximately 220 ft msl. This site finished grade elevation is much higher than the probable maximum flood (PMF) elevation discussed in Subsection 2.4.3 and the dam break level discussed in Subsection 2.4.4. Therefore, no new embankments or dams would be required to be constructed at the site for flood protection. Also, the new AP1000 units use cooling towers, and makeup water would be pumped from the Savannah River. Therefore, no new embankments or dams would be required to be constructed at the site for impounding cooling water required to operate the new AP1000 units.

In summary, no embankments and dams are required to be addressed in this section.

2.5.7 Combined License Information

2.5.7.1 Basic Geologic and Seismic Information

Regional and site-specific geological, seismological, and geophysical information as well as conditions caused by human activities are addressed in Subsections 2.5.1, 2.5.2, and 2.5.4.

2.5.7.2 Seismic and Tectonic Characteristics Information

Site-specific information related to the vibratory ground motion aspects of the site and region are addressed in Subsections 2.5.2 and 2.5.4.

2.5.7.3 Geoscience Parameters

Site-specific seismic analyses are addressed in Subsections 2.5.2 and 2.5.4.

2.5.7.4 Surface Faulting

Surface and subsurface geological, seismological, and geophysical information related to the potential for surface or near-surface faulting affecting the site is addressed in Subsection 2.5.3.

2.5.7.5 Site and Structures

Site-specific information regarding the underlying site conditions and geologic features is addressed in Subsection 2.5.4.

2.5.7.6 Properties of Underlying Materials

The properties of the foundation soils for design of the nuclear island basemat are addressed in Subsection 2.5.4.

2.5.7.7 Excavation and Backfill

Seismic Category I excavations, fills, and slopes are addressed in Subsection 2.5.4.

2.5.7.8 Ground Water Conditions

Groundwater conditions are addressed in Subsection 2.5.4.

2.5.7.9 Liquefaction Potential

Liquefaction potential is addressed in Subsection 2.5.4.

2.5.7.10 Bearing Capacity

The allowable soil bearing capacities for static and dynamic loads are addressed in Subsection 2.5.4.

2.5.7.11 Earth Pressures

The static and dynamic lateral earth pressures and hydrostatic groundwater pressures acting on plant safety-related facilities are addressed in Subsection 2.5.4.

2.5.7.12 Soil Properties for Seismic Analysis of Buried Pipes

The AP1000 does not utilize safety-related buried piping. No additional information is required on soil properties.

2.5.7.13 Static and Dynamic Stability of Facilities

Soil characteristics affecting the stability of the nuclear island are addressed in Subsection 2.5.4.

2.5.7.14 Subsurface Instrumentation

Instrumentation for monitoring the performance of the foundations of the nuclear island is addressed in Subsection 2.5.4 and Appendix 2.5E.

2.5.7.15 Stability of Slopes

The static and dynamic stability of soil and rock slopes, the failure of which could adversely affect the nuclear island, is addressed in Subsection 2.5.5.

2.5.7.16 Embankments and Dams

The static and dynamic stability of embankments and dams, the failure of which could adversely affect the nuclear island, is addressed in Subsection 2.5.6.

2.5.7.17 Settlement of Nuclear Island

Settlement of the nuclear island foundation and adjacent buildings is addressed in Subsection 2.5.4.

2.5.7.18 Waterproofing System

The waterproofing system used for the foundation mat (mudmat) and below grade exterior walls exposed to flood and groundwater under seismic Category I structures is addressed in Subsections 3.8.5.1 and 3.4.1.1.1.1.

2.5.8 References

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Table 2.5-1
Limits of Acceptable Settlement Without Additional Evaluation

Differential Across Nuclear Island Foundation Mat	Total for Nuclear Island Foundation Mat	Differential Between Nuclear Island and Turbine Building(1)	Differential Between Nuclear Island and Other Buildings(1)
1/2 inch 50 ft	6 inches	3 inches	3 inches

Note:
1. Differential settlement is measured at the center of the nuclear island and the center of the adjacent structures.

Table 2.5-201
Definitions of Classes Used in the Compilation of Quaternary Faults, Liquefaction Features, and Deformation in the Central and Eastern United States

Class Category	Definition
Class A	Geologic evidence demonstrates the existence of a Quaternary fault of tectonic origin, whether the fault is exposed for mapping or inferred from liquefaction to other deformational features.
Class B	Geologic evidence demonstrates the existence of a fault or suggests Quaternary deformation, but either (1) the fault might not extend deeply enough to be a potential source of significant earthquakes, or (2) the currently available geologic evidence is too strong to confidently assign the feature to Class C but not strong enough to assign it to Class A.
Class C	Geologic evidence is insufficient to demonstrate (1) the existence of tectonic fault, or (2) Quaternary slip or deformation associated with the feature.
Class D	Geologic evidence demonstrates that the feature is not a tectonic fault or feature; this category includes features such as demonstrated joints or joint zones, landslides, erosional or fluvial scarps, or landforms resembling fault scarps, but of demonstrable non-tectonic origin.

Source: Crone and Wheeler 2000; Wheeler 2005

Table 2.5-202 (Sheet 1 of 2)
Earthquakes 1985–2005, Update to the EPRI (NP-4726-A 1988) Seismicity Catalog with $Em_b \geq 3.0$, Within a 30° to 37° N, 78° to 86° W Latitude-Longitude Window, Incorporating the 200 mi (320 km) Radius Site Region

Year	Mo	Dy	Hr	Mn	Sec	Lat	Lon	Z(km)	Int	Emb	Smb	Rmb
1985	12	22	0	56	5.0	35.701	-83.720	13.4		3.25	0.30	3.35
1986	1	7	1	26	43.3	35.610	-84.761	23.1		3.06	0.30	3.17
1986	2	13	11	35	45.6	34.755	-82.943	5.0		3.50	0.10	3.51
1986	3	13	2	29	31.4	33.229	-83.226	5.0	4	3.30	0.25	3.37
1986	7	11	14	26	14.8	34.937	-84.987	13.0	6	3.80	0.10	3.81
1986	9	17	9	33	49.5	32.931	-80.159	6.7	4	3.30	0.25	3.37
1987	3	16	13	9	26.8	34.560	-80.948	3.0		3.06	0.30	3.17
1987	3	27	7	29	30.5	35.565	-84.230	18.5	6	4.20	0.10	4.21
1987	7	11	0	4	29.5	36.105	-83.816	25.1	5	3.79	0.10	3.80
1987	7	11	2	48	5.9	36.103	-83.819	23.8	4	3.43	0.10	3.44
1987	9	1	23	2	49.4	35.515	-84.396	21.1		3.06	0.30	3.17
1987	9	22	17	23	50.1	35.623	-84.312	19.4	5	3.50	0.10	3.51
1987	11	27	18	58	29.3	36.852	-83.110	26.8	5	3.50	0.10	3.51
1987	12	12	3	53	28.8	34.244	-82.628	5.0		3.00	0.10	3.01
1988	1	9	1	7	40.6	35.279	-84.199	12.2	4	3.30	0.25	3.37
1988	1	23	1	57	16.4	32.935	-80.157	7.4	5	3.50	0.25	3.57
1988	2	16	15	26	54.8	36.595	-82.274	4.0	4	3.30	0.10	3.31
1988	2	18	0	37	45.4	35.346	-83.837	2.4	4	3.50	0.10	3.51
1989	6	2	5	4	34.0	32.934	-80.166	5.8	4	3.30	0.25	3.37
1990	8	17	21	1	15.9	36.934	-83.384	0.6	5	4.00	0.10	4.01
1990	11	13	15	22	13.0	32.947	-80.136	3.4	5	3.50	0.10	3.51
1991	6	2	6	5	34.9	32.980	-80.214	5.0	5	3.50	0.25	3.57
1991	9	24	7	21	7.0	35.701	-84.117	13.3	4	3.30	0.10	3.31
1991	10	30	14	54	12.6	34.904	-84.713	8.1		3.06	0.30	3.17
1992	1	3	4	21	23.9	33.981	-82.421	3.3	5	3.50	0.25	3.57
1992	8	21	16	31	56.1	32.985	-80.163	6.5	6	4.10	0.10	4.11
1993	1	15	2	2	50.9	35.039	-85.025	8.1	4	3.30	0.10	3.31
1993	7	12	4	48	20.8	36.035	-79.823	5.0	4	3.30	0.10	3.31
1993	8	8	9	24	32.4	33.597	-81.591	8.5	5	3.50	0.10	3.51
1994	2	12	2	40	24.5	36.800	-82.000	5.0		3.42	0.41	3.61
1994	4	5	22	22	0.4	34.969	-85.491	24.3	5	3.50	0.10	3.51
1994	4	16	20	10	12.2	35.752	-83.968	1.8	5	3.50	0.25	3.57
1995	3	11	8	15	52.3	36.959	-83.133	1.0		3.80	0.10	3.81
1995	3	11	9	50	4.4	36.990	-83.180	1.0		3.30	0.10	3.31
1995	3	18	22	6	20.8	35.422	-84.941	26.0		3.25	0.30	3.35
1995	4	17	13	46	0.0	32.997	-80.171	8.4	6	3.90	0.10	3.91
1995	6	26	0	36	17.1	36.752	-81.481	1.8	5	3.40	0.10	3.41
1995	7	5	14	16	44.7	35.334	-84.163	10.0	4	3.70	0.10	3.71
1995	7	7	21	1	3.0	36.493	-81.833	10.0	4	3.06	0.10	3.08
1996	4	19	8	50	14.0	36.981	-83.018	0.0		3.90	0.10	3.91
1997	5	19	19	45	35.8	34.622	-85.353	2.7	4	3.06	0.10	3.08
1997	7	19	17	6	34.4	34.953	-84.811	2.8	4	3.61	0.10	3.62

Table 2.5-202 (Sheet 2 of 2)
Earthquakes 1985–2005, Update to the EPRI (NP-4726-A 1988)
Seismicity Catalog with $Em_b \geq 3.0$, Within a 30° to 37° N, 78° to 86° W
Latitude-Longitude Window, Incorporating the 200 mi (320 km) Radius Site Region

Year	Mo	Dy	Hr	Mn	Sec	Lat	Lon	Z(km)	Int	Emb	Smb	Rmb
1997	7	30	12	29	25.3	36.512	-83.547	23.0	5	3.80	0.10	3.81
1998	4	13	9	56	15.6	34.471	-80.603	6.6	5	3.90	0.10	3.91
1998	6	5	2	31	3.9	35.554	-80.785	9.4		3.34	0.10	3.35
1998	6	17	8	0	23.9	35.944	-84.392	11.3	5	3.60	0.10	3.61
1999	1	17	18	38	5.1	36.893	-83.799	1.0	3	3.06	0.27	3.15
2000	1	18	22	19	32.2	32.920	-83.465	19.2	5	3.50	0.10	3.51
2001	3	7	17	12	23.8	35.552	-84.850	6.8	3	3.20	0.10	3.21
2001	3	21	23	35	34.9	34.847	-85.438	0.0	3	3.16	0.27	3.24
2001	6	11	18	27	54.3	30.226	-79.885	10.0		3.33	0.41	3.53
2001	7	26	5	26	46.0	35.971	-83.552	14.3	3	3.25	0.10	3.26
2002	11	8	13	29	3.2	32.422	-79.950	3.9		3.50	0.41	3.69
2002	11	11	23	39	29.7	32.404	-79.936	2.4		4.23	0.41	4.42
2003	3	18	6	4	24.2	33.689	-82.888	5.0		3.50	0.41	3.69
2003	4	29	8	59	38.1	34.445	-85.620	9.1	6	4.70	0.10	4.71
2003	5	2	10	48	43.5	34.512	-85.604	10.0		3.01	0.41	3.20
2003	5	5	10	53	49.9	33.055	-80.190	11.4		3.06	0.30	3.17
2003	7	13	20	15	17.0	32.335	-82.144	5.0		3.58	0.41	3.77
2004	7	20	9	13	14.4	32.972	-80.248	10.3		3.17	0.41	3.37
2004	9	17	15	21	43.6	36.932	-84.006	1.2		3.66	0.41	3.85

Table 2.5-203 (Sheet 1 of 2)
Summary of Bechtel Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Inter-dependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
Sources within 200 mi (320 km) that contribute to 99% of hazard								
H	**Charleston Area**	0.50	6.8 [0.20] 7.1 [0.40] 7.4 [0.40]	1 [0.33] 2 [0.34] 4 [0.33]	P(H|N3)=0.15	**Yes[8]**	**Yes[8]**	**Yes[8]**
N3	**Charleston Faults**	0.53	6.8 [0.20] 7.1 [0.40] 7.4 [0.40]	1 [0.33] 2 [0.34] 4 [0.33]	P(N3|H)=0.16	**Yes[8]**	**Yes[8]**	**Yes[8]**
BZ4	Atlantic Coastal Region	1.00	6.6 [0.10] 6.8 [0.40] 7.1 [0.40] 7.4 [0.10]	1 [0.33] 2 [0.34] 3 [0.33]	Background; P_B=1.00	No	No	No
BZ5	S. Appalachians	1.00	5.7 [0.10] 6.0 [0.40] 6.3 [0.40] 6.6 [0.10]	1 [0.33] 2 [0.34] 3 [0.33]	Background; P_B=1.00	No	No	No
F	S.E. Appalachians	0.35	5.4 [0.10] 5.7 [0.40] 6.0 [0.40] 6.6 [0.10]	1 [0.33] 2 [0.34] 4 [0.33]	ME with G; ME with 13, 15, 16, 17	No	No	No
G	NW South Carolina	0.35	5.4 [0.10] 5.7 [0.40] 6.0 [0.40] 6.6 [0.10]	1 [0.33] 2 [0.34] 4 [0.33]	ME with F; ME with 13, 15, 16, 17	No	No	No
Other Sources within 200 mi (320 km) that do not contribute to 99% of hazard								
13	Eastern Mesozoic Basins	0.10	5.4 [0.10] 5.7 [0.40] 6.0 [0.40] 6.6 [0.10]	1 [0.33] 2 [0.34] 4 [0.33]	no overlap with H or N3; ME with all sources in BZ5	No	No	No
24	Bristol Trends	0.25	5.7 [0.10] 6.0 [0.40] 6.3 [0.40] 6.6 [0.10]	1 [0.33] 2 [0.34] 4 [0.33]	ME with 19, 25, 25A	No	No	No
15	Rosman Fault	0.05	5.4 [0.10] 5.7 [0.40] 6.0 [0.40] 6.6 [0.10]	1 [0.33] 2 [0.34] 4 [0.33]	ME with all other sources	No	No	No

Table 2.5-203 (Sheet 2 of 2)
Summary of Bechtel Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Inter-dependencies[4]	New Information to Suggest Change in Source:		
						Geometry?[5]	Mmax?[6]	RI?[7]
16	Belair Fault	0.05	5.4 [0.10] 5.7 [0.40] 6.0 [0.40] 6.6 [0.10]	1 [0.33] 2 [0.34] 4 [0.33]	ME with all other sources	No	No	No

1 Pa = probability of activity; (from EPRI NP-6452-D 1989)
2 Maximum Magnitude (Mmax) and weights (wts.); (from EPRI NP-6452-D 1989)
3 Smoothing options are defined as follows (from EPRI NP-6452-D 1989):
1 = constant a, constant b (no prior b);
2 = low smoothing on a, high smoothing on b (no prior b);
3 = low smoothing on a, low smoothing on b (no prior b);
4 = low smoothing on a, low smoothing on b (weak prior of 1.05).
Weights on magnitude intervals are [1.0, 1.0, 1.0, 1.0, 1.0, 1.0, 1.0].
4 ME = mutually exclusive; PD = perfectly dependent
5 No, unless (1) new geometry proposed in literature or (2) new seismicity pattern
6 No, unless (1) new data suggests Mmax exceeds or differs significantly from the EPRI Mmax distribution or (2) exceeded by historical seismicity.
7 RI = recurrence interval; assumed no change if no new paleoseismic data or rate of seismicity has not significantly changed
8 Replace this source with the Updated Charleston Seismic Source (UCSS) Model

Table 2.5-204 (Sheet 1 of 2)
Summary of Dames & Moore Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
Sources within 200 mi (320 km) that contribute to 99% of hazard								
54	**Charleston Seismic Zone**	1.00	6.6 [0.75] 7.2 [0.25]	1 [0.22] 2 [0.08] 3 [0.52] 4 [0.18]	none	**Yes[8]**	**Yes[8]**	**Yes[8]**
52	Charleston Mesozoic Rift	0.46	4.7 [0.75] 7.2 [0.25]	3 [0.75] 4 [0.25]	ME with 47 thru 50, 65; ME with 52	No	No	No
53	S. Appalachian Mobile Belt (Default Zone)	0.26	5.6 [0.80] 7.2 [0.20]	1 [0.75] 2 [0.25]	Default for 47 thru 52, 65	No	No	No
41	S. Cratonic Margin (Default Zone)	0.12	6.1 [0.80] 7.2 [0.20]	1 [0.75] 2 [0.25]	Default for 42, 43, and 46	No	No	No
20	S. Coastal Margin	1.00	5.3 [0.80] 7.2 [0.20]	1 [0.75] 2 [0.25]	none	No	No	No
Other Sources within 200 mi (320 km) that do not contribute to 99% of hazard								
4	Appalachian Fold Belts	0.35	6.0 [0.80] 7.2 [0.20]	1 [0.75] 2 [0.25]	ME with 4A, 4B, 4C, 4D	No	No	No
4A	Kink in Fold Belt	0.65	5.0 [0.75] 7.2 [0.25]	3 [0.75] 4 [0.25]	ME with 4	No	No	No
49	Jonesboro Basin	0.28	6.0 [0.75] 7.2 [0.25]	3 [0.75] 4 [0.25]	PD with 47, 48, 50, 51, 65; ME with 52	No	No	No
50	Buried Triassic Basins	0.28	6.0 [0.75] 7.2 [0.25]	3 [0.75] 4 [0.25]	PD with 47, 48, 49, 51, 65; ME with 52	No	No	No
51	Florence Basin	0.28	6.0 [0.75] 7.2 [0.25]	3 [0.75] 4 [0.25]	PD with 47 thru 50, 65; ME with 52	No	No	No

Table 2.5-204 (Sheet 2 of 2)
Summary of Dames & Moore Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
65	Dunbarton Triassic Basin	0.28	5.9 [0.75] 7.2 [0.25]	3 [0.75] 4 [0.25]	PD with 47 thru 51; ME with 52	No	No	No
C01	Combination zone 4-4A-4B-4C-4D	NA	6.0 [0.80] 7.2 [0.20]	1 [0.75] 2 [0.25]	NA	No	No	No

1 Pa = probability of activity; (from EPRI NP-6452-D 1989)
2 Maximum Magnitude (Mmax) and weights (wts.); (from EPRI NP-6452-D 1989)
3 Smoothing options are defined as follows (from EPRI NP-6452-D 1989)
1 = No smoothing on a, no smoothing on b (strong prior of 1.04);
2 = No smoothing on a, no smoothing on b (weak prior of 1.04);
3 = Constant a, constant b (strong prior of 1.04);
4 = Constant a, constant b (weak prior of 1.04).
Weights on magnitude intervals are [0.1, 0.2, 0.4, 1.0, 1.0, 1.0, 1.0]
4 ME = mutually exclusive; PD = perfectly dependent
5 No, unless (1) new geometry proposed in literature or (2) new seismicity pattern
6 No, unless (1) new data suggests Mmax exceeds or differs significantly from the EPRI Mmax distribution or (2) exceeded by historical seismicity.
7 RI = recurrence interval; assumed no change if no new paleoseismic data or rate of seismicity has not significantly changed
8 Replace this source with the Updated Charleston Seismic Source (UCSS) Model

Table 2.5-205 (Sheet 1 of 2)
Summary of Law Engineering Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Inter-dependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
Sources within 200 mi (320 km) that contribute to 99% of hazard								
35	**Charleston Seismic Zone**	0.45	6.8 [1.00]	2a [1.00]	Overlaps 8 and 22	**Yes[8]**	**Yes[8]**	**Yes[8]**
17	Eastern Basement	0.62	5.7 [0.20] 6.8 [0.80]	1b [1.00]	none	No	No	No
22	Reactivated E. Seaboard Normal	0.27	6.8 [1.00]	2a [1.00]	ME with 8 and 21; overlaps 24, 35, and 39	No	No	No
108	Brunswick, NC Background	1.00	4.9 [0.50] 5.5 [0.30] 6.8 [0.20]	2a [1.00]	Background; P_B=0.42	No	No	No
C09	Mesozoic Basins (8 - Bridged)	NA	6.8 [1.00]	2a [1.00]	NA	No	No	No
C10	8-35	NA	6.8 [1.00]	2a [1.00]	NA	No	No	No
C11	22 - 35	NA	6.8 [1.00]	2a [1.00]	NA	No	No	No
M33	Mafic Pluton	0.43	6.8 [1.00]	5 [1.00]	none	No	No	No
M36	Mafic Pluton	0.43	6.8 [1.00]	5 [1.00]	none	No	No	No
M37	Mafic Pluton	0.43	6.8 [1.00]	5 [1.00]	none	No	No	No
M38	Mafic Pluton	0.43	6.8 [1.00]	5 [1.00]	none	No	No	No
M39	Mafic Pluton	0.43	6.8 [1.00]	5 [1.00]	none	No	No	No
M40	Mafic Pluton	0.43	6.8 [1.00]	5 [1.00]	none	No	No	No
M41	Mafic Pluton	0.43	6.8 [1.00]	5 [1.00]	none	No	No	No
M42	Mafic Pluton	0.43	6.8 [1.00]	5 [1.00]	none	No	No	No
Other Sources within 200 mi (320 km) that do not contribute to 99% of hazard								
217	Eastern Basement Background	1.00	4.9 [0.50] 5.7 [0.50]	1b [1.00]	Background; P_B=0.29; same geometry as 17	No	No	No

Table 2.5-205 (Sheet 2 of 2)
Summary of Law Engineering Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Inter-dependencies[4]	New Information to Suggest Change in Source:		
						Geometry?[5]	Mmax?[6]	RI?[7]
107	Eastern Piedmont	1.00	4.9 [0.30] 5.5 [0.40] 5.7 [0.30]	1a [1.00]	Background; P_B=0.42	No	No	No
GC13	22 - 24 - 35	NA	6.8 [1.00]	2a [1.00]	NA	No	No	No
GC12	22 - 24	NA	6.8 [1.00]	2a [1.00]	NA	No	No	No
8	Mesozoic Basins	0.27	6.8 [1.00]	a and b values calculated for C09	ME with 22; overlaps with 35	No	No	No

1 Pa = probability of activity; (from EPRI NP-6452-D 1989)
2 Maximum Magnitude (Mmax) and weights (wts.); (from EPRI NP-6452-D 1989)
3 Smoothing options are defined as follows: (from EPRI NP-6452-D 1989)
1a = High smoothing on a, constant b (strong prior of 1.05);
1b = High smoothing on b, constant b (strong prior of 1.00);
1c = High smoothing on a, constant b (strong prior of 0.95);
1d = High smoothing on a, constant b (strong prior of 0.90);
1e = High smoothing on a, constant b (strong prior of 0.70);
2a = Constant a, constant b (strong prior of 1.05);
2c = Constant a, constant b (strong prior of 0.95);
2d = Constant a, constant b (strong prior of 0.90).
Weights on magnitude intervals are all 1.0 for above options.
3a = High smoothing on a, constant b (strong prior of 1.05).
Weights on magnitude intervals are [0.0, 1.0, 1.0, 1.0, 1.0, 1.0, 1.0] for option 3a.
4 ME = mutually exclusive; PD = perfectly dependent
5 No, unless (1) new geometry proposed in literature or (2) new seismicity pattern
6 No, unless (1) new data suggests Mmax exceeds or differs significantly from the EPRI Mmax distribution or (2) exceeded by historical seismicity.
7 RI = recurrence interval; assumed no change if no new paleoseismic data or rate of seismicity has not significantly changed
8 Replace this source with the Updated Charleston Seismic Source (UCSS) Model

Table 2.5-206 (Sheet 1 of 2)
Summary of Rondout Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
Sources within 200 mi (320 km) that contribute to 99% of hazard								
24	**Charleston**	1.00	6.6 [0.20] 6.8 [0.60] 7.0 [0.20]	1 [1.00] (a=-0.710, b=1.020)	none	**Yes[8]**	**Yes[8]**	**Yes[8]**
26	South Carolina	1.00	5.8 [0.15] 6.5 [0.60] 6.8 [0.25]	1 [1.00] (a=-1.390, b=0.970)	none	No	No	No
Other Sources within 200 mi (320 km) that do not contribute to 99% of hazard								
49	Appalachian	1.00	4.8 [0.20] 5.5 [0.60] 5.8 [0.20]	2 [1.00]	Background; P_B=1.00	No	No	No
C01	Background 49	NA	4.8 [0.20] 5.5 [0.60] 5.8 [0.20]	3 [1.00]	none	No	No	No
C09	49+32	NA	4.8 [0.20] 5.5 [0.60] 5.8 [0.20]	3 [1.00]	none	No	No	No
50	Grenville	1.00	4.8 [0.20] 5.5 [0.60] 5.8 [0.20]	2 [1.00]	Background; P_B=1.00	No	No	No
C02	Background 50	NA	4.8 [0.20] 5.5 [0.60] 5.8 [0.20]	3 [1.00]	does not contain 12 or 13	No	No	No
C07	50 (02) + 12	NA	4.8 [0.20] 5.5 [0.60] 5.8 [0.20]	3 [1.00]	none	No	No	No
25	Southern Appalachians	0.99	6.6 [0.30] 6.8 [0.60] 7.0 [0.10]	1 [1.00] (a=-0.630, b=1.150)	none	No	No	No

Table 2.5-206 (Sheet 2 of 2)
Summary of Rondout Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source:		
						Geometry?[5]	Mmax?[6]	RI?[7]
27	Tennessee-VA Border Zone	0.99	5.2 [0.30] 6.3 [0.55] 6.5 [0.15]	1 [1.00] (a=-1.120, b=0.930)	none	No	No	No

1 Pa = probability of activity; (from EPRI NP-6452-D 1989)
2 Maximum Magnitude (Mmax) and weights (wts.); (from EPRI NP-6452-D 1989)
3 Smoothing options are defined as follows: (from EPRI NP-6452-D 1989)
1, 6, 7, 8 = a, b values as listed above, with weights shown;
3 = Low smoothing on a, constant b (strong prior of 1.0);
5 = a, b values as listed above, with weights shown.
4 ME = mutually exclusive; PD = perfectly dependent
5 No, unless (1) new geometry proposed in literature or (2) new seismicity pattern
6 No, unless (1) new data suggests Mmax exceeds or differs significantly from the EPRI Mmax distribution or (2) exceeded by historical seismicity.
7 RI = recurrence interval; assumed no change if no new paleoseismic data or rate of seismicity has not significantly changed
8 Replace this source with the Updated Charleston Seismic Source (UCSS) Model

Table 2.5-207 (Sheet 1 of 3)
Summary of Weston Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
Sources within 200 mi (320 km) that contribute to 99% of hazard								
25	**Charleston Seismic Zone**	0.99	6.6 [0.90] 7.2 [0.10]	1b [1.00]	none	**Yes[8]**	**Yes[8]**	**Yes[8]**
26	South Carolina	0.86	6.0 [0.67] 6.6 [0.27] 7.2 [0.06]	1b [1.00]	none	No	No	No
104	Southern Coastal Plain	1.00	5.4 [0.24] 6.0 [0.61] 6.6 [0.15]	1a [0.20] 2a [0.80]	Background; P_B=1.00	No	No	No
C19	103-23-24	NA	5.4 [0.26] 6.0 [0.58] 6.6 [0.16]	1a [1.00]	NA	No	No	No
C20	104-22	NA	6.0 [0.85] 6.6 [0.15]	1a [0.30] 2a [0.70]	NA	No	No	No
C21	104-25	NA	5.4 [0.24] 6.0 [0.61] 6.6 [0.15]	1a [0.30] 2a [0.70]	NA	No	No	No
C23	104-22-26	NA	5.4 [0.80] 6.0 [0.14] 6.6 [0.06]	1a [0.50] 2a [0.50]	NA	No	No	No
C24	104-22-25	NA	5.4 [0.80] 6.0 [0.14] 6.6 [0.06]	1a [0.50] 2a [0.50]	NA	No	No	No
C26	104-28BCDE-22	NA	5.4 [0.24] 6.0 [0.61] 6.6 [0.15]	1a [0.30] 2a [0.70]	NA	No	No	No
C27	104-28BCDE-22-25	NA	5.4 [0.30] 6.0 [0.70]	1a [0.70] 2a [0.30]	NA	No	No	No

Table 2.5-207 (Sheet 2 of 3)
Summary of Weston Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
C33	26-25		6.6 [0.90] 7.2 [0.10]	1b [1.00]	NA	No	No	No
C35	104-28BE-25	NA	5.4 [0.24] 6.0 [0.61] 6.6 [0.15]	1a [0.20] 1b [0.80]	NA	No	No	No
Other Sources within 200 mi (320 km) that do not contribute to 99% of hazard								
C22	104-26	NA	5.4 [0.24] 6.0 [0.61] 6.6 [0.15]	1a [0.30] 1b [0.70]	NA	No	No	No
C34	104-28BE-26	NA	5.4 [0.24] 6.0 [0.61] 6.6 [0.15]	1a [0.20] 1b [0.80]	NA	No	No	No
C25	104-28BCDE	NA	5.4 [0.24] 6.6 [0.61] 6.6 [0.15]	1a [0.30] 2a [0.70]	NA	No	No	No
C28	104-28BCDE-22-26	NA	5.4 [0.30] 6.0 [0.70]	1a [0.70] 2a [0.30]	NA	No	No	No
28B	Zone of Mesozoic Basin	0.26	5.4 [0.65] 6.0 [0.25] 6.6 [0.10]	1b [1.00]	PD with 28C, 28D, and 28E	No	No	No
C01	28A thru E	NA	5.4 [0.65] 6.0 [0.25] 6.6 [0.10]	1b [1.00]	NA	No	No	No
103	Southern Appalachians	1.00	5.4 [0.26] 6.0 [0.58] 6.6 [0.16]	1a [0.20] 2a [0.80]	Background; P_B=1.00	No	No	No
C17	103-23	NA	5.4 [0.26] 6.0 [0.58] 6.6 [0.16]	1a [0.70] 2a [0.30]	NA	No	No	No
C18	103-24	NA	5.4 [0.26] 6.0 [0.58] 6.6 [0.16]	1a [0.70] 1b [0.30]	NA	No	No	No

Table 2.5-207 (Sheet 3 of 3)
Summary of Weston Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source:		
						Geometry?[5]	Mmax?[6]	RI?[7]
28D	Zone of Mesozoic Basin	0.26	5.4 [0.65] 6.0 [0.25] 6.6 [0.10]	1b [1.00]	PD with 28B, 28C, and 28E	No	No	No
28E	Zone of Mesozoic Basin	0.26	5.4 [0.65] 6.0 [0.25] 6.6 [0.10]	1b [1.00]	PD with 28B, 28C, and 28D	No	No	No
102	Appalachian Plateau	1.00	5.4 [0.62] 6.0 [0.29] 6.6 [0.09]	1a [0.20] 2a [0.80]	Background; P_B=1.00	No	No	No
24	New York-Alabama-Clingman	0.90	5.4 [0.26] 6.0 [0.58] 6.6 [0.16]	1b [1.00]	Contained in 103	No	No	No

1 Pa = probability of activity; (from EPRI NP-6452-D 1989)
2 Maximum Magnitude (Mmax) and weights (wts.); (from EPRI NP-6452-D 1989)
3 Smoothing options are defined as follows: (from EPRI NP-6452-D 1989
1a = Constant a, constant b (medium prior of 1.0);
1b = Constant a, constant b (medium prior of 0.9);
1c = Constant a, constant b (medium prior of 0.7);
2a = Medium smoothing on a, medium smoothing on b (medium prior of 1.0);
2b = Medium smoothing on a, medium smoothing on b (medium prior of 0.9);
2c = Medium smoothing on a, medium smoothing on b (medium prior of 0.7).
4 ME = mutually exclusive; PD = perfectly dependent
5 No, unless (1) new geometry proposed in literature or (2) new seismicity pattern
6 No, unless (1) new data suggests Mmax exceeds or differs significantly from the EPRI Mmax distribution or (2) exceeded by historical seismicity.
7 RI = recurrence interval; assumed no change if no new paleoseismic data or rate of seismicity has not significantly changed
8 Replace this source with the Updated Charleston Seismic Source (UCSS) Model

Table 2.5-208 (Sheet 1 of 2)
Summary of Woodward-Clyde Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
Sources within 200 mi (320 km) that contribute to 99% of hazard								
30	**Charleston (includes NOTA)**	0.573	6.8 [0.33] 7.3 [0.34] 7.5 [0.33]	2 [0.10] 3 [0.10] 4 [0.10] 5 [0.10] 9 [0.60] (a = -1.005, b = 0.852)	ME with 29, 29A	**Yes[8]**	**Yes[8]**	**Yes[8]**
29	**S. Carolina Gravity Saddle (Extended)**	0.122	6.7 [0.33] 7.0 [0.34] 7.4 [0.33]	2 [0.25] 3 [0.25] 4 [0.25] 5 [0.25]	ME with 29A, 29B, and 30	**Yes[8]**	**Yes[8]**	**Yes[8]**
29A	**SC Gravity Saddle No. 2 (Combo C3)**	0.305	6.7 [0.33] 7.0 [0.34] 7.4 [0.33]	2 [0.25] 3 [0.25] 4 [0.25] 5 [0.25]	ME with 29, 29B, and 30	**Yes[8]**	**Yes[8]**	**Yes[8]**
29B	SC Gravity Saddle No. 3 (NW Portion)	0.183	5.4 [0.33] 6.0 [0.34] 7.0 [0.33]	2 [0.25] 3 [0.25] 4 [0.25] 5 [0.25]	ME with 29, 29A	No	No	No
	Vogtle Background		5.8 [0.33] 6.0 [0.34] 6.6 [0.33]		None	No	No	No
Other Sources within 200 mi (320 km) that do not contribute to 99% of hazard								
31	Blue Ridge Combo	0.024	5.9 [0.33] 6.3 [0.34] 7.0 [0.33]	2 [0.25] 3 [0.25] 4 [0.25] 5 [0.25]	ME with 31A	No	No	No

Table 2.5-208 (Sheet 2 of 2)
Summary of Woodward-Clyde Seismic Sources

Source	Description	Pa[1]	Mmax (m_b) and Wts.[2]	Smoothing Options and Wts.[3]	Interdependencies[4]	New Information to Suggest Change in Source: Geometry?[5]	Mmax?[6]	RI?[7]
31A	Blue Ridge Combination - Alternate Configuration	0.211	5.9 [0.33] 6.3 [0.34] 7.0 [0.33]	2 [0.25] 3 [0.25] 4 [0.25] 5 [0.25]	ME with 31	No	No	No

1 Pa = probability of activity; (from EPRI NP-6452-D 1989)
2 Maximum Magnitude (Mmax) and weights (wts.); (from EPRI NP-6452-D 1989)
3 Smoothing options are defined as follows: (from EPRI NP-6452-D 1989)
1 = Low smoothing on a, high smoothing on b (no prior);
2 = High smoothing on a, high smoothing on b (no prior);
3 = High smoothing on a, high smoothing on b (moderate prior of 1.0);
4 = High smoothing on a, high smoothing on b (moderate prior of 0.9);
5 = High smoothing on a, high smoothing on b (moderate prior of 0.8);
6 = Low smoothing on a, high smoothing on b (moderate prior of 1.0);
7 = Low smoothing on a, high smoothing on b (moderate prior of 0.9);
8 = Low smoothing on a, high smoothing on b (moderate prior of0.8).
Weights on magnitude intervals are all 1.0
9 = a and b values as listed.
4 ME = mutually exclusive; PD = perfectly dependent
5 No, unless (1) new geometry proposed in literature or (2) new seismicity pattern
6 No, unless (1) new data suggests Mmax exceeds or differs significantly from the EPRI Mmax distribution or (2) exceeded by historical seismicity.
7 RI = recurrence interval; assumed no change if no new paleoseismic data or rate of seismicity has not significantly changed
8 Replace this source with the Updated Charleston Seismic Source (UCSS) Model

Table 2.5-209
Summary of USGS Seismic Sources (Frankel et al. 2002)

Source	Mmax (Mw) and Wts.	Largest Mmax Value Considered by USGS	
		Mw	mb[1]
Sources within 200 mi (320 km)			
Extended Margin Background	7.5 [1.00]	7.5	7.2
Charleston	**6.8 [0.20]** **7.1 [0.20]** **7.3 [0.45]** **7.5 [0.15]**	7.5	7.2
Eastern Tennessee	7.5 [1.00]	7.5	7.2
Selected Sources Beyond 200 mi (320km)			
New Madrid	7.3 [0.15] 7.5 [0.20] 7.7 [0.50] 8.0 [0.15]	8.0	7.5
Stable Craton Background	7.0 [1.00]	7.0	6.9

1 m_b converted from Mw using average of Atkinson and Boore (1995), Frankel et al (1996), and EPRI (TR-102293 1993) relations

Table 2.5-210
Chapman and Talwani (2002) Seismic Source Zone Parameters

Charleston Characteristic Sources	Mean Recurrence	Mmax[2] m_{blg}	Mmax[2] M
Charleston Area Source	550 years	nr	7.1 [.2] 7.3 [.6] 7.5 [.2]
ZRA Fault Source (Zone of River Anomalies)	550 years	nr	7.1 [.2] 7.3 [.6] 7.5 [.2]
Ashley River-Woodstock Fault Source (modeled as 3 parallel faults)	550 years	nr	7.1 [.2] 7.3 [.6] 7.5 [.2]

	Non-Characteristic Background Sources	a[1]	b[1]	m_{blg}	M
1.	Zone1	0.242	0.84	6.84	7.00
2.	Zone2	-0.270	0.84	6.84	7.00
3.	Central Virginia	1.184	0.64	6.84	7.00
4.	Zone4	0.319	0.84	6.84	7.00
5.	Zone5	0.596	0.84	6.84	7.00
6.	Piedmont and Coastal Plain	1.537	0.84	6.84	7.00
6a.	Pied&CP NE	0.604	0.84	6.84	7.00
6b.	Pied&CP SW	1.312	0.84	6.84	7.00
7.	South Carolina Piedmont	2.220	0.84	6.84	7.00
8.	Middleton Place	1.690	0.77	6.84	7.00
9.	Florida and continental margin	1.371	0.84	6.84	7.00
10.	Alabama	1.800	0.84	6.84	7.00
11.	Eastern Tennessee	2.720	0.90	6.84	7.00
12.	Southern Appalachian	2.420	0.84	6.84	7.00
12a.	Southern Appalachian North	2.185	0.84	6.84	7.00
13.	Giles County, VA	1.070	0.84	6.84	7.00
14.	Central Appalachians	1.630	0.84	6.84	7.00
15.	Western Tennessee	2.431	1.00	6.84	7.00
16.	Central Tennessee	2.273	1.00	6.84	7.00
17.	Ohio-Kentucky	2.726	1.00	6.84	7.00
18.	West VA-Pennsylvania	2.491	1.00	6.84	7.00
19.	USGS (1996) gridded seismicity rates and b value	nr[3]	0.95	6.84	7.00

1 a and b values in terms of mblg magnitude, reported in Chapman and Talwani (2002).

2 Mmax range for characteristic events was designed to "represent the range of magnitude estimates of the 1886 Charleston shock proposed by Johnston (1996)" (Chapman and Talwani, 2002, p. 12). Square brackets indicate weights assigned to characteristic magnitudes. For non-characteristic background events, a truncated form of the exponential probability density function was used (Chapman and Talwani, 2002, p. 6-7).

3 nr = not reported

Table 2.5-211
Local Charleston-Area Tectonic Features

Name of Feature	Evidence	Key References
Adams Run fault	**subsurface stratigraphy**	**Weems and Lewis (2002)**
Ashley River fault	microseismicity	Talwani (1982, 2000) Weems and Lewis (2002)
Appalachian detachment (decollement)	gravity & magnetic data seismic reflection & refraction	Cook *et al.* (1979, 1981) Behrendt *et al.* (1981, 1983) Seeber and Armbruster (1981)
Blake Spur fracture zone	oceanic transform postulated to extend westward to Charleston area	Fletcher *et al.* (1978) Sykes (1978) Seeber and Armbruster (1981)
Bowman seismic zone	microseismicity	Smith and Talwani (1985)
Charleston fault	subsurface stratigraphy	Colquhoun *et al*. (1983) Lennon (1986) Talwani (2000) Weems and Lewis (2002)
Cooke fault	seismic reflection	Behrendt *et al.* (1981, 1983) Hamilton *et al.* (1983) Wentworth and Mergner-Keefer (1983) Behrendt and Yuan (1987)
Drayton fault	seismic reflection	Hamilton *et al.* (1983) Behrendt *et al*. (1983) Behrendt and Yuan (1987)
East Coast fault system/ Zone of river anomalies (ZRA)	**geomorphology seismic reflection microseismicity**	**Marple and Talwani (1993) Marple and Talwani (2000, 2004)**
Gants fault	seismic reflection	Hamilton *et al*. (1983) Behrendt and Yuan (1987)
Garner-Edisto fault	subsurface stratigraphy	Colquhoun *et al.* (1983)
Helena Banks fault zone	seismic reflection	Behrendt *et al.* (1981, 1983) Behrendt and Yuan (1987)
Middleton Place-Summerville seismic zone	microseismicity	Tarr *et al.* (1981) Madabhushi and Talwani (1993)
Sawmill Branch fault	**microseismicity**	**Talwani and Katuna (2004)**
Summerville fault	**microseismicity**	**Weems *et al.* (1997)**
Woodstock fault	geomorphology microseismicity	Talwani (1982, 1999, 2000) Marple and Talwani (1990, 2000)

Note: Those tectonic features identified following publication of the EPRI teams' reports (post-1986) are highlighted by **bold-face** type.

Table 2.5-212
Geographic Coordinates (Latitude and Longitude) of Corner Points of Updated Charleston Seismic Source (UCSS) Geometries

Source Geometry	Longitude (decimal degrees)	Latitude (decimal degrees)
A	-80.707	32.811
A	-79.840	33.354
A	-79.527	32.997
A	-80.392	32.455
B	-81.216	32.485
B	-78.965	33.891
B	-78.3432	33.168
B	-80.587	31.775
B'	-78.965	33.891
B'	-78.654	33.531
B'	-80.900	32.131
B'	-81.216	32.485
C	-80.397	32.687
C	-79.776	34.425
C	-79.483	34.351
C	-80.109	32.614

Table 2.5-213
Comparison of Post-EPRI NP-6395-D 1989 Magnitude Estimates for the 1886 Charleston Earthquake

Study	Magnitude Estimation Method	Reported Magnitude Estimate	Assigned Weights	Mean Magnitude (M)
Johnston *et al.* (1994)	worldwide survey of passive-margin, extended-crust earthquakes	**M**7.56 ± 0.35 [a]	--	7.56
Martin and Clough (1994)	geotechnical assessment of 1886 liquefaction data	**M**7 - 7.5	--	7.25
Johnston (1996)	isoseismal area regression, accounting for eastern North America anelastic attenuation	**M**7.3 ± 0.26	--	7.3
Chapman and Talwani (2002) (South Carolina Department of Transportation)	consideration of available magnitude estimates	**M**7.1 **M**7.3 **M**7.5	0.2 0.6 0.2	7.3
Frankel *et al.* (2002) (USGS National seismic hazard mapping project)	consideration of available magnitude estimates	**M**6.8 **M**7.1 **M**7.3 **M**7.5	0.20 0.20 0.45 0.15	7.2
Bakun and Hopper (2004)	isoseismal area regression, including empirical site corrections	M_I 6.4 - 7.2 [b]	--	6.9 [c]

Notes:

[a] Estimate from Johnston *et al*. (1994) Chapter 3.

[b] 95% confidence interval estimate; M_I (intensity magnitude) is considered equivalent to **M** (Bakun and Hopper, 2004).

[c] Bakun and Hopper's (2004) *preferred* estimate.

Table 2.5-214
Comparison of Talwani and Schaeffer (2001) and UCSS Age Constraints on Charleston-Area Paleoliquefaction Events

Liquefaction Event	Event Age (YBP) [b]	Talwani and Schaeffer (2001) [a] *scenario 1* Source	*scenario 1* M	*scenario 2* Source	*scenario 2* M	(this study) Event Age (YBP) [b, c, d]
1886 A.D.	64	Charleston	7.3	Charleston	7.3	64
A	546 ± 17	Charleston	7+	Charleston	7+	600 ± 70
B	1,021 ± 30	Charleston	7+	Charleston	7+	1,025 ± 25
C	1,648 ± 74	*Northern*	6+	--	--	--
C'	1,683 ± 70	--		Charleston	7+	1,695 ± 175
D	1,966 ± 212	*Southern*	6+	--	--	--
E	3,548 ± 66	Charleston	7+	Charleston	7+	3,585 ± 115
F	5,038 ± 166	*Northern*	6+	Charleston	7+	--
F'	--	--	--	--	--	5,075 ± 215
G	5,800 ± 500	Charleston	7+	Charleston	7+	--

Notes:

[a] Modified after Talwani and Schaeffer's (2001) Table 2.

[b] Years before present, relative to 1950 A.D.

[c] Event ages based upon our recalibration of radiocarbon (to 2-sigma using OxCal 3.8 (Bronk Ramsey, 1995; 2001) data presented in Talwani and Schaeffer's (2001) Table 2.

[d] See Table B-1 for recalibrated 2-sigma sample ages and Table B-2 for 2-sigma age constraints on paleoliquefaction events.

Table 2.5-215
Seismic Sources Used for Each 1986 EPRI Team

Earth Science Team	Sources used
Bechtel	F, G, H, ,N3,BZ4, BZ5
Dames & Moore	20, 41, 52, 53, 54
Law Engineering	17, 22, 35, 108, C09, C10, C11, M33, M36, M37, M38, M39, M40, M41, M42
Rondout Associates	24, 26
Woodward-Clyde Cons.	29, 29A, 29B, 30, 32
Weston Geophysical Corp.	25, 26, 104, C19, C20, C21, C23, C24, C26, C27, C33, C35

Table 2.5-216
Comparison of Seismic Hazard at VEGP ESP

Mean Hazard Comparison

PGA	EPRI-SOG	REI 2005	
cm/s2	hazard	hazard	% diff
50	8.15E-04	8.23E-04	0.97%
100	2.23E-04	2.26E-04	1.48%
250	2.84E-05	2.91E-05	2.29%
500	4.04E-06	4.21E-06	4.11%
700	1.36E-06	1.42E-06	4.71%
1000	3.82E-07	4.02E-07	5.10%

Median Hazard Comparison

PGA	EPRI-SOG	REI 2005	
cm/s2	hazard	hazard	% diff
50	5.65E-04	5.75E-04	1.84%
100	1.43E-04	1.45E-04	1.05%
250	1.99E-05	2.16E-05	8.69%
500	2.53E-06	2.63E-06	3.95%
700	7.86E-07	8.13E-07	3.41%
1000	2.05E-07	2.19E-07	6.73%

85% Hazard Comparison

PGA	EPRI-SOG	REI 2005	
cm/s2	hazard	hazard	% diff
50	1.49E-03	1.32E-03	-11.54%
100	4.16E-04	3.67E-04	-11.71%
250	4.96E-05	4.79E-05	-3.51%
500	7.01E-06	7.16E-06	2.15%
700	2.44E-06	2.46E-06	0.61%
1000	6.98E-07	7.08E-07	1.42%

Table 2.5-217
Hard Rock Mean UHS Results (in g) for VEGP ESP

Mean annual frequency of exceedance	Spectral frequency						
	PGA	25 Hz	10 Hz	5 Hz	2.5 Hz	1 Hz	0.5 Hz
10^{-4}	0.214	0.551	0.399	0.317	0.223	0.101	0.0653
$5x10^{-5}$	0.288	0.762	0.532	0.412	0.294	0.134	0.0924
10^{-5}	0.559	1.54	0.983	0.728	0.512	0.235	0.185
$5x10^{-6}$	0.747	2.06	1.28	0.914	0.635	0.294	0.241
10^{-6}	1.48	4.09	2.33	1.54	1.02	0.465	0.423

Table 2.5-218
Computed and Recommended Mbar and Dbar Values Used for Development of High and Low Frequency Target Spectra

High Frequency (5-10 Hz)				
	10^{-4}	**10^{-5}**	**10^{-6}**	**Recommended Values**
Mbar (Mw)	5.5	5.6	5.6	5.6
Dbar (km)	17.7	11.5	9.1	12
Low Frequency (1-2.5 Hz)				
	10^{-4}	**10^{-5}**	**10^{-6}**	**Recommended Values**
Mbar (Mw)	7.2	7.2	7.2	7.2
Dbar (km)	136.5	134.3	132.9	130

Table 2.5-219
Candidate High-Frequency (M5.6, R = 12km)
Time Histories for Spectral Matching

Earthquake	Date	Mw	Station	Distance (km)	Vs30m (m/s)
Saguenay	11/25/88	5.9	GSC Site 16	51.9	“???”
San Francisco	03/22/57	5.28	Golden Gate Park	11.13	874.0
Coyote Lake	08/06/79	5.74	Gilroy Array #1	10.67	1428.0
Mammoth Lakes-09	06/11/80	4.85	USC McGee Creek	7.49	684.9
Coalinga-04	07/09/83	5.18	Sulphur Baths (temp)	14.47	617.4
Coalinga-05	07/22/83	5.77	Sulphur Baths (temp)	13.40	617.4
Morgan Hill	04/24/84	6.19	Gilroy - Gavilan Coll.	14.84	729.7
Morgan Hill	04/24/84	6.19	Gilroy Array #1	14.91	1428.0
N. Palm Springs	07/08/86	6.06	Silent Valley - Poppet Flat	17.03	684.9
Whittier Narrows-01	10/01/87	5.99	Mt Wilson - CIT Seis Sta	22.73	821.7
Whittier Narrows-02	10/04/87	5.27	Mt Wilson - CIT Seis Sta	18.74	821.7
Anza-02	10/31/01	4.92	Anza - Pinyon Flat	12.37	724.9
Anza-02	10/31/01	4.92	Anza - Tripp Flats Training	24.73	684.9
Anza-02	10/31/01	4.92	Idyllwild - Keenwild Fire Sta.	29.07	845.4
Gilroy	05/14/02	4.90	Gilroy - Gavilan Coll.	2.82	729.7

Table 2.5-220
Candidate Low-Frequency (M7.2, R = 130 km)
Time Histories for Spectral Matching

Earthquake	Date	Mw	Station	Distance (km)	Vs30m (m/s)
San Fernando	02/09/1971	6.61	Isabella Dam (Aux Abut)	130.98	684.9
Loma Prieta	10/18/1989	6.93	SF-Rincon Hill	74.14	873.1
Loma Prieta	10/18/1989	6.93	So. San Francisco, Sierra Pt.	63.15	1020.6
Loma Prieta	10/18/1989	6.93	Yerba Buena Island	75.17	659.8
Northridge	01/17/1994	6.69	Rancho Cucamonga-Deer Canyon	79.99	821.7
Northridge	01/17/1994	6.69	Wrightwood-Jackson Flat	64.66	821.7
Kobe	01/16/1995	6.90	OKA	86.94	609.0
Kocaeli	08/17/1999	7.51	Bursa Sivil	65.53	659.6
Chi-Chi	09/20/1999	7.62	ILA031	83.31	649.3
Kobe	01/16/1995	6.90	MZH	70.26	609.0
Hector Mine	10/16/1999	7.13	Anza-Pinyon Flat	89.98	724.9
Hector Mine	10/16/1999	7.13	Anza-Tripp Flats Training	102.40	684.9
Hector Mine	10/16/1999	7.13	Banning-Twin Pines Road	83.43	684.9
Hector Mine	10/16/1999	7.13	Heart Bar State Park	61.21	684.9
Hector Mine	10/16/1999	7.13	Seven Oaks Dam Project Office	87.20	659.6

Table 2.5-221
Site Response Analyses Performed

Probability (per year) ->	10^{-4}		10^{-5}		10^{-6}				Total No. Analyses
Time Histories Analyzed ->	30 High Freq.	30 Low Freq.	30 High Freq.	30 Low Freq.	30 High Freq.	30 Low Freq.			
Randomized Soil Columns (EPRI) ->	60	60	60	60	60	60			360
Randomized Soil Columns (SRS) ->	60	60	60	60	60	60			360
									720

Table 2.5-222
Amplification Factors as a Function of Input Hard Rock Motion at Top of Blue Bluff Marl (depth 86 feet), as Developed from Site Response Analysis using SRS and EPRI Soil Degradation Models, for High-frequency Rock Motions

-	10^{-4}			10^{-5}			10^{-6}		
-	Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors	
Freq, Hz		EPRI	SRS		EPRI	SRS		EPRI	SRS
100	0.294	1.18	1.20	0.703	0.979	0.920	1.60	0.766	0.620
76	0.400	0.903	0.930	0.957	0.740	0.695	2.17	0.571	0.462
60	0.499	0.769	0.799	1.19	0.606	0.573	2.71	0.456	0.369
50	0.595	0.697	0.722	1.42	0.531	0.500	3.23	0.386	0.313
40	0.631	0.775	0.819	1.51	0.553	0.523	3.43	0.379	0.306
30	0.655	0.961	1.02	1.57	0.664	0.626	3.63	0.398	0.319
25	0.647	1.14	1.21	1.55	0.812	0.768	3.71	0.446	0.354
20	0.615	1.33	1.39	1.47	0.991	0.937	3.34	0.579	0.453
16.5	0.575	1.47	1.52	1.38	1.133	1.07	3.13	0.705	0.560
13.4	0.521	1.67	1.69	1.25	1.312	1.23	2.83	0.875	0.685
12.2	0.494	1.78	1.81	1.18	1.417	1.33	2.69	0.953	0.754
10	0.438	1.81	1.82	1.05	1.600	1.50	2.38	1.15	0.928
8.1	0.377	2.19	2.18	0.902	1.747	1.65	2.05	1.34	1.09
7	0.339	2.30	2.26	0.811	1.984	1.87	1.84	1.47	1.21
6	0.298	2.05	2.03	0.713	2.096	1.93	1.62	1.68	1.38
5	0.257	2.11	2.08	0.615	2.022	1.88	1.40	1.90	1.56
4	0.212	2.56	2.54	0.507	2.300	2.16	1.15	2.09	1.70
3.3	0.175	2.88	2.81	0.419	2.687	2.51	0.952	2.42	2.00
2.5	0.131	3.16	3.05	0.314	3.089	2.83	0.713	2.78	2.33
2	0.101	2.49	2.38	0.242	2.651	2.38	0.549	2.96	2.39
1.5	0.064	3.22	3.12	0.154	3.193	2.86	0.350	3.28	2.48
1	0.035	2.34	2.30	0.0828	2.542	2.41	0.188	3.00	2.55
0.8	0.024	2.63	2.59	0.0563	2.695	2.55	0.128	2.95	2.54
0.7	0.0187	3.15	3.10	0.0447	3.141	2.97	0.101	3.31	2.86
0.61	0.0148	3.80	3.78	0.0354	3.842	3.69	0.0804	4.02	3.52
0.5	0.0109	3.40	3.43	0.0260	3.597	3.59	0.0590	4.00	3.81
0.33	0.00525	2.19	2.19	0.0126	2.269	2.25	0.0286	2.52	2.40
0.25	0.00314	1.98	1.97	0.00751	2.059	2.00	0.0171	2.24	2.07
0.15	0.00106	2.06	2.04	0.00254	2.149	2.05	0.00577	2.37	2.06
0.1	0.000370	2.27	2.23	0.000890	2.341	2.18	0.00201	2.43	2.06

Table 2.5-223
Amplification Factors as a Function of Input Hard Rock Motion at Top of Blue Bluff Marl (depth 86 feet), as Developed from Site Response Analysis using SRS and EPRI Soil Degradation Models, for Low-frequency Rock Motions

	10^{-4}			10^{-5}			10^{-6}		
	Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors	
Freq, Hz		EPRI	SRS		EPRI	SRS		EPRI	SRS
100	0.224	1.31	1.25	0.517	1.111	0.896	1.03	0.931	0.591
76	0.305	0.987	0.942	0.704	0.828	0.667	1.40	0.692	0.439
60	0.380	0.802	0.765	0.878	0.660	0.532	1.74	0.550	0.349
50	0.453	0.695	0.662	1.047	0.557	0.449	2.08	0.462	0.293
40	0.483	0.677	0.644	1.115	0.532	0.428	2.22	0.437	0.277
30	0.506	0.764	0.73	1.168	0.529	0.417	2.32	0.417	0.264
25	0.505	0.90	0.86	1.167	0.570	0.440	2.32	0.422	0.266
20	0.493	1.07	1.02	1.139	0.653	0.492	2.26	0.445	0.276
16.5	0.476	1.21	1.16	1.101	0.762	0.57	2.19	0.481	0.293
13.4	0.453	1.41	1.34	1.046	0.877	0.66	2.08	0.536	0.316
12.2	0.440	1.49	1.42	1.017	0.943	0.71	2.02	0.571	0.335
10	0.413	1.61	1.54	0.954	1.151	0.87	1.90	0.68	0.389
8.1	0.381	1.91	1.82	0.880	1.343	1.05	1.75	0.83	0.46
7	0.359	2.09	1.96	0.830	1.534	1.23	1.65	0.97	0.55
6	0.334	1.99	1.88	0.771	1.734	1.35	1.53	1.12	0.66
5	0.307	1.97	1.89	0.709	1.804	1.38	1.41	1.36	0.78
4	0.275	2.46	2.37	0.635	1.967	1.62	1.26	1.57	0.93
3.3	0.246	2.90	2.78	0.569	2.443	2.05	1.13	1.94	1.21
2.5	0.209	3.29	3.05	0.483	2.813	2.29	0.960	2.43	1.61
2	0.181	2.34	2.16	0.418	2.817	2.24	0.831	2.82	1.82
1.5	0.137	3.30	3.07	0.318	3.124	2.29	0.632	3.19	1.70
1	0.0917	2.27	2.21	0.214	2.697	2.42	0.423	3.70	2.32
0.8	0.0768	2.67	2.56	0.193	2.754	2.41	0.405	3.26	2.42
0.7	0.0703	3.25	3.10	0.184	3.233	2.80	0.397	3.50	2.48
0.61	0.0652	4.00	3.90	0.177	3.933	3.43	0.390	3.94	2.71
0.5	0.0590	3.66	3.72	0.167	4.107	4.01	0.382	4.75	3.46
0.33	0.0317	1.97	2.00	0.0901	2.219	2.30	0.206	2.85	2.96
0.25	0.0209	1.64	1.65	0.0592	1.726	1.75	0.136	2.05	2.06
0.15	0.0095	1.36	1.36	0.0270	1.395	1.39	0.0617	1.55	1.54
0.1	0.0047	1.30	1.29	0.0134	1.321	1.31	0.0307	1.45	1.40

Table 2.5-224
Amplification Factors as a Function of Input Hard Rock Motion at 40-ft Depth Horizon (FIRS), as Developed from Site Response Analysis using SRS and EPRI Soil Degradation Models, for High-Frequency Rock Motions

	10^{-4}			10^{-5}			10^{-6}		
	Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors	
Freq, Hz		EPRI	SRS		EPRI	SRS		EPRI	SRS
100	0.294	1.13	1.17	0.703	0.874	0.874	1.60	0.608	0.568
76	0.400	0.851	0.885	0.957	0.655	0.655	2.17	0.452	0.422
60	0.499	0.706	0.739	1.19	0.527	0.528	2.71	0.361	0.336
50	0.595	0.627	0.660	1.42	0.451	0.453	3.23	0.304	0.283
40	0.631	0.687	0.733	1.51	0.457	0.458	3.43	0.292	0.272
30	0.655	0.826	0.89	1.57	0.516	0.516	3.63	0.291	0.269
25	0.647	0.99	1.07	1.55	0.621	0.626	3.71	0.310	0.284
20	0.615	1.19	1.27	1.47	0.776	0.778	3.34	0.390	0.358
16.5	0.575	1.34	1.42	1.38	0.919	0.92	3.13	0.480	0.444
13.4	0.521	1.56	1.63	1.25	1.102	1.10	2.83	0.609	0.554
12.2	0.494	1.71	1.78	1.18	1.216	1.22	2.69	0.675	0.617
10	0.438	1.76	1.82	1.05	1.430	1.43	2.38	0.85	0.795
8.1	0.377	2.08	2.15	0.902	1.575	1.59	2.05	1.03	0.96
7	0.339	2.19	2.23	0.811	1.780	1.80	1.84	1.15	1.09
6	0.298	2.05	2.08	0.713	1.916	1.89	1.62	1.34	1.27
5	0.257	2.22	2.24	0.615	1.966	1.94	1.40	1.57	1.49
4	0.212	2.76	2.82	0.507	2.335	2.33	1.15	1.79	1.68
3.3	0.175	3.09	3.16	0.419	2.777	2.79	0.952	2.12	2.03
2.5	0.131	3.30	3.34	0.314	3.160	3.16	0.713	2.52	2.47
2	0.101	2.56	2.56	0.242	2.702	2.65	0.549	2.68	2.57
1.5	0.064	3.26	3.26	0.154	3.162	3.04	0.350	2.96	2.61
1	0.035	2.35	2.37	0.0828	2.510	2.50	0.188	2.72	2.61
0.8	0.024	2.64	2.64	0.0563	2.655	2.62	0.128	2.71	2.57
0.7	0.0187	3.15	3.14	0.0447	3.097	3.03	0.101	3.03	2.86
0.61	0.0148	3.79	3.82	0.0354	3.773	3.72	0.0804	3.72	3.51
0.5	0.0109	3.40	3.46	0.0260	3.556	3.63	0.0590	3.76	3.81
0.33	0.00525	2.18	2.21	0.0126	2.237	2.28	0.0286	2.35	2.40
0.25	0.00314	1.98	2.00	0.00751	2.015	2.03	0.0171	2.06	2.06
0.15	0.00106	2.08	2.10	0.00254	2.102	2.10	0.00577	2.15	2.07
0.1	0.000370	2.31	2.33	0.000890	2.295	2.27	0.00201	2.18	2.08

Table 2.5-225
Amplification Factors as a Function of Input Hard Rock Motion at 40-ft Depth Horizon (FIRS), as Developed from Site Response Analysis Using SRS and EPRI Soil Degradation Models, for Low-Frequency Rock Motions

	10^{-4}			10^{-5}			10^{-6}		
	Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors	
Freq, Hz		EPRI	SRS		EPRI	SRS		EPRI	SRS
100	0.224	1.26	1.25	0.517	0.978	0.888	1.03	0.715	0.549
76	0.305	0.947	0.942	0.704	0.728	0.661	1.40	0.531	0.408
60	0.380	0.762	0.759	0.878	0.581	0.527	1.74	0.422	0.324
50	0.453	0.653	0.647	1.047	0.489	0.443	2.08	0.354	0.272
40	0.483	0.629	0.623	1.115	0.462	0.418	2.22	0.333	0.255
30	0.506	0.682	0.67	1.168	0.450	0.405	2.32	0.319	0.244
25	0.505	0.78	0.77	1.167	0.467	0.415	2.32	0.321	0.246
20	0.493	0.93	0.92	1.139	0.520	0.453	2.26	0.334	0.254
16.5	0.476	1.08	1.07	1.101	0.600	0.52	2.19	0.355	0.267
13.4	0.453	1.28	1.27	1.046	0.701	0.59	2.08	0.388	0.286
12.2	0.440	1.38	1.37	1.017	0.758	0.65	2.02	0.411	0.301
10	0.413	1.51	1.50	0.954	0.943	0.80	1.90	0.48	0.344
8.1	0.381	1.77	1.76	0.880	1.101	0.96	1.75	0.56	0.40
7	0.359	1.96	1.92	0.830	1.271	1.14	1.65	0.66	0.48
6	0.334	1.94	1.91	0.771	1.464	1.28	1.53	0.78	0.57
5	0.307	2.02	2.01	0.709	1.594	1.37	1.41	0.96	0.69
4	0.275	2.59	2.60	0.635	1.835	1.67	1.26	1.15	0.84
3.3	0.246	3.06	3.09	0.569	2.292	2.16	1.13	1.45	1.10
2.5	0.209	3.37	3.33	0.483	2.617	2.44	0.960	1.83	1.51
2	0.181	2.38	2.35	0.418	2.661	2.43	0.831	2.11	1.69
1.5	0.137	3.29	3.19	0.318	2.871	2.35	0.632	2.46	1.61
1	0.0917	2.26	2.26	0.214	2.517	2.45	0.423	3.00	2.21
0.8	0.0768	2.65	2.59	0.193	2.605	2.42	0.405	2.75	2.30
0.7	0.0703	3.23	3.13	0.184	3.075	2.80	0.397	2.98	2.35
0.61	0.0652	3.97	3.92	0.177	3.766	3.43	0.390	3.40	2.59
0.5	0.0590	3.64	3.74	0.167	3.953	4.01	0.382	4.18	3.32
0.33	0.0317	1.96	2.00	0.0901	2.158	2.29	0.206	2.59	2.87
0.25	0.0209	1.63	1.65	0.0592	1.688	1.75	0.136	1.88	2.01
0.15	0.0095	1.35	1.36	0.0270	1.372	1.39	0.0617	1.46	1.51
0.1	0.0047	1.29	1.30	0.0134	1.295	1.31	0.0307	1.36	1.38

Table 2.5-226
Amplification Factors as a Function of Input Hard Rock Motion at Ground Surface (GMRS), as Developed from Site Response Analysis Using SRS and EPRI Soil Degradation Models, for High-Frequency Rock Motions

-	10^{-4}			10^{-5}			10^{-6}		
-	Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors	
Freq, Hz		EPRI	SRS		EPRI	SRS		EPRI	SRS
100	0.294	1.22	1.26	0.703	0.849	0.847	1.60	0.540	0.510
76	0.400	0.915	0.945	0.957	0.634	0.632	2.17	0.401	0.379
60	0.499	0.743	0.768	1.19	0.508	0.506	2.71	0.319	0.301
50	0.595	0.640	0.665	1.42	0.428	0.427	3.23	0.268	0.253
40	0.631	0.664	0.694	1.51	0.415	0.414	3.43	0.254	0.240
30	0.655	0.775	0.82	1.57	0.434	0.434	3.63	0.244	0.230
25	0.647	0.96	1.02	1.55	0.495	0.495	3.71	0.245	0.232
20	0.615	1.25	1.33	1.47	0.627	0.629	3.34	0.289	0.274
16.5	0.575	1.42	1.50	1.38	0.777	0.78	3.13	0.344	0.326
13.4	0.521	1.68	1.75	1.25	0.950	0.96	2.83	0.420	0.397
12.2	0.494	1.86	1.93	1.18	1.071	1.08	2.69	0.469	0.444
10	0.438	1.95	2.02	1.05	1.307	1.31	2.38	0.61	0.585
8.1	0.377	2.38	2.46	0.902	1.517	1.53	2.05	0.76	0.72
7	0.339	2.55	2.60	0.811	1.793	1.81	1.84	0.88	0.85
6	0.298	2.40	2.44	0.713	2.013	1.98	1.62	1.09	1.06
5	0.257	2.55	2.57	0.615	2.136	2.10	1.40	1.39	1.33
4	0.212	3.09	3.17	0.507	2.554	2.55	1.15	1.71	1.62
3.3	0.175	3.37	3.45	0.419	3.010	3.03	0.952	2.16	2.07
2.5	0.131	3.49	3.53	0.314	3.336	3.33	0.713	2.72	2.67
2	0.101	2.66	2.66	0.242	2.804	2.75	0.549	2.93	2.79
1.5	0.064	3.32	3.32	0.154	3.208	3.08	0.350	3.20	2.79
1	0.035	2.37	2.40	0.0828	2.528	2.52	0.188	2.83	2.69
0.8	0.024	2.65	2.66	0.0563	2.656	2.62	0.128	2.75	2.59
0.7	0.0187	3.17	3.16	0.0447	3.088	3.02	0.101	3.06	2.88
0.61	0.0148	3.80	3.82	0.0354	3.761	3.71	0.0804	3.74	3.51
0.5	0.0109	3.40	3.46	0.0260	3.538	3.61	0.0590	3.77	3.80
0.33	0.00525	2.20	2.23	0.0126	2.236	2.27	0.0286	2.37	2.40
0.25	0.00314	2.01	2.02	0.00751	2.027	2.04	0.0171	2.09	2.07
0.15	0.00106	2.14	2.17	0.00254	2.130	2.13	0.00577	2.21	2.13
0.1	0.000370	2.41	2.44	0.000890	2.339	2.32	0.00201	2.26	2.15

Table 2.5-227
Amplification Factors as a Function of Input Hard Rock Motion at Ground Surface (GMRS), as Developed from Site Response Analysis Using SRS and EPRI Soil Degradation Models, for Low-Frequency Rock Motions

-	10^{-4}			10^{-5}			10^{-6}		
-	Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors		Hard rock input motion	mean amp. factors	
Freq, Hz		EPRI	SRS		EPRI	SRS		EPRI	SRS
100	0.224	1.33	1.33	0.517	0.957	0.871	1.03	0.662	0.527
76	0.305	1.002	0.997	0.704	0.713	0.648	1.40	0.492	0.392
60	0.380	0.803	0.799	0.878	0.568	0.516	1.74	0.391	0.311
50	0.453	0.680	0.676	1.047	0.478	0.434	2.08	0.328	0.261
40	0.483	0.654	0.648	1.115	0.450	0.409	2.22	0.308	0.245
30	0.506	0.687	0.68	1.168	0.434	0.395	2.32	0.294	0.234
25	0.505	0.77	0.76	1.167	0.442	0.401	2.32	0.296	0.235
20	0.493	0.95	0.94	1.139	0.478	0.429	2.26	0.305	0.242
16.5	0.476	1.12	1.11	1.101	0.541	0.48	2.19	0.320	0.253
13.4	0.453	1.33	1.32	1.046	0.625	0.55	2.08	0.343	0.270
12.2	0.440	1.44	1.42	1.017	0.676	0.60	2.02	0.359	0.281
10	0.413	1.62	1.60	0.954	0.838	0.74	1.90	0.40	0.315
8.1	0.381	1.95	1.94	0.880	1.008	0.91	1.75	0.47	0.36
7	0.359	2.18	2.14	0.830	1.205	1.10	1.65	0.55	0.42
6	0.334	2.17	2.13	0.771	1.434	1.28	1.53	0.65	0.51
5	0.307	2.25	2.23	0.709	1.600	1.39	1.41	0.81	0.62
4	0.275	2.82	2.84	0.635	1.883	1.72	1.26	1.00	0.77
3.3	0.246	3.26	3.30	0.569	2.360	2.23	1.13	1.28	1.05
2.5	0.209	3.50	3.45	0.483	2.658	2.48	0.960	1.72	1.47
2	0.181	2.43	2.39	0.418	2.662	2.43	0.831	2.06	1.66
1.5	0.137	3.30	3.20	0.318	2.845	2.33	0.632	2.43	1.58
1	0.0917	2.26	2.25	0.214	2.481	2.42	0.423	2.92	2.16
0.8	0.0768	2.64	2.58	0.193	2.564	2.39	0.405	2.66	2.24
0.7	0.0703	3.21	3.11	0.184	3.031	2.77	0.397	2.90	2.30
0.61	0.0652	3.96	3.90	0.177	3.716	3.39	0.390	3.30	2.53
0.5	0.0590	3.62	3.73	0.167	3.903	3.96	0.382	4.08	3.26
0.33	0.0317	1.95	1.99	0.0901	2.136	2.27	0.206	2.53	2.83
0.25	0.0209	1.63	1.65	0.0592	1.673	1.73	0.136	1.84	1.98
0.15	0.0095	1.35	1.36	0.0270	1.362	1.38	0.0617	1.43	1.49
0.1	0.0047	1.29	1.29	0.0134	1.287	1.30	0.0307	1.35	1.37

Table 2.5-228
Spectral Accelerations (SA, in g) for Hard Rock Conditions and for Hypothetical Outcrop of Highest Competent In Situ Layer (Top of Blue Bluff Marl)

	Hard Rock spectral accel, g			Soil spectral accel, g		
Freq	10^{-4}	10^{-5}	10^{-6}	10^{-4}	10^{-5}	10^{-6}
100	0.214	0.559	1.480	0.255	0.531	1.025
76	0.293	0.777	2.059	0.268	0.558	1.063
60	0.394	1.057	2.802	0.311	0.629	1.167
50	0.464	1.257	3.334	0.333	0.656	1.180
40	0.517	1.416	3.758	0.423	0.778	1.310
30	0.545	1.511	4.011	0.545	0.984	1.452
25	0.551	1.540	4.090	0.646	1.217	1.636
20	0.522	1.419	3.685	0.723	1.390	1.925
16.5	0.493	1.309	3.330	0.758	1.474	2.139
13.4	0.456	1.176	2.914	0.784	1.523	2.299
12.2	0.438	1.115	2.727	0.800	1.553	2.349
10	0.399	0.983	2.330	0.722	1.522	2.405
8.1	0.375	0.904	2.071	0.831	1.551	2.517
7	0.359	0.852	1.909	0.801	1.658	2.574
6	0.339	0.792	1.728	0.671	1.601	2.650
5	0.317	0.728	1.540	0.612	1.306	2.665
4	0.287	0.659	1.369	0.694	1.190	2.419
3.3	0.259	0.595	1.213	0.735	1.335	2.350
2.5	0.223	0.512	1.020	0.706	1.300	2.184
2	0.193	0.445	0.886	0.440	1.153	2.036
1.5	0.152	0.352	0.698	0.484	0.952	1.705
1	0.101	0.235	0.465	0.226	0.597	1.396
0.8	0.091	0.230	0.489	0.237	0.595	1.388
0.7	0.083	0.220	0.481	0.264	0.664	1.436
0.61	0.076	0.207	0.462	0.299	0.761	1.535
0.5	0.065	0.185	0.423	0.238	0.745	1.741
0.33	0.038	0.107	0.245	0.075	0.242	0.712
0.25	0.026	0.072	0.166	0.042	0.126	0.341
0.15	0.012	0.033	0.075	0.016	0.046	0.116
0.1	0.006	0.016	0.036	0.007	0.021	0.051

Table 2.5-229
Spectral Accelerations (SA, in g) for Hard Rock Conditions and for Hypothetical Outcrop at 40-ft Depth Horizon (FIRS)

	Hard Rock spectral accel, g			Soil spectral accel, g		
Freq	10^{-4}	10^{-5}	10^{-6}	10^{-4}	10^{-5}	10^{-6}
100	0.214	0.559	1.480	0.246	0.489	0.870
76	0.293	0.777	2.059	0.254	0.509	0.900
60	0.394	1.057	2.802	0.287	0.563	0.986
50	0.464	1.257	3.334	0.302	0.575	0.991
40	0.517	1.416	3.758	0.372	0.658	1.074
30	0.545	1.511	4.011	0.473	0.788	1.134
25	0.551	1.540	4.090	0.566	0.961	1.214
20	0.522	1.419	3.685	0.656	1.120	1.396
16.5	0.493	1.309	3.330	0.699	1.230	1.562
13.4	0.456	1.176	2.914	0.744	1.319	1.714
12.2	0.438	1.115	2.727	0.778	1.374	1.777
10	0.399	0.983	2.330	0.713	1.398	1.901
8.1	0.375	0.904	2.071	0.803	1.442	2.068
7	0.359	0.852	1.909	0.775	1.539	2.145
6	0.339	0.792	1.728	0.673	1.512	2.261
5	0.317	0.728	1.540	0.637	1.265	2.346
4	0.287	0.659	1.369	0.745	1.163	2.164
3.3	0.259	0.595	1.213	0.796	1.324	2.093
2.5	0.223	0.512	1.020	0.747	1.289	1.902
2	0.193	0.445	0.886	0.457	1.133	1.690
1.5	0.152	0.352	0.698	0.492	0.918	1.418
1	0.101	0.235	0.465	0.227	0.580	1.208
0.8	0.091	0.230	0.489	0.238	0.579	1.233
0.7	0.083	0.220	0.481	0.265	0.647	1.282
0.61	0.076	0.207	0.462	0.299	0.743	1.381
0.5	0.065	0.185	0.423	0.238	0.731	1.592
0.33	0.038	0.107	0.245	0.075	0.239	0.670
0.25	0.026	0.072	0.166	0.042	0.124	0.322
0.15	0.012	0.033	0.075	0.016	0.045	0.112
0.1	0.006	0.016	0.036	0.007	0.020	0.049

Table 2.5-230
Spectral Accelerations (SA, in g) for Hard Rock Conditions and for Ground Surface Motions (GMRS)

	Hard Rock spectral accel, g			Soil spectral accel, g		
Freq	10^{-4}	10^{-5}	10^{-6}	10^{-4}	10^{-5}	10^{-6}
100	0.214	0.559	1.480	0.266	0.474	0.777
76	0.293	0.777	2.059	0.272	0.492	0.803
60	0.394	1.057	2.802	0.300	0.541	0.877
50	0.464	1.257	3.334	0.306	0.545	0.879
40	0.517	1.416	3.758	0.356	0.595	0.942
30	0.545	1.511	4.011	0.440	0.662	0.959
25	0.551	1.540	4.090	0.547	0.762	0.976
20	0.522	1.419	3.685	0.686	0.905	1.050
16.5	0.493	1.309	3.330	0.739	1.042	1.132
13.4	0.456	1.176	2.914	0.802	1.140	1.205
12.2	0.438	1.115	2.727	0.846	1.213	1.256
10	0.399	0.983	2.330	0.789	1.279	1.379
8.1	0.375	0.904	2.071	0.920	1.390	1.542
7	0.359	0.852	1.909	0.892	1.551	1.662
6	0.339	0.792	1.728	0.767	1.586	1.861
5	0.317	0.728	1.540	0.709	1.335	2.076
4	0.287	0.659	1.369	0.812	1.197	2.060
3.3	0.259	0.595	1.213	0.849	1.365	2.060
2.5	0.223	0.512	1.020	0.775	1.309	1.893
2	0.193	0.445	0.886	0.466	1.134	1.654
1.5	0.152	0.352	0.698	0.494	0.910	1.397
1	0.101	0.235	0.465	0.227	0.572	1.178
0.8	0.091	0.230	0.489	0.237	0.570	1.197
0.7	0.083	0.220	0.481	0.263	0.638	1.250
0.61	0.076	0.207	0.462	0.297	0.734	1.346
0.5	0.065	0.185	0.423	0.237	0.722	1.556
0.33	0.038	0.107	0.245	0.075	0.236	0.657
0.25	0.026	0.072	0.166	0.042	0.123	0.317
0.15	0.012	0.033	0.075	0.016	0.045	0.110
0.1	0.006	0.016	0.036	0.007	0.020	0.049

Table 2.5-231
Amplitudes (g) for the Hypothetical Outcrop of Highest Competent In Situ Layer (Top of Blue Bluff Marl)

	Soil amplitudes				raw	smoothed
Freq	10^{-4}	10^{-5}	AR	DF2	SSE	SSE
100	0.255	0.531	2.08	1.08	0.275	0.275
76	0.268	0.558	2.08	1.08	0.289	0.295
60	0.311	0.629	2.02	1.05	0.328	0.326
50	0.333	0.656	1.97	1.03	0.344	0.366
40	0.423	0.778	1.84	0.978	0.423	0.435
30	0.545	0.984	1.80	0.962	0.545	0.551
25	0.646	1.217	1.88	0.995	0.646	0.646
20	0.723	1.390	1.92	1.01	0.732	0.725
16.5	0.758	1.474	1.95	1.02	0.774	0.764
13.4	0.784	1.523	1.94	1.02	0.800	0.795
12.2	0.800	1.553	1.94	1.02	0.816	0.803
10	0.722	1.522	2.11	1.09	0.787	0.787
8.1	0.831	1.551	1.87	0.989	0.831	0.789
7	0.801	1.658	2.07	1.07	0.860	0.773
6	0.671	1.601	2.39	1.20	0.807	0.758
5	0.612	1.306	2.13	1.10	0.673	0.748
4	0.694	1.190	1.71	0.924	0.694	0.724
3.3	0.735	1.335	1.82	0.967	0.735	0.710
2.5	0.706	1.300	1.84	0.977	0.706	0.706
2	0.440	1.153	2.62	1.30	0.571	0.580
1.5	0.484	0.952	1.96	1.03	0.499	0.480
1	0.226	0.597	2.65	1.31	0.295	0.295
0.8	0.237	0.595	2.51	1.25	0.297	0.297
0.7	0.264	0.664	2.51	1.25	0.332	0.332
0.61	0.299	0.761	2.55	1.27	0.379	0.379
0.5	0.238	0.745	3.13	1.50	0.356	0.356
0.33	0.0750	0.242	3.23	1.53	0.115	0.115
0.25	0.0420	0.126	3.00	1.44	0.0606	0.0606
0.15	0.0158	0.0458	2.90	1.41	0.0222	0.0222
0.1	0.00718	0.0207	2.88	1.40	0.0100	0.0100

Table 2.5-232
FIRS Amplitudes (g) for the Hypothetical Outcrop at 40-ft Depth Horizon

	Soil amplitudes				raw	smoothed
Freq	10^{-4}	10^{-5}	AR	DF2	FIRS	FIRS
100	0.246	0.489	1.99	1.04	0.255	0.255
76	0.254	0.509	2.00	1.05	0.266	0.270
60	0.287	0.563	1.96	1.03	0.295	0.293
50	0.302	0.575	1.90	1.00	0.304	0.325
40	0.372	0.658	1.77	0.946	0.372	0.381
30	0.473	0.788	1.67	0.903	0.473	0.480
25	0.566	0.961	1.70	0.916	0.566	0.566
20	0.656	1.120	1.71	0.92	0.656	0.649
16.5	0.699	1.230	1.76	0.94	0.699	0.697
13.4	0.744	1.319	1.77	0.95	0.744	0.734
12.2	0.778	1.374	1.77	0.95	0.778	0.749
10	0.713	1.398	1.96	1.03	0.733	0.733
8.1	0.803	1.442	1.80	0.958	0.803	0.749
7	0.775	1.539	1.99	1.04	0.805	0.745
6	0.673	1.512	2.25	1.15	0.771	0.745
5	0.637	1.265	1.99	1.04	0.662	0.748
4	0.745	1.163	1.56	0.857	0.745	0.737
3.3	0.796	1.324	1.66	0.902	0.796	0.753
2.5	0.747	1.289	1.72	0.928	0.747	0.747
2	0.457	1.133	2.48	1.24	0.567	0.582
1.5	0.492	0.918	1.87	0.99	0.492	0.478
1	0.227	0.580	2.55	1.27	0.288	0.288
0.8	0.238	0.579	2.44	1.22	0.291	0.291
0.7	0.265	0.647	2.45	1.23	0.325	0.325
0.61	0.299	0.743	2.49	1.24	0.372	0.372
0.5	0.238	0.731	3.07	1.47	0.350	0.350
0.33	0.075	0.239	3.18	1.52	0.114	0.114
0.25	0.042	0.124	2.96	1.43	0.060	0.060
0.15	0.016	0.045	2.88	1.40	0.022	0.022
0.1	0.007	0.020	2.85	1.39	0.010	0.010

Table 2.5-233
SSE Amplitudes (g) for the Ground Surface (GMRS)

-	Soil amplitudes		-	-	raw	smoothed
Freq	10^{-4}	10^{-5}	AR	DF2	SSE	SSE
100	0.266	0.474	1.78	0.95	0.266	0.266
76	0.272	0.492	1.81	0.96	0.272	0.277
60	0.300	0.541	1.80	0.96	0.300	0.297
50	0.306	0.545	1.78	0.95	0.306	0.321
40	0.356	0.595	1.67	0.905	0.356	0.365
30	0.440	0.662	1.50	0.832	0.440	0.452
25	0.547	0.762	1.39	0.783	0.547	0.547
20	0.686	0.905	1.32	0.75	0.686	0.670
16.5	0.739	1.042	1.41	0.79	0.739	0.737
13.4	0.802	1.140	1.42	0.80	0.802	0.789
12.2	0.846	1.213	1.43	0.80	0.846	0.809
10	0.789	1.279	1.62	0.88	0.789	0.789
8.1	0.920	1.390	1.51	0.835	0.920	0.818
7	0.892	1.551	1.74	0.93	0.892	0.815
6	0.767	1.586	2.07	1.07	0.823	0.814
5	0.709	1.335	1.88	1.00	0.709	0.814
4	0.812	1.197	1.47	0.818	0.812	0.787
3.3	0.849	1.365	1.61	0.877	0.849	0.802
2.5	0.775	1.309	1.69	0.912	0.775	0.775
2	0.466	1.134	2.43	1.22	0.569	0.589
1.5	0.494	0.910	1.84	0.98	0.494	0.481
1	0.227	0.572	2.52	1.26	0.285	0.285
0.8	0.237	0.570	2.41	1.21	0.287	0.287
0.7	0.263	0.638	2.42	1.22	0.321	0.321
0.61	0.297	0.734	2.47	1.24	0.367	0.367
0.5	0.237	0.722	3.05	1.46	0.347	0.347
0.33	0.0747	0.236	3.16	1.51	0.113	0.113
0.25	0.0419	0.123	2.95	1.42	0.0597	0.0597
0.15	0.0157	0.0451	2.86	1.39	0.0219	0.0219
0.1	0.00718	0.0204	2.84	1.38	0.00992	0.00992

Table 2.5-234
Coversion Between Body-Wave (m_b) and Moment (M) Magnitudes

Convert	To	Convert	To
m_b	M	M	m_b
4.00	3.77	4.00	4.28
4.10	3.84	4.10	4.41
4.20	3.92	4.20	4.54
4.30	4.00	4.30	4.66
4.40	4.08	4.40	4.78
4.50	4.16	4.50	4.90
4.60	4.24	4.60	5.01
4.70	4.33	4.70	5.12
4.80	4.42	4.80	5.23
4.90	4.50	4.90	5.33
5.00	4.59	5.00	5.43
5.10	4.69	5.10	5.52
5.20	4.78	5.20	5.61
5.30	4.88	5.30	5.70
5.40	4.97	5.40	5.78
5.50	5.08	5.50	5.87
5.60	5.19	5.60	5.95
5.70	5.31	5.70	6.03
5.80	5.42	5.80	6.11
5.90	5.54	5.90	6.18
6.00	5.66	6.00	6.26
6.10	5.79	6.10	6.33
6.20	5.92	6.20	6.40
6.30	6.06	6.30	6.47
6.40	6.20	6.40	6.53
6.50	6.34	6.50	6.60
6.60	6.49	6.60	6.66
6.70	6.65	6.70	6.73
6.80	6.82	6.80	6.79
6.90	6.98	6.90	6.85
7.00	7.16	7.00	6.91
7.10	7.33	7.10	6.97
7.20	7.51	7.20	7.03
7.30	7.69	7.30	7.09
7.40	7.87	7.40	7.15
7.50	8.04	7.50	7.20
		7.60	7.26
		7.70	7.32
		7.80	7.37
		7.90	7.43
		8.00	7.49

Table 2.5-235
Summary of Bedrock Faults Mapped Within the 5-Mile VEGP Site Radius

Fault Name	Proximity to VEGP Site (mi)	Length (mi/km)	Orientation	Sense of Slip	Relationship to Dunbarton Basin	Evidence for Non-Capability
Pen Branch	On site	>20/>30	NE	SE up, reverse	NW border (normal) fault, reactivated as reverse	a, b, c, d
Ellenton	~4	~4/~6.5	NNW	E down, unknown	Unknown; located NW of basin	b, c, e
Steel Creek	~2	>11/>18	NNE	NW up, reverse	Secondary structure forming horst with Pen Branch	b, c, d
Upper Three Runs	~5	>20/>30	NE-NNE	Unknown	Unknown; located NW of basin	b, c, f

Note: Fault locations based on Cumbest et al. (1998), Stieve and Stephenson (1995), and work performed as part of this ESP study

a Seismic reflection and borehole data show lack of post-Eocene slip (NUREG-1137-8; Cumbest et al. 2000)
b Lack of geomorphic expression
c Lack of seismicity associated with fault
d Quaternary fluvial terraces of Savannah River overlying projection of fault appear undeformed (Geomatrix 1993)
e Fault does not appear in most recent SRS fault maps (Cumbest et al. 1998, 2000)
f No disruption to base of Coastal Plain section (pre-Cretaceous age) (Stieve and Stephenson 1995)

Table 2.5-236
Static Engineering Properties of Subsurface Materials (ESP)

Parameter[1]	Stratum			
	Upper Sand	Compacted Structural Fill	Blue Bluff Marl	Lower Sand
Range of Thickness, feet	79 to 124	79 to 124	63 to 95	900
Average thickness, feet	92	92	76	900
USCS symbol	SP/SM/SC/ML	SP/SM/SC	CL/ML	SP/SM/ML
Natural moisture content (ω), %	N/A	N/A	35	N/A
Unit weight (pcf)	115	123 (moist) 133 (saturated)	115	115
Atterberg Limits				
Liquid limit (LL), %	N/A[2]	N/A	51	N/A
Plastic limit (PL), %	N/A	N/A	26	N/A
Plasticity index (PI), %	N/A	N/A	25	N/A
Measured SPT N-value, bpf	20	N/A	80	50
Adjusted SPT N60-value, bpf	25	N/A	100	62
Strength properties				
Undrained shear strength (c_u), ksf	—	0	10	0
Internal friction angle (Ø'), degrees	34	34	0	34
Elastic modulus (high strain) (E_s), ksf	900	1,500	10,000	10,800[3] 13,500[4]
Shear modulus (high strain) (G_s), ksf	350	600	3,500	4,200[3] 5,200[4]
Shear modulus (low strain) (G_{max}), ksf	3,088	3,820	20,475	20,538
Coefficient of Subgrade Reaction (k_1), tcf	N/A	300	N/A	N/A
Earth Pressure Coefficients				
Active (K_a)	N/A	0.3	N/A	N/A
Passive (K_p)	N/A	3.5	N/A	N/A
At Rest (K_0)	N/A	0.5	N/A	N/A
Coefficient of Sliding	N/A	0.45	N/A	N/A
Poisson's Ratio	0.09–0.49[5]		0.33–0.48	0.32–0.49

Notes.
(1) The values tabulated above are for use as a design guideline only. Reference should be made to specific boring and CPT logs and laboratory test results for appropriate modifications at specific design locations.
(2) N/A indicates that the properties were not measured or are not applicable.
(3) This value applies between depths of 0 to 100 ft below the bottom of the Blue Bluff Marl.
(4) This value applies between depths of 100 to 300 ft below the bottom of the Blue Bluff Marl.
(5) Values not determined during COL investigation, retain ESP values.

Table 2.5-237
Static Engineering Properties of Subsurface Materials (COL)

Parameter[1]	Stratum			
	Upper Sand	Compacted Structural Fill	Blue Bluff Marl	Lower Sand(5)
Range of Thickness, feet	82 to 94	82 to 94	60 to 77	900
Average thickness, feet	88	88	68	900
USCS symbol	SP/SM/SC/ML	SP/SM	CL/CH/ML/MH	SP/SM/ML/CL
Natural moisture content (ω), %	N/A	N/A	32	N/A
Unit weight (pcf)	113	123 (moist) 133 (saturated)	115	120
Atterberg Limits				
Liquid limit (LL), %	N/A[2]	N/A	63	N/A
Plastic limit (PL), %	N/A	N/A	33	N/A
Plasticity index (PI), %	N/A	N/A	30	N/A
Measured SPT N-value, bpf	18	32	71	50
Adjusted SPT N_{60}-value, bpf	25	43	95	62
Strength properties				
Undrained shear strength (c_u), ksf	—	-	10	—
Internal friction angle (Ø'), degrees	34	36	0	34
Elastic modulus (high strain) (E_s), ksf	900	1,500	9,000	10,800[3] 13,500[4]
Shear modulus (high strain) (G_s), ksf	350	520	3,000	4,200[3] 5,200[4]
Shear modulus (low strain) (G_{max}), ksf	3,100	3,800	15,000	20,538
Coefficient of Subgrade Reaction (k_1), tcf	N/A	1,000	N/A	N/A
Earth Pressure Coefficients				
Active (K_a)	N/A	0.26	N/A	N/A
Passive (K_p)	N/A	3.9	N/A	N/A
At Rest (K_0)	N/A	0.4	N/A	N/A
Coefficient of Sliding	N/A	0.45	N/A	N/A
Poisson's Ratio	0.09–0.49[5]	0.24–0.45	0.43	0.32–0.49

Notes.
(1) The values tabulated above are for use as a design guideline only. Reference should be made to specific boring and CPT logs and laboratory test results for appropriate modifications at specific design locations.
(2) N/A indicates that the properties were not measured or are not applicable.
(3) This value applies between depths of 0 to 100 ft below the bottom of the Blue Bluff Marl.
(4) This value applies between depths of 100 to 300 ft below the bottom of the Blue Bluff Marl.
(5) Values not fully evaluated during COL investigation, ESP values retained.

Table 2.5-238
Design Dynamic Shear Modulus (ESP)

Geologic Formation	Depth (ft)	Elevation (ft)	G_{max} (ksf)
Upper Sand Stratum	0 to 16	223 to 207	7,000
(Barnwell Group)	16 to 41	207 to 182	2,286
	41 to 58	182 to 165	2,580
	58 to 86	165 to 137	2,893
Blue Bluff Marl	86 to 92	137 to 131	6,978
(Lisbon Formation)	92 to 97	131 to 126	10,321
	97 to 102	126 to 121	15,750
	102 to 105	121 to 118	10,321
	105 to 111	118 to 112	17,286
	111 to 123	112 to 100	19,723
	123 to 149	100 to 74	25,080
Lower Sand Stratum	149 to 156	74 to 67	14,286
(Still Branch)	156 to 216	67 to 7	9,723
(Congaree)	216 to 331	7 to -108	13,580
(Snapp)	331 to 438	–108 to -215	15,009
(Black Mingo)	438 to 477	–215 to -254	19,723
(Steel Creek)	477 to 587	–254 to -364	25,080
(Gaillard/Black Creek)	587 to 798	–364 to -575	29,009
(Pio Nono)	798 to 858	–575 to -635	29,418
(Cape Fear)	858 to 1,049	–635 to -826	26,229
Dunbarton Triassic Basin	1,049		

Note: Gmax was calculated using g from Table 2.5-236, and the shear wave velocity values from Table 2.5-243.

Table 2.5-239
Types and Numbers of Laboratory Tests Completed for the ESP Application

Type of Test	Number of Tests Performed
Grain size	61
Unit Weight	31
Natural Moisture Content	75
Atterberg Limits	27
UU Triaxial (1-point)	15

Table 2.5-240
Types and Numbers of Completed Laboratory Tests in the Powerblock Footprint for the COL Investigation

Type of Test	Number of Tests Performed
Moisture Content	113
Wash #200	272
Unit Weight	100
Atterberg Limits	109
Chemical Analysis	5
Unconfined Compression	27
Unconsolidated Undrained Triaxial	11
Consolidated Undrained Triaxial	27
1-D Consolidation	18
Resonant Column Torsional Shear	19

Table 2.5-241 (Sheet 1 of 4)
Summary of Laboratory Tests Performed on Selected Soils Samples from ESP Borings

SAMPLE DETAILS						SOIL TESTING							
Boring No.	Top Depth (ft)	Length (ft)	Type	Formation	SPT N-value (bpf)	% Fines	γ (pcf)	ω_N (%)	PL (%)	LL (%)	PI (%)	USCS Classification	UU s_u (ksf)
B-1002	7.5	1.5	SS	Fill	20	9.4		6.2					
	18.5	1.5	SS	Barnwell	19	37.1		24.4					
	28.5	1.5	SS	Barnwell	8	24.9		31.8					
	33.5	1.5	SS	Barnwell	6	31.6		58.8					
	38.5	1.5	SS	Barnwell	7			92.8	27	48	21		
	53.5	1.5	SS	Barnwell	8	10.5		42.9					
	63.5	1.5	SS	Barnwell	13	7.2		29.3					
	73.5	1.5	SS	Barnwell	12	10		24.5					
	83.5	1.5	SS	Barnwell	9	6.1		27.6					
	92.0	2.5	UD-Upper	Lisbon	N/A	67.2	103.6	52.1	50	83	33	MH	1.15
			UD-Middle				102.4						3.35
	103.5	2.5	UD	Lisbon	N/A	35.9	114.3	56.6	22	34	12	CL	
							114.5	26.5					2.4
	113.5	2.5	UD	Lisbon	N/A	33.8	132.8	25.5	19	29	10	SC	
							132.9	16.3					2.15
	123.5	2.5	UD	Lisbon	N/A	24.5	140.2	13.5	17	22	5	GC-GM	
	133.5	2.0	UD	Lisbon	N/A	96.6	118.0	28.6	26	40	14	CL	
							118.1	29.8					2.4
	153.5	1.5	SS	Lisbon	27	39.4		23.3	21	34	13	ML	
	188.5	1.5	SS	Still Branch	9	6.6		40.7	NP	NP	NP	SM	
	238.5	1.5	SS	Congaree	77	12.3		18.5					
B-1003	15	5	C	Barnwell	N/A	20.9		13.4					
	35	5	C	Barnwell	N/A	29.8		42.1					
	55	5	C	Barnwell	N/A	13.4		17.5					
	75	5	C	Barnwell	N/A	8.2		32.3					

Table 2.5-241 (Sheet 2 of 4)
Summary of Laboratory Tests Performed on Selected Soils Samples from ESP Borings

SAMPLE DETAILS						SOIL TESTING							
Boring No.	Top Depth (ft)	Length (ft)	Type	Formation	SPT N-value (bpf)	% Fines	γ (pcf)	ω_N (%)	PL (%)	LL (%)	PI (%)	USCS Classification	UU s_u (ksf)
B-1003	88	5	C	Lisbon	N/A	33.4		67.4	42	93	51	SM	
	93	2.5	UD-1	Lisbon	N/A	40.6	115.7	30.6	32	54	22	SM	
							115.8	29.5					4.3
	104.7	2	C	Lisbon	N/A	31.7	111.5	40.6	51	83	32	SM	
	121.7	5	C	Lisbon	N/A	42.5	122.5	28.0	NP	NP	NP	SM	
	141.7	5	C	Lisbon	N/A	34.2	126.1	25.9	28	46	18	SM	
B-1003	165.7	5	C	Still Branch	N/A	5.4	121.7	23.6	NP	NP	NP	SP-SM	
	185.7	5	C	Still Branch	N/A	16.4		32.3					
	205.7	5	C	Still Branch	N/A	21.4		39.3					
	240.7	5	C	Congaree	N/A	10.9		23.2					
	280.7	5.0	C	Congaree	N/A	14.2		23.2					
	315.7	5.0	C	Congaree	N/A	79.8		32.7	24	43	19	CL	
							119.4	31.0					
	350.7	5.0	C	Snapp	N/A	78.5	128.3	21.3	22	41	19	ML	
	400.7	5.0	C	Snapp	N/A	15.8		18.9					
	450.7	5.0	C	Black Mingo	N/A	15.9		28.6					
	496.7	5.0	C	Steel Creek	N/A	13.2		26.4					
B-1004	9.0	1.5	SS	Barnwell	13	24.4		13.8					
	12.0	1.5	SS	Barnwell	12	23.1		14.5					
	23.5	1.5	SS	Barnwell	8	14.9		18.5					
	43.5	1.5	SS	Barnwell	4	60.0		46.2	24	58	34	ML	
	53.5	1.5	SS	Barnwell	7	41.0		62.9					
	68.5	1.5	SS	Barnwell	6	19.9		24.1					
	83.5	1.5	SS	Barnwell	6	11.5		28.8					
	123.5	1.5	SS	Barnwell	5	19.2		19.7	19	43	24	GM	

Table 2.5-241 (Sheet 3 of 4)
Summary of Laboratory Tests Performed on Selected Soils Samples from ESP Borings

SAMPLE DETAILS						SOIL TESTING							
Boring No.	Top Depth (ft)	Length (ft)	Type	Formation	SPT N-value (bpf)	% Fines	γ (pcf)	ω_N (%)	PL (%)	LL (%)	PI (%)	USCS Classification	UU s_u (ksf)
B-1004	144.0	1.5	UD-Upper	Lisbon	N/A	46.3	105.1	44.6	38	59	21	SM	
							105.2	52.0					0.15
			UD-Middle				114.2	29.8					0.8
	153.5	1.5	UD	Lisbon	N/A	41.7		30.1	27	43	16	SM	
							117.4	25.2					
							119.3	28.7					3.75
	163.5	2.5	UD-Upper	Lisbon	N/A	58.3		25.1	37	55	18	MH	
							117.4	30.2					1.05
			UD-Middle				125.6	24.5					1.2
	177.0	2.5	UD-Upper	Lisbon	N/A	41.7	124.7	20.8	22	31	9	SM	
							124.6	22.4					0.8
			UD-Middle				131.8	39.2					1.9
B-1004	188.5	2.0	UD	Lisbon	N/A	75.2	120.4	29.0	24	41	17	CL	
							120.6	28.4					4.0
	198.5	2.0	UD	Lisbon	N/A	34.5	128.1	26.2	21	31	10	SM	
							128.2	21.7					3.0
B-1006	7.5	1.5	SS	Barnwell	3	7.3		3.8					
	33.5	1.5	SS	Barnwell	13	26.1		19.7					
	58.5	1.5	SS	Barnwell	W HAMM	58.3		92.8	30	97	67	CH	
	68.5	1.5	SS	Barnwell	W HAMM	3.1		25.4					
	88.5	1.5	SS	Barnwell	W HAMM	15.7		51.9					
	108.5	1.5	SS	Barnwell	42	21.5		22.0					
	123.5	1.5	SS	Lisbon	50/2"	64.1		53.7	43	99	56	MH	

Table 2.5-241 (Sheet 4 of 4)
Summary of Laboratory Tests Performed on Selected Soils Samples from ESP Borings

SAMPLE DETAILS						SOIL TESTING							
Boring No.	Top Depth (ft)	Length (ft)	Type	Formation	SPT N-value (bpf)	% Fines	γ (pcf)	ω_N (%)	PL (%)	LL (%)	PI (%)	USCS Classification	UU s_u (ksf)
B-1010	7.5	1.5	SS	Barnwell	27	7.8		5.7					
	33.5	1.5	SS	Barnwell	23	17.0		18.9					
	58.5	1.5	SS	Barnwell	19	13.3		27.3					
	73.5	1.5	SS	Barnwell	6	23.9		30.8					
	98.5	1.5	SS	Lisbon	77	91.3		49.9	47	94	58	CH	

Legend:
NP = non-plastic
ωN = natural moisture content
γ = unit weight
% Finer = % finer than the #200 sieve
PL = plastic limit
LL = liquid limit
PI = plasticity index
UU s_u = undrained strength from UU triaxial test
SS = split spoon or split barrel sample
UD = undisturbed sample
UD-Upper = test specimen taken from top of UD sample
UD-Middle = test specimen taken from middle of UD sample
C = soil core
W HAMM = weight of hammer (sampler penetrated at least 18" under the weight of the hammer, no blows applied by the hammer)

Table 2.5-242
Summary of SPT N-Values Measured at the ESP Borings

Boring Number	Measured SPT N-value (blows/ft) for Different Formations		
	Upper Sand Stratum (Barnwell Group)	Blue Bluff Marl (Lisbon Formation)	Lower Sand Stratum
B-1001	47, 32, 22, 22, 22, 23, 21, 23, 23, 37, 13, 10, 7, 5, 6, 12, 13, 30, 11, 37, 36, 47, WOR, 50/5"	50/5", 50/4", 51, 50/4", 50/6", 50/4", 50/5"	Not measured
B-1002	30, 67, 28, 33, 19, 10, 8, 6, 7, 12, 22, 8, 11, 13, 18, 12, 10, 9	77/11", 68/7", 54, 72, 50/2", 78/8", 65, 40, 27	46, 26, 50/4", 40, 9, 43, 32, 41, 50, 77
B-1004	21, 24, 25, 16, 16, 13, 19, 12, 14, 10, 8, 17, 13, 14, 4, 5, 7, 7, 18, 6, 5, 9, 5, 5, 17, 11, 16, 20,18, 34, 5, 9, 50/5"	77, 50/4", 50/0", 50/3", 50/3", 77, 79, 50/5", 50/4", 70/10", 81, 78, 58	79/10", 35, 50/5", 95, 47, 104
B-1005	27, 29, 26, 15, 11, 11, 10, 17, 13, 19, 17, 19, 11, 7, WOH, 37, 17, 34, 28, 25, 50/1", 56, 37,69, 46, 54, 57, 33, 31, 37, 95, 30, 32, 50/4", 80/9", 39	50/5", 50/4"	Not measured
B-1006	19, 20, 15, 9, 2, 3, 4, 8, 10, 11, 30, 24, 17, 13, 10, 2, 8, 7, WOH, 9, WOH, WOH, 13, 7, WOH,14, 19, 28, 42, 50	50/5", 50/2"	Not measured
B-1007	30, 32, 10, 10, 8, 14, 23, 20, 27, 26, 31, 25, 23, 15, 15, 24, 21, 26, 36, 37, 27, 36, 18, 13	50/2", 50/3", 45, 50/2", 50/5", 50/4", 74	Not measured
B-1008	19, 30, 53, 67, 34, 31, 19, 24, 30, 36, 30, 20, 17, 17, 25, 18, 22, 33, 39, 22, 25, 50/5", 50/4", 50/5"	46, 65, 53, 71/9", 50/3", 50/3", 50/4"	Not measured
B-1009	19, 37, 42, 44, 20, 21, 27, 21, 20, 30, 29, 35, 19, 31, 37, 42, 23, 13, 27, 32, 20, 8, 10, 40, 24	51, 50/5"	Not measured
B-1010	13, 18, 29, 24, 20, 27, 9, 13, 18, 29, 72, 23, 27, 23, 30, 26, 15, 34, 19, 6, 28, 6, 20, 10, 15, 21	67, 50/4"	Not measured
B-1011	8, 7, 11, 10, 14, 15, 15, 20, 13, 44, 42, 12, 25, 48, 28, 41, 37, 49, 60, 40, 50/0", 50/4"	69, 74, 50/3", 50/1", 36	Not measured
B-1013	9, 14, 26, 26, 12, 26, 26, 33, 9, 22, 16, 41, 16, 34, 22, 25, 21, 28, 12, 26, 15, 8, 18, 36, 13, 26	50/2", 76	Not measured
Range:	WOR-50/0"	27-50/1"	9-50/4"
Average:	25	83	59
Median	21	100	47

NOTES:

[a] SPT blow counts will be adjusted to reflect the measured hammer efficiencies.

[b] WOR means that the sampler penetrated 18" or more under weight of the rods, and WOH means that the sampler penetrated 18" or more under weight of the rods and hammer. These values were taken as zero when calculating the average.

[c] SPT blow counts linearly extrapolated to more than 100 bpf were truncated at 100 bpf when calculating the average.

[d] SPT N-values shown for the Barnwell Group exclude measurements in the fill layers encountered at borings B-1001, B-1002, B-1004, and B-1005.

Table 2.5-243
Typical Shear Wave Velocity Values for Existing Strata (ESP)

Geologic Formation	Depth (ft)	Elevation (ft)	V_s (fps)
Upper Sand Stratum	0 to 16	223 to 207	1,400
(Barnwell Group)	16 to 41	207 to 182	800
	41 to 58	182 to 165	850
	58 to 86	165 to 137	900
Blue Bluff Marl	86 to 92	137 to 131	1,400
(Lisbon Formation)	92 to 97	131 to 126	1,700
	97 to 102	126 to 121	2,100
	102 to 105	121 to 118	1,700
	105 to 111	118 to 112	2,200
	111 to 123	112 to 100	2,350
	123 to 149	100 to 74	2,650
Lower Sand Stratum	149 to 156	74 to 67	2,000
(Still Branch)	156 to 216	67 to 7	1,650
(Congaree)	216 to 331	7 to -108	1,950
(Snapp)	331 to 438	-108 to -215	2,050
(Black Mingo)	438 to 477	-215 to -254	2,350
(Steel Creek)	477 to 587	-254 to -364	2,650
(Gaillard/Black Creek)	587 to 798	-364 to -575	2,850
(Pio Nono)	798 to 858	-575 to -635	2,870
(Cape Fear)	858 to 1,049	-635 to -826	2,710
Dunbarton Triassic Basin	1,049	-826	2,710
	1,093	-870	5,300
	1,323	-1,100	7,800

Table 2.5-244
Summary of ESP Borings and CPTs

Boring Number	Plant Coordinates		State Coordinates		Elevation (ft msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
B-1001	7,662	6,220	1,142,662	620,220	221.64	123.9
B-1002[a,b]	7,999	6,985	1,142,999	620,985	221.98	260
B-1002A[a,d]	7,986	6,986	1,142,986	620,986	222.27	105
B-1003[a,b,c]	7,974	7,890	1,142,974	621,890	223.21	1338
B-1004[a,b]	7,985	6,131	1,142,985	620,131	249.78	304
B-1005	8,992	6,155	1,143,992	620,155	253.14	164.3
B-1006	8,810	7,343	1,143,810	621,343	255.95	124.2
B-1007	7,662	7,120	1,142,662	621,120	221.02	125
B-1008	7,671	7,996	1,142,671	621,996	219.51	124.3
B-1009	6,001	6,361	1,141,001	620,361	220.39	98.9
B-1010	6,000	7,280	1,141,000	621,280	218.60	104.3
B-1011	8,741	8,378	1,143,741	622,378	219.38	100
B-1013	5,976	8,272	1,140,976	622,272	218.62	105
C-1005A[a,d]	7,990	8,179	1,142,990	622,179	223.66	90
CPT Number	Plant Coordinates		State Coordinates		Elevation (ft msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
C-1001A	8,028	6,356	1,143,028	620,356	248.57	116.7
C-1002	7,668	6,575	1,142,668	620,575	222.13	78.5
C-1003[e,f]	7,669	7,478	1,142,669	621,478	219.80	80
C-1004[f]	7,646	8,362	1,142,646	622,362	220.82	77
C-1005[e,f]	7,995	8,175	1,142,995	622,175	223.81	82
C-1006	8,001	7,262	1,143,001	621,262	222.80	74
C-1007	8,271	8,055	1,143,271	622,055	222.81	81.7
C-1008	8,268	6,931	1,143,268	620,931	221.30	76
C-1009A[e,f]	5,980	6,798	1,140,980	620,798	218.93	99
C-1010	6,008	7,754	1,141,008	621,754	219.06	96

a Location of suspension P-S velocity logging.
b Location of caliper, natural gamma, resistivity, and spontaneous potential measurements.
c Location of borehole deviation survey.
d Boreholes drilled without sampling to allow the performance of suspension P-S velocity logging above the zone of drilling fluid loss.
e Location of seismic CPT.
f Location of pore pressure dissipation tests.

Note: State Plane Coordinates are from NAD27 Georgia East state grid system. Plant coordinates are converted from the following formula:
Plant North + 1,135,000 = State North
Plant East + 614,000 = State East

Table 2.5-245 (Sheet 1 of 6)
Summary of COL Borings, CPTs, and Test Pits

Boring Number	Plant Coordinates		State Coordinates		Elevation (ft, msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
B-1105	9,168	6,003	1,144,168	620,003	257.89	148.8
B-1107	9,154	6,916	1,144,154	620,916	266.66	150.0
B-1108	9,214	7,273	1,144,214	621,273	273.56	149.8
B-1109	9,180	7,581	1,144,180	621,581	276.48	150.0
B-1110	9,171	8,011	1,144,171	622,011	265.14	150.0
B-1111	9,213	8,334	1,144,213	622,334	224.90	150.0
B-1112	9,223	8,691	1,144,223	622,691	213.74	23.0
B-1112A	9,219	8,561	1,144,219	622,561	227.14	150.0
B-1113	8,901	6,217	1,143,901	620,217	249.99	170.0
B-1116	8,894	7,265	1,143,894	621,265	261.82	138.5
B-1117	8,891	7,628	1,143,891	621,628	263.89	149.3
B-1118	8,886	8,008	1,143,886	622,008	257.91	149.4
B-1119	8,888	8,334	1,143,888	622,334	223.57	150.0
B-1120	8,893	8,558	1,143,893	622,558	227.18	149.8
B-1121	8,576	6,216	1,143,576	620,216	241.33	150.0
B-1123	8,575	6,922	1,143,575	620,922	241.27	150.0
B-1124	8,628	7,422	1,143,628	621,422	241.21	150.0
B-1125	8,587	7,628	1,143,587	621,628	240.97	150.0
B-1126	8,568	7,980	1,143,568	621,980	219.88	150.0
B-1127	8,573	8,332	1,143,573	622,332	219.67	150.0
B-1128	8,573	8,682	1,143,573	622,682	218.26	73.0
B-1128A	8,574	8,685	1,143,574	622,685	217.92	148.8
B-1129	8,278	7,894	1,143,278	621,894	221.84	100.0
B-1130	7,483	8,250	1,142,483	622,250	217.46	99.2
B-1131	8,173	7,823	1,143,173	621,823	222.18	98.6
B-1132	7,614	7,450	1,142,614	621,450	218.73	100.0
B-1133	7,969	7,451	1,142,969	621,451	221.20	100.0
B-1134	8,283	7,104	1,143,283	621,104	222.04	100.0
B-1136	8,178	7,023	1,143,178	621,023	221.65	100.0
B-1138	8,470	5,193	1,143,470	619,193	215.82	100.0
B-1139	7,290	7,027	1,142,290	621,027	216.68	150.0
B-1140	7,290	7,824	1,142,290	621,824	216.58	150.0
B-1142	9,417	6,650	1,144,417	620,650	224.69	100.0
B-1146	10,428	8,272	1,145,428	622,272	240.04	98.6
B-1148	10,538	9,237	1,145,538	623,237	218.94	100.0
B-1150	10,467	10,235	1,145,467	624,235	170.69	100.0
B-1152	10,582	11,227	1,145,582	625,227	117.05	100.0
B-1153	10,569	11,673	1,145,569	625,673	103.58	100.0
B-1154	10,664	12,216	1,145,664	626,216	95.08	98.8

Table 2.5-245 (Sheet 2 of 6)
Summary of COL Borings, CPTs, and Test Pits

Boring Number	Plant Coordinates		State Coordinates		Elevation (ft, msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
B-1155	12,390	10,936	1,147,390	624,936	84.95	150.0
B-1156	12,302	10,572	1,147,302	624,572	85.70	99.2
B-1157	12,210	11,062	1,147,210	625,062	86.77	150.0
B-1158	10,195	12,669	1,145,195	626,669	88.74	149.5
B-1159	12,286	10,955	1,147,286	624,955	88.70	150.0
B-1161	12,363	10,862	1,147,363	624,862	86.10	150.0
B-1162	12,235	10,815	1,147,235	624,815	85.55	200.0
B-1163	12,171	10,939	1,147,171	624,939	85.95	150.0
B-1164	11,995	10,519	1,146,995	624,519	220.50	150.0
B-1166	12,453	9,962	1,147,453	623,962	203.40	100.0
B-1168	12,688	9,468	1,147,688	623,468	202.20	100.0
B-1170	12,424	8,954	1,147,424	622,954	223.29	98.9
B-1172	11,983	8,539	1,146,983	622,539	249.49	100.0
B-1174	11,476	8,228	1,146,476	622,228	225.81	100.0
B-1176	10,876	8,195	1,145,876	622,195	221.48	35.0
B-1176A	10,879	8,197	1,145,879	622,197	221.51	100.0
B-1185	9,717	8,232	1,144,717	622,232	226.78	148.9
B-1186	9,712	4,819	1,144,712	618,819	277.51	178.8
B-1187	9,710	5,260	1,144,710	619,260	277.68	150.0
B-1189	9,460	4,997	1,144,460	618,997	279.98	150.0
B-1191	9,302	5,491	1,144,302	619,491	260.30	150.0
B-1192	9,217	4,841	1,144,217	618,841	243.17	179.5
B-1193	9,091	5,278	1,144,091	619,278	254.11	178.8
B-1194	12,505	7,630	1,147,505	621,630	199.35	50.0
B-1195	12,575	8,478	1,147,575	622,478	220.60	50.0
B-1196	12,287	8,018	1,147,287	622,018	217.52	50.0
B-1197	11,875	8,004	1,146,875	622,004	245.60	50.0
B-3001(DH)	7,600	7,800	1,142,600	621,800	218.40	420.0
B-3002(DH)	7,600	7,872	1,142,600	621,872	218.89	249.9
B-3002A	7,598	7,879	1,142,598	621,879	218.83	21.5
B-3003(DH)	7,600	7,727	1,142,600	621,727	218.29	250.0
B-3004	7,447	7,867	1,142,447	621,867	218.51	160.0
B-3005	7,718	7,749	1,142,718	621,749	219.20	155.0
B-3006	7,426	7,925	1,142,426	621,925	217.59	155.0
B-3007	7,719	7,877	1,142,719	621,877	220.78	159.8
B-3008	7,425	7,773	1,142,425	621,773	217.86	155.0
B-3009	7,484	7,957	1,142,484	621,957	217.85	153.9
B-3010	7,635	8,025	1,142,635	622,025	219.69	160.0
B-3011	7,777	8,025	1,142,777	622,025	220.57	165.0
B-3012	7,773	7,912	1,142,773	621,912	220.40	159.3
B-3013(C)	7,843	7,825	1,142,843	621,825	220.51	155.0

Table 2.5-245 (Sheet 3 of 6)
Summary of COL Borings, CPTs, and Test Pits

Boring Number	Plant Coordinates		State Coordinates		Elevation (ft, msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
B-3014	7,799	7,749	1,142,799	621,749	220.26	158.7
B-3015	7,957	7,824	1,142,957	621,824	221.78	150.0
B-3016	7,978	7,913	1,142,978	621,913	222.48	150.0
B-3017	8,034	7,750	1,143,034	621,750	222.10	150.0
B-3018	7,738	8,116	1,142,738	622,116	219.80	155.0
B-3019	7,977	8,167	1,142,977	622,167	222.42	153.8
B-3020	7,978	8,075	1,142,978	622,075	222.44	149.4
B-3021	8,070	8,033	1,143,070	622,033	223.19	154.5
B-3022	8,070	7,873	1,143,070	621,873	223.86	150.0
B-3023	8,061	7,680	1,143,061	621,680	222.81	150.5
B-3024	7,906	7,400	1,142,906	621,400	220.16	150.0
B-3025	7,460	7,425	1,142,460	621,425	218.21	150.0
B-3026	7,290	7,404	1,142,290	621,404	215.76	149.2
B-3027	7,059	7,423	1,142,059	621,423	218.80	150.0
B-3028	6,867	7,409	1,141,867	621,409	220.12	150.0
B-3029	6,882	7,804	1,141,882	621,804	220.13	149.9
B-3030	6,700	7,800	1,141,700	621,800	221.99	150.0
B-3031	6,399	8,042	1,141,399	622,042	222.70	150.0
B-3032	6,158	7,710	1,141,158	621,710	220.05	149.5
B-3033	6,405	7,715	1,141,405	621,715	222.26	149.3
B-3034	6,400	7,915	1,141,400	621,915	224.67	149.2
B-3035	7,729	7,675	1,142,729	621,675	219.34	150.5
B-3036	7,442	7,676	1,142,442	621,676	217.87	155.0
B-3037	8,057	7,769	1,143,057	621,769	222.94	150.0
B-3038	6,883	7,543	1,141,883	621,543	220.76	98.9
B-3039	7,918	7,754	1,142,918	621,754	219.17	150.0
B-4001(DH)	7,600	7,000	1,142,600	621,000	218.88	399.9
B-4002(DH)	7,600	7,072	1,142,600	621,072	219.06	250.0
B-4003(DH)	7,600	6,927	1,142,600	620,927	218.99	249.8
B-4004	7,460	7,047	1,142,460	621,047	218.45	150.0
B-4005	7,715	6,949	1,142,715	620,949	221.13	164.9
B-4006	7,720	7,076	1,142,720	621,076	220.98	165.0
B-4007	7,426	7,125	1,142,426	621,125	217.90	170.0
B-4008	7,424	6,974	1,142,424	620,974	218.08	169.4
B-4009	7,486	7,157	1,142,486	621,157	217.91	164.9
B-4010	7,668	7,249	1,142,668	621,249	219.09	160.0
B-4011	7,773	7,236	1,142,773	621,236	219.08	150.0
B-4013(C)	7,843	7,020	1,142,843	621,020	222.24	165.0
B-4014	7,832	6,950	1,142,832	620,950	220.74	158.6
B-4015	7,773	7,115	1,142,773	621,115	220.11	155.0
B-4016	7,996	7,113	1,142,996	621,113	221.23	149.6

Table 2.5-245 (Sheet 4 of 6)
Summary of COL Borings, CPTs, and Test Pits

Boring Number	Plant Coordinates		State Coordinates		Elevation (ft, msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
B-4017	8,035	6,950	1,143,035	620,950	220.94	150.0
B-4018	7,735	7,316	1,142,735	621,316	220.30	160.0
B-4019	7,976	7,371	1,142,976	621,371	221.76	160.0
B-4020	7,969	7,280	1,142,969	621,280	222.79	89.4
B-4020A	7,974	7,280	1,142,974	621,280	222.56	165.0
B-4021	8,093	7,247	1,143,093	621,247	224.55	150.0
B-4022	8,081	7,074	1,143,081	621,074	220.71	148.7
B-4023	8,062	6,880	1,143,062	620,880	220.71	150.0
B-4024	7,905	6,602	1,142,905	620,602	223.80	150.0
B-4025	7,510	6,625	1,142,510	620,625	220.80	150.0
B-4026	7,330	6,598	1,142,330	620,598	221.54	150.0
B-4027	7,180	6,633	1,142,180	620,633	217.73	150.0
B-4028	6,984	6,588	1,141,984	620,588	219.57	150.0
B-4029	6,875	6,700	1,141,875	620,700	220.28	150.0
B-4030	6,677	6,698	1,141,677	620,698	222.35	150.3
B-4031	6,400	6,975	1,141,400	620,975	222.13	150.0
B-4032	6,118	6,795	1,141,118	620,795	220.24	38.5
B-4032A	6,124	6,795	1,141,124	620,795	220.22	150.0
B-4033	6,398	6,349	1,141,398	620,349	219.93	149.4
B-4034	6,376	6,795	1,141,376	620,795	222.79	150.0
B-4035	7,729	6,876	1,142,729	620,876	220.52	164.8
B-4036	7,457	6,876	1,142,457	620,876	218.05	170.0
B-5001	11,177	7,808	1,146,177	621,808	218.99	150.0
B-5002	11,340	7,808	1,146,340	621,808	241.53	150.0
B-5003	11,387	7,575	1,146,387	621,575	227.94	148.7
B-5004	11,548	7,568	1,146,548	621,568	236.61	149.8
B-6002	9,134	5,627	1,144,134	619,627	247.90	150.0
B-6003	8,925	5,423	1,143,925	619,423	229.76	179.4
B-6004	8,718	5,473	1,143,718	619,473	231.59	150.0
B-6005	8,718	5,874	1,143,718	619,874	242.59	178.8
B-6006	8,070	6,302	1,143,070	620,302	248.22	50.0
B-6007	7,731	6,302	1,142,731	620,302	222.28	50.0
B-6008	10,444	8,676	1,145,444	622,676	240.11	150.0
B-6009	9,774	7,748	1,144,774	621,748	246.04	100.0
B-6010	8,893	7,059	1,143,893	621,059	263.39	169.3
B-6011	9,558	7,262	1,144,558	621,262	244.00	120.0
B-6012	9,257	6,481	1,144,257	620,481	194.20	120.0
B-6013	8,170	3,235	1,143,170	617,235	251.14	50.0
B-6014	8,168	4,281	1,143,168	618,281	209.79	50.0
B-6015	8,166	5,318	1,143,166	619,318	221.52	50.0
B-6018	7,909	4,367	1,142,909	618,367	204.66	50.0

Table 2.5-245 (Sheet 5 of 6)
Summary of COL Borings, CPTs, and Test Pits

Boring Number	Plant Coordinates		State Coordinates		Elevation (ft, msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
B-6019	7,133	4,344	1,142,133	618,344	163.94	50.0
B-6020	7,634	5,556	1,142,634	619,556	221.48	130.0
B-6021	7,186	5,103	1,142,186	619,103	209.80	120.0
B-6022	7,225	6,040	1,142,225	620,040	216.23	90.0
B-6023	6,553	5,178	1,141,553	619,178	202.77	50.0
B-6024	6,546	5,998	1,141,546	619,998	216.07	50.0
B-6025	5,519	5,190	1,140,519	619,190	172.69	50.0
B-6026	5,538	5,900	1,140,538	619,900	215.46	50.0
B-6027	10,779	12,145	1,145,779	626,145	96.65	75.0
B-6028	10,611	12,062	1,145,611	626,062	95.70	50.0
B-6029	12,772	9,967	1,147,772	623,967	85.41	50.0
B-6030	12,588	10,223	1,147,588	624,223	88.37	50.0
CPT Number	Plant Coordinates		State Coordinates		Elevation (ft, msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
C-1101	9,357	6,185	1,144,357	620,185	265.76	71.4
C-1102	9,424	7,333	1,144,424	621,333	267.61	51.4
C-1103	10,012	8,037	1,145,012	622,037	236.52	27.4
C-1104	10,602	8,747	1,145,602	622,747	230.19	77.1
C-1105	10,483	9,734	1,145,483	623,734	200.57	50.2
C-1106	10,534	10,748	1,145,534	624,748	138.02	20.0
C-1107	12,234	10,202	1,147,234	624,202	211.92	71.0
C-1108	12,628	9,753	1,147,628	623,753	200.89	59.6
C-1109	12,622	9,172	1,147,622	623,172	209.79	72.5
C-1110	12,199	8,740	1,147,199	622,740	242.39	72.3
C-1111	11,753	8,346	1,146,753	622,346	250.69	32.2
C-3001(S)	7,611	7,727	1,142,611	621,727	218.37	70.1
C-3002(S)	7,607	7,873	1,142,607	621,873	218.89	67.9
C-3003(S)	6,772	7,802	1,141,772	621,802	221.38	82.0
C-3004	6,542	7,807	1,141,542	621,807	223.25	72.7
C-3005(S)	6,267	7,792	1,141,267	621,792	221.27	101.1
C-4001(S)	7,600	6,919	1,142,600	620,919	218.87	74.2
C-4002(S)	7,600	7,064	1,142,600	621,064	219.08	82.2
C-4003(S)	6,785	6,708	1,141,785	620,708	221.16	82.5
C-4004	6,543	6,598	1,141,543	620,598	219.99	77.1
C-4005(S)	6,250	6,594	1,141,250	620,594	220.01	90.2

Table 2.5-245 (Sheet 6 of 6)
Summary of COL Borings, CPTs, and Test Pits

Test Pit Number	Plant Coordinates		State Coordinates		Elevation (ft, msl)	Depth (ft)
	Northing (ft)	Easting (ft)	Northing (ft)	Easting (ft)		
TP-B-1108	9,312	7,146	1,144,312	621,146	264.14	12.2
TP-B-1117	8,967	7,628	1,143,967	621,628	269.50	9.0
TP-B-1121	8,592	6,402	1,143,592	620,402	241.17	14.0
TP-B-1125	8,604	7,686	1,143,604	621,686	240.61	11.0
TP-B-1185	9,634	8,242	1,144,634	622,242	225.17	11.0
TP-B-1194	12,501	7,708	1,147,501	621,708	202.73	11.5
TP-B-1195	12,648	8,363	1,147,648	622,363	212.15	8.0
TP-B-1197	11,874	8,075	1,146,874	622,075	245.94	11.0

(DH) - Location of suspension P-S velocity logging and/or geophysical measurements.
(S) - Location of seismic CPT.
(C) – Borings with continuous sampling
Note: State Plane Coordinates are from NAD27 Georgia East state grid system. Plant coordinates are converted from the following formula:
Plant North + 1,135,000 = State North
Plant East + 614,000 = State East
Plant vertical datum is NGVD29, for this study msl = NGVD29

Table 2.5-246
Summary of Undisturbed Samples of the Blue Bluff Marl (ESP)

Boring Number	Sample Number	Depth at Top of Sample (ft)	Length of Sample (in.)
B-1002	UD-1	92.0	30
B-1002	UD-2	103.5	30
B-1002	UD-3	113.5	30
B-1002	UD-4	123.5	30
B-1002	UD-5	133.4	30
B-1003	UD-1	92.0	30
B-1004	UD-1	144.0	18
B-1004	UD-2	148.5	18
B-1004	UD-3	163.5	30
B-1004	UD-4	177.0	30
B-1004	UD-5	188.5	30
B-1004	UD-6	198.5	30

Table 2.5-247
Summary of SPT Hammer Energy Transfer Efficiency from ESP Investigation

Borehole and Sample Number	Energy Transfer Efficiency (%)
B1013-SS5	65
B1013-SS8	70
B1013-SS10	68
B1013-SS13	71
B1013-SS14	72
B1013-SS15	73
B1008-SS26	79
B1008-SS27	75
B1008-SS28	75
B1006-SS7	71
B1006-SS8	74
B1006-SS10	77
B1006-SS15	85
B1006-SS16	86
B1006-SS17	87
B1006-SS26	83
B1006-SS27	80
B1006-SS28	82
Range:	65-87
Average:	76
Median:	75

Table 2.5-248
Summary of SPT Hammer Energy Transfer Efficiency from COL Investigation

Hammer Serial No.	Rig Type	Number of Measurements	Min. ETR (%)	Max. ETR (%)	Avg. ETR (%)	Hammer Correction (Ce)
100	Diedrich D-50 ATV	6	69.1	75.1	72.4	1.21
165952	CME 850 ATV	7	78.9	90.0	83.4	1.39
200587	CME 75 Truck	5	83.7	86.6	84.2	1.40
211797	CME 75 Truck	3	75.1	80.3	77.6	1.29
219505	CME 55 Truck	3	67.1	80.6	70.1	1.17
219907	CME 75 Truck	3	76.6	84.6	80.2	1.34
270256	CME 85 Truck	5	77.7	88.0	82.5	1.38
311025	CME 55 Truck	4	88.3	92.6	90.2	1.50
328848	CME 750 ATV	3	83.1	85.1	84.0	1.40
331145	CME 55LC Truck	5	85.7	90.0	88.4	1.47
337153	CME 550 ATV	4	76.0	87.7	82.0	1.37
XO2958	CME 850 ATV	3	78.0	79.4	78.9	1.32

Table 2.5-249
Estimated Shear Wave Velocity and Dynamic Shear Modulus Values for the Compacted Backfill (ESP)

Depth (ft)	Vs(1) (fps)	Gmax(2) (ksf)
0 to 6	573	1,255
6 to 10	732	2,049
10 to 14	811	2,510
14 to 18	871	2,898
18 to 23	927	3,280
23 to 29	983	3,694
29 to 36	1040	4,130
36 to 43	1092	4,553
43 to 50	1137	4,940
50 to 56	1175	5,274
56 to 63	1209	5,588
63 to 71	1232	5,796
71 to 79	1253	6,001
79 to 86	1273	6,186

(1) From Figure 6-1 of Bechtel (1984).
(2) Gmax were calculated using γ from Table 2.5-236.

Table 2.5-250
Shear Wave Velocity Values for the Compacted Backfill (COL)

Depth (ft)	Vs (fps)
0	550
5	724
10	832
20	975
30	1064
40	1130
50	1183
60	1228
70	1267
80	1302
85	1318
86.5	1327
88	1327

Table 2.5-251
Shear Wave Velocity Values for Site Amplification Analysis
Part A: Soil Shear-Wave Velocities (ESP)

Geologic Formation	Depth (feet)	V_s (fps)
Compacted Backfill	0 to 6	573
	6 to 10	732
	10 to 14	811
	14 to 18	871
	18 to 23	927
	23 to 29	983
	29 to 36	1,040
	36 to 43	1,092
	43 to 50	1,137
	50 to 56	1,175
	56 to 63	1,209
	63 to 71	1,232
	71 to 79	1,253
	79 to 86	1,273
Blue Bluff Marl (Lisbon Formation)	86 to 92	1,400
	92 to 97	1,700
	97 to 102	2,100
	102 to 105	1,700
	105 to 111	2,200
	111 to 123	2,350
	123 to 149	2,650
Lower Sand Stratum (Still Branch)	149 to 156	2,000
	156 to 216	1,650
(Congaree)	216 to 331	1,950
(Snapp)	331 to 438	2,050
(Black Mingo)	438 to 477	2,350
(Steel Creek)	477 to 587	2,650
(Gaillard/Black Creek)	587 to 798	2,850
(Pio Nono)	798 to 858	2,870
(Cape Fear)	858 to 1,049	2,710
Dunbarton Triassic Basin & Paleozoic Crystalline Rock	> 1,049	see Table 2.5-252, Part B

Table 2.5-252
Shear Wave Velocity Values for Site Amplification Analysis
Part B: Rock Shear-Wave Velocities - Six Alternate Profiles

	Vs (ft/s)	
Depth (ft)	**Gradient #1**	**Gradient #2**
1,049 to 1,100	4,400	4,400
1,100 to 1,150	5,650	5,650
1,150 to 1,225	6,650	6,650
1,225 to 1,337.5	7,600	7,600
1,337.5 to 1,402.5	8,000	8,700
1,402.5 to 1,405	8,005	8,703
1,405 to 1,525	8,059	8,739
> 1,525	9,200	9,200

Rock Vs profile corresponding to the location midway between B-1002 and B-1003.

	Vs (ft/s)	
Depth (ft)	**Gradient #1**	**Gradient #2**
1,049 to 1,100	4,400	4,400
1,100 to 1,150	5,650	5,650
1,150 to 1,225	6,650	6,650
1,225 to 1,337.5	7,600	7,600
1,337.5 to 1,450	8,000	8,700
1,450 to 1,550	8,090	8,760
1,550 to 1,650	8,180	8,820
1,650 to 1,750	8,270	8,880
1,750 to 1,830	8,360	8,940
1,830 1,900	8,414	8,976
> 1,900	9,200	9,200

Rock Vs profile corresponding to the location of B-1003.

	Vs (ft/s)	
Depth (ft)	**Gradient #1**	**Gradient #2**
1,049 to 1,100	4,400	4,400
1,100 to 1,150	5,650	5,650
1,150 to 1,225	6,650	6,650
1,225 to 1,337.5	7,600	7,600
1,337.5 to 1,450	8,000	8,700
1,450 to 1,550	8,090	8,760
1,550 to 1,650	8,180	8,820
1,650 to 1,750	8,270	8,880
1,750 to 1,850	8,360	8,940
1,850 to 1,950	8,450	9,000
1,950 to 2,050	8,540	9,060
2,050 to 2,127.5	8,630	9,120
2,127.5 to 2,155	8,679.5	9,153
2,155 to 2,275	8,733.5	9,189
> 2,275	9,200	9,200

Table 2.5-253
Shear Wave Velocity Values for Site Amplification Analysis
Part A: Soil Shear-Wave Velocities (COL Soil Column)

Geologic Formation	Depth (feet) (ft)	V_s (fps) (fps)
Compacted Backfill	0	550
	5	724
	10	832
	20	975
	30	1064
	40	1130
	50	1183
	60	1228
	70	1267
	80	1302
	85	1318
	86.5	1327
	88	1327
Blue Bluff Marl (Lisbon Formation)	88 to 96	1,341
	96 to 102	1,747
	102 to 110	1,988
	110 to 122	2,300
	122 to 156	2,541
Lower Sand Stratum (Still Branch)	156 to 164	1,820
	164 to 220	1,560
(Congaree)	220 to 236	1,757
	236 to 280	2,000
	280 to 328	1,926
	328 to 340	1,727
(Snapp)	340 to 447	2,050
(Black Mingo)	447 to 486	2,350
(Steel Creek)	486 to 596	2,650
(Gaillard/Black Creek)	596 to 807	2,850
(Pio Nono)	807 to 867	2,870
(Cape Fear)	867 to 1,059	2,710

Table 2.5-254
Summary of Modulus Reduction and Damping Ratio Values – EPRI-Base

Shear Strain (%)	0-20 ft (Compacted Backfill)		20-50 ft (Compacted Backfill)		50-86 ft (Compacted Backfill)		86-149 ft (Blue Bluff Marl)		149-215.7 ft (Lower Sand Stratum-Still Branch Formation)		Between 215.7 and 500 ft (Lower Sand Stratum below Still Branch)		Soil between 500 ft and top of rock (about 1,000 ft) (Deep Sands)	
	G/G_{max}	Damping Ratio	G/G_{max}	Damping Ratio	G/G_{max}	Damping Ratio	G/G_{max}	Damping Ratio	G/G_{max}	Damping Ratio	G/G_{max}	Damping Ratio	G/G_{max}	Damping Ratio
0.0001	1	1.4	1	1.2	1	1	1	1.4	1	0.8	1	0.7	1	0.6
0.00032	1	1.5	1	1.2	1	1	1	1.4	1	0.9	1	0.8	1	0.6
0.001	0.98	1.8	0.99	1.4	1	1.2	0.99	1.5	1	1	1	0.8	1	0.6
0.00316	0.914	2.8	0.946	2.1	0.97	1.64	0.96	2	0.98	1.33	0.988	1.12	0.99	0.81
0.01	0.75	5	0.82	3.6	0.87	2.8	0.84	2.9	0.9	2.2	0.93	1.8	0.95	1.2
0.03162	0.509	9.3	0.608	7	0.68	5.49	0.63	6	0.74	4.36	0.791	3.53	0.852	2.5
0.1	0.27	15.3	0.36	12.4	0.43	10.2	0.36	11.4	0.5	8.6	0.57	7.1	0.65	5.3
0.3162	0.116	21.9	0.165	19.1	0.22	16.5	0.16	17	0.27	14.61	0.321	12.78	0.41	10.27
1	0.04	27	0.06	24.9	0.09	22.9	0.06	19.4	0.12	21.2	0.15	19.3	0.2	16.7

Table 2.5-255
Summary of Modulus Reduction and Damping Ratio Values – Site Specific

Stratum	Backfill				Blue Bluff Marl				Lower Sands			
Sub strata	<25ft		≥25ft		Low PI		High PI		Sands		Clay (Congaree/ Snapp)	
Shear Strain (%)	G/Gmax	Damping Ratio	G/Gmax	Damping Ratio	G/Gmax	Damping Ratio	G/Gmax	Damping Ratio	G/Gmax	Damping Ratio	G/Gmax	Damping Ratio
0.00010	1	0.97	1	0.62	1	1.44	1	1	1	0.62	1	0.86
0.00032	1	1.05	1	0.62	1	1.56	1	1.05	1	0.62	1	0.87
0.00100	0.998	1.05	1	0.7	1	1.67	1	1.32	1	0.7	1	0.93
0.00359	0.942	1.44	0.975	0.89	0.96	2.34	0.9965	1.71	0.997	0.89	0.99	1.21
0.01019	0.826	2.26	0.902	1.3	0.867	3.23	0.97	2.3	0.954	1.32	0.928	1.8
0.03170	0.603	4.55	0.748	2.6	0.673	5.75	0.88	3.97	0.858	2.6	0.8	3.62
0.10000	0.355	8.97	0.495	5.64	0.395	10.63	0.679	6.715	0.649	5.59	0.56	7.54
0.30690	0.172	14.94	0.269	10.65	0.187	16.39	0.433	11.115	0.411	10.65	0.327	13
0.65313	0.089	19.38	0.158	14.73	0.1	19.08	0.2785	14.545	0.263	14.68	0.198	17.42
1.00000	0.072	22.12	0.117	17.11	0.068	19.12	0.217	15.77	0.209	17.11	0.154	19.87

Table 2.5-256
Summary of Modulus Reduction and Damping Ratio Values – SRS-Based

Cyclic Shear Strain (%)	Blue Bluff Marl		Shallow Sand (<300 ft)		Deep Sand (>300 ft)	
	G/G_{max}	Damping Ratio	G/G_{max}	Damping Ratio	G/G_{max}	Damping Ratio
0.0001	1	0.8	1	0.6	1	0.5
0.0002	1	0.8	1	0.6	1	0.5
0.0003	1	0.8	1	0.7	1	0.5
0.0005	1	0.8	1	0.7	1	0.5
0.001	0.99	0.9	0.99	0.8	0.995	0.6
0.002	0.98	1.1	0.98	1	0.99	0.7
0.003	0.965	1.2	0.96	1.1	0.985	0.8
0.005	0.94	1.5	0.93	1.4	0.96	0.9
0.01	0.89	2.1	0.87	2.2	0.92	1.4
0.02	0.8	3.3	0.77	3.5	0.85	2.2
0.03	0.72	4.3	0.69	4.7	0.78	3
0.05	0.61	6.1	0.57	6.7	0.69	4.5
0.1	0.43	9.6	0.4	10.4	0.53	7.3
0.2	0.28	13.1	0.25	14.8	0.36	11.2
0.3	0.205		0.18		0.27	13.8
0.5	0.13	19	0.12	21	0.18	
0.7	0.1		0.09		0.14	
1	0.08		0.07	27	0.1	23

Table 2.5-257
Acceptable Gradation Envelope for Compacted Backfill

Sieve No.	Opening Size (mm)	Percent Passing	
		Minimum	Maximum
4	4.75	97	100
10	2.00	95	100
20	0.85	85	98
40	0.425	50	95
60	0.25	17	80
100	0.15	7	50
140	0.106	4	28
200	0.075	3	25

Table 2.5-258
Criteria for Evaluation of Borrow Material from Outside of the Three Designated Category 1 and 2 Borrow Areas

Parameter	Acceptance Criteria
Location	Exclusion Area Boundary (Figure 1.1-202)
Geological Origin	Barnwell Group
Soil Classification	SP, SP-SM or SM
Maximum Dry Density (Modified Proctor)	Engineering Evaluation
Fines Content, Percent passing on a #200 Sieve	3% Minimum 25% Maximum
Gradation	Table 2.5-257 and associated text in Subsection 2.5.4.5.3

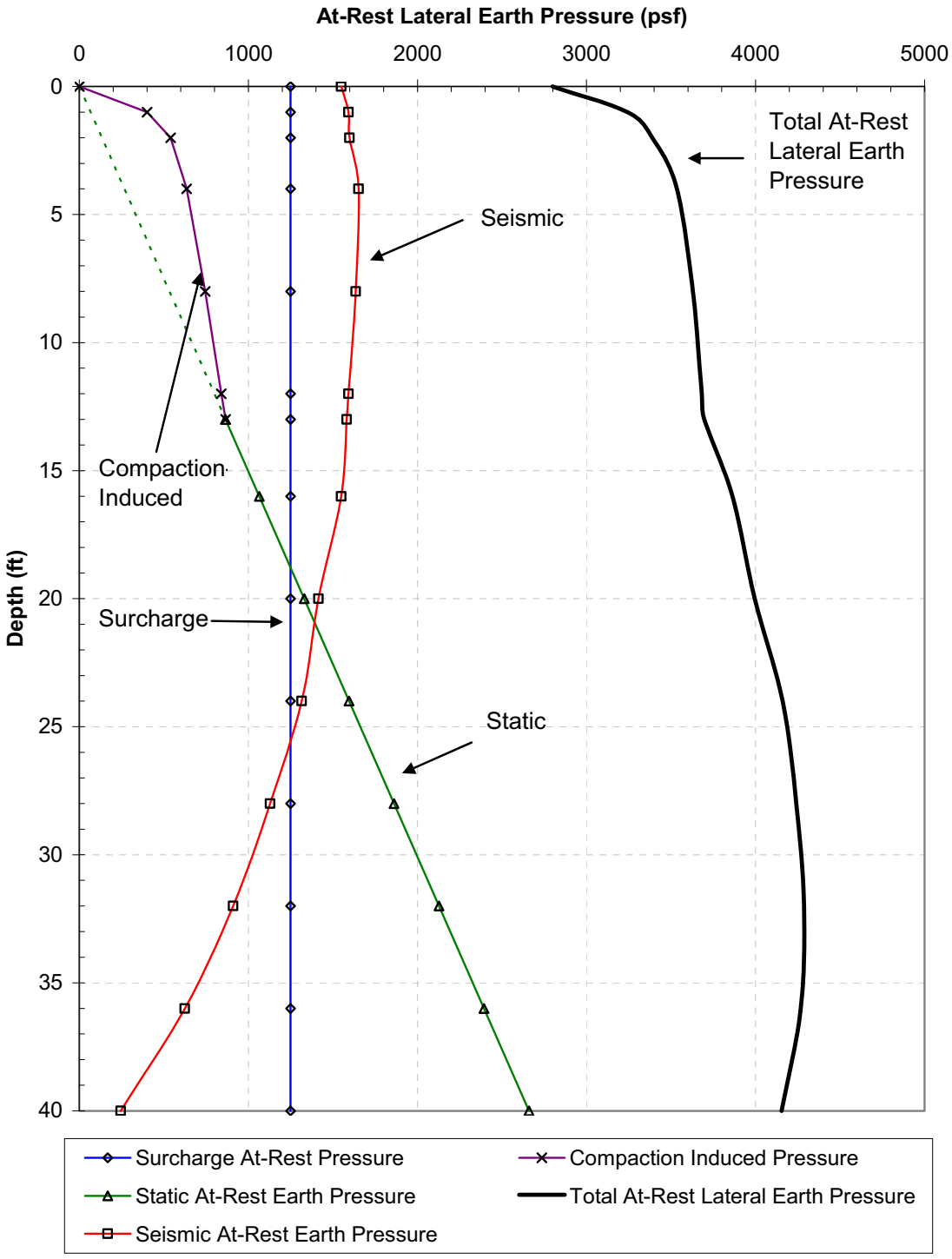


Figure 2.5-201
Vogtle Site-Specific At-Rest Lateral Earth Pressure Diagrams for Rigid Below Grade Nuclear Island (NI) Walls

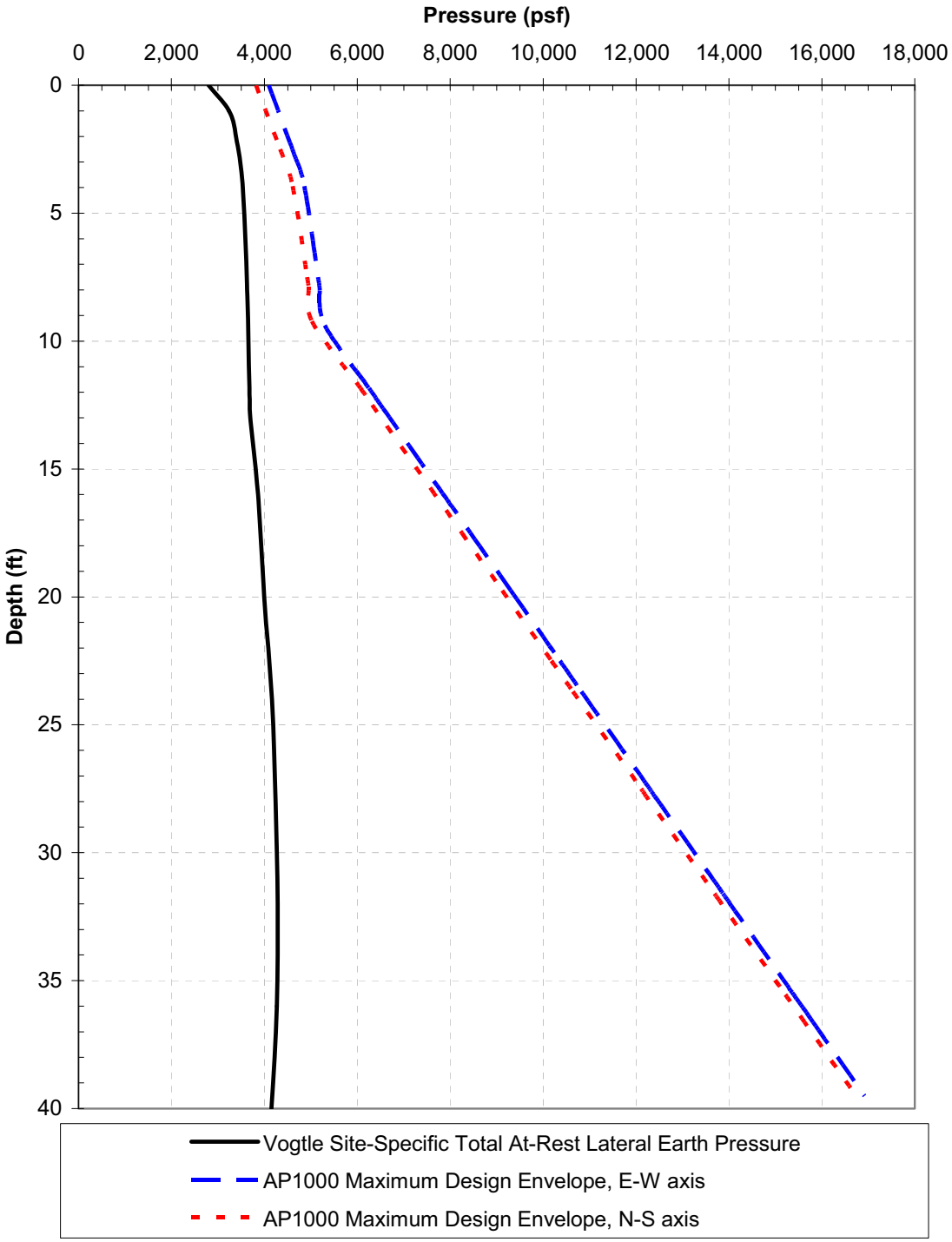


Figure 2.5-202
Comparison of Vogtle Site-Specific Total At-Rest Lateral Earth Pressure Diagrams and AP1000 Maximum Design Envelopes

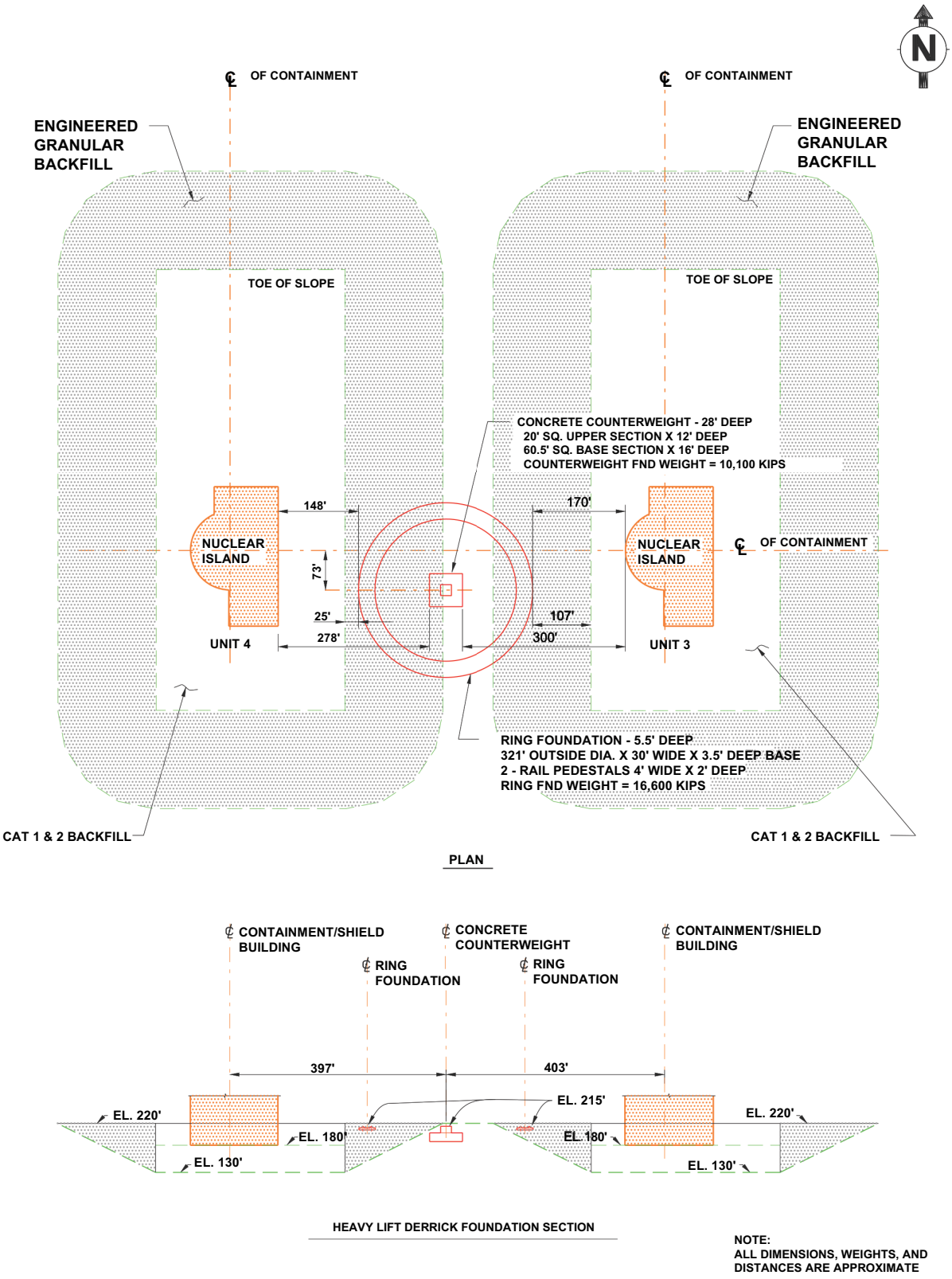


Figure 2.5-203
Heavy Lift Derrick Foundation Location

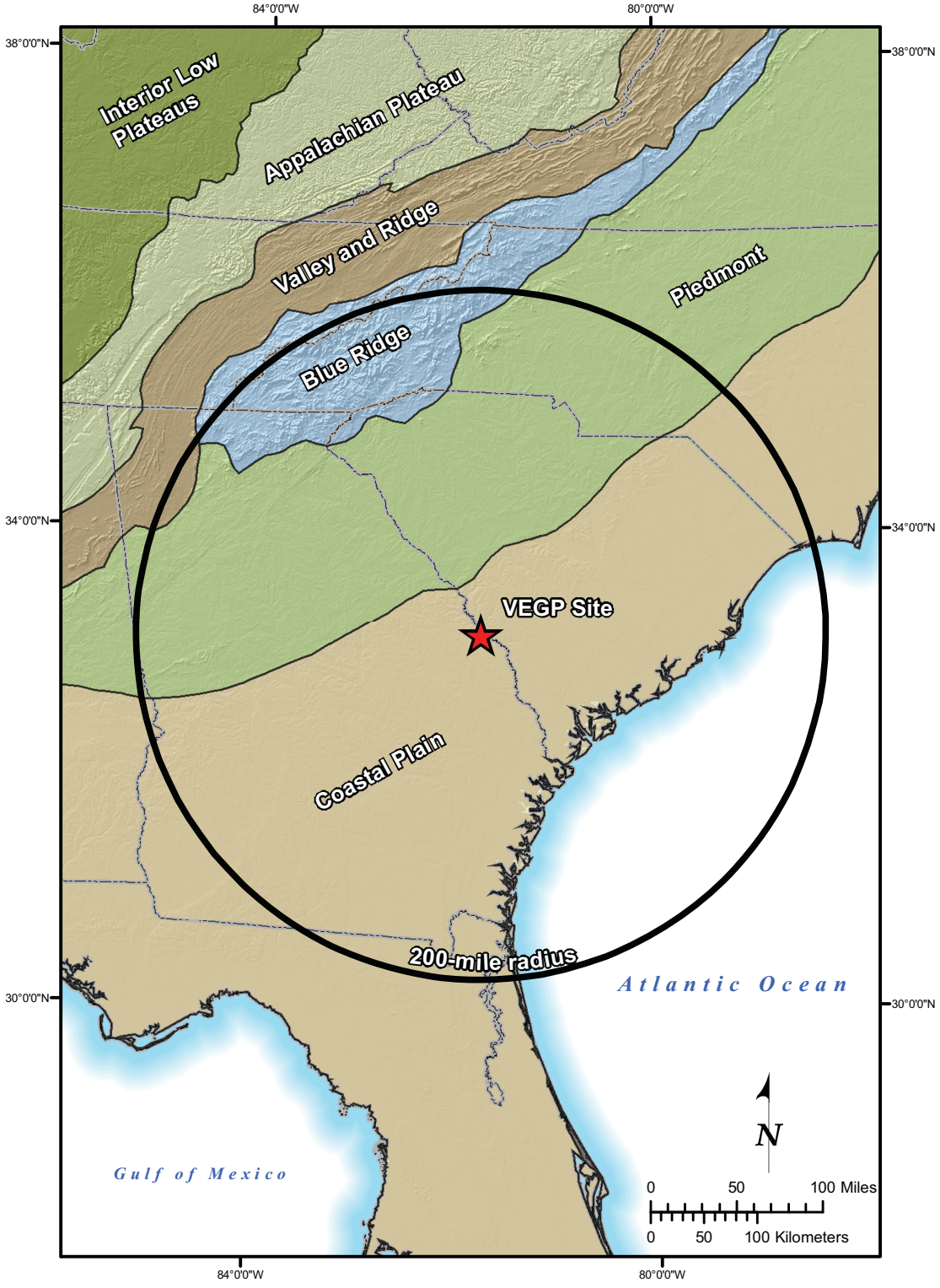


Figure 2.5-204
Physiographic Provinces of the Southeastern United States

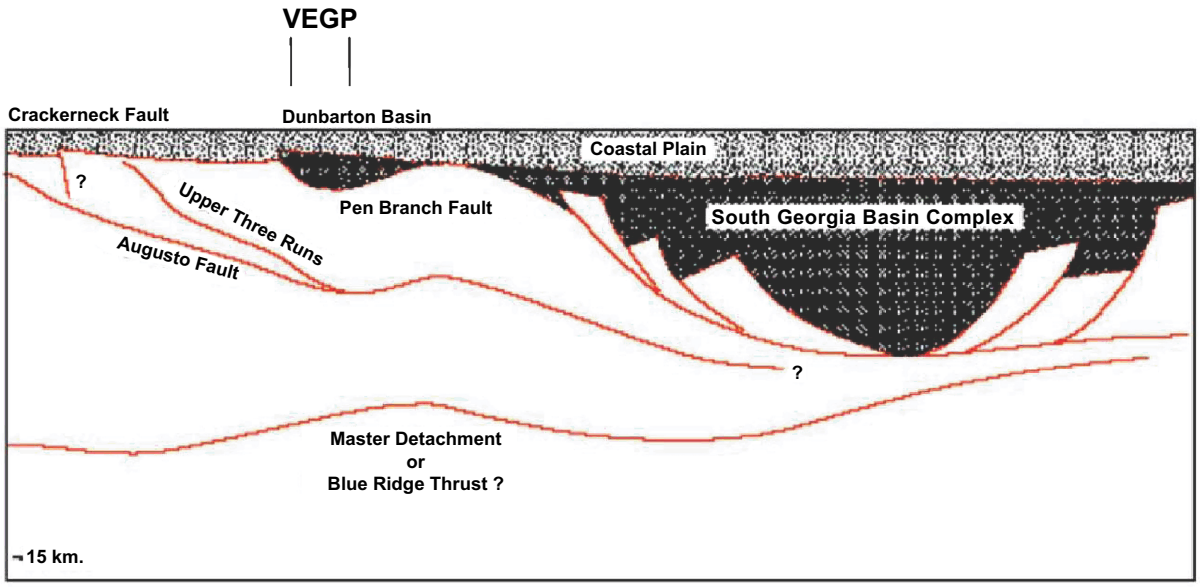


Figure 2.5-205
Conceptual Section Linking Dunbarton Basin with South Georgia Basin Complex

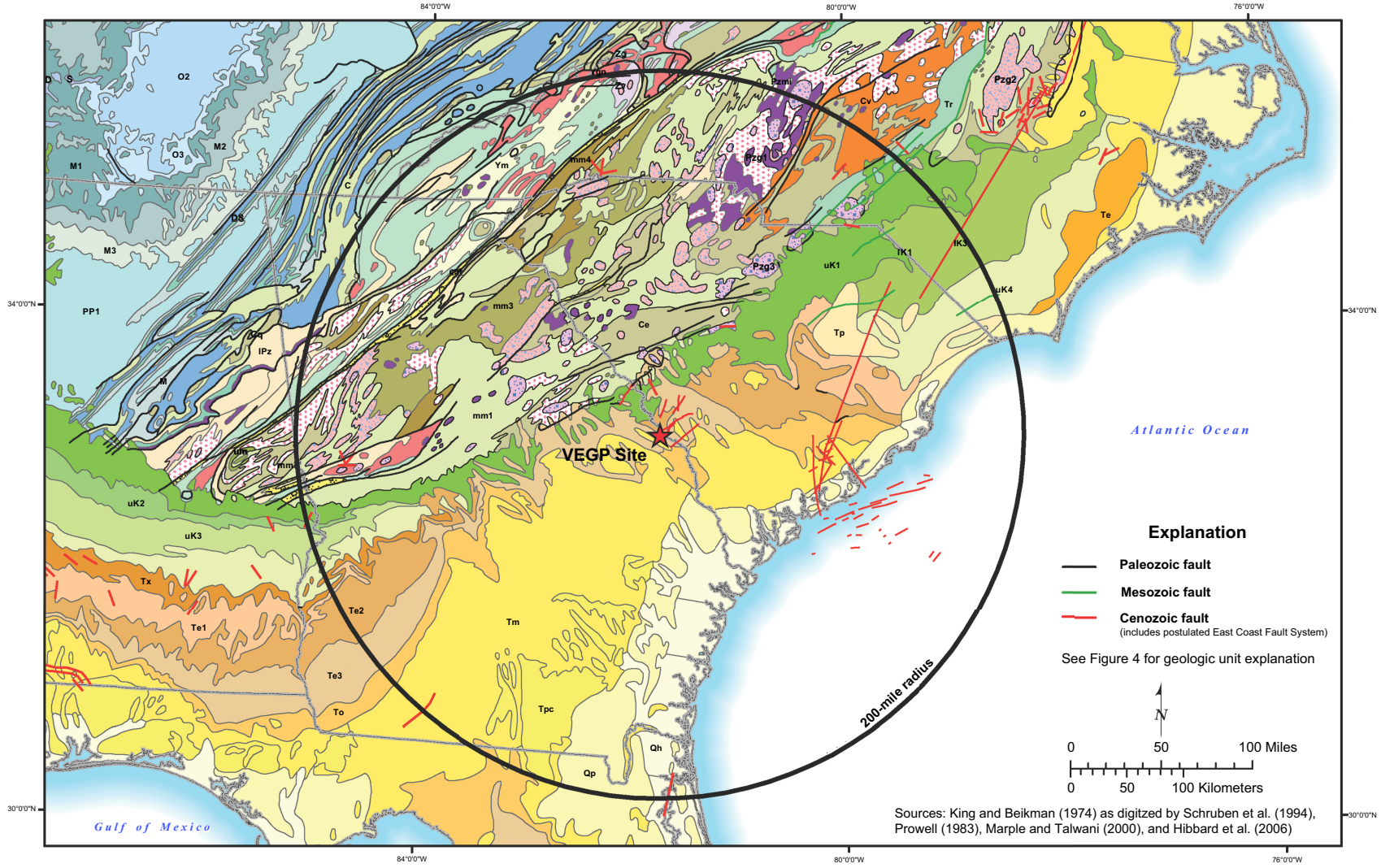


Figure 2.5-206
Regional Geologic Map (200-Mile Radius)

Explanation

Vogtle 200-mile geology
King and Beikman (1974) unit descriptions

Qh	Holocene
Qp	Pleistocene
Tp	Pliocene
Tpc	Pliocene continental
Tm	Miocene
To	Oligocene
Te	Eocene
Te1	Eocene Wilcox Group
Te2	Eocene Claiborne Group
Te3	Eocene Jackson Group
Tx	Paleocene
uK1	Woodbine and Tuscaloosa groups
uK2	Austin and Eagle Ford Groups
uK3	Taylor Group
uK4	Navarro Group
lK1	Trinity group
lK3	Washita Group
Tr	Triassic
PP1	Atokan and Morrowan Series
M	Mississippian
M1	Osagean and Kinderhookian Series
M2	Meramecian Series
M3	Chesterian Series
D	Devonian
DS	Devonian and Silurian
S	Silurian
O	Ordovician
O2	Middle Ordovician (Mohawkian)
O3	Upper Ordovician (Cincinnatian)
C	Cambrian
Ce	Cambrian eugeosynclinal
Cq	basal Lower Cambrian clastic rocks
Cv	Cambrian volcanics
lPz	Lower Paleozoic
Pzmi	Paleozoic mafic intrusives
Pzg3	Upper Paleozoic granitic rocks
Pzg2	Middle Paleozoic granitic rocks
Pzg1	Lower Paleozoic granitic rocks
Ygn	Orthogneiss
Ym	Paragneiss and schist
Z	sedimentary rocks
Zg	granitic rocks
Zv	volcanic rocks
cat	Catacalastic rocks
mm1	felsic paragneiss and schist
mm2	mafic paragneiss
mm3	migmatite
mm4	felsic orthogneiss
um	Ultramafic rocks

Figure 2.5-207
Regional Geologic Map (200-Mile Radius) Explanation

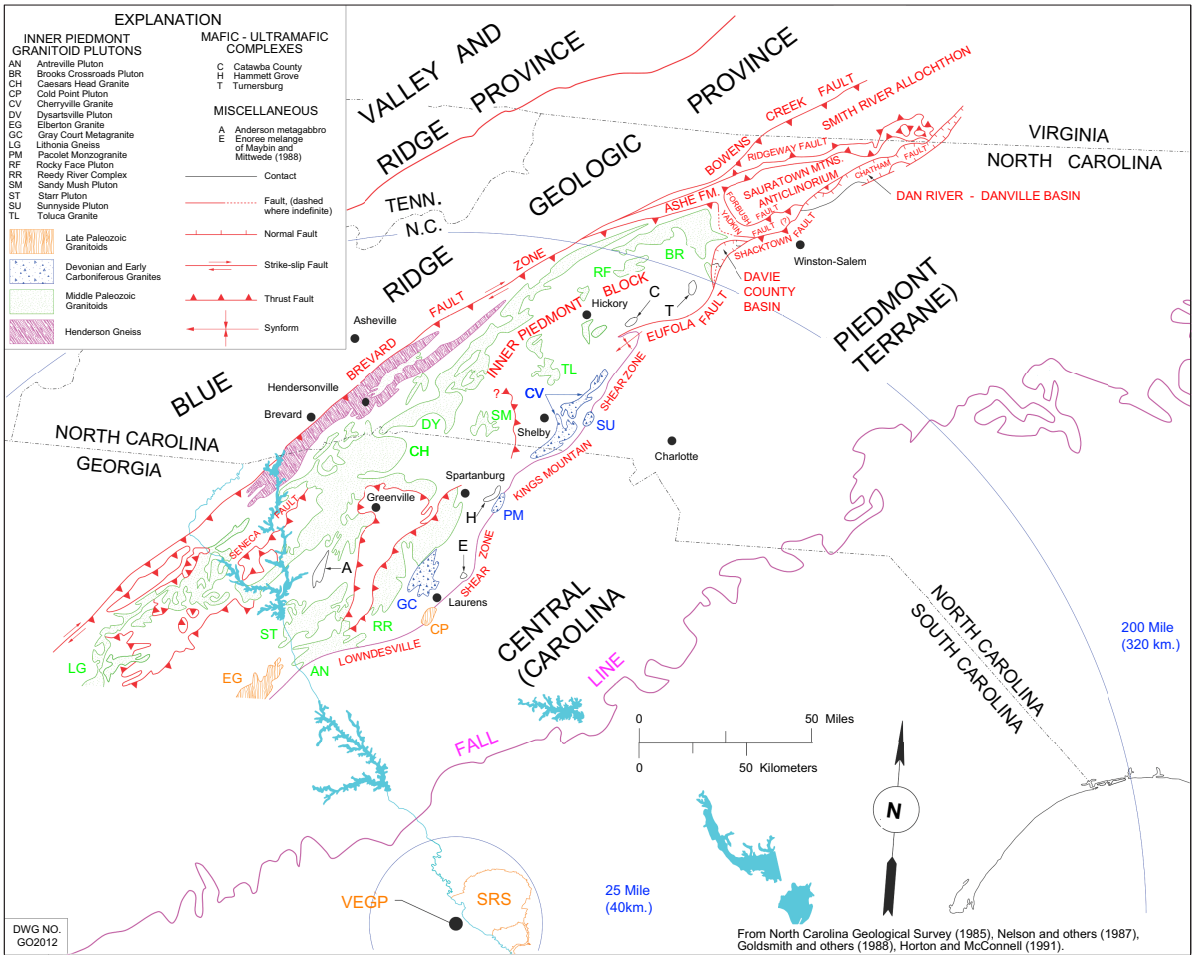


Figure 2.5-208
Simplified Geologic Map of Western Piedmont Terrane in Relation to Blue Ridge and Carolina Terranes

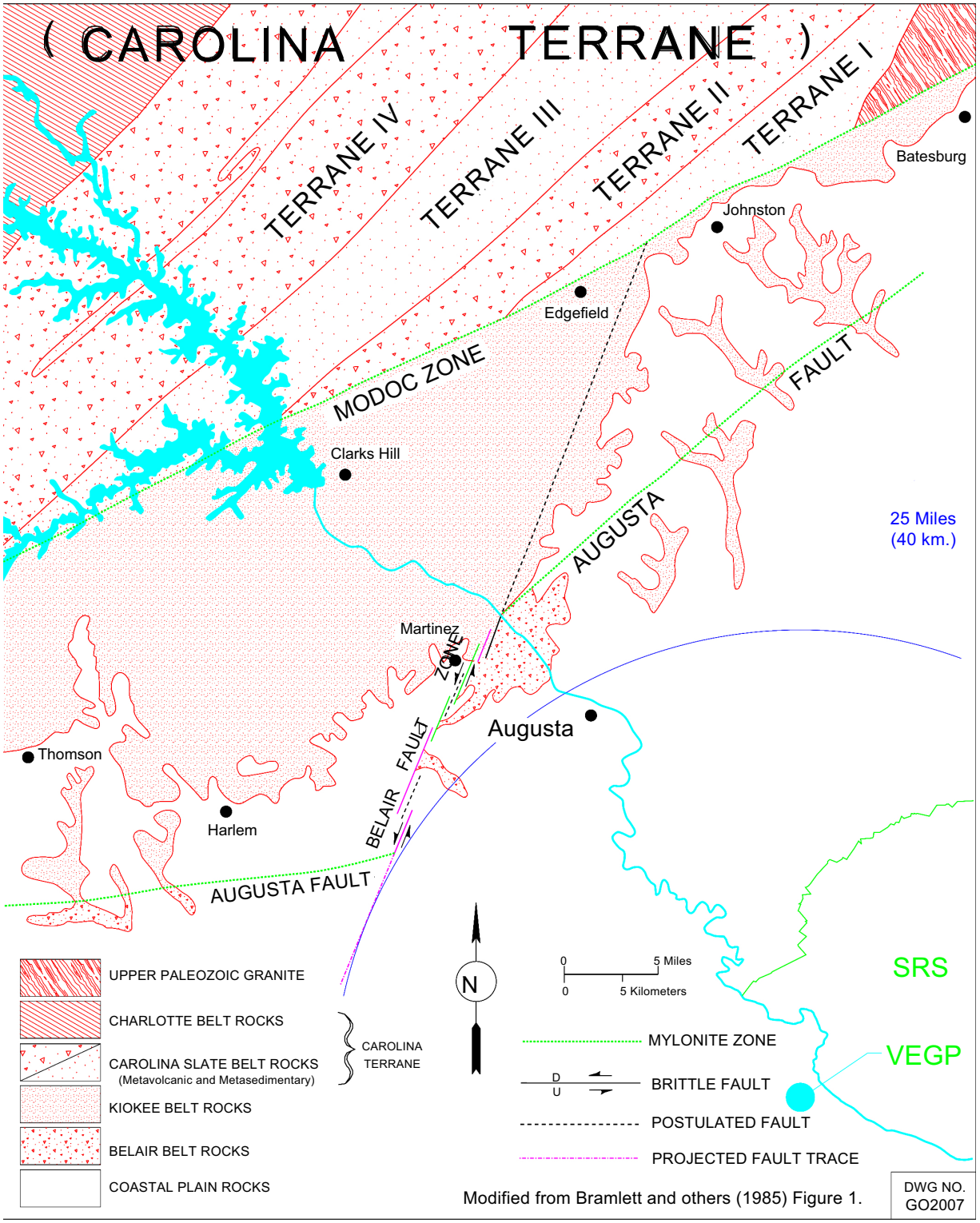


Figure 2.5-209
Map of Carolina Terrane and Modoc Zone

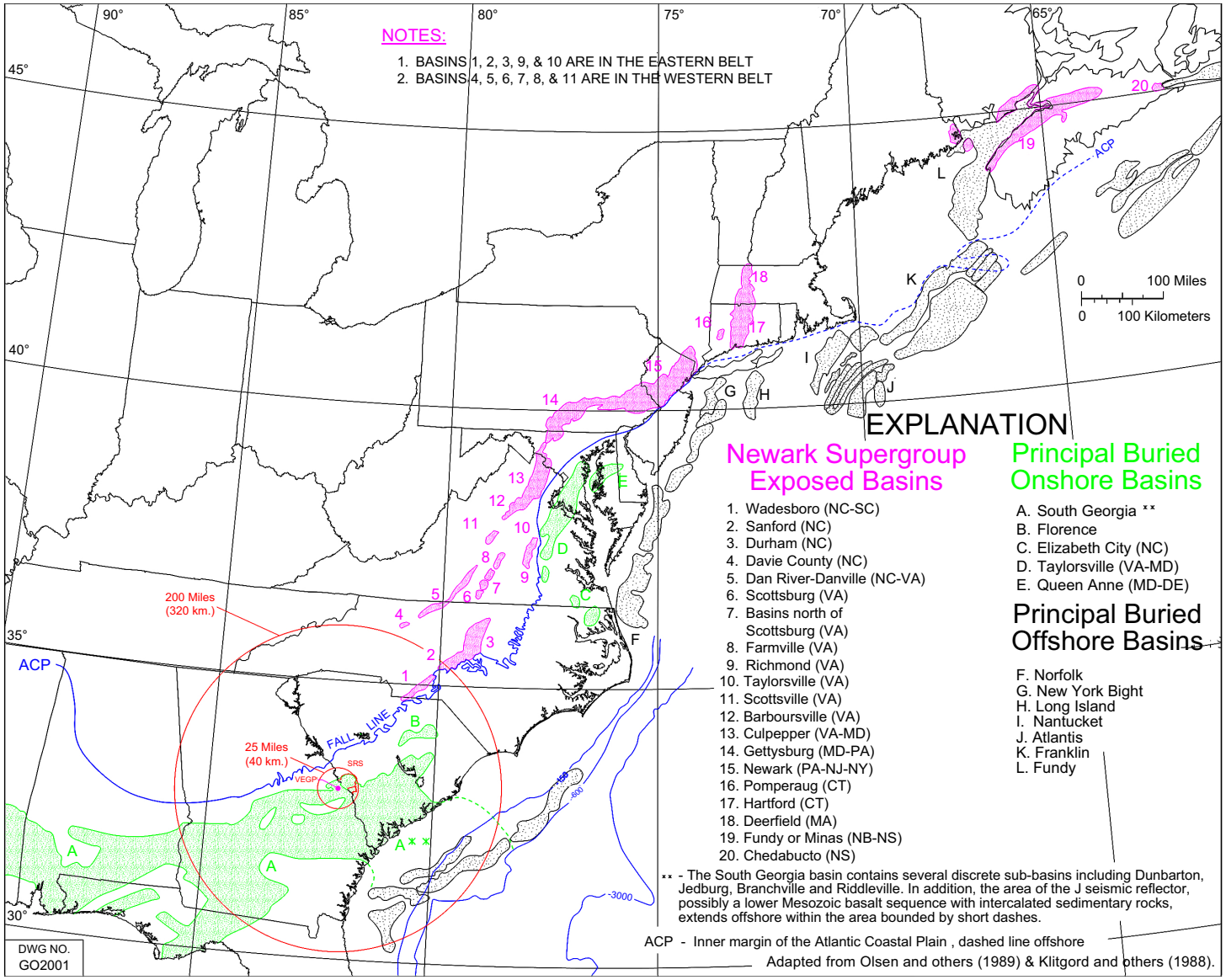


Figure 2.5-210
Triassic Basins in the Eastern United States

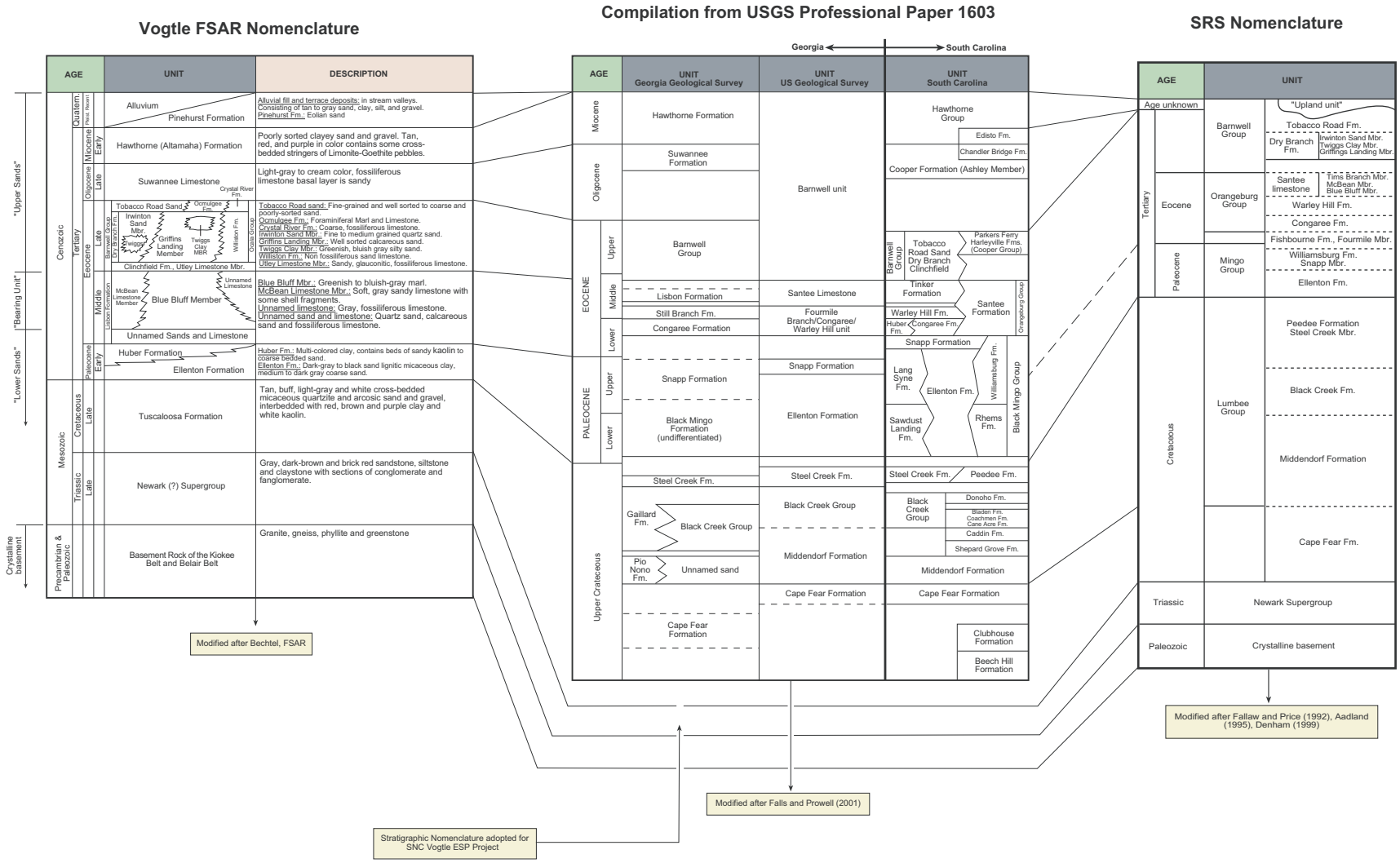


Figure 2.5-211
Stratigraphic Correlation Chart

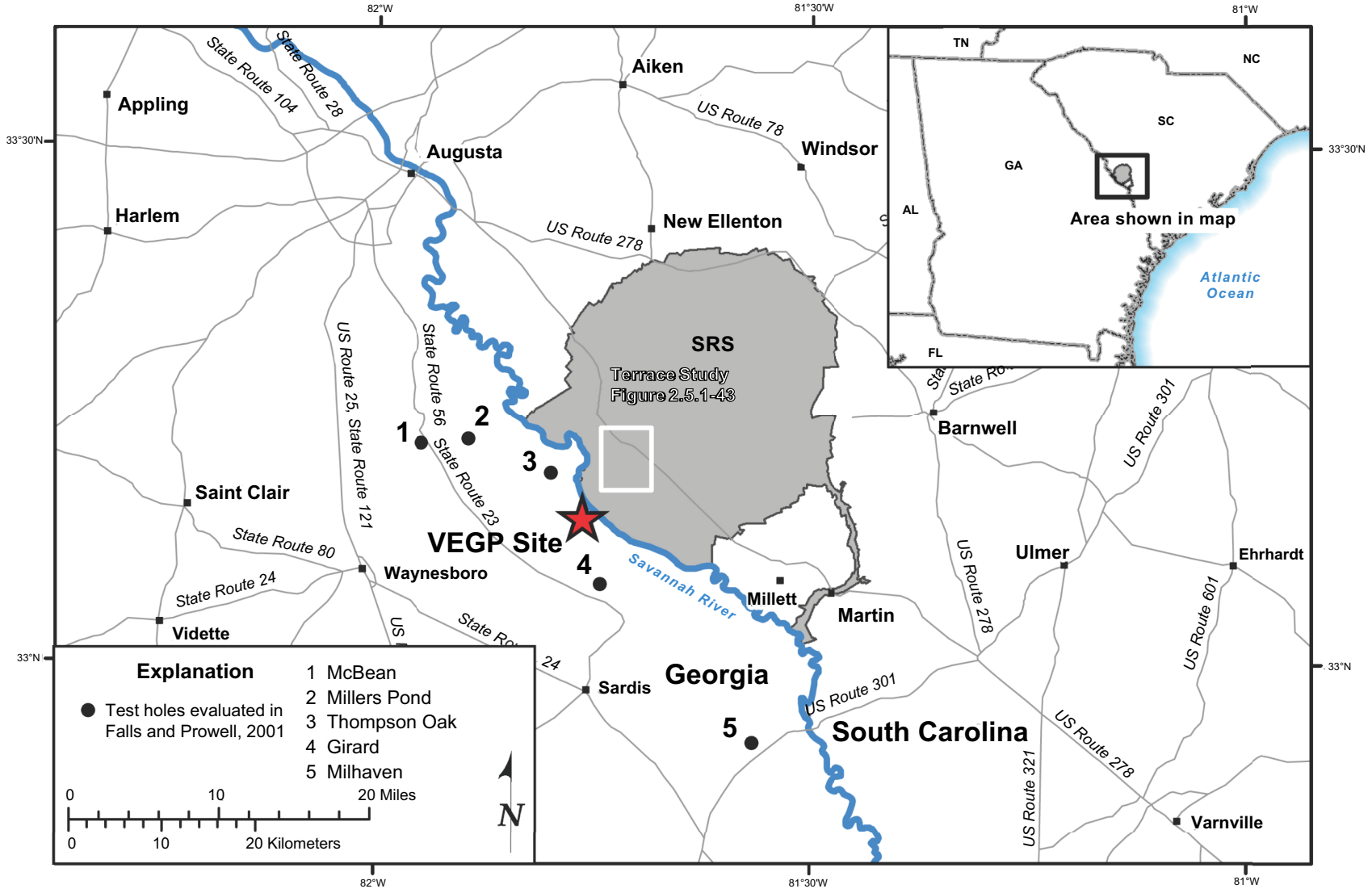


Figure 2.5-212
Location Map Showing SRS Boundary and VEGP Site

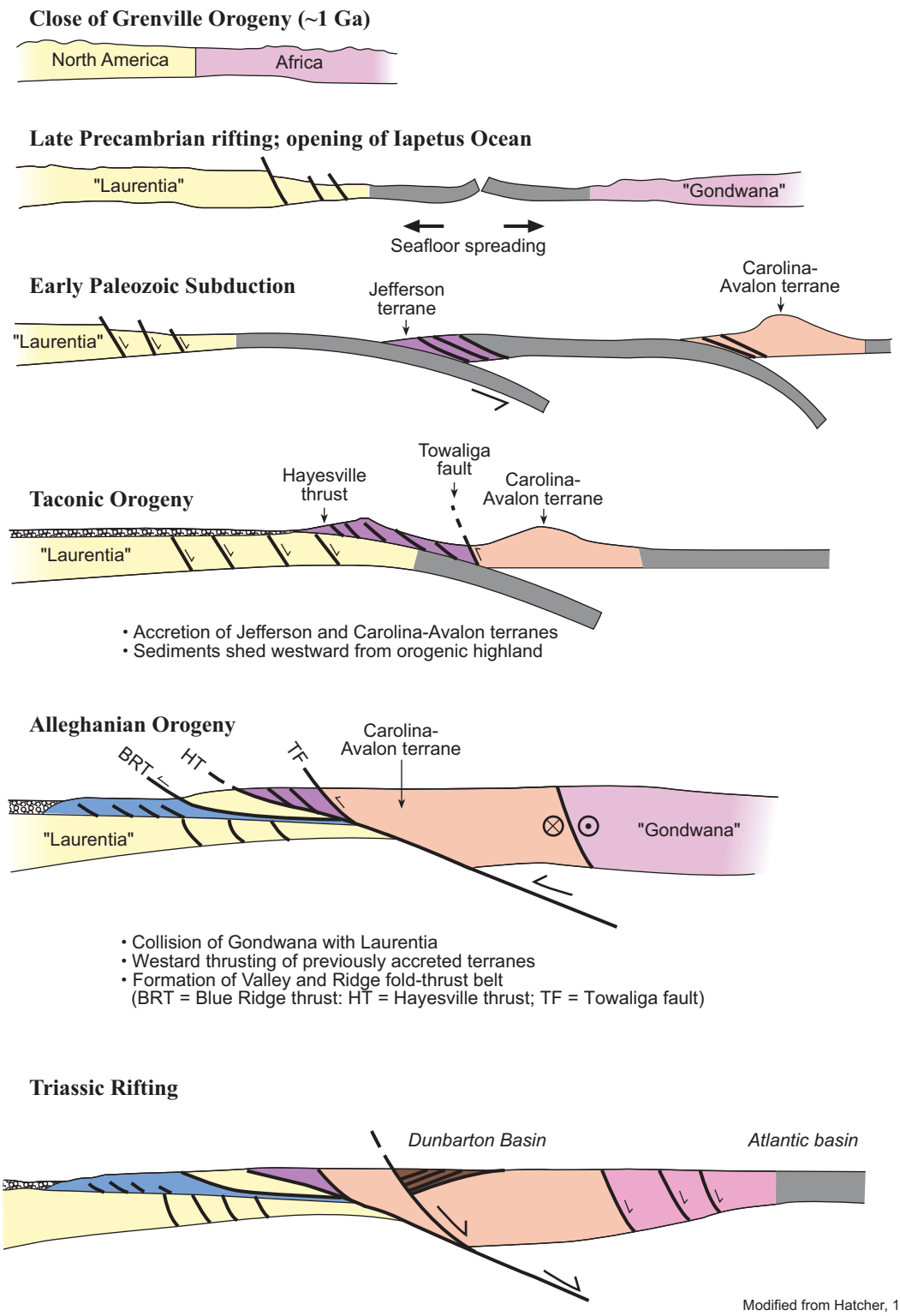


Figure 2.5-213
Evolution of the Appalachian Orogen

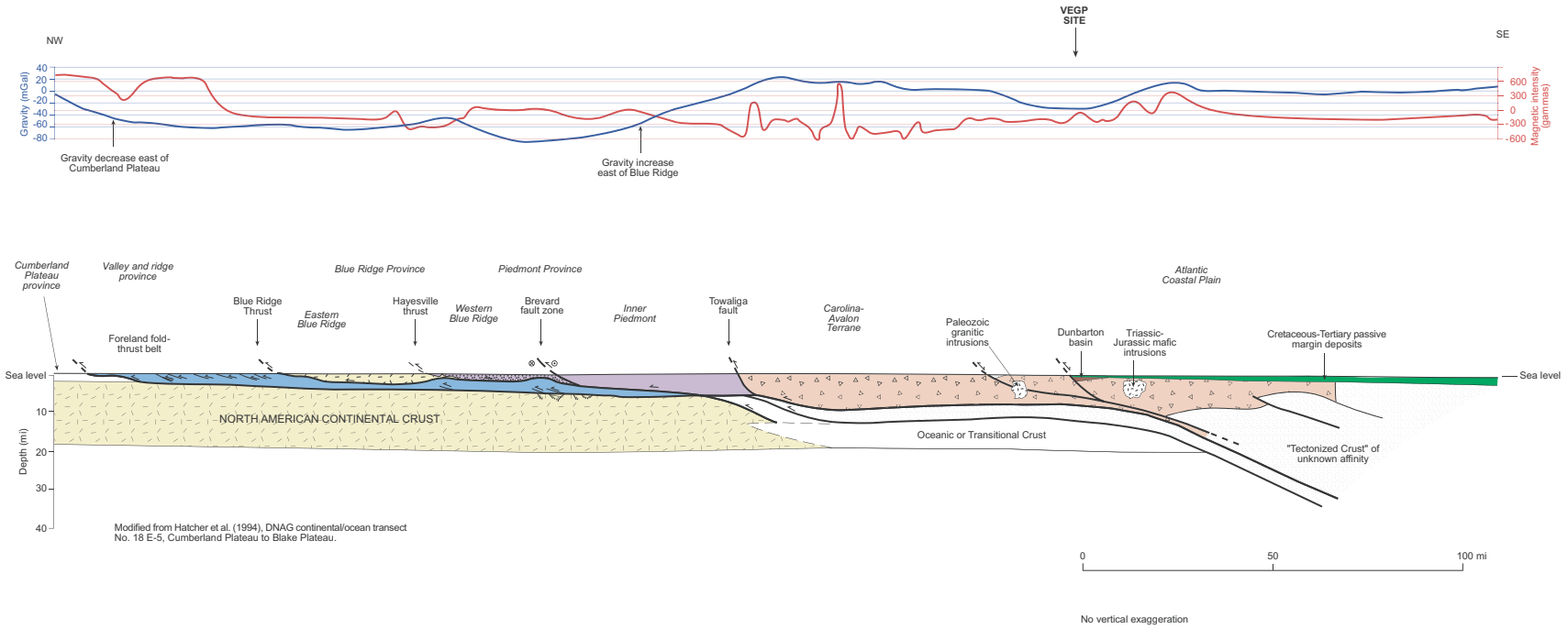


Figure 2.5-214
Regional Cross Section – DNAG E-5

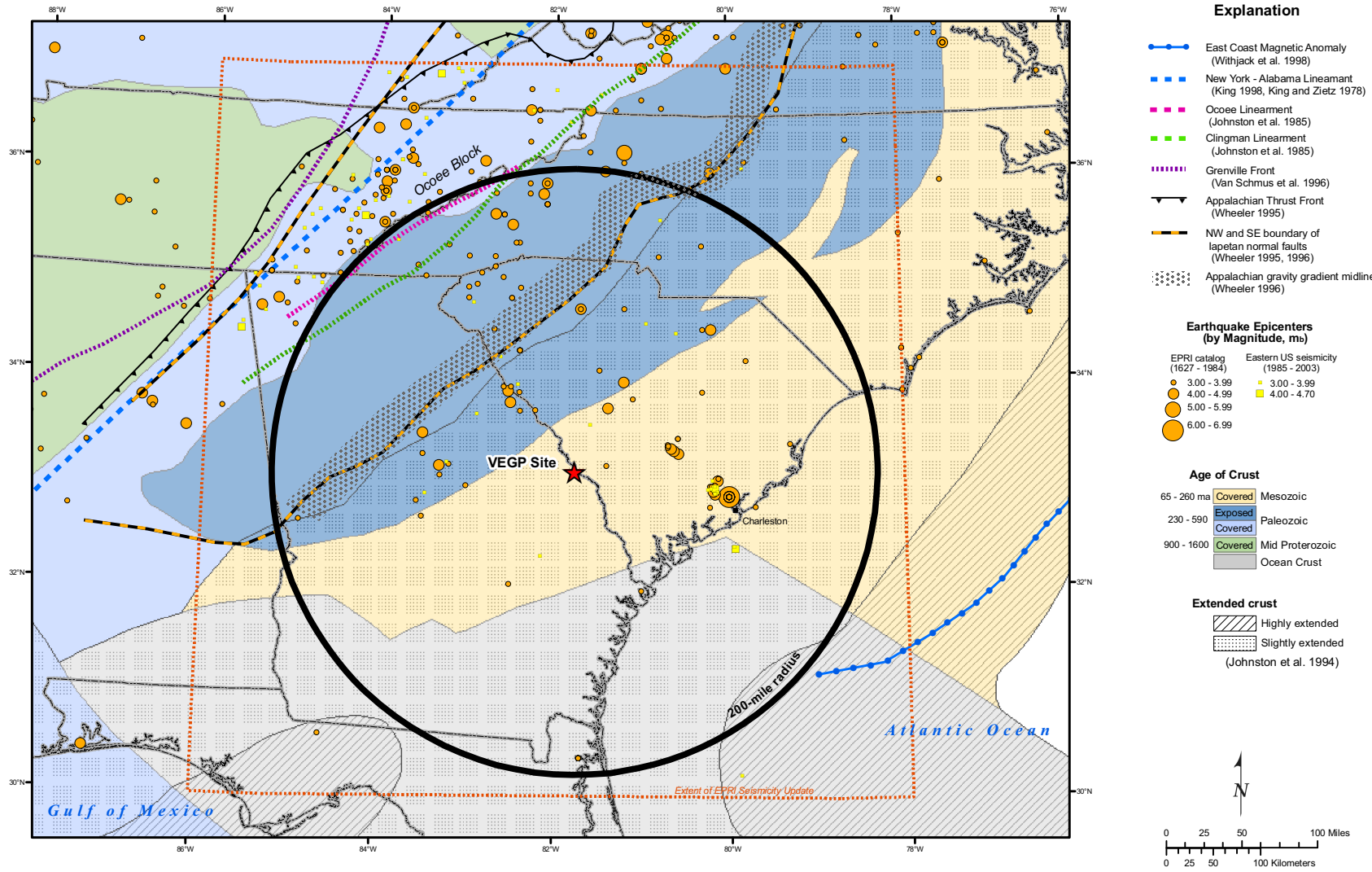


Figure 2.5-215
Tectonic Features of the Southeastern United States

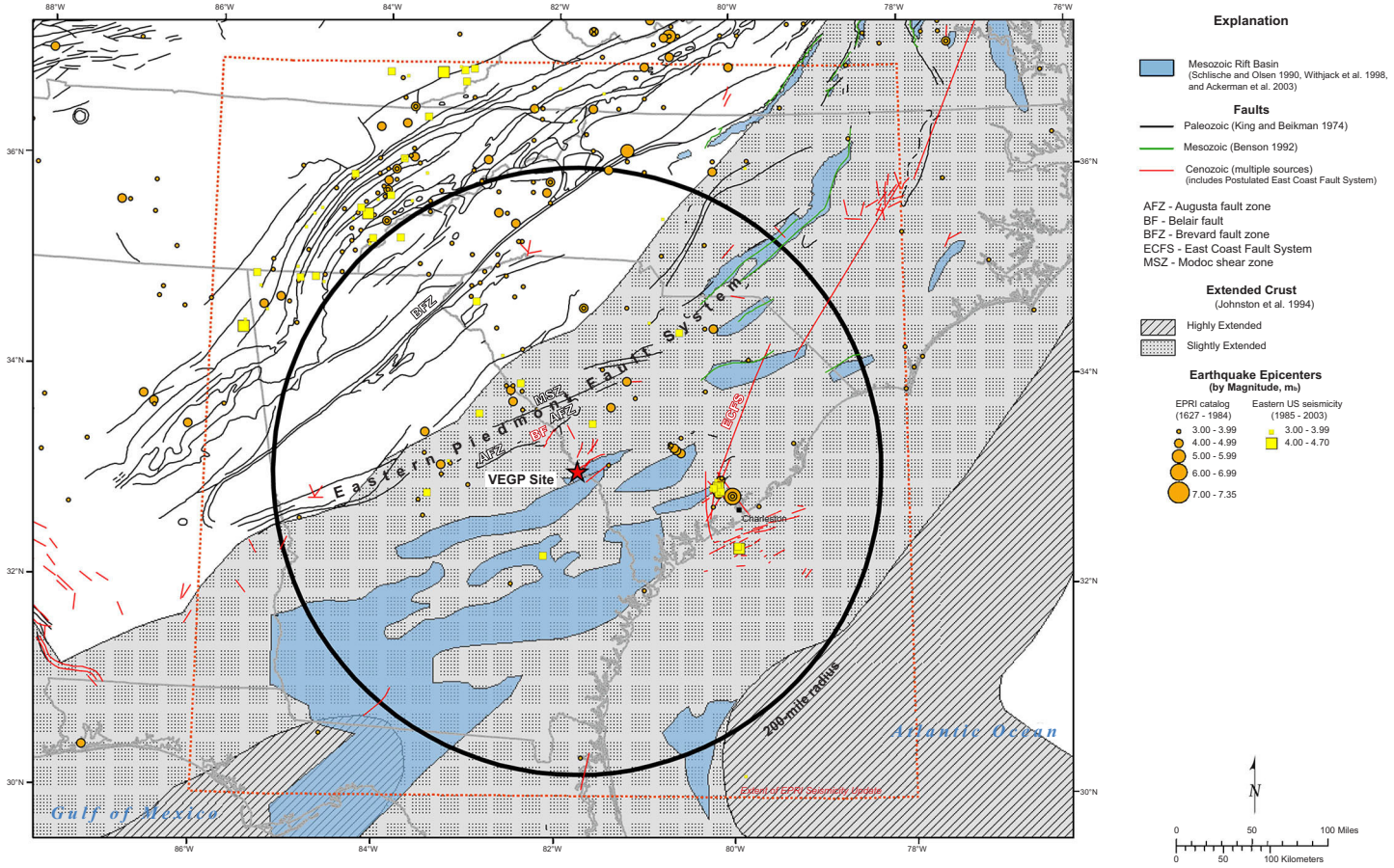


Figure 2.5-216
Regional Tectonic Features Map (200-Mile Radius)

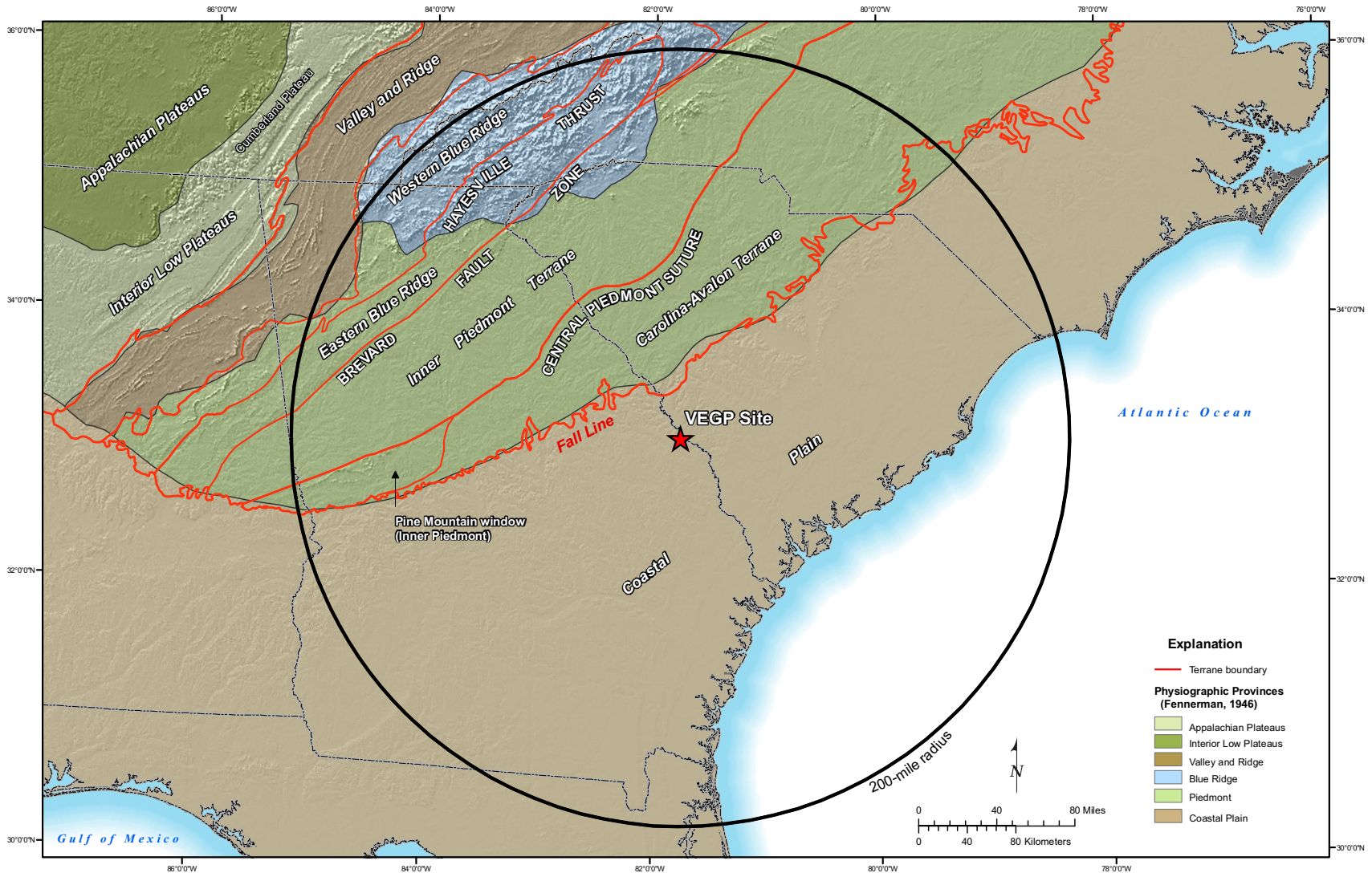
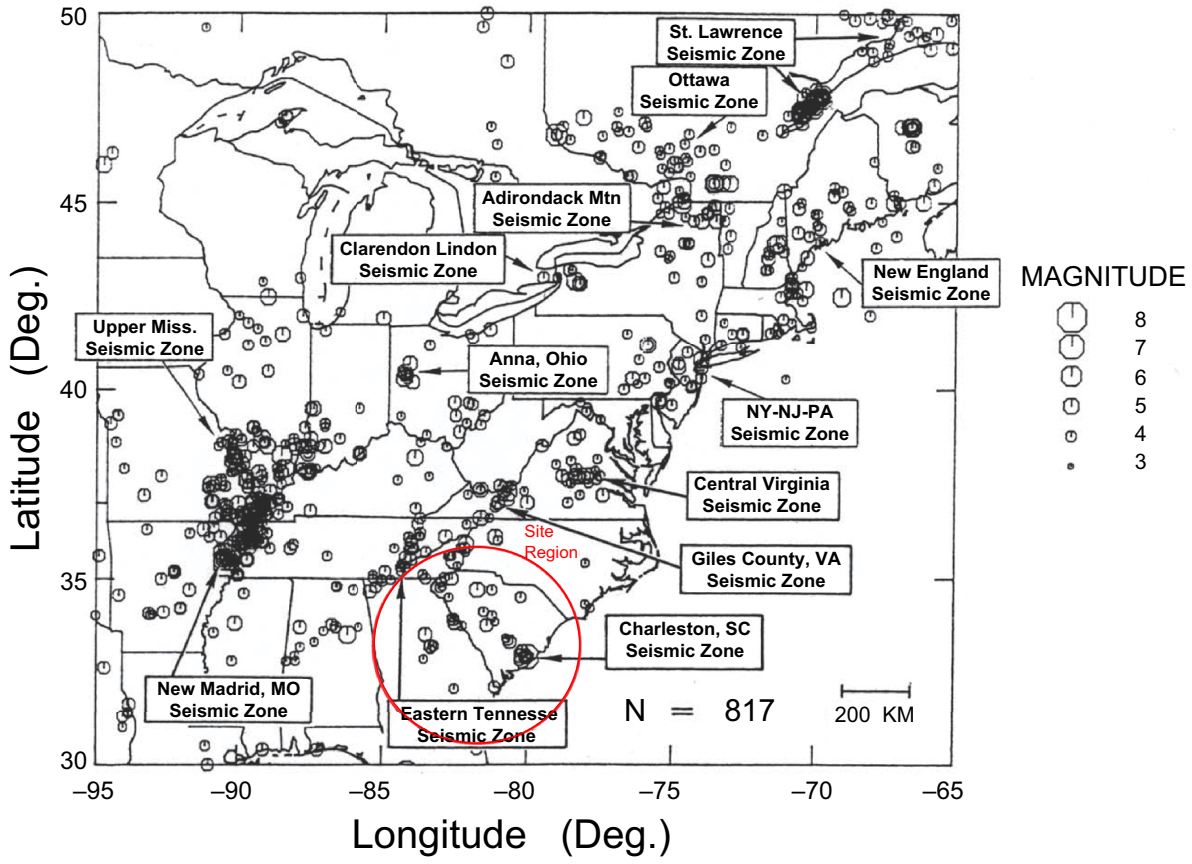


Figure 2.5-217
Terrains and Physiographic Provinces of Site Region



Source: Bollinger et al. 1992

Figure 2.5-218
Seismic Source Zones and Seismicity in Central and Eastern North America

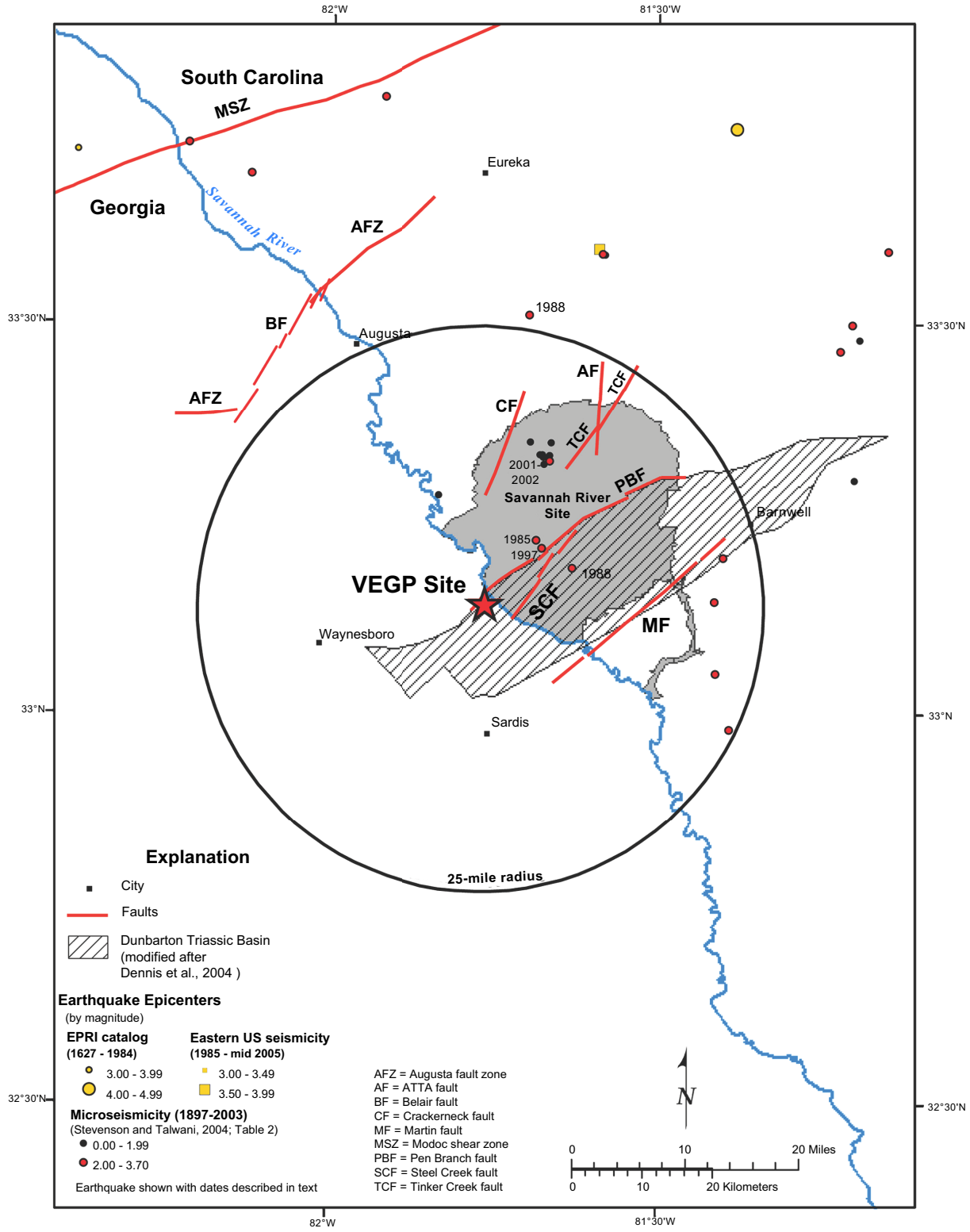
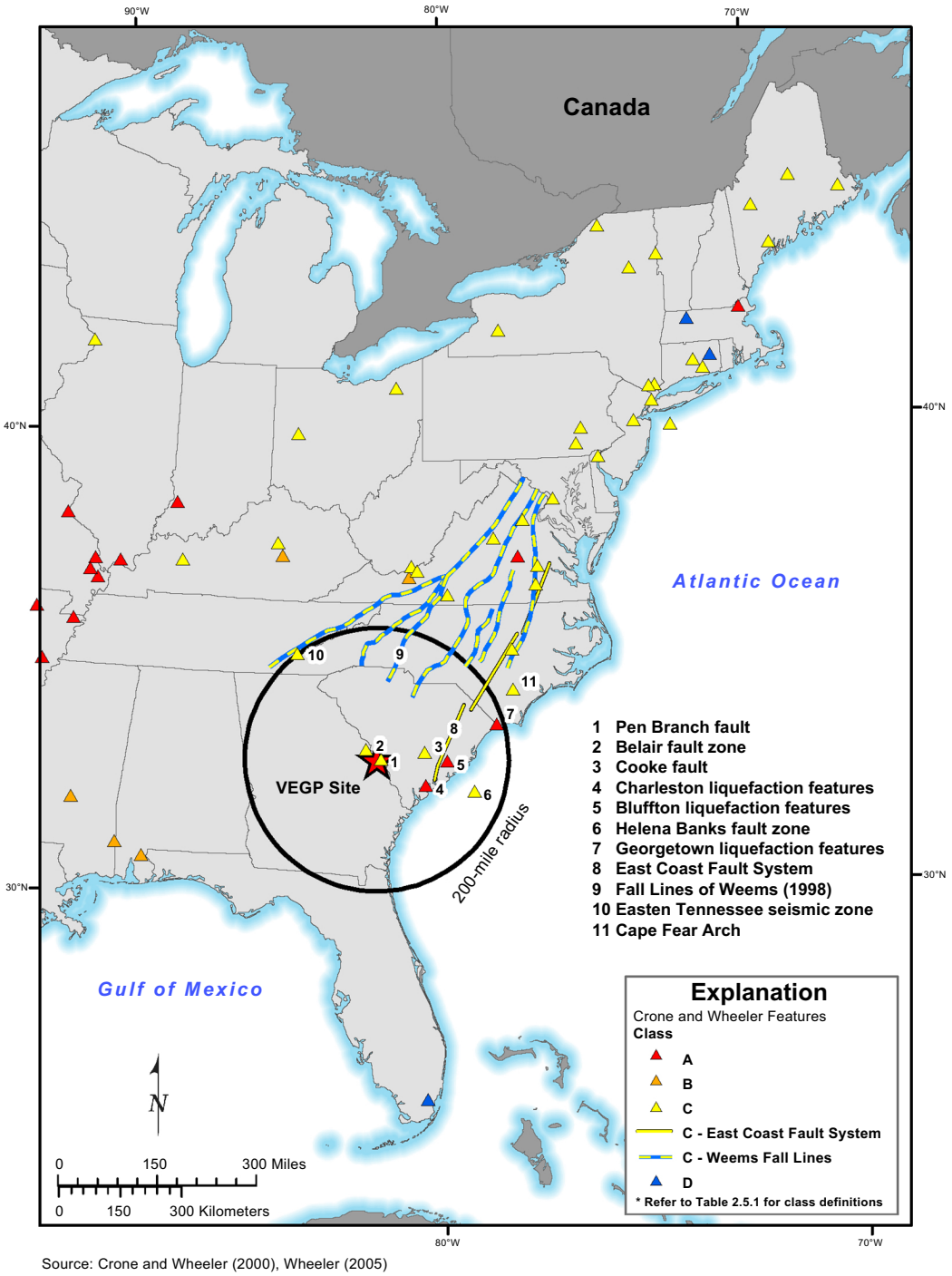


Figure 2.5-219
Site Vicinity Tectonic Features and Seismicity



Source: Crone and Wheeler (2000), Wheeler (2005)

Figure 2.5-220
Potential Quaternary Features Map

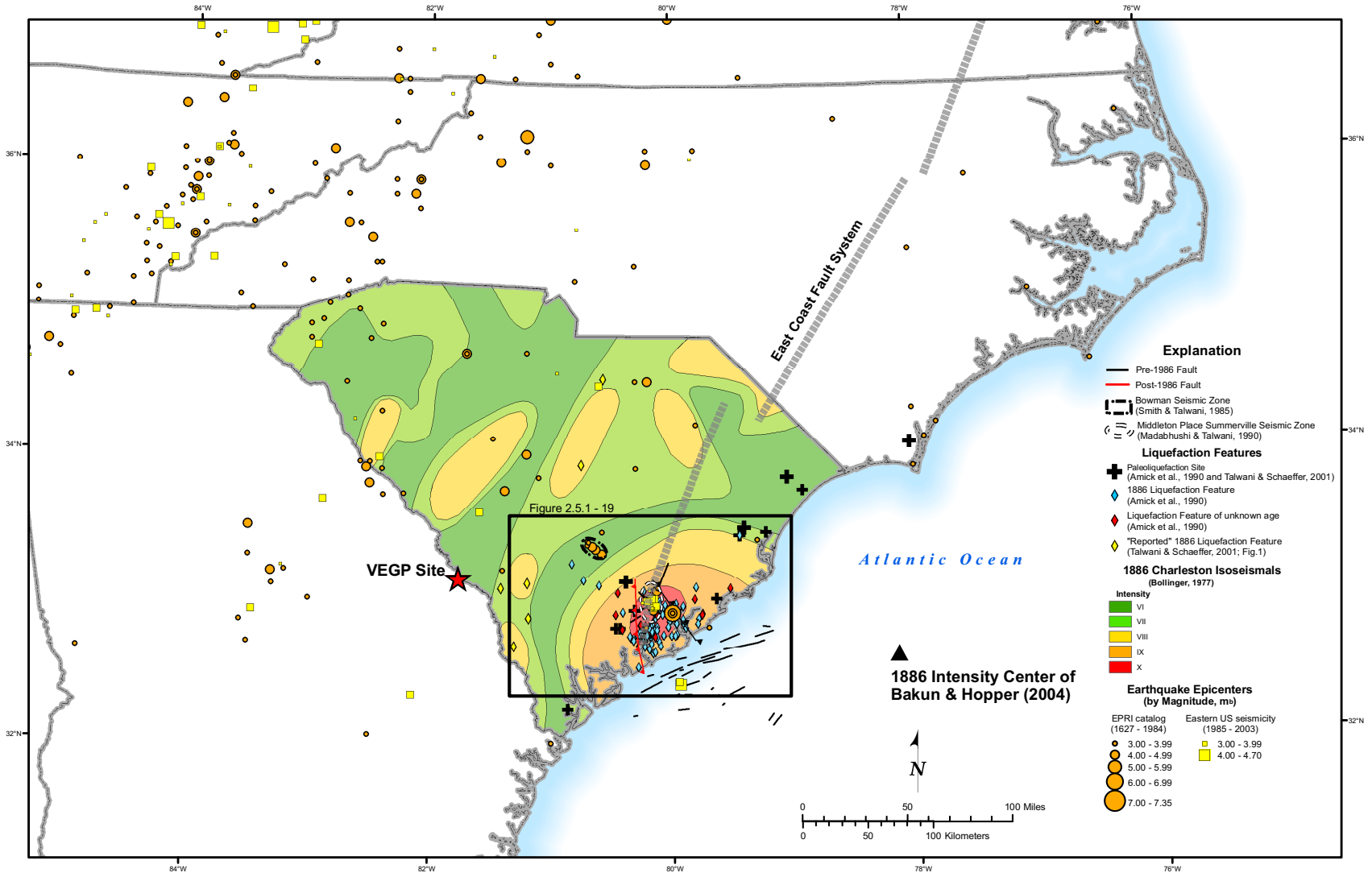


Figure 2.5-221
Regional Charleston Tectonic Features

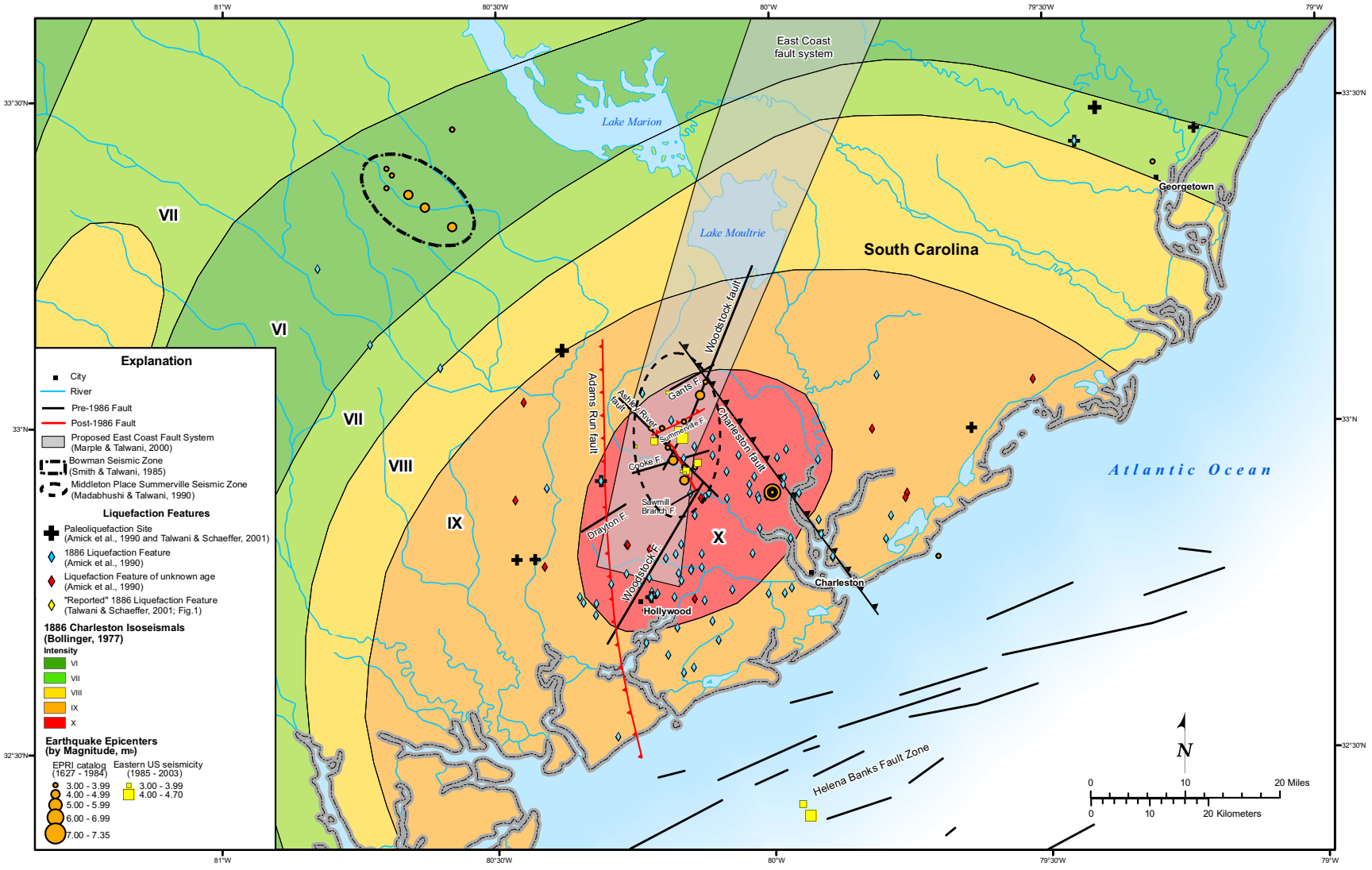


Figure 2.5-222
Local Charleston Tectonic Features

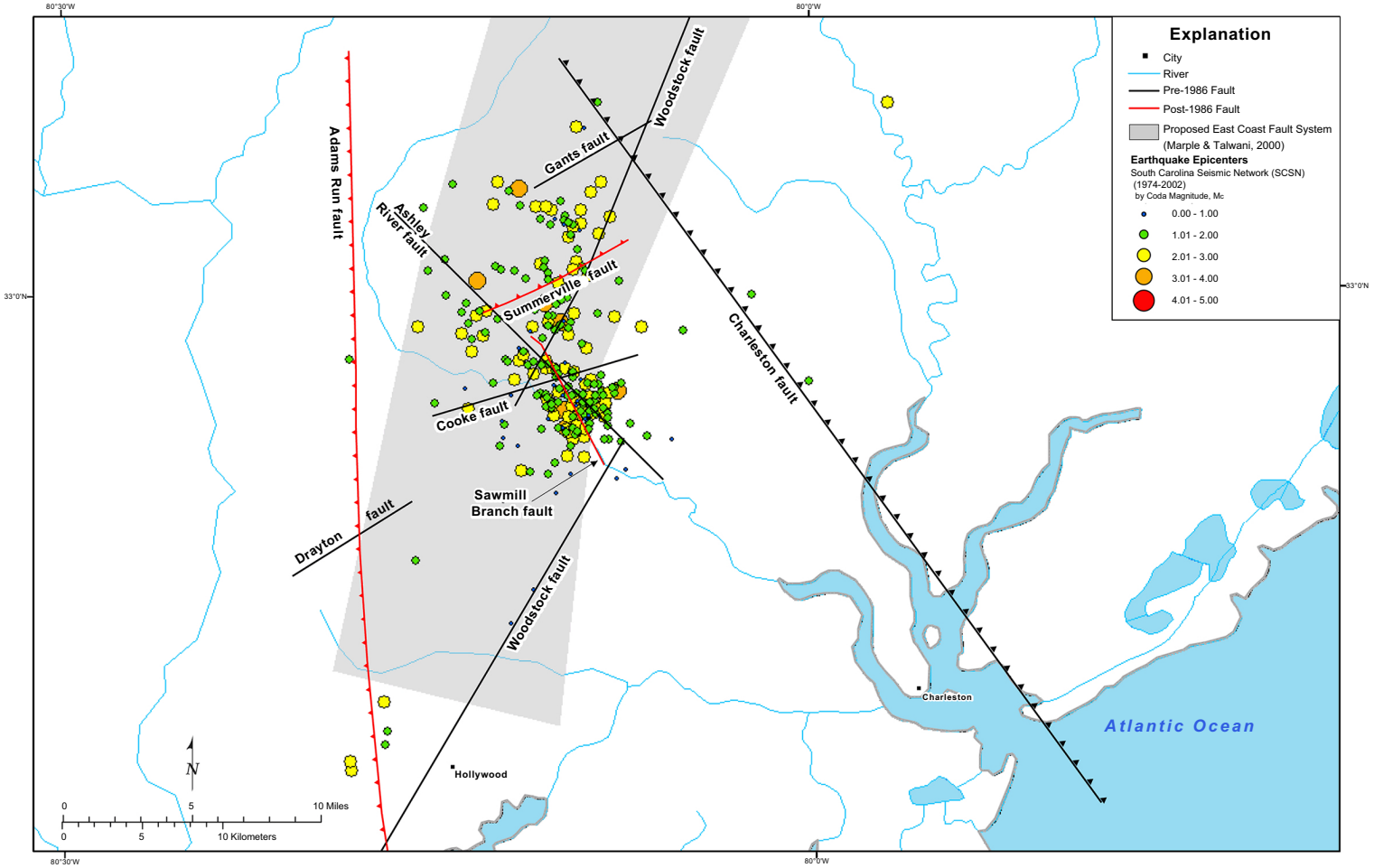
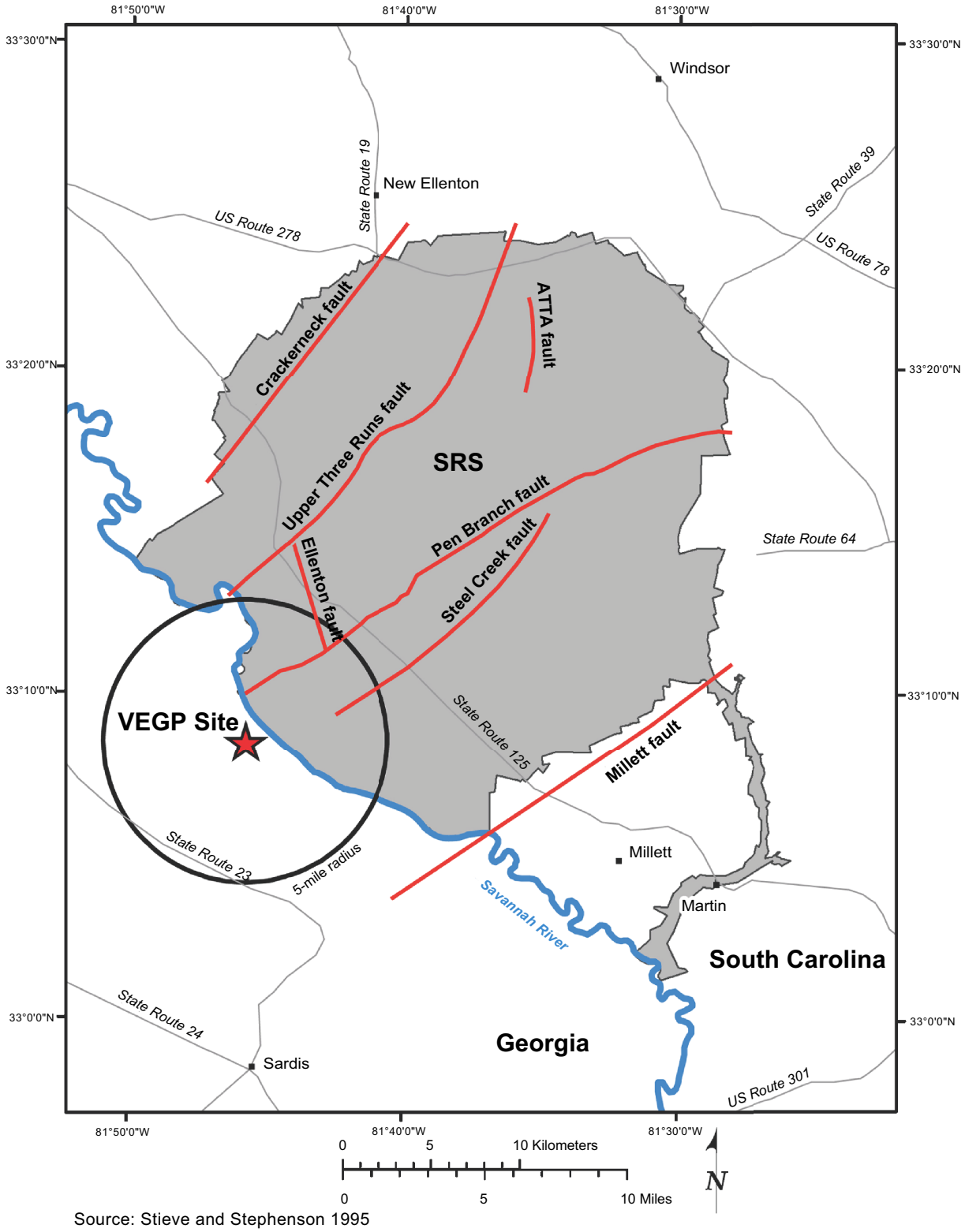
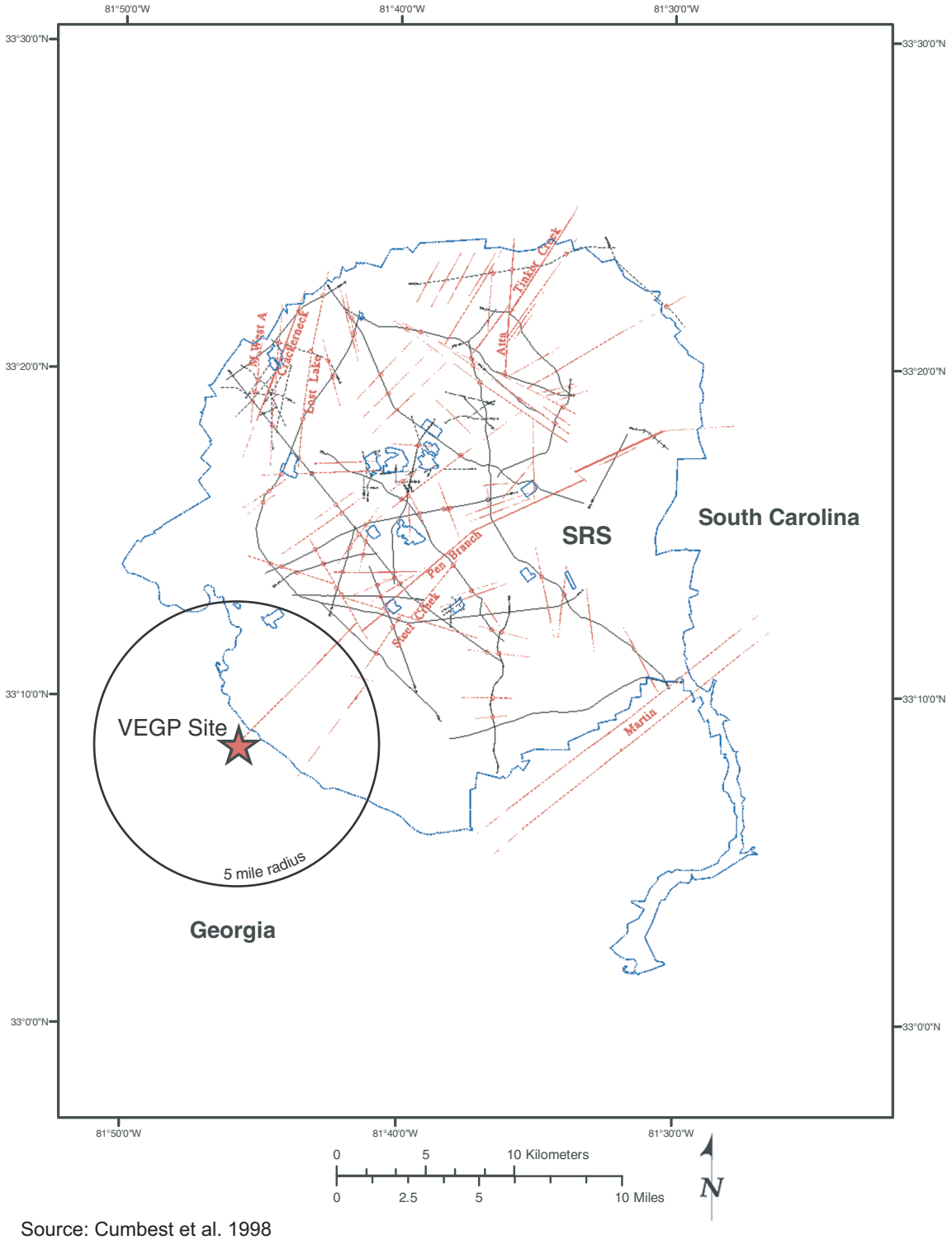


Figure 2.5-223
Local Charleston Seismicity



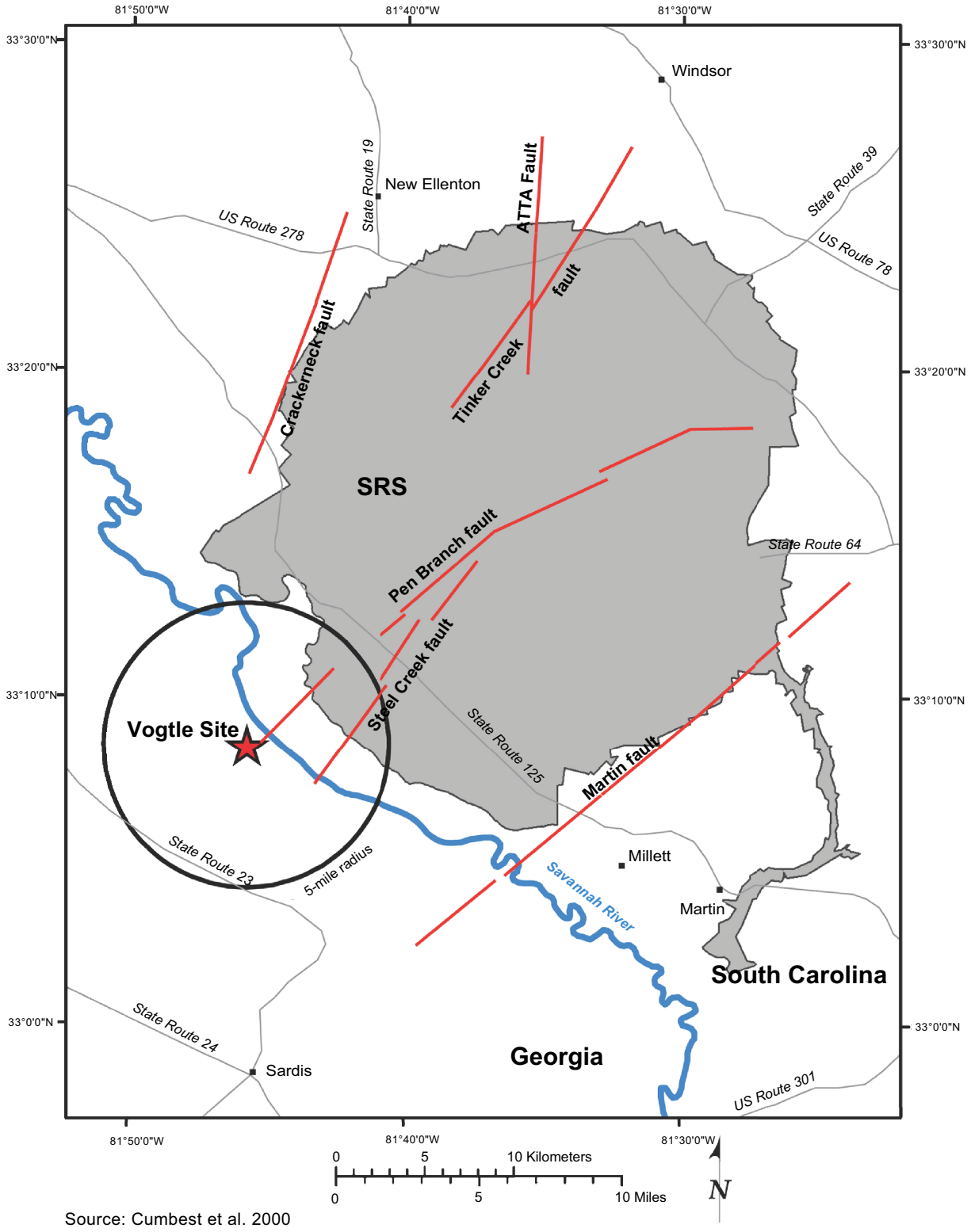
Source: Stieve and Stephenson 1995

Figure 2.5-224
SRS Faults from Stieve and Stephenson (1995)



Source: Cumbest et al. 1998

Figure 2.5-225
SRS Faults from Cumbest et al. (1998)



Source: Cumbest et al. 2000

Figure 2.5-226
SRS Faults—First-Order Faults of Cumbest et al. (2000)

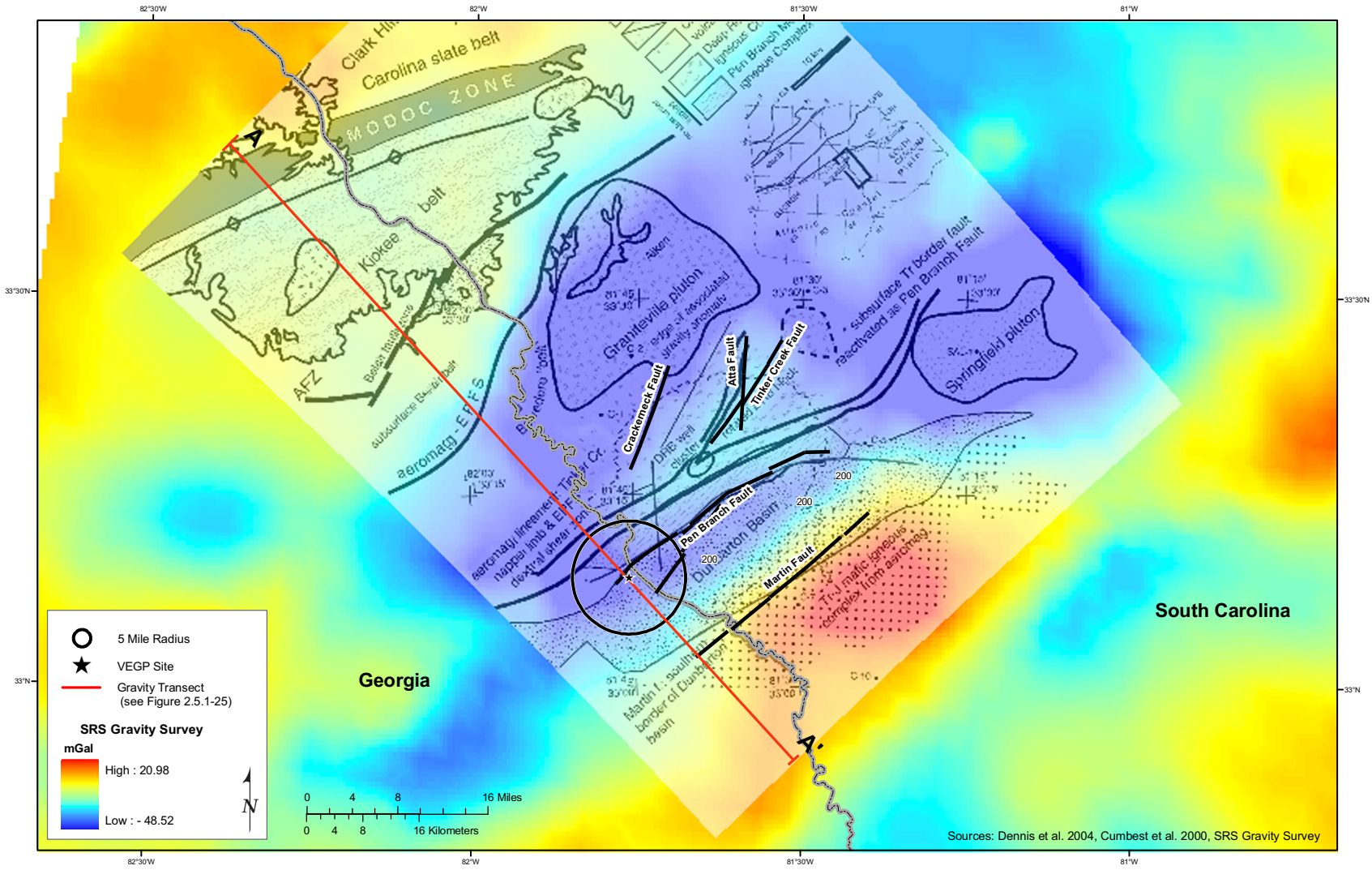


Figure 2.5-227
Gravity Field in the Vicinity of the VEGP Site

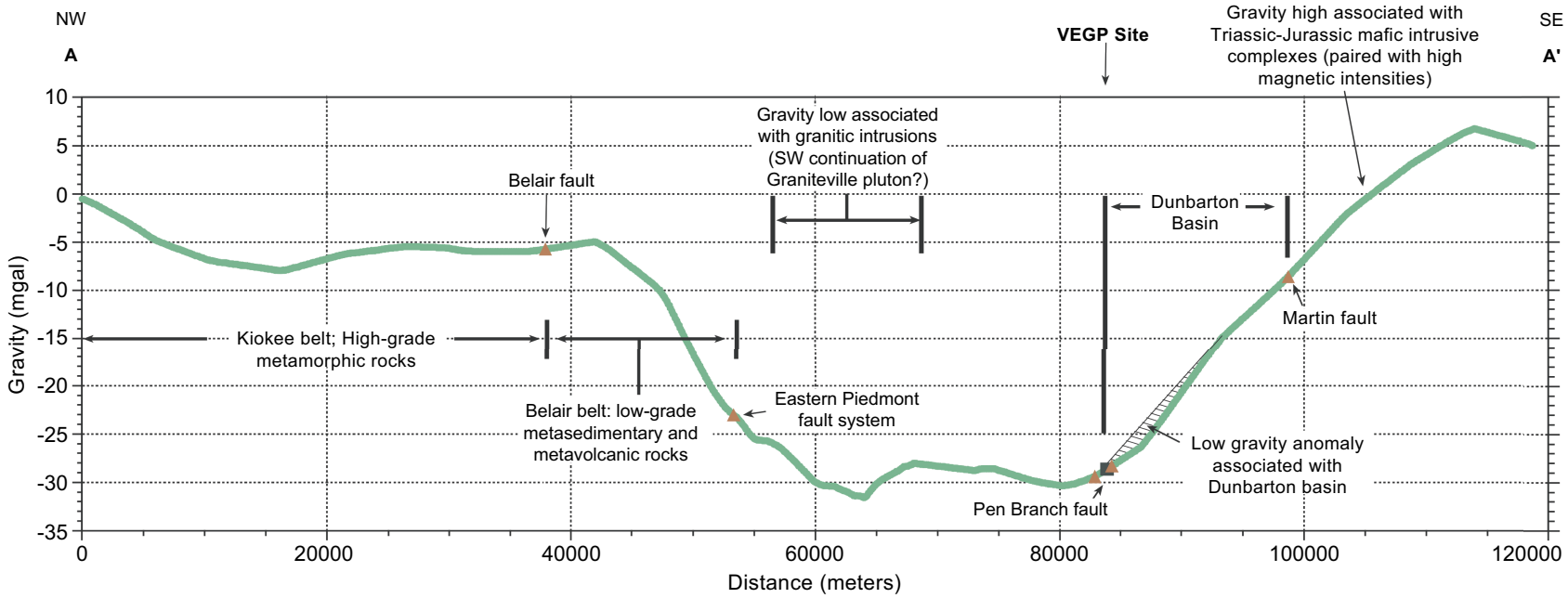


Figure 2.5-228
Northwest–Southeast Gravity Profile Through the VEGP Site

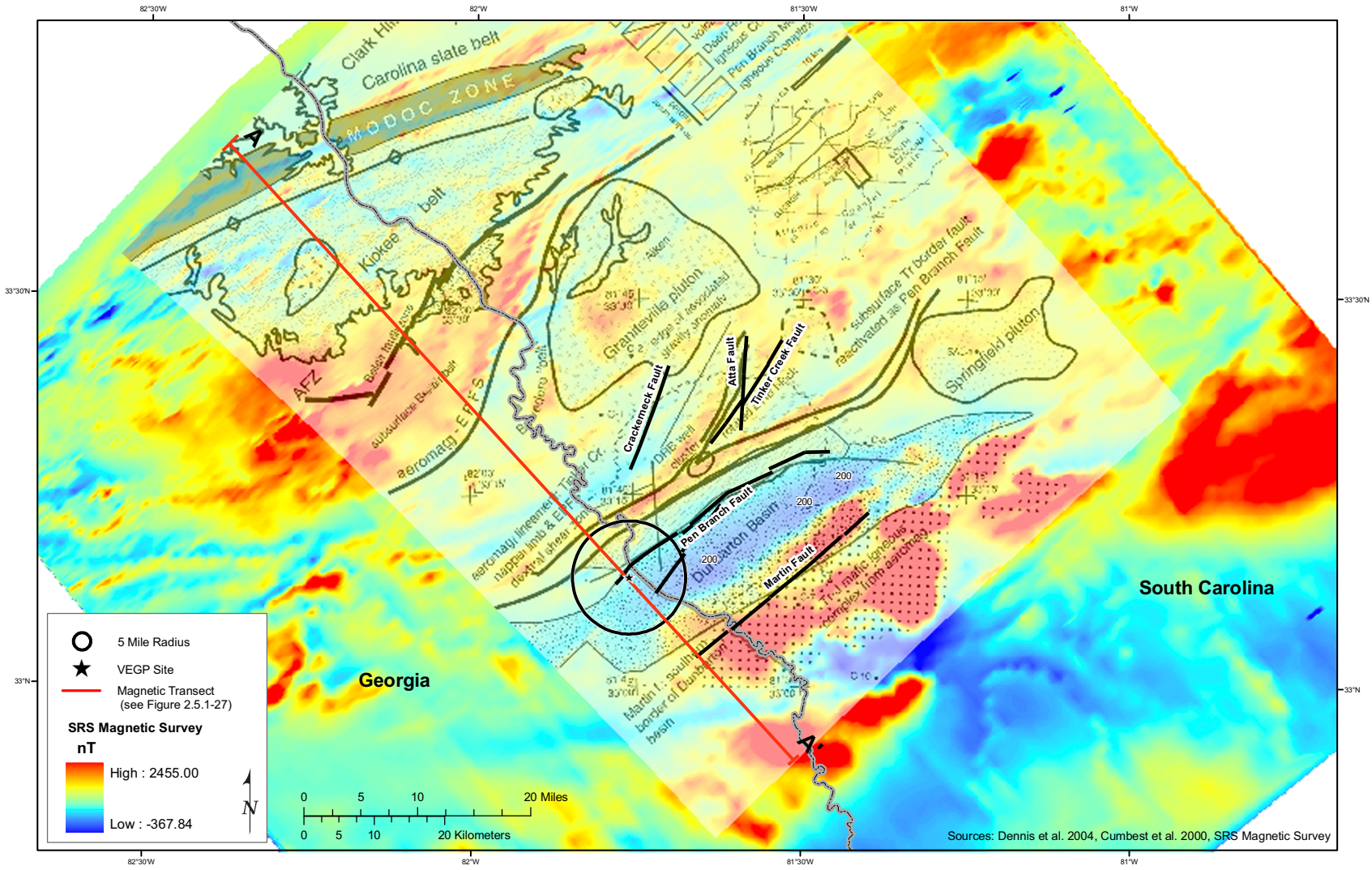


Figure 2.5-229
Magnetic Field in the Vicinity of the VEGP Site

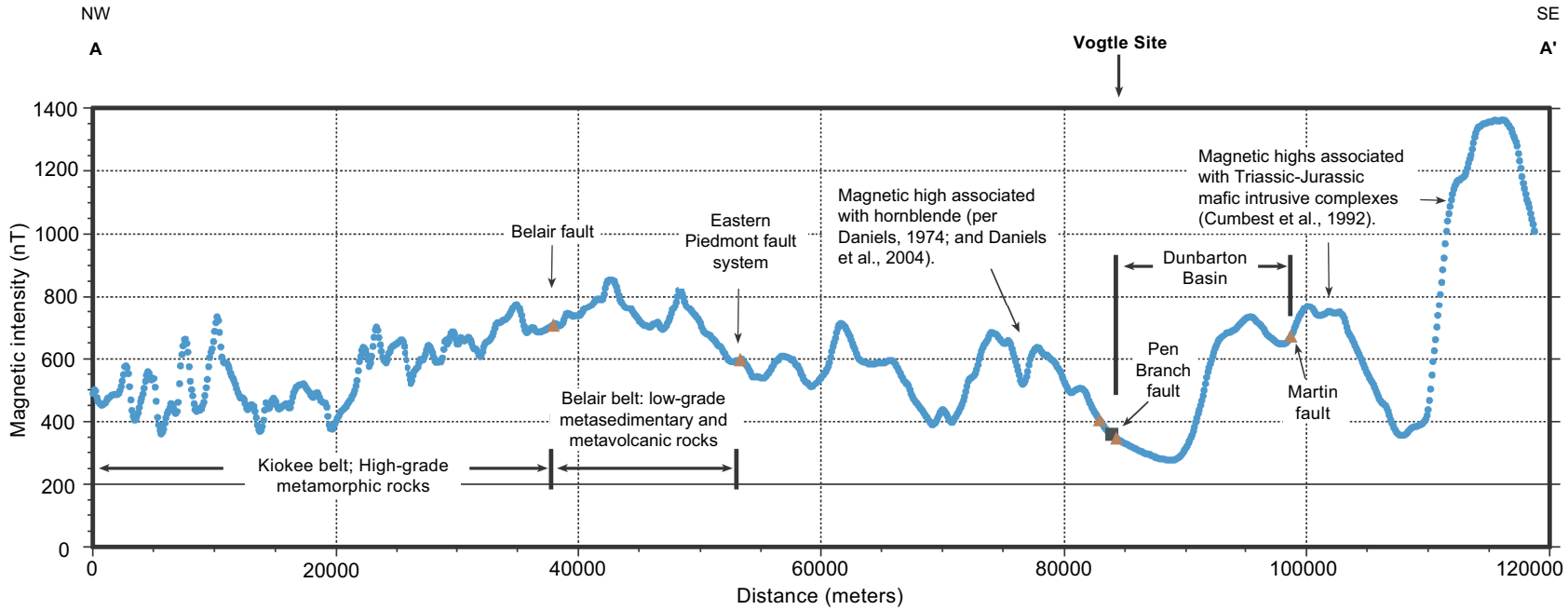


Figure 2.5-230
Northwest–Southeast Profile of Magnetic Intensity Through the VEGP Site

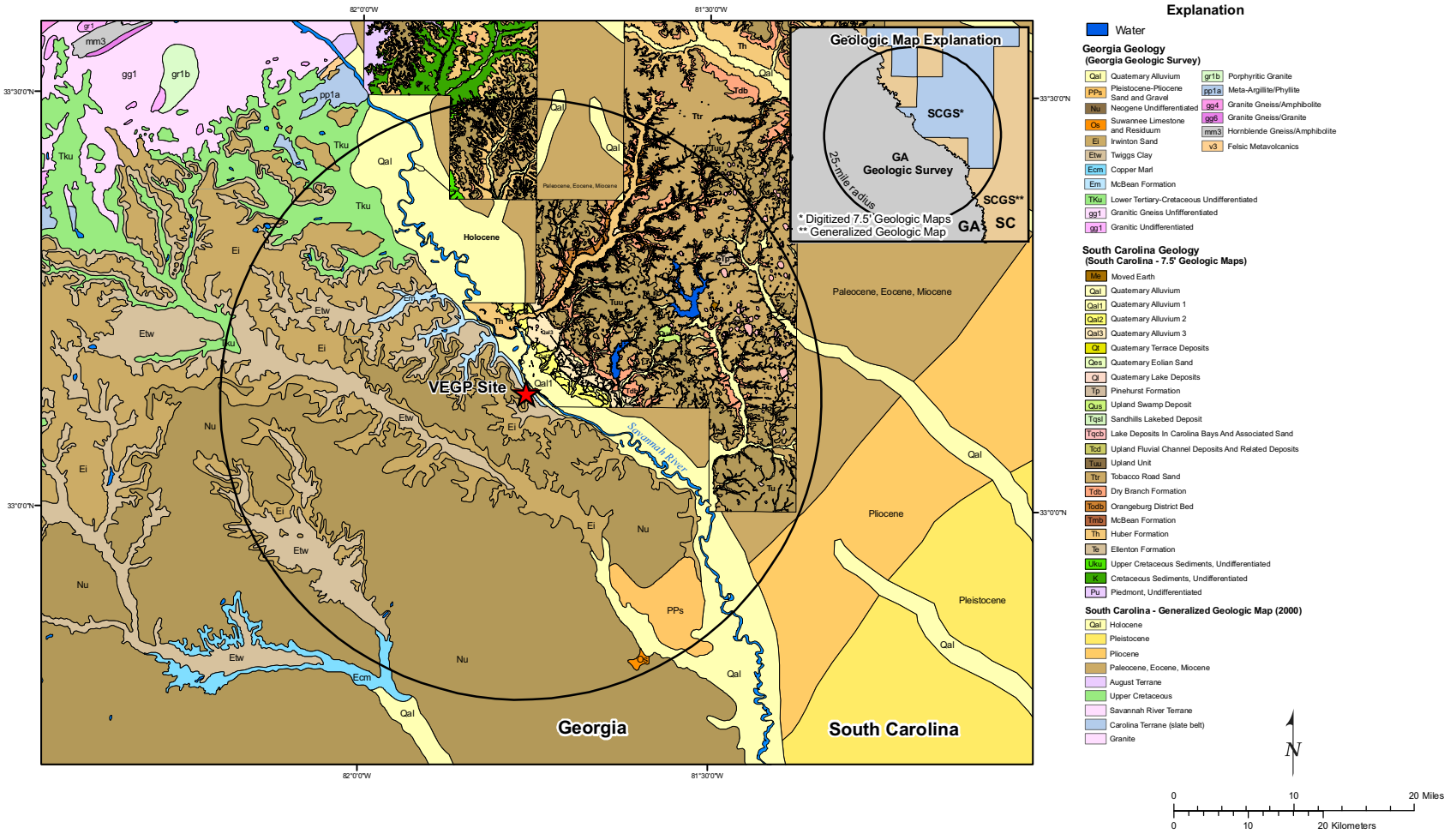


Figure 2.5-231
Site Vicinity Geologic Map (25-Mile Radius)

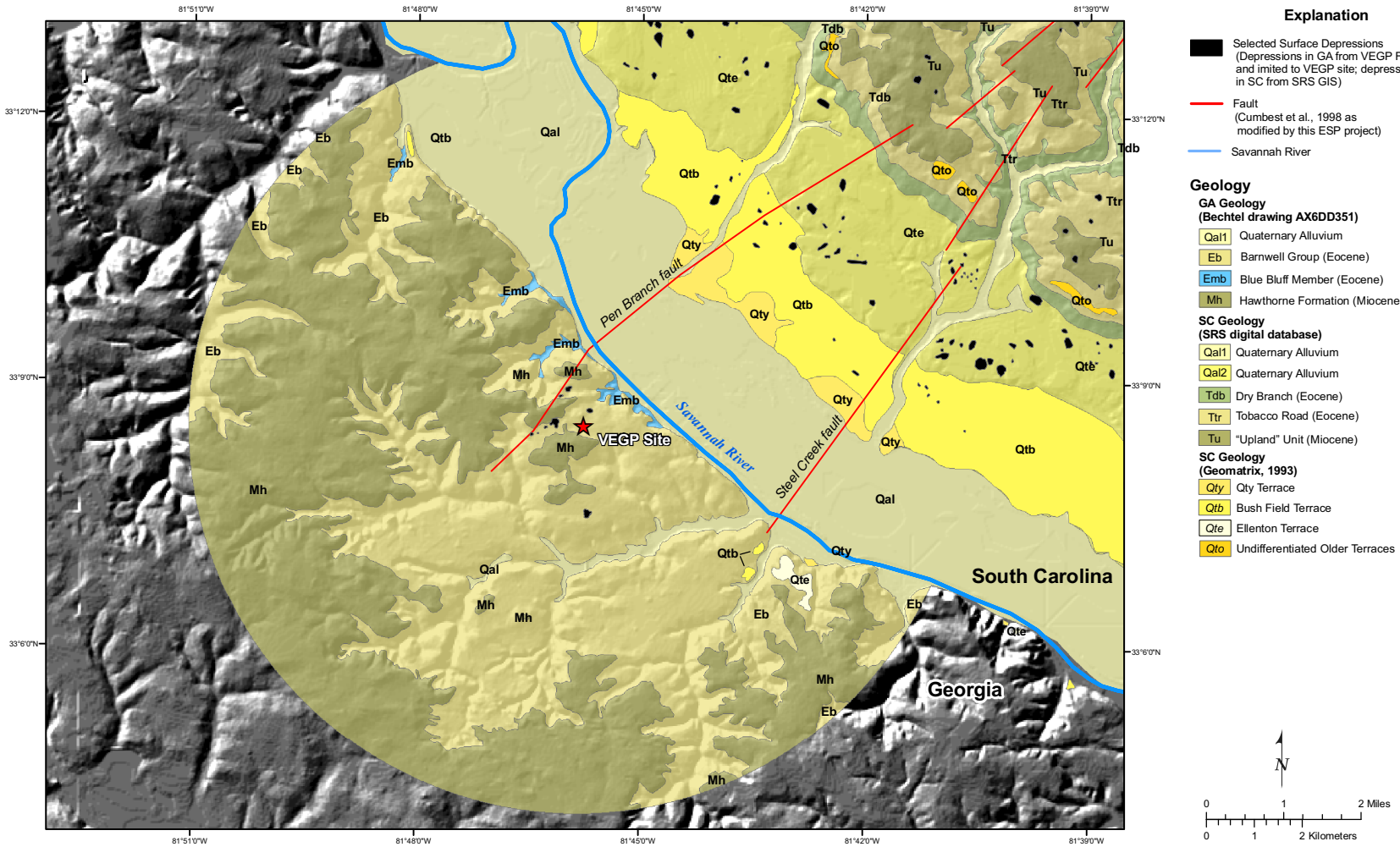


Figure 2.5-232
Site Area Geologic Map (5-Mile Radius)

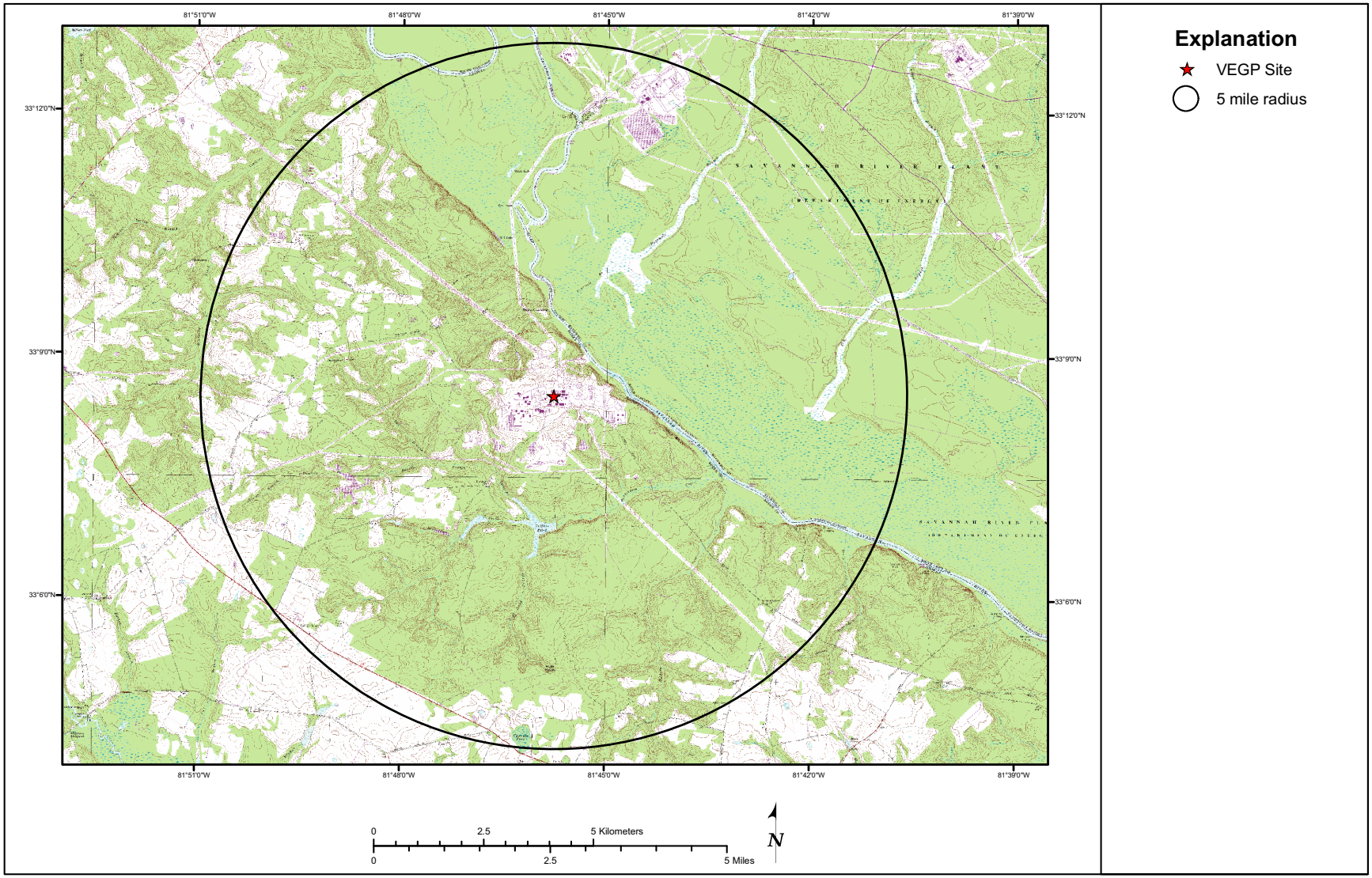


Figure 2.5-233
Site Area Topographic Map (5-Mile Radius)

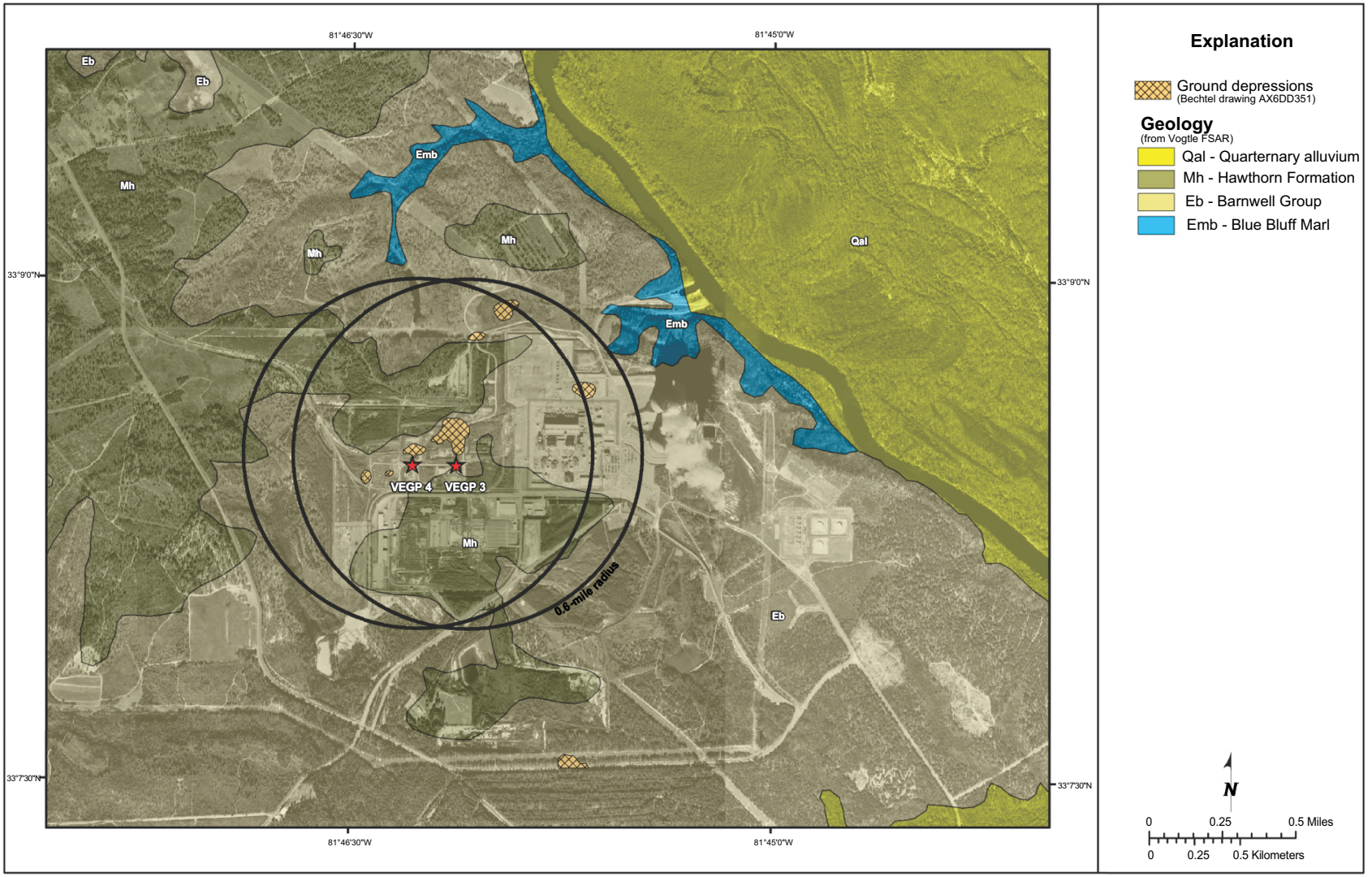
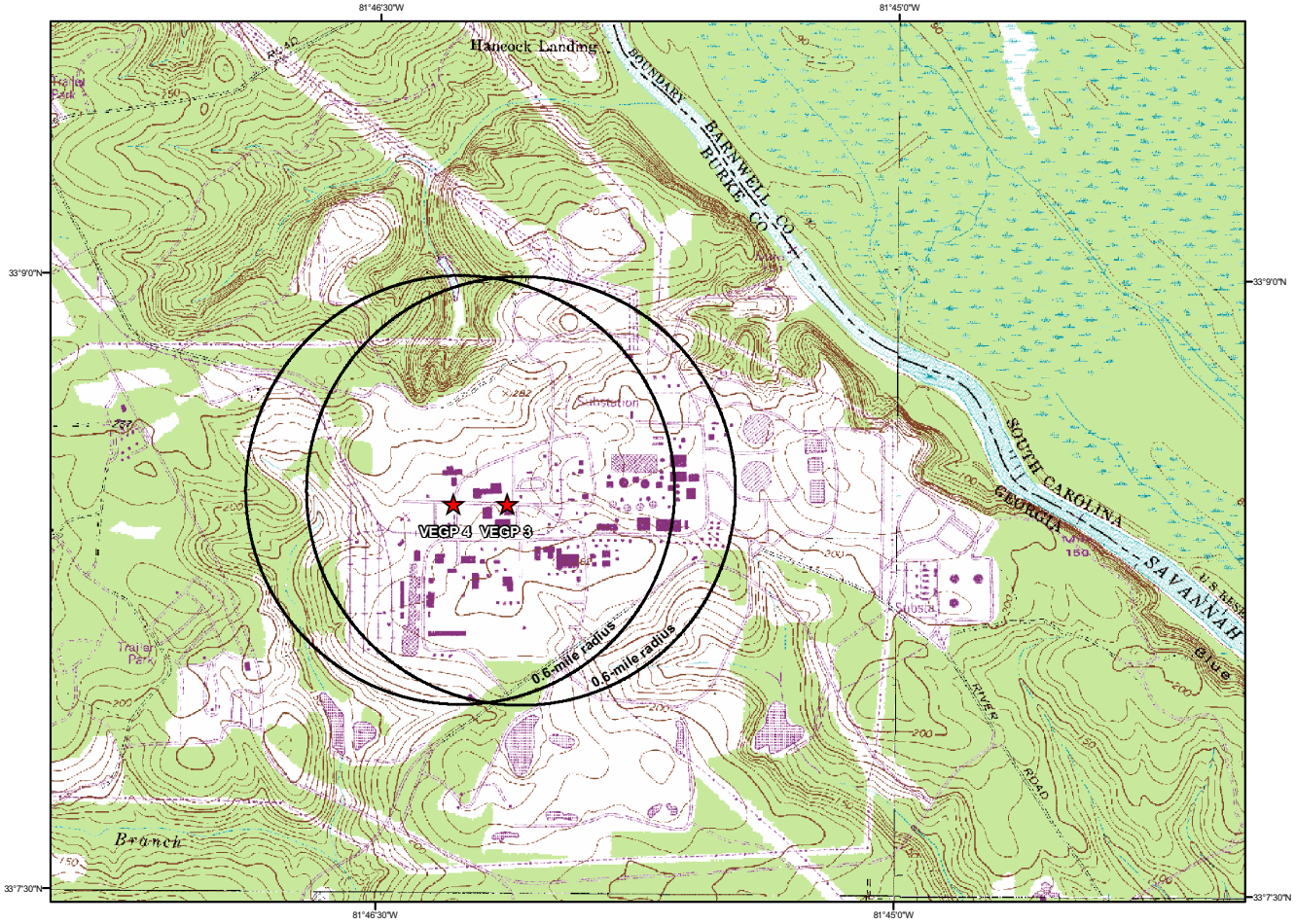


Figure 2.5-234
Site Geologic Map (0.6-Mile Radius)



Sources: USGS topographic maps of the 7.5-minute Shell Bluff Landing (1987), Girard NW (1964), Alexander (1964), and Girard (1989) quadrangles.

Figure 2.5-235
Site Topographic Map (0.6-Mile Radius)

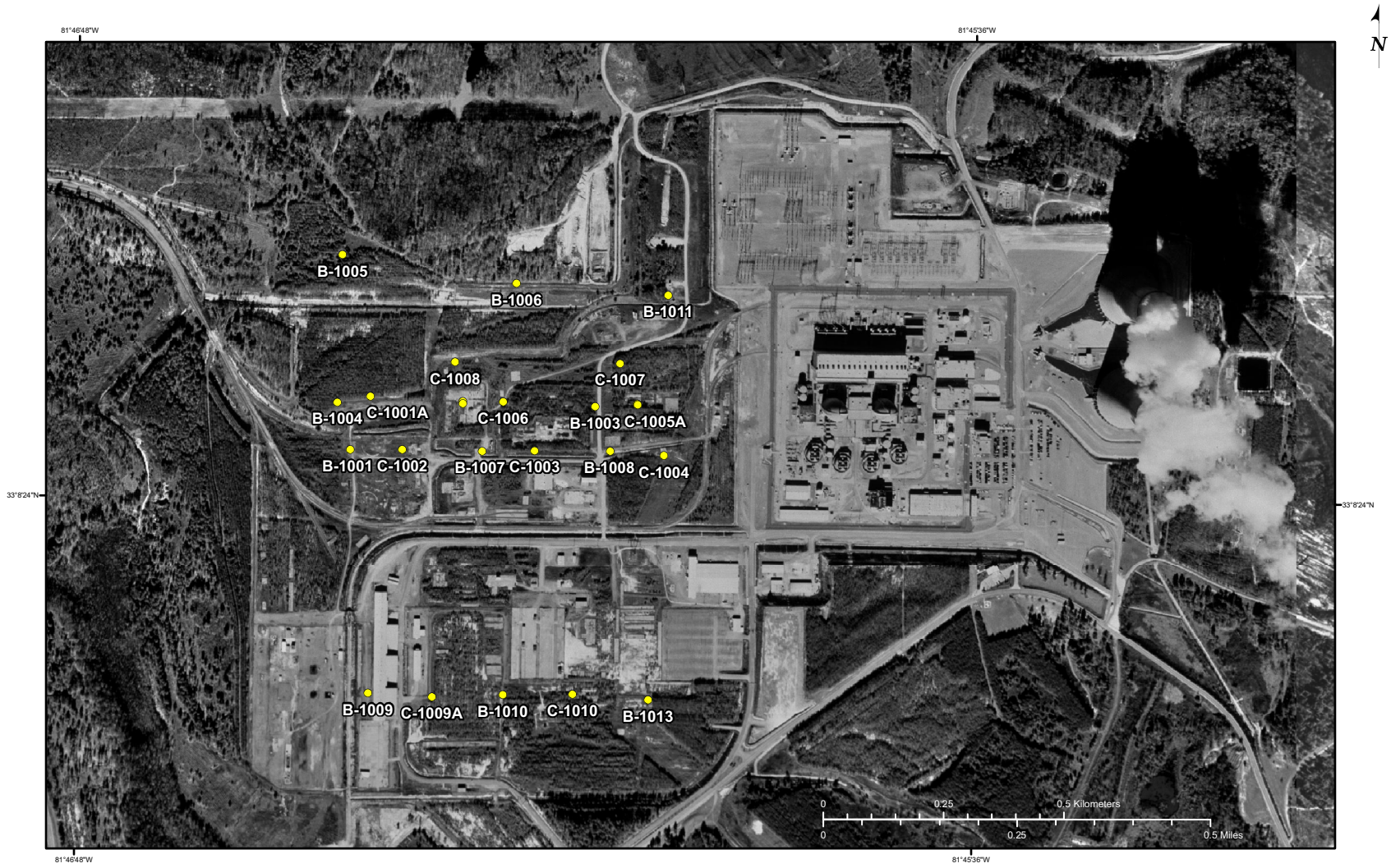


Figure 2.5-236
Site Borings Location Map

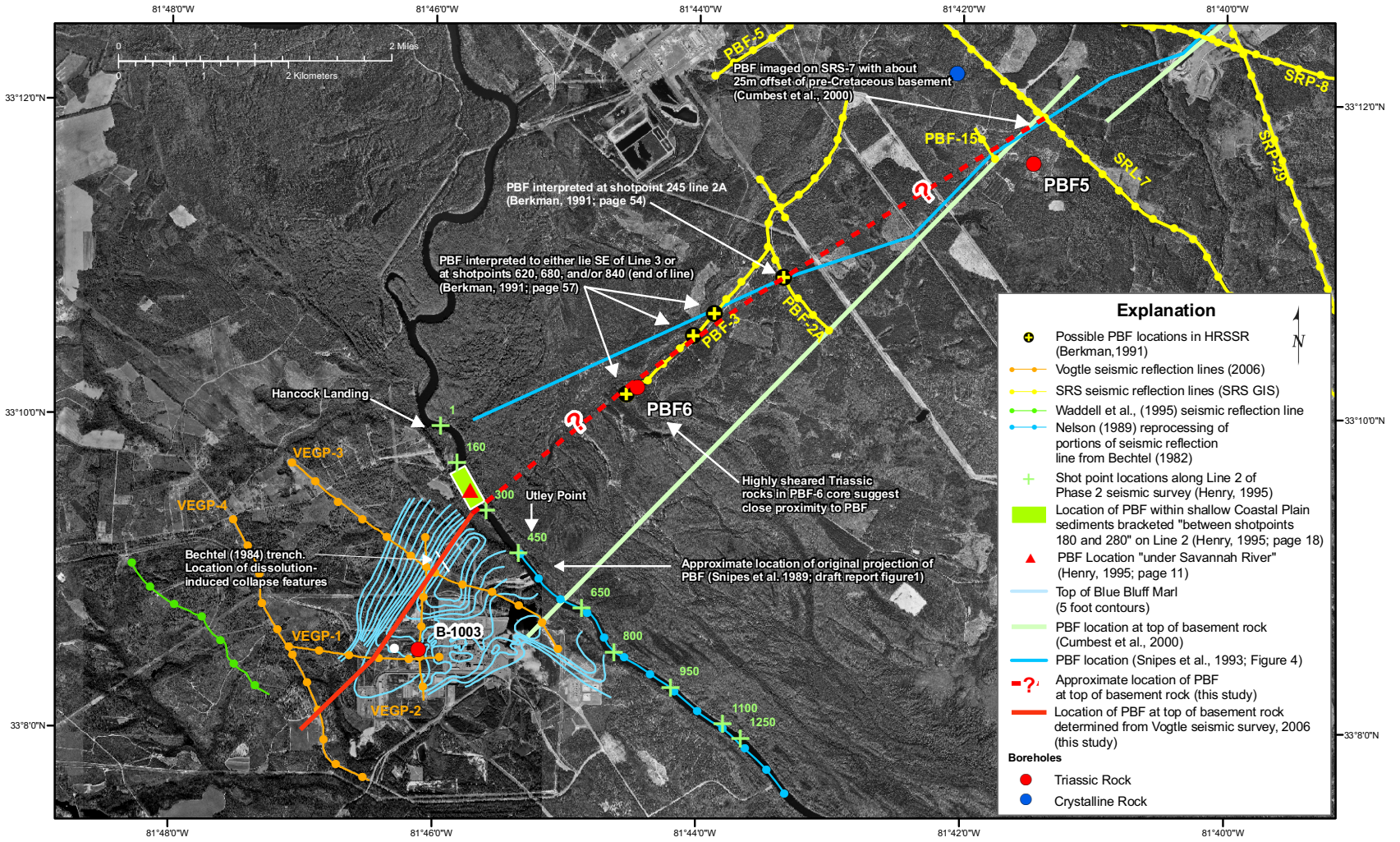


Figure 2.5-237
Location of Pen Branch Fault

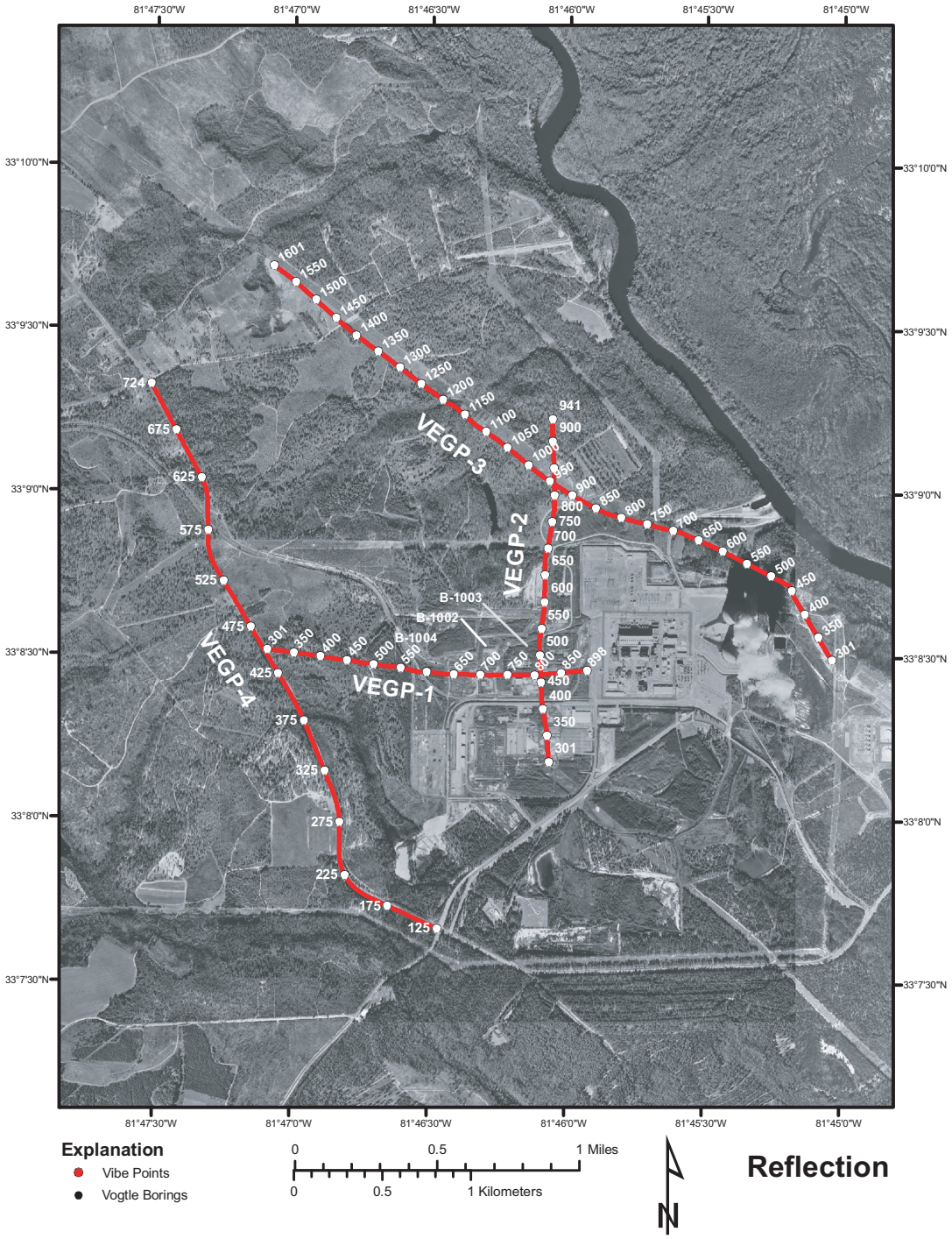


Figure 2.5-238
Seismic Reflection Array

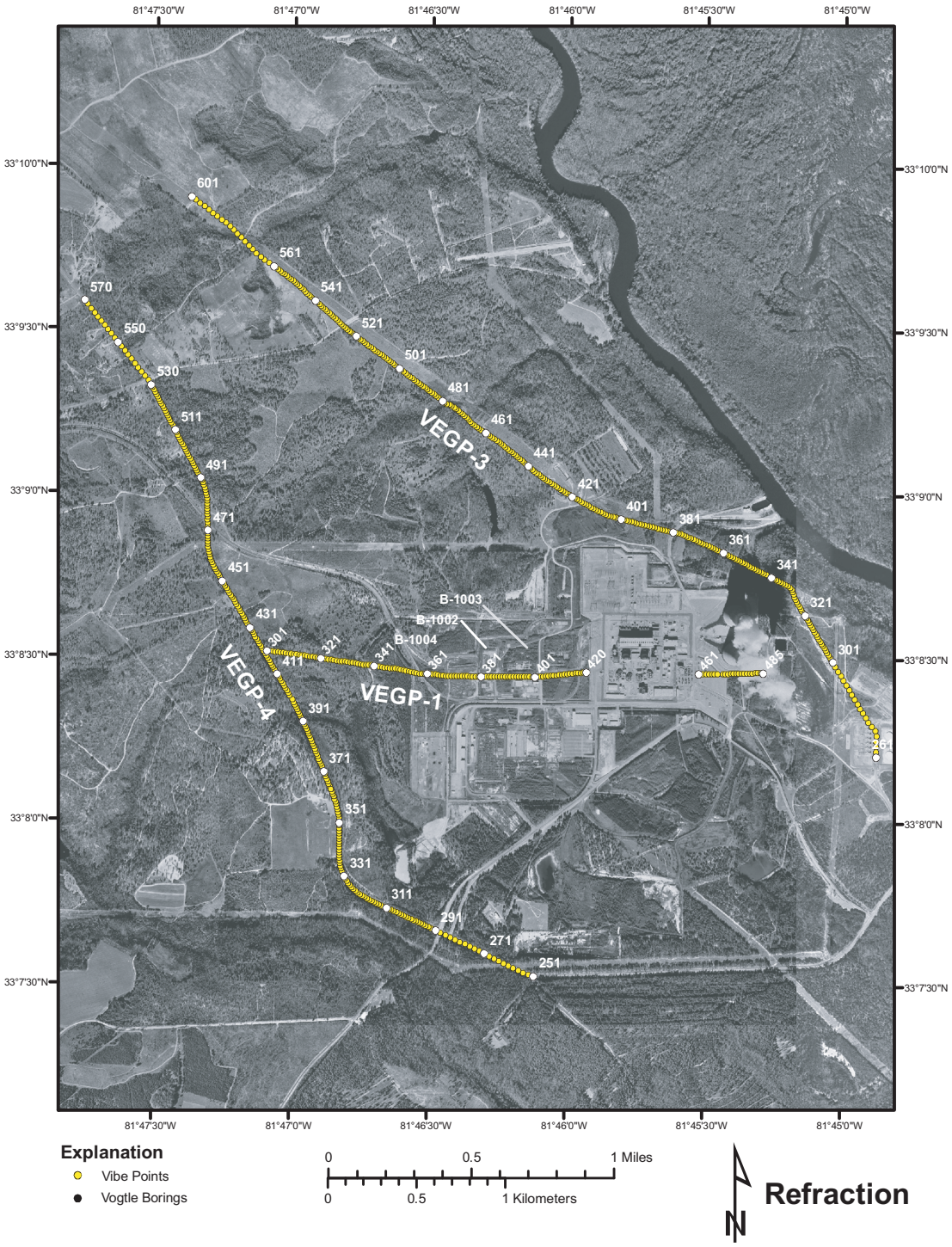


Figure 2.5-239
Seismic Refraction Array

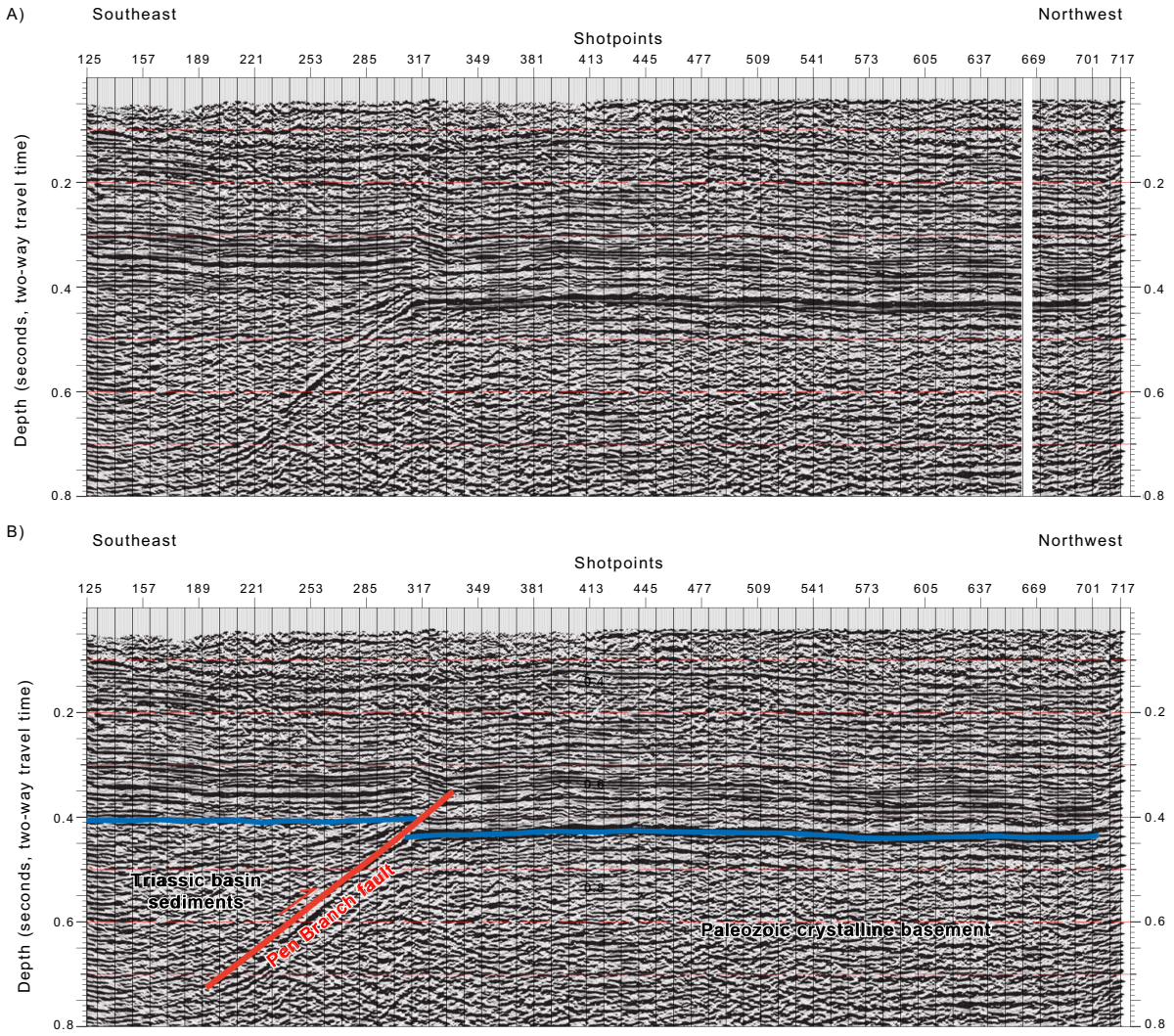


Figure 2.5-240
(A) Seismic Reflection Line 4 (Time Section; Display Velocity = 12,000 fps)
(B) Interpretation (Blue Line Represents Top of Basement)

AGE				UNIT	DEPTH (FT)	ELEVATION (FT MSL)
Cenozoic	TerTiary	Eocene	Upper	Barnwell Group • Tobacco Road Sand • Dry Branch Formation • Clinchfield Formation o Utley Limestone Member	Ground surface 74	+218 +144
			Middle	Claiborne Group • Lisbon Formation o Blue Bluff Member • Still Branch Sand • Congaree Formation	 88 173 216	 +130 +50 +7
			Lower			
		Paleocene	Upper	• Snapp Formation • Black Mingo Formation	331 438	-108 -215
			Lower			
Mesozoic	Cretaceous	Upper		• Steel Creek Formation • Gaillard Formation/ Black Creek Formation • Pio Nono Formation / Unnamed Sand • Cape Fear Formation	477 587 798 858	-254 -364 -575 -635
	Triassic			Triassic (Dunbarton) basin	1049 Boring terminated at 1338	-826

Note: The site stratigraphic column is based primarily on cored boring B-1003. The data on the Utley Limestone and Blue Bluff Marl have been revised based on more extensive data from the ESP and COL borings.

Figure 2.5-241
Site Stratigraphic Column

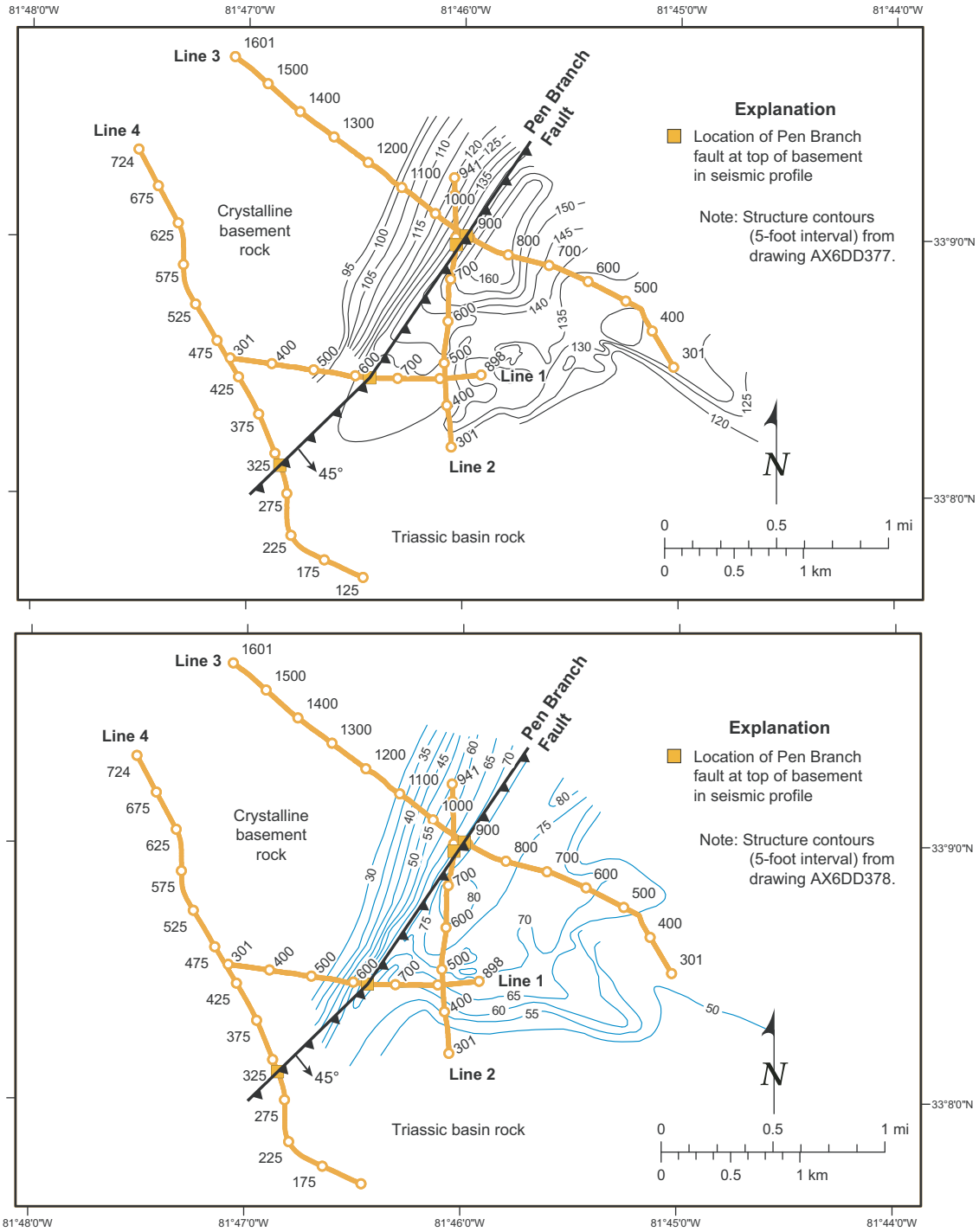


Figure 2.5-242
Location of the Pen Branch Fault at Top of Basement Beneath the Overlying Monocline in the Blue Bluff Marl

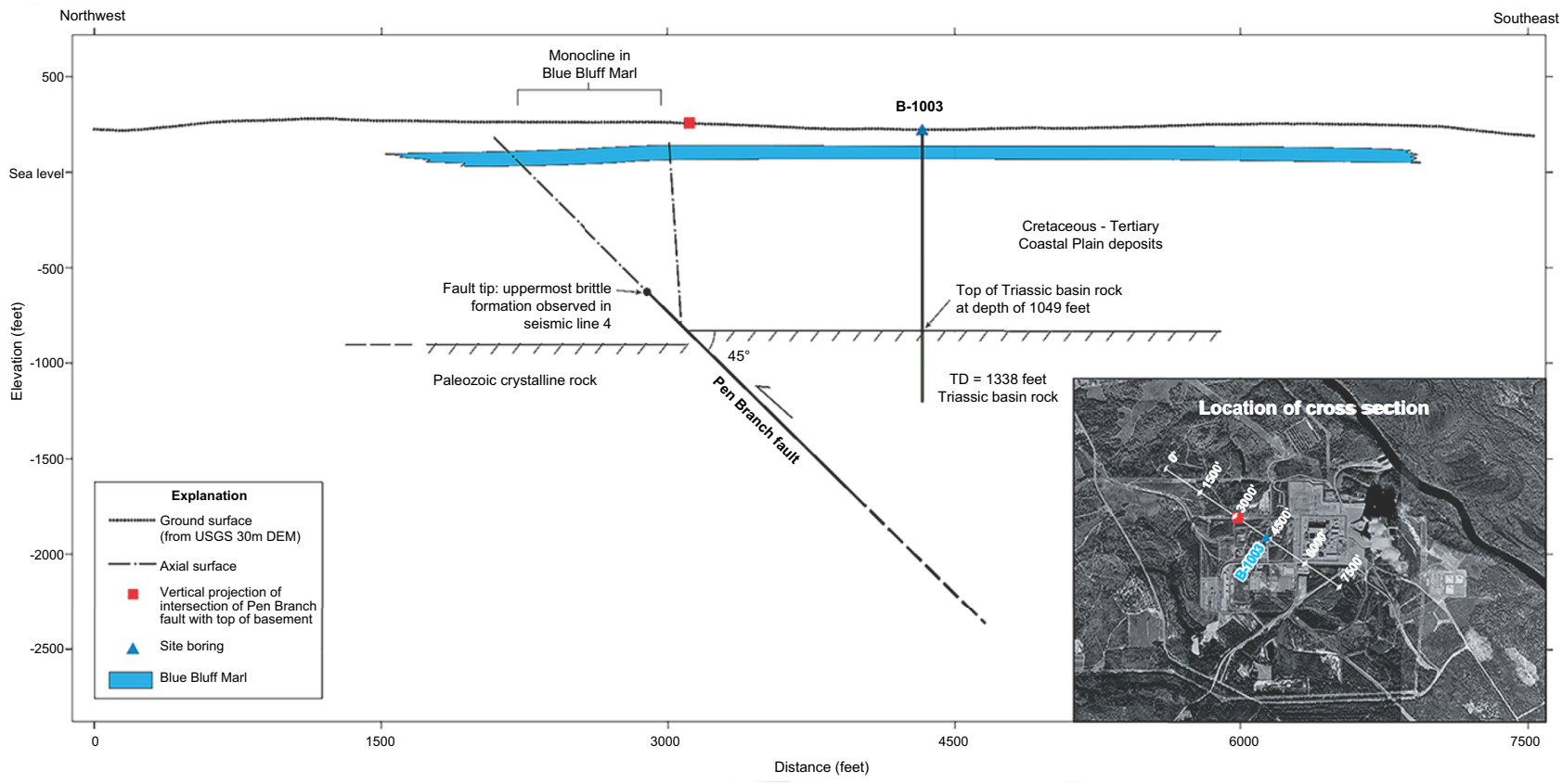


Figure 2.5-243
Northwest–Southeast Cross Section Showing Pen Branch Fault Beneath VEGP Site

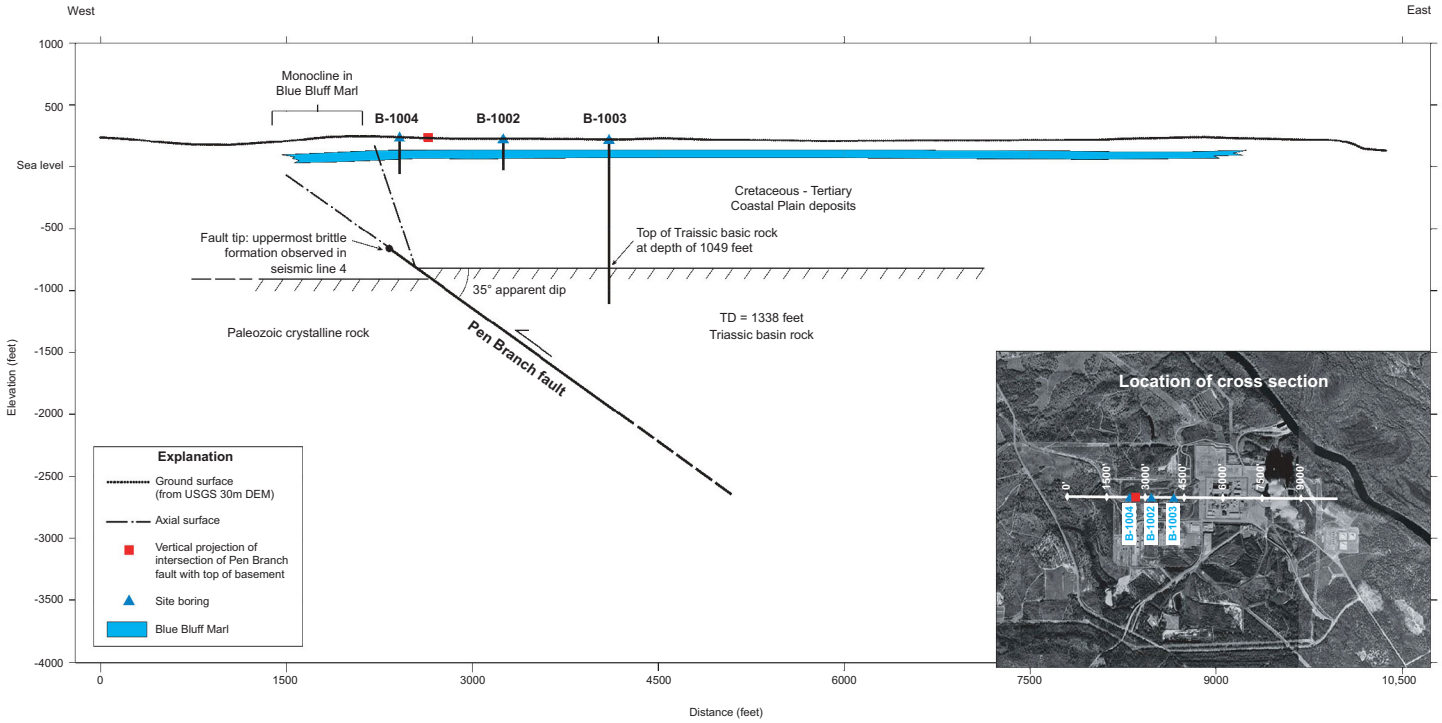


Figure 2.5-244
East–West Cross Section Showing Pen Branch Fault Beneath VEGP Site

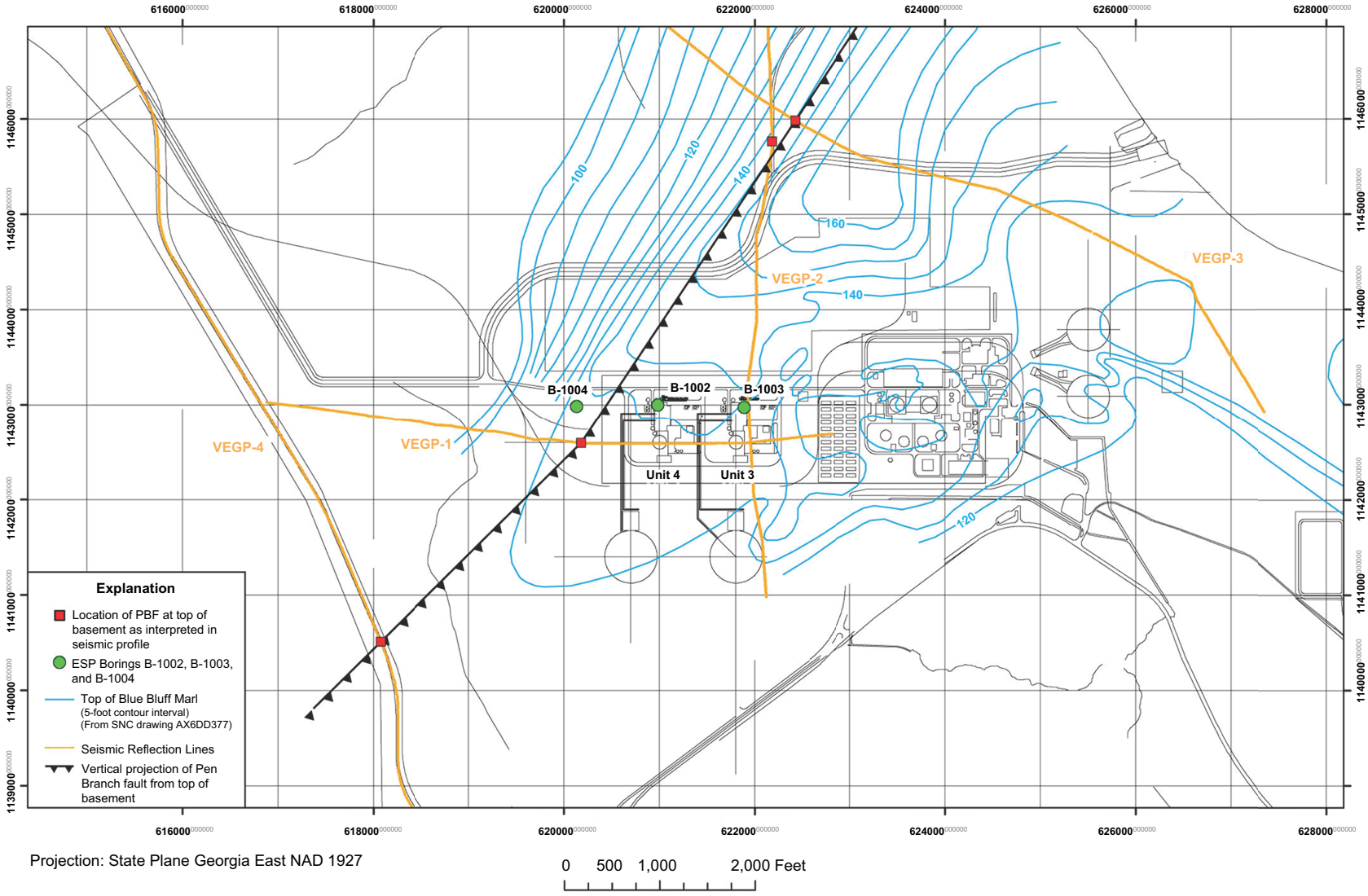


Figure 2.5-245
VEGP Site Plant Layout

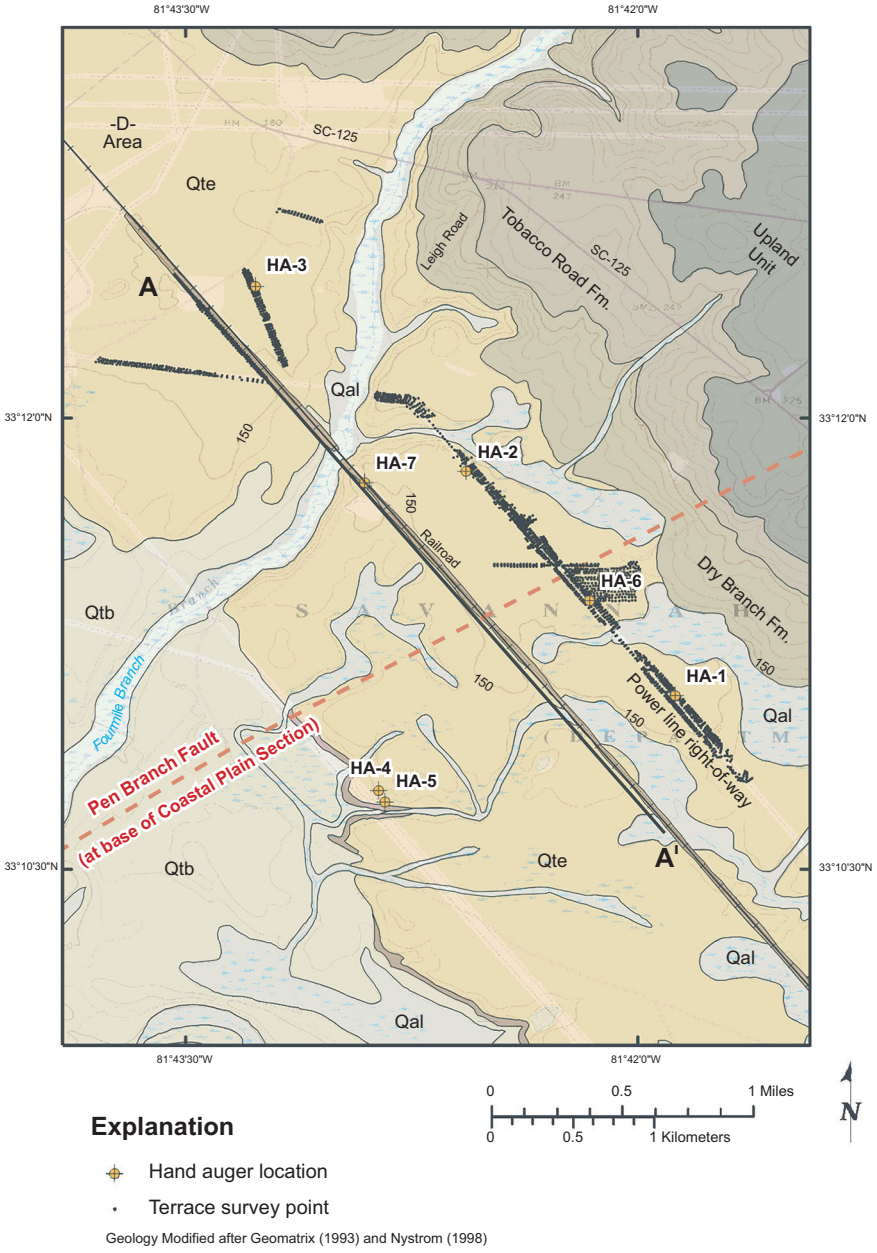


Figure 2.5-246
Geologic Map of Qte Terrace Study Area

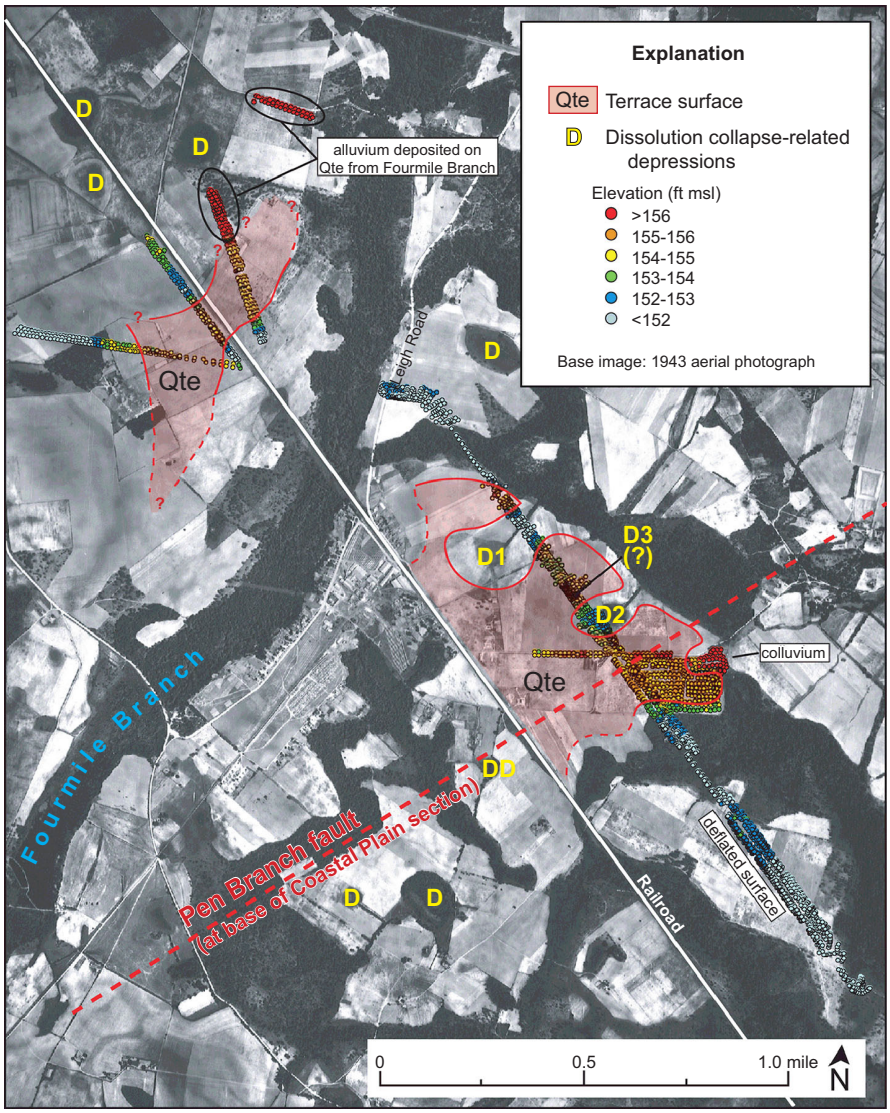


Figure 2.5-247
Geomorphic Map Showing Best-Preserved Remnants of Qte Terrace Surface (Red Shading) in Study Area at the SRS. Yellow Ds Indicate Dissolution Collapse-Related Depressions. Base Image is 1943 Aerial Photograph.

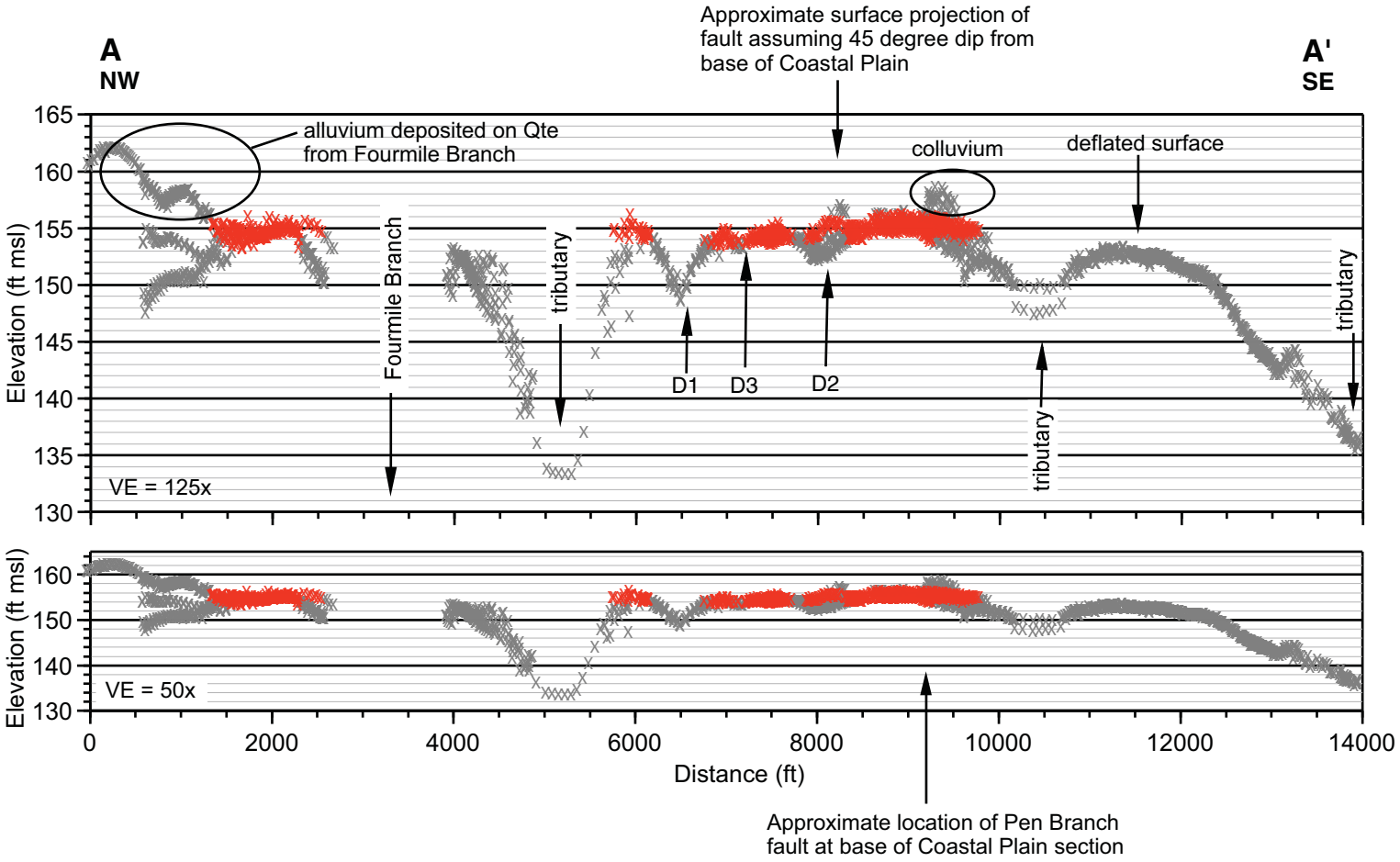


Figure 2.5-248
Longitudinal Profile A-A' from SRS Qte Terrace Surface. Points Interpreted as Representing the Best-Preserved Remnant of the Qte Surface are Shown in Red, all Other Points that Do Not Represent the Terrace Surface are Shown in Gray.

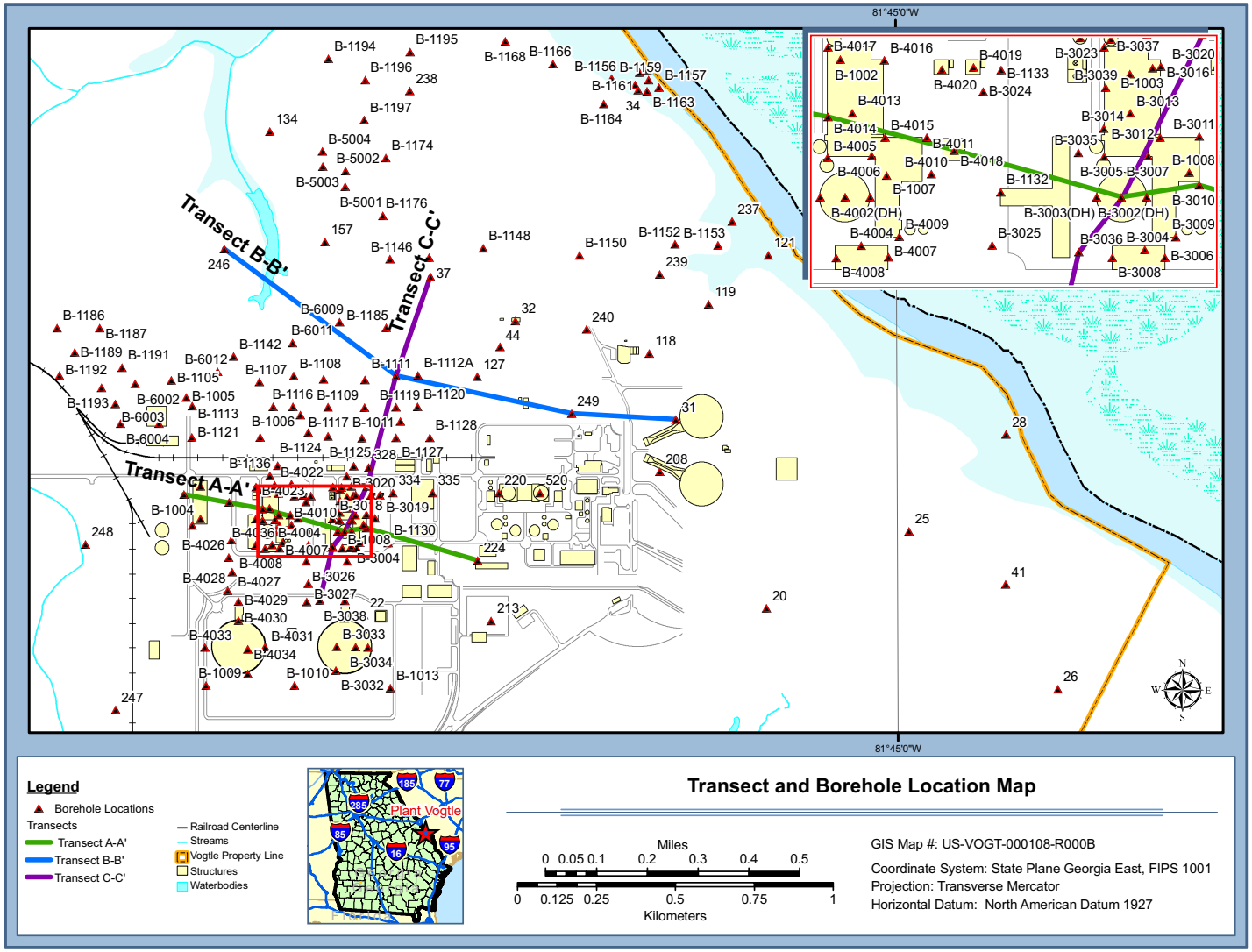


Figure 2.5-249
Transect and Borehole Location Map

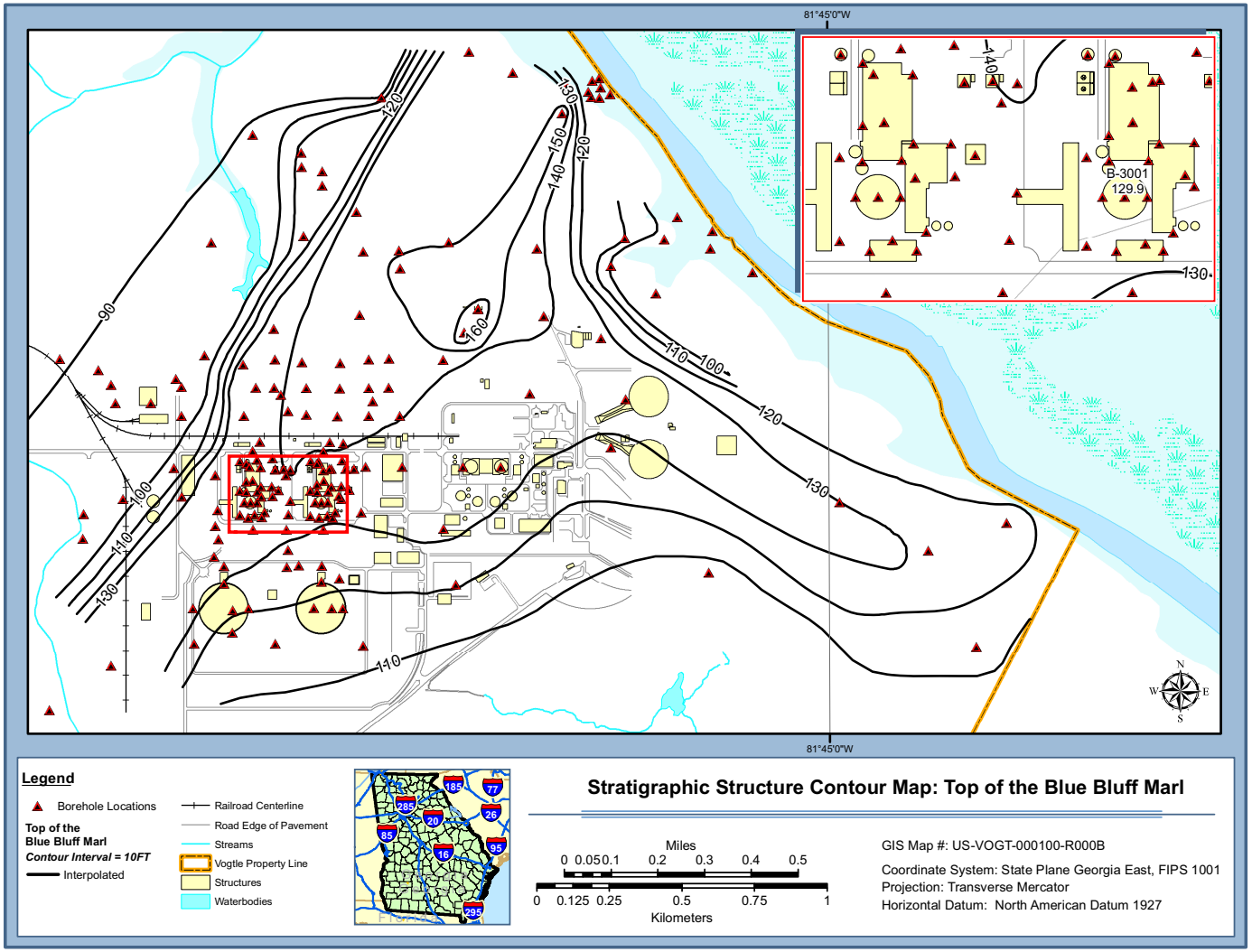


Figure 2.5-250
Stratigraphic Structure Contour Map: Top of Blue Bluff Marl

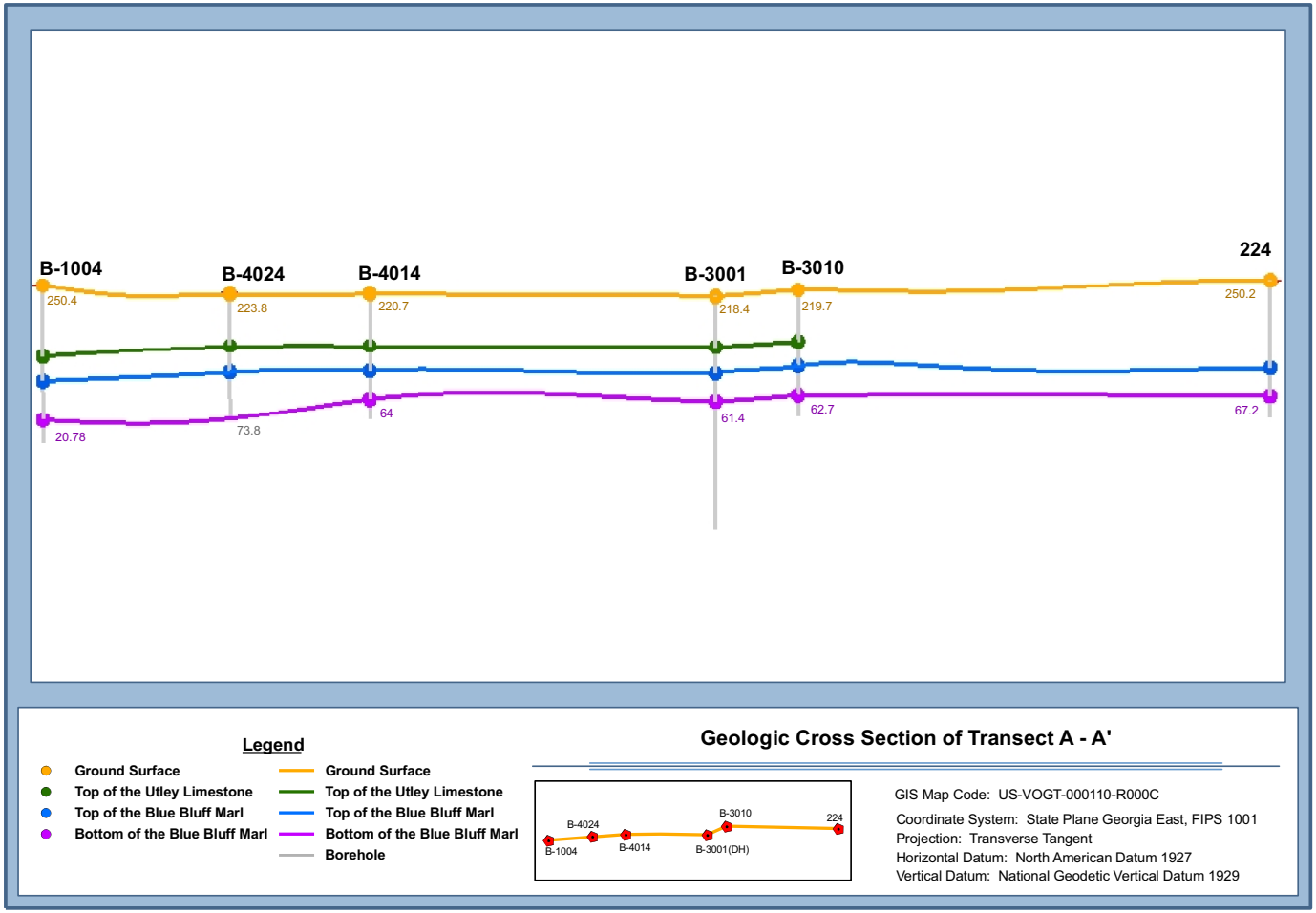


Figure 2.5-251
Geologic Cross section of Transect A-A'



Figure 2.5-252
Geologic Cross Section of Transect B-B'

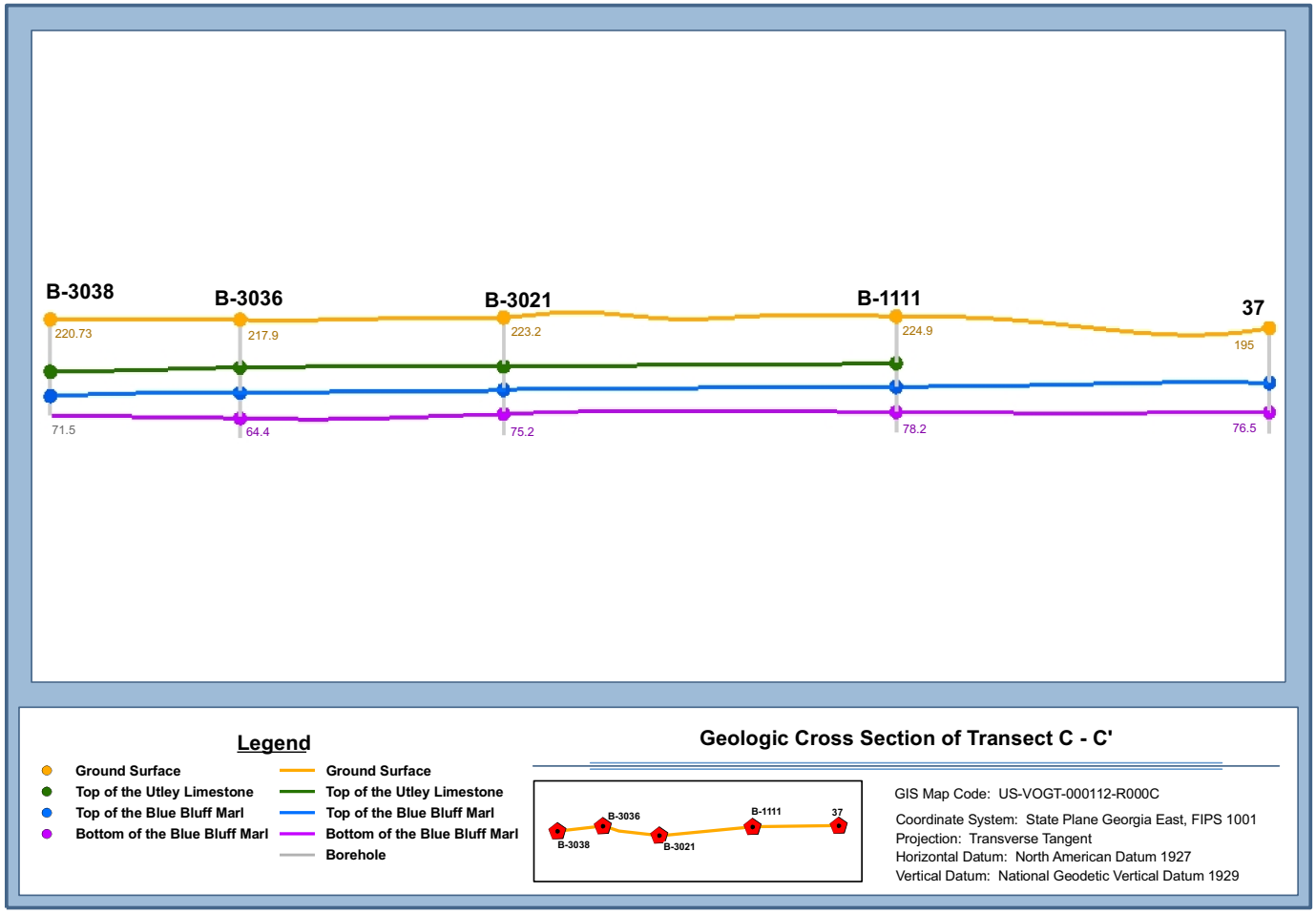


Figure 2.5-253
Geologic Cross Section of Transect C-C'

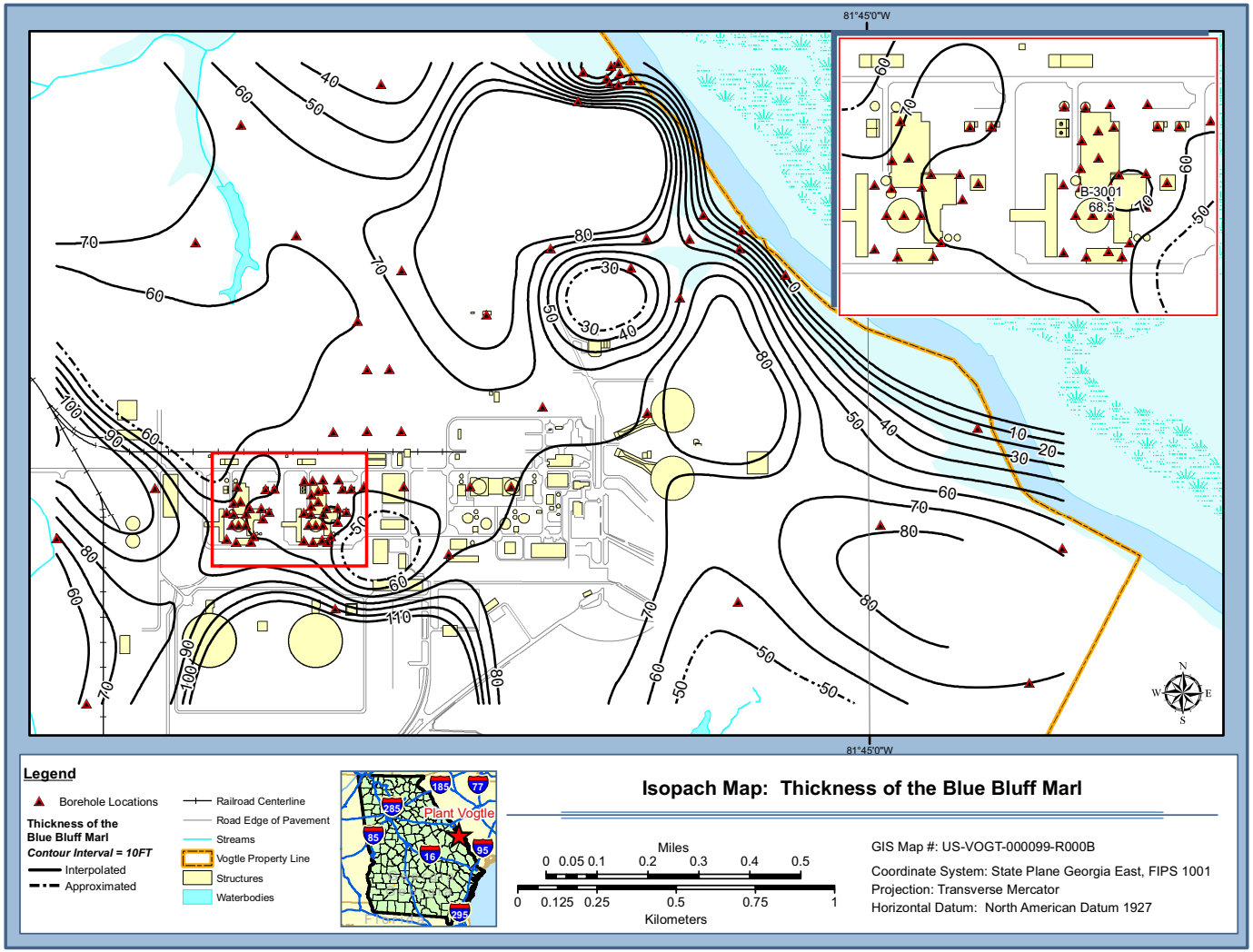


Figure 2.5-254
Isopach Map: Thickness of the Blue Bluff Marl

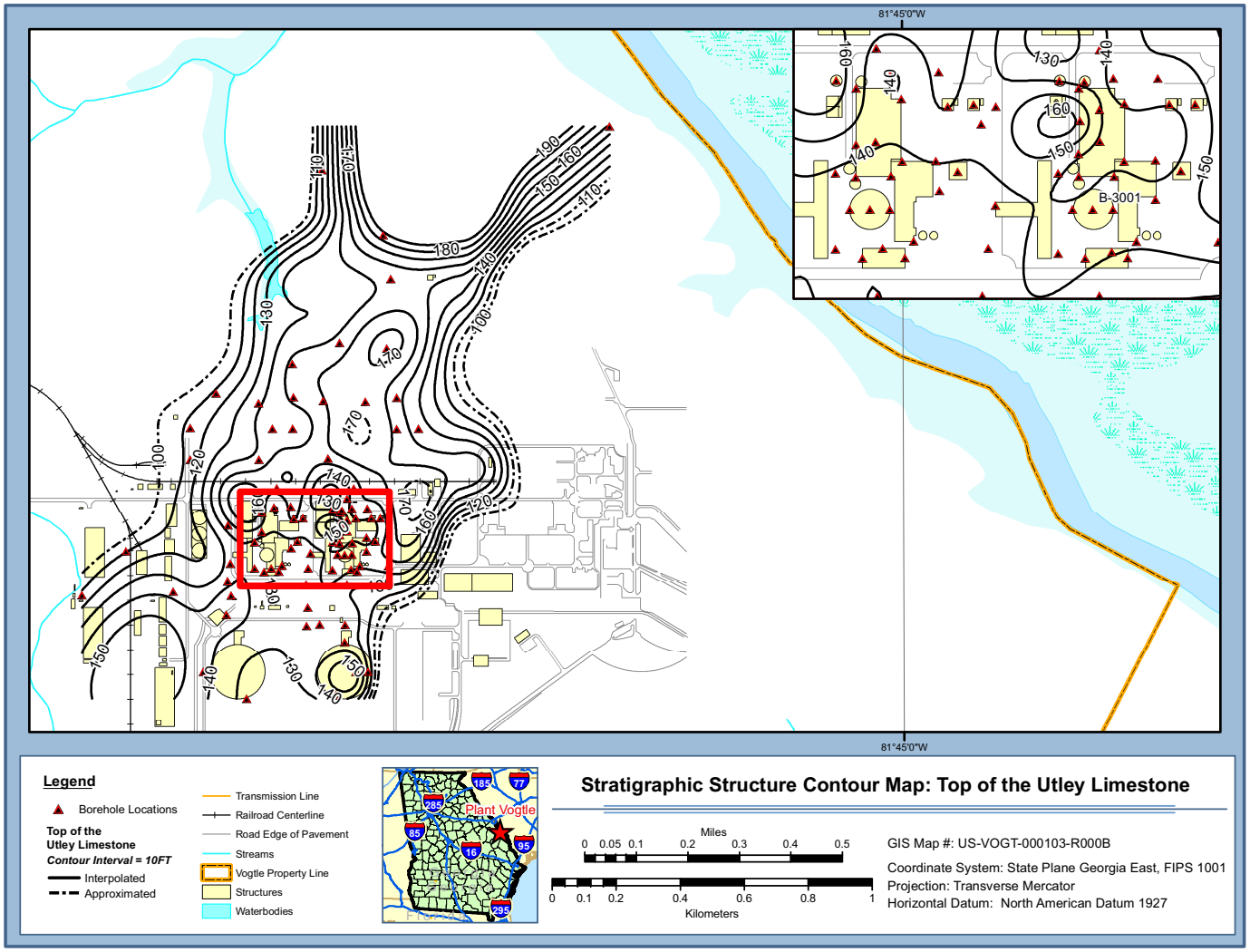


Figure 2.5-255
Stratigraphic Structure Contour Map: Top of the Utley Limestone

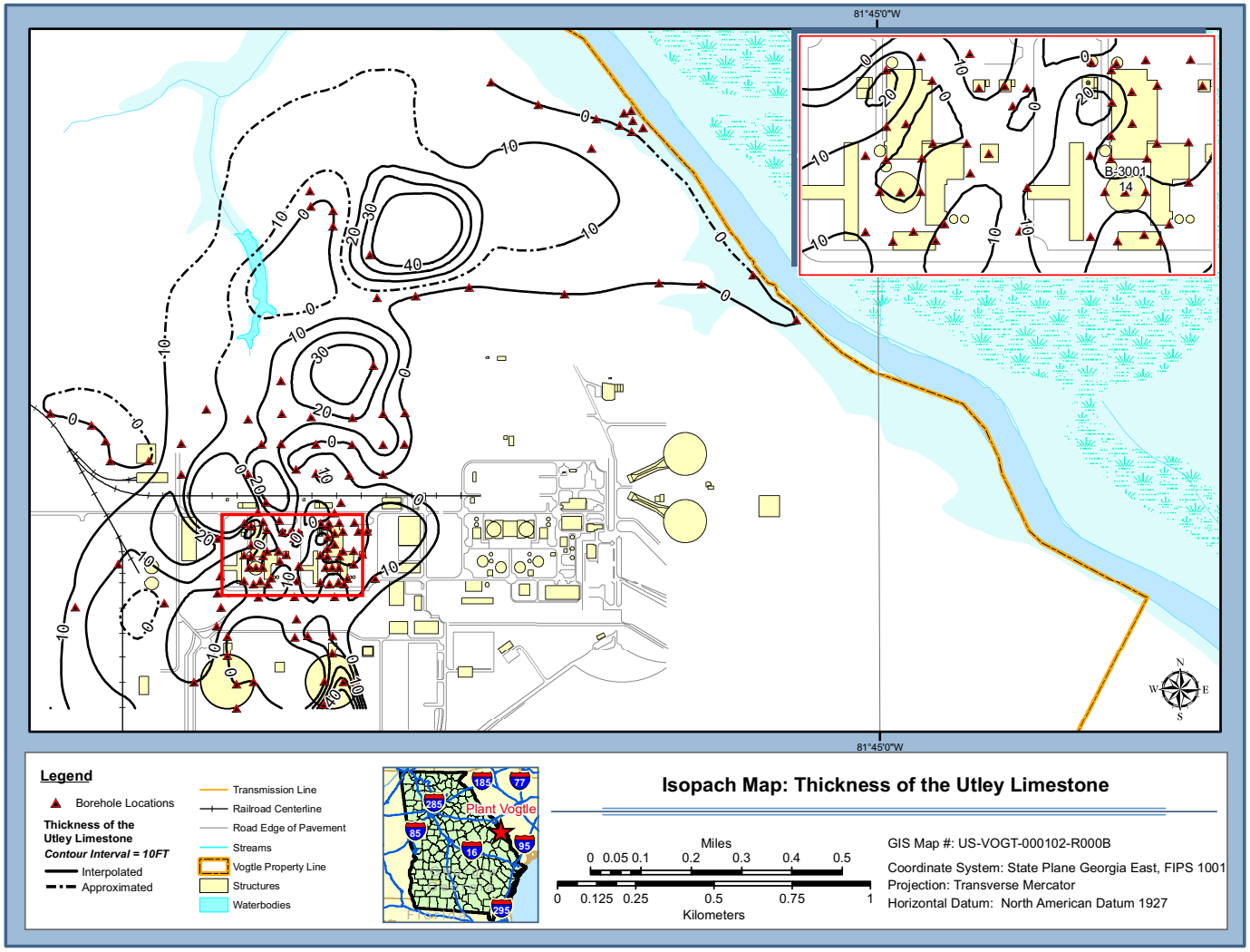


Figure 2.5-256
Isopach Map: Thickness of the Utley Limestone

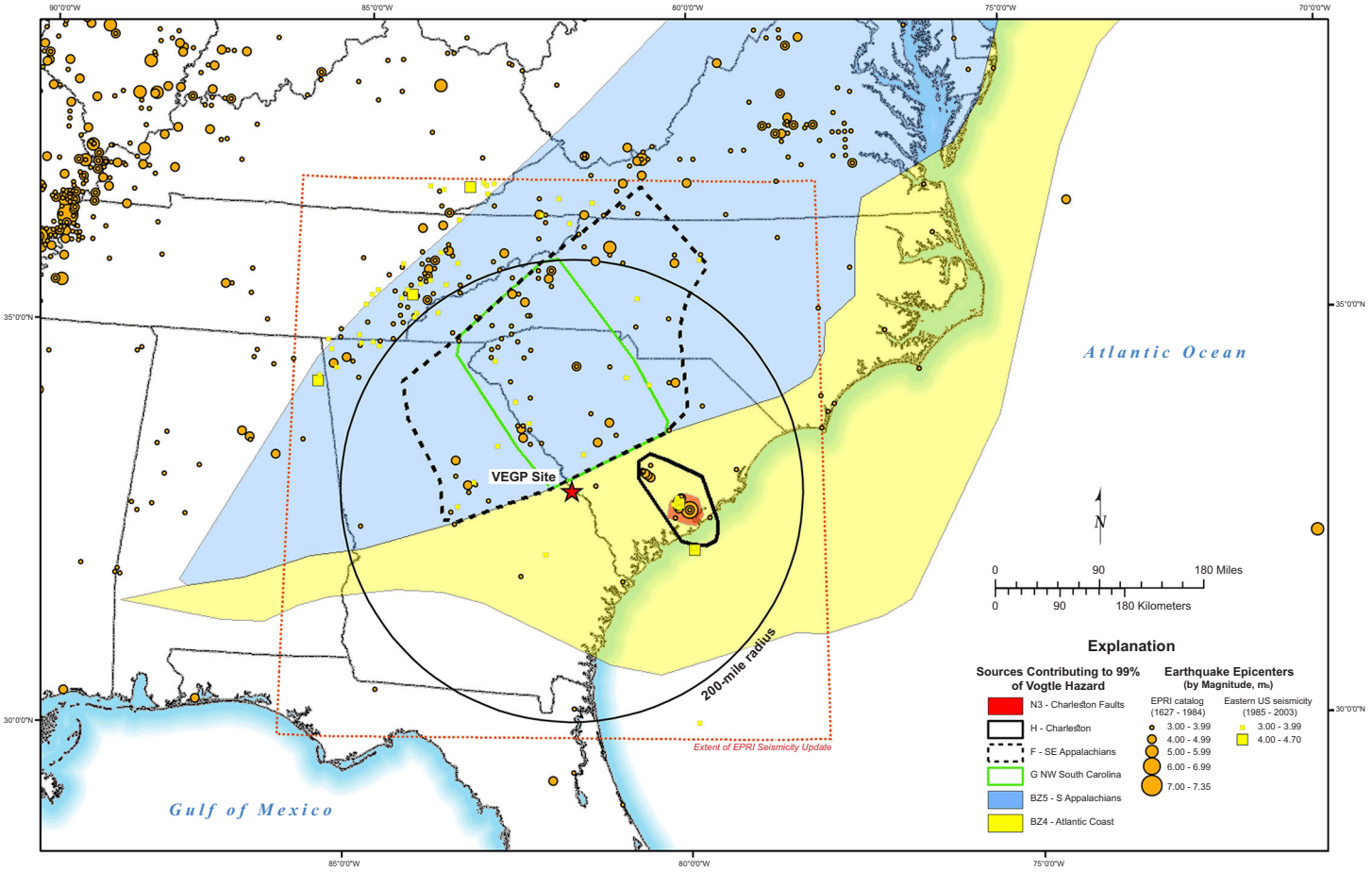


Figure 2.5-257
Bechtel EPRI Zones

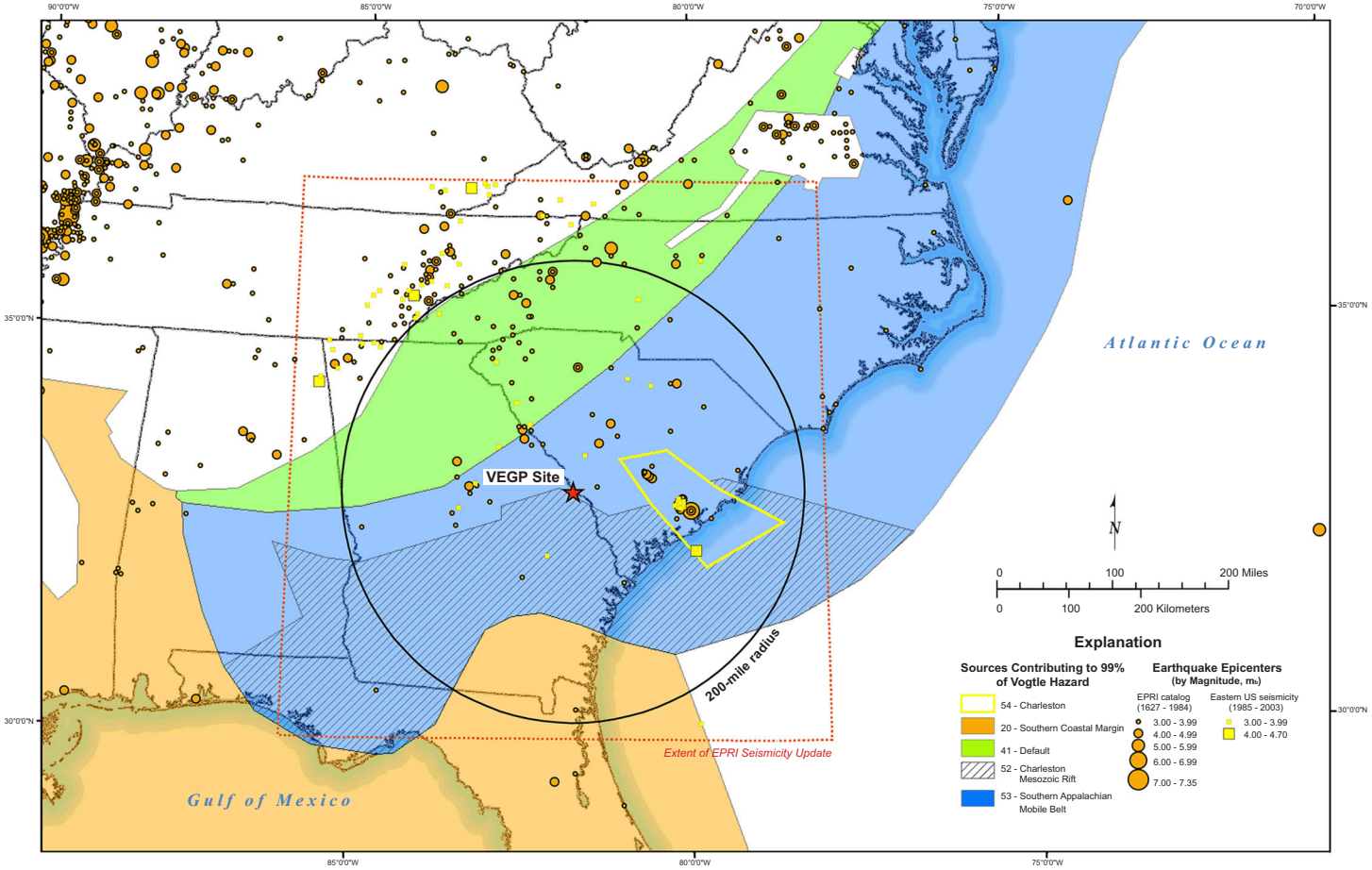


Figure 2.5-258
Dames and Moore EPRI Zones

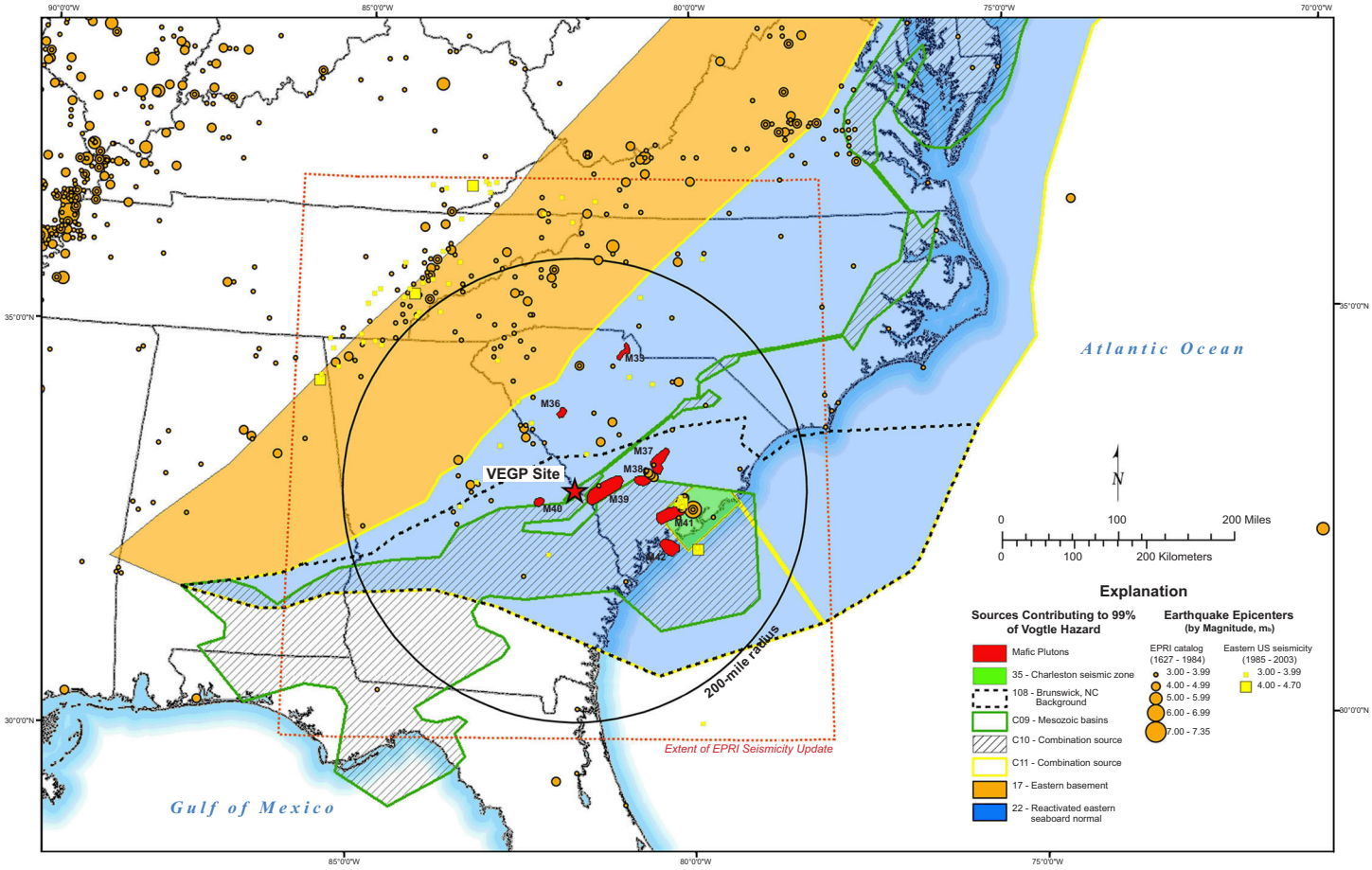


Figure 2.5-259
Law EPRI Zones

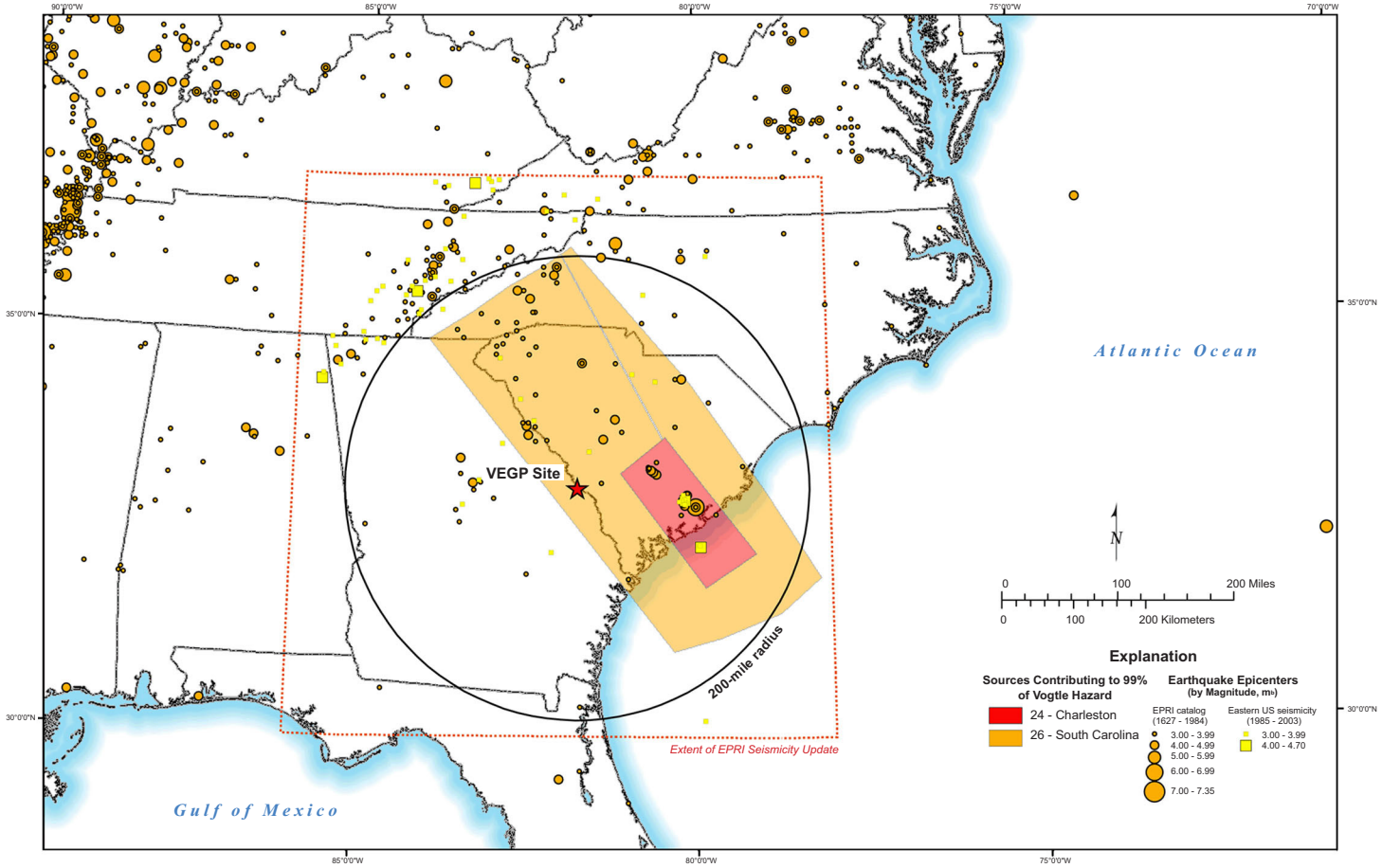


Figure 2.5-260
Rondout EPRI Zones

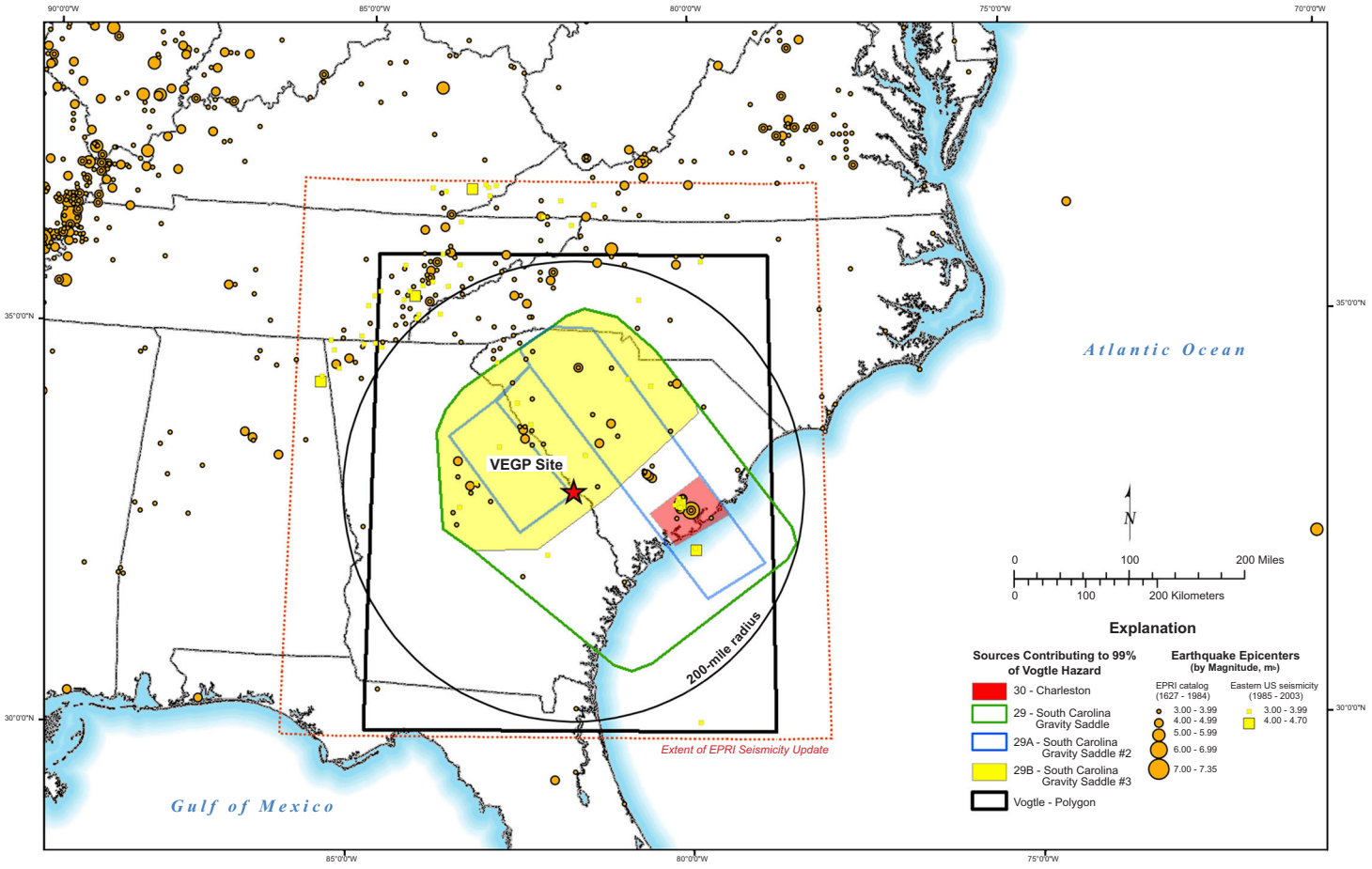


Figure 2.5-261
Woodward-Clyde EPRI Zones

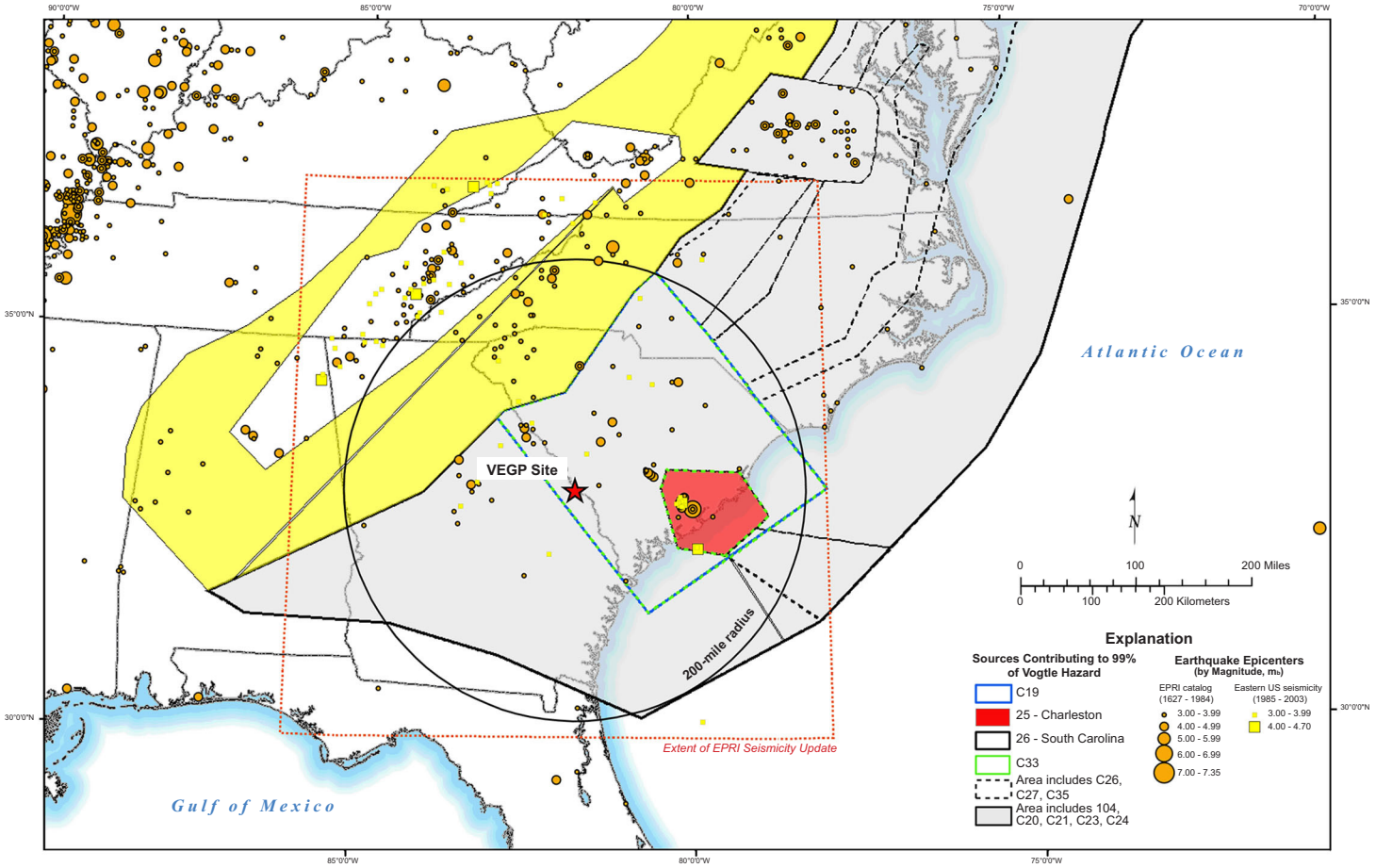


Figure 2.5-262
Weston EPRI Zones

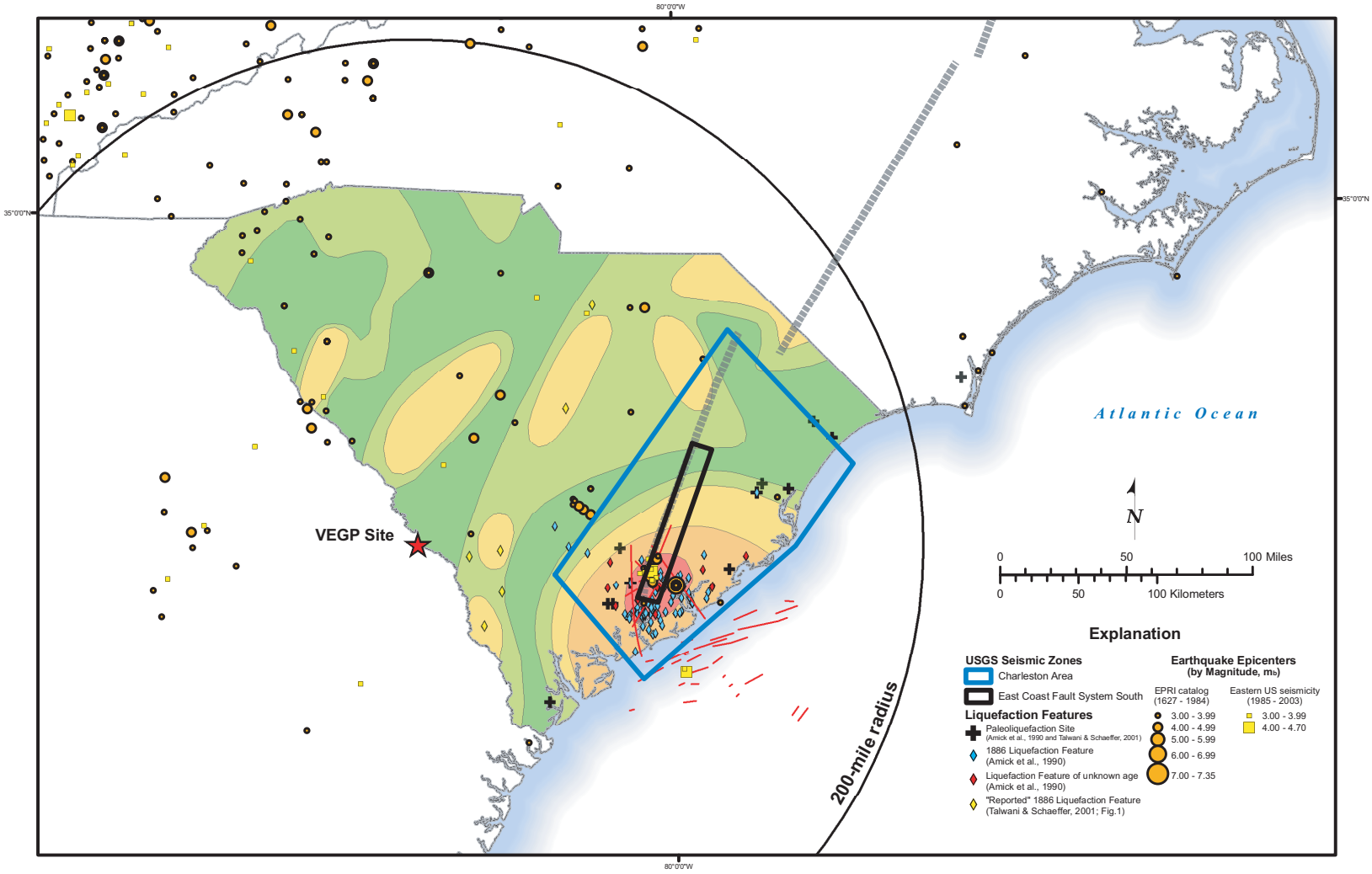


Figure 2.5-263
USGS Model

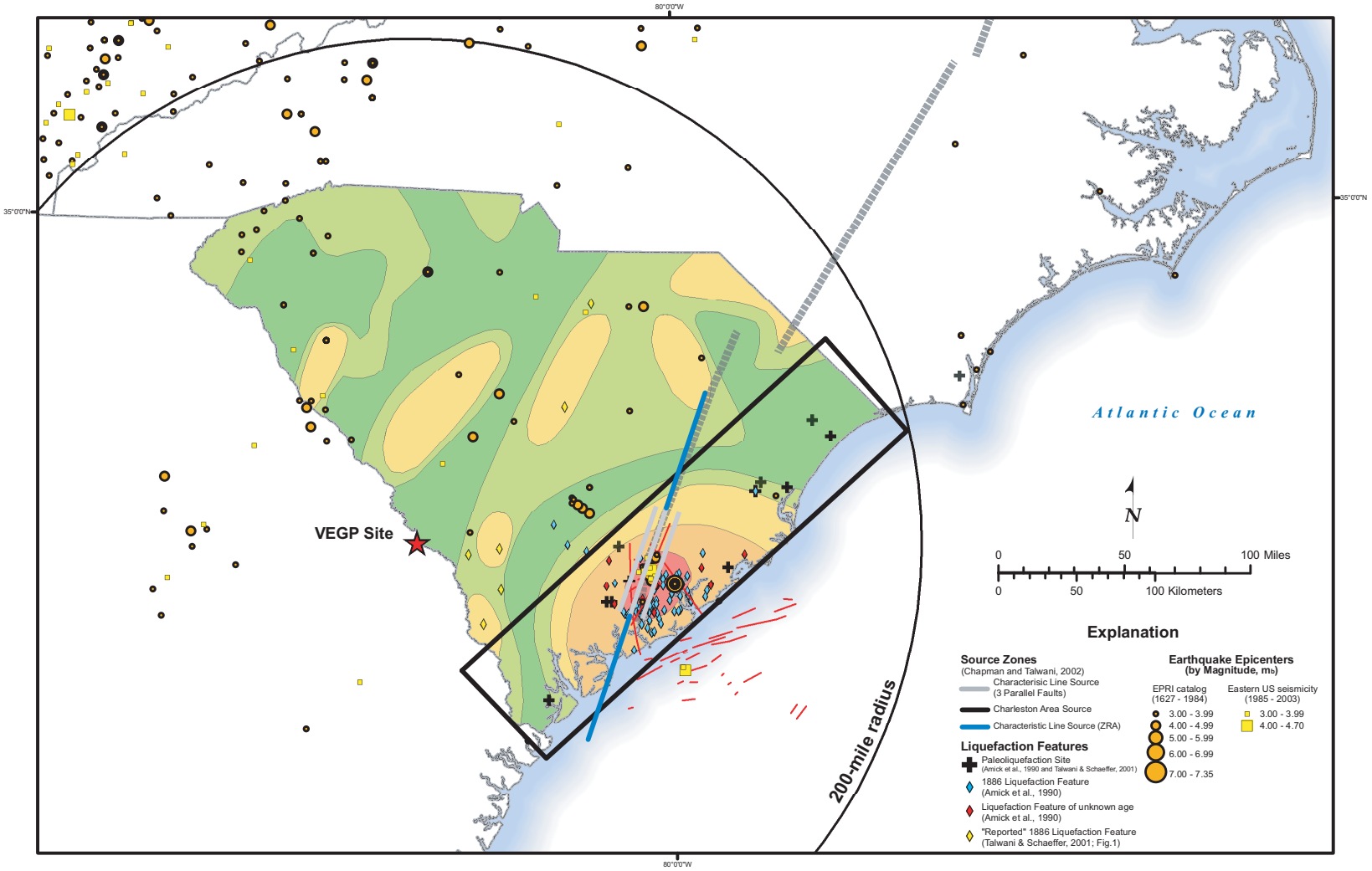


Figure 2.5-264
SCDOT Model

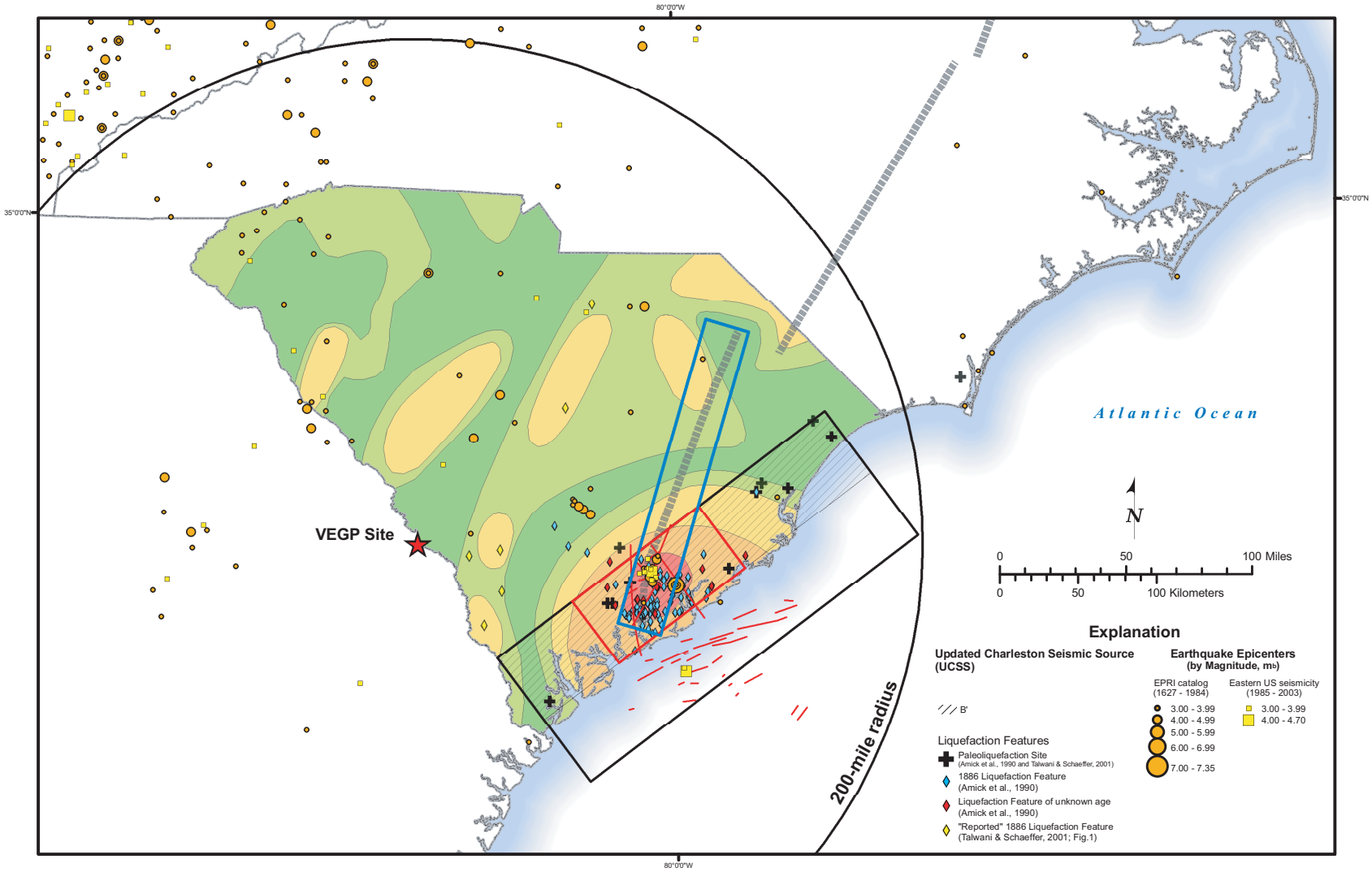


Figure 2.5-265
UCSS Map

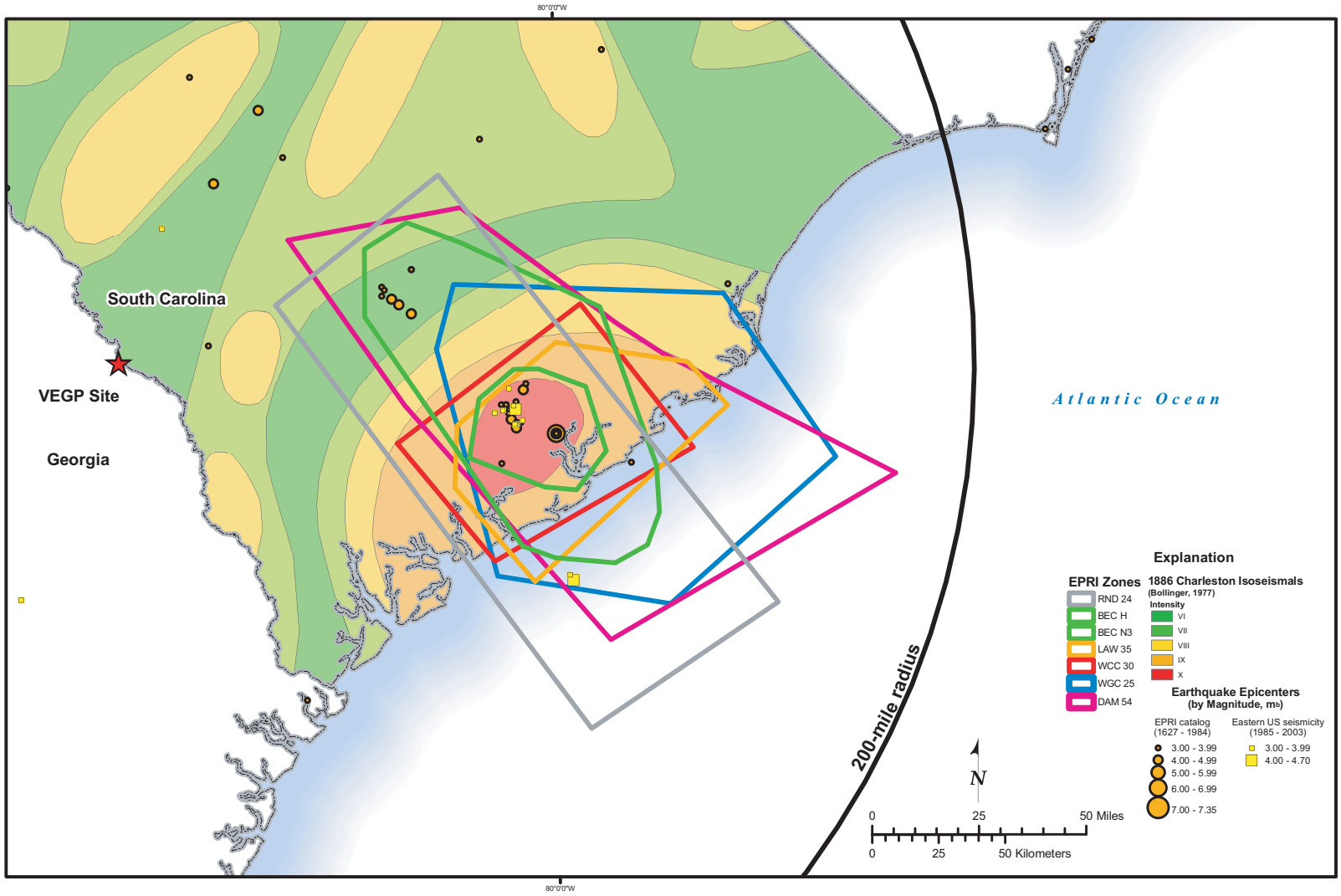


Figure 2.5-266
EPRI All Charleston Map

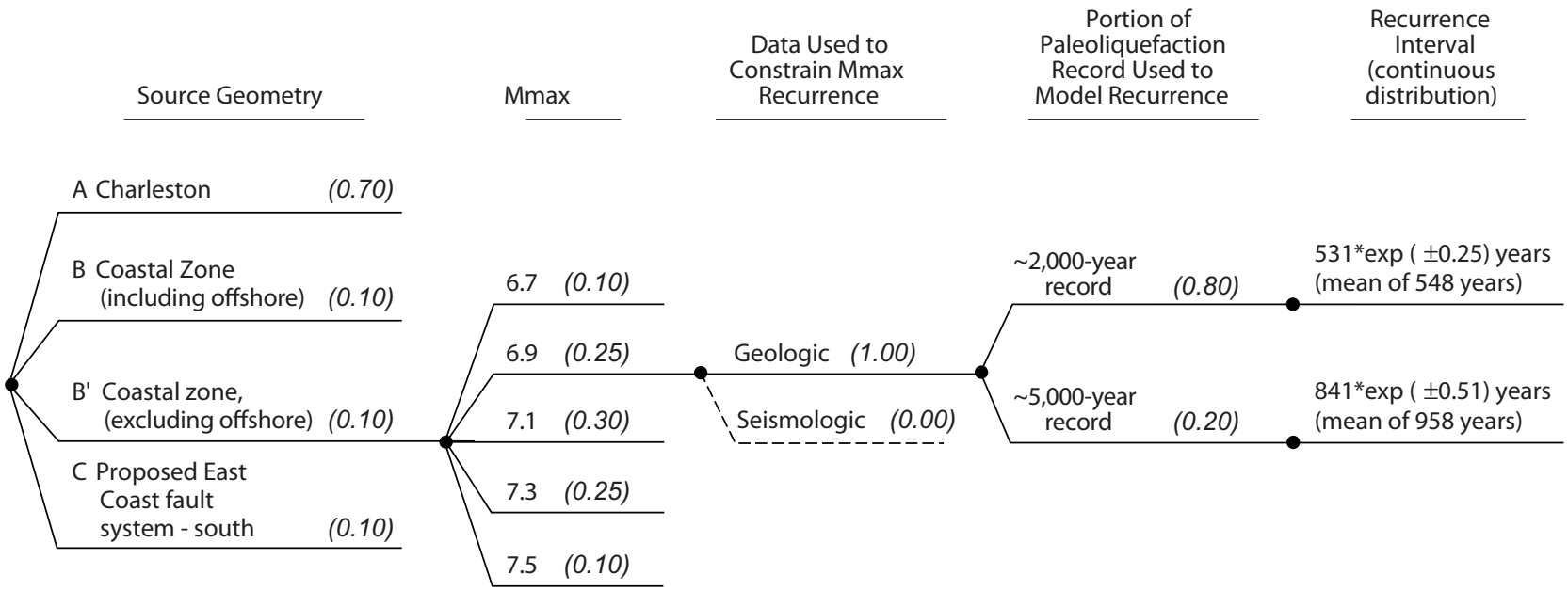
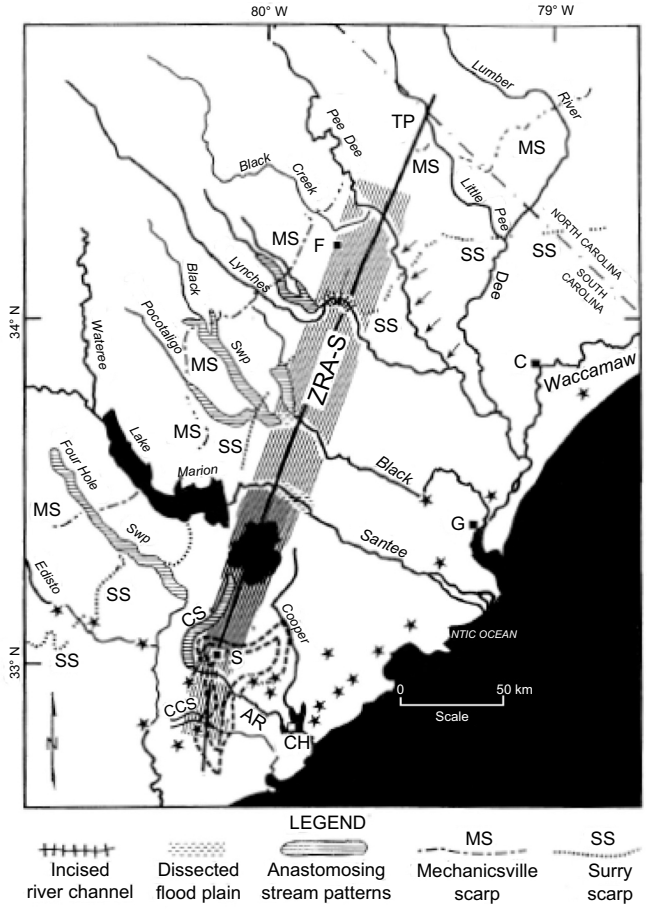


Figure 2.5-267
Updated Charleston Seismic Source (USGS) Logic Tree with Weights for each Branch Shown in Italics



Map of ZRA-S from Marple and Talwani (2000). Figure shows southern zone of river anomalies (ZRA-S; striped area), anastomosing stream patterns, pre 1886 sandblow sites (stars), and topographic profile (TP, bold line) approximately along the ZRA-S axis. Arrows along Pee Dee River denote reach flowing against southwest valley wall. Closed dashed contours near Summerville are highest-intensity isoseismals of the 1886 Charleston, South Carolina, earthquake (from Dutton, 1889).Abbreviations are as follows: AR - Ashley River; C - Conway; CCS - Caw Caw Swamp; CH - Charleston; CS - Cypress Swamp; F - Florence; G - Georgetown; LM - Lake Moultrie; MS - Mechanicsville littoral scarp; S - Summerville; SS - Surry littoral scarp.

Figure 2.5-268
Map of ZRA-S from Marple and Talwani (2000)

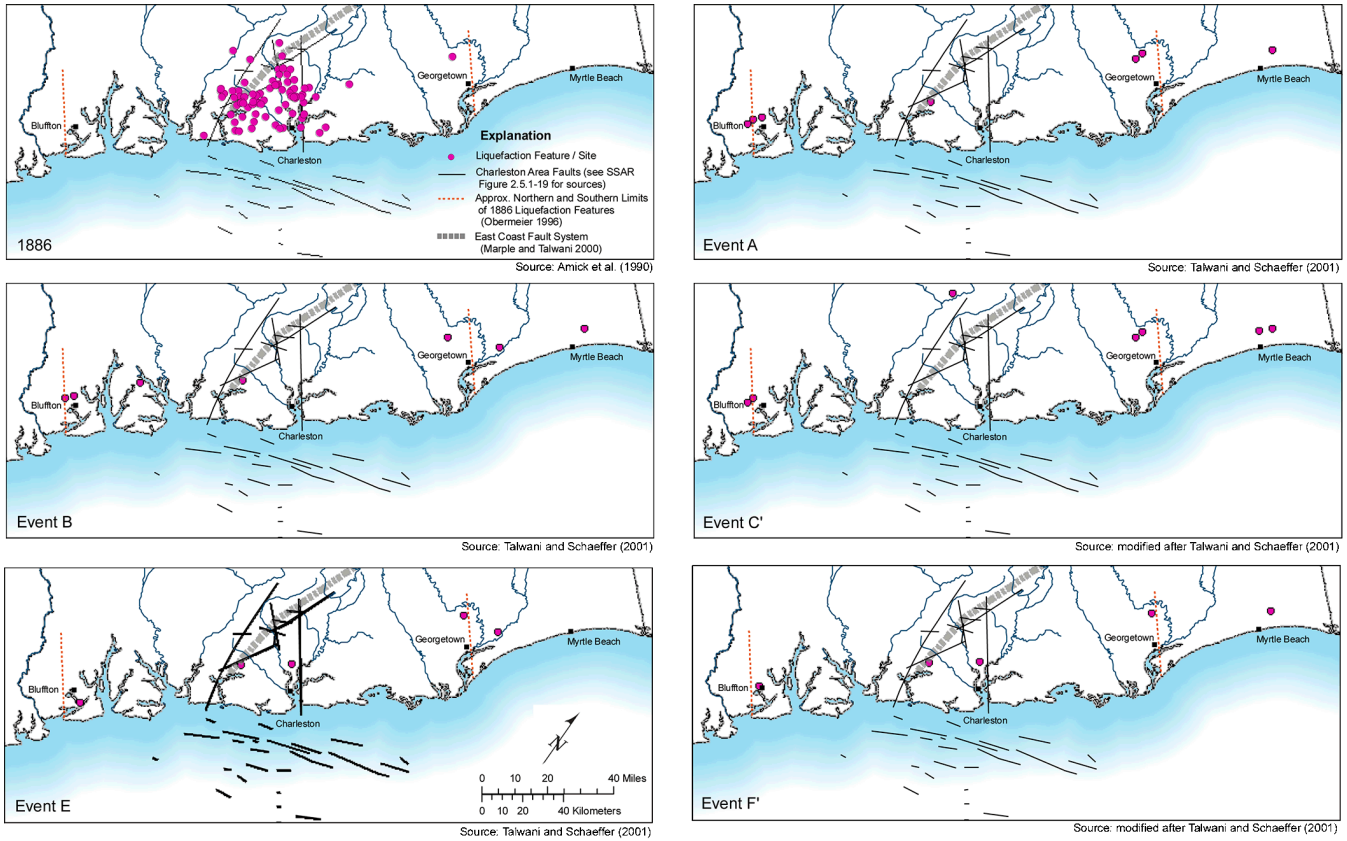


Figure 2.5-269
Geographic Distribution of Liquefaction Features Associated with Charleston Earthquakes

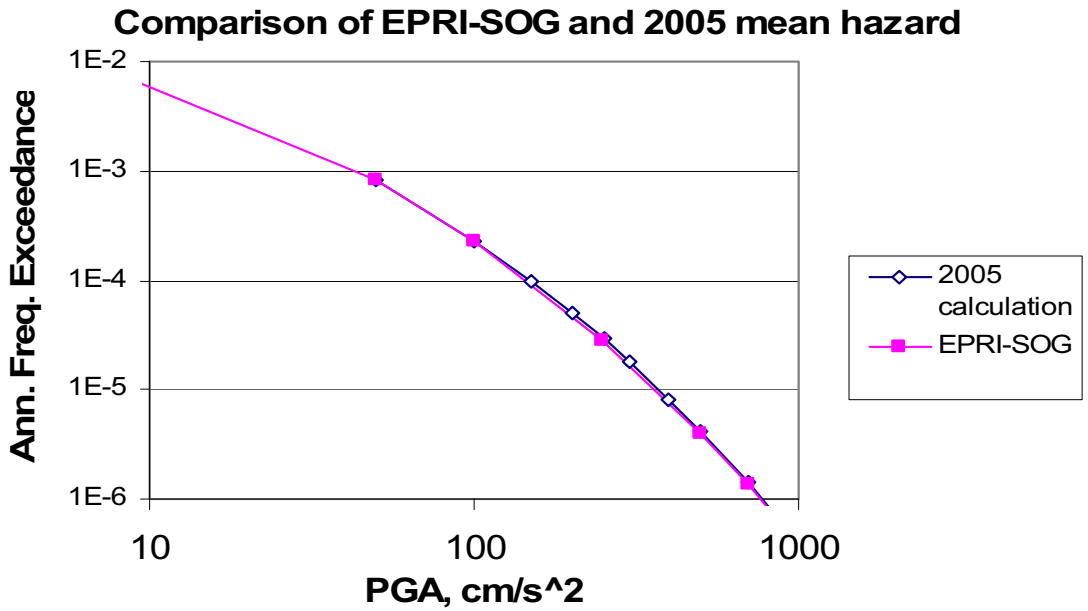


Figure 2.5-270
PGA Mean Seismic Hazard Curves for Current (2005) Calculation and for EPRI-SOG

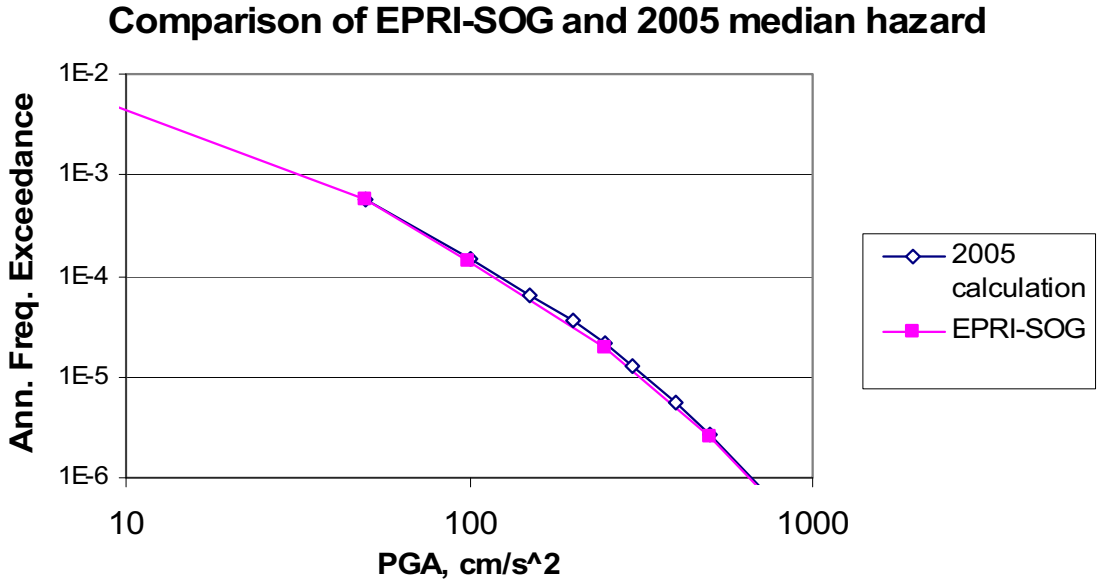


Figure 2.5-271
PGA Median Seismic Hazard Curves for Current (2005) Calculation and for EPRI-SOG

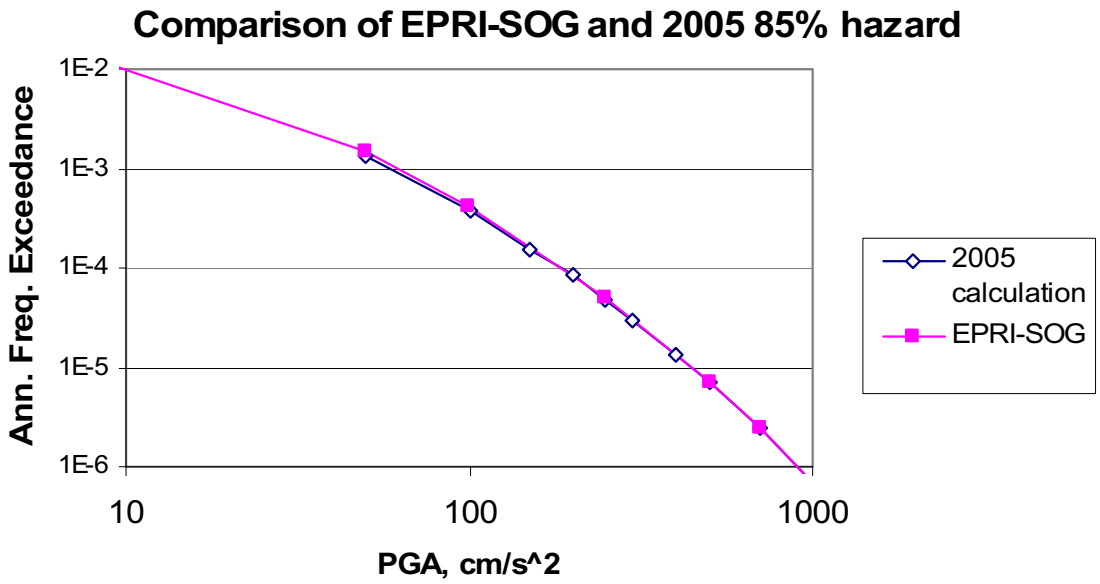


Figure 2.5-272
PGA 85 Percent Seismic Hazard Curves for Current (2005) Calculation and for EPRI-SOG

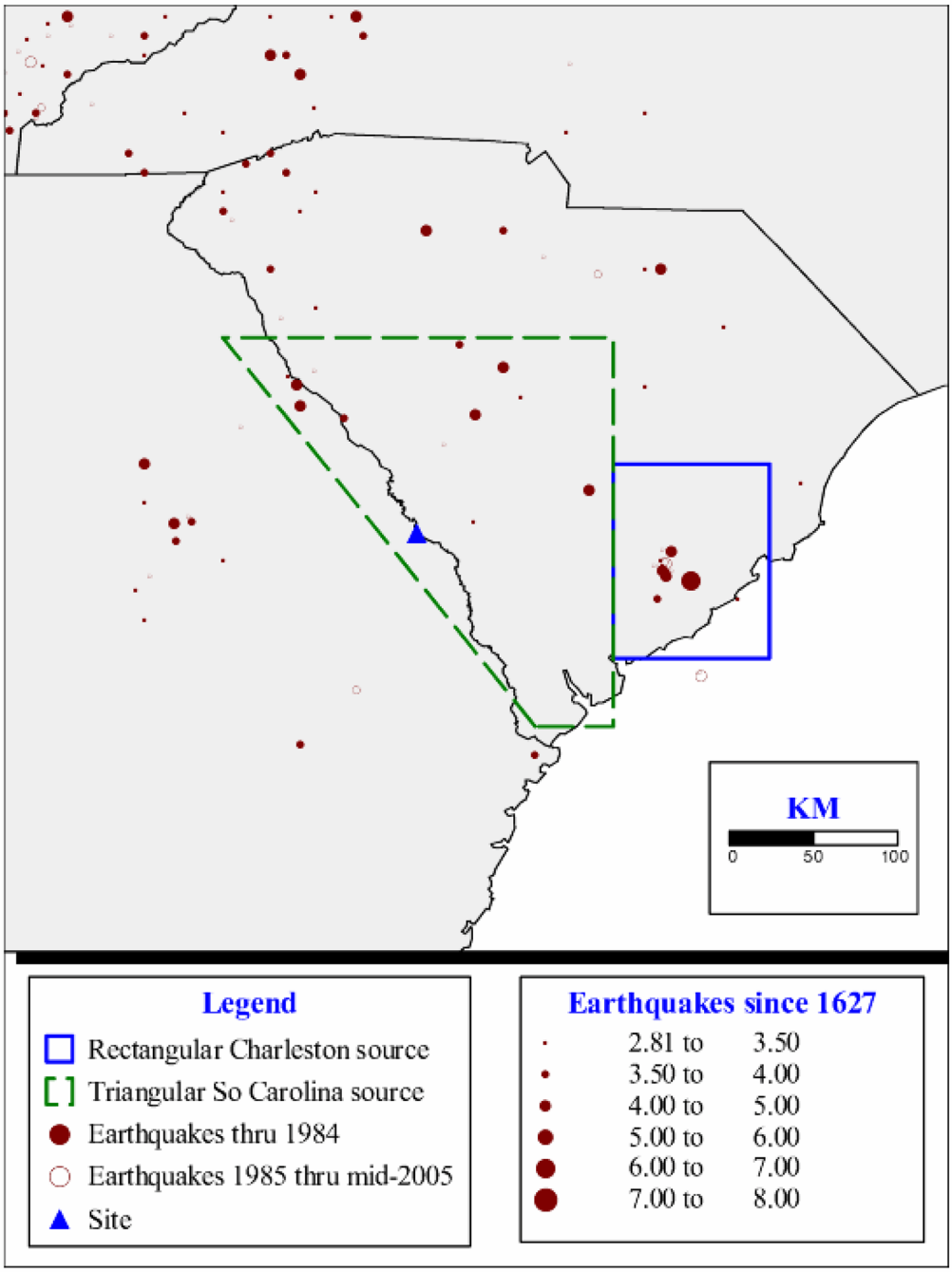


Figure 2.5-273
Map Showing Two Areas Used To Examine Effect of New Seismicity Information

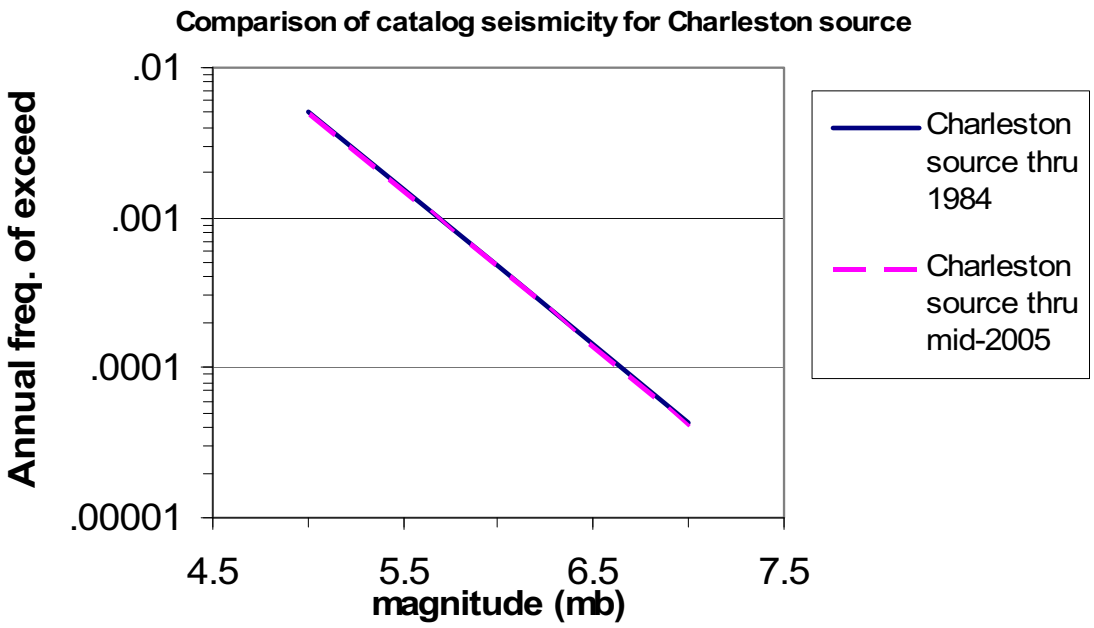


Figure 2.5-274
Comparison of Recurrence Rates for Rectangular Charleston Source

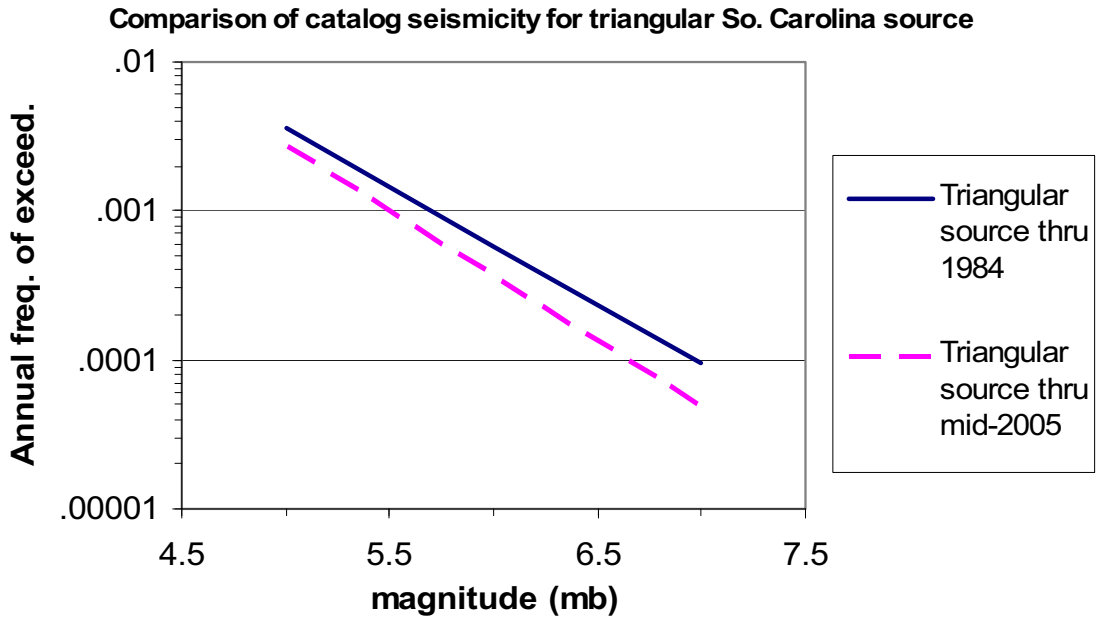


Figure 2.5-275
Comparison of Recurrence Rates for Triangular South Carolina Source

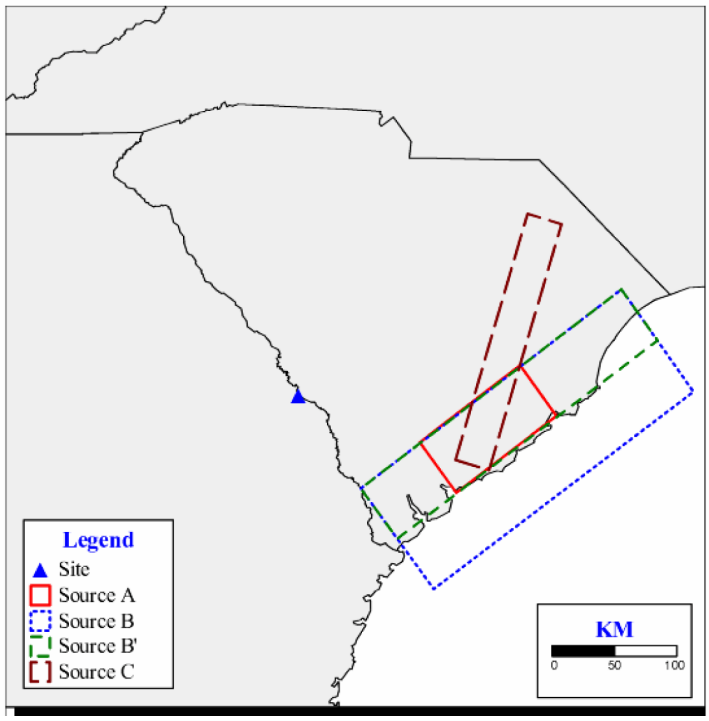


Figure 2.5-276
Geometry of Four New Charleston Sources

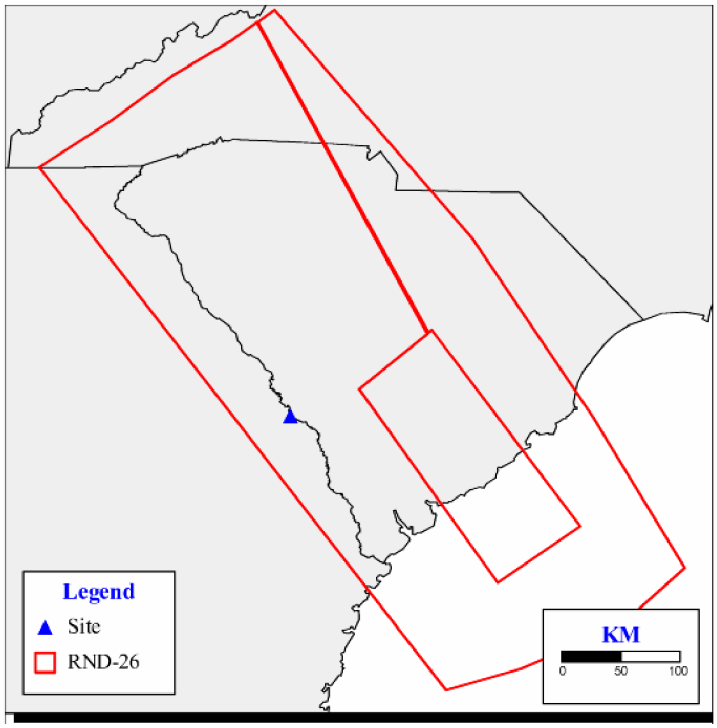


Figure 2.5-277
Original Rondout Source 26

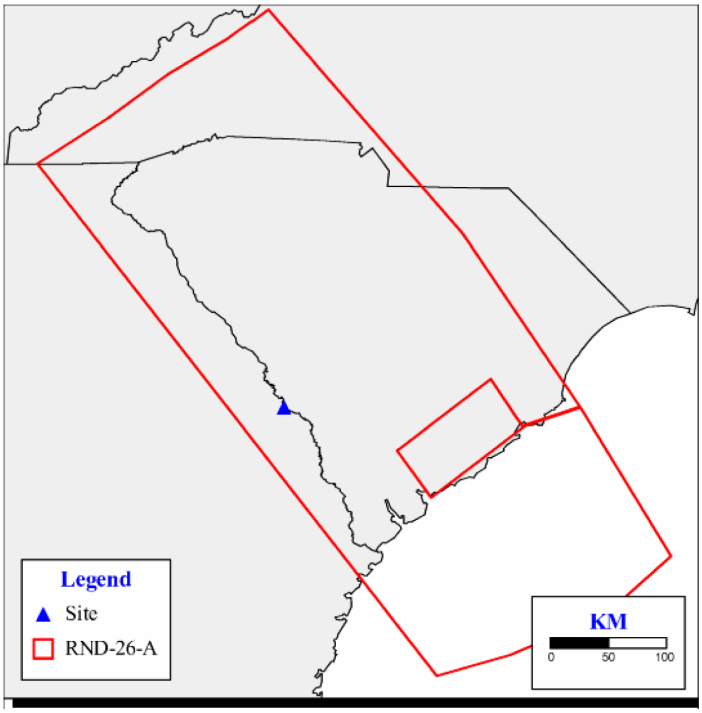


Figure 2.5-278
New Rondout Source 26-A that Surrounds Charleston Source A

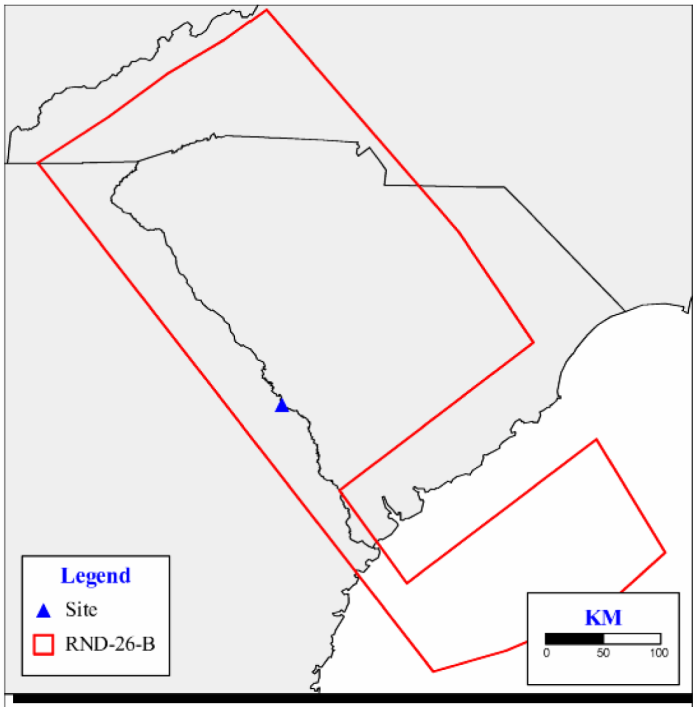


Figure 2.5-279
New Rondout Source 26-B that Surrounds Charleston Source B

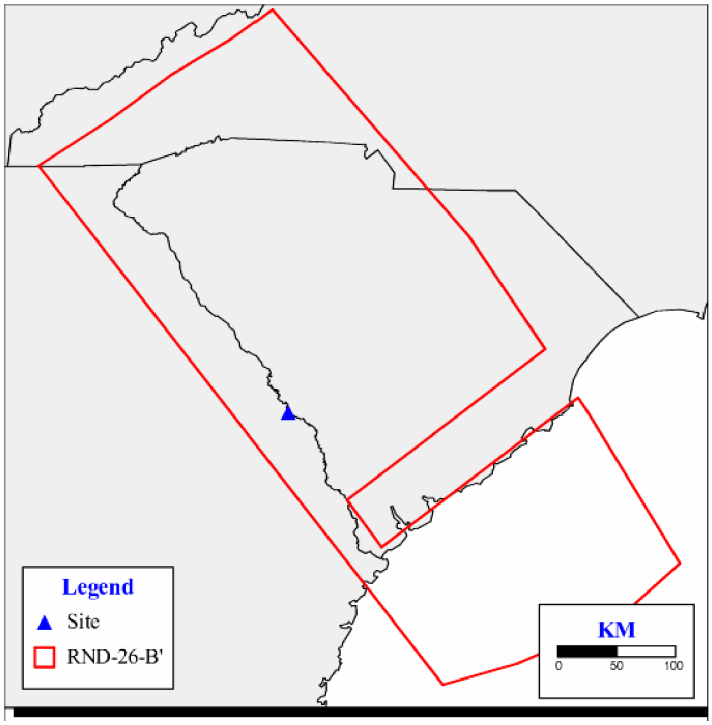


Figure 2.5-280
New Rondout Source 26-B´ that Surrounds Charleston Source B

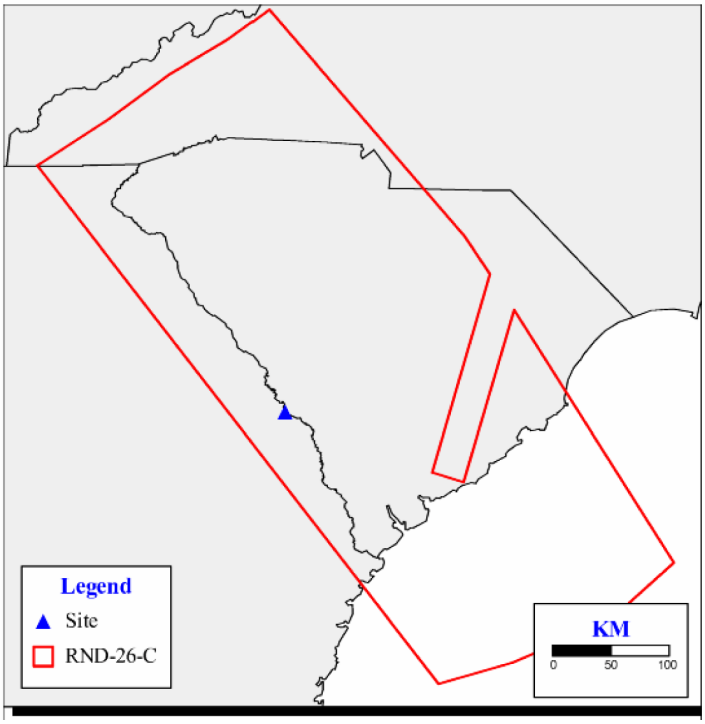


Figure 2.5-281
New Rondout Source 26-C that Surrounds Charleston Source C

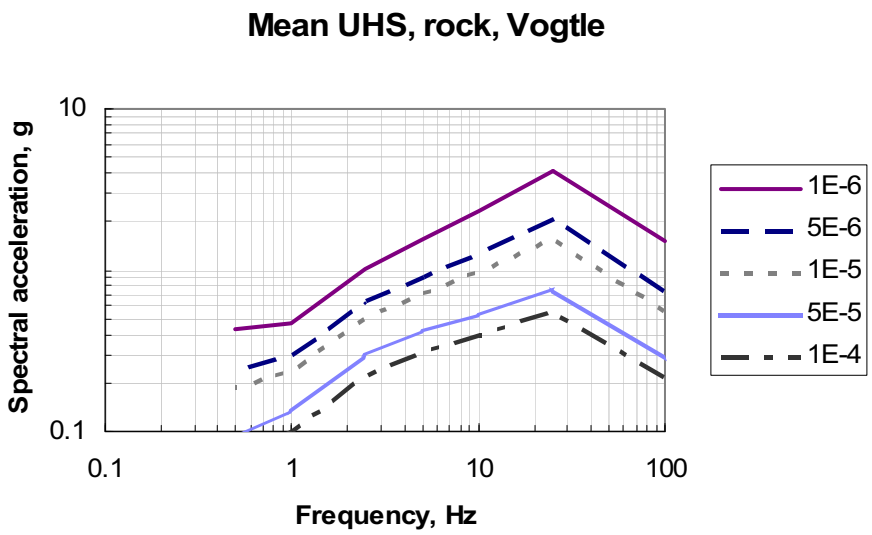


Figure 2.5-282
Mean Uniform Hazard Spectra, Hard Rock Conditions, for VEGP ESP

High Frequency, 1.0e-4

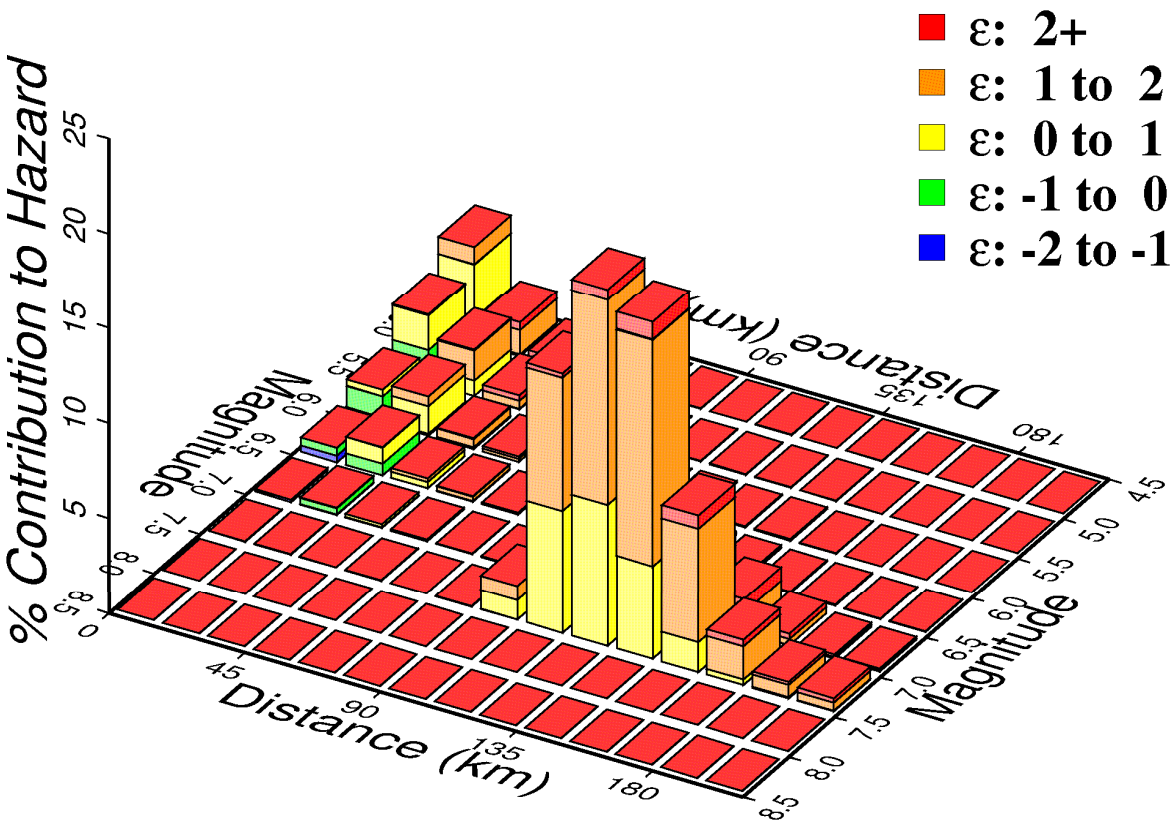


Figure 2.5-283
Hard Rock Magnitude-Distance Deaggregation for High Frequencies, 10^{-4} Mean Annual Frequency of Exceedance

Low Frequency, 1.0e-4

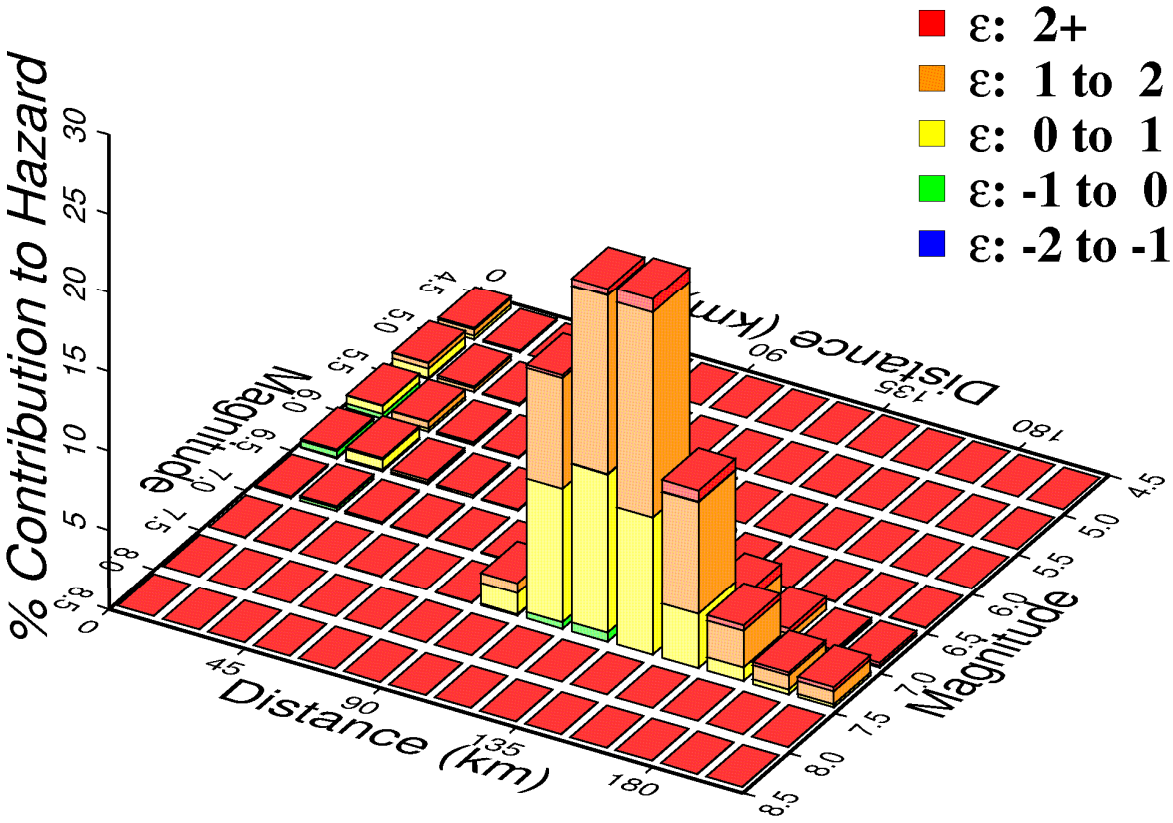


Figure 2.5-284
Hard Rock Magnitude-Distance Deaggregation for Low Frequencies, 10^{-4} Mean Annual Frequency of Exceedance

High Frequency, 1.0e-5

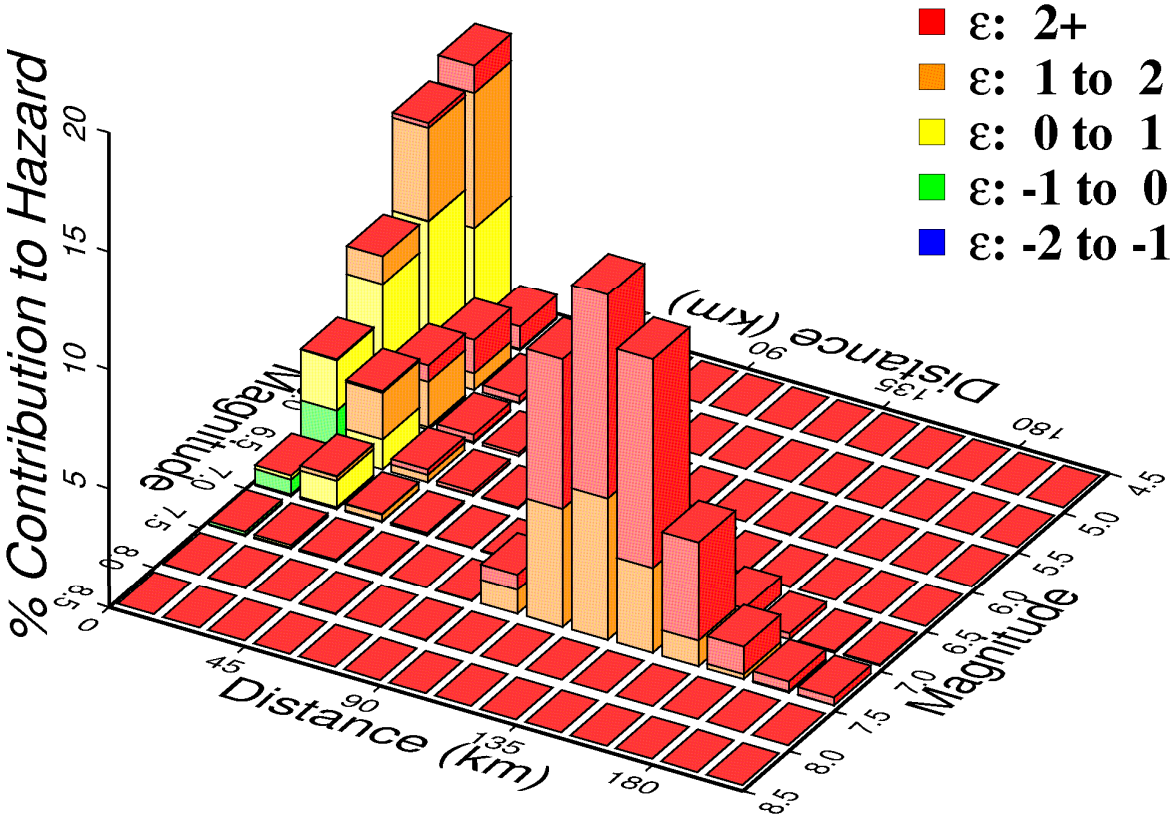


Figure 2.5-285
Hard Rock Magnitude-Distance Deaggregation for High Frequencies, 10^{-5} Mean Annual Frequency of Exceedance

Low Frequency, 1.0e-5

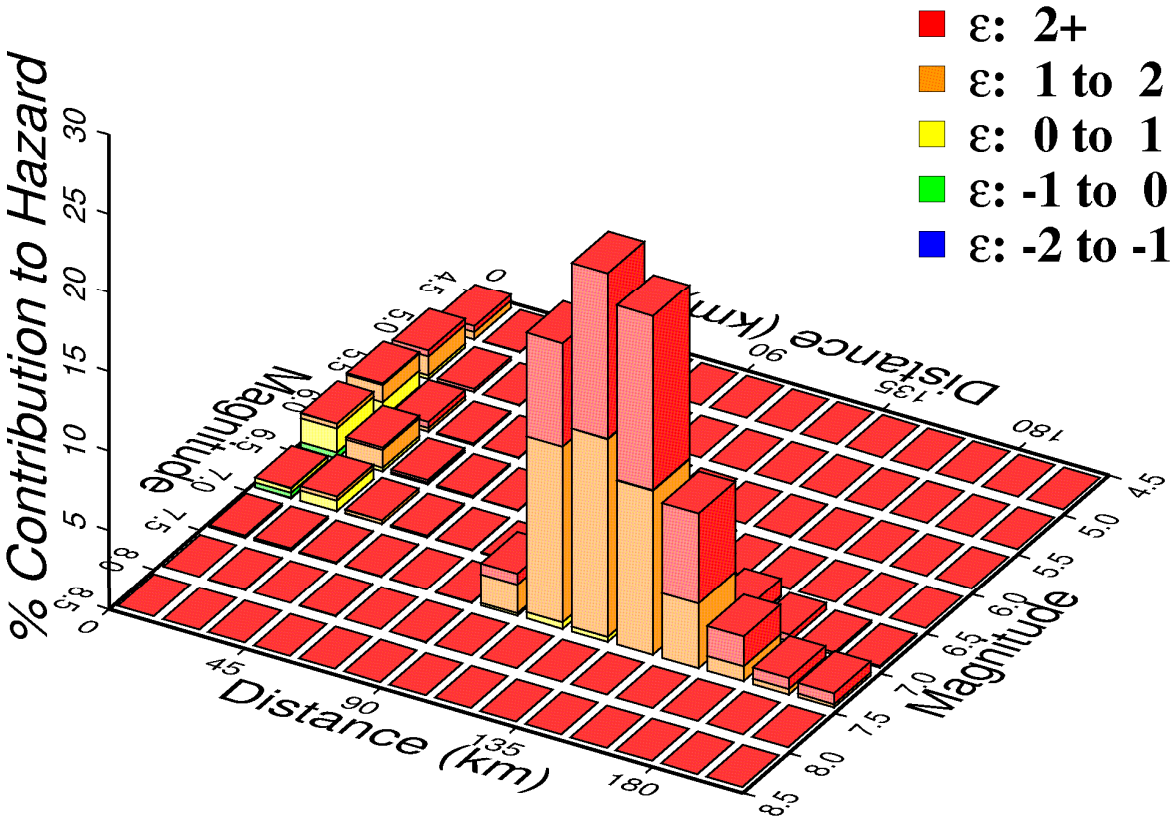


Figure 2.5-286
Hard Rock Magnitude-Distance Deaggregation For Low Frequencies, 10^{-5} Mean Annual Frequency of Exceedance

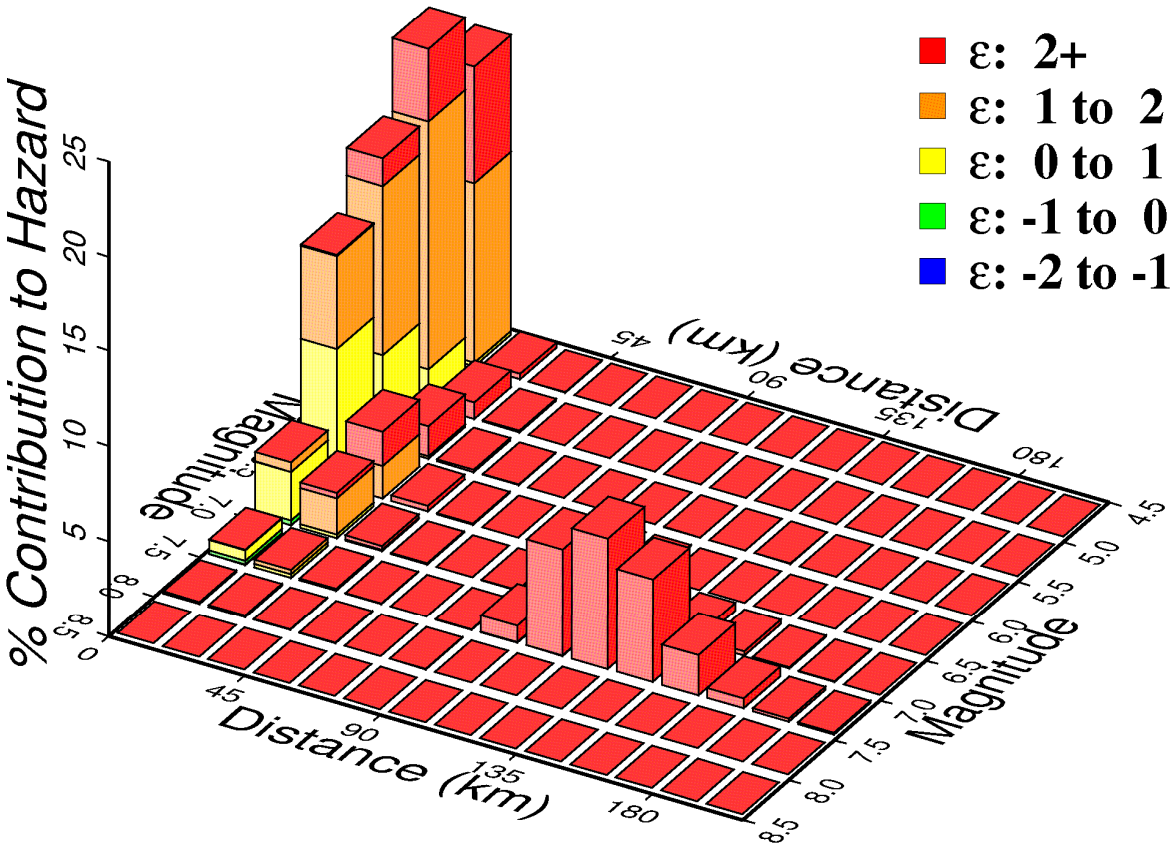


Figure 2.5-287
Hard Rock Magnitude-Distance Deaggregation for High Frequencies, 10^{-6} Mean Annual Frequency of Exceedance

Low Frequency, 1.0e-6

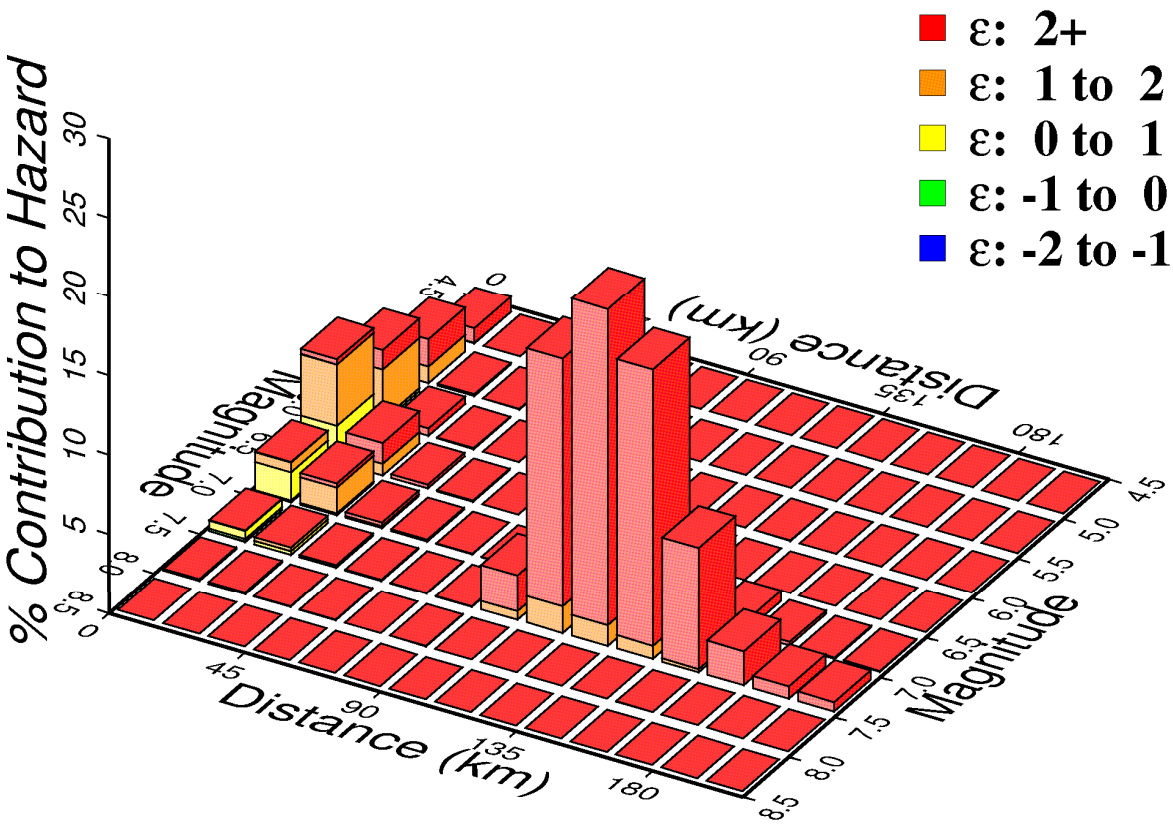


Figure 2.5-288
Hard Rock Magnitude-Distance Deaggregation for Low Frequencies, 10^{-6} Mean Annual Frequency of Exceedance

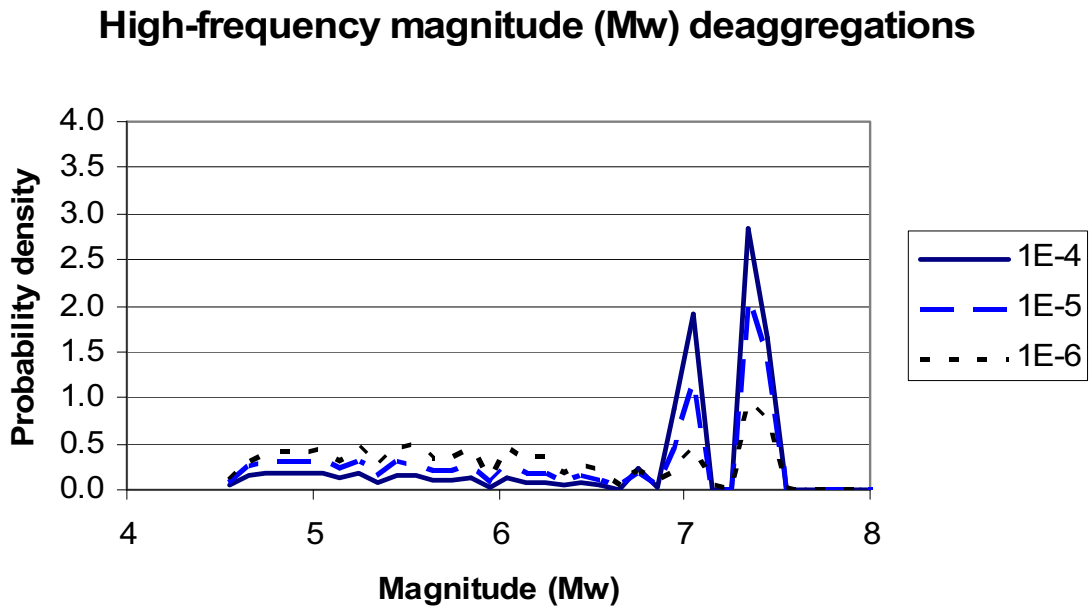


Figure 2.5-289
Magnitude Deaggregation for High Frequencies
for Three Mean Annual Frequencies of Exceedance

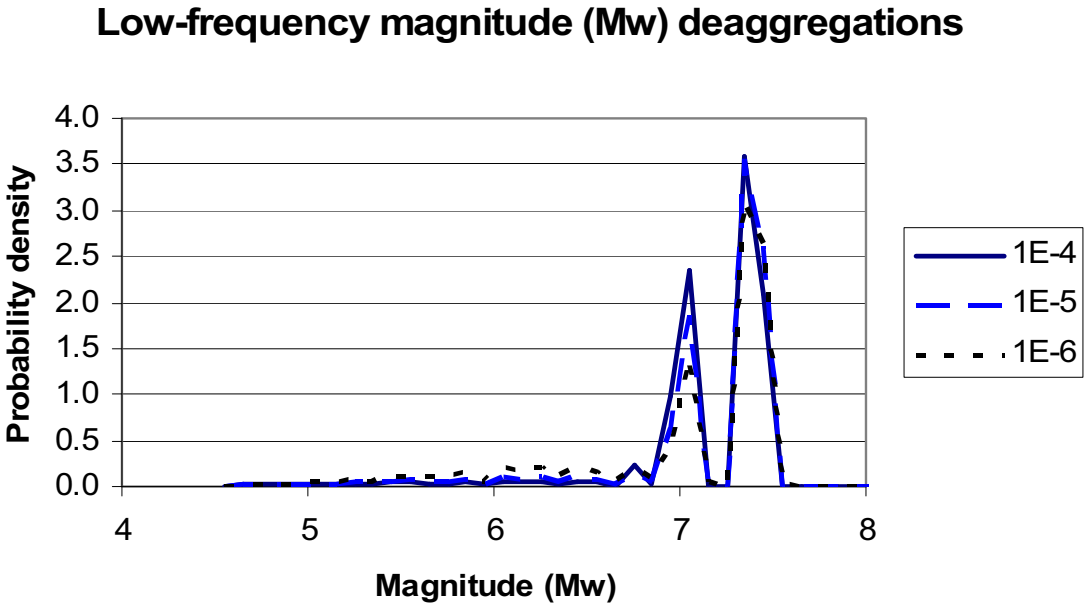


Figure 2.5-290
Magnitude Deaggregation for Low Frequencies
for Three Mean Annual Frequencies of Exceedance

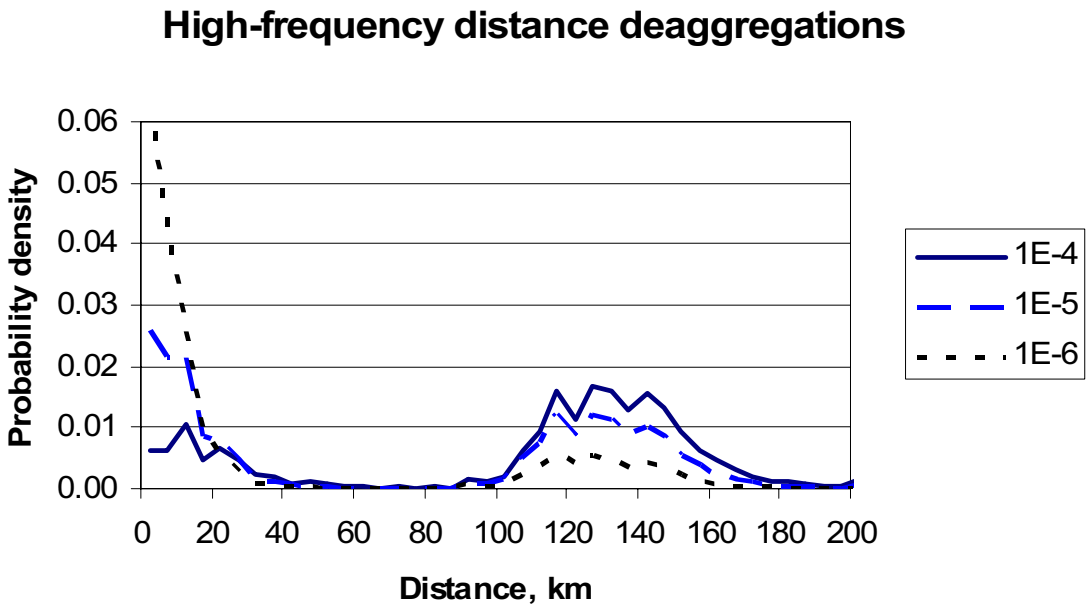


Figure 2.5-291
Hard Rock Distance Deaggregation for High Frequencies for Three Mean Annual Frequencies of Exceedance

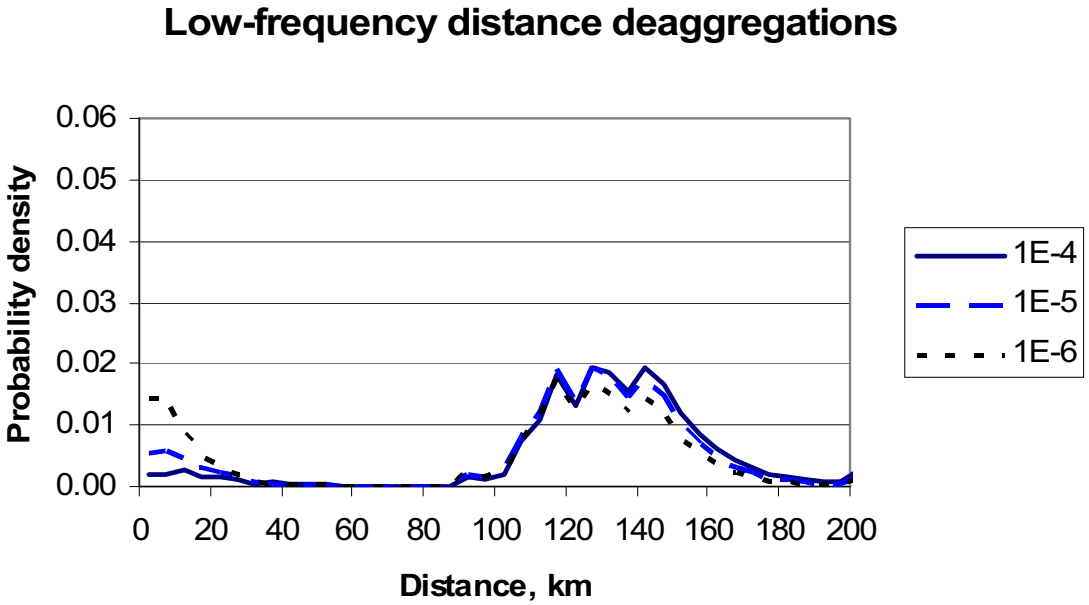


Figure 2.5-292
Hard Rock Magnitude Deaggregation for Low Frequencies for Three Mean Annual Frequencies of Exceedance

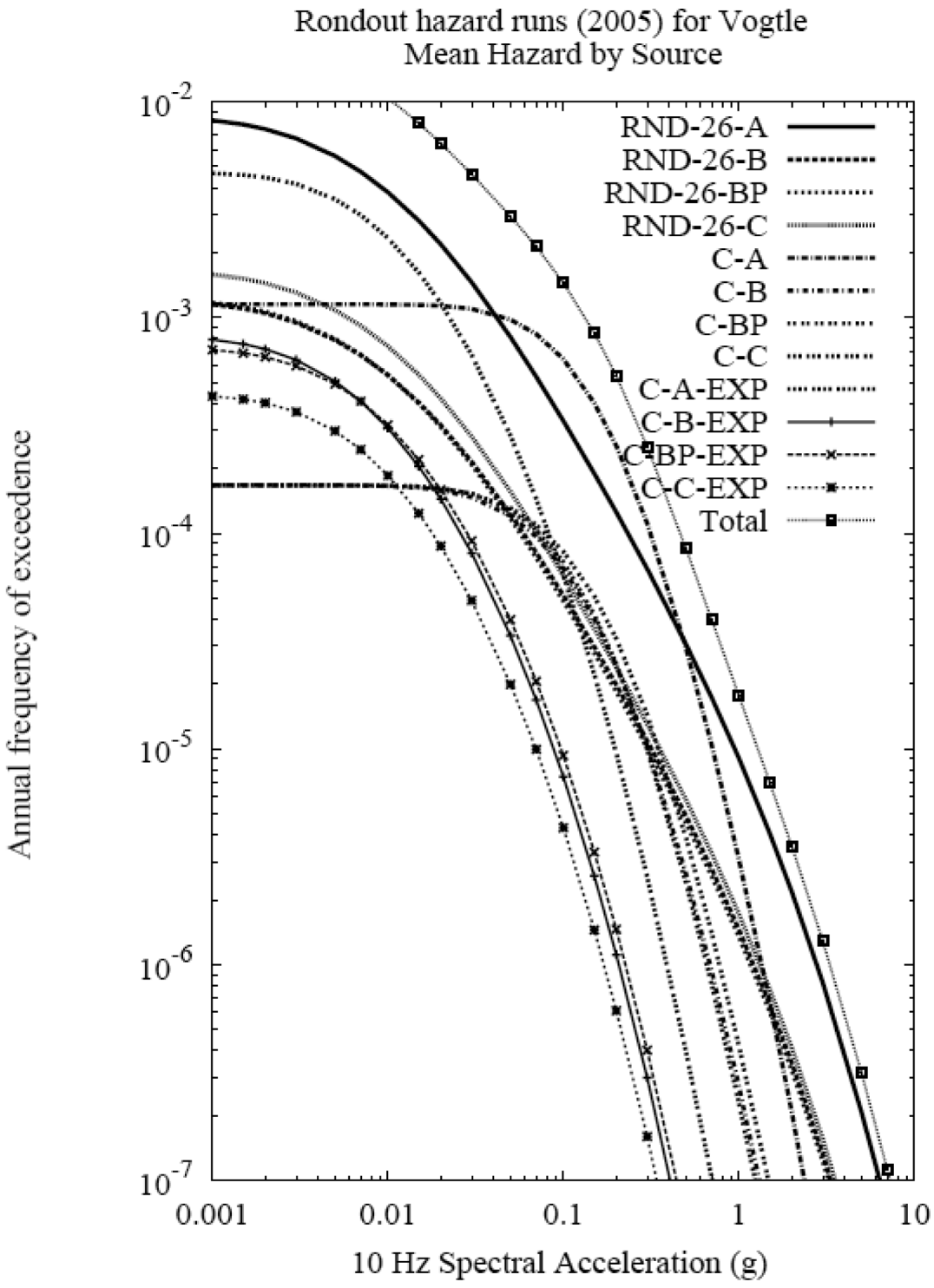


Figure 2.5-293
10 Hz Hard Rock Seismic Hazard Curves by Seismic Source for Rondout Team

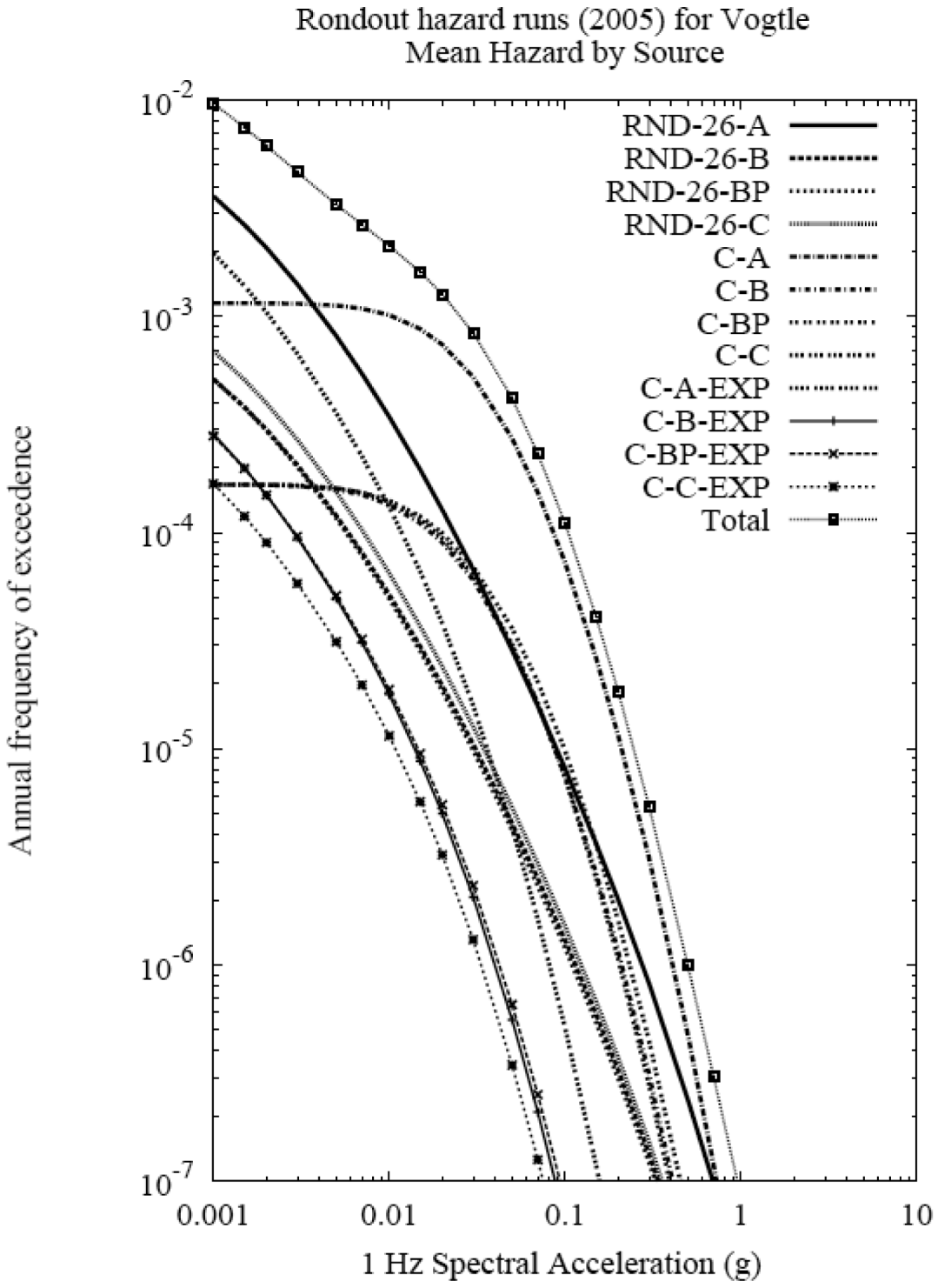
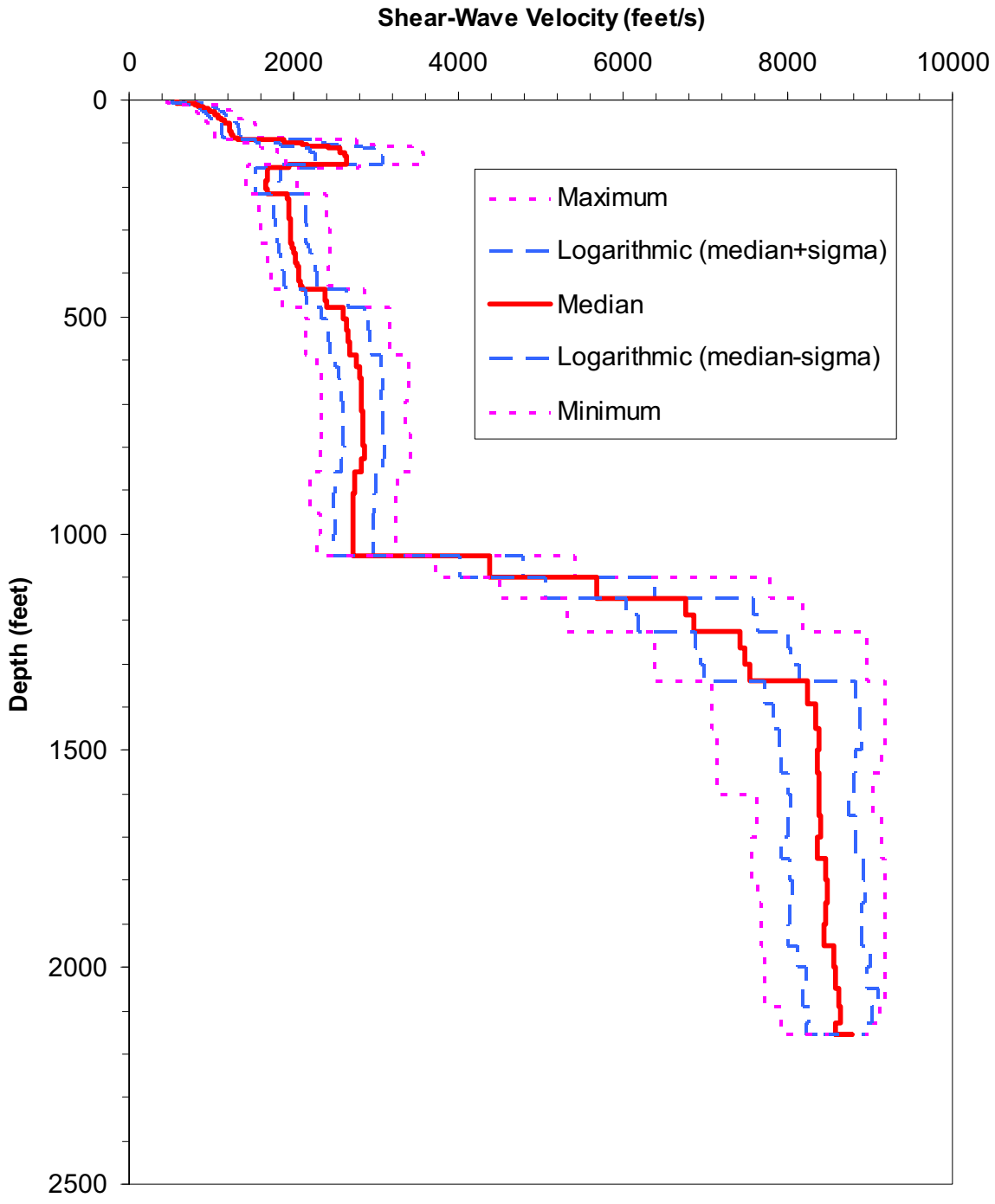


Figure 2.5-294
1 Hz Hard Rock Seismic Hazard Curves by Seismic Source for the Rondout Team



Note: Statistics do not include the velocities on the crystalline bedrock.

Figure 2.5-295
Summary Statistics Calculated from the 60 Shear-Wave Velocity Profiles

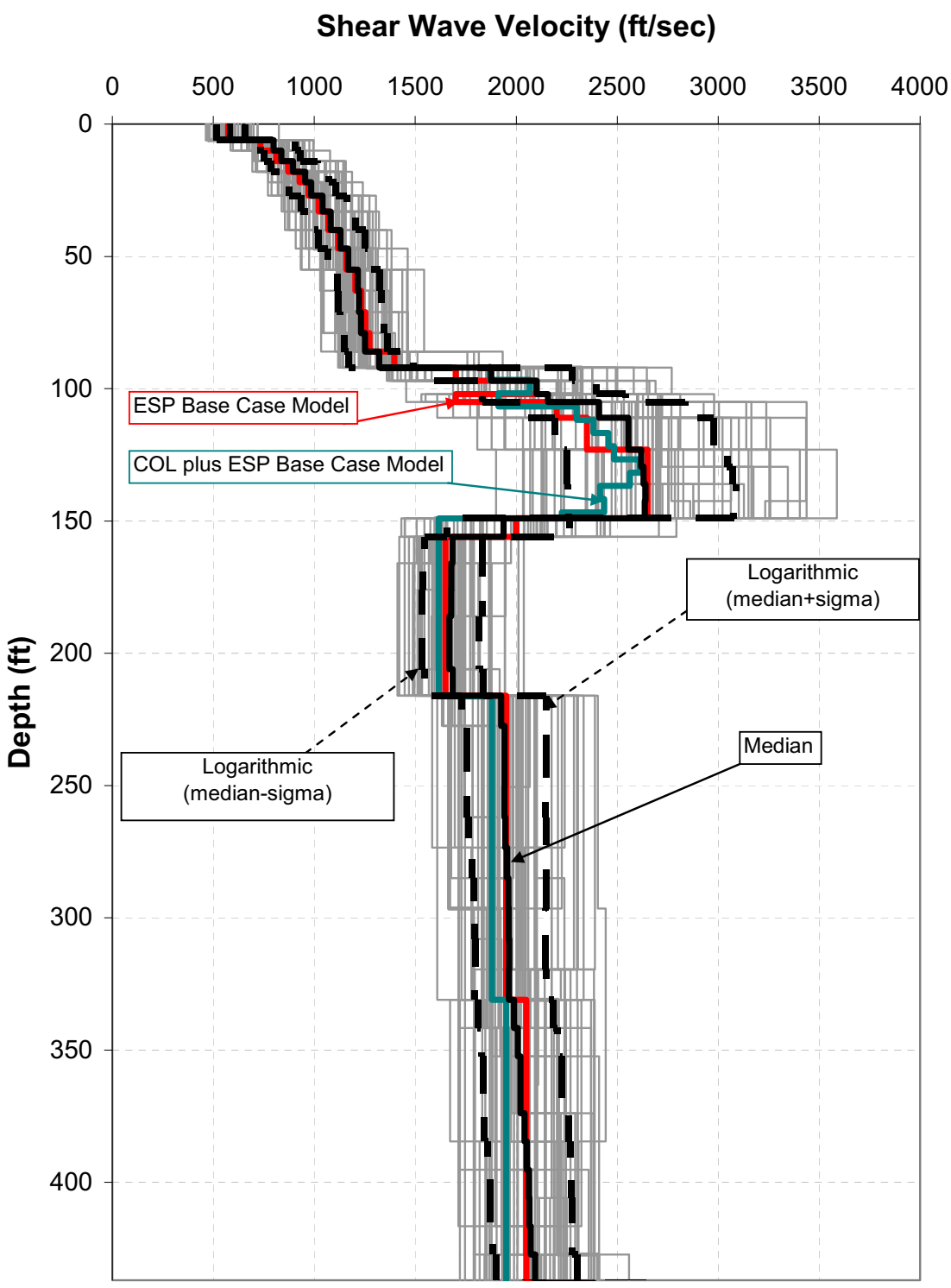


Figure 2.5-296
ESP and COL plus ESP Soil Models

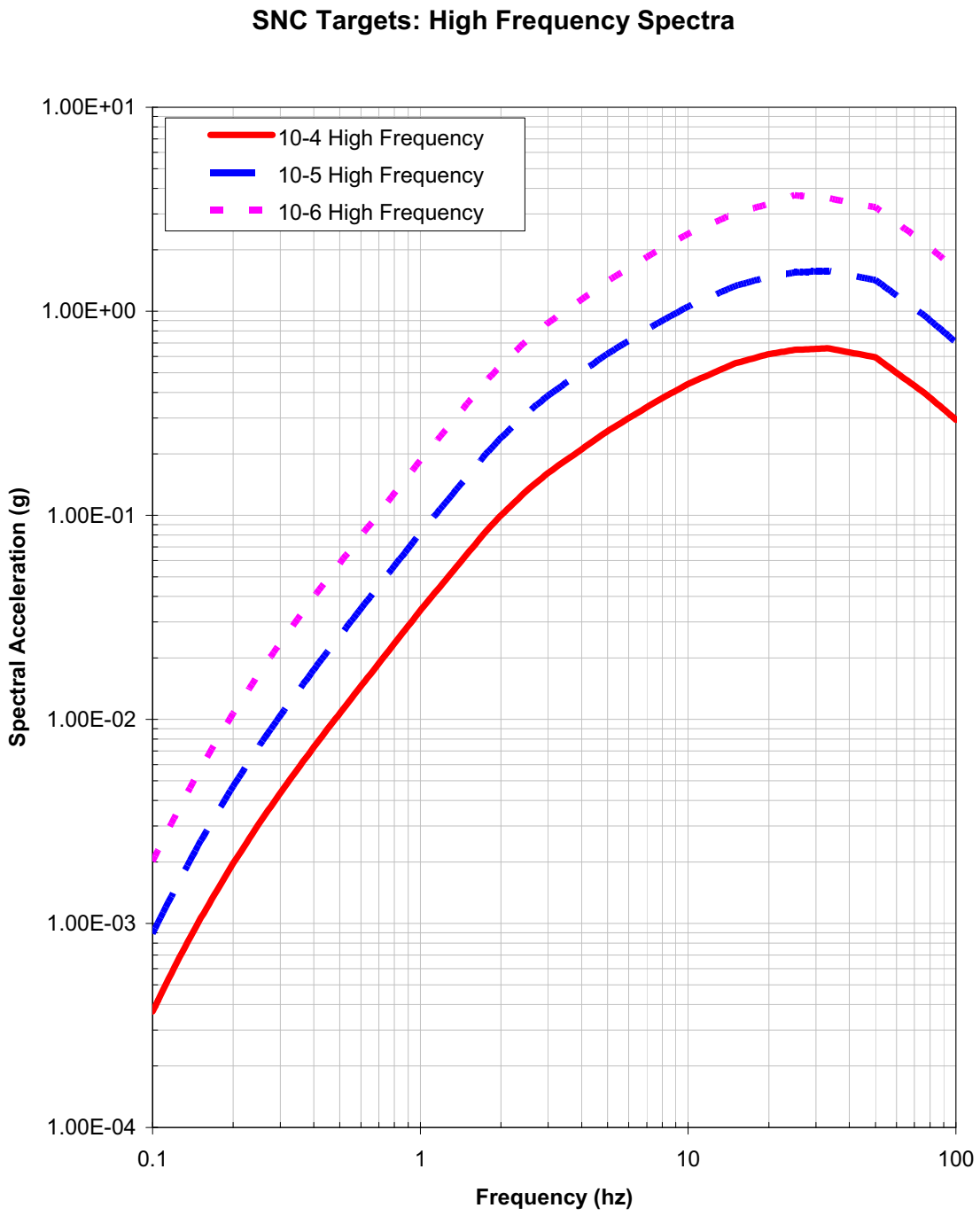


Figure 2.5-297
High Frequency Hard Rock Target Spectra for the Three Annual Probability Levels of 10^{-4}, 10^{-5}, and 10^{-6}

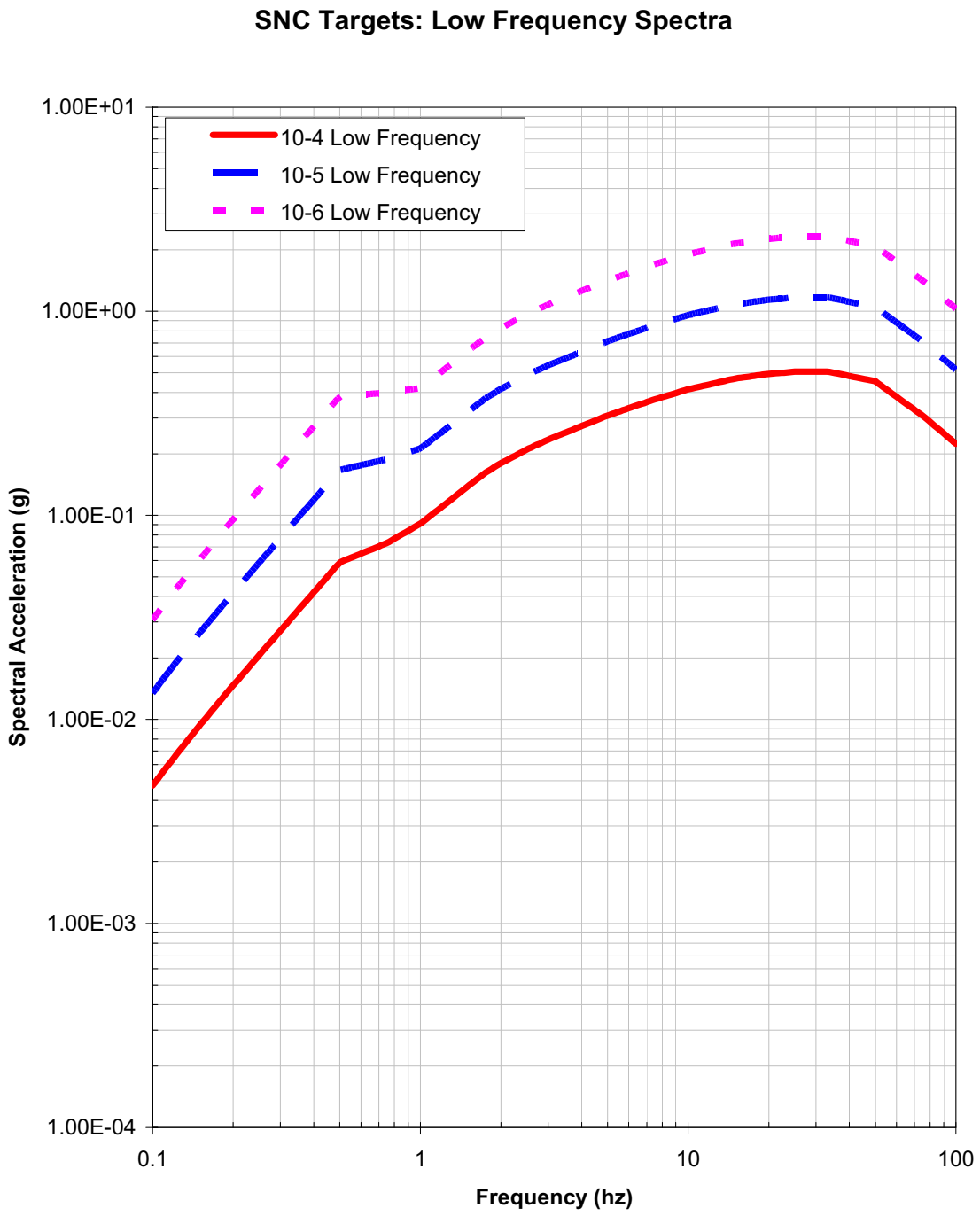
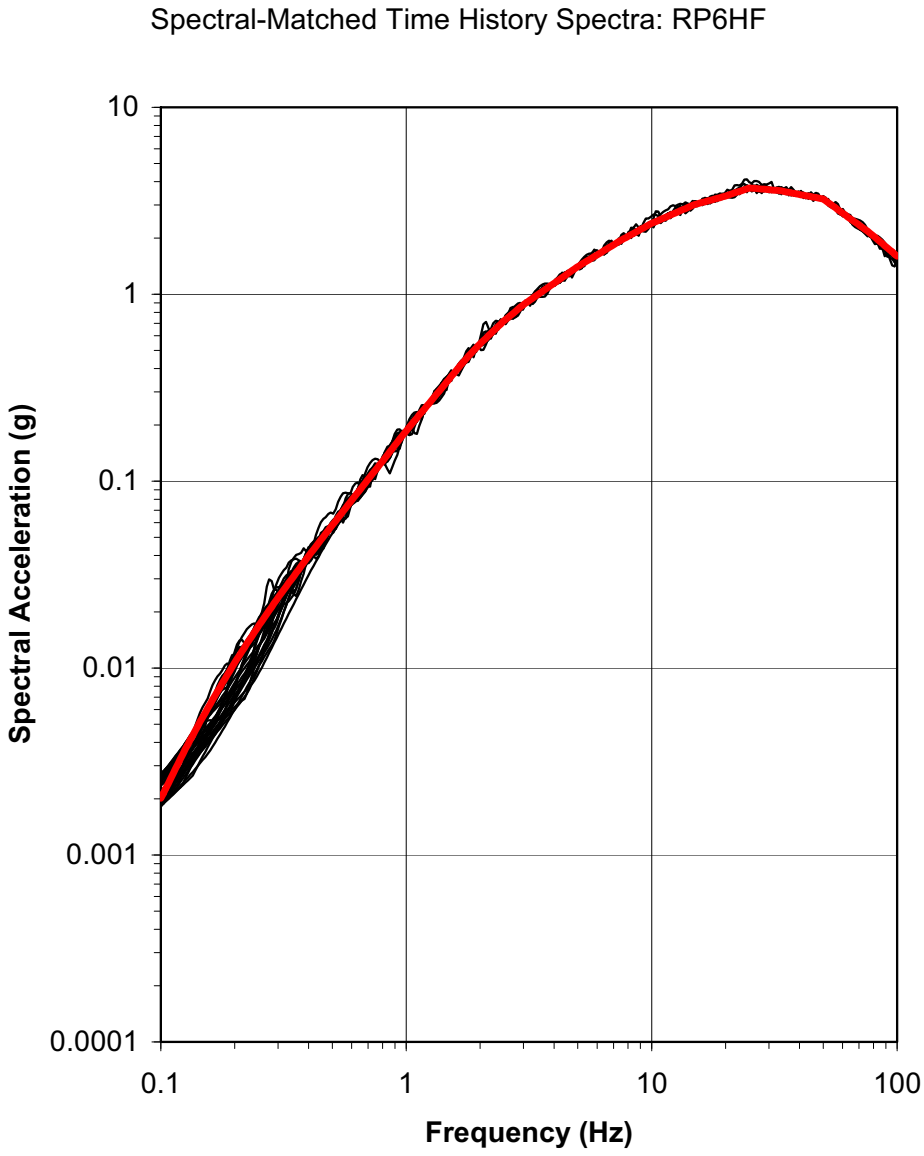
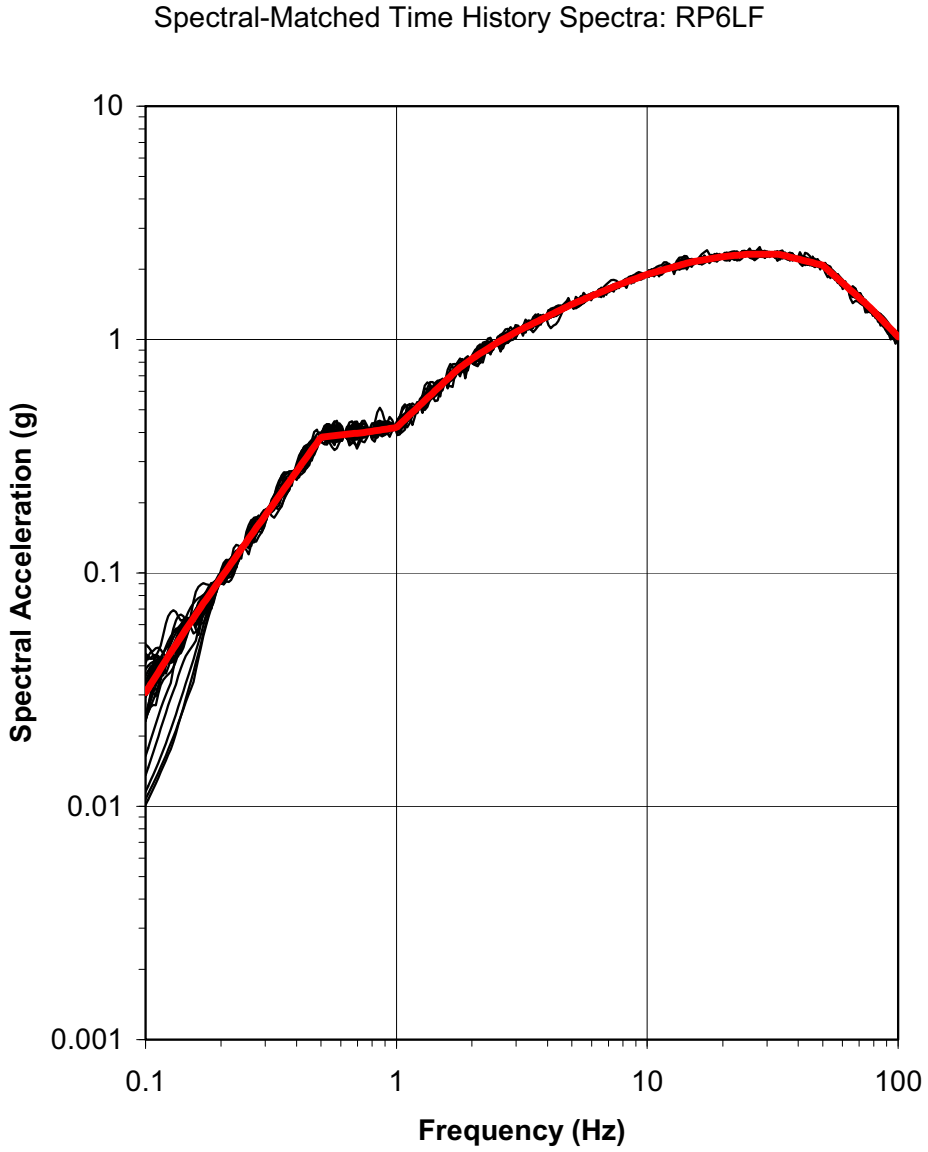


Figure 2.5-298
Low Frequency Hard Rock Target Spectra
for the Three Annual Probability Levels of 10^{-4}, 10^{-5}, and 10^{-6}



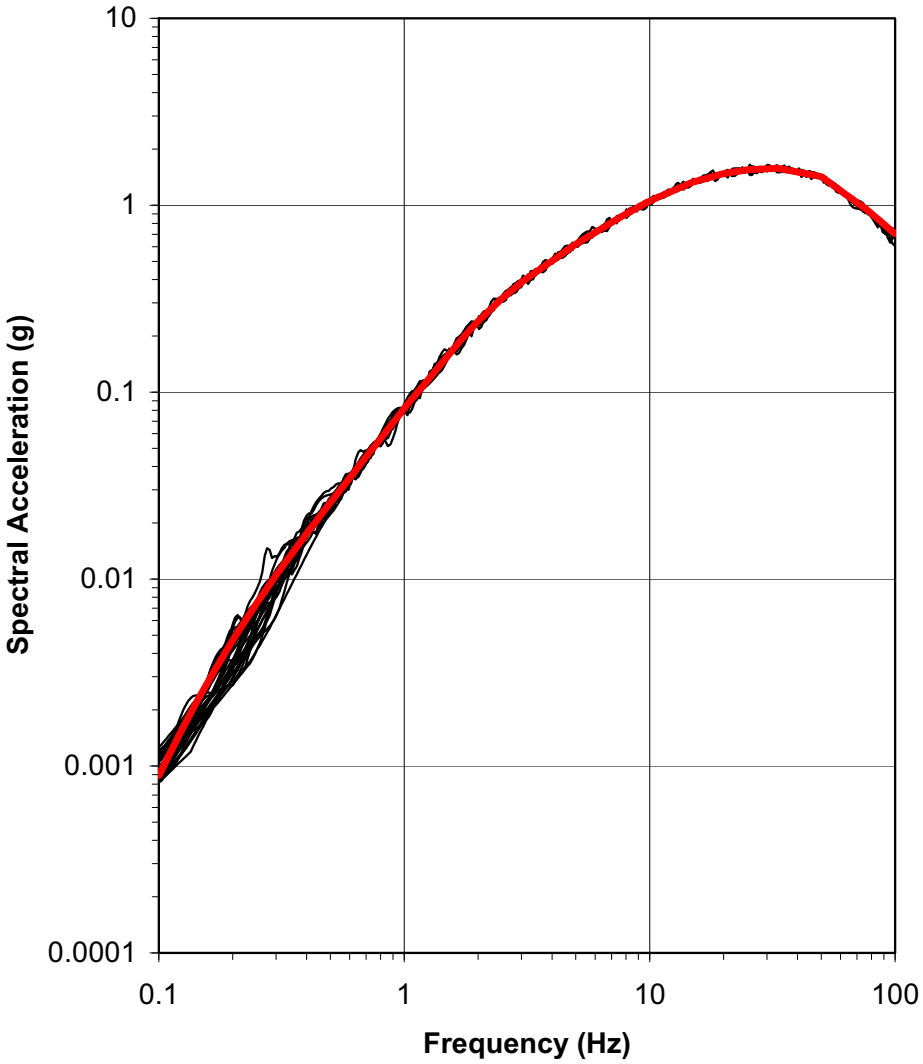
Note: Heavy red line is the target spectrum and thin black lines are the individual matches.

Figure 2.5-299
High Frequency (10^{-6}) Match for the 30 Time Histories



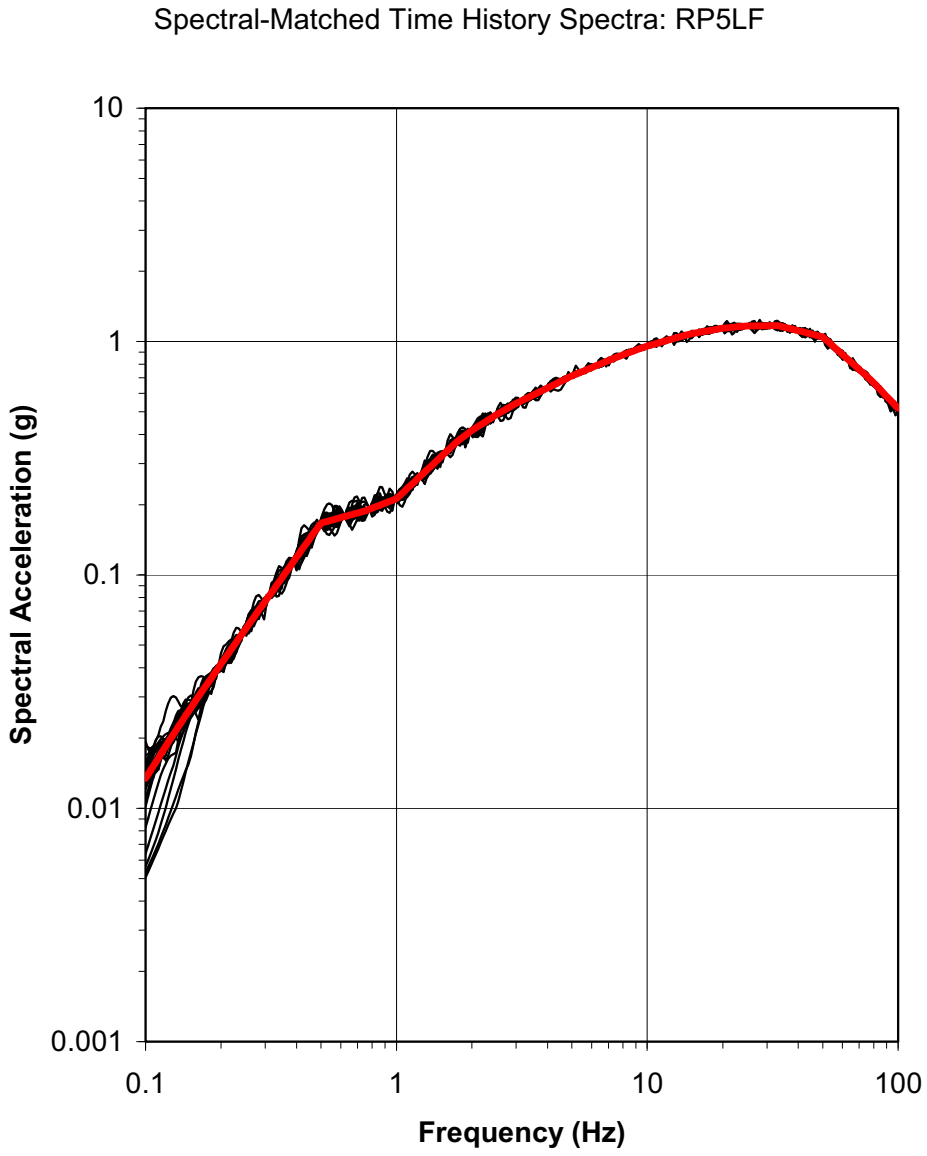
Note: Heavy red line is the target spectrum and thin black lines are the individual matches.

Figure 2.5-300
Low Frequency (10^{-6}) Match for the 30 Time Histories



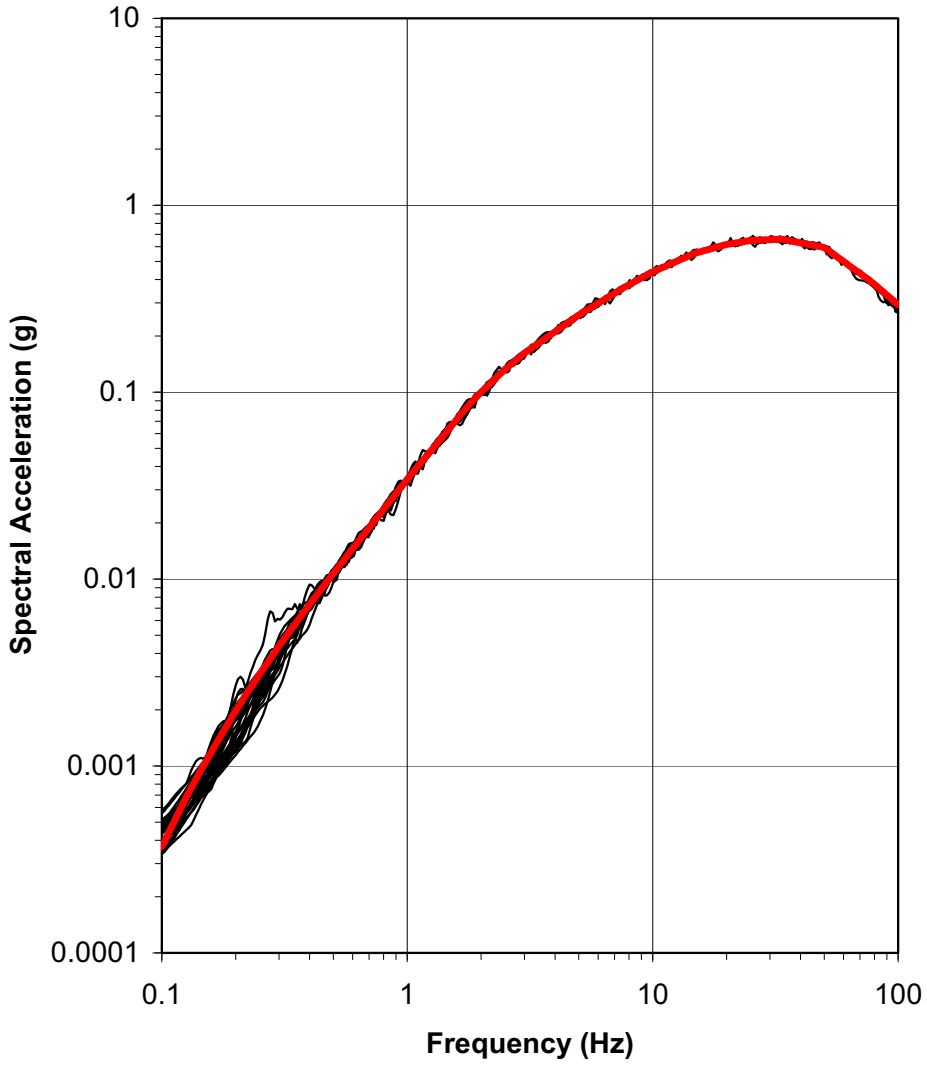
Note: Heavy red line is the target spectrum and thin black lines are the individual matches.

Figure 2.5-301
High Frequency (10^{-5}) Match for the 30 Time Histories



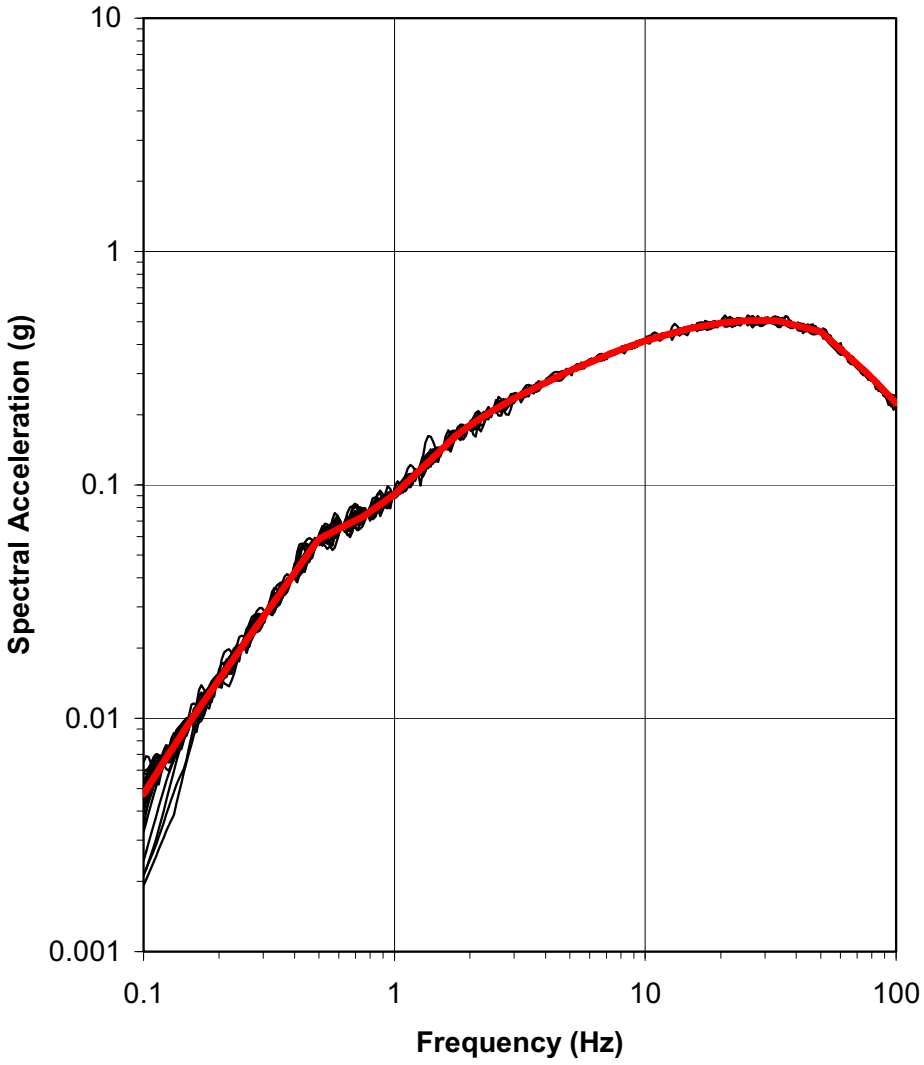
Note: Heavy red line is the target spectrum and thin black lines are the individual matches.

Figure 2.5-302
Low Frequency (10^{-5}) Match for the 30 Time Histories



Note: Heavy red line is the target spectrum and thin black lines are the individual matches.

Figure 2.5-303
High Frequency (10^{-4}) Match for the 30 Time Histories



Note: Heavy red line is the target spectrum and thin black lines are the individual matches.

Figure 2.5-304
Low Frequency (10^{-4}) Match for the 30 Time Histories

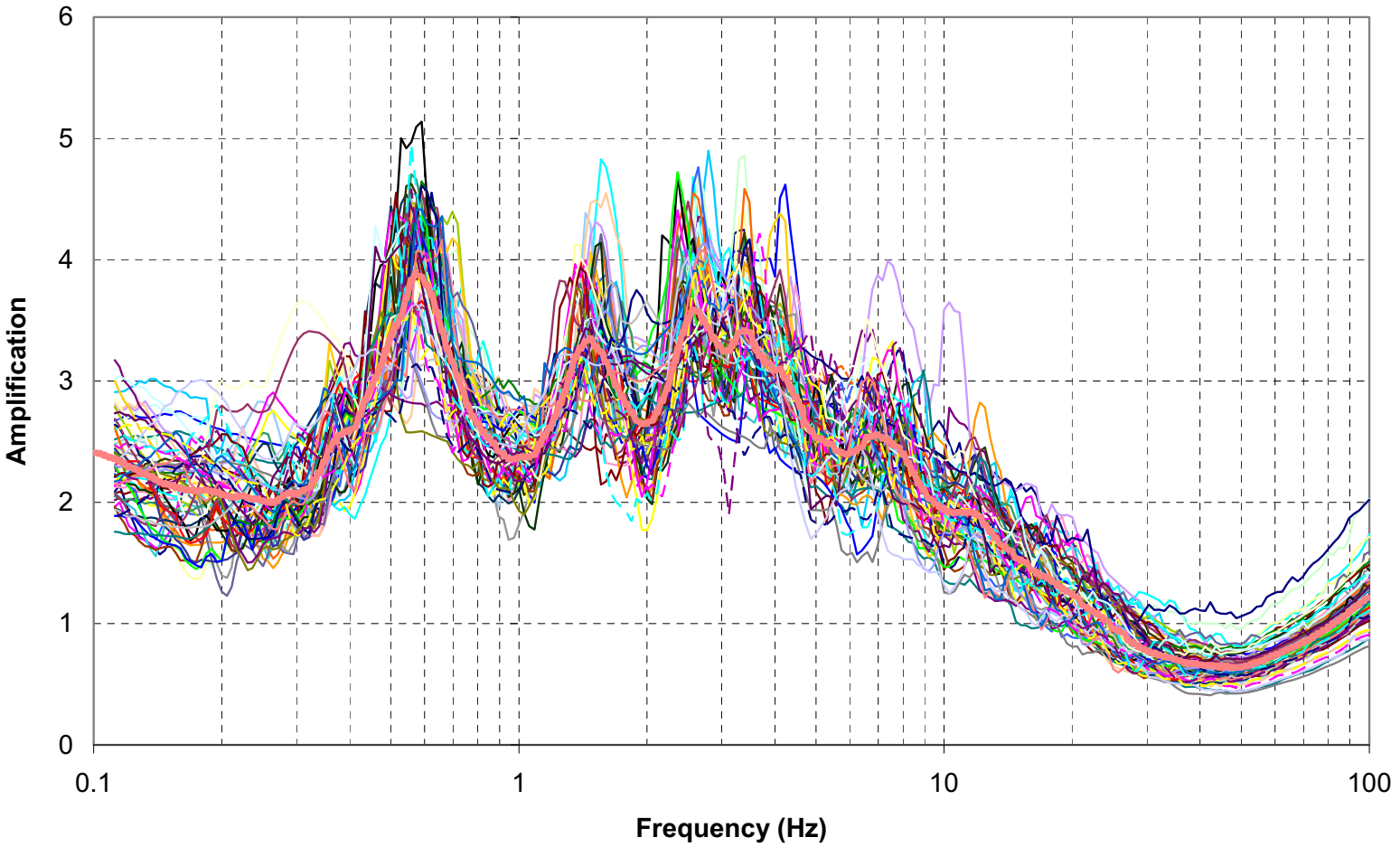


Figure 2.5-305
Typical Results of Spectral Amplification at 86-ft Depth (Top of Blue Bluff Marl) Using EPRI Degradation Curves for High Frequency Time Histories of 10^{-4} MAFE Input Motion Level

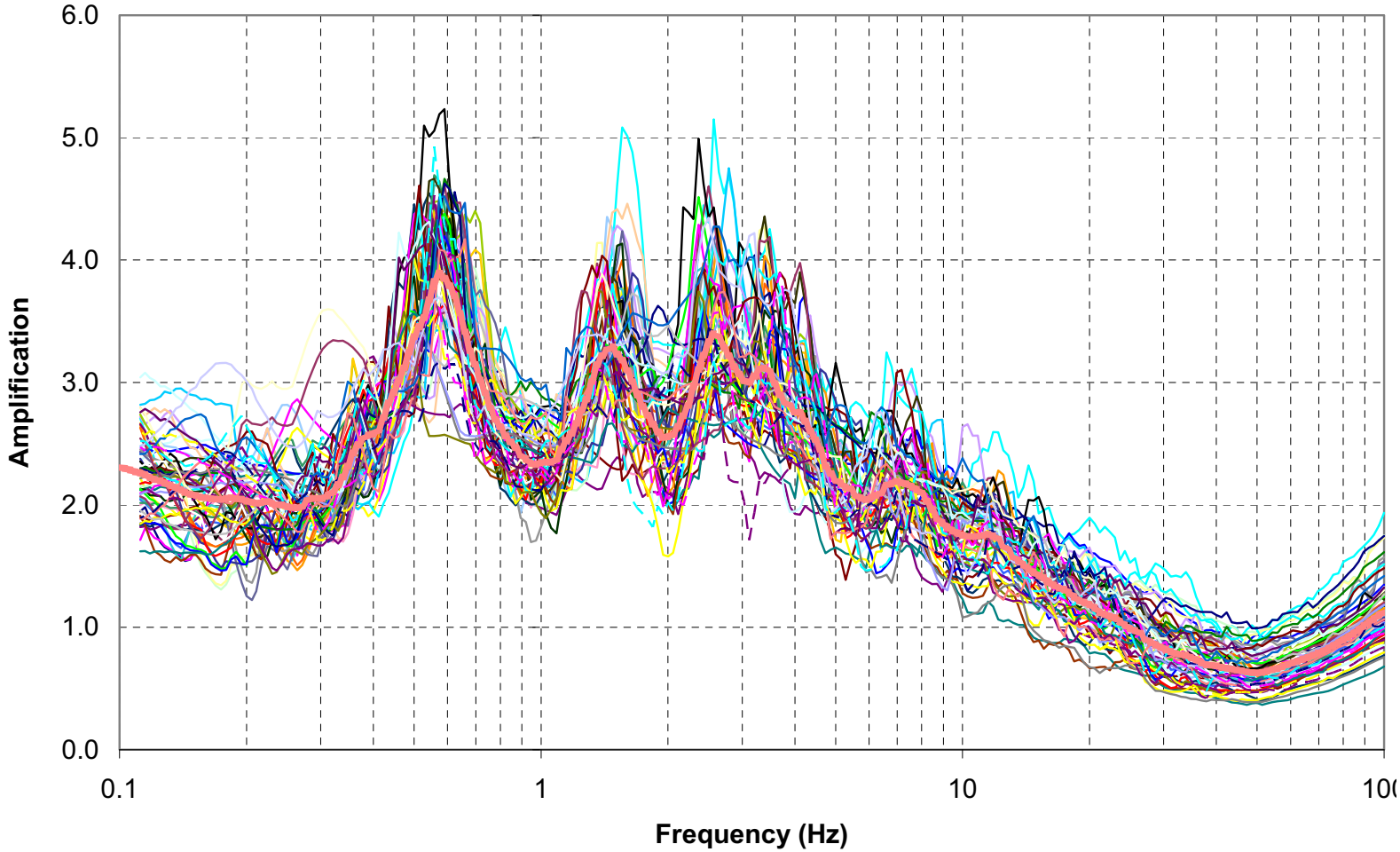


Figure 2.5-306
Typical Results of Spectral Amplification at 40-ft Horizon Outcrop Motion Using EPRI Degradation Curves for High-Frequency Time Histories of 10^{-4} MAFE Input Motion Level

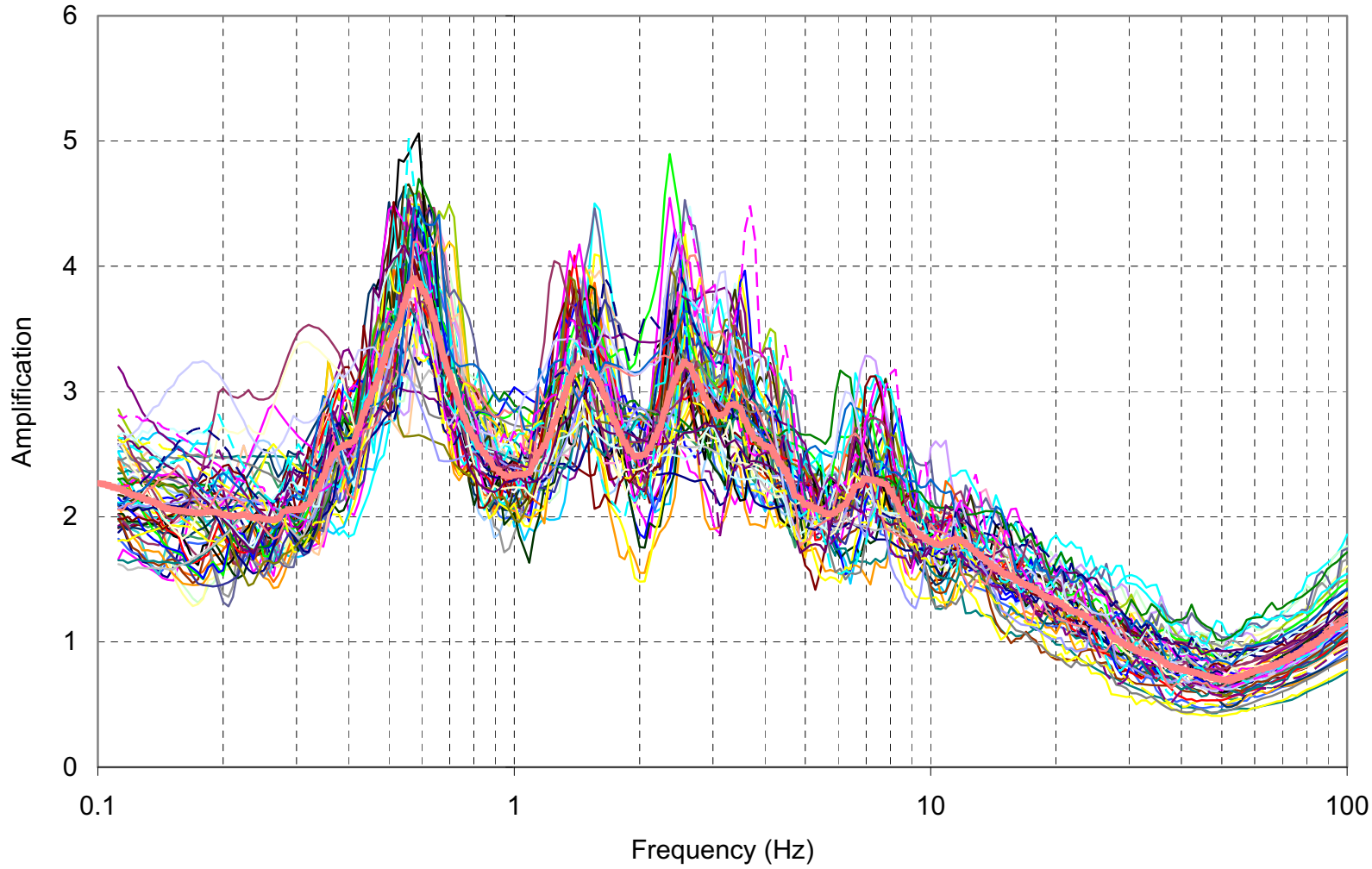


Figure 2.5-307
Typical Results of Spectral Amplification Ground Surface using EPRI Degradation Curves for High Frequency Time Histories of 10^{-4} MAFE Input Motion Level

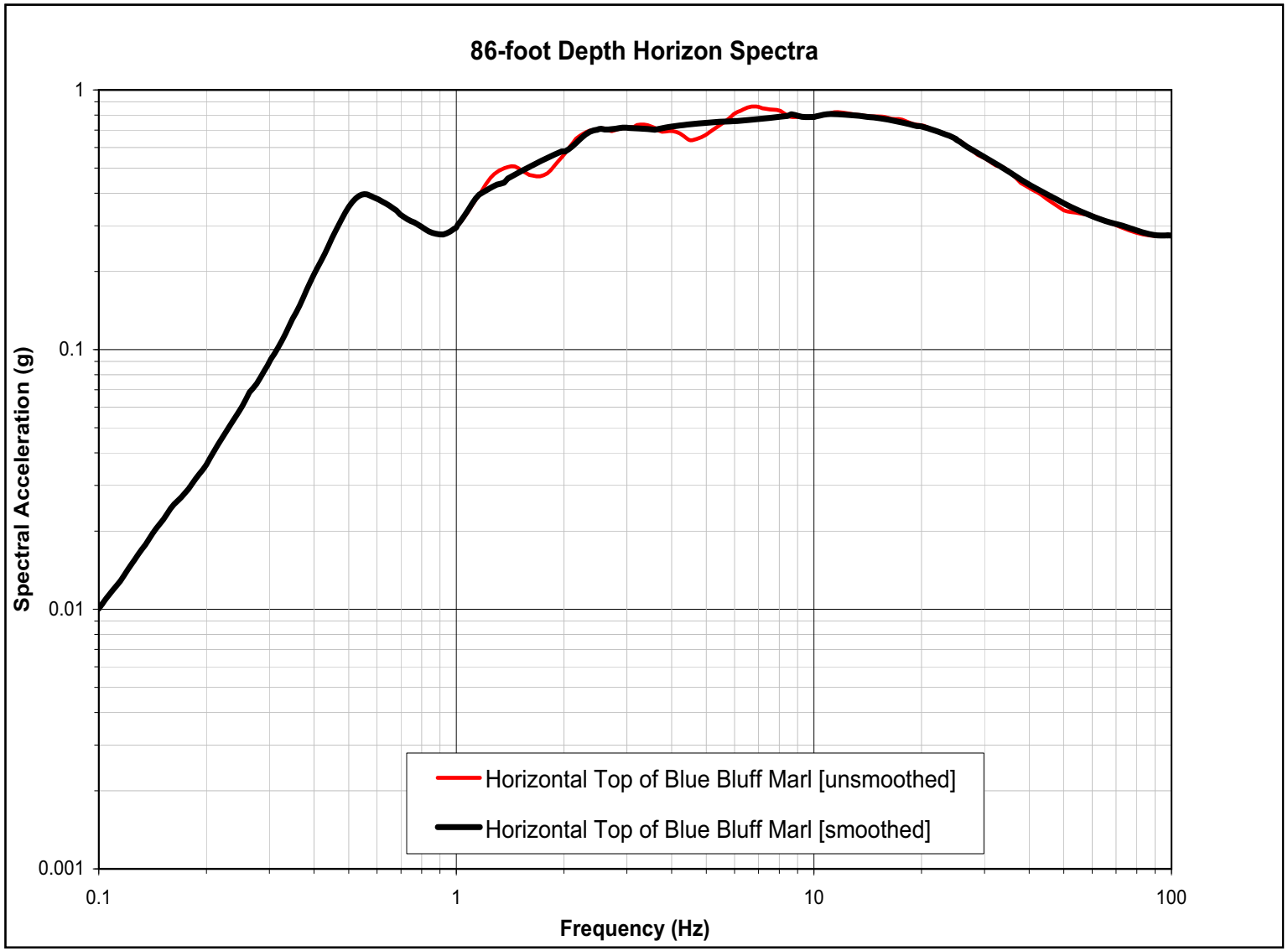


Figure 2.5-308
Horizontal Raw and Smoothed, Top of Blue Bluff Marl

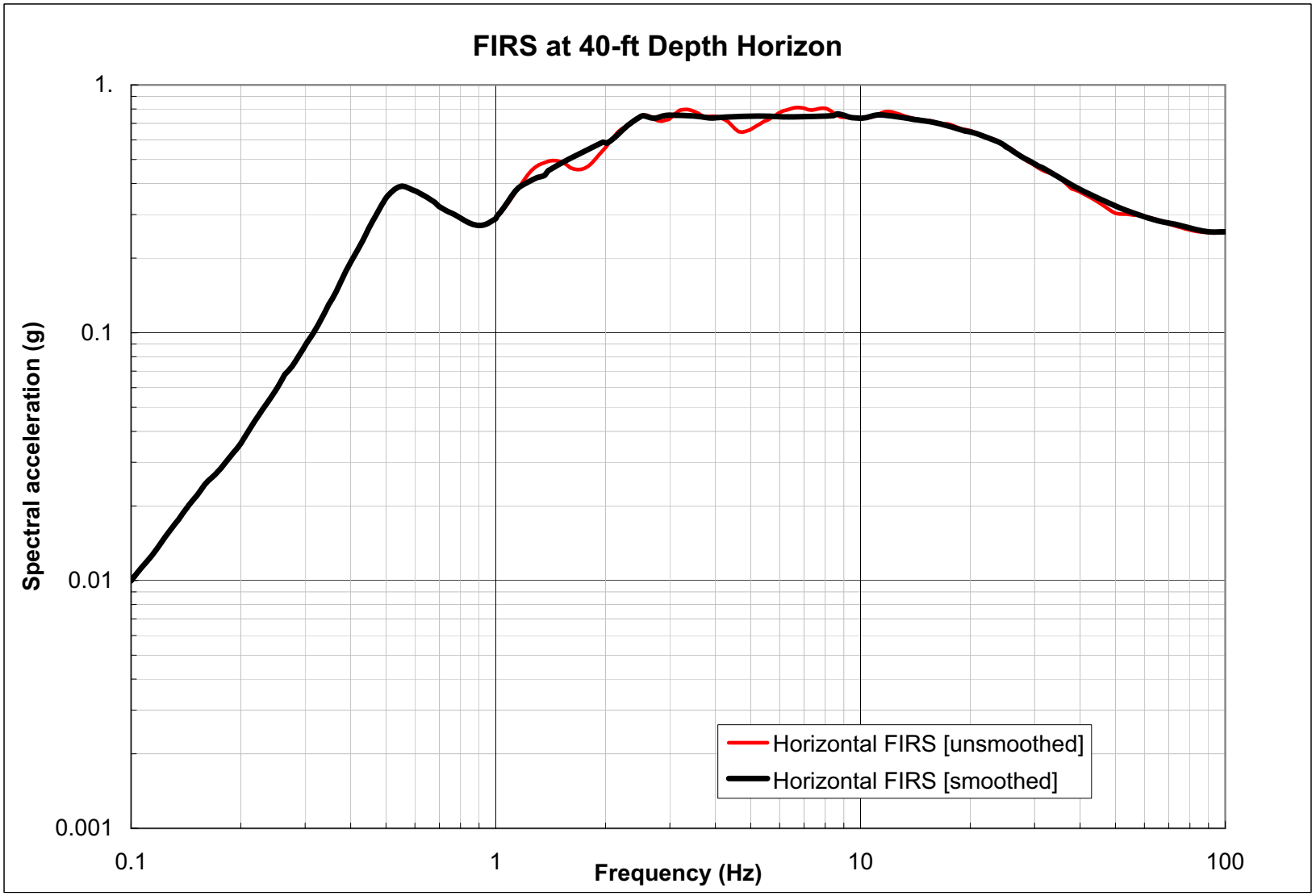


Figure 2.5-309
Horizontal Raw and Smoothed FIRS, 40-ft Depth Horizon

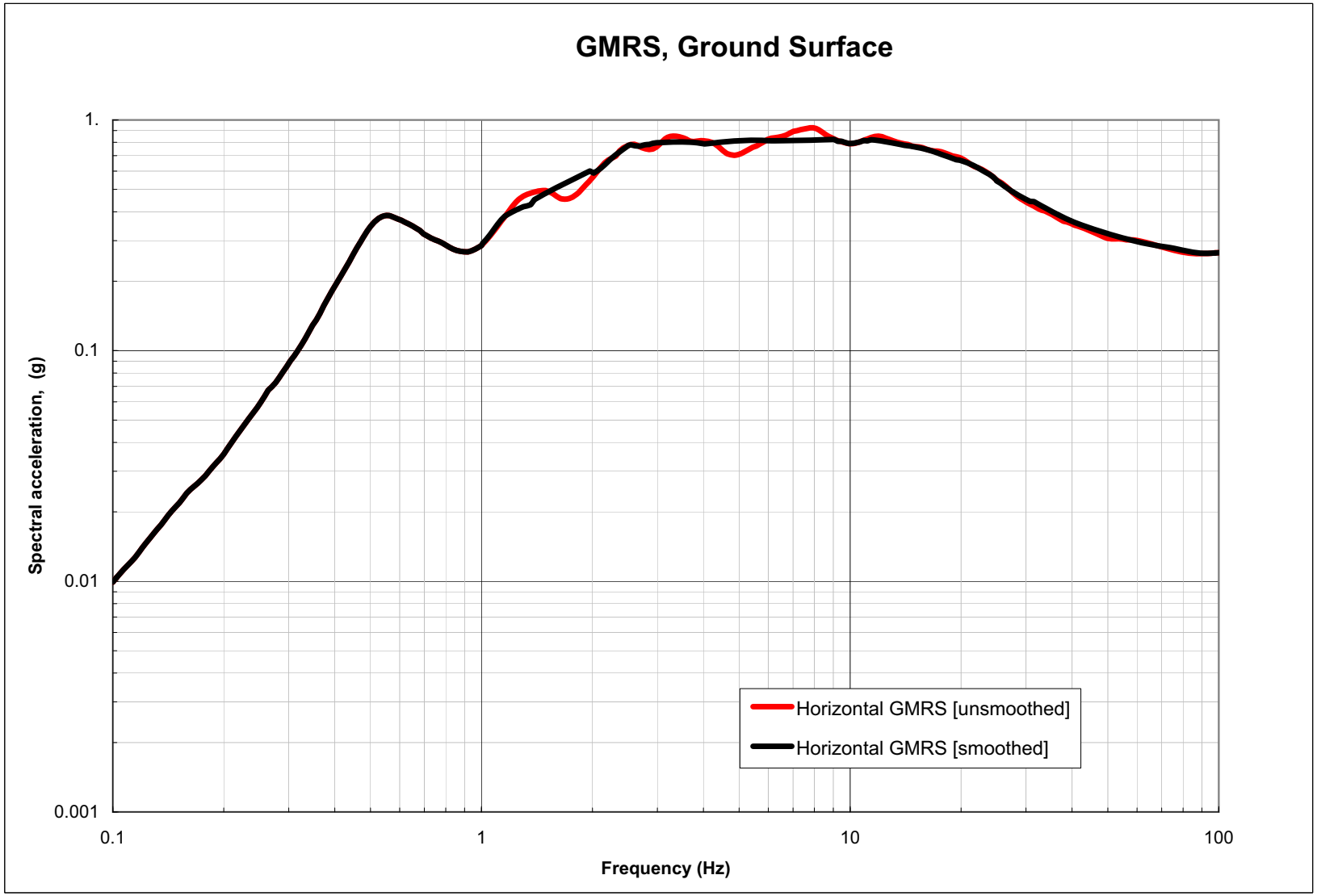


Figure 2.5-310
Horizontal Raw and Smoothed GMRS, Ground Surface

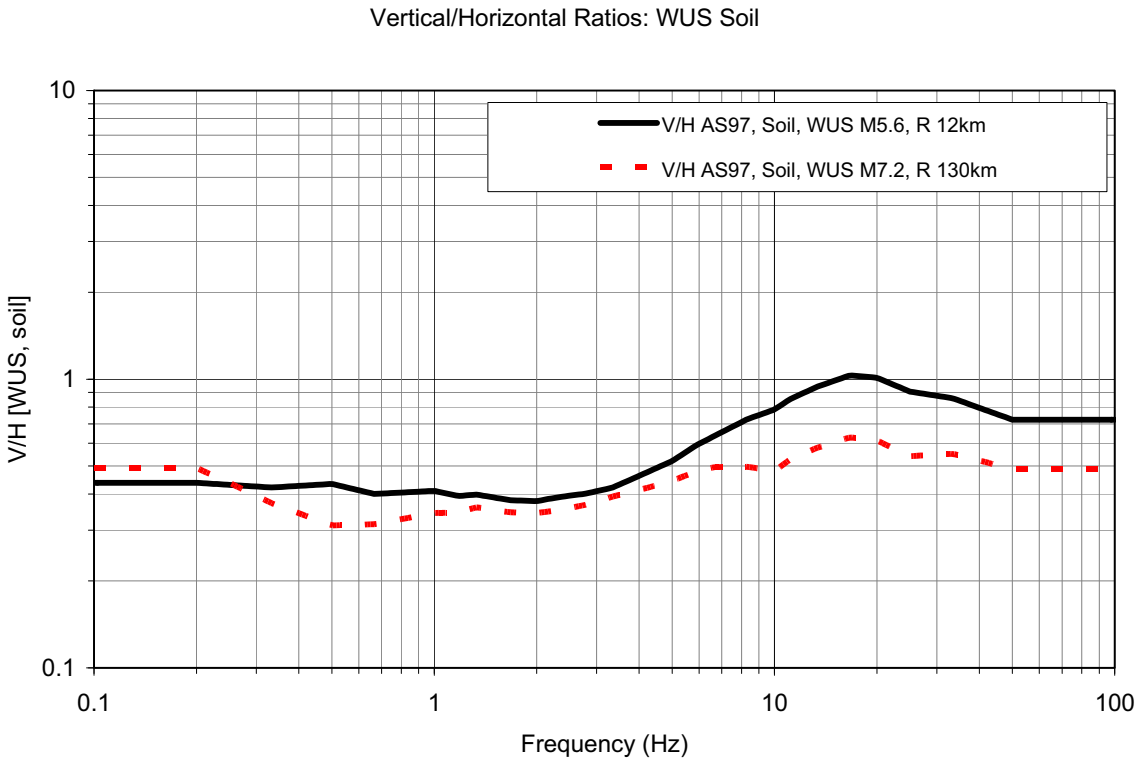
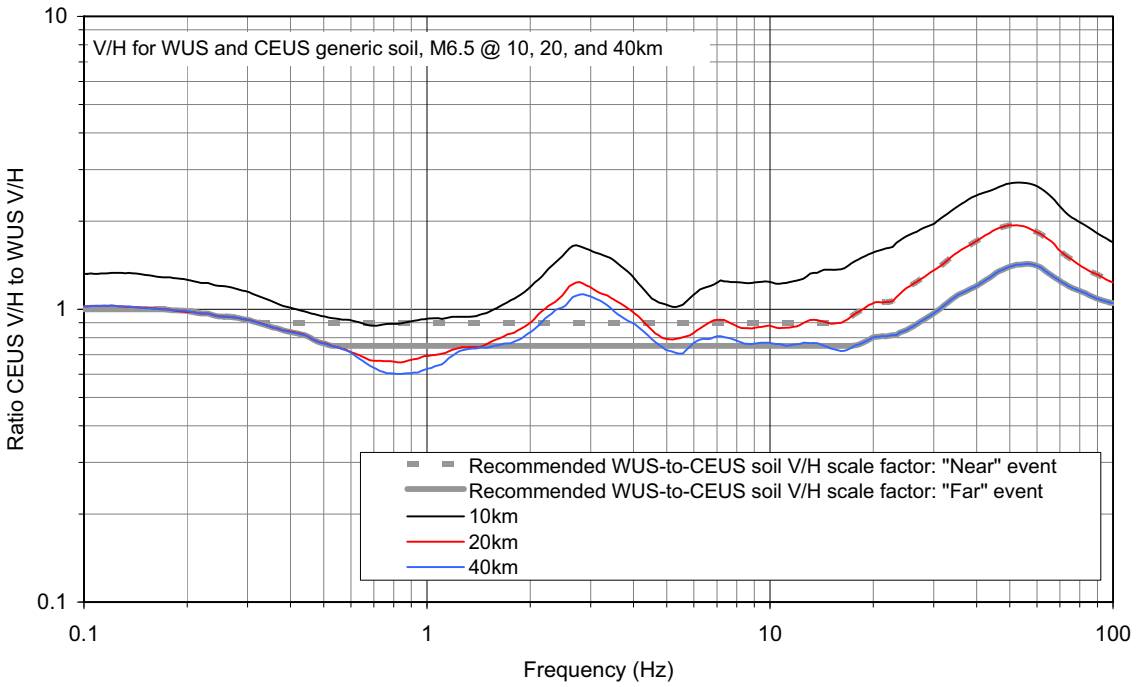


Figure 2.5-311
Plots of V/HWUS,Soil,Empirical Term of Equation 2.5.2-6 for "Near" [M5.6 at a Distance of 12 km] and "Far" [M7.2 at a Distance of 130 km] Events Using the Attenuation Relation of Abrahamson and Silva (1997)

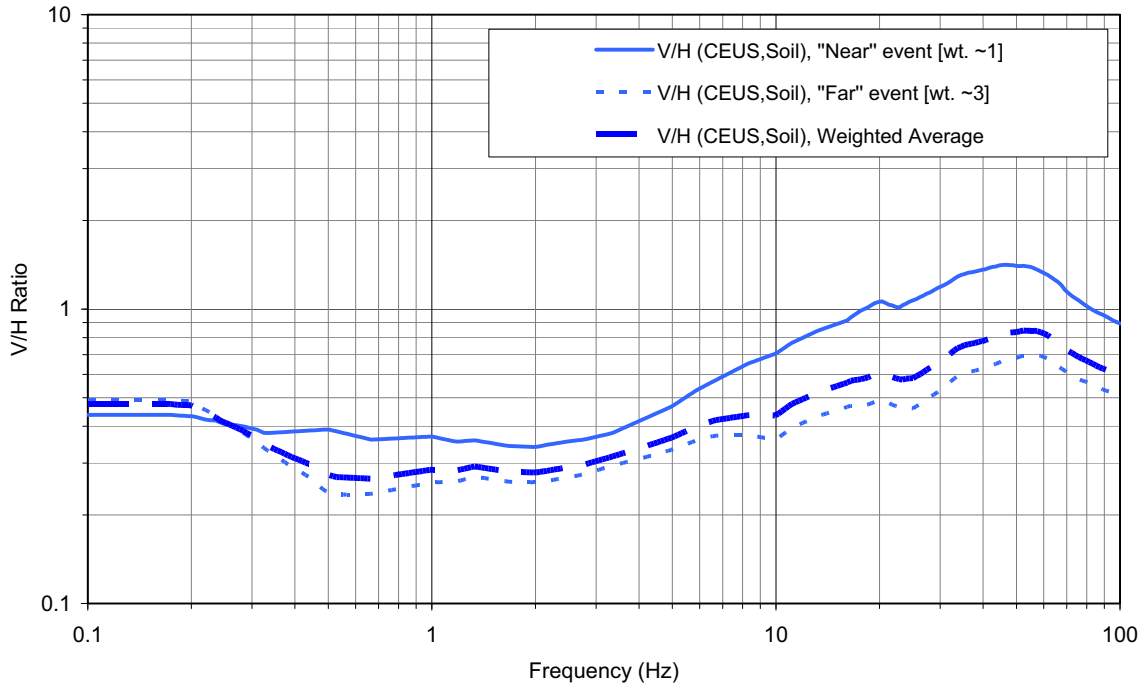
NUREG/CR-6728, Figure J-31 and J-32



Note: The “near” and “far” ratios of V/H ratios recommended for this study are also shown.

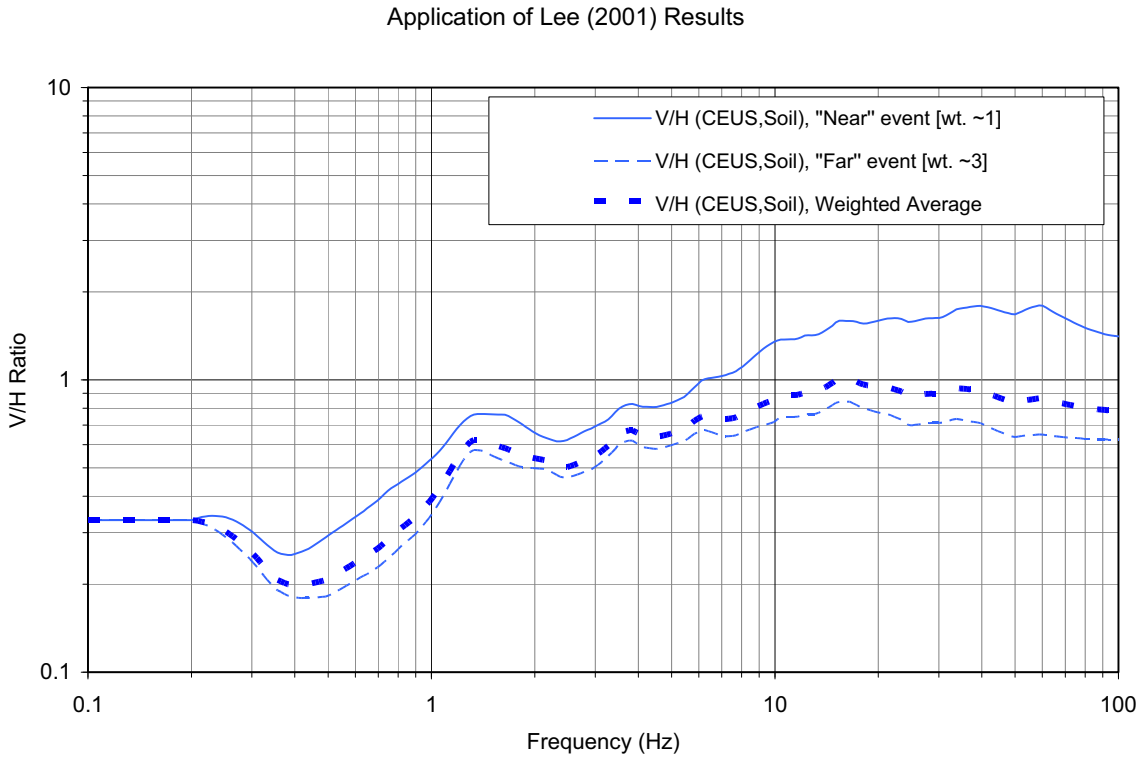
Figure 2.5-312
Plots of [V/HCEUS,Soil,Model / V/HWUS,Soil,Model] Term of Equation 2.5.2-6 for M6.5 and Distances of 10, 20, and 40 km, as Available in NUREG/CR-6728 (McGuire et al 2001)

Application of NUREG/CR-6728 Method and Available Results



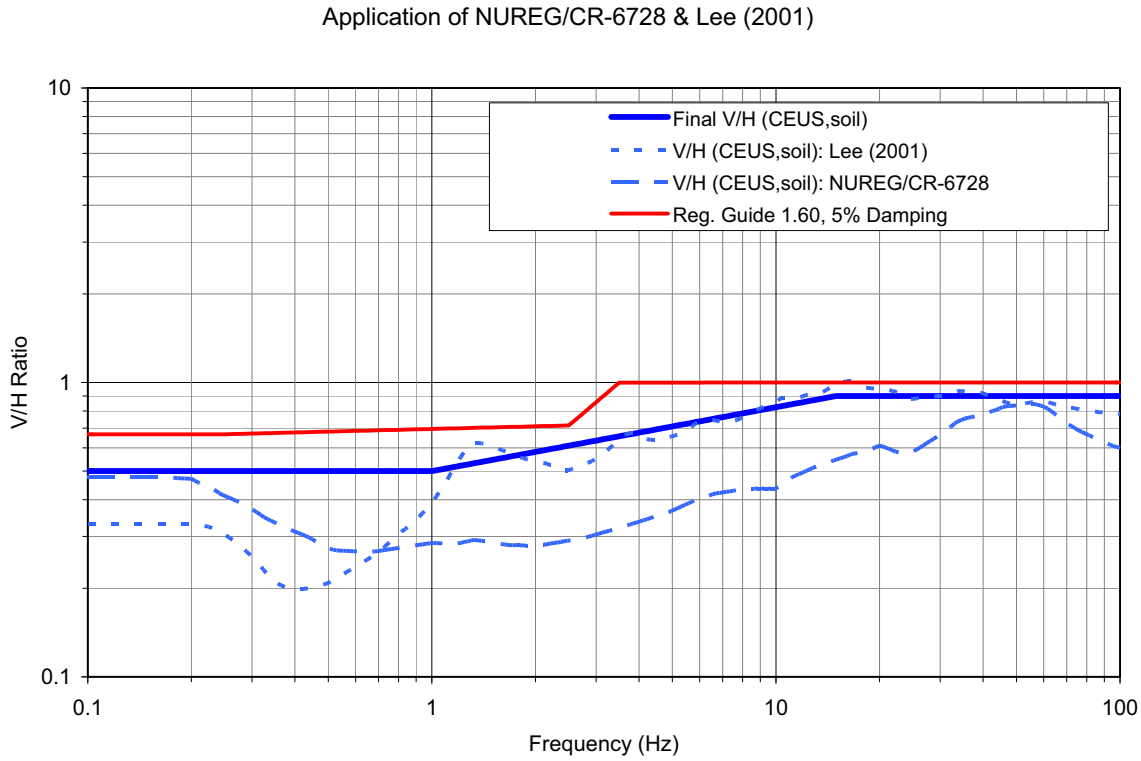
Note: Considering the relative contribution of the “near” and “far” events to the horizontal SSE design response spectrum, the approximately 1:3 weighted average is the recommended $V/H_{CEUS,Soil}$.

Figure 2.5-313
Plots of Recommended V/HCEUS,Soil from Equation 2.5.2-6 for “Near” and “Far” Events Using Results from NUREG/CR-6728 (McGuire et al 2001)



Note: Considering the relative contribution of the “near” and “far” events to the horizontal SSE design response spectrum, the approximately 1:3 weighted average is shown.

Figure 2.5-314
Plots of Recommended V/HCEUS,Soil from Equation 2.5.2-6 for “Near” and “Far” Events Using Results from Lee (2001)



Note: Considering the site-specific aspects of the Lee (2001), it is preferred, guiding the recommended final $V/H_{CEUS,Soil}$ (blue solid). The V/H from RG 1.60 is shown (red) for comparison.

Figure 2.5-315
Plots of V/HCEUS,Soil (Blue Patterned) Derived from Results from NUREG/CR-6728 (McGuire et al 2001) and Lee (2001)

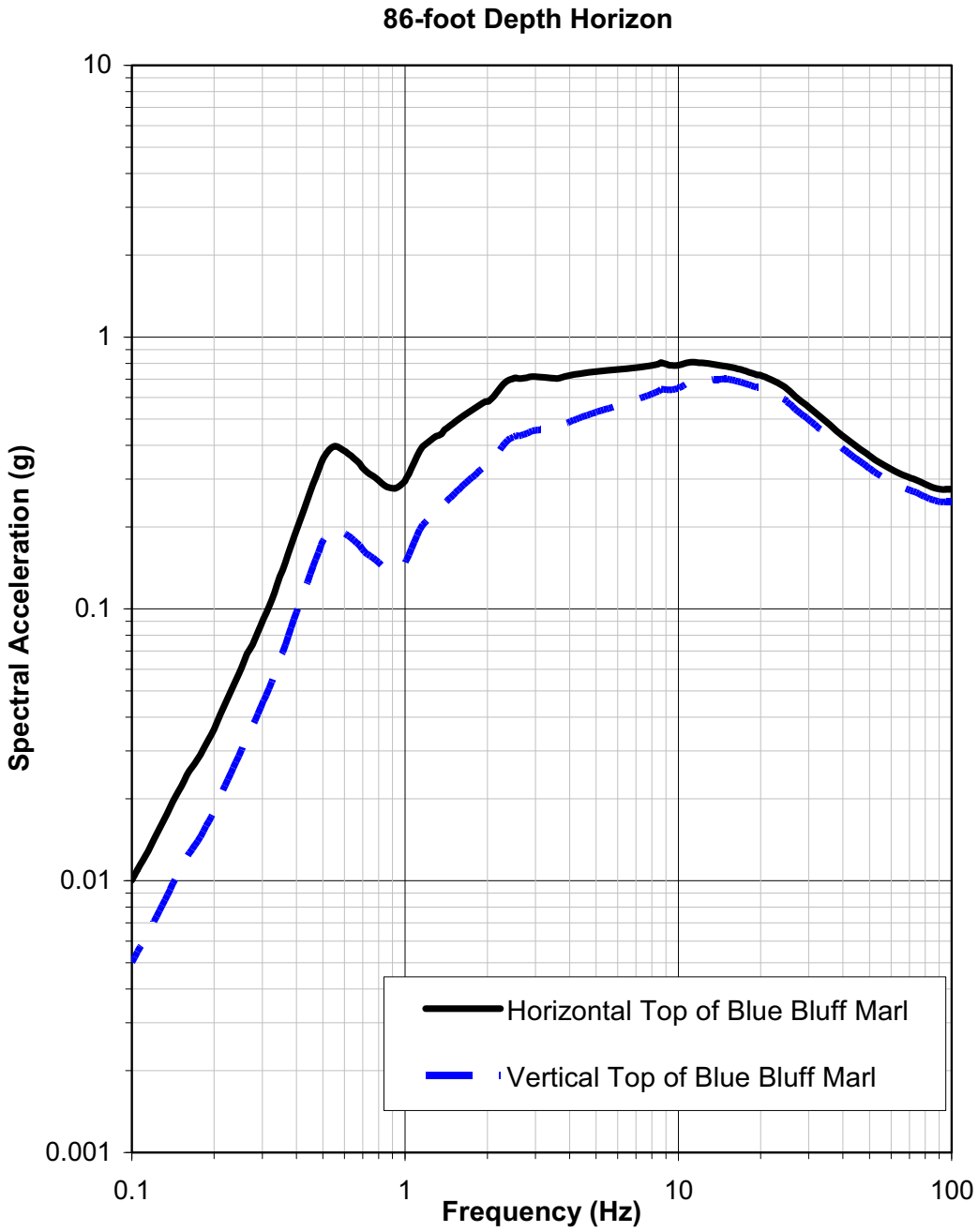


Figure 2.5-316
VEGP ESP Horizontal and Vertical Top of Blue Bluff Marl (5% Damping)

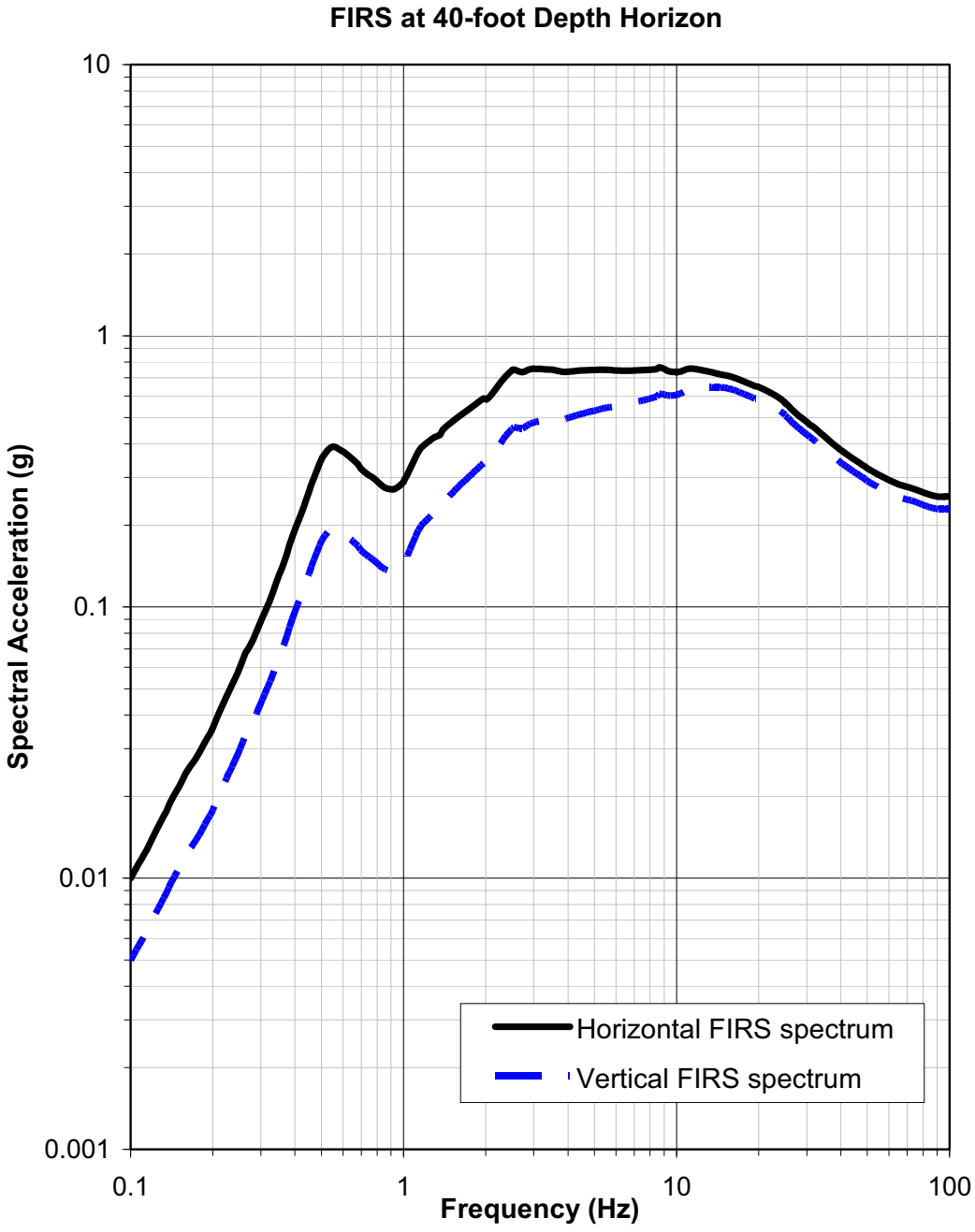


Figure 2.5-317
VEGP ESP Horizontal and Vertical FIRS Spectra, at the 40-ft Depth Horizon

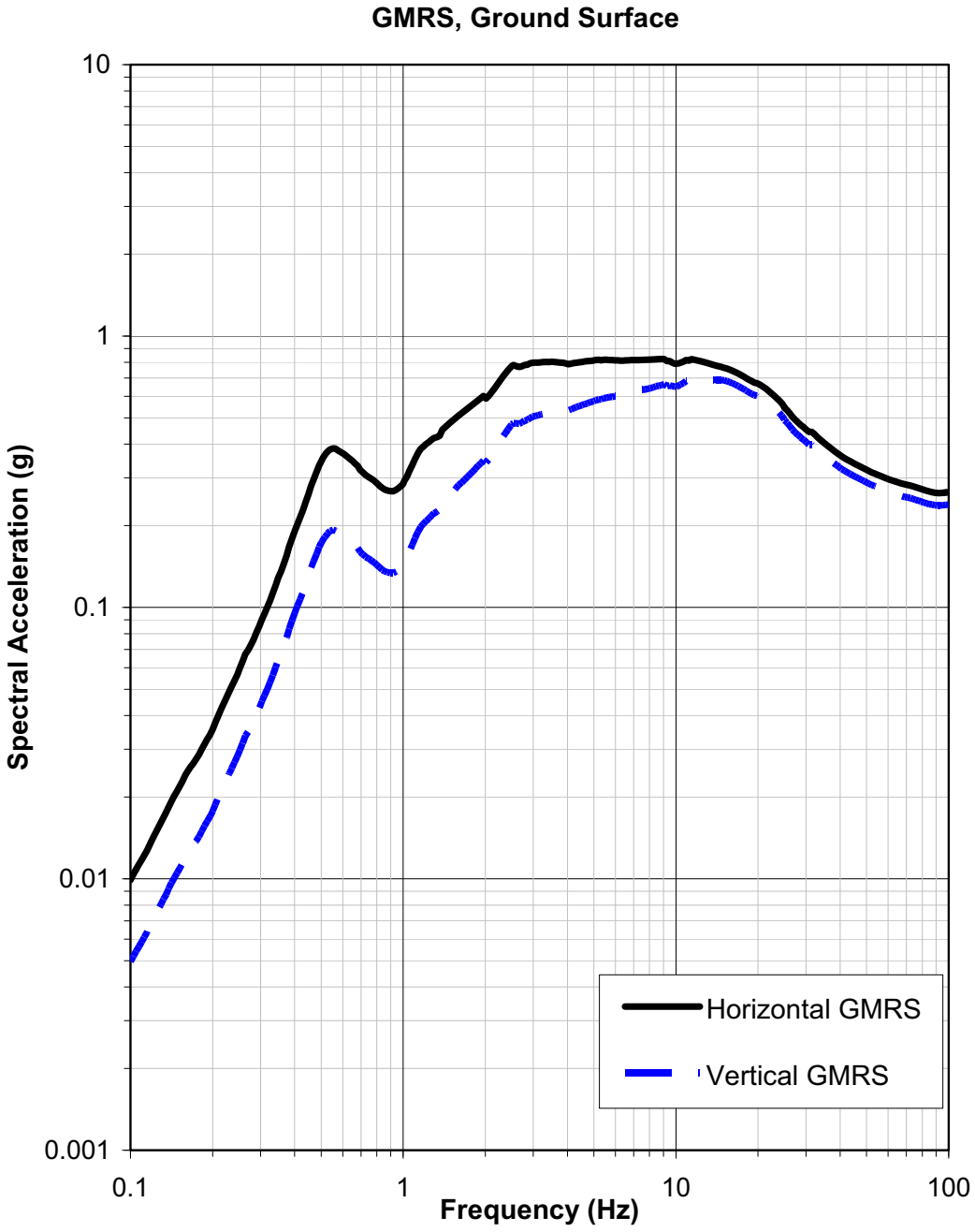


Figure 2.5-318
VEGP ESP Horizontal and Vertical GMRS Spectra (5% Damping)

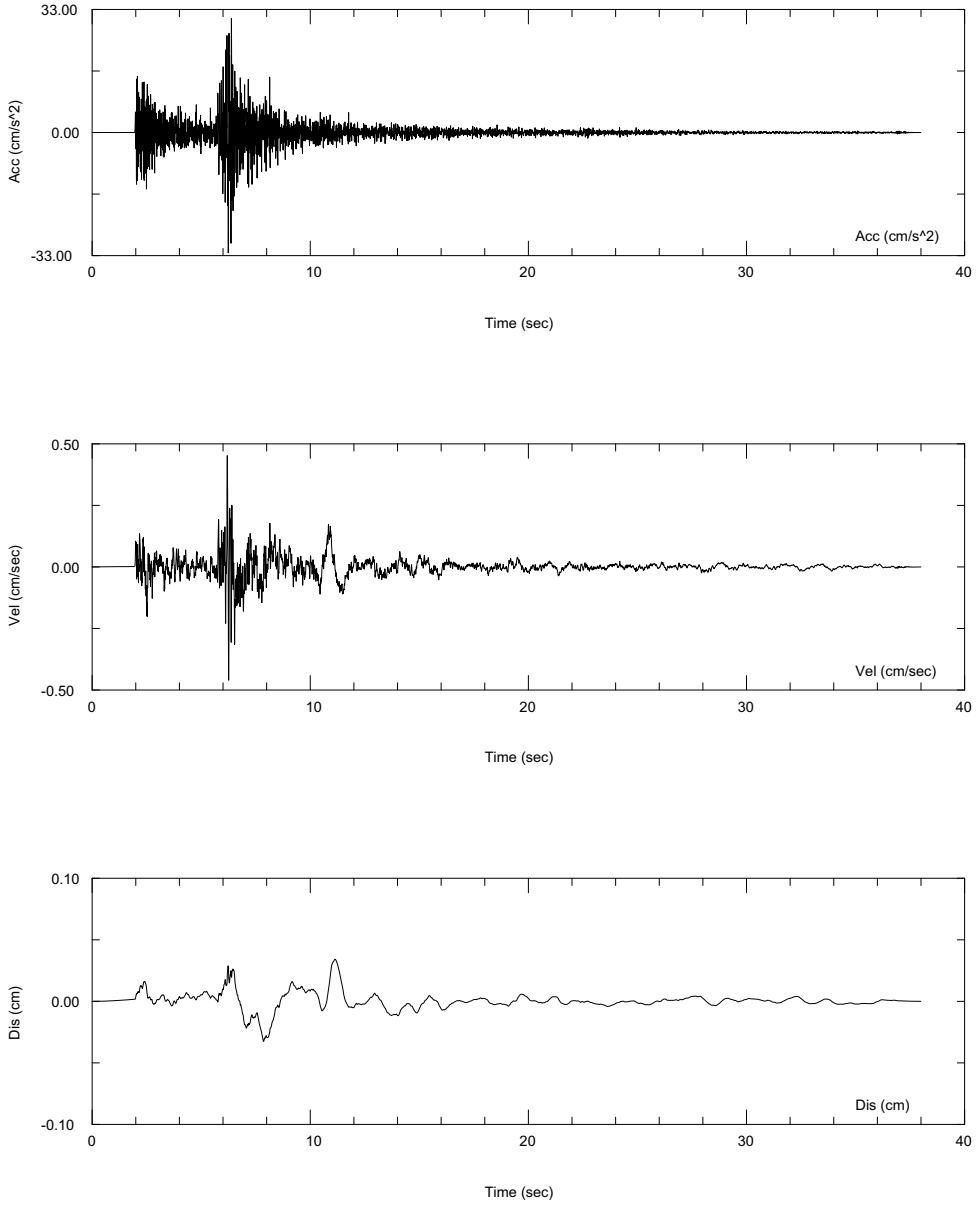


Figure 2.5-319
Example of Initial Seed Input Time Acceleration, Velocity, and Displacement Time Histories (One of Thirty) for High Frequency Target Spectrum

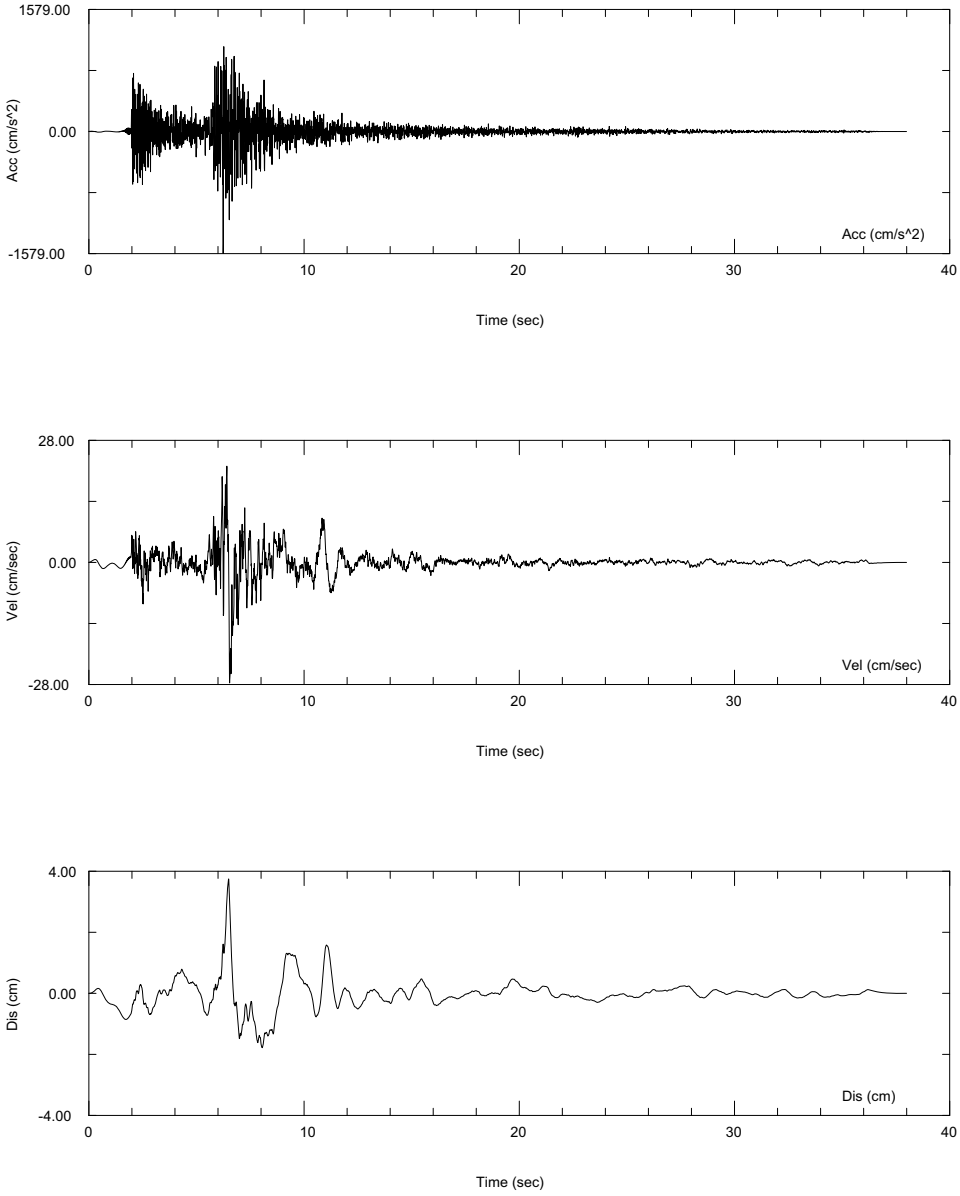


Figure 2.5-320
Final Modified Spectrum-Compatible Acceleration, Velocity, and Displacement Time Histories (One of Thirty) for 10^{-6} High Frequency Target Spectrum

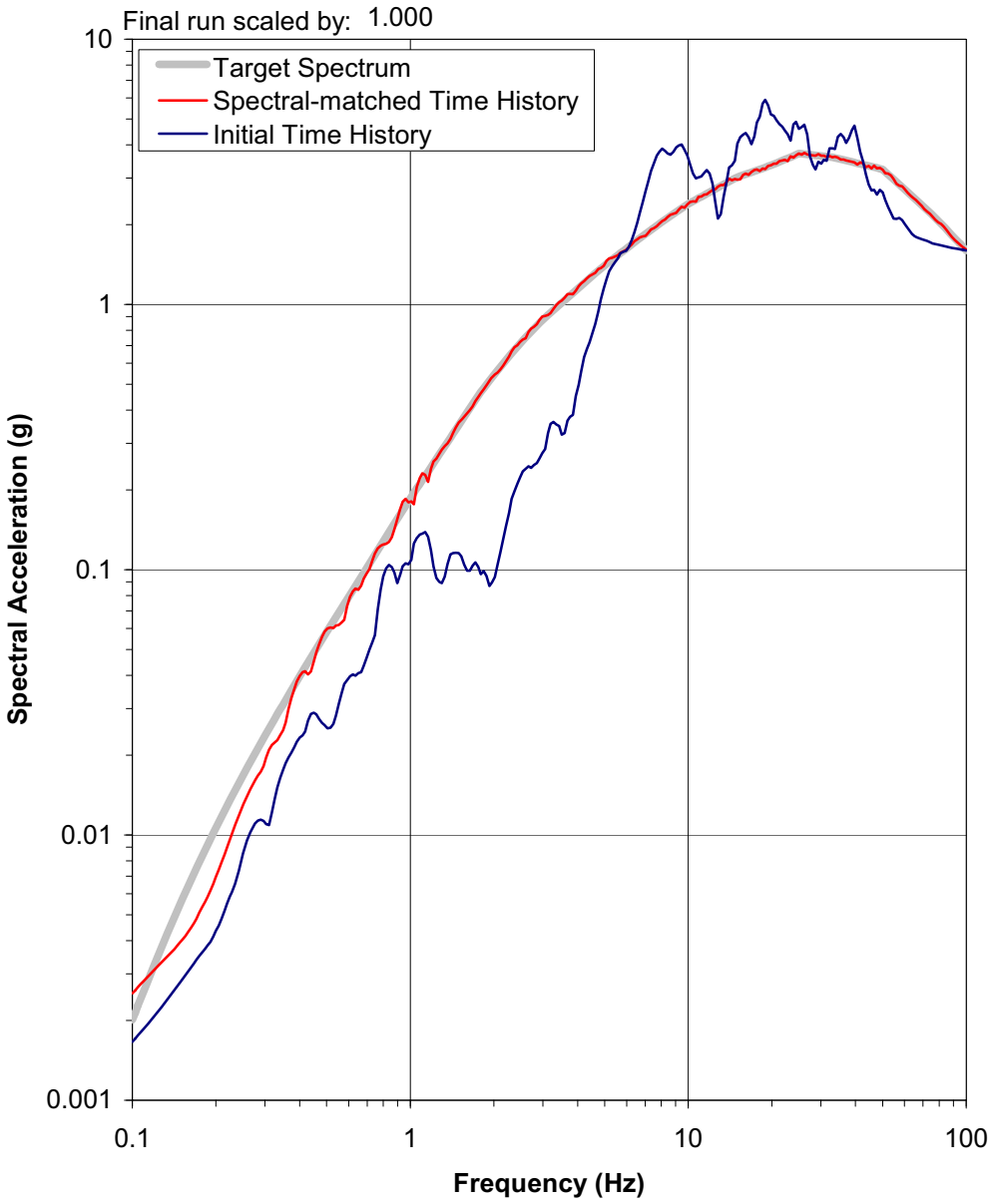


Figure 2.5-321

Comparison of 10^{-6} High Frequency Target Spectrum (Thick Grey Line), Response Spectrum from Initial Seed Input Acceleration Time History Scaled to Target PGA (Thin Blue Line), and Acceleration Response Spectrum for Final Modified Spectrum Compatible Time History (Thin Red Line)

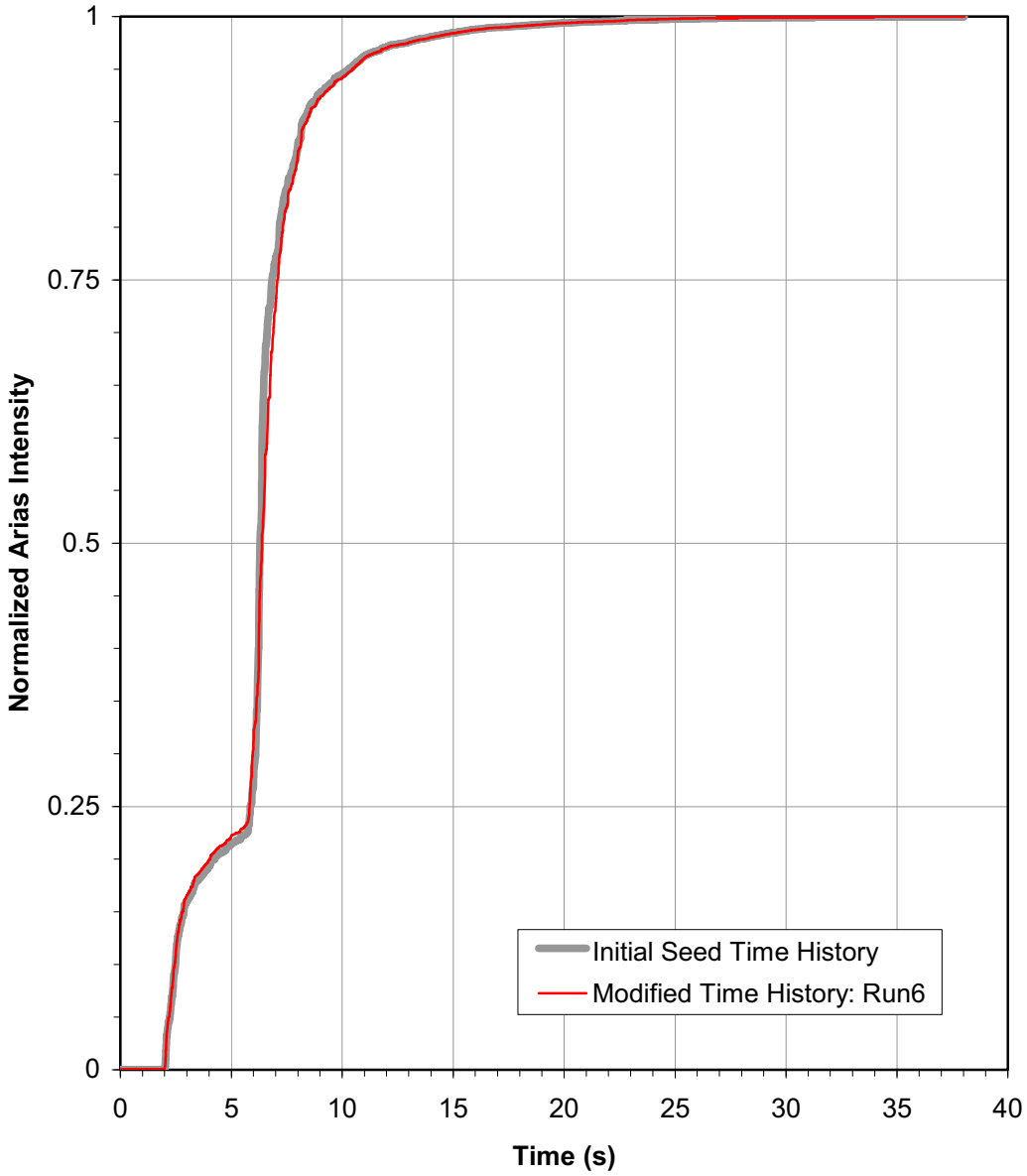


Figure 2.5-322
Comparison of Normalized Arias Intensity from Initial Seed Input Time History (Thick Grey Line) and Final Modified Spectrum Compatible (10^{-6} High Frequency Target Spectrum) Time History (Thin Red Line) for an Example Case

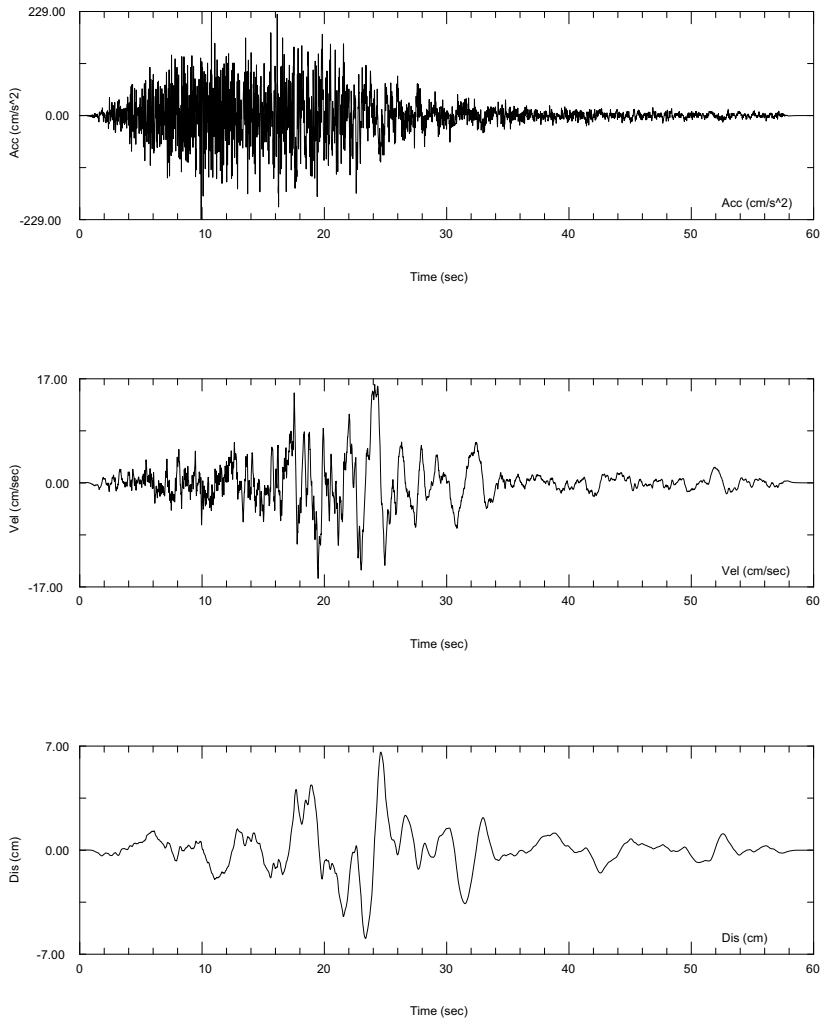


Figure 2.5-323
Horizontal Component 1 Modified Spectrum Compatible Time Acceleration, Velocity, and Displacement Time Histories for FIRS Horizontal Target Spectrum Prior to Application of 1.01 Scale Factor

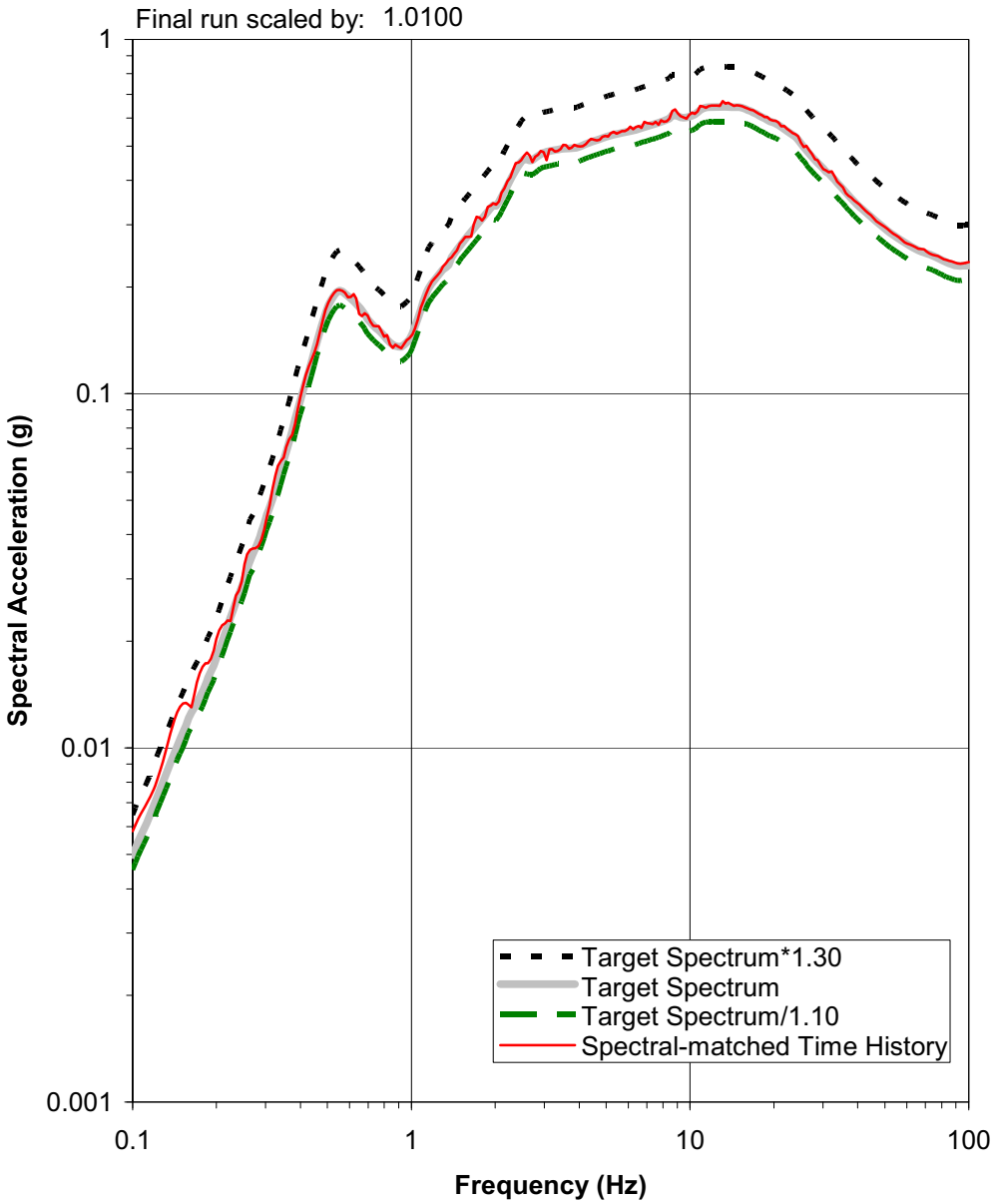


Figure 2.5-324
Comparison of Horizontal FIRS Target Spectrum (Thick Grey Line), 1.3*FIRS Target Spectrum (Dashed Black Line), 0.9*FIRS Target Spectrum (Dashed Green Line), and Acceleration Response Spectrum for Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Horizontal Component 1

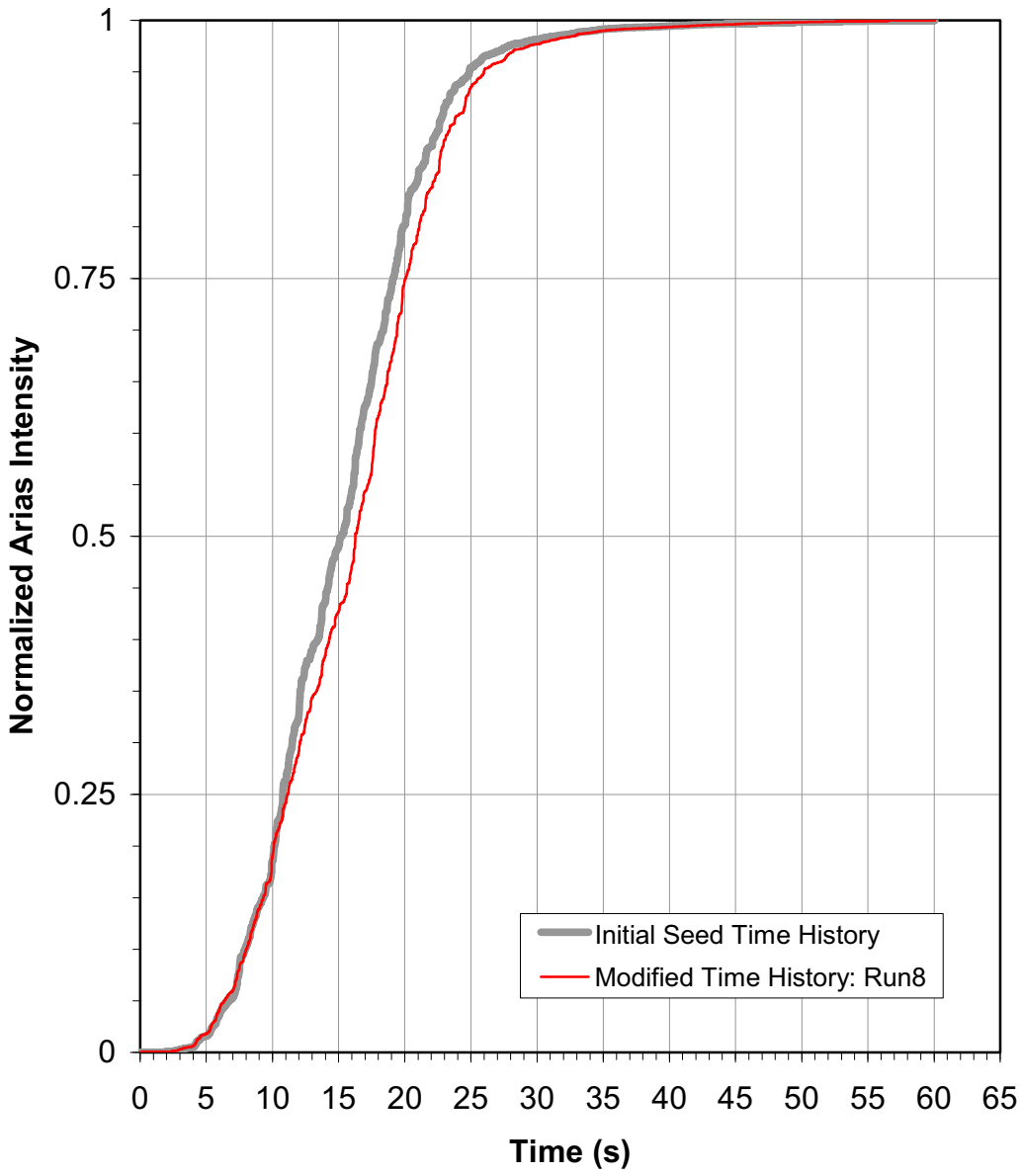


Figure 2.5-325
Comparison of Normalized Arias Intensity from Initial Seed Input Time History (Thick Grey Line) and Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Horizontal Component 1

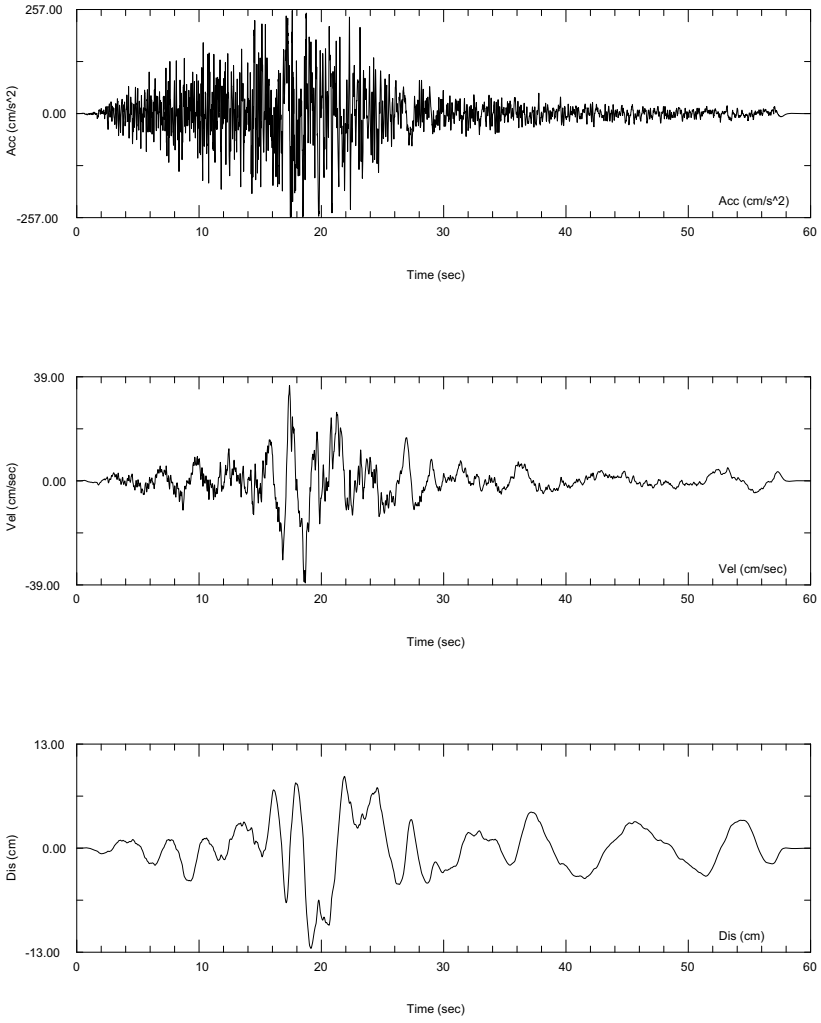


Figure 2.5-326
Horizontal Component 2 Modified Spectrum Compatible Time Acceleration, Velocity, and Displacement Time Histories for FIRS Horizontal Target Spectrum Prior to Application of 1.01 Scale Factor

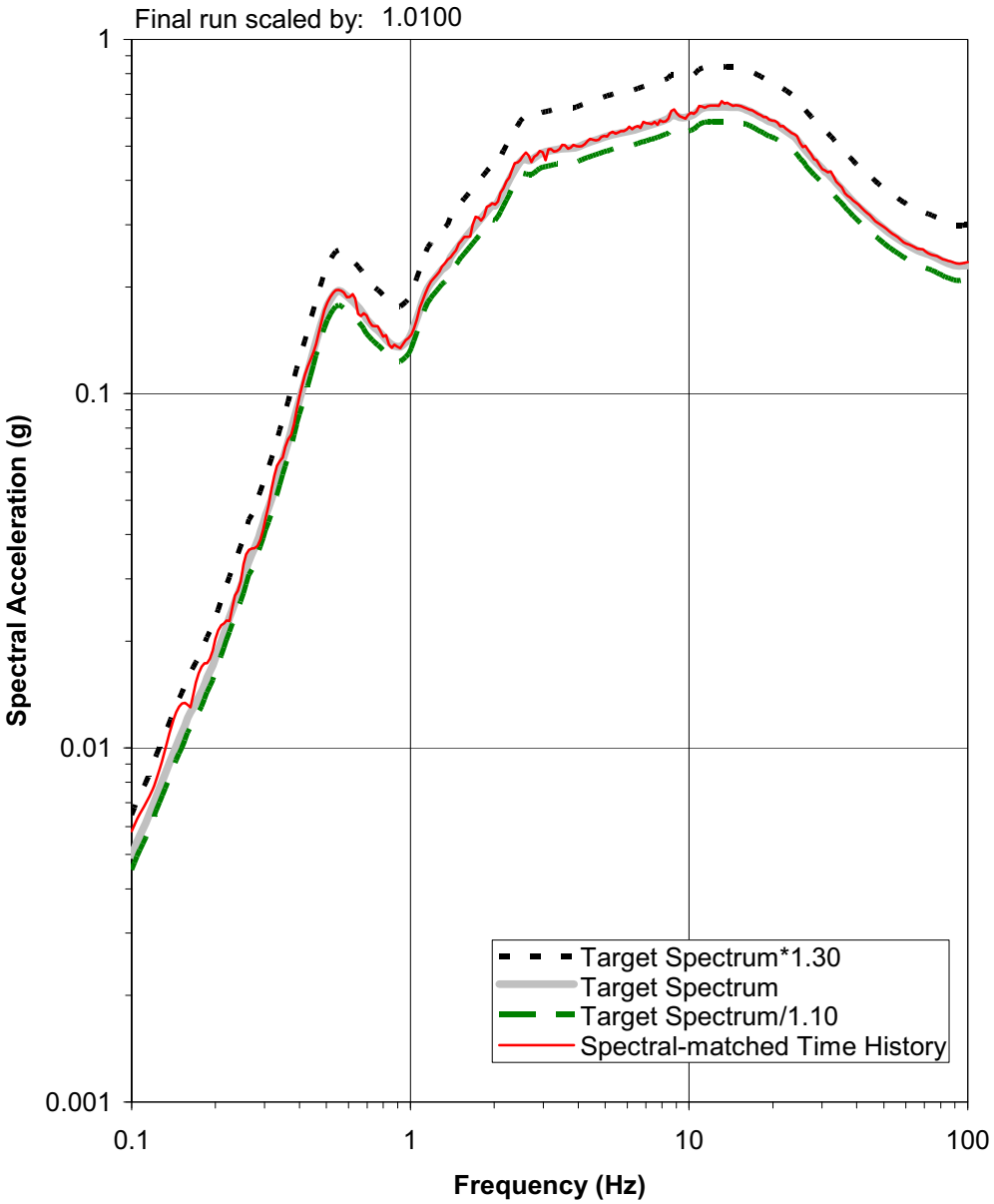


Figure 2.5-327
Comparison of Horizontal FIRS Target Spectrum (Thick Grey Line), 1.3*FIRS Target Spectrum (Dashed Black Line), 0.9*FIRS Target Spectrum (Dashed Green Line), and Acceleration Response Spectrum for Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Horizontal Component 2

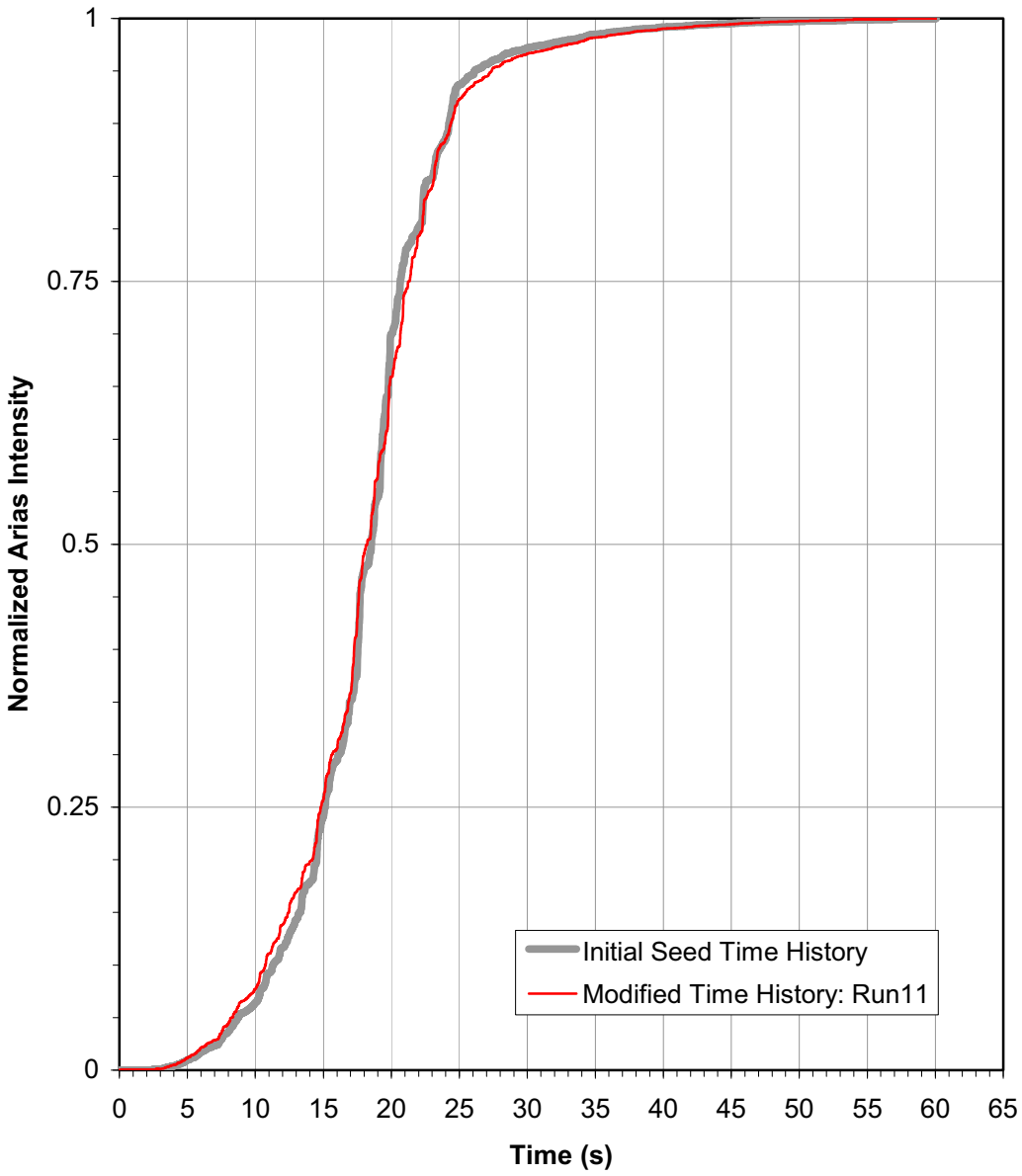


Figure 2.5-328
Comparison of Normalized Arias Intensity from Initial Seed Input Time History (Thick Grey Line) and Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Horizontal Component 2

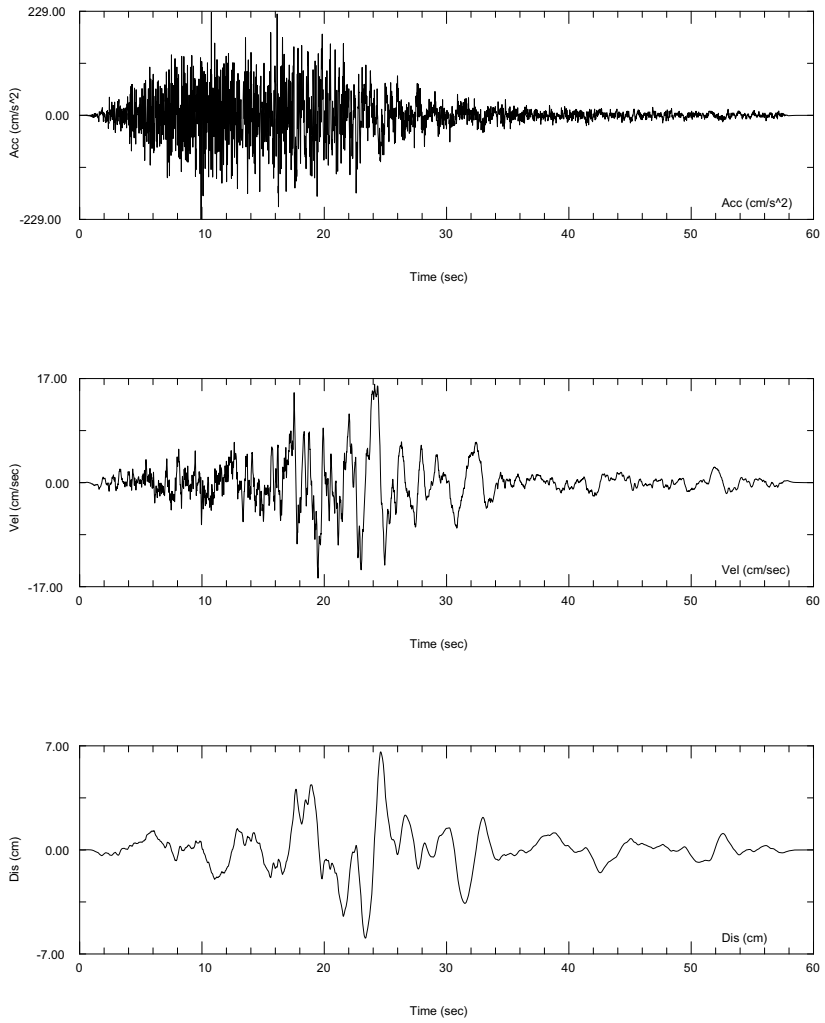


Figure 2.5-329
Vertical Component Modified Spectrum Compatible Time Acceleration, Velocity, and Displacement Time Histories for FIRS Vertical Target Spectrum Prior to Application of 1.01 Scale Factor

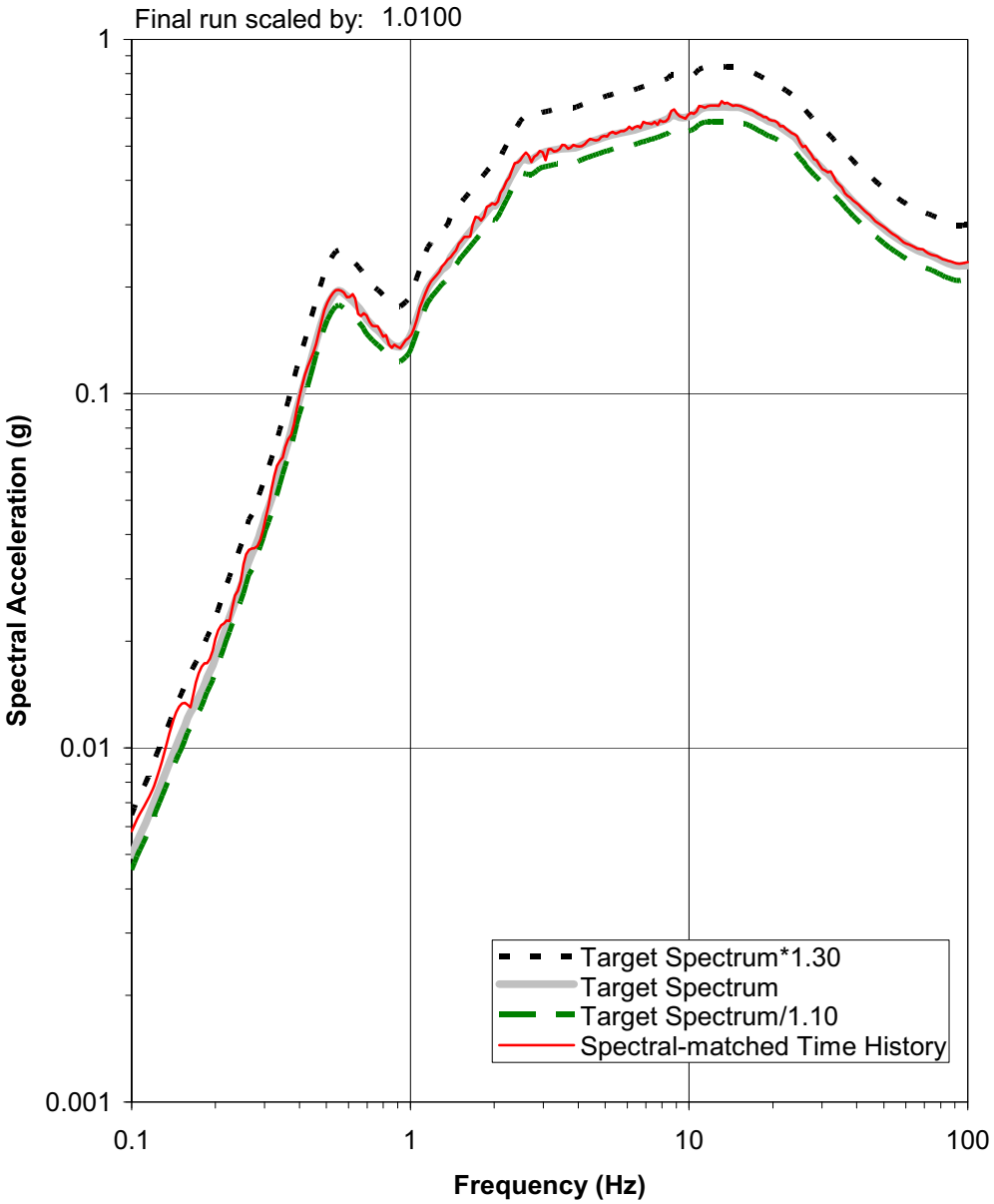


Figure 2.5-330
Comparison of Vertical FIRS Target Spectrum (Thick Grey Line), 1.3*FIRS Target Spectrum (Dashed Black Line), 0.9*FIRS Target Spectrum (Dashed Green Line), and Acceleration Response Spectrum for Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Vertical Component

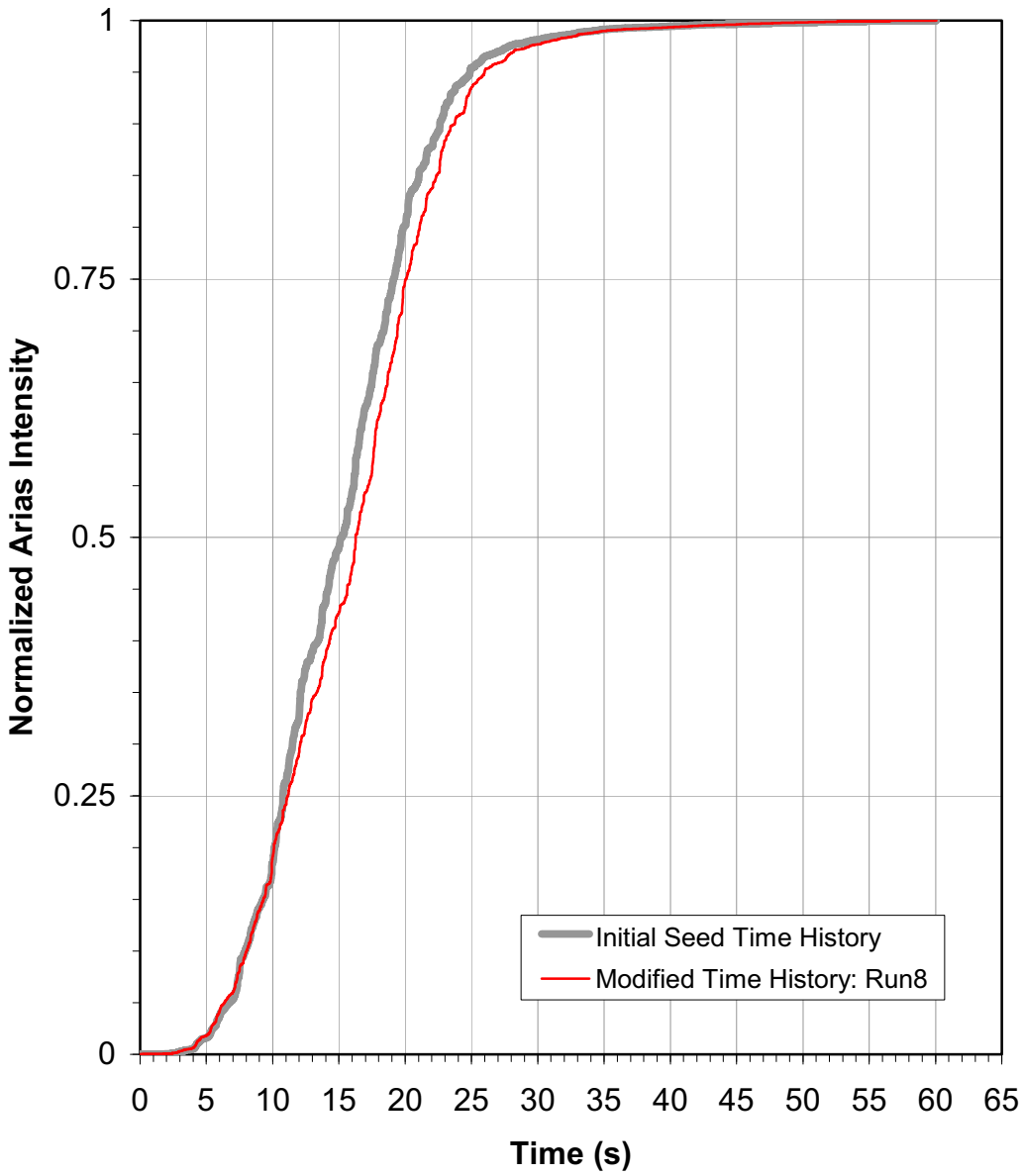


Figure 2.5-331
Comparison of Normalized Arias Intensity from Initial Seed Input Time History (Thick Grey Line) and Final Modified Spectrum Compatible Time History (Thin Red Line) Including Application of 1.01 Scale Factor for Vertical Component

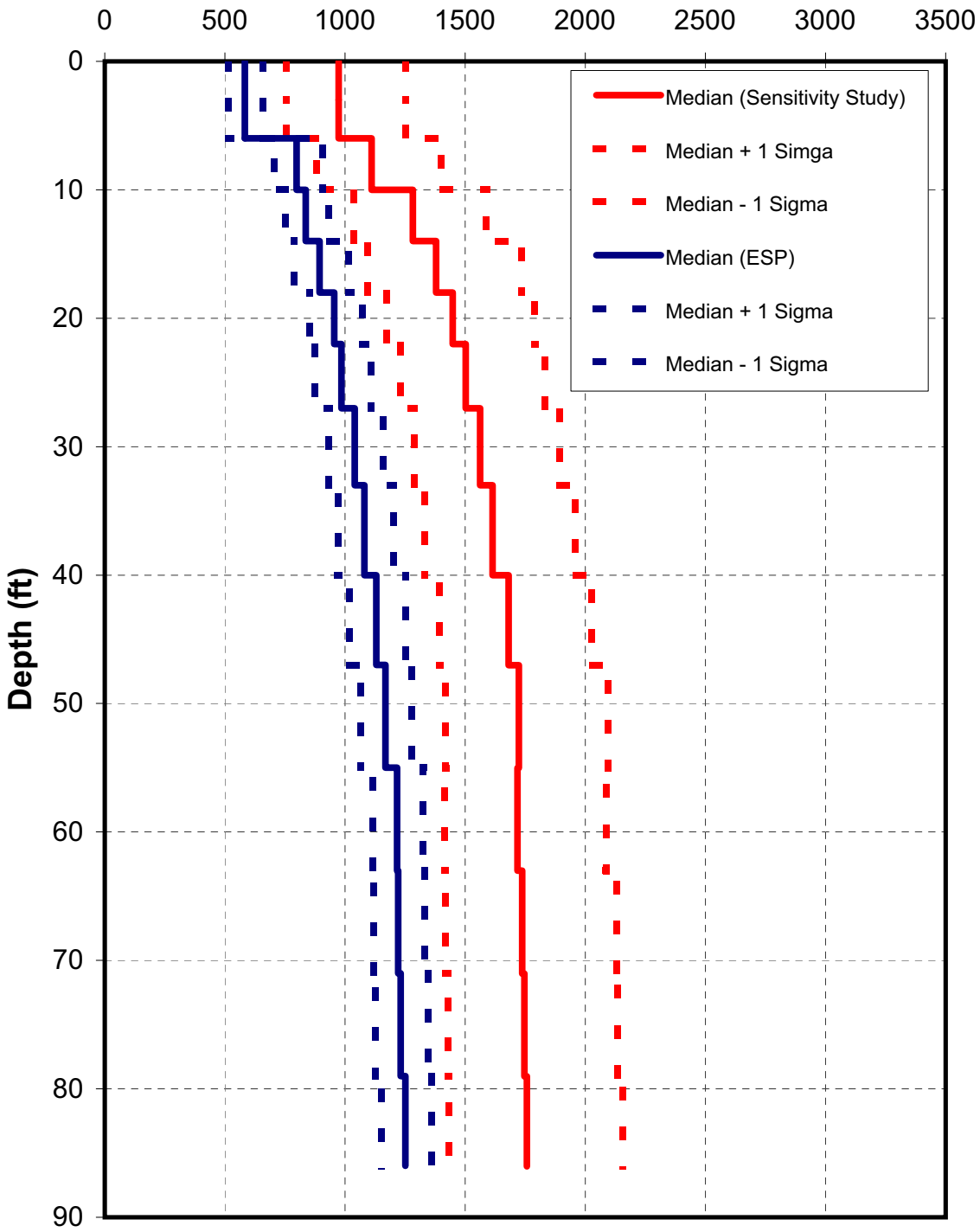


Figure 2.5-332
Low Strain Backfill Shear Wave Velocity (ft/sec)

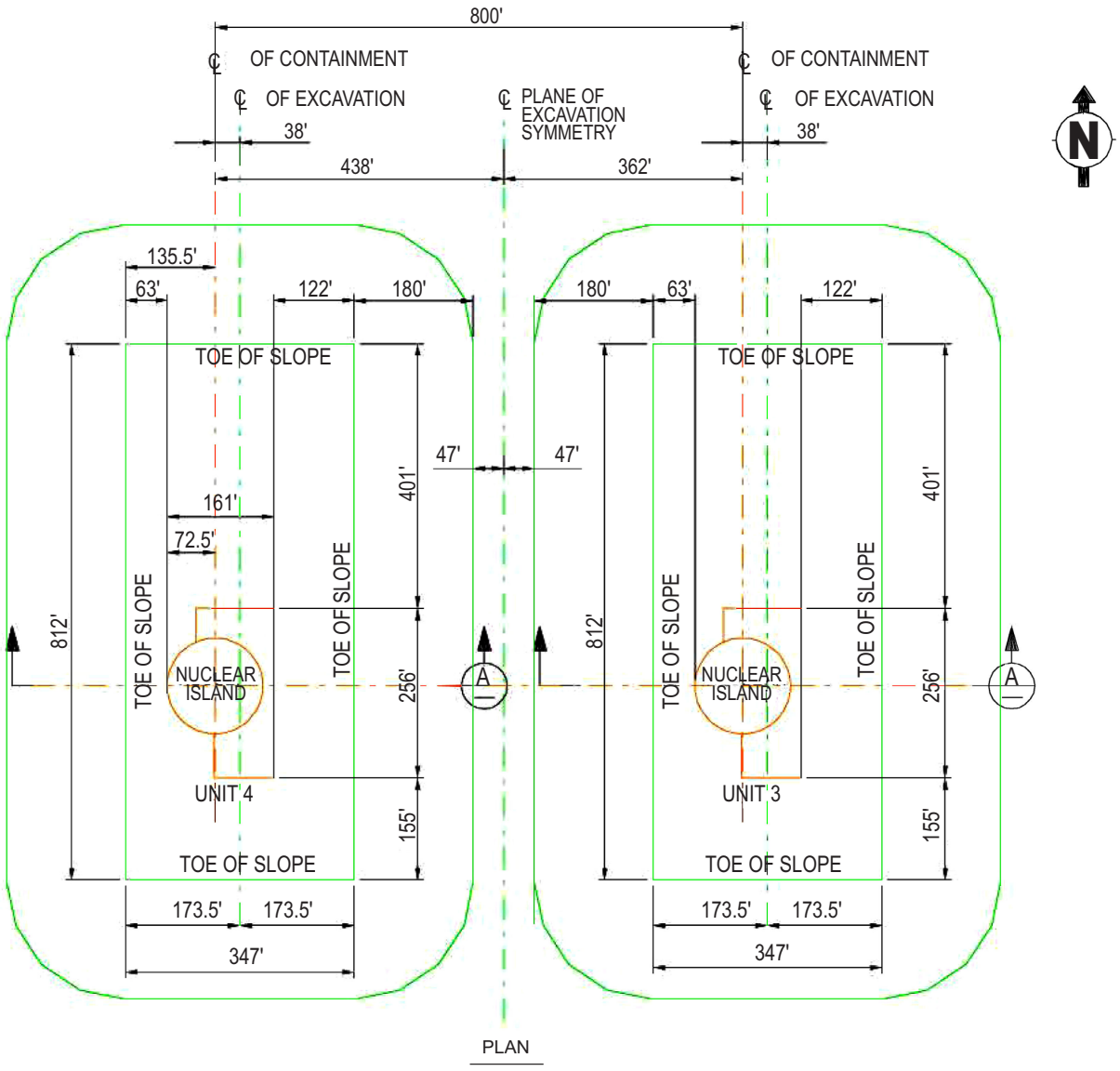


Figure 2.5-333
Plant Layout

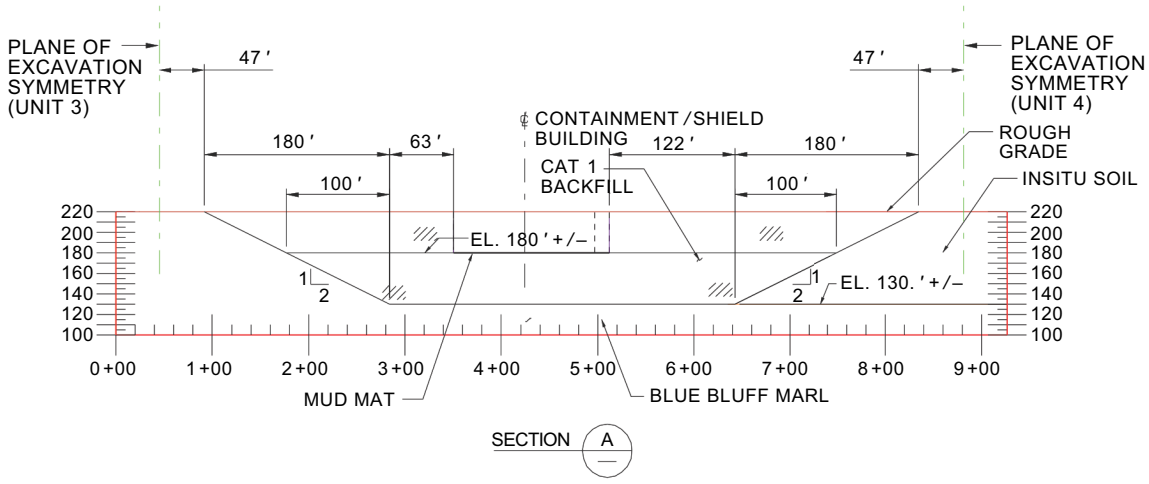


Figure 2.5-334
Cross Section A

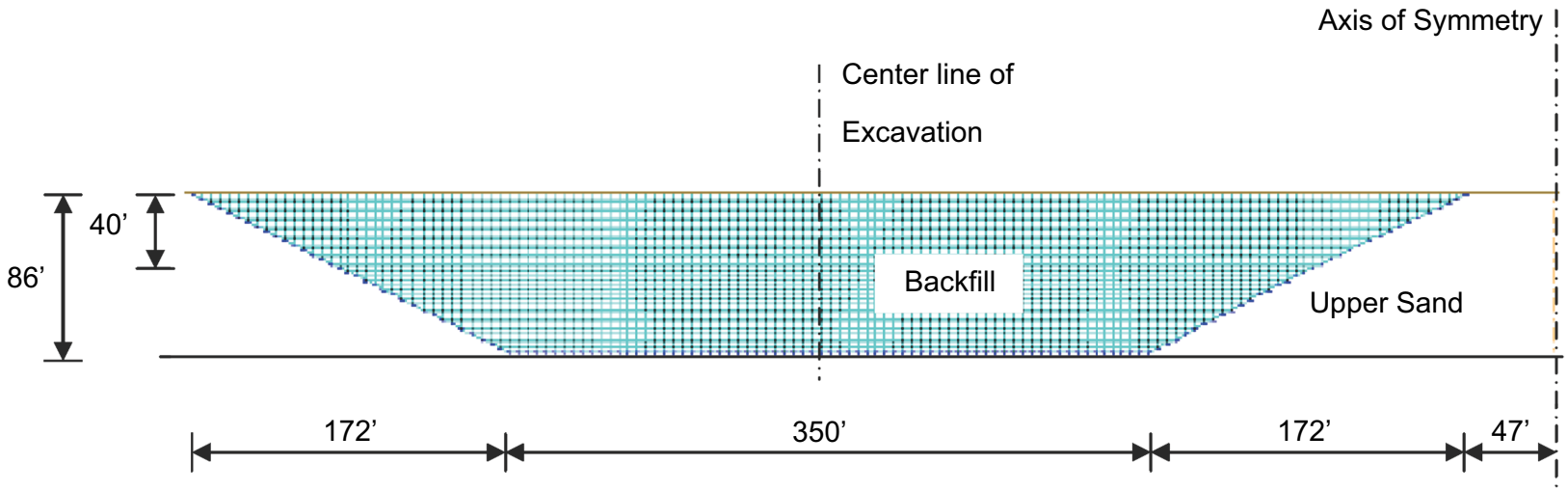


Figure 2.5-335
SASSI 2D-Model

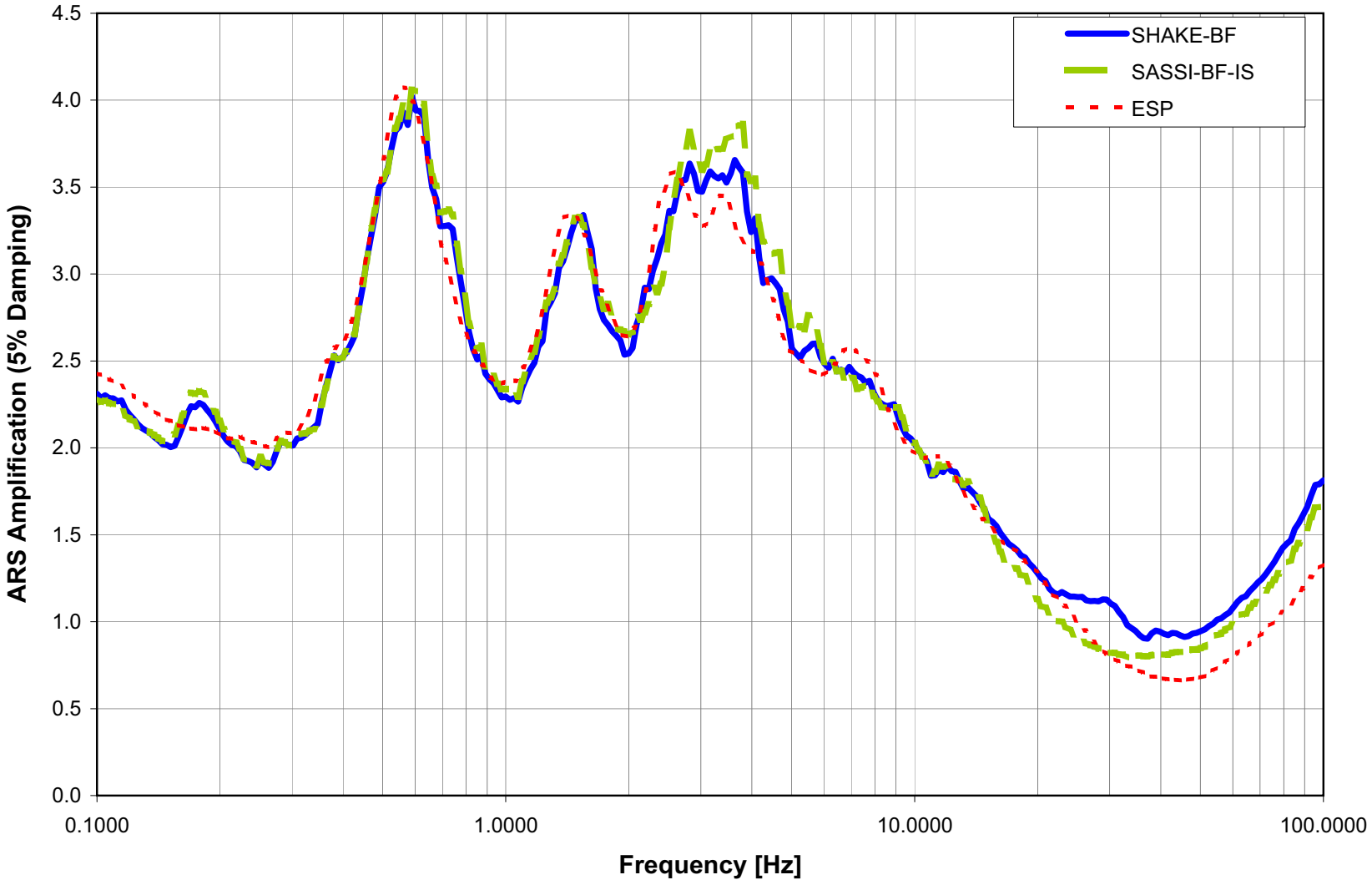


Figure 2.5-336
Amplification at 0 ft (GMRS Horizon)

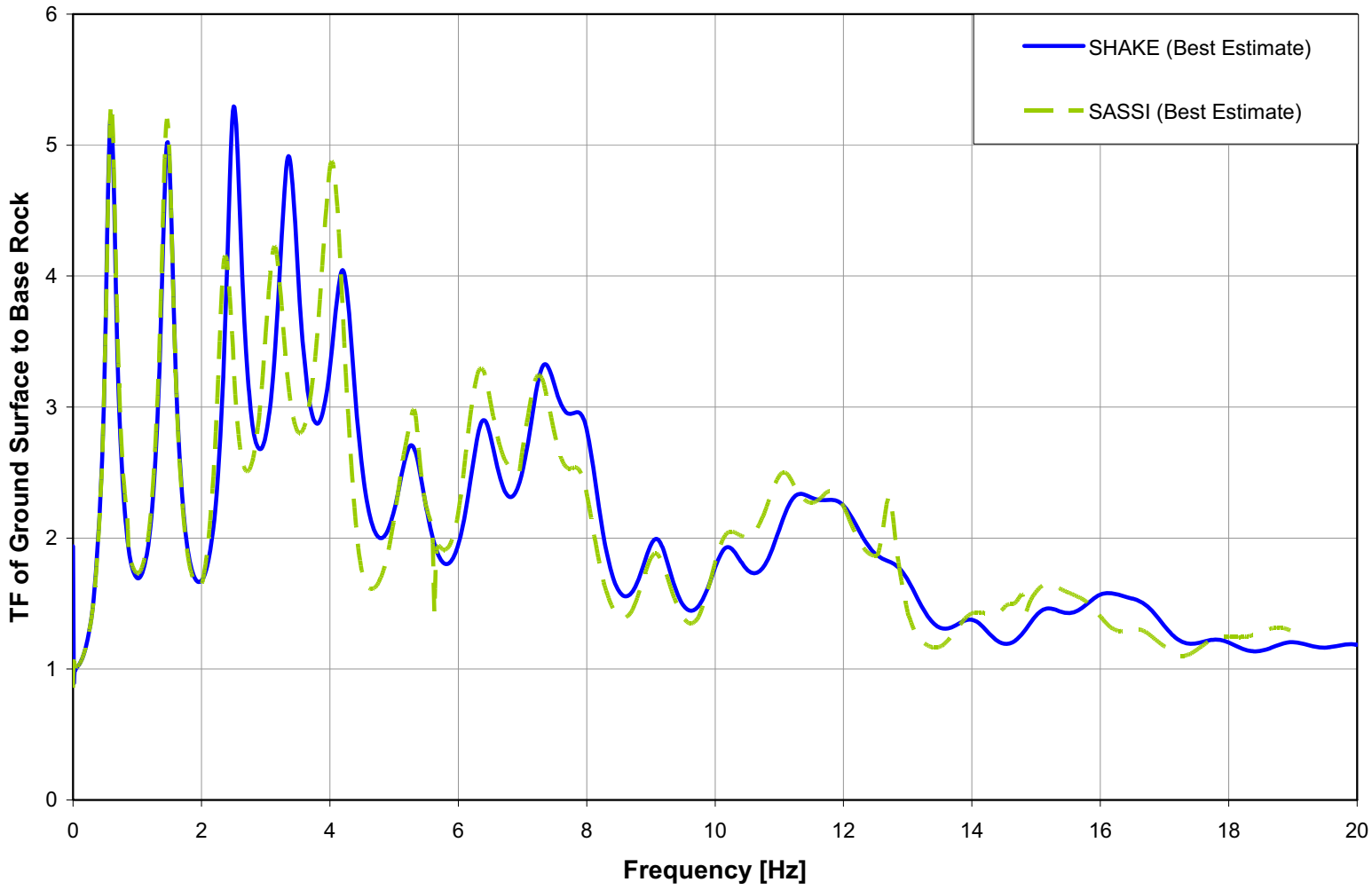


Figure 2.5-337
Transfer Functions at 0 ft (GMRS Horizon)

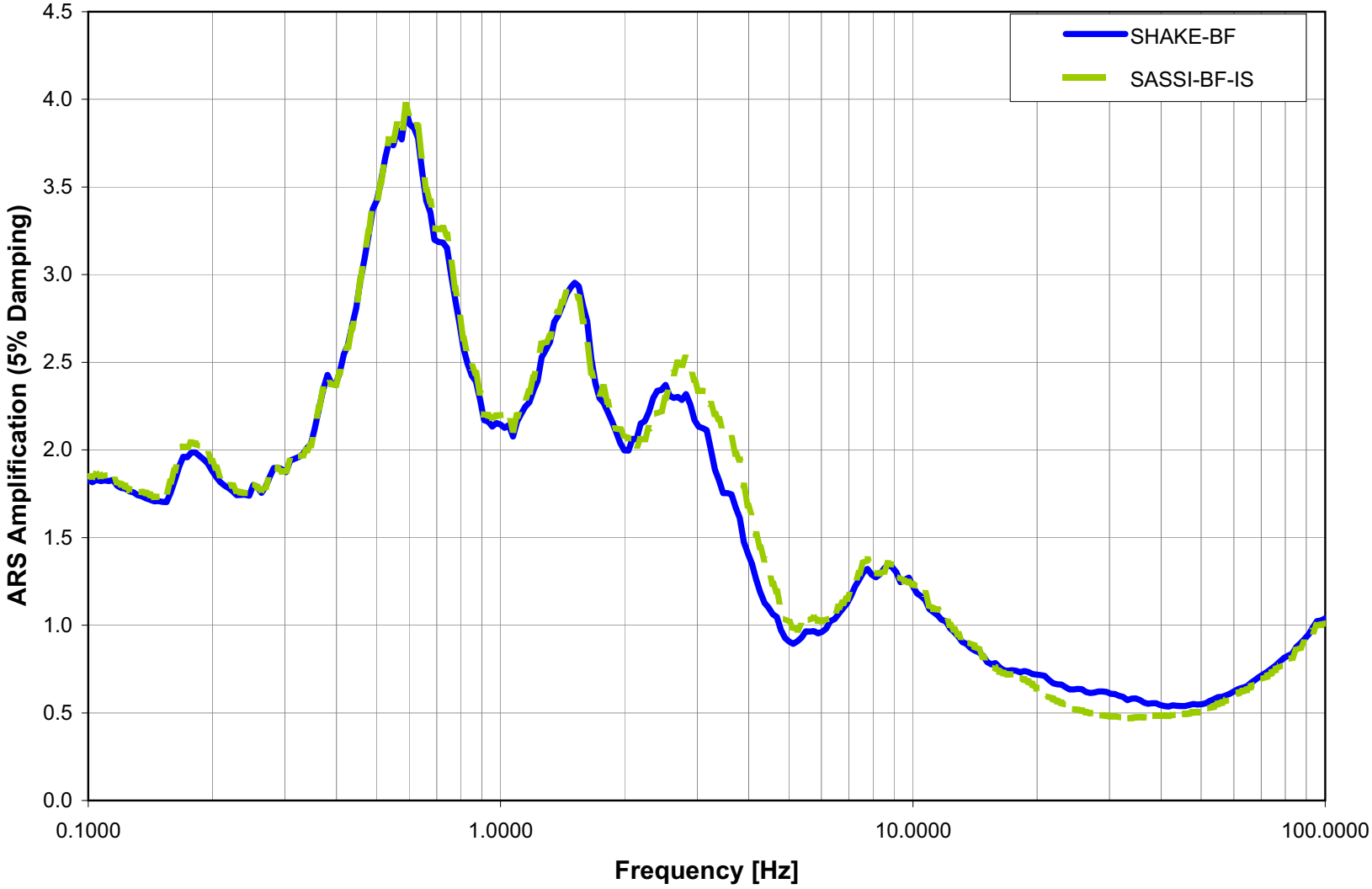


Figure 2.5-338
Amplification at 40 ft depth (FIRS horizon)

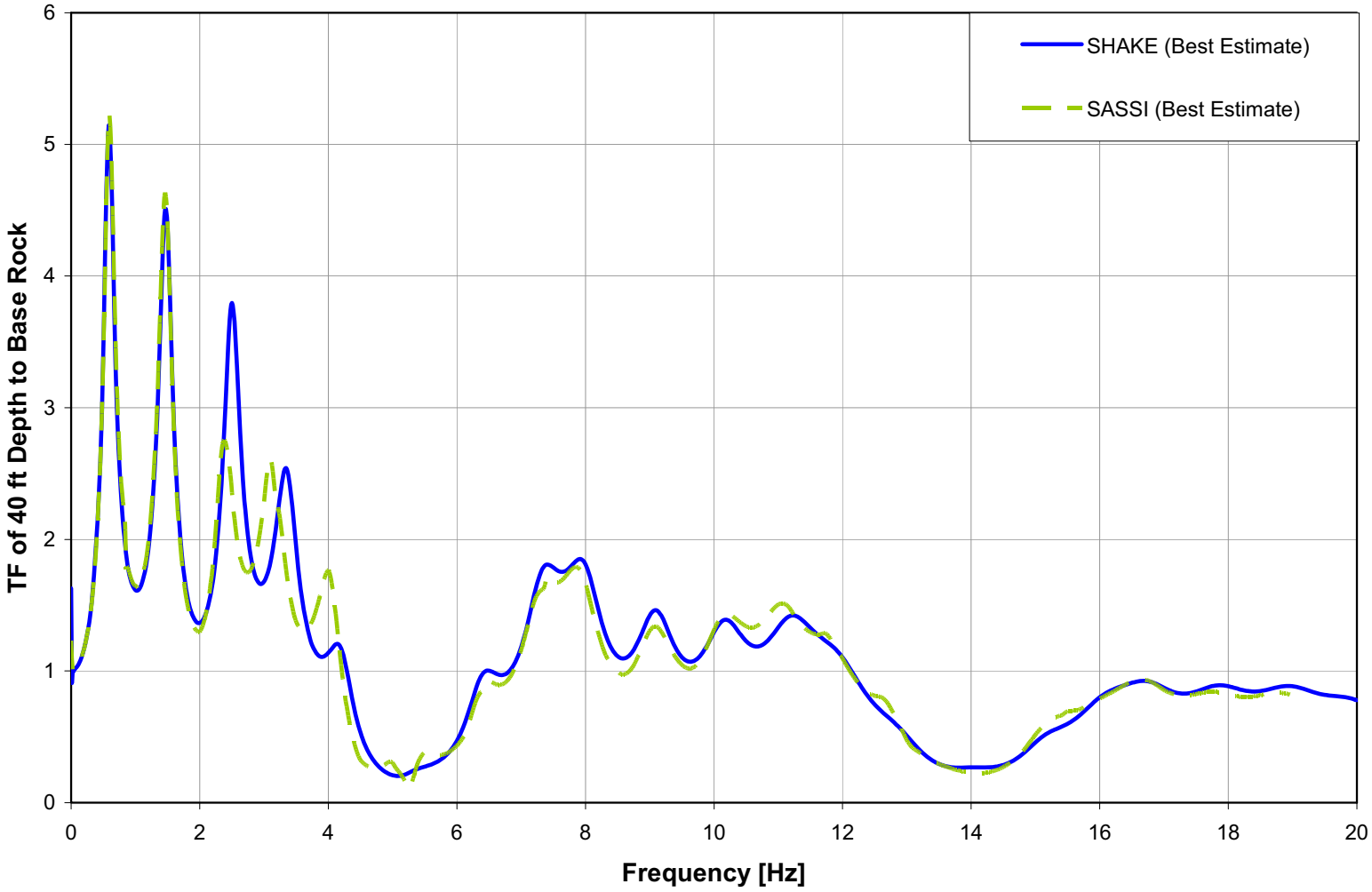


Figure 2.5-339
Transfer Functions at 40 ft (FIRS Horizon)

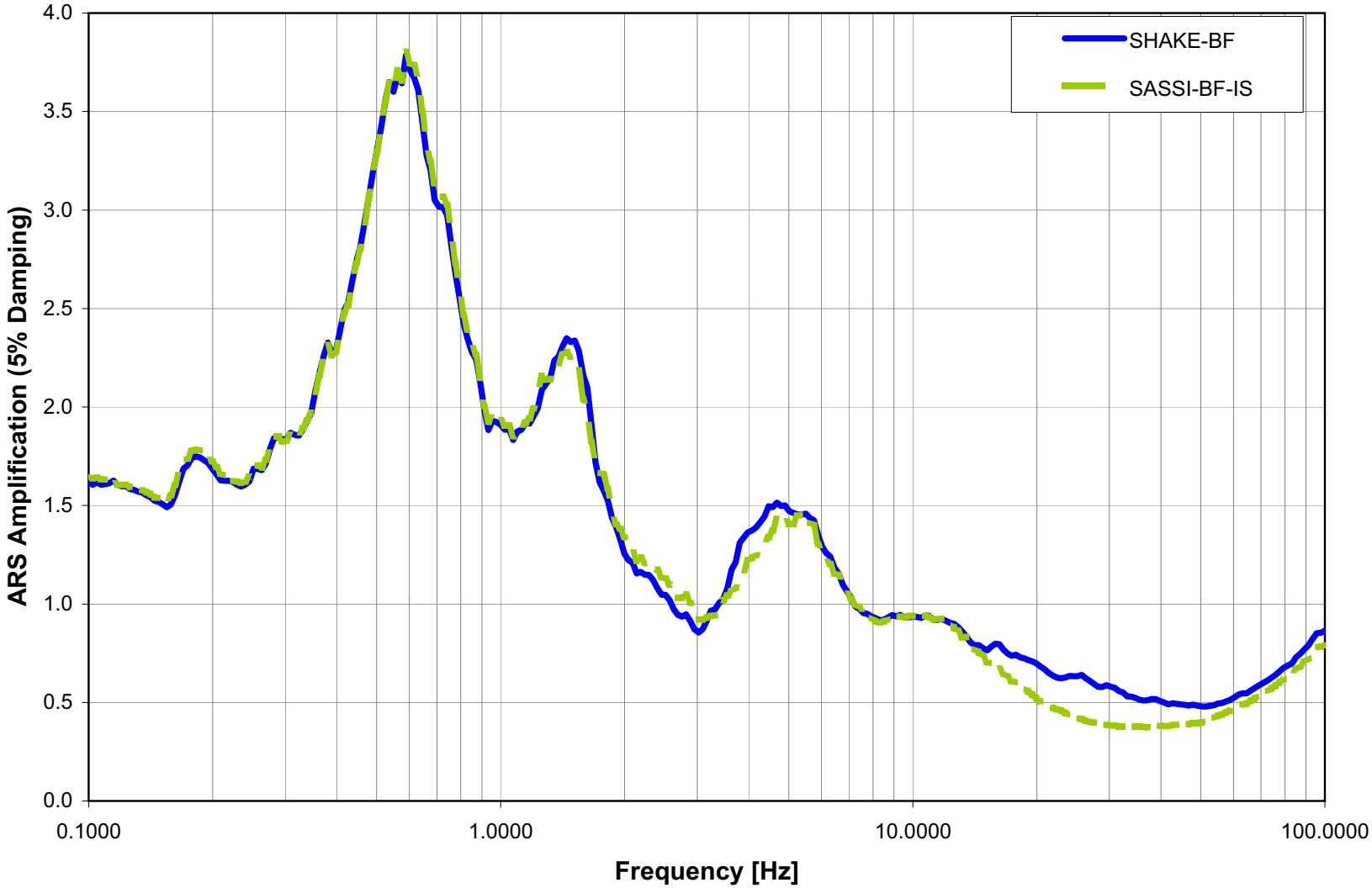


Figure 2.5-340
Amplification at 86 ft depth (Top of Blue Bluff Marl)

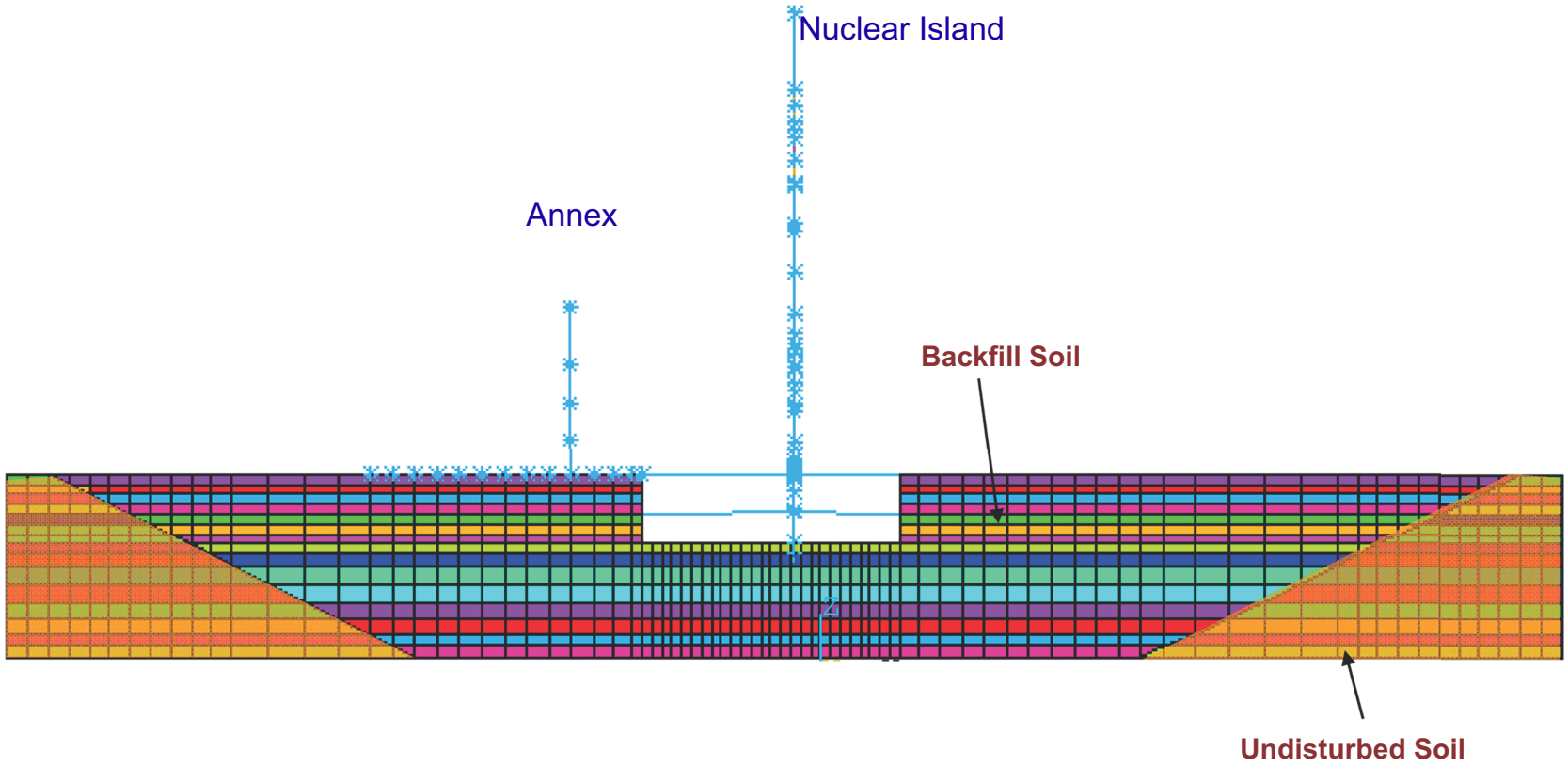


Figure 2.5-341
2D SASSI Backfill Model

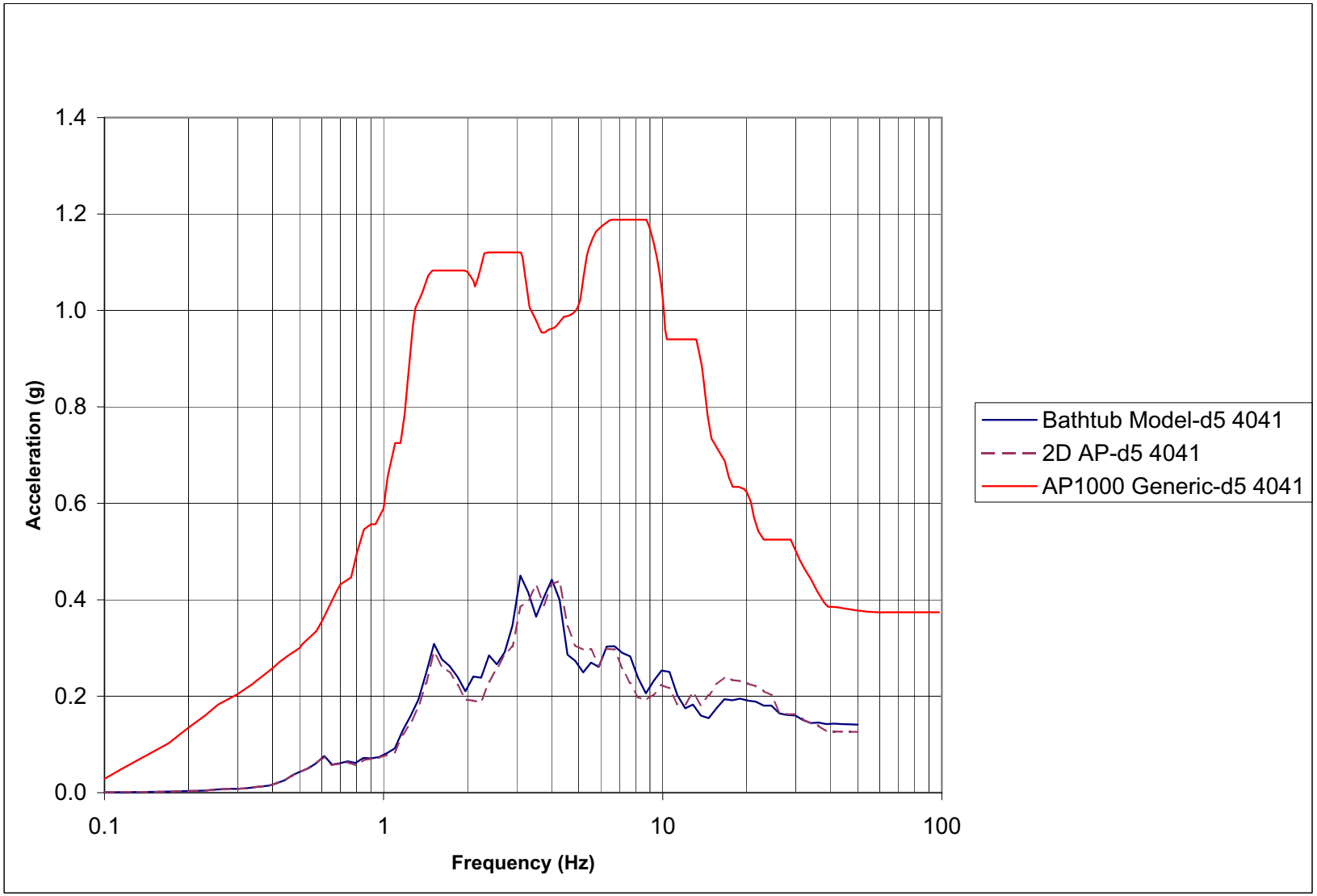


Figure 2.5-342
Node 4041 — EL 99.00 NI at Reactor Vessel Support Elevation

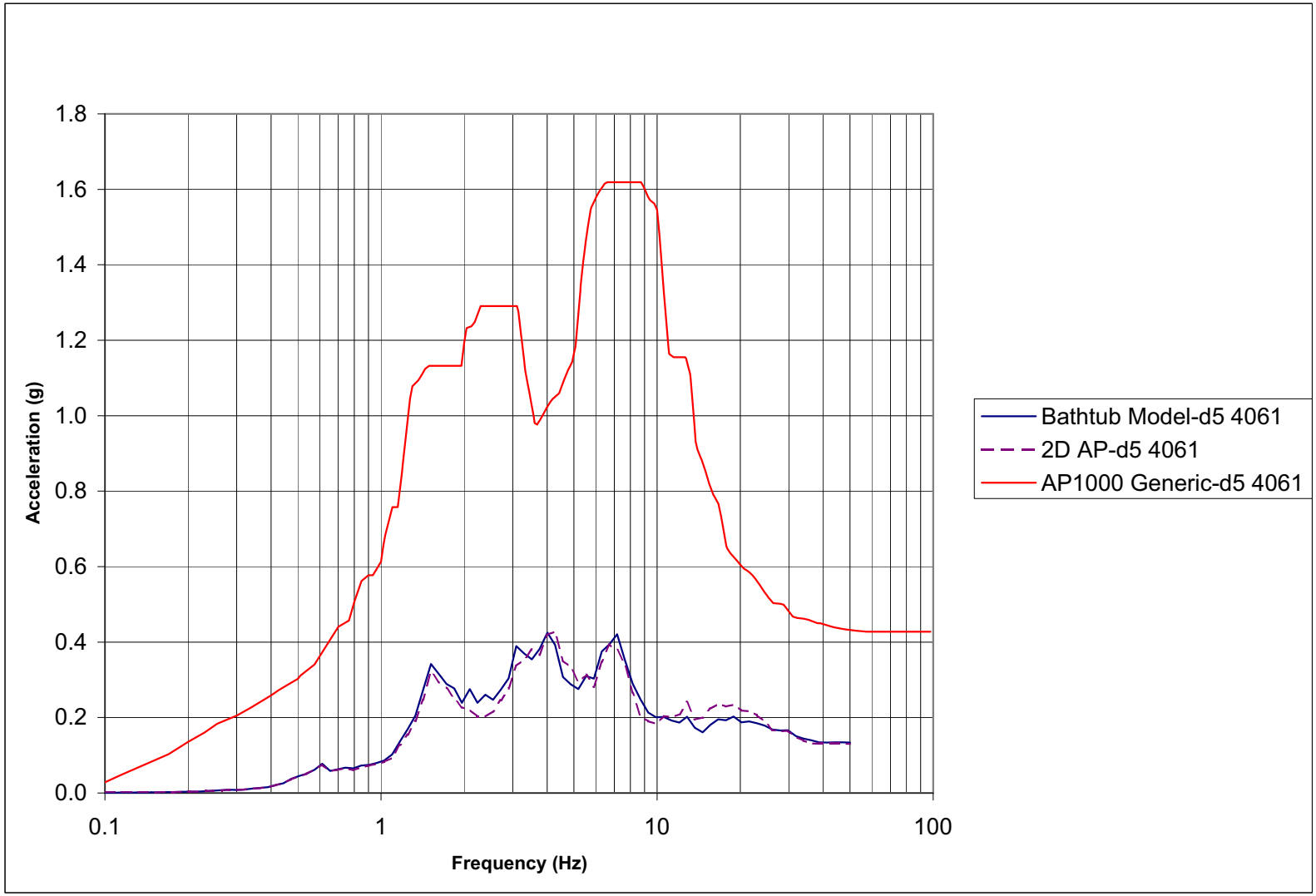


Figure 2.5-343
Node 4061 — EL 116.5 Auxiliary Shield Building at Control Room Floor

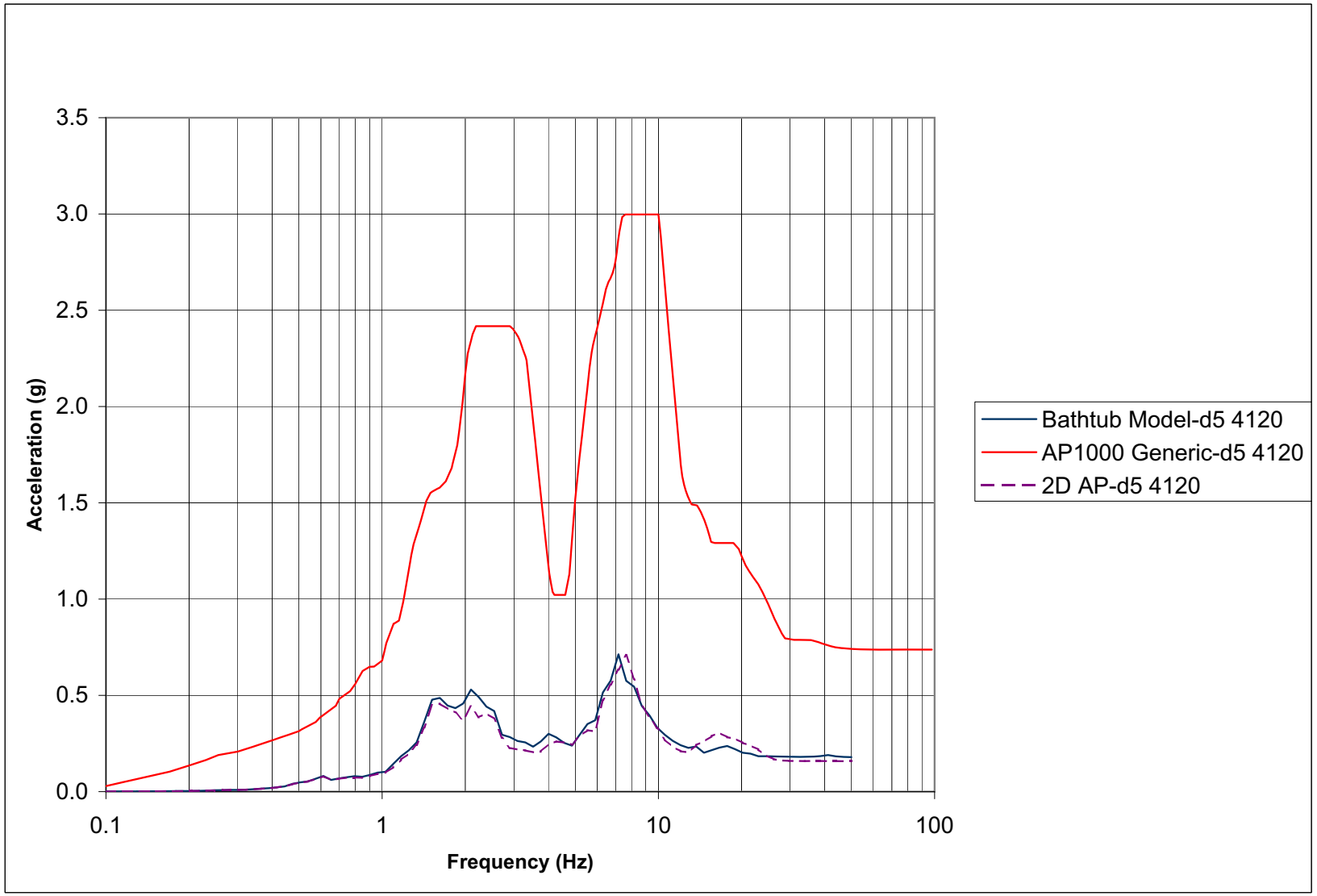


Figure 2.5-344
Node 4120 — EL 179.56 ASB Auxiliary Building Roof Area

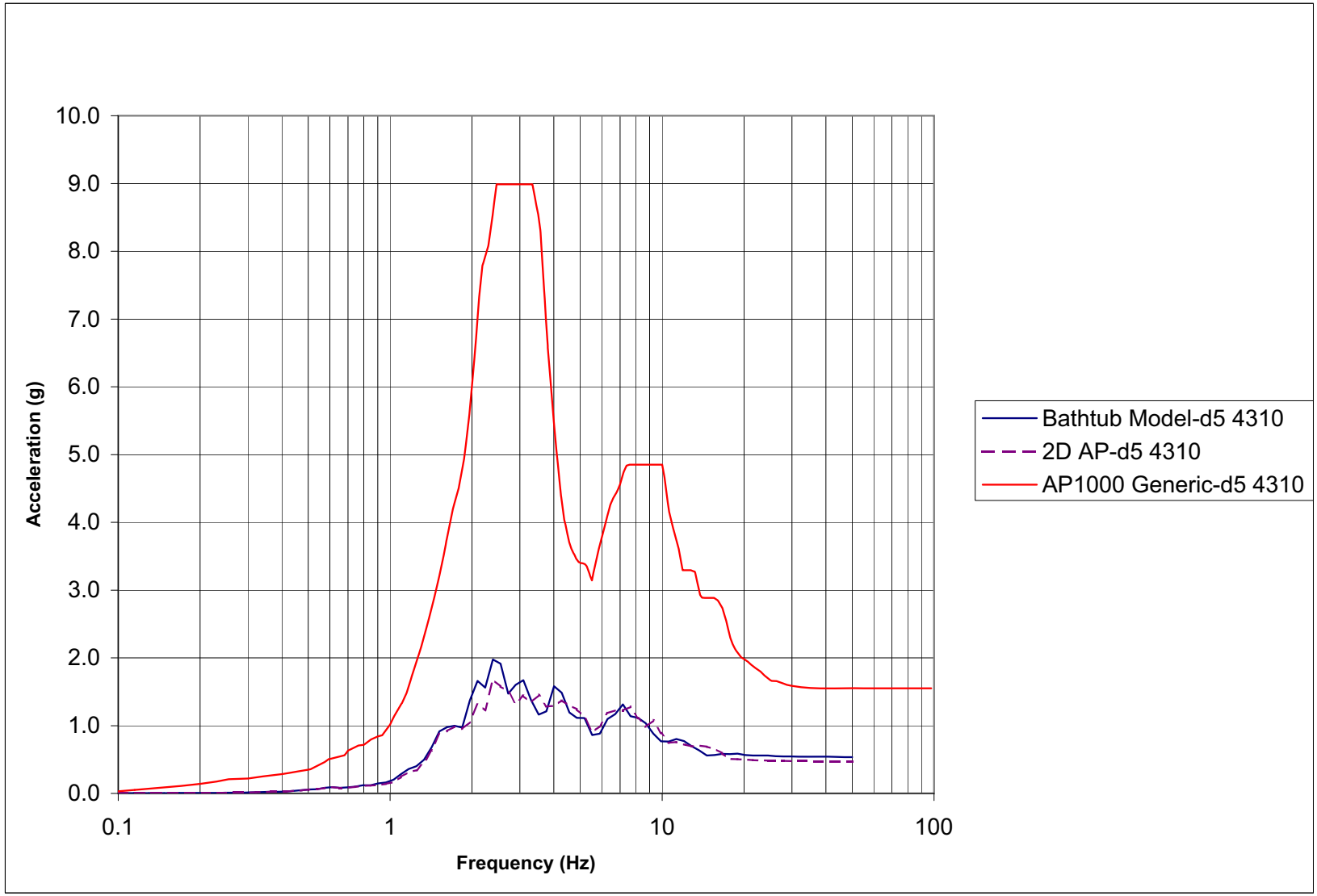


Figure 2.5-345
Node 4310 — EL 327.41 ASB Shield Building Roof Area

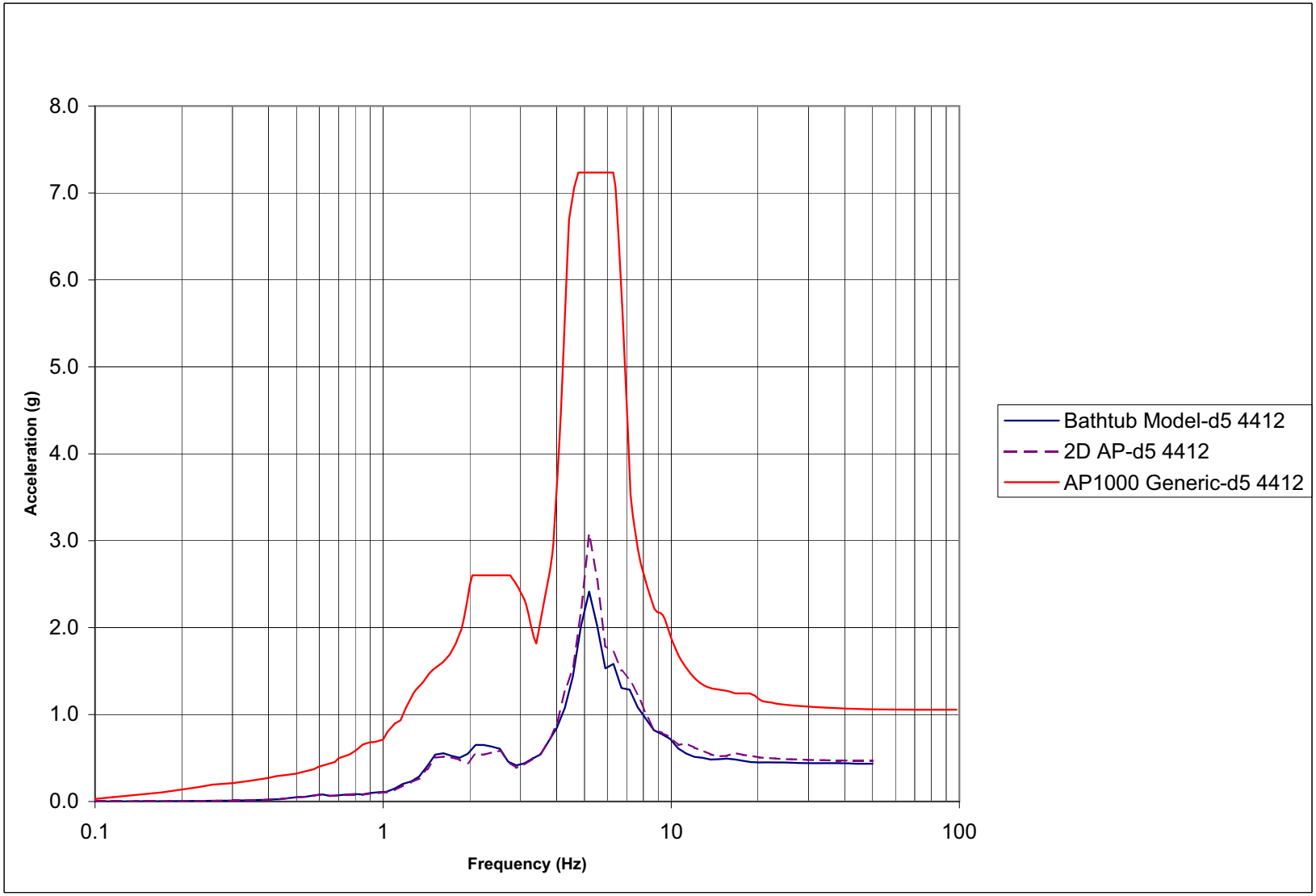


Figure 2.5-346
Node 4412 — EL 224 Steel Containment Vessel Near Polar Crane

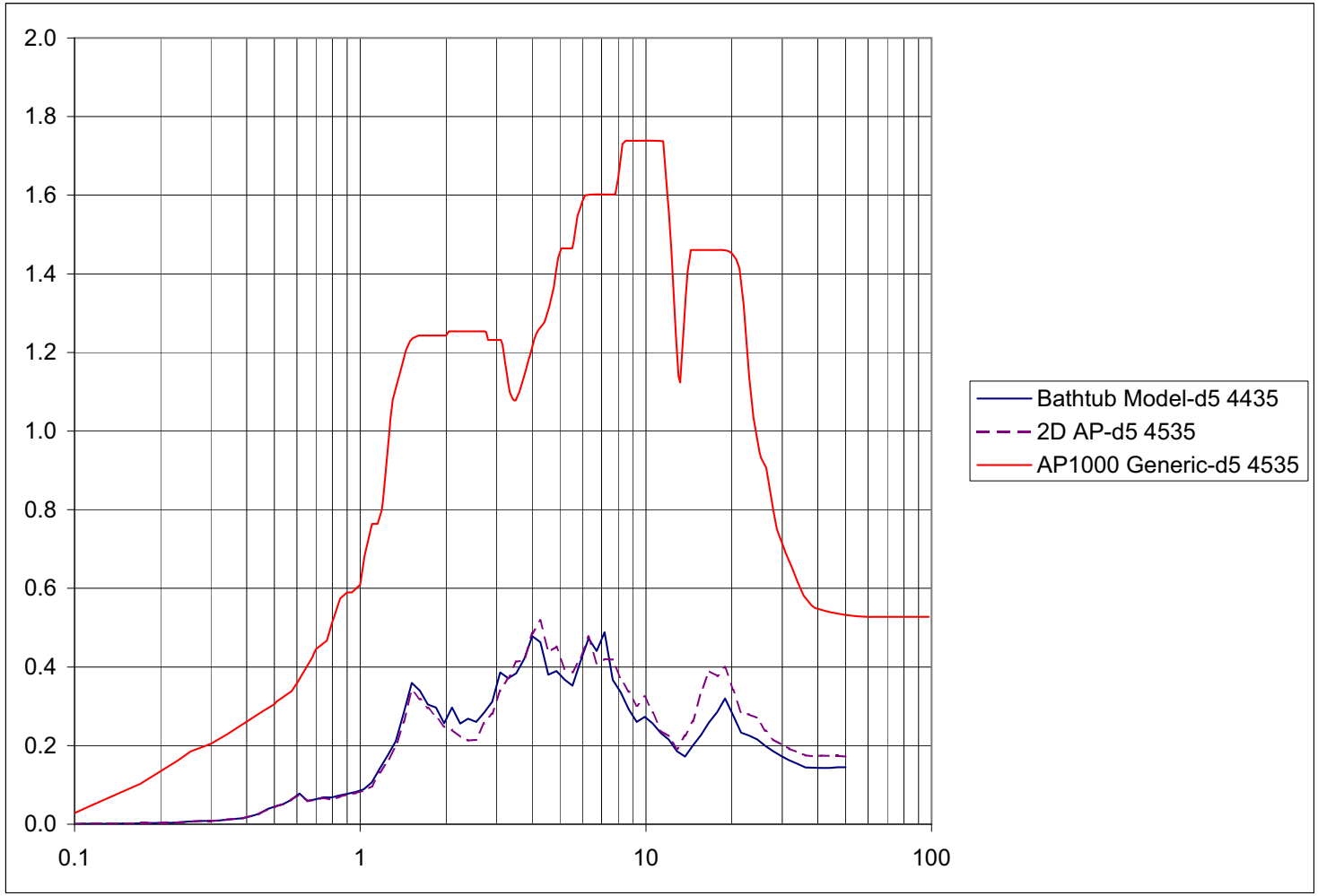


Figure 2.5-347
Node 4335 — EL 135.25 Containment Internal Structure at Operating Deck

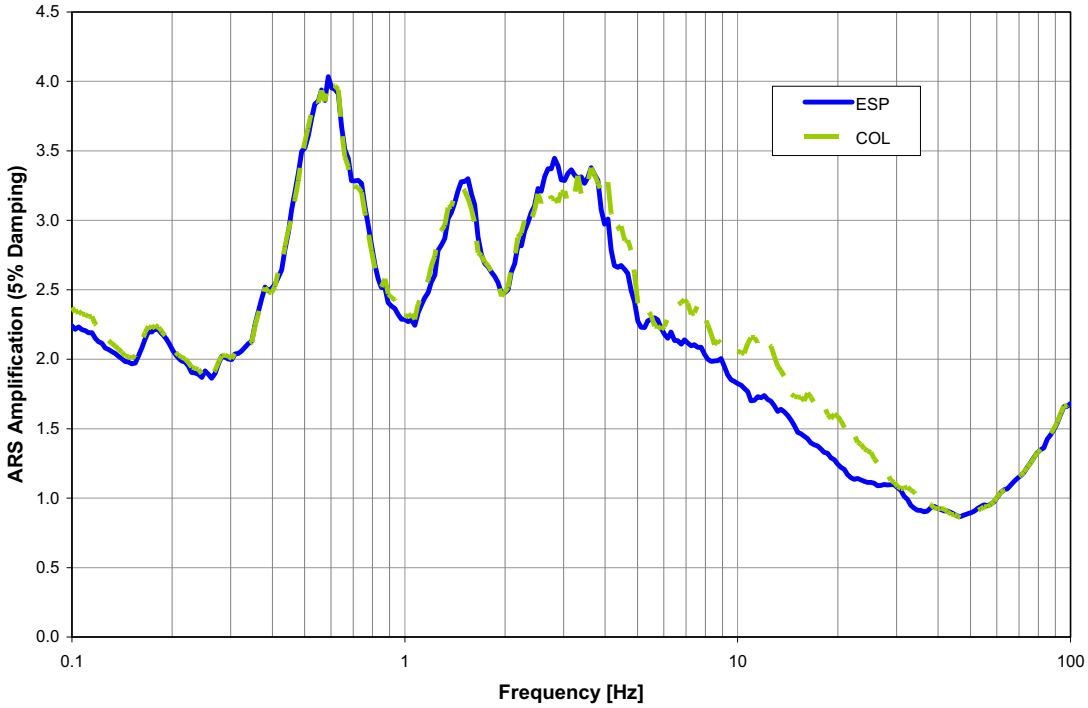


Figure 2.5-348
Amplification at 40-ft Outcrop Depth (FIRS Horizon)

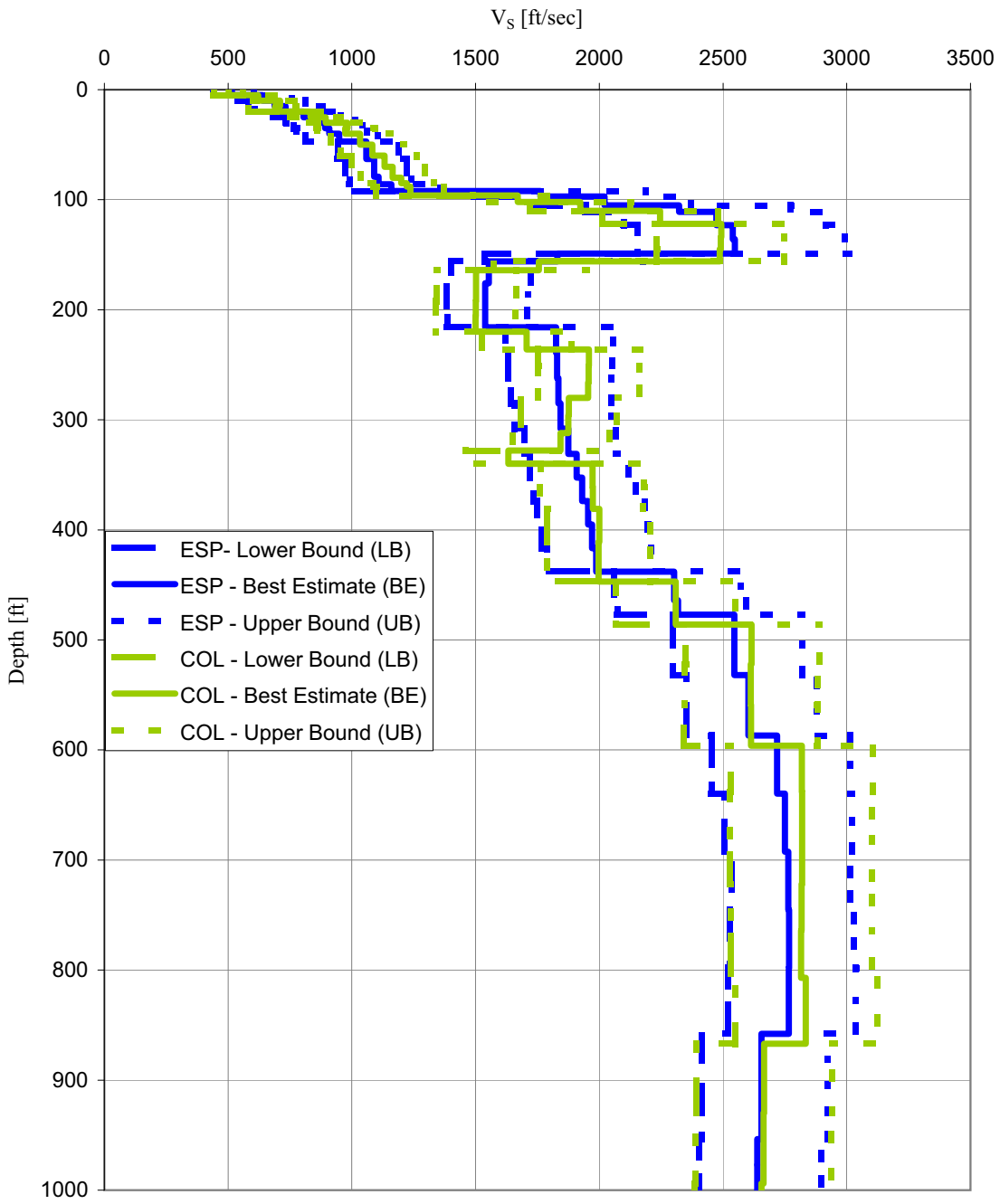


Figure 2.5-349
Vogtle Strain Compatible Profiles (S-Wave Velocity)

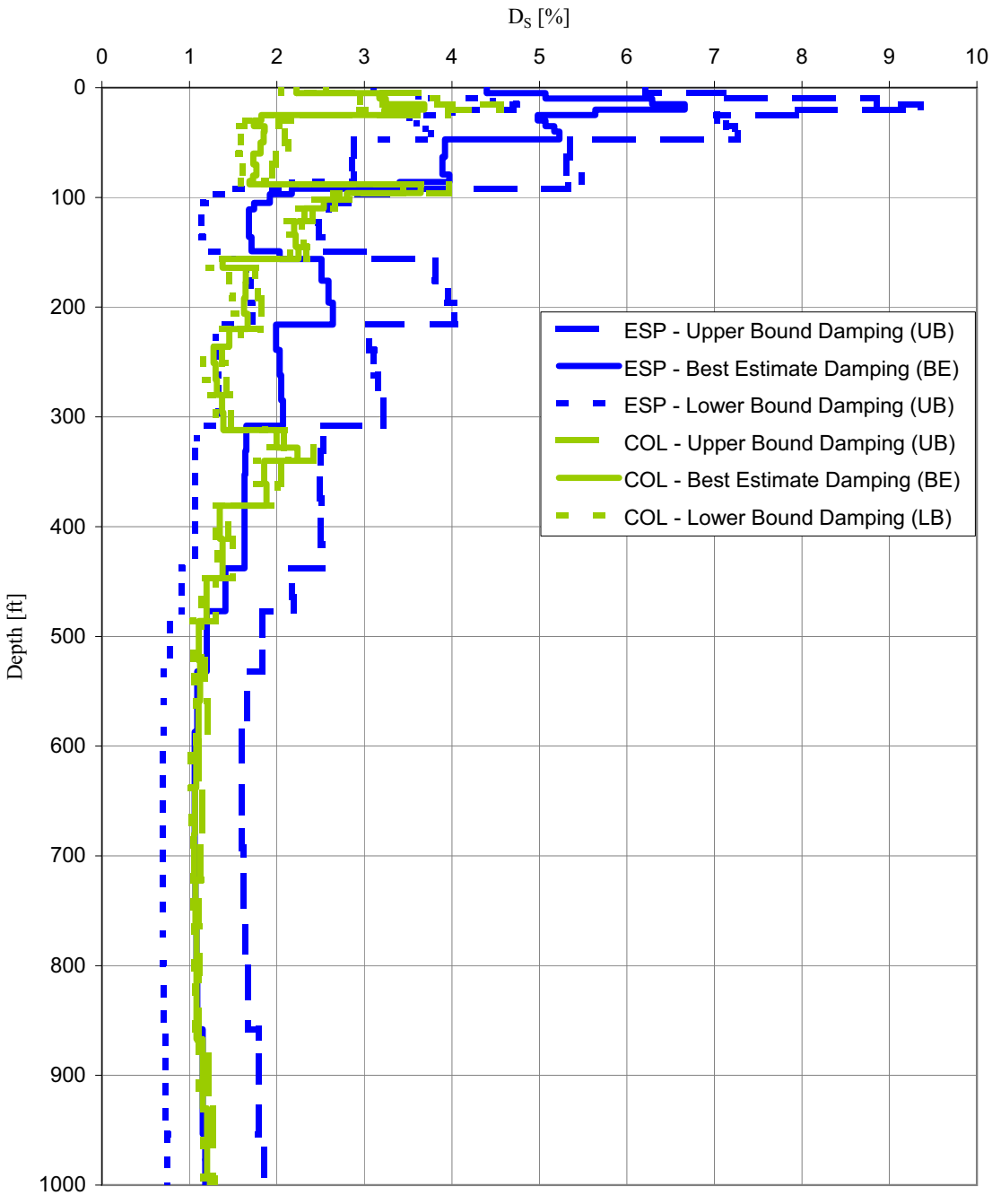


Figure 2.5-350
Vogtle Strain Compatible Profiles (S-Wave Damping)

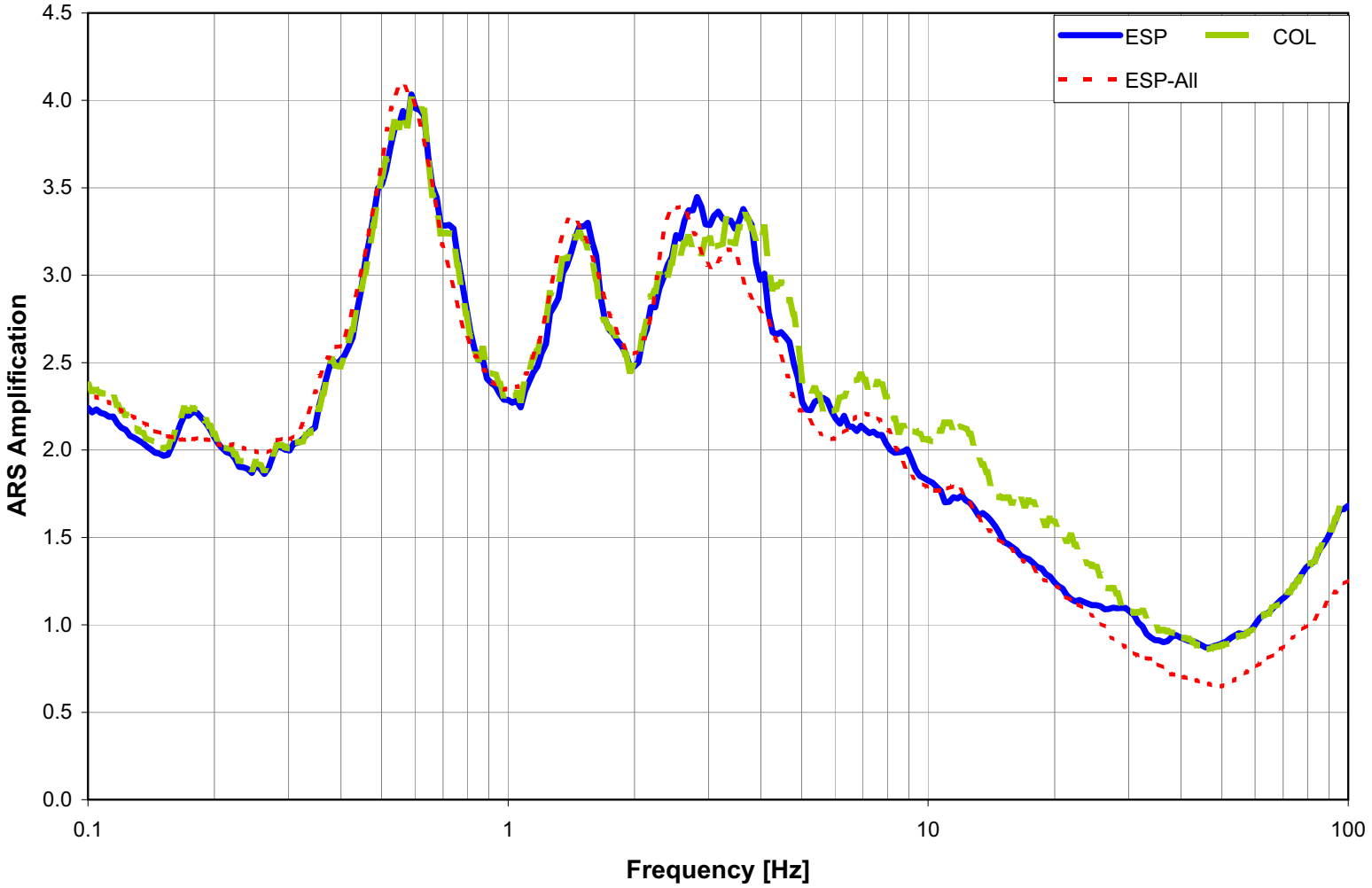


Figure 2.5-351
Envelope at 40 ft Depth (FIRS Horizon)

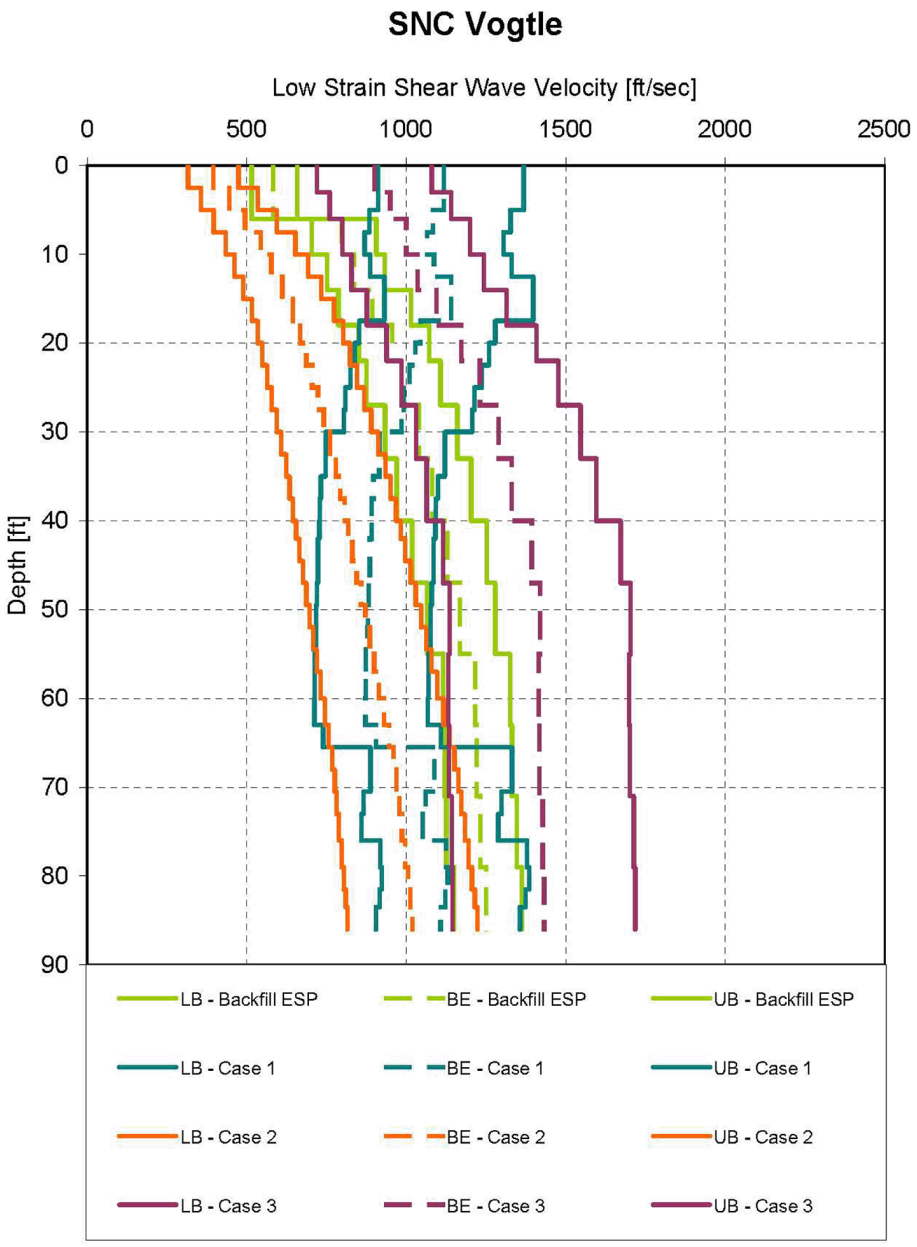


Figure 2.5-352
Low Strain Shear Wave Velocity Profile Cases (LB, BE, UB) - Study for Material Over Excavation Slopes

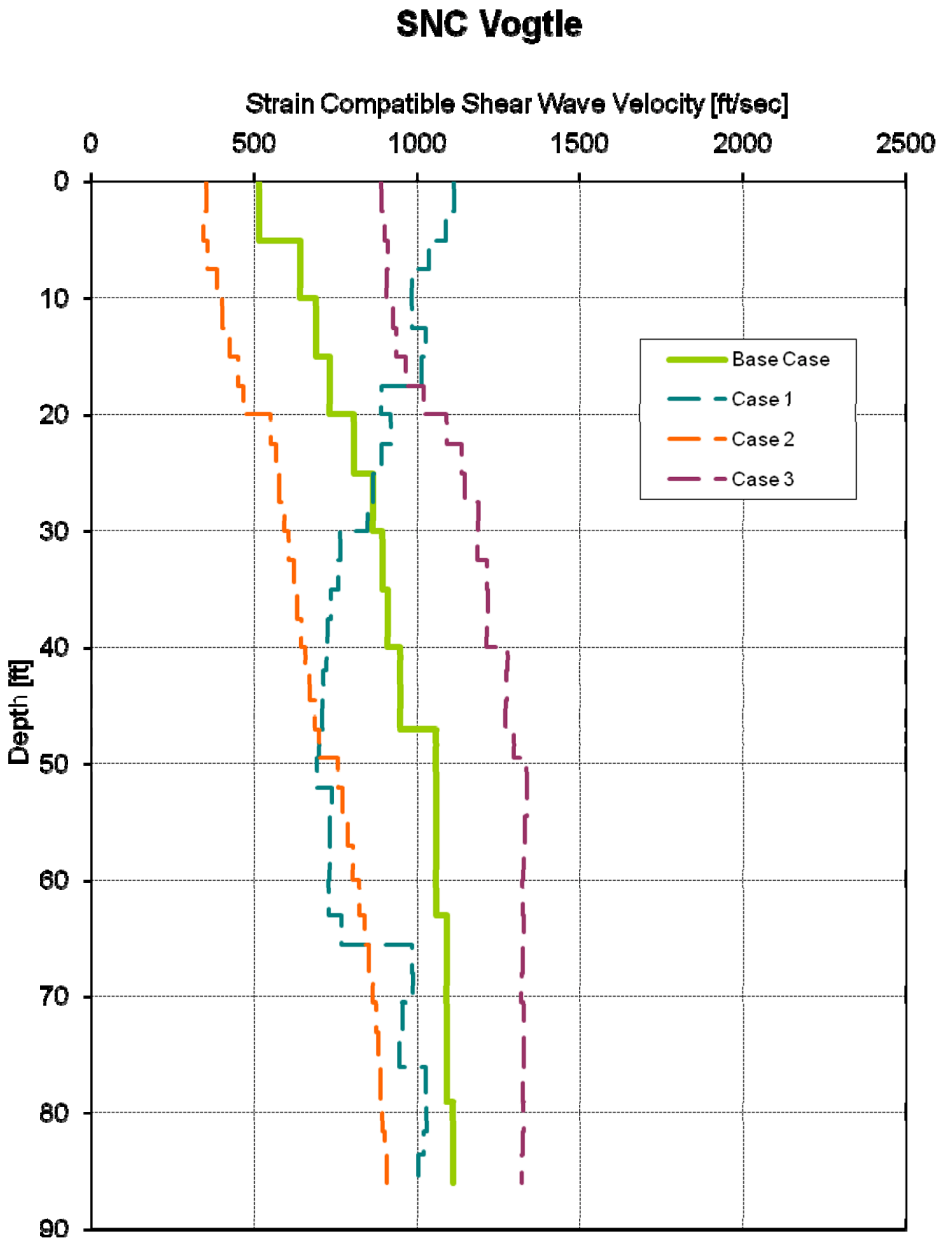


Figure 2.5-353
Strain Compatible BE Shear Wave Velocity Profiles
Cases-for Material Over Excavation Slopes
(2D SASSI SSI Bathtub Analyses)

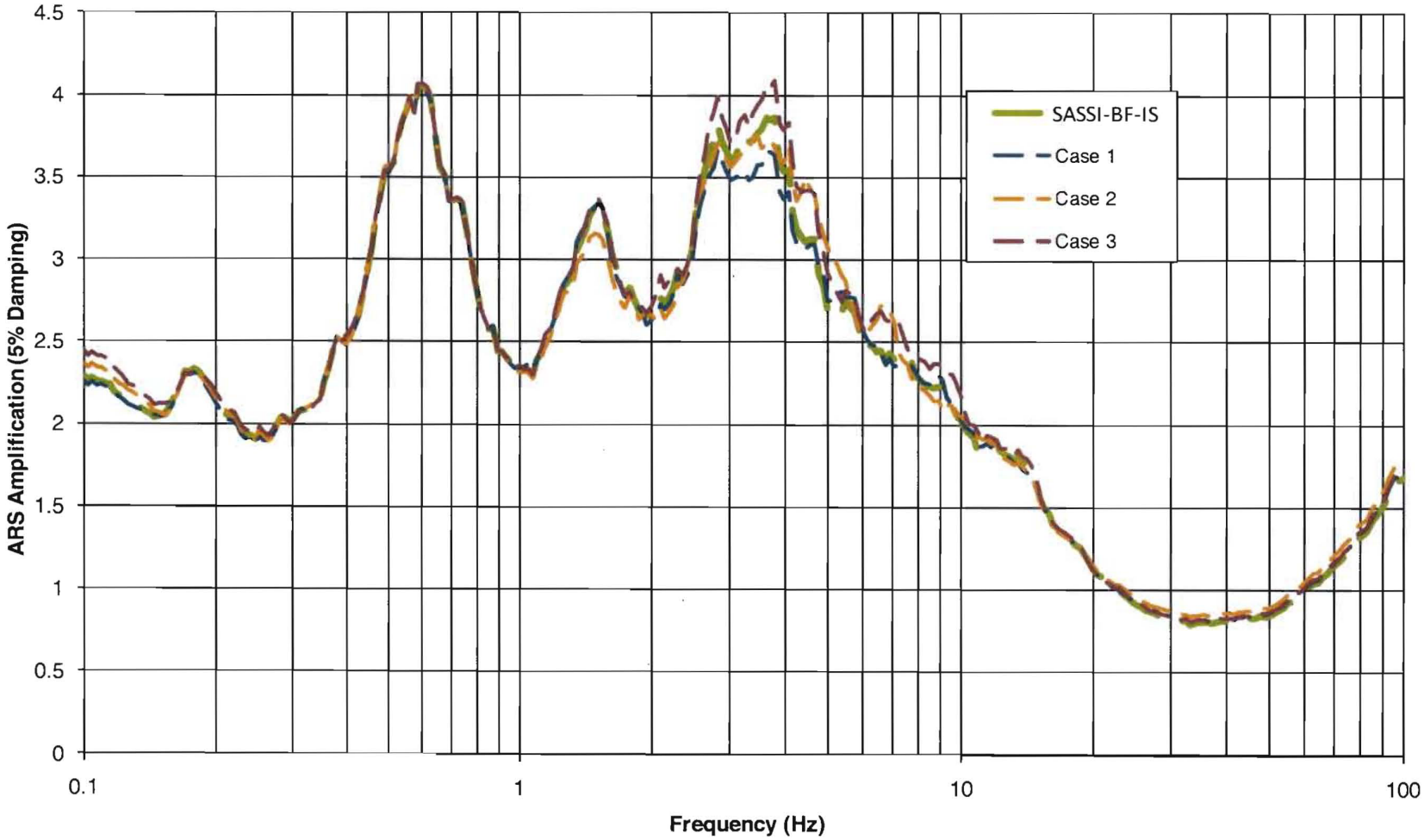


Figure 2.5-354
Comparison of SASSI 2D Bathtub Model Site Response:
Amplification at 0 ft (GMRS horizon)

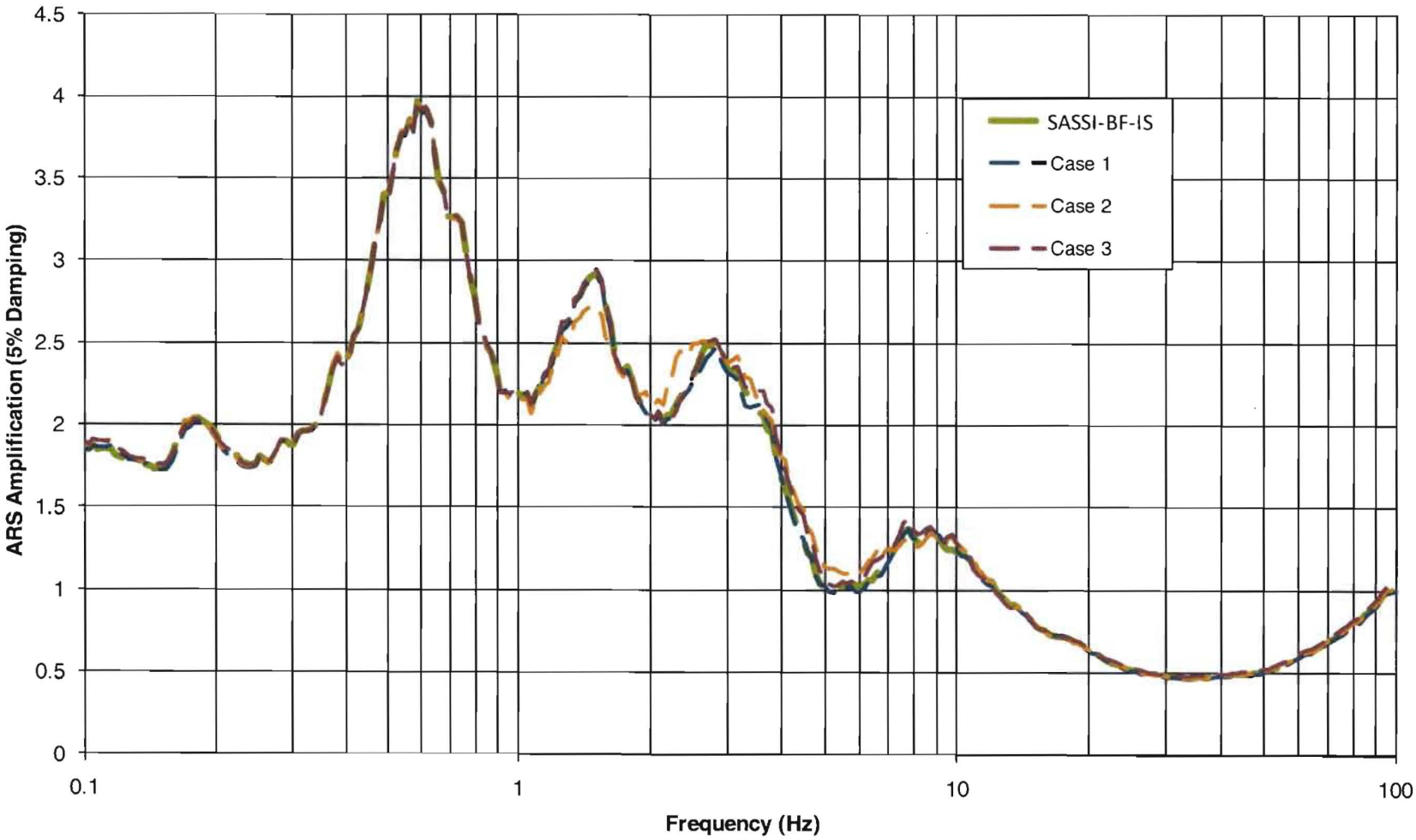


Figure 2.5-355
Comparison of SASSI 2D Bathtub Model Site Response: Amplification at 40 ft depth (FIRS horizon)

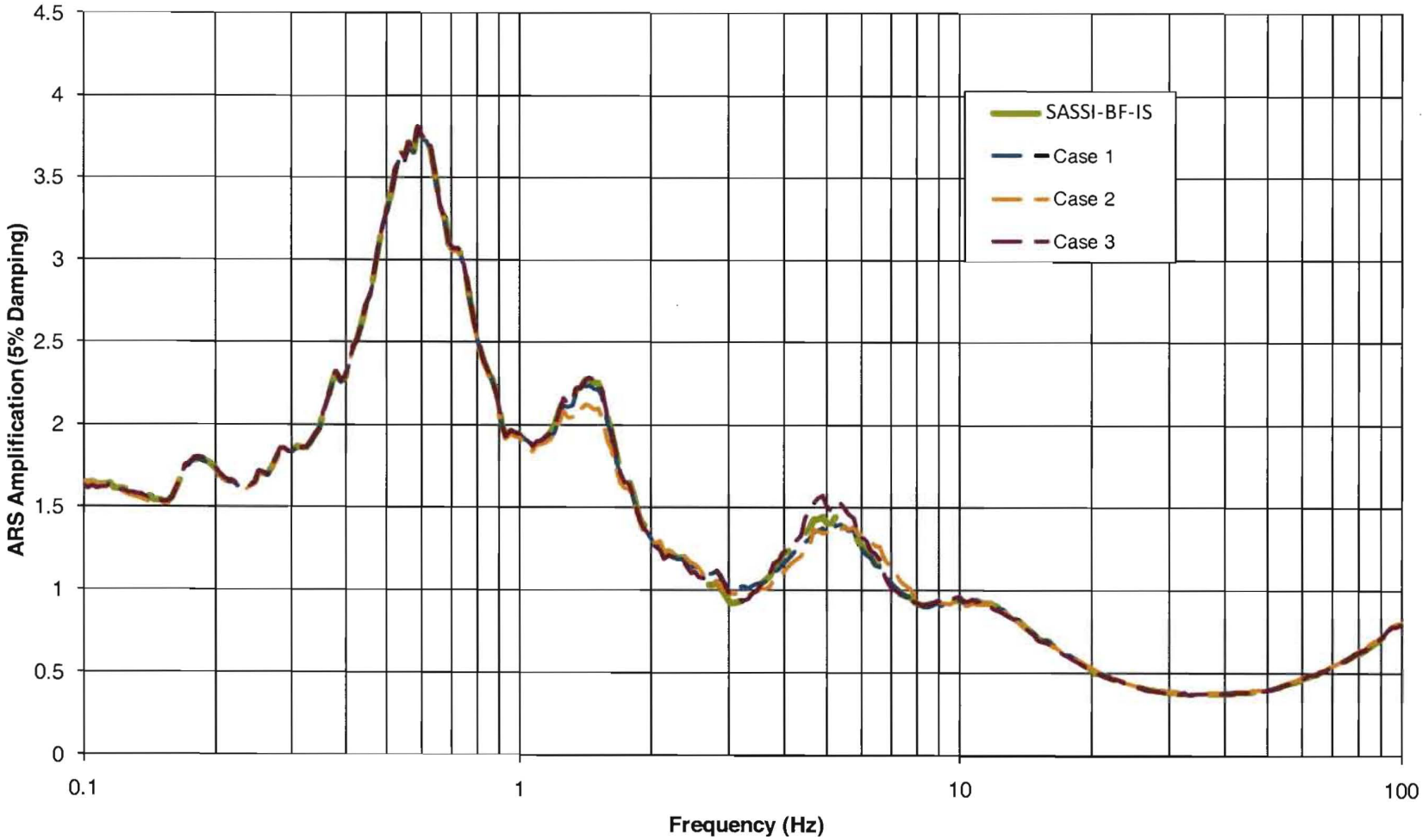


Figure 2.5-356
Comparison of SASSI 2D Bathtub Model Site Response: Amplification at 86 ft depth (Top of Blue Bluff Marl)

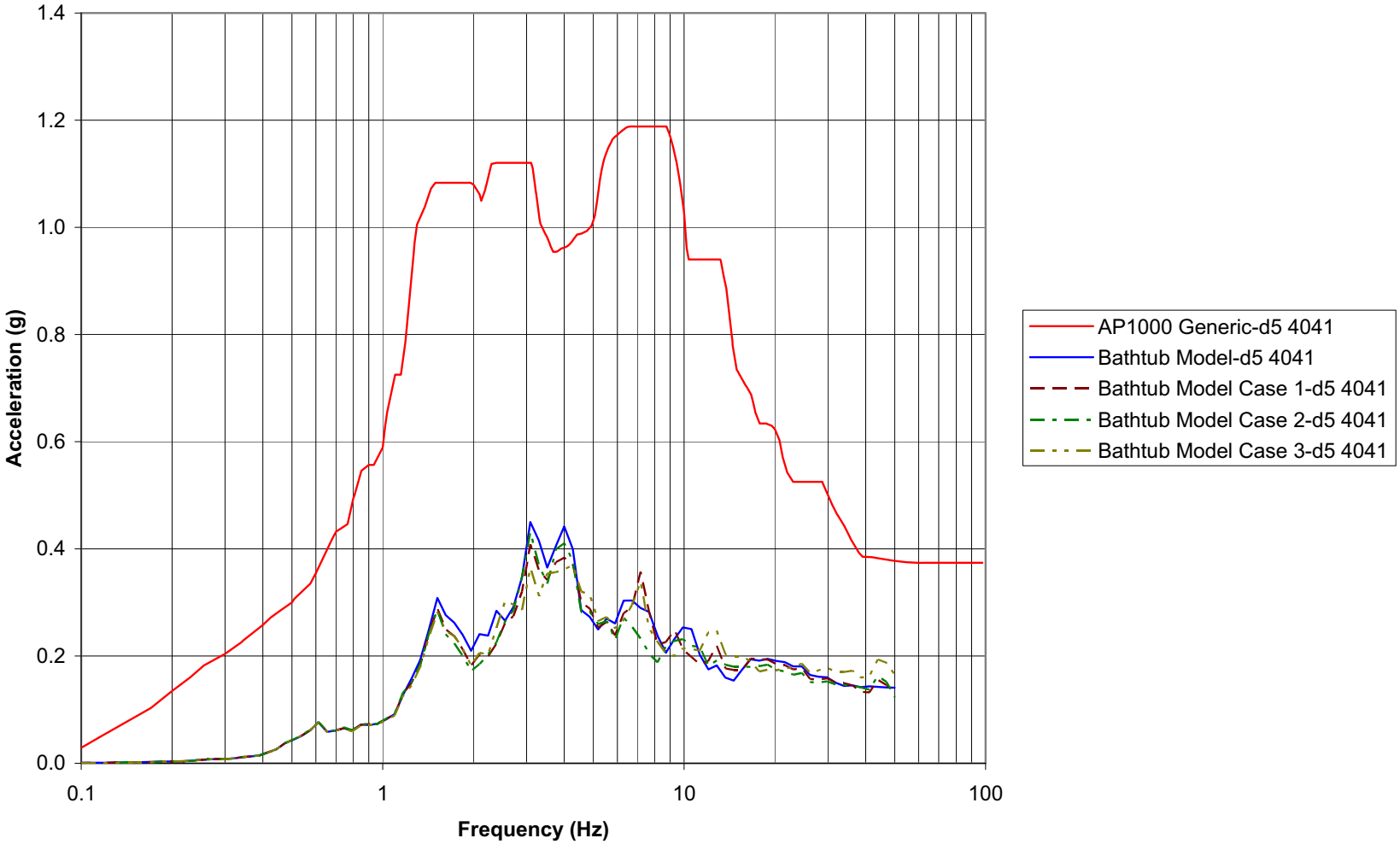


Figure 2.5-357
Comparison of SASSI 2D Bathtub NI Model SSI Responses:
Node 4041-EL 99 NI at Reactor Vessel Support Elevation

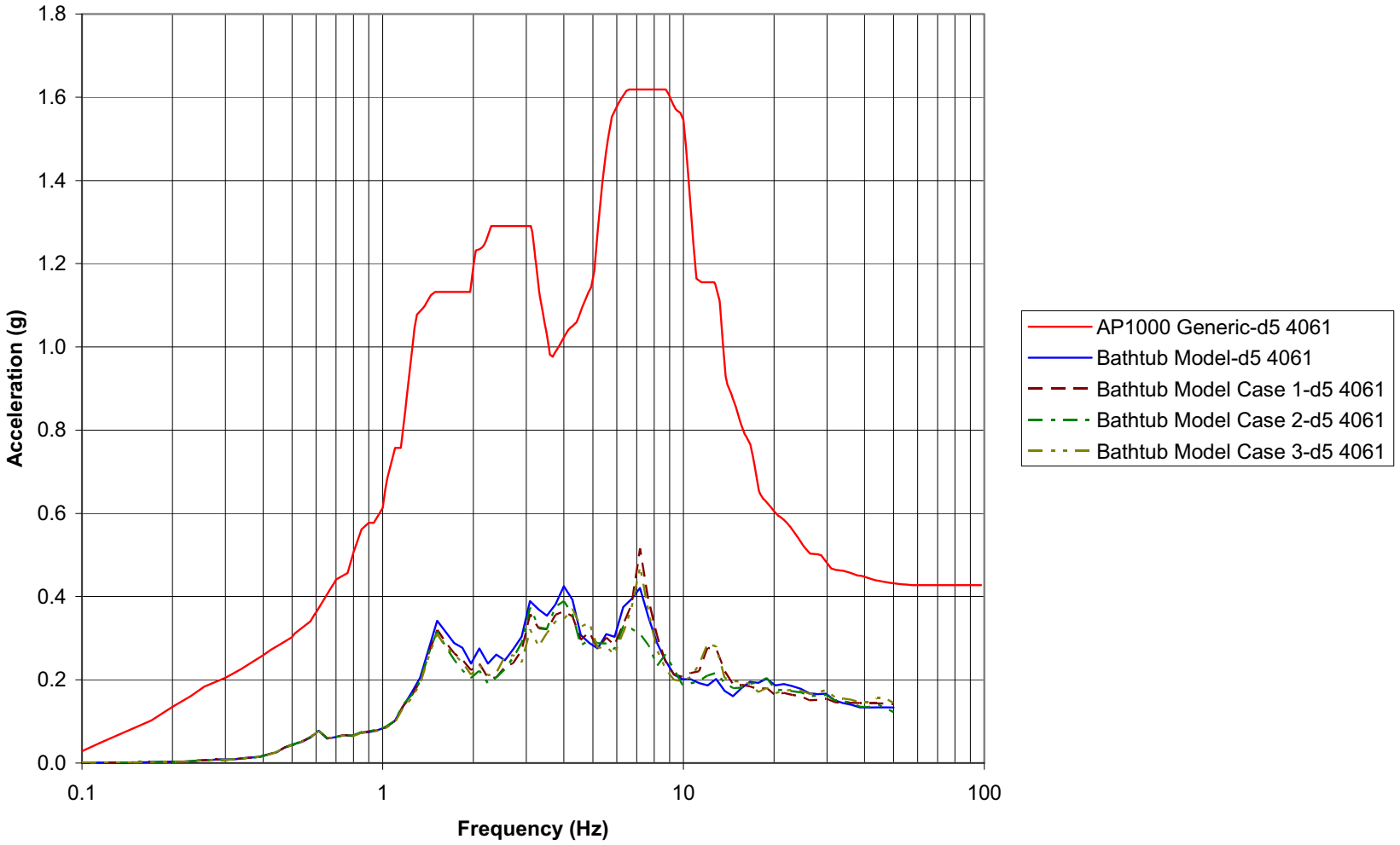


Figure 2.5-358
Comparison of SASSI 2D Bathtub NI Model SSI Responses:
Node 4061-EL 116.5 Auxiliary Shield Building at Control Room Floor

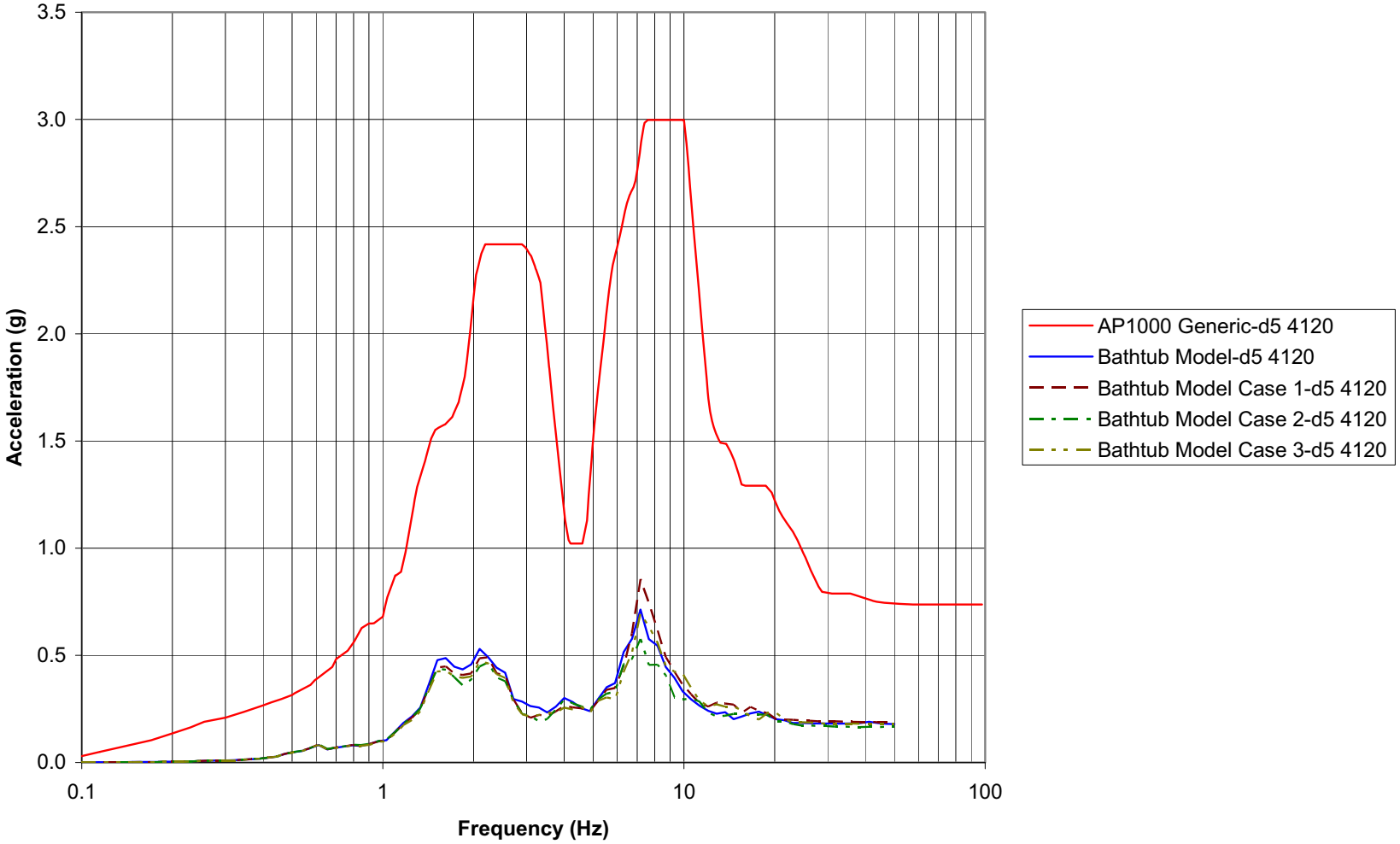


Figure 2.5-359
Comparison of SASSI 2D Bathtub NI Model SSI Responses:
Node 4120-EL 179.56 ASB Auxiliary Building Roof Area

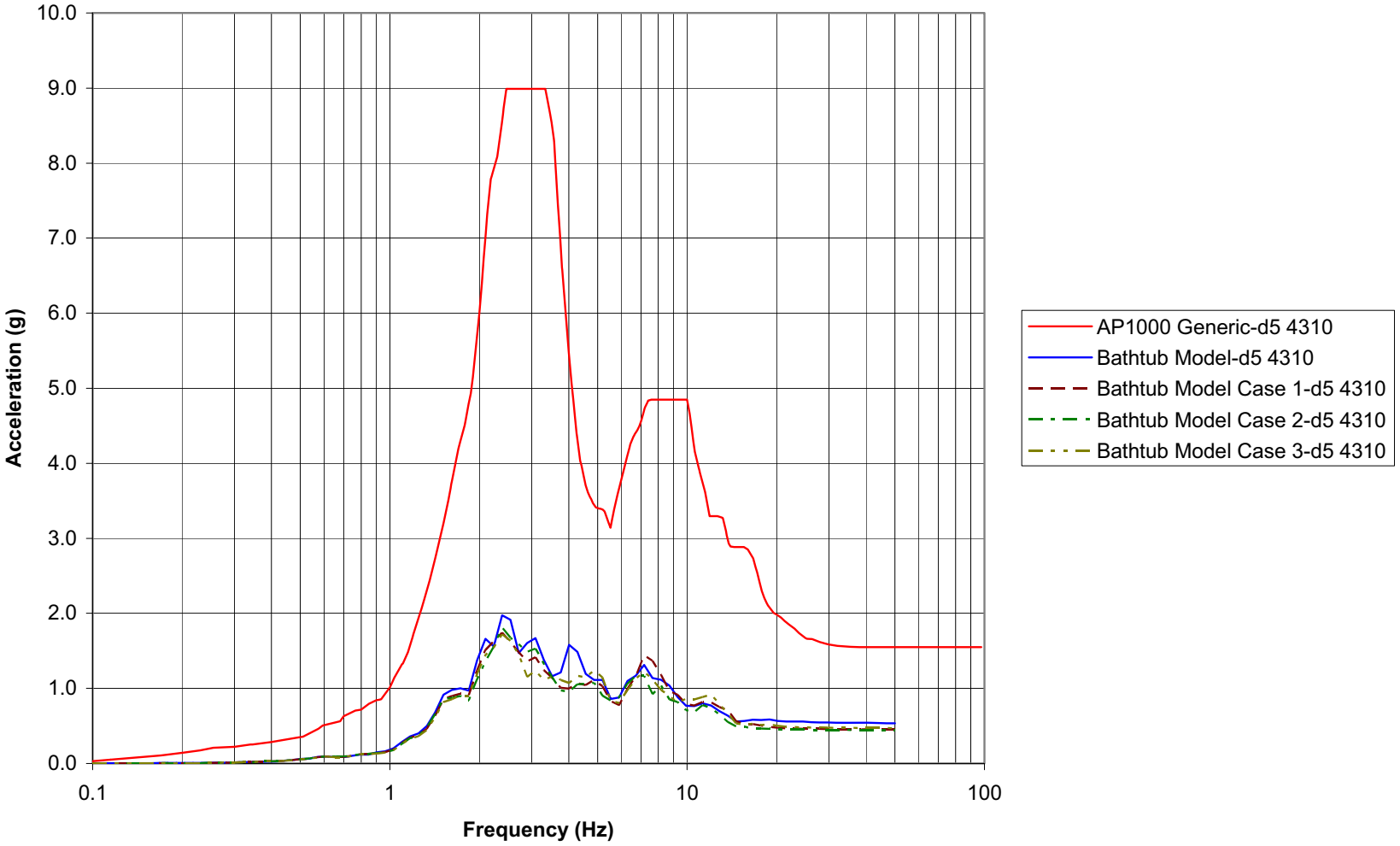


Figure 2.5-360
Comparison of SASSI 2D Bathtub NI Model SSI Responses:
Node 4310-EL 327.41 ASB Shield Building Roof Area

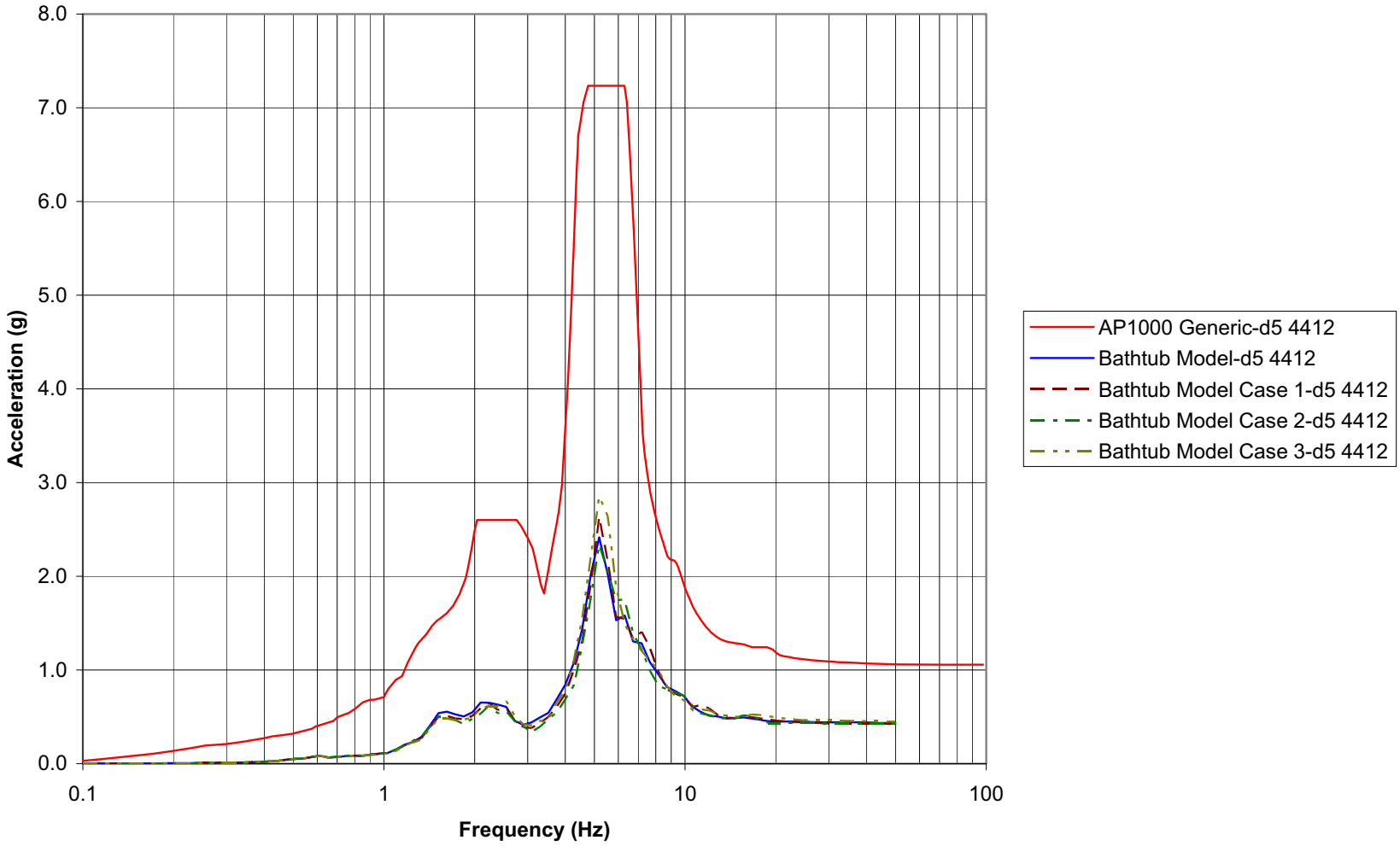


Figure 2.5-361
Comparison of SASSI 2D Bathtub NI Model SSI Responses:
Node 4412-EL 224 Steel Containment Vessel Near Polar Crane

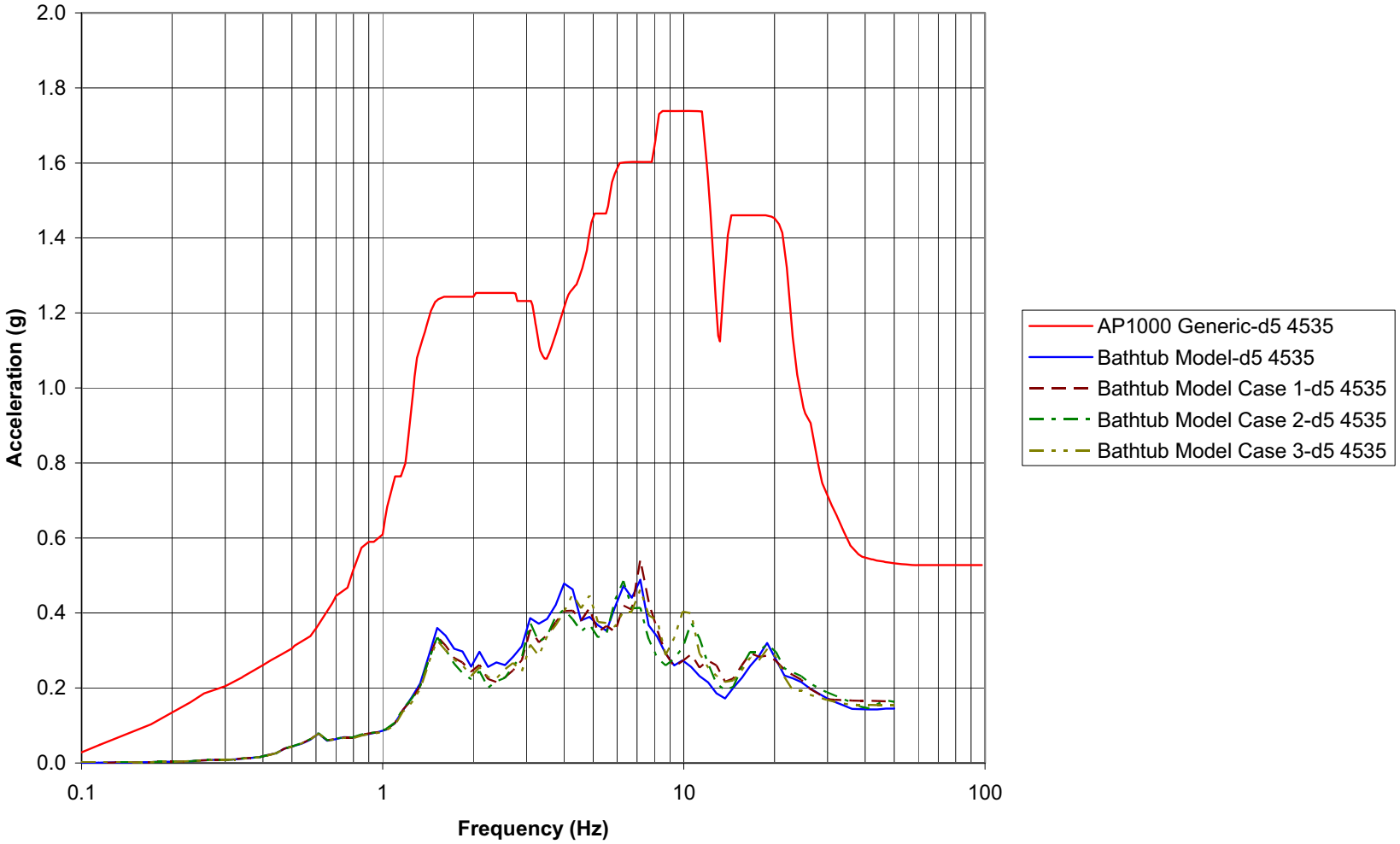
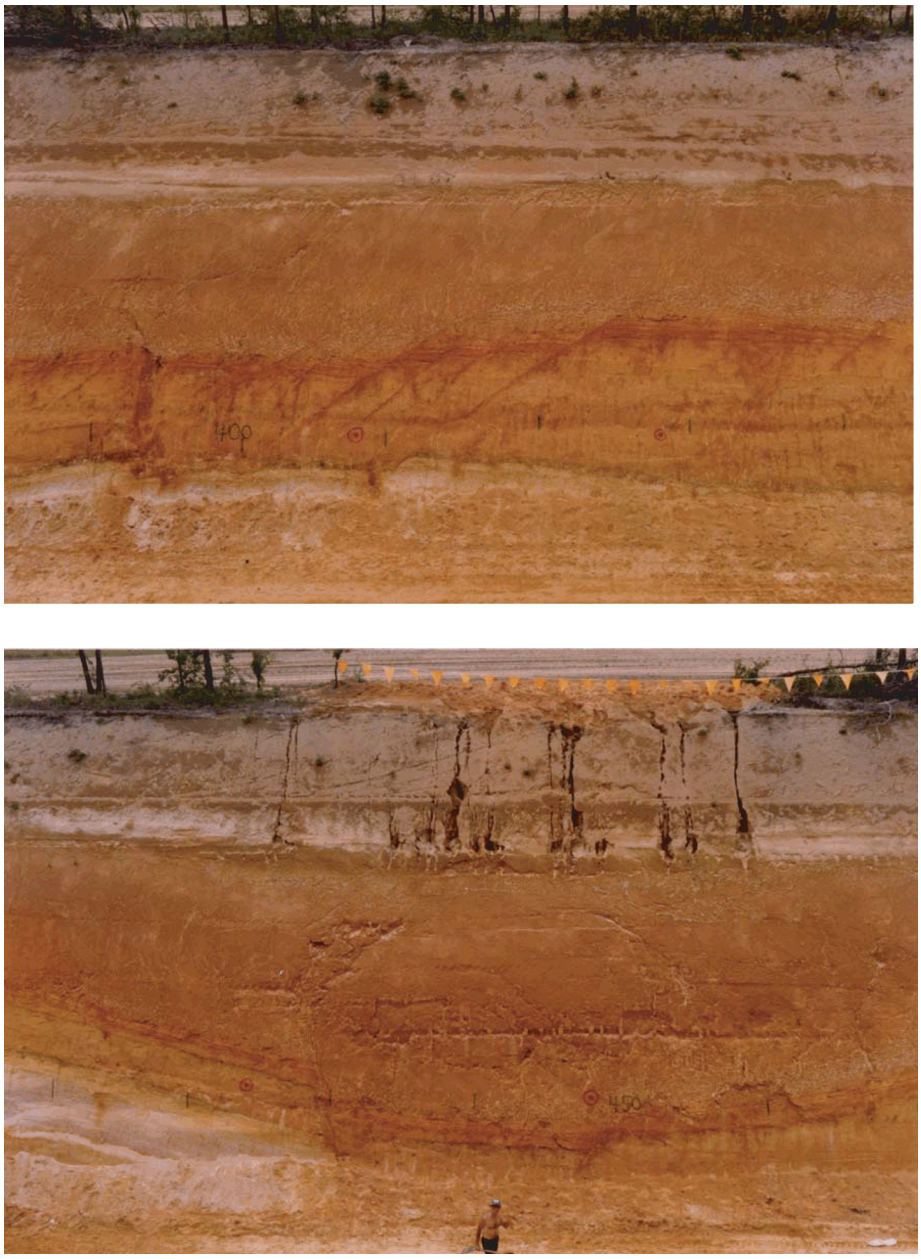


Figure 2.5-362
Comparison of SASSI 2D Bathtub NI Model SSI Responses:
Node 4535-EL 135.25 Containment Internal Structure at Operating Deck



Source: Bechtel 1984b

Figure 2.5-363
Contorted Bedding in Garbage Trench at VEGP Site



Source: Bechtel 1984b

Figure 2.5-364
West Wall of Garbage Trench Showing Small Offsets (1–24 inches) (Upper) and Arcuate Fractures and Clastic Dikes Over Center of Depression (Lower)

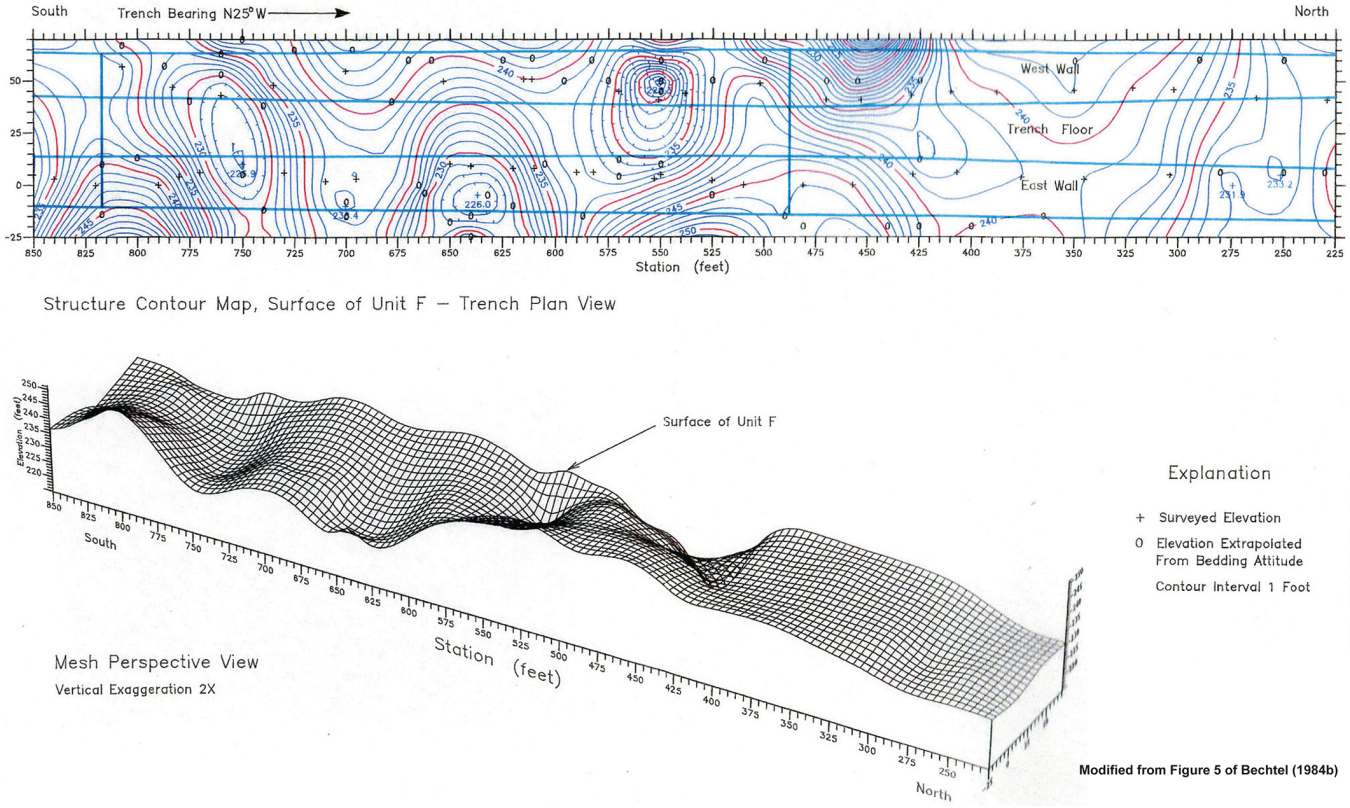
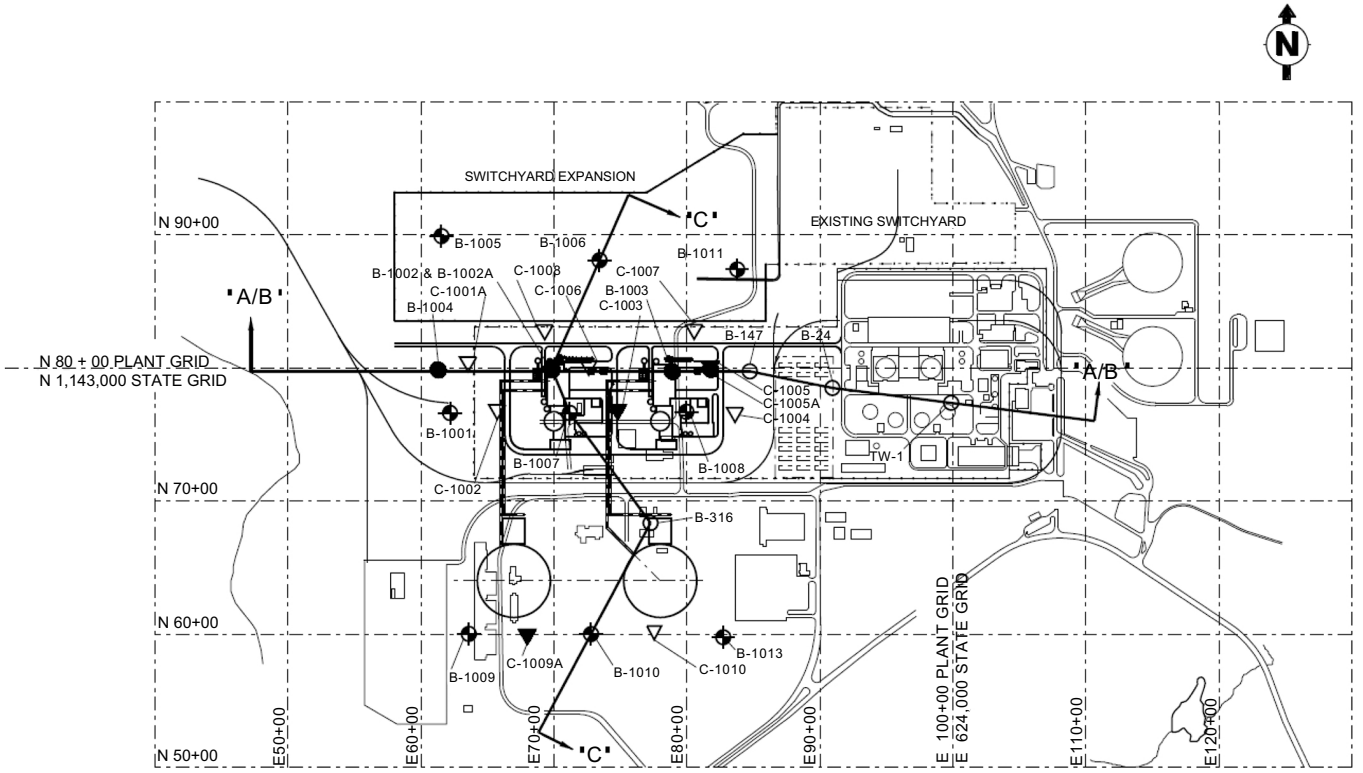


Figure 2.5-365
Surface Geometry of Unit F Illustrating Localized Nature of Deformation



NOTES:

1. REFER TO FIGURES 2.5.4-3, 2.5.4-4, AND 2.5.4-5 FOR SUBSURFACE PROFILES.
2. SUBSURFACE PROFILES 'A-A' AND "B-B' USE THE SAME BORINGS, BUT SHOW DIFFERENT AMOUNTS OF DETAIL.
3. THE GRID SYSTEM SHOWN IS DESIGNATED 'PLANT GRID SYSTEM". THE FOLLOWING FACTORS MAY BE APPLIED TO CONVERT TO THE GEORGIA EAST (NAD27) STATE GRID SYSTEM.

   PLANT NORTH + 1,135,000 = STATE NORTH
   PLANT EAST + 614,000 = STATE EAST

LEGEND:

- ESP BORING
- ESP BORING WITH GEOGRAPHICAL TESTS
- ESP CONE PENETRATION TEST (CPT)
- ESP CPT WITH SEISMIC DOWN-HOLE TESTING
- EXISTING BORING

Figure 2.5-366
ESP Study Boring Location Plan



Figure 2.5-367
COL Site Boring Location Plan

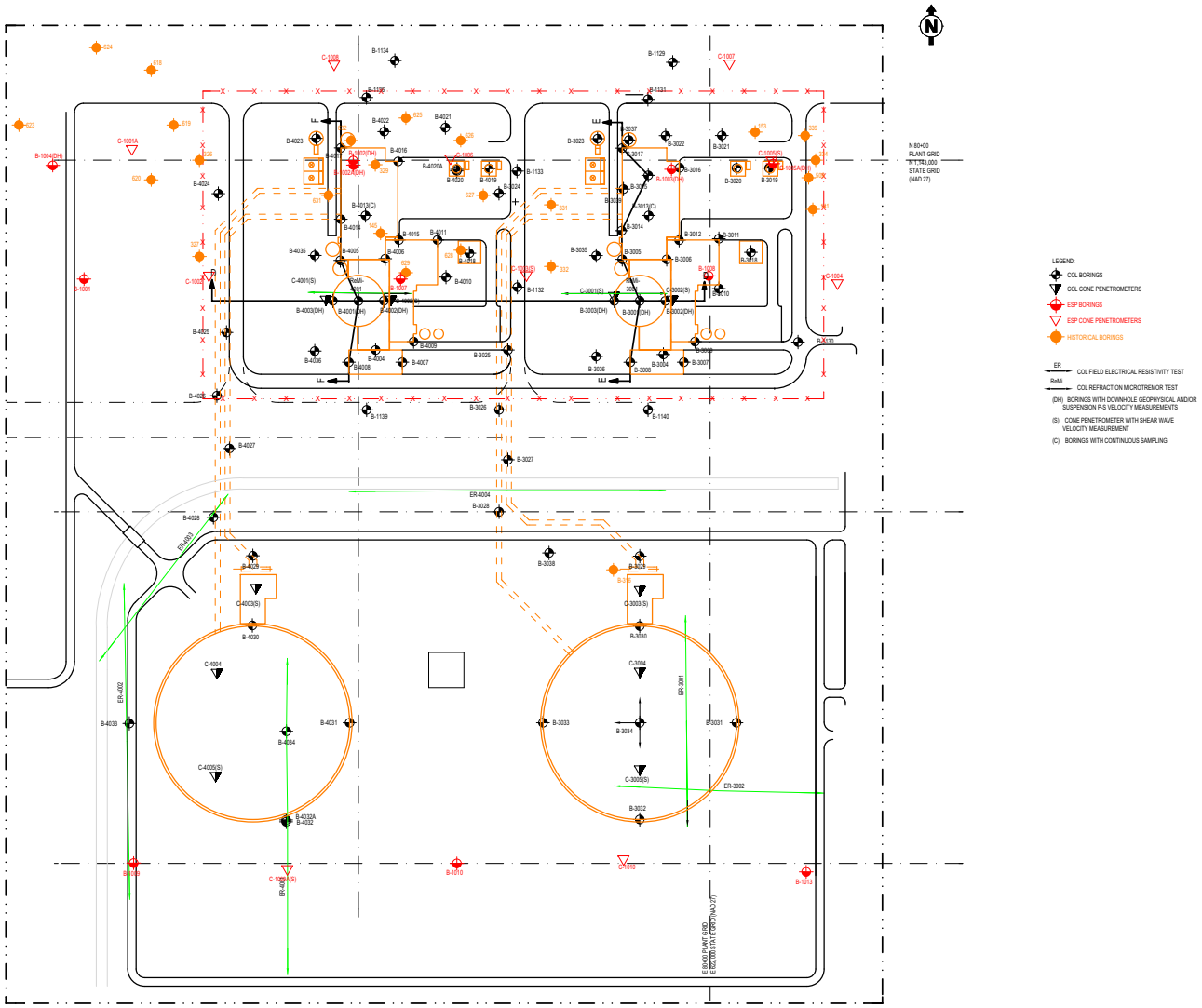
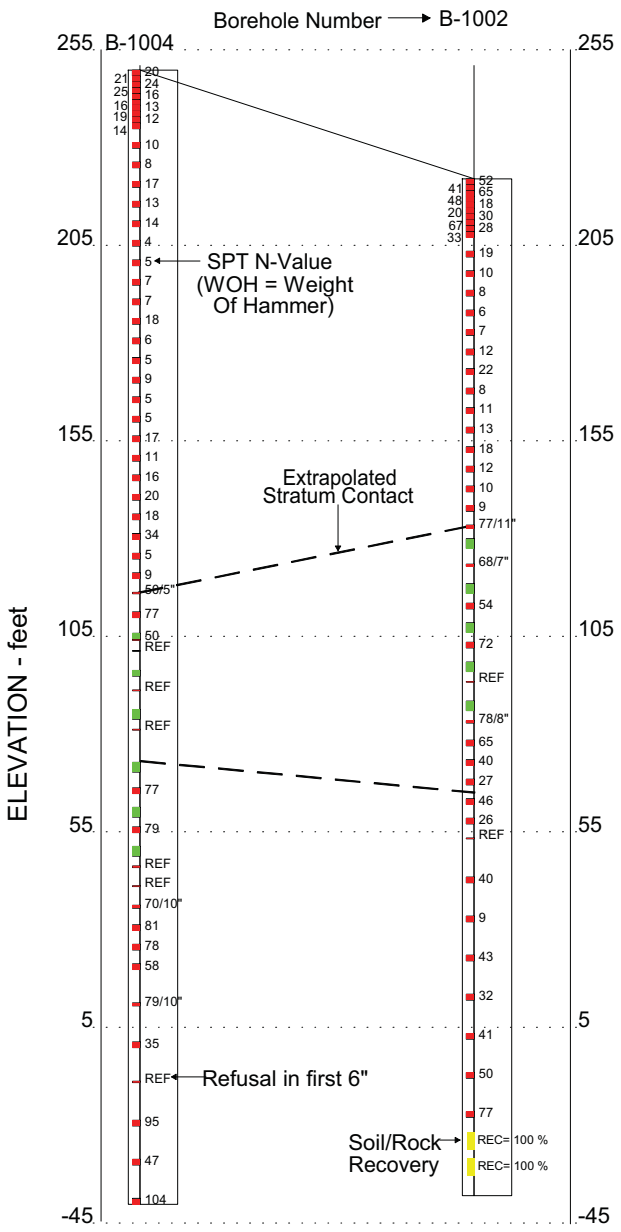


Figure 2.5-368
COL Power Block — Cooling Tower Boring Location



Stratum Descriptions Continued

GAILLARD/BLACK CREEK FM. Interbedded SAND, SILT and CLAY

PIO NONO/UNNAMED FM. SAND with silt

CAPE FEAR FM. Silty, clayey SAND with silt and clay layers

TRIASSIC BASIN (BEDROCK). Interbedded CONGLOMERATE, BRECCIA, SANDSTONE and MUDSTONE.

Notes

Subsurface data have been obtained only at the actual boring locations. The stratification shown by the dashed lines between borings is based on extrapolation of the data from the borings. Actual stratification between the borings may differ from that shown.

Stratum Descriptions

BARNWELL GROUP. Silty, clayey SAND with layers of silt and clay. Lower limestone / shell hash (UTLEY LMST FM.)

LISBON FM (BLUE BLUFF MEMBER). Marl with limestone layers

STILL BRANCH FM. Silty, clayey SAND

CONGAREE FM. SAND with silt and clay

SNAPP FM. Interbedded SAND, SILT and CLAY

BLACK MINGO FM. Interbedded SAND, SILT and CLAY

STEEL CREEK FM. SAND with silt and clay

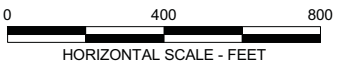


Figure 2.5-369
Subsurface Profile Legend

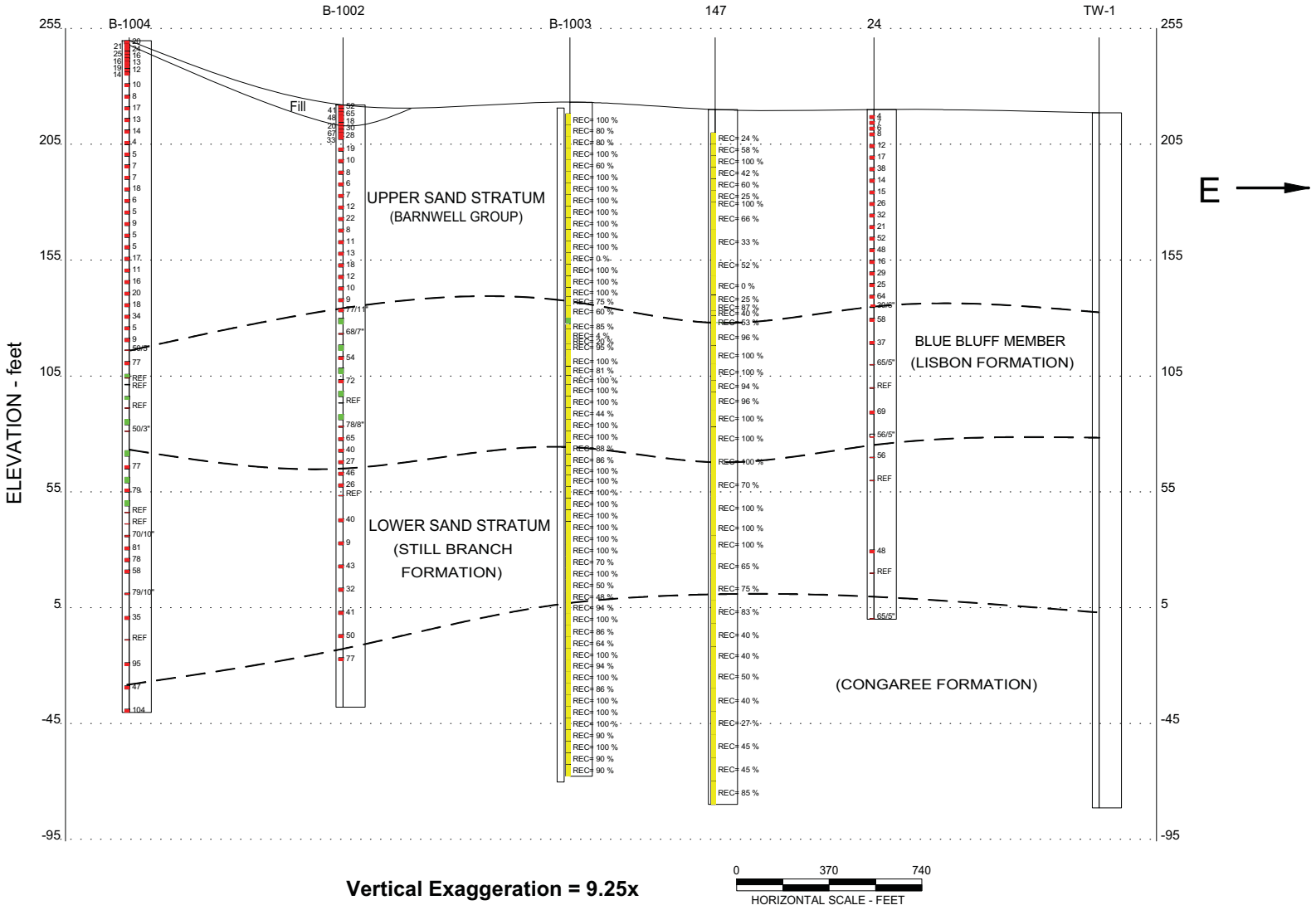


Figure 2.5-370
Subsurface Profile A–A'

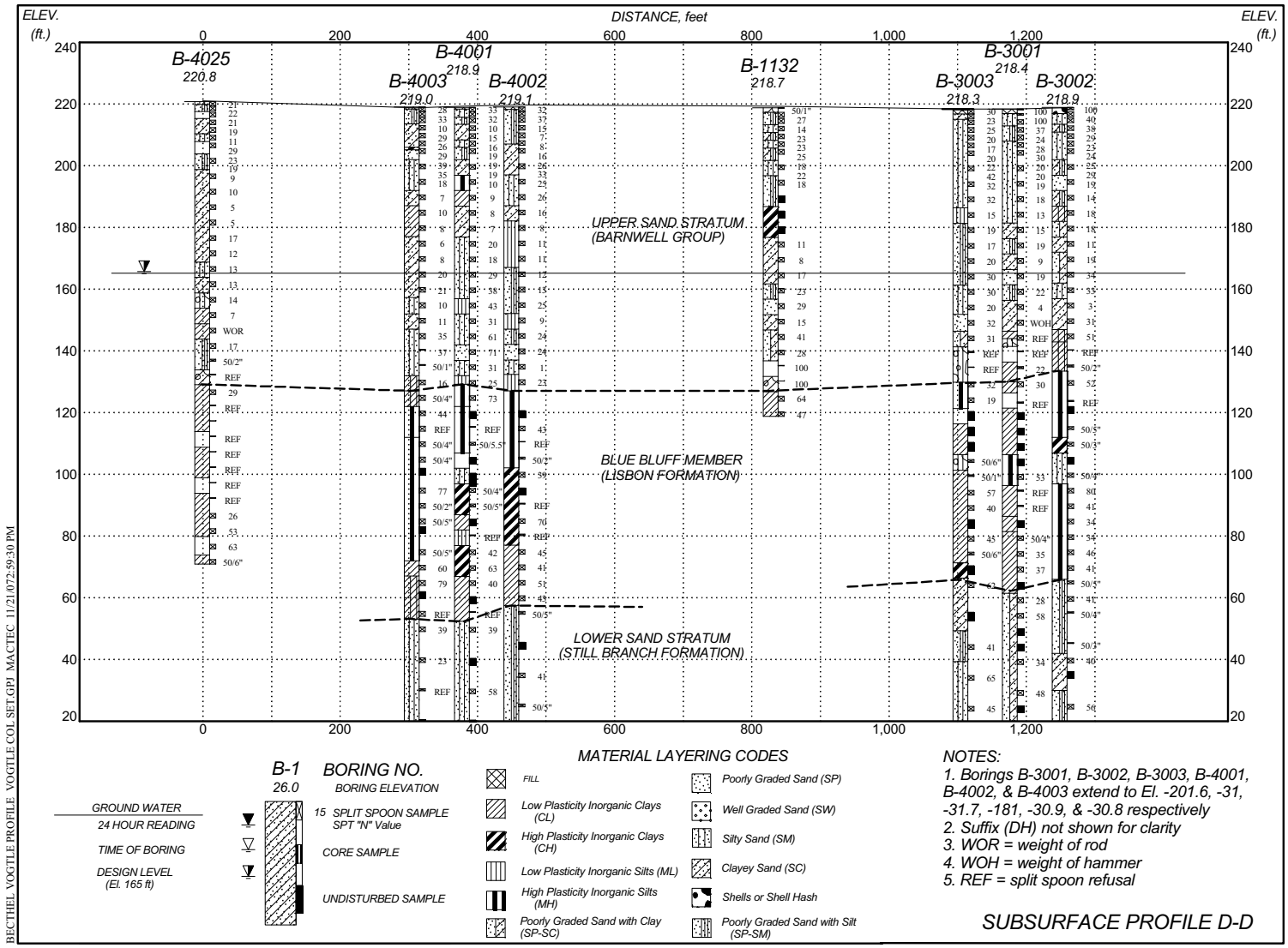


Figure 2.5-371
Subsurface Profile D–D'

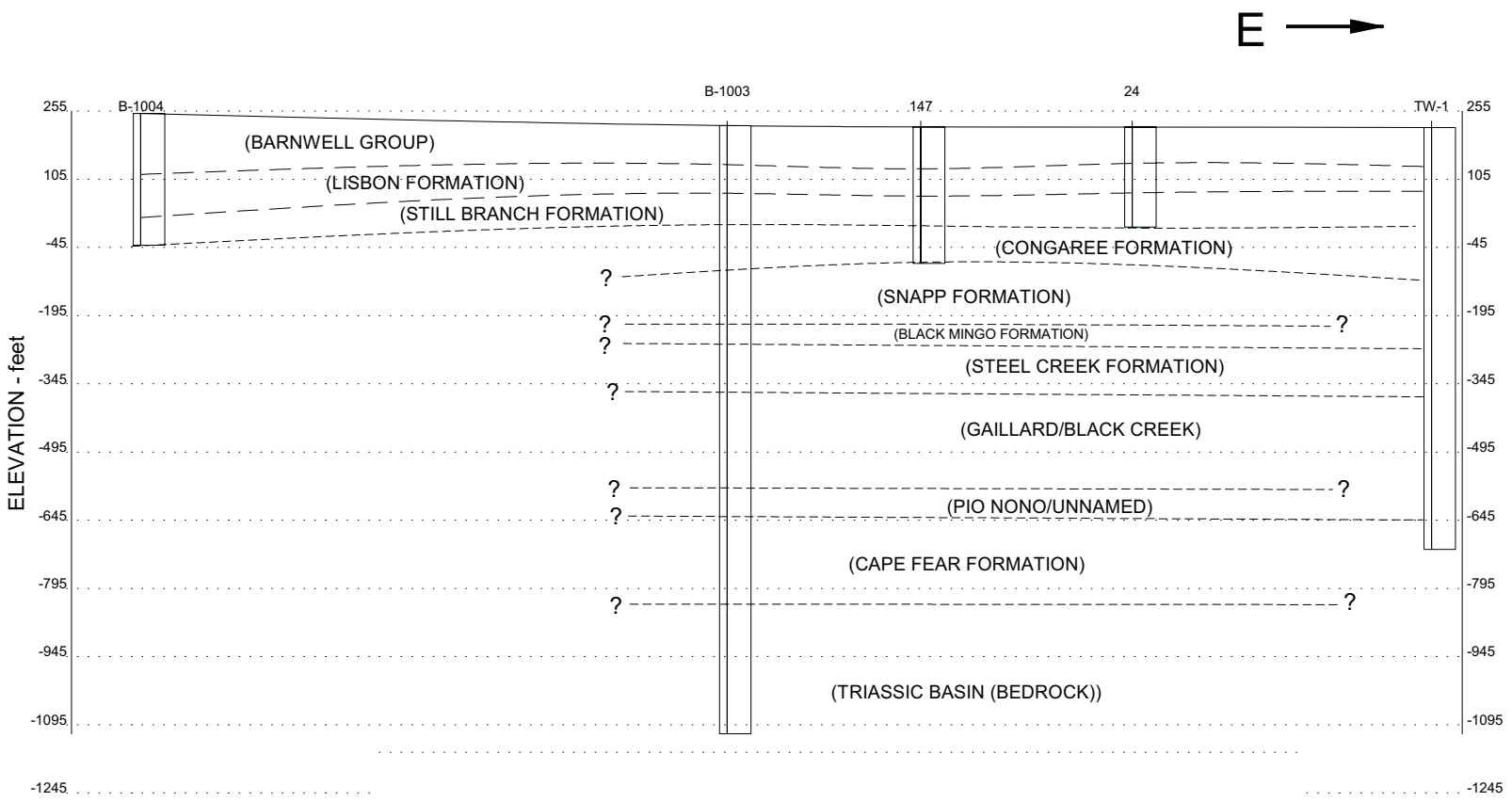


Figure 2.5-372
Subsurface Profile B–B'

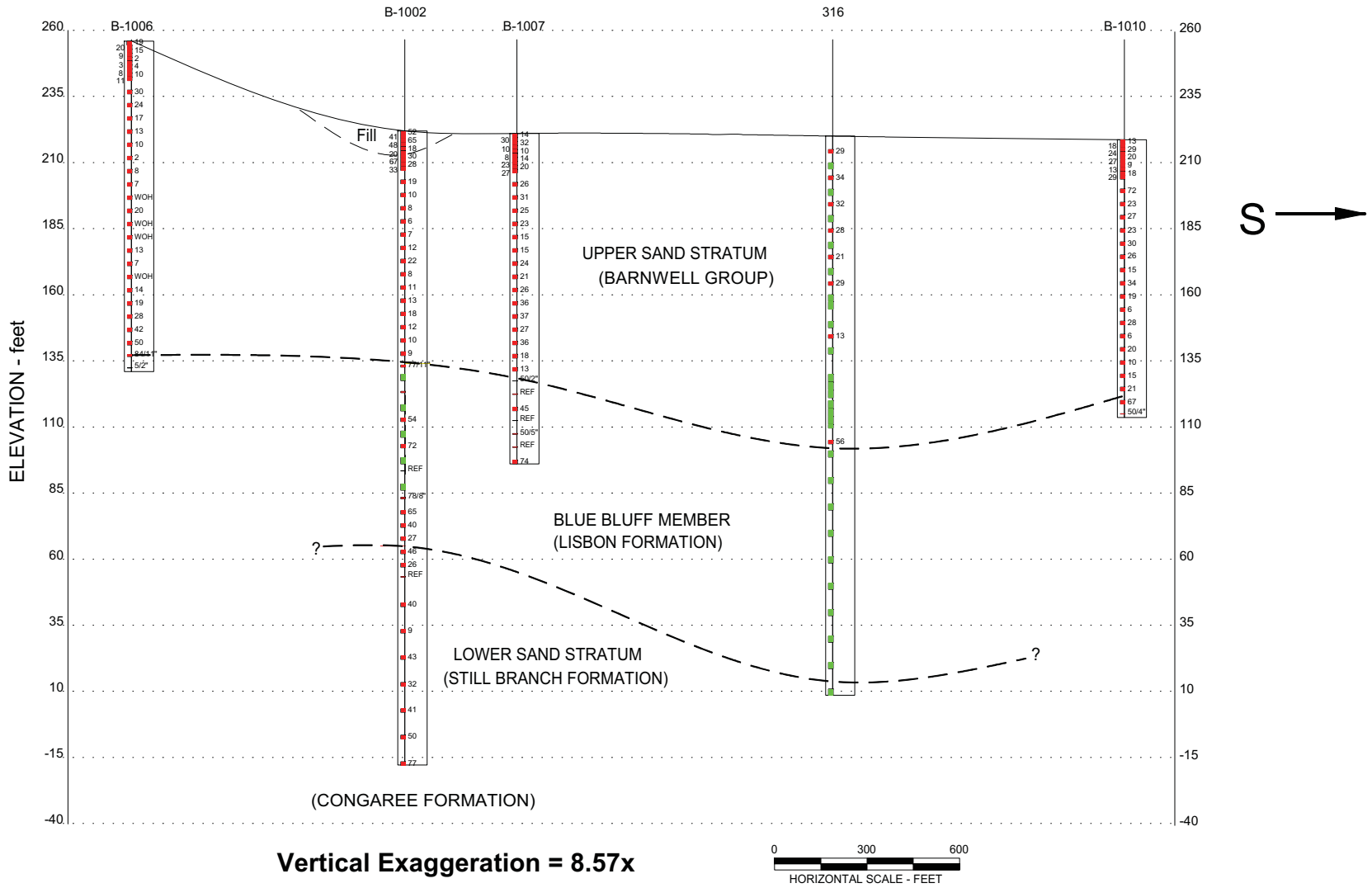


Figure 2.5-373
Subsurface Profile C–C'

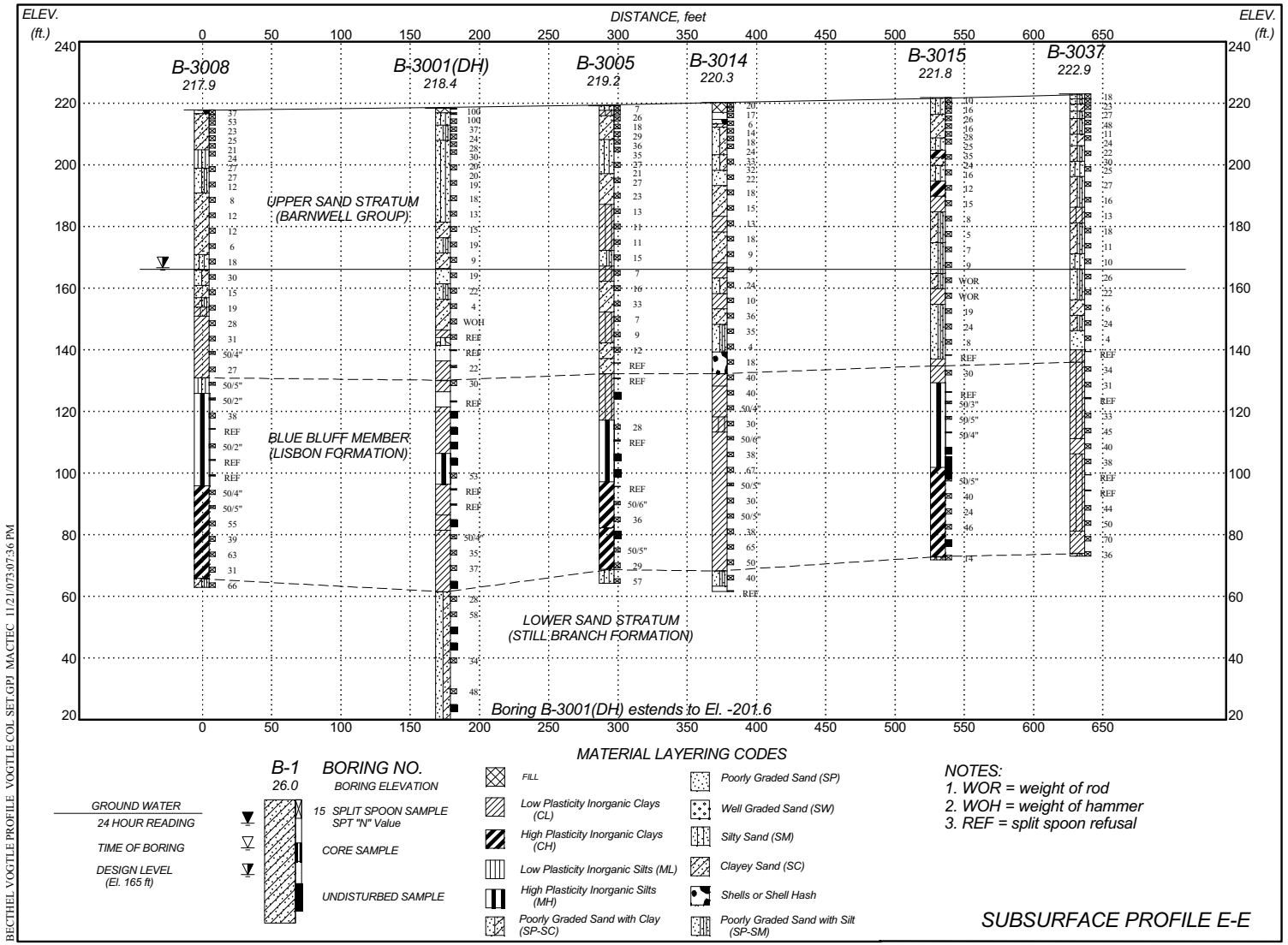


Figure 2.5-374
Subsurface Profile E–E'

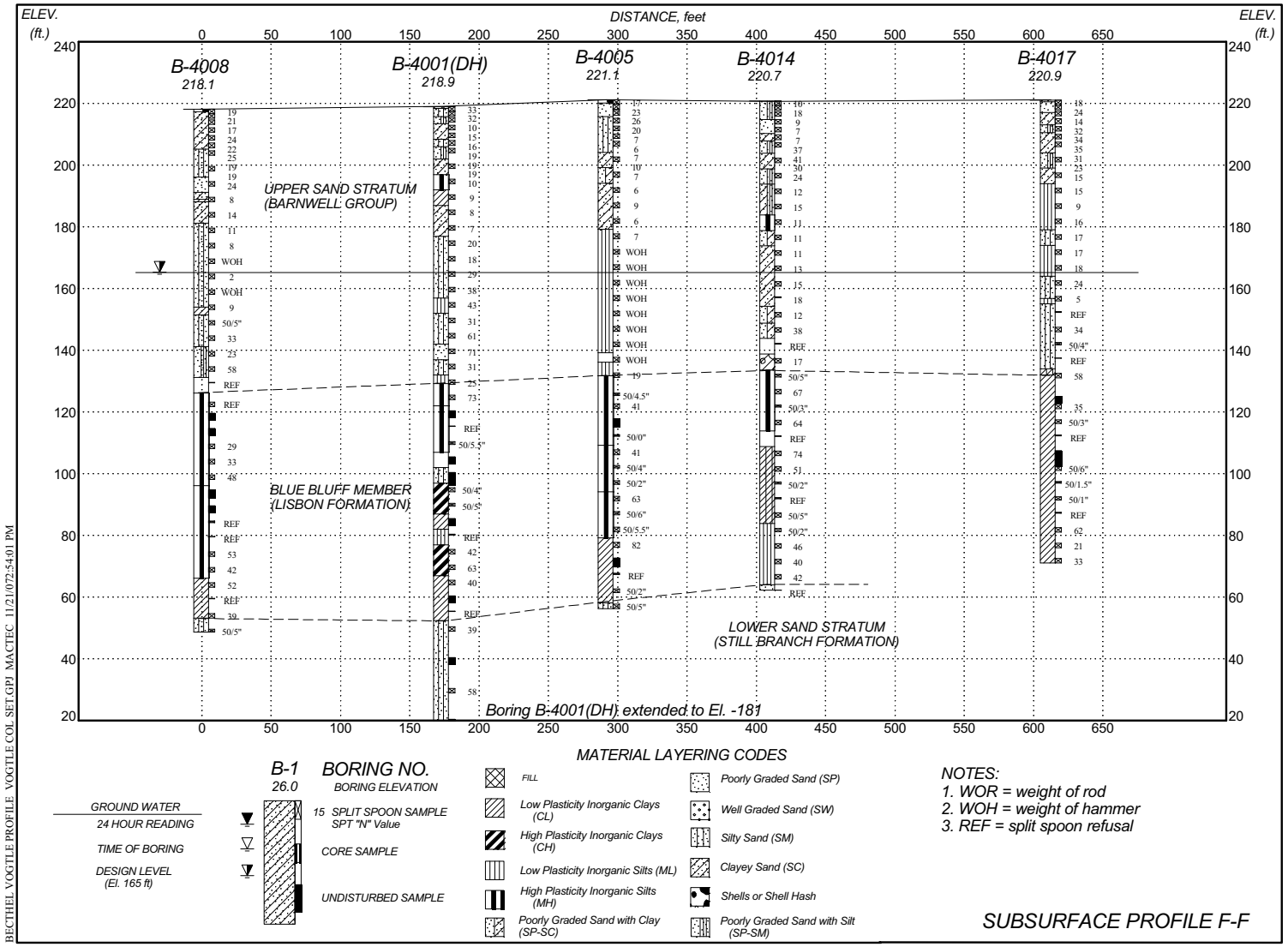


Figure 2.5-375
Subsurface Profile F–F'

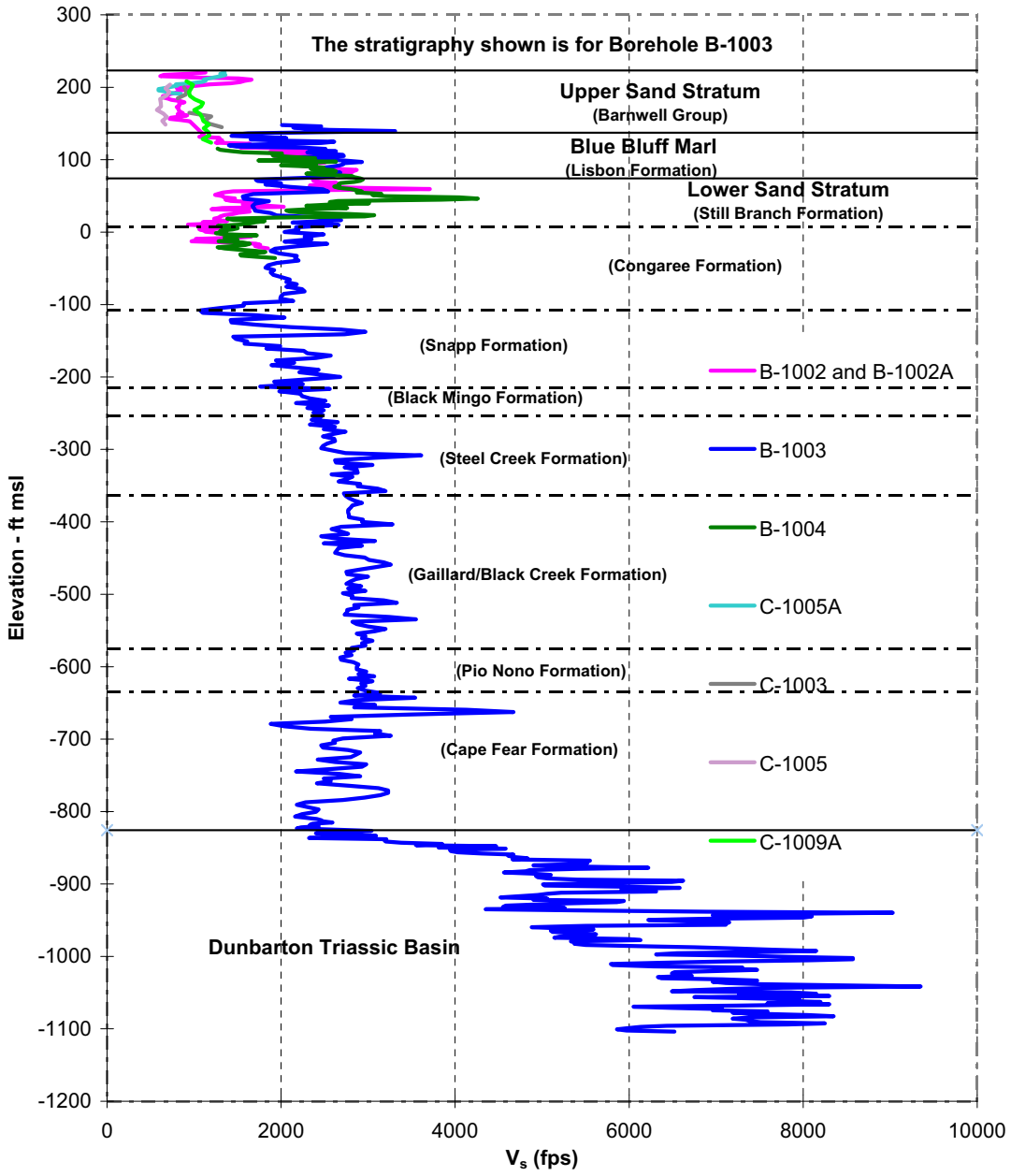


Figure 2.5-376
Shear Wave Velocity Measurements

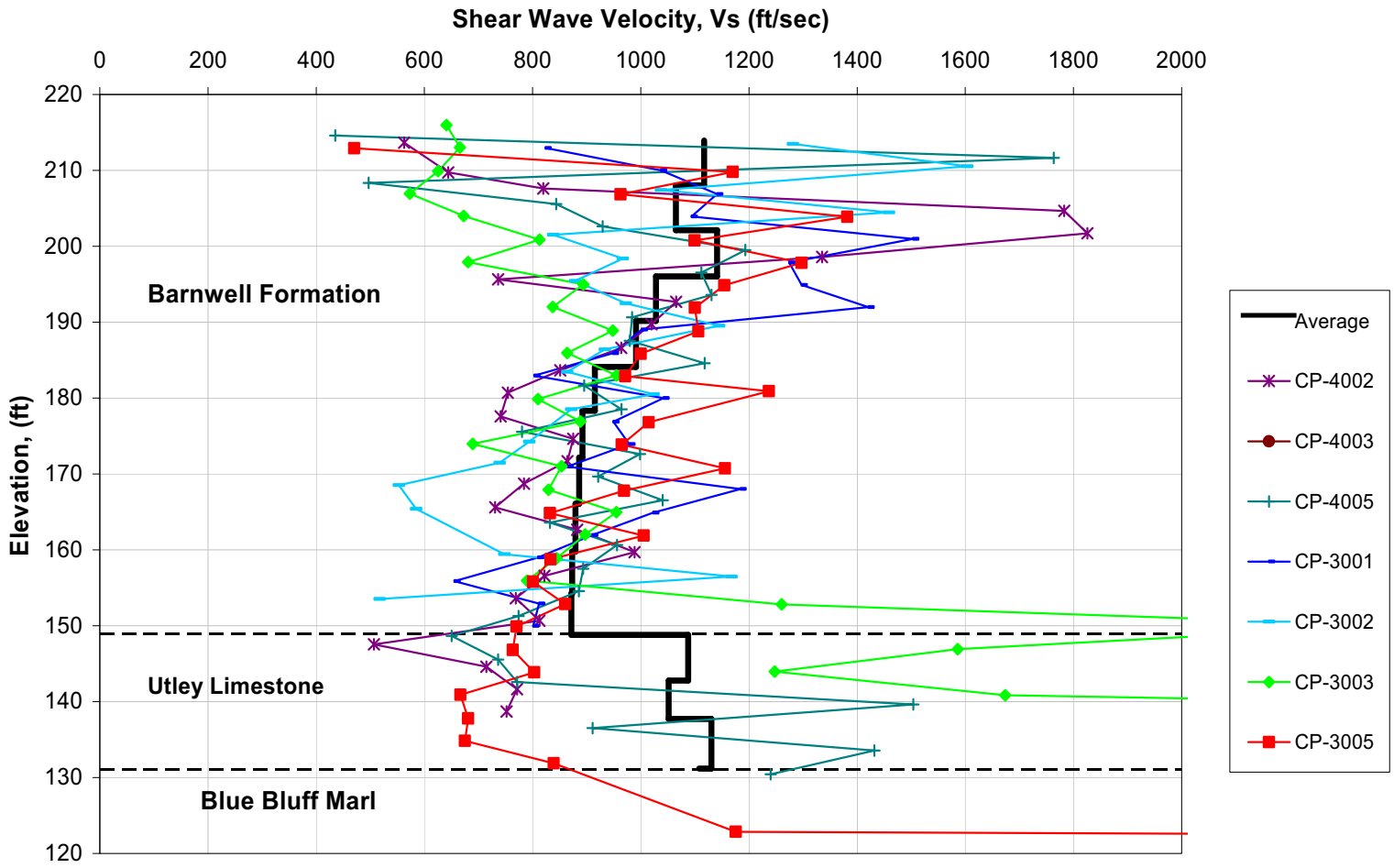


Figure 2.5-377
Shear Wave Velocity Measurements in the Upper Sand Stratum as Measured by COL SCPT

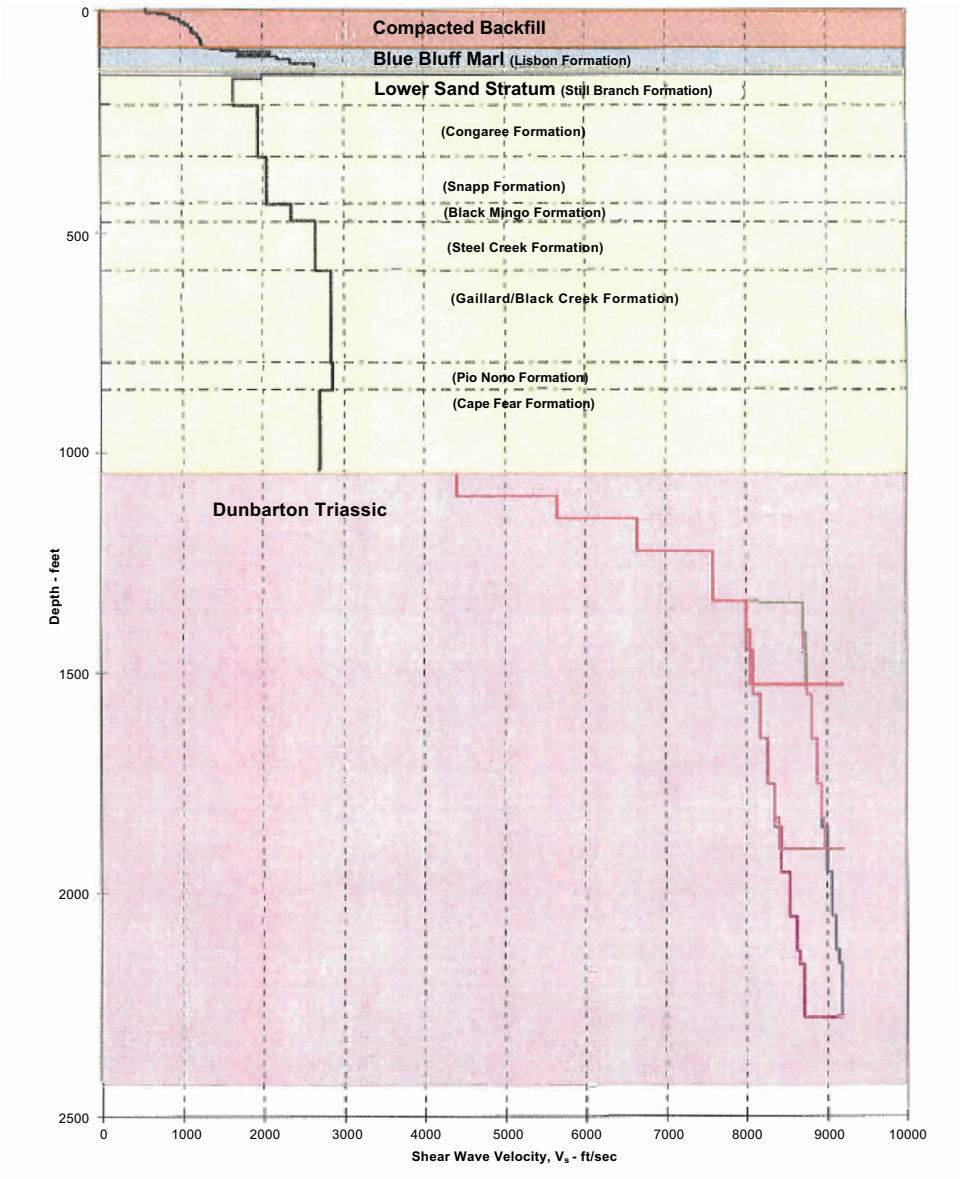


Figure 2.5-378
Shear Wave Velocity Profile for SHAKE Analysis

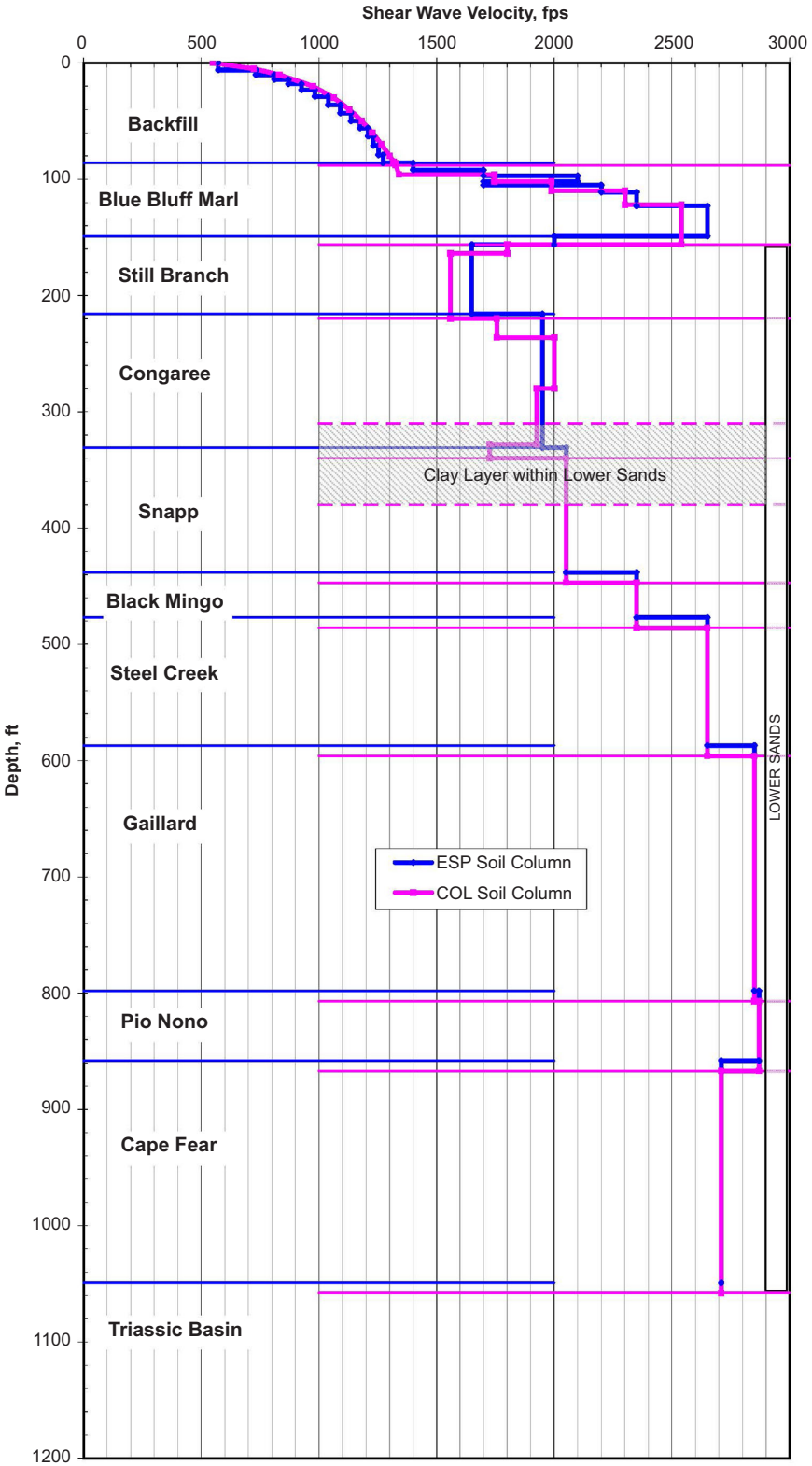


Figure 2.5-379
Shear Wave Velocity Profile — ESP and COL Soil Columns

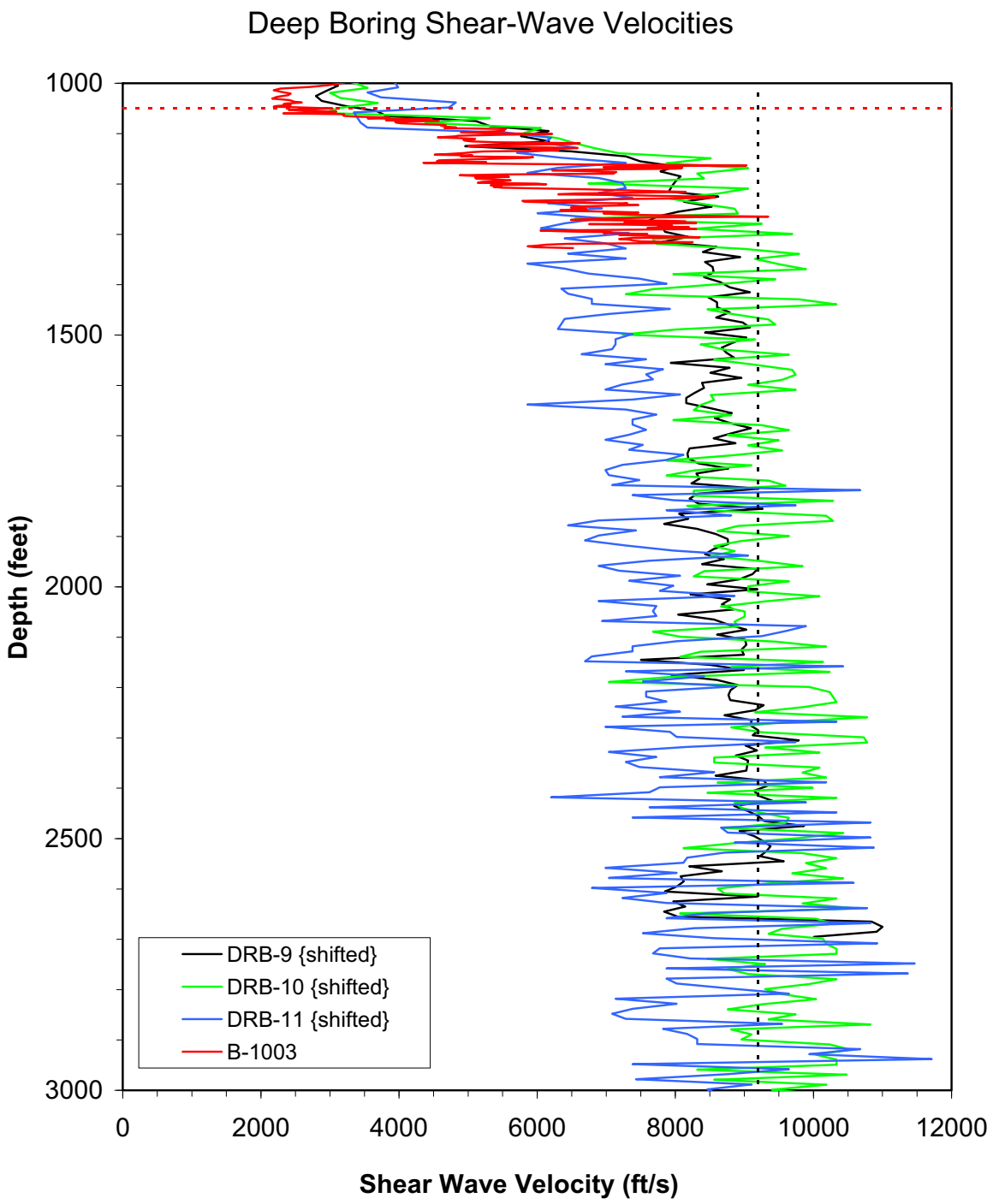


Figure 2.5-380
Rock shear-wave velocities for three SRS sites [DRB] (SRS 2005) and B-1003 [Figure 2.5.4-6]. The DRB data has been shifted in depth so that the depth to top of rock is consistent with B-1003.

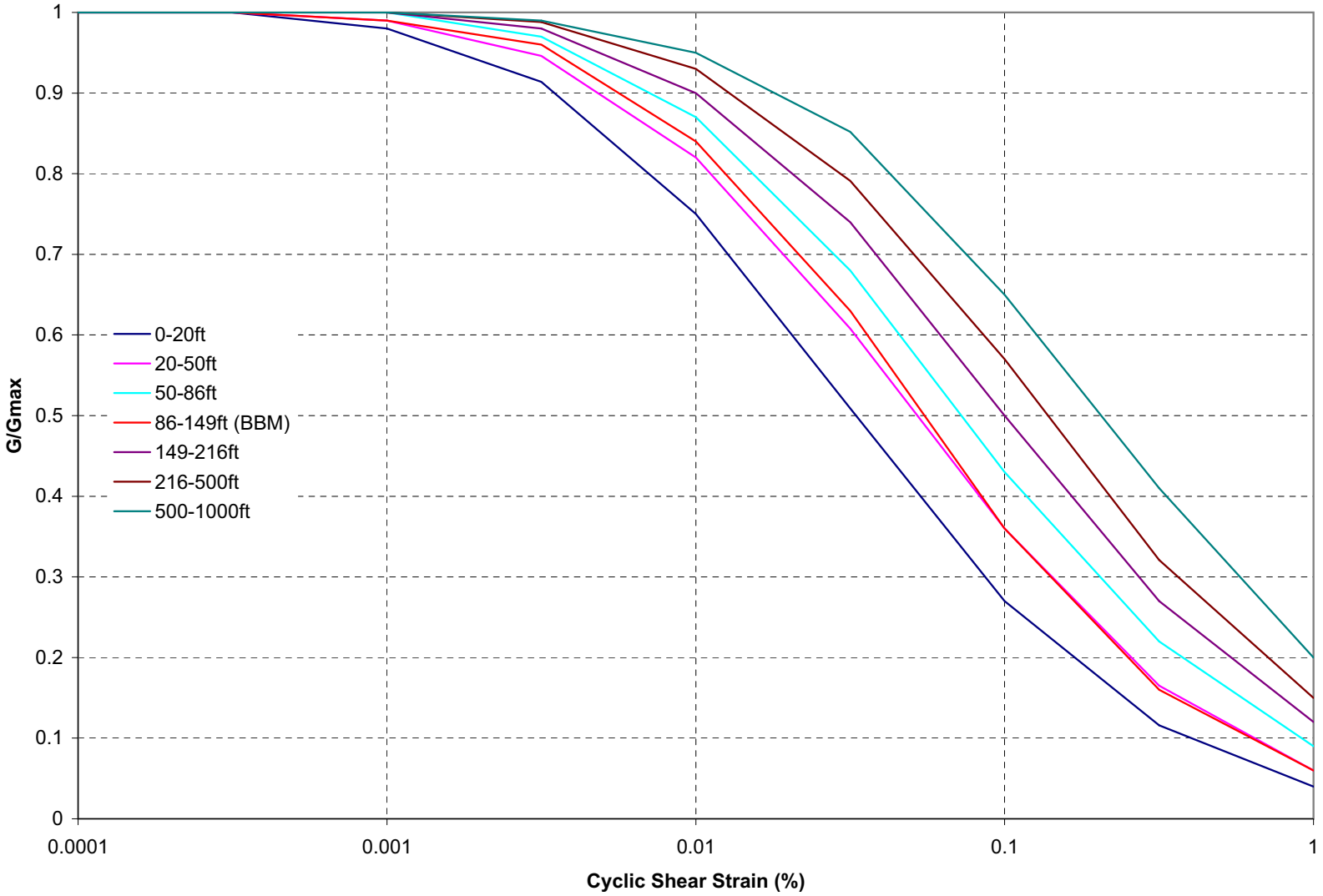


Figure 2.5-381
Shear Modulus Reduction Curves for SHAKE Analysis – EPRI Curves

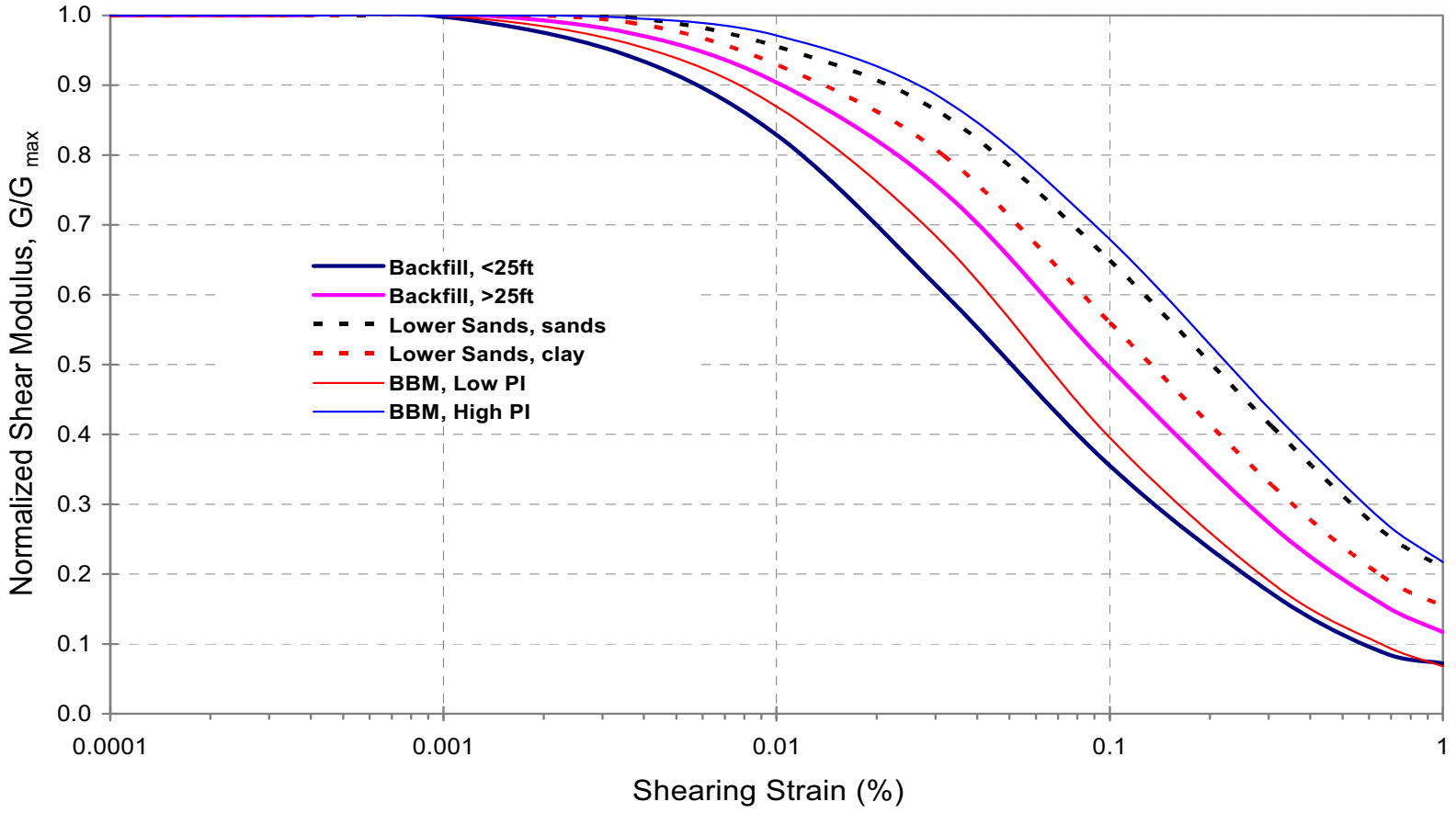


Figure 2.5-382
Site-Specific Shear Modulus Reduction Curves

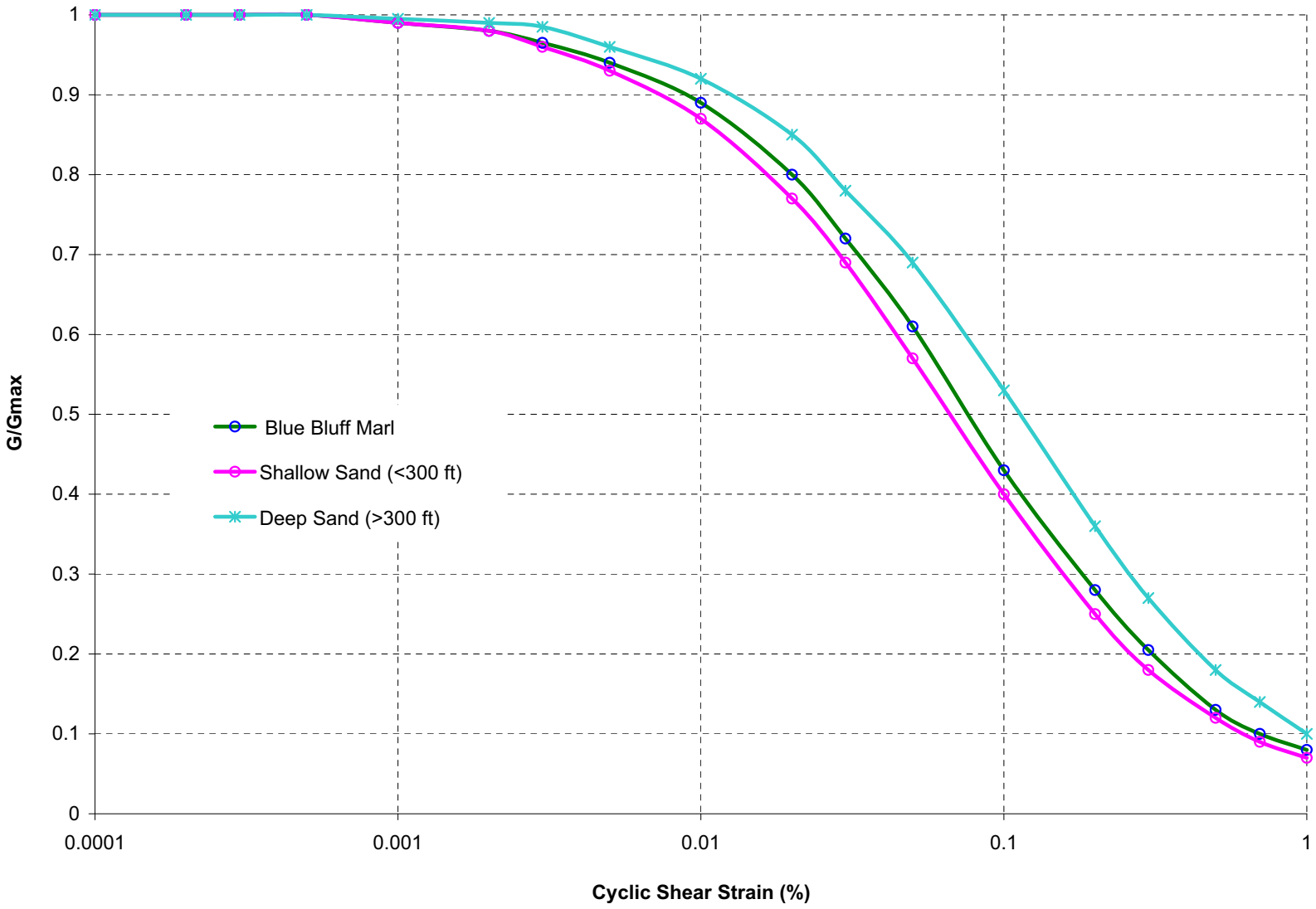


Figure 2.5-383
Shear Modulus Reduction Curves for SHAKE Analysis – SRS Curves

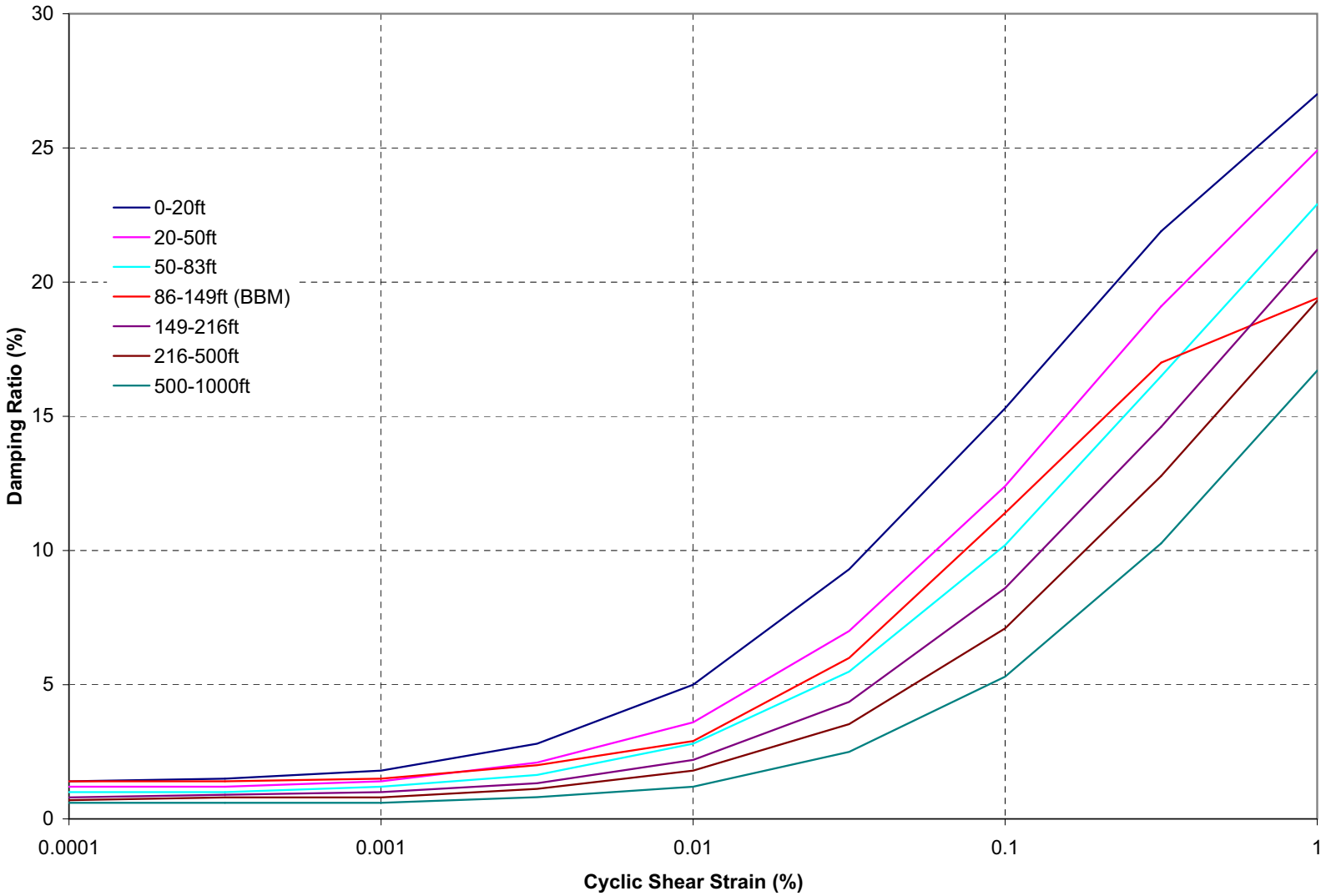


Figure 2.5-384
Damping Ratio Curves for SHAKE Analysis – EPRI Curves

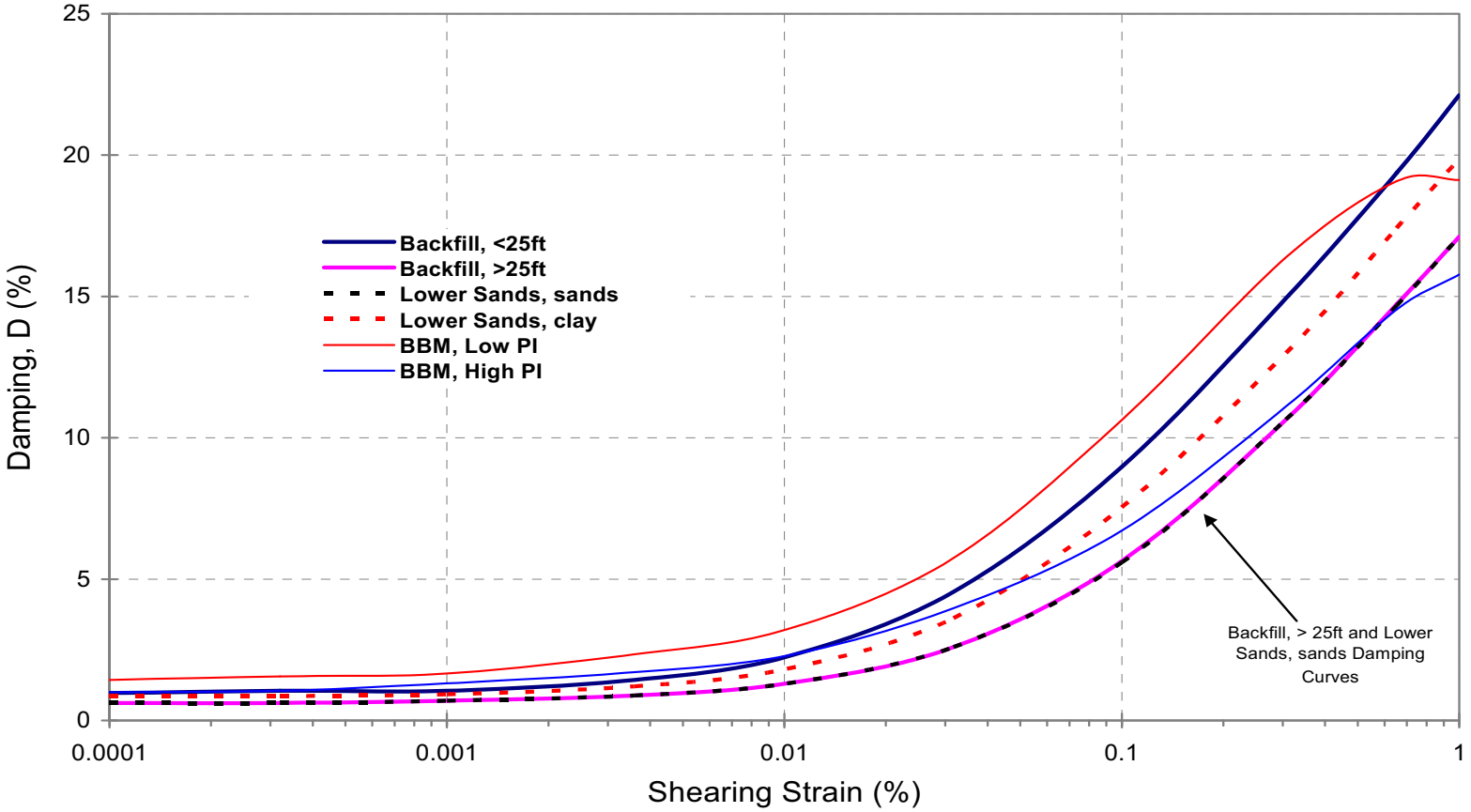


Figure 2.5-385
Site-Specific Damping Ratio Curves

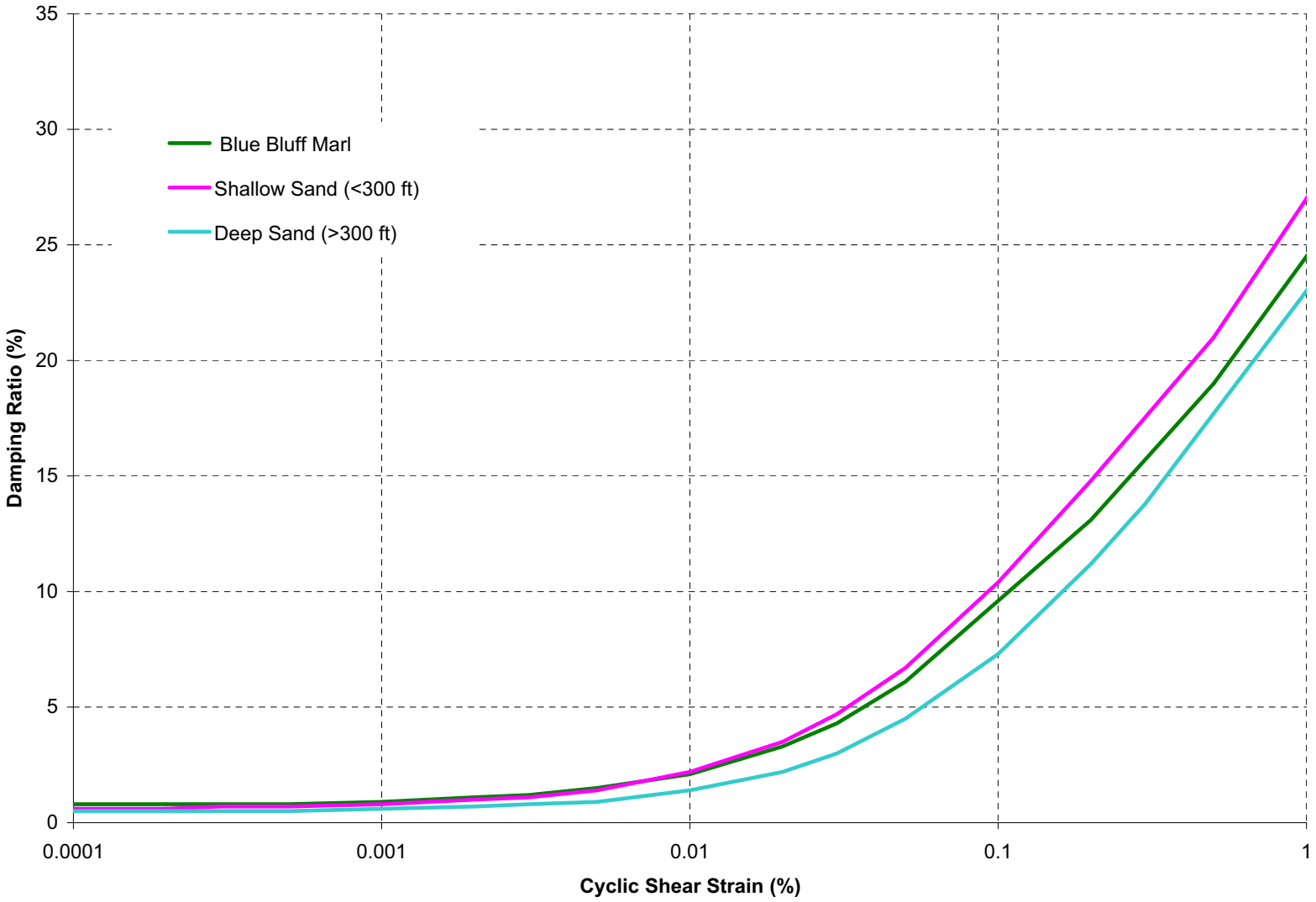


Figure 2.5-386
Damping Ratio Curves for SHAKE Analysis – SRS Curves

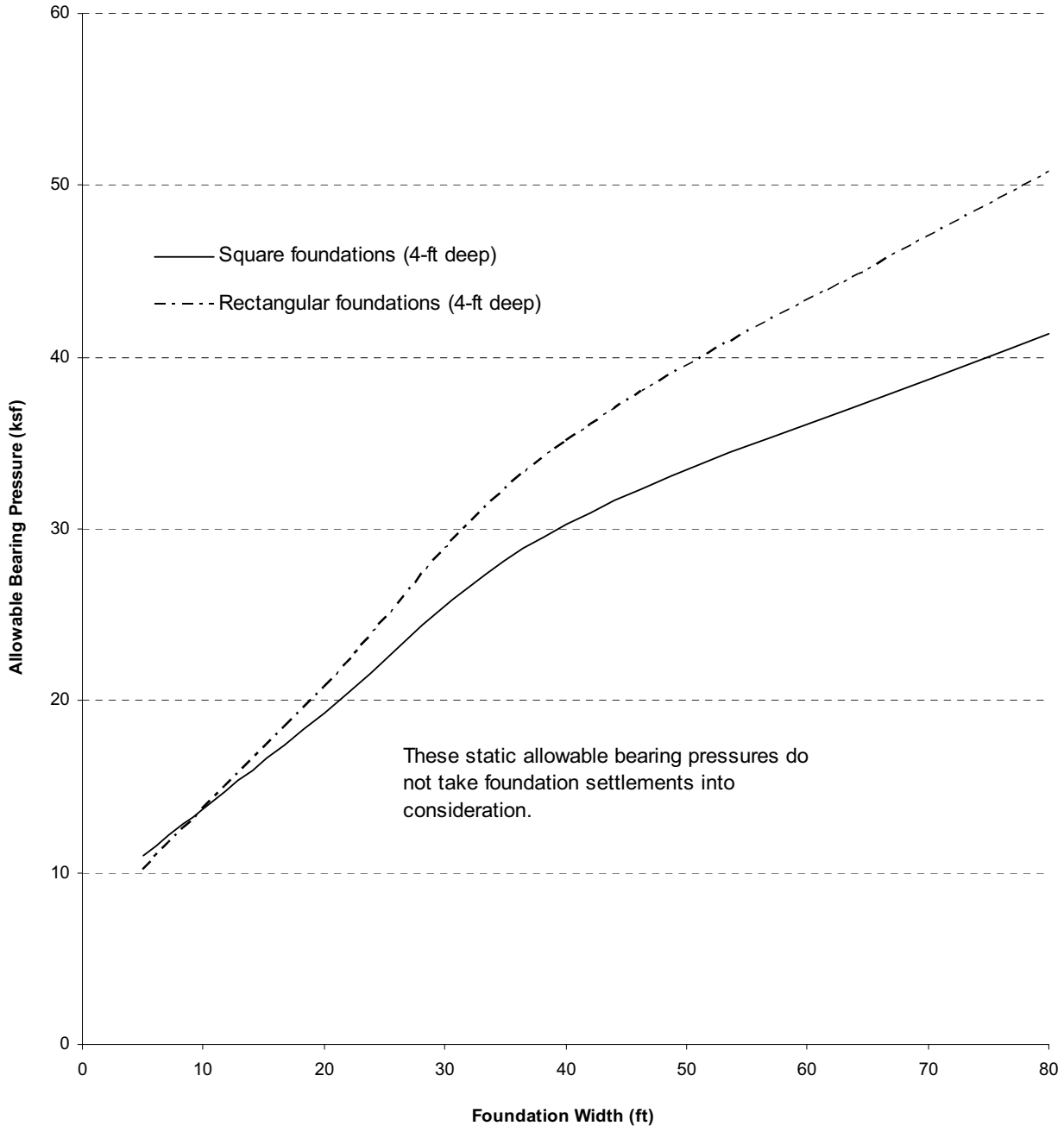


Figure 2.5-387
Allowable Bearing Capacity of Typical Foundation

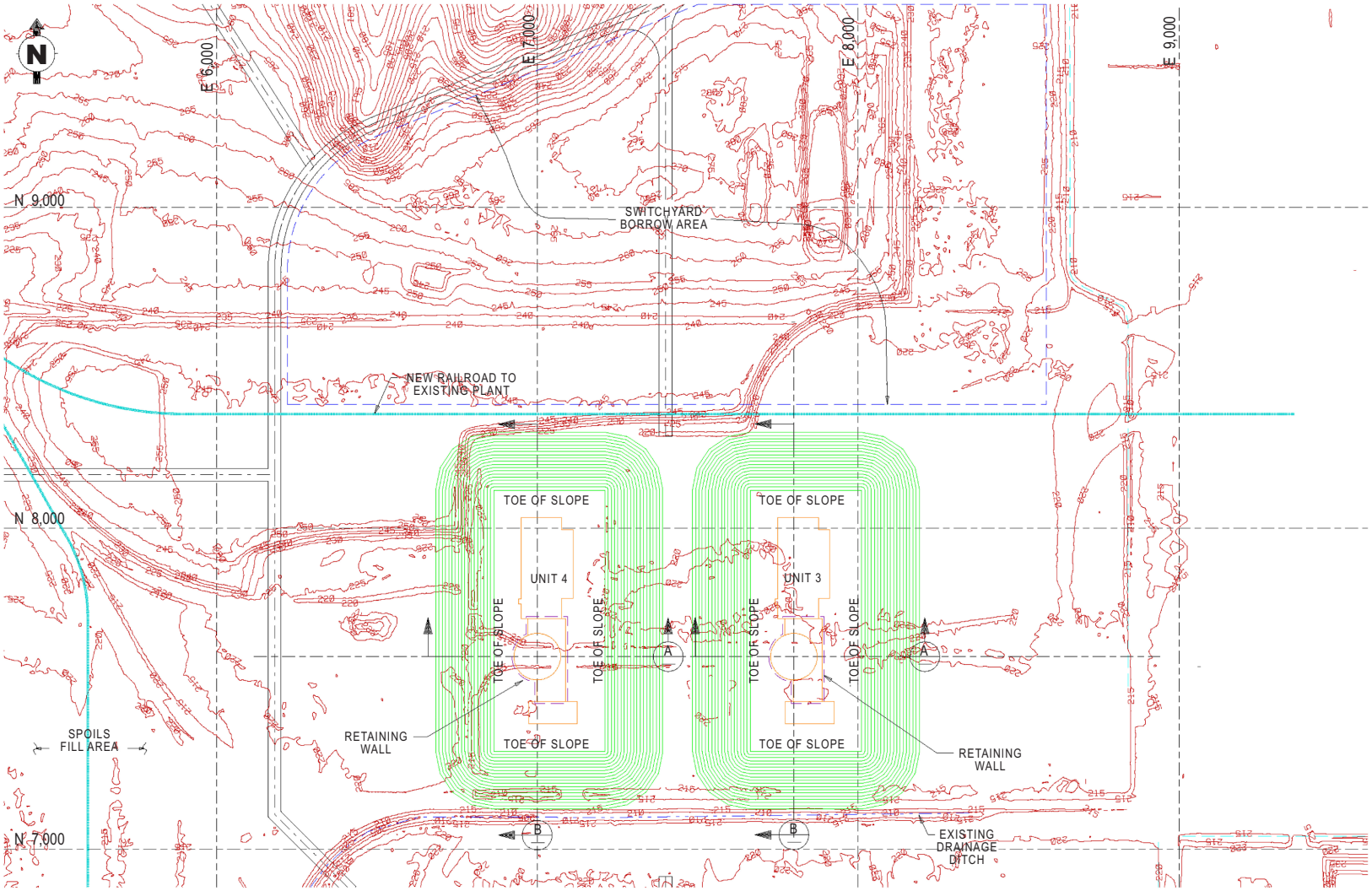


Figure 2.5-388
Power Block Excavation and Switchyard Borrow Area

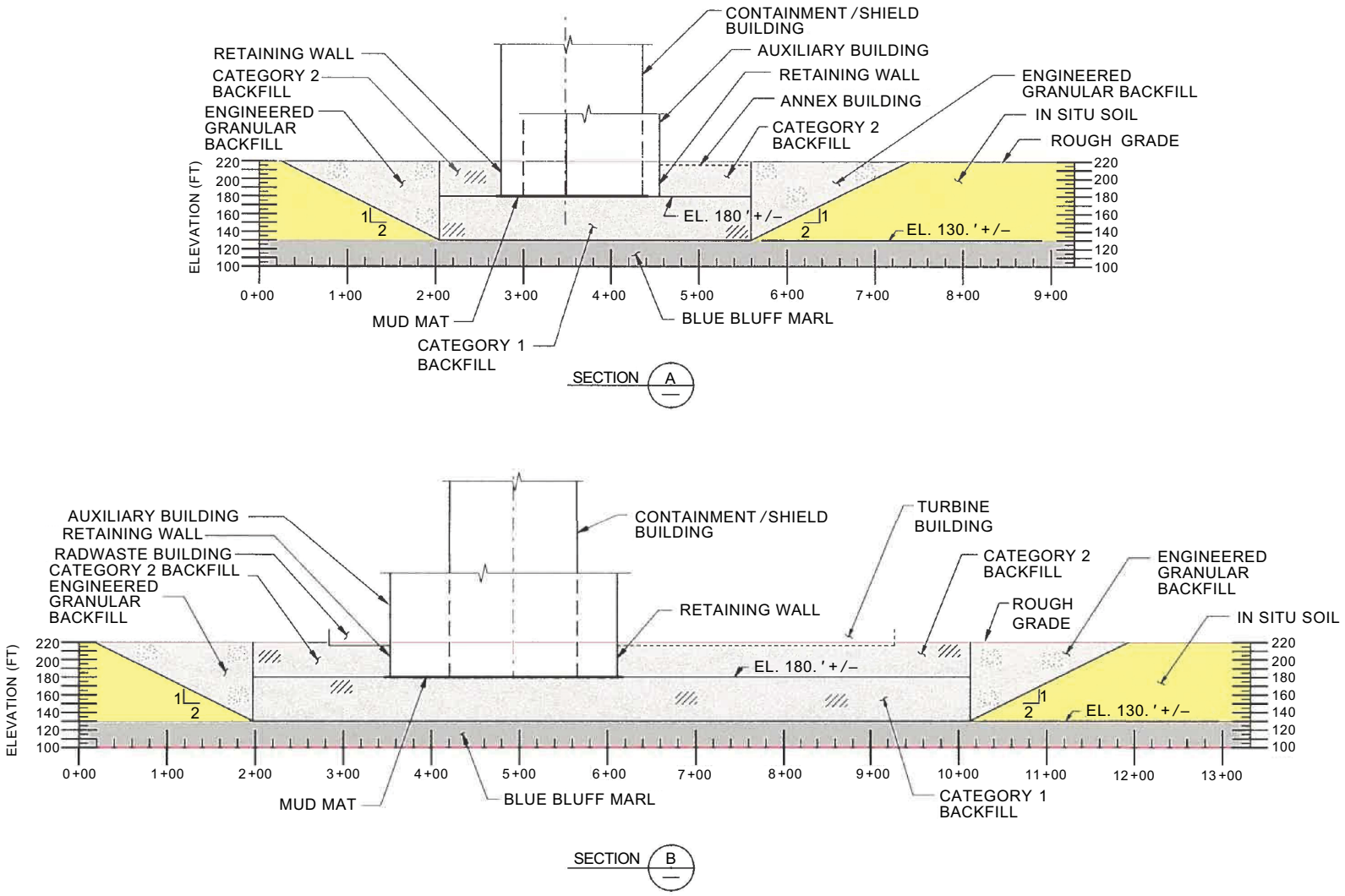


Figure 2.5-389
Power Block Excavation Sections

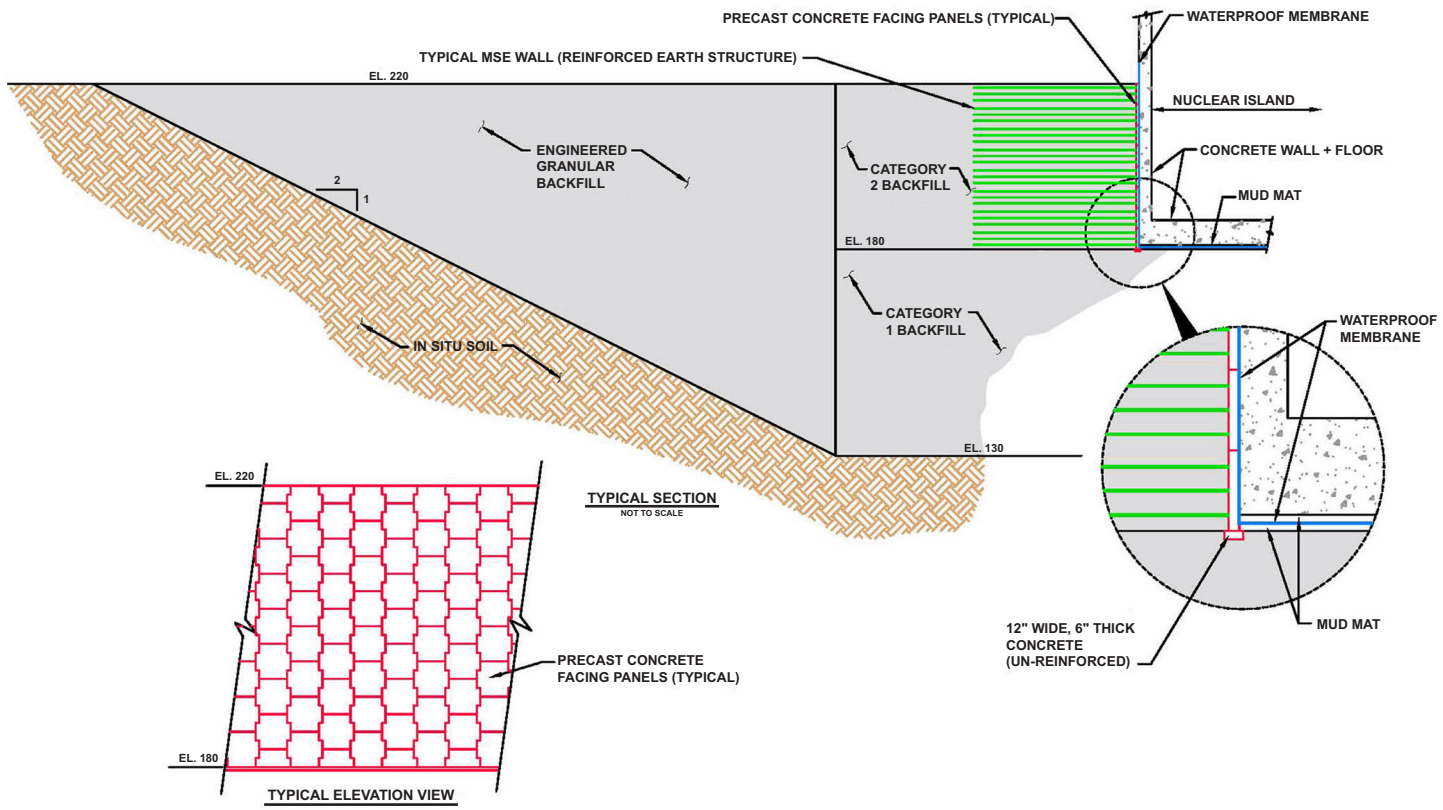


Figure 2.5-390
Nuclear Island Temporary Retaining Wall

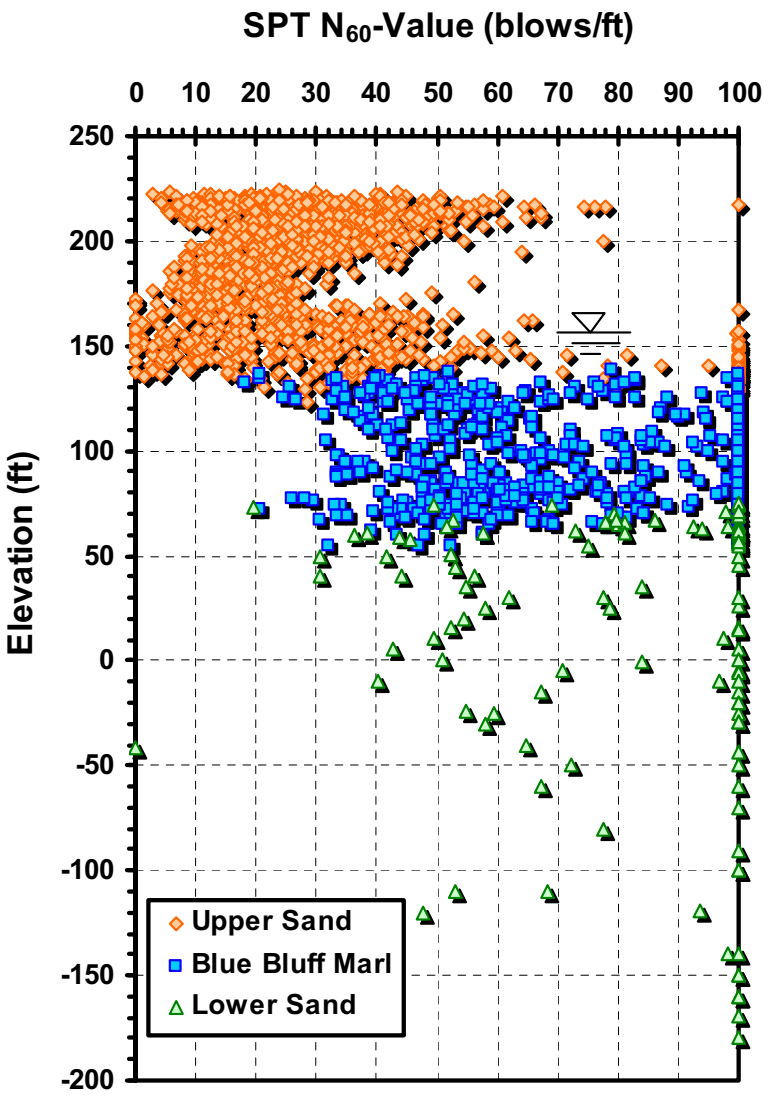


Figure 2.5-391
Distribution of SPT N60–Value with Elevation (COL)

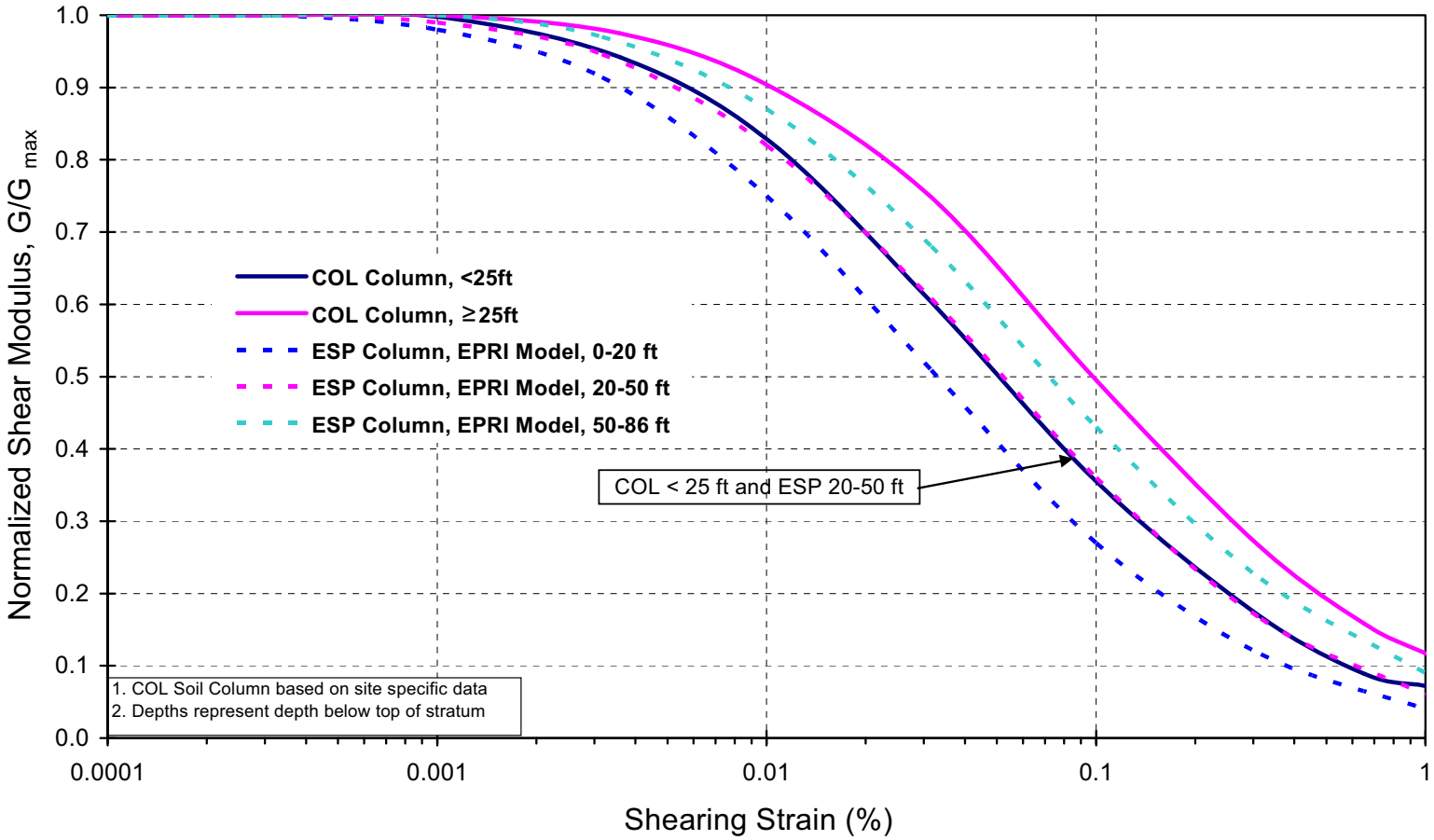


Figure 2.5-392
Comparison of Shear Modulus Reduction Curves - Backfill Soils

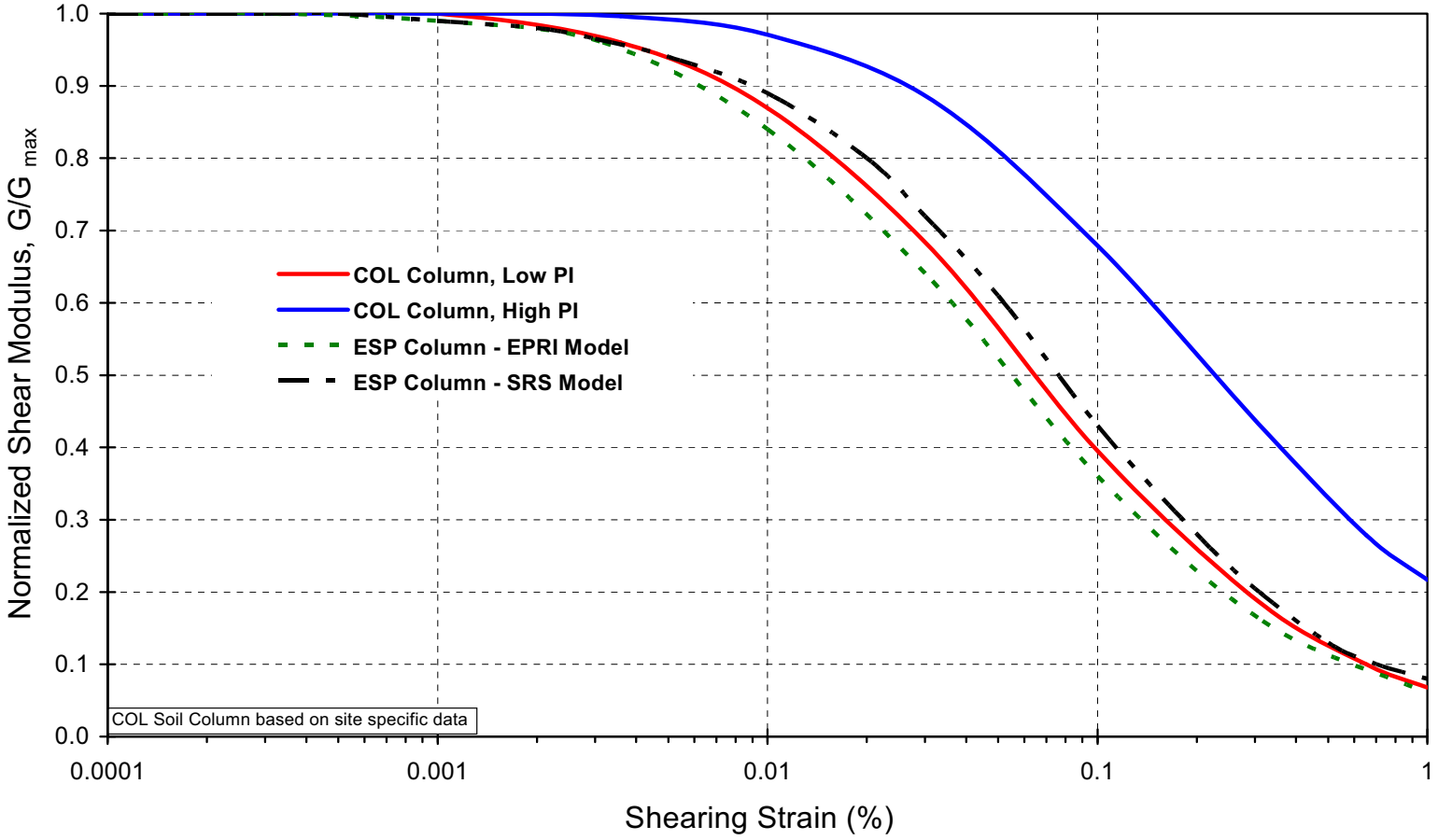


Figure 2.5-393
Comparison of Shear Modulus Reduction Curves - Blue Bluff Marl

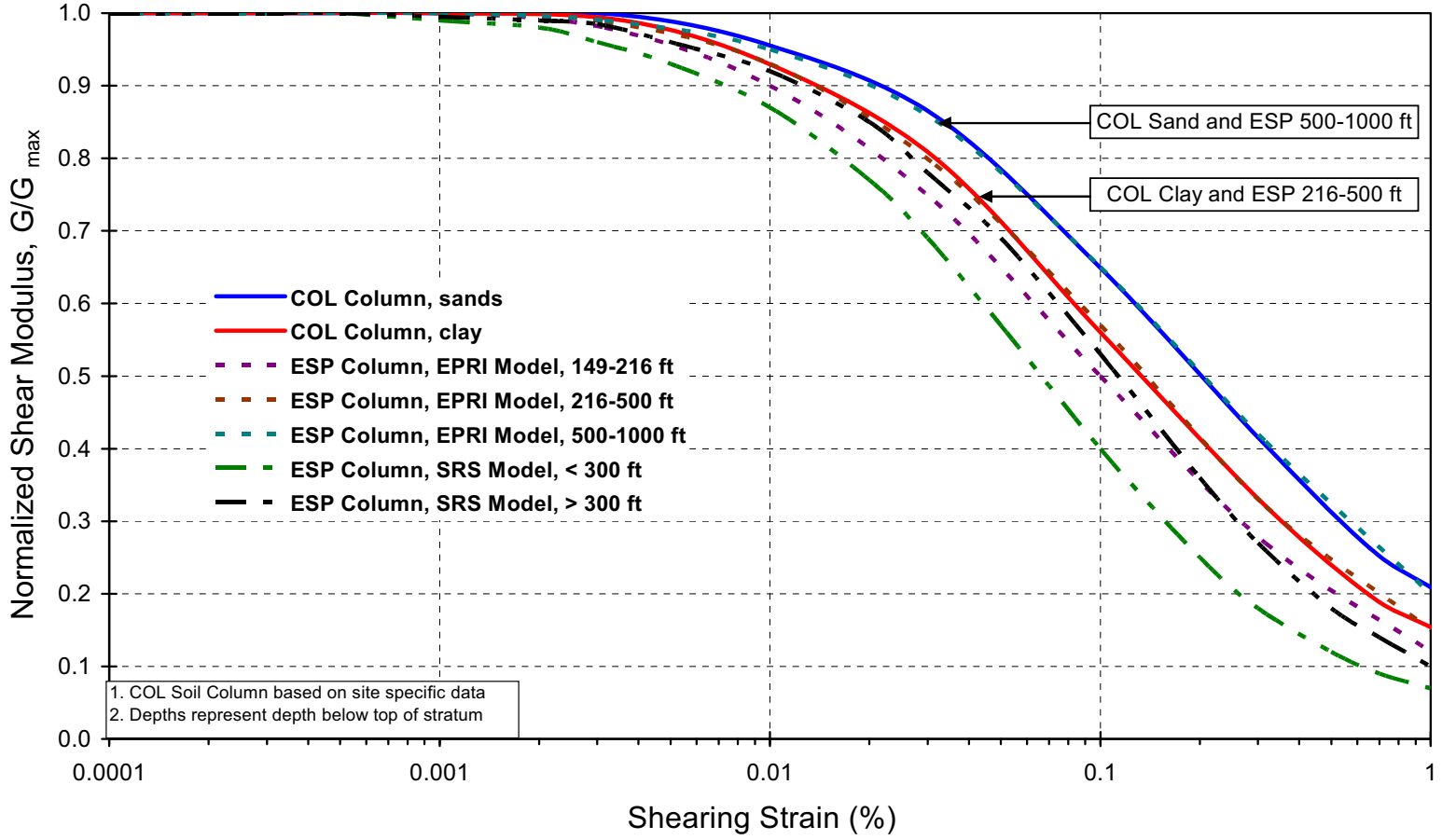


Figure 2.5-394
Comparison of Shear Modulus Reduction Curves - Lower Sands

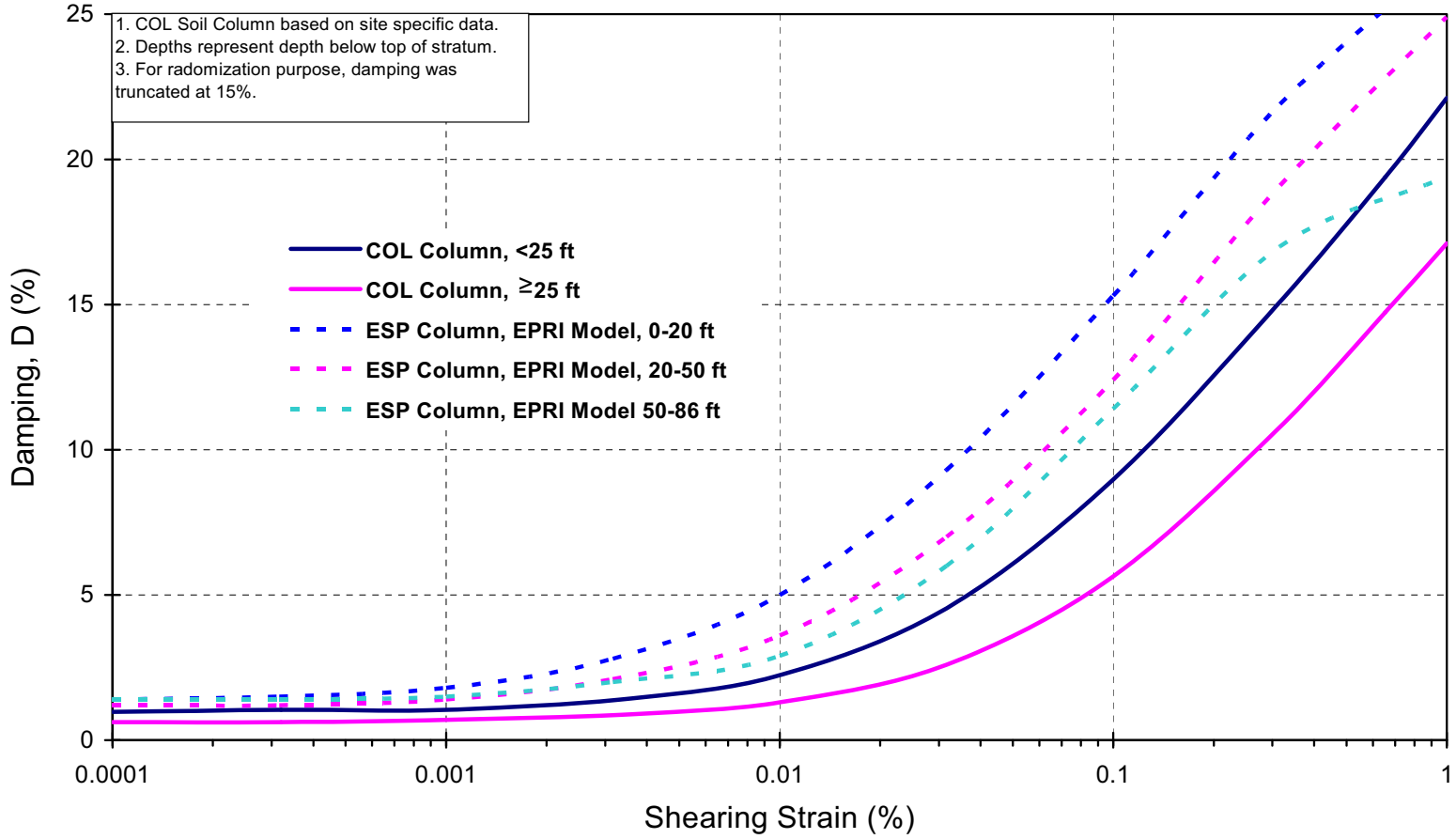


Figure 2.5-395
Comparison of Damping Ratio Curves - Backfill Soils

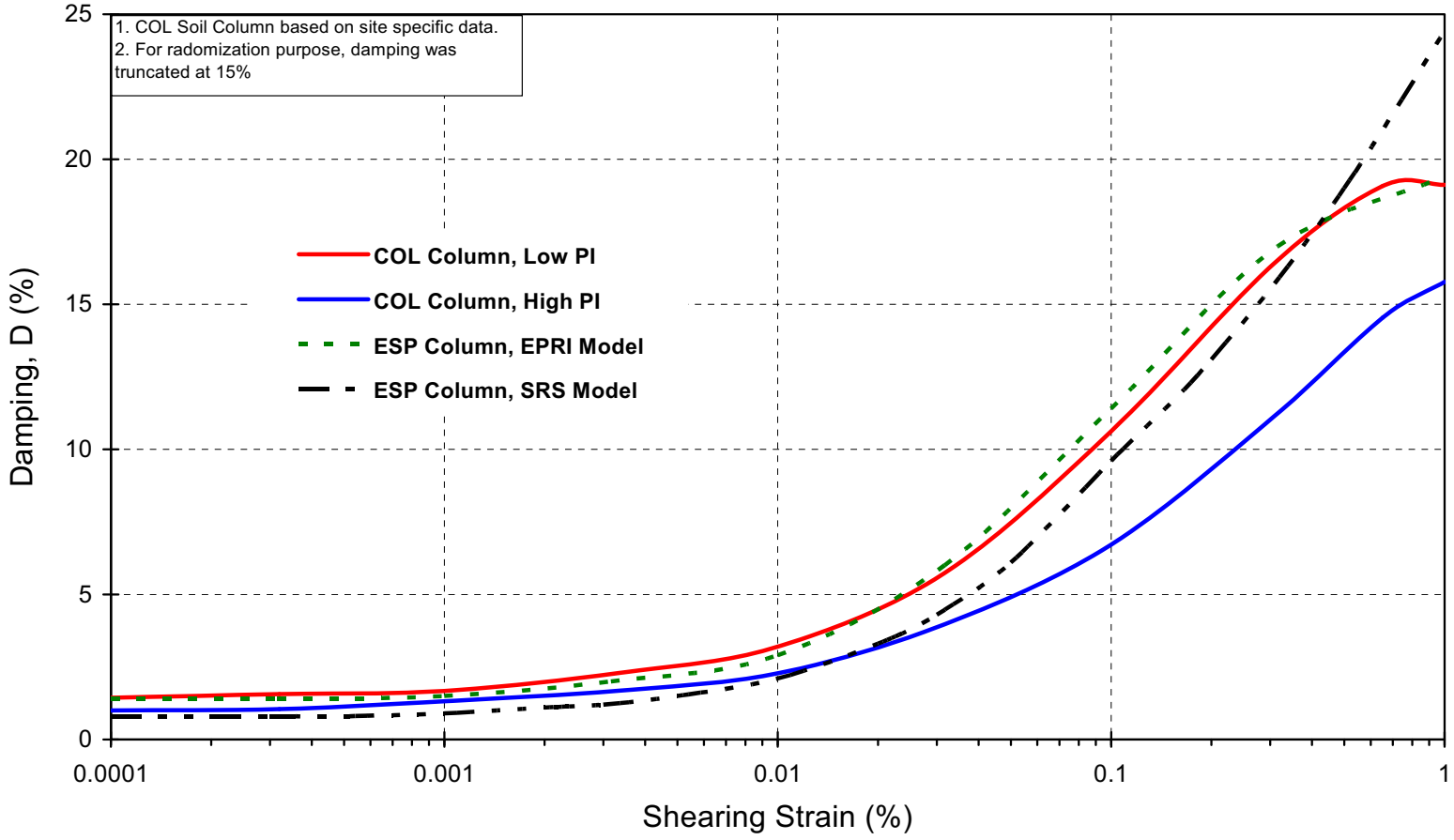


Figure 2.5-396
Comparison of Damping Ratio Curves - Blue Bluff Marl

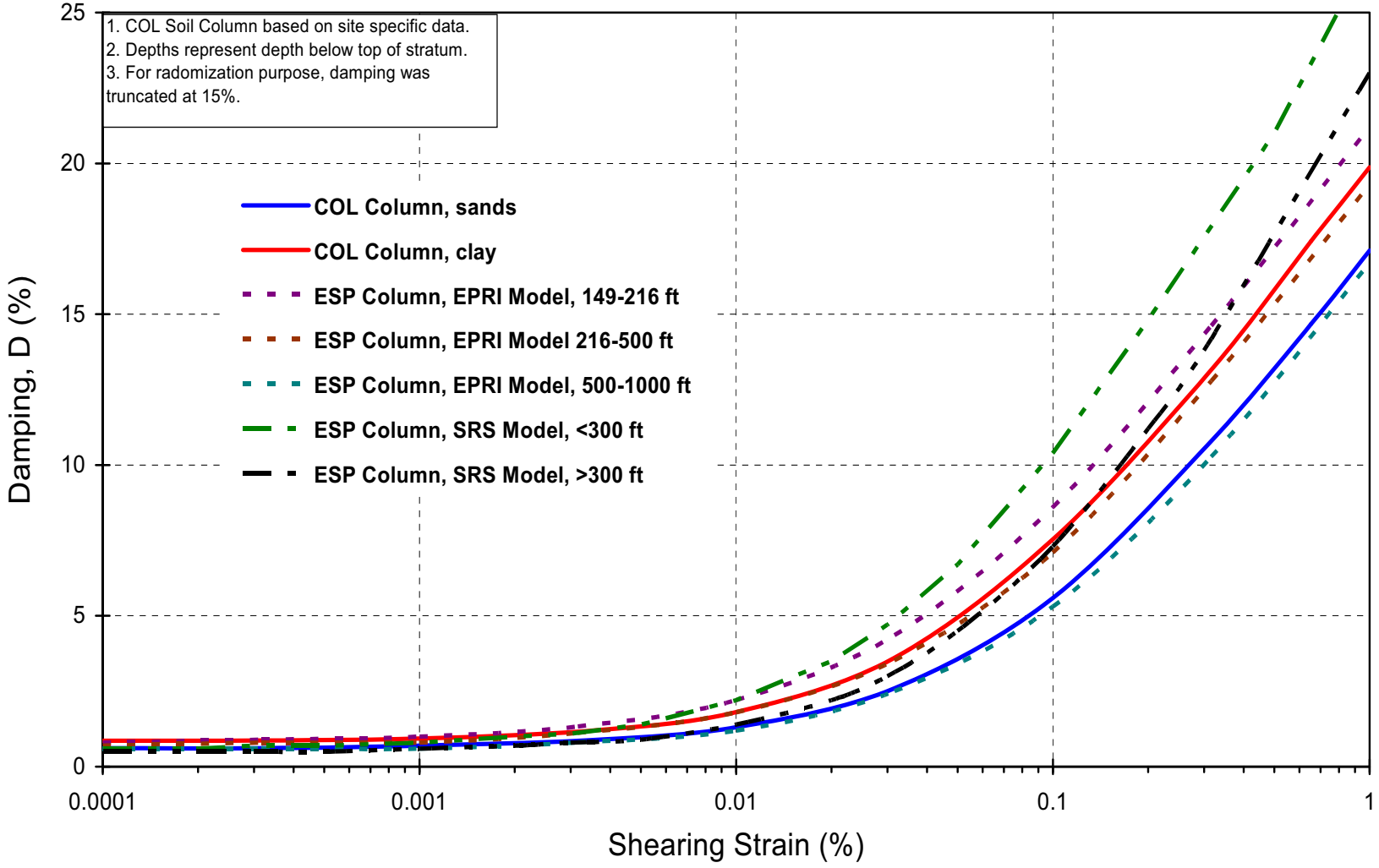


Figure 2.5-397
Comparison of Damping Ratio Curves - Lower Sands

Appendix 2.5A—Geotechnical Investigation and Laboratory Testing Data Report – ESP

(Excludes contents of report; cover page only)

Prepared by
MACTEC Engineering and Consulting, Inc.

November 16, 2007

Appendix 2.5B—High Resolution Compressional Seismic Survey Field Report

(Excluding Report and all Appendices; Cover Page Only)

Prepared by
Bay Geophysical, Inc.

February 8, 2006

Appendix 2.5C—Geotechnical Investigation and Laboratory Testing Data Report – COL

(Excludes Report; Cover Page Only)

Prepared by
MACTEC Engineering and Consulting, Inc.

November 16, 2007

Appendix 2.5D—Engineered Fill Below Grade Test Pad, Phase 1

(Excludes Report; Cover Page Only)

Prepared by
MACTEC Engineering and Consulting, Inc.

March 14, 2008

Appendix 2.5E—AP1000 Vogtle Site Specific Seismic Evaluation Report

Prepared by
Westinghouse Electric Company LLC

October 2008

SV0-1000-S2R-802
Revision 4

October 2008

AP1000
Vogtle Site Specific Seismic Evaluation Report

Westinghouse Electric Company LLC
Nuclear Power Plants
Post Office Box 355
Pittsburgh, PA 15230-0355

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Record of Revisions

Rev	Date	Revision Description[1]
0	See EDMS	Original Issue
1	3/20/08	Comments addressed from Southern Company, Bechtel, and Shaw.
2	3/24/08	Changed note on Figure 3-3 from "Note: DRS = GMRS" to "Note: DRS = FIRS".
3	8/12/08	Revised section 2.0, 3.0, 6.0, 7.0, Table 5.1-2 and Figure 5.1-1 to 5.1-36. Add Section 5.3 and Appendix A.
4	10/29/08	Added reference to DCD Rev. 15, replaced Reference 2, revised Figures 5.2-1 and 5.2-2

Note (1) Significant changes are briefly described in this table. In the rest of the report, each row that has changed is marked using a revision bar in the margin of the page. This approach satisfies the change identification requirements in WP 4.5 Section 7.4.

Table of Contents

1.0 INTRODUCTION 7
1.1 ACRONYMS 7
2.0 VOGTLE SITE CHARACTERISTICS 8
3.0 VOGTLE SITE SEISMIC INPUT 9
4.0 SEISMIC MODELS 18
4.1 2D MODELS 19
4.2 ADJACENT BUILDINGS (ANNEX, TURBINE, AND RADWASTE BUILDINGS) 22
5.0 SOIL CASES AND SSI ANALYSES 23
5.1 2D SASSI ANALYSES AND PARAMETER STUDIES 26
5.2 ADJACENT BUILDING SEISMIC DEMAND 64
5.3 SENSITIVITY STUDY OF BACKFILL BEHIND MSE WALL 66
6.0 STABILITY ANALYSES 76
6.1 SEISMIC STABILITY FORMULAS 77
6.2 VOGTLE SITE-SPECIFIC STABILITY EVALUATION 78
7.0 FOUNDATION BEARING PRESSURES 81
8.0 SETTLEMENT OF FOUNDATIONS 81
9.0 SETTLEMENT MONITORING PROGRAM 82
10.0 REFERENCES 84
APPENDIX A: VOGTLE 2D BATHTUB MODEL AND AP 2D MODEL COMPARISON 85

List of Tables

Table 4.0-1 – Seismic Reactions at the Bottom of the Basemat (Elevation 60.5')....19
Table 5.1-1 – Critical Nodes Selected 27
Table 5.1-2 – Sloshing Frequencies 27
Table 5.2-1 – Turbine and Radwaste Base Seismic Accelerations 64
Table 6-1 – Stability Factors of Safety for Non-Seismic Loading for AP1000 NI 77
Table 6.2-1 –Comparison of Seismic Stability Factors of Safety - ESP....79
Table 6.2-2 –Comparison of Seismic Stability Factors of Safety - SEN....79
Table 6.2-3 –Comparison of Seismic Stability Factors of Safety – ESP 79
Table 6.2-4 –Comparison of Seismic Stability Factors of Safety – SEN....80
Table 7-1 – Vogtle Specific Maximum Pressures Under Basemat (ksf) 81
Table 8-1 – The maximum settlements for the Vogtle site....82

List of Figures

Figure 3-1 – AP1000 Horizontal Design Response Spectra for Safe Shutdown Earthquake....11
Figure 3-2 – AP1000 Vertical Design Response Spectra Safe Shutdown Earthquake 12
Figure 3-3 - Acceleration Response Spectra – Input Outcrop Motion at 40 ft Depth....13
Figure 3-4 – Comparison of AP1000 Horizontal CSDRS to Vogtle 40' Outcrop FIRS and GMRS 14
Figure 3-5 – Comparison of AP1000 Vertical CSDRS to Vogtle 40' Outcrop FIRS and GMRS 14
Figure 3-6 - Acceleration Response Spectra – Horizontal H1 Motions at Ground Surface 15
Figure 3-7 - Acceleration Response Spectra – Horizontal H2 Motions at Ground Surface 16
Figure 3-8 - Acceleration Response Spectra – Vertical Motions at Ground Surface 17
Figure 4.1-1 – 2D Soil Structure Interaction Model....20
Figure 4.1-2 – ESP Shear Wave Velocity Profiles for 2D Site Soil Layers 21
Figure 4.2-1 – Turbine and Radwaste Adjacent Buildings....22
Figure 4.2-2 – Annex Adjacent Building....23
Figure 5.0-1 – Shear Wave Velocities for the ESP and SEN Soil Cases....24
Figure 5.0-2 – FIRS and GMRS Locations in Vogtle Site Specific SASSI AP1000 NI Analyses ...25
Figure 5.1-1 - Comparison of Node 4041 ESP Response to AP1000 SSI Envelope, NS Dir. 28
Figure 5.1-2 - Comparison of Node 4041 ESP Response to AP1000 SSI Envelope, EW Dir. 29
Figure 5.1-3 - Comparison of Node 4041 ESP to AP1000 SSI Envelope, Vertical Dir. 30
Figure 5.1-4 - Comparison of Node 4061 ESP to AP1000 SSI Envelope, NS Dir. 31
Figure 5.1-5 - Comparison of Node 4061 ESP to AP1000 SSI Envelope, EW Dir 32
Figure 5.1-6 - Comparison of Node 4061 ESP to AP1000 SSI Envelope, Vertical Dir 33
Figure 5.1-7 - Comparison of Node 4120 ESP to AP1000 SSI Envelope, NS Dir 34
Figure 5.1-8 - Comparison of Node 4120 ESP to AP1000 SSI Envelope, EW Dir 35
Figure 5.1-9 - Comparison of Node 4120 ESP to AP1000 SSI Envelope, Vertical Dir 36
Figure 5.1-10 - Comparison of Node 4310 ESP to AP1000 SSI Envelope, NS Dir 37
Figure 5.1-11 - Comparison of Node 4310 ESP to AP1000 SSI Envelope, EW Dir 38
Figure 5.1-12 - Comparison of Node 4310 ESP to AP1000 SSI Envelope, Vertical Dir 39
Figure 5.1-13 - Comparison of Node 4412 ESP to AP1000 SSI Envelope, NS Dir 40
Figure 5.1-14 - Comparison of Node 4412 ESP to AP1000 SSI Envelope, EW Dir 41
Figure 5.1-15 - Comparison of Node 4412 ESP to AP1000 SSI Envelope, Vertical Dir 42
Figure 5.1-16 - Comparison of Node 4535 ESP to AP1000 SSI Envelope, NS Dir 43
Figure 5.1-17 - Comparison of Node 4535 ESP to AP1000 SSI Envelope, EW Dir 44
Figure 5.1-18 - Comparison of Node 4535 ESP to AP1000 SSI Envelope, Vertical Dir 45
Figure 5.1-19 - Comparison of Node 4041 SEN to AP1000 SSI Envelope, NS Dir....46
Figure 5.1-20 - Comparison of Node 4041 SEN to AP1000 SSI Envelope, EW Dir 47

Figure 5.1-21 - Comparison of Node 4041 SEN to AP1000 SSI Envelope, Vertical Dir 48
Figure 5.1-22 - Comparison of Node 4061 SEN to AP1000 SSI Envelope, NS Dir 49
Figure 5.1-23 - Comparison of Node 4061 SEN to AP1000 SSI Envelope, EW Dir 50
Figure 5.1-24 - Comparison of Node 4061 SEN to AP1000 SSI Envelope, Vertical Dir 51
Figure 5.1-25 - Comparison of Node 4120 SEN to AP1000 SSI Envelope, NS Dir 52
Figure 5.1-26 - Comparison of Node 4120 SEN to AP1000 SSI Envelope, EW Dir 53
Figure 5.1-27 - Comparison of Node 4120 SEN to AP1000 SSI Envelope, Vertical Dir 54
Figure 5.1-28 - Comparison of Node 4310 SEN to AP1000 SSI Envelope, NS Dir 55
Figure 5.1-29 - Comparison of Node 4310 SEN to AP1000 SSI Envelope, EW Dir 56
Figure 5.1-30 - Comparison of Node 4310 SEN to AP1000 SSI Envelope, Vertical Dir 57
Figure 5.1-31 - Comparison of Node 4412 SEN to AP1000 SSI Envelope, NS Dir 58
Figure 5.1-32 - Comparison of Node 4412 SEN to AP1000 SSI Envelope, EW Dir 59
Figure 5.1-33 - Comparison of Node 4412 SEN to AP1000 SSI Envelope, Vertical Dir 60
Figure 5.1-34 - Comparison of Node 4535 SEN to AP1000 SSI Envelope, NS Dir 61
Figure 5.1-35 - Comparison of Node 4535 SEN to AP1000 SSI Envelope, EW Dir 62
Figure 5.1-36 - Comparison of Node 4535 SEN to AP1000 SSI Envelope, Vertical Dir 63
Figure 5.2-1 - Horizontal Seismic Response Spectra at Base of Annex Building 65
Figure 5.2-2 – Vertical Seismic Response Spectra at Base of Annex Building 65
Figure 5.3-1 –2D SASSI Model with MSE Wall 66
Figure 5.3-2 – FRS Comparison at Node 4041 (X Direction).....67
Figure 5.3-3 – FRS Comparison at Node 4041 (Y Direction).....67
Figure 5.3-4 – FRS Comparison at Node 4041 (Z Direction).....68
Figure 5.3-5 – FRS Comparison at Node 4061 (X Direction).....68
Figure 5.3-6 – FRS Comparison at Node 4061 (Y Direction).....69
Figure 5.3-7 – FRS Comparison at Node 4061 (Z Direction).....69
Figure 5.3-8 – FRS Comparison at Node 4120 (X Direction).....70
Figure 5.3-9 – FRS Comparison at Node 4120 (Y Direction).....70
Figure 5.3-10 – FRS Comparison at Node 4120 (Z Direction).....71
Figure 5.3-11 – FRS Comparison at Node 4310 (X Direction) 71
Figure 5.3-12 – FRS Comparison at Node 4310 (Y Direction) 72
Figure 5.3-13 – FRS Comparison at Node 4310 (Z Direction).....72
Figure 5.3-14 – FRS Comparison at Node 4412 (X Direction) 73
Figure 5.3-15 – FRS Comparison at Node 4412 (Y Direction) 73
Figure 5.3-16 – FRS Comparison at Node 4412 (Z Direction).....74
Figure 5.3-17 – FRS Comparison at Node 4535 (X Direction) 74
Figure 5.3-18 – FRS Comparison at Node 4535 (Y Direction) 75
Figure 5.3-19 – FRS Comparison at Node 4535 (Z Direction).....75
Figure 6.2-1 – Sliding Factor of Safety versus Passive Pressure 80
Figure 9-1 – Proposed Monitoring Points for Vogtle 83

1.0 Introduction

This report describes the site-specific analyses that have been performed to show the acceptability of the AP1000 plant at the Vogtle site. The site specific seismic analyses were performed to address the following:

- Parametric analyses to identify the importance of the different geotechnical variations at the site that could affect the nuclear island dynamic response and settlement.
- Analyses of nuclear island, turbine building, and annex building (structure to structure interaction) to confirm surface input against design basis of annex building (Seismic Category II).
- Seismic analyses of the AP1000 nuclear island (NI) using Vogtle site specific soil and site specific SSE seismic input to confirm that the AP1000 NI seismic response is less severe than the design basis seismic response.
- Demonstration that the NI site-specific stability factors of safety are within the limits established by the NRC using a sliding friction coefficient of 0.45.
- Provision of dynamic bearing pressure loads.
- Settlement analyses of the nuclear island to show that the differential settlement at Vogtle is less than those used for the AP1000 design and to establish the parameters for the settlement monitoring program to be used during construction.

1.1 Acronyms

ASB = Auxiliary and Shield Building
BE = Best Estimate
CIS = Containment Internal Structures
CSDRS = Certified Seismic Design Response Spectra
DCD = Design Control Document
DRS = Design Response Spectra
EL (El.) = Elevation (unless otherwise noted all EL are generic AP1000 EL where grade is at EL 100')
ESP = Early Site Permit
EW = East West
FIRS = Foundation Input Response Spectra
GMRS = Ground Motion Response Spectra
LB = Lower Bound
NI = Nuclear Island
NS = North South
SEN = Sensitivity
SSI = Soil Structure Interaction
SCV = Steel Containment Vessel
UB = Upper Bound
ZPA = Zero Period Acceleration

2.0 Vogtle Site Characteristics

The Vogtle GMRS, geotechnical conditions, and ground material have differences from the design analyses performed for the AP1000 seismic analyses (Reference 2) that site specific analyses must be performed for the Vogtle site. The differences between the Vogtle GMRS and the AP1000 CSDRS, that in part require these site-specific seismic analyses, are presented in section 3.0. The results of the Vogtle ESP soil investigation and the resulting site response calculations are used to determine the AP1000 Nuclear Island site-specific responses presented in this report unless otherwise noted.

The plant specific evaluations are based on 2D SASSI analyses as discussed in section 4. Comparisons of the site specific response spectra to the AP1000 SSI envelop response spectra at six key locations are provided in section 5. These 2D SASSI site-specific results were used to calculate inertia loads for stability, section 6, and bearing, section 7.

The results of these response spectra comparisons and the resulting stability evaluations and bearing pressures demonstrate that the AP1000 plant designed for the CSDRS is acceptable for the Vogtle site.

The Vogtle Electric Generating Plant (VEGP) site is located near Waynesboro, Georgia in Eastern Burke County. Two units already exist and two more will be added. The results of the ESP site investigations are the baseline for this report. Subsurface materials at the VEGP site were placed into generalized groups, which included:

a. Upper Sand Stratum (Barnwell Group)

- Very loose to very dense sands
- Average thickness of about 90 ft
- Vogtle ground water elevation at 165 ft (55-60 ft below grade)

b. Blue Bluff Marl (Lisbon Formation)

- Very hard, slightly sandy, cemented, calcareous silt/clay
- Average thickness of 76 ft

c. Lower Sand Stratum (coastal plain deposits)

- Dense sands
- Thickness of 900 ft

d. Dunbarton Basin Bedrock

- Triassic sandstone
- 1,049 ft below grade at B-1003

e. Paleozoic Crystalline Rock

- High shear-wave velocity

- The Pen Branch fault is the boundary of the Triassic Basin and Paleozoic basement rocks.

The Upper Sand Stratum was removed before construction of Units 1 and 2 and will be removed for Units 3 and 4 because it has highly variable density along the depth and from borehole to borehole. Also, a porous material was encountered at the bottom of the Barnwell Group/top of Blue Bluff Marl that caused drilling fluid losses.

This soil was removed and replaced with compacted granular fill for the construction of the existing units. The materials above the Blue Bluff Marl in the area of the Units 3 and 4 nuclear islands are assumed for the purposes of these analyses to consist of compacted granular fill as specified in Revision 3 of the ESP SSAR.

3.0 Vogtle Site Seismic Input

The AP1000 Certified Seismic Design Response Spectra (CSDRS) has peak ground accelerations for the safe shutdown earthquake equal to 0.30g for the AP1000 design. The vertical peak ground acceleration is conservatively assumed to equal the horizontal value of 0.30g. These seismic response spectra are shown in Figures 3-1 and 3-2. These response spectra are based on Regulatory Guide (RG) 1.60 (Reference 1) with an additional control point specified at 25 Hz. The spectral amplitude at 25 Hz is 30 percent higher than the Regulatory Guide 1.60 spectral amplitude. The AP1000 CSDRS are applied at the foundation level in the free field at hard rock sites, and at the finished grade for the other soil generic conditions.

For the Vogtle site, foundation input response spectra (FIRS) and the associated response spectra compatible time histories were generated at the depth of 40 ft below plant level (Vogtle plant level elevation 220 ft) consistent with the same site response calculation of the full soil profile that was used to generate the Ground Motion Response Spectra (GMRS) at grade. Using the FIRS motion, three sets of “in-column" time histories corresponding to the upper, mean, and lower bound soil properties were developed and used in the respective upper, mean, and lower bound SSI analysis. Computation of FIRS and "in-column" time histories are fully consistent with its application for SSI analysis.

The soil properties and soil amplification analysis used to develop the design motion at the ground surface were used to obtain Vogtle FIRS at the depth of 40 ft as a full soil profile outcrop motion.

Three time histories, two in horizontal direction (H1, H2) and one in vertical direction (Vt), were generated to match the FIRS at 40 ft. The strain-compatible soil properties from the full soil column analyses were extracted and compared with the velocity profiles that correspond to the variation of shear modulus with a factor of 1.5. The wider range of the two sets was shown to be for the variation of G with a factor of 1.5. The three profiles were subsequently used in the soil column analyses using the input motion time histories (H1, H2, Vt) to obtain “within” time histories at the depth of 40 ft for SSI analyses. The “within” time histories are applied as control motions in the SSI analysis and were input at the depth of 40 ft in the free-field site model.

Figure 3-3 shows the seismic response spectra associated with the three outcrop time histories components compared to the outcrop FIRS at 40 ft depth.

Each of the two horizontal input motions (H1 and H2) was used for site response analyses of the three strain compatible S-wave soil profiles: lower bound (LB), best estimate (BE) and upper bound (UB). These analyses provided six sets of acceleration time histories of the "within" soil-column motion at depth of 40 ft that are to be used as input for the SSI analysis. Similarly, for vertical motion, three "within" time histories were obtained at the depth of 40 ft using the outcrop vertical time history at the depth of 40 ft and each of three soil profiles (LB, BE, UB). Development of vertical "within" time histories is fully consistent with its application for SSI analysis.

The Vogtle GMRS which is the site-specific safe shutdown earthquake (SSE) is defined at the ground surface. The Vogtle foundation input response spectra are at an outcrop located at the 40' depth. These Vogtle response spectra are compared to the AP1000 SSE design response spectra that are also referred to as the AP1000 certified seismic design response spectra. The CSDRS also represents the AP1000 FIRS. This is because: (1) the CSDRS at a hard rock site is essentially the same at the grade level and at the foundation level; and (2) the CSDRS envelopes the in-column motions of the other generic soil conditions. The comparisons are shown in Figures 3-4 and 3-5. As seen from this comparison there are exceedances above the CSDRS; therefore, a plant specific seismic evaluation is performed to demonstrate that the AP1000 plant designed for the CSDRS is acceptable for the Vogtle site.

The surface response motion using the FIRS input motion at the depth of 40 ft for the LB, BE, and UB profiles are compared with the GMRS at the ground surface level in Figures 3-6 through 3-8. The GMRS at the ground surface level is computed in the same calculation that provided outcrop motion at 40' depth and includes use of fully randomized soil profiles and soil properties. The comparison shows that the free-field motion within the embedment depth of 40 ft and based on three soil profiles is adequately captured.

The site specific SSI analysis at Vogtle is based on the site specific soil profile and the site specific FIRS developed for the site. The development of the FIRS is fully consistent with its application for SSI analysis. The comparison presented in Figures 3-6 through 3-8 is to illustrate that use of FIRS along with the UP, BE and LB profiles results in a surface motion in the SSI free-field model that envelops the GMRS. This study confirms that the foundation motion as well as the free field motion along the embedment depth of the NI is adequately and conservatively modeled in the SSI analysis.

These spectra and time histories presented in this section are all based on the ESP soil properties. The site response was completely recalculated assuming a different higher shear wave velocity profile of the backfill. This resulted in a new set of FIRS; time histories; and lower bound, best estimate, and upper bound strain compatible soil profiles. These were developed for a sensitivity analysis to determine the sensitivity of the Vogtle AP1000 NI seismic response to a very wide range of shear wave velocity profiles of the backfill. This was done in part since the final backfill is not in place. The results of this sensitivity study (SEN) are provided in Sections 5.0, 6.0, and 7.0.

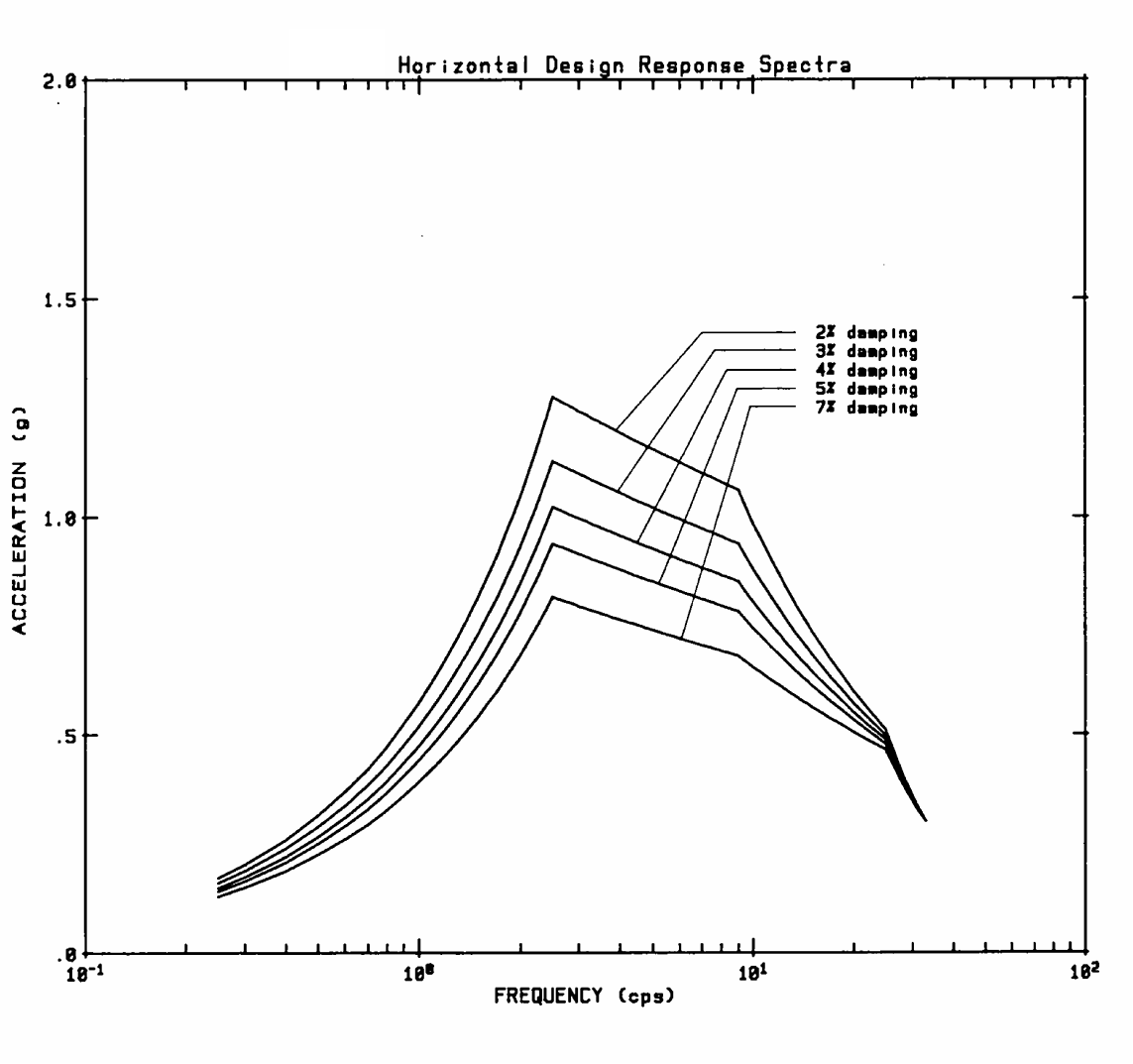


Figure 3-1 – AP1000 Horizontal Design Response Spectra for Safe Shutdown Earthquake

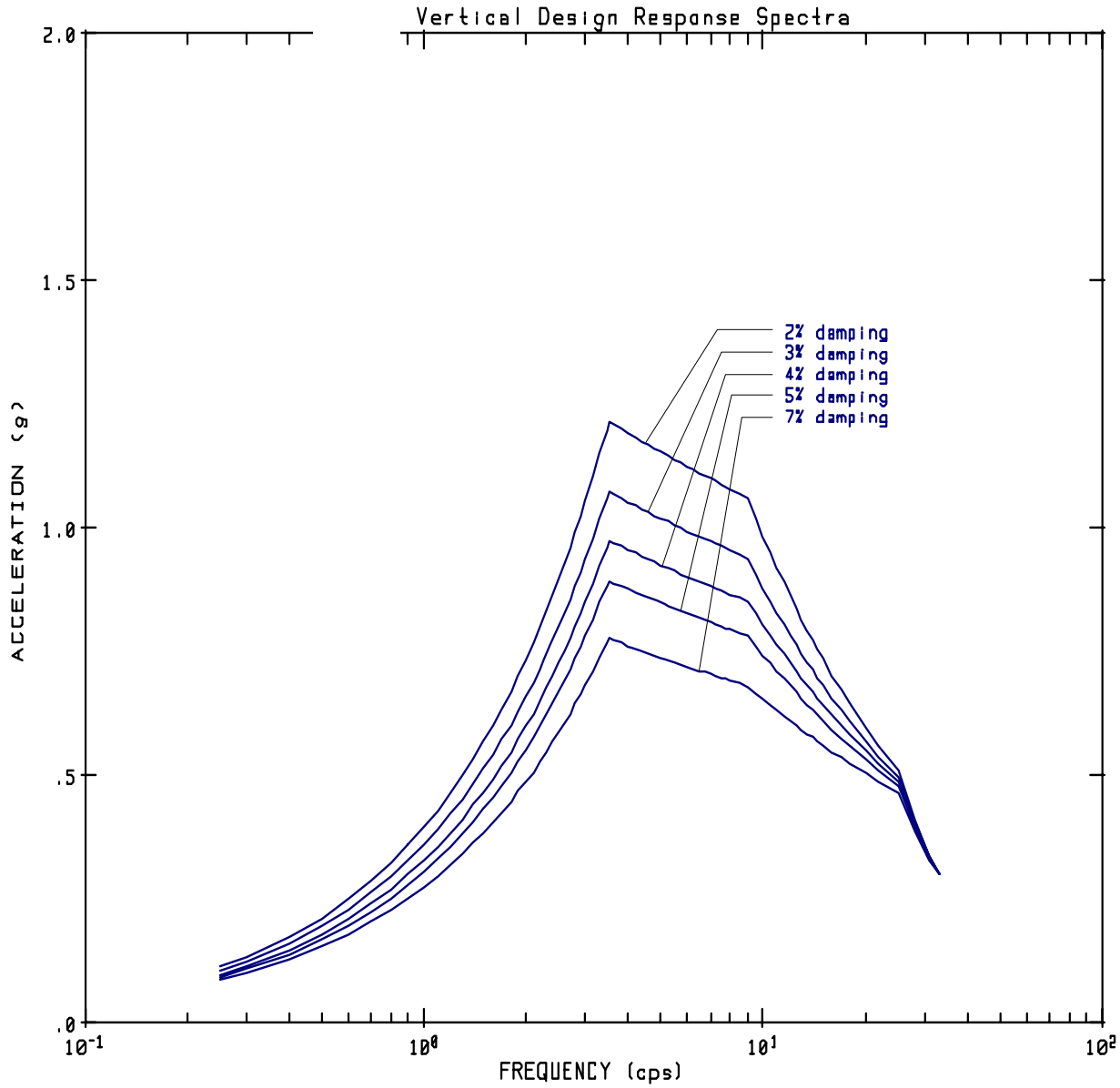
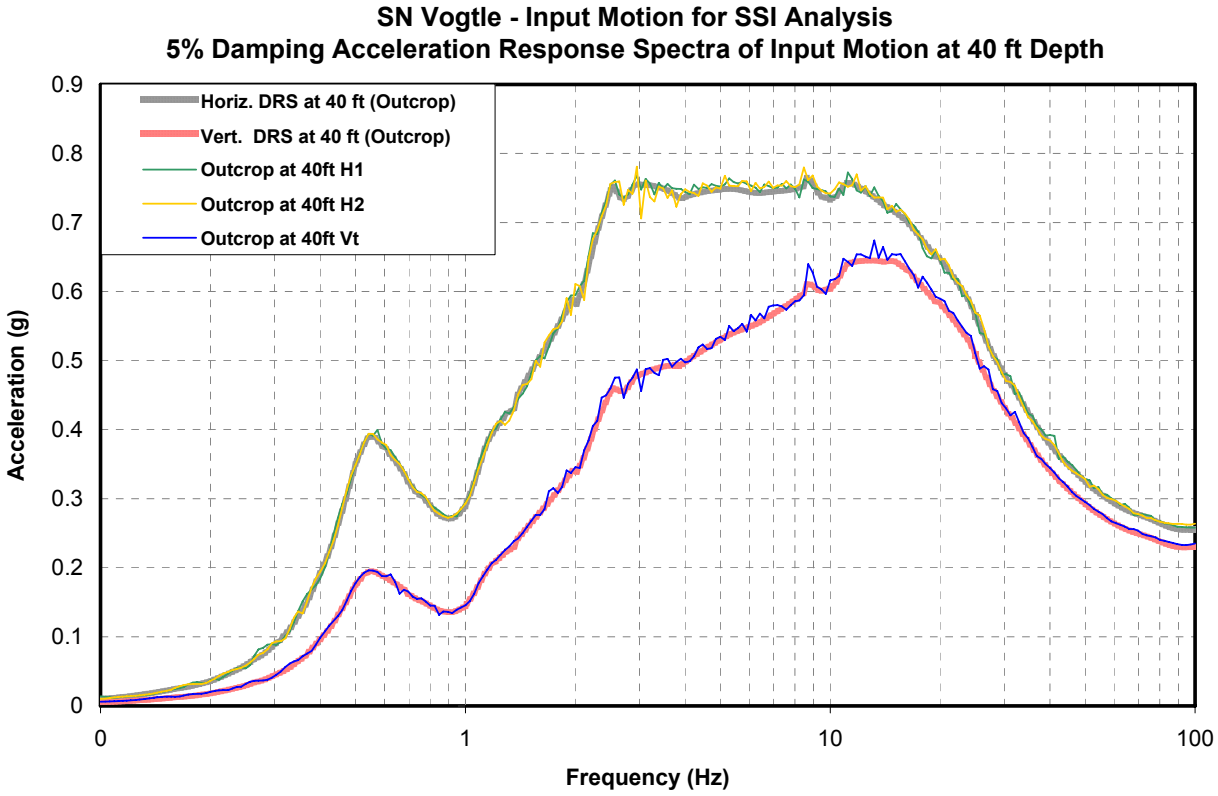


Figure 3-2 – AP1000 Vertical Design Response Spectra Safe Shutdown Earthquake



Note: DRS = FIRS

Figure 3-3 - Acceleration Response Spectra – Input Outcrop Motion at 40 ft Depth

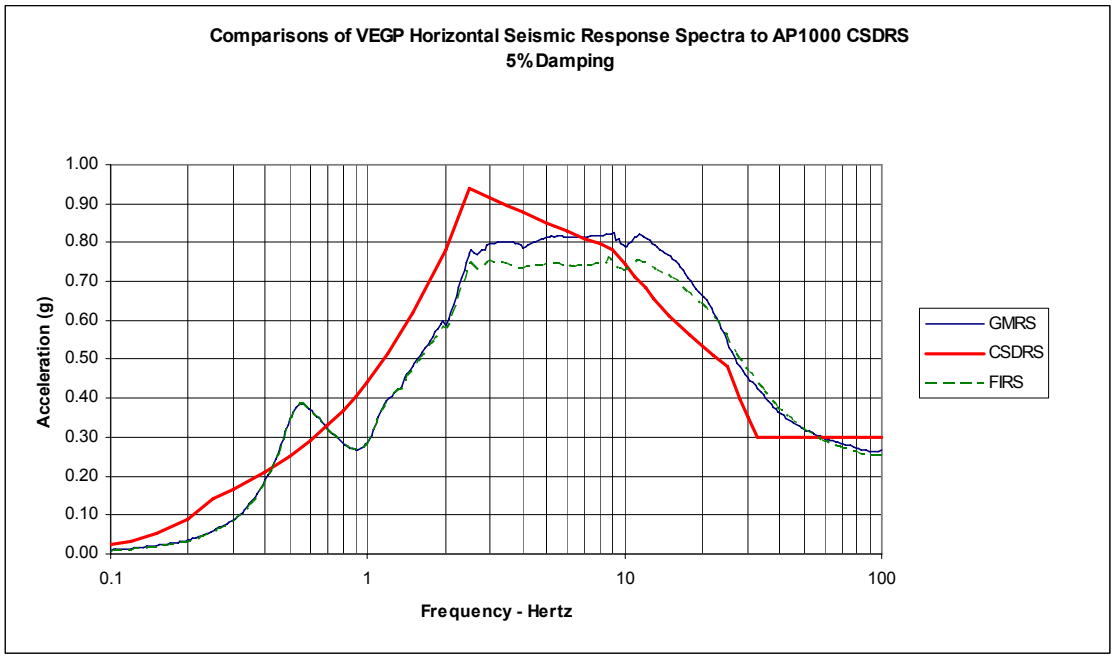


Figure 3-4 – Comparison of AP1000 Horizontal CSDRS to Vogtle 40' Outcrop FIRS and GMRS

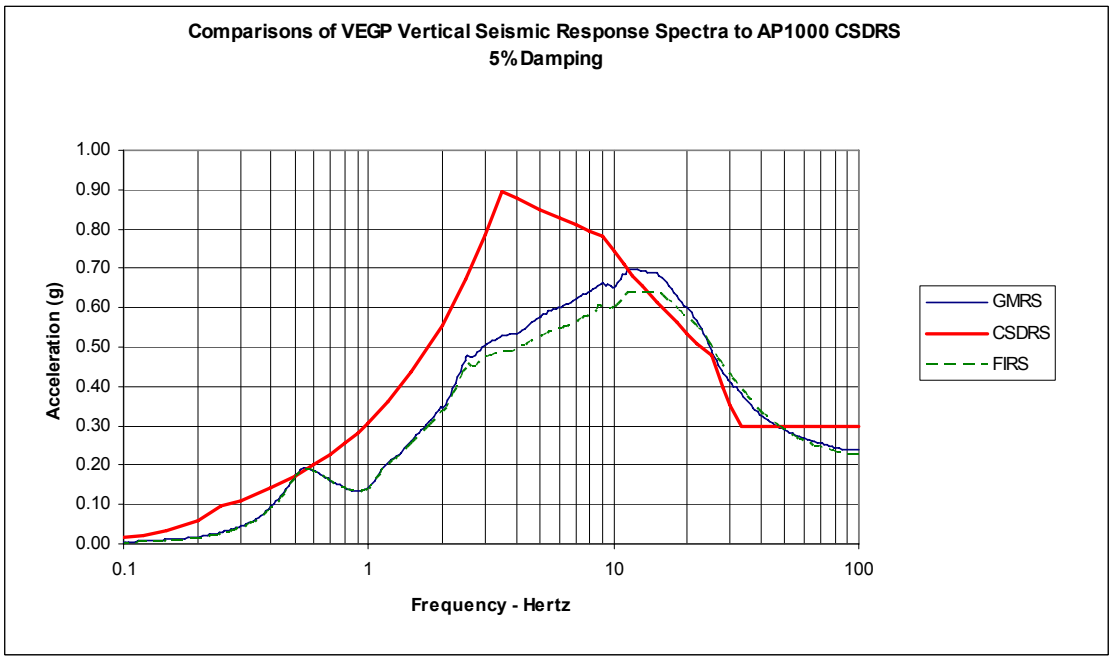
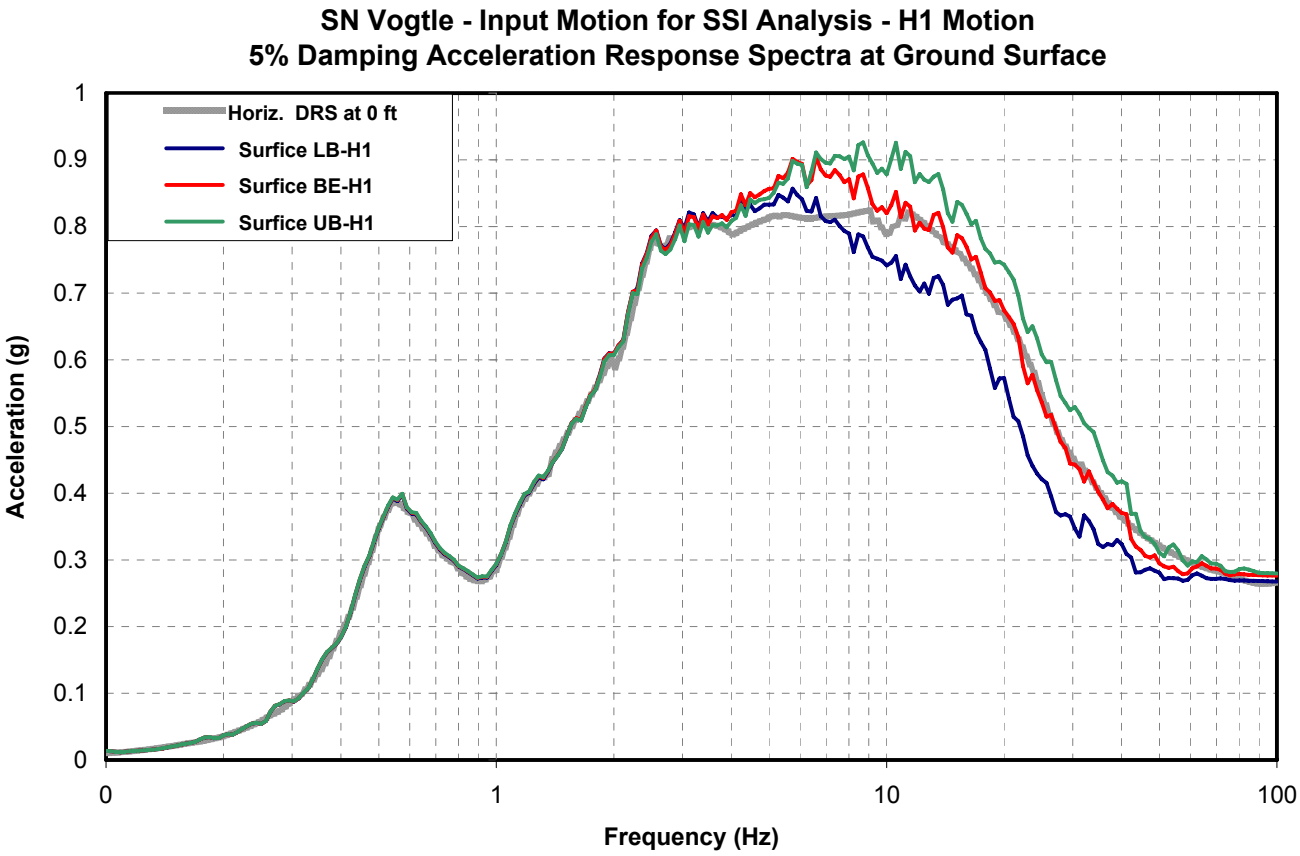
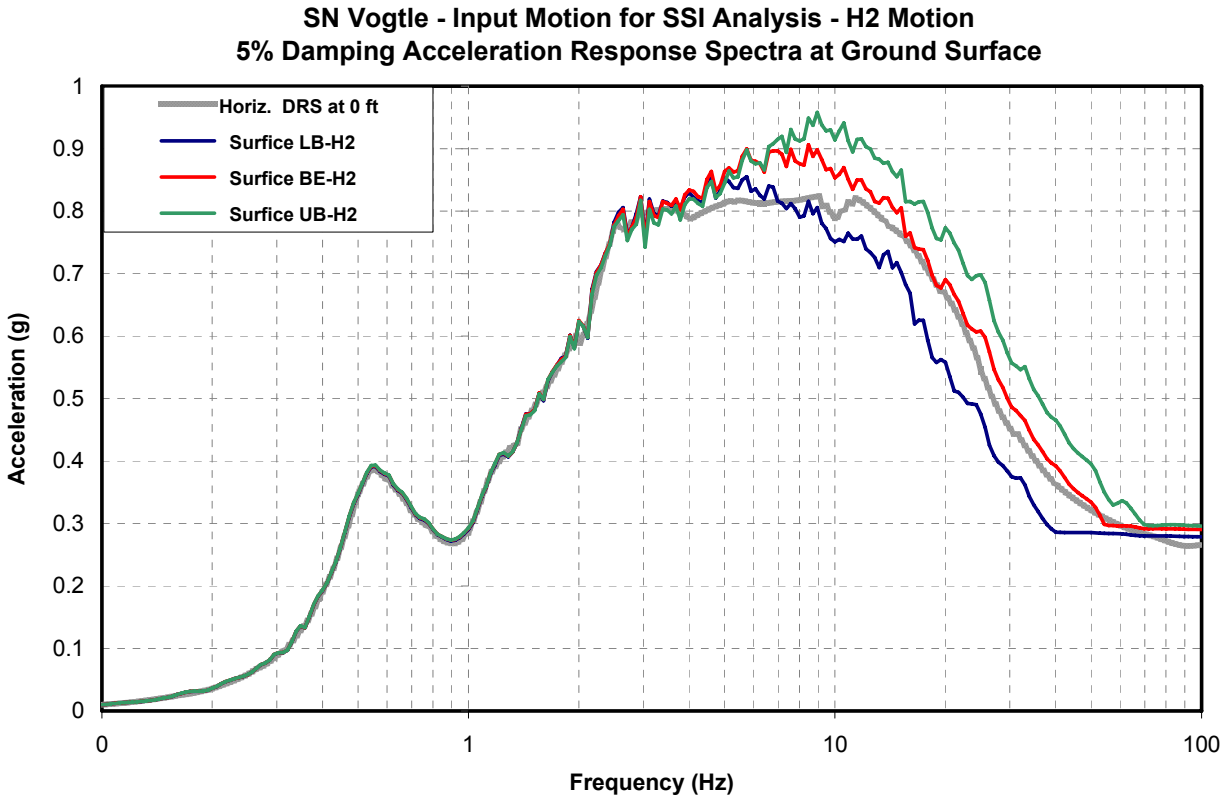


Figure 3-5 – Comparison of AP1000 Vertical CSDRS to Vogtle 40' Outcrop FIRS and GMRS



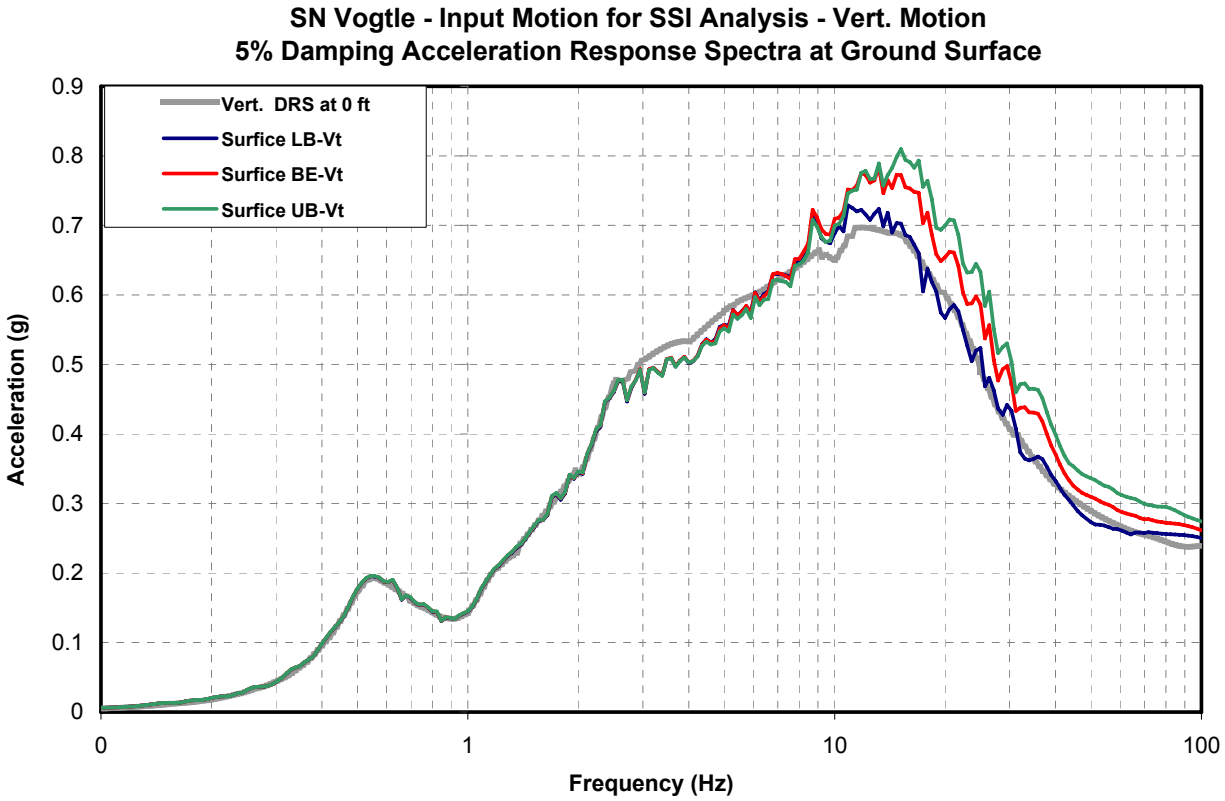
Note: DRS = GMRS

Figure 3-6 - Acceleration Response Spectra – Horizontal H1 Motions at Ground Surface



Note: DRS = GMRS

Figure 3-7 - Acceleration Response Spectra – Horizontal H2 Motions at Ground Surface



Note: DRS = GMRS

Figure 3-8 - Acceleration Response Spectra – Vertical Motions at Ground Surface

4.0 Seismic Models

The AP1000 nuclear island (NI) consists of three distinct Seismic Category I structures. The three building structures that make up the nuclear island are the coupled auxiliary and shield building (ASB), the steel containment vessel (SCV), and the containment internal structures (CIS).

The nuclear island structures, including the SCV, the CIS, and the ASB are founded on a common basemat. The nuclear island is embedded approximately forty feet below an assumed plant grade (for modeling purposes) located at Elevation 100'-0". Thus, the bottom of the basemat is located at Elevation 60'-0". See Figure 5-2 for Vogtle site elevations.

The steel containment vessel is a freestanding cylindrical steel structure with elliptical upper and lower heads. It is surrounded by the reinforced concrete shield building. The inside diameter and height are equal to 130' and 215'-4", respectively. The top of containment is at Elevation 281'-10".

The containment internal structures are designed using reinforced concrete and structural steel. At the lower elevations conventional concrete and reinforcing steel are used, except that permanent steel forms are used in some areas in lieu of removable forms based on constructability considerations. These modules are structural elements built up with welded structural shapes and plates. Concrete is used where required for shielding, but reinforcing steel in the form of bars is not normally used.

The shield building is an enhanced cylindrical reinforced concrete structure which includes the open annulus area surrounding the containment vessel. It has a conical roof structure which supports the containment air cooling diffuser and the Passive Containment Cooling System (PCS) water storage tank.

The auxiliary building is a reinforced concrete structure. Structural modules, similar to those used in the containment internal structures, are used in the southern portion of the auxiliary building. It essentially wraps approximately 50 percent of the circumference of the shield building. The floor slabs and the structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building. The auxiliary building includes the fuel handling area located south of the shield building.

The AP1000 NI structural models used to analyze the Vogtle site were modified from the models used during the hard rock licensing (Design Control Document, Revision 15). The seismic analyses performed for the Vogtle site includes site-specific soil properties and embedment effects and uses the current seismic models that represent the latest AP1000 NI structural configuration (Reference 2). The shield building design has been enhanced to mitigate the effects of aircraft impact. Shown in Table 4.0-1 is a comparison of the base seismic reactions at Elevation 60.5' (AP1000 generic elevation of the bottom of the NI foundation) for the 2D hard rock case with the enhanced shield building to the DCD Rev. 15 configuration. The vertical seismic reactions are combined (+/-) with the dead weight (DW). As seen from this comparison, larger seismic reactions are obtained using the current NI structural configuration (the enhanced shield building) to those associated with the NI structural configuration for the AP1000 design during the hard rock licensing (DCD Rev. 15). Therefore, it is concluded that using NI structural models that includes the enhanced shield building for the Vogtle site-specific seismic assessments would

bound the foundations loads from the same Vogtle site-specific seismic assessment using the DCD Rev. 15 NI structural configuration.

Table 4.0-1 – Seismic Reactions at the Bottom of the Basemat (Elevation 60.5')

Seismic Reaction	2D Hard Rock Enhanced Shield Building	2D Hard Rock (DCD 15)
Shear NS	123.75	99.81
Shear EW	112.31	93.52
DW + Vertical	385.1	382.2
DW - Vertical	187.6	179.2
Moment about Line I	13,011	12,639
Moment about SBW side	14,034	13,644
Moment about Line 11	17,506	14,791
Moment about Line 1	17,607	14,903

The Vogtle site-specific seismic analyses are performed using the same 2D stick models of the Nuclear Island used to obtain the 2D Certified Design AP1000 broaden envelop response spectra at the key locations (Reference 2).

4.1 2D Models

The 2D models of the Nuclear Island are stick models of the Auxiliary Shield Building (ASB), the Steel Containment Vessel (SCV), and the Containment Internal Structure (CIS). The concrete structures are modeled with linear elastic uncracked properties. However, the modulus of elasticity is reduced to 80% of its value to reduce stiffness to reflect the observed behavior of concrete when stresses do not result in significant cracking as recommended in Table 6.5 of FEMA 356.

The 2D models of the Nuclear Island are considered in conjunction with their foundation and supporting media to form a soil-structure interaction model. The 2D models provide good representation of the important modes of the structure and seismic interaction between the nuclear island structures. The SASSI model with adjacent soil layers to the Nuclear Island basemat is shown in Figure 4.1-1. It is noted that in this figure the different sticks for the ASB, SCV, and CIS are collocated, and therefore, appear as one stick even if there are three sticks present. The soil adjacent to the foundation is modeled by eight layers as shown. The horizontal soil element spacing is approximately 5 feet. Spring elements are used to connect the foundation to these adjacent soil layers. The springs transfer the compression between the structure and the soil. The soil beneath the foundation is modeled using 81 elements to a depth of 1050 feet. Three ESP soil profiles are used as shown in Figure 4.1-2. Two lines show in each figure; one is the ESP soil profile and the other is SASSI input soil profile data. The maximum sizes of the soil layers for the different depths are shown. The three soil profiles are lower bound, best estimate, and upper bound. The ESP profiles are discussed in Section 3.0.

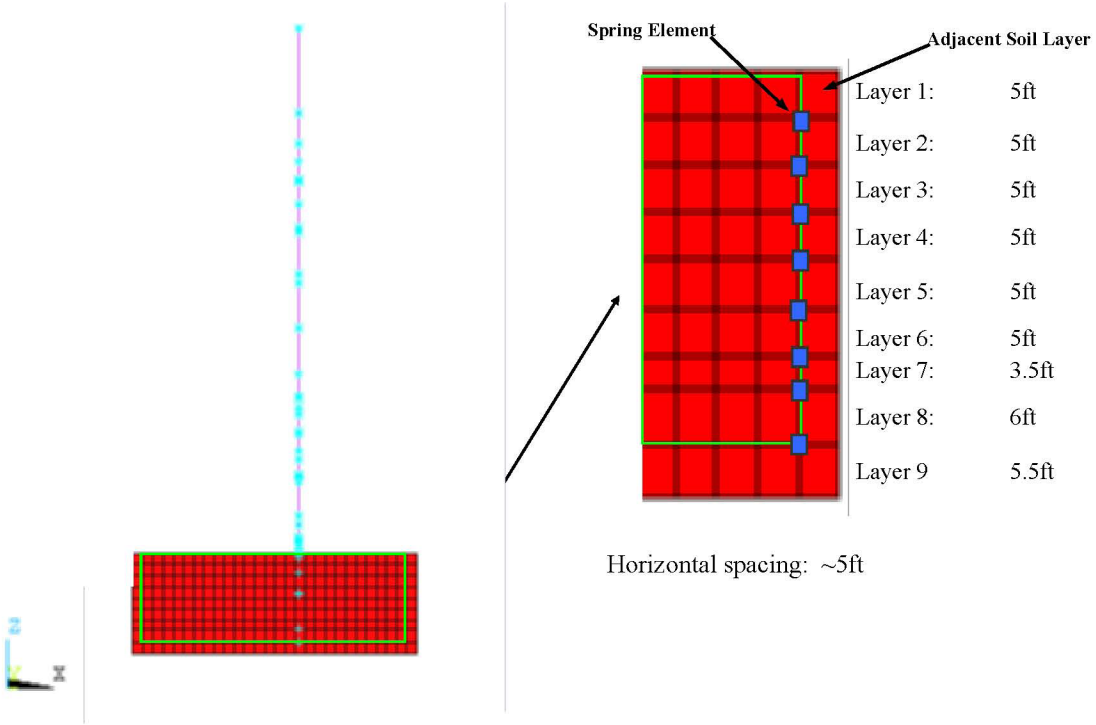
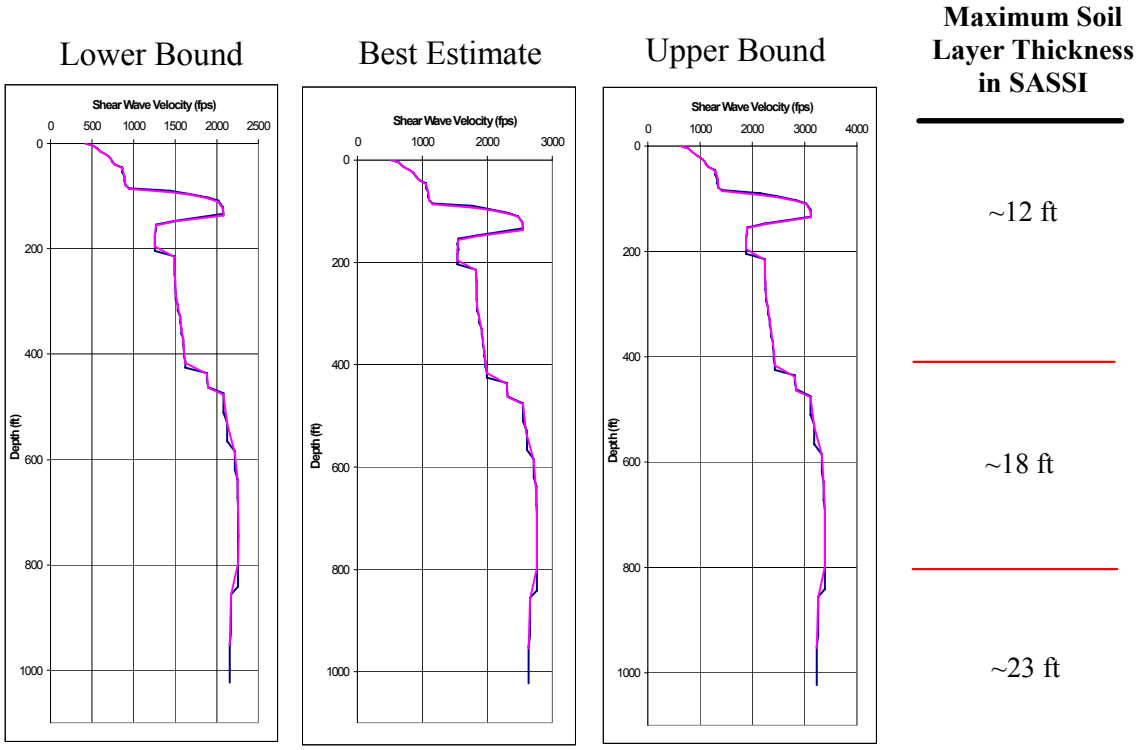


Figure 4.1-1 – 2D Soil Structure Interaction Model



Note: The blue line indicates the data provided by Bechtel and the red line indicates the data used by Westinghouse. The difference is due to layer thicknesses which is minor.

Figure 4.1-2 – ESP Shear Wave Velocity Profiles for 2D Site Soil Layers

4.2 Adjacent Buildings (Annex, Turbine, and Radwaste Buildings)

Since the Vogtle site is a deep soil site with a shallow inversion as shown in Figure 4.1-2, adjacent buildings (Annex, Radwaste, and Turbine buildings) dynamic models are included in the SASSI analyses. By including these buildings into the SASSI model, the adjacent building seismic demands can be obtained. The SASSI models with these building models are shown in Figures 4.2-1 and 4.2-2. It is noted that the Radwaste and Turbine buildings are represented as a lump mass at grade, whereas the Annex buildings are represented as sticks.

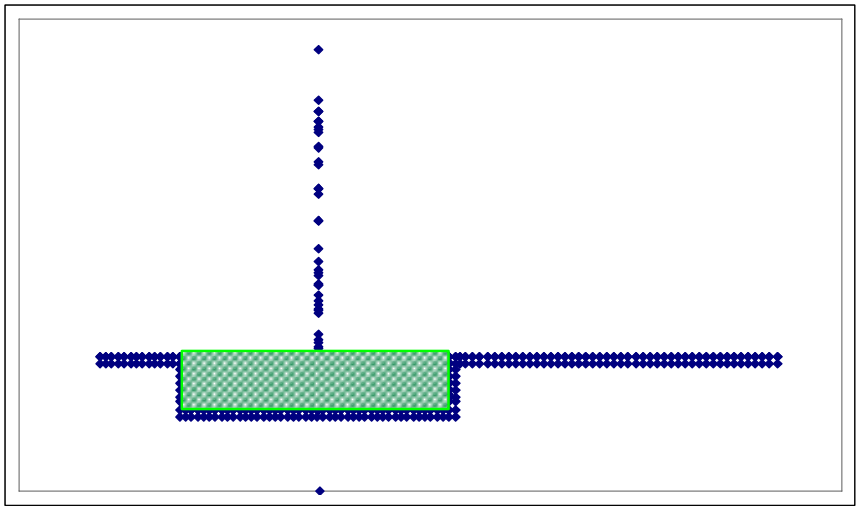
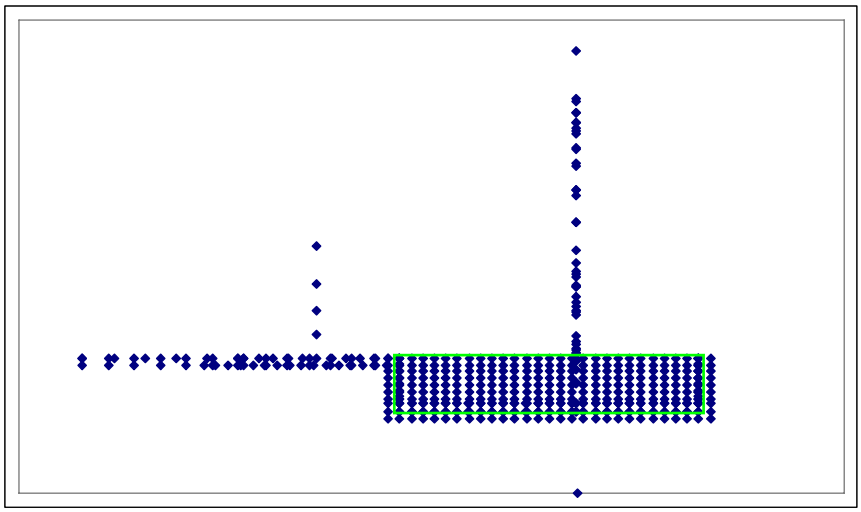


Figure 4.2-1 – Turbine and Radwaste Adjacent Buildings



East-West Model (y-dir)

Figure 4.2-2 – Annex Adjacent Building

5.0 Soil Cases and SSI Analyses

The SSI analyses are performed for the Early Site Permit (ESP) and Sensitivity (SEN) soil cases. The ESP and SEN each have three soil cases: lower bound, best estimate, and upper bound. Figure 5-1 is the shear wave velocity profiles to a depth of 160' for each of the soil cases evaluated. Figure 5-2 shows the FIRS and GMRS locations used in the Vogtle site specific SASSI AP1000 NI Analyses.

Note that the SEN soil cases are based on a complete recalculation of site response assuming a higher shear wave velocity profile of the backfill than used for the ESP soil profiles. This resulted in a new set of FIRS, time histories, and strain compatible lower bound, best estimate, and upper bound soil profiles. The purpose of this study is to determine the sensitivity of the Vogtle AP1000 NI seismic response to a much wider range of backfill shear wave velocity profiles.

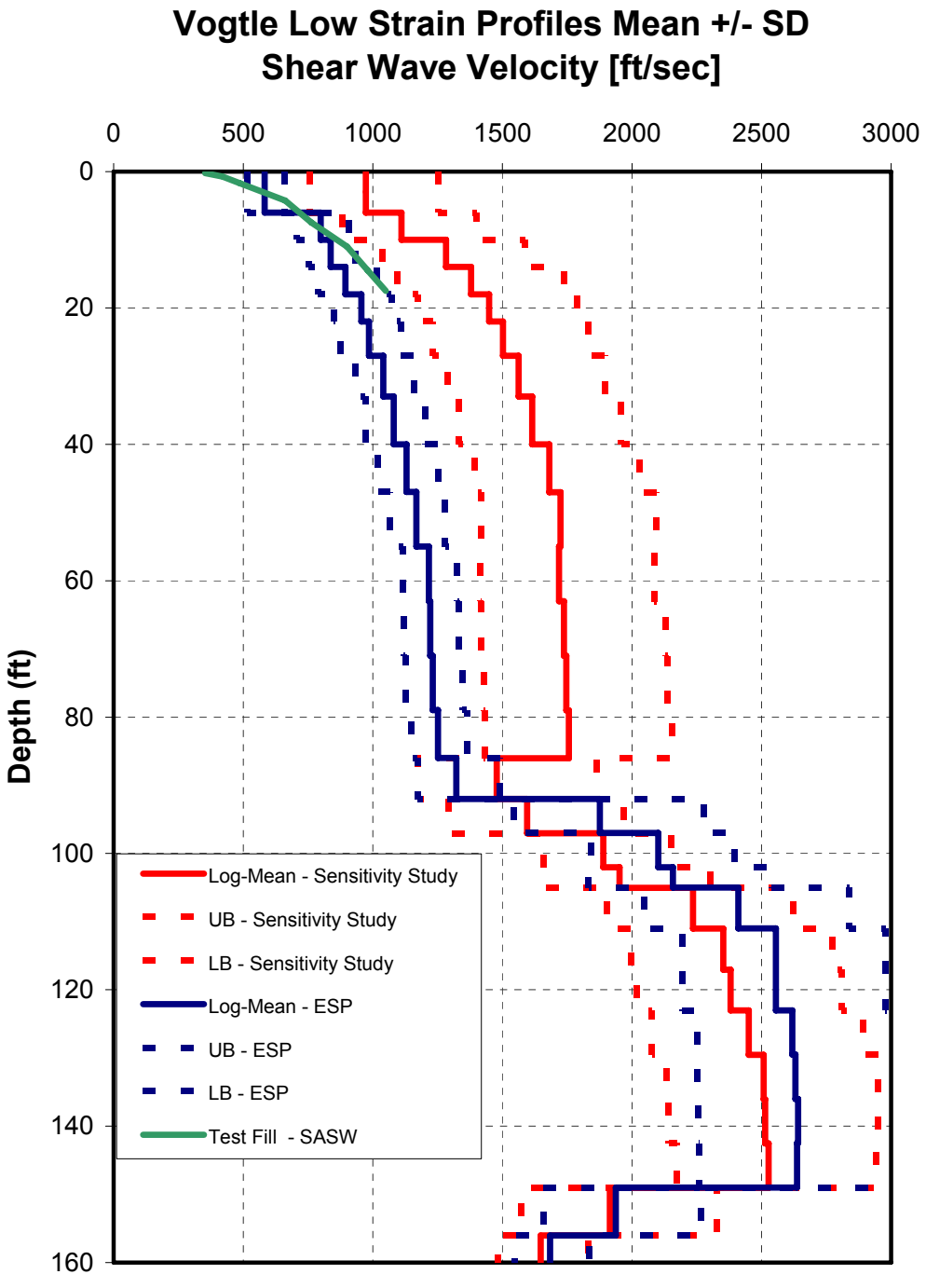


Figure 5.0-1 – Shear Wave Velocities for the ESP and SEN Soil Cases

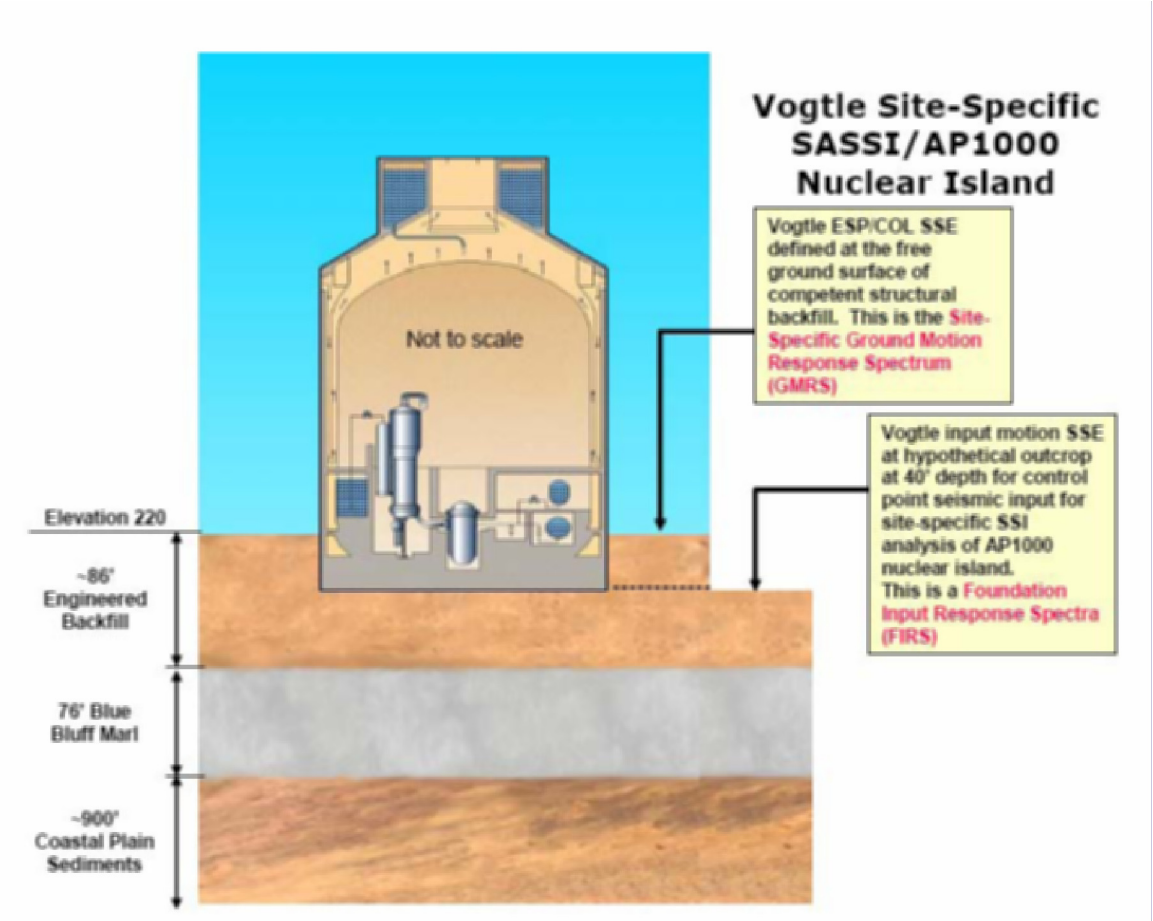


Figure 5.0-2 – FIRS and GMRS Locations in Vogtle Site Specific SASSI AP1000 NI Analyses

5.1 2D SASSI Analyses and Parameter Studies

This section describes the SASSI and parametric analyses performed using the 2D models that include the adjacent structures described in Section 4.2. The Vogtle site-specific soil cases are analyzed.

Figures 5.1-1 to 5.1-18 are the response spectra with 5% damping compared to the AP1000 SSI Envelope for the ESP soil cases. Figures 5.1-19 to 5.1-36 are the comparisons for the SEN soil cases. These spectra are also at 5% damping. The floor response spectra are given at the six key locations as defined in Table 5.1-1.

As seen from these spectra, there is a slight exceedance in the range from 0.5 hertz to 0.6 hertz in the NS direction and 0.45 hertz to 0.65 hertz in the EW direction. The only dynamic response in this region is due to tank sloshing. As seen from Table 5.1-2, the sloshing frequencies are away from this region of exceedance. Sloshing within the tanks will not affect the AP1000 plant design.

Table 5.1-1 – Critical Nodes Selected

Nodes	AP 1000 Generic Plant Elevation (ft)	Description
4041	99.00	NI at Reactor Vessel Support Elevation
4061	116.5	Auxiliary Shield Building at Control Room Floor
4120	179.56	ASB Auxiliary Building Roof Area
4310	327.41	ASB Shield Building Roof Area
4412	224	Steel Containment Vessel near Polar Crane
4535	134.25	Containment Internal Structure at Operating Deck

Table 5.1-2 – Sloshing Frequencies

Tank and Seismic Response Direction	Frequency Hertz
Fuel Area	
Fuel Pool, EW	0.39
Fuel Pool, NS	0.26
Fuel Transfer Canal, EW	0.68
Fuel Transfer Canal, NS	0.26
Cask Loading Pit, EW	0.39
Cask Loading Pit, NS	0.37
Cask Washdown Pit, EW	0.39
Cask Washdown Pit, NS	0.36
IRWST Tank	
Steel Wall, EW	0.41
Steel Wall, NS	0.25
NE Wall, EW	0.36
North Wall Pressurizer, NS	0.29
West Wall, EW	0.29
South Wall, NS	0.29
Shield Building	
PCCWST	0.136

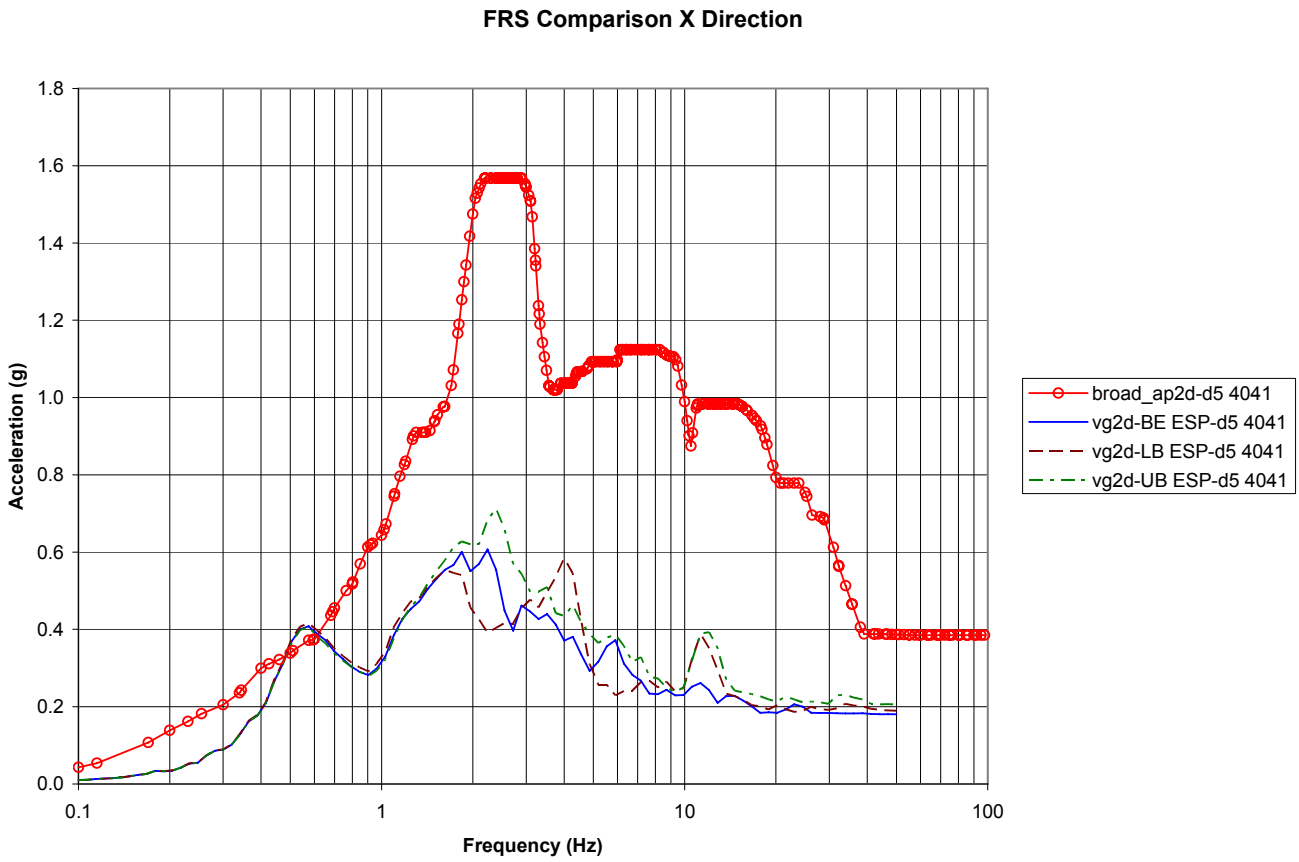


Figure 5.1-1 - Comparison of Node 4041 ESP Response to AP1000 SSI Envelope, NS Dir.

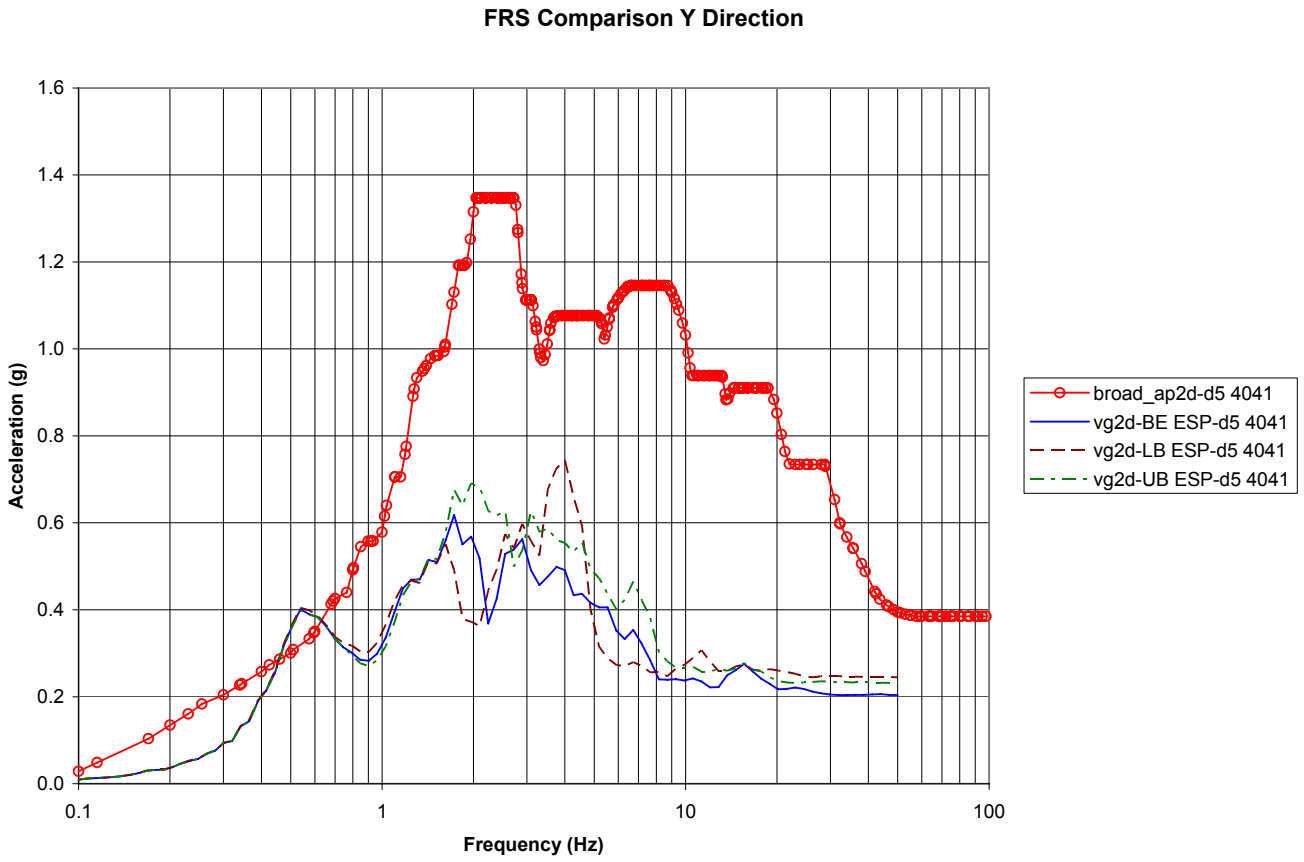


Figure 5.1-2 - Comparison of Node 4041 ESP Response to AP1000 SSI Envelope, EW Dir.

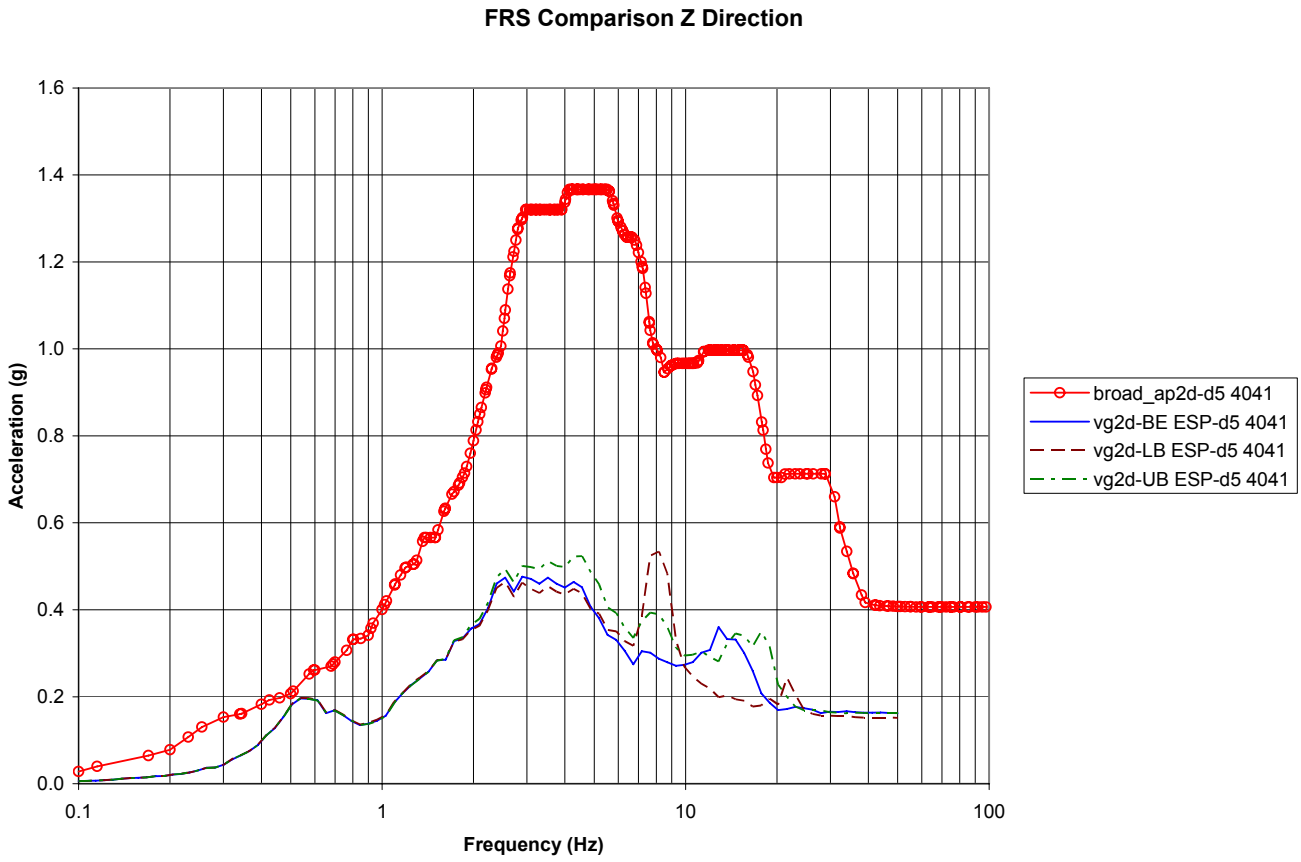


Figure 5.1-3 - Comparison of Node 4041 ESP to AP1000 SSI Envelope, Vertical Dir.

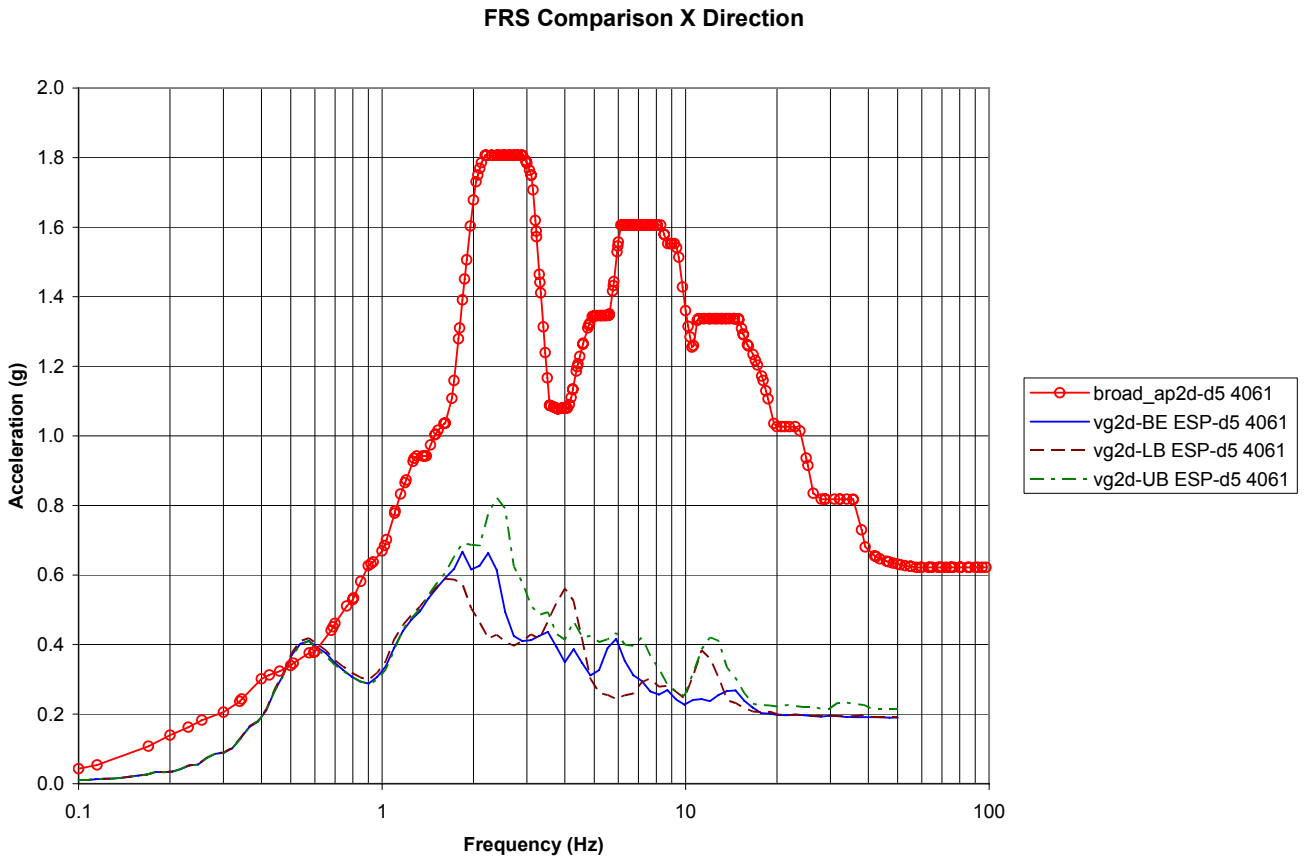


Figure 5.1-4 - Comparison of Node 4061 ESP to AP1000 SSI Envelope, NS Dir.

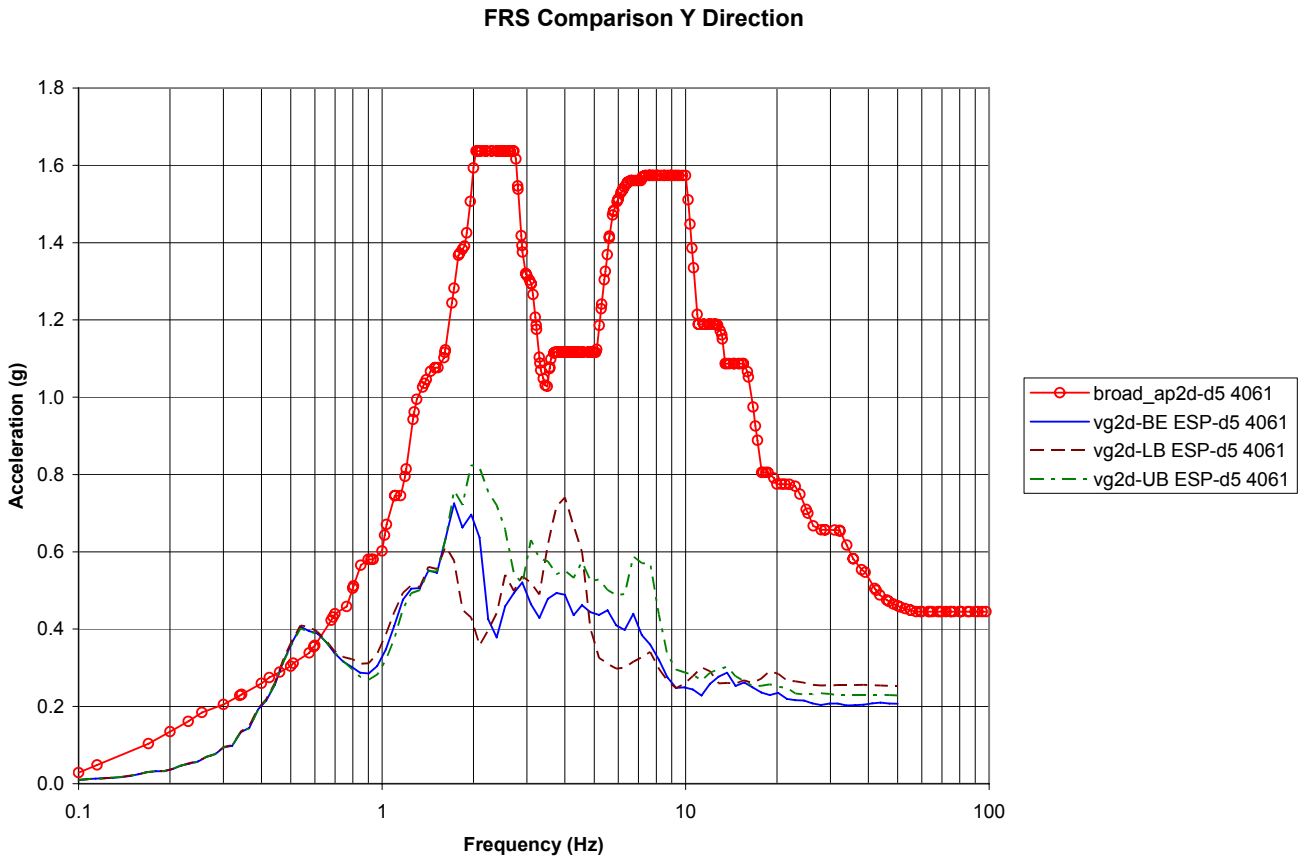


Figure 5.1-5 - Comparison of Node 4061 ESP to AP1000 SSI Envelope, EW Dir

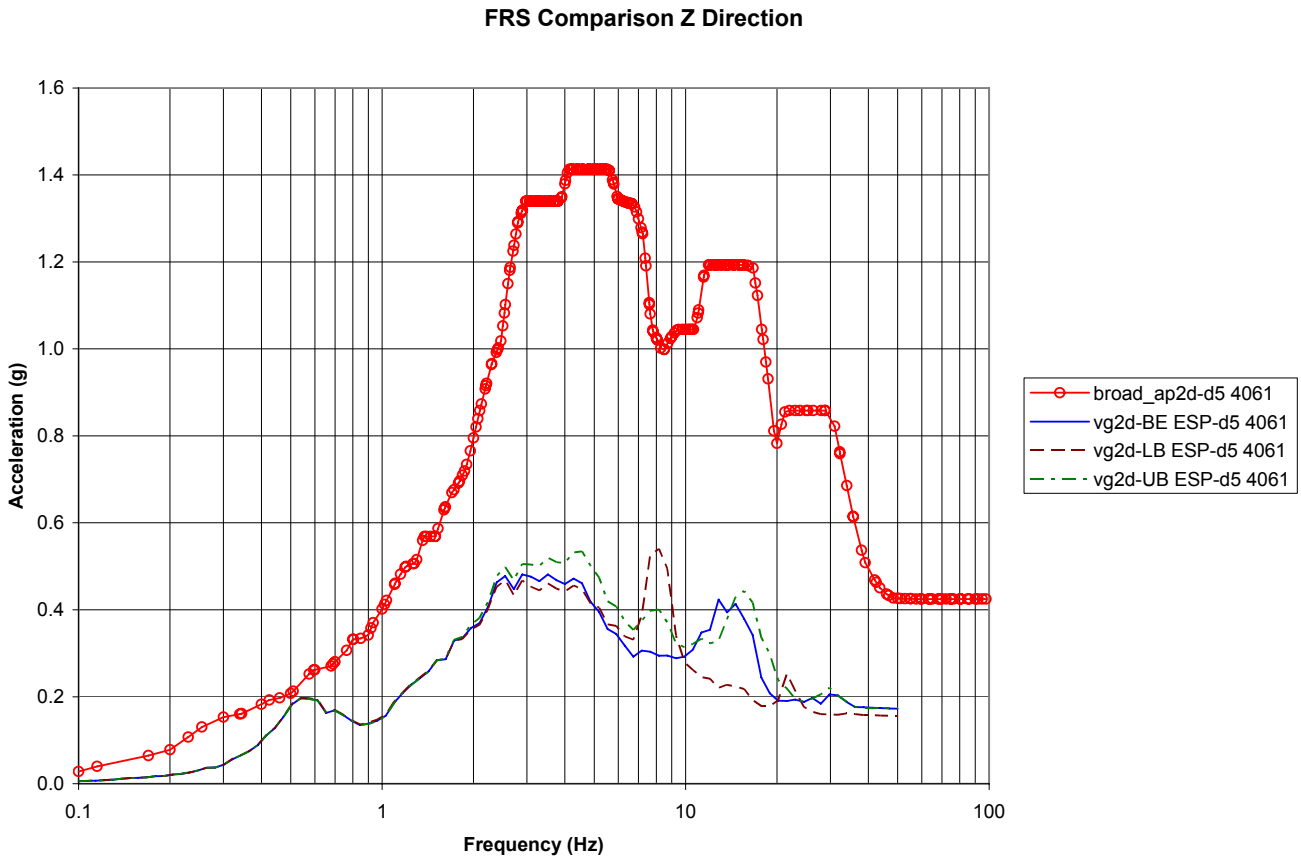


Figure 5.1-6 - Comparison of Node 4061 ESP to AP1000 SSI Envelope, Vertical Dir

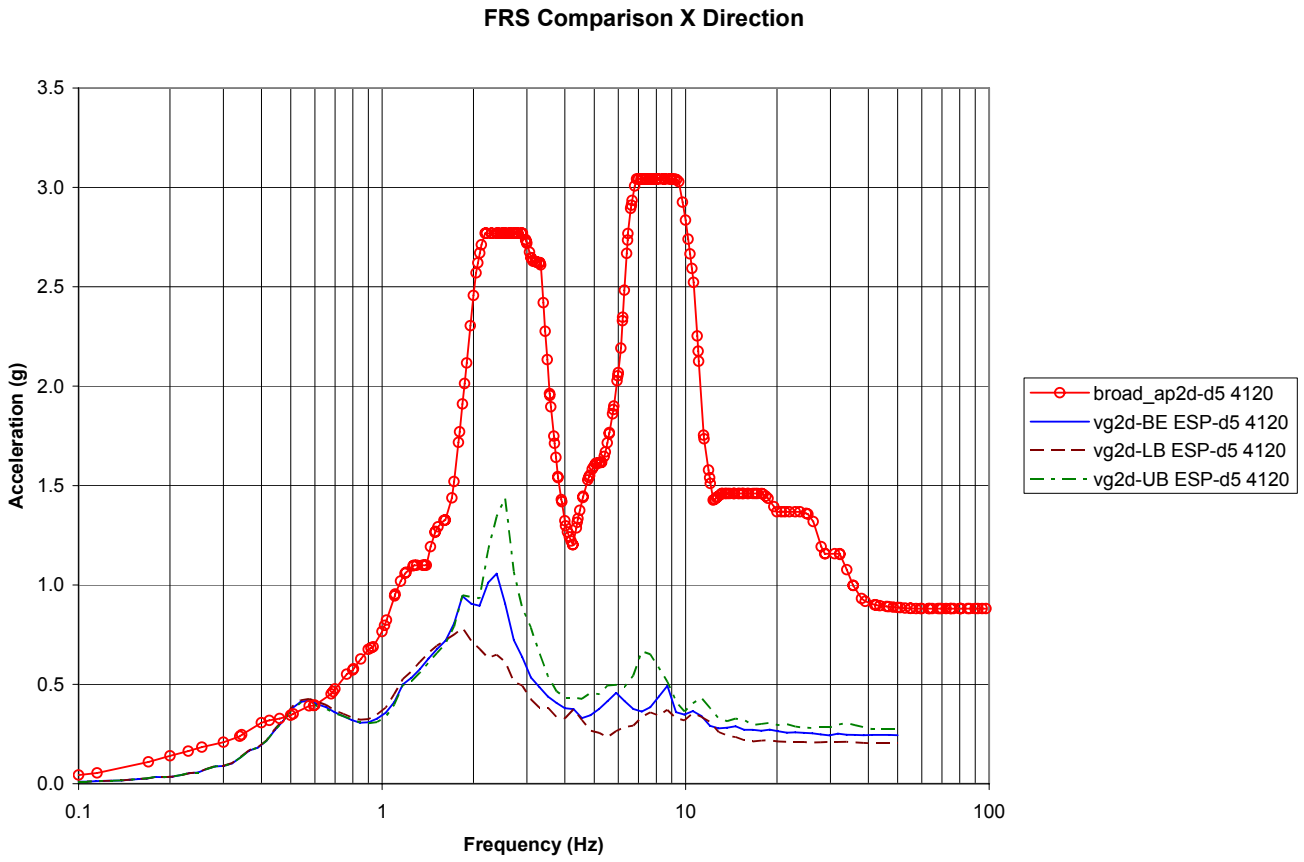


Figure 5.1-7 - Comparison of Node 4120 ESP to AP1000 SSI Envelope, NS Dir

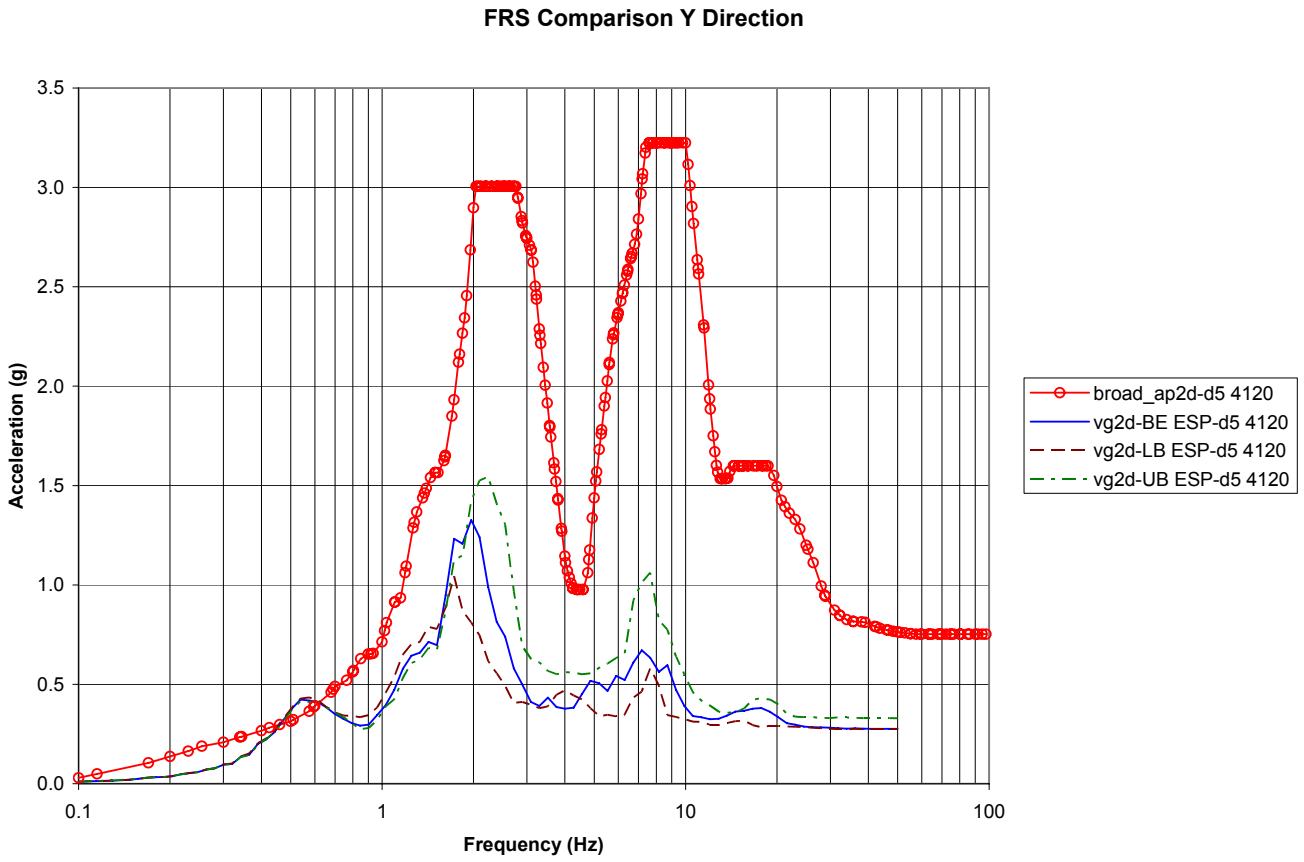


Figure 5.1-8 - Comparison of Node 4120 ESP to AP1000 SSI Envelope, EW Dir

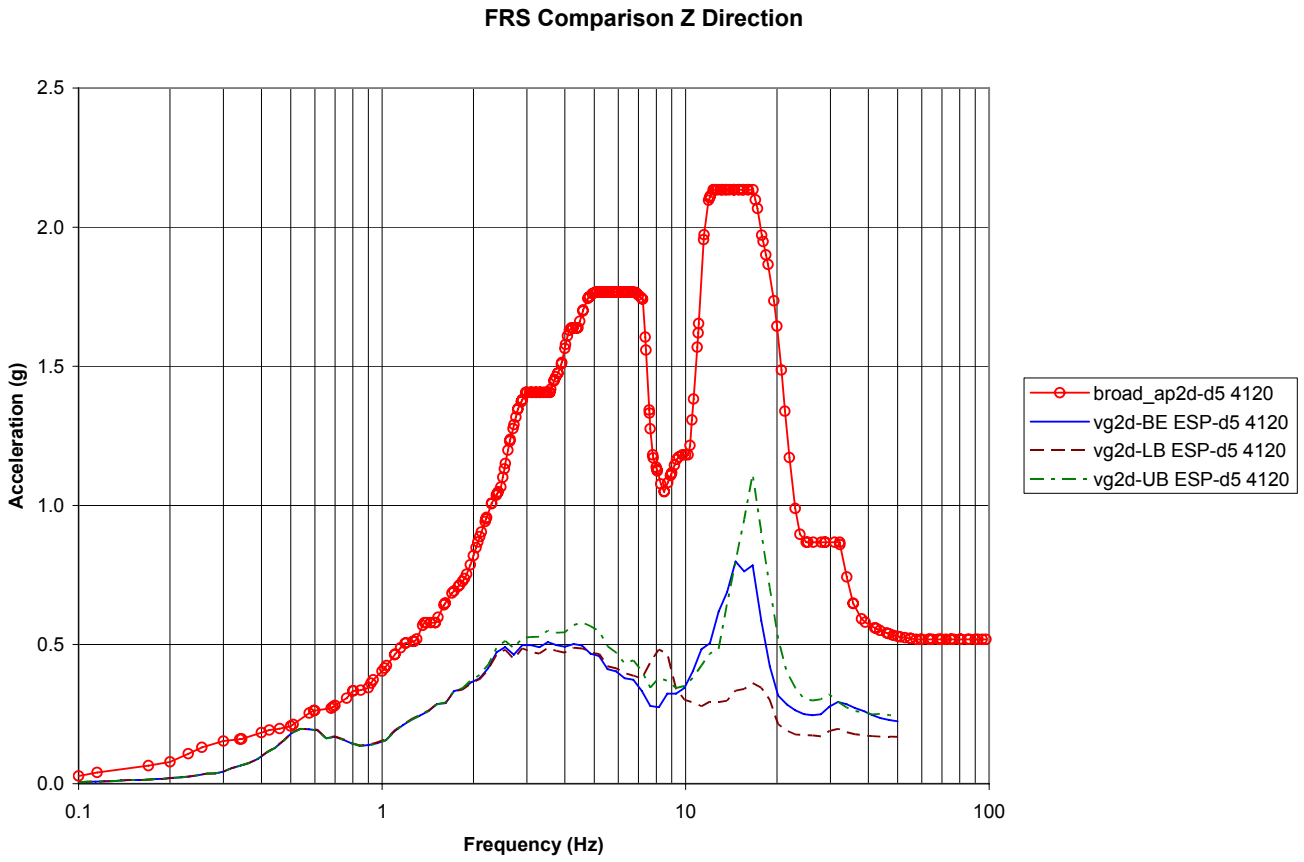


Figure 5.1-9 - Comparison of Node 4120 ESP to AP1000 SSI Envelope, Vertical Dir

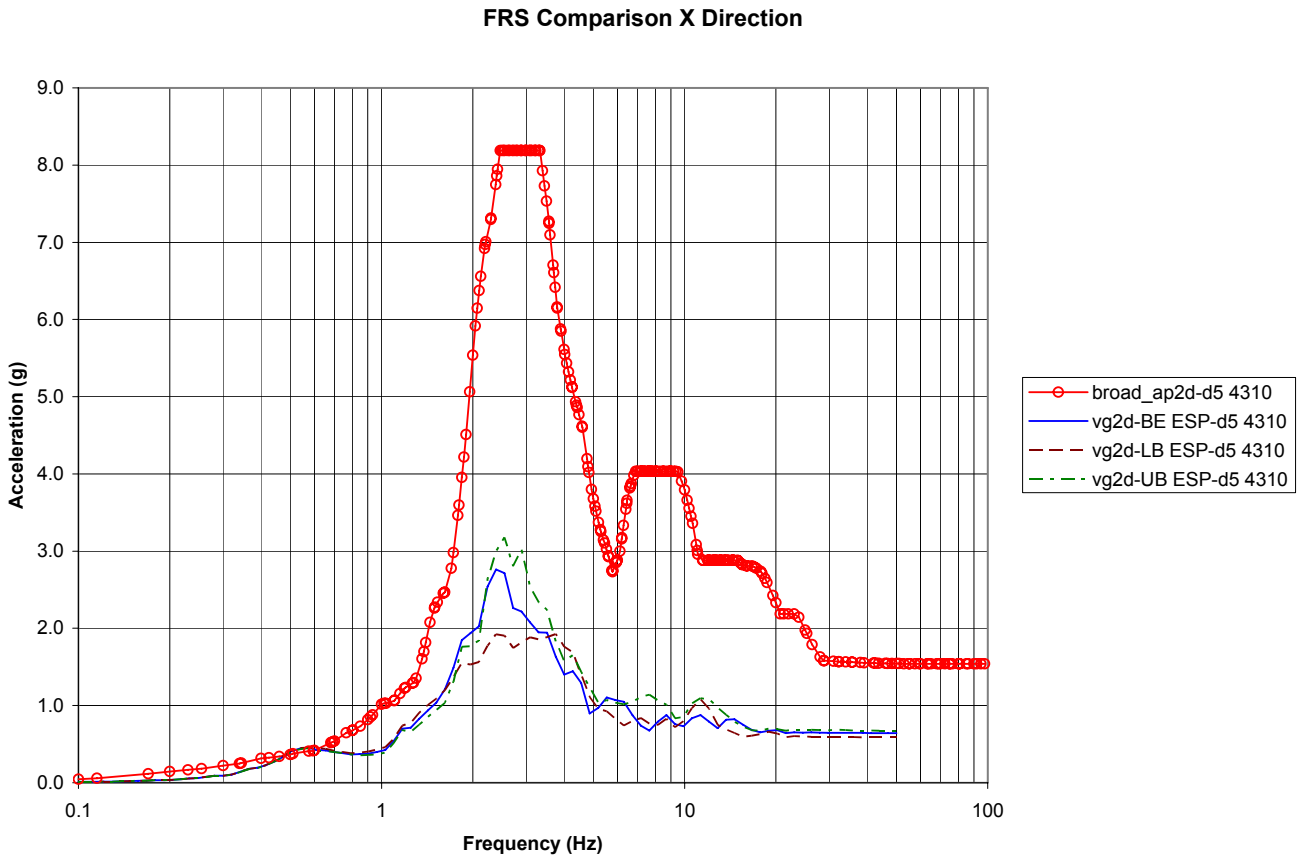


Figure 5.1-10 - Comparison of Node 4310 ESP to AP1000 SSI Envelope, NS Dir

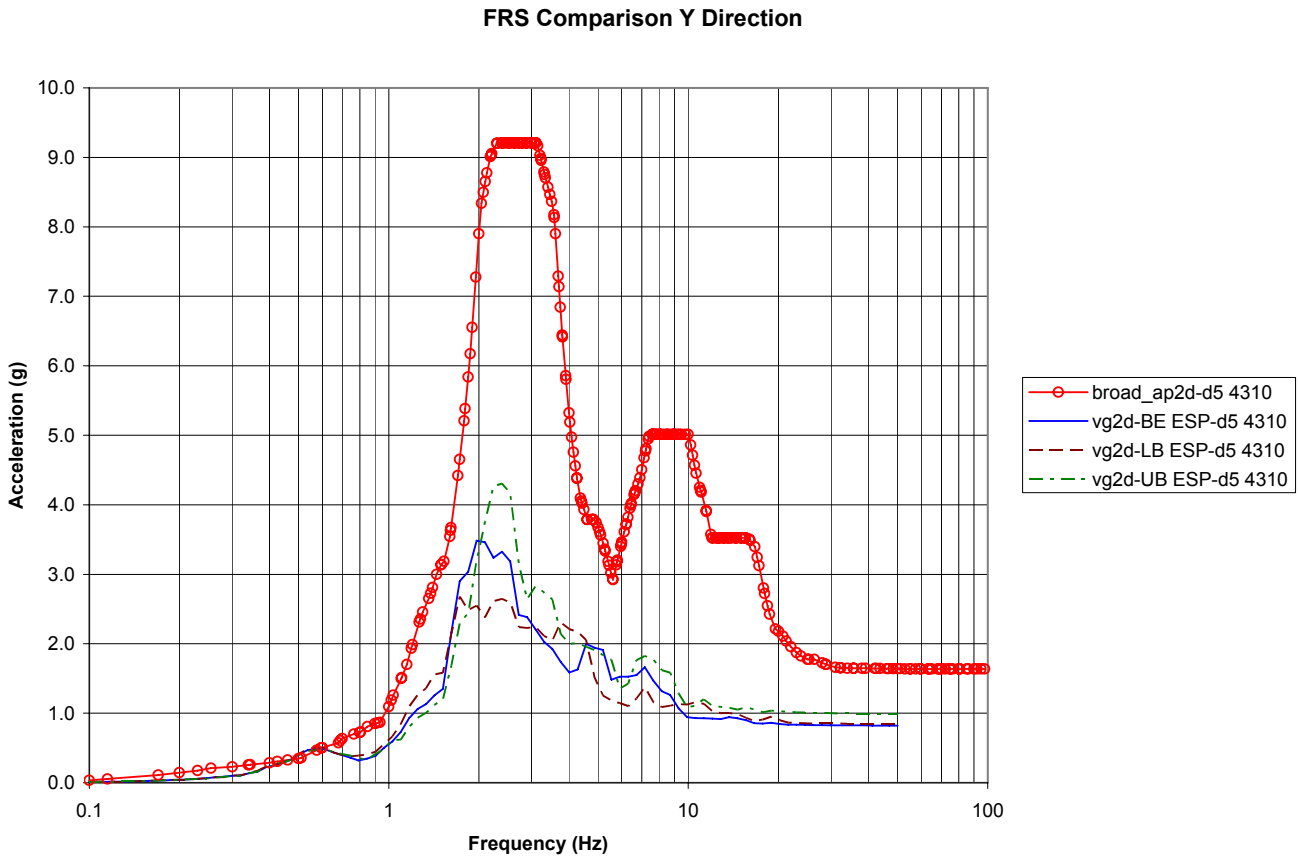


Figure 5.1-11 - Comparison of Node 4310 ESP to AP1000 SSI Envelope, EW Dir

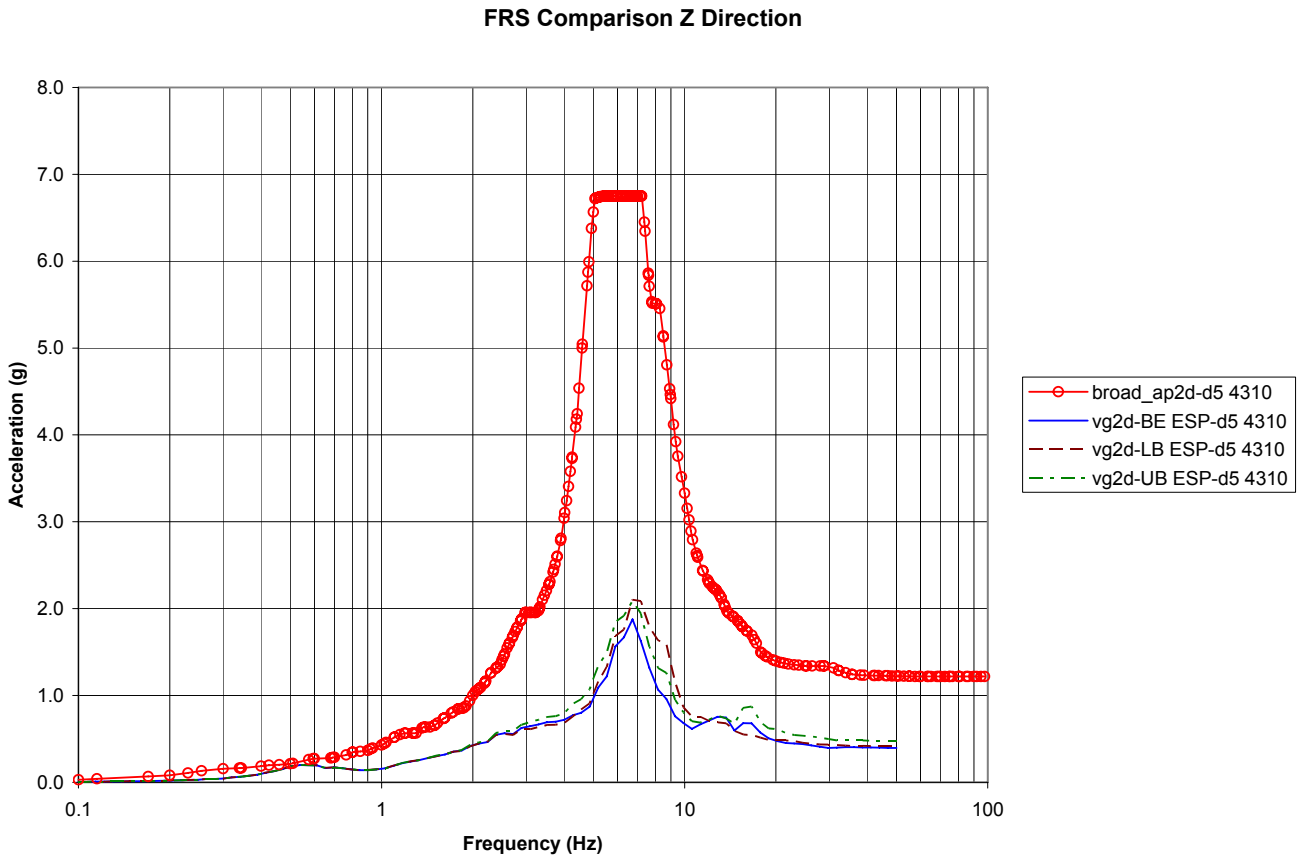


Figure 5.1-12 - Comparison of Node 4310 ESP to AP1000 SSI Envelope, Vertical Dir

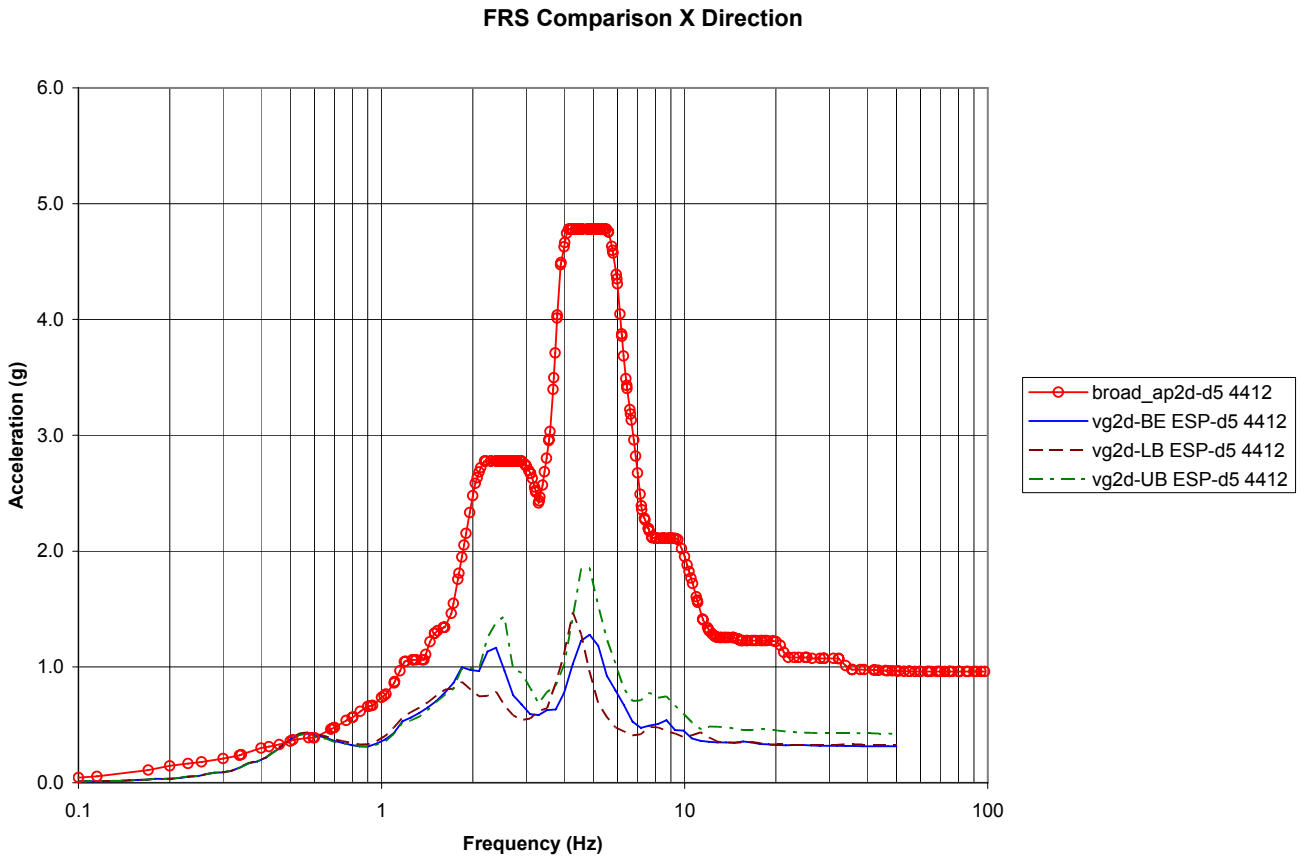


Figure 5.1-13 - Comparison of Node 4412 ESP to AP1000 SSI Envelope, NS Dir

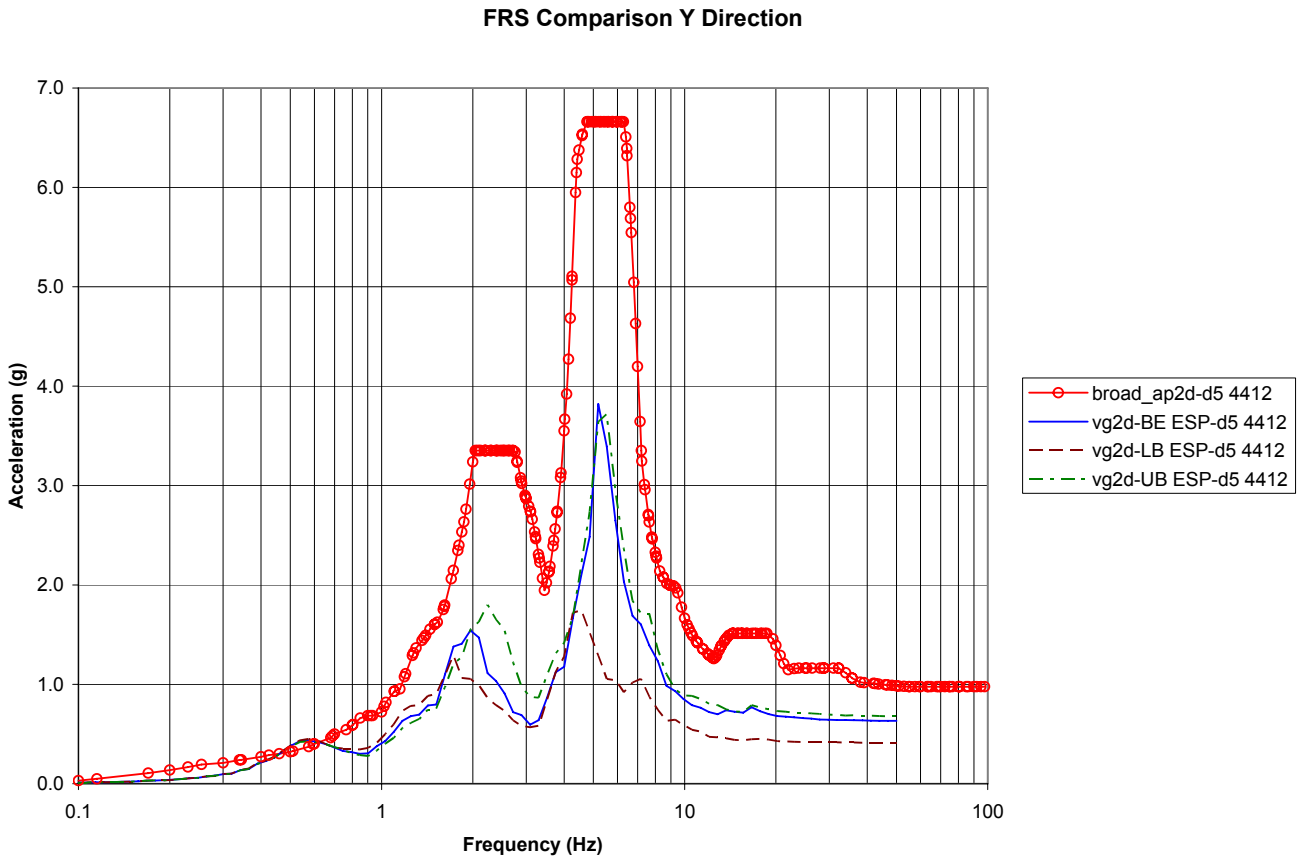


Figure 5.1-14 - Comparison of Node 4412 ESP to AP1000 SSI Envelope, EW Dir

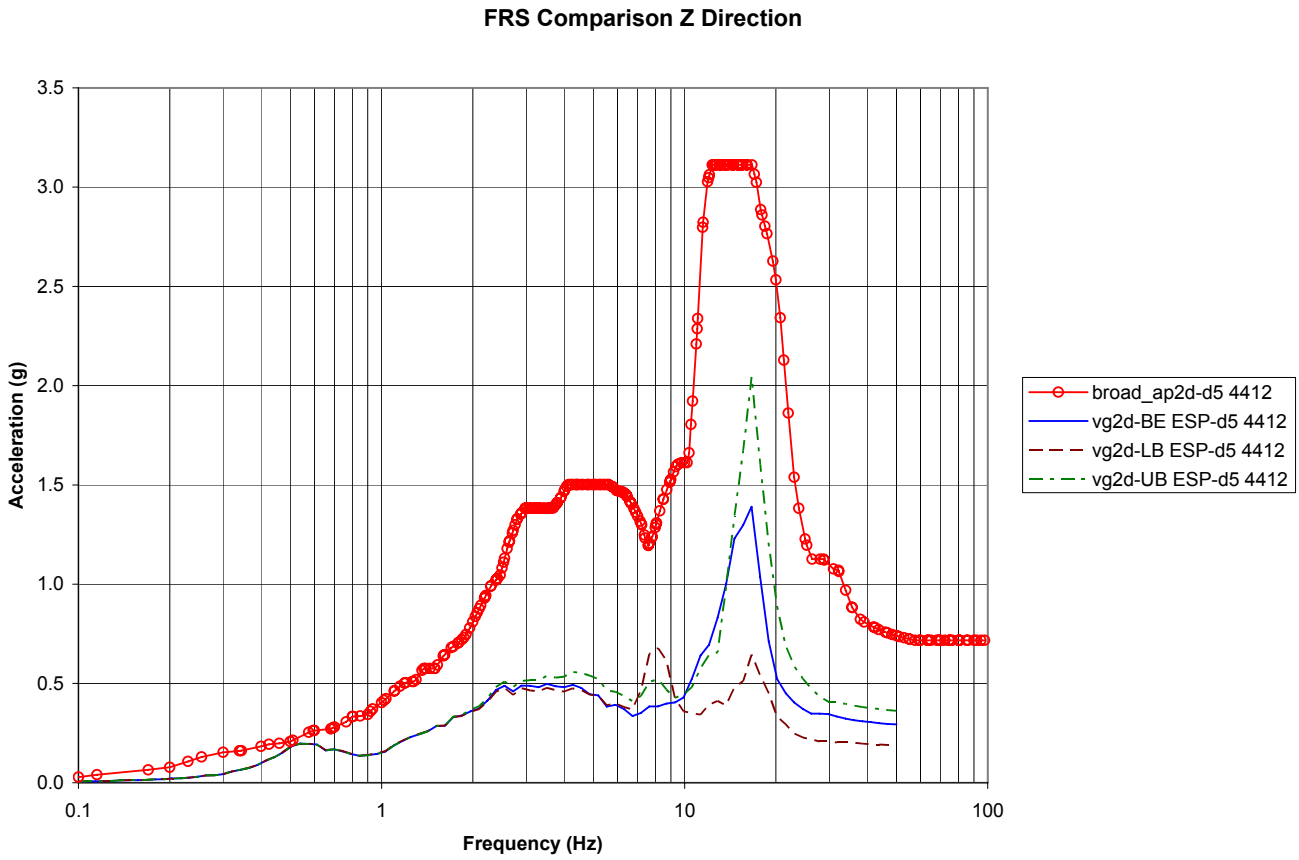


Figure 5.1-15 - Comparison of Node 4412 ESP to AP1000 SSI Envelope, Vertical Dir

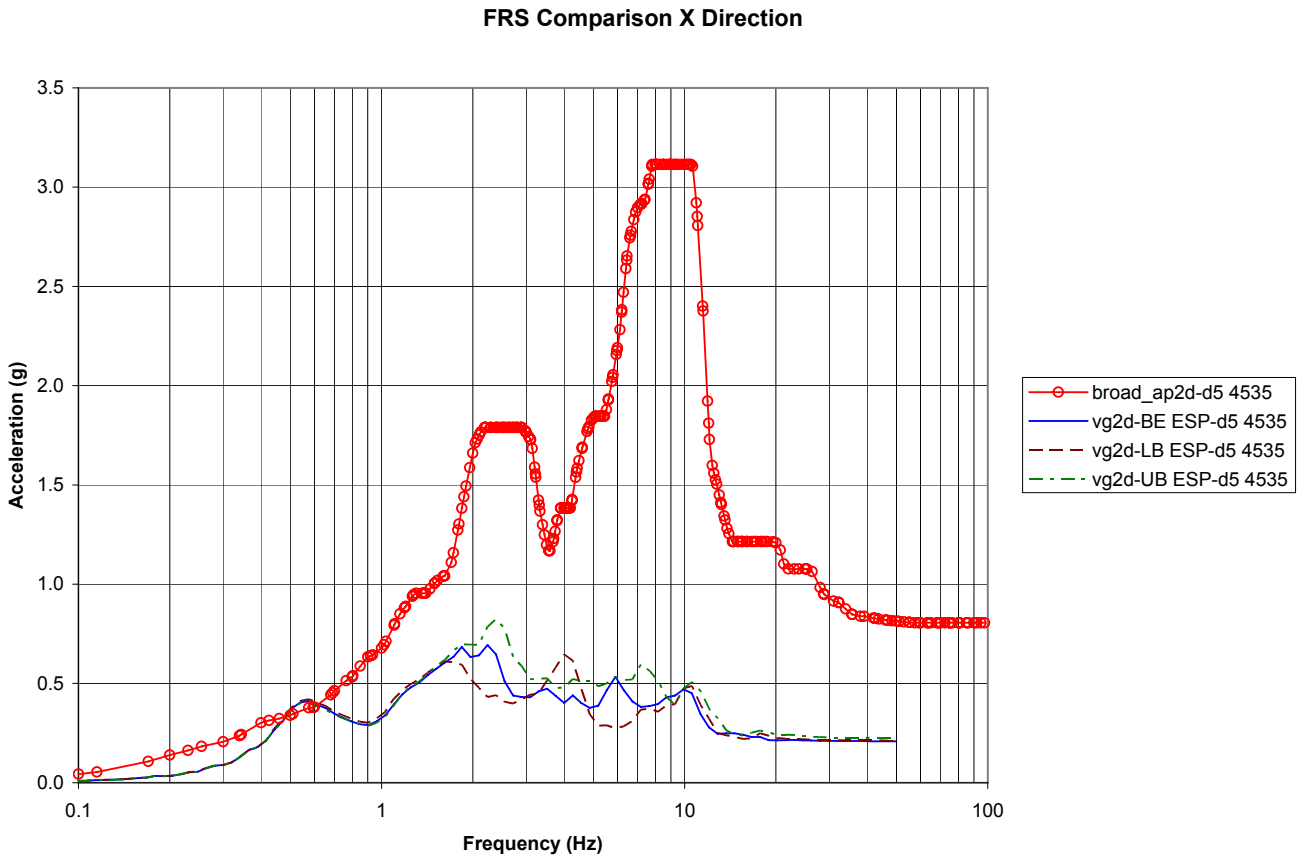


Figure 5.1-16 - Comparison of Node 4535 ESP to AP1000 SSI Envelope, NS Dir

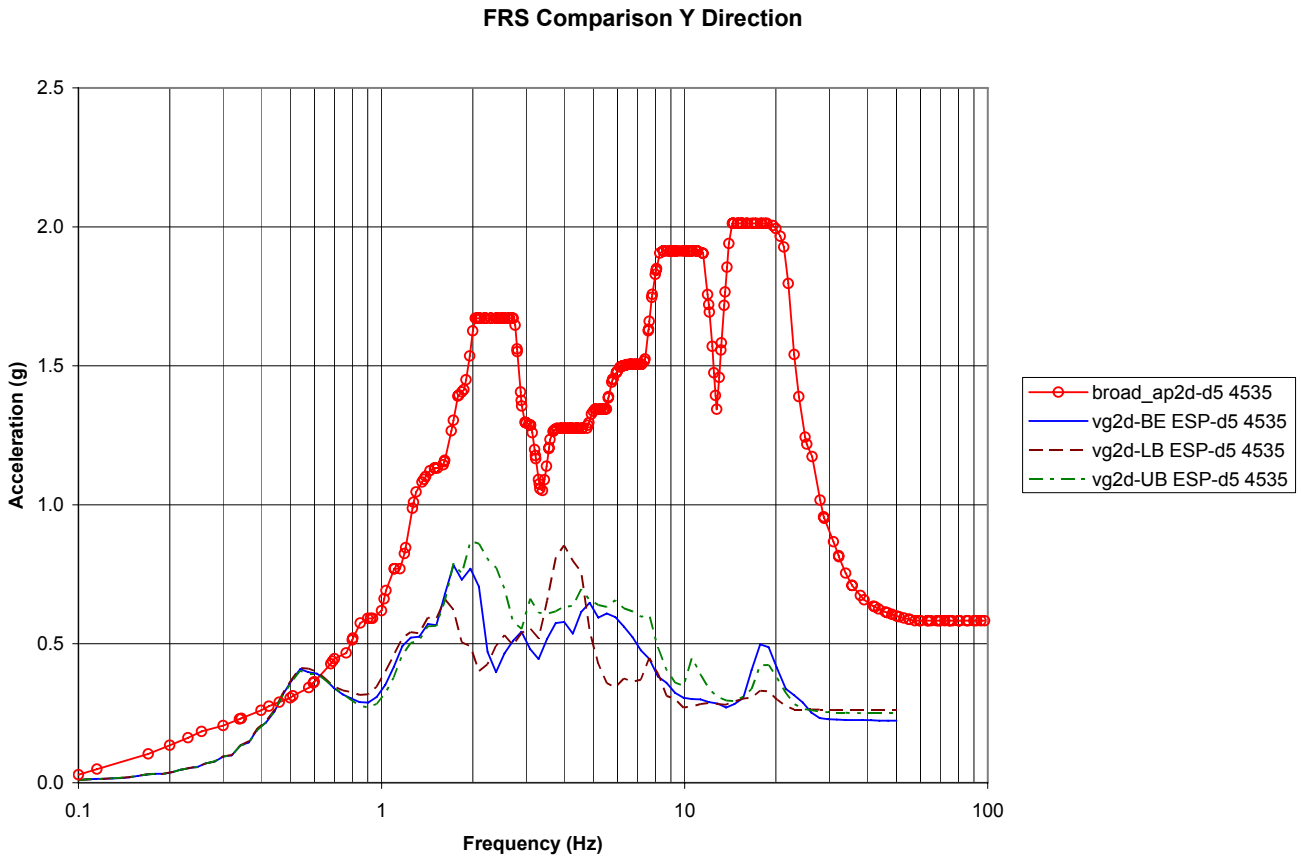


Figure 5.1-17 - Comparison of Node 4535 ESP to AP1000 SSI Envelope, EW Dir

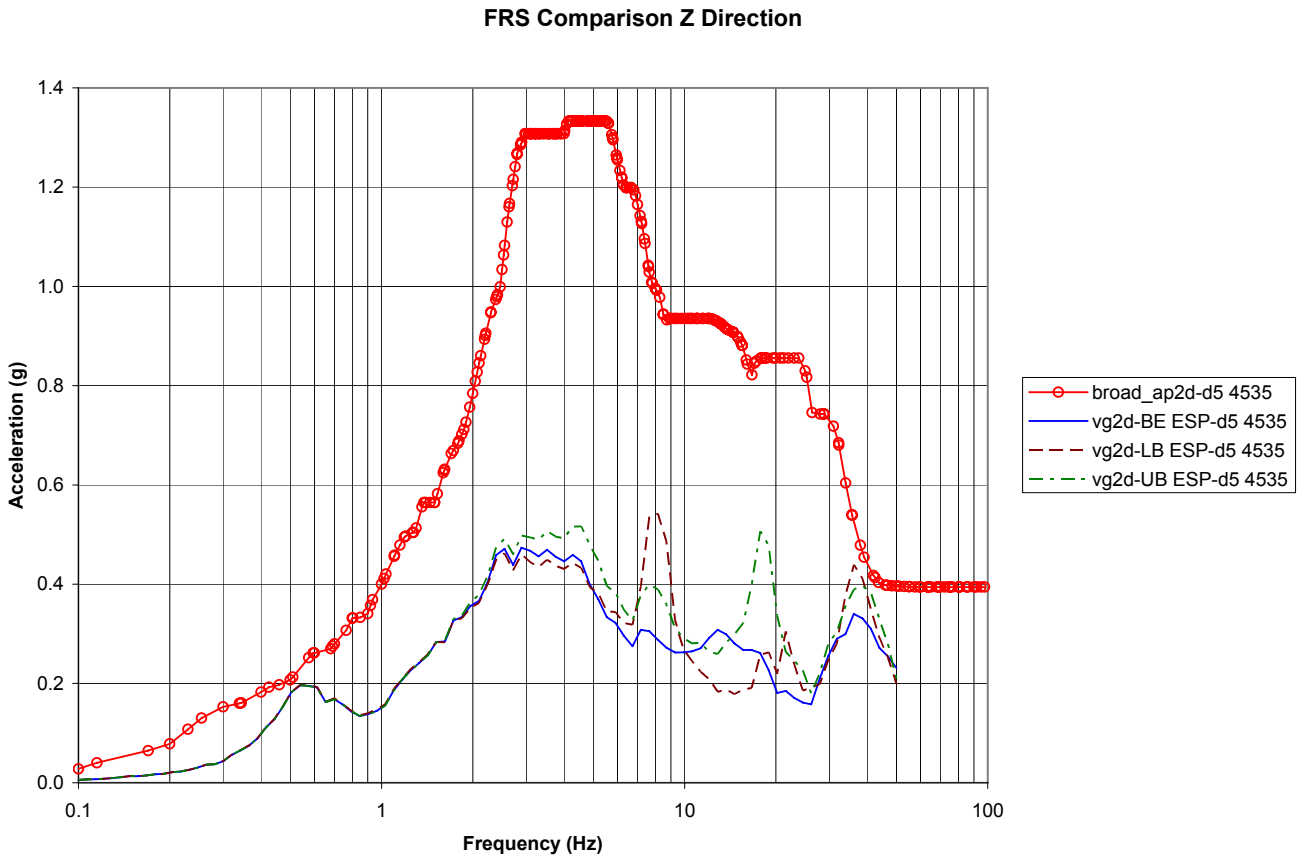


Figure 5.1-18 - Comparison of Node 4535 ESP to AP1000 SSI Envelope, Vertical Dir

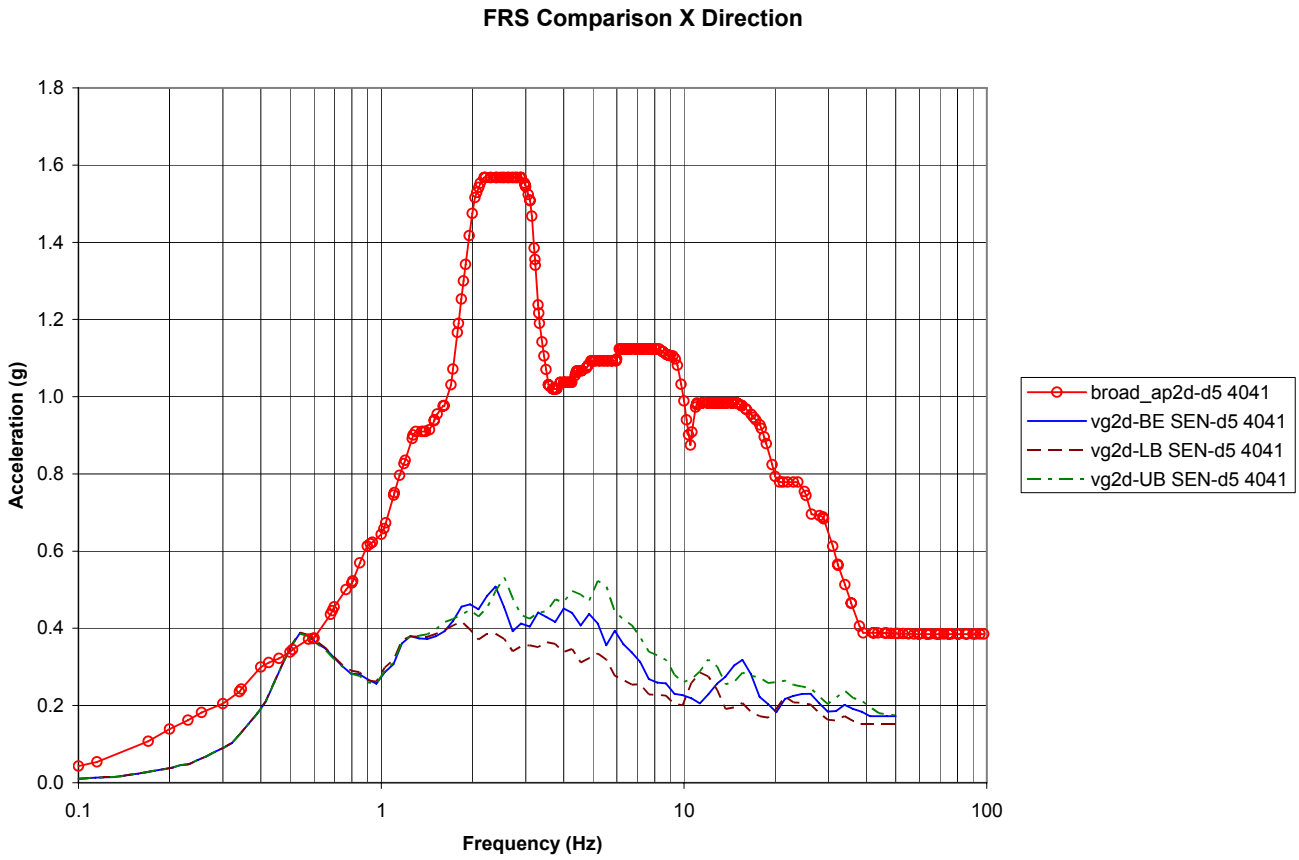


Figure 5.1-19 - Comparison of Node 4041 SEN to AP1000 SSI Envelope, NS Dir

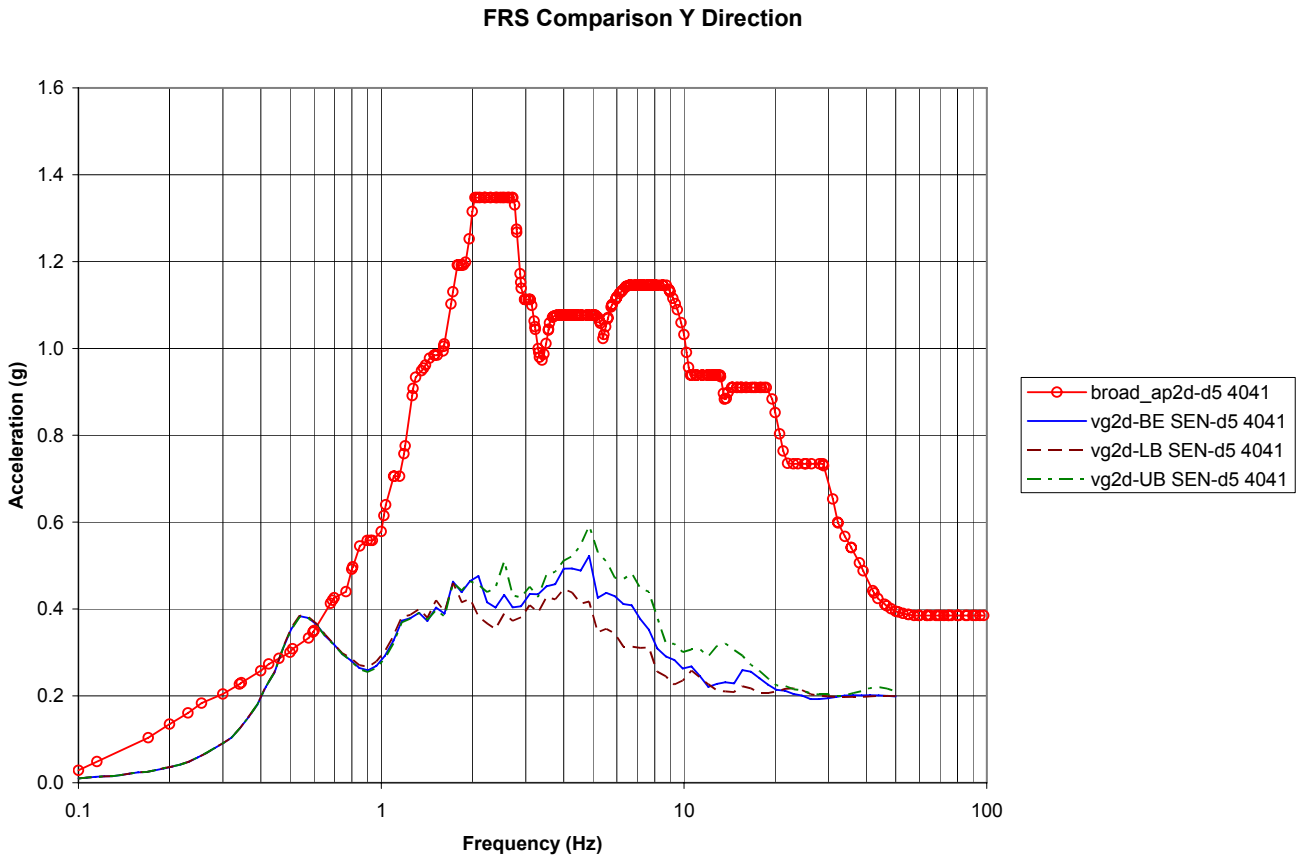


Figure 5.1-20 - Comparison of Node 4041 SEN to AP1000 SSI Envelope, EW Dir

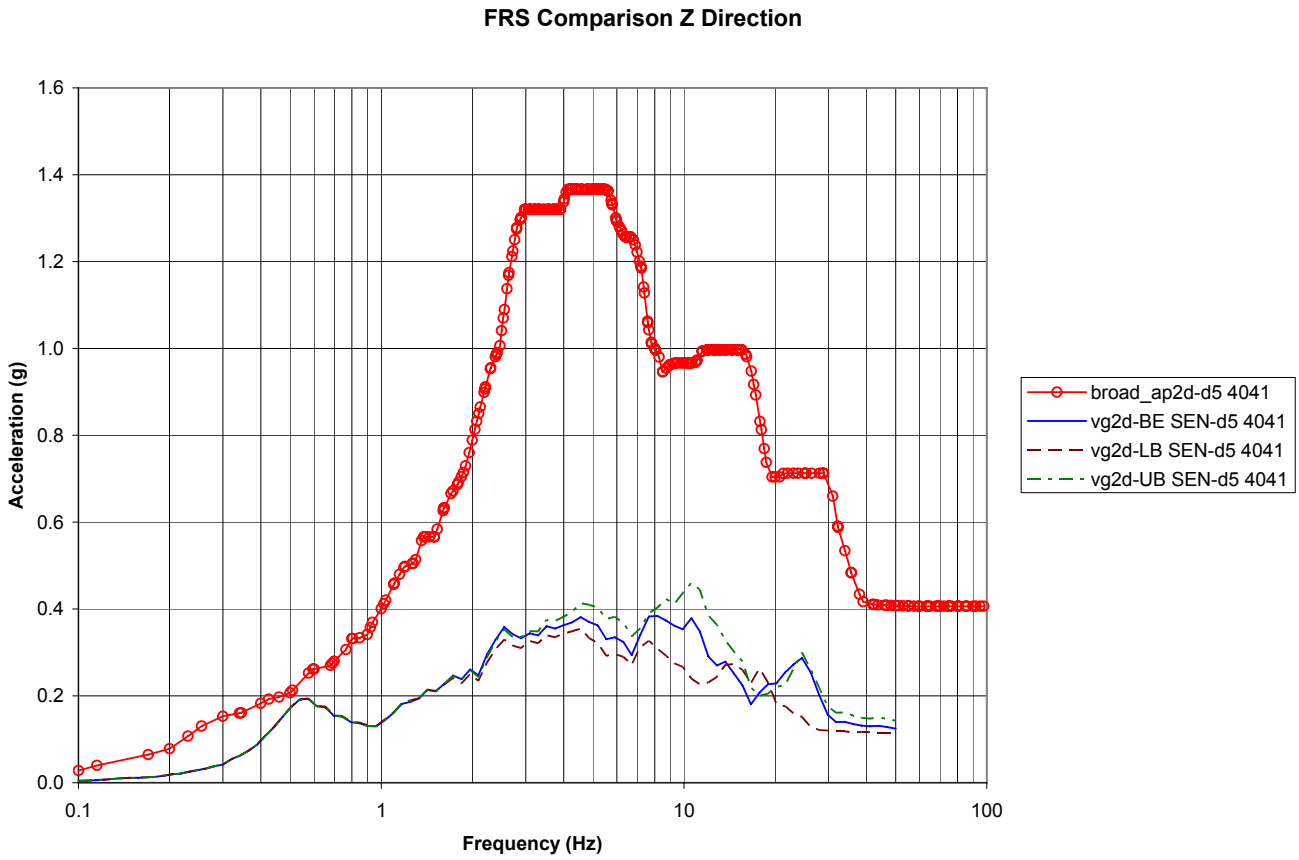


Figure 5.1-21 - Comparison of Node 4041 SEN to AP1000 SSI Envelope, Vertical Dir

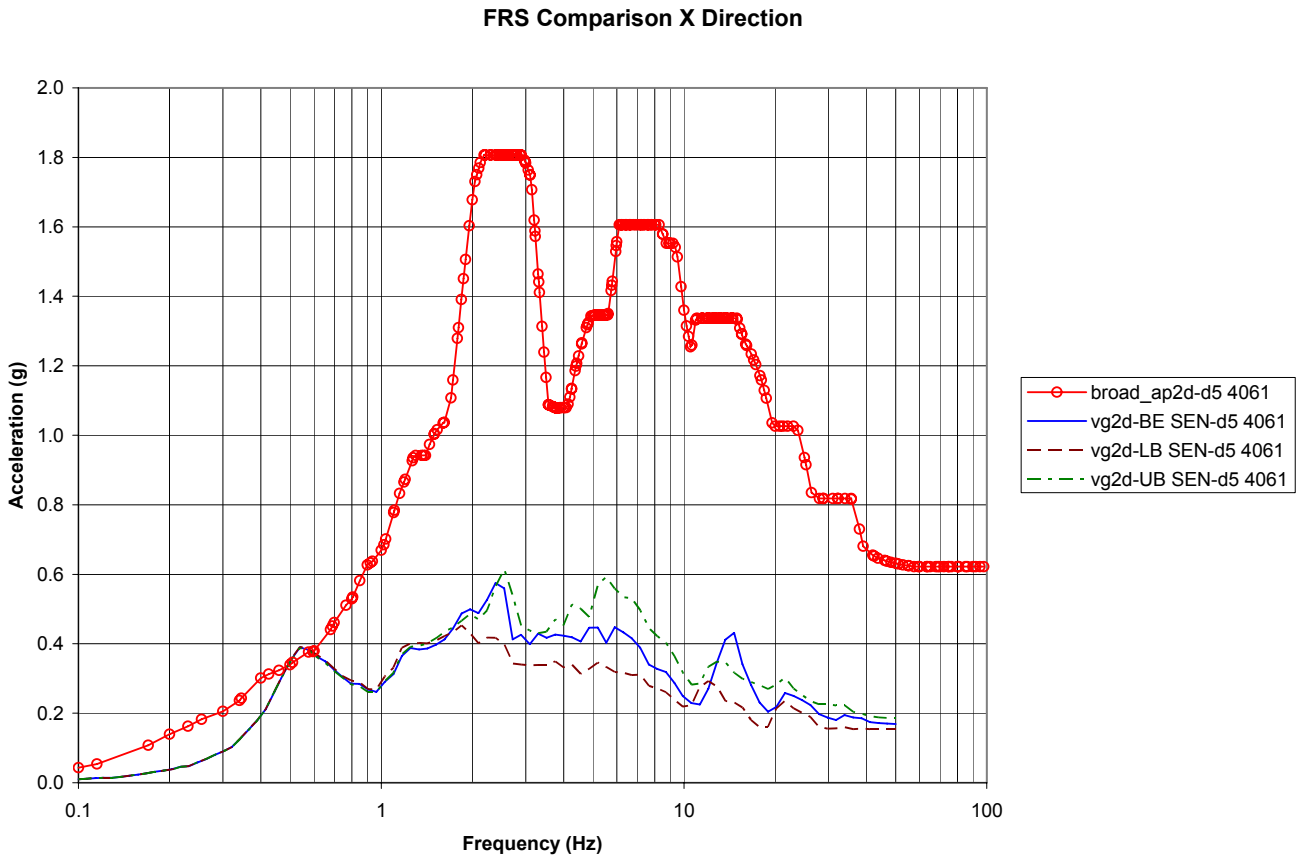


Figure 5.1-22 - Comparison of Node 4061 SEN to AP1000 SSI Envelope, NS Dir

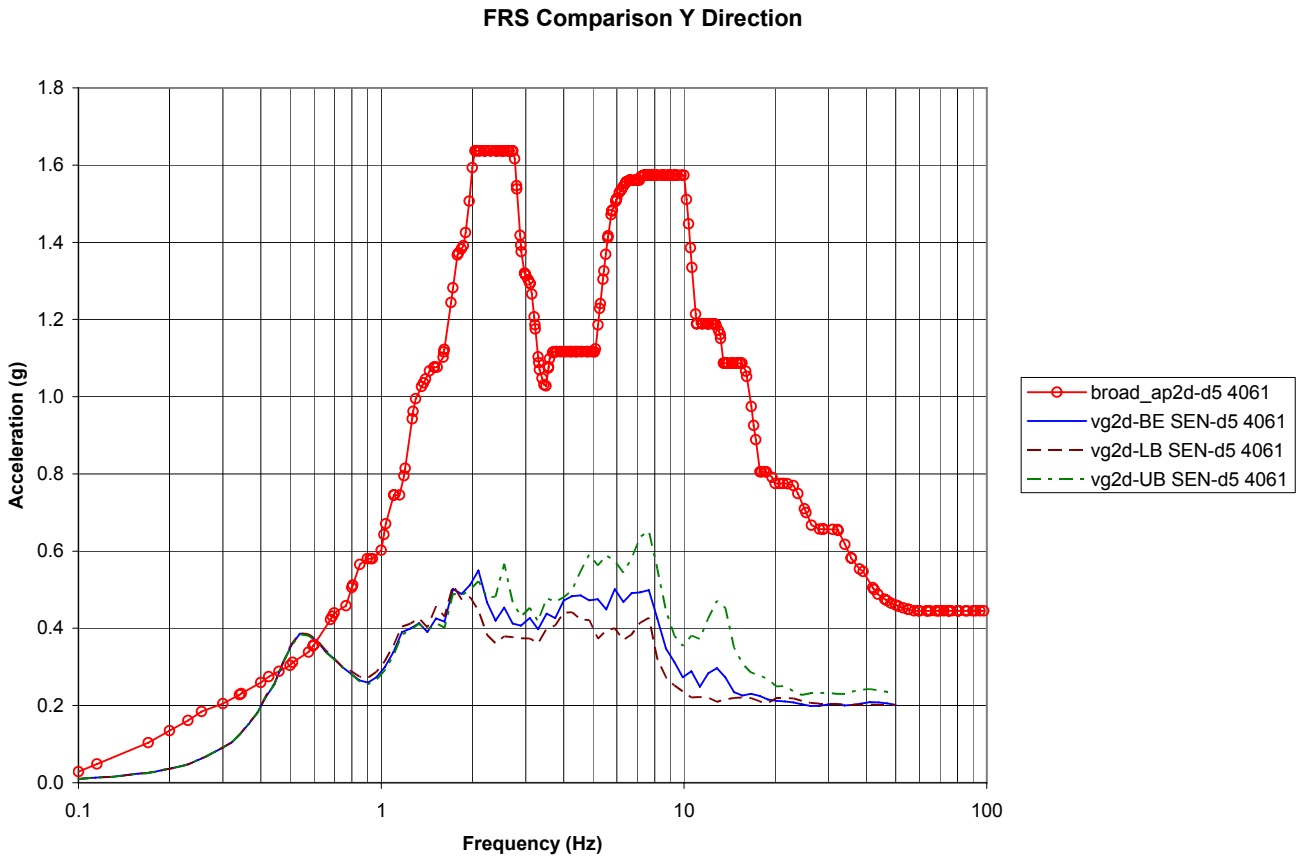


Figure 5.1-23 - Comparison of Node 4061 SEN to AP1000 SSI Envelope, EW Dir

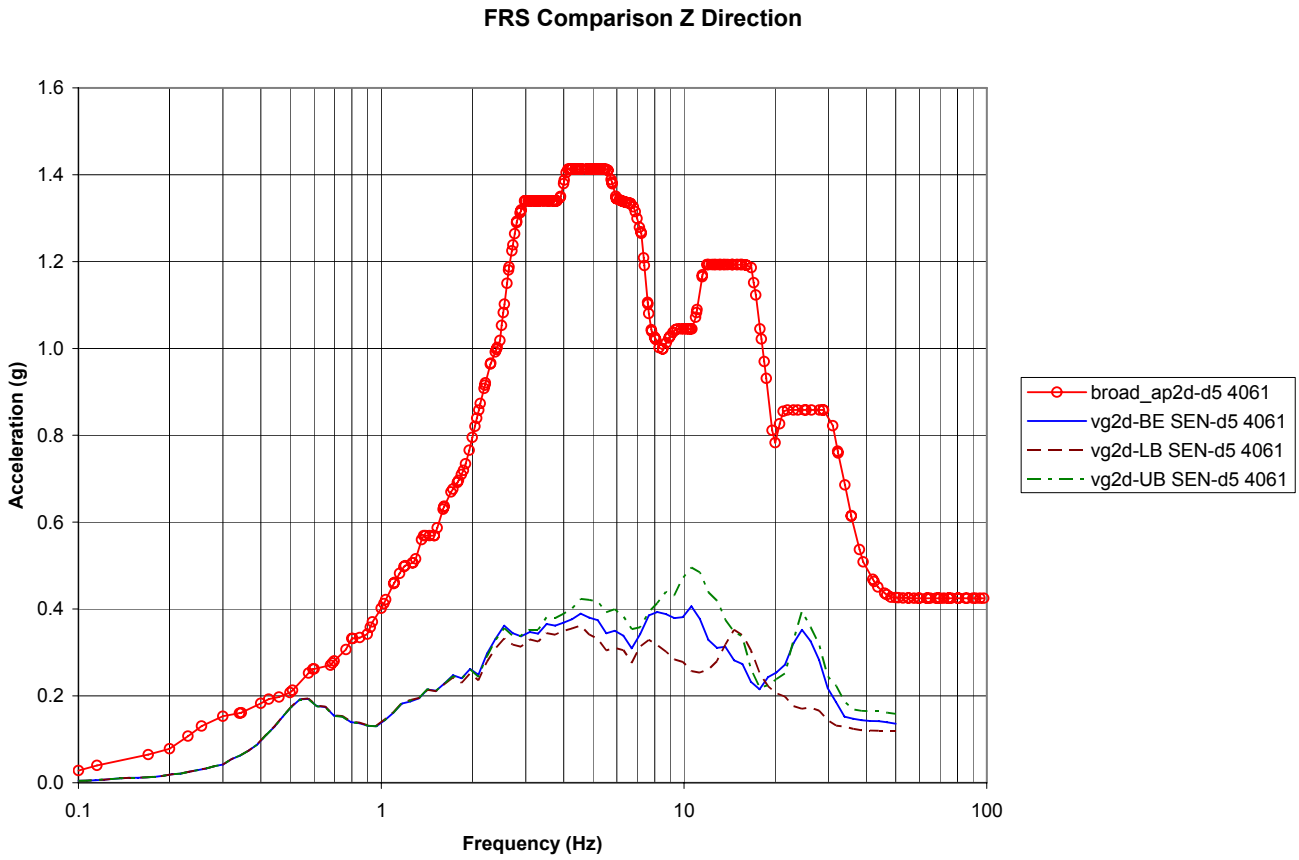


Figure 5.1-24 - Comparison of Node 4061 SEN to AP1000 SSI Envelope, Vertical Dir

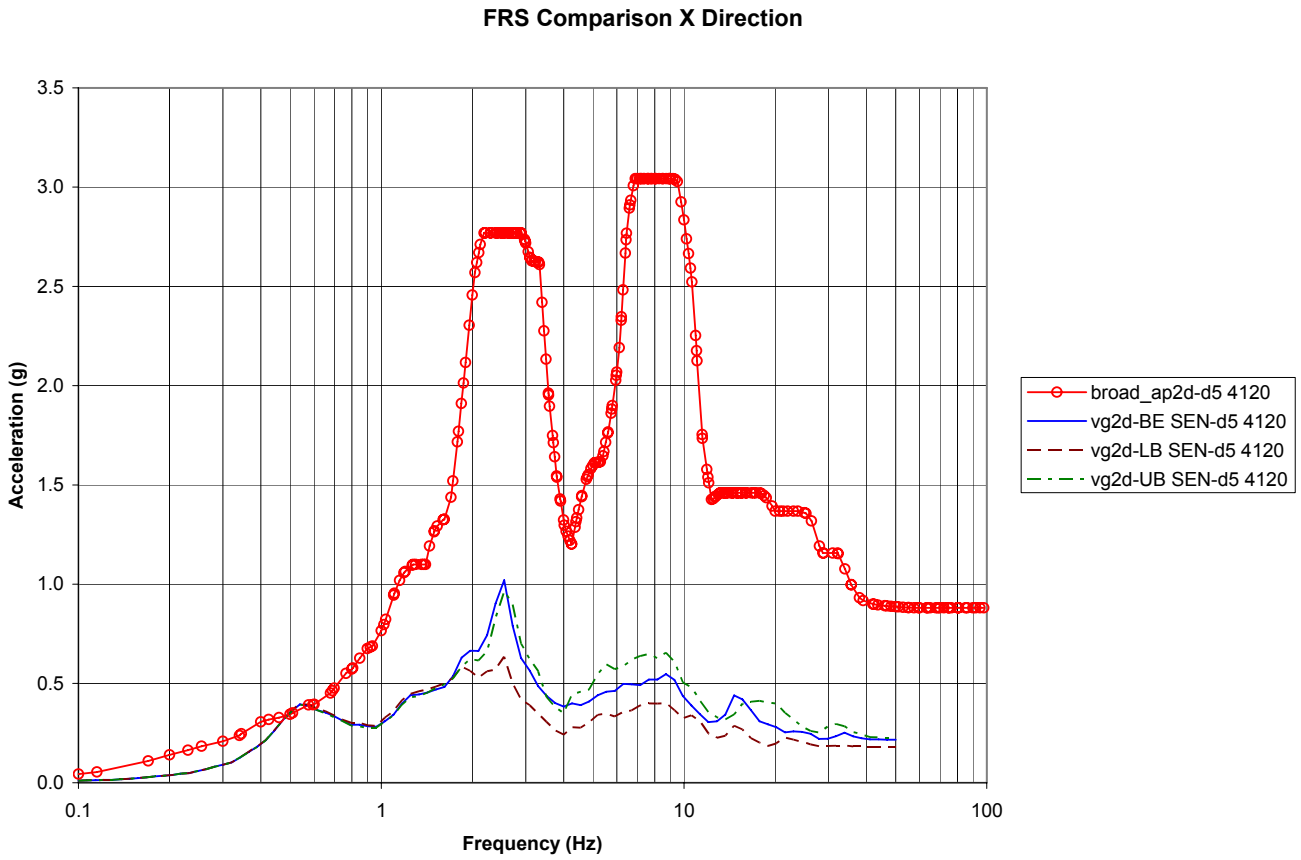


Figure 5.1-25 - Comparison of Node 4120 SEN to AP1000 SSI Envelope, NS Dir

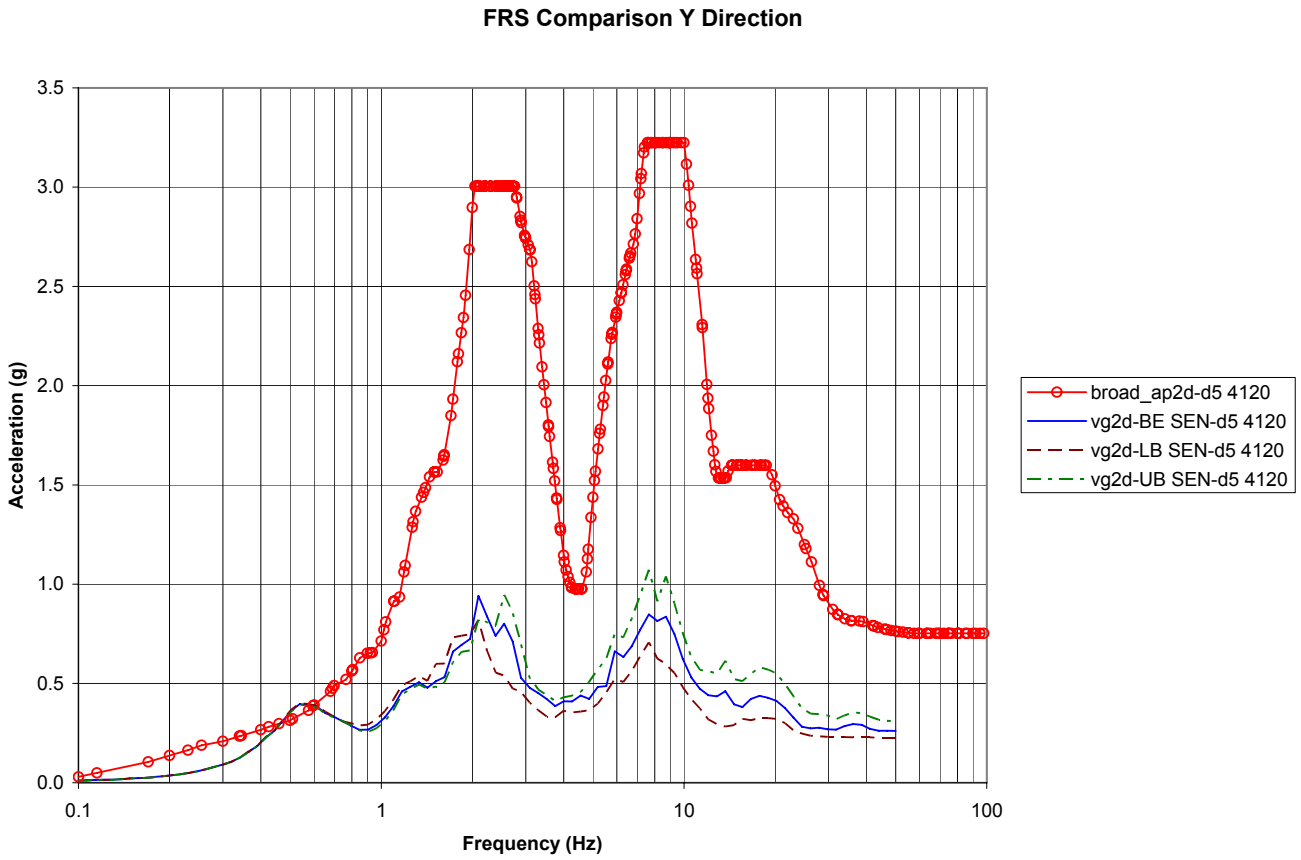


Figure 5.1-26 - Comparison of Node 4120 SEN to AP1000 SSI Envelope, EW Dir

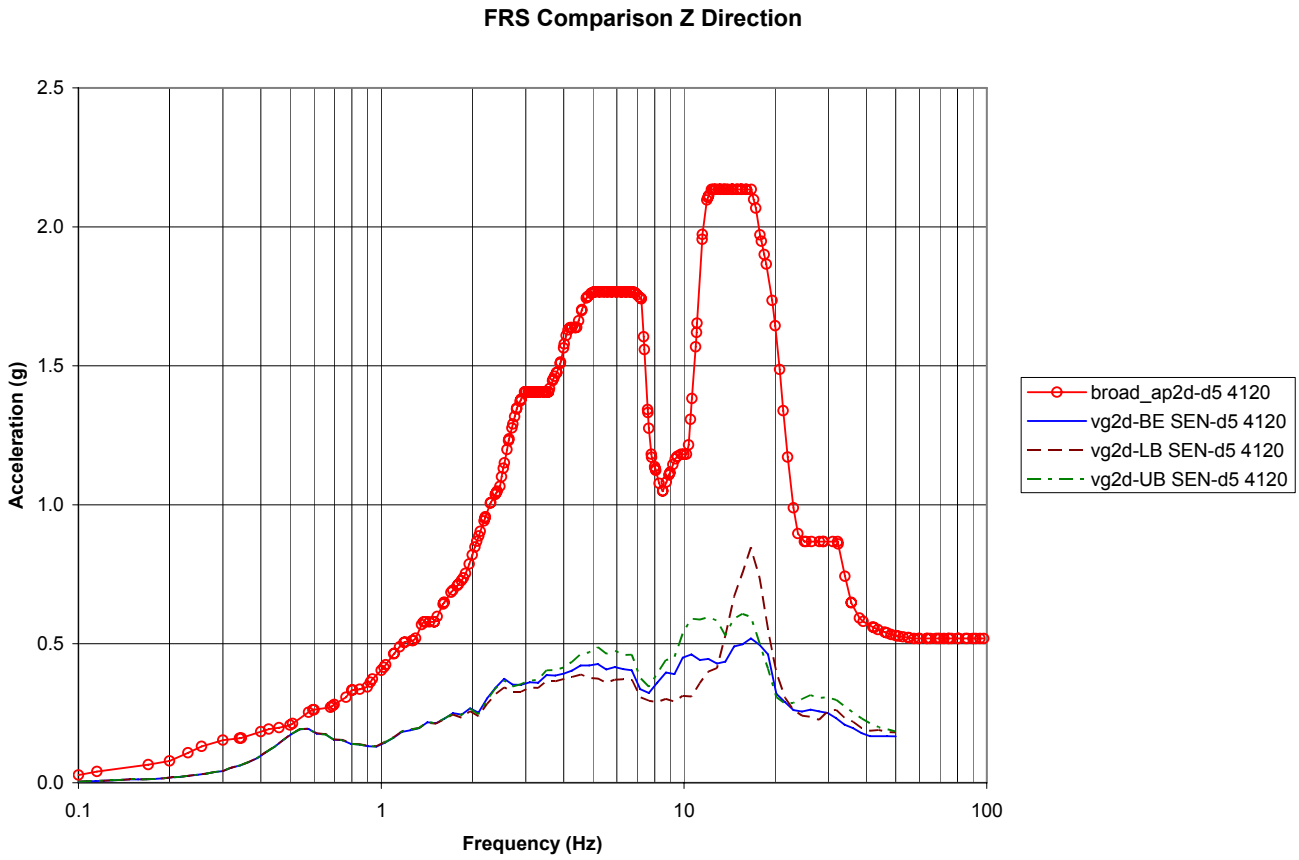


Figure 5.1-27 - Comparison of Node 4120 SEN to AP1000 SSI Envelope, Vertical Dir

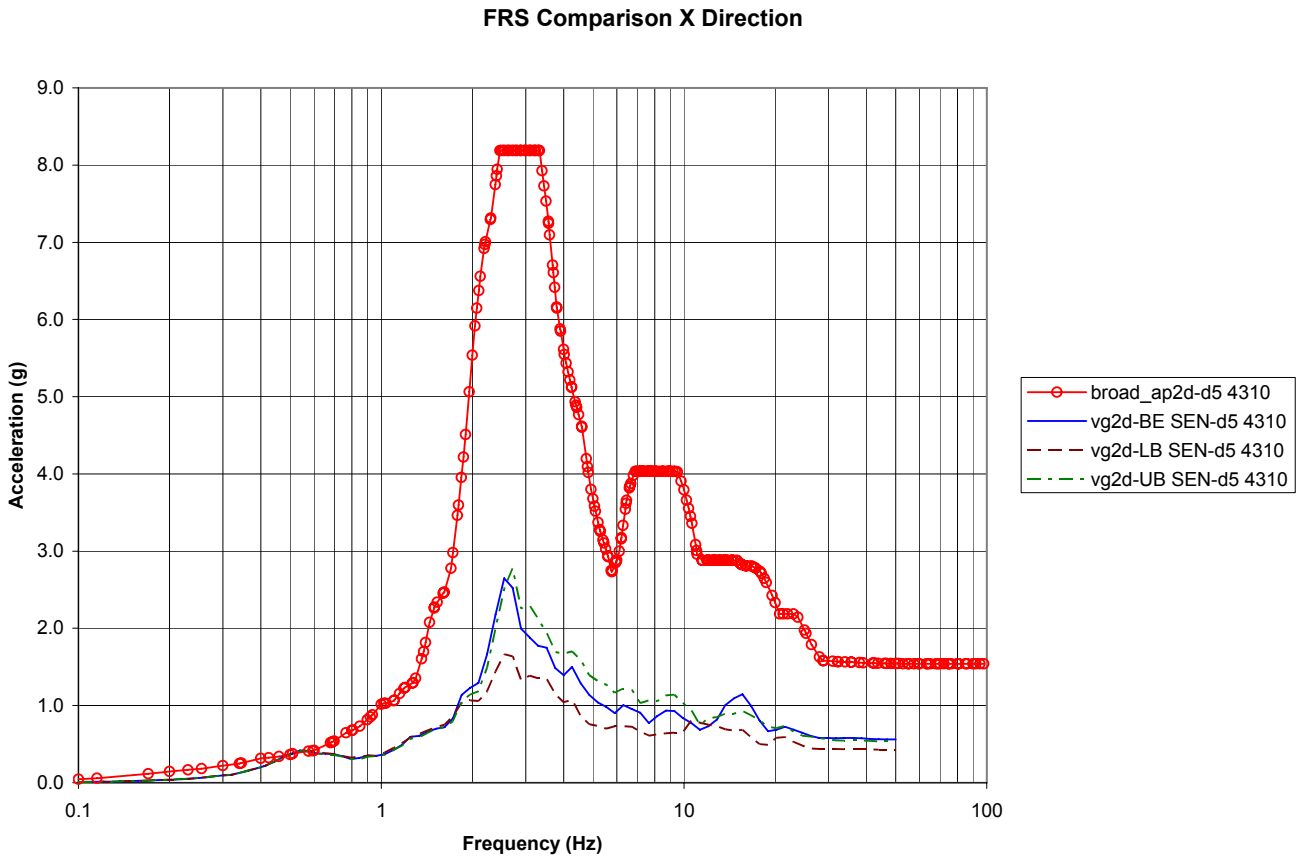


Figure 5.1-28 - Comparison of Node 4310 SEN to AP1000 SSI Envelope, NS Dir

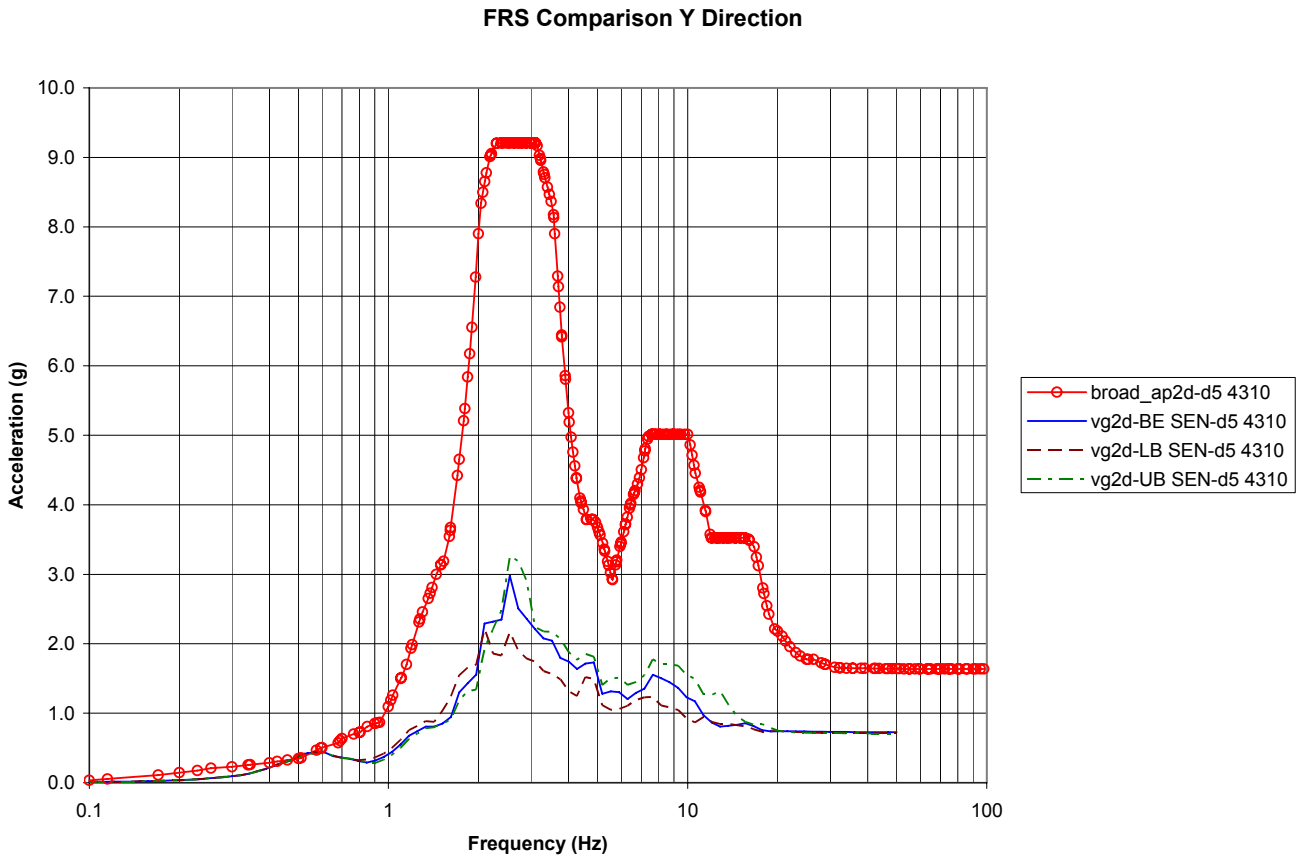


Figure 5.1-29 - Comparison of Node 4310 SEN to AP1000 SSI Envelope, EW Dir

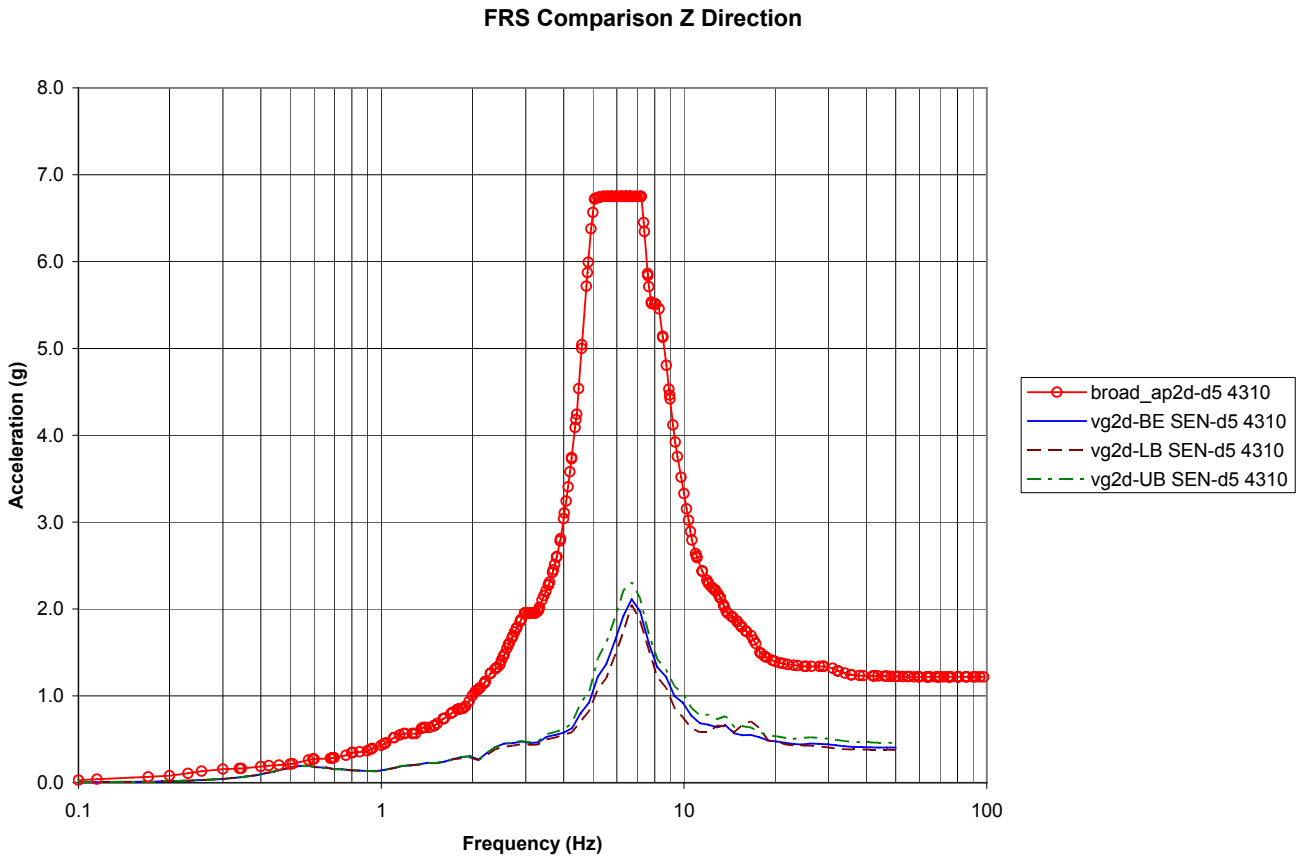


Figure 5.1-30 - Comparison of Node 4310 SEN to AP1000 SSI Envelope, Vertical Dir

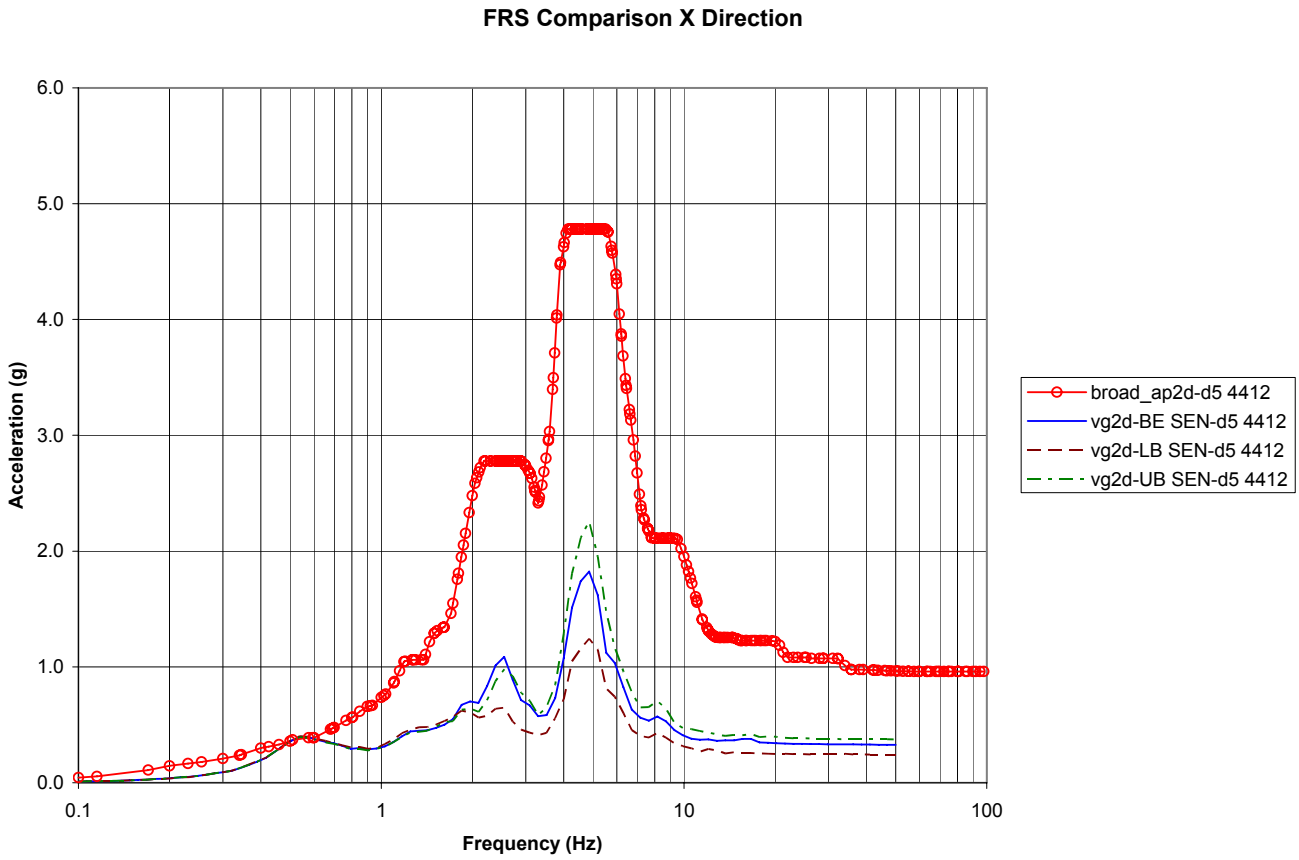


Figure 5.1-31 - Comparison of Node 4412 SEN to AP1000 SSI Envelope, NS Dir

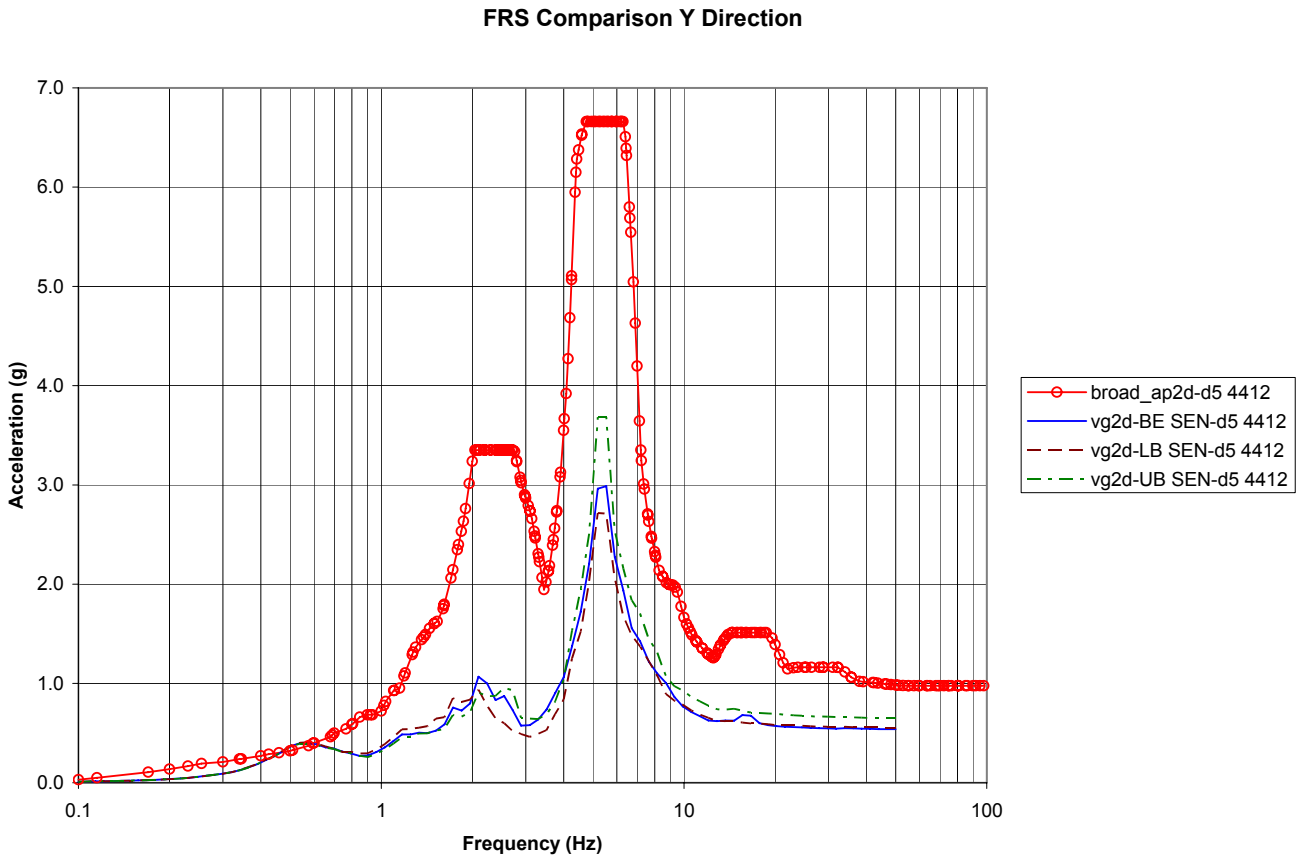


Figure 5.1-32 - Comparison of Node 4412 SEN to AP1000 SSI Envelope, EW Dir

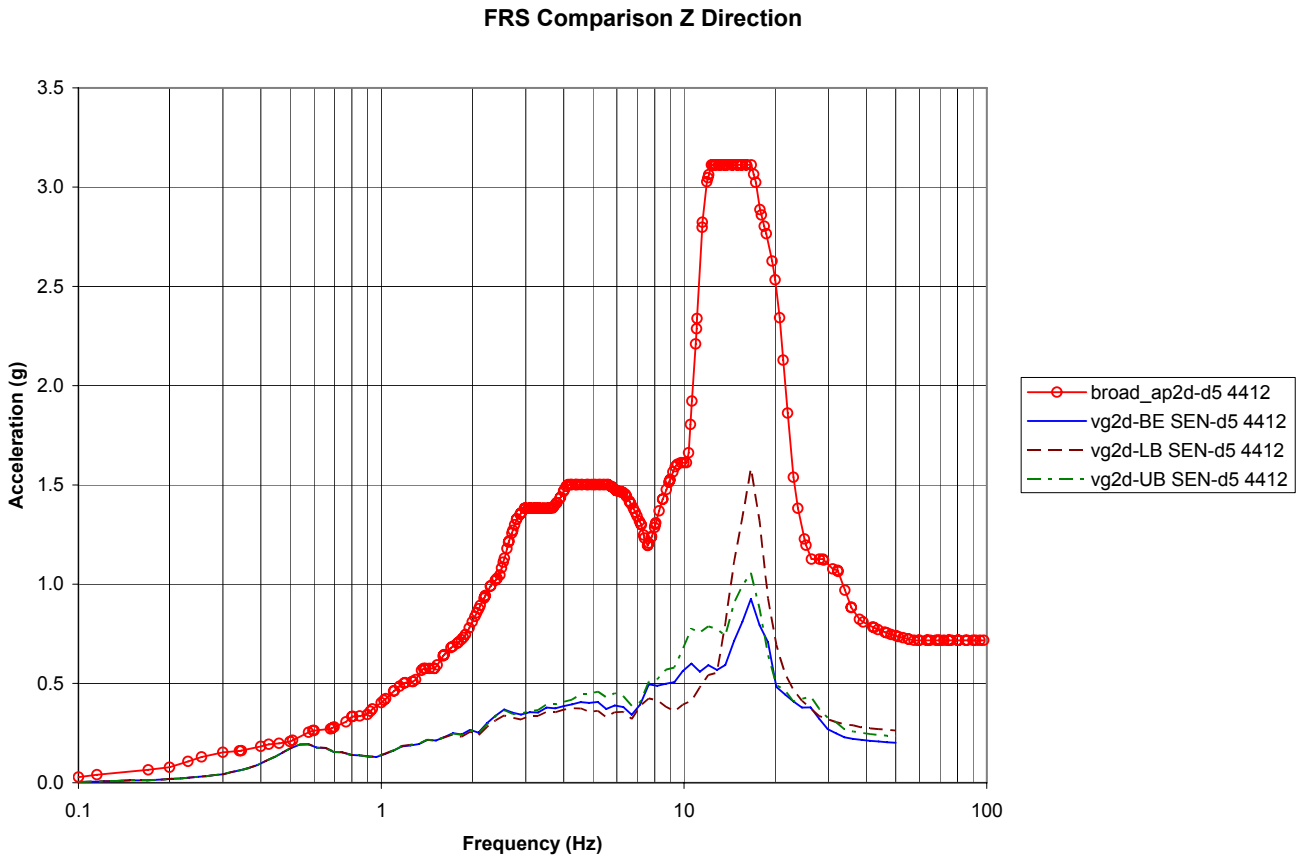


Figure 5.1-33 - Comparison of Node 4412 SEN to AP1000 SSI Envelope, Vertical Dir

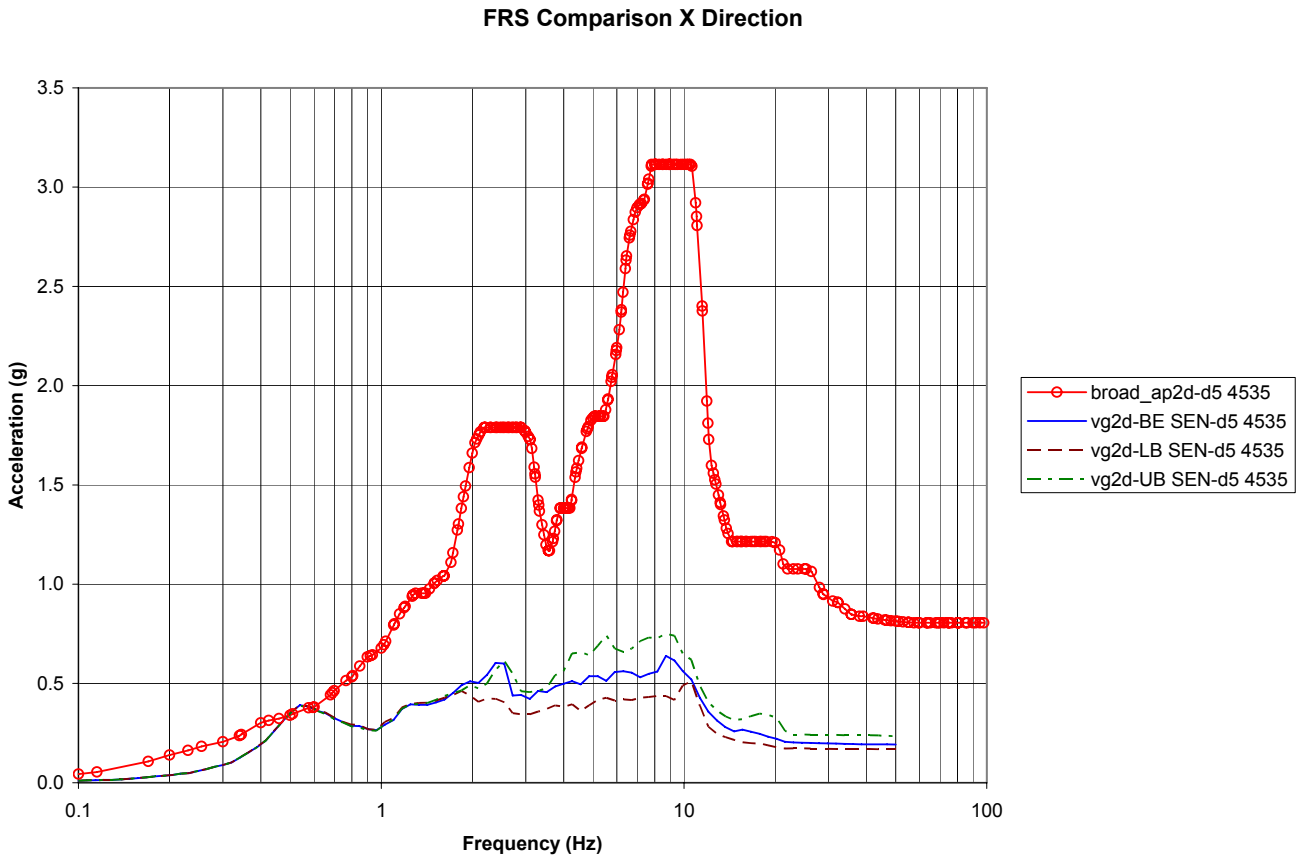


Figure 5.1-34 - Comparison of Node 4535 SEN to AP1000 SSI Envelope, NS Dir

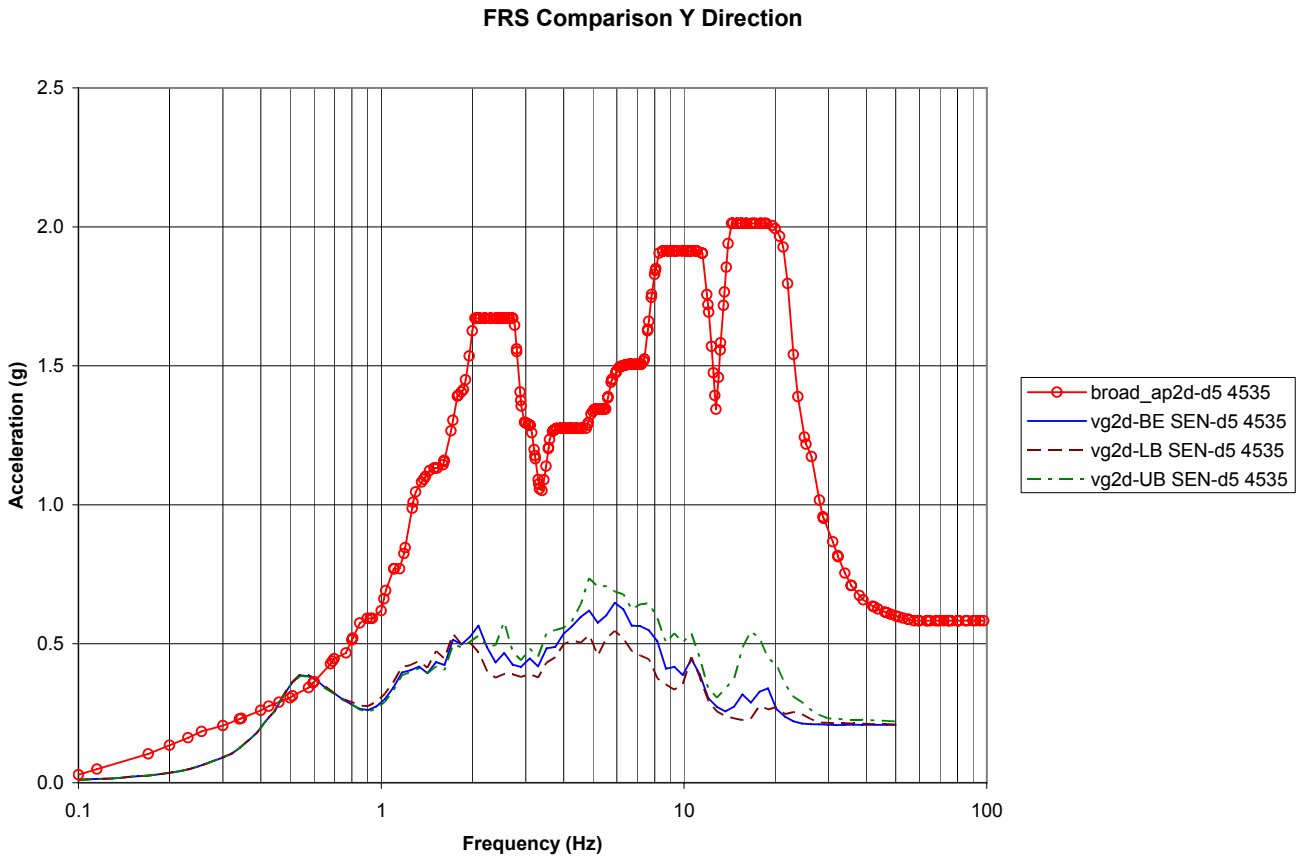


Figure 5.1-35 - Comparison of Node 4535 SEN to AP1000 SSI Envelope, EW Dir

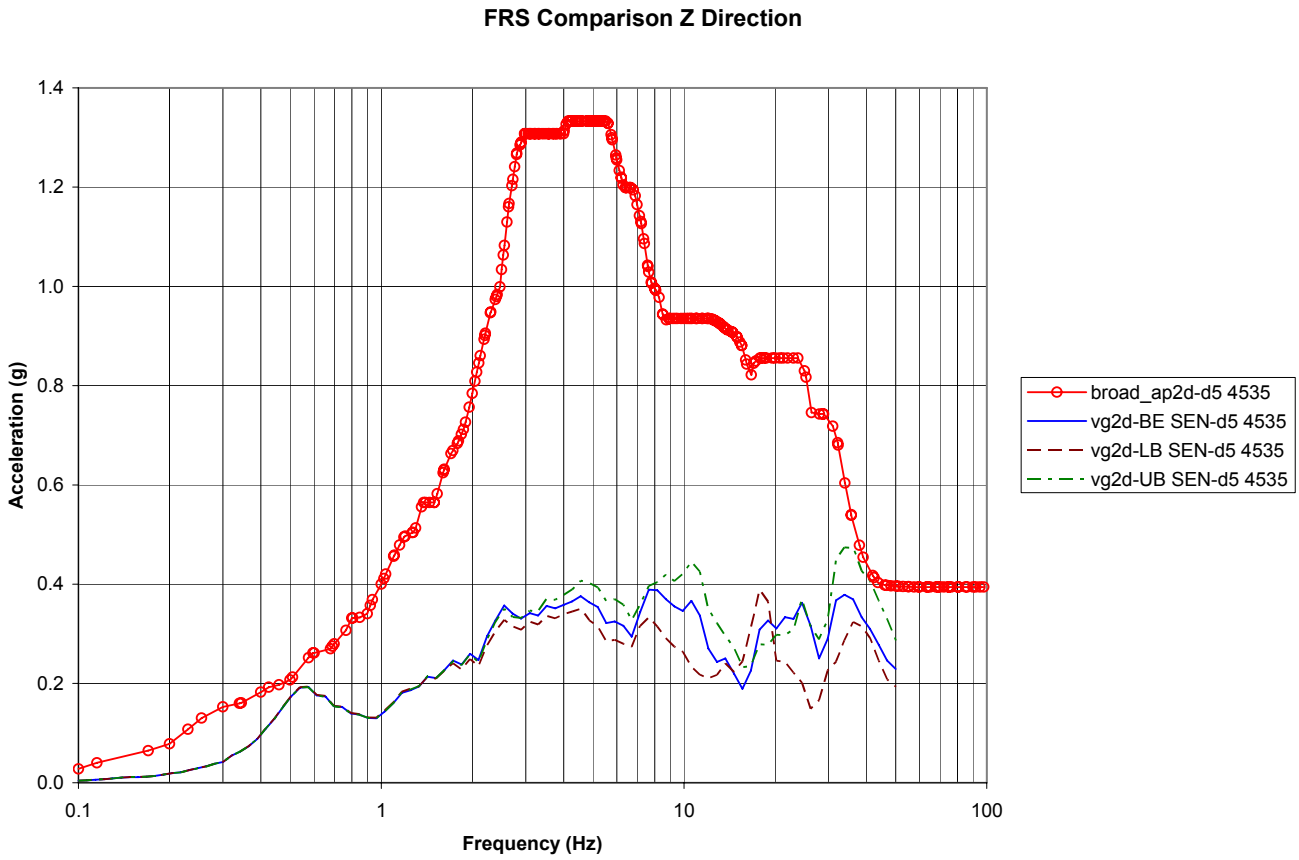


Figure 5.1-36 - Comparison of Node 4535 SEN to AP1000 SSI Envelope, Vertical Dir

5.2 Adjacent Building Seismic Demand

The 2D SASSI east-west model, nuclear island and Annex building (Seismic Category II building), was used to obtain the relative displacement between nuclear island and at top of the annex building at NI elevation 179'-7" and annex building elevation 182'-8". The maximum relative displacement between nuclear island and at top of the Annex building for the ESP Best Estimate soil case is 2", which is less than the 3 inch minimum gap between nuclear island and annex building and which is less than the 2-1/16 inches north-south minimum gap at Unit 3 between nuclear island and annex building between elevations 141'-0" and 154'-0" west of column line I. The response spectra at the location of the Seismic Category II Annex building are given in Figures 5.2-1 and 5.2-2 for the horizontal and vertical directions. The response spectra is compared to the AP1000 SSI Envelope (identified as ap2d) for the ESP best estimate soil case (identified as vg2d) at 5% damping.

The seismic accelerations at the base of the seismic Category III Turbine and Radwaste buildings are given in Table 5.2-1 for the soil cases associated with ESP and SEN soil cases. For the AP1000 generic analysis, the seismic maximum seismic acceleration in each building is greater than 0.5g.

The Vogtle specific maximum bearing pressures for the Radwaste, Annex, and Turbine buildings are given in Section 7.0.

Table 5.2-1 – Turbine and Radwaste Base Seismic Accelerations

(Units: g)

	BE ESP	UB ESP	LB ESP	Max. ESP	BE SEN	UB SEN	LB SEN	Max SEN
Turbine Building								
South Side	0.18	0.20	0.19	0.20	0.17	0.15	0.15	0.17
Center	0.26	0.27	0.31	0.31	0.22	0.22	0.22	0.22
North Side	0.32	0.32	0.41	0.41	0.25	0.25	0.25	0.25
Radwaste Building								
South Side	0.19	0.20	0.20	0.20	0.18	0.16	0.16	0.18
Center	0.29	0.31	0.37	0.37	0.21	0.22	0.22	0.22
North Side	0.21	0.22	0.23	0.23	0.18	0.18	0.18	0.18

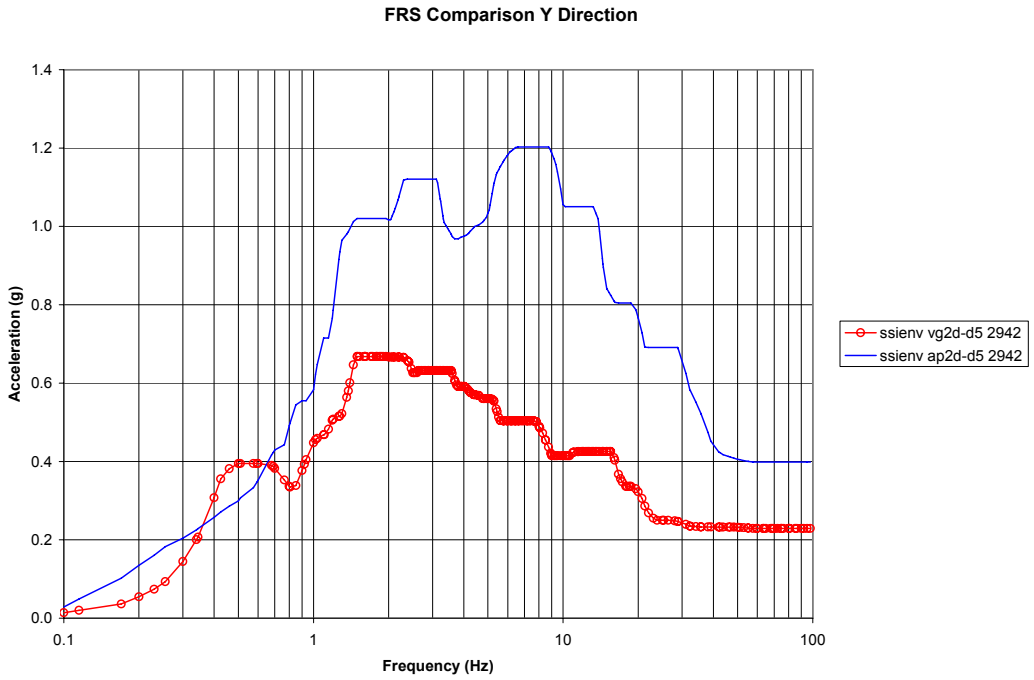


Figure 5.2-1 - Horizontal Seismic Response Spectra at Base of Annex Building

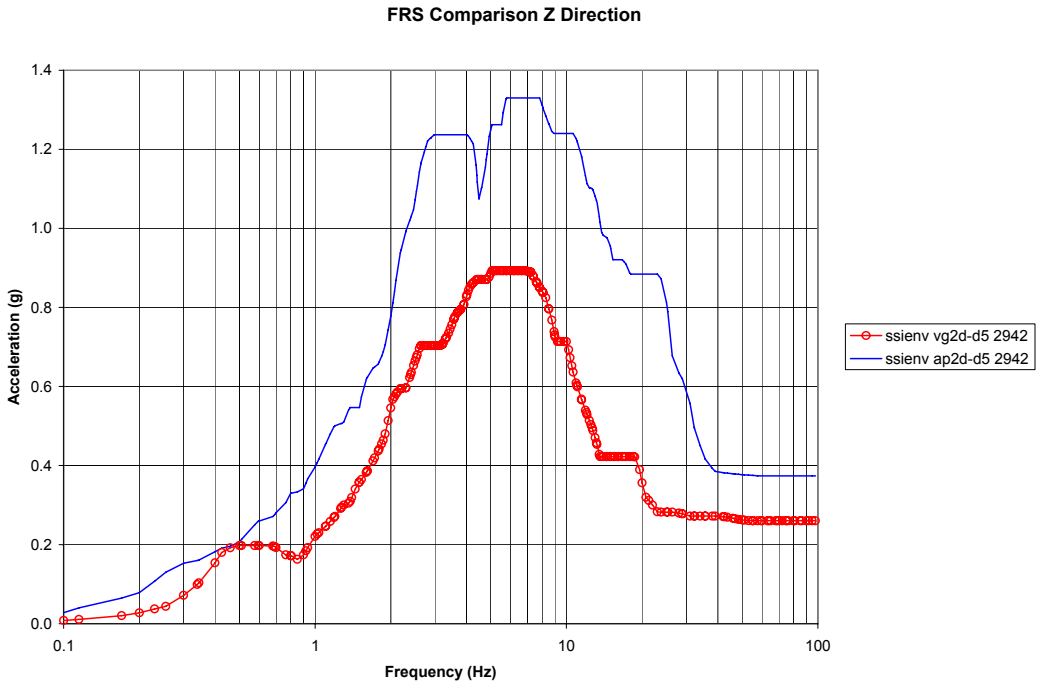


Figure 5.2-2 – Vertical Seismic Response Spectra at Base of Annex Building

5.3 Sensitivity Study of Backfill Behind MSE Wall

A sensitivity study of the Vogtle site-specific NI SSI seismic responses was performed to evaluate the effect of reduced backfill shear wave velocity (V_s) directly behind the MSE wall due to the use of different backfill compaction methods adjacent to the MSE wall. This sensitivity analysis was performed using two-dimensional (2D) seismic soil structure interaction SASSI models. The first model assumes the V_s of the backfill is the same throughout, and is the ESP best estimate (BE) backfill V_s (515-909 fps). The second model utilizes the same BE backfill V_s, except for an area extending from the face of the wall five feet into the backfill for the full height of the wall. Figure 5.3-1 shows the MSE wall configuration. For this area of fill, the ESP LB V_s (421-755 fps) is used. For the sensitivity analysis the ESP BE input time histories are used.

Figure 5.3-2 through 5.3-19 show the FRS comparisons between the Vogtle 2D model with the reduced shear wave velocity directly behind the MSE wall (VG2dMSE-BE ESP-d5) and the Vogtle ESP BE 2D SASSI (vg2d-BE ESP-d5) model at Nodes as shown in Table 5.1-1. These figures also show the AP1000 SASSI 2D SSI FRS envelope.

The FRS for the model that included the LB backfill V_s directly behind the MSE wall were almost identical to the FRS of the same model without any reduction in V_s directly behind the MSE wall. Therefore, the potentially reduced shear wave velocity of the backfill directly behind the MSE wall does not affect the Nuclear Island building responses.

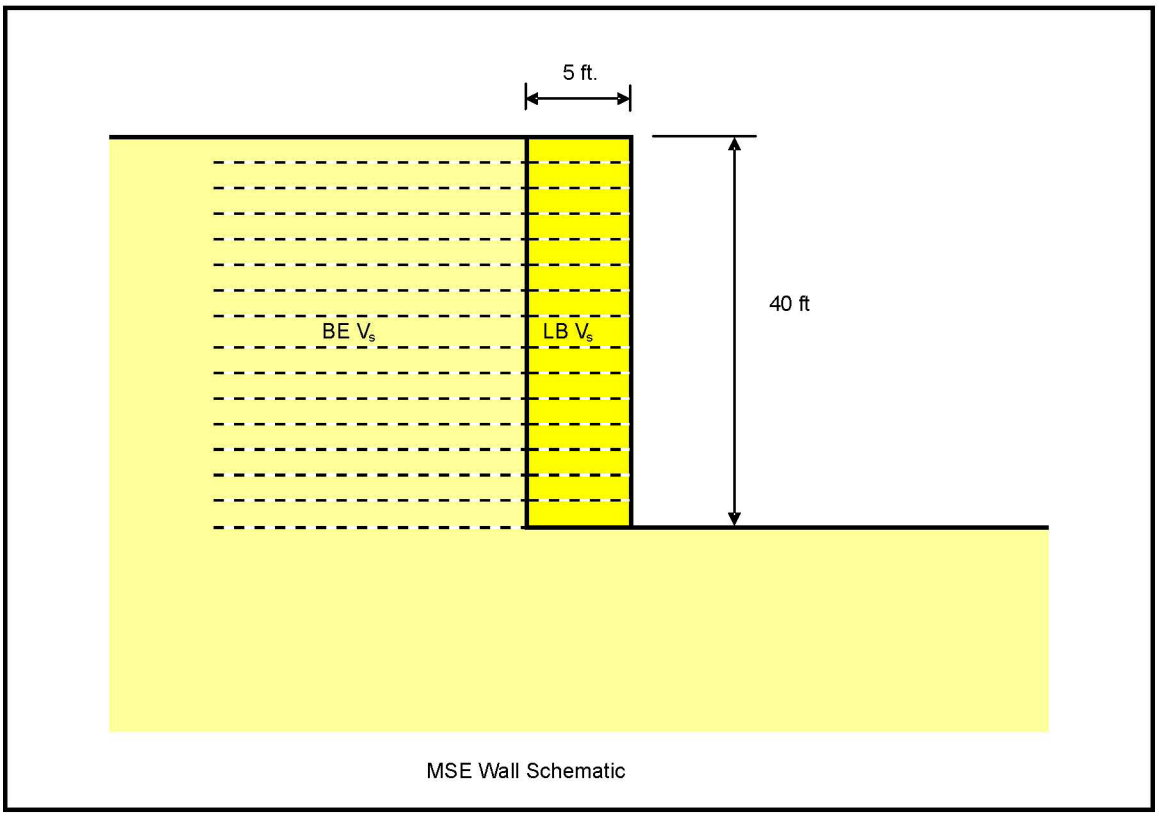


Figure 5.3-1 –2D SASSI Model with MSE Wall
Figure Not To Scale

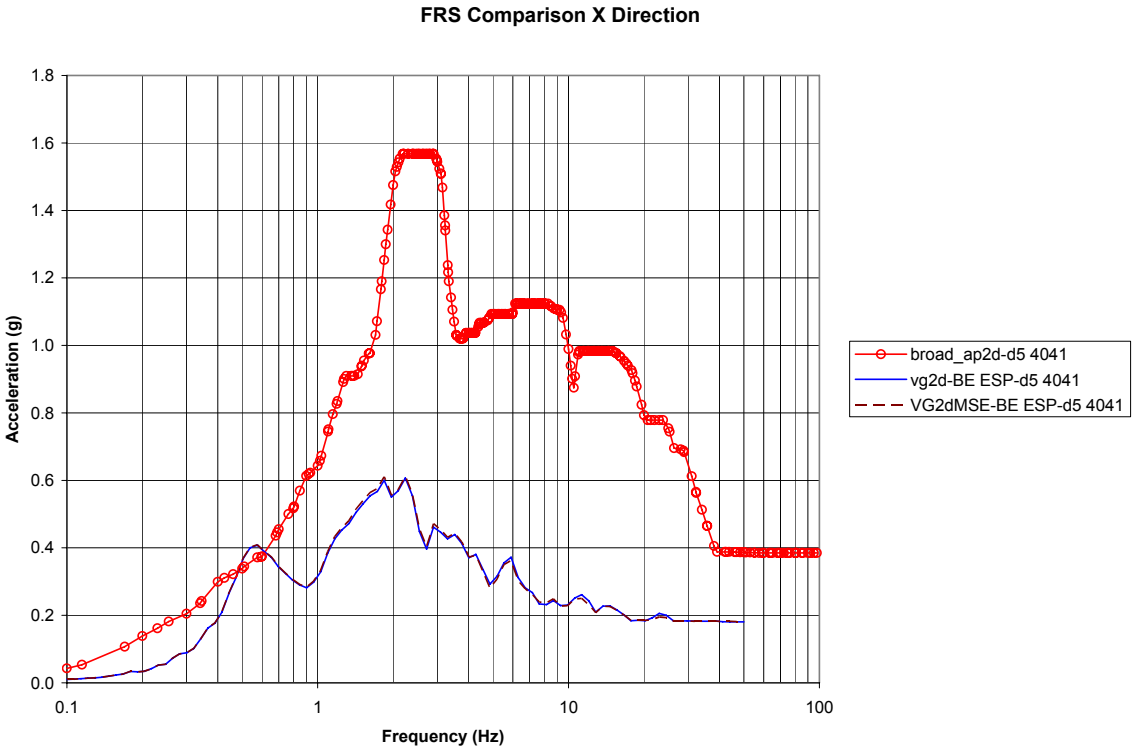


Figure 5.3-2 – FRS Comparison at Node 4041 (X Direction)

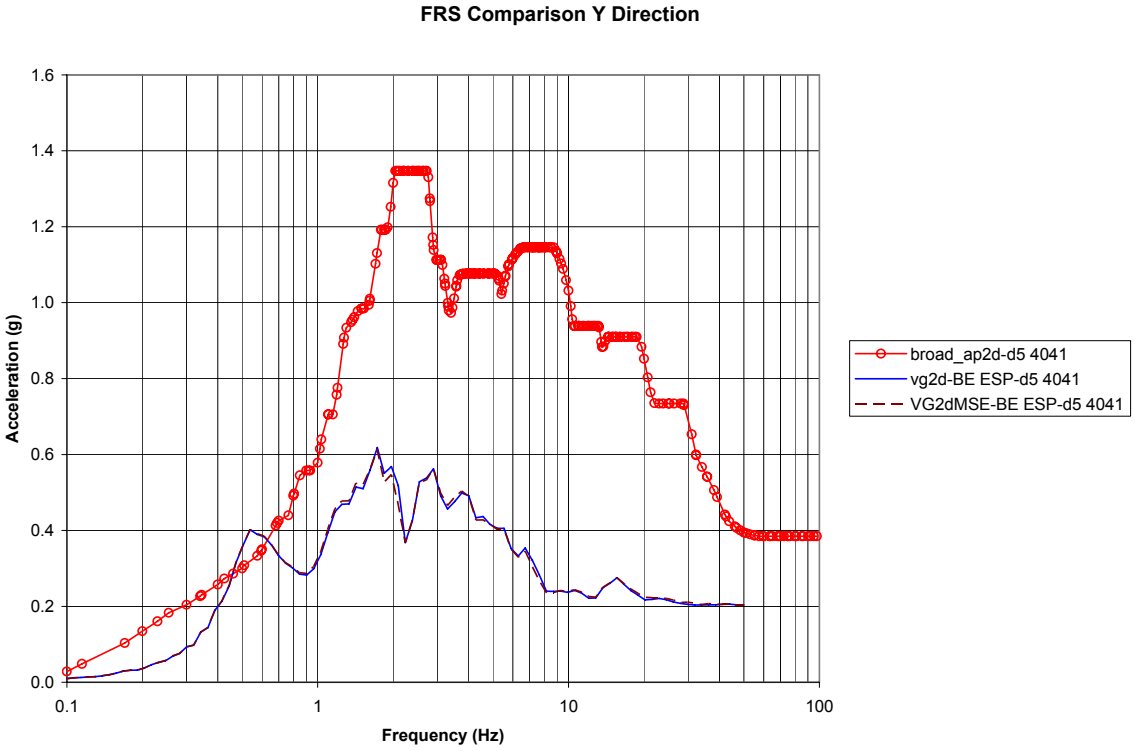


Figure 5.3-3 – FRS Comparison at Node 4041 (Y Direction)

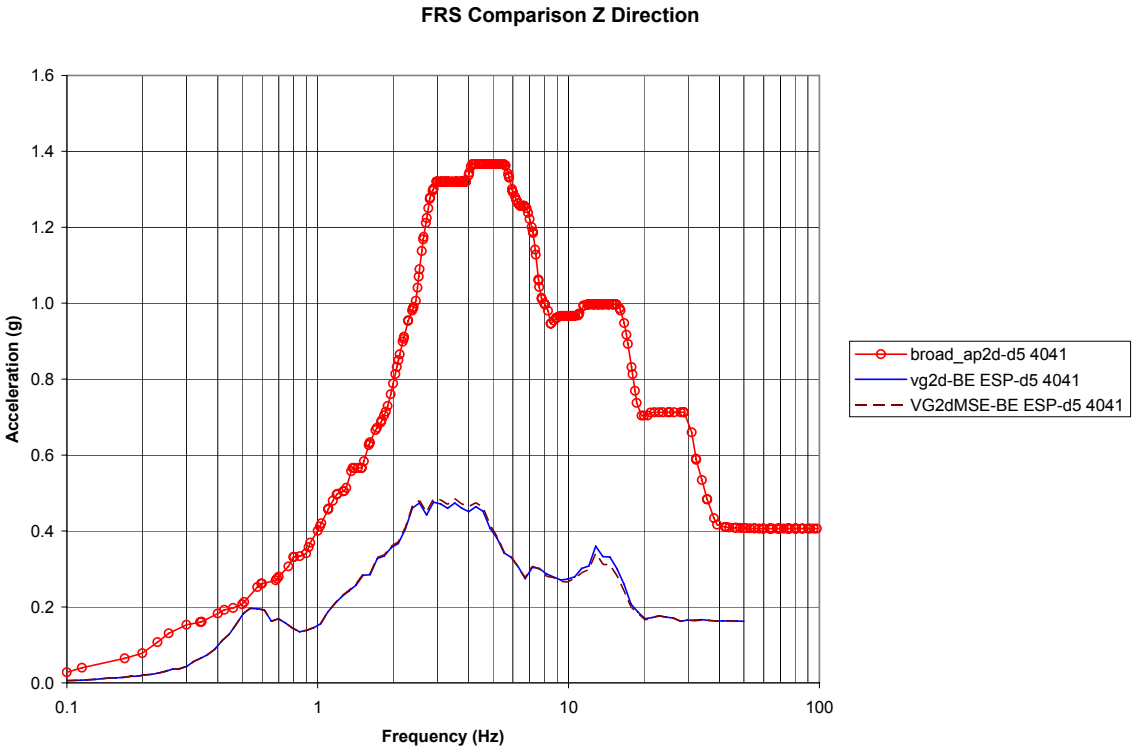


Figure 5.3-4 – FRS Comparison at Node 4041 (Z Direction)

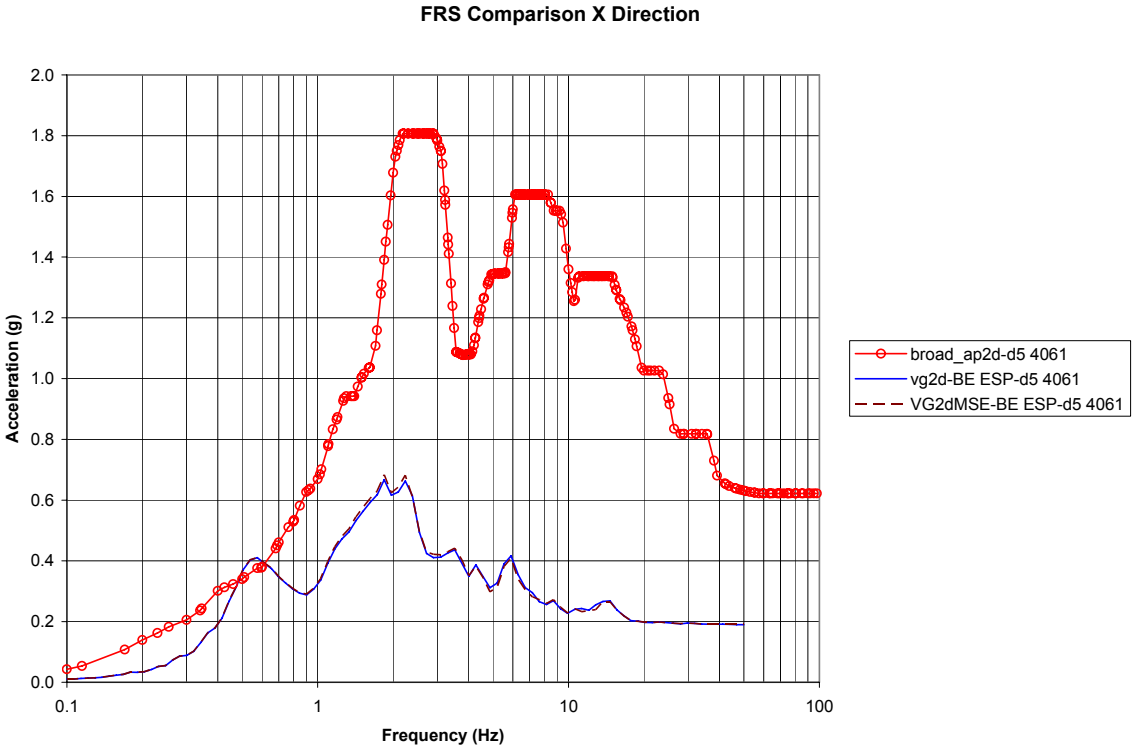


Figure 5.3-5 – FRS Comparison at Node 4061 (X Direction)

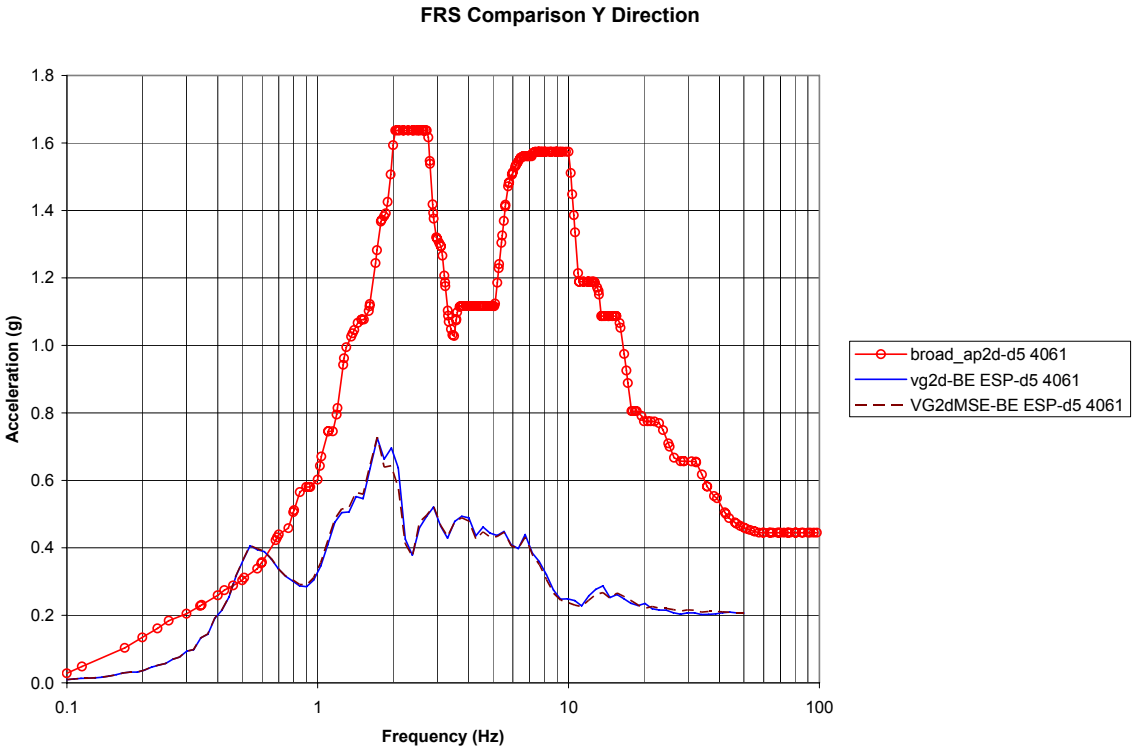


Figure 5.3-6 – FRS Comparison at Node 4061 (Y Direction)

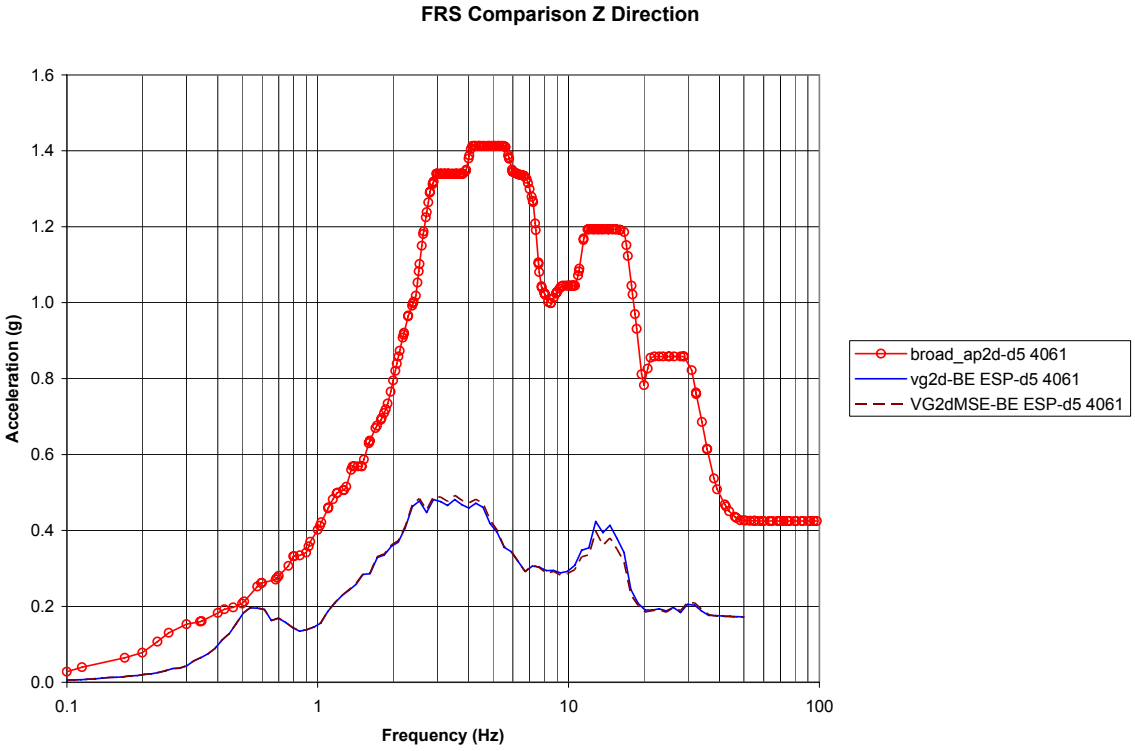


Figure 5.3-7 – FRS Comparison at Node 4061 (Z Direction)

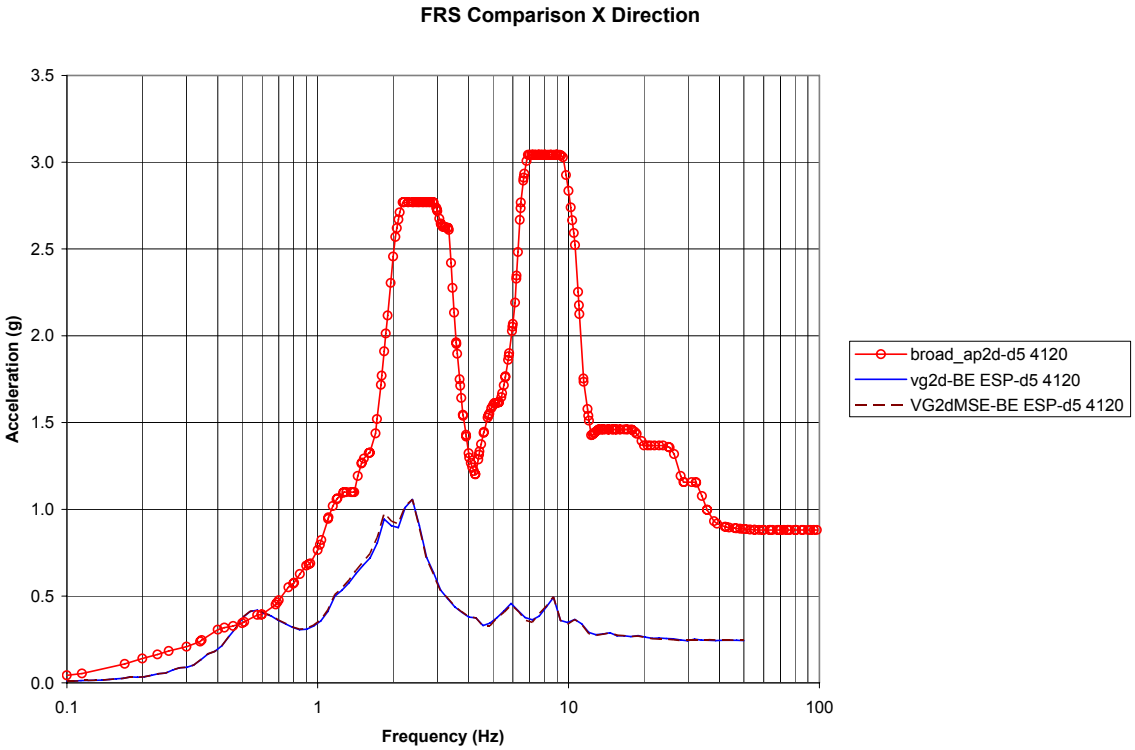


Figure 5.3-8 – FRS Comparison at Node 4120 (X Direction)

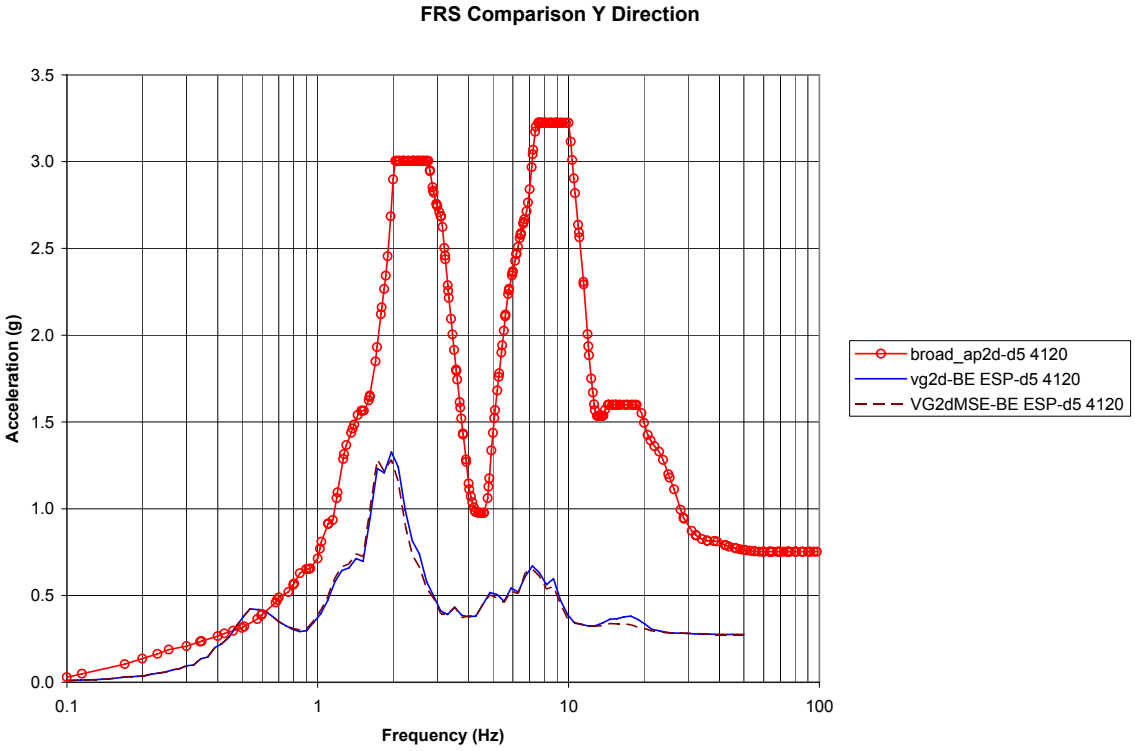


Figure 5.3-9 – FRS Comparison at Node 4120 (Y Direction)

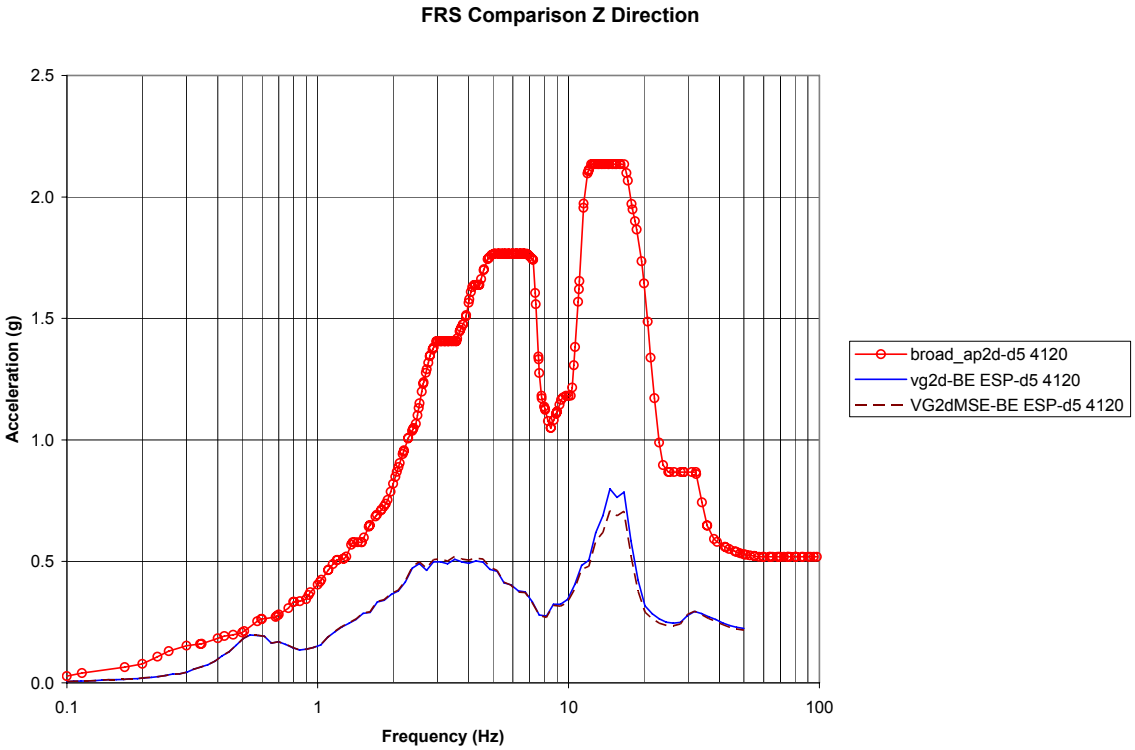


Figure 5.3-10 – FRS Comparison at Node 4120 (Z Direction)

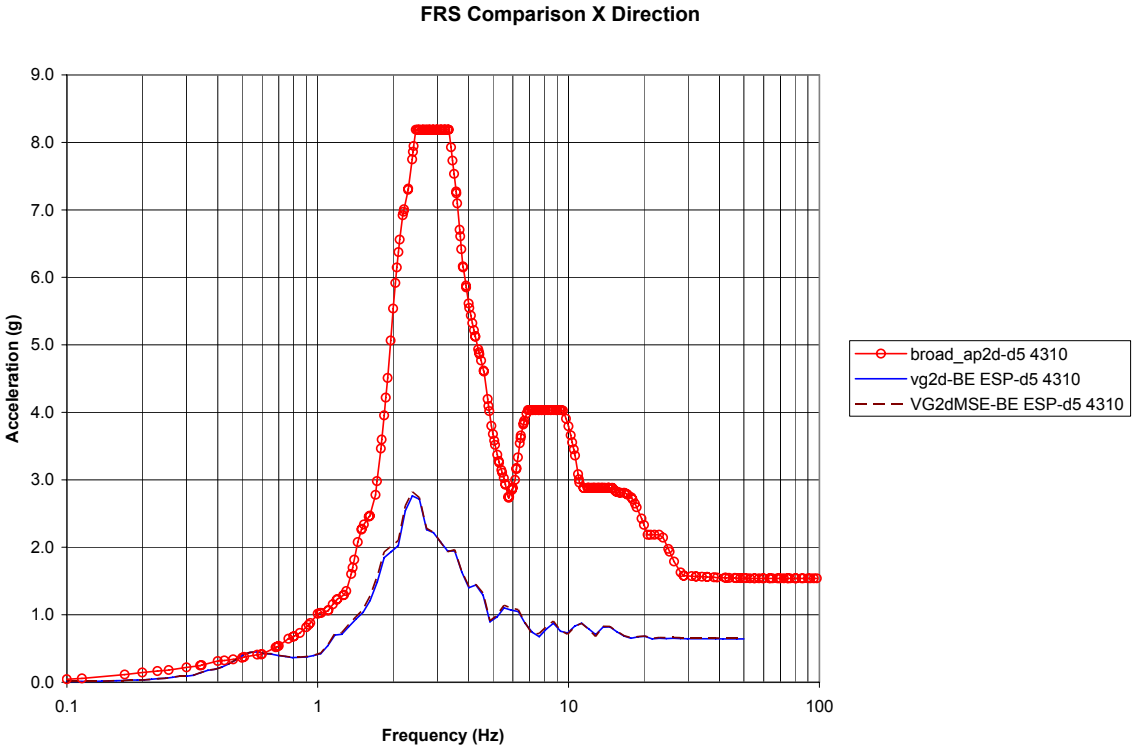


Figure 5.3-11 – FRS Comparison at Node 4310 (X Direction)

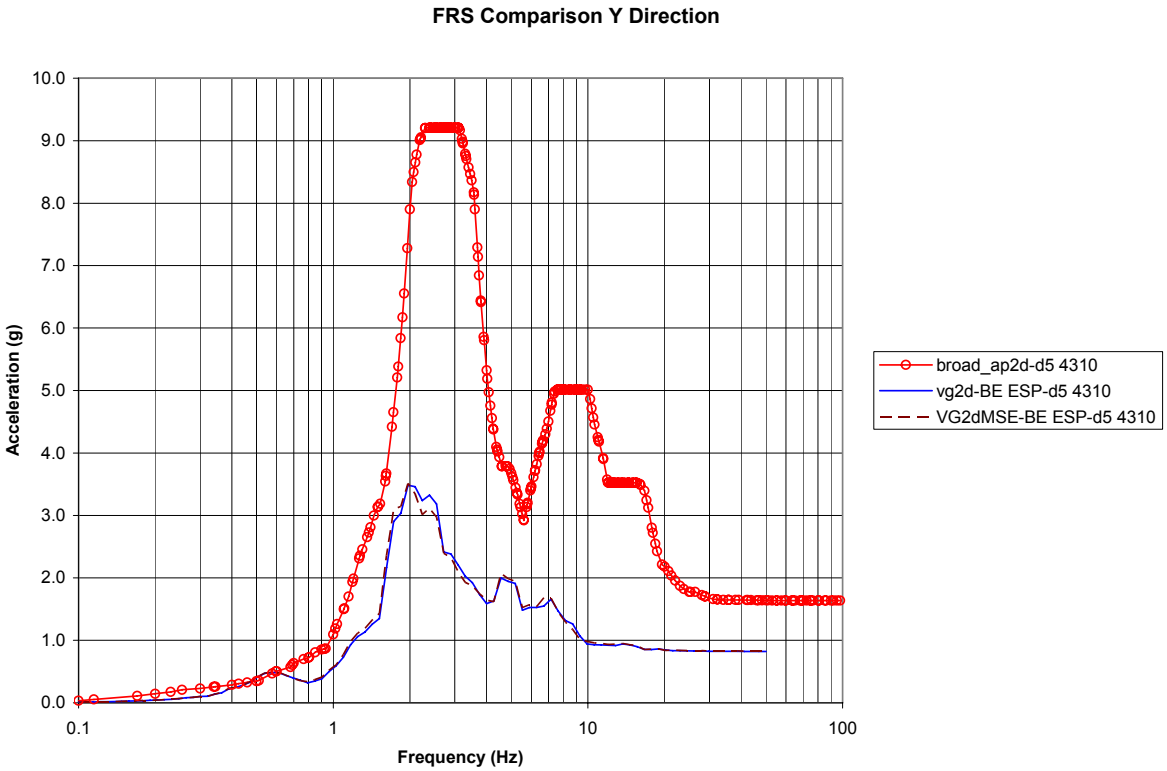


Figure 5.3-12 – FRS Comparison at Node 4310 (Y Direction)

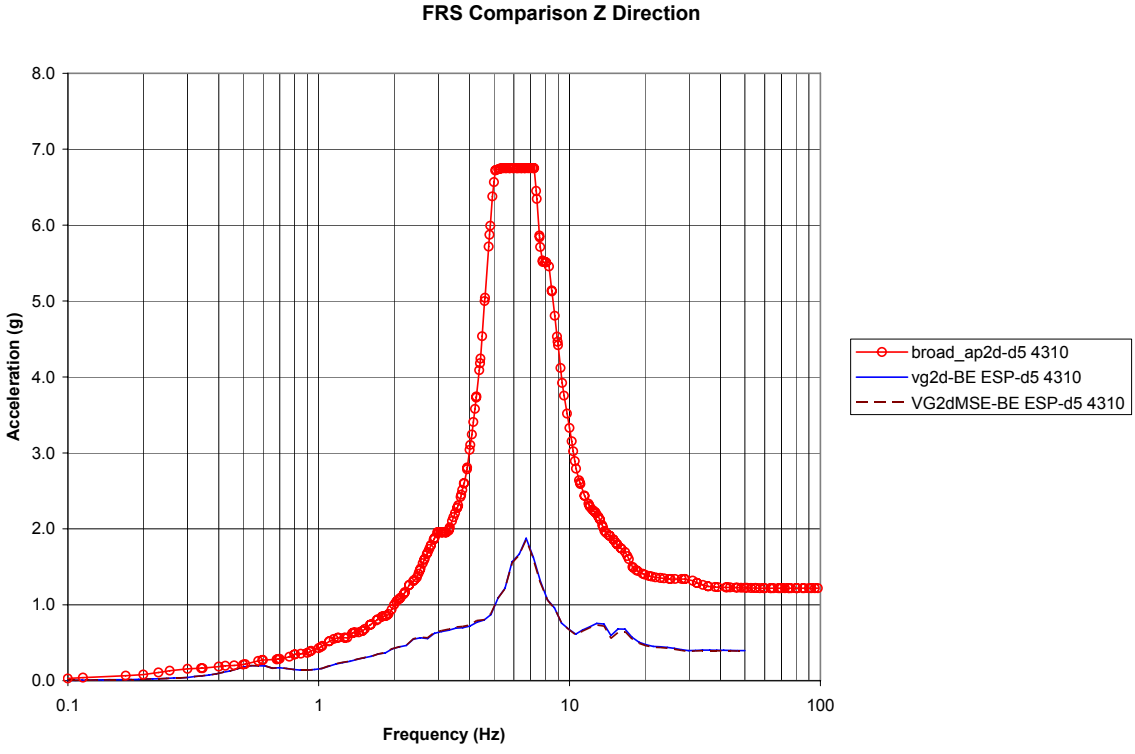


Figure 5.3-13 – FRS Comparison at Node 4310 (Z Direction)

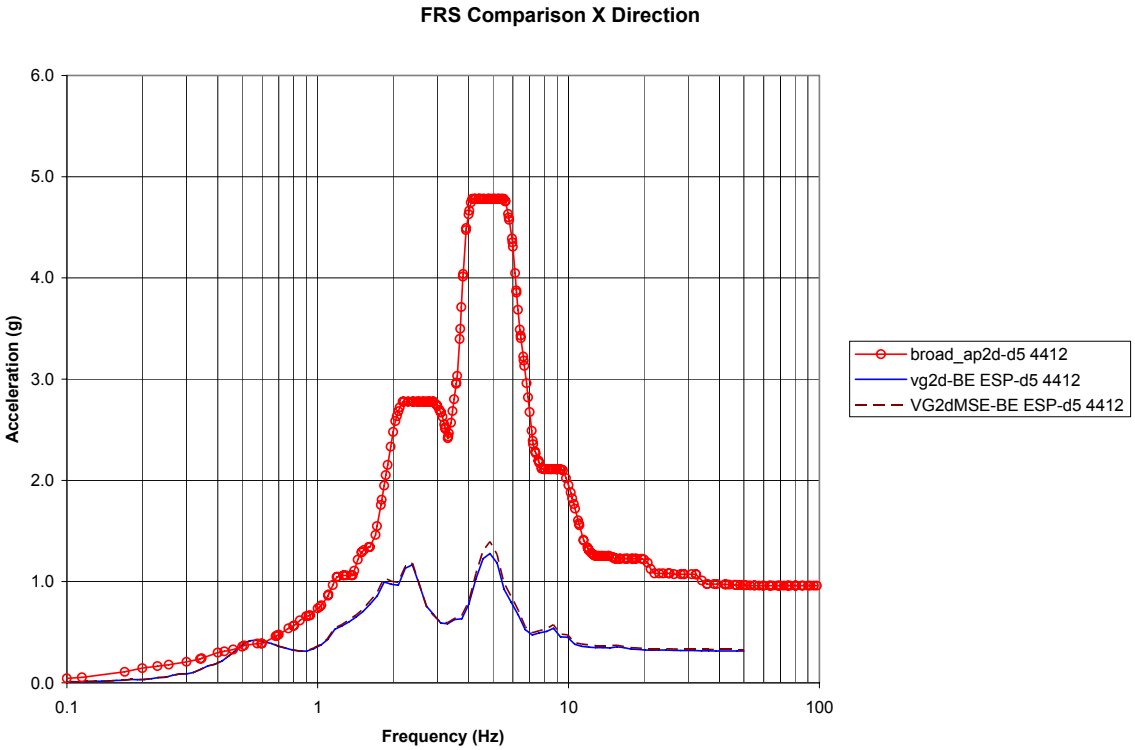


Figure 5.3-14 – FRS Comparison at Node 4412 (X Direction)

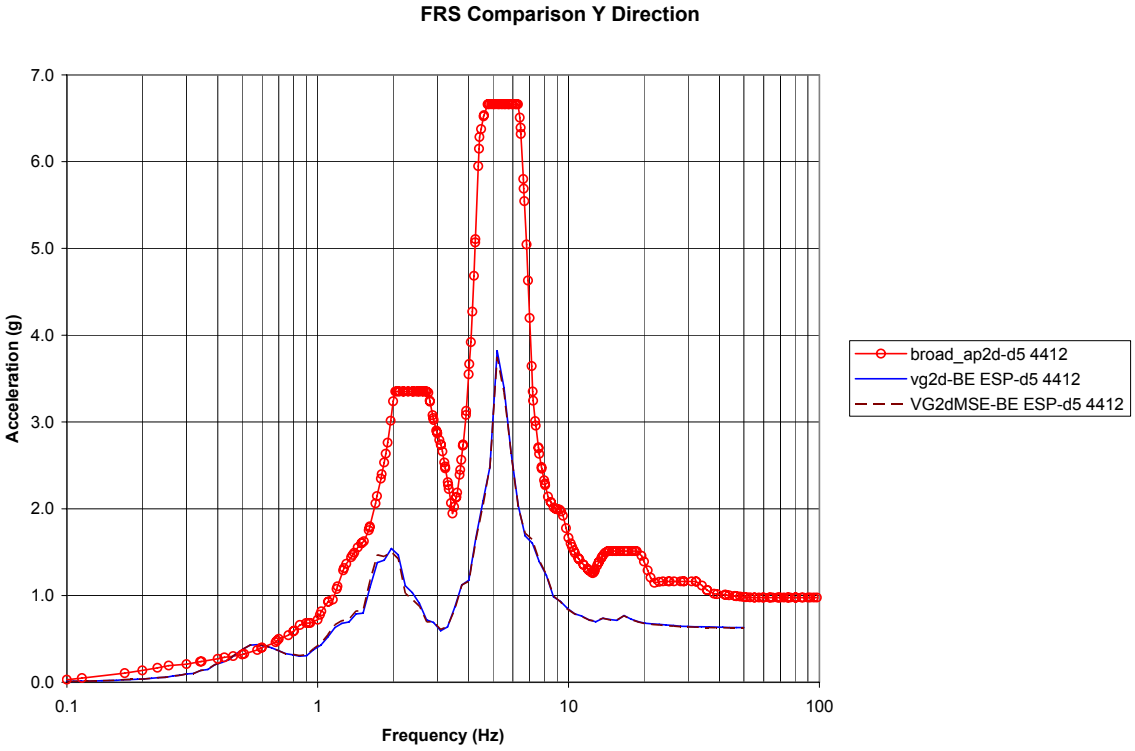


Figure 5.3-15 – FRS Comparison at Node 4412 (Y Direction)

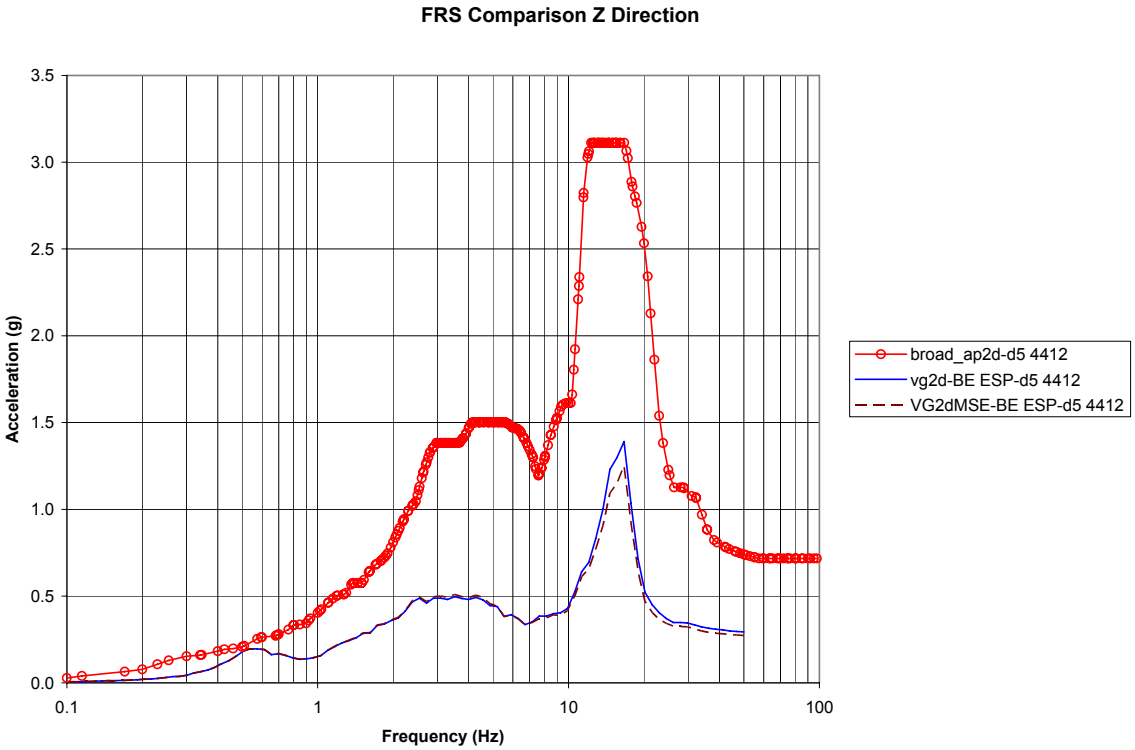


Figure 5.3-16 – FRS Comparison at Node 4412 (Z Direction)

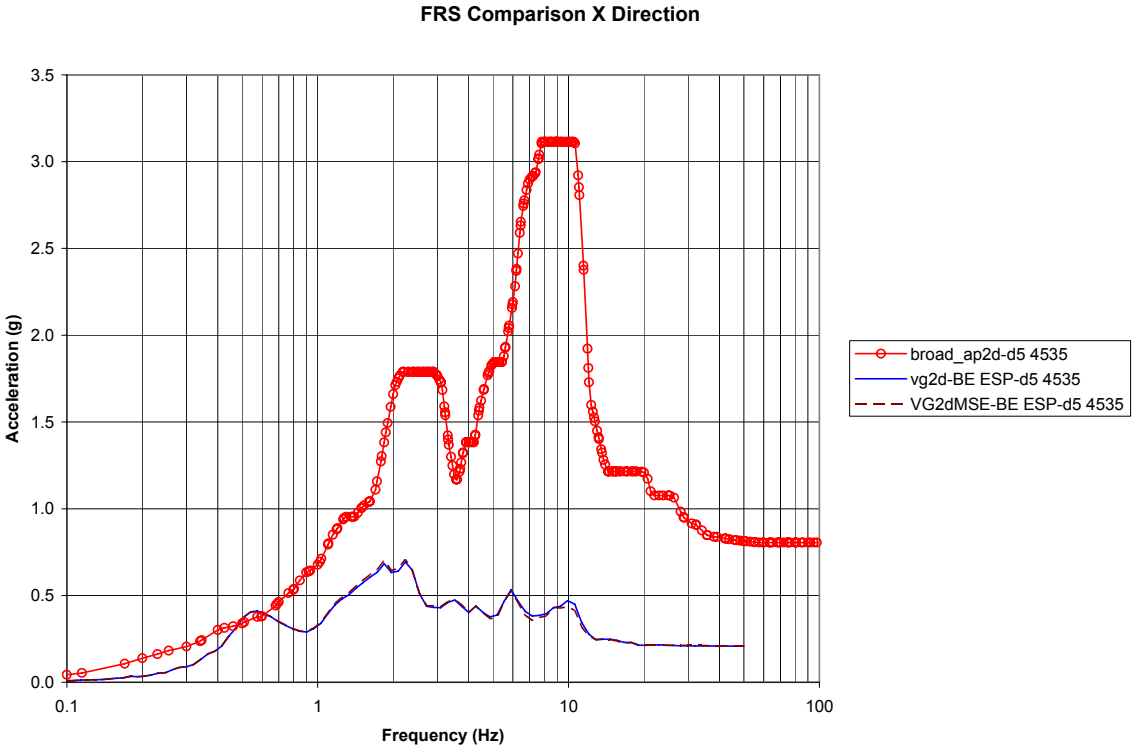


Figure 5.3-17 – FRS Comparison at Node 4535 (X Direction)

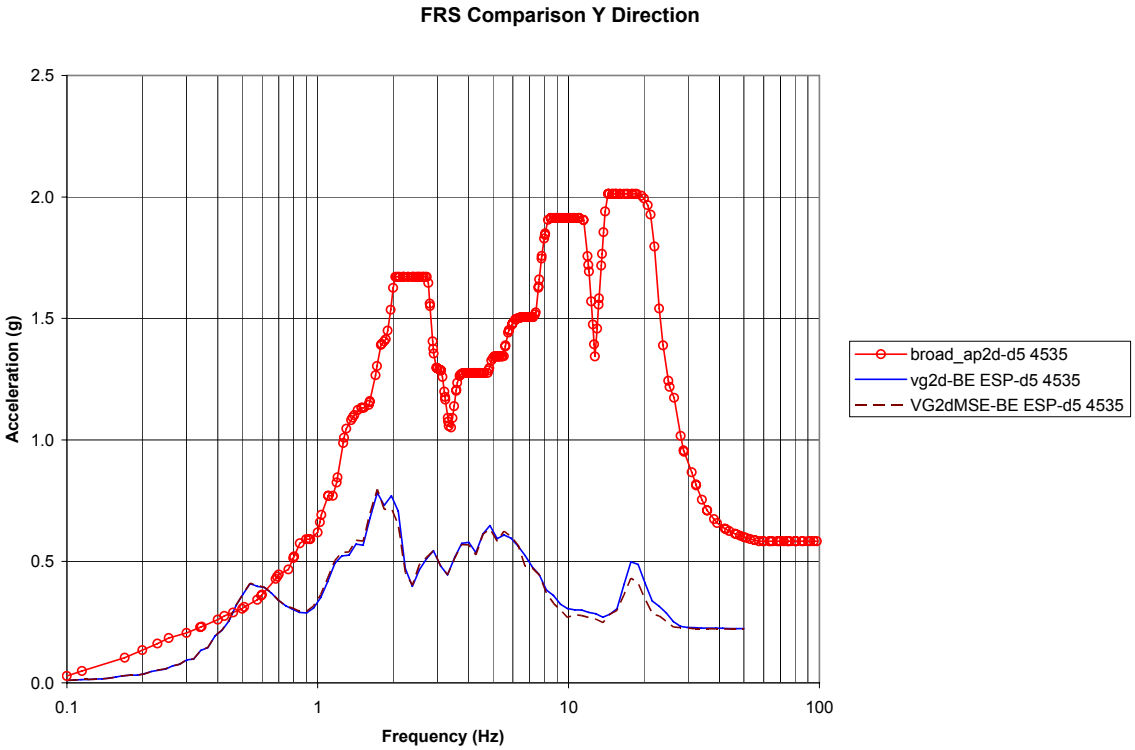


Figure 5.3-18 – FRS Comparison at Node 4535 (Y Direction)

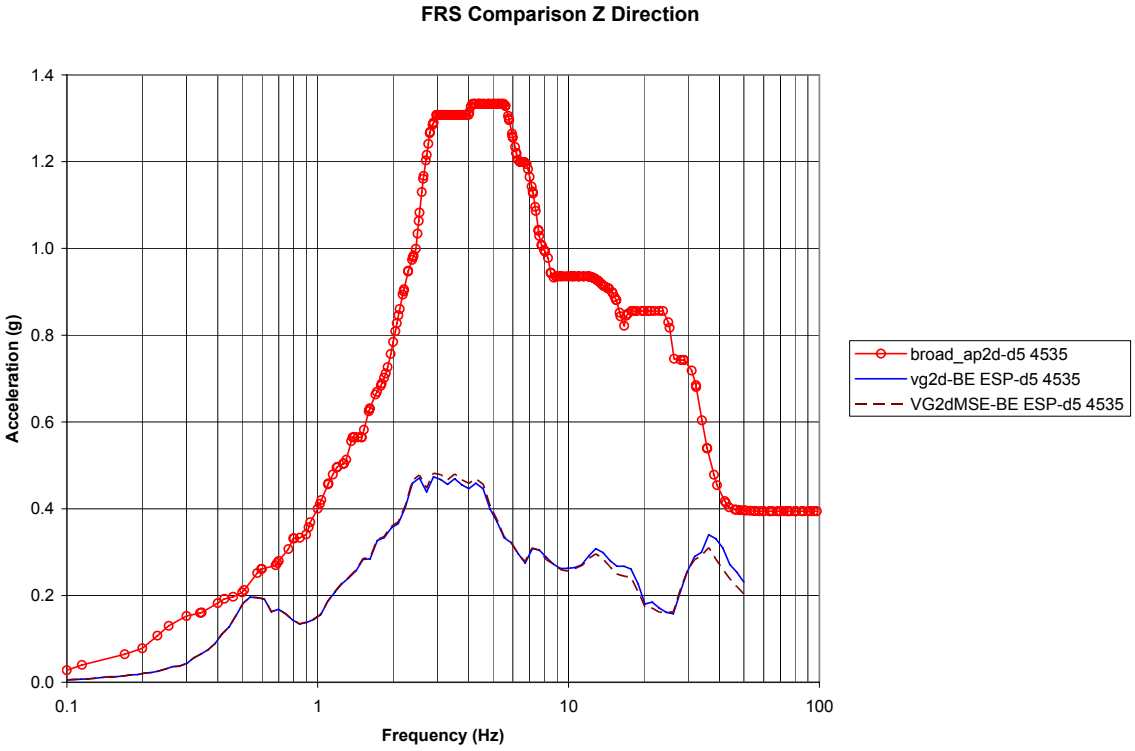


Figure 5.3-19 – FRS Comparison at Node 4535 (Z Direction)

6.0 Stability Analyses

A stability analysis of the Nuclear Island (NI) has been performed with factors of safety determined for:

- Flotation for ground water and maximum flood effect
- Overturning and sliding during tornado/wind/hurricane conditions
- Overturning and sliding during the SSE

These "generic" analyses have been performed for six site profiles: hard rock, firm rock, soft rock, upper bound soft-to-medium soil, soft to medium soil, and soft soil. The stability factors of safety for non-seismic loading for the AP1000 NI are given in Table 6-1. The sliding analyses have been performed using a coefficient of friction of 0.7. For the Vogtle site, a sliding coefficient of friction of 0.45 is used. Since all of the sliding factors of safety are larger than 10, it is not necessary to calculate new sliding factors of safety for these cases using a coefficient of friction of 0.45 since there is a lot of margin between the factors of safety and the limit. The minimum sliding factor of safety will be above 7 for the Vogtle site if a sliding coefficient of friction of 0.45 is considered.

The water table at the Vogtle site is below the NI basemat. The water table is at Vogtle site elevation 165', and the lowest point of the basemat is at Vogtle site elevation 180'. The Vogtle seismic stability analyses reflect this and, therefore, the NI dead weight is not reduced by the buoyancy force.

A seismic stability analysis has been refined for the Vogtle site for the following soil cases using results from the 2D SASSI analysis:

Early Site Permit Soil Cases (ESP)

- Lower Bound
- Best Estimate
- Upper Bound

Sensitivity Soil Cases (SEN)

- Lower Bound
- Best Estimate
- Upper Bound

The acceptability of using seismic response from the 2D SASSI model has been documented by Westinghouse generically. It has been shown that the shear and overturning moments compare closely between the 3D (NI20) shell model and 2D analyses. In addition it has been shown that there are very little changes in the seismic factors of safety associated with overturning and sliding when using the 2D SASSI model or NI20 3D shell model.

Table 6-1 – Stability Factors of Safety for Non-Seismic Loading for AP1000 NI

Load Combination	Sliding		Overturning		Flotation	
	Factor of Safety	Limit	Factor of Safety	Limit	Factor of Safety	Limit
D + H + B + W	Design Wind					
North-South	23.2	1.5	51.5	1.5	–	–
East –West	17.4	1.5	27.9	1.5	–	–
D + H + B + Wt	Tornado Condition					
North-South	12.8	1.1	17.7	1.1	–	–
East –West	10.6	1.1	9.6	1.1	–	–
D + H + B + Wh	Hurricane Condition					
North-South	18.1	1.1	31	1.1	–	–
East –West	14.2	1.1	16.7	1.1	–	–
	Flotation					
D + F	–	–	–	–	3.51	1.1
D + B	–	–	–	–	3.7	1.5

6.1 Seismic Stability Formulas

The calculation of the seismic stability factors of safety are based on the following formulations for overturning and sliding given below.

Overturning Seismic Stability Formula

$$FS = (MR + MP) / (MO + MAO) \quad (6.1)$$

FS = Factor of safety against overturning from a safe shutdown earthquake
MR = Nuclear Island's resisting moment against overturning (due to the force of deadweight - buoyancy)
MO = Maximum SSE induced overturning moment acting on the nuclear island
MP = Resistance moment associated with passive pressure
MAO = Moment due to lateral forces caused by active and overburden pressures

Maximum SSE overturning moments are calculated about column line I, west side of shield building, and column lines 1 and 11. Column line I is located along the east side of the auxiliary building. Shield Building West (SB West) is located on the west side of the shield building. Column line 11 is the north side of the auxiliary building and column line 1 is the south side.

Sliding Seismic Stability Formula

$$FS = [Ff + Fp] / [FSSE + FAO] \quad (6.2)$$

FS = Factor of safety against Sliding
Ff = Sliding resistance based coefficient of friction factor of 0.45
Fp = Passive soil pressure resistance
FAO = Active soil pressure + Overburden
FSSE = Seismic Shear

6.2 Vogtle Site-Specific Stability Evaluation

The site-specific evaluation is performed using the seismic response of the NI from the lower bound, best estimate, and upper bound soil cases as described in Section 3.0. The site specific stability factors of safety for the Vogtle site are summarized in Tables 6.2-1 and 6.2-2 for the soil profiles associated with the Early Site Permit and Sensitivity cases. As seen from this table, all of the factors of safety are well above the limit, and reflect much more margin than the AP1000 generic all soil analysis.

Increasing the Vogtle site-specific seismic response spectra at the 40' outcrop location to be equal to 0.3g (ZPA), new stability factors of safety are calculated. The increase in seismic level is 1.2 in the horizontal directions, and 1.36 in the vertical direction. The summary of stability factors of safety are given in Tables 6.2-3 and 6.2-4, and they are well above the limits.

The sliding factors of safety are based on full passive pressure. The sensitivity of the sliding factor of safety versus passive pressure is shown in Figure 6.2-1 using the upper bound ESP estimate that has the lowest sliding factors of safety. It is noted that at the limit of the sliding factor of safety (1.1) the passive pressure is close to the At Rest Pressure (15% Passive Pressure vs. At Rest Pressure which is 11% of the Passive Pressure).

It can be concluded from the stability evaluation for the Vogtle site that:

- Seismic stability factors of safety for the Vogtle site have significant margin.
- The Vogtle site seismic stability factors of safety have significant margin above the AP1000 generic design considering a 0.3g (ZPA) level. The reduction of seismic load at Vogtle is due to SSI effects that do not exist in the hard rock case.
- The seismic stability factors of safety for sliding have significant margin using a sliding coefficient of friction of 0.45. Even though the Vogtle coefficient of friction is less than that standard AP1000 certified design value, the standard design capacity would not be reduced for the Vogtle site.
- When the seismic stability factor of safety for sliding is equal to the factor of safety limit of 1.1, the passive pressure is close to the At Rest Pressure. Therefore, the NI at the Vogtle site will not slide and consideration of a dynamic coefficient of friction in the stability calculation for sliding is not required.

Table 6.2-1 –Comparison of Seismic Stability Factors of Safety - ESP

Stability Factors of Safety	AP1000 Generic Analyses	Vogtle Site Specific Lower Bound Estimate	Vogtle Site Specific Best Estimate	Vogtle Site Specific Upper Bound Estimate	Limit
Sliding NS earthquake	1.28	2.07	1.97	1.83	1.1
Sliding EW earthquake	1.33	2.10	2.08	1.96	1.1
Overturning NS earthquake	1.35	3.74	3.52	3.37	1.1
Overturning EW earthquake	1.12	2.77	2.67	2.45	1.1

Table 6.2-2 –Comparison of Seismic Stability Factors of Safety - SEN

Stability Factors of Safety	AP1000 Generic Analyses	Vogtle Site Specific Lower Bound Estimate	Vogtle Site Specific Best Estimate	Vogtle Site Specific Upper Bound Estimate	Limit
Sliding NS earthquake	1.28	2.17	2.04	2.02	1.1
Sliding EW earthquake	1.33	2.24	2.19	2.10	1.1
Overturning NS earthquake	1.35	3.97	3.80	3.68	1.1
Overturning EW earthquake	1.12	3.01	2.90	2.81	1.1

Table 6.2-3 –Comparison of Seismic Stability Factors of Safety – ESP

Increased to 0.3g at 40' Outcrop

Stability Factors of Safety	AP1000 Generic Analyses	Vogtle Site Specific Lower Bound Estimate	Vogtle Site Specific Best Estimate	Vogtle Site Specific Upper Bound Estimate	Limit
Sliding NS earthquake	1.28	1.89	1.78	1.64	1.1
Sliding EW earthquake	1.33	1.92	1.89	1.77	1.1
Overturning NS earthquake	1.35	2.85	2.69	2.58	1.1
Overturning EW earthquake	1.12	2.23	2.15	1.98	1.1

Table 6.2-4 –Comparison of Seismic Stability Factors of Safety – SEN
Increased to 0.3g at 40' Outcrop

Stability Factors of Safety	AP1000 Generic Analyses	Vogtle Site Specific Lower Bound Estimate	Vogtle Site Specific Best Estimate	Vogtle Site Specific Upper Bound Estimate	Limit
Sliding NS earthquake	1.28	1.99	1.86	1.84	1.1
Sliding EW earthquake	1.33	2.06	2.00	1.91	1.1
Overturning NS earthquake	1.35	2.99	2.89	2.80	1.1
Overturning EW earthquake	1.12	2.38	2.32	2.25	1.1

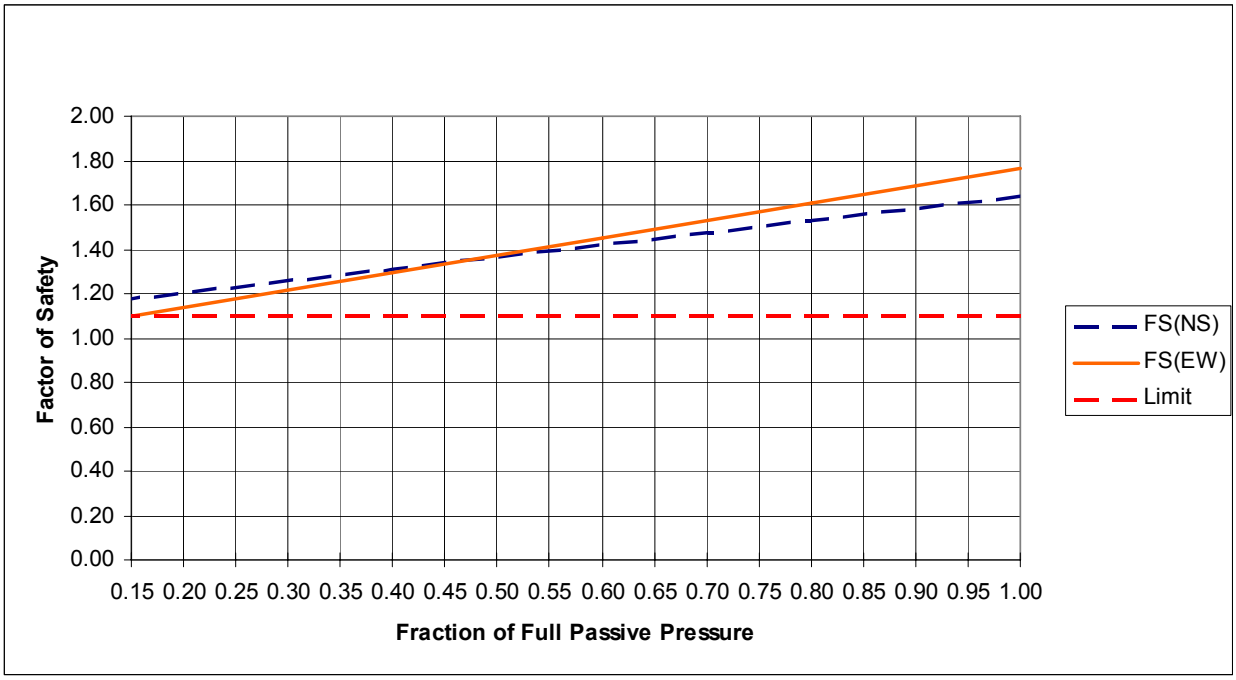


Figure 6.2-1 – Sliding Factor of Safety versus Passive Pressure
ESP- Increased to 0.3g at 40 ft Outcrop – UB

7.0 Foundation Bearing Pressures

The foundation bearing pressures from the Vogtle site specific evaluation are the maximum pressures associated with the dead load plus seismic load cases. To account for 3D seismic effects, the maximum bearing pressures were calculated using the square root sum of squares of the seismic responses in the NS, EW, and vertical directions. The maximum bearing pressure given in Table 7-1 includes the bearing pressure due to seismic excitation plus the building dead load pressure.

Table 7-1 – Vogtle Specific Maximum Pressures Under Basemat (ksf)

	Nuclear Island	Radwaste	Annex	Turbine
Best Estimate ESP	16.53	1.43	3.73	2.48
Best Estimate SEN	15.44	1.54	4.92	2.42
Lower Bound ESP	15.71	1.50	3.77	2.54
Lower Bound SEN	14.77	1.26	7.20	2.42
Upper Bound ESP	17.95	1.38	6.92	2.49
Upper Bound SEN	15.59	1.68	5.35	2.41

8.0 Settlement of Foundations

The details of the foundation settlement analysis for the Vogtle site are reported in Reference 3. The foundation mat displacements for the AP1000 buildings due to potential elastic settlements of the subgrade soils at the Vogtle site are documented in this reference. The evaluation examines the construction conditions including the structural loading sequences and calculates the resulting settlements and the foundation mat displacement time histories. Based on the evaluation, it estimates maximum foundation mat displacements rotations and the maximum differential displacements between buildings.

The settlement analysis and the subsequent structural evaluation estimates foundation mat vertical displacements, tilting, and differential displacements between buildings. The analysis is based on the proposed construction schedule and sequence.

The predicted maximum settlements are less than 3 inches total and 1/2 inch in 50 feet tilt across the basemat (Reference 3). The settlements calculated for the Vogtle site are given in Table 8-1 below.

Table 8-1 – The maximum settlements for the Vogtle site

Building	Settlement Summary				Differential Settlement (center-to-center)			
	Max. Settlement	Min. Settlement	Tilt (inch per 50')		Nuclear Island	Turbine Bldg.	Radwaste Bldg.	Annex Bldg.
			NS	EW				
Nuclear Island	2.66	1.39	0.06	0.39	---	0.44	0.12	0.32
Turbine Bldg.	1.85	1.51	0.05	0.01	0.44	---	0.32	0.75
Radwaste Bldg.	2.00	1.98	0.00	0.00	0.12	0.32	---	0.44
Annex Bldg.	2.47	2.37	0.01	0.05	0.32	0.75	0.44	---

Note: All values in inches unless noted otherwise.
Settlement calculation assumes non-NI buildings are constructed at an elevation relative to the settled NI.

The maximum foundation tilt is 0.39” in 50’ and occurs in the east-west direction of the Nuclear Island(less than ½” in 50’ tilt across basemat in Reference 3). The most significant differential settlement between the Nuclear Island and adjacent buildings is 0.44 inch, between the Nuclear Island and the Turbine Building.

9.0 Settlement Monitoring Program

The proposed settlement monitoring plan addresses the expected heave or rebound during the excavation and dewatering phase, as well as the settlements due to the building construction loads. Compared to the predicted settlements for the generic profiles considered in the standard design, the calculated settlements for the Vogtle conditions are relatively small and all within the limiting settlement parameters utilized in the standard design.

The proposed settlement monitoring program will include:

- Piezometers to measure pore water pressures in the Blue Bluff Marl and the Lower Sand layer. Vibrating wire piezometers are preferred for this purpose, as they are adequately sensitive and responsive and easily record positive and negative changes on a real-time basis.

- Settlement monuments placed directly on concrete, preferably on the mud mat and on the corners of the structures at grade that are accessible with conventional surveying equipment.

Settlements will be monitored continuously during all construction stages to verify structural displacements due to construction loads. Figure 9-1 presents a distribution of the suggested monitoring points located at the building’s foundation mats.

Monitoring will be performed continuously for all the structures during and after construction, particularly when large loads are applied early in the NI construction (CV Head, M20, M21).

Particular emphasis will be placed on the rotation about the north-south axis of the Nuclear Island, as this study estimates that a noticeable tilt may occur in this direction.

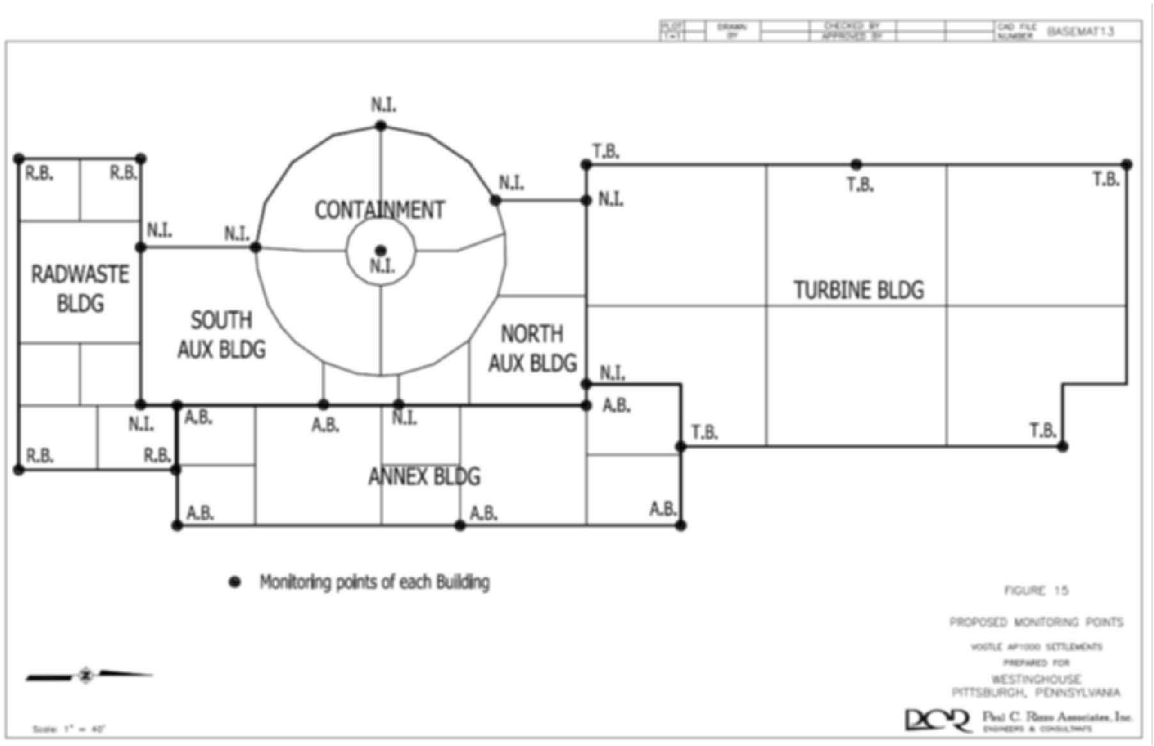


Figure 9-1 – Proposed Monitoring Points for Vogtle

10.0 References

1. Regulatory Guide 1.60, Design Response Spectra for Seismic Design of Nuclear Power Plants, Rev. 1.
2. APP-1000-S2C-025, Rev. 2 “AP1000 2D SSI Analysis with Adjacent Buildings.”
3. Foundation Mats Settlements, Vogtle AP1000 Foundations, Report No. 05-3423-R1, Rev. 0, Paul C. Rizzo Associates.
4. Calculation of Transfer Functions Using WEC Response Time History, SNC Calculation Number SV0-SSAR-XSC-2018 Bechtel National, Inc.,

Appendix A: Vogtle 2D Bathtub Model and AP 2D Model Comparison

Due to the large volume of excavation and the lateral extent of the backfill at the Vogtle site, the backfill layers were modeled as free-field soil layers in the characterization of the soil profile for both the site amplification for development of ground motion (GMRS and FIRS) and the site-specific seismic SSI analysis of the AP1000. A sensitivity analysis was performed to assess the sensitivity of this modeling assumption to the explicit modeling of the geometry of the excavation and backfill on site response and seismic SSI response. The results provided here pertain to the SSI portion of the sensitivity analysis for the Vogtle site-specific seismic SSI analysis of the AP1000.

A 2D SASSI bathtub model (Bathtub Model-d5) was developed to represent the E-W cross section of the Vogtle excavation and backfill soil condition as shown in Figure A-1. The bathtub model is constructed with the nuclear island and adjacent annex building with the backfill soil modeled as part of the structural model. For this model the strain-compatible soil properties for the in-situ upper sand layer were used as part of the free-field SASSI model. The seismic response of the bathtub model is compared to the seismic response obtained using the standard Vogtle site-specific 2D SASSI model (2D-AP-d5). The input time histories and the compatible soil profiles were provided for both models from the site response portion of this sensitivity analysis. For each of the two 2D SASSI models, the SSI response was limited to using the mean soil profile and one time history from the site response portion of the sensitivity analysis. The input motions for the two SSI analyses were from the respective 1D SHAKE analysis from the site response portion of the sensitivity analysis and consistent with the free-field soil characterization used in each SASSI model. For the bathtub model the single time history is called the “in-situ time history” since it is developed from a 1D soil column that included the 86 foot in-situ upper sand layer. For the standard Vogtle site-specific 2D SASSI model the single time history is called “backfill time history” since it is developed from a 1D soil column where the top 86 feet is backfill.

Figures A-2 and A-7 are the horizontal floor response spectra 5% damping comparisons of the Vogtle 2D SASSI bathtub model (Bathtub Model-d5) using in-situ time history and the Vogtle site-specific 2D SASSI AP model (2D-AP-d5) using the backfill time history. The AP1000 2D standard design enveloped floor response spectra are shown to provide an overall assessment of the available margin. The floor response spectra are compared at six critical locations. It should be noted that the single time histories that were used represent time histories from 1D soil columns analyses with a high frequency rock input time history which resulted in input motion that had relatively low frequency content. This does not invalidate the one to one comparison needed for a sensitivity analysis. The backfill model, Bathtub Model-d5, used an in-situ time history. The AP model, 2D-AP-d5, used a time history that was developed assuming the backfill was of infinite extent.

Figures A-8 to A-13 compare the Vogtle 2D AP model and the Vogtle bathtub model transfer functions at the same six key locations. Bath-tub represents the Bathtub Model and Backfill represents the AP model. Transfer functions represent the harmonic amplification of the input motion at base rock to the response motion at the selected locations in the SSI model. This result is documented in Bechtel National, Inc. “Calculation of Transfer Functions Using WEC Response Time History”, SNC Calculation Number SV0-SSAR-XSC-2018 (Reference 4).

Although the bathtub model shows slightly higher transfer function peaks, the transfer function comparisons are very close and indicated no significant differences. The response spectra obtained from the 2D bathtub and 2D AP model are similar. There are some variations between

the 2D bathtub model and the 2D AP model due to the modeling of the backfill but these differences are small. There is significant margin between the AP1000 2D and the Vogtle 2D results compared to the AP1000 generic spectra. From the analyses performed using the 2D AP model and the backfill model, it can be concluded that the AP1000 plant design is acceptable for the Vogtle plant site. The difference between the AP model and the bathtub model are negligible.

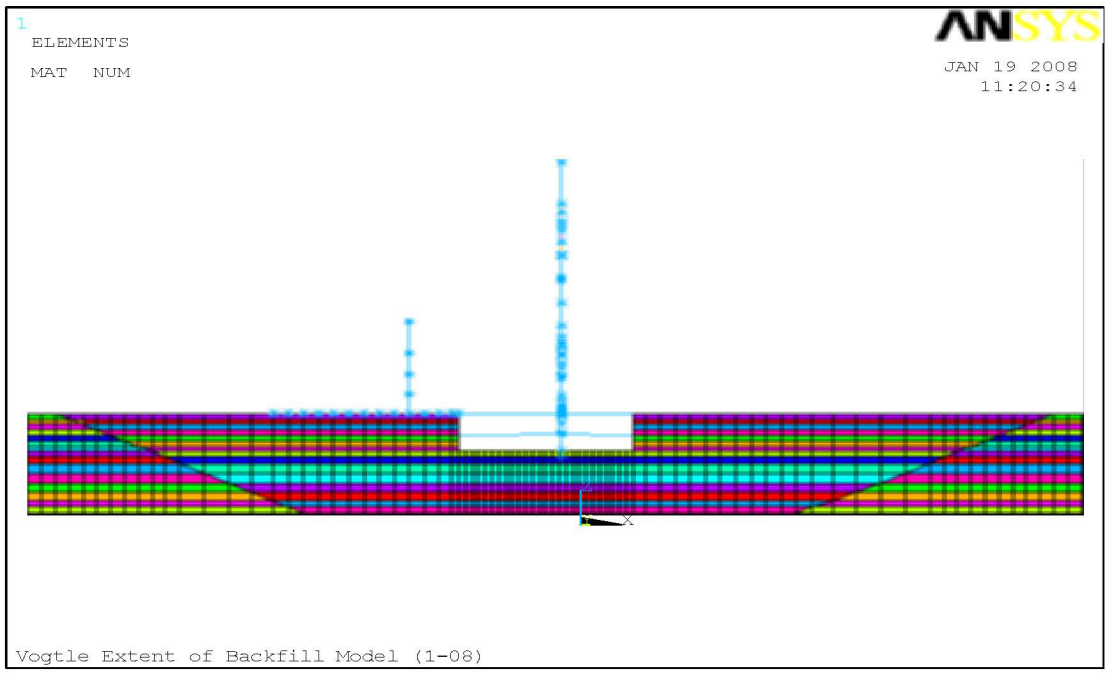


Figure A-1: 2D SASSI Backfill Model

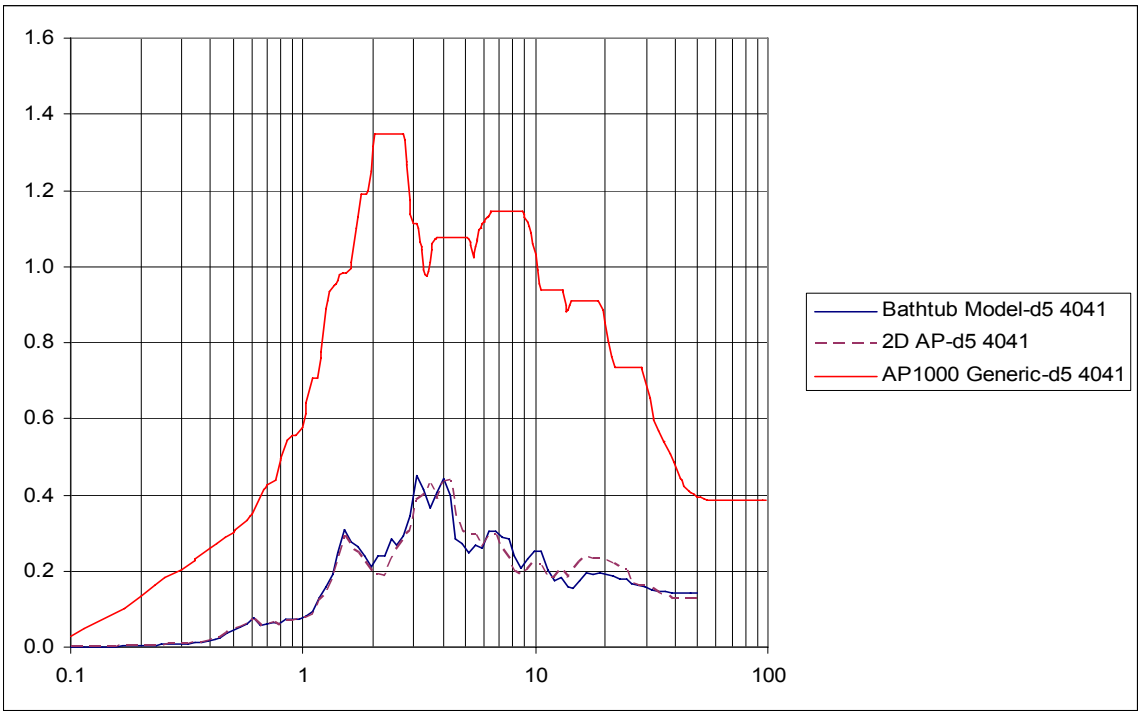


Figure A-2: FRS Comparison at Node 4041

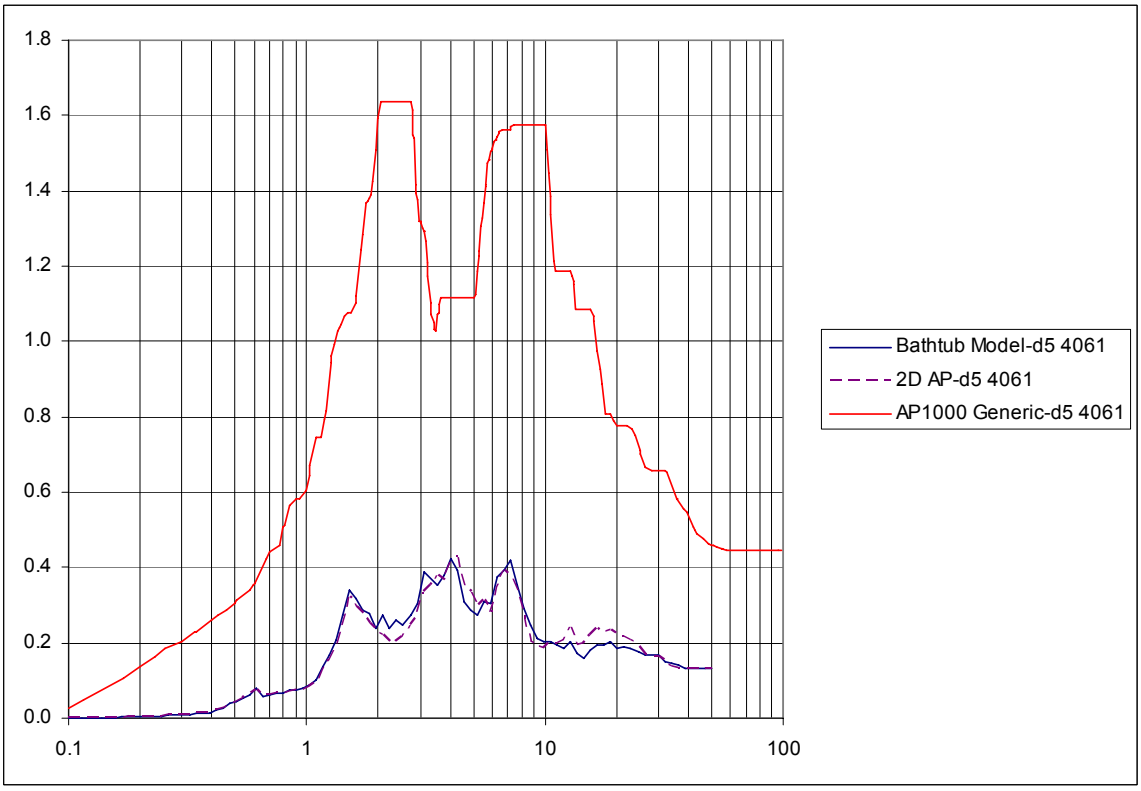


Figure A-3: FRS Comparison at Node 4061

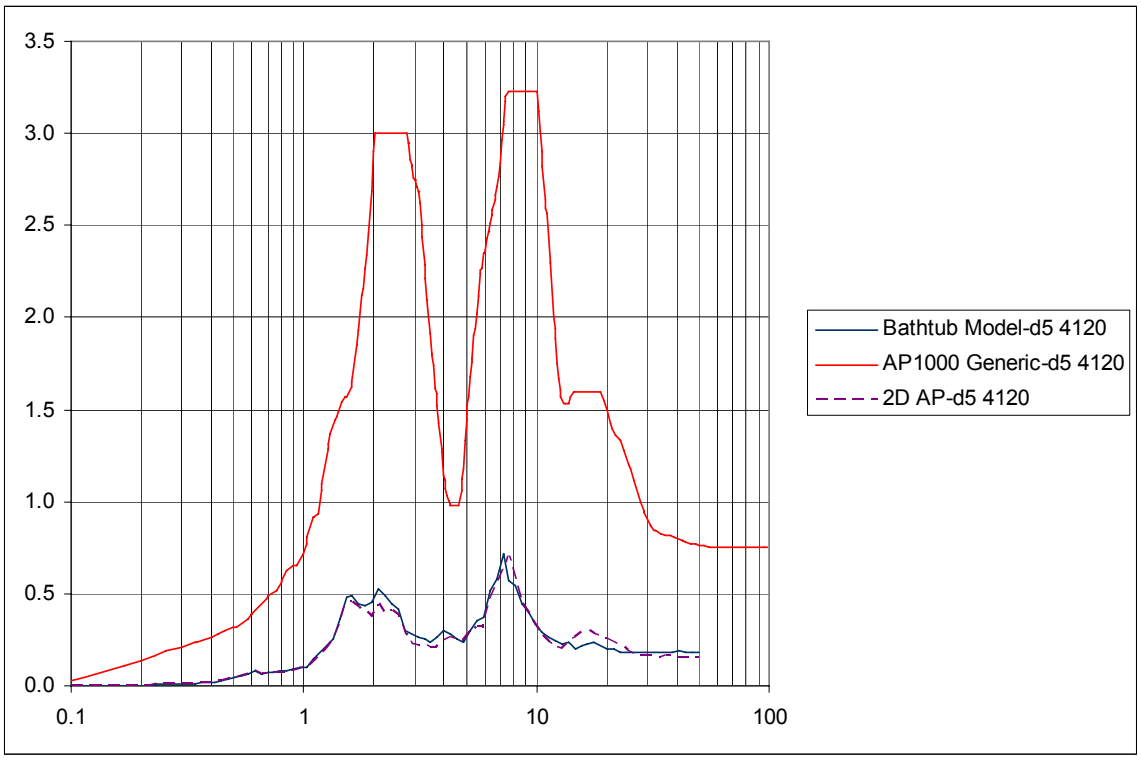


Figure A-4: FRS Comparison at Node 4120

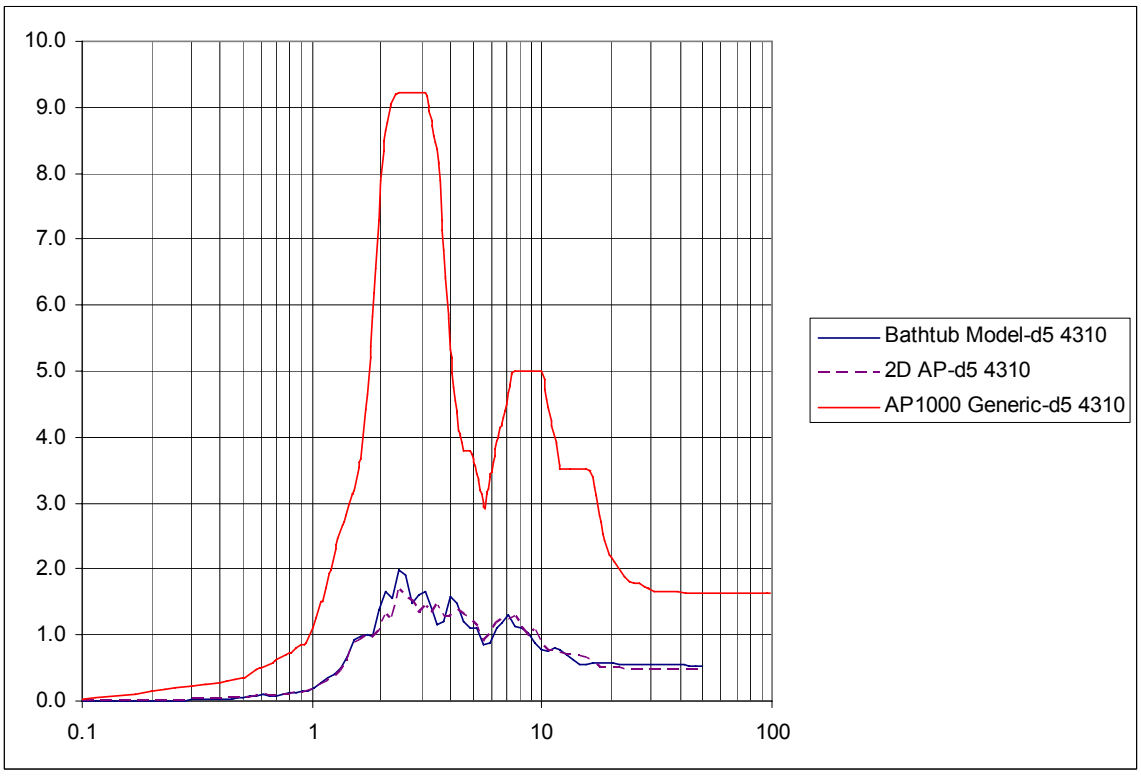


Figure A-5: FRS Comparison at Node 4310

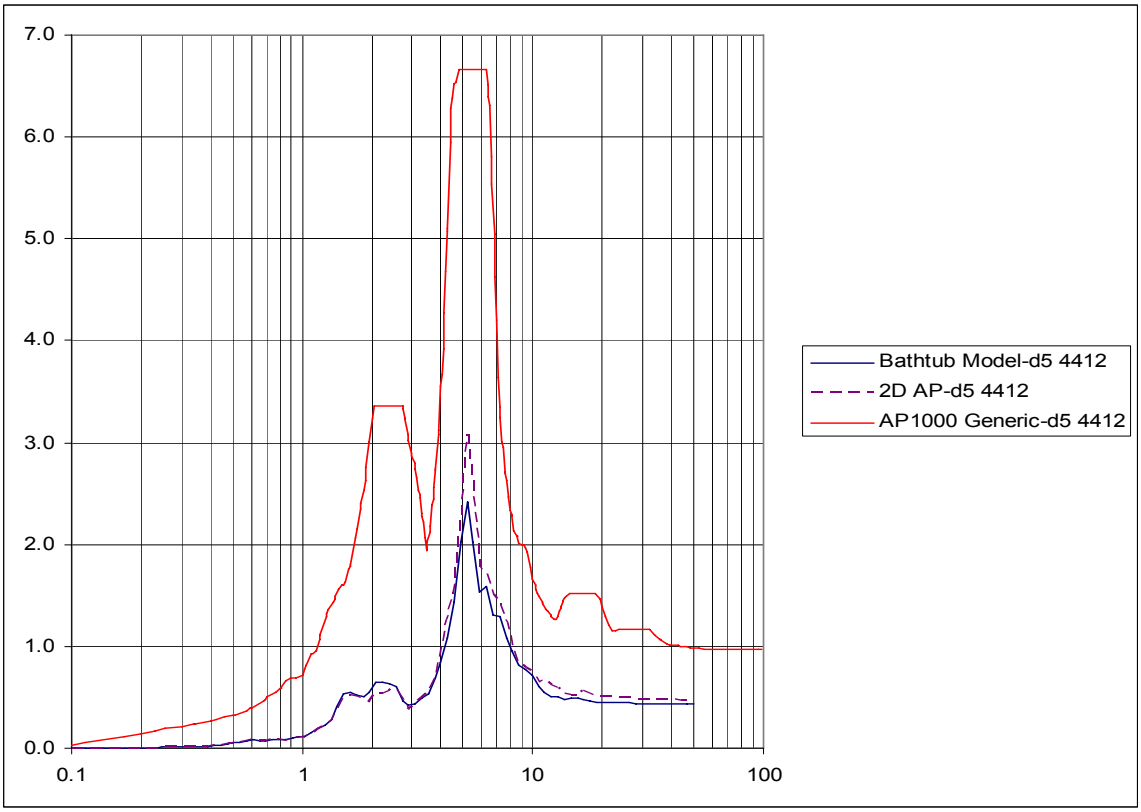


Figure A-6: FRS Comparison at Node 4412

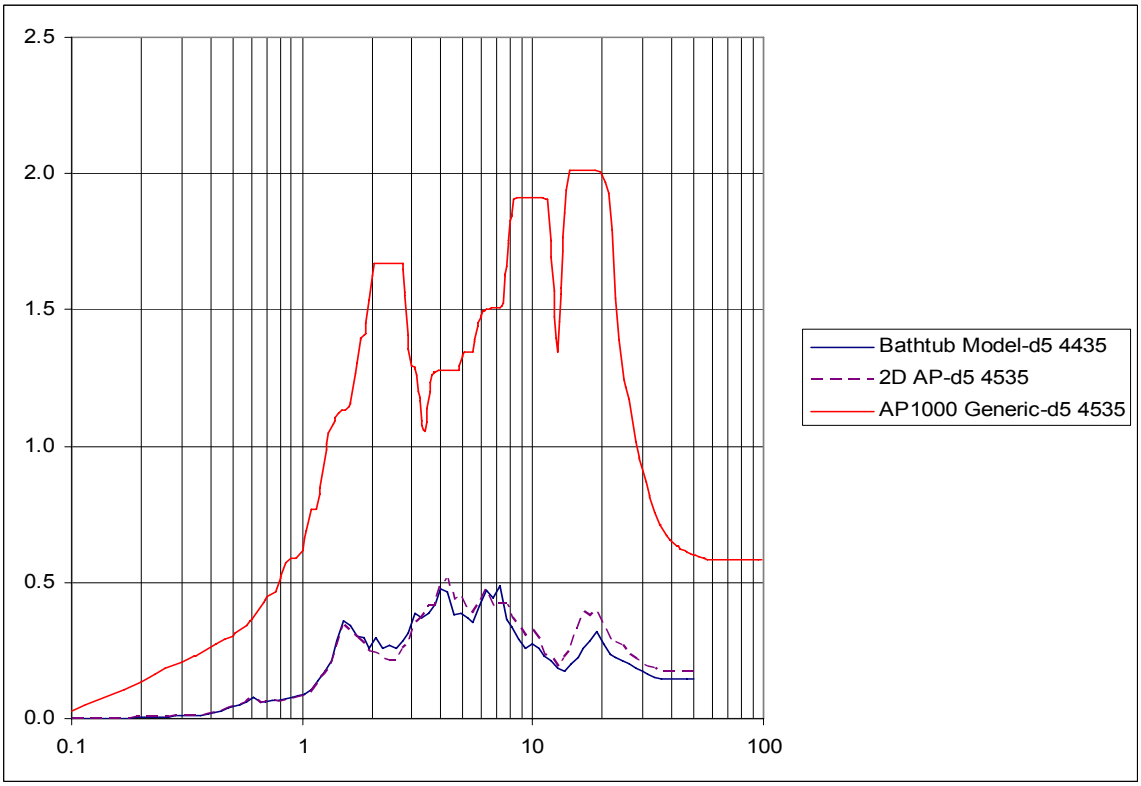


Figure A-7: FRS Comparison at Node 4535

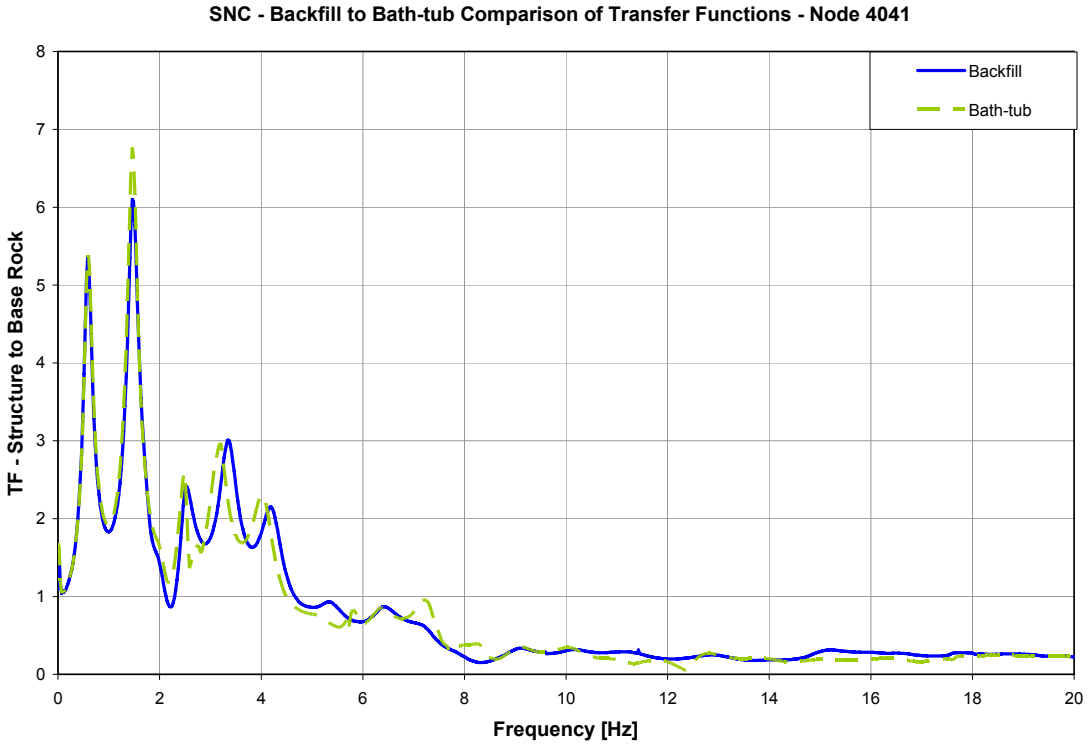


Figure A-8: Vogtle AP vs. BT Transfer Function from Bed Rock to Node 4041

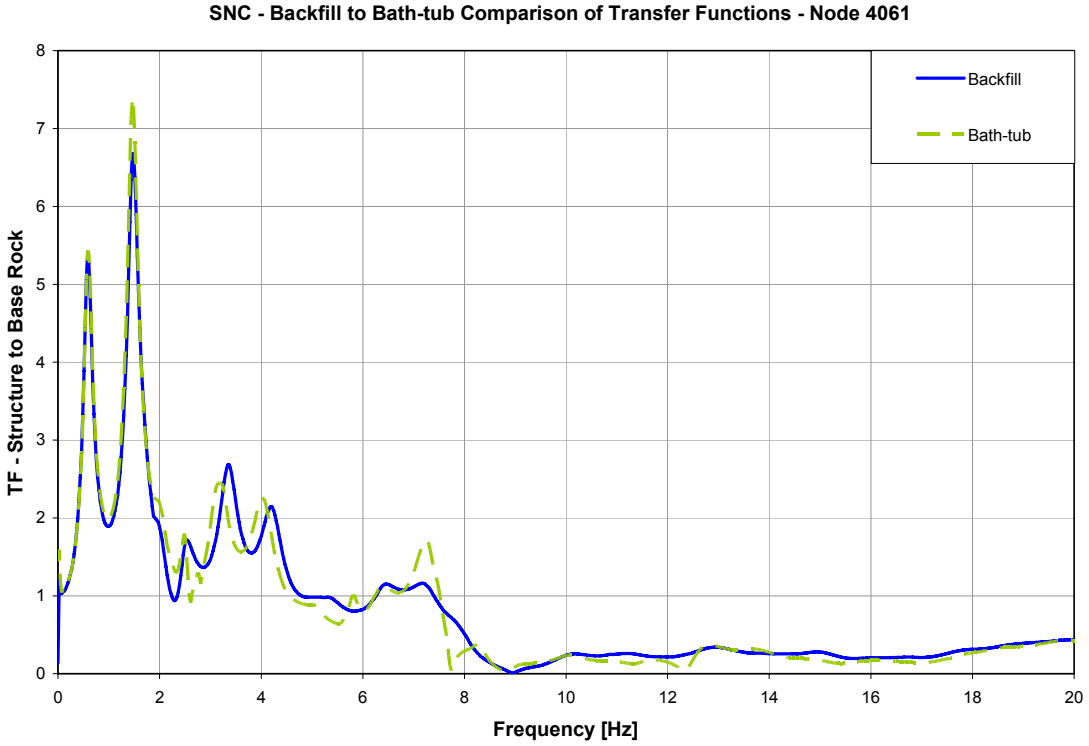


Figure A-9: Vogtle AP vs. BT Transfer Function from Bed Rock to Node 4061

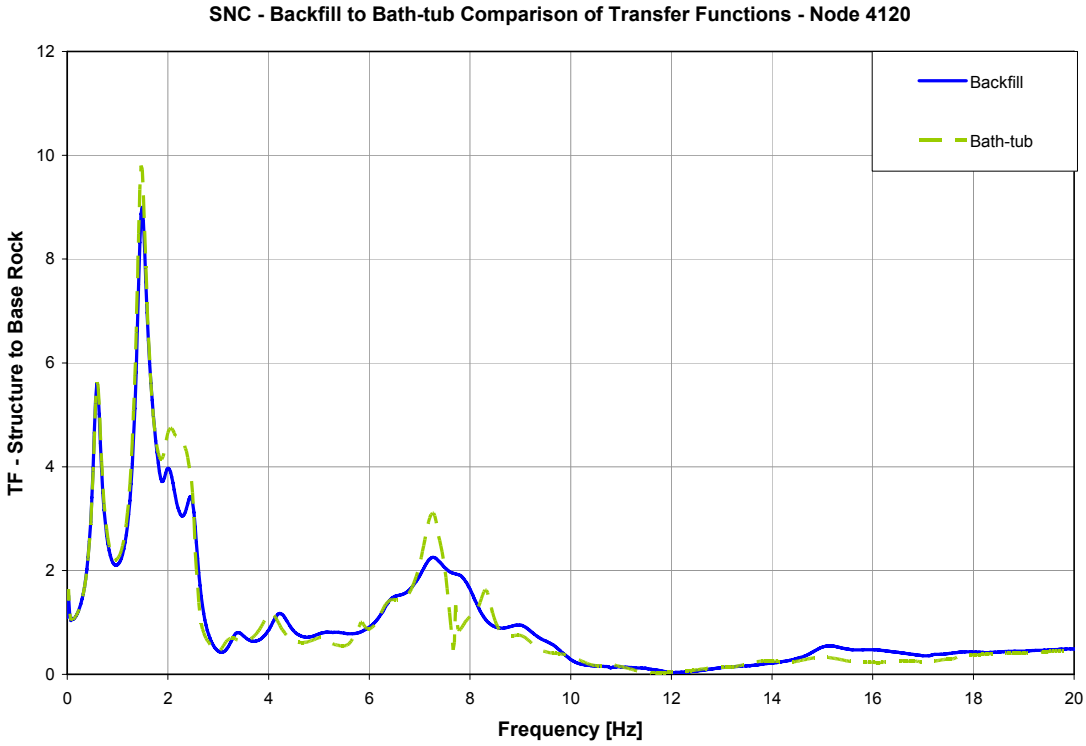


Figure A-10: Vogtle AP vs. BT Transfer Function from Bed Rock to Node 4120.

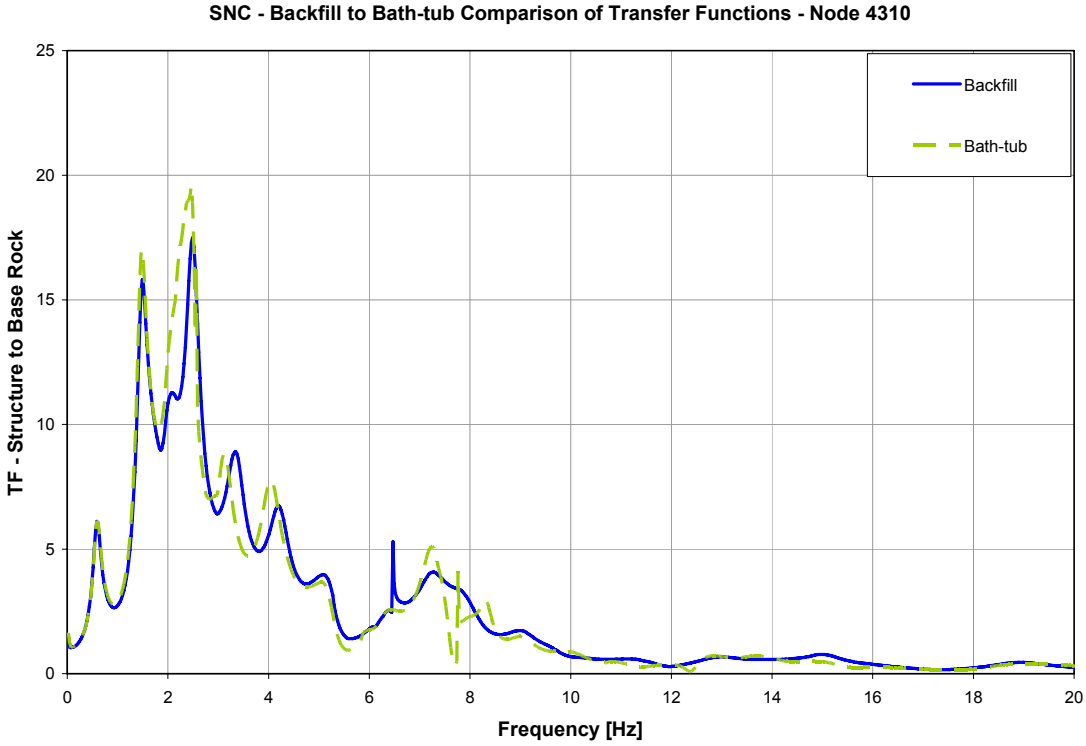


Figure A-11: Vogtle AP vs. BT Transfer Function from Bed Rock **to Node 4310**

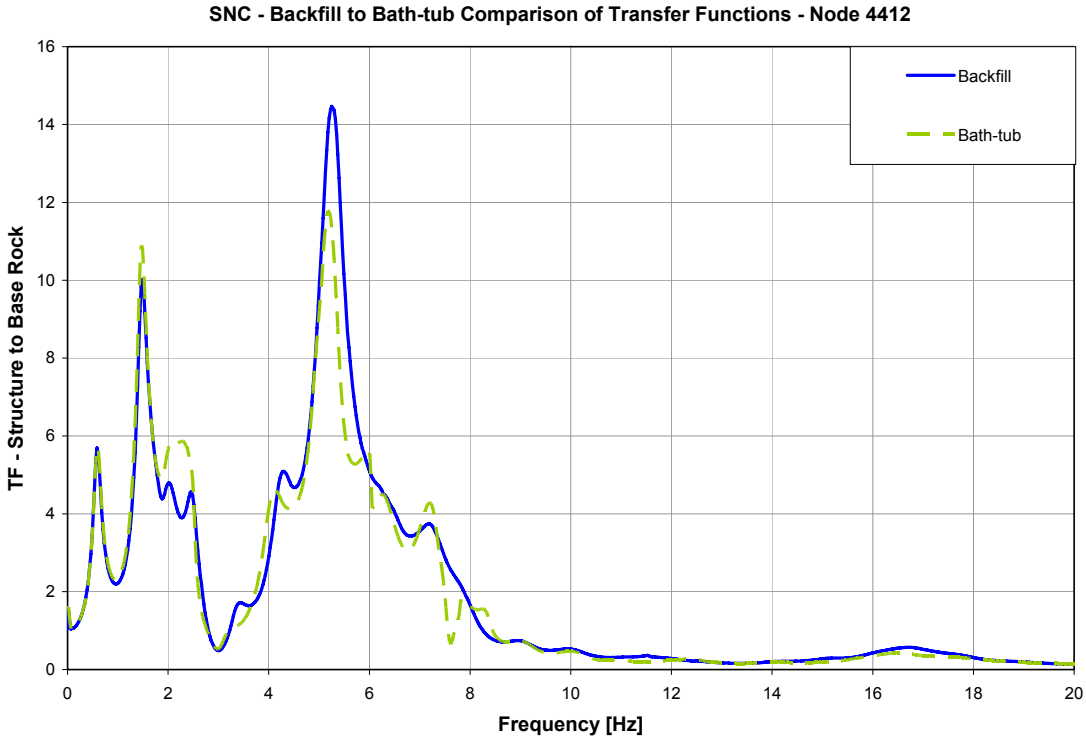


Figure A-12: Vogtle AP vs. BT Transfer Function from Bed Rock to Node 4412

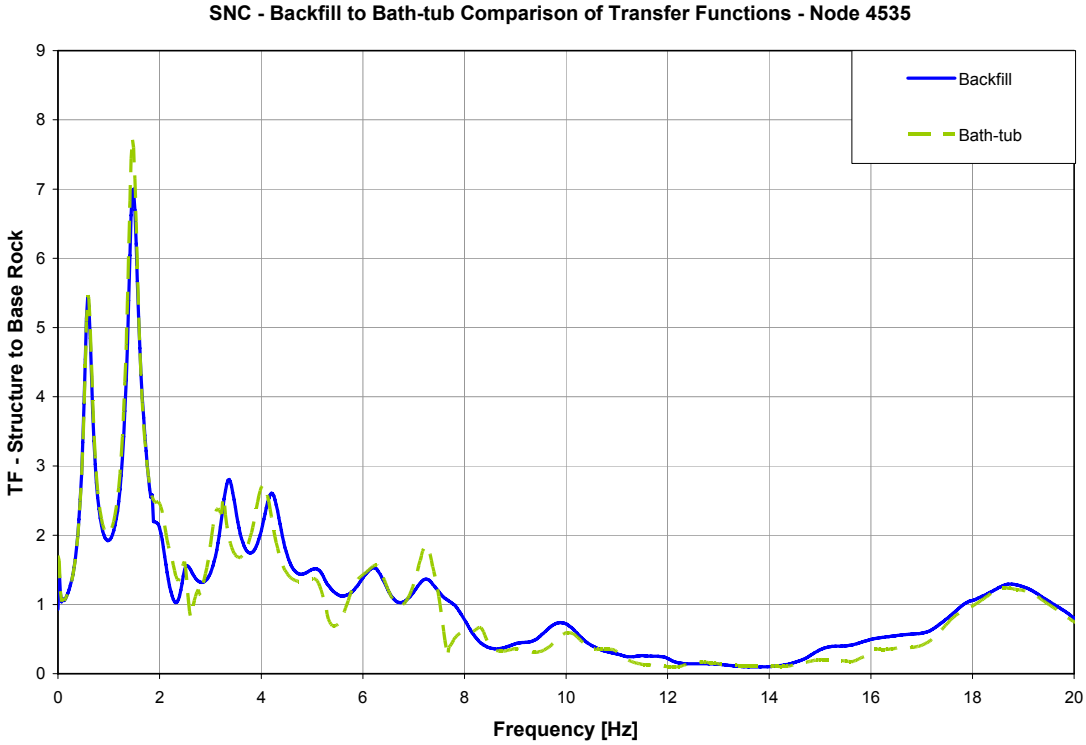


Figure A-13: Vogtle AP vs. BT Transfer Function from Bed Rock to Node 4535

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 3	DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT AND SYSTEMS	3.1-1
3.1	Conformance with Nuclear Regulatory Commission General Design Criteria	3.1-1
3.1.1	Overall Requirements	3.1-1
3.1.2	Protection by Multiple Fission Product Barriers	3.1-4
3.1.3	Protection and Reactivity Control Systems	3.1-10
3.1.4	Fluid Systems	3.1-14
3.1.5	Reactor Containment	3.1-23
3.1.6	Fuel and Reactivity Control	3.1-26
3.1.7	Combined License Information	3.1-29
3.1.8	References	3.1-29
3.2	Classification of Structures, Components, and Systems	3.2-1
3.2.1	Seismic Classification	3.2-1
3.2.1.1	Definitions	3.2-1
3.2.1.2	Classifications	3.2-3
3.2.1.3	Classification of Building Structures	3.2-3
3.2.2	AP1000 Classification System	3.2-3
3.2.2.1	Classification Definitions	3.2-4
3.2.2.2	Application of Classification	3.2-4
3.2.2.3	Equipment Class A	3.2-5
3.2.2.4	Equipment Class B	3.2-5
3.2.2.5	Equipment Class C	3.2-6
3.2.2.6	Equipment Class D	3.2-8
3.2.2.7	Other Equipment Classes	3.2-10
3.2.2.8	Instrumentation and Control Line Interface Criteria	3.2-11
3.2.2.9	Electrical Classifications	3.2-11
3.2.3	Inspection Requirements	3.2-12
3.2.4	Application of AP1000 Safety-Related Equipment and Seismic Classification System	3.2-12
3.2.5	Combined License Information	3.2-17
3.2.6	References	3.2-17
3.3	Wind and Tornado Loadings	3.3-1
3.3.1	Wind Loadings	3.3-1
3.3.1.1	Design Wind Velocity	3.3-1
3.3.1.2	Determination of Applied Forces	3.3-1
3.3.2	Tornado Loadings	3.3-1
3.3.2.1	Applicable Design Parameters	3.3-2
3.3.2.2	Determination of Forces on Structures	3.3-2
3.3.2.3	Effect of Failure of Structures or Components Not Designed for Tornado Loads	3.3-3
3.3.2.4	Tornado Loads on the Passive Containment Cooling System Air Baffle	3.3-3
3.3.3	Combined License Information	3.3-4
3.3.4	References	3.3-4
3.4	Water Level (Flood) Design	3.4-1
3.4.1	Flood Protection	3.4-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	3.4.1.1 Flood Protection Measures for Seismic Category I Structures, Systems, and Components	3.4-1
	3.4.1.2 Evaluation of Flooding Events	3.4-4
	3.4.1.3 Permanent Dewatering System	3.4-22
	3.4.2 Analytical and Test Procedures	3.4-22
	3.4.3 Combined License Information	3.4-22
	3.4.4 References	3.4-22
3.5	Missile Protection	3.5-1
	3.5.1 Missile Selection and Description	3.5-3
	3.5.1.1 Internally Generated Missiles (Outside Containment)	3.5-3
	3.5.1.2 Internally Generated Missiles (Inside Containment)	3.5-7
	3.5.1.3 Turbine Missiles	3.5-10
	3.5.1.4 Missiles Generated by Natural Phenomena	3.5-10
	3.5.1.5 Missiles Generated by Events Near the Site	3.5-11
	3.5.1.6 Aircraft Hazards	3.5-11
	3.5.2 Protection from Externally Generated Missiles	3.5-14
	3.5.2.1 Protection from Externally Generated Missile through Wall 11	3.5-14
	3.5.2.2 Protection of MSSV Functions from Externally Generated Missile	3.5-15
	3.5.2.3 Protection from Externally Generated Missile through Wall I	3.5-15
	3.5.2.4 Protection from Externally Generated Missile through Shield Building Air Inlets	3.5-16
	3.5.3 Barrier Design Procedures	3.5-16
	3.5.3.1 Ductility Factors for Steel Structures	3.5-18
	3.5.4 Combined License Information	3.5-19
	3.5.5 References	3.5-19
3.6	Protection Against the Dynamic Effects Associated with the Postulated Rupture of Piping	3.6-1
	3.6.1 Postulated Piping Failures in Fluid Systems Inside and Outside Containment	3.6-2
	3.6.1.1 Design Basis	3.6-3
	3.6.1.2 Description	3.6-5
	3.6.1.3 Safety Evaluation	3.6-8
	3.6.2 Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping	3.6-10
	3.6.2.1 Criteria Used to Define High- and Moderate-Energy Break and Crack Locations and Configurations	3.6-11
	3.6.2.2 Analytical Methods to Define Jet Thrust Forcing Functions and Response Models	3.6-18
	3.6.2.3 Dynamic Analysis Methods to Verify Integrity and Operability	3.6-19
	3.6.2.4 Protective Assembly Design Criteria	3.6-23
	3.6.2.5 Evaluation of Dynamic Effects of Pipe Ruptures	3.6-24
	3.6.2.6 Evaluation of Flooding Effects from Pipe Failures	3.6-26

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	3.6.2.7 Evaluation of Spray Effects from High- and Moderate-Energy Through-Wall Cracks	3.6-26
	3.6.3 Leak-before-Break Evaluation Procedures	3.6-27
	3.6.3.1 Application of Mechanistic Pipe Break Criteria	3.6-28
	3.6.3.2 Design Criteria for Leak-before-Break	3.6-29
	3.6.3.3 Analysis Methods and Criteria	3.6-31
	3.6.3.4 Documentation of Leak-before-Break Evaluations	3.6-32
	3.6.4 Combined License Information	3.6-32
	3.6.4.1 Pipe Break Hazard Analysis	3.6-32
	3.6.4.2 Leak-before-Break Evaluation of As-Designed Piping	3.6-33
	3.6.4.3 Leak-before-Break Evaluation of As-Built Piping	3.6-33
	3.6.4.4 Primary System Inspection Program for Leak-before-Break Piping	3.6-33
	3.6.5 References	3.6-33
3.7	Seismic Design	3.7-1
	3.7.1 Seismic Input	3.7-1
	3.7.1.1 Design Response Spectra	3.7-1
	3.7.1.2 Design Time History	3.7-3
	3.7.1.3 Critical Damping Values	3.7-5
	3.7.1.4 Supporting Media for Seismic Category I Structures	3.7-6
	3.7.2 Seismic System Analysis	3.7-7
	3.7.2.1 Seismic Analysis Methods	3.7-8
	3.7.2.2 Natural Frequencies and Response Loads	3.7-10
	3.7.2.3 Procedure Used for Modeling	3.7-10
	3.7.2.4 Soil-Structure Interaction	3.7-13
	3.7.2.5 Development of Floor Response Spectra	3.7-14
	3.7.2.6 Three Components of Earthquake Motion	3.7-14
	3.7.2.7 Combination of Modal Responses	3.7-15
	3.7.2.8 Interaction of Seismic Category II and Nonseismic Structures with Seismic Category I Structures, Systems, or Components	3.7-15
	3.7.2.9 Effects of Parameter Variations on Floor Response Spectra	3.7-19
	3.7.2.10 Use of Constant Vertical Static Factors	3.7-19
	3.7.2.11 Method Used to Account for Torsional Effects	3.7-19
	3.7.2.12 Methods for Seismic Analysis of Dams	3.7-20
	3.7.2.13 Determination of Seismic Category I Structure Overturning Moments	3.7-20
	3.7.2.14 Analysis Procedure for Damping	3.7-20
	3.7.3 Seismic Subsystem Analysis	3.7-20
	3.7.3.1 Seismic Analysis Methods	3.7-20
	3.7.3.2 Determination of Number of Earthquake Cycles	3.7-21
	3.7.3.3 Procedure Used for Modeling	3.7-21
	3.7.3.4 Basis for Selection of Frequencies	3.7-22
	3.7.3.5 Equivalent Static Load Method of Analysis	3.7-22
	3.7.3.6 Three Components of Earthquake Motion	3.7-23

TABLE OF CONTENTS (CONTINUED)

Section			Title	Page
		3.7.3.7	Combination of Modal Responses	3.7-24
		3.7.3.8	Analytical Procedure for Piping	3.7-28
		3.7.3.9	Combination of Support Responses	3.7-32
		3.7.3.10	Vertical Static Factors	3.7-35
		3.7.3.11	Torsional Effects of Eccentric Masses	3.7-35
		3.7.3.12	Seismic Category I Buried Piping Systems and Tunnels	3.7-35
		3.7.3.13	Interaction of Other Systems with Seismic Category I Systems	3.7-35
		3.7.3.14	Seismic Analyses for Reactor Internals	3.7-40
		3.7.3.15	Analysis Procedure for Damping	3.7-41
		3.7.3.16	Analysis of Seismic Category I Tanks	3.7-41
		3.7.3.17	Time History Analysis of Piping Systems	3.7-41
	3.7.4		Seismic Instrumentation	3.7-42
		3.7.4.1	Comparison with Regulatory Guide 1.12	3.7-42
		3.7.4.2	Location and Description of Instrumentation	3.7-43
		3.7.4.3	Control Room Operator Notification	3.7-44
		3.7.4.4	Comparison of Measured and Predicted Responses	3.7-44
		3.7.4.5	Tests and Inspections	3.7-45
	3.7.5		Combined License Information	3.7-45
		3.7.5.1	Seismic Analysis of Dams	3.7-45
		3.7.5.2	Post-Earthquake Procedures	3.7-45
		3.7.5.3	Seismic Interaction Review	3.7-45
		3.7.5.4	Reconciliation of Seismic Analyses of Nuclear Island Structures	3.7-45
		3.7.5.5	Free Field Acceleration Sensor	3.7-45
	3.7.6		References	3.7-45
3.8			Design of Category I Structures	3.8-1
	3.8.1		Concrete Containment	3.8-1
	3.8.2		Steel Containment	3.8-1
		3.8.2.1	Description of the Containment	3.8-1
		3.8.2.2	Applicable Codes, Standards, and Specifications	3.8-5
		3.8.2.3	Loads and Load Combinations	3.8-5
		3.8.2.4	Design and Analysis Procedures	3.8-7
		3.8.2.5	Structural Criteria	3.8-15
		3.8.2.6	Materials, Quality Control, and Special Construction Techniques	3.8-15
		3.8.2.7	Testing and In-Service Inspection Requirements	3.8-16
	3.8.3		Concrete and Steel Internal Structures of Steel Containment	3.8-16
		3.8.3.1	Description of the Containment Internal Structures	3.8-16
		3.8.3.2	Applicable Codes, Standards, and Specifications	3.8-22
		3.8.3.3	Loads and Load Combinations	3.8-23
		3.8.3.4	Analysis Procedures	3.8-25
		3.8.3.5	Design Procedures and Acceptance Criteria	3.8-31
		3.8.3.6	Materials, Quality Control, and Special Construction Techniques	3.8-39

TABLE OF CONTENTS (CONTINUED)

Section			Title	Page
		3.8.3.7	In-Service Testing and Inspection Requirements	3.8-40
		3.8.3.8	Construction Inspection	3.8-40
	3.8.4		Other Category I Structures	3.8-40
		3.8.4.1	Description of the Structures	3.8-41
		3.8.4.2	Applicable Codes, Standards, and Specifications	3.8-46
		3.8.4.3	Loads and Load Combinations	3.8-47
		3.8.4.4	Design and Analysis Procedures	3.8-50
		3.8.4.5	Structural Criteria	3.8-55
		3.8.4.6	Materials, Quality Control, and Special Construction Techniques	3.8-62
		3.8.4.7	Testing and In-Service Inspection Requirements	3.8-65
		3.8.4.8	Construction Inspection	3.8-65
	3.8.5		Foundations	3.8-66
		3.8.5.1	Description of the Foundations	3.8-66
		3.8.5.2	Applicable Codes, Standards, and Specifications	3.8-69
		3.8.5.3	Loads and Load Combinations	3.8-69
		3.8.5.4	Design and Analysis Procedures	3.8-69
		3.8.5.5	Structural Criteria	3.8-75
		3.8.5.6	Materials, Quality Control, and Special Construction Techniques	3.8-79
		3.8.5.7	In-Service Testing and Inspection Requirements	3.8-79
		3.8.5.8	Construction Inspection	3.8-79
	3.8.6		Combined License Information	3.8-79
		3.8.6.1	Containment Vessel Design Adjacent to Large Penetrations	3.8-79
		3.8.6.2	Passive Containment Cooling System Water Storage Tank Examination	3.8-80
		3.8.6.3	As-Built Summary Report	3.8-80
		3.8.6.4	In-Service Inspection of Containment Vessel	3.8-80
		3.8.6.5	Structures Inspection Program	3.8-80
		3.8.6.6	Construction Procedures Program	3.8-80
	3.8.7		References	3.8-80
3.9			Mechanical Systems and Components	3.9-1
	3.9.1		Special Topics for Mechanical Components	3.9-1
		3.9.1.1	Design Transients	3.9-1
		3.9.1.2	Computer Programs Used in Analyses	3.9-23
		3.9.1.3	Experimental Stress Analysis	3.9-23
		3.9.1.4	Considerations for the Evaluation of the Faulted Conditions	3.9-23
		3.9.1.5	Module Interaction, Coupling, and Other Issues	3.9-24
	3.9.2		Dynamic Testing and Analysis	3.9-24
		3.9.2.1	Piping Vibration, Thermal Expansion, and Dynamic Effects	3.9-24
		3.9.2.2	Seismic Qualification Testing of Safety-Related Mechanical Equipment	3.9-26
		3.9.2.3	Dynamic Response Analysis of Reactor Internals under Operational Flow Transients and Steady-State Conditions	3.9-28

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
3.9.2.4	Pre-operational Flow-Induced Vibration Testing of Reactor Internals	3.9-31
3.9.2.5	Dynamic System Analysis of the Reactor Internals Under Faulted Conditions	3.9-32
3.9.2.6	Correlation of Reactor Internals Vibration Tests with the Analytical Results	3.9-35
3.9.3	ASME Code Classes 1, 2, and 3 Components, Component Supports, and Core Support Structures	3.9-36
3.9.3.1	Loading Combinations, Design Transients, and Stress Limits	3.9-36
3.9.3.2	Pump and Valve Operability Assurance	3.9-50
3.9.3.3	Design and Installation Criteria of Class 1, 2, and 3 Pressure Relieving Devices	3.9-52
3.9.3.4	Component and Piping Supports	3.9-54
3.9.3.5	Instrumentation Line Supports	3.9-59
3.9.4	Control Rod Drive System (CRDS)	3.9-59
3.9.4.1	Descriptive Information of CRDS	3.9-59
3.9.4.2	Applicable CRDS Design Specifications	3.9-65
3.9.4.3	Design Loads, Stress Limits, and Allowable Deformations	3.9-67
3.9.4.4	Control Rod Drive Mechanism Performance Assurance Program	3.9-68
3.9.5	Reactor Pressure Vessel Internals	3.9-68
3.9.5.1	Design Arrangements	3.9-68
3.9.5.2	Design Loading Conditions	3.9-71
3.9.5.3	Design Bases	3.9-72
3.9.6	Inservice Testing of Pumps and Valves	3.9-74
3.9.6.1	Inservice Testing of Pumps	3.9-74
3.9.6.2	Inservice Testing of Valves	3.9-74
3.9.6.3	Deviations from Code Requirements	3.9-75
3.9.6.4	Additional Testing	3.9-75
3.9.7	Integrated Head Package	3.9-77
3.9.7.1	Design Bases	3.9-78
3.9.7.2	Design Description	3.9-79
3.9.7.3	Design Evaluation	3.9-80
3.9.7.4	Inspection and Testing Requirements	3.9-81
3.9.8	Combined License Information	3.9-81
3.9.8.1	Reactor Internals Vibration Assessment and Predicted Response	3.9-81
3.9.8.2	Design Specifications and Reports	3.9-81
3.9.8.3	Snubber Operability Testing	3.9-82
3.9.8.4	Valve Inservice Testing	3.9-82
3.9.8.5	Surge Line Thermal Monitoring	3.9-82
3.9.8.6	Piping Benchmark Program	3.9-82
3.9.8.7	As-Designed Piping Analysis	3.9-82
3.9.9	References	3.9-82
3.10	Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment	3.10-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
3.10.1	Seismic and Dynamic Qualification Criteria	3.10-2
3.10.1.1	Qualification Standards	3.10-2
3.10.1.2	Performance Requirements for Seismic Qualification	3.10-2
3.10.1.3	Performance Criteria	3.10-2
3.10.2	Methods and Procedures for Qualifying Electrical Equipment, Instrumentation, and Mechanical Components	3.10-3
3.10.2.1	Seismic Qualification of Instrumentation and Electrical Equipment	3.10-4
3.10.2.2	Seismic and Operability Qualification of Active Mechanical Equipment	3.10-4
3.10.2.3	Valve Operator Qualification	3.10-6
3.10.2.4	Seismic Qualification of Other Seismic Category I Mechanical Equipment	3.10-6
3.10.3	Method and Procedures for Qualifying Supports of Electrical Equipment, Instrumentation, and Mechanical Components	3.10-6
3.10.4	Documentation	3.10-6
3.10.5	Standard Review Plan Evaluation	3.10-7
3.10.6	Combined License Information Item on Experienced-Based Qualification	3.10-7
3.10.7	References	3.10-7
3.11	Environmental Qualification of Mechanical and Electrical Equipment	3.11-1
3.11.1	Equipment Identification and Environmental Conditions	3.11-1
3.11.1.1	Equipment Identification	3.11-1
3.11.1.2	Definition of Environmental Conditions	3.11-1
3.11.1.3	Equipment Operability Times	3.11-2
3.11.1.4	Standard Review Plan Evaluation	3.11-3
3.11.2	Qualification Tests and Analysis	3.11-3
3.11.2.1	Environmental Qualification of Electrical Equipment	3.11-3
3.11.2.2	Environmental Qualification of Mechanical Equipment	3.11-3
3.11.3	Loss of Ventilation	3.11-4
3.11.4	Estimated Radiation and Chemical Environment	3.11-4
3.11.5	Combined License Information Item for Equipment Qualification File	3.11-5
3.11.6	References	3.11-6
APPENDIX 3A	HVAC DUCTS AND DUCT SUPPORTS	3A-1
3A.1	Codes and Standards	3A-1
3A.2	Loads and Load Combinations	3A-1
3A.2.1	Loads	3A-1
3A.2.1.1	Dead Load (D)	3A-1
3A.2.1.2	Construction Live Load (L)	3A-1
3A.2.1.3	Pressure (P)	3A-1
3A.2.1.4	Safe Shutdown Earthquake (E_s)	3A-2
3A.2.1.5	Wind Loads (W)	3A-2
3A.2.1.6	Tornado Loads (W_t)	3A-2
3A.2.1.7	External Pressure Differential Loads (P_A)	3A-2

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	3A.2.1.8 Thermal (T_O/T_A)	3A-2
	3A.2.2 Load Combinations	3A-2
3A.3	Analysis and Design	3A-2
	3A.3.1 Response Due to Seismic Loads	3A-3
	3A.3.2 Deflection Criteria	3A-3
	3A.3.3 Relative Movement	3A-3
	3A.3.4 Allowable Stresses	3A-3
	3A.3.5 Connections	3A-3
APPENDIX 3B	LEAK-BEFORE-BREAK EVALUATION OF THE AP1000 PIPING	3B-1
3B.1	Leak-before-Break Criteria for AP1000 Piping	3B-1
3B.2	Potential Failure Mechanisms for AP1000 Piping	3B-2
	3B.2.1 Erosion-Corrosion Induced Wall Thinning	3B-2
	3B.2.2 Stress Corrosion Cracking	3B-3
	3B.2.3 Water Hammer	3B-4
	3B.2.4 Fatigue	3B-5
	3B.2.5 Thermal Aging	3B-6
	3B.2.6 Thermal Stratification	3B-6
	3B.2.7 Other Mechanisms	3B-7
3B.3	Leak-before-Break Bounding Analysis	3B-8
	3B.3.1 Procedure for Stainless Steel Piping	3B-8
	3B.3.1.1 Pipe Geometry, Material and Operating Conditions	3B-8
	3B.3.1.2 Pipe Physical Properties	3B-9
	3B.3.1.3 Low Normal Stress Case (Case 1)	3B-9
	3B.3.1.4 High Normal Stress Case (Case 2)	3B-9
	3B.3.1.5 Develop the Bounding Analysis Curve	3B-10
	3B.3.2 Procedure for Non-stainless Steel Piping	3B-10
	3B.3.2.1 Pipe Geometry, Material and Operating Conditions	3B-10
	3B.3.2.2 Calculations Steps	3B-10
	3B.3.2.3 Low Normal Stress Case (Case 1)	3B-11
	3B.3.2.4 High Normal Stress Case (Case 2)	3B-11
	3B.3.2.5 Develop the Bounding Analysis Curve	3B-11
	3B.3.3 Evaluation of Piping System Using Bounding Analysis Curves	3B-12
	3B.3.3.1 Calculation of Stresses	3B-12
	3B.3.3.2 Normal Loads	3B-13
	3B.3.3.3 Maximum Loads	3B-13
	3B.3.3.4 Bounding Analysis Curve Comparison – LBB Criteria	3B-14
	3B.3.4 Bounding Analysis Results	3B-14
3B.4	Differences in Leak-before-Break Analysis for Stainless Steel and Ferritic Steel Pipe	3B-14
3B.5	Differences in Inspection Criteria for Class 1, 2, and 3 Systems	3B-14
3B.6	Differences in Fabrication Requirements of ASME Class 1, Class 2, and Class 3 Piping	3B-14
3B.7	Sensitivity Study for the Constraint Effect on LBB	3B-15
3B.8	References	3B-15

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
APPENDIX 3C	REACTOR COOLANT LOOP ANALYSIS METHODS	3C-1
3C.1	Reactor Coolant Loop Model Description	3C-1
3C.1.1	Steam Generator Model	3C-1
3C.1.1.1	Steam Generator Mass and Geometrical Model	3C-1
3C.1.1.2	Steam Generator Supports	3C-1
3C.1.2	Reactor Coolant Pump Model	3C-1
3C.1.2.1	Static Model	3C-1
3C.1.2.2	Seismic Model	3C-1
3C.1.2.3	Reactor Coolant Pump Supports	3C-2
3C.1.3	Reactor Pressure Vessel Model	3C-2
3C.1.3.1	Mass and Geometrical Model	3C-2
3C.1.3.2	Reactor Pressure Vessel Supports	3C-2
3C.1.4	Containment Interior Building Structure Model	3C-2
3C.1.5	Reactor Coolant Loop Piping Model	3C-2
3C.2	Design Requirements	3C-2
3C.3	Static Analyses	3C-3
3C.3.1	Deadweight Analysis	3C-3
3C.3.2	Internal Pressure Analysis	3C-3
3C.3.3	Thermal Expansion Analysis	3C-3
3C.4	Seismic Analyses	3C-3
3C.5	Reactor Coolant Loop Piping Stresses	3C-4
3C.6	Description of Computer Programs	3C-4
APPENDIX 3D	METHODOLOGY FOR QUALIFYING AP1000 SAFETY-RELATED ELECTRICAL AND MECHANICAL EQUIPMENT	3D-1
3D.1	Purpose	3D-2
3D.2	Scope	3D-2
3D.3	Introduction	3D-2
3D.4	Qualification Criteria	3D-2
3D.4.1	Qualification Guides	3D-3
3D.4.1.1	IEEE Standards	3D-3
3D.4.1.2	NRC Regulatory Guides	3D-4
3D.4.2	Definitions	3D-6
3D.4.3	Mild Versus Harsh Environments	3D-6
3D.4.4	Test Sequence	3D-7
3D.4.5	Aging	3D-8
3D.4.5.1	Design Life	3D-8
3D.4.5.2	Shelf Life	3D-8
3D.4.5.3	Qualified Life	3D-8
3D.4.5.4	Qualified Life Reevaluation	3D-9
3D.4.6	Operability Time	3D-10
3D.4.7	Performance Criterion	3D-10
3D.4.8	Margin	3D-11
3D.4.8.1	Normal and Abnormal Extremes	3D-11
3D.4.8.2	Aging	3D-11
3D.4.8.3	Radiation	3D-12
3D.4.8.4	Seismic Conditions	3D-12
3D.4.8.5	High-Energy Line Break Conditions	3D-13
3D.4.9	Treatment of Failures	3D-13

TABLE OF CONTENTS (CONTINUED)

Section		Title	Page
	3D.4.10	Traceability	3D-13
		3D.4.10.1 Auditable Link Document	3D-13
		3D.4.10.2 Similarity	3D-14
3D.5	Design Specifications		3D-14
	3D.5.1	Normal Operating Conditions	3D-15
		3D.5.1.1 Pressure, Temperature, Humidity	3D-15
		3D.5.1.2 Radiation Dose	3D-15
	3D.5.2	Abnormal Operating Conditions	3D-16
		3D.5.2.1 Abnormal Environments Inside Containment	3D-16
		3D.5.2.2 Abnormal Environments Outside Containment	3D-16
	3D.5.3	Seismic Events	3D-17
	3D.5.4	Containment Test Environment	3D-17
	3D.5.5	Design Basis Event Conditions	3D-17
		3D.5.5.1 High-Energy Line Break Accidents Inside Containment	3D-17
		3D.5.5.2 High-Energy Line Break Accidents Outside Containment	3D-20
3D.6	Qualification Methods		3D-20
	3D.6.1	Type Test	3D-21
	3D.6.2	Analysis	3D-21
		3D.6.2.1 Similarity	3D-21
		3D.6.2.2 Substitution	3D-22
		3D.6.2.3 Analysis of Safety-Related Mechanical Equipment	3D-22
	3D.6.3	Operating Experience	3D-24
	3D.6.4	On-Going Qualification	3D-25
	3D.6.5	Combinations of Methods	3D-25
		3D.6.5.1 Use of Existing Qualification Reports	3D-25
3D.7	Documentation		3D-26
	3D.7.1	Equipment Qualification Data Package	3D-26
	3D.7.2	Specifications	3D-27
		3D.7.2.1 Equipment Identification	3D-27
		3D.7.2.2 Installation Requirements	3D-27
		3D.7.2.3 Electrical Requirements	3D-27
		3D.7.2.4 Auxiliary Devices	3D-27
		3D.7.2.5 Preventive Maintenance	3D-27
		3D.7.2.6 Safety Functions	3D-28
		3D.7.2.7 Performance Requirements	3D-28
		3D.7.2.8 Environmental Conditions	3D-28
	3D.7.3	Qualification Program	3D-28
	3D.7.4	Qualification by Test	3D-28
		3D.7.4.1 Specimen Description	3D-29
		3D.7.4.2 Number Tested	3D-29
		3D.7.4.3 Mounting	3D-29
		3D.7.4.4 Connections	3D-29
		3D.7.4.5 Test Sequence	3D-29
		3D.7.4.6 Simulated Service Conditions	3D-30
		3D.7.4.7 Measured Variables	3D-30

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	3D.7.4.8 Type Test Summary	3D-30
	3D.7.5 Qualification by Analysis	3D-31
	3D.7.6 Qualification by Experience	3D-31
	3D.7.7 Qualification Program Conclusions	3D-31
	3D.7.8 Combined License Information	3D-31
3D.8	References	3D-31
Appendix 3D-Attachment A — Sample Equipment Qualification Data Package (EQDP)		3D-58
Appendix 3D-Attachment B — Aging Evaluation Program		3D-75
B.1	Introduction	3D-75
B.2	Objectives	3D-75
B.3	Basic Approach	3D-75
B.4	Harsh Environment	3D-75
	B.4.1 Scope	3D-76
	B.4.2 Aging Mechanisms	3D-76
	B.4.3 Time	3D-76
	B.4.4 Operational Stresses	3D-76
	B.4.5 External Stresses	3D-77
	B.4.6 Synergism	3D-78
	B.4.7 Design Basis Event Testing	3D-78
	B.4.8 Aging Sequence	3D-78
	B.4.9 Performance Criterion	3D-78
	B.4.10 Failure Treatment	3D-78
B.5	Mild Environment	3D-79
	B.5.1 Scope	3D-79
	B.5.2 Performance Criteria	3D-79
	B.5.3 Failure Treatment	3D-80
Appendix 3D-Attachment C — Effects of Gamma Radiation Doses Below 10^4 Rads on the Mechanical Properties of Materials		3D-83
C.1	Introduction	3D-83
C.2	Scope	3D-83
C.3	Discussion	3D-84
C.4	Conclusions	3D-84
C.5	References	3D-85
Appendix 3D-Attachment D — Accelerated Thermal Aging Parameters		3D-89
D.1	Introduction	3D-89
D.2	Arrhenius Model	3D-89
D.3	Activation Energy	3D-90
D.4	Thermal Aging (Normal/Abnormal Operating Conditions)	3D-91
	D.4.1 Normal Operation Temperature (T_0)	3D-91
	D.4.1.1 External Ambient Temperature (T_a)	3D-91
	D.4.1.2 Temperature Rise in Enclosure (T_r)	3D-91
	D.4.1.3 Self-Heating Effects (T_j)	3D-92
	D.4.2 Accelerated Aging Temperature (T_i)	3D-92
	D.4.3 Examples of Arrhenius Calculations	3D-92
D.5	Post-Accident Thermal Aging	3D-93
	D.5.1 Post-Accident Operating Temperatures	3D-93
	D.5.2 Accelerated Thermal Aging Parameters for Post-Accident Conditions	3D-93

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
D.6	References	3D-93
Appendix 3D-Attachment E — Seismic Qualification Techniques		3D-99
E.1	Purpose	3D-99
E.2	Definitions	3D-99
E.2.1	1/2 Safe Shutdown Earthquake	3D-99
E.2.2	Seismic Category I Equipment	3D-99
E.2.3	Seismic Category II Equipment	3D-99
E.2.4	Non-seismic Equipment	3D-99
E.2.5	Active Equipment	3D-99
E.2.6	Passive Equipment	3D-99
E.3	Qualification Methods	3D-99
E.3.1	Use of Qualification by Testing	3D-100
E.3.2	Use of Qualification by Analysis	3D-100
E.4	Requirements	3D-100
E.4.1	Damping	3D-100
E.4.1.1	Testing	3D-100
E.4.1.2	Analysis	3D-101
E.4.2	Interface Requirements	3D-101
E.4.3	Mounting Simulation	3D-101
E.4.4	1/2 Safe Shutdown Earthquake	3D-101
E.4.5	Safe Shutdown Earthquake	3D-101
E.4.6	Other Dynamic Loads	3D-101
E.5	Qualification by Test	3D-102
E.5.1	Qualification of Hard-Mounted Equipment	3D-102
E.5.2	Qualification of Line-Mounted Equipment	3D-103
E.5.2.1	Seismic Qualification Test Sequence	3D-103
E.5.2.2	Line Vibration Aging	3D-104
E.5.2.3	Single Frequency Testing	3D-104
E.5.2.4	Seismic Aging	3D-104
E.5.2.5	Static Deflection Testing of Active Valves	3D-104
E.5.3	Operational Conditions	3D-105
E.5.4	Resonant Search Testing	3D-105
E.6	Qualification by Analysis	3D-105
E.6.1	Modeling	3D-105
E.6.2	Qualification by Static Analysis	3D-106
E.6.3	Qualification by Dynamic Analysis	3D-106
E.6.3.1	Response Spectrum Analysis	3D-106
E.6.3.2	Static Coefficient Method	3D-107
E.6.3.3	Time History Analysis	3D-107
E.7	Qualification by Test Experience	3D-107
E.8	Performance Criteria	3D-107
E.8.1	Equipment Qualification by Test	3D-107
E.8.2	Equipment Qualification by Analysis	3D-107
E.8.2.1	Structural Integrity	3D-107
E.8.2.2	Operability	3D-108
APPENDIX 3E	HIGH-ENERGY PIPING IN THE NUCLEAR ISLAND	3E-1
APPENDIX 3F	CABLE TRAYS AND CABLE TRAY SUPPORTS	3F-1
3F.1	Codes and Standards	3F-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
3F.2	Loads and Load Combinations	3F-1
3F.2.1	Loads	3F-1
3F.2.1.1	Dead Load (D)	3F-1
3F.2.1.2	Construction Live Load (L)	3F-1
3F.2.1.3	Safe Shutdown Earthquake (E_s)	3F-1
3F.2.1.4	Thermal Load	3F-2
3F.2.2	Load Combinations	3F-2
3F.3	Analysis and Design	3F-2
3F.3.1	Damping	3F-2
3F.3.2	Seismic Analysis	3F-2
3F.3.3	Allowable Stresses	3F-3
3F.3.4	Connections	3F-3
APPENDIX 3G	NUCLEAR ISLAND SEISMIC ANALYSES	3G-1
3G.1	Introduction	3G-1
3G.2	Nuclear Island Finite Element Models	3G-1
3G.2.1	Individual Building and Equipment Models	3G-2
3G.2.1.1	Coupled Auxiliary and Shield Building	3G-2
3G.2.1.2	Containment Internal Structures	3G-2
3G.2.1.3	Containment Vessel	3G-2
3G.2.1.4	Polar Crane	3G-3
3G.2.1.5	Major Equipment and Structures Using Stick Models	3G-4
3G.2.2	Nuclear Island Dynamic Models	3G-4
3G.2.2.1	NI10 Model	3G-4
3G.2.2.2	NI20 Model	3G-5
3G.2.2.3	Nuclear Island Stick Model	3G-5
3G.2.2.4	NI05 Model	3G-5
3G.2.2.5	Seismic Stability Model	3G-5
3G.2.3	Static Models	3G-6
3G.2.3.1	Quadrant Model of Shield Building Roof	3G-6
3G.2.3.2	Containment Vessel 3D Finite Element Model	3G-6
3G.2.3.3	Containment Vessel Axisymmetric Model	3G-6
3G.3	2D SASSI Analyses	3G-6
3G.4	Nuclear Island Dynamic Analyses	3G-8
3G.4.1	ANSYS Fixed Base Analysis	3G-8
3G.4.2	3D SASSI Analyses	3G-8
3G.4.3	Seismic Analysis	3G-9
3G.4.3.1	Response Spectrum Analysis	3G-9
3G.4.3.2	Absolute Accelerations	3G-9
3G.4.3.3	Seismic Response Spectra	3G-9
3G.4.3.4	Bearing Pressure Demand	3G-10
3G.5	References	3G-10
APPENDIX 3GG	3-D SSI ANALYSIS OF AP1000 AT VOGTLE SITE USING NI15 MODEL	3GG-1
APPENDIX 3H	AUXILIARY AND SHIELD BUILDING CRITICAL SECTIONS	3H-1
3H.1	Introduction	3H-1
3H.2	Description of Auxiliary and Shield Buildings	3H-1
3H.2.1	Description of Auxiliary Building	3H-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
3H.2.2	Description of Shield Building	3H-2
3H.3	Design Criteria	3H-4
3H.3.1	Governing Codes and Standards	3H-4
3H.3.2	Seismic Input	3H-4
3H.3.3	Loads	3H-5
3H.3.4	Load Combinations and Acceptance Criteria	3H-8
3H.4	Seismic Analyses	3H-8
3H.4.1	Live Load for Seismic Design	3H-8
3H.5	Structural Design of Critical Sections	3H-9
3H.5.1	Shear Walls	3H-10
3H.5.1.1	Exterior Wall at Column Line 1	3H-11
3H.5.1.2	Wall at Column Line 7.3	3H-11
3H.5.1.3	Wall at Column Line L	3H-12
3H.5.1.4	Wall at Column Line 11	3H-12
3H.5.2	Composite Structures (Floors and Roof)	3H-13
3H.5.2.1	Roof at Elevation 180′-0″, Area 6 (Critical Section is between Col. Lines N & K-2 and 3 & 4)	3H-14
3H.5.2.2	Floor at Elevation 135′-3″, Area 1 (Between Column Lines M and P)	3H-15
3H.5.3	Reinforced Concrete Slabs	3H-15
3H.5.3.1	Operations Work Area (Tagging Room) Ceiling	3H-16
3H.5.4	Concrete Finned Floors	3H-16
3H.5.5	Structural Modules	3H-18
3H.5.5.1	West Wall of Spent Fuel Pool	3H-18
3H.5.6	Shield Building Roof and Connections	3H-19
3H.5.6.1	Air Inlets and Tension Ring	3H-20
3H.5.6.2	Compression Ring and Interior Wall of Passive Containment Cooling Water Storage Tank	3H-20
3H.5.6.3	Knuckle Region and Exterior Wall of Passive Containment Cooling System Tank	3H-20
3H.5.7	Shield Building Cylinder (SC)	3H-21
3H.5.7.1	Shield Building Cylindrical Wall	3H-21
3H.5.7.2	Reinforced Concrete (RC)/Steel Concrete Composite (SC) Horizontal and Vertical Connections	3H-22
3H.5.8	References	3H-22
APPENDIX 3I	EVALUATION FOR HIGH FREQUENCY SEISMIC INPUT	3I-1
3I.1	Introduction	3I-1
3I.2	High Frequency Seismic Input	3I-1
3I.3	NI Models Used To Develop High Frequency Response	3I-1
3I.4	Evaluation Methodology	3I-2
3I.5	General Selection Screening Criteria	3I-2
3I.6	Evaluation	3I-3
3I.6.1	Building Structures	3I-3
3I.6.2	Primary Coolant Loop	3I-4
3I.6.3	Piping Systems	3I-5
3I.6.4	Electrical and Electro-Mechanical Equipment	3I-5
3I.7	References	3I-8

LIST OF TABLES

Table Number	Title	Page
3.2-1	Comparison of Safety Classification Requirements	3.2-19
3.2-2	Seismic Classification of Building Structures	3.2-20
3.2-3	AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment	3.2-21
3.2-201	Not Used	3.2-79
3.5-1	External Missile Protection Provided for Auxiliary Building Wall 11 Openings	3.5-20
3.5-2	External Missile Protection Provided for Annex Building Wall I Openings	3.5-22
3.5-3	External Missile Protection Provided for Shield Building Air Inlet Openings	3.5-23
3.5-201	Augusta APO Terminal Area Forecast Summary Report – Itinerant Operations	3.5-24
3.5-202	Deleted in Revision 2	3.5-25
3.6-1	High-Energy and Moderate-Energy Fluid Systems Considered for Protection of Essential Systems	3.6-35
3.6-2	Subcompartments and Postulated Pipe Ruptures	3.6-36
3.6-3	NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets	3.6-43
3.7.1-1	Safe Shutdown Earthquake Damping Values	3.7-49
3.7.1-2	Embedment Depth and Related Dimensions of Category I Structures	3.7-50
3.7.1-3	AP1000 Design Response Spectra Amplification Factors for Control Points	3.7-51
3.7.1-4	Strain Compatible Soil Properties	3.7-52
3.7.2-1–3.7.2-16	Not Used	3.7-57
3.7.3-1	Seismic Category I Equipment Outside Containment by Room Number	3.7-58
3.7.3-2	Equipment Classified as Sensitive Targets for Seismically Analyzed Piping, HVAC Ducting, Cable Tray Systems	3.7-61
3.8.2-1	Load Combinations and Service Limits for Containment Vessel	3.8-84
3.8.2-2	Containment Vessel Pressure Capabilities	3.8-85
3.8.2-3	Analysis and Test Results of Fabricated Heads	3.8-86
3.8.2-4	Summary of Containment Vessel Models and Analysis Methods	3.8-87
3.8.2-5	Maximum Absolute Nodal Acceleration (ZPA) Steel Containment Vessel	3.8-88
3.8.3-1	Shear and Flexural Stiffnesses of Structural Module Walls	3.8-89
3.8.3-2	Summary of Containment Internal Structures Models and Analysis Methods	3.8-90
3.8.3-3	Definition of Critical Locations and Thicknesses for Containment Internal Structures	3.8-91
3.8.3-4	Design Summary of Southwest Wall of Refueling Cavity Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Mid-Height	3.8-92
3.8.3-5	Design Summary of South Wall of West Steam Generator Compartment Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Mid-Height	3.8-95

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
3.8.3-6	Design Summary of North-East Wall of IRWST Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Mid-Height	3.8-98
3.8.3-7	Design Summary of Steel Wall of IRWST	3.8-101
3.8.4-1	Load Combinations and Load Factors for Seismic Category I Steel Structures	3.8-102
3.8.4-2	Load Combinations and Load Factors for Seismic Category I Concrete Structures	3.8-103
3.8.4-3	Acceptance Tests for Concrete Aggregates	3.8-104
3.8.4-4	Criteria for Water Used in Production of Concrete	3.8-105
3.8.4-5	Not Used	3.8-106
3.8.4-6	Materials Used in Structural and Miscellaneous Steel	3.8-107
3.8.5-1	Minimum Required Factor of Safety for Overturning and Sliding of Structures	3.8-109
3.8.5-2	Factors of Safety for Flotation, Overturning and Sliding of Nuclear Island Structures	3.8-110
3.8.5-3	Definition of Critical Locations, Thicknesses and Reinforcement for Nuclear Island Basemat (in^2/ft)	3.8-111
3.8-201	Waterproof Membrane Inspections, Tests, Analyses, and Acceptance Criteria	3.8-112
3.9-1	Reactor Coolant System Design Transients	3.9-86
3.9-2	Pump Starting/Stopping Conditions	3.9-88
3.9-3	Loadings for ASME Class 1, 2, 3, CS and Supports	3.9-89
3.9-4	Not Used	3.9-91
3.9-5	Minimum Design Loading Combinations For ASME Class 1, 2, 3 And CS Systems And Components	3.9-92
3.9-6	Additional Load Combinations and Stress Limits for ASME Class 1 Piping	3.9-93
3.9-7	Additional Load Combinations and Stress Limits for ASME Class 2, 3 Piping	3.9-94
3.9-8	Minimum Design Loading Combinations for Supports for ASME Class 1, 2, 3 Piping and Components	3.9-95
3.9-9	Stress Criteria for ASME Code Section III Class 1 Components and Supports and Class CS Core Supports	3.9-96
3.9-10	Stress Criteria for ASME Code Section III Class 2 and 3 Components and Supports	3.9-97
3.9-11	Piping Functional Capability – ASME Class 1, 2, and 3	3.9-99
3.9-12	List of ASME Class 1, 2, and 3 Active Valves	3.9-100
3.9-13	Control Rod Drive Mechanism Production Tests	3.9-107
3.9-14	Maximum Deflections Allowed for Reactor Internal Support Structures	3.9-108
3.9-15	Computer Programs for Seismic Category 1 Components	3.9-109
3.9-16	Valve Inservice Test Requirements	3.9-110
3.9-17	System Level Operability Test Requirements	3.9-111
3.9-18	AP1000 Pressure Isolation Valves	3.9-112
3.9-19	Critical Piping Design Methods and Criteria (Piping Design Criteria)	3.9-113
3.9-20	Piping Packages Chosen to Demonstrate Piping Design for Piping DAC Closure	3.9-115

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
3.9-201	Safety Related Snubbers	3.9-117
3.11-1	Environmentally Qualified Electrical and Mechanical Equipment	3.11-7
3B-1	AP1000 Leak-Before-Break Bounding Analysis Systems and Parameters	3B-16
3D.4-1	Typical Mild Environment Parameter Limits	3D-33
3D.4-2	Equipment Post-Accident Operability Times	3D-34
3D.4-3	AP1000 EQ Program Margin Requirements	3D-35
3D.5-1	Normal Operating Environments	3D-36
3D.5-2	60-Year Normal Operating Doses	3D-39
3D.5-3	Abnormal Operating Environments Inside Containment	3D-40
3D.5-4	Abnormal Operating Environments Outside Containment	3D-41
3D.5-5	Accident Environments	3D-44
3D.6-1	Mechanical Equipment Components Requiring Environmental Qualification	3D-45
3D.B-1	Example Class 1E Equipment Scope and Category Allocation	3D-81
3D.B-2	Aging Mechanism Sequence	3D-82
3D.C-1	Radiation-Induced Degradation of Material Mechanical Properties	3D-86
3D.D-1	Activation Energies From Westinghouse Reports	3D-94
3G.1-1	Summary of Models and Analysis Methods	3G-11
3G.1-2	Summary of Dynamic Analyses and Combination Techniques	3G-15
3G.2-1	Steel Containment Vessel Lumped-Mass Stick Model (Without Polar Crane) Modal Properties	3G-16
3G.2-2	Comparison of Frequencies for Containment Vessel Seismic Model	3G-18
3G.3-1	AP1000 ZPA for 2D SASSI Cases	3G-19
3G.4-1	Key Nodes at Location	3G-20
3G.4-2	Maximum Bearing Pressure from 2D Time History Analyses	3G-21
3H.5-1	Nuclear Island: Design Temperatures for Thermal Gradient	3H-23
3H.5-2	Exterior Wall at Column Line 1 Forces and Moments in Critical Locations	3H-24
3H.5-3	Exterior Wall on Column Line 1 Details of Wall Reinforcement (in^2/ft)	3H-25
3H.5-4	Interior Wall at Column Line 7.3 Forces and Moments in Critical Locations	3H-26
3H.5-5	Interior Wall on Column Line 7.3 Details of Wall Reinforcement	3H-27
3H.5-6	Interior Wall at Column Line L Forces and Moments in Critical Locations	3H-28
3H.5-7	Interior Wall on Column Line L Details of Wall Reinforcement	3H-29
3H.5-8	Design Summary of Spent Fuel Pool Wall Design Loads, Load Combinations, and Comparisons to Acceptance Criteria – Element No. 20477	3H-30
3H.5-9	Shield Building Roof Reinforcement Summary	3H-37
3H.5-10	Design Summary Of Roof At Elevation 180′-0″, Area 6	3H-42
3H.5-11	Design Summary Of Floor At Elevation 135′-3″ Area 1 (Between Column Lines M And P)	3H-43
3H.5-12	Design Summary Of Floor At Elevation 135′-3″ (Operations Work Area (Previously Known As ‘Tagging Room’) Ceiling))	3H-44
3H.5-13	Design Summary Of Floor At Elevation 135′-3″ Area 2 (Main Control Room Ceiling)	3H-45

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
3H.5-14	Design Summary of Enhanced Shield Building Cylindrical Wall Load Combinations, and Comparison to Acceptance Criteria Elevation 180 Feet Near Fuel Handling Building Roof	3H-46
3H.5-15	Shield Building Roof Reinforcement Ratio of Code Required Versus Provided	3H-49
3I.6-1	Potential High Frequency Sensitive Equipment List	3I-10
3I.6-2	List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment	3I-11
3I.6-3	List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive	3I-32

LIST OF FIGURES

Figure Number	Title	Page
3.3-1	Velocity Pressure Variation with Radius from Center of Tornado	3.3-6
3.4-1	Typical Details of Nuclear Island Waterproofing Below Grade	3.4-23
3.4-2	Typical Details of Nuclear Island Waterproofing Below Grade with Step Back	3.4-24
3.4-3	Not Used	3.4-25
3.4-4	Typical Details of Membrane Corner Detail at Basemat and Exterior Wall	3.4-26
3.5-201	Airports Within 30 Miles of Vogtle Facility	3.5-26
3.6-1	Typical U-Bar Restraint	3.6-53
3.6-2	Typical Structural Components of Crushable Pipe Type Whip Restraints	3.6-54
3.6-3	Terminal Ends Definitions	3.6-55
3.7.1-1	Horizontal Design Response Spectra Safe Shutdown Earthquake	3.7-62
3.7.1-2	Vertical Design Response Spectra Safe Shutdown Earthquake	3.7-63
3.7.1-3	Design Horizontal Time History, "H1" Acceleration, Velocity & Displacement Plots	3.7-64
3.7.1-4	Design Horizontal Time History, "H2" Acceleration, Velocity & Displacement Plots	3.7-65
3.7.1-5	Design Vertical Time History Acceleration, Velocity & Displacement Plots	3.7-66
3.7.1-6	Acceleration Response Spectra of Design Horizontal Time History, "H1"	3.7-67
3.7.1-7	Acceleration Response Spectra of Design Horizontal Time History, "H2"	3.7-68
3.7.1-8	Acceleration Response Spectra of Design Vertical Time History	3.7-69
3.7.1-9	Minimum Power Spectral Density Curve (Normalized to 0.3g)	3.7-70
3.7.1-10	Power Spectral Density of Design Horizontal Time History, "H1"	3.7-71
3.7.1-11	Power Spectral Density of Design Horizontal Time History, "H2"	3.7-72
3.7.1-12	Power Spectral Density of Design Vertical Time History	3.7-73
3.7.1-13	Not Used	3.7-74
3.7.1-14	Nuclear Island Structures Dimensions	3.7-75
3.7.1-15	Strain Dependent Properties of Rock Material (Ref. 37)	3.7-76
3.7.1-16	Strain Dependent Properties of Soil Material (Ref. 38)	3.7-77
3.7.1-17	Generic Soil Profiles	3.7-78
3.7.2-1–3.7.2-11	Not Used	3.7-79
3.7.2-12	(Sheet 1 of 12) Nuclear Island Key Structural Dimensions Plan at El. 66′-6″	3.7-80
3.7.2-12	(Sheet 2 of 12) Nuclear Island Key Structural Dimensions Plan at El. 82′-6″	3.7-81
3.7.2-12	(Sheet 3 of 12) Nuclear Island Key Structural Dimensions Plan at El. 100′-0″ & 107′-2″	3.7-82
3.7.2-12	(Sheet 4 of 12) Nuclear Island Key Structural Dimensions Plan at El. 117′-6″	3.7-83
3.7.2-12	(Sheet 5 of 12) Nuclear Island Key Structural Dimensions Plan at El. 135′-3″	3.7-84
3.7.2-12	(Sheet 6 of 12) Nuclear Island Key Structural Dimensions Plan at El. 153′-0″ & 160′-6″	3.7-85
3.7.2-12	(Sheet 7 of 12) Nuclear Island Key Structural Dimensions Plan at El. 160′-6″, 180′-0″, & 329′-0″	3.7-86

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
3.7.2-12	(Sheet 8 of 12) Nuclear Island Key Structural Dimensions Section A - A	3.7-87
3.7.2-12	(Sheet 9 of 12) Nuclear Island Key Structural Dimensions Section B - B	3.7-88
3.7.2-12	(Sheet 10 of 12) Nuclear Island Key Structural Dimensions Sections C - C and H - H	3.7-89
3.7.2-12	(Sheet 11 of 12) Nuclear Island Key Structural Dimensions Section G - G	3.7-90
3.7.2-12	(Sheet 12 of 12) Nuclear Island Key Structural Dimensions Section J - J	3.7-91
3.7.2-13	Not Used	3.7-92
3.7.2-14	Typical Design Floor Response Spectrum	3.7-93
3.7.2-15–3.7.2-18	Not Used	3.7-94
3.7.2-19	(Sheet 1 of 10) Annex Building Key Structural Dimensions Plan at Elevation 100′-0″	3.7-95
3.7.2-19	(Sheet 2 of 10) Annex Building Key Structural Dimensions Plan at Elevation 107′-2″ and 117′-6″	3.7-96
3.7.2-19	(Sheet 3 of 10) Annex Building Key Structural Dimensions Plan at Elevation 135′-3″	3.7-97
3.7.2-19	(Sheet 4 of 10) Annex Building Key Structural Dimensions Plan at Elevation 158′-0″ and 150′-3″	3.7-98
3.7.2-19	(Sheet 5 of 10) Annex Building Key Structural Dimensions Roof Plan at Elevation 154′-0″ and 181′-11 3/4″	3.7-99
3.7.2-19	(Sheet 6 of 10) Annex Building Key Structural Dimensions Section A - A	3.7-100
3.7.2-19	(Sheet 7 of 10) Annex Building Key Structural Dimensions Section B - B	3.7-101
3.7.2-19	(Sheet 8 of 10) Annex Building Key Structural Dimensions Section C - C	3.7-102
3.7.2-19	(Sheet 9 of 10) Annex Building Key Structural Dimensions Sections D - D, E - E, & F - F	3.7-103
3.7.2-19	(Sheet 10 of 10) Annex Building Key Structural Dimensions Sections G - G, H - H, & J - J	3.7-104
3.7.2-20	East-West 2D SASSI Model with Adjacent Buildings	3.7-105
3.7.2-21	2D North-South SASSI Model with Adjacent Buildings	3.7-106
3.7.2-22	3D SASSI Model with Adjacent Buildings	3.7-107
3.7.3-1	Impact Evaluation Zone	3.7-108
3.7.3-2	Impact Evaluation Zone and Seismic Supported Piping	3.7-109
3.7-201	VEGP AP1000 Horizontal Spectra Comparison	3.7-110
3.7-202	VEGP AP1000 Vertical Spectra Comparison	3.7-111
3.8.2-1	(Sheet 1 of 3) Containment Vessel General Outline	3.8-113
3.8.2-1	(Sheet 2 of 3) Containment Vessel General Outline	3.8-114
3.8.2-1	(Sheet 3 of 3) Containment Vessel General Outline	3.8-115
3.8.2-2	Equipment Hatches	3.8-116
3.8.2-3	Personnel Airlock	3.8-117
3.8.2-4	(Sheet 1 of 8) Containment Penetrations Main Steam	3.8-118
3.8.2-4	(Sheet 2 of 8) Containment Penetrations Startup Feedwater	3.8-119
3.8.2-4	(Sheet 3 of 8) Containment Penetrations Normal RHR Piping	3.8-120
3.8.2-4	(Sheet 4 of 8) Containment Penetrations	3.8-121

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
3.8.2-4	(Sheet 5 of 8) Containment Penetrations Fuel Transfer Penetration	3.8-122
3.8.2-4	(Sheet 6 of 8) Containment Penetrations Typical Electrical Penetration	3.8-123
3.8.2-4	(Sheet 7 of 8) Containment Penetrations Steam Line and Feedwater Line Insert Plates	3.8-124
3.8.2-4	(Sheet 8 of 8) Containment Penetrations Main Feedwater	3.8-125
3.8.2-5	(Sheet 1 of 5) Containment Vessel Response to Internal Pressure of 59 psig Displaced Shape Plot	3.8-126
3.8.2-5	(Sheet 2 of 5) Containment Vessel Response to Internal Pressure of 59 psig Membrane Stresses (ksi)	3.8-127
3.8.2-5	(Sheet 3 of 5) Containment Vessel Response to Internal Pressure of 59 psig Surface Meridional Stress (ksi)	3.8-128
3.8.2-5	(Sheet 4 of 5) Containment Vessel Response to Internal Pressure of 59 psig Outside Surface Stresses (ksi)	3.8-129
3.8.2-5	(Sheet 5 of 5) Containment Vessel Response to Internal Pressure of 59 psig Outer Stress Intensity (ksi)	3.8-130
3.8.2-6	(Sheet 1 of 2) Containment Vessel Axisymmetric Model	3.8-131
3.8.2-6	(Sheet 2 of 2) Containment Vessel Axisymmetric Model	3.8-132
3.8.2-7	Finite Element Model for Local Buckling Analyses	3.8-133
3.8.2-8	(Sheet 1 of 2) Location of Containment Seal	3.8-134
3.8.2-8	(Sheet 2 of 2) Seal Sections and Details	3.8-135
3.8.3-1	(Sheet 1 of 7) Structural Modules in Containment Internal Structures	3.8-136
3.8.3-1	(Sheet 2 of 7) Structural Modules in Containment Internal Structures	3.8-137
3.8.3-1	(Sheet 3 of 7) Structural Modules in Containment Internal Structures	3.8-138
3.8.3-1	(Sheet 4 of 7) Structural Modules in Containment Internal Structures	3.8-139
3.8.3-1	(Sheet 5 of 7) Structural Modules in Containment Internal Structures	3.8-140
3.8.3-1	(Sheet 6 of 7) Structural Modules in Containment Internal Structures	3.8-141
3.8.3-1	(Sheet 7 of 7) Structural Modules in Containment Internal Structures	3.8-142
3.8.3-2	Typical Structural Wall Module	3.8-143
3.8.3-3	Structural Floor Module	3.8-144
3.8.3-4	Reactor Vessel Supports	3.8-145
3.8.3-5	(Sheet 1 of 5) Steam Generator Supports	3.8-146
3.8.3-5	(Sheet 2 of 5) Steam Generator Supports	3.8-147
3.8.3-5	(Sheet 3 of 5) Steam Generator Supports	3.8-148
3.8.3-5	(Sheet 4 of 5) Steam Generator Supports	3.8-149
3.8.3-5	(Sheet 5 of 5) Steam Generator Supports	3.8-150
3.8.3-6	(Sheet 1 of 4) Pressurizer Support Columns	3.8-151
3.8.3-6	(Sheet 2 of 4) Pressurizer Lower Lateral Supports	3.8-152
3.8.3-6	(Sheet 3 of 4) Pressurizer Lower Supports	3.8-153
3.8.3-6	(Sheet 4 of 4) Pressurizer Upper Supports	3.8-154
3.8.3-7	IRWST Temperature Transient	3.8-155
3.8.3-8	(Sheet 1 of 3) Structural Modules – Typical Design Details	3.8-156

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
3.8.3-8	(Sheet 2 of 3) Structural Modules – Typical Design Details	3.8-157
3.8.3-8	(Sheet 3 of 3) Structural Modules – Typical Design Details	3.8-158
3.8.3-9	Test Tank Finite Element Model	3.8-159
3.8.3-10	(Sheet 1 of 2) IRWST Fluid Structure Finite Element Model CIS Structural Model	3.8-160
3.8.3-10	(Sheet 2 of 2) IRWST Fluid Structure Finite Element Model IRWST Structural Model	3.8-161
3.8.3-11	IRWST Fluid Structure Finite Element Model Fluid Model	3.8-162
3.8.3-12	IRWST Fluid Structure Finite Element Model Sparger Region Detail	3.8-163
3.8.3-13	Effective Sections for Floor Modules	3.8-164
3.8.3-14	(Sheet 1 of 5) CA-01 Module	3.8-165
3.8.3-14	(Sheet 2 of 5) CA-02 Module	3.8-166
3.8.3-14	(Sheet 3 of 5) CA-03 Module	3.8-167
3.8.3-14	(Sheet 4 of 5) CA-04 Structural Module	3.8-168
3.8.3-14	(Sheet 5 of 5) CA-05 Module	3.8-169
3.8.3-15	(Sheet 1 of 2) Typical Submodule	3.8-170
3.8.3-15	(Sheet 2 of 2) Typical Submodule	3.8-171
3.8.3-16	Liner Modules	3.8-172
3.8.3-17	(Sheet 1 of 2) Structural Modules – Design Details Standard Floor Connection	3.8-173
3.8.3-17	(Sheet 2 of 2) Structural Modules – Design Details Heavily Loaded Floor Connection	3.8-174
3.8.3-18	Location of Structural Wall Modules	3.8-175
3.8.4-1	(Sheet 1 of 4) Containment Air Baffle General Arrangement	3.8-176
3.8.4-1	(Sheet 2 of 4) Containment Air Baffle Panel Types	3.8-177
3.8.4-1	(Sheet 3 of 4) Containment Air Baffle Typical Panel on Cylinder	3.8-178
3.8.4-1	(Sheet 4 of 4) Containment Air Baffle Flexible Seal	3.8-179
3.8.4-2	Passive Containment Cooling Tank	3.8-180
3.8.4-3	Not Used	3.8-181
3.8.4-4	(Sheet 1 of 5) Structural Modules in Auxiliary Building	3.8-182
3.8.4-4	(Sheet 2 of 5) Structural Modules in Auxiliary Building	3.8-183
3.8.4-4	(Sheet 3 of 5) Structural Modules in Auxiliary Building	3.8-184
3.8.4-4	(Sheet 4 of 5) Structural Modules in Auxiliary Building	3.8-185
3.8.4-4	(Sheet 5 of 5) Structural Modules in Auxiliary Building	3.8-186
3.8.4-5	Shield Building Structure Key Areas	3.8-187
3.8.5-1	Foundation Plan	3.8-188
3.8.5-2	Isometric View of Finite Element Model	3.8-189
3.8.5-3	(Sheet 1 of 7) Radial Reinforcement, Top Side of DISH	3.8-190
3.8.5-3	(Sheet 2 of 7) Circumferential Reinforcement, Top Side of DISH	3.8-191
3.8.5-3	(Sheet 3 of 7) Longitudinal Reinforcement Map, Top Side in NS Direction	3.8-192
3.8.5-3	(Sheet 4 of 7) Longitudinal Reinforcement Map, Top Side in EW Direction	3.8-193
3.8.5-3	(Sheet 5 of 7) Longitudinal Reinforcement, Bottom Side of DISH and 6′ Basemat (NS)	3.8-194
3.8.5-3	(Sheet 6 of 7) Longitudinal Reinforcement, Bottom Side of DISH and 6′ Basemat (EW)	3.8-195
3.8.5-3	(Sheet 7 of 7) Shear Reinforcement Map	3.8-196
3.9-1–3.9-3	Not Used	3.9-118

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
3.9-4	Control Rod Drive Mechanism	3.9-119
3.9-5	Lower Reactor Internals	3.9-120
3.9-6	Upper Core Support Structure	3.9-121
3.9-7	Integrated Head Package	3.9-122
3.9-8	Reactor Internals Interface Arrangement	3.9-123
3.9-9	Flow Skirt Schematic	3.9-124
3B-1	Typical Bounding Analysis Curve (BAC)	3B-18
3B-2	Bounding Analysis Curve for Primary Loop Hot Leg	3B-19
3B-3	Bounding Analysis Curve for Primary Loop Cold Leg	3B-20
3B-4	Bounding Analysis Curve for 38″ Main Steam Line	3B-21
3B-5	Bounding Analysis Curve for 20″ Normal RHR	3B-22
3B-6	(Sheet 1 of 2) Bounding Analysis Curve for 18″ Surge Line	3B-23
3B-6	(Sheet 2 of 2) Bounding Analysis Curve for 18″ Surge Line	3B-24
3B-7	Bounding Analysis Curve for 18″ PRHR Supply/ADS 4	3B-25
3B-8	Bounding Analysis Curve for 14″ PRHR Supply to Cold Trap, PRHR Supply/ADS4	3B-26
3B-9	Bounding Analysis Curve for 14″ PRHR Supply after Cold Trap, Return – to Isolation Valve	3B-27
3B-10	(Sheet 1 of 2) Bounding Analysis Curve for 14″ ADS Stage 2, 3	3B-28
3B-10	(Sheet 2 of 2) Bounding Analysis Curve for 14" ADS Stage 2, 3	3B-29
3B-11	Bounding Analysis Curve for 14″ PRHR Return – after Isolation Valve, 14″ PRHR Return	3B-30
3B-12	Not Used	3B-31
3B-13	Bounding Analysis Curve for 8″ Accumulator to Isolation Valve	3B-32
3B-14	Bounding Analysis Curve for 8″ CMT Cold Leg Balance Line and Vent, DVI Cold Trap to RV	3B-33
3B-15	Bounding Analysis Curve for 8″ CMT, DVI IRWST (Various Sections)	3B-34
3B-16	Not Used	3B-35
3B-17	Bounding Analysis Curve for Accumulator after Isolation Valve	3B-36
3B-18	Bounding Analysis Curve for RNS Discharge	3B-37
3B-19	(Sheet 1 of 2) Bounding Analysis Curve for ADS Header to RCS Safety Valve	3B-38
3B-19	(Sheet 2 of 2) Bounding Analysis Curve for ADS Header to RCS Safety Valve	3B-39
3B-20	Bounding Analysis Curve for 12″ Normal RHR	3B-40
3B-21	Bounding Analysis Curve for 10″ Normal RHR	3B-41
3B-22	Bounding Analysis Curve for 8″ ADS Stage 2, 3	3B-42
3D.5-1	(Sheet 1 of 3) Typical Abnormal Environmental Test Profile: Main Control Room	3D-46
3D.5-1	(Sheet 2 of 3) Typical Abnormal Environmental Test Profile: I&C and DC Equipment Rooms	3D-47
3D.5-1	(Sheet 3 of 3) Typical Abnormal Environmental Test Profile: Voltage and Frequency Variations	3D-48
3D.5-2	Gamma Dose and Dose Rate Inside Containment After a LOCA	3D-49
3D.5-3	Beta Dose and Dose Rate Inside Containment After a LOCA	3D-50
3D.5-4	Gamma Dose and Dose Rate Inside Containment After a Steam Line Break	3D-51

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
3D.5-5	Beta Dose and Dose Rate Inside Containment After a Steam Line Break	3D-52
3D.5-6–3D.5-7	Not Used	3D-53
3D.5-8	(Sheet 1 of 2) Typical Combined LOCA/SLB/FLB EQ Design Envelope for Inside Containment Temperature	3D-54
3D.5-8	(Sheet 2 of 2) Typical Combined LOCA/SLB/FLB EQ Design Envelope for Inside Containment Pressure	3D-55
3D.5-9	(Sheet 1 of 2) MSIV Compartment Response to MSLB (Short Term)	3D-56
3D.5-9	(Sheet 2 of 2) MSIV Compartment Response to MSLB (Long Term)	3D-57
3D.C-1	Histogram of Threshold Gamma Dose for Mechanical Damage to Elastomers, Plastics, and Encapsulation Compounds	3D-88
3D.D-1	Frequency Distribution of Activation Energies of Various Components/Materials (EPRI Data)	3D-96
3D.D-2	Frequency Distribution of Activation Energies of Various Components/Materials (Westinghouse Data)	3D-97
3D.D-3	Not Used	3D-98
3E-1	(Sheet 1 of 2) High Energy Piping – Steam Generator System	3E-2
3E-1	(Sheet 2 of 2) High Energy Piping – Steam Generator System	3E-3
3E-2	High Energy Piping – Normal Residual Heat Removal System	3E-4
3E-3	(Sheet 1 of 2) High Energy Piping – Reactor Coolant System	3E-5
3E-3	(Sheet 2 of 2) High Energy Piping – Reactor Coolant System	3E-6
3E-4	(Sheet 1 of 2) High Energy Piping – Passive Core Cooling System	3E-7
3E-4	(Sheet 2 of 2) High Energy Piping – Passive Core Cooling System	3E-8
3E-5	(Sheet 1 of 2) High Energy Piping – Chemical and Volume Control System	3E-9
3E-5	(Sheet 2 of 2) High Energy Piping – Chemical and Volume Control System	3E-10
3G.1-1	Nuclear Island Seismic Analysis Models	3G-22
3G.2-1	3D Finite Element Model of Coupled Shield and Auxiliary Building	3G-23
3G.2-2	3D Finite Element Model of Containment Internal Structures	3G-24
3G.2-3	3D Finite Element Model of Containment Outer Basemat (Dish)	3G-25
3G.2-4	Steel Containment Vessel and Polar Crane Models	3G-26
3G.2-5A	Polar Crane Model Simplified Model	3G-27
3G.2-5B	Polar Crane Model Detailed Model	3G-28
3G.2-6	Reactor Coolant Loop Lumped-Mass Stick Model	3G-29
3G.2-7	Pressurizer Model	3G-30
3G.2-8	Core Makeup Tank Models	3G-31
3G.2-9	AP1000 Nuclear Island Solid-Shell Model (NI10)	3G-32
3G.2-10	Containment Internal Structure with the SCV, PC, Reactor Coolant Loop, and Pressurizer	3G-33
3G.2-11	Soil Structure Interaction Model – NI20 Looking East	3G-34
3G.2-12	Coarse Model of Containment Internal Structures	3G-35
3G.2-13	Fine Mesh (NI05) Model of Auxiliary and Shield Building	3G-36
3G.2-14	NI05 Model of Containment Internal Structures	3G-37
3G.2-15	3D NI05 Refined Mesh Model of Outer Containment Basemat (Dish)	3G-38

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
3G.2-16	Quadrant Model of Shield Building Roof	3G-39
3G.2-17	Detailed 3D Finite Element Model of Containment Vessel Including Large Penetrations	3G-40
3G.2-18	Axisymmetric Model of Containment Vessel	3G-41
3G.2-19	Schematic of Non-linear 2D East-West Nuclear Island Stick Model Used for Stability Evaluation that Addresses Sliding and Overturning	3G-42
3G.3-1	Generic Soil Profiles	3G-43
3G.3-2	2D SASSI FRS – Node 41 X (ASB El. 99′)	3G-44
3G.3-3	2D SASSI FRS – Node 41 Y (ASB El. 99′)	3G-45
3G.3-4	2D SASSI FRS – Node 120 X (ASB El. 179.6′)	3G-46
3G.3-5	2D SASSI FRS – Node 120 Y (ASB El. 179.6′)	3G-47
3G.3-6	2D SASSI FRS – Node 310 X (ASB El. 333.2′)	3G-48
3G.3-7	2D SASSI FRS – Node 310 Y (ASB El. 333.2′)	3G-49
3G.3-8	2D SASSI FRS – Node 411 X (SCV El. 200.0′)	3G-50
3G.3-9	2D SASSI FRS – Node 411 Y (SCV El. 200.0′)	3G-51
3G.3-10	2D SASSI FRS – Node 535 X (CIS El. 134.3′)	3G-52
3G.3-11	2D SASSI FRS – Node 535 Y (CIS El. 134.3′)	3G-53
3G.4-1	Auxiliary Shield Building “Rigid” Nodes at El. 135′	3G-54
3G.4-2	Auxiliary Shield Building “Flexible” Nodes at El. 135′	3G-55
3G.4-3	Excavated Soil	3G-56
3G.4-4	Additional Elements for Soil Pressure Calculations	3G-57
3G.4-5X	X Direction FRS for Node 130401 (NI10) or 1761 (NI20) CIS at Reactor Vessel Support Elevation of 100′	3G-58
3G.4-5Y	Y Direction FRS for Node 130401 (NI10) or 1761 (NI20) CIS at Reactor Vessel Support Elevation of 100′	3G-59
3G.4-5Z	Z Direction FRS for Node 130401 (NI10) or 1761 (NI20) CIS at Reactor Vessel Support Elevation of 100′	3G-60
3G.4-6X	X Direction FRS for Node 105772 (NI10) or 2199 (NI20) CIS at Operating Deck Elevation 134.25′	3G-61
3G.4-6Y	Y Direction FRS for Node 105772 (NI10) or 2199 (NI20) CIS at Operating Deck Elevation 134.25′	3G-62
3G.4-6Z	Z Direction FRS for Node 105772 (NI10) or 2199 (NI20) CIS at Operating Deck Elevation 134.25′	3G-63
3G.4-7X	X Direction FRS for Node 4724 (NI10) or 2078 (NI20) ASB Control Room Side Elevation 116.50′	3G-64
3G.4-7Y	Y Direction FRS for Node 4724 (NI10) or 2078 (NI20) ASB Control Room Side Elevation 116.50′	3G-65
3G.4-7Z	Z Direction FRS for Node 4724 (NI10) or 2078 (NI20) ASB Control Room Side Elevation 116.50′	3G-66
3G.4-8X	X Direction FRS for Node 5754 (NI10) or 2675 (NI20) ASB Fuel Building Roof Elevation 179.19′	3G-67
3G.4-8Y	Y Direction FRS for Node 5754 (NI10) or 2675 (NI20) ASB Fuel Building Roof Elevation 179.19′	3G-68
3G.4-8Z	Z Direction FRS for Node 5754 (NI10) or 2675 (NI20) ASB Fuel Building Roof Elevation 179.19′	3G-69
3G.4-9X	X Direction FRS for Node 8573 (NI10) or 3329 (NI20) ASB Shield Building Roof Elevation 327.41′	3G-70
3G.4-9Y	Y Direction FRS for Node 8573 (NI10) or 3329 (NI20) ASB Shield Building Roof Elevation 327.41′	3G-71

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
3G.4-9Z	Z Direction FRS for Node 8573 (NI10) or 3329 (NI20) ASB Shield Building Roof Elevation 327.41′	3G-72
3G.4-10X	X Direction FRS for Node 130412 (NI10) or 2788 (NI20) SCV Near Polar Crane Elevation 224.00′	3G-73
3G.4-10Y	Y Direction FRS for Node 130412 (NI10) or 2788 (NI20) SCV Near Polar Crane Elevation 224.00′	3G-74
3G.4-10Z	Z Direction FRS for Node 130412 (NI10) or 2788 (NI20) SCV Near Polar Crane Elevation 224.00′	3G-75
3H.2-1	General Layout of Auxiliary Building	3H-50
3H.5-1	(Sheet 1 of 3) Nuclear Island Critical Sections Plan at El. 135′-3″	3H-51
3H.5-1	(Sheet 2 of 3) Nuclear Island Critical Sections Plan at El. 180′-0″	3H-52
3H.5-1	(Sheet 3 of 3) Nuclear Island Critical Sections Section A-A	3H-53
3H.5-2	(Sheet 1 of 3) Wall on Column Line 1	3H-54
3H.5-2	(Sheet 2 of 3) Wall on Column Line 7.3	3H-55
3H.5-2	(Sheet 3 of 3) Wall on Column Line L	3H-56
3H.5-3	Typical Reinforcement in Wall on Column Line 1	3H-57
3H.5-4	Typical Reinforcement in Wall 7.3	3H-58
3H.5-5	(Sheet 1 of 3) Concrete Reinforcement in Wall 11	3H-59
3H.5-5	(Sheet 2 of 3) Concrete Reinforcement Layers in Wall 11 (Looking East)	3H-60
3H.5-5	(Sheet 3 of 3) Wall 11 at Main Steamline Anchor Section A-A	3H-61
3H.5-6	Auxiliary Building Typical Composite Floor	3H-62
3H.5-7	Typical Reinforcement and Connection to Shield Building	3H-63
3H.5-8	Auxiliary Building Operations Work Area (Tagging Room) Ceiling	3H-64
3H.5-9	(Sheet 1 of 3) Auxiliary Building Finned Floor	3H-65
3H.5-9	(Sheet 2 of 3) Auxiliary Building Finned Floor	3H-66
3H.5-9	(Sheet 3 of 3) Auxiliary Building Finned Floor	3H-67
3H.5-10	Spent Fuel Pool Wall Divider Wall Element Locations	3H-68
3H.5-11	(Sheet 1 of 6) Design of Shield Building: Roof and Air Inlets	3H-69
3H.5-11	(Sheet 2 of 6) Design of Shield Building: Concrete Detail at Tension Ring	3H-70
3H.5-11	(Sheet 3 of 6) Design of Shield Building: Roof/Air Inlet Interface	3H-71
3H.5-11	(Sheet 4 of 6) Design of Shield Building at Air Inlets	3H-72
3H.5-11	(Sheet 5 of 6) Design of Shield Building: Tank/Roof Interface Reinforcement	3H-73
3H.5-11	(Sheet 6 of 6) Design of Shield Building: Tank/Compression Ring Roof Interface Reinforcement	3H-74
3H.5-12	Typical Reinforcement in Wall L	3H-75
3H.5-13	Enhanced Shield Building Wall Panel Layout	3H-76
3H.5-14	Elevation View of Tension Ring and Air Inlets	3H-77
3H.5-15	Shield Building Tension Ring	3H-78
3H.5-16	(Sheet 1 of 2) Design of Shield Building: Surface Plates on Cylindrical Section – Developed View 90-270 Degrees	3H-79
3H.5-16	(Sheet 2 of 2) Design of Shield Building: Surface Plates on Cylindrical Section – Developed View 270-90 Degrees	3H-80
3I.1-1	Comparison of Horizontal AP1000 CSDRS and HRHF Envelope Response Spectra	3I-55
3I.1-2	Comparison of Vertical AP1000 CSDRS and HRHF Envelope Response Spectra	3I-56

Chapter 3 Design of Structures, Components, Equipment and Systems

3.1 Conformance with Nuclear Regulatory Commission General Design Criteria

This section discusses the extent to which the AP1000 design criteria for safety-related structures, systems, and components comply with 10 CFR 50, Appendix A. As presented in this section, each criterion is first quoted and then discussed. For some criteria, the AP1000 advanced passive design features are deemed to be significantly different in certain specific areas from those design features considered when the General Design Criteria were formulated. In those instances, the means by which the AP1000 design complies with the intent of the General Design Criterion is indicated. Where additional information is required for a complete discussion, the appropriate Design Control Document (DCD) sections are referenced.

3.1.1 Overall Requirements

Criterion 1 – Quality Standards and Records

Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified, as necessary, to assure a quality product, in keeping with the required safety function.

A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

AP1000 Compliance

The Quality Assurance Program for the AP1000 provides confidence that safety-related items and services are designed, procured, fabricated, inspected, and tested to quality standards commensurate with the safety-related functions to be performed. This program also applies to design services subcontracted to external organizations. The quality assurance program for erection of structures, systems, and components will be identified before the construction phase of the AP1000 project. The AP1000 quality assurance program is described in Chapter 17, including its compliance with ASME NQA-1.

Design, procurement, fabrication, inspection, and testing are performed according to recognized codes, standards, and design criteria that comply with the requirements of 10 CFR 50.55a. As necessary, supplemental standards, design criteria, and requirements are developed by the AP1000 designers. A portion of the chemical and volume control system that is defined as reactor coolant pressure boundary uses an alternate classification in conformance with the requirements of 10 CFR 50.55a(z). The alternate classification is discussed in Subsection 5.2.1.3.

Appropriate records documenting that design, procurement, fabrication, inspection, and testing comply with the applicable codes, standards, and design criteria are maintained according to appropriate, applicable laws and regulations, either by or under the control of the Combined License applicant.

In the passive AP1000 design, systems necessary to provide the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, and the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures

comparable to the guideline exposures of 10 CFR 50.34 are classified as safety-related. Therefore, the AP1000 complies with the intent of Criterion 1.

The principal design criteria, design bases, codes, and standards applied to the facility are identified in Section 3.2. Additional details may be found in the pertinent sections dealing with safety-related structures, systems, and components.

Criterion 2 – Design Bases for Protection Against Natural Phenomena

Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without the loss of the capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect: (1) appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena, and (3) the importance of the safety functions to be performed.

AP1000 Compliance

The safety-related structures, systems, and components are designed to withstand the effects of natural phenomena without loss of the capability to perform their safety-related functions, or are designed such that their response or failure will be in a safe condition. Those structures, systems, and components vital to the shutdown capability of the reactor are designed to withstand the maximum probable natural phenomena at the intended site.

Accident analyses consider conservative site conditions that envelope expected sites. Appropriate combinations of structural loadings from normal, accident, and natural phenomena are considered in the plant design. The design of the plant in relationship to those natural phenomena is addressed.

Seismic and quality group classifications and other pertinent standards and information are given in the sections discussing individual structures, systems, and components as well as in Chapter 3. The nature and magnitude of the natural phenomena considered in the design of this plant are discussed in Chapter 2.

Criterion 3 – Fire Protection

Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Fire fighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

AP1000 Compliance

The safety-related structures, systems, and components are designed to minimize the probability and effect of fires and explosions. Noncombustible and fire-resistant materials are used in the containment and main control room. Additionally noncombustible and fire-resistant materials are used on components of safety-related systems, and elsewhere in the plant where fire is a potential risk to safety-related systems.

For example, electrical cables have a fire-retardant jacketing, and fire barriers are used at fire area boundaries. The AP1000 design approach includes designing the safety-related systems with redundant divisions, and locating these redundant divisions in separate safety-related areas.

Equipment and facilities for fire protection, including detecting, alarming, and extinguishing functions, are provided to help protect both plant equipment and personnel from fire, explosion, and the resultant release of toxic vapors. Fire protection is provided by deluge systems (water spray), sprinklers, and portable extinguishers. Fire fighting systems are designed so that their rupture or inadvertent operation will not prevent safety-related systems from performing their design functions.

The following codes, guides, and standards are used as guidelines in the design of the fire protection system and equipment. The system and equipment conform to the applicable portions of the following documents:

- National Fire Protection Association Codes and Standards
- BTP-CMEB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," July 1981, as addressed in Table 9.5.1-1

Subsection 9.5.1 describes the AP1000 fire protection system and equipment, including conformance with the applicable portions of these codes and standards and reference to specific fire protection codes and standards.

Criterion 4 – Environmental and Dynamic Effects Design Bases

Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

AP1000 Compliance

Safety-related structures, systems, and components are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss of coolant accidents.

The AP1000 design has emphasized the minimization of missiles, pipe whip, and fluid discharge by a combination of separation of safe shutdown components and design to prevent the dynamic effects of postulated pipe ruptures based on the application of the leak-before-break approach. This analysis is discussed in Subsection 3.4.3.5 and Section 3.6.

The AP1000 structures, systems, and components are appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. Details of the design, environmental testing, and construction of these structures, systems, and components are given in the sections that discuss individual structures, systems, and components, as well as in Sections 3.5 and 3.6.

Criterion 5 – Sharing of Structures, Systems, and Components

Structures, systems, and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining unit.

AP1000 Compliance

The AP1000 is a single-unit plant. If more than one unit were built on the same site, none of the safety-related systems would be shared.

3.1.2 Protection by Multiple Fission Product Barriers

Criterion 10 – Reactor Design

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

AP1000 Compliance

The reactor core and associated coolant, control, and protection systems are designed to the following criteria:

- No fuel damage occurs during normal core operation and operational transients (Condition I) or during transient conditions arising from occurrences of moderate frequency (Condition II). For normal operation, the plant is designed to accommodate a fuel defect level of up to 0.25 percent. Fuel damage, as used here, is defined as penetration of the fission product barrier, that is, the fuel rod cladding. The small number of clad defects that may occur are within the capability of the plant cleanup system and are consistent with the plant design bases. For additional information see Section 11.1.

- The reactor can be returned to a safe shutdown state following a Condition III event, with only a small fraction of the fuel rods damaged, although sufficient fuel damage might occur to preclude the immediate resumption of operation.

- The core remains intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

The reactor protection system is designed to actuate a reactor trip whenever necessary to prevent exceeding the fuel design limits. The core design, together with the process and decay heat removal systems, provide this capability under expected conditions of normal operation, with appropriate margins for uncertainties and anticipated transient situations. This includes the effects of the loss of reactor coolant flow, trip of the turbine generator, loss of normal feedwater, and loss of both normal and preferred power sources.

Chapter 4, Reactor, describes the mechanical components of the reactor and reactor core, including the fuel rods and fuel assemblies, the mechanical design, nuclear design, and the thermal hydraulic design. Chapter 7 provides details of the control and protection systems instrumentation design and logic. This information supports the accident analyses documented in Chapter 15. The acceptable fuel design limits are not exceeded for Condition I and II events. Acceptable core cooling is provided for Condition III and IV events.

Criterion 11 – Reactor Inherent Protection

The reactor core and associated coolant systems shall be designed so that in the power-operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

AP1000 Compliance

When the reactor is critical, the negative fuel temperature reactivity effects (Doppler feedback) provide prompt reactivity feedback to compensate for a rapid, uncontrolled reactivity excursion. The negative Doppler coefficient of reactivity is provided by the use of a low-enrichment fuel design. This Doppler feedback is the primary reactivity feedback mechanism to provide the inherent core reactivity protection during rapid core reactivity excursions.

For slower reactivity transients that result in moderator temperature increases, the nonpositive moderator temperature coefficient of reactivity provides compensatory reactivity feedback to help control these slower transients. The overall core design establishes a nonpositive moderator temperature coefficient of reactivity.

Chapter 4 provides information pertaining to the core design.

Criterion 12 – Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

AP1000 Compliance

Power oscillations of the fundamental mode are inherently eliminated by negative Doppler and nonpositive moderator temperature coefficients of reactivity.

Oscillations, due to xenon spatial effects, in the radial and azimuthal overtone modes are heavily damped because of the inherent design and due to the negative Doppler and nonpositive moderator temperature coefficients of reactivity.

Oscillations due to xenon spatial effects may occur in the axial first overtone mode. Reactor trip functions are provided, using the measured axial power imbalance as an input, so that the fuel design limits are not exceeded during axial xenon oscillations.

If it is necessary to maintain axial imbalance within the limits (that is, imbalances that are alarmed to the operator and are within the imbalance trip setpoints), the operator can suppress axial xenon oscillations by control rod motions or temporary power reductions or both.

Oscillations due to spatial xenon effects, in axial modes higher than the first overtone, are heavily damped because of the inherent design and the negative Doppler coefficient of reactivity.

The stability of the core against xenon-induced power oscillations and the functional requirements of instrumentation for monitoring and measuring core power distribution are discussed in Chapter 4. Details of the instrumentation design and logic are discussed in Chapter 7.

Criterion 13 – Instrumentation and Control

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its

associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

AP1000 Compliance

Instrumentation and controls are provided to monitor and control neutron flux, control rod position, fluid temperatures, pressures, flows, and levels, as necessary, to maintain plant safety. Instrumentation is provided in the reactor coolant system, steam and power conversion system, containment, engineered safety systems, radioactive waste management systems, and other auxiliary systems.

See Section 7.5 for a discussion of indications that are required for operator use under normal operating and accident conditions. Criteria regarding layout of the controls and displays are provided in Chapter 18.

The quantity and types of process instrumentation used provide safe and orderly operation of systems over the design range of plant operations, including accident conditions.

Criterion 14 – Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

AP1000 Compliance

The reactor coolant pressure boundary is designed to accommodate the system pressures and temperatures attained under the expected modes of plant operation, including anticipated transients, while maintaining stresses within applicable limits. Consideration is given to loadings under normal operating conditions and to abnormal loadings, such as seismic loadings. The piping is protected from overpressure by means of pressure-relieving devices, as required by ASME Code, Section III. See Subsection 5.2.2 for additional information.

Reactor coolant pressure boundary materials and fabrication techniques are such that there is a low probability of gross rupture or significant leakage. The AP1000 reactor coolant system design incorporates revised pipe-break criteria (leak-before-break) to reduce or eliminate the need to consider the dynamic effects of pipe breaks. The configuration and materials of the reactor coolant system have been selected such that the pipe stresses meet the leak-before-break criteria. See Subsection 3.6.3 for additional information.

The AP1000 reactor core and reactor internals are designed to limit neutron fluence on the reactor vessel. See Section 5.4 and Chapter 4 for additional information.

The reactor vessel is manufactured from low-alloy carbon steel clad with 308L stainless steel weld overlay on wetted surfaces. The vessel shell is constructed of ring-rolled forgings that eliminate vertical weld seams. Chemical composition of the forging material is controlled to improve radiation resistance of the vessel. (See Criterion 31 for further discussion of the reactor coolant pressure boundary.)

Coolant chemistry is controlled to protect the materials of construction of the reactor coolant pressure boundary from corrosion. See Subsection 5.2.3 for additional information.

The reactor coolant pressure boundary welds are accessible for in-service inspections to assess structural and leaktight integrity. For the reactor vessel, a material surveillance program is provided. Instrumentation is provided to detect significant leakage from the reactor coolant pressure boundary, with indication in the main control room. See Subsection 5.2.4 for additional information.

A portion of the chemical and volume control system that is defined as reactor coolant pressure boundary is nonsafety-related. This portion of the system is capable of being automatically isolated by safety-related valves that are designed and qualified for the design requirements.

Criterion 15 – Reactor Coolant System Design

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during normal operation, including anticipated operational occurrences.

AP1000 Compliance

Steady-state and transient analyses are performed to demonstrate that reactor coolant system design conditions are not exceeded during normal operation. Protection and control setpoints are based on these analyses. See Chapter 15 for additional information.

The reactor coolant system stress analysis and the leak-before-break analyses are described in Appendices 3B and 3C. See Section 5.3 for additional information.

Two safety valves are provided for the reactor coolant system. These valves and their setpoints meet the ASME Code, Section III criteria for overpressure protection. See Subsection 5.2.2 for additional information.

Criterion 16 – Containment Design

The reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

AP1000 Compliance

The containment is an integral part of the overall containment system, whose function is to contain the release of airborne radioactivity following postulated design basis accidents and to provide shielding for the reactor core and the reactor coolant system during normal operations. The containment consists of a steel containment vessel and is surrounded by a concrete shield building.

The containment vessel, which is a free-standing steel shell, is an integral part of the passive containment cooling system, whose function is to provide the safety-related ultimate heat sink for the removal of the reactor coolant system sensible heat, core decay heat, and stored energy. The containment vessel and the passive containment cooling system are designed to remove sufficient energy from the containment to prevent the containment from exceeding its design pressure following postulated design basis accidents.

The containment is designed to house the reactor coolant system and other related systems. The containment vessel functions as an essentially leaktight barrier. It is protected against postulated missiles from external sources as well as missiles produced by internal equipment failures.

Containment penetrations are isolated according to the provisions of GDCs 54, 55, 56, and 57.

Criterion 17 – Electrical Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming that the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational

occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system shall have sufficient independence, redundancy, and testability to perform their safety functions, assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights-of-way) designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time, following a loss of all onsite alternating current power supplies and other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

AP1000 Compliance

The AP1000 plant design supports an exemption to the requirement of GDC 17 for two physically independent offsite circuits by providing safety-related passive systems for core cooling and containment integrity, and multiple nonsafety-related onsite and offsite electric power sources for other functions. See Section 6.3 for additional information on the systems for core cooling.

A reliable dc power source supplied by batteries provides power for the safety-related valves and instrumentation during transient and accident conditions.

The Class 1E dc and UPS system is the only safety-related power source required to monitor and actuate the safety-related passive systems. Otherwise, the plant is designed to maintain core cooling and containment integrity, independent of nonsafety-related ac power sources indefinitely. The only electric power source necessary to accomplish these safety-related functions is the Class 1E dc and UPS power system which includes the associated safety-related 120V ac distribution switchgear.

Although the AP1000 is designed with reliable nonsafety-related offsite and onsite ac power that are normally expected to be available for important plant functions, nonsafety-related ac power is not relied upon to maintain the core cooling or containment integrity.

The nonsafety-related ac power system is designed such that plant auxiliaries can be powered from the grid under all modes of operation. During loss of normal ac power and offsite power, the ac power is supplied by the onsite standby diesel-generators. Preassigned loads and equipment are automatically loaded on the diesel-generators in a predetermined sequence. Additional loads can be manually added as required. The onsite standby power system is not required for safe shutdown of the plant.

Criterion 18 – Inspection and Testing of Electric Power Systems

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The

systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

AP1000 Compliance

The AP1000 is designed so that only the Class 1E dc and UPS system is required in order to initiate and actuate the systems necessary for maintaining core cooling and containment integrity. The safety-related dc power system design complies with GDC 18. Compliance with GDC 18 is achieved by designing testability and inspection capability into the system. The associated testing requirements are contained in the Technical Specifications.

Criterion 19 – Control Room

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

AP1000 Compliance

The AP1000 main control room provides the man-machine interfaces required to operate the plant safely and efficiently under normal conditions and to maintain it in a safe manner under accident conditions, including LOCAs. Simplified passive safety-related system designs are provided that do not rely upon operator action to maintain core cooling for design basis accidents. Operator action outside the main control room to mitigate the consequences of an accident is permitted.

The main control room is shielded by the containment and auxiliary building from direct gamma radiation and inhalation doses resulting from the postulated release of fission products inside containment. Refer to Chapter 15 for additional information on accident conditions. The main control room/control support area HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS) allows access to and occupancy of the main control room under accident conditions as described in Subsection 9.4.1. Sufficient shielding and the main control room/control support area HVAC subsystem provide adequate protection so that personnel will not receive radiation exposure in excess of 5 rem whole-body or its equivalent to any part of the body for the duration of the accident.

If ac power is unavailable for more than 10 minutes or if main control room differential pressure is below the “Low” setpoint for more than 10 minutes or if “High-2” particulate or “High-2” iodine radioactivity is detected in the main control room supply air duct, which may lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The main control room emergency habitability system also allows access to and occupancy of the main control room under accident conditions. The emergency main control room habitability system is designed to satisfy seismic Category I requirements as described in Section 3.2; the system design is described in Section 6.4.

In the event that the operators are forced to abandon the main control room, a workstation is provided with remote shutdown capability. A main control room evacuation is not assumed to occur simultaneously with design basis events. The remote shutdown workstation is described in Section 7.4.

3.1.3 Protection and Reactivity Control Systems

Criterion 20 – Protection System Functions

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems, including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

AP1000 Compliance

The protection system is a microprocessor-based system that trips the reactor and actuates engineered safety features when predetermined limits are exceeded or when manually initiated.

The reactor trip portion of the protection system includes four independent, redundant, physically separated, electrically-isolated divisions. The coincidence circuits guard against the loss of protection or the generation of false protection signals due to equipment failures through the use of a two-out-of-four logic and built-in operational bypasses.

Independent, redundant, physically separated, electrically-isolated engineered safety features trains are provided. Signal conditioning for the plant sensors is provided.

See Chapter 7 for additional information concerning the design of the protection system.

Criterion 21 – Protection System Reliability and Testability

The protection system shall be designed for high functional reliability and in-service testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (l) no single failure results in the loss of the protection function and (2) removal from service of any component or channel does not result in the loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

AP1000 Compliance

The protection system is designed for functional reliability and in-service testability. The design employs redundant logic trains and measurement and equipment diversity.

The protection system equipment includes integral testing circuits. System equipment, from input to output, in the protection cabinets and the engineered safety features cabinets, is tested. Simulated inputs replace the field signals. Outputs are monitored for validity. Manual and automatic testing is used to test the final stages of the reactor trip circuits and the reactor trip switchgear. Testing of cabinets and communications links verifies the functional operation of the equipment and the hardware. See Chapter 7 for further information concerning the test capabilities of the protection system.

Criterion 22 – Protection System Independence

The protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels

do not result in the loss of the protection function or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

AP1000 Compliance

Design of the protection systems includes consideration of natural phenomena, normal maintenance, testing, and accident conditions so that the protection functions are available.

Protection system components are designed, arranged, and qualified for operation in the environment accompanying any emergency situation in which the components are required to function.

Functional diversity has been designed into the system. The extent of this functional diversity is demonstrated for a variety of postulated accidents. Diverse protection functions automatically serve to mitigate the consequences of an event. Chapter 15 identifies the primary and diverse protective functions for each of the analyzed events.

Sufficient redundancy and independence are designed into the protection systems so that no single failure or removal from service of any component or channel of a system results in loss of the protection function. Functional diversity and location diversity are designed into the system.

Automatic reactor trip is initiated by neutron flux measurements, reactor coolant system overtemperature delta-T, reactor coolant system overpower delta-T, pressurizer pressure and level measurements, reactor coolant flow, reactor coolant pump speed, reactor coolant pump bearing water temperature, either of the PRHR heat exchanger discharge valves is not closed, ADS actuation, CMT actuation and steam generator water level measurements. Trips may also be initiated manually or by a safeguards actuation signal.

For additional information pertaining to the reactor trip logic, see Section 7.2.

High-quality components, conservative design and quality control, inspection, calibration, and tests are used to guard against common-mode failure. Qualification testing and analysis are performed on the safety-related systems to demonstrate functional operation at normal and post-accident conditions of temperature, humidity, pressure, and radiation for specified periods, as required. Typical protection system equipment is subjected to type tests under simulated seismic conditions, using conservatively large accelerations and applicable frequencies.

See Section 7.1 for additional information concerning the equipment design of the protection and safety monitoring system.

See Sections 3.10 and 3.11 for information pertaining to environmental and seismic qualification of the protection system equipment.

The AP1000 includes a nonsafety-related diverse actuation system. The diverse actuation system provides specific automatic functions including control rod insertion, turbine trip, passive residual heat removal heat exchanger actuation, core makeup tank actuation, isolation of critical containment lines, and passive containment cooling system actuation. This system is diverse and independent from the reactor protection system from sensors up to the actuation devices.

See Section 7.7 for additional information concerning the diverse actuation system.

Criterion 23 – Protection System Failure Modes

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air) or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

AP1000 Compliance

The protection system is designed considering the most probable failure modes of the components under various perturbations of the environment and energy sources. Reactor trip channels are designed on the deenergize-to-trip principle so that a single event (that is, loss of power) that could affect many functions at the same time causes the channels to actuate to their tripped conditions.

Criterion 24 – Separation of Protection and Control Systems

The protection system shall be separated from the control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

AP1000 Compliance

The protection system is separate and distinct from the control systems. Control systems are, in some cases, dependent on the protection system for control signals that are derived from protection system measurements, where applicable. These signals are transferred to the control system by isolation devices classified as protection components.

The adequacy of the system isolation is verified by testing under conditions of postulated credible faults. Due to their inherent electrical isolation characteristics, fiber optic cables are exempt from electrical isolation qualification testing. The failure of a single control system component or channel, or the failure or removal from service of a single protection system component or channel common to the control and protection system, leaves intact a system that satisfies the requirements of the protection system. The removal of a protection division from service is allowed during testing of the division.

Criterion 25 – Protection System Requirements for Reactivity Control Malfunctions

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of the control rods.

AP1000 Compliance

The protection system is designed to limit reactivity transients so that the fuel design limits are not exceeded. Reactor shutdown by control rod insertion is independent of the normal control functions since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Thus, in the postulated accidental withdrawal of a control rod or control rod bank (assumed to be initiated by a control malfunction), neutron flux, temperature, pressure, level, and flow signals would be generated independently. Any of these signals (trip demands) would operate the breakers to trip the reactor.

The AP1000 is designed to automatically terminate a boron dilution during manual or automatic operation at power, and also during startup and shutdown conditions. See Chapter 7 for a discussion of the signals used in the logic to terminate a boron dilution. Subsection 9.3.6.4.5 discusses the

chemical and volume control system design features for addressing boron dilution. The Chapter 15 safety analyses demonstrate that fuel design limits are not exceeded.

Criterion 26 – Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure that the acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

AP1000 Compliance

Two reactivity control systems are provided. These are rod cluster control assemblies and gray rod assemblies, and chemical shim (boric acid). The rod cluster control and gray rod assemblies are inserted into the core by the force of gravity.

During operation, the shutdown rod banks are fully withdrawn. The control rod system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. See Section 4.3 for additional information.

The shutdown and control rod banks are designed to provide reactivity margin to shut down the reactor during normal operating conditions and during anticipated operational occurrences, without exceeding specified fuel design limits. The safety analyses assume the most restrictive time in the core operating cycle and that the most reactive control rod cluster assembly is in the fully withdrawn position. See Chapter 15 for summaries of the analyses, assumptions, and results.

The safety-related passive systems provide the required boration to establish and maintain safe shutdown condition for the reactor core. See Section 6.3 for additional information.

Criterion 27 – Combined Reactivity Control Systems Capability

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

AP1000 Compliance

The plant is provided with the means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. Combined use of the control rod and the chemical shim control system permits the necessary shutdown margin to be maintained during long-term xenon decay and plant cooldown. The single highest worth control rod assembly is assumed to be stuck in the fully withdrawn position for this determination.

Criterion 28 – Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (l) result in damage to the reactor coolant pressure boundary greater than limited local yielding nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include

consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

AP1000 Compliance

The maximum reactivity worth of the control rods and the maximum rates of reactivity increase employing control rods and boron removal are limited by design and operating procedures.

The appropriate reactivity addition rate for the withdrawal of control rods and the dilution rate of the boric acid in the reactor coolant system are specified in the precautions, limitations, and setpoint document and the control system setpoint study. Technical specifications explicitly specify control rod bank alignment and insertion limits in addition to shutdown margin reactivity requirements.

The control rod reactivity addition rate is determined by the allowable rod control system withdrawal speed, in conjunction with the control rod worth, which varies throughout the operating cycle. The capability to change boron concentration is determined by the various plant systems that provide makeup to the reactor coolant system. The reactivity insertion rates, rod withdrawal limits, and boron dilution limits are discussed in Chapter 4.

Core cooling capability following events such as rod ejection and steam line breaks is provided by keeping the reactor coolant pressure boundary stresses within faulted condition limits, as specified by applicable ASME codes. Structural deformations are also checked and limited to values that do not jeopardize the operation of needed safety-related features.

Criterion 29 – Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

AP1000 Compliance

The protection and reactivity control systems have an extremely high probability of performing their required safety-related functions in the event of anticipated operational occurrences. High-quality equipment, diversity, and redundancy, support this probability. Loss of power to the protection system results in a reactor trip. Defense in depth is designed into AP1000 to reduce challenges to the protection and reactivity control systems.

3.1.4 Fluid Systems

Criterion 30 – Quality of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

AP1000 Compliance

Reactor coolant pressure boundary components are designed, fabricated, inspected, and tested in conformance with the ASME Code, Section III. A portion of the chemical and volume control system that is defined as reactor coolant pressure boundary uses an alternate classification in conformance with the requirements of 10 CFR 50.55a(z). The alternate classification is discussed in Section 5.2.

Leakage detection monitoring is accomplished using instrumentation and other components of several systems. See Subsection 5.2.5 for additional information. Reactor coolant pressure boundary leakage is classified as either identified or unidentified leakage.

Auxiliary systems connected to the reactor coolant pressure boundary incorporate design and administrative provisions that limit leakage. Leakage is detected by increasing auxiliary system level, temperature, flow, or pressure, by lifting of relief valves, or by increasing values of monitored radiation in the auxiliary system.

Leakage from the reactor coolant pressure boundary and other components not otherwise identified inside the containment will condense and flow by gravity via the floor drains and other drains to the containment sump. Leakage is indicated by an increase in the sump level.

Reactor coolant system inventory monitoring provides an indication of system leakage. The reactor coolant system inventory balance is a quantitative inventory or mass balance calculation.

Leakage from the reactor coolant pressure boundary will result in an increase in the radioactivity levels inside containment. The containment atmosphere is monitored for airborne gaseous radioactivity and F18 particulate. From the concentration of F18 particulate and the power level, reactor coolant pressure boundary leakage can be estimated.

Criterion 31 – Fracture Prevention of Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (l) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (l) material properties, (2) the effects of irradiation on material properties, (3) residual, steady state, and transient stresses, and (4) size of flaws.

AP1000 Compliance

Control is maintained over material selection and fabrication for the reactor coolant pressure boundary components so that the boundary behaves in a nonbrittle manner. The portion of the chemical and volume control system that uses an alternate classification is not required to meet the requirements to prevent brittle failure. The reactor coolant pressure boundary materials exposed to the coolant are corrosion-resistant stainless steel or nickel-chromium-iron alloy. The nil-ductility transition reference temperature of the reactor vessel structural steel is established by Charpy V-notch and drop weight tests in accordance with 10 CFR 50, Appendix G (Reference 1). See Section 5.3 for additional information.

The following requirements are imposed in addition to those specified by the ASME Code, Section III.

- A 100 percent volumetric ultrasonic shear wave test of reactor vessel plate and a post-hydrotest ultrasonic map of welds in the pressure vessel are required. Cladding bond ultrasonic inspection to more restrictive requirements than those specified in the ASME Code, Section III is also required in order to preclude interpretation problems during in-service inspection.

- In the surveillance programs, the evaluation of the radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, tensile, and l/2T compact tension specimens. These programs are directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the reference transition temperature approach and the fracture mechanics approach, and are in accordance with ASTM, E-185 (Reference 2).

- Reactor vessel core region material chemistry (copper, phosphorous, and vanadium) is controlled to reduce sensitivity to embrittlement due to irradiation over the life of the plant.

The fabrication and quality control techniques used in the fabrication of the reactor coolant system are governed by ASME Code, Section III requirements.

Allowable pressure-temperature relationships for plant heatup and cooldown rates are calculated using methods derived from the ASME Code, Section III, Appendix G. The approach specifies that the allowable stress intensity factors for vessel-operating conditions do not exceed the reference stress intensity factor for the metal temperature. Operating specifications include conservative margins for predicted changes in the material reference temperatures due to irradiation.

Criterion 32 – Inspection of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed to permit (l) periodic inspection and testing of important areas and features to assess their structural and leak-tight integrity and (2) an appropriate material surveillance program for the reactor pressure vessel.

AP1000 Compliance

The design of the reactor coolant pressure boundary provides accessibility to the internal surfaces of the reactor vessel and most external zones of the vessel, including the nozzle-to-reactor coolant piping welds, the top and bottom heads, and external surfaces of the reactor coolant piping, except for the area of pipe within the primary shield concrete. The inspection capability complements the leakage detection systems in assessing the integrity of the pressure boundary components. The reactor coolant pressure boundary will be periodically inspected under the provisions of the ASME Code, Section XI. Section 5.1 provides the reactor coolant system primary loop drawings. The portion of the chemical and volume control system that uses an alternate classification is constructed to requirements that do not require in-service inspection.

Monitoring of changes in the fracture toughness properties of the reactor vessel core region plates, forgings, weldments, and associated heat-treated zones is performed according to 10 CFR 50, Appendix H. Additionally, samples of reactor vessel plate materials are retained and catalogued in case future engineering development shows the need for further testing.

The material properties surveillance program includes conventional tensile and impact tests and fracture mechanics specimens. The observed shifts in the nil-ductility transition reference temperature of the core region materials with irradiation is used to confirm the allowable limits calculated for operational transients.

The design of the reactor coolant pressure boundary piping provides for accessibility of welds requiring in-service inspection under the provisions of the ASME Code, Section XI. Removable insulation is provided at welds requiring in-service inspection. See Section 5.3 and Subsection 5.2.4 for additional information.

Criterion 33 – Reactor Coolant Makeup

A system to supply reactor coolant makeup for protection against small breaks in the reactor coolant pressure boundary shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the reactor coolant pressure boundary and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished

using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.

AP1000 Compliance

Changes in the reactor coolant volume will be accommodated by the pressurizer level program for normal power changes, including the transition from hot standby to full-power operation and returning to hot standby. In addition, the pressurizer has sufficient volume to accommodate minor reactor coolant system leakage.

Safety-related passive reactor coolant system makeup is provided to accommodate small leaks when the normal makeup system is unavailable and to accommodate larger leaks resulting from loss of coolant accidents. Safety-related reactor coolant makeup and safety injection are provided by two core makeup tanks, two accumulators, and an in-containment refueling water storage tank. Long-term cooling is provided by containment gravity recirculation of reactor coolant within containment. See Section 6.3 for additional information. The safety-related reactor coolant makeup relies on the Class 1E and UPS system. Neither onsite or offsite ac power is required.

In addition, the nonsafety-related chemical and volume control system automatically provides inventory control to accommodate minor leakage from the reactor coolant system, expansion during heatup from cold shutdown, and contraction during cooldown. This inventory control is provided by letdown and makeup connections to the chemical and volume control system purification loop. Redundant pumps with connections to redundant nonsafety-related onsite ac power are provided when offsite power is not available and these pumps can be supplied from offsite power when onsite power is not available. See Section 5.2 for additional information.

Criterion 34 – Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

"Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

AP1000 Compliance

The AP1000 design satisfies the intent of GDC 34 by reducing the risk associated with loss of the decay heat removal function through a combination of safety-related passive systems, together with nonsafety-related active systems. Specific decay heat removal systems include the following:

- A safety-related passive residual heat removal heat exchanger that uses natural circulation flow and that does not require electrical power for operation
- Automatic, safety-related feed and bleed using the core makeup tanks, accumulators, and the in-containment refueling water storage tank for injection and the automatic depressurization system valves for reactor coolant system venting
- The nonsafety-related main feedwater system with motor-driven pumps supplied by the main generator or by offsite power

- The nonsafety-related startup feedwater system with motor-driven pumps supplied by offsite or onsite power, including automatic sequencing on the nonsafety-related diesel generators

- The nonsafety-related normal residual heat removal system with motor-driven pumps supplied by offsite or onsite power, including nonsafety-related diesel generators, for use at low reactor coolant system pressures

A safety-related emergency feedwater system is not required for the AP1000 design. An active safety-related residual heat removal system is not required for the AP1000.

The AP1000 passive core cooling system, in conjunction with the passive containment cooling system, provides a reliable capability for removing decay heat from the reactor core and maintains sufficient water inventory to provide adequate core cooling for an extended period of time. The system does not depend upon pumped injection or recirculation, and actuates automatically, requiring no operator actions.

The containment arrangement addresses the Regulatory Guide 1.82 issues. Functional performance of the system addresses the guidelines of Regulatory Guide 1.139, except that cooldown rate is somewhat more limited when using the passive residual heat removal equipment. See Subsection 1.9.1 for additional information.

The passive core cooling system provides both gravity injection and gravity recirculation, automatically shifting injection modes when the proper containment flood-up conditions are achieved.

The AP1000 design provides a passive decay heat removal system that functions independent of nonsafety-related ac power supplies and can accommodate single active failures. (The Class 1E dc and UPS system supplies power to the safety-related monitoring and control instrumentation.) The passive core cooling system complies with General Design Criterion 34 by providing the capability to remove decay heat without relying on nonsafety-related ac power.

Criterion 35 – Emergency Core Cooling

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (l) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

AP1000 Compliance

The AP1000 design provides for safety-related passive reactor coolant makeup. Core makeup tanks accommodate small leaks when the normal makeup system is unavailable and provide safety injection for small-break loss of coolant accidents. Accumulators provide the high makeup flow required for a large loss of coolant accident and initiate injection when the reactor coolant system pressure is below the static accumulator pressure during a small-break loss of coolant accident.

The in-containment refueling water storage tank, and after containment flood-up, containment recirculation capability provide the long-term source of gravity injection to the core after the reactor coolant system is depressurized. The automatic depressurization system valves provide the vent path to transfer the core decay heat to the containment and then to the ultimate heat sink.

The AP1000 design provides a passive core cooling system that functions independent of ac power supplies, assuming single active failures. The passive core cooling system does not need the nonsafety-related diesel-generators for electrical power to either actuate or operate the various system components. Therefore, the passive core cooling system complies with the intent of GDC 35 by providing the capability for core cooling without relying on nonsafety-related ac power sources.

Criterion 36 – Inspection of Emergency Core Cooling System

The emergency core cooling system shall be designed to permit appropriate periodic inspection of important components, such as spray rings in the reactor pressure vessel, water injection nozzles, and piping, to assure the integrity and capability of the system.

AP1000 Compliance

The AP1000 design includes a passive core cooling system that provides emergency core decay heat removal, emergency reactor coolant system makeup and boration, safety injection, and containment sump pH control. The system piping and components are designed to permit access for periodic inspection and testing of equipment, according to the ASME Code and technical specification requirements, to provide confidence in the integrity and capability of the system.

The core makeup tanks, accumulators, and passive residual heat removal heat exchanger have manways which permit access for inspection and required maintenance. The in-containment refueling water storage tank design provides access for both the tank itself and for the passive residual heat removal heat exchanger, spargers, and other components located inside the tank.

In addition, the system piping provides accessibility for inspection and maintenance to the extent practical. See Section 6.3 for additional information.

Criterion 37 – Testing of Emergency Core Cooling System

The emergency core cooling system shall be designed to permit appropriate periodic pressure and functional testing to assure (l) the structural and leak-tight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

AP1000 Compliance

The AP1000 passive core cooling system is designed to permit the periodic inspection and testing of the appropriate system components. The testing capabilities of the system including in-service testing and inspection to confirm the structural and leaktight integrity of various components, technical specification operability and performance of the active system components, and additional in-service testing to confirm the overall operability of the system.

The stage 1, 2, and 3 automatic depressurization system valves have provisions for shutdown in-service testing and at-power operability testing.

Planned shutdown testing includes operability testing of the component and system performance, including operation of applicable portions of the protection and safety monitoring system and the use of the appropriate power sources for the system.

The AP1000 design has significantly reduced the support systems required for system operation. In-service testing of the required support systems is also planned.

Criterion 38 – Containment Heat Removal System

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss of coolant accident and maintain them at acceptably low levels.

Suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

AP1000 Compliance

The AP1000 design uses passive systems for post-loss of coolant accident core and containment heat removal and for the prevention of overpressurization failure of the containment building. Heat is transferred from the containment atmosphere to the steel containment shell by natural convection and condensation. Heat removal from the exterior of the containment shell is enhanced by a directed-flow natural convection design and a passive, external cooling water distribution system.

The AP1000 passive containment cooling system is designed with sufficient capacity to prevent the containment from exceeding its design pressure with no operator action or outside assistance for a minimum of 3 days. After 3 days, limited operator action is required.

The AP1000 passive containment cooling system consists of a steel containment shell and associated water supplies, piping, valves, and air baffle. The passive containment cooling system is a passive system that uses gravity and natural circulation as driving forces. The design of the AP1000 passive containment cooling system does not require the use of any pumps, and it functions independent of nonsafety-related ac power sources for 3 days. Therefore, the passive containment cooling system can function during loss of offsite or onsite power. GDC 38 is satisfied by using appropriate redundancy and by the design of the passive containment cooling system and its reliance on natural forces.

Criterion 39 – Inspection of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as the torus, sumps, spray nozzles and piping, to assure the integrity and capability of the system.

AP1000 Compliance

The AP1000 design uses safety-related passive means for containment heat removal. The design of the system allows for inspection of piping, valves, the containment shell and air baffle, and other components to provide confidence in the integrity and capability of the system.

The periodic inspections specified in the ASME Code and technical specifications provide confidence that the capability of these heat removal systems is retained through plant life.

Criterion 40 – Testing of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure (l) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole, and, under conditions as close to the design as practical the performance of the full operational sequence that brings the system into operation, including operation of applicable

portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

AP1000 Compliance

The AP1000 design includes a passive containment cooling system that provides containment heat removal to limit the peak containment pressure following design basis events. The system piping and components are designed to permit access for periodic inspection and testing of equipment, according to the ASME Code and technical specification requirements, to provide confidence in the integrity and capability of the system.

The passive containment cooling water storage tank design allows access for both the tank and for the various components located inside the tank.

In addition, the system piping provides accessibility for inspection and maintenance to the extent practical. See Section 6.2 for additional information.

Criterion 41 – Containment Atmosphere Cleanup

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided, as necessary, to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

AP1000 Compliance

Fission product control for the AP1000 plant is provided via natural removal processes within containment and by limiting containment leakage. The passive removal processes such as deposition and sedimentation are evaluated based on a physically-based source term with large scale core damage. See Section 6.5 for additional details. The containment and penetration design includes features specifically designed to minimize overall containment leakage. See Subsection 6.2.3 for additional details.

The generation of hydrogen in the containment under post-accident conditions has been evaluated, and the containment hydrogen control system has been designed such that the following criteria are satisfied:

- In compliance with Section 50.44 of 10 CFR 50, means are provided to measure and control post-loss of coolant accident hydrogen concentrations.

- The combustible concentrations of hydrogen do not accumulate in the areas where unintended combustion or detonation could cause loss of containment integrity or loss of appropriate mitigating features.

- Internal passive autocatalytic recombiners are provided for hydrogen control following a design basis loss of coolant accident.

- Hydrogen igniters are provided to limit local and global hydrogen concentrations to below 10 percent following a degraded core event with the reaction of 100 percent of the zircaloy cladding.

- The concentration of uniformly distributed hydrogen produced by the equivalent of a 75 percent active fuel-clad metal water reaction does not exceed 13 percent by volume during and following a degraded core event. (The AP1000 containment volume is large enough to provide passive protection for the hydrogen produced by 75 percent zircaloy cladding reaction following a severe accident.)

- The nonsafety-related ventilation system, normally used during refueling, is designed with the capability for a controlled purge of the containment atmosphere to assist in post-accident cleanup, but is not required for hydrogen control.

Criterion 42 – Inspection of Containment Atmosphere Cleanup System

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components such as filter frames, ducts, and piping, to assure the integrity and capability of the systems.

AP1000 Compliance

The containment atmosphere cleanup systems are designed and located so that they can be inspected periodically, as appropriate.

Criterion 43 – Testing of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leak-tight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves, and (3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

AP1000 Compliance

The appropriate portions of the containment atmosphere cleanup system are designed to permit periodic pressure and functionality testing.

As described in GDC 41, the containment atmosphere cleanup system has no safety-related post-accident cleanup functions. Dose mitigation is passively provided by the containment isolation and integrity, natural removal processes, and limited containment leakage. Periodic containment integrity is verified in accordance with 10 CFR 50 Appendix J testing as described in Subsection 6.2.3.

Criterion 44 – Cooling Water

A system to transfer heat from structures, systems, and components important to safety to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished assuming a single failure.

AP1000 Compliance

The passive containment cooling system is the ultimate heat sink for the AP1000 and does not rely upon offsite or onsite ac power sources. Heat transfer by convection from the containment shell to the atmosphere meets the intent of GDC 44. Additional information is provided in the responses for GDC 34 and GDC 38.

Criterion 45 – Inspection of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

AP1000 Compliance

Refer to the discussion provided for GDC 39.

Criterion 46 – Testing of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leak-tight integrity of its components, (2) the operability and the performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for loss of coolant accidents, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

AP1000 Compliance

Refer to the discussion provided for GDC 40.

3.1.5 Reactor Containment

Criterion 50 – Containment Design Basis

The reactor containment structure, including access opening, penetrations, and the containment heat removal system, shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any loss of coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

AP1000 Compliance

The design of the containment structure is based on the containment design basis accidents, which include the rupture of a reactor coolant pipe or the rupture of a main steam or feedwater line. The maximum pressure and temperature reached, a description of the calculational model, and input parameters for a containment design basis accident are presented in Section 6.2. The containment design provides margin to the design basis limits.

Criterion 51 – Fracture Prevention of Containment Pressure Boundary

The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions (1) its ferritic materials behave in

a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining (1) material properties, (2) residual, steady-state, and transient stresses, and (3) size of flaws.

AP1000 Compliance

Principal load-carrying components of ferritic materials of the reactor containment boundary exposed to the external environment are selected so that they behave in a nonbrittle manner and so that the probability of fracture propagation is minimized. See Subsection 3.8.2 for additional information.

Criterion 52 – Capability for Containment Leakage Rate Testing

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

AP1000 Compliance

The containment system is designed and constructed and the necessary equipment is provided to permit periodic integrated leakage rate tests according to the requirements of 10 CFR 50, Appendix J.

Criterion 53 – Provisions for Containment Testing and Inspection

The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important areas, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leak-tightness of penetrations which have resilient seals and expansion bellows.

AP1000 Compliance

Provisions exist for conducting individual leakage rate tests on containment penetrations. Penetrations are visually inspected and pressure-tested for leak tightness at periodic intervals. Other inspections are performed as required by 10 CFR 50, Appendix J.

Criterion 54 – Piping Systems Penetrating Containment

Piping systems penetrating the primary reactor containment shall be provided with leak detection, isolation and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

AP1000 Compliance

Piping systems penetrating the primary reactor containment are provided with containment isolation valves. Penetrations that close for containment isolation have redundant valving. Automatic isolation valves with air-, solenoid-, or motor-operators, which do not restrict normal plant operation, are periodically tested to verify operability.

The AP1000 containment isolation design satisfies the current NRC requirements including the post-TMI requirements, as discussed in Subsection 1.9.3. In general, this means that two barriers are provided, one inside containment and the other outside containment. Usually these barriers are valves, but in some cases they are closed piping systems not connected to the reactor coolant system or to the containment atmosphere.

The AP1000 design incorporates a reduction in the number of existing penetrations. Most penetrations are normally closed. Those few that are normally open and are required to close use remotely operated valves for isolation that close automatically. See Subsection 6.2.3 for additional information.

Nonessential systems that may be normally open, such as the mini-purge system, are provided with automatic containment isolation valves that close automatically on a containment isolation signal. The containment isolation signal is actuated by the protection and safety monitoring system. See Section 7.3 for additional information.

Piping and electrical containment penetrations are equipped with test connections and test vents or have other provisions to allow periodic leak rate testing so that leakage is within the acceptable limits established in technical specifications consistent with 10 CFR 50, Appendix J.

Criterion 55 – Reactor Coolant Pressure Boundary Penetrating Containment

Each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

1. One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

2. One automatic isolation valve inside and one locked closed isolation valve outside containment; or

3. One locked closed isolation valve inside and one automatic isolation valve outside the containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

4. One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and, upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided, as necessary, to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for in-service inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, and use characteristics, and physical characteristics of the site environs.

AP1000 Compliance

Lines that penetrate containment that are connected to the reactor coolant pressure boundary are provided with containment isolation valves in accordance with one of the acceptable arrangements as described in GDC 55. Additional information is found in Subsection 6.2.3.

Criterion 56 – Primary Containment Isolation

Each line that connects directly to the containment atmosphere and penetrates the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be

demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

1. One locked closed isolation valve inside and one locked closed isolation valve outside the containment; or

2. One automatic isolation valve inside and one locked closed isolation valve outside the containment; or

3. One locked closed isolation valve inside and one automatic isolation valve outside the containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

4. One automatic isolation valve inside and one automatic isolation valve outside the containment. A simple check valve may not be used as the automatic isolation valve outside the containment.

Isolation valves outside the containment shall be located as close to the containment as practical and, upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

AP1000 Compliance

Lines connecting directly with the containment atmosphere and penetrating the reactor containment are normally provided with two isolation valves in series, one inside and one outside the containment, in accordance with one of the acceptable arrangements as described in GDC 56. Isolation of instrument lines for containment pressure measurement is demonstrated on a different basis and does not require isolation valves. Additional information is found in Subsection 6.2.3.

Criterion 57 – Closed System Isolation Valves

Each line that penetrates the primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked closed, or capable of remote manual operation. This valve shall be outside the containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

AP1000 Compliance

Lines that penetrate the containment and are neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere are considered closed systems within the containment and are equipped with at least one containment isolation valve of one of the following types:

- An automatic isolation valve (a simple check valve is not used as this automatic valve)

- A locked-closed valve

This valve is located outside the containment and as close to the containment wall as practical.

3.1.6 Fuel and Reactivity Control

Criterion 60 – Control of Releases of Radioactive Materials to the Environment

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during

normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for the retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

AP1000 Compliance

Means are provided to control the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences.

The radioactive waste management systems are designed to minimize the potential for an inadvertent release of radioactivity from the facility and to provide confidence that the discharge of radioactive wastes is maintained below regulatory limits of 10 CFR 50, Appendix I, during normal operation. The gaseous radwaste and liquid radwaste processing systems include continuous radiation monitoring of their discharge paths. High radiation automatically closes a discharge isolation valve. The liquid radwaste system also has provisions to prevent inadvertent siphoning of its monitor tank contents which could cause an uncontrolled discharge. The radioactive waste management systems, the design bases, and the estimated amounts of radioactive effluent releases to the environment are described in Chapter 11.

Criterion 61 – Fuel Storage and Handling and Radioactivity Control

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit appropriate periodic inspection and testing of components important to safety, (2) with suitable shielding for radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

AP1000 Compliance

The spent fuel pool cooling system, and the fuel handling and refueling system are designed to provide cooling and shielding for the fuel assemblies stored in the spent fuel pool and to provide purification of the water in the pit. The system design provides adequate safety under normal and postulated accident conditions.

The spent fuel pool cooling system normal system operation is described in Subsection 9.1.3. Sampling of the spent fuel pool water for gross activity, tritium, and particulate matter is conducted periodically. The concentration of tritium in the spent fuel pool water is maintained at less than 0.5 microcuries per gram to provide confidence that the airborne concentration of tritium in the fuel handling area is within the limits specified in 10 CFR 20, Appendix B. See Subsection 12.2.2 for additional information.

The spent fuel pool is designed so that a water level is maintained above the spent fuel assemblies for at least 72 hours following a loss of the spent fuel pool cooling system, without ac power. See Subsection 9.1.2 for additional information.

The spent fuel pool cooling system maintains the water in the in-containment refueling water storage tank consistent with activity requirements of the water in the refueling cavity during a refueling. Two spent fuel pool cooling filters are provided, one downstream of each demineralizer in the purification branch line of each mechanical train. The filters are sized to collect particulates and suspended solids passed by the demineralizer.

The AP1000 spent fuel pool cooling system is not required to operate to mitigate design basis events. In the event the spent fuel pool cooling system is unavailable, the spent fuel pool cooling is provided by the heat capacity of the water in the pool and in the passive sources of makeup water.

Normal HVAC to the spent fuel pool area is provided by a subsystem of the radiologically controlled area ventilation system described in Subsection 9.4.3. No credit is taken for this system in evaluation of fuel handling accidents discussed in Subsection 15.7.4.

Connections to the spent fuel pool are provided at an elevation that prevents inadvertent draining of the water in the pool to an unacceptable level.

The design of spent fuel storage pool and the spent fuel pool cooling system satisfies GDC 61. See Subsection 9.1.3 for additional information.

Criterion 62 – Prevention of Criticality in Fuel Storage and Handling

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

AP1000 Compliance

The restraints, interlocks, and physical arrangement provided for the safe handling and storage of new and spent fuel are discussed in Section 9.1. The spent fuel assemblies are stored in the spent fuel pool until fission product activity is low enough to permit shipment.

Criterion 63 – Monitoring Fuel and Waste Storage

Appropriate systems shall be provided in the fuel storage and radioactive waste systems and associated handling areas (1) to detect conditions that may result in the loss of residual heat removal capability and excessive radiation levels and (2) to initiate appropriate safety actions.

AP1000 Compliance

Instrumentation is provided to monitor spent fuel storage pool temperature and water level. Indication and alarms are provided in the main control room. Area radiation monitoring is provided in the fuel storage area for personnel protection and general surveillance. The area monitor alarms locally and in the main control room.

If radiation levels in the ventilation effluent reach a predetermined point, an alarm is actuated in the main control room, and the ventilation discharge path is automatically transferred through filter absorber units that provide filtration before discharge from the plant vent.

Criterion 64 – Monitoring Radioactivity Releases

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

AP1000 Compliance

The containment atmosphere is monitored during normal and transient operations by the containment gaseous radiation monitors. Under accident conditions, samples of the containment atmosphere taken via the sampling system provide data on airborne radioactive concentrations within the containment.

No reactor coolant fluids are required to be recirculated outside of containment following an accident. Radioactivity levels contained in the facility effluent and discharge paths and in the plant environs are monitored during normal and accident conditions by the plant radiation monitoring systems. High radiation in a discharge path causes automatic closure of the discharge isolation valve.

Area radiation monitors (ARMs) are provided to supplement the personnel and area radiation survey provisions of the AP1000 health physics program described in Section 12.5 and to comply with the personnel radiation protection guidelines of 10 CFR 20, 10 CFR 50, and Regulatory Guides 1.97, 8.2, 8.8, and 8.12. In addition to the installed detectors, periodic plant environmental surveillance is established.

Measurement capability and reporting of effluents are based on the guidelines of Regulatory Guides 1.4 and 1.21, as discussed in Subsection 1.9.1. Additional information is contained in Chapters 11 and 12.

3.1.7 Combined License Information

This section contained no requirement for additional information.

3.1.8 References

1. 10 CFR 50, Appendix G, "Fracture Toughness Requirements."

2. American Society of Testing Materials E-185, Standard Recommended Practice for Surveillance Test for Nuclear Reactor Vessels, and the requirements for 10 CFR 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements."

3.2 Classification of Structures, Components, and Systems

Structures, systems, and components in the AP1000 are classified according to nuclear safety classification, quality groups, seismic category, and codes and standards. This section provides the methodology used for safety-related and seismic classification of AP1000 structures, systems, and components. The seismic classification is described in Subsection 3.2.1. Subsection 3.2.2 describes the classification including nuclear safety-related classification and the corresponding codes and standards. Additionally, Subsection 3.2.2 describes nonsafety-related equipment classifications.

3.2.1 Seismic Classification

General Design Criterion 2 requires that nuclear power plant "Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena, such as earthquakes, tornados, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions." 10 CFR 100, Appendix A sets forth the criteria to which the plant design bases demonstrate the capability to function during and after vibratory ground motion associated with the safe shutdown earthquake conditions.

The seismic classification methodology used in AP1000 complies with the preceding criteria, as well as with recommendations stated within Regulatory Guide 1.29. Conformance with the recommendations of Regulatory Guide 1.29 is discussed in Subsection 1.9.1. The methodology classifies structures, systems, and components into three categories: seismic Category I (C-I), seismic Category II (C-II) and non-seismic (NS).

Seismic Category I applies to both functionality and integrity, and seismic Category II applies only to integrity. Non-seismic items located in the proximity of safety-related items, the failure of which during a safe shutdown earthquake could result in loss of function of safety-related items, are designated as seismic Category II.

There are no safety-related structures, systems, or components outside the scope of the DCD, except for engineered fill which is classified as a Seismic Category I, safety-related structure. See Table 3.2-2. Refer to Subsection 2.5.4 for a discussion of safety-related backfill.

The nonsafety-related structures, systems, and components outside the scope of the DCD are classified as non-seismic (NS).

3.2.1.1 Definitions

3.2.1.1.1 Seismic Category I (C-I)

Seismic Category I applies to, in general, safety-related structures, systems, and components. Seismic Category I also applies to those structures, systems, and components required to support or protect safety-related structures, systems, and components. The exceptions to this general rule are a limited number of structures, such as those required for tornado missile protection, which do not have a safety-related function to perform during or following a seismic event. (See Subsection 3.2.2.5.)

Safety-related items are those necessary to provide for the following:

- The integrity of the reactor coolant pressure boundary
- The capability to shut down the reactor and maintain it in a safe shutdown condition
- Capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 50.34.

Seismic Category I structures, systems, and components are designed to withstand the appropriate seismic loads, as discussed in Section 3.7, and other applicable loads without loss of function. Seismic Category I structures are protected from interaction with adjacent non-seismic structures as described in Subsection 3.7.2.8.

Systems and components identified as safety-related systems and components in Table 3.2-3, and electrical and instrumentation components identified in Table 3.11-1, are the systems and components necessary for continued operation that must remain functional without undue risk of the health and safety of the public during and following an operating basis earthquake. Systems and components identified as Equipment Class A, B, and C in Table 3.2-3, and electrical and instrumentation components identified in Table 3.11-1, are the systems and components that per the criteria of 10 CFR Part 50, Appendix S, must be demonstrated, prior to resuming operations, to have no functional damage following a seismic ground motion exceeding the operating basis earthquake ground motion. See Section 3.7 for information on the operating basis earthquake.

Seismic Category I structures, systems, and components meet the quality assurance requirements of 10 CFR 50, Appendix B. The criteria used for the design of seismic Category I structures, systems, and components are discussed in Section 3.7.

3.2.1.1.2 Seismic Category II (C-II)

Seismic Category II applies to plant structures, systems, and components which perform no safety-related function, and the continued function of which is not required. Seismic Category II applies to structures, systems, and components designed to prevent their collapse under the safe shutdown earthquake. Structures, systems and components are classified as seismic Category II to preclude their structural failure during a safe shutdown earthquake or interaction with seismic Category I items which could degrade the functioning of a safety-related structure, system, or component to an unacceptable level, or could result in incapacitating injury to occupants of the main control room. The turbine building first bay building structure, including Wall 11.2, is a seismic Category II structure as identified in Table 3.2-2. The seismic Category II systems, structures, and components which provide tornado missile protection for openings and penetrations are described in Subsection 3.5.2. Wall 11.2 protects Wall 11 from the dynamic effects of pipe failure events in the nonseismic portion of the turbine building.

Seismic Category II structures, systems, and components are designed so that the safe shutdown earthquake does not cause unacceptable structural failure of or interaction with seismic Category I items. Seismic Category II fluid systems require an appropriate level of pressure boundary integrity if located near sensitive equipment.

The criteria used for the design of seismic Category II structures, systems, and components are discussed in Section 3.7. As identified in Subsection 3.7.2, seismic Category II building structures are designed for the safe shutdown earthquake using the same methods and design stress limits as are used for seismic Category I structures. Seismic Category II building structures are also designed to withstand the design basis tornado loads, including missiles, in accordance with the loading combinations identified in Table 3.8.4-2.

Pertinent portions of 10 CFR 50, Appendix B apply to the analysis and design of seismic Category II structures, systems, and components. The quality assurance requirements for the analysis and design of seismic Category II structures, systems, and components are performed in accordance with the Westinghouse AP1000 quality plan as described in Section 17.3 and are sufficient to provide that these components will meet the requirement to not cause unacceptable structural failure of or interaction with seismic Category I items. See Section 17.7 for the Combined License applicant quality assurance program requirement. These quality requirements are applicable to the seismic Category II turbine building first bay building structure.

3.2.1.1.3 Non-Seismic

Non-seismic (NS) structures, systems, and components are those that are not classified seismic Category I or Category II.

The criteria used for the design of non-seismic structures, components and systems are discussed in Section 3.7.

The non-seismic lines and associated equipment are routed, to the extent practicable, outside of safety-related buildings and rooms to avoid adverse system interactions. In cases where these lines are routed in safety-related areas, the non-seismic item is evaluated for the safe shutdown earthquake and is upgraded to seismic Category II if a credible failure could cause an unacceptable interaction.

Although the seismic category for an item located in the proximity of safety-related structures, systems, and components may be upgraded to seismic Category II, its pre-assigned equipment class remains unchanged.

3.2.1.2 Classifications

Table 3.2-1 illustrates the general relationship between safety-related equipment classes and seismic categories. In most cases, except as noted in Subsection 3.2.2.5, safety-related items are also seismic Category I items. When portions of systems are identified as seismic Category I, the boundaries of seismic Category I portions of the system are shown on the piping and instrumentation diagram (P&ID) of that system. See Subsection 1.7.2 for a list of the piping and instrumentation diagrams.

3.2.1.3 Classification of Building Structures

Building structures are assigned a seismic category as indicated in Table 3.2-2. Codes and standards used in the design and construction of building structures are given in Section 3.8. The building structures are not assigned a safety classification in Subsection 3.2.2 with the exception of the containment vessel.

3.2.2 AP1000 Classification System

The assignment of safety-related classification and use of codes and standards conforms to the requirements of 10 CFR 50.55a for the development of a Quality Group classification and the use of codes and standards. The description of the equipment classification which follows identifies the classifications requiring the full 10 CFR 50, Appendix B quality assurance program as described in Chapter 17 and the Quality Group associated with each classification.

The classification system provides a means of identifying the extent to which structures, systems, and components are related to safety-related and seismic requirements. The classification system provides an easily recognizable means of identifying the extent to which structures, systems, and components are related to ANS nuclear safety classification, NRC quality groups, ASME Code, Section III classification, seismic category and other applicable industry standards, as shown in Table 3.2-3.

There are no safety-related structures, systems, or components outside the scope of the DCD, except for engineered fill which is classified as a Seismic Category I, safety-related structure. See Table 3.2-2. Refer to Subsection 2.5.4 for a discussion of safety-related backfill.

3.2.2.1 Classification Definitions

The definitions used in the classification of structures, systems and components are provided in the following. Unless otherwise noted these definitions apply throughout the Design Control Document. These definitions are consistent with the ANS Definitions for Light Water Reactor Standards (ANS-58.14-1993).

Safety-related is a classification applied to items relied upon to remain functional during or following a design basis event to provide a safety-related function. Safety-related also applies to documentation and services affecting a safety-related item.

Safety-related function is a function that is relied upon during or following a design basis event to provide for the following:

- The integrity of the reactor coolant pressure boundary
- The capability to shut down the reactor and maintain it in a safe shutdown condition
- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 50.34.

Design basis event is an event that is a condition of normal operation (including anticipated operational occurrences), a design basis accident, an external event, or natural phenomena for which the plant must be designed so that the safety-related functions are achievable.

Design basis accidents and transients are those design basis events that are accidents and transients and are postulated in the safety analyses. The design basis accidents and transients are used in the design of the plant to establish acceptable performance requirements for structures, systems, and components.

3.2.2.2 Application of Classification

The AP1000 requires adaptation of safety classification documents and standards because of the way that the AP1000 accomplishes safety-related functions.

In addition to 10 CFR 50.55a, the AP1000 classification has been developed considering requirements and guidelines in the following:

- ANSI N18.2a (Reference 1) – safety classification
- ANS 51.1 (Reference 2) – safety classification
- Regulatory Guide 1.26 – Quality Groups
- Regulatory Guide 1.97 – instrumentation requirements
- 10 CFR 21.

Conformance with the guidelines of Regulatory Guides 1.26 and 1.97 is discussed in Subsection 1.9.1.

The general guidelines for safety classification in the ANSI and ANS standards are useful in the development of the AP1000 classification. The specific classifications for various structures, systems, and components included in Regulatory Guide 1.26 and ANSI N18.2a and ANS 51.1 are based on a nuclear power plant with active safety systems and are not necessarily appropriate for the passive safety systems of the AP1000.

For the purposes of equipment classification, structures, systems, and components are classified as Class A, B, C, D, E, F, G, L, P, R, or W. For mechanical equipment Classes A, B, and C are equivalent to ANS Safety Class 1, 2, and 3. For electrical equipment Class C is equivalent to Class 1E. Structures, systems, and components classified equipment class A, B, or C or seismic Category I are basic components as defined in 10 CFR Part 21.

Equipment Class D is a nonsafety-related class. Classes E, F, G, L, P, R, and W are nonsafety-related classes associated with different industry codes and standards.

Components are classified down to the replacement part level according to the definitions and criteria of the classification system. A single item or portion thereof, which provides two or more functions of different classes, is classified according to the most stringent function. Different portions of the same structure, system, or component may perform different functions and be assigned to different equipment classes if the structure, system, or component contains a suitable interface boundary.

The definitions and criteria for the AP1000 equipment classes follow.

3.2.2.3 Equipment Class A

Class A is a safety-related class equivalent to ANS Safety Class 1. It applies to the reactor coolant system pressure boundary, including the required isolation valves and mechanical supports. This class has the highest integrity, and the lowest probability of leakage.

10 CFR 21 applies to Class A structures, systems, and components. Class A structures, systems, and components are seismic Category I and use codes and standards consistent with the guidelines for NRC Quality Group A. 10 CFR 50, Appendix B applies. ASME Code, Section III, Class 1 applies to pressure retaining components.

3.2.2.4 Equipment Class B

Class B is a safety-related class equivalent to ANS Safety Class 2. It limits the leakage of radioactive material from the containment following a design basis accident. This class is designed to accomplish the following:

- It provides fission product barrier or primary containment radioactive material holdup or isolation.

- It provides the containment boundary including penetrations and isolation valves. This also includes piping that functions as the containment boundary. For example, the steam and feedwater system inside containment and the secondary shell of the steam generator are Class B by this criterion.

- It circulates a non-containment/non-reactor coolant fluid to provide a post-accident safety-related function into and out of the containment. These lines have a Class B pressure boundary inside the containment. The outside containment lines in this circulation loop can be Class C or a nonsafety-related class if suitable containment isolation valves are provided.

- It introduces emergency negative reactivity to make the reactor subcritical (for example, control rods).

- This class also applies to structures, systems, and components where leakage could cause a loss of adequate core cooling. In isolating leaks, credit can be taken for automatic safety-related isolation and for appropriate operator action. As a minimum, operator action needs redundant safety-related indication and alarm followed by 30 minutes for operator action.

10 CFR 21 applies to Class B structures, systems, and components. Class B structures, systems, and components are seismic Category I and use codes and standards consistent with the guidelines for NRC Quality Group B. 10 CFR 50, Appendix B applies. ASME Code, Section III, Class 2 or Class MC applies to pressure retaining components. ASME Code, Section III, Subsection NE applies to the containment vessel and guard pipes.

3.2.2.5 Equipment Class C

Class C is a safety-related class equivalent to ANS Safety Class 3. It applies to other safety-related functions required to mitigate design basis accidents and other design basis events. Minor leakage will not prevent Class C structures, systems, and components from meeting the safety-related function, either from the regard of radiation dose or system functioning.

This class also applies to equipment that, upon rupturing, would cause dose limits for unrestricted areas, as specified in 10 CFR 20, to be exceeded or would cause a loss of core cooling.

10 CFR 21 applies to Class C structures, systems, and components. Class C structures, systems, and components use codes and standards consistent with the guidelines for NRC Quality Group C. Class C structures, systems, and components are seismic Category I except those noted below which are not required to provide a safety-related function following a seismic event. 10 CFR 50, Appendix B applies. ASME Code, Section III, Class 3 applies to pressure retaining components with some exceptions as identified below. In addition to these requirements, for systems that provide emergency core cooling functions, full radiography in accordance with the requirements of ASME Code, Section III, ND-5222 of a random sample of welds will be conducted on the piping butt welds during construction. For Class C air and gas storage tanks fabricated without welding, ASME Code, Section VIII, Appendix 22 may be used in lieu of Section III, Class 3. For Class C fuel handling system weir gate pressure boundary components containing only compressed air, Manufacturer's Standard may be used in lieu of Section III, Class 3. 10 CFR 50, Appendix B requirements and 10 CFR 21 apply to the manufacture of safety-related air and gas storage tanks. For core support structures ASME Code, Section III, Subsection NG applies. For electrical systems, appropriate IEEE standards, including IEEE standard 323-74 (Reference 3) and IEEE standard 344-87 (Reference 4), apply.

Class C applies to structures, systems, and components not included in Class A or Class B that are designed and relied upon to accomplish one or more of the following safety-related functions:

- Provide safety injection or maintain sufficient reactor coolant inventory to allow for core cooling
- Provide core cooling
- Provide containment cooling
- Provide for removal of radiation from the containment atmosphere as necessary to meet the offsite dose limits
- Limit the buildup of radioactive material in the atmosphere of rooms and areas outside containment as necessary to meet the offsite dose limits
- Introduce negative reactivity control measures to achieve or maintain safe shutdown conditions (for example, boron addition)
- Maintain geometry of structures inside the reactor vessel so that the control rods can be inserted (when required) and the fuel remains in a coolable geometry

- Provide load-bearing structures and supports for Class A, B, and C structures, systems, and components. This applies to structures and supports that are not part of the pressure boundary.

- Provide structures to protect Class A, B, and C structures, systems, and components from events such as internal/external missiles, seismic, flooding, and the dynamic and environmental effects of pipe failures. Structures protecting equipment from nonseismic events are not required to be seismic Category I. Exceptions to this equipment Class C criterion are the equipment Class D barriers and seismic Category II structures described in Subsection 3.5.2 that provide tornado missile protection. Turbine building first bay building structure Wall 11.2 provides protection of Wall 11 from HELB loads resulting from postulated ruptures in main steam and main feedwater piping north of the turbine building first bay.

- Provide permanent radiation shielding to allow operator access to the main control room and to limit the exposure to Class A, B and C structures, systems, and components

- Provide safety support functions to Class A, B and C structures, systems, and components, such as, heat removal, room cooling, and electrical power

- Provide instrumentation and controls for automatic or manual actuation of Class A, B, and C structures, systems, and components necessary to perform the safety-related functions of the Class A, B, or C structure, system or component. This includes the processing of signals and interlock functions required for proper safety performance of these structures, systems, and components.

- Maintain spent fuel integrity, the failure of which could result in fuel damage such that significant quantities of radioactive material could be released from the fuel and results in offsite doses greater than normal limits (for example, spent fuel pool, fuel transfer tube isolation valve)

- Maintain spent fuel sub-critical

- Monitor variables to indicate status of Class A, B or C structures, systems, and components required for post-accident mitigation

- Provide for functions defined in Class B where structures, systems, and components, or portions thereof are not within the scope of the ASME Code, Section III, Class 2.

- Provide provisions for connecting temporary equipment to extend the use of safety related systems. See Subsection 1.9.5 for a discussion of actions required for an extended loss of onsite and offsite ac power sources.

The components and portions of systems that provide emergency core cooling functions and are required to have radiography of a random sample of welds during construction include the following:

- Accumulators

- Injection piping from the accumulators to the reactor coolant system isolation check valves in the direct vessel injection line

- Piping from the in-containment refueling water storage tank (IRWST) and recirculation screens to the reactor coolant system isolation check valves in the direct vessel injection line

- Piping from the Stage 1, 2, and 3 automatic depressurization system valves to the IRWST including the spargers.

The IRWST is formed from portions of structural modules that are elements of the containment internal structures. The inspection requirements for the welds in these structural modules are provided in Subsection 3.8.3.6.2.

3.2.2.6 Equipment Class D

Class D is nonsafety-related with some additional requirements on procurement, inspection or monitoring.

For Class D structures, systems, and components containing radioactivity, it is demonstrated by conservative analysis that the potential for failure due to a design basis event does not result in exceeding the normal offsite doses per 10 CFR 20. This criterion is in conformance with the definition of Class D in Regulatory Guide 1.26.

A structure, system or component is classified as Class D when it directly acts to prevent unnecessary actuation of the passive safety systems. Structures, systems and components which support those which directly act to prevent the actuation of passive safety systems are also Class D. The inclusion of these nonsafety-related structures, systems, and components in Class D recognizes that these systems provide an important first level of defense that helps to reduce the calculated probabilistic risk assessment core melt frequency. These structures, systems, and components are normally used to support plant cooldown and depressurization and to maintain shutdown conditions during maintenance and refueling outages.

For Class D structures, systems, and components considered to be risk significant as defined in the reliability assurance program (see Section 16.2). Provisions are made to check for operability, including appropriate testing and inspection, and to repair out-of-service structures, systems, and components. These provisions are documented and administered in the plant reliability assurance plan and operating and maintenance procedures.

A portion of chemical and volume control system is defined as the reactor coolant pressure boundary and is Class D. This portion of the chemical and volume control system is seismically analyzed. See Subsection 5.2.1.1 for the seismic analysis requirements.

Some Class D structures, systems, and components are assumed to function in a severe containment environment. The design requirements for these components include operation in such an environment. An evaluation is done to confirm that the structure, system, or component can be expected to function in such an environment.

Standard industrial quality assurance standards are applied to Class D structures, systems, and components to provide appropriate integrity and function although 10 CFR 50, Appendix B and 10 CFR 21 do not apply. 10 CFR 50, Appendix B and 10 CFR 21 do apply to Class D structures, systems, and components that are seismic Category I. Pertinent portions of 10 CFR 50, Appendix B are applied to seismic Category II applications as described in Subsection 3.2.1.1.2. These industrial quality assurance standards are consistent with the guidelines for NRC Quality Group D. The industry standards used for Class D structures, systems and components are widely used industry standards. Typical industrial standards used for Class D systems and components are provided as follows:

- Pressure vessels – ASME Code, Section VIII

- Piping – ASME B31.1. Power Piping, (Reference 5). NDE of welds during fabrication and installation may use methods and acceptance criteria of ASME B31.1, 2007 Edition. Post Weld Heat Treatment of welds may use methods and acceptance criteria of ASME B31.1, 2014 Edition.
- Pumps – API 610 (Reference 6), or Hydraulic Institute Standards
- Valves – ANSI B16.34 (Reference 8)
- Atmospheric storage tanks – API-650 (Reference 9), AWWA D 100 (Reference 10), or ANSI B96.1 (Reference 11)
- 0 - 15 psig Storage Tanks – API-620 (Reference 12)
- AC motor and generators – NEMA MG1 (Reference 13)
- Circuit breakers, switchgear, relays, substations and fuses – IEEE C37 (Reference 14).

The NS buildings (except for the NS portions of the turbine and annex buildings outlined in Table 3.2-2) containing Class D structures, systems, and components, as well as the anchorage of the structures, systems, and components to the building, are designed to the seismic requirements of the Uniform Building Code (Reference 15). The NS portions of the turbine building and annex building are designed to the requirements of the International Building Code, IBC-06 (Reference 19). The systems and components are not designed for seismic loads. However, when Class D structures, systems, and components are located near a Class A, B, or C structure, system, or component, the requirements for seismic Category II may apply. The tornado missile barriers in the turbine building first bay building structure identified in Table 3.5-1 are seismic Category II, equipment Class D.

For Class D structures, systems, and components required to be monitored for maintenance effectiveness by 10 CFR 50.65, the availability parameters and criteria are included in the maintenance monitoring plan for evaluating the effectiveness of the maintenance program.

As examples, Class D applies to structures, systems, and components not included in Class A, B or C that provide the following functions:

- Provide core or containment cooling which prevents challenges to the passive core cooling system and the passive containment cooling system
- Process, extract, encase, store or reuse radioactive fluid or waste
- Verify that plant operating conditions are within technical specification limits
- Provide permanent shielding for post accident access to Class A, B or C structures, systems, and components or of offsite personnel
- Handle spent fuel, the failure of which could result in fuel damage such that limited quantities of radioactive material could be released from the fuel (for example, fuel handling machine, spent fuel handling tool, new and spent fuel racks)
- Protect Class B or C structures, systems, and components necessary to attain or maintain safe shutdown following fire

- Indicate the status of protection system bypasses that are not automatically removed as a part of the protection system operation
- Aid in determining the cause or consequences of an event for post-accident investigation
- Prevent interaction that could result in preventing Class A, B or C structures, systems, and components from performing required safety-related functions
- Limit the buildup of hydrogen in the containment atmosphere to acceptable values

3.2.2.7 Other Equipment Classes

Equipment classes E, F, G, L, P, R, and W are nonsafety-related. They apply to structures, systems, and components not covered in the above classes. They have no safety-related function to perform. They do not contain sufficient radioactive material that a release could exceed applicable limits.

Structures, systems, and components that do not normally contain radioactive fluids, gases, or solids but have the potential to become radioactively contaminated are classified as one of these nonsafety-related classes if all of the following criteria are satisfied:

- The system is only potentially radioactive and does not normally contain radioactive material, and
- The system has shown in plant operations that the operation with the system containing radioactive material meets or can meet unrestricted area release limits, and
- An evaluation of the system confirms that the system contains features and components that keep the consequences of a system failure as low as reasonably achievable, and
- The system has no other regulatory guidance requiring its inclusion in Classes A, B, C or D.

This review of the system functions, features, and components includes the following as a minimum:

- Features and components that control and limit the radioactive contamination in the system
- Features that facilitate an expeditious cleanup should the system become contaminated
- Features and components that limit and control the radiological consequences of a potential system failure
- Monitor radioactive effluent to confirm that release rates or total releases are within limits established for normal operations and transient operation
- The means by which the system prevents propagation to an event of greater consequence.

There are no special quality assurance requirements for Class E, F, G, L, P, R, and W structures, systems, and components. Unless specifically specified, 10 CFR Part 21 and Part 50, Appendix B do not apply. The systems and components are normally not designed for seismic loading. However, there may be special cases where some seismic design is required. See Subsection 3.2.1 for more details.

Procurement, design, fabrication, and testing of structures, systems, and components is performed using normal industrial quality standards at the discretion of the designer. The following provides examples of industry standards which may be used for these classes:

Class E – This class is used for nonsafety-related structures, systems, and components constructed to normal industrial quality standards which are not noted in the following classes. Class Y is a subset of Class E and is not utilized in the UFSAR.

Class F and G – These classes are used for Fire Protection Systems. They comply with National Fire Protection Association Codes which invoke ANSI B31.1 (Reference 5), AWWA (American Water Works Association), API (American Petroleum Institute), Underwriters Laboratories (UL), and other codes, depending on service. See Subsection 9.5.1 for quality assurance requirements for fire protection structures, systems, and components. Portions of fire protection systems that protect safety-related SSCs are designated as AP1000 equipment **Class F**, which meets the requirements of ASME B31.1 and requires seismic analysis. NDE of welds during fabrication and installation may use methods and acceptance criteria of ASME B31.1, 2007 Edition. Post Weld Heat Treatment of welds may use methods and acceptance criteria of ASME B31.1, 2014 Edition.

Class L – This class is used in heating, ventilation and air-conditioning systems. It complies with SMACNA - 1995 (Reference 16). Components may also be procured to AMCA, ASHRAE, and other SMACNA standards, as described in Section 9.4.

Class P – This class is used for plumbing equipment. It complies with the National Plumbing Code (Reference 17).

Class R – This class is for air cleaning units and components that may be required to contain, clean, or exclude radioactively contaminated air. It complies with ASME N509 (Reference 18) and ASME AG-1 (Reference 20) as noted in Table 3.2-3. When used with 10 CFR Part 50 Appendix B quality assurance and 10 CFR Part 21, it is equivalent to Class C. If Class R components are nonsafety-related, the quality assurance requirements invoked in ASME N509 and ASME AG-1 do not apply.

Class W – This class complies with American Water Works Association guidelines with no specific quality assurance requirements.

3.2.2.8 Instrumentation and Control Line Interface Criteria

Class C instrumentation, as defined in Subsection 3.2.2.5 have a safety-related equipment class pressure boundary including the sensing line, valves and instrument sensor. The pressure boundary is the same safety-related equipment class as the systems or components it is connected to. Sensing lines connected to the reactor coolant system pressure boundary are Class B if a suitable flow restrictor is provided.

Nonsafety-related instrumentation that monitors safety-related fluid systems is Class D, as defined in Subsection 3.2.2.6. The instrument sensing line is safety-related, seismic Category I from the connected fluid system to the instrument manifold. The instrument, manifold, and impulse line (interconnecting tubing between the manifold and instrument) are Class D, seismic Category II, as defined in Subsection 3.2.1.1.2. The Class D quality requirements include a pressure test at 1.5 times design pressure and a requirement for certified material test reports.

The parts of the sensor, outside the pressure boundary, are designated Class C (1E) if they provide a safety-related function per Subsection 3.2.2.1. They are Class D if the instrument supports Class D functions per Subsection 3.2.2.6. Otherwise the parts are Class E.

3.2.2.9 Electrical Classifications

Safety-related electrical equipment is equipment Class C, as outlined in Subsection 3.2.2.5, and is constructed to IEEE standards for Class 1E. The nonsafety-related electrical equipment and

instrumentation is constructed to standards including non-Class 1E IEEE standards and National Electrical Manufacturers Association (NEMA) standards. Safety-related electrical equipment and instrumentation is identified in Section 3.11.

3.2.3 Inspection Requirements

Safety-related structures, systems, and components built to the requirements of the ASME Code, Section III, are required by 10 CFR 50.55a to have in-service inspections. The requirements of the in-service inspection program for ASME Code, Section III structures, systems, and components are found in Section XI of the ASME Code.

The following ASME standards apply to safety-related structures, systems, and components:

- Pumps (Class A, B, C) – ASME OM Code, Subsection ISTB
- Valves (Class A, B, C) – ASME OM Code, Subsection ISTC
- Equipment supports (Class A, B, C) – ASME Code, Section XI, Subsection IWF
- Metal containments and vessels – ASME Code, Section XI, Subsection IWE
- Other Class A components such as pipes and tanks – ASME Code, Section XI, Subsection IWB
- Other Class B components such as pipes and tanks – ASME Code, Section XI, Subsection IWC
- Other Class C components such as pipes and tanks – ASME Code, Section XI, Subsection IWD.

The inspection requirements, if applicable, for Class D structures, systems, and components are established by the designer for each structure, system, and component. These inspection requirements are developed so that the reliability of the structures, systems, and components is not degraded. The inspection requirements are included in the administratively controlled inspection or maintenance plans.

3.2.4 Application of AP1000 Safety-Related Equipment and Seismic Classification System

The application of the AP1000 equipment and seismic classification system to AP1000 systems and components is shown in Table 3.2-3. Table 3.2-3 lists safety-related and seismic Category I mechanical and fluid system component and associated equipment class and seismic category as well as other related information. The table also provides information on the systems that contain Class D components. Additional information on the Class D functions of the various systems can be found in the description in the Design Certification Document (DCD) for the systems. Mechanical and fluid systems that contain no safety-related or Class D systems are included in the table and general information provided on the system. Supports for piping and components have the same classification as the component or piping supported. Supports for AP1000 equipment Class A, B, and C mechanical components and piping are constructed to ASME Code, Section III, Subsection NF requirements. The principal construction code for supports for nonsafety-related components and piping is the same as that for the supported component or piping.

Following the name of each system is the building location of the system components. Some of the systems supply all or most of the buildings. This is indicated by identifying the location as various.

Where a system includes piping or ducts that only passed through a building without including any components that building is generally not included in the list.

The following list includes the systems in Table 3.2-3. The three letters in the beginning of each line is the acronym for the system. The systems included in Table 3.2-3 are listed alphabetically by three letter acronym. Those systems marked with an asterisk * are electrical or instrumentation systems and are not included in Table 3.2-3. The components in the incore instrumentation system that have a pressure boundary function are included in the table. See Section 3.11 for identification of safety-related electrical and instrumentation equipment.

NSSS/Steam Generator Controls and Auxiliaries

BDS	Steam Generator Blowdown System
CNS	Containment System
CVS	Chemical and Volume Control System
PCS	Passive Containment Cooling System
PXS	Passive Core Cooling System
RCS	Reactor Coolant System
RNS	Normal Residual Heat Removal System
RXS	Reactor System
SGS	Steam Generator System

Nuclear Control and Monitoring

*DAS	Diverse Actuation System
IIS	Incore Instrumentation System
*OCS	Operation and Control Centers
*PMS	Protection and Safety Monitoring System
PSS	Primary Sampling System
*RMS	Radiation Monitoring System
*SJS	Seismic Monitoring System
*SMS	Special Monitoring System

Main Power Cycle and Auxiliaries

CDS	Condensate System

CFS	Turbine Island Chemical Feed System
CPS	Condensate Polishing System
DTS	Demineralized Water Treatment System
DWS	Demineralized Water Transfer and Storage System
FWS	Main and Startup Feedwater System
GSS	Gland Seal System
HDS	Heater Drain System
MSS	Main Steam System
MTS	Main Turbine System
RWS	Raw Water System
TDS	Turbine Island Vents, Drains and Relief System

Class 1E and Emergency Power Systems

*IDS	Class 1E dc and UPS System

Cooling and Circulating Water

CCS	Component Cooling Water System
CES	Condenser Tube Cleaning System
CWS	Circulating Water System
SFS	Spent Fuel Pool Cooling System
SWS	Service Water System
TCS	Turbine Building Closed Cooling Water System

Auxiliary Steam

ASS	Auxiliary Steam Supply System

Generation and Transmission

*ZAS	Main Generation System

*ZBS	Transmission Switchyard and Offsite Power System
*ZVS	Excitation and Voltage Regulation System

Radwaste

WGS	Gaseous Radwaste System
WLS	Liquid Radwaste System
WRS	Radioactive Waste Drain System
WSS	Solid Radwaste System

HVAC

VAS	Radiologically Controlled Area Ventilation System
VBS	Nuclear Island Nonradioactive Ventilation System
VCS	Containment Recirculation Cooling System
VES	Main Control Room Emergency Habitability System
VFS	Containment Air Filtration System
VHS	Health Physics and Hot Machine Shop HVAC System
VLS	Containment Hydrogen Control System
VRS	Radwaste Building HVAC System
VTS	Turbine Building Ventilation System
VUS	Containment Leak Rate Test System
VWS	Central Chilled Water System
VXS	Annex/Auxiliary Nonradioactive Ventilation System
VYS	Hot Water Heating System
VZS	Diesel Generator Building Ventilation System

Turbine-Generator Controls and Auxiliary

CMS	Condenser Air Removal System
HCS	Generator Hydrogen and CO_2 Systems

HSS Hydrogen Seal Oil System

LOS Main Turbine and Generator Lube Oil System

*TOS Main Turbine Control and Diagnostics System

Material Handling

FHS Fuel Handling and Refueling System

MHS Mechanical Handling System

Piping Services

CAS Compressed and Instrument Air Systems

DOS Standby Diesel Fuel Oil System

FPS Fire Protection System

PGS Plant Gas Systems

PWS Potable Water System

Non-Class 1E Power Systems

*ECS Main AC Power System

*EDS Non-Class 1E dc and UPS System

ZOS Onsite Standby Power System

*ZRS Offsite Retail Power System

Miscellaneous Electrical Systems

*EFS Communication Systems

*EGS Grounding and Lightning Protection System

*EHS Special Process Heat Tracing System

*ELS Plant Lighting System

*EQS Cathodic Protection System

Non-Nuclear Controls and Monitoring

*DDS	Data Display and Processing System
*MES	Meteorological and Environmental Monitoring System
*PLS	Plant Control System
*SES	Plant Security System
SSS	Secondary Sampling System
*TVS	Closed Circuit TV System

Non-Radioactive Drains

DRS	Storm Drain System
RDS	Gravity and Roof Drain Collection System
SDS	Sanitary Drainage System
WWS	Waste Water System

Those systems marked with an asterisk (*) are electrical or instrumentation systems and are not included in Table 3.2-3.

3.2.5 Combined License Information

This section contained no requirement for additional information.

3.2.6 References

1. ANSI N18.2a - 1975, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

2. ANS/ANSI 51.1 - 1983, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

3. IEEE 323-74, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.”

4. IEEE 344-1987, “IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”

5. ASME B31.1-1989 Edition, “Power Piping,” including 1989 Addenda.

6. API 610-81, “Centrifugal Pumps for General Refinery Services.”

7. Not used.

8. ANSI B 16.34 - 1981, “Valves - Flanged and Buttwelding End.”

9. API-650-80, “Welded Steel Tanks for Oil Storage,” Revision 1, February 1984.

10. AWWA D100-84, “Welded Steel Tanks for Water Storage.”

11. ANSI B96.1-81, “Welded Aluminum-Alloy Storage Tanks.”

12. API-620-82, “Recommended Rules for Design and Construction of Large, Welded, Low-Pressure Storage Tanks,” Revision 1, April 1985.

13. NEMA MG-1-98, “Motors and Generators,” Revision 1, January 1998, National Electric Manufacturers Association.

14. IEEE C37, IEEE standards on circuit breakers, switch gear, relays, substations, fuses, etc.

15. “Uniform Building Code (1997),” International Conference of Building Officials.

16. SMACNA - 1995, HVAC Duct Construction Standards - Metal and Flexible, Sheet Metal and Air-Conditioning Contractors National Association.

17. The BOCA Basic/National Plumbing Code 1984: Model Plumbing Regulations for the Protection of Public Health, Safety and Welfare: Sixth Edition, Building Officials and Code Administrators International.

18. ASME N509-1989, “Nuclear Power Plant Air Cleaning Units and Components.”

19. International Building Code, 2006.

20. ASME AG-1-1997, “Code on Nuclear Air and Gas Treatment.”

Table 3.2-1
Comparison of Safety Classification Requirements

AP1000 Code Letter (1)	ANS Equipment Safety Class (2)	RG 1.29 Seismic Design Reqmnts (3)	ASME Code, Sec. III Class (4)	IEEE Requirements	RG 1.26 NRC Quality Group (5)	10 CFR 50 Appendix B (6)	Inspection & Testing Requirements	Required Test & Maint.
A	SC-1	I	1	NA	GROUP A	YES	YES(7)	(8)
B	SC-2	I	2	NA	GROUP B	YES	YES(7)	(8)
C	SC-3	I(14)	3	1E	GROUP C	YES	YES(7)	(8)
D	NNS(2)	NA(9)(14)	NA(10)	(10)	GROUP D	NO(10)	YES(11)	(11)
OTHER	NNS(2)	NA(13)	NA	NA	NA	NA(12)	NA	NA

NA - Not Applicable OTHER includes Classes E, F, L, P, R, and W.

Notes:

1. A single letter equipment classification identifies the safety class, quality group, and other classifications for AP1000. See the Subsection 3.2.2 for definition.
2. AP1000 safety classification is an adaptation of that defined in ANSI 51.1. The NNS defined in the ANSI 51.1 standard is divided into several AP1000 equipment classifications namely, Classes D E, F, L, P, R, and W.
3. See Subsection 3.2.1 for definition of seismic categories.
4. ASME Boiler and Pressure Vessel Code, Section III defines various classes of structures, systems, and components for nuclear power plants. It defines criteria and requirements based on the classification. It is not applicable for nonsafety-related components.
5. The quality group classification corresponds to those provided in Regulatory Guide 1.26.
6. “Yes” means quality assurance program is required according to 10 CFR 50 Appendix B.
   “No” means quality assurance program is not required according to 10 CFR 50 Appendix B.
7. Class A, B, and C, structures, systems, and components built to ASME Code, Section III are inspected to ASME Code, Section XI requirements. See the text for additional specification of requirements.
8. Class A, B, and C structures, systems, and components that are required to function to mitigate design base accidents have some testing requirements included in the plant technical specifications. In addition to the requirements in the technical specifications, testing and maintenance requirements are included in an administratively controlled reliability assurance plan.
9. See Subsection 3.2.1 for cases when seismic Category II requirements are applicable for Class D structures, systems, and components.
10. See the text for a discussion of the industry standards used in the construction of Class D structures, systems and components.
11. Class D structures, systems, and components have selected reliability assurance programs and procedures to provide availability when needed. These programs are administratively controlled programs and are not included in the technical specifications.
12. Normal industrial quality standards are followed in procuring, designing, fabricating, and testing these nonsafety-related structures, systems, and components, at the discretion of the designer. When documentation of compliance with normal industrial quality standards is unavailable, the SSC's adequacy may be affirmed with an evaluation by the designer of the confirmed attributes of the SSC design or construction.
13. Some Class E, F, G, L, P, R, and W structures, systems, and components may be classified as seismic Category II. See Subsection 3.7.3.
14. See Subsection 3.5.2 for seismic Category II tornado missile barriers that provide tornado missile protection for the openings and penetrations in auxiliary building walls.

Table 3.2-2
Seismic Classification of Building Structures

Structure	Category[1]
Nuclear Island Basemat Containment Interior Shield Building Auxiliary Building Containment Air Baffle	C-I
Containment Vessel	C-I
Plant Vent and Stair Structure	C-II
Turbine Building – First bay adjacent to Nuclear Island outlined by Columns I.1 to R, 11.05 to 11.2, and 11.02 to 11.2	C-II
Turbine Building – All portions of Turbine Building except first bay adjacent to Nuclear Island as outlined by Columns H.05 to R and 12.1 to 20	NS[2]
Turbine Building	NS[2]
Annex Building Area Outlined by Columns A - D and 8 - 13 Area Outlined by Columns A - G and 13 - 16	NS[2]
Annex Building Area Outlined by Columns E - I.1 and 2 - 13	C-II
Radwaste Building	NS[2]
Diesel-Generator Building	NS[3]
Circulating Water Pumphouse and Towers	NS
Safety-Related Backfill	C-I

C-I – Seismic Category I
C-II – Seismic Category II
NS – Non-seismic

Note:

1. Within the broad definition of seismic Category I and II structures, these buildings contain members and structural subsystems the failure of which would not impair the capability for safe shutdown. Examples of such systems would be elevators, stairwells not required for access in the event of a postulated earthquake, and nonstructural partitions in nonsafety-related areas. These substructures are classified as non-seismic.
2. The NS designation for the turbine building, the radwaste building, and a portion of the annex building indicates that the buildings are not seismic Category I or seismic Category II. The seismic requirements for these buildings are outlined in Subsection 3.7.2.8.
3. The NS designation for the diesel-generator building indicates that the building is not seismic Category I or seismic Category II. The seismic requirements for buildings containing Class D equipment, including the diesel generator building, are outlined in Subsection 3.2.2.6.

Table 3.2-3 (Sheet 1 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Auxiliary Steam Supply System (ASS)				Location: Turbine Building	
System components are Class E					
Steam Generator Blowdown System (BDS)				Location: Turbine Building	
BDS-PL-V009	Discharge to WLS Vent	D	NS	ANSI B16.34	
BDS-PL-V037	Discharge to WLS Valve	D	NS	ANSI B16.34	
BDS-PL-V046	WWS Contaminated Flow Connection	D	NS	ANSI B16.34	
Balance of system components are Class E					
Compressed and Instrument Air System (CAS)				Location: Various	
CAS-PL-V014	Instrument Air Supply Outside Containment Isolation	B	I	ASME III-2	
CAS-PL-V015	Instrument Air Supply Inside Containment Isolation	B	I	ASME III-2	
CAS-PL-V027	Containment Penetration Test Connection Isolation	B	I	ASME III-2	
CAS-PL-V204	Service Air Supply Outside Containment Isolation	B	I	ASME III-2	
CAS-PL-V205	Service Air Supply Inside Containment Isolation	B	I	ASME III-2	
CAS-PL-V219	Containment Penetration Test Connection Isolation	B	I	ASME III-2	
CAS-PY-C02	Containment Instrument Air Inlet Penetration	B	I	ASME III, MC	
CAS-PY-C03	Containment Service Air Inlet Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Component Cooling Water System (CCS)			Location: Auxiliary Building and Turbine Building		
n/a	Heat Exchangers, CCS and SWS Side	D	NS	ASME VIII	
n/a	Pumps	D	NS	Hydraulic Institute Stds.	
n/a	Tanks	D	NS	ASME VIII	
n/a	Valves Providing CCS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
CCS-PL-V200	CCS Containment Isolation Valve - Inlet Line ORC	B	I	ASME III-2	
CCS-PL-V201	CCS Containment Isolation Valve - Inlet Line IRC	B	I	ASME III-2	
CCS-PL-V207	CCS Containment Isolation Valve - Outlet Line IRC	B	I	ASME III-2	
CCS-PL-V208	CCS Containment Isolation Valve - Outlet Line ORC	B	I	ASME III-2	
CCS-PL-V209	Containment Isolation Valve Test Connection - Outlet Line	B	I	ASME III-2	
CCS-PL-V214	CCS Supply Containment Isolation - IRC	C	I	ASME III-3	

Table 3.2-3 (Sheet 2 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Component Cooling Water System (Continued)					
CCS-PL-V215	CCS Supply Containment Isolation Valve Test Connection - IRC	C	I	ASME III-3	
CCS-PL-V216	Containment Leak Test Outlet Line - IRC	C	I	ASME III-3	
CCS-PL-V217	Containment Isolation Valve V207 Body Test Connection Valve	C	I	ASME III-3	
CCS-PL-V270	CCS IRC Relief Valve	C	I	ASME III-3	
CCS-PL-V271	CCS IRC Relief Valve	C	I	ASME III-3	
CCS-PL-V220	CCS Containment Isolation Relief Valve	B	I	ASME III-2	
CCS-PL-V257	Containment Isolation Valve Test Connection - Inlet Line	B	I	ASME III-2	
CCS-PY-C01	Containment Supply Header Penetration	B	I	ASME III, MC	
CCS-PY-C02	Containment Return Header Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Condensate System (CDS)				Location: Turbine Building	
System components are Class E					
Condenser Tube Cleaning System (CES)				Location: Turbine Building	
System components are Class E					
Turbine Island Chemical Feed System (CFS)				Location: Turbine Building and SWS Chemical Treatment Building/Area	
System components are Class E					
Condenser Air Removal System (CMS)				Location: Turbine Building	
n/a	Condenser Vacuum Breakers	E	NS	ANSI B16.34	
Balance of system components are Class D					
Containment System (CNS)				Location: Containment	
CNS-MV-01	Containment Vessel	B	I	ASME III, MC	
CNS-MY-Y01	Equipment Hatch	B	I	ASME III, MC	
CNS-MY-Y02	Maintenance Hatch	B	I	ASME III, MC	
CNS-MY-Y03	Upper Personnel Hatch - 135′-3″	B	I	ASME III, MC	
CNS-MY-Y04	Lower Personnel Hatch - 107′-2″	B	I	ASME III, MC	
n/a	Spare Containment Penetrations	B	I	ASME III, MC	
Condensate Polishing System (CPS)				Location: Turbine Building	
System components are Class E					
Chemical and Volume Control System (CVS)				Location: Containment, Auxiliary Building, and Annex Building	
n/a	Heat Exchangers, CVS and CCS Side	D	NS	ASME VIII/ TEMA	

Table 3.2-3 (Sheet 3 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Chemical and Volume Control System (Continued)					
n/a	Pumps	D	NS	Hydraulic Institute Stds.	
n/a	Tanks (Except CVS-MT-03 and CVS-MT-05)	D	NS	API 650	
CVS-MT-03	CVS Chemical Mixing Tank	E	NS	ASME VIII	
CVS-MT-05	CVS Air Intrusion Prevention Tank	D	NS	ASME VIII	
n/a	Demineralizers	D	NS	ASME VIII	
n/a	Filters	D	NS	ASME VIII	
n/a	Valves Providing CVS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
CVS-PL-V001	RCS Purification Stop	A	I	ASME III-1	
CVS-PL-V002	RCS Purification Stop	A	I	ASME III-1	
CVS-PL-V003	RCS Purification Stop	C	I	ASME III-3	
CVS-PL-V040	Resin Flush IRC Isolation	B	I	ASME III-2	
CVS-PL-V041	Resin Flush ORC Isolation	B	I	ASME III-2	
CVS-PL-V042	Flush Line Containment Isolation Relief	B	I	ASME III-2	
CVS-PL-V045	Letdown Containment Isolation IRC	B	I	ASME III-2	
CVS-PL-V046	Letdown Pressure Instrument Root	B	I	ASME III-2	
CVS-PL-V047	Letdown Containment Isolation ORC	B	I	ASME III-2	
CVS-PL-V058	Letdown Line Containment Isolation Thermal Relief	B	I	ASME III-2	
CVS-PL-V065	Zinc Addition – IRC Shutoff	C	I	ASME III-3	
CVS-PL-V067	Makeup Return Line Bypass Check Valve	A	I	ASME III-1	
CVS-PL-V080	RCS Purification Return Line Check Valve	C	I	ASME III-3	
CVS-PL-V081	RCS Purification Return Line Stop Valve	A	I	ASME III-1	
CVS-PL-V082	RCS Purification Return Line Check Valve	A	I	ASME III-1	
CVS-PL-V084	Auxiliary Pressurizer Spray Line Isolation	A	I	ASME III-1	
CVS-PL-V085	Auxiliary Pressurizer Spray Line	A	I	ASME III-1	
CVS-PL-V090	Makeup Line Containment Isolation	B	I	ASME III-2	
CVS-PL-V091	Makeup Line Containment Isolation	B	I	ASME III-2	
CVS-PL-V092	Zinc Injection Containment Isolation ORC	B	I	ASME III-2	

Table 3.2-3 (Sheet 4 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Chemical and Volume Control System (Continued)					
CVS-PL-V094	Zinc Injection Containment Isolation IRC	B	I	ASME III-2	
CVS-PL-V095	Zinc Add Containment Isolation Test Connection	C	I	ASME III-3	
CVS-PL-V096	Zinc Injection Containment Isolation Test Connection	B	I	ASME III-2	
CVS-PL-V098	Zinc Addition Line Containment Isolation Thermal Relief Valve	B	I	ASME III-2	
CVS-PL-V100	Makeup Line Containment Isolation Relief	B	I	ASME III-2	
CVS-PL-V136A	Demineralized Water System Isolation	C	I	ASME III-3	
CVS-PL-V136B	Demineralized Water System Isolation	C	I	ASME III-3	
CVS-PL-V215	Hydrogen Injection – IRC Shutoff	C	I	ASME III-3	
CVS-PL-V216	Hydrogen Injection Containment Isolation Test Connection	C	I	ASME III-3	
CVS-PL-V217	Hydrogen Injection Containment Isolation Check IRC	B	I	ASME III-2	
CVS-PL-V218	Hydrogen Injection Containment Isolation Test Connection	B	I	ASME III-2	
CVS-PL-V219	Hydrogen Injection Containment Isolation ORC	B	I	ASME III-2	
CVS-PY-C01	Demineralizer Resin Flush Line Containment Penetration	B	I	ASME III, MC	
CVS-PY-C02	Letdown Line Containment Penetration	B	I	ASME III, MC	
CVS-PY-C03	Makeup Line Containment Penetration	B	I	ASME III, MC	
CVS-PY-C04	Zinc Add Line Containment Penetration	B	I	ASME III, MC	
CVS-PY-C05	Hydrogen Add Line Containment Penetration	B	I	ASME III, MC	
Balance of system components are Class D or E					
Circulating Water System (CWS)			Location: Turbine Building and pump intake structure		
System components are Class E					

Table 3.2-3 (Sheet 5 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Standby Diesel Fuel Oil System (DOS)				Location: Diesel Generator Building and yard	
n/a	Fuel Oil Transfer Package	D	NS	Manufacturer Std.	
n/a	Fuel Oil Storage Tanks	D	NS	API 650	
n/a	Fuel Oil Day Tanks	D	NS	ASME VIII	
n/a	Valves Providing DOS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
n/a	Ancillary Diesel Generator Fuel Tank	D	II	Non-Stamped ASME VIII	Located in Annex Building
Balance of system components are Class E					
Storm Drain System (DRS)				Location: Various	
System components are Class E					
Demineralized Water Treatment System (DTS)				Location: Turbine Building	
System components are Class E					
Demineralized Water Transfer and Storage System (DWS)				Location: Various	
n/a	Condensate Storage Tanks	D	NS	API 650	
n/a	Valves Providing DWS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
DWS-PL-V241	DWS Containment Penetration Thermal Relief Valve	C	I	ASME III-3	
DWS-PL-V244	Demineralized Water Supply Containment Isolation - Outside	B	I	ASME III-2	
DWS-PL-V245	Demineralized Water Supply Containment Isolation - Inside	B	I	ASME III-2	
DWS-PL-V248	Containment Penetration Test Connection Isolation	B	I	ASME III-2	
DWS-PY-C01	Containment Demineralized Water Supply Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Electrical Distribution System (ECS)				Location: Annex Building	
n/a	Ancillary Diesel Generator Engines	D	NS	Manufacturer Standard	Anchorage is SCII
n/a	Ancillary Diesel Generator Radiators	D	NS	Manufacturer Std.	
n/a	Ancillary Diesel Generator Silencers	D	NS	Manufacturer Std.	
n/a	Valve providing fuel to ECS Ancillary Diesel Generators	D	NS	ANSI B16.34	
Balance of system components are Class E					

Table 3.2-3 (Sheet 6 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Fuel Handling and Refueling System (FHS)			Location: Containment and Auxiliary Building		
FHS-FH-01	Refueling Machine	D	II	AISC	
FHS-FH-02	Fuel Handling Machine	D	II	AISC	
FHS-FH-04	New Fuel Elevator	D	II	AISC	
FHS-FH-05	Fuel Transfer System	D	II	AISC	
FHS-FH-52	Spent Fuel Assembly Handling Tool	D	II	AISC	
FHS-FS-01	New Fuel Storage Rack	D	I	Manufacturer Std.	
FHS-FS-06	In-containment Fuel Storage Rack	D	I	Manufacturer Std.	
FHS-FS-21	Spent Fuel Storage Rack A1	D	I	Manufacturer Std.	
FHS-FS-22	Spent Fuel Storage Rack A2	D	I	Manufacturer Std.	
FHS-FS-23	Spent Fuel Storage Rack A3	D	I	Manufacturer Std.	
FHS-FS-24	Spent Fuel Storage Rack B1	D	I	Manufacturer Std.	
FHS-FS-25	Spent Fuel Storage Rack B2	D	I	Manufacturer Std.	
FHS-FS-26	Spent Fuel Storage Rack B3	D	I	Manufacturer Std.	
FHS-FS-27	Spent Fuel Storage Rack B4	D	I	Manufacturer Std.	
FHS-FS-28	Spent Fuel Storage Rack C1	D	I	Manufacturer Std.	
FHS-FT-01	Fuel Transfer Tube	B	I	ASME III Class MC	Jurisdictional Boundary CV Only, Remaining Portion Optional
FHS-MT-01	Spent Fuel Pool	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only
FHS-MT-02	Fuel Transfer Canal	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only
FHS-MT-03	Refueling Cavity	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only
FHS-MT-05	Spent Fuel Cask Loading Pit	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only
FHS-MT-06	Spent Fuel Cask Washdown Pit	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only
FHS-MY-Y01	Spent Fuel Transfer Gate	C	I	ANSI/AISC N690 for structural steel	Manufacturer's Std for non-structural components
FHS-MY-Y02	Spent Fuel Cask Loading Pit Gate	C	I	ANSI/AISC N690 for structural steel	Manufacturer's Std for non-structural components
FHS-MY-Y03	Permanent Cavity Seal Ring	C	I	ANSI/AISC N690	
FHS-PL-V001	Fuel transfer tube Isolation Valve	C	I	ASME-III-3	
FHS-PY-B01	Fuel Transfer Tube Hatch/Blind Flange	B	I	ASME III Class MC	
Balance of system components are Class E					

Table 3.2-3 (Sheet 7 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Fire Protection System (FPS)				Location: Various	
FPS-PL-V050	Fire Water Containment Supply Isolation	B	I	ASME III-2	
FPS-PL-V051	Fire Water Containment Test Connection Isolation	B	I	ASME III-2	
FPS-PL-V052	Fire Water Containment Supply Isolation - Inside	B	I	ASME III-2	
FPS-PY-C01	Fire Protection Containment Penetration	B	I	ASME III, MC	
FPS-PL-V441	Auxiliary Connection to CCS Isolation	D	NS	ASME B31.1	
FPS-PL-V702	FPS Containment Penetration Thermal Relief Valve	C	I	ASME III-3	
Containment standpipe and fire hose connections	Includes all FPS components Inside Reactor Containment with the exception of those used for containment isolation, cable tray suppression, and containment spray	F	NS	ASME B31.1	Seismic Analysis Consistent with ASME Section III Class 3 Systems
Various	Auxiliary Building (Non-Radiologically Controlled) Standpipe and Non-1E Equipment Penetration Room Preaction Sprinkler System piping	F	NS	ASME B31.1	Seismic Analysis Consistent with ASME Section III Class 3 Systems
Balance of system components are Class E, F & G					
Main and Startup Feedwater System (FWS)				Location: Turbine Building	
n/a	Startup Feedwater Pumps	D	NS	Hydraulic Institute Standards	
n/a	Valves Providing SFW AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
Balance of system components are Class E					
Gland Seal System (GSS)				Location: Turbine Building	
System components are Class D					
Generator Hydrogen and CO_2 Systems (HCS)				Location: Turbine Building	
System components are Class E					
Heater Drain System (HDS)				Location: Turbine Building	
System components are Class E					
Hydrogen Seal Oil System (HSS)				Location: Turbine Building	
System components are Class E					
Incore Instrumentation System (IIS)				Location: Containment	
n/a	In-core Instrument Thimble Assembly Tubes	D	II	Manufacturer Std.	
n/a	Thimble assemblies	B	I	Manufacturer Std.	

Table 3.2-3 (Sheet 8 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Main Turbine and Generator Lube Oil System (LOS)				Location: Turbine Building	
System components are Class E					
Mechanical Handling System (MHS)				Location: Various	
MHS-MH-01	Containment Polar Crane	D	I	NUREG-0554 supplemented by ASME NOG-1	
MHS-MH-02	Cask Handling Crane	D	I	NUREG-0554 supplemented by ASME NOG-1	
MHS-MH-05	Equipment Hatch Hoist	C	I	NUREG-0554 supplemented by ASME NOG-1	
MHS-MH-06	Maintenance Hatch Hoist	C	I	NUREG-0554 supplemented by ASME NOG-1	
Balance of system components are Class E					
Main Steam System (MSS)				Location: Turbine Building	
System components are Class E					
Main Turbine System (MTS)				Location: Turbine Building	
System components are Class E					
Passive Containment Cooling System (PCS)			Location: Containment Shield Building and Auxiliary Building		
PCS-JE-FE001	PCCWST Flow Through L001A Element	C	I	ASME III-3	
PCS-JE-FE002	PCCWST Flow Through L001B Element	C	I	ASME III-3	
PCS-JE-FE003	PCCWST Flow Through L001C Element	C	I	ASME III-3	
PCS-JE-FE004	PCCWST Flow Through L001D Element	C	I	ASME III-3	
PCS-MT-01	Passive Containment Cooling Water Storage Tank	C	I	ACI 349	See subsection 6.2.2.2.3 for additional design requirements
PCS-MT-02	PCS Chemical Addition Tank	D	II	ASME VIII	
PCS-MT-03	Water Distribution Bucket	C	I	Manufacturer Std.	See subsection 6.2.2.2.3 for additional design requirements
PCS-MT-04	Water Collection Troughs	C	I	Manufacturer Std.	See subsection 6.2.2.2.3 for additional design requirements
PCS-MT-05	Passive Containment Cooling Ancillary Water Storage Tank	D	II	API 650	
PCS-MT-06	PCCWST Leak Chase Collection Pot	D	II	ASME VIII	
PCS-MY-Y01	PCCWST Screen 1	C	I	Manufacturer Std.	
PCS-MY-Y02	PCCWST Screen 2	C	I	Manufacturer Std.	
PCS-MY-Y03	PCCWST Screen 3	C	I	Manufacturer Std.	

Table 3.2-3 (Sheet 9 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-MY-Y04	PCCWST Screen 4	C	I	Manufacturer Std.	
PCS-MY-Y05	PCCWST Screen 5	C	I	Manufacturer Std.	
PCS-PL-V001A	PCCWST Isolation	C	I	ASME III-3	
PCS-PL-V001B	PCCWST Isolation	C	I	ASME III-3	
PCS-PL-V001C	PCCWST Isolation	C	I	ASME III-3	
PCS-MP-01A	PCS Recirculation Pump	D	NS	Hydraulic Institute Standards	Equipment Anchorage is Seismic Category II
PCS-MP-01B	PCS Recirculation Pump	D	NS	Hydraulic Institute Standards	Equipment Anchorage is Seismic Category II
PCS-PL-V002A	PCCWST Series Isolation	C	I	ASME III-3	
PCS-PL-V002B	PCCWST Series Isolation	C	I	ASME III-3	
PCS-PL-V002C	PCCWST Series Isolation	C	I	ASME III-3	
PCS-PL-V004	Recirculation Bypass Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V005	PCCWST Supply to FPS Isolation	C	I	ASME III-3	
PCS-PL-V009	Spent Fuel Pool Emergency Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V010A	Flow Transmitter FT001 Root Valve	C	I	ASME III-3	
PCS-PL-V010B	Flow Transmitter FT001 Root Valve	C	I	ASME III-3	
PCS-PL-V011A	Flow Transmitter FT002 Root Valve	C	I	ASME III-3	
PCS-PL-V011B	Flow Transmitter FT002 Root Valve	C	I	ASME III-3	
PCS-PL-V012A	Flow Transmitter FT003 Root Valve	C	I	ASME III-3	
PCS-PL-V012B	Flow Transmitter FT003 Root Valve	C	I	ASME III-3	
PCS-PL-V013A	Flow Transmitter FT004 Root Valve	C	I	ASME III-3	
PCS-PL-V013B	Flow Transmitter FT004 Root Valve	C	I	ASME III-3	
PCS-PL-V014	Chemical Addition Tank Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V015	Water Bucket Makeup Line Drain Valve	C	I	ASME III-3	
PCS-PL-V016	PCCWST Drain Isolation Valve	C	I	ASME III-3	
PCS-PL-V017	Chemical Addition Tank Vent Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V018	Recirculation Pump Throttle Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V019	Chemical Addition Tank Fill Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II

Table 3.2-3 (Sheet 10 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-PL-V020	Water Bucket Makeup Line Isolation Valve	C	I	ASME III-3	
PCS-PL-V021	PCCWST TO Recirculation Pump Suction Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V022	Chemical Addition Tank Drain Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V023	PCS Recirculation Return Isolation	C	I	ASME III-3	
PCS-PL-V025	Pressure Transmitter PT 031 Root Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V026	Makeup to Distribution Bucket Isolation Valve	C	I	ASME III-3	
PCS-PL-V029	PCCWST Isolation Valve Leakage Detection Drain	C	I	ASME III-3	
PCS-PL-V030	PCCWST Isolation Valve Leakage Detection Crossconnect Valve	C	I	ASME III-3	
PCS-PL-V031A	Level Transmitter LT 016 & 010 Root Isolation Valve	C	I	ASME III-3	
PCS-PL-V031B	Level Transmitter LT 015 & 011 Root Isolation Valve	C	I	ASME III-3	
PCS-PL-V033	Recirculation Pump Suction from Long Term Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V035A	Recirculation Pump Suction Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V035B	Recirculation Pump Suction Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V036A/B	Recirculation Pump Discharge Check Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V037	PCCAWST Discharge Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V038	PCCAWST Drain Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V039	PCCWST Long-Term Makeup Check Valve	C	I	ASME III-3	
PCS-PL-V040	Recirculation Pump Suction from PCCAWST Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V041	PCCAWST Recirculation Return Line Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V042	PCCWST Long-Term Makeup Isolation Drain Valve	C	I	ASME III-3	
PCS-PL-V043	PCCAWST Recirculation Return Line Drain Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II

Table 3.2-3 (Sheet 11 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-PL-V044	PCCWST Long-Term Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V045	Emergency Makeup to the Spent Fuel Pool Isolation Valve	C	I	ASME III-3	
PCS-PL-V046	PCCWST Recirculation Return Isolation Valve	C	I	ASME III-3	
PCS-PL-V047A/B	PCS Recirculation Pump Discharge Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V048	Recirculation Pump Fire Suction Isolation Valve	D	NS	ANSI B16.34	Seismically Analyzed for Operability
PCS-PL-V049	Emergency Makeup to the Spent Fuel Pool Drain Isolation Valve	C	I	ASME III-3	
PCS-PL-V050	Spent Fuel Pool Long Term Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V051	Spent Fuel Pool Emergency Makeup Lower Isolation	C	I	ASME III-3	
PCS-PL-V052	Spent Fuel Pool Emergency Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V053	PCS Recirculation Heater Pressure Relief Valve	D	NS	ASME VIII	
PCS-PL-V060A	Shutoff Valve for Leakage Sensor	C	I	ASME III-3	
PCS-PL-V060B	Shutoff Valve for Leakage Sensor	C	I	ASME III-3	
PCS-PL-V100	Temporary Containment Washdown Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V301	PCCWST to Recirculation Pump Suction Drain Isolation Valve	D	NS	ANSI B16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V303	Recirculation Header Discharge to SFS Pool Vent Isolation Valve	C	I	ASME III-3	
PCS-PL-V304	Recirculation Header Discharge to SFS Pool Drain Isolation Valve	C	I	ASME III-3	
PCS-PL-V305	PCCWST Recirculation Return Drain Isolation Valve	C	I	ASME III-3	
PCS-PY-B01	Spent Fuel Pool Emergency Makeup Isolation	C	I	ASME III-3	
PCS-PY-C01	Containment Pressure Instrument Line Penetration	B	I	ASME, MC	
PCS-PY-C02	Containment Pressure Instrument Line Penetration	B	I	ASME, MC	
PCS-PY-C03	Containment Pressure Instrument Line Penetration	B	I	ASME, MC	

Table 3.2-3 (Sheet 12 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-PY-C04	Containment Pressure Instrument Line Penetration	B	I	ASME, MC	
Balance of system components are Class E or F					
Plant Gas Systems (PGS)				Location: Various	
System components are Class E					
Primary Sampling System (PSS)			Location: Containment and Auxiliary Building		
n/a	Grab Sample Unit	D	NS	Manufacturer Std.	
n/a	Sample Cooler, PSS and CCS Side	D	NS	ASME VIII/ TEMA	
n/a	Valves Providing PSS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
PSS-PL-V001A	Hot Leg Sample Isolation	B	I	ASME III-2	
PSS-PL-V001B	Hot Leg Sample Isolation	B	I	ASME III-2	
PSS-PL-V003	Pressurizer Sample Isolation	B	I	ASME III-2	
PSS-PL-V004A	PXS Accumulator Sample Isolation	C	I	ASME III-3	
PSS-PL-V004B	PXS Accumulator Sample Isolation	C	I	ASME III-3	
PSS-PL-V005A	PXS CMT A Sample Isolation	B	I	ASME III-2	
PSS-PL-V005B	PXS CMT B Sample Isolation	B	I	ASME III-2	
PSS-PL-V005C	PXS CMT A Sample Isolation	B	I	ASME III-2	
PSS-PL-V005D	PXS CMT B Sample Isolation	B	I	ASME III-2	
PSS-PL-V008	Containment Air Sample Containment Isolation IRC	B	I	ASME III-2	
PSS-PL-V010A	Liquid Sample Line Containment Isolation IRC	B	I	ASME III-2	
PSS-PL-V010B	Liquid Sample Line Containment Isolation IRC	B	I	ASME III-2	
PSS-PL-V011A	Liquid Sample Line Containment Isolation ORC	B	I	ASME III-2	
PSS-PL-V011B	Liquid Sample Line Containment Isolation ORC	B	I	ASME III-2	
PSS-PL-V012A	Liquid Sample Isolation Valve	C	I	ASME III-3	
PSS-PL-V012B	Liquid Sample Check Valve	C	I	ASME III-3	
PSS-PL-V013	RCS Pressurizer Sample Isolation Valve	B	I	ASME III-2	
PSS-PL-V014A	RCS Hot Leg 1 Sample Isolation Valve	B	I	ASME III-2	
PSS-PL-V014B	RCS Hot Leg 2 Sample Isolation Valve	B	I	ASME III-2	
PSS-PL-V015A	PXS Accumulator Sample Isolation Valve	C	I	ASME III-3	

Table 3.2-3 (Sheet 13 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Primary Sampling System (Continued)					
PSS-PL-V015B	PXS Accumulator Sample Isolation Valve	C	I	ASME III-3	
PSS-PL-V016A	PXS CMT A Sample Isolation Valve	B	I	ASME III-2	
PSS-PL-V016B	PXS CMT B Sample Isolation Valve	B	I	ASME III-2	
PSS-PL-V016C	PXS CMT A Sample Isolation Valve	B	I	ASME III-2	
PSS-PL-V016D	PXS CMT B Sample Isolation Valve	B	I	ASME III-2	
PSS-PL-V023	Sample Return Line Containment Isolation ORC	B	I	ASME III-2	
PSS-PL-V024	Sample Return Containment Isolation IRC	B	I	ASME III-2	
PSS-PL-V046	Air Sample Line Containment Isolation ORC	B	I	ASME III-2	
PSS-PL-V076A	Containment Testing Boundary Isolation Valve	C	I	ASME III-3	
PSS-PL-V076B	Containment Testing Boundary Isolation Valve	C	I	ASME III-3	
PSS-PL-V082	Containment Isolation Test Connection Isolation Valve	C	I	ASME III-3	
PSS-PL-V083	Containment Isolation Test Connection Isolation Valve	C	I	ASME III-3	
PSS-PL-V085	Containment Isolation Test Connection Isolation Valve	B	I	ASME III-2	
PSS-PL-V086	Containment Isolation Test Connection Isolation Valve	C	I	ASME III-3	
PSS-PL-V902A	PXS CMT A Sample Isolation Valve (Unit 3 Only)	B	I	ASMEIII-2	
PSS-PL-V902B	PXS CMT B Sample Isolation Valve (Unit 3 Only)	B	I	ASMEIII-2	
PSS-PL-V903	PXS CMT B Sample Isolation Valve (Unit 3 Only)	B	I	ASMEIII-2	
PSS-PY-C01	Common Primary Sample Line Penetration	B	I	ASME III, MC	
PSS-PY-C02	Containment Atmosphere Sample Line Penetration	B	I	ASME III, MC	
PSS-PY-C03	Containment Atmosphere Sample Line Penetration	B	I	ASME III, MC	
PSS-PY-C04	RCS Hot Leg Sample Line Penetration	B	I	ASME III, MC	
PSS-PY-Y01	Delay Coil 1 for RCS Hot Leg 1	C	I	ASME III-3	
PSS-PY-Y02	Delay Coil 2 for RCS Hot Leg 2	C	I	ASME III-3	
PSS-MY-Y05	Delay Coil Assembly	C	I	ASME III-3	

Table 3.2-3 (Sheet 14 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Primary Sampling System (Continued)					
Balance of system components are Class E					
Potable Water System (PWS)				Location: Various	
PWS-PL-V418	PWS MCR Isolation Valve	C	I	ASME III-3	
PWS-PL-V420	PWS MCR Isolation Valve	C	I	ASME III-3	
PWS-PL-V498	PWS MCR Vacuum Relief	C	I	ASME III-3	
Balance of system components are Class E, P, and W					
Passive Core Cooling System (PXS)				Location: Containment	
PXS-ME-01	Passive Residual Heat Removal Heat Exchanger	A	I	ASME III-1	
PXS-MT-01A	Accumulator Tank A	C	I	ASME III-3	
PXS-MT-01B	Accumulator Tank B	C	I	ASME III-3	
PXS-MT-02A	Core Makeup Tank A	A	I	ASME III-1	
PXS-MT-02B	Core Makeup Tank B	A	I	ASME III-1	
PXS-MT-03	In-Containment Refueling Water Storage Tank	C	I	ACI 349/ANSI/AISC N690	ACI 349 is used for Evaluation of Structural Boundary
PXS-MT-04	IRWST Gutter	C	I	Manufacturer Std.	
PXS-MW-01A	Reactor Coolant Depressurization Sparger A	C	I	ASME III-3	
PXS-MW-01B	Reactor Coolant Depressurization Sparger B	C	I	ASME III-3	
PXS-MY-Y01A	IRWST Screen A	C	I	Manufacturer Std.	Structural frame and attachment use ASME III, Subsection NF criteria. Screen modules use manufacturer std.
PXS-MY-Y01B	IRWST Screen B	C	I	Manufacturer Std.	Structural frame and attachment use ASME III, Subsection NF criteria. Screen modules use manufacturer std.
PXS-MY-Y01C	IRWST Screen C	C	I	Manufacturer Std.	Structural frame and attachment use ASME III, Subsection NF criteria. Screen modules use manufacturer std.
PXS-MY-Y02A	Containment Recirculation Screen A	C	I	Manufacturer Std.	Structural frame and attachment use ASME III, Subsection NF criteria. Screen modules use manufacturer std.

Table 3.2-3 (Sheet 15 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-MY-Y02B	Containment Recirculation Screen B	C	I	Manufacturer Std.	Structural frame and attachment use ASME III, Subsection NF criteria. Screen modules use manufacturer std.
PXS-MY-Y03A	pH Adjustment Basket 3A	C	I	Manufacturer Std.	
PXS-MY-Y03B	pH Adjustment Basket 3B	C	I	Manufacturer Std.	
PXS-MY-Y04A	pH Adjustment Basket 4A	C	I	Manufacturer Std.	
PXS-MY-Y04B	pH Adjustment Basket 4B	C	I	Manufacturer Std.	
PXS-MY-Y11A	CMT A Upper Level Standpipe	A	I	ASME III-1	
PXS-MY-Y11B	CMT B Upper Level Standpipe	A	I	ASME III-1	
PXS-MY-Y12A	CMT A Upper Level Standpipe	A	I	ASME III-1	
PXS-MY-Y12B	CMT B Upper Level Standpipe	A	I	ASME III-1	
PXS-MY-Y13A	CMT A Lower Level Standpipe	A	I	ASME III-1	
PXS-MY-Y13B	CMT B Lower Level Standpipe	A	I	ASME III-1	
PXS-MY-Y14A	CMT A Lower Level Standpipe	A	I	ASME III-1	
PXS-MY-Y14B	CMT B Lower Level Standpipe	A	I	ASME III-1	
PXS-MY-Y21	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y22	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y23	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y24	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y25	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y26	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y27	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y28	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y29	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y30	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y31	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y32	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y33	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y41	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y47	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y48	IRWST Hood Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y61	IRWST SG Wall Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y62	IRWST SG Wall Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y63	IRWST SG Wall Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y64	IRWST SG Wall Vent Cover	C	I	Manufacturer Std.	
PXS-MY-Y71	IRWST Overflow Weir Cover	C	I	Manufacturer Std.	
PXS-MY-Y72	IRWST Overflow Weir Cover	C	I	Manufacturer Std.	
PXS-MY-Y73	IRWST Overflow Weir Cover	C	I	Manufacturer Std.	
PXS-MY-Y74	IRWST Overflow Weir Cover	C	I	Manufacturer Std.	
PXS-MY-Y75	IRWST Overflow Weir Cover	C	I	Manufacturer Std.	
PXS-MY-Y76	IRWST Overflow Weir Cover	C	I	Manufacturer Std.	

Table 3.2-3 (Sheet 16 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-MY-Y81	Downspout Screen 1A	C	I	Manufacturer Std.	
PXS-MY-Y82	Downspout Screen 1B	C	I	Manufacturer Std.	
PXS-MY-Y83	Downspout Screen 1C	C	I	Manufacturer Std.	
PXS-MY-Y84	Downspout Screen 1D	C	I	Manufacturer Std.	
PXS-MY-Y85	Downspout Screen 2A	C	I	Manufacturer Std.	
PXS-MY-Y86	Downspout Screen 2B	C	I	Manufacturer Std.	
PXS-MY-Y87	Downspout Screen 2C	C	I	Manufacturer Std.	
PXS-MY-Y88	Downspout Screen 2D	C	I	Manufacturer Std.	
PXS-PL-V002A	CMT A CL Inlet Isolation	A	I	ASME III-1	
PXS-PL-V002B	CMT B CL Inlet Isolation	A	I	ASME III-1	
PXS-PL-V010A	CMT A Upper Sample	B	I	ASME III-2	
PXS-PL-V010B	CMT B Upper Sample	B	I	ASME III-2	
PXS-PL-V011A	CMT A Lower Sample	B	I	ASME III-2	
PXS-PL-V011B	CMT B Lower Sample	B	I	ASME III-2	
PXS-PL-V012A	CMT A Drain	A	I	ASME III-1	
PXS-PL-V012B	CMT B Drain	A	I	ASME III-1	
PXS-PL-V013A	CMT A Discharge Manual Isolation	A	I	ASME III-1	
PXS-PL-V013B	CMT B Discharge Manual Isolation	A	I	ASME III-1	
PXS-PL-V014A	CMT A Discharge Isolation	A	I	ASME III-1	
PXS-PL-V014B	CMT B Discharge Isolation	A	I	ASME III-1	
PXS-PL-V015A	CMT A Discharge Isolation	A	I	ASME III-1	
PXS-PL-V015B	CMT B Discharge Isolation	A	I	ASME III-1	
PXS-PL-V016A	CMT A Discharge Check	A	I	ASME III-1	
PXS-PL-V016B	CMT B Discharge Check	A	I	ASME III-1	
PXS-PL-V017A	CMT A Discharge Check	A	I	ASME III-1	
PXS-PL-V017B	CMT B Discharge Check	A	I	ASME III-1	
PXS-PL-V019A	RNS to CMT Injection Line A Drain	B	I	ASME III-2	
PXS-PL-V019B	RNS to CMT Injection Line B Drain	B	I	ASME III-2	
PXS-PL-V020A	IRWST Injection Line A Drain	B	I	ASME III-2	
PXS-PL-V020B	IRWST Injection Line B Drain	B	I	ASME III-2	
PXS-PL-V021A	Accumulator A Nitrogen Vent	C	I	ASME III-3	
PXS-PL-V021B	Accumulator B Nitrogen Vent	C	I	ASME III-3	
PXS-PL-V022A	Accumulator A Pressure Relief	C	I	ASME III-3	
PXS-PL-V022B	Accumulator B Pressure Relief	C	I	ASME III-3	
PXS-PL-V023A	Accumulator A Pressure Transmitter B Isolation	C	I	ASME III-3	
PXS-PL-V023B	Accumulator B Pressure Transmitter B Isolation	C	I	ASME III-3	
PXS-PL-V024A	Accumulator A Pressure Transmitter A Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 17 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V024B	Accumulator B Pressure Transmitter A Isolation	C	I	ASME III-3	
PXS-PL-V025A	Accumulator A Sample	C	I	ASME III-3	
PXS-PL-V025B	Accumulator B Sample	C	I	ASME III-3	
PXS-PL-V026A	Accumulator A Drain	C	I	ASME III-3	
PXS-PL-V026B	Accumulator B Drain	C	I	ASME III-3	
PXS-PL-V027A	Accumulator A Discharge Isolation	C	I	ASME III-3	
PXS-PL-V027B	Accumulator B Discharge Isolation	C	I	ASME III-3	
PXS-PL-V028A	Accumulator A Discharge Check	A	I	ASME III-1	
PXS-PL-V028B	Accumulator B Discharge Check	A	I	ASME III-1	
PXS-PL-V029A	Accumulator A Discharge Check	A	I	ASME III-1	
PXS-PL-V029B	Accumulator B Discharge Check	A	I	ASME III-1	
PXS-PL-V030A	CMT A Highpoint Vent	B	I	ASME III-2	
PXS-PL-V030B	CMT B Highpoint Vent	B	I	ASME III-2	
PXS-PL-V031A	CMT A Highpoint Vent	B	I	ASME III-2	
PXS-PL-V031B	CMT B Highpoint Vent	B	I	ASME III-2	
PXS-PL-V033A	Accumulator A Check Valve Drain	B	I	ASME III-2	
PXS-PL-V033B	Accumulator B Check Valve Drain	B	I	ASME III-2	
PXS-PL-V042	Nitrogen Supply Containment Isolation ORC	B	I	ASME III-2	
PXS-PL-V043	Nitrogen Supply Containment Isolation IRC Check Valve	B	I	ASME III-2	
PXS-PL-V052	Accumulator Nitrogen Containment Penetration TC	B	I	ASME III-2	
PXS-PL-V080A	CMT A WR Level Isolation	B	I	ASME III-2	
PXS-PL-V080B	CMT B WR Level Isolation	B	I	ASME III-2	
PXS-PL-V081A	CMT A WR Level Isolation	B	I	ASME III-2	
PXS-PL-V081B	CMT B WR Level Isolation	B	I	ASME III-2	
PXS-PL-V082A	CMT A Upper Level A Isolation 1	A	I	ASME III-1	
PXS-PL-V082B	CMT B Upper Level A Isolation 1	A	I	ASME III-1	
PXS-PL-V083A	CMT A Upper Level A Isolation 2	A	I	ASME III-1	
PXS-PL-V083B	CMT B Upper Level A Isolation 2	A	I	ASME III-1	
PXS-PL-V084A	CMT A Upper Level A Vent	B	I	ASME III-2	
PXS-PL-V084B	CMT B Upper Level A Vent	B	I	ASME III-2	

Table 3.2-3 (Sheet 18 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V085A	LT-011 A/C Drain Valve	B	I	ASME III-2	
PXS-PL-V085B	LT-012 A/C Drain Valve	B	I	ASME III-2	
PXS-PL-V086A	CMT A Upper Level B Isolation 1	A	I	ASME III-1	
PXS-PL-V086B	CMT B Upper Level B Isolation 1	A	I	ASME III-1	
PXS-PL-V087A	CMT A Upper Level B Isolation 2	A	I	ASME III-1	
PXS-PL-V087B	CMT B Upper Level B Isolation 2	A	I	ASME III-1	
PXS-PL-V088A	CMT A Upper Level B Vent	B	I	ASME III-2	
PXS-PL-V088B	CMT B Upper Level B Vent	B	I	ASME III-2	
PXS-PL-V089A	CMT A Upper Level B Drain	B	I	ASME III-2	
PXS-PL-V089B	CMT B Upper Level B Drain	B	I	ASME III-2	
PXS-PL-V092A	CMT A Lower Level A Isolation 1	A	I	ASME III-1	
PXS-PL-V092B	CMT B Lower Level A Isolation 1	A	I	ASME III-1	
PXS-PL-V093A	CMT A Lower Level A Isolation 2	A	I	ASME III-1	
PXS-PL-V093B	CMT B Lower Level A Isolation 2	A	I	ASME III-1	
PXS-PL-V094A	CMT A Lower Level A Vent	B	I	ASME III-2	
PXS-PL-V094B	CMT B Lower Level A Vent	B	I	ASME III-2	
PXS-PL-V095A	CMT A Lower Level A Drain	B	I	ASME III-2	
PXS-PL-V095B	CMT B Lower Level A Drain	B	I	ASME III-2	
PXS-PL-V096A	CMT A Lower Level B Isolation 1	A	I	ASME III-1	
PXS-PL-V096B	CMT B Lower Level B Isolation 1	A	I	ASME III-1	
PXS-PL-V097A	CMT A Lower Level B Isolation 2	A	I	ASME III-1	
PXS-PL-V097B	CMT B Lower Level B Isolation 2	A	I	ASME III-1	
PXS-PL-V098A	CMT A Lower Level B Vent	B	I	ASME III-2	
PXS-PL-V098B	CMT B Lower Level B Vent	B	I	ASME III-2	
PXS-PL-V099A	CMT A Lower Level B Drain	B	I	ASME III-2	
PXS-PL-V099B	CMT B Lower Level B Drain	B	I	ASME III-2	
PXS-PL-V101	PRHR HX Inlet Isolation	A	I	ASME III-1	
PXS-PL-V102A	PRHR HX Inlet Head Vent	B	I	ASME III-2	
PXS-PL-V102B	PRHR HX Inlet Head Drain	B	I	ASME III-2	
PXS-PL-V103A	PRHR HX Outlet Head Vent	B	I	ASME III-2	
PXS-PL-V103B	PRHR HX Outlet Head Drain	B	I	ASME III-2	
PXS-PL-V104A	PRHR HX Flow Transmitter A Isolation	B	I	ASME III-2	

Table 3.2-3 (Sheet 19 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V104B	PRHR HX Flow Transmitter B Isolation	B	I	ASME III-2	
PXS-PL-V105A	PRHR HX Flow Transmitter A Isolation	B	I	ASME III-2	
PXS-PL-V105B	PRHR HX Flow Transmitter B Isolation	B	I	ASME III-2	
PXS-PL-V106	Containment Recirculation A Highpoint Vent	C	I	ASME III-3	
PXS-PL-V107	Containment Recirculation A Highpoint Vent	C	I	ASME III-3	
PXS-PL-V108A	PRHR HX Control	A	I	ASME III-1	
PXS-PL-V108B	PRHR HX Control	A	I	ASME III-1	
PXS-PL-V109	PRHR HX/RCS Return Isolation	A	I	ASME III-1	
PXS-PL-V111A	PRHR HX Highpoint Vent	B	I	ASME III-2	
PXS-PL-V111B	PRHR HX Highpoint Vent	B	I	ASME III-2	
PXS-PL-V113	PRHR HX Pressure Transmitter Isolation	B	I	ASME III-2	
PXS-PL-V115A	Containment Recirculation A Drain	C	I	ASME III-3	
PXS-PL-V115B	Containment Recirculation B Drain	C	I	ASME III-3	
PXS-PL-V116A	Containment Recirculation A Drain	C	I	ASME III-3	
PXS-PL-V116B	Containment Recirculation B Drain	C	I	ASME III-3	
PXS-PL-V117A	Containment Recirculation A Isolation	C	I	ASME III-3	
PXS-PL-V117B	Containment Recirculation B Isolation	C	I	ASME III-3	
PXS-PL-V118A	Containment Recirculation A Isolation	C	I	ASME III-3	
PXS-PL-V118B	Containment Recirculation B Isolation	C	I	ASME III-3	
PXS-PL-V119A	Containment Recirculation A Check	C	I	ASME III-3	
PXS-PL-V119B	Containment Recirculation B Check	C	I	ASME III-3	
PXS-PL-V120A	Containment Recirculation A Isolation	C	I	ASME III-3	
PXS-PL-V120B	Containment Recirculation B Isolation	C	I	ASME III-3	
PXS-PL-V121A	IRWST Line A Isolation	C	I	ASME III-3	
PXS-PL-V121B	IRWST Line B Isolation	C	I	ASME III-3	
PXS-PL-V122A	IRWST Injection A Check	A	I	ASME III-1	
PXS-PL-V122B	IRWST Injection B Check	A	I	ASME III-1	

Table 3.2-3 (Sheet 20 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V123A	IRWST Injection A Isolation	A	I	ASME III-1	
PXS-PL-V123B	IRWST Injection B Isolation	A	I	ASME III-1	
PXS-PL-V124A	IRWST Injection A Check	A	I	ASME III-1	
PXS-PL-V124B	IRWST Injection B Check	A	I	ASME III-1	
PXS-PL-V125A	IRWST Injection A Isolation	A	I	ASME III-1	
PXS-PL-V125B	IRWST Injection B Isolation	A	I	ASME III-1	
PXS-PL-V126A	IRWST Injection Check Test	C	I	ASME III-3	
PXS-PL-V126B	IRWST Injection Check Test	C	I	ASME III-3	
PXS-PL-V127	IRWST Injection Line A Drain	C	I	ASME III-3	
PXS-PL-V128A	IRWST Injection Check Test	A	I	ASME III-1	
PXS-PL-V128B	IRWST Injection Check Test	A	I	ASME III-1	
PXS-PL-V129A	IRWST Injection Check Test	A	I	ASME III-1	
PXS-PL-V129B	IRWST Injection Check Test	A	I	ASME III-1	
PXS-PL-V130A	IRWST Gutter Bypass A Isolation	C	I	ASME III-3	
PXS-PL-V130B	IRWST Gutter Bypass B Isolation	C	I	ASME III-3	
PXS-PL-V131A	IRWST Injection Line A Drain	B	I	ASME III-2	
PXS-PL-V131B	IRWST Injection Line B Drain	B	I	ASME III-2	
PXS-PL-V132A	IRWST Injection Line A Drain	B	I	ASME III-2	
PXS-PL-V132B	IRWST Injection Line B Drain	B	I	ASME III-2	
PXS-PL-V133A	IRWST Injection Line A Highpoint Vent	B	I	ASME III-2	
PXS-PL-V133B	IRWST Injection Line B Highpoint Vent	B	I	ASME III-2	
PXS-PL-V134A	IRWST Injection Line A Highpoint Vent	B	I	ASME III-2	
PXS-PL-V134B	IRWST Injection Line B Highpoint Vent	B	I	ASME III-2	
PXS-PL-V135A	IRWST Injection Line A Highpoint Vent Isolation	B	I	ASME III-2	
PXS-PL-V135B	IRWST Injection Line B Highpoint Vent Isolation	B	I	ASME III-2	
PXS-PL-V149	RNS Suction Pump Line Drain	C	I	ASME III-3	
PXS-PL-V151B	IRWST Wide Range Level Transmitter B Isolation	C	I	ASME III-3	
PXS-PL-V151C	IRWST Wide Range Level Transmitter C Isolation	C	I	ASME III-3	
PXS-PL-V151D	IRWST Wide Range Level Transmitter D Isolation	C	I	ASME III-3	
PXS-PL-V161A	IRWST Lower Narrow Range Level Transmitter A Isolation	C	I	ASME III-3	
PXS-PL-V161B	IRWST Lower Narrow Range Level Transmitter B Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 21 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V161C	IRWST Lower Narrow Range Level Transmitter C Isolation	C	I	ASME III-3	
PXS-PL-V161D	IRWST Lower Narrow Range Level Transmitter D Isolation	C	I	ASME III-3	
PXS-PL-V162A	IRWST Lower Narrow Range Level Transmitter A Reference Leg Isolation	C	I	ASME III-3	
PXS-PL-V162B	IRWST Lower Narrow Range Level Transmitter B Reference Leg Isolation	C	I	ASME III-3	
PXS-PL-V162C	IRWST Lower Narrow Range Level Transmitter C Reference Leg Isolation	C	I	ASME III-3	
PXS-PL-V162D	IRWST Lower Narrow Range Level Transmitter D Reference Leg Isolation	C	I	ASME III-3	
PXS-PL-V170A	PRHR Flow Transmitter A Vent	B	I	ASME III-2	
PXS-PL-V170B	PRHR Flow Transmitter B Vent	B	I	ASME III-2	
PXS-PL-V171A	PRHR Flow Transmitter A Vent	B	I	ASME III-2	
PXS-PL-V171B	PRHR Flow Transmitter B Vent	B	I	ASME III-2	
PXS-PL-V201A	Accumulator A Leak Test	B	I	ASME III-2	
PXS-PL-V201B	Accumulator B Leak Test	B	I	ASME III-2	
PXS-PL-V202A	Accumulator A Leak Test	C	I	ASME III-3	
PXS-PL-V202B	Accumulator B Leak Test	C	I	ASME III-3	
PXS-PL-V205A	RNS Discharge Leak Test	B	I	ASME III-2	
PXS-PL-V205B	RNS Discharge Leak Test	B	I	ASME III-2	
PXS-PL-V206	RNS Discharge Leak Test	C	I	ASME III-3	
PXS-PL-V207A	RNS Suction Leak Test	B	I	ASME III-2	
PXS-PL-V207B	RNS Suction Leak Test	B	I	ASME III-2	
PXS-PL-V208A	RNS Suction Leak Test	B	I	ASME III-2	
PXS-PL-V217	PXS Leak Test Line Isolation	D	NS	ASME B31.1	
PXS-PL-V221	Test Header to IRWST	D	NS	ASME B31.1	
PXS-PL-V230A	CMT A Fill Isolation	B	I	ASME III-2	
PXS-PL-V230B	CMT B Fill Isolation	B	I	ASME III-2	
PXS-PL-V231A	CMT A Fill Check	B	I	ASME III-2	
PXS-PL-V231B	CMT B Fill Check	B	I	ASME III-2	
PXS-PL-V232A	Accumulator A Fill/Drain Isolation	C	I	ASME III-3	
PXS-PL-V232B	Accumulator B Fill/Drain Isolation	C	I	ASME III-3	
PXS-PL-V233A	Accumulator A to PXS Test Header Iso Valve (Unit 3 Only)	C	I	ASME III-3	

Table 3.2-3 (Sheet 22 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V233B	Accumulator B to PXS Test Header Iso Valve (Unit 3 Only)	C	I	ASME III-3	
PXS-PL-V250A	CMT A Check Valve Test Valve	A	I	ASME III-1	
PXS-PL-V250B	CMT B Check Valve Test Valve	A	I	ASME III-1	
PXS-PL-V251A	CMT A Check Valve Test Valve	A	I	ASME III-1	
PXS-PL-V251B	CMT B Check Valve Test Valve	A	I	ASME III-1	
PXS-PL-V252A	CMT A Check Valve Test Valve	A	I	ASME III-1	
PXS-PL-V252B	CMT B Check Valve Test Valve	A	I	ASME III-1	
PXS-PY-C01	Nitrogen Makeup Containment Penetration	B	I	ASME III, MC	
PXS-PY-E01	DVI-B Inline Expansion Joint	C	I	ASME III-3	
PXS-PY-R01A	Core Makeup Tank A Orifice	A	I	ASME III-1	
PXS-PY-R01B	Core Makeup Tank B Orifice	A	I	ASME III-1	
PXS-PY-R02A	Accumulator Tank A Orifice	C	I	ASME III-3	
PXS-PY-R02B	Accumulator Tank B Orifice	C	I	ASME III-3	
Balance of system components are Class E					
Reactor Coolant System (RCS)				Location: Containment	
RCS-MB-01	Steam Generator 1	A	I	ASME III-1	
n/a	SG 1 Shell	B	I	ASME III-1	
n/a	SG 1 Channel Head Divider Plate	B	I	ASME III-1	
n/a	SG 1 Tube Bundle Support Assembly	C	I	Manufacturer Std	
n/a	SG 1 Steam Flow Limiting Venturi	B	I	ASME III-1	See Subsections 5.4.4.2 and 5.4.4.3 for additional requirements.
n/a	SG 1 Feedwater Distribution Ring Supports	C	I	Manufacturer Std	
RCS-MB-02	Steam Generator 2	A	I	ASME III-1	
n/a	SG 2 Shell	B	I	ASME III-1	
n/a	SG 2 Channel Head Divider Plate	B	I	ASME III-1	
n/a	SG 2 Tube Bundle Support Assembly	C	I	Manufacturer Std	
n/a	SG 2 Steam Flow Limiting Venturi	B	I	ASME III-1	See Subsections 5.4.4.2 and 5.4.4.3 for additional requirements.

Table 3.2-3 (Sheet 23 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
n/a	SG 2 Feedwater Distribution Ring Supports	C	I	Manufacturer Std	
RCS-MP-01A/B	SG 1A(B) Reactor Coolant Pump	A	I	ASME III-1	Pump Motor – Class D
n/a	Rotor Shaft	C	I	Manufacturer Std	
n/a	Impeller	C	I	Manufacturer Std	
n/a	Flywheel	C	I	Manufacturer Std	
n/a	RCP Heat Exchanger (Tube Side)	A	I	ASME III-1	Shellside – Class D, ASME VIII, Div. 1
n/a	Pump Motor Cooling Water to HX Inlet Connector	A	I	ASME III-1	
n/a	Pump Motor Cooling Water from HX Outlet Connector	A	I	ASME III-1	
RCS-MP-02A/B	SG 2A(B) Reactor Coolant Pump	A	I	ASME III-1	Pump Motor – Class D
n/a	Rotor Shaft	C	I	Manufacturer Std	
n/a	Impeller	C	I	Manufacturer Std	
n/a	Flywheel	C	I	Manufacturer Std	
n/a	RCP Heat Exchanger (Tube Side)	A	I	ASME III-1	Shellside – Class D, ASME VIII, Div. 1
n/a	Pump Motor Cooling Water to HX Inlet Connector	A	I	ASME III-1	
n/a	Pump Motor Cooling Water from HX Outlet Connector	A	I	ASME III-1	
RCS-MV-01	Reactor Vessel	A	I	ASME III-1	The reactor vessel has two tag numbers; RCS-MV-01 for the reactor coolant system (RCS) and RXS-MV-01 for the reactor system (RXS)
RCS-MV-02	Pressurizer	A	I	ASME III-1	
RCS-PL-V001A	First Stage ADS	A	I	ASME III-1	
RCS-PL-V001B	First Stage ADS	A	I	ASME III-1	
RCS-PL-V002A	Second Stage ADS	A	I	ASME III-1	
RCS-PL-V002B	Second Stage ADS	A	I	ASME III-1	
RCS-PL-V003A	Third Stage ADS	A	I	ASME III-1	
RCS-PL-V003B	Third Stage ADS	A	I	ASME III-1	
RCS-PL-V004A	Fourth Stage ADS	A	I	ASME III-1	
RCS-PL-V004B	Fourth Stage ADS	A	I	ASME III-1	
RCS-PL-V004C	Fourth Stage ADS	A	I	ASME III-1	
RCS-PL-V004D	Fourth Stage ADS	A	I	ASME III-1	
RCS-PL-V005A	Pressurizer Safety Valve	A	I	ASME III-1	
RCS-PL-V005B	Pressurizer Safety Valve	A	I	ASME III-1	
RCS-PL-V007A	ADS Test Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 24 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-PL-V007B	ADS Test Valve	B	I	ASME III-2	
RCS-PL-V007C	ADS Test Valve	B	I	ASME III-2	
RCS-PL-V008	ADS Valve Leakage Check Valve	C	I	ASME III-3	
RCS-PL-V010A	ADS Discharge Header A Vacuum Relief	C	I	ASME III-3	
RCS-PL-V010B	ADS Discharge Header B Vacuum Relief	C	I	ASME III-3	
RCS-PL-V011A	First Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V011B	First Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V012A	Second Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V012B	Second Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V013A	Third Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V013B	Third Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V014A	Fourth Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V014B	Fourth Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V014C	Fourth Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V014D	Fourth Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V095	Hot Leg 2 Level Instrument Root	B	I	ASME III-2	
RCS-PL-V096	Hot Leg 2 Level Instrument Root	B	I	ASME III-2	
RCS-PL-V097	Hot Leg 1 Level Instrument Root	B	I	ASME III-2	
RCS-PL-V098	Hot Leg 1 Level Instrument Root	B	I	ASME III-2	
RCS-PL-V101A	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101B	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101C	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101D	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101E	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101F	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102A	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102B	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102C	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102D	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	

Table 3.2-3 (Sheet 25 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-PL-V102E	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102F	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V103	PRHR HX Outlet Line Drain	B	I	ASME III-2	
RCS-PL-V108A	Hot Leg 1 Sample Isolation	B	I	ASME III-2	
RCS-PL-V108B	Hot Leg 2 Sample Isolation	B	I	ASME III-2	
RCS-PL-V110A	Pressurizer Spray Valve	A	I	ASME III-1	
RCS-PL-V110B	Pressurizer Spray Valve	A	I	ASME III-1	
RCS-PL-V111A	Pressurizer Spray Block Valve	A	I	ASME III-1	
RCS-PL-V111B	Pressurizer Spray Block Valve	A	I	ASME III-1	
RCS-PL-V120	Reactor Vessel Flange Leakoff	D	NS	ASME B31.1	
RCS-PL-V121	Reactor Vessel Flange Leakoff	D	NS	ASME B31.1	
RCS-PL-V122A	Reactor Vessel Flange Leakoff	D	NS	ASME B31.1	
RCS-PL-V122B	Reactor Vessel Flange Leakoff	D	NS	ASME B31.1	
RCS-PL-V150A	Reactor Vessel Head Vent	A	I	ASME III-1	
RCS-PL-V150B	Reactor Vessel Head Vent	A	I	ASME III-1	
RCS-PL-V150C	Reactor Vessel Head Vent	A	I	ASME III-1	
RCS-PL-V150D	Reactor Vessel Head Vent	A	I	ASME III-1	
RCS-PL-V171A	Cold Leg 1A Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V171B	Cold Leg 1A Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V172A	Cold Leg 1B Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V172B	Cold Leg 1B Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V173A	Cold Leg 2A Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V173B	Cold Leg 2A Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V174A	Cold Leg 2B Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V174B	Cold Leg 2B Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V204	Pressurizer Manual Vent	A	I	ASME III-1	
RCS-PL-V205	Pressurizer Manual Vent	A	I	ASME III-1	
RCS-PL-V210A	Pressurizer Spray Bypass	B	I	ASME III-2	
RCS-PL-V210B	Pressurizer Spray Bypass	B	I	ASME III-2	

Table 3.2-3 (Sheet 26 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-PL-V015	Pressurizer Vent to RCDT Test Valve	D	NS	ANSI B16.34	
RCS-PL-V225A	Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V225B	Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V225C	Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V225D	Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V226A	Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V226B	Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V226C	Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V226D	Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V227A	Pressurizer Level Reference Leg Tubing Instrumentation Root	B	I	ASME III-2	
RCS-PL-V227B	Pressurizer Level Reference Leg Tubing Instrumentation Root	B	I	ASME III-2	
RCS-PL-V227C	Pressurizer Level Reference Leg Tubing Instrumentation Root	B	I	ASME III-2	
RCS-PL-V227D	Pressurizer Level Reference Leg Tubing Instrumentation Root	B	I	ASME III-2	
RCS-PL-V228	Pressurizer Liquid Sample Isolation	B	I	ASME III-2	
RCS-PL-V229	Wide Range Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V232	Manual Head Vent	C	I	ASME III-3	
RCS-PL-V233	Head Vent Isolation	C	I	ASME III-3	
RCS-PL-V241	ADS Valve Discharge Header Drain Isolation	C	I	ASME III-3	
RCS-PL-V242	ADS Valve Discharge Header Drain Check	D	NS	ANSI B16.34	
RCS-PL-V250	ADS Discharge Line Isolation	C	I	ASME III-3	
RCS-PL-V260A	RCP 1A Vent	A	I	ASME III-1	
RCS-PL-V260B	RCP 1B Vent	A	I	ASME III-1	
RCS-PL-V260C	RCP 2A Vent	A	I	ASME III-1	
RCS-PL-V260D	RCP 2B Vent	A	I	ASME III-1	
RCS-PL-V261A	RCP 1A Drain	A	I	ASME III-1	

Table 3.2-3 (Sheet 27 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-PL-V261B	RCP 1B Drain	A	I	ASME III-1	
RCS-PL-V261C	RCP 2A Drain	A	I	ASME III-1	
RCS-PL-V261D	RCP 2B Drain	A	I	ASME III-1	
RCS-PY-B01	ADS Hydrostatic Test Spectacle Flange	C	I	ASME III-3	
RCS-PY-B02	ADS Hydrostatic Test Spectacle Flange	C	I	ASME III-3	
RCS-PY-B03	RCS Vacuum Pump Suction Spectacle Blind	C	I	ASME III-3	
RCS-PY-B04	RCS Vacuum Ejector Package Suction Spectacle Blind	C	I	ASME III-3	
RCS-PY-K03	Safety Valve Discharge Chamber Rupture Disk	C	I	ASME III-3	
RCS-PY-K04	Safety Valve Discharge Chamber Rupture Disk	C	I	ASME III-3	
RCS-PY-R01A	Reactor Vessel Head Vent Flow Orifice A	C	I	ASME III-3	
RCS-PY-R01B	Reactor Vessel Head Vent Flow Orifice B	C	I	ASME III-3	
RCS-PY-Y01A	Pressurizer Level Reference Leg L225A Flex Hose	B	I	ASME III-2	
RCS-PY-Y01B	Pressurizer Level Reference Leg L225B Flex Hose	B	I	ASME III-2	
RCS-PY-Y01C	Pressurizer Level Reference Leg L225C Flex Hose	B	I	ASME III-2	
RCS-PY-Y01D	Pressurizer Level Reference Leg L225D Flex Hose	B	I	ASME III-2	
Gravity and Roof Drain Collection System (RDS)				Location: Various	
System components are Class E					
Normal Residual Heat Removal System (RNS)			Location: Containment and Auxiliary Building		
RNS-JE-FE001A	RNS Train A Discharge Flow Element	C	I	ASME III-3	
RNS-JE-FE001B	RNS Train B Discharge Flow Element	C	I	ASME III-3	
RNS-ME-01A	Normal Residual Heat Removal Heat Exchanger A (Tube Side)	C	I	ASME III-3	Shellside – Class D ASME VIII, Div. 1
RNS-ME-01B	Normal Residual Heat Removal Heat Exchanger B (Tube Side)	C	I	ASME III-3	Shellside – Class D ASME VIII, Div. 1
RNS-MP-01A	Residual Heat Removal Pump A	C	I	ASME III-3	Pump Motor - Class D
RNS-MP-01B	Residual Heat Removal Pump B	C	I	ASME III-3	Pump Motor - Class D
RNS-PL-V001A	RNS HL Suction Isolation - Inner	A	I	ASME III-1	

Table 3.2-3 (Sheet 28 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Normal Residual Heat Removal System (Continued)					
RNS-PL-V001B	RNS HL Suction Isolation - Inner	A	I	ASME III-1	
RNS-PL-V002A	RNS HL Suction and Containment Isolation - Outer	A	I	ASME III-1	
RNS-PL-V002B	RNS HL Suction and Containment Isolation - Outer	A	I	ASME III-1	
RNS-PL-V003A	RCS Pressure Boundary Valve Thermal Relief	B	I	ASME III-2	
RNS-PL-V003B	RCS Pressure Boundary Valve Thermal Relief	B	I	ASME III-2	
RNS-PL-V004A	RCS Pressure Boundary Valve Thermal Relief Isolation	B	I	ASME III-2	
RNS-PL-V004B	RCS Pressure Boundary Valve Thermal Relief Isolation	B	I	ASME III-2	
RNS-PL-V005A	RNS Pump A Suction Isolation	C	I	ASME III-3	
RNS-PL-V005B	RNS Pump B Suction Isolation	C	I	ASME III-3	
RNS-PL-V006A	RNS HX A Outlet Flow Control	C	I	ASME III-3	
RNS-PL-V006B	RNS HX B Outlet Flow Control	C	I	ASME III-3	
RNS-PL-V007A	RNS Pump A Discharge Isolation	C	I	ASME III-3	
RNS-PL-V007B	RNS Pump B Discharge Isolation	C	I	ASME III-3	
RNS-PL-V008A	RNS HX A Bypass Flow Control	C	I	ASME III-3	
RNS-PL-V008B	RNS HX B Bypass Flow Control	C	I	ASME III-3	
RNS-PL-V010	RNS Discharge Containment Isolation Valve Test	C	I	ASME III-3	
RNS-PL-V011	RNS Discharge Containment Isolation Valve - ORC	B	I	ASME III-2	
RNS-PL-V012	RNS Discharge Containment Isolation Valve Test Connection ORC	B	I	ASME III-2	
RNS-PL-V013	RNS Discharge Containment Isolation - IRC	B	I	ASME III-2	
RNS-PL-V014	RNS Discharge Containment Isolation Valve Test Connection	C	I	ASME III-3	
RNS-PL-V015A	RNS Discharge RCS Pressure Boundary	A	I	ASME III-1	
RNS-PL-V015B	RNS Discharge RCS Pressure Boundary	A	I	ASME III-1	
RNS-PL-V016	RNS Discharge Containment Penetration Isolation Valves Test	C	I	ASME III-3	
RNS-PL-V017A	RNS Discharge RCS Pressure Boundary	A	I	ASME III-1	

Table 3.2-3 (Sheet 29 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Normal Residual Heat Removal System (Continued)					
RNS-PL-V017B	RNS Discharge RCS Pressure Boundary	A	I	ASME III-1	
RNS-PL-V020	RNS HL Suction Pressure Relief	B	I	ASME III-2	
RNS-PL-V021	RNS HL Suction Pressure Relief	B	I	ASME III-2	
RNS-PL-V022	RNS Suction Header Containment Isolation - ORC	B	I	ASME III-2	
RNS-PL-V023	RNS Suction from IRWST - Containment Isolation	B	I	ASME III-2	
RNS-PL-V024	RNS Discharge to IRWST Isolation	C	I	ASME III-3	
RNS-PL-V025	RNS Suction from IRWST - Bonnet Relief Isolation	C	I	ASME III-3	
RNS-PL-V026	RNS Suction from IRWST - Containment Isolation Test	C	I	ASME III-3	
RNS-PL-V029	RNS Discharge to CVS	C	I	ASME III-3	
RNS-PL-V030A	RNS HX A Shell Drain	D	NS	ASME B31.1	
RNS-PL-V030B	RNS HX B Shell Drain	D	NS	ASME B31.1	
RNS-PL-V031A	RNS Train A Discharge Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V031B	RNS Train B Discharge Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V032A	RNS Train A Discharge Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V032B	RNS Train B Discharge Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V033A	RNS Pump A Suction Pressure Instrument Isolation	C	I	ASME III-3	
RNS-PL-V033B	RNS Pump B Suction Pressure Instrument Isolation	C	I	ASME III-3	
RNS-PL-V034A	RNS Pump A Discharge Pressure Instrument Isolation	C	I	ASME III-3	
RNS-PL-V034B	RNS Pump B Discharge Pressure Instrument Isolation	C	I	ASME III-3	
RNS-PL-V035A	RNS HX A Shell Vent	D	NS	ANSI B16.34	
RNS-PL-V035B	RNS HX B Shell Vent	D	NS	ANSI B16.34	
RNS-PL-V036A	RNS Pump A Suction Piping Drain. Isolation	C	I	ASME III-3	
RNS-PL-V036B	RNS Pump B Suction Piping Drain. Isolation	C	I	ASME III-3	
RNS-PL-V045	RNS Pump Discharge Relief	C	I	ASME III-3	
RNS-PL-V048A	RNS Pump Seal Cooler A Vent Isolation	C	I	ASME III-3	
RNS-PL-V048B	RNS Pump Seal Cooler B Vent Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 30 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Normal Residual Heat Removal System (Continued)					
RNS-PL-V049A	RNS Pump Seal Cooler A Drain Isolation	C	I	ASME III-3	
RNS-PL-V049B	RNS Pump Seal Cooler B Drain Isolation	C	I	ASME III-3	
RNS-PL-V050	RNS Pump A Casing Drain. Isolation	C	I	ASME III-3	
RNS-PL-V051	RNS Pump B Casing Drain. Isolation	C	I	ASME III-3	
RNS-PL-V052	RNS Pump Suction From Spent Fuel Pool Isolation	C	I	ASME III-3	
RNS-PL-V053	RNS Pump Discharge to Spent Fuel Pool Isolation	C	I	ASME III-3	
RNS-PL-V055	RNS Pump Suction to Cask Loading Pit Isolation	C	I	ASME III-3	
RNS-PL-V056	RNS Pump Suction to Cask Loading Pit Isolation	C	I	ASME III-3	
RNS-PL-V057A	RNS Pump A Miniflow Isolation	C	I	ASME III-3	
RNS-PL-V057B	RNS Pump B Miniflow Isolation	C	I	ASME III-3	
RNS-PL-V059	RNS Pump Suction Containment Isolation Test Connection	C	I	ASME III-3	
RNS-PL-V061	RNS Return from CVS - Containment Isolation	B	I	ASME III-2	
RNS-PL-V065	RNS Discharge Drain Valve	C	I	ASME III-3	
RNS-PL-V066A	RNS Discharge to DVI Line A Drain	C	I	ASME III-3	
RNS-PL-V066B	RNS Discharge to DVI Line B Drain	C	I	ASME III-3	
RNS-PL-V067A	RNS Discharge to DVI Line A Drain	B	I	ASME III-2	
RNS-PL-V067B	RNS Discharge to DVI Line B Drain	B	I	ASME III-2	
RNS-PL-V068	RNS Discharge to IRWST Drain	C	I	ASME III-3	
RNS-PL-V069A	RNS Pump A Miniflow Vent	C	I	ASME III-3	
RNS-PL-V069B	RNS Pump B Miniflow Vent	C	I	ASME III-3	
RNS-PL-V071A	RNS HX A Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V071B	RNS HX B Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V072A	RNS HX A Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V072B	RNS HX B Channel Head Drain Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 31 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Normal Residual Heat Removal System (Continued)					
RNS-PL-V073A	RNS HX A Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V073B	RNS HX B Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V074A	RNS HX A Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V074B	RNS HX B Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V075A	RNS HX A Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V075B	RNS HX B Channel Head Drain Isolation	C	I	ASME III-3	
RNS-PL-V080	IRWST Suction Line to RNS Pump Vent	B	I	ASME III-2	
RNS-PL-V081	RNS Cask Loading Pit Suction Line Vent	C	I	ASME III-3	
RNS-PL-V082	RNS Discharge Drain	C	I	ASME III-3	
RNS-PY-C01	Normal Residual Heat Removal Suction Line Penetration	B	I	ASME III, MC	
RNS-PY-C02	Normal Residual Heat Removal Discharge Line Penetration	B	I	ASME III, MC	
RNS-PY-R01A	Residual Heat Removal Discharge to DVI Line Orifice A	C	I	ASME III-3	
RNS-PY-R01B	Residual Heat Removal Discharge to DVI Line Orifice B	C	I	ASME III-3	
RNS-PY-R02A	Residual Heat Removal Pump Miniflow Orifice A	C	I	ASME III-3	
RNS-PY-R02B	Residual Heat Removal Pump Miniflow Orifice B	C	I	ASME III-3	
RNS-PY-R03	Residual Heat Removal to IRWST Line Orifice	C	I	ASME III-3	
RNS-PY-R04	Residual Heat Removal to Spent Fuel Pool Line Orifice	C	I	ASME III-3	
Balance of system components are Class E					
Raw Water System (RWS)				Location: Yard, Turbine Building	
System components are Class E					
Reactor System (RXS)				Location: Containment	
n/a	Fuel Assemblies	C	I	Manufacturer Std.	
RXS-FR-B06	Control Rod Cluster B6	B	I	Manufacturer Std.	
RXS-FR-B10	Control Rod Cluster B10	B	I	Manufacturer Std.	
RXS-FR-C05	Control Rod Cluster C5	B	I	Manufacturer Std.	
RXS-FR-C07	Control Rod Cluster C7	B	I	Manufacturer Std.	

Table 3.2-3 (Sheet 32 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-FR-C09	Control Rod Cluster C9	B	I	Manufacturer Std.	
RXS-FR-C11	Control Rod Cluster C11	B	I	Manufacturer Std.	
RXS-FR-D06	Control Rod Cluster D6	B	I	Manufacturer Std.	
RXS-FR-D08	Control Rod Cluster D8	B	I	Manufacturer Std.	
RXS-FR-D10	Control Rod Cluster D10	B	I	Manufacturer Std.	
RXS-FR-E03	Control Rod Cluster E3	B	I	Manufacturer Std.	
RXS-FR-E05	Control Rod Cluster E5	B	I	Manufacturer Std.	
RXS-FR-E07	Control Rod Cluster E7	B	I	Manufacturer Std.	
RXS-FR-E09	Control Rod Cluster E9	B	I	Manufacturer Std.	
RXS-FR-E11	Control Rod Cluster E11	B	I	Manufacturer Std.	
RXS-FR-E13	Control Rod Cluster E13	B	I	Manufacturer Std.	
RXS-FR-F02	Control Rod Cluster F2	B	I	Manufacturer Std.	
RXS-FR-F04	Control Rod Cluster F4	B	I	Manufacturer Std.	
RXS-FR-F12	Control Rod Cluster F12	B	I	Manufacturer Std.	
RXS-FR-F14	Control Rod Cluster F14	B	I	Manufacturer Std	
RXS-FR-G03	Control Rod Cluster G3	B	I	Manufacturer Std.	
RXS-FR-G05	Control Rod Cluster G5	B	I	Manufacturer Std.	
RXS-FR-G07	Control Rod Cluster G7	B	I	Manufacturer Std.	
RXS-FR-G09	Control Rod Cluster G9	B	I	Manufacturer Std.	
RXS-FR-G11	Control Rod Cluster G11	B	I	Manufacturer Std.	
RXS-FR-G13	Control Rod Cluster G13	B	I	Manufacturer Std.	
RXS-FR-H04	Control Rod Cluster H4	B	I	Manufacturer Std.	
RXS-FR-H08	Control Rod Cluster H8	B	I	Manufacturer Std.	
RXS-FR-H12	Control Rod Cluster H12	B	I	Manufacturer Std.	
RXS-FR-J03	Control Rod Cluster J3	B	I	Manufacturer Std.	
RXS-FR-J05	Control Rod Cluster J5	B	I	Manufacturer Std.	
RXS-FR-J07	Control Rod Cluster J7	B	I	Manufacturer Std.	
RXS-FR-J09	Control Rod Cluster J9	B	I	Manufacturer Std.	
RXS-FR-J11	Control Rod Cluster J11	B	I	Manufacturer Std.	
RXS-FR-J13	Control Rod Cluster J13	B	I	Manufacturer Std.	
RXS-FR-K02	Control Rod Cluster K2	B	I	Manufacturer Std.	
RXS-FR-K04	Control Rod Cluster K4	B	I	Manufacturer Std.	
RXS-FR-K12	Control Rod Cluster K12	B	I	Manufacturer Std.	
RXS-FR-K14	Control Rod Cluster K14	B	I	Manufacturer Std.	
RXS-FR-L03	Control Rod Cluster L3	B	I	Manufacturer Std.	
RXS-FR-L05	Control Rod Cluster L5	B	I	Manufacturer Std.	
RXS-FR-L07	Control Rod Cluster L7	B	I	Manufacturer Std.	
RXS-FR-L09	Control Rod Cluster L9	B	I	Manufacturer Std.	
RXS-FR-L11	Control Rod Cluster L11	B	I	Manufacturer Std.	
RXS-FR-L13	Control Rod Cluster L13	B	I	Manufacturer Std.	
RXS-FR-M06	Control Rod Cluster M6	B	I	Manufacturer Std.	
RXS-FR-M08	Control Rod Cluster M8	B	I	Manufacturer Std.	
RXS-FR-M10	Control Rod Cluster M10	B	I	Manufacturer Std.	

Table 3.2-3 (Sheet 33 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-FR-N05	Control Rod Cluster N05	B	I	Manufacturer Std.	
RXS-FR-N07	Control Rod Cluster N07	B	I	Manufacturer Std.	
RXS-FR-N09	Control Rod Cluster N09	B	I	Manufacturer Std.	
RXS-FR-N11	Control Rod Cluster N11	B	I	Manufacturer Std.	
RXS-FR-P06	Control Rod Cluster P06	B	I	Manufacturer Std.	
RXS-FR-P10	Control Rod Cluster P10	B	I	Manufacturer Std.	
RXS-MI-01	Reactor Upper Internals	C	I	ASME III, CS	
RXS-MI-02	Reactor Lower Internals	C	I	ASME III, CS	
RXS-MI-10	Non-Threaded Fasteners	D	II	Manufacturer Std.	
RXS-MI-11	Threaded Structural Fasteners	C	I	ASME III, CS	
RXS-MI-20	Lower Core Support Plate	C	I	ASME III, CS	
RXS-MI-22	Vortex Suppression Plate	D	II	Manufacturer Std.	
RXS-MI-23	Core Shroud Assembly	D	II	Manufacturer Std.	
RXS-MI-24	Radial Supports [4]	C	I	ASME III, CS	
RXS-MI-25	Core Barrel	C	I	ASME III, CS	
RXS-MI-26	Core Barrel Nozzle	C	I	Manufacturer Std.	
RXS-MI-27	Head and Vessel Pins	D	II	Manufacturer Std.	
RXS-MI-28	Lower Support Plate Fuel Alignment Pins	C	I	ASME III, CS	
RXS-MI-29	Core Barrel Hold Down Spring	C	I	Manufacturer Std.	
RXS-MI-50	Upper Support	C	I	ASME III, CS	
RXS-MI-51	Upper Core Plate	C	I	ASME III, CS	
RXS-MI-52	Support Columns [42]	C	I	ASME III, CS	
RXS-MI-53	Guide Tube Assemblies [69]	C	I	Manufacturer Std.	
RXS-MI-54	Upper Core Plate Fuel Alignment Pins	C	I	ASME III, CS	
RXS-MI-55	Upper Core Plate Inserts	C	I	ASME III, CS	
RXS-MI-56	Safety Injection Deflector	D	II	Manufacturer Std.	
RXS-MI-57	Irradiation Specimen Guide Tubes	D	II	Manufacturer Std.	
RXS-MI-58	Head Cooling Nozzles	D	II	Manufacturer Std.	
n/a	Neutron Pad	D	II	Manufacturer Std.	
n/a	Instrument Grid Assembly	D	II	Manufacturer Std.	
n/a	DVI Flow Diverter	D	II	Manufacturer Std.	
RXS-MI-80	Reactor Vessel Flow Skirt	D	II	Manufacturer Std.	
RXS-MN-01	Reactor Vessel Cavity Reflective Insulation	D	II	Manufacturer Std.	
RXS-MV-01	Reactor Vessel	A	I	ASME III-1	The reactor vessel has two tag numbers; RCS-MV-01 for the reactor coolant system (RCS) and RXS-MV-01 for the reactor system (RXS)

Table 3.2-3 (Sheet 34 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-10	Reactor Integrated Head Package	C	I	ANSI/AISC N690	
RXS-MV-10A	Integrated Head Package Shroud	C	I	ASME-NF	
RXS-MV-10B	Integrated Head Package Seismic Support System	C	I	ASME-NF	
RXS-MV-11B06/ B08/B10/C05/C07/ C09/C11/D04/ D06/D08/D10/ D12/E03/E05/E07/ E09/E11/E13/F02/ F04/F06/F08/F10/ F12/F14/G03/G05/ G07/G09/G11/G13/ H02/H04/H06/H08/ H10/H12/H14/J03/ J05/J07/J09/J11/ J13/K02/K04/K06/ K08/K10/K12/K14/ L03/L05/L07/L09/ L11/L13/M04/M06/ M08/M10/M12/ N05/N07/N09/N11/ P06/P08/P10	CRDM Latch Assemblies	C	I	Manufacturer Std.	
RXS-MV-11B06/ B08/B10/C05/C07/ C09/C11/D04/ D06/D08/D10/ D12/E03/E05/E07/ E09/E11/E13/F02/ F04/F06/F08/F10/ F12/F14/G03/G05/ G07/G09/G11/G13/ H02/H04/H06/H08/ H10/H12/H14/J03/ J05/J07/J09/J11/ J13/K02/K04/K06/ K08/K10/K12/K14/ L03/L05/L07/L09/ L11/L13/M04/M06/ M08/M10/M12/ N05/N07/N09/N11/ P06/P08/P10	CRDM Drive Rod Assemblies	D	NS	Manufacturer Std.	

Table 3.2-3 (Sheet 35 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11B06/ B08/B10/C05/C07/ C09/C11/D04/D06/ D08/D10/D12/E03/ E05/E07/E09/E11/ E13/F02/F04/F06/ F08/F10/F12/F14/ G03/G05/G07/G09/ G11/G13/H02/H04/ H06/H08/H10/H12/ H14/J03/J05/J07/ J09/J11/J13/K02/ K04/K06/K08/K10/ K12/K14/L03/L05/ L07/L09/L11/L13/ M04/M06/M08/ M10/M12/N05/ N07/N09/N11/P06/ P08/P10	CRDM Coil Stack Assemblies	D	NS	Manufacturer Std.	
RXS-MV-11B06L/ B08L/B10L/C05L/ C07L/C09L/C11L/ D04L/D06L/D08L/ D10L/D12L/E03L/ E05L/E07L/E09L/ E11L/E13L/F02L/ F04L/F06L/F08L/ F10L/F12L/F14L/ G03L/G05L/G07L/ G09L/G11L/G13L/ H02L/H04L/H06L/ H08L/H10L/H12L/ H14L/J03L/J05L/ J07L/J09L/J11L/ J13L/K02L/K04L/ K06L/K08L/K10L/ K12L/K14L/L03L/ L05L/L07L/L09L/ L11L/L13L/M04L/ M06L/M08L/ M10L/M12L/N05L/ N07L/N09/N11L/ P06L/P08L/P10L	CRDM Latch Housings	A	I	ASME III-1	

Table 3.2-3 (Sheet 36 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11B06R/ B08R/B10R/C05R/ C07R/C09R/C11R/ D04R/D06R/D08R/ D10R/D12R/E03R/ E05R/E07R/E09R/ E11R/E13R/F02R/ F04R/F06R/F08R/ F10R/F12R/F14R/ G03R/G05R/G07R/ G09R/G11R/G13R/ H02R/H04R/H06R/ H08R/H10R/H12R/ H14R/J03R/J05R/ J07R/J09R/J11R/ J13R/K02R/K04R/ K06R/K08R/K10R/ K12R/K14R/L03R/ L05R/L07R/L09R/ L11R/L13R/M04R/ M06R/M08R/ M10R/M12R/ N05R/N07R/N11R/ P06R/P08R/P10R	CRDM Rod Travel Housings	A	I	ASME III-1	
RXS-MY-Y01	IHP Lower Shroud Assembly	C	I	ASME-NF	
RXS-MY-Y51	Integrated Head Package Lifting Rig	C	II	NUREG-0612, ANSI N14.6	
RXS-MY-Y11	Incore Instrumentation QuickLoc Assembly 1	A	I	ASME III-1	
RXS-MY-Y12	Incore Instrumentation QuickLoc Assembly 2	A	I	ASME III-1	
RXS-MY-Y13	Incore Instrumentation QuickLoc Assembly 3	A	I	ASME III-1	
RXS-MY-Y14	Incore Instrumentation QuickLoc Assembly 4	A	I	ASME III-1	
RXS-MY-Y15	Incore Instrumentation QuickLoc Assembly 5	A	I	ASME III-1	
RXS-MY-Y16	Incore Instrumentation QuickLoc Assembly 6	A	I	ASME III-1	
RXS-MY-Y17	Incore Instrumentation QuickLoc Assembly 7	A	I	ASME III-1	
RXS-MY-Y18	Incore Instrumentation QuickLoc Assembly 8	A	I	ASME III-1	
Balance of system components are Class E					

Table 3.2-3 (Sheet 37 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Sanitary Drainage System (SDS)				Location: Various	
SDS-PL-V001	SDS MCR Vent Isolation Valve	C	I	ASME III-3	
SDS-PL-V002	SDS MCR Vent Isolation Valve	C	I	ASME III-3	
Balance of system components are Class D, P, and W					
Spent Fuel Pool Cooling System (SFS)			Location: Auxiliary Building, Containment		
n/a	Heat Exchangers, SFS and CCS Side	D	NS	ASME VIII	
n/a	Pumps	D	NS	Hydraulic Institute Std.	
n/a	Demineralizers	D	NS	ASME VIII	
n/a	Filters	D	NS	ASME VIII	
n/a	Valves Providing SFS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
SFS-PL-V024A	Spent Fuel Pool Level Instrument Isolation	C	I	ASME III-3	
SFS-PL-V024B	Spent Fuel Pool Level Instrument Isolation	C	I	ASME III-3	
SFS-PL-V024C	Spent Fuel Pool Level Instrument Isolation	C	I	ASME III-3	
SFS-PL-V028	Cask Washdown Pit Level Instrument Isolation	C	I	ASME III-3	
SFS-PL-V031	SFS Refueling Cavity Drain to SGS Compartment Isolation	C	I	ASME III-3	
SFS-PL-V032	SFS Refueling Cavity Suction Isolation	C	I	ASME III-3	
SFS-PL-V033	SFS Refueling Cavity Drain to Containment Sump Isolation	C	I	ASME III-3	
SFS-PL-V034	SFS Suction Line Containment Isolation	B	I	ASME III-2	
SFS-PL-V035	SFS Suction Line Containment Isolation	B	I	ASME III-2	
SFS-PL-V037	SFS Discharge Line Containment Isolation	B	I	ASME III-2	
SFS-PL-V038	SFS Discharge Line Containment Isolation	B	I	ASME III-2	
SFS-PL-V039	SFS Suction Line from IRWST Isolation	C	I	ASME III-3	
SFS-PL-V040	SFS Fuel Transfer Canal Drain Isolation	C	I	ASME III-3	
SFS-PL-V041	SFS Cask Loading Pit Drain Isolation	C	I	ASME III-3	
SFS-PL-V042	Cask Loading Pit to Pump Suction Isolation	C	I	ASME III-3	
SFS-PL-V043	Cask Loading Pit Level Transmitter Root Isolation Valve	C	I	ASME III-3	

Table 3.2-3 (Sheet 38 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Spent Fuel Pool Cooling System (Continued)					
SFS-PL-V045	SFS Discharge to Cask Loading Pit Isolation	C	I	ASME III-3	
SFS-PL-V047	SFS Demineralized Water Makeup to SFP Reverse Flow Prevent	D	NS	ANSI B16.34	
SFS-PL-V048	SFS Containment Penetration Test Connection	B	I	ASME III-2	
SFS-PL-V049	SFS Cask Loading Pit Drain to WLS Isolation	C	I	ASME III-3	
SFS-PL-V056	SFS Containment Penetration Test Connection Isolation	B	I	ASME III-2	
SFS-PL-V058	SFS Containment Isolation Valve V034 Test	C	I	ASME III-3	
SFS-PL-V066	Spent Fuel Pool to Cask Washdown Pit Isolation	C	I	ASME III-3	
SFS-PL-V067	SFS Containment Isolation Relief Valve	B	I	ASME III-2	
SFS-PL-V068	Cask Washdown Pit Drain Isolation	C	I	ASME III-3	
SFS-PL-V071	Refueling Cavity Overflow to SG Compartment	C	I	ASME III-3	
SFS-PL-V072	Refueling Cavity Overflow to SG Compartment	C	I	ASME III-3	
SFS-PL-V075	SFS Containment Floodup Isolation Valve	C	I	ASME III-3	
SFS-PL-V117	Refueling Cavity Drain Line Test Connection	C	I	ASME III-3	
SFS-PY-C01	Spent Fuel Cooling Pump Discharge to IRWST	B	I	ASME III, MC	
SFS-PY-C02	Spent Fuel Cooling Pump Suction from IRWST	B	I	ASME III, MC	
SFS-PY-R04	SFS Cask Loading and Washdown Orifice	C	I	ASME III-3	
Balance of system components are Class D					
Steam Generator System (SGS)			Location: Containment and Auxiliary Building		
SGS-MY-Y01A	Steam Generator A PORV Silencer	D	NS	Manufacturer Std.	
SGS-MY-Y01B	Steam Generator B PORV Silencer	D	NS	Manufacturer Std.	
SGS-PL-V001A	LT001, LT011 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V001B	LT005, LT013 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V002A	LT001 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V002B	LT005 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V003A	LT002, LT012 Root Isolation Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 39 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V003B	LT006, LT014 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V004A	LT002 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V004B	LT006 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V005A	LT003, LT015, LT044 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V005B	LT007, LT017, LT046 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V006A	LT003 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V006B	LT007 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V007A	LT004, LT016, LT045 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V007B	LT008, LT018, LT047 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V008A	LT004 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V008B	LT008 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V010A	LT011 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V010B	LT013 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V011A	LT011 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V011B	LT013 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V012A	LT012 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V012B	LT014 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V013A	LT012 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V013B	LT014 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V014A	PORV Discharge Condensate Drain Isolation	D	NS	ASME B31.1	
SGS-PL-V014B	PORV Discharge Condensate Drain Isolation	D	NS	ASME B31.1	
SGS-PL-V015A	FT021 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V015B	FT023 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V016A	FT020 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V016B	FT022 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V017A	FT021 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V017B	FT023 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V018A	FT020 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V018B	FT022 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V019A	Main Steam Line Vent Isolation	B	I	ASME III-2	
SGS-PL-V019B	Main Steam Line Vent Isolation	B	I	ASME III-2	
SGS-PL-V020A	FT024 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V020B	FT025 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V021A	FT024 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V021B	FT025 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V022A	PT030 Root Isolation Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 40 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V022B	PT034 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V023A	PT031 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V023B	PT035 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V024A	PT032 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V024B	PT036 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V025A	PT033 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V025B	PT037 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V027A	PORV Block Valve SG 01	B	I	ASME III-2	
SGS-PL-V027B	PORV Block Valve SG 02	B	I	ASME III-2	
SGS-PL-V030A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V030B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V031A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V031B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V032A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V032B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V033A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V033B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V034A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V034B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V035A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V035B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V036A	Steam Line Condensate Drain Isolation	B	I	ASME III-2	
SGS-PL-V036B	Steam Line Condensate Drain Isolation	B	I	ASME III-2	
SGS-PL-V038A	Steam Line #1 Nitrogen Supply Isolation	B	I	ASME III-2	
SGS-PL-V038B	Steam Line #2 Nitrogen Supply Isolation	B	I	ASME III-2	
SGS-PL-V040A	Main Steam Line Isolation	B	I	ASME III-2	
SGS-PL-V040B	Main Steam Line Isolation	B	I	ASME III-2	
SGS-PL-V042A	MSIV Bypass Control Isolation	B	I	ASME III-2	
SGS-PL-V042B	MSIV Bypass Control Isolation	B	I	ASME III-2	
SGS-PL-V043A	MSIV Bypass Control Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 41 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V043B	MSIV Bypass Control Isolation	C	I	ASME III-3	
SGS-PL-V045A	SG 1 Condensate Pipe Drain Valve	B	I	ASME III-2	
SGS-PL-V045B	SG 2 Condensate Pipe Drain Valve	B	I	ASME III-2	
SGS-PL-V046A	LT015 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V046B	LT017 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V047A	LT015, LT044 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V047B	LT017, LT046 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V048A	LT016 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V048B	LT018 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V049A	LT016, LT045 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V049B	LT018, LT047 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V050A	LT044 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V050B	LT046 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V051A	LT044 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V051B	LT046 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V052A	LT045 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V052B	LT047 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V053A	LT045 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V053B	LT047 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V056A	PT062 Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V056B	PT063 Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V057A	Main Feedwater Isolation	B	I	ASME III-2	
SGS-PL-V057B	Main Feedwater Isolation	B	I	ASME III-2	
SGS-PL-V058A	Main Feedwater Check	B	I	ASME III-2	
SGS-PL-V058B	Main Feedwater Check	B	I	ASME III-2	
SGS-PL-V062A	FT055A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V062B	FT056A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V063A	FT055A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V063B	FT056A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V064A	FT055B Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V064B	FT056B Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V065A	FT055B Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V065B	FT056B Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V066A	FT055 Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V066B	FT056 Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V067A	Startup Feedwater Isolation	B	I	ASME III-2	
SGS-PL-V067B	Startup Feedwater Isolation	B	I	ASME III-2	
SGS-PL-V068A	FT055 Root Isolation Valve	C	I	ASME III-3	

Table 3.2-3 (Sheet 42 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V068B	FT056 Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V074A	SG Blowdown Isolation	B	I	ASME III-2	
SGS-PL-V074B	SG Blowdown Isolation	B	I	ASME III-2	
SGS-PL-V075A	SG Series Blowdown Isolation	C	I	ASME III-3	
SGS-PL-V075B	SG Series Blowdown Isolation	C	I	ASME III-3	
SGS-PL-V076A	Blowdown Vent Line Isolation	C	I	ASME III-3	
SGS-PL-V076B	Blowdown Vent Line Isolation	C	I	ASME III-3	
SGS-PL-V084A	SG 1 Nitrogen Sparging Isolation	B	I	ASME III-2	
SGS-PL-V084B	SG 2 Nitrogen Sparging Isolation	B	I	ASME III-2	
SGS-PL-V086A	Steam Line Condensate Drain Control	C	I	ASME III-3	
SGS-PL-V086B	Steam Line Condensate Drain Control	C	I	ASME III-3	
SGS-PL-V093A	Orifice Isolation Valve	C	I	ASME III-3	
SGS-PL-V093B	Orifice Isolation Valve	C	I	ASME III-3	
SGS-PL-V094A	Orifice Cleanout Line Isolation Valve	C	I	ASME III-3	
SGS-PL-V094B	Orifice Cleanout Line Isolation Valve	C	I	ASME III-3	
SGS-PL-V095A	Orifice Isolation Valve	C	I	ASME III-3	
SGS-PL-V095B	Orifice Isolation Valve	C	I	ASME III-3	
SGS-PL-V096A	Steam Line Condensate Drain Level Isolation Valve	B	I	ASME III-2	
SGS-PL-V096B	Steam Line Condensate Drain Level Isolation Valve	B	I	ASME III-2	
SGS-PL-V097A	Steam Line Condensate Drain Level Isolation Valve	B	I	ASME III-2	
SGS-PL-V097B	Steam Line Condensate Drain Level Isolation Valve	B	I	ASME III-2	
SGS-PL-V100A	Startup Feedwater Drain Isolation Valve	C	I	ASME III-3	
SGS-PL-V100B	Startup Feedwater Drain Isolation Valve	C	I	ASME III-3	
SGS-PL-V101A	Main Feedwater Drain Isolation Valve	B	I	ASME III-2	
SGS-PL-V101B	Main Feedwater Drain Isolation Valve	B	I	ASME III-2	
SGS-PL-V102A	Startup Feedwater Vent Isolation Valve	C	I	ASME III-3	
SGS-PL-V102B	Startup Feedwater Vent Isolation Valve	C	I	ASME III-3	
SGS-PL-V103A	Main Feedwater Vent Isolation Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 43 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V103B	Main Feedwater Vent Isolation Valve	B	I	ASME III-2	
SGS-PL-V104A	Main Feedwater Drain Isolation Valve	C	I	ASME III-3	
SGS-PL-V104B	Main Feedwater Drain Isolation Valve	C	I	ASME III-3	
SGS-PL-V233A	Power Operated Relief Valve	C	I	ASME III-3	
SGS-PL-V233B	Power Operated Relief Valve	C	I	ASME III-3	
SGS-PL-V240A	MSIV Bypass Isolation	B	I	ASME III-2	
SGS-PL-V240B	MSIV Bypass Isolation	B	I	ASME III-2	
SGS-PL-V250A	Main Feedwater Control	C	I	ASME III-3	
SGS-PL-V250B	Main Feedwater Control	C	I	ASME III-3	
SGS-PL-V255A	Startup Feedwater Control	C	I	ASME III-3	
SGS-PL-V255B	Startup Feedwater Control	C	I	ASME III-3	
SGS-PL-V256A	Startup Feedwater Check Valve	C	I	ASME III-3	
SGS-PL-V256B	Startup Feedwater Check Valve	C	I	ASME III-3	
SGS-PL-V257A	Main Feedwater Thermal Relief Valve	C	I	ASME III-3	
SGS-PL-V257B	Main Feedwater Thermal Relief Valve	C	I	ASME III-3	
SGS-PL-V258A	Startup Feedwater Thermal Relief Valve	C	I	ASME III-3	
SGS-PL-V258B	Startup Feedwater Thermal Relief Valve	C	I	ASME III-3	
SGS-PL-V300	SG1 NR LT001 Upper Isol	B	I	ASME III-2	
SGS-PL-V301	SG1 NR LT001 Lower Isol	B	I	ASME III-2	
SGS-PL-V302	SG1 NR LT002 Upper Isol	B	I	ASME III-2	
SGS-PL-V303	SG1 NR LT002 Lower Isol	B	I	ASME III-2	
SGS-PL-V304	SG1 NR LT003 Upper Isol	B	I	ASME III-2	
SGS-PL-V305	SG1 NR LT003 Lower Isol	B	I	ASME III-2	
SGS-PL-V306	SG1 NR LT004 Upper Isol	B	I	ASME III-2	
SGS-PL-V307	SG1 NR LT004 Lower Isol	B	I	ASME III-2	
SGS-PL-V308	SG1 NR LT011 Lower Isol	B	I	ASME III-2	
SGS-PL-V309	SG1 NR LT012 Lower Isol	B	I	ASME III-2	
SGS-PL-V310	SG1 NR LT015 Lower Isol	B	I	ASME III-2	
SGS-PL-V311	SG1 NR LT016 Lower Isol	B	I	ASME III-2	
SGS-PL-V312	SG1 Main Steam FT020 Isol	B	I	ASME III-2	
SGS-PL-V313	SG1 Main Steam FT021 Isol	B	I	ASME III-2	
SGS-PL-V314	SG1 Main Steam FT024 Isol	B	I	ASME III-2	
SGS-PL-V320	SG2 NR LT005 Upper Isol	B	I	ASME III-2	
SGS-PL-V321	SG2 NR LT005 Lower Isol	B	I	ASME III-2	
SGS-PL-V322	SG2 NR LT006 Upper Isol	B	I	ASME III-2	

Table 3.2-3 (Sheet 44 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V323	SG2 NR LT006 Lower Isol	B	I	ASME III-2	
SGS-PL-V324	SG2 NR LT007 Upper Isol	B	I	ASME III-2	
SGS-PL-V325	SG2 NR LT007 Lower Isol	B	I	ASME III-2	
SGS-PL-V326	SG2 NR LT008 Upper Isol	B	I	ASME III-2	
SGS-PL-V327	SG2 NR LT008 Lower Isol	B	I	ASME III-2	
SGS-PL-V328	SG2 NR LT013 Lower Isol	B	I	ASME III-2	
SGS-PL-V329	SG2 NR LT014 Lower Isol	B	I	ASME III-2	
SGS-PL-V330	SG2 NR LT017 Lower Isol	B	I	ASME III-2	
SGS-PL-V331	SG2 NR LT018 Lower Isol	B	I	ASME III-2	
SGS-PL-V332	SG2 Main Steam FT022 Isol	B	I	ASME III-2	
SGS-PL-V333	SG2 Main Steam FT023 Isol	B	I	ASME III-2	
SGS-PL-V334	SG2 Main Steam FT025 Isol	B	I	ASME III-2	
SGS-PY-C01A	Main Steam Line A Penetration	B	I	ASME III, MC	
SGS-PY-C01B	Main Steam Line B Penetration	B	I	ASME III, MC	
SGS-PY-C02A	Main Feedwater Line A Penetration	B	I	ASME III, MC	
SGS-PY-C02B	Main Feedwater Line B Penetration	B	I	ASME III, MC	
SGS-PY-C03A	Steam Generator A Blow-down Line Penetration	B	I	ASME III, MC	
SGS-PY-C03B	Steam Generator B Blow-down Line Penetration	B	I	ASME III, MC	
SGS-PY-C05A	Startup Feedwater Line A Penetration	B	I	ASME III, MC	
SGS-PY-C05B	Startup Feedwater Line B Penetration	B	I	ASME III, MC	
SGS-PY-R02A	SG 1 Main Steam Line Drain Plug-Resistant Orifice	C	I	ASME III-3	
SGS-PY-R02B	SG 2 Main Steam Line Drain Plug-Resistant Orifice	C	I	ASME III-3	
SGS-PY-Y01A	Flexible Hose from SG 1 to Upper Tap LT001/LT011	B	I	ASME III-2	
SGS-PY-Y01B	Flexible Hose from SG 2 to Upper Tap LT005/LT013	B	I	ASME III-2	
SGS-PY-Y02A	Flexible Hose from SG 1 to Upper Tap LT001	B	I	ASME III-2	
SGS-PY-Y02B	Flexible Hose from SG 2 to Upper Tap LT005	B	I	ASME III-2	
SGS-PY-Y03A	Flexible Hose from SG 1 to Upper Tap LT002/LT015	B	I	ASME III-2	
SGS-PY-Y03B	Flexible Hose from SG 2 to Upper Tap LT006/LT014	B	I	ASME III-2	
SGS-PY-Y04A	Flexible Hose from SG 1 to Upper Tap LT002	B	I	ASME III-2	

Table 3.2-3 (Sheet 45 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PY-Y04B	Flexible Hose from SG 2 to Upper Tap LT006	B	I	ASME III-2	
SGS-PY-Y05A	Flexible Hose from SG 1 to Upper Tap LT003/LT012/ LT044	B	I	ASME III-2	
SGS-PY-Y05B	Flexible Hose from SG 2 to Upper Tap LT007/LT017/ LT046	B	I	ASME III-2	
SGS-PY-Y06A	Flexible Hose from SG 1 to Upper Tap LT003	B	I	ASME III-2	
SGS-PY-Y06B	Flexible Hose from SG 2 to Upper Tap LT007	B	I	ASME III-2	
SGS-PY-Y07A	Flexible Hose from SG 1 to Upper Tap LT004/LT016/ LT045	B	I	ASME III-2	
SGS-PY-Y07B	Flexible Hose from SG 2 to Upper Tap LT008/LT018/ LT047	B	I	ASME III-2	
SGS-PY-Y08A	Flexible Hose from SG 1 to Upper Tap LT004	B	I	ASME III-2	
SGS-PY-Y08B	Flexible Hose from SG 2 to Upper Tap LT008	B	I	ASME III-2	
SGS-PY-Y09A	Flexible Hose from SG 1 to Upper Tap LT011	B	I	ASME III-2	
SGS-PY-Y09B	Flexible Hose from SG 2 to Upper Tap LT013	B	I	ASME III-2	
SGS-PY-Y10A	Flexible Hose from SG 1 to Upper Tap LT012	B	I	ASME III-2	
SGS-PY-Y10B	Flexible Hose from SG 2 to Upper Tap LT014	B	I	ASME III-2	
SGS-PY-Y11A	Flexible Hose from SG 1 to Upper Tap LT015/LT044	B	I	ASME III-2	
SGS-PY-Y11B	Flexible Hose from SG 2 to Upper Tap LT017/LT046	B	I	ASME III-2	
SGS-PY-Y12A	Flexible Hose from SG 1 to Upper Tap LT016/LT045	B	I	ASME III-2	
SGS-PY-Y12B	Flexible Hose from SG 2 to Upper Tap LT018/LT047	B	I	ASME III-2	
SGS-PY-Y13A	Flexible Hose from SG 1 to Lower Tap FT024	B	I	ASME III-2	
SGS-PY-Y13B	Flexible Hose from SG 2 to Lower Tap FT025	B	I	ASME III-2	
SGS-PY-Y14A	Flexible Hose from SG 1 to Lower Tap FT021	B	I	ASME III-2	
SGS-PY-Y14B	Flexible Hose from SG 2 to Lower Tap FT023	B	I	ASME III-2	

Table 3.2-3 (Sheet 46 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PY-Y15A	Flexible Hose from SG 1 to Lower Tap FT020	B	I	ASME III-2	
SGS-PY-Y15B	Flexible Hose from SG 2 to Lower Tap FT022	B	I	ASME III-2	
SGS-PY-Y16A	Flexible Hose from Main Steam Line to Upper Tap FT020	B	I	ASME III-2	
SGS-PY-Y16B	Flexible Hose from Main Steam Line to Upper Tap FT022	B	I	ASME III-2	
SGS-PY-Y17A	Flexible Hose from Main Steam Line to Upper Tap FT021	B	I	ASME III-2	
SGS-PY-Y17B	Flexible Hose from Main Steam Line to Upper Tap FT023	B	I	ASME III-2	
SGS-PY-Y18A	Flexible Hose from Main Steam Line to Upper Tap FT024	B	I	ASME III-2	
SGS-PY-Y18B	Flexible Hose from Main Steam Line to Upper Tap FT025	B	I	ASME III-2	
SGS-PY-Y19A	Flexible Hose from Main Steam Line to PT030	B	I	ASME III-2	
SGS-PY-Y19B	Flexible Hose from Main Steam Line to PT034	B	I	ASME III-2	
SGS-PY-Y20A	Flexible Hose from Main Steam Line to PT032	B	I	ASME III-2	
SGS-PY-Y20B	Flexible Hose from Main Steam Line to PT036	B	I	ASME III-2	
Secondary Sampling System (SSS)				Location: Turbine Building	
System components are Class E					
Service Water System (SWS)				Location: Turbine Building and Yard	
n/a	Service Water Cooling Tower Fans	D	NS	Manufacturer Std.	
n/a	Service Water Cooling Tower	D	NS	Manufacturer Std.	
n/a	Service Water Pumps	D	NS	Hydraulic Institute Std.	
n/a	Valves Providing SWS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
Turbine Building Closed Cooling Water System (TCS)				Location: Turbine Building	
System components are Class E					

Table 3.2-3 (Sheet 47 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Turbine Island Vents, Drains and Relief System (TDS)				Location: Turbine Building	
n/a	Piping and components that provide the path from the GSS and CMS to atmosphere and rad monitor	D	NS	ASME B31.1	
Balance of system components are Class E					
Main Turbine Control and Diagnostic System (TOS)				Location: Turbine Building	
System components are Class E					
Radiologically Controlled Area Ventilation System (VAS)			Location: Auxiliary Building and Annex Building		
n/a	CVS Pump Room Coolers	Note 2	NS	Manufacturer Std.	
n/a	RNS Pump Room Coolers	Note 2	II	Manufacturer Std.	
n/a	Valves Providing VAS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
n/a	Shutoff, Isolation, and Balancing Dampers	L	NS	ANSI/AMCA-500-D	
n/a	Shutoff and Isolation Dampers	R	NS	ASME AG-1	
n/a	Fire Dampers	L	NS	UL-555	
n/a	Air Handling Units	L	NS	Manufacturer Std.	
n/a	Filters	L	NS	UL 900	
n/a	Ductwork	L	NS	SMACNA, Note 7	
n/a	Ductwork in Auxiliary Building except ductwork attached to mechanical modules	L	II	SMACNA, Note 7	Ductwork in radiation chemistry laboratory is nonseismic.
n/a	Ductwork	R	II	ASME AG-1	
n/a	Fans	L	NS	AMCA, Note 7	
Balance of system components are Class E or Class L					
Nuclear Island Nonradioactive Ventilation System (VBS)			Location: Shield Building, Auxiliary Building, and Annex Building		
n/a	Battery Rooms Exhaust Fans	Note 2	II	AMCA, Note 7	
n/a	PCS Room Heaters	Note 3	II	Manufacturer Std.	
n/a	Fire Dampers	Note 2, L	NS	UL-555	
n/a	Fire Dampers	Note 2, R	NS	ASME AG-1 and UL-555	
n/a	Combination Fire/Smoke Dampers	Note 2, L	NS	UL-555 and UL-555S	
n/a	Combination Fire/Smoke Dampers	Note 2, R	NS	ASME AG-1, UL-555, and UL-555S	
n/a	Dampers Providing AP1000 Equipment Class D Function	Note 2	NS	ANSI/AMCA-500-D	
n/a	Shutoff, Balancing, and Isolation Dampers	R	NS	ASME AG-1	
n/a	Shutoff and Balancing Dampers	L	NS	ANSI/AMCA-500-D	
VBS-MP-01A	Sample Pump A	C	I	Manufacturer Std.	
VBS-MP-01B	Sample Pump B	C	I	Manufacturer Std.	

Table 3.2-3 (Sheet 48 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Nuclear Island Nonradioactive Ventilation System (Continued)					
n/a	MCR/CSA Supplemental Air Filtration Units	Note 2	II	ASME AG-1, ASME N509, Note 4	
VBS-PL-V186	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V187	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V188	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V189	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V190	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V191	MCR Isolation Valve	C	I	ASME III-3	
n/a	Valves Providing VBS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
n/a	Other Air Handling Units	Note 2	NS	Manufacturer Std.	
n/a	Filters	Note 2	NS	UL 900	
n/a	Other Fans	Note 2, L	NS	AMCA, Note 7	
VBS-MA-10A	Ancillary Fan	D	II	ANSI/AMCA 210, 300	Equipment Anchorage is Seismic Category II
VBS-MA-10B	Ancillary Fan	D	II	ANSI/AMCA 210, 300	Equipment Anchorage is Seismic Category II
VBS-MA-11	Ancillary Fan	D	II	ANSI/AMCA 210, 300	Equipment Anchorage is Seismic Category II
VBS-MA-12	Ancillary Fan	D	II	ANSI/AMCA 210, 300	Equipment Anchorage is Seismic Category II
n/a	MCR Pressure Boundary Penetration Cast Sleeve	C	I	ANSI/AISC N690	CA52
n/a	Ductwork in Auxiliary Building	Note 2, L	II	SMACNA, Note 7	
n/a	Ductwork in Annex Building	Note 2, L	NS	SMACNA, Note 7	
n/a	Ductwork in Auxiliary Building	Note 2, R	II	ASME AG-1	
n/a	Ductwork in Annex Building	Note 2, R	NS	ASME AG-1	
VBS-MY-Y100	Silencer	D	II	Manufacturer Std.	Equipment Anchorage is Seismic Category II
VBS-MY-Y101	Silencer	D	II	Manufacturer Std.	Equipment Anchorage is Seismic Category II
VBS-MY-Y102	Static Air Mixer	Note 1	I	Manufacturer Std.	Inside Seismic Category II Supported Duct; Commercially dedicated to ASME AG-1
VBS-PL-V184A	VBS-PDT-032A Isolation Valve	C	I	ASME III-3	
VBS-PL-V184B	VBS-PDT-032B Isolation Valve	C	I	ASME III-3	
VBS-PL-V184C	VBS-PDT-032C Isolation Valve	C	I	ASME III-3	
Balance of system components are Class E or Class L					

Table 3.2-3 (Sheet 49 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Containment Recirculation Cooling System (VCS)				Location: Containment	
n/a	Dampers	L	II	ANSI/AMCA-500-D	
n/a	Fan Coil Units	L	II	Manufacturer Std.	
n/a	Ductwork	L	II	SMACNA, Note 7	
n/a	Fans	L	II	AMCA, Note 7	
n/a	Fire Damper	L	II	UL-555	
Balance of system components are Class L					
Main Control Room Emergency Habitability System (VES)				Location: Auxiliary Building	
VES-MT-01	Emergency Air Storage Tank 01	C	I	ASME VIII, Appendix 22	
VES-MT-02	Emergency Air Storage Tank 02	C	I	ASME VIII, Appendix 22	
VES-MT-03	Emergency Air Storage Tank 03	C	I	ASME VIII, Appendix 22	
VES-MT-04	Emergency Air Storage Tank 04	C	I	ASME VIII, Appendix 22	
VES-MT-05	Emergency Air Storage Tank 05	C	I	ASME VIII, Appendix 22	
VES-MT-06	Emergency Air Storage Tank 06	C	I	ASME VIII, Appendix 22	
VES-MT-07	Emergency Air Storage Tank 07	C	I	ASME VIII, Appendix 22	
VES-MT-08	Emergency Air Storage Tank 08	C	I	ASME VIII, Appendix 22	
VES-MT-09	Emergency Air Storage Tank 09	C	I	ASME VIII, Appendix 22	
VES-MT-10	Emergency Air Storage Tank 10	C	I	ASME VIII, Appendix 22	
VES-MT-11	Emergency Air Storage Tank 11	C	I	ASME VIII, Appendix 22	
VES-MT-12	Emergency Air Storage Tank 12	C	I	ASME VIII, Appendix 22	
VES-MT-13	Emergency Air Storage Tank 13	C	I	ASME VIII, Appendix 22	
VES-MT-14	Emergency Air Storage Tank 14	C	I	ASME VIII, Appendix 22	
VES-MT-15	Emergency Air Storage Tank 15	C	I	ASME VIII, Appendix 22	
VES-MT-16	Emergency Air Storage Tank 16	C	I	ASME VIII, Appendix 22	
VES-MT-17	Emergency Air Storage Tank 17	C	I	ASME VIII, Appendix 22	
VES-MT-18	Emergency Air Storage Tank 18	C	I	ASME VIII, Appendix 22	
VES-MT-19	Emergency Air Storage Tank 19	C	I	ASME VIII, Appendix 22	

Table 3.2-3 (Sheet 50 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Main Control Room Emergency Habitability System (Continued)					
VES-MT-20	Emergency Air Storage Tank 20	C	I	ASME VIII, Appendix 22	
VES-MT-21	Emergency Air Storage Tank 21	C	I	ASME VIII, Appendix 22	
VES-MT-22	Emergency Air Storage Tank 22	C	I	ASME VIII, Appendix 22	
VES-MT-23	Emergency Air Storage Tank 23	C	I	ASME VIII, Appendix 22	
VES-MT-24	Emergency Air Storage Tank 24	C	I	ASME VIII, Appendix 22	
VES-MT-25	Emergency Air Storage Tank 25	C	I	ASME VIII, Appendix 22	
VES-MT-26	Emergency Air Storage Tank 26	C	I	ASME VIII, Appendix 22	
VES-MT-27	Emergency Air Storage Tank 27	C	I	ASME VIII, Appendix 22	
VES-MT-28	Emergency Air Storage Tank 28	C	I	ASME VIII, Appendix 22	
VES-MT-29	Emergency Air Storage Tank 29	C	I	ASME VIII, Appendix 22	
VES-MT-30	Emergency Air Storage Tank 30	C	I	ASME VIII, Appendix 22	
VES-MT-31	Emergency Air Storage Tank 31	C	I	ASME VIII, Appendix 22	
VES-MT-32	Emergency Air Storage Tank 32	C	I	ASME VIII, Appendix 22	
VES-PL-V001	Air Delivery Alternate Isolation Valve	C	I	ASME III-3	
VES-PL-V002A	Pressure Regulating Valve A	C	I	ASME III-3	
VES-PL-V002B	Pressure Regulating Valve B	C	I	ASME III-3	
VES-PL-V005A	Air Delivery Main Isolation Valve A	C	I	ASME III-3	
VES-PL-V005B	Air Delivery Main Isolation Valve B	C	I	ASME III-3	
VES-PL-V006A	Air Delivery Line Pressure Instrument Isolation Valve A	C	I	ASME III-3	
VES-PL-V006B	Air Delivery Line Pressure Instrument Isolation Valve B	C	I	ASME III-3	
VES-PL-V010A	Air Delivery Line Maintenance Isolation Valve A	C	I	ASME III-3	
VES-PL-V010B	Air Delivery Line Maintenance Isolation Valve B	C	I	ASME III-3	
VES-PL-V011A	Air Delivery Line Maintenance Isolation Valve A	C	I	ASME III-3	
VES-PL-V011B	Air Delivery Line Maintenance Isolation Valve B	C	I	ASME III-3	

Table 3.2-3 (Sheet 51 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Main Control Room Emergency Habitability System (Continued)					
VES-PL-V016	Temporary Instrument Isolation Valve A	C	I	ASME III-3	
VES-PL-V018	Temporary Instrument Isolation Valve A	C	I	ASME III-3	
VES-PL-V019	Temporary Instrument Isolation Valve B	C	I	ASME III-3	
VES-PL-V020	Temporary Instrument Isolation Valve B	C	I	ASME III-3	
VES-PL-V022A	Pressure Relief Isolation Valve A	C	I	ASME III-3	
VES-PL-V022B	Pressure Relief Isolation Valve B	C	I	ASME III-3	
VES-PL-V024A	Air Bank 1 Isolation Valve A	C	I	ASME III-3	
VES-PL-V024B	Air Bank 2 Isolation Valve B	C	I	ASME III-3	
VES-PL-V024C	Air Bank 3 Isolation Valve C	C	I	ASME III-3	
VES-PL-V024D	Air Bank 4 Isolation Valve D	C	I	ASME III-3	
VES-PL-V025A	Air Bank 1 Isolation Valve A	C	I	ASME III-3	
VES-PL-V025B	Air Bank 2 Isolation Valve B	C	I	ASME III-3	
VES-PL-V025C	Air Bank 3 Isolation Valve C	C	I	ASME III-3	
VES-PL-V025D	Air Bank 4 Isolation Valve D	C	I	ASME III-3	
VES-PL-V026A	Air Bank 1 Fill/Vent Isolation Valve A	C	I	ASME III-3	
VES-PL-V026B	Air Bank 2 Fill/Vent Isolation Valve B	C	I	ASME III-3	
VES-PL-V026C	Air Bank 3 Fill/Vent Isolation Valve C	C	I	ASME III-3	
VES-PL-V026D	Air Bank 4 Fill/Vent Isolation Valve D	C	I	ASME III-3	
VES-PL-V040A	Air Tank Safety Relief Valve A	C	I	ASME III-3	
VES-PL-V040B	Air Tank Safety Relief Valve B	C	I	ASME III-3	
VES-PL-V040C	Air Tank Safety Relief Valve C	C	I	ASME III-3	
VES-PL-V040D	Air Tank Safety Relief Valve D	C	I	ASME III-3	
VES-PL-V043A	Differential Pressure Instrument Line Isolation Valve A	C	I	ASME III-3	
VES-PL-V043B	Differential Pressure Instrument Line Isolation Valve B	C	I	ASME III-3	
VES-PL-V044	Main Air Flowpath Isolation Valve	C	I	ASME III-3	
VES-PL-V045	Eductor Flow Path Isolation Valve	C	I	ASME III-3	
VES-PL-V046	Eductor Bypass Isolation Valve	C	I	ASME III-3	
VES-PY-N01	MCR Air Filtration Line Eductor	C	I	ASME III-3	

Table 3.2-3 (Sheet 52 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Main Control Room Emergency Habitability System (Continued)					
VES-PY-N02	Eductor Bypass Isolation Discharge Silencer	C	I	ASME III-3	
VES-PY-R02	Eductor Bypass Flow Orifice	C	I	ASME III-3	
VES-MY-F01	MCR Air Filtration Line Charcoal Filter	Note 1	I	ASME AG-1 Section FD	
VES-MY-F02	MCR Air Filtration Line HEPA Filter	Note 1	I	ASME AG-1 Section FC	
VES-MY-F03	MCR Air Filtration Line Postfilter	Note 1	1	ASME AG-1	
VES-MD-D001A	Relief Damper A	Note 1	I	ASME N509/N510	
VES-MD-D001B	Relief Damper B	Note 1	I	ASME N509/N510	
VES-MD-D002	MCR Air Filtration Line Supply Damper	Note 1	I	ASME AG-1 Section DA	
VES-MD-D003	MCR Air Filtration Line Supply Damper	Note 1	I	ASME AG-1 Section DA	
VES-MY-G001	Ducting Grill	Note 1	I	ASME N509/N510	
VES-MY-R001	Ducting Register	Note 1	I	ASME N509/N510	
VES-MY-R002	Ducting Register	Note 1	I	ASME N509/N510	
VES-MY-R003	Ducting Register	Note 1	I	ASME N509/N510	
VES-MY-Y01	MCR Air Filtration Line Silencer	Note 1	I	ASME AG-1 Section SA	
VES-MY-Y02	MCR Air Filtration Line Silencer	Note 1	I	ASME AG-1 Section SA	
Containment Air Filtration System (VFS)			Location: Containment, Auxiliary Building, and Annex Building		
VFS-PY-C01	Containment Supply Duct Penetration	B	I	ASME III, MC	
VFS-PY-C02	Containment Exhaust Duct Penetration	B	I	ASME III, MC	
VFS-MY-Y01	Containment Air Supply Debris Screen	C	I	ASME Sec. III Class 3	
VFS-MY-Y02	Containment Air Exhaust Debris Screen	C	I	ASME Sec. III Class 3	
VFS-PL-V003	Containment Purge Supply Containment Isolation Valve	B	I	ASME III-2	
VFS-PL-V004	Containment Purge Supply Containment Isolation Valve	B	I	ASME III-2	
VFS-PL-V006	Containment Isolation Test Connection	C	I	ASME III-3	
VFS-PL-V007	RCS Ejector Discharge Isolation	C	I	ASME III-3	
VFS-PL-V008	Containment Isolation Test Connection	B	I	ASME III-2	
VFS-PL-V009	Containment Purge Discharge Containment Isolation Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 53 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Containment Air Filtration System (Continued)					
VFS-PL-V010	Containment Purge Discharge Containment Isolation Valve	B	I	ASME III-2	
VFS-PL-V012	Containment Isolation Test Connection	B	I	ASME III-2	
VFS-PL-V015	Containment Isolation Test Connection	B	I	ASME III-2	
VFS-PL-V101	Containment Air Supply Line Test Connection	C	I	ASME III-3	
VFS-PL-V202	Containment Atmosphere to Filtration Units Isolation	C	I	ASME III-3	
VFS-PL-V587	Filtration Units to Containment Atmosphere Manual Isolation	C	I	ASME III-3	
VFS-PL-V800A	Vacuum Relief Containment Isolation A – ORC	B	I	ASME III-2	
VFS-PL-V800B	Vacuum Relief Containment Isolation B – ORC	B	I	ASME III-2	
VFS-PL-V803A	Vacuum Relief Containment Isolation Check Valve A – IRC	B	I	ASME III-2	
VFS-PL-V803B	Vacuum Relief Containment Isolation Check Valve B – IRC	B	I	ASME III-2	
n/a	Valves Providing VFS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
n/a	Shutoff, Balancing, Isolation, and Pressure Differential Control Dampers	R	NS	ASME AG-1	
n/a	Shutoff and Balancing Dampers	L	NS	ANSI/AMCA-500-D	
n/a	Fire Dampers	L	NS	UL-555	
n/a	Fire Damper	R	NS	ASME AG-1 and UL-555	
n/a	Supply Air Handling Units	L	NS	Manufacturer Std.	
n/a	Air Exhaust Filtration Units	R	NS	ASME AG-1, ASME N509, Note 4	
n/a	Other Fans	L	NS	AMCA, Note 7	
n/a	Ductwork in Auxiliary Building	L	II	SMACNA, Note 7	
n/a	Ductwork in Annex Building	L	NS	SMACNA, Note 7	
n/a	Ductwork in Containment	R	II	ASME AG-1	
n/a	Ductwork in Annex Building	R	NS	ASME AG-1, Note 4	
Balance of system components are Class E, L and R					
Health Physics and Hot Machine Shop HVAC System (VHS)				Location: Annex Building	
n/a	Shutoff, Isolation, Balancing, and Backdraft Dampers	L	NS	ANSI/AMCA-500-D	
n/a	Shutoff Dampers	R	NS	ASME AG-1	
n/a	Fire Dampers	L	NS	UL-555	
n/a	Air Handling Units w/ Filters	L	NS	Manufacturer Std.	
n/a	Ductwork	L	NS	SMACNA, Note 7	

Table 3.2-3 (Sheet 54 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Health Physics and Hot Machine Shop HVAC System (Continued)					
n/a	Ductwork	R	NS	ASME AG-1	
n/a	Fans	L	NS	AMCA, Note 7	
Balance of system components are Class E or Class L					
Containment Hydrogen Control System (VLS)				Location: Containment	
n/a	Hydrogen Igniters	D	NS	Manufacturer Std.	Provides Hydrogen Control Following Severe Accidents
VLS-MY-E01A	Catalytic Hydrogen Recombiner A	D	NS	Manufacturer Std.	
VLS-MY-E01B	Catalytic Hydrogen Recombiner B	D	NS	Manufacturer Std.	
Balance of system components are Class E or Class L					
Radwaste Building Ventilation System (VRS)				Location: Annex Building and Radwaste Building	
n/a	Shutoff, Isolation, Balancing, and Backdraft Dampers	L	NS	ANSI/AMCA-500-D	
n/a	Shutoff Dampers	R	NS	ASME AG-1	
n/a	Fire Damper	R	NS	ASME AG-1 & UL-555	
n/a	Air Handling Units	L	NS	Manufacturer Std.	
n/a	Filters	L	NS	UL 900	
n/a	Ductwork	L	NS	SMACNA, Note 7	
n/a	Ductwork	R	NS	ASME AG-1	
n/a	Fans	L	NS	AMCA, Note 7	
Balance of system components are Class E or Class L					
Turbine Building Ventilation System (VTS)				Location: Turbine Building	
n/a	Shutoff, Isolation, Balancing, and Backdraft Dampers	L	NS	ANSI/AMCA-500-D	
n/a	Fire Dampers	L	NS	UL-555	
n/a	Air Handling Units w/ Filters	L	NS	Manufacturer Std., UL-900	
n/a	Ductwork	L	NS	SMACNA, Note 7	
n/a	Fans	L	II	AMCA, Note 7	
n/a	Fire Damper	L	II	UL-555	
Balance of system components are Class E or Class L					
Containment Leak Rate Test System (VUS)			Location: Containment and Auxiliary Building		
VUS-PL-V013	Main Equipment Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V014	Maintenance Equipment Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V015	Main Equipment Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V016	Maintenance Equipment Hatch Test Connection	B	I	ASME III-2	

Table 3.2-3 (Sheet 55 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Containment Leak Rate Test System (Continued)					
VUS-PL-V017	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V018	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V019	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V020	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V021	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V022	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V023	Fuel Transfer Tube Test Connection	B	I	ASME III-2	
VUS-PL-V140	Spare Penetration Test Connection	B	I	ASME III-2	
VUS-PL-V141	Spare Penetration Test Connection	B	I	ASME III-2	
VUS-PL-V142	Spare Penetration Test Connection	B	I	ASME III-2	
Balance of system components are Class E					
Central Chilled Water System (VWS)				Location: Various	
VWS-MS-02	Air-Cooled Chiller 2	D	NS	ARI/ASME VIII	
VWS-MS-03	Air-Cooled Chiller 3	D	NS	ARI/ASME VIII	
n/a	Pumps	D	NS	Manufacturer Std.	
n/a	Tanks	D	NS	ASME VIII	
n/a	Valves Providing VWS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
VWS-PY-C01	Containment Chilled Water Return Penetration	B	I	ASME III, MC	
VWS-PY-C02	Containment Chilled Water Supply Penetration	B	I	ASME III, MC	
VWS-PL-V053	VWS Containment Penetration Thermal Relief Valve	C	I	ASME III-3	
VWS-PL-V057	VWS Containment Penetration Thermal Relief Valve	C	I	ASME III-3	
VWS-PL-V058	Fan Coolers Supply Containment Isolation	B	I	ASME III-2	
VWS-PL-V062	Fan Coolers Supply Containment Isolation Check Valve	B	I	ASME III-2	
VWS-PL-V080	VWS Containment Isolation Relief Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 56 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Central Chilled Water System (Continued)					
VWS-PL-V082	Fan Coolers Return Containment Isolation	B	I	ASME III-2	
VWS-PL-V086	Fan Coolers Return Containment Isolation	B	I	ASME III-2	
VWS-PL-V424	Containment Penetration Test Connection	B	I	ASME III-2	
VWS-PL-V425	Containment Penetration Test Connection	B	I	ASME III-2	
Balance of system components are Class E					
Annex/Auxiliary Nonradioactive Ventilation System (VXS)			Location: Auxiliary Building and Annex Building		
n/a	Air Handling Unit Fans Providing AP1000 Equipment Class D Function	Note 2	NS	AMCA, Note 7	
n/a	Dampers Providing VXS AP1000 Equipment Class D Function	Note 2	NS	ANSI/AMCA-500-D	
n/a	Exhaust Fan Providing Ancillary Diesel Room Ventilation	Note 2	NS	AMCA, Note 7	
n/a	Fire Dampers	L	NS	UL-555	
n/a	Fire Dampers	R	NS	ASME AG-1 and UL-555	
n/a	Combination Fire/Smoke Dampers	L	NS	UL-555 and UL-555S	
n/a	Combination Fire/Smoke Dampers	R	NS	ASME AG-1, UL-555, and UL-555S	
n/a	Air Handling Units	L	NS	Manufacturer Std.	
n/a	Filters	L	NS	UL 900	
n/a	Ductwork	L	NS	SMACNA, Note 7	
n/a	Ductwork in Auxiliary Building except ductwork attached to mechanical modules	L	II	SMACNA, Note 7	
n/a	Ductwork	R	NS	ASME AG-1	
n/a	Fans	L	NS	AMCA, Note 7	
Balance of system components are Class E or Class L					
Hot Water Heating System (VYS)				Location: Various	
System components are Class E					

Table 3.2-3 (Sheet 57 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Diesel Generator Building Ventilation System (VZS)				Location: Diesel Generator Building	
n/a	Unit Heaters Providing AP1000 Equipment Class D Function	Note 3	NS	UL-2021; NFPA 70	
n/a	Fans Providing AP1000 Equipment Class D Function	Note 2	NS	AMCA, Note 7	
n/a	Dampers Providing VZS AP1000 Equipment Class D Function	Note 2	NS	ANSI/AMCA 500-D	
n/a	Fire Dampers	L	NS	UL-555	
n/a	Air Handling Units	L	NS	Manufacturer Std.	
n/a	Filters	L	NS	UL 900	
n/a	Ductwork	L	NS	SMACNA, Note 7	
n/a	Fans	L	II	AMCA, Note 7	
n/a	Fire Damper	L	II	UL-555	
Balance of system components are Class E or Class L					
Gaseous Radwaste System (WGS)				Location: Auxiliary Building	
n/a	Gas Cooler	D	NS	Manufacturer Std.	
n/a	Sample Pumps	D	NS	Manufacturer Std.	
n/a	Guard and Delay Beds	D	NS	ASME VIII	Design for 1/2 SSE
n/a	Moisture Separator	D	NS	ASME VIII	
n/a	Valves Providing WGS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
Liquid Radwaste System (WLS)			Location: Containment, Auxiliary, and Radwaste Buildings		
n/a	Heat Exchangers, WLS and CCS Side	D	NS	ASME VIII/ TEMA	
n/a	Pumps	D	NS	Manufacturer Std.	
n/a	Tanks (except WLS-MT-13A, WLS-MT-13B, WLS-MT-17, WLS-MT-23A, WLS-MT-23B	D	NS	ASME III without Code Stamp	
WLS-MT-13A	Waste Holdup Tank A Chemical Addition Pot	D	NS	ASME VIII-1	
WLS-MT-13B	Waste Holdup Tank B Chemical Addition Pot	D	NS	ASME-VIII-1	
WLS-MT-17	Chemical Waste Tank Chemical Addition Pot	D	NS	ASME VIII-1	
WLS-MT-23A	WLS Leak Chase Collection Pot A	D	NS	ASME VIII-1	
WLS-MT-23B	WLS Leak Chase Collection Pot B	D	NS	ASME VIII-1	
n/a	Degasifier	D	NS	ASME VIII	
n/a	Ion Exchangers	D	NS	ASME VIII	
n/a	Filters	D	NS	ASME VIII	

Table 3.2-3 (Sheet 58 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Liquid Radwaste System (Continued)					
n/a	Valves Providing WLS AP1000 Equipment Class D Function (local drain valves in Radwaste Building)	D	NS	ANSI B16.34	
n/a	Floor Drain Hubs	D	NS	Manufacturer Std.	
WLS-MT-02	Containment Sump	D	NS	ACI 349	ACI 349 Evaluation of Structural Boundary Only
WLS-PL-V055	Sump Discharge Containment Isolation IRC	B	I	ASME III-2	
WLS-PL-V057	Sump Discharge Containment Isolation ORC	B	I	ASME III-2	
WLS-PL-V058	WLS Containment Isolation Relief Valve	B	I	ASME III-2	
WLS-PL-V067	RCDT Gas Outlet Containment Isolation IRC	B	I	ASME III-2	
WLS-PL-V068	RCDT Gas Outlet Containment Isolation ORC	B	I	ASME III-2	
WLS-PL-V071A	CVS Compartment to Sump	C	I	ASME III-3	
WLS-PL-V071B	PXS A Compartment to Sump	C	I	ASME III-3	
WLS-PL-V071C	PXS B Compartment to Sump	C	I	ASME III-3	
WLS-PL-V072A	CVS Compartment to Sump	C	I	ASME III-3	
WLS-PL-V072B	PXS A Compartment to Sump	C	I	ASME III-3	
WLS-PL-V072C	PXS B Compartment to Sump	C	I	ASME III-3	
WLS-PY-C02	Reactor Coolant Drain Tank WLS Connection Penetration	B	I	ASME III, MC	
WLS-PY-C03	Containment Sump Pumps Combined Discharge Penetration	B	I	ASME III, MC	
WLS-MY-Y34	Containment Sump Level Instrument Stilling Well	D	I	Manufacturer Std.	
WLS-MY-Y35	Containment Sump Level Instrument Stilling Well	D	I	Manufacturer Std.	
WLS-MY-Y36	Containment Sump Level Instrument Stilling Well	D	I	Manufacturer Std.	
Balance of system components are Class E					
Radioactive Waste Drain System (WRS)				Location: Auxiliary Building	
n/a	Pumps	D	NS	Manufacturer Std.	
n/a	Valves Providing WRS AP1000 Equipment Class D Function	D	NS	ANSI B16.34	
n/a	Floor Drain Hubs	D	NS	Manufacturer Std.	
WRS-MT-02A	WRS Leak Chase Collection Pot A	D	NS	ASME VIII-1	
WRS-MT-02B	WRS Leak Chase Collection Pot B	D	NS	ASME VIII-1	

Table 3.2-3 (Sheet 59 of 59)
AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment

Tag Number	Description	AP1000 Class	Seismic Category, Note 6	Principal Construction Code	Comments
Solid Radwaste System (WSS)				Location: Auxiliary Building	
n/a	Pumps	D	NS	Manufacturer Std.	
n/a	Tanks	D	NS	ASME VIII	
n/a	Filters	D	NS	ASME VIII	
n/a	Valves Providing WSS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
Balance of system components are Class E					
Waste Water System (WWS)				Location: Various	
WWS-PL-V506	MCR WWS Isolation Valve	C	I	ASME III-3	
Balance of system components are Class E					
Onsite Standby Power System (ZOS)				Location: Diesel Generator Building	
n/a	Diesel Generator Engines	D	NS	Manufacturer Std.	
n/a	Diesel Generator Starting Units	D	NS	CAGI	
n/a	Diesel Generator Radiators	D	NS	API 661	
n/a	Diesel Generator Silencers	D	NS	Manufacturer Std.	
n/a	Valves Providing ZOS Diesel Generator Engines AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
Balance of system components are Class E					

Notes:

1. Component performs a safety-related function equivalent to AP1000 equipment Class C. The component is constructed using the standards for Class R and a quality assurance program in conformance with 10 CFR Part 50 Appendix B.
2. Component performs an AP1000 equipment Class D function and is constructed using the standards for Class L or Class R.
3. Component performs an AP1000 Equipment Class D function and is constructed using the standards for Class E.
4. Construction is non-seismic and meets applicable portions of ASME AG-1 consistent with RG 1.140.
5. Not used.
6. The classification of NS for structures, systems and components is upgraded to seismic Category II if the criterion in Subsection 3.2.1.1.3 is met.
7. For specific SMACNA and AMCA standards, see the descriptions in Section 9.4.

Table 3.2-201
Not Used

3.3 Wind and Tornado Loadings

3.3.1 Wind Loadings

The wind loadings for seismic Category I structures are in accordance with American Society of Civil Engineers, "Minimum Design Loads for Buildings and Other Structures," ASCE 7-98 (Reference 1).

3.3.1.1 Design Wind Velocity

The design wind is specified as a basic wind speed of 145 mph with an annual probability of occurrence of 0.02 based on the most severe location identified in Reference 1 This wind speed is the 3 second gust speed at 33 feet above the ground in open terrain (Reference 1, exposure C). The basic wind speed of 145 mph is the 3 second gust speed that has become the basis of wind design codes since 1995. It corresponds to the 110 mph fastest mile wind used as the basis for the AP600 design in accordance with the 1988 edition of Reference 1.

Higher winds with a probability of occurrence of 0.01 are used in the design of seismic Category I structures by using an importance factor of 1.15. This is obtained by classifying the AP1000 seismic Category I structures as essential facilities and using the design provisions for Category IV of Reference 1.

Velocity pressure exposure coefficients and gust response factors are calculated according to Reference 1 for exposure C, which is applicable to shorelines in hurricane prone areas in the 1998 edition of Reference 1. The topographic factor is taken as unity.

The design wind loads calculated as described above exceed those required at other locations in the United States, where the more severe Exposure Category D is specified in Reference 1. Exposure Category D is applicable for sites near the open inland waterways, the Great Lakes, and the coastal areas of California, Oregon, Washington, and Alaska. For such locations, the basic wind speed is less than 130 mph.

The wind velocity characteristics for the Vogtle Electric Generating Plant, Units 3 and 4 (VEGP), are given in Subsection 2.3.1.3.1. These values are bounded by the design wind velocity values given in Subsection 3.3.1.1 for the AP1000 plant.

3.3.1.2 Determination of Applied Forces

The procedures used in transforming the wind velocity into an effective pressure to be applied to structures and parts and portions of structures follow the guidelines of Reference 1.

Effective pressures applied to interior and exterior surfaces of the buildings and corresponding shape coefficients are calculated according to Reference 1 for exposure C. Shape coefficients, defining the variation around the circumference of the shield building, are calculated using ASCE Paper No. 3269 (Reference 2). These shape coefficients are consistent with those observed in the model tests described in Reference 6.

3.3.2 Tornado Loadings

Seismic Category I structures are designed to resist tornado wind loads without exceeding the allowable stresses defined in Subsection 3.8.4. These tornado loads exceed the loads for hurricanes with a probability of occurrence comparable to that of the tornado. In addition, seismic Category I structures are designed to remain functional when subjected to tornado-generated missiles as discussed in Subsection 3.5.1.4. Seismic Category I structures are permitted to sustain local missile damage such as partial penetration and local cracking or permanent deformation or both, provided

that structural integrity is maintained and seismic Category I systems, components, and equipment required to function during or after passage of a tornado are not subject to damage by secondary missiles, such as from concrete spalling. See Subsection 3.5.2.

3.3.2.1 Applicable Design Parameters

The design parameters applicable to the design basis tornado are as follows:

- Maximum wind speed – 300 mph
- Maximum rotational speed – 240 mph
- Maximum translational speed – 60 mph
- Radius of maximum rotational wind from center of tornado – 150 ft
- Atmospheric pressure drop – 2.0 psi
- Rate of pressure change – 1.2 psi/sec

It is estimated that the probability of wind speeds greater than the design basis tornado is between 10^{-6} and 10^{-7} per year for an AP1000 at a "worst location" anywhere within the contiguous United States.

The tornado characteristics for the VEGP are given in Subsection 2.3.1.3.2. These values are bounded by the tornado design parameters given in Subsection 3.3.2.1 for the AP1000 plant.

3.3.2.2 Determination of Forces on Structures

The procedures described in Subsection 3.3.1.2 are used to transform the tornado wind loading and differential pressure loading into effective loads on structures, with a wind velocity of 300 mph (translational plus rotational velocities). The dynamic wind pressure is applied to the structures in the same manner as the wind loads described in Subsection 3.3.1.2, except that the importance factor, gust factor, and the variation of wind speed with height do not apply. Loading combinations and load factors used are as follows:

$W_t = W_w$

$W_t = W_p$

$W_t = W_m$

$W_t = W_w + 0.5\ W_p$

$W_t = W_w + W_m$

$W_t = W_w + 0.5\ W_p + W_m$

where:

W_t = total tornado load

W_w = total wind load

W_p = total differential pressure load

W_m = total missile load

The maximum pressure drop of 2.0 psi, applicable to a nonvented structure, is used for W_p for all structures except the upper portion of the shield building. The portion of the shield building surrounding the upper annulus is designed as fully vented (zero differential pressure) due to the large area of the air inlets and discharge stack. Figure 3.3-1 shows the velocity pressure variation with the radius from the center of the tornado. When the tornado loading includes the missile load, the structure locally may go into the plastic range because of missile impact. Subsection 3.5.3 discusses the procedure for analyzing local missile effects.

3.3.2.3 Effect of Failure of Structures or Components Not Designed for Tornado Loads

The failure of structures not designed for tornado loadings does not affect the capability of seismic Category I structures or safety-related systems performance. This is accomplished by one of the following:

- Designing the adjacent structure to seismic Category I structure tornado loading
- Investigating the effect of adjacent structure failure on seismic Category I structures to determine that no impairment of function results
- Designing a structural barrier to protect seismic Category I structures from adjacent structural failure.

The structures adjacent to the nuclear island are the annex building, the radwaste building, and the turbine building.

The portions of the annex and turbine buildings adjacent to the nuclear island are classified as seismic Category II and are designed to seismic Category I structure tornado loading. The acceptance criteria are based on ACI 349 for concrete structures, on ANSI/AISC N690 for steel structures, including the supplemental requirements described in Subsections 3.8.4.4.1 and 3.8.4.5, and on AWS D1.1-2000 for weld design, qualification, fabrication, and inspection as described in Subsections 3.8.3.2 and 3.8.4.2. The structures are constructed to the same requirements as nonseismic structures, ACI 318 for concrete structures, and AISC Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design — June 1989 for steel structures. Siding is permitted to blow off during the tornado.

The radwaste building is a small steel-frame building. If it were to collapse in the tornado, it would not impair the integrity of the reinforced concrete nuclear island.

The main area of the turbine building is classified as nonseismic and is designed to seismic Category I structure tornado loading. The acceptance criteria for tornado loading are based on ACI 318 for concrete structures using a load factor of 1.0 and on 1.7 times the AISC 360 allowables for steel structures. Siding is permitted to blow off during the tornado.

Consideration of the effects of wind and tornado due to failures in an adjacent AP1000 plant and VEGP Units 1 and 2 are bounded by the evaluation of the buildings and structures in a single unit.

3.3.2.4 Tornado Loads on the Passive Containment Cooling System Air Baffle

The containment air baffle is located within the annulus between the containment vessel and the shield building. It interfaces with the passive containment cooling system and separates downward flowing air entering at the air intake openings at the top of the cylindrical portion of the shield building from upward flowing air that cools the containment vessel and flows out of the discharge diffuser.

Loads due to the atmospheric pressure drop (W_p) are calculated assuming the tornado is centered over the containment. Differential pressure between the air intakes and the discharge is calculated based on the radius of the shield building and the parameters of the tornado defined in Subsection 3.3.2.1. The differential pressure is used with the pressure loss coefficients in the air flow path to determine pressures throughout the flow path.

The development of loads on the air baffle due to the design wind and tornado (W_w) are described in the test reports (References 3, 4, and 5). Models of the AP600 were tested in a wind tunnel and subjected to representative wind profiles. Pressures were measured on each side of the baffle, and the differential pressures were normalized to the input wind velocity. The pressure coefficients are applied to the effective dynamic pressure for the design wind and the tornado to obtain the wind loads across the baffle. The tornado wind is specified to be constant with height. The tornado loads calculated for the AP600 are applicable to the AP1000. The AP1000 configuration is similar to the AP600. The height of the shield building roof increases by 20′ 6"; the exterior diameter of the passive containment cooling storage tank increases from 80′ 0" to 89′ 0". The pressure coefficients measured in the AP600 tests are not significantly affected by these changes in geometry.

Wind conditions result in a pressure reduction in the annulus between the shield building and the containment vessel as well as above the containment dome. This reduced pressure is equivalent to an increase in containment internal pressure and is within the normal operating range for containment pressure (-0.2 to 1.0 psig).

Wind conditions result in a small wind load across the containment vessel. This is maximum opposite the air intakes where positive pressures occur on the windward side and negative pressures occur on the leeward side. Lateral loads on the containment vessel are developed in Reference 5.

3.3.3 Combined License Information

The site interface criteria for wind and tornado are addressed in APP-GW-GLR-020 (Reference 7).

The VEGP site satisfies the site interface criteria for wind and tornado (see Subsections 3.3.1.1, 3.3.2.1 and 3.3.2.3) and will not have a tornado-initiated failure of structures and components within the applicant's scope that compromises the safety of AP1000 safety-related structures and components (see also Subsection 3.5.4).

Subsection 1.2.2 discusses differences between the plant specific site plan and the AP1000 typical site plan.

There are no other structures adjacent to the nuclear island other than as described and evaluated in the DCD.

Missiles caused by external events separate from the tornado are addressed in Subsections 3.5.1.3, 3.5.1.5, and 3.5.1.6.

3.3.4 References

1. American Society of Civil Engineers, "Minimum Design Loads for Buildings and Other Structures," ASCE 7-98.

2. ASCE Paper No. 3269, "Wind Forces on Structures," Transactions of the American Society of Civil Engineers, Vol. 126, Part II (1961).

3. WCAP-13323-P and WCAP-13324-NP, "Phase II Wind Tunnel Testing for the Westinghouse AP600 Reactor," August 1992.

4. WCAP-14068-P, "Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor," May, 1994.

5. WCAP-14169-P, "Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor, Supplemental Report," September, 1994.

6. WCAP-13294-P and WCAP-13295-NP, "Phase I Wind Tunnel Testing for the Westinghouse AP600 Reactor," April 1992.

7. APP-GW-GLR-020, "Wind and Tornado Site Interface Criteria," Westinghouse Electric Company LLC.

8. American Society of Civil Engineers, "Minimum Design Loads for Buildings and Other Structures," ASCE 7-05.

9. AISC 360, "Specification for Structural Steel Buildings," March 9, 2005.

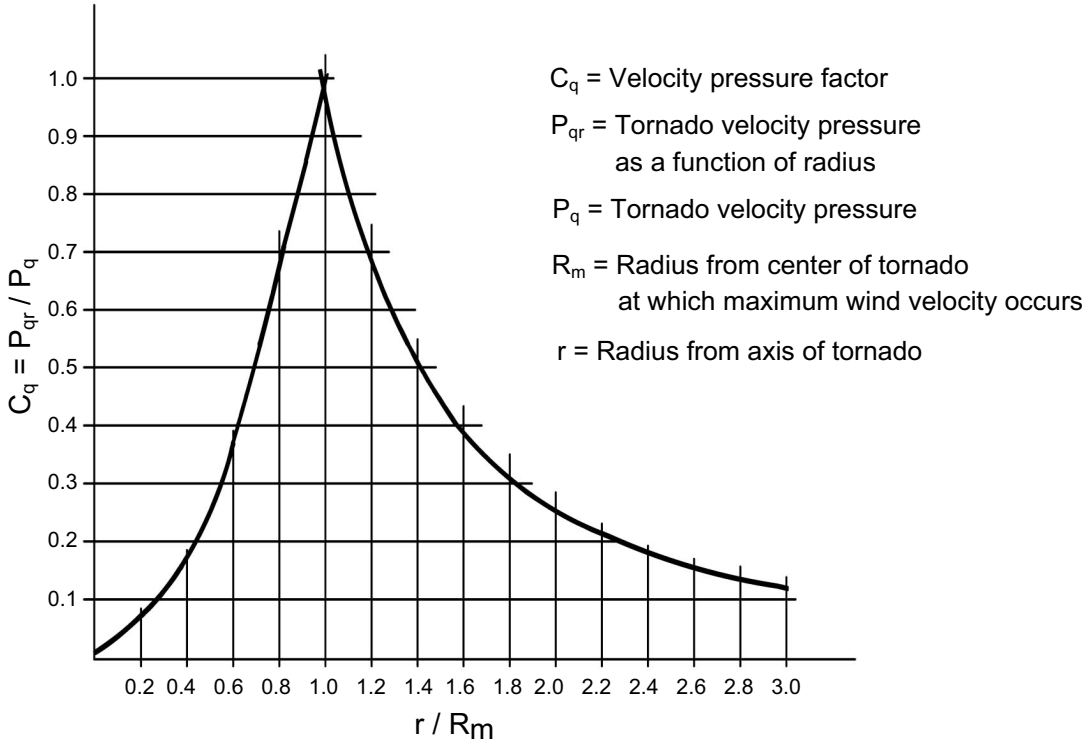


Figure 3.3-1
Velocity Pressure Variation with Radius from Center of Tornado

3.4 Water Level (Flood) Design

External flooding of a nuclear power plant from natural causes can be attributed to probable maximum flood, site and adjacent area probable maximum precipitation runoff, seiche, and ground water. Criteria for the design basis flood are in accordance with the provisions of Regulatory Guide 1.59, Design Basis Floods for Nuclear Power Plants, and Regulatory Guide 1.102, Flood Protection for Nuclear Power Plants. Conformance with the Regulatory Guides is described in Section 1.9. External events are described in Section 2.4. Chapter 2 provides interface data for AP1000 which has an interface flood level at plant grade.

Internal plant flooding can be attributed to piping ruptures, tank failures, or the actuation of fire suppression systems.

3.4.1 Flood Protection

3.4.1.1 Flood Protection Measures for Seismic Category I Structures, Systems, and Components

The seismic Category I structures, systems, and components identified in Section 3.2 are designed to withstand the effects of flooding due to natural phenomena or postulated component failures. A description of the structures is provided in Subsections 3.8.2, 3.8.3, and 3.8.4. None of the nonsafety-related structures, systems and components were found to be important based on flooding considerations. As a result, nonsafety-related structures, systems and components are not important in mitigation of flood events and are not required to be protected from either internal or external flooding.

3.4.1.1.1 Protection from External Flooding

The probable maximum flood for the AP1000 has been established at less than plant elevation 100′ as discussed previously in Section 2.4. The probable maximum flood results from site specific events, such as river flooding, upstream dam failure, or other natural causes.

Flooding does not occur from the probable maximum precipitation. The roofs do not have internal roof drains. The annex, radwaste, and diesel generator buildings have parapets with large openings to drain to scuppers/drains to preclude accumulation of water on the roofs. The roofs are sloped such that rainfall is directed towards gutters located along the edges of the roofs. Therefore, ponding of water on the roofs is precluded. Water from roof drains and/or scuppers, as well as runoff from the plant site and adjacent areas, is conveyed to catch basins, underground pipes, or directly to open ditches by sloping the tributary surface area. The site is graded to offer protection to the seismic Category I structures.

The high ground water table interface is at two feet below the grade elevation, as discussed in Section 2.4.

The components that may be potential sources for external flooding are nonsafety-related, nonseismic tanks as shown in Figure 1.2-2:

- Fire water tanks as described in Subsection 9.5.1. These two tanks have maximum usable volumes of approximately 504,000 gallons each, and are located at the north end of the turbine building. Water will drain from the tanks away from the nuclear island and adjacent buildings due to the required site grading.

- Condensate storage tank as described in Subsection 9.2.4. This tank has a volume of approximately 656,000 gallons, and is located at the west side of the turbine building. Water will drain from the tank away from the turbine and auxiliary buildings due to site grading.

- Demineralized water tank as described in Subsection 9.2.4. This tank has a volume of 126,000 gallons and is located adjacent to the annex building at elevation 107′-2″. Water will drain from the tank away from the annex building to elevation 100′-0″. Nearby doors lead to areas in the annex building which do not contain safety-related components or systems.

- Boric acid storage tank as described in Subsection 9.3.6. This tank has a volume of 79,315 gallons and is located adjacent to the demineralized water storage tank.

- Diesel fuel oil tanks as described in Subsection 9.5.4. These two tanks have volumes of 94,000 gallons each. They are located remote from safety-related structures and are provided with dikes to retain leaks and spills.

- Passive containment cooling ancillary water storage tank, which is seismic category II, as described in Subsection 6.2.2.2.3. This tank has a volume of 1,080,027 gallons and is located at the west side of the auxiliary building. Water will drain from the tank away from the auxiliary building due to site grading.

In addition, failure of the cooling tower or the service water or circulating water piping under the yard could result in a potential flood source. However, these potential sources are located far from safety-related structures and the consequences of a failure in the yard would be enveloped by the analysis described in Subsection 10.4.5.

For the AP1000, the 100′-0″ building floor elevations are slightly above the grade elevation. In addition, the slope of the yard grade directs water away from the buildings. Because the probable maximum flood for AP1000 is less than grade elevation, the exterior doors are not required to be watertight for protection from external flooding.

Process piping penetrations through the exterior walls of the nuclear island below grade are embedded in the wall or are welded to a steel sleeve embedded in the wall. There are no access openings or tunnels penetrating the exterior walls of the nuclear island below grade.

The reinforced concrete seismic Category I structures, incorporating the waterproofing and sealing features described above and in Subsection 3.4.1.1.1.1, provide hardened protection for safety-related structures, systems, and components as defined in Regulatory Guide 1.59.

3.4.1.1.1.1 Waterproofing

A waterproof membrane or waterproofing system for the seismic Category I structures below grade will be installed as an architectural aide to limit the infiltration of subsurface water. The COL applicant will use a waterproofing system for foundation mat (mudmat) and the below grade exterior walls exposed to flood and groundwater that will demonstrate a friction coefficient ≥ 0.55 with all horizontal concrete surfaces. This friction coefficient is maintained for the life expectancy of the plant and will not introduce a horizontal slip plane increasing the potential for movement during an earthquake (see Subsection 3.8.5.5.3). Typical waterproofing approaches are described as follows:

- HDPE Double-Sided Textured Waterproof Membrane

  Figures 3.4-1and 3.4-2 show the typical application of this waterproofing approach for a mechanically stabilized earth (MSE) wall and for a step-back configuration.

- HDPE Single-Sided Self-Adhering Sheet Waterproofing Membrane

  The HDPE single-sided adhesive sheet membrane is interchangeable with the HDPE double-sided textured membrane for use in the mudmat, and it may be used in certain circumstances to waterproof the walls.

- Self-adhesive, Rubberized Asphalt/Polyethylene Waterproofing Membrane

  The self-adhesive rubberized membrane is for application to waterproof the walls only.

- Sprayed-on Waterproofing Membrane

  This method may be used either for soil sites, in conjunction with an MSE wall, or for rock sites, where an open excavation may be used. The membrane consists of 100-percent solids materials based on polymer-modified asphalt or polyurea. This system may include a polyester reinforcement fabric having properties necessary to meet the performance requirements for the system. Figure 3.4-4 shows the typical installation using MSE walls with the sprayed-on, liquid-applied waterproofing membrane placed on the MSE wall panels and between the two layers of the mudmat. Where the vertical face of excavation is used as a form for the exterior walls, the waterproof membrane is installed on the vertical face of the excavation prior to placement of concrete in the exterior walls. An alternate waterproofing system for the seismic Category I structures below grade is as presented in Subsection 3.8.5.1.1.

- HDPE Waterproof Membrane System

  The HDPE waterproof membrane system uses an embedded HDPE Liner, with additional rubberized waterproof sealant materials forming a transition to the waterproof membrane on the MSE walls. It may be used for vertical waterproofing applications on the NI wall.

The waterproof function of the membrane is not safety-related; however, the membrane between the mudmats must provide adequate shear strength to transfer horizontal shear forces due to seismic (SSE) loading. This function is seismic Category I. The waterproof membrane will have physical properties, including surface and texture, to achieve the required coefficient of friction. Primer or geotextile may be added as required.

3.4.1.1.2 Protection from Internal Flooding

The nuclear island general arrangement drawings provided in Section 1.2 are a useful reference for the internal flooding discussion.

The AP1000 arrangement provides physical separation of redundant safety-related components and systems from each other and from nonsafety-related components. As a result, component failures resulting from internal flooding do not prevent safe shutdown of the plant or prevent mitigation of the flooding event. Protection mechanisms are generally described in Subsection 3.6.1.3.2. The protection mechanisms related to minimizing the consequences of internal flooding include the following:

- Structural enclosures
- Structural barriers
- Curbs, weirs and elevated thresholds
- Watertight hatches
- Leak detection systems
- Drain systems
- Flood relief louvers

- Pressure relief panels
- Flappers

The AP1000 minimizes the number of penetrations through enclosure or barrier walls below the flood level. Those few penetrations through flood protection walls that are below the maximum flood level are watertight. Any process piping penetrating below the maximum flood level either is embedded in the wall or floor or is welded to a steel sleeve embedded in the wall or floor. There are no watertight doors in the AP1000 used for internal flood protection because, as described in Subsection 3.4.1.2.2, they are not needed to protect safe shutdown components from the effects of internal flooding. Watertight hatches are provided to close openings not required for hydrogen venting. The walls, floors, hatches, and penetrations are designed to withstand the maximum anticipated hydrostatic loads associated with a pipe failure as described in Section 3.6. The two watertight doors on the waste holdup tank compartments limit the consequence of a failure on spent fuel pool water level.

3.4.1.2 Evaluation of Flooding Events

3.4.1.2.1 External Flooding

Base mat and exterior walls of seismic Category I structures are designed to resist upward and lateral pressures caused by the probable maximum flood and high ground water level. The vertical hydrostatic pressure acting uniformly at the bottom of the base mat is the product of the height to the high water level and the unit weight of water assumed as 62.4 lb/ft^3. The horizontal hydrostatic pressure acting on the exterior walls varies with height, with the maximum at the bottom of the wall and zero at the maximum water level. Minimum factors of safety for overturning, sliding, and flotation are described in Subsection 3.8.5. There are no dynamic water forces associated with the probable maximum flood or high ground water level because they are below the finished grade. Dynamic forces associated with the probable maximum precipitation are not factors in the analysis or design since the finished grade is adequately sloped.

There are no safety-related hydraulic structures for AP1000.

3.4.1.2.2 Internal Flooding

This section describes the consequences of compartment flooding for various postulated component failures. The equipment required to achieve and maintain safe shutdown depends on the initiating event. The safety-related systems and components available for safe shutdown are described in Section 7.4. This equipment is located in the auxiliary building and inside containment. Except for floor drains, no credit is taken in this evaluation for the availability of nonsafety-related systems or components.

Each area of the plant containing safety-related systems or equipment is reviewed to determine the postulated fluid system failures which would result in the most adverse internal flooding conditions. For the internal flooding analysis, the failure of safety-related systems, structures or components is acceptable provided they have no safe shutdown function or the safe shutdown function is otherwise accomplished. The internal flooding analysis shows that systems, structures, and components are not prevented from performing their required safe shutdown functions due to the effects of the postulated failure. In addition, the analysis identifies the protection features that mitigate the consequences of flooding in an area that contains safety-related equipment.

The flooding sources considered in the analysis consist of the following:

- High-energy piping (breaks and cracks)
- Through-wall cracks in seismically-supported moderate energy piping
- Breaks and through-wall cracks in non-seismically-supported moderate energy piping

- Pump mechanical seal failures
- Storage tank ruptures
- Actuation of fire suppression systems
- Flow from upper elevations, lower elevations and adjacent areas

The analysis is performed based on the criteria and assumptions provided in Section 3.6 and ANS-56.11 (Reference 1). Section 3.6 provides the criteria used to define break and crack locations and configurations for high and moderate-energy piping failures. Additional design criteria pertaining to the internal flooding analysis are provided in this section.

The analysis consists of the following steps:

- Identification of the flood sources
- Identification of essential equipment in area
- Determination of flowrates and flood levels
- Evaluation of effects on essential equipment

As stated in Section 3.6, high-energy ASME Code Class 1, 2, and 3 piping of 6 inch nominal diameter or larger inside the containment is evaluated for mechanistic pipe break (leak-before-break) for AP1000. Those high-energy piping systems that do not satisfy the mechanistic pipe break requirements inside containment and high-energy lines outside containment are evaluated for non-mechanistic breaks and cracks, as above.

Fluid flowrates from high- and moderate-energy piping ruptures are determined based on the criteria provided in Section 3.6 and ANSI 56.11 (Reference 1). Fluid flowrates through stairwells, floor openings, and floor sleeves are determined in accordance with the formulas given in Reference 1.

No breaks or cracks are assumed for piping with nominal diameters of 1 inch or less. For each storage tank rupture, it is assumed that the entire tank inventory is drained.

The analysis of potential flooding events is performed on a floor-by-floor and room-by-room basis depending upon the relative location of safety-related equipment. No credit is taken for operation of sump pumps to mitigate the consequences of flooding.

3.4.1.2.2.1 Containment Flooding Events

General

The safe shutdown systems and components located inside the containment are associated with the passive core cooling system (PXS), the automatic depressurization system (ADS), and containment isolation.

The evaluation of containment flooding events addresses the impact of flooding on the safe shutdown systems and components. The AP1000 passive core cooling system, the internal containment compartments, and the equipment locations are designed for internal flooding to maintain post accident long-term cooling flow to the reactor core from the flooded volumes.

In the unlikely event of a loss-of-coolant accident (LOCA), the combined water inventory from available sources within the containment is sufficient to flood the reactor and steam generator compartments to a level above the reactor coolant system piping to provide water flow back into the reactor coolant system via the break location or via the passive core cooling system containment recirculation subsystem (see Section 6.3) flow path.

The potential for flooding safe shutdown components inside containment that would be required to perform safe shutdown functions is limited to two equipment compartments. These compartments

are located in the southeast and northeast quadrants of the containment below the floor at elevation 107′-2″. For flood evaluation, these compartments extend up to the top of the curbs through the openings in the floor. These two compartments contain passive core cooling system components that provide two redundant means for delivering borated water to the reactor coolant system when required for safe shutdown.

The two passive core cooling system compartments primarily contain passive core cooling system components. The southeast compartment is referred to as the PXS-A compartment. The northeast compartment is interconnected with the RNS valve room by a passageway. These two compartments are treated, in this discussion, as one floodable volume referred to as the PXS-B compartment. The principal passive core cooling system component in each passive core cooling system compartment is an accumulator. A passive core cooling system core makeup tank is located above each passive core cooling system compartment. Each passive core cooling system compartment also contains isolation valves for the accumulator, the core makeup tank, the in-containment refueling water storage tank, and the passive core cooling system containment recirculation subsystem line.

There are eight automatically actuated containment isolation valves inside containment subject to flooding. These normally closed containment isolation valves are not required to operate during a safe shutdown operation and they would not fail open as a result of the compartment flooding. Also, there is a redundant, normally closed, containment isolation valve located outside containment in series with each of these valves.

The PXS-A compartment contains one normally closed spent fuel pool cooling system containment isolation valve and one normal residual heat removal system containment isolation valve. The PXS-B compartment contains four normally closed normal residual heat removal system containment isolation valves. The maintenance floor contains two normally closed liquid radwaste system containment isolation valves located partially below the maximum flood level.

Except for the valves mentioned above, the rest of the automatically actuated containment isolation valves are located above the maximum flood level; therefore, these components would not be adversely affected by postulated flooding.

Flooding can be postulated from a failure of several systems located inside the containment. The worst case flooding scenario is a LOCA. The maximum flood level for a LOCA is based on the combined inventory of the reactor coolant system, the two accumulators, the two core makeup tanks, and the in-containment refueling water storage tank flooding the containment. The maximum inventory also considers makeup from the cask loading pit and boric acid tank.

Curbs are provided around openings through the maintenance floor at elevation 107′-2″ or watertight hatches are provided to close openings not required for hydrogen venting to control flooding. Overflow into the refueling canal occurs through a pipe centered at elevation 110′-0″. Curbs around openings into the chemical and volume control system compartment extend up to elevation 110′-0″. Curbs around openings into the PXS-A compartment extend up to elevation 110′-2″. Curbs around openings into the PXS-B compartment extend up to elevation 110′-1″. With these curb elevations, water flooding the maintenance floor is directed first into the refueling canal, then into the CVS compartment, then into the PXS-B compartment, and finally into the PXS-A compartment.

The evaluation of containment flooding from postulated component failures includes the compartments that are located below the maximum flood level. There are seven subcompartments that contain components below the floor at elevation 107′-2″. The active safe shutdown components inside containment which are located below the maximum flood level are located in only two of the seven floodable compartments.

The seven compartments partially or completely below the maximum flood level include the reactor vessel cavity, the two steam generator compartments, the vertical access tunnel, the two passive core cooling system compartments, and the chemical and volume control system compartment. The safe shutdown components are located in the two passive core cooling system compartments.

The reactor vessel cavity and the two steam generator compartments are interconnected by a large vertical access tunnel. These four compartments are treated, in this discussion, as one large floodable volume and they are referred to as the reactor coolant system compartment. Flooding of this compartment above elevation 107′-2″ also includes the maintenance floor outside the curbs around the other three compartments.

The PXS-A compartment (Room 11206), PXS-B compartment (Room 11207 and its connected RNS Valve Room 11208), and the chemical and volume control system compartment (Room 11209) are physically separated and isolated from each other by structural walls and curbs such that flooding in any one of these compartments or in the reactor coolant system compartment cannot cause flooding in any of the other compartments. Located in the 107'-2" floor are hatches which allow personnel access into PXS-A, PXS-B, and the CVS compartment for maintenance. These hatches are leak-tight and designed to prevent flooding through the 107'-2" floor into the compartments below. The access hatch to the PXS-B compartment is located near the containment wall and is normally closed to address severe accident considerations. The access hatch to the PXS-B compartment is accessible from Room 11300 on elevation 107′-2″.

The access hatches and curb on the 107'-2" maintenance floor are important design features which support containment flood-up during a LOCA. The access hatches are designed to be opened or removed during plant shutdown to support maintenance work in the PXS-A, PXS-B, and CVS compartments. The design of the curbs may also allow them to be removed to support component inspections or other plant shutdown maintenance activities. Removal of these components to conduct shutdown maintenance activities include limitations and compensatory measures to preserve an adequate flood-up recirculation level to be able to support core cooling in the unlikely event of a loss of shutdown cooling or loss of RCS inventory.

The fire protection system and the demineralized water transfer and storage system are open-cycle systems that enter the containment. During plant operation, the containment piping for these systems is isolated by containment isolation valves and is not a potential flooding source. These systems are not open systems as defined in Bulletin 80-24 (one that has an essentially unlimited source).

Reactor Coolant System Compartment

The reactor coolant system compartment, represented by the reactor vessel cavity, the two steam generator compartments, and the large vertical access tunnel, is the largest of the separate floodable compartments. With the exception of the pressurizer which is at a higher elevation, the principal components of the reactor coolant system are contained in this compartment.

The reactor vessel cavity and the adjoining equipment room are at the lowest level in the containment. The floor level of these rooms is at elevation 71′-6″. The floor level of the two steam generator compartments is at elevation 83′-0″. A portion of each compartment has low point areas at elevation 80′-0″.

The containment sump pumps are located in the equipment room at elevation 71′-6″. The arrangement for the floor drains from the two passive core cooling system compartments and the chemical and volume control system compartment provide a drain path for each compartment to the lowest level of containment (elevation 71′-6″) where the containment sump is located. Therefore, the source of the flooding in the reactor coolant system compartment is not limited to the components or systems contained within this compartment.

Any leakage that occurs within the containment drains by gravity to the elevation 71′-6″ equipment room. Reverse flow into the two passive core cooling system compartments and the chemical and volume control system compartment is prevented by redundant backflow preventers in each of the three compartment drain lines.

Flooding in any compartment of the containment is detected by the containment sump level monitoring system and the containment flood-up level instrumentation.

The containment sump level monitoring system consists of three seismically qualified level sensors for the containment sump. These sensors transmit the sump level indication through a qualified isolation device to the main control room and the plant instrumentation system.

The plant instrumentation system monitors the rate of the sump level rise, calculates the leakage collection rate, and initiates the appropriate alarms in the main control room. A description of this leak detection system is provided in Subsection 5.2.5.3.1.

Another indication of flooding in this compartment is provided by the containment flood-up level instrumentation consisting of three redundant Class 1E level sensor racks. Multiple discrete level signals are provided from the bottom of the reactor vessel cavity to the top of the vertical access tunnel. These level sensors transmit the containment sump water level indication to the main control room.

In the event that the source of the containment flooding can not be terminated, the water level in the reactor vessel cavity and the steam generator compartment continues to increase until the water source has been depleted or the leak has been isolated. The maximum level that could occur in the compartment from all of the water which is available in containment is elevation 110′-2″.

Essential, safety-related components in the RCS compartment subjected to submergence are either protected or qualified for submergence. The flooding of this compartment has no impact on safe shutdown capability.

Passive Core Cooling System Compartments

The PXS-A and PXS-B compartments, located in the southeast and northeast quadrants of the containment, primarily contain components associated with the passive core cooling system. The safe shutdown related components of the passive core cooling system located in these two compartments are redundant and essentially identical. One set of the redundant equipment is located in each of the two separate compartments.

The redundant passive core cooling system components located in these two compartments provide coolant to the reactor vessel from the two core makeup tanks, the two accumulators, and the in-containment refueling water storage tank via two independent and redundant direct vessel injection lines.

Each passive core cooling system compartment contains a parallel set of normally closed, air operated, core makeup tank isolation valves that receive actuation signals to open during a safe shutdown operation. These valves are approximately 10 feet above the floor level of the passive core cooling system compartments and 26 feet above the floor of the reactor vessel cavity.

Each passive core cooling system compartment also contains one normally open accumulator isolation valve and one normally open in-containment refueling water storage tank isolation valve. These valves do not have to be repositioned during a safe shutdown operation and a coincident flooding event.

In addition, each passive core cooling system compartment contains four passive core cooling system containment recirculation subsystem isolation valves. A normally closed, squib valve is located in each of two parallel flow paths. One of the lines includes a check valve in series with the squib valve. The other line includes a normally open, motor-operated valve in series with the squib valve. The squib valve and motor-operated valves are opened on a Low-3 in-containment refueling water storage tank level signal to provide a redundant flow path from the flooded reactor/steam generator compartments to the reactor vessel. One set of these redundant containment recirculation subsystem isolation valves is required to open to provide a redundant recirculation flow path to the reactor vessel. In the unlikely event that one of the two passive core cooling system compartments were to be flooded, the set of recirculation valves in the other, unflooded, compartment could be opened. Note that these squib valves are qualified to operate after being flooded.

The design bases for this system are described in Section 6.3. The passive core cooling system is designed to perform its safety functions in the unlikely event of the most limiting single failure occurring coincident with any design basis event. For example, a direct vessel injection line could break in one of the two passive core cooling system compartments, thus preventing the core makeup tank and the accumulator located in the compartment from delivering borated water to the reactor vessel. A coincident single failure in the other passive core cooling system compartment would prevent only one of the two parallel injection paths from opening. This series of events would not prevent the passive core cooling system from performing its safety function.

The maximum flooding rate to either of these passive core cooling system compartments would occur on a postulated LOCA of one of the eight inch direct vessel injection lines at a location inside one of the two compartments. This postulated rupture would result in direct blowdown from the reactor coolant system to the compartment as well as blowdown of the associated core makeup tank and accumulator. The resulting flooding in one of two passive core cooling system compartments would not prevent the passive core cooling system from performing its safe shutdown function.

Another postulated LOCA, that would cause rapid flooding in the PXS-B compartment, is a rupture of the 12 inch normal residual heat removal system line. This line is routed from one of two reactor coolant system hot legs to a containment penetration in the PXS-B compartment.

The evaluation of containment flooding events is also concerned with non-LOCA flooding events. The maximum flooding rate to either of the passive core cooling system compartments, for a non-LOCA event, would be based on a postulated rupture of one of the two in-containment refueling water storage tank lines or a postulated rupture of one of the two accumulator injection lines.

A 10-inch line is routed from the in-containment refueling water storage tank to the PXS-A compartment and a 10-inch line is routed to the PXS-B compartment. The driving head from a full in-containment refueling water storage tank to either of these two compartments is approximately 35 feet. A rupture in one of these lines would result in flooding of the associated passive core cooling system compartment and the reactor coolant system compartment via the normal drain path or by overflowing the passive core cooling system compartment.

The 8-inch accumulator injection lines are routed from the accumulators to the 8-inch direct vessel injection lines. A rupture of either of these two injection lines at a point upstream of the two series reactor coolant system pressure boundary check valves would result in the blowdown of the accumulator to the associated compartment. The water level attained in this case would be limited to the water volume of the accumulator. The water level would not reach the level of the core makeup tank isolation valves.

The total flood-up of either the PXS-A or PXS-B compartments from any source of water is acceptable and does not prevent the passive core cooling system from performing its required safe shutdown function.

The PXS-A and the PXS-B compartments are physically separated and isolated from each other by a structural wall so that flooding in one compartment can not cause flooding in the other compartment. They are located below the maintenance floor level which is at elevation 107′-2″. A curb or watertight hatch is provided at openings that penetrate through the maintenance floor into these compartments from the elevation 107′-2″ floor level.

There are several HVAC ducts, cable trays, and pipes that penetrate the maintenance floor into the passive core cooling system compartments. These penetrations are properly protected to prevent leakage into the passive core cooling system compartments.

The floor drains for these two compartments are located at elevation 84′-6″. Reverse flow through the floor drains is blocked by redundant, safety-related backflow preventers in the drain lines.

When the flooding rate exceeds the ability of the floor drain lines to drain the water from the compartment, or in the event that the floor drain line is blocked, the water level in that compartment increases to the entrance curb elevation.

Should the flooding continue, the water overflows from that compartment to the maintenance floor at elevation 107′-2″. The water overflowing to this level would immediately drain to the reactor coolant system compartment via the vertical access tunnel. There is no curb at the entrance to the vertical access tunnel; therefore, water on the maintenance floor (elevation 107′-2″) flows freely into the reactor coolant system compartment. For LOCA events, flooding via this path continues to a level above the reactor coolant system cold legs.

If the leakage rate into PXS-A or PXS-B were not excessive, the compartment drain lines would prevent significant flood-up in that compartment. Consequently, the flooding of the components could be prevented for postulated flooding events of limited duration and flowrates less than the drain line capacity.

The flowrate from the compartments is a function of the water height in the PXS compartments and the water height in the reactor coolant system compartment. The differential head between the two water levels establishes the flowrate from the compartment.

The draining of these compartments initiates flooding of the reactor vessel cavity and the adjoining cavity equipment room. If the operator does not terminate the leak, action is taken to shut down the reactor.

If the flooding rate is not greater than the compartment drain line capacity, the large volume of the reactor vessel cavity and the adjoining equipment room provides additional time for the operator to identify the source of leakage before any significant flooding occurs in the compartments containing the passive core cooling system equipment.

Should the flooding continue, the water level eventually reaches the steam generator compartment floor at elevation 83′-0″. The large floor area of the two steam generator compartments and the vertical access tunnel provides additional volume for flood-up and reduces the rate of level increase.

The containment isolation valves in these two passive core cooling system compartments are located above elevation 95′-0″, but below the maximum flood-up level. The PXS-A compartment contains one normally closed, motor operated, spent fuel pool cooling system containment isolation valve. The PXS-B compartment contains four normally closed, motor operated, normal residual heat removal system containment isolation valves. These containment isolation valves are not required to operate for safe shutdown and they do not fail open as a result of compartment flooding. Also, there are redundant outside containment isolation valves for each line that penetrates the containment boundary.

Chemical and Volume Control System Compartment

The majority of the components associated with the chemical and volume control system are located inside the containment in a separate compartment in the north quadrant of the containment below elevation 107′-2″.

There are several HVAC ducts, cable trays, and pipes that penetrate the maintenance floor into the chemical and volume control system compartment. These penetrations are properly protected to prevent leakage around the ducts into the chemical and volume control system compartment. The entrance curb elevation for the chemical and volume control system compartment is lower than the PXS-A and B compartment curbs to preferentially flood the chemical and volume control system compartment.

A single floor drain line is routed from this compartment to the containment sump at elevation 71′-6″. Reverse flow from the containment sump to this compartment is prevented by redundant, safety-related backflow preventers in the drain lines.

In the event that the single drain line were to be blocked, the water level in the chemical and volume control system compartment would flood to the level of the entrance curb elevation and would over flow to the maintenance floor at elevation 107′-2″. The water overflowing to this level would drain to the reactor coolant system compartment via the vertical access tunnel. There is no adverse effect on safe shutdown of the plant from flooding of the chemical and volume control system compartment.

The fire protection system and the demineralized water transfer and storage system are open-cycle systems that enter the containment. During plant operation, the containment piping for these systems is isolated by containment isolation valves and is not a potential flooding source. These systems are not open systems as defined in Bulletin 80-24 (one that has an essentially unlimited source).

3.4.1.2.2.2 Auxiliary Building Flooding Events

General

The AP1000 auxiliary building contains radiologically controlled areas and nonradiologically controlled areas which are physically separated by 2 and 3 foot structural walls and floor slabs. These structural barriers are designed to prevent flooding across the boundary between these areas by locating penetrations for piping and HVAC duct above maximum flood levels, or by sealing these penetrations. Process piping penetrations between the radiologically controlled areas and nonradiologically controlled areas are embedded in the wall or are welded to a steel sleeve in the wall. Electrical penetrations between the radiologically controlled areas and nonradiologically controlled areas are located above the maximum flood level. Electrical penetrations subject to the effects of the local build up of water on floors above the maximum flood level are also sealed.

For example, flooding in the auxiliary building at elevation 66′-6″ of the radiologically controlled area would not cause flooding in the nonradiologically controlled areas since the two areas are completely separated by a three foot thick structural wall. In the non-radiologically controlled area (non-RCA) of the auxiliary building, the four Class 1E electrical divisions are separated by 3-hour fire barriers. Portions of these fire barriers also serve as flood barriers.

- **Nonradiologically Controlled Areas**

  The safe shutdown systems and components that are located in the nonradiologically controlled area are associated with the protection and safety monitoring and Class 1E dc system, and containment isolation. The safe shutdown components associated with the protection and safety monitoring system are the instrumentation and control (I&C) cabinets located in the nonradioactive controlled area on level 3 (elevation 100′-0″). The safe shutdown components

associated with the Class 1E dc system are the Class 1E batteries on level 1 (elevation 66′-6″) and level 2 (elevation 82′-6″) and dc electrical equipment also on level 2.

The nonradiologically controlled areas of the auxiliary building are designed to provide maximum separation between the mechanical and electrical equipment areas. This separation prevents the propagation of leaks from the piping areas and the mechanical equipment areas to the Class 1E electrical and Class 1E I&C equipment rooms.

The major piping compartments in the nonradiologically controlled area are the main steam isolation valve compartments on levels 4 and 5 (elevations 117′-6″ and 135′-3″, respectively) and the valve/piping penetration compartment on level 3 (elevation 100′-0″). The mechanical equipment rooms in the nonradiologically controlled area are the HVAC compartments on levels 4 and 5.

Drain lines are provided in each of the piping and mechanical equipment compartments which drain to the turbine building drain tank. Leakage from postulated pipe ruptures in these compartments will drain to the turbine building.

- **Radiologically Controlled Areas**

  The safe shutdown components located in radiologically controlled areas (RCA) are primarily containment isolation valves which are located near the containment vessel and above elevation 82′-6″. The containment isolation valves below the maximum flood level are either air-operated and fail closed, or remain closed during a safe shutdown operation.

The evaluation of potential flooding within the radiologically and nonradiologically controlled areas of the auxiliary building is performed on a floor-by-floor basis as described below.

Auxiliary Building Level 1 (Elevation 66′-6″)

- **Nonradiologically Controlled Area**

  Level 1 of the nonradiologically controlled area has five individual rooms that contain Class 1E batteries: four divisional (A, B, C, and D) Class 1E battery rooms and one Class 1E spare battery room. The doors are not water tight.

  The primary line of defense for level 1 is to exclude fluid systems and their associated piping from this area. The only fluid systems in level 1 are the potable water and fire protection systems. Potable or demineralized water brought into the area in portable containers is used for battery washdown. Potable water is used for the emergency eye wash/shower facilities. The maximum nominal diameter of potable water piping in this area is 1 inch; therefore, it is excluded from consideration as a source of flooding.

  The seismically qualified fire protection system piping routed through levels 1, 2, 3, and 4 is the only piping in level 1 that is greater than 1 inch in diameter.

  Fire fighting activities or fire protection system piping through-wall cracks in levels 1, 2, 3, or 4 would contribute to flooding in level 1. The drain lines, stairwells, and the elevator shaft direct the water from fire fighting activities down to the auxiliary building nonradiologically controlled area sump located on level 1.

  Fire fighting in these five battery rooms is accomplished by manual means from two fire hose stations located adjacent to the two stairwells. The maximum flowrate to this area from the two hose stations is assumed to be 250 gpm.

A limited supply of water is initially provided to the fire protection system standpipe fire hose stations (see Subsection 9.5.1) from the passive containment cooling water storage tank. A nominal volume of 18,000 gallons is provided for the fire protection system. A volume of approximately 26,200 gallons is conservatively assumed; this is the volume in the tank between the elevations of the fire protection system inlet and the tank overflow, and associated system piping. In the event of a through-wall crack in the fire protection system piping, the maximum water depth in the battery rooms would be less than 7.5 inches, assuming that the water could propagate into all rooms on this level. This maximum water depth is substantially below the terminal height on the first row of battery jars, which are located 7.5 inches above the floor. The terminal height is approximately 30 inches above the floor.

Since a limited supply of fire water is provided, inadvertent initiation of the fire protection system can not exceed the flooding levels described above. Operator action to stop inadvertent water flow from the fire protection system is expected to limit flooding to only a small fraction of this water supply.

Structural walls, drain line routing, and raised platforms prevent leakage that may occur in piping or mechanical areas on levels 4 and 5 from propagating to the electrical areas on levels 1, 2, 3, or 4.

Dual sump pumps and water level sensors are also provided in the sump on level 1. The level sensors transmit water level indication to the main control room and the plant control system. Level alarms alert the operator to take corrective action.

The sump pumps are sized to remove approximately 250 gpm (with two pumps operating) based on a maximum flow from two fire hose stations of 250 gpm. The discharge of these pumps is directed to the turbine building drain tank of the waste water system (WWS) located on elevation 89′-0″ of the turbine building as described in Subsection 9.2.9. The discharge line into the tank is provided with a standpipe to prevent siphoning back to the auxiliary building nonradiologically controlled area sump. These sump pumps and level sensors are not required to maintain safe shutdown capability.

- **Radiologically Controlled Area**

  There are no safe shutdown components located on level 1 of the radiologically controlled area. The radiologically controlled area of the auxiliary building is subject to flooding from a variety of potential sources including, but not limited to, the component cooling water, central chilled water, hot water, spent fuel pool cooling, normal residual heat removal system, fire protection system, and chemical and volume control system, as well as various tanks. Most of the piping associated with these systems is above level 1; however, the flow from any postulated rupture in the radiologically controlled area will eventually flood level 1. The principal flow paths to level 1 are the vertical pipe chase and the floor gratings provided in the elevator lobbies on levels 2 and 3. Other flow paths include the floor drain system, the stairwell, and the elevator shaft. The western wall of the stairwell contains a safety-related, seismically qualified, and fire-rated flood relief louver that provides a flow path into the adjacent corridor in the event of a fire protection system line rupture.

  The auxiliary building radiologically controlled area sump is located on level 1 with dual sump pumps and water level sensor provided in the sump. The level sensor transmits water level indication to the main control room and the plant control system. High level alarms alert the operator to take corrective action. Two seismic Category I flood level sensors, which alert in the main control room, are also located in this area.

The sump pumps are sized to remove approximately 250 gpm (with two pumps operating) based on a maximum flow from two fire hose stations of 250 gpm. The discharge of these pumps is directed to the waste holdup tanks of the liquid radioactive waste system as described in Section 11.2. These sump pumps and sump level sensors are not required to maintain safe shutdown capability.

For the component cooling water and central chilled water systems, the maximum flooding volume is bounded by the system volume plus a reasonable period of makeup. This includes any discharges from the pressure relief valves on the cooling water lines from the RNS heat exchangers. Flow from these two valves is also directed to the auxiliary building sump through the radioactive waste drain system. For the spent fuel pool cooling system, the maximum flooding volume is limited to the volume of water above the non-seismic spent fuel pool cooling suction line, plus a reasonable period of makeup. This flooding volume is approximately equal to that of the component cooling water and chilled water systems above.

The normal residual heat removal system is primarily operated when the plant is being shutdown. Since it is not normally operating, it is evaluated as a moderate-energy system. Flooding is determined based on the maximum flowrate from a through-wall crack in a 10 inch normal residual heat removal system suction line.

Flooding due to a break in the high-energy chemical and volume control system makeup pump discharge line bounds the normal residual heat removal system through-wall crack.

For a flooding event due to a moderate-energy line break of the fire protection system main header loop running through the auxiliary building, the maximum connected fire protection system inventory is assumed to be drained.

A flooding event due to a moderate-energy line break of the fire protection system main header loop running through the auxiliary building bounds the above conditions. Due to a circumferential break in this non-seismic moderate-energy piping, flooding flow output from both break ends originating from higher elevations eventually flows down to elevation 66'-6". Based on notification of flooding conditions received in the main control room, credited operator action is taken after pipe ruptures occur to limit the flood to the design basis level. Due to limited volume of the fire water storage tanks, maximum height is limited to 19 feet in non-tank rooms. To provide indication that supports initiation of credited operator action, two redundant, seismic Category I flood level sensors are used to alert the operators in the main control room of a floodup within the radiologically controlled area of the auxiliary building.

Flow from the postulated bounding break spreads throughout the level 1 rooms and corridor via flow under doors and interconnecting floor drains if the auxiliary building radiologically controlled area sump pumps are inoperable. The maximum flood level in the area, for any of the cases above, is 19 ft. This flooding will extend up to level 2 to elevation 85'-6" after credited operator action is taken to isolate fire protection system makeup at 7 hours past rupture initiation. This flooding has no impact on safe shutdown since there are no flooded components on level 1 or 2 that cannot perform the functions required for safe shutdown. The maximum flood height in waste holdup tank rooms (12166 and 12167) is 23 feet due to the water-tight doors and the locked-closed drain.

Flow from a tank rupture in one of the tank rooms will initially flood the tank room, and begin to flow to the auxiliary building radiologically controlled area sump via floor drains. If the sump pumps are inoperable, the tank volume floods the balance of level 1 via the interconnecting floor drains. The maximum flood level for this event is less than for the piping failures discussed above.

Auxiliary Building Level 2 (Elevation 82′-6″)

- **Nonradiologically Controlled Area**

  Level 2 of the nonradiologically controlled area has two Class 1E battery rooms, four divisional Class 1E dc electrical equipment rooms, and one Class 1E reactor coolant pump trip switchgear room. The doors to these rooms are not water tight.

  Level 2 contains an arrangement of fire protection and potable water piping similar to level 1.

  The potential for flooding on this level is limited to fire fighting activities and through-wall cracks in fire protection system piping. Fire fighting in these rooms is accomplished by manual means from two fire hose stations located adjacent to the two stairwells. The maximum flowrate to this area from the two hose stations is assumed to be 250 gpm.

  The drains, elevator shafts, and stairwells drain water spilled on this level to level 1. Therefore, no significant accumulation of water occurs on level 2.

- **Radiologically Controlled Area**

  The radiologically controlled area on level 2 contains a few containment isolation valves and an effluent monitor tank at elevation 92’-6". The horizontal pipe chase at elevation 92′-6″ contains two normally closed normal residual heat removal system isolation valves. One spent fuel pool cooling system containment isolation valve is located, above 92′-6″, in the adjacent vertical pipe chase. The area on the north side of the lower annulus contains two chemical and volume control system and two liquid radwaste automatically operated containment isolation valves above elevation 82′-6″. These valves are required to close or remain closed during a safe shutdown operation.

  Two chemical and volume control system valves used to isolate the chemical and volume control system makeup pump suction from the demineralized water storage tank are located in the demineralizer/filter access area at 82′-6″. These safety-related valves close or remain closed to prevent boron dilution events. They are not required for safe shutdown.

  Potential sources of flooding for this area include, but are not limited to, the chemical and volume control system, a liquid radioactive waste system effluent monitor tank, and the fire protection system, including an automatic suppression system in the CVS makeup pump room. Flow from a component rupture or from fire fighting activities on level 2 drains to level 1 as described below.

  To protect the above valves from flooding, the makeup pump compartment at elevation 82′-6″ drains, via the floor grating located in the corridor adjacent to the stairwell, directly to elevation 66′-6″. Flooding in the lower annulus drains directly to elevation 66′-6″ via the floor grating, drains, and various openings to the tank rooms. The stairwell and elevator shaft on the east wall are additional flow paths to level 1. The horizontal pipe chase at elevation 92′-6″ drains under the door to elevation 66′-6″ via the vertical pipe chase in the spent fuel pool cooling system penetration room. As a result of these drain paths, there is less than a 12-inch accumulation of water in the horizontal pipe chase from any postulated pipe ruptures. The containment isolation valves in these areas are capable of moving to their safety position during the event.

  Due to the moderate-energy line break of the fire protection system and the subsequent drainage of the entire connected fire protection system inventory to level 1, the bounding flood height originating from elevation 66'-6" is 19 feet. That flood height extends up to level 2 and terminates at elevation 85'-6". Therefore, the bounding flood height for the rooms on auxiliary building level 2 is 3 feet for a room with a floor elevation of 82'-6". This flooding has no impact on safe shutdown

since there are no components on level 2 that cannot perform the functions required for safe shutdown if flooded.

Auxiliary Building Level 3 (Elevation 100′-0″)

- **Nonradiologically Controlled Area**

  Level 3 of the nonradiologically controlled area includes the remote shutdown room, one reactor coolant pump trip switchgear room, four divisional Class 1E I&C rooms, one equipment room, and the valve/piping penetration room. The division A, B, C and D I&C rooms and the electrical room also include containment electrical penetrations. The doors are not water tight.

  The level 3 Class 1E and non-Class 1E electrical areas contain only fire protection system piping. Fire hose stations are provided near each of the two stairwells and normally dry fire protection piping, supplied from the passive containment system tank, serves the preaction sprinkler system in the non-1E equipment/penetration room. The potential for flooding in the electrical areas on this level is limited to fire fighting activities. The maximum flowrate to this area from either automatic or manual fire fighting activities is assumed to be 250 gpm. The floor drains, stairwells, and elevator shaft drain water spilled on this level down to level 1. Therefore, no significant accumulation of water occurs in this area.

  The valve/piping penetration room on level 3 is physically separated from the electrical rooms. The valve/piping penetration room contains automatically actuated containment isolation valves for the steam generator blowdown system and the hydrogen line in the chemical and volume control system. Access to this room is from the turbine building. The access door and drain lines provided in this room drain from the auxiliary building to the turbine building. Maximum postulated flood level for this room is less than 36 inches. The containment isolation valves in the area are located above this maximum flood level.

- **Radiologically Controlled Area**

  Level 3 of the radiologically controlled area includes two containment pressure transmitters, three spent fuel pool level transmitters, four spent fuel pool cooling system isolation valves, and two passive containment cooling system safety-related valves, which are required for safe shutdown.

  Potential sources of flooding for this area include, but are not limited to, the normal residual heat removal system, the component cooling water system, an effluent monitor tank and the fire protection system, including an automatic suppression system in the rail car bay. The worst case flooding scenario on this level is the moderate-energy line break in the fire protection system located in the rail car bay area. This scenario results in significant flooding in the rail car bay, residual heat removal system heat exchanger room, and resin transfer pump room due to the high flow rate in the fire protection system and limited flow paths out of the room. The maximum flood level in the rail car bay, resin transfer pump room, and residual heat removal system heat exchanger room is less than 4 feet. Fluid from this break will flow from the rail car bay through a safety-related flood relief flapper into the normal residual heat removal heat exchanger room, and through floor penetrations to the lower levels.

  The containment pressure transmitters and one of the spent fuel pool level transmitters are located in the middle annulus. The safety-related passive containment cooling valves are located in the maintenance floor staging area. A moderate-energy line break in the fire protection system located in the maintenance floor staging area causes significant flooding in the middle annulus. The maximum flood level in the middle annulus and the staging area is below elevation 107'-9". The spent fuel pool level transmitter will be submerged; however, the transmitter is qualified for submergence.

The other safe shutdown components are located above the maximum flood level. The other two spent fuel pool level transmitters and the spent fuel pool cooling system isolation valves are located in the waste monitor tank room B. The maximum flood level in this room is due to a waste monitor tank rupture and will be less than 109 inches. The spent fuel pool level transmitters in this area are located below the maximum flood level; however, they are qualified for submergence.

For each scenario, the plant is maintained in a safe condition and the safety functions maintain their integrity without the need for operator action to mitigate the flooding. Flow from a component rupture or from fire fighting activities in other rooms on level 3 drains directly to level 1.

Auxiliary Building Level 4 (Elevation 117′-6″)

- **Nonradiologically Controlled Area**

  Level 4 of the nonradiologically controlled area includes the main control room, one divisional Class 1E penetration room, one non-Class 1E electrical penetration room, two main steam isolation valve compartments, and one mechanical equipment room.

  The doors to these rooms are not water tight. There are no doors from the main steam isolation valve compartments to the Class 1E electrical areas. The main steam isolation valve compartments are only accessible from the turbine building at elevation 135′-3″. The mechanical equipment room is only accessible from the turbine building at elevation 117′-6″.

  The potential for flooding Class 1E electrical areas on this level is limited to fire fighting activities. The Class 1E electrical penetration room and main control room are accessible from a hose station near the east stairwell. While the main control room kitchen and restroom are provided with potable water, the lines are 1 inch and smaller, and are not evaluated for pipe ruptures. The main control room contains a water heater tank and expansion tank Section in the men's toilet room to provide hot water for hand washing and dishwashing. To mitigate the effects of a postulated tank rupture, the water heater tank and expansion tank are enclosed in a seismic Category I structure and the room design is configured to contain the water and direct it to the floor drain, where it is gravity-drained to the sanitary drainage system (SDS).

  Fire fighting in the control room is done manually using portable extinguishers or a fire hose from a hose station in the east corridor. In the event that a hose is brought into the main control room through the east corridor access doors, water accumulation is limited by flow through the access doors which are open. The threshold of the east corridor access door is at the elevation of the floor slab. Once in the corridor this flow drains, via floor drains, the stairwell and elevator shaft, to level 1. An emergency egress door and stairwell is located on the west end of the main control room, which leads down to the remote shutdown room. The threshold of the emergency egress door is flush with the raised portion of flooring in the main control room, which is approximately 14 inches above the east corridor entrance. Water being discharged in this area will flow through the porous raised flooring and flow back out the east access doors. The main control room has a normally closed floor drain which can be manually opened to drain water to the auxiliary building non-RCA sump at level 1. The drain paths prevent significant flooding of the adjacent rooms.

  In the event of fire fighting activity in the non-Class 1E electrical penetration rooms, the accumulation of water is prevented by floor drains and flows through the stairwell and elevator shaft to level 1.

  The mechanical equipment room contains containment isolation valves for the chilled water, compressed air, component cooling water, and passive core cooling (nitrogen) systems. Flooding in the mechanical equipment room due to fire fighting or piping ruptures is directed to the turbine building through the access door at elevation 117′-6″ or through floor drains to the turbine

building. The maximum flood level for this room is 4 inches. The containment isolation valves in this area are located above this maximum flood level.

The main steam isolation valve compartments contain the main steam and main feedwater piping and their isolation valves. In the event of a pipe break or leak in the area, floor drains to the turbine building are provided. Structural walls and floors are designed to prevent flow of water to levels 1, 2, or 3. For larger flows, wall openings and pressure relief panels, located at floor elevation, open to drain the rooms to the turbine building. The maximum flood level for these rooms is less than 36 inches. The isolation valves in this area are located above this maximum flood level.

- **Radiologically Controlled Area**

In the radiologically controlled area, there are six containment isolation valves on level 4. Five of these are located in the vertical pipe chase. These are for the primary sampling system, spent fuel pool cooling system and containment air filtration system. The primary source of flooding in the vertical pipe chase is from a moderate-energy line break in the fire protection system located in the personnel access area on level 5. Flow from this break will be directed through the open pipe penetration on level 5, into the vertical pipe chase, through the grating down to level 3 where water will flow under the door to the waste monitor tank room and through floor drains and an open sleeve penetration to the auxiliary building RCA sump which limits the flood level to less than 12 inches in the vertical pipe chase and 109 inches in the waste monitor tank room. The containment isolation valves are located above maximum flood level. The other containment isolation valve for the containment air filtration system is located in a separate compartment adjacent to column line 5. The principal source of flooding for this area is from a moderate-energy line break in the fire protection system located in the personnel access on level 5. Flow from this source will be directed through the open pipe penetration on level 5, into the containment air filtration system penetration room, under the door and through floor drains to the auxiliary building radiologically controlled area sump which limits the flood level to less than 30 inches in the containment air filtration system penetration room. The containment isolation valve body will be partially submerged; however, the limit switch and solenoid are above the maximum flood level. No other safe shutdown equipment is located in this area.

Auxiliary Building Level 5 (Elevation 135′-3″)

- **Nonradiologically Controlled Area**

Level 5 of the nonradiologically controlled area contains two mechanical HVAC equipment rooms and the upper portion of the two main steam isolation valve compartments. The only safety-related equipment on level 5 that could be affected by flooding is the potable water system main control room isolation valve located in the main mechanical HVAC equipment room, but it is positioned above the maximum flood height for this room.

The evaluation of the main steam isolation valve compartments is addressed in the discussion of level 4.

Water from fire fighting, postulated pipe, or potable water storage tank ruptures in the main mechanical HVAC equipment rooms drains to the turbine building via floor drains. Therefore, no significant accumulation of water occurs in this room. Floor penetrations are sealed and a 6 inch platform is provided at the elevator and stairwell such that flooding in these rooms does not propagate to levels below.

The mechanical room between the main steam isolation valve compartments at level 5 is accessed from the turbine building on the same level. This room is drained to the turbine building. In the event of fire fighting or postulated pipe ruptures, the accumulation of water is prevented by

directing the flow to the drains into the turbine building. Floor penetrations are sealed such that flooding in this area does not propagate to other areas of the auxiliary building.

- **Radiologically Controlled Area**

  Level 5 of the radiologically controlled area contains the fuel handling area operating deck, HVAC equipment and access rooms, the main equipment hatch staging area, and the component cooling water system valve room. Safety-related equipment on level 5 includes the compressed air tanks for the main control room emergency habitability system and associated valves located in the main equipment hatch staging area, containment leak rate test system valves in the personnel access area, and spent fuel equipment located in the fuel transfer canal and spent fuel pool.

  Over-filling of the spent fuel pool would flood the fuel handling area operating deck. The flooding flowrate is limited by the makeup capacity from the demineralized water or chemical and volume control systems. Accumulation of water in this area is prevented by floor drains. Spent fuel pool cooling is not adversely affected by this event. There is no safe shutdown equipment in this area. The component cooling water system valves with the regulatory treatment of nonsafety-related system important missions located in the component cooling water system valve room which support the normal residual heat removal system, are located well above the maximum flood level for this area and are expected to remain functional in a flooding event.

  The shield building stairwell serves as a pipe chase for passive containment cooling system supply and return lines, drains for the passive containment cooling system valve room and passive containment cooling system air outlet shield plug, and a fire water line. Leakage from a crack in one of these lines flows down the stairwell to level 5, under the stairwell door to the HVAC equipment room, and then to the auxiliary building radiologically controlled area sump via floor drains or to the annex building. There is no significant accumulation in the stairwell or the equipment and access rooms. There is no safe shutdown equipment in this area. The passive containment cooling system supply and return line connections to the passive containment cooling system storage tank are above the maximum water level, thus a leak in these lines would not adversely affect the safe shutdown capability of the passive containment cooling system.

  Water from fire fighting in the main equipment hatch staging area drains to the auxiliary building radiologically controlled area sump via floor drains. Therefore, no significant accumulation of water occurs in this area.

Auxiliary Building Upper Annulus (Elevation 132′-3″)

This area serves as the air flow path for the passive containment cooling system. It is bounded by the seismic Category I shield building on the outside and the seismic Category I containment vessel on the inside. The floor has a curb on the outside with a flexible seal connected to the shield building. The curb and seal block communication with the middle annulus area, below. The outside wall of the annulus is provided with redundant safety-related drains to the yard drainage system.

The worst case flooding scenario is postulated as blockage of the nonsafety-related floor drains concurrent with inadvertent opening of a passive containment cooling system cooling water isolation valve. The maximum flood level is determined by the flow gradient to the operating drains. Maximum level will be approximately 2 feet. This level does not affect the capability of passive containment cooling system air cooling. No other safe shutdown equipment is affected. Passive containment cooling system operation or leakage is detected by sensors on the passive containment cooling system discharge line. During non-accident conditions the annulus is accessible to manually clear any drain blockage.

PCS Valve Room (Elevation 284′-10″)

This room contains three redundant safety-related valve trains for the passive containment cooling system water cooling subsystem. One train must open to provide the required containment cooling. The only source of flooding for this room is a through-wall crack in the passive containment cooling system piping. The bounding through-wall crack is postulated in the 4 inch recirculation piping. This leak is not isolable from the 756,700-gallon passive containment cooling system water storage tank above the valve room.

The PCS valve room contains floor drains with sufficient capacity to prevent water accumulation in the room following a postulated through-wall crack. Water from the through-wall crack flows into the floor drains out to the auxiliary building roof, then to the storm drain system. The passive containment cooling system isolation valves are located above the maximum flood level in the valve room, so they remain operable.

The passive containment cooling water storage tank (PCCWST) level instruments are relied upon to monitor PCCWST water level for operation of the PCS and to identify leakage from the PCS. The leakage does not adversely affect containment or any other essential system.

3.4.1.2.2.3 Adjacent Structures Flooding Events

Turbine Building

The turbine building is subject to flooding from a variety of potential sources including the circulating water, service water, condensate/feedwater, component cooling water, turbine building cooling water, demineralized water and fire protection systems as well as the deaerator storage tank. Flow from any postulated ruptures above elevation 100′-0″ flows down to elevation 100′-0″ via floor grating and stairwells. Thus, there will be a negligible contribution from these sources to flooding of the auxiliary building compartments at elevations 135′-3″ and 117′-6″ via flow under doors. Auxiliary building flooding is bounded by the effects of postulated breaks in the compartments.

The bounding flooding source for the turbine building is a break in the circulating water piping which would result in flooding of the elevation 100′-0″ floor. Flow from this break runs out of the building to the yard through a relief panel in the turbine building west wall and limits the maximum flood level to less than 6 inches. The only area of the auxiliary building which interfaces with the turbine building at elevation 100′-0″ is the valve/piping penetration room. This room could be flooded via flow under the door or backflow through the drains, however the flood level would be less than postulated for a break in the valve/piping penetration room itself.

The waste water system (WWS) sump pumps located in the nonradiologically controlled area of the auxiliary building discharge to the turbine building drain tank. Backflow from the drain tank is prevented as described in Subsection 3.4.1.2.2.2

There is no safety-related equipment in the turbine building. The component cooling water and service water components on elevation 100′-0″, which provide the regulatory treatment of nonsafety-related systems important to support the normal residual heat removal system, are expected to remain functional following a flooding event in the turbine building since the pump motors and valve operators are above the expected flood level.

Annex Building

- **Nonradiologically Controlled Areas**

  The primary sources of flooding in the nonradiologically controlled areas of the annex building are the component cooling water, chilled water and fire protection systems. Water from postulated breaks above elevation 100′-0″ flows primarily through floor drains to the annex

building sump that discharges to the turbine building drain tank. Alternate paths include flows to the turbine building via flow under access doors at elevations 135′-3″ and 117′-6″ and flows down to elevation 100′-0″ via stairwells and elevator shaft. Water accumulation at elevation 100′-0″ is minimized by floor drains to the annex building sump and by flow under the access doors leading directly to the yard area.

There is no safety-related equipment in the nonradiologically controlled area portion of the annex building. The main ac power system components with regulatory treatment of nonsafety-related systems important missions are located on elevation 117′-6″ in the electrical switchgear rooms, which are separated from potential flood sources. Water from manual fire fighting operations is collected by floor drains discharging to the annex building sump or down a hatch or stairwell to elevation 100′-0″. The non-Class 1E dc and UPS system (EDS) equipment with regulatory treatment of nonsafety-related systems important missions is located on elevation 100′-0″ in separate battery rooms. Water in one of these rooms due to manual fire fighting in the room is collected by floor drains to the annex building sump and by flow under the access doors leading directly to the yard area. This is not expected to affect functionality of equipment in the adjacent rooms.

- **Radiologically Controlled Areas**

  There is no safety-related equipment in the radiologically controlled area portion of the annex building. The primary sources of flooding in the radiologically controlled areas of the annex building are the component cooling water, chilled water and fire protection systems, including an automatic suppression system that protects the containment access corridor. Water from postulated breaks above elevation 100′-0″ drains through floor drains to the radioactive waste drain system sump in the radiologically controlled area of the auxiliary building or drains to elevation 100′-0″ via stairwells and equipment handling hatches or under access doors to the radiologically controlled area portion of the auxiliary building. Accumulated water at elevation 100′-0″ is minimized by floor drains discharging to the radioactive waste drain system sump or chemical waste tank in the auxiliary building. The contribution of water to the flooding of the radiologically controlled area portion of the auxiliary building is bounded by flooding events which could occur in the auxiliary building.

Radwaste Building

The potential sources of flooding in the radwaste building are the chilled water, hot water, and fire protection systems or from failure of one of the three waste monitor tanks. Flow from postulated breaks is directed to floor drains via a curb/sloped floor around the perimeter to drain to the radioactive waste drain system sump in the radiologically controlled area of auxiliary building. The contribution of water to flooding of the auxiliary building is bounded by flooding events which could occur in the auxiliary building. There are no safety-related systems or components or equipment with regulatory treatment of nonsafety-related systems important missions in the radwaste building.

Diesel Generator Building

The potential source of flooding in the diesel generator building is the fire protection system. There is no safety-related equipment in the diesel generator building. The diesel generator system which has regulatory treatment of nonsafety-related systems important mission has each diesel and associated auxiliaries in a separate compartment. Flooding due to a break in a fire water header is directed to the respective diesel generator building sump and subsequently pumped to the yard oil separator or is drained by gravity to the yard area under the access doors. The equipment in the adjacent diesel generator compartment should remain functional following the event.

3.4.1.3 Permanent Dewatering System

The need for a permanent dewatering system is site specific and is defined as discussed in Subsection 3.4.3.

No permanent dewatering system is required because site groundwater levels are two feet or more below site grade level as described in Subsection 2.4.12.

3.4.2 Analytical and Test Procedures

The AP1000 is designed so that the maximum water levels considered due to natural phenomena or internal flooding do not jeopardize the safety of the plant or the ability to achieve and maintain safe shutdown conditions. The analytical approach in the consideration of external and internal flooding events is described in Subsection 3.4.1.2.

3.4.3 Combined License Information

The site-specific water levels given in Subsection 3.4.1.3 and Section 2.4 satisfy the interface requirements identified in Section 2.4.

3.4.4 References

1. ANSI/ANS-56.11-1988, "Design Criteria for Protection against the Effects of Compartment Flooding in Light Water Reactor Plants."

NOTES:

1. HDPE DOUBLE-SIDED TEXTURED WATERPROOF MEMBRANE ON TOP OF FIRST LAYER OF MUDMAT AND ON OUTSIDE VERTICAL FACE OF AUXILIARY BUILDING WALL UP TO EL. 100' -0" GRADE LEVEL (WITH PROTECTIVE SHIELD ON VERTICAL FACE)

2. MSE WALL TO BE DESIGNED WITH GEOREINFORCED MATERIALS AND 18" THICK LAYERS OF COMPACTED FREE DRAINING GRANULAR SOIL

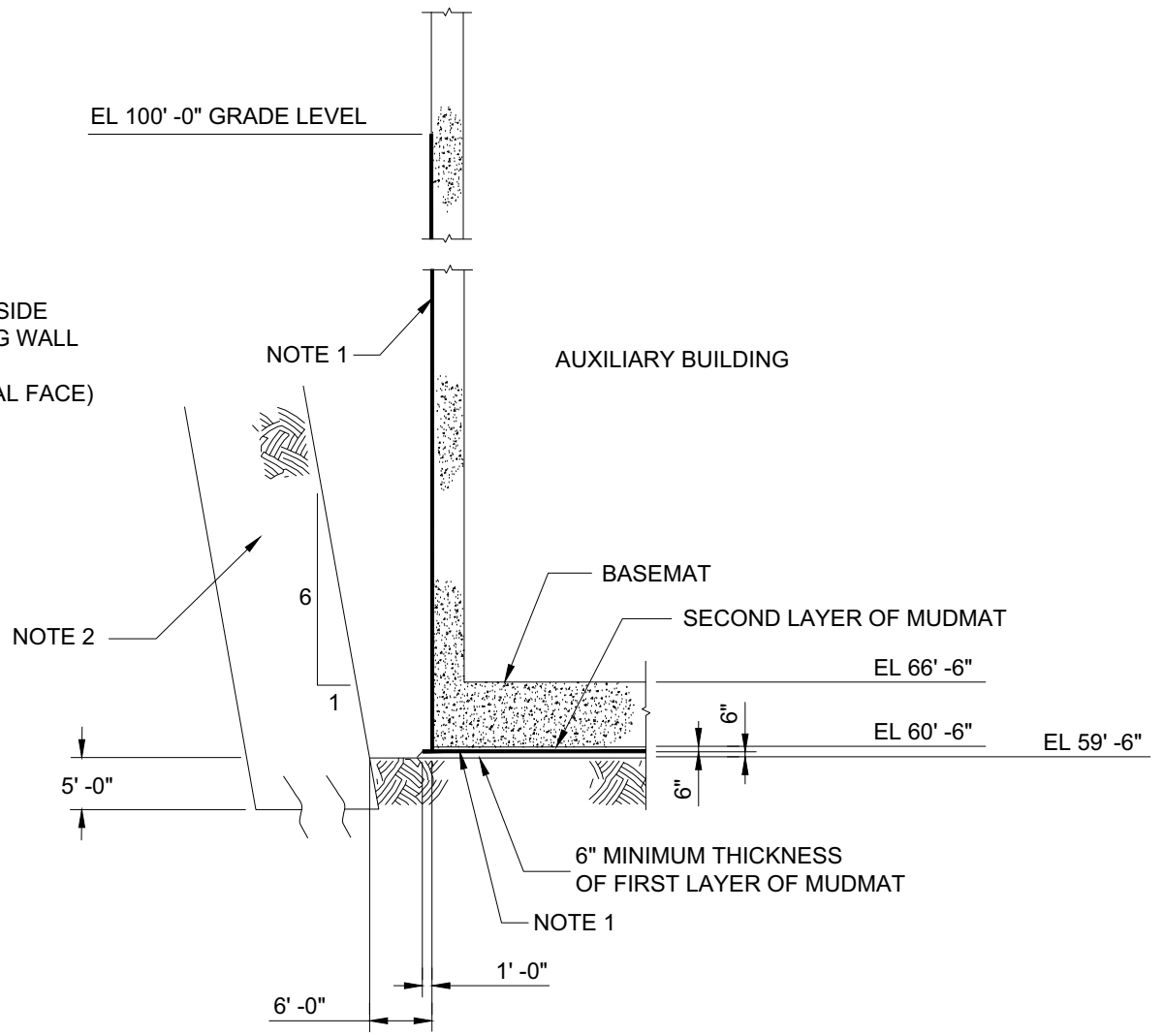
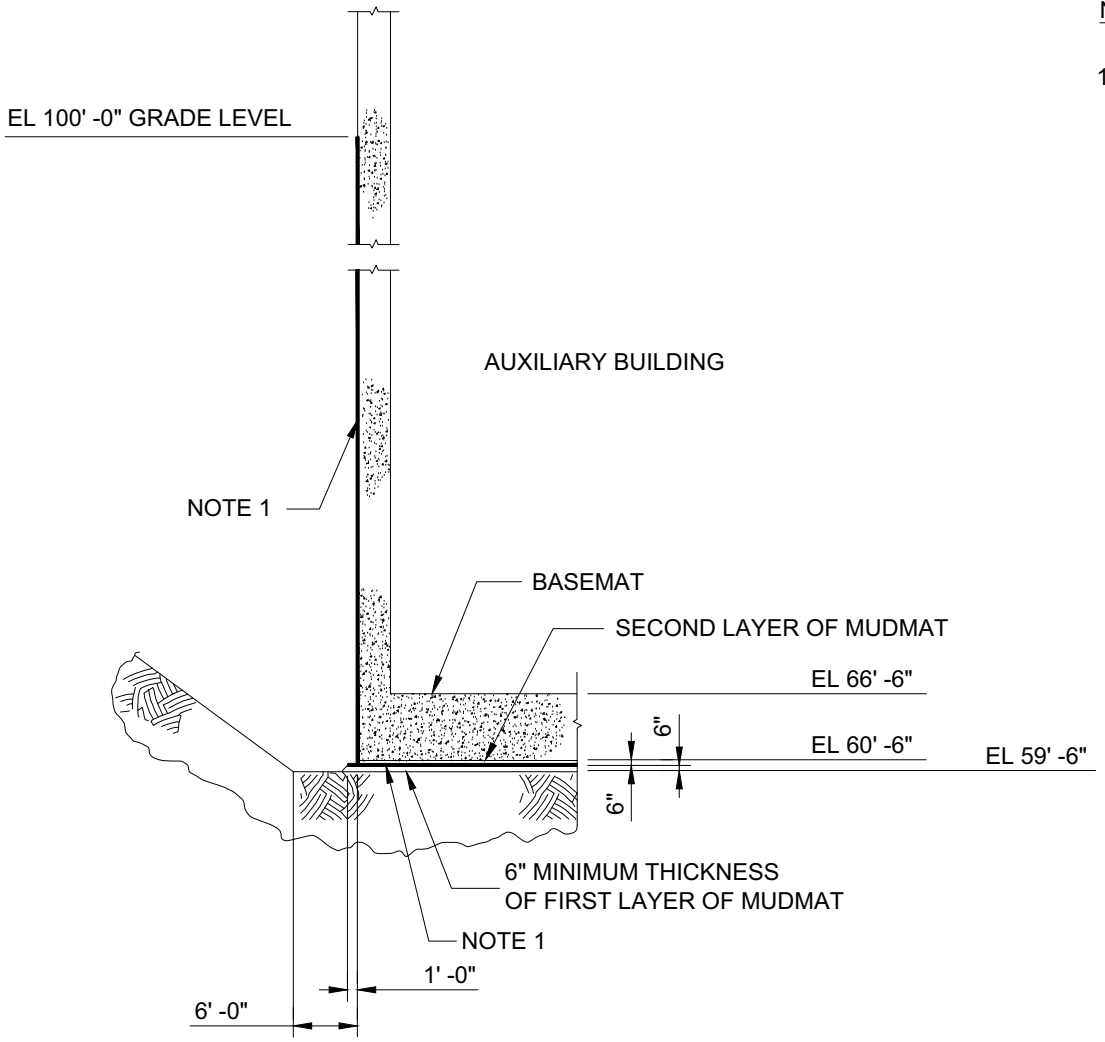


Figure 3.4-1
Typical Details of
Nuclear Island Waterproofing Below Grade



NOTES:

1. HDPE DOUBLE-SIDED TEXTURED WATERPROOF MEMBRANE ON TOP OF FIRST LAYER OF MUDMAT AND ON OUTSIDE VERTICAL FACE OF AUXILIARY BUILDING WALL UP TO EL 100' -0" GRADE LEVEL (WITH PROTECTIVE SHIELD ON VERTICAL FACE)

Figure 3.4-2
Typical Details of Nuclear Island Waterproofing Below Grade with Step Back

Figure 3.4-3 Not Used

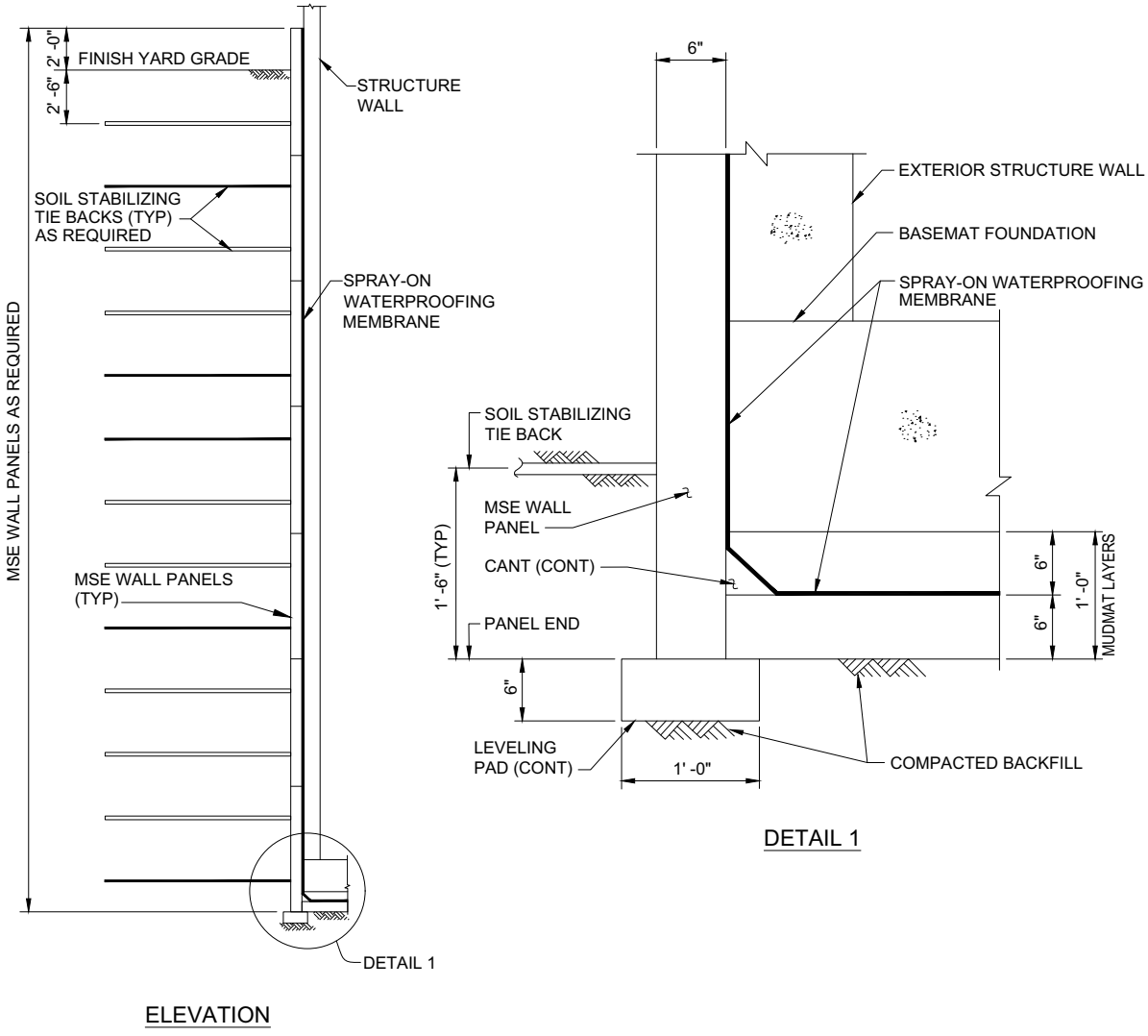


Figure 3.4-4
Typical Details of Membrane Corner Detail at Basemat and Exterior Wall

3.5 Missile Protection

General Design Criterion 4 of Appendix A to 10 CFR 50 requires that structures systems and components important to safety be protected from the effects of missiles. The AP1000 criteria for protection from postulated missiles provide the capability to safely shut down the reactor and maintain it in a safe shutdown condition. The AP1000 criteria also protect the integrity of the reactor coolant system pressure boundary and maintain offsite radiological dose/concentration levels within the limits defined in 10 CFR 50.34.

Missiles may be generated by pressurized components, rotating machinery, and explosions within the plant and by tornadoes or transportation accidents external to the plant. Potential missile hazards are eliminated to the extent practical by minimizing the potential sources of missiles through proper selection of equipment, and by arrangement of structures and equipment in a manner to minimize the potential for damage from missiles. Potential missiles due to failures of nonseismic items are addressed in Subsection 3.7.3.13. Heavy load-drop evaluations are described in Subsection 9.1.5.

The following are definitions for missile protection terminology:

Internally Generated Missile – A mass that may be accelerated by energy sources continuously present on site.

Single Active Failure – Malfunction or loss of a component of electrical or fluid systems. The failure of an active component of a fluid system is considered to be a loss of component function as a result of mechanical, hydraulic, pneumatic, or electrical malfunction, but not the loss of component structural integrity.

High-Energy System – Fluid systems that, during normal plant conditions, are operated or maintained pressurized with a maximum operating temperature greater than 200°F and/or a maximum operating pressure greater than 275 psig, as discussed in Subsection 3.6.1.

The following criteria are applied in the identification of missiles and the protection requirements that must be satisfied:

- A missile must not damage structures, systems, or components to the extent that could prevent achieving or maintaining safe shutdown of the plant or result in a significant release of radioactivity.

- A single active component failure is assumed in systems used to mitigate the consequences of the postulated missile and achieve a safe shutdown condition. The single active component failure is assumed to occur in addition to the postulated missile and any direct consequences of the missile. When the postulated missile is generated in one of two or more redundant trains of a dual-purpose safety-related fluid system, which is designed to seismic Category I standards and is capable of being powered from both onsite and offsite sources, a single active component failure need not be assumed in the remaining train(s), or associated supporting trains.

- Walls, partitions, and other items that enclose safety-related systems, or separate redundant trains of safety related equipment, must be constructed so that a postulated missile cannot damage components required to achieve safe shutdown nor damage components required to prevent a release of radioactivity producing offsite doses in excess of 10 CFR 50.34 limits.

- A postulated missile from the reactor coolant system must not cause loss of integrity of the primary containment, main steam, feedwater, or other loop of the reactor coolant system.

- A postulated missile from any system other than the reactor coolant system must not cause loss of integrity of the containment or the reactor coolant system pressure boundary.
- Other plant accidents or severe natural phenomena are not assumed to occur in conjunction with a postulated missile (except for tornado).
- Offsite power is assumed to be unavailable if a trip of the turbine-generator or reactor protection system is a direct consequence of the postulated missile.
- Safe shutdown is accomplished using only safety-related systems with a coincident single active failure, although nonsafety-related systems not affected by the missile are available to support safe shutdown.
- Missiles are postulated to occur where the single failure of a retention mechanism can result in a missile, unless the missile is not considered credible as discussed later. Missiles created by the independent failures of two retention mechanisms are not postulated.
- The energy of postulated missiles produced by rotating components is based on a 120 percent overspeed condition, unless such an overspeed condition is not possible (such as a synchronous motor).
- Equipment required for safe shutdown is located in plant areas separate from potential missile sources wherever practical.
- Spatial separation may be used to demonstrate protection from missile hazards when it is shown that the range and trajectory of the generated missile is less than the distance to or is directed away from the potential target.

The AP1000 passive design minimizes the number of safety-related structures, systems, and components required for safe shutdown. Systems required for safe shutdown are identified in Chapter 7. Safety class structures, systems and components, their location, seismic category, and quality group classifications are given in Section 3.2. General arrangement drawings showing locations of the structures, systems, and components are given in Section 1.2 The areas required for safe shutdown, and the major systems and components housed therein that are required to be protected from internally and externally generated missiles for safe shutdown, are summarized below:

- The containment vessel, including the reactor coolant loop, and passive core cooling system inside containment
- The shield building, including the passive containment cooling system
- Containment penetration areas, including containment isolation valves and Class IE cables
- The control complex including the main control room, reactor protection system, batteries, and dc switchgear
- The spent fuel pool

The AP1000 relies on safety-related systems and equipment to establish and maintain safe shutdown conditions. There are no nonsafety-related systems or components that require protection from missiles.

Evaluations are performed to demonstrate that the criteria are satisfied in the event a credible missile is produced coincident with a single active component failure. These evaluations include the following:

- For those potential missiles considered to be credible, a realistic assessment is made of the postulated missile size and energy, and its potential trajectories.
- Potentially impacted components associated with systems required to achieve and maintain safe shutdown are identified.
- Loss of these potentially impacted components coincident with an assumed single active component failure is evaluated to determine if sufficient redundancy remains to achieve and maintain a safe shutdown condition. If these criteria are satisfied, no further protection is required for the identified missile. If these conditions are not satisfied, additional protective features are incorporated (for example, plant layout is modified, or barriers are added).

3.5.1 Missile Selection and Description

3.5.1.1 Internally Generated Missiles (Outside Containment)

3.5.1.1.1 Criteria for Missile Prevention

Equipment for the AP1000 is selected to minimize the potential for missiles to be generated. Missiles are postulated as described in Subsection 3.5.1.1.2. The following items are the major equipment selection considerations with regards to missile prevention:

- Safety-related rotating equipment is designed so that the surrounding housings would contain fragments in the event of failure of the rotating parts.
- Valves that have only a threaded connection between the body and the bonnet are not used in high-energy systems. ASME Code, Section III valves with removable bonnets should be of the pressure-seal type or have bolted bonnets.
- Valve stems of valves located in high-energy systems have at least two retention features. In addition to the stem threads, acceptable features include back seats on the stem or a power actuator, such as an air or motor operator.
- Thermowells and other instrument wells, vents, drains, test connections, and other fittings located in high-energy systems are attached to the piping or pressurized equipment by welding. The completed joint should have a greater design strength than the parent metal. Threaded connections in high-energy systems are avoided.
- High-pressure gas cylinders permanently installed in safety-related areas are constructed to the criteria of ASME Code, Section III or Section VIII. Portable and temporary cylinders and cylinders periodically replaced in safety-related areas are constructed and handled in accordance with applicable Department of Transportation requirements for seamless steel cylinders.

3.5.1.1.2 Missile Selection

3.5.1.1.2.1 Missiles not Considered Credible

This subsection describes internally generated missiles (outside of containment) not considered credible. Missiles not considered credible include the following:

- Catastrophic failure of safety-related rotating equipment (such as pumps, fans, and compressors) leading to the generation of missiles is not considered credible. These components are designed to preclude having sufficient energy to move the masses of their rotating parts through the housings in which they are contained. In addition, material characteristics, inspections, quality control during fabrication and erection, and prudent operation as applied to the particular component reduce the likelihood of missile generation.

- Catastrophic failure of nonsafety-related rotating equipment is not considered credible in situations where measures similar to those just described for safety-related rotating equipment are applied to them. Protection from nonsafety-related equipment will normally be provided by separation. In special situations, equipment features may be used to prevent missile formation.

- Provisions to preclude generation of missiles due to failure of the turbine generator are discussed in Subsection 3.5.1.3.

- Missiles originating in non-high-energy fluid systems are not considered credible because these systems have insufficient stored energy.

- The valve bonnets of pressure-seal, bonnet-type valves, constructed in accordance with ASME Code, Section III, are not considered credible missiles. The valve bonnets are prevented from becoming missiles by the retaining ring, which would have to fail in shear, and by the yoke capturing the bonnet or reducing bonnet energy. Because of the conservative design of the retaining ring of these valves, bonnet ejection is unlikely.

- The valves of the bolted bonnet design, constructed in accordance with ASME Code, Section III, are not considered credible missiles. These bolted bonnets are prevented from becoming missiles by limiting stresses in the bonnet-to-body bolting material according to ASME Code, Section III requirements, and by designing flanges in accordance with applicable code requirements. Even if bolt failure would occur, the likelihood of all bolts experiencing simultaneous complete severance failure is not credible. The widespread use of valves with bolted bonnets, and the low historical incidence of complete severance failure of the bonnet, confirm that bolted valve bonnets are not credible missiles. Safety-relief valves in high energy systems use the bolted bonnet design.

- Valve stems are not considered as credible missiles if at least one feature (in addition to the stem threads) is included in their design to prevent ejection. Valve stems with back seats are prevented from becoming missiles by this feature. In addition, the valve stems of valves with power actuators, such as air- or motor-operated valves, are effectively restrained by the valve actuator. Valve stems of rotary motion valves, such as plug valves, ball valves (except single-seat ball valves) and butterfly valves, as well as diaphragm and bellows type valves are not considered as credible missiles. Because these valves do not have a large reservoir of pressurized fluid acting on the valve stem, there is little stored energy available to produce a missile.

- Nuts, bolts, nut and bolt combinations, and nut and stud combinations have only a small amount of stored energy and thus are not considered as credible missiles.

- Thermowells and similar fittings attached to piping or pressurized equipment by welding are not considered as credible missiles where the completed joint has a greater design strength than the parent metal. Such a design makes missile formation not credible. Threaded connections are not used to connect instrumentation to high-energy systems or components.

- Instrumentation such as pressure, level, and flow transmitters and associated piping and tubing are not considered as credible missiles. The quantity of high energy fluid in these instruments is limited and will not result in the generation of missiles. The connecting piping and tubing is made up using welded joints or compression fittings for the tubing. Tubing is small diameter and has only a small amount of stored energy.

- ASME Code, Section III vessel ruptures and ruptures of gas storage vessels constructed without welding using ASME Code, Section VIII criteria are not considered credible due to the conservative design, material characteristics, inspections, quality control during fabrication and erection, and prudent operation.

- Rotating components that operate less than 2 percent of the time are not considered credible sources of missiles. Components that are excluded by this criterion include motors on valve operators and pumps in systems that operate infrequently, such as the chemical and volume control makeup pumps. This exclusion is similar to the exclusion mentioned in Subsection 3.6.1.1, that is, of lines from the high-energy category of lines that have limited operating time in high energy conditions.

- Valves, rotating equipment, vessels, and small fittings not otherwise considered to be credible missiles due to design features or other considerations are not considered to be a potential source of missiles when struck by a falling object.

3.5.1.1.2.2 Explosions

Missiles can potentially be generated by a hydrogen explosion. Missiles that could prevent achieving or maintaining a safe shutdown or result in significant release of radioactivity are precluded by design of the plant systems that use or generate hydrogen.

- The battery compartments are ventilated by a system that is designed to preclude the possibility of hydrogen accumulation. Therefore, a hydrogen explosion in a battery compartment is not postulated.

- The hydrogen injection package (CVS-MS-02) in the turbine building is supplied from the Plant Gas System (PGS) high pressure hydrogen switchover station bottles located in the yard, adjacent to the turbine building. The hydrogen is not located in a compartment that contains safety-related systems or components. The hydrogen is supplied to the chemical and volume control system inside the containment. There are two parallel flow paths: one for “continuous” addition of hydrogen during power operation, and one for “batch” additions of hydrogen during startup and restart. Each line has a control valve and flow transmitter to provide operators with system parameters and control capabilities. The hydrogen injection line break analysis has determined that a worst case failure of the Chemical and Volume Control System (CVS) hydrogen injection line outside the containment building would not lead to an explosive atmosphere in the compartment where the failure occurred.

- Mixing within a compartment is achieved by normal convection caused by thermal forces from hot surfaces and air movement due to operation of HVAC systems. The hydrogen supply line is not routed through compartments that do not have air movement due to HVAC systems.

- The bulk gas plant storage area for the plant gas system (PGS) stores hydrogen for use in generator cooling. This storage area is located sufficiently far from the nuclear island that an explosion would not result in missiles more energetic than the tornado missiles for which the

nuclear island is designed. The hydrogen is piped to the generator in the turbine building. The turbine building includes sufficient ventilation to prevent an explosive concentration of hydrogen in the event of a leak.

- A detonation of a flammable vapor cloud (delayed ignition) due to the accidental release of hydrogen from the PGS bulk gas storage area or from the high-pressure hydrogen bottles area would not result in missiles more energetic than the tornado missiles for which the nuclear island is designed.

3.5.1.1.2.3 Missiles to be Considered

The following missiles are considered:

- Nonsafety-related rotating equipment, not excluded above,
- Pressurized components, not excluded above, located in high-energy systems
- High pressure gas storage cylinders that may experience a failure of the outlet pipe or valve if accidentally impacted.

3.5.1.1.2.4 Credible Sources of Internally Generated Missiles (Outside Containment)

The consideration of missile sources outside containment that can adversely affect safety-related structures, systems or components is limited to a few rotating components inside the auxiliary building and a few pressurized components in the chemical and volume control system. The safety-related systems and components needed as described in Section 7.4 to bring the plant to a safe shutdown are located inside the containment shield building and auxiliary building, both of which have thick structural concrete exterior walls that provide protection from missiles generated in other portions of the plant. Safety-related systems and components located in the auxiliary building, including the main control room, are protected from missiles generated in other portions of the auxiliary building by the structural concrete interior walls and floors. Protection against potential missiles from the turbine-generator is discussed in Subsection 3.5.1.3.

Rotating components located inside the auxiliary building that are either safety-related or are constructed as canned motor pumps would contain fragments from a postulated fracture of the rotating elements. These are excluded from evaluation as missile sources. Rotating components used less than 2 percent of the time are also excluded from evaluation as missile sources. This exclusion of equipment that is used for a limited time is similar to the approach used for the definition of high-energy systems. Nonsafety-related rotating equipment in compartments surrounded by structural concrete walls with no safety-related systems or components inside the compartment is not considered a missile source. Rotating equipment with a housing or an enclosure that contains the fragments of a postulated impeller failure is not considered a credible source of missiles. For one or more of these reasons the nonsafety-related rotating equipment inside the auxiliary building is not considered to be a credible missile source. Nonsafety-related rotating equipment in compartments with safety-related systems or components that do not provide other separation features have design requirements for a housing or an enclosure to retain fragments from postulated failures of rotating elements.

The high-energy system inside the auxiliary building that includes pressurized components in the high-energy portions that are constructed to standards other than the ASME Code criteria outlined in Subsection 3.5.1.1.1 is the chemical and volume control system. The high-energy portion of this system inside the auxiliary building that is not constructed to ASME Code criteria outlined in Subsection 3.5.1.1.1 is from the makeup pumps to the containment and system isolation valves. The nonsafety-related, high-energy portion of this system is not required to be protected from missiles.

The nonsafety-related, high-energy portion of the chemical and volume control system is not to be considered a missile source. It includes the design features that are outlined above to exclude components from consideration as missile sources. These considerations include features such as a pump housing or enclosure that contains fragments of a postulated impeller fracture, valve design requirements, vessel design requirements, or enclosure requirements. See Table 3.6-1 for a list of the high-energy systems.

Falling objects (i.e. gravitational missiles) heavy enough to generate a secondary missile are postulated as a result of movement of a heavy load or from a nonseismically designed structure, system, or component during a seismic event. Movements of heavy loads are controlled to protect safety-related structures, systems, and components, see Subsection 9.1.5. Safety-related structures, systems, or components are protected from nonseismically designed structures, systems, or components or the interaction is evaluated. See Subsection 3.7.3.13 for additional discussion on the interaction of other systems with Seismic Category I systems. Valves, rotating equipment, vessels, and small fittings not otherwise considered to be credible missiles due to design features or other considerations are not considered to be a potential source of missiles when struck by a falling object. The outlet pipes and valves for the air storage bottles for the main control room are constructed to the ASME Code, Section III, requirements and are designed for seismic loads. The attached pipes and valves are not credible missile sources due to an accidental impact. The air storage bottles are located within a structural steel frame and are in an area with no activity directly above. For the reasons noted above, secondary missiles are not considered credible missiles.

3.5.1.2 Internally Generated Missiles (Inside Containment)

Selection of equipment for the AP1000 considers provisions to minimize the potential for missiles to be generated. The considerations previously discussed in Subsection 3.5.1.1 are also applicable to equipment inside the containment.

3.5.1.2.1 Missile Selection

3.5.1.2.1.1 Missiles not Considered Credible

Potential missiles are not considered credible when sufficient energy is not available to produce the missile, or by design the probability of creating a missile is negligible. The following are not considered credible sources of internally generated missiles:

- Reactor coolant pump design requirements are established so that any failure of the rotating parts would be retained within the casing at specified overspeed conditions. This is discussed in Subsection 5.4.1.3.6.

- Catastrophic failure of rotating equipment such as pumps, fans, and compressors leading to the generation of missiles is not considered credible as described previously in Subsection 3.5.1.1.2.

- Failure of the reactor vessel, steam generators, pressurizer, core makeup tanks, accumulators, reactor coolant pump castings, passive residual heat exchangers, and piping leading to the generation of missiles is not considered credible. This is due to the material characteristics, preservice and inservice inspections, quality control during fabrication, erection and operation, conservative design, and prudent operation as applied to the particular component.

- Gross failure of a control rod drive mechanism housing, sufficient to create a missile from a piece of the housing or to allow a control rod to be ejected rapidly from the core, is not considered credible. This is because of the same reasons listed above for the reactor vessel and other components and is based on the following:

  – The control rod drive mechanisms are shop hydrotested to 125 percent of system design pressure.

  – The housings are hydrotested to 125 percent of system design pressure after they are installed on the reactor vessel head. They are included as part of the hydrotest of the completed reactor coolant system.

  – The housings are made of Type 304 or 316 stainless steel, which exhibits excellent notch toughness.

  – The allowable stress levels in the mechanism are not exceeded due to system thermal transients at power or by thermal movement of the coolant loops.

  – The welds in the pressure boundary of the control rod drive mechanism meet the same design, procedure, examination, and inspection requirements as the welds on other ASME Code, Section III, Class 1 components.

  – A nonmechanistic control rod ejection is considered in the safety analyses in Chapter 15 and the design transients in Subsection 3.9.1.1. The integrated head package and control rod drive mechanisms are not designed for the dynamic effects of a missile generated by a rupture of the control rod housing.

- Valves, valve stems, nuts and bolts, and thermowells in high-energy fluid systems and missiles originating in non-high-energy fluid systems are not considered credible missiles as discussed previously in Subsection 3.5.1.1.2.1.

3.5.1.2.1.2 Explosions

Missiles can potentially be generated by a hydrogen explosion. Missiles that could prevent achieving or maintaining a safe shutdown or result in significant release of radioactivity are precluded by design of the plant systems that use or generate hydrogen.

- The hydrogen injection package (CVS-MS-02) in the turbine building is supplied from the Plant Gas System (PGS) high pressure hydrogen switchover station bottles located in the yard, adjacent to the turbine building. The hydrogen is supplied to the chemical and volume control system inside the containment. Hydrogen is injected into the Reactor Coolant System (RCS) at a steady “continuous” flow rate for normal operation and at higher flows for “batch” operation when it is desirable to change the hydrogen concentration in the coolant quickly. In case of a Chemical and Volume Control System (CVS) hydrogen injection line failure inside containment, hydrogen would rapidly dilute due to the mixing with air. The hydrogen injection line break analysis conclusion has determined that a failure of the CVS hydrogen injection line inside the containment would not lead to an explosive atmosphere in the compartment where the failure occurred. Mixing within a compartment is achieved by normal convection caused by thermal forces from hot surfaces and air movement due to operation of HVAC systems.

3.5.1.2.1.3 Missiles to be Considered

The following missiles are considered:

- Nonsafety related rotating equipment, not excluded above,
- Pressurized components, not excluded above, located in high-energy systems

3.5.1.2.1.4 Evaluation of Internally Generated Missiles (Inside Containment)

The consideration of credible missile sources inside containment that can adversely affect safety-related structures, systems, or components is limited to a few rotating components. The safety-related systems and components needed to bring the plant to a safe shutdown are inside the containment shield building and auxiliary building both of which have thick structural concrete exterior walls that provide protection from missiles generated in other portions of the plant.

Rotating components inside containment that are either safety-related or are constructed as sealless pumps would contain fragments from a postulated fracture of the rotating elements and are excluded from evaluation as missile sources. Rotating components in use less than 2 percent of the time are also excluded from evaluation as missile sources. This exclusion of equipment that is used for a limited time is similar to the approach used for the definition of high-energy systems. This includes the reactor coolant drain pumps, the containment sump pumps and motors for valve operators, and mechanical handling equipment. Non-safety-related rotating equipment in compartments surrounded by structural concrete walls with no safety-related systems or components inside the compartment is not considered a missile source. Rotating equipment with a housing or an enclosure that contains the fragments of a postulated impeller failure is not considered a credible source of missiles. For one or more of these reasons the nonsafety-related rotating equipment inside containment is considered not to be a credible missile source. Non-safety-related rotating equipment in compartments with safety-related systems or components that do not provide other separation features has design requirements for a housing or an enclosure to retain fragments from postulated failures of rotating elements.

The high-energy portions of high-energy systems inside the containment shield building except for a portion of the chemical and volume control system are constructed to the requirements of the ASME Code, Section III. The nonsafety-related, high-energy portion of the chemical and volume control system between the inside containment isolation valves and the outermost reactor coolant system isolation valves is not required to be protected from missiles and is not to be considered a missile source. It includes design features outlined above to exclude components from consideration as missile sources. In addition most of the nonsafety-related portion of the chemical and volume control system is contained in a compartment located away from safety-related equipment. See Table 3.6-1 for a list of the high-energy systems.

Falling objects heavy enough to generate a secondary missile are postulated as a result of movement of a heavy load or from a nonseismically designed structure, system, or component during a seismic event. Movements of heavy loads are controlled to protect safety-related structures, systems, and components (see Subsection 9.1.5). Design and operational procedures of the polar crane inside containment precludes dropping a heavy load. Additionally, movements of heavy loads inside containment occur during shutdown periods when most of the high-energy systems are depressurized. Valves, rotating equipment, vessels, and small fittings not otherwise considered to be credible missiles due to design features or other considerations are not considered to be a potential source of missiles when struck by a falling object. Secondary missiles are not considered credible. Striking a component with a falling object will not generate a secondary missile if design of the component precludes generation of missiles due to pressurization of the component. Safety-related structures, systems, or components are protected from nonseismically designed structures, systems, or components or the interaction is evaluated. Nonsafety-related equipment that could fall and damage safety-related equipment during an earthquake is classified as seismic Category II and is designed and supported to preclude such failure. See Subsection 3.7.3.13 for additional discussion on the interaction of other systems with Seismic Category I systems. There are no high-pressure gas

storage cylinders inside the containment shield building. For the reasons noted above, secondary missiles are not considered credible missiles.

3.5.1.3 Turbine Missiles

The turbine generator is located north of the nuclear island with its shaft oriented north-south. In this orientation, the potential for damage from turbine missiles is negligible. Safety-related structures, systems and components are located outside the high-velocity, low-trajectory missile strike zone, as defined by Regulatory Guide 1.115. Thus, postulated low-trajectory missiles cannot directly strike safety-related areas.

The turbine and rotor design is described in Section 10.2. Protection is provided by the orientation of the turbine-generator and by the use of robust turbine rotors as described in Section 10.2. The rotor design, manufacturing, and material specification and the inspections recommended for the AP1000 provide an acceptably very low probability (see Subsection 10.2.2) of missile generation. Turbine rotor integrity is discussed in Subsection 10.2.3. This discussion includes fatigue and fracture analysis, material selection, and the maintenance program requirements.

The potential for a high-trajectory missile to impact safety-related areas of the AP1000 is less than 10^{-7}. Based on this very low probability, the potential damage from a high-trajectory missile is not evaluated. The probability of an impact in the safety-related areas is the product of the probability of missile generation from the turbine; the probability, assuming a turbine failure, that a high-trajectory missile would land within a few hundred feet from the turbine (10^{-7} per square foot); and the area of the safety-related area. In the AP1000, the safety-related area is contained within the containment shield building and the auxiliary building.

The potential for a turbine missile from another AP1000 plant in close proximity has been considered. As noted in Subsection 10.2.2, the probability of generation of a turbine missile (or P1 as identified in SRP 3.5.1.3) is less than 1×10^{-5} per year. This missile generation probability (P1) combined with an unfavorable orientation P2 x P3 conservative product value of 10^{-2} (from SRP 3.5.1.3) results in a probability of unacceptable damage from turbine missiles (or P4 value) of less than 10^{-7} per year per plant which meets the SRP 3.5.1.3 acceptance criterion and the guidance of Regulatory Guide 1.115. Thus, neither the orientation of the side-by-side AP1000 turbines nor the separation distance is pertinent to meeting the turbine missile generation acceptance criterion. In addition, the shield building and auxiliary building walls, roofs, and floors, provide further conservative, inherent protection of the safety-related SSCs from a turbine missile.

The orientation of the Units 1 and 2 turbines has been evaluated and Vogtle Units 3 and 4 are located outside of the low trajectory strike zones as described in Regulatory Guide 1.115. Therefore, there is no potential for a turbine missile from Units 1 and 2 to impact Units 3 and 4.

The turbine system maintenance and inspection program is discussed in Subsection 10.2.3.6.

3.5.1.4 Missiles Generated by Natural Phenomena

Tornado missiles are defined in accordance with Standard Review Plan, Subsection 3.5.1.4. The velocities are adjusted to the maximum wind velocity defined in Section 3.3. The following missiles are postulated:

- A massive high-kinetic-energy missile, which deforms on impact. It is assumed to be a 4000-pound automobile impacting the structure at normal incidence with a horizontal velocity of 105 mph or a vertical velocity of 74 mph. This missile is considered at all plant elevations up to 30 feet above grade. In addition, to consider automobiles parked within half a mile of the plant at higher elevations than the plant grade elevation, the evaluation of the automobile

missile is considered at all plant elevations up to the junction of the outer wall of the passive containment cooling water storage tank with the roof of the shield building. This elevation is approximately 193 feet above grade. This evaluation bounds sites with automobiles parked within half a mile of the shield building and auxiliary building at elevations up to the equivalent of 163 feet above grade.

- A rigid missile of a size sufficient to test penetration resistance. It is assumed to be a 275 pound, eight inch armor-piercing artillery shell impacting the structure at normal incidence with a horizontal velocity of 105 mph or a vertical velocity of 74 mph.

- A small rigid missile of a size sufficient to just pass through any openings in protective barriers. It is assumed to be a one inch diameter solid steel sphere assumed to impinge upon barrier openings in the most damaging direction at a velocity of 105 mph.

In addition to the missile spectrum specified above, the impact of tornado-driven sheet metal siding on the shield building is evaluated. The evaluation considers siding representative of the siding used on the turbine building, radwaste building, diesel generator building, and portions of the annex building. The evaluation considers a flat steel sheet, which bounds the corrugated siding design used on the buildings adjacent to the nuclear island.

3.5.1.5 Missiles Generated by Events Near the Site

As described previously in Section 2.2, the site interface is established to address site specific missiles as discussed in Subsection 3.5.4. The AP1000 missile interface criteria are based on the tornado missiles described in Subsection 3.5.1.4. Additional analyses are required to evaluate other site specific missiles.

The primary access point, administrative building, communications support center, warehouse and shops, engineering and administrative building, maintenance support building and miscellaneous structures are common structures that are located at a nuclear power plant. They are of similar design and construction to those that are typical at nuclear power plants. Therefore, any missiles resulting from a tornado-initiated failure are not more energetic than tornado missiles postulated for design of the AP1000. Additionally, there are no other structures adjacent to the nuclear island other than the turbine building, annex building, radwaste building and passive containment cooling ancillary water storage tank.

In accordance with Subsection 2.2.3, the effects of explosions have been evaluated and it has been determined that the overpressure criteria of Regulatory Guide 1.91 is not exceeded. Consistent with Regulatory Guide 1.91, the effects of blast-generated missiles will be less than those associated with the blast overpressure levels considered; therefore, no further evaluation of blast-generated missiles is required.

3.5.1.6 Aircraft Hazards

As described previously in Section 2.2, the site interface is established to address aircraft hazards as discussed in Subsection 3.5.4. The AP1000 missile interface criteria are based on the tornado missiles described in Subsection 3.5.1.4. Additional analyses are required to evaluate other site specific missiles. Aircraft crash probability, and the effects of this hazard on the plant, is determined as described in Section 2.2.

Airports and airways in the VEGP site vicinity are discussed in Subsection 2.2.2.6. Aircraft hazards related to these airports and airways (shown in Figure 3.5-201) have been evaluated in accordance with Regulatory Standard 002, *Processing Applications for Early Site Permits*, May 2004 (RS-002),

and NUREG-0800, *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants*, Draft Revision 3, 1996 (NUREG-0800), Subsection 3.5.1.6.

3.5.1.6.1 Airports

RS-002 acceptance criteria provide a distance threshold for evaluating aircraft hazards due to nearby airports.

All airports in the VEGP site vicinity are greater than 10 mi from the site. The hazard probability for these airports is considered acceptable if the projected annual number of operations is less than 1,000 D^2, where D is the site-to-airport distance.

Bush Field is the closest (17 mi) and largest commercial airport in the VEGP site vicinity. The Federal Aviation Administration (FAA) (Reference 201) has projected the number of aircraft that will be in operation at Bush Field for every year up to 2025 for each of the following four types of aircraft: general aviation, air taxi and commuter, commercial air carrier, and military. The projected flight data (which include landings and takeoffs) are provided in Table 3.5-201. As noted in the table, the total number of projected aircraft operations is substantially less than 1,000 D^2 (289,000).

The other airports in the vicinity are much smaller than Bush Field. Since they are all at least 10 mi from the VEGP site, their aircraft hazard threshold is greater than 100,000 operations, which significantly exceeds their annual traffic.

As discussed in Subsection 2.2.2.6.1, a small unimproved grass airstrip is located immediately north of the VEGP site (north of Hancock Landing Road and west of the Savannah River). This privately owned and operated airstrip has a 1,650-foot turf runway oriented 80° East – 260° West. The airstrip is for personal use and the associated traffic consists only of small single-engine aircraft. In addition, there is a small helicopter landing pad on the VEGP site. This facility exists for corporate use and for use in case of emergency. The traffic associated with either of these facilities may be characterized as sporadic. Due to the small amount and the nature of the traffic, these facilities do not present a safety hazard to the VEGP site.

3.5.1.6.2 Airway V185

The VEGP site is approximately 1.5 mi east of the centerline of Federal Airway V185, which runs between Augusta and Savannah. A more detailed review of aircraft hazards was performed because the VEGP site is within the 2 statute mile limit. This review is summarized below.

Airways are typically used by commercial flights and by general aviation for inclement weather and nighttime operations. In general, military aircraft do not use the federal airways. To be allowed to fly in a federal airway, an aircraft needs to have the proper communication equipment and the pilot needs to have specific qualifications. In addition, most general aviation flights do not use a federal airway in favorable weather conditions. When these factors are considered, along with the fact that there are no regularly scheduled direct commercial flights between Augusta and Savannah, it is expected that the total number of aircraft using Airway V185 is relatively small.

Although the FAA does not maintain records of air traffic in Airway V185, informal communications with air traffic control personnel at the Augusta airport revealed that the southeast quadrant of the air space around the airport (of which Airway V185 is a part) has the least air traffic compared to the other quadrants and that the total traffic in Airway V185 is a fraction of the total operations into and out of the Augusta airport.

Because of the unavailability of traffic data for Airway V185, the following evaluation calculates the maximum number of airway flights per year above which the acceptance guideline probability of 10^{-7}

per year contained in RS-002 and NUREG-0800 is exceeded. Regulation 14 CFR 71 provides the criteria for determining the width of the airway. It is 4 nautical miles on either side of the centerline, for a total width of 8 nautical miles (9.2 mi).

$$P_{FA} = C \times N \times A / W$$

where:

P_{FA} = probability per year of an aircraft crashing into a VEGP Units 3 and 4 safety-related structure, 1×10^{-7}

C = in-flight crash rate per mile for aircraft using airway = 4×10^{-10} (RS-002)

N = number of flights per year along the airway

A = effective area of plant or site area in square miles, see below

W = airway width, 9.2 mi

By rearranging this equation, the maximum number of flights corresponding to the acceptance guideline probability of 10^{-7} may be calculated.

NUREG-0800 and RS-002 also provide alternate guidance on the acceptable method for calculating area *A*. RS-002 specifies the use of the site area because, for ESP Applications where the type of power plant has not been selected, the plant cross-sectional area cannot be defined. However, because the Westinghouse AP1000 design has been selected, the effective area of the plant was used in this analysis.

The effective plant area (*A*) depends on the length, width, and height of the facility, as well as the aircraft's wingspan, skid distance, and impact angle (Reference 203).

The safety-related structures of the AP1000 design include only the containment and the auxiliary building; the remainder of the structures is not safety related. The AP1000 containment height is about 234 ft above grade, and the diameter is about 146 ft (Reference 204).

For traffic in Airway V185, the fractions of the types of aircraft using the airway were assumed to be the same as the fractions of the types of aircraft using Bush Field. Representative values for wingspan, skid distance, and impact angle for each aircraft type follow those suggested in (Reference 203). For military aviation, large aircraft are conservatively used in the estimates. The effective areas for general aviation, air taxi and commuter, commercial air carrier, and military aircraft are 0.025, 0.061, 0.073, and 0.086 sq mi, respectively. Using these effective areas and the fractions of aircraft types (52.9, 29.3, 12.8, and 5 percent for general aviation, air taxi and commuter, commercial air carrier, and military aircraft, respectively), the average of the weighted effective plant area, 0.045 mi^2, is determined for the calculation.

Among the representative wingspans, the large military aircraft has the longest wingspan of 223 ft (Reference 203). The physical separation of the new reactor buildings is about 650 ft. Since this distance is longer than the largest representative wingspan (223 ft), the estimate of the effective area involves only one unit. In addition, Subsection 3.5.1.6 of NUREG-0800 also suggests the use of an effective area of one unit of the plant.

To reach the permissible crash probability of 1×10^{-7}, the total number of flights traveling along Airway V185 would need to be about 51,100 per year. This value is higher than the total of all projected itinerant flights for 2025 at Bush Field (see Table 3.5-201).

Although the flight data associated with Airway V185 are not available from the FAA, the number of flights in this airway is expected to be only a fraction of the total Bush Field flights. Therefore, the presence of Airway V185 is not a safety concern for the VEGP site.

3.5.2 Protection from Externally Generated Missiles

Systems required for safe shutdown are protected from the effects of missiles. These systems are identified in Section 7.4. Protection from external missiles, including those generated by natural phenomena, is provided by the external walls and roof of the Seismic Category I nuclear island structures. The external walls and roofs are reinforced concrete. The structural design requirements for the shield building and auxiliary building are outlined in Subsection 3.8.4. Openings through these walls are evaluated on a case-by-case basis to provide confidence that a missile passing through the opening would not prevent safe shutdown and would not result in an offsite release exceeding the limits defined in 10 CFR 50.34.

Where necessary, adjacent structures and/or missile barriers are used to protect openings in the nuclear island building structures. Building structures credited in this evaluation to protect openings in seismic Category I nuclear island building structures are seismic Category I or seismic Category II (see Subsection 3.2.1.1.2). As identified in Subsection 3.7.2, seismic Category II building structures are designed for the safe shutdown earthquake using the same methods and design stress limits as are used for seismic Category I structures. Seismic Category II building structures are also designed to withstand the design basis tornado loads, including missiles, in accordance with the loading combinations identified in Table 3.8.4-2. The evaluation of site-specific hazards for external events that may produce missiles more energetic than tornado missiles is discussed in Subsection 2.2.1. Evaluation of turbine missiles is provided in Subsection 3.5.1.3. Evaluation of tornado missiles is provided in Subsection 3.5.1.4. Conformance with regulatory guide recommendations is provided in Appendix 1A.

3.5.2.1 Protection from Externally Generated Missile through Wall 11

Evaluation of the openings in the north wall of the auxiliary building (Wall 11) considered the protection provided by the seismic Category II turbine building first bay building structure and associated missile barriers, consistent with the provisions in Subsections 3.2.1.1.1, 3.2.1.1.2, 3.2.2.5, and 3.2.2.6. Since the turbine building first bay is surrounded by a large amount of structures, equipment and components in the turbine building and adjacent annex building, large deformable missiles (represented by automobile) passing through turbine building and annex building into turbine building first bay is a highly tortuous path. The structures, equipment and components in the turbine building and part of the annex building are credited to stop or break apart an automobile missile and protect Wall 11 from an automobile missile.

In accordance with the missile identification and protection criteria provided in Section 3.5, a realistic assessment of potential missile paths was conducted. Where the line of sight of a missile passing through a turbine building first bay building structure opening could potentially result in missile impact upon a Wall 11 opening, the missile was considered credible, and additional protection was provided or additional evaluation performed. As a result of this analysis, two missile barriers designed to stop the 8-inch artillery shell and 1-inch sphere missiles are provided within the interior of the turbine building first bay building structure, at elevation 117'-6", northeast of MSIV Compartment B, and at elevation 100', north of Valve/Piping Penetration Room. Where the 1-inch diameter solid steel sphere or 8-inch artillery shell missiles were determined to have a line of sight to a Wall 11 penetration, analysis was performed to confirm that there was no line of sight through the penetration, the contents of the penetration would prevent the missile from passing through Wall 11, or equipment required to achieve safe shutdown could not be adversely affected.

The steel tornado missile barriers located within the turbine building first bay are designed and analyzed in accordance with the barrier design procedures contained in Subsection 3.5.3 and applicable ANSI/AISC N690 requirements.

The steel tornado missile barriers located within the turbine building first bay, identified in Table 3.5-1, are designed and analyzed in accordance with the barrier design procedures and ductility requirements contained in Subsection 3.5.3 and applicable ANSI/AISC N690 requirements. The missile barriers are permanently anchored to the turbine building first bay or auxiliary building as applicable. Where anchored to concrete, the anchors conform with the anchorage requirements contained in Subsection 3.8.4.5.1. The configuration of the barriers is based on the lines of sight to be eliminated and the missile sizes pertinent to those lines of sight. The configuration also provides for functional requirements such as airflow, venting, and personnel access. Steel barrier designs are provided in both solid and grating-type configurations to address the required missile protection and functional requirements on a case-by-case basis. The missile protection provided for Wall 11 openings and penetrations is tabulated in Table 3.5-1. Protection of Wall 11 openings from external missiles is provided by the seismic Category II turbine building first bay building structure, the seismic Category II missile barriers located within the turbine building first bay building structure, the seismic Category I Wall 11 doors, and the seismic Category I Wall 11 penetrations and spare penetration covers within missile lines of sight.

3.5.2.2 Protection of MSSV Functions from Externally Generated Missile

The main steam safety valve (MSSV) vent stacks are evaluated for tornado missiles in the horizontal and vertical directions. Based on elevation of the vent stacks, site topography, and arrangement of surrounding buildings, large debris (represented by the automobile) does not have a line of sight to the MSSV vent stacks. For horizontal missile impact, it is analyzed and confirmed that the steam can be relieved through Wall 11 doors and vents into turbine building first bay without impacting the pressure limit in the MSIV rooms and Valve/Piping Penetration Room if a vent stack is crimped. For the vertical missile impact, it is evaluated and confirmed that 1) ASME limits are not exceeded under impact of small debris; 2) The main steam pressure boundary remains intact under the impact of the 8-inch artillery shell and 1-inch sphere missiles; 3) the passive safety features are not impacted. Therefore, the tornado missile impact on the MSSV vent stacks does not affect safe shutdown.

3.5.2.3 Protection from Externally Generated Missile through Wall I

Evaluation of the openings in the east wall of the auxiliary building (Wall I) considered the protection provided by the seismic Category II annex building structures and associated missile barriers. Since the auxiliary building is surrounded by a large amount of structures, equipment, and components in the annex building, large deformable missiles (represented by automobile) passing through the annex building into auxiliary building is a highly tortuous path. The structures, equipment and components in the annex building are credited to stop or break apart an automobile missile and protect Wall I from an automobile missile.

In accordance with the missile identification and protection criteria provided in Section 3.5, a realistic assessment of potential missile paths was conducted. Where the line of sight of a missile passing through the annex could potentially result in missile impact upon a Wall I opening or penetration, the missile was considered credible, and additional protection was provided or additional evaluation performed. The rooms with line of sight are 12351, 12421, 12501, and 12541. The missile protection provided for Wall I openings and penetrations is tabulated in Table 3.5-2.

3.5.2.4 Protection from Externally Generated Missile through Shield Building Air Inlets

Evaluation of the openings in the shield building air inlets considered the protection provided by the seismic Category I missile barriers and air baffles, and seismic Category II missile barriers, consistent with the provisions in Subsections 3.2.1.1.1, 3.2.1.1.2, 3.2.2.5, and 3.2.2.6.

In accordance with the missile identification and protection criteria provided in Section 3.5, a realistic assessment of potential missile paths was conducted. Where the line of sight of a missile passing through the shield building air inlets could potentially result in missile impact upon a safe shutdown required SSC, the missile was considered credible, and additional protection was provided or additional evaluation performed. As a result of this analysis, potential missile paths through some of the upper and lower air inlet openings to some PCS piping and Class 1E cabling/conduit are identified. Four missile barriers are provided on the outside of the exterior circular walkway of the shield building to prevent the 1-inch diameter solid steel sphere or 8-inch artillery shell missiles from entering the upper air inlet openings. The external shield building walkway prevents the 1-inch diameter solid steel sphere and 8-inch artillery shell missiles from entering the lower air inlet openings. The automobile missile is too large to enter the air inlets and therefore can be stopped by the shield building wall. The missile protection provided for the shield building air inlet openings is tabulated in Table 3.5-3.

3.5.3 Barrier Design Procedures

Missile barriers and protective structures are designed to withstand and absorb missile impact loads to prevent damage to safety-related components.

Formulae used for missile penetration calculations into steel or concrete barriers are the Modified National Defense Research Committee (NDRC) formula for concrete and either the Ballistic Research Laboratory (BRL) or Stanford formulae for steel.

Concrete (Modified NDRC Formula)

$$x = \left[4\,KNWd\left(\frac{V}{1000\,d}\right)^{1.8}\right]^{0.5} \qquad \text{for } \frac{x}{d} \le 2.0$$

$$x = KNW\left(\frac{V}{1000\,d}\right)^{1.8} + d \qquad \text{for } \frac{x}{d} > 2.0$$

where

x = penetration depth, inches

W = missile weight, lbs

d = missile diameter, inches

N = missile shape factor = 1.0

V = impact velocity, feet/sec

K = experimentally obtained material coefficient for penetration = $\frac{180}{\sqrt{f_c'}}$

fc′ = concrete compressive strength

Scabbing thickness, t_s, and perforation thickness, t_p is given by:

$$\frac{t_s}{d} = 2.12 + 1.36\frac{x}{d} \qquad \text{for } 0.65 \le \frac{x}{d} \le 11.75$$

$$\frac{t_s}{d} = 7.91\left(\frac{x}{d}\right) - 5.06\left(\frac{x}{d}\right)^2 \qquad \text{for } \frac{x}{d} \le 0.65$$

$$\frac{t_p}{d} = 1.32 + 1.24\frac{x}{d} \qquad \text{for } 1.35 \le \frac{x}{d} \le 13.5$$

$$\frac{t_p}{d} = 3.19\left(\frac{x}{d}\right) - 0.718\left(\frac{x}{d}\right)^2 \qquad \text{for } \frac{x}{d} \le 1.35$$

Steel (Stanford Formula)

$$\frac{E}{D} = \frac{S}{46{,}500}\left(16{,}000\,T^2 + 1{,}500\frac{W}{W_s}T\right)$$

Where:

E = critical kinetic energy required for perforation, foot pounds

D = effective missile diameter, inches

S = ultimate tensile strength of the target (steel plate), pounds per square inch

T = target plate thickness, inches

W = length of a square side between rigid supports, inches

Ws = length of a standard window, 4 inches

The ultimate tensile strength is directly reduced by the amount of bilateral tension stress already in the target. The equation is good within the following ranges:

$0.1 < T/D < 0.8$,

$0.002 < T/L < 0.05$,

$10 < L/D < 50$,

$5 < W/D < 8$,

$8 < W/T < 100$,

$70 < V < 400$

Where:

L = missile length, inches

V = impact velocity, feet/second

Steel (BRL Formula)

$$t_p = \frac{(E_k)^{2/3}}{672D}$$

Where:

t_p = steel plate thickness for threshold of perforation, inches

D = equivalent missile diameter, inches

E_k = missile kinetic energy, foot pounds

= $M V^2/2$

M = mass of the missile, lb-sec^2/ft.

In using the Modified NDRC, BRL and Stanford formulae for missile penetration, it is assumed that the missile impacts normal to the plane of the wall on a minimum impact area and, in the case of reinforced concrete, does not strike the reinforcing. Due to the conservative nature of these assumptions, the minimum thickness required for missile shields is taken as the thickness just perforated.

Structural members designed to resist missile impact are designed for flexural, shear, and buckling effects using the equivalent static load obtained from the evaluation of structural response. Stress and strain limits for the equivalent static load comply with applicable codes and Regulatory Guide 1.142, and the limits on ductility of steel structures as given in Subsection 3.5.3.1. The consequences of scabbing are evaluated if the thickness is less than the minimum thickness to preclude scabbing.

The thicknesses of the exterior walls above grade and of the roof of the nuclear island are 24 inches and 15 inches, respectively. The roof is constructed using left-in-place metal deck. These thicknesses exceed the minimum thicknesses for Region II tornado missiles specified in Standard Review Plan 3.5.3.

3.5.3.1 Ductility Factors for Steel Structures

Ductility factors for the design of steel structures are as follows:

- For tension due to flexure, $\mu \leq 10.0$
- For columns with slenderness ratio (L/r) equal to or less than 20, $\mu \leq 1.3$
- For columns with slenderness ratio greater than 20, $\mu \leq 1.0$
  Where: L = effective length of the member
  r = the least radius of gyration
- For members subjected to tension, $\mu \leq .5*(e_u/e_y)$
  Where: e_u = ultimate strain
  e_y = yield strain

3.5.4 Combined License Information

The evaluation for those external events that produce missiles that are more energetic than the tornado missiles postulated for design of the AP1000 is addressed in APP-GW-GLR-020 (Reference 1).

In addition, the VEGP site satisfies the site interface criteria for wind and tornado (see Subsections 3.3.1.1, 3.3.2.1 and 3.3.2.3) and will not have a tornado-initiated failure of structures and components within the applicant's scope that compromises the safety of AP1000 safety-related structures and components (see also Subsection 3.3.3).

Subsection 1.2.2 discusses differences between the plant specific site plan and the AP1000 typical site plan.

There are no other structures adjacent to the nuclear island other than as described and evaluated in this document.

Missiles caused by external events separate from the tornado are addressed in Subsections 3.5.1.3, 3.5.1.5, and 3.5.1.6.

3.5.5 References

1. APP-GW-GLR-020, "Wind and Tornado Site Interface Criteria," Westinghouse Electric Company LLC.

201. **(APO 2006)** *APO Terminal Area Forecast Summary Report*, Federal Aviation Administration, http://www.apo.data.faa.gov/wtaf/, issued February 2006, accessed 5/2/2006.

202. **(Atlanta 2005)** *Atlanta Sectional Aeronautical Chart*, 74th Edition, U.S. Department of Transportation, Federal Aviation Administration, March 17, 2005.

203. **(DOE 1996)** *Accident Analysis for Aircraft Crash into Hazardous Facilities*, DOE Standard, DOE-STD-3014-96, US Department of Transportation, October 1996.

204. **(Westinghouse 2001)** *Nuclear Island General Arrangement, AP1000 Advanced Passive Light Water Reactor*, Rev. 0, Section B-B, DCD Number APP 1000 P2 902, Westinghouse Electric Company, 08/06/2001.

Table 3.5-1 (Sheet 1 of 2)
External Missile Protection Provided for Auxiliary Building Wall 11 Openings

Wall 11 Opening	Protected Room	Elevation	Missile[1]	Protection[2][3]
Room 12306 doorway	Valve/Piping Penetration Room	100'-0"	Sphere	First bay building structure First bay interior missile barrier
			Artillery Shell	First bay building structure first bay interior missile barrier
			Automobile	First bay building structure Structure, equipment, and components in turbine building and annex building
Room 12404 vent	Lower MSIV Compartment B	117'-6"	Sphere	First bay building structure First bay interior missile barrier
			Artillery Shell	First bay building structure First bay interior missile barrier
			Automobile	First bay building structure Structure, equipment, and components in turbine building and annex building
Room 12405 doorway	Lower VBS B&D Equipment Room	117'-6"	Sphere	Room 12405 Wall 11 door
			Artillery Shell	Room 12405 Wall 11 door
			Automobile	First bay building structure Structure, equipment, and components in turbine building and annex building
Room 12406 vent	Lower MSIV Compartment A	117'-6"	Sphere	First bay building structure
			Artillery Shell	First bay building structure
			Automobile	First bay building structure Structure, equipment, and components in turbine building and annex building
Room 12504 doorway	Upper MSIV Compartment B	135'-3"	Sphere	First bay building structure
			Artillery Shell	First bay building structure
			Automobile	First bay building structure Structure, equipment, and components in turbine building and annex building
Room 12505 doorway	Upper VBS B&D Equipment Room	135'-3"	Sphere	Room 12505 Wall 11 door
			Artillery Shell	Room 12505 Wall 11 door
			Automobile	First bay building structure Structure, equipment, and components in turbine building and annex building
Room 12506 doorway	Upper MSIV Compartment A	135'-3"	Sphere	First bay building structure
			Artillery Shell	First bay building structure
			Automobile	First bay building structure Structure, equipment, and components in turbine building and annex building

Table 3.5-1 (Sheet 2 of 2)
External Missile Protection Provided for Auxiliary Building Wall 11 Openings

Wall 11 Opening	Protected Room	Elevation	Missile[1]	Protection[2][3]
Wall 11 penetrations	Various	Various	Sphere	First bay building structure Pipe sleeves Penetration contents Spare penetration covers
			Artillery Shell	First bay building structure Pipe sleeves Penetration contents Spare penetration covers
			Automobile	First bay building structure Structure, equipment, and components in turbine building and annex building

Notes:

1. Tornado missiles are defined in Subsection 3.5.1.4.
2. Turbine building first bay is a seismic Category II building structure. Wall 11 doors, Wall 11 penetration sleeves, and Wall 11 spare penetration covers that provide tornado missile protection are equipment Class C. Barriers in the turbine building first bay building structure that provide tornado missile protection are equipment Class D.
3. The materials of construction for the missile barriers installed within the turbine building first bay and on Wall 11 shall be steel as specified below, or steel with equal or better material properties:
   - First bay interior missile barrier at elevation 117'-6"
     - barrier plate - ASTM A572, Gr. 50
     - barrier support frame - ASTM A500, Gr. B
     - anchors - ASTM A325 or ASTM A490, and ASTM F1554, Gr. 105 as required
   - First bay interior missile barrier at elevation 100'-0"
     - barrier plate - ASTM A572, Gr. 50
     - barrier support frame - ASTM A500, Gr. B
     - anchors - manufacturer standard
   - Wall 11 missile doors
     - door plate - ASTM A572, Gr. 50
     - embed plates - ASTM A572, Gr. 50
     - anchors - ASTM A 1064
   - Wall 11 spare penetration covers
     - ASTM A240
   - Pipe sleeves
     - material shall be as specified for their penetration function

Table 3.5-2
External Missile Protection Provided for Annex Building Wall I Openings[3]

Wall I Opening	Protected Room	Elevation	Missile[1]	Protection[2]
Room 12351 doorway	Maintenance Floor Staging Area	107'-2"	Sphere	Room 12351 Wall I door
			Artillery Shell	Room 12351 Wall I door
			Automobile	Room 12351 Wall I door
Room 12421 electrical penetrations	Non 1E Equipment/ Penetration Room	117'-6"	Sphere	Pipe sleeves Penetration contents Spare penetration covers
			Artillery Shell	Pipe sleeves Penetration contents Spare penetration covers
			Automobile	Annex Building Wall along column line E
Room 12501 doorway	VBS MCR/A&C Equipment Room	135'-3"	Sphere	Room 12501 Wall I door
			Artillery Shell	Security grating Electrical control panels Room 12501 Wall I door
			Automobile	Structures, equipment, and components in annex building
Room 12541 doorway	Operating Deck Staging Area	135'-3"	Sphere	Room 12556 Wall I door
			Artillery Shell	Room 12556 Wall I door
			Automobile	Room 12556 Wall I door

Notes:

1. Tornado missiles are defined in Subsection 3.5.1.4.
2. Annex Building Areas 1, 2 and 3 are a Seismic Category II building structure. Wall I doors, Wall I penetration sleeves and Wall I spare penetration covers that provide tornado missile protection are equipment Class C. Barriers in the Annex Building Areas 1, 2 and 3 building structures that provide tornado missile protection are equipment Class D.
3. Other Wall I door and penetrations are protected from the tornado missiles by the Seismic Category II Annex Building Structure.

Table 3.5-3
External Missile Protection Provided for Shield Building Air Inlet Openings

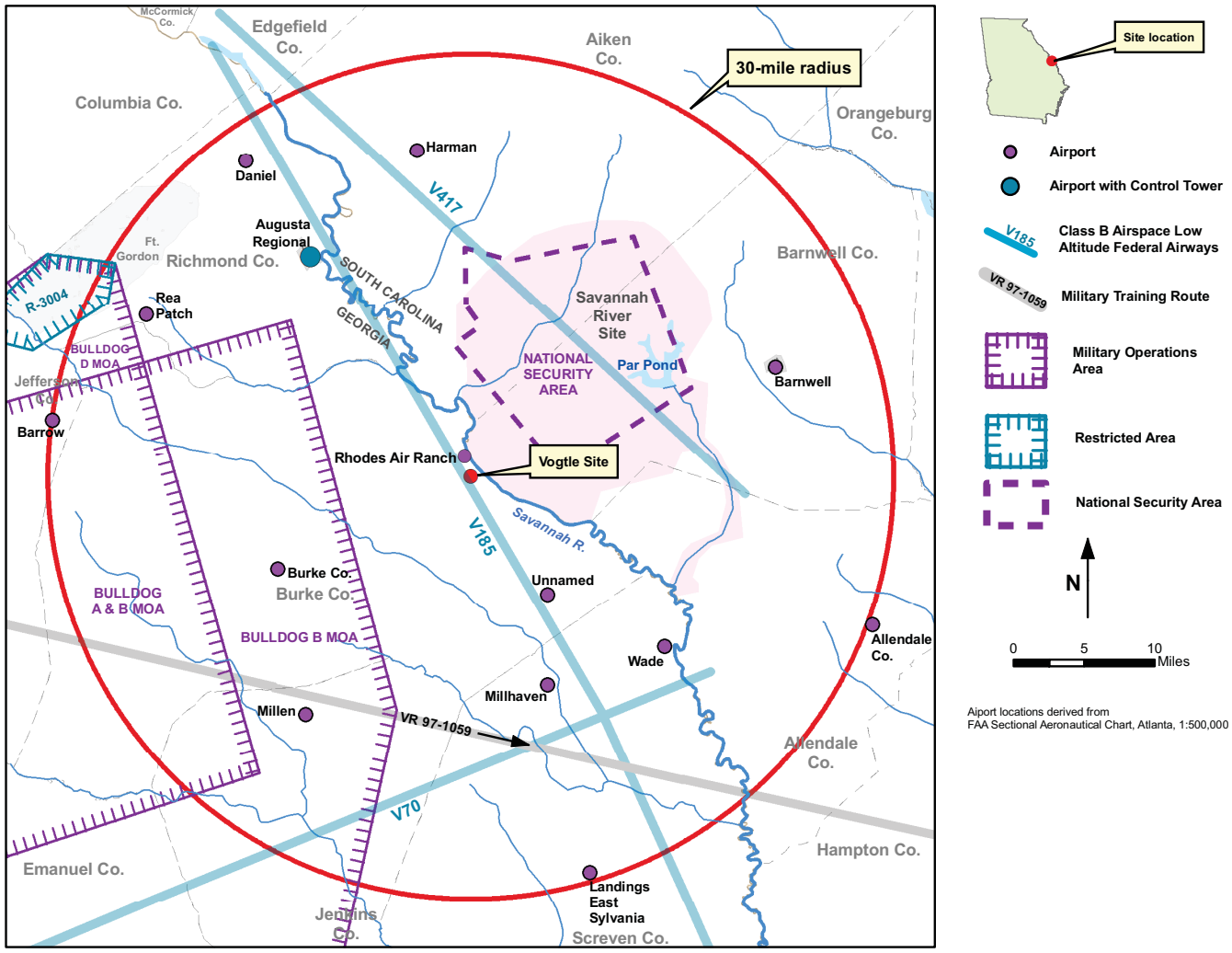
Opening	Protected Room	Elevation	Missile	Protection
Shield Building Lower Air Inlet Openings	Upper Annulus	251'-8"	Sphere	External Shield Building Walkway
			Artillery Shell	External Shield Building Walkway
			Automobile	Shield Building Wall around Air Inlets
Shield Building Upper Air Inlet Openings	Upper Annulus	257'-9"	Sphere	Upper Air Baffle (SB02) External Shield Building Walkway Missile Barriers
			Artillery Shell	Upper Air Baffle (SB02) External Shield Building Walkway Missile Barriers
			Automobile	Shield Building Wall around Air Inlets

Table 3.5-201
Augusta APO Terminal Area Forecast Summary Report – Itinerant Operations

Year	General Aviation	Air Taxi & Commuter	Commercial Air Carrier	Military	Total
1990	22,023	14,941	6,495	4,522	47,981
1991	19,175	9,462	6,576	3,242	38,455
1992	17,872	9,393	7,196	3,221	37,682
1993	16,902	8,821	6,455	4,068	36,246
1994	16,896	5,961	6,473	3,727	33,057
1995	16,597	8,876	5,024	3,511	34,008
1996	17,016	9,325	4,225	2,780	33,346
1997	18,995	8,304	4,599	2,561	34,459
1998	19,611	7,518	5,028	2,271	34,428
1999	22,653	6,954	5,183	2,841	37,631
2000	21,975	6,663	4,969	3,354	36,961
2001	19,961	7,378	4,929	2,954	35,222
2002	20,085	7,164	4,286	3,082	34,617
2003	17,622	9,058	4,393	2,843	33,916
2004	18,658	9,441	4,934	2,528	35,561
2005	13,307	8,226	4,585	1,799	27,917
2006	13,618	8,328	4,585	1,799	28,330
2007	13,937	8,432	4,585	1,799	28,753
2008	14,263	8,537	4,585	1,799	29,184
2009	14,597	8,644	4,585	1,799	29,625
2010	14,939	8,751	4,585	1,799	30,074
2011	15,288	8,860	4,585	1,799	30,532
2012	15,646	8,971	4,585	1,799	31,001
2013	16,012	9,083	4,585	1,799	31,479
2014	16,387	9,196	4,585	1,799	31,967
2015	16,611	9,310	4,585	1,799	32,305
2016	16,837	9,426	4,585	1,799	32,647
2017	17,067	9,544	4,585	1,799	32,995
2018	17,300	9,663	4,585	1,799	33,347
2019	17,536	9,783	4,585	1,799	33,703
2020	17,776	9,905	4,585	1,799	34,065
2021	18,018	10,028	4,585	1,799	34,430
2022	18,264	10,153	4,585	1,799	34,801
2023	18,514	10,280	4,585	1,799	35,178
2024	18,766	10,408	4,585	1,799	35,558
2025	19,023	10,538	4,585	1,799	35,945

Source: Reference 201

Table 3.5-202
Deleted in Revision 2



Source: Reference 202

Figure 3.5-201
Airports Within 30 Miles of Vogtle Facility

3.6 Protection Against the Dynamic Effects Associated with the Postulated Rupture of Piping

The effects of a postulated pipe rupture in the AP1000 are of several types. This section considers the effects that are localized to the area of the break and are a result of the dynamic effects of the pipe rupture including jet impingement, pipe whip, subcompartment pressurization, and fluid system decompression. This section describes the evaluation of the potential for and effects of these dynamic effects. It describes measures taken to protect systems and equipment from dynamic effects of pipe rupture when necessary. This section also considers the effects of spray wetting and flooding from pipe ruptures and cracks.

Chapters 6 and 15 discuss the response of the system to changes in flow and pressure and loss of coolant and the response of the containment to the pressure and temperature changes. Pressure due to a break in a high energy line in the auxiliary building is vented into an adjacent building or to the atmosphere. The design transients listed in Subsection 3.9.1 are used in evaluating the components of the reactor coolant system for effects due to internal pressure and temperature changes from postulated accidents. Section 3.11 discusses the qualification of the equipment required to function in the adverse environmental conditions including temperature, humidity, pressure, radiation, spray wetting, and chemical consequences.

Pipe failure protection is provided according to the requirements of 10 CFR 50, Appendix A, General Design Criterion 4. In the event of a high- or moderate-energy pipe failure within the plant, adequate protection is provided so that essential structures, systems, or components are not impacted by the adverse effects of postulated piping failure. Essential systems and components are those required to shut down the reactor and mitigate the consequences of the postulated piping failure. Nonsafety-related systems are not required to be protected from the dynamic and environmental effects associated with the postulated rupture of piping except as described in Subsection 3.6.1.1, item Q.

The criteria used to evaluate pipe failure protection are generally consistent with NRC guidelines including those in the Standard Review Plan Sections 3.6.1 and 3.6.2, NUREG-1061, Volume 3 (Reference 11) and applicable Branch Technical Positions.

Subsection 3.6.1 provides the design bases and criteria for the analysis required to demonstrate that essential systems are protected. The high- and moderate-energy systems representing the potential source of adverse effects are listed. Additionally, the criteria for separation and the effects of adverse consequences are defined.

Subsection 3.6.2 defines the criteria for postulated break location and configuration. High-energy pipes are evaluated for the effects of circumferential and longitudinal pipe breaks and through-wall cracks. Moderate-energy pipes are evaluated for the effects of through-wall cracks. Analysis methods and criteria for evaluating pipe whip and evaluating the consequences of jet impingement, motions of the pipe, and system depressurization on integrity and operability are provided. The evaluation of containment penetrations, pipe whip restraints, guard pipes, and other protective devices is also described. The criteria for excluding breaks in high-energy piping adjacent to containment penetrations are also provided.

Evaluation of the dynamic effects of postulated breaks in the reactor coolant loop, main steam lines inside containment, and other primary piping inside containment equal to or greater than the 6-inch nominal pipe size (NPS) is eliminated for AP1000 based on mechanistic pipe break (leak-before-break) considerations. Those sections of high-energy piping that qualify for mechanistic pipe break are evaluated for only the effects of leakage cracks.

Subsection 3.6.3 describes the application of leak-before-break criteria to permit the elimination of pipe rupture dynamic effects considerations. Design guidelines aid in the design of piping systems

that satisfy the requirements for mechanistic pipe break. Dynamic effects of postulated breaks are evaluated for those analyzable sections of high-energy piping systems that do not use the mechanistic pipe break methods.

The safety analyses in Chapter 15 and the requirements for emergency core cooling discussed in Section 6.3 and the environmental qualification of equipment discussed in Section 3.11 of this report are not changed by the use of mechanistic pipe break considerations for pipe rupture dynamic effects evaluations. Chapter 6 describes the containment subcompartment pressurization analyses including mechanistic pipe break considerations.

3.6.1 Postulated Piping Failures in Fluid Systems Inside and Outside Containment

A number of systems and components are necessary to shut the plant down in the event of a pipe rupture. These systems, termed essential systems, are protected from the postulated pipe ruptures. The essential systems for various pipe ruptures are the reactor coolant system, the steam generator system, the passive core cooling system, and the passive containment cooling system. In addition to these fluid systems, the protection and safety monitoring system and the Class 1E dc and UPS system are essential. The main control room and main control room habitability system are also protected as essential systems. In addition, containment penetrations and isolation valves (including those for nonessential systems) are essential.

Most of the equipment required for plant safety or safety-related shutdown is located inside containment. The piping inside containment also represents the most significant piping relative to plant safety and, therefore, is subject to the most stringent design and analysis requirements.

Essential equipment in the vicinity of piping that does not satisfy leak-before-break criteria is protected as required by the use of protective structures, pipe restraints, and separation. The need for protection of essential structures, systems and components is determined by evaluation of the dynamic effects. The design bases and criteria for the evaluation follow.

Evaluations are made based upon circumferential or longitudinal pipe breaks, through-wall cracks, or leakage cracks as determined by the appropriate criteria. At locations determined to be subject to a circumferential or longitudinal pipe break, dynamic effects such as jet impingement and pipe whip are evaluated.

At locations subject to through-wall cracks, only environmental effects (temperature, humidity, pressure, radiation, spray wetting and chemical consequences) and flooding are evaluated.

The pressurization loads on structures and components are evaluated for postulated circumferential breaks and longitudinal breaks in piping that does not meet leak-before-break requirements and for postulated leakage cracks in piping that meets the leak-before-break requirements. See Subsection 3.8.3.4 and Subsection 3.8.4.3.1.4 for a discussion of pressurization loads on structures.

The in-containment refueling water storage tank is evaluated for pressurization as described in Subsection 3.6.1.2.1.

Pressurization loads for pipe failures in the main steam and feedwater break exclusion zones for high-energy lines in the vicinity of containment penetrations are evaluated for a 1.0 square foot break. Structures in the steam generator blowdown break exclusion zone are evaluated for subcompartment pressurization effects due to worst case circumferential pipe rupture in the 4-inch steam generator blowdown piping. Pipe whip and jet impingement are not evaluated for structures in the break exclusion zones per NRC Branch Technical Position MEB 3-1, section B.1.b, except that the east wall and the floor at elevation 117′-6″ of the east main steam subcompartment is designed

for pipe whip and jet impingement loads for worst case breaks in either the main steam line or the main feedwater line. See Subsection 3.6.1.2.2.

3.6.1.1 Design Basis

The following design bases relate to the evaluation of the effects of the pipe failures at locations determined in Subsection 3.6.2.

A. The selection of the failure type is based on whether the system is high or moderate-energy during normal operating conditions of the system. High-energy piping includes those systems or portions of systems in which the maximum normal operating temperature exceeds 200°F or the maximum normal operating pressure exceeds 275 psig. Piping systems or portions of systems pressurized above atmospheric pressure during normal plant conditions and not identified as high-energy are considered moderate-energy. Piping systems that exceed 200°F or 275 psig for two percent or less of the time during which the system is in operation or that experience high-energy pressures or temperatures for less than one percent of the plant operation time are considered moderate-energy.

B. The following assumptions are used to determine the thermodynamic state in the piping system for the calculation of fluid reaction forces:

   1. For those portions of piping systems normally pressurized during operation at power, the thermodynamic state in the pipe and associated reservoirs is that of normal full-power operation.

   2. For those portions of piping systems pressurized only during other normal plant conditions (for example, startup, hot standby, reactor cooldown), the thermodynamic state and associated operating condition are determined as the mode giving the most severe fluid reaction forces. Moderate-energy systems that are occasionally at higher temperature or pressure (see design basis A.) are not evaluated for pipe failures at the high-energy conditions.

   3. High-stress pipe rupture locations are based on calculated stresses due to Level A and Level B loading. Seismic loads are not included.

C. Circumferential and longitudinal breaks in high-energy pipes, except in pipes satisfying leak-before-break requirements, are evaluated for effects including subcompartment pressurization, pipe whip, jet impingement, jet reaction thrust, internal fluid decompression loads, spray wetting, and flooding.

D. High-energy and moderate-energy pipe through-wall cracks are evaluated for environmental and flooding effects. Moderate-energy systems that are occasionally at higher temperature or pressure (see design basis A.) are evaluated for environmental effects at only the moderate-energy conditions. Dynamic effects are not evaluated for these cracks.

E. Through-wall cracks are not postulated in the break exclusion zones. The effects of flooding, spray wetting, and subcompartment pressurization are evaluated for a postulated 1.0 square foot break for the main steam and feedwater lines.

F. Where postulated, each longitudinal or circumferential break in high-energy fluid system piping, leakage crack in high-energy piping with mechanistic pipe break, or through-wall crack in high-energy or moderate-energy fluid system piping is considered separately as a single initial event occurring during normal plant conditions.

For systems not seismically analyzed for a safe shutdown earthquake, the safe shutdown earthquake is assumed to cause a pressure boundary failure, as described in Subsections 3.6.2.1.1.3 and 3.6.2.1.2.2.

G. AC power is not required for the actuation of the passive safety systems. The only electrical system required to function is the Class 1E dc and UPS system.

H. A single active component failure is assumed in systems used to mitigate the consequences of the postulated piping failure or to safely shut down the reactor. The single active component failure is assumed to occur in addition to the postulated piping failure and any direct consequences of the piping failure, such as unit trip and loss of offsite power.

I. The function of the containment to act as the ultimate heat sink is maintained for any postulated pipe rupture.

J. Safety-related systems and components are used to mitigate the effects of postulated pipe ruptures. However, the seismic Category II wall separating the first bay of the turbine building from the main area of the turbine building (Wall 11.2) is credited with protecting the north wall of the auxiliary building (Wall 11) from high energy line break (HELB) loads resulting from postulated ruptures in the main steam and main feedwater piping north of the turbine building first bay. In addition, the turbine control and stop, moisture separator reheater 2nd stage steam isolation, and turbine bypass (steam dump) valves (which are not safety-related) are credited in single failure analyses to mitigate postulated steam line ruptures.

K. A whipping pipe is considered capable of rupturing impacted pipes of smaller nominal pipe diameter, irrespective of pipe-wall thickness. This is based on the assumption that only piping is determined to do the impacting. A whipping pipe is considered capable of developing a through-wall crack in a pipe of equal or larger nominal pipe size with equal or thinner wall thickness, assuming that only piping is determined to do the impacting. The preceding criterion is not used where the potential exists for valves or other components in the whipping pipe to impact the targets, since these are treated on a case-by-case basis.

L. Pipe whip is assumed to occur in the plane defined by the piping geometry and to cause movement in the direction of the jet reaction.

   If unrestrained, a whipping pipe having a constant energy source sufficient to form a plastic hinge is considered to form a plastic hinge and rotate about the nearest rigid pipe whip restraint, anchor, or wall penetration capable of resisting the pipe whip loads or the calculated dynamic plastic hinge location.

   If the direction of the initial pipe movement caused by the thrust force is such that the whipping pipe impacts a flat surface normal to its direction of travel, it is assumed that the pipe comes to rest against that surface, with no pipe whip in other directions.

   Pipe whip restraints are provided wherever postulated pipe breaks could impair the capability of any essential system or component to perform its intended safety functions.

M. The calculation of thrust and jet impingement forces considers any line restrictions (that is, flow limiter) between the pressure source and break location and the absence of energy reservoirs, as applicable.

N. Breaks are not postulated to occur in pump and valve bodies since the wall thickness exceeds that of connecting pipe.

O. Components impacted by jets from breaks in piping containing high-pressure (870 to 2466 psia) steam or subcooled liquid (subcooled no more than 126°F) that would flash at the break, such as piping connected to the steam generators or reactor coolant loops, are evaluated as follows:

   1. Impacted components within 10 piping inside diameters of the broken pipe are assumed to fail. Specific jet loads are calculated and evaluated only when failure of the component, when combined with a single active failure, could adversely affect safe shutdown or accident mitigation capability. These jet loads are calculated according to Subsection 3.6.2.3.1.

   2. Components beyond 10 inside diameters of the broken pipe are considered to be undamaged by the jet and are not analyzed. The basis for these criteria is contained in NUREG/CR-2913 (Reference 1).

P. Pipe breaks are not postulated to occur in systems for which postulated leakage cracks have been shown to be stable for worst case loadings. (See Subsection 3.6.3.) Leak detection systems are provided that are capable of detecting the leakage from a postulated leakage crack.

   For these systems, leakage cracks are postulated and evaluated for subcompartment pressure loads on structures and components. When the mechanistic pipe break approach is used, subcompartment pressure loads on structures and essential components are based on the small leakage crack determined from the mechanistic pipe break approach. Where the subcompartment includes lines not qualified for mechanistic pipe break, subcompartment pressurization is evaluated for a break in the line with the largest effect.

   The leakage crack effects of jet impingement, pipe whip, and internal fluid system loads are considered negligible and are not evaluated. The leakage crack effects of flooding and environmental effects are less limiting than the corresponding effects for postulated high-energy through-wall cracks. These through-wall cracks are not eliminated by mechanistic pipe break.

Q. Nonessential systems, structures, and components are not required to meet the criteria outlined in this section. However, while none of the nonessential systems are needed during or following a pipe break event, pipe whip protection is evaluated in cases where a high-energy nonessential system failure could initiate a failure in an essential system or component or where a high-energy nonessential system failure could initiate a failure in another nonessential system whose failure could affect an essential system.

R. The escape of steam, water, combustible or corrosive fluids, gases, and heat in the event of a pipe rupture will not preclude:

   - Subsequent access to any areas, as required, to recover from the postulated pipe rupture
   - Habitability of the control room
   - Capability of essential instrumentation, electric power supplies, components, and controls to perform safety functions to the extent necessary to meet the criteria outlined in this section

3.6.1.2 Description

Essential systems are evaluated to demonstrate conformance with the design bases and to determine their susceptibility to the failure effects. Table 3.6-1 identifies systems which contain high

and moderate-energy lines. The systems listed include all high- and moderate-energy systems inside containment plus the high- and moderate-energy systems in the auxiliary building near containment penetrations (including access hatches), the main control room, the Class 1E dc and UPS system or the portions of the passive containment cooling system located in the auxiliary building. The table does not list systems that operate at or close to atmospheric pressure including air handling and gravity drains. High energy system piping in the turbine building adjacent to the auxiliary building is evaluated for potential effects on the main control room. These systems are included on Table 3.6-1.

The definition of high and moderate-energy systems is provided in paragraph A of Subsection 3.6.1.1.

The postulated break, through-wall crack, and leakage crack locations are determined according to Subsections 3.6.2 and 3.6.3.

Equipment is considered to be separated from the dynamic effects of pipe rupture when the equipment is located in a different subcompartment. For the case of pipe whip, equipment may be considered separated for dynamic effects based on the distance from the pipe and the length of pipe that is moving. For the case of jet impingement in a line with saturated or subcooled fluid, equipment more than ten inside pipe diameters from the break location and the tip of the pipe whip trajectory, including the resting location of the broken pipe, is considered separated for dynamic effects.

Equipment located in the same subcompartment as a break, through-wall crack, or leakage crack is subject to potential environmental and flooding effects. Equipment may also be subject to environmental and flooding effects of steam and water vented into a subcompartment from an adjoining subcompartment.

3.6.1.2.1 Pressurization Response

Pressurization response analyses are performed for subcompartments containing high-energy piping for which break locations are defined by Subsections 3.6.2.1.1.1, 3.6.2.1.1.2, and 3.6.2.1.1.3 or postulated leakage flaws are defined based on Subsection 3.6.3.3. Table 3.6-2 identifies those pipe breaks considered for the evaluation of the effects of pressurization loads on subcompartments. The pipe breaks inside containment that are postulated in piping that is not evaluated to the leak-before-break requirements of Subsection 3.6.3 are summarized in Table 3.6-2. The subcompartments are identified using the room numbers and room names given on Figures 1.2-4 through 1.2-10 as supplemented by Table 3.6-2. The subcompartments inside containment are designed to accommodate the pressurization loads from these breaks. In order to account for high stress break locations and the additional pressure boundary leakages from manways and flanges, pressurization loads on compartments inside containment enclosing high-energy piping are designed as described in Subsection 3.8.3.4.

There is no high-energy piping that can pressurize the annulus between the containment vessel and the shield building. Guard pipes are provided for the main steam, feedwater, startup feedwater and steam generator blowdown containment penetrations passing through the annulus as shown on Figure 3.8.2-4. The chemical and volume control system makeup piping is classified as high energy due to its design pressure, but does not cause pressurization because it is at ambient temperature.

The pressurization loads for the in-containment refueling water storage tank are based on the pressure and hydrodynamic loads due to the maximum discharge through the first, second, and third stages of the automatic depressurization system valves.

The pressurization loads for the reactor vessel annulus for the evaluation of asymmetric compartment pressurization are negligible based on a 5-gallon per minute leakage crack in the primary loop piping. The internal reactor pressure vessel asymmetric pressurization loads are based

on a break in the largest pipe connected to the reactor coolant system that does not qualify for the application of mechanistic pipe break.

There are limited areas in the auxiliary building where the potential for pressurization loads from high-energy lines are considered. The pressurization loads for the steam tunnels are addressed in the discussion of loads due to a break in the break exclusion zone of the main steam and feedwater lines. The pressurization loads for the Elevation 100′ containment penetration room containing the steam generator blowdown break exclusion zone are based on a circumferential rupture of the 4-inch steam generator blowdown piping. The areas through which the chemical and volume control system make-up line run, including the annulus between the containment and the containment shield building, are not subject to pressurization since the temperature of these lines is less than 212°F.

For a discussion of the criteria and analysis methods for subcompartment pressurization analysis, see Subsection 6.2.1.2. The analytical methods for transient mass distribution, used for pressure response analysis, are the same as described in WCAP-8077 (Reference 2).

3.6.1.2.2 Main Control Room Habitability

The high-energy lines in closest proximity to the main control room are the main steam line and main feedwater line. The portions of these lines near the main control room are in the main steam line isolation valve compartment and are part of the break exclusion areas.

The main control room is separated from the isolation valve compartment by two structural walls. The areas between the two walls is used for nonessential office and administrative space associated with the control room. The walls separating the main control room from the main steam isolation valve compartment are thick, reinforced-concrete walls.

Consistent with the criteria for evaluation of leaks in the break exclusion area, the subcompartment, including the walls, is evaluated for the effects of flooding, spray wetting and subcompartment pressurization from a 1-square-foot break from either main steam or feedwater line within the respective break exclusion areas. The wall between the main steam line isolation valve compartment and the main control room, and the floor slab between the main steam line isolation valve compartment and the safety related electrical equipment room are also evaluated for pipe whip and jet impingement loads for worse case breaks in either the main steam line or the main feedwater line. The subcompartment pressure loads from the 1-square-foot break are not combined with the pipe whip and jet impingement loads for the worse case breaks.

The effects upon the habitability of the main control room resulting from postulated pipe breaks and cracks in the auxiliary building are evaluated. In addition to pipe ruptures and cracks in lines in the auxiliary building, the main control room is evaluated for the dynamic effects and environmental effects of a postulated circumferential or longitudinal break of either the main steam line or main feedwater line in the turbine building.

Further description of the control room habitability systems, including options for remote shutdown, is provided in Section 6.4. The remote shutdown workstation is not subject to adverse effects of high-energy pipe rupture.

Main Steam Isolation Valve Compartment De-Pressurization Flow Paths

The MSIV Compartment B (Figures 1.2-7, 1.2-8, 1.2-10, and 1.2-11), which is adjacent to the main control room, houses the main feedwater, startup feedwater, and main steam lines, as they pass to and from primary containment through the shield building, and to and from the turbine building, the MSIVs, the main steam safety valves (MSSVs), the power-operated relief valves (PORVs), the PORV block valves, and other essential components. As a result of a main steam or main feedwater

high-energy line pipe break in MSIV Compartment B adjacent to the Main Control Room or MSIV Compartment A, the MSIV compartments de-pressurize by venting through the following pathways:

- MSIV Compartment A
  - drains/vents to Turbine Building first bay
  - floor penetrations to Room 12306, which is the Valve/Piping Penetration Room located below, through Room 12306 door to Turbine Building first bay
  - door to Turbine Building first bay
  - roof vent to atmosphere
- MSIV Compartment B
  - drains/vents to Turbine Building first bay
  - door to Turbine Building first bay
  - roof vent to atmosphere

These pressure relief flow paths limit the design pressure loading while maintaining the environmental and structural integrity of the MSIV compartments, adjacent compartments, the Main Control Room, and equipment housed therein.

3.6.1.3 Safety Evaluation

3.6.1.3.1 General

An analysis of postulated pipe failures is performed to determine the impact of such failures on those safety-related systems or components that provide protective actions and are required to mitigate the consequences of the failure. Through such protective measures, as separation, barriers, and pipe whip restraints, the effects of breaks, through-wall cracks, and leakage cracks are prevented from damaging essential items to an extent that would impair their essential function or necessary component operability.

Typical measures used for protecting the essential systems, components, and equipment are outlined in the next subsection and are discussed in Subsection 3.6.2. The capability of specific safety-related systems to withstand a single active failure concurrent with the postulated event is discussed, as applicable. When the results of the pipe failure effects analysis show that the effects of a postulated pipe failure are isolated, physically remote, or restrained by protective measures from essential systems or components, no further dynamic analysis is performed.

3.6.1.3.2 Protection Mechanisms

The plant arrangement is based on maximizing the physical separation of redundant or diverse safety-related components and systems from each other and from nonsafety-related items. Therefore, in the event a pipe failure occurs, there is a minimal effect on other essential systems or components required for safe shutdown of the plant or to mitigate the consequences of the failure.

The effects associated with a particular pipe failure are mechanistically consistent with the failure. Thus, pipe dimensions, piping layouts, material properties, and equipment arrangements are considered in defining the specific measures for protection against the consequences of postulated failures.

Protection against the dynamic effects of pipe failures is provided by physical separation of systems and components, barriers, equipment shields, and pipe whip restraints. The precise method chosen depends largely upon considerations such as accessibility and maintenance. The preferred method of providing protection is by separation. When separation is not practical pipe whip restraints are used. Barriers or shields are used when neither separation nor pipe whip restraints are practical. This protection is not required when piping satisfies leak-before-break criteria.

Separation

The plant arrangement provides separation, to the extent practicable, between redundant safety systems (including their appurtenances) to prevent loss of safety function as a result of events for which the system is required to be functional. Separation between redundant safety systems, with their related appurtenances, therefore, is the basic protective measure incorporated in the design to protect against the dynamic effects of postulated pipe failures.

In general, separation is achieved by:

- Safety-related systems located remotely from high-energy piping, where practicable
- Redundant safety systems located in separate compartments, where practicable
- Specific components enclosed to retain the redundancy required for those systems that must function to mitigate specific piping failures
- Drainage systems provided for flooding control
- Pressure relief panels, safety-related, seismically qualified, and fire-rated barrier louvers and flappers to prevent flooding of essential areas

Where physical separation is not possible, the pipe rupture hazard analysis includes an evaluation to determine the systems and components that require a structure for separation from the effects of a break in a high energy line. For these structures specifically included to separate breaks from essential systems or components, the evaluation considers that the break may be at the closest point in the line to the separating structure; not only at the break locations identified in Subsection 3.6.2.1.1. High energy lines qualified as leak-before-break lines and the lines in containment penetration break exclusion areas are not included as possible break locations in this evaluation. For a discussion of the information included in the pipe rupture hazard analysis see Subsection 3.6.2.5.

Barriers and Shields

Protection requirements are met through the protection afforded by walls, floors, columns, abutments, and foundations. Where adequate protection does not already exist as a result of separation, a separating structure such as additional barriers, deflectors, or shields is provided to meet the functional protection requirements.

Inside the containment, the secondary shield wall serves as a barrier between the reactor coolant loops and the containment. In addition, the refueling cavity walls, operating floor, and secondary shield walls minimize the possibility of an accident that may occur in any one reactor coolant loop affecting the other loop or the containment. Those portions of the steam and feedwater lines located within the containment are routed in such a manner that possible interaction between these lines and the reactor coolant piping is minimized. The direct vessel injection valves for train A and train B are separated by the secondary shield wall.

Outside the containment, the wall separating the first bay of the turbine building from the main area of the turbine building (Wall 11.2) is credited with protecting the north wall of the auxiliary building (Wall 11) from HELB loads resulting from postulated ruptures in main steam and main feedwater piping north of the turbine building first bay. The wall is designed and analyzed for the loadings associated with the effects of postulated pipe ruptures in high energy lines north of the turbine building first bay in conjunction with the required load combinations identified in Subsection 3.8.4, and determined to meet the acceptance criteria contained in ACI 349-01 and ANSI/AISC N690-1994.

Barriers and shields that are identified as required by the pipe rupture hazard analysis are designed for loads from a break in the line at the closest location to the structure. This criterion is in conformance with the guidance of Branch Technical Position MEB 3-1. Rev. 2. Subsection 3.6.2.4 further discusses barriers and shields.

Piping Restraint Protection

Measures for protection against pipe whip are provided where the unrestrained pipe movement of either end of the ruptured pipe could cause damage at an unacceptable level to any structure, system, or components required to meet the criteria outlined in this subsection.

Subsection 3.6.2.3 gives the design criteria for and description of pipe whip restraints.

3.6.1.3.3 Specific Protection Considerations

The analysis of the consequences of pipe breaks, through-wall cracks, and leakage cracks uses the following criteria.

- High-energy containment penetrations are subject to special protection mechanisms. Restraints are provided to maintain the operability of the isolation valves and the integrity of the penetration due to a break in the safety-related and nonsafety piping beyond the restraint if required. These restraints are located as close as practicable to the containment isolation valves associated with these penetrations.

- Instrumentation required to function following a pipe rupture is protected.

- High-energy fluid system pipe whip restraints and protective measures are designed so that a postulated break in one pipe cannot lead to a rupture of other nearby essential pipes or components, if the secondary rupture results in consequences that are unacceptable for the initial postulated break.

For those cases in which the rupture of the main steam or feedwater piping inside containment is the postulated initiating event, the turbine control, turbine stop, moisture separator reheater 2nd stage steam isolation, and turbine bypass valves, and to a limited extent, the control systems for the turbine stop and feedwater control valves, are credited in single failure analysis to mitigate the event. This equipment is not protected from pipe ruptures in the turbine building because the postulated pipe rupture for which it provides protection is inside containment. The assumed single active failure for this analysis is the function of the safety-related valve that would normally isolate the piping. This isolation function is addressed in more detail in Chapter 10.

3.6.2 Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping

This subsection describes the design bases for locating postulated breaks and cracks in high- and moderate-energy piping systems inside and outside the containment; the procedures used to define the jet thrust reaction at the break location; the procedures used to define the jet impingement loading on adjacent essential structures, systems, or components; pipe whip restraint design; and the protective assembly design. Pipe breaks in several high-energy systems, including the reactor coolant loop and surge line, are replaced by small leakage cracks when the leak-before-break criteria are applied. (See Subsection 3.6.3.) Jet impingement and pipe whip effects are not evaluated for these small leakage cracks.

3.6.2.1 Criteria Used to Define High- and Moderate-Energy Break and Crack Locations and Configurations

The NRC Branch Technical Position MEB 3-1 is used as the basis of the criteria for the postulation of high-energy pipe breaks and through-wall cracks, except for piping that satisfies the requirements for mechanistic pipe break, as described in Subsection 3.6.3.

A postulated high-energy pipe break is defined as a sudden, gross failure of the pressure boundary of a pipe either in the form of a complete circumferential severance (that is, a guillotine break) or as a sudden longitudinal, uncontrolled crack. For high-energy and moderate-energy fluid systems, pipe failures are also defined by postulation of controlled through-wall cracks in piping. For those piping lines that satisfy leak-before-break requirements, the guillotine breaks and sudden longitudinal cracks are replaced by postulated controlled leakage cracks.

Subsection 3.6.1 describes the evaluation and criteria for the effects of these breaks and cracks on the safety-related equipment.

3.6.2.1.1 High-Energy Break Locations

The locations for postulated breaks in high-energy piping are dependent on the classification, quality group, and design standards used for the piping system. The break locations for high-energy piping are described in the following subsections. These locations are based on the design configuration and include changes due to the as-built piping configuration. As a result of piping reanalysis due to differences between the design configuration and the as-built configuration, the high stress and usage factor location may be shifted. The intermediate break (if any) locations need not be changed unless one of the following conditions exists:

A. The dynamic effects from new (as-built) intermediate break locations are not mitigated by the original pipe whip restraints and jet shields.

B. There is a significant change in pipe design parameters such as pipe size, wall thickness or pressure rating.

Breaks are not postulated in piping in the vicinity of containment penetrations. The portion of the piping that does not have postulated breaks is the break exclusion area. Subsection 3.6.2.1.1.4 identifies the requirements for the piping in the containment penetration break exclusion area.

Breaks are not postulated for those sections of pipe, including the reactor coolant loop and pressurizer surge line, that meet the requirements for leak-before-break as described in Subsection 3.6.3.

The leak-before-break methodology is applied to the candidate high-energy lines in the nuclear island identified in Appendix 3E. This appendix also identifies other high-energy lines in the nuclear island with diameters larger than 1 inch and the break exclusion areas inside and outside containment. The evaluation criteria for lines that do not satisfy the leak-before-break criteria are described in Subsection 3.6.2.

3.6.2.1.1.1 ASME Code, Section III, Division 1 – Class 1 Piping

[*Pipe breaks are postulated to occur at the following locations in piping designed and constructed to the requirements for Class 1 piping in the ASME Code, Section III, Division 1.*

- *At terminal ends of the piping, including:*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

– *The extremity of piping connected to structures, components, or anchors that act as essentially rigid restraints to piping translation and rotational motion due to static or dynamic loading.*

– *Branch intersection points are considered a terminal end for the branch line unless the following are met: The branch and the main piping systems are modeled in the same static, dynamic and thermal analyses, and the branch and main run are of comparable size and fixity (that is, the nominal size of the branch is at least one-half of that of the main run).*

– *In piping runs that are maintained pressurized during normal plant conditions for only a portion of the run, the terminal end, for purposes of defining break locations, is the piping connection to the first normally closed valve.*

- *At intermediate locations where the following conditions are satisfied:*

  – *Intermediate locations where the maximum stress range as calculated by Equation (10) of Paragraph NB-3653 of the ASME Code, Section III exceeds 2.4 Sm (where Sm is the design stress intensity), and either Equation (12) or Equation (13) of Paragraph NB-3653.6, exceed 2.4 Sm.*

  – *Intermediate locations where the cumulative usage factor as determined by the ASME Code exceeds 0.1.*

  – *Efforts will be made to avoid intermediate break locations through appropriate piping layout and pipe support design.*

The loading conditions considered for the stress range and usage factors calculated to determine break locations are those defined for Level A and B Service conditions for the piping system with the exception that seismic loads do not need to be considered for the postulation of intermediate break locations.

For those sections of pipe that satisfy the requirements for leak-before-break, leakage cracks are postulated for evaluation of subcompartment pressurization.]*

3.6.2.1.1.2 ASME Code, Section III – Class 2 and Class 3 Piping Systems

[*For those piping system lines designed and analyzed to the requirements of the ASME Code, Section III, Class 2 and 3, except for those sections that satisfy the mechanistic pipe break criteria (subsection 3.6.3), the following criteria apply.*

- *Pipe breaks are postulated to occur at terminal ends, using the same definition for terminal ends as for Class 1 pipe.*

- *Pipe breaks are postulated at intermediate locations between terminal ends where the maximum stress value, as calculated by the sum of Equations (9) and (10) in Subarticle NC-3600 (Class 2) and ND-3600 (Class 3) of the ASME Code, Section III, considering Level A and B Service conditions. That is, breaks are postulated at locations for sustained loads, occasional loads, and thermal expansion exceeding 0.8 (1.8 Sh + SA) or 0.8 (1.5 Sy + SA), where Sh, SA, and Sy are the allowable stress at maximum hot temperature stress, allowable stress range for thermal expansion, and yield strength, respectively, for Class 2 and 3 piping, as defined in Subarticle NC-3600 and Subarticle ND-3600 of the ASME Code, Section III. Efforts will be made to avoid intermediate break locations through appropriate piping layout and pipe support design.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

For those ASME Code, Section III, Class 2 and 3 systems that satisfy the leak-before-break criteria, postulated leakage crack locations are defined in the same way as for the Class 1 systems.]*

3.6.2.1.1.3 Piping Not Designed to ASME Code

[*Breaks in piping systems designed to requirements other than the ASME Code, such as ASME B31.1 (Reference 3), are postulated at the following locations:*

- *If the piping is analyzed and supported to withstand safe shutdown earthquake loadings, pipe ruptures are postulated to occur at the following locations:*
  - *At terminal ends, using the same definition for terminal ends as for Class 1 pipe*
  - *At intermediate locations where the stresses, as calculated by the sum of Equations (9) and (10) in Subarticle NC3600 of the ASME Code, Section III, considering normal and upset plant conditions, exceeds 0.8 (1.8 Sh + SA) or 0.8 (1.5 Sy + SA)*
  - *Efforts will be made to avoid intermediate break locations through appropriate piping layout and pipe support design.*]*
- In the absence of stress analysis, breaks in non-nuclear piping are postulated at the following locations in each run or branch run:
  - Terminal ends
  - Intermediate fittings; (short- and long-radius elbows, crosses, flanges, nonstandard fittings, tees, reducers, welded attachments, and valves)

3.6.2.1.1.4 High-Energy Piping in Containment Penetration Areas

The AP1000 does not have any ASME Code, Section III Class 1 pipe in containment penetration areas. Breaks are not postulated in the portions of ASME Code, Section III, Class 2 or Class 3 piping, defined below as break exclusion piping, provided subject piping meets the following provisions:

- Stresses do not exceed those specified in Subsection 3.6.2.1.1.2.
- The maximum stress in this piping as calculated by Equation (9), of paragraph NC-3653 of ASME Code Section III, when subjected to the combined loadings of internal pressure, deadweight, and postulated pipe rupture outside the break exclusion zone, does not exceed 2.25 Sh or 1.8 Sy.
- The number of circumferential piping welds is minimized by using pipe bends in place of welding elbows when practicable. There are no longitudinal piping welds in the break exclusion zone. Where guard pipes are used, there are no circumferential or longitudinal welds in the piping enclosed within the guard pipe. Details of the arrangement are shown in Figure 3.8.2-4.
- When required for isolation valve operability, structural integrity, or containment integrity, anchors or five-way restraints capable of resisting torsional and bending moments produced by a postulated pipe break, either upstream or downstream of the piping and valves which form the containment isolation boundary, are located reasonably close to the isolation valves or penetration.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The anchors or five-way restraints do not prevent the access required to conduct in-service inspection examinations specified in Section XI of the ASME Code. In-service examinations completed during each inspection interval provide 100-percent volumetric examination (according to IWA-2400, ASME Code, Section XI) of circumferential pipe welds within the boundary of these portions of piping during each inspection interval. This volumetric inspection applies to circumferential piping welds that are equal to or greater than a 3-inch nominal diameter and piping branch connection welds that are equal to or greater than 4-inch nominal diameter.

- Welded attachments to these portions of piping for pipe supports or other purposes are avoided. Where welded attachments are necessary, detailed stress analyses are performed to demonstrate compliance with the limits of Subsection 3.6.2.1.1 and applicable requirements of Section XI of the ASME Code.

- The requirements of ASME Code, Section III, Subarticle NE-1120, are satisfied for the containment penetration.

- Class 3 pipe satisfies the fabrication and inspection requirements for Section III, Class 2 pipe.

- For evaluation of spray wetting, flooding, and subcompartment pressurization effects, longitudinal cracks (with crack flow areas of 1 square foot) are postulated in the main steam and main feedwater piping. The dynamic effects of pipe whip and jet impingement are not evaluated for these cracks. Locations having the greatest effect on essential equipment are chosen.

- Guard pipe assemblies for high-energy piping in the containment annulus region between the containment shell and shield building that are part of the containment boundary are designed according to the rules of Class MC, subsection NE, of the ASME Code. The following requirements also apply. The design pressure and temperature are equal to or greater than the maximum operating pressure and temperature of the enclosed process pipe under normal plant conditions. Level C service limits of the ASME Code, Section III, Paragraph NE-3221, are not exceeded by the loadings associated with containment design pressure and temperature in combination with a safe shutdown earthquake. The guard pipe assemblies are subjected to a pressure test performed at the maximum operating pressure of the enclosed process pipe.

Areas of system piping where no breaks, except as noted in Subsections 3.6.1.2.1 and 3.6.1.2.2, are postulated are as follows:

- The main steam piping from the containment penetration flued head inboard weld to the auxiliary building anchor downstream of the main steam isolation valves, including the main steam safety valves and the connecting branch piping

- The main feedwater piping from the auxiliary building side of the containment penetration flued head to the auxiliary building anchor upstream of the isolation valve

- The startup feedwater piping from the auxiliary building side of the containment penetration flued head to the auxiliary building anchor upstream of the isolation valve

- The steam generator blowdown piping from the auxiliary building side of the containment penetration flued head to the auxiliary building anchor downstream of the isolation valve

- The chemical and volume control system makeup piping from the containment penetration flued head to the outboard isolation valve

- The chemical and volume control system makeup piping from the containment penetration flued head to the inboard isolation valve

For main steam line breaks in the Turbine Building, Wall 11 is capable of resisting torsional and bending moments produced by the postulated pipe breaks. When Wall 11.2 protects Wall 11 against the whipping effects of main steam line breaks, its piping sleeve helps in minimizing axial movement of Wall 11. The axial movement is due to pipe deflection at Wall 11.2, resulting from a main steam piping break in the Turbine Building north of Wall 11.2, and deflection of the main steam piping at Wall 11.2. Wall 11.2, along with its piping sleeve, acts as a barrier which helps in minimizing the lateral displacement of the main steam piping at Wall 11.2. This, in turn, reduces the axial piping displacements at Wall 11 due to pipe deflection at Wall 11.2, resulting in stresses in the break exclusion zone portion of the main steam piping that meet the criteria of Subsection 3.6.2.1.1.4.

Those portions of the containment penetration flued heads identified above that have the same nominal dimensions as the connected pipe are also considered as part of the break exclusion zone piping. The auxiliary building anchors also have flued head designs and the same requirement applies to these.

The main steam and main feedwater containment penetration flued heads are attached to expansion bellows, which are attached to the containment vessel via insert plates (Subsection 3.8.2.1.5, Figure 3.8.2-4, Sheet 1 and Sheet 8, respectively). The function of the expansion bellows is to minimize any piping loads applied to the containment vessel. The containment is not a terminal end for these piping analyses; the terminal ends are the main steam and main feedwater piping anchors in the auxiliary building exterior wall and their respective steam generator nozzles inside containment. The portion of the main steam piping that is inside containment is evaluated to meet the leak-before-break mechanistic pipe break criteria in accordance with Subsection 3.6.3; the portion of the main feedwater piping that is inside containment is analyzed to meet the high-energy pipe break criteria in accordance with Subsection 3.6.2.

All other fluid system containment penetrations are for moderate-energy systems or for pipe of 1-inch nominal diameter or smaller. See Subsection 6.2.3 for a discussion of containment penetrations.

3.6.2.1.2 Types of Breaks/Cracks Postulated

3.6.2.1.2.1 Break in Piping – High-Energy

The following types of breaks are postulated to occur in ASME Code Class 1, 2, and 3 and non-ASME Code, Section III high-energy piping at the locations determined according to Subsection 3.6.2.1.1, except when the leak-before-break criteria are satisfied.

- In piping with a nominal diameter of greater than or equal to 4 inches, both circumferential and longitudinal breaks are postulated at each selected break location unless eliminated by comparison of longitudinal and axial stresses with the maximum stress as follows:
  - If the maximum stress range exceeds the limits specified in Subsections 3.6.2.1.1.1, 3.6.2.1.1.2, and 3.6.2.1.1.3, but the circumferential stress range is at least 1.5 times the axial stress range, only a longitudinal break is postulated.
  - If the maximum stress range exceeds the limits specified in Subsections 3.6.2.1.1.1, 3.6.2.1.1.2, and 3.6.2.1.1.3, but the axial stress is at least 1.5 times the circumferential stress range, only a circumferential break is postulated.
  - Longitudinal breaks, however, are not postulated at terminal ends.

- In piping with a nominal diameter of greater than 1 inch but less than 4 inches, only circumferential breaks are postulated at each selected break location.

- No breaks are postulated for piping with a nominal diameter of 1 inch or less.

3.6.2.1.2.2 Through-Wall Cracks in High- or Moderate-Energy Piping

Through-wall cracks are postulated in high-energy or moderate-energy piping, including branch runs larger than 1-inch nominal diameter as defined in the following paragraphs:

A. Through-wall cracks are not postulated in the break exclusion areas of high-energy pipe defined in Subsection 3.6.2.1.1.4 and in those portions of moderate-energy piping between containment isolation valves, provided the containment penetration meets the requirements of ASME Code, Section III, Sub-article NE-1120, and the piping is designed so that the maximum stress range based on the sum of equations (9) and (10) in Subarticle NC3600 of the ASME Code, Section III, considering Level A and B Service conditions, does not exceed either 0.4 (1.8 Sh + SA) or 0.4 (1.5 Sy + SA).

B. Through-wall cracks are not postulated in high- or moderate-energy fluid system piping located in an area where a break in the high-energy fluid system is postulated, provided that such cracks do not result in environmental conditions more limiting than the high-energy pipe break.

C. Subject to Paragraphs A and D, through-wall cracks are postulated in:

    - ASME Code, Section III, Division 1 – Class 1 piping where the maximum stress range as calculated by Equation (10) of Paragraph NB-3653 of the ASME Code, Section III exceeds 1.2 Sm. Cracks are also postulated at locations where the cumulative usage factor exceeds 0.1.

    - ASME Code, Section III, Division 1 – Class 2 or 3 piping at locations where the maximum stress range, as calculated by the sum of Equations (9) and (10) in Subarticle NC-3600 (Class 2) and ND-3600 (Class 3) of the ASME Code, Section III, considering Level A and B Service conditions, is greater than 0.4 (1.8 Sh + SA) or 0.4 (1.5 Sy + SA).

    - Seismically analyzed ASME B31.1 piping at locations defined in the same way as ASME Code, Section III, Class 3 piping.

    - Nonseismically analyzed ASME B31.1 piping at the following locations:

        – Terminal ends

        – Intermediate fittings; (short- and long-radius elbows, crosses, flanges, nonstandard fittings, tees, reducers, welded attachments, and valves)

D. Individual through-wall cracks are not postulated at specific locations determined by stress analyses when a review of the piping layout and plant arrangement drawings shows that the effects of through-wall leakage cracks at any location in the piping designed to seismic or nonseismic standards are isolated or are physically remote from structures, systems, and components required for safe shutdown.

E. Through-wall cracks are postulated to be in those circumferential locations that result in the most severe environmental consequences.

3.6.2.1.2.3 Leakage Cracks in High-Energy Piping with Leak-before-Break

In those sections of piping that satisfy the requirements for leak-before-break, leakage cracks are postulated for evaluation of subcompartment pressurization. The size of the crack is such that the expected leakage is 10 times the minimum leak detection capability for that location. See Subsection 3.6.3 for a discussion of crack size and leakage detection.

3.6.2.1.3 Break and Crack Configuration

3.6.2.1.3.1 High-Energy Break Configuration

Following a circumferential break, the two ends of the broken pipe are assumed to move clear of each other unless physically limited by piping restraints, structural members, or piping stiffness. The effective cross-sectional (inside diameter) flow area of the pipe is used in the jet discharge evaluation. Movement is assumed to be in the direction of the jet reaction initially with the total path controlled by the piping geometry.

The orientation of a longitudinal break, except when otherwise justified by a detailed stress analysis, is assumed to be at opposing points on a line perpendicular to the plane of a fitting for a non-axisymmetric fitting. The flow area of such a break is equal to the cross-sectional flow area of the pipe. The geometry of the longitudinal break may be assumed elliptical (2D along pipe axis and D/2 along pipe transverse) or circular. Both circumferential and longitudinal breaks are postulated to occur, but not concurrently, in high-energy piping systems at the locations specified in Subsection 3.6.2.1.2.1, except as follows:

- Where the postulated break location is at a tee or elbow, the locations and types of breaks are determined as follows:

  – Without the benefit of a detailed stress analysis, such as a finite element analysis, circumferential breaks are postulated to occur individually at each pipe-to-fitting weld. Longitudinal breaks are postulated to occur individually (except in piping with a nominal diameter less than 4-inches) on each side of the fitting at its center and oriented perpendicular to the plane of the fitting, or

  – Alternatively, if a detailed stress analysis or test is performed, the results may be used to predict the most probable rupture location(s) and type of break.

- Where the postulated break location is at a branch/run connection, a circumferential break is postulated at the branch pipe-to-branch fitting weld unless otherwise justified by detailed analysis.

- Where the postulated break location is at a welded attachment (lugs, stanchions), a circumferentially oriented break is postulated at the centerline of the welded attachment unless otherwise justified by a detailed analysis. The break area is equal to the pipe surface area that is bounded by the welded attachment.

- Where the postulated break location is at a reducer, circumferential breaks are postulated at each pipe-to-fitting weld. Longitudinal breaks are oriented to produce out-of-plane bending of the piping configuration on both sides of the reducer at each pipe-to-fitting weld.

3.6.2.1.3.2 High-Energy and Moderate-Energy Through-Wall Crack Configuration

High-and moderate-energy through-wall crack openings are assumed to be a circular orifice with cross-sectional flow area equal to that of a rectangle one-half the pipe inside diameter in length and

one-half pipe wall thickness in width. The flow from a through-wall crack is assumed to result in an environment that wets unprotected components within the compartment with consequent flooding in the compartment and communicating compartments, unless analysis shows otherwise. Flooding effects are determined on the basis of a conservatively estimated time period required to take corrective actions.

3.6.2.2 Analytical Methods to Define Jet Thrust Forcing Functions and Response Models

To determine the forcing function, the fluid conditions at the upstream source and at the break exit dictate the analytical approach and approximations that are used.

Analytical methods for calculation of jet thrust for the preceding situations are discussed in ANS-58.2-1988 (Reference 4) and Moody, F. J. (Reference 5). The discussion of the jet thrust forcing functions on the reactor coolant loop follows.

Since a rupture of the large-diameter reactor coolant loop piping does not have to be considered, based on satisfying mechanistic pipe break criteria, the jet thrust and reactive loads considered in the analysis are those associated with breaks in branch line sections that do not satisfy the mechanistic pipe break criteria.

To determine the thrust and reactive force loads to be applied to the reactor coolant loop during the postulated pipe rupture, it is necessary to have a detailed description of the hydraulic transient. Hydraulic forcing functions are calculated for the reactor coolant loops as a result of a postulated loss of coolant accident. These forces result from the transient flow and pressure histories in the reactor coolant system (RCS).

The calculation is performed in two steps. The first step is to calculate the transient pressure, mass flowrates, and thermodynamic properties as a function of time. The second step uses the results obtained from the hydraulic analysis, along with input of areas and direction coordinates, and calculates the time-history of forces at appropriate locations in the reactor coolant loops.

The hydraulic model represents the behavior of the coolant fluid within the entire reactor coolant system. Key parameters calculated by the hydraulic model are pressure, mass flowrate, and density. These are supplied to the thrust calculation, together with plant layout information, to determine the time-dependent loads exerted by the fluid on the loops. In evaluating the hydraulic forcing functions during a postulated loss of coolant accident, the pressure and momentum flux terms are dominant. The inertia and gravitational terms are taken into account in the evaluation of the local fluid conditions in the hydraulic model.

The blowdown hydraulic analysis provides the basic information concerning the dynamic behavior of the reactor core environment for the loop forces. This requires the ability to predict the flow, quality, and pressure of the fluid throughout the reactor system. [*MULTIFLEX (Reference 6) or an equivalent computer code is used to provide this information.*]*

MULTIFLEX calculates the hydraulic transients within the entire primary coolant system. This hydraulic program considers a coupled, fluid-structure interaction by accounting for the deflection of the core support barrel. The depressurization of the system is calculated using the method of characteristics applicable to transient flow of a homogenous fluid in thermal equilibrium.

The ability to treat multiple flow branches and a large number of mesh points gives MULTIFLEX the flexibility to represent the various flow passages within the primary reactor coolant system. The system geometry is represented by a network of one-dimensional flow passages.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

[*The THRUST computer program or equivalent is used to compute the transient (blowdown) hydraulic loads resulting from a loss of coolant accident.*]*

The blowdown hydraulic loads on primary loop components are computed from the equation:

$$F = 144\,A\left[(P - 14.7) + \left(\frac{\dot{m}^2}{144\,\rho\,g\,(A_m)^2}\right)\right]$$

where:

F = Force (lbf)

A = Aperture area (ft^2)

P = System pressure (psia)

$\dot{m}$ = Mass flowrate (lbm/s)

ρ = Density (lbm/ft^3)

g = Gravitational constant = 32.174 ft-lbm/lbf - s2

A_m = Mass flow area (ft^2)

In the model to compute forcing functions, the reactor coolant loop system is represented by a model similar to that employed in the blowdown analysis. The entire loop layout is represented in a global coordinate system. Each node is described by blowdown hydraulic information and the orientation of the streamline of the force nodes in the system, which includes flow areas and projection coefficients along the three axes of the global coordinate system.

Each node is modeled as a separate control volume with one or two flow apertures associated with it. Two apertures are used to simulate a change in flow direction and area.

Each force is divided into its x, y and z components using the projection coefficients. The force components are then summed over the total number of apertures in any one node to give a total x force, a total y force, and a total z force. These thrust forces serve as input to the piping/ restraint dynamic analysis.

[*The THRUST code calculates forces the same way as the STHRUST code described in WCAP-8252 (Reference 7).*]*

3.6.2.3 Dynamic Analysis Methods to Verify Integrity and Operability

This subsection describes the pipe rupture design criteria for auxiliary piping systems. Subsection 3.6.2.2 describes the analysis methods for thrust loadings. To mitigate each postulated pipe rupture, auxiliary piping systems required to maintain pressure boundary integrity or to provide for fluid flow are identified. The loadings on these systems may consist of jet impingement loads, transient motions at terminal end connections, or internal system depressurization loadings.

The application of leak-before-break analysis eliminates evaluation of postulated pipe ruptures in the primary coolant loop piping and selected piping systems of 6-inch nominal size or larger. The piping

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

system mechanical components and supports are designed for the effects of the remaining postulated pipe ruptures and leaks.

To confirm the continued integrity of the essential components and the engineered safety systems, consideration is given to the consequential effects of the pipe break to the extent that:

- The minimum performance capabilities of the engineered safety systems are not reduced below that required to protect against the postulated break.
- The containment leaktightness is not decreased below the design value if the break leads to a loss of coolant accident.
- Propagation of damage is limited in type or degree or both to the extent that:
  - A pipe break that is not a loss of coolant accident, steam line break, or main feedwater break will not cause a loss of coolant accident or steam line or feedwater line break.
  - A break in the nonsafety portion of the chemical and volume control system purification loop will not cause a break in the safety-related portion of the system. In addition, the ability to isolate the reactor coolant system flow will not be adversely affected.
  - A reactor coolant system pipe break will not cause a steam or feedwater system pipe break, and vice versa.

3.6.2.3.1 Jet Impingement

Analytical methods for the calculation of jet impingement forces are based on Moody, F. J. (Reference 5), NUREG/CR-2913 (Reference 1), and Section 7.3 of ANS-58.2-1988 (Reference 4). For piping systems this loading is a suddenly applied load that can have significant energy content. These loads are generally treated as statically applied constant loads.

Two separate structural evaluations are performed. For the short-term response, snubber supports are considered to be active and a dynamic load factor of 2 is used. For the longer-term response, snubber supports are considered inactive, and no dynamic load factor is used.

If simplified static analysis is performed instead of a dynamic analysis, the preceding jet load (FT) is multiplied by a dynamic load factor. For an equivalent static analysis of the target structure, the jet impingement force is multiplied by a dynamic load factor of 1.2 to 2.0, depending upon the time variance of the jet load and the elastic/plastic behavior of the target. This factor assumes that the target can be represented as essentially a one-degree-of-freedom system.

3.6.2.3.2 Transient Motions at Terminal Ends

This loading is displacement limited and has a short duration of about 0.5 seconds. An example is the motions of the primary loop piping at the terminal end connection of the Class 1 pressurizer surge line piping due to a postulated pipe rupture in a Class 2 pipe connected to the steam generator.

When there are active in-line components in the piping system that must function to mitigate the postulated pipe rupture, dynamic structural analyses are performed for the terminal end motions. The calculated accelerations are evaluated to confirm the operability of the active in-line components. For piping systems with no active in-line components, static structural analyses with no dynamic amplification are performed for the terminal end motions.

These analyses may consider nonlinear geometric and material characteristics of the piping system.

3.6.2.3.3 Internal System Depressurization

This loading has a short duration of approximately 0.5 seconds and arises from rapidly traveling pressure waves in piping systems connected to the broken piping system. Two types of configurations are possible: systems without check valves and systems with check valves. In systems with check valves, the valve closure can increase the duration and magnitude of these loads.

An example of the former is the pressure waves in the Class 1 letdown line of the chemical and volume control system piping due to a postulated pipe rupture in a Class 1 pipe connected to the primary loop piping. An example of the latter is the closure of the feedwater check valve due to a postulated pipe rupture upstream of the valve.

For piping systems without closing check valves, there is little energy in the high-frequency depressurization loadings. These loadings are therefore not considered in the piping and support analysis.

For piping system with closing check valves, the magnitude of the loadings depends on the valve closure time, with shorter closing times generally causing higher loadings. For this loading the potential system failure mechanisms evaluated are: 1) excessive pipe and valve hoop stress; 2) tensile loads on the valve pressure boundary bolting; and 3) excessive distortion of the valve disc or seat.

The maximum internal pressure and the kinetic energy of the valve disc at the time of closure are used to verify the pressure boundary integrity of the piping and valve based on the preceding failure mechanisms. RELAP5 is used to calculate the pressure and kinetic energy. The supports on these systems are designed in such a way that support failure will occur prior to local pipe pressure boundary failure at the support connection.

3.6.2.3.4 Pipe Whip Restraints

To satisfy varying requirements of available space, permissible pipe deflection, and equipment operability, the restraints are generally designed as a combination of an energy-absorbing element and a restraint structure suitable for the geometry required to pass the restraint load from the whipping pipe to the main building structure. The restraint structure is typically a structural steel frame or truss, and the energy-absorbing element is usually either stainless steel U-bars or energy-absorbing material.

Another option is for the restraints to be designed as entirely elastic structures and simply transfer the pipe break loads to the main building structure. In addition, pipe supports (including snubbers, struts, or rigid frames) can be used as pipe whip restraints when qualified for the pipe break loads.

3.6.2.3.4.1 Location of Pipe Whip Restraints

For purposes of determining pipe hinge length and thus locating the pipe whip restraints, the plastic moment of the pipe is determined in the following manner:

$$M_p = 1.1\, z_p S_y$$

where:

z_p = Plastic section modulus of pipe

S_y = Yield stress at pipe operating temperature

1.1 = 10-percent factor to account for strain hardening.

Pipe whip restraints are located as close to the axis of the reaction thrust force as practicable. Pipe whip restraints are generally located so that a plastic hinge does not form in the pipe. If, because of physical limitations, pipe whip restraints are located so that a plastic hinge can form, the consequences of the whipping pipe and the jet impingement effect are further investigated. Lateral guides are provided where necessary to predict and control pipe motion.

Generally, pipe whip restraints are designed and located with sufficient clearances between the pipe and the restraint in such a way that they do not interact and cause additional piping stresses. A design hot position gap is provided that allows maximum predicted thermal, seismic, and seismic anchor movement displacements to occur without interaction.

Exception to this general criterion may occur when a pipe support and restraint are incorporated into the same structural steel frame, or when a zero design gap is required. In these cases, the pipe whip restraint is included in the piping analysis and designed to the requirements of pipe support structures for all loads except pipe break and designed to the requirements of pipe whip restraints when pipe break loads are included.

In general, the pipe whip restraints do not prevent the access required to conduct in-service inspection examination of piping welds. When the location of the restraint makes the piping welds inaccessible for in-service inspection, a portion of the restraint is designed to be removable to provide accessibility.

3.6.2.3.4.2 Analysis and Design of Pipe Whip Restraints

The criteria for analysis and design of pipe whip restraints for postulated pipe break effects are provided in the following. These criteria are consistent with the guidelines in ANS-58.2-1988 (Reference 4).

- Pipe whip restraints are designed based on energy absorption principles by considering the elastic-plastic, strain-hardening behavior of the materials used.

- Non-energy absorbing portions of the pipe whip restraints are designed to the requirements of ANSI/AISC N690 Code supplemented by the requirements given in Subsection 3.8.4.5. American Welding Society (AWS), Structural Welding Code-Steel, AWS D1.1-2000 provides an acceptable alternative for ANSI/AISC N690 weld requirements as described in Subsections 3.8.3.2 and 3.8.4.2.

- Standard pipe support components, such as struts and snubbers, used as pipe whip restraints are designed to ASME Section III, Subsection NF, Service Level D allowables.

- Loads on pipe whip restraints are developed either from an energy balance method (as described in ANS-58.2) with a 1.1 rebound factor or from dynamic time-history analyses.

- Except in cases where calculations are performed to verify that a plastic hinge is formed, the energy absorbed by the ruptured pipe is conservatively assumed to be zero. That is, the thrust force developed goes directly into moving the broken pipe and is not reduced by the force required to bend the pipe.

- Other structural members of the pipe whip restraints are designed for elastic response. A dynamic increase factor is used for those members that are designed to remain elastic.

- The criteria for allowable strain in a pipe whip restraint are dependent on the type of restraint. The following discussions address the types of restraints used and the allowable strain for each. Note -ε = allowable strain used in design.

Energy Absorbing Materials

Stainless Steel U-Bar – This type of restraint consists of one or more U-shaped, upset-threaded rods of stainless steel looped around the pipe but not in contact with the pipe. This allows unimpeded pipe motion during seismic and thermal movement of the pipe. At rupture, the pipe moves against the U-bars, which absorb the kinetic energy of pipe motion by yielding plastically. Figure 3.6-1 shows a typical example of a U-bar restraint.

$$\varepsilon = 0.5\varepsilon u$$

where:

εu = ultimate uniform strain of stainless steel (strain at ultimate stress)

Crushable Pipe – The crushable pipe type of restraint consists of a short section of standard pipe (length at least three times diameter of crushable pipe) that is situated approximately perpendicular to the process pipe and whose longitudinal axis is approximately perpendicular to the plane of pipe movement. The crushable pipe is attached to a supporting structure. The crushable pipe is the part of the assembly that absorbs the kinetic energy that the broken pipe has accumulated after rupture, and the crushable pipe typically undergoes considerable plastic deformation during the pipe whip event. A design hot position gap is provided between the process pipe and the energy-absorbing crushable pipe to allow unimpeded pipe motion during seismic and thermal pipe movements. Figure 3.6-2 shows typical examples of a crushable pipe type whip restraint. The allowable capacity of the crushable pipe is limited to 80 percent of its rated energy dissipating capacity as determined by dynamic testing, at loading rates within ± 50 percent of the specified design loading rate. An additional conservative measure is used to maintain ductile yield of the energy absorbing pipe by limiting flattening of the crushed pipe to the limits provided in ASTM A530. The rated energy dissipating capacity is not greater than the area under the load-deflection curve as illustrated in Figure 3.6.2-1 of NUREG-0800, Standard Review Plan, Section 3.6.2, Revision 2.

3.6.2.4 Protective Assembly Design Criteria

In addition to pipe whip restraints, other protective devices are designed to protect against the effects of postulated pipe ruptures. Barriers and shields are designed to protect against jet impingement. Guard pipes in the break exclusion zones provide additional confidence that pipes will not leak into the annulus between the containment vessel and the shield building.

3.6.2.4.1 Jet Impingement Barriers and Shields

Barriers and shields, constructed of either steel or concrete, are provided to protect essential equipment, including instrumentation, from the effects of jet impingement resulting from postulated pipe breaks. Barriers differ from shields in that they may also accept the impact of whipping pipes. Barriers and shields include walls, floors, and structures specifically designed to provide protection from postulated pipe breaks. Barrier and shield design is based on elastic methods and the elastic-plastic methods for dynamic analysis included in Biggs, J. M. (Reference 9). Design criteria and loading combinations are according to Subsections 3.8.3 and 3.8.4.

3.6.2.4.2 Auxiliary Guardpipes

The use of guard pipes has been minimized by plant arrangement and routing of high-energy piping. Guard pipes in the containment annulus areas of the break exclusion zones are designed as

described in Subsection 3.6.2.1.1.4. Other guard pipes are designed and constructed to the same ASME rules as the enclosed process pipe.

3.6.2.5 Evaluation of Dynamic Effects of Pipe Ruptures

The preceding information provides the criteria and methods for the evaluation of the dynamic effects of pipe ruptures. The pipe rupture hazard analysis report (also referred to as the pipe break evaluation report) includes the following:

- Prepare a stress summary
- Identify pipe break locations in high energy piping
- Identify through-wall crack locations in high and moderate energy piping
- Identify and locate essential structures, systems, and components
- Evaluate consequences of pipe whip and jet impingement

  For rooms with both high energy breaks and essential items, confirm that there is no adverse interaction between the essential items and the whipping pipe or jet.

  The plant layout is modified as required to provide separation to protect essential systems.
- Evaluate consequences of flooding, environment, and compartment pressurization

  Evaluate compartment pressurization in the break exclusion zones in the vicinity of containment penetrations due to 1.0 square foot breaks in the main steam and feedwater lines.
- Design and locate protective hardware
- Prepare isometric piping sketches that identify the break locations, the basis for these locations and the protective hardware which mitigates the consequences of these breaks.
- Reconciliation of as-built condition

Pipe breaks that are larger than 1-inch nominal diameter are evaluated for pipe whip and jet impingement. Lines that are located in a break exclusion zone or are qualified to leak-before-break are not evaluated for pipe whip and jet impingement effects on systems and components, except for the portions of the lines in the MSIV compartment adjacent to the main control room as noted in Subsection 3.6.1.2.2.

Where these systems are qualified for mechanistic pipe break and pipe rupture loads prior to fabrication, the qualification is based on design information, not on as-built information. As-built information and the final configuration of valves and other equipment is used to verify the design analysis.

High Energy Break Locations

High energy break locations evaluated are on the nuclear island and in the turbine building for evaluation of the wall loadings in the south end of the turbine building adjacent to the main control room.

For ASME Class 1 piping terminal end locations are determined from the piping isometric drawings. Intermediate break locations depend on the ASME Code stress report fatigue analysis results. These

results were not available at design certification. For the design of the AP1000, breaks are postulated at locations typically associated with a high cumulative fatigue usage factor. These locations are at valves, tees, and branch connections which have significant structural discontinuities. These locations are part of the as-built reconciliation as discussed in Subsection 3.6.4.1. The following ASME Class 1 lines are evaluated to terminal end and intermediate high energy break locations if applicable.

Line	Diameter (inches)
Pressurizer Spray	4
Automatic Depressurization Stage 1	4
Chemical and Volume Control Letdown	3
Chemical and Volume Control Makeup	3
Reactor Coolant Pump Piping to/from Heat Exchangers (2/pump)	3
Pressurizer Auxiliary Spray	2

For ASME Class 2 and 3 piping, terminal end break locations are determined from the piping isometric drawings. The intermediate break locations depend on the stress level. The AP1000 ASME Class 2 and 3 lines do not have intermediate breaks based on the low stress. The following ASME Class 2 and 3 lines have terminal end high energy break locations.

Line	Diameter (inches)
Main Feedwater	16, 20
Startup Feedwater	6
Steam Generator Blowdown	4

For ASME B31.1 piping, terminal end break locations are determined from the piping isometric drawings. The intermediate break locations in seismically analyzed pipe depend on the stress level. The AP1000 ASME seismically analyzed ASME B31.1 piping does not have intermediate breaks based on the low stress. For nonseismically analyzed high-energy ASME B31.1, intermediate breaks locations are postulated at each fitting.

Rooms subject to pressurization due to high energy pipe break are listed in Table 3.6-2 with the break location.

Essential Systems and Components

In rooms that contain high energy pipe breaks, the systems and components that are needed to mitigate the postulated break and achieve a safe plant shutdown are identified. Rooms that contain both high energy pipe break locations and essential systems or components that must be protected are listed in Table 3.6-3. No high energy pipe break protection is required in other areas of the plant.

Essential Target Evaluation

To complete the essential target evaluation jet parameters, volumetric area of affected compartments, plant layout, and separating structures are considered. Parameters that determine the shape of the jet and the magnitude of the jet and thrust loads include pressure, temperature, and friction losses between the break and the reservoir. The volumetric area affected is determined by considering jet shape and loads at the postulated location of the breaks. Where an initial evaluation of essential targets indicated adverse effects, layout may be changed to relocate the target or

postulated break. If necessary, the location of whip restraints and jet shields is established to protect essential systems and components. Essential equipment protected by pipe whip restraints or jet shields is listed in Table 3.6-3. The criteria for the break location postulated for evaluation of separating structures is outlined in Subsection 3.6.1.3.2.

Verification of the Pipe Break Hazard Analysis

A pipe rupture hazard analysis is prepared based on the as-designed piping stress analyses and pipe whip restraint design information. The as-designed piping analysis is based on piping routings, layouts, and isometrics. Intermediate break locations are identified using the as-designed piping stress analysis, including the fatigue analysis required for ASME Code Class 1 piping. As-designed piping stress analysis information is used to confirm the location and configuration of pipe whip restraints and jet impingement shields. The information included in Tables 3.6-2 and 3.6-3 is updated and validated as part of the as-designed pipe rupture hazard analysis. Large leakage cracks in moderate energy pipes are evaluated for adverse effects as part of the pipe break hazard evaluation.

The ASME Code, Section III, requires that each plant have a Design Report for the piping system that includes as-built information. Included in the Design Reports are the loads and loading combinations used in the analysis. Where mechanistic pipe break requirements are used to eliminate the evaluation of dynamic effects of pipe rupture in ASME Code, Section III, Class 1, 2, and 3 piping system, the basis for the exclusion is documented in the Design Report.

The final piping stress analyses, pipe whip restraint design, and as-built reconciliation of the pipe break hazard analysis is discussed in Subsection 3.6.4.1. The final piping stress analysis includes design properties and characteristics of procured components selected to be included in the piping system that are not available for the as-designed evaluation. The as-built reconciliation is required prior to fuel loading and includes evaluation of the ASME Code fatigue analysis, pipe break dynamic loads, reconciliation to the certified design floor response spectra, confirmation of the reactor coolant loop time history seismic analyses, changes in support locations, preoperational testing, and construction deviations.

3.6.2.6 Evaluation of Flooding Effects from Pipe Failures

The effect of flooding due to high and moderate energy pipe failures on essential systems and components is described in Section 3.4.

3.6.2.7 Evaluation of Spray Effects from High- and Moderate-Energy Through-Wall Cracks

Essential systems and components are evaluated for the potential effects of spray from high- and moderate-energy through-wall cracks. Spray effects are assumed to be limited to the compartment where the pipe failure occurs. The spray is assumed to wet unprotected components in the compartment. It is further assumed the spray does not damage non-electrical passive components, including piping, ducts, valve bodies, or mechanical components of valve operators. Spray may cause failure of electrical components not designed to withstand wetting. Components protected by NEMA 4 or NEMA 12 enclosures are not affected by spray effects.

The safe shutdown components inside containment are subject to wetting from design basis events inside containment. These conditions bound the effects of spray from moderate energy cracks. Sensitive components are qualified for this environment as described in Section 3.11.

The doors to the auxiliary Class 1E battery rooms are normally closed, so spray cannot affect the batteries if fire fighting activities or a pipe crack were to occur in the corridor. If fire fighting activities were to occur in a particular room, all of the equipment is assumed inoperable due to the fire, therefore, no further spray effects need be considered. The containment isolation valves subject to

spray and the safe shutdown components in the main steam tunnels are evaluated for the consequence of spray; and, if essential functions are compromised, are provided with spray protection. The sensitive components of the main control room emergency habitability system are protected from spray effects.

3.6.3 Leak-before-Break Evaluation Procedures

This subsection describes the design basis for mechanistic pipe break (leak-before-break) evaluation of high-energy piping systems.

Mechanistic pipe break evaluations demonstrate that for piping lines meeting the criteria, sudden catastrophic failure of the pipe is not credible. It is demonstrated that piping that satisfies the criteria leaks at a detectable rate from postulated flaws prior to growth of the flaw to a size that would fail because of applied loads resulting from normal conditions, anticipated transients, and a postulated safe shutdown earthquake.

The use of mechanistic pipe break criteria represents a higher level of confidence of the integrity of piping systems based on additional criteria compared to the existing high level of integrity provided by the requirements of the ASME Code. Evaluations of the mechanistic pipe break criteria are commonly called leak-before-break evaluations.

The use of mechanistic pipe break criteria permits the elimination of the evaluation of dynamic effects of sudden circumferential and longitudinal pipe breaks in the design basis analysis of structures, systems, and components. General Design Criterion 4 of Appendix A, 10 CFR Part 50 allows the use of analyses to eliminate from the design basis the dynamic effects of pipe ruptures.

Without the application of mechanistic pipe break criteria, the dynamic effects are evaluated for pipe ruptures postulated at locations defined in Subsection 3.6.2. Dynamic effects include jet impingement, pipe whip, jet reaction forces on other portions of the piping and components, subcompartment pressurization including reactor cavity asymmetric pressurization transients, pump overspeed and traveling pressure waves from the depressurization of the system.

Incorporating leak-before-break criteria and guidelines into the design process maximizes the benefits of applying mechanistic pipe break. Eliminating the dynamic effects permits minimizing the size and number of protective structures and eliminates the use of pipe whip restraints. This permits design optimization and avoids obstruction of pipe welds for in-service inspection by protective structures and restraints.

High-energy ASME Code Section III piping that is evaluated to the leak-before-break criteria is identified in Appendix 3E. This applies to the main steam piping as follows. The main steam piping from the steam generator outlet nozzle to the anchor downstream of the isolation valve is analyzed for applicable loadings including the safe shutdown earthquake. This anchor is at the exterior wall of the auxiliary building. The portion of this piping from the containment penetration flued head inboard weld to the above anchor satisfies the break exclusion zone requirements described in Subsection 3.6.2. The portion of this piping from the steam generator outlet nozzle to flued head inboard weld, including the welds, is evaluated to the leak-before-break criteria. The portion of the auxiliary building flued head (anchor in the wall) that has the same nominal dimensions as the main steam pipe is also classified as a break exclusion zone. High-energy piping that does not satisfy the leak-before-break criteria is designed to the requirements discussed in Subsections 3.6.1 and 3.6.2.

The piping to which mechanistic pipe break is applied is analyzed to demonstrate that the piping has leak-before-break characteristics. The leak-before-break analysis is either a fracture-mechanics based stability analysis or a plastic-instability limit load analysis as appropriate. The analysis combines normal and abnormal (including seismic) loads to determine a critical crack size for a

postulated through-wall crack. The critical crack size is compared to the size of a leakage crack for which, with appropriate margin, detection is certain. When the critical crack size is sufficiently larger than the leakage crack size the leak-before-break requirements are satisfied.

Mechanistic pipe break is not used for purposes of specifying non-structural design criteria for emergency core cooling, containment systems, or other non-structural engineered safety features, or for the evaluation of environmental effects including spray wetting, humidity, temperature, pressure, radiation, and adverse reactions with chemicals in the coolant. This includes piping for which leak-before-break is demonstrated.

A bounding analysis is performed for each piping system. The bounding analysis is applied as discussed in Subsection 3.6.4.2 to verify that the as-built piping satisfies the requirements for leak-before-break.

3.6.3.1 Application of Mechanistic Pipe Break Criteria

Piping systems to which mechanistic pipe break are applied are high integrity systems with well understood loading combinations and conditions. The piping systems to which it is applied satisfy the requirements of the ASME Code, Section III. ASME Code requirements also apply to the pre-service and in-service inspection which confirm continued integrity.

The mechanistic pipe break approach is applicable to high-energy piping provided plant design, operating experience, tests, or analyses have indicated low probability of failure from effects of intergranular stress corrosion cracking, water hammer, steam hammer, fatigue (thermal or mechanical), or erosion.

The plant design and operating features permit the application of the mechanistic pipe break approach. The piping to which the leak-before-break criteria is applied is evaluated for fatigue due to cyclic loads as required by the appropriate requirements of the ASME Code.

The piping in the AP1000 does not operate at temperatures for which creep or creep fatigue must be considered.

The reactor coolant loop piping, branch lines, and other lines in contact with reactor coolant are fabricated of austenitic stainless steel, which is very resistant to erosion and corrosion in typical reactor coolant chemistries and flowrates. Intergranular stress corrosion cracking has not been associated with reactor coolant piping in pressurized water reactors.

The design of the reactor coolant loop is not conducive to the generation of water hammer loads. The reactor coolant loop does not have any valves that could result in a water hammer due to rapid valve closure. The steam bubble in the pressurizer is not subject to the introduction of a large volume of cold water sufficient to result in a bubble collapse water hammer.

The design and component selection of reactor coolant branch lines and other lines evaluated for mechanistic pipe break follow design guidelines intended to minimize the potential for water hammer. Comparison of the AP1000 piping to the screening criteria in Subsection 5.29 of NUREG/CR-6519 (Reference 13) demonstrates that there is not a significant potential for water hammer in the leak-before-break piping.

Thermal stratification of water in stagnant or slowly flowing lines can result in thermal fatigue in a pipe. The piping and system design requirements for AP1000 address the potential for thermal stratification. For additional information of thermal stratification, see Subsections 3.9.3, 5.4.3, and 5.4.5.

The composition of the main steam lines has been selected to minimize the potential for erosion and corrosion. The main steam lines are fabricated from SA335 Grade P11 Alloy steel, which is composed of sufficient levels of chromium to preclude erosion and corrosion mechanisms. The main steam lines are not subject to water hammer or thermal stratification by the nature of the fluid transported.

The steam line is protected from being filled with water due to steam generator overfill by implementation of operating instructions or isolation requirements included in the protection system logic or both. See Section 7.3 for information on the protection system design to prevent overfill.

In addition to requirements on the design, fabrication, and inspection of the piping systems, the application of mechanistic pipe break requires a qualified leak detection capability. Leak detection systems inside containment meet the guidelines of Regulatory Guide 1.45. See Subsection 5.2.5 for a discussion of the leak detection system for the reactor coolant system and connected piping.

3.6.3.2 Design Criteria for Leak-before-Break

The methods and criteria to evaluate leak-before-break in the AP1000 are consistent with the guidance in NUREG-1061 (Reference 11) and Draft Standard Review Plan 3.6.3 (Reference 12) The application of the mechanistic pipe break in AP1000 requires that the following design requirements are met.

- Pre-service inspection of welds is required.

- For ASME Code Class 1, Class 2, and Class 3 systems for which leak-before break is demonstrated, the ASME Code, Section III and Section XI preservice and inservice inspection requirements will provide for the integrity of each system. The weld and welder qualification, and weld inspection requirements for ASME Code, Section III, Class 3 leak-before-break lines are equivalent to the requirements for Class 2. The inservice inspection requirement for each Class 3 leak-before-break line includes a volumetric inspection equivalent to the requirements for Class 2 for the weld at or closest to the high stress location.

- Inservice inspection and testing of snubbers (if used) are performed to provide for a low snubber failure rate.

- For the maximum stress due to steady-state vibration refer to Subsection 3.9.2.

- The leak-before-break bounding analysis curves are developed for each applicable piping system. The bounding analysis methods are described in Appendix 3B. These curves give the design guidance to satisfy the stress limits and leak-before-break acceptance criteria. The highest stressed point (critical location) determined from the piping stress analysis is compared to the bounding analysis curve and has to fall on or under the curve. The points on or under the bounding analysis curve satisfy the requirements for leak-before-break.

  The analyzed normal stress and maximum stress are not required to construct the bounding analysis curve. The analyzed stresses are calculated by the equation;

$$\sigma = \frac{F_x}{A} + \frac{M}{Z}$$

where:

σ is the stress

F_x is the axial force

M is the applied moment

A is the piping cross-sectional area

Z is the piping section modulus.

The normal stress is calculated by the algebraic summation of load combination method and the maximum stress is calculated by the absolute summation of load combination method.

- The corrosion-resistant piping materials, including base metal and welds, have an appropriate toughness. The piping materials containing primary coolant are wrought stainless steel. The welds in stainless steel pipe are made using the gas tungsten arc (GTAW) process. These materials are very resistant to crack extension. The tensile properties for the leak-before-break evaluation are those found in the Section II Appendices of the ASME Code. During the design stage, the material properties used are based on the ASME Code minimum values. During the as-built reconciliation stage, certified material test report values are reviewed to verify that ASME Code requirements are satisfied.

- For those lines fabricated using non-stainless ferritic materials, the materials used and the associated welds have adequate toughness to demonstrate that leak-before-break criteria are satisfied. The welds are made using the gas tungsten arc (GTAW) process. The tensile properties for the leak-before-break evaluation are obtained from actual material tests. During the design stage, the material properties are based on test results. During the as-built reconciliation stage, certified material test report values are reviewed to verify that the toughness and strength requirements of the ASME Code, Section III are satisfied.

- Potential degradation by erosion, erosion/corrosion and erosion cavitation is examined to provide low probability of pipe failure.

- Wall thicknesses in elbows and other fittings are evaluated to confirm that ASME Code, Section III piping requirements are met as a minimum.

- The as-built condition of the piping and support system is evaluated based on the guidelines in EPRI NP-5630 (Reference 10) and reconciled to the analysis of the leak-before-break criteria based on the design information. The locations and characteristics of the supports, including any gaps between the supports and piping, or other configurations that result in a nonlinear response are included in the as-built evaluation.

- Adjacent structures and components are designed for the safe shutdown earthquake event to provide low probability of indirect pipe failure.

- The piping supports are anchored to reinforced concrete structures, to concrete-filled steel plate structures, or to steel structures anchored to these types of structures. Piping is not supported by masonry block walls.

3.6.3.3 Analysis Methods and Criteria

The methods used to develop the bounding analysis curves are described in Appendix 3B. Development of the bounding analysis curves provides an evaluation method that is consistent with NRC requirements and guidance. The calculation method and computer codes used for AP1000 are benchmarked to test data and have been previously accepted by the NRC for leak-before-break evaluations in operating nuclear power plants.

Analyzable sections run from one terminal end or anchor to another terminal end or anchor. A terminal end is typically a connection to a larger pipe or a component. For the structural analysis, a normally closed valve between pressurized and unpressurized portions of a line is not considered a terminal end. Figure 3.6-3 is a schematic of a portion of a piping system that illustrates the meaning of analyzable segments. In the figure the analyzable portion of the pipe runs from point A to point D.

The leak-before-break evaluation is based on a fracture mechanics stability analysis comparing the selected leakage crack to the critical crack size. The following discussion outlines the analysis method.

The development of leak-before-break bounding analysis curves assume that circumferentially oriented postulated cracks are limiting. Stability is established by analyzing through-wall flaws.

Leakage Flaw

Through-wall flaws in candidate leak-before break piping systems are postulated. [*The size of the postulated flaws are large enough so that the leakage is detectable with adequate margin, using 10 times the minimum installed leak detection capability when the pipes are subjected to normal operational loads combining by algebraic sum method.*]* That is, the size of the leakage flaw postulated would be expected to have a leak rate 10 times the size of the rated leak rate detection capability.

As noted in Subsection 5.2.5, the rated capability of the leak detection systems for the primary coolant inside containment is 0.5 gpm. The methods used to detect leakage are described in Subsection 5.2.5.3. The methods used for primary coolant are the containment sump level, inventory balance, and containment atmosphere radiation. The method used to detect leakage from the main steam line inside containment is the containment sump level. Containment water level sensors provide a diverse backup for main steam line leakage by detecting a 0.5 gpm leak within 17 days. Containment air cooler condensate flow, and containment atmosphere pressure, temperature, and humidity also provide an indication of possible leakage.

Stability and Critical Flaw Sizes

The local and global failure mechanisms are evaluated, as appropriate, to provide margin on flaw size and load. The local mode of failure addresses crack tip behavior: blunting, initiation, extension, and instability. The local failure mechanism is evaluated for ferritic steel piping systems using the J-integral method. The global mode of failure addresses the behavior of the net section: initial yielding, strain hardening, and plastic hinge formation. The global failure mechanism (limit load method) is evaluated for stainless steel piping with no cast material and GTAW welding. From these evaluations a critical crack size is determined. That is, a crack larger than the critical crack size would have unstable growth characteristics.

Acceptance Standards

[*The results of the preceding evaluations are compared to show that the critical flaw size, which is shown to be stable when the maximum loads are combined based on individual absolute values, is at least twice the size (to satisfy margin of 2 on flaw size) of the leakage flaw size. To satisfy a margin*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

on load of 1.0, the maximum loads are combined using absolute summation of individual values.]* The maximum loads are described in Appendix 3B Subsection 3B.3.3.

Bounding Analyses

Evaluations are provided for each different combination of material type, pipe size, pressure, and temperature. These evaluations are used to develop a set of curves of maximum faulted stress versus the corresponding normal stress that satisfy the criteria for leak-before-break. These curves are used in the design of the piping systems and will be used to verify that the as-built piping satisfies the requirements for leak-before-break as discussed in Subsection 3.6.4.2.

3.6.3.4 Documentation of Leak-before-Break Evaluations

The leak-before-break evaluation is used to support the elimination of dynamic effects of pipe breaks from the loading conditions for the piping analysis. An evaluation of leak-before-break using the as-built configuration of the piping system and supports is required as part of the Design Report (also referred to as LBB evaluation report where applicable) of the as-built configuration required to meet ASME Code requirements and LBB criteria. Appendix 3B contains a discussion of the bounding analysis methods for the leak-before-break evaluation.

The analysis methods, criteria, and loads used for evaluation of stress in piping systems are outlined in Subsections 3.7.3 and 3.9.3.

3.6.4 Combined License Information

3.6.4.1 Pipe Break Hazard Analysis

The as-built reconciliation of the pipe break hazards analysis and as-built pipe rupture hazard analysis are addressed in APP-GW-GLR-021 (Reference 14), and the applicable changes are incorporated into the UFSAR.

The as-designed pipe rupture hazards evaluation is made available for NRC review. The completed as-designed pipe rupture hazards evaluation will be in accordance with the criteria outlined in Subsections 3.6.1.3.2 and 3.6.2.5. Systems, structures, and components identified to be essential targets protected by associated mitigation features (Reference is Table 3.6-3) will be confirmed as part of the evaluation, and updated information will be provided as appropriate.

A pipe rupture hazard analysis is part of the piping design. The evaluation will be performed for high and moderate energy piping to confirm the protection of systems, structures, and components which are required to be functional during and following a design basis event. The locations of the postulated ruptures and essential targets will be established and required pipe whip restraints and jet shield designs will be included. The report will address environmental and flooding effects of cracks in high and moderate energy piping. The as-designed pipe rupture hazards evaluation is prepared on a generic basis to address COL applications referencing the AP1000 design.

The pipe whip restraint and jet shield design includes the properties and characteristics of procured components connected to the piping, components, and walls at identified break and target locations. The design will be completed prior to installation of the piping and connected components.

The as-built reconciliation of the pipe rupture hazards evaluation whip restraint and jet shield design in accordance with the criteria outlined in Subsections 3.6.1.3.2 and 3.6.2.5 will be completed prior to fuel load (in accordance with DCD Tier 1 Table 3.3-6, item 8).

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

This COL item is also addressed in Subsection 14.3.3.

3.6.4.2 Leak-before-Break Evaluation of As-Designed Piping

The leak-before-break evaluation of the as-designed piping is addressed in APP-GW-GLR-022 (Reference 15), and the applicable changes are incorporated into the UFSAR.

3.6.4.3 Leak-before-Break Evaluation of As-Built Piping

Not used.

3.6.4.4 Primary System Inspection Program for Leak-before-Break Piping

Alloy 690 is not used in leak-before-break piping. No additional or augmented inspections are required beyond the inservice inspection program for leak-before-break piping. An as-built verification of the leak-before-break piping is required to verify that no change was introduced that would invalidate the conclusion reached in this subsection.

3.6.5 References

1. NUREG/CR-2913, “Two-Phase Jet Loads,” January 1983.

2. WCAP-8077 (Proprietary) and WCAP-8078 (Nonproprietary), “Ice Condenser Containment Pressure Transient Analysis Methods,” March 1973.

3. ASME B31.1 1989 Edition, “Power Piping,” including 1989 Addendum.

4. ANSI/ANS-58.2-1988, “Design Bases for Protection of Light Water Nuclear Power Plants Against Effects of Postulated Pipe Rupture.”

5. Moody, F. J., Fluid Reaction and Impingement Loads, paper presented at the ASCE Specialty Conference, Chicago, December 1973.

6. “MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics,” WCAP-8708 (Proprietary) and WCAP-8709 (Nonproprietary), February 1976.

7. WCAP-8252, “Documentation of Selected Westinghouse Structural Analysis Computer Codes,” Revision 1, May 1977.

8. Not used.

9. Biggs, J. M., Introduction to Structural Dynamics, McGraw-Hill Book Company, New York, 1964.

10. EPRI NP-5630, “Guidelines for Piping System Reconciliation” (NCIG-05, Revision 1), May 1988.

11. NUREG-1061, Volume 3, Report of the U. S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks, November 1984.

12. Standard Review Plan 3.6.3, “Leak Before Break Evaluation Procedures,” Federal Register, Volume 52, Number 167, Friday, August 28, 1987; Notice (Public Comment Solicited), pp. 32626-32633.

13. NUREG/CR-6519, Screening Reactor Steam/Water Systems for Water Hammer, November 1996.

14. APP-GW-GLR-021, “AP1000 As-Built COL Information Items,” Westinghouse Electric Company LLC.

15. APP-GW-GLR-022, “AP1000 Leak-Before-Break Evaluation of As-Designed Piping,” Westinghouse Electric Company LLC.

16. Information Systems Laboratories (2006), “RELAP5/MOD3.3 (Patch03) Code Manual Volume I to VIII, NUREG/CR-5535/Rev P3-Vol I to VIII,” prepared for U.S. Nuclear Regulatory Commission.

17. ASTM A530/A530M - 99, “Standard Specification for General Requirements for Specialized Carbon and Alloy Steel Pipe.”

Table 3.6-1
High-Energy and Moderate-Energy Fluid Systems Considered for Protection of Essential Systems[a]

System	High-Energy	Moderate-Energy
Reactor coolant (RCS)	•	
Steam generator (SGS)[b]	•	
Passive core cooling (PXS)	•	
Passive containment cooling (PCS)[c]		•
Main control room habitability (VES)	•	
Chemical and volume control (CVS)	•	
Primary sampling (PSS)	•	
Compressed and instrument air (CAS)	•	
Normal residual heat removal (RNS)[a]		•
Component cooling water (CCS)		•
Spent fuel pool cooling (SFS)		•
Demineralized water (DWS)		•
Liquid radwaste (WLS)		•
Radioactive drain (WRS)		•
Central chilled water (VWS)		•
Fire protection (FPS)		•
Steam generator blowdown (BDS)[d]	•	
Main and startup feedwater (FWS)[d]	•	
Main steam (MSS)[d]	•	
Hot water heating (VYS)		•

Notes:

a. Systems included on this list are high-energy or moderate-energy fluid systems located in the containment or the auxiliary building. Systems that operate at or close to atmospheric pressure such as ventilation and gravity drains are not included. The normal residual heat removal system lines are classified as moderate-energy based on the 1 percent rule. These lines experience high-energy conditions for less than 1 percent of the plant operating time. The portions of the normal residual heat removal system from the connections to the reactor coolant system and passive core cooling system to the first closed valve in each line are high energy. The spent fuel pool cooling system is classified as moderate energy based on the 2 percent rule. These systems experience high-energy conditions for less than 2 percent of the system operating time. See Subsection 3.6.1.1 Item A and Subsection 3.6.1.2 for additional information.

b. Main and startup feedwater, main steam, and steam generator blowdown lines located in the containment and auxiliary building are part of the steam generator system.

c. The essential portion of the system is at atmospheric pressure.

d. The portion of these systems in the turbine building adjacent to the auxiliary building are evaluated for the effect of a circumferential or longitudinal break on the main control room.

Table 3.6-2 (Sheet 1 of 7)
Subcompartments and Postulated Pipe Ruptures

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	Room Number	Description	Terminal End Break Location Excluded by LBB	Description	Break Location
Steam Generator Compart-ment 1	11201	22 in. Cold Leg (RCS)	RC Pump Nozzles (2)	4 in. Pressurizer Spray (RCS)	Cold Leg Nozzles (2)
		18 in. Fourth Stage ADS (RCS)	Hot Leg Nozzle	3 in. RC Pump External Piping to/from Motor Bearing HX	RC Pump Cooling Nozzles: A/B (4)
				3 in. RC Pump External Piping to/from Motor Bearing HX	Motor Bearing Water Cooling HX Nozzles: A/B (4)
				3 in. RC Pump External Piping to/ from Motor Bearing HX	Intermediate breaks along elbow fittings: pumps A/B (8)
	11301	31 in. Hot Leg (RCS)	SG Nozzle	3 in. Purification (CVS)	3 in. SG Channel Head Nozzle
		18 in. Surge Line (RCS)	Hot Leg Nozzle		
		18 in. & 14 in. Fourth Stage ADS (RCS)	Valves: V004A/C		
		14 in. PRHR Return (RCS)	SG Channel Head Nozzle		
	11401	None		4 in. SG Blowdown (SGS)	4 in. SG Nozzle
	11501	None		None	
	11601			16 in and 20 in. Feedwater (SGS) 6 in. Startup Feedwater (SGS)	SG Nozzle SG Nozzle
	11701	38 in. Main Steam (SGS)	SG Nozzle	None	

Table 3.6-2 (Sheet 2 of 7)
Subcompartments and Postulated Pipe Ruptures

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	Room Number	Description	Terminal End Break Location Excluded by LBB	Description	Break Location
Steam Generator Compart-ment 2	11202	22 in. Cold Leg (RCS)	RC Pump Nozzles (2)	3 in. RC Pump External Piping to/from Motor Bearing HX	RC Pump Cooling Nozzles: A/B (4)
		18 in. Fourth Stage ADS (RCS)	Hot Leg Nozzle	3 in. RC Pump External Piping to/from Motor Bearing HX	Motor Bearing Water Cooling HX Nozzles: A/B (4)
		20 in. Normal RHR (RCS)	Hot Leg Nozzle	3 in. RC Pump External Piping to/from Motor Bearing HX	Intermediate breaks along elbow fittings: pumps A/B (8)
		12 in. Normal RHR (RCS)	20 in. x 12 in. Reducer (This is not a terminal end)		
	11302	31 in. Hot Leg (RCS)	SG Nozzle	None	
		18 in. & 14 in. Fourth Stage ADS (RCS)	Valves: V004B/D		
		8 in. Cold Leg to CMT (RCS)	Cold Leg Nozzles (2)		
	11402	None		4 in. SG Blowdown (SGS)	4 in. SG Nozzle
	11502	None		None	
	11602			16 in. and 20 in. Feedwater (SGS) 6 in. Startup Feedwater (SGS)	SG Nozzle SG Nozzle

Table 3.6-2 (Sheet 3 of 7)
Subcompartments and Postulated Pipe Ruptures

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	Room Number	Description	Terminal End Break Location Excluded by LBB	Description	Break Location
	11702	38 in. Main Steam (SGS)	SG Nozzle	None	
Reactor Vessel Nozzle Area	11205	31 in. Hot Leg (RCS)	Reactor Vessel Nozzles (2)	None	
		22 in. Cold Leg (RCS)	Reactor Vessel Nozzles (4)		
		8 in. Direct Vessel Injection (RCS)	Reactor Vessel Nozzles (2)		
PXS Valve and Accumulator Room A	11206	8 in. Accumulator Injection (PXS)	Accumulator Nozzle	None	
		8 in. CMT Injection (PXS)	CMT Nozzle		
		6 in. Line from Normal RHR (RNS)	Valve: V017A		
		8 in. Line from IRWST (PXS)	Valves: V125A & V123A		
PXS Valve Room B	11207 PXS	6 in. Line from Normal RHR (RNS)	Valve: V017B	None	
		8 in. Line from IRWST (PXS)	Valves: V125B & V123B		
Accumulator Room B	11207 ACCUM	8 in. Accumulator Injection (PXS)	Accumulator Nozzle	None	
		8 in. CMT Injection (PXS)	CMT Nozzle		
RNS Valve Room	11208	10 in. Normal RHR (RNS)	Valves: V001A/B	None	

Table 3.6-2 (Sheet 4 of 7)
Subcompartments and Postulated Pipe Ruptures

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	Room Number	Description	Terminal End Break Location Excluded by LBB	Description	Break Location
Vertical Access	11204	None		3 in. Line from Regen HX to SG 01 (CVS)	Anchor to Wall
				3 in. Purification from Cold Leg to Regen HX (CVS)	Anchor to Wall
Lower Pressurizer Compartment	11303	18 in. Surge Line (RCS)	Pressurizer Nozzle	None	
Upper Pressurizer Compartment	11503	14 in. ADS (RCS)	Pressurizer Nozzle (2)	4 in. Pressurizer Spray (RCS)	Pressurizer Nozzle
Lower ADS Valve Area	11603	14 in. & 8 in. ADS (RCS) 6 in. Pressurizer Safety (RCS)	Valves: V012B & V013B Valves: V005A and V005B 14 in. x 6 in. Tees (2)	4 in. ADS (RCS)	Valve V0011B & 14 in. x 4 in. Branch
Upper ADS Valve Area	11703	14 in. & 8 in., ADS (RCS)	Valves: V012A & V013A	4 in. ADS (RCS)	Valve V0011A & 14 in. x 4 in. Branch
Maintenance Floor/ Mezzanine	11400	38 in. Main Steam (SGS)	Non-terminal End Location (2) at Boundary of Break Exclusion Zone	6 in. Startup Feedwater (SGS)	Anchors (2) at Containment Penetration
		14 in. Passive RHR (PXS)	PRHR HX Inlet Nozzle		
		8 in. CMT Balance Line Piping	CMT Nozzles (2)		

Table 3.6-2 (Sheet 5 of 7)
Subcompartments and Postulated Pipe Ruptures

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	Room Number	Description	Terminal End Break Location Excluded by LBB	Description	Break Location
SG01 Access Room	11304	None		3 in. CVS Return from Regen HX	Intermediate breaks along pipe fittings: valve transition (3), weldolet (1)
Pressurizer Spray Valve Room	11403	None		4 in. Pressurizer Spray to 2 in. Auxiliary Spray	Intermediate breaks along pipe fitting: 4"x2" reducing tee (9)
Maintenance Floor	11300	14 in. Passive RHR (PXS)	PRHR HX Outlet Nozzle	1.5 in. PRHR Return flow instrument branch line (PXS)	Sockolet for flow element
Operating Deck	11500	None		None	
CVS Room	11209	None		3 in. Purification from Pressurizer Spray to Regen HX (CVS)	Regen HX Nozzle
				3 in. Return, Auxiliary Spray (CVS)	Regen HX Nozzle
				3 in. Return to RNS from Regen HX (CVS)	Valve: V079
				3 in. Supply from RNS to Letdown HX (CVS)	Valve: V072
				3 in. Supply from Regen HX to Letdown HX (CVS)	Nozzles: Regen HX, Letdown HX
CVS Room	11209 Pipe Chase	None		3 in. Purification from Anchor to Regen HX	Anchor
				3 in. Return from Regen HX to Anchor (CVS)	Anchor
				4 in. SG Blowdown (SGS)	Anchors (2) at Containment Penetration

Table 3.6-2 (Sheet 6 of 7)
Subcompartments and Postulated Pipe Ruptures

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	Room Number	Description	Terminal End Break Location Excluded by LBB	Description	Break Location
Reactor Coolant Drain Tank Room	11104	None		None	
Reactor Vessel Cavity	11105	None		None	
MSIV Compartment B (Upper/Lower)	12504/ 12404	None		Main Steam Main Feedwater Startup Feedwater Lines[a]	Longitudinal Cracks with Crack Flow Areas of 1 Square Foot are Postulated
MSIV Compartment A (Upper/Lower)	12506/ 12406	None		Main Steam Main Feedwater Startup Feedwater Lines[a]	Longitudinal Cracks with Crack Flow Areas of 1 Square Foot are Postulated
Valve/Piping Penetration Room	12306	None		4 in. Steam Generator Blowdown[a]	Anchors (2) at Containment Penetrations Anchors (2) at Wall to Turbine Building

Note:

a. The piping in these areas is included in break exclusion zones. For additional information on the evaluation of these lines, see Subsection 3.6.1.2.1 for the steam generator blowdown line; Subsection 3.6.1.2.2 for information on the evaluation of lines in MSIV compartment B because of the proximity to the main control room; and Subsection 3.6.2.1.1.4 for general break exclusion zone requirements.

Table 3.6-2 (Sheet 7 of 7)
Subcompartments and Postulated Pipe Ruptures

Room #	Description	Bottom Elevation	Top Elevation
11104	RCDT Room	66′-6″	81′-0″
11105	Reactor Vessel Cavity	66′-6″	98′
11205	Reactor Vessel Nozzle Area	98′	107′-2″
11201	SG Compartment 1	83′	104′-7″
11202	SG Compartment 2	83′	104′-7″
11204	Vertical Access	83′	107′-2″
11206	PXS Valve and Accumulator Room A	87′-6″	105′-2″
11300	Maintenance Floor	107′-2″	118′-6″
11301	SG Compartment 1	104′-7″	116′-6″
11302	SG Compartment 2	104′-7″	116′-6″
11400	Maintenance Floor/Mezzanine	118′-6″	133′-3″
11401	SG Compartment 1	116′-6″	135′-3″
11402	SG Compartment 2	116′-6″	135′-3″
11501	SG Compartment 1	135′-3″	153′-0″
11502	SG Compartment 2	135′-3″	153′-0″
11601	SG Compartment 1	153′-0″	166′-4″
11602	SG Compartment 2	153′-0″	166′-6″
11701	SG Compartment 1	166′-4″	----
11702	SG Compartment 2	166′-4″	----
11500	Operating Deck	135′-3″	281′-8 3/8″
11303	Lower Pressurizer Compartment	107′-2″	135′-3″
11304	SG01 Access Room	107′-2″	118′-6″
11403	Pressurizer Spray Valve Room	118′-6″	133′-3″
11503	Upper Pressurizer Compartment	135′-3″	166′-1.5″
11603	Lower ADS Valve Area	166′-1.5″	176′-10.5″
11703	Upper ADS Valve Area	176′-10.5″	----
11207 ACCUM	Accumulator Room B	87′-6″	105′-2″
11207 PXS	PXS Valve Room B	87′-6″	105′-2″
11208	RNS Valve Room	94′	105′-2″
11209	CVS Room	80′-6″	105′-2″
11209 PIPE CHASE	CVS Room Pipe Chase	100′-0″	105′-2″
12306	Valve/Piping Penetration Room	100′-0″	117′-6″
12504/12404	MSIV Compartment B (Upper/Lower)	117′-6″	153′-0″
12506/12406	MSIV Compartment A (Upper/Lower)	117′-6″	153′-0″

Table 3.6-3 (Sheet 1 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11201	Steam Generator Compartment-01	Pipe Whip Restraint RCS-SH-W002 (RCS-002)	Reactor Coolant System (RCS) Pressurizer Spray Line, 4" L110A: Terminal End Break at RCS Cold Leg RCS-PL-L002A/N11A	RCS spray control valve (RCS-V110A) (Room 11403). RCS pressurizer spray bypass valve (RCS-V210A) (Room 11403). RCS spray control valve (RCS-V110B) (Room 11403). RCS pressurizer spray bypass valve (RCS-V210B) (Room 11403).
		Pipe Whip Restraint RCS-SH-W003 (RCS-003)	RCS Pressurizer Spray Line, 4" L106: Terminal End Break at RCS Cold Leg RCS-PL-L002B/N11B	RCS spray control valve (RCS-V110A) (Room 11403). RCS pressurizer spray bypass valve (RCS-V210A) (Room 11403). RCS spray control valve (RCS-V110B) (Room 11403). RCS pressurizer spray bypass valve (RCS-V210B) (Room 11403).
11204	Vertical Access Room	Dual Acting Pipe Support CVS-PH-11R2270 (CVS-004U)	Chemical and Volume Control System (CVS) Letdown Line, 3" L002: Terminal End Break at In-Line Anchor	SGS blowdown piping (L009B). CCS isolation valve (CCS-V201) (Room 11400). CCS isolation valve (CCS-V207) (Room 11400). CCS isolation valve (CCS-V220) (Room 11400). CVS purification stop valve (CVS-V001) (Room 11403). CVS purification stop valve (CVS-V002) (Room 11403). CVS purification stop valve (CVS-V003) (Room 11403).

Table 3.6-3 (Sheet 2 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11204	Vertical Access Room	Dual Acting Pipe Support CVS-PH-11R2271 (CVS-007D)	CVS Purification Return Line, 3" L018: Terminal End Break at In-Line Anchor	CCS isolation valve (CCS-V201) (Room 11400). CCS isolation valve (CCS-V207) (Room 11400). CCS isolation valve (CCS-V220) (Room 11400). CVS regenerative HX shell side outlet check valve (CVS-V080) (Room 11303). CVS purification return line stop check valve (CVS-V081) (Room 11304). CVS purification return line check valve (CVS-V082) (Room 11303). CVS auxiliary pressurizer spray line isolation valve (CVS-V084) (Room 11304). CVS auxiliary pressurizer spray line isolation valve (CVS-V085) (Room 11304).
11209	CVS Room (Pipe Chase)	Pipe Whip Restraint SGS-SH-W004 (SGS-004)	Steam Generator System (SGS) Blowdown Line, 4" L009A: Terminal End Break at Containment Penetration P27	SGS blowdown piping (L009B). CVS isolation valve (CVS-V042) (Room 11209). CVS isolation valve (CVS-V045) (Room 11300). CVS isolation valve (CVS-V058) (Room 11300). CVS isolation valve (CVS-V091) (Room 11300). CVS isolation valve (CVS-V100) (Room 11300). CVS isolation valve (CVS-V217) (Room 11300). WLS isolation valve (WLS-V055) (Room 11300). WLS isolation valve (WLS-V058) (Room 11300). WLS isolation valve (WLS-V067) (Room 11300).

Table 3.6-3 (Sheet 3 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11209 (cont.)	CVS Room (Pipe Chase)	Pipe Whip Restraint SGS-SH-W008 (SGS-008)	SGS Blowdown Line, 4" L009B: Terminal End Break at Containment Penetration P28	CVS isolation valve (CVS-V042) (Room 11209). CVS isolation valve (CVS-V045) (Room 11300). CVS isolation valve (CVS-V058) (Room 11300). CVS isolation valve (CVS-V091) (Room 11300). CVS isolation valve (CVS-V100) (Room 11300). CVS isolation valve (CVS-V217) (Room 11300). WLS isolation valve (WLS-V067) (Room 11300).
		Dual Acting Pipe Supports CVS-PH-11Y2265 CVS-PH-11Y2266 (CVS-056U)	CVS Makeup Line, 3" L056: Terminal End Break at In-Line Anchor	SGS blowdown piping (L009A). SGS blowdown piping (L009B). CVS isolation valve (CVS-V045) (Room 11300). CVS isolation valve (CVS-V058) (Room 11300). CVS isolation valve (CVS-V091) (Room 11300). CVS isolation valve (CVS-V100) (Room 11300). WLS isolation valve (WLS-V055) (Room 11300). WLS isolation valve (WLS-V058) (Room 11300). WLS isolation valve (WLS-V067) (Room 11300).

Table 3.6-3 (Sheet 4 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11209 (cont.)	CVS Room (Pipe Chase)	Pipe Whip Restraint CVS-SH-W004D (CVS-004D)	CVS Letdown Line, 3" L002: Terminal End Break at In-Line Anchor	SGS blowdown piping (L009A). SGS blowdown piping (L009B). CVS isolation valve (CVS-V042) (Room 11209). CVS isolation valve (CVS-V045) (Room 11300). CVS isolation valve (CVS-V058) (Room 11300). CVS isolation valve (CVS-V091) (Room 11300). CVS isolation valve (CVS-V100) (Room 11300). CVS isolation valve (CVS-V217) (Room 11300). WLS isolation valve (WLS-V055) (Room 11300). WLS isolation valve (WLS-V058) (Room 11300). WLS isolation valve (WLS-V067) (Room 11300).
		Pipe Whip Restraint CVS-SH-W007U (CVS-007U)	CVS Purification Return Line, 3" L018: Terminal End Break at In-Line Anchor	SGS blowdown piping (L009A). SGS blowdown piping (L009B). CVS isolation valve (CVS-V042) (Room 11209). CVS isolation valve (CVS-V045) (Room 11300). CVS isolation valve (CVS-V058) (Room 11300). CVS isolation valve (CVS-V091) (Room 11300). CVS isolation valve (CVS-V100) (Room 11300). CVS isolation valve (CVS-V217) (Room 11300). WLS isolation valve (WLS-V055) (Room 11300). WLS isolation valve (WLS-V058) (Room 11300). WLS isolation valve (WLS-V067) (Room 11300).

Table 3.6-3 (Sheet 5 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11301	Steam Generator 1 Lower Manway Area	Pipe Whip Restraint RCS-SH-W001 A/B (RCS-001)	CVS Purification Return Nozzle, 3" RCS L112: Terminal End Break at RCS-MB-01/N05	CVS isolation valve (CVS-V084) (Room 11304). SGS blowdown piping (L009A) (Room 11301). RCS Passive Residual Heat Removal (PRHR) Heat Exchanger (HX) return piping (L113) (Room 11301).
11303	Lower Pressurizer Compartment	Pipe Whip Restraint CVS-SH-W210 (CVS-210-C)	CVS Purification Return Line 3" RCS L112: Intermediate Break at Outlet CVS-V082	Column support for pressurizer (RCS-MV-02) (Room 11303). SG nozzle RCS-MB-01/nozzle N05 (Room 11301). RCS surge line – line RCS-L003 (Room 11303).
		Dual Acting Pipe Support RCS-PH-11Y1132 (RCS-201-C)	RCS Pressurizer Spray Line, 4" L215: Intermediate Break at 4" x 2" Reducing Tee	Lateral support struts for pressurizer (RCS-MV-02) (Room 11303). RCS instrument piping (L225A) (Room 11303). RCS level instrument (LT195A) (Room 11300). RCS pressure transmitter (PT191A) (Room 11300). Pressurizer nozzle – RCS-MV-02/nozzle N02 (Room 11503).
11400	Maintenance Floor Mezzanine	Pipe Whip Restraint SGS-SH-W006 (SGS-006)	SGS Startup Feedwater Line, 6" L005B: Terminal End Break at SGS-PY-C05B, Containment Penetration P45	Steam generator 2 (RCS-MB-02) (Room 11602).
		Pipe Whip Restraint SGS-SH-W002 (SGS-002)	SGS Startup Feedwater Line, 6" L005A: Terminal End Break at SGS-PY-C05A, Containment Penetration P44	Steam generator 1 (RCS-MB-01) (Room 11601). Main steam 1 pressure transmitters – PT030/PT032 (Room 11400). Steam generator 1 (RCS-MB-01) level instrumentation piping – SGS-PL-L039A/SGS-PL-L041A, (Room 11400).

Table 3.6-3 (Sheet 6 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11401	Steam Generator 1 Tube Sheet Area	Pipe Whip Restraint SGS-SH-W003 (SGS-003)	SGS Blowdown Line, 4" L009A: Terminal End Break at RCS-MB-01/N06A	SGS blowdown penetration (SGS-PY-C03A).
11402	Steam Generator 2 Tube Sheet Area	Pipe Whip Restraint SGS-SH-W007 (SGS-007)	SGS Blowdown Line, 4" L009B: Terminal End Break at RCS-MB-02/N06A	SGS blowdown penetration (SGS-PY-C03B). Main steam 2 pressure transmitters – PT034/PT036 (Room 11402). Steam generator 2 (RCS-MB-02) level instrumentation piping – SGS-PL-L039B/SGS-PL-L041B (Room 11402).
11403	Pressurizer Spray Valve Room	Dual Acting Pipe Support RCS-PH-11R0084 (RCS-203-C)	RCS Pressurizer Spray Valve Line, 4" L213: Intermediate Break at 4" x 2" Reducing Tee	RCS spray control valve (RCS-V110A) (Room 11403). RCS pressurizer spray bypass valve (RCS-V210A) (Room 11403). RCS spray control valve (RCS-V110B) (Room 11403). RCS pressurizer spray bypass valve (RCS-V210B) (Room 11403).

Table 3.6-3 (Sheet 7 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11503	Upper Pressurizer Compartment	Pipe Whip Restraint RCS-SH-W006 (RCS-006)	RCS Pressurizer Spray Line, 4" L215: Terminal End Break at RCS-MV-02/N02	ADS Stage 1, 2, and 3 valves (RCS-V001B, RCS-V002B, RCS-V003B, RCS-V011B, RCS-V012B, and RCS-V013B) (Room 11603). ADS Stage 1, 2, and 3 valves (RCS-V001A, RCS-V002A, RCS-V003A, RCS-V011A, RCS-V012A, and RCS-V013A) (Room 11703). Pressurizer safety valves (RCS-V005A, RCS-V005B) (Room 11603). ADS discharge header B vacuum relief valve (RCS-V010B) (Room 11603). ADS discharge header A vacuum relief valve (RCS-V010A) (Room 11703). ADS Stage 1, 2, and 3 support steel (Rooms 11503, 11603, and 11703). RCS spray control valve (RCS-V110A) (Room 11403). RCS pressurizer spray bypass valve (RCS-V210A) (Room 11403). RCS spray control valve (RCS-V110B) (Room 11403). RCS pressurizer spray bypass valve (RCS-V210B) (Room 11403).

Table 3.6-3 (Sheet 8 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11601	Steam Generator 1 Feedwater Nozzle Area (153'-0")	Pipe Whip Restraint SGS-SH-W001 (SGS-001)	SGS Startup Feedwater Line, 6" L005A: Terminal End Break at RCS-MB-01/N20	RCS head vent valve (RCS-V150A) (Room 11601). RCS head vent valve (RCS-V150B) (Room 11601). RCS head vent valve (RCS-V150C) (Room 11601). RCS head vent valve (RCS-V150D) (Room 11601). SGS startup feedwater penetration (SGS-PY-C05A).
		Pipe Whip Restraint SGS-SH-W021 (SGS-021)	SGS Main Feedwater Line, 16" L008A/L003A: Terminal End Break at RCS-MB-01/N04.	SGS main feedwater penetration (SGS-PY-C02A). Break exclusion zone: SGS main feedwater piping (L002A).
11602	Steam Generator 2 Feedwater Nozzle Area (153'-0")	Pipe Whip Restraint SGS-SH-W005 (SGS-005)	SGS Startup Feedwater Line, 6" L005B: Terminal End Break at RCS-MB-02/N20	SGS startup feedwater penetration (SGS-PY-C05B).
		Pipe Whip Restraint SGS-SH-W022 (SGS-022)	SGS Main Feedwater Line, 16" L008B/L003B: Terminal End Break at RCS-MB-02/N04	SGS main feedwater penetration (SGS-PY-C02B). Break exclusion zone: SGS main feedwater piping (L002B).
		Jet Shield SGS-SH-P022 (SGS-022)	SGS Main Feedwater Line, 16" L008B/L003B: Terminal End Break at RCS-MB-02/N04	Main steam line snubber for support APP-SGS-PH-11Y7057 (Room 11602).

Table 3.6-3 (Sheet 9 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
11603	ADS Valve Area – Lower Tier	Pipe Whip Restraint RCS-SH-W108 (RCS-108)	RCS ADS Stage 1 Train B Inlet Line, 4" L010B: Terminal End Break at First Stage ADS Isolation Valve RCS-PL-V011B	ADS stage 1, 2, and 3 valves (RCS-V002B, RCS-V003B, RCS-V012B, and RCS-V013B) (Room 11603). ADS stage 1, 2, and 3 valves (RCS-V001A, RCS-V002A, RCS-V003A, RCS-V011A, RCS-V012A, and RCS-V013A) (Room 11703). ADS discharge header B vacuum relief valve (RCS-V010B) (Room 11603). ADS discharge header A vacuum relief valve (RCS-V010A) (Room 11703). ADS stage 1, 2, and 3 support steel 1102-Q6-01 (Rooms 11503, 11603, and 11703).
11703	Upper ADS Valve Area – 176'-10 1/2"	Pipe Whip Restraint RCS-SH-W106 (RCS-106)	RCS ADS Stage 1 Train A Inlet Line, 4" L010A: Terminal End Break at First Stage ADS Isolation Valve RCS-PL-V011A	ADS stage 1, 2, and 3 valves (RCS-V001B, RCS-V002B, RCS-V003B, RCS-V011B, RCS-V012B, and RCS-V013B) (Room 11603). ADS stage 1, 2, and 3 valves (RCS-V002A, RCS-V003A, RCS-V012A, and RCS-V013A) (Room 11703). ADS discharge header B vacuum relief valve (RCS-V010B) (Room 11603). ADS discharge header A vacuum relief valve (RCS-V010A) (Room 11703). ADS stage 1, 2, and 3 support steel 1102-Q6-01 (Rooms 11503, 11603, and 11703).

Table 3.6-3 (Sheet 10 of 10)
NI Rooms With Pipe Whip Restraints, Dual Acting Pipe Supports, Jet Shields and Corresponding Hazard Sources and Essential Targets

Room Number	Room Description	Protection Mechanism (Break ID)	Hazard Source	Essential Target Description/Room
12258	Degasifier Column Room	Dual Acting Pipe Supports CVS-PH-12R2272 CVS-PH-12R2273 (CVS-061D)	CVS Makeup Pump Discharge Header, 3" L131: Terminal End Break at Anchor CVS-PH-12A0122	Break exclusion zone: CVS makeup piping (L053).
12404	East MSIV Compartment	Pipe Whip Restraint SGS-SH-W033 SGS-SH-W034 SGS-SH-W035	Main Feedwater Line, 20" L002B and L003B: Longitudinal Splits	Floor of Room 12404 (protection of electrical/I&C components in Room 12304 – room below east MSIV compartment).
		Pipe Whip Restraint SGS-SH-W031 SGS-SH-W032	Main Feedwater Line, 20" L002B and L003B: Longitudinal Splits and Guillotine Breaks	Wall 11 (Room 12404) and Wall L (Room 12404 – protection of main control room).

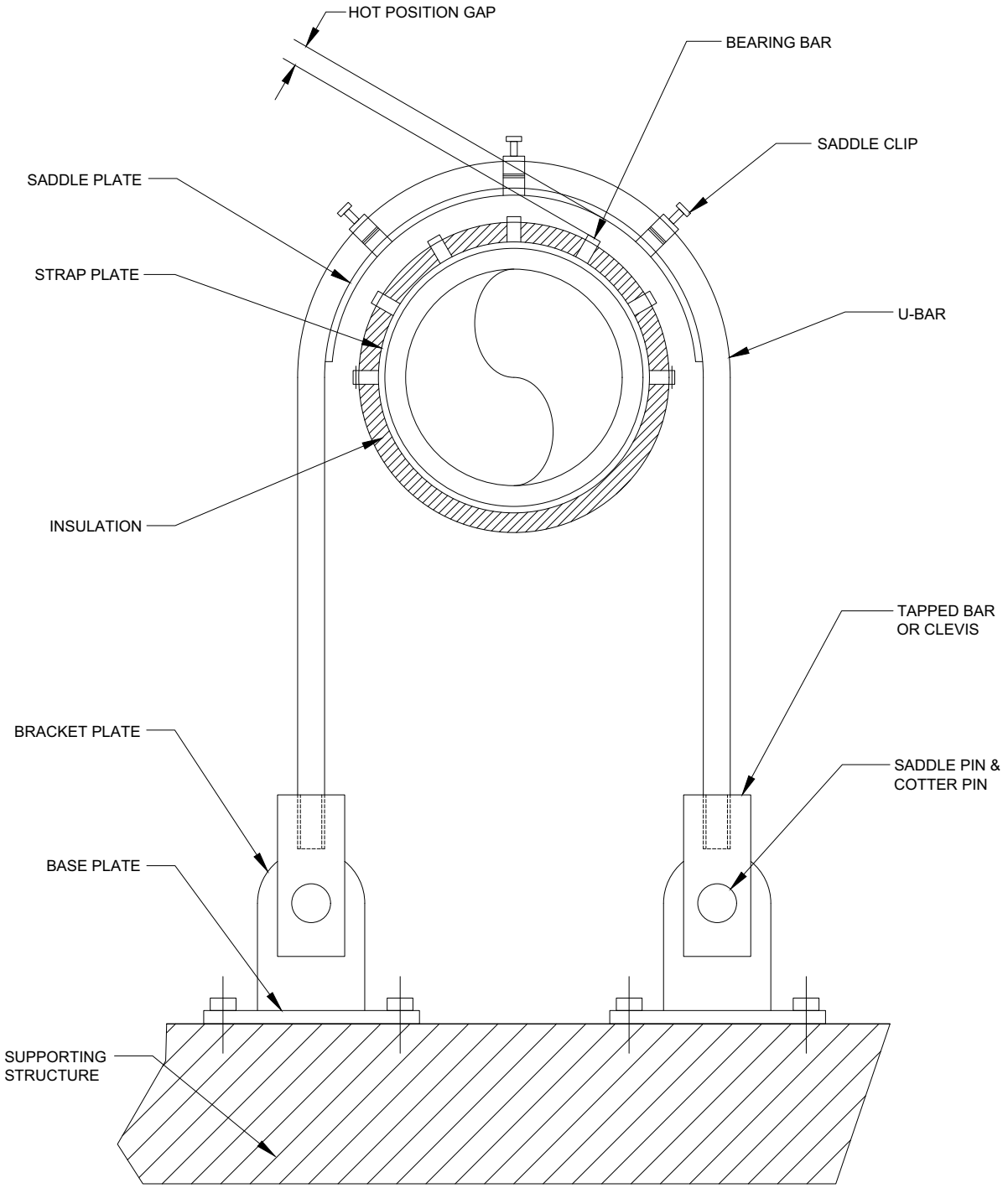


Figure 3.6-1
Typical U-Bar Restraint

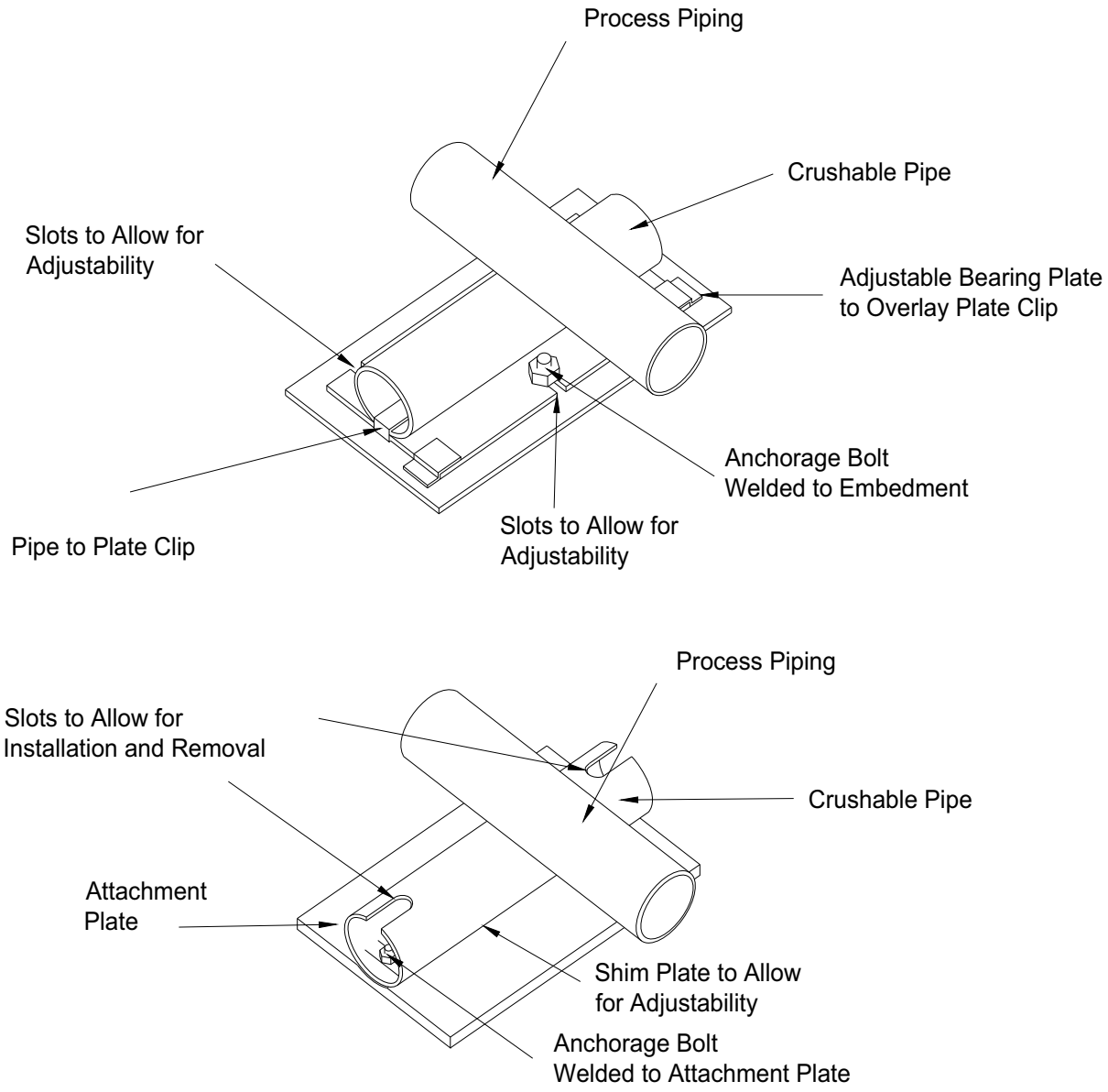
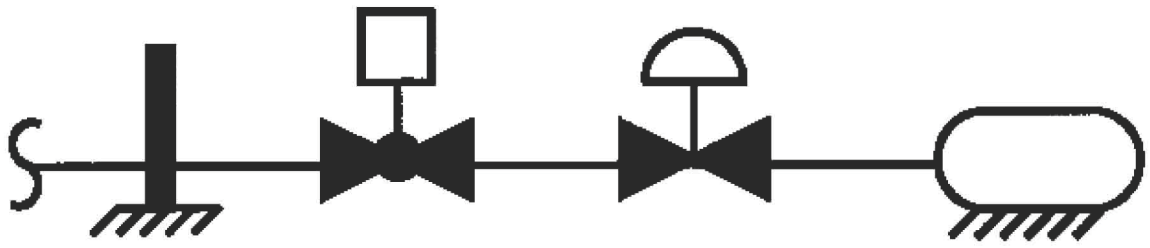


Figure 3.6-2
Typical Structural Components of Crushable Pipe Type Whip Restraints



A B C D

A – Anchor
B – Closed Valve
C – Closed Valve
D – Terminal End

A to B – High Energy
B to D – Moderate Energy

Figure 3.6-3
Terminal Ends Definitions

3.7 Seismic Design

Plant structures, systems, and components important to safety are required by General Design Criterion (GDC) 2 of Appendix A of 10 CFR 50 to be designed to withstand the effects of earthquakes without loss of capability to perform their safety functions.

Each plant structure, system, equipment, and component is classified in an applicable seismic category depending on its function. A three-level seismic classification system is used for the AP1000: seismic Category I, seismic Category II, and nonseismic. The definitions of the seismic classifications and a seismic classifications listing of structures, systems, equipment, and components are presented in Section 3.2.

Seismic design of the AP1000 seismic Categories I and II structures, systems, equipment, and components is based on the safe shutdown earthquake (SSE). The safe shutdown earthquake is defined as the maximum potential vibratory ground motion at the generic plant site as identified in Section 2.5.

The operating basis earthquake (OBE) has been eliminated as a design requirement for the AP1000. Low-level seismic effects are included in the design of certain equipment potentially sensitive to a number of such events based on a percentage of the responses calculated for the safe shutdown earthquake. Criteria for evaluating the need to shut down the plant following an earthquake are established using the cumulative absolute velocity approach according to EPRI Report NP-5930 (Reference 1) and EPRI Report TR-100082 (Reference 17). For the purposes of the shutdown criteria in Reference 1 the operating basis earthquake for shutdown is considered to be one-third of the safe shutdown earthquake.

Seismic Category I structures, systems, and components are designed to withstand the effects of the safe shutdown earthquake event and to maintain the specified design functions. Seismic Category II and nonseismic structures are designed or physically arranged (or both) so that the safe shutdown earthquake could not cause unacceptable structural interaction with or failure of seismic Category I structures, systems, and components.

3.7.1 Seismic Input

The geologic and seismologic considerations of the plant site are discussed in Section 2.5.

The peak ground acceleration of the safe shutdown earthquake, now referred to as the Certified Seismic Design Response Spectra (CSDRS), has been established as 0.30g for the AP1000 design. The vertical peak ground acceleration is conservatively assumed to equal the horizontal value of 0.30g as discussed in Section 2.5.

3.7.1.1 Design Response Spectra

The AP1000 design response spectra of the safe shutdown earthquake, now referred to as the Certified Seismic Design Response Spectra (CSDRS), are provided in Figures 3.7.1-1 and 3.7.1-2 for the horizontal and the vertical components, respectively.

The horizontal design response spectra for the AP1000 plant are developed, using the Regulatory Guide 1.60 spectra as the base and several evaluations to investigate the high frequency amplification effects. These evaluations included:

- Comparison of Regulatory Guide 1.60 spectra with the spectra predicted by recent eastern U.S. spectral velocity attenuation relations (References 23, 24, 25, and 26) using a suite of magnitudes and distances giving a 0.3 g peak acceleration

- Comparison of Regulatory Guide 1.60 spectra with the 10^{-4} annual probability uniform hazard spectra developed for eastern U.S. nuclear power plants by both Lawrence Livermore National Laboratory (Reference 27) and Electric Power Research Institute (Reference 28)

- Comparison of Regulatory Guide 1.60 spectra with the spectra of 79 additional old and newer components of strong earthquake time histories not considered in the original derivation of Regulatory Guide 1.60

Based on the above described evaluations, it is concluded that the eastern U.S. seismic data exceed Regulatory Guide 1.60 spectra by a modest amount in the 15 to 33 hertz frequency range when derived either from published attenuation relations or from the 10^{-4} annual probability of exceedance uniform hazard spectra at eastern U.S. sites. This conclusion is consistent with findings of other investigators that eastern North American earthquakes have more energy at high frequencies than western earthquakes. Exceedance of Regulatory Guide 1.60 spectra at the high frequency range, therefore, would be expected since Regulatory Guide 1.60 spectra are based primarily on western U.S. earthquakes. The evaluation shows that, at 25 hertz (approximately in the middle of the range of high frequencies being considered, and a frequency for which spectral amplitudes are explicitly evaluated) the mean-plus-one-standard-deviation spectral amplitudes for 5 percent damping range from about 2.1 to 4 cm/sec and average 2.7 cm/sec. Whereas, the Regulatory Guide 1.60 spectral amplitude at the same frequency and damping value equal just over 2 cm/sec.

It is concluded, therefore, that an appropriate augmented 5 percent damping horizontal design velocity response spectrum for the AP1000 project is one with spectral amplitudes equal to the Regulatory Guide 1.60 spectrum at control frequencies 0.25, 2.5, 9 and 33 hertz augmented by an additional control frequency at 25 hertz with an amplitude equal to 3 cm/sec. This spectral amplitude equals 1.3 times the Regulatory Guide 1.60 amplitude at the same frequency. The additional control point's spectral amplitude of other damping values were determined by increasing the Regulatory Guide 1.60 spectral amplitude by 30 percent.

The AP1000 design vertical response spectrum is, similarly, based on the Regulatory Guide 1.60 vertical spectra at lower frequencies but is augmented at the higher frequencies equal to the horizontal response spectrum.

The AP1000 design response spectra's relative values of spectrum amplification factors for control points are presented in Table 3.7.1-3.

The design response spectra are applied at the foundation level in the free field at hard rock sites and at the finished grade in the free field at firm rock and soil sites. The resulting peak horizontal ground acceleration values are above 0.1g. This satisfies 10 CFR Part 50, Appendix S, which requires that the horizontal component of the SSE ground motion in the free-field at the foundation elevation (that is, bottom of foundation) has a peak ground acceleration of at least 0.1g together with an appropriate response spectrum. The definitions (characteristics) of hard rock, firm rock, and soil sites are provided in Subsection 3.7.1.4.

3.7.1.1.1 Design Ground Motion Response Spectra

The Vogtle site-specific safe shutdown earthquake (SSE) design response spectra (DRS) are the site-specific ground motion response spectra (GMRS) determined in Subsection 2.5.2.6. These response spectra are determined in the free-field on the ground surface.

The Vogtle foundation input response spectra (FIRS) are at an outcrop located at the 40' depth. The development of these FIRS is discussed in Subsection 2.5.2.7. These Vogtle response spectra are compared to the AP1000 SSE design response spectra that are also referred to as the AP1000 certified seismic design response spectra (CSDRS). The CSDRS also represents the AP1000 FIRS.

This is because: (1) the CSDRS at a hard rock site is essentially the same at grade and at foundation; and (2) the CSDRS envelopes the in-column motions of the other generic soil conditions. The AP1000 CSDRS are applied at the foundation level in the free field at hard rock sites, and at the finished grade for the other soil generic conditions. The comparisons are shown in Figures 3.7-201 and 3.7-202. As seen from those comparisons, there are exceedances above the CSDRS; therefore, plant specific seismic evaluations are performed that demonstrate that the AP1000 plant designed for the CSDRS is acceptable for the Vogtle site. The results from a Vogtle site specific two-dimensional seismic evaluation that demonstrates the acceptability of the Vogtle site are given in Appendix 2.5E. Additionally, a Vogtle site specific three-dimensional seismic evaluation that demonstrates the acceptability of the Vogtle site is given in Appendix 3GG. Based on these Vogtle site specific seismic evaluations it can also be concluded that the standard AP1000 plant certified design is fully acceptable to a SSE design response spectra level of the CSDRS at Vogtle's plant grade.

As discussed in Subsection 2.5.4.13, the heavy lift derrick (HLD) counterweight and ring foundation were abandoned in place after construction. The HLD counterweight is outside the defined excavation of Unit 3 and Unit 4 and therefore does not need to be evaluated. Portions of the HLD ring foundation extend over the Unit 3 and Unit 4 excavation slopes within the engineered granular backfill (EGB); but outside the Category 1 and 2 backfill. The presence of the HLD ring foundation has no effect on the VEGP site-specific 3D SASSI SSI analyses of the Nuclear Island (NI) presented in Appendix 3GG based on the following information.

The VEGP site-specific 3D SASSI SSI of the NI is consistent with the accepted DCD 3D SASSI NI modeling approach of not including structure-to-structure interaction of the adjacent structures such as the Annex Building and the Turbine Building; and therefore the more distant abandoned HLD ring foundation has even less structure-to-structure effects on the NI seismic response. Additionally only a portion of the abandoned HLD ring foundation is within a limited area of the non-safety EGB over the slopes of the excavation. It has been demonstrated in the ESP as amended that a large variation of the EGB properties does not significantly affect the site-specific seismic analyses; therefore, it is concluded the abandoned portion of the HLD ring foundation in the EGB has no significant effect on the site-specific seismic analyses.

The operating basis earthquake ground motion (OBE) spectral values are used as one measure of potential damage to those structures, systems, and components designed to the SSE design ground motion to determine the severity of the seismic event and make a determination of whether the plant must be shut down. For the AP1000 certified design, OBE is not an explicit design load; as such it is therefore defined as one-third the CSDRS. Since it has been demonstrated that the Vogtle site characteristics do not limit the AP1000 design to the CSDRS, the Vogtle OBE for the AP1000 is defined as one-third the AP1000 CSDRS.

The FIRS and the CSDRS in the horizontal direction in the free-field at the foundation of the AP1000 Nuclear Island exceed the minimum spectrum requirements of 10 CFR50 Appendix S.

3.7.1.2 Design Time History

A "single" set of three mutually orthogonal, statistically independent, synthetic acceleration time histories is used as the input in the dynamic analysis of seismic Category I structures. The synthetic time histories were generated by modifying a set of actual recorded "TAFT" earthquake time histories. The design time histories include a total time duration equal to 20 seconds and a corresponding stationary phase, strong motion duration greater than 6 seconds. The acceleration, velocity, and displacement time-history plots for the three orthogonal earthquake components, "H1," "H2," and "V," are presented in Figures 3.7.1-3, 3.7.1-4, and 3.7.1-5. Design horizontal time history, H1, is applied in the north-south (Global X or 1) direction; design horizontal time history, H2, is applied in the east-west (global Y or 2) direction; and design vertical time history is applied in the

vertical (global Z or 3) direction. The cross-correlation coefficients between the three components of the design time histories are as follows:

$$\rho_{12} = 0.05, \rho_{23} = 0.043, \text{ and } \rho_{31} = 0.140$$

where 1, 2, 3 are the three global directions.

Since the three coefficients are less than 0.16 as recommended in Reference 30, which was referenced by NRC Regulatory Guide 1.92, Revision 1, it is concluded that these three components are statistically independent. The design time histories are applied at the foundation level in the free field.

The ground motion time histories (H1, H2, and V) are generated with time step size of 0.010 second for applications in soil structure interaction analyses. For applications in the fixed-base mode superposition time-history analyses, the time step size is reduced to 0.005 second by linear interpolation. The maximum frequency of interest in the horizontal and vertical seismic analysis of the nuclear island is 33 hertz. Modes with higher frequencies are included in the analysis so that the mass in these higher modes is included in the member forces. The cutoff frequencies used in the soil structure interaction analyses are 33 hertz. The maximum "cut-off" frequency for the soil structure interaction analyses and the fixed-base analyses is well within the Nyquist frequency limit.

The comparison plots of the acceleration response spectra of the time histories versus the design response spectra for 2, 3, 4, 5, and 7 percent critical damping are shown in Figures 3.7.1-6, 3.7.1-7, and 3.7.1-8. The SRP 3.7.1, Table 3.7.1-1, provision of frequency intervals is used in the computation of these response spectra.

In SRP 3.7.1 the NRC introduced the requirement of minimum power spectral density to prevent the design ground acceleration time histories from having a deficiency of power over any frequency range. SRP 3.7.1, Revision 2, specifies that the use of a single time history is justified by satisfying a target power spectral density (PSD) requirement in addition to the design response spectra enveloping requirements. Furthermore, it specifies that when spectra other than Regulatory Guide 1.60 spectra are used, a compatible power spectral density shall be developed using procedures outlined in NUREG/CR-5347 (Reference 29).

The NUREG/CR-5347 procedures involve ad hoc hybridization of two earlier power spectral density envelopes. Since the modification to the RG 1.60 design spectra adopted for AP1000 (see Subsection 3.7.1.1) is relatively small (compared to the uncertainty in the fit to RG 1.60 of power spectral density-compatible time histories referenced in NUREG/CR-5347) and occurs only in the frequency range between 9 to 33 hertz, a project-specific power spectral density is developed using a slightly different hybridization for the higher frequencies.

Since the original RG 1.60 spectrum and the project-specific modified RG 1.60 spectrum are identical for frequencies less than 9 hertz, no modification to the power spectral density is done in this frequency range. At frequencies above 9 hertz, the third and the fourth legs of the power spectral density are slightly modified as follows:

- The frequency at which the design response spectrum inflected towards a 1.0 amplification factor at 33 hertz takes place at 25 hertz in the AP1000 spectrum rather than at 9 hertz as in the RG 1.60 spectrum. The third leg of the power spectral density, therefore, is extended to about 25 hertz rather than 16 hertz.

- The lead coefficient to the fourth leg of the power spectral density is changed to connect with the extended third leg.

The AP1000 augmented power spectral density, anchored to 0.3 g, is as follows:

$S_0(f) = 58.5\ (f/2.5)^{0.2}\ in^2/sec^3$, $f \leq 2.5$ hertz

$S_0(f) = 58.5\ (2.5/f)^{1.8}\ in^2/sec^3$, 2.5 hertz $\leq f \leq$ 9 hertz

$S_0(f) = 5.832\ (9/f)^{3}\ in^2/sec^3$, 9 hertz $\leq f \leq$ 25 hertz

$S_0(f) = 0.27\ (25/f)^{8}\ in^2/sec^3$, 25 hertz $\leq f$

The AP1000 Minimum Power Spectral Density is presented in Figure 3.7.1-9. This AP1000 target power spectral density is compatible with the AP1000 horizontal design response spectra and envelops a target power spectral density compatible with the AP1000 vertical design response spectra. This AP1000 target power spectral density, therefore, is conservatively applied to the vertical response spectra.

The comparison plots of the power spectral density curve of the AP1000 acceleration time histories versus the target power spectral density curve are presented in Figures 3.7.1-10, 3.7.1-11, and 3.7.1-12. The power spectral density functions of the design time histories are calculated at uniform frequency steps of 0.0489 hertz. The power spectral densities presented in Figures 3.7.1-10 through 3.7.1-12 are the averaged power spectral density obtained over a moving frequency band of ±20 percent centered at each frequency. The power spectral density amplitude at frequency (f) has the averaged power spectral density amplitude between the frequency range of 0.8 f and 1.2 f as stated in appendix A of Revision 2 of SRP 3.7.1.

3.7.1.3 Critical Damping Values

Energy dissipation within a structural system is represented by equivalent viscous dampers in the mathematical model. The damping coefficients used are based on the material, load conditions, and type of construction used in the structural system. The safe shutdown earthquake damping values used in the dynamic analysis of various structures, supports, and equipment are presented in Table 3.7.1-1. The damping values are based on Regulatory Guide 1.61, Revision 0, ASCE Standard 4-98 (Reference 3), except for the damping value of the primary coolant loop piping, which is based on Reference 22, and conduits, cable trays and their related supports.

The damping values for conduits, cable trays and their related supports are shown in Table 3.7.1-1. The damping value of conduit, empty cable trays, and their related supports is similar to that of a bolted structure, namely 7 percent of critical. The damping value of filled cable trays and supports increases with increased cable fill and level of seismic excitation. Full cable trays use a 10-percent damping value consistent with RG 1.61, Revision 1. The limiting condition for design of the AP1000 standard cable tray supports is for full cable tray weight.

For structures or components composed of different material types, the composite modal damping is calculated using the stiffness-weighted method based on Reference 3. The modal damping values equal:

$$\beta_n = \sum_{i=1}^{nc} \frac{\{\phi_n\}^T \beta_i [K_t]_i \{\phi_n\}}{\{\phi_n\}^T [K_t] \{\phi_n\}}$$

where:

β_n = ratio of critical damping for mode n

nc = number of elements

$\{\phi_n\}$ = mode n (eigenvector)

$[K_t]_i$ = stiffness matrix of element i

β_i = ratio of critical damping associated with element i

$[K_t]$ = total system stiffness matrix

The linear structural damping values were defined in the modeling codes as a parameter of material property defined for each element. This form of structural damping is used for seismic time history analyses. The structural models analyzed follow the damping criteria stated in Table 3.7.1-1 using 5-percent SSE damping for steel composite (SC) structures, including the shield building wall and modules, and 7-percent SSE damping for the remaining reinforced concrete (RC) structures throughout the nuclear island. A time history non-linear analysis confirms only minor cracking in the nuclear island structure.

3.7.1.4 Supporting Media for Seismic Category I Structures

The supporting media will be described consistent with the information items in Subsection 2.5.4. Seismic analyses for both rock and soil sites are described in Subsection 3.7.2 and Appendix 3G.

The AP1000 nuclear island consists of three seismic Category I structures founded on a common basemat. The three structures that make up the nuclear island are the coupled auxiliary and shield buildings, the steel containment vessel, and the containment internal structures. [*The nuclear island is shown in Figure 3.7.1-14.*]* The foundation embedment depth, foundation size, and total height of the seismic Category I structures are presented in Table 3.7.1-2.

For the design of seismic Category I structures, a set of six design soil profiles (that include hard rock) of various shear wave velocities is established from parametric studies as described in Appendix 3G.3. The soil cases selected for the AP1000 use parameters from the AP600 design, and the AP600 conclusions are applicable to the AP1000 due to the identical footprint to the AP600 and the similarity in overall mass.

For the AP1000 2D and 3D soil-structure interaction analyses, although some of the parabolic soil profiles are defined using a depth of 240 feet, the actual soil profile defined in SASSI (System for Analysis of Soil-Structure Interaction) (base rock) goes to only elevation 120′.

Soil-structure interaction analyses on soil sites for the AP1000 used the latest soil degradation curves recommended by EPRI TR-102293, although these represent more recent soils data and differ slightly for those used for the AP600.

These six profiles are sufficient to envelope sites where the shear wave velocity of the supporting medium at the foundation level exceeds 1000 feet per second (see Subsection 2.5.2). The design soil profiles include a hard rock site, a soft rock site, a firm rock site, an upper bound soft-to-medium soil site, a soft-to-medium soil site, and a soft soil site. The shear wave velocity profiles and related governing parameters of the six sites considered are as follows:

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- For the hard rock site, an upper bound case for rock sites using a shear wave velocity of 8000 feet per second.

- For the firm rock site, a shear wave velocity of 3500 feet per second to a depth of 120 feet and base rock at the depth of 120 feet.

- For the soft rock site, a shear wave velocity of 2400 feet per second at the ground surface, increasing linearly to 3200 feet per second at a depth of 240 feet, and base rock at the depth of 120 feet.

- For the upper bound soft-to-medium soil site, a shear wave velocity of 1414 feet per second at ground surface, increasing parabolically to 3394 feet per second at 240 feet, base rock at the depth of 120 feet, and ground water at grade level. The initial soil shear modulus profile is twice that of the soft-to-medium soil site.

- For the soft-to-medium soil site, a shear wave velocity of 1000 feet per second at ground surface, increasing parabolically to 2400 feet per second at 240 feet, base rock at the depth of 120 feet, and ground water is assumed at grade level.

- For the soft soil site, a shear wave velocity of 1000 feet per second at ground surface, increasing linearly to 1200 feet per second at 240 feet, base rock at the depth of 120 feet, and ground water is assumed at grade level

The strain-dependent shear modulus curves for the foundation materials, together with the corresponding damping curves are taken from References 37 and 38 and are shown in Figures 3.7.1-15 and 3.7.1-16 for rock material and soil material respectively. The different curves for soil in Figure 3.7.1-16 apply to the range of depth within a soil column below grade. The strain-dependent soil material damping is limited to 15 percent of critical damping. The strain-dependent properties used in the SSI analyses for the safe shutdown earthquake are shown in Table 3.7.1-4 and Figure 3.7.1-17 for the firm rock, soft rock, upper bound soft-to-medium soil, soft-to-medium soil, and soft soil properties.

Some variation of soil modeling (water table, soil layering, soil degradation model, and the like) and combinations of these have been demonstrated to have no significant effect on the seismic response of the nuclear island structures. The governing parameters obtained for the AP600 soil studies are also applicable to the AP1000. Each of the parameters deemed not significant has been analyzed.

For instance, the combination of effects of the different strain dependent soil parameters that affect the strain-iterated shear wave velocity profiles was evaluated and shown not to result in exceedances of the envelope of the generic seismic design in-structure response spectra (ISRS).

3.7.2 Seismic System Analysis

Seismic Category I structures, systems, and components are classified according to Regulatory Guide 1.29. Seismic Category I building structures of AP1000 consist of the containment building (the steel containment vessel and the containment internal structures), the shield building, and the auxiliary building. These structures are founded on a common basemat and are collectively known as the nuclear island or nuclear island structures. [*Key dimensions, such as thickness of the basemat, floor slabs, roofs and walls, of the seismic Category I building structures are shown in Figure 3.7.2-12.*]*

Seismic systems are defined, according to SRP 3.7.2, Section II.3.a, as the seismic Category I structures that are considered in conjunction with their foundation and supporting media to form a soil-structure interaction model. The following subsections describe the seismic analyses performed

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for the nuclear island. Other seismic Category I structures, systems, equipment, and components not designated as seismic systems (that is, heating, ventilation, and air-conditioning systems; electrical cable tray systems; piping systems) are designated as seismic subsystems. The analysis of seismic subsystems is presented in Subsection 3.7.3.

Seismic Category I building structures are on the nuclear island. Other building structures are classified nonseismic or seismic Category II. Nonseismic structures are analyzed and designed for seismic loads according to the Uniform Building Code (Reference 2) requirements for Zone 2A. The main area of the turbine building structure is analyzed and designed for seismic loads in accordance with International Building Code requirements for an earthquake magnitude equivalent to the Uniform Building Code, Zone 3. Seismic Category II building structures are designed for the safe shutdown earthquake using the same methods and design allowables as are used for seismic Category I structures. The acceptance criteria are based on ACI 349 for concrete structures, on ANSI/AISC N690 for steel structures, including the supplemental requirements described in Subsections 3.8.4.4.1 and 3.8.4.5, and on AWS D1.1-2000 for weld design, qualification, fabrication, and inspection as described in Subsections 3.8.3.2 and 3.8.4.2.

Separate seismic analyses are performed for the nuclear island for each of the six design soil profiles defined in Subsection 3.7.1.4. The analyses generate one set of in-structure responses for each of the design soil profiles. The six sets of in-structure responses are enveloped to obtain the seismic design envelope (design member forces, nodal accelerations, nodal displacements, and floor response spectra), which are used in the design and analysis of seismic Category I structures, components, and seismic subsystems.

Appendix 3G summarizes the types of models and analysis methods that are used in the seismic analyses of the nuclear island, as well as the type of results that are obtained and where they are used in the design. The seismic analyses of the nuclear island are summarized in a seismic analysis summary report. This report describes the development of the finite element models, the soil structure interaction and fixed base analyses, and the results thereof. Seismic response spectra are given in Appendix 3G for the six key locations:

- Containment internal structures at reactor vessel support elevation 100.00′.
- Containment internal structures at operating deck elevation 134.25′.
- Auxiliary shield building north east corner at control room floor elevation 116.50′.
- Auxiliary shield building corner of fuel building roof at shield building elevation 179.19′.
- Auxiliary shield building roof area elevation 327.41′.
- Steel containment vessel near polar crane elevation 224.000′.

3.7.2.1 Seismic Analysis Methods

Seismic analyses of the nuclear island are performed in conformance with the criteria within SRP 3.7.2.

Seismic analyses – using response spectra analysis, the equivalent static acceleration method, the mode superposition time-history method, and the complex frequency response analysis method – are performed for the safe shutdown earthquake to determine the seismic force distribution for use in the design of the nuclear island structures, and to develop in-structure seismic responses (accelerations, displacements, and floor response spectra) for use in the analysis and design of seismic subsystems.

3.7.2.1.1 Equivalent Static Acceleration Analysis

Equivalent static analyses, using computer program ANSYS (Reference 36), are performed to obtain the seismic forces and moments required for the structural design of the steel containment vessel

and the nuclear island basemat (see Subsection 3.8.2.4.1.1). Equivalent static loads are applied to the finite element models using the maximum acceleration results from the time history analyses for the six design soil profiles. Accidental torsional moments are applied as described in Subsection 3.7.2.11.

Equivalent static analyses are also performed for design of the shield building roof and radial roof beams, passive containment cooling water storage tank (PCWST), tension ring, and air inlet structure (see Subsection 3.8.4.4.1). The equivalent static loads are based on the maximum acceleration results from time history dynamic analysis of the nuclear island in Subsection 3.7.2.1.2.

3.7.2.1.2 Time-History Analysis and Complex Frequency Response Analysis

Mode superposition time-history analyses using computer program ANSYS and complex frequency response analysis using computer program SASSI are performed to obtain the in-structure seismic response needed in the analysis and design of seismic subsystems. Three-dimensional finite element shell models of the nuclear island structures are used in conjunction with the design soil profiles presented in Subsection 3.7.1.4 to obtain the in-structure responses. Stick models are coupled to the shell models of the concrete structures for the containment vessel, polar crane, reactor coolant loop, pressurizer, and core makeup tanks. Three models are used. The fine (NI10) model, as described in Subsection 3G.2.2.1, is used to define the seismic response for the hard rock site. The coarse (NI20) model, as described in Subsection 3G.2.2.2, is used for the soil structure interaction (SSI) analyses and is set up in both ANSYS and SASSI. The NI05 model, as described in Appendix 3G.2.2.4, is used to develop amplified seismic response for the envelope of soil profiles presented in Subsection 3.7.1.4 for flexible regions not captured by the coarser NI20 model. The models and analyses are described in Appendix 3G.

For the hard rock site, the soil-structure interaction effect is negligible. Therefore, for the hard rock site, the nuclear island is analyzed as a fixed-base structure, using computer program ANSYS without the foundation media. The three components of earthquake (two horizontal and one vertical time histories) are applied simultaneously in the analysis. Since the NI10 finite element model of the auxiliary and shield building uses shell elements to represent the 6-foot-thick basemat, the nodes of the basemat element are at the center of the basemat (elevation 63′-6″). The finite element model of the containment internal structures uses solid elements, which extend down to elevation 60′-6″. When the finite element models are combined and used in the time history analyses, the auxiliary building finite element model is fixed at the shell element basemat nodes (elevation 63′-6″) and the base of the containment internal structures is fixed at the bottom of the solid element base nodes (elevation 60′-6″). This difference in elevation of the base fixity is not significant since the concrete between elevations 60′-6″ and 63′-6″, below the auxiliary building, is nearly rigid. There is no lateral support due to soil or hard rock below grade. This case results in higher response than a case analyzed with full lateral support below grade.

For additional information on the method used to calculate displacement, see Appendix 3G.4.1 and Appendix 3G.4.2.

3.7.2.1.3 Response Spectrum Analysis

Response spectral analysis is used for the evaluation of the nuclear island structures. Response spectrum analyses are used to perform an analysis of a particular structure or portion of structure using the procedures described in Appendix 3G.4.3.1 and Subsections 3.7.2.6, 3.7.2.7, and 3.7.3.

Seismic response spectrum analysis of the auxiliary building, shield building, and containment internal structure is performed to develop the seismic design loads for these buildings, and the loads generated include the amplified load due to flexibility and the distribution of this load to the surrounding structures.

3.7.2.2 Natural Frequencies and Response Loads

Modal analyses are performed for the shell and lumped-mass stick models of the seismic Category I structures on the nuclear island, as described in Appendix 3G. Seismic response spectra at the six key locations (Subsection 3.7.2) are given in Appendix 3G.

3.7.2.3 Procedure Used for Modeling

Based on the general plant arrangement, three-dimensional, finite element models are developed for the nuclear island structures: a finite element model of the coupled shield and auxiliary buildings, a finite element model of the containment internal structures, a finite element model of the shield building roof, and an axisymmetric shell model of the steel containment vessel. These three-dimensional, finite element models provide the basis for the development of the dynamic model of the nuclear island structures.

The finite element models of the coupled shield and auxiliary buildings, and the containment internal structures are based on the gross concrete section with the modulus based on the specified compressive strength of concrete reduced by a factor of 0.8 to consider the effect of cracking as recommended in Table 6-5 of FEMA 356 (Reference 5). This 80-percent value is supported by non-linear ABAQUS analyses performed on the nuclear island finite element model. The comparison between linear and non-linear models shows that the 80-percent stiffness model response spectra enveloped the non-linear model, providing a conservative approach in terms of response spectra and maximum stresses obtained in the shield building wall.

Seismic subsystems coupled to the overall dynamic model of the nuclear island include the coupling of the reactor coolant loop model to the model of the containment internal structures, and the coupling of the polar crane model to the model of the steel containment vessel. The criteria used for decoupling seismic subsystems from the nuclear island model are according to Section II.3.b of SRP 3.7.2, Revision 2. The total mass of other major subsystems and equipment is less than one percent of the respective supporting nuclear island structures; therefore, the mass of other major subsystems and equipment is included as concentrated lumped-mass only.

Several minor (basic building configuration not modified) design changes and model improvements include the following:

- Provision for heavier fuel racks in the spent fuel pool area. Fuel and rack masses are updated, and pool water volumes are modeled as lumped masses.
- Changes in the annulus configuration are incorporated into the dish model, and lower shield building and upper containment internal structures basemat nodes and elements are modified for compatibility.
- The core makeup tanks were added as stick models.
- The polar crane model has an updated weight and updated steel containment vessel local stiffness, and now includes polar crane truck stiffness.

The seismic analysis of the water inside the PCCWST was performed for the AP600. It was concluded that the low-frequency sloshing mode is not significant to the response of the nuclear island away from the shield building roof and that this conclusion could be extended to the AP1000 design. Further analysis indicated that the sloshing mass ratio remained essentially unchanged between the AP600 and AP1000.

3.7.2.3.1 Coupled Shield and Auxiliary Buildings and Containment Internal Structures

The finite element models of the coupled shield and auxiliary buildings and the reinforced concrete portions of the containment internal structures are based on the gross concrete section with the modulus based on the specified compressive strength of concrete of contributing structural walls and slabs. The properties of the concrete-filled structural modules are computed using the combined gross concrete section and the transformed steel face plates of the structural modules. The modulus is reduced by a factor of 0.8 to consider the effect of cracking. Furthermore, the weight density of concrete plus the uniformly distributed miscellaneous dead weights are considered by adding surface mass or by adjusting the material mass density of the structural elements. An equivalent tributary slab area load of 50 pounds per square foot is considered to represent miscellaneous deadweight such as minor equipment, piping and raceways. 25 percent of the floor live load or 75 percent of the roof snow load, whichever is applicable, is considered as mass in the global seismic models.

Major equipment weights are distributed over the floor area or are included as concentrated lumped masses at the equipment locations. The major equipment supported by the containment internal structures is represented by stick models connected to the containment internal structures, and includes the reactor coolant loop, the pressurizer, and the core makeup tank. The core makeup tank model is used only in the nuclear island fine (NI10) model; the core makeup tank is represented by mass in the nuclear island coarse model (NI20). The finite element models of the coupled shield and auxiliary buildings and the containment internal structures are described in Appendix 3G. The auxiliary and shield building is modeled with shell elements and the base of the finite element model is at the middle of the basemat at elevation 63′-6″. The bottom of the containment and internal structures are modeled with solid elements and the base of the finite element model is at the underside of the basemat at elevation 60′-6″. The interface between the models is at a radius of 71′-0″ at the mid-surface of the shield building.

3.7.2.3.2 Steel Containment Vessel

The steel containment vessel is a freestanding, cylindrical, steel shell structure with ellipsoidal upper and lower steel domes. The three-dimensional, lumped-mass stick model of the steel containment vessel is developed based on the axisymmetric shell model. Figure 3G.2-4 presents the steel containment vessel stick model. In the stick model, the properties are calculated as follows:

- Members representing the cylindrical portion are based on the properties of the actual circular cross section of the containment vessel.

- Members representing the bottom head are based on equivalent stiffnesses calculated from the shell of revolution analyses for static 1.0g in vertical and horizontal directions.

- Shear, bending and torsional properties for members representing the top head are based on the average of the properties at the successive nodes, using the actual circular cross section. These are the properties that affect the horizontal modes. Axial properties, which affect the vertical modes, are based on equivalent stiffnesses calculated from the shell of revolution analyses for static 1.0g in the vertical direction.

The equivalent static acceleration analyses of the containment vessel use a finite element shell model with a refined mesh in the area adjacent to the large penetrations. Comparison of this with a time history analysis for the regions immediately surrounding the large penetrations verifies that the loads from equivalent static analysis are conservative to time history using a representative study.

This method used to construct a stick model from the axisymmetric shell model of the containment vessel is verified by comparison of the natural frequencies determined from the stick model and the shell of revolution model as shown in Table 3G.2-2. The shell of revolution vertical model (n = 0

harmonic) has a series of local shell modes of the top head above elevation 265′ between 23 and 30 hertz. These modes are predominantly in a direction normal to the shell surface and cannot be represented by a stick model. These local modes have small contribution to the total response to a vertical earthquake as they are at a high frequency where seismic excitation is small. The only seismic Category I components attached to this portion of the top head are the water distribution weirs of the passive containment cooling system. These weirs are designed such that their fundamental frequencies are outside the 23 to 30 hertz range of the local shell modes.

Additional details of the steel containment vessel stick model are included in Appendix 3G.2.1.3.

The containment air baffle, presented in Subsection 3.8.4.1.3, is supported from the steel containment vessel at regular intervals so that a gap is maintained for airflow. It is constructed with individual panels which do not contribute to the stiffness of the containment vessel. The fundamental frequency of the baffle panels and supports is about twice the fundamental frequency of the containment vessel. The mass of the air baffle is small, equal to approximately 10 percent of the vessel plates to which it is attached. The air baffle, therefore, is assumed to have negligible interaction with the steel containment vessel. Only the mass of the air baffle is considered and added at the appropriate elevations of the steel containment vessel stick model.

The interaction between the polar crane and the containment vessel is significant and is included in the model. This polar crane model reflects the polar crane wheel assemblies. The polar crane is supported on a ring girder which is an integral part of the steel containment vessel at elevation 228′-0″ as shown in Figure 3.8.2-1. It is modeled as a multi-degree of freedom system attached to the steel containment shell at elevation 224′ (midpoint of ring girder) as shown in Figure 3G.2-4. The polar crane is modeled as shown in Figure 3G.2-5A with five masses at the mid-height of the bridge at elevation 236′-6″ and one mass for the trolley. The polar crane model includes the flexibility of the crane bridge girders and truck assembly. The containment shell's local flexibility is considered when combined with the global model. When fixed at the center of containment, the model shows fundamental frequencies of 4.6 hertz transverse to the bridge, 6.9 hertz vertically, and 9.4 hertz along the bridge.

[*During plant operating conditions, the polar crane is parked in the plant north-south direction with the trolley located at one end near the containment shell.*]* In the seismic model, the crane bridge spans in the north-south direction and the mass eccentricity of the trolley is considered by locating the mass of the trolley at the northern limit of travel of the main hook. Furthermore, the mass eccentricity of the two equipment hatches and the two personnel airlocks are considered by placing their mass at their respective center of mass as shown in Figure 3G.2-4. Any modeling change due to the as-procured crane data is resolved with the COL holder item in Subsection 3.7.5.4, "Reconciliation of Seismic Analyses of Nuclear Island Structures."

3.7.2.3.3 Nuclear Island Seismic Model

The nuclear island seismic models are described in Appendix 3G. The various building models are interconnected to form the overall dynamic model of the nuclear island. The mass properties of the models include all tributary mass expected to be present during plant operating conditions. This includes the dead weight of walls and slabs, weight of major equipment, and equivalent tributary slab area loads representing miscellaneous equipment, piping and raceways.

The hydrodynamic mass effect of the water within the passive containment cooling system water tank on the shield building roof, the in-containment refueling water storage tank within the containment internal structures, and the spent fuel pool in the auxiliary building is evaluated. Since the water in the PCCWST responds at a very low frequency (sloshing) and does not affect building response, the PCCWST water horizontal mass is reduced to exclude the low frequency water sloshing mass. The total mass of the water in the in-containment refueling water storage tank within the containment

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internal structures, and the spent fuel pool in the auxiliary building is included in the nuclear island seismic model.

Seismic response spectra are developed at the locations of the nodes. These response spectra are grouped and enveloped to define the seismic design response spectra. The nodes associated with a specific elevation and building structure (i.e., auxiliary and shield building and containment internal structures) are grouped. For the auxiliary and shield building where the floor at the elevation of interest is rigid (i.e. frequency > 33 hertz), it is only necessary to envelop the response spectra at edge points and interior nodes at the shield wall to obtain the largest seismic response spectra because of rigid motion. The edge nodes reflect the largest rocking and translational response of the auxiliary building, and the response spectra associated with the nodes on the shield wall will reflect the shield wall dynamic response. It is not necessary to include any nodes between the shield wall and auxiliary building edge since the floor is rigid, and the response cannot be worse than those enveloped.

A refined finite element shell model of the nuclear island concrete structures is reviewed for flexible regions, which may produce amplified response spectra. This model, called the NI05 model, has a tetrahedral mesh size of approximately 5 feet by 5 feet. Each of the principal walls and floors in the auxiliary and shield building as well as the containment internal structures are reviewed. A modal analysis of the NI05 model for both auxiliary and shield building and containment internal structures is reviewed for each of these regions for the existence of out of plane modes, which are considered flexible (less than 33 hertz) with significant participating mass. The survey reveals that some regions, typically in the middle of a floor or wall, exhibit amplified behavior compared to the critical nodes at the corner and edge building locations. [*These regions, which have flexible areas, are evaluated in one of two ways:*

- *Flexible areas, which have been previously identified, have amplified response spectra developed directly from the time history analyses for the envelope of soil sites.*

- *Flexible regions, which require a detailed analysis to obtain the amplified response spectra, use input directly from time history analysis. The NI05 finite element model is used to capture out-of-plane flexibilities that, because of mesh refinement, a more course model could not capture.*

If equipment or a structure is supported at more than one elevation, then the seismic input as an envelope of multiple groups based on the support locations will be defined. Therefore, if the equipment or structure is supported on rigid and flexible floor areas the response spectra (horizontal and vertical directions) used by the analysts will be the envelope of the rigid and flexible areas that include inside and outside nodes.

If an equipment or structure is supported exclusively by a floor or wall, only that spectra will be used for design.]*

3.7.2.4 Soil-Structure Interaction

Soil-structure interaction is not significant for the nuclear island founded on rock with a shear wave velocity greater than 8000 feet per second. The soil-structure interaction analyses for the firm rock and soil sites are described in Appendix 3G.

The computer program SASSI is used to perform the soil-structure interaction analysis. The SASSI model of the nuclear island is based on the NI20 Coarse Finite Element model. Soil-structure interaction analyses are performed based on the nuclear island 3D SASSI model for the three soil conditions established from the AP1000 2D SASSI analyses, in addition to soft rock and soft soil.

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SASSI uses key frequencies to perform its transfer function calculations. For a large model, resting on a very stiff soil (hard rock), SASSI gives conservative results at high frequencies. The significant responses for AP1000 soil cases occur at less than 10 hertz so the SASSI model is adequate for use.

Analyses are performed with large solid-shell finite element models at two levels. The fine (NI10) model is used to define the seismic response for the hard rock site. The coarse (NI20) model is used for the soil-structure interaction analyses. The NI20 coarse model has fewer nodes and elements than the NI10 model. It captures the essential features of the nuclear island configuration. The nominal shell and solid element dimension is about 20 feet.

3.7.2.5 Development of Floor Response Spectra

The design floor response spectra are generated according to Regulatory Guide 1.122.

Seismic floor response spectra are computed using time-history responses determined from the nuclear island seismic analyses. The time-history responses for the hard rock condition are determined from a mode superposition time history analysis using computer program ANSYS.

The time-history responses for the firm rock and soil conditions are determined from a complex frequency response analysis using computer program SASSI. Floor response spectra for damping values equal to 2, 3, 4, 5, 7, 10, and 20 percent of critical damping are computed at the required locations.

The floor response spectra for the design of subsystems and components are generated by broadening the enveloped nodal response spectra determined for the hard rock site and soil sites.

The spectral peaks are broadened by ±15 percent to account for the variation in the structural frequencies, due to the uncertainties in parameters such as material and mass properties of the structure and soil, damping values, seismic analysis technique, and the seismic modeling technique. Figure 3.7.2-14 shows the broadening procedure used to generate the design floor response spectra. Spectral peaks at frequencies associated with fundamental soil structure interaction frequencies are reviewed. If there is a “valley” between peaks due to different soil profiles and not the building modal response, then this valley is filled by extending the broadening of the lower peak horizontally until it meets the broadened upper peak.

Floor response spectra for the auxiliary building are obtained from the three-dimensional model as described in Appendix 3G. These spectra are developed for the specific location in the auxiliary building. Where spectra at a number of nodes have similar characteristics, a single set of spectra may be developed by enveloping the broadened spectra at each of the nodes.

The safe shutdown earthquake floor response spectra for 5 percent damping, at representative locations of the coupled auxiliary and shield buildings, the steel containment vessel, and the containment internal structures are presented in Appendix 3G.

3.7.2.6 Three Components of Earthquake Motion

Seismic system analyses are performed considering the simultaneous occurrences of the two horizontal and the vertical components of earthquake.

In mode superposition time-history analyses using computer program ANSYS, the three components of earthquake are applied either simultaneously or separately. In the ANSYS analyses with the three earthquake components applied simultaneously, the effect of the three components of earthquake motion is included within the analytical procedure so that further combination is not necessary.

In analyses with the earthquake components applied separately and in the response spectrum and equivalent static analyses, the effect of the three components of earthquake motion are combined using one of the following methods:

- For seismic analyses with the statistically independent earthquake components applied separately, the time-history responses from the three earthquake components are combined algebraically at each time step to obtain the combined response time-history. This method is used in the SASSI analyses.

- The peak responses due to the three earthquake components from the response spectrum and equivalent static analyses are combined using the square root of the sum of squares (SRSS) method.

- The peak responses due to the three earthquake components from the equivalent static analyses are combined directly, using the assumption that when the peak response from one component occurs, the responses from the other two components are 40 percent of the peak (100 percent-40 percent-40 percent method). Combinations of seismic responses from the three earthquake components, together with variations in sign (plus or minus), are considered. This method is used in the nuclear island basemat analyses, the containment vessel analyses, and the shield building roof analyses.

The containment vessel is analyzed using axisymmetric finite element models. These axisymmetric building structures are analyzed for one horizontal seismic input from any horizontal direction and one vertical earthquake component. Responses are combined by either the square root of the sum of squares method or by the 100 percent-40 percent-40 percent method in which one component is taken at 100 percent of its maximum value and the other components are taken at 40 percent of their maximum value.

For the seismic responses presented in Appendix 3G, the effect of three components of earthquake are considered as follows:

- Mode Superposition Time History Analysis (program ANSYS) and the Complex Frequency Response Analysis (program SASSI) – the time history responses from the three components of earthquake motion are combined algebraically at each time step.

A summary of the dynamic analyses performed and the combination techniques used are presented in Appendix 3G.

3.7.2.7 Combination of Modal Responses

The modal responses of the response spectrum system structural analysis are combined using the procedures described in Appendix 3G.4.3. In the fixed base mode superposition time history analysis of the hard rock site, the total seismic response is obtained by superposing the modal responses within the analytical procedure so that further combination is not necessary.

A summary of the dynamic analyses performed and the combination techniques used are presented in Appendix 3G.

3.7.2.8 Interaction of Seismic Category II and Nonseismic Structures with Seismic Category I Structures, Systems, or Components

Nonseismic structures are evaluated to determine that their seismic response does not preclude the safety functions of seismic Category I structures, systems or components. This is accomplished by satisfying one of the following:

- The collapse of the nonseismic structure will not cause the nonseismic structure to strike a seismic Category I structure, system or component.

- The collapse of the nonseismic structure will not impair the integrity of seismic Category I structures, systems or components.

- The structure is classified as seismic Category II and is analyzed and designed to prevent its collapse under the safe shutdown earthquake.

The structures adjacent to the nuclear island are the annex building, the radwaste building, and the turbine building.

3.7.2.8.1 Annex Building

The portion of the annex building adjacent to the nuclear island is classified as seismic Category II. The structural configuration is shown in Figure 3.7.2-19. The annex building is analyzed for the safe shutdown earthquake for the six soil profiles described in Subsection 3.7.1.4. For the hard rock site, a range of soil properties is assumed for the layer above rock at the level of the nuclear island foundation. Seismic input is defined by response spectra applied at the base of a dynamic model of the annex building. The seismic response spectra input at the base of the annex building are the envelopes of the range of soil sites and also envelope the AP1000 design free field ground spectra shown in Figures 3.7.1-1 and 3.7.1-2. The envelope of the maximum building response acceleration values is applied as equivalent static loads to a more detailed static model. See Subsection 3.7.2.8.4 for more discussion of modeling and seismic analysis.

The minimum space required between the annex building and the nuclear island to avoid contact is obtained by absolute summation of the deflections of each structure obtained from either a time history or a response spectrum analysis for each structure. The maximum displacement of the roof of the annex building is 1.6 inches in the east-west direction. The minimum clearance between the structural elements of the annex building above grade and the nuclear island is 3 inches; except that the north-south minimum clearance at Unit 3 between elevations 141'-0" and 154'-0" between structural elements of the annex building and the nuclear island west of column line I is 2-1/16 inches.

3.7.2.8.2 Radwaste Building

The radwaste building is classified as nonseismic and is designed to the seismic requirements of the Uniform Building Code, Zone 2A with an Importance Factor of 1.25. As shown in the radwaste building general arrangement in Figure 1.2-22, it is a small steel framed building. If it were to impact the nuclear island or collapse in the safe shutdown earthquake, it would not impair the integrity of the reinforced concrete nuclear island. The gap between the structural elements of the radwaste building above grade and the nuclear island is 4 inches.

Three methods are used to demonstrate that a potential radwaste building impact on the nuclear island during a seismic event will not impair its structural integrity:

- The maximum kinetic energy of the impact during a seismic event considers the maximum radwaste building and nuclear island velocities. The total kinetic energy is considered to be absorbed by the nuclear island and converted to strain energy. The deflection of the nuclear island is less than 0.2″. The shear forces in the nuclear island walls are less than the ultimate shear strength based on a minus one standard deviation of test data.

- Stress wave evaluation shows that the stress wave resulting from the impact of the radwaste building on the nuclear island has a maximum compressive stress less than the concrete compressive strength.

- An energy comparison shows that the kinetic energy of the radwaste building is less than the kinetic energy of tornado missiles for which the exterior walls of the nuclear island are designed.

3.7.2.8.3 Turbine Building

The south end of the turbine building is separated from the rest of the turbine building by a 2'-0" thick reinforced concrete wall that provides a robust structure around the first bay. This wall isolates the first bay of the turbine building from the general area of the turbine building and from the adjacent yard area. The main segment of this wall is located on column line 11.2. This wall extends from El.100'-0" basemat to El.169'-0". The first bay of the turbine building is classified as seismic Category II. The other bays are classified as non-seismic. The modeling used to represent the structural configuration in the soil structure interaction analysis is shown in Figure 3.7.2-21.

The first bay of the turbine building is analyzed for the safe shutdown earthquake for the six soil profiles described in Subsection 3.7.1.4. For the hard rock site, a range of soil properties is assumed for the layer above rock at the level of the nuclear island foundation. Seismic input is defined by response spectra applied at the base of a dynamic model of the first bay of the turbine building. The seismic response spectra input at the base of the first bay of the turbine building are the envelopes of the range of soil sites and also envelope the AP1000 design free field ground spectra shown in Figures 3.7.1-1 and 3.7.1-2. See Subsection 3.7.2.8.4 for more discussion of modeling and seismic analysis.

The first bay is designed in accordance with ACI-349 for concrete features, ANSI/AISC N690 for steel features, including the supplemental requirements described in Subsections 3.8.4.4.1 and 3.8.4.5, and AWS D1.1-2000 for weld design, qualification, fabrication, and inspection as described in Subsections 3.8.3.2 and 3.8.4.2.

For the non-seismic portion of the Turbine Building, seismic design is upgraded in order to provide margin against collapse during the safe shutdown earthquake. The turbine building is a braced steel frame structure designed to meet the following criteria:

- The turbine building is designed in accordance with the 2006 International Building Code (Reference 40). This references ACI-318 for concrete structures and AISC for steel structures. Seismic loads are defined in accordance with the International Building Code with the maximum considered earthquake spectral parameters S_{DS} = 0.9, S_{D1} = 0.54 for Site Class D. This is consistent with the 1997 Uniform Building Code provisions for Zone 3 with an Importance Factor of 1.0. For a braced structure that has a mix of eccentric and special concentric bracing, the response modification factor is 6 (ASCE 7-05, Reference 42) using strength design.

- The design complies with the seismic requirements for eccentrically braced frames and special concentrically braced frames given in the 2005 AISC Seismic Provisions for Structural Steel Buildings (Reference 41). Quality assurance is in accordance with ASCE 7-05 (Reference 42).

3.7.2.8.4 Seismic Modeling and Analysis of Seismic Category II Building Structures

Seismic Category II structures, systems, and components are designed so that the safe shutdown earthquake does not cause unacceptable structural failure or interaction with seismic Category I

items. Therefore, the seismic response of seismic Category II buildings must be obtained so that they can be designed to meet the seismic Category II requirements as given in Subsection 3.2.1.1.2. Seismic Category II structures are analyzed and evaluated in the same manner as seismic Category I structures. The foundation of the non-seismic portion is modeled with the associated mass distributed on it so that the soil structure interaction during a seismic event is reflected in the analysis.

The seismic analyses performed for the adjacent seismic Category II structures are simulated 3D analyses. The seismic analyses are performed primarily using 2D SASSI models. To properly account for the 3D effect, the response from 2D and 3D SASSI analyses of the seismic Category II buildings on rigid foundations are compared and a 3D effects factor is developed from this comparison. Three soil cases (upper bound soft to medium UBSM, soft to medium SM, and soft soil SS) are used to determine the 3D factor. Shown in Figures 3.7.2-20 and 3.7.2-21 are the 2D SASSI models with adjacent building structures. The seismic Category II buildings are modeled as stick models. The 3D model with adjacent structures is shown in Figure 3.7.2-22.

Seismic Category II buildings are designed using envelope foundation input response spectra (FIRS). The development of these FIRS shall be based on a number of analyses results from the SASSI analyses. The seismic Category II FIRS shall be the envelope of the SASSI seismic Category II foundation response spectra resulting from the following seismic inputs/soil profiles:

- AP1000 CSDRS – Hard rock at El. 60.5′.
- AP1000 CSDRS – Firm rock, soft rock, upper bound soft to medium, soft to medium, and soft soil, soil profiles with AP1000 CSDRS spectra input at plant grade; and
- AP1000 hard rock high frequency (HRHF) – For rock sites, HRHF at plant grade shall be developed using AP1000 HRHF spectra at El. 60.5′ and a range of backfill soil profiles. The backfill soil under the annex and turbine buildings has a parabolic soil profile as a function of depth (El. 100′ to El. 60.5′) and uses EPRI (1993) strain dependent curves. The HRHF at plant grade spectrum shall be generated using soil profiles corresponding to a shear wave velocity of 500 fps, 750 fps, and 1000 fps at El. 100′. The HRHF at plant grade shall be used as input to SASSI analyses to determine the FIRS at the base of the seismic Category II structures.

For each soil case, 2D SASSI analyses shall be performed and the results at three locations at the base of the seismic Category II structures are enveloped. The maximum bearing demand and maximum relative displacement shall be established from the 2D SASSI analyses. The 3D effect factor is applied to the envelope foundation spectra and used for the design of the annex building and turbine building first bay.

Response spectrum analyses (using detailed finite element building models) shall be used to obtain seismic design loads for the seismic Category II building design. The seismic input to the response spectrum analyses is the envelope foundation response spectra obtained from the SASSI analyses. The COL applicant will perform the following screening criteria to determine if it has to perform further analysis for its site. If the requirements given below are not met, then the site applicant can perform site-specific analyses to demonstrate that its site-specific seismic Category II foundation seismic response spectra are less than the AP1000 annex building and turbine building first bay generic design envelope foundation spectra.

- The site meets Subsection 2.5.4.2 DCD soil uniformity requirements.
- For soil sites, the site GMRS is enveloped by the AP1000 CSDRS with soil profiles SS, SM, UBSM, SR, FR, and HR.

- For HRHF sites, the site GMRS is enveloped by the AP1000 HRHF response spectra with a minimum backfill surface shear wave velocity of 500 fps, and a minimum lateral extent of the backfill corresponding to a line extending down from the surface at a one horizontal to one vertical (1H:1V) slope from the outside footprint limit of the seismic Category II structure.

- The bearing capacity with appropriate factor of safety is greater than or equal to the bearing demand.

3.7.2.9 Effects of Parameter Variations on Floor Response Spectra

Seismic model uncertainties due to, among other things, uncertainties in material properties, mass properties, damping values, the effect of concrete cracking, and the modeling techniques are accounted for in the widening of floor response spectra, as described in Subsection 3.7.2.5. The effect of cracking of the concrete-filled structural modules inside containment due to thermal loads is discussed in Subsection 3.8.3.4.2.

3.7.2.10 Use of Constant Vertical Static Factors

The vertical component of the safe shutdown earthquake is considered to occur simultaneously with the two horizontal components in the seismic analyses. Therefore, constant vertical static factors are not used for the design of seismic Category I structures.

3.7.2.11 Method Used to Account for Torsional Effects

The seismic analysis models of the nuclear island incorporate the mass and stiffness eccentricities of the seismic Category I structures and the torsional degrees of freedom.

For the response spectrum analysis of the nuclear island, the seismic loads are combined by means of the square root of the sum of the squares (SRSS). The equation for SRSS is shown below.

$$\sqrt{(\alpha \cdot A_{NS})^2 + (\alpha \cdot A_{EW})^2 + (A_{VT})^2}$$

where,

A_{NS} maximum element forces due to SSE response analysis in X (NS)

A_{EW} maximum element forces due to SSE response analysis in Y (EW)

A_{VT} maximum element forces due to SSE response analysis in Z (VT)

α factor to account for accidental torsion effect in NS or EW (1.05)

Alternatively, for equivalent static analysis, the 100-40-40 rule is applicable in order to cover both negative and positive member forces. The equation for the 100-40-40 rule is shown below.

$$k_1 \cdot \text{sign}(A_{NS}) \cdot (\alpha \cdot A_{NS}) + k_2 \cdot \text{sign}(A_{EW}) \cdot (\alpha \cdot A_{EW}) + k_3 \cdot A_{VT}$$

where,

k_i combination factors (±1.0, ±0.4, ±0.4)

sign(X) sign of variable X: X < 0 results -1; X ≥ 0 results +1

α factor to account for accidental torsion effect in NS or EW (1.05)

3.7.2.12 Methods for Seismic Analysis of Dams

Seismic analysis of dams is site specific design.

The evaluation of existing dams whose failure could affect the site interface flood level specified in Subsection 2.4.12, is included in Subsection 2.4.4. As discussed in Subsection 2.4.1.2.4, the U.S. Army Corps of Engineers has no current plans for the construction of additional reservoirs on the Savannah River.

3.7.2.13 Determination of Seismic Category I Structure Overturning Moments

Subsection 3.8.5.5.4 describes the effects of seismic overturning moments.

3.7.2.14 Analysis Procedure for Damping

Subsection 3.7.1.3 presents the damping values used in the seismic analyses. [*For structures comprised of different material types, the composite modal damping approach utilizing the strain energy method is used to determine the composite modal damping values.*]* Subsection 3.7.2.4 presents the damping values used in the soil-structure interaction analysis.

3.7.3 Seismic Subsystem Analysis

This subsection describes the seismic analysis methodology for subsystems, which are those structures and components that do not have an interface with the soil-structure interaction analyses. Structures and components considered as subsystems include the following:

- Structures, such as floor slabs, walls, miscellaneous steel platforms and framing
- Equipment modules consisting of components, piping, supports, and structural frames
- Equipment including vessels, tanks, heat exchangers, valves, and instrumentation
- Distributive systems including piping and supports, electrical cable trays and supports, HVAC ductwork and supports, instrumentation tubing and supports, and conduits and supports

Subsection 3.9.2 describes dynamic analysis methods for the reactor internals. Subsection 3.9.3 describes dynamic analysis methods for the primary coolant loop support system. Subsection 3.7.2 describes the analysis methods for seismic systems, which are those structures and components that are considered with the foundation and supporting media. Section 3.2 includes the seismic classification of building structures, systems, and components.

3.7.3.1 Seismic Analysis Methods

The methods used for seismic analysis of subsystems include, modal response spectrum analysis, time-history analysis, and equivalent static analysis. The methods described in this subsection are acceptable for any subsystem. The particular method used is selected by the designer based on its appropriateness for the specific item. Items analyzed by each method are identified in the descriptions of each method in the following paragraphs.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.7.3.2 Determination of Number of Earthquake Cycles

Seismic Category I structures, systems, and components are evaluated for one occurrence of the safe shutdown earthquake (SSE). In addition, subsystems sensitive to fatigue are evaluated for cyclic motion due to earthquakes smaller than the safe shutdown earthquake. Using analysis methods, these effects are considered by inclusion of seismic events with an amplitude not less than one-third of the safe shutdown earthquake amplitude. The number of cycles is calculated based on IEEE-344-1987 (Reference 16) to provide the equivalent fatigue damage of two full safe shutdown earthquake events with 10 high-stress cycles per event. Typically, there are five seismic events with an amplitude equal to one-third of the safe shutdown earthquake response. Each of the one-third safe shutdown earthquake events has 63 high-stress cycles. [*For ASME Class 1 piping, the fatigue evaluation is performed based on five seismic events with an amplitude equal to one-third of the safe shutdown earthquake response. Each event has 63 high-stress cycles.*]*

When seismic qualification is based on dynamic testing for structures, systems, or components containing mechanisms that must change position in order to function, operability testing is performed for the safe shutdown earthquake preceded by one or more earthquakes. The number of preceding earthquakes is calculated based on IEEE-344-1987 (Reference 16) to provide the equivalent fatigue damage of one safe shutdown earthquake event. Typically, the preceding earthquake is one safe shutdown earthquake event or five one-half safe shutdown earthquake events.

3.7.3.3 Procedure Used for Modeling

The dynamic analysis of any complex system requires the discretization of its mass and elastic properties. This is accomplished by concentrating the mass of the system at distinct characteristic points or nodes, and interconnecting them by a network of elastic springs representing the stiffness properties of the systems. The stiffness properties are computed either by hand calculations for simple systems or by finite element methods for more complex systems.

Nodes are located at mass concentrations and at additional points within the system. They are selected in such a way as to provide an adequate representation of the mass distribution and high-stress concentration points of the system.

At each node, degrees of freedom corresponding to translations along three orthogonal axes, and rotations about these axes are assigned. The number of degrees of freedom is reduced by the number of constraints, where applicable. For equipment qualification, reduced degrees of freedom are acceptable provided that the analysis adequately and conservatively predicts the response of the equipment.

The size of the model is reviewed so that a sufficient number of masses or degrees of freedom are used to compute the response of the system. A model is considered adequate provided that additional degrees of freedom do not result in more than a 10 percent increase in response, or the number of degrees of freedom equals or exceeds twice the number of modes with frequencies less than 33 hertz.

Dynamic models of floor and roof slabs and miscellaneous steel platforms and framing include masses equal to 25 percent of the floor live load or 75 percent on the roof snow load, whichever is applicable.

Dynamic models are prepared for the following seismic Category I steel structures. Response spectrum or time history analyses are performed for structural design.

- Passive containment cooling valve room (room number 12701)

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- Steel framing around steam generators
- Containment air baffle

Seismic input for the subsystem and component design are the enveloped floor response spectra described in Subsection 3.7.2.5 or the response time histories as described in Subsection 3.7.2.1. Where amplified response spectra are required on the subsystem for design of components, such as for use in the decoupled analyses of piping or components described in Subsection 3.7.3.8.3, the amplified response spectra are generated and enveloped as described in Subsection 3.7.2.5.

3.7.3.4 Basis for Selection of Frequencies

The effect of the building amplification on equipment and components is addressed by the floor response spectra method or by a coupled analysis of the building and equipment. Certain components are designed for a natural frequency greater than 33 hertz. In those cases where it is practical to avoid resonance, the fundamental frequencies of components and equipment are selected to be less than one-half or more than twice the dominant frequencies of the support structure.

3.7.3.5 Equivalent Static Load Method of Analysis

[*The equivalent static load method involves equivalent horizontal and vertical static forces applied at the center of gravity of various masses. The equivalent force at a mass location is computed as the product of the mass and the seismic acceleration value applicable to that mass location. Loads, stresses, or deflections, obtained using the equivalent static load method, are adjusted to account for the relative motion between points of support when significant.*]*

3.7.3.5.1 Single Mode Dominant or Rigid Structures or Components

For rigid structures and components, or for cases where the response can be classified as single mode dominant, the following procedures are used. Examples of these systems, structures, and components are equipment, and piping lines, instrumentation tubing, cable trays, HVAC, and floor beams modeled on a span by span basis.

- For rigid systems, structures, and components (fundamental frequency ≥ 33 hertz), an equivalent seismic load is defined for the direction of excitation as the product of the component mass and the zero period acceleration value obtained from the applicable floor response spectra.

- A rigid component (fundamental frequency ≥ 33 hertz), whose support can be represented by a flexible spring, can be modelled as a single degree of freedom model in the direction of excitation (horizontal or vertical directions). The equivalent static seismic load for the direction of excitation is defined as the product of the component mass and the seismic acceleration value at the natural frequency from the applicable floor response spectra. If the frequency is not determined, the peak acceleration from the applicable floor response spectrum is used.

[● *If the component has a distributed mass whose dynamic response will be single mode dominant, the equivalent static seismic load for the direction of excitation is defined as the product of the component mass and the seismic acceleration value at the component natural frequency from the applicable floor response spectra times a factor of 1.5. A factor of less than 1.5 may be used if justified. Static factors smaller than 1.5 are not used for piping systems.*]* A factor of 1.0 is used for structures or equipment that can be represented as uniformly loaded cantilever, simply supported, fixed-simply supported, or fixed-fixed beams

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

(References 10 and 11) when the fundamental frequency is higher than the peak acceleration frequency associated with the applicable floor response spectrum. If the frequency is not determined, the peak acceleration from the applicable floor response spectrum is used.

3.7.3.5.2 Multiple Mode Dominant Response

This procedure applies to piping, instrumentation tubing, cable trays, and HVAC that are multiple span models. The equivalent static load method of analysis can be used for design of piping systems, instrumentation and supports that have significant responses at several vibrational frequencies. In this case, [*a static load factor of 1.5 is applied to the peak accelerations of the applicable floor response spectra. For runs with axial supports which are rigid in the axial direction (fundamental frequency greater than or equal to 33 hertz), the acceleration value of the mass of piping in its axial direction may be limited to 1.0 times its calculated spectral acceleration value. The spectral acceleration value is based on the frequency of the piping system along the axial direction. The relative motion between support points is also considered.*]*

3.7.3.6 Three Components of Earthquake Motion

[*Two horizontal components and one vertical component of seismic response spectra are employed as input to a modal response spectrum analysis.*]* The spectra are associated with the safe shutdown earthquake. In the response spectrum and equivalent static analyses, the effects of the three components of earthquake motion are combined using one of the following methods:

[● *The peak responses due to the three earthquake components from the response spectrum analyses are combined using the square root of the sum of squares (SRSS) method.*

● *The peak responses due to the three earthquake components are combined directly, using the assumption that when the peak response from one component occurs, the responses from the other two components are 40 percent of the peak (100 percent-40 percent-40 percent method). Combinations of seismic responses from the three earthquake components, together with variations in sign (plus or minus), are considered. This method is not used for piping systems.*

One set of three mutually orthogonal artificial time histories is used when time-history analyses are performed. The components of earthquake motion specified in the three directions are statistically independent and applied simultaneously. When this method is used, the responses from each of the three components of motion are combined algebraically at each time step.]*

In addition, an optional method for combining the response of the three components of earthquake motion is presented in the following paragraphs.

[*The time-history safe shutdown earthquake analysis of a subsystem can be performed by simultaneously applying the displacements and rotations at the interface point(s) between the subsystem and the system. These displacements and rotations are the results obtained from a model of a larger subsystem or a system that includes a simplified representation of the subsystem. The time-history safe shutdown earthquake analysis of the system is performed by applying three mutually orthogonal and statistically independent, artificial time histories.*]* Possible examples of the use of this method of seismic analysis include the following:

● The subsystem analysis is a flexible floor or miscellaneous structural steel frame. The corresponding system analysis is the soil-structure interaction analysis of the nuclear island structures.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- The subsystem analysis is the primary loop piping system and interior concrete building structure. The interface point is the top of the basemat. The corresponding system analysis is the soil-structure interaction analysis of the nuclear island structures.

- The subsystem analysis is the reactor coolant pump and internal components. The interface points are the welds on the pump suction and discharge nozzles. The corresponding system analysis is the primary loop piping system and interior concrete building structure.

3.7.3.7 Combination of Modal Responses

[*For the seismic response spectra analyses, the zero period acceleration cut-off frequency is 33 hertz. High frequency or rigid modes are considered using the left-out-force method or the missing mass method*]* described in Subsection 3.7.3.7.1. The method to combine the low frequency modes is described in Subsection 3.7.3.7.2. [*The rigid mode results in the three perpendicular directions of the seismic input are combined by the SRSS method. The resultant response of the rigid modes is combined by SRSS with the flexible mode results.*]* The combination of modal responses in time history analyses of piping systems is described in Subsection 3.7.3.17. Modal responses in time history analyses of other subsystems are combined as described in Subsection 3.7.2.6.

3.7.3.7.1 Combination of High-Frequency Modes

This subsection describes alternative methods of accounting for high-frequency modes (generally greater than 33 hertz) in seismic response spectrum analysis. Higher-frequency modes can be excluded from the response calculation if the change in response is less than or equal to 10 percent.

3.7.3.7.1.1 Left-Out-Force Method or Missing Mass Correction for High Frequency Modes

The left-out-force method is based on the Left-Out-Force Theorem. This theorem states that for every time history load there is a frequency, f_r, called the "rigid mode cutoff frequency" above which the response in modes with natural frequencies above f_r will very closely resemble the applied load at each instant of time. These modes are called "rigid modes." [*The left-out-force method is used in program PIPESTRESS.*]*

The left-out-force vector, $\{Fr\}$, is calculated based on lower modes:

$$\{Fr\} = \left[1 - \Sigma M e_j e_j^T\right] f(t)$$

where:

f (t) = the applied load vector

M = the mass matrix

e_j = the eigenvector

Note that Σ is only for all the flexible modes, not including the rigid modes.

In the response spectra analysis, the total inertia force contribution of higher modes can be interpreted as:

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

$$\{Fr\} = Am[M]\left[\{r\} - \Sigma P_j e_j\right]$$

where:

Am = the maximum spectral acceleration beyond the flexible modes

[M] = the mass matrix

$\{r\}$ = the influence vector or displacement vector due to unit displacement

P_j = participation factor

Since,

$$P_j = e_j{}^T[M]\{r\}, \{Fr\} = Am[M]\{r\}\left[1 - \Sigma M e_j e_j{}^T\right]$$

[*In PIPESTRESS, the low frequency modes are combined by one of the Regulatory Guide 1.92 methods in the response spectrum analysis.*]* For each support level, there is a pseudo-load vector or left-out-force vector in the X, Y and Z directions. These left-out-force vectors are used to generate left-out-force solutions which are multiplied by a scalar amplitude equal to a magnification factor specified by the user. This factor is usually the ZPA (zero period acceleration) of the response spectrum for the corresponding direction. The resultant low frequency responses are combined by square root of the sum of the squares with the high frequency responses (rigid modes results).

[*In GAPPIPE, the results from the high frequency responses are also combined by the square root of the sum of the squares with those from the resultant loads contributed by lower modes.*]* The missing mass correction for an independent support motion or multiple response spectra analysis is exactly the same as that for the single enveloped response spectrum analysis except that Am used is the envelope of all the zero period accelerations of all the independent support inputs.

3.7.3.7.1.2 SRP 3.7.2 Method

[*The method described in SRP Section 3.7.2 may also be used for combination of high-frequency modes.*]*

The following is the procedure for incorporating responses associated with high-frequency modes.

Step 1 Determine the modal responses only for those modes having natural frequencies less than that at which the spectral acceleration approximately returns to the zero period acceleration (33 hertz for the Regulatory Guide 1.60 response spectra). Combine such modes according to the methods discussed in Subsection 3.7.3.7.2.

Step 2 For each degree of freedom included in the dynamic analysis, determine the fraction of degree of freedom mass included in the summation of all modes included in Step 1. This fraction d_i for each degree of freedom is given by:

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

$$d_i = \sum_{n=1}^{N} C_n \times \phi_{n,i}$$

where:

n = order of mode under consideration

N = number of modes included in Step 1

$\phi_{n,i}$ = nth natural mode of the system

C_n is the participation factor given by:

$$C_n = \frac{(\phi_n)^T [m] (1)}{(\phi_n)^T [m] (\phi_n)}$$

Next, determine the fraction of degree of freedom mass not included in the summation of these modes:

$$e_i = d_i - \delta_{ij}$$

where δ_{ij} is the Kronecker delta, which is 1 if degree of freedom i is in the direction of the earthquake motion and 0 if degree of freedom i is a rotation or not in the direction of the earthquake input motion.

If, for any degree of freedom i, the absolute value of this fraction e_i exceeds 0.1, the response from higher modes is included with those included in Step 1.

Step 3 Higher modes can be assumed to respond in phase with the zero period acceleration and, thus, with each other. Hence, these modes are combined algebraically, which is equivalent to pseudostatic response to the inertial forces from these higher modes excited at the zero period acceleration. The pseudostatic inertial forces associated with the summation of all higher modes for each degree of freedom i are given by:

$$P_i = ZPA \times M_i \times e_i$$

where:

P_i = force or moment to be applied by degree of freedom i

M_i = mass or mass moment of inertia associated with degree of freedom i.

The subsystem is then statically analyzed for this set of pseudo static inertial forces applied to all degrees of freedom to determine the maximum responses associated with high-frequency modes not included in Step 1.

Step 4 The total combined response to high-frequency modes (Step 3) is combined by the square root of sum of the squares method with the total combined response from lower-frequency modes (Step 1) to determine the overall structural peak responses.

3.7.3.7.2 Combination of Low-Frequency Modes

This subsection describes the method for combining modal responses in the seismic response spectra analysis. [*The total unidirectional seismic response for subsystems is obtained by combining the individual modal responses using the square root sum of the squares method. For subsystems having modes with closely spaced frequencies, this method is modified to include the possible effect of these modes. For piping systems, the methods in Regulatory Guide 1.92 are used for modal combinations.*]* For other subsystems, the methods in Regulatory Guide 1.92 or the following alternative methods may be used. [*The groups of closely spaced modes are chosen so that the differences between the frequencies of the first mode and the last mode in the group do not exceed 10 percent of the lower frequency.*

Combined total response for systems having such closely spaced modal frequencies is obtained by adding to the square root sum of squares of all modes the product of the responses of the modes in each group of closely spaced modes and coupling factor.]* This can be represented mathematically as:

$$R_T^{\,2} = \sum_{i=1}^{N} R_i^{\,2} + 2 \sum_{j=1}^{S} \sum_{k=Mj}^{Nj-1} \sum_{\ell=k+1}^{Nj} R_k \, R_\ell \, \varepsilon_{k\ell}$$

where:

R_T = total unidirectional response

R_i = absolute value of response of mode i

N = total number of modes considered

S = number of groups of closely spaced modes

= lowest modal number associated with group j of closely spaced modes

N_j = highest modal number associated with group j of closely spaced modes

$\varepsilon_{k\ell}$ = coupling factor, defined as follows:

$$\varepsilon_{k\ell} = \left(1 + \frac{\left(w_k^{'} - w_\ell^{'} \right)^2}{\left(\beta_k^{'} w_k + \beta_\ell^{'} w_\ell \right)^2} \right)^{-1}$$

and,

$$w_k^{'} = w_k \left[1 - \left(\beta_k \right)^2 \right]^{1/2}$$

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

$$\beta_k^{'} = \beta_k + \frac{2}{w_k t_d}$$

where:

w_k = frequency of closely spaced mode k

β_k = fraction of critical damping in closely spaced mode k

t_d = duration of the earthquake (= 30 seconds)

[*Alternatively, a more conservative grouping method can be used in the seismic response spectra analyses. The groups of closely spaced modes are chosen so that the difference between two frequencies is no greater than 10 percent.*]* Therefore,

$$R_T{}^2 = \sum_{i=1}^{N} R_i{}^2 + 2\Sigma\, \varepsilon_{k\ell}\, R_k\, R_\ell$$

where:

$$\frac{|\, w_k - w_\ell \,|}{w_\ell} \leq 0.1$$

All other terms for the modal combination remain the same. The 10 percent grouping method is more conservative than the grouping method because the same mode can appear in more than one group.

In addition to the above methods, any of the other methods in Regulatory Guide 1.92 may be used for modal combination.

[*3.7.3.8 Analytical Procedure for Piping*

This subsection describes the modeling methods and analytical procedures for piping systems.

The piping system is modeled as beam elements with lump masses connected by a network of elastic springs representing the stiffness properties of the piping system. Concentrated weights such as valves or flanges are also modeled as lump masses. The effects of torsion (including eccentric masses), bending, shear, and axial deformations, and effects due to the changes in stiffness values of curved members are accounted for in the piping dynamic model.

The lump masses are selected so that the maximum spacing is not greater than the length that would produce a natural frequency equal to the zero period acceleration (ZPA) frequency of the seismic input when calculated based on a simply supported beam. As a minimum, the number of degrees of freedom is equal to twice the number of modes with frequencies less than the zero period acceleration frequency.

The piping system analysis model includes the effect of piping support mass when the contributory mass of the support is greater than 10 percent of the total mass of the effected piping spans. The contributory mass of the support is the portion of the support mass that is attached to the piping; such as clamps, bolts, trunnions, struts, and snubbers. Supports that are not directly attached to the

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

piping, such as box frames, need not be considered for mass effects. The mass of the applicable support will not affect the response of the system in the supported direction, herefore only the unsupported direction needs to be considered. Based on this reasoning, the mass of full anchors can be neglected. The total mass of each effected piping span includes the mass of the piping, fluid contents, insulation, and any concentrated masses (for example, valves or flanges) between the adjacent supports in each unrestrained direction on both sides of the applicable support. For example; the contributory mass of an X direction support must be compared to the mass of the piping spans in the unrestrained Y and Z directions. A contributory support mass that is less than 10 percent of the masses of the effected spans will have insignificant effect on the response of the piping system and can be neglected.

The stiffness matrix of the piping system is calculated based on the stiffness values of the pipe elements and support elements. Default rigid or calculated support stiffness values are used (see subsections 3.9.3.1.5 and 3.9.3.4). When the support deflections are limited to 1/8 inches for the dynamic combined faulted loads, default rigid support stiffness values are used. If the dynamic combined faulted load deflection for any support exceeds 1/8 inches, calculated support stiffness values are used for the affected support.

Valves, equipment and piping modules are considered as rigid if the natural frequencies are greater than 33 hertz. Valves with lower frequencies are included in the piping system model. See subsection 3.7.3.8.2.1 for flexible equipment and subsection 3.7.3.8.3 for flexible modules.

See subsection 3.9.3.1.4 for the primary loop piping and support system.]*

3.7.3.8.1 Supporting Systems

This subsection deals with the analysis of piping systems that provide support to other piping systems. The methods used for the analysis of the primary loop piping are described in Appendix 3C. [*The supported piping system may be excluded from the analysis of the supporting piping system when the ratio of the supported pipe to supporting pipe moment of inertia is less than or equal to 0.04.*

If the ratio of the run piping outside diameter to the branch piping outside diameter (nominal pipe size) exceeds or equals 3.0, the branch piping can be excluded from the analysis of the run piping. The mass and stiffness effects of the branch piping are considered as described below.

Stiffness Effect

The stiffness effect of the decoupled branch pipe is considered significant when the distance from the run pipe outside diameter to the first rigid or seismic support on the decoupled branch pipe is less than or equal to one half the deadweight span of the branch pipe (given in ASME III Code Subsection NF).

Mass Effect

Considering one direction at a time, the mass effect is significant when the weight of half the span (from the decoupling point) of the branch pipe in one direction is more than 20 percent the weight of the main run pipe span in the same direction. Concentrated weights in the branch pipe are considered. A branch pipe span in x direction is the span between the decoupled branch point and the first seismic or rigid support in the x direction. A main run pipe span in the x direction is the piping bounded by the first seismic or rigid support in the x direction on both sides of the decoupled branch point. Similarly, the same definition applies to the spans in other directions (y and z).

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If the calculated branch pipe weight is less than 20 percent but more than 10 percent of the main run pipe weight, this weight is lumped at the decoupling point of the run pipe for the run pipe analysis. This weight can be neglected if it is less than 10 percent of the main run pipe weight.

Required Coupled Branch Piping

If the stiffness and/or mass effects are considered significant, the branch piping is included in the piping analysis for the run pipe analysis. The portion of branch piping considered in the analysis adequately represents the behavior of the run pipe and branch pipe. The branch line model ends in one of the following ways:

- *First six-way anchor*
- *Four rigid/seismic supports in each of the three perpendicular directions*
- *Rigidly supported zone as described* in *subsection 3.7.3.13.4.2*]*

3.7.3.8.2 Supported Systems

This subsection deals with the analysis of piping systems that are supported by other piping systems or by equipment.

3.7.3.8.2.1 Large Diameter Auxiliary Piping

[*This subsection deals with ASME Class 1 piping larger than 1-inch nominal pipe size and ASME Class 2 and 3 piping with nominal pipe size larger than 2 inches. The response spectra methodology is used.*

When the supporting system is a piping system, the supported pipe (branch) can be decoupled from the supporting pipe (run) when the ratio of the run piping nominal pipe size to branch pipe nominal pipe size is greater than or equal to three to one. Decoupling can also be done when the moment of inertia of the branch pipe is less than or equal to 4 percent of the moment of inertia of the run pipe.

During the analysis of the branch piping, resulting values of tee anchor reactions are checked against the capabilities of the tee.

The seismic inertia effects of equipment and piping that provide support to supported (branch) piping systems are considered when significant. When the frequency of the supporting equipment is less than 33 hertz, then either a coupled dynamic model of the piping and equipment is used, or the amplified response spectra at the equipment connection point is used with a decoupled model of the supported piping. When supported piping is supported by larger piping, one of the following methods is used:

- *A coupled dynamic model of the supported piping and the supporting piping*

- *Amplified response spectra at the connection point to the supporting piping with a decoupled model of the supported piping*]*

3.7.3.8.2.2 Small-Diameter Auxiliary Piping

[*This subsection deals with ASME Code Class 1 piping equal to or less than 1-inch nominal pipe size and ASME Class 2 and 3 piping with nominal pipe sizes less than or equal to 2 inches. This includes instrumentation tubing. These piping systems may be supported by equipment or primary loop piping or other auxiliary piping or both. The response spectra or equivalent static load methodology is used. One of the following methods may be used for these systems:*

- *Same method as described in subsection 3.7.3.8.2.1*

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- *Equivalent static analysis based on appropriate load factors applied to the response spectra acceleration values*]*

Subsections 3.9.3 and 3.9.8.2 discuss the final design and as built reconciliation of small bore piping.

3.7.3.8.3 Piping Systems on Modules

Many portions of the systems for the AP1000 are assembled as modules offsite and shipped to the plant as completed units. This method of construction does not result in any unique requirements for the analysis of these structures, systems, or components. Existing industry standards and regulatory requirements and guidelines are appropriate for the evaluation of structures, systems, and components included in modules.

The modules are constructed using a structural steel framework to support the equipment, pipe, and pipe supports in the module. The structural steel framework is designed as part of the building structure according to the criteria given in Subsection 3.8.4.

One exception is the pressurizer and safety relief valve module, which is attached to the top of the pressurizer. For this module the structures and piping arrangements support valves off the pressurizer and not the building structure. The structural steel frame is designed as a component support according to ASME Code, Section III, Subsection NF. [*Piping in modules is routed and analyzed in the same manner as in a plant not employing modules. Piping is analyzed from anchor point to anchor point, which are not necessarily at the boundaries of the module.*]* This is consistent with the manner in which room walls are treated in a nonmodule plant.

[*The supported piping or component may be decoupled from the seismic analysis of the structural frame based on the following criteria. The mass ratio, Rm, and the frequency ratio, Rf, are defined as follows:*

- *Rm = mass of supported component or piping/mass of supporting structural frame*
- *Rf = frequency of the component or piping/frequency of the structural frame*

Decoupling may be done when:

- *Rm < 0.01, for any Rf, or*
- *Rm ≥ 0.01 and ≤ 0.10, if Rf ≤ 0.8 or if Rf is ≥ 1.25.*

In addition, supported piping may be decoupled if analysis shows that the effect on the structural frame is small, that is, when the change in response is less than 10 percent. When piping or components are decoupled from the analysis of the frame, the contributory mass of the piping and components is included as a rigid mass in the model of the structural frame.]*

When piping or components are decoupled from the analysis of the frame using the preceding criteria, the effect of the frame is accounted for in the analysis of the decoupled components or piping. Either an amplified response spectra or a coupled model is used. The amplified response spectra are obtained from the time history safe shutdown earthquake analysis of the frame. The coupled model consists of a simplified mass and stiffness model of the frame connected to the seismic model of the components or piping.

Alternative criteria may be applied to simple frames that behave as pipe support miscellaneous steel. Decoupling may be done when the deflection of the frame due to dynamic combined faulted loading is less than or equal to 1/8 inch. These deflections are defined with respect to the structure to which the structural frame is attached. The stiffness of the intervening elements between the frame and the supported piping or component is considered as follows: Default rigid stiffness values are used for

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supports except that vendor stiffness values are used for snubbers and rigid gapped supports. The mass of the structural frame is evaluated as a self-weight excitation loading on the frame and the structures supporting the frame. The same approach is used for pipe support miscellaneous steel, as described in Subsection 3.9.3.4.

When the supported components or piping cannot be decoupled, they are included in the analysis model of the structural frame. The interaction between the piping and the frame is incorporated by including the appropriate stiffness and mass properties of the components, piping, and frame in the coupled model.

[***3.7.3.8.4 Piping Systems with Gapped Supports***

This subsection describes the analysis methods for piping systems with rigid gapped supports. These supports may be used to minimize the number of pipe support snubbers and the corresponding inservice testing and maintenance activities.

The analysis consists of an iterative response spectra analysis of the piping and support system. Iterations are performed to establish calculated piping displacements that are compatible with the stiffness and gap of the rigid gapped supports. The results of the computer program GAPPIPE, which uses this methodology, are supported with test data (Reference 13).

The method implemented in GAPPIPE to analyze piping systems supported by rigid gapped supports is based on the equivalent linearization technique. GAPPIPE analysis is performed whenever snubber supports are replaced by rigid gapped supports.

The basis of the concept is to find an equivalent linear spring with a response-dependent stiffness for each nonlinear rigid gapped support, or limit stop, in the mathematical model of the piping system. The equivalent linearized stiffness minimizes the mean difference in force in the support between the equivalent spring and the corresponding original gapped support. The mean difference is estimated by an averaging process in the time domain, that is, across the response duration, using the concept of random vibration. Details of the design and analysis methods and modeling assumptions are described in Reference 12.]*

3.7.3.9 Combination of Support Responses

This subsection describes alternative methods for combining the responses from the individual support or attachment points that connect the supported system or subsystem to the supporting system or subsystem. There are two aspects to the responses from the support or attachment points: seismic anchor motions and envelope or multiple-input response spectra methodology.

Seismic Anchor Motions – The response due to differential seismic anchor motions is calculated using static analysis (without including a dynamic load factor). In this analysis, the static model is identical to the static portion of the dynamic model used to compute the seismic response due to inertial loading. In particular, the structural system supports in the static model are identical to those in the dynamic model.

[*The effect of relative seismic anchor displacements is obtained either by using the worst combination of the peak displacements or by proper representation of the relative phasing characteristics associated with different support inputs. For components supported by a single concrete building (coupled shield and auxiliary buildings, or containment internal structures), the seismic motions at all elevations above the basemat are taken to be in phase. When the component supports are in the same structure, the relative seismic anchor motions are small and the effects are neglected. This is applicable to building structures and to those supplemental steel frames that are rigid in comparison to the components. Supplemental steel frames that are flexible can have*

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*significant seismic anchor motions which are considered. When the components supports are in different structures, the relative seismic anchor motion between the structures is taken to be out-of-phase and the effects are considered. The results of the modal spectra analysis (multiple input or envelope) are combined with the results from seismic anchor motion by the absolute sum method or the SRSS method, as described in Tables 3.9-5 and 3.9-6.]**

Response Spectra Methods – The envelope broadened uniform-input response spectra can lead to excessive conservatism and unnecessary pipe supports. The peak shifting method and independent support motion spectra method are used to avoid unnecessary conservatism.

Seismic Response Spectra Peak Shifting

The peak shifting method may be used in place of the broadened spectra method, as described below.

Determine the natural frequencies $(f_e)_n$ of the system to be qualified in the broadened range of the maximum spectrum acceleration peak.

If no equipment or piping system natural frequencies exist in the ±15 percent interval associated with the maximum spectrum acceleration peak, then the interval associated with the next highest spectrum acceleration peak is selected and used in the following procedure.

Consider all N natural frequencies in the interval

$f_j - 0.15f_j \le (f_e)_n \le f_j + 0.15f_j$

where:

f_j = the frequency of maximum acceleration in the envelope spectra

n = 1 to N

The system is then evaluated by performing N + 3 separate analyses using the envelope unbroadened floor design response spectrum and the envelope unbroadened spectrum modified by shifting the frequencies associated with each of the spectral values by a factor of +0.15; -0.15; and

$$\frac{(f_e)_n - f_j}{f_j}$$

where:

n = 1 to N

The results of these separate seismic analyses are then enveloped to obtain the final result desired (e.g., stress, support loads, acceleration, etc.) at any given point in the system. If three different floor response spectrum curves are used to define the response in the two horizontal and the vertical directions, then the shifting of the spectral values as defined above may be applied independently to these three response spectrum curves.

Independent Support Response Spectrum Methods

The use of multiple-input response spectra accounts for the phasing and interdependence characteristics of the various support points. The following alternative methods are used for the

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AP1000 plant. These are based on the guidelines provided by the "Pressure Vessel Research Committee Technical Committee on Piping Systems" (Reference 14).

[*Envelope Uniform Response Spectra - Method A - The seismic response spectrum that envelopes the supports is used in place of the spectra at each support in the envelope uniform response spectra. Also, the contribution from the seismic anchor motion of the support points is assumed to be in phase and is added algebraically as follows:*

$$q_i = d_i \sum_{j=1}^{N} P_{ij}$$

where:

q_i = *combined displacement response in the normal coordinate for mode i*

d_i = *maximum value of* d_{ij}

d_{ij} = *displacement spectral value for mode i associated with support "j"*

P_{ij} = *participation factor for mode i associated with support j*

N = *number of support points*

Enveloped response spectra are developed as the seismic input in three perpendicular directions of the piping coordinate system to include the spectra at the floor elevations of the attachment points and the piping module or equipment if applicable. The mode shapes and frequencies below the cut-off frequency are calculated in the response spectrum analysis. The modal participation factors in each direction of the earthquake motion and the spectral accelerations for each significant mode are calculated. Based on the calculated mode shapes, participation factors, and spectral accelerations of individual modes, the modal inertia response forces, moments, displacements, and accelerations are calculated. For a given direction, these modal inertia responses are combined based on consideration of closely spaced modes and high frequency modes to obtain the resultant forces, moments, displacements, accelerations, and support loads. The total seismic responses are combined by square-root-sum-of-the-squares method for all three earthquake directions.

Independent Support Motion - Method B - When there are more than one supporting structure, the independent support motion (ISM) method for seismic response spectra may be used.

Each support group is considered to be in a random-phase relationship to the other support groups. The responses caused by each support group are combined by the square-root-sum-of-the-square method. The displacement response in the modal coordinate becomes:

$$q_i = \left[\sum_{j=1}^{N} \left(P_{ij}\, d_{ij} \right)^2 \right]^{1/2}$$

A support group is defined by supports that have the same time-history input. This usually means all supports located on the same floor (or portions of a floor) of a structure.]*

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3.7.3.10 Vertical Static Factors

Constant static factors can be used in some cases for the design of seismic Category I subsystems and equipment. The criteria for using this method are presented in Subsection 3.7.3.5.

3.7.3.11 Torsional Effects of Eccentric Masses

[*The methods used to account for the torsional effects of valves and other eccentric masses (for example, valve operators) in the seismic subsystem analyses are as follows:*

- *When valves and other eccentric masses are considered rigid, the mass of the operator and valve body or other eccentric mass are located at their respective center of gravity. The eccentric components (that is, yoke, valve body) are modeled as rigid members.*

- *When valves and other eccentric masses are not considered rigid, the dynamic models are simulated by the lumped masses in discrete locations (that is, center of gravity of valve body and valve operator), coupled by elastic members with properties of the eccentric components.*]*

3.7.3.12 Seismic Category I Buried Piping Systems and Tunnels

[*There are no seismic Category I buried piping systems and tunnels in the AP1000 design.*]*

3.7.3.13 Interaction of Other Systems with Seismic Category I Systems

The safety functions of seismic Category I structures, systems, and components are protected from interaction with nonseismic structures, systems, and components; or their interaction is evaluated. The safety-related systems and components required for safe shutdown are described in Section 7.4. This equipment is located in selected areas of the auxiliary building and inside containment. The primary means of protecting safety-related structures, systems, and components from adverse seismic interactions are discussed in the following paragraphs in the order of preference.

- Separation – separation with the use of physical barriers

- Segregation – routing away from location of seismic Category I systems, structures, and components

- Impact Evaluation – contact with seismic Category I systems, structures, and components may occur, and there is insufficient energy in the impact to cause loss of safety function

- Support as seismic Category II

[*Interaction of connected systems with seismic Category I piping is considered by including the other piping in the analysis of the seismic Category I system.*]* Interaction of piping systems that are adjacent to Category I structures, systems, and components is also considered. This is discussed in Subsection 3.7.3.13.4.

The containment and each room outside containment containing safety-related systems or equipment, as identified in Table 3.7.3-1, are reviewed for potential adverse seismic interactions to demonstrate that systems, structures, and components are not prevented from performing their required safe shutdown functions. In addition, the review identifies the protection features required to mitigate the consequences of seismic interaction in an area that contains safety-related equipment.

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The evaluation steps to address seismic interaction taken for each room or building area containing seismic Category I systems, structures, and components are:

1. Define targets susceptible to damage (sensitive targets);
   Sensitive targets are those seismic Category I components for which adverse spatial interaction can result in loss of safety function.

2. Define sources which can potentially interact in an adverse manner with the target.

3. If possible, assure adequate free space to eliminate the possibility of seismically-induced damaging impacts for the sensitive targets.

4. Assess impact effects (interaction) when adequate free space is not present.

5. Correct adverse seismic interaction conditions.

The three-dimensional computer model and composites developed for the nuclear island are used during the design process of the systems and components in the nuclear island, to aid in evaluating and documenting the review for seismic interactions. This review is performed using the design criteria and guidelines described in Subsections 3.7.3.13.1 through 3.7.3.13.4.

The seismic interaction review is discussed in Subsection 3.7.5.3. This review is performed in parallel with the seismic margin evaluation. The review is based on as-procured data, as well as the as-constructed condition.

3.7.3.13.1 Separation and Segregation

Separation – The general plant arrangement provides physical separation between the seismic Category I and nonseismic structures, systems, and components to the maximum extent practicable in the nuclear island. The objective is to assist in the preclusion of a potential adverse interaction if the nonseismic structures, systems and components were to fail during a seismic event. Whenever possible, nonseismic pipe, electrical raceway, or ductwork is not routed above or adjacent to safety-related equipment, pipe, electrical raceway systems, or ductwork, thereby eliminating the possibility of seismic interaction.

Workstations and other equipment in the Main Control Room are separated from piping. Further, as stated in Subsection 3.2.1.1.2, structures, systems, and components that are located overhead in the Main Control Room are supported as seismic Category II.

Segregation – Where separation by physical means cannot be accomplished and it becomes necessary to locate or route nonseismic structures, systems, and components in or through safety-related areas, the nonseismic structures, systems and components are segregated from the seismic Category I items to the extent practicable.

Nonseismic cabinets are separated or segregated from seismic Category I cabinets. Also, if a cabinet is a source or a target, the cabinet doors must be secured by latches or fasteners to assure they do not open during a seismic event.

3.7.3.13.2 Impact Analysis

Adverse spatial interaction (i.e., loss of structural integrity or function effecting safety) can potentially occur when two items are in close proximity. Adverse spatial interaction can result from contact or impact from overturning. Seismic Category I systems, structures, and components that are sensitive to seismic interaction are identified as potential targets. Sources are structures or components that

can have adverse spatial interaction with the seismic Category I systems, structures, and components. Identification and evaluation of spatial interactions includes the following considerations:

- Proximity of the source to the target. That is, the location of the source within the impact evaluation zone (shown in Figure 3.7.3-1)

  If a source is outside the impact evaluation zone, and does not enter this zone if overturning occurs, no adverse spatial interaction can occur with the identified target. If the source is within the impact evaluation zone and the supports of the source fail, the source could free fall, potentially impacting the target.

- Robustness of target

  If a target has significant structural integrity, and its function is not an issue, adverse spatial interaction could not occur with the identified source.

- Energy of impact

  The energy of the source impacting the target may be so low as not to cause adverse spatial interaction with the target.

A specific nonseismic structure, system, or component identified as a source to a specific safety-related component can be acceptable without being supported as seismic Category II, if an analysis demonstrates that the weight and configuration of the source, relative to the target, and the trajectory of the source are such that the interaction would not cause unacceptable damage to the target. For example, a nonseismic instrument tube routed above a seismic Category I electrical cable tray system would not pose a hazard and would be acceptable.

Nonseismic equipment can overturn as a result of a safe shutdown earthquake. The trajectory of its fall is evaluated to determine if it poses a potential impact hazard to a safety-related structure, system, or component. If it poses a hazard, the equipment is relocated, or it is supported as described in Subsection 3.7.3.13.3.

Nonseismic walls, platforms, stairs, ladders, grating, handrail installations, or other structures next to safety-related structures, systems, and components are evaluated to determine if their failure is credible.

Should a nonseismic structure, system, or component be capable of being dislodged from its supports, the trajectory of its fall is evaluated for potential adverse impacts. If these present a hazard, the structure, system or component is relocated or supported as described in Subsections 3.7.3.13.3 and 3.7.3.13.4. Impact is assumed for sources within an impact evaluation zone around the safety-related equipment. The impact evaluation zone is defined as the envelope around the target for which a source, if located outside of the envelope, would not impact the target during a safe shutdown earthquake in the event the supports of the source were to fail and allow the source to fall. The impact evaluation zone is defined by the volume extending 6 feet horizontally from the perimeter of the seismic Category I object up to a height of 35 feet. The impact evaluation zone above 35 feet is defined by a 10-degree cone radiating vertically from the foot of the object, projected from its perimeter. This definition of the impact evaluation zone is illustrated in Figure 3.7.3-1. The impact evaluation zone need not extend beyond seismic Category I structures such as walls or floor slabs.

Using seismic experience data, the following seismic Category I equipment (potential targets) are not sensitive to piping, HVAC ducts, and cable tray interaction because they are robust to these types of impact:

- Tanks, "heavy" equipment (for example, heat exchangers)
- Mechanical or electrical penetrations
- Heating, ventilation, and air conditioning (HVAC)
- Adjacent piping
- Raceway Systems
- Structures

3.7.3.13.3 Seismic Category II Supports

Where the preceding approaches of separation, segregation, or impact analysis cannot prevent unacceptable interaction, the source is classified and supported as seismic Category II. The seismic Category II designation provides confidence that these nonseismic structures, systems, and components can withstand the forces of a safe shutdown earthquake in addition to the loading imparted on the seismic Category II supports due to failure of the remaining nonseismically supported portions. This includes nozzle loads from the nonseismic piping. Design methods and stress criteria for systems, structures, and components classified as seismic Category II are the same as for seismic Category I systems, structures, and components, except for piping which is described in Subsection 3.7.3.13.4.2. However, the functionality of these seismic Category II sources does not have to be maintained following a safe shutdown earthquake.

HVAC duct and/or cable trays within the impact evaluation zone are seismically supported using the criteria given in Appendices 3F and 3A for seismic Category I assuring that the HVAC and cable tray segments identified as a source will not fall or adversely impact the sensitive target. Adequate free space between the source and target is assured using the load combination that includes the safe shutdown earthquake. The seismic displacement of the HVAC duct and/or cable tray is 6 inches or the calculated displacement.

Nonseismic equipment identified as a source within the impact evaluation zone is supported as seismic Category II. Support seismic loads include seismic inertia loads of the equipment determined as described in Subsection 3.7.3.5 and nozzle loads from attached piping determined as described in Subsection 3.7.3.13.4.2. Adequate free space is assessed considering a 6-inch deflection envelope for equipment identified as a source, or calculated deflections obtained using the safe shutdown earthquake load combination and elastic analysis.

[*3.7.3.13.4 Interaction of Piping with Seismic Category I Piping Systems, Structures, and Components*

This subsection describes the design methods for piping to prevent adverse spatial interactions.

3.7.3.13.4.1 Seismic Category I Piping

The safe shutdown earthquake piping displacements obtained for the seismic Category I piping are used for the evaluation of seismic interaction with sensitive equipment. Adequate free space between a source and a target is checked adding absolutely the piping safe shutdown earthquake deflection and the safe shutdown earthquake target deflection along with the other loads (e.g., dead weight, thermal) that are in the appropriate design criteria load combinations. Sensitive equipment for piping as the source is seismic Category I equipment shown in Table 3.7.3-2 along with the portion that must be protected ("zone of protection"). Supports may be added to limit seismic movement to eliminate potential adverse interaction.

3.7.3.13.4.2 Seismic Category II Piping

This subsection describes the methods and criteria for piping that is connected to seismic Category I piping. Interaction of seismic Category I piping and nonseismic Category I piping connected to it is

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achieved by incorporating into the analysis of the seismic Category I system a length of pipe that represents the actual dynamic behavior of the complete run of the nonseismic Category I system. The length considered is classified as seismic Category II and extends to the interface anchor or rigid support as described below.

The seismic Category II portion of the line, up to the interface anchor or interface rigid support (last seismic support), is analyzed according to Equation 9 of ASME Code, Section III, Class 3, with a stress limit equal to the smaller of 4.5 S_h and 3.0 S_y. In either case, the nonseismic piping is isolated from the seismic Category I piping by anchors or seismic supports. The anchor or seismic Category II supports are designed for loads from the nonseismic piping. This includes three plastic moment components (M_{p1}, M_{p2}, or M_{p3}) in each of three local coordinate directions. The responses to the three moments are evaluated independently. The seismic Category II portion of the line is analyzed by the response spectrum or equivalent static load method for safe shutdown earthquake.

Single Interface Anchor

The seismic Category II piping may be terminated at a single interface anchor (six-way). This anchor and the supports on the seismic Category II piping are evaluated for safe shutdown earthquake loadings using the rules of ASME III Subsection NF. If the anchor is an equipment nozzle, then the equipment load path through the equipment supports are evaluated to the same acceptance criteria as seismic Category I equipment.

Anchor Followed by a Series of Seismic Supports

The seismic Category II piping may be terminated at the last seismic support which follows a six-way anchor on the seismic Category II piping. This last seismic support and the supports on the seismic Category II piping are evaluated for safe shutdown earthquake loadings using the rules of ASME III Subsection NF. From the anchor to the last seismic support, the response to the plastic moments (M_{p1}, M_{p2}, or M_{p3}) is combined with the responses to seismic anchor motions and equivalent static seismic inertia of the piping system by the absolute sum method. The responses to these moments are evaluated independently. The support and anchor loads due to the plastic moments (M_{p1}, M_{p2}, or M_{p3}) of the seismically analyzed and supported section can be reduced if the elbow/bend resultant moments have exceeded the plastic limit moments of the elbow/bend. The value of the reduction factor RF is as follows:

RF = *Multiplier used to reduce the interface anchor and support loads*

RF = *< l, (if RF > l, no reduction is applicable)*

$RF = M_L/M_a$

M_a = *Resultant moment at elbow/bend. Use maximum value if several elbows/bends are within seismically supported region.*

$M_L = 0.8h^{0.6} D^2t\ Sy$ *for* $h < 1.45$

$M_L = D^2t\ Sy$ *for* $h > 1.45$

h = *Flexibility characteristic of elbow/bend*

D = *Outside diameter of elbow/bend*

t = *Thickness of elbow/bend*

R = *Bend radius of elbow/bend*

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Rigid Region

The seismic Category II piping may be terminated at the last seismic support of a rigidly supported region of the piping system. The rigid region is typically defined as either four bi-lateral supports around an elbow or six bilateral supports around a tee. The structural behavior of the rigid region is similar to that of a six-way anchor. The frequency of the piping system in the rigid region is greater than or equal to 33 hertz. This last seismic support in the rigid region and the supports on the seismic Category II piping are evaluated for safe shutdown earthquake loadings using the rules of ASME III Subsection NF.

3.7.3.13.4.3 Nonseismic Piping

Nonseismic piping within the impact evaluation zone is seismically supported, thereby ensuring that the pipe segment identified as a source will not fall or adversely impact the sensitive target (Table 3.7.3-2). This situation is shown in Figure 3.7.3-2, and the seismic supported piping criteria described below:

- *Supports within the impact evaluation zone, plus one transverse support in each transverse direction beyond the impact evaluation zone, are classified as seismic Category II and are evaluated for the safe shutdown earthquake loading using the rules of ASME III, Subsection NF.*

- *Piping within the impact evaluation zone plus one transverse support in each transverse direction are evaluated to Equation 9 of ASME Code, Section III, Class 3, with a stress limit equal to the smaller of 4.5 S_h and 3.0 S_y. Outside the impact evaluation zone, the nonseismic piping meets ASME B31.1 requirements.*

- *The nonseismic piping and seismic Category II supports are designed for loads from the nonseismic piping beyond the impact evaluation zone. This includes three plastic moment components (M_{p1}, M_{p2}, or M_{p3}) in each of three local coordinate directions applied at the first and last seismic Category II support. The responses to the three moments are evaluated independently. The response from the moments applied at the first seismic Category II support is combined with the response from the moments applied at the last seismic Category II support and with the responses to seismic anchor motions and equivalent static seismic inertia of the piping system by the absolute sum method. The support and anchor loads due to the plastic moments (M_{p1}, M_{p2}, or M_{p3}) of the seismically analyzed and supported section can be reduced if the elbow/bend resultant moments have exceeded the plastic limit moments of the elbow/bend. The value of the reduction factor RF is the same as the value for connected seismic Category II piping described above.*

- *The piping segment identified as the source has at least one effective axial support.*

- *Adequate free space between a source and a target is checked adding absolutely the piping safe shutdown earthquake deflections (defined following seismic Category II piping analysis methodology) and the safe shutdown earthquake target deflection. Also included are the displacements associated with the appropriate load cases.*

- *When the anchor is an equipment nozzle, the equipment is supported as seismic Category II as described in subsection 3.7.3.13.3.*]*

3.7.3.14 Seismic Analyses for Reactor Internals

See Subsection 3.9.2 for the dynamic analyses of reactor internals.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.7.3.15 Analysis Procedure for Damping

Damping values used in the seismic analyses of subsystems are presented in Subsection 3.7.1.3. Safe shutdown earthquake damping values used for different types of analysis are provided in Table 3.7.1-1. For subsystems that are composed of different material types, the composite modal damping approach with the weighted stiffness method is used to determine the composite modal damping value. Alternately, the minimum damping value may be used for these systems. [*Composite modal damping for coupled building and piping systems is used for piping systems that are coupled to the primary coolant loop system and the interior concrete building. Composite modal damping is used for piping systems that are coupled to flexible equipment or flexible valves. Piping systems analyzed by the uniform envelope response spectra method with rigid valves can be evaluated with 5 percent damping. Five percent damping is not used in piping systems that are susceptible to stress corrosion cracking.*]*

For the time history dynamic analysis and independent support motion response spectra analysis of piping systems, 4 percent, 3 percent, and 2 percent damping values are used as described in Table 3.7.1-1.

When piping systems and nonsimple module steel frames (simple frames are described in Subsection 3.7.3.8.3) are in a single coupled model, composite damping, as described in Subsection 3.7.1.3 is used.

3.7.3.16 Analysis of Seismic Category I Tanks

This subsection describes the seismic analyses for the large, atmospheric seismic Category I pools and tanks. These are reinforced concrete structures with stainless steel liners or with structural modules, as discussed in Subsections 3.8.3 and 3.8.4. They include the spent fuel pool in the auxiliary building, the in-containment refueling water storage tank, and the passive containment cooling water tank incorporated into the shield building roof. There are no other seismic Category I tanks.

The seismic analyses of the tank consider the impulsive and convective forces of the water as well as the flexibility of the walls. For the spent fuel pool, cask loading pit, cask washdown pit and fuel transfer canal, the impulsive loads are calculated by considering a portion of the water mass responding with the concrete walls. The impulsive forces are calculated by conventional methods for rigid tanks. The passive containment cooling water tank is analyzed using methods described in Reference 15 for toroidal tanks. It is also analyzed by finite element methods. The in-containment refueling water storage tank is irregular in plan and is analyzed by finite element methods.

3.7.3.17 Time History Analysis of Piping Systems

[*The time history dynamic analysis is an alternate seismic analysis method for response spectrum analysis when time history seismic input is used. This method is also used for dynamic analyses of piping systems subjected to time history hydraulic transient loadings or forcing functions induced by postulated pipe breaks. The modal superposition method is used to solve the equations of motion. The computer programs used are GAPPIPE, PIPESTRESS, ANSYS, and WECAN.*

The modal superposition method is based on the equations of motion which can be decoupled as long as the piping system is within its elastic limit. The modal responses are obtained from integrating the decoupled equations. The total responses are obtained by the algebraic sum of the individual responses of the individual modes at each time step. The cutoff frequency is selected based on the frequency content of the input forcing function and the highest significant frequency of the piping system. The integration time step is no larger than 10 percent of the period of the cutoff frequency.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

For dynamic analysis, including seismic analysis at a hard rock site, three separate analyses are performed for each loading case to account for uncertainties. The three analyses correspond to three different time scales: normal time, time expanded by 15 percent, and time compressed by 15 percent. For time history analysis of piping system models that include a dynamic model of the supporting concrete building either the building stiffness is varied by + and - 30 percent, or the time scale is shifted by + and - 15 percent. Alternately, when uniform enveloping time history analysis is performed, modeling uncertainties are accounted for by the spreading that is included in the broadened response spectra.

For time history analysis using the PIPESTRESS program, the response from the high frequency modes above the cutoff frequency is calculated based on the static response to the left-out-forces. This response is combined with the response from the low frequency modes by algebraic sum at each time step. Composite modal damping is used with PIPESTRESS program. The damping of the individual components is as listed in Table 3.7.1-1.

Alternately, for time history analysis using the PIPESTRESS, GAPPIPE, ANSYS, or WECAN programs, the number of modes used in the modal analysis is chosen so that the results of the dynamic analysis based on the chosen number of modes are within 10 percent of the results of the dynamic analysis based on the next higher number of modes used. The number of modes analyzed is selected to account for the principal vibration modes of the piping system. The modes are combined by algebraic sum. Composite modal damping is used with the ANSYS or WECAN programs. The damping of the individual components is as listed in Table 3.7.1-1.]*

3.7.4 Seismic Instrumentation

3.7.4.1 Comparison with Regulatory Guide 1.12

Compliance with Regulatory Guide 1.12 is discussed in this section and in Subsection 1.9.1.

Administrative procedures define the maintenance and repair of the seismic instrumentation to keep the maximum number of instruments in-service during plant operation and shutdown in accordance with Regulatory Guide 1.12.

3.7.4.1.1 Safety Design Basis

The seismic instrumentation serves no safety-related function and therefore has no nuclear safety design basis.

3.7.4.1.2 Power Generation Design Basis

The seismic instrumentation is designed to provide the following:

- Collection of seismic data in digital format
- Analysis of seismic data after a seismic event
- Operator notification that a seismic event meeting one-third SSE exceedance criteria has occurred
- Operator notification (after analysis of data) that a predetermined cumulative absolute velocity value has been exceeded

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.7.4.2 Location and Description of Instrumentation

The following instrumentation and associated equipment are used to measure plant response to earthquake motion.Four triaxial acceleration sensor units, located as stated in Subsection 3.7.4.2.1, are connected to a time-history analyzer. The time-history analyzer recording and playback system is located in a panel in the nuclear island in a room near the main control room. Seismic event data from these sensors are recorded on a solid-state digital recording system at 200 samples per second per data channel.

This solid-state recording and analysis system has internal batteries and a charger to prevent the loss of data during a power outage, and to allow data collection and analysis in a seismic event during which the power fails. Normally 120 volt alternating current power is supplied from the non-Class 1E dc and uninterruptible power supply system. The system uses triaxial acceleration sensor input signals to initiate the time-history analyzer recording and main control room alarms. The system initiation value is adjustable from 0.002g to 0.02g.

The time-history analyzer starts recording triaxial acceleration data from each of the triaxial acceleration sensors after the initiation value has been exceeded. Pre-event recording time is adjustable from 1.2 to 15.0 seconds, and will be set to record at least 3 seconds of pre-event signal. Post-event run time is adjustable from 10 to 90 seconds. A minimum of 25 minutes of continuous recording is provided. Each recording channel has an associated timing mark record with 2 marks per second, with an accuracy of about 0.02 percent.

The instrumentation components are qualified to IEEE 344-1987 (Reference 16).

The sensor installation anchors are rigid so that the vibratory transmissibility over the design spectra frequency range is essentially unity.

3.7.4.2.1 Triaxial Acceleration Sensors

Each sensor unit contains three accelerometers mounted in a mutually orthogonal array mounted with one horizontal axis parallel to the major axis assumed in the seismic analysis. The triaxial acceleration sensors have a dynamic range of 1000 to 1 (0.001 to 1.0g) and a frequency range of 0.2 to 50 hertz.

One sensor unit will be located in the free field, as discussed in below. The AP1000 seismic monitoring system will provide for signal input from the free field sensor.

A second sensor unit is located on the nuclear island basemat in the spare battery charger room at elevation 66′-6″ near column lines 9 and L.

A third sensor unit is located on the shield building structure at elevation 266′ near column lines 4-1 and K.

The fourth sensor unit is located on the containment internal structure on the east wall of the east steam generator compartment just above the operating floor at elevation 138′ close to column lines 6 and K.

Seismic instrumentation is not located on equipment, piping, or supports since experience has shown that data obtained at these locations are obscured by vibratory motion associated with normal plant operation.

A free-field sensor will be located and installed to record the ground surface motion representative of the site. To be representative of this site in regards to seismic response of structures, systems, and

components, the free-field sensor is located on the ground surface of the engineered backfill. The backfill directly supports the Nuclear Island and the adjacent structures and extends out from these structures a significant distance. The free-field sensor is located where the backfill vertically extends from the top of the Blue Bluff Marl to the ground surface, but horizontally at a distance where possible effects on recorded ground motion associated with surface features, buildings, and components would be minimized. The trigger value is initially set at 0.01g.

3.7.4.2.2 Time-History Analyzer

The time-history analyzer receives input from the triaxial acceleration sensors and, when activated as described in Subsection 3.7.4.3, begins recording the triaxial data from each triaxial acceleration sensor and initiates audio and visual alarms in the main control room.

This recorded data will be used to evaluate the seismic acceleration of the structure on which the triaxial acceleration sensors are mounted.

The time-history analyzer is a multichannel, digital recording system with the capability to automatically download the recorded acceleration data to a dedicated computer for data storage, playback, and analysis after a seismic event.

The time-history analyzer can compute cumulative absolute velocity (CAV) and the 5 percent of critical damping response spectrum for frequencies between 1 and 10 Hz. The operator may select the analysis of either CAV or the response spectrum. Analysis results are printed out on a dedicated graphics printer that is part of the system and is located in the same panel as the time-history analyzer.

3.7.4.3 Control Room Operator Notification

The time-history analyzer provides for initiation of audible and visual alarms in the main control room when the one-third SSE levels sensed by any of the triaxial acceleration sensors are exceeded and when the system is activated to record a seismic event. In addition to alarming when the system is activated, the analyzer portion of the system will provide a second alarm if the predetermined cumulative absolute velocity value has been exceeded by any of the sensors. Alarms are annunciated in the main control room.

3.7.4.4 Comparison of Measured and Predicted Responses

The recorded seismic data is used by the combined license holder operations and engineering departments to evaluate the effects of the earthquake on the plant structures and equipment.

The criterion for initiating a plant shutdown following a seismic event will be exceedance of a specified response spectrum limit and a cumulative absolute velocity limit. The seismic instrumentation system is capable of computing the cumulative absolute velocity as described in EPRI Report NP-5930 (Reference 1) and EPRI Report TR-100082 (Reference 17).

Post-earthquake operating procedures utilize the guidance of EPRI Reports NP-5930, TR-100082, and NP-6695, as modified and endorsed by the NRC in Regulatory Guides 1.166 and 1.167. A response spectrum check up to 10Hz and the cumulative absolute velocity will be calculated based on the recorded motions at the free field instrument. If the operating basis earthquake ground motion is exceeded or significant plant damage occurs, the plant must be shutdown in an orderly manner.

In addition, the procedures address measurement of the post-seismic event gaps between the new fuel rack and walls of the new fuel storage pit, between the individual spent fuel racks, and from the

spent fuel racks to the spent fuel pool walls, and provide for appropriate corrective actions to be taken if needed (such as repositioning the racks or analysis of the as-found condition).

3.7.4.5 Tests and Inspections

Periodic testing of the seismic instrumentation system is accomplished by the functional test feature included in the software of the time-history recording accelerograph. The system is modular and is capable of single-channel testing or single channel maintenance without disabling the remainder of the system.

Installation and acceptance testing of the triaxial acceleration sensors described in Subsection 3.7.4.2.1 is completed prior to initial startup. Installation and acceptance testing of the time-history analyzer described in Subsection 3.7.4.2.2 is completed prior to initial startup.

3.7.5 Combined License Information

3.7.5.1 Seismic Analysis of Dams

Dams whose failure could affect the site interface flood level are addressed in Subsection 3.7.2.12 and Subsection 2.4.4.

3.7.5.2 Post-Earthquake Procedures

Site-specific procedures for activities following an earthquake are addressed in Subsection 3.7.4.4.

3.7.5.3 Seismic Interaction Review

The seismic interaction review will be updated for as-built information. This review is performed in parallel with the seismic margin evaluation. The review is based on as-procured data, as well as the as-constructed condition. The as-built seismic interaction review is completed prior to fuel load.

3.7.5.4 Reconciliation of Seismic Analyses of Nuclear Island Structures

The seismic analyses described in Subsection 3.7.2 will be reconciled for detailed design changes, such as those due to as-procured or as-built changes in component mass, center of gravity, and support configuration based on as-procured equipment information. Deviations are acceptable based on an evaluation consistent with the methods and procedure of Section 3.7 provided the amplitude of the seismic floor response spectra, including the effect due to these deviations, does not exceed the design basis floor response spectra by more than 10 percent. This reconciliation will be completed prior to fuel load.

3.7.5.5 Free Field Acceleration Sensor

The location for the free-field acceleration sensor is addressed in Subsection 3.7.4.2.1.

3.7.6 References

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3. ASCE Standard 4-98, "Seismic Analysis of Safety-Related Nuclear Structures and Commentary," American Society of Civil Engineers, September 1998.

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Table 3.7.1-1
Safe Shutdown Earthquake Damping Values

	Percent
Welded and friction-bolted steel structures and equipment	4
Bearing bolted structures and equipment	7
Prestressed concrete structures	5
Reinforced concrete structures	7
Concrete filled steel plate structures	5
[*Piping (for uniform envelope response spectra analysis)*	*5*
Piping (alternative for time history analysis and independent support motion response spectra analysis)	
Less than or equal to 12-inch diameter	*2*
Greater than 12-inch diameter	*3*
Primary coolant loop	*4*]*
Fuel assemblies	20
Control rod drive mechanisms	5
Full cable trays and related supports	10
Empty cable trays and related supports	7
Conduits and related supports	7
HVAC ductwork	7
HVAC welded ductwork	4
Cabinets and panels for electrical equipment	5
Equipment such as welded instrument racks and tanks	3

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.7.1-2
Embedment Depth and Related Dimensions of Category I Structures

Structure	Foundation Embedment Depth (ft)	Least Foundation Width (ft)	Structure Height (ft)
Shield Building	See Note	See Note	268.25
Steel Containment Vessel	See Note	See Note	215.33
Auxiliary Building	See Note	See Note	119.50

Note:

1. The seismic Category I structures are founded on a common basemat embedded 39.5 feet, [*with dimensions shown in Figure 3.7.1-14.*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.7.1-3
AP1000 Design Response Spectra
Amplification Factors for Control Points

HORIZONTAL					
Percent of Critical Damping	Acceleration[1]				Displacement[1]
	A (33 cps)	B' (25 cps)[2]	B (9 cps)	C (2.5 cps)	D (0.25 cps)
2.0	1.0	1.70	3.54	4.25	2.50
3.0	1.0	1.66	3.13	3.76	2.34
4.0	1.0	1.63	2.84	3.41	2.19
5.0	1.0	1.60	2.61	3.13	2.05
7.0	1.0	1.55	2.27	2.72	1.88

VERTICAL					
Percent of Critical Damping	Acceleration[1]				Displacement[1]
	A (33 cps)	B' (25 cps)[2]	B (9 cps)	C (3.5 cps)	D (0.25 cps)
2.0	1.0	1.70	3.54	4.05	1.67
3.0	1.0	1.66	3.13	3.58	1.56
4.0	1.0	1.63	2.84	3.25	1.46
5.0	1.0	1.60	2.61	2.98	1.37
7.0	1.0	1.55	2.27	2.59	1.25

Notes:

1. Maximum ground displacement is taken proportional to maximum ground acceleration, and is 36 inches for ground acceleration of 1.0 gravity.
2. The 5 percent damping amplification factor for control point B' is derived per discussion in Subsection 3.7.1.1. This 5 percent damping amplification factor equals 1.3 times the RG 1.60 response spectra at 25 hertz. The amplification factors at control point B' for other damping values are determined by increasing the RG 1.60 response spectra at 25 hertz by 30 percent.

Table 3.7.1-4 (Sheet 1 of 5)
Strain Compatible Soil Properties

Depth to Bottom of Layer (ft)	Thickness of Layer (ft)	Layer Number	Total Unit Weight (kcf)	Initial G (ksf)	Initial Vs (fps)	Final G (ksf)	Final Vs (fps)	Damping
Firm Rock								
0.0	–	–	–	–	–	–	–	–
5.0	5.0	1	0.15	57422	3500	57032	3499	0.015
10.0	5.0	2	0.15	57422	3500	56600	3486	0.016
15.0	5.0	3	0.15	57422	3500	55943	3465	0.017
20.0	5.0	4	0.15	57422	3500	55511	3452	0.018
25.0	5.0	5	0.15	56442	3500	55933	3465	0.016
30.0	5.0	6	0.15	56442	3500	55436	3450	0.017
33.5	3.5	7	0.15	57422	3500	56076	3470	0.015
39.5	6.0	8	0.15	57422	3500	55898	3464	0.015
45.0	5.5	9	0.15	57422	3500	55716	3458	0.016
50.0	5.0	10	0.15	57422	3500	55575	3454	0.016
60.0	10.0	11	0.15	56442	3500	55400	3449	0.017
80.0	20.0	12	0.15	56442	3500	54695	3427	0.019
100.0	20.0	13	0.15	56442	3500	53358	3384	0.021
120.0	20.0	14	0.15	56442	3500	52295	3351	0.023
Bedrock	–	–	0.15	300000	8000	298137	8000	0.02

Table 3.7.1-4 (Sheet 2 of 5)
Strain Compatible Soil Properties

Depth to Bottom of Layer (ft)	Thickness of Layer (ft)	Layer Number	Total Unit Weight (kcf)	Initial G (ksf)	Initial Vs (fps)	Final G (ksf)	Final Vs (fps)	Damping
Soft Rock								
0.0	–	–	–	–	–	–	–	–
5.0	5.0	1	0.15	27660	2429	27425	2426	0.016
10.0	5.0	2	0.15	29180	2495	28318	2466	0.018
15.0	5.0	3	0.15	30262	2541	28819	2487	0.020
20.0	5.0	4	0.15	30620	2556	28589	2477	0.023
25.0	5.0	5	0.15	30920	2568	29290	2508	0.019
30.0	5.0	6	0.15	31384	2588	29481	2516	0.021
33.5	3.5	7	0.15	31932	2610	30768	2570	0.017
39.5	6.0	8	0.15	32464	2632	31144	2586	0.018
45.0	5.5	9	0.15	33042	2655	31314	2593	0.019
50.0	5.0	10	0.15	33668	2680	31598	2604	0.020
60.0	10.0	11	0.15	34341	2707	31826	2614	0.021
80.0	20.0	12	0.15	35021	2733	31738	2610	0.024
100.0	20.0	13	0.15	35708	2760	31585	2604	0.026
120.0	20.0	14	0.15	36401	2787	31585	2604	0.028
Bedrock	–	–	0.15	300000	8000	298137	8000	0.020

Table 3.7.1-4 (Sheet 3 of 5)
Strain Compatible Soil Properties

Depth to Bottom of Layer (ft)	Thickness of Layer (ft)	Layer Number	Total Unit Weight (kcf)	Initial G (ksf)	Initial Vs (fps)	Final G (ksf)	Final Vs (fps)	Damping
Upper Bound Soft to Medium Soil								
0	–	–	–	–	–	–	–	–
5.0	5.0	1	0.11	6873	1414	6664	1397	0.018
10.0	5.0	2	0.11	9844	1692	9202	1641	0.023
15.0	5.0	3	0.11	13917	2012	12880	1942	0.024
20.0	5.0	4	0.11	14971	2087	13629	1997	0.027
25.0	5.0	5	0.11	15645	2133	14574	2065	0.022
30.0	5.0	6	0.11	16419	2186	15045	2099	0.024
33.5	3.5	7	0.11	17873	2280	16908	2225	0.019
39.5	6.0	8	0.11	19036	2353	17873	2287	0.020
45.0	5.5	9	0.11	20387	2435	18996	2358	0.021
50.0	5.0	10	0.11	21726	2514	20136	2428	0.021
60.0	10.0	11	0.11	23234	2600	21366	2501	0.022
80.0	20.0	12	0.11	24712	2681	22314	2556	0.024
100.0	20.0	13	0.11	26151	2758	23137	2602	0.026
120.0	20.0	14	0.11	27546	2831	24009	2651	0.027
Bedrock	–	–	0.15	300000	8000	298137	8000	0.020

Table 3.7.1-4 (Sheet 4 of 5)
Strain Compatible Soil Properties

Depth to Bottom of Layer (ft)	Thickness of Layer (ft)	Layer Number	Total Unit Weight (kcf)	Initial G (ksf)	Initial Vs (fps)	Final G (ksf)	Final Vs (fps)	Damping
Soft-to-Medium Soil								
0.0	–	–	–	–	–	–	–	–
5.0	5.0	1	0.11	3438	1000	3222	971	0.023
10.0	5.0	2	0.11	4923	1197	4355	1129	0.031
15.0	5.0	3	0.11	6960	1423	5987	1324	0.035
20.0	5.0	4	0.11	7487	1476	6161	1343	0.040
25.0	5.0	5	0.11	7824	1509	6699	1400	0.031
30.0	5.0	6	0.11	8211	1546	6891	1420	0.033
33.5	3.5	7	0.11	8938	1613	7872	1518	0.026
39.5	6.0	8	0.11	9520	1664	8317	1560	0.027
45.0	5.5	9	0.11	10195	1722	8834	1608	0.028
50.0	5.0	10	0.11	10864	1778	9347	1654	0.029
60.0	10.0	11	0.11	11618	1838	9818	1695	0.031
80.0	20.0	12	0.11	12357	1896	10031	1714	0.036
100.0	20.0	13	0.11	13077	1950	10201	1728	0.040
120.0	20.0	14	0.11	13774	2002	10512	1754	0.043
Bedrock	–		0.15	300000	8000	298137	8000	0.020

Table 3.7.1-4 (Sheet 5 of 5)
Strain Compatible Soil Properties

Depth to Bottom of Layer (ft)	Thickness of Layer (ft)	Layer Number	Total Unit Weight (kcf)	Initial G (ksf)	Initial Vs (fps)	Final G (ksf)	Final Vs (fps)	Damping
Soft Soil								
0.0	–	–	–	–	–	–	–	–
5.0	5.0	1	0.11	3438	1000	3222	971	0.023
10.0	5.0	2	0.11	3633	1028	3042	944	0.038
15.0	5.0	3	0.11	3865	1060	2974	933	0.047
20.0	5.0	4	0.11	3921	1068	2752	898	0.059
25.0	5.0	5	0.11	3955	1073	2922	925	0.049
30.0	5.0	6	0.11	3994	1078	2762	899	0.056
33.5	3.5	7	0.11	4065	1088	3022	941	0.046
39.5	6.0	8	0.11	4121	1095	2958	931	0.049
45.0	5.5	9	0.11	4183	1103	2896	921	0.053
50.0	5.0	10	0.11	4244	1111	2851	914	0.056
60.0	10.0	11	0.11	4310	1120	2774	901	0.062
80.0	20.0	12	0.11	4374	1128	2668	884	0.068
100.0	20.0	13	0.11	4434	1136	2691	888	0.069
120.0	20.0	14	0.11	4492	1143	2718	892	0.069
Bedrock	–	–	0.15	300000	8000	298137	8000	0.020

Tables 3.7.2-1–3.7.2-16 Not Used

Table 3.7.3-1 (Sheet 1 of 3)
Seismic Category I Equipment Outside Containment by Room Number

Room No.	Room Name	Equipment Description
12101	Division A battery room	Batteries
12102	Division C battery room 1	Batteries
12103	Spare battery room	Spare batteries
12104	Division B battery room 1	Batteries
12105	Division D battery room	Batteries
12113	Spare battery charger room	
12154	Auxiliary building sump room	RCA floodup level sensors
12162	RNS pump room A	RNS pressure boundary
12163	RNS pump room B	RNS pressure boundary
12201	Division A dc equipment room	dc equipment
12202	Division C battery room 2	Batteries
12203	Division C dc equipment room	dc equipment
12204	Division B battery room 2	Batteries
12205	Division D dc equipment room	dc equipment
12207	Division B dc equipment room	dc equipment
12211	Corridor	Divisional cables SGS instrumentation tubing
12212	Division B RCP trip switchgear room	RCP trip switchgear
12244	Lower annulus valve area	CVS/WLS containment isolation valves
12251	Demineralizer/filter access area	CVS/DWS isolation valves
12254	SFS penetration room	SFS containment isolation valve
12256	Containment isolation valve room	RNS containment isolation valves
12259	Pipe chase	RNS piping
12262	Piping/Valve room	RNS pressure boundary, SFS piping
12265	Waste monitor tank room C	SFS piping
12269	Pipe chase	RNS pressure boundary
12300	Corridor	Divisional cable, MCR load shed panel SGS instrumentation tubing
12301	Division A I&C room	Divisional I&C
12302	Division C I&C room	Divisional I&C

Table 3.7.3-1 (Sheet 2 of 3)
Seismic Category I Equipment Outside Containment by Room Number

Room No.	Room Name	Equipment Description
12303	Remote shutdown room	Divisional cabling
12304	Division B I&C/penetration room	Divisional I&C/electrical penetrations
12305	Division D I&C/penetration room	Divisional I&C/electrical penetrations
12306	Valve/piping penetration room	CCS/CVS/DWS/FPS/SGS containment isolation valves SGS instrumentation tubing
12311	Corridor	Divisional cabling
12312	Division C RCP trip switchgear room	RCP trip switchgear
12313	Division C I&C/penetration room	Divisional I&C/electrical penetrations
12321	Non-1E equipment/penetration room	Divisional cabling/electrical penetrations
12341	Middle annulus	Class 1E electrical penetrations Various mechanical piping penetrations
12343	Division C middle annulus penetration room	Class 1E electrical penetrations
12344	Division B middle annulus penetration room	Class 1E electrical penetrations
12345	Division D middle annulus penetration room	Class 1E electrical penetrations
12351	Maintenance floor staging area	Divisional cabling (ceiling)
12352	Personnel hatch	Personnel airlock (interlocks)
12354	Middle annulus access room	PSS/SFS containment isolation valves
12362	RNS HX room	RNS pressure boundary
12365	Waste monitor tank room B	SFS piping
12400	Control room vestibule	Control room access
12401	Main control room	Dedicated safety panel VBS HVAC dampers VES isolation valves Lighting circuits Mounting for lighting fixtures
12404	Lower MSIV compartment B	SGS containment isolation valves, instrumentation
12405	Lower VBS B and D equipment room	VWS/PXS/CAS containment isolation valves
12406	Lower MSIV compartment A	SGS containment isolation valves, instrumentation
12411	Corridor	Divisional cabling
12412	Electrical penetration room Division A	Divisional electrical penetrations, MCR load shed panel

Table 3.7.3-1 (Sheet 3 of 3)
Seismic Category I Equipment Outside Containment by Room Number

Room No.	Room Name	Equipment Description
12421	Non 1E equipment/penetration room	Divisional cabling/electrical penetrations
12422	Reactor trip switchgear II	Reactor trip switchgear
12423	Reactor trip switchgear I	Reactor trip switchgear
12452	VFS penetration room	VFS containment isolation valves, divisional cabling
12454	VFS/SFS/PSS penetration room	SFS/PSS/VFS containment isolation valves, RNS pressure boundary
12462	Cask washdown pit	SFS piping
12463	Cask loading pit/Spent fuel storage pit	Spent fuel transfer gate
12501	VBS MCR/A&C equipment room	Divisional cabling
12504	Upper MSIV compartment B	SGS CIVs, instrumentation
12506	Upper MSIV compartment A	SGS CIVs, instrumentation
12541	Upper annulus	PCS piping and cabling PCS air baffle
12553	Personnel access area	Personnel airlock (interlocks)
12555	VES air storage	VES high pressure air bottles
12651	VAS Equipment Room	VFS containment isolation valves
12563	Spent fuel storage pit	Spent fuel storage racks Spent fuel transfer gate Spent fuel cask loading pit gate
12701	PCS valve room	PCS isolation valves/instrumentation
12703	PCS water storage tank	PCS piping, level and temperature instrumentation

Table 3.7.3-2
Equipment Classified as Sensitive Targets for Seismically Analyzed Piping, HVAC Ducting, Cable Tray Systems

Component	Discussion	Zone of Protection
Seismic Category I Valve No Class 1E Electrical Equipment Not pressure sensitive	These are manual valves. The actuator must be protected from impact.	Valve body and actuator area
Seismic Category I Valve Class 1E Electrical Equipment Pressure sensitive	These valves have sensitive Class 1E equipment (e.g., Position indicators, limit switches, motor operator) or solenoid valves.	One support (acting in direction of impact) on each side of valve
Seismic Category I Dampers	The actuator must be protected along with any Class 1E equipment.	Within one support (acting in direction of impact) on each side of HVAC
Monitors	This includes: neutron detectors, radiation monitors, resistance temperature detectors, speed sensors, thermocouples, and transmitters.	Monitors and associated wiring
Sensitive Electrical Equipment Housed in Cabinets, Panels or Boards	This includes: relays, contractors, breakers, and switchgear.	Cabinets, panels, and boards housing sensitive devices
Class 1E exposed cables and wiring	Cables and wiring which are not housed in cable trays or conduits must be protected.	Exposed cables and wiring
Device or Instrument Tubing	Any device or tubing that could be damaged resulting in the loss of the pressure boundary of a safety class line.	Device or tubing
Penetrations	Rigid penetrations are considered robust. Floating penetrations with bellows are considered sensitive.	Floating penetration and associated bellows

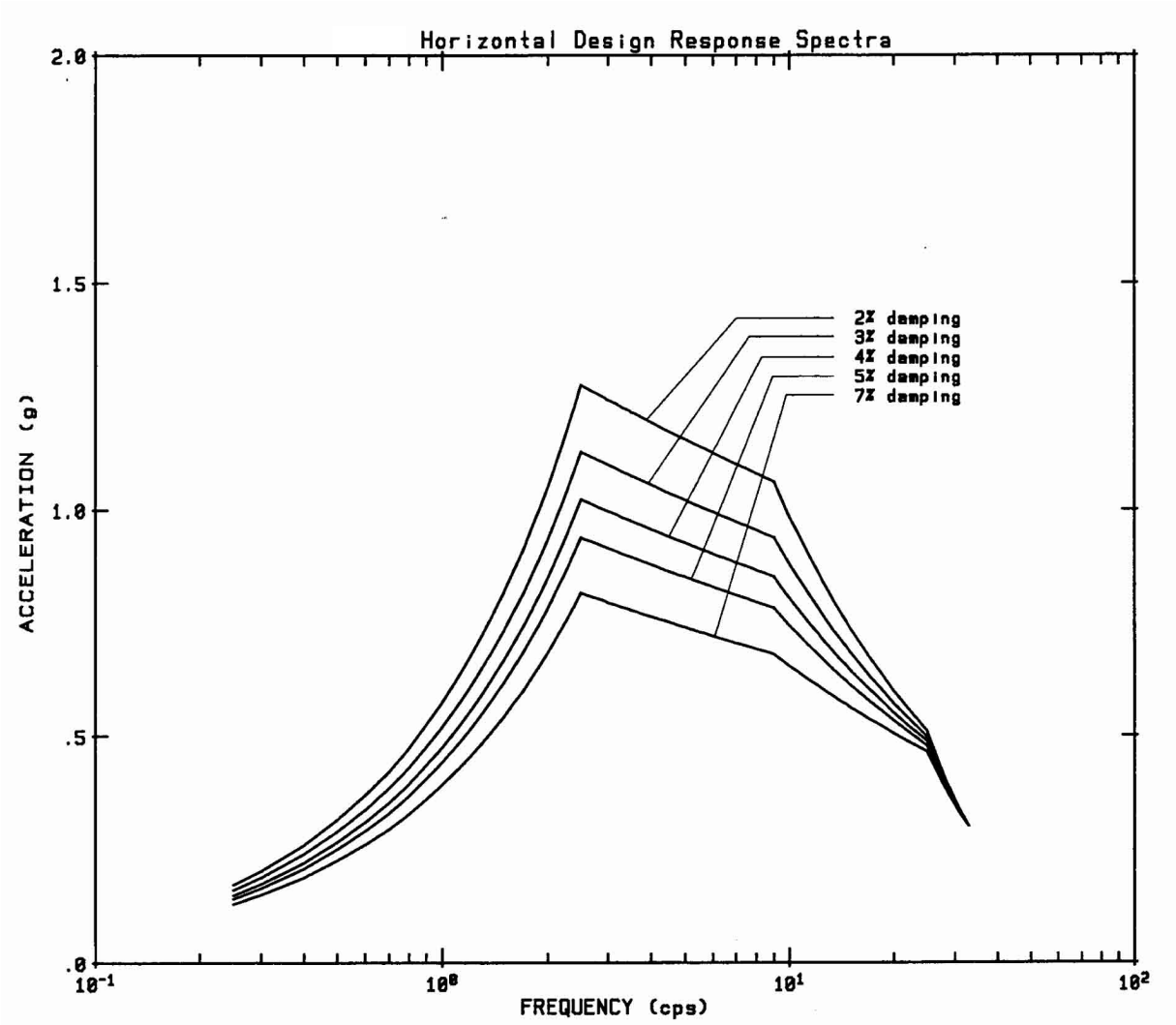


Figure 3.7.1-1
Horizontal Design Response Spectra
Safe Shutdown Earthquake

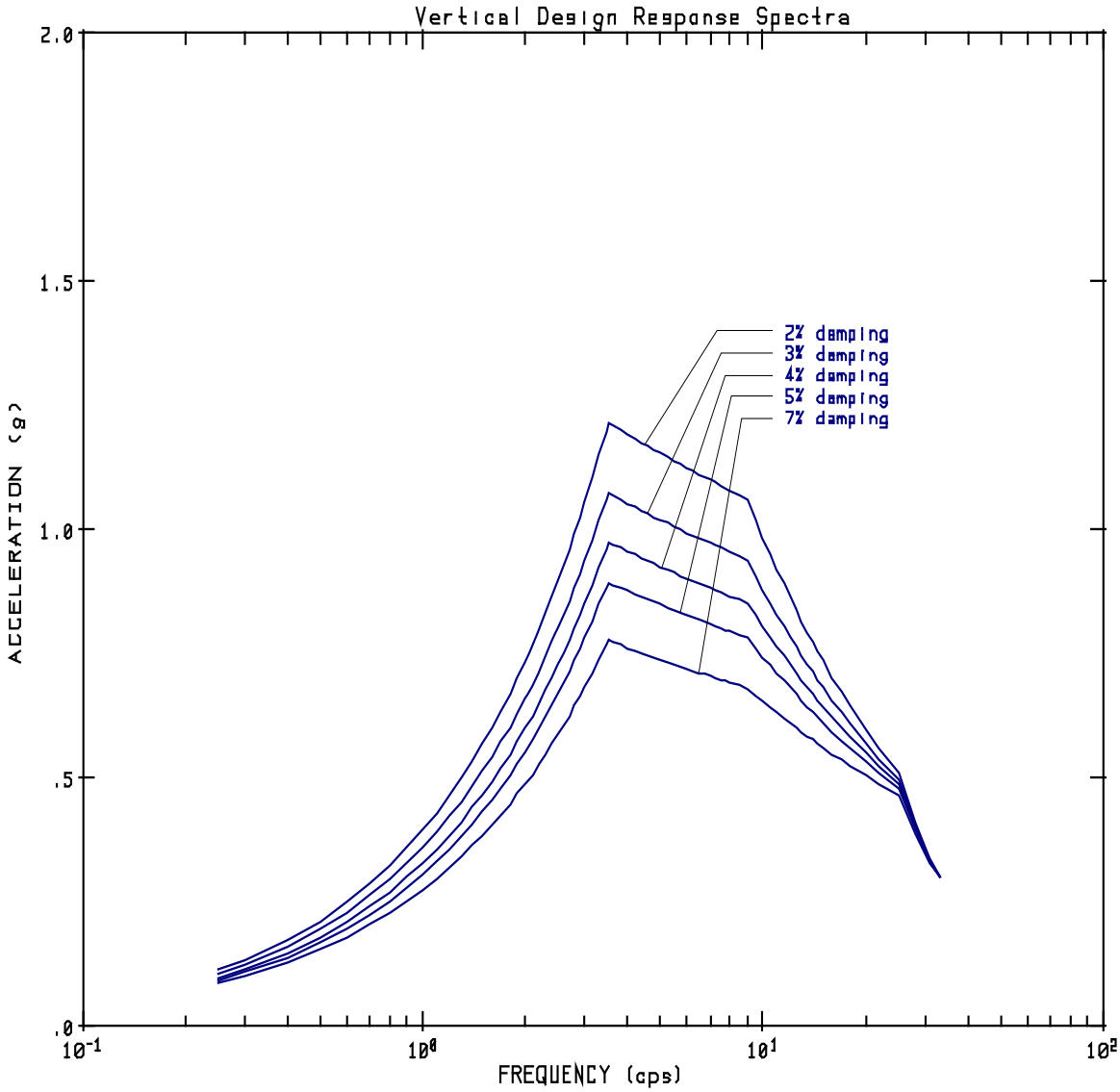


Figure 3.7.1-2
Vertical Design Response Spectra
Safe Shutdown Earthquake

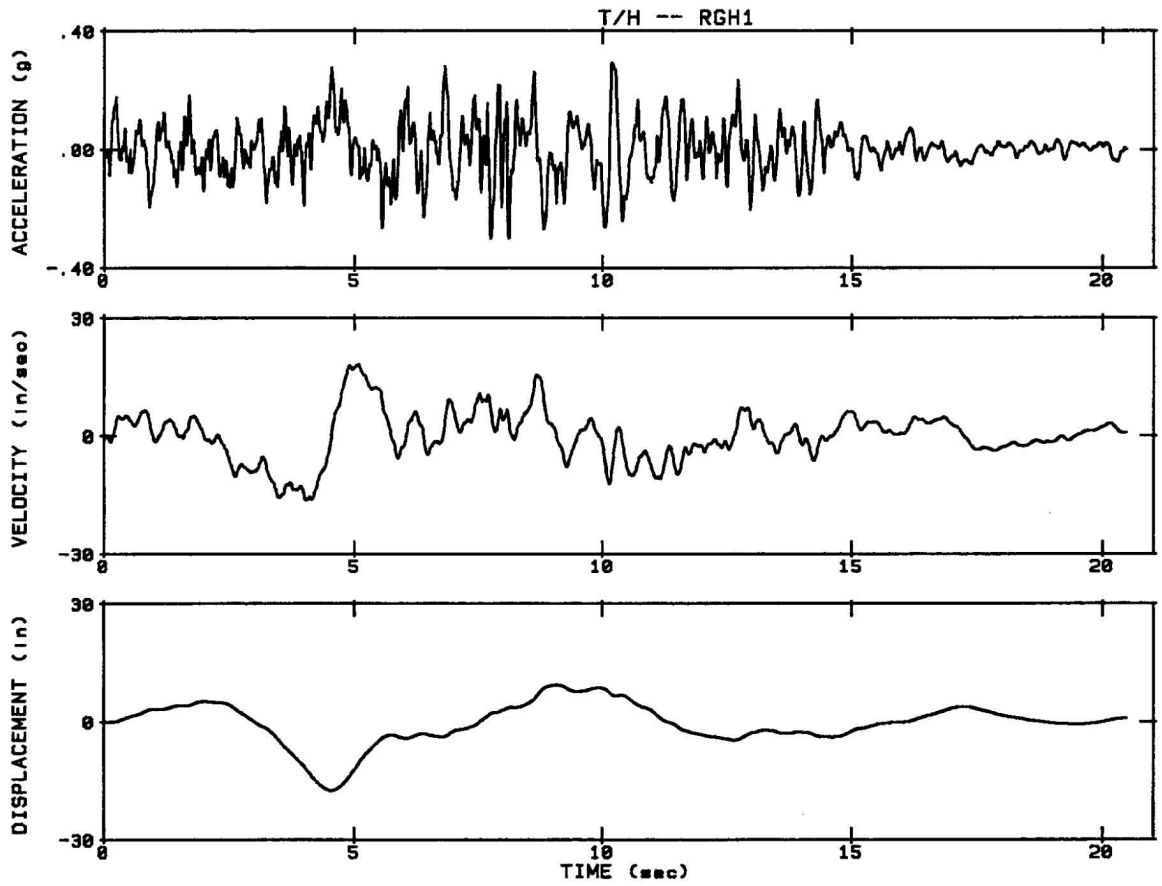


Figure 3.7.1-3
Design Horizontal Time History, "H1"
Acceleration, Velocity & Displacement Plots

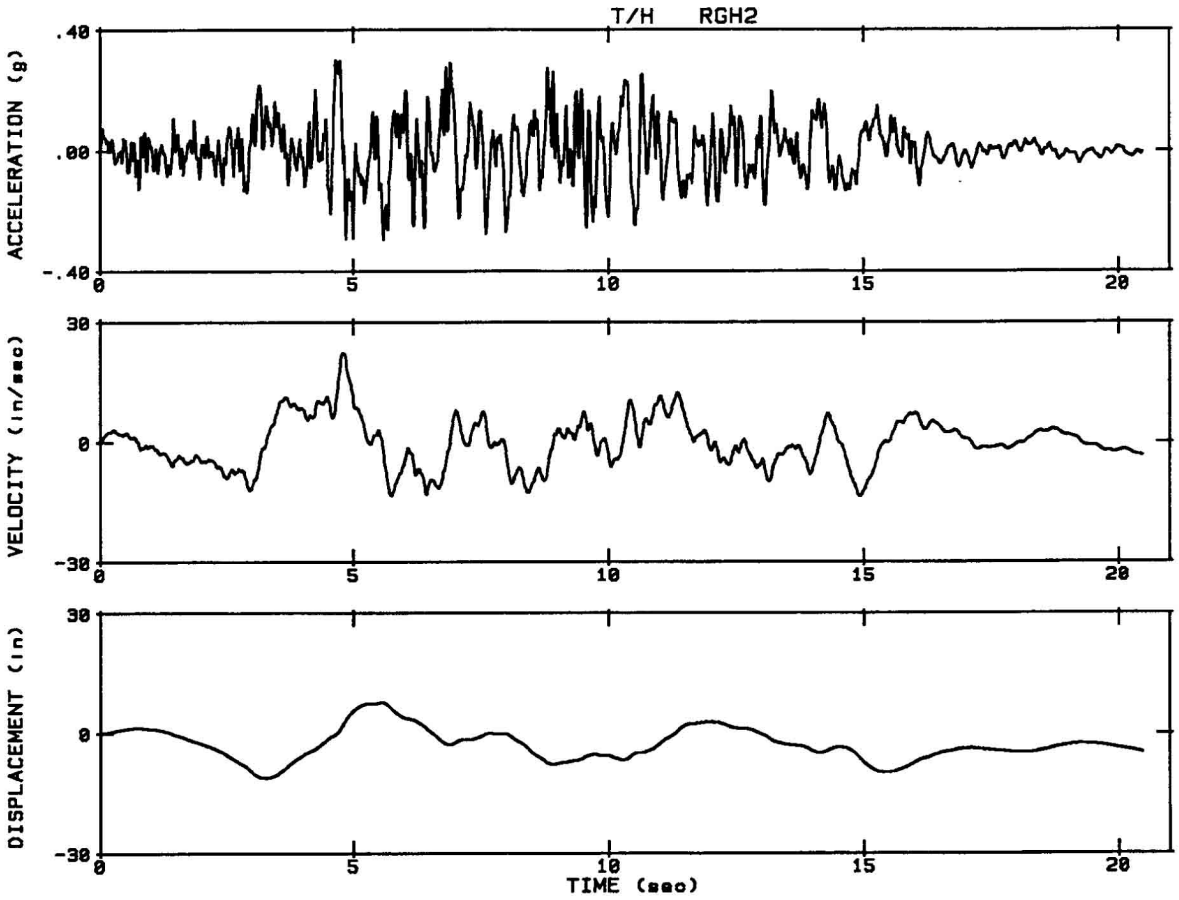


Figure 3.7.1-4
Design Horizontal Time History, "H2"
Acceleration, Velocity & Displacement Plots

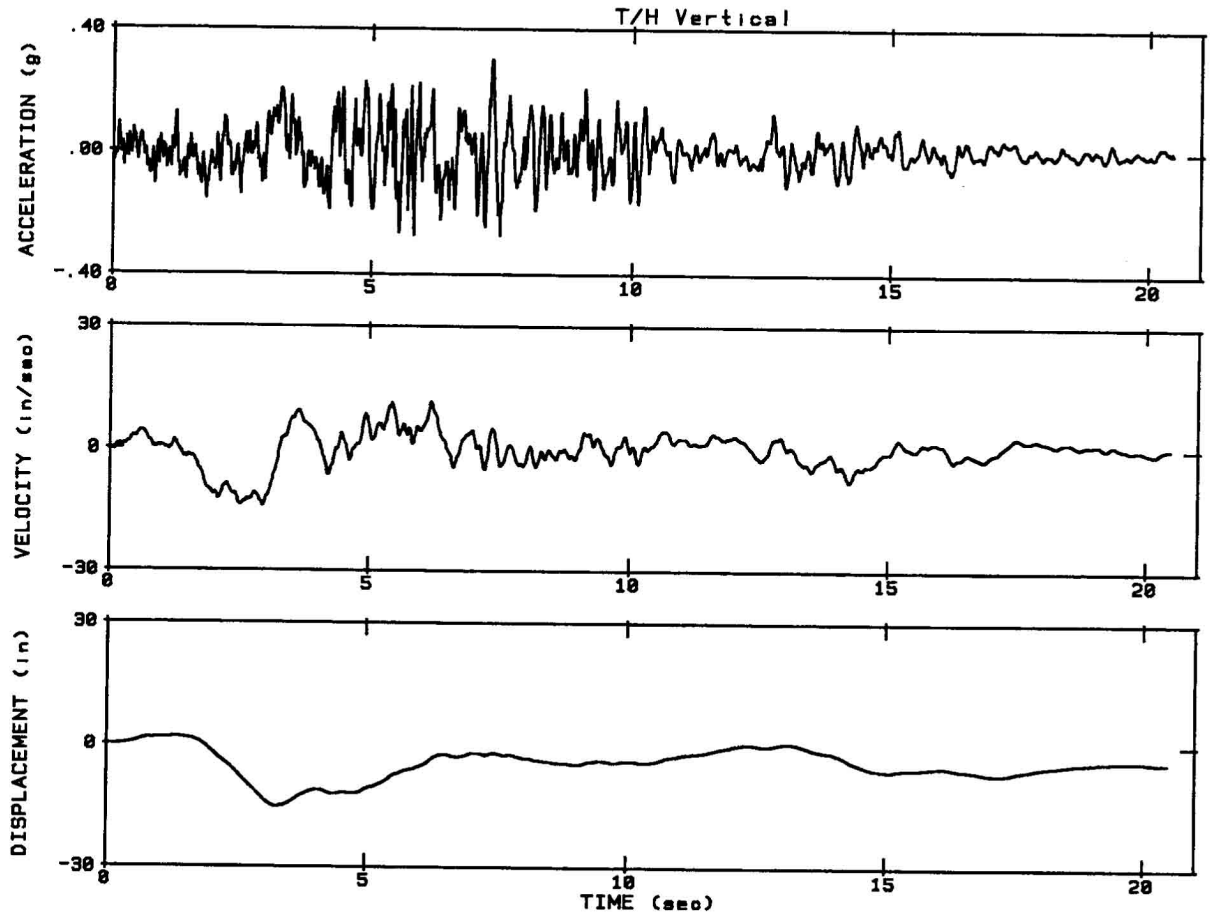


Figure 3.7.1-5
Design Vertical Time History
Acceleration, Velocity & Displacement Plots

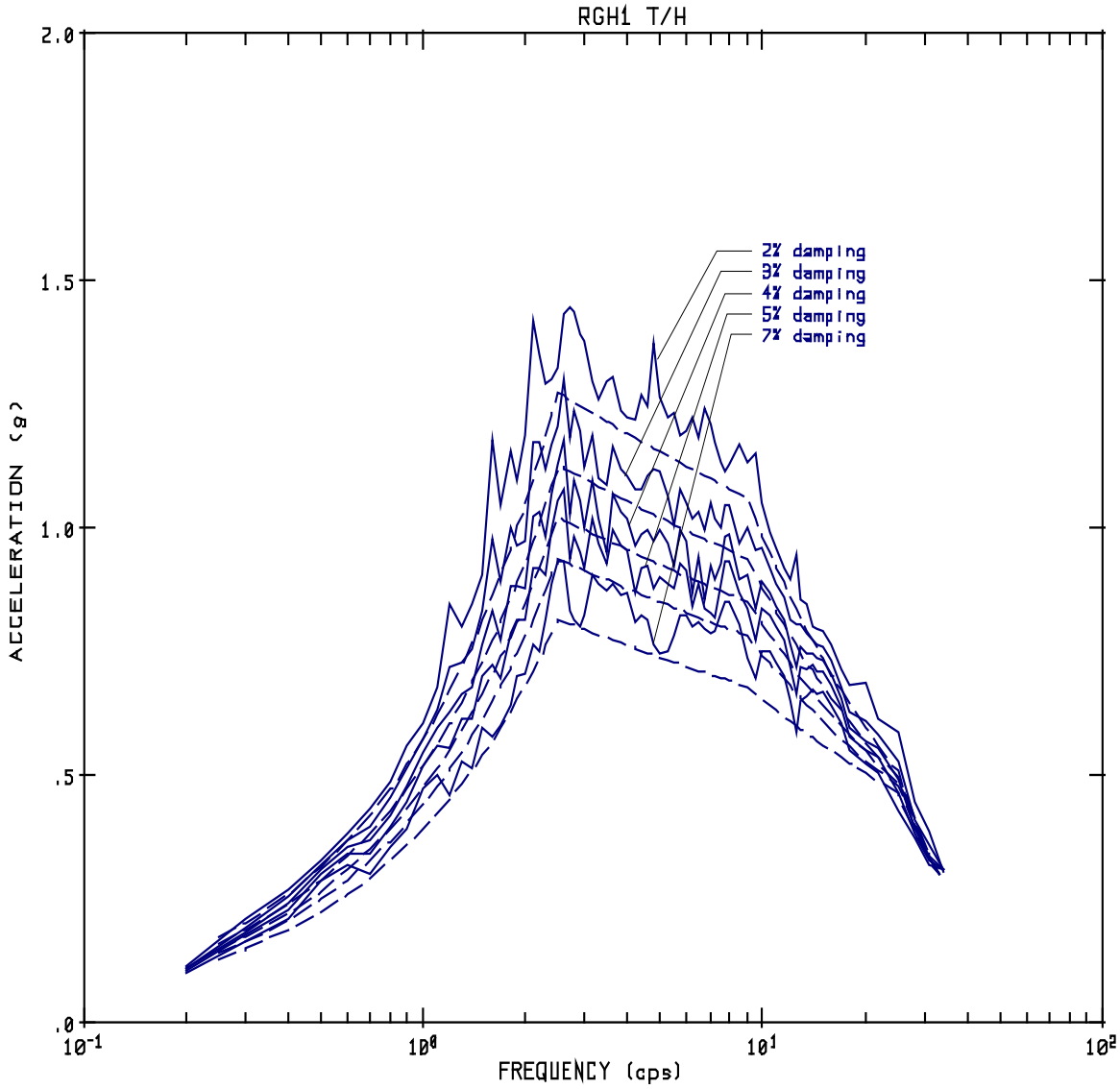


Figure 3.7.1-6
Acceleration Response Spectra of
Design Horizontal Time History, "H1"

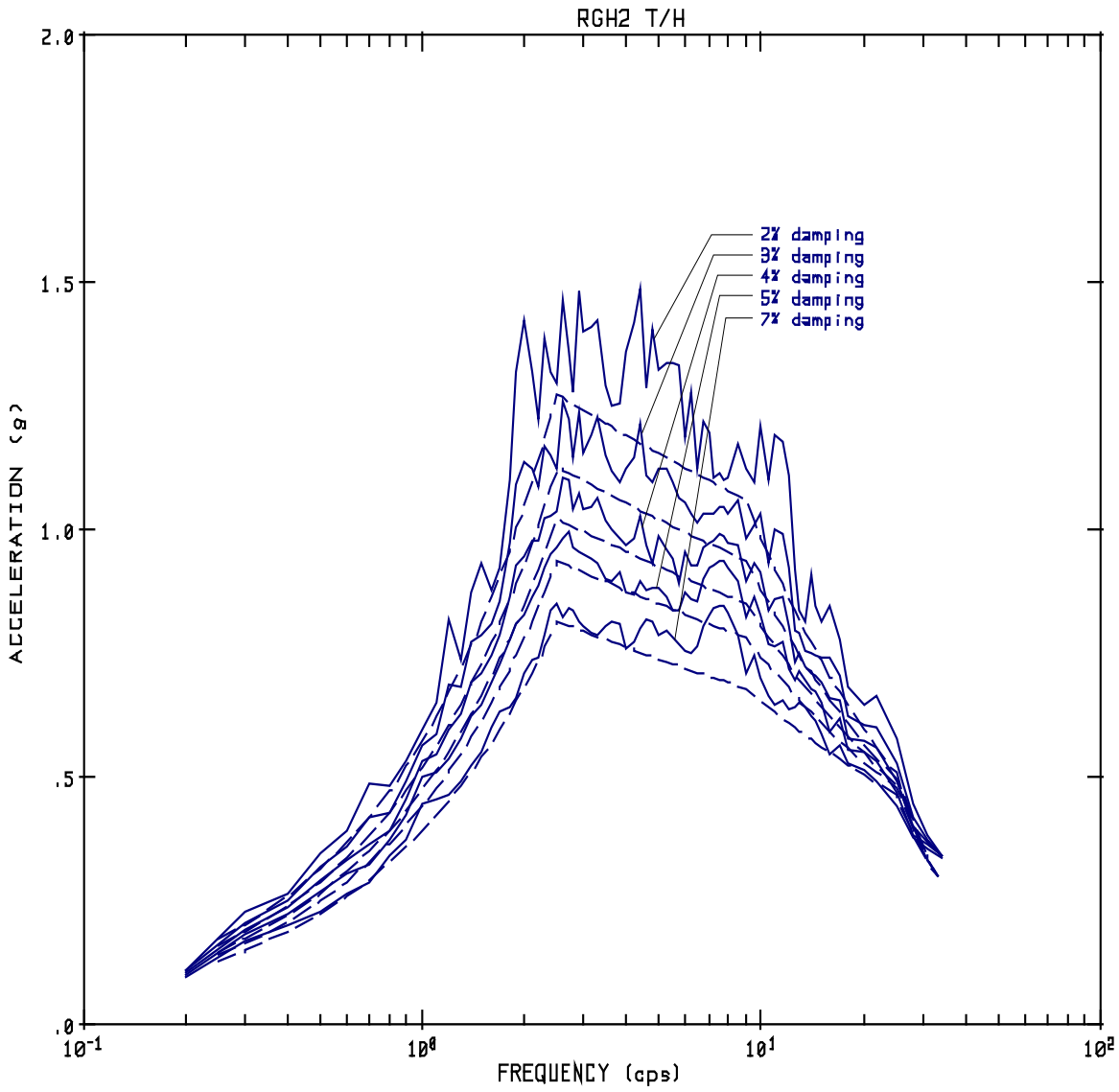


Figure 3.7.1-7
Acceleration Response Spectra of
Design Horizontal Time History, "H2"

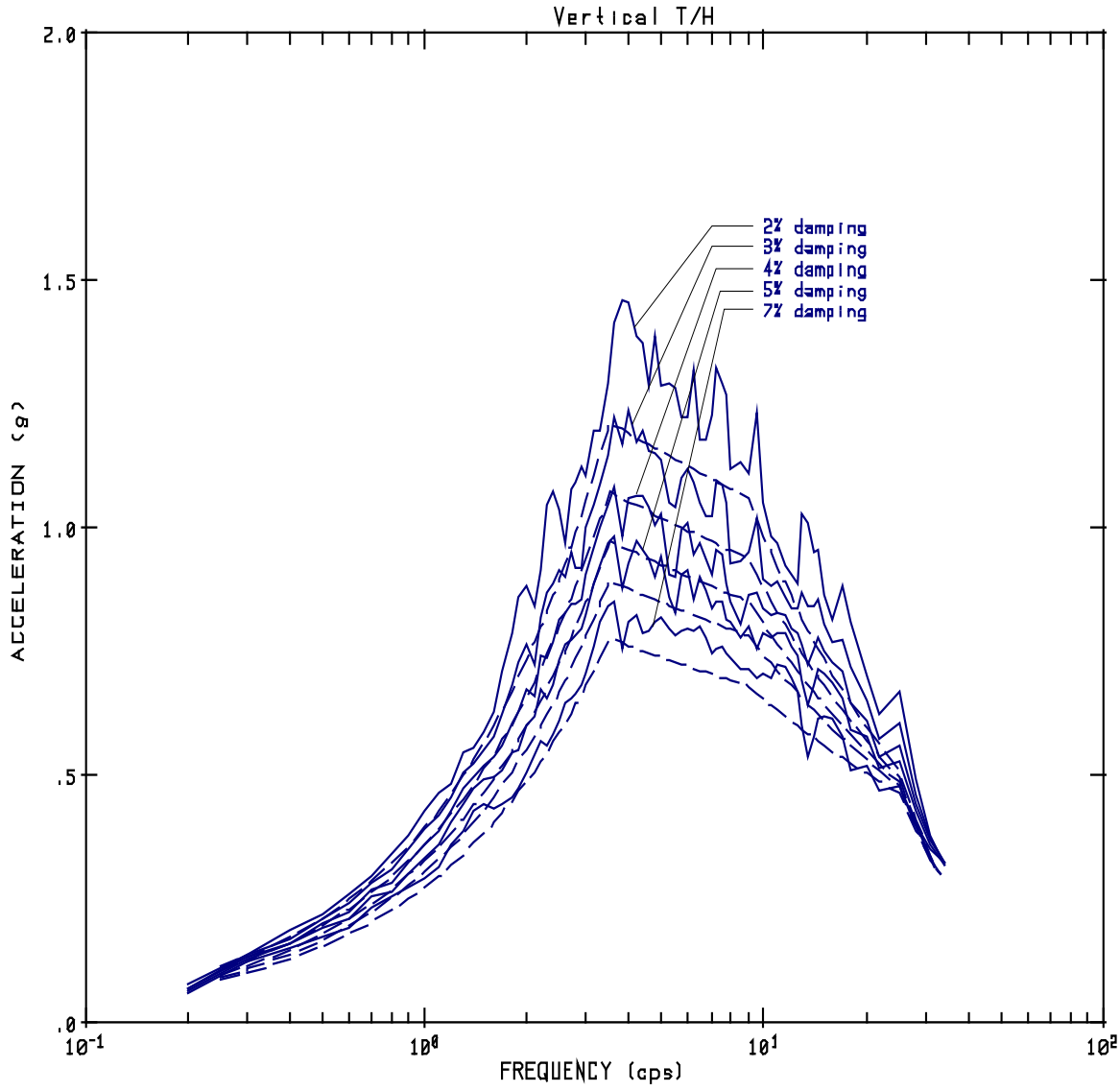


Figure 3.7.1-8
Acceleration Response Spectra of
Design Vertical Time History

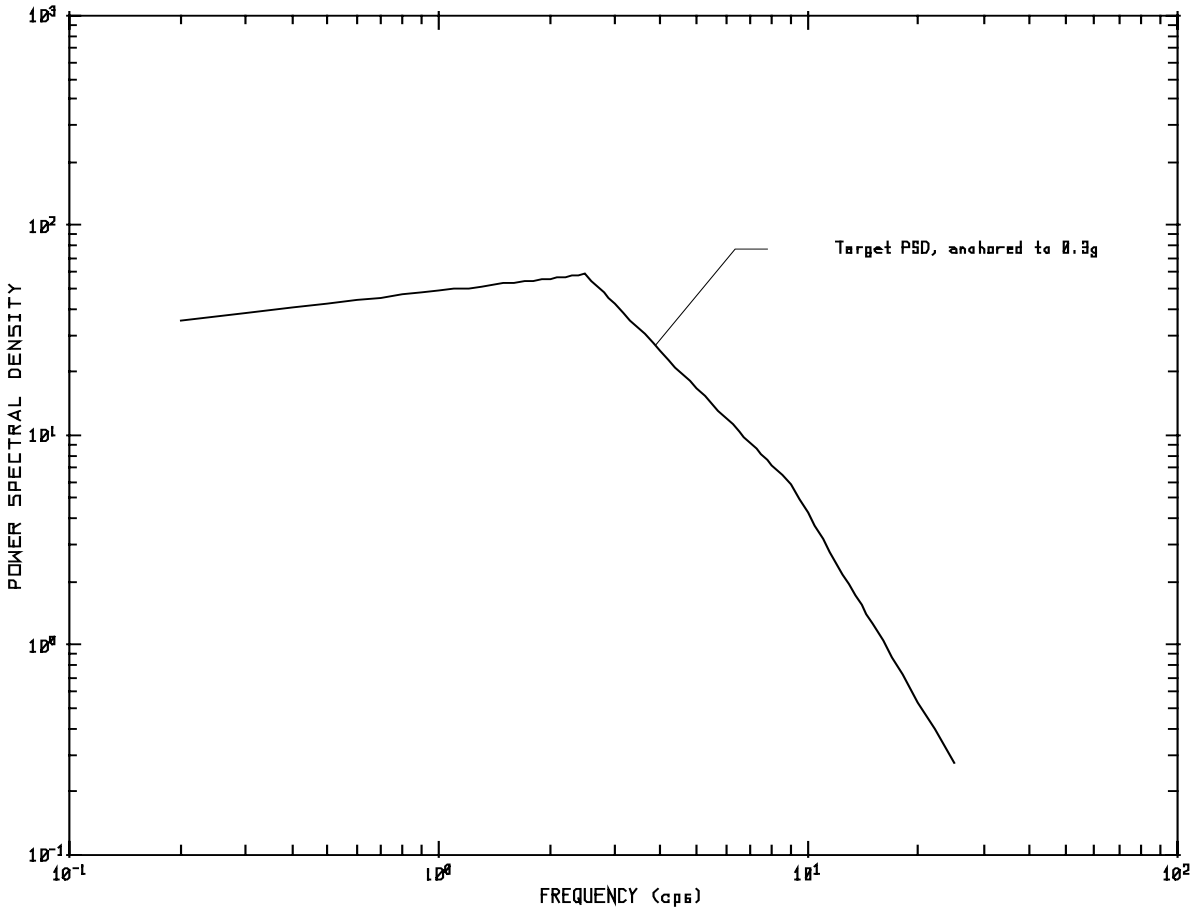


Figure 3.7.1-9
Minimum Power Spectral Density Curve
(Normalized to 0.3g)

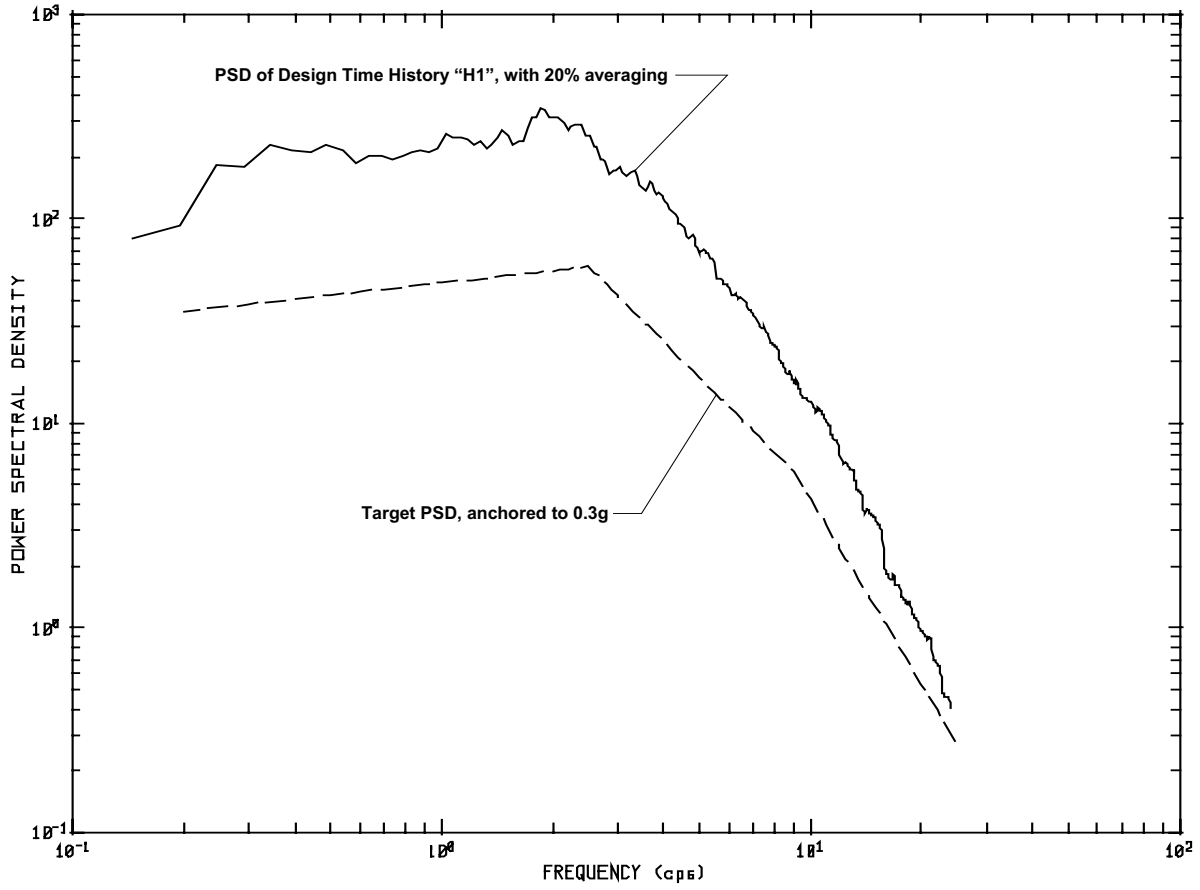


Figure 3.7.1-10
Power Spectral Density of
Design Horizontal Time History, "H1"

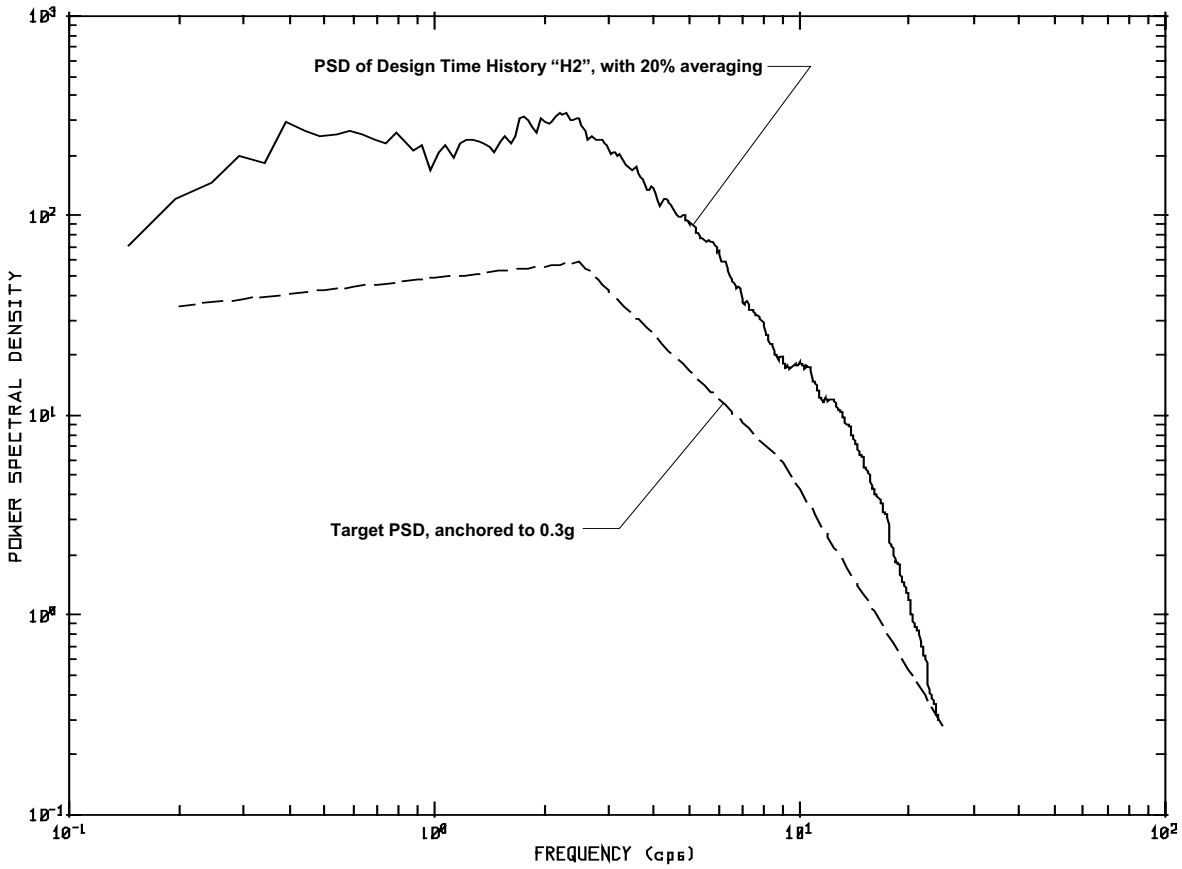


Figure 3.7.1-11
Power Spectral Density of
Design Horizontal Time History, "H2"

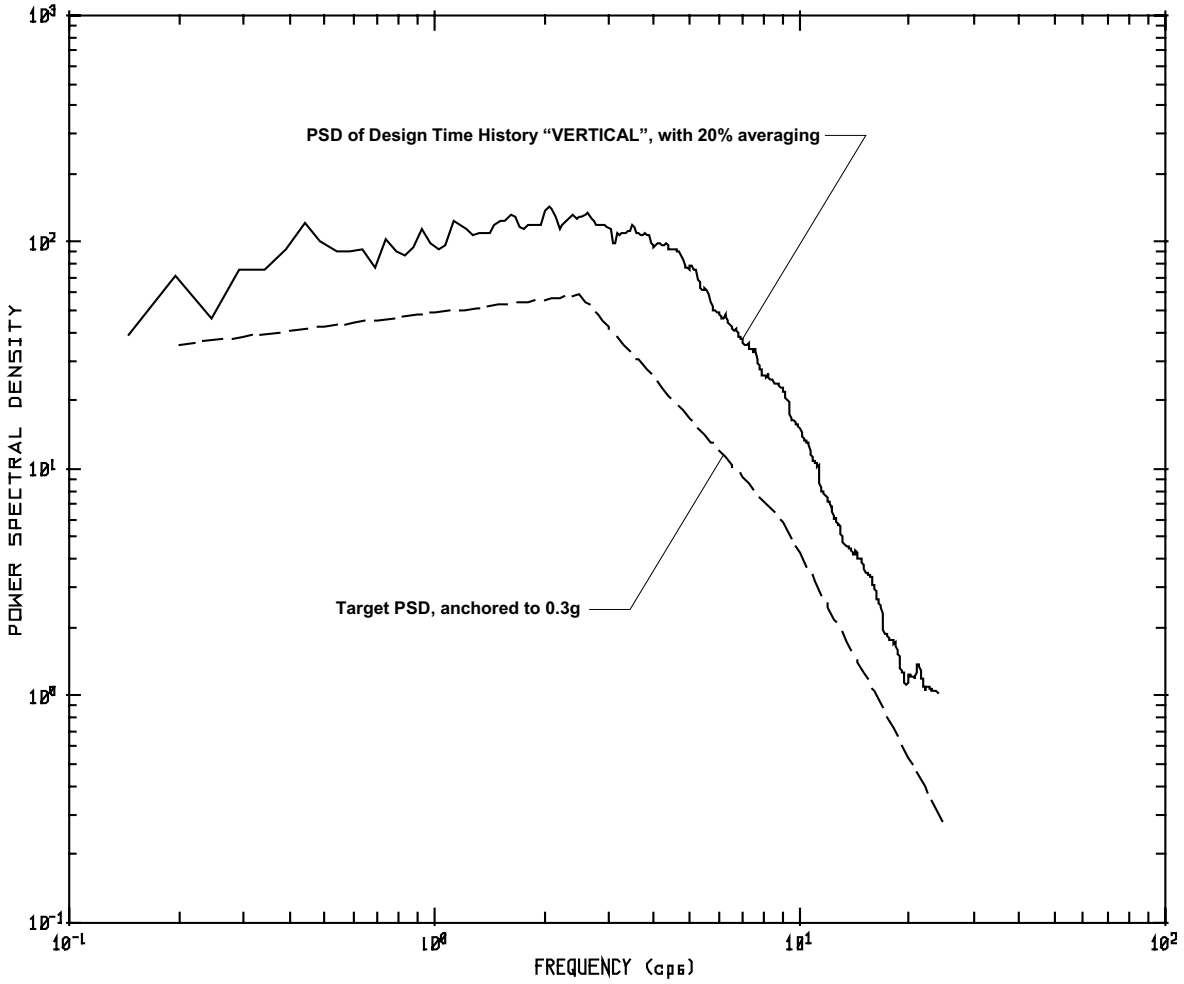


Figure 3.7.1-12
Power Spectral Density of
Design Vertical Time History

Figure 3.7.1-13 Not Used

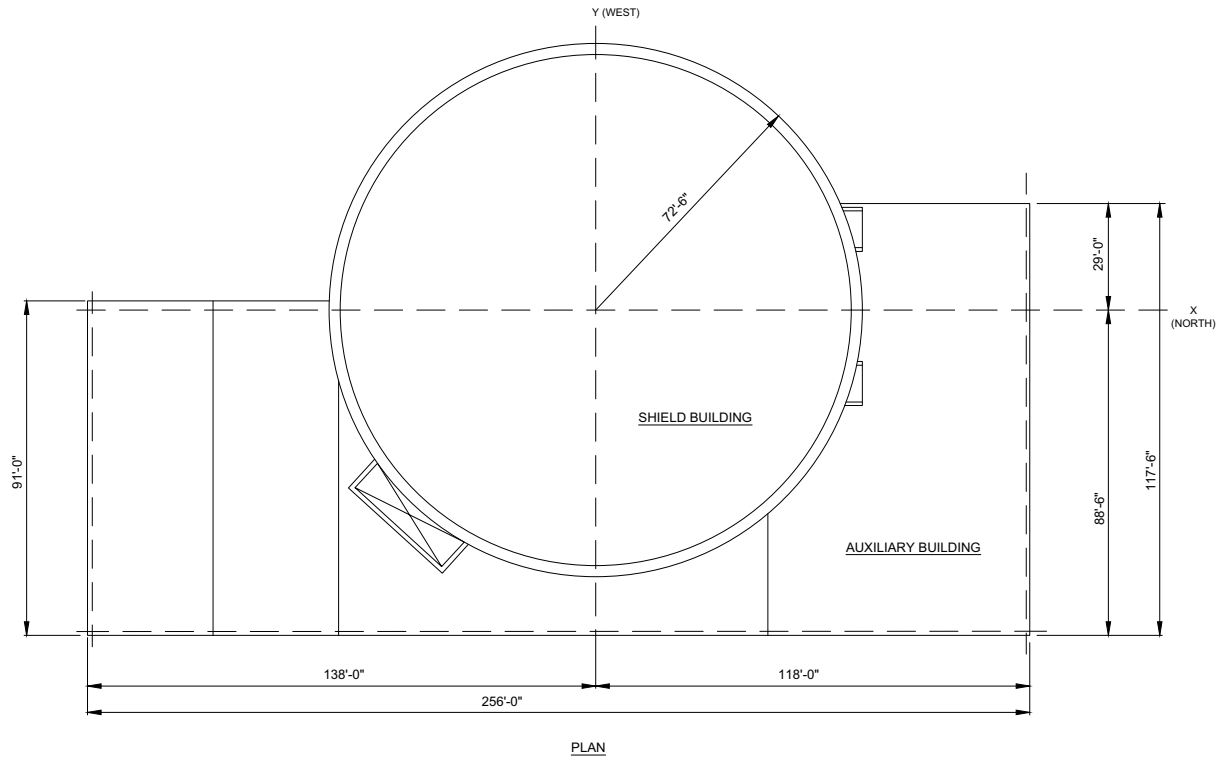
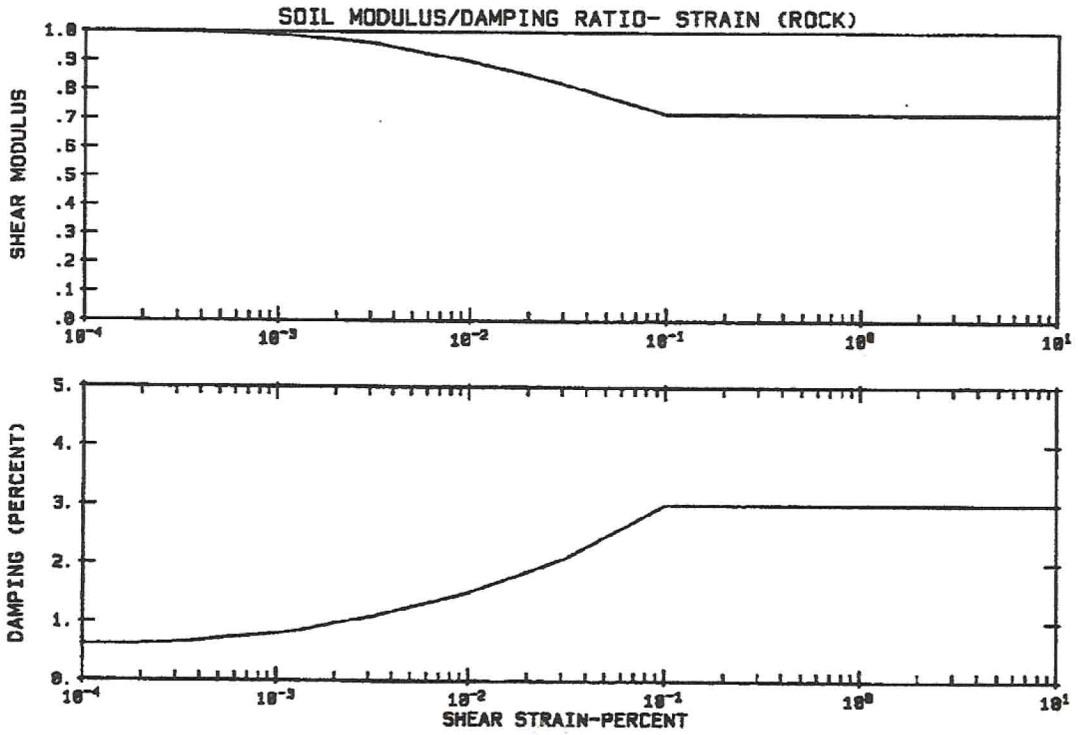


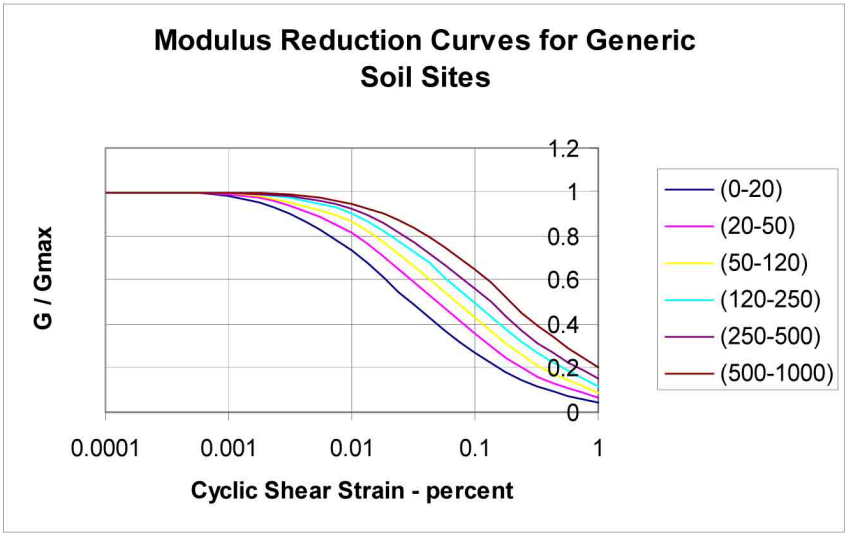
Figure 3.7.1-14
[*Nuclear Island Structures Dimensions*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



Modulus Reduction Curves for Generic Soil Sites

Figure 3.7.1-15
Strain Dependent Properties of Rock Material (Ref. 37)



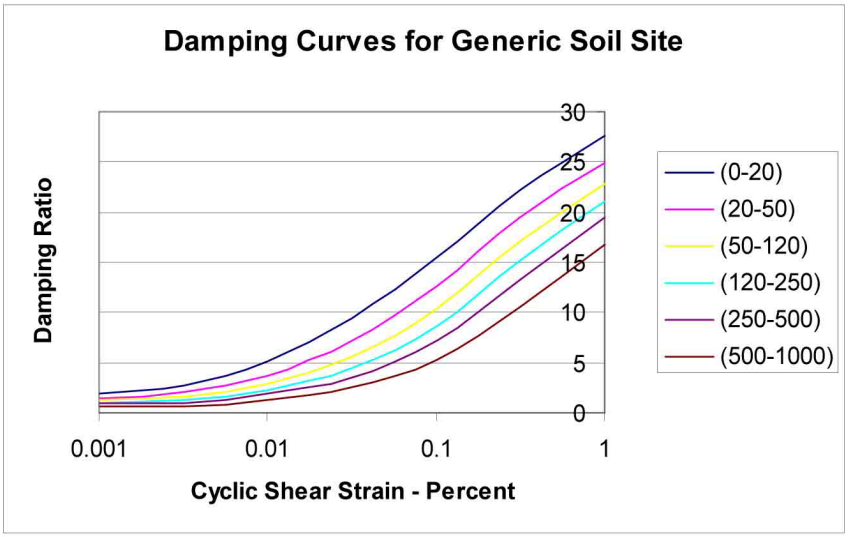
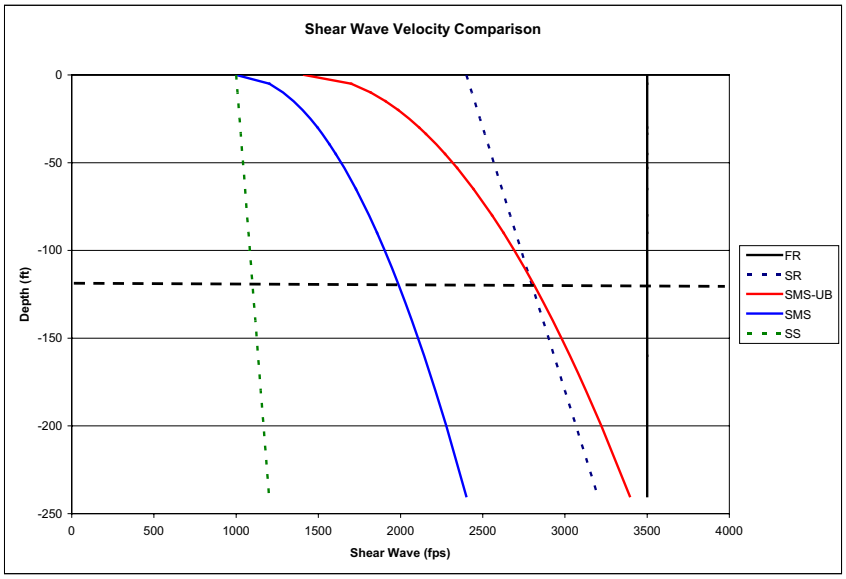
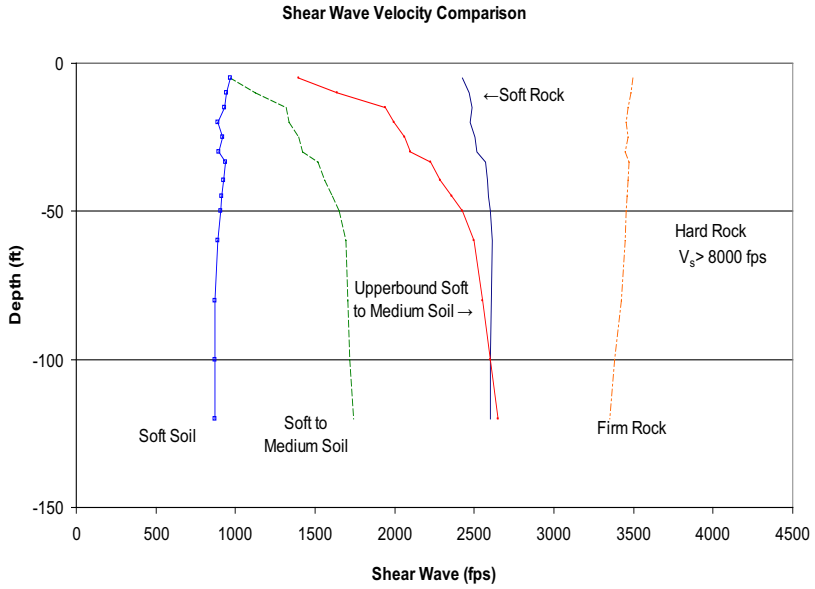


Figure 3.7.1-16
Strain Dependent Properties of Soil Material (Ref. 38)



Initial Properties



Strain-Iterated Shear Wave Velocity Profiles

Note: Fixed base analyses were performed for hard rock sites. These analyses are applicable for shear wave velocity greater than 8000 feet per second.

Figure 3.7.1-17
Generic Soil Profiles

Figures 3.7.2-1–3.7.2-11 Not Used

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 1 of 12)
[*Nuclear Island Key Structural Dimensions Plan at El. 66'-6"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 2 of 12)
[*Nuclear Island Key Structural Dimensions Plan at El. 82'-6"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 3 of 12)
[*Nuclear Island Key Structural Dimensions Plan at El. 100'-0" & 107'-2"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 4 of 12)
[*Nuclear Island Key Structural Dimensions Plan at El. 117'-6"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 5 of 12)
[*Nuclear Island Key Structural Dimensions Plan at El. 135'-3"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 6 of 12)
[*Nuclear Island Key Structural Dimensions Plan at El. 153'-0" & 160'-6"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 7 of 12)
[*Nuclear Island Key Structural Dimensions Plan at El. 160'-6", 180'-0", & 329'-0"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 8 of 12)
[*Nuclear Island Key Structural Dimensions Section A - A*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 9 of 12)
[*Nuclear Island Key Structural Dimensions Section B - B*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 10 of 12)
[*Nuclear Island Key Structural Dimensions Sections C - C and H - H*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 11 of 12)
[*Nuclear Island Key Structural Dimensions Section G - G*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-12 (Sheet 12 of 12)
**[*Nuclear Island Key Structural Dimensions*
Section J - J*]

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Figure 3.7.2-13 Not Used

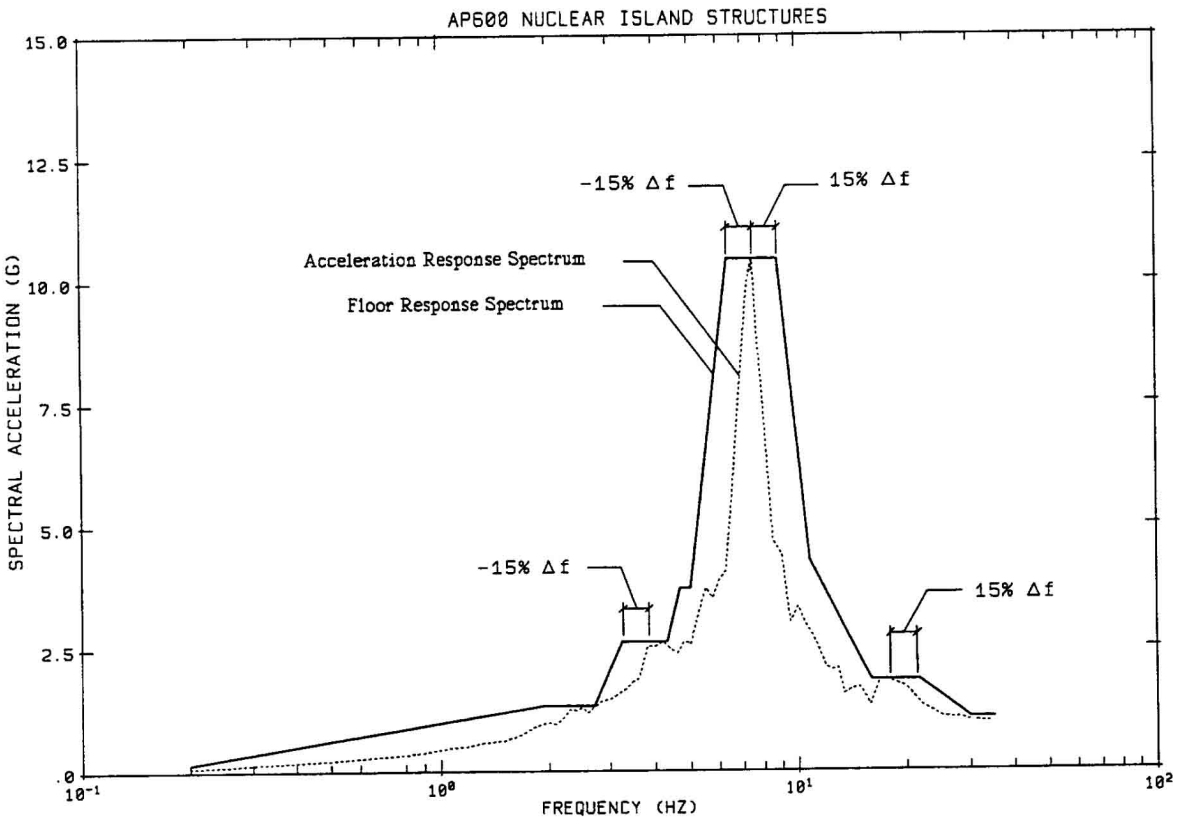


Figure 3.7.2-14
Typical Design Floor Response Spectrum

Figures 3.7.2-15–3.7.2-18 Not Used

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 1 of 10)
Annex Building Key Structural Dimensions
Plan at Elevation 100′-0″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 2 of 10)
Annex Building Key Structural Dimensions
Plan at Elevation 107′-2″ and 117′-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 3 of 10)
Annex Building Key Structural Dimensions
Plan at Elevation 135′-3″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 4 of 10)
Annex Building Key Structural Dimensions
Plan at Elevation 158′-0″ and 150′-3″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 5 of 10)
Annex Building Key Structural Dimensions
Roof Plan at Elevation 154′-0″ and 181′-11 3/4″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 6 of 10)
Annex Building Key Structural Dimensions
Section A - A

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 7 of 10)
Annex Building Key Structural Dimensions
Section B - B

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 8 of 10)
Annex Building Key Structural Dimensions
Section C - C

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 9 of 10)
Annex Building Key Structural Dimensions
Sections D - D, E - E, & F - F

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.7.2-19 (Sheet 10 of 10)
Annex Building Key Structural Dimensions
Sections G - G, H - H, & J - J

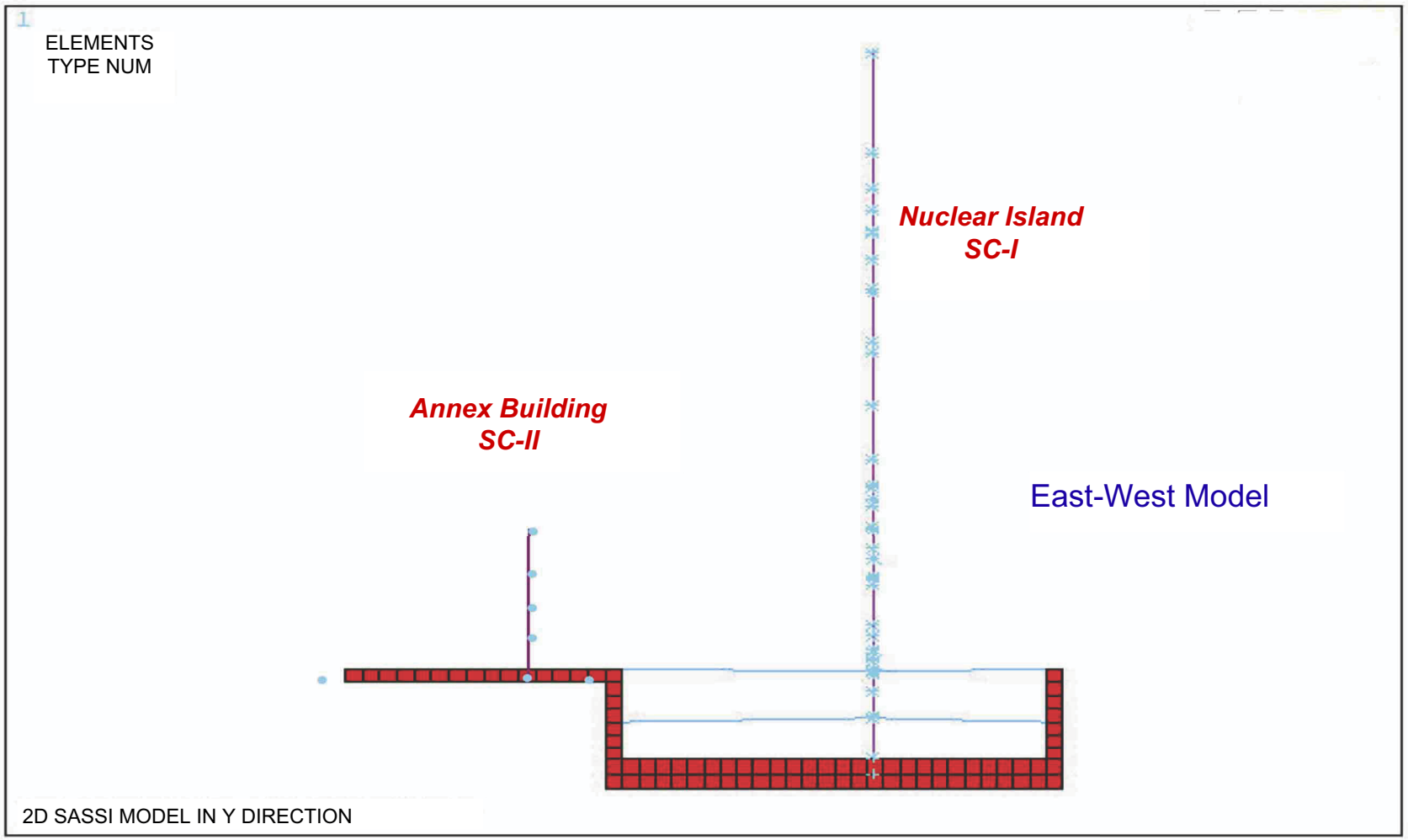


Figure 3.7.2-20
East-West 2D SASSI Model with Adjacent Buildings

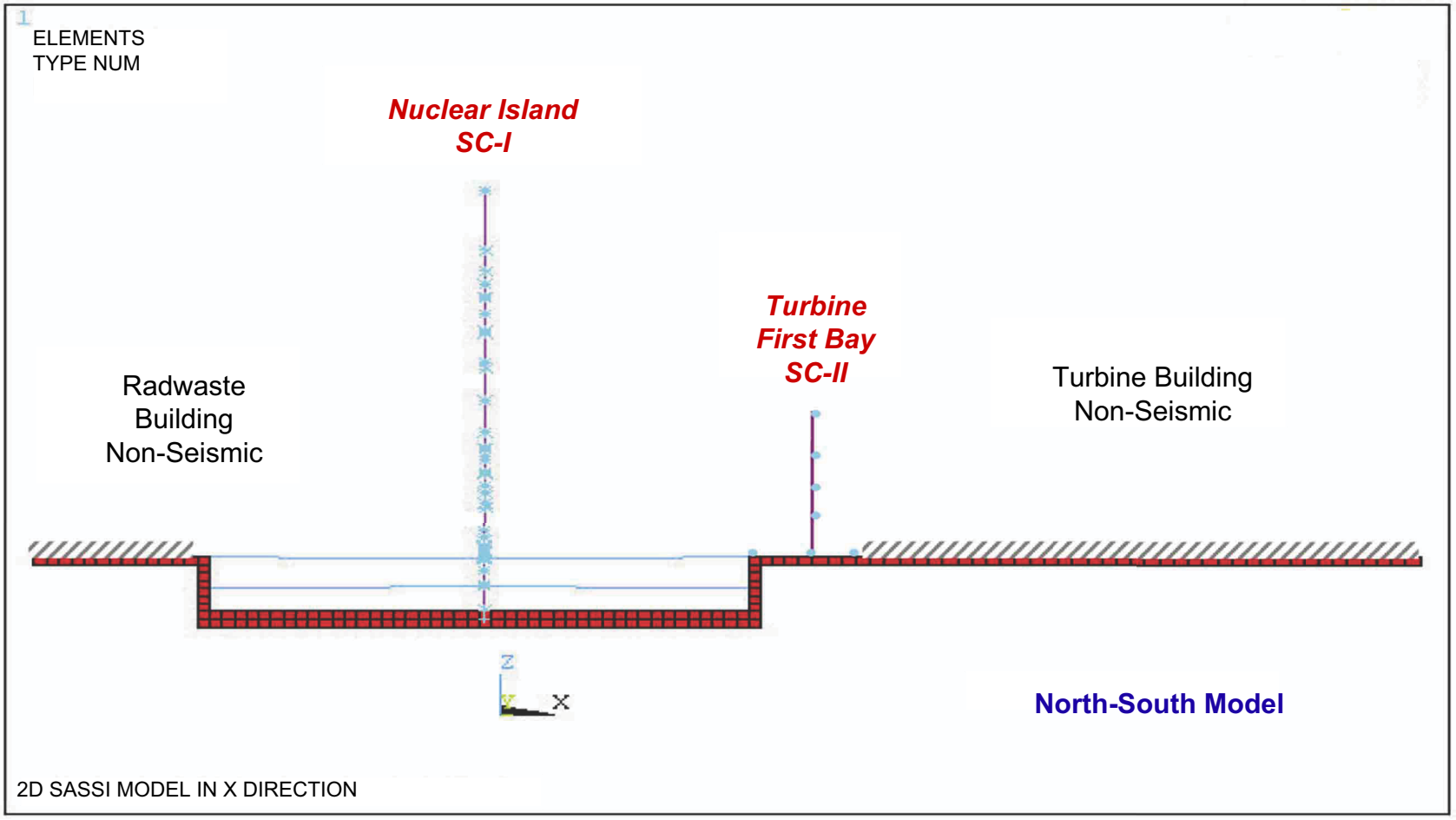


Figure 3.7.2-21
2D North-South SASSI Model with Adjacent Buildings

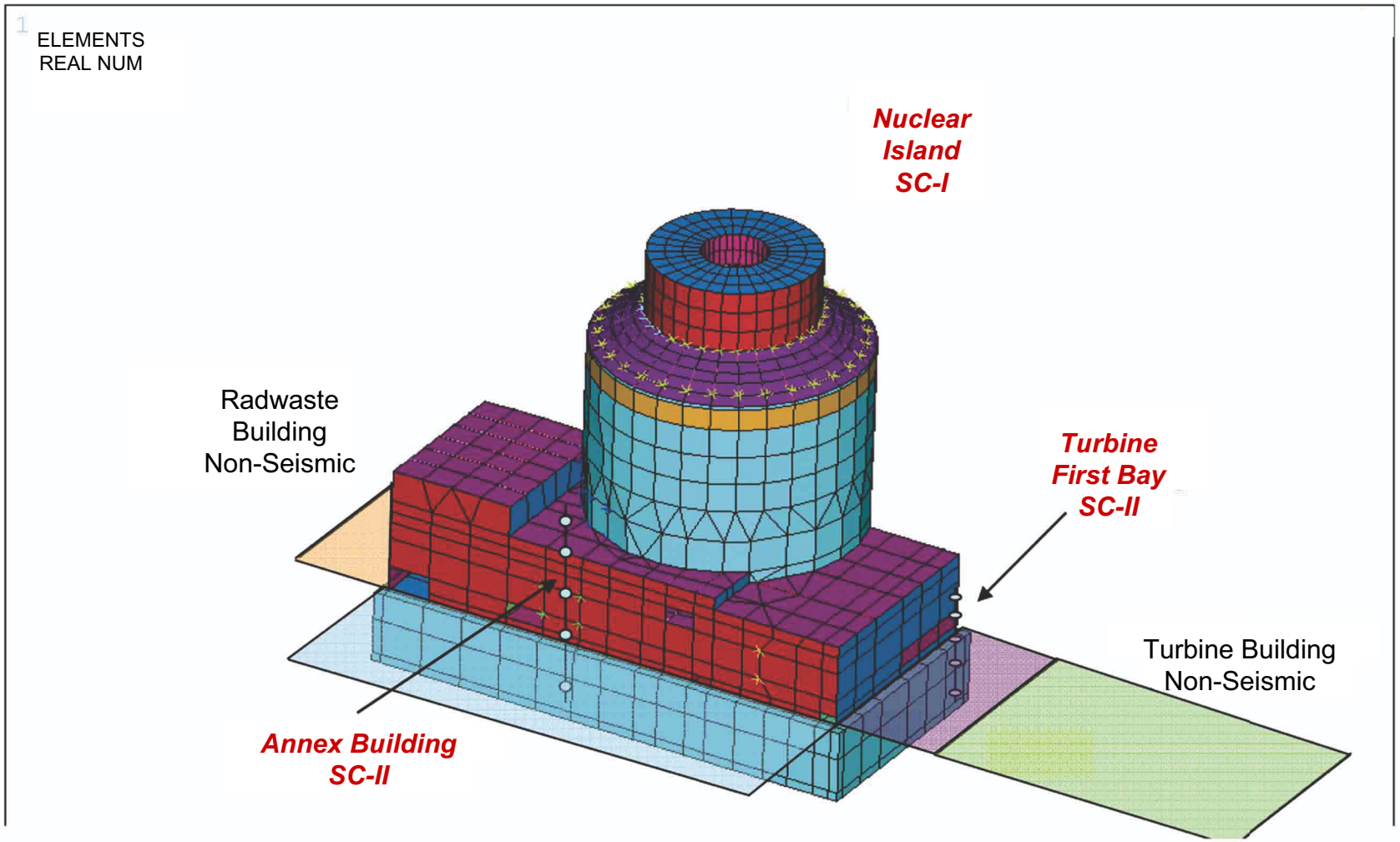


Figure 3.7.2-22
3D SASSI Model with Adjacent Buildings

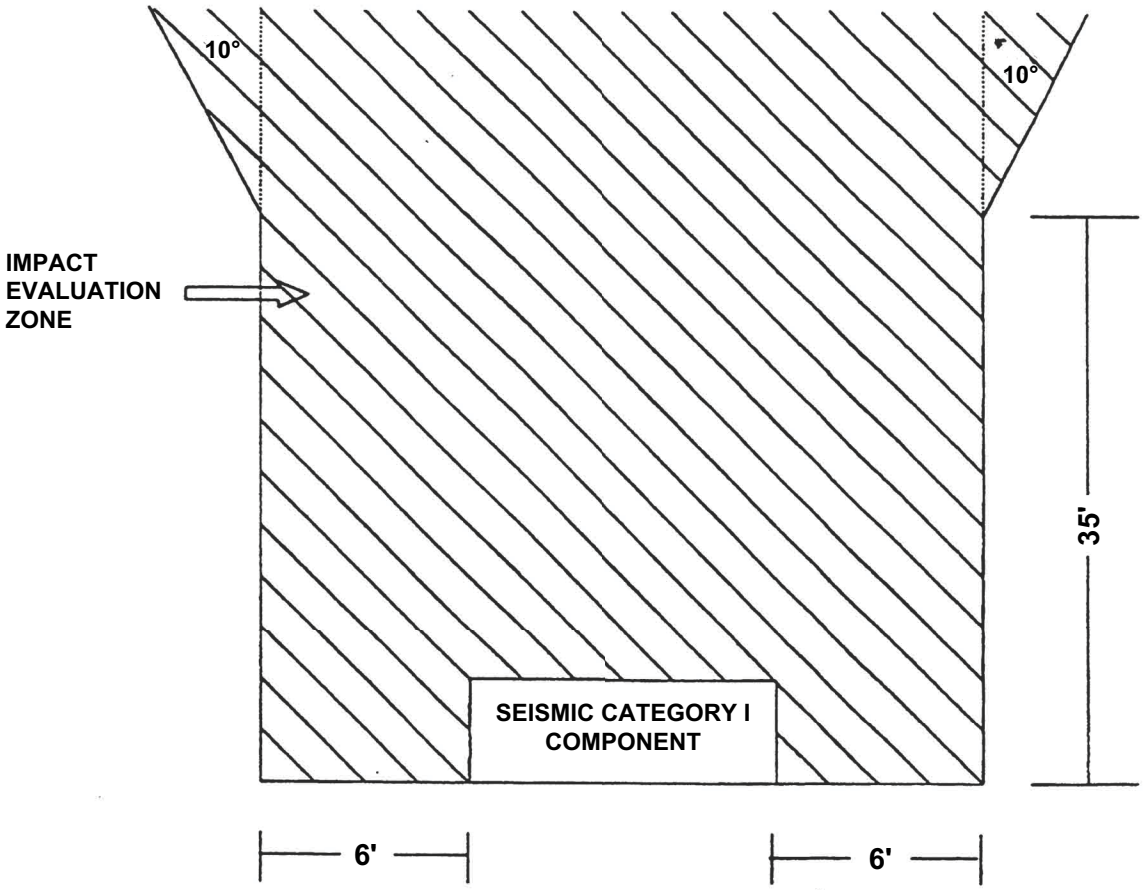


Figure 3.7.3-1
Impact Evaluation Zone

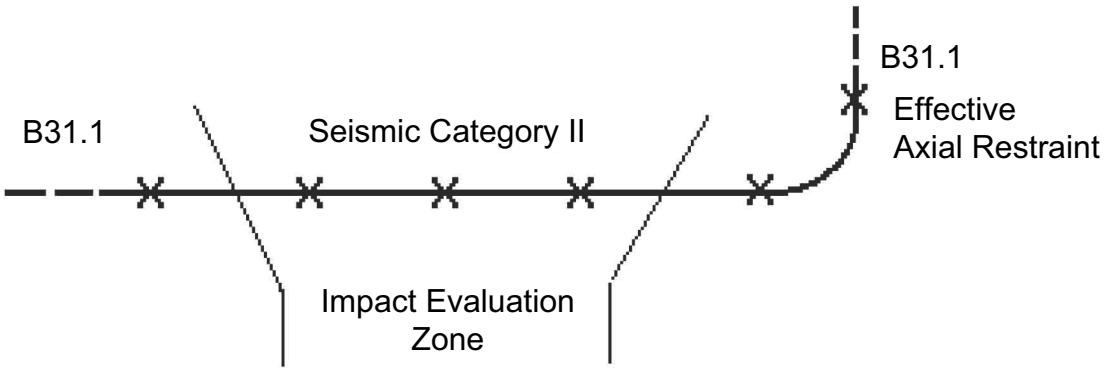


Figure 3.7.3-2
Impact Evaluation Zone and Seismic Supported Piping

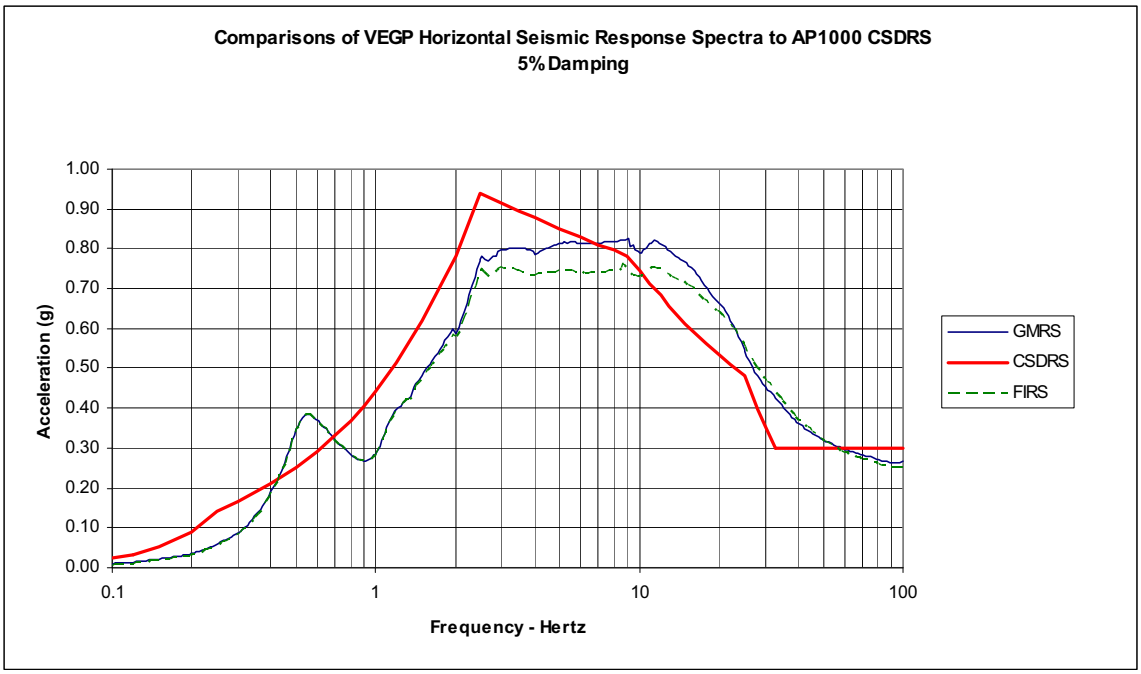


Figure 3.7-201
VEGP AP1000 Horizontal Spectra Comparison

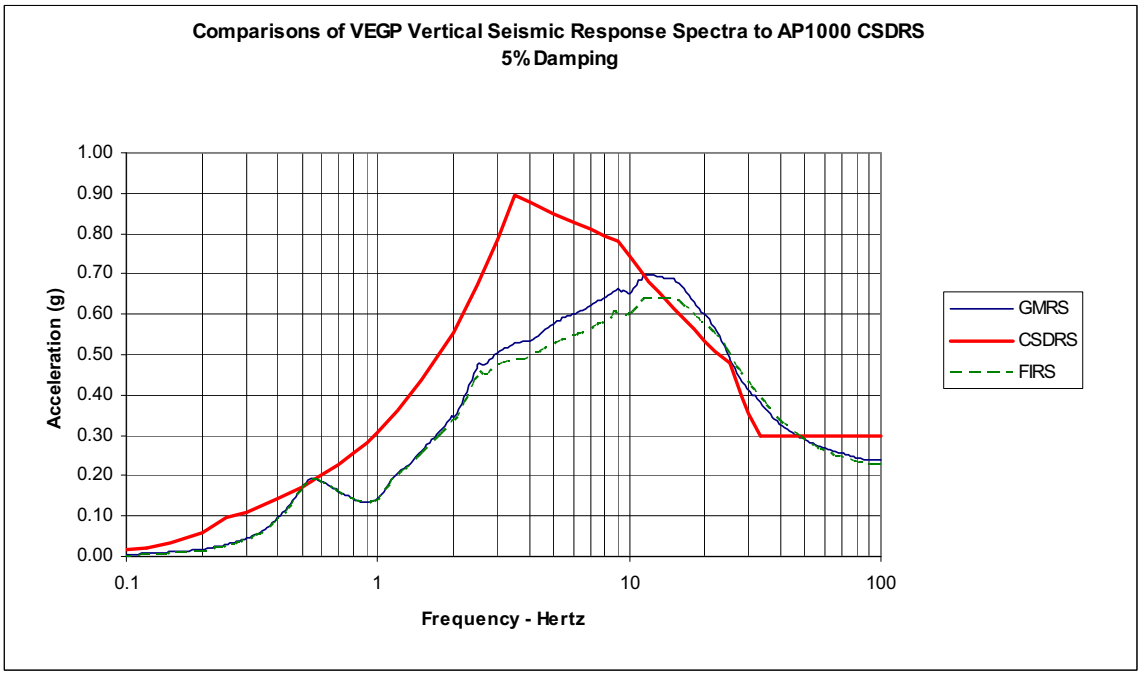


Figure 3.7-202
VEGP AP1000 Vertical Spectra Comparison

3.8 Design of Category I Structures

3.8.1 Concrete Containment

This subsection is not applicable to the AP1000.

3.8.2 Steel Containment

3.8.2.1 Description of the Containment

3.8.2.1.1 General

This subsection describes the structural design of the steel containment vessel and its parts and appurtenances. The steel containment vessel is an integral part of the containment system whose function is described in Section 6.2. It serves both to limit releases in the event of an accident and to provide the safety-related ultimate heat sink.

The containment vessel is an ASME metal containment. The information contained in this subsection is based on the design specification and preliminary design and analyses of the vessel. Final detailed analyses will be documented in the ASME Design Report.

The containment arrangement is indicated in the general arrangement figures in Section 1.2. The portion of the vessel above elevation 132′-3″ is surrounded by the shield building but is exposed to ambient conditions as part of the passive cooling flow path. A flexible watertight and airtight seal is provided at elevation 132′-3″ between the containment vessel and the shield building. The portion of the vessel below elevation 132′-3″ is fully enclosed within the shield building.

Figure 3.8.2-1 shows the containment vessel outline. It is a free-standing, cylindrical steel vessel with ellipsoidal upper and lower heads. [*The containment vessel has the following design characteristics:*

Diameter: 130 feet

Height: 215 feet 4 inches

Design Code: ASME III, Div. 1

Material: SA738, Grade B

Design Pressure: 59 psig

Design Temperature: 300°F

Design External Pressure: 1.7 psid

Lower Personnel Airlock: Elevation 110′-6″ and 107 degrees azimuth

Lower Equipment Hatch: Elevation 112′-6″ and 126 degrees azimuth

Upper Personnel Airlock Elevation 138′-7″ and 107 degrees azimuth

Upper Equipment Hatch Elevation 141′-6″ and 67 degrees azimuth

External Stiffener: Elevation 131′-9″

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Internal Stiffener: Elevation 170′-0″

Bottom Head Tangent Line Elevation 104′-1 1/2″

Upper Head Tangent Line Elevation 244′-2 1/2″

The tangent line is the elevation at which the vessel transitions from the cylinder to the head.

The wall thickness in most of the cylinder is 1.75 inches. The wall thickness of the lowest course of the cylindrical shell is increased to 1.875 inches to provide margin in the event of corrosion in the embedment transition region. The thickness of the heads is 1.625 inches.]* The heads are [*ellipsoidal*]* with a major diameter of 130 feet and a height of 37 feet, 7.5 inches.

The containment vessel includes the shell, hoop stiffeners and crane girder, equipment hatches, personnel airlocks, penetration assemblies, and miscellaneous appurtenances and attachments. The design for external pressure is dependent on the spacing of the hoop stiffeners and crane girder, which are shown on Figure 3.8.2-1. [*The spacing between each pair of ring supports (the bottom flange of the crane girder, the hoop stiffeners, and the concrete floor at elevation 100′-0″) is less than 50 feet, 6 inches. The design of the stiffeners and polar crane girder provides equal or greater radial and rotational stiffness than the design evaluated for the design certification.*]*

The polar crane is designed for handling the reactor vessel head during normal refueling. The crane girder and wheel assemblies are designed to support a special trolley to be installed in the event of steam generator replacement.

The containment vessel supports most of the containment air baffle as described in Subsection 3.8.4. The air baffle is arranged to permit inspection of the exterior surface of the containment vessel. Steel plates are welded to the dome as part of the water distribution system, described in Subsection 6.2.2. The polar crane system is described in Subsection 9.1.5.

3.8.2.1.2 Containment Vessel Support

The bottom head is embedded in concrete, with concrete up to elevation 100′ on the outside and to the maintenance floor at elevation 107′-2″ on the inside. The containment vessel is assumed as an independent, free-standing structure above elevation 100′. The thickness of the lower head is the same as that of the upper head. There is no reduction in shell thickness even though credit could be taken for the concrete encasement of the lower head.

Vertical and lateral loads on the containment vessel and internal structures are transferred to the basemat below the vessel by shear studs, friction, and bearing. The shear studs are not required for design basis loads. They provide additional margin for earthquakes beyond the safe shutdown earthquake.

Seals are provided at the top of the concrete on the inside and outside of the vessel to prevent moisture between the vessel and concrete. A typical cross section design of the seal is presented in Figure 3.8.2-8, sheets 1 and 2.

3.8.2.1.3 Equipment Hatches

Two equipment hatches are provided. One is at the operating floor (elevation 135′-3″) with an inside diameter of 16 feet. The other is at floor elevation 107′-2″ to permit grade-level access into the containment, with an inside diameter of 16 feet. The hatches, shown in Figure 3.8.2-2, consist of a cylindrical sleeve with a pressure seated dished head bolted on the inside of the vessel. The containment internal pressure acts on the convex face of the dished head and the head is in

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

compression. The flanged joint has double O-ring or gum-drop seals with an annular space that may be pressurized for leak testing the seals. Each of the two equipment hatches is provided with an electrically powered hoist and with a set of hardware, tools, equipment and a self-contained power source for moving the hatch from its storage location and installing it in the opening. [*The information in Figure 3.8.2-2 that is considered to be Tier 2* information is the minimum thickness of the hatch cover, the inside diameter of the sleeve, the diameter of the insert plate, the minimum thickness of the insert plate, and the nominal spherical radius of the hatch cover.*]*

3.8.2.1.4 Personnel Airlocks

Two personnel airlocks are provided, one located adjacent to each of the equipment hatches. Figure 3.8.2-3 shows the typical arrangement. Each personnel airlock has about a 10-foot external diameter to accommodate a door opening of width 3 feet 6 inches and height 6 feet 8 inches. The airlocks are long enough to provide a clear distance of 8 feet, which is not impaired by the swing of the doors within the lock. The airlocks extend radially out from the containment vessel through the shield building. They are supported by the containment vessel. [*Area reinforcement for the personnel airlocks is provided by a minimum of 3-3/4-inch-thick insert plates. The surface area of the personnel airlock insert plate, not including the sleeve, is a minimum of 51.9 ft^2.*]*

Each airlock has two double-gasketed, pressure-seated doors in series. The doors are mechanically interlocked to prevent simultaneous opening of both doors and to allow one door to be completely closed before the second door can be opened. The interlock can be bypassed by using special tools and procedures.

3.8.2.1.5 Mechanical Penetrations

The mechanical penetrations consist of the fuel transfer penetration and mechanical piping penetrations and are listed in Table 6.2.3-1. Area is added to the shell by the addition of an insert plate that is thicker than the shell or by increasing the thickness of the nozzle neck or a combination of both. This piping penetration design is then evaluated for external loads on the penetration imposed by the piping system.

Design requirements for the mechanical penetrations are as follows:

- Design and construction of the process piping follow ASME, Section III, Subsection NC. Design and construction of the remaining portions follow ASME Code, Section III, Subsection NE. The boundary of jurisdiction is according to ASME Code, Section III, Subsection NE.
- Penetrations are designed to maintain containment integrity under design basis accident conditions, including pressure, temperature, and radiation.
- Guard pipes are designed for pipe ruptures as described in Subsection 3.6.2.1.1.4.
- Bellows are stainless steel or nickel alloy and are designed to accommodate axial and lateral displacements between the piping and the containment vessel. These displacements include thermal growth of the main steam and feedwater piping during plant operation, relative seismic movements, and containment accident and testing conditions. Cover plates are provided to protect the bellows from foreign objects during construction and operation. The cover plates for the main steam bellows are removable to permit in-service inspection. Access to permit in-service inspection of the pressure retaining portions of the main feedwater bellows is provided via holes in the weld ends of the bellows assembly.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Figure 3.8.2-4, sheet 1, shows typical details for the main steam penetration. This includes bellows to minimize piping loads applied to the containment vessel and a guardpipe to protect the bellows and to prevent overpressurization of the containment annulus in a postulated pipe rupture event. Details for the main feedwater penetration are shown in Figure 3.8.2-4, Sheet 8. [*The main steam and feedwater penetrations are combined into a common 3-3/4-inch-thick insert plate. This thickness is a minimum value. The main steam penetration has an inside sleeve diameter of 57 inches. The feedwater penetration has an inside sleeve diameter of 38 inches.*]* The insert plates for the main steam and feedwater penetrations are shown in Figure 3.8.2-4, Sheet 7. The insert plate also includes the penetration for the 6-inch-diameter startup feedwater pipe. The insert plate is designed in accordance with NE-3330, “Openings and Reinforcement,” of the ASME Code.

Figure 3.8.2-4, sheet 2, shows typical details for the startup feedwater penetration. This includes a guardpipe to prevent overpressurization of the containment annulus in a postulated pipe rupture event. Similar details are used for the steam generator blowdown penetration.

Figure 3.8.2-4, sheet 3, shows typical details for the normal residual heat removal penetration. Similar details are used for other penetrations below elevation 107′-2″ where there is concrete inside the containment vessel. The flued head is integral with the process piping and is welded to the containment sleeve. The welds are accessible for in-service inspection. The containment sleeve is separated from the concrete by compressible material with one exception.

For Vogtle Unit 3, the as-built configuration of penetration RNS-PY-C01 (P19) differs from Figure 3.8.2-4, sheet 3. During construction, a layer of concrete intruded between the compressible material and the containment sleeve, where it remains. This condition does not impair the safety function of the penetration. This configuration is only applicable to penetration RNS-PY-C01 for Vogtle Unit 3.

Figure 3.8.2-4, sheet 4 shows representative details for the other mechanical penetrations. These consist of:

- A sleeve welded to containment with flued head welded to the sleeve (detail A).
- A sleeve welded to containment with the process pipe welded directly to the sleeve and in direct contact with the process fluid (detail B).
- A sleeve welded to containment with process pipe passing through the sleeve (detail C).
- A sleeve welded to a thicker insert place welded to containment with sleeve welded to pipe and in contact with process fluid (detail D).

Flued heads are used for stainless piping greater than 2 inches in nominal diameter and for piping with high operating temperatures.

Note: The type of weld connecting the sleeve to pipe may vary.

The fuel transfer penetration, shown in Figure 3.8.2-4, sheet 5, is provided to transfer fuel between the containment and the fuel handling area of the auxiliary building. The fuel transfer tube is welded to the penetration sleeve. The containment boundary is a double-gasketed blind flange at the refueling canal end. The expansion bellows are not a part of the containment boundary. Rather, they are water seals during refueling operations and accommodate differential movement between the containment vessel, containment internal structures, and the auxiliary building.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.8.2.1.6 Electrical Penetrations

Figure 3.8.2-4, sheet 6, shows a typical 18-inch-diameter electrical penetration. The penetration assemblies consist of conductor modules (or medium voltage cable modules in a similar 18-inch-diameter penetration) passing through a bulkhead attached to the containment nozzle. Electrical design of these penetrations is described in Subsection 8.3.1.1.6.

Electrical penetrations are designed to maintain containment integrity under design basis accident conditions, including pressure, temperature, and radiation. Double barriers permit testing of each assembly to verify that containment integrity is maintained. Design and testing is according to IEEE Standard 317-83 and IEEE Standard 323-74.

3.8.2.1.7 Instrument Line Penetrations

Instrument line penetrations are designed to maintain containment integrity under design basis accident conditions, including pressure, temperature, and radiation.

Figure 3.8.2-4, sheet 4, detail B, shows typical details for the containment pressure instrumentation penetrations. The penetrations consist of sleeves welded to the containment vessel. Pressure transmitters outside containment are connected to pressure sensors inside containment by sealed, fluid-filled tubing (capillary), which passes through the sleeves. The capillary tubing is welded directly to the sleeve at a tubing coupling, which has a thicker wall and larger diameter than the capillary tubing.

Design and construction of the penetrations are in accordance with ASME Section III. The penetration sleeves, including the welds to the tubing couplings, follow ASME Section III, Subsection NE. Because ASME Section III, Subsection NCA excludes the sealed-tubing instrument configuration from the scope of Section III, the capillary tubing is designed and fabricated in accordance with ASME B31.1.

3.8.2.2 Applicable Codes, Standards, and Specifications

[*The containment vessel is designed*]* and constructed [*according to the 2001 edition of the ASME Code, Section III, Subsection NE, Metal Containment, including the 2002 Addenda. Stability of the containment vessel and appurtenances is evaluated using ASME Code, Case N-284-1, Metal Containment Shell Buckling Design Methods, Class MC, Section III, Division 1, as published in the 2001 Code Cases, 2001 Edition, July 1, 2001.*]*

Structural steel nonpressure parts, such as ladders, walkways, and handrails are designed to the requirements for steel structures defined in Subsection 3.8.4.

Section 1.9 discusses compliance with the Regulatory Guides and the Standard Review Plans.

3.8.2.3 Loads and Load Combinations

Table 3.8.2-1 summarizes the design loads, load combinations and ASME Service Levels. They meet the requirements of the ASME Code, Section III, Subsection NE. The loads and load combinations used in the analysis are considered to be part of the method of evaluation. The containment vessel is designed for the following loads specified during construction, test, normal plant operation and shutdown, and during accident conditions:

D Dead loads or their related internal moments and forces, including any permanent piping and equipment loads

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

L Live loads or their related internal moments and forces, including crane loads

P_o Operating pressure loads during normal operating conditions resulting from pressure variations either inside or outside containment

T_o Thermal effects and loads during normal operating conditions, based on the most critical transient or steady-state condition

R_o Piping and equipment reactions during normal operating conditions, based on the most critical transient or steady-state condition

W Loads generated by the design wind on the portion of the containment vessel above elevation 132′, as described in Subsection 3.3.1.1

E_s Loads generated by the safe shutdown earthquake (SSE) as described in Section 3.7

W_t Loads generated by the design tornado on the portion of the containment vessel above elevation 132′, as described in Subsection 3.3.2

P_t Test pressure

P_d Containment vessel design pressure that exceeds the pressure load generated by the postulated pipebreak accidents and passive cooling function

P_e Containment vessel external pressure

T_a Thermal loads under thermal conditions generated by the postulated break or passive cooling function and including T_o. This includes variations around the shell due to the surrounding buildings and maldistribution of the passive containment cooling system water.

R_a Piping and equipment reactions under thermal conditions generated by the postulated break, as described in Section 3.6, and including R_o

Y_r Loads generated by the reaction on the broken high-energy pipe during the postulated break, as described in Section 3.6

Y_j Jet impingement load on a structure generated by the postulated break, as described in Section 3.6

Y_m Missile impact load on a structure generated by or during the postulated break, as from pipe whipping, as described in Section 3.6

Post-accident flooding load combination is not applicable in the design of the AP1000 containment vessel. The post-loss-of-coolant accident (LOCA) flooding event is enveloped by the other design cases.

The AP1000 addresses the production of large quantities of hydrogen from the oxidation of zirconium and other metals as a result of a postulated severe accident. The AP1000 includes hydrogen igniters inside containment to ensure that hydrogen generated in a severe accident is burned prior to reaching an explosive mixture. The discussion of the generation and burning of hydrogen as a result of a severe accident is included in Section 19.18.

The containment vessel is protected from the direct effects of wind/tornado loads (and associated potential missiles) by virtue of its location inside the shield building. The differential pressure effects

of a tornado are also reduced because of the location and are bounded by other pressure loadings for which the containment vessel is designed.

The containment is evaluated for the deterministic severe accident pressure capacity. This evaluation is discussed in Subsection 3.8.2.4.2, "Evaluation of Ultimate Capacity." According to 10 CFR 50.44, the hydrogen generated pressure loads from 100 percent fuel clad-coolant reaction plus the peak pressure from a hydrogen burn must be less than ASME Service Level C (not including buckling). The Service Level C maximum capacity is 117 psig at 300°F as presented in Subsection 3.8.2.4.2.8 The peak pressure from the 100 percent fuel clad-coolant reaction plus the hydrogen burn (Pg1 + Pg2) is 90.3 psig as reported in Section 41.11 and Table 41-4 of the AP1000 Probabilistic Risk Assessment report. The severe accident conditions are beyond design basis accidents, and the load combinations for these severe accident evaluations are not included in the load combinations and service limits for the containment vessel.

The AP1000 does not have a post-accident inerting system. Therefore, there is no load combination that includes inerting of the containment.

Note that loads associated with flooding of the containment below elevation 107′ are resisted by the concrete structures and not by the containment vessel.

3.8.2.4 Design and Analysis Procedures

The design and analysis procedures for the containment vessel are according to the requirements of the ASME Code, Section III, Subsection NE.

The design certification analyses are summarized in Table 3.8.2-4. The detailed analyses used a series of general-purpose finite element, axisymmetric shell and special purpose computer codes to conduct such analyses. Code development, verification, validation, configuration control, and error reporting and resolution are according to the Quality Assurance requirements of Chapter 17.

Subsections 3.8.2.4.1 through 3.8.2.4.2.8 describe containment vessel (CV) design and analysis procedures to support design certification of the AP1000. The Vogtle-specific, as-built CV analyses are documented in the ASME Design Report and demonstrate that the CV meets the requirements of ASME Section III, Subsection NE.

3.8.2.4.1 Analyses for Design Conditions

3.8.2.4.1.1 Axisymmetric Shell Analyses

The containment vessel is modelled as an axisymmetric shell and analyzed using the ANSYS computer program. A model used for static analyses is shown in Figure 3.8.2-6.

Dynamic analyses of the axisymmetric model, which is similar to that shown in Figure 3.8.2-6, are performed to obtain frequencies and mode shapes. These are used to confirm the adequacy of the containment vessel stick model as described in Subsection 3.7.2.3.2. Stress analyses are performed for each of the following loads:

- Dead load
- Internal pressure
- Seismic
- Polar crane wheel loads
- Wind loads
- Thermal loads

The seismic analysis performed envelopes all soil conditions. The global seismic loads are applied as equivalent static accelerations using the maximum accelerations shown in Table 3.8.2-5. These accelerations are the maximum accelerations from the nuclear island stick model on hard rock. The global member forces from the equivalent static case exceed those from the soil cases for soil conditions described in Appendix 3G. Based on these comparisons, the design acceleration values used for the global analyses are appropriate for both the hard rock and the soil sites. The seismic analysis of the nuclear island is discussed in Section 3.7 and Appendix 3G. The torsional moments, which include the effects of the eccentric masses, are increased to account for accidental torsion and are evaluated in a separate calculation.

The results of these load cases are factored and combined in accordance with the load combinations identified in Table 3.8.2-1. These results are used to evaluate the general shell away from local penetrations and attachments, that is, for areas of the shell represented by the axisymmetric geometry. The results for the polar crane wheel loads are also used to establish local shell stiffnesses for inclusion in the containment vessel stick model described in Subsection 3.7.2.3. The results of the analyses and evaluations are included in the containment vessel design report.

Design of the containment shell is primarily controlled by the internal pressure of 59 psig. The meridional and circumferential stresses for the internal pressure case are shown in Figure 3.8.2-5. The most highly stressed regions for this load case are the portions of the shell away from the hoop stiffeners and the knuckle region of the top head. In these regions the stress intensity is close to the allowable for the design condition.

Table 3.8.2-1 includes a design load combination to address external pressure. For the design external pressure, a conservatively large magnitude of 1.7 psi differential pressure is used. Design external pressure is defined as a value greater than the external pressure at which the vacuum relief system will open and mitigate the external pressure. This is a part of the containment air filtration system (see Subsection 9.4.7). Upon actuation, the external pressure transient is immediately controlled and the external pressure is relieved. This design external pressure is combined with a coincident -40°F outside air temperature, which corresponds to a -18.5°F metal temperature for the portions of the containment vessel shell not insulated from ambient conditions. The portions of the containment vessel shell that are below the external stiffener are insulated from the cold outside air conditions and result in a metal temperature of 70°F.

A bounding case was analyzed to provide an indication of the margin to acceptance criteria associated with the minimum allowable service metal temperature for the AP1000 containment vessel. Various types of transients were considered to evaluate the minimum service metal temperature, including inadvertent fan cooler cases, inadvertent passive containment cooling system (PCS) actuation, and loss of ac power. The evaluation considered variations in initial conditions for parameters, including humidity, internal temperature, external temperature, and wind speed. These evaluations demonstrate that the -18.5°F service metal temperature is adequate.

Design external pressure is used in load combinations that include thermal loads and are used to evaluate Service Level A and D stress limits. These external pressure conditions are included in the loading combinations in Table 3.8.2-1.

Operating pressures range from -0.2 psig to 1.0 psig, which are then combined with an ambient temperature for the containment vessel. Design internal pressure is 59 psig combined with a containment vessel metal temperature of 300°F to be evaluated in the ASME service limits as well as the design conditions.

A load combination that combines design wind plus internal design pressure is not included in Table 3.8.2-1 because the wind loads are small (within the normal operating range for containment

pressure) and because the combination of the design wind and accident pressure is a lower probability than either the design wind or the accident pressure acting alone.

Major loads that induce compressive stresses in the containment vessel are internal and external pressure and crane and seismic loads. Each of these loads and the evaluation of the compressive stresses are discussed below.

- Internal pressure causes compressive stresses in the knuckle region of the top head and in the equipment hatch covers. The evaluation methods are similar to those discussed in Subsection 3.8.2.4.2 for the ultimate capacity.

- Evaluation of external pressure loads is performed in accordance with ASME Code, Section III, Subsection NE, Paragraph NE-3133.

- Crane wheel loads due to crane dead load, live load, and seismic loads result in local compressive stresses in the vicinity of the crane girder. These are evaluated in accordance with ASME Code, Case N-284.

- Overall seismic loads result in axial compression and tangential shear stresses at the base of the cylindrical portion. These are evaluated in accordance with ASME Code, Case N-284.

The bottom head is embedded in the concrete base at elevation 100 feet. This leads to circumferential compressive stresses at the discontinuity under thermal loading associated with the design basis accident. The containment vessel design includes a Service Level A combination in which the vessel above elevation 107′-2″ is specified at the design temperature of 300°F and the portion of the embedded vessel (and concrete) below elevation 100 feet is specified at a temperature of 70°F. The temperature profile for the vessel is linear between these elevations. Containment shell buckling close to the base is evaluated against the criteria of ASME Code, Case N-284.

Revision 1 of Code Case N-284 is used for the evaluation of the containment shell and equipment hatches.

3.8.2.4.1.2 Local Analyses

The penetrations and penetration reinforcements are designed in accordance with the rules of ASME III, Subsection NE. The design of the large penetrations for the two equipment hatches and the two airlocks use the results of finite element analyses which consider the effect of the penetration and its dynamic response (Reference 53).

The personnel airlocks and equipment hatches are modeled in a 3-D shell finite element model of the containment. A 3D shell, finite element model of the containment vessel was developed in ANSYS to consider the effect of the penetrations and their quasi-static response due to a seismic event. The large masses and local stiffness of the personnel locks and equipment hatches are discretely modeled. The polar crane wheel loads are incorporated by appropriate loadings (dead load and seismic loadings). The bottom of the model is fixed at elevation 100′ where the containment vessel is embedded in concrete. This means that rotations and displacements are conservatively fixed at this location.

Static analyses are performed using the finite element model shown in Figure 3.8.2-7 for internal pressure, dead load (including the polar crane in the parked position), thermal loads and seismic loads. The global seismic loads are applied as equivalent static accelerations using the maximum accelerations shown in Table 3.8.2-5. The amplified local responses are included separately for each of the four penetrations. Local seismic axial and rotational accelerations about both horizontal and

vertical axes are applied based on the maximum amplified response determined from a time history analysis on a less refined dynamic model with seismic time histories at elevation 100′.

Stresses are evaluated against the stress intensity criteria of ASME Section III, Subsection NE for the load combinations described in Table 3.8.2-1. Stability is evaluated against ASME Code Case N-284. Local stresses in the regions adjacent to the major penetrations are evaluated in accordance with paragraph 1700 of the code case. Stability is not evaluated in the reinforced penetration neck and insert plate which are substantially stiffer than the adjacent shell.

3.8.2.4.2 Evaluation of Ultimate Capacity

The capacity of the containment vessel has been calculated for internal pressure loads for use in the probabilistic risk assessment analyses and severe accident evaluations. These analyses include the evaluation of the peak pressure from the hydrogen-generated pressure loads from 100-percent fuel cladding metal-water reaction plus the hydrogen burn. Each element of the containment vessel boundary was evaluated to estimate the maximum pressure at an ambient temperature of 100°F corresponding to the following stress and buckling criteria:

- Deterministic severe accident pressure capacity corresponding to ASME Service Level C limits on stress intensity, ASME paragraph NE-3222, and ASME Code Case N-284 for buckling of the equipment hatch covers, and 60 percent of critical buckling for the top head. The deterministic severe accident pressure capacity corresponds to the approach in SECY 93-087, to maintain a reliable leak-tight barrier approximately 24 hours following the onset of core damage under the more likely severe accident challenges. This approach was approved by the Nuclear Regulatory Commission as outlined in the Staff Requirements Memorandum on SECY-93-087 - Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light Water Reactor (ALWR) Designs, Dated July 21, 1993.

- Best estimate capacity corresponding to gross membrane yield at the ASME-specified minimum yield stress (SA738, Grade B, yield stress = 60 ksi, ultimate stress = 85 ksi), and critical buckling for the equipment hatch covers and top head.

The results are shown in Table 3.8.2-2. The analyses at a temperature of 100°F are described in the following paragraphs for each element. The critical regions identified in this table are then examined further for their response at higher temperatures. This results in the best-estimate capacity based on the ASME-specified minimum yield properties. The evaluation considered the containment boundary elements including:

- Cylindrical shell
- Top and bottom heads
- Equipment hatches and covers
- Personnel airlocks
- Mechanical and electrical penetrations

The evaluation identified the most likely failure mode to be that associated with gross yield of the cylindrical shell. Loss of containment function would be expected to occur because the large post-yield deflections would lead to local failures at penetrations, bellows, or other local discontinuities.

3.8.2.4.2.1 Tensile Stress Evaluation of Shell

Results of the axisymmetric analyses of the cylinder and top head described in Subsection 3.8.2.4.1 for dead load and internal pressure were evaluated to determine the pressure at which stresses reach yield at an ambient temperature of 100°F. The analyses assume the shell is fixed at elevation

100′, where the bottom head is embedded in concrete. The steel bottom head is identical to the top head and has a pressure capability greater than the top head due to the additional strength of the embedment concrete.

The allowable stress intensity under Service Level C loads is equal to yield. This corresponds to an internal pressure of 135 psig. The critical section is the cylinder, where the general primary membrane stress intensity is greatest.

The best-estimate yield analysis uses the von Mises criterion to establish yield rather than the more conservative ASME stress intensity approach. This increases the yield stress by about 15 percent for the cylinder, where the longitudinal stress is equal to one-half of the hoop stress resulting in first yield at an internal pressure of 155 psig. At this pressure, hoop stresses in the cylinder reach yield. The radial deflection is about 1.6 inches. As pressure increases further, large deflections occur. For a material such as SA738, where the yield plateau extends from a strain of 0.2 percent to 0.6 percent, deflections would increase to 4.8 inches at yield without a substantial increase in pressure. Strain hardening would then permit a further increase in pressure with large radial deflections, as described in Subsection 3.8.2.4.2.6.

3.8.2.4.2.2 Buckling Evaluation of Top Head

The top head has a radius-to-height ratio of 1.728. This is not as shallow as most ellipsoidal or torispherical heads, which typically have a radius-to-height ratio of 2. The ratio was specifically selected to minimize the local stresses and buckling in the knuckle region due to internal pressure. As the ratio decreases, the magnitude of compressive stresses in the knuckle region decreases; for a radius-to-height ratio of 1.4 or smaller, there are no compressive stresses and therefore there is no potential for buckling.

Theoretical Buckling Capacity

The top head was analyzed using the BOSOR-5 computer code (Reference 1). This code permits consideration of both large displacements and nonlinear material properties. It calculates shell stresses and checks stability at each load step. The analysis included a portion of the cylinder with a thickness of 1.625 inches. In this analysis, yield of the cylinder started at a pressure of 144 psig using elastic – perfectly plastic material properties, a yield stress of 60 ksi, and the von Mises yield criterion. Yield of the top of the crown started at an internal pressure of 146 psig. Yield of the knuckle region started at 152 psig. A theoretical plastic buckling pressure of 174 psig was determined. At this pressure, the maximum effective prebuckling strain was 0.23 percent in the knuckle region where buckling occurred and 2.5 percent at the crown. The maximum deflection at the crown was 15.9 inches. A similar analysis was performed using nonlinear material properties considering the effects of residual stresses; buckling did not occur in this analysis, and failure would occur once strains at the crown reach ultimate. The failure mode was found to be an axisymmetric plastic collapse resulting from excessive vertical displacements at the crown. The maximum displacement was 43 inches at 195 psig.

Predicted Pressure Capacity

The actual buckling capacity may be lower than the theoretical buckling capacity because of effects not included in the analysis such as imperfections and residual stresses. This is considered by the use of capacity reduction factors that are based upon a correlation of theory and experiment. The capacity reduction factor for the top head was evaluated based on comparisons of BOSOR-5 analyses against test results of ellipsoidal and torispherical heads. This evaluation is described below and concludes that no reduction in capacity need be considered; that is, a capacity reduction factor of 1.0 is appropriate.

The knuckle region of ellipsoidal and torispherical heads is subjected to meridional tension and circumferential compression. The meridional tension tends to stabilize the knuckle region and reduces its sensitivity to imperfection. The radius-to-height ratio of 1.728 of the AP1000 head results in a larger ratio of meridional tension to circumferential compression than on shallower heads, further reducing the sensitivity to imperfection.

Welding Research Council Bulletin 267 (Reference 22) shows a comparison of BOSOR-5 predictions of buckling against the results of 20 tests of small head models. These results are summarized in Table 4 of the reference and show ratios (capacity reduction factors) of actual buckling to the BOSOR-5 prediction with an average of 1.2. Only one of the 20 cases shows a capacity reduction factor less than 1.0.

Table 3.8.2-3 shows the key parameters, test results, and BOSOR-5 predictions for two large, fabricated 2:1 torispherical heads tested and reported in NUREG/CR-4926 (Reference 23). The theoretical plastic buckling pressure predicted by BOSOR-5 represents initial buckling based on actual material properties. The initial buckling did not cause failure for either of the tests, and test pressure continued to increase until rupture occurred in the spherical cap. The collapse pressures were three to four times the initial buckling pressures.

- **Test Head 1** – The test result of 58 psig is 79 percent of the predicted theoretical plastic buckling pressure of 74 psig. Many of the buckles occurred directly on the meridional weld seams of the knuckle. The knuckle welds were noticeably flatter than the corresponding welds of the Test 2 head. The as-built configuration extended inside the theoretical shape at some of the meridional weld seams and was most pronounced at the location of the first observed buckle. Model 1 exceeded the tolerances for formed heads specified for containment vessels in NE-4222.2 of ASME, Section III, Subsection NE.

- **Test Head 2** – The test result of 106 psi is 100 percent of the BOSOR-5 predicted theoretical plastic buckling pressure. For test head 2, the welds had no noticeable flat spots and there was a smooth transition between the sphere and knuckle sections. Test head 2 was well within the Code allowable deviations.

The low-capacity reduction factor of 0.79 for test head 1 is attributed to excessive imperfections associated with the fabrication of relatively thin plate (0.196 inch). These imperfections were visible and were outside the tolerances permitted by the ASME Code. The results of test head 1 are therefore not considered applicable to the AP1000. The results of test head 2 and of the small-scale models described in the Welding Research Council Bulletin support the application of a capacity reduction factor of 1.0.

The capacity of the AP1000 head was also investigated using an approach similar to that permitted in ASME Code, Case N284. This code case provides alternate rules for certain containment vessel geometries such as cylindrical shells. The theoretical elastic buckling pressure was calculated to be 536 psi using the linear elastic computer code, BOSOR-4 (Reference 24). A reduction factor (defined as the product of the capacity reduction factor and the plastic reduction factor) was established as 0.385 based on the lower bound curve of test results of 20 ellipsoidal and 28 torispherical test specimens, which also include the two large fabricated heads previously discussed. This resulted in a predicted buckling capacity of 206 psig.

The preceding paragraphs addressed incipient buckling. It is concluded that buckling would not occur prior to reaching the pressure of 174 psig predicted in the BOSOR-5 analyses. Tests indicate that pressure can be significantly increased prior to rupture after the formation of the initial buckles. Failure would occur when local strains reach ultimate either close to a local buckle in the knuckle or at the center of the crown. The best estimate capacity of the head is taken as the theoretical plastic buckling pressure of 174 psig predicted in the BOSOR-5 analyses.

The deterministic severe accident pressure capacity is taken as 60 percent of critical buckling. This is consistent with the safety factor for Service Level C in ASME Code, Case N-284 and results in a containment head capacity of 104 psig.

3.8.2.4.2.3 Equipment Hatches

SECY 93-087 permits evaluation of certain severe accident scenarios against ASME Service Level C limits. The equipment hatch covers were evaluated for buckling against ASME paragraph NE-3222 and according to ASME Code, Case N-284. Use of ASME Code, Case N-284 for this application was confirmed to be appropriate by ASME. The containment internal pressure acts on the convex face of the dished head and the hatch covers are in compression under containment internal pressure loads. The critical buckling capacity is based on classical buckling capacities reduced by capacity reduction factors to account for the effects of imperfections and plasticity. These capacity reduction factors are based on test data and are generally lower-bound values for the tolerances specified in the ASME Code.

The critical buckling pressure is 211 psig for the 16-foot-diameter hatch at an ambient temperature of 100°F. For the Service Level C limits in accordance with paragraph NE 3222, a safety factor of 2.50 is specified, resulting in capabilities of 84 psig (16-foot-diameter). For the Service Level C limits in accordance with Code Case N284, a safety factor of 1.67 is specified, resulting in capabilities of 126 psig (16-foot-diameter).

Typical gaskets have been tested for severe accident conditions as described in NUREG/CR-5096 (Reference 25). The gaskets for the AP1000 will be similar to those tested with material such as Presray EPDM E 603. For such gaskets the onset of leakage occurred at a temperature of about 600°F.

3.8.2.4.2.4 Personnel Airlocks

The capacity of the personnel airlocks was determined by comparing the airlock design to that tested and reported in NUREG/CR-5118 (Reference 3). Critical parameters are the same, so the results of the test apply directly. In the tests the inner door and end bulkhead of the airlock withstood a maximum pressure of 300 psig at 400°F. The capacity of the airlock is therefore at least 300 psig at ambient temperature. The maximum pressure corresponding to Service Level C is conservatively estimated by reducing this capacity in the ratio of the minimum specified material yield to ultimate.

3.8.2.4.2.5 Mechanical and Electrical Penetrations

Subsections 3.8.2.1.3 through 3.8.2.1.7 describe the containment penetrations. Penetration reinforcement is designed following the area replacement method of the ASME Code. The insert plates and sleeves permit development of the hoop tensile yield stresses predicted as the limiting capacity in Subsection 3.8.2.4.1. Capacities of the equipment hatch covers are discussed in Subsection 3.8.2.4.2.3 and of the personnel airlocks in Subsection 3.8.2.4.2.4.

Mechanical penetrations welded directly to the containment vessel are generally piping systems with design pressures greater than that of the containment vessel. Thicknesses of the flued head or end plate are established based on piping support loads or stiffness requirements. The capacities of these penetrations are greater than the capacity of the containment vessel cylinder.

Mechanical penetrations for the large-diameter high-energy lines, such as the main steam and feedwater piping, include expansion bellows. The piping and flued head have large pressure capability. The response of expansion bellows to severe pressure and deformations is described in NUREG/CR-5561 (Reference 4). The bellows can withstand large pressure loading but may tear once the containment vessel deflection becomes large. Testing reported in NUREG/CR-6154

(Reference 26) has shown that the bellows remain leaktight even when subjected to large deflections sufficient to fully compress the bellows. Such large deflections do not occur as long as the containment vessel remains elastic. As described in Subsection 3.8.2.4.2.6, the radial deflection of the shell increases substantially once the containment cylinder yields. The resulting deflections are assumed to cause loss of containment function. The containment penetration bellows are designed for a pressure of 90 psig at design temperature within Service Level C limits, concurrent with the relative displacements imposed on the bellows when the containment vessel is pressurized to these magnitudes.

Electrical penetrations have a pressure boundary consisting of the sleeve and an end plate containing a series of modules. The electrical pressure boundary is designed and built to the requirements of the ASME Code, Section III, Class MC, Subsection NE. The pressure capacity of these elements is large and is greater than the capacity of the containment vessel cylinder at temperatures up to the containment design temperature. Electrical penetration assemblies are also designed to satisfy ASME Service Level C stress limits under a pressure of 90 psig at design temperature. Tests at pressures and temperatures representative of severe accident conditions are described in NUREG/CR-5334 (Reference 5), where typical nuclear industry penetrations were irradiated, aged, then tested. One design was tested to 135 psia at 700°F. Other electrical penetration assemblies were tested to 75 psia at 400°F and 155 psia at 361°F. These tests showed that the electrical penetration assemblies withstand severe accident conditions. The electrical penetration assemblies are qualified for the containment design basis event conditions as described in Appendix 3D. The assemblies are similar to one of those tested by Sandia as reported in NUREG/CR-5334 (Reference 5). The ultimate pressure capacity of the electrical penetration assemblies is primarily determined by the temperature. The maximum temperature of the containment vessel below the operating deck during a severe accident is below the temperature at which the assemblies from the three suppliers in the Sandia tests were tested.

3.8.2.4.2.6 Material Properties

The containment vessel is designed using SA738, Grade B material. This has a specified minimum yield of 60 ksi and ultimate of 85 ksi. Test data for materials having similar chemical properties were reviewed. In a sample of 122 tests for thicknesses equaling or exceeding 1.50 inches and less than 1.75 inches, the actual yield had a mean value of 69.1 ksi with a standard deviation of 3.3 ksi. Thus, the actual yield is expected to be about 15 percent higher than the minimum yield. Membrane yield of the cylinder is predicted to occur at an internal pressure of 178 psig.

A stress-strain curve for material with chemistry similar to SA738, Grade B, indicated constant yield stress of 81.3 ksi from a strain of 0.002 to 0.006 followed by strain-hardening up to a maximum stress of 94.5 ksi at a strain of 0.079. The first portion of the strain-hardening is nearly linear, with a stress of 90 ksi at a strain of 4 percent. This strain occurs at a stress 10 percent above yield. Thus, a pressure load 10 percent higher than that corresponding to yield of the shell would result in 4 percent strain and a 31-inch radial deflection of the containment cylinder. Such a deflection is expected to cause major distress for penetrations, the air flow path, and local areas where other structures are close to the containment vessel. Loss of function is therefore assumed for the containment once gross yield of the containment cylinder occurs.

3.8.2.4.2.7 Effect of Temperature

The evaluations described in the preceding subsections are based on an ambient temperature of 100°F. Nonmetallic items, such as gaskets, are qualified to function at the design temperature. The capacity of steel elements is reduced in proportion to the reduction due to temperature in yield stress, ultimate stress, or elastic modulus. The cylinder is governed by yield stress, and elastic buckling of the hatch covers is governed by the elastic modulus. The reduction in capacity is estimated using the

tables given for material properties in the ASME Code. At 400°F, the yield stress is reduced by 17 percent and the pressure capacity corresponding to gross yield is reduced from 155 to 129 psig.

3.8.2.4.2.8 Summary of Containment Pressure Capacity

The ultimate pressure capacity for containment function is expected to be associated with leakage caused by excessive radial deflection of the containment cylindrical shell. This radial deflection causes distress to the mechanical penetrations, and leakage would be expected at the expansion bellows for the main steam and feedwater piping. There is high confidence that this failure would not occur before stresses in the shell reach the minimum specified material yield. This is calculated to occur at a pressure of 155 psig at ambient temperature and 129 psig at 400°F. Failure would be more likely to occur at a pressure about 15 percent higher based on expected actual material properties.

The deterministic severe accident pressure that can be accommodated according to the ASME Service Level C stress intensity limits and using a factor of safety of 1.67 for buckling of the top head is determined by the capacity of the 16-foot-diameter equipment hatch cover and the ellipsoidal head. The maximum capacity of the hatch cover, calculated according to ASME paragraph NE-3222, Service Level C, is 84 psig at an ambient temperature of 100°F and 81 psig at 300°F. When calculated in accordance with ASME Code, Case N-284, Service Level C, the maximum capacity is 126 psig at an ambient temperature of 100°F and 121 psig at 300°F. The maximum capacity of the ellipsoidal head is 104 psig at 100°F and 91 psig at 300°F.

The maximum pressure that can be accommodated according to the ASME Service Level C stress intensity limits, excluding evaluation of instability, is determined by yield of the cylinder and is 135 psig at an ambient temperature of 100°F and 117 psig at 300°F. This limit is used in the evaluations required by 10 CFR 50.44.

3.8.2.5 Structural Criteria

The containment vessel is designed, fabricated, installed, and tested according to the ASME Code, Section III, Subsection NE, and will receive a code stamp.

Stress intensity limits are according to ASME Code, Section III, Paragraph NE-3221 and Table NE-3221-1. [*Critical buckling stresses are checked according to the provisions of ASME Code, Section III, Paragraph NE-3222, or ASME Code Case N-284.*]*

3.8.2.6 Materials, Quality Control, and Special Construction Techniques

Materials for the containment vessel, including the equipment hatches, personnel locks, penetrations, attachments, and appurtenances meet the requirements of NE-2000 of the ASME Code. [*The basic containment material is SA-738, Grade B, plate. The procurement specification for the SA-738, Grade B, plate includes SA-20 supplemental requirements S1, Vacuum Treatment and S20, Maximum Carbon Equivalent for Weldability*.]* This material has been selected to satisfy the lowest service metal temperature requirement of -18.5°F. This temperature is established by analysis for the portion of the vessel exposed to the environment when the minimum ambient air temperature is -40°F. Impact test requirements are as specified in NE-2000.

[*The material of construction for the insert plates and fabricated nozzle necks of penetrations is SA-738 Grade B. The material of construction for forged nozzle neck forgings is SA-350, LF2, Class 1 for penetrations greater than 2 inches nominal diameter and less than 24 inches inside diameter, and for the containment air filtration system penetration nozzle necks. The maximum carbon equivalent for the SA-350, LF2, Class 1 used for penetrations is 0.52 percent. A vacuum refining process is required for SA-350, LF2, Class 1. The SA-350, LF2, Class 1 material is used in portions of the containment vessel that are below the external stiffener.*]* These portions of the containment vessel

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

are insulated from the cold outside air temperature. Insulation is provided around the upper equipment hatch and personnel airlock, including the insert plates, in order to insulate the penetrations from the ambient air temperature in the upper annulus.

The containment vessel is coated with an inorganic zinc coating, except for those portions fully embedded in concrete. The inside of the vessel below the operating floor also has an epoxy top coat. Below elevation 100′ the vessel is fully embedded in concrete with the exception of the few penetrations at low elevations (see Figure 3.8.2-4, sheet 3, for typical details). Embedding the steel vessel in concrete protects the steel from corrosion.

The AP1000 configuration is shown in the general arrangement figures in Section 1.2 and in Figure 3.8.2-1. The exterior of the vessel is embedded at elevation 100′ and concrete is placed against the inside of the vessel up to the maintenance floor at elevation 107′-2″. Above this elevation the inside and outside of the containment vessel are accessible for inspection of the coating. The vessel is coated with an inorganic zinc primer to a level just below the concrete.

Seals are provided at the surface of the concrete inside and outside the vessel so that moisture is not trapped next to the steel vessel just below the top of the concrete. The seal on the inside accommodates radial growth of the vessel due to pressurization and heatup.

The plate thickness for the first course (elevation 104′-1.5″ to minimum 109′-0″) of the cylinder is 1.875 inches, which is 1/8-inch thicker than the rest of the vessel. This provides margin in the event there would be any corrosion in the transition region despite the coatings and seals described previously. Equivalent margin is available for the 1.625-inch-thick bottom head in the transition region (elevation 100′ to 104′-1.5″). The plate thickness for the head is a constant thickness and is established by the stresses in the knuckle. As a result, the pressure stresses in the transition zone are well below the allowable stress, providing margin in the event of corrosion in this region.

The quality control program involving welding procedures, erection tolerances, and nondestructive examination of shop- and field-fabricated welds conforms with Subsections NE-4000 and NE-5000 of the ASME Code. The containment vessel is designed to permit its construction using large subassemblies. These subassemblies consist of the two heads and three or more ring sections. These are assembled in an area near the final location, using plates fabricated in a shop facility.

3.8.2.7 Testing and In-Service Inspection Requirements

Testing of the containment vessel and the pipe assemblies forming the pressure boundary within the containment vessel will be according to the provisions of NE-6000 and NC-6000, respectively.

Subsection 6.2.5 describes leak-rate testing of the containment system including the containment vessel.

In-service inspection of the containment vessel will be performed. See Section 6.6 for information on inservice inspection for the containment vessel and penetrations.

3.8.3 Concrete and Steel Internal Structures of Steel Containment

3.8.3.1 Description of the Containment Internal Structures

The containment internal structures are those concrete and steel structures inside (not part of) the containment pressure boundary that support the reactor coolant system components and related piping systems and equipment. The concrete and steel structures also provide radiation shielding. The containment internal structures are shown on the general arrangement drawings in Section 1.2. The containment internal structures consist of the primary shield wall, reactor cavity, secondary

shield walls, in-containment refueling water storage tank (IRWST), refueling cavity walls, operating floor, intermediate floors, and various platforms. The polar crane girders are considered part of the containment vessel. They are described in Subsection 3.8.2.

Component supports are those steel members designed to transmit loads from the reactor coolant system to the load-carrying building structures. The component configuration is described in this subsection including the local building structure backing up the component support. The design and construction of the component supports are described in Subsection 5.4.10.

The containment internal structures are designed using reinforced concrete and structural steel. At the lower elevations conventional concrete and reinforcing steel are used, except that permanent steel forms are used in some areas in lieu of removable forms based on constructibility considerations. These steel form modules (liners) consist of plate reinforced with angle stiffeners and tee sections, as shown in Figure 3.8.3-16. The angles and the tee sections are on the concrete side of the plate. Welded studs, or similar embedded steel elements, are attached on the concrete face of the permanent steel form where surface attachments transfer loads into the concrete. Where these surface attachments are seismic Category I, the portion of the steel form module transferring the load into the concrete is classified as seismic Category I.

Walls and floors are concrete filled steel plate structural modules. The walls are supported on the mass concrete containment internal structures basemat with the steel surface plate extending down to the concrete floor on each side of the wall. The steel surface plates of the structural modules provide reinforcement in the concrete. The structural modules are anchored to the base concrete by mechanical connections welded to the steel plate as shown in Figure 3.8.3-8, Sheet 2. Figure 3.8.3-1 shows the location of the structural modules. Figures 3.8.3-2 and 3.8.3-15 show the typical structural configuration of the wall modules. Key structural elements of the module design are identified as Tier 2* information in the text and figures of this section. See DCD Introduction, Section 3.5 for a discussion of Tier 2* information. [*The information in Figure 3.8.3-2 that is Tier 2* is the minimum size of the angles and channels used to fabricate the modules. The information in Figure 3.8.3-15 that is Tier 2* is the design spacing between the face plates for the 4-foot-thick refueling canal wall in the containment internal structures and the design spacing between the trusses used to fabricate the modules in locations away from openings or penetrations in the wall. Local variation in the design of the trusses and spacing of the trusses and shear studs may be required to address internal obstructions and accessibility for fabrication and inspection. The obstructions include features such as leak chases; internal structures such as reinforcements, embedments, and backup structures; and internal conduit and piping.*]* See Subsection 3.8.3.5.3.6 for criteria for design of the shear stud size and spacing.

A representative floor module is shown in Figure 3.8.3-3 and also in Figure 3.8.3-16 combined with the liner module. These structural modules are structural elements built up with welded steel structural shapes and plates. The details shown in Figure 3.8.3-3 are a representative design for a specific portion of the operating deck floor in containment. The size, material, and configuration of the structural shapes and plates, the amount and arrangement of the reinforcement, and the type and size of the welds may vary in the final design of floor modules in this and other locations. Concrete is used where required for shielding, but reinforcing steel is not normally used.

Walls and floors exposed to water during normal operation or refueling are constructed using stainless steel plates.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.8.3.1.1 Reactor Coolant Loop Supports

3.8.3.1.1.1 Reactor Vessel Support System

The reactor vessel is supported by four supports located under the cold legs, which are spaced 90 degrees apart in the primary shield wall. The supports are designed to provide for radial thermal growth of the reactor coolant system, including the reactor vessel, but they prevent the vessel from lateral and torsional movement. The ends of the supports are bolted to steel embedments in the concrete wall surrounding the reactor vessel. Each support connects to the embedments with eight 2-3/8-inch-diameter dowel studs. In addition, the center portion of the support is attached to the concrete with eight threaded anchor bolts embedded in the primary shield wall concrete. The reactor vessel supports loads are carried by the dowel studs to embedded steel structures and the anchor bolts to the concrete. Figure 3.8.3-4 shows the reactor vessel supports.

3.8.3.1.1.2 Steam Generator Support System

The steam generator vertical support consists of a single vertical column extending from the steam generator compartment floor to the bottom of the steam generator channel head. The column is constructed of heavy plate sections and is pinned at both ends to permit unrestricted radial displacement of the steam generator during plant heatup and cooldown. The location of this column is such that it will allow full access to the steam generator for routine maintenance activities. It is located a sufficient distance away from the reactor coolant pump motors to permit pump maintenance and in-service inspection.

The lower steam generator horizontal support is located at the top of the vertical column. It consists of a tension/compression link bar and extension bar oriented approximately perpendicular to the hot leg. The link bar and extension bar is pinned at both the wall bracket and the vertical column to permit movement of the generator during plant heatup and cooldown.

The upper steam generator horizontal support in the direction of the hot leg is located on the upper shell just above the transition cone. It consists of two large hydraulic snubbers oriented parallel with the hot leg centerline. One snubber is mounted on each side of the generator on top of the steam generator compartment wall. The hydraulic snubbers are valved to permit steam generator movement for thermal transition conditions, and to "lock-up" and act as rigid struts under dynamic loads.

The upper steam generator horizontal support in the direction normal to the hot leg is located on the lower shell just below the transition cone. It consists of two rigid tension/compression struts oriented perpendicular to the hot leg. The two rigid struts are mounted on the steam generator compartment wall at the elevation of the operating deck. The steam generator loads are transferred to the struts and snubbers through trunnions on the generator shell. Figure 3.8.3-5 shows the steam generator supports.

The steam generator supports are anchored using anchor bolts or steel weldments embedded in the concrete, designed in accordance with Appendix B of ACI 349. The lower portion of the column pedestal, embedded in the concrete, as shown on sheet 1 of Figure 3.8.3-5, transfers the vertical load into the reinforced concrete basemat. The lower and intermediate horizontal supports are located so that the loads are transferred into the plane of the adjacent floor. The upper supports are located so that the loads are transferred into the plane of the steam generator compartment walls.

3.8.3.1.1.3 Reactor Coolant Pump Support System

Because the reactor coolant pumps are integrated into the steam generator channel head, they do not have individual supports. They are supported by the steam generators.

3.8.3.1.1.4 Pressurizer Support System

The pressurizer is supported by four columns mounted from the pressurizer compartment floor. A lateral support is provided at the top of the columns. This lateral support consists of eight struts connecting it to the pressurizer compartment walls. A lateral support is also provided on the upper portion of the pressurizer. This lateral support consists of a ring girder around the pressurizer and eight struts connecting it to the pressurizer compartment walls. Figure 3.8.3-6 shows the pressurizer supports.

3.8.3.1.2 Containment Internal Structures Basemat

The containment internal structures basemat is the reinforced concrete structure filling the bottom head of the containment vessel. It extends from the bottom of the containment vessel head at elevation 66′-6″ up to the bottom of the structural modules that start between elevations 71′-6″ and 103′-0″. The basemat includes rooms as shown on Figure 1.2-5. The primary shield wall and reactor cavity extend from elevation 71′-6″ to elevation 107′-2″. They provide support for the reactor vessel and portions of the secondary shield walls and refueling cavity walls. The general arrangement drawings in Section 1.2 show the location and configuration of the primary shield wall and reactor cavity. The walls of the primary shield, the steam generator compartment and the CVS room are structural modules as shown in Figure 3.8.3-1. The rest of the basemat is reinforced concrete.

3.8.3.1.3 Structural Wall Modules

Structural wall modules are used for the primary shield wall around the reactor vessel, the wall between the vertical access and the CVS room, secondary shield walls around the steam generators and pressurizer, for the east side of the in-containment refueling water storage tank, and for the refueling cavity. The general arrangement drawings in Section 1.2 show the location and configuration. Locations of the structural modules are shown in Figure 3.8.3-1. Isometric views of the structural modules are shown in Figure 3.8.3-14. The figure shows the use of modules, overall configuration, and general design approach for incorporation of structural modules into the structural design. Alternatives to the design details shown in Figure 3.8.3-14, including the size, location, and type of structural shapes attached to the faceplates and embedded in the concrete, may be used. The embedded lower portions of the modules in the concrete, attachments, and penetrations may also be added or differ from that shown in the figure. The secondary shield walls are a series of walls that, together with the refueling cavity wall, enclose the steam generators. Each of the two secondary shield wall compartments provides support and houses a steam generator and reactor coolant loop piping. The in-containment refueling water storage tank is approximately 30 feet high. The floor elevation of this tank is 103′-0″. The tank extends up to about elevation 133′-3″, directly below the operating deck. On the west side, along the containment vessel wall, the tank wall consists of a stainless steel plate stiffened with structural steel sections in the vertical direction and angles in the horizontal direction. Structural steel modules, filled with concrete and forming, in part, the refueling cavity, steam generator compartment, and pressurizer compartment walls, compose the east wall. The refueling cavity has two floor elevations. The area around the reactor vessel flange is at elevation 107′-2″. The lower level is at elevation 98′-1″. The upper and lower reactor internals storage is at the lower elevation, as is the fuel transfer tube. The center line of the fuel transfer tube is at elevation 100′-5.75″.

Structural wall modules consist of steel faceplates connected by steel trusses. The primary purpose of the trusses is to stiffen and hold together the faceplates during handling, erection, and concrete placement. The nominal spacing of the trusses is 30 inches. The nominal thickness of the steel faceplates is 0.5 inch. [*In the CA01 and CA05 structural wall modules, the faceplate thickness is greater than the nominal thickness where required to support local demand. For areas subject to these high out-of-plane loads, the faceplate thickness may be increased up to a thickness of 1.5 inches. To support loading associated with the steam generator lateral supports, the faceplate*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

thickness may be increased up to a thickness of 3.0 inches.]* At corner locations, the trusses are replaced with diaphragms. These diaphragms have similar purpose as the trusses and are used to fabricate the modules in the corners. The detail design of the trusses and the design of the diaphragms shown in Figure 3.8.3-8, Sheet 1 are representative. Details such as the location, type, and size of welds and length and end configuration of channels used to assemble the internal trusses may vary in the design implemented from that shown in the figure. The size, shape, and location of welds, structural shapes, and other elements used to fabricate and stiffen the diaphragms and connect them to the faceplates and the location, size, and shape of the access opening may vary from that shown in the figure. Steel plates, structural shapes, reinforcement bars, or tie bars are installed between the structural wall module faceplates and embedded in the concrete as additional structural elements that support out-of-plane loads and structural integrity. This reinforcement is designed to the applicable requirements of ACI 349 and ANSI/AISC N690. Each module has different characteristics that require the detailed design to be specific for that module and loading and interferences within that module.Shear studs are welded to the inside faces of the steel faceplates. Face plates are welded to adjacent plates with full penetration welds so that the weld is at least as strong as the plate. The full penetration welds are identified in Figure 3.8.3-8, Sheet 1 with the weld symbol that includes the notation CJP for complete joint penetration. Plates on each face of the wall module extend down to the elevation of the adjacent floor. Where the floors in the rooms on each side of the wall module are at different elevations, one of the plates at the bottom of the module extends further down than the other. This single-sided configuration is designated on Figure 3.8.3-1 as “CA Structure Module with Single Surface Plate” for lower elevations in containment. A typical example with the single-sided configuration at the bottom of the module is shown in Figure 3.8.3-8. Some modules or portions of modules do not have the single-sided configuration at the bottom of the module. The module functions as a wall above the upper floor level (elevation 103′-0″ in Figure 3.8.3-8). The single plate below this elevation is designed to transfer the reactions at the base of the wall into the basemat. This plate also acts as face reinforcement for the basemat. Basemat reinforcement dowels are provided at the bottom of the single plate as shown in Figure 3.8.3-8.

[*Shear studs, structural shapes, or horizontally oriented reinforcement bars mechanically connected or welded to the module faceplates may be used to anchor the CA01 and CA05 structural modules to the base concrete. Shear lugs designed in accordance with ACI 349 may also be used to transfer loads at the connection. Where horizontal bars are attached perpendicular to the faceplate, they function like shear studs to provide for faceplate development. Where additional reinforcement is required for detailing base concrete at module walls with offsets in faceplate elevation, the reinforcement is developed in accordance with ACI 349. Where horizontal bars are attached to the edge of a faceplate at an elevation offset, the bars are designed for a combination of applicable demand and developed in accordance with ACI 349.*]*

[*The information in Figure 3.8.3-8, Sheet 1 that is considered to be Tier 2* information is the design spacing of the faceplates, trusses, channels in the trusses and the minimum size and design spacing of the headed studs for the modular wall in the containment internal structure in locations away from openings or penetrations in the walls. Local variation in the design of the trusses and spacing of the trusses and shear studs may be required to address internal obstructions and accessibility for fabrication and inspection. As shown in Figure 3.8.3-1, Sheets 2 and 4, some CA01 and CA05 wall thicknesses are different than the wall thicknesses listed in Figure 3.8.3-8. Wall thickness increase due to local faceplate thickness increase is below the level of detail depicted in Figure 3.8.3-1. The module wall thicknesses are determined based on radiation protection considerations and are designed to the applicable requirements of ANSI/AISC N690 and ACI 349. The use of full penetration welds to connect the faceplates of the modules is also considered to be Tier 2* information. The information in Figure 3.8.3-8, Sheet 2 that is considered to be Tier 2* information is the use of mechanical connectors and the development length requirement for the mechanical connectors.*]* The detail design of the mechanical connectors is governed by ANSI/AISC N690 and ACI 349, and the representative design shown is not considered to be Tier 2* information. The material, size, and configuration of plates, size and type of welds, method of attaching the connectors to the modules,

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

and size of deformed bars anchoring the embedments into the concrete may be different for each module and may vary from that shown in the figure provided that the embedment design satisfies the ANSI/AISC N690 and ACI 349 codes. Sheet 3 of Figure 3.8.3-8 shows a wall of the IRWST that is a steel structure anchored in concrete and is not a concrete filled module. [*The information in Figure 3.8.3-8, Sheet 3 that is considered to be Tier 2* information is the plate thickness for the IRWST wall, the use, spacing, and size of angles and tees to stiffen the wall, the number, size, and use of studs provided to anchor the module, and the number, size, vertical spacing, and development length of the deformed bars provided to connect the module to the mass concrete. The design implemented in fabrication and construction drawings and instructions will have the design shown, an equal design, or a better design for the key structural elements.*]*

The structural wall modules are anchored to the concrete base by reinforcing steel dowels or other types of connections mechanically connected or welded to the modules and embedded in the reinforced concrete below or adjacent to the module. [*The reinforcing steel used to anchor the modules to the concrete may be oriented horizontally or vertically and has a development that satisfies the requirements of ACI 349.*]* After erection, concrete is placed between the faceplates. Typical design details of the structural modules are shown in Figures 3.8.3-2 and 3.8.3-8. Shear-friction reinforcement may be included in construction joints at the transition between the base concrete and concrete in the modules and is not part of the mechanical connection between the module and base concrete described above. The shear-friction reinforcement at the construction joints is spaced and sized in accordance with ACI 349 requirements and is not connected to the module faceplates.

Representative design details of the connections of floor modules to structural wall modules are shown in Figure 3.8.3-17. These connections connect the floor modules that make up the maintenance floor at elevation 107'-2" and the operating deck at elevation 135'-3". Similar connection designs are used within structural modules to connect floors to walls. The design details for the floor modules, including the size and spacing of the reinforcement, the use of shear studs, and the sizes of the structural shapes, are provided for background information and vary based on loading conditions and geometry. The seat angles, beam seats, shear plates, and other design elements supporting the floor modules and connecting the floors to the wall modules are sized to satisfy ANSI/AISC N690 criteria and requirements. The clip angles and shear plates shown in Figure 3.8.3-17 and other design elements are used as required at beam locations for the connection. The module faceplates in the area of the connection may be thicker than 0.5 inch, up to 1.5-inch thick, in some locations. The backup structure shown in the module wall is a representative design, and the details for the design implemented include variation of the size and thickness of the plates used in the backup structure. The designs of the backup structures satisfy ANSI/AISC N690 criteria and requirements. As an alternative, locally thicker faceplates or other design elements embedded in the wall and connected to the faceplate may be used to provide sufficient strength in the connection. Where the reinforcement is included as part of the connection design, the size, spacing, and length of the reinforcement satisfies ACI 349 requirements. The standard hooks in the wall module and the reinforcement bar connectors on the faceplates satisfy ACI 349 requirements.

3.8.3.1.4 Structural Floor Modules

Structural floor modules are used for the operating floor at elevation 135′-3″ over the in-containment refueling water storage tank, for the southeast quadrant of the operating floor and for the 107′-2″ floor over the rooms in the containment internal structures basemat. The floors are shown on the general arrangement drawings in Section 1.2. The floor modules consist of shear studs, steel tee, wide flange, and channel sections, welded to horizontal steel bottom plates stiffened by transverse stiffeners. Shear studs are welded on the top of the floor bottom plate. After erection, concrete is placed on top of the horizontal plate and around the structural steel section. The remaining region of the operating floor consists of a concrete slab, placed on Q decking supported by structural steel beams. The operating floor is supported by the in-containment refueling water storage tank walls,

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

refueling cavity walls, the secondary shield walls, and steel columns originating at elevation 107′-2″. Structural details for a representative example of the containment operating deck floor structural module are shown in Figure 3.8.3-3. The design details for the floor module are provided for background information and vary based on loading conditions and geometry.

3.8.3.1.5 Internal Steel Framing

The region of the operating floor away from the in-containment refueling water storage tank consists of a concrete slab, placed on Q decking supported by structural steel beams. The floor at elevation 118′-6″ consists of steel grating supported by structural steel framing. In addition, a number of steel platforms are located above and below the operating floor. These platforms support either grating floors or equipment, such as piping and valves.

3.8.3.2 Applicable Codes, Standards, and Specifications

The following documents are applicable to the design, materials, fabrication, construction, inspection, or testing of the containment internal structures:

[● *American Concrete Institute (ACI), Code Requirements for Nuclear Safety Related Concrete Structures, ACI 349-01*]* (refer to Subsection 3.8.4.5 for supplemental requirements)

- American Concrete Institute (ACI), ACI Detailing Manual
- American Concrete Institute (ACI), Standard Specifications for Tolerances for Concrete Construction and Materials, ACI-117
- American Concrete Institute (ACI), Guide to Formwork for Concrete, ACI-347

[● *American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, ANSI/AISC N690-1994*]* (refer to Subsection 3.8.4.5 for supplemental requirements)

[● *American Welding Society (AWS), Structural Welding Code - Steel, AWS D1.1-2000*

AWS D1.1-2000 is an acceptable code for use in lieu of AWS D1.1-1992 for the design, qualification, fabrication, and inspection for ANSI/AISC N690 applications.

The use of AWS D1.1-2000 to replace and supplement provisions in ANSI/AISC N690-1994 includes the provisions noted below:

– *The provisions in Section 2.3.4.1 of AWS D1.1-2000 are used to size complete joint penetration groove welds for tubular members.*

– *ASTM A992 is an alternative to ASTM A36 steel for structural steel shapes. Where ASTM A992 steel is used, the provisions for matching weld metal identified in AWS D1.1-2000, Section 3.3 and Table 3.1 are used to supplement the information in ANSI/AISC N690 Section Q1.4.4.*

– *Where directionality is applied to increase allowable weld stress for fillet welds identified in ANSI/AISC N690, Section Q1.5.3 and Table Q1.5.3, the provisions in Sections 2.14.4 and 2.14.5 of AWS D1.1-2000 shall be used.*

For fillet weld groups concentrically loaded in the plane of the axis of the weld and consisting of elements oriented both longitudinally and transversely to the direction of applied load, the

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

deformation capability of the elements shall be considered. As a supplement to the provisions in AWS D1.1-2000, the strength of the weld group is limited to the larger of the two following evaluations:

1. *The combined strength of the individual weld elements using 1.0 times the strength of the longitudinally oriented element and 1.0 times the strength of the transversely oriented element*

2. *The combined strength of the individual weld elements using 0.825 times the strength of the longitudinally oriented element and 1.5 times the strength of the transversely oriented element*

The provisions for directionality are not applied to fillet welds of tubular member T, Y, and K connections described in Table 2.5 of AWS D1.1-2000.

The provisions in AWS D1.1-2000 for the application of directionality to linear fillet welds are supplemented by extending the provisions to weld configurations not specified in AWS D1.1-2000 as noted below:

– *Where directionality is considered for concentric out-of-plane loading for linear fillet weld groups, including lines and rectangular configurations, the directionality provisions in AWS D1.1-2000 are applied.*

– *Where directionality is considered for concentric out-of-plane loading for circular-shaped fillet weld configurations, the directionality provisions in AWS D1.1-2000 are applied. The use of directionality provisions in AWS D1.1-2000 for circular-shaped fillet weld configurations is limited to tension loading concentrically applied out-of-plane to the axis of the weld.*]*

Nationally recognized industry standards, such as American Society for Testing and Materials, American Concrete Institute, and American Iron and Steel Institute, are used to specify material properties, testing procedures, fabrication, and construction methods. Section 1.9 describes conformance with the Regulatory Guides and the Standard Review Plans.

Welding and inspection activities for seismic Category I structural steel, including building structures, structural modules, cable tray supports, and heating, ventilating and air-conditioning (HVAC) duct supports are accomplished in accordance with written procedures and meet the requirements of the American Institute of Steel Construction (ANSI/AISC N690). The welded seams of the plates forming part of the leaktight boundary of the in-containment refueling water storage tank are examined by liquid penetrant after fabrication to confirm that the boundary does not leak.

3.8.3.3 Loads and Load Combinations

The loads and load combinations used in the analysis are considered to be part of the method of evaluation. The loads and load combinations for the containment internal structures are the same as for other Category I structures described in Subsection 3.8.4.3 and the associated tables, except for the following modifications:

Wind loads (W), tornado loads (W_t), and precipitation loads (N) are not applicable to the design of the containment internal structures because of the protection provided by the steel containment. Therefore, these loading terms have been excluded in the load combinations for the containment internal structures.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.8.3.3.1 Passive Core Cooling System Loads

Structures are evaluated for pressure and thermal transients associated with operation of the passive core cooling system. The effects of temperatures higher than 100°F on the modulus of elasticity and yield strength of steel are considered.

The passive core cooling system and the automatic depressurization system (ADS) are described in Section 6.3. The automatic depressurization system is in part composed of two spargers that are submerged in the in-containment refueling water storage tank. The spargers provide a controlled distribution of steam flow to prevent imposing excessive dynamic loads on the tank structures. Capped vent pipes are installed in the roof of the tank on the side near the containment wall.

These caps prevent debris from entering the tank from the containment operating deck, but they open under slight pressurization of the in-containment refueling water storage tank. This provides a path to vent steam released by the spargers. An overflow is provided from the in-containment refueling water storage tank to the refueling cavity to accommodate volume and mass increases during automatic depressurization system operation. Two sets of loads representing bounding operational or inadvertent transients are considered in the design of the in-containment refueling water storage tank.

- ADS_1 – This automatic depressurization system load is associated with blowdown of the primary system through the spargers when the water in the in-containment refueling water storage tank is cold and the tank is at ambient pressure. Dynamic loads on the in-containment refueling water storage tank due to automatic depressurization system operation are determined using the results from the automatic depressurization system hydraulic test as described in Subsection 3.8.3.4.2. The hydrodynamic analyses described in Subsection 3.8.3.4.2 show that member forces in the walls of the in-containment refueling water storage tank are bounded by a case with a uniform pressure of 5 psi applied to the walls. The in-containment refueling water storage tank is designed for a uniform pressure of 5 psi applied to the walls. This pressure is taken as both positive and negative due to the oscillatory nature of the hydrodynamic loads. This automatic depressurization system transient is of short duration such that the concrete walls do not heat up significantly. It is combined with ambient thermal conditions. Long-term heating of the tank is bounded by the design for the ADS_2 load.

- ADS_2 – This automatic depressurization system transient considers heatup of the water in the in-containment refueling water storage tank. This may be due to prolonged operation of the passive residual heat removal heat exchanger or due to an automatic depressurization system discharge. For structural design, an extreme transient is defined starting at 50°F since this maximizes the temperature gradient across the concrete-filled structural module walls. Prolonged operation of the passive residual heat removal heat exchanger raises the water temperature from an ambient temperature of 50°F to saturation in about 4 hours, increasing to about 260°F within about 10 hours. Steaming to the containment atmosphere initiates once the water reaches its saturation temperature. The temperature transient is shown in Figure 3.8.3-7. Blowdown of the primary system through the spargers may occur during this transient and occurs prior to 24 hours after the initiation of the event. Since the flow through the sparger cannot fully condense in the saturated conditions, the pressure increases in the in-containment refueling water storage tank and steam is vented through the in-containment refueling water storage tank roof. The in-containment refueling water storage tank is designed for an equivalent static internal pressure of 5 psi in addition to the hydrostatic pressure occurring at any time up to 24 hours after the initiation of the event.

The ADS_1 and ADS_2 loads are considered as live loads. The dynamic ADS_1 load is combined with the safe shutdown earthquake by the square root sum of the squares (SRSS). ADS_2 is an equivalent

static pressure which is included algebraically with other normal loads and then combined with plus/ minus SSE loads.

3.8.3.3.2 Concrete Placement Loads

The steel faceplates of the structural wall modules, designed for the hydrostatic pressure of the concrete, act as concrete forms. The concrete placement loads are 1050 pounds per square foot determined in accordance with ACI-347. The bending stress in the faceplate due to this hydrostatic pressure of the concrete is approximately 13 ksi, based on the assumption of a continuous faceplate, or 20 ksi based on the assumption of simple spans. The minimum yield strength of material for the faceplates is 36 ksi. The stress is well below the allowable, since the plate is designed to limit the out-of-plane deflection. After the concrete has gained strength, these stresses remain in the steel; however, since the average residual stress is zero and since the concrete no longer requires hydrostatic support, the ultimate strength of the composite section is not affected, and the full steel plate is available to carry other loads as described below.

The steel plates and the concrete act as a composite section after the concrete has reached sufficient strength. The composite section resists bending moment by one face resisting tension and the other face resisting compression. The steel plate resists the tension and behaves as reinforcing steel in reinforced concrete. The composite section is underreinforced so that the steel would yield before the concrete reaches its strain limit of 0.003 in/in. As the steel faceplates are strained beyond yield to allow the composite section to attain its ultimate capacity, the modest residual bending stress from concrete placement is relieved, since the stress across the entire faceplate in tension is at yield. The small residual strain induced by the concrete placement loads is secondary and has negligible effect on the ultimate bending capacity of the composite section. The stresses in the faceplates resulting from concrete placement are therefore not combined with the stresses in the post-construction load combinations.

3.8.3.4 Analysis Procedures

This subsection describes the modelling and overall analyses of the containment internal structures, including the concrete-filled structural modules. Concrete and steel composite structures are used extensively in conventional construction. Applications include concrete slabs on steel beams and concrete-filled steel columns. Testing of concrete-filled structural modules is described in References 27 through 29 for in-plane loading and in References 30 through 33 for out-of-plane loading. The tests indicate that these composite structures behave in a manner similar to reinforced concrete structures. The initial load deflection behavior is well predicted using the gross properties of the steel and concrete. This is similar to the behavior of reinforced concrete elements where the initial stiffness is predicted by the gross properties. As the load is increased on reinforced concrete members, cracking of the concrete occurs and the stiffness decreases. The behavior of concrete and steel composite structures is similar in its trends to reinforced concrete but has a superior performance. The results of the test program by Akiyama et al. (Reference 27)

indicate that concrete and steel composites similar to the structural modules have significant advantages over reinforced concrete elements of equivalent thickness and reinforcement ratios:

- Over 50 percent higher ultimate load carrying capacity
- Three times higher ductility
- Less stiffness degradation under peak cyclic loads, 30 percent for concrete and steel composites versus 65 percent for reinforced concrete

Methods of analysis for the structural modules are similar to the methods used for reinforced concrete. Table 3.8.3-2 summarizes the finite element analyses of the containment internal structures and identifies the purpose of each analysis and the stiffness assumptions for the concrete filled steel modules. For static loads the analyses use the monolithic (uncracked) stiffness of each concrete element. The elastic modulus is taken as 0.80 times the value calculated based on the ACI Code. This reduced elastic modulus considers a small degree of cracking as described in the seismic analyses in Subsection 3.7.2.3. For thermal and dynamic loads the analyses consider the extent of concrete cracking as described in later subsections.

Stiffnesses are established based on analyses of the behavior and review of the test data related to concrete-filled structural modules. The stiffnesses directly affect the member forces resulting from restraint of thermal growth. The in-plane shear stiffness of the module influences the fundamental horizontal natural frequencies of the containment internal structures in the nuclear island seismic analyses described in Subsection 3.7.2. The out-of-plane flexural stiffness of the module influences the local wall frequencies in the seismic and hydrodynamic analyses of the in-containment refueling water storage tank. Member forces are evaluated against the strength of the section calculated as a reinforced concrete section with zero strength assigned to the concrete in tension.

ACI 349, Section 9.5.2.3 specifies an effective moment of inertia for calculating the deflection of reinforced concrete beams. For loads less than the cracking moment, the moment of inertia is the gross (uncracked) inertia of the section. The cracking moment is specified as the moment corresponding to a maximum flexural tensile stress of $7.5\sqrt{f_c'}$. For large loads, the moment of inertia is that of the cracked section transformed to concrete. The effective moment of inertia provides a transition between these two dependent on the ratio of the cracking moment to the maximum moment in the beam at the stage the deflection is to be computed.

Table 3.8.3-1 summarizes in-plane shear and out-of-plane flexural stiffness properties of the 48-inch and 30-inch walls based on a series of different assumptions. The stiffnesses are expressed for unit length and height of each wall. The ratio of the stiffness to the stiffness of the monolithic case is also shown.

- Case 1 assumes monolithic behavior of the steel plate and uncracked concrete. This stiffness is supported by the test data described in References 27 through 33 for loading that does not cause significant cracking. This stiffness is the basis for the stiffness of the concrete-filled steel module walls in the nuclear island seismic analyses and in the uncracked case for the hydrodynamic analyses.

- Case 2 considers the full thickness of the wall as uncracked concrete. This stiffness value is shown for comparison purposes. It is applicable for loads that do not result in significant cracking of the concrete and is the basis for the stiffness of the reinforced concrete walls in the nuclear island seismic analyses (prior to the reduction in concrete stiffness by a factor of 0.8). This stiffness was used in the harmonic analyses of the internal structures described in Subsection 3.8.3.4.2.2.

- Case 3 assumes that the concrete in tension has no stiffness. For the flexural stiffness this is the conventional stiffness value used in working stress design of reinforced concrete sections. For in-plane shear stiffness, a 45-degree diagonal concrete compression strut is assumed with tensile loads carried only by the steel plate. The in-plane stiffnesses calculated by these assumptions are lower than the stiffnesses measured in the tests described in References 27 through 29 for loading that causes cracking.

3.8.3.4.1 Seismic Analyses

3.8.3.4.1.1 Finite Element Model

The structural modules are simulated within the finite element model using 3D shell elements. Equivalent shell element thickness and modulus of elasticity of the structural modules are computed as shown below. The shell element properties are computed using the combined gross concrete section and the transformed steel faceplates of the structural modules. This representation models the composite behavior of the steel and concrete. The equivalent modulus of concrete, E_m, is reduced by a factor of 0.8 to consider the effect of cracking as recommended in Table 6-5 of FEMA 356 (Reference 5 in Subsection 3.7.6). See Section 3.7 and Appendix 3G for further discussion of the containment internal structures finite element model.

- Axial and Shear Stiffnesses of module:

$$\sum E A = E_c (L t + 2 (n - 1) L t_s)$$

- Bending Stiffness of module:

$$\sum E I = E_c \left[\frac{L}{12} t^3 + 2 \frac{L}{12} (n-1)\ t_s^3 + 2 (n-1) L t_s \left(\frac{t}{2} \right)^2 \right]$$

where:

E_c = concrete modulus of elasticity

n = modular ratio of steel to concrete

L = length of wall module

t = thickness of wall module

t_s = thickness of plate on each face of wall module

These equations lead to an equivalent thickness, t_m, and modulus of elasticity of the plate elements, E_m, as shown below:

$$t_m = \left[\frac{1 + 3 \alpha (n-1)}{1 + \alpha (n-1)} \right]^{1/2} t$$

$$E_m = [1 + \alpha (n-1)] \left[\frac{1 + 3 \alpha (n-1)}{1 + \alpha (n-1)} \right]^{-1/2} E_c$$

where $\alpha = 2t_s / t$ and terms of order α^3 are neglected (for a typical 30-inch thick wall with 1/2-inch steel plates, $\alpha = 0.033$).

3.8.3.4.1.2 Stiffness Assumptions for Local Seismic Analyses of In-Containment Refueling Water Storage Tank

The seismic analyses of the in-containment refueling water storage tank address the local response of the walls and water and are performed to verify the structural design of the tank. The local analyses performed uses the cracked section stiffness values based on composite behavior with zero stiffness for the concrete in tension (Case 3 of Table 3.8.3-1). The local analyses use the finite element model described in Subsection 3.8.3.4.2.2. Response spectrum analyses are performed using the floor response spectra at the base of the tank.

3.8.3.4.1.3 Damping of Structural Modules

Damping of the structural modules is reported in Reference 27 based on the cyclic load tests of a containment internal structure model. The equivalent viscous damping at the design load level was 5 percent for the concrete-filled steel model. This was almost constant up to the load level at which the steel plate started yielding. Dynamic analyses are performed using 7 percent damping for the reinforced concrete and 5 percent for the structural modules as shown in Subsection 3.7.1.

3.8.3.4.2 Hydrodynamic Analyses

This subsection describes the hydrodynamic analyses performed for the AP600 which demonstrated that design of the walls of the in-containment refueling water storage tank for 5 psi as described in Subsection 3.8.3.3.1 would bound the loads from the time history transient analysis. The analyses were performed using the AP600 test results. The peak values from these tests are also applicable to the AP1000 since they occur at the beginning of the transient, and the automatic depressurization system and the initial conditions are the same for the two plant designs (Reference 52). The structural configuration of the tank is identical. The minor differences in the height of the steam generator and pressurizer compartment walls and in the mass of the steam generators and pressurizer will have only a minor effect on the significant structural frequencies. Since the time histories applied in the AP600 analyses cover a broad range of frequencies the response of the AP1000 tank boundary will be similar to that of the AP600. The 5 psi pressure design basis for the tank boundary is therefore also applicable to the AP1000.

Hydrodynamic analyses were performed for the AP600 for automatic depressurization system discharge into the in-containment refueling water storage tank. This discharge is designated as ADS_1 in the load description of Subsection 3.8.3.3.1 and results in higher hydrodynamic loading than the ADS discharge into a hot tank in ADS_2. The first three stages of the automatic depressurization system valves discharge into the tank through spargers under water, producing hydrodynamic loads on the tank walls and equipment. Hydrodynamic loads, measured in hydraulic tests of the automatic depressurization system sparger in a test tank, are evaluated using the source load approach (Reference 34). Analyses of the tests define source pressure loads that are then used in analyses of the in-containment refueling water storage tank to give the dynamic responses of the containment internal structures. The basic analysis approach consists of the following steps:

1. A pressure source, an impulsive forcing function at the sparger discharge, is selected from the tests using a coupled fluid structure finite element model of the test tank, taking into account fluid compressibility effects. This source development procedure is based on a comparison between analysis and test results, both near the sparger exit and at the boundaries of the test tank.

2. The pressure source is applied at each sparger location in a coupled fluid structure finite element model of the in-containment refueling water storage tank structure and of the contained water. The mesh characteristics of the model at the sparger locations and the applied forcing functions correspond to those of the test tank analysis.

3.8.3.4.2.1 Sparger Source Term Evaluation

A series of tests was conducted with discharge conditions representative of one sparger for the AP600 (References 35 and 36). Pressure traces measured during the test discharges were investigated, at both sparger exit and tank boundaries to (1) bound the expected discharge from the automatic depressurization system; (2) characterize the pressure wave transmission through the pool water; (3) determine the maximum pressure amplitudes and the frequency content; and (4) produce reference data for qualification of the analytical procedure. Pressure time histories and power spectrum densities were examined at reference sensors, both for the total duration of the discharge transient (about 50 seconds) and for critical time intervals.

Fluid-structure interaction analyses were performed with the ANSYS computer code (Reference 37). The mathematical model consists of a 3D sector finite element model, 15 degrees wide, as shown in Figure 3.8.3-9. It uses STIF30 fluid and STIF63 structural ANSYS finite elements, which take into account fluid compressibility and fluid-structure interaction. Rayleigh damping of 4 percent is used for the concrete structure, and fluid damping is neglected. Direct step-by-step time integration is used. The measured discharge pressures for single time intervals are imposed as uniform forcing functions on the idealized spherical surface of the steam/water interface, and pressures transmitted through the water to the tank boundary are calculated and compared with test measurements. The analyses of the test tank showed satisfactory agreement for the pressures at the tank boundary.

The examination of test results related to the structural design of the in-containment refueling water storage tank under automatic depressurization system hydrodynamic excitation and the comparison with the analytical procedure previously described, lead to the following conclusions regarding the sparger source term definition:

- The automatic depressurization system discharge into cold water produces the highest hydrodynamic pressures. The tests at higher water temperatures produce significantly lower pressures.

- Two pressure time histories, characterized by different shapes and frequency content, can be selected as representative of the sparger discharge pressures; they are assumed as acting on a spherical bubble centered on the sparger centerline and enveloping the ends of the sparger arms.

- The application of such time histories as forcing functions to an analytical model, simulating the fluid structure interaction effects in the test tank, has been found to predict the measured tank wall pressures, for the two selected reference time intervals.

- The two defined sparger source term pressure time histories can be used as forcing functions for global hydrodynamic analyses of the in-containment refueling water storage tank by developing a comprehensive fluid-structure finite element model and reproducing the test tank mesh pattern in the sparger region.

- The hydrodynamic loads on the vessel head support columns and ADS sparger piping located in the IRWST are developed from the forcing functions using the methodology documented in Reference 51.

3.8.3.4.2.2 In-Containment Refueling Water Storage Tank Analyses

The in-containment refueling water storage tank is constructed as an integral part of the containment internal structures as described in Subsection 3.8.3.1.3. It contains two depressurization spargers that are submerged approximately 9 feet below the normal water level. Transmission of the hydrodynamic pressures from the sparger discharge to the wetted in-containment refueling water

storage tank is evaluated using the coupled fluid-structure interaction method similar to that described for the test tank analysis in the previous subsection.

The 3D ANSYS finite element model includes the in-containment refueling water storage tank boundary, the water within the in-containment refueling water storage tank, the adjacent structural walls of the containment internal structures, and the operating floor. The model of the in-containment refueling water storage tank, shown in Figures 3.8.3-10 (sheet 2), 3.8.3-11, and 3.8.3-12, represents the outer steel structures, the inner concrete walls, and the water. The model of the adjacent structural walls and floors is shown in Figure 3.8.3-10 (sheet 1). The flexible steel outer wall is represented using beam and shell elements; isotropic plate elements are used to represent the inner structural module walls. The water is modelled as a compressible fluid to provide an acoustic medium to transmit the source pressure. The model has two bubble boundaries representing the spargers. Pressure loads are applied to the solid element faces adjacent to the air bubbles. The forcing functions at the sparger locations are conservatively assumed to be in phase. Rayleigh damping of 5 percent is used for the concrete-filled structural modules and fluid damping is neglected. All degrees of freedom were retained in the step-by-step direct integration solution procedure for the in-containment refueling water storage tank boundary and the water. Degrees of freedom in the adjacent walls and floor were condensed by Guyon reduction.

Significant structural frequencies of the AP600 containment internal structures were analyzed using the harmonic response option with the ANSYS model of the in-containment refueling water storage tank and containment internal structures. A harmonic unit pressure is applied at the surface of the spherical bubble representing the automatic depressurization system spargers. Material properties for the concrete elements are based on the uncracked gross concrete section (Case 2 of Table 3.8.3-1). The results of these harmonic response analyses show the response deflection as a function of input frequency at nodes in the containment internal structures. The harmonic response analyses show that the largest responses are close to the wetted boundary of the in-containment refueling water storage tank and that the significant frequencies are from 18 to 50 hertz.

Two time histories are identified for the structural hydrodynamic analyses; one has significant frequencies below 40 hertz while the other has significant frequencies in the range of 40 to 60 hertz. Both time history inputs are used in the hydrodynamic analyses with the monolithic uncracked section properties for all walls. The lower frequency input is also applied in lower bound analyses using the cracked section stiffness values (Case 3 of Table 3.8.3-1) for the concrete walls that are boundaries of the in-containment refueling water storage tank. Monolithic properties are used for the other walls. Results from these cases are enveloped, thereby accounting for variabilities in the structural analyses.

The analyses of the AP600 in-containment refueling water storage tank give wall pressures, displacements, accelerations, hydrodynamic floor response spectra, and member forces due to the automatic depressurization system discharge pressure forcing functions. Consideration of pressure wave transmission and fluid-structure interaction shows a significant wall pressure attenuation with distance from the sparger region and with increasing wall flexibilities, relative to the measured sparger pressure forcing function. The member stresses are evaluated against the allowable stresses specified in Subsection 3.8.3.5 for seismic Category I structures, considering the hydrodynamic loads as live loads. The analyses show that the member forces in the walls of the in-containment refueling water storage tank are bounded by a case with a uniform pressure of 5 psi applied to the walls.

3.8.3.4.3 Thermal Analyses

The in-containment refueling water storage tank water and containment atmosphere are subject to temperature transients as described in Subsection 3.8.3.3.1. The temperature transients result in a nonlinear temperature distribution within the wall modules. Temperatures within the concrete wall are

calculated in a unidimensional heat flow analysis. The average and equivalent linear gradients are applied to a finite element model of the containment internal structures at selected times during the transient. The effect of concrete cracking is considered in the stiffness properties for the concrete elements subjected to the thermal transient. The finite element model is that described in Subsection 3.8.3.4.2.2 except that the model of the water in the IRWST is not needed.

The structural modules are subject to a rapid temperature transient in the event of a loss-of-coolant accident (LOCA) or a main steam line break (MSLB). The structural modules were evaluated for these rapid temperature transients. The evaluation considered both carbon and stainless steel faceplates. The steel plate heats up most rapidly in the LOCA event with temperatures up to 270°F in the first few minutes for an ambient initial temperature of 50°F. The faceplate of the structural module will see differential temperatures of 220°F relative to the concrete. The concrete heats up more slowly and does not see a significant temperature increase during the early part of the transient. There is relative thermal growth of the faceplate, causing shear loads in the shear studs, and embedded angles of the structural steel trusses that are welded to the faceplate. The heatup of the surface plates during the initial portion of the LOCA transient results in cracking of the concrete walls except in regions where there is significant external restraint. The structural module maintains its integrity throughout the rapid thermal transient.

Thermal transients for the design basis accidents are described in Section 6.3. The analyses for these transients are similar to those described above.

3.8.3.5 Design Procedures and Acceptance Criteria

The containment internal structures that contain reinforcing steel including most of the areas below elevation 98′, are designed by the strength method, as specified in the ACI Code Requirements for Nuclear Safety Related Structures, ACI-349. This code includes ductility criteria for use in detailing, placing, anchoring, and splicing of the reinforcing steel.

The internal steel framing is designed according to the AISC Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, ANSI/AISC N690, supplemented by the requirements given in Subsection 3.8.4.5

[*The design and construction of anchors and embedments conform to the procedures and standards of Appendix B to ACI 349-01*]* and are in conformance with the regulatory positions of NRC Regulatory Guide 1.199, Revision 0. [*Alternative requirements to ACI 349, Appendix B apply to the anchoring of headed shear reinforcement for the basemat (see Subsection 3.8.4.4.1). Alternative requirements to ACI 349, Appendix B apply to the anchoring of headed reinforcement above the basemat (see Subsection 3.8.4.4.1).*]*

The secondary shield walls, in-containment refueling water storage tank, refueling cavity, and operating floor above the in-containment refueling water storage tank are designed using structural modules. Concrete-filled structural wall modules are designed as reinforced concrete structures in accordance with the requirements of ACI-349, as supplemented in the following paragraphs. Structural floor modules are designed as composite structures in accordance with ANSI/AISC N690. Methods of analysis used are based on accepted principles of structural mechanics and are consistent with the geometry and boundary conditions of the structures.

The methods described in Subsection 3.7.2 are employed to obtain the safe shutdown earthquake loads at various locations in the containment internal structures. The safe shutdown earthquake loads are derived from the equivalent static analysis of a three-dimensional, finite element model representing the entire containment internal structures.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The determination of pressure and temperature loads due to pipe breaks is described in Subsections 3.6.1 and 6.2.1.2. Subcompartments inside containment containing high energy piping are designed for a pressurization load of 5 psi. The pipe tunnel in the CVS room (room 11209, Figure 1.2-6) is designed for a pressurization load of 7.5 psi. These subcompartment design pressures bound the pressurization effects due to postulated breaks in high energy pipe. The design for the effects of postulated pipe breaks is performed as described in Subsection 3.6.2. Determination of pressure loads resulting from actuation of the automatic depressurization system is described in Subsection 3.8.3.3.1.

Determination of reactor coolant loop support loads is described in Subsection 3.9.3. Design of the reactor coolant loop supports within the jurisdiction of ASME Code, Section III, Division 1, Subsection NF is described in Subsections 3.9.3 and 5.4.10.

Computer codes used are general purpose codes. The code development, verification, validation, configuration control, and error reporting and resolution are according to the Quality Assurance requirements of Chapter 17.

3.8.3.5.1 Reactor Coolant Loop Supports

3.8.3.5.1.1 Reactor Vessel Support System

The reactor vessel supports are described in Subsection 3.8.3.1.1.1. Figure 3.8.3-4 shows the embedments and anchor bolts for the reactor vessel supports. The embedded portions of the reactor vessel supports, which are outside the ASME jurisdictional boundary, are designed by elastic methods of analysis. Note the dowel studs connecting the support to the steel embedment are not embedded in the concrete and are within the ASME jurisdictional boundary. The embedded portions, including the anchor bolts, are analyzed and designed to resist the applicable loads and load combinations given in Subsection 3.8.4.3. The design is according to ANSI/AISC N690 and ACI-349. The design of the steel to resist the loads satisfies the AISC-N690 requirements. The design and evaluation to assure that the embedment transfers the loads to the concrete and is retained in the concrete satisfies the requirements of ACI 349.

3.8.3.5.1.2 Steam Generator Support System

The embedded portions of the steam generator supports, which are outside the ASME jurisdictional boundary, are designed by elastic methods of analysis. They are analyzed and designed to resist the applicable loads and load combinations given in Subsection 3.8.4.3. The design is according to ANSI/AISC N690 and ACI-349. Figure 3.8.3-5 shows the jurisdictional boundaries.

3.8.3.5.1.3 Reactor Coolant Pump Support System

The reactor coolant pumps are integrated into the steam generator channel head and consequently do not have a separate support system.

3.8.3.5.1.4 Pressurizer Support System

The embedded portions of the pressurizer supports, which are outside the ASME jurisdictional boundary, are designed by elastic methods of analysis. They are analyzed and designed to resist the applicable loads and load combinations given in Subsection 3.8.4.3. The design is according to ANSI/AISC N690 and ACI-349. Figure 3.8.3-6 shows the jurisdictional boundaries.

3.8.3.5.2 Containment Internal Structures Basemat

The containment internal structures basemat including the primary shield wall and reactor cavity are designed for dead, live, thermal, pressure, and safe shutdown earthquake loads. The structural modules are designed as described in Subsection 3.8.3.5.3.

The reinforced concrete forming the base of the containment internal structures is designed according to ACI 349.

3.8.3.5.3 Structural Wall Modules

Structural modules without concrete fill, such as the west wall of the in-containment refueling water storage tank, are designed as steel structures, according to the requirements of ANSI/AISC N690. This code is applicable since the module is constructed entirely out of structural steel plates and shapes. In local areas stresses due to restraint of thermal growth may exceed yield and the allowable stress intensity is 3 S_{m1}. This allowable is based on the allowable stress intensity for Service Level A loads given in ASME Code, Section III, Subsection NE, Paragraph NE-3221.4.

The concrete-filled steel module walls are designed for dead, live, thermal, pressure, safe shutdown earthquake, and loads due to postulated pipe breaks. The in-containment refueling water storage tank walls are also designed for the hydrostatic head due to the water in the tank and the hydrodynamic pressure effects of the water due to the safe shutdown earthquake, and automatic depressurization system pressure loads due to sparger operation. The walls of the refueling cavity are also designed for the hydrostatic head due to the water in the refueling cavity and the hydrodynamic pressure effects of the water due to the safe shutdown earthquake.

Figure 3.8.3-8 shows the typical design details of the structural modules, typical configuration of the wall modules, typical anchorages of the wall modules to the reinforced base concrete, and connections between adjacent modules. Variations in the module design details and design elements used are described in the Figure 3.8.3-8 notes and in Subsections 3.8.3.1 and 3.8.3.1.3. Concrete-filled structural wall modules are designed as reinforced concrete structures in accordance with the requirements of ACI-349, as supplemented in the following paragraphs. The faceplates are considered as the reinforcing steel, bonded to the concrete by headed studs. The application of ACI-349 and the supplemental requirements are supported by the behavior studies described in Subsection 3.8.3.4.1. The steel plate modules are anchored to the reinforced concrete basemat by mechanical connections welded to the steel plate. Loads are transferred directly from the faceplates to the base concrete using reinforcing bars, structural shapes, and shear studs connected directly to the modules with mechanical connectors or welds. The reinforcing steel used to anchor the modules to the concrete has a development that satisfies the requirements of ACI 349. The design of the surface plate, base plate, and vertical stiffeners is checked by finite element analysis. The design of critical sections is described in Subsection 3.8.3.5.8.

3.8.3.5.3.1 Design for Axial Loads and Bending

Design for axial load (tension and compression), in-plane bending, and out-of-plane bending is in accordance with the requirements of ACI-349, Chapters 10 and 14.

3.8.3.5.3.2 Design for In-Plane Shear

Design for in-plane shear is in accordance with the requirements of ACI-349, Chapters 11 and 14. The steel faceplates are treated as reinforcing steel, contributing as provided in Section 11.10 of ACI-349.

3.8.3.5.3.3 Design for Out-of-Plane Shear

Design for out-of-plane shear is in accordance with the requirements of ACI-349, Chapter 11.

3.8.3.5.3.4 Evaluation for Thermal Loads

The effect of thermal loads on the structural wall modules, with and without concrete fill, is evaluated by using the working stress design method for load combination 3 of Tables 3.8.4-1 and 3.8.4-2. This evaluation is in addition to the evaluation using the working stress design method of ANSI/AISC N690 or the strength design method of ACI-349 for the load combinations without the thermal load. Acceptance for the load combination with normal thermal loads, which includes the thermal transients described in Subsection 3.8.3.3.1, is that the stress in general areas of the steel plate be less than yield. In local areas where the stress may exceed yield the total stress intensity range is less than twice yield. This evaluation of thermal loads is based on the ASME Code philosophy for Service Level A loads given in ASME Code, Section III, Subsection NE, Paragraphs NE-3213.13 and 3221.4.

3.8.3.5.3.5 Design of Trusses

The trusses provide a structural framework for the modules, maintain the separation between the faceplates, support the modules during transportation and erection, and act as "form ties" between the faceplates when concrete is being placed. After the concrete has cured, the trusses act with shear studs to provide interfacial shear transfer between the faceplates and concrete. The trusses also provide structural integrity and permit the development of the nominal out-of-plane shear strength of the concrete without shear reinforcement. In areas of a module wall where the hooked dowels from a floor slab do not overlap the hooked dowels of an opposing floor slab on the opposite face of the wall, the horizontal channel member of the trusses may be credited as a tension tie, by confinement of the faceplates, preventing separation of the concrete. The welded connection of the truss to the faceplate is sized to fully develop the specified minimum yield strength of the channel member. As described in Subsection 3.8.3.1.3, additional structural capacity is provided between the module faceplates in some areas to support localized loads. The trusses, connecting steel plates, structural shapes, reinforcement bars, and tie bars are designed according to the applicable requirements of ANSI/AISC N690 and ACI 349.

3.8.3.5.3.6 Design of Shear Studs

The wall structural modules are designed as reinforced concrete elements, with the faceplates serving as reinforcing steel. Since the faceplates do not have deformation patterns typical of reinforcing steel, shear studs are provided to transfer the forces between the concrete and the steel faceplates. The shear studs make the concrete and steel faceplates behave compositely. In addition, the shear studs permit anchorage for piping and other items attached to the walls.

The design of the shear stud size and spacing includes consideration of shear transfer and faceplate buckling. Shear transfer is evaluated in accordance with ANSI/AISC N690 Sections Q1.11.1 and Q1.11.4. Faceplate buckling is evaluated in accordance with ANSI/AISC N690 Section Q1.5.1.3. Conformance with these requirements precludes the possible failure modes for structural module construction for design basis loads.

3.8.3.5.4 Structural Floor Modules

Figure 3.8.3-3 shows the design details for a representative example of the floor modules. The details shown in Figure 3.8.3-3 are the representative design for a specific portion of the operating deck floor in containment. The size, material, and configuration of the structural shapes and plates, the amount and arrangement of the reinforcement, the location, size, and spacing of the shear studs

welded on the top of the floor bottom plate, and the type and size of the welds may vary in the final design of floor modules in this and other locations. The operating floor is designed for dead, live, thermal, safe shutdown earthquake, and pressure due to automatic depressurization system operation or due to postulated pipe break loads. The operating floor region above the in-containment refueling water storage tank is a series of structural modules. The remaining floor is designed as a composite structure of concrete slab and steel beams in accordance with ANSI/AISC N690.

For vertical downward loads, the floor modules are designed as a composite section, according to the requirements of Section Q1.11 of ANSI/AISC N690. Composite action of the steel section and concrete fill is assumed based on meeting the intent of Section Q1.11.1 for beams totally encased in concrete. Although the bottom plate of the floor, which is welded to the web and acts as the bottom flange, is not encased within concrete, the design configuration of the floor module provides complete concrete confinement to prevent spalling. It also provides a better natural bonding than the code-required configuration. When used, the shear studs welded on the top of the floor bottom plate supplement the natural bottom plate-to-concrete bond capability. The shear stud size and spacing is not directly credited in the composite section design. The capacity of the studs, whenever required for localized effects, is determined in accordance with ACI 349.

For vertical upward loads, no credit is taken for composite action. The steel members are relied upon to provide load-carrying capacity. Concrete, together with the embedded angle stiffeners, is assumed to provide stability to the plates.

Floor modules are designed using the following basic assumptions and related requirements:

- Concrete provides restraint against buckling of steel plates. The buckling unbraced length of the steel plate, therefore, is assumed to equal the span length between the fully embedded steel plates and shapes.

- Although the floor modules forming the top (ceiling) of the in-containment refueling water storage tank are not in contact with water, stainless steel plates are used for the tank boundary.

- The floor modules are designed as simply supported beams.

3.8.3.5.4.1 Design for Vertical Downward Loads

The floor modules are designed as a one-way composite concrete slab and steel beam system in supporting the vertical downward loads. The effective width of the concrete slab is determined according to Section Q1.11.1 of ANSI/AISC N690. The effective concrete compression area is extended to the neutral axis of the composite section. The concrete compression area is treated as an equivalent steel area based on the modular ratio between steel and concrete material. Figure 3.8.3-13 shows the effective composite sections. The steel section is proportioned to support the dead load and construction loads existing prior to hardening of the concrete. The allowable stresses are provided in Table 3.8.4-1.

3.8.3.5.4.2 Design for Vertical Upward Loads

For vertical upward loads, the floor modules are designed as noncomposite steel structures. The effective width, b_e, of the faceplate in compression is based on post-buckling strength of steel plates and is determined from Equation (4.16) of Reference 44. The faceplates of the structural floor modules are stiffened and supported by embedded horizontal angles. Hence, the buckling unbraced length of the faceplates is equal to the span length between the horizontal angles. The buckling stress, f_{cr}, of the faceplates is determined from Sections 9.2 and 9.3 of Reference 45. The effective

width of the faceplates of the structural floor modules in compression is shown in Figure 3.8.3-13. The allowable stresses are provided in Table 3.8.4-1.

3.8.3.5.4.3 Design for In-Plane Loads

In-plane shear loads acting on the floor modules are assumed to be resisted only by the steel faceplate without reliance on the concrete for strength. The stresses in the faceplate due to the in-plane loads are combined with those due to vertical loads. The critical stress locations of the floor faceplate are evaluated for the combined normal and shear stress, based on the von Mises yield criterion:

For the particular case of a two-dimension stress condition the equation is:

$$(\sigma_1)^2 - \sigma_1\sigma_2 + (\sigma_2)^2 = (f_y)^2$$

where σ_1 and σ_2 are the principal stresses and f_y is the uniaxial yield stress.

For the faceplate where normal, σ, and shear, τ, stresses are calculated, the principal stresses can be expressed as follows:

$$\sigma_1 = \left(\frac{\sigma}{2}\right) + \sqrt{\frac{\sigma^2}{4} + \tau^2}$$

$$\sigma_2 = \left(\frac{\sigma}{2}\right) - \sqrt{\frac{\sigma^2}{4} + \tau^2}$$

Therefore, the condition at yield becomes:

$$\sigma^2 + 3\tau^2 = (f_y)^2$$

For the design of the structural floor module faceplate, the allowable stresses for the various loading conditions are as follows:

Normal condition:

$$\sigma^2 + 3\tau^2 \leq (0.6\ f_y)^2$$

Severe condition:

$$\sigma^2 + 3\tau^2 \leq (0.6\ f_y)^2$$

Extreme/abnormal condition:

$$\sigma^2 + 3\tau^2 \leq (0.96\ f_y)^2$$

Thermal stresses in the faceplates result from restraint of growth during the thermal transients described in Subsection 3.8.3.3.1. Evaluation for thermal stresses is the same as discussed in Subsection 3.8.3.5.3.4 for the wall modules.

3.8.3.5.5 Internal Steel Framing

Internal steel framing is analyzed and designed according to ANSI/AISC N690. Seismic analysis methods are described in Subsection 3.7.3.

3.8.3.5.6 Steel Form Modules

The steel form modules consist of plate reinforced with angle stiffeners and tee sections as shown in Figure 3.8.3-16. The steel form modules are designed for concrete placement loads defined in Subsection 3.8.3.3.2.

The steel form modules are designed as steel structures according to the requirements of ANSI/AISC N690. This code is applicable since the form modules are constructed entirely out of structural steel plates and shapes and the applied loads are resisted by the steel elements.

3.8.3.5.7 Design Summary Report

A design summary report is prepared for containment internal structures documenting that the structures meet the acceptance criteria specified in Subsection 3.8.3.5.

Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Section 3.7 and 3.8 provided the following acceptance criteria are met.

- The structural design meets the acceptance criteria specified in Section 3.8
- The seismic floor response spectra meet the acceptance criteria specified in Subsection 3.7.5.4

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgment to performance of a revised analysis and design. The results of the evaluation will be documented in an as-built summary report.

3.8.3.5.8 Design Summary of Critical Sections

3.8.3.5.8.1 Structural Wall Modules

[*This subsection summarizes the design of the following critical sections:*

- *Southwest wall of the refueling cavity (4´0˝thick)*
- *South wall of west steam generator compartment (2´6˝thick)*
- *North east wall of in-containment refueling water storage tank (2´6˝thick)*

The thicknesses and locations of these walls which are part of the boundary of the in-containment refueling water storage tank are shown in Figure 3.8.3-18. The structural configuration and typical details are shown in Figures 3.8.3-1, 3.8.3-2, 3.8.3-8, 3.8.3-14 and 3.8.3-15. Plate thickness, structural shape size, and reinforcement provided may be increased locally. The design implemented in fabrication and construction drawings and instructions may have alternative structural shapes or reinforcement arrangements if they provide equal or better load capacity. As described in Subsection 3.8.3.1.3, steel plates, structural shapes, reinforcement bars, or tie bars are used in other locations between the structural module faceplates to address local out-of-plane loads.]* The

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structural analyses are described in Subsection 3.8.3.4 and summarized in Table 3.8.3-2. The design procedures are described in Subsection 3.8.3.5.3.

[*The details shown in Figure 3.8.3-17 are representative of connections between floors in containment and walls constructed using steel plate concrete composite construction.*]* The design details for the floor module are provided for background information and vary based on loading conditions and geometry. The seat angles, beam seats, clip angles, shear plates, shear studs, and reinforcement bars shown in Figure 3.8.3-17 and other design elements are used as required for the connection. A key feature of the connection design is that the design elements provide a direct load path from the floor into the wall. Additional information on the connection design is provided in Subsection 3.8.3.1.3. Details of the connection design, including plate thickness, structural shape type and size, use of specific design elements, and reinforcement arrangement, vary based on local loads. The design implemented in fabrication and construction drawings and instructions may have alternative structural shapes or reinforcement arrangements if they provide sufficient load capacity to satisfy ANSI/AISC N690 and ACI 349 criteria and requirements.

[*The three walls extend from the floor of the in-containment refueling water storage tank at elevation 103´0˝to the operating floor at elevation 135´3˝. The south west wall is also a boundary of the refueling cavity and has stainless steel plate on both faces. The other walls have stainless steel on one face and carbon steel on the other.*]* For each wall design information is summarized in Tables 3.8.3-3, 3.8.3-4, 3.8.3-5, and 3.8.3-6. [*Results are shown at the middle of the wall (mid span at mid height), at the base of the wall at its mid point (mid span at base) and at the base of the wall at the end experiencing greater demand (corner at base). The first part of each table shows the member forces due to individual loading. The lower part of the table shows governing load combinations. The steel plate thickness required to resist mechanical loads is shown at the bottom of the table as well as the thickness provided. The maximum principal stress for the load combination including thermal is also tabulated. If this value exceeds the yield stress at temperature a supplemental evaluation is performed*]* as described in Subsection 3.8.3.5.3.4; [*for these cases the maximum stress intensity range is shown together with the allowable stress intensity range which is twice the yield stress at temperature.*]*

3.8.3.5.8.2 In-Containment Refueling Water Storage Tank Steel Wall

[*The in-containment refueling water storage tank steel wall is the circular boundary of the in-containment refueling water storage tank. The structural configuration and typical details are shown in sheet 3 of Figure 3.8.3-8.*]* The structural analyses are described in Subsection 3.8.3.4 and summarized in Table 3.8.3-2. The design procedures are described in Subsection 3.8.3.5.3. [*The steel wall extends from the floor of the in-containment refueling water storage tank at elevation 103´0˝to the operating floor at elevation 135´3˝. The wall is a 5/8˝thick stainless steel plate. It has internal vertical stainless steel T-section columns spaced 4´-8˝apart and external hoop carbon steel (L-section) angles spaced 18˝to 24˝apart. The wall is fixed to the adjacent modules and floor except for the top of columns which are free to slide radially and to rotate around the hoop direction.*

The wall is evaluated as vertical and horizontal beams. The vertical beams comprise the T-section columns plus the effective width of the plate. The horizontal beams comprise the L-section angles plus the effective width of the plate. Table 3.8.3-7 shows the ratio of the design stresses to the allowable stresses. When thermal effects result in stresses above yield, the evaluation is in accordance with the supplemental criteria]* as described in Subsection 3.8.3.5.3.4.

3.8.3.5.8.3 Column Supporting Operating Floor

[*This subsection summarizes the design of the most heavily loaded column in the containment internal structures. The column extends from elevation 107´-2˝to the underside of the operating floor*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

at elevation 135′-3″. In addition to supporting the operating floor, it also supports a steel grating floor at elevation 118′-0″.

The load combinations in Table 3.8.4-1 were used to assess the adequacy of the column. For mechanical load combinations, the maximum interaction factor due to biaxial bending and axial load is 0.59. For load combinations with thermal loads, the maximum interaction factor is 0.94. Since the interaction factors are less than 1, the column is adequate for all the applied loads.]*

3.8.3.6 Materials, Quality Control, and Special Construction Techniques

Subsection 3.8.4.6 describes the materials and quality control program used in the construction of the containment internal structures.

[*The structural steel modules are constructed using carbon steel plates and shapes (ASTM A36, ASTM A992, or steel with equal or better material properties*). *Duplex 2101 (American Society for Testing and Materials A240, designation S32101) stainless steel plates or steel with equal or better material properties*]* are used on the surfaces of the modules in contact with water during normal operation or refueling. [*The material of construction for studs attached to the module plates used to transfer loads into the concrete is A-108 or steel with equal or better material properties. Bars used to anchor the modules in the concrete are deformed bars according to Reference 19, Grade 60, and Reference 20.*]*

The structural wall and floor modules are fabricated and erected in accordance with ANSI/AISC N690. Loads during fabrication and erection due to handling and shipping are considered as normal loads as described in Subsection 3.8.4.3.1.1. Packaging, shipping, receiving, storage and handling of structural modules are in accordance with NQA-1, Part II, Subpart 2.2 (formerly ANSI/ASME N45.2.2 as specified in ANSI/AISC N690).

3.8.3.6.1 Fabrication, Erection, and Construction of Structural Modules

Modular construction techniques are used extensively in the containment internal structures (Figure 3.8.3-1). Subassemblies, sized for commercial rail shipment, are assembled offsite and transported to the site. Onsite fabrication consists of combining the subassemblies in structural modules, which are then installed in the plant. A typical modular construction technique is described in the following paragraphs for Module CA01, which is the main structural module in the containment internal structures.

The CA01 module is a multicompartmented structure which, in its final form, comprises the central walls of the containment internal structures. The vertical walls of the module house the refueling cavity, the reactor vessel compartment, and the two steam generator compartments. The module (Figure 3.8.3-14) is in the form of a "T" and is approximately 88 feet long, 95 feet wide and 77 feet high. The module is assembled from about 40 prefabricated wall sections called structural submodules (Figure 3.8.3-15). The submodules are designed for railroad transport from the fabricator's shop to the plant site with sizes up to 12 feet by 12 feet by 80 feet long. The submodule weights range from approximately 1 to 49 tons. The submodules are assembled outside the nuclear island with full penetration welds between the faceplates of adjacent subunits.

The completed CA01 module is lifted to its final location within the containment vessel by the heavy lift construction crane. Following placement of the CA01 module within the containment building, the hollow wall structures are filled with concrete, forming a portion of the structural walls of the containment internal structures.

Tolerances for fabrication, assembly and erection of the structural modules conform to the requirements of section 4 of ACI-117, applicable sections of AWS D1.1, and sections Q1.23 and

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Q1.25 of ANSI/AISC N690. In walls around the reactor vessel cavity, where the concrete is placed between portions of unconnected modules or between a module and a left-in-place form, the tolerance for the wall thickness may be increased over those in ACI 117. These walls have been evaluated against ACI 349-01 reinforcement design requirements and demonstrated sufficient margin to accommodate the increased tolerance. Tolerances for shear stud spacing requirements are identified on Figure 3.8.3-8, Sheet 1 and conform to AWS D1.1, Paragraph 7.4.5.

3.8.3.6.2 Nondestructive Examination

Nondestructive examination of the submodules and module is performed according to ANSI/AISC N690 and AWS D1.1. Welds are visually examined for 100 percent of their length. Full penetration welds are inspected by ultrasonic or radiographic examination for 10 percent of their length, or for 100 percent of the length of 1 weld in 10. Partial penetration welds are inspected by magnetic particle or liquid penetrant examination for 10 percent of their length, or for 100 percent of the length of 1 weld in 10.

3.8.3.6.3 Concrete Placement

After installation of the CA01 module in the containment, the hollow walls are filled with concrete. The concrete is placed through multiple delivery trunks located along the top of the wall or through windows in the module walls or pumping ports built into the module wall. It is placed in incremental layers with the placement rate based on the pressure of the wet concrete and its setting time. During concrete placement, workers and inspectors have access to the inside of the modules. The arrangement of the module internal trusses provides communication to aid in the free flow of concrete and movement of personnel.

3.8.3.7 In-Service Testing and Inspection Requirements

The inspection program for structures is identified in Section 17.6. This inspection program is consistent with the requirements of 10 CFR 50.65 and the guidance in Regulatory Guide 1.160.

3.8.3.8 Construction Inspection

Construction inspection is conducted to verify the concrete wall thickness and the surface plate thickness. The location for measurement of the structural wall modules is at the locations of the trusses used to provide the structural framework for the modules. Inspections will be measured at applicable sections excluding designed openings or penetrations. Inspections will confirm that each section provides the minimum required steel and concrete thicknesses as shown in Table 3.8.3-3. The minimum required steel and concrete thicknesses represent the minimum values to meet the design basis loads. Table 3.8.3-3 also indicates the steel plate thickness provided which may exceed the minimum required value for the following reasons:

- Structural margin
- Ease of construction
- Construction loads
- Use of standard thicknesses

[*As described in subsection 3.8.3.1.3, some CA01 and CA05 module wall faceplate thicknesses are greater than the 0.5-inch nominal faceplate thickness.*]*

3.8.4 Other Category I Structures

The other seismic Category I structures are the shield building and the auxiliary building. New fuel and spent fuel racks are described in Section 9.1.

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General criteria in this section describing the loads, load combinations, materials, and quality control are also applicable to the containment internal structures described in Subsection 3.8.3.

3.8.4.1 Description of the Structures

3.8.4.1.1 Shield Building

The shield building is the structure and annulus area that surrounds the containment building. It shares a common basemat with the containment building and the auxiliary building. The shield building uses concrete-filled steel plate construction (SC) as well as reinforced concrete (RC) structure. The figures in Section 1.2 show the layout of the shield building and its interface with the other buildings of the nuclear island.

A non-linear analyses performed on the nuclear island finite element model is used to validate the stiffness used in the evaluation of concrete-filled steel modules. This analysis used benchmarked layered shell elements for the reinforced concrete/steel concrete composite (RC/SC) connection, which transferred all stresses to the steel in the connections once a maximum yield stress in concrete was reached. These elements were included in the comparison made between linear and non-linear models. Results show the 80-percent stiffness model response spectra enveloped the non-linear model and provide a conservative approach in terms of response spectra and maximum stresses obtained in the shield building wall.

Figure 3.8.4-5 shows the following significant features and the principal systems and components of the shield building:

- Shield building cylindrical structure
- Shield building roof structure
- RC/SC connections
- Air inlets and tension ring
- Knuckle region (connection to exterior wall of PCS tank)
- Compression ring (connection to interior wall of PCS tank)
- Passive containment cooling system water storage (PCS) tank

The overall configuration of the shield building is established from functional requirements related to radiation shielding, missile barrier, passive containment cooling, tornado, and seismic event protection. These functional requirements led to establishing the design based on two primary design codes used for nuclear plant structures: 1) ACI 349 for reinforced concrete design, and 2) ANSI/AISC N690 for structural steel design.

The shield building SC walls are anchored to the RC basemat and shield building RC wall by mechanical connections. [*These RC-to-SC connections are shown in Figures 1, 2, 3, and 4 of APP-GW-GLR-602 (Reference 57).*]* These RC-to-SC connections are also used in the other regions of the shield building, including:

- Auxiliary building RC roof connection to the shield building SC wall
- Auxiliary building RC wall connection to shield building SC wall
- Tension ring connection to the shield building RC roof

The connections provide for the direct transfer of forces from the RC reinforcing steel to the SC liner plates. A typical auxiliary building RC roof connection to the shield building SC wall is shown in [*Figure 7 of APP-GW-GLR-602 (Reference 57).*]*

The cylindrical shield wall has an outside radius of 72.5 feet and a thickness of 36 inches. The cylindrical wall section that is a few feet below the auxiliary building roof line is a reinforced concrete

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structure. The section that is not protected by the auxiliary building is a steel concrete composite structure; see Figure 3H.5-16. The overall thickness of 36 inches is the same as the RC wall below. The concrete for the SC portion is standard concrete with compressive strength of 6000 psi. The SC portion is constructed with steel surface plates, which act as concrete reinforcement. The 0.75-inch tie bars are welded to the steel faceplates to develop composite behavior of the steel faceplates and concrete. The shear studs are welded to the inside surface of the steel plate. The tie bar spacing is reduced in the higher stress regions. A typical SC wall panel is shown in Figure 3H.5-13 and [*Figure 5 of APP-GW-GLR-602 (Reference 57)*.]*

The tension ring is located at the interface of the shield building steel concrete composite air inlet structures and the shield building reinforced concrete roof. The top of the tension ring interfaces with the RC roof slab. The tension ring supports the roof girders that are located under the RC roof slab. The bottom of the tension ring is attached to the air inlets structure. The bottom of the air inlets structure is attached to the top of the cylindrical SC wall of the shield building. The connection of the tension ring to the roof is a mechanical connection design and is described above. The tension ring and air inlets are shown in Figure 3H.5-14.

The primary function of the tension ring is to resist the thrust from the shield building roof. The air inlets structure is located directly below the tension ring and includes the air openings that provide for natural circulation of cooling air. Though its steel plates are connected to the concrete infill by studs and tie bars, the tension ring is conservatively designed as a hollow steel box girder. The concrete infill is credited only for out-of-plane shear transfer and for stability of the steel plates. The tension ring is designed to have high stiffness and to remain elastic under required load combinations.

The air inlets structure is a 4.5-foot-thick SC structure with through-wall openings for air flow. The air inlet openings consist of circular pipes at a downward inclination of 38 degrees from the vertical. Steel plates on each face, aligned with the inner and outer flanges of the tension ring, serve as primary reinforcement. The concrete infill is connected to the steel plates with tie bars and studs. The top of the air inlets structure is welded to the underside of the tension ring. The bottom of the air inlets structure is welded to the SC wall.

The shield building conical roof steel structure consists of 32 radial beams. Between each pair of radial beams there are circumferential beams. A steel plate is welded to the top flanges of each beam and forms a surface on which the concrete is placed. The steel structure forms a conical shell that spans the area from the compression ring to the tension ring.

The outside diameter of the passive containment cooling water storage tank (PCCWST) intersects with the shield building roof at the knuckle region. Outside of the PCCWST, the concrete roof slab thickness is 3 feet and at the bottom of the PCCWST the concrete thickness is 2 feet. The wall from the PCCWST applies a load to the roof slab, and also provides stiffness and increases the strength of the roof in that region.

The inside diameter of the PCCWST intersects with the roof slab at the compression ring. The compression ring provides the compression support for the conical roof dome. It consists of a composite structure having a curved steel beam section, which supports the concrete roof directly above it. The inside wall of the PCCWST is located above the concrete roof. Studs are placed on the top flange of the steel girder to allow the steel and concrete sections to act as a composite unit. The curved girder is designed to provide support for the steel structure during construction and during the initial placement of the concrete roof before the concrete has hardened sufficiently.

The PCCWST sits on top of the shield building roof. It is supported by and acts integrally with the conical roof. The inside surface has a liner that functions to provide leak protection, but is not required to provide structural strength to the structure. Leak chase channels are provided over the

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liner welds. The top elevation of the water inside the PCCWST has sufficient freeboard to preclude impact on the roof during the SSE.

Appendix 3H provides additional information regarding the shield building design, testing, and analysis that demonstrates the robust behavior of the design with respect to ductility, effects of creep, reserve strength of seismic margins, buckling, and shrinkage.

3.8.4.1.2 Auxiliary Building

The auxiliary building is a reinforced concrete and structural steel structure. Three floors are above grade and two are located below grade. It is one of the three buildings that make up the nuclear island and shares a common basemat with the containment building and the shield building.

The auxiliary building is a C-shaped section of the nuclear island that wraps around approximately 50 percent of the circumference of the shield building. The floor slabs and the structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building.

The figures in Section 1.2 show the layout of the auxiliary building and its interface with the other buildings of the nuclear island. The following are the significant features and the principal systems and components of the auxiliary building:

- Main control room
- Remote shutdown room
- Class 1E dc switchgear
- Class 1E batteries
- Reactor trip switchgear
- Reactor coolant pump trip switchgear
- Main steam and feedwater piping
- Main control room heating, ventilating, and air conditioning (HVAC)
- Class 1E switchgear rooms heating, ventilating, and air conditioning
- Spent fuel pool
- Fuel transfer canal
- Cask loading and washdown pits
- New fuel storage area
- Cask handling crane
- Fuel handling machine
- Chemical and volume control system (CVS) makeup pumps
- Normal residual heat removal system (RNS) pumps and heat exchangers
- Liquid radwaste tanks and components
- Spent fuel cooling system
- Gaseous radwaste processing system
- Mechanical and electrical containment penetrations

Structural modules are used for part of the south side of the auxiliary building. These structural modules are structural elements built up with welded steel structural shapes and plates. Concrete is used where required for shielding, but reinforcing steel is not normally used. These modules include the spent fuel pool, fuel transfer canal, and cask loading and cask washdown pits.

The configuration of the auxiliary building structural modules is similar to the structural modules described in Subsection 3.8.3.1 for the containment internal structures. As in the containment internal structures, the structural wall modules consist of steel faceplates connected by steel trusses with shear studs welded to the inside faces of the steel faceplates. Figure 3.8.4-4 shows the location of the structural modules in the auxiliary building. The structural modules extend from elevation 66′-6″ to elevation 135′-3″.

The auxiliary building modules are different in configuration and design details compared to the containment internal structures. The following examples are provided. The thickness of the structural wall modules differs from the figures for the containment internal structures modules and ranges from 2′-6″ to 5′-0″ for the key structural walls. The auxiliary building modules also includes smaller structural walls that act as labyrinth walls or barrier access walls with thicknesses less than 2′-6″. Local variation in the design of the trusses and spacing of the trusses and shear studs may be required to address internal obstructions and accessibility for fabrication and inspection. The minimum design thickness of the faceplates is 0.5 inch. Portions of the faceplates are thicker than the nominal design thickness to provide strength for localized loads due to attachments and connections. The auxiliary building modules are placed on the nuclear island basemat and do not have an offset of elevation of the bottom of the module faceplates through the thickness of the wall that is shown in Figure 3.8.3-8 for a portion of a module inside containment. The detail design of the internal connections within the modules including those at the corners, and for design elements and structures within the modules such as the diaphragms associated with the corner design, is different than depicted for the containment internal structures. The design of the mechanical connection of the module to the basemat varies for details such as size of deformed bars, thickness and configuration of plates, design of welds, and use of bolted connections in lieu of welds.

The ceiling of the main control room (floor at elevation 135′-3″), and the instrumentation and control rooms (floor at elevation 117′-6″) are designed as finned floor modules (Figure 3H.5-9). A finned floor consists of a 24-inch-thick concrete slab poured over a stiffened steel plate ceiling. The fins are rectangular plates welded perpendicular to the plate. Shear studs are welded on the other side of the steel plate, and the steel and concrete act as a composite section. Figure 3H.5-9 shows the finned floor above the main control room and the connection of the floor to the wall on column line 11. The finned floors above the instrumentation and control rooms are similar, but differ with some design details, such as the size and spacing of reinforcement and the connecting dowels used in the connection of the floor to the wall. Penetrations and other interferences in the floors and adjacent walls may cause localized variances with the design details shown in the figure. The fins are exposed to the environment of the room, and enhance the heat-absorbing capacity of the ceiling (see Design Control Document (DCD) Subsection 6.4.2.2). Several shop-fabricated steel panels, placed side by side, are used to construct the stiffened plate ceiling in a modularized fashion. The number of panels used is determined by the size of the room and fabricator capabilities. The stiffened plate is designed to withstand construction loads prior to concrete hardening. Additional bottom layer reinforcing steel is provided in the finned floors at elevation 117'-6" where needed to maintain the structural integrity of the fire barrier during a fire event due to potential deterioration of mechanical properties of exposed steel fin plates during the fire.

The new fuel storage area is a separate reinforced concrete pit providing temporary dry storage for the new fuel assemblies.

A cask handling crane travels in the east-west direction. The location and travel of this crane prevents the crane from carrying loads over the spent fuel pool, thus precluding them from falling into the spent fuel pool.

3.8.4.1.3 Containment Air Baffle

The containment air baffle is located within the upper annulus of the shield building, providing an air flow path for the passive containment cooling system. The air baffle separates the downward air flow entering at the air inlets from the upward air flow that cools the containment vessel and flows out of the discharge stack. The upper portion is supported from the shield building roof and the remainder is supported from the containment vessel. The air baffle is a seismic Category I structure designed to withstand the wind and tornado loads defined in Section 3.3. The air baffle structural configuration is depicted in Figures 1.2-14 and 3.8.4-1. The baffle includes the following sections:

- A wall supported off the shield building roof (see Figure 1.2-14)
- A series of panels attached to the containment vessel cylindrical wall and the knuckle region of the dome
- A flexible seal closing the gap between the wall and the panels fixed to the containment vessel, designed to accommodate the differential movements between the containment vessel and shield building

The air baffle is designed to meet the following functional requirements:

- The baffle and its supports are configured to minimize pressure losses as air flows through the system
- The baffle and its supports have a design objective of 60 years
- The baffle and its supports are configured to permit visual inspection and maintenance of the air baffle as well as the containment vessel. Periodic visual inspections are primarily to inspect the condition of the coatings
- The baffle is designed to maintain its function during postulated design basis accidents
- The baffle is designed to maintain its function under specified external events including earthquakes, hurricanes and tornadoes

The general arrangement of the containment air baffle is shown in sheet 1 of Figure 3.8.4-1. The course layout, plate/insert plate geometry, weld seams for the containment, hatches, airlocks, and the number and configuration of the containment air baffle panels are provided for illustrative purposes only. The lowest elevation of the air baffle is approximately 146′-3″. The upper air baffle panels are on the head. The air baffle is supported by U-shaped support attachments welded to the containment vessel. The attachments can be installed in the subassembly area and, therefore, should not interfere with the containment vessel erection welds. The only penetrations through the containment vessel above the operating deck at elevation 135′-3″ are the main equipment hatch and personnel airlock. Air baffle panels around the equipment hatch and personnel airlock are designed to accomodate the hatch and airlock insulated enclosures.

Panels are attached to the containment vessel above the cylindrical portion. The panels are angled to follow the curvature of the knuckle region of the containment vessel head, forming a conical baffle that provides a transitional flow region into the upper shield building. A flexible seal is provided between this upper row of panels and the air baffle that is attached directly to the shield building roof as shown in sheet 4 of Figure 3.8.4-1. This flexible seal is attached to the top of the upper row of panels. The flexible seal is set at ambient conditions to permit relative movements from minus 2 inches to plus 3 inches radially and minus 1 inch to plus 4 inches vertically. This accommodates the differential movement between the containment vessel and the shield building, based on the absolute sum of the containment pressure and temperature deflections and of the seismic deflections, such that the integrity of the air baffle is maintained.

The panels accommodate displacements between each panel due to containment pressure and thermal growth. Radial and circumferential growth of the containment vessel are accommodated by slip at the bolts between the horizontal beams and the U shaped attachment resulting in small gaps between adjacent panels. Vertical growth is accommodated by slip between the panel and the horizontal beam supporting the top of the panel. Seal plates between the panels limit leakage during and after occurrence of these differential displacements.

3.8.4.1.4 Seismic Category I Cable Tray Supports

Electric cables are routed in horizontal and vertical steel trays supported by channel type struts made out of cold rolled channel type sections. Spacing of the supports is determined by allowable loads in the trays and stresses in the supports. The supports are attached to the walls, floors, and ceiling of the structures as required by the arrangement of the cable trays. Longitudinal and transverse bracing is provided where required.

3.8.4.1.5 Seismic Category I Heating, Ventilating, and Air Conditioning Duct Supports

Heating, ventilating, and air conditioning duct supports consist of structural steel members or cold rolled channel type sections attached to the walls, floors, and ceiling of the structures as required by the arrangement of the duct. Spacing of the supports is determined by allowable stresses in the duct work and supports. Longitudinal and transverse bracing is provided where required.

3.8.4.2 Applicable Codes, Standards, and Specifications

The following standards are applicable to the design, materials, fabrication, construction, inspection, or testing:

[• *American Concrete Institute (ACI), Code Requirements for Nuclear Safety Related Concrete Structures, ACI 349-01*]* (refer to Subsection 3.8.4.5 for supplemental requirements)

• [*American Concrete Institute (ACI), Building Code Requirements for Structural Concrete, ACI 318-11, Section 12.6*]* (refer to subsection 3.8.4.4.1 for application of ACI 318-11 Section 12.6)

• American Concrete Institute (ACI), ACI Detailing Manual

• American Concrete Institute (ACI), Self-Consolidating Concrete, ACI-237R

[• *American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, ANSI/AISC N690-1994*]* (refer to Subsection 3.8.4.5 for supplemental requirements)

[• *American Welding Society (AWS), Structural Welding Code - Steel, AWS D1.1-2000*

AWS D1.1-2000 is an acceptable code for use in lieu of AWS D1.1-1992 for the design, qualification, fabrication, and inspection for ANSI/AISC N690 applications.

The use of AWS D1.1-2000 to replace and supplement provisions in ANSI/AISC N690-1994 includes the provisions noted below:

– *The provisions in Section 2.3.4.1 of AWS D1.1-2000 are used to size complete joint penetration groove welds for tubular members.*

– *ASTM A992 is an alternative to ASTM A36 steel for structural steel shapes. Where ASTM A992 steel is used, the provisions for matching weld metal identified in AWS D1.1-2000, Section 3.3 and Table 3.1 are used to supplement the information in ANSI/AISC N690 Section Q1.4.4.*

– *Where directionality is applied to increase allowable weld stress for fillet welds identified in ANSI/AISC N690, Section Q1.5.3 and Table Q1.5.3, the provisions in Sections 2.14.4 and 2.14.5 of AWS D1.1-2000 shall be used.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

For fillet weld groups concentrically loaded in the plane of the axis of the weld and consisting of elements oriented both longitudinally and transversely to the direction of applied load, the deformation capability of the elements shall be considered. As a supplement to the provisions in AWS D1.1-2000, the strength of the weld group is limited to the larger of the two following evaluations:

1. *The combined strength of the individual weld elements using 1.0 times the strength of the longitudinally oriented element and 1.0 times the strength of the transversely oriented element*

2. *The combined strength of the individual weld elements using 0.825 times the strength of the longitudinally oriented element and 1.5 times the strength of the transversely oriented element*

The provisions for directionality are not applied to fillet welds of tubular member T, Y, and K connections described in Table 2.5 of AWS D1.1-2000.

The provisions in AWS D1.1-2000 for the application of directionality to linear fillet welds are supplemented by extending the provisions to weld configurations not specified in AWS D1.1-2000 as noted below:

– *Where directionality is considered for concentric out-of-plane loading for linear fillet weld groups, including lines and rectangular configurations, the directionality provisions in AWS D1.1-2000 are applied.*

– *Where directionality is considered for concentric out-of-plane loading for circular-shaped fillet weld configurations, the directionality provisions in AWS D1.1-2000 are applied. The use of directionality provisions in AWS D1.1-2000 for circular-shaped fillet weld configurations is limited to tension loading concentrically applied out-of-plane to the axis of the weld.*]*

- American Iron and Steel Institute (AISI), Specification for the Design of Cold Formed Steel Structural Members, Parts 1 and 2, 1996 Edition and 2000 Supplement

Section 1.9 describes conformance with the Regulatory Guides.

Welding and inspection activities for seismic Category I structural steel, including building structures, structural modules, cable tray supports and heating, ventilating, and air conditioning duct supports are accomplished in accordance with written procedures and meet the requirements of the American Institute of Steel Construction (ANSI/AISC N690). The welded seam of the plates forming part of the leaktight boundary of the spent fuel pool, fuel transfer canal, cask loading pit, and cask washdown pit is examined by liquid penetrant and vacuum box after fabrication to confirm that the boundary does not leak. Vacuum box examination is not required where geometry prevents examination from being performed and where an alternative leak detection method can be performed.

3.8.4.3 Loads and Load Combinations

The loads and load combinations used in the analysis are considered to be part of the method of evaluation.

3.8.4.3.1 Loads

The loads considered are normal loads, severe environmental loads, extreme environmental loads, and abnormal loads.

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3.8.4.3.1.1 Normal Loads

Normal loads are those loads to be encountered, as specified, during initial construction stages, during test conditions, and later, during normal plant operation and shutdown. They include the following:

D = Dead loads or their related internal moments and forces, including any permanent piping and equipment loads

F = Lateral and vertical pressure of liquids or their related internal moments and forces

L = Live loads or their related internal moments and forces, including any movable equipment loads and other loads that vary with intensity and occurrence

H = Static earth pressure or its related internal moments and forces

T_o = Thermal effects and loads during normal operating or shutdown conditions, based on the most critical transient or steady-state condition

R_o = Piping and equipment reactions during normal operating or shutdown conditions, based on the most critical transient or steady-state condition.

3.8.4.3.1.2 Severe Environmental Loads

The severe environmental load is the following:

W = Loads generated by the design wind specified for the plant in Subsection 3.3.1.1

3.8.4.3.1.3 Extreme Environmental Loads

Extreme environmental loads are the following:

E_s = Loads generated by the safe shutdown earthquake specified for the plant, including the associated hydrodynamic and dynamic incremental soil pressure. Loads generated by the safe shutdown earthquake are specified in Section 3.7.

Wt = Loads generated by the design tornado specified for the plant in Subsection 3.3.2, including loads due to tornado wind pressure, differential pressure, and tornado-generated missiles.

N = Loads generated by the probable maximum precipitation (provided previously in Table 2.0-201).

The application of the 48-hour PMWP and the 100-year return period ground-level snowpack in the roof design of safety-related structures is addressed in Subsection 2.3.1.3.4.

3.8.4.3.1.4 Abnormal Loads

Abnormal loads are those loads generated by a postulated high-energy pipe break accident for pipes not qualified for leak-before-break. Abnormal loads include the following:

P_a = Pressure load within or across a compartment generated by the postulated break. The main steam isolation valve (MSIV) compartments are designed for a 6.5 psi pressurization load. The steam generator blowdown valve compartment is

designed for a 6 psi pressurization load. The subcompartment design pressure bounds the pressurization effects due to postulated breaks in high energy pipe. Determination of subcompartment pressure loads is discussed in Subsection 6.2.1.2.

Ta = Thermal loads under thermal conditions generated by the postulated break and including To. Determination of subcompartment temperatures is discussed in Subsection 6.2.1.3.

R_a = Piping and equipment reactions under thermal conditions generated by the postulated break and including R_o. Determination of pipe reactions generated by postulated breaks is discussed in Section 3.6.

Y_r = Load on the structure generated by the reaction on the broken high-energy pipe during the postulated break. Determination of the loads is discussed in Section 3.6.

Y_j = Jet impingement load on the structure generated by the postulated break. Determination of the loads is discussed in Section 3.6.

Y_m = Missile impact load on the structure generated by or during the postulated break, as from pipe whipping. Determination of the loads is discussed in Section 3.6.

3.8.4.3.1.5 Dynamic Effects of Abnormal Loads

The dynamic effects from the impulsive and impactive loads caused by P_a, R_a, Y_r, Y_j, Y_m, and tornado missiles are considered by one of the following methods:

- Applying an appropriate dynamic load factor to the peak value of the transient load
- Using impulse, momentum, and energy balance techniques
- Performing a time-history dynamic analysis

Elastoplastic behavior may be assumed with appropriate ductility ratios, provided excessive deflections will not result in loss of function of any safety-related system.

Dynamic increase factors appropriate for the strain rates involved may be applied to static material strengths of steel and concrete for purposes of determining section strength.

3.8.4.3.2 Load Combinations

3.8.4.3.2.1 Steel Structures

The steel structures and components are designed according to the elastic working stress design methods of the ANSI/AISC N690 specification using the load combinations specified in Table 3.8.4-1.

3.8.4.3.2.2 Concrete Structures

The concrete structures and components are designed according to the strength design methods of ACI-349 Code, using the load combinations specified in Table 3.8.4-2.

3.8.4.3.2.3 Live Load for Seismic Design

Floor live loads, based on requirements during plant construction and maintenance activities, are specified varying from 50 to 250 pounds per square foot (with the exception of the containment operating deck which is designed for 800 pounds per square foot specified for plant maintenance condition).

For the local design of members, such as the floors and beams, seismic loads include the response due to masses equal to 25 percent of the specified floor live loads or 75 percent of the roof snow load, whichever is applicable. These seismic loads are combined with 100 percent of these specified live loads, or 75 percent of the roof snow load, whichever is applicable, except in the case of the containment operating deck. For the seismic load combination, the containment operating deck is designed for a live load of 200 pounds per square foot which is appropriate for plant operating condition. The mass of equipment and distributed systems is included in both the dead and seismic loads.

3.8.4.4 Design and Analysis Procedures

3.8.4.4.1 Seismic Category I Structures

[*The design and analysis procedures for the seismic Category I structures (other than the containment vessel, containment internal structures, and other structures constructed using concrete-filled steel plate construction), including assumptions on boundary conditions and expected behavior under loads, are in accordance with ACI-349 with clarification as provided below for concrete structures, with ANSI/AISC N690 for steel structures, and AISI for cold formed steel structures.*]* For the column line N Wall from 2 to 4 from 100'-0" to 135'-3", the tolerance for the wall thickness is increased over those in ACI 349-01. These walls were evaluated against ACI 349-01 reinforcement design requirements and demonstrated sufficient margin to accommodate the increased tolerance. The structural wall modules in the auxiliary building are designed using similar design concepts as the structural modules in the containment internal structures described in Subsection 3.8.3.5.3. The shield building is designed using the procedures and requirements described in Subsection 3.8.4.5.5.

[*The criteria of ACI-349, Chapter 12, are applied in development and splicing of the reinforcing steel. The ductility criteria of ACI-349, Chapter 21, are applied in detailing and anchoring of the reinforcing steel. Provisions in ACI 318-11 Section 12.6*]* (Reference 58) [*for headed and mechanically anchored deformed bars apply to development of headed reinforcement as an alternative to the provisions in ACI 349 Appendix B.*]* The specific application of ACI 318-11 Section 12.6 is used for development of the headed reinforcement to provide ductile behavior. Alternatively, a rebar hook with requirements according to ACI 349 may also be used.

[*The application of Chapter 21 detailing is demonstrated in the reinforcement details of critical sections*]* in Subsection 3.8.5 and Appendix 3H.

[*Sections 21.2 through 21.5 of Chapter 21 of ACI 349 are applicable to frame members resisting earthquake effects. These requirements are considered in detailing structural elements subjected to significant flexure and out-of-plane shear. These elements include the following examples described in Appendix 3H*:]*

- Reinforcement details for the basemat are described in Subsection 3.8.5. [*Shear stirrups have T headed anchors at each end. Provisions in ACI 318-11 Section 12.6*]* (Reference 58) [*for headed and mechanically anchored deformed bars apply to headed shear reinforcement as an alternative to the provisions in ACI 349 Appendix B.*]* The specific application of ACI 318-11 Section 12.6 is used for development of the headed shear reinforcement to provide ductile behavior.

- Reinforcement details for the exterior walls below grade are described in Subsection 3H.5.1.1. [*Shear ties have T headed anchors at each end. Provisions in ACI 318-11 Section 12.6*]* (Reference 58) [*for headed and mechanically anchored deformed bars apply to headed reinforcement as an alternative to the provisions in ACI 349 Appendix B.*]* The specific

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application of ACI 318-11 Section 12.6 is used for development of the headed reinforcement to provide ductile behavior. Alternatively, a conventional tie with alternating 90 and 135 degree hooks around the longitudinal reinforcement may be used.

[*Sections 21.2 and 21.6 of Chapter 21 of ACI 349 are applicable to walls, diaphragms, and trusses serving as parts of the earthquake force-resisting systems as well as to diaphragms, struts, ties, chords and collector elements. These requirements are considered in the detailing of reinforcement in the walls and floors of the auxiliary building and in the shield building cylindrical wall and roof.*]*

- Reinforcement for the shear walls and floors are shown in Subsections 3H.5.1 to 3H.5.4. [*Transverse reinforcement terminating at the edges of structural walls or at openings is detailed in accordance with 21.6.6.5 of ACI 349.*]*

The bases of design for the tornado, pipe breaks, and seismic effects are discussed in Sections 3.3, 3.6, and 3.7, respectively. The foundation design is described in Subsection 3.8.5.

The seismic Category I structures are reinforced concrete, concrete-filled steel plate, and structural module shear wall structures consisting of vertical shear/bearing walls and horizontal slabs supported by structural steel framing. Seismic forces are obtained from the response spectrum analysis of the three dimensional finite element models described in Table 3G.1-1. These results are modified to account for accidental torsion as described in Subsection 3.7.2.11. Where the refinement of these finite element models is insufficient for design of the reinforcement, for example in walls with a large number of openings, detailed finite element models are used. Also evaluated and considered in the shear wall and floor slab design are out-of-plane bending and shear loads, such as live load, dead load, seismic, lateral earth pressure, hydrostatic, hydrodynamic, and wind pressure. These out-of-plane bending and shear loads are obtained from the response spectrum analyses supplemented by hand calculations.

The exterior walls of the seismic Category I structures below the grade are designed to resist the worst case lateral earth pressure loads (static and dynamic), soil surcharge loads, and loads due to external flooding as described in Section 3.4. The lateral earth pressure loads are evaluated for two cases:

- Lateral earth pressure equal to the sum of the static earth pressure plus the dynamic earth pressure calculated in accordance with ASCE 4-98 (Reference 56), Subsection 3.5.3, Figure 3.5-1, “Variation of Normal Dynamic Soil Pressures for the Elastic Solution”

- Lateral earth pressure equal to the passive earth pressure

The shield building roof and the passive containment cooling water storage tank are analyzed using the three-dimensional finite element quadrant model described in Subsection 3G.2.3.1 with the ANSYS computer code. Loads and load combinations are given in Subsection 3.8.4.3 and include construction, dead, live, thermal, wind and seismic loads. The seismic response of the water in the tank is applied as static pressures corresponding to the impulsive and convective response. The results are used in the design of the tension ring, air inlet structure, PCS tank, shield building roof, and radial roof beams. The PCS tank is designed using the maximum accelerations at the applicable elevation resulting from time history dynamic analyses of the nuclear island. The tension ring and air inlet use maximum accelerations that are increased such that the member forces in these regions envelope those from a response spectrum analysis using the refined NI05 model, as described in Appendix 3G.2.2.4.

The liner for the passive containment cooling water storage system tank is analyzed by hand calculation. The design considers construction loads during concrete placement, loads due to handling and shipping, normal loads including thermal, and the safe shutdown earthquake. Buckling

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of the liner is prevented by anchoring the liner using the embedded stiffeners and welded studs. The liner is designed as a seismic Category I steel structure in accordance with ANSI/AISC N690 with the supplemental requirements given in Subsection 3.8.4.

The structural steel framing is used primarily to support the concrete slabs and roofs. Metal decking, supported by the steel framing, is used as form work for the concrete slabs and roofs. The structural steel framing is designed for vertical loads. Appendix 3H shows typical structural steel framing in the auxiliary building.

Computer codes used are general purpose computer codes. The code development, verification, validation, configuration control, and error reporting and resolution are according to the quality assurance requirements of Chapter 17.

[*The finned floors for the main control room and the instrumentation and control room ceilings are designed as reinforced concrete slabs in accordance with ACI-349. The steel panels are designed and constructed in accordance with ANSI/AISC N690. For positive bending, the steel plate is in tension and the steel plate with fin stiffeners serves as the bottom reinforcement. For negative bending, compression is resisted by the stiffened plate and tension by top reinforcement in the concrete.*]*

The concrete floors on steel plates, including the floors in the CA20 module, are designed as reinforced concrete slabs in accordance with ACI-349. The steel panels are designed and constructed in accordance with ANSI/AISC N690. For positive bending, the steel plate is in tension and the steel plate serves as the bottom reinforcement. For negative bending, compression is resisted by the concrete and steel plate and the tension by top reinforcement in the concrete. This methodology is similar to that described for the control room ceiling in Subsection 3H.5.4.

The design of the connection meets ACI 349 and ANSI/AISC N690 requirements for shear stud capacity. The anchorage of the reinforcing dowels may vary from that shown in Figure 3H.5-9, Sheet 2. Differences in dowel anchorage details meet ACI 349 requirements for standard hooks and ACI 318-11 requirements for headed reinforcement.

The construction sequence for CA20 floors is as follows:

- Each panel (steel plates, structural tees, and shear connectors) is fabricated in the shop, brought to the floor location, and placed in position. In some cases, panels are preassembled and placed as a module. The bottom plate is supported by brackets connected to the walls.
- The steel plate is used as the formwork for concrete placement. The wet concrete load is carried by the steel plates and the structural tees that act to stiffen the bottom plate.
- During concrete placement, shoring may be provided for floors with longer spans. Local shoring of the steel plates at penetrations and other openings in the floor and supporting wall, or to act as temporary support, may also be provided.

3.8.4.4.2 Seismic Category I Cable Tray Supports

The design and analysis procedures for seismic Category I cable trays and their supports are described in Appendix 3F.

3.8.4.4.3 Seismic Category I Heating, Ventilating, and Air Conditioning Duct Supports

The design and analysis procedures for seismic Category I heating, ventilating, and air conditioning ducts and their supports are described in Appendix 3A.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.8.4.4.4 Below Grade Exterior Walls

The design and analysis procedures for seismic Category I exterior walls below grade are described below.

The nuclear island exterior walls below grade are subjected to various loads, including the lateral earth pressure loads. Lateral loads used in design of the nuclear island are based on conservative assumptions (soil profiles with highest lateral loads) for the properties of the soil adjacent to the exterior walls. Lateral loads are calculated for a range of possible soil properties and a conservative set of loads is specified for design.

The plant grade elevation is 100′-0″, the high groundwater level is 98′-0″, and the maximum flood level is at plant elevation 100′-0″.

Load Conditions

Hydrostatic (groundwater) (Live, L)

The design high groundwater level is at elevation 98′-0″, and the probable maximum flood level is at elevation 100′-0″. Both of these loads are treated as live loads. The hydrostatic unit water pressure (P_w) at a depth h (units: feet) below ground level is calculated as:

$$P_w = \gamma_w h \quad (1)$$

Where, γ_w = unit weight of water = 62.4 pcf

At-Rest Earth Pressure (Earth, H)

Static earth pressure is based on “at -rest” conditions, and the coefficient of earth pressure for the at-rest condition (K_o) is determined from the following relationship:

$$P_o = K_o \gamma h \quad (2)$$

Where,

K_o = 1-SIN(φ)

φ = angle of internal friction

h = depth below grade (El. 100′-0″)

$\gamma = \gamma_s$ = Saturated unit weight of granular back fill above water table, or

$\gamma = \gamma_s - \gamma_w$ below water table

Static and Dynamic Surcharge Pressures

The static surcharge pressure (Dead, D) is considered a static pressure load, and therefore, the at-rest coefficient (K_o) is used. The static lateral surcharge pressure is defined for the same soil case as the at-rest pressure as follows:

$$P_{surch} = K_o q \quad (3)$$

Where,

q = static surcharge pressure based on footprint loads of adjacent structures

The dynamic lateral surcharge pressure (Seismic, Es_1) is based on 0.3 times the static surcharge pressure. The static and dynamic lateral surcharge pressures act uniformly along the height of the exterior walls.

Dynamic Earth Pressure (Seismic, Es_2)

The dynamic earth pressure is calculated in accordance with ASCE 4-98 (Reference 56), Subsection 3.5.3, Figure 3.5-1, "Variation of Normal Dynamic Soil Pressures for the Elastic Solution." The Poisson's ratio (v) for the soil varies between 0.35 and 0.4. The most conservative dynamic soil pressure distribution, obtained using 0.4 for v, is used. The seismic acceleration levels are the maximum accelerations associated with the seismic response of the nuclear island from elevation 60.5′ to elevation 100′. The north-south seismic excitation acceleration values are associated with Walls 1 and 11. The east-west seismic acceleration values apply to Walls N, Q, and I.

Passive Earth Pressure (Seismic, Es_3)

The nuclear island includes passive pressure on the exterior walls to resist sliding during an SSE. Therefore, the exterior walls below grade shall also be designed for passive earth pressure in the load combinations that include Es. The passive earth pressure is calculated from:

$$P_P = K_P \gamma h \quad (4)$$

Where,

$K_P = \text{Tan}^2(45^\circ + \varphi / 2)$

φ = angle of internal friction

h = depth below grade (El. 100′-0″)

$\gamma = \gamma_s$ = Saturated unit weight of granular back fill above water table or

$\gamma = \gamma_s - \gamma_w$ below water table

Load Combinations

Lateral loading conditions, identified above, are used for the following load combinations:

- Load Combination 3: (L) + (H) + (D) + (Es_1) + (Es_2)
- Load Combination 7: (L) + (D) + (Es_1) + (Es_3)
- Load Combinations 1 & 2: 1.4 x (D) + 1.7 x ((L) + (H))
- Load Combinations 4, 5 & 6: (L) + (H) + (D)
- Load Combinations 8 & 9: 1.05 x (D) + 1.3 x ((L) + (H))

The design of the exterior below grade walls is designed from the load combinations listed above, which incorporate the effects of full lateral passive earth pressure.

Based on the results for the load combinations, the critical lateral pressure distribution for the design loads along the exterior, below grade walls would result when combining the effects of Load Combinations (LC) 3 and 7 along the nuclear island's east-west axis. The pressure distribution for LC 3 would control from elevation 100′ (ground surface) to the intersection with the LC 7 pressure

distribution. Graphically, this occurs at approximately elevation 91′. The LC 7 plot would control from this intersection to elevation 60.5′ (bottom of the basemat). LC 7 incorporates the effects of full lateral passive earth pressure.

Lateral Soil Pressure with Vertical Seismic Effects

Soil Pressure – Vertical seismic is the at-rest earth pressure for the generic soil model multiplied by 0.3 (seismic acceleration factor). This same factor was used to determine the dynamic lateral surcharge pressure (Seismic, Es_2) noted above. These tabular values where combined with the values from the dynamic soil pressure (along the east-west axis) by the SRSS Method (square root, sum of squares) and plotted against the dynamic soil pressure (along the east-west axis) alone. The contribution of vertical seismic effect on the at-rest earth pressure is negligible to the dynamic soil pressure. Therefore, vertical seismic effect is neglected and the dynamic soil pressure alone was used in determining the load combination.

3D SASSI Analyses

3D SASSI soil-structure interaction (SSI) analyses for soil conditions soft-to-medium (SM) and upper-bound-soft-to-medium (UBSM) soil were used to estimate the dynamic soil pressure on the exterior nuclear island walls. Five locations were used to calculate lateral pressure on the structure, including spring elements at elevation 100′ and 82.5′, and structure elements at elevation 91′, 71′, and 57′. Axial spring forces normal to and along each wall are tabulated and converted to a unit load and corresponding stress at each elevation. Similarly, element stresses normal to the plane of the wall are tabulated for each elevation, and the maximum normal stress was determined.

The 3D SASSI UBSM and SM dynamic soil pressure for the north-south and east-west vertical profiles are compared to the ASCE 4-98 lateral soil pressure distribution curve.

3D ANSYS Analyses

The analyses of the nuclear island for the lateral earth pressure loads are performed using 3D linear elastic ANSYS analysis. The lateral earth pressure loads are applied to the finite element nodes associated with embedded nuclear island structural walls. The analysis performed is linear elastic. Loads and moments at the base of the exterior walls are extracted from the analyses and are added in the design analyses of the basemat.

3.8.4.5 Structural Criteria

[*The analysis and design of concrete conform to ACI-349 as supplemented below and with clarifications provided in Subsection 3.8.4.4.1. The analysis and design of structural steel conform to ANSI/AISC N690 as supplemented below and with clarifications provided in Subsection 3.8.4.5.2. The analysis and design of cold-formed steel structures conform to AISI. The margins of structural safety are as specified by those codes.*]*

3.8.4.5.1 Supplemental Requirements for Concrete Structures

[*Supplemental requirements for ACI-349-01 are given in the position on Regulatory Guide 1.142 in Appendix 1A. The structural design meets the supplemental requirements identified in Regulatory Positions 2 through 8, 10 through 13, and 15.*]*

Paragraph 21.6.1 of ACI 349-01 should reference 21.6.6 instead of 21.6.5. Paragraph 21.6.5 in ACI 349-97 was renumbered to 21.6.6 in ACI 349-01, and the reference in 21.6.1 was not updated. The errata for ACI 349-01 are being updated to include this correction. This makes the paragraph consistent with ACI 349-97, which was endorsed by Regulatory Guide 1.142.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

[*Design and construction of fastening to concrete is in accordance with ACI 349-01, Appendix B*]* and are in conformance with the regulatory positions of NRC Regulatory Guide 1.199, Revision 0. [*Alternative requirements to ACI 349, Appendix B apply to the anchoring of headed shear reinforcement for the basemat (see Subsection 3.8.4.4.1). Alternative requirements to ACI 349, Appendix B apply to the anchoring of headed reinforcement above the basement (see Subsection 3.8.4.4.1).*

Weldable coupler connections of reinforcing bar to structural steel shall develop 125% of the specified yield strength of the bar in accordance with ACI 349-01 Section 12.14.3.4. Qualification of the C2/C3J coupler welds is demonstrated as follows:

For reinforcing bar sizes #4, #5, and #6, the coupler connection weld adequacy is demonstrated by calculations in accordance with ANSI/AISC N690-1994 requirements using a stress limit coefficient (SLC) of 1.6.

For reinforcing bar sizes #7, #8, #9, #10, and #11, coupler connection weld adequacy is demonstrated through testing, as permitted by ANSI/AISC N690-1994 Section Q1.0.1, and more specifically, Section Q1.22.2. Two sets of testing are performed to demonstrate that the strength of the reinforcing bar is the limiting feature of the coupler reinforcing bar splice and weld system:

(1) Six static tension tests are performed for each reinforcing bar size on samples of the coupler reinforcing bar splice and weld system, retaining the 90%/95% upper confidence limit of the coupler system static tension test results. Three cyclic tests are also performed as described in ACI 349-01 12.14.3.4.1(b) to confirm that there is not significant coupler system degradation under cyclic demand.

(2) Static tension testing of the coupler weld to failure using ten representative sample weld configurations from each of the five reinforcing bar coupler sizes is performed to determine the 90%/95% lower confidence limit weld capacity.

The tests demonstrate that the factor of safety between the weld 90%/95% lower confidence limit and 125% of the specified yield strength of the reinforcing bar exceeds 1.4. The tests also demonstrate that the factor of safety between the weld 90%/95% lower confidence limit and the 90%/95% upper confidence limit of the coupler system static tension test results exceeds 1.0. The analyses and tests establish a minimum fillet reinforcement size for the C2/C3J couplers:

C2/C3J Coupler Size	*#4*	*#5*	*#6*	*#7*	*#8*	*#9*	*#10*	*#11*
Min. Fillet Weld Size (inches)	*1/4*	*1/4*	*1/4*	*1/4*	*1/4*	*5/16*	*1/4*	*3/8*]*

The tests also demonstrate that non-conforming 1/4-inch fillet welds for #9 and #11 C3J couplers identified in module CA20 are acceptable by comparing the 90%/95% lower confidence limit weld strength to 125% of the specified yield strength of the reinforcing bar and to the 90%/95% upper confidence limit of the coupler system static tension test results. The factor of safety exceeds 1.3 in comparison to 125% of the specified yield strength of the reinforcing bar and 1.0 in comparison to the 90%/95% upper confidence limit of the coupler system.

3.8.4.5.2 Supplemental Requirements for Steel Structures

[*Supplemental requirements for use of ANSI/AISC N690 are as follows:*

- *In Section Q1.0.2, the definition of secondary stress applies to stresses developed by temperature loading only.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- *In Section Q1.3, where the structural effects of differential settlement are present, they are included with the dead load, D.*

- *In Table Q1.5.7.1, the stress limit coefficients for compression are as follows:*

  1.3 instead of 1.5 in load combinations 2, 5, and 6.

  1.4 instead of 1.6 in load combinations 7, 8, and 9.

  1.6 instead of 1.7 in load combination 11.

- *In Section Q1.5.8, for constrained members (rotation and/or displacement constraint such that a thermal load causes significant stresses), supporting safety-related structures, systems, or components, the stresses under load combinations 9, 10, and 11 are limited to those allowed in Table Q1.5.7.1 as modified above.*

- *Sections Q1.24 and Q1.25.10 are supplemented as follows:*

  Shop painting is in accordance with Section M of the Manual of Steel Construction, Load and Resistance Factor Design, First Edition. Exposed areas after installation are field painted in accordance with the applicable portion of Chapter M of the Manual of Steel Construction, Load and Resistance Factor Design, First Edition.]* See Subsection 6.1.2.1 for additional description of the protective coatings.

- [*In Sections Q1.26.2.2, Q1.26.2.3, and Q1.26.3 for the non-conforming partial penetration welds associated with reinforcement bar sizes #6 and #9 C3J couplers installed on ASTM A240 stainless steel embedment plates under CA01 that did not undergo non-destructive examination at the time of fabrication, as identified in Amendment Nos. 80 and 79 for VEGP Units 3 and 4, respectively, the quality and strength of the welds is demonstrated through visual examination and through static tension testing of an uninstalled representative population as follows:*

  - *Visual Examination: Coupler welds from the production fabrication population underwent visual examination by the manufacturer. The manufacturer visual examinations provided satisfactory results.*

  - *Static Tension Testing: Weldable coupler connections of reinforcing bar to structural steel shall develop 125% of the specified yield strength of the bar in accordance with ACI 349-01, Section 12.14.3.4. The mechanical connection strength requirement is applied to the weld to demonstrate that the coupler weld is stronger than the reinforcing bar strength requirement, thereby satisfying provisions for design limits outlined in ANSI/AISC N690-1994. To determine that the population of #6 and #9 C3J coupler welds on ASTM A240 stainless steel embedment plates are adequate in their ability to perform their intended design function, static tension testing of an uninstalled representative population of production welds is evaluated experimentally in two phases.*

    Phase I: Static tension testing has been performed on a total of six #9 sized couplers and a total of fifteen #6 sized couplers. The static tension tests results were evaluated to obtain the 90/95% confidence interval break strength for both coupler sizes. The Phase I test results demonstrate that the 90/95% confidence interval break strength exceeds 125% of the specified yield strength of the reinforcing bar and demonstrate that the rebar or coupler thread is the weak link in the mechanical connection system.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Phase II: Testing was performed to investigate the strength of the coupler weld. A total of 47 samples were tested, 37 #6 sized couplers and 10 #9 sized couplers. The statically-tested samples failed within the coupler body, and demonstrate that the production PJP with fillet weld is stronger than the coupler body. To confirm that the statically-tested sample population is representative of the installed population of coupler welds, the test sample population considered factors such as sample size, weld process, automatic/manual processes, human performance factors, welding procedure specifications, non-destructive examination, fabrication schedule, filler metal, and coupler material.

Safety margin was calculated using the nominal tensile strength and the 90/95% confidence interval test coefficient based on the test samples and is penalized by lower bound failure modes and a finite sample size. The safety margin, or Factor of Safety (FoS), was calculated against both the 125% yield strength of the rebar and against the system strength (i.e., weakest link of the system, rebar or coupler thread). The minimum safety margin with respect to the 125% yield strength of the rebar was calculated to be 2.91 for the #6 sized couplers and 2.26 for the #9 sized couplers. The minimum safety margin with respect to the system strength was calculated to be 2.16 for the #6 sized couplers and 1.68 for the #9 sized couplers.]*

- [*In Section Q1.26.2.2, for the non-conforming partial penetration welds associated with reinforcement bar size #9 C3J couplers installed on carbon steel embedment plates under CA20 at Vogtle Unit 3 and Unit 4 and under CA01 at Vogtle Unit 3 that did not undergo non-destructive examination at the time of fabrication, as identified in Amendment Nos. 86 and 85 for VEGP Units 3 and 4, respectively, the strength and quality of the welds is demonstrated through non-destructive examination and static tension testing of portions of the original production and supplemental, uninstalled populations and through visual examination of the production populations as follows:*

  - *Visual Examination: Coupler welds from the production fabrication populations underwent visual examination by the manufacturers. The manufacturers' visual examinations provided satisfactory results.*

  - *Static Tension Testing: Weldable coupler connections of reinforcing bar to structural steel shall develop 125% of the specified yield strength of the bar in accordance with ACI 349-01, Section 12.14.3.4. The mechanical connection strength requirement is applied to the weld to demonstrate that the coupler weld is stronger than the reinforcing bar strength requirement, thereby satisfying provisions for design limits outlined in ANSI/AISC N690-1994. To determine that the populations of #9 sized C3J coupler welds on carbon steel embedment plates is adequate in the ability to perform their intended design function, static tension testing of portions of the original production and supplemental, uninstalled populations of welds is evaluated experimentally in two phases.*

    Phase I: Static tension testing has been performed on a total of four #9 sized couplers. The static tension test results were evaluated to obtain the 90/95% confidence interval break strength. The Phase I test results demonstrate that the 90/95% confidence interval break strength exceeds 125% of the specified yield strength of the reinforcing bar and demonstrate that the rebar or thread is the weak link in the mechanical connection system.

    Phase II: Testing was performed to investigate the strength of the coupler weld. A total of 30 #9 sized couplers and 3 #11 sized couplers were tested. The statically-tested samples failed within the coupler body, and demonstrate that the

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

production PJP with fillet weld is stronger than the coupler body. To confirm that the statically-tested sample population is representative of the installed populations of coupler welds, the test sample population considered factors such as sample size, weld process, semi-automatic processes, human performance factors, welding procedure specification, non-destructive examination, filler metal, and coupler material.

Safety margin was calculated using the nominal tensile strength and the 90/95% confidence interval test coefficient based on the test samples and is penalized by lower bound failure modes and a finite sample size. The safety margin, or Factor of Safety (FoS), was calculated against both the 125% yield strength of the rebar and against the system strength (i.e., weakest link of the system, rebar or thread). The minimum safety margin with respect to the 125% yield strength of the rebar was calculated to be 2.08 for the #9 sized couplers. The minimum safety margin with respect to the system strength was calculated to be 1.42 for the #9 sized couplers.

- *Non-destructive examination of portions of the original production and supplemental, uninstalled populations: Magnetic particle examination was performed on 10% of the total populations of welds from the uninstalled original production population and from the uninstalled supplemental population. The magnetic particle examinations provided satisfactory results.*]*

3.8.4.5.3 Design Summary Report

A design summary report is prepared for seismic Category I structures documenting that the structures meet the acceptance criteria specified in Subsection 3.8.4.5.

Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Sections 3.7 and 3.8 provided the following acceptance criteria are met:

- the structural design meets the acceptance criteria specified in Section 3.8
- the seismic floor response spectra meet the acceptance criteria specified in Subsection 3.7.5.4

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgment to performance of a revised analysis and design. The results of the evaluation will be documented in an as-built summary report.

3.8.4.5.4 Design Summary of Critical Sections

[*The design of representative critical elements of the following structures is described in Appendix 3H.*

- *South wall of auxiliary building (column line 1), elevation 66'-6" to elevation 180'-0" – see subsection 3H.5.1.1 and Figures 3H.5-2 and 3H.5-3*

- *Interior wall of auxiliary building (column line 7.3), elevation 66'-6" to elevation 160'-6" – see subsection 3H.5.1.2 and Figure 3H.5-4*

- *West wall of main control room in auxiliary building (column line L), elevation 117'-6" to elevation 153'-0" – see subsection 3H.5.1.3 and Figure 3H.5-12*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- *North wall of MSIV east compartment (column line 11 between lines L and M), elevation 117'-6" to elevation 153'-0" – see subsection 3H.5.1.4 and Figure 3H.5-5*
- *Roof slab at elevation 180'-0" adjacent to shield building cylinder – see subsection 3H.5.2.1 and Figure 3H.5-7*
- *Floor slab on metal decking at elevation 135'-3" – see subsection 3H.5.2.2 and Figure 3H.5-6*
- *2'-0" slab in auxiliary building (operations work area (tagging room) ceiling) at elevation 135'-3" – see subsection 3H.5.3.1 and Figure 3H.5-8 (Note: The 'Tagging Room' has been renamed as "Operations Work Area." However, to avoid changing the associated design and analysis documents, this room is referred to as the 'Tagging Room.')*
- *Finned floor in the main control room at elevation 135'-3" – see subsection 3H.5.4 and Figure 3H.5-9*
- *Shield building roof, exterior wall of the PCS water storage tank – see subsection 3H.5.6.3 and Figure 3H.5-11*
- *Shield building roof, interior wall of the PCS water storage tank – see subsection 3H.5.6.2 and Figure 3H.5-11*
- *Shield building roof, tension ring, and air inlet structure – see subsections 3H.5.6 and 3H.5.6.1*
- *Divider wall between the spent fuel pool and the fuel transfer canal – see subsection 3H.5.5.1 and Figure 3H.5-10*
- *Shield building SC cylinder – see subsection 3H.5.7.1, Figure 3H.5-16, and Figures 5 and 6 of APP-GW-GLR-602 (Reference 57)*
- *Shield building SC to RC connection – see Subsection 3H.5.7.2, Figure 3H.5-16, and Figures 1, 2, 3, and 4 of APP-GW-GLR-602 (Reference 57)*]*

3.8.4.5.5 Shield Building Structural Wall Modules

[*The shield building concrete-filled steel module walls are designed for loads such as dead, live, thermal, wind, and safe shutdown earthquake loads as identified in Table 3.8.4-2. Concrete-filled structural wall modules are designed as reinforced concrete structures in accordance with the requirements of ACI 349, and supplemented with additional requirements discussed in subsection 3.8.3.5.3 and below. The faceplates are considered as the reinforcing steel, bonded to the concrete by headed studs. The steel plate modules are anchored to the reinforced concrete by mechanical connections welded to the steel plate.*]*

Figure 5 in Reference 57 shows the typical design details of the shield building concrete-filled steel module walls. The design of the shield building critical sections is described in Appendix 3H.

3.8.4.5.5.1 Design for Axial Loads and Bending

Design for axial load (tension and compression), in-plane bending, and out-of-plane bending is in accordance with the requirements of ACI 349, Chapters 10 and 14. The reinforcement for in-plane tension and compression combined with out-of-plane moments is calculated using a rectangular concrete stress distribution, in accordance with Sections 10.2 and 10.3 of the ACI 349 code.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.8.4.5.5.2 Design for In-Plane Shear

Design for in-plane shear is in accordance with the requirements of ACI 349, Chapters 11 and 14. The steel faceplates are treated as reinforcing steel, contributing as provided in Section 11.10 of ACI 349.

3.8.4.5.5.3 Design for Out-of-Plane Shear

Design for out-of-plane shear is in accordance with the requirements of ACI 349, Chapter 11.

3.8.4.5.5.4 Evaluation for Thermal Loads

Thermal loads are combined with other loads according to the load combinations defined in Table 3.8.4-2. The effect of concrete cracking is considered in the stiffness properties for the concrete elements subjected to the thermal loads. Thermal forces and moments are calculated by multiplying linear elastic thermal stress analysis results by a stiffness reduction ratio α. The stiffness reduction ratio α is calculated as the ratio of the cracked stiffness to the elastic stiffness of the section to be evaluated.

3.8.4.5.5.5 Design of Shear Studs and Tie Bars

[*The shear stud connectors and tie bars are sized to carry the horizontal shear at the junction of the steel faceplates and the concrete infill. The shear stud and tie bar design is such that the shear stud and tie bar strength is sufficient to develop the full yield strength of the steel plate in approximately 3 x the thickness of the wall, or about 9 feet.*

The tie bars provide a structural framework for the modules, maintain the separation between the faceplates, support the modules during transportation and erection, and act as "form ties" between the faceplates when concrete is being placed. The tie bars provide additional shear capacity between the steel plates and concrete as well as additional strength similar to that provided by stirrups in reinforced concrete. The area and spacing of the tie bars satisfy the requirement for minimum shear reinforcement for beams given in the ACI codes. The connection between the tie bars and the steel faceplates is designed to develop 125% of the specified yield strength of the tie bar.]*

3.8.4.5.5.6 Design of Connections

The shield building steel plate modules are connected to standard reinforced concrete using a connection design satisfying the requirements outlined below. The locations of these connections include the following:

1. At the base of the shield building wall into the concrete below

2. Between SC and RC portions of the shield building wall

3. Where RC floors, roofs, and walls connect to the SC modules.

The steel plate modules are connected to the reinforced concrete by reinforcement or deformed bars directly connected to the modules. These connections are sized using a strength design approach, and the mechanical connection portion of the connection satisfies the requirements of ANSI/AISC N690. In the area of the connections, the faceplates are thicker (up to 1.0-inch nominal thickness), as necessary, to address loads from the connections. The connection design satisfies the following requirements:

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- The connections provide for the direct transfer of forces from the RC reinforcing steel to the SC faceplates. Lap splice type connections between dowels extending out of the RC into the SC adjacent to the headed shear studs are not used to connect the modules to the base concrete.

- Loads are transferred directly from the faceplates to the reinforced concrete using reinforcing bars, mechanical connection, and welds.

- The mechanical connections develop 125 percent of specified yield of the connected reinforcement bar.

- Loads that are out of plane of the wall, such as from roofs or walls, are carried through the full thickness of the shield building walls.

Figures 1, 2, 3, and 4 in APP-GW-GLR-602 (Reference 57) show the typical design details for the connection of the wall modules to the reinforced concrete. Figure 5 in Reference 57 shows the typical design details of the shield building concrete-filled steel module walls.

Figure 3H.5-7 and Figure 7 in Reference 57 show typical auxiliary building reinforced concrete roof connections to the shield building SC wall. The details of the connections between the auxiliary building roof and the shield building wall vary because of loads on the connection and the orientation of the wall to the roof reinforcement arrangement as outlined in the notes on Figure 3H.5-7 and in Section 4 of Reference 57. Figure 3H.5-7 also shows typical connections between the auxiliary building walls and the shield building SC wall modules. The connection elements used and the design details vary because of the orientation of the auxiliary building wall to the shield building wall. These connection design details satisfy the requirements of ANSI/AISC N690 and the requirements identified above.

3.8.4.6 Materials, Quality Control, and Special Construction Techniques

This subsection contains information relating to the materials, quality control program, and special construction techniques used in the construction of the other seismic Category I structures, as well as the containment internal structures. An edition of the referenced specifications applicable after the start of construction or procurement activities will be used.

3.8.4.6.1 Materials

3.8.4.6.1.1 Concrete

[*The compressive strength of concrete used in the seismic Category I structures and containment internal structures is f_c' = 4000 psi except as noted in the following. For the nuclear island basemat (the nominal 6 ft. thick foundation described in Subsection 3.8.5.1) the compressive strength of concrete is f_c' = 5000 psi. For the SC composite portion of the shield building structure including the connection region below the SC/RC interface and the shield building roof, the compressive strength of concrete is f_c' = 6000 psi except as noted in the following. For Vogtle Unit 3 lower shield building roof between azimuth 90 degrees and 270 degrees from EL. 272'-11/16" to EL. 293'-9" the concrete compressive strength, f_c', is between 5500 psi and 6000 psi.*]* The test age of concrete containing pozzolan is up to 56 days. The test age of concrete without pozzolan is up to 28 days. Concrete is mixed, batched, and placed according to Reference 6, Reference 7, and ACI-349.

Portland cement conforms to Reference 8, Type II. Certified copies of mill test reports showing that the chemical composition and physical properties conform to the specification are obtained for each cement delivery.

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Aggregates conform to Reference 9. The fineness modulus of fine aggregate (sand) is not less than 2.3, nor more than 3.1, per Reference 9. In at least four of five successive test samples, such modulus is not allowed to vary more than 0.20 from the moving average established by the last five tests. Coarse aggregates may be rejected if the loss from the Los Angeles abrasion test, Reference 10, using Grading A or Reference 11, exceeds 40 percent by weight at 500 revolutions. Acceptance of source and aggregates is based on the tests specified in Table 3.8.4-3 as applicable based on type of aggregate and ACI-349 requirements.

Water and ice used in mixing concrete do not contain more than 250 parts per million of chlorides (as Cl) as determined in accordance with Reference 12. They do not contain more than 2000 parts per million of total solids as determined in accordance with Reference 13. Water meets the criteria in Table 3.8.4-4 in regard to the effects of the proposed mixing water on hardened cement pastes and mortars compared with distilled water.

The concrete contains an air entraining admixture when required by ACI-349 and may contain pozzolans and a water-reducing admixture. A viscosity modifying admixture (VMA) may be used in self-consolidating concrete (SCC) for adjusting the viscosity and improving its stability as outlined in ACI 237R, “Self-Consolidating Concrete.” Admixtures, except pozzolan, are stored in liquid solution.

Admixture types A, B, C, and F are used as noted herein to produce quality concrete. The admixtures shall be proven compatible with all constituents and other admixtures in mix prior to use in production of concrete. Furthermore, all admixtures shall be measured, introduced into the mix, and used in strict accordance to the manufacturer’s recommendations.

Admixtures do not contain added chlorides except as contained in potable drinking water used for manufacture of the admixtures. The chloride content is stated in the manufacturer's material certification.

Pozzolan conforms to Reference 14, except that the ignition loss does not exceed 6 percent.

Pozzolan is sampled and tested in accordance with Reference 15 for source approval.

Air entraining admixture conforms to Reference 16.

Water-reducing admixtures conform to Reference 17 and are of types A or F. A type A admixture may be used to increase the slump for conventional mixes (may use type F, optional). A type F admixture shall be used for SCC admixtures.

Retarding admixtures conform to Reference 17 and are of type B. Type B admixtures may be used to retard set times for conventional and SCC mixes (i.e., for mass concrete).

Accelerating admixtures conform to Reference 17 and are type C. Type C admixtures may be used to accelerate the set time for conventional and SCC mixes (i.e., for thin members placed in cold weather).

Manufacturer's certification for the air entraining admixture is required demonstrating compliance with Reference 16, Section 4 requirements.

Manufacturer's certification for the water-reducing admixture is required demonstrating compliance with Reference 17, Section 5 requirements.

Manufacturer's test reports are required for each delivery of pozzolan showing the chemical composition and physical properties and certifying that the pozzolan complies with the specification.

Proportioning of the concrete mix is in accordance with Reference 18 and Option B of Reference 6.

A testing laboratory designs and tests the concrete mixes. Only mixes meeting the design requirements specified for concrete are used.

Forms for concrete are designed as recommended in ACI 347.

3.8.4.6.1.2 Reinforcing Steel

[*Reinforcing bars for concrete are deformed bars according to Reference 19, Grade 60, and Reference 20.*]* Certified material test reports are provided by the supplier for each heat of reinforcing steel delivered showing physical (both tensile and bend test results) and chemical analysis. In addition, a minimum of one tensile test is performed for each 50 tons of each bar size produced from each heat of steel.

In areas where reinforcing steel splices are necessary and lap splices are not practical, welded splices and other mechanical connections are acceptable.

[*Headed reinforcement meeting the requirements of ASTM A970 (Reference 49) is used where mechanical anchorage is required,*]* such as for shear reinforcement in the nuclear island basemat and in the exterior walls below grade.

As stated in Subsection 3.4.1.1.1, seismic Category I structures that are located below grade elevation are protected against flooding by a waterproofing system. This, in conjunction with the ACI 349 Code requirements for concrete cover for exposure to earth or weather for the reinforcing steel, provides sufficient protection for the reinforcing steel. Therefore, the use of coated reinforcing steel is not planned.

3.8.4.6.1.3 Structural Steel

Basic materials used in the structural and miscellaneous steel construction conform to the ASTM standards listed in Table 3.8.4-6. The table includes the major structural steel materials of construction. Materials used in limited applications and minor amounts may not be included. [*Additional information on structural and reinforcing steel for the shield building is provided in Table 1 of APP-GW-GLR-602 (Reference 57).*]*

3.8.4.6.1.4 Masonry Walls

There are no safety-related masonry walls used in the nuclear island.

3.8.4.6.2 Quality Control

The quality assurance program is described in Chapter 17. Conformance to Regulatory Guide 1.94 is as described in Section 1.9.

3.8.4.6.3 Special Construction Techniques

Construction techniques for the structural modules are the same as special construction techniques for the containment internal structures discussed previously in Subsection 3.8.3.6.1. Design-specific tolerances for alignment of the faceplates at welds connecting the shield building structural wall modules permit up to 1/4" offset in the alignment of the faceplates. The separation between the faying surfaces of the shield building wall modules butt joints landing on a backing bar is allowed up to 1/4". These design-specific tolerances modify plate alignment tolerances and faying surface separation requirements specified in AWS D1.1 (subsections 5.22.1.1 and 5.22.3) and are used in

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conjunction with a weld configuration that is designed for the larger alignment offset and the larger backing bar gap. The shield building wall design using the modified weld joint is in conformance with applicable requirements of ACI 349 and ANSI/AISC N690.

Where out-of-plane shear reinforcement is provided within the radial/circumferential reinforcement pattern for the main steam line anchor in auxiliary building Wall 11 (Figure 3H.5-5), tolerance on shear reinforcement is specified to maintain the maximum spacing requirements of ACI 349-01, and the minimum spacing requirements of ACI 318-11 for headed reinforcement.

3.8.4.7 Testing and In-Service Inspection Requirements

Structures supporting the passive containment cooling water storage tank on the shield building roof will be examined before and after first filling of the tank.

- The boundaries of the passive containment cooling water storage tank and the shield building roof above the tension ring at the intersection of the shield building roof and the shield building cylinder will be inspected visually for excessive concrete cracking before and after first filling of the tank. Any significant concrete cracking will be documented and evaluated in accordance with ACI 349.3R-96 (Reference 50). The structure around the passive containment cooling water storage tank will be inspected for water leaking out of the tank through the concrete.

- The vertical elevation of the passive containment cooling water storage tank relative to the top of the shield building cylindrical wall at the tension ring will be measured before and after first filling. The change in relative elevation will be compared against the predicted deflection.

- A test will be performed to measure the leakage from the passive containment cooling water storage tank based on measuring the water flow out of the leak chase collection system.

- A report will be prepared summarizing the test and evaluating the results.

During the operation of the plant, the condition of these structures should be monitored by the Combined License holder to provide reasonable confidence that the structures are capable of fulfilling their intended functions. The inspection program for structures is identified in Section 17.6. This inspection program is consistent with the requirements of 10 CFR 50.65 and the guidance in Regulatory Guide 1.160.

3.8.4.8 Construction Inspection

Construction inspection is conducted to verify the concrete wall thickness and quantity of concrete reinforcement. The construction inspection includes concrete wall thickness and reinforcement expressed in units of in^2/ft (linear length) equivalent when compared to standard reinforcement bar sections. Inspections will be measured at applicable sections excluding designed openings or penetrations. Inspections will confirm that each applicable section provides the minimum required reinforcement, steel plate thickness, and concrete thickness. The minimum required reinforcement, steel plate thickness, and concrete thickness represent the minimum values to meet the design basis loads. Appendix 3H also indicates the reinforcement provided which may exceed the minimum required reinforcement for the following reasons:

- Structural margin
- Ease of construction
- Use of standardized reinforcement sizes and spacing

A shield building construction mockup program will be used to build full-scale replicas of areas of the shield building that present critical construction areas identified as challenging areas of construction. These mockups provide an opportunity to apply and evaluate alternate and innovative construction and inspection methods and procedures. The fabrication, assembly, and erection of a full-scale mockup provides the accurate physical representation needed to evaluate true working conditions, physical configuration, accessibility, and quality control issues that may be encountered in construction. Construction practices review and examination of the mockups will be used to confirm the adequacy of construction means, methods, and procedures. If defects are found, the procedures will be revised and the mockup repeated until the required result is obtained. The major tasks that will be performed on each mockup include the following: field performance testing of the quality of concrete mixes, methods of concrete placement, inspections and surveillance, and post-placement activities.

In addition to these important process control tasks performed on the mockups, an inspection program will be undertaken on the AP1000 construction site mockups that uses the enhanced shield building design. Both visual inspection and non-destructive examination (NDE) will be performed for assessing defects that may impact structural integrity, such as crack distress, deterioriation caused by honeycomb, voids, and delaminations. The NDE inspection of the mockups will be performed at the first construction site of an AP1000 plant with an enhanced shield building design, and mockups applicability will be evaluated for the subsequent AP1000 site. This is to demonstrate the construction quality process control for concrete placement, and develop and document insights and requirements for corrective action, if required, to be used in the construction inspection program for all AP1000 plants.

3.8.5 Foundations

3.8.5.1 Description of the Foundations

The nuclear island structures, consisting of the containment building, shield building, and auxiliary building are founded on a common 6-foot-thick, cast-in-place, reinforced concrete basemat foundation. The top of the foundation is at elevation 66′-6″.

The depth of overburden and depth of embedment are given in Subsection 2.5.4.5.

A description of the safety-related backfill, which supports Category I structures, is given in Subsection 2.5.4.5.

[*The turbine building and annex building are structurally separated from the nuclear island structures by a 2-inch gap at and below the grade. A 3-inch minimum gap is provided above grade; except that the north-south minimum gap for Unit 3 between the nuclear island and the annex building between elevations 141'-0" and 154'-0" west of column line I is 2-1/16 inches.*]* This provides space to prevent interaction between the nuclear island structures and the adjacent seismic Category II structures during a seismic event. The maximum relative seismic displacement between the roof of the nuclear island and the turbine and annex buildings is less than 2 inches. This results in a clearance (gap) between buildings greater than 1 inch during a seismic event. Therefore, there are no interactions between the nuclear island and adjacent seismic Category II buildings during a seismic event. The radwaste building(1) is separated from the nuclear island by a 2-inch gap at and below grade and a 4-inch gap above grade. Figure 3.8.5-1 shows the foundations for the nuclear island structures and the adjoining structures.

1. It should be noted that an evaluation of the radwaste building was made to consider its impact on the nuclear island or collapse in the safe shutdown earthquake; it was concluded that it would not impair the integrity of the nuclear island (see Subsection 3.7.2.8.2).

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Resistance to sliding of the concrete basemat foundation is provided by passive soil pressure and soil friction. This provides the required factor of safety against lateral movement under the most stringent loading conditions.

For ease of construction, the foundation is built on a mud mat. The mud mat is lean, nonstructural concrete and rests upon the load-bearing soil. Waterproofing requirements are described in Subsection 3.4.1.1.1.

The scope of the LWA foundation work includes: placing the mud mats, water proofing membrane, concrete forms, drains and other items necessary to prepare the Nuclear Island base slab for the first concrete pour.

After backfill beneath the NI (Nuclear Island) has been placed and compacted to roughly the required elevation for the first mud mat, the construction of the retaining wall will begin. The retaining wall will be a vertical mechanically-stabilized earth (MSE) wall with smooth-faced concrete panels. This wall will function as both a retaining wall as the backfill outside the NI volume is brought up to plant grade and as the exterior concrete form for the outer walls of the NI. Subsection 2.5.4.5, Excavation and Backfill, provides additional information on the backfill and MSE wall.

The construction of the MSE wall begins with installation of a concrete footer. The top surface of the MSE wall footer will be installed below the bottom elevation of the first mud mat. The size and reinforcement for the concrete footer will be as required by the designer of the MSE wall. The MSE wall footer is a relatively thin concrete structure that provides a stable, level surface for construction of the MSE wall. It provides no structural support for the mud mats or the NI itself.

The first course of the MSE wall will be placed on top of the footer at the surveyed locations required to outline the NI footprint. Inspections will be performed as required to assure that the outer dimensions of the NI are properly set.

Backfill around the outer sides of the MSE wall will commence as required by the designer of the MSE wall, with the standard large compaction equipment being used away from the wall, and smaller equipment providing the required compaction at the edges of the wall. During backfill placement and compaction, the backfill surface will be sloped away from the NI to drain surface water away from the NI excavation volume. Additional courses of the MSE wall will be added until final plant grade is reached.

In parallel with the construction of the MSE wall, work within the NI footprint will continue. Temporary features to provide removal of surface water within the confined area of the NI will be installed as required. These features may include plastic sheeting, temporary sumps and pumps. In addition, the surface may be sloped to provide adequate drainage.

After the first few courses of the MSE wall have been placed, the backfill within the NI volume will be prepared for placement of the mud mat. Temporary drainage features will be removed, and material will be removed or added as required to establish the final elevation for the mud mat placement.

The first mud mat will consist of a 6-inch layer of non-reinforced concrete placed uniformly within the confines of the MSE wall. No additional formwork will be required. When this lower mud mat slab has reached the specified strength, a layer of waterproof membrane will be applied to the entire top of the slab, and extended vertically up the face of the MSE wall surface. The top portion of the mud mat slab (also a 6-inch layer of non-reinforced concrete) will then be placed, sandwiching the waterproof membrane. Additional detail concerning the waterproof membrane is provided in following Subsection 3.8.5.1.1. Figure 2.5-390 provides an illustration of the location of the waterproof membrane. Rebar and foundation embedments are not incorporated in either of these mud mats; therefore installation of such elements will not puncture the waterproofing membrane.

3.8.5.1.1 Waterproof Membrane

For Vogtle Electric Generating Plant (VEGP) Units 3 and 4 an alternate waterproofing system is presented as a departure from the DCD design. The alternate waterproofing system is an elastomeric “spray-on” waterproof membrane. The membrane is applied as a high-viscosity liquid that cures after exposure to air. This material may be applied by brush, roller or airless spray equipment.

Prior to procurement of the membrane material, a qualification program will be developed to demonstrate that the selected material will meet the waterproofing and friction requirements. This qualification program will address, as a minimum, the following:

- chemical properties of the membrane material,
- physical properties of the membrane material,
- surface finish requirements for the lower mudmat, and
- installation procedures necessary to achieve the required properties and coefficients of friction.

The qualification program will include testing to demonstrate that the ITAAC design commitment in Table 3.8-201 for friction coefficient has been met. Testing methods will simulate field conditions to demonstrate that a minimum 0.7 coefficient of friction is achieved by the mudmat waterproof membrane structural interface. A technical report will be provided for the ITAAC to document the basis for determining that the material will meet the required friction factor. Application procedures will be developed based on the results of qualification testing to assure that the conditions and assumptions of the qualification tests are maintained during product application.

Based upon the qualification program requirements, it is concluded that the installed waterproof membrane will provide a level of protection from external flooding and meet the coefficient of friction at the waterproof membrane-mudmat interface that is consistent with that of the existing DCD design.

The elastomeric waterproof membrane will be applied to the entire surface of the lower mudmat and the inner face of the MSE wall. Final thickness of the membrane will be specified based on the physical properties of the selected material but is expected to be on the order of 80 to 120 mils. The membrane may be applied in multiple coats to achieve the required thickness.

The surface of both the mudmat and the MSE wall will be prepared in accordance with procedures that are consistent with the surface preparation requirements determined during the material qualification testing program. At the transition between the lower mudmat and the MSE wall, a small transition (chamfer or fillet) between the mudmat and wall will be provided to allow a smooth transition for the membrane.

The surface of the MSE wall will be prepared as necessary to assure that the waterproof coating application can bridge the small gaps and corners of the MSE blocks. This preparation process will likely include attaching a geo-textile material to the wall prior to application of the membrane material. It should be noted that the cured membrane has a degree of flexibility which allows it to accommodate thermal expansion and other minor movements between substrate members.

The application procedures will address all aspects of the coating application including batch qualification, surface preparation, application techniques, film thickness, cure time, and repair procedures.

The final mudmat will be placed on top of the waterproof membrane. Procedures will address inspection and testing as required to assure that the membrane surface will meet the required coefficient of friction.

The gap between the MSE wall and the NI wall is sealed to prevent water intrusion.

3.8.5.2 Applicable Codes, Standards, and Specifications

The applicable codes, standards, and specifications are described in Subsection 3.8.4.2.

3.8.5.3 Loads and Load Combinations

Loads and load combinations are described in Subsection 3.8.4.3. The loads and load combinations used in the analysis are considered to be part of the method of evaluation. As described in Subsection 3.8.2.1.2, the bottom head of the steel containment vessel is the same as the upper head and is capable of resisting the containment internal pressure without benefit of the nuclear island basemat. However, containment pressure loads affect the nuclear island basemat since the concrete is stiffer than the steel head. The containment design pressure is included in the design of the nuclear island basemat as an accident pressure in load combinations 5, 6, and 7 of Table 3.8.4-2. In addition to the load combinations described in Subsection 3.8.4.3, the nuclear island is checked for resistance against sliding and overturning due to the safe shutdown earthquake, winds and tornados, and against flotation due to floods and groundwater according to the load combinations presented in Table 3.8.5-1.

The effect of the groundwater level has been studied extensively. For the AP1000, Westinghouse has performed a time history analysis using a saturated and unsaturated soft-medium soil profile (Poisson's ratio = 0.35) and compared the floor response spectra of the two analyses. Generic SSI analyses for the AP1000 assume the water table to be at grade level with saturated soil properties supporting the nuclear island. The unsaturated soil profile was produced where the water table was assumed to be well below the nuclear island.

The results of this analysis concluded that the depth of the water table used for SSI analyses has a negligible effect on the floor response spectra at the key nodes. Since the floor response spectra differences between the two models are negligible, no additional analyses are required to compare member forces or deformations.

3.8.5.4 Design and Analysis Procedures

The seismic Category I structures are concrete, shear-wall structures consisting of vertical shear/bearing walls and horizontal floor slabs. The walls carry the vertical loads from the structure to the basemat. Lateral loads are transferred to the walls by the roof and floor slabs. The walls then transmit the loads to the basemat. The walls also provide stiffness to the basemat and distribute the foundation loads between them.

The design of the basemat consists primarily of applying the design loads to the structures, calculating shears and moments in the basemat, and determining the required reinforcement. For a site with hard rock below the underside of the basemat vertical loads are transmitted directly through the basemat into the rock. Horizontal loads due to seismic are distributed on the underside of the basemat resulting primarily in small membrane forces in the mat. The 6-foot-thick basemat is designed for the upward hydrostatic pressure due to groundwater reduced by the downward deadweight of the mat.

[*Seismic loads for the evaluation of the basemat of the Nuclear Island are developed from the results of the global seismic analyses on hard rock. They are specified as equivalent static accelerations.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The equivalent static accelerations used in the non-linear design analyses of the nuclear island basemat are evaluated for the revised design with the enhanced shield building by comparing total base reactions and bearing pressures in a linear analysis using these equivalent static accelerations to those from a dynamic analysis of the nuclear island 3D finite element model. A time history fixed base analysis of the model is performed using time history inputs that envelope the basemat response given by the 3D SASSI analyses at the corners and centers of the basemat for all the specified generic soil cases.]*

The basemat reactions for the equivalent static analyses compare well against those of the “all soils” time history. [*Bearing pressures are calculated from the basemat reactions assuming a rigid basemat for dead, live, and seismic loads. Seismic loads are considered using the 1.0, 0.4, 0.4 combination method.*]* The bearing pressures resulting from the equivalent static accelerations are similar to those due to the “all soils” time history analysis demonstrating the adequacy of the equivalent static accelerations applied in the basemat analyses.

3.8.5.4.1 Analyses for Loads during Operation

The analyses of the basemat use the three-dimensional ANSYS finite element models of the auxiliary building and containment internal structures, which are described in Subsections 3G.2.1.1 and 3G.2.1.2 and shown in Figures 3G.2-1 and 3G.2-2. The model considers the interaction of the basemat with the overlying structures and with the soil. Provisions are made in the model for two possible uplifts. One is the uplift of the containment internal structures from the lower basemat. The other is the uplift of the basemat from the soil.

The three-dimensional finite element model of the basemat includes the structures above the basemat and their effect on the distribution of loads on the basemat. The finite element model of the basemat is shown on sheet 1 of Figure 3.8.5-2.

The subgrade is modeled with one vertical spring and two horizontal springs at each node of the basemat. The vertical springs act in compression only. The horizontal springs are active when the vertical spring is closed and inactive when the vertical spring lifts off. The analyses of the basemat accounted for the range of soil sites described in Section 2.5. Horizontal bearing reactions on the side walls below grade are conservatively neglected.

The nuclear island basemat below the containment vessel, and the containment internal structures basemat above the containment vessel, are simulated with solid tetrahedral elements. Nodes on the two basemats are connected with spring elements normal to the theoretical surface of the containment vessel.

Normal and extreme environmental loads and containment pressure loads are considered in the analysis. The normal loads include dead loads and live loads. Extreme environmental loads include the safe shutdown earthquake.

Dead loads are applied as inertia loads. Live loads and the safe shutdown earthquake loads are applied as concentrated loads on the nodes. The safe shutdown earthquake loads are applied as equivalent static loads using the assumption that while maximum response from one direction occurs, the responses from the other two directions are 40 percent of the maximum. Combinations of the three directions of the safe shutdown earthquake are considered.

Linear analyses are performed for all specified load combinations assuming that the soil springs can take tension. Critical load cases are then selected for non-linear analyses with basemat liftoff based on the results of the linear cases. The results from the analysis include the forces, shears, and moments in the basemat; the bearing pressures under the basemat; and the area of the basemat that

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is uplifted. Reinforcing steel areas are calculated from the member forces for each load combination case.

The required reinforcing steel for the portion of the basemat under the auxiliary building and under the shield building is determined by considering the reinforcement envelope for the full non-linear iteration of the most critical load combination cases. Additional reinforcement is provided in the design of the 6′ mat for soil sites such that the basemat can resist loads 20 percent greater than the demand calculated by the equivalent static acceleration analyses on uniform soil springs. This increase accommodates potential site specific lateral variability of the soil investigated separately in a series of parametric studies. Figure 3.8.5-3 shows the basemat reinforcement.

3.8.5.4.2 Analyses of Settlement During Construction

Construction loads are evaluated in the design of the nuclear island basemat. This evaluation is performed for soil sites meeting the site interface requirements of Subsection 2.5.4 at which settlement is predicted to be maximum. In the expected basemat construction sequence, concrete for the mat is placed in a single placement. Concrete may be placed below the sumps and elevator pits, if determined to enhance constructability, prior to the remaining single pour of the nuclear island basemat. The placement includes the first 6 feet of the thicker basemat below the containment vessel and shield building, but excludes the central zone directly below the bottom of the containment vessel. Construction continues with a portion of the shield building foundation and containment internal structure and the walls of the auxiliary building. The critical location for shear and moment in the basemat is around the perimeter of the shield building. Once the shield building and auxiliary building walls are completed to elevation 82′-6″, the load path changes and loads are resisted by the basemat stiffened by the shear walls.

The analyses account for the construction sequence, the associated time varying load and stiffness of the nuclear island structures, and the resulting settlement time history. To maximize the potential settlement, the analyses consider a 360 feet deep soft soil site with soil properties consistent with the soft soil case described in Subsection 2A.2. Two soil profiles are analyzed to represent limiting foundation conditions, and address both cohesive and cohesionless soils and combinations thereof:

- A soft soil site with alternating layers of sand and clay. The assumptions in this profile maximize the settlement in the early stages of construction and maximize the impact of dewatering.

- A soft soil site with clay. The assumptions maximize the settlement during the later stages of construction and during plant operation.

The analyses focus on the response of the basemat in the early stages of construction when it could be susceptible to differential loading and deformations. As subsequent construction incorporates concrete shear walls associated with the auxiliary building and the shield building, the structural system significantly strengthens, minimizing the impact of differential settlement. The displacements, and the moments and shear forces induced in the basemat are calculated at various stages in the construction sequence. These member forces are evaluated in accordance with ACI 349 using the load factors given in Table 3.8.4-2. Three construction sequences are examined to demonstrate construction flexibility within broad limits.

- A base construction sequence which assumes no unscheduled delays. The site is dewatered and excavated. Concrete for the basemat is placed. Concrete for the exterior walls below grade is placed after the basemat is in place. Exterior and interior walls of the auxiliary building are placed in 16 to 18-foot lifts.

- A delayed shield building case which assumes a delay in the placement of concrete in the shield building while construction continues in the auxiliary building. This bounding case maximizes tension stresses on the top of the basemat. The delayed shield building case assumes that no additional concrete is placed in the shield building after the pedestal for the containment vessel head is constructed. The analysis incorporates construction in the auxiliary building to elevation 117′-6″ and filling the CA20 module with concrete to elevation 135′-3″, and thereafter assumes that construction is suspended.

- A delayed auxiliary building case which assumes a delay in the construction of the auxiliary building while concrete placement for the shield building continues. This bounding case maximizes tension stresses in the bottom of the basemat. There are two construction sequence limitations from this case:

  – The first construction sequence limitation assumes a delayed auxiliary building case in which construction can continue in the shield building to elevation 139′-6″. Shield building construction may proceed up to 139′-6″ with the following requirements and exceptions:

    - Auxiliary building walls must be completed up to an elevation of 82′-6″. Completion of auxiliary building 82′-6″ floors is not required. Completion of module CA20 is not required provided that the steel portions are constructed.

    - Wall N is an exception to the completion of the auxiliary building walls to elevation 82′-6″. This wall does not have to be constructed in order for the shield building to proceed up to 139′-6″.

    - Construction of module CA01 is limited to steel only.

    - No concrete is placed in the SC shield building walls above elevation 131′-6″.

    - Construction in the RC portion of the shield building between AZ 181.98° and AZ 340.00° may proceed to an elevation of 141′-6″ provided that no concrete is placed above elevation 100′-0″.

    - Shield building construction may proceed to an elevation of 149′-6″ between AZ 181.98° and AZ 183.01° to permit installation of the RC/SC connection panel. No concrete is placed in this panel.

    - Containment vessel rings 1 and 2 may be placed.

    - Modules CA02, CA03, CA04, and CA05 may be fully constructed.

  – The second construction sequence limitation assumes the auxiliary building is complete to 82′-6″ excluding floors, and that the concrete has been placed in module CA20 walls to elevation 128′-0″ except for the north end of the east and west walls of the spent fuel pool, which has been placed to elevation 87′-3″. Construction in the shield building may proceed up to elevation 159′-6″, with the following requirements and exceptions:

    - Shield building concrete elevation must remain at or below elevation 149′-6″.

    - Wall N is an exception to the completion of the auxiliary building walls to elevation 82′-6″. This wall does not have to be constructed in order for the shield building concrete to continue to 149′-6″.

    - The containment vessel ring 3 and top head are not placed.

- Module CA01 may be fully constructed.

– Resumption in construction of the shield building above elevation 159′-6″ can proceed once the auxiliary building is completed to elevation 100′-0″, including all walls and 100′-0″ elevation floors.

For the base construction sequence, the largest basemat moments and shears occur at the interface with the shield building before the connections between the auxiliary building and the shield building are credited. Once the shield building and auxiliary building walls are completed to elevation 82′-6″, the load path for successive loads changes and the loads are resisted by the basemat stiffened by the shear walls. Dewatering is discontinued once construction reaches grade, resulting in the rebound of the subsurface.

Of the three construction scenarios analyzed, the delayed auxiliary building case results in the largest demand for the bottom reinforcement in the basemat. The delayed shield building results in the largest demand for the top reinforcement in the basemat. The analyses of the three construction sequences demonstrate the following:

- The design of the basemat and superstructure accommodates the construction-induced stresses considering the construction sequence and the effects of the settlement time history.

- The design of the basemat can accommodate delays in the shield building so long as the auxiliary building construction is suspended at elevation 117′-0″. Resumption in construction of the auxiliary building can proceed once the shield building is advanced to elevation 100′-0″.

- The design of the basemat can accommodate delays in the auxiliary building so long as the shield building construction is suspended at the elevation limits as previously discussed in the delayed auxiliary building case.

- After the structure is in place and cured to elevation 100′-0″, the basemat and structure act as an integral 40 foot deep structure and the loading due to construction above this elevation is not expected to cause significant additional flexural demand with respect to the basemat and the shield building concrete below the containment vessel. Accordingly, there is no need for placing constraints on the construction sequence above elevation 100′-0″.

The site conditions considered in the evaluation provide reasonable bounds on construction induced stresses in the basemat. Accordingly, the basemat design is adequate for practically all soil sites and it can tolerate major variations in the construction sequence without causing excessive deformations, moments and shears due to settlement over the plant life.

The analyses of alternate construction scenarios considered the softest material properties satisfying the shear wave velocity limit of 1000 feet per second. These analyses show that member forces in the basemat are acceptable subject to the limits shown below on the relative level of construction of the buildings. Construction of the AP1000 will satisfy the limits shown below, or a site-specific analysis of settlement and member forces will be completed. These limits do not apply to AP1000 units with a soil profile where the shear wave velocity exceeds 7500 feet per second.

Prior to completion of the shield building at elevation 82′-6″:

- Concrete may not be placed above elevation 117′-6″ in the auxiliary building, except in the CA20 structural module, where it may be placed to elevation 135′-3″.

Member forces in the basemat considering settlement during construction differ from those obtained from the analyses on uniform elastic soil springs described in Subsection 3.8.5.4.1.

Although the bearing pressures at the end of construction are similar in the two analyses, the resulting member forces differ due to the progressive changes in structural configuration during construction. The design using the results of the analyses of Subsection 3.8.5.4.1 provides sufficient structural strength to resist the specified loads including bearing reactions on the underside of the basemat. The member forces in these analyses are those due to primary externally applied loads and do not consider secondary stresses and strains locked in during early stages of construction. A confirmatory evaluation was performed to demonstrate that the member forces due to design basis loads, including locked-in forces due to construction settlement, remain within the capacity of the section. The evaluation was performed for critical locations which were selected as locations where the effect of locked in member forces were judged to be most significant.

The governing scenario is the case with a delay in the auxiliary building construction for the soft soil site with alternating layers of sand and clay. The delay is postulated to occur just prior to the stage where the auxiliary building walls are constructed. Member forces at the end of construction are calculated considering the effects of settlement during construction. The difference in these member forces from those calculated for dead load in the analyses on soil springs are added as additional dead loads in the critical safe shutdown earthquake load combination.

The member forces for the load combination of dead load plus safe shutdown earthquake, including the member forces locked-in during various stages of plant construction, are within the design capacity for the five critical locations. The evaluation demonstrates that the member forces including locked-in forces calculated by elastic analyses remain within the capacity of the section.

3.8.5.4.3 Design Summary Report

A design summary report is prepared for the basemat documenting that the structures meet the acceptance criteria specified in Subsection 3.8.5.5.

Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Sections 3.7 and 3.8 provided the following acceptance criteria are met.

- The structural design meets the acceptance criteria specified in Section 3.8
- The seismic floor response spectra meet the acceptance criteria specified in Subsection 3.7.5.4

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgment to performance of a revised analysis and design. The results of the evaluation will be documented in an as-built summary report.

3.8.5.4.4 Design Summary of Critical Sections

The basemat is designed to meet the acceptance criteria specified in Subsection 3.8.4.5. Two critical portions of the basemat are identified below together with a summary of their design. The boundaries are defined by the walls and column lines which are shown in Figure 3.7.2-12 (sheet 1 of 12). Table 3.8.5-3 shows the reinforcement required and the reinforcement provided for the critical sections.

[*Basemat between column lines 9.1 and 11 and column lines K and L*

This portion of the basemat is designed as a two way slab with the shorter directions spanning a distance of 23´6˝ between the walls on column lines K and L. The slab is continuous with the adjacent slabs to the east and west. The critical loading is the bearing pressure on the underside of the slab due to dead and seismic loads. This establishes the demand for the top flexural reinforcement at mid span and for the bottom flexural and shear reinforcement at the walls. The basemat is designed for the member forces from the analyses]* described in Subsection 3.8.5.4.1. [*The top and bottom reinforcement in the east west direction of span are equal. The reinforcement provided is shown in sheets 1, 2 and 5 of Figure 3.8.5-3. Typical reinforcement details showing use of headed reinforcement for shear reinforcement are shown in Figure 3H.5-3.*

Basemat between column lines 1 and 2 and column lines K-2 and N

This portion of the basemat is designed as a two way slab with the shorter direction spanning a distance of 22´0˝ between the walls on column lines 1 and 2. The slab is continuous with the adjacent slabs to the north and with the exterior wall to the south. The critical loading is the bearing pressure on the underside of the slab due to dead and seismic loads. This establishes the demand for the top flexural reinforcement at mid span and for the bottom flexural and shear reinforcement at wall 2. The basemat is designed for the member forces from the analyses on uniform soil springs]* described in Subsection 3.8.5.4.1. [*The reinforcement provided is shown in sheets 1, 2 and 5 of Figure 3.8.5-3. Typical reinforcement details showing use of headed reinforcement for shear reinforcement are shown in Figure 3H.5-3.*]*

Figure 3.8.5-3 shows minimum design reinforcement for the concrete in the areas defined. This location information does not define the exact length or position of the reinforcement bars. The detailed reinforcement design, including requirements for detailing and concrete cover, is in conformance with ACI-349 requirements for foundations. The reinforcement arrangement implemented may have a greater amount of reinforcement than that shown in the figure. The size and spacing of the reinforcement bars may vary from that shown as long as the reinforcement area provided is equal to or greater than the area for the size and spacing identified in the figure. Incorporation of embedments, drains and other piping, support structures, and other obstructions may result in local variations from the reinforcement arrangement shown. Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Sections 3.7 and 3.8 provided the following acceptance criteria are met.

- The structural design meets the acceptance criteria specified in Section 3.8.
- The amplitude of the seismic floor response spectra does not exceed the design basis floor response spectra by more than 10 percent.

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgment to performance of a revised analysis and design.

3.8.5.5 Structural Criteria

The analysis and design of the foundation for the nuclear island structures are according to ACI-349 with margins of structural safety as specified within it. The limiting conditions for the foundation medium, together with a comparison of actual capacity and estimated structure loads, are described in Section 2.5. The minimum required factors of safety against sliding, overturning, and flotation for the nuclear island structures are given in Table 3.8.5-1.

[*The design and construction of anchors and embedments conform to the procedures and standards of Appendix B to ACI 349-01*]* and are in conformance with the regulatory positions of NRC

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Regulatory Guide 1.199, Revision 0. [*Alternative requirements to ACI 349, Appendix B apply to the anchoring of headed shear reinforcement for the basemat (see Subsection 3.8.4.4.1).*]*

[*The basemat below the auxiliary building is designed for shear in accordance with the following supplemental provisions which are based on requirements for continuous deep flexural members in ACI 349-01. As permitted by paragraph 11.5.5.1 of ACI 349-01, shear reinforcement is not provided when the factored shear force, V_u, is less than one half of the shear strength provided by the concrete, φV_c.*

- *The design for shear is based on 11.1 through 11.5 of ACI 349-01 except that the critical section measured from the face of the support is taken at a distance of 0.15 l_n.*
- *Shear strength, V_n, is not taken greater than $8\sqrt{f_c'}\, b_w d$ when l_n/d is less than 2.*
  – *When l_n/d is between 2 and 5, $V_n = 2/3\ (10 + l_n/d)\ \sqrt{f_c'}\, b_w d$*
- *Minimum vertical shear reinforcement is provided in each bay. The area of vertical shear reinforcement, A_v, is not less than $0.0015\ b_w s$*
  – *Spacing of shear reinforcement, s, based on provisions in Paragraph 11.5.4.1 does not exceed d/2, nor 24 in.*
- *Shear reinforcement required at the critical section is used throughout the span.*

The terms φ, d, l_n, V_c, A_v, b_w, s, and f_c' are defined in ACI 349.]*

3.8.5.5.1 Nuclear Island Maximum Bearing Pressures

The foundation will be demonstrated to be capable of withstanding the bearing demand from the nuclear island as described in Subsection 2.5.4.10.1.

3.8.5.5.2 Flotation

The factor of safety against flotation of the nuclear island is shown in Table 3.8.5-2 and is calculated as follows:

$$\text{F. S.} = \frac{\text{D}}{(\text{F or B})}$$

where:

F.S. = factor of safety against flotation

D = total weight of structures and foundation

F = buoyant force due to the design basis flood

B = buoyant force due to high ground water table

3.8.5.5.3 Sliding

The factor of safety against sliding of the nuclear island during a tornado or a design wind is shown in Table 3.8.5-2 and is calculated as follows:

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

$$F.S. = \frac{F_S}{F_H}$$

where:

F.S. = factor of safety against sliding from tornado or design wind

F_S = shearing or sliding resistance at bottom of basemat

F_H = maximum lateral force due to active soil pressure, including surcharge, and tornado or design wind load

The factor of safety against sliding of the nuclear island during a safe shutdown earthquake is shown in Table 3.8.5-2 and is calculated as follows:

$$F.S. = \frac{F_S}{F_D}$$

where:

F.S. = factor of safety against sliding from a safe shutdown earthquake

F_S = shearing or sliding resistance at bottom of basemat

F_D = seismic force from safe shutdown earthquake

The sliding resistance is based on the friction force developed between the basemat and the foundation with a static coefficient of friction of 0.55. The governing friction value in the soil below the mudmat has an angle of internal friction of 35°. The effect of buoyancy due to the water table is included in calculating the sliding resistance. Passive soil pressure resistance is not included in the equations above because passive pressure is not considered for sliding stability. Since there is no passive pressure considered, active and overburden soil pressures are also not considered.

3.8.5.5.4 Overturning

The factor of safety against overturning of the nuclear island during a tornado or a design wind is shown in Table 3.8.5-2 and is calculated as follows:

$$F.S. = \frac{M_R}{M_O}$$

where:

F.S. = factor of safety against overturning from tornado or design wind

M_R = resisting moment

M_O = overturning moment of tornado or design wind

The factor of safety against overturning of the nuclear island during a safe shutdown earthquake is shown in Table 3.8.5-2 and is evaluated using the time history analysis assuming overturning about the edge of the nuclear island at the bottom of the basemat. The factor of safety is defined as follows:

$$F.S. = (M_R)/(M_O + M_{AO})$$

where:

F.S. = factor of safety against overturning from a safe shutdown earthquake

M_R = nuclear island's resisting moment against overturning

M_O = maximum safe shutdown earthquake induced overturning moment acting on the nuclear island, applied as a static moment

M_{AO} = Moment due to lateral forces caused by active and overburden pressures

The resisting moment is equal to the nuclear island dead weight, minus buoyant force from ground water table, multiplied by the distance from the edge of the nuclear island to its center of gravity. The overturning moment is the maximum moment about the same edge from the time history analyses of the nuclear island NI20 model described in Subsection 3.7.2 and Appendix 3G.2. Resistance moment due to passive pressure is not included in the equation above because passive pressure is not considered for overturning stability.

3.8.5.5.5 Seismic Stability Analysis

The factors of safety for sliding and overturning for the SSE are calculated for each soil case for the base reactions in terms of shear and bending moments about column lines 1, 11, I, and the west side of the shield building at each time step of the seismic time history. The 2D SASSI reactions (Fx, Fy, and Fz) are used to obtain seismic response factors between the hard rock (HR) case to the UBSM soil case, and the SM soil case. These factors are used to adjust the hard rock time history to reflect the seismic response for the other two potential governing soil cases UBSM and SM. The firm rock, soft rock, and soft soil cases have higher factors of safety against sliding and, therefore, are not considered.

A non-linear analysis with sliding friction elements using a 2D ANSYS model was performed. The 2D ANSYS model that was used to study the basemat uplift (see Subsection 3.8.5.5.6 and Appendix 3G.2.2.5). This 2D non-linear model is for the east-west direction. There is no need to consider the north-south direction since the nuclear island deflections calculated to maintain a factor of safety of 1.1 are largest in the east-west direction. This model was modified introducing friction elements along the bottom of the basemat and soil media interface. Direct time integration analysis was performed with vertical uplift and sliding allowed. The three cases that have the lowest factor of safety related to sliding were evaluated. These three cases are HR, UBSM, and SM. The seismic input was increased by 10 percent to maintain the factor of safety against sliding of 1.1. No passive soil resistance is considered. The resulting maximum displacement at the base of the nuclear island basemat (elevation 60.5′) using a coefficient of friction of 0.55 is 0.12 inch without buoyant force consideration, and 0.19 inch with buoyant force considered. This is negligible sliding during the seismic event, and no passive soil resistance is necessary from the backfill (side soil). Therefore, it can be concluded that the nuclear island is stable against sliding.

The minimum seismic stability factors of safety values are reported in Table 3.8.5-2.

3.8.5.5.6 Effect of Nuclear Island Basemat Uplift on Seismic Response

The effects of basemat uplift were evaluated using an east-west lumped-mass stick model of the nuclear island structures supported on a rigid basemat with nonlinear springs (see Appendix 3G.2.2.5). Floor response spectra from safe shutdown earthquake time history analyses, which included basemat uplift, were compared to those from analyses that did not include uplift. The comparisons showed that the effect of basemat uplift on the floor response spectra is not significant.

The design analyses of the nuclear island basemat include consideration of sliding and liftoff between the containment internal structures and the containment vessel and of sliding between the containment vessel and the nuclear island basemat. Analyses of stability demonstrate that there was no uplift or sliding at the interface of the containment internal structures and the containment vessel.

3.8.5.6 Materials, Quality Control, and Special Construction Techniques

The materials and quality control program used in the construction of the nuclear island structures foundation are described in Subsection 3.8.4.6.

There are no special construction techniques used in the construction of the nuclear island structures foundation. Subsection 2.5.4.2 describes information related to the excavation, backfill, and mudmat.

3.8.5.7 In-Service Testing and Inspection Requirements

The inspection program for structures is identified in Section 17.6. This inspection program is consistent with the requirements of 10 CFR 50.65 and the guidance in Regulatory Guide 1.160.

The need for foundation settlement monitoring is site-specific as discussed in Subsection 2.5.4.3.

3.8.5.8 Construction Inspection

Construction inspection is conducted to verify the concrete wall thickness and quantity of concrete reinforcement. The construction inspection includes concrete wall thickness and reinforcement expressed in units of in^2/ft (linear length) equivalent when compared to standard reinforcement bar sections. Inspections will be measured at applicable sections excluding designed openings or penetrations. Inspections will confirm that each section provides the minimum required reinforcement and concrete thickness as shown in Table 3.8.5-3. The minimum required reinforcement and concrete thickness represent the required minimum values to meet the design basis loads. Table 3.8.5-3 also indicates the reinforcement provided which may exceed the required minimum reinforcement for the following reasons:

- Structural margin
- Ease of construction
- Use of standardized reinforcement sizes and spacing

3.8.6 Combined License Information

3.8.6.1 Containment Vessel Design Adjacent to Large Penetrations

The final design of containment vessel elements (reinforcement) adjacent to concentrated masses (penetrations) is addressed in APP-GW-GLR-005 (Reference 53), and the applicable changes are incorporated into the UFSAR.

3.8.6.2 Passive Containment Cooling System Water Storage Tank Examination

Not used.

3.8.6.3 As-Built Summary Report

Not used.

3.8.6.4 In-Service Inspection of Containment Vessel

Not used.

3.8.6.5 Structures Inspection Program

The structures inspection program to address maintenance requirements for the seismic Category I and seismic Category II structures is addressed in Subsections 3.8.3.7, 3.8.4.7, 3.8.5.7, and 17.6.

3.8.6.6 Construction Procedures Program

Construction and inspection procedures for concrete filled steel plate modules address activities before and after concrete placement, use of construction mock-ups, and inspection of modules before and after concrete placement as discussed in Subsection 3.8.4.8. The procedures will be made available to NRC inspectors prior to use.

3.8.7 References

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Table 3.8.2-1
Load Combinations and Service Limits for Containment Vessel

Load Description		Load Combination and Service Limit										
		Con	**Test**	**Des.**	**Des.**	**A**	**A**	**A**	**C**	**D**	**C**	**D**
Dead	D	x	x	x	x	x	x	x	x	x	x	x
Live	L	x	x	x	x	x	x	x	x	x	x	x
Wind(5)	W	x						x				
Safe shutdown earthquake	E_s								x	x		x
Tornado	W_t										x	
Test pressure	P_t		x									
Test temperature	T_t		x									
Operating pressure	P_o							x			x	
Design pressure	P_d			x			x		x			x
Design external pressure	P_e				x	x				x		
Normal reaction	R_o				x	x		x		x	x	
Normal thermal(4)	T_o				x	x		(3)		x	(3)	
Accident thermal reactions	R_a			x			x		x			x
Accident thermal	T_a			x			x		x			x
Accident pipe reactions	Y_r											x
Jet impingement	Y_j											x
Pipe impact	Y_m											x

Notes:

1. Service limit levels are per ASME-NE.
2. Where any load reduces the effects of other loads, that load is to be taken as zero, unless it can be demonstrated that the load is always present or occurs simultaneously with the other loads.
3. Temperature of vessel is 70°F.
4. Temperature distribution for normal operation in cold weather.
5. Wind load for the construction load combination is based on a 70 mph wind. Wind load for the Service Level A load combination is analyzed as a reduction in external pressure.

Table 3.8.2-2
Containment Vessel Pressure Capabilities

Containment Element		Pressure Capability				
		Deterministic Severe Accident Capacity[1]			Maximum Pressure Capability[2]	
Temperature		100°F	300°F	400°F	100°F	400°F
Cylinder		135 psig	117 psig	112 psig	155 psig	129 psig
Ellipsoidal Head		104 psig	91 psig	87 psig	174 psig	144 psig
16-foot equipment hatch	F.S. = 1.67	126 psig	121 psig	118 psig	210 psig	198 psig
	F.S. = 2.50	84 psig	81 psig	79 psig		
Personnel airlocks[3]		>163 psig	>163 psig	>163 psig	>300 psig	>300 psig

Notes:

1. The buckling capacity of the ellipsoidal head is taken as 60 percent of the critical buckling pressure calculated by the BOSOR-5 nonlinear analyses; the buckling capacity at higher temperatures is calculated by reducing the capacity at 100°F by the ratio of yield at 100°F to yield at the higher temperature. Evaluations of the equipment hatch covers are shown both for ASME paragraph NE-3222 (F.S. = 2.50) and Code Case N-284 (F.S. = 1.67). Evaluations of the other elements are according to ASME Service Level C.
2. The estimated maximum pressure capability is based on minimum specified material properties.
3. The capacities of the personnel airlocks are estimated from test results.

Table 3.8.2-3
Analysis and Test Results of Fabricated Heads
(Reference 23)

	Test Model #1	Test Model #2
Cylinder radius	96.0 inches	96.0 inches
Knuckle radius	32.64 inches	32.64 inches
Spherical radius	172.8 inches	172.8 inches
Thickness	0.196 inches	0.27 inches
Head height/radius	0.5	0.5
Radius/thickness	490	356
Test initial buckling pressure	58 psig	106 psig
Test collapse pressure	229 psig	332 psig
Collapse pressure/initial buckling pressure	3.95	3.13
BOSOR-5 predicted buckling pressure	73.6 psig	106.6 psig

Table 3.8.2-4
Summary of Containment Vessel Models and Analysis Methods

Model	Analysis Method	Program	Purpose
Axisymmetric shell	Modal analysis	ANSYS	To calculate frequencies and mode shapes for comparison against stick model
Lumped mass stick model	Modal analysis	ANSYS	To create equivalent stick model for use in nuclear island seismic analyses
Axisymmetric shell	Static analyses using Fourier harmonic loads	ANSYS	To calculate containment vessel shell stresses
Axisymmetric shell	Nonlinear bifurcation	BOSOR5	To calculate buckling capacity close to base under thermal loads To calculate pressure capacity of top head
Finite element shell	Linear bifurcation	ANSYS	To study local effect of large penetrations and embedment on buckling capacity for axial and external pressure loads
Finite element shell	Modal analysis	ANSYS	To calculate frequencies and mode shapes for local effects of equipment hatches and personnel airlocks
Finite element shell	Static analyses	ANSYS	To calculate local shell stress in vicinity of the equipment hatches and personnel airlocks

Table 3.8.2-5
Maximum Absolute Nodal Acceleration (ZPA)
Steel Containment Vessel

Hard Rock Site Condition

Elevation (ft)	Maximum Absolute Nodal Acceleration, ZPA (g)					
	N-S Direction		E-W Direction		Vertical Direction	
	Mass Center	Edge	Mass Center	Edge	Mass Center	Edge
281.90	1.48		1.56		1.25	
273.83	1.43		1.50		1.02	
265.83	1.38		1.43		0.85	
255.02	1.31		1.34		0.73	
244.21	1.23	1.28	1.26	1.30	0.68	0.71
224.00	1.09	1.13	1.11	1.17	0.66	0.68
200.00	0.90	0.94	0.94	0.98	0.61	0.63
169.93	0.69	0.71	0.72	0.75	0.53	0.55
162.00	0.63	0.65	0.67	0.68	0.51	0.53
141.50	0.49	0.50	0.54	0.54	0.45	0.47
131.68	0.43	0.44	0.47	0.48	0.41	0.44
112.50	0.40	0.41	0.37	0.38	0.35	0.40
104.12	0.38	0.40	0.38	0.40	0.32	0.38
100.00	0.38	0.40	0.39	0.41	0.31	0.34

Notes:

1. Enveloped response results at the north, south, east, and west edge nodes of the structure are shown. This is the maximum value of the response at any of these edge nodes.
2. Elevation 236'-6" is the mid-height of the polar crane bridge.

Table 3.8.3-1
Shear and Flexural Stiffnesses of Structural Module Walls

Case	Analysis Assumption	Shear Stiffness[1],[2]				Flexural Stiffness[1],[2]			
		48" Wall		30" Wall		48" Wall		30" Wall	
		GA x 10^6 lbs	Ratio	GA x 10^6 lbs	Ratio	EI x 10^9 lbs. in^2	Ratio	EI x 10^9 lbs. in^2	Ratio
1	Monolithic section considering steel plates and uncracked concrete. For shear stiffness this is (A_c G_c + A_s G_s).	83.5	1.0	55.8	1.0	47.5	1.0	13.6	1.0
2	Uncracked gross concrete section (full wall thickness considering steel plate as concrete)	73.9	0.89	46.2	0.83	33.2	0.70	8.1	0.60
3	Transformed cracked section considering steel plates and concrete (no concrete tension stiffness)	25.0	0.30	22.6	0.41	22.1	0.47	8.0	0.59

Notes:
1. The shear stiffness, GA, is calculated for the full thickness of wall. The flexural stiffness is calculated per unit length of the wall.
2. Stiffness calculations are based on the following material properties: E_c = 3,605,000 psi,n = 8, v_c = 0.17, v_s = 0.30

Table 3.8.3-2
Summary of Containment Internal Structures Models and Analysis Methods

Computer Program and Model	Analysis Method	Purpose	Concrete Stiffness (1)
3D ANSYS finite element of containment internal structures	Static	To obtain the in-plane and out-of-plane mechanical forces for the design of floors and walls (dead, live, hydrostatic, pressure)	Monolithic Case 1 with E_c reduced by factor of 0.8
3D ANSYS finite element of containment internal structures	Response spectra analyses(2)	To obtain the in-plane and out-of-plane seismic forces for the design of floors and walls	Monolithic Case 1 with E_c reduced by factor of 0.8.
3D ANSYS finite element of containment internal structures	Static analyses	To obtain the in-plane and out-of-plane member forces for thermal loads	Cracked Case 3
The following AP600 analyses are used as background to develop the AP1000 design loads.			
3D ANSYS finite element of containment internal structures fixed at elevation 103′-0″	Harmonic analyses	To evaluate natural frequencies potentially excited by hydrodynamic loads	Uncracked Case 2
	Time history analyses	To obtain dynamic response of IRWST boundary for hydrodynamic loads	Monolithic and cracked Cases 1 & 3

Note:
1. See Table 3.8.3-1 for stiffness case description.
2. See Section 3.7 for discussion of the containment internal structures seismic analyses.

Table 3.8.3-3
Definition of Critical Locations and Thicknesses for Containment Internal Structures(1)(4)

Wall Description (see detail in subsection 3.8.3.5.8.1)	Applicable Column Lines	Applicable Elevation Range	[*Concrete Thickness*(2)]*	Required Thickness of Surface Plates (inches)(3)	[*Thickness of Surface Plates Provided (inches)*]*
Containment Structures					
Module Wall 1	Southwest wall of refueling cavity	Wall separating IRWST and refueling cavity from elevation 103′ to 135′-3″	[*4′-0″ concrete-filled structural wall module with 0.5-in.-thick steel plate on inside and outside of wall*]*	0.12	[*0.5 -0.01 +0.1*]*
Module Wall 2	South wall of west steam generator compartment	Wall separating IRWST and west steam generator compartment from elevation 103′ to 135′-3″	[*2′-6″ concrete-filled structural wall module with 0.5-in.-thick steel plate on inside and outside of wall*]*	0.43	[*0.5 -0.01 +0.1*]*
CA02 Module Wall	North east boundary wall of IRWST	Wall separating IRWST and maintenance floor from elevation 103′ to 135′-3″	[*2′-6″ concrete-filled structural wall module with 0.5-in.-thick steel plate on inside and outside of wall*]*	0.36	[*0.5 -0.01 +0.1*]*

Notes:

1. The applicable column lines and elevation levels are identified and included in Figures 1.2-9, 3.7.2-12 (sheets 1 through 12), 3.7.2-19 (sheets 1 through 3) and on Table 1.2-1.

[*2. The concrete thickness includes the steel face plates. Thickness greater than 3'-0" have a construction tolerance of +1", -3/4". Thickness less than or equal to 3'-0" have a construction tolerance of +1/2", -3/8".*]*

3. These plate thicknesses represent the thickness required for operating and design basis loads except for designed openings or penetrations. These values apply for each face of the applicable wall unless specifically indicated on the table. For load combinations with thermal loads, the evaluation is performed as described in Subsection 3.8.3.5.3.4.

[*4. As described in subsection 3.8.3.1.3, some CA01 and CA05 module wall faceplate thicknesses are greater than the 0.5-inch nominal faceplate thicknesses.*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-4 (Sheet 1 of 3)
Design Summary of Southwest Wall of Refueling Cavity Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Mid-Height

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	1	-20	1	1	1	0	0	0	–
Hydro (F)	2	0	1	24	30	-2	0	0	–
Live (L)	0	-7	0	3	2	0	0	1	During refueling
Live (L_o)	0	-2	0	1	1	0	0	0	During operation
ADS	2	7	6	19	19	-4	0	1	–
E_s	13	49	56	41	40	15	1	8	During operation
Thermal (T_0)	-74	-34	-47	141	113	0	4	-1	During operation
LC (1)	8	-18	14	70	76	-8	0	3	[*1.4D+1.4F+1.7L_o+1.7ADS*]*
LC (2)	5	-40	3	41	46	-2	0	2	[*1.4D+1.4F+1.7L_r*]*
LC (3)	8	-15	14	69	76	-8	0	3	[*1.4D+1.4F+1.7ADS*]*
LC (4)	18	35	65	87	90	17	1	10	[*D+F+L_o +|ADS|+E_s*]*
LC (5)	-12	-78	-60	-34	-28	-20	-1	-8	[*D+F+L_o -|ADS|- E_s*]*
LC (6)	-56	0	18	228	203	17	5	9	[*D+F+L_o +|ADS|+T_0+E_s*]*
LC (7)	-86	-112	-108	107	85	-19	3	-9	[*D+F+L_o -|ADS|+T_0-E_s*]*
LC (8)	18	39	65	86	90	17	1	10	[*0.9D+1.0F+1.0|ADS|+1.0E_s*]*

Notes:

x-direction is horizontal; y-direction is vertical.

Element number 101870

Plate thickness required for load combinations excluding thermal: 0.12 inches (Maximum)

[*Plate thickness provided:* *0.50 inches -0.01 +0.10*

As described in subsection 3.8.3.1.3, some CA01 and CA05 module wall faceplate thicknesses are greater than the 0.5-inch nominal faceplate thickness.]*

Maximum principal stress for load combinations including thermal: 12.9 ksi

[*Yield stress at temperature:* *65.0 ksi (Minimum)*]*

Maximum stress intensity range for load combinations including thermal: 19.6 ksi

Allowable stress intensity range for load combinations including thermal: 130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-4 (Sheet 2 of 3)
Design Summary of Southwest Wall of Refueling Cavity Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Base

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	-1	-31	1	-1	-4	0	0	1	–
Hydro (F)	3	1	2	-2	-41	-1	-1	17	–
Live (L)	-1	-6	0	0	-3	0	0	1	During refueling
Live (L_o)	0	-2	0	0	-1	0	0	0	During operation
ADS	2	6	7	-2	-32	-1	-1	10	–
E_s	11	55	65	12	87	3	3	18	During operation
Thermal (T_0)	-189	-31	-76	165	86	-2	-5	0	During operation
LC (1)	7	-35	16	-8	118	-3	-3	41	[*1.4D+1.4F+1.7L_o+1.7ADS*]*
LC (2)	2	-53	5	-5	-68	-2	-1	25	[*1.4D+1.4F+1.7L_r*]*
LC (3)	7	-32	16	-8	117	-3	-3	41	[*1.4D+1.4F+1.7ADS*]*
LC (4)	15	29	75	11	73	3	4	45	[*D+F+L_o +|ADS|+E_s*]*
LC (5)	-11	-93	-68	-17	165	-6	-5	-10	[*D+F+L_o -|ADS|- E_s*]*
LC (6)	-174	-2	-1	175	160	1	-1	44	[*D+F+L_o +|ADS|+T_0+E_s*]*
LC (7)	-200	124	144	147	78	-8	-10	-11	[*D+F+L_o -|ADS|+T_0-E_s*]*
LC (8)	16	34	74	11	74	3	4	45	[*0.9D+1.0F+1.0|ADS|+1.0E_s*]*

Notes:

x-direction is horizontal; y-direction is vertical.

Element number 101788

Plate thickness required for load combinations excluding thermal: 0.09 inches (Maximum)

[*Plate thickness provided:* *0.50 inches -0.01 +0.10*

As described in subsection 3.8.3.1.3, some CA01 and CA05 module wall faceplate thicknesses are greater than the 0.5-inch nominal faceplate thickness.]*

Maximum principal stress for load combinations including thermal: 15.5 ksi

[*Yield stress at temperature:* *65.0 ksi (Minimum)*]*

Maximum stress intensity range for load combinations including thermal: 24.8 ksi

Allowable stress intensity range for load combinations including thermal: 130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-4 (Sheet 3 of 3)
Design Summary of Southwest Wall of Refueling Cavity Design Loads, Load Combinations, and Comparison to Acceptance Criteria North End Bottom Corner

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	-2	-29	-7	0	-3	0	0	0	–
Hydro (F)	3	1	4	-10	-16	4	1	3	–
Live (L)	-1	-4	0	0	-1	0	0	0	During refueling
Live (L_o)	0	-1	0	0	0	0	0	0	During operation
ADS	3	-2	7	-7	-18	2	1	2	–
E_s	23	43	64	14	68	6	6	7	During operation
Thermal (T_0)	-173	-88	-42	138	94	-15	-30	13	During operation
LC (1)	6	-44	8	-27	-57	8	4	7	[*1.4D+1.4F+1.7L_o+1.7ADS*]*
LC (2)	0	-46	-4	-16	-28	5	3	4	[*1.4D+1.4F+1.7L_r*]*
LC (3)	6	-42	9	-27	-57	8	4	7	[*1.4D+1.4F+1.7ADS*]*
LC (4)	26	16	68	10	66	11	9	11	[*D+F+L_o +|ADS|+E_s*]*
LC (5)	-25	-74	-74	-32	-104	-4	-6	-5	[*D+F+L_o -|ADS|- E_s*]*
LC (6)	-147	-73	26	148	160	-4	-21	25	[*D+F+L_o +|ADS|+T_0+E_s*]*
LC (7)	-198	-162	-116	106	-11	-20	-36	8	[*D+F+L_o -|ADS|+T_0-E_s*]*
LC (8)	26	19	69	11	67	11	9	11	[*0.9D+1.0F+1.0|ADS|+1.0E_s*]*

Notes:

x-direction is horizontal; y-direction is vertical.

Element number 101794

Plate thickness required for load combinations excluding thermal: 0.09 inches (Maximum)

[*Plate thickness provided:* *0.50 inches -0.01 +0.10*

As described in subsection 3.8.3.1.3, some CA01 and CA05 module wall faceplate thicknesses are greater than the 0.5-inch nominal faceplate thickness.]*

Maximum principal stress for load combinations including thermal: 11.1 ksi

[*Yield stress at temperature:* *65.0 ksi (Minimum)*]*

Maximum stress intensity range for load combinations including thermal: 21.3 ksi

Allowable stress intensity range for load combinations including thermal: 130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-5 (Sheet 1 of 3)
Design Summary of South Wall of West Steam Generator Compartment Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Mid-Height

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	-1	-23	0	1	1	0	0	0	–
Hydro (F_o)	-2	3	-5	20	22	0	0	-1	–
Live (L)	0	-7	-1	1	0	0	0	0	During refueling
Live (L_o)	0	-2	0	0	0	0	0	0	During operation
ADS	-1	9	-10	17	16	-1	0	1	–
E_s	7	65	58	30	26	5	1	4	During operation
Thermal (T_0)	-42	-53	19	69	59	2	-1	-1	During operation
LC (1)	-5	-17	-24	59	59	-2	1	0	[*1.4D+1.4F+1.7L_o+1.7ADS*]*
LC (2)	-4	-39	-7	32	32	-1	1	-1	[*1.4D+1.4F+1.7L_r*]*
LC (3)	-5	-13	-24	59	59	-2	1	0	[*1.4D+1.4F+1.7ADS*]*
LC (4)	6	52	64	69	65	5	2	4	[*D+F+L_o +|ADS|+E_s*]*
LC (5)	-11	-96	-73	-26	-19	-6	-1	-6	[*D+F+L_o -|ADS|- E_s*]*
LC (6)	-36	-1	83	138	124	8	1	3	[*D+F+L_o +|ADS|+T_0+E_s*]*
LC (7)	-53	-149	-54	43	41	-4	-2	-7	[*D+F+L_o -|ADS|+T_0-E_s*]*
LC (8)	6	56	64	68	64	5	2	4	[*0.9D+1.0F+1.0|ADS|+1.0E_s*]*

Notes:

x-direction is horizontal; y-direction is vertical.

Element number 104228

Plate thickness required for load combinations excluding thermal: 0.15 inches (Maximum)

[*Plate thickness provided:* *0.50 inches -0.01 +0.10*

As described in subsection 3.8.3.1.3, some CA01 and CA05 module wall faceplate thicknesses are greater than the 0.5-inch nominal faceplate thickness.]*

Maximum principal stress for load combinations including thermal: 16.5 ksi

[*Yield stress at temperature:* *36.0 ksi (Minimum)*]*

Maximum stress intensity range for load combinations including thermal: 16.5 ksi

Allowable stress intensity range for load combinations including thermal: 72.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-5 (Sheet 2 of 3)
Design Summary of South Wall of West Steam Generator Compartment Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Base

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	-3	-28	-1	0	2	0	0	0	–
Hydro (F)	3	4	-9	-4	-38	0	0	15	–
Live (L)	-1	-5	-1	0	-1	0	0	0	During refueling
Live (L_o)	0	-2	0	0	0	0	0	0	During operation
ADS	2	10	-10	-3	-30	0	0	9	–
E_s	14	74	52	9	62	1	1	14	During operation
Thermal (T_0)	-136	-13	43	79	65	5	4	-1	During operation
LC (1)	3	-20	-32	-10	-102	-1	-1	36	[*1.4D+1.4F+1.7L_o+1.7ADS*]*
LC (2)	-2	-43	-16	-5	-52	-1	0	21	[*1.4D+1.4F+1.7L_r*]*
LC (3)	4	-17	-32	-10	-102	-1	-1	36	[*1.4D+1.4F+1.7ADS*]*
LC (4)	16	58	52	9	55	1	1	38	[*D+F+L_o +|ADS|+E_s*]*
LC (5)	-17	-110	-73	-16	-128	-2	-2	-8	[*D+F+L_o -|ADS|- E_s*]*
LC (6)	-120	45	95	88	120	6	5	37	[*D+F+L_o +|ADS|+T_0+E_s*]*
LC (7)	-152	-122	-30	63	-63	3	3	-9	[*D+F+L_o -|ADS|+T_0-E_s*]*
LC (8)	16	62	52	9	55	1	1	38	[*0.9D+1.0F+1.0|ADS|+1.0E_s*]*

Notes:

x-direction is horizontal; y-direction is vertical.

Element number 101943

Plate thickness required for load combinations excluding thermal: 0.14 inches (Maximum)

[*Plate thickness provided:* *0.50 inches -0.01 +0.10*

As described in subsection 3.8.3.1.3, some CA01 and CA05 module wall faceplate thicknesses are greater than the 0.5-inch nominal faceplate thickness.]*

Maximum principal stress for load combinations including thermal: 17.6 ksi

[*Yield stress at temperature:* *36.0 ksi (Minimum)*]*

Maximum stress intensity range for load combinations including thermal: 18.7 ksi

Allowable stress intensity range for load combinations including thermal: 72.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-5 (Sheet 3 of 3)
Design Summary of South Wall of West Steam Generator Compartment Design Loads, Load Combinations, and Comparison to Acceptance Criteria West End Bottom Corner

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	-6	-37	3	-1	6	1	-1	-3	–
Hydro (F)	5	14	-10	-6	-14	3	2	4	–
Live (L)	-2	-11	1	0	1	0	0	-1	During refueling
Live (L_o)	-1	-4	0	0	1	0	0	-1	During operation
ADS	9	36	-10	-3	-15	2	2	4	–
E_s	49	248	53	10	72	4	10	31	During operation
Thermal (T_0)	-125	-61	91	26	64	-4	-27	-23	During operation
LC (1)	14	21	-28	-15	-34	9	5	7	[*1.4D+1.4F+1.7L_o+1.7ADS*]*
LC (2)	-4	-52	-8	-10	-8	6	0	-1	[*1.4D+1.4F+1.7L_r*]*
LC (3)	15	27	-28	-15	-35	9	5	8	[*1.4D+1.4F+1.7ADS*]*
LC (4)	57	256	57	6	80	10	13	35	[*D+F+L_o +|ADS|+E_s*]*
LC (5)	-59	-311	-71	-20	-93	-2	-12	-36	[*D+F+L_o -|ADS|- E_s*]*
LC (6)	-67	195	147	32	144	6	-14	13	[*D+F+L_o +|ADS|+T_0+E_s*]*
LC (7)	-184	-372	20	7	-29	-6	-39	-58	[*D+F+L_o -|ADS|+T_0-E_s*]*
LC (8)	59	264	56	6	79	10	14	36	[*0.9D+1.0F+1.0|ADS|+1.0E_s*]*

Notes:

x-direction is horizontal; y-direction is vertical.

Element number 101933

Plate thickness required for load combinations excluding thermal: 0.43 inches (Maximum)

[*Plate thickness provided:* *0.50 inches -0.01 +0.10*

As described in subsection 3.8.3.1.3, some CA01 and CA05 module wall faceplate thicknesses are greater than the 0.5-inch nominal faceplate thickness.]*

Maximum principal stress for load combinations including thermal: 31.9 ksi

[*Yield stress at temperature:* *36.0 ksi (Minimum)*]*

Maximum stress intensity range for load combinations including thermal: 36.0 ksi

Allowable stress intensity range for load combinations including thermal: 72.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-6 (Sheet 1 of 3)
Design Summary of North-East Wall of IRWST Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Mid-Height

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	-1	-18	-1	0	1	-1	-2	-2	–
Hydro (F)	0	1	-1	16	17	3	2	0	–
Live (L)	0	-13	-1	5	5	-1	-2	-1	During refueling
Live (L_o)	0	-4	-1	4	5	-1	-2	-1	During operation
ADS	-2	3	0	16	14	5	2	1	–
E_s	16	42	47	35	39	12	11	16	During operation
Thermal (T_0)	-32	-13	48	49	51	-2	-5	-3	During operation
LC (1)	-5	-26	-3	58	58	8	0	-3	[$1.4D+1.4F+1.7L_o+1.7ADS$]*
LC (2)	-2	-46	-4	30	33	0	-3	-5	[$1.4D+1.4F+1.7L_r$]*
LC (3)	-5	-19	-1	51	48	10	3	-1	[$1.4D+1.4F+1.7ADS$]*
LC (4)	16	24	45	72	76	17	11	14	[$D+F+L_o+\|ADS\|+E_s$]*
LC (5)	-19	-67	-49	-31	-31	-16	-15	-21	[$D+F+L_o-\|ADS\|-E_s$]*
LC (6)	-16	11	93	121	127	15	6	11	[$D+F+L_o+\|ADS\|+T_0+E_s$]*
LC (7)	-51	-80	-1	18	20	-18	-20	-24	[$D+F+L_o-\|ADS\|+T_0-E_s$]*
LC (8)	16	29	46	68	71	18	13	16	[$0.9D+1.0F+1.0\|ADS\|+1.0E_s$]*

Notes:
x-direction is horizontal; y-direction is vertical.
Element number 140027

Plate thickness required for load combinations excluding thermal:	0.13 inches (Maximum)
[*Plate thickness provided:*	*0.50 inches -0.01 +0.10*]*
Maximum principal stress for load combinations including thermal:	18.1 ksi
[*Yield stress at temperature:*	*36.0 ksi (Minimum)*]*
Maximum stress intensity range for load combinations including thermal:	18.1 ksi
Allowable stress intensity range for load combinations including thermal:	72.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-6 (Sheet 2 of 3)
Design Summary of North-East Wall of IRWST Design Loads, Load Combinations, and Comparison to Acceptance Criteria Mid-Span at Bottom-Elevation 107'-2"

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	0	-19	1	0	0	0	0	0	–
Hydro (F)	1	2	-1	2	-8	2	0	11	–
Live (L)	-1	-7	0	0	-3	0	0	1	During refueling
Live (L_o)	-1	-1	0	0	-2	0	0	1	During operation
ADS	0	4	1	2	-7	3	0	8	–
E_s	23	54	47	13	48	8	6	17	During operation
Thermal (T_0)	-92	-58	71	64	63	-1	0	-1	During operation
LC (1)	0	-20	3	7	-27	8	-1	32	[$1.4D+1.4F+1.7L_o+1.7ADS$]*
LC (2)	1	-37	1	3	-16	3	-1	18	[$1.4D+1.4F+1.7L_r$]*
LC (3)	1	-18	3	6	-24	8	0	30	[$1.4D+1.4F+1.7ADS$]*
LC (4)	24	39	49	17	45	13	5	38	[$D+F+L_o+\|ADS\|+E_s$]*
LC (5)	-23	-77	-47	-12	-65	-8	-7	-13	[$D+F+L_o-\|ADS\|-E_s$]*
LC (6)	-68	-18	120	81	108	12	5	37	[$D+F+L_o+\|ADS\|+T_0+E_s$]*
LC (7)	-114	-134	24	52	-2	-9	-7	-14	[$D+F+L_o-\|ADS\|+T_0-E_s$]*
LC (8)	25	42	49	17	47	13	6	37	[$0.9D+1.0F+1.0\|ADS\|+1.0E_s$]*

Notes:
x-direction is horizontal; y-direction is vertical.
Element number 140005

Plate thickness required for load combinations excluding thermal:	0.12 inches (Maximum)
[*Plate thickness provided:*	*0.50 inches -0.01 +0.10*]*
Maximum principal stress for load combinations including thermal:	17.0 ksi
[*Yield stress at temperature:*	*36.0 ksi (Minimum)*]*
Maximum stress intensity range for load combinations including thermal:	21.9 ksi
Allowable stress intensity range for load combinations including thermal:	72.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-6 (Sheet 3 of 3)
Design Summary of North-East Wall of IRWST Design Loads, Load Combinations, and Comparison to Acceptance Criteria
North End Bottom Corner-Elevation 107'-2"

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	-1	-19	1	0	-4	0	0	0	–
Hydro (F)	2	12	6	5	10	12	-7	-11	–
Live (L)	0	-10	1	-1	-4	1	1	1	During refueling
Live (L_o)	0	-3	0	0	-2	1	0	0	During operation
ADS	0	19	7	7	16	11	-5	-11	–
E_s	8	136	38	26	98	17	14	31	During operation
Thermal (T_0)	38	28	60	-39	24	-11	17	34	During operation
LC (1)	2	17	21	16	31	35	-17	-33	[$1.4D+1.4F+1.7L_o+1.7ADS$]*
LC (2)	2	-28	10	4	2	17	-8	-13	[$1.4D+1.4F+1.7L_r$]*
LC (3)	2	21	21	17	35	34	-18	-33	[$1.4D+1.4F+1.7ADS$]*
LC (4)	10	144	52	37	118	40	12	32	[$D+F+L_o+\|ADS\|+E_s$]*
LC (5)	-7	-165	-38	-29	-110	-16	-25	-52	[$D+F+L_o-\|ADS\|-E_s$]*
LC (6)	48	172	111	-2	142	29	29	66	[$D+F+L_o+\|ADS\|+T_0+E_s$]*
LC (7)	31	-137	22	-68	-86	-27	-8	-19	[$D+F+L_o-\|ADS\|+T_0-E_s$]*
LC (8)	10	149	51	37	120	39	12	32	[$0.9D+1.0F+1.0\|ADS\|+1.0E_s$]*

Notes:
x-direction is horizontal; y-direction is vertical.

Element number 140001

Plate thickness required for load combinations excluding thermal:	0.36 inches (Maximum)
[*Plate thickness provided:*	*0.50 inches -0.01 +0.10*]*
Maximum principal stress for load combinations including thermal:	29.5 ksi
[*Yield stress at temperature:*	*36.0 ksi (Minimum)*]*
Maximum stress intensity range for load combinations including thermal:	30.3 ksi
Allowable stress intensity range for load combinations including thermal:	72.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.3-7
Design Summary of Steel Wall of IRWST

Mechanical Loads Only AISC Interaction Ratio				
Section Location and Element Number	**T Section**	**L Section**		**Load Combination**
TYPICAL COLUMN AT MIDDLE OF WALL				
Top	0.15	0.15		*[D+F+L_o -|ADS|- E_s (LC#5)]**
Mid-height	0.30	0.12		*[D+F+L_o -|ADS|- E_s (LC#5)]**
	0.17	0.26		*[D+F+L_o +|ADS|+E_s (LC#4)]**
Bottom	0.22	0.01		*[D+F+L_o -|ADS|- E_s (LC#5)]**
ENVELOPE OF ALL LOCATIONS AND LOAD COMBINATIONS				
	0.47	0.64		*[D+F+ADS (LC#3)]**
Mechanical Plus Thermal Loads Ratio of Stress to AISC or ASME (2 * Sy = 105.6 ksi at T_0 = 260 F)[2]				
Section Location and Element Number	**Flange of T Section**	**Flange of L Section**	**Plate**	**Load Combination**
TYPICAL COLUMN AT MIDDLE OF WALL				
Top	0.17 AISC	0.16 AISC	0.28 AISC	*[D+F+L_o -|ADS|+T_0-E_s (LC#7)]**
	0.10 AISC	0.34 AISC	0.17 AISC	*[D+F+L_o +|ADS|+T_0+E_s (LC#6)]**
Mid-height	0.52 AISC	0.24 AISC	0.34 AISC	*[D+F+L_o -|ADS|+T_0-E_s (LC#7)]**
Bottom	0.27 ASME	0.32 AISC	0.44 AISC	*[D+F+L_o +|ADS|+T_0+E_s (LC#6)]**
	0.15 AISC	0.52 AISC	0.64 AISC	*[D+F+L_o -|ADS|+T_0-E_s (LC#7)]**
ENVELOPE OF ALL LOCATIONS AND LOAD COMBINATIONS				
–	0.67 ASME	0.50 ASME	0.84[2] ASME	*[D+F+L_o +|ADS|+T_0+E_s (LC#6)]**

Notes:

1. Results of the evaluation of mechanical and thermal loads are shown against the AISC allowables when the stresses are less than yield. Portions of the steel wall at the end of the wall exceed yield due to the restraint provided by the adjacent concrete. These areas are evaluated against the ASME allowables as described in Subsection 3.8.3.5.3.4.
2. T_0 = 260 F ADS2 event per Subsection 3.8.3.3.1.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.4-1
[*LOAD COMBINATIONS AND LOAD FACTORS FOR SEISMIC CATEGORY I STEEL STRUCTURES*]*

Combination No.		Load Combination and Factors								
		1	2	3	4	5	6	7	8	9
Load Description										
Dead	D	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Liquid	F	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Live	L	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Earth pressure	H	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Normal reaction	R_o	1.0	1.0	1.0	1.0				1.0	1.0
Normal thermal	T_o			1.0	1.0				1.0	1.0
Wind	W		1.0							1.0
Safe shutdown earthquake	E_S			1.0				1.0		
Tornado	W_t				1.0					
Accident pressure	P_a					1.0	1.0	1.0		
Accident thermal	T_a					1.0	1.0	1.0		
Accident thermal reactions	R_a					1.0	1.0	1.0		
Accident pipe reactions	Y_r						1.0	1.0		
Jet impingement	Y_j						1.0	1.0		
Pipe impact	Y_m						1.0	1.0		
Stress Limit Coefficient [1],[3] (except for compression)		1.0	1.0	1.6	1.6	1.6	1.6	1.7	1.5	1.5
(for compression)		1.0	1.0	1.4	1.4	1.4	1.4	1.6	1.3	1.3

Notes:

1. *Allowable stress limits coefficients are applied to the basic stress allowables of AISI or AISC. The coefficients for ANSI/AISC N690 are supplemented by the requirements identified in subsection 3.8.4.5.*
2. *Where any load reduces the effects of other loads, the coefficient for that load is taken as zero unless it can be demonstrated that the load is always present or occurs simultaneously with the other loads.*
3. *In no instance does the allowable stress exceed $0.7F_u$ in axial tension nor $0.7F_u$ times the ratio of the plastic to elastic section modulus for tension plus bending.*
4. *Loads due to maximum precipitation are evaluated using load combination 4 with the maximum precipitation in place of the tornado load.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.4-2
[*LOAD COMBINATIONS AND LOAD FACTORS FOR SEISMIC CATEGORY I CONCRETE STRUCTURES*]*

Load Combination and Factors												
Combination No.		***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***
Dead	D	*1.4*	*1.4*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.05*	*1.05*	*1.4*	*1.0*
Liquid	F	*1.4*	*1.4*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.05*	*1.05*	*1.4*	*1.0*
Live	L	*1.7*	*1.7*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.3*	*1.3*	*1.7*	*1.0*
Earth	H	*1.7*	*1.7*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.3*	*1.3*	*1.7*	*1.0*
Design Pressure	P_d										*1.5*	*1.0*
Normal reaction	R_o	*1.7*	*1.7*	*1.0*	*1.0*				*1.3*	*1.3*	*1.7*	*1.0*
Normal thermal	T_o			*1.0*	*1.0*				*1.2*	*1.2*		
Wind	W		*1.7*							*1.3*		
Safe shutdown earthquake	E_s			*1.0*				*1.0*				*1.0*
Tornado	W_t				*1.0*							
Accident pressure	P_a					*1.4*	*1.25*	*1.0*				
Accident thermal	T_a					*1.0*	*1.0*	*1.0*				
Accident thermal reactions	R_a					*1.0*	*1.0*	*1.0*				
Accident pipe reactions	Y_r						*1.0*	*1.0*				
Jet impingement	Y_j						*1.0*	*1.0*				
Pipe impact	Y_m						*1.0*	*1.0*				

Notes:

1. *Design for mechanical loads is in accordance with ACI-349 Strength Design Method for all load combinations. Design for combinations including thermal loads is described in subsection 3.8.3.5.3.4. Shield building design for combinations including thermal loads is described in subsection 3.8.4.5.5.4.*
2. *Where any load reduces the effects of other loads, the corresponding coefficient for that load is taken as 0.9 if it can be demonstrated that the load is always present or occurs simultaneously with the other loads. Otherwise the coefficient for the load is taken as zero.*
3. *Loads due to maximum precipitation are evaluated using load combination 4 with the maximum precipitation in place of the tornado load.*
4. *Load combinations 10 and 11 are applicable to nuclear island basemat design only. P_d, the containment design pressure, is 59 psig.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8.4-3
Acceptance Tests for Concrete Aggregates

Method of Test	Designation
Organic impurities in sand	ASTM C 40
Effect of organic impurities on strength of mortar	ASTM C 87
Soundness of aggregates	ASTM C 88
Material finer than No. 200 sieve	ASTM C 117
Specific gravity and absorption - coarse aggregates	ASTM C 127
Specific gravity and absorption - fine aggregates	ASTM C 128
Los Angeles abrasion of small-size coarse aggregates	ASTM C 131
Sieve analysis	ASTM C 136
Friable particles	ASTM C 142
Potential reactivity of aggregates (chemical)	ASTM C 289
Petrographic examination of aggregates	ASTM C 295
Resistance to degradation of large-size coarse aggregates by abrasion and impact in the Los Angeles machine	ASTM C 535
Potential alkali reactivity of carbonate rocks for concrete aggregates	ASTM C 586
Resistance of concrete to rapid freezing and thawing	ASTM C 666
Flat and elongated particles	ASTM D4791

Table 3.8.4-4
Criteria for Water Used in Production of Concrete

Requirements and Test Method	Criteria
Compressive strength ASTM C 109	Reduction in strength not in excess of 10 percent
Soundness ASTM C 151	Increase in length limited to 0.10 percent
Time of setting ASTM C 191	± 10 min for initial set, ± 1 hour for final set

Table 3.8.4-5
Not Used

Table 3.8.4-6 (Sheet 1 of 2)
Materials Used in Structural and Miscellaneous Steel

Standard	Construction Material
ASTM A1	Carbon steel rails
ASTM A36/A36M	Rolled shapes, plates, and bars
ASTM A53	Welded and Seamless Steel Pipe, Grade B
ASTM A106	Seamless Carbon Steel Pipe For High Temperature Service
ASTM A108	Weld studs
ASTM A123	Zinc coatings (hot galvanized)
ASTM A167	Stainless and Heat-Resisting Chromium Nickel Steel Plate, Sheet and Strip
ASTM A193	Alloy Steel and Stainless Steel Bolting Materials for High-Temperature Service
ASTM A194	Carbon and Alloy Steel Nuts for Bolts for High-Pressure or High-Temperature Service, or Both
ASTM A240	Duplex 2101 stainless steel (designation S32101)
ASTM A242	High-strength low alloy structural steel
ASTM A276	Stainless and Heat-Resisting Steel Bars and Shapes
ASTM A307	Low carbon steel bolts
ASTM A312	Seamless and Welded Austenitic Stainless Steel Pipe
ASTM A325	High strength bolts
ASTM A354	Quenched and tempered alloy steel bolts (Grade BC)
ASTM A441	High-strength low alloy structural manganese vanadium steel
ASTM A490	Structural Bolts, Alloy Steel, Heat Treated, 150 ksi Minimum Tensile Strength
ASTM A496	High strength deformed wire
ASTM A500	Cold-Formed Welded and Seamless Carbon Steel Structural Tubing in Rounds and Shapes
ASTM A501	Hot-Formed Welded and Seamless Carbon Steel Structural Tubing
ASTM A505	Standard Specification for Steel, Sheet and Strip, Alloy, Hot-Rolled and Cold-Rolled
ASTM A514	High-Yield Strength Quenched and Tempered Alloy Steel Plate, Suitable for Welding
ASTM A517	Standard Specification for Pressure Vessel Plates, Alloy Steel, High-Strength, Quenched and Tempered
ASTM A540	Alloy Steel Bolting for Special Applications

Table 3.8.4-6 (Sheet 2 of 2)
Materials Used in Structural and Miscellaneous Steel

Standard	Construction Material
ASTM A564	Hot-Rolled and Cold-Finished, Age-Hardening Stainless and Heat-Resisting Steel Bars and Shapes
ASTM A570	Hot-Rolled Carbon Steel Sheets and Strip, Structural Quality, Grades C, D, and E
ASTM A572	High-strength low alloy structural steel
ASTM A588	High-strength low alloy structural steel
ASTM A607	Steel Sheet and Strip, Hot-Rolled and Cold-Rolled, High-Strength, Low Alloy, Columbium, and/or Vanadium
ASTM A615	Deformed and Plain Billet Steel Bars for Concrete Reinforcement
ASTM A618	Hot-Formed Welded and Seamless High-Strength Low Alloy Structural Tubing
ASTM A706	Low Alloy Steel Deformed Bars for Concrete Reinforcement
ASTM A970	Headed Steel Bars for Concrete Reinforcement
ASTM A992	Rolled shapes, plates, and bars
ASTM-F1554	Steel anchor bolts, 36, 55, and 105-ksi yield strength

Table 3.8.5-1
Minimum Required Factor of Safety
for Overturning and Sliding of Structures

Load Combination	Overturning	Sliding	Flotation
D + H + B + W	1.5	1.5	-
D + H + B + E_s	1.1	1.1	-
D + H + B + W_t	1.1	1.1	-
D + F	-	-	1.1
D + B	-	-	1.5

where:

D	=	dead load excluding the fluid loads
H	=	lateral earth pressure
W	=	wind load
E_s	=	safe shutdown earthquake load
W_t	=	tornado load
F	=	buoyant force due to the design basis flood
B	=	buoyant force on submerged structure due to high ground water table

Table 3.8.5-2
Factors of Safety for Flotation, Overturning and Sliding of Nuclear Island Structures

Environmental Effect	Factor of Safety[1]
Flotation	
High Ground Water Table	3.7
Design Basis Flood	3.5
Sliding	
Design Wind, North-South	14.0
Design Wind, East-West	10.1
Design Basis Tornado, North-South	7.7
Design Basis Tornado, East-West	5.9
Safe Shutdown Earthquake, North-South	1.1[2]
Safe Shutdown Earthquake, East-West	1.1[2]
Overturning	
Design Wind, North-South	51.5
Design Wind, East-West	27.9
Design Basis Tornado, North-South	17.7
Design Basis Tornado, East-West	9.6
Safe Shutdown Earthquake, North-South	1.77
Safe Shutdown Earthquake, East-West	1.17

Notes:
1. Factor of safety is calculated for the envelope of the soil and rock sites described in Subsection 3.7.1.4.
2. From non-linear sliding analysis using friction elements, the horizontal movement is negligible (0.12 inch without buoyant force consideration, and 0.19 inch with buoyant force considered).

Table 3.8.5-3
Definition of Critical Locations, Thicknesses and Reinforcement for Nuclear Island Basemat(1) (in^2/ft)

Basemat Segment (see detail in subsection 3.8.5.4.4)	Location	Required(3)			[*Provided (Minimum)*(4)]*		
		North-South	East-West	Shear	*North-South*	*East-West*	*Shear*
Auxiliary Building Basemat Elevation 66′ 6″							
Column line K to L and from Shield Building to Col. Line 11(2)(6)							
	Top Face	Note 5	Note 5		[2.25	*2.25*	
	Bottom Face	Note 5	1.85		*2.25*	*2.25*	
				0.24			*0.25*]*
Column line 1 to 2 and from Column Line K-2 to N wall(2)							
General area	Top Face	Note 5	Note 5		[*2.25*	*2.25*	
Central zone	Top Face	3.11	Note 5		*3.25*	*2.25*	
	Bottom Face	Note 5	1.85		*2.25*	*2.25*	
				0.47			*0.50*]*

Notes:

1. The applicable column lines and elevation levels are identified and included in Figures 1.2-9 and 3.7.2-12 (sheets 1 through 12).

[2. *The thickness of these sections is 6′0″ with a construction tolerance of +4 inches, -3/4 inch.*]*

3. These concrete reinforcement values represent the minimum reinforcement required for structural requirements except for designed openings, penetrations, sumps or elevator pits.

[4. *These concrete reinforcement values represent the provided reinforcement for structural requirements except for designed openings, penetrations, sumps or elevator pits.*]*

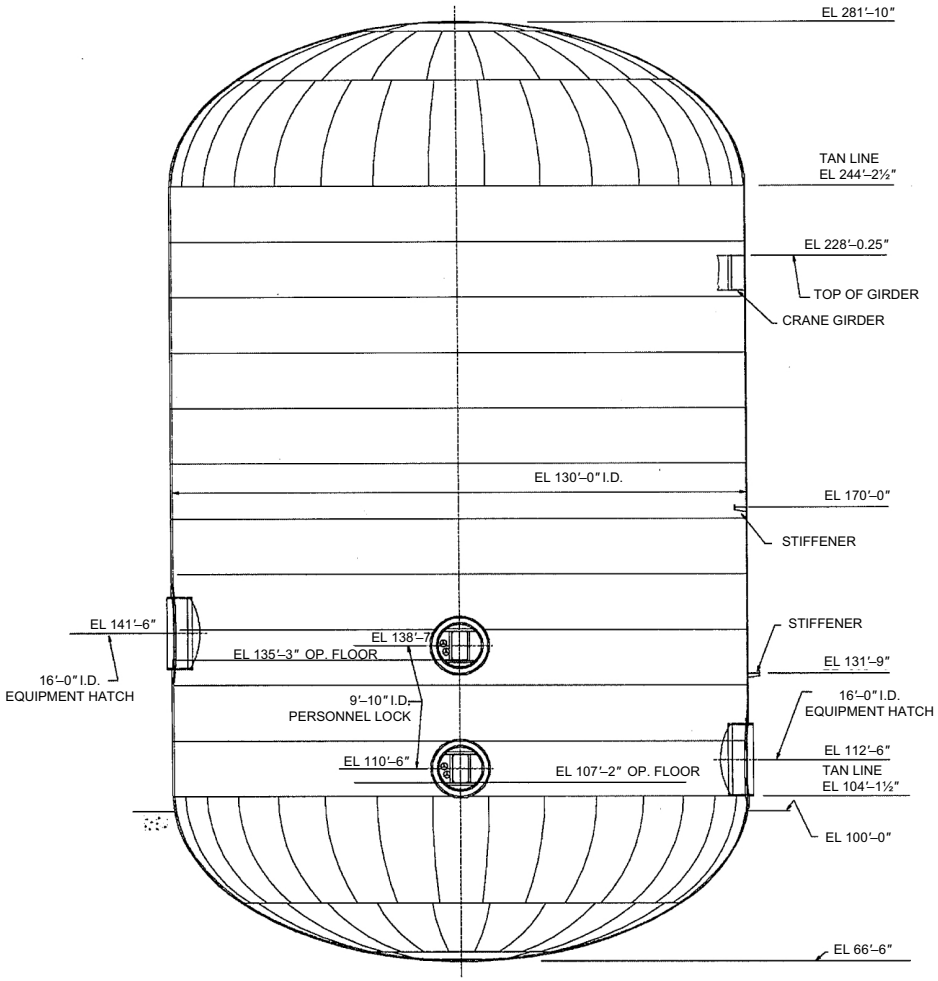
5. Reinforcement demand is low. Basemat reinforcement is fairly uniform across all of the basemat and the governing location is in other segments (see Figure 3.8.5-3, sheets 3 to 6).

6. The 5'-0" portion of the Basemat between column line L to 5' east of column line and shield building to column line 9.2, as shown in Figure 3.8.5-3, Sheet 6, are not included in this area.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.8-201
Waterproof Membrane Inspections, Tests, Analyses, and Acceptance Criteria

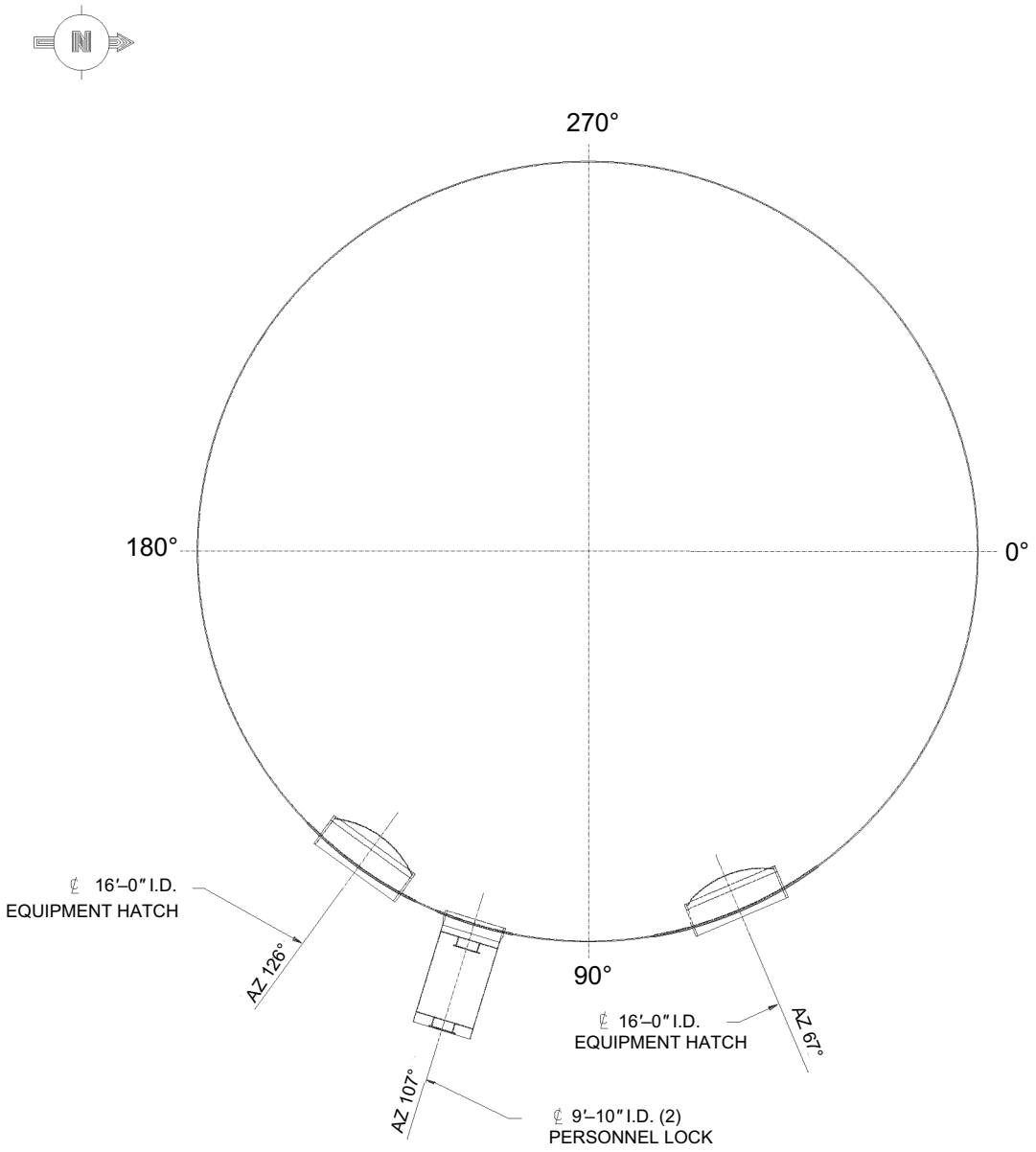
Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1) The friction coefficient to resist sliding is 0.7 or higher.	Testing will be performed to confirm that the mudmat-waterproofing-mudmat interface beneath the Nuclear Island basemat has a minimum coefficient of friction to resist sliding of 0.7.	A report exists and documents that the as-built waterproof system (mudmat-waterproofing-mudmat interface) has a minimum coefficient of friction of 0.7 as demonstrated through material qualification testing.



Equipment hatches rotated out of position to show configuration: see Sheet 2 for azimuth orientation.

Note: Course layout, plate/insert plate geometry, and weld seams are shown for illustrative purposes only.

Figure 3.8.2-1 (Sheet 1 of 3)
Containment Vessel General Outline



ORIENTATION OF MAJOR PENETRATIONS

Equipment hatch at azimuth of 126° is the lower hatch.
Equipment hatch at azimuth of 67° is the upper hatch.

Figure 3.8.2-1 (Sheet 2 of 3)
Containment Vessel General Outline

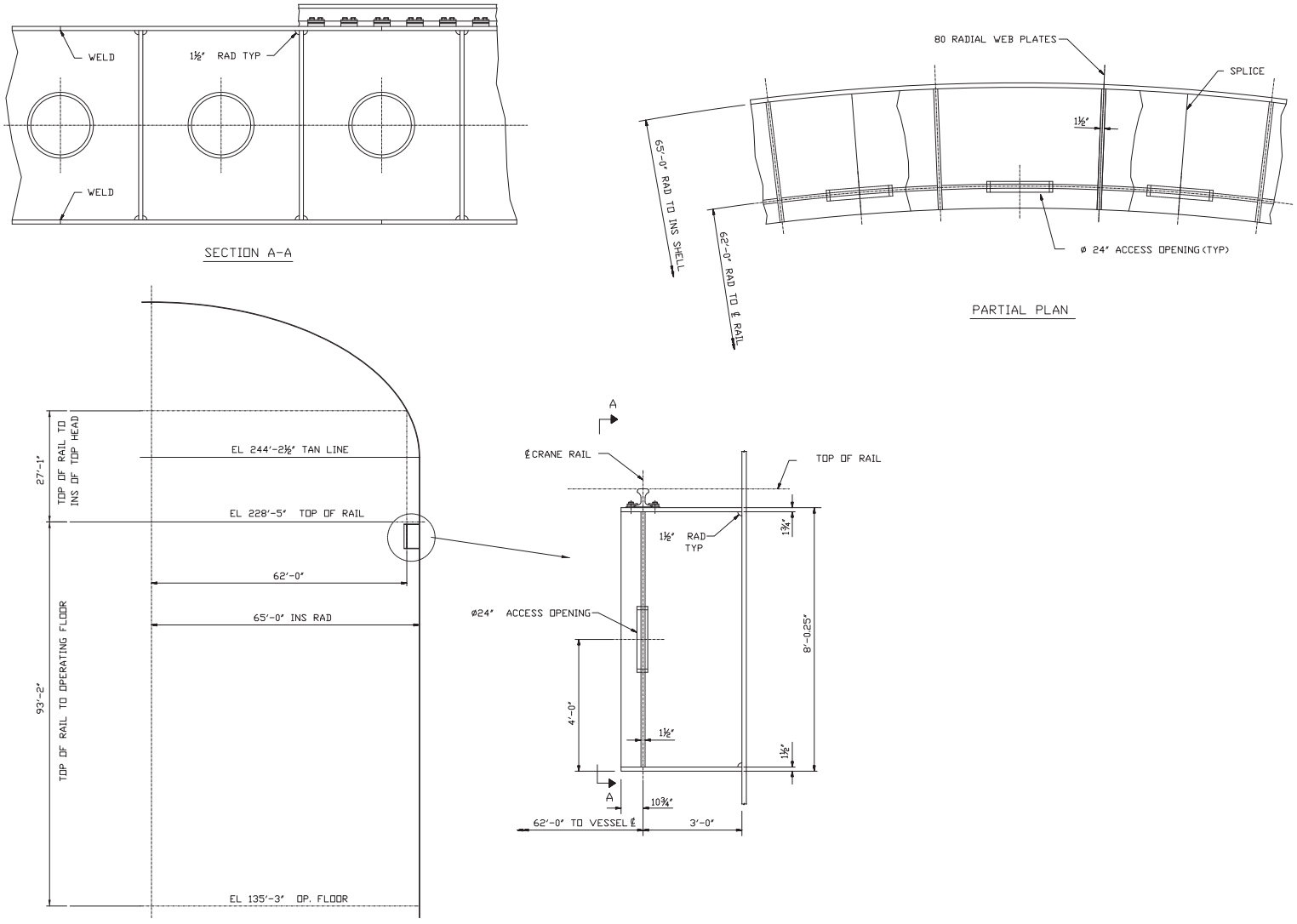
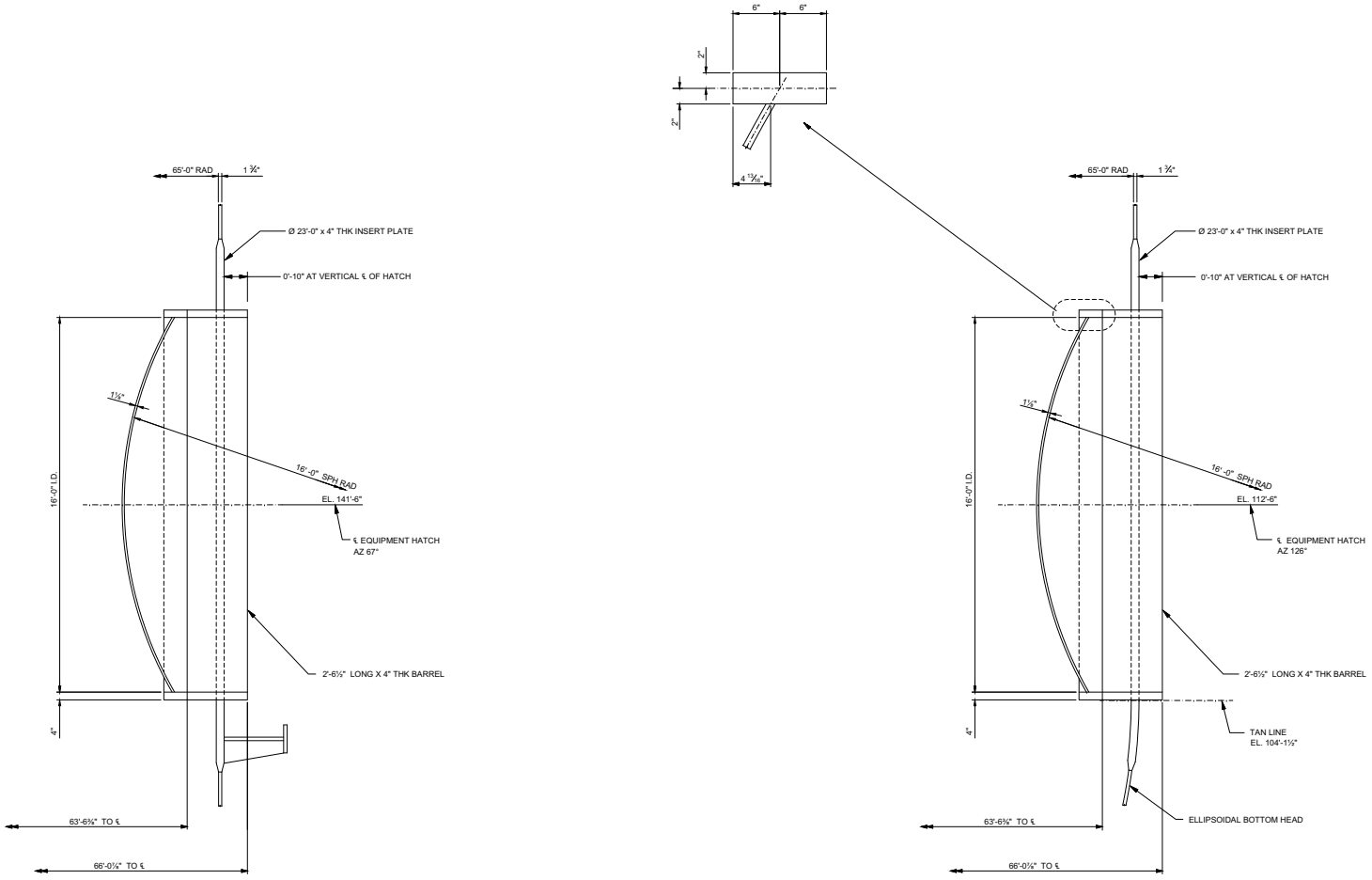


Figure 3.8.2-1 (Sheet 3 of 3)
Containment Vessel General Outline



MATERIAL: SA738 GRADE B

See subsection 3.8.2.1.3 for information that is designated as Tier 2 *.

Figure 3.8.2-2
Equipment Hatches

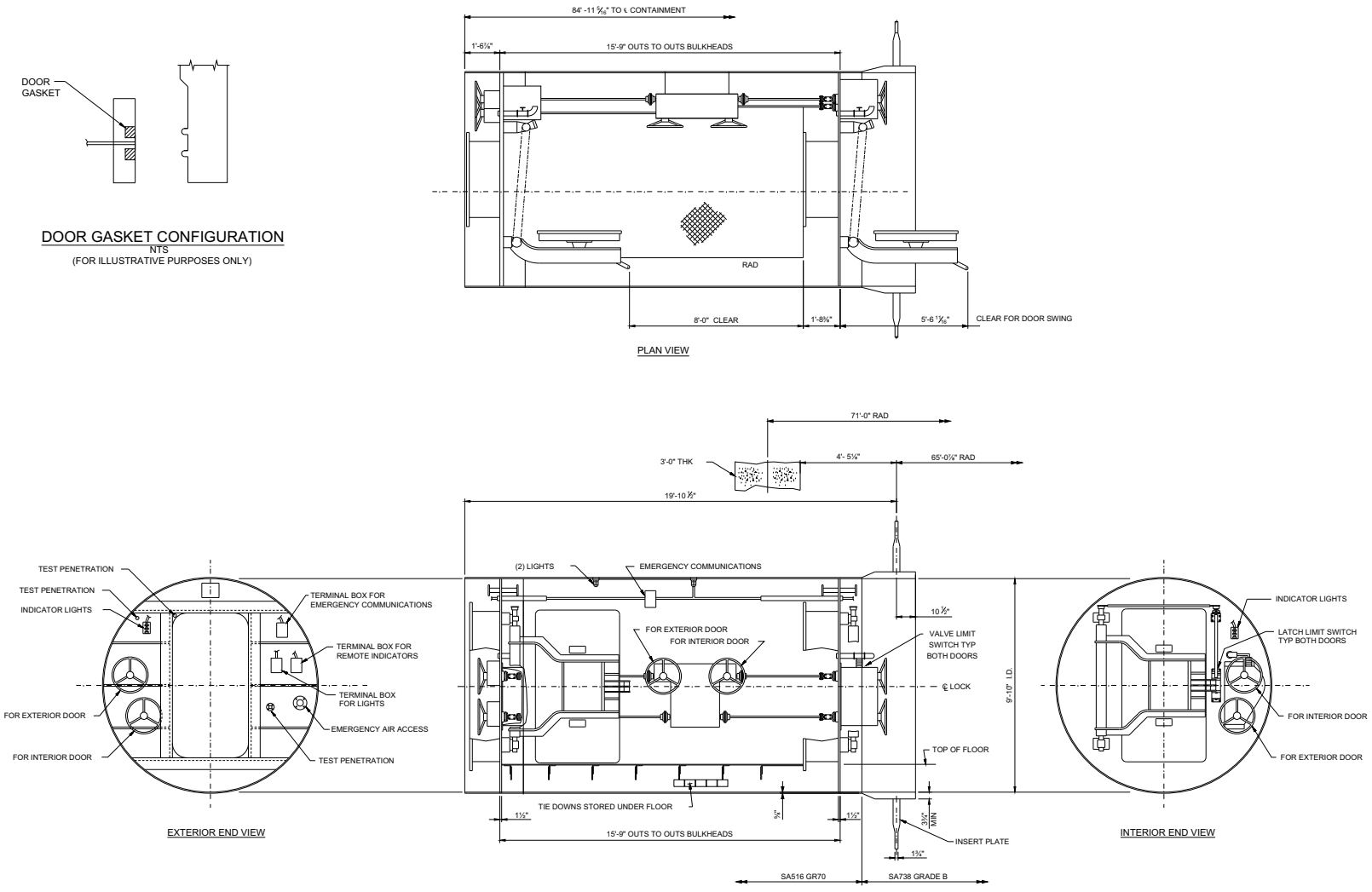


Figure 3.8.2-3
Personnel Airlock

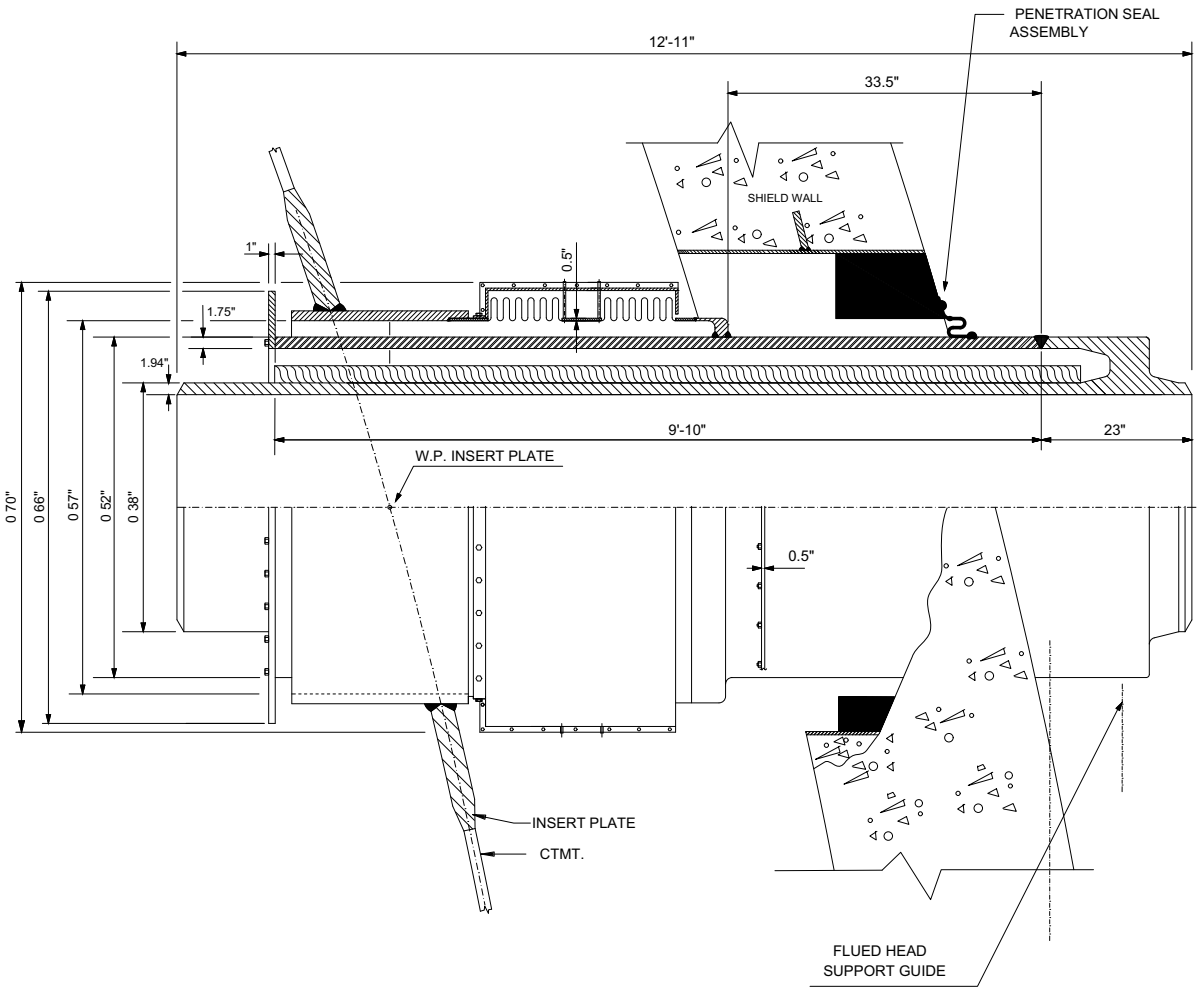


Figure 3.8.2-4 (Sheet 1 of 8)
Containment Penetrations Main Steam

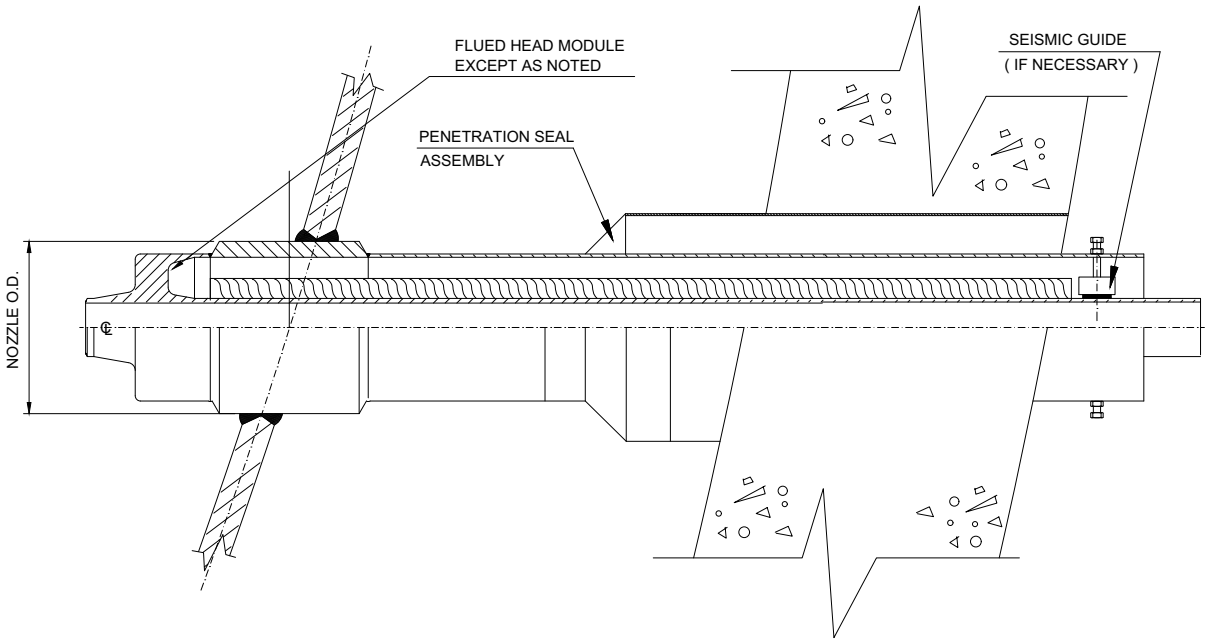
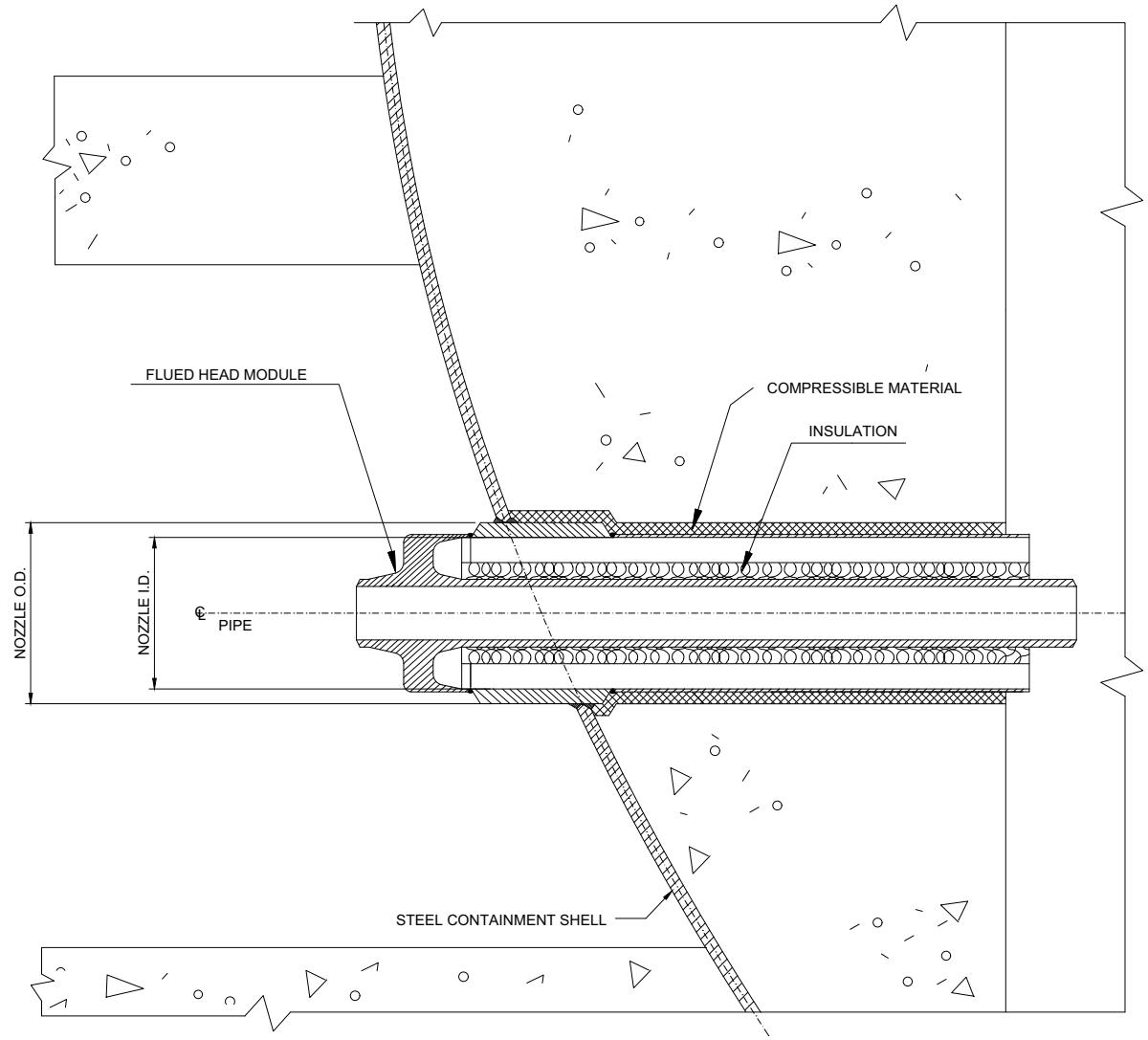


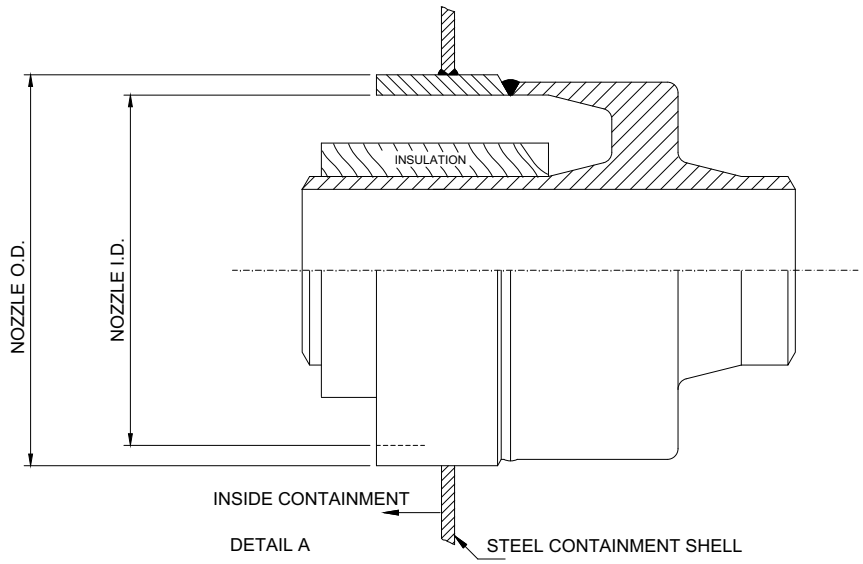
Figure 3.8.2-4 (Sheet 2 of 8)
Containment Penetrations Startup Feedwater

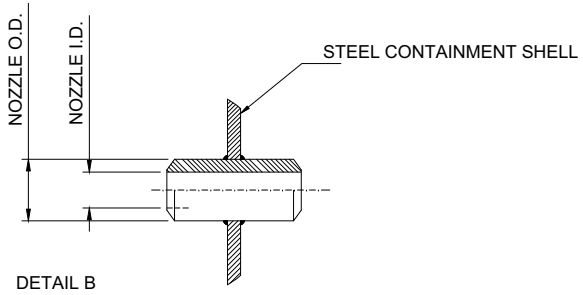
(P20) RNS-PY-C02 PENETRATION

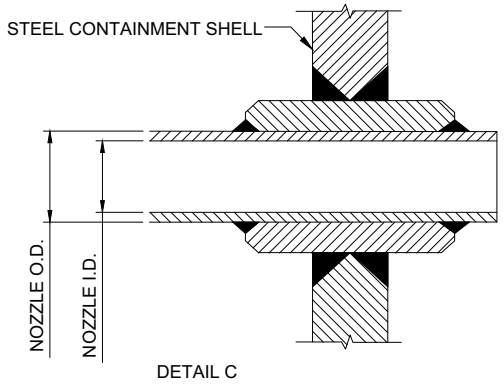


Note: For Vogtle Unit 3, penetration detail differs slightly for RNS-PY-C01 (P19). See Subsection 3.8.2.1.5.

Figure 3.8.2-4 (Sheet 3 of 8)
Containment Penetrations Normal RHR Piping







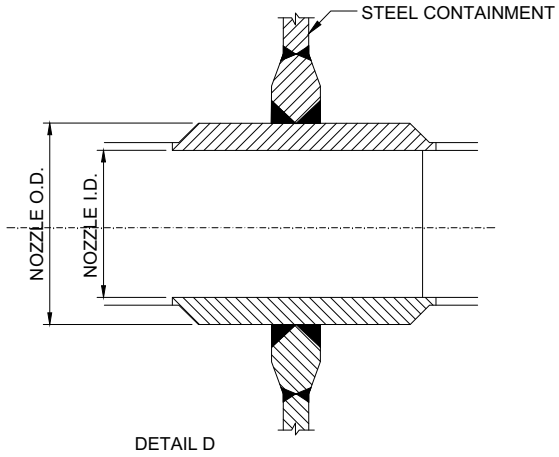


Figure 3.8.2-4 (Sheet 4 of 8)
Containment Penetrations

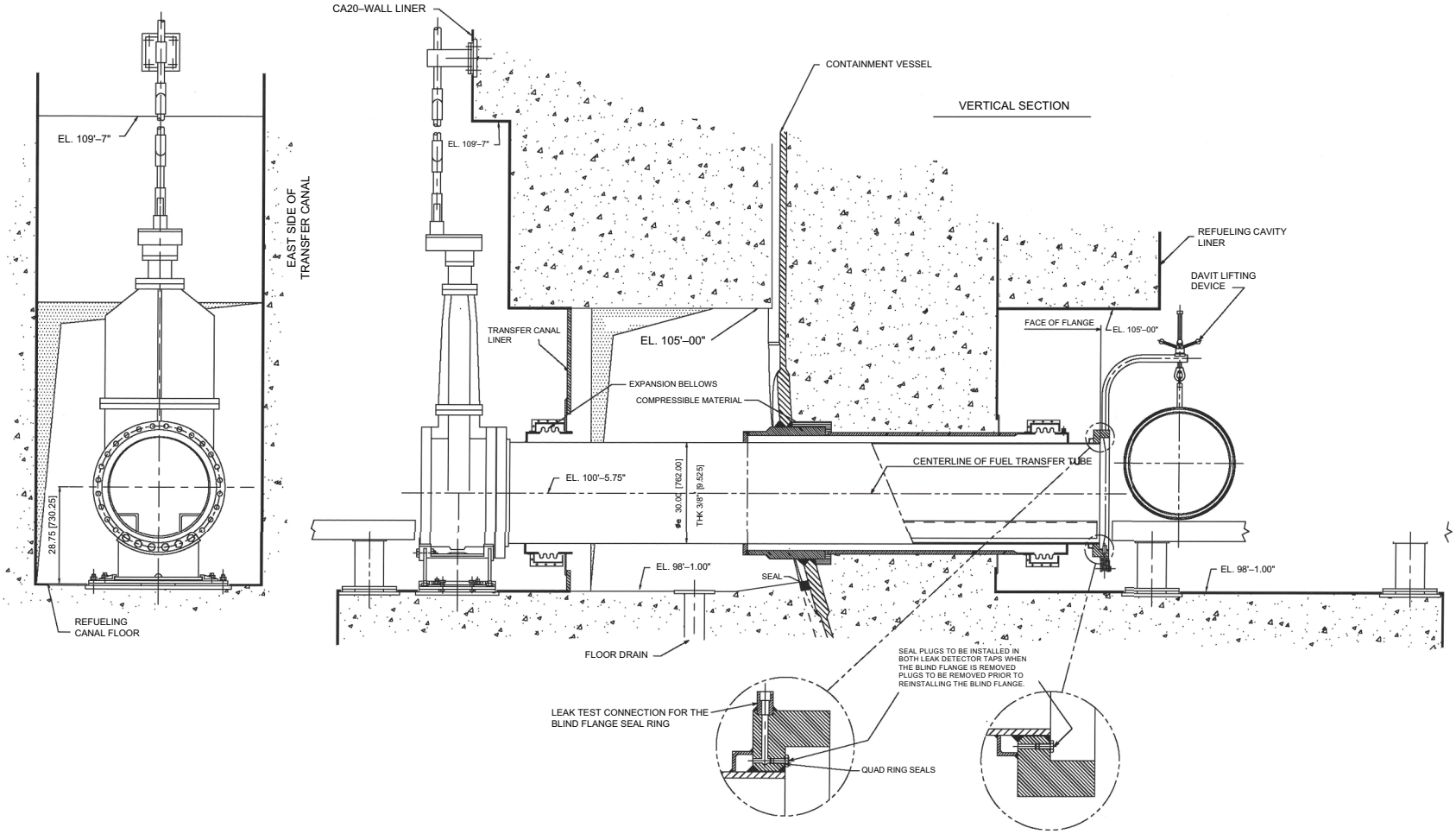


Figure 3.8.2-4 (Sheet 5 of 8)
Containment Penetrations
Fuel Transfer Penetration

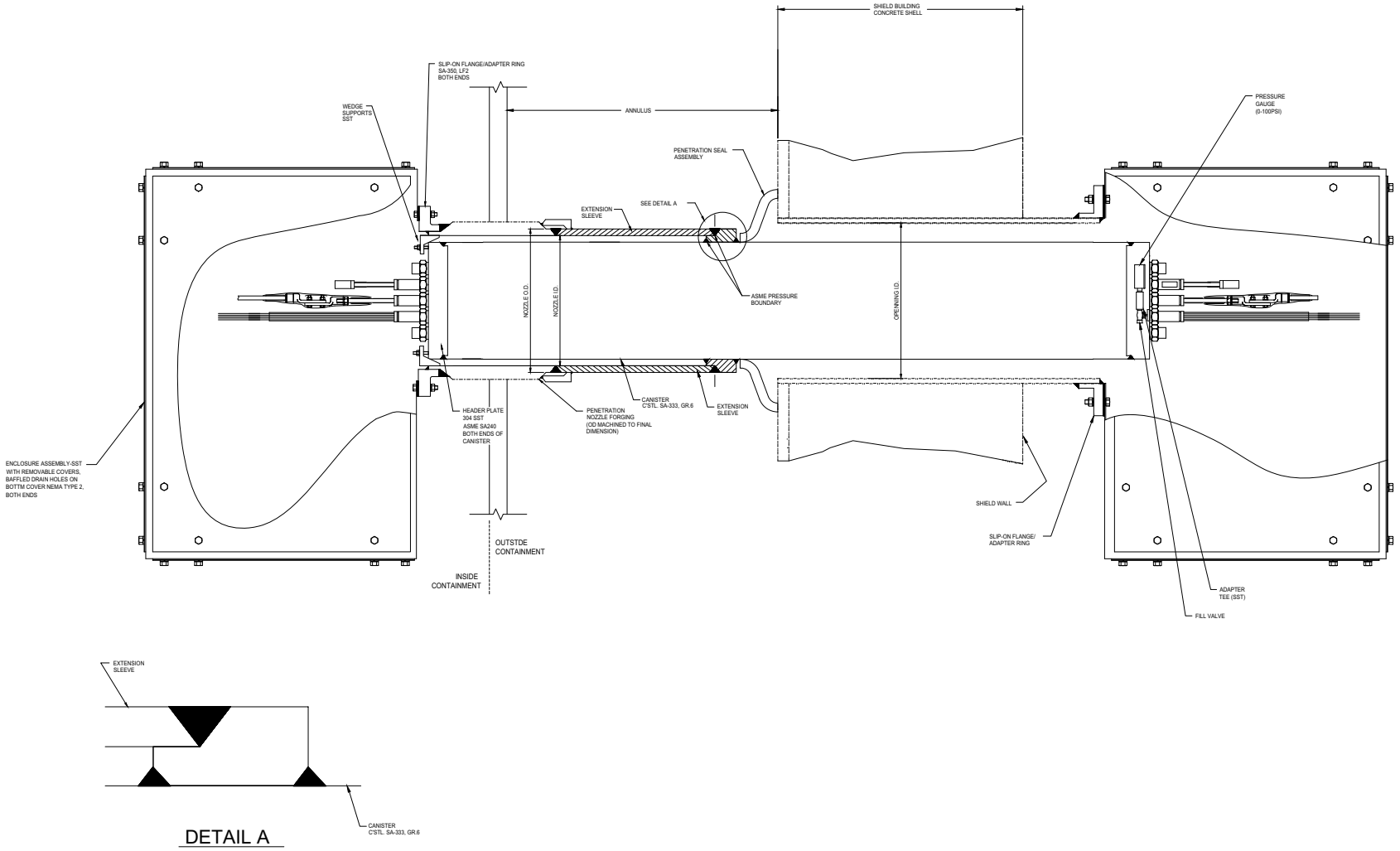
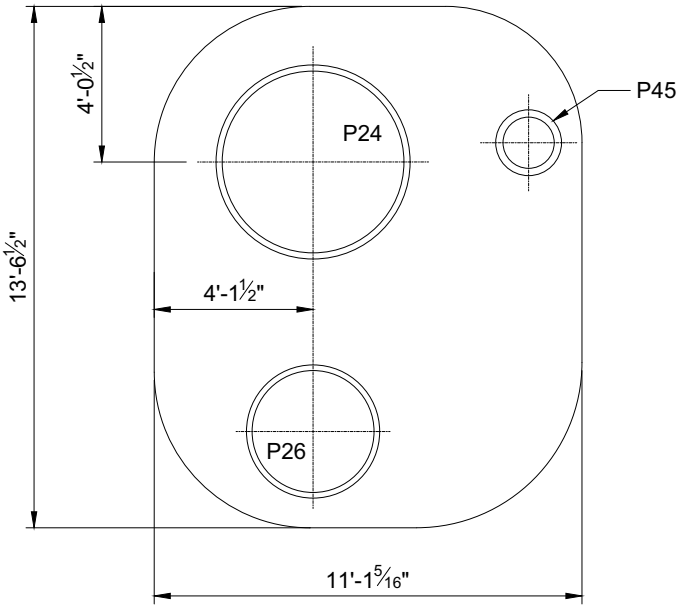


Figure 3.8.2-4 (Sheet 6 of 8)
Containment Penetrations
Typical Electrical Penetration



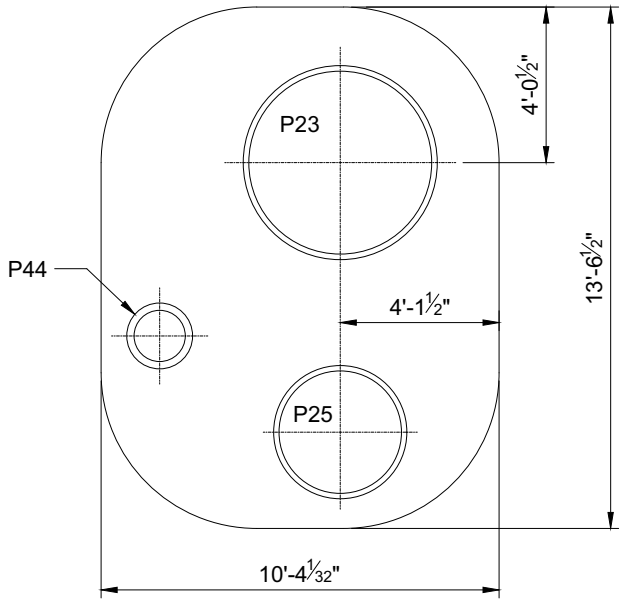


Figure 3.8.2-4 (Sheet 7 of 8)
Containment Penetrations
Steam Line and Feedwater Line Insert Plates

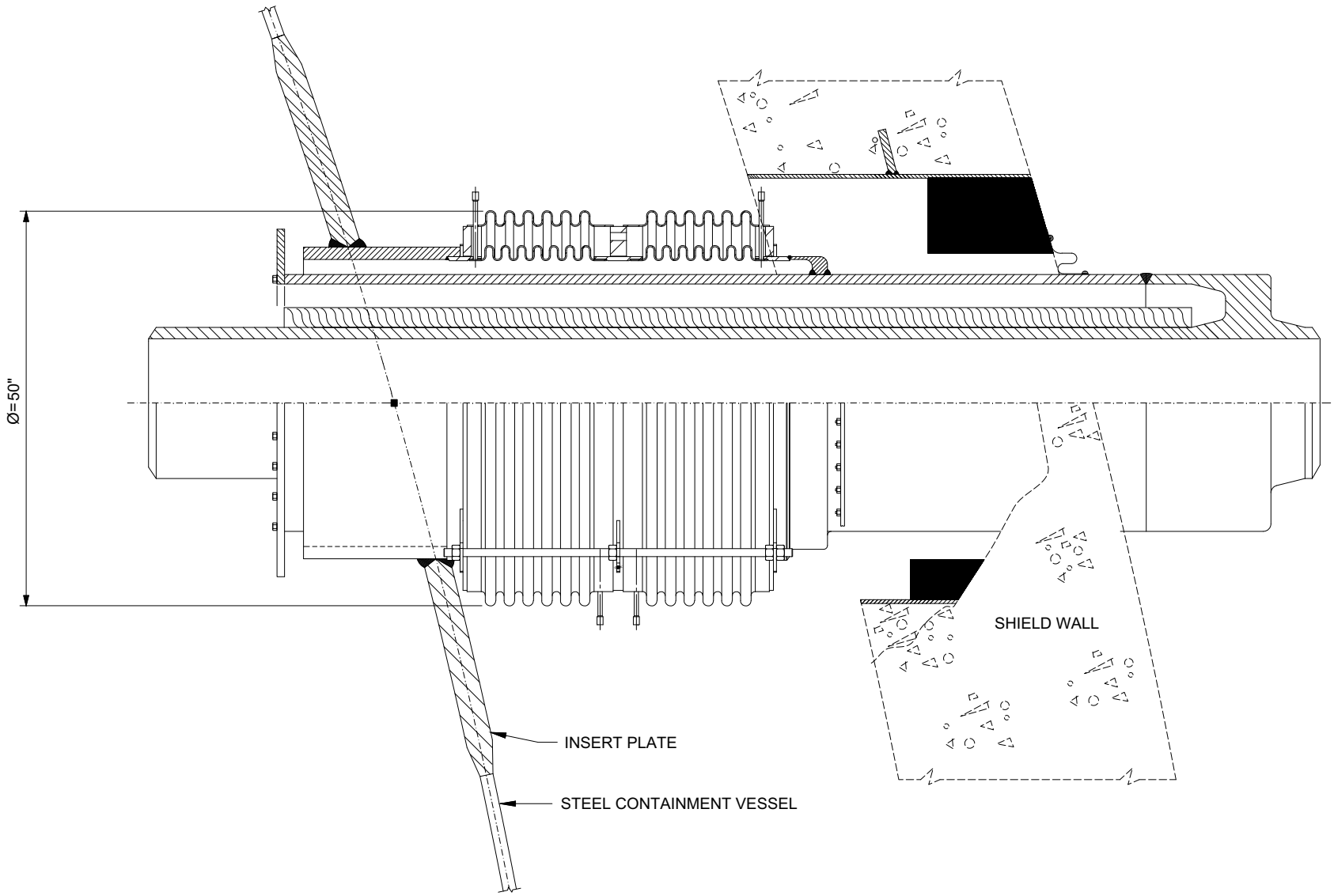


Figure 3.8.2-4 (Sheet 8 of 8)
Containment Penetrations Main Feedwater

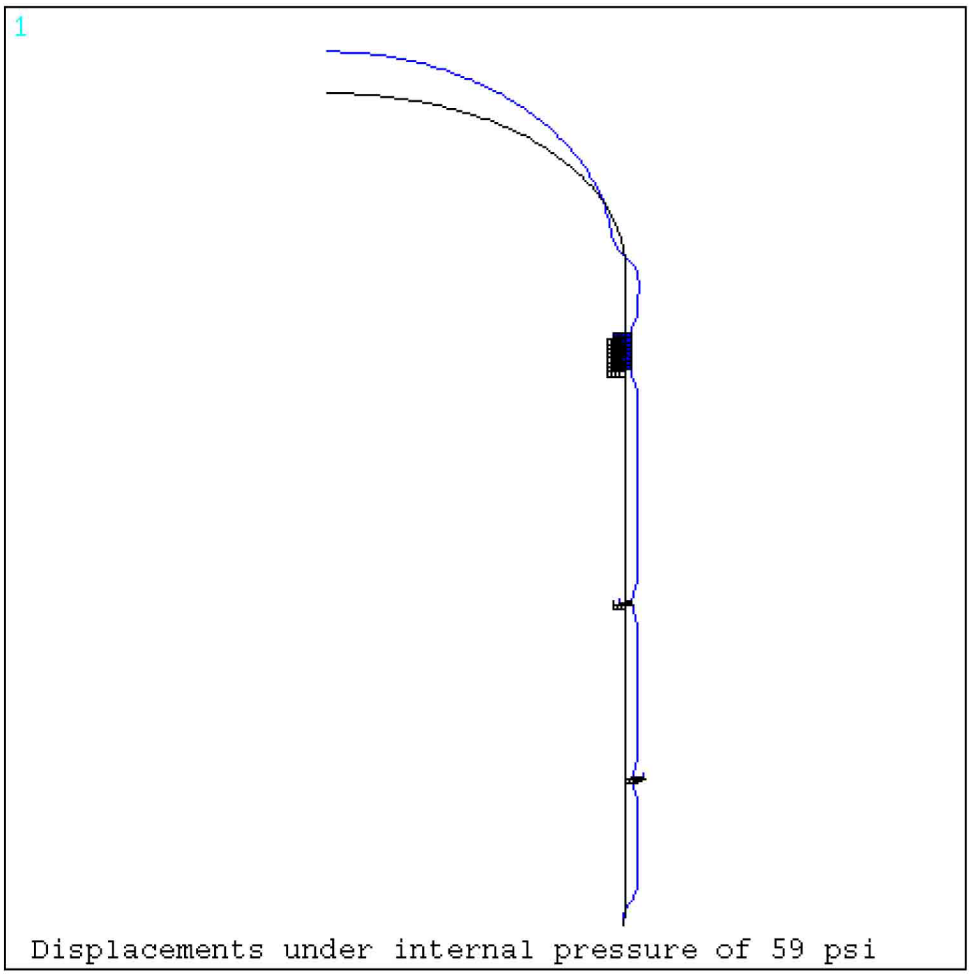
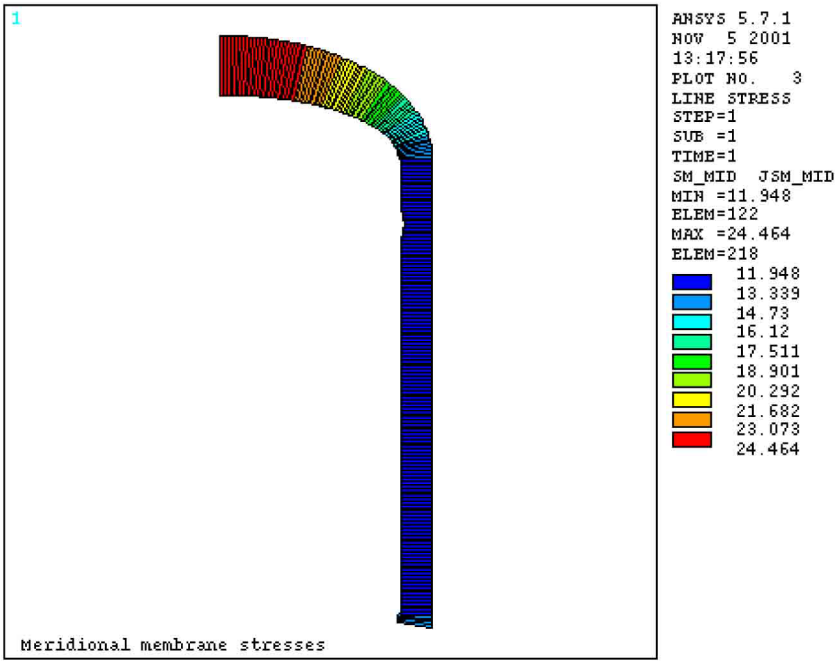
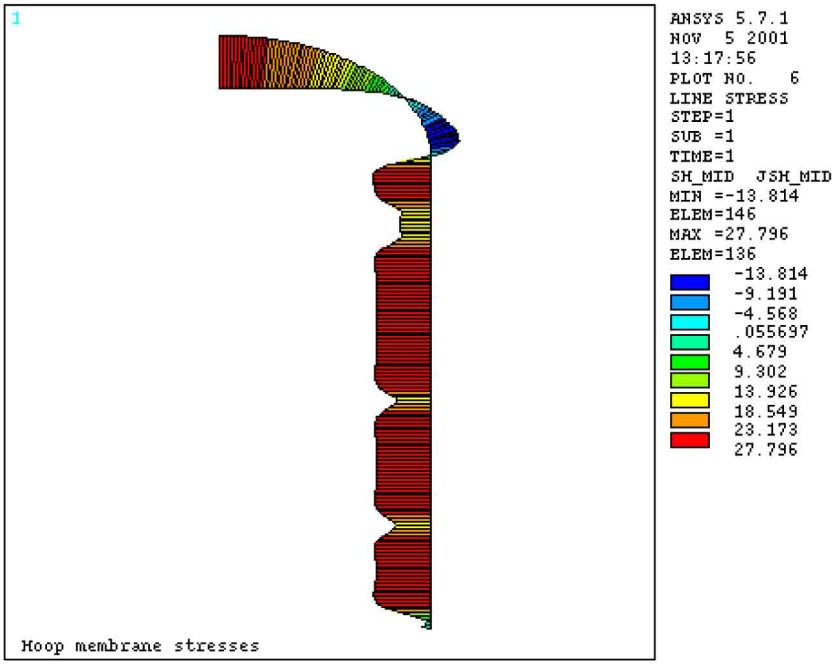


Figure 3.8.2-5 (Sheet 1 of 5)
Containment Vessel Response to Internal Pressure of 59 psig
Displaced Shape Plot



Meridional Membrane Stress (ksi)



Circumferential Membrane Stress (ksi)

Figure 3.8.2-5 (Sheet 2 of 5)
Containment Vessel Response to Internal Pressure of 59 psig
Membrane Stresses (ksi)

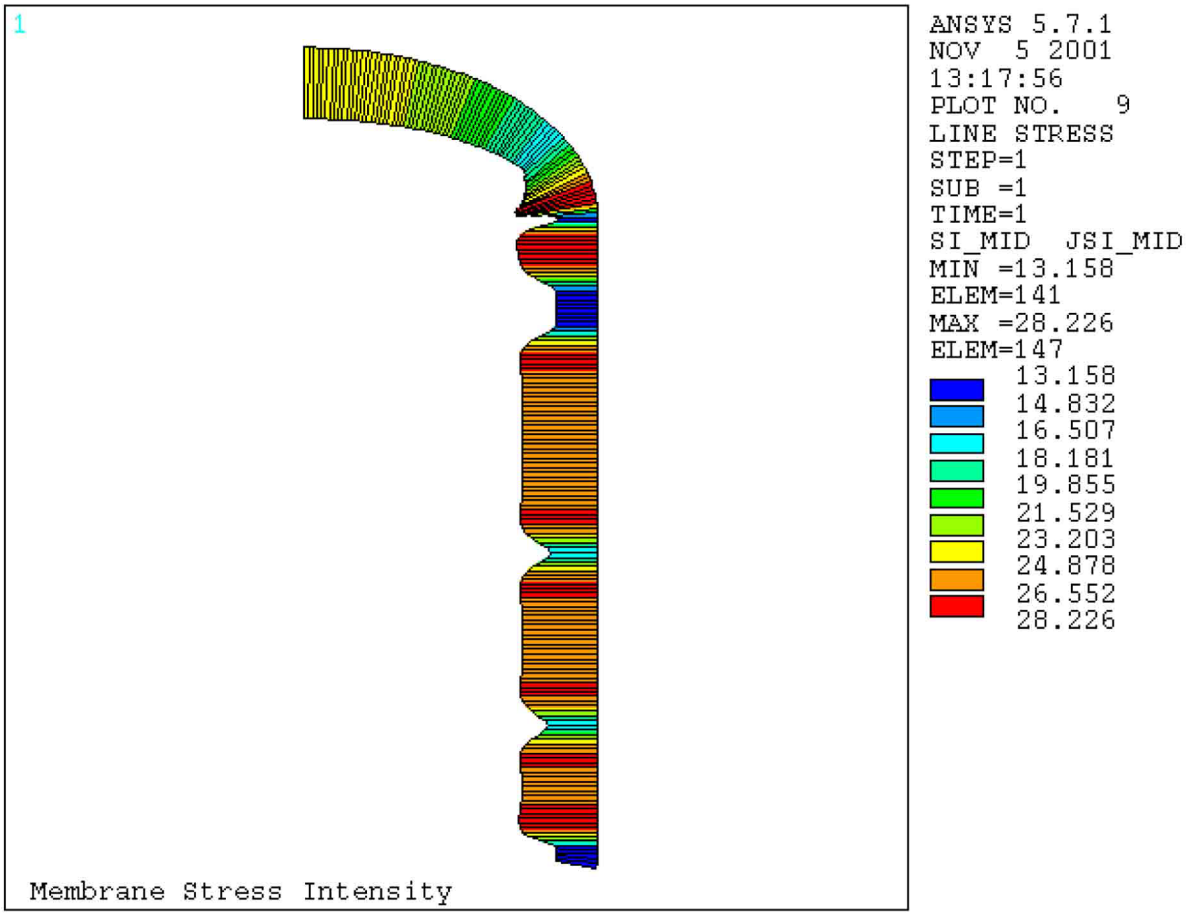
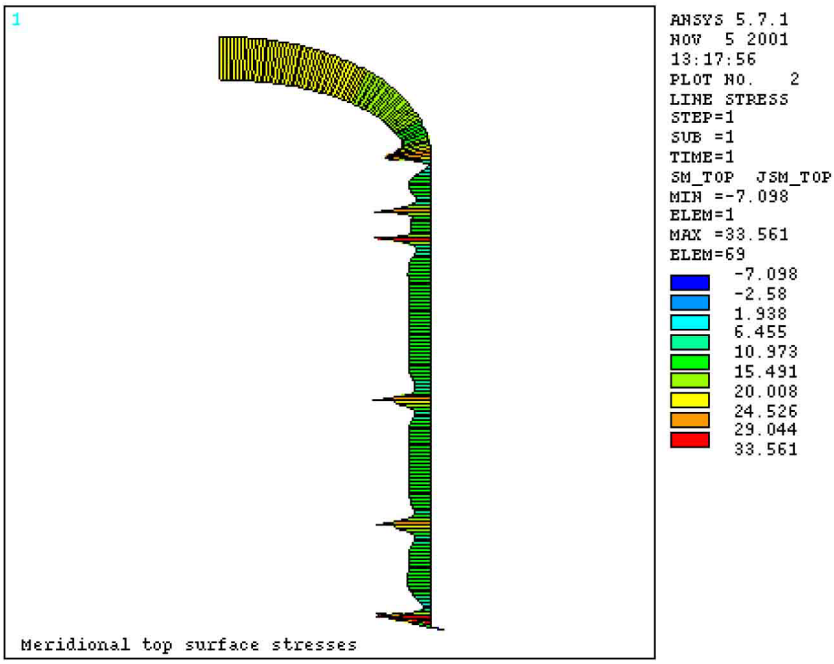
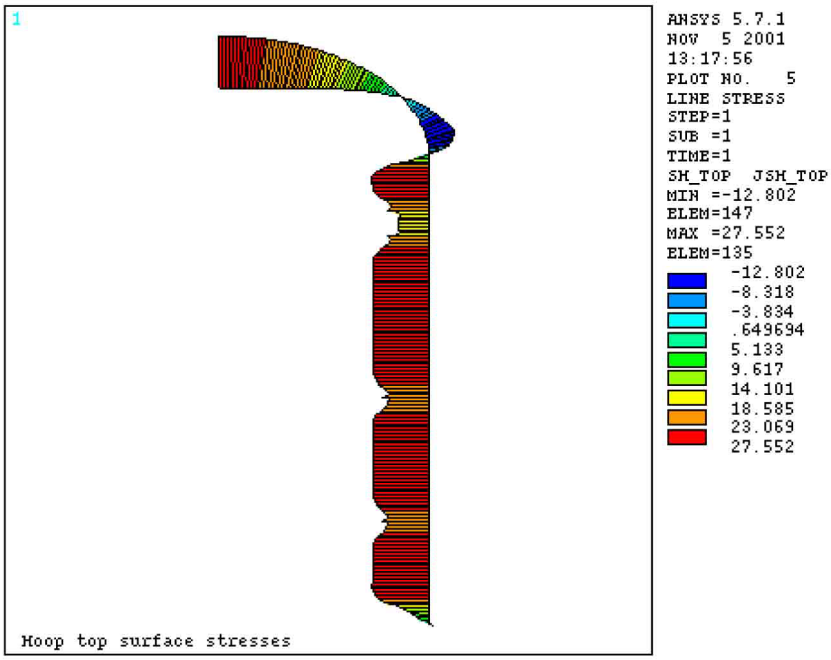


Figure 3.8.2-5 (Sheet 3 of 5)
Containment Vessel Response to Internal Pressure of 59 psig
Surface Meridional Stress (ksi)



Meridional Top Surface Stress (ksi)



Circumferential Top Surface Stress (ksi)

Figure 3.8.2-5 (Sheet 4 of 5)
Containment Vessel Response to Internal Pressure of 59 psig
Outside Surface Stresses (ksi)

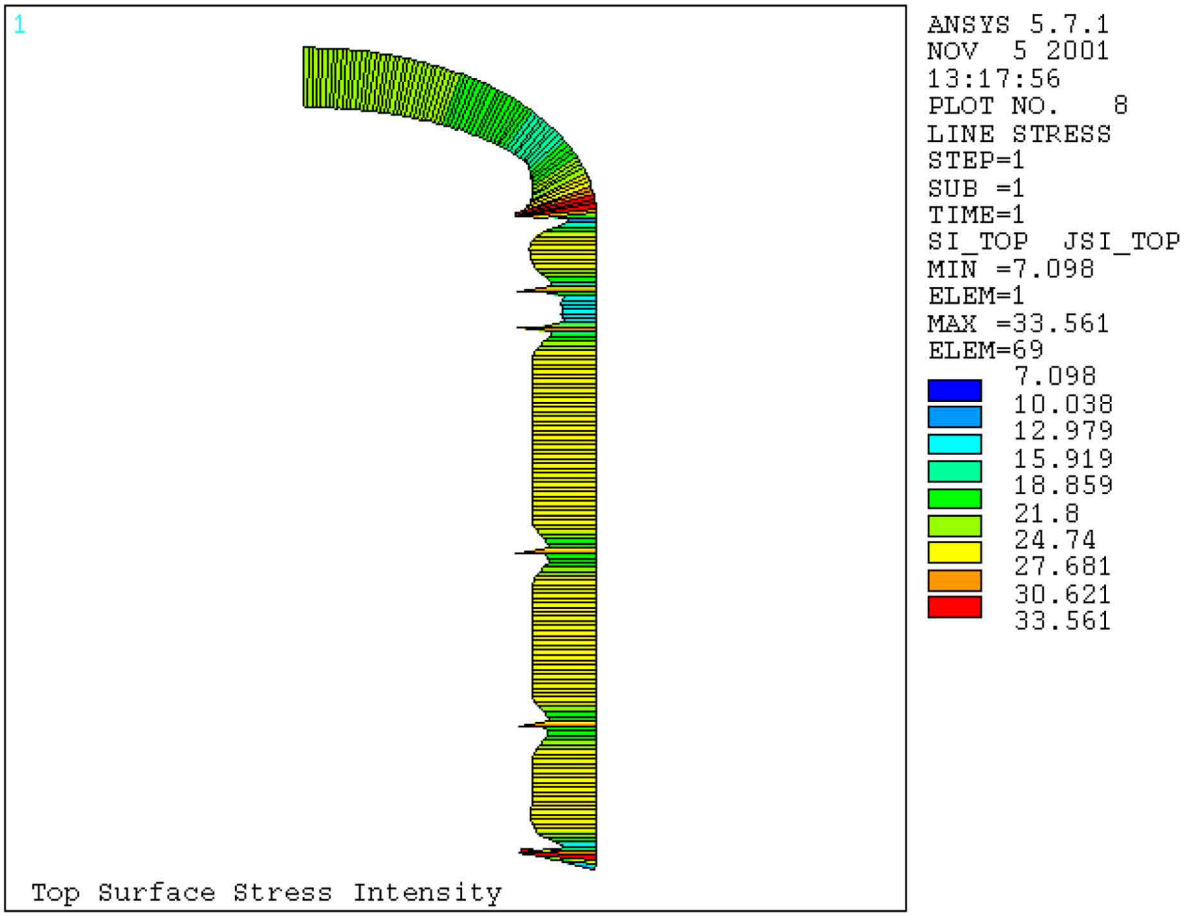


Figure 3.8.2-5 (Sheet 5 of 5)
Containment Vessel Response to Internal Pressure of 59 psig
Outer Stress Intensity (ksi)

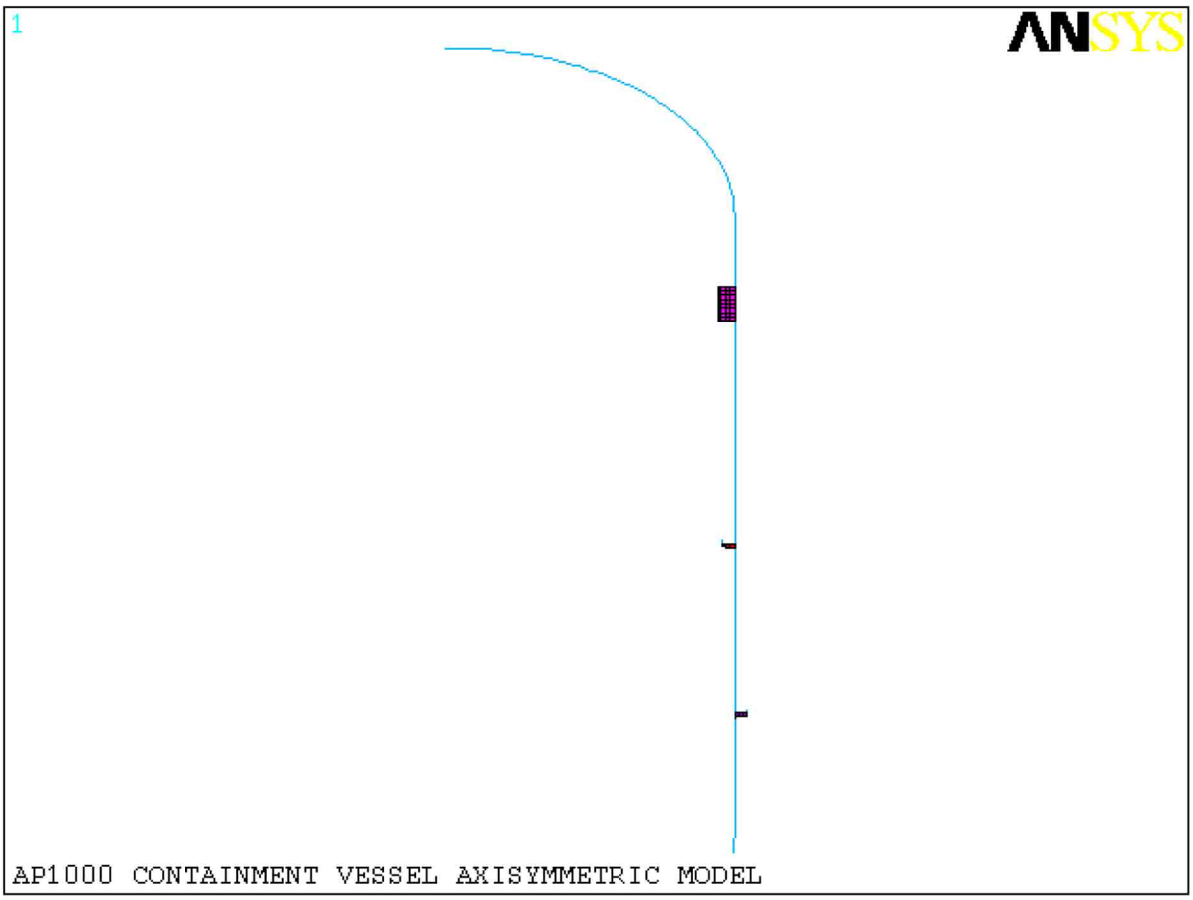
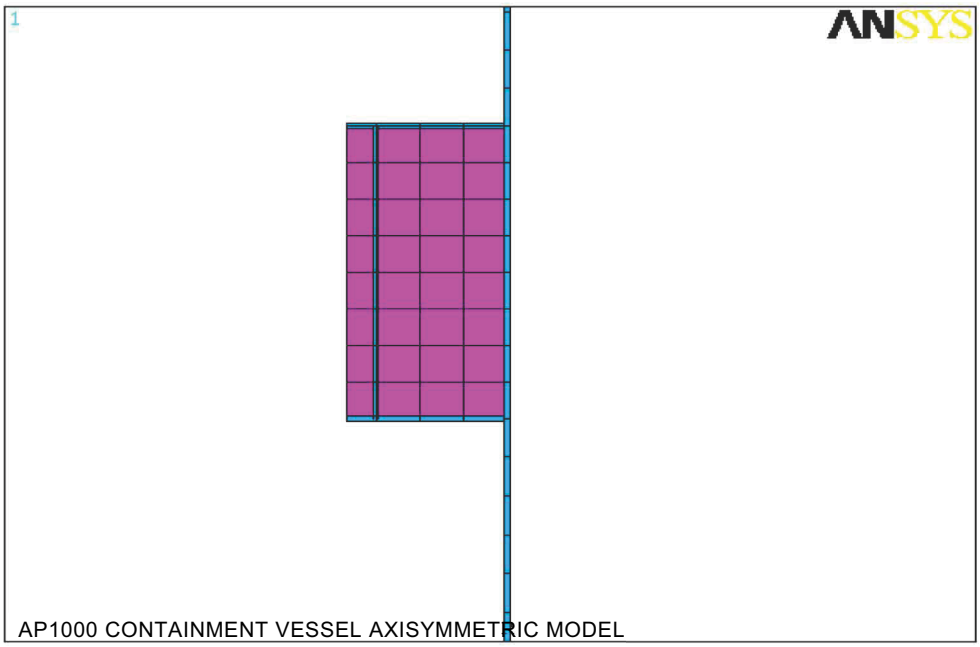
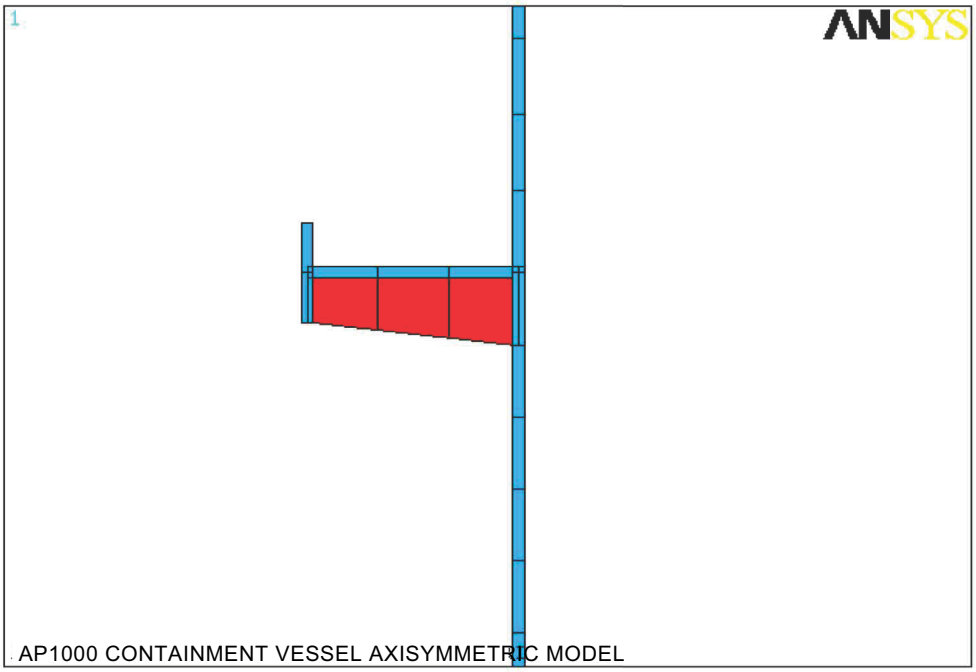


Figure 3.8.2-6 (Sheet 1 of 2)
Containment Vessel Axisymmetric Model



Crane Girder



Internal Stiffener at Elev. 170′–0″

Figure 3.8.2-6 (Sheet 2 of 2)
Containment Vessel Axisymmetric Model

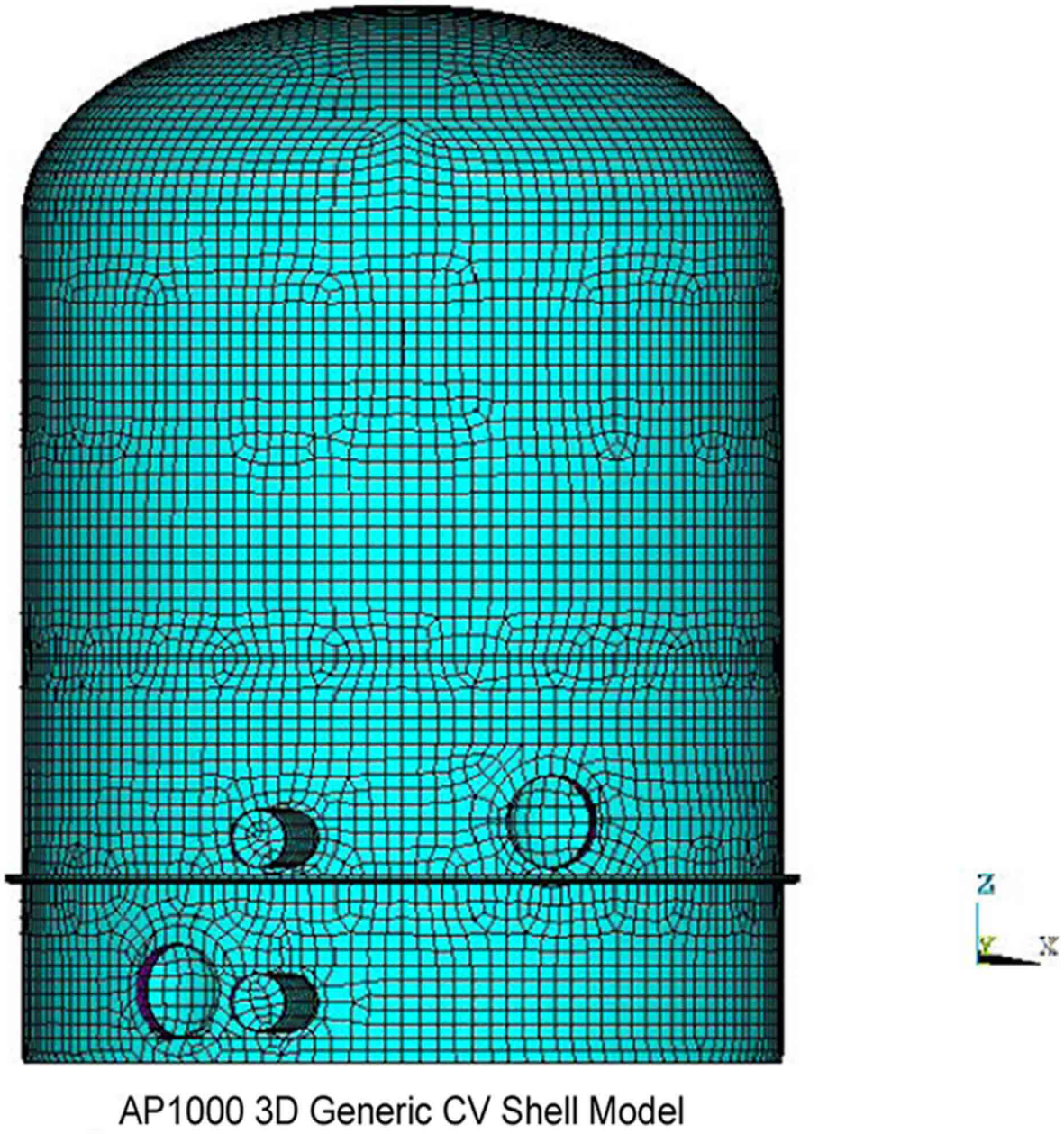


Figure 3.8.2-7
Finite Element Model for Local Buckling Analyses

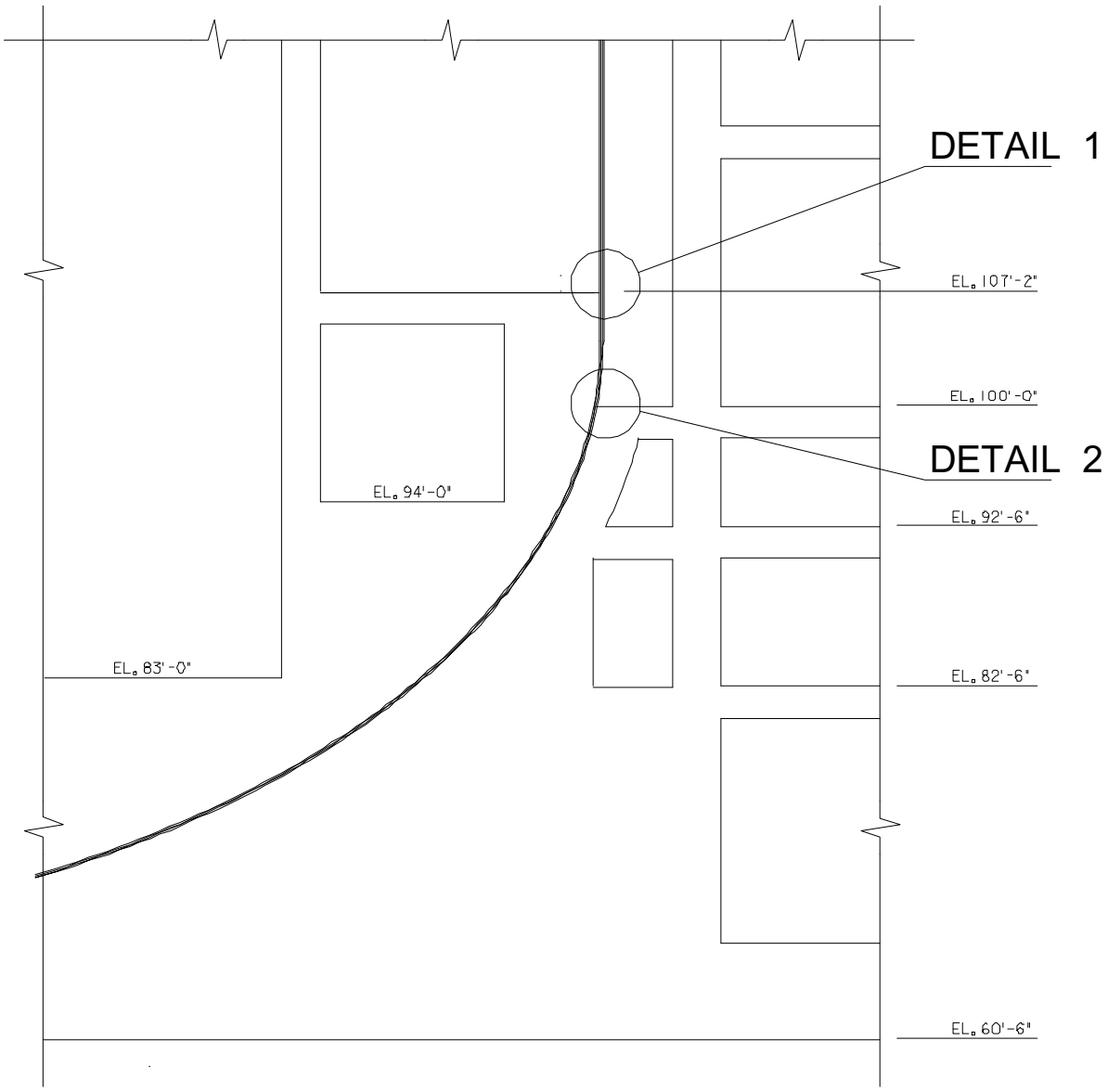
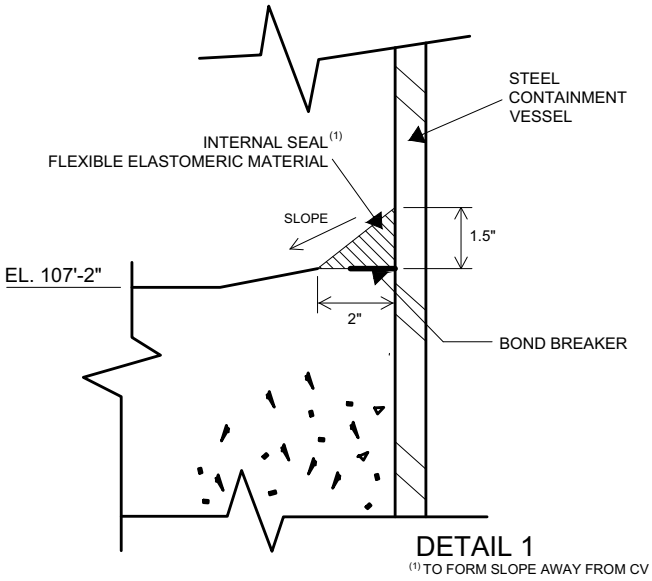
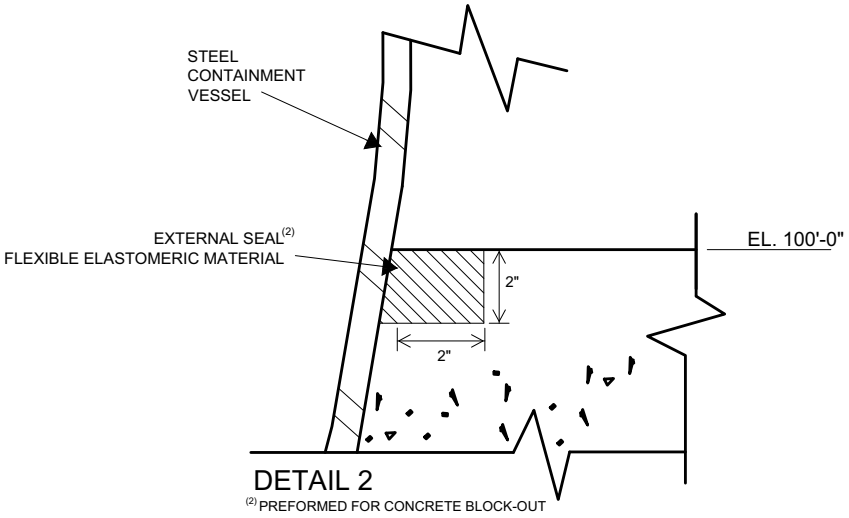


Figure 3.8.2-8 (Sheet 1 of 2)
Location of Containment Seal





GENERAL NOTE: DIMENSIONS, ELEVATIONS AND CONFIGURATIONS SHOWN ARE APPROXIMATE AND CAN VARY WITH DIFFERENT SEAL MATERIALS. ALTERNATE SEAL CONFIGURATIONS AT ELEVATIONS OTHER THAN TYPICAL CAN BE UTILIZED WHERE REQUIRED TO ACCOMMODATE INTERFERENCES PROVIDED THE SEAL PREVENTS MOISTURE ACCUMULATION BETWEEN THE VESSEL AND CONCRETE.

Figure 3.8.2-8 (Sheet 2 of 2)
Seal Sections and Details

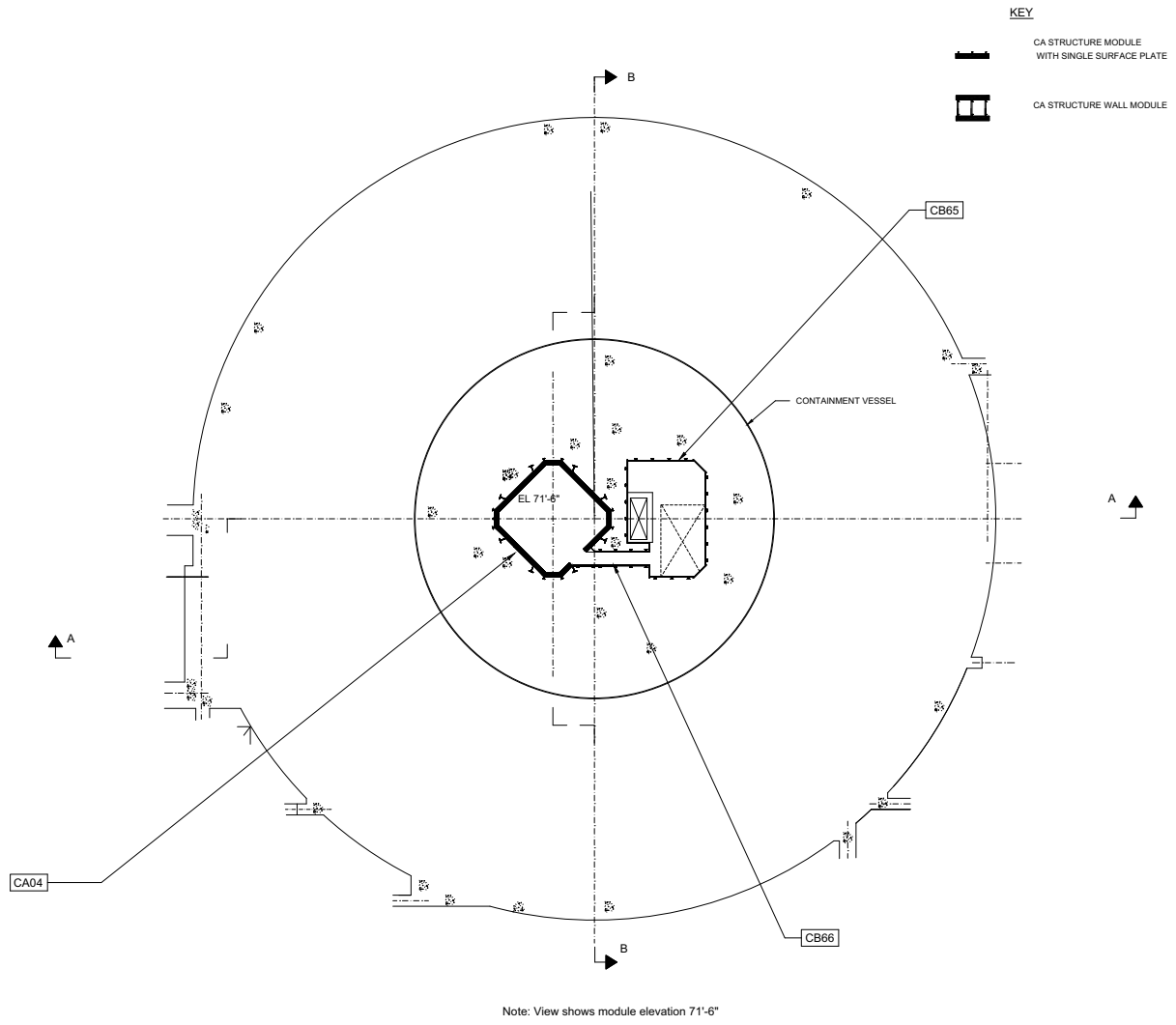


Figure 3.8.3-1 (Sheet 1 of 7)
[*Structural Modules in Containment Internal Structures*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.8.3-1 (Sheet 2 of 7)
[*Structural Modules in Containment Internal Structures*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

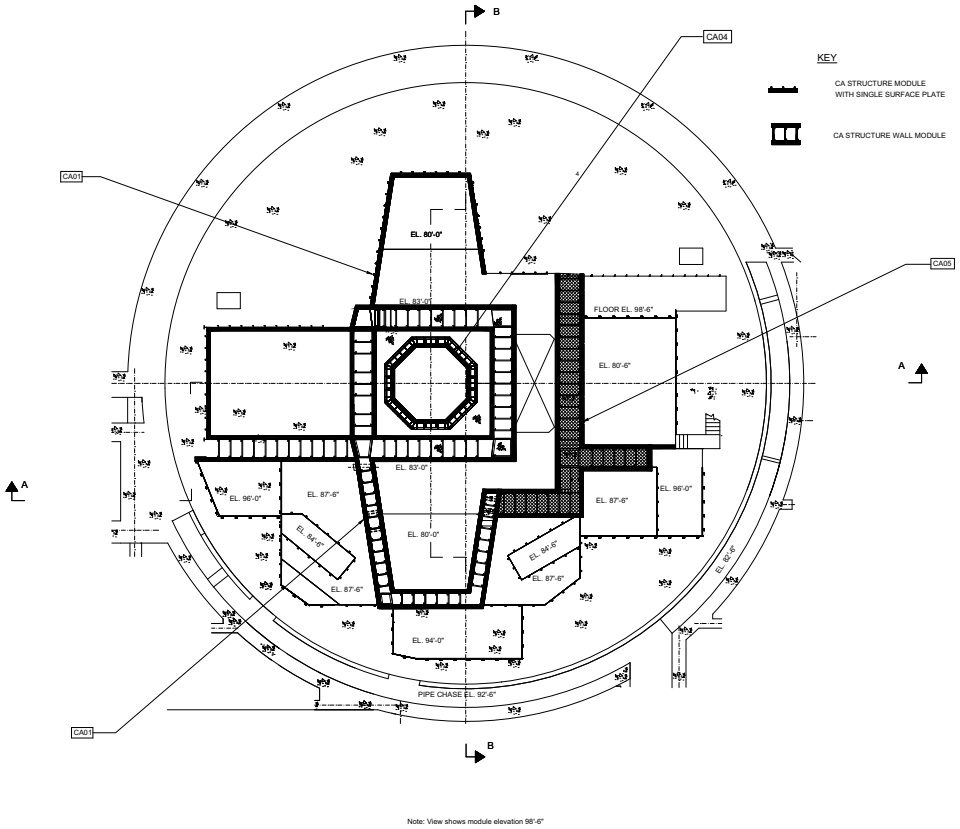


Figure 3.8.3-1 (Sheet 3 of 7)
[*Structural Modules in Containment Internal Structures*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3.8.3-1 (Sheet 4 of 7)
[*Structural Modules in Containment Internal Structures*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

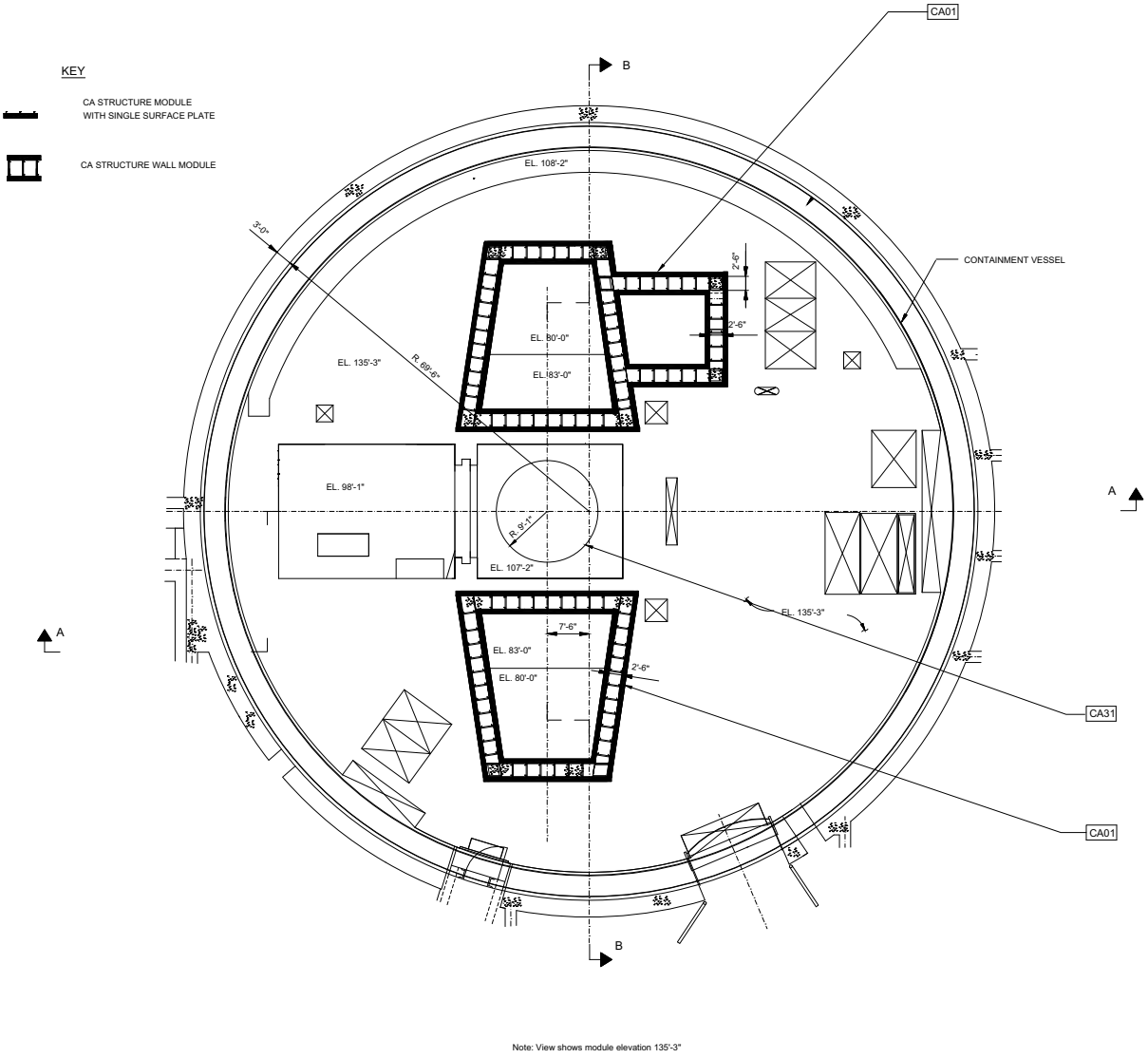


Figure 3.8.3-1 (Sheet 5 of 7)
[*Structural Modules in Containment Internal Structures*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

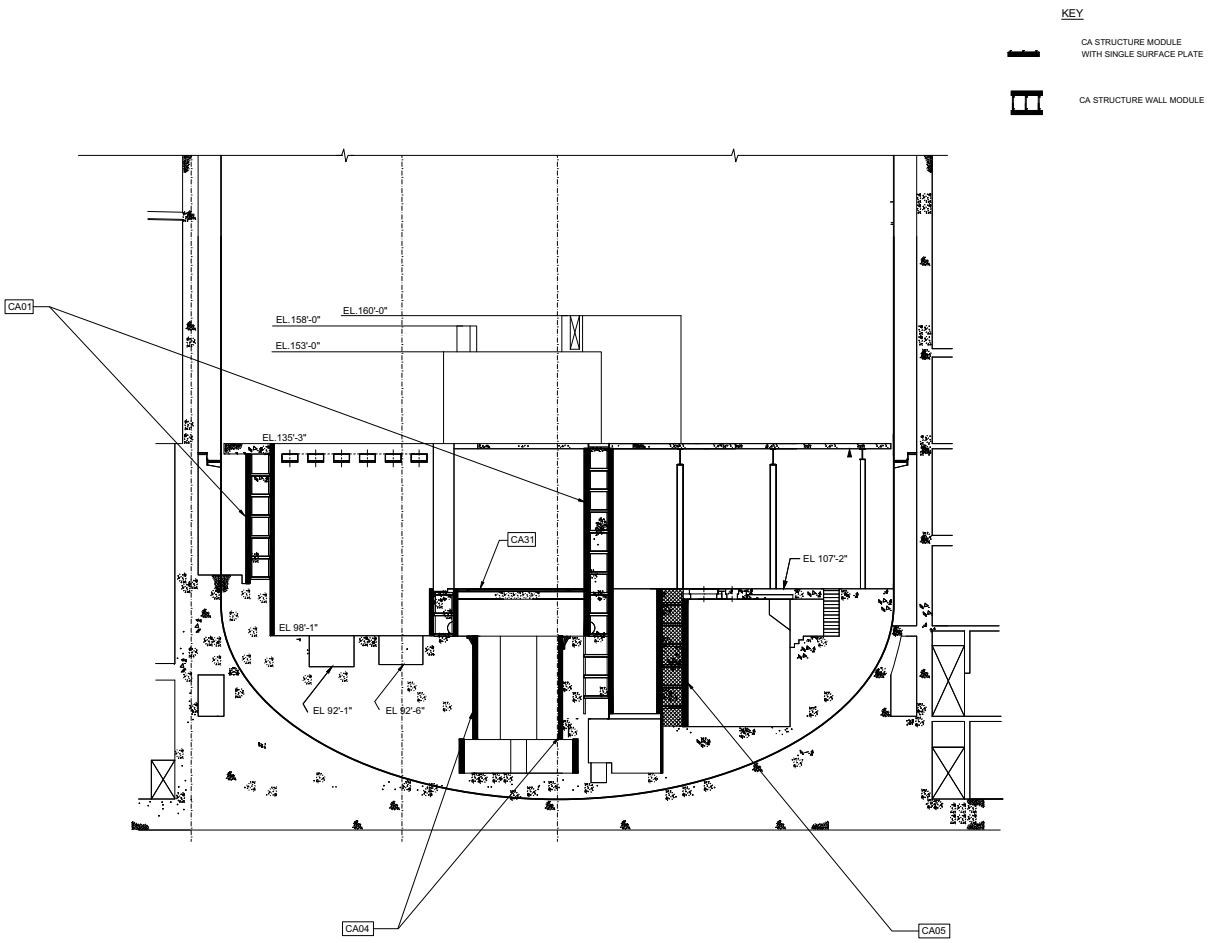


Figure 3.8.3-1 (Sheet 6 of 7)
[*Structural Modules in Containment Internal Structures*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

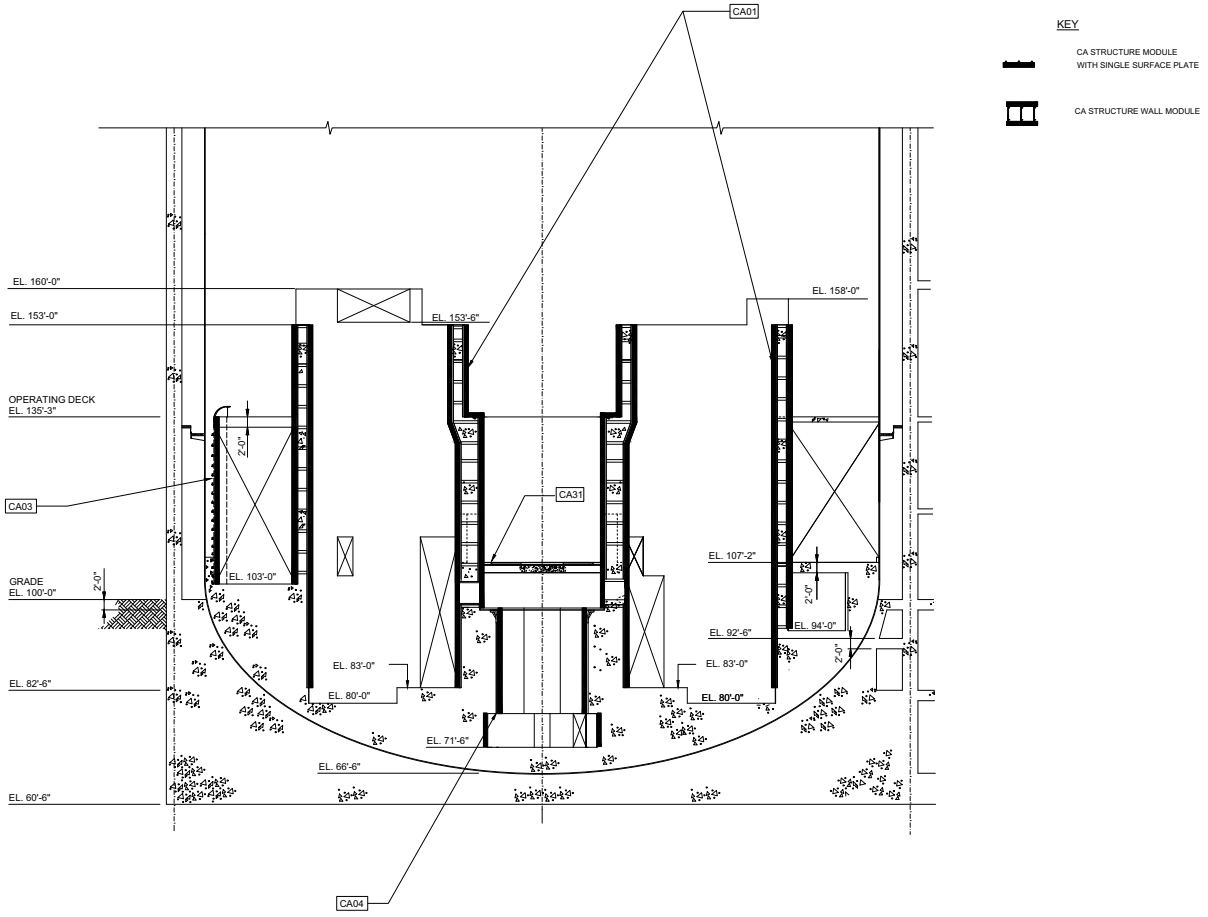
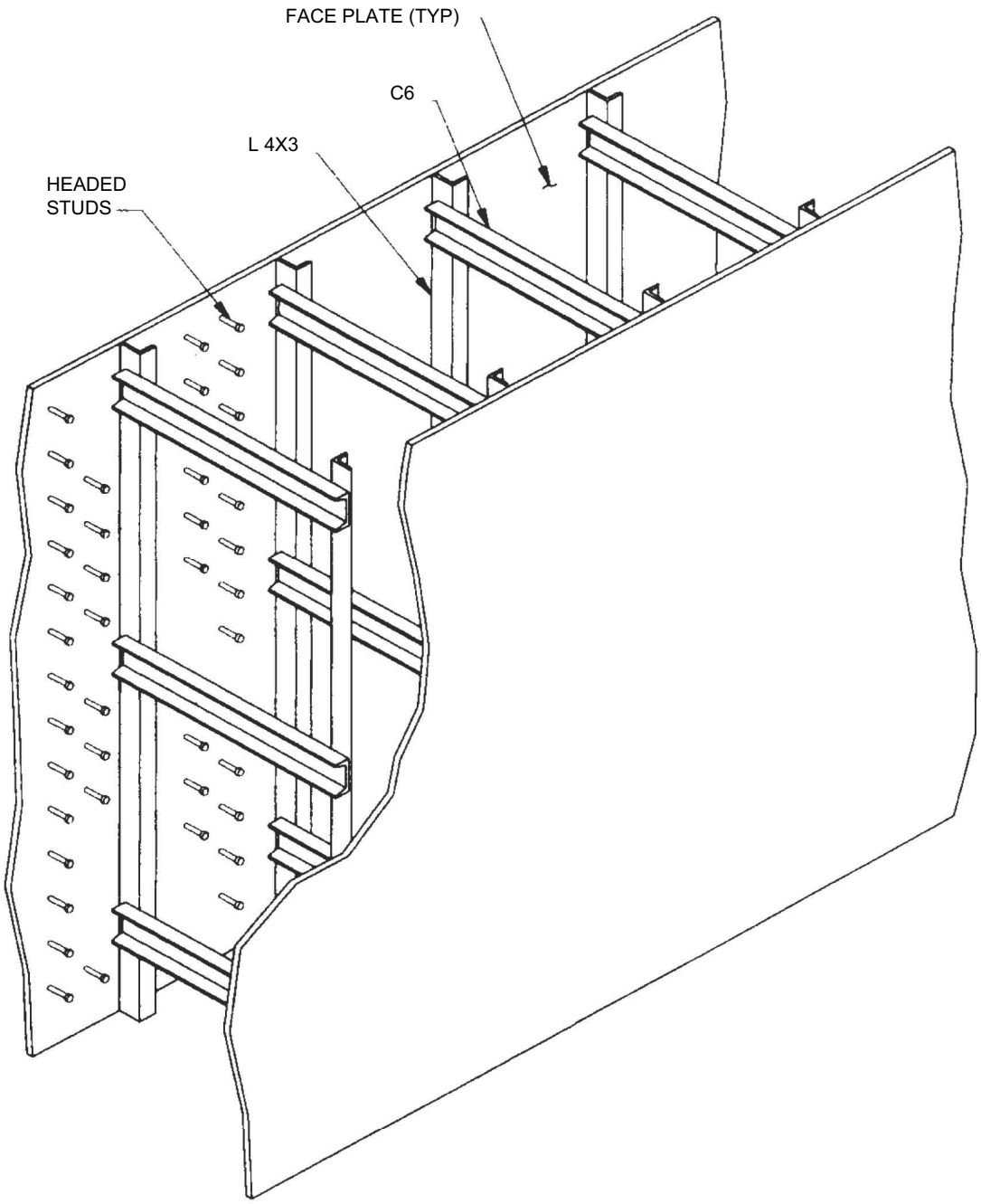


Figure 3.8.3-1 (Sheet 7 of 7)
[*Structural Modules in Containment Internal Structures*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



Note: See Figure 3.8.3-8 for fabrication detail.

Figure 3.8.3-2
[*Typical Structural Wall Module*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

NOTES:

1. DETAILS SHOWN ARE REPRESENTATIVE OF FLOOR MODULES INSIDE CONTAINMENT. CHANNELS AND WIDE FLANGE BEAMS USED IN SOME LOCATIONS ARE NOT SHOWN. REFER TO SUBSECTION 3.8.3.1.4 AND OTHER NOTES FOR ADDITIONAL INFORMATION ABOUT DESIGN DETAILS AND VARIATIONS.
2. REINFORCEMENT USE, SIZE, AND SPACING IN THE FLOOR MODULE CONCRETE SATISFY THE REQUIREMENTS OF ACI 349. WHERE USED, THE REINFORCEMENT SIZE RANGE IS #7 TO #11.
3. THE REINFORCEMENT AND FLOOR DESIGN ELEMENTS SHOWN ARE FOR LOCATIONS AWAY FROM OPENINGS, PENETRATIONS AND OTHER OBSTRUCTIONS.
4. DESIGN OF THE PLATES, BEAMS, AND STIFFENERS IN THE FLOOR, INCLUDING PLATE SIZE AND SPACING, AND TYPE, SIZE, AND SPACING OF STRUCTURAL SHAPES VARIES AND SATISFIES THE REQUIREMENTS OF AISC N690.
5. REFER TO SUBSECTION 3.8.3.5.4 FOR INFORMATION ABOUT THE SHEAR STUDS IN THE FLOOR MODULE.

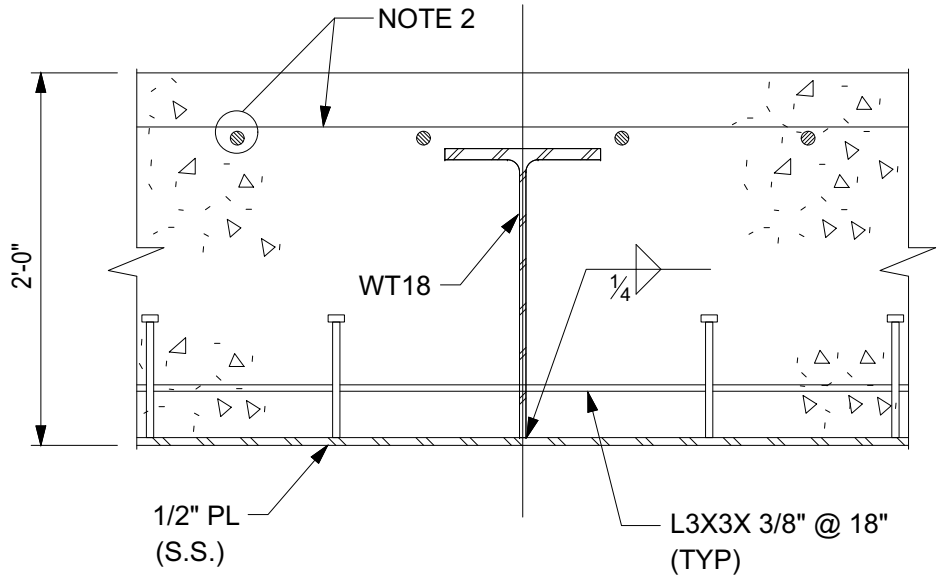


Figure 3.8.3-3
Structural Floor Module

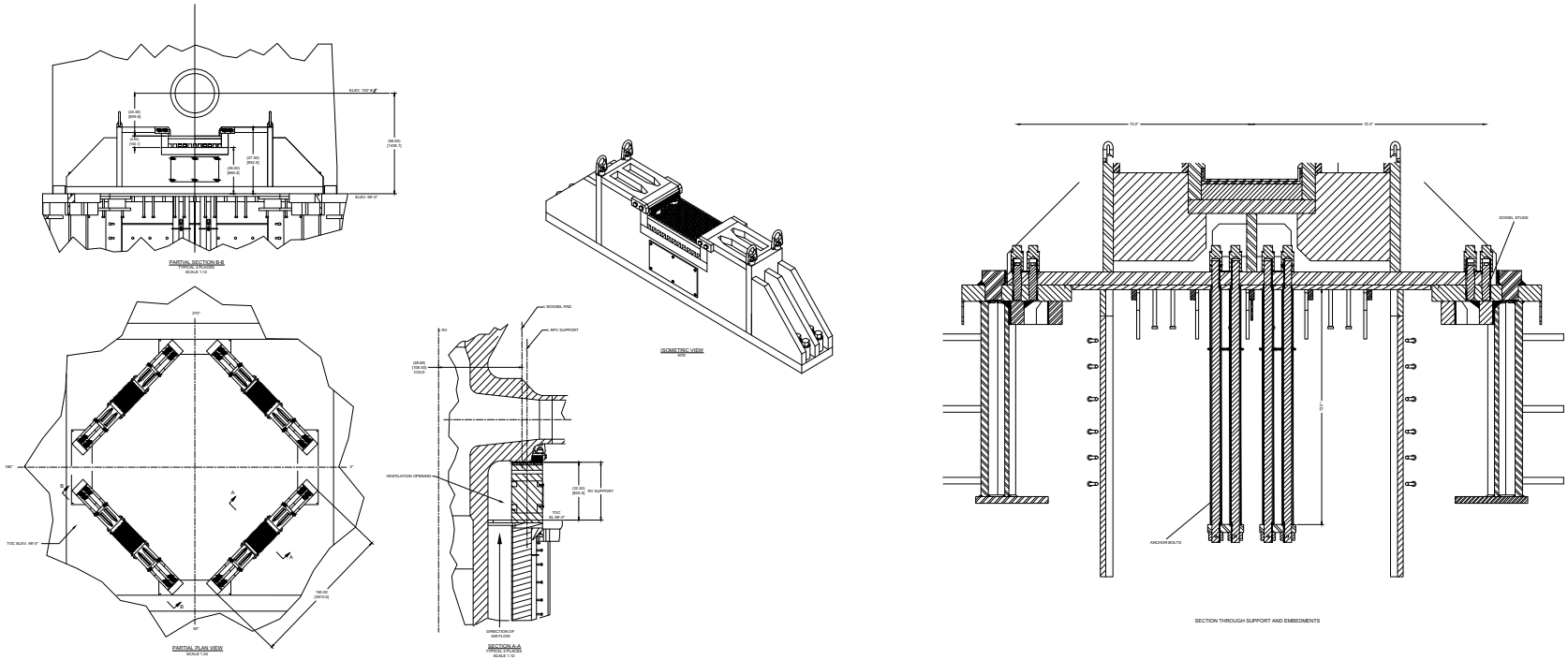
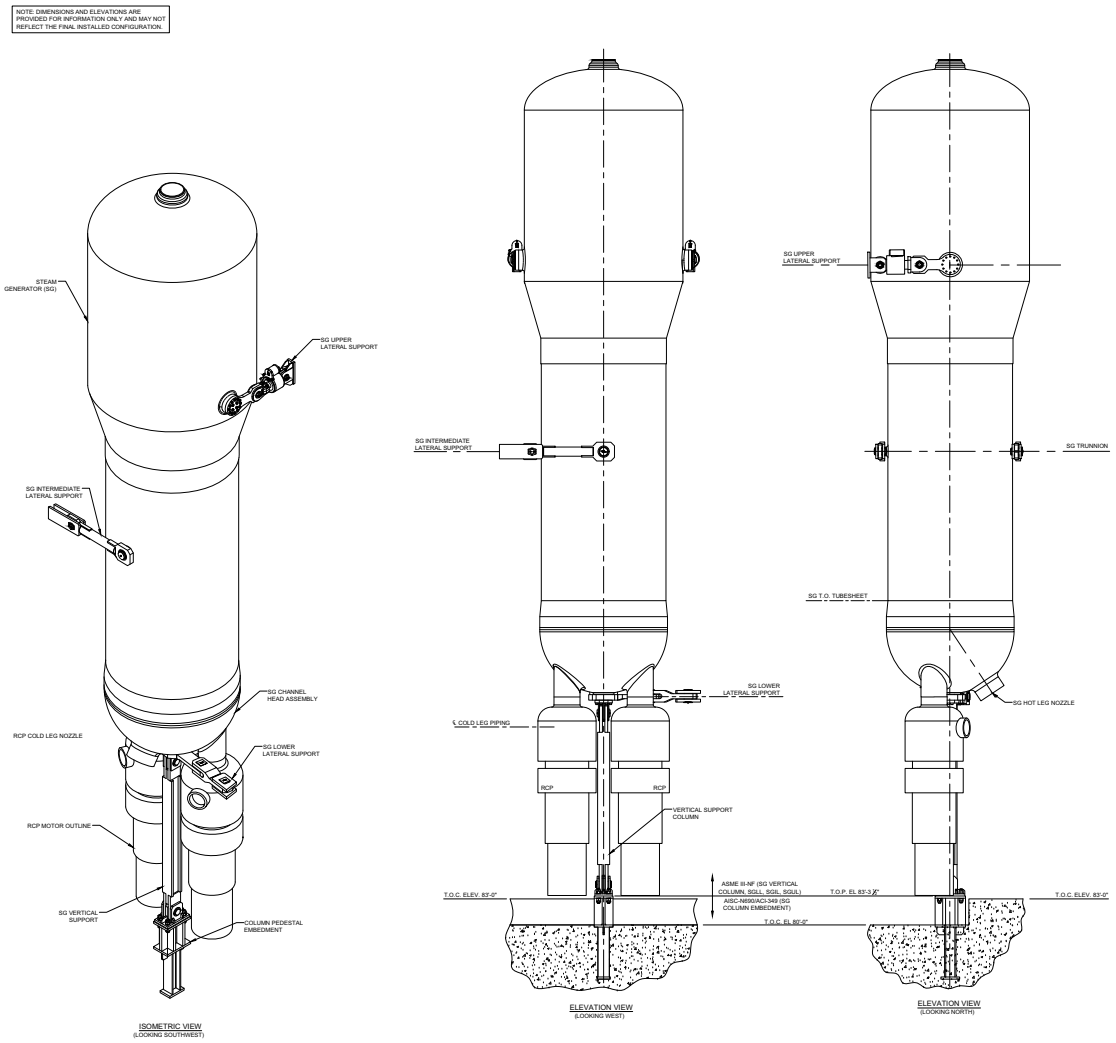


Figure 3.8.3-4
Reactor Vessel Supports



SG Support Assembly

Figure 3.8.3-5 (Sheet 1 of 5)
Steam Generator Supports

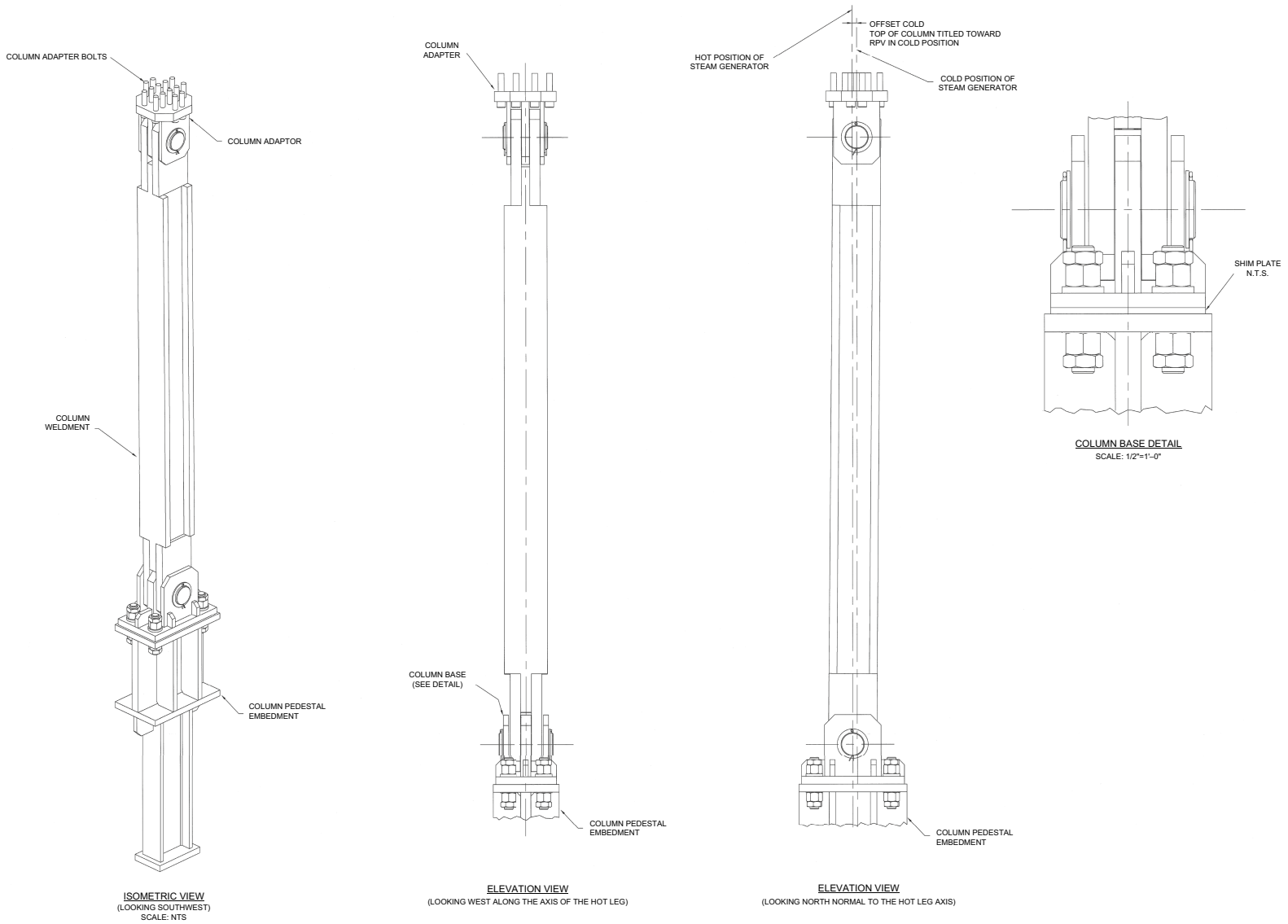
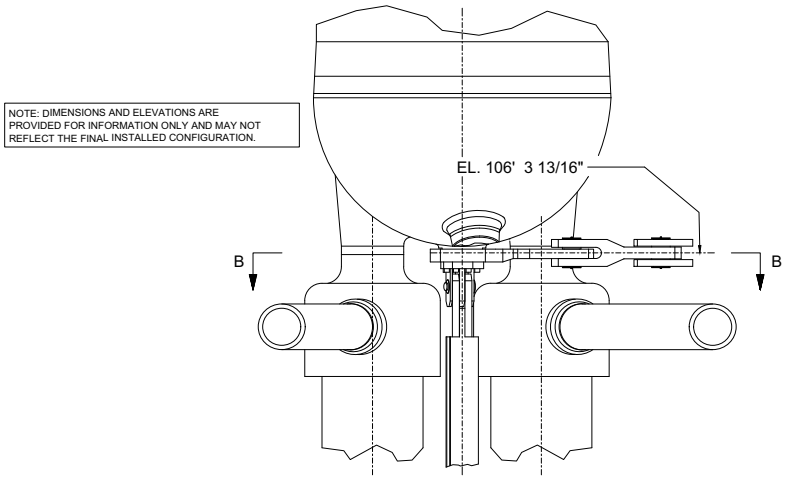
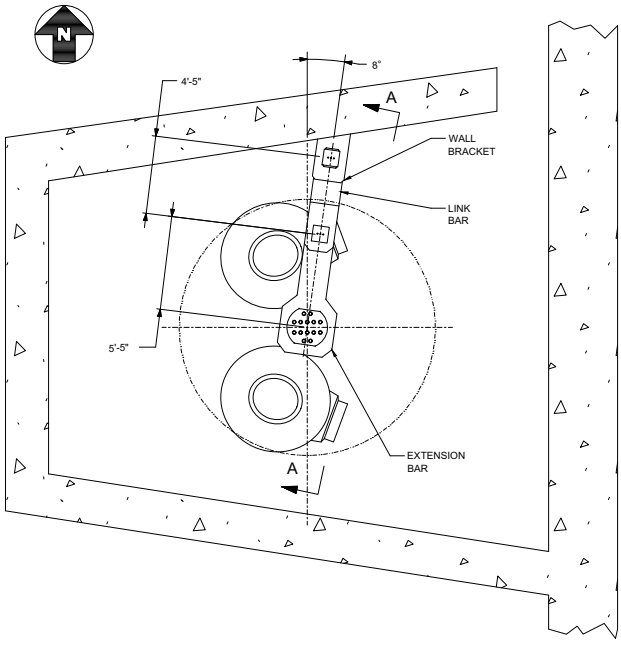


Figure 3.8.3-5 (Sheet 2 of 5)
Steam Generator Supports



ELEVATION VIEW
(ROTATED VIEW A-A)

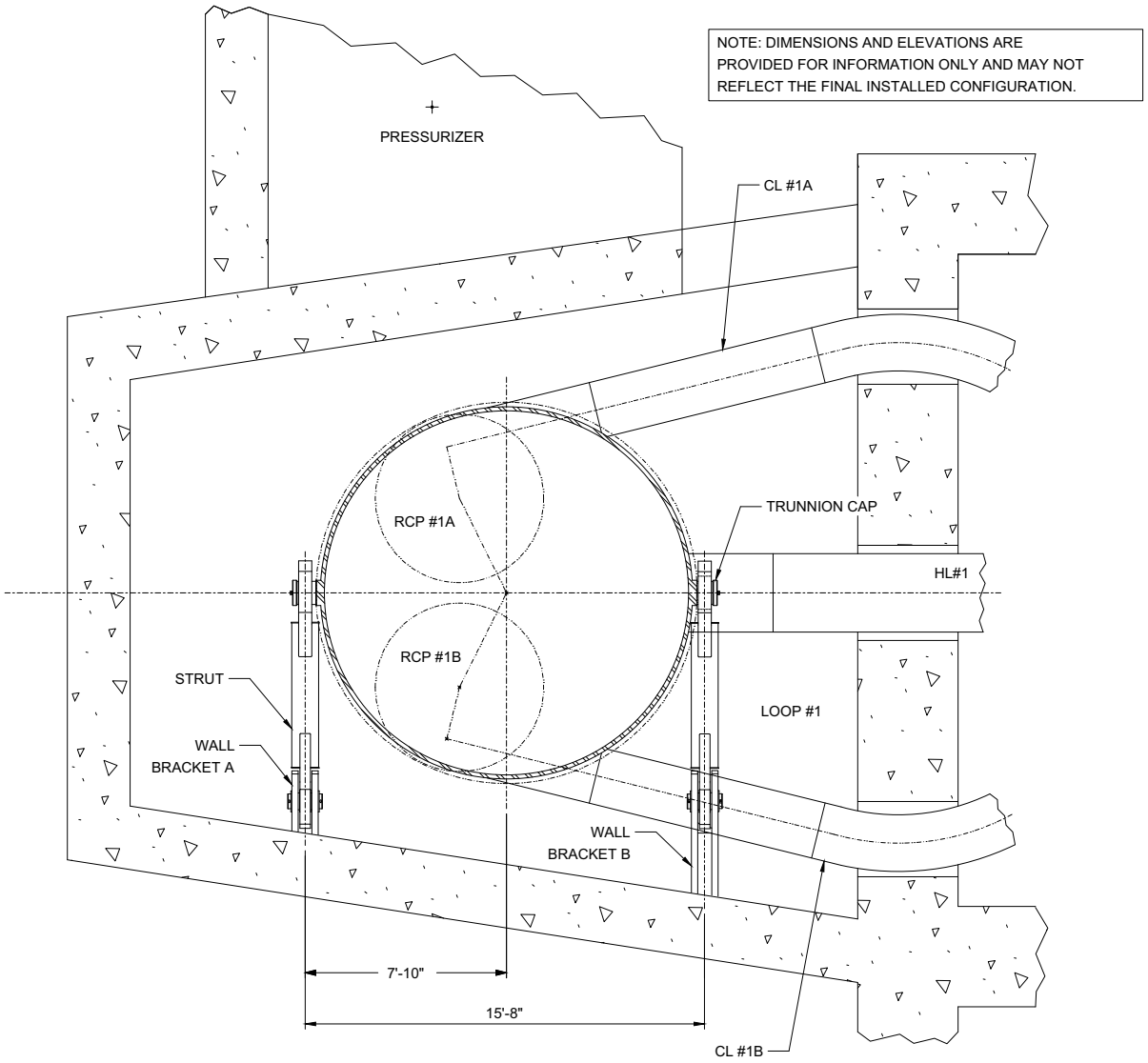
Lower Lateral Support Elevation View



PLAN VIEW
SECTION B-B

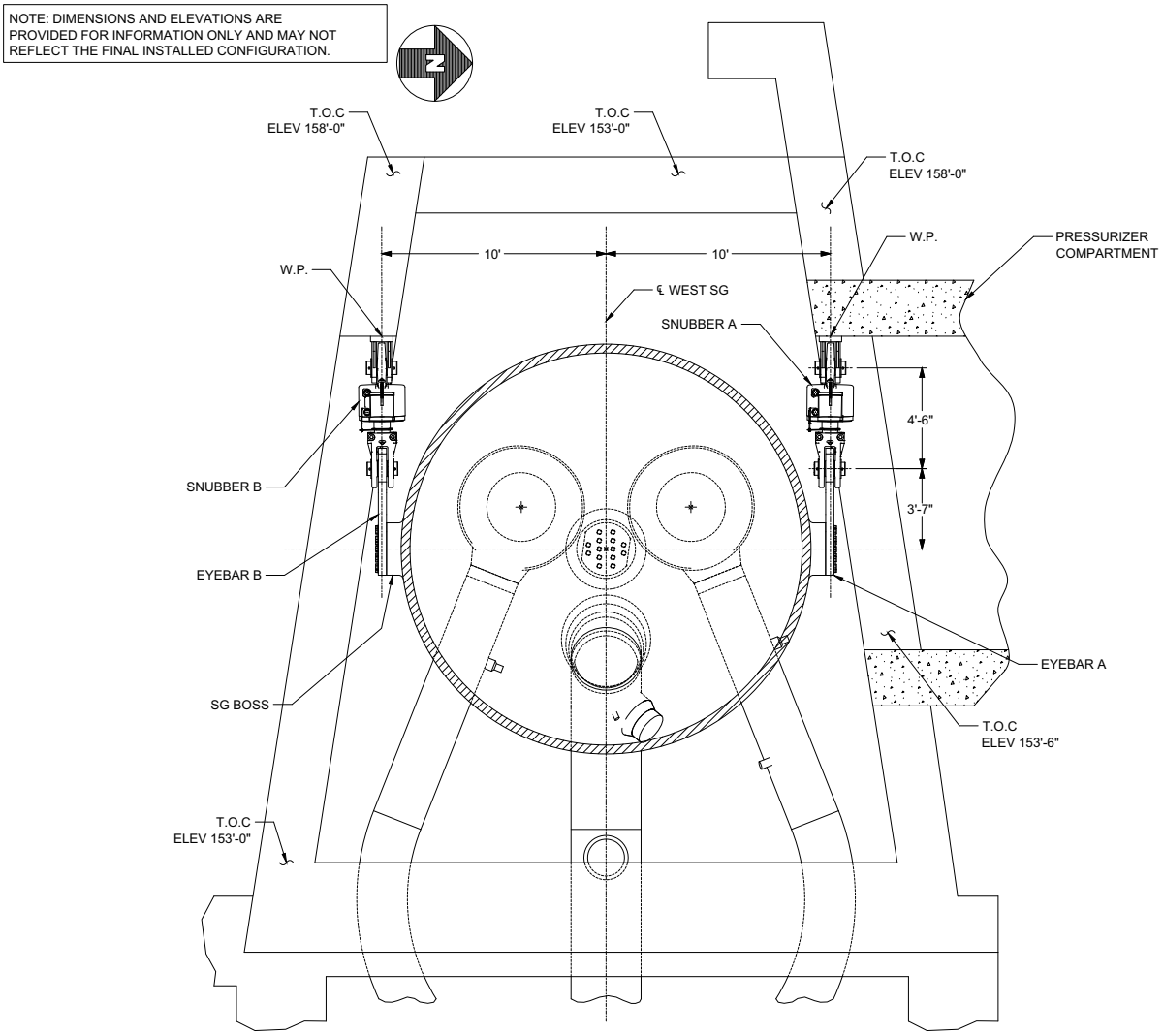
Lower Lateral Support Plan View

Figure 3.8.3-5 (Sheet 3 of 5)
Steam Generator Supports



INTERMEDIATE LATERAL SUPPORT

Figure 3.8.3-5 (Sheet 4 of 5)
Steam Generator Supports



PLAN VIEW

Upper Lateral Support

Figure 3.8.3-5 (Sheet 5 of 5)
Steam Generator Supports

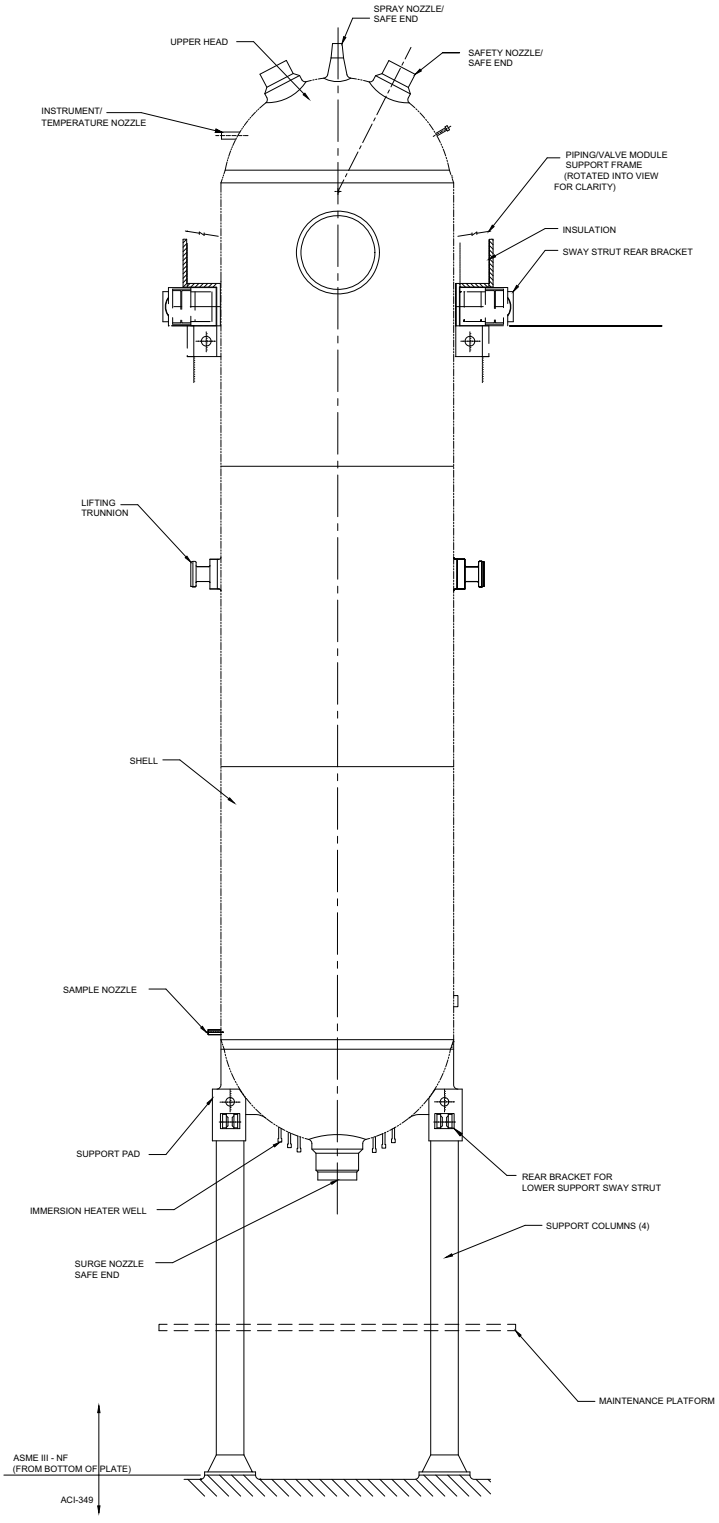


Figure 3.8.3-6 (Sheet 1 of 4)
Pressurizer Support Columns

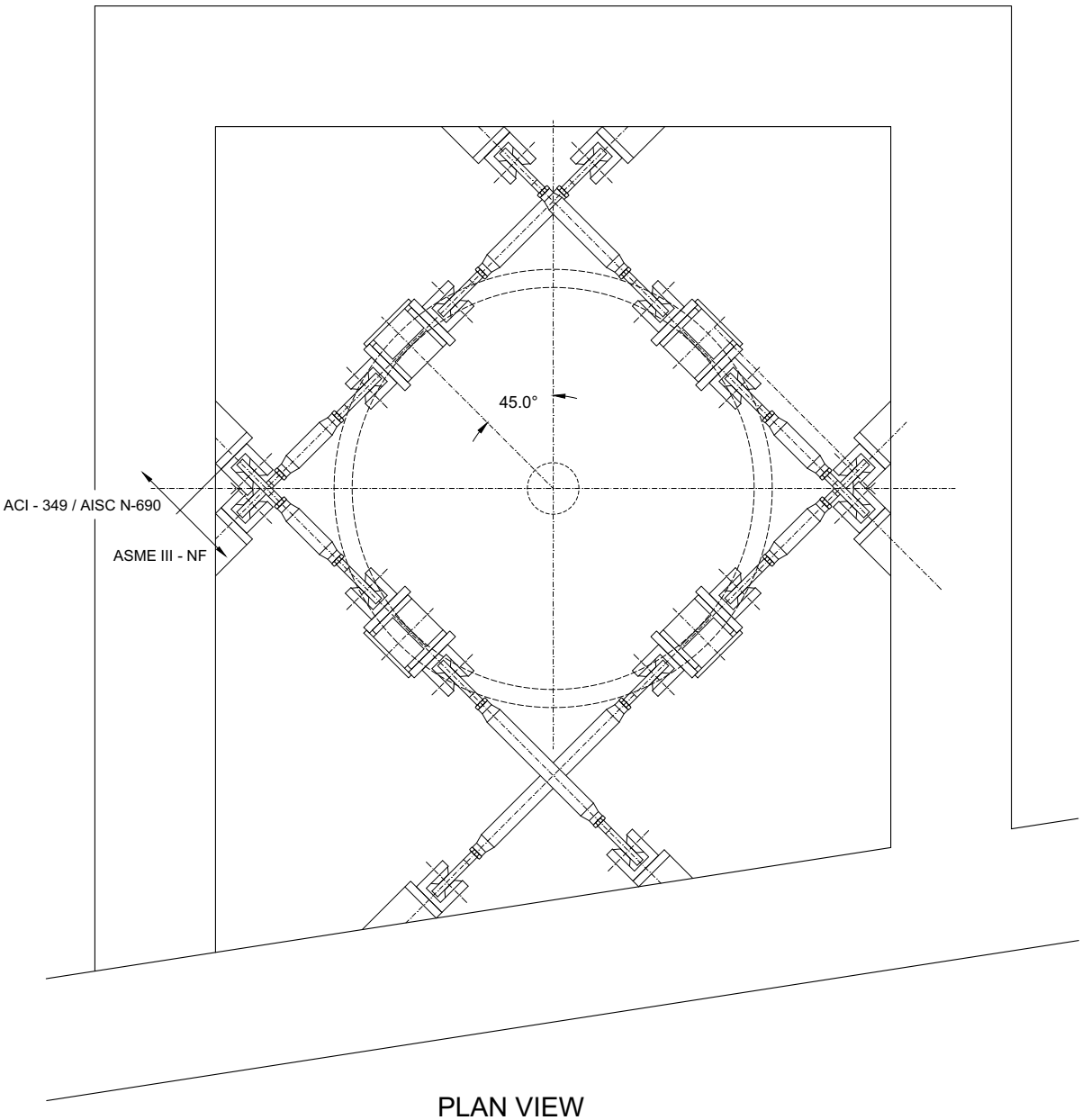
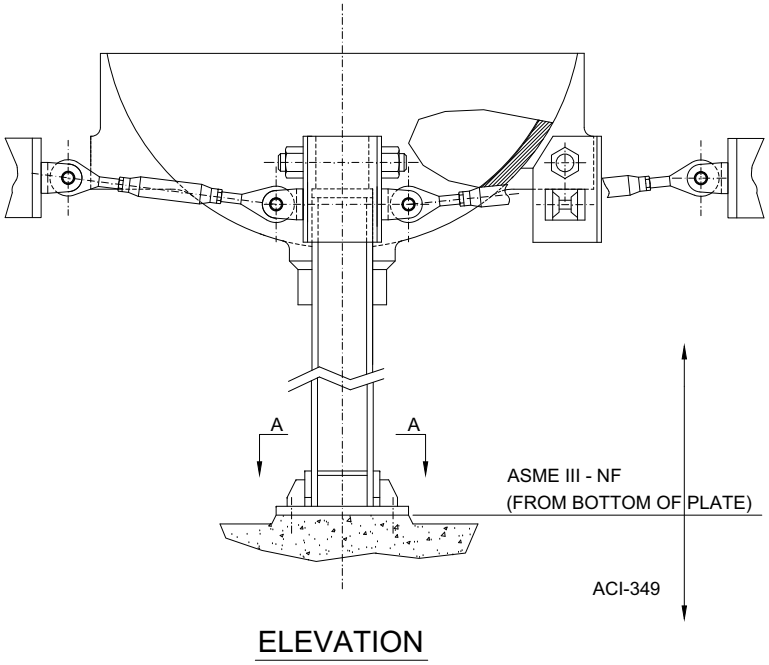
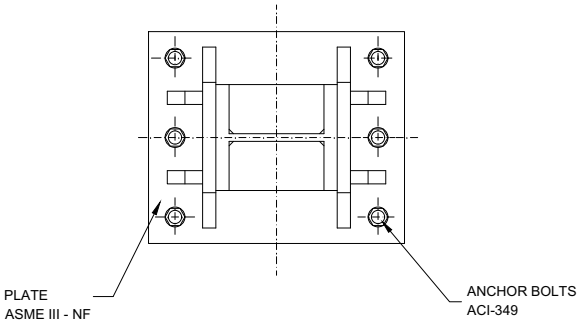


Figure 3.8.3-6 (Sheet 2 of 4)
Pressurizer Lower Lateral Supports



ELEVATION



VIEW A-A

Figure 3.8.3-6 (Sheet 3 of 4)
Pressurizer Lower Supports

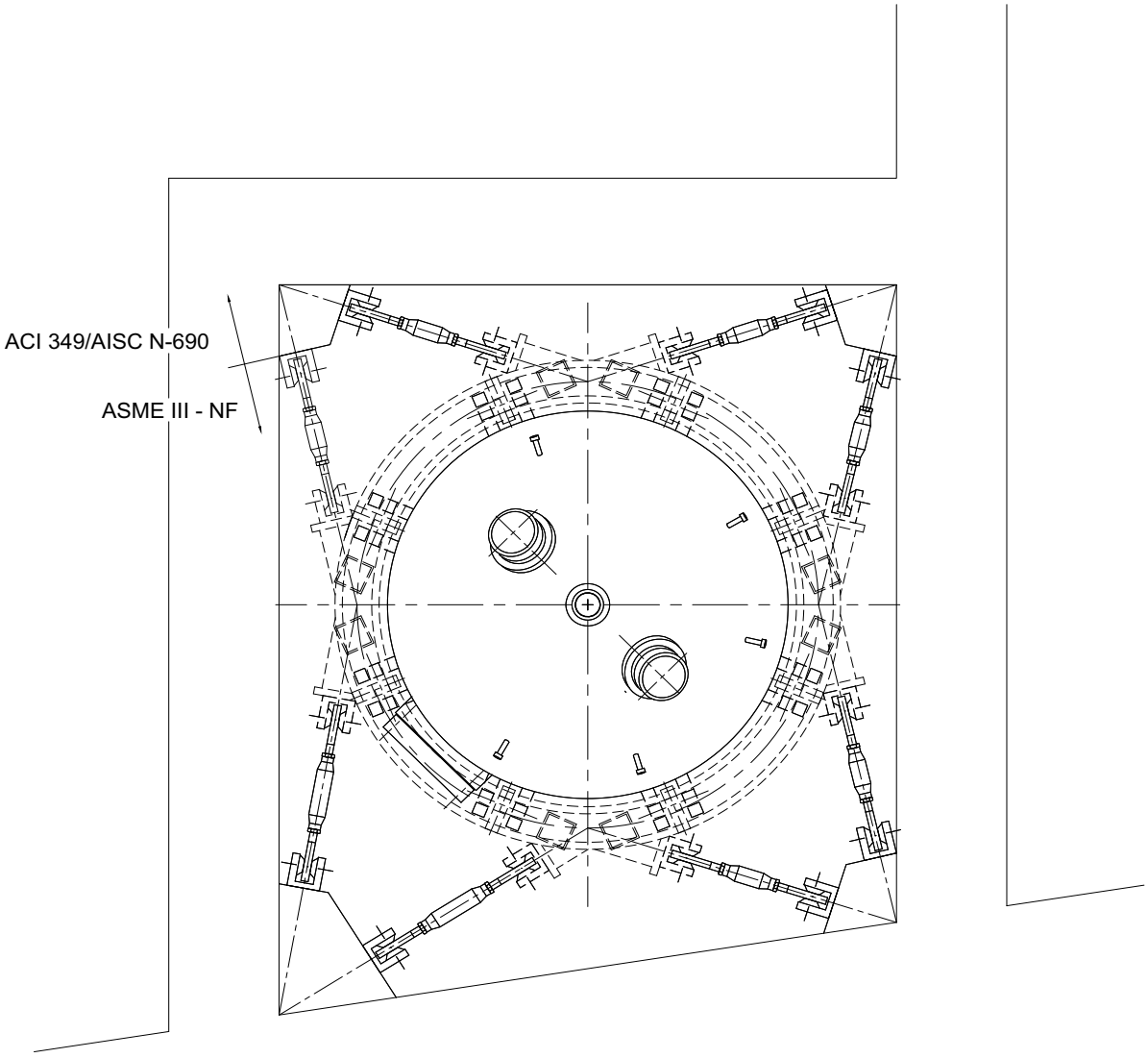


Figure 3.8.3-6 (Sheet 4 of 4)
Pressurizer Upper Supports

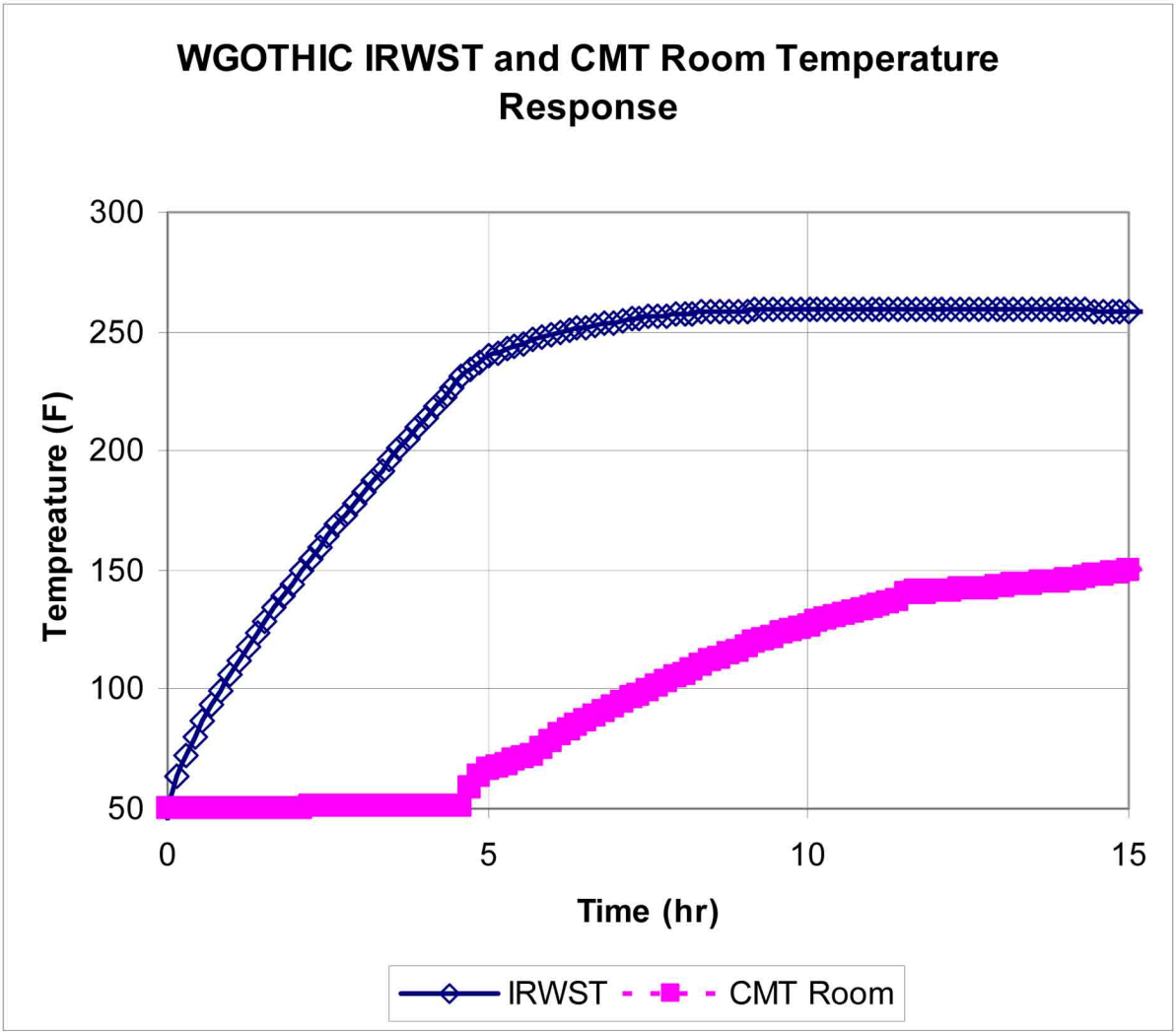
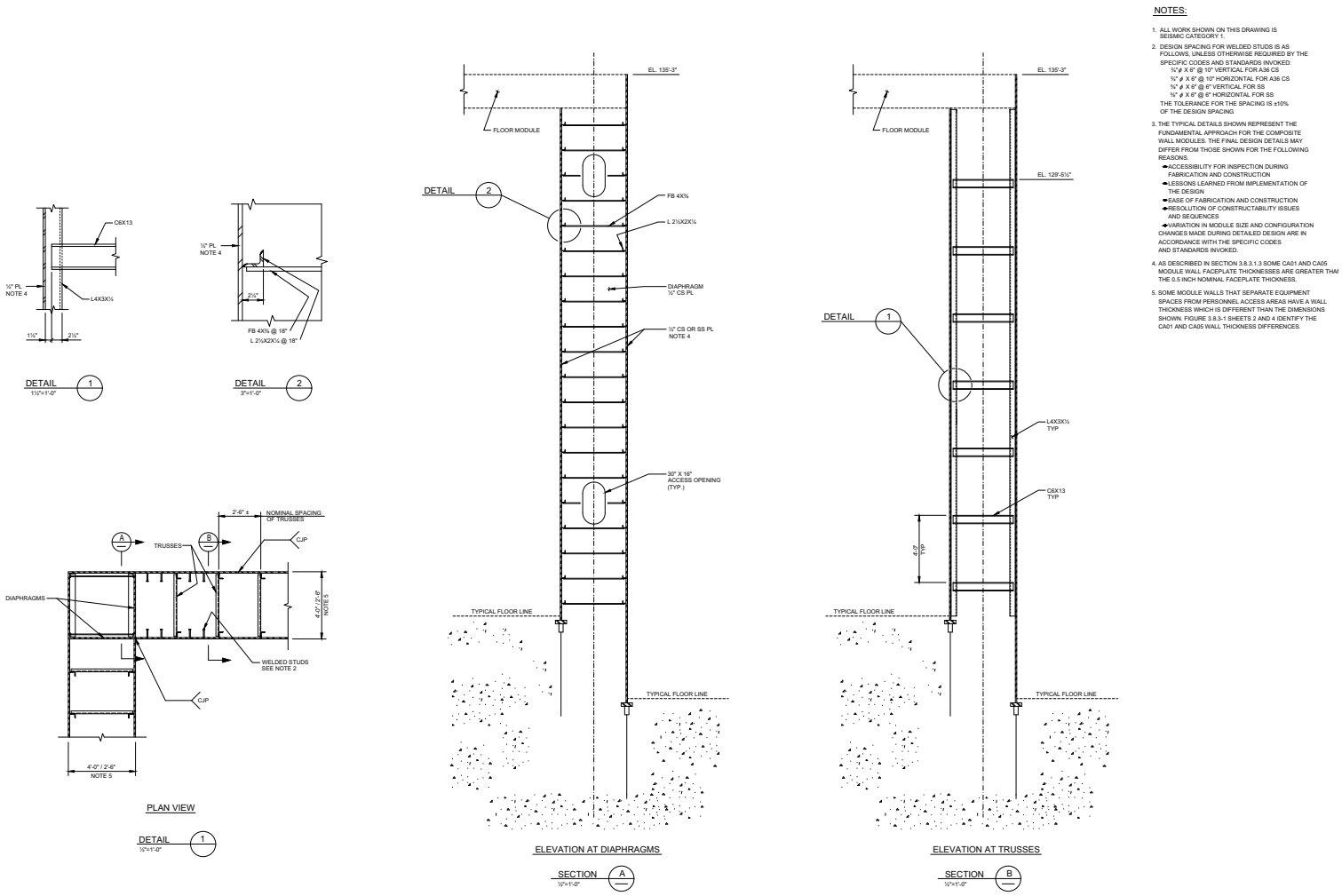


Figure 3.8.3-7
IRWST Temperature Transient



See subsection 3.8.3.1.3 for information that is designated as Tier 2*

TYPICAL STRUCTURAL WALL MODULE

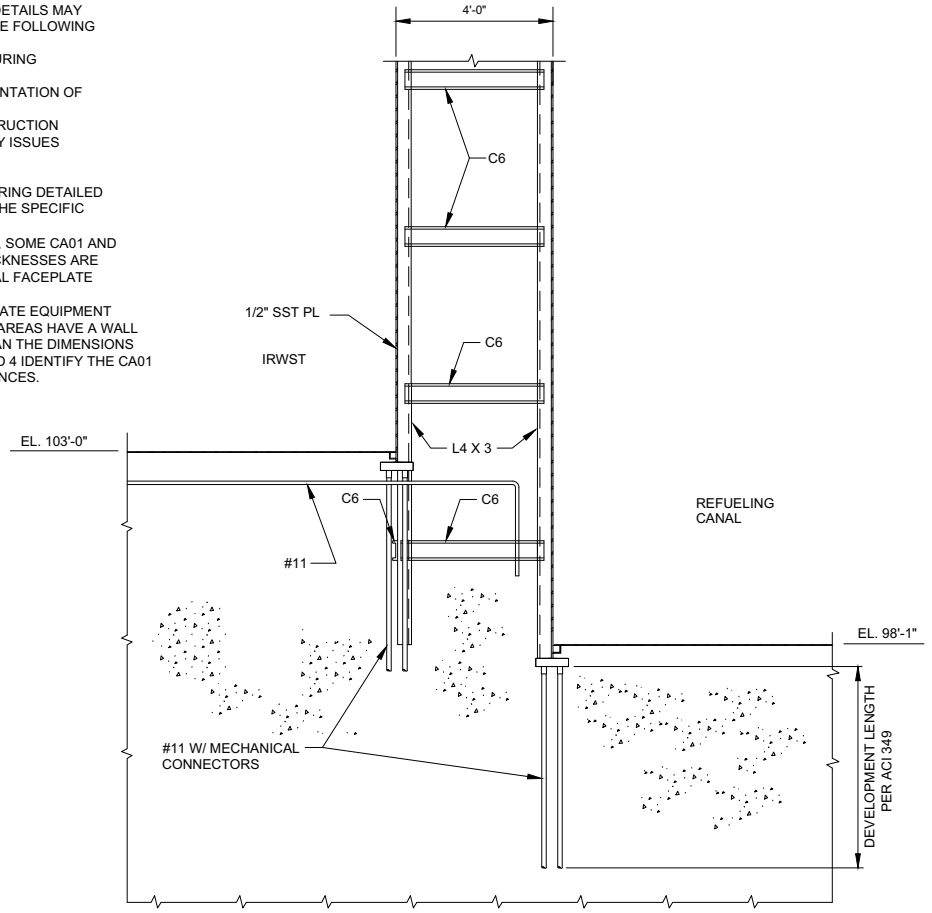
Figure 3.8.3-8 (Sheet 1 of 3)
[*Structural Modules – Typical Design Details*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

NOTES:

THE TYPICAL DETAILS SHOWN REPRESENT THE FUNDAMENTAL APPROACH FOR THE COMPOSITE WALL MODULES. THE FINAL DESIGN DETAILS MAY DIFFER FROM THOSE SHOWN FOR THE FOLLOWING REASONS.

- ACCESSIBILITY FOR INSPECTION DURING FABRICATION AND CONSTRUCTION
- LESSONS LEARNED FROM IMPLEMENTATION OF THE DESIGN
- EASE OF FABRICATION AND CONSTRUCTION
- RESOLUTION OF CONSTRUCTABILTY ISSUES AND SEQUENCES
- VARIATION IN MODULE SIZE AND CONFIGURATION CHANGES MADE DURING DETAILED DESIGN ARE IN ACCORDANCE WITH THE SPECIFIC CODES AND STANDARDS INVOKED.
- AS DESCRIBED IN SECTION 3.8.3.1.3, SOME CA01 AND CA05 MODULE WALL FACEPLATE THICKNESSES ARE GREATER THAN THE 0.5 INCH NOMINAL FACEPLATE THICKNESS.
- SOME MODULE WALLS THAT SEPARATE EQUIPMENT SPACES FROM PERSONNEL ACCESS AREAS HAVE A WALL THICKNESS WHICH IS DIFFERENT THAN THE DIMENSIONS SHOWN. FIGURE 3.8.3-1 SHEETS 2 AND 4 IDENTIFY THE CA01 AND CA05 WALL THICKNESS DIFFERENCES.



CHANGES TO THE MECHANICAL CONNECTOR DETAIL SHOWN WILL MAINTAIN A DIRECT LOAD PATH TO TRANSFER LOADS FROM THE MODULE FACE PLATES TO THE REINFORCEMENT BARS IN THE BASE CONCRETE THROUGH THE USE OF INTERVENING PLATES, MECHANICAL CONNECTORS, AND WELDS.

SEE SUBSECTION 3.8.3.1.3 FOR INFORMATION THAT IS DESIGNATED AS TIER 2*.

Figure 3.8.3-8 (Sheet 2 of 3)
[*Structural Modules – Typical Design Details*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

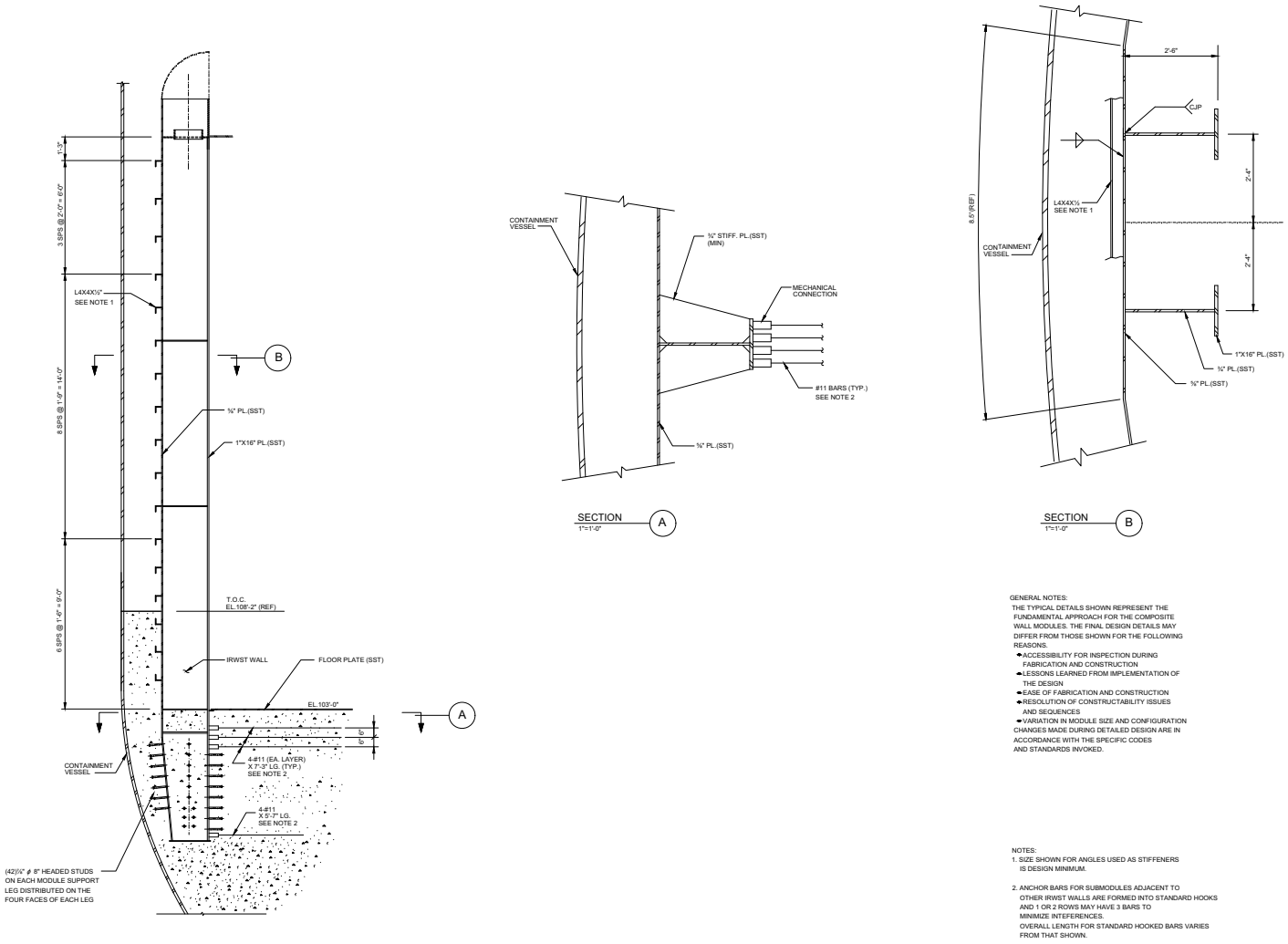


Figure 3.8.3-8 (Sheet 3 of 3)
[*Structural Modules – Typical Design Details*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

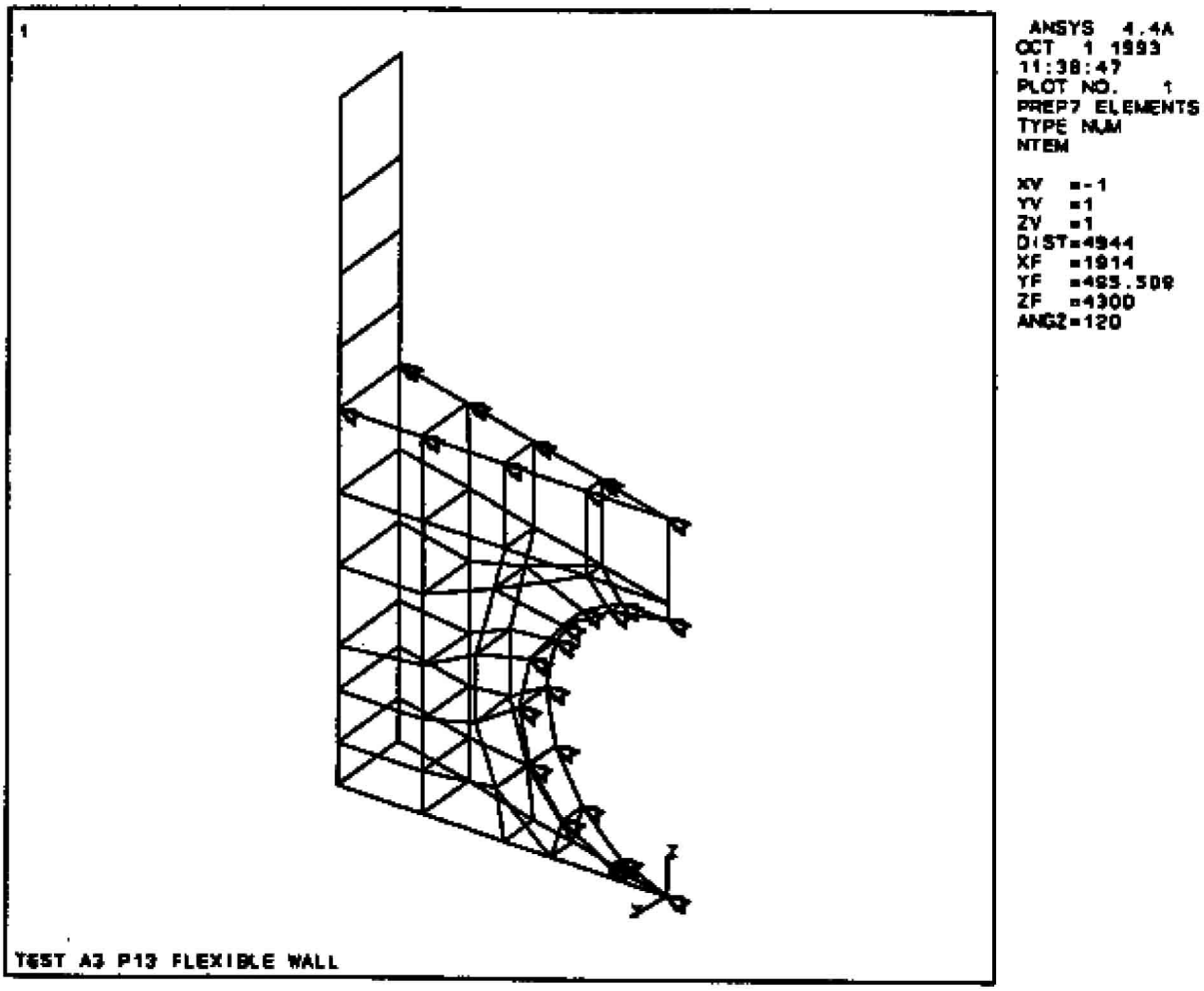


Figure 3.8.3-9
Test Tank Finite Element Model

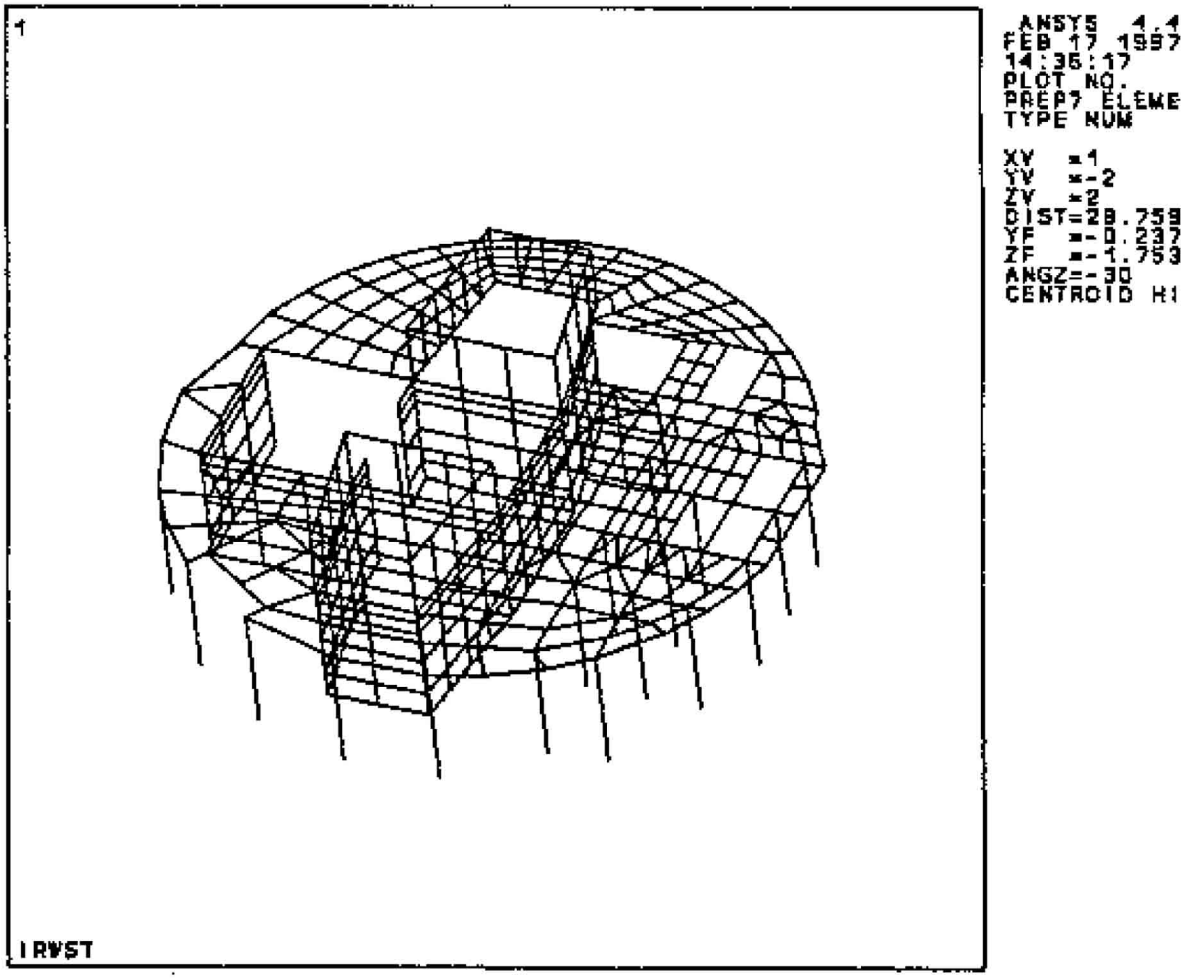


Figure 3.8.3-10 (Sheet 1 of 2)
IRWST Fluid Structure Finite Element Model
CIS Structural Model

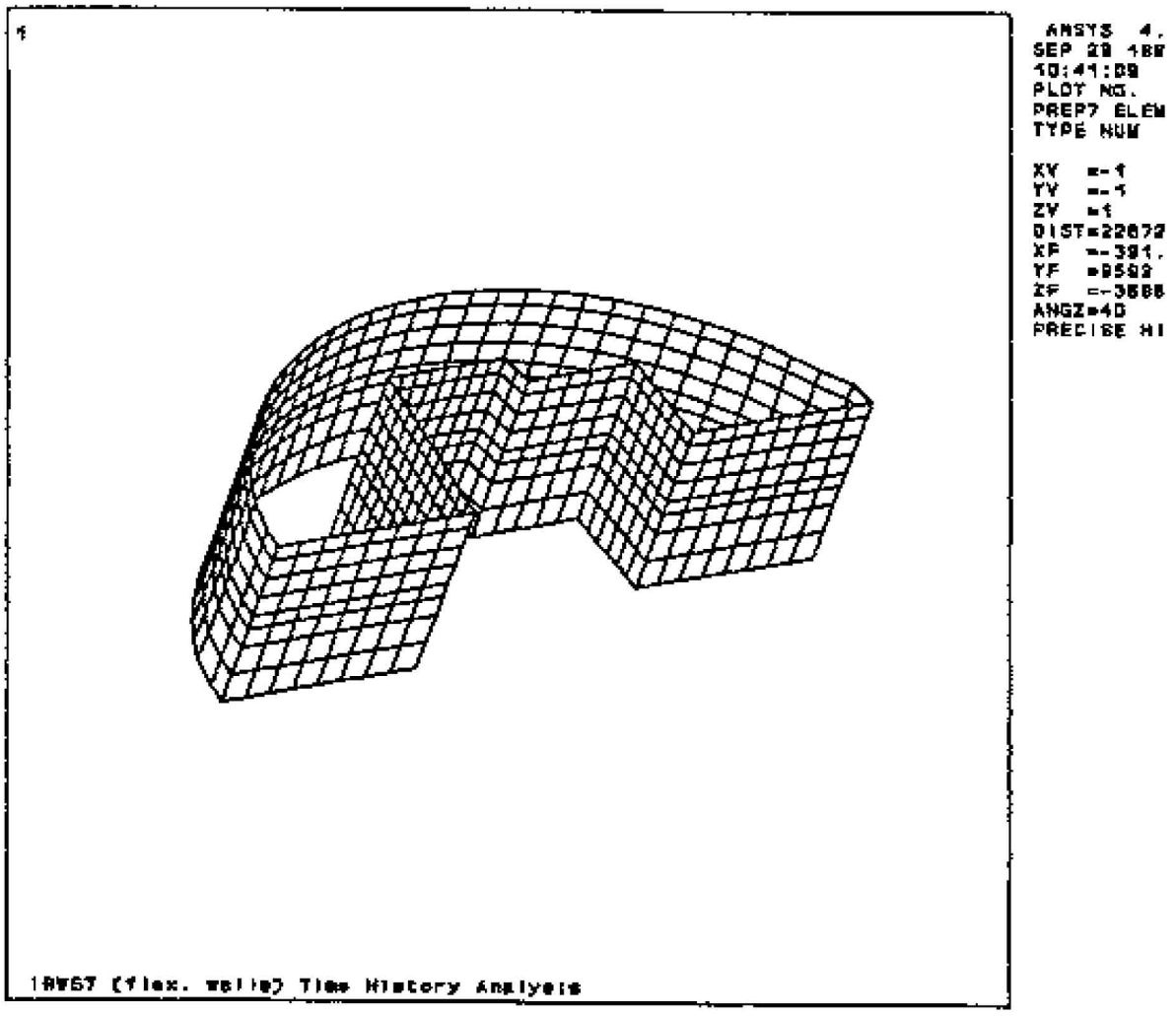


Figure 3.8.3-10 (Sheet 2 of 2)
IRWST Fluid Structure Finite Element Model
IRWST Structural Model

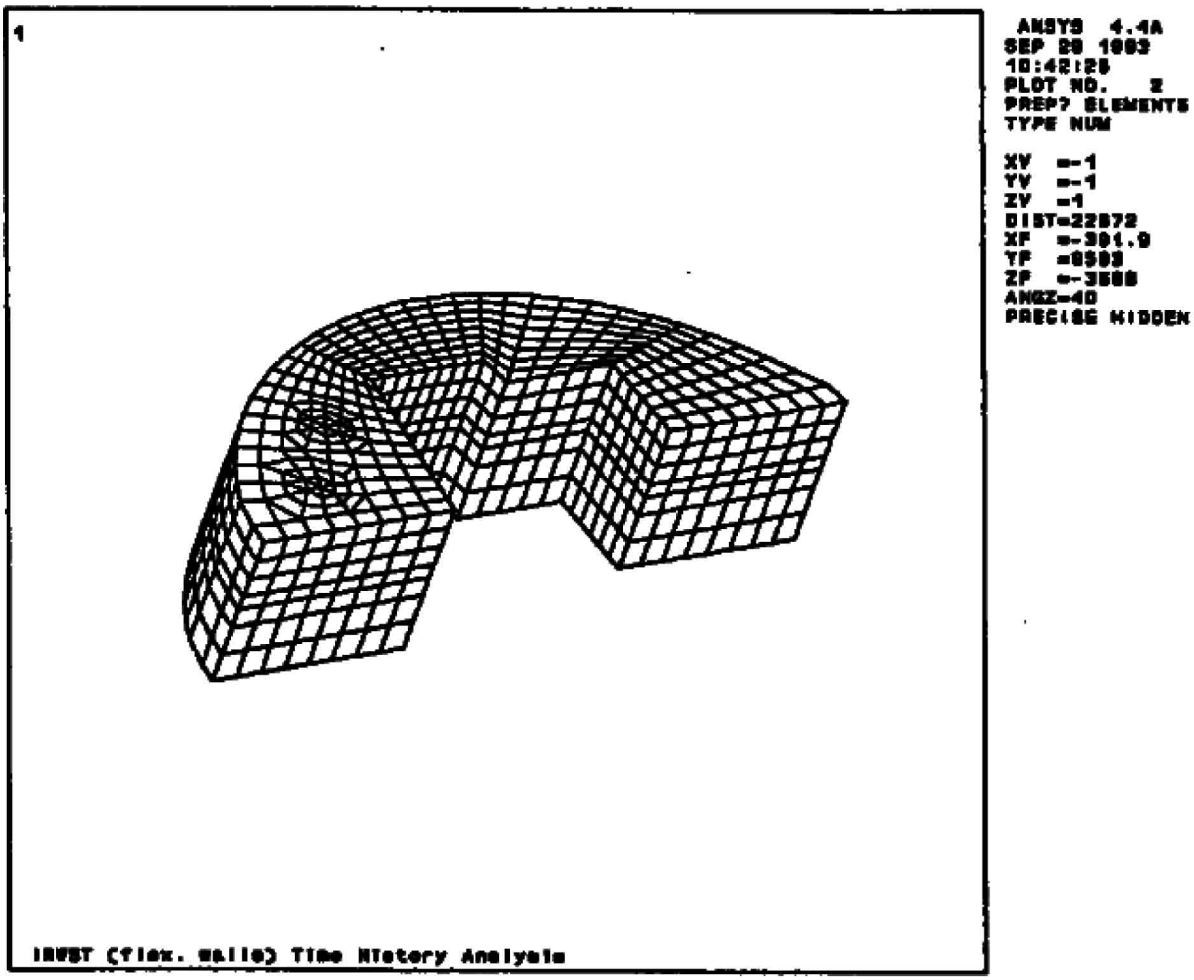


Figure 3.8.3-11
IRWST Fluid Structure Finite Element Model
Fluid Model

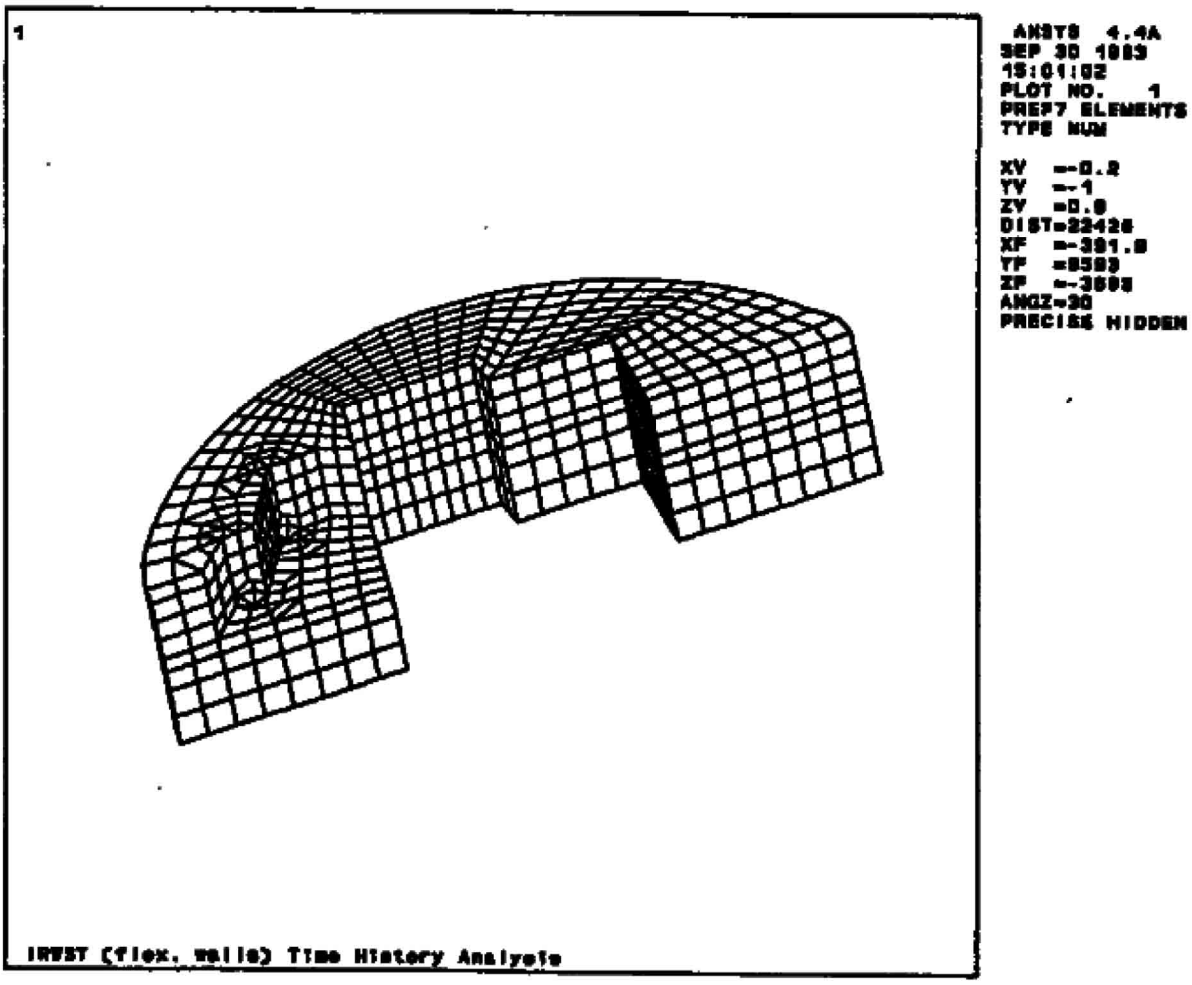
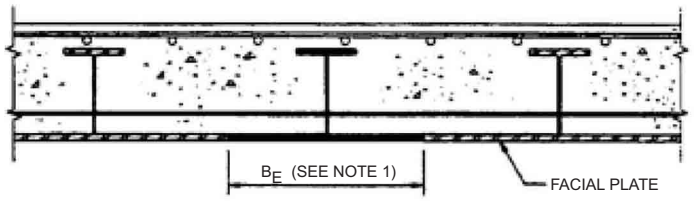
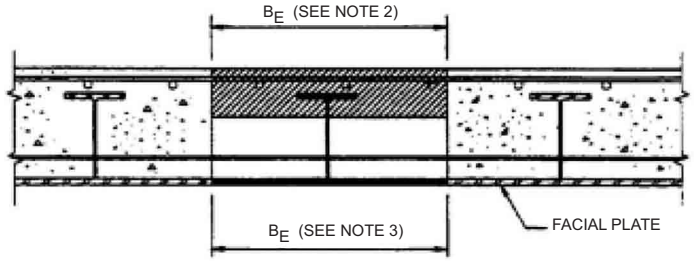


Figure 3.8.3-12
IRWST Fluid Structure Finite Element Model
Sparger Region Detail



FACIAL PLATE IN COMPRESSION



FACIAL PLATE IN TENSION

EFFECTIVE SOLUTIONS FOR FLOOR MODULES

NOTES:

1. FOR FACIAL PLATE IN COMPRESSION, b_e, IS DETERMINED PER SECTION 3.8.3.5.4.2
2. EFFECTIVE WIDTH OF CONCRETE b_e, IS DETERMINED PER SECTION Q 1.11.1 OF AISC N690.
3. FOR FACIAL PLATE IN TENSION, b_e, IS TAKEN TO BE ONE HALF OF THE DISTANCE TO THE ADJACENT BEAMS.

Figure 3.8.3-13
Effective Sections for Floor Modules

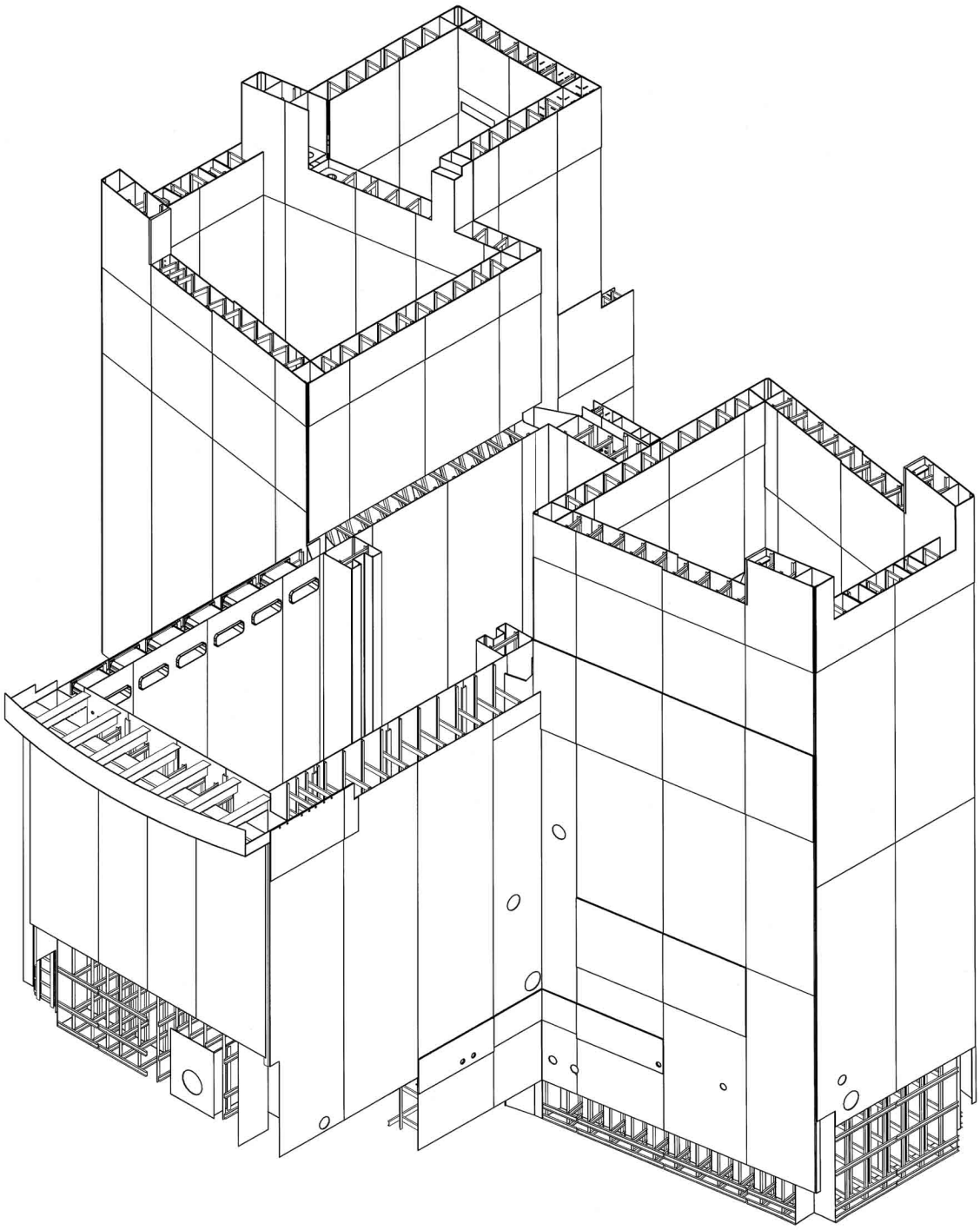


Figure 3.8.3-14 (Sheet 1 of 5)
[*CA-01 Module*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

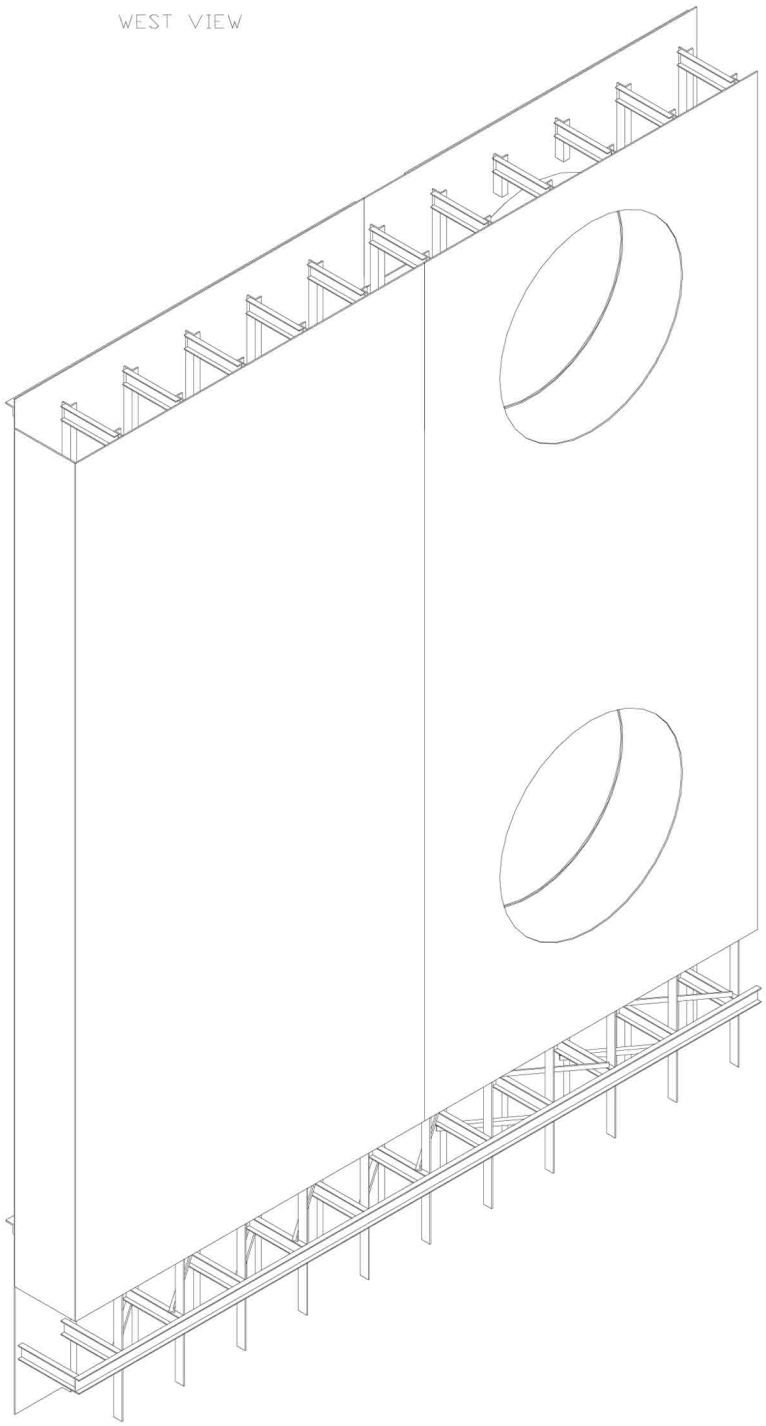


Figure 3.8.3-14 (Sheet 2 of 5)
[*CA-02 Module*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

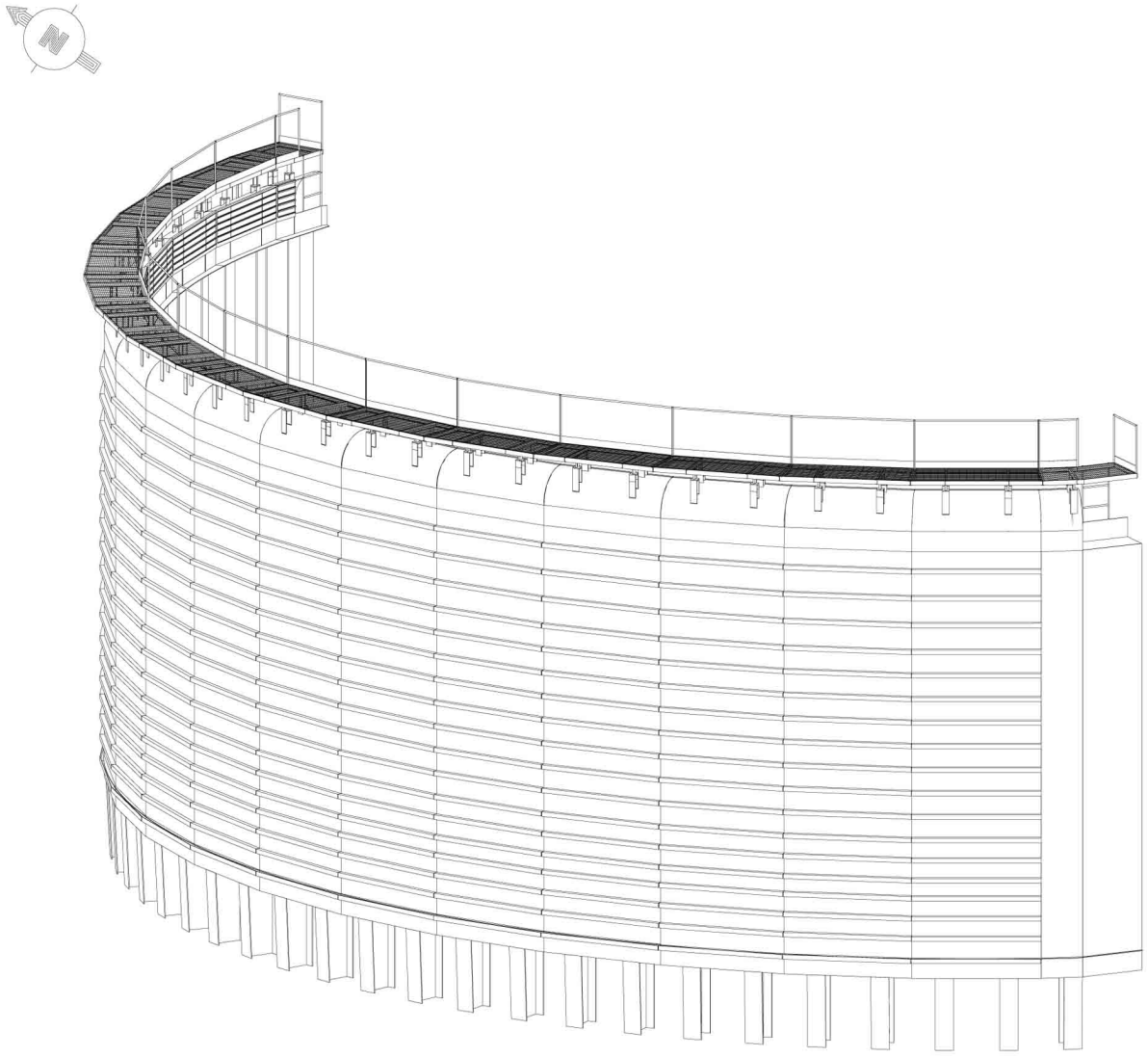


Figure 3.8.3-14 (Sheet 3 of 5)
[*CA-03 Module*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



Figure 3.8.3-14 (Sheet 4 of 5)
[*CA-04 Structural Module*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

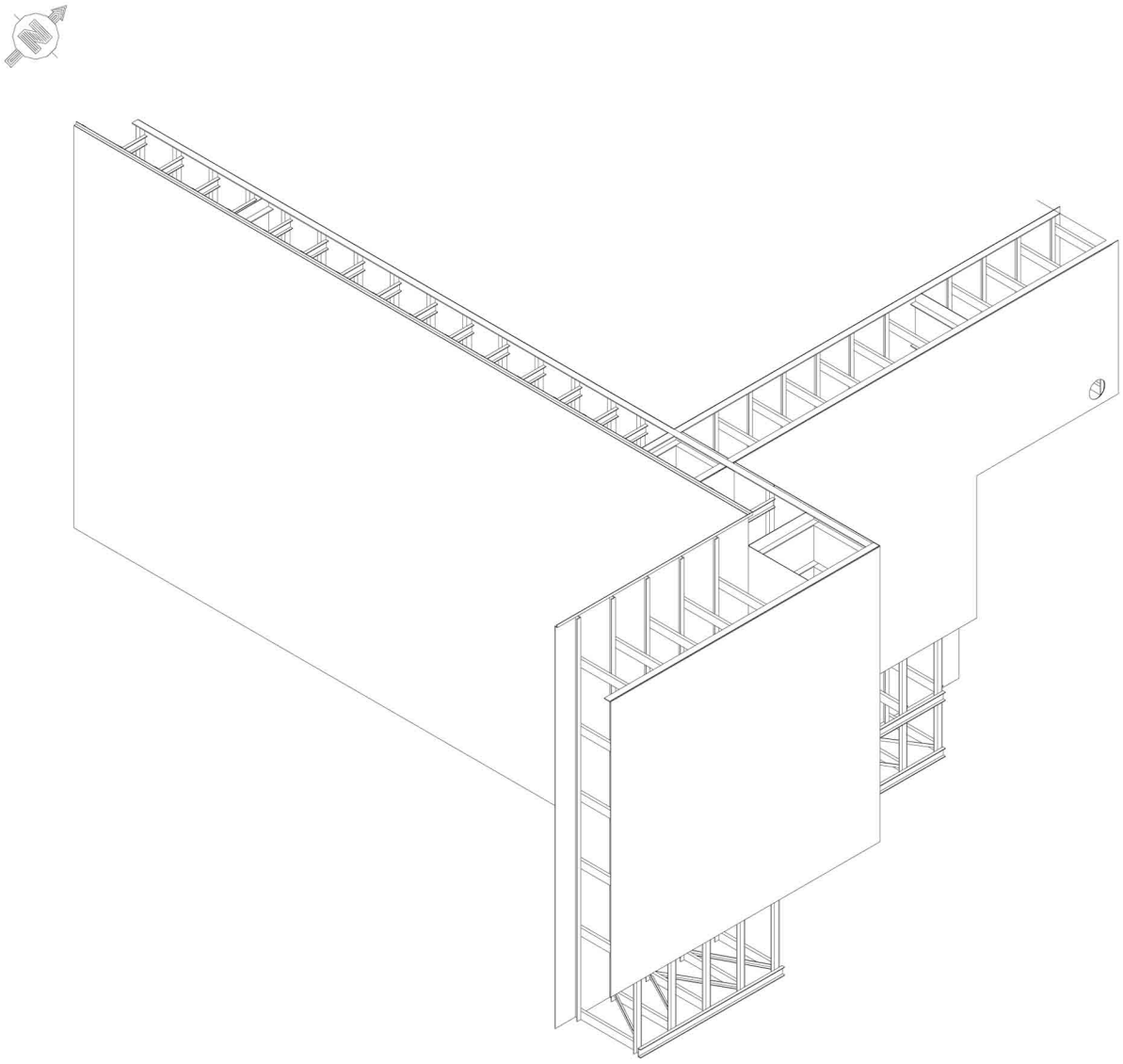
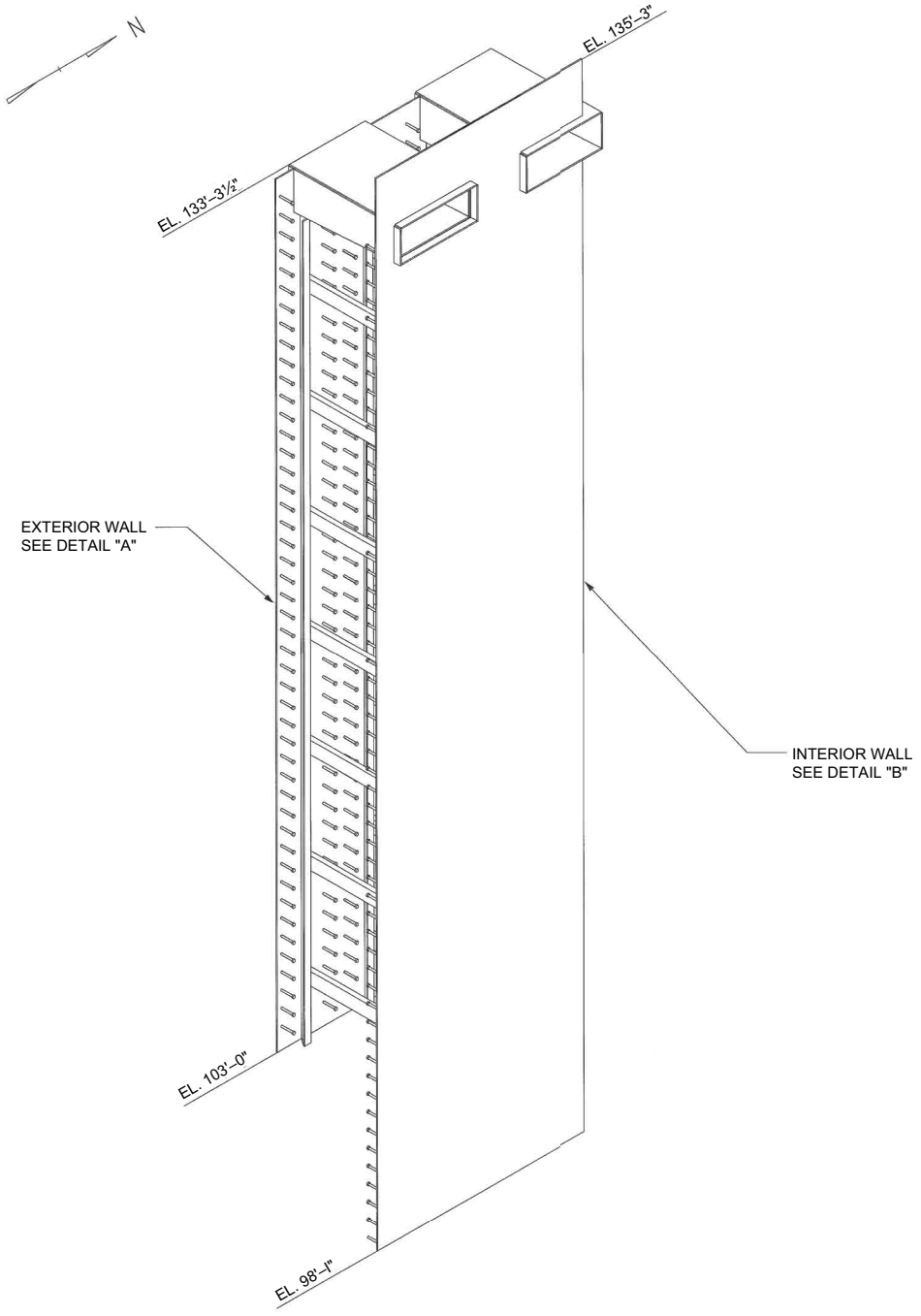


Figure 3.8.3-14 (Sheet 5 of 5)
[*CA-05 Module*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



Note: See Figure 3.8.3-8 for fabrication detail.

Figure 3.8.3-15 (Sheet 1 of 2)
[*Typical Submodule*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

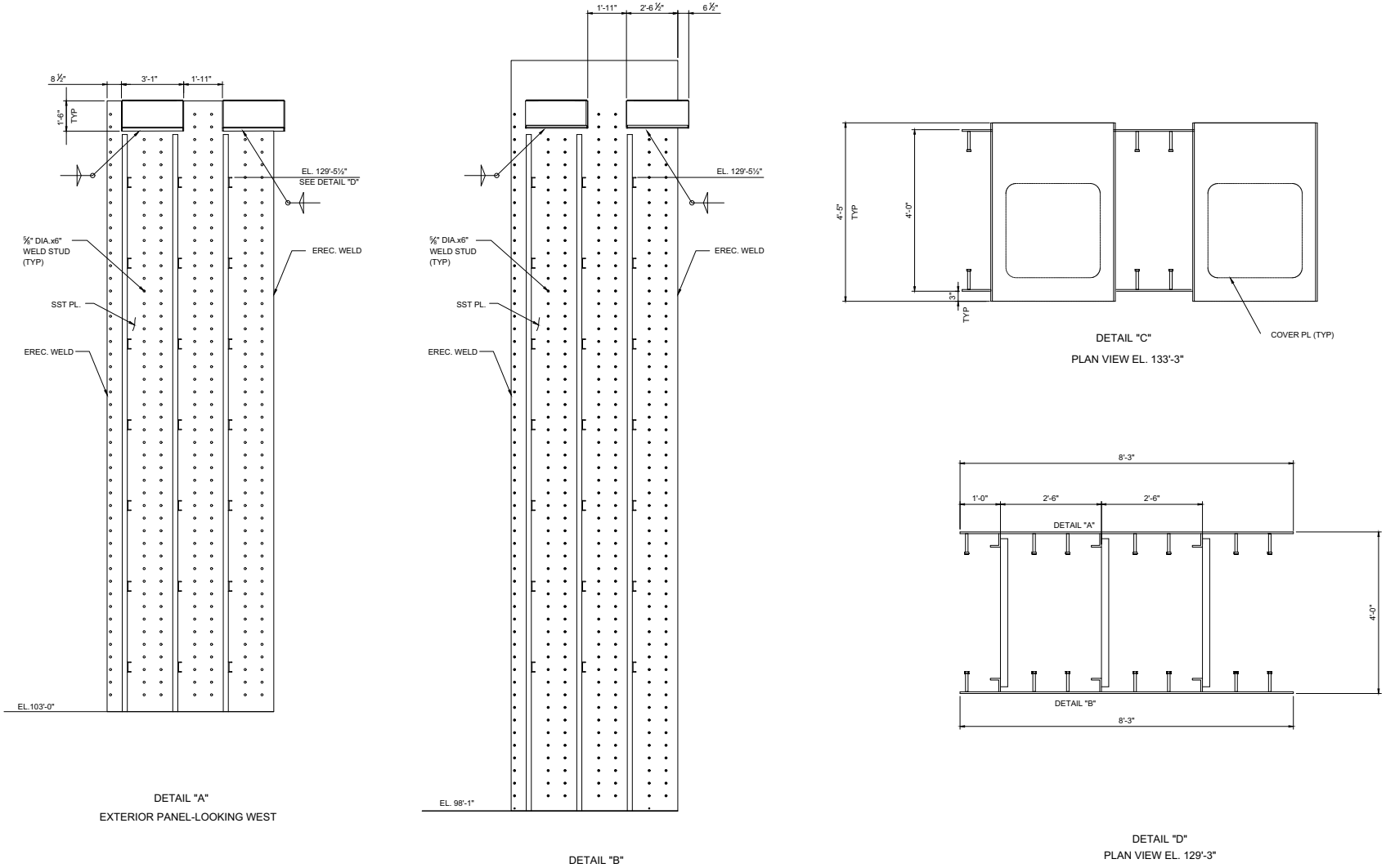


Figure 3.8.3-15 (Sheet 2 of 2)
[*Typical Submodule*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

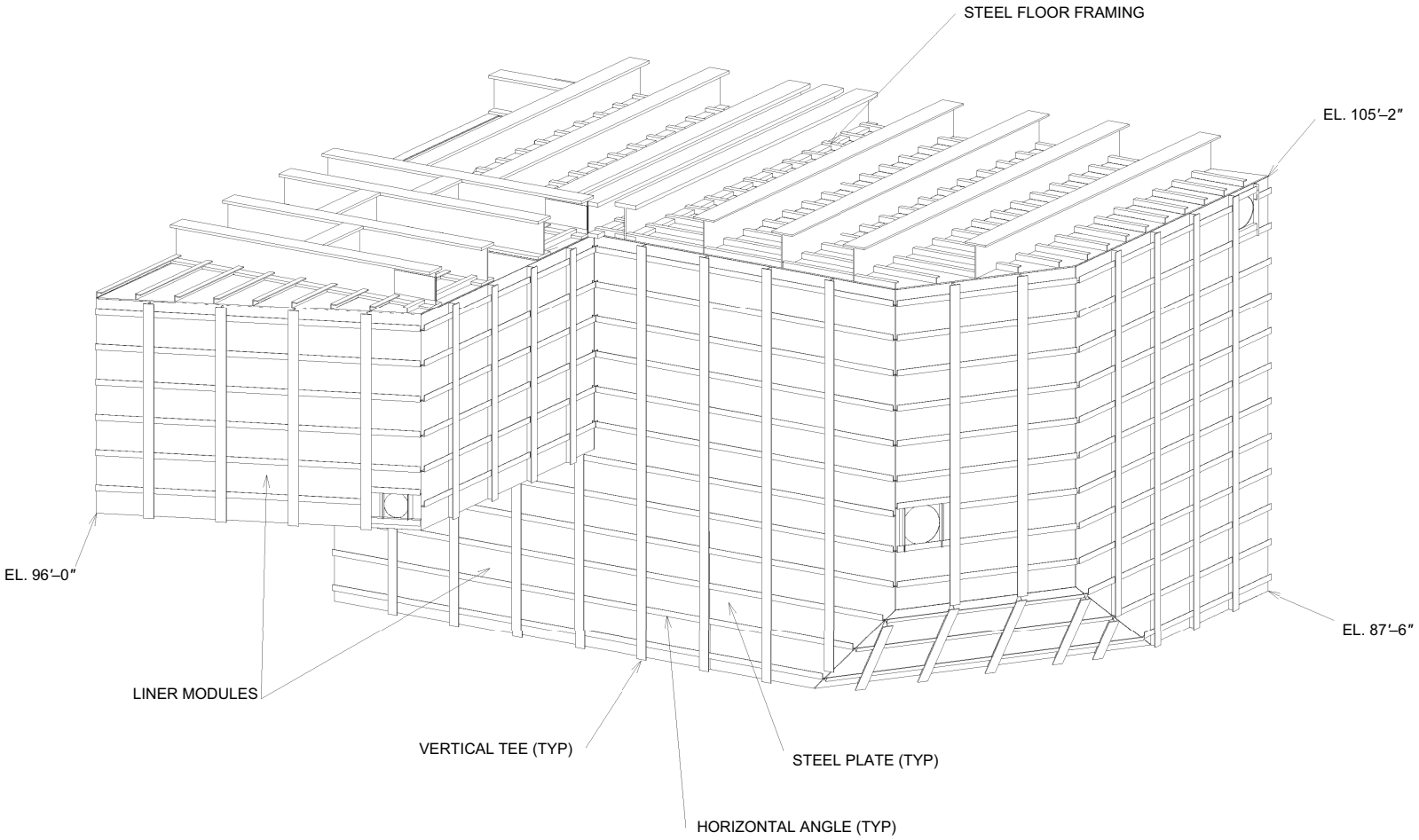
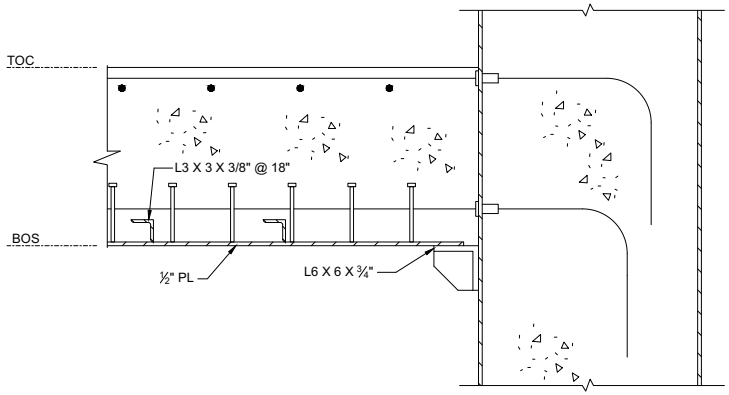
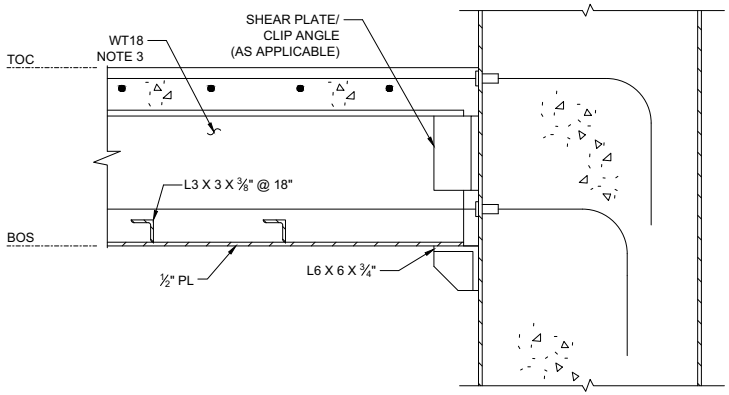


Figure 3.8.3-16
Liner Modules



SECTION BETWEEN BEAMS IN FLOOR
NOTES: 1, 2, 3, 4, 5, 6, 8 & 9



SECTION AT BEAMS IN FLOOR
NOTES: 1, 2, 3, 4, 5, 6, 7 & 8

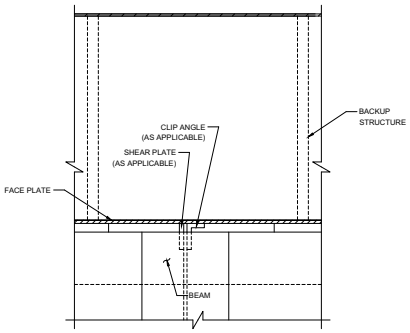
SEE SUBSECTION 3.8.3.5.8.1 FOR INFORMATION ON TIER 2* DESIGNATION.

NOTES:

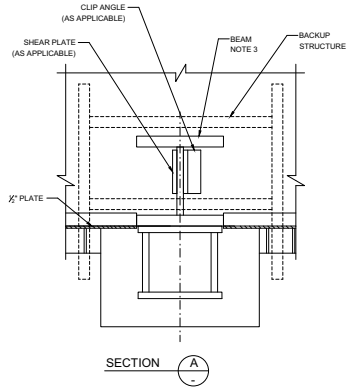
1. DETAILS SHOWN ARE REPRESENTATIVE OF FLOOR MODULES AT EL 107'-2" AND 135'-3" AND THE CONNECTIONS OF FLOOR MODULES TO WALL MODULES INSIDE CONTAINMENT. REFER TO SUBSECTION 3.8.3.1.3 AND OTHER NOTES FOR ADDITIONAL INFORMATION ABOUT DESIGN DETAILS AND VARIATIONS FOR FLOOR MODULE TO WALL MODULE CONNECTIONS.
2. REINFORCEMENT USE, SIZE, AND SPACING IN THE FLOOR MODULE CONCRETE SATISFY THE REQUIREMENTS IN ACI 349. WHERE USED, THE REINFORCEMENT SIZE RANGE IS #7 TO #11. THE DESIGN OF THE STANDARD HOOKS IN THE WALL MODULES AND THE COUPLERS CONNECTING THE FLOOR REINFORCEMENT TO THE HOOKS IN THE WALL MODULES SATISFIES THE REQUIREMENTS OF ACI 349.
3. DESIGN OF THE PLATES, BEAMS, AND STIFFENERS IN THE FLOOR, INCLUDING PLATE SIZE AND SPACING, AND TYPE, SIZE, AND SPACING OF STRUCTURAL SHAPES VARIES AND SATISFIES THE REQUIREMENTS OF AISC N690.
4. THE REINFORCEMENT AND FLOOR DESIGN ELEMENTS SHOWN ARE FOR LOCATIONS AWAY FROM OPENINGS, PENETRATIONS, AND OTHER OBSTRUCTIONS.
5. IN SOME LOCATIONS, REINFORCEMENT AT THE CONNECTION IS NOT REQUIRED BECAUSE THE LOADS ARE TRANSFERRED THROUGH THE STEEL SECTION DIRECTLY TO THE BACKUP STRUCTURES OR THE SEAT ANGLE. THE DESIGN OF THE FLOORS SATISFIES THE APPLICABLE REQUIREMENTS IN ACI 349 AND AISC N690.
6. THE DETAIL DESIGN, LOCATION, AND ATTACHMENT OF THE FLOOR AND BEAM SUPPORTS ARE DESIGNED TO THE REQUIREMENTS OF AISC N690. SUPPORT CONFIGURATIONS, INCLUDING THE USE OF PLATES, STRUCTURAL SHAPES, AND STIFFENERS, ARE BASED ON LOADING AND LOCAL GEOMETRY CONSIDERATIONS.
7. THE DESIGNS OF THE CONNECTIONS AND BACKUP STRUCTURES WITHIN THE MODULES WALL, INCLUDING PLATE SIZE, AND SPACING, AND TYPE, SIZE, AND SPACING OF STRUCTURAL SHAPES VARY AND SATISFY THE REQUIREMENTS OF AISC N690.
8. THE THICKNESS OF THE ADJACENT WALL IS BASED ON THE WALL DESIGN REQUIREMENTS AND LOCATION.
9. REFER TO SUBSECTION 3.8.3.5.4 FOR INFORMATION ABOUT THE SHEAR STUDS IN THE FLOOR MODULE.

Figure 3.8.3-17 (Sheet 1 of 2)
[*Structural Modules – Design Details Standard Floor Connection*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

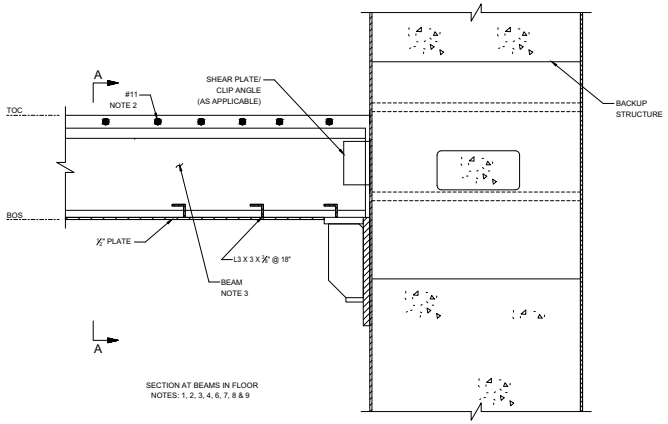


TOP VIEW AT BEAMS IN FLOOR
NOTE: 7

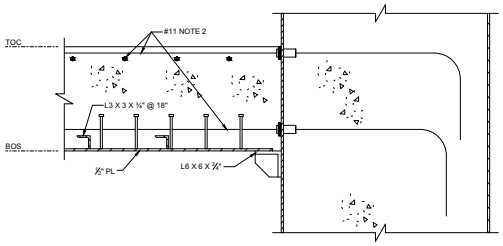


END VIEW AT BEAMS IN FLOOR
NOTES: 3, 6, 7 & 9

NOTES:
1. DETAILS SHOWN ARE REPRESENTATIVE OF FLOOR MODULES AT EL 107'-2" AND 135'-3" AND THE CONNECTIONS OF FLOOR MODULES TO WALL MODULES INSIDE CONTAINMENT. REFER TO SUBSECTION 3.8.3.1.3 AND OTHER NOTES FOR ADDITIONAL INFORMATION ABOUT DESIGN DETAILS AND VARIATIONS FOR FLOOR MODULE TO WALL MODULE CONNECTIONS.
2. REINFORCEMENT USE, SIZE, AND SPACING IN THE FLOOR MODULE CONCRETE SATISFY THE REQUIREMENTS IN ACI 349. WHERE USED, THE REINFORCEMENT SIZE RANGE IS #7 TO #11. THE DESIGN OF THE STANDARD HOOKS IN THE WALL MODULES AND THE COUPLERS CONNECTING THE FLOOR REINFORCEMENT TO THE HOOKS IN THE WALL MODULES SATISFIES THE REQUIREMENTS OF ACI 349.
3. DESIGN OF THE PLATES, BEAMS, AND STIFFENERS IN THE FLOOR, INCLUDING PLATE SIZE AND SPACING, AND TYPE, SIZE, AND SPACING OF STRUCTURAL SHAPES VARIES AND SATISFIES THE REQUIREMENTS OF AISC N690.
4. THE REINFORCEMENT AND FLOOR DESIGN ELEMENTS SHOWN ARE FOR LOCATIONS AWAY FROM OPENINGS, PENETRATIONS, AND OTHER OBSTRUCTIONS.
5. IN SOME LOCATIONS, REINFORCEMENT AT THE CONNECTION IS NOT REQUIRED BECAUSE THE LOADS ARE TRANSFERRED THROUGH THE STEEL SECTION IRECTLY TO THE BACKUP STRUCTURES OR THE SEAT ANGLE. THE DESIGN OF THE FLOORS SATISFIES THE APPLICABLE REQUIREMENTS IN ACI 349 AND AISC N690.
6. THE DETAIL DESIGN, LOCATION, AND ATTACHMENT OF THE FLOOR AND BEAM SUPPORTS ARE DESIGNED TO THE REQUIREMENTS OF AISC N690. SUPPORT CONFIGURATIONS, INCLUDING THE USE OF PLATES, STRUCTURAL SHAPES, AND STIFFENERS, ARE BASED ON LOADING AND LOCAL GEOMETRY CONSIDERATIONS.
7. THE DESIGNS OF THE CONNECTIONS AND BACKUP STRUCTURES WITHIN THE MODULES WALL, INCLUDING PLATE SIZE AND SPACING, AND TYPE, SIZE, AND SPACING OF STRUCTURAL SHAPES VARY AND SATISFY THE REQUIREMENTS OF AISC N690.
8. THE THICKNESS OF THE ADJACENT WALL IS BASED ON THE WALL DESIGN REQUIREMENTS AND LOCATION.
9. THE BEAM SEAT SHOWN IS NOT USED AT ALL BEAM LOCATIONS. THE SEAT ANGLE SHOWN ON SHEET 1 IS USED AT OTHER LOCATIONS.
10. REFER TO SUBSECTION 3.8.3.5.4 FOR INFORMATION ABOUT THE SHEAR STUDS IN THE FLOOR MODULE.



SECTION AT BEAMS IN FLOOR
NOTES: 1, 2, 3, 4, 6, 7, 8 & 9



SECTION BETWEEN BEAMS IN FLOOR
NOTES: 1, 2, 3, 4, 5, 6, 8 & 10

SEE SUBSECTION 3.8.3.5.8.1 FOR INFORMATION ON TIER 2* DESIGNATION.

Figure 3.8.3-17 (Sheet 2 of 2)
[*Structural Modules – Design Details Heavily Loaded Floor Connection*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

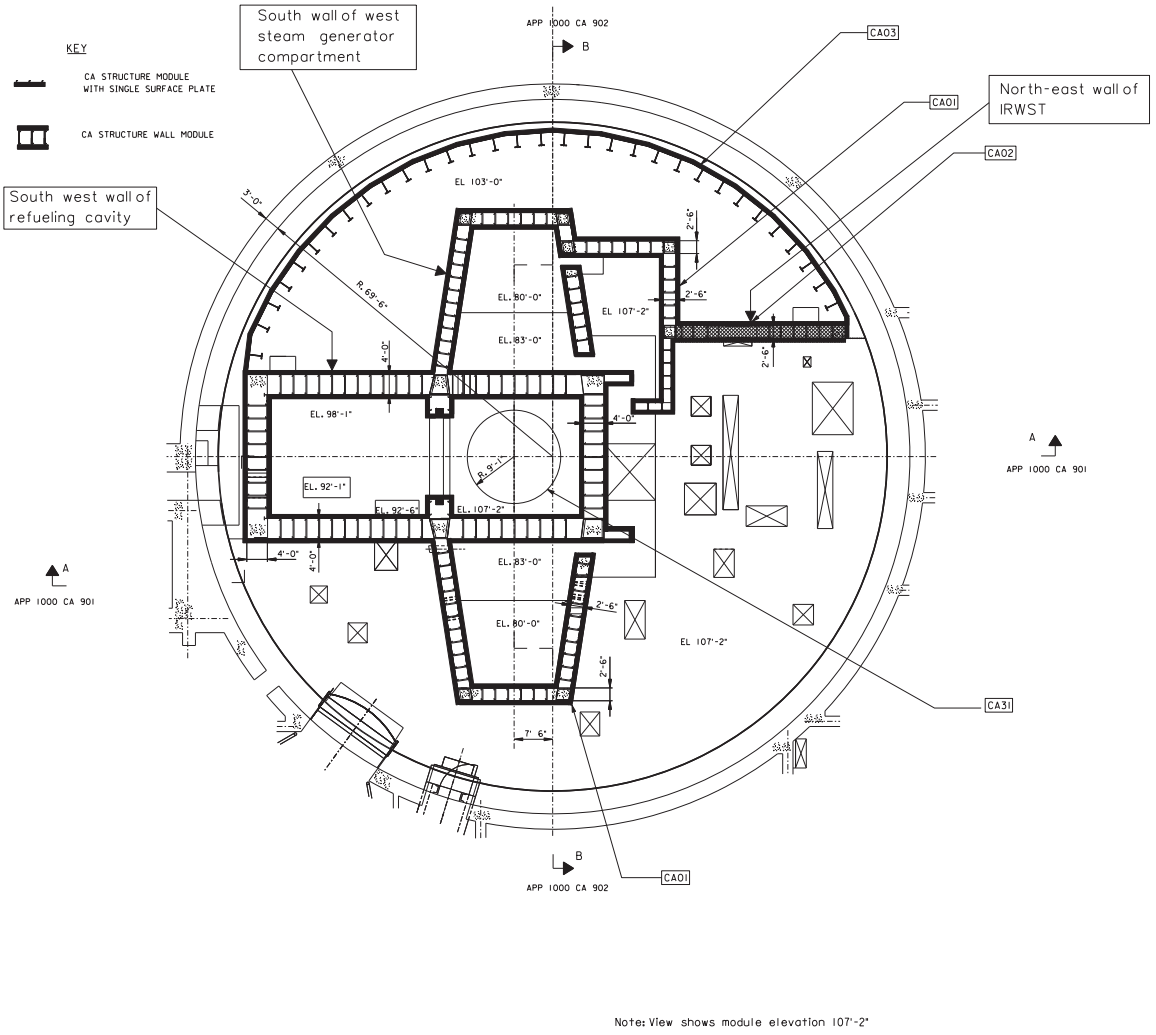
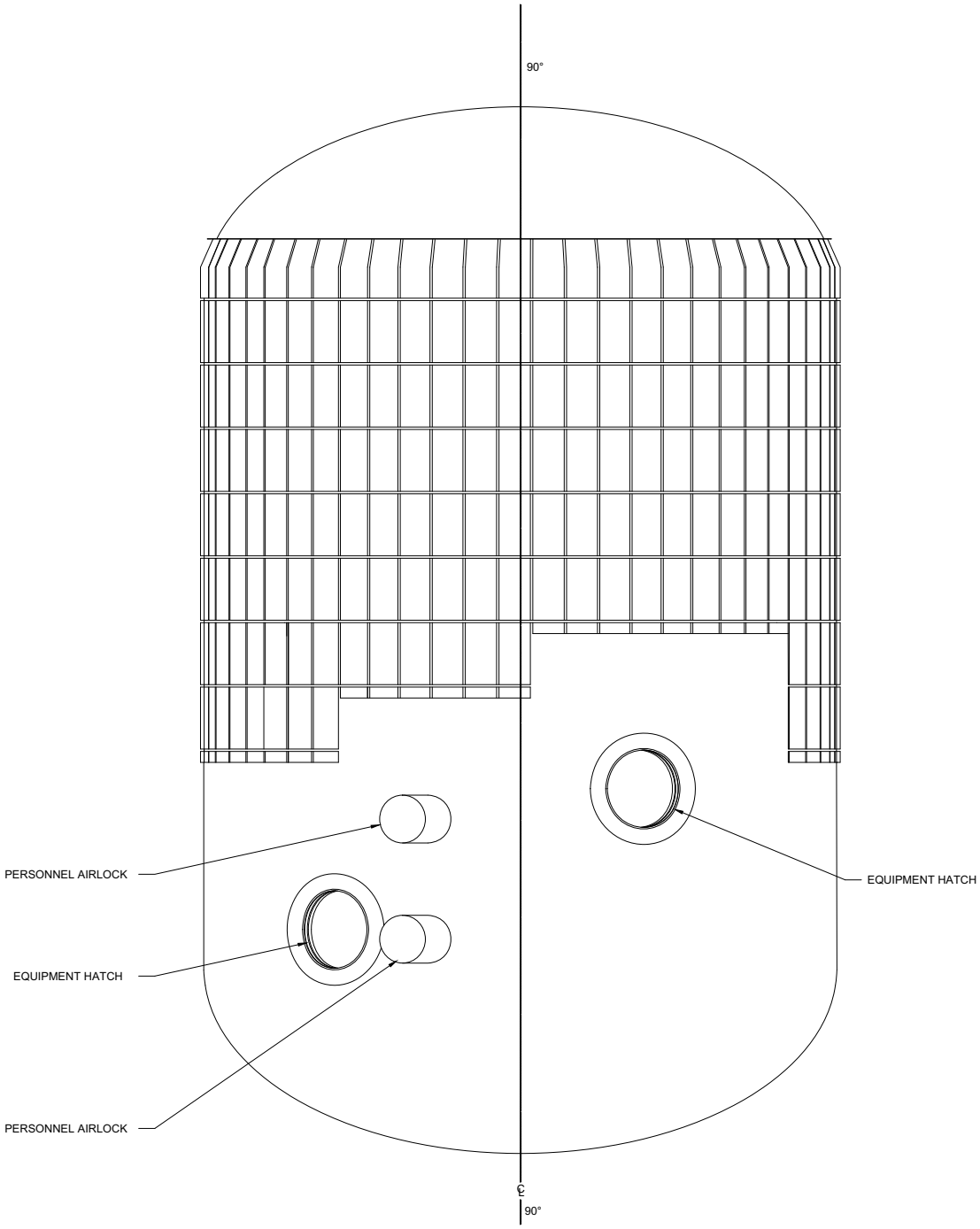


Figure 3.8.3-18
[*Location of Structural Wall Modules*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



NOTE: COURSE LAYOUT, PLATE/INSERT PLATE GEOMETRY, WELD SEAMS FOR THE CONTAINMENT, HATCHES, AIRLOCKS, AND THE NUMBER AND CONFIGURATION OF THE CONTAINMENT AIR BAFFLE PANELS ARE PROVIDED FOR ILLUSTRATIVE PURPOSES ONLY.

Figure 3.8.4-1 (Sheet 1 of 4)
Containment Air Baffle
General Arrangement

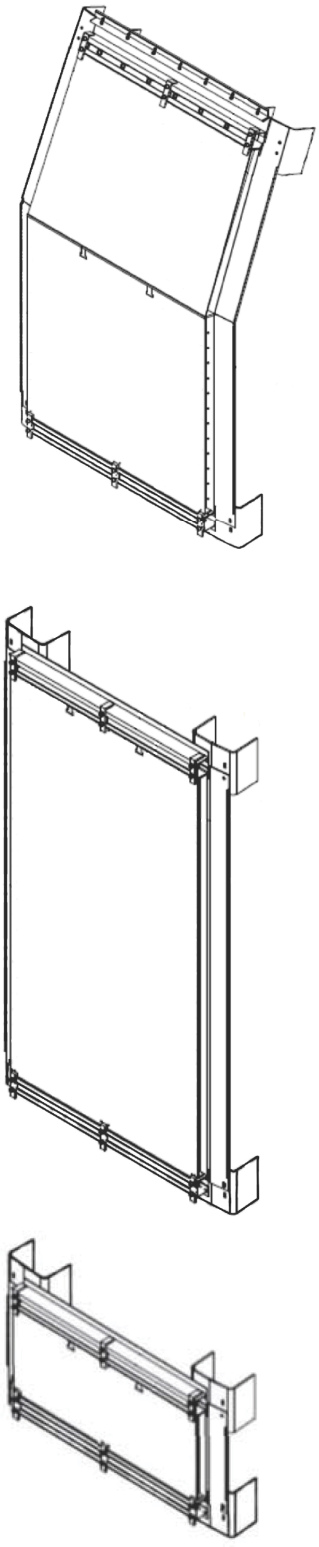


Figure 3.8.4-1 (Sheet 2 of 4)
Containment Air Baffle
Panel Types

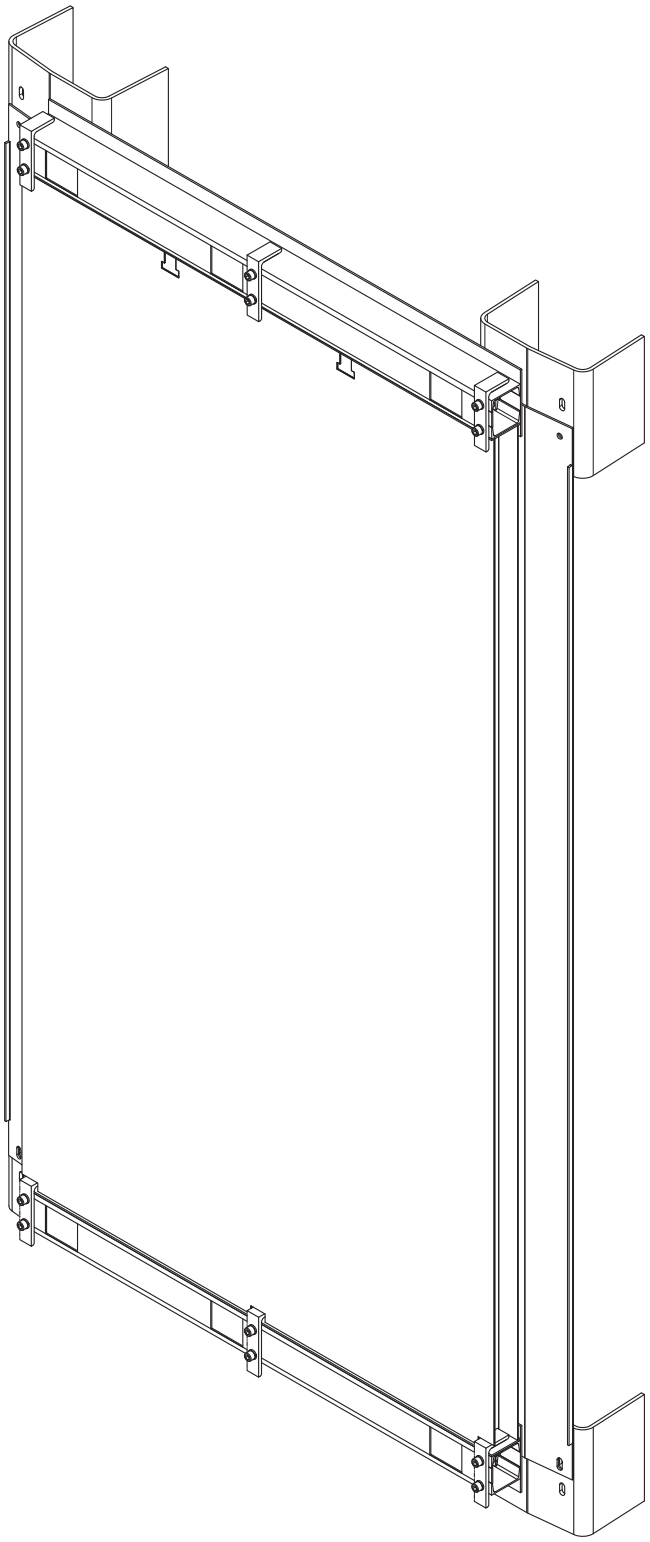


Figure 3.8.4-1 (Sheet 3 of 4)
Containment Air Baffle
Typical Panel on Cylinder

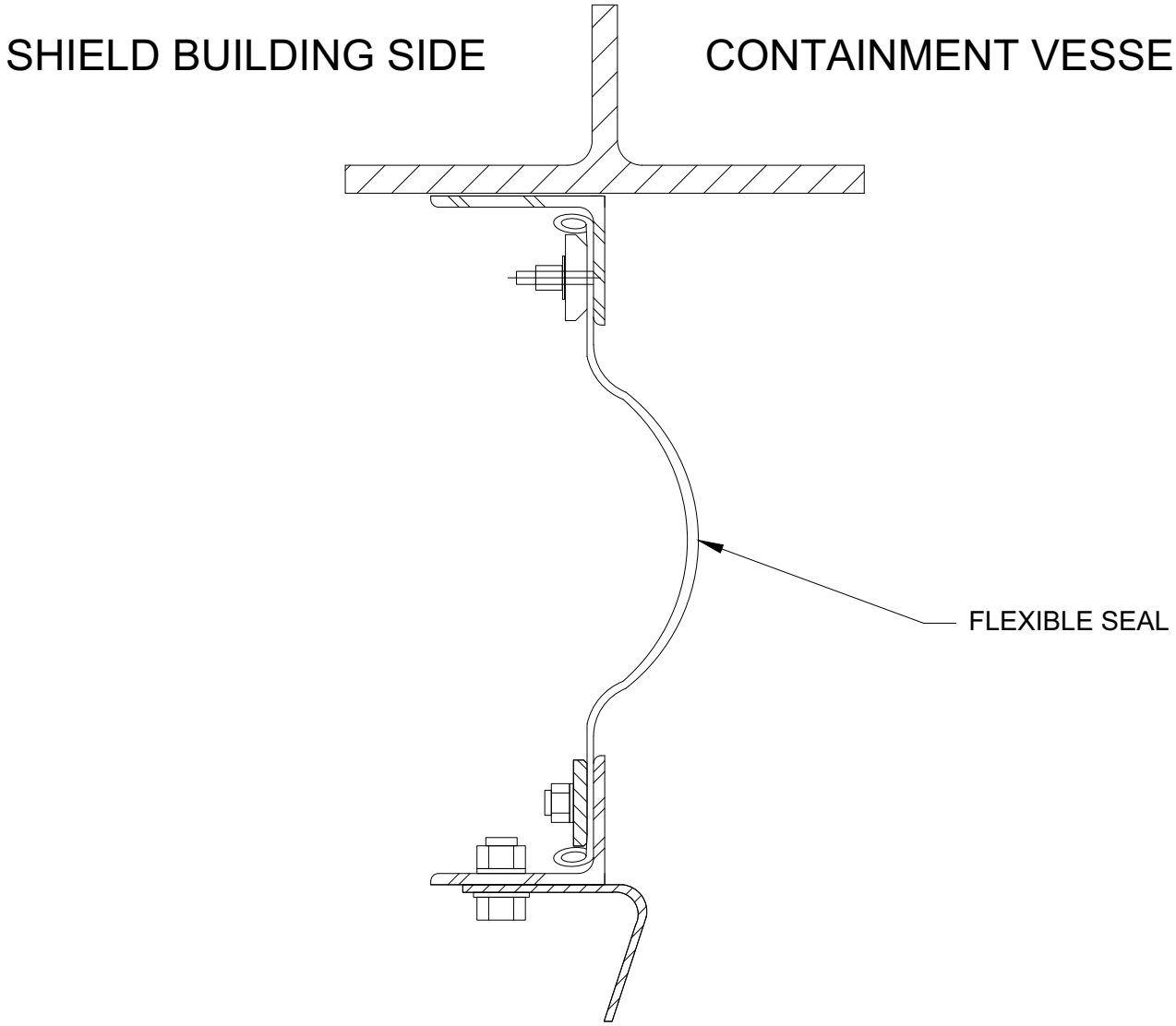


Figure 3.8.4-1 (Sheet 4 of 4)
Containment Air Baffle
Flexible Seal

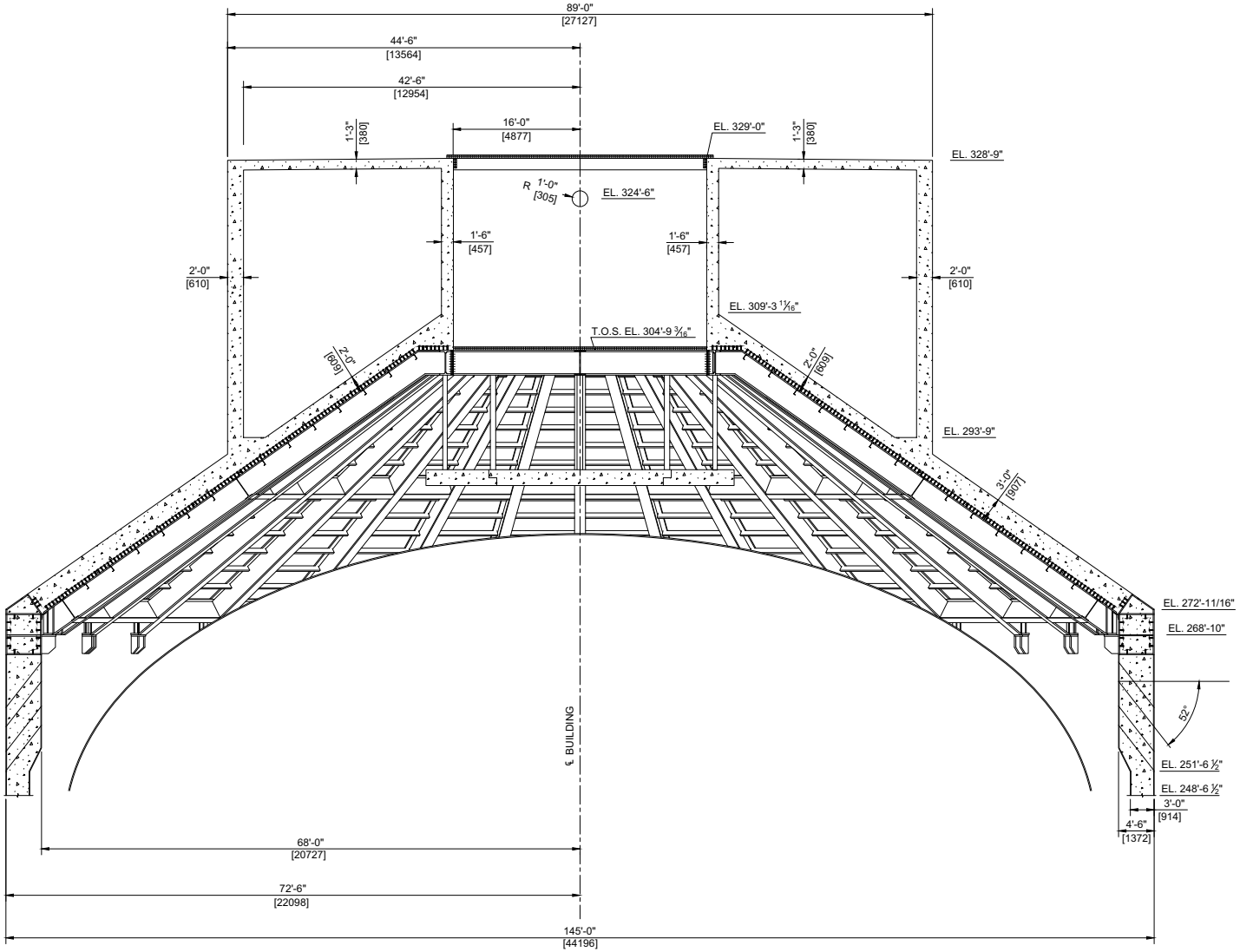


Figure 3.8.4-2
[*Passive Containment Cooling Tank*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Figure 3.8.4-3 Not Used

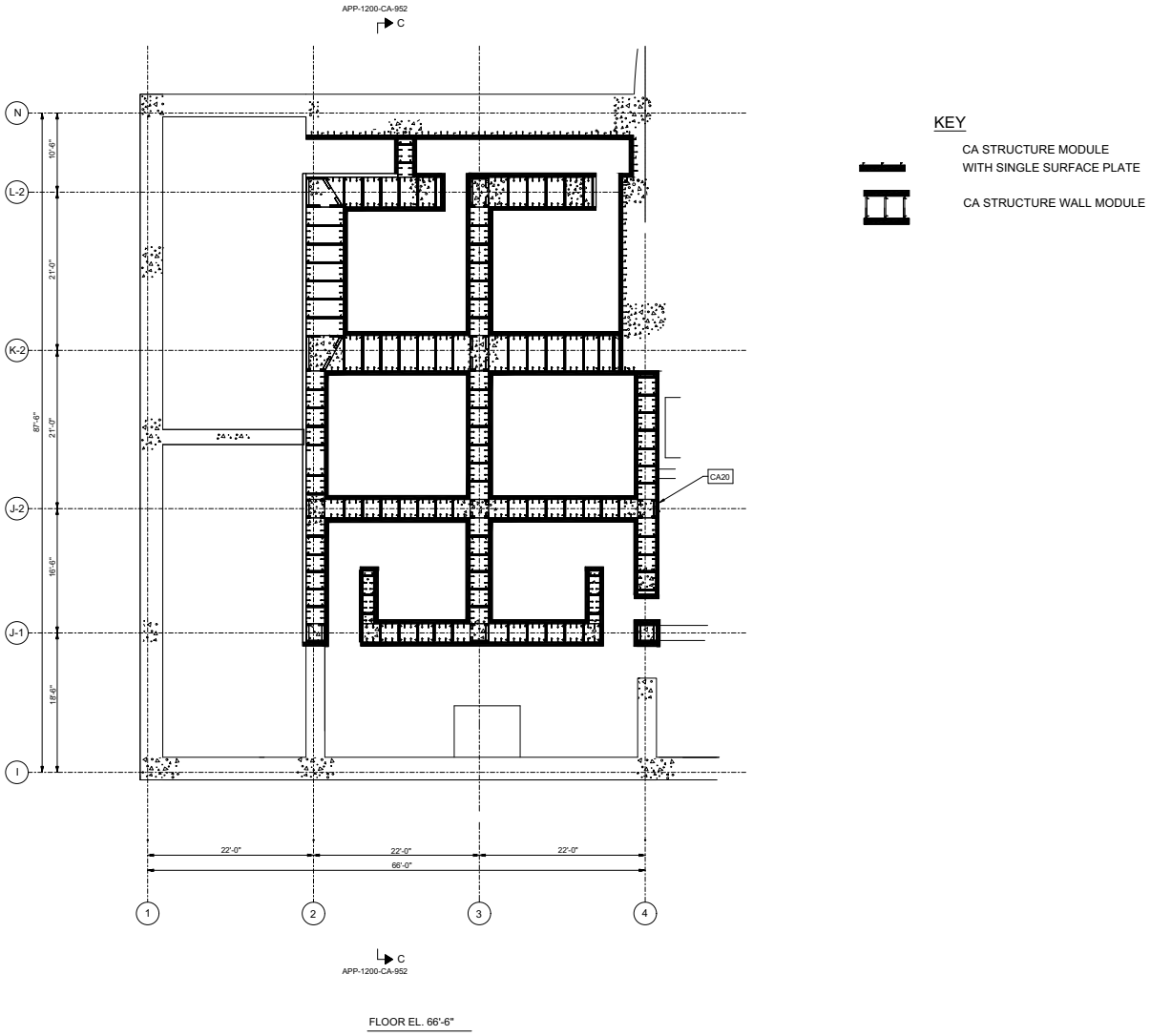


Figure 3.8.4-4 (Sheet 1 of 5)
[*Structural Modules in Auxiliary Building*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

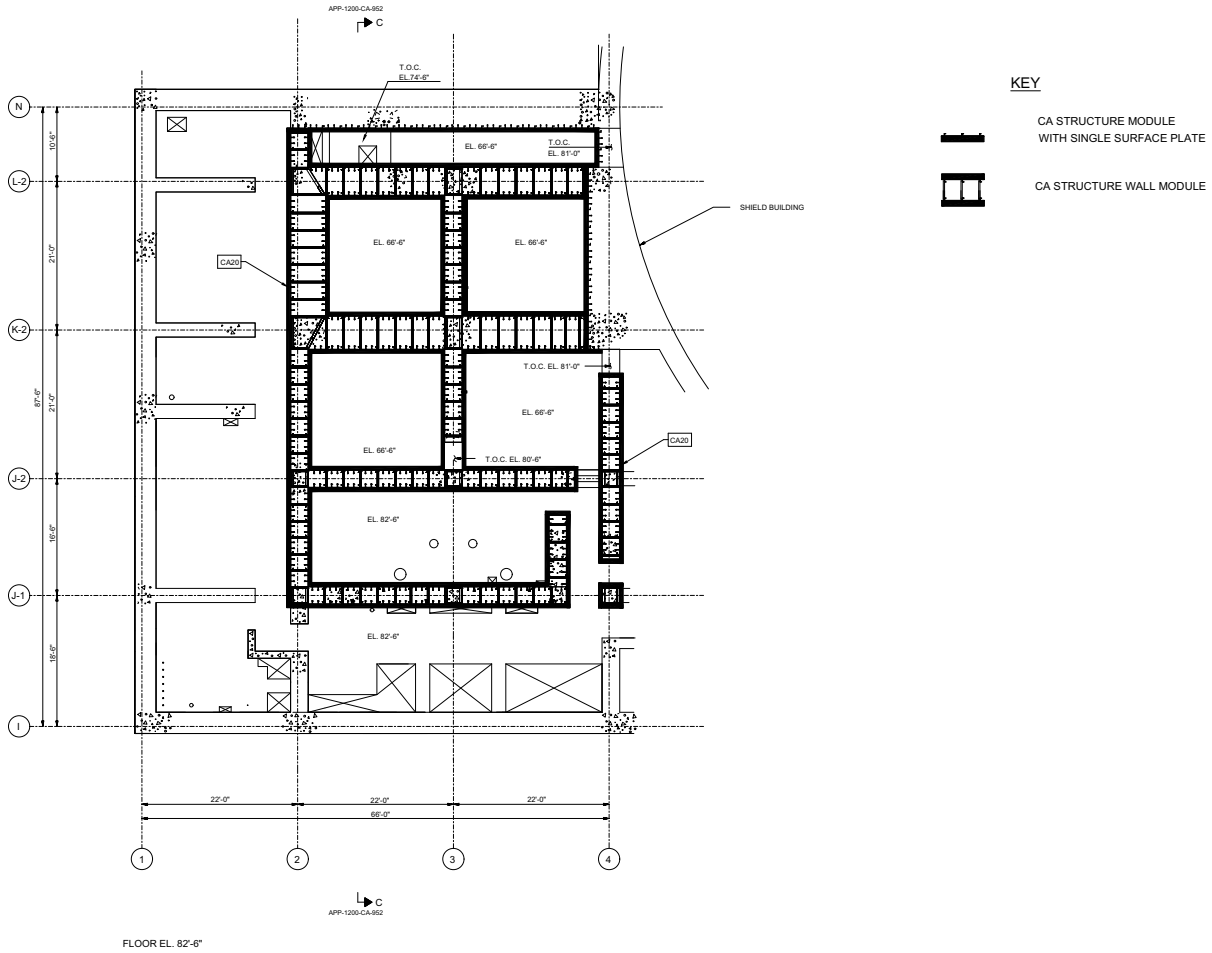


Figure 3.8.4-4 (Sheet 2 of 5)
[*Structural Modules in Auxiliary Building*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

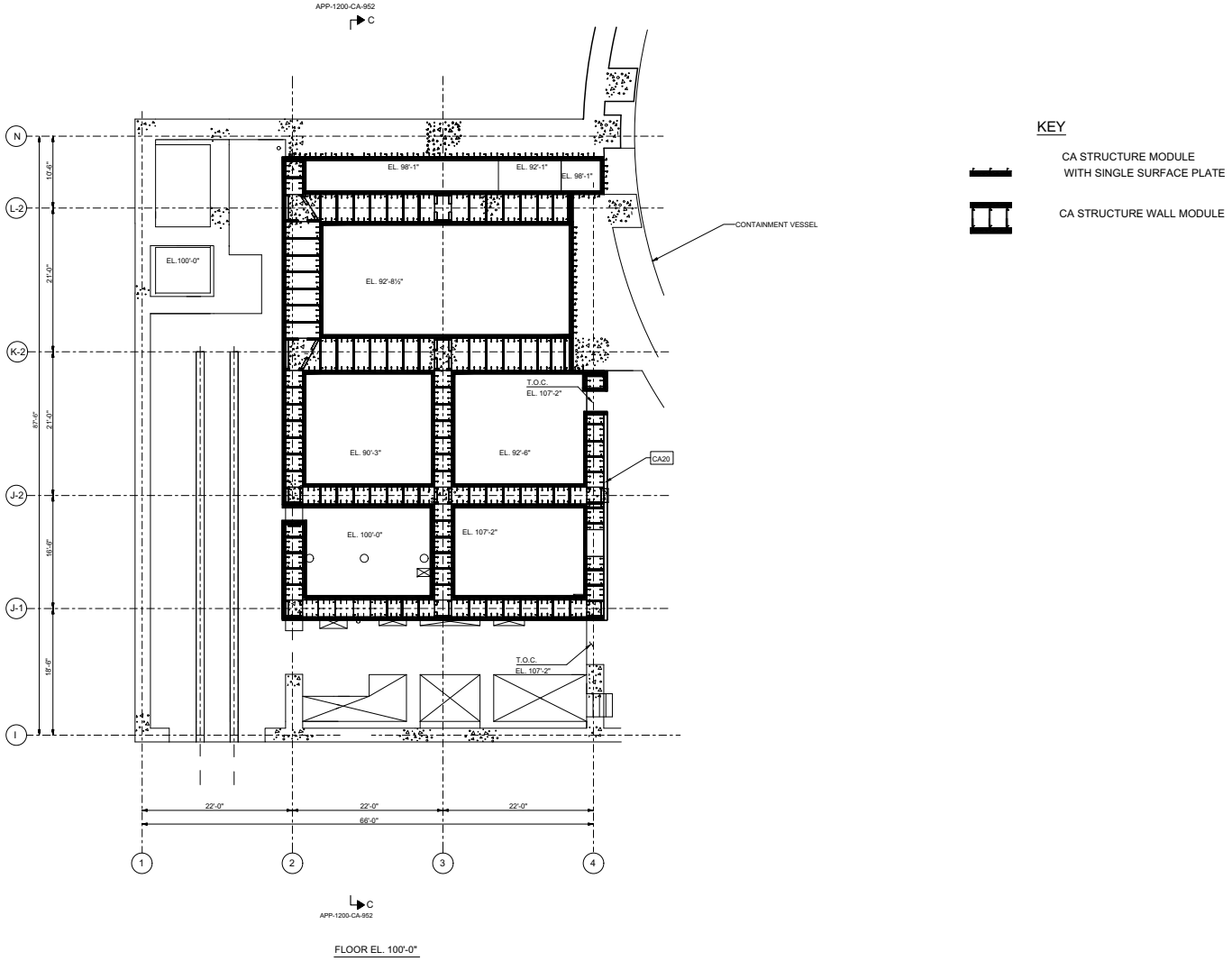


Figure 3.8.4-4 (Sheet 3 of 5)
[*Structural Modules in Auxiliary Building*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

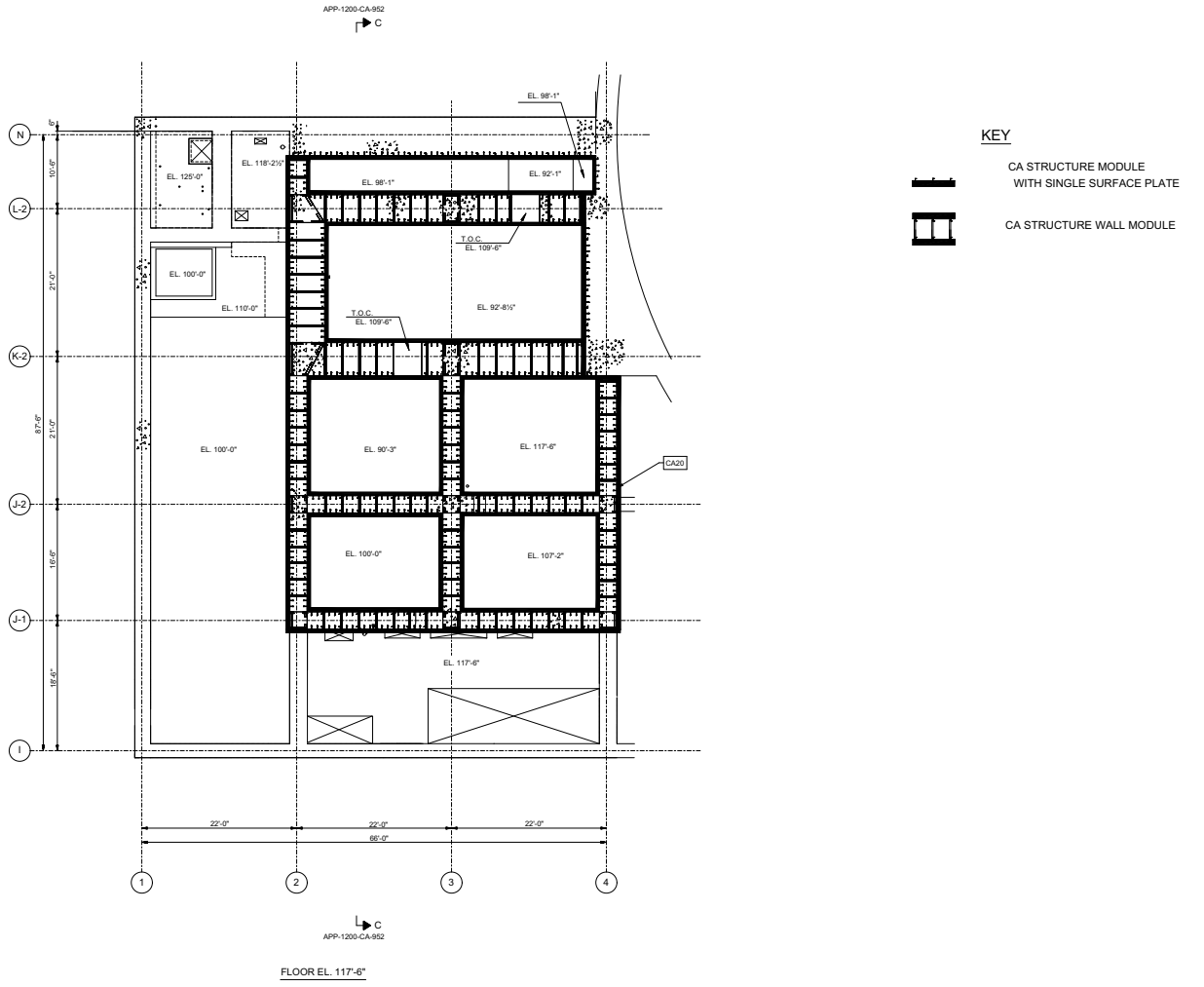


Figure 3.8.4-4 (Sheet 4 of 5)
[*Structural Modules in Auxiliary Building*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

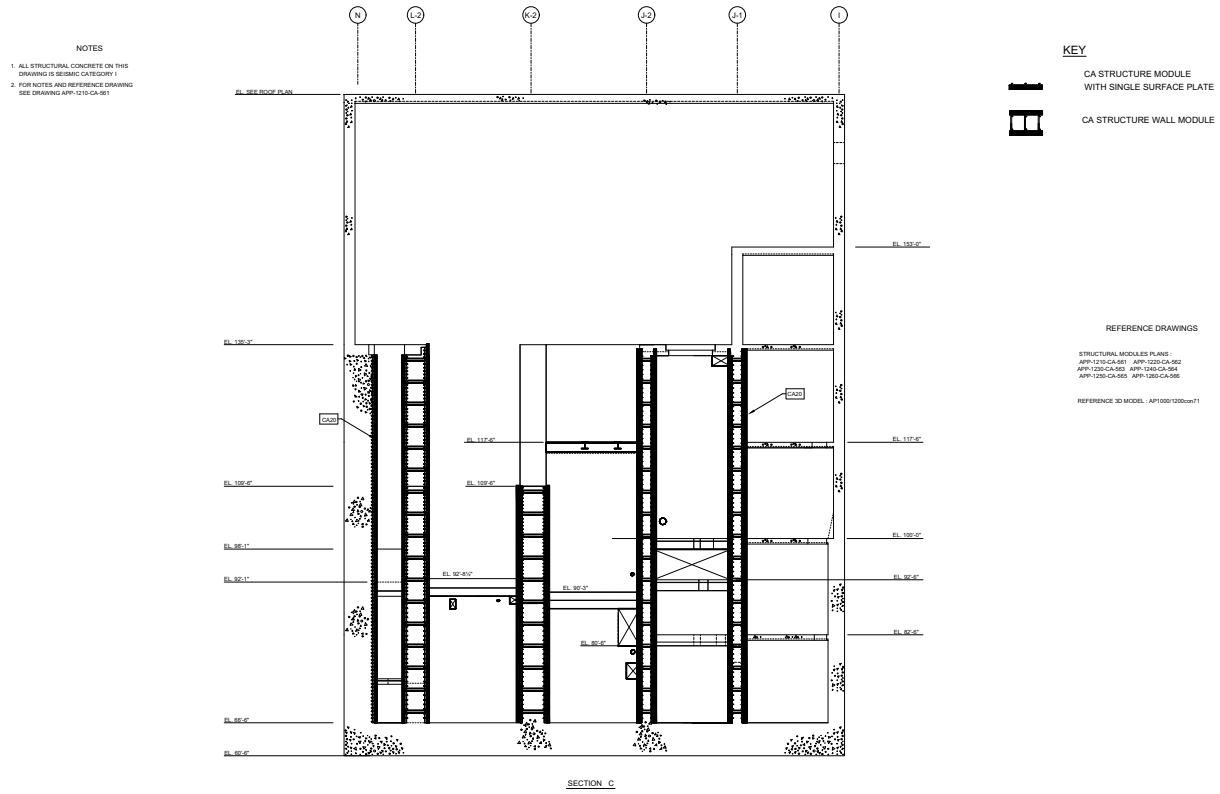


Figure 3.8.4-4 (Sheet 5 of 5)
[*Structural Modules in Auxiliary Building*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

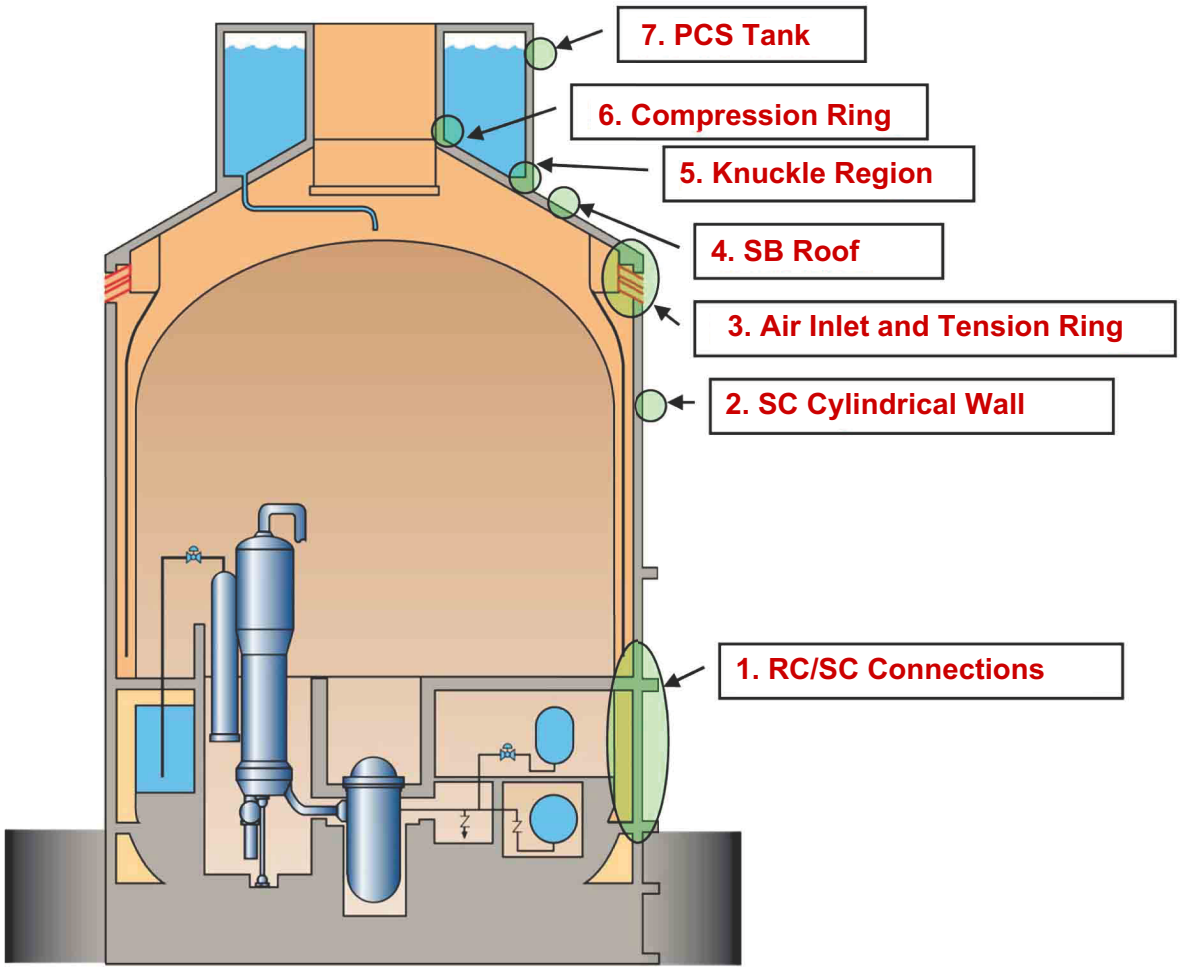
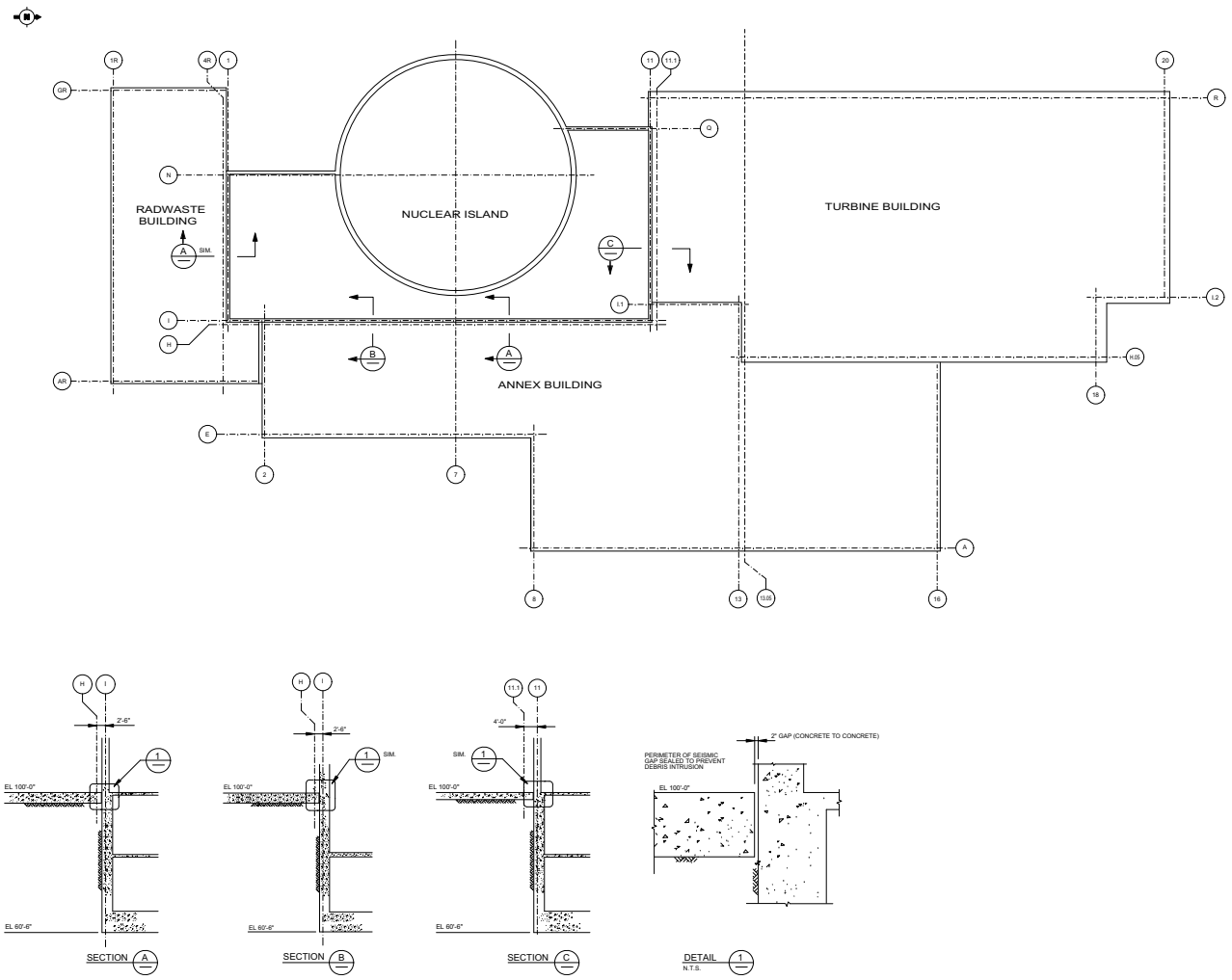


Figure 3.8.4-5
Shield Building Structure Key Areas



NUCLEAR ISLAND AND ADJACENT STRUCTURES

FOUNDATION PLANS AND SECTIONS

Figure 3.8.5-1
Foundation Plan

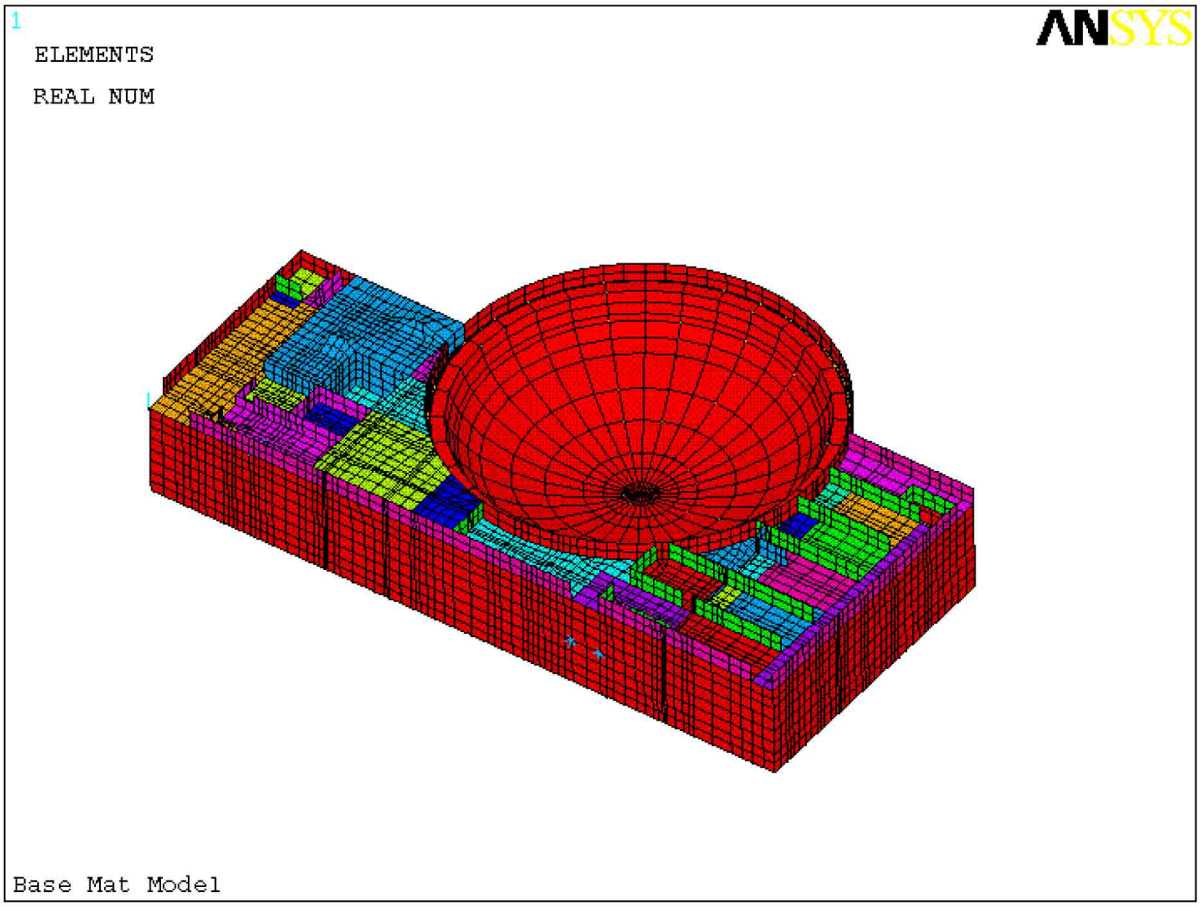


Figure 3.8.5-2
Isometric View of Finite Element Model

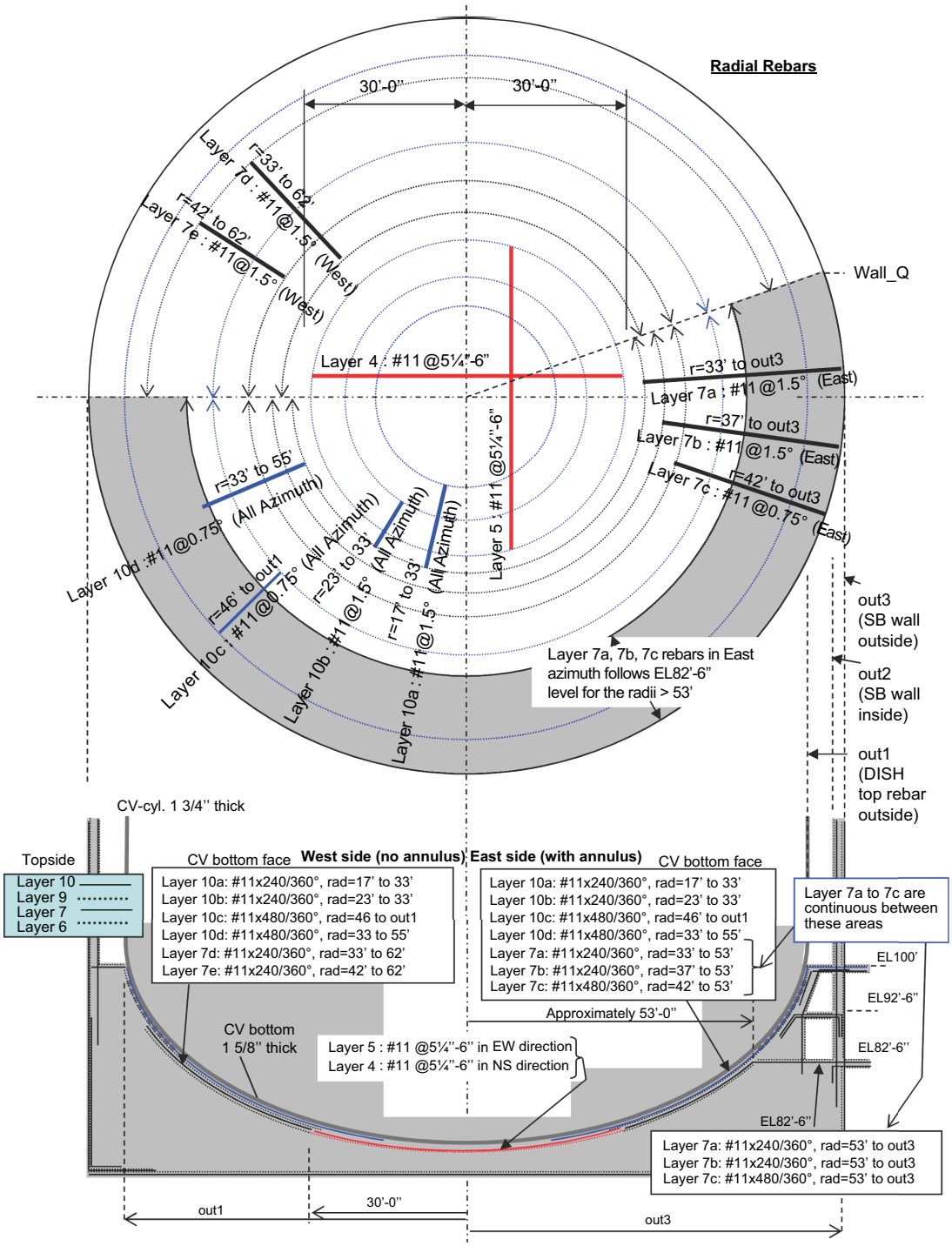


Figure 3.8.5-3 (Sheet 1 of 7)
Radial Reinforcement, Top Side of DISH

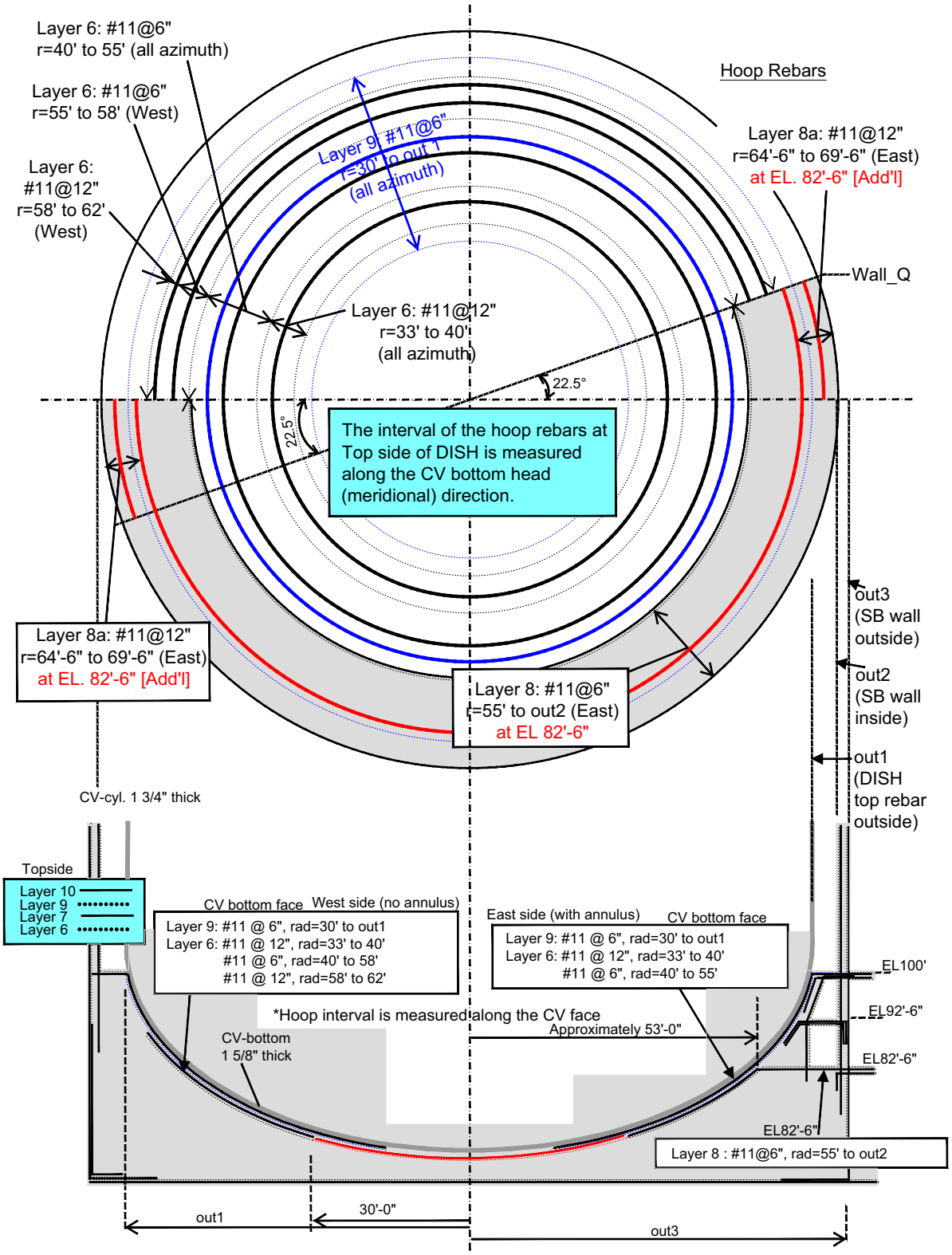


Figure 3.8.5-3 (Sheet 2 of 7)
Circumferential Reinforcement, Top Side of DISH

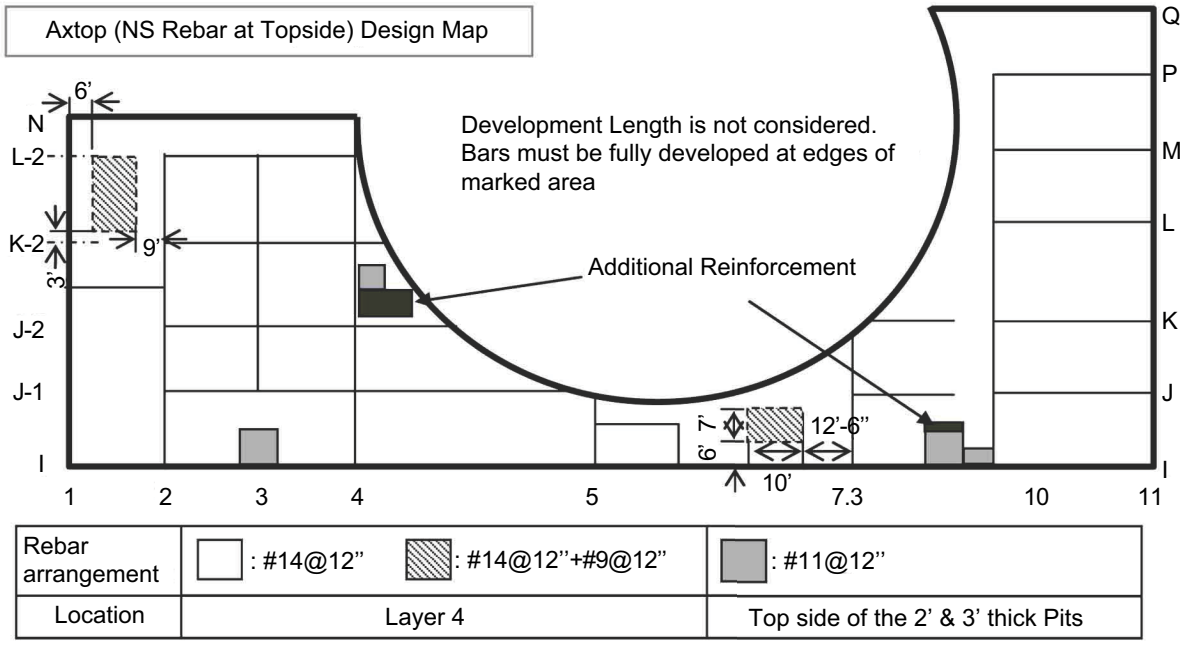


Figure 3.8.5-3 (Sheet 3 of 7)
Longitudinal Reinforcement Map,
Top Side in NS Direction

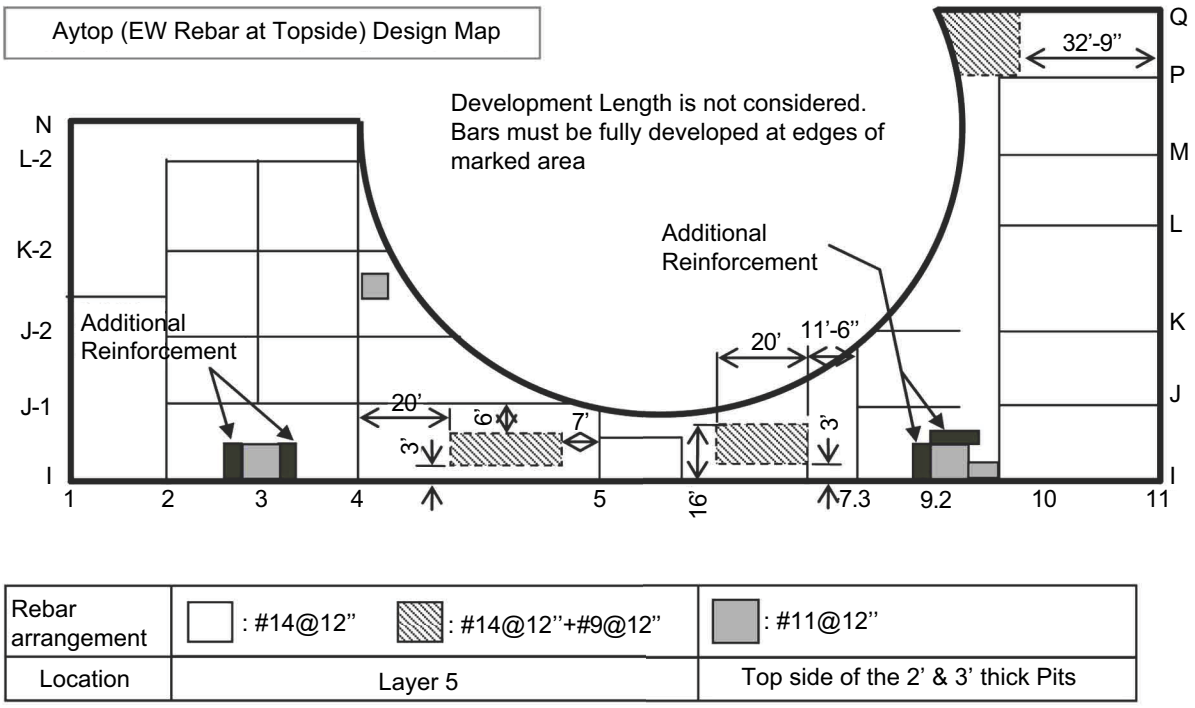


Figure 3.8.5-3 (Sheet 4 of 7)
Longitudinal Reinforcement Map,
Top Side in EW Direction

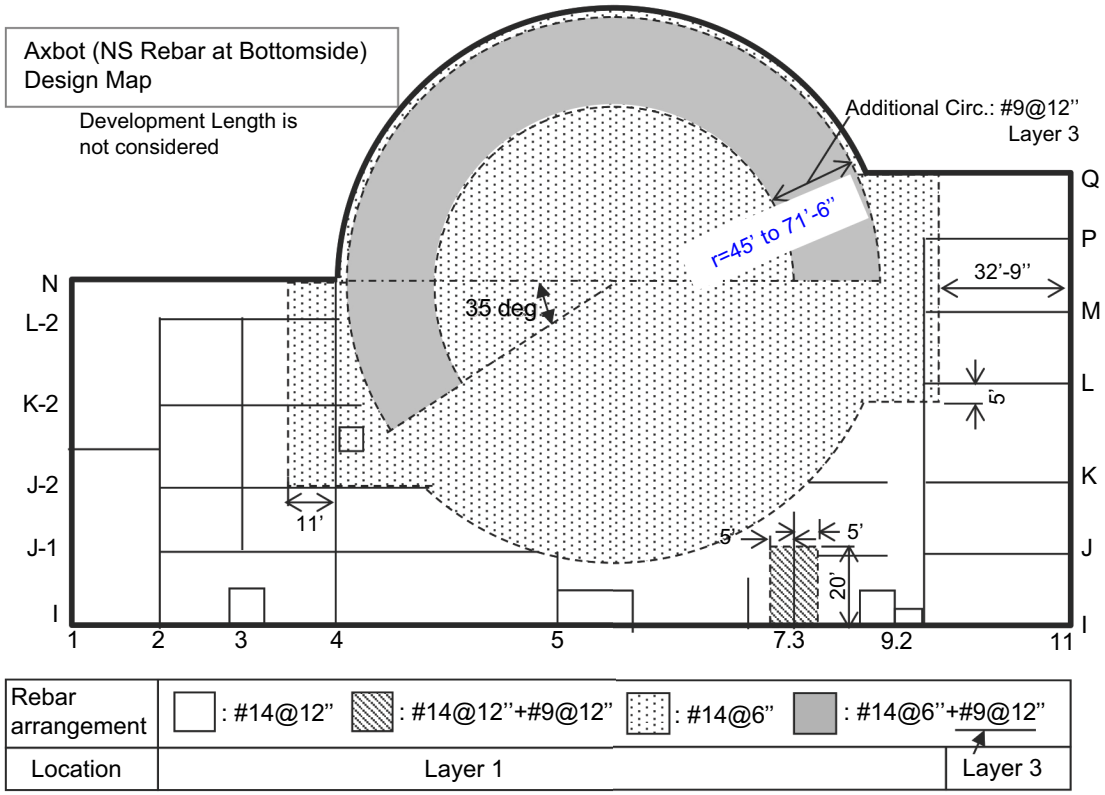


Figure 3.8.5-3 (Sheet 5 of 7)
Longitudinal Reinforcement,
Bottom Side of DISH and 6′ Basemat (NS)

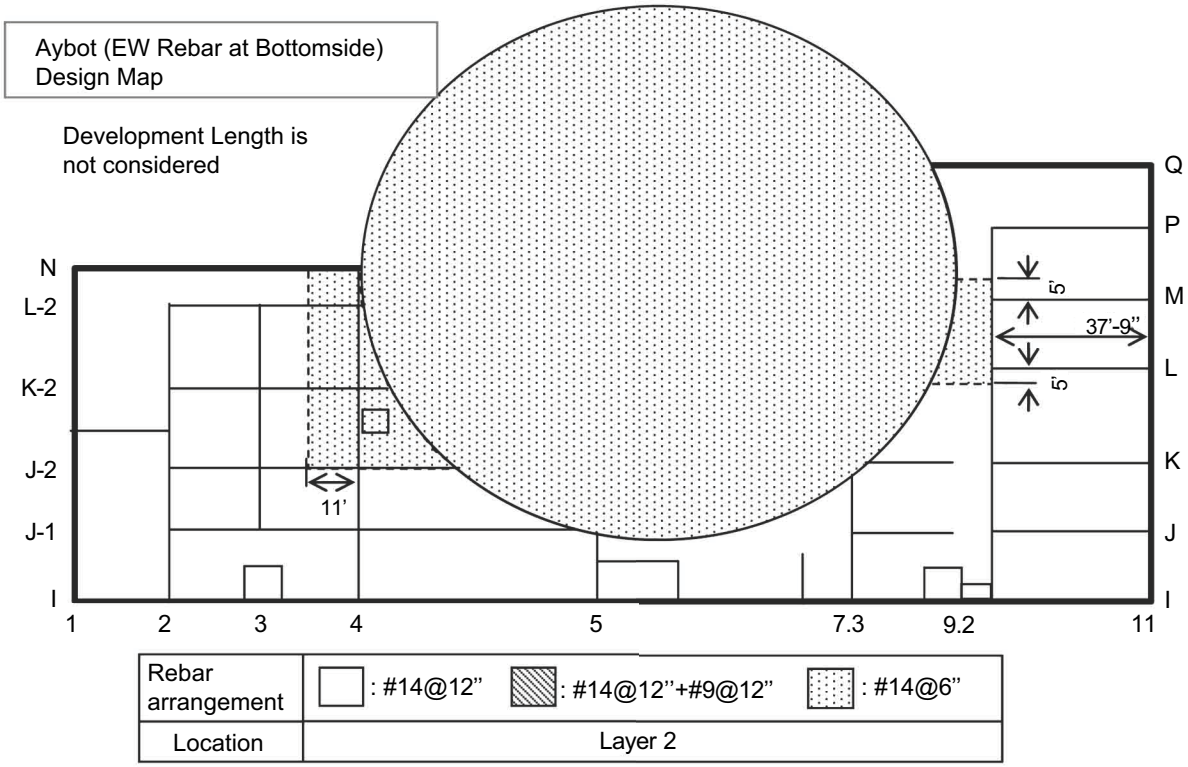


Figure 3.8.5-3 (Sheet 6 of 7)
Longitudinal Reinforcement,
Bottom Side of DISH and 6′ Basemat (EW)

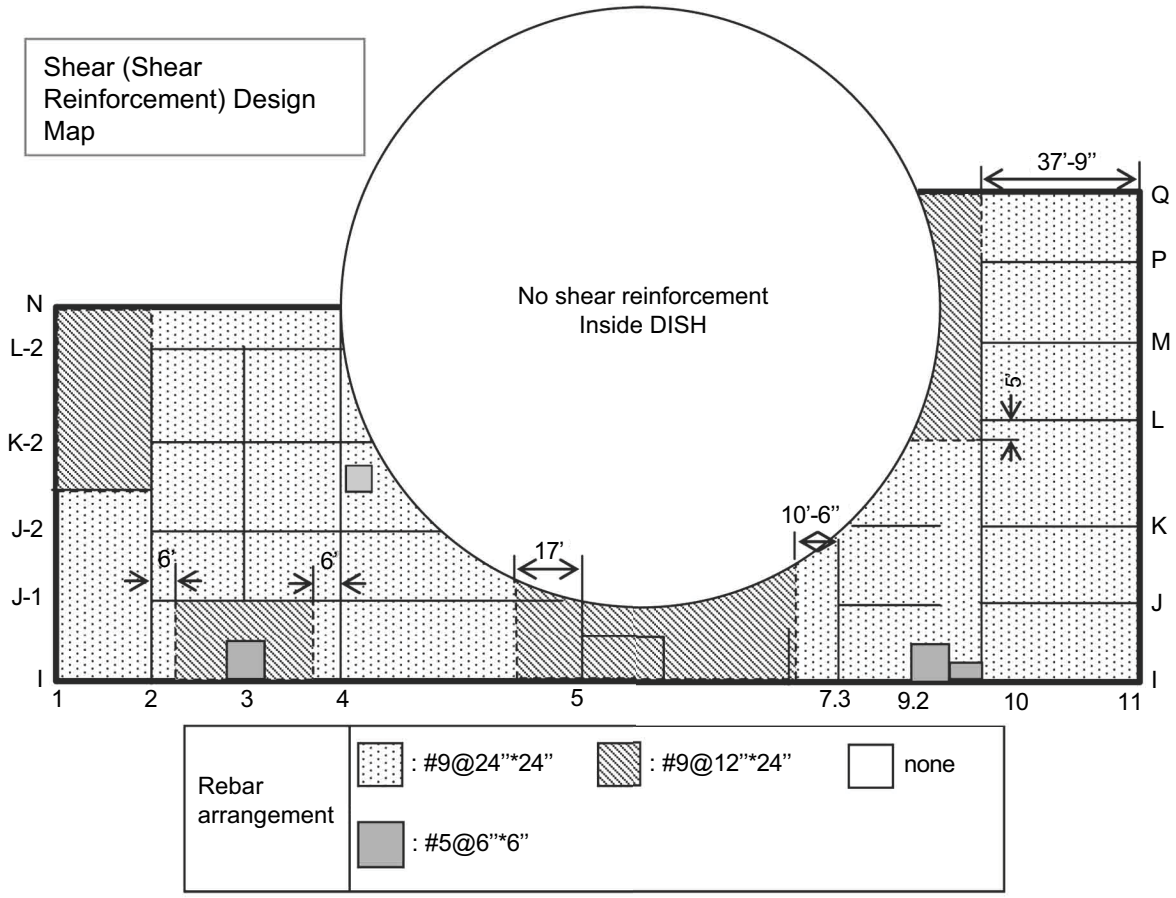


Figure 3.8.5-3 (Sheet 7 of 7)
Shear Reinforcement Map

3.9 Mechanical Systems and Components

3.9.1 Special Topics for Mechanical Components

3.9.1.1 Design Transients

To provide a high degree of integrity for the equipment in the reactor coolant system (RCS), components designed and constructed to the requirements for Class 1 in ASME Code, Section III are evaluated for design, service, and test conditions.

The design conditions include those pressure, temperature, and mechanical loadings selected as the basis for the design. Service conditions cover those normal operating conditions, anticipated transients, and accident conditions expected or postulated to occur during operation. The evaluation of the service and testing conditions includes an evaluation of fatigue due to cyclic stresses.

The following five operating conditions, as defined in ASME Code, Section III, are considered in the design of the reactor coolant system Class 1 components, auxiliary Class 1 components, reactor coolant system component supports, and reactor internals.

Level A Service Conditions - (Normal Conditions) These conditions include any condition in the course of system startup, operation in the design power range, hot standby, and system shutdown other than Level B, Level C, or Level D service conditions or testing conditions. Tests not requiring a pressure greater than the component design pressure are considered to be normal condition design transients.

Level B Service Conditions - (Upset Conditions, Incidents of Moderate Frequency) These conditions include any deviations from Level A service conditions anticipated to occur often enough that the design includes a capability to withstand the conditions without operational impairment. The Level B service conditions include those transients resulting from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power. Level B service conditions include any abnormal incidents not resulting in a forced outage and also forced outages for which the corrective action does not include any repair of mechanical damage. The estimated duration of Level B service condition is included in the design specifications.

Level C Service Conditions - (Emergency Conditions, Infrequent Incidents) These conditions include those deviations from Level A service conditions that require shutdown for correction of the conditions or repair of damage in the system. The conditions have a low probability of occurrence but are included to establish that no gross loss of structural integrity will result as a concomitant effect of any damage developed in the system. The postulated occurrences for such events which result in more than 25 strong stress cycles are evaluated for cyclic fatigue using Level B service limits. Strong stress cycles are those having an alternating stress intensity value greater than that for 10^6 cycles from the applicable fatigue design curves.

Level D Service Conditions - (Faulted Conditions, Limiting Faults) These conditions include those combinations of conditions associated with extremely low-probability postulated events whose consequences are such that the integrity and operability of the nuclear energy system may be impaired to the extent that consideration of public health and safety is involved. Such considerations require compliance with safety criteria as may be specified by regulatory authorities.

Testing Conditions - Testing conditions are those pressure overload tests that include primary and secondary hydrostatic tests and steam generator tube leak tests specified. Other types of tests are classified under one of the other service condition categories.

In addition to the design transients defined for evaluation of the ASME Code, Section III, Class 1 components, other transients are defined to address the same normal operating conditions, anticipated transients, and postulated accident conditions. These alternate transients are developed for evaluations of other effects. For example, a set of transients is developed for equipment qualification (see Section 3.11) and a set for accident analysis (see Chapter 15). These transients have somewhat different assumptions for the number of transients and sequence of events than do the design transients.

To provide a high degree of integrity for the equipment in the reactor coolant system, the transient conditions selected for equipment fatigue evaluation are based upon a conservative estimate of the magnitude and frequency of the temperature and pressure transients that may occur during plant operation.

To a large extent, the specific transients to be considered for equipment fatigue analyses are based upon engineering judgment and experience. The plant condition (PC) categorization defined in ANS/ANSI 51.1 (Reference 1), which categorizes transients on the basis of expected frequency, are also part of the process to define transients and which service condition applies for a given transient.

The transients selected are severe enough or frequent enough to be of possible significance to component cyclic behavior. The transients selected are a conservative representation of transients that, used as a basis for component fatigue evaluation, provide confidence that the component is appropriate for its application for the 60-year design objective. These transients are described by pertinent variations in pressure, fluid temperature, and fluid flow. Because of the large number of possible operating transients, design transients are chosen to provide a conservative representation for component cyclic analysis. The frequency in some cases is greater than the maximum frequency that defines the plant condition in ANS N51.1 (Reference 1).

The design transients and the number of events of each that are normally used for fatigue evaluations of components are presented in Table 3.9-1. A limited number of events affecting only the core makeup tank or passive residual heat removal heat exchanger are not included in the design transients. Subsections 5.4.13 and 5.4.14 describe these events.

The effects of each transient vary in consequence for each of the analyzed components. For example, the reactor vessel is subject to the pressure and temperature variations in the reactor coolant loop flow, but, the core makeup tank and passive residual heat removal heat exchangers are subject only to the pressure changes for many of the reactor coolant system transients. Additionally, the steam generator is subject to changes in the feedwater and steam system parameters that may have little or no effect on the other Class 1 components.

The individual component fatigue evaluations are based on component specific analyses of the stress levels and cycles of applied stress of the design transients. In many cases, the fatigue evaluations for the individual components combine two or more of the design transients into one bounding condition for that component.

In some cases the use of the total number of the design transients in a component fatigue analysis may indicate the requirement for a significant redesign of a portion of a component. In such cases, the number of one or more of the transients evaluated in the analysis may be reduced. In each case, the number of transients to be included in the analysis is specified in the component design specification.

In accordance with ASME Code, Section III, Level D service conditions and up to 25 stress cycles for Level C service conditions may be excluded from cyclic fatigue analysis. Any Level C service condition in excess of the 25-cycle limit is evaluated for the effect on cyclic fatigue, using Level B

criteria. The determination of which transients and seismic events are included in the 25-cycle exclusion is made separately for each component and piping line.

Levels C and D events are included in the design transients to provide the basis for pressure and temperatures used in the component stress analyses of these events. The number of events is given in the description of the transients and in Table 3.9-1 to support the determination that the fatigue evaluations do not have to consider these events.

[*The stress analysis, including analysis of fatigue, of the piping, applicable component nozzles, and piping and component supports includes the effect of thermal stratification and thermal cycling.*]* Thermal stratification may occur in piping when fluid rates are low and do not result in adequate mixing. Thermal cycling due to stratification may occur because of leaking valves or operational practices.

The design of piping and component nozzles in the AP1000 includes provisions to minimize the potential for and the effects of thermal stratification and cycling. [*Piping and component supports are designed and evaluated for the thermal expansion of the piping resulting from potential stratification modes. The evaluation includes consideration of the information on thermal cycling and thermal stratification included in NRC Bulletins 88-08 and 88-11 and other applicable design standards.*]*

The effects of earthquakes are not considered directly in the analyses leading to the fluid systems design transients. The presence or absence of seismic activity has no effect on the input data used for the analyses nor on the resulting pressure, temperature, and flow transients. Therefore, where applicable, in addition to the effects produced by the transients, earthquake loadings must be considered. See Subsection 3.9.3 for a description of the seismic loads and other mechanical loads and loading combinations evaluated.

3.9.1.1.1 Level A Service Conditions (Normal Conditions)

The following reactor coolant system transients are considered normal operating transients (plant condition PC-1 per ANS/ANSI 51.1) and are analyzed using Level A service limits:

- Reactor coolant pump startup and shutdown
- Plant heatup and cooldown
- Unit loading and unloading between 0 and 15 percent of full power
- Unit loading and unloading at 5 percent of full power per minute
- Step load increase and decrease of 10 percent of full power
- Large step load decrease with steam dump
- Steady-state fluctuations and load regulation
- Boron concentration equalization
- Feedwater cycling
- Core lifetime extension
- Feedwater heaters out of service
- Refueling
- Turbine roll test
- Primary leakage test
- Secondary leakage test
- Passive residual heat removal test
- Reactor coolant system makeup
- Daily load follow operations

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.9.1.1.1.1 Reactor Coolant Pump Startup and Shutdown

The reactor coolant pumps are started and stopped during such routine operations as plant heatup and cooldown and in connection with recovery from certain transients, such as loss of power. Other (undefined) circumstances may also require pump starting and stopping.

Of the spectrum of reactor coolant system pressure and temperature conditions under which these operations may occur, three conditions have been selected for defining transients:

- Cold condition: 70°F and 400 psig - The minimum pressure required for reactor coolant pump operation may be as low as 100 psig. A pressure of 400 psig is considered a conservative value for design purposes.

- Pump restart condition: 100°F and 400 psig - These conditions are included to cover situations requiring stopping and restarting the pumps after plant heatup has commenced.

- Hot condition: 557°F and 2235 psig

These pressure and temperature values are defined for use in the design and fatigue evaluation processes. Actual pump starting and stopping conditions may be controlled by other factors such as reactor vessel material ductility considerations.

For reactor coolant pump starting and stopping operations, it is assumed that variations in reactor coolant system primary-side temperature and in-pressurizer pressure and temperature are negligible. Temperature and pressure changes in the steam generator secondary side are also assumed negligible. The only significant variables are the primary system flow and the pressure changes resulting from the pump operations.

The following cases are considered.

Case 1 - Pump Startup

Two startup cases are defined as described below.

One case represents the variations in reactor coolant loop flow at cold conditions, which accompany the simultaneous ramp up in speed of both reactor coolant pumps in one loop being driven from low speed to high speed. This case involves both the highest dynamic pressure loss and the largest change in dynamic pressure loss for cold conditions and, thus, conservatively represents the variations in reactor coolant flow accompanying operation of any single pump during cold conditions.

A case is also defined that represents the variations in reactor coolant loop flow at hot conditions, which accompany the startup of a second pump in the loop with a pump currently operating and both pumps in the other loop idle. This case involves both the highest dynamic pressure loss and the largest change in dynamic pressure loss and, thus, conservatively represents the variations in reactor coolant loop flow accompanying startup of any given single pump during hot conditions.

Case 2 - Pump Shutdown

This case represents the variations in reactor coolant loop flow, which accompany the shutdown of a pump when the only other operating pump is in the same loop. This transient is the reverse of the hot condition pump startup transient and involves an equally limiting change in dynamic pressure loss. It thus conservatively represents the variations in reactor coolant flow accompanying shutdown of any given single pump.

Design values for the pump starting/stopping conditions are given in Table 3.9-2 along with the assumed number of occurrences.

An example of the consequence of a pump startup is that the loop flow change associated with pump startup develops a pressure differential in the normal (forward) direction across the divider plate of the steam generator in that loop. In the loop undergoing reverse flow, the direction of the divider plate differential is reversed. The magnitude of the dynamic pressure drop depends on the volumetric flowrate through the loop and on the density and viscosity of the reactor coolant.

3.9.1.1.1.2 Plant Heatup and Cooldown

For the purpose of designing the major reactor coolant system components, the plant heatup and cooldown operations are conservatively represented by uniform ramp temperature changes of 100°F per hour when the system temperature is above 350°F. (For the pressurizer vessel, the design cooldown rate is 200°F per hour.) This rate bounds both potential nuclear heatup operations and cooldown using the steam dump system when system temperatures are greater than 350°F. Below 350°F, only reactor coolant pump heat and small amounts of decay heat are available to heat the reactor coolant system. Cooldown between 350°F and the shutdown temperature of 125°F is accomplished via the normal residual heat removal system. In this range, a uniform ramp rate of 50°F per hour is considered to bound the temperature changes resulting from these operations.

The number of plant heatup and cooldown operations is defined as 200 each, which corresponds to approximately three occurrences per year for design purposes.

3.9.1.1.1.3 Unit Loading and Unloading Between 0 and 15 Percent of Full Power

The unit loading and unloading cases between the 0 and 15 percent load are represented by continuous and uniform ramp steam load changes, which require 30 minutes for loading and five minutes for unloading. During loading, reactor coolant temperatures are changed from their no-load values to their normal load programmed temperature values at 15 percent load. The reverse temperature change occurs during unloading.

Before loading, it is assumed that the plant is at hot standby, with feedwater cycling from the main or startup feedwater system. Loading commences, and during the first two hours, the feedwater temperature increases to the 15 percent load value, because of steam dump and turbine startup heat input to the feedwater.

After unloading, feedwater heating is reduced, steam dump is reduced to residual heat removal requirements, and feedwater temperature decreases from the 15 percent load value. Reactor coolant system pressure and pressurizer pressure are assumed to remain constant at the normal operating values during these operations.

The number of these loading and unloading transients is assumed to be 500 each for design purposes.

3.9.1.1.1.4 Unit Loading and Unloading at Five Percent of Full Power per Minute

The unit loading and unloading operations are conservatively represented by continuous and uniform ramp power changes of 5 percent per minute between the 15 percent and 100 percent power levels. This load swing is the maximum possible that is consistent with operation under automatic reactor control. The reactor temperature will vary with load prescribed by the reactor control system.

The number of loading and unloading operations is defined as 2000 each for the 60-year plant design objective. The 2000 occurrences includes the plant loading and unloading for the normal plant

startup/shutdown, and loading resulting from all service levels B, C, and D transients that result in a reactor trip.

3.9.1.1.1.5 Step Load Increase and Decrease of 10 Percent of Full Power

The 10 percent step change in load demand results from disturbances in the electrical network to which the unit is tied. The reactor control system is designed to restore plant equilibrium without reactor trip following a 10 percent step change in turbine load demand initiated from nuclear plant equilibrium conditions between 15 and 100 percent of full load (the power range for automatic reactor control).

Following a step decrease in turbine load, the secondary-side steam pressure and temperature initially increase. The reactor coolant system average temperature and pressurizer pressure also increase, but this change lags slightly behind the secondary-side change. Because of the coolant temperature increase and the power mismatch between turbine and reactor, the control system automatically inserts the control rods to reduce core power. The reactor coolant temperature then decreases from its peak value to a value below its initial equilibrium value.

Pressurizer pressure also decreases from its peak value and follows the reactor coolant decreasing temperature trend. At some point during the decreasing pressure transient, the saturated water in the pressurizer begins to flash. This reduces the rate of pressure decrease. Subsequently, the pressurizer heaters turn on and restore the pressure to its normal value.

Following a step increase in turbine load, the reverse situation occurs. The secondary-side steam pressure and temperature initially decreases and the reactor coolant average temperature pressure initially decreases. The control system automatically withdraws the control rods to increase core power.

The decreasing pressure transient is reversed by actuation of the pressurizer heaters, and eventually the system pressure is restored to its normal value. The reactor coolant average temperature rises to a value above its initial equilibrium value.

The number of operations is specified as 3000 times each, or 50 times per year, for design purposes.

3.9.1.1.1.6 Large Step Load Decrease With Steam Dump

This transient applies to a step decrease in turbine load from full power. This step decrease in turbine load results in a rapid mismatch between nuclear and turbine power that automatically initiates a secondary-side steam dump and actuates the rapid power reduction system, which prevents both reactor trip and lifting of steam generator safety valves.

After the large step load decrease, reactor power is reduced at a controlled rate, which results in lower flow through the steam dump system.

The AP1000 plant is designed to accept a step load change to house load, without a reactor trip, with up to 40 percent of the load reduction provided by the steam dump capability. The balance of the load reduction is provided by the rapid power reduction system. The number of occurrences of this transient is specified at 200 times for design purposes.

3.9.1.1.1.7 Steady-State Fluctuations and Load Regulation

Reactor coolant pressure and temperature can vary around the nominal (steady-state) values during power operation. These variations can occur at many frequencies but for design purposes two cases are considered.

Initial Fluctuations - Initial fluctuations are due to rod cycling during the first 20 full power months of reactor operation. Reactor coolant temperature is assumed to vary by ± 3°F, and pressure by ± 25 psi once during each 2-minute period. The total number of occurrences is specified as 1.5×10^5. The fluctuations are assumed to occur consecutively, but not simultaneously, with random fluctuations.

Random Fluctuations - Reactor coolant temperature is assumed to vary by ± 0.5°F, and pressure by ± six psi, once during each six-minute period. The total number of occurrences for design purposes does not exceed 4.6×10^6.

These small, primary-side fluctuations have no effect on the steam generator secondary side.

The above described steady-state fluctuations and the following load regulation transients are considered to be mutually exclusive. Component evaluations are based on the more limiting of either the steady-state fluctuations or the load regulation transients.

Load Regulation - Load regulation refers to the relatively small, rapid fluctuations in load, regarding some nominal operating condition that is the result of the participation of the plant in some form of grid frequency control. The nominal operating condition is either a constant power level or a very slowly changing power level such as that which occurs because of a daily load follow maneuver.

For design purposes it is assumed that the plant experiences load changes of 10 percent of rated load peak-to-peak at a rate of 2 percent of rated load per minute. It is assumed that up to 35 of these load swings may occur during any given day of plant operation. Frequency control capability is to be provided while performing ramp power changes required for load follow maneuvers. This capability is to be provided within 15 to 100 percent of full power. Load regulation is performed with backup heaters continuously energized and spray flow modulated to control pressure.

The load regulation transient can result in considerable cycling of components affected by pressurizer spray, the pressurizer backup heaters, and the control rod drive mechanisms (CRDMs). The 37,000 design occurrences of load regulation correspond to the following component cycles:

- Control rod drive mechanism stepping ≤ 1.3×10^6 steps
- Pressurizer spray on-off cycling ≤ 94,000
- Pressurizer backup heater on-off cycling ≤ 20,000

This cycling of the components should be considered to occur in addition to the duty cycles imposed on these components due to other modes of plant operation.

3.9.1.1.1.8 Boron Concentration Equalization

Following any large change in boron concentration in the reactor coolant system, the pressurizer spray is operated to equalize the concentration between the loops and the pressurizer. This can be done by manually operating the pressurizer backup heaters, which causes a pressure increase and spray initiation at a pressurizer pressure of approximately 2275 psia. The pressure increases to approximately 2280 psia before being returned to 2250 psia by the proportional spray. The pressure is maintained at 2250 psia by spray operation, matching the heat input from the backup heaters, until the concentration is equalized.

Since reactor coolant system boron concentration changes are not required for daily load follow, it is assumed that this operation is performed about once each week. For design purpose the total number of occurrences is placed at 2900.

The operations cause no significant effects on the steam generator secondary side. The only effects of these operations on the primary system are as follows:

- The reactor coolant pressure varies in step with the pressurizer pressure.

- The pressurizer surge line nozzle at the hot leg will experience the temperature transient associated with outflow from the pressurizer.

3.9.1.1.1.9 Feedwater Cycling

The feedwater cycling transient occurs when the plant is being maintained at hot standby or no-load condition. With the plant in the steam pressure mode of steam dump control, a low steam generation rate occurs because of dissipation of decay and/or pump heat. This low steam generation rate decreases steam generator water level.

To compensate for the decreasing level, the steam generators are fed using the startup feedwater control. Either the main or startup feedwater pumps can continuously provide flow to the steam generators and maintain the desired steam generator level. For this case the reactor coolant system transient is relatively moderate.

If the startup feedwater control system is unavailable, the feedwater is provided intermittently in a slug-feeding mode.

Two modes of slug-feeding the steam generators are considered. In the first mode, it is assumed that the steam generators are slug-fed through the startup feedwater nozzle once every two hours. In the second mode, it is assumed that tighter control of steam generator water level is maintained by slug-feeding once every 24 minutes.

For design purposes, the following numbers of feedwater cycling transients are considered:

- Mode 1: Slug feed every 2 hours – 3000 cycles
- Mode 2: Slug feed every 24 minutes – 15,000 cycles

The component designers consider both modes of slug-feeding. Each component evaluation is based on the more limiting of the two modes.

3.9.1.1.1.10 Core Lifetime Extension

These transients occur at the end of core life when the critical boron concentration required to maintain full thermal power conditions becomes less than achievable (approximately 10 ppm). To extend core lifetime beyond this point, the operator does the following:

- Allows the reactor coolant system average temperature to decrease below the normal programmed temperature, thereby adding reactivity to the core through the negative moderator temperature coefficient.

- Manually controls the turbine to maintain full electrical load until the turbine control valves have fully opened.

- Reduces steam flow by an amount that will maintain the plant at full rated electrical load after a feedwater heater has been taken out of service and allow plant conditions to reach a new steady state.

- Takes a feedwater heater out of service.

This process is repeated until the maximum allowable feedwater heaters have been taken out of service and the turbine control valves have fully opened.

For design purposes, the number of occurrences of these transients is a total of 40 transients. During this mode of operation, the plant is not capable of daily load follow operation. Thus, this transient is considered separately from unit loading and unloading transients.

3.9.1.1.1.11 Feedwater Heaters Out of Service

These transients occur when one or more feedwater heaters are taken out of service. During the time that the heaters are out of service, the operator maintains the plant at full rated thermal load. To accomplish this, the operator performs the following:

- Calculates the appropriate steam flow reduction which will maintain the plant at full rated thermal load after the heater has been taken out of service.
- Reduces steam flow by the appropriate amount and allow plant conditions to reach a new steady state (approximately 10 minutes).
- Takes heater (or heaters) out of service.

The transient is based on the maximum allowable number of heaters out of service. For design purposes, the number of occurrences of this transient is a total of 180.

3.9.1.1.1.12 Refueling

At the beginning of the refueling operation, the reactor coolant system is assumed to have been cooled down to 140°F. The vessel head is removed and the refueling canal is filled. This is done by transferring water from the in-containment refueling water storage tank, which is conservatively assumed to be at 70°F, to the refueling cavity by the spent fuel pool cooling system (SFS).

This operation is assumed to occur 40 times over the expected plant design. This transient is experienced only by the primary system.

3.9.1.1.1.13 Turbine Roll Test

This transient is imposed upon the plant during the hot functional test for turbine cycle checkout. Reactor coolant pump power is used to heat the reactor coolant to operating temperature (no-load conditions), and the steam generator is used to perform a turbine roll test. However, the plant cooldown during this test exceeds the 100°F per hour design rate.

The number of such test cycles is specified at 20 times, to be performed at the beginning of plant operation before reactor operation. This transient occurs before plant startup, so the number of cycles is independent of other operating transients.

The transient curves and the number of cycles are based on a conservatively high steam flowrate for turning the turbine.

3.9.1.1.1.14 Primary-Side Leakage Test

A leakage test is performed after each opening of the primary system. During this test the primary system pressure is raised (for design purposes) to 2500 psia, with the system temperature above the minimum temperature imposed by reactor vessel material ductility requirements, while the system is checked for leaks.

The secondary side of the steam generator is pressurized so that the pressure differential across the tubesheet does not exceed 1650 psi. This is accomplished with the steam, feedwater, and blowdown lines closed.

For design purposes the number of occurrences is a total of 200 cycles.

3.9.1.1.1.15 Secondary-Side Leakage Test

A secondary side leakage test is performed after each opening of the secondary system to check closures for leakage. For design purposes, it is assumed that the steam generator secondary side is pressurized to just below its design pressure to prevent the safety valves from lifting. So that a secondary-side to primary-side pressure differential of 670 psi is not exceeded, the primary side must also be pressurized. The 670 psi differential is the steam generator design differential pressure for secondary-to-primary pressure. The primary system must be above the minimum temperature imposed by reactor vessel material ductility requirements (that is, between 120°F and 250°F). It is assumed that this test is performed 80 times for design purposes.

3.9.1.1.1.16 Not Used

3.9.1.1.1.17 Passive Residual Heat Removal Test

During the initial test program, the passive residual heat removal flow and heat transfer rates are tested. Passive residual heat removal flow is initiated by opening the passive residual heat removal isolation valves. For component design purposes, the temperature and pressure responses to this testing are based on a conservative definition of the test conditions with a total of 5 occurrences.

3.9.1.1.1.18 Reactor Coolant System Makeup

The chemical and volume control system makeup subsystem is used to accommodate normal minor leakage from the reactor coolant system. On a low programmed pressurizer level signal one of the chemical and volume control system makeup pumps starts automatically in order to provide makeup. The pump automatically stops when the pressurizer level increases to the high programmed setpoint. The addition of the makeup water to the reactor coolant system via the chemical and volume control system purification loop and attendant changes in reactor coolant system parameters constitute the reactor coolant system makeup design transient. The total number of occurrences of the makeup transient is 5640, which corresponds to twice per week during the plant design objective of 60 years assuming a 90 percent availability factor for the plant.

3.9.1.1.1.19 Daily Load Follow Operations

During the load follow operations, the plant power is reduced from the 100-percent power to 50-percent at a prescribed rate and remains there for a specified time, and then the power ramps up to 100-percent power at a prescribed rate. Power remains at 100-percent power for the remainder of the 24-hour cycle. The reactor coolant temperature will vary with load as prescribed by the reactor control systems.

The AP1000 features a rod control system that provides a load follow capability without requiring a change in the boron concentration in the coolant. Thus, the reactivity gain available from temperature reduction is not required for load follow, and reduced temperature return to power is not applicable to the AP1000.

The number of daily load follow operations is specified as 17,800 times during the plant design objective of 60 years. One swing of load follow operation consists of one power ramp down from

steady-state 100-percent power to 50-percent power and one power ramp up from steady-state 50-percent power to 100-percent power.

3.9.1.1.2 Level B Service Conditions (Upset Conditions)

The following paragraphs describe the reactor coolant system upset condition transients, which are considered to be plant condition PC-2 and PC-3 per ANS/ANSI 51.1. From the standpoint of the use of design transient in the evaluation of cyclic fatigue, there is no difference between PC-2 and PC-3. These transients are analyzed using Level B service limits and are as follows:

- Loss of load
- Loss of power
- Reactor trip from reduced power
- Reactor trip from full power
  Case A - with no inadvertent cooldown
  Case B - with cooldown and no safeguards actuation
  Case C - with cooldown and safeguards actuation
- Control rod drop - three cases
- Cold overpressure
- Inadvertent safeguards actuation - three cases
- Partial loss of reactor coolant flow
- Inadvertent reactor coolant system depressurization
- Excessive feedwater flow
- Loss of power with natural circulation cooldown
  Case A - loss of power with natural circulation cooldown with onsite ac power
  Case B - loss of power with natural circulation cooldown without onsite ac power

Under the upset condition transients listed, 505 reactor trip cases are assumed. A total of 505 reactor trips for design purposes exceeds the design goal. The design goal for the AP1000 is less than one unplanned trip per year. The number of reactor trips in the design transients represents a conservative number for the analysis of cyclic stresses in the components and is not to be considered an estimate of expected plant performance.

For some component or portions of components, the number of reactor trips analyzed for the effects of cyclic loads may be reduced from 505. In each case the number of reactor trips analyzed is greater than the design goal of one per year.

3.9.1.1.2.1 Loss of Load

This transient involves a step decrease in turbine load from full power (turbine trip) without immediate automatic reactor trip or rapid power reduction. These conditions produce the most severe pressure transient on the reactor coolant system under upset conditions. The reactor is assumed to trip as a consequence of a trip initiated by the reactor protection system. Since redundant means for tripping

the reactor are provided by the reactor protection system, a transient of this nature is not expected, but is included to confirm conservative component design.

The number of occurrences of this transient is specified at 30 times for design purposes.

3.9.1.1.2.2 Loss of Power

This transient applies to a blackout situation involving the loss of outside electrical power to the station, assumed to be operating initially at 102 percent power, followed by reactor and turbine trips. The reactor coolant pumps are de-energized, as are electrical loads connected to the turbine-generator bus, including the main feedwater and condensate pumps.

As the reactor coolant pumps coast down, reactor coolant system flow reaches an equilibrium value through natural circulation. This condition permits removal of core residual heat through the steam generators, which receive feedwater from the startup feedwater system. For this event reactor coolant temperature stabilizes at hot standby conditions.

The number of occurrences of this transient is specified at 30 times for design purposes.

For one occurrence, a worst case is postulated in which the shell side of a single steam generator is assumed to be emptied after the blackout. The startup feedwater flow is then delivered into the hot, dry shell side. The steam generator tube and secondary shell integrity are evaluated for this condition.

3.9.1.1.2.3 Reactor Trip from Reduced Power

A significant percentage of reactor trips occur at low power as the plant is being brought up from hot standby to power. The low power reactor trip is provided to bound these occurrences without the excessive conservatism associated with the reactor trip from full power. The transient is assumed to start at 25 percent load, which bounds the conditions associated with achieving criticality, turbine roll, and turbine synchronization; establishing automatic rod control; and making the transitions in feedwater control from the startup feedwater nozzle to the main feedwater nozzle.

Reactor coolant system temperature and pressure variations are similar to those of reactor trip from full power, but are smaller. The transients continue until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. Controlled steam dump and startup feedwater remove any core residual heat and prevent steam generator safety valve actuation. For design purposes, 180 reactor trips from reduced power are postulated.

3.9.1.1.2.4 Reactor Trip from Full Power

Reactor trips from full power may occur for a variety of reasons. The reactor coolant temperature and pressure undergo rapid decreases from full power values as the reactor protection system causes the control rods to move into the core. Transients also occur in the secondary side of the steam generator because of continued heat transfer from the reactor coolant through the steam generators.

These transients continue until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. Continuation of feedwater flow and controlled steam dump remove the core residual heat and prevent steam generator safety valve actuation. For design purposes, reactor trip from full power is assumed to occur 120 times.

Three reactor trip cooldown transients are considered.

Case A - Reactor Trip With No Inadvertent Cooldown

Case A of the reactor trip transient represents the likely case in which the systems function as designed and as such no inadvertent cooldown occurs. This case maintains conservatism over the best estimate reactor trip via assumptions that result in the RCS temperatures initially cooling below the no load conditions before steam and feedwater flow are both controlled to bring the plant back to no-load conditions and maintain it at no load. For design purposes, 50 occurrences of this transient are specified.

It is assumed that for most reactor trip Case A transients, the turbine control system operates as designed. For five of the reactor trip Case A transients, it is conservatively assumed that the control system fails, which results in an emergency turbine overspeed. This situation could be initiated with malfunction of the turbine control system, which results in a turbine speed increase past the overspeed trip setpoint. It is assumed that the reactor then trips and that the turbine speed increases to 120 percent of nominal, with accompanying proportional increases in generator bus frequency, reactor coolant pump speed and reactor coolant flowrate. None of the other reactor coolant system primary side, pressurizer, or steam generator secondary side variables is affected.

For design purposes it is assumed that the emergency turbine overspeed constitutes a special case of the reactor trip with no inadvertent cooldown transient. Thus, for five of the 50 occurrences, the effects of the reactor coolant flow variation are considered in addition to the basic pressure and temperature variations.

Case B - Reactor Trip With Cooldown and No Safeguards Actuation

This transient is similar to Case A, except that a failure in the main feedwater control valves is assumed to delay main feedwater isolation. Additionally, for this case, it is assumed that the startup feedwater pumps are started within five seconds of the reactor trip. Both main and startup feedwater flow continue until the feedwater flow is assumed to be isolated just prior to the actuation of safeguards system. This maintains a high heat transfer rate through the steam generator, which continues to drive the primary side pressure and temperature down. Flow through the startup feedwater nozzle is continued until isolated on Low-2 T_{cold}. No other safety functions are assumed to be actuated following the Low-2 T_{cold} signal. The plant is then brought back to the no-load condition.

For design purposes, 50 occurrences of this transient are specified.

Case C - Reactor Trip with Cooldown and Safeguards Actuation

This transient is similar to Case B, but it is assumed that the steam generator secondary side shrinkage is sufficient to actuate the passive residual heat removal heat exchanger in addition to the PLS starting of the startup feedwater pumps. The core makeup tanks are then actuated on Low-2 pressurizer water level signal. Main and startup feedwater are assumed to continue until isolated on Low-2 T_{cold}. After 30 minutes, the plant is assumed to be manually controlled to either cold shutdown or returned to the no-load conditions.

For design purposes, 20 occurrences of this transient are specified. The components analyses should be based on 20 occurrences of either the reactor trip - Case C transients or 20 occurrences of the control rod drop - Case B transients, whichever transient is more severe for the component being evaluated.

3.9.1.1.2.5 Control Rod Drop

This transient occurs when one or more rod cluster control assemblies inadvertently drop into the core because of equipment failure or operator error. If this rod drop occurs while the plant is at power, pressure and temperature transients will occur in the reactor coolant system and on the secondary side of the steam generators. The severity of the rod drop accident depends on a number of factors,

such as the number and worth of rod cluster control assemblies that drop, and the value of the moderator temperature coefficient of reactivity.

The following three types of control rod drop transients are postulated for design purposes.

Control Rod Drop - Case A

This transient occurs when the worth of the dropped control rods is high. When the rods drop, reactor power quickly decreases, but plant load is maintained at its initial value.

The steam load-reactor power mismatch causes the plant to cool down, eventually leading to a reactor trip, main feedwater isolation, turbine trip, and steamline isolation following a Low-2 steam line pressure signal. No other safety functions are assumed to be actuated during this transient. Following the reactor trip, the steam generator water level falls because of shrinkage in the secondary side. This is assumed to cause startup feedwater flow to actuate on low steam generator level, thus continuing to drive the primary system temperature and pressure down. The transient is terminated 10 minutes after rod drop.

For design purposes, 30 occurrences of this transient are specified.

Control Rod Drop - Case B

This transient is similar to Case A, except the PRHR HX and CMT are assumed to be actuated. Therefore, the response of the various plant parameters during this transient are very similar to those of reactor trip from full power - Case C.

For design purposes, a combined total of 20 occurrences of the control rod drop - Case B transient and the reactor trip from full power - Case C transient are defined. The components analyses should be based on 20 occurrences of either the control rod drop - Case B transients or 20 occurrences of the reactor trip - Case C transients, whichever transient is more severe for the component being evaluated.

Control Rod Drop - Case C

This transient occurs when the worth of the dropped rod is relatively low and the moderator temperature coefficient of reactivity is negative. When the rod drops, reactor power is reduced but no trip occurs.

However, plant steam load is maintained at the initial value through the transient.

The steam load-reactor power mismatch causes the plant to cool down. With a negative moderator temperature coefficient of reactivity, reactor power returns to its initial value. The plant eventually stabilizes, with reactor power, plant steam flow, reactor coolant system pressure, and pressurizer pressure equal to their initial values, but the reactor coolant system temperature and steam generator secondary-side temperature and pressure are lower.

The magnitude of the reactor coolant system temperature reduction is proportional to the relative worth of the dropped control rod and the negative moderator temperature coefficient of reactivity. For design purposes, 30 occurrences of this transient are specified.

At the end of the control rod drop - Case C transient, plant parameters stabilize at their final values. After plant parameters achieve their final values, the plant remains at these conditions indefinitely. Subsequently, plant parameters are returned to their initial values.

Following initiation of recovery, hot and cold leg temperatures and steam generator steam temperature and pressure return to their initial values over a 30 minute period. Pressurizer water

volume returns to its initial value in about the same amount of time as the return of hot and cold leg temperatures to their initial values. Pressurizer surge rate variation is consistent with the increase in pressurizer water level.

3.9.1.1.2.6 Cold Overpressure

The relief valves located in the residual heat removal pump suction piping provide the capability for additional reactor coolant system inventory letdown in order to maintain the reactor coolant system pressure consistent with the reactor vessel pressure temperature limits, as required by Appendix G of 10 CFR Part 50. Reactor coolant system cold overpressurization occurs at low temperature (below 350°F) during plant heatup or cooldown, and can occur with or without a steam bubble in the pressurizer. A cold overpressurization is especially severe when the reactor coolant system is water solid. The event is inadvertent, and can be generated by an equipment malfunction or an operator error.

Cold overpressure events are initiated by either a mass addition that exceeds normal letdown capabilities, or a heat addition that attempts to expand the reactor coolant system water volume.

Under water-solid conditions, a worst-case scenario, the mass addition causes an increase in system pressure until the relief valve set pressure, plus accumulation, is reached. The relief valves remain open, with the system pressure stabilizing at the set pressure plus accumulation, until the mass injection is terminated by the operator. Heat addition, also under water-solid conditions, results in a system pressure increase that eventually is terminated by the relief valves.

Once thermal equilibrium is established between the heat source and the reactor coolant system, and the volume expansion has been let down through the relief valves, system pressure stabilizes at the relief valve set pressure.

Fifteen reactor coolant system cold overpressure events, as described above, are specified for design purposes.

3.9.1.1.2.7 Inadvertent Safeguards Actuation

A spurious system-level actuation of the passive core cooling system results in an immediate reactor trip followed by actuation of the various components of the passive core cooling system. The resulting transient is bounded by the reactor trip Case C. The number of reactor trip transients is sufficient to cover a system-level inadvertent safeguards actuation.

A spurious actuation of the passive residual heat removal heat exchanger isolation valves or the core makeup tank valves causes cold reactor coolant to flow into the reactor coolant system. Rapid changes in the temperature of the core makeup tank or passive residual heat removal heat exchanger and associated piping occur. Ten events of this limited transient are postulated.

3.9.1.1.2.8 Partial Loss of Reactor Coolant Flow

This transient applies to a partial loss of flow from full power in which a reactor coolant pump is tripped out of service as a result of loss of power to that pump. The consequences of such an accident are a reactor trip on Low-2 reactor coolant flow, followed by a turbine trip; actuation of startup feed control; and automatic opening of the steam dump system. Flow reversal occurs in the associated cold leg. The normal flow direction is maintained in the hot leg of the affected loop but at a reduced rate. Flow through the operating pump in this loop increases.

Operation of the steam dump system tends to bring the plant toward no-load conditions. Cold feedwater from the startup feedwater system then enters the steam generators, causing the plant to

cool down. This cooldown continues until termination of startup feed water. The plant is then returned to no-load conditions.

The number of occurrences of this transient is specified as 60 times for design purposes.

3.9.1.1.2.9 Inadvertent Reactor Coolant System Depressurization - Umbrella Case

Several events can be postulated as occurring during normal plant operation that cause rapid depressurization of the reactor coolant system. These include the following:

- Actuation of a single pressurizer safety valve with failure of the valve to reclose
- Malfunction of a single pressurizer pressure controller causing two pressurizer spray valves to open
- Inadvertent opening of one pressurizer spray valve
- Inadvertent opening of the auxiliary spray valve

Umbrella Case - Of these events, the pressurizer safety valve actuation causes the most severe reactor coolant system pressure and temperature transients. It can be used as an umbrella case to conservatively represent the reactor coolant pressure and temperature variations arising from any of them.

Although inadvertent actuation of the pressurizer spray is included among the transient events covered by the umbrella case, the pressurizer safety valve actuation case selected to represent the depressurization transients does not involve spray operation. Therefore, for the umbrella case, it is assumed that pressurizer spray is not actuated and that no temperature transients due to flow occur at the spray nozzle.

Inadvertent Pressurizer Spray - The inadvertent pressurizer spray transient represents the depressurization transient, with the most significant temperature variations on portions of the pressurizer, spray nozzle, and spray piping. Should auxiliary spray flow be inadvertently initiated, it could cause a rapid temperature change at the pressurizer spray nozzle and on the pressurizer vessel. Therefore, to provide a conservative design for these components, an inadvertent pressurizer spray transient is defined.

An inadvertent pressurizer spray occurs if the normal spray valve is opened during normal plant operation because of either failure of a control component or operator error. This introduces water at reactor coolant system cold leg temperature into the pressurizer. The flowrate is assumed to be the maximum design spray flowrate. This transient results in a pressure decrease and, eventually, in a low-pressure reactor trip.

An inadvertent auxiliary spray occurs if the auxiliary spray valve is opened during normal plant operation because of either failure of a control component or operator error. The opening of the auxiliary spray valve causes an inadvertent spray transient only during the limited time that the makeup pump in the chemical and volume control system is operating. The inadvertent auxiliary spray introduces cold water into the pressurizer, which results in a sharp pressure decrease and, eventually, in a Low-2 pressure reactor trip.

The temperature of the auxiliary spray flow is dependent upon the performance of the regenerative heat exchanger. The most conservative case assumes that the letdown stream is shut off and that unheated charging fluid enters the 653°F pressurizer. It is assumed that the temperature of the spray water is 70°F and that the spray flowrate is equal to the normal charging rate.

For inadvertent auxiliary spray, it is also assumed that the spray flow continues for five minutes before it is shut off and that the temperature changes at the pressurizer and spray nozzle occur as steps. For design purposes, it is assumed that no reactor coolant temperature changes occur as the result of inadvertent auxiliary spray.

For design purposes, 20 occurrences of the inadvertent reactor coolant system depressurization transient are specified. Component evaluations are based on the more limiting of either the umbrella case or the inadvertent spray case, or, alternatively, are based on a combination of design transients (5 stuck open PSV and 15 inadvertent spray) that total up to the 20 transients. For those components for which the limiting transient is caused by the inadvertent pressurizer spray transient, 10 occurrences of inadvertent normal spray and five occurrences of inadvertent auxiliary spray are postulated.

3.9.1.1.2.10 Excessive Feedwater Flow

An excessive feedwater flow transient is conservatively defined as an umbrella case to cover the occurrence of several events of the same general nature. The postulated transient results from inadvertent opening of a feedwater control valve while the plant is at the hot standby or no-load condition, with the feedwater, condensate, and heater drain systems in operation.

It is assumed that the stem of a feedwater control valve fails and the valve immediately reaches the full open position. In the steam generator directly affected by the malfunctioning valve (failed loop), the feedwater flow step increases from essentially zero flow to the value determined by the system resistance and the developed head of the operating feedwater pumps. Steam flow is assumed to remain at zero.

The CMTs and PRHR HX are actuated on the Low-2 pressurizer water level signal. The startup feedwater and main feedwater flow in the faulted loop are effectively isolated on Low-2 T_{cold}.

This transient is assumed to occur 30 times for design purposes.

3.9.1.1.2.11 Loss of Power with Natural Circulation Cooldown

This event is the same as a loss of power transient, except that the reactor coolant system temperature is reduced by natural circulation through the operation of either the startup feedwater pumps and steam dump through the power-operated relief valves if onsite power is available or the passive residual heat removal system transferring heat to the in-containment refueling water storage tank if onsite power is not available. For design purposes 30 natural circulation cooldown occurrences, are assumed. These two cases are discussed below.

Case A - Loss of Power with Natural Circulation Cooldown with Onsite ac Power

For this case, natural circulation cooldown is performed with onsite ac power available. This permits operation of the startup feedwater pumps which enables steam dump through the steam generator power-operated relief valves. This transient is analyzed assuming at least one onsite diesel is operable. For this case the startup feedwater pumps operate and the control rod drive mechanism fan coolers operate to maintain the temperature of the reactor vessel head close to the temperature of the remainder of the reactor vessel. For design purposes, 20 occurrences of this transient are assumed.

Case B - Loss of Power with Natural Circulation Cooldown without Onsite ac Power

For this case, the reactor coolant is cooled by natural circulation with the passive residual heat removal heat exchangers. For this case, no credit is taken for nonsafety-related equipment including the diesel generators. For design purposes, 10 occurrences of this transient are assumed.

3.9.1.1.3 Level C Service Conditions (Emergency Conditions)

The following paragraphs describe the reactor coolant system emergency condition transients considered to be plant condition PC-4 per ANS/ANSI 51.1. A list of these transients follows. The effect of these events are analyzed using Service Level C limits. As noted previously, up to 25 strong stress cycles due to these transients are not analyzed for cyclic fatigue. Any cycles exceeding the 25 excluded are analyzed for cyclic fatigue using Service Level B limits. The mechanical loads due to pipe rupture are analyzed using Service Level D limits. See Subsection 3.6.2 for a discussion of the analysis of mechanical loads due to pipe break.

- Small loss of coolant accident
- Small steam line break
- Complete loss of flow
- Small feedwater line break
- Steam generator tube rupture
- Inadvertent opening of automatic depressurization system valves

3.9.1.1.3.1 Small Loss-of-Coolant Accident

For design transient purposes, the small loss-of-coolant accident is a pipe break equivalent to the severance of a 1-inch ID branch connection to the reactor coolant system. It is assumed that the passive core cooling system is actuated and that it delivers water at a minimum temperature of 70°F to the reactor vessel.

It is assumed that this transient occurs five times for design purposes.

3.9.1.1.3.2 Small Steam Line Break

For design purposes, a small steam line break is a break equivalent to a steam generator safety valve opening and remaining open.

For design purposes, it is assumed that this transient occurs five times.

3.9.1.1.3.3 Complete Loss of Flow

This accident involves a complete loss of flow from full power resulting from the simultaneous loss of power to all reactor coolant pumps. The consequences are a reactor trip on Low-2 pump speed, followed by an automatic turbine trip.

This event is considered to be bounded by the loss of power transient. The frequency of occurrence of loss of power transients incorporates the frequency of occurrence of complete loss of flow accidents.

3.9.1.1.3.4 Small Feedwater Line Break

This transient is postulated as a small break in the piping between the steam generator and the main feedwater isolation valve. The main feedwater control system is assumed to malfunction. The malfunction of the main feedwater flow in the affected loop is equivalent to the fluid spilling through the break. No main feedwater is supplied to either steam generator.

After reactor trip, the main feedwater control system is assumed to be lost and reverse flow is assumed to be initiated from the pipe with the break. During the course of the transient, reactor trip, turbine trip, the passive core cooling system and the startup feedwater system are actuated because of low level in the steam generator.

For design purposes, this transient is assumed to occur five times.

3.9.1.1.3.5 Steam Generator Tube Rupture

This transient is postulated as the double-ended rupture of a single steam generator tube, which results in decreases in pressurizer level and reactor coolant pressure. Assuming no operator action, the reactor eventually trips on overtemperature ΔT or Low-2 pressurizer pressure. Reactor trip initiates a turbine trip. Reactor coolant system pressure continues to decrease after the trip because of energy transfer from the primary system to the secondary side and continued primary to secondary leakage through the ruptured steam generator tube. Continued reactor coolant system leakage results in an actuation of the passive core cooling system because of Low-2 pressurizer level or pressure.

For design purposes this transient is assumed to occur five times.

3.9.1.1.3.6 Inadvertent Opening of Automatic Depressurization System Valves

Rapid depressurization of the reactor coolant system results from the inadvertent opening of the automatic depressurization system (ADS) valves. This event is postulated to occur by:

- Inadvertent opening of an ADS flowpath through two 4-inch (ADS Stage 1) motor-operated valves connected to the pressurizer. Inadvertent opening of an ADS flowpath through two 8-inch valves (ADS Stage 2 or ADS Stage 3), prior to ADS Stage 1 actuation, is not a credible design transient. Inadvertent opening of the 14-inch (ADS Stage 4) valves connected to the reactor coolant system hot legs is not possible at normal operating pressure. The inadvertent opening of the ADS Stage 1 - 4 valves out of sequence is prevented by the Protection and Safety Monitoring System (PMS) logic for a controlled, staged opening (Figure 7.2-1, Sheet 15) and inadvertent opening of ADS valves individually or in any sequence is prevented by the PMS ADS blocking device described in Subsection 7.3.1.2.4.1 and Figure 7.2-1, Sheet 19.

- Inadvertent automatic depressurization system actuation due to a spurious system level signal.

For design purposes, 15 occurrences of the system level inadvertent opening of automatic depressurization system valves transient are assumed, which bounds the inadvertent opening of a single 4-inch flowpath.

3.9.1.1.4 Level D Service Condition (Faulted Conditions)

The following paragraphs discuss the reactor coolant system faulted condition transients considered to be plant condition PC-5 per ANS/ANSI 51.1. A list of these transients follows. These transients are analyzed using Level D service limits and are not analyzed for fatigue due to cyclic loads. See Subsection 3.6.2 for a discussion of the analysis of mechanical loads due to pipe break.

The components are not evaluated for the dynamic effects of pipe rupture for the pipe break events when the requirements for mechanistic pipe break have been satisfied for the connecting piping. See Subsection 3.6.3 for a discussion of the leak-before-break requirements for mechanistic pipe break. The maximum fluid pressure on components is evaluated for these events when leak-before-break requirements are satisfied.

- Reactor coolant pipe break (large loss-of-coolant accident)
- Large steam line break
- Large feedwater line break

- Reactor coolant pump locked rotor
- Control rod ejection

Each of these accidents is evaluated for one occurrence only.

3.9.1.1.4.1 Reactor Coolant Pipe Break (Large Loss-of-Coolant Accident)

Following a rupture of a reactor coolant pipe or connecting branch line that results in a large loss of coolant, the primary system pressure decreases rapidly. This rapid decrease causes the primary system temperature to decrease. Because of the rapid blowdown of coolant from the system and the comparatively large heat capacity of the metal sections of the components, it is likely that the metal will remain at or near operating temperature during blowdown. The passive safety injection system is actuated to introduce water into the reactor coolant system (reactor vessel). The RCS thermal hydraulic response to this transient is developed assuming injection occurs at a maximum initial temperature of 120°F, while the component analyses account for stress associated with injection at a minimum temperature of 50°F. The safeguards actuation signal also trips the reactor and the turbine.

3.9.1.1.4.2 Large Steam Line Break

This transient is based on a double-ended rupture of a main steam line. The analyses performed are based on the following conservative assumptions:

- The plant is initially at no-load condition.
- The steam line break results in an immediate reactor trip.
- Main steam line isolation valves are initially open.
- The passive core cooling system operates as designed, and no single failures are assumed. This maximizes the extent and rate of plant cooldown.
- Reactor coolant pumps continue to operate until tripped on core makeup tank actuation coincident with Low-2 pressurizer water level.

An alternate definition of large steam break if postulated for evaluation of steam generator pressure boundary components, with respect to stress levels in the steam generator tubes and tubesheet, may represent a more severe transient. The alternate definition is as follows: If the break should occur while the plant is operating at full power instead of no load, and the break is located outside of containment, the affected steam generator will quickly blow down to atmospheric pressure. Flow through the startup feedwater nozzle is then delivered to the hot, dry shell side of the affected steam generator. The primary side pressurizes to 2600 psia (set pressure of pressurizer safety valves plus one percent set pressure error plus 3 percent accumulation). This results in a large differential pressure across the tubes and tubesheet. The combination of parameters giving the most conservative results is used.

The simultaneous, complete severance of both a main steam line and a feedwater line is not a credible event in the AP1000. In addition to the application of criteria to demonstrate leak-before-break on these lines, layout and support requirements are imposed to prevent extensive steam line or feedwater line displacement following rupture.

3.9.1.1.4.3 Large Feedwater Line Break

This postulated accident involves the double-ended rupture of a main feedwater line, which results in rapid blowdown of the affected steam generator and termination of feedwater flow to the other. The

plant is assumed to be operating at an initial power level of 102 percent of design rating, with temperatures conservatively higher than the nominal full power values when the break occurs. The feedwater line break results in immediate reactor and turbine trips. The passive core cooling system is actuated, the passive residual heat removal heat exchanger operates, and the reactor coolant pumps are tripped.

In the analysis, no credit is taken for operation of pressure control systems, steam dump, or steam generator power-operated relief valves. The intact steam generator feeds the break through the main steam header after the faulted steam generator discharges its liquid inventory. Steam flow continues until the main steam lines are isolated on Low-2 steam line pressure.

3.9.1.1.4.4 Reactor Coolant Pump Locked Rotor

This accident is based on the seizure of the rotating assembly of a reactor coolant pump rotor, with the plant operating at full power. Reactor trip occurs rapidly, as the result of Low-2 coolant flow in the affected cold leg. Assumptions made in the analysis include the following:

- Initially the plant is operating at 102 percent of design rating.
- Initially temperature is conservatively higher than the program value.
- No return to criticality occurs in the core.
- No credit is taken for reactor coolant system pressure control.

For the determination of the increase in pressure and response of the reactor core to the reduction in flow, the seizure is assumed to occur instantaneously. For the evaluation of dynamic effects imposed on the pump casing, steam generator, and connecting piping, the rotating assembly is assumed to come to a stop rapidly but not instantaneously. See Subsection 5.4.1 for a discussion of the time for a locked rotor to occur.

Level D pressure limits are applied to the affected reactor coolant pump, steam generator channel head and piping, and Level B pressure limits are applied to the rest of the reactor coolant system. The system effects and the maximum fluid pressure are evaluated for this condition on components not affected by the dynamic effects.

3.9.1.1.4.5 Control Rod Ejection

This accident is based on the single most reactive control rod being instantaneously ejected from the core. This reactivity insertion in a particular region of the core causes a severe pressure increase in the reactor coolant system in such a way that the pressurizer safety valves will lift. It also causes a more severe temperature transient in the loop associated with the affected region (the hot loop) than in the other loop.

Since the pressure boundary of the control rod drive mechanism is constructed using the requirements of the ASME Code, Section III, the ejection of the control rod is postulated as a nonmechanistic event and not as the result of a rupture of the control rod drive housing. The analysis of the system response is based on the reactivity insertion without any mitigating effects (on the pressure transient) of coolant blowdown through the hole in the vessel head above the rod. The maximum fluid pressure on the components is evaluated for this condition.

3.9.1.1.5 Test Conditions Transients

The following paragraphs describe the following reactor coolant system test conditions transients:

- Primary-side hydrostatic test
- Secondary-side hydrostatic test

- Tube leakage test

3.9.1.1.5.1 Primary-Side Hydrostatic Test

The pressure tests covered by this subsection include both shop and field hydrostatic tests that occur as a result of component or system testing. This hydrostatic test is performed at a water temperature compatible with reactor material ductility requirements and a test pressure of 3107 psig (1.25 times design pressure). In this test, the reactor coolant system is pressurized to 3107 psig coincident with steam generator secondary-side pressure of zero psig. The reactor coolant system is designed for 10 cycles of these hydrostatic tests. The number of cycles is independent of other operating transients.

Additional, lower-pressure hydrostatic tests may be performed to meet the inservice inspection requirements of ASME Code, Section XI, Subarticle IWB-5200. Four such tests are expected. The increase in the fatigue usage factor caused by these tests is covered by the primary-side leakage tests that are considered for design. No additional specification is required.

3.9.1.1.5.2 Secondary-Side Hydrostatic Test

The secondary side of the steam generator is pressurized to 1.25 design pressure, with a minimum water temperature of 70°F. For design purposes it is assumed that the steam generator will experience 10 cycles of this test. These hydrostatic test cycles are considered in the stress and fatigue analyses.

These tests may be performed either before plant startup or after major repairs or both. The number of cycles is independent of other operating transients.

3.9.1.1.5.3 Tube Leakage Test

It may be necessary to check the steam generator for tube leakage and tube-to-tubesheet leakage. This is done by inspecting the underside (channel-head side) of the tubesheet for water leakage, with the secondary side pressurized. Tube leakage tests are performed during plant cold shutdown.

For these tests, the secondary side of the steam generator is pressurized with water, initially at a relatively low pressure, and the primary system remains depressurized. The underside of the tubesheet is examined for leaks. If any are observed, the secondary side is depressurized and the leaking tube is plugged. The secondary side is then repressurized (to a higher pressure), and the underside of the tubesheet is again checked for leaks. This process is repeated until the leaks are repaired. The maximum (final) secondary-side test pressure reached is 840 psig.

The total number of tube leakage test cycles is defined as 800 for design purposes. The following is a breakdown of the anticipated number of occurrences at each secondary side test pressure:

Test Pressure (psig)	Number of Occurrences
200	400
400	200
600	120
840	80

During these tests, both the primary and the secondary sides of the steam generators are at ambient temperatures. Neither the primary-side nor secondary-side design pressure is exceeded. The

expected secondary-to-primary pressure differential exceeds the design value of 670 psi for some of the test cycles.

3.9.1.2 Computer Programs Used in Analyses

A number of computer programs that are used in the dynamic and static analyses of mechanical loads, stresses, and deformations, and in the hydraulic transient load analyses, of seismic Category I components and supports are listed in Table 3.9-15. [*The Combined License applicant will implement the NRC benchmark program using AP1000 specific problems (Reference 20) if a piping analysis computer program other than those used for design certification (PIPESTRESS, GAPPIPE, WECAN, and ANSYS) is used.*]*

The development process, verification, validation, configuration control and error reporting and resolution for computer programs used in these analyses for the AP1000 are completed in compliance with an established quality assurance program. The quality assurance program is described in Chapter 17. The verification conforms to at least one of the following methods:

- Hand calculations
- Alternate verified calculational methods
- Results of other verified programs
- Results obtained from experiments and tests
- Known solutions for similar or standard problems
- Measured and documented plant data
- Confirmed published data and correlations
- Results of standard programs and benchmarks
- Parametric sensitivity analysis
- Reference to a verification and validation that has been reviewed and accepted by an independent third party

3.9.1.3 Experimental Stress Analysis

For the reactor internals, measured results from prototype plants and various scale model tests are used to validate the analysis of vibrations of reactor vessel internals as discussed in Subsection 3.9.2. [*No other experimental stress analysis is used for the AP1000.*]*

3.9.1.4 Considerations for the Evaluation of the Faulted Conditions

Subsection 3.9.3 describes the analytical methods used to evaluate ASME Code, Section III, Class 1 components for Service Level D Conditions (faulted conditions).

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.9.1.5 Module Interaction, Coupling, and Other Issues

Many portions of the systems for the AP1000 are assembled as modules and shipped to the plant as completed or partially completed units. The following provides a discussion of influence of modularization on the structural analysis, inservice inspection, and maintenance in the AP1000.

The modules are constructed using a structural steel framework to support the equipment, pipe, and pipe supports in the module. Piping in the modules is routed and analyzed in the same manner as in a plant built by traditional methods. See Subsection 3.7.3 for additional discussion of the structural analysis of modules.

The modules are designed and engineered to provide access for inservice inspection and maintenance activities. Field run pipes and equipment supports do not hinder access for maintenance and inspection.

The quality assurance requirements for the installation and welding of components, piping, supports, and structural elements are the same as in a plant built by traditional methods. The improved access to the parts of the module during fabrication enhances inspection.

3.9.2 Dynamic Testing and Analysis

3.9.2.1 Piping Vibration, Thermal Expansion, and Dynamic Effects

A pre-operational test program as described in Section 14.2 is implemented as required by NB-3622.3, NC-3622, and ND-3622 of the ASME Code, Section III to verify that the piping and piping restraints will withstand dynamic effects due to transients, such as pump trips and valve trips, and that piping vibrations are within acceptable levels. The piping systems to be tested include ASME Code, Section III, Class 1, 2, and 3 systems, high energy systems inside seismic Category I structures, high energy portions of systems whose failure could reduce the functioning of seismic Category I features to an unacceptable level, and the seismic Category I portions of moderate-energy piping systems located outside containment. This includes ASME instrumentation lines up to the first support in each of three orthogonal directions from the process pipe or equipment connection point.

The pre-operational test program for the ASME Code, Section III, Class 1, 2, and 3, and other high-energy or seismic Category I piping systems simulates actual operating modes to demonstrate that the components comprising these systems meet functional design requirements and that piping vibrations are within acceptable levels. The pre-operational testing programs are outlined in Subsection 14.2.9. Piping systems are checked in three sequential steps or series of tests and inspections.

Construction acceptance, the first step, entails inspection of components for correct installation. During this phase, pipe and equipment supports are checked for correct assembly and setting. The cold locations of reactor coolant system components, such as steam generators and reactor coolant pumps, are recorded.

During the second step of testing, plant heatup, the plant is heated to normal operating temperatures. During the heatup, systems are observed periodically to verify proper expansion. Expansion data is recorded at the end of heatup.

During the third step of testing, performance testing, systems are operated to check the performance of critical pumps, valves, controls, and auxiliary equipment. This phase of testing includes transient tests performed as outlined in Chapter 14. During this phase of testing, the piping and piping restraints are observed for vibration and expansion response. Automatic safety devices, control

devices, and other major equipment are observed for indications of overstress, excess vibration, overheating, and noise. Each system test includes critical valve operation during transient system modes.

The locations in the piping system selected for observation during the testing, and the respective acceptance standards, are provided in the preoperational vibration, thermal expansion, and dynamic effects test program plan.

Provisions are made to verify the operability of essential snubbers by recording hot and cold positions. If vibration during testing exceeds the acceptance standard, corrective measures are taken and the test is performed again to demonstrate adequacy.

3.9.2.1.1 Piping Vibration Details

Piping vibration loadings can be placed in two categories: transient-induced vibrations and steady-state vibrations. The first is a dynamic system response to a transient, time-dependent forcing function, such as fast valve closure. The second is a constant vibration, usually flow-induced. Piping vibration testing and assessment is performed in accordance with ASME OM-S/G (Reference 39), Part 3.

Transient Response

Dynamic events falling in this category are anticipated operational occurrences. The systems and the transients included in the preoperational test program are outlined in Section 14.2.

For those types of transients where a time-dependent dynamic analysis is performed on the system, the stresses obtained are combined with system stresses resulting from other operating conditions in according to the criteria identified in Subsection 3.9.3.

Details of the program and the pipe monitoring displacement transducers or scratch plates and strain gage or load cells locations, including the criteria for evaluation of data gained, are provided in the test procedures.

Steady-State Vibration

System vibrations resulting from flow disturbances are considered steady-state vibration. Since the exact nature of the flow disturbance is not known prior to pump operation, no analysis is performed. If system vibration is evident during initial operation, the maximum amplitudes are measured and related to alternating stress intensity levels based on the guidance of ASME OM-S/G (Reference 39), Part 3.

In some locations, vibration monitors are installed to provide additional indication to the operator of the vibration levels on the piping system and supports. The information provided by the monitoring prevents unnecessary fatigue accumulation in the piping system.

The AP1000 preoperational vibration monitoring program includes appropriate safety-related instrument lines up to the first support in each of three orthogonal directions from the process pipe or equipment connection point. The acceptance standard is that the maximum alternating stress intensity, S_{alt}, calculated from the measured amplitudes, shall be limited as defined in the following:

A. For ASME Class 1 piping systems:

$$S_{alt} = \frac{C_2 K_2}{Z} M \leq \frac{S_{el}}{\infty}$$

where:

C_2 = secondary stress index as defined in the ASME Code

$\propto$ = allowable stress reduction factor: 1.3 for materials covered by Figure I-9.1; or 1.0 for materials covered by Figure I-9.2.1 or I-9.2.2 of the ASME Code, Section III, Appendices

K_2 = local stress index as defined in the ASME Code

M = maximum zero to peak dynamic moment loading due to vibration only, or in combination with other loads as required by the system design specification

S_{el} = 0.8 S_A, where S_A is the alternating stress at 10^6 cycles from Figure I-9.1; or S_A at 10^{11} cycles from Figure I-9.2.2 of the ASME Code. The influence of temperature on the modulus of elasticity is considered.

Z = section modulus of the pipe

B. For ASME Class 2 and 3 or ASME B31.1 piping:

$$S_{alt} = \frac{C_2 K_2}{Z} M \leq \frac{S_{el}}{\propto}$$

where:

C_2K_2 = 2i

i = stress intensification factor, as defined in subsection NC and ND of the ASME Code or in ASME B31.1.

If significant vibration levels are detected during the test program that have not been previously considered in the piping system analysis, consideration is given to modifying the design specification to re-verify applicable code conformance using the measured vibration as input.

If required, additional restraints are provided to reduce stresses to below the acceptance levels.

3.9.2.1.2 Piping Thermal Expansion Program

The piping thermal expansion testing program verifies that the piping systems expand within acceptable limits during heatup and cooldown. Also, this program verifies that the standard component supports (including spring hangers, snubbers, and struts) can accommodate the expansion of the piping within an acceptable range for required modes of operation. Test specifications for thermal expansion testing of piping systems during preoperational and start-up testing will be in accordance with ASME OM-S/G (Reference 39), Part 7.

3.9.2.2 Seismic Qualification Testing of Safety-Related Mechanical Equipment

Safety-related mechanical equipment and supports are tested or analyzed to demonstrate functional integrity during and following a postulated safe shutdown earthquake. Equipment that must be active to shut down the plant or mitigate the effects of postulated accidents is analyzed or tested to verify operability. The operability requirements for active valves are discussed more fully in Subsection 3.9.3.2.

Section 3.2 lists the equipment classification and seismic category for components and equipment in the AP1000. Table 3.9-12 lists the active valves. The AP1000 has no safety-related active pumps or turbines.

Seismic Category I safety-related equipment is shown to have structural integrity by analysis satisfying the stress criteria applicable to the particular piece of equipment or by tests showing that the equipment retains its structural integrity under the simulated test environment.

Analyses used to verify functional integrity demonstrate that stresses do not exceed the allowables specified for the appropriate loading combinations listed in Subsection 3.9.3. Deformations do not exceed those that permit the component to perform its required safety function.

Subsection 3.7.3 describes the methods for seismic subsystem analysis.

Tests used to verify operability demonstrate that the component is not prevented from performing its required safety function during and after the test.

The testing procedures used in the seismic qualification of instrumentation and electrical equipment are discussed in Section 3.10. The operability of active valves includes the operability of the valve operator. Valves and operators are tested for operability as an assembly. Section 3.10 includes a description of operability testing for ASME Code Classes 1, 2, and 3 valves and respective drives, operators, and vital auxiliary equipment. That section includes a description of the seismic operability criteria.

Dynamic testing, analysis, or a combination of the two may be used to qualify safety-related seismic Category I mechanical equipment for a postulated safe shutdown earthquake. The criteria used to decide whether dynamic testing or analysis is used are as follows:

Analysis without Testing

Structural analysis without testing is used if structural integrity alone can verify the intended design function. Equipment which falls into this category includes:

- Piping
- Ductwork
- Tanks and vessels
- Heat exchangers
- Filters
- Passive valves

Dynamic analysis without testing is used to qualify heavy machinery too large to be tested. For active equipment, it is verified that deformations due to seismic loadings do not cause binding of moving parts to the extent that the component cannot perform its required safety function.

Dynamic Testing

Dynamic testing is used for components with mechanisms that must change position in order to perform the required safety function. Section 3.10 discusses the seismic qualification of electrical equipment and combinations of valves and valve operators. Such components include the following:

- Electric motor valve operators
- Valve position sensors
- Similar appurtenances for other active valves

Combinations of Analysis with Testing

Combinations of analysis, static testing, and dynamic testing are used for seismic qualification of complex valves. Section 3.10 discusses the requirements for these combinations for equipment, which includes the following:

- Main steam and main feedwater isolation valves
- Other active valves

3.9.2.3 Dynamic Response Analysis of Reactor Internals under Operational Flow Transients and Steady-State Conditions

The vibration characteristics and behavior due to flow-induced excitation are complex and not readily ascertained by analytical means alone. Assessment of vibrational response is done using a combination of analysis and testing. Comparisons of results obtained from reference plant vibration measurement programs have been used to confirm the validity of scale model tests and other prediction methods as well to confirm the adequacy of reference plant internals regarding flow-induced vibration (FIV). The flow-induced vibration assessment was originally documented in WCAP-15949 (Reference 18) during development of the AP1000 Design Control Document. The FIV assessment program for the final reactor internals design is provided in WCAP-17983 (Reference 40) and WCAP-17984 (Reference 41). WCAP-17983 and WCAP-17984 supersede WCAP-15949, and the reference to WCAP-15949 is retained for historical purposes.

Reactor components are excited by flowing coolant, which causes oscillatory pressures on the surfaces. The integration of these pressures over the applied area provides the forcing functions to be used in the dynamic analysis of the structures. In view of the complexities of the geometries and the random character of the pressure oscillations, a closed form solution of the vibration problem by the integration of the differential equations is not always practical and realistic.

The determination of forcing functions as a direct correlation of pressure oscillations cannot be practically performed independently of the dynamic characteristics of the reactor vessel internals structure. The main objective is to establish the characteristics of the forcing functions that determine the response of the structures.

By studying the dynamic properties of the structure from previous analytical and experimental work, the characteristics of the forcing function are deduced. These studies indicate that the most important forcing functions are flow turbulence and pump-related excitation. The relevance of such excitation depends on factors that include the type and location of components and flow conditions.

The effects of these forcing functions have been studied in tests performed on models and reference plants. These effects will be factored into the analysis models used to evaluate flow-induced vibrations in the AP1000 reactor internals.

The structural analysis models include modeling of the gaps between the core barrel and reactor vessel, the core barrel and upper core plate, and the core barrel and core shroud. To ensure that the range of possible gaps between the components is evaluated, time-history analyses are performed with various sets of gaps. The resulting loads are evaluated, and the resulting highest load for each component is used in the structural analysis.

Loads on the reactor vessel internals components result from the reactor coolant pump pulsations. Using a reactor coolant system analysis, the resulting pressure differences across the components are calculated for inclusion in the structural evaluation models. The uncertainties associated with these component loads are considered by using a general design basis in which the reactor coolant pump related pressure pulsations are taken to be coincident with the component natural frequency if

the natural frequency is within ±10% of the reactor coolant pump excitation frequency. The calculated maximum forces from this resonance condition are used in the component structural evaluation.

The vibration assessment program for the AP1000 reactor internals determines, prior to testing of the first AP1000, that the internals are not expected to be subject to unacceptable flow-induced vibrations. The assessment is consistent with the guidelines of Regulatory Guide 1.20. Conformance with Regulatory Guide 1.20 is summarized in Subsection 1.9.1.

The reactor vessel internals in the AP1000 are similar in size and overall configurations to the reactor vessel internals in previous Westinghouse-designed three-loop nuclear power plants.

The original reference plant for Westinghouse three-loop plant reactor internals flow-induced vibration is H. B. Robinson. The results of vibrations testing at H. B. Robinson are reported in WCAP-7765-AR (Reference 3).

Successive design changes that have been incorporated into the AP1000 design since the reference plant tests have also been included in previous preoperational plant vibration testing including the following:

- Inverted hat upper internals and 17x17 guide tubes at DOEL 3 and Sequoyah 1
- XL lower core support structure at DOEL 4
- Core shroud at Yonggwang 4
- Neutron panels at Trojan 1

These tests confirmed that the internals behaved as expected and that the vibration levels were within allowable values. The vibration testing for 17x17 fuel internals and inverted hat upper internals is reported in WCAP-8766 (Reference 4) and WCAP-8516-P (Reference 5). The vibration testing of three-loop XL type lower core support structure in DOEL 4 is reported in WCAP-10846 (Reference 6). The vibration evaluations of upper and lower internals assemblies for a four-loop XL plant are reported in WCAP-10865 (Reference 7). The vibration testing of the core shroud lower internals design is reported in Reference 13.

The results of the Doel 3 and Doel 4 reactor internals vibration test programs are utilized to support the vibration assessment of the AP1000 reactor internals. The measured responses from Doel 3 and Doel 4 are adjusted to the higher AP1000 flowrate to support the determination of the expected upper internals and lower internals vibration levels respectively. The velocity through the core is approximately the same as that of Doel 4.

The results of the Trojan 1 tests showed that the lower internals vibrations are lower with neutron panels than with a circular thermal shield as reported in WCAP-8766 (Reference 4).

Subsequent operation of numerous plants has further demonstrated the adequacy of the reactor vessel internals regarding flow-induced vibration.

AP1000 includes design features that differ from the design in plants in which the reactor internals have been tested as outlined previously. These design differences include the following:

- The design has four inlet nozzles and two outlet nozzles in a three-loop size reactor vessel with a three-loop size core barrel diameter.

- The AP1000 core barrel overall length is 11 inches longer than that of the standard 3XL design.

- The skirt of the internals support structure is 11-inches longer than the skirt of previous three-loop internals designs.
- The upper support plate has sixty-nine 9.78 inch diameter holes as compared to sixty-one 9.50 inch diameter holes in the previous three-loop design. The plate thickness is identical at 12 inches in both designs.
- The design has a new in-core instrumentation system.
- The structures below the lower core support plate and the height of the lower plenum have been changed. The core barrel restraint elevation is within the radius of the lower head.
- The reactor coolant is moved using a sealless pump instead of a shaft seal pump.
- A flow skirt is included in the reactor vessel lower head.

The vibrations of the upper internals components are well characterized by previous plant testing based on the following: The control assembly guide tubes and support column designs are similar to those in a previously tested plant. Vibratory loads on these components are expected to be comparable to previously tested three-loop plants, because the AP1000 outlet nozzle velocity is approximately the same as in the three-loop plants.

The AP1000 upper internals design is substantially the same as that measured in the Doel 3 plant and 3XL scale model tests. The AP1000 support columns, guide tubes and upper support assembly are nearly identical to the components in the 3XL scale model test, although the AP1000 arrangement includes more guide tubes and support columns. Preliminary consideration indicates that the corresponding AP1000 responses will be calculated to be similar to the previous plant responses.

The vibration assessment evaluation will demonstrate that the vibration levels of the AP1000 lower internals are acceptable. Comparison of lower internals design features between the AP1000 and standard 3XL are discussed below.

The core barrel outside diameter, inside diameter, and the reactor vessel inside diameter are approximately the same as the tested three-loop plants. The core barrel length is 11 inches longer (~6%). Although the inlet nozzle and upper downcomer configuration of the AP1000 design differs from that of the 3XL design, the AP1000 reactor coolant inlet velocity is approximately the same as in the three-loop plants. The reactor coolant velocity in the lower plenum is comparable to the lower plenum velocity in the three-loop plants. The coolant velocity in the downcomer annulus between the core barrel and the reactor vessel wall is lower in the AP1000 design than in previous three-loop plants.

The vibrational response of the core barrel was measured during the Doel 4 reactor internals vibration measurement program. The diameter, length, and thickness are nearly identical to the AP1000 core barrel, and both use the single combined lower core support plate and neutron panels.

The core shroud is shorter than the core barrel, has a smaller outer diameter than the core barrel inside diameter, and is more rigidly clamped at its axially supported end, so that it is not expected to have a significant effect on core barrel vibration.

The replacement of the baffle-former structure with the core shroud reduces the stiffness of the lower internals assembly. The AP1000 shell mode amplitudes are estimated to be higher than three-loop core barrel responses based on scaling the measured responses to the AP1000 reduced core barrel stiffness. The AP1000 shell mode amplitudes are expected to be acceptable.

The AP1000 core barrel and core shroud will be instrumented during the pre-operational testing of the first plant to determine the shell mode and beam mode frequencies and amplitudes.

The in-core instrumentation cables are inside the upper internals support columns and are thus shielded from core plenum coolant flows. The instrumentation cables are subjected to fuel assembly outlet nozzle turbulence. This is judged to be not greater than the inlet nozzle turbulence to which in-core instrumentation thimbles in previous plants were subjected.

One of the changes below the lower core support is the addition of a vortex suppressor. The vortex suppressor design is subject to flow-induced vibrations from coolant flows in the core inlet plenum and by motions of the core barrel. The other significant changes below the lower core support plate are the removal of bottom mounted instrumentation and associated guide tubes and the reduction of the plenum height.

The sealless reactor coolant pumps of the AP1000, have a higher rotational speed and the same number of impeller blades as in previous plants. An evaluation of pump-induced loads is included in the vibration assessment. Calculations of the pump induced pulsations acting on the AP1000 reactor internals are based on full-scale AP1000 pump test data.

3.9.2.4 Pre-operational Flow-Induced Vibration Testing of Reactor Internals

The VEGP Units 3 & 4 reactor internals are classified as non-prototype, Category I as defined in Regulatory Guide 1.20. Sanmen Unit 1, as the first AP1000 plant, is the valid prototype for the AP1000 reactor internal design. Based on this classification, an instrumented test is not required. The recommendations of Regulatory Guide 1.20 are satisfied by conducting the confirmatory pre- and post-hot functional examination for integrity. Conformance with Regulatory Guide 1.20 is summarized in Subsection 1.9.1.

The reactor internals flow-induced vibration assessment program is documented in WCAP-17983 (Reference 40) and WCAP-17984 (Reference 41), including comparison of the AP1000 plant and operating plants that have undergone vibration measurement programs.

The acceptance criteria for the vibration predictions are established and related to the ASME Code allowables for long term steady-state conditions.

During the hot functional test, the internals are subjected to flow conditions representative of normal operation for a sufficient length of time to generate a cyclic loading of greater than 10^6 cycles on the main structural elements of the internals. In addition, there is some operating time with one, two, or three pumps operating.

Inspection before and after the hot functional test serves to confirm that the structural integrity of the internals with regard to flow-induced vibrations. When no indications of harmful vibrations or signs of abnormal wear are detected and no apparent structural changes take place, the core support structures are considered to be structurally adequate and sound for operation. If such indications are detected, further evaluation is required.

The testing and inspection plan includes features with emphasis on the areas susceptible to FIV, including flow-induced wear. Consistent with Regulatory Guide 1.20, these areas include as a minimum:

- The major load-bearing elements of the reactor internals relied upon to retain the core support structures in position,
- The lateral, vertical, and torsional restraints provided within the vessel,

- The locking and bolting components whose failure could adversely affect the structural integrity of the reactor internals,
- Those surfaces that are known to be or may become contact surfaces during operation,
- Those critical locations on the reactor vessel internal components as identified by the vibration analysis, and
- The interior of the reactor vessel for evidence of loose parts or foreign material.

The expected and acceptable vibration levels and expected natural frequencies will be determined as part of the vibration assessment program. Appropriate acceptance criteria for the inspection of the reactor internals before and after the hot functional testing are defined as part of the vibration assessment program (WCAP-17983, Reference 40).

3.9.2.5 Dynamic System Analysis of the Reactor Internals Under Faulted Conditions

The reactor internals analysis for Level D Service condition events considers safe shutdown earthquake seismic events and pipe rupture conditions. Subsection 3.9.3 defines the loads and loading combinations considered.

The standard for acceptability, in regard to mechanical integrity analyses, are that adequate core cooling and core shutdown must be provided. This implies that the deformation of the reactor internals must be sufficiently small so that the geometry remains substantially intact. Consequently, the limitations established for the internals are concerned with the deflections and stability of the parts in addition to stress criteria to confirm integrity of the components.

The AP1000 design loads for LOCA conditions are based on the use of mechanistic pipe break criteria (see Subsection 3.6.3).

3.9.2.5.1 Reactor Internals Analysis Methodology

The evaluation of the reactor internals consists of two major steps. The first step is the three-dimensional response of the reactor internals resulting from the seismic and pipe rupture conditions caused by breaks in the pipe that are not qualified by leak-before-break criteria. The breaks evaluated are those which have the greatest dynamic effect on the reactor internals.

The second step of the evaluation is the component stress evaluations. Maximum stresses and displacements under seismic plus pipe rupture conditions are obtained for the reactor internal components and are combined by the square root of the sum of the squares rule. These maximum stresses and displacements are compared to the allowable values for Level D service conditions.

3.9.2.5.1.1 Dynamic Response of Reactor Pressure Vessel System for Postulated Pipe Rupture

The structural analysis of the reactor vessel system for a postulated pipe rupture considers simultaneous application of the time-history loads that could result from the rupture. The mechanical loads are limited to those due to the movement of the fluid through the reactor internals and a small depressurization effect. Because of the application of mechanistic pipe rupture criteria, evaluation of dynamic effects such as cavity pressurization loads, jet impingement loads, and internal hydraulic pressure transients is limited to those pipe breaks which are not excluded by mechanistic pipe break criteria.

The vessel is restrained by reactor vessel supports beneath four of the reactor vessel nozzles and the reactor coolant loop piping. The reactor coolant loop piping is also supported by the steam generator and steam generator supports.

Analysis of the reactor internals for the loads resulting from a postulated pipe rupture is based on the time-history response of the internals to simultaneously applied forcing functions. The forcing functions are defined at points in the system where changes in cross section or direction of flow occur in such a way that differential loads are generated during the transient. The dynamic mechanical analysis can employ the displacement method, lumped parameters, and stiffness matrix formulations. Because of the complexity of the system and the components, finite element stress analysis codes are used to provide information at various points.

A digital computer program modeling the blowdown of coolant out of the break (see WCAP-8708-P-A, Reference 8), has been developed to calculate local fluid pressure, flow, and density transients that occur in pressurized water reactor coolant systems during a loss of coolant accident. This program is applied to the subcooled, transition, and saturated two-phase blowdown regimes. The program is based on the method of characteristics wherein the resulting set of ordinary differential equations, obtained from the laws of conservation of mass, momentum, and energy are solved numerically, using a fixed mesh in both space and time.

Although spatially, one-dimensional conservation laws are used, the code can be applied to describe three-dimensional system geometries by use of the equivalent piping networks. Such piping networks may contain any number of channels of various diameters, dead ends, branches (with up to six pipes connected to each branch), contractions, expansions, orifices, pumps, and free surfaces (such as in the pressurizer). System losses such as friction, contraction, and expansion, are considered.

The program evaluates the pressure and velocity transients for a maximum of 2400 locations throughout the system. These pressure and velocity transients are stored as a permanent tape file and are made available to a program that uses a detailed geometric description in evaluating the loadings on the reactor internals.

Each reactor component for which calculations are required is designated as an element and assigned an element number. Forces acting upon each of the elements are calculated summing up the effects of the following:

- Pressure differential across the element
- Flow stagnation on and unrecovered orifice losses across the element
- Friction losses along the element

Input to the code, in addition to the pressure and velocity transients, includes the effective area of each element on which the force acts because of the pressure differential across the element, a coefficient to account for flow stagnation and unrecovered orifice losses, and the total area of the element along which the shear forces act.

The pressure waves generated within the reactor are highly dependent on the location and nature of the postulated pipe failure. In general, the more rapid the severance of the pipe and the larger the pipe, the more severe the imposed loading is on the components. With the application of mechanistic pipe rupture and the determination of leak-before-break characteristics in large diameter pipe, the pressure waves are of small consequence compared with the seismic loads.

3.9.2.5.1.2 Reactor Vessel, Core Support, and Internal Components Modeling

The mathematical model of the reactor pressure vessel (RV) is a three-dimensional, nonlinear, finite element model that represents the dynamic characteristics of the reactor vessel and its internals in the six geometric degrees of freedom. This model is known as the Reactor Equipment System Model (RESM). The model is developed using a general purpose finite element computer code. The model consists of four major concentric, structural submodels connected by nonlinear impact elements and hydrodynamic mass. The four major concentric submodels represent the following components:

- Reactor vessel shell, hemispherical domed head, the lower dome, flow skirt, inlet and outlet nozzles, and integrated head package
- Lower internals assembly including: the core barrel (CB), core shroud (CS), lower core support plate (LCSP), secondary core support structure (SCSS) and vortex suppression plate, and CB neutron panels
- Upper internals (UI) assembly consisting of the upper support plate (USP), guide tubes (GT), upper support columns (USC), upper core plate (UCP), and instrumentation grid assembly (IGA)
- “Simplified” fuel assemblies (FA)

Several structural interfaces, for both linear and nonlinear impact elements, and hydrodynamic mass matrices include the following:

- Lower radial keys between the RV and CB
- RV flange and CB flange
- RV and UI flange
- UI flange and hold-down spring
- Hydrodynamic mass matrices between the RV and CB, and between the CB and CS
- Restraint provided by the support stiffness at the RV four inlet nozzle support pads of the primary loop and ground
- Hot and cold leg loops

Nonlinear impact elements are included for both radial and tangential gaps and stiffnesses at several interface locations. The RV-to-USP flange, USP-flange-to-CB flange (hold-down spring), and CB-flange-to-RV interfaces are modeled as a series of elements that simulate preload, friction, rotational stiffness, and impact stiffness in the joints. Stiffnesses are developed for each interface, while gaps are established by calculating the steady-state hot gap values. Likewise, the CS-FA annulus is simulated using gap elements at various elevations. The locations of gap elements in the AP1000 RESM are as follows:

- RV and CB at the lower radial keys
- CB nozzles and RV outlet nozzles
- RV and CB flanges and the RV and UI flanges.
- UCP-CB alignment plate
- CS-CB alignment plate
- CB-CS annulus and

- CS-FA annulus

The dynamic time history of the RESM for seismic and loss-of-coolant-accident (LOCA) events provide a number of outputs for all of the components that are included in the model. Thus, for example, the impact forces at all the gap elements are one of the key output results provided to the component analysts. Other results include the internal forces and moments, acceleration and displacement time histories for the detailed stress analyses of the core support, and internals components. Head and lower dome motions, core plate, and CS displacement time histories are also provided for evaluation of the CRDMs, SCCS, flow skirt, and fuel assembly (core) components.

3.9.2.5.2 Analytical Methods

The time-history effects of the internals hydraulic loads and loop mechanical loads are combined and applied simultaneously to the appropriate nodes of the mathematical model of the reactor vessel and internals. The analysis is performed by numerically integrating the differential equations of motion to obtain the transient response.

The output of the analysis includes the displacements of the reactor vessel and the loads in the reactor vessel supports that are combined with other applicable Level D Service condition loads and used to calculate the stresses in the supports.

Also, the reactor vessel displacements are applied as input to the pipe rupture blowdown analysis of the primary loop piping. The resulting loads and stresses in the piping components and supports include both pipe rupture blowdown loads and reactor vessel displacements. Thus, the effect of vessel displacements upon loop response and the effect of loop blowdown upon vessel displacements are both evaluated.

The system seismic analysis of the reactor vessel and its internals for the safe shutdown earthquake (SSE) event is performed using the time-history method. The seismic response is combined with the pipe rupture response, as outlined in Subsection 3.9.3, in order to obtain the maximum stresses and deflections.

Reactor internals components are within acceptable stress and deflection limits for the postulated pipe rupture combined with the safe shutdown earthquake condition.

3.9.2.5.3 Control Rod Insertion

During full power plant operation, rod cluster control assemblies and the corresponding drive rod assemblies are held at a fully withdrawn position by their respective control rod drive mechanisms. During certain accident conditions, such as small break loss of coolant accident or a safe shutdown earthquake condition or both, control assemblies are assumed to drop to their fully inserted position. The guide tubes are evaluated to demonstrate the function of the control rods for a break size consistent with use of the leak-before-break criteria.

No credit for the function of the control rods is assumed for large breaks in the safety analyses outlined in Chapter 15. However, for break sizes consistent with use of the leak-before-break criteria, the design of the guide tubes permits control rod insertion at each control rod position.

3.9.2.6 Correlation of Reactor Internals Vibration Tests with the Analytical Results

The results of dynamic analysis of reactor internals have been compared to the results of preoperational testing in reference plants. This comparison verifies that the analytical model used provides appropriate results.

The preoperational vibration test program for the reactor vessel internals of the AP1000 conducted on the first plant, conforms to the intent of the guidelines in Regulatory Guide 1.20 for a comprehensive vibration assessment program. This program includes a correlation of the analysis and test results. This comparison provides additional verification for the analytical model.

3.9.3 ASME Code Classes 1, 2, and 3 Components, Component Supports, and Core Support Structures

Pressure-retaining components, core support structures, and component supports that are safety-related are classified as Class A, B, or C (see Subsection 3.2.2) and are constructed according to the rules of the ASME Code, Section III, Division 1. As noted in Subsection 3.2.2, Classes A, B, and C mechanical components meet the requirements of Code Classes 1, 2, and 3 respectively.

This subsection discusses the application of the ASME Code to safety-related components and core support structures, the operability of pumps and valves, the design and installation criteria for overpressure protection devices, automatic depressurization devices and the requirements for component supports.

Section 3.8 addresses the loads, loading combinations, and stress limits for structures, including containment.

The ASME Code, Section III requires that a design specification be prepared for ASME Class 1, 2, and 3 components. The specification conforms to and is certified to the requirements of ASME Code, Section III. The Code also requires a design report for safety-related components, to demonstrate that the as-built component meets the requirements of the relevant ASME Design Specification and the applicable ASME Code. The design specifications and design reports will be completed as discussed in Subsection 3.9.8.2. Design specifications for ASME Class 1, 2, and 3 components and piping are prepared utilizing procedures that meet the ASME Code. The design report includes as-built reconciliation.

The as-built reconciliation includes the evaluation of pipe break dynamic loads, changes in support locations, construction deviations, and completion of the small bore piping analysis.

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

The integrity of the pressure boundary of safety-related components is provided by the use of the ASME Code. Using the methods and equations in the ASME Code, stress levels in the components and supports are calculated for various load combinations. These load combinations may include the effects of internal pressure, dead weight of the component and insulation, and fluid, thermal expansion, dynamic loads due to seismic motion, and other loads.

To determine if a design is acceptable for the loading combination, the calculated stress levels are compared to acceptance standards in the ASME Code. The acceptance standards in the ASME Code differ depending on the plant operating modes and loads considered. The ASME Code includes a design limit and four service limits (A, B, C, and D) against which to evaluate design conditions and plant and system operating conditions.

The design transients for the AP1000 are defined in Subsection 3.9.1. The transients are classified into Level A, B, C, and D Service conditions and test conditions, depending on the expected frequency of occurrence and severity. The description of the transients in Subsection 3.9.1 provides the initial plant operating condition and identifies the different component operating conditions. The design transients for Levels A and B are used in the evaluation of cyclic fatigue for the Class 1 components and piping. The effects of seismic events are also included in the evaluation of cyclic

fatigue (See Subsection 3.9.3.1.2). Level D and up to 25 strong stress cycles of Level C service conditions are not required by the rules of the ASME Code to be included in the fatigue evaluation.

3.9.3.1.1 Seismic Loads and Combinations Including Seismic Loads

Seismic Category I systems and components, including core support structures, are designed for one occurrence of the safe shutdown earthquake which is evaluated as a Service Level D condition for pressure boundary integrity. In addition, systems and components sensitive to fatigue are evaluated for cyclic motion due to earthquakes smaller than the safe shutdown earthquake. Using analysis methods, these effects are considered by inclusion of seismic events with an amplitude not less than one-third of the safe shutdown earthquake amplitude. The number of cycles is calculated based on IEEE-344-1987 (Reference 21) to provide the equivalent fatigue damage of two full safe shutdown earthquake events with 10 high-stress cycles per event. There are five seismic events with an amplitude equal to one-third of the safe shutdown earthquake response. Each of the one-third safe shutdown earthquake events has 63 high-stress cycles.

ASME Class 1, 2, 3 and CS systems, components and supports are analyzed for the safe shutdown earthquake with other dynamic events. See Tables 3.9-5 and 3.9-8 for load combinations.

The safe shutdown earthquake is analyzed in combination with those operating modes that occur more than 10 percent of the time. Plant conditions combined with safe shutdown earthquake include the following:

- Normal 100-percent power operation. Material properties are based on those at operating temperatures. Water inventories are based on normal operating levels. The in-containment refueling water storage tank is full, the refueling canal is empty, the spent fuel pool, fuel transfer canal, cask loading pit and cask washdown pit are full, and the passive containment cooling system tank is full.

- The safe shutdown earthquake, which is postulated to occur with the plant at normal 100-percent power operation, is assumed to cause nonsafety-related systems, including ac power sources, to be unavailable. A single active failure in the safety-related systems is also postulated.

- The timing and causal relationships that exist between the safe shutdown earthquake and transients such as valve discharge are considered and the events combined when the safe shutdown earthquake is the cause of the transient condition. For analysis of piping systems, the timing and causal relationships are not used to exclude load combinations. The safe shutdown earthquake duration is assumed to be 30 seconds. Nonseismically analyzed structures and components are assumed to be unavailable at the beginning of the safe shutdown earthquake. A single active component failure is assumed to occur at the time the component would be expected to function after the failure of the nonseismic components and structures.

- Nonsafety-related systems are evaluated to confirm that their failure in an earthquake does not jeopardize plant safety.

- A water source is provided for limited fire protection after occurrence of the safe shutdown earthquake. See Section 9.5 for additional information on fire protection.

The AP1000 is also designed for special combinations of events that are not based on the probability of occurrence but are based on past precedents and regulatory guidelines. These special combinations are treated as load combinations, not event sequences. That is, even though the safe

shutdown earthquake event does not occur coincident with another event, the loads were combined to provide additional design margin.

- ASME Code components, supports, and support miscellaneous steel for these components are designed for the safe shutdown earthquake combined by the square root of the sum of the squares method, with short-term dynamic loads due to postulated pipe ruptures. The pipe ruptures included in this combination are those postulated in accordance with Subsections 3.6.1 and 3.6.2, but do not include those postulated in the break exclusion zone for evaluation of spray wetting, flooding, and subcompartment pressurization effects, nor those excluded by application of mechanistic pipe rupture criteria. (See Subsection 3.6.3.) This combination is used for components and supports that are required to mitigate the effects of the postulated pipe rupture.

- The containment boundary is designed for the safe shutdown earthquake in combination with containment design pressure at containment design temperature.

- The polar crane is designed assuming occurrence of the safe shutdown earthquake during handling of a critical load, such as the reactor vessel head.

3.9.3.1.2 Loads for Class 1 Components, Core Support, and Component Supports

The loads used in the analysis of the Class 1 components, core supports, and component supports are described in the following paragraphs. The loads are listed in Table 3.9-3. Additional information on the loads, stress limits and analysis methods for piping is described in Subsection 3.9.3.1.5.

Pressure loading is identified as either design pressure or operating pressure. [*The design pressure is used in minimum wall thickness calculations in accordance with the ASME Code.*]* The term “operating pressure” is associated with Service Levels A, B, C, and D conditions.

[*A dead-weight analysis is performed to meet ASME Code requirements by applying a load equal to the acceleration due to gravity (1.0g) downward on the piping system and components. The piping is assigned a distributed mass or weight as a function of its properties. This method provides a distributed loading to the piping system as a function of the weight of the pipe, insulation, and contained fluid during normal operating conditions.*]*

The analysis of the safe shutdown earthquake loads demonstrates pressure boundary integrity of the Class 1 systems and components. Seismic loads are identified as either seismic inertia loads or seismic anchor motion loads. The seismic inertia loads represent the dynamic portion of the response, and the seismic anchor motion loads represent the static portion. Subsection 3.7.3 describes seismic analysis methods.

Transient dynamic flow and pressure loads resulting from a postulated pipe break are analyzed. Structural consideration of dynamic effects of postulated pipe breaks requires postulation of a finite number of break locations. Section 3.6 defines postulated pipe break locations.

Safety-related piping including the reactor coolant loops, the main steam piping, and reactor coolant system branch lines equal to or larger than six inches nominal pipe size is evaluated with a leak-before-break analysis to verify that there are no locations subject to a sudden, unanticipated rupture of one of these lines. As a result, the piping and components in these systems do not have to be analyzed for the dynamic effects of a break in the pipe when the leak-before-break criteria are satisfied.

The pipe rupture event considered as a loading is the largest pipe that does not satisfy leak-before-break criteria. The leak-before-break analyses use the acceptance standard of the broad scope rule

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

change to General Design Criterion 4 and NUREG 1061, Volume 3. Subsection 3.6.3 outlines the acceptance standard and approach, including application, methodology, and limits.

Transient dynamic loads are also associated with valve opening and closing. The categories associated with valve operation include automatic depressurization system actuation, fast valve closure, relief valve closed system, relief valve open system, and safety valve discharge. Transient dynamic loads include those due to actuation of the explosive device in squib valves. Components and piping are evaluated for the dynamic response to these transient loads. The relief valve open system (sustained) is evaluated as a static load.

In addition to the loads that apply to the ASME Code Class 1 components, additional miscellaneous loads apply to selected components. These loads are evaluated on a case-by-case basis and are not combined with any other Level C or D Service condition. These miscellaneous loads include the following circumstances.

The reactor coolant pump, steam generator channel head, and connected piping are evaluated for a postulated seized rotor event. For this condition, the rotating mass of the reactor coolant pump is assumed to come to a rapid (but not instantaneous) stop and to transfer the angular momentum through the motor enclosure and pump casing to the steam generator nozzle and reactor coolant piping. The stresses calculated for this event are evaluated using Level D limits for the immediately affected components and supports and using Level B limits for components in the other loop.

For additional information on the specification and analysis of locked rotor loads, see the description in the reactor coolant pump information in Subsection 5.4.1.

The passive residual heat removal heat exchanger is evaluated for hydraulic loads from the discharge of steam from the automatic depressurization system valves through the spargers in the in-containment refueling water storage tank. These loads include pressure pulses from the introduction of steam into the tank and collapse of the steam bubbles and the gross movement of water in the tank. The stresses in the passive residual heat removal heat exchanger calculated for this event are evaluated using Level B stress limits.

For additional information on the specification and analysis of hydraulic loads see the description in the passive residual heat removal heat exchanger information in Subsection 5.4.14.

Portions of the integrated head package that provide seismic restraint for the control rod drive mechanisms also act as part of the load path for the lifting rig function of the integrated head package. These components are designed and evaluated for heavy load lifting.

For additional information on the design and evaluation of the components of the integrated head package in the load path of the lifting rig, see Subsection 3.9.7.

The ASME Code, Section III requires satisfaction of certain requirements relative to design transient conditions for Class 1 components. Subsection 3.9.1.1 summarizes the design transients.

To provide integrity for the reactor coolant system, the transient conditions selected for fatigue evaluation are based on conservative estimates of the magnitude and anticipated frequency of occurrence of the temperature and pressure transients resulting from various plant operation conditions. Generally, only Level A and B service condition design transients are evaluated in the analysis of cyclic fatigue. Up to 25 stress cycles for Level C service conditions may be excluded from cyclic fatigue analysis in conformance with ASME Code, Section III criteria. Any Level C service conditions which are in excess of the 25-cycle limit are evaluated for the effect on cyclic fatigue using Level B criteria. For the evaluation of cyclic fatigue, the cycles included for seismic events are evaluated using Level B criteria and are not excluded from the fatigue evaluation regardless of the

size of the stress range considered. The determination of which transient events are included in the 25-cycle exclusion is made separately for each component and line of piping.

The effects of seismic events on the design of components other than piping are considered in one of the following ways. The effects of seismic events are considered by including 20 full cycles of the maximum safe shutdown earthquake stress range in the fatigue analysis. The seismic contribution to the fatigue evaluation is based on five seismic events with an amplitude of one-third the safe shutdown earthquake and 63 cycles per event. The seismic evaluation of piping components is discussed in Subsection 3.9.3.1.5.

Thermal Stratification, Cycling, and Striping

Thermal stratification, cycling and striping (TASCS) are phenomena that have resulted in pipe cracking at nuclear power plants. As a result of these incidents, the United States Nuclear Regulatory Commission has issued several bulletins, which are discussed below.

Thermal stratification may occur in piping when flowrates are low and adequate mixing of hot and cold fluid layers does not occur. Thermal cycling due to stratification may occur because of leaking valves or plant operation. Thermal striping is a cyclic mechanism caused by instabilities in the hot-cold fluid interface in stratified fluid during relatively steady flow conditions. The design of piping and component nozzles in the AP1000 includes provisions to minimize the potential for and the effects of thermal stratification and cycling. [*Piping and component supports are designed and evaluated for the thermal expansion of the piping resulting from potential stratification modes. The evaluation includes consideration of the information on thermal cycling and thermal stratification included in NRC Bulletins 79-13, 88-08, and 88-11, and other applicable design standards.*]*

NRC Bulletin 79-13

Bulletin 79-13 (Reference 16) was issued as a result of a feedwater line cracking incident at Donald C. Cook Unit 2. This bulletin required that inspections of operating plant feedwater lines be performed. This resulted in the discovery of cracks in the feedwater lines of several plants. To provide a uniform approach to address this issue, a Feedwater Line Cracking Owners Group was established. The specific tasks of the Owners Group Program were to evaluate the thermal, hydraulic, structural and environmental conditions which could individually or collectively contribute to feedwater line crack initiation and growth. The Feedwater Line Cracking Owners Group was disbanded in 1981, after the original investigations were completed. The results of this program indicated that the primary cause of the cracking was thermal fatigue loading induced by thermal stratification and high-cycle thermal striping during low flow auxiliary feedwater injection. The mode of failure was concluded to be corrosion fatigue. This information is documented in WCAP-9693 (Reference 17).

The AP1000 steam generators are equipped with separate nozzles for the main feedwater and startup feedwater lines. Analyses of the AP1000 main feedwater nozzles are performed to demonstrate that the applicable requirements of the ASME Section III Code are met. Thermal stratification is prevented in the main feedwater line based on the flowrate limitations within the main feedwater line and the flow control stability for feedwater control. Low feedwater flow duty is provided by the startup feedwater line while higher feedwater flowrates are provided and controlled via the main feedwater line. The switchover from the startup to the main feedwater line occurs above a minimum flowrate to prevent thermal stratification for limiting temperature deviations. Main feedwater control valve positioning during normal operation is the function of the plant control system. The control scheme enhances steam generator level stability and thus reduces potential feedwater thermal stratification resulting from temporary low flow transients

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

NRC Bulletin 88-08

Bulletin 88-08, Supplement 1, Supplement 2, and Supplement 3 (Reference 12) were issued following the discovery of cracks in unisolable piping at several nuclear power plants. These cracks were attributed to unanalyzed thermal stresses resulting from isolation valve leakage. This bulletin required that utilities: 1) review systems connected to the reactor coolant system to determine whether unisolable sections of piping connected to the reactor coolant system can be subjected to stresses from temperature stratification or temperature oscillations that could be induced by leaking valves and that were not evaluated in the design analysis of the piping, 2) nondestructively examine the welds, heat-affected zones and high stress locations, including geometric discontinuities and base metal, as appropriate, to provide assurance that there are no existing flaws, and 3) plan and implement a program to provide continuing assurance of piping integrity. This assurance may be provided by designing the system to withstand the stresses from valve leakage, instrumenting the piping to detect adverse temperature distributions and establishing appropriate limits on these temperature distributions, or providing a means that pressure upstream from isolation valves that might leak into the reactor coolant system is monitored and does not exceed reactor coolant system pressure. In addition to leakage into the reactor coolant system, leakage out of the reactor coolant system may also result in adverse thermal stresses as discussed in Supplement 3 of the bulletin.

For adverse stresses from leakage to occur in unisolable piping, three conditions are necessary:

1. A component with the potential for leakage must exist. In most cases, this will be a valve.

2. A pressure differential capable of forcing leakage through the pressure-retaining component must exist. Leakage in unisolable piping sections may be directed toward the reactor coolant system (“inleakage”), or from the reactor coolant system (“outleakage”).

3. A temperature differential between the unisolable piping section and the leakage source sufficient to produce significant stresses in the event of leakage must exist. For cases involving inleakage, this could result from a cold leakage entering hot sections of unisolable piping. For cases involving outleakage, this could result from hot leakage from the reactor coolant system entering cold sections of unisolable piping.

The criteria used in the evaluation of the AP1000 systems design for susceptibility to adverse stresses from valve leakage are summarized below:

- Single isolation valves can leak, regardless of design except for explosively actuated valves.

- It is generally assumed that two or more closed valves in series are sufficient to limit the amount of leakage to a magnitude which would have a negligible effect on piping integrity.

- Valves which have external operators may leak through the valve seat and packing. In the case of leaking through the packing, additional in-series closed valves may not be beneficial.

- A positive pressure difference should be considered as a possible leak source.

- Cross-leakage is possible between interconnected lines that are attached to different reactor coolant loop pipes and are isolated by single check valves.

[- *Sections of piping systems which have a slope of greater than 45 degrees from the horizontal plane are not subject to thermal stratification, cycling and striping thermal loadings.*

- *Pipe lines, or sections of lines less than or equal to 1-inch nominal size do not require a thermal stratification, cycling and striping evaluation.*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The unisolable portions of the following lines connected to the reactor coolant system have been reviewed and are not susceptible to thermal stratification, cycling or striping:

- Core make up lines from the cold legs to the core make up tanks.
- Auxiliary pressurizer spray from the pressurizer spray line to the auxiliary spray check valve.
- Chemical and volume control purification line from the passive residual heat removal line to the charging valve.
- Pressurizer safety valve lines from the pressurizer to the safety valve.
- Pressurizer spray lines from the cold legs to the pressurizer.
- Automatic depressurization Stage 1, 2, and 3 lines from the pressurizer to the depressurization valves.

The unisolable portions of the following lines connected to the reactor coolant system have been reviewed and are determined to be susceptible to thermal stratification, cycling or striping:

- Passive residual heat removal line from the passive residual heat removal heat exchanger to the steam generator channel head.
- Automatic depressurization Stage 4 lines from the hot legs to the Stage 4 depressurization valves.
- Passive residual heat removal lines from the hot leg to the passive residual heat removal heat exchanger.
- Chemical and volume control purification line from the pressurizer spray line to the letdown valve.
- Normal residual heat removal suction lines from the hot legs to the isolation valves.

Direct vessel injection lines from the reactor vessel nozzle up to the accumulator injection valves, core make up injection valves, in-containment refueling water storage tank injection valves, and normal residual heat removal injection valves.

Analyses of these lines are performed to demonstrate that the applicable requirements of the ASME Section III Code are met. This analysis includes consideration of plant operation and thermal stratification using temperature distributions which are developed from finite element fluid flow and heat transfer analysis.

The final design reports for ASME components, including reconciliation of the as-built piping is discussed in Subsection 3.9.8. This reconciliation includes verification of the thermal cycling and stratification loadings considered in the stress analysis.

NRC Bulletin 88-11

Bulletin 88-11 (Reference 14) was issued after Portland General Electric Company experienced difficulties in setting whip restraint gap sizes on the pressurizer surge line at Trojan plant. The cold gaps were adjusted to design settings several times and were found to be out of specification after each operating cycle. The gap changes were caused by plastic deformation in the surge line piping resulting from excessive thermal loadings. The thermal loadings were determined to be caused by thermal stratification based on monitoring and analysis. Several similar incidents were subsequently

discovered in other surge lines, and an industry-wide program to evaluate this phenomena was undertaken by the various PWR owners groups.

The purpose of Bulletin 88-11 was a request to addresses, establish, and implement a program to confirm pressurizer surge line integrity in view of the occurrence of thermal stratification, and to require addressees to inform the NRC staff of the actions taken to resolve this issue.

The actions requested in the bulletin are discussed below, and the manner in which AP1000 addresses the actions, if required, for surge line stratification:

For all licensees of operating PWRs:

Request 1.

The actions included under this heading are not applicable to the AP1000.

For all applicants for PWR Operating Licenses:

Request 2. a)

Before issuance of the low power license, applicants are requested to demonstrate that the pressurizer surge line meets the applicable design codes and other FSAR and regulatory commitments for the licensed life of the plant. This may be accomplished by performing a plant specific or generic bounding analysis. The analysis should include consideration of thermal stratification and thermal striping to ensure that fatigue and stresses are in compliance with applicable code limits. The analysis and hot functional testing should verify that piping thermal deflections result in no adverse consequences, such as contacting the pipe whip restraints. If analysis or test results show Code noncompliance, conduct of all actions specified below is requested.

AP1000 Conformance

Analysis of the AP1000 surge line considers thermal stratification and thermal striping, and demonstrates that the surge line meets applicable code requirements for the licensed life of the plant. Hot functional testing requirements for the AP1000 ensure that piping thermal deflections result in no adverse consequences.

Request 2. b)

Applicants are requested to evaluate operational alternatives or piping modifications needed to reduce fatigue and stresses to acceptable levels.

AP1000 Conformance

Analysis of the AP1000 surge line ensures that stress and fatigue requirements are satisfied, therefore the evaluation of operational alternatives or piping modifications is not required.

Request 2. c)

Applicants are requested to either monitor the surge line for the effects of thermal stratification, beginning with hot functional testing, or obtain data through collective efforts to assess the extent of thermal stratification, thermal striping and piping displacements.

AP1000 Conformance

As part of the Westinghouse Owners Group program on surge line thermal stratification, Westinghouse collected surge line physical design and plant operational data for all domestic Westinghouse PWRs. In addition, Westinghouse collected surge line monitoring data from approximately 30 plants. This experience was used in the development of the AP1000 thermal stratification loadings. As described in the AP1000 Conformance to Request 3 of Bulletin 88-11, monitoring will be performed during hot functional testing and during the first cycle of the first AP1000 plant. This Combined License item is identified in Subsection 3.9.8.5. Subsequent monitoring of the AP1000 surge line is not required.

Request 2. d)

Applicants are requested to update stress and fatigue analyses, as necessary, to ensure Code compliance. The analyses should be completed no later than one year after issuance of the low power license.

AP1000 Conformance

Revision of the stress and fatigue analyses is not required for the AP1000 surge line, since the design analysis considers thermal stratification and thermal striping.

Request 3)

Addressees are requested to generate records to document the development and implementation of the program requested by Items 1 or 2, as well as any subsequent corrective actions, and maintain these records in accordance with 10 CFR Part 50, Appendix B and plant procedures.

AP1000 Conformance

AP1000 procedures require documentation and maintenance of records in accordance with 10 CFR Part 50, Appendix B.

A monitoring program will be implemented as discussed in Subsection 3.9.8.5 at the first AP1000 to record temperature distributions and thermal displacements of the surge line piping, as well as pertinent plant parameters such as pressurizer temperature and level, hot leg temperature, and reactor coolant pump status. Monitoring will be performed during hot functional testing and during the first fuel cycle. The resulting monitoring data will be evaluated to show that it is within the bounds of the analytical temperature distributions and displacements.

PRESSURIZER SURGE LINE MONITORING

General

The pressurizer surge line is monitored at the first AP1000 plant to record temperature distributions and thermal displacements of the surge line piping, as well as pertinent plant parameters. This monitoring occurs during the hot functional testing and first fuel cycle. The resulting monitoring data is evaluated to verify that the pressurizer surge line is within the bounds of the analytical temperature distributions and displacements.

Subsequent AP1000 plants (after the first AP1000 plant) confirm that the heatup and cooldown procedures are consistent with the pertinent attributes of the first AP1000 plant surge line monitoring. In addition, changes to the heatup and cooldown procedures consider the potential impact on stress and fatigue analyses consistent with the concerns of NRC Bulletin 88-11.

The pressurizer surge line monitoring activities include the following methodology and requirements:

Monitoring Method

The pressurizer surge line pipe wall is instrumented with outside mounted temperature and displacement sensors. The data from this instrumentation is supplemented by data display and processing system data from related process and control parameters.

Locations to be Monitored

In addition to the existing permanent plant temperature instrumentation, temperature and displacement monitoring will be included at critical locations on the surge line. The additional locations utilized for monitoring during the hot functional testing and the first fuel cycle (see Subsection 14.2.9.2.22) are selected based on the capability to provide effective monitoring.

Data Evaluation

Data evaluation is performed at the completion of the monitoring period (one fuel cycle). The evaluation includes a comparison of the data evaluation results with the thermal profiles and transient loadings defined for the pressurizer surge line, accounting for expected pipe outside wall temperatures. Interim evaluations of the data are performed during the hot functional testing period, up to the start of normal power operation, and again once three months worth of normal operating data has been collected, to identify any unexpected conditions in the pressurizer surge line.

Other Applications

Thermal stratification in the reactor coolant loops resulting from actuation of passive safety features is evaluated as a design transient. Stratification effects due to both Level B and Level D service conditions are considered. The criteria used in the evaluation of the stress in the loop piping due to stratification is the same as that applicable for other Level B and Level D service conditions.

3.9.3.1.3 ASME Code Class 1 Components and Supports and Class CS Core Support Loading Combinations and Stress Limits

Tables 3.9-5 and 3.9-8 list loading combinations for ASME Class 1 components and component supports and Class CS core support structures. Table 3.9-9 lists the stress limits for these components. Table 3.9-3 lists the loads included in the loading combinations.

The stress limits for Service Level D that allow inelastic deformation are supplemented with the requirements of “Rules for Evaluation of Service Loadings with Level D Service Limits,” Appendix F of ASME Code, Section III. The limits and rules of Appendix F confirm that pressure boundary integrity and core support structural integrity are maintained but do not confirm operability. The limits and rules of Appendix F do not apply to the portion of the component or support in which the failure has been postulated. Subsection 3.9.1 provides a discussion of design transients used in the analysis of cyclic fatigue.

The structural stress analyses performed on the ASME Code Class 1 components and supports and Class CS core support structures consider the loadings specified, as shown in Table 3.9-3. These loads result from thermal expansion, pressure, weight, earthquake, pipe rupture, and plant operational thermal and pressure transients. Dynamic effects of pipe rupture, including the loss of coolant accident, are not included in loading combinations when the leak-before-break criteria are satisfied. The methods and acceptance standard for leak-before-break analyses are described in Subsection 3.6.3.

[*The combination of safe shutdown earthquake plus pipe rupture*]* (those breaks not excluded by mechanistic pipe break criteria) [*loads by square-root-sum-of the squares is considered.*]* This loading combination is evaluated for ASME Code components and piping that are required to mitigate the effects of the postulated pipe rupture and the supports for those components and piping.

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The dynamic effects of pipe rupture that are combined with safe shutdown earthquake in loading combinations are those for lines for which the leak-before-break criteria are not satisfied. [*When the safe shutdown earthquake event is determined mechanistically to result in concurrent transient loads due to relief valve or safety valve discharge in ASME Code Class 1, 2, or 3 systems, the maximum response due to the safe shutdown earthquake is combined with the maximum response due to the valve opening discharge transient. The responses are combined using the square-root-sum-of-the-squares method.*]* Concurrent sustained loads due to open system relief valve discharge are combined with safe shutdown earthquake by absolute sum.

3.9.3.1.4 Analysis of Reactor Coolant Loop Piping

The reactor coolant loop and support system model consists of the primary loop piping (hot and cold legs), the connecting components (reactor vessel, steam generator, and reactor coolant pump) and the components supports (steam generator and reactor vessel).

The integrated reactor coolant loop and supports system model is the basic system model used to compute loadings on components, component supports, and piping. The system model includes the stiffness and mass characteristics of the reactor coolant loop piping and components, the stiffness of supports, and the stiffnesses of auxiliary line piping affecting the system. This model is used to determine the static and dynamic loads on the primary loop piping and the component supports and the interfacing loads on the connecting components.

The analysis of the connecting components is based on more detailed models of the steam generator, reactor vessel, and reactor coolant pump. Appendix 3C describes the analytical methods used in evaluating the piping of the reactor coolant loops.

[*The primary loop analysis for the safe shutdown earthquake uses the time-history integration or response spectra methods for seismic dynamic analysis.*]* Appendix 3C provides a description of the model.

The model used in the static analysis is modified for the dynamic analysis by including the mass characteristics of the piping and equipment. [*In the time-history seismic analysis, the containment internals structure is included in the system coupled model unless appropriate time-history seismic input from the building is provided at multiple support locations.*]* The effect of the equipment motion on the reactor coolant loop and supports system is obtained by modeling the mass and the stiffness characteristics of the equipment in the overall system model.

The main loop piping and the surge line satisfy the leak-before-break requirements for the elimination of nonmechanistic pipe breaks. See Subsection 3.6.3 for a description of the evaluation of piping for leak-before-break requirements. Reactor coolant system piping of 6-inch nominal pipe size or larger is evaluated for leak-before-break characteristics. The reactor coolant loop piping is evaluated for loads due to a break in the largest connected pipe that does not meet leak-before-break requirements. [*The primary loop analysis for pipe breaks uses time-history integration or equivalent static analysis to determine the structural response due to jet impingement loads, thrust loads, and subcompartment pressure loads.*]*

Operating transients in a nuclear power plant cause thermal or pressure fluctuations or both in the reactor coolant fluid. The thermal transients cause time-varying temperature distributions across the pipe wall. The transients as summarized in Subsection 3.9.1.1 are used to define the fluctuations in plant parameters.

A one-dimensional finite difference heat transfer program is generally used to solve the thermal transient problem. The pipe is represented by many elements through the thickness of the pipe. The convective heat-transfer coefficient used in this program represents the time-varying heat transfer

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due to free and forced convection. The outer surface is assumed to be adiabatic, while the inner surface boundary experiences the temperature of the coolant fluid.

Fluctuations in the temperature of the coolant fluid produce a temperature distribution through the pipe wall thickness that varies with time. The average through-wall temperature, T_A, is calculated by integrating the temperature distribution across the wall. This integration is performed over each time step so that T_A is determined as a function of time.

A load-set is defined as a set of pressure loads, moment loads, and through-wall thermal effects at a given location and time in each transient. The through-wall thermal effects are functions of time and can be subdivided into four parts:

- Average temperature (T_A), which is the average temperature through-wall of the pipe that contributes to general expansion loads
- Radial linear thermal gradient, which contributes to the through-wall bending moment (ΔT_1)
- Radial nonlinear thermal gradient (ΔT_2), which contributes to a peak stress associated with shearing of the surface
- Discontinuity temperature ($T_A - T_B$) which represents the difference in average temperature at the cross sections on each side of a discontinuity

Each transient is described by at least two load-sets representing the maximum and minimum stress states during each transient. The construction of the load-sets is accomplished by combining the following to yield the maximum (minimum) stress state during each transient.

- ΔT_1
- ΔT_2
- $\alpha_A T_A - \alpha_B T_B$
- Moment loads due to T_A
- Pressure loads

This procedure produces at least twice as many load-sets as transients for each point.

For the possible load-set combinations, the primary-plus-secondary and peak stress intensities, fatigue reduction factors (K_e), and cumulative usage factors (U) are calculated.

The combination of load-sets yielding the highest alternating stress intensity range is first used to calculate the incremental usage factor. The next most severe combination is then determined, and the incremental usage factor is calculated. This procedure is repeated until the combinations having an allowable number of cycles less than 10^{11} are formed. The total cumulative usage factor at a point is the summation of the incremental usage factors.

3.9.3.1.5 ASME Classes 1, 2, and 3 Piping

The loads for ASME Code Classes 1, 2, and 3 piping are included in the loads listed in Table 3.9-3. [*Tables 3.9-5, 3.9-6, and 3.9-9 list the loading combinations and stress limits for Class 1 piping. Tables 3.9-5, 3.9-7, and 3.9-10 list the loading combinations and stress limits for Class 2 and 3 piping.*

Piping systems are designed and analyzed for Levels A, B, and C service conditions, and corresponding service level requirements to the rules of the ASME Code, Section III. The analysis or test methods and associated stress or load allowable limits that are used in evaluation of Level D

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service conditions are those that are defined in Appendix F of the ASME Code, Section III. Inelastic analysis methods are not used.]*

Subsection 3.7.3 summarizes seismic analysis methods and criteria. Subsection 3.6.2 summarizes pipe break analysis methods.

The supports are represented by stiffness matrices in the system model for the dynamic analysis. Alternate methods for support stiffnesses representation is provided in Subsection 3.9.3.4. Shock suppressors that resist rapid motions and limit stop supports with gaps are also included in the analysis. The solution for the seismic disturbance uses the response spectra method. This method uses the lumped mass technique, linear elastic properties, and the principle of modal superposition. Alternatively, the time-history method may be used for the solution of the seismic disturbance.

The total response obtained from the seismic analysis consists of two parts: the inertia response of the piping system and the response from differential anchor motions (see Subsection 3.7.3). The stresses resulting from the anchor motions are considered to be secondary and are evaluated to the limits in Tables 3.9-6 and 3.9-7.

The mathematical models used in the seismic analyses of the Class 1, 2, and 3 piping systems lines are also used for pipe rupture effect analysis. To obtain the dynamic solution for auxiliary lines with active valves, the time-history deflections from the analysis of the reactor coolant loop are applied at nozzle connections. For other lines that must maintain structural integrity or that have no active valves, the motion of the reactor coolant loop is applied statically.

[*The functional capability requirements for ASME piping systems that must maintain an adequate fluid flow path to mitigate a Level C or Level D plant event are shown in Table 3.9-11.*]* These requirements are based on Reference 19.

Thermal analysis is required to obtain the stresses and loadings above the stress free state of the system. The stress free state of a piping system is defined as a temperature of 70°F. [*If the piping system operating temperature is 150°F or less, no thermal expansion analysis is required. If the piping system does not contain at least one 90-degree bend, then thermal expansion analysis is required.*]* This type of layout is avoided when practical. [*The thermal anchor displacements are also considered as negligible if they are 1/16 inches or less.*]* This is consistent with the practice that 1/16-inch of gap is allowed at a pipe support.

[*A thermal transient heat transfer analysis is performed for each different piping component on the Class 1 branch lines larger than 1-inch nominal diameter.*]* The following discussion on the evaluation of cyclic fatigue is not applicable to Class 2 and 3 pipe.

[*The Level A and B service condition and test condition transients identified in subsection 3.9.1.1 are included in the fatigue evaluation. For each thermal transient, two load-sets are defined representing the maximum and minimum stress states for that transient. The effects of seismic events on the design of piping are considered in one of the following ways. The effects of seismic events are considered by including 20 full cycles of the maximum safe shutdown earthquake stress range in the fatigue analysis. Alternatively, the seismic contribution to the fatigue evaluation is based on five seismic events with an amplitude of one-third the safe shutdown earthquake and 63 cycles per event.*

The primary-plus-secondary and peak stress intensity ranges, fatigue reduction factors, and cumulative usage factors are calculated for the possible load-set combinations. It is conservatively assumed that the transients can occur in any sequence, thus resulting in the most conservative and restrictive combinations of transients.]*

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The combination of load-sets yielding the highest alternating stress intensity range is determined, and the incremental usage factor is calculated. Likewise, the next most severe combination is then determined, and the incremental usage factor is calculated. This procedure is repeated until the combinations having an allowable cycle of less than 10^{11} are formed. The total cumulative usage factor at a point is the summation of the incremental usage factors.

The methods and criteria used in the design and analysis of the ASME Code Classes 1, 2, and 3 piping are itemized in Table 3.9-19. These methods are included in the design specifications and design reports required for piping in Subsection 3.9.8.2. Use of these methods is documented in both as-designed and as-built reports.

3.9.3.1.6 Analysis of Primary Components and Class 1 Valves and Auxiliary Components

Primary components that serve as part of the pressure boundary in the reactor coolant loop include the steam generators, reactor coolant pumps, pressurizer, and reactor vessel. This equipment is AP1000 Equipment Class A. The pressure boundary meets the requirements of ASME Code, Section III. This equipment is evaluated for the loading combinations outlined in Table 3.9-5. The equipment is analyzed for the normal loads of weight, pressure, and temperature; mechanical transients of safe shutdown earthquake and auxiliary line pipe ruptures; and pressure and temperature transients are outlined in Subsection 3.9.1.1.

The results of the reactor coolant loop analysis and other ASME Code, Section III, Class 1, 2, and 3 piping analyses are used to determine the seismic loads acting on the equipment nozzles and the support and component interface locations. Subsection 3.7.3 summarizes seismic analysis methods and criteria used for analysis of primary components. The results of the reactor coolant loop analysis, other ASME Code, Section III, Class 1, 2, and 3 piping analyses, and the reactor vessel system analysis are used to determine pipe break loads on the equipment nozzles and the support component interface locations for those lines that do not meet the leak-before-break requirements.

Section 3.6 summarizes the pipe break analysis methods used to determine pipe rupture loads for the ASME Code Class 1 components.

Seismic analyses are performed individually for the reactor coolant pump, pressurizer, and steam generator. Detailed and complex dynamic models are used for the dynamic analyses. Seismic analyses for the steam generator, reactor coolant pump, and pressurizer are performed using 4 percent damping for the safe shutdown earthquake.

The reactor pressure vessel is seismically qualified in accordance with ASME Code, Section III. The loadings used in the analysis are based on loads generated by a dynamic system analysis.

Auxiliary equipment that serves as part of the reactor coolant system pressure boundary includes ASME Code, Section III, Class 1 valves, core makeup tanks, and passive residual heat removal heat exchanger. Components and valves which form part of the reactor coolant system pressure boundary are designed and analyzed according to the appropriate portions of the ASME Code, Section III. This equipment is evaluated for the loading combinations and stress limits in Tables 3.9-5 and 3.9-9. The operability criteria for these valves are described in Subsection 3.9.3.2.

Valves in sample and instrument lines connected to the reactor coolant system are not considered to be AP1000 Equipment Class A nor ASME Class 1. This is because the nozzles where the lines connect to the primary system piping include an orifice with a 3/8-inch hole. This hole restricts the flow so that loss through a severance of one of these lines can be made up by normal charging flow. These small lines are seismically analyzed as described in Subsection 3.7.3.

3.9.3.1.7 ASME Code Class 2 and 3 Components

Table 3.9-3 lists the loads for ASME Code Class 2 and 3 components. Table 3.9-5 provides the loading combinations. The loading conditions for ASME Class 2 and 3 piping are presented in Table 3.9-3. Table 3.9-10 presents the stress limits for the various service levels. Functional capability requirements are presented in Table 3.9-11. Subsection 3.7.3 summarizes the seismic analysis methods and criteria for these components. The pipe break analysis methods are summarized in Subsection 3.6.2. Analysis methods for Class 2 and 3 piping are summarized in Subsection 3.9.3.1.5.

The allowable stress limits established for the components are low enough so that breach of the pressure-retaining boundary does not occur. Active valves requirements are further described in Subsection 3.9.3.2.

3.9.3.2 Pump and Valve Operability Assurance

The design and service limits specified by the ASME Code, Section III are established to confirm the pressure-retaining or support function of the ASME Code-class component. To assess the functional capability of required components to operate, additional criteria and considerations, including collapse and deflection limits, are developed.

3.9.3.2.1 Pump Operability

There are no active pumps relied upon to perform a safety-related function in the AP1000.

3.9.3.2.2 Valve Operability

Active valves are those whose operability is relied upon to perform a safety-related function during transients or events considered in the respective operating condition categories. Inactive components are those whose operability is not relied upon to perform a safety-related function for the various transients and plant conditions. Table 3.9-12 lists the active valves.

Table 3.9-9 provides the stress limits used for active Class 1 valves. Table 3.9-10 provides the stress limits used for active Class 2 and Class 3 valves.

Active valves are subjected to a series of tests and inspections prior to service and during the plant life. These tests and inspections along with controls on maintenance and operation provide appropriate reliability of the valve for the design life objective of the plant.

Prior to service, qualification of functional capability of active valve assemblies is performed in accordance with the requirements of ASME QME-1-2007 (Reference 36). Prior to installation, the following tests, as appropriate to the function and mission of the valve, are performed: shell hydrostatic test, backseat and main seat leakage tests, disc hydrostatic tests, and operational tests to verify that the valve opens and closes.

Cold hydro tests, hot functional tests, periodic inservice inspections, and periodic inservice operations are performed in situ to verify the functional capability of the valve.

Refer to Section 3.11 for the operability qualification of motor operators for the environmental conditions.

For active valves with extended structures, an analysis of the extended structure is performed for equivalent static seismic safe shutdown earthquake loads applied at the center of gravity of the extended structure.

In addition to these tests and analyses, a representative number of valves of each design type are tested for verification of operability during a simulated Service Level D (safe shutdown earthquake) condition event by demonstrating operational capabilities within the specified limits. Valve sizes that cover the range of sizes in service are tested.

When seismic qualification is based on dynamic or equivalent static load testing for structures, systems or subsystems that contain mechanisms that must change position in order to function, operability testing is performed for the safe shutdown earthquake preceded by one or more earthquakes. The number of preceding earthquakes is calculated based on IEEE-344-1987 to provide the equivalent fatigue damage of one safe shutdown earthquake event.

The seismic qualification testing procedures for valve operability testing are as follows: The valve is mounted in a manner that will conservatively represent typical valve installations. The valve includes the operator, accessory solenoid valves, and position sensors when attached to the valve in service.

The operability of the valve during a Service Level D condition is demonstrated by satisfying the following criteria:

- A static load or loads equivalent to those resulting from the accelerations due to Service Level D conditions is applied to the extended structure center of gravity so that the resulting deflection is in the nearest direction of the extended structure. The design pressure of the valve is applied to the valve during the static deflection tests.

- The valve is cycled while in the deflected position. The valve must function within the specified operating time limits while subject to design pressure.

- Electrical motor operators, position sensors, and pilot solenoid valves necessary for operation are qualified in accordance with IEEE seismic qualification standards. Section 3.10 describes the methods and criteria used to qualify electrical equipment.

Active valves that do not have an extended structure, such as check valves and safety valves, are considered separately.

Check valves are characteristically simple in design, and their operation is not affected by seismic accelerations or the maximum applied nozzle loads. The check valve design is compact, and there are no extended structures or masses whose motion could cause distortions that could restrict operation of the valve. These valves are designed such that if structural integrity is maintained, the valve operability is maintained. In addition to these design considerations, the check valves also undergo the following: in-shop hydrostatic test, in-shop seat leakage test, and periodic in situ valve testing and inspection.

Pressurizer and main steam safety valves are qualified for operability in the same manner as valves with extended structures. The qualification methods include analysis of the bonnet for equivalent static safe shutdown earthquake loads, in shop hydrostatic and seat leakage tests, and periodic in situ valve inspection.

To verify analysis methods, representative safety valves are tested. This test is described as follows:

- The safety valve is mounted to represent the specified installation.

- The valve body is pressurized to its normal system pressure.

- A static load representing the Service Level D condition load is applied to the top of the valve bonnet in the weakest direction of the extended structure.

- The pressure is increased until the valve actuates.
- Actuation of the valve at its setpoint provides for operability during the Service Level D condition load.

Using these methods, the active valves in the system are qualified for operability during a Service Level D condition event. These methods conservatively simulate the seismic event, and confirm that the active valves perform their safety-related function when necessary.

3.9.3.3 Design and Installation Criteria of Class 1, 2, and 3 Pressure Relieving Devices

[*The design of pressure relieving valves comply with the requirements of ASME Code, Section III, Appendix O, "Rules for the Design of Safety Valve Installations."*]* When there is more than one valve on the same run of pipe, the sequence of valve openings is based on the anticipated sequence of valve opening. This sequence is determined by the set point pressures or control system logic. The applicable stress limits are satisfied for the components in the piping run and connecting systems including supports. The reaction forces and moments are based on a dynamic load factor of 2.0 unless a dynamic structural analysis is performed to calculate these forces and moments.

3.9.3.3.1 Pressure Relief Devices and Automatic Depressurization Valves Connected to the Pressurizer

The pressurizer safety valves provide overpressure protection for the reactor coolant system. The safety valves connected to the pressurizer are the only ASME Code, Section III, Class 1 pressure relief valves in the AP1000. The automatic depressurization system valves that provide a means to reduce reactor coolant system pressure to allow the passive core cooling system to fully function are not designed to provide overpressure protection and are not classified as pressure relief devices.

The safety valves and the first three stages of the automatic depressurization valves are mounted in and supported by the pressurizer safety and relief valve (PSARV) module located above the pressurizer. The valves are connected to two piping manifolds that are connected to two nozzles located in the pressurizer upper head. [*The spring loaded safety valves are designed to prevent system pressure from exceeding design pressure by more than ten percent.*]*

If the pressure exceeds the setpoint of either safety valve, the valve opens and steam is discharged through a rupture disk to the containment atmosphere. Normal pressurizer liquid and vapor volumes combined with operation of the plant control systems limit pressure increases so that opening of the safety valves is not required for any Level A or B service condition transient. The connecting pipe between the pressurizer and safety valves does not include a loop seal. The safety valves seal against the steam and any noncondensible gas in the upper portion of the pressurizer.

The valves for the automatic depressurization system open when required for the passive safety injection system. The motor-operated automatic depressurization valves open in sequence to reduce reactor coolant system pressure when required to allow stored water sources to cool the core. The valves open in stages as required by the controls for the automatic depressurization system. The automatic depressurization system valves open more slowly than do the safety valves. The operation of the automatic depressurization system is outlined in Subsection 5.4.6 and Section 6.3. For the three stages that are connected to the pressurizer, the valves discharge into the in-containment refueling water storage tank through a sparger. The piping connection of the automatic depressurization system valves to the pressurizer contain loop seals.

The valve opening generates transient thrust forces at each change in flow direction or area. The analysis of the piping system and support considers the transient forces associated with valve opening.

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For each pressurizer safety and automatic depressurization system piping system, an analytical hydraulic model is developed. The piping from the pressurizer nozzle to the rupture disk and in-containment refueling water storage tank sparger is modeled as a series of single pipes. The pressurizer is modeled as a reservoir that contains steam at constant pressure and at constant temperature. Fluid acceleration inside the pipe generates reaction forces on the segments of the line that are bounded at either end by an elbow or bend. Reaction forces resulting from fluid pressure and momentum variations are calculated. These forces are defined in terms of the fluid properties for the transient hydraulic analysis.

3.9.3.3.2 Pressure Relief Devices for Class 2 Systems and Components

Pressure relieving devices for ASME Code, Section III, Class 2 systems include the safety valves and power operated relief valves on the steam line and the relief valves on the containment isolation portion of the normal residual heat removal system.

The design and analysis requirements for the safety and relief valves and discharge piping for the steam line are described in Subsection 10.3.2.

In addition to providing overpressure protection for the normal residual heat removal system, the relief valves also provide low temperature overpressure protection for the reactor coolant system. The location and connection for the valves on the residual heat removal system are discussed in Subsection 5.4.7.

3.9.3.3.3 Design and Analysis Requirements for Pressure Relieving Devices

The design of pressure-relieving devices can be generally grouped in two categories: open discharge and closed discharge.

Open Discharge

An open discharge is characterized by a relief or safety valve discharging to the atmosphere or to a vent stack open to the atmosphere. [*The design and analysis of open discharge valve stations includes the following considerations:*

- *Stresses in the valve header, the valve inlet piping, and local stresses in the header-to-valve inlet piping junction due to thermal effects, internal pressure, seismic loads, and thrust loads are considered.*
- *Thrust forces include both pressure and momentum effects.*
- *Where more than one safety or relief valve is installed on the same pipe run, valve spacing requirements are as specified in the ASME Code. The minimum moments to be used in stress calculations are those specified in the ASME Code.*
- *The effects of the valve discharge on piping connected to the valve header are considered.*
- *The reaction forces and moments used in stress calculations include the effects of a dynamic load factor (DLF), or are the maximum instantaneous values obtained from a time-history structural analysis.*]*

Closed Discharge

The closed discharge system is characterized by piping between the valve and a tank or some other terminal end. Under steady-state conditions, there are no net unbalanced forces. [*The initial transient response and resulting stresses are determined using either a time-history computer solution*]* or a

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conservative equivalent static solution. [*In calculating initial transient forces, pressure and momentum terms as well as water slug effects are included.*]*

3.9.3.4 Component and Piping Supports

[*The supports for ASME Code, Section III, Class 1, 2, and 3 components including pipe supports satisfy the requirements of the ASME Code, Section III, Subsection NF.*]* In addition to meeting the requirements of ASME Code, Section III, Subsection NF, the welded connections of ASTM A500 Grade B tube steel members (identified as hollow structural sections [HSSs]) satisfy the requirements of the AISC "Load and Resistance Factor Design Specification for Steel Hollow Structural Sections," November 10, 2000. The nominal strength of the connections, as provided in Sections 8 and 9 of the AISC "Load and Resistance Factor Design Specification for Steel Hollow Structural Sections," November 10, 2000, will be divided by a safety factor to generate the allowable stress design (ASD) connection capacity. [*The boundary between the supports and the building structure is based on the rules found in Subsection NF.*]* Table 3.9-3 presents the loading conditions. [*Table 3.9-8 summarizes the load combinations. The stress limits are presented in Tables 3.9-9 and 3.9-10 for the various service levels.*]*

The criteria of Appendix F of the ASME Code Section III is used for the evaluation of Level D service conditions. When supports for components not built to ASME Code, Section III criteria are evaluated for the effect of Level D service conditions, the allowable stress levels are based on tests or accepted industry standards comparable to those in Appendix F of ASME Code, Section III.

In order to provide for operability of active equipment, including valves, ASME limits for Service Level C loadings are met for the supports of these items.

Dynamic loads for components loaded in the elastic range are calculated using dynamic load factors, time-history analysis, or any other method that accounts for elastic behavior of the component. A component is assumed to be in the elastic range if yielding across a section does not occur. Local yielding due to stress concentration is assumed not to affect the validity of the assumptions of elastic behavior. The stress allowables of Appendix F for elastically analyzed components are used for Code components. Inelastic stress analysis is not used.

The stiffness of the pipe support miscellaneous steel is controlled by one of the following methods so that component nozzle loads are not adversely affected by support deformation:

[*Pipe support miscellaneous steel deflections are limited for dynamic combined faulted loading to 1/8 inch in each restrained direction. The dynamic faulted loading combinations considered are those in Table 3.9-8 associated with Level D service limits.*]* These deflections are defined with respect to the structure to which the miscellaneous steel is attached. These deflection limits, provide adequate stiffness for seismic analysis and are small enough so that nozzle loads are not affected by pipe support deformation. In this case, the pipe support and miscellaneous steel are represented by the following stiffness values in the piping system analysis. Default rigid stiffness values are used for supports except that vendor stiffness values are used for snubbers and rigid gapped supports. [*The mass of the pipe support miscellaneous steel is evaluated as a self-weight excitation loading on the steel and the structures supporting the steel.*]*

[*Alternatively, if the deflections for dynamic loading exceeds 1/8 inches, the pipe support and miscellaneous steel are represented by calculated stiffness values in the piping system analysis.*]*

Use of baseplates with concrete expansion anchors is minimized in the AP1000. Concrete expansion anchors may be used for pipe supports. For these pipe support baseplate designs, the baseplate flexibility requirements of IE Bulletin 79-02, Revision 2, dated November 8, 1979 are met by

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accounting for the baseplate flexibility in the calculation of anchor bolt loads. Supplemental requirements for fastening anchor bolts to concrete are outlined in Subsection 3.8.4.5.1.

[*Friction forces induced by the pipe on the support must be considered in the analysis of sliding type supports, such as guides or box supports, when the resultant unrestrained thermal motion is greater than 1/16 inch. The friction force is equal to the coefficient of friction times the pipe load, and acts in the direction of pipe movement. A coefficient of friction of 0.35 for steel-on-steel sliding surfaces shall be used. If a self-lubricated bearing plate is used, a 0.15 coefficient of friction shall be used. The pipe load from which the friction force is developed includes only deadweight and thermal loads. The friction force can not be greater than the product of the pipe movement and the stiffness of the pipe support in the direction of movement.*]*

Small gaps are provided for frame type supports built around the pipe. These gaps allow for radial thermal expansion of the pipe as well as allowing for pipe rotation. The minimum gap (total of opposing sides) between the pipe and the support is equal to the diametral expansion of the pipe due to temperature and pressure. [*The maximum gap is equal to the diametral expansion of the pipe due to temperature and pressure plus 1/8 inch.*]*

For standard component pipe supports, the manufacturer's functional limitations for example, travel limits and sway angles, should be followed. This criterion is applicable to limit stops, snubbers, rods, hangers and sway struts. Snubber settings should be chosen such that pipe movement occurs over the mid range of the snubber travel. Some margin should be provided between the expected pipe movement and the maximum or minimum snubber-stroke to accommodate construction tolerance.

3.9.3.4.1 ASME Code Class 1 Component Supports

The load combinations and allowable stresses for ASME Code Class 1 component supports are given in Tables 3.9-8 and 3.9-9.

3.9.3.4.1.1 Class 1 Component Supports Models and Methods

The static and dynamic structural analyses employ the matrix method and normal mode theory for the solution of lumped-parameter, multimass structural models. The equipment support structure models are dual-purpose, since they represent quantitatively the elastic restraints that the supports impose upon the component, and represent the individual support member stresses due to the forces imposed upon the supports by the component.

A description of the supports for the reactor pressure vessel, steam generator, and pressurizer is found in Subsection 5.4.10. The supports are modeled using elements such as beams, plates, and springs where applicable.

The reactor vessel supports are located at each of the four inlet nozzles and are modeled using a finite element computer program.

Steam generator supports include a column support below the steam generator, a lateral support attached to the top of the column support, a lateral support transverse to the hot leg attached to the secondary shell at the operating floor, and a lateral support (snubbers) parallel to the hot leg attached to the secondary shell at the top of the steam generator compartment, and are normally modeled as linear or nonlinear springs. The reactor coolant pump is supported by the connection to the steam generator and does not have separate supports.

The pressurizer is supported by four columns. Each core makeup tank is supported by eight columns.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The passive residual heat removal heat exchanger is supported by the in-containment refueling water storage tank. The channel heads are outside of the tank and the tubesheets are connected to the tank wall. The tubes are inside the tank, exposed to fluid motion and supported by a structure resting on the floor of the tank and attached to the tank wall.

For each operating condition, the loads (obtained from the reactor coolant loop analysis or the analysis of the component) acting on the reactor pressure vessel, steam generator, and pressurizer supports are appropriately combined. The adequacy of each member of the supports, is verified by solving the stress and interaction equations of ASME Code, Section III, Subsection NF and Appendix F. The adequacy of the reactor pressure vessel support structure is verified using a finite element computer program and comparing the resultant stresses to the criteria given in ASME Code, Section III, Subsection NF and Appendix F.

The test load method given in Appendix F is an acceptable method of qualifying components in lieu of satisfying the stress/load limits established for the component analysis. The test load method is not used in the AP1000 to qualify supports of components built to ASME Code, Section III requirements.

3.9.3.4.2 ASME Code Class 2 and 3 Supports

[*Class 2 and 3 component supports are designed and analyzed for design condition, and Level A, B, C, and D service conditions to the rules and requirements of ASME Section III, Subsection NF, and Appendix F.*]* The analyses or test methods and associated stress or load allowable limits that are used in the evaluation of linear supports for Level D service conditions are those defined in the ASME Code. Plate and shell type supports satisfy the Level D service condition limits provided in Appendix F of the ASME Code, Section III. Tables 3.9-8 and 3.9-10 outline the allowable stresses and loading combinations for ASME Code, Section III, Class 2 and 3 component supports.

3.9.3.4.3 Snubbers Used as Component and Piping Supports

The location and size of the snubbers are determined by stress analysis. Access for the testing, inspection, and maintenance of snubbers is considered in the AP1000 layout. The location and line of action of a snubber are selected based on the necessity of limiting seismic stresses in the piping and nozzle loads on equipment. Snubbers are chosen in lieu of rigid supports where restricting thermal growth would induce excessive thermal stresses in the piping or nozzle loads or equipment. Snubbers that are designed to lock up at a given velocity are specified with lock-up velocities sufficiently large to envelope the highest thermal growth rates of the pipe or equipment for design thermal transients. The snubbers are constructed to ASME Code, Section III, Subsection NF standards.

[*In the piping system seismic stress analysis, the snubbers are modeled as stiffness elements. The stiffness value is based on vendor stiffness data for the snubber, snubber extension, and pipe clamp assembly.*]* Supports for active valves are included in the overall design and qualification of the valve.

The elimination of the analysis of dynamic effects of pipe breaks due to leak-before-break considerations, as outlined in Subsection 3.6.3, permits the use of fewer snubbers than in plants that were designed without considering leak before break. Also, the AP1000 uses gapped support devices to minimize the use of snubbers. The evaluation of those snubbers used as supports is outlined below.

Design specifications for snubbers include:

- Seismic requirements
- Normal environmental parameters

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- Accident/post-accident environmental parameters
- Full-scale performance test to measure pertinent performance requirements
- Instructions for periodic maintenance (in technical manuals)

Two types of tests will be performed on the snubbers to verify proper operation:

- Production tests, including dynamic testing, on every unit to verify proper operability

- Qualification tests on randomly selected production models to demonstrate the required load performance (load rating)

The tests for large hydraulic snubbers (that is, those with capacities of 50 kips or greater) include the following qualification tests:

1) a full Level D load test to verify sufficient load capacity,

2) testing at full load to verify proper bleed with the control valve closed,

and the following production tests:

1) testing to verify the control valve closes within the specified velocity range, and

2) testing to demonstrate that breakaway and drag loads are within the design limits.

The operability of essential snubbers is verified as described in Subsection 3.9.3.4.4 and in the inservice testing program required by Subsection 3.9.8.3 by verifying the proper installation of the snubbers, and performing visual inspections and measurements of the cold and hot positions of the snubbers as required during plant heatup to verify the snubbers are performing as intended.

3.9.3.4.4 Inspection, Testing, Repair, and/or Replacement of Snubbers

A program for inservice examination and testing of dynamic supports (snubbers) is prepared in accordance with the requirements of ASME OM Code, Subsection ISTD.

The inservice examination and testing includes a thermal motion monitoring program that is established for verification of snubber movement, adequate clearance and gaps, including motion measurements, and acceptance criteria to assure compliance with ASME Section III, Subsection NF.

The inservice examination and testing plan for applicable snubbers is prepared in accordance with the requirements of the ASME OM Code, Subsection ISTD. Snubber maintenance, repairs, replacements, and modifications are performed in accordance with the requirements of the ASME OM Code, Subsection ISTD. Details of the inservice examination and testing program are reported in the inservice inspection and testing plan included in the inservice testing program required by Subsection 3.9.8.3.

a. Snubber Design and Testing

   1. A list of safety-related snubbers is included in Table 3.9-201.

   2. The snubbers are tested to verify they can perform as required during the seismic events, and under anticipated operational transient loads or other mechanical loads associated with the design requirements for the plant. Production and qualification test programs for

both hydraulic and mechanical snubbers are carried out by the snubber vendors. Acceptance criteria for compliance with ASME Section III Subsection NF, and other applicable codes, standards, and requirements, are as follows:

- Snubber production and qualification test programs are carried out by strict adherence to the manufacturer's testing and technical manuals. These manuals are prepared by the snubber manufacturer and subjected to review for compliance with the applicable provisions of the ASME Pressure Vessel and Piping Code of record. The test program is periodically audited during implementation for compliance.

- Snubbers are inspected and tested for compliance with the design drawings and functional requirements of the procurement specifications.

- Snubbers are load rated by testing in accordance with the snubber manufacturer's testing program.

- Design compliance of the snubbers per ASME Section III Paragraph NF-3128, and Subparagraphs NF-3411.3 and NF-3412.4.

- The snubbers are tested for various abnormal environmental conditions. Upon completion of the abnormal environmental transient test, the snubber is tested dynamically at a frequency within a specified frequency range. The snubber must operate normally during the dynamic test. The functional parameters cited in Subparagraph NF-3412.4 are included in the snubber qualification and testing program. Other parameters in accordance with the ASME OM Code will be incorporated.

- The codes and standards used for snubber qualification and production testing are as follows:

  – ASME B&PV Code Section III (Code of Record date) and Subsection NF.

  – ASME OM Code, Subsection ISTD.

- Large bore hydraulic snubbers are full Service Level D load tested on a random sampling basis, including verifying proper bleed rates with the control valve closed. Snubbers receive testing that ensure control valve closure within the specified velocity range and demonstration that drag forces/breakaway forces are within design limits.

3. Safety-related snubbers are identified in Table 3.9-201, including the snubber identification and the associated system or component, e.g., line number. The snubbers on the list are hydraulic and constructed to ASME Section III, Subsection NF. The snubbers are used for shock loading only. None of the snubbers are dual purpose or vibration arrestor type snubbers. Dual purpose snubbers are those snubbers used for shock arrestor (low cycle) and vibration arrestor (high cycle), i.e. snubbers used for a) impact loads from seismic, pipe break, etc., and b) control of high cycle operational vibration. Snubbers used for low cycle shock loadings for any purpose are considered a single purpose.

b. Snubber Installation Requirements

Installation instructions contain instructions for storage, handling, erection, and adjustments (if necessary) of snubbers. Each snubber has an installation location drawing that contains the installation location of the snubber on the pipe and structure, the cold setting, and additional information needed to install the particular snubber.

c. Snubber Preservice Examination and Testing

Snubbers are examined and tested during the preservice period in accordance with the Preservice Test Plan, which was prepared in accordance with the requirements of the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code) (Reference 2), Subsection ISTD. The required ISTD examinations are supplemented with an additional examination requirement to verify that snubbers are not seized, frozen or jammed.

d. Snubber Inservice Examination and Testing

Inservice examination and testing of snubbers is conducted in accordance with the requirements of the ASME OM Code, Subsection ISTD as outlined in the Inservice Test program plan.

Visual examinations are performed on the snubbers to identify conditions that could adversely affect a snubber's operational readiness. Snubbers evaluated as unacceptable during visual examination may be accepted for continued service by successful completion of an operational readiness test. The schedule of snubber visual examinations is based on snubber performance.

Snubbers are tested according to the established sampling plan each fuel cycle. When an in-place test or bench test cannot be performed, snubber subcomponents that control the parameters to be verified are examined and tested. Snubbers that do not meet test requirements are evaluated and additional testing is conducted until the appropriate sample plan completion criteria are satisfied.

There is also an assessment performed to ensure that the service life of a snubber is not exceeded prior to removing the snubber from service.

3.9.3.5 Instrumentation Line Supports

[*The design loads, load combinations, and acceptance criteria for safety-related instrumentation supports are similar to those of pipe supports. Design loads include deadweight, thermal, and seismic (as appropriate). The acceptance criteria is ASME Subsection NF.*]*

3.9.4 Control Rod Drive System (CRDS)

3.9.4.1 Descriptive Information of CRDS

3.9.4.1.1 Control Rod Drive Mechanism (CRDM)

The AP1000 control rod drive mechanism is based on a proven Westinghouse design that has been used in many operating nuclear power plants. Figure 3.9-4 shows the control rod drive mechanism. Figure 4.2-8 shows the configuration of the driveline, including the control rod drive mechanism. Subsection 4.2.2 describes the design of the rod cluster control assemblies and gray rod cluster assemblies. The material requirements for the control rod drive mechanisms and the control assemblies are discussed in Section 4.5.

Control rod drive mechanisms are located on the head of the reactor vessel. They are coupled to rod cluster control assemblies (RCCAs) that have neutron absorber material over the active length of the control rods. The control rod drive mechanisms are also attached to gray rod cluster assemblies (GRCAs) that are used for load follow. The gray rod cluster assemblies are geometrically identical to the rod cluster control assemblies except that most of the rodlets are fabricated from a material specified in Subsection 4.2.2.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The control rod drive mechanisms for both the rod cluster control assemblies and the gray rod cluster assemblies are identical. Although the gray rod cluster assemblies are expected to drop during a trip insertion, the insertion of these assemblies is not required in order to shut down the reactor.

The primary functions of the control rod drive mechanism is to insert or withdraw, at a designated speed, 53 rod cluster control assemblies and 16 gray rod cluster assemblies from the core to control average core temperature. During startup and shutdown the control assemblies control changes in reactivity.

Operation of the control rod drive mechanisms is integrated to move groups of assemblies together. Each cluster assembly is in a bank of assemblies which is used for reactivity control, axial power distribution control, or shutdown control. The assemblies of each bank of several rod cluster control assemblies or gray rod cluster assemblies move at the same time.

The design of the control rod drive mechanisms and the control assemblies permits load follow without the use of chemical shim over most of the life of the core. The design of the control rod drive mechanisms also permits holding the rod cluster control assemblies and the gray rod cluster assemblies at any step elevation within the range of rod travel during normal operation. The rod cluster control assemblies and gray rod cluster assemblies have the same mechanical coupling with the control rod drive mechanism.

The control rod drive mechanism is a magnetically operated jack (magjack). A magnetic jack is an arrangement of three electromagnets energized in a controlled sequence by a power cycle to insert or withdraw rod cluster control assemblies and gray rod cluster assemblies in the reactor core in discrete steps. The control rod drive mechanism is designed to release the drive rod and rod cluster control assembly during any part of the power cycle sequencing if electrical power to the coils is interrupted. When released from the control rod drive mechanism, the drive rod and rod cluster control assembly or gray rod cluster assembly falls by gravity into a fully inserted position.

The control rod drive mechanism consists of four separate subassemblies. These are the pressure vessel, coil stack assembly, latch assembly, and drive rod assembly.

The pressure vessel includes a latch housing and a rod travel housing that are connected by a threaded, seal-welded, maintenance joint that facilitates removal of the latch assembly. The top of the rod travel housing provides seismic support by an interface with the integrated head package. The latch housing is the lower portion of the vessel and contains the latch assembly. The latch housing is welded to the mechanism nozzle by a bi-metallic weld. The nozzle of the control rod drive mechanism is attached to the vessel head by a shrink-fit and a partial penetration weld. The rod travel housing is the upper portion of the vessel and provides space for the drive rod during its upward movement as the control rods are withdrawn from the core.

The coil stack assembly includes the coil housings, electrical conduit and connector, and three operating coils: the stationary gripper coil, the movable gripper coil, and the lift coil. The coil stack assembly is a separate unit. It is installed on the drive mechanism by sliding it over the outside of the latch housing. It rests on the base of the latch housing without mechanical attachment. Energizing the operating coils causes movement of the pole pieces and latches in the latch assembly.

The latch assembly includes the guide tube, stationary pole pieces, movable pole pieces, and two sets of latches: the movable gripper latches and the stationary gripper latches. The latches engage grooves in the drive rod assembly. The movable gripper latches are moved up or down in 5/8-inch steps by the lift pole to raise or lower the drive rod. The stationary gripper latches hold the drive rod assembly while the movable gripper latches are repositioned for the next 5/8-inch step.

The drive rod assembly includes a coupling, drive rod, disconnect button, disconnect rod, and locking button. The drive rod has a 5/8-inch pitch from groove to groove that engage the latches during holding or moving of the drive rod. The coupling is attached to the drive rod and provides the means for coupling to the rod cluster control assembly directly below the control rod drive mechanism. The disconnect button, disconnect rod, and locking button provide positive locking of the coupling to the rod cluster control assembly and permit remote disconnection of the drive rod.

The control rod drive mechanism withdraws and inserts a rod cluster control assembly or gray rod cluster assembly as shaped electrical pulses are received by the operating coils. An on or off sequence, repeated by silicon-controlled rectifiers in the power programmer, causes either withdrawal or insertion of the control rod. Withdrawal of the drive rod and rod cluster control assembly or gray rod cluster assembly is accomplished by magnetic forces. Insertion is by gravity. The mechanism is capable of raising or lowering a maximum 400-pound load (which includes the drive rod weight) at a rate of 45 inches per minute.

During plant operation, the stationary gripper coil and movable gripper coil of the drive mechanism holds the rod cluster control assembly in a static position until a stepping sequence is initiated, at which time the stationary gripper coil, movable gripper coil, and lift coil are energized sequentially.

The control rod position is measured by 48 discrete coils mounted on the position indicator assembly surrounding the rod travel housing. Each coil magnetically senses the entry and presence of the top of the ferromagnetic drive rod assembly as it moves through the coil center line.

The mechanism internals are designed to operate in 650°F reactor coolant. The pressure vessel is designed to contain reactor coolant at 650°F and 2500 psia. The three operating coils are designed to operate at 392°F, with forced-air cooling required to maintain the coil internal temperature at or below 392°F. The air for cooling is provided by fans and shrouds included as part of the integrated head package. A loss of the air cooling would be expected to result in the release of the drive rod in the worst case. For this reason, the cooling air is not required to be a safety-related system and does not require an emergency power supply.

The design and construction of the control rod drive mechanism includes provisions to establish that gross failure of the housing sufficient to allow a control rod to be ejected from the core is not credible. These provisions include the following:

- Construction of the housing of Type 304 or 316 stainless steel, which exhibits excellent notch toughness at the temperatures that will be encountered.
- The allowable stress levels in the mechanism are not exceeded due to system thermal transients at power or by thermal movement of the reactor coolant loops.
- The control rod drive mechanisms are hydrotested after manufacture at a minimum of 125 percent of system design pressure.
- The housings are hydrotested at a minimum of 125 percent of system design pressure after installation to the reactor vessel head and included as part of the hydro test of the completed reactor coolant system.

The analyses of postulated accidents discussed in Chapter 15 include the evaluation of a nonmechanistic control rod ejection. Section 3.5 does not consider ejected rods to be a credible missile.

3.9.4.1.2 Control Rod Withdrawal

The rod cluster control assembly is withdrawn by repeating the following sequence of events. The sequence, starting with the stationary and movable grippers energized in the hold position, is as follows:

1. Moveable Gripper Coil B - OFF

   The latch-locking plunger separates from the movable gripper pole under the force of a spring and gravity. Three links, pinned to the plunger, swing the three movable gripper latches out of the drive rod assembly groove. Note: the movable gripper is turned off at the start of rod motion even though it will be turned on in step 2 to provide identical CRDM cycling for all steps since a step ends with the movable gripper off.

2. Movable Gripper Coil B - ON

   The latch-locking plunger rises and swings the movable gripper latches into the drive rod assembly groove. A small axial clearance exists between the latch teeth and the drive rod.

3. Stationary Gripper Coil A - OFF

   The force of gravity, acting upon the drive rod assembly and attached control rod, causes the stationary gripper latches and plunger to move downward 1/16 inch, transferring the load of the drive rod assembly and attached control rod to the movable gripper latches. The plunger continues to move downward and swings the stationary gripper latches out of the drive rod assembly groove.

4. Lift Coil C - ON

   The 5/8-inch gap between the movable gripper pole and the lift pole closes, and the drive rod assembly rises one step length (5/8 inch).

5. Stationary Gripper Coil A - ON

   The plunger rises and closes the gap below the stationary gripper pole. The three links, pinned to the plunger, swing the stationary gripper latches into a drive rod assembly groove. The latches contact the drive rod assembly and lift it (and the attached control rod) a small fraction of an inch. The small vertical drive rod assembly movement transfers the drive rod assembly load from the movable gripper latches to the stationary gripper latches.

6. Movable Gripper Coil B - OFF

   The latch-locking plunger separates from the movable gripper pole under the force of a spring and gravity. Three links, pinned to the plunger, swing the three movable gripper latches out of the drive rod assembly groove.

7. Lift Coil C - OFF

   The gap between the movable gripper pole and the lift pole opens. The movable gripper latches drop 5/8 inch to a position adjacent to a drive rod assembly groove.

8. Repeat Step

The sequence just described (items 1 through 6) is termed one step or one cycle. The rod cluster control assembly moves 5/8 inch for each step or cycle. The sequence is repeated at a rate of up to 72 steps per minute, and the drive rod assembly (which has a 5/8-inch groove pitch) is raised 72 grooves per minute. The rod cluster control assembly is thus withdrawn at a rate of up to 45 inches per minute. The gray rod cluster assemblies are withdrawn in an identical manner.

After rod motion has ended, movable gripper coil B is turned on to re-establish double-hold (that is, holding the rod in place with both the stationary and movable grippers).

3.9.4.1.3 Control Rod Insertion

The sequence for rod cluster control assembly insertion is similar to that for control rod withdrawal, except that the timing of lift coil C ON and OFF is changed to permit lowering of the control assembly. The sequence, starting with the stationary gripper energized in the hold position, is as follows:

1. Movable Gripper Coil B - OFF

   The latch-locking plunger separates from the movable gripper pole under the force of a spring and gravity. Three links, pinned to the plunger, swing the three movable gripper latches out of the drive rod assembly groove.

2. Lift Coil C - ON

   The 5/8-inch gap between the movable gripper and lift the pole closes. The movable gripper latches are raised to a position adjacent to a drive rod assembly groove.

3. Movable Gripper Coil B - ON

   The latch-locking plunger rises and swings the movable gripper latches into a drive rod assembly groove. A small axial clearance exists between the latch teeth and the drive rod assembly.

4. Stationary Gripper Coil A - OFF

   The force of gravity, acting upon the drive rod assembly and attached rod cluster control assembly, causes the stationary gripper latches and plunger to move downward 1/16 inch transferring the load of the drive rod assembly and attached rod cluster control assembly to the movable gripper latches. The plunger continues to move downward and swings the stationary gripper latches out of the drive rod assembly groove.

5. Lift Coil C - OFF

   The force of gravity and spring force separate the movable gripper pole from the lift pole. The drive rod assembly and attached rod cluster control assembly drop down 5/8 inch.

6. Stationary Gripper Coil A - ON

   The plunger rises and closes the gap below the stationary gripper pole. The three links, pinned to the plunger, swing the three stationary gripper latches into a drive rod assembly groove. The latches contact the drive rod assembly and lift it (and the attached control rod) a small fraction of an inch. The small, vertical drive rod assembly movement transfers the drive rod assembly load from the movable gripper latches to the stationary gripper latches.

7. Movable Gripper Coil B - OFF

The latch-locking plunger separates from the movable gripper pole under the force of a spring and gravity. Three links, pinned to the plunger, swing the three movable gripper latches out of the drive rod assembly groove.

8. Repeat Step

   The sequence is repeated, as for rod cluster control assembly withdrawal, up to 72 times per minute, which gives an insertion rate of 45 inches per minute. The gray rod cluster assemblies are inserted in an identical manner.

   After rod motion has ended, movable gripper coil B is turned on to re-establish double-hold (that is, holding the rod in place with both the stationary and movable grippers).

3.9.4.1.4 Holding and Tripping of the Control Rods

During most of the plant operating time, the control rod drive mechanisms hold the rod cluster control assemblies withdrawn from the core in a static position. During most plant operation the gray rod cluster assemblies are held by the control rod drive mechanisms withdrawn or inserted in the core in a static position as directed by flux shape considerations. In the holding mode, two coils – stationary gripper coil A and movable gripper coil B – are energized on each mechanism. The drive rod assembly and attached rod cluster control assemblies or gray rod cluster assemblies hang suspended from the three latches of the stationary gripper. Additionally, the three latches of the movable gripper are engaged to hold the drive rod assembly in place in the event of a failure that would cause the release of the stationary gripper.

When the drive line is positioned in the last few steps, the rod cluster control assemblies and gray rod cluster assemblies are out of the last portion of the core, although not fully withdrawn from the fuel assemblies. This covers the range of steps from 263-266. The control rod drive mechanism may be located at any one or more of these step locations during operation of the plant and be considered fully out without any adverse impact on the control rod drive mechanism or plant operation.

The rod clusters cannot be physically withdrawn from the guide tubes by the control rod drive mechanisms since no additional grooves are machined in the drive rod past the last position.

If power to the stationary and movable gripper coils is cut off, the combined weights of the drive rod assembly and the rod cluster control assembly or gray rod cluster assembly (plus the stationary gripper and movable gripper return springs) move the latches out of the drive rod assembly groove. The trip occurs as follows:

- The magnetic field, holding the stationary gripper plunger against the stationary gripper pole, collapses, and the stationary gripper plunger is forced down by the stationary gripper return spring and the weight acting upon the latches.

- The magnetic field, holding the moveable gripper plunger against the movable gripper pole, collapses, and the movable gripper plunger is forced down by the moveable gripper return spring and the weight acting upon the latches.

The control rod falls by gravity into the core. After the driveline is released by the mechanism, it falls freely until the control rods enter the dashpot section of the fuel assembly where the coolant in the guide tubes slows the rate of descent until the rods are fully inserted.

3.9.4.1.5 Testing Program

As noted earlier, the AP1000 control rod drive mechanism is based on a proven Westinghouse design that has been used in many operating nuclear power plants. The control rod cluster and fuel assembly thimble tube mechanical design is also based on a proven design. The production tests that each control rod drive mechanism undergoes are outlined in Subsection 3.9.4.4.

3.9.4.2 Applicable CRDS Design Specifications

The specifications for the design, fabrication, construction, and operation of the control rod drive system (CRDS) include provisions related to the functional requirements, pressure boundary integrity, strength and durability of the internal components, and electrical requirements for the operating mechanism. The specifications and design requirements are consistent with the safety classification of the various parts of the control rod drive system as defined in Section 3.2.

The materials used in the control rod drive mechanisms are discussed in Subsection 4.5.1. The rod position instrumentation is described in Section 7.7.

Since the AP1000 control rod drive mechanism is a design previously provided for other nuclear power plants the specifications are well established. The specifications are outlined in the following discussions.

3.9.4.2.1 Control Rod Drive Mechanism Functional Requirements

The suitability of the functional requirements for the step size and rate of withdrawal and insertion during normal operation and the time to drop into the core have been demonstrated during many years of successful operation of similar Westinghouse-designed control rod drive mechanisms. The time required for the control rod drive system to release the rod cluster control assemblies into the core is evaluated to determine that it is sufficient in analyses of postulated accident conditions. For a discussion of the evaluation of the performance of the reactivity control function of the AP1000 control rod drive system and specific AP1000 accident analyses see Section 4.6 and Chapter 15.

The basic operational requirements for the control rod drive mechanisms follow:

- 5/8-inch step
- 166.755 inch travel, maximum (cold conditions)
- 400-pound maximum load
- Step in or out at 45 inches per minute (72 steps per minute) maximum, 5 inches per minute (8 steps per minute) minimum
- Electrical power interruption initiating release of drive rod assembly
- Trip delay time of less than or equal to 150 millisecond. Free fall of drive rod assembly is to begin less than 150 millisecond after power interruption, no matter what holding or stepping action is being executed, with any load and coolant temperature of 100°F to 650°F.
- 60-year design objective with normal refurbishment

  Testing and operating experience has validated these requirements and the capability of the AP1000 control rod drive mechanism design to meet them.

3.9.4.2.2 Pressure Housing Requirements

The pressure housing portion of the control rod drive mechanism, the latch housing and rod travel housing, comprises a portion of the reactor coolant pressure boundary. The design pressure and temperature for the control rod drive mechanism pressure housing are the same as for the reactor vessel.

As part of the reactor coolant pressure boundary, the pressure housing is constructed in conformance with requirements in 10 CFR 50.55a. The conformance of the reactor coolant pressure boundary with applicable code and standards is discussed in Section 5.2. The pressure housing meets design, material, fabrication, analysis, quality assurance, and other requirements for Class 1 components in ASME Code, Section III. The pressure housing is required to meet stress requirements for design and transient conditions. The AP1000 control rod drive mechanism pressure housing uses only one canopy seal weld, which is between the latch housing and the rod travel housing. The rod travel housing includes a vent hole to allow water to drain from the canopy seal weld area. This eliminates the presence of an oxygenated environment near the weld. The single AP1000 canopy seal weld has reduced stresses compared to the lower seal weld in past designs. These design improvements over past control rod drive mechanisms aid to prevent the occurrence of stress corrosion cracking.

3.9.4.2.3 Internal Component Requirements

The internal components of the control rod drive mechanism include the latch assembly, drive rod and the coupling that attaches the drive rod to the rod cluster control assemblies and gray rod cluster assemblies.

The design, fabrication, inspection, and testing of these non-pressure boundary components typically do not come under the jurisdiction of the ASME Code. For those materials which do not have established stress limits the limits are based on the material specification mechanical property requirements.

In addition to dead-weight and operational loads, the design of the driveline is evaluated for loads due to safe shutdown earthquake and flow induced vibration as described in Subsection 3.9.5.3, and the resulting deflections are limited such that the CRDM will function properly.

Postulated failures of drive rod assemblies and latch mechanisms by fracture or decoupling lead to a decrease in reactivity. A postulated failure leading to the release of a drive rod or portion of a drive rod results in an insertion of control rods guided by the control rod assembly. A control rod drop is indicated by instrumentation that monitors the nuclear reaction and detect a decrease in reactivity.

A postulated failure of a control rod drive mechanism to insert a control assembly due to sticking or galling of the drive rod or latch assembly is accounted for in the safety analyses, which assume that the control assembly at the most reactive core location is inoperable.

In addition to the requirements related to the strength of the internal components, criteria have been developed for clearances in the latch assembly and between the latch arms and drive rod. The latch assembly has parts of austenitic and ferritic stainless steels and other alloys. Differential thermal expansion could eliminate clearances and result in binding or otherwise restrict movement of the latch assembly if not allowed for in the design.

The design requirement is that sufficient clearance exist between the moving parts in the latch assembly at expected operating and design condition temperatures. An evaluation of the thermal expansion, room temperature clearances, and geometry demonstrates that an appropriate clearance is available at design and normal operating conditions.

For the magjack mechanism to work properly to insert or withdraw the control rods, the latch arms contacting the drive rod, (that is the movable and stationary gripper latches) must not be under load at the same time. The effect of the differential thermal expansion on the latch arms, pressure housing, is evaluated to provide that the appropriate clearance between the drive rod and the unloaded latch arm is maintained.

3.9.4.2.4 Coil Stack Assembly Requirements

The coil stack assembly provides the electromotive force to move the latches in the latch assembly. The safety function of rapid insertion of the control rods can be accomplished by removing power from the coils. The separation and redundancy required of the control system and power supplied to the control rod drive system is discussed in Section 4.6.

Postulated electrical or structural failures of the coil assembly do not result in a condition which would prevent control rod insertion. As a result, the electrical coils are built using standard industrial quality assurance and are not required to be built to IEEE Class 1E standards.

The coil stack assembly is located outside the pressure housing. The assembly does not come in contact with the reactor coolant and does not have any pressure-retaining function. The operating temperature of the coils is maintained below 392°F.

The coil stack assembly slides over the pressure housing and remains in place without a permanent mechanical or welded attachment. The assembly clearances permit removal of an assembly even when the control rod drive mechanism is at normal operating temperature. Thus, a malfunctioning coil assembly could be replaced without a complete cooldown of the plant. The clearances between the coil and coil housing are selected to minimize the gap at normal operating temperature to facilitate coil cooling.

3.9.4.3 Design Loads, Stress Limits, and Allowable Deformations

The pressure housing portion of the control rod drive mechanism is a Class 1 component required to meet the requirements of ASME Code, Section III. Subsection 3.9.3 defines the loading combinations considered in the evaluation of ASME Code, Section III, pressure boundary components.

For each loading combination, the appropriate stresses due to pressure, component weight, external loads, hydraulic forces, thermal gradients, and seismic dynamic forces are evaluated and demonstrated to be less than the applicable stress limits. The cyclic stresses are combined with constant stresses to evaluate the fatigue usage due to cyclic loads. The transients used in the evaluation of cyclic loads are described in Subsection 3.9.1. The effect of seismic events is addressed by considering a seismic event with an amplitude equal to one-third of the safe shutdown earthquake evaluated as a Level B event. The seismic contribution to the fatigue evaluation is based on five seismic events with an amplitude of one-third the safe shutdown earthquake and with 63 cycles per event. The results of the stress evaluation are documented in a component stress report, as required by the ASME Code.

The control rod drive mechanism is supported by the attachment of the bottom of the assembly to the reactor vessel head and a connection to the integrated head package at the top of the rod travel housing. The integrated head package also provides the support to the cooling air shrouds and control rod drive mechanism electrical supply cables to prevent excessive loading on the control rod drive mechanisms during seismic events.

Hydrostatic tests according to the requirements of the ASME Code verify the pressure boundary integrity of the pressure housing prior to operation. The nozzle is attached to the reactor vessel head

by the head supplier and is hydro tested as required. The rod travel housing seal weld is performed prior to final assembly following the assembly of the travel housing to the latch assembly housing. The hydrostatic test of the connection between the rod travel housing and the latch housing is done on the reactor vessel closure head after the housings are threaded together and seal welded.

To assure functional capability of the control rod dive mechanism following a seismic event or a pipe break, the bending moments on the control rod drive mechanisms are limited to those that produce stress levels in the pressure boundary of the control rod drive mechanism less than ASME Code limits during anticipated transient conditions. This limit provides that the rod travel housing does not bend to the extent that the drive rod binds during insertion of the control rods. The analysis evaluates the load combinations that include safe shutdown earthquake and pipe break. The pipe break considered is at least as large as the largest pipe in or connected to the reactor coolant system that is not qualified as leak before break line. See Subsection 3.9.7 for information on the control rod drive mechanism deflection limit requirements for the integrated head package.

3.9.4.4 Control Rod Drive Mechanism Performance Assurance Program

The capability of the pressure housing components to perform throughout the 60 year design objective is confirmed by the stress analysis report required by the ASME Code, Section III.

To confirm the operational adequacy of the combination of fuel assembly, control rod drive mechanism, and rod cluster control assembly, functional test programs have been conducted. These tests verify that the trip time achieved by the control rod drive mechanisms meets the design requirements. These tests have been reported in WCAP-8446 (Reference 9).

The units are production tested prior to shipment to confirm the capability of the control rod drive mechanism to meet design specification operation requirements. Each production control rod drive mechanism undergoes a production test as listed in Table 3.9-13.

The trip time requirement is confirmed for each control rod drive mechanism prior to initial reactor operation and at periodic intervals after initial reactor operation, as required by the technical specifications. See Section 14.2 for preoperational and startup testing.

To demonstrate proper operation of the control rod drive mechanism and to provide acceptable core power distributions, rod cluster control assembly partial movement checks are performed as required by the Technical Specifications. In addition, periodic drop tests of the rod cluster control assembly are performed at each refueling shutdown to demonstrate continued capability to meet trip time requirements, consistent with safety analyses in Chapter 15.

3.9.5 Reactor Pressure Vessel Internals

3.9.5.1 Design Arrangements

The AP1000 reactor internals consist of two major assemblies - the lower internals and the upper internals. The reactor internals provide the protection, alignment and support for the core, control rods, and gray rods to provide safe and reliable reactor operation. In addition, the reactor internals help to accomplish the following: direct the main coolant flow to and from the fuel assemblies; absorb control rod dynamic loads, fuel assembly loads, and other loads and transmit these loads to the reactor vessel; support instrumentation within the reactor vessel; provide protection for the reactor vessel against excessive radiation exposure from the core; and position and support reactor vessel radiation surveillance specimens.

During reactor operation, the core barrel directs the coolant flow from the reactor vessel inlet nozzles, through the downcomer annulus, and into the lower plenum below the lower core support plate. The

flow then turns and passes through the lower support plate and into the core region. After leaving the core, it passes through the upper core plate; then bypasses through and around the control rod guide tubes and the support columns to reach the outlet nozzles. During operation, a small amount of inlet coolant is diverted from the core to cool the core shroud and the vessel head area.

3.9.5.1.1 Lower Core Support Assembly

The major containment and support member of the reactor internals is the lower core support assembly, shown in Figure 3.9-5. This assembly consists of the core barrel, lower core support plate, secondary core support, vortex suppression plate, core shroud, neutron panels, radial supports, and related attachment hardware. The major material for this structure is 300 series austenitic stainless steel. The lower core support assembly is supported at its upper flange from a ledge in the reactor vessel flange. Its lower end is restrained in its transverse movement by a radial support system attached to the vessel wall. The radial support system consists of keys attached to the lower end of the core barrel subassembly. These keys engage clevis inserts in the reactor vessel. This system restricts the lower end of the core barrel from rotational and/or translational movement, but allows for radial thermal growth and axial displacement.

The core shroud is located inside the core barrel and above the lower core support. This shroud forms the radial periphery of the core. Through the dimensional control of the cavity (the gap between the fuel assemblies and the shroud) and the shroud cooling flow inlets, the core shroud provides directional and metered control of the reactor coolant through the core. The core shroud serves to provide a transition from the round core barrel to the square fuel assemblies.

Loads acting vertically downward from weight, fuel assembly preload, control rod dynamic loading, hydraulic loads, and earthquake acceleration are carried by the lower core support plate into the core supports. The loads are then carried through the core barrel shell to the core barrel flange, which is supported by the vessel flange. Transverse loads from earthquake acceleration, coolant cross-flow, and vibration are carried by the core barrel shell and distributed through the lower radial support to the vessel wall and to the vessel flange. Transverse loads from the fuel assemblies are transmitted to the core barrel shell by direct connection of the lower core support plate to the barrel wall, and by the upper core plate inserts to the core barrel alignment plates described in Subsection 3.9.5.1.2.

The main radial support system of the lower end of the core barrel is accomplished by key and keyway joints to the reactor vessel wall. Clevis blocks are welded to the vessel inner diameter at equally spaced points around the inner circumference of the vessel. Another insert block is bolted to each of these blocks and has a keyway geometry. Opposite each of these is a key attached to the internals. During assembly, as the internals are lowered into the vessel, the keys engage the keyways in the axial direction. Correct positioning of the internals is provided by the installation equipment (lifting rig) guide studs and bushings. In this design, the internals have a support at the furthest extremity, such that the core barrel is laterally supported at the top and bottom.

Radial and axial expansion of the core barrel is accommodated, but transverse movement of the core barrel is restricted by this design. With this system, cyclic stresses in the internal structures are within ASME Code, Section III, Subsection NG limits.

In the event of an abnormal downward vertical displacement of the internals following a hypothetical failure, energy-absorbing devices limit the dynamic force imposed on the reactor vessel. The energy absorbing device is the secondary core support. In addition, the secondary core support also transmits the vertical load of the core uniformly to the reactor vessel, limits the displacement to prevent withdrawal of the control rods from the core, and limits the displacement to prevent loss of alignment of the core with the upper core support to allow the control rods to be inserted into the reactor.

The lower plenum vortex suppressor plate is positioned in the vessel lower plenum to suppress flow vortices formed by the reactor coolant flow reversal in this region. The suppressor plate is supported by columns from the lower core support plate.

3.9.5.1.2 Upper Core Support Assembly

The AP1000 upper core support assembly consists of the upper support, the upper core plate, the support columns, and the guide tube assemblies. Figure 3.9-6 shows the upper core support assembly.

The support grid assembly establishes the spacing between the upper support and the upper core plate. The support columns are fastened at the top and bottom to these plates. The support columns transmit the mechanical loadings between the two plates and some serve the supplementary function of supporting the tubes that house the fixed in-core detectors.

The IGA feeds instrumentation from eight reactor vessel head penetrations to 42 locations within the fuel assemblies. The IGA is composed of a number of plate and shell members welded or bolted together, and rests on the top surface of the upper support plate. The top of the IGA is constrained where Quickloc stalks interface with the vessel head penetrations.

The IGA is designed to prevent excessive vibration of the incore instrumentation thimble assemblies (IITAs), which contain the fixed in-core flux detectors and core-exit thermocouples. The IGA provides a pathway from the Quickloc instrument nozzles through the upper support assemblies and upper support columns to the top of the fuel assemblies. The pathway protects and guides the IITAs during initial installation, reactor operation, and withdrawal/insertion during outages.

The guide tube assemblies sheath and guide the control rod drive shafts and control rods. The guide tubes are fastened to the upper support and are restrained by pins in the upper core plate for proper orientation and support.

The upper core support assembly is positioned in its proper orientation, with respect to the lower core support assembly, by alignment plates in the core barrel. Four equally spaced alignment plates are located at an elevation in the core barrel where the upper core plate is positioned. Four mating sets of inserts are located in the upper core plate at the same positions. As the upper support assembly is lowered into the lower support assembly, the inserts engage the alignment plates in the axial direction. Lateral displacement of the plate and of the upper support assembly is restricted by this design.

Fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper assembly is lowered into place. This system of locating pins and guidance arrangement provides proper alignment of the lower core support assembly, the upper core support assembly, the fuel assemblies, and control rods.

The upper and lower core support assemblies are preloaded by a large circumferential spring, which rests between the upper barrel flange and the upper core support assembly. This spring is compressed by installation of the reactor vessel head.

Vertical loads from weight, earthquake acceleration, hydraulic loads, and fuel assembly preload are transmitted through the upper core plate via the support columns, to the upper support, and then into the reactor vessel head. Transverse loads from coolant cross-flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the upper support and upper core plate. The upper support plate is particularly stiff to minimize deflection.

3.9.5.1.3 Core Shroud

The core shroud is between the lower core barrel and core, surrounding the core and forming the core cavity. The core shroud consists of formed vertical plates with fully welded vertical seams to prevent lateral flow from the fuel assemblies. This core shroud is a proven design that is currently utilized in operating plants.

3.9.5.1.4 Flow Skirt

The flow skirt is a perforated cylindrical ring, shown schematically in Figure 3.9-9, that is an attachment to the reactor vessel bottom head. However, since this structure is located entirely within the pressure boundary, it will be described in this reactor internals section. The flow skirt is welded to support lugs on the inside surface of the reactor vessel bottom head. A vertical clearance is provided between the top of the flow skirt and the bottom surface of the lower core support plate to prevent contact during operation and postulated core drop accident conditions. The flow skirt provides a more uniform core inlet flow distribution.

3.9.5.1.5 Reactor Internals Interface Arrangement

Figure 3.9-8 shows the arrangement of reactor internals components shown in Figures 3.9-5 and 3.9-6 and their relative position in the reactor vessel. As shown in the figure, the lower reactor internal (Figure 3.9-5) rests on the vessel ledge. The upper core support structure (Figure 3.9-6) also rests at the same location on the top of a large compression spring (hold down spring). The hold down spring is between the upper support plate flange and the core barrel flange as shown in the figure. Both the assemblies are held together by reactor vessel closure studs, which clamp the upper head to upper shell of reactor vessel. The lower reactor internals are also guided laterally by four support lugs welded to the bottom head of reactor vessel.

3.9.5.2 Design Loading Conditions

3.9.5.2.1 Level A and B Service Conditions

The level A and B service conditions that provide the basis for the design of the reactor internals are:

- Fuel assembly and reactor internals weight
- Fuel assembly and core component spring forces, including spring preloading forces
- Differential pressure and coolant flow forces
- Temperature gradients
- Operational thermal transients listed in Table 3.9-1
- Differences in thermal expansion, due to temperature differences and differential expansion of materials
- Loss of load/pump overspeed
- Earthquake (included only in fatigue evaluation; amplitude equal to one-third of the safe shutdown earthquake response)

3.9.5.2.2 Level C Service Conditions

The Level C service conditions that are the basis for the design of the reactor internals are small break loss of coolant accident, and small steam line break.

3.9.5.2.3 Level D Service Conditions

The Level D service conditions that are the basis for the design of the reactor internals are safe shutdown earthquake (SSE), and pipe rupture. The pipe ruptures are evaluated for lines for which dynamic effect can not be excluded based on mechanistic pipe break criteria. See Subsection 3.6.3 for a description of mechanistic pipe break criteria. The breaks considered are those inside containment, in systems that carry reactor coolant, steam and feedwater. These breaks have the greatest effect on the reactor internals response.

3.9.5.2.4 Design Loading Categories

The combination of design loadings fit into either the service level A, B, C, or D conditions shown on Figures NG-3221-1 and NG-3224-1, NG-3232-1, and by Appendix F of the ASME Code, Section III.

3.9.5.3 Design Bases

The reactor vessel internals components designated as ASME III Class CS core support structures are designed, fabricated, and examined in accordance with the requirements of ASME III, Subsection NG for Core Support Structures. The design documentation for these Class CS core support structures include a certified Design Specification and a certified Design Report conforming to the requirements of ASME III, Subsection NCA.

The basis used for design, construction, and examination, for those reactor vessel internals components not designated ASME III Class CS core support structures, is defined by Westinghouse as provided in the ASME Code, Subsection NG.

The scope of the stress analysis requires many different techniques and methods, both static and dynamic. The analysis performed depends on the mode of operation.

3.9.5.3.1 Mechanical Design Basis

The design bases for the mechanical design of the AP1000 reactor vessel internals components are as follows:

- The reactor internals, in conjunction with the fuel assemblies, direct reactor coolant through the core to achieve an acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements are met for the varying modes of operation. In addition, required cooling for the reactor pressure vessel head is provided so that the temperature differences between the vessel flange and head do not result in leakage from the flange during reactor operation.

- The core shroud forms the core cavity and directs the reactor coolant flow through the fuel assemblies.

- Provisions are made for installing in-core instrumentation useful for plant operation, and vessel material test specimens required for a pressure vessel irradiation surveillance program.

- The core internals are designed to withstand mechanical loads arising from the safe shutdown earthquake and to meet the requirements of the following item.

  The reactor has mechanical provisions which are sufficient to adequately support the core and internals and to maintain the core intact with acceptable heat transfer geometry following transients arising from abnormal operating conditions.

- Following a design basis accident, the plant is capable of being shut down and cooled in an orderly fashion, so that the fuel cladding temperature is kept within specified limits. Therefore, the deformation of certain critical reactor internals is kept sufficiently small to allow continued core cooling.

The functional limitations for the core structures and internal structures during the design basis accident are shown in Table 3.9-14.

Details of the dynamic analyses, input forcing functions, and response loadings are presented in Subsection 3.9.2.

3.9.5.3.2 Allowable Deflections

Loads and deflections imposed on components, as a result of shock and vibration, are determined analytically and/or experimentally in both scaled models and operating reactors. The cyclic stresses resulting from these dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces, and thermal gradients for the determination of the total stresses of the internals.

The reactor internals are designed to withstand stresses originating from various operating conditions, as summarized in Table 3.9-1.

For normal operating conditions, downward vertical deflection of the lower core support plate is negligible.

For normal operating and accident conditions, the deflection criteria of internal structures are the limiting values given in Table 3.9-14. The upper barrel radial inward deflection limit is based on preventing contact between the barrel and the peripheral upper guide tubes during a LOCA event. The rod cluster control assembly can be dropped during the LOCA event if the guide tubes are not contacted by the barrel. The radial outward (uniform) deflection is based on maintaining flow in the downcomer annulus between the core barrel and pressure vessel wall. A peak deflection greater than the uniform allowable is acceptable provided that the annulus blockage from the deflected core barrel is less than the non-uniform radial outward deflection limit. The upper package allowable deflection is based on the clearance between the upper core plate and guide tube support pin shoulder. Exceeding this value could result in potential buckling of the guide tube and potential loss of function during operating or accident conditions. The rod cluster guide tube allowable lateral deflection is based on test data that indicates the rod cluster control assembly drop time will not be impaired.

The criteria for the postulated core drop accident are based on analyses that determine the total downward displacement of the internal structures, following a hypothetical core drop resulting from loss of the normal core barrel supports. The initial clearance between the secondary core support structure and the reactor vessel lower head in the hot condition is approximately 0.6 inches. An additional displacement of approximately 0.7 inches would occur from the strain of the energy-absorbing devices of the secondary core support. Therefore, the total drop distance is about 1.3 inches. That distance is less than the distance that permits the tips of the rod cluster control assembly to come out of the guide thimble in the fuel assemblies.

The secondary core support is only required to function during an accident involving the hypothetical catastrophic failure of core support (such as core barrel or barrel flange). There are four supports in each reactor. This structure limits the fall of the core and absorbs much of the energy of the fall which otherwise would be imparted to the vessel.

The energy of the fall is calculated assuming a complete and instantaneous failure of the primary core support. The energy is absorbed during the plastic deformation of the controlled volume of stainless steel loaded in tension. The maximum deformation of this austenitic stainless piece is limited to approximately 0.7 inches in the hot condition, after which a positive stop is provided. The maximum deformation of the secondary core support allows for the maintenance of flow paths through the lower portion of the vessel and lower core support to provide cooling of the fuel under forced and natural circulation conditions.

3.9.6 Inservice Testing of Pumps and Valves

Inservice testing of pumps and valves is performed in accordance with the ASME Operations and Maintenance (OM) Code (Reference 2) as required by 10 CFR 50.55a(f), except where a deviation from Code requirements has been granted by the NRC as outlined in Subsection 3.9.6.3.

The requirements for system pressure tests are defined in the ASME Code, Section XI, IWA-5000. These tests verify the pressure boundary integrity and are part of the inservice inspection program, not part of the inservice test program.

The Vogtle 3&4 Preservice Test Plan and Inservice Testing Program Plan are submitted to the NRC. These plans document compliance with the OM Code except where a deviation from Code requirements has been granted by the NRC as outlined in Subsection 3.9.6.3. The execution and updating of these plans, as required, will ensure that all applicable pumps and valves are in a state of operational readiness to perform their safety function throughout the life of the plant.

Table 13.4-201 provides milestones for preservice and inservice test program implementation.

3.9.6.1 Inservice Testing of Pumps

ASME OM Code ISTA-1100 and ISTF-1000 provide the scoping criteria for pumps to be included in the preservice testing and inservice testing (IST) program plans. ISTF-1000 limits pumps to be included in the IST program to those that have an emergency power source. The emergency power source (Class 1E) for the AP1000 is the Class 1E DC distribution system, and there are no pumps powered from this source. Therefore, no pumps are included in the Vogtle 3&4 preservice test plan or IST program plan.

3.9.6.2 Inservice Testing of Valves

The Vogtle 3&4 Preservice Test Plan and IST Program Plan include lists of safety-related valves (i.e., those valves that perform a specific function in shutting down the reactor to a safe shutdown condition, in maintaining a safe shutdown condition, or in mitigating the consequences of an accident) and other selected valves are subject to operational readiness testing. The valve testing portion of the preservice and IST plans conforms to the requirements of the ASME OM Code and complies with all applicable portions of 10 CFR 50.55a(f), except where a deviation from Code requirements has been authorized by the NRC as outlined in Subsection 3.9.6.3.

Leakage testing requirements for pressure isolation valves, which provide isolation between high and low pressure systems, are contained in both the surveillance requirements for Technical Specification 3.4.15 and the OM Code. The pressure isolation valves that require leakage testing are identified in Table 3.9-18.

Pre-conditioning of valves or their associated actuators or controls prior to IST testing undermines the purpose of IST testing and is not allowed. Pre-conditioning includes manipulation, pre-testing, maintenance, lubrication, cleaning, exercising, stroking, operating, or disturbing the valve to be tested in any way, except as may occur in an unscheduled, unplanned, and unanticipated manner during normal operation. The IST program includes practices to prevent, where practical, unacceptable preconditioning.

3.9.6.3 Deviations from Code Requirements

When it is desirable to deviate from the requirements of the OM Code for Inservice or Preservice testing an NRC approved alternative can be used. The alternative can be an ASME OM Code Case approved by the NRC in 10 CFR 50.55a. Also, an Alternative to the OM Code requirements, or requirements of 10 CFR 50.55a, may be submitted in accordance with 10 CFR 50.55a(z), however this Alternative must be authorized by the NRC prior to use.

3.9.6.4 Additional Testing

This section contains the testing commitments that are outside of the OM Code/IST.

3.9.6.4.1 System Level Tests

The test program includes periodic systems level tests and inspections that demonstrate the capability of safety-related features to perform their safety-related functions such as passing flow or transferring heat. For this system level testing, the test and inspection frequency is once every 10 years. Staggering of the tests of redundant components is not required. These tests may be performed in conjunction with inservice tests conducted to exercise check valves or to perform power-operated valve operability tests. Alternate means of performing these tests and inspections that provide equivalent demonstration may be developed. Table 3.9-17 identifies the system level tests.

3.9.6.4.2 Check Valve Low Differential Pressure Tests

Safety-related check valves that perform a safety related mission to transfer open under low differential pressure conditions have periodic testing to verify the capability of the valve to initiate flow.

The intent of this supplemental test is to determine the pressure required to initiate flow. This differential pressure will verify that the valve will initiate flow at low differential pressure. This low pressure differential test is performed in addition to exercise inservice tests.

The specified frequency for this testing is once each refueling cycle.

3.9.6.4.3 CVS/RCS Pressure Boundary Valve Leakage Testing

To support the nonsafety-related classification of the CVS purification subsystem inside containment the CVS RCS pressure boundary valves are subject to leak testing. These valves are not included as pressure isolation valves in Table 3.9-18, as the non-safety CVS inside containment is designed for full RCS pressure. The leakage through valves CVS-V001, CVS-V002, and CVS-V080 will be tested separately with a leakage limit of 1.5 gpm for each valve. The leakage through valves CVS-V067, V081, V082, V084, and V085 will be tested at the same time as a group with a leakage limit of 1 gpm for the group. The leak test(s) will be performed at reduced RCS pressure. The observed leakage at lower pressure will be confirmed to be below the limit when adjusted to normal operating conditions using an NRC-accepted methodology. The test requirements including the test pressure and method

for verifying test acceptability are defined in the testing procedures. The specified frequency for this testing is once each refueling cycle.

3.9.6.4.4 Control Room Emergency Ventilation Pressure Regulating Valves (VES-V002A/B)

Pressure regulating valves that cannot be externally controlled are exempt from testing per the OM Code, and the Code does not provide testing methodology for these valves. These valves are functionally tested quarterly, and by the Technical Specification surveillance which requires monthly operation of VES for ≥ 15 minutes. Additionally, these valves will be tested through the range of inlet pressures, on a frequency established by the Equipment Reliability program.

3.9.6.4.5 Air-Operated Valves Additional Testing

Additional testing is performed as part of the air-operated valve (AOV) program, which includes the key elements for an AOV Program as identified in the JOG AOV program document, Joint Owners Group Air Operated Valve Program Document, Revision 1, December 13, 2000 (References 203 and 204). The AOV program incorporates the attributes for a successful power-operated valve long-term periodic verification program, as discussed in Regulatory Issue Summary 2000-03, Resolution of Generic Safety Issue 158: Performance of Safety-Related Power-Operated Valves Under Design Basis Conditions, by incorporating lessons learned from previous nuclear power plant operations and research programs as they apply to the periodic testing of air- and other power-operated valves included in the IST program. For example, key lessons learned addressed in the AOV program include:

- Valves are categorized according to their safety significance and risk ranking.
- Setpoints for AOVs are defined based on current vendor information or valve qualification diagnostic testing, such that the valve is capable of performing its design-basis function(s).
- Periodic static testing is performed, at a minimum on high risk (high safety significance) valves, to identify potential degradation, unless those valves are periodically cycled during normal plant operation, under conditions that meet or exceed the worst case operating conditions within the licensing basis of the plant for the valve, which would provide adequate periodic demonstration of AOV capability. If required based on valve qualification or operating experience, periodic dynamic testing is performed to re-verify the capability of the valve to perform its required functions.
- Sufficient diagnostics are used to collect relevant data (e.g., valve stem thrust and torque, fluid pressure and temperature, stroke time, operating and/or control air pressure, etc.) to verify the valve meets the functional requirements of the qualification specification.
- Uncertainties associated with performance of these tests and use of the test results (including those associated with measurement equipment and potential degradation mechanisms) are addressed appropriately. Uncertainties may be considered in the specification of acceptable valve setup parameters or in the interpretation of the test results (or a combination of both). Uncertainties affecting both valve function and structural limits are addressed.
- Test frequency is specified, and is evaluated each refueling outage based on data trends as a result of testing. Frequency for periodic testing is in accordance with References 203 and 204, with a minimum of 5 years (or 3 refueling cycles) of data collected and evaluated before extending test intervals.

- Post-maintenance procedures include appropriate instructions and criteria to ensure baseline testing is re-performed as necessary when maintenance on the valve, repair or replacement, have the potential to affect valve functional performance.
- Guidance is included to address lessons learned from other valve programs specific to the AOV program.
- Documentation from AOV testing, including maintenance records and records from the corrective action program are retained and periodically evaluated as a part of the AOV program.

3.9.6.4.6 Regulatory Treatment of Non-Safety Systems (RTNSS) Component Testing

10 CFR 50.55a(b)(3)(iii)(D) requires that the operational readiness of pumps, valves and dynamic restraints within the scope of Regulatory Treatment of Non-Safety Systems be assessed. Since the components are outside the scope of the OM Code the method used to meet this requirement is not included in the IST program. The method for assessment of operational readiness for these components is documented in the equipment reliability assessment for the associated components and includes testing of the components performed per Section 16.3.

3.9.6.4.7 Additional Testing of POVs Other Than MOVs or AOVs

The attributes of the AOV testing program described in Subsection 3.9.6.4.5 above, to the extent that they apply to and can be implemented on other safety-related power-operated valves, such as electro-hydraulic valves, are applied to those other power-operated valves.

3.9.6.4.8 Valve Disassembly to Assess Valve Degradation

Disassembly and inspection of valves will be performed based on information from inservice testing, or other program requirements, as noted below:

- PRA importance measures.
- Design reliability assurance program contained in Section 16.2.
- Historical performance of power-operated valves (identify valve types which experience unacceptable degradation in service.)
- Basic design of valves including the use of components subject to aging and requiring periodic replacement.
- Analysis of trends of valve test parameters during valve inservice tests.
- Results of nonintrusive techniques. Disassembly and inspection may not be needed if nonintrusive techniques are sufficient to detect unacceptable valve degradation.

3.9.7 Integrated Head Package

The integrated head package (IHP) combines several components in one assembly to simplify refueling the reactor. Figure 3.9-7 illustrates the integrated head package. The integrated head package includes a lifting rig, seismic restraints for control rod drive mechanisms, support for reactor head vent piping, cable bridge, power cables, cables for in-core instrumentation, cable supports, and shroud assembly.

The integrated head package provides the ability to rapidly disconnect cables, including the CRDM power cables, digital rod position indication cables, and in-core instrument cables from the components. The integrated head package also provides the ability to rapidly disconnect the reactor head vent system.

The integrated head package provides the ability to move these components as an assembly to permit their lifting and removal with the reactor vessel head. In addition, the integrated head package provides support for the vessel head stud tensioner/detensioner during refueling.

The lifting rig function is discussed in Subsection 9.1.5. The control rod drive mechanisms are discussed in Subsection 3.9.4. The control rod drive mechanism support and cooling function is discussed in Section 4.6. The reactor vessel head vent function is discussed in Subsection 5.4.12. The function and requirements of the in-core instrumentation are discussed in Chapter 7.

3.9.7.1 Design Bases

Components required to provide seismic restraint for the control rod drive mechanisms and the valves and piping of the reactor head vent are AP1000 equipment Class C, seismic Category I. These are designed in accordance with the ASME Code, Section III, Subsection NF requirements.

The loads and loading combinations due to seismic loads for these components are developed using the appropriate seismic spectra.

The structural design of the integrated head package is based on a design temperature consistent with the heat loads from the vessel head, the control rod drive mechanisms, and electrical power cables. The design also considers changes in temperature resulting from plant design transients and loss of power to the cooling fans.

Components required to provide cooling to the control rod drive mechanisms are nonnuclear safety-related AP1000 equipment Class E. Section 4.6 offers a discussion of the effect of failure of cooling of the control rod drive mechanisms.

Those components that function as part of the lifting rig are required to be capable of lifting and carrying the total assembled load of the package. This includes the vessel head, control rod drive mechanisms, control rod drive mechanism seismic supports, shroud, cooling ducts, and insulation. The lifting rig components are required to meet the guidance for special lifting rigs, in NUREG-0612 (Reference 10). The lifting rig components are safety-related, AP1000 equipment Class C, seismic Category II.

The components of the incore instrumentation system (IIS) that interface with the IHP are the QuickLoc stalk assembly and the IIS cables and connectors. Access to each QuickLoc assembly – including connection/disconnection of the QuickLoc, connection/disconnection of the IIS cables, and attaching/removing the bullet nose assembly – is a maintenance requirement for design of the IHP shroud. The IHP must also provide support of the IIS cables.

The shroud assembly is required to provide radiation shielding of the control rod drive mechanism.

The shroud also minimizes the effects of external events such as jets from through-wall cracks in high- and moderate-energy pipes. The control rod drive mechanisms and small diameter piping, tubing and conduit within the shroud do not represent credible sources of missiles or jets due to breaks or cracks. Therefore, the shroud is not required to act as a missile shield to contain missiles generated within the integrated head package. It is also not required to deflect any jets originating within the integrated head package.

The cables and connectors, within the integrated head package, for the in-core instrumentation system are AP1000 equipment Class C, Class 1E. These cables are required to be physically and electrically independent of other cables including control rod drive mechanism power cables. Section 7.1 describes separation requirements. The cables and connector must be environmentally qualified, as discussed in Section 3.11. The cables are required to terminate at a connector plate located so that the cables can be readily connected or disconnected. The other cables within the integrated head package, including power cables and cables for the digital rod position indicator system, are not Class 1E.

The cable support provides seismic support and maintains separation for instrumentation and power cables.

3.9.7.2 Design Description

The integrated head package combines several separate components in one assembly to simplify refueling of the reactor. The purpose of the integrated head package is to reduce the outage time and personnel radiation exposure by combining operations associated with movement of the reactor vessel head during the refueling outage. In addition, the integrated head concept reduces the laydown space required in the containment. With the integrated head package, disconnections from and connections to the control rod drive mechanisms and rod position indicators (RPI) and other components within the cooling shroud assembly are not made at the individual component.

The integrated head package consists of the following main elements:

- Shroud assembly
- Lifting system
- Mechanism seismic support structure
- Cable support structure
- Cables
- In-core instrumentation
- Cable bridge

Brief descriptions of the principal elements of the integrated head package are provided in the following paragraphs.

Shroud assembly - The shroud assembly is a carbon steel structure that includes a shielding shroud and an air baffle. During normal operation, it directs the flow of cooling air to the control rod drive mechanism coil stacks. The rod position indicators are also cooled by this air flow. The duct work and air baffle are integral with, and supported by, the shroud assembly. The air cooling fans are attached to the IHP. Structurally, the shroud is integrated with the mechanism seismic support structure. The shroud also provides shielding at the vessel flange region.

The shroud structure is bolted to attachment lugs on the reactor vessel head.

Cabling, conduit and their supports and attachment hardware for the nonsafety-related control rod drive mechanism cables; digital rod position indication cables; miscellaneous power, control, and instrumentation cables; and safety-related in-core instrumentation cables are routed around the cable support attached to the shroud. The cable bridge attaches to the shroud.

Lifting system - This apparatus lifts the reactor vessel head and integrated head package as a unit. The lift legs transfer the head load during a head lift from the head attachment lugs to the lift rig. The lifting system consists of lift legs, sling block, clevises, and sling rods required to interface with the polar crane hook.

Mechanism seismic support structure - This structure provides seismic restraint for the control rod drive mechanisms. It is located near the top of the control rod drive mechanism rod travel housings. The digital rod position indication connector plate attached to the rod travel housing interfaces with spacer plates, where required, to form a system of bumpers that interface with the mechanism seismic support structure. This support interfaces with the shroud assembly to transfer seismic loads from the mechanisms to the reactor vessel head.

Cable support structure - The cable support is located at an elevation above the top of the rod travel housings. It provides permanent support and routing for the control rod drive mechanism power cables and rod position indication cables, which remain with the integrated head package and are normally not disturbed. These cables terminate at the connector plates, which constitute the interface with the mating cables. Cable disconnects are made at the connector plates.

Cables - The integrated head package cables include those portions of the control rod drive mechanism power cables, in-core instrumentation, and rod position indication instrumentation cables extending from the connector plates to the user devices. These cables remain with the integrated head package and are normally not disturbed. The individual cable length is sized to provide an orderly arrangement. A cable bridge spanning between the integrated head package to the operating deck is used to support the routing of integrated head package cables. A connector rack mounted to the end of the cable bridge is used to manage, support, and provide a means to quickly connect and disconnect the cables during the refueling outage.

In-core instrumentation – The in-core instrumentation system consists of thermocouples to measure fuel assembly coolant outlet temperature, and in-core flux thimbles containing fixed detectors for measurement of the neutron flux distribution within the reactor core. The incore thimble tubes have enhanced resistance to fluid-induced vibration and wear. The thimble is stiffer than the design in previous operating plants and the gap between the thimble tube and the tubes used to guide and protect the thimble inside the reactor vessel is smaller to minimize vibration. The design of the thimble tube assembly also precludes an non-isolable leak of reactor coolant. The thermocouples and neutron detectors are routed through the integrated head package. These are inserted into the core through the reactor vessel head and upper internals assembly.

Cable bridge – The cables from the integrated head package are routed in circumferential trays mounted to the shroud. Cables routed to those cable trays are routed via a cable bridge that attaches to the shroud. The cable bridge is raised to a vertical position during the outage and sits on the head stand during refueling as part of the integrated head package.

3.9.7.3 Design Evaluation

The components of the integrated head package, which provide seismic support including the control rod drive mechanism seismic support and the shroud, are designed using the ASME Code, Section III, Subsection NF. Because of the application of mechanistic pipe break evaluations, the supporting elements do not have to be designed for loads due to a postulated break in a reactor coolant loop pipe. Pipes down to 6-inch nominal diameter are evaluated using mechanistic pipe break criteria and the integrated head package is analyzed for movement of the reactor vessel due to a break of any pipe not qualified for leak-before-break. See Subsection 3.6.3 for a discussion of the mechanistic pipe break requirements.

The integrated head package satisfies the limit on deflection of the top of the control rod drive mechanism rod travel housing. This limit restricts the bending moments on the control rod drive mechanisms to less than those that produce stress levels in the pressure boundary of the control rod drive mechanism greater than ASME Code limits during anticipated transient or postulated accident conditions. This deflection limit provides that the rod travel housing does not bend to the extent that

the drive rod binds during insertion of the control rods. This limit is based on the results of drive line drop testing with control rod drives travel housings in deflected positions.

The components of the integrated head package included in the load path of the lifting rig are designed to satisfy the requirements for lifting of heavy loads in NUREG-0612 (Reference 10). The criteria of ANSI N14.6, (Reference 11) is used to evaluate the loads and stresses during a lift. See Subsection 9.1.5 for discussion of special lifting rigs for heavy loads. Components which are part of the lifting load path are evaluated for the load due to the proof test required per ANSI N14.6.

Those cables and connectors for the in-core instrumentation system that are required to meet Class 1E requirements are evaluated for environmental conditions including normal operation and postulated accident conditions.

3.9.7.4 Inspection and Testing Requirements

The components in the lifting load path are proof tested to 300 percent of the rated load per the requirements of ANSI N14.6. The components load tested are surface examined by appropriate examination methods before and after the proof test.

3.9.8 Combined License Information

3.9.8.1 Reactor Internals Vibration Assessment and Predicted Response

The information consistent with the guidance of Regulatory Guide 1.20 is addressed in WCAP-16687-P (Reference 34), and the applicable changes are incorporated into the UFSAR.

3.9.8.2 Design Specifications and Reports

As-designed design specifications and design reports for the major ASME Code, Section III components are available for NRC review. Design Specifications and selected design analysis information for ASME Code, Section III valves and auxiliary components are available for NRC review.

Design specifications and design reports for ASME Section III piping are made available for NRC review. Reconciliation of the as-built piping (verification of the thermal cycling and stratification loading considered in the stress analysis discussed in Subsection 3.9.3.1.2) is completed by the COL holder after the construction of the piping systems and prior to fuel load (in accordance with DCD Tier 1 Section 2 ITAAC line item for the applicable systems).

The consistency of the reactor vessel core support materials relative to known issues of irradiation-assisted stress corrosion cracking or void swelling has been evaluated and addressed in APP-GW-GLR-035 (Reference 21).

The following words represent the original Combined License Information item commitment, which has been addressed as discussed above:

> Combined License applicants referencing the AP1000 design will have available for NRC audit the design specifications and design reports prepared for ASME Section III components. Combined License applicants will address consistency of the reactor vessel core support materials relative to known issues of irradiation-assisted stress corrosion cracking or void swelling (see Subsection 4.5.2.1). [*The design report for the ASME Class 1, 2, and 3 piping will include the reconciliation of the as-built piping as outlined in subsection 3.9.3. This reconciliation includes verification of the thermal cycling and stratification loadings considered in the stress analysis discussed in subsection 3.9.3.1.2.*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3.9.8.3 Snubber Operability Testing

A program to verify operability of essential snubbers is addressed in Subsection 3.9.3.4.4.

3.9.8.4 Valve Inservice Testing

The inservice test program is addressed in Subsection 3.9.6.

3.9.8.5 Surge Line Thermal Monitoring

A monitoring program to record temperature distributions and thermal displacements of the surge line piping is addressed in Subsection 3.9.3.1.2 and Subsection 14.2.9.2.22

3.9.8.6 Piping Benchmark Program

The benchmark program as described in Subsection 3.9.1.2 (if a piping analysis computer program other than one of those used for design certification is used) is addressed in APP-GW-GLR-006 (Reference 35).

The piping benchmark problems identified in (Reference 20) for the Westinghouse AP600 are also representative for the AP1000 and can be used for the AP1000 piping benchmark program if required.

3.9.8.7 As-Designed Piping Analysis

The piping packages chosen to demonstrate the AP1000 piping design are identified to be any piping package containing Class 1 piping larger than 1 inch in diameter plus the additional packages identified in Table 3.9-20.

Note: Piping packages included in Table 3.9-20 are generally Class 2/3 lines, with the exception of APP-RCS-PLR-230, which contains the 1-inch Class 1 reactor head vent piping.

The as-designed piping analysis is provided for the piping lines chosen to demonstrate all aspects of the piping design. A design report referencing the as-designed piping calculation packages, including ASME Section III piping analysis, support evaluations and piping component fatigue analysis for Class 1 piping using the methods and criteria outlined in Table 3.9-19 is made available for NRC review.

This topic is also addressed in Subsection 14.3.3.

3.9.9 References

1. ANS/ANSI 51.1 - 1983, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

2. ANSI/ASME OM Code 2012 Edition, “Code for Operation and Maintenance of Nuclear Power Plants.”

3. Kuenzel, A. J., “Westinghouse PWR Internals Vibrations Summary Three-Loop Internals Assurance,” WCAP-7765-AR, November 1973.

4. Bloyd, C. N., Ciaramitaro, W., and Singleton, N. R., “Verification of Neutron Pad and 17 x 17 Guide Tube Designs by Preoperational Tests on the Trojan 1 Power Plant,” WCAP-8766 (Proprietary) and WCAP-8780, (Nonproprietary), May 1976.

5. Bloyd, C. N., and Singleton, N. R., “UHI Plant Internals Vibrations Measurement Program and Pre- and Post-Hot Functional Examinations,” WCAP-8516-P (Proprietary) and WCAP-8517 (Nonproprietary), March 1975.

6. Abou-Jaude, K. F. and Nitkiewicz, J. S., “Doel 4 Reactor Internals Flow-Induced Vibration Measurement Program,” WCAP-10846 (Proprietary), March 1985.

7. Bhandari, D. R. and Yu, C., “South Texas Plant (TGX) Reactor Internals Flow-Induced Vibration Assessment,” WCAP-10865 (Proprietary) and WCAP-10866 (Nonproprietary), February 1985.

8. Takeuchi, K., et al., “Multiflex-A Fortran-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics,” WCAP-8708-P-A, Volumes 1 and 2 (Proprietary) and WCAP-8709-A Volumes 1 and 2. (Nonproprietary), February 1976.

9. Cooper, F. W., Jr., “17 x 17 Drive Line Components Tests - Phase 1B 11, 111 D-Loop Drop and Deflection,” WCAP-8446 (Proprietary) and WCAP-8449 (Nonproprietary), December 1974.

10. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, Nuclear Regulatory Commission, July 1980.

11. “Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More,” ANSI N14.6.

12. NRC BULLETIN NO. 88-08: Thermal Stresses in Piping Connected to Reactor Coolant Systems, June 22, 1988, including Supplements 1, 2, and 3, dated: June 24, 1988; August 4, 1988; and April 11, 1989.

13. “A Comprehensive Vibration Assessment Program for Yonggwang Nuclear Generating Station, Final Evaluation of Pre-Core Hot Functional Measurement and Inspection Programs,” CE Report 10487-ME-TE-240-03, August 22, 1995.

14. NRC BULLETIN NO. 88-11: Pressurizer Surge Line Thermal Stratification, December 20, 1988.

15. Not used.

16. NRC IE Bulletin 79-13, “Cracking in Feedwater System Piping,” June 25, 1979 and Revisions 1 and 2, dated August 30, 1979 and November 16, 1979.

17. “Investigation of Feedwater Line Cracking in Pressurized Water Reactor Plants,” (Proprietary) WCAP-9693, June 1980.

18. {HISTORICAL — “AP1000 Reactor Internals Flow-Induced Vibration Assessment Program,” WCAP-15949-P (Proprietary) and WCAP-15949-NP (Nonproprietary), Revision 2, June 2007. — HISTORICAL}

19. “Functional Capability of Piping Systems,” NUREG-1367, Nuclear Regulatory Commission, November 1992.

20. “Piping Benchmark Problems for the Westinghouse AP600 Standardized Plant,” NUREG/CR-6414 (BNL-NUREG-52487), Brookhaven National Laboratory, January 1997, Prepared for the U.S. Nuclear Regulatory Commission.

21. APP-GW-GLR-035, “Consistency of Reactor Vessel Core Support Materials Relative to Known Issues of Irradiation-Assisted Stress Corrosion Cracking (IASCC) and Void Swelling for the AP1000 Plant,” Westinghouse Electric Company LLC.

22. Not used.

23. Not used.

24. Not used.

25. Not used.

26. Not used.

27. Not used.

28. Not used.

29. Not used.

30. Not used.

31. Not used.

32. Not used.

33. APP-GW-GLR-021, “AP1000 As-Built COL Information Items,” Westinghouse Electric Company LLC.

34. {HISTORICAL — WCAP-16687-P (Proprietary), WCAP-16687-NP (Non-proprietary), “AP1000 Reactor Internals Expected and Acceptable Responses During Preoperational Vibration Measurement Program,” Revision 1, March 2007. — HISTORICAL}

35. APP-GW-GLR-006, “Benchmark Program for Piping Analysis Computer Programs,” Westinghouse Electric Company LLC.

36. ASME-QME-1-2007, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants.”

37. MPR-2524, “Joint Owners’ Group (JOG) Motor Operated Valve Periodic Verification Program Summary,” Revision A, November 2006.

38. Final Safety Evaluation by the Office of Nuclear Reactor Regulation Joint Owners’ Group Program on Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves Project Nos. 691, 693, and 694, U.S. Nuclear Regulatory Commission, September 2006 (ADAMS Accession Number ML061280315) and its Supplement, September 2008 (ADAMS Accession Number ML082480638).

39. ASME OM-S/G-2000, “Standards and Guides for Operation and Maintenance of Nuclear Power Plants.”

40. WCAP-17983-P (Proprietary), WCAP-17983-NP (Non-proprietary), “Comprehensive Vibration Assessment Program (CVAP) Measurement and Inspection Programs for the AP1000 Plant,” Revision 0, March 2015.

41. WCAP-17984-P (Proprietary), WCAP-17984-NP (Non-proprietary), “Comprehensive Vibration Assessment Program (CVAP) Vibration Analysis Program for the AP1000 Plant,” Revision 0, July 2015.

201. Not used.

202. Not used.

203. Joint Owners Group Air Operated Valve Program Document, Revision 1, December 13, 2000.

204. USNRC, Eugene V. Imbro, letter to Mr. David J. Modeen, Nuclear Energy Institute, Comments on Joint Owners’ Group Air Operated Valve Program Document, dated October 8, 1999.

Table 3.9-1 (Sheet 1 of 2)
Reactor Coolant System Design Transients

Event	Cycles
Level A Service Conditions	
Reactor coolant pump startup and shutdown (cycles of start and stop)	3000
Heatup at 100°F per hour	200
Cooldown at 100°F per hour	200
Unit loading between 0 and 15 percent of full power	500
Unit unloading between 0 and 15 percent of full power	500
Unit loading at 5 percent of full power per minute	2000
Unit unloading at 5 percent of full power per minute	2000
Step load increase of 10 percent of full power	3000
Step load decrease of 10 percent of full power	3000
Large step load decrease with steam dump	200
Steady-state fluctuation and load regulation	
Initial	1.5×10^5
Random	4.6×10^6
Load regulation	37,000(3)
Boron concentration equalization	2900
Feedwater cycling at hot shutdown	
Mode 1	3000
Mode 2	15,000
Core lifetime extension	40
Feedwater heaters out of service	180
Refueling	40
Turbine roll test	20
Primary-side leakage test	200
Secondary-side leakage test	80
Passive residual heat removal tests	5
Reactor coolant system makeup	5640
Daily load follow operation	17,800
Level B Service Conditions	
Loss of load (without reactor trip)	30
Loss of offsite power	30
Reactor trip from reduced power	180
Reactor trip from full power	
Case A - With no inadvertent cooldown	50
Case B - With cooldown and no safeguards actuation	50
Case C - With cooldown and safeguards actuation	20(1)

Table 3.9-1 (Sheet 2 of 2)
Reactor Coolant System Design Transients

Event	Cycles
Level B Service Conditions	
Control rod drop	
Case A	30
Case B	20[2]
Case C	30[2]
Cold overpressure	15
Inadvertent safeguards actuation	10
Partial loss of reactor coolant flow	60
Inadvertent RCS depressurization	20
Excessive feedwater flow	30
Loss of offsite power - with natural circulation cooldown	
Case A - loss of power with natural circulation cooldown with onsite ac power	20
Case B - loss of power with natural circulation cooldown without onsite ac power	10
Level C Service Conditions	
Small loss of coolant accident	5
Small steam line break	5
Small feedwater line break	5
Steam generator tube rupture	5
Inadvertent opening of automatic depressurization system valves	15
Level D Service Conditions	
Reactor coolant pipe break (large loss-of-coolant accident)	1
Large steam line break	1
Large feedwater line break	1
Reactor coolant pump locked rotor	1
Control rod ejection	1
Test Conditions	
Primary side hydrotest	10
Secondary side hydrotest	10
Steam generator tube leakage test	
Secondary-side pressure, psig	
200	400
400	200
600	120
840	80

Notes:
1. Reactor Trip - Case C shares its number of occurrences (20) with Control Rod Drop Case B
2. Control Rod Drop - Case B shares its number of occurrences (20) with Reactor Trip Case C
3. The Load Regulation transient occurrences are limited to 37,000 to maintain main spray flow cycles within PRHA fatigue design limits of the pressurizer spray piping. Other RCS components continue to be designed for 750,000 Load Regulation transient occurrences.

Table 3.9-2 Pump Starting/Stopping Conditions

Plant Condition	RCS (°F)/(psig)	SG Secondary (°F)/(psig)	Number of Starts/Stops	Operation
Cold	70/400	70/0	200	Cold Startup Transients
Cold	70/400	70/0	200	RCS heatup, cooldown
Restart	100/400	100/0	400	Hot functional RCP stops, starts
Hot	557/2235	557/1091	2200	Transients and miscellaneous

Table 3.9-3 (Sheet 1 of 2)
Loadings for ASME Class 1, 2, 3, CS and Supports

Load	Description
P	Internal design pressure
PMAX	Peak pressure
DW	Dead weight
DML	Design Mechanical Loads (other than DW). This includes Service Level A loads and RVOS loads that are Service Level B.
XL	External mechanical loads, such as the nozzle reactions associated with piping systems, shall be combined with other loads in the loading combination expressions.
SSE	Safe shutdown earthquake (inertia portion)
E	Earthquake smaller than SSE (inertia portion)
FV	Fast valve closure
RVC	Relief/safety valve - closed system (transient)
RVOS	Relief/safety valve - open system (sustained)
RVOT	Relief/safety valve - open system (transient)
DY	Dynamic load associated with various service conditions including FV, RVC, and RVOT as applicable (transient)
DN	Dynamic load associated with Level A (Normal) service conditions including FV, RVC, and RVOT as applicable (transient)
DU	Dynamic load associated with Level B (Upset) service conditions including FV, RVC, and RVOT as applicable (transient)
DE	Dynamic load associated with Level C (Emergency) service conditions including FV, RVC, and RVOT as applicable (transient)
DF	Dynamic load associated with Level D (Faulted) service conditions during which, or following which, the piping system being evaluated must remain intact including FV, RVC, and RVOT as applicable. This includes postulated pipe rupture events (transient)
DYS	Dynamic load associated with various service conditions (sustained)
SSES	Seismic anchor motion portion of SSE
ES	Seismic anchor motion of earthquake smaller than SSE
TH	Thermal loads for the various service conditions

Table 3.9-3 (Sheet 2 of 2)
Loadings for ASME Class 1, 2, 3, CS and Supports

Load	Description
TNU	Service Level A and B (normal and upset) plant condition thermal loads; including thermal stratification and thermal cycling
TN	Service Level A (normal) plant condition thermal loads
TU	Service Level B (upset) plant condition thermal loads
TE	Service Level C (emergency) plant condition thermal loads
TF	Service Level D (faulted) plant condition thermal loads
SCVNU	Static displacement of steel containment vessel - normal and upset conditions
SCVE	Static displacement of steel containment vessel - emergency condition
SCVF	Static displacement of steel containment vessel - faulted condition
HTDW	Hydrostatic test dead weight
DBPB	Design basis pipe break, includes LOCA and non-LOCA (transient)
LOCA	Loss-of-coolant accident
HYDSP	Building structure motions due to automatic depressurization system sparger discharge
DBPBS	Design basis pipe break, includes LOCA and non-LOCA (sustained)

Table 3.9-4
Not Used

Table 3.9-5
Minimum Design Loading Combinations For ASME Class 1, 2, 3 And CS Systems And Components

Condition	Design Loading Combinations[3][6]
[*Design*	*P + DW + DML + XL*
Level A Service	*PMAX[1] + DW + XL[4]*
	PMAX + DW + DN + XL[8]
Level B Service	*PMAX + DW + DU + XL[8]*
Level C Service	*PMAX + DW + DE[5] + XL[8]*
	PMAX + DW + DY + HYDSP + XL[9]
Level D Service	*PMAX + DW + DF + XL[8]*
	PMAX + DW + SRSS[2] ((SSE + SSES) + DBPB)[7] + XL[4]
	PMAX + DW + RVOS + SRSS (SSE + SSES)[7] + XL[11]
	PMAX + DW + DYS + DBPBS + SRSS ((SSE + SSES)[7] + DY + HYDSP) + XL[9][10]]*

Notes:

1. The values of PMAX in the load combinations may be different for different levels of service conditions as provided in the design transients. For earthquake loadings PMAX is equal to normal operating pressure at 100% power.
2. SRSS equals the square root of the sum of the squares.
3. Appropriate loads due to static displacements of the steel containment vessel and building settlement should be added to the loading combinations expressions for ASME Code, Section III, Class 2 and 3 systems.
4. In combining loads, the timing and causal relationships that exist between PMAX, and XL, are considered for determination of the appropriate load combinations.
5. The pressurizer safety valve discharge is a Level C service condition.
6. See Table 3.9-3 for description of loads.
7. For components that behave as anchors to the piping system, such as equipment nozzles, SSE and SSES are combined by absolute sum. For other components, such as straight pipe, tees, and valves, SSE and SSES are combined by SRSS method.
8. In combining loads, the timing and causal relationships that exist between PMAX, DN, DU, DE, DF, and XL, are considered for determination of the appropriate load combinations.
9. In combining loads, the timing and causal relationships that exist between PMAX, DY, HYDSP, and XL, are considered for determination of the appropriate load combinations.
10. In combining loads, the timing and causal relationships that exist between PMAX, DY, and XL, are considered for determination of the appropriate load combinations.
11. In combining loads, the timing and causal relationships that exist between PMAX, RVOS, and XL, are considered for determination of the appropriate load combinations.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.9-6
Additional Load Combinations and Stress Limits for ASME Class 1 Piping[9]

Condition	Loads[7]	Equation (NB3650)	Stress Limit
[*Level A/B*	*PMAX*[1], *TNU, E, ES, RVC, DN, DU,*	*10*	*3.0 S_m*
	SCVNU[2][4][5]	*11, 14*	*CUF = 1.0*
	RVOS[2]		
	TNU	*12*	*3.0 S_m*
	PMAX + DW + DU	*13*	*3.0 S_m*
	PMAX + DW + RVOS[2]	*13*	*3.0 S_m*
Level C	*TE + SCVE*	*Note 3*	*Note 3*
Level D[8]	*SSES*	*F_{AM}/A_M*[6]	*1.0 S_m*
	TF + SCVF	*Note 3*	*Note 3*
	TNU + SSES	*C_2D_o (M1 + M2)/2I*[8]	*6.0 S_m*]*

Notes:

1. The values of PMAX in the load combinations may be different for different levels of service conditions. For earthquake loading, PMAX is equal to normal operating pressure at 100% power.
2. Pressurizer safety valve discharge is classified as a Level C event.
3. See Table 3.9-11 for functional capability requirements.
4. The earthquake loads are assumed to occur at normal 100 percent power operation for the purposes of determining the total moment ranges.
5. Square root sum of the squares (SRSS) combination is used for ES, E, and other transient loads.
6. F_{AM} is amplitude of axial force for SSES; A_M is nominal pipe metal area.
7. See Table 3.9-3 for description of loads.
8. Where: M1 is range of moments for TNU, M2 is one half the range of SSES moments,
   M1 + M2 is larger of M1 plus one half the range of SSES, or full range of SSES
   C_2, D_o, I based on ASME III
9. When the simplified requirements of ASME Section III, NB-3640 and NB-3650 are not satisfied, the more detailed methods of NB-3200 may be used as stated in NB-3630.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.9-7
Additional Load Combinations and Stress Limits for ASME Class 2, 3 Piping

Condition	Loads[3]	Equation (NC/ND3650)	Stress Limit
[*Level A/B*	*PMAX[1] + DW + TNU + SCVNU[4]*	*11*	$S_h + S_A$
	Building Settlement	*10a*	$3.0\ S_C$
Level C	*TE + SCVE[4]*	*Note 6*	*Note 6*
Level D	*TNU + SSES*	*i (M1 + M2)/Z[2]*	$3.0\ S_h$
	SSES	F_{AM}/A_M[5]	$1.0\ S_h$
	TF + SCVF[4]	*Note 6*	*Note 6*]*

Notes:

1. The values of PMAX in the load combinations may be different for different levels of service conditions. For earthquake loading PMAX is equal to normal operating pressure at 100% power.
2. Where: M1 is range of moments for TNU, M2 is one half the range of SSES moments, M1 + M2 is larger of M1 plus one half the range of SSES, or full range of SSES
3. See Table 3.9-3 for description of loads.
4. The timing and causal relationships among TNU, TE, TF, SCVNU, SCVE, and SCVF are considered to determine appropriate load combinations.
5. F_{AM} is amplitude of axial force for SSES; A_M is nominal pipe metal area.
6. See Table 3.9-11 for functional capability requirements.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.9-8
Minimum Design Loading Combinations for Supports for ASME Class 1, 2, 3 Piping and Components(2)

Condition	Design Loading Combinations(3)
[*Design*	*DW + DML*
Level A Service	*DW + TH + DN*(4)
Level B Service	*DW + TH + DU*(4)
Level C Service	*DW + TH + DE*(5)(4)
	DW + TH + DY + HYDSP(7)
Level D Service	*DW + TH + RVOS + SSE + SSES + SWE*(6)(8)
	DW + TH + DF(4)
	DW + TH + SRSS (DBPB + (SSE + SSES + SWE))(6)
	DW + TH + DYS + DBPBS + SRSS ((SSE + SSES + SWE)(6) *+ DY + HYDSP)*(7)(9)
Hydrostatic Test	*HTDW*]*

Notes:

1. SRSS - square root of the sum of the squares
2. Appropriate loads due to static displacement of the steel containment vessel and building settlement should be added to the loading combinations expressions for Class 2 and 3 systems.
3. See Table 3.9-3 for description of loads.
4. The timing and causal relationships between TH and DY are considered to determine appropriate load combinations.
5. The pressurizer safety valve discharge is a Level C Service condition.
6. Combine SSE, SSES, and SWE by absolute sum method. SWE is self weight excitation, the effect of the acceleration of the support mass caused by building filtered loads such as SSE.
7. In combining loads, the timing and causal relationships that exist among TH, DY, and HYDSP are considered for determination of the appropriate load combinations.
8. In combining loads, the timing and causal relationships that exist among TH and RVOS are considered for determination of the appropriate load combinations.
9. In combining loads, the timing and causal relationships that exist among TH and DY are considered for determination of the appropriate load combinations.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.9-9
Stress Criteria for ASME Code Section III
Class 1 Components[a] and Supports and Class CS Core Supports

Design/Service Level	Vessels/Tanks Pumps	Piping (h, i)	Core Supports	Valves, Disks & Seats	Components Supports [c,d]
Design and Service Level A	ASME Code, Section III NB-3221, 3222	[*ASME Code, Section III NB-3652, Equation 9*]*	ASME Code, Section III NG-3221, 3222, 3231, 3232	ASME Code, Section III NB-3520, 3525	[*ASME Code, Section III Subsection NF (e)*]*
Service Level B (Upset)	ASME Code, Section III NB-3223	[*ASME Code, Section III NB-3654, Equation 9*]*	ASME Code, Section III NG-3223, 3233	ASME Code, Section III NB-3525	[*ASME Code, Section III Subsection NF (e)*]*
Service Level C (Emergency)	ASME Code, Section III NB-3224	[*ASME Code, Section III NB-3655, Equation 9*]*	ASME Code, Section III NG-3224, 3234	ASME Code, Section III NB-3526	[*ASME Code, Section III Subsection NF (e)*]*
Service Level D (Faulted)	ASME Code, Section III (see Chapter 3.9.1.4) NB-3225 (no active Class 1 pumps used)	[*ASME Code, Section III NB-3656, Equation 9*]*	ASME Code, Section III (see chapter 3.9.1) NG-3225, 3235	(b) (g)	[*ASME Code, Section III Subsection NF, (e) (see Chapter 3.9.1) (f)*]*

Notes:

a. A test of the components may be performed in lieu of analysis.
b. Class 1 valve service Level D criteria for inactive valves is based on the criteria in ASME III, Appendix F, F-1420 for verification of pressure boundary integrity.
c. Including pipe supports.
d. In instances where the determination of allowable stress values utilizes S_u (ultimate tensile stress) at temperatures not included in ASME Code Section III, S_u shall be calculated using one of the methods provided in Regulatory Guide 1.124, Revision 1.
e. ASME Table 3131(a)-1.
f. See Subsection 3.9.3.4 for supports for active equipment, valves, and piping with active valves.
g. For active valves, pressure integrity verification will be based on using the ASME Code allowables one level less than the service loading condition. For example, for the evaluation of Level D loading, Level C allowables will be used. Valve operability is demonstrated by testing or analysis. Check valve operability may be shown by analysis. See Subsection 3.9.3.2.2 for an outline of test requirements.
h. Table 3.9-6 includes additional stress limits for Class 1 piping.
i. When the simplified requirements of ASME Section III, NB-3640 and NB-3650 are not satisfied, the more detailed methods of NB-3200 may be used as stated in NB-3630.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.9-10
Stress Criteria for ASME Code Section III
Class 2 and 3 Components and Supports

Design/ Service Level	Vessels/Tanks	Piping (f)	Pumps	Valves, Disks, Seats	Component Supports (a) (b)
Design and Service Level A	ASME Code Section III NC-3217 NC/ ND-3310, 3320	[*ASME Code, Section III NC/ND-3652, Equation 8*]*	ASME Code Section III NC/ND-3400	ASME Code Section III NC/ND-3510	[*ASME Code Section III (c)*]*
Service Level B (Upset)	ASME Code Section III NC/ND-3310, 3320	[*ASME Code, Section III NC/ND-3653, Equation 9*]*	ASME Code Section III NC/ND-3400	ASME Code Section III NC/ND-3520	[*ASME Code Section III (c)*]*
Service Level C (Emergency)	ASME Code Section III NC/ND-3310, 3320	[*ASME Code, Section III NC/ND-3654, Equation 9*]*	ASME Code Section III NC/ND-3400	ASME Code Section III NC/ND-3520	[*ASME Code Section III (c)*]*
Service Level D (Faulted)	ASME Code Section III NC/ND-3310, 3320	[*ASME Code, Section III NC/ND-3655, Equation 9*]*	ASME Code Section III NC/ND-3400	ASME Code Section III NC/ND-3520 (e)	[*ASME Code Section III (c) (d)*]*

See following page for notes.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Notes:

a. Including pipe supports.

b. In instances where the determination of allowable stress values utilizes S_u (ultimate tensile stress) at temperatures not included in ASME Code Section III, S_u shall be calculated using one of the methods provided in Regulatory Guide 1.124, Revision 1.

c. ASME Table 3131(a)-1.

d. See Subsection 3.9.3.4 for supports for active equipment, valves, and piping with active valves.

e. For active valves, pressure integrity verification will be based on using the ASME Code allowables one level less than the service loading condition. For example, for the evaluation of Level D loading, Level C allowables will be used. Valve operability is demonstrated by testing or analysis. Check valve operability may be shown by analysis. See Subsection 3.9.3.2.2 for an outline of test requirements.

f. Table 3.9-7 includes additional stress limits for Class 2 and 3 piping.

Table 3.9-11
Piping Functional Capability – ASME Class 1, 2, and 3(1)

[*Wall Thickness:*	$D_o/t \leq 50$, where D_o, t are per ASME III
Service Level D Conditions	Equation 9 ≤ smaller of 2.0 S_y and 3.0 S_m(2, 4, 5) Equation 9 ≤ smaller of 2.0 S_y and 3.0 S_h(3, 4, 6)
External Pressure:	$P_{external} \leq P_{internal}$
TE + SCVE	$C2*M*D_o/2I \leq 6.0\ S_m$(2) (NB-3650) Equation 10a (NC3653.2) ≤ 3.0 S_c(3)
TF + SCVF	$C2*M*D_o/2I \leq 6.0\ S_m$(2) (NB-3650) Equation 10a (NC 3653.2) ≤ 3.0 S_c(3]*

Notes:

1. Applicable to Level C or Level D plant events for which the piping system must maintain an adequate fluid flow path
2. Applicable to ASME Code Class 1 piping. When the simplified requirements of ASME Section III, NB-3640 and NB-3650 are not satisfied, the more detailed methods of NB-3200 may be used to calculate stress. The allowables listed above shall be met.
3. Applicable to ASME Code Class 2 and 3 piping
4. Applicable to ASME Code Class 1, 2 and 3 piping when the following limitations are met:
   - 4.1 Dynamic loads are reversing (slug-flow water hammer loads are non-reversing)
   - 4.2 Slug-flow water-hammer loads are combined with other design basis loads (for example: SSE; pipe break loads)
   - 4.3 Steady-state bending stress from deadweight loads does not exceed:

$$\frac{B2 * M}{Z} \leq 0.25\, S_Y$$

   - 4.4 When elastic response spectrum analysis is used, dynamic moments are calculated using 15% peak broadening and not more than 5% damping
5. For Class 1 piping, when slug-flow water hammer loads are only combined with pressure, weight and other sustained mechanical loads, the Equation 9 stress does not exceed the smaller of 1.8 S_y and 2.25 S_m.
6. For Class 2 and 3 piping, when slug-flow water hammer loads are only combined with pressure, weight and other sustained mechanical loads, the Equation 9 stress does not exceed the smaller of 1.8 S_y and 2.25 S_h.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3.9-12 (Sheet 1 of 7)
List of ASME Class 1, 2, and 3 Active Valves

Valve No.	Description	Function[a]
Compressed and Instrument Air System		
CAS-PL-V014	Instrument Air Supply Outside Containment Isolation	2
CAS-PL-V015	Instrument Air Supply Inside Containment Isolation Check Valve	2
CAS-PL-V205	Service Air Supply Inside Containment Isolation Check Valve	2
Component Cooling Water System		
CCS-PL-V200	Containment Isolation Valve – Inlet Line Isolation	2, 3
CCS-PL-V201	Containment Isolation Valve – Inlet Line Check Valve	2, 3
CCS-PL-V207	Containment Isolation Valve – Outlet Line Isolation	2, 3
CCS-PL-V208	Containment Isolation Valve – Outlet Line Isolation	2, 3
CCS-PL-V220	Containment Isolation Thermal Relief Valve	2
CCS-PL-V270	CCS IRC Relief Valve	3
CCS-PL-V271	CCS IRC Relief Valve	3
Chemical and Volume Control System		
CVS-PL-V001	Reactor Coolant System Purification Stop	1
CVS-PL-V002	Reactor Coolant System Purification Stop	1
CVS-PL-V003	Reactor Coolant System Purification Stop	1
CVS-PL-V042	Flush Line Containment Isolation Relief	2
CVS-PL-V045	Letdown Containment Isolation IRC	2
CVS-PL-V047	Letdown Containment Isolation ORC	2
CVS-PL-V058	Letdown Line Containment Isolation Thermal Relief	2
CVS-PL-V067	Makeup Return Line Bypass Check Valve	1
CVS-PL-V080	Reactor Coolant System Purification Return Line Check Valve	1
CVS-PL-V081	Reactor Coolant System Purification Return Line Stop Valve	1
CVS-PL-V082	Reactor Coolant System Purification Return Line Check Valve	1
CVS-PL-V084	Auxiliary Pressurizer Spray Line Isolation	1
CVS-PL-V085	Auxiliary Pressurizer Spray Line Check Valve	1
CVS-PL-V090	Makeup Line Containment Isolation	2
CVS-PL-V091	Makeup Line Containment Isolation	2
CVS-PL-V092	Zinc Injection Containment Isolation Valve ORC	2
CVS-PL-V094	Zinc Injection Containment Isolation Valve IRC	2
CVS-PL-V098	Zinc Addition Line Containment Isolation Thermal Relief Valve	2
CVS-PL-V100	Makeup Line Containment Isolation Thermal Relief Check Valve	2
CVS-PL-V136A	Demineralized Water System Isolation	3
CVS-PL-V136B	Demineralized Water System Isolation	3
CVS-PL-V217	Hydrogen Injection Containment Isolation Check Valve IRC	2
CVS-PL-V219	Hydrogen Injection Containment Isolation Valve ORC	2
Demineralized Water System		
DWS-PL-V241	DWS Containment Penetration Thermal Relief Valve	3
DWS-PL-V245	Demineralized Water Supply Inside Containment Isolation Check Valve	2
Fuel Handing System		
FHS-PL-V001	Fuel Transfer Tube Isolation Valve	3

Table 3.9-12 (Sheet 2 of 7)
List of ASME Class 1, 2, and 3 Active Valves

Valve No.	Description	Function[a]
Fire Protection System		
FPS-PL-V052	Fire Water Supply Inside Containment Isolation Check Valve	2
FPS-PL-V702	FPS Containment Penetration Thermal Relief Valve	3
Passive Containment Cooling System		
PCS-PL-V001A	Passive Containment Cooling Water Storage Tank Isolation	3,4
PCS-PL-V001B	Passive Containment Cooling Water Storage Tank Isolation	3,4
PCS-PL-V001C	Passive Containment Cooling Water Storage Tank Isolation	3,4
PCS-PL-V002A	Passive Containment Cooling Water Storage Tank Series Isolation	3,4
PCS-PL-V002B	Passive Containment Cooling Water Storage Tank Series Isolation	3,4
PCS-PL-V002C	Passive Containment Cooling Water Storage Tank Series Isolation	3,4
PCS-PL-V005	Passive Containment Cooling Water Storage Tank Supply to Fire Protection System Isolation Valve	3,4
PCS-PL-V009	Spent Fuel Pool Emergency Makeup Isolation	3
PCS-PL-V015	Water Bucket Makeup Line Drain Valve	3,4
PCS-PL-V020	Water Bucket Makeup Line Isolation Valve	3,4
PCS-PL-V023	PCS Recirculation Return Isolation Valve	3,4
PCS-PL-V039	PCCWST Long-Term Makeup Check Valve	3,4
PCS-PL-V042	PCCWST Long Term Makeup Isolation Drain Valve	3,4
PCS-PL-V044	PCCWST Long Term Makeup Isolation Valve	3,4
PCS-PL-V045	Emergency Makeup to the Spent Fuel Pool Isolation Valve	3
PCS-PL-V046	PCCWST Recirculation Return Isolation Valve	3,4
PCS-PL-V049	Emergency Makeup to the Spent Fuel Pool Drain Isolation Valve	3
PCS-PL-V050	Spent Fuel Pool Long Term Makeup Isolation Valve	3
PCS-PL-V051	Spent Fuel Pool Emergency Makeup Lower Isolation Valve	3
Primary Sampling System		
PSS-PL-V008	Containment Isolation – Containment Air Sample Isolation	2
PSS-PL-V010A	Containment Isolation – Liquid Sample Line	2
PSS-PL-V010B	Containment Isolation – Liquid Sample Line	2
PSS-PL-V011A	Containment Isolation – Liquid Sample Line	2
PSS-PL-V011B	Containment Isolation – Liquid Sample Line	2
PSS-PL-V023	Containment Isolation – Sample Return Line	2
PSS-PL-V024	Containment Isolation – Sample Return Line	2
PSS-PL-V046	Containment Isolation – Air Sample Line	2
Potable Water System		
PWS-PL-V418	PWS MCR Isolation Valve	3
PWS-PL-V420	PWS MCR Isolation Valve	3
PWS-PL-V498	PWS MCR Vacuum Relief	3
Passive Core Cooling System		
PXS-PL-V014A	Core Makeup Tank A Discharge Isolation	3,4
PXS-PL-V014B	Core Makeup Tank B Discharge Isolation	3,4

Table 3.9-12 (Sheet 3 of 7)
List of ASME Class 1, 2, and 3 Active Valves

Valve No.	Description	Function[a]
Passive Core Cooling System (Cont.)		
PXS-PL-V015A	Core Makeup Tank A Discharge Isolation	3,4
PXS-PL-V015B	Core Makeup Tank B Discharge Isolation	3,4
PXS-PL-V016A	Core Makeup Tank A Discharge Check	3,4
PXS-PL-V016B	Core Makeup Tank Discharge Check	3,4
PXS-PL-V017A	Core Makeup Tank A Discharge Check	3,4
PXS-PL-V017B	Core Makeup Tank B Discharge Check	3,4
PXS-PL-V022A	Accumulator A Pressure Relief	3
PXS-PL-V022B	Accumulator B Pressure Relief	3
PXS-PL-V028A	Accumulator A Discharge Check	1,3,4
PXS-PL-V028B	Accumulator B Discharge Check	1,3,4
PXS-PL-V029A	Accumulator A Discharge Check	1,3,4
PXS-PL-V029B	Accumulator B Discharge Check	1,3,4
PXS-PL-V042	Nitrogen Supply Containment Isolation ORC Isolation Valve	2
PXS-PL-V043	Nitrogen Supply Containment Isolation IRC Check Valve	2
PXS-PL-V108A	Passive Residual Heat Removal Heat Exchanger Control	3,4
PXS-PL-V108B	Passive Residual Heat Removal Heat Exchanger Control	3,4
PXS-PL-V118A	Recirculation Sump A Isolation	3,4
PXS-PL-V118B	Recirculation Sump B Isolation	3,4
PXS-PL-V119A	Recirculation Sump A Check	3,4
PXS-PL-V119B	Recirculation Sump B Check	3,4
PXS-PL-V120A	Recirculation Sump A Isolation	3,4
PXS-PL-V120B	Recirculation Sump B Isolation	3,4
PXS-PL-V122A	In-Containment Refueling Water Storage Tank Injection A Check	1,3,4
PXS-PL-V122B	In-Containment Refueling Water Storage Tank Injection B Check	1,3,4
PXS-PL-V123A	In-Containment Refueling Water Storage Tank Injection A Isolation	1,3,4
PXS-PL-V123B	In-Containment Refueling Water Storage Tank Injection B Isolation	1,3,4
PXS-PL-V124A	In-Containment Refueling Water Storage Tank Injection A Check	1,3,4
PXS-PL-V124B	In-Containment Refueling Water Storage Tank Injection B Check	1,3,4
PXS-PL-V125A	In-Containment Refueling Water Storage Tank Injection A Isolation	1,3,4
PXS-PL-V125B	In-Containment Refueling Water Storage Tank Injection B Isolation	1,3,4
PXS-PL-V130A	In-Containment Refueling Water Storage Tank Gutter Isolation	3,4
PXS-PL-V130B	In-Containment Refueling Water Storage Tank Gutter Isolation	3,4
Reactor Coolant System		
RCS-PL-V001A	First Stage Automatic Depressurization System	1,3,4
RCS-PL-V001B	First Stage Automatic Depressurization System	1,3,4
RCS-PL-V002A	Second Stage Automatic Depressurization System	1,3,4
RCS-PL-V002B	Second Stage Automatic Depressurization System	1,3,4

Table 3.9-12 (Sheet 4 of 7)
List of ASME Class 1, 2, and 3 Active Valves

Valve No.	Description	Function[a]
Reactor Coolant System (Cont.)		
RCS-PL-V003A	Third Stage Automatic Depressurization System	1,3,4
RCS-PL-V003B	Third Stage Automatic Depressurization System	1,3,4
RCS-PL-V004A	Fourth Stage Automatic Depressurization System	1,3,4
RCS-PL-V004B	Fourth Stage Automatic Depressurization System	1,3,4
RCS-PL-V004C	Fourth Stage Automatic Depressurization System	1,3,4
RCS-PL-V004D	Fourth Stage Automatic Depressurization System	1,3,4
RCS-PL-V005A	Pressurizer Safety Valve	1,3
RCS-PL-V005B	Pressurizer Safety Valve	1,3
RCS-PL-V010A	Automatic Depressurization System Discharge Header A Vacuum Relief	3
RCS-PL-V010B	Automatic Depressurization System Discharge Header B Vacuum Relief	3
RCS-PL-V011A	First Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V011B	First Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V012A	Second Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V012B	Second Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V013A	Third Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V013B	Third Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V150A	Reactor Vessel Head Vent	1,3
RCS-PL-V150B	Reactor Vessel Head Vent	1,3
RCS-PL-V150C	Reactor Vessel Head Vent	1,3
RCS-PL-V150D	Reactor Vessel Head Vent	1,3
Normal Residual Heat Removal System		
RNS-PL-V001A	Reactor Coolant System Inner HL Suction Isolation	1
RNS-PL-V001B	Reactor Coolant System Inner HL Suction Isolation	1
RNS-PL-V002A	Reactor Coolant System Outer HL Suction Isolation	1,2
RNS-PL-V002B	Reactor Coolant System Outer HL Suction Isolation	1,2
RNS-PL-V003A	Reactor Coolant System Pressure Boundary Valve Thermal Relief Check Valve	1
RNS-PL-V003B	Reactor Coolant System Pressure Boundary Valve Thermal Relief Check Valve	1
RNS-PL-V011	RNS Discharge Containment Isolation Valve	2, 4
RNS-PL-V012	RNS Discharge Containment Isolation Test Connection Valve	2, 4
RNS-PL-V013	RNS Discharge Containment Isolation Check Valve	2, 4
RNS-PL-V015A	RNS Discharge Reactor Coolant System Pressure Boundary	1, 4
RNS-PL-V015B	RNS Discharge Reactor Coolant System Pressure Boundary	1, 4
RNS-PL-V017A	RNS Discharge Reactor Coolant System Pressure Boundary	1, 4
RNS-PL-V017B	RNS Discharge Reactor Coolant System Pressure Boundary	1, 4
RNS-PL-V020	RNS HL Suction Pressure Relief	2
RNS-PL-V021	RNS HL Suction Pressure Relief	2

Table 3.9-12 (Sheet 5 of 7)
List of ASME Class 1, 2, and 3 Active Valves

Valve No.	Description	Function[a]
Normal Residual Heat Removal System (Cont.)		
RNS-PL-V022	RNS Suction Header Containment Isolation	2
RNS-PL-V023	RNS Suction from In-Containment Refueling Water Storage Tank Isolation	2
RNS-PL-V061	RNS – Chemical and Volume Control System Containment Isolation	2
Sanitary Drainage System		
SDS-PL-V001	SDS MCR Vent Isolation Valve	3
SDS-PL-V002	SDS MCR Vent Isolation Valve	3
Spent Fuel Pool Cooling System		
SFS-PL-V034	Spent Fuel Pool Cooling System Suction Line Containment Isolation	2
SFS-PL-V035	Spent Fuel Pool Cooling System Suction Line Containment Isolation	2
SFS-PL-V037	Spent Fuel Pool Cooling System Discharge Line Containment Isolation	2
SFS-PL-V038	Spent Fuel Pool Cooling System Discharge Line Containment Isolation	2
SFS-PL-V042	Cask Loading Pit to SFS Pump Suction Isolation Valve	3
SFS-PL-V045	SFS Pump Discharge Line to Cask Loading Pit Isolation Valve	3
SFS-PL-V049	Cask Loading Pit to WLS Isolation Valve	3
SFS-PL-V066	Spent Fuel Pool to Cask Washdown Pit Isolation	3
SFS-PL-V067	Containment Isolation Thermal Relief Valve	2
SFS-PL-V068	Cask Washdown Pit Drain Isolation	3
SFS-PL-V071	Refueling Cavity to Steam Generator Compartment	3
SFS-PL-V072	Refueling Cavity to Steam Generator Compartment	3
Steam Generator System		
SGS-PL-V027A	Power Operated Relief Valve Block Valve Steam Generator 01	2,3,4
SGS-PL-V027B	Power Operated Relief Valve Block Valve Steam Generator 02	2,3,4
SGS-PL-V030A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V030B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V031A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V031B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V032A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V032B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V033A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V033B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V034A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V034B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V035A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V035B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V036A	Steam Line Condensate Drain Isolation	2,3,4
SGS-PL-V036B	Steam Line Condensate Drain Isolation	2,3,4

Table 3.9-12 (Sheet 6 of 7)
List of ASME Class 1, 2, and 3 Active Valves

Valve No.	Description	Function[a]
Steam Generator System (Cont.)		
SGS-PL-V040A	Main Steam Line Isolation	2,3,4
SGS-PL-V040B	Main Steam Line Isolation	2,3,4
SGS-PL-V057A	Main Feedwater Isolation	2,3,4
SGS-PL-V057B	Main Feedwater Isolation	2,3,4
SGS-PL-V067A	Startup Feedwater Isolation	2,3,4
SGS-PL-V067B	Startup Feedwater Isolation	2,3,4
SGS-PL-V074A	Steam Generator Blowdown Isolation	2,3,4
SGS-PL-V074B	Steam Generator Blowdown Isolation	2,3,4
SGS-PL-V075A	Steam Generator Series Blowdown Isolation	3,4
SGS-PL-V075B	Steam Generator Series Blowdown Isolation	3,4
SGS-PL-V086A	Steam Line Condensate Drain Control	3,4
SGS-PL-V086B	Steam Line Condensate Drain Control	3,4
SGS-PL-V233A	Power Operated Relief Valve	3,4
SGS-PL-V233B	Power Operated Relief Valve	3,4
SGS-PL-V240A	Main Steam Isolation Valve Bypass Isolation	2,3,4
SGS-PL-V240B	Main Steam Isolation Valve Bypass Isolation	2,3,4
SGS-PL-V250A	Main Feedwater Control	3,4
SGS-PL-V250B	Main Feedwater Control	3,4
SGS-PL-V255A	Startup Feedwater Control	3,4
SGS-PL-V255B	Startup Feedwater Control	3,4
SGS-PL-V257A	Main Feedwater Thermal Relief Valve	3,4
SGS-PL-V257B	Main Feedwater Thermal Relief Valve	3,4
SGS-PL-V258A	Startup Feedwater Thermal Relief Valve	3,4
SGS-PL-V258B	Startup Feedwater Thermal Relief Valve	3,4
Nuclear Island Nonradioactive Ventilation System		
VBS-PL-V186	MCR Supply Air Isolation Valve	3
VBS-PL-V187	MCR Supply Air Isolation Valve	3
VBS-PL-V188	MCR Return Air Isolation Valve	3
VBS-PL-V189	MCR Return Air Isolation Valve	3
VBS-PL-V190	MCR Exhaust Air Isolation Valve	3
VBS-PL-V191	MCR Exhaust Air Isolation Valve	3
Main Control Room Habitability System		
VES-PL-V001	Air Delivery Alternate Isolation Valve	3
VES-PL-V002A	Pressure Regulating Valve A	3
VES-PL-V002B	Pressure Regulating Valve B	3
VES-PL-V005A	Air Delivery Isolation Valve A	3
VES-PL-V005B	Air Delivery Isolation Valve B	3
VES-PL-V018	Temporary Instrument Isolation Valve A	3
VES-PL-V019	Temporary Instrument Isolation Valve B	3
VES-PL-V022A	Pressure Relief Isolation Valve A	3
VES-PL-V022B	Pressure Relief Isolation Valve B	3
VES-PL-V040A	Air Tank Safety Relief Valve A	3
VES-PL-V040B	Air Tank Safety Relief Valve B	3

Table 3.9-12 (Sheet 7 of 7)
List of ASME Class 1, 2, and 3 Active Valves

Valve No.	Description	Function[a]
Main Control Room Habitability System (Cont.)		
VES-PL-V040C	Air Tank Safety Relief Valve C	3
VES-PL-V040D	Air Tank Safety Relief Valve D	3
VES-PL-V044	Main Air Flow Path Isolation Valve	3
VES-PL-V045	Eductor Flow Path Isolation Valve	3
VES-PL-V046	Eductor Bypass Isolation Valve	3
Containment Air Filtration System		
VFS-PL-V003	Containment Purge Inlet Containment Isolation Valve	2
VFS-PL-V004	Containment Purge Inlet Containment Isolation Valve	2
VFS-PL-V009	Containment Purge Discharge Containment Isolation Valve	2
VFS-PL-V010	Containment Purge Discharge Containment Isolation Valve	2
VFS-PL-V800A	Vacuum Relief Containment Isolation A ORC	2
VFS-PL-V800B	Vacuum Relief Containment Isolation B ORC	2
VFS-PL-V803A	Vacuum Relief Containment Isolation Check Valve A IRC	2
VFS-PL-V803B	Vacuum Relief Containment Isolation Check Valve B IRC	2
Central Chilled Water System		
VWS-PL-V053	VWS Containment Penetration Thermal Relief Valve	3
VWS-PL-V057	VWS Containment Penetration Thermal Relief Valve	3
VWS-PL-V058	Fan Coolers Supply Containment Isolation	2
VWS-PL-V062	Fan Coolers Supply Containment Isolation Check Valve	2
VWS-PL-V080	Containment Isolation Thermal Relief Valve	2
VWS-PL-V082	Fan Coolers Return Containment Isolation	2
VWS-PL-V086	Fan Coolers Return Containment Isolation	2
Liquid Radwaste System		
WLS-PL-V055	Sump Containment Isolation IRC	2
WLS-PL-V057	Sump Containment Isolation ORC	2
WLS-PL-V058	Containment Isolation Relief Valve	2
WLS-PL-V067	Reactor Coolant Drain Tank Gas Containment Isolation IRC	2
WLS-PL-V068	Reactor Coolant Drain Tank Gas Containment Isolation ORC	2
WLS-PL-V071A	Chemical and Volume Control System Compartment to Sump	3
WLS-PL-V071B	Passive Core Cooling System A Compartment to Sump	3
WLS-PL-V071C	Passive Core Cooling System B Compartment to Sump	3
WLS-PL-V072A	Chemical and Volume Control System Compartment to Sump	3
WLS-PL-V072B	Passive Core Cooling System A Compartment to Sump	3
WLS-PL-V072C	Passive Core Cooling System B Compartment to Sump	3

Note:

a. Function: 1 – Reactor coolant system pressure boundary
2 – Containment isolation
3 – Accident mitigation
4 – Safe shutdown

Table 3.9-13
Control Rod Drive Mechanism Production Tests

Test	Acceptance Standard
Cold (ambient) hydrostatic	ASME Code, Section III
Confirm step length and load transfer (stationary gripper to movable gripper or movable gripper to stationary gripper)	Step length: 0.625 ± 0.015 inch axial movement Load transfer: 0.055 inch nominal axial movement
Performance test at design load - Cycled under ambient water temperature conditions for approximately one full drive rod travel excursion. Cycled under hot test conditions for approximately 5,000 steps.	Operating speed: 45 inches/minute Trip delay: Free fall of drive rod to begin within 150 milliseconds

Table 3.9-14
Maximum Deflections Allowed for Reactor Internal Support Structures

Component	Allowable Deflections (in.)
Upper Core Barrel	
Radial inward (uniform)	4.1
Radial outward (uniform)(1)	1.0
Upper package – relative vertical motion between upper core plate and upper support plate	0.20
Rod cluster guide tubes – radial toward the reactor vessel outlet	1.00

Note:
1. Non-uniform radial outward deflections are limited such that > 90-percent of the annulus area is maintained.

Table 3.9-15
Computer Programs for Seismic Category 1 Components

Program	Application
ABAQUS	Finite element structural analysis
ANSYS	Finite element structural analysis
FATCON	ASME fatigue analysis of piping components
GAPPIPE	Static and dynamic analysis of piping systems
MAXTRAN	Transient stress evaluation of piping components
WESTEMS	ASME Class 1 fatigue analysis of piping and components
PIPESTRESS	Static and dynamic analysis of piping systems
PIPSAN	Structural and ASME stress analysis of piping and component supports
GTSTRUDL	Structural and ASME stress analysis of piping and component supports and structural frames
STAAD-III	Static and dynamic analysis of structural frames
THERST	Transient heat transfer analysis of piping components
WECAN	Finite element structural analysis
WEGAP	Dynamic structural response of the reactor core
WECEVAL	ASME stress evaluation of mechanical components
ITCH	Transient hydraulic analysis
FORFUN	Computes unbalanced hydraulic forces between piping elbows
RELAP5	Transient dynamic analysis
THRUST	Computes time-history hydraulic forcing functions
MULTIFLEX	Thermal-hydraulic-structural system analysis
GEC2	Computes time-history hydraulic forcing functions
FATSTR	ASME stress evaluation of piping components
HSTA	Hydraulic system transient analysis
E0781	Axisymmetric containment shell analysis
FLOW 3D	Finite element fluid flow and heat transfer

Table 3.9-16
Valve Inservice Test Requirements

See Inservice Testing Program Plan[(1)]

Notes:

1. Inservice Testing Program is controlled by 10 CFR 50.55a and is not incorporated by reference.

Table 3.9-17
System Level Operability Test Requirements

System/Feature	Test Purpose	Test Method	Tech Spec[a]
PCS			
PCCWST drain lines	Flow capability and water coverage	Note 1	SR 3.6.6.6
PXS			
Accumulator injection lines	Flow capability	Note 2	SR 3.5.1.6
CMT injection lines	Flow capability	Note 3	SR 3.5.2.7
PRHR HX	Heat transfer capability	Note 4	SR 3.5.4.9
IRWST injection lines	Flow capability	Note 5	SR 3.5.6.11
Containment recirculation lines	Flow capability	Note 6	SR 3.5.6.11

Alpha Note:

a. Refer to the Technical Specification surveillance identified in this column for the test frequency.

Notes:

1. The flow capability of each PCS water drain line is demonstrated by conducting a test where water is drained from the PCS water storage tank onto the containment shell by opening two of the three parallel isolation valves. During this flow test the water coverage is also demonstrated. The test is terminated when the flow measurement is obtained and the water coverage is observed. The test demonstrates that the PCS delivers water from the PCCWST to the outside, top of the containment vessel, such that a) the minimum allowable flowrate is 469.1 gpm with the passive containment cooling water storage tank level 27.5 feet (nominal) above the tank floor, or b) a report exists and concludes that the as-measured flow rates delivered by the PCCWST to the containment vessel provide sufficient heat removal capability such that the limiting containment pressure and temperature values are not affected and the PCS is able to perform its safety function to remove heat from containment to maintain plant safety (see item 7.a)(i) of ITAAC Table 2.2.2-3). The test may be run with a higher water level and the test results adjusted for the increased level. Water coverage is demonstrated by visual inspection that there is unobstructed flow from the lower weirs. In addition, air baffle panels may be removed at the containment vessel spring line, if needed, to permit visual inspection of the water coverage and the vessel coating. The water coverage observed at four locations, approximately 90 degrees apart, will be compared against the coverage measured at the same locations during pre-operational testing (see item 7.b)(i) of ITAAC Table 2.2.2-3).
2. The flow capability of each accumulator is demonstrated by conducting a test during cold shutdown conditions. The initial conditions of the test include reduced accumulator pressure. Flow from the accumulator to the RCS is initiated by opening the accumulator isolation valve. Sufficient flow is provided to fully open the check valves. The test is terminated when the flow measurement is obtained. The allowable calculated flow resistance between each accumulator and the reactor vessel is $\geq 1.47 \times 10^{-5}$ ft/gpm^2 and $\leq 1.83 \times 10^{-5}$ ft/gpm^2.
3. The flow capability of each CMT is demonstrated by conducting a test during cold shutdown conditions. The initial conditions of the test include the RCS loops drained to a level below the top of the RCS hot leg. Flow from the CMT to the RCS is initiated by opening both CMT discharge isolation valves. The test is terminated when the flow measurement is obtained. The allowable calculated flow resistance between each CMT and the reactor vessel is $\geq 1.81 \times 10^{-5}$ ft/gpm^2 and $\leq 2.25 \times 10^{-5}$ ft/gpm^2.
4. The heat transfer capability of the passive residual heat exchanger is demonstrated by conducting a test during shutdown conditions. The test is conducted with the RCPs in operation and the RCS at a reduced temperature. Due to the low RCS temperature, RCP limitations require the test to be run at 50-percent RCP speed. Flow through the heat exchanger is initiated by opening one outlet isolation valve. The test is terminated when the flow and temperature measurements are obtained. The allowable calculated heat transfer is $\geq$ 8.46E7-Btu/hr (50-percent pump speed) with an inlet temperature of 250°F and an initial IRWST temperature of 80°F and the design basis number of tubes plugged. The heat transfer rate measured in the test should be adjusted to account for differences in the hot leg and IRWST temperatures and the number of tubes plugged.
5. The flow capability of each IRWST injection line is demonstrated by conducting flow tests and inspections. A flow test is conducted to demonstrate the flow capability of the injection line from the IRWST through the IRWST injection check valves. Water flow from the IRWST through the IRWST injection check valve demonstrates the flow capability of this portion of the line. Sufficient flow is provided to open the check valves. The test is terminated when the flow measurement is obtained. The allowable calculated flow resistance from the IRWST through each direct vessel injection flow path to the reactor vessel is: Line A: $\geq 5.35 \times 10^{-6}$ ft/gpm^2 and $\leq 9.09 \times 10^{-6}$ ft/gpm^2 and Line B: $\geq 6.15 \times 10^{-6}$ ft/gpm^2 and $\leq 1.05 \times 10^{-5}$ ft/gpm^2. The flow capability of the portion of the line from the IRWST check valves to the DVI line is demonstrated by conducting an inspection of the inside of the line. The inspection shows that the lines are not obstructed. It is not necessary to operate the IRWST injection squib valves for this inspection.
6. The flow capability of each containment recirculation line is demonstrated by conducting an inspection. The line from the containment to the containment recirculation squib valve is inspected from the containment side. The line from the squib valve to the IRWST injection line is inspected from the IRWST side. The inspection shows that the lines are not obstructed. It is not necessary to operate the containment recirculation squib valves for this inspection.

Table 3.9-18
AP1000 Pressure Isolation Valves

Valve Number	Description
PXS-V028A PXS-V028B PXS-V029A PXS-V029B	Accumulator Discharge Check Valves
RNS-V001A RNS-V001B RNS-V002A RNS-V002B	RNS Hot Leg Suction Isolation Valves
RNS-V015A RNS-V015B RNS-V017A RNS-V017B	RNS Discharge RCS Pressure Boundary

Table 3.9-19 (Sheet 1 of 2)
Critical Piping Design Methods and Criteria (Piping Design Criteria)

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

Table 3.9-19 (Sheet 2 of 2)
Critical Piping Design Methods and Criteria (Piping Design Criteria)

Commitment	Tier 2 Reference (Section or Table)
Design Transients Use of NRC Bulletins 88-08 and 88-11	3.9.1.1
Loads for Class 1 Components and Core/Component Supports	3.9.3.1.2
Use of Square-Root-Sum-of-the-Squares Method for SSE plus Pipe Rupture	3.9.3.1.3
Analysis of Reactor Coolant Loop Piping	3.9.3.1.4
ASME Classes 1, 2, and 3 Piping Use of ASME Code, Section III	3.9.3.1.5
Design of Spring-Loaded Safety Valves	3.9.3.3.1
Design and Analysis Requirement for Open and Closed Discharge Systems	3.9.3.3.3
Component and Piping Supports for Dynamic Loading	3.9.3.4
Class 2 and Class 3 Component Supports Use of ASME Section III	3.9.3.4.2
Piping System Seismic Stress Analysis	3.9.3.4.3
Design Report for ASME Classes 1, 2, and 3 Piping	3.9.8.2
Hard Rock High Frequency (HRHF) Seismic Response Effect on Piping Systems	Appendix 3I.6.3
Integrity of Nonsafety-Related CVS Piping Inside Containment Compliance with 10 CFR 50.55a and ASME B31.1 Code	5.2.1.1

Table 3.9-20 (Sheet 1 of 2)
Piping Packages Chosen to Demonstrate Piping Design for Piping DAC Closure

(in addition to Class 1 lines larger than 1 inch in diameter)

ASME Class	Inside/Outside Containment (IC/OC)	Line(s) Description	Piping Package Number
2	IC	Hot Leg 2 I&C	APP-RCS-PLR-210
1,3	IC	Reactor Head Vent	APP-RCS-PLR-230
2	IC	Hot Leg 1 I&C	APP-RCS-PLR-260
2	IC	Hot Leg 1 Sampling	APP-RCS-PLR-460
2	IC	Hot Leg 2 Sampling	APP-RCS-PLR-470
2	IC	Pressurizer Sampling	APP-RCS-PLR-480
2	IC	Pressurizer I&C	APP-RCS-PLR-510
2/3	IC	Component Cooling from Penetration C01 IRC	APP-CCS-PLR-040
2/3	IC	Component Cooling from Penetration C02 IRC	APP-CCS-PLR-050
2/3	IC	CVS Makeup from Penetration C03 IRC	APP-CVS-PLR-090
2/3	IC	CVS Letdown from Penetration 002 IRC 2	APP-CVS-PLR-100
2/3	IC	ACC-A/B3 Makeup	APP-PXS-PLR-620
2/3	IC	SFS from Penetration C01	APP-SFS-PLR-600
2/3	IC/OC	Feedwater to SG 01	APP-SGS-PLR-010
2/3	IC/OC	Feedwater to SG 02	APP-SGS-PLR-020
2/3	IC/OC	Main Steam to SG 01	APP-SGS-PLR-030
2/3	IC/OC	Main Steam to SG 02	APP-SGS-PLR-040
2/3	IC	SG01 Blowdown to Penetration C03A	APP-SGS-PLR-070
2/3	IC	SG02 Blowdown to Penetration C03B	APP-SGS-PLR-080
2/3	IC	SG01 Startup Feed Water from Penetration C05A	APP-SGS-PLR-310
2/3	IC	SG02 Startup Feed Water from Penetration C05B	APP-SGS-PLR-320
2/3	IC	VWS Supply from Containment Penetration C02	APP-VWS-PLR-500
2/3	IC	VWS Return to Containment Penetration C01	APP-VWS-PLR-530
2/3	OC	Component Cooling from Penetration C01 ORC	APP-CCS-PLR-810

Table 3.9-20 (Sheet 2 of 2)
Piping Packages Chosen to Demonstrate Piping Design for Piping DAC Closure

(in addition to Class 1 lines larger than 1 inch in diameter)

ASME Class	Inside/Outside Containment (IC/OC)	Line(s) Description	Piping Package Number
2/3	OC	Component Cooling from Penetration C02 ORC	APP-CCS-PLR-820
2/3	OC	CVS Makeup from Penetration C03 ORC	APP-CVS-PLR-530
2/3	OC	PCS Recirculation, DWS Supply, and FPS Supply	APP-PCS-PLR-100
2/3	OC	From Spent Fuel to RNS and PCCWST Drain	APP-RNS-PLR-100
2/3	OC	Normal RHR to Heat Exchangers and Pumps from Containment Penetrations C01 and C02	APP-RNS-PLR-170
2/3	OC	Spent Fuel Cooling Module R3-65	APP-SFS-PLR-350
2/3	OC	SG01 Startup Feedwater to Penetration C05A	APP-SGS-PLR-110
2/3	OC	SG02 Startup Feedwater to Penetration C05B	APP-SGS-PLR-120
2/3	OC	Nonradioactive Vent Return from Main Control Room	APP-VBS-PLR-010
2/3	OC	Nonradioactive Vent Supply to Main Control Room	APP-VBS-PLR-030
2/3	OC	VWS Supply to Containment Penetration C02	APP-VWS-PLR-910
2/3	OC	VWS Return from Containment Penetration C01	APP-VWS-PLR-920

Table 3.9-201
Safety Related Snubbers

System	Snubber (Hanger) No.	Line #
CVS	APP-CVS-PH-11Y0262	L040
CVS	APP-CVS-PH-11Y0268	L038
CVS	APP-CVS-PH-11Y2040	L001
CVS	APP-CVS-PH-11Y2223	L001
CVS	APP-CVS-PH-11Y2224	L001
CVS	APP-CVS-PH-11Y2227	L040
CVS	APP-CVS-PH-11Y2229	L071
CVS	APP-CVS-PH-11Y2265	L056
CVS	APP-CVS-PH-11Y2266	L056
CVS	APP-CVS-PH-11Y7074	L068
PXS	APP-PXS-PH-11Y0020	L127A
PXS	APP-PXS-PH-11Y0578	L113A
PXS	APP-PXS-PH-11Y2052	L114
PXS	APP-PXS-PH-11Y2057	L117A
PXS	APP-PXS-PH-11Y2059	L132A
RCS	APP-RCS-PH-11Y0039	L215
RCS	APP-RCS-PH-11Y0060	L215
RCS	APP-RCS-PH-11Y0067	L005B
RCS	APP-RCS-PH-11Y0081	L112
RCS	APP-RCS-PH-11Y0082	L112
RCS	APP-RCS-PH-11Y0090	L118A
RCS	APP-RCS-PH-11Y0103	L003
RCS	APP-RCS-PH-11Y0112	L032A
RCS	APP-RCS-PH-11Y0388	L133B
RCS	APP-RCS-PH-11Y0391	L137B
RCS	APP-RCS-PH-11Y0528	L005A
RCS	APP-RCS-PH-11Y0810	L011A
RCS	APP-RCS-PH-11Y0811	L010A
RCS	APP-RCS-PH-11Y0813	L010B
RCS	APP-RCS-PH-11Y1127	L110A
RCS	APP-RCS-PH-11Y1130	L212B
RCS	APP-RCS-PH-11Y1132	L215
RCS	APP-RCS-PH-11Y1134	L215
RCS	APP-RCS-PH-11Y1140	L214
RCS	APP-RCS-PH-11Y1141	L215
RCS	APP-RCS-PH-11Y1144	L214
RCS	APP-RCS-PH-11Y2005	L022A
RCS	APP-RCS-PH-11Y2101	L032B
RCS	APP-RCS-PH-11Y2106	L137A
RCS	APP-RCS-PH-11Y2107	L133A
RCS	APP-RCS-PH-11Y2264	L112
RNS	APP-RNS-PH-12Y2060	L006
SGS	APP-SGS-PH-11Y0001	L003B
SGS	APP-SGS-PH-11Y0002	L003B
SGS	APP-SGS-PH-11Y0004	L003B
SGS	APP-SGS-PH-11Y0057	L003A
SGS	APP-SGS-PH-11Y0058	L003A
SGS	APP-SGS-PH-11Y0063	L003A
SGS	APP-SGS-PH-11Y0463	L006A
SGS	APP-SGS-PH-11Y0464	L006A
SGS	APP-SGS-PH-11Y0470	L006B
SGS	APP-SGS-PH-11Y2002	L006A
SGS	APP-SGS-PH-11Y2021	L006A
SGS	APP-SGS-PH-11Y3101	L006B
SGS	APP-SGS-PH-11Y3102	L006B
SGS	APP-SGS-PH-11Y3121	L006B
SGS	APP-SGS-PH-11Y7057	L006B
SGS	APP-SGS-PH-12Y0108	L023B
SGS	APP-SGS-PH-12Y0136	L023A
SGS	APP-SGS-PH-12Y0507	L022B
SGS	APP-SGS-PH-12Y0510	L022A
SGS	APP-SGS-PH-12Y7056	L022A
SGS	APP-SGS-PH-12Y7058	L022B
SGS	SG 1 Snubber A (1A)	(1)
SGS	SG 1 Snubber B (1B)	(1)
SGS	SG 2 Snubber A (2A)	(1)
SGS	SG 2 Snubber B (2B)	(1)

(1) These snubbers are on the upper lateral support assembly of the steam generators.

Figures 3.9-1–3.9-3 Not Used

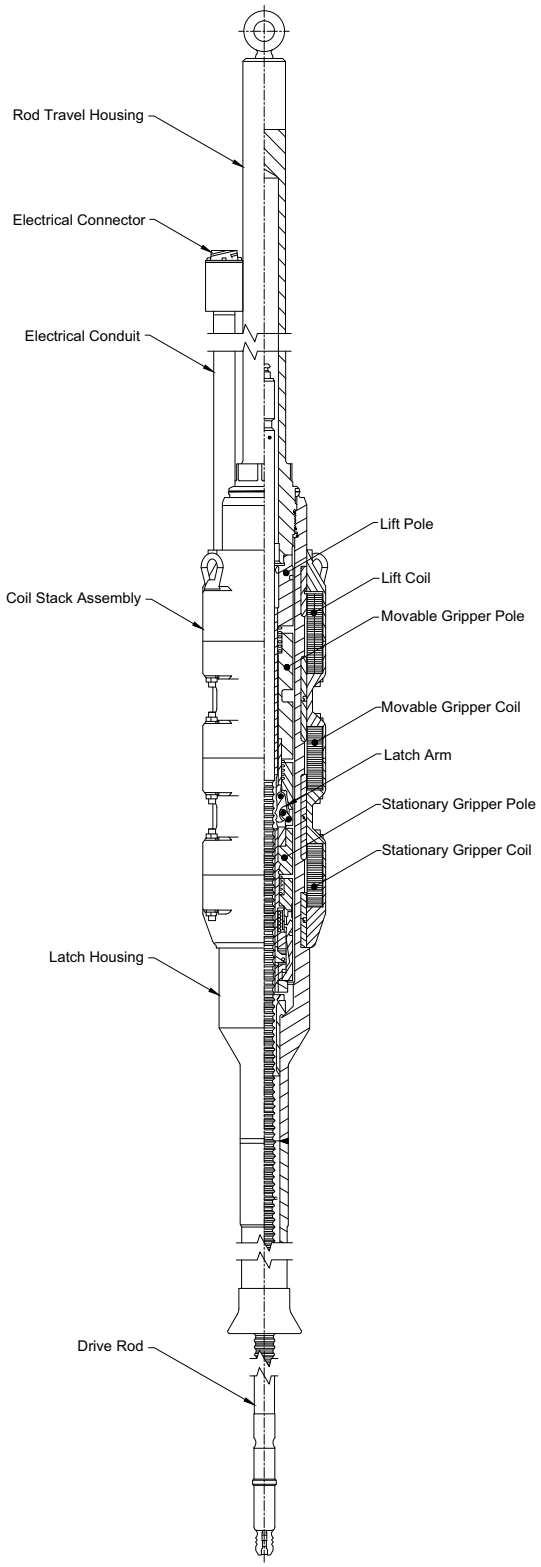

Figure 3.9-4
Control Rod Drive Mechanism

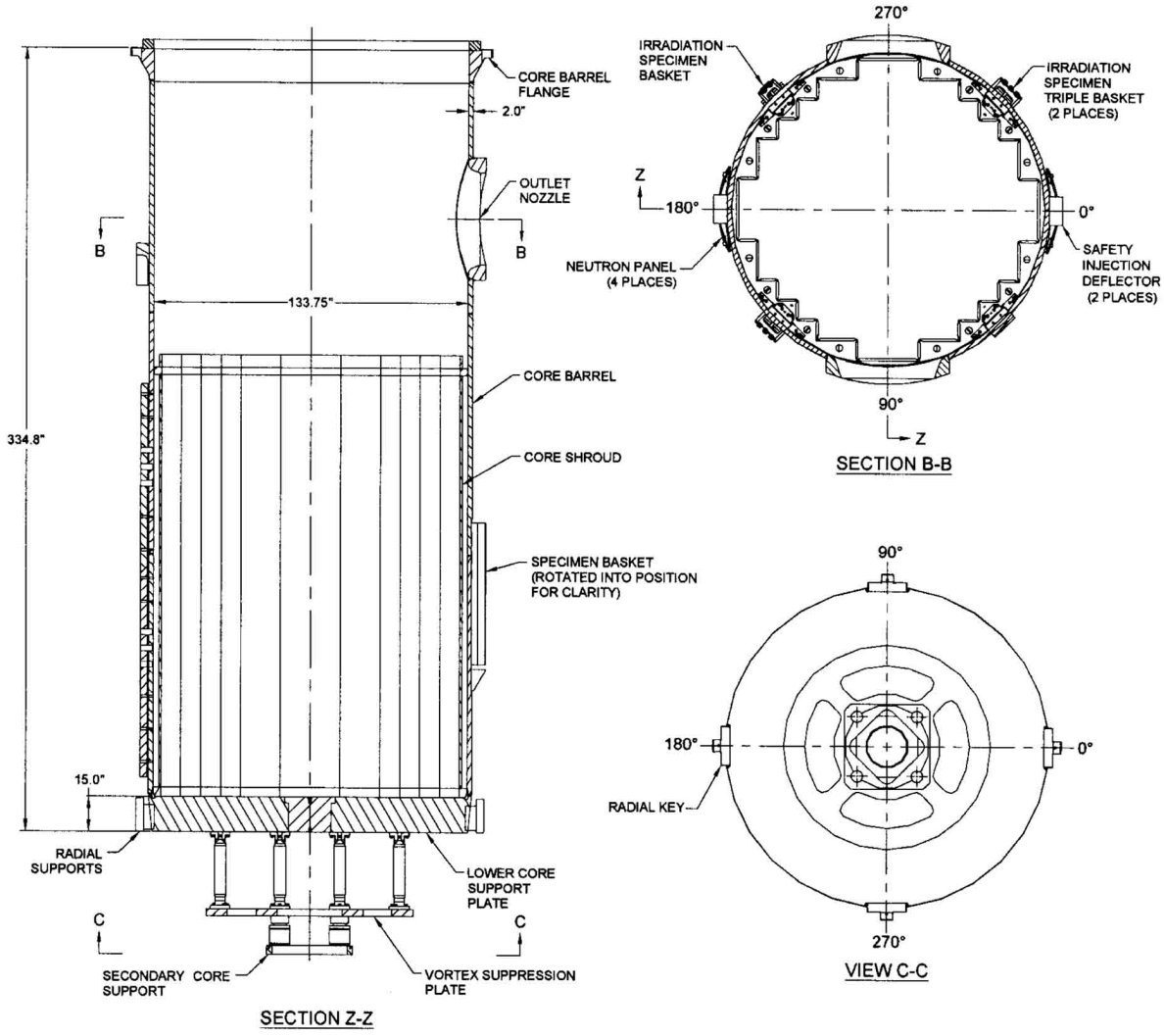

Figure 3.9-5
Lower Reactor Internals

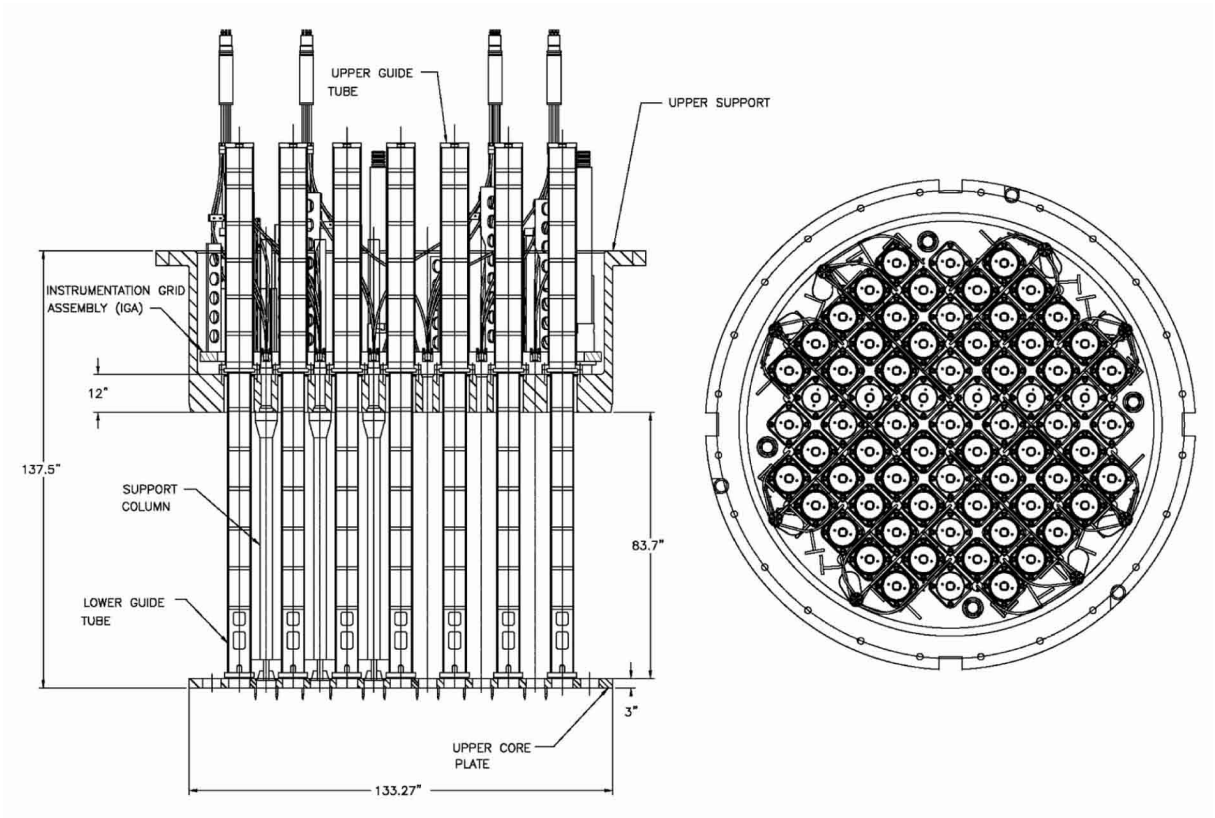

Figure 3.9-6
Upper Core Support Structure

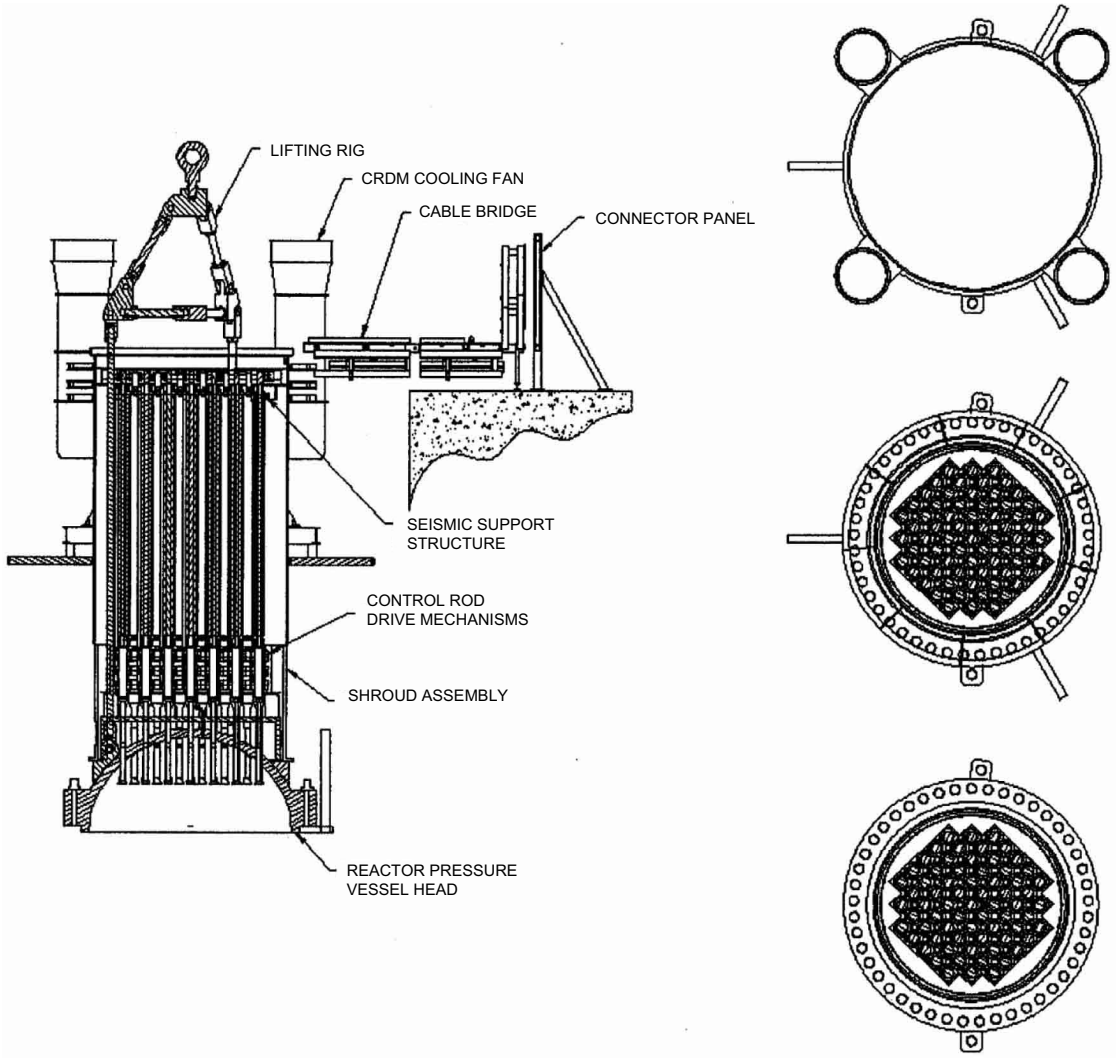

Figure 3.9-7
Integrated Head Package

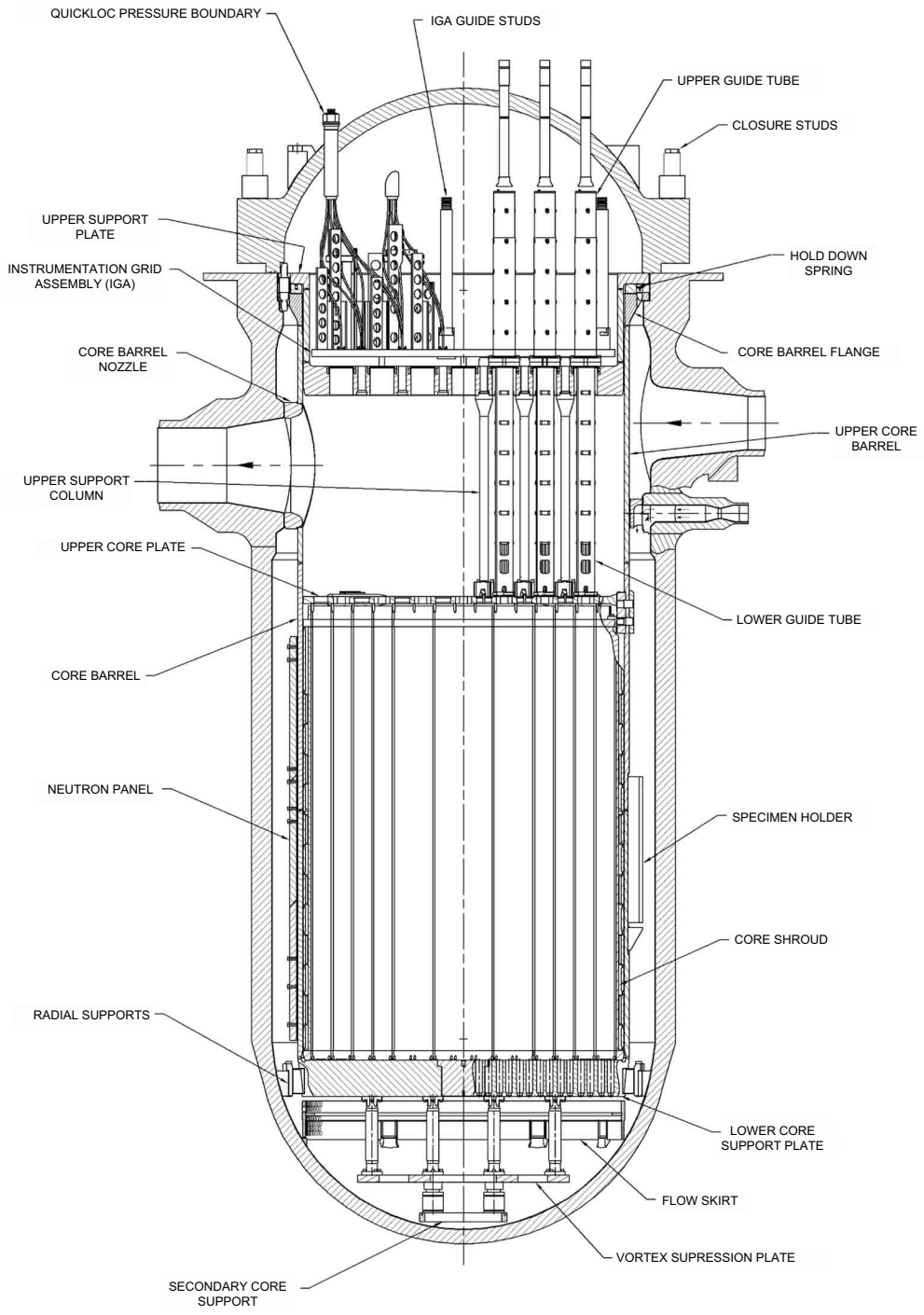

Figure 3.9-8
Reactor Internals Interface Arrangement

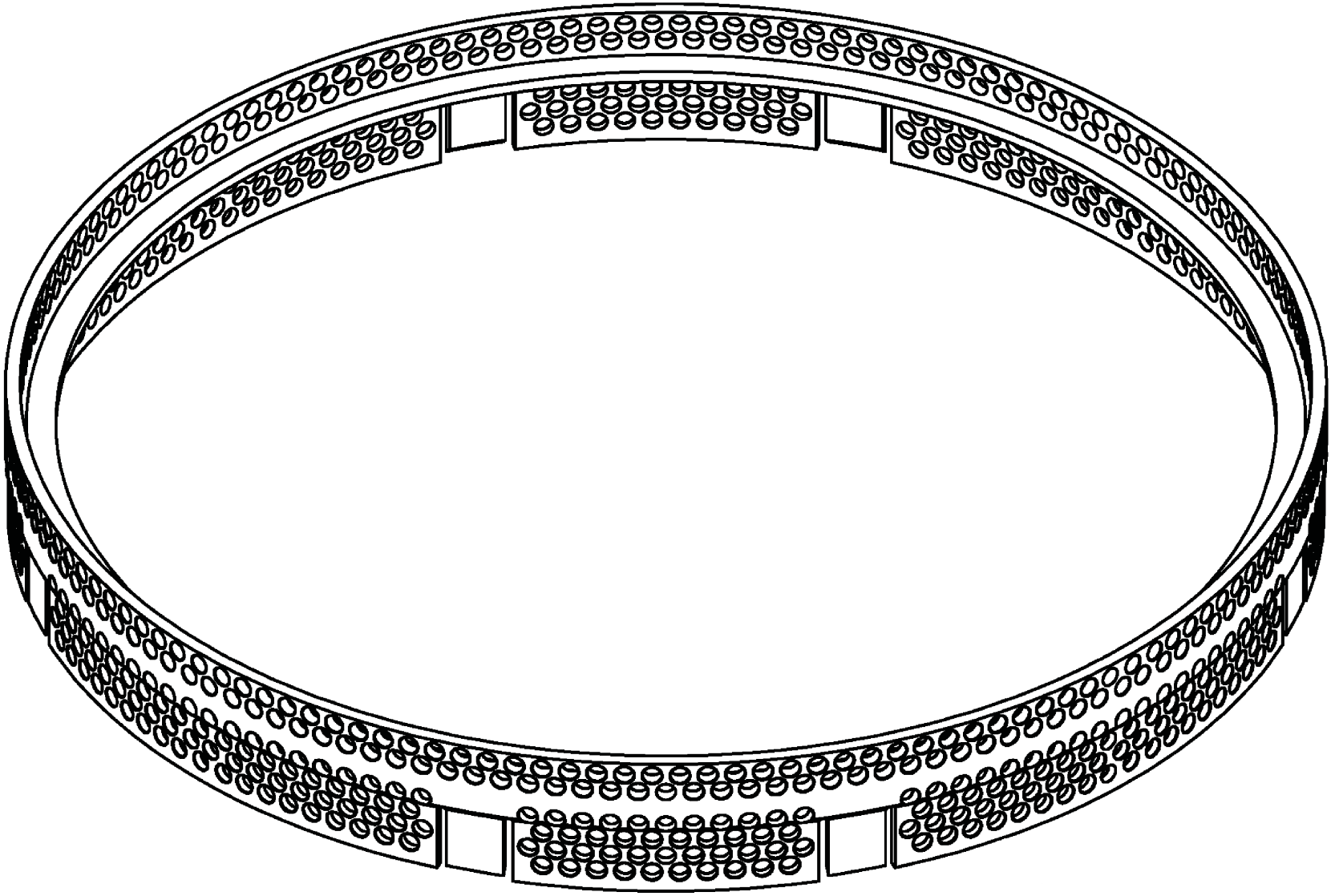

Figure 3.9-9
Flow Skirt Schematic

3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

Safety-related equipment and selected portions of post-accident monitoring equipment are classified as seismic Category I, as discussed in Subsection 3.2.1.1. This section addresses the seismic and dynamic qualification of this equipment other than piping and includes the following types:

- Safety-related instrumentation and electrical equipment and certain monitoring equipment.
- Safety-related active mechanical equipment that performs a mechanical motion while accomplishing a system safety-related function. These devices include the control rod drive mechanisms; HVAC and fluid system valves.
- Safety-related, nonactive mechanical equipment whose mechanical motion is not required while accomplishing a system safety-related function, but whose structural integrity must be maintained in order to fulfill its design safety-related function.

This section presents or references information to demonstrate that mechanical equipment, electrical equipment, instrumentation, and, where applicable, their supports classified as seismic Category I are capable of performing their designated safety-related functions under the full range of normal and accident (including seismic) loadings. This equipment includes devices associated with systems essential to safe shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or are otherwise essential in preventing significant release of radioactive material to the environment or in mitigating the consequences of accidents. The information presented or referenced includes:

- Identification of the seismic Category I instrumentation, electrical equipment, and appropriate mechanical equipment
- Qualification criteria employed for each type of equipment
- Designated safety-related functional requirements
- Definition of the applicable seismic environment
- Definition of other normal and accident loadings
- Documentation of the qualification process employed to demonstrate the required structural integrity and operability of mechanical and electrical equipment and instrumentation in the event of a safe shutdown earthquake (SSE) after a number of postulated occurrences of an earthquake smaller than a safe shutdown earthquake in combination with other relevant dynamic and static loads.

The AP1000 plant is based on the Certified Seismic Design Response Spectra (CSDRS) defined in Subsection 3.7.1.1. The CSDRS are based on Regulatory Guide 1.60 design response spectra with an increase in the 25 hertz region. The Ground Motion Response Spectra (GMRS) for some

Central and Eastern United States rock sites show higher amplitude at high frequency than the CSDRS. Evaluations for high frequency exceedance at AP1000 plant rock sites have been performed as described in Appendix 3I. It is the conclusion of these evaluations that AP1000 plant systems, structures, and components are qualified for the high frequency seismic response based on the CSDRS with the exception of potential high frequency sensitive components (APP-GW-GLN-144, Reference 3). Specific models of components are not identified as part of the AP1000 certified design and are evaluated for high frequency sensitivity as part of the equipment qualification. Appendix 3I

provides the criteria for addressing potential high frequency sensitive components for plant locations where there is CSDRS exceedance in the high frequency region.

3.10.1 Seismic and Dynamic Qualification Criteria

3.10.1.1 Qualification Standards

The methods of meeting the general requirements for the seismic and dynamic qualification of seismic Category I mechanical and electrical equipment and instrumentation as described by General Design Criteria (GDC) 1, 2, 4, 14, 23, and 30 are described in Section 3.1. The general methods of implementing the requirements of Appendix B to 10CFR50 are described in Chapter 17.

The Nuclear Regulatory Commission (NRC) recommendations concerning the methods employed for seismic qualification of mechanical and electrical equipment are contained in Regulatory Guide 1.100, which endorses IEEE 344-1987 (Reference 1).

[*AP1000 meets IEEE 344-1987, as modified by Regulatory Guide 1.100, by either type testing or analysis or by an appropriate combination of these methods*]* employing the methodology described in Appendix 3D.

The guidance provided in the ASME Code, Section III, is followed in the design of seismic Category I mechanical equipment to achieve the structural integrity of pressure boundary components. In addition, the AP1000 implements an operability program for active valves based on ASME QME-1-2007, as addressed in Section 3.9.

3.10.1.2 Performance Requirements for Seismic Qualification

An equipment qualification data package (EQDP) is developed for the instrumentation and electrical equipment classified as seismic Category I. Table 3.11-1 of Section 3.11 identifies the seismic Category I electrical equipment and instrumentation supplied for the AP1000. Each equipment qualification data package contains a section entitled “Performance Requirements.” This section establishes the safety-related functional requirements of the equipment to be demonstrated during and after a seismic event. The required response spectra employed by the AP1000 for generic seismic qualification are also identified in the section.

For active seismic Category I mechanical components, the performance requirements are defined in the appropriate design and equipment specifications. Requirements for active valves are discussed in Subsection 3.10.2.2.

For other seismic Category I mechanical components, the performance requirement is to maintain structural integrity under appropriate loading conditions. Seismic qualification documentation requirements for mechanical equipment are discussed in Subsection 3.10.4.

A master list and summary of seismic qualification of safety-related seismic Category I electrical and mechanical equipment are maintained as part of the equipment qualification file.

3.10.1.3 Performance Criteria

Seismic and dynamic loading qualification demonstrates that seismic Category I instrumentation and electrical equipment and active valves are capable of performing their designated safety-related functions under applicable plant loading conditions, including the safe shutdown earthquake. The qualification also demonstrates the structural integrity of seismic Category I nonactive valves, mechanical supports, and structures. Some permanent deformation of supports and structures is

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

acceptable at the safe shutdown earthquake level, provided that the capability to perform the designated safety-related functions is not impaired.

3.10.2 Methods and Procedures for Qualifying Electrical Equipment, Instrumentation, and Mechanical Components

Testing is the preferred method to qualify equipment. Both dynamic and static test approaches are used to demonstrate structural integrity and operability of mechanical and electrical equipment in the event of a safe shutdown earthquake preceded by five earthquakes of a magnitude equal to 50 percent of the calculated safe shutdown earthquake. Test samples are selected according to type, load level, and size, as well as other pertinent factors on a prototype basis.

Analysis using mathematical modeling techniques correlated to tests performed on similar equipment or structures and verified analytical approaches are used to qualify equipment. Combined analysis and testing is also used to qualify equipment.

The analytical approach to seismic qualification without testing is used under the following conditions:

- If operability can be demonstrated by analysis alone.
- If only maintaining structural integrity is required for the safety-related function.
- If the equipment is too large or heavy to obtain a representative test input at existing test facilities. (The essential control devices and electrical parts of large equipment are tested separately if required.)
- If the interfaces (for example, interconnecting cables to the cabinet or other complex inputs) cannot be conservatively considered during testing.
- If the response of the equipment is essentially linear or has a simple nonlinear behavior that can be predicted by conservative analytical methods.

A combination of testing and analysis is used when complete testing is not practical.

Equipment that has been previously qualified by means of test and analysis equivalent to those described herein is acceptable provided that proper documentation is submitted.

Seismic qualification of seismic Category I instrumentation and electrical equipment is demonstrated by either type testing or a combination of test and analysis. The qualification method employed by the AP1000 for a particular item of equipment is based upon many factors including practicability, complexity of equipment, economics, and availability of previous seismic qualification. The qualification method employed for a particular item of instrumentation or electrical equipment is identified in the individual equipment qualification data package.

For active valves, the AP1000 uses a combination of tests and analyses to demonstrate the structural integrity and operability of such components. Other seismic Category I mechanical equipment is qualified by analysis to demonstrate structural integrity.

The methods of load combination and methods of combining dynamic responses for mechanical equipment are discussed in Section 3.9. For instrumentation and electrical equipment, the only dynamic loads considered in testing are seismic loads and hydrodynamic and vibratory loads where applicable. Other dynamic loads to which instrumentation and electrical equipment may be subjected are enveloped by this testing or are addressed by analysis.

3.10.2.1 Seismic Qualification of Instrumentation and Electrical Equipment

3.10.2.1.1 Type Testing

For seismic Category I instrumentation and electrical equipment, seismic qualification by test is performed according to IEEE 344-1987. Where testing is used, multifrequency, multiaxis inputs are developed by the general procedures outlined in Appendix 3D. The test results contained in the individual equipment qualification data packages demonstrate that the measured test response spectrum envelops the required response spectrum defined in the equipment qualification data package.

Alternative test methods, such as single-frequency, single-axis inputs for line-mounted equipment, are used in selected cases as permitted by IEEE 344-1987 and Regulatory Guide 1.100. These methods are further described in Appendix 3D.

3.10.2.1.2 Analysis

Seismic qualification by the analysis method can be used to demonstrate qualification for equipment where structural integrity or limitations of deformation provide the safety-related function. Seismic analysis is widely used to demonstrate qualification of equipment where testing is impractical, equipment is easily modeled (no secondary structures), and no complex equipment functions are required.

Analysis may complement tests when needed to extrapolate or interpolate experimental data. Analysis may be used to investigate established failure modes related to structural integrity, fatigue, and stress-strain behavior. Two methods of computation are: (1) static equivalent load, which yields conservative results, and (2) dynamic analysis, which takes into account the dynamic response properties of the structure and which can be suitably represented by linear models.

The analysis method is not recommended for complex equipment that cannot be modeled to adequately predict its response.

3.10.2.1.3 Combination of Test and Analysis

The AP1000 uses a combination of test and analysis to qualify seismic Category I instrumentation and electrical equipment. The test methods are similar to those described for type testing. Available test results are employed in combination with the analysis methods described in IEEE 344-1987 to demonstrate seismic qualification. The analytical methods include both static and dynamic techniques, which are described in detail in Appendix 3D.

3.10.2.2 Seismic and Operability Qualification of Active Mechanical Equipment

Active mechanical equipment is qualified for both structural integrity and operability for its intended service conditions by a combination of test and analysis. These methods address the applicable loading conditions, such as thermal transients, significant flow loads, and/or degraded flow conditions. The test and analysis methods utilized in qualification of these components provide adequate confidence of operability under required plant conditions.

Qualification methods used for active valves are described in this subsection. The qualification methods used for control rod drive mechanisms and snubbers are described in Section 3.9. The qualification program for valves that are part of the reactor coolant pressure boundary shall include testing or analysis that demonstrate that these valves will not experience leakage beyond the limits defined in the design specification for each valve when subjected to design loading.

Safety-related active valves, listed in Table 3.11-1, are required to function at the time of an accident. Tests and analyses are conducted to qualify active valves providing confidence that these valves operate during a seismic event.

The safety-related valves are subjected to a series of type tests or actual tests before service and during the plant life. Before installation, the following tests are performed: body hydrostatic test to ASME Code, Section III, requirements, back-seat and main seat leakage tests, disc hydrostatic tests, and operational tests to verify that the valve opens and closes within stroke time requirements. For the qualification of motor operators for environmental conditions, see Section 3.11. After installation, the valves undergo system level pressure tests, construction acceptance tests, and preoperational tests. Where applicable, periodic in-service inspections and operations are performed in-situ to verify the functional capability of the valve. On active valves, an analysis of the extended structure is performed for static equivalent seismic safe shutdown earthquake loads applied at the center of gravity of the extended structure. The maximum stress limits used for active Class 1, 2, and 3 valves are compared to acceptable standards in the ASME Code. Valve discs are evaluated for maximum design line pressure and maximum differential pressure resulting from plant operating, transient, and accident conditions. Feedwater line valve discs are evaluated, using appropriate ASME Code, Section III limits, for the effect of dynamic loads by considering the effect of an equivalent differential pressure. The equivalent differential pressure is developed from a transient analysis based on wave mechanics that includes consideration of system arrangement and valve closing dynamics. Valve operating conditions are included as part of the valve design specification and are used to evaluate the valve disc. Additional information is provided on the controlled-closure, feedwater check valve in Subsection 10.4.7.2.2.

In addition to these tests and analyses, representative valves of each design type having extended structures are subjected to static pull tests and nozzle load tests as appropriate. These tests verify operability of a rigid valve (natural frequency equaling or exceeding 33 hertz) during a simulated plant faulted-condition event by demonstrating operational capabilities within the specified limits. A representative valve of a specific design type is identified for this testing by the specification (for example, globe valve, motor-operated valve) for that particular type of valve. A further subdivision of design is based upon the valve size, pressure rating, type of operator, and previous operability testing to evaluate the need for additional testing of a particular design type. The testing procedures are described in Appendix 3D.

The accelerations used for the static valve qualification are equivalent, as justified by analysis, to 6.0g in two orthogonal horizontal directions and 6.0g vertical. For testing, the required input motion (RIM) curve shall be consistent with the profile of Figure 6 of IEEE 382-1996 (Reference 2), with the acceleration magnitude increased to 6.0g. The piping design maintains the operator accelerations to these levels. If the natural frequency of the valve is less than 33 hertz, a dynamic analysis of the valve is performed to determine the equivalent loads to be applied during the static test.

Valves that are safety related but are classified as not having an extended structure, such as check valves and safety valves, are considered separately.

Check valves are characteristically simple in design. Their operation is not affected by seismic accelerations or the maximum applied nozzle loads. These valves are designed so that once the structural integrity of the valve is verified using standard methods, the capability of the valve to operate is demonstrated by its design features. The valve also undergoes in-shop hydrostatic and seat leakage tests, and periodic in situ valve exercising and inspection to verify the functional capability of the valve.

The pressurizer safety valves are qualified by the following procedures (these valves are also subjected to tests and analysis similar to check valves): stress and deformation analyses of critical items that affect operability for faulted condition loads, in-shop hydrostatic and seat leakage tests,

and periodic in situ valve inspection. In addition to these tests, a static load equivalent to that applied by the faulted condition is applied at the top of the bonnet, and the fluid pressure is increased until the valve mechanism actuates. Successful actuation within the design requirements of the valve demonstrates its over-pressurization safety capabilities during a seismic event.

Safety-related active valves mounted in HVAC ductwork used to isolate main control room areas during design events are listed in Table 3.11-1. These valves are qualified to operate on demand using air operators.

Using these methods, the safety-related valves are qualified for operability during a faulted event. These methods conservatively simulate the seismic event and demonstrate that the active valves perform their safety-related function when necessary.

3.10.2.3 Valve Operator Qualification

Active valve motor operators, position sensors, and solenoid valves are seismically qualified according to IEEE 382-1996, as discussed in the appropriate equipment qualification data packages.

3.10.2.4 Seismic Qualification of Other Seismic Category I Mechanical Equipment

For seismic Category I mechanical equipment not defined as active, the AP1000 uses analysis to demonstrate structural integrity. The analysis methods are described in Sections 3.7 and 3.9 and in Appendix 3D.

3.10.3 Method and Procedures for Qualifying Supports of Electrical Equipment, Instrumentation, and Mechanical Components

The equipment qualification data packages and seismic analysis report for non-active mechanical equipment (with no environmental qualification requirements) identify the equipment mounting employed for qualification and establish interface requirements for the equipment to provide confidence that subsequent in-plant installation does not degrade the established qualification. Interface requirements are defined based on the test configuration and other design requirements. Dynamic coupling effects resulting from mounting the component according to these interface criteria are considered in the qualification program.

Information concerning the structural integrity of pressure-retaining components, their supports, and core supports is presented in Section 3.9.

The following bases are used in the design and analysis of cable tray supports and instrument tubing supports:

- The methods used in the seismic analysis of cable tray supports are described in Appendix 3F.

- The seismic Category I instrument tubing systems are supported so that the allowable stresses permitted by ASME Code, Section III, are not exceeded when the tubing is subjected to the loads specified in Section 3.9.

3.10.4 Documentation

The results of tests and analyses verifying that the criteria established in Subsection 3.10.1 are satisfied, employing the qualification methods described in Subsections 3.10.2 and 3.10.3, are included in the individual equipment qualification data packages, seismic analysis report, and test

reports. The upkeep of the equipment qualification file is maintained during the equipment selection and procurement phase is discussed in Subsection 3.11.5.

Seismic qualification of equipment is documented in equipment qualification data packages, seismic analysis report, and test reports. Appendix 3D provides guidance in this area.

3.10.5 Standard Review Plan Evaluation

A summary describing the Standard Review Plan differences in regard to seismic and dynamic qualification of mechanical and electrical equipment is provided Subsection 1.9.2.

3.10.6 Combined License Information Item on Experienced-Based Qualification

Not used.

3.10.7 References

1. IEEE 344-1987, “Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”

2. IEEE 382-1996, “IEEE Standard for Qualification of Actuators for Power-Operated Valve Assemblies with Safety-Related Functions for Nuclear Power Plants.”

3. APP-GW-GLN-144, “AP1000 Design Control Document High Frequency Seismic Tier 1 Changes,” Westinghouse Electric Company LLC.

3.11 Environmental Qualification of Mechanical and Electrical Equipment

This section presents information to demonstrate that the mechanical and electrical portions of the engineered safety features, the reactor protection systems, and selected portions of the post-accident monitoring system are capable of performing their designated functions while exposed to applicable normal, abnormal, test, accident, and post-accident environmental conditions. The information presented includes identification of the equipment required to be environmentally qualified and, for each item of equipment, the designated functional requirements, definition of the applicable environmental parameters, and documentation of the qualification process employed to demonstrate the required environmental capability. The seismic qualification of mechanical and electrical equipment is presented in Section 3.10. The portions of post-accident monitoring equipment required to be environmentally qualified are identified in Table 7.5-1.

3.11.1 Equipment Identification and Environmental Conditions

3.11.1.1 Equipment Identification

A complete list of environmentally qualified electrical and mechanical equipment that is essential to emergency reactor shutdown, containment isolation, reactor core cooling, or containment and reactor heat removal, or that is otherwise essential in preventing significant release of radioactive material to the environment, is provided in Table 3.11-1. A list of environmentally qualified electrical and mechanical equipment and a summary of electrical and mechanical equipment qualification results are maintained as part of the equipment qualification file, as outlined in Appendix 3D. The equipment qualification file is maintained during the equipment selection and procurement phase as defined in Subsection 3.11.5.

3.11.1.2 Definition of Environmental Conditions

Appendix 3D identifies applicable normal, abnormal, and design basis accident environmental conditions conforming to General Design Criterion 4. These environmental conditions are associated with various plant areas by an environmental zone, as noted in Table 3D.5-1 and Table 3.11-1.

For mild environments, the area conditions do not change as the result of an accident. There are no degrading environmental effects that lead to common mode failure of the equipment. The qualification of mechanical and electrical equipment located in a mild environment is demonstrated by conducting the plant surveillance activities carried out during the operational phase of the plant.

The environmental conditions identified in Appendix 3D are defined as follows.

Normal operating environmental conditions are defined as those conditions existing during routine plant operations for which the equipment is expected to be available on a continuous basis to perform required functions.

Abnormal environmental conditions are those plant conditions for which the equipment is designed to operate for a period of time without accelerating normal periodic tests, inspections, and maintenance schedules for that equipment. The maximum and minimum conditions identified as the abnormal condition are based on the design limits for the affected areas.

Design basis accident (DBA) and post-design basis accident conditions are those plant conditions resulting from various postulated equipment and piping failures during which the equipment identified in Table 3.11-1 must operate without impairment of the function. The design basis accident and post-design basis accident conditions are discussed in Appendix 3D.

Compatibility of equipment with the specified environmental conditions is achieved by the following.

Systems and components required to mitigate the consequences of a design basis accident or to perform safe shutdown operation are qualified to remain functional after exposure to the environmental conditions in Table 3D.5-5.

Environmentally qualified equipment exposed to a harsh environment has a qualified life goal of 60 years. Demonstration of qualified life by test or test and analysis is provided to address applicable aging effects. For critical components susceptible to aging, a qualified life is established that includes the effects of the total integrated radiation dose experienced at their respective locations within the plant. When a 60-year qualified life is not achievable, a shorter qualified life is established, and a replacement program is implemented.

For equipment located in a mild environment, a design life goal is established by using known significant aging mechanisms and reliability data.

Equipment qualification takes into account the most severe environmental conditions resulting from the design basis high-energy line break. Included in these conditions are the short-term peak transient temperature following a main steam line break (MSLB) and a radiation exposure and temperature due to a loss of coolant accident (LOCA) within the reactor containment.

Postulated high-energy line failures as defined in Subsection 3.6.2.1.2 are assumed in areas where high-energy lines greater than 1 inch are routed. Essential equipment is protected against the effects of jet impingement (Subsection 3.6.2.4.1) and evaluated for spray effects if required (Subsection 3.6.2.7).

Active mechanical equipment is qualified for operability as discussed in Subsection 3.9.3 and Section 3.10. This operability program, combined with the qualification of the electrical appurtenances (valve operators, solenoids, limit switches), demonstrates qualification under required environmental conditions. Active mechanical equipment is defined as equipment that performs a mechanical motion as part of its safety-related function.

Nonactive mechanical equipment whose only safety function is structural integrity is designed according to ASME Code guidelines. The accident and post-accident environmental effects are considered in the design of such structural components as pump casings and valve bodies.

The environmental qualification program is restricted to evaluating the design of critical nonmetallic subcomponents of active devices in a harsh environment, where failure results in loss of the active component.

In the event of potential flooding/wetting, one of the following criteria is applied for protection of equipment for service in such an environment:

- Equipment will be qualified for submergence due to flooding/wetting.
- Equipment will be protected from wetting due to spray.
- Equipment will be evaluated to show that failure of the equipment due to flooding/wetting is acceptable since its safety-related function is not required or has otherwise been accomplished.

3.11.1.3 Equipment Operability Times

For the AP1000 Class 1E electrical and active mechanical equipment, post-accident operability times are shown in Table 3D.4-2 in Appendix 3D.

Specific information for each device qualified as part of the IEEE 323-1974 qualification program is contained in the appropriate equipment qualification data package.

The active mechanical component is qualified for operability as discussed in Section 3.10, using test, analysis, or a combination of tests and analyses. This operability program, combined with the qualification of the electrical appurtenances (for example, valve operators) discussed in the appropriate equipment qualification data packages, demonstrates qualification.

3.11.1.4 Standard Review Plan Evaluation

A discussion of the Standard Review Plan requirements in regard to environmental qualification of mechanical equipment is provided in Subsection 1.9.2.

3.11.2 Qualification Tests and Analysis

3.11.2.1 Environmental Qualification of Electrical Equipment

The AP1000 approach for environmental qualification of Class 1E equipment is outlined in Appendix 3D. The Appendix 3D methodology is developed based on the guidelines provided in IEEE 323-1974 (Reference 1) and IEEE 344-1987 (Reference 2).

Qualification for equipment in a harsh environment is based on type testing or testing and analysis. Analysis may be used to determine significant aging mechanisms in mild environment applications. Type testing includes thermal and mechanical aging, radiation, and exposure to extremes of environmental, seismic, and vibration effects. Type testing is done with representative samples of the production line equipment according to the sequence indicated in IEEE 323-1974 to the specified service conditions, including margin. The testing takes into account normal and abnormal plant operation and design basis accident and post-design basis accident operations, as required.

When reliable data and proven analytical methods are available, environmental qualification may be based on analysis supported by partial type test data. This method includes justification of the methods, theories, and assumptions used (that is, mathematical or logical proof based on actual test data) that the equipment meets or exceeds its specified performance requirements when subjected to normal, abnormal, and design basis accident environmental conditions.

Regulatory guides providing guidance for meeting the requirements of 10CFR50, Appendix A, General Design Criteria 1, 2, 4, 23, and 50; Appendix B, Criteria III, XI, and XVII to 10CFR50 and 10CFR50.49, include Regulatory Guide 1.89, Regulatory Guide 1.30, Regulatory Guide 1.63, Regulatory Guide 1.73, Regulatory Guide 1.100, and Regulatory Guide 1.131. The maintenance surveillance program follows the guidance of Regulatory Guide 1.33.

Additional information regarding conformance with each of these regulatory guides is given in Section 1.9.

3.11.2.2 Environmental Qualification of Mechanical Equipment

AP1000 mechanical components identified in Table 3.11-1 are qualified by design to perform their required functions under the appropriate environmental effects of normal, abnormal, accident, and post-accident conditions as required by General Design Criterion 4 and discussed in Appendix 3D. For mild environments, the area conditions do not change as a result of an accident. There are no degrading environmental effects that lead to common mode failure of equipment in mild environments. Mechanical equipment located in harsh environmental zones is designed to perform under the appropriate environmental conditions.

For mechanical equipment, there are two categories of components:

- Active equipment – equipment that performs a mechanical motion as part of its safety-related function.

  The program for environmental qualification of active mechanical components is based on a combination of design, test, and analysis of critical sub-components, which is supported by maintenance and surveillance programs.

- Nonactive equipment – equipment whose only safety-related function is structural integrity. Nonactive components are designed for structural integrity according to ASME Code, Section III, as discussed in Section 3.9.

3.11.3 Loss of Ventilation

The abnormal environmental conditions shown on Tables 3D.5-3 and 3D.5-4 reflect anticipated maximum conditions based on loss of normal ventilation systems.

Normal containment heat removal is provided by the nonsafety-related containment air recirculation cooling system. If this system is out of service for an extended period of time, the passive containment cooling system may be initiated to maintain the temperature and pressure below the limits noted. Environmentally qualified equipment located in containment performs its functions under these conditions until the normal containment cooling system is restored.

Equipment areas outside containment and outside the main control room are maintained at normal environmental conditions by nonsafety-related HVAC systems. If these systems are disabled, the heat generated by this equipment is absorbed by the surrounding passive heat sinks with an ambient temperature rise that does not exceed the abnormal condition. Normal HVAC is restored within 8 hours or ventilation is provided as discussed in Subsection 9.4.1.2.3.2.

If the normal nonsafety-related main control room HVAC is lost, the heat generated by equipment and people is absorbed by the surrounding passive heat sinks. Normal heating, ventilation, and air-conditioning is restored within 72 hours or ventilation is provided as discussed in Section 6.4.

3.11.4 Estimated Radiation and Chemical Environment

The plant-specific estimates of the radiation dose incurred by equipment during normal operation is shown in Table 3D.5-2 and the estimated doses following a loss-of-coolant accident are defined in Table 3D.5-5.

The identified equipment is qualified to perform functions in the radiation environments present during normal and design basis accident conditions. The normal operational exposure is based upon design source terms presented in Chapter 11 and Subsection 12.2.1. The equipment and shielding configurations are presented in Section 12.3. Post-accident monitoring, reactor trip and engineered safety features system and component radiation exposures are dependent on the location of the equipment in the plant. Source terms and other accident parameters are presented in Subsection 12.2.1 and Chapter 15.

The maximum combined integrated radiation dose inside containment is based on the effects of the normally expected radiation environment (gamma) over the equipment's installed life plus that associated with the most severe design basis event (gamma and beta) during or following which the equipment is required to remain functional.

The chemical environment following a loss of coolant accident is primarily based on the chemistry of the reactor coolant system fluid since there is no caustic containment spray. Sump pH adjustments are considered for certain qualification tests. This is discussed further in Appendix 3D.

3.11.5 Combined License Information Item for Equipment Qualification File

Westinghouse Electric Company LLC will act as the contractor for the COL holder during the equipment design phase, equipment selection and procurement phase, equipment qualification phase, plant construction phase, and ITAAC inspection phases.

The COL holder is responsible for the maintenance of the equipment qualification file upon receipt from the reactor vendor. The documentation necessary to support the continued qualification of the equipment installed in the plant that is within the Environmental Qualification (EQ) Program scope is available in accordance with 10 CFR Part 50 Appendix A, General Design Criterion 1.

EQ files developed by the reactor vendor are maintained as applicable for equipment and certain post-accident monitoring devices that are subject to a harsh environment. The contents of the qualification files are discussed in Section 3D.7. The files are maintained for the operational life of the plant.

For equipment not located in a harsh environment, design specifications received from the reactor vendor are retained. Any plant modifications that impact the equipment use the original specifications for modification or procurement. This process is governed by applicable plant design control or configuration control procedures.

Central to the EQ Program is the EQ Master Equipment List (EQMEL). This EQMEL identifies the electrical and mechanical equipment or components that must be environmentally qualified for use in a harsh environment. The EQMEL consists of equipment that is essential to emergency reactor shutdown, containment isolation, reactor core cooling, or containment and reactor heat removal, or that is otherwise essential in preventing significant release of radioactive material to the environment. This list is developed from the equipment list provided in Table 3.11-1. The EQMEL and a summary of equipment qualification results are maintained as part of the equipment qualification file for the operational life of the plant.

Administrative programs are in place to control revision to the EQ files and the EQMEL. When adding or modifying components in the EQ Program, EQ files are generated or revised to support qualification. The EQMEL is revised to reflect these new components. To delete a component from the EQ Program, a deletion justification is prepared that demonstrates why the component can be deleted. This justification consists of an analysis of the component, an associated circuit review if appropriate, and a safety evaluation. The justification is released and/or referenced on an appropriate change document. For changes to the EQMEL, supporting documentation is completed and approved prior to issuing the changes. This documentation includes safety reviews and new or revised EQ files. Plant modifications and design basis changes are subject to change process reviews, e.g. reviews in accordance with 10 CFR 50.59 or Section VIII of Appendix D to 10 CFR Part 52, in accordance with appropriate plant procedures. These reviews address EQ issues associated with the activity. Any changes to the EQMEL that are not the result of a modification or design basis change are subject to a separate review that is accomplished and documented in accordance with plant procedures.

Engineering change documents or maintenance documents generated to document work performed on an EQ component, which may not have an impact on the EQ file, are reviewed against the current revision of the EQ files for potential impact. Changes to EQ documentation may be due to, but not limited to, plant modifications, calculations, corrective maintenance, or other EQ concerns.

Table 13.4-201 provides milestones for EQ implementation.

3.11.6 References

1. IEEE 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.”

2. IEEE 344-1987, “IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”

Table 3.11-1 (Sheet 1 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
BATTERIES					
IDSA 125V 60 Cell Battery 1A	IDSA-DB-1A	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSA 125V 60 Cell Battery 1B	IDSA-DB-1B	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB 125V 60 Cell Battery 1A	IDSB-DB-1A	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB 125V 60 Cell Battery 1B	IDSB-DB-1B	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB 125V 60 Cell Battery 2A	IDSB-DB-2A	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSB 125V 60 Cell Battery 2B	IDSB-DB-2B	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSC 125V 60 Cell Battery 1A	IDSC-DB-1A	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSC 125V 60 Cell Battery 1B	IDSC-DB-1B	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSC 125V 60 Cell Battery 2A	IDSC-DB-2A	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSC 125V 60 Cell Battery 2B	IDSC-DB-2B	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSD 125V 60 Cell Battery 1A	IDSD-DB-1A	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSD 125V 60 Cell Battery 1B	IDSD-DB-1B	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
Spare 125V 60 Cell Battery 1A	IDSS-DB-1A	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
Spare 125V 60 Cell Battery 1B	IDSS-DB-1B	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E

Table 3.11-1 (Sheet 2 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
BATTERY CHARGERS					
IDSA Battery Charger	IDSA-DC-1	2	ISOL RT ESF	24 hrs 5 min 24 hrs	E
IDSB Battery Charger 1	IDSB-DC-1	2	ISOL RT ESF	24 hrs 5 min 24 hrs	E
IDSB Battery Charger 2	IDSB-DC-2	2	ISOL	72 hrs	E
IDSC Battery Charger 1	IDSC-DC-1	2	ISOL RT ESF	24 hrs 5 min 24 hrs	E
IDSC Battery Charger 2	IDSC-DC-2	2	ISOL	72 hrs	E
IDSD Battery Charger	IDSD-DC-1	2	ISOL RT ESF	24 hrs 5 min 24 hrs	E
Spare Battery Charger	IDSS-DC-1	2	ISOL	72 hrs	E
DISTRIBUTION PANELS					
IDSA 250 Vdc Dist Panel	IDSA-DD-1	2	ESF	24 hrs	E
IDSB 250 Vdc Dist Panel	IDSB-DD-1	2	ESF	24 hrs	E
IDSC 250 Vdc Dist Panel	IDSC-DD-1	2	ESF	24 hrs	E
IDSD 250 Vdc Dist Panel	IDSD-DD-1	2	ESF	24 hrs	E
IDSA 120 Vac Dist Panel 1	IDSA-EA-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSA 120 Vac Dist Panel 2	IDSA-EA-2	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB 120 Vac Dist Panel 1	IDSB-EA-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB 120 Vac Dist Panel 2	IDSB-EA-2	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
IDSB 120 Vac Dist Panel 3	IDSB-EA-3	2	PAMS	2 wks	E
IDSC 120 Vac Dist Panel 1	IDSC-EA-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSC 120 Vac Dist Panel 2	IDSC-EA-2	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
IDSC 120 Vac Dist Panel 3	IDSC-EA-3	2	PAMS	2 wks	E
IDSD 120 Vac Dist Panel 1	IDSD-EA-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E

Table 3.11-1 (Sheet 3 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
IDSD 120 Vac Dist Panel 2	IDSD-EA-2	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
FUSE PANELS					
IDSA Fuse Panel	IDSA-EA-4	2	ISOL	24 hrs	E
IDSA Battery Monitor Fuse Panel	IDSA-EA-5	2	ISOL	24 hrs	E
IDSB Fuse Panel	IDSB-EA-4	2	ISOL	24 hrs	E
IDSB Fuse Panel	IDSB-EA-5	2	ISOL	2 wks	E
IDSB Fuse Panel	IDSB-EA-6	2	ISOL	2 wks	E
IDSB Battery Monitor Fuse Panel	IDSB-EA-7	2	ISOL	24 hrs	E
IDSB Battery Monitor Fuse Panel	IDSB-EA-8	2	ISOL	2 wks	E
IDSC Fuse Panel	IDSC-EA-4	2	ISOL	24 hrs	E
IDSC Fuse Panel	IDSC-EA-5	2	ISOL	2 wks	E
IDSC Fuse Panel	IDSC-EA-6	2	ISOL	2 wks	E
IDSC Battery Monitor Fuse Panel	IDSC-EA-7	2	ISOL	24 hrs	E
IDSC Battery Monitor Fuse Panel	IDSC-EA-8	2	ISOL	2 wks	E
IDSD Fuse Panel	IDSD-EA-4	2	ISOL	24 hrs	E
IDSD Battery Monitor Fuse Panel	IDSD-EA-5	2	ISOL	24 hrs	E
IDSS Battery Monitor Fuse Panel	IDSS-EA-1	2	ISOL	2 wks	E
STAND-ALONE ELECTRICAL ISOLATION DEVICES					
Current-to-Current Transmitter 1	WLS-JD-MISX01	2	ISOL	24 hrs	E
Current-to-Current Transmitter 1	WLS-JD-MISX02	2	ISOL	24 hrs	E
Current-to-Current Transmitter 1	WLS-JD-MISX03	2	ISOL	24 hrs	E
TRANSFER SWITCHES					
IDSA Fused Transfer Switch Box 1	IDSA-DF-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB Fused Transfer Switch Box 1	IDSB-DF-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB Fused Transfer Switch Box 2	IDSB-DF-2	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSC Fused Transfer Switch Box 1	IDSC-DF-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSC Fused Transfer Switch Box 2	IDSC-DF-2	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSD Fused Transfer Switch Box 1	IDSD-DF-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E

Table 3.11-1 (Sheet 4 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
IDSS Fused Transfer Switch Box 1 (Spare)	IDSS-DF-1	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSS Spare Battery Termination Box	IDSS-DF-3	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
MOTOR CONTROL CENTERS					
IDSA 250 Vdc MCC	IDSA-DK-1	2	ESF	24 hrs	E
IDSB 250 Vdc MCC	IDSB-DK-1	2	ESF	24 hrs	E
IDSC 250 Vdc MCC	IDSC-DK-1	2	ESF	24 hrs	E
IDSD 250 Vdc MCC	IDSD-DK-1	2	ESF	24 hrs	E
SWITCHBOARDS					
IDSA 250 Vdc Switchboard 1	IDSA-DS-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB 250 Vdc Switchboard 1	IDSB-DS-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB 250 Vdc Switchboard 2	IDSB-DS-2	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSC 250 Vdc Switchboard 1	IDSC-DS-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSC 250 Vdc Switchboard 2	IDSC-DS-2	2	RT ESF PAMS	5 min 24 hrs 72 hrs	E
IDSD 250 Vdc Switchboard 1	IDSD-DS-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
TRANSFORMERS					
IDSA Regulating Transformer 1	IDSA-DT-1	2	ISOL	24 hrs	E
IDSB Regulating Transformer 1	IDSB-DT-1	2	ISOL PAMS	72 hrs 2 wks	E
IDSC Regulating Transformer 1	IDSC-DT-1	2	ISOL PAMS	72 hrs 2 wks	E
IDSD Regulating Transformer 1	IDSD-DT-1	2	ISOL	24 hrs	E
INVERTERS					
IDSA Inverter	IDSA-DU-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSB Inverter 1	IDSB-DU-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E

Table 3.11-1 (Sheet 5 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
IDSB Inverter 2	IDSB-DU-2	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
IDSC Inverter 1	IDSC-DU-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
IDSC Inverter 2	IDSC-DU-2	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
IDSD Inverter	IDSD-DU-1	2	RT ESF PAMS	5 min 24 hrs 24 hrs	E
SWITCHGEAR					
RCP 1A 6900V Switchgear 31	ECS-ES-31	2	ESF PAMS	5 min 2 wks	E
RCP 1A 6900V Switchgear 32	ECS-ES-32	2	ESF PAMS	5 min 2 wks	E
RCP 2A 6900V Switchgear 51	ECS-ES-51	2	ESF PAMS	5 min 2 wks	E
RCP 2A 6900V Switchgear 52	ECS-ES-52	2	ESF PAMS	5 min 2 wks	E
RCP 1B 6900V Switchgear 41	ECS-ES-41	2	ESF PAMS	5 min 2 wks	E
RCP 1B 6900V Switchgear 42	ECS-ES-42	2	ESF PAMS	5 min 2 wks	E
RCP 2B 6900V Switchgear 61	ECS-ES-61	2	ESF PAMS	5 min 2 wks	E
RCP 2B 6900V Switchgear 62	ECS-ES-62	2	ESF PAMS	5 min 2 wks	E
Junction Box Division A	PMS-EJ-001A	1	RT ESF PAMS	5 min 24 hrs 4 mos	E*S
Junction Box Division B	PMS-EJ-001B	1	RT ESF PAMS	5 min 24 hrs 4 mos	E*S
Junction Box Division C	PMS-EJ-001C	1	RT ESF PAMS	5 min 24 hrs 4 mos	E*S
Junction Box Division D	PMS-EJ-001D	1	RT ESF PAMS	5 min 24 hrs 4 mos	E*S
Junction Box Division A	PMS-EJ-002A	1	RT ESF PAMS	5 min 24 hrs 4 mos	E * S

Table 3.11-1 (Sheet 6 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Junction Box Division B	PMS-EJ-002B	1	RT ESF PAMS	5 min 24 hrs 4 mos	E * S
Junction Box Division C	PMS-EJ-002C	1	RT ESF PAMS	5 min 24 hrs 4 mos	E * S
Junction Box Division D	PMS-EJ-002D	1	RT ESF PAMS	5 min 24 hrs 4 mos	E * S
Reactor Trip Switchgear	PMS-JD-RTSA01	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS-JD-RTSA02	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS-JD-RTSB01	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS-JD-RTSB02	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS-JD-RTSC01	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS-JD-RTSC02	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS-JD-RTSD01	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS-JD-RTSD02	4	RT PAMS	5 min 2 wks	E
LEVEL TRANSMITTERS					
Core Makeup Tank A Narrow Range Upper Level	PXS-JE-LE011A	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT011A	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank A Narrow Range Upper Level	PXS-JE-LE011B	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT011B	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank A Narrow Range Upper Level	PXS-JE-LE011C	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT011C	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank A Narrow Range Upper Level	PXS-JE-LE011D	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT011D	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank B Narrow Range Upper Level	PXS-JE-LE012A	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT012A	2	ESF PAMS	24 hrs 4 mos	E

Table 3.11-1 (Sheet 7 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Core Makeup Tank B Narrow Range Upper Level	PXS-JE-LE012B	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT012B	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank B Narrow Range Upper Level	PXS-JE-LE012C	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT012C	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank B Narrow Range Upper Level	PXS-JE-LE012D	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT012D	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank A Narrow Range Lower Level	PXS-JE-LE013A	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT013A	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank A Narrow Range Lower Level	PXS-JE-LE013B	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT013B	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank A Narrow Range Lower Level	PXS-JE-LE013C	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT013C	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank A Narrow Range Lower Level	PXS-JE-LE013D	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT013D	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank B Narrow Range Lower Level	PXS-JE-LE014A	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT014A	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank B Narrow Range Lower Level	PXS-JE-LE014B	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT014B	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank B Narrow Range Lower Level	PXS-JE-LE014C	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT014C	2	ESF PAMS	24 hrs 4 mos	E
Core Makeup Tank B Narrow Range Lower Level	PXS-JE-LE014D	1	ESF PAMS	24 hrs 4 mos	E * S
	PXS-JE-LT014D	2	ESF PAMS	24 hrs 4 mos	E
Containment Floodup Level	PXS-JE-LE050	1	PAMS	4 mos	E * S
	PXS-JE-LT050	2	PAMS	4 mos	E
Containment Floodup Level	PXS-JE-LE051	1	PAMS	4 mos	E * S
	PXS-JE-LT051	2	PAMS	4 mos	E

Table 3.11-1 (Sheet 8 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Containment Floodup Level	PXS-JE-LE052	1	PAMS	4 mos	E * S
	PXS-JE-LT052	2	PAMS	4 mos	E
NEUTRON DETECTORS					
Source Range Neutron Detector	RXS-JE-NE001A	1	RT ESF	Note 3 Note 3	E *
Source Range Neutron Detector	RXS-JE-NE001B	1	RT ESF	Note 3 Note 3	E *
Source Range Neutron Detector	RXS-JE-NE001C	1	RT ESF	Note 3 Note 3	E *
Source Range Neutron Detector	RXS-JE-NE001D	1	RT ESF	Note 3 Note 3	E *
Intermediate Range Neutron Detector	RXS-JE-NE002A	1	RT PAMS	Note 3 4 mos	E * S
Intermediate Range Neutron Detector	RXS-JE-NE002B	1	RT PAMS	Note 3 4 mos	E * S
Intermediate Range Neutron Detector	RXS-JE-NE002C	1	RT PAMS	Note 3 4 mos	E * S
Intermediate Range Neutron Detector	RXS-JE-NE002D	1	RT PAMS	Note 3 4 mos	E * S
Power Range Neutron Detector (Lower)	RXS-JE-NE003A	1	RT	5 min	E * S
Power Range Neutron Detector (Lower)	RXS-JE-NE003B	1	RT	5 min	E * S
Power Range Neutron Detector (Lower)	RXS-JE-NE003C	1	RT	5 min	E * S
Power Range Neutron Detector (Lower)	RXS-JE-NE003D	1	RT	5 min	E * S
Power Range Neutron Detector (Upper)	RXS-JE-NE004A	1	RT	5 min	E * S
Power Range Neutron Detector (Upper)	RXS–JE-NE004B	1	RT	5 min	E * S
Power Range Neutron Detector (Upper)	RXS-JE-NE004C	1	RT	5 min	E * S
Power Range Neutron Detector (Upper)	RXS-JE-NE004D	1	RT	5 min	E * S
RADIATION MONITORS					
Containment High Range Area Monitor	PXS-JE-RE160	1	ESF PAMS	24 hrs 4 mos	E * S
Containment High Range Area Monitor	PXS-JE-RE161	1	ESF PAMS	24 hrs 4 mos	E * S
Containment High Range Area Monitor	PXS-JE-RE162	1	ESF PAMS	24 hrs 4 mos	E * S
Containment High Range Area Monitor	PXS-JE-RE163	1	ESF PAMS	24 hrs 4 mos	E * S

Table 3.11-1 (Sheet 9 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Control Room Supply Air Area Radiation Monitor - Particulate Detector	VBS-JE-RE001A	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Particulate Detector	VBS-JE-RE001B	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Iodine Detector	VBS-JE-RE002A	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Iodine Detector	VBS-JE-RE002B	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Noble Gas Detector	VBS-JE-RE003A	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Noble Gas Detector	VBS-JE-RE003B	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Air Flow Transmitter	VBS-JE-FT011A	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Air Flow Transmitter	VBS-JE-FT011B	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Sample Pump	VBS-MP-01A	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Sample Pump	VBS-MP-01B	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Local Radiation Processor	VBS-JE-RY001A	2	ESF	24 hrs	E
Control Room Supply Air Area Radiation Monitor - Local Radiation Processor	VBS-JE-RY001B	2	ESF	24 hrs	E
RESISTANCE TEMPERATURE DETECTORS					
PRHR HX Outlet Temperature	RCS-JE-TE161	1	PAMS	4 mos	E * S
RCS Cold Leg 1A Narrow Range Temperature	RCS-JE-TE121A	1	RT ESF	5 min 5 min	E * S
RCS Cold Leg 1A Narrow Range Temperature	RCS-JE-TE121D	1	RT ESF	5 min 5 min	E * S
RCS Cold Leg 1B Narrow Range Temperature	RCS-JE-TE121B	1	RT ESF	5 min 5 min	E * S
RCS Cold Leg 1B Narrow Range Temperature	RCS-JE-TE121C	1	RT ESF	5 min 5 min	E * S
RCS Cold Leg 2A Narrow Range Temperature	RCS-JE-TE122B	1	RT ESF	5 min 5 min	E * S
RCS Cold Leg 2A Narrow Range Temperature	RCS-JE-TE122C	1	RT ESF	5 min 5 min	E * S
RCS Cold Leg 2B Narrow Range Temperature	RCS-JE-TE122A	1	RT ESF	5 min 5 min	E * S
RCS Cold Leg 2B Narrow Range Temperature	RCS-JE-TE122D	1	RT ESF	5 min 5 min	E * S

Table 3.11-1 (Sheet 10 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE131A	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE131C	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE132A	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE132C	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE133C	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE133A	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE131B	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE131D	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE132B	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE132D	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE133B	1	RT ESF	5 min 5 min	E * S
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE133D	1	RT ESF	5 min 5 min	E * S
RCS Cold Leg 1A Dual Range Temperature	RCS-JE-TE125A	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
RCS Cold Leg 1B Dual Range Temperature	RCS-JE-TE125C	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
RCS Cold Leg 2A Dual Range Temperature	RCS-JE-TE125B	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
RCS Cold Leg 2B Dual Range Temperature	RCS-JE-TE125D	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
RCS Hot Leg 1 Wide Range Temperature	RCS-JE-TE135A	1	PAMS	4 mos	E * S
RCS Hot Leg 2 Wide Range Temperature	RCS-JE-TE135B	1	PAMS	4 mos	E * S
PZR Reference Leg Level Temperature	RCS-JE-TE193A	1	RT ESF PAMS	5 min 5 min 4 mos	E * S

Table 3.11-1 (Sheet 11 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PZR Reference Leg Level Temperature	RCS-JE-TE193B	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
PZR Reference Leg Level Temperature	RCS-JE-TE193C	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
PZR Reference Leg Level Temperature	RCS-JE-TE193D	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
RCP 1A Bearing Water Temperature	RCS-JE-TE211A	1	RT ESF	Note 3 5 min	E *
RCP 1A Bearing Water Temperature	RCS-JE-TE211B	1	RT ESF	Note 3 5 min	E *
RCP 1A Bearing Water Temperature	RCS-JE-TE211C	1	RT ESF	Note 3 5 min	E *
RCP 1A Bearing Water Temperature	RCS-JE-TE211D	1	RT ESF	Note 3 5 min	E *
RCP 1B Bearing Water Temperature	RCS-JE-TE212A	1	RT ESF	Note 3 5 min	E *
RCP 1B Bearing Water Temperature	RCS-JE-TE212B	1	RT ESF	Note 3 5 min	E *
RCP 1B Bearing Water Temperature	RCS-JE-TE212C	1	RT ESF	Note 3 5 min	E *
RCP 1B Bearing Water Temperature	RCS-JE-TE212D	1	RT ESF	Note 3 5 min	E *
RCP 2A Bearing Water Temperature	RCS-JE-TE213A	1	RT ESF	Note 3 5 min	E *
RCP 2A Bearing Water Temperature	RCS-JE-TE213B	1	RT ESF	Note 3 5 min	E *
RCP 2A Bearing Water Temperature	RCS-JE-TE213C	1	RT ESF	Note 3 5 min	E *
RCP 2A Bearing Water Temperature	RCS-JE-TE213D	1	RT ESF	Note 3 5 min	E *
RCP 2B Bearing Water Temperature	RCS-JE-TE214A	1	RT ESF	Note 3 5 min	E *
RCP 2B Bearing Water Temperature	RCS-JE-TE214B	1	RT ESF	Note 3 5 min	E *
RCP 2B Bearing Water Temperature	RCS-JE-TE214C	1	RT ESF	Note 3 5 min	E *
RCP 2B Bearing Water Temperature	RCS-JE-TE214D	1	RT ESF	Note 3 5 min	E *
Containment Operating Floor Temperature	VCS-JE-TE052A	1	PAMS	4 mos	E *
Containment Operating Floor Temperature	VCS-JE-TE052B	1	PAMS	4 mos	E *

Table 3.11-1 (Sheet 12 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Steam Generator 1 Area Containment Temperature	VCS-JE-TE054	1	PAMS	4 mos	E *
Pressurizer Area Containment Temperature	VCS-JE-TE055	1	PAMS	4 mos	E *
CVS Module Containment Temperature	VCS-JE-TE056	1	PAMS	4 mos	E *
Accumulator Room B Containment Temperature	VCS-JE-TE057	1	PAMS	4 mos	E *
Steam Generator 2 Area Containment Temperature	VCS-JE-TE058	1	PAMS	4 mos	E *
Accumulator Room A Containment Temperature	VCS-JE-TE-059	1	PAMS	4 mos	E *
SPEED SENSORS					
RCP 1A Pump Speed	RCS-JE-ST281	1	RT	Note 3	E *
RCP 1B Pump Speed	RCS-JE-ST282	1	RT	Note 3	E *
RCP 2A Pump Speed	RCS-JE-ST283	1	RT	Note 3	E *
RCP 2B Pump Speed	RCS-JE-ST284	1	RT	Note 3	E *
RCP 1A Speed Sensor Preamplifier Enclosure	PMS-JD-MIS01A	2	RT	Note 3	E
RCP 1B Speed Sensor Preamplifier Enclosure	PMS-JD-MIS01B	2	RT	Note 3	E
RCP 2A Speed Sensor Preamplifier Enclosure	PMS-JD-MIS02A	2	RT	Note 3	E
RCP 2B Speed Sensor Preamplifier Enclosure	PMS-JD-MIS02B	2	RT	Note 3	E
THERMOCOUPLES					
Incore Thermocouples (Note 4)	IIS-JE-TE001 through IIS-JE-TE042	1	PAMS	1 yr	E * S
TRANSMITTERS					
PCS Water Delivery Flow	PCS-JE-FT001	9	PAMS	2 wks	E **
PCS Water Delivery Flow	PCS-JE-FT002	9	PAMS	2 wks	E **
PCS Water Delivery Flow	PCS-JE-FT003	9	PAMS	2 wks	E **
PCS Water Delivery Flow	PCS-JE-FT004	9	PAMS	2 wks	E **
PCS Storage Tank Water Level	PCS-JE-LT010	9	PAMS	2 wks	E **
PCS Storage Tank Water Level	PCS-JE-LT011	9	PAMS	2 wks	E **
PRHR HX Flow	PXS-JE-FT049A	1	PAMS	4 mos	E * S
PRHR HX Flow	PXS-JE-FT049B	1	PAMS	4 mos	E * S
RCS Hot Leg 1 Flow	RCS-JE-FT101A	1	RT	Note 3	E *
RCS Hot Leg 1 Flow	RCS-JE-FT101B	1	RT	Note 3	E *
RCS Hot Leg 1 Flow	RCS-JE-FT101C	1	RT	Note 3	E *
RCS Hot Leg 1 Flow	RCS-JE-FT101D	1	RT	Note 3	E *
RCS Hot Leg 2 Flow	RCS-JE-FT102A	1	RT	Note 3	E *
RCS Hot Leg 2 Flow	RCS-JE-FT102B	1	RT	Note 3	E *
RCS Hot Leg 2 Flow	RCS-JE-FT102C	1	RT	Note 3	E *
RCS Hot Leg 2 Flow	RCS-JE-FT102D	1	RT	Note 3	E *

Table 3.11-1 (Sheet 13 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
SG1 Startup Feedwater Flow	SGS-JE-FT055A	2	ESF PAMS	5 min 2 wks	E
SG1 Startup Feedwater Flow	SGS-JE-FT055B	2	ESF PAMS	5 min 2 wks	E
SG2 Startup Feedwater Flow	SGS-JE-FT056A	2	ESF PAMS	5 min 2 wks	E
SG2 Startup Feedwater Flow	SGS-JE-FT056B	2	ESF PAMS	5 min 2 wks	E
Flexible Hose from SG1 to Upper Tap LT001/LT011	SGS-PY-Y01A	1	PB	1 yr	M *
Flexible Hose from SG2 to Upper Tap LT005/LT013	SGS-PY-Y01B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap LT001	SGS-PY-Y02A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap LT005	SGS-PY-Y02B	1	PB	1 yr	M *
Flexible Hose from SG1 to Upper Tap LT002/LT015	SGS-PY-Y03A	1	PB	1 yr	M *
Flexible Hose from SG2 to Upper Tap LT006/LT014	SGS-PY-Y03B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap LT002	SGS-PY-Y04A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap LT006	SGS-PY-Y04B	1	PB	1 yr	M *
Flexible Hose from SG1 to Upper Tap LT003/LT012/LT044	SGS-PY-Y05A	1	PB	1 yr	M *
Flexible Hose from SG2 to Upper Tap LT007/LT017/LT046	SGS-PY-Y05B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap LT003	SGS-PY-Y06A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap LT007	SGS-PY-Y06B	1	PB	1 yr	M *
Flexible Hose from SG1 to Upper Tap LT004/LT016/LT045	SGS-PY-Y07A	1	PB	1 yr	M *
Flexible Hose from SG2 to Upper Tap LT008/LT018/LT047	SGS-PY-Y07B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap LT004	SGS-PY-Y08A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap LT008	SGS-PY-Y08B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap LT011	SGS-PY-Y09A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap LT013	SGS-PY-Y09B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap LT012	SGS-PY-Y10A	1	PB	1 yr	M *

Table 3.11-1 (Sheet 14 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Flexible Hose from SG2 to Lower Tap LT014	SGS-PY-Y10B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap LT015/LT044	SGS-PY-Y11A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap LT017/LT046	SGS-PY-Y11B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap LT016/LT045	SGS-PY-Y12A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap LT018/LT047	SGS-PY-Y12B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap FT024	SGS-PY-Y13A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap FT025	SGS-PY-Y13B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap FT021	SGS-PY-Y14A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap FT023	SGS-PY-Y14B	1	PB	1 yr	M *
Flexible Hose from SG1 to Lower Tap FT020	SGS-PY-Y15A	1	PB	1 yr	M *
Flexible Hose from SG2 to Lower Tap FT022	SGS-PY-Y15B	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to Upper Tap FT020	SGS-PY-Y16A	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to Upper Tap FT022	SGS-PY-Y16B	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to Upper Tap FT021	SGS-PY-Y17A	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to Upper Tap FT023	SGS-PY-Y17B	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to Upper Tap FT024	SGS-PY-Y18A	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to Upper Tap FT025	SGS-PY-Y18B	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to PT030	SGS-PY-Y19A	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to PT034	SGS-PY-Y19B	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to PT032	SGS-PY-Y20A	1	PB	1 yr	M *
Flexible Hose from Main Steam Line to PT036	SGS-PY-Y20B	1	PB	1 yr	M *
MCR Air Delivery Line Flowrate – A	VES-JE-FT003A	3	PAMS	72 hrs	E
MCR Air Delivery Line Flowrate – B	VES-JE-FT003B	3	PAMS	72 hrs	E
IRWST Wide Range Level	PXS-JE-LT046	1	PAMS	4 mos	E * S
IRWST Wide Range Level	PXS-JE-LT047	1	PAMS ESF	4 mos 24 hrs	E * S

Table 3.11-1 (Sheet 15 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
IRWST Wide Range Level	PXS-JE-LT048	1	PAMS ESF	4 mos 24 hrs	E * S
IRWST Lower Narrow Range Level	PXS-JE-LT066	1	ESF PAMS	24 hrs 24 hrs	E * S
IRWST Lower Narrow Range Level	PXS-JE-LT067	1	ESF PAMS	24 hrs 24 hrs	E * S
IRWST Lower Narrow Range Level	PXS-JE-LT068	1	ESF PAMS	24 hrs 24 hrs	E * S
IRWST Lower Narrow Range Level	PXS-JE-LT069	1	ESF PAMS	24 hrs 24 hrs	E * S
RCS Hot Leg Water Level	RCS-JE-LT160A	1	PAMS	2 wks	E * S
RCS Hot Leg Water Level	RCS-JE-LT160B	1	PAMS	2 wks	E * S
PZR Level	RCS-JE-LT195A	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
PZR Level	RCS-JE-LT195B	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
PZR Level	RCS-JE-LT195C	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
PZR Level	RCS-JE-LT195D	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
SG1 Narrow Range Level	SGS-JE-LT001	1	RT ESF PAMS	5 min 5 min 2 wks	E * S
SG1 Narrow Range Level	SGS-JE-LT002	1	RT ESF PAMS	5 min 5 min 2 wks	E * S
SG1 Narrow Range Level	SGS-JE-LT003	1	RT ESF PAMS	5 min 5 min 2 wks	E * S
SG1 Narrow Range Level	SGS-JE-LT004	1	RT ESF PAMS	5 min 5 min 2 wks	E * S
SG2 Narrow Range Level	SGS-JE-LT005	1	RT ESF PAMS	5 min 5 min 2 wks	E * S
SG2 Narrow Range Level	SGS-JE-LT006	1	RT ESF PAMS	5 min 5 min 2 wks	E * S
SG2 Narrow Range Level	SGS-JE-LT007	1	RT ESF PAMS	5 min 5 min 2 wks	E * S

Table 3.11-1 (Sheet 16 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
SG2 Narrow Range Level	SGS-JE-LT008	1	RT ESF PAMS	5 min 5 min 2 wks	E * S
SG1 Wide Range Level	SGS-JE-LT011	1	ESF PAMS	5 min 2 wks	E * S
SG1 Wide Range Level	SGS-JE-LT012	1	ESF PAMS	5 min 2 wks	E * S
SG1 Wide Range Level	SGS-JE-LT015	1	ESF PAMS	5 min 2 wks	E * S
SG1 Wide Range Level	SGS-JE-LT016	1	ESF PAMS	5 min 2 wks	E * S
SG2 Wide Range Level	SGS-JE-LT013	1	ESF PAMS	5 min 2 wks	E * S
SG2 Wide Range Level	SGS-JE-LT014	1	ESF PAMS	5 min 2 wks	E * S
SG2 Wide Range Level	SGS-JE-LT017	1	ESF PAMS	5 min 2 wks	E * S
SG2 Wide Range Level	SGS-JE-LT018	1	ESF PAMS	5 min 2 wks	E * S
Spent Fuel Pool Level	SFS-JE-LT019A	6	ESF PAMS	24 hrs 2 wks	E ** S
Spent Fuel Pool Level	SFS-JE-LT019B	7	ESF PAMS	24 hrs 2 wks	E ** S
Spent Fuel Pool Level	SFS-JE-LT019C	6	ESF PAMS	24 hrs 2 wks	E ** S
WLS Auxiliary Building RCA Floodup Level	WLS-JE-LT400A	6	(Note 8)	24 hrs	E ** S
WLS Auxiliary Building RCA Floodup Level	WLS-JE-LT400B	6	(Note 8)	24 hrs	E ** S
Containment Pressure Normal Range	PCS-JE-PT005	7	ESF PAMS	5 min 4 mos	E
Containment Pressure Normal Range	PCS-JE-PT006	7	ESF PAMS	5 min 4 mos	E *
Containment Pressure Normal Range	PCS-JE-PT007	7	ESF PAMS	5 min 4 mos	E
Containment Pressure Normal Range	PCS-JE-PT008	7	ESF PAMS	5 min 4 mos	E *
Containment Pressure Extended Range	PCS-JE-PT012	7	PAMS	4 mos	E
Containment Pressure Extended Range	PCS-JE-PT013	7	PAMS	4 mos	E *
Containment Pressure Extended Range	PCS-JE-PT014	7	PAMS	4 mos	E
Containment Pressure Sensor (Shared Diaphragm)	PCS-JE-PT005 PCS-JE-PT012	1	ESF PAMS	5 min 4 mos	E *

Table 3.11-1 (Sheet 17 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Containment Pressure Sensor (Shared Diaphragm)	PCS-JE-PT006 PCS-JE-PT013	1	ESF PAMS	5 min 4 mos	E *
Containment Pressure Sensor (Shared Diaphragm)	PCS-JE-PT007 PCS-JE-PT014	1	ESF PAMS	5 min 4 mos	E *
Containment Pressure Sensor (Diaphragm)	PCS-JE-PT008	1	ESF PAMS	5 min 4 mos	E *
Accumulator A Pressure Transmitter	PXS-JE-PT027	1	PAMS	4 mos	E *
Accumulator B Pressure Transmitter	PXS-JE-PT028	1	PAMS	4 mos	E *
Accumulator A Pressure Transmitter	PXS-JE-PT029	1	PAMS	4 mos	E *
Accumulator B Pressure Transmitter	PXS-JE-PT030	1	PAMS	4 mos	E *
RCS Wide Range Pressure	RCS-JE-PT140A	1	PAMS ESF	4 mos 5 min	E * S
RCS Wide Range Pressure	RCS-JE-PT140B	1	PAMS ESF	4 mos 5 min	E * S
RCS Wide Range Pressure	RCS-JE-PT140C	1	PAMS ESF	4 mos 5 min	E * S
RCS Wide Range Pressure	RCS-JE-PT140D	1	PAMS ESF	4 mos 5 min	E * S
PZR Pressure	RCS-JE-PT191A	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
PZR Pressure	RCS-JE-PT191B	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
PZR Pressure	RCS-JE-PT191C	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
PZR Pressure	RCS-JE-PT191D	1	RT ESF PAMS	5 min 5 min 4 mos	E * S
Main Steam Line SG1 Pressure	SGS-JE-PT030	1	ESF PAMS	5 min 2 wks	E * S
Main Steam Line SG1 Pressure	SGS-JE-PT031	2	ESF PAMS	5 min 2 wks	E
Main Steam Line SG1 Pressure	SGS-JE-PT032	1	ESF PAMS	5 min 2 wks	E * S
Main Steam Line SG1 Pressure	SGS-JE-PT033	2	ESF PAMS	5 min 2 wks	E
Main Steam Line SG2 Pressure	SGS-JE-PT034	1	ESF PAMS	5 min 2 wks	E * S
Main Steam Line SG2 Pressure	SGS-JE-PT035	2	ESF PAMS	5 min 2 wks	E
Main Steam Line SG2 Pressure	SGS-JE-PT036	1	ESF PAMS	5 min 2 wks	E * S

Table 3.11-1 (Sheet 18 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Main Steam Line SG2 Pressure	SGS-JE-PT037	2	ESF PAMS	5 min 2 wks	E
Main Control Room Differential Pressure	VES-JE-PDT004A	3	ESF PAMS	2 wks 2 wks	E
Main Control Room Differential Pressure	VES-JE-PDT004B	3	ESF PAMS	2 wks 2 wks	E
PROTECTION AND SAFETY MONITORING SYSTEMS					
Bistable Coincident Logic Cabinet 01 Division A	PMS-JD-BCCA01	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Bistable Coincident Logic Cabinet 02 Division A	PMS-JD-BCCA02	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Bistable Coincident Logic Cabinet 01 Division B	PMS-JD-BCCB01	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Bistable Coincident Logic Cabinet 02 Division B	PMS-JD-BCCB02	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Bistable Coincident Logic Cabinet 01 Division C	PMS-JD-BCCC01	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Bistable Coincident Logic Cabinet 02 Division C	PMS-JD-BCCC02	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Bistable Coincident Logic Cabinet 01 Division D	PMS-JD-BCCD01	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Bistable Coincident Logic Cabinet 02 Division D	PMS-JD-BCCD02	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Integrated Logic Cabinet 01 Division A	PMS-JD-ILCA01	2	ESF	24 hrs	E
Integrated Logic Cabinet 02 Division A	PMS-JD-ILCA02	2	ESF	24 hrs	E
Integrated Logic Cabinet 03 Division A	PMS-JD-ILCA03	2	ESF	24 hrs	E
Integrated Logic Cabinet 01 Division B	PMS-JD-ILCB01	2	ESF	24 hrs	E
Integrated Logic Cabinet 02 Division B	PMS-JD-ILCB02	2	ESF	24 hrs	E
Integrated Logic Cabinet 03 Division B	PMS-JD-ILCB03	2	ESF	24 hrs	E
Integrated Logic Cabinet 04 Division B	PMS-JD-ILCB04	2	ESF	24 hrs	E
Integrated Logic Cabinet 01 Division C	PMS-JD-ILCC01	2	ESF	24 hrs	E
Integrated Logic Cabinet 02 Division C	PMS-JD-ILCC02	2	ESF	24 hrs	E
Integrated Logic Cabinet 01 Division D	PMS-JD-ILCD01	2	ESF	24 hrs	E
Integrated Logic Cabinet 02 Division D	PMS-JD-ILCD02	2	ESF	24 hrs	E
Integrated Logic Cabinet 03 Division D	PMS-JD-ILCD03	2	ESF	24 hrs	E
Integrated Logic Cabinet 04 Division D	PMS-JD-ILCD04	2	ESF	24 hrs	E
Maintenance and Test Cabinet Division A	PMS-JD-MTCA01	2	PAMS	2 wks	E
Maintenance and Test Cabinet Division B	PMS-JD-MTCB01	2	PAMS	2 wks	E
Maintenance and Test Cabinet Division C	PMS-JD-MTCC01	2	PAMS	2 wks	E

Table 3.11-1 (Sheet 19 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Maintenance and Test Cabinet Division D	PMS-JD-MTCD01	2	PAMS	2 wks	E
Nuclear Instrumentation Cabinet Division A	PMS-JD-NICA01	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Nuclear Instrumentation Cabinet Division B	PMS-JD-NICB01	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Nuclear Instrumentation Cabinet Division C	PMS-JD-NICC01	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Nuclear Instrumentation Cabinet Division D	PMS-JD-NICD01	2	RT ESF PAMS	5 min 24 hrs 2 wks	E
Qualified Data Processing System Cabinet Division B	PMS-JD-QDPB01	2	ESF PAMS	24 hrs 2 wks	E
Qualified Data Processing System Cabinet Division C	PMS-JD-QDPC01	2	ESF PAMS	24 hrs 2 wks	E
Division A Squib Valve Controller Cabinet	PMS-JD-SVCA01	2	ESF	24 hrs	E
Division B Squib Valve Controller Cabinet	PMS-JD-SVCB01	2	ESF	24 hrs	E
Division C Squib Valve Controller Cabinet	PMS-JD-SVCC01	2	ESF	24 hrs	E
Division D Squib Valve Controller Cabinet	PMS-JD-SVCD01	2	ESF	24 hrs	E
Source Range Neutron Flux Preamplifier Panel A	PMS-JW-005A	2	RT, ESF	Note 3	E
Source Range Neutron Flux Preamplifier Panel B	PMS-JW-005B	2	RT, ESF	Note 3	E
Source Range Neutron Flux Preamplifier Panel C	PMS-JW-005C	2	RT, ESF	Note 3	E
Source Range Neutron Flux Preamplifier Panel D	PMS-JW-005D	2	RT, ESF	Note 3	E
Intermediate Range Neutron Flux Preamplifier Panel A	PMS-JW-006A	2	RT PAMS	Note 3 2 wks	E
Intermediate Range Neutron Flux Preamplifier Panel B	PMS-JW-006B	2	RT PAMS	Note 3 2 wks	E
Intermediate Range Neutron Flux Preamplifier Panel C	PMS-JW-006C	2	RT PAMS	Note 3 2 wks	E
Intermediate Range Neutron Flux Preamplifier Panel D	PMS-JW-006D	2	RT PAMS	Note 3 2 wks	E
MAIN CONTROL ROOM					
Operator Workstation A	N/A	3	RT ESF PAMS	5 min 24 hrs 2 wks	E
Operator Workstation B	N/A	3	RT ESF PAMS	5 min 24 hrs 2 wks	E

Table 3.11-1 (Sheet 20 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Supervisor Workstation	N/A	3	RT ESF PAMS	5 min 24 hrs 2 wks	E
Primary Dedicated Safety Panel	OCS-JC-10	3	RT ESF	5 min 24 hrs	E
Secondary Dedicated Safety Panel	OCS-JC-11	3	RT ESF	5 min 24 hrs	E
MCR/RSR Transfer Switch Panel	OCS-JW-001	2	RT ESF	5 min 24 hrs	E
Qualified Safety Display Division A	PMS-JD-QSPA01	3	ESF PAMS	24 hrs 2 wks	E
Qualified Safety Display Division B	PMS-JD-QSPB01	3	ESF PAMS	24 hrs 2 wks	E
Qualified Safety Display Division C	PMS-JD-QSPC01	3	ESF PAMS	24 hrs 2 wks	E
Qualified Safety Display Division D	PMS-JD-QSPD01	3	ESF PAMS	24 hrs 2 wks	E
MCR Load Shed Panel 1	VES-EP-01	2	ESF PAMS	24 hrs 2 wks	E S
MCR Load Shed Panel 2	VES-EP-02	2	ESF PAMS	24 hrs 2 wks	E
PENETRATIONS					
Penetrations (Mechanical)	See Table 6.2.3-1				M * S
Equipment Hatch	CNS-MY-Y01	1, 7, 9	PB	4 mos	M * S
Maintenance Hatch	CNS-MY-Y02	1, 7	PB	4 mos	M * S
Upper Personnel Hatch – 135'-3"	CNS-MY-Y03	1, 7, 9	PB	4 mos	M * S
Lower Personnel Hatch – 107'-2"	CNS-MY-Y04	1, 7	PB	4 mos	M * S
Penetrations (Electrical)	See Figure 3.8.2-4				E * S
ACTIVE VALVES					
Containment Isolation – Air Out	CAS-PL-V014	2	ESF	5 min	M **
Solenoid Valve	CAS-PL-V014-S	2	ESF	5 min	E
Limit Switch	CAS-PL-V014-L	2	PAMS	2 wks	E
Containment Isolation – Air In	CAS-PL-V015	1	ESF	24 hrs	M * S
Containment Isolation – Inlet	CCS-PL-V200	2	ESF	5 min	M **
Limit Switch	CCS-PL-V200-L	2	PAMS	2 wks	E
Motor Operator	CCS-PL-V200-M	2	ESF	5 min	E
Service Air Supply Inside Containment Isolation	CAS-PL-V205	1	ESF	24 hrs	M * S
Containment Isolation – Inlet	CCS-PL-V201	1	ESF	24 hrs	M * S
Containment Isolation – Outlet	CCS-PL-V207	1	ESF	5 min	M * S
Limit Switch	CCS-PL-V207-L	1	PAMS	1 yr	E * S
Motor Operator	CCS-PL-V207-M	1	ESF	5 min	E * S
Containment Isolation – Outlet	CCS-PL-V208	2	ESF	5 min	M **
Limit Switch	CCS-PL-V208-L	2	PAMS	2 wks	E
Motor Operator	CCS-PL-V208-M	2	ESF	5 min	E

Table 3.11-1 (Sheet 21 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
CCS Containment Isolation Relief	CCS-PL-V220	1	ESF	24 hrs	M * S
CCS IRC Relief Valve	CCS-PL-V270	1	ESF	24 hrs	M* S
CCS IRC Relief Valve	CCS-PL-V271	1	ESF	24 hrs	M* S
RCS Purification Stop Valve	CVS-PL-V001	1	ESF	5 min	M * S
Limit Switch	CVS-PL-V001-L	1	PAMS	1 yr	E * S
Motor Operator	CVS-PL-V001-M	1	ESF	5 min	E * S
RCS Purification Stop Valve	CVS-PL-V002	1	ESF	5 min	M * S
Limit Switch	CVS-PL-V002-L	1	PAMS	1 yr	E * S
Motor Operator	CVS-PL-V002-M	1	ESF	5 min	E * S
RCS Letdown Stop Valve	CVS-PL-V003	1	ESF	5 min	M * S
Limit Switch	CVS-PL-V003-L	1	PAMS	1 yr	E * S
Motor Operator	CVS-PL-V003-M	1	ESF	5 min	E * S
Demineralizer Flush Line Relief Valve	CVS-PL-V042	1	ESF	24 hrs	M * S
WLS Letdown IRC Isolation	CVS-PL-V045	1	ESF	5 min	M * S
Limit Switch	CVS-PL-V045-L	1	PAMS	1 yr	E * S
Solenoid Valve	CVS-PL-V045-S1	1	ESF	5 min	E * S
Letdown Flow ORC Isolation	CVS-PL-V047	7	ESF	5 min	M ** S
Limit Switch	CVS-PL-V047-L	7	PAMS	2 wks	E ** S
Solenoid Valve	CVS-PL-V047-S1	7	ESF	5 min	E ** S
Letdown Line Containment Isolation Thermal Relief	CVS-PL-V058	1	ESF	24 hrs	M * S
CVS Makeup Line Bypass Check Valve	CVS-PL-V067	1	ESF	5 min	M* S
RCS Purification Check Valve	CVS-PL-V080	1	ESF	5 min	M * S
RCS Purification Stop Valve	CVS-PL-V081	1	ESF	5 min	M * S
RCS Purification Check Valve	CVS-PL-V082	1	ESF	5 min	M * S
Auxiliary PZR Spray Isolation	CVS-PL-V084	1	ESF	5 min	M * S
Limit Switch	CVS-PL-V084-L	1	PAMS	1 yr	E * S
Solenoid Valve	CVS-PL-V084-S	1	ESF	5 min	E * S
Auxiliary PZR Spray Isolation	CVS-PL-V085	1	ESF	5 min	M * S
Makeup Line Containment Isolation	CVS-PL-V090	7	ESF	5 min	M ** S
Limit Switch	CVS-PL-V090-L	7	PAMS	2 wks	E ** S
Motor Operator	CVS-PL-V090-M	7	ESF	5 min	E ** S
Makeup Line Containment Isolation	CVS-PL-V091	1	ESF	5 min	M * S
Limit Switch	CVS-PL-V091-L	1	PAMS	1 yr	E * S
Motor Operator	CVS-PL-V091-M	1	ESF	5 min	E * S
Zinc Injection Containment Isolation	CVS-PL-V092	10	ESF	5 min	M * S
Limit Switch	CVS-PL-V092-L	10	PAMS	2 wks	E * S
Solenoid Valve	CVS-PL-V092-S	10	ESF	5 min	E * S
Zinc Injection Containment Isolation IRC	CVS-PL-V094	1	ESF	5 min	M * S
Limit Switch	CVS-PL-V094-L	1	PAMS	1 yr	E * S
Solenoid Valve	CVS-PL-V094-S	1	ESF	5 min	E * S
Zinc Injection Containment Isolation Thermal Overpressurization Relief Valve	CVS-PL-V098	1	ESF	24 hrs	M * S

Table 3.11-1 (Sheet 22 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Makeup Containment Isolation	CVS-PL-V100	1	ESF	24 hrs	M * S
Demineralizer Water System Isolation	CVS-PL-V136A	7	ESF	5 min	M **
Limit Switch	CVS-PL-V136A-L	7	PAMS	2 wks	E **
Solenoid Valve	CVS-PL-V136A-S	7	ESF	5 min	E **
Demineralized Water System Isolation	CVS-PL-V136B	7	ESF	5 min	M **
Limit Switch	CVS-PL-V136B-L	7	PAMS	2 wks	E **
Solenoid Valve	CVS-PL-V136B-S	7	ESF	5 min	E **
Hydrogen Injection Containment Isolation Check IRC	CVS-PL-V217	1	ESF	24 hrs	M * S
Hydrogen Injection Containment Isolation	CVS-PL-V219	10	ESF	5 min	M * S
Limit Switch	CVS-PL-V219-L	10	PAMS	2 wks	E * S
Solenoid Valve	CVS-PL-V219-S	10	ESF	5 min	E * S
DWS Containment Penetration Thermal Relief Valve	DWS-PL-V241	1	ESF	24 hrs	M * S
Demin Water Supply Containment Isolation – Inside	DWS-PL-V245	1	ESF	24 hrs	M * S
Fuel Transfer Tube Gate Valve	FHS-PL-V001	11	ESF	2 wks	M **
Fire Water Containment Supply Isolation – Inside	FPS-PL-V052	1	ESF	24 hrs	M * S
FPS Containment Penetration Thermal Relief Valve	FPS-PL-V702	1	ESF	24 hrs	M * S
PCCWST Isolation Valve	PCS-PL-V001A	9	ESF	5 min	M **
Limit Switch	PCS-PL-V001A-L	9	PAMS	2 wks	E **
Solenoid Valve	PCS-PL-V001A-S1	9	ESF	5 min	E **
PCCWST Isolation Valve	PCS-PL-V001B	9	ESF	5 min	M **
Limit Switch	PCS-PL-V001B-L	9	PAMS	2 wks	E **
Solenoid Valve	PCS-PL-V001B-S1	9	ESF	5 min	E **
PCCWST Isolation Valve	PCS-PL-V001C	9	ESF	5 min	M **
Limit Switch	PCS-PL-V001C-L	9	PAMS	2 wks	E **
Motor Operator	PCS-PL-V001C-M	9	ESF	5 min	E **
PCCWST Isolation Valve	PCS-PL-V002A	9	ESF	5 min	M **
Limit Switch	PCS-PL-V002A-L	9	PAMS	2 wks	E **
Motor Operator	PCS-PL-V002A-M	9	ESF	5 min	E **
PCCWST Isolation Valve	PCS-PL-V002B	9	ESF	5 min	M **
Limit Switch	PCS-PL-V002B-L	9	PAMS	2 wks	E **
Motor Operator	PCS-PL-V002B-M	9	ESF	5 min	E **
PCCWST Isolation Valve	PCS-PL-V002C	9	ESF	5 min	M **
Limit Switch	PCS-PL-V002C-L	9	PAMS	2 wks	E **
Motor Operator	PCS-PL-V002C-M	9	ESF	5 min	E **
PCCWST Fire Protection Isolation	PCS-PL-V005	10	ESF	72 hrs	M * S
PCCWST Emergency Spent Fuel Pool Makeup Isolation	PCS-PL-V009	9	ESF	2 wks	M **
Water Bucket Makeup Line Drain Valve	PCS-PL-V015	10	ESF	2 wks	M * S

Table 3.11-1 (Sheet 23 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Water Bucket Makeup Line Isolation Valve	PCS-PL-V020	10	ESF	2 wks	M * S
PCS Recirculation Isolation	PCS-PL-V023	10	ESF	72 hrs	M * S
PCCWST Long-Term Makeup Check Valve	PCS-PL-V039	10	ESF	2 wks	M * S
PCCWST Long Term Makeup Isolation Drain Valve	PCS-PL-V042	10	ESF	2 wks	M * S
PCCWST Long Term Makeup Isolation Valve	PCS-PL-V044	10	ESF	2 wks	M * S
Emergency Makeup to the Spent Fuel Pool Isolation Valve	PCS-PL-V045	7	ESF	2 wks	M
PCCWST Recirculation Return Isolation Valve	PCS-PL-V046	10	ESF	2 wks	M * S
Emergency Makeup to the Spent Fuel Pool Drain Isolation Valve	PCS-PL-V049	7	ESF	2 wks	M
Spent Fuel Pool Long Term Makeup Isolation Valve	PCS-PL-V050	10	ESF	2 wks	M * S
Spent Fuel Pool Emergency Makeup Lower Isolation Valve	PCS-PL-V051	7	ESF	2 wks	M
Containment Isolation – Air Sample Line	PSS-PL-V008	1	ESF	4 mos	M * S
Limit Switch	PSS-PL-V008-L	1	PAMS	1 yr	E * S
Solenoid Operator	PSS-PL-V008-S	1	ESF	5 min	E * S
Voltage Control Box	PSS-DJ-05	2	ESF	5 min	E
Containment Isolation – Liquid Sample Line	PSS-PL-V010A	1	ESF	4 mos	M * S
Limit Switch	PSS-PL-V010A-L	1	PAMS	1 yr	E * S
Solenoid Operator	PSS-PL-V010A-S	1	ESF	5 min	E * S
Voltage Control Box	PSS-DJ-03	2	ESF	5 min	E
Containment Isolation – Liquid Sample Line	PSS-PL-V010B	1	ESF	4 mos	M * S
Limit Switch	PSS-PL-V010B-L	1	PAMS	1 yr	E * S
Solenoid Operator	PSS-PL-V010B-S	1	ESF	5 min	E * S
Voltage Control Box	PSS-DJ-04	2	ESF	5 min	E
Containment Isolation – Liquid Sample Line	PSS-PL-V011A	6	ESF	2 wks	M **
Limit Switch	PSS-PL-V011A-L	6	PAMS	2 wks	E **
Solenoid Valve	PSS-PL-V011A-S	6	ESF	5 min	E **
Containment Isolation – Liquid Sample Line	PSS-PL-V011B	6	ESF	2 wks	M **
Limit Switch	PSS-PL-V011B-L	6	PAMS	2 wks	E **
Solenoid Valve	PSS-PL-V011B-S	6	ESF	5 min	E **
Containment Isolation - Sample Return Line	PSS-PL-V023	6	ESF	2 wks	M **
Limit Switch	PSS-PL-V023-L	6	PAMS	2 wks	E **
Solenoid Valve	PSS-PL-V023-S	6	ESF	5 min	E **

Table 3.11-1 (Sheet 24 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Containment Isolation – Sample Return Line	PSS-PL-V024	1	ESF	4 mos	M * S
Limit Switch	PSS-PL-V024-L	1	PAMS	1 yr	E * S
Solenoid Operator	PSS-PL-V024-S	1	ESF	5 min	E * S
Voltage Control Box	PSS-DJ-06	2	ESF	5 min	E
Containment Isolation - Air Sample Line	PSS-PL-V046	6	ESF	2 wks	M **
Limit Switch	PSS-PL-V046-L	6	PAMS	2 wks	E **
Solenoid Valve	PSS-PL-V046-S	6	ESF	2 wks	E **
PWS MCR Isolation Valve	PWS-PL-V418	2	ESF	5 min	M
PWS MCR Isolation Valve	PWS-PL-V420	3	ESF	5 min	M
PWS MCR Vacuum Relief	PWS-PL-V498	3	ESF	5 min	M
Core Makeup Tank A Discharge Isolation	PXS-PL-V014A	1	ESF	5 min	M * S
Limit Switch	PXS-PL-V014A-L	1	PAMS	1 yr (Note 9)	E * S
Solenoid Valve	PXS-PL-V014A-S1	1	ESF	5 min	E * S
Core Makeup Tank B Discharge Isolation	PXS-PL-V014B	1	ESF	5 min	M * S
Limit Switch	PXS-PL-V014B-L	1	PAMS	1 yr (Note 9)	E * S
Solenoid Valve	PXS-PL-V014B-S1	1	ESF	5 min	E * S
Core Makeup Tank A Discharge Isolation	PXS-PL-V015A	1	ESF	5 min	M * S
Limit Switch	PXS-PL-V015A-L	1	PAMS	1 yr (Note 9)	E * S
Solenoid Valve	PXS-PL-V015A-S1	1	ESF	5 min	E * S
Core Makeup Tank B Discharge Isolation	PXS-PL-V015B	1	ESF	5 min	M * S
Limit Switch	PXS-PL-V015B-L	1	PAMS	1 yr (Note 9)	E * S
Solenoid Valve	PXS-PL-V015B-S1	1	ESF	5 min	E * S
Core Makeup Tank A Discharge	PXS-PL-V016A	1	ESF	5 min	M * S
Core Makeup Tank B Discharge	PXS-PL-V016B	1	ESF	5 min	M * S
Core Makeup Tank A Discharge	PXS-PL-V017A	1	ESF	5 min	M * S
Core Makeup Tank B Discharge	PXS-PL-V017B	1	ESF	5 min	M * S
Accumulator A Pressure Relief	PXS-PL-V022A	1	ESF	5 min	M * S
Accumulator B Pressure Relief	PXS-PL-V022B	1	ESF	5 min	M * S
Accumulator A Discharge	PXS-PL-V028A	1	ESF	5 min	M * S
Accumulator B Discharge	PXS-PL-V028B	1	ESF	5 min	M * S
Accumulator A Discharge	PXS-PL-V029A	1	ESF	5 min	M * S
Accumulator B Discharge	PXS-PL-V029B	1	ESF	5 min	M * S
Nitrogen Supply Outside Containment Isolation	PXS-PL-V042	2	ESF	5 min	M **
Limit Switch	PXS-PL-V042-L	2	PAMS	2 wks	E
Solenoid Valve	PXS-PL-V042-S	2	ESF	5 min	E
Nitrogen Supply Containment Isolation IRC Check Valve	PXS-PL-V043	1	ESF	24 hrs	M * S

Table 3.11-1 (Sheet 25 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PRHR HX Discharge Isolation	PXS-PL-V108A	1	ESF	5 min	M * S
Limit Switch	PXS-PL-V108A-L	1	PAMS	1 yr (Note 10)	E * S
Solenoid Valve	PXS-PL-V108A-S1	1	ESF	5 min	E * S
PRHR HX Discharge Isolation	PXS-PL-V108B	1	ESF	5 min	M * S
Limit Switch	PXS-PL-V108B-L	1	PAMS	1 yr (Note 10)	E * S
Solenoid Valve	PXS-PL-V108B-S1	1	ESF	5 min	E * S
Recirc Sump A Isolation	PXS-PL-V118A	1	ESF	72 hrs	M * S
Limit Switch	PXS-PL-V118A-L	1	PAMS	1 yr (Note 9)	E * S
Squib Operator	PXS-PL-V118A-T	1	ESF	72 hrs	E * S
Recirc Sump B Isolation	PXS-PL-V118B	1	ESF	72 hrs	M * S
Limit Switch	PXS-PL-V118B-L	1	PAMS	1 yr (Note 9)	E * S
Squib Operator	PXS-PL-V118B-T	1	ESF	72 hrs	E * S
Recirc Sump A	PXS-PL-V119A	1	ESF	1 yr	M * S
Recirc Sump B	PXS-PL-V119B	1	ESF	1 yr	M * S
Recirc Sump A	PXS-PL-V120A	1	ESF	72 hrs	M * S
Limit Switch	PXS-PL-V120A-L	1	PAMS	1 yr (Note 9)	E * S
Squib Operator	PXS-PL-V120A-T	1	ESF	72 hrs	E * S
Recirc Sump B	PXS- PL-V120B	1	ESF	72 hrs	M * S
Limit Switch	PXS-PL-V120B-L	1	PAMS	1 yr (Note 9)	E * S
Squib Operator	PXS-PL-V120B-T	1	ESF	72 hrs	E * S
IRWST Injection A	PXS-PL-V122A	1	ESF	1 yr	M * S
IRWST Injection B	PXS-PL-V122B	1	ESF	1 yr	M * S
IRWST Injection A	PXS-PL-V123A	1	ESF	72 hrs	M * S
Limit Switch	PXS-PL-V123A-L	1	PAMS	1 yr (Note 9)	E * S
Squib Operator	PXS-PL-V123A-T	1	ESF	72 hrs	E * S
IRWST Injection B	PXS-PL-V123B	1	ESF	72 hrs	M * S
Limit Switch	PXS-PL-V123B-L	1	PAMS	1 yr (Note 9)	E * S
Squib Operator	PXS-PL-V123B-T	1	ESF	72 hrs	E * S
IRWST Injection A	PXS-PL-V124A	1	ESF	1 yr	M * S
IRWST Injection B	PXS-PL-V124B	1	ESF	1 yr	M * S
IRWST Injection A	PXS-PL-V125A	1	ESF	72 hrs	M * S
Limit Switch	PXS-PL-V125A-L	1	PAMS	1 yr (Note 9)	E * S
Squib Operator	PXS-PL-V125A-T	1	ESF	72 hrs	E * S
IRWST Injection B	PXS-PL-V125B	1	ESF	72 hrs	M * S
Limit Switch	PXS-PL-V125B-L	1	PAMS	1 yr (Note 9)	E * S
Squib Operator	PXS-PL-V125B-T	1	ESF	72 hrs	E * S
IRWST Gutter Drain Isolation A	PXS-PL-V130A	1	ESF	5 min	M * S
Limit Switch	PXS-PL-V130A-L	1	PAMS	1 yr	E * S
Solenoid Valve	PXS-PL-V130A-S1	1	ESF	5 min	E * S
IRWST Gutter Drain Isolation B	PXS-PL-V130B	1	ESF	5 min	M * S
Limit Switch	PXS-PL-V130B-L	1	PAMS	1 yr	E * S
Solenoid Valve	PXS-PL-V130B-S1	1	ESF	5 min	E * S

Table 3.11-1 (Sheet 26 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
First Stage ADS	RCS-PL-V001A	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V001A-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V001A-M	1	ESF	24 hrs	E * S
First Stage ADS	RCS-PL-V001B	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V001B-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V001B-M	1	ESF	24 hrs	E * S
Second Stage ADS	RCS-PL-V002A	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V002A-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V002A-M	1	ESF	24 hrs	E * S
Second Stage ADS	RCS-PL-V002B	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V002B-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V002B-M	1	ESF	24 hrs	E * S
Third Stage ADS	RCS-PL-V003A	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V003A-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V003A-M	1	ESF	24 hrs	E * S
Third Stage ADS	RCS-PL-V003B	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V003B-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V003B-M	1	ESF	24 hrs	E * S
Fourth Stage ADS	RCS-PL-V004A	1	ESF	72 hrs	M * S
Limit Switch	RCS-PL-V004A-L	1	PAMS	1 yr	E * S
Squib Operator	RCS-PL-V004A-T	1	ESF	72 hrs	E * S
Fourth Stage ADS	RCS-PL-V004B	1	ESF	72 hrs	M * S
Limit Switch	RCS-PL-V004B-L	1	PAMS	1 yr	E * S
Squib Operator	RCS-PL-V004B-T	1	ESF	72 hrs	E * S
Fourth Stage ADS	RCS-PL-V004C	1	ESF	72 hrs	M * S
Limit Switch	RCS-PL-V004C-L	1	PAMS	1 yr	E * S
Squib Operator	RCS-PL-V004C-T	1	ESF	72 hrs	E * S
Fourth Stage ADS	RCS-PL-V004D	1	ESF	72 hrs	M * S
Limit Switch	RCS-PL-V004D-L	1	PAMS	1 yr	E * S
Squib Operator	RCS-PL-V004D-T	1	ESF	72 hrs	E * S
PZR Safety Valve	RCS-PL-V005A	1	ESF	5 min	M * S
Limit Switch	RCS-PL-V005A-L	1	PAMS	1 yr	E * S
PZR Safety Valve	RCS-PL-V005B	1	ESF	5 min	M * S
Limit Switch	RCS-PL-V005B-L	1	PAMS	1 yr	E * S
ADS Discharge Header A Relief	RCS-PL-V010A	1	ESF	24 hrs	M * S
ADS Discharge Header B Relief	RCS-PL-V010B	1	ESF	24 hrs	M * S
First Stage ADS Isolation	RCS-PL-V011A	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V011A-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V011A-M	1	ESF	24 hrs	E * S
First Stage ADS Isolation	RCS-PL-V011B	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V011B-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V011B-M	1	ESF	24 hrs	E * S

Table 3.11-1 (Sheet 27 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Second Stage ADS Isolation	RCS-PL-V012A	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V012A-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V012A-M	1	ESF	24 hrs	E * S
Second Stage ADS Isolation	RCS-PL-V012B	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V012B-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V012B-M	1	ESF	24 hrs	E * S
Third Stage ADS Isolation	RCS-PL-V013A	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V013A-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V013A-M	1	ESF	24 hrs	E * S
Third Stage ADS Isolation	RCS-PL-V013B	1	ESF	24 hrs	M * S
Limit Switch	RCS-PL-V013B-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V013B-M	1	ESF	24 hrs	E * S
Reactor Vessel Head Vent	RCS-PL-V150A	1	ESF	1 yr	M * S
Limit Switch	RCS-PL-V150A-L	1	PAMS	1 yr	E * S
Solenoid Operator	RCS-PL-V150A-S	1	ESF	1 yr	E * S
Voltage Control Box	RCS-DJ-01	2	ESF	1 yr	E
Reactor Vessel Head Vent	RCS-PL-V150B	1	ESF	1 yr	M * S
Limit Switch	RCS-PL-V150B-L	1	PAMS	1 yr	E * S
Solenoid Operator	RCS-PL-V150B-S	1	ESF	1 yr	E * S
Voltage Control Box	RCS-DJ-02	2	ESF	1 yr	E
Reactor Vessel Head Vent	RCS-PL-V150C	1	ESF	1 yr	M * S
Limit Switch	RCS-PL-V150C-L	1	PAMS	1 yr	E * S
Solenoid Operator	RCS-PL-V150C-S	1	ESF	1 yr	E * S
Voltage Control Box	RCS-DJ-03	2	ESF	1 yr	E
Reactor Vessel Head Vent	RCS-PL-V150D	1	ESF	1 yr	M * S
Limit Switch	RCS-PL-V150D-L	1	PAMS	1 yr	E * S
Solenoid Operator	RCS-PL-V150D-S	1	ESF	1 yr	E * S
Voltage Control Box	RCS-DJ-04	2	ESF	1 yr	E
RCS Inner Suction Isolation	RNS-PL-V001A	1	ESF	5 min	M * S
Limit Switch	RNS-PL-V001A-L	1	PAMS	1 yr (Note 9)	E * S
Motor Operator	RNS-PL-V001A-M	1	ESF	5 min	E * S
RCS Inner Suction Isolation	RNS-PL-V001B	1	ESF	5 min	M * S
Limit Switch	RNS-PL-V001B-L	1	PAMS	1 yr (Note 9)	E * S
Motor Operator	RNS-PL-V001B-M	1	ESF	5 min	E * S
RCS Outer Suction Isolation	RNS-PL-V002A	1	ESF	5 min	M * S
Limit Switch	RNS-PL-V002A-L	1	PAMS	1 yr (Note 9)	E * S
Motor Operator	RNS-PL-V002A-M	1	ESF	5 min	E * S
RCS Outer Suction Isolation	RNS-PL-V002B	1	ESF	5 min	M * S
Limit Switch	RNS-PL-V002B-L	1	PAMS	1 yr (Note 9)	E * S
Motor Operator	RNS-PL-V002B-M	1	ESF	5 min	E * S
RCS Thermal Relief	RNS-PL-V003A	1	ESF	24 hrs	M * S
RCS Thermal Relief	RNS-PL-V003B	1	ESF	24 hrs	M * S

Table 3.11-1 (Sheet 28 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RHR Control/Isolation Valve	RNS-PL-V011	6	ESF	5 min	M **
Limit Switch	RNS-PL-V011-L	6	PAMS	2 wks	E **
Motor Operator	RNS-PL-V011-M	6	ESF	5 min	E **
RNS Discharge Containment Isolation Valve Test Connection	RNS-PL-V012	6	ESF	1 yr	M **
RNS Discharge Containment Isolation	RNS-PL-V013	1	ESF	24 hrs	M * S
RNS Discharge RCS Pressure Boundary	RNS-PL-V015A	1	ESF	5 min	M * S
RNS Discharge RCS Pressure Boundary	RNS-PL-V015B	1	ESF	5 min	M * S
RNS Discharge RCS Pressure Boundary	RNS-PL-V017A	1	ESF	5 min	M * S
RNS Discharge RCS Pressure Boundary	RNS-PL-V017B	1	ESF	5 min	M * S
RNS Hot Leg Suction Relief	RNS-PL-V020	1	ESF	24 hrs	M * S
RNS Hot Leg Suction Relief	RNS-PL-V021	1	ESF	24 hrs	M * S
RNS Suction Header Containment Isolation	RNS-PL-V022	6	ESF	5 min	M **
Limit Switch	RNS-PL-V022-L	6	PAMS	2 wks	E **
Motor Operator	RNS-PL-V022-M	6	ESF	5 min	E **
IRWST Suction Line Isolation	RNS-PL-V023	1	ESF	5 min	M * S
Limit Switch	RNS-PL-V023-L	1	PAMS	1 yr (Note 9)	E * S
Motor Operator	RNS-PL-V023-M	1	ESF	5 min	E * S
RNS – CVS Containment Isolation	RNS-PL-V061	1	ESF	5 min	M * S
Limit Switch	RNS-PL-V061-L	1	PAMS	1 yr (Note 9)	E * S
Air Operator	RNS-PL-V061-S	1	ESF	5 min	E * S
SDS MCR Vent Isolation Valve	SDS-PL-V001	3	ESF	24 hrs	M
Limit Switch	SDS-PL-V001-L	3	PAMS	2 wks	E
Motor Operator	SDS-PL-V001-M	3	ESF	5 min	E
SDS MCR Vent Isolation Valve	SDS-PL-V002	3	ESF	24 hrs	M
Limit Switch	SDS-PL-V002-L	3	PAMS	2 wks	E
Motor Operator	SDS-PL-V002-M	3	ESF	5 min	E
SFS Suction Line Containment Isolation	SFS-PL-V034	1	ESF	5 min	M * S
Limit Switch	SFS-PL-V034-L	1	PAMS	1 yr (Note 9)	E * S
Motor Operator	SFS-PL-V034-M	1	ESF	5 min	E * S
SFS Suction Line Containment Isolation	SFS-PL-V035	6	ESF	5 min	M **
Limit Switch	SFS-PL-V035-L	6	PAMS	2 wks	E **
Motor Operator	SFS- PL-V035-M	6	ESF	5 min	E **
SFS Discharge Containment Isolation	SFS-PL-V037	1	ESF	24 hrs	M * S
SFS Discharge Line Containment Isolation	SFS-PL-V038	6	ESF	5 min	M **
Limit Switch	SFS-PL-V038-L	6	PAMS	2 wks	E **
Motor Operator	SFS-PL-V038-M	6	ESF	5 min	E **
SFS Cask Loading Pit to SFS Pump	SFS-PL-V042	6	ESF	2 wks	M **
SFS Pump to Cask Loading Pit	SFS-PL-V045	6	ESF	2 wks	M **
Cask Loading Pit to WLS	SFS-PL-V049	6	ESF	2 wks	M **

Table 3.11-1 (Sheet 29 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Spent Fuel Pool to Cask Washdown Pit Isolation	SFS-PL-V066	6	ESF	2 wks	M **
SFS Containment Isolation Relief	SFS-PL-V067	1	ESF	24 hrs	M * S
Cask Washdown Pit Drain Isolation	SFS-PL-V068	6	ESF	2 wks	M **
Refueling Cavity to SG Compartment	SFS-PL-V071	1	ESF	2 wks	M * S
Refueling Cavity to SG Compartment	SFS-PL-V072	1	ESF	2 wks	M * S
PORV Block Valve	SGS-PL-V027A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V027A-L	5	PAMS	2 wks	E * S
Motor Operator	SGS-PL-V027A-M	5	ESF	5 min	E * S
PORV Block Valve	SGS-PL-V027B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V027B-L	5	PAMS	2 wks	E * S
Motor Operator	SGS-PL-V027B-M	5	ESF	5 min	E * S
Main Steam Safety Valve SG01	SGS-PL-V030A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V030A-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG02	SGS-PL-V030B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V030B-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG01	SGS-PL-V031A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V031A-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG02	SGS-PL-V031B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V031B-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG01	SGS-PL-V032A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V32A-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG02	SGS-PL-V032B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V032B-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG01	SGS-PL-V033A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V033A-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG02	SGS-PL-V033B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V033B-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG01	SGS-PL-V034A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V034A-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG02	SGS-PL-V034B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V034B-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG01	SGS-PL-V035A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V035A-L	5	PAMS	2 wks	E * S
Main Steam Safety Valve SG02	SGS-PL-V035B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V035B-L	5	PAMS	2 wks	E * S
Steam Line Condensate Drain Isolation	SGS-PL-V036A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V036A-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V036A-S	5	ESF	5 min	E * S
Steam Line Condensate Drain Isolation	SGS-PL-V036B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V036B-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V036B-S	5	ESF	5 min	E * S

Table 3.11-1 (Sheet 30 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Main Steam Line Isolation	SGS-PL-V040A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V040A-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V040A-S1	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V040A-S2	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V040A-S3	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V040A-S4	5	ESF	5 min	E * S
Main Steam Line Isolation	SGS-PL-V040B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V040B-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V040B-S1	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V040B-S2	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V040B-S3	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V040B-S4	5	ESF	5 min	E * S
Main Feedwater Isolation	SGS-PL-V057A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V057A-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V057A-S1	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V057A-S2	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V057A-S3	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V057A-S4	5	ESF	5 min	E * S
Main Feedwater Isolation	SGS-PL-V057B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V057B-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V057B-S1	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V057B-S2	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V057B-S3	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V057B-S4	5	ESF	5 min	E * S
Startup Feedwater Isolation	SGS-PL-V067A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V067A-L	5	PAMS	2 wks	E * S
Motor Operator	SGS-PL-V067A-M	5	ESF	5 min	E * S
Startup Feedwater Isolation	SGS-PL-V067B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V067B-L	5	PAMS	2 wks	E * S
Motor Operator	SGS-PL-V067B-M	5	ESF	5 min	E * S
SG Blowdown Isolation	SGS-PL-V074A	10	ESF	5 min	M * S
Limit Switch	SGS-PL-V074A-L	10	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V074A-S	10	ESF	5 min	E * S
SG Blowdown Isolation	SGS-PL-V074B	10	ESF	5 min	M * S
Limit Switch	SGS-PL-V074B-L	10	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V074B-S	10	ESF	5 min	E * S
SG Series Blowdown Isolation	SGS-PL-V075A	10	ESF	5 min	M * S
Limit Switch	SGS-PL-V075A-L	10	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V075A-S	10	ESF	5 min	E * S
SG Series Blowdown Isolation	SGS-PL-V075B	10	ESF	5 min	M * S
Limit Switch	SGS-PL-V075B-L	10	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V075B-S	10	ESF	5 min	E * S

Table 3.11-1 (Sheet 31 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Steam Line Condensate Drain	SGS-PL-V086A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V086A-L	5	PAMS	2 wks	E * S
Isolation Solenoid Valve	SGS-PL-V086A-S	5	ESF	5 min	E * S
Steam Line Condensate Drain	SGS-PL-V086B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V086B-L	5	PAMS	2 wks	E * S
Isolation Solenoid Valve	SGS-PL-V086B-S	5	ESF	5 min	E * S
Power Operated Relief Valve	SGS-PL-V233A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V233A-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V233A-S	5	ESF	5 min	E * S
Power Operated Relief Valve	SGS-PL-V233B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V233B-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V233B-S	5	ESF	5 min	E * S
MSIV Bypass Isolation Valve	SGS-PL-V240A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V240A-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V240A-S1	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V240A-S2	5	ESF	5	E * S
MSIV Bypass Isolation Valve	SGS-PL-V240B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V240B-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V240B-S1	5	ESF	5 min	E * S
Solenoid Valve	SGS-PL-V240B-S2	5	ESF	5 min	E * S
Main Feedwater Control Valve	SGS-PL-V250A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V250A-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V250A-S	5	ESF	5 min	E * S
Main Feedwater Control Valve	SGS-PL-V250B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V250B-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V250B-S	5	ESF	5 min	E * S
Startup Feedwater Control Valve	SGS-PL-V255A	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V255A-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V255A-S	5	ESF	5 min	E * S
Startup Feedwater Control Valve	SGS-PL-V255B	5	ESF	5 min	M * S
Limit Switch	SGS-PL-V255B-L	5	PAMS	2 wks	E * S
Solenoid Valve	SGS-PL-V255B-S	5	ESF	5 min	E * S
Main Feedwater Thermal Relief Valve	SGS-PL-V257A	5	ESF	24 hrs	M * S
Main Feedwater Thermal Relief Valve	SGS-PL-V257B	5	ESF	24 hrs	M * S
Startup Feedwater Thermal Relief Valve	SGS-PL-V258A	5	ESF	24 hrs	M * S
Startup Feedwater Thermal Relief Valve	SGS-PL-V258B	5	ESF	24 hrs	M * S
MCR Isolation Valve	VBS-PL-V186	3	ESF	24 hrs	M
Limit Switch	VBS-PL-V186-L	3	PAMS	2 wks	E
Motor Operator	VBS-PL-V186-M	3	ESF	24 hrs	E
MCR Isolation Valve	VBS-PL-V187	3	ESF	24 hrs	M
Limit Switch	VBS-PL-V187-L	3	PAMS	2 wks	E
Motor Operator	VBS-PL-V187-M	3	ESF	24 hrs	E

Table 3.11-1 (Sheet 32 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
MCR Isolation Valve	VBS-PL-V188	3	ESF	24 hrs	M
Limit Switch	VBS-PL-V188-L	3	PAMS	2 wks	E
Motor Operator	VBS-PL-V188-M	3	ESF	24 hrs	E
MCR Isolation Valve	VBS-PL-V189	3	ESF	24 hrs	M
Limit Switch	VBS-PL-V189-L	3	PAMS	2 wks	E
Motor Operator	VBS-PL-V189-M	3	ESF	24 hrs	E
MCR Isolation Valve	VBS-PL-V190	3	ESF	24 hrs	M
Limit Switch	VBS-PL-V190-L	3	PAMS	2 wks	E
Motor Operator	VBS-PL-V190-M	3	ESF	24 hrs	E
MCR Isolation Valve	VBS-PL-V191	3	ESF	24 hrs	M
Limit Switch	VBS-PL-V191-L	3	PAMS	2 wks	E
Motor Operator	VBS-PL-V191-M	3	ESF	24 hrs	E
Air Delivery Isolation Valve	VES-PL-V001	3	ESF	2 wks	M
Pressure Regulator Valve A	VES-PL-V002A	7	ESF	2 wks	M **
Pressure Regulator Valve B	VES-PL-V002B	7	ESF	2 wks	M **
Air Delivery Isolation Valve A	VES-PL-V005A	3	ESF	2 wks	M
Limit Switch	VES-PL-V005A-L	3	PAMS	2 wks	E
Solenoid Operator	VES-PL-V005A-S	3	ESF	2 wks	E
Voltage Control Box	VES-DJ-01	2	ESF	2 wks	E
Air Delivery Isolation Valve B	VES-PL-V005B	3	ESF	2 wks	M
Limit Switch	VES-PL-V005B-L	3	PAMS	2 wks	E
Solenoid Operator	VES-PL-V005B-S	3	ESF	2 wks	E
Voltage Control Box	VES-DJ-02	2	ESF	2 wks	E
Temporary Instrument Isolation Valve A	VES-PL-V018	7	ESF	2 wks	M **
Temporary Instrument Isolation Valve B	VES-PL-V019	7	ESF	2 wks	M **
Relief Isolation Valve A	VES-PL-V022A	3	ESF	2 wks	M
Limit Switch	VES-PL-V022A-L	3	PAMS	2 wks	E
Solenoid Valve	VES-PL-V022A-S	3	ESF	2 wks	E
Relief Isolation Valve B	VES-PL-V022B	3	ESF	2 wks	M
Limit Switch	VES-PL-V022B-L	3	PAMS	2 wks	E
Solenoid Valve	VES-PL-V022B-S	3	ESF	2 wks	E
Air Tank Safety Relief Valve A	VES-PL-V040A	7	ESF	2 wks	M **
Air Tank Safety Relief Valve B	VES-PL-V040B	7	ESF	2 wks	M **
Air Tank Safety Relief Valve C	VES-PL-V040C	7	ESF	2 wks	M **
Air Tank Safety Relief Valve D	VES-PL-V040D	7	ESF	2 wks	M **
Main Air Flow Path Isolation Valve	VES-PL-V044	3	ESF	2 wks	M
Eductor Flow Path Isolation Valve	VES-PL-V045	3	ESF	2 wks	M
Eductor Bypass Isolation Valve	VES-PL-V046	3	ESF	2 wks	M
Containment Purge Inlet Isolation	VFS-PL-V003	7	ESF	5 min	M
Limit Switch	VFS-PL-V003-L	7	PAMS	2 wks	E
Solenoid Valve	VFS-PL-V003-S1	7	ESF	5 min	E
Containment Purge Inlet Isolation	VFS-PL-V004	1	ESF	5 min	M * S
Limit Switch	VFS-PL-V004-L	1	PAMS	1 yr	E * S
Solenoid Valve	VFS-PL-V004-S1	1	ESF	5 min	E * S

Table 3.11-1 (Sheet 33 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Containment Purge Discharge Isolation	VFS-PL-V009	1	ESF	5 min	M * S
Limit Switch	VFS-PL-V009-L	1	PAMS	1 yr	E * S
Solenoid Valve	VFS-PL-V009-S1	1	ESF	5 min	E * S
Containment Purge Discharge Isolation	VFS-PL-V010	6	ESF	5 min	M **
Limit Switch	VFS-PL-V010-L	6	PAMS	2 wks	E **
Solenoid Valve	VFS-PL-V010-S1	6	ESF	5 min	E **
Vacuum Relief Containment Isolation Valve A - ORC	VFS-PL-V800A	7	ESF	24 hrs	M **
Limit Switch	VFS-PL-V800A-L	7	PAMS	1 yr	E **
Motor Operator	VFS-PL-V800A-M	7	ESF	24 hrs	E
Vacuum Relief Containment Isolation Valve B - ORC	VFS-PL-V800B	7	ESF	24 hrs	M **
Limit Switch	VFS-PL-V800B-L	7	PAMS	1 yr	E **
Motor Operator	VFS-PL-V800B-M	7	ESF	24 hrs	E
Vacuum Relief Containment Isolation Check Valve A - IRC	VFS-PL-V803A	1	ESF	24 hrs	M* S
Vacuum Relief Containment Isolation Check Valve B - IRC	VFS-PL-V803B	1	ESF	24 hrs	M* S
VWS Containment Penetration Thermal Relief Valve	VWS-PL-V053	1	ESF	24 hrs	M* S
VWS Containment Penetration Thermal Relief Valve	VWS-PL-V057	1	ESF	24 hrs	M* S
Fan Cooler Supply Isolation	VWS-PL-V058	2	ESF	5 min	M **
Limit Switch	VWS-PL-V058-L	2	PAMS	2 wks	E
Solenoid Valve	VWS-PL-V058-S	2	ESF	5 min	E
Fan Coolers Supply Containment Isolation Check Valve	VWS-PL-V062	1	ESF	24 hrs	M * S
VWS Containment Isolation Relief	VWS-PL-V080	1	ESF	24 hrs	M * S
Fan Cooler Return Isolation	VWS-PL-V082	1	ESF	5 min	M * S
Limit Switch	VWS-PL-V082-L	1	PAMS	1 yr	E * S
Solenoid Valve	VWS-PL-V082-S	1	ESF	5 min	E * S
Fan Cooler Return Isolation	VWS-PL-V086	2	ESF	5 min	M **
Limit Switch	VWS-PL-V086-L	2	PAMS	2 wks	E
Solenoid Valve	VWS-PL-V086-S	2	ESF	5 min	E
Sump Containment Isolation IRC	WLS-PL-V055	1	ESF	5 min	M * S
Limit Switch	WLS-PL-V055-L	1	PAMS	1 yr	E * S
Solenoid Valve	WLS-PL-V055-S1	1	ESF	5 min	E * S
Sump Containment Isolation ORC	WLS-PL-V057	7	ESF	5 min	M ** S
Limit Switch	WLS-PL-V057-L	7	PAMS	2 wks	E **
Solenoid Valve	WLS-PL-V057-S1	7	ESF	5 min	E ** S
WLS Containment Isolation Relief	WLS-PL-V058	1	ESF	24 hrs	M * S
RCDT Gas Containment Isolation	WLS-PL-V067	1	ESF	5 min	M * S
Limit Switch	WLS-PL-V067-L	1	PAMS	1 yr (Note 9)	E * S
Solenoid Valve	WLS-PL-V067-S	1	ESF	5 min	E * S

Table 3.11-1 (Sheet 34 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RCDT Gas Containment Isolation	WLS-PL-V068	7	ESF	5 min	M ** S
Limit Switch	WLS-PL-V068-L	7	PAMS	2 wks	E **
Solenoid Valve	WLS-PL-V068-S	7	ESF	5 min	E ** S
CVS To Sump	WLS-PL-V071 A	1	ESF	2 wks	M * S
PXS A To Sump	WLS-PL-V071 B	1	ESF	2 wks	M * S
PXS B To Sump	WLS-PL-V071 C	1	ESF	2 wks	M * S
CVS To Sump	WLS-PL-V072 A	1	ESF	2 wks	M * S
PXS A To Sump	WLS-PL-V072 B	1	ESF	2 wks	M * S
PXS B To Sump	WLS-PL-V072 C	1	ESF	2 wks	M * S
MISCELLANEOUS					
Non-Active Valves					
Containment Penetration Test Connection Isolation	CAS-PL-V027	1	PB	1 yr	M* S
Service Air Supply Outside Containment Isolation	CAS-PL-V204	2	PB	1 yr	M **
Containment Penetration Test Connection Isolation	CAS-PL-V219	1	PB	1 yr	M * S
Containment Isolation Valve Test Connection – Outlet Line	CCS-PL-V209	1	PB	1 yr	M * S
CCS Supply Containment Isolation – IRC	CCS-PL-V214	1	PB	1 yr	M* S
CCS Supply Containment Isolation Valve Test Connection – IRC	CCS-PL-V215	1	PB	1 yr	M* S
Containment Leak Test Outlet Line – IRC	CCS-PL-V216	1	PB	1 yr	M* S
Containment Isolation Valve V207 Body Test Connection Valve	CCS-PL-V217	1	PB	1 yr	M* S
Containment Isolation Valve Test Connection – Inlet Line	CCS-PL-V257	2	PB	1 yr	M **
Resin Flush IRC Isolation	CVS-PL-V040	1	PB	1 yr	M * S
Resin Flush ORC Isolation	CVS-PL-V041	7	PB	1 yr	M ** S
Letdown PZR Instrument Root	CVS-PL-V046	7	PB	1 yr	M ** S
Zinc Addition – IRC Shutoff	CVS-PL-V065	1	PB	1 yr	M * S
Zinc Add Cont Isolation Test Connection	CVS-PL-V095	1	PB	1 yr	M * S
Zinc Addition Containment Isolation Test Connection	CVS-PL-V096	10	PB	1 yr	M * S
Hydrogen Injection – IRC Shutoff	CVS-PL-V215	1	PB	1 yr	M * S
Hydrogen Addition Containment Isolation Test Connection	CVS-PL-V216	1	PB	1 yr	M * S
Hydrogen Addition Containment Isolation Test Connection	CVS-PL-V218	1	PB	1 yr	M * S
Demin Water Supply Containment Isolation – Outside	DWS-PL-V244	10	PB	1 yr	M * S
Containment Penetration Test Connection Isolation	DWS-PL-V248	10	PB	1 yr	M * S
Fire Water Containment Supply Isolation	FPS-PL-V050	10	PB	1 yr	M * S

Table 3.11-1 (Sheet 35 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Fire Water Containment Test Connection Isolation	FPS-PL-V051	10	PB	1 yr	M * S
Flow Transmitter FT001 Root Valve	PCS-PL-V010A	9	PB	1 yr	M **
Flow Transmitter FT001 Root Valve	PCS-PL-V010B	9	PB	1 yr	M **
Flow Transmitter FT002 Root Valve	PCS-PL-V011A	9	PB	1 yr	M **
Flow Transmitter FT002 Root Valve	PCS-PL-V011B	9	PB	1 yr	M **
Flow Transmitter FT003 Root Valve	PCS-PL-V012A	9	PB	1 yr	M **
Flow Transmitter FT003 Root Valve	PCS-PL-V012B	9	PB	1 yr	M **
Flow Transmitter FT004 Root Valve	PCS-PL-V013A	9	PB	1 yr	M **
Flow Transmitter FT004 Root Valve	PCS-PL-V013B	9	PB	1 yr	M **
PCCWST Drain Isolation Valve	PCS-PL-V016	9	PB	1 yr	M **
Makeup to Distr. Bucket Isolation Valve	PCS-PL-V026	6	ESF	2 wks	M **
PCCWST Isolation Valve Leakage Detection Drain	PCS-PL-V029	9	PB	1 yr	M **
PCCWST Isolation Valve Leakage Detection Crossconn	PCS-PL-V030	9	PB	1 yr	M **
PCCWST Level Instrument Root Valve	PCS-PL-V031A	9	PB	1 yr	M **
PCCWST Level Instrument Root Valve	PCS-PL-V031B	9	PB	1 yr	M **
Recirculation Pump Suction from Long Term Makeup Isolation Valve	PCS-PL-V033	10	ESF	2 wks	M * S
Spent Fuel Pool Emergency Makeup Isolation	PCS-PL-V052	7	PB	1 yr	M
Shutoff Valve for Leakage Sensor	PCS-PL-V060A	9	PB	1 yr	M **
Shutoff Valve for Leakage Sensor	PCS-PL-V060B	9	PB	1 yr	M **
Recirculation Header Discharge to SFS Pool Vent Isolation Valve	PCS-PL-V303	10	PB	1 yr	M * S
Recirculation Header Discharge to SFS Pool Drain Isolation Valve	PCS-PL-V304	7	PB	1 yr	M *
PCCWST Recirculation Return Drain Isolation Valve	PCS-PL-V305	10	PB	1 yr	M * S
Hot Leg 1 Sample Isolation	PSS-PL-V001A	1	PB	1 yr	M * S
Limit Switch	PSS-PL-V001A-L	1	PAMS	1 yr	E * S
Solenoid Valve	PSS-PL-V001A-S	1	ESF	24 hrs	E * S
Voltage Control Box	PSS-DJ-01	2	ESF	24 hrs	E
Hot Leg 2 Sample Isolation	PSS-PL-V001B	1	PB	1 yr	M * S
Limit Switch	PSS-PL-V001B-L	1	PAMS	1 yr	E * S
Solenoid Valve	PSS-PL-V001B-S	1	ESF	24 hrs	E * S
Voltage Control Box	PSS-DJ-02	2	ESF	24 hrs	E
Pressurizer Sample Isolation	PSS-PL-V003	1	PB	1 yr	M * S
PXS Accumulator Sample Isolation	PSS-PL-V004A	1	PB	1 yr	M * S
PXS Accumulator Sample Isolation	PSS-PL-V004B	1	PB	1 yr	M * S
PXS CMT A Sample Isolation	PSS-PL-V005A	1	PB	1 yr	M * S
PXS CMT B Sample Isolation	PSS-PL-V005B	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 36 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PXS CMT A Sample Isolation	PSS-PL-V005C	1	PB	1 yr	M * S
PXS CMT B Sample Isolation	PSS-PL-V005D	1	PB	1 yr	M * S
Liquid Sample Isolation Valve	PSS-PL-V012A	1	PB	1 yr	M * S
Liquid Sample Check Valve	PSS-PL-V012B	1	PB	1 yr	M * S
RCS Pressurizer Sample Isolation Valve	PSS-PL-V013	1	PB	1 yr	M * S
RCS Hot Leg 1 Sample Isolation Valve	PSS-PL-V014A	1	PB	1 yr	M * S
RCS Hot Leg 2 Sample Isolation Valve	PSS-PL-V014B	1	PB	1 yr	M * S
PXS Accumulator Sample Isolation Valve	PSS-PL-V015A	1	PB	1 yr	M * S
PXS Accumulator Sample Isolation Valve	PSS-PL-V015B	1	PB	1 yr	M * S
PXS CMT A Sample Isolation Valve	PSS-PL-V016A	1	PB	1 yr	M * S
PXS CMT B Sample Isolation Valve	PSS-PL-V016B	1	PB	1 yr	M * S
PXS CMT A Sample Isolation Valve	PSS-PL-V016C	1	PB	1 yr	M * S
PXS CMT B Sample Isolation Valve	PSS-PL-V016D	1	PB	1 yr	M * S
Containment Testing Boundary Isolation Valve	PSS-PL-V076A	1	PB	1 yr	M * S
Containment Testing Boundary Isolation Valve	PSS-PL-V076B	1	PB	1 yr	M * S
Containment Isolation Test Connection Isolation Valve	PSS-PL-V082	1	PB	1 yr	M * S
Containment Isolation Test Connection Isolation Valve	PSS-PL-V083	1	PB	1 yr	M * S
Containment Isolation Test Connection Isolation Valve	PSS-PL-V085	1	PB	1 yr	M * S
Containment Isolation Test Connection Isolation Valve	PSS-PL-V086	1	PB	1 yr	M * S
PXS CMT A Sample Isolation Valve (Unit 3 Only)	PSS-PL-V902A	1	PB	1 yr	M * S
PXS CMT B Sample Isolation Valve (Unit 3 Only)	PSS-PL-V902B	1	PB	1 yr	M * S
PXS CMT B Sample Isolation Valve (Unit 3 Only)	PSS-PL-V903	1	PB	1 yr	M * S
Core Makeup Tank A CL Inlet Isolation	PXS-PL-V002A	1	PB	1 yr	M * S
Limit Switch	PXS-PL-V002A-L	1	PAMS	1 yr	E * S
Motor Operator	PXS-PL-V002A-M	1	ESF	5 min	E * S
Core Makeup Tank B CL Inlet Isolation	PXS-PL-V002B	1	PB	1 yr	M * S
Limit Switch	PXS-PL-V002B-L	1	PAMS	1 yr	E * S
Motor Operator	PXS-PL-V002B-M	1	ESF	5 min	E * S
Core Makeup Tank A Upper Sample	PXS-PL-V010A	1	PB	1 yr	M * S
Core Makeup Tank B Upper Sample	PXS-PL-V010B	1	PB	1 yr	M * S
Core Makeup Tank A Lower Sample	PXS-PL-V011A	1	PB	1 yr	M * S
Core Makeup Tank B Lower Sample	PXS-PL-V011B	1	PB	1 yr	M * S
Core Makeup Tank A Drain	PXS-PL-V012A	1	PB	1 yr	M * S
Core Makeup Tank B Drain	PXS-PL-V012B	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 37 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Core Makeup Tank A Discharge Manual Isolation	PXS-PL-V013A	1	PB	1 yr	M * S
Core Makeup Tank B Discharge Manual Isolation	PXS-PL-V013B	1	PB	1 yr	M * S
RNS to CMT Injection Line A Drain	PXS-PL-V019A	1	PB	1 yr	M * S
RNS to CMT Injection Line B Drain	PXS-PL-V019B	1	PB	1 yr	M * S
IRWST Injection Line A Drain	PXS-PL-V020A	1	PB	1 yr	M * S
IRWST Injection Line B Drain	PXS-PL-V020B	1	PB	1 yr	M * S
Accumulator A N_2 Vent	PXS-PL-V021A	1	PB	1 yr	M * S
Accumulator B N_2 Vent	PXS-PL-V021B	1	PB	1 yr	M * S
Accumulator A PZR Transmitter Isolation	PXS-PL-V023A	1	PB	1 yr	M * S
Accumulator B PZR Transmitter Isolation	PXS-PL-V023B	1	PB	1 yr	M * S
Accumulator A PZR Transmitter Isolation	PXS-PL-V024A	1	PB	1 yr	M * S
Accumulator B PZR Transmitter Isolation	PXS-PL-V024B	1	PB	1 yr	M * S
Accumulator A Sample	PXS-PL-V025A	1	PB	1 yr	M * S
Accumulator B Sample	PXS-PL-V025B	1	PB	1 yr	M * S
Accumulator A Drain	PXS-PL-V026A	1	PB	1 yr	M * S
Accumulator B Drain	PXS-PL-V026B	1	PB	1 yr	M * S
Accumulator A Discharge Isolation	PXS-PL-V027A	1	PB	1 yr	M * S
Accumulator B Discharge Isolation	PXS-PL-V027B	1	PB	1 yr	M * S
Core Makeup Tank A Highpoint Vent	PXS-PL-V030A	1	PB	1 yr	M * S
Core Makeup Tank B Highpoint Vent	PXS-PL-V030B	1	PB	1 yr	M * S
Core Makeup Tank A Highpoint Vent	PXS-PL-V031A	1	PB	1 yr	M * S
Core Makeup Tank B Highpoint Vent	PXS-PL-V031B	1	PB	1 yr	M * S
Accumulator A Check Valve Drain	PXS-PL-V033A	1	PB	1 yr	M * S
Accumulator B Check Valve Drain	PXS-PL-V033B	1	PB	1 yr	M * S
Accumulator N_2 Containment Penetration Test Connection	PXS-PL-V052	1	PB	1 yr	M * S
CMT A Wide Level Upper Root	PXS-PL-V080A	1	PB	1 yr	M * S
CMT B Wide Level Upper Root	PXS-PL-V080B	1	PB	1 yr	M * S
CMT A Wide Level Lower Root	PXS-PL-V081A	1	PB	1 yr	M * S
CMT B Wide Level Lower Root	PXS-PL-V081B	1	PB	1 yr	M * S
CMT A Upper Level A Isolation 1	PXS-PL-V082A	1	PB	1 yr	M * S
CMT B Upper Level A Isolation 1	PXS-PL-V082B	1	PB	1 yr	M * S
CMT A Upper Level A Isolation 2	PXS-PL-V083A	1	PB	1 yr	M * S
CMT B Upper Level A Isolation 2	PXS-PL-V083B	1	PB	1 yr	M * S
CMT A Upper Level A Vent	PXS-PL-V084A	1	PB	1 yr	M * S
CMT B Upper Level A Vent	PXS-PL-V084B	1	PB	1 yr	M * S
LT-011 A/C Drain Valve	PXS-PL-V085A	1	PB	1 yr	M * S
LT-012 A/C Drain Valve	PXS-PL-V085B	1	PB	1 yr	M * S
CMT A Upper Level B Isolation 1	PXS-PL-V086A	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 38 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
CMT B Upper Level B Isolation 1	PXS-PL-V086B	1	PB	1 yr	M * S
CMT A Upper Level B Isolation 2	PXS-PL-V087A	1	PB	1 yr	M * S
CMT B Upper Level B Isolation 2	PXS-PL-V087B	1	PB	1 yr	M * S
CMT A Upper Level B Vent	PXS-PL-V088A	1	PB	1 yr	M * S
CMT B Upper Level B Vent	PXS-PL-V088B	1	PB	1 yr	M * S
CMT A Upper Level B Drain	PXS-PL-V089A	1	PB	1 yr	M * S
CMT B Upper Level B Drain	PXS-PL-V089B	1	PB	1 yr	M * S
CMT A Lower Level A Isolation 1	PXS-PL-V092A	1	PB	1 yr	M * S
CMT B Lower Level A Isolation 1	PXS-PL-V092B	1	PB	1 yr	M * S
CMT A Lower Level A Isolation 2	PXS-PL-V093A	1	PB	1 yr	M * S
CMT B Lower Level A Isolation 2	PXS-PL-V093B	1	PB	1 yr	M * S
CMT A Lower Level A Vent	PXS-PL-V094A	1	PB	1 yr	M * S
CMT B Lower Level A Vent	PXS-PL-V094B	1	PB	1 yr	M * S
CMT A Lower Level A Drain	PXS-PL-V095A	1	PB	1 yr	M * S
CMT B Lower Level A Drain	PXS-PL-V095B	1	PB	1 yr	M * S
CMT A Lower Level B Isolation 1	PXS-PL-V096A	1	PB	1 yr	M * S
CMT B Lower Level B Isolation 1	PXS-PL-V096B	1	PB	1 yr	M * S
CMT A Lower Level B Isolation 2	PXS-PL-V097A	1	PB	1 yr	M * S
CMT B Lower Level B Isolation 2	PXS-PL-V097B	1	PB	1 yr	M * S
CMT A Lower Level B Vent	PXS-PL-V098A	1	PB	1 yr	M * S
CMT B Lower Level B Vent	PXS-PL-V098B	1	PB	1 yr	M * S
CMT A Lower Level B Drain	PXS-PL-V099A	1	PB	1 yr	M * S
CMT B Lower Level B Drain	PXS-PL-V099B	1	PB	1 yr	M * S
PRHR HX Inlet Isolation	PXS-PL-V101	1	PB	1 yr	M * S
Limit Switch	PXS-PL-V101-L	1	PAMS	1 yr	E * S
Motor Operator	PXS-PL-V101-M	1	ESF	5 min	E * S
PRHR HX Inlet Head Vent	PXS-PL-V102A	1	PB	1 yr	M * S
PRHR HX Inlet Head Drain	PXS-PL-V102B	1	PB	1 yr	M * S
PRHR HX Outlet Head Vent	PXS-PL-V103A	1	PB	1 yr	M * S
PRHR HX Outlet Head Drain	PXS-PL-V103B	1	PB	1 yr	M * S
PRHR HX Flow Transmitter A Isolation	PXS-PL-V104A	1	PB	1 yr	M * S
PRHR HX Flow Transmitter B Isolation	PXS-PL-V104B	1	PB	1 yr	M * S
PRHR HX Flow Transmitter A Isolation	PXS-PL-V105A	1	PB	1 yr	M * S
PRHR HX Flow Transmitter B Isolation	PXS-PL-V105B	1	PB	1 yr	M * S
Containment Recirculation A Highpoint Vent	PXS-PL-V106	1	PB	1 yr	M * S
Containment Recirculation A Highpoint Vent	PXS-PL-V107	1	PB	1 yr	M * S
PRHR HX/RCS Return Isolation	PXS-PL-V109	1	PB	1 yr	M * S
PRHR HX Highpoint Vent	PXS-PL-V111A	1	PB	1 yr	M * S
PRHR HX Highpoint Vent	PXS-PL-V111B	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 39 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PRHR HX Pressure Transmitter Isolation	PXS-PL-V113	1	PB	1 yr	M * S
Containment Recirculation A Drain	PXS-PL-V115A	1	PB	1 yr	M * S
Containment Recirculation B Drain	PXS-PL-V115B	1	PB	1 yr	M * S
Containment Recirculation A Drain	PXS-PL-V116A	1	PB	1 yr	M * S
Containment Recirculation B Drain	PXS-PL-V116B	1	PB	1 yr	M * S
Recirc Sump A Isolation	PXS-PL-V117A	1	ESF	24 hrs	M * S
Limit Switch	PXS-PL-V117A-L	1	PAMS	1 yr (Note 9)	E * S
Motor Operator	PXS-PL-V117A-M	1	ESF	24 hrs	E * S
Recirc Sump B Isolation	PXS-PL-V117B	1	ESF	24 hrs	M * S
Limit Switch	PXS-PL-V117B-L	1	PAMS	1 yr (Note 9)	E * S
Motor Operator	PXS-PL-V117B-M	1	ESF	24 hrs	E * S
IRWST Line A Isolation	PXS-PL-V121A	1	PB	1 yr	M * S
IRWST Line B Isolation	PXS-PL-V121B	1	PB	1 yr	M * S
IRWST Injection Check Test	PXS-PL-V126A	1	PB	1 yr	M * S
IRWST Injection Check Test	PXS-PL-V126B	1	PB	1 yr	M * S
IRWST Injection Line A Drain	PXS-PL-V127	1	PB	1 yr	M * S
IRWST Injection Check Test	PXS-PL-V128A	1	PB	1 yr	M * S
IRWST Injection Check Test	PXS-PL-V128B	1	PB	1 yr	M * S
IRWST Injection Check Test	PXS-PL-V129A	1	PB	1 yr	M * S
IRWST Injection Check Test	PXS-PL-V129B	1	PB	1 yr	M * S
IRWST Injection Line A Drain	PXS-PL-V131A	1	PB	1 yr	M * S
IRWST Injection Line B Drain	PXS-PL-V131B	1	PB	1 yr	M * S
IRWST Injection Line A Drain	PXS-PL-V132A	1	PB	1 yr	M * S
IRWST Injection Line B Drain	PXS-PL-V132B	1	PB	1 yr	M * S
IRWST Injection Line A Highpoint Vent	PXS-PL-V133A	1	PB	1 yr	M * S
IRWST Injection Line B Highpoint Vent	PXS-PL-V133B	1	PB	1 yr	M * S
IRWST Injection Line A Highpoint Vent	PXS-PL-V134A	1	PB	1 yr	M * S
IRWST Injection Line B Highpoint Vent	PXS-PL-V134B	1	PB	1 yr	M * S
IRWST Injection Line A Highpoint Vent Isolation	PXS-PL-V135A	1	PB	1 yr	M * S
IRWST Injection Line B Highpoint Vent Isolation	PXS-PL-V135B	1	PB	1 yr	M * S
RNS Suction Pump Line Drain	PXS-PL-V149	1	PB	1 yr	M * S
IRWST Wide Range Level Transmitter B Isolation	PXS-PL-V151B	1	PB	1 yr	M * S
IRWST Wide Range Level Transmitter C Isolation	PXS-PL-V151C	1	PB	1 yr	M * S
IRWST Wide Range Level Transmitter D Isolation	PXS-PL-V151D	1	PB	1 yr	M * S
IRWST Lower Narrow Range Level Transmitter A Isolation	PXS-PL-V161A	1	PB	1 yr	M * S
IRWST Lower Narrow Range Level Transmitter B Isolation	PXS-PL-V161B	1	PB	1 yr	M * S
IRWST Lower Narrow Range Level Transmitter C Isolation	PXS-PL-V161C	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 40 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
IRWST Lower Narrow Range Level Transmitter D Isolation	PXS-PL-V161D	1	PB	1 yr	M * S
IRWST Lower Narrow Range Level Transmitter A Reference Leg Isolation	PXS-PL-V162A	1	PB	1 yr	M * S
IRWST Lower Narrow Range Level Transmitter B Reference Leg Isolation	PXS-PL-V162B	1	PB	1 yr	M * S
IRWST Lower Narrow Range Level Transmitter C Reference Leg Isolation	PXS-PL-V162C	1	PB	1 yr	M * S
IRWST Lower Narrow Range Level Transmitter D Reference Leg Isolation	PXS-PL-V162D	1	PB	1 yr	M * S
PRHR Flow Transmitter A Vent	PXS-PL-V170A	1	PB	1 yr	M * S
PRHR Flow Transmitter B Vent	PXS-PL-V170B	1	PB	1 yr	M * S
PRHR Flow Transmitter A Vent	PXS-PL-V171A	1	PB	1 yr	M * S
PRHR Flow Transmitter B Vent	PXS-PL-V171B	1	PB	1 yr	M * S
Accumulator A Leak Test	PXS-PL-V201A	1	PB	1 yr	M * S
Accumulator B Leak Test	PXS-PL-V201B	1	PB	1 yr	M * S
Accumulator A Leak Test	PXS-PL-V202A	1	PB	1 yr	M * S
Accumulator B Leak Test	PXS-PL-V202B	1	PB	1 yr	M * S
RNS Discharge Leak Test	PXS-PL-V205A	1	PB	1 yr	M * S
RNS Discharge Leak Test	PXS-PL-V205B	1	PB	1 yr	M * S
RNS Discharge Leak Test	PXS-PL-V206	1	PB	1 yr	M * S
RNS Suction Leak Test	PXS-PL-V207A	1	PB	1 yr	M * S
RNS Suction Leak Test	PXS-PL-V207B	1	PB	1 yr	M * S
RNS Suction Leak Test	PXS-PL-V208A	1	PB	1 yr	M * S
Core Makeup Tank A Fill Isolation	PXS-PL-V230A	1	PB	1 yr	M * S
Core Makeup Tank B Fill Isolation	PXS-PL-V230B	1	PB	1 yr	M * S
Core Makeup Tank A Fill Check	PXS-PL-V231A	1	PB	1 yr	M * S
Core Makeup Tank B Fill Check	PXS-PL-V231B	1	PB	1 yr	M * S
Accumulator A Fill/Drain Isolation	PXS-PL-V232A	1	PB	1 yr	M * S
Accumulator B Fill/Drain Isolation	PXS-PL-V232B	1	PB	1 yr	M * S
Accumulator A to PXS Test Header Iso Valve (Unit 3 Only)	PXS-PL-V233A	1	PB	1 yr	M * S
Accumulator B to PXS Test Header Iso Valve (Unit 3 Only)	PXS-PL-V233B	1	PB	1 yr	M * S
CMT A Check Valve Test Valve	PXS-PL-V250A	1	PB	1 yr	M * S
CMT B Check Valve Test Valve	PXS-PL-V250B	1	PB	1 yr	M * S
CMT A Check Valve Test Valve	PXS-PL-V251A	1	PB	1 yr	M * S
CMT B Check Valve Test Valve	PXS-PL-V251B	1	PB	1 yr	M * S
CMT A Check Valve Test Valve	PXS-PL-V252A	1	PB	1 yr	M * S
CMT B Check Valve Test Valve	PXS-PL-V252B	1	PB	1 yr	M * S
ADS Test Valve	RCS-PL-V007A	1	PB	1 yr	M * S
ADS Test Valve	RCS-PL-V007B	1	PB	1 yr	M * S
ADS Test Valve	RCS-PL-V007C	1	PB	1 yr	M * S
ADS Valve Leakage Check Valve	RCS-PL-V008	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 41 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Fourth Stage ADS Isolation	RCS-PL-V014A	1	PB	1 yr	M * S
Limit Switch	RCS-PL-V014A-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V014A-M	1	ESF	24 hrs	E * S
Fourth Stage ADS Isolation	RCS-PL-V014B	1	PB	1 yr	M * S
Limit Switch	RCS-PL-V014B-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V014B-M	1	ESF	24 hrs	E * S
Fourth Stage ADS Isolation	RCS-PL-V014C	1	PB	1 yr	M * S
Limit Switch	RCS-PL-V014C-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V014C-M	1	ESF	24 hrs	E * S
Fourth Stage ADS Isolation	RCS-PL-V014D	1	PB	1 yr	M * S
Limit Switch	RCS-PL-V014D-L	1	PAMS	1 yr	E * S
Motor Operator	RCS-PL-V014D-M	1	ESF	24 hrs	E * S
Hot Leg 2 Level Instrument Root	RCS-PL-V095	1	PB	1 yr	M * S
Hot Leg 2 Level Instrument Root	RCS-PL-V096	1	PB	1 yr	M * S
Hot Leg 1 Level Instrument Root	RCS-PL-V097	1	PB	1 yr	M * S
Hot Leg 1 Level Instrument Root	RCS-PL-V098	1	PB	1 yr	M * S
Hot Leg 1 Flow Instrument Root	RCS-PL-V101A	1	PB	1 yr	M * S
Hot Leg 1 Flow Instrument Root	RCS-PL-V101B	1	PB	1 yr	M * S
Hot Leg 1 Flow Instrument Root	RCS-PL-V101C	1	PB	1 yr	M * S
Hot Leg 1 Flow Instrument Root	RCS-PL-V101D	1	PB	1 yr	M * S
Hot Leg 1 Flow Instrument Root	RCS-PL-V101E	1	PB	1 yr	M * S
Hot Leg 1 Flow Instrument Root	RCS-PL-V101F	1	PB	1 yr	M * S
Hot Leg 2 Flow Instrument Root	RCS-PL-V102A	1	PB	1 yr	M * S
Hot Leg 2 Flow Instrument Root	RCS-PL-V102B	1	PB	1 yr	M * S
Hot Leg 2 Flow Instrument Root	RCS-PL-V102C	1	PB	1 yr	M * S
Hot Leg 2 Flow Instrument Root	RCS-PL-V102D	1	PB	1 yr	M * S
Hot Leg 2 Flow Instrument Root	RCS-PL-V102E	1	PB	1 yr	M * S
Hot Leg 2 Flow Instrument Root	RCS-PL-V102F	1	PB	1 yr	M * S
PRHR HX Outlet Line Drain	RCS-PL-V103	1	PB	1 yr	M * S
Hot Leg 1 Sample Isolation	RCS-PL-V108A	1	PB	1 yr	M * S
Hot Leg 2 Sample Isolation	RCS-PL-V108B	1	PB	1 yr	M * S
PZR Spray Valve	RCS-PL-V110A	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 42 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PZR Spray Valve	RCS-PL-V110B	1	PB	1 yr	M * S
PZR Spray Block Valve	RCS-PL-V111A	1	PB	1 yr	M * S
PZR Spray Block Valve	RCS-PL-V111B	1	PB	1 yr	M * S
Cold Leg 1A Bend Instrument Root	RCS-PL-V171A	1	PB	1 yr	M * S
Cold Leg 1A Bend Instrument Root	RCS-PL-V171B	1	PB	1 yr	M * S
Cold Leg 1B Bend Instrument Root	RCS-PL-V172A	1	PB	1 yr	M * S
Cold Leg 1B Bend Instrument Root	RCS-PL-V172B	1	PB	1 yr	M * S
Cold Leg 2A Bend Instrument Root	RCS-PL-V173A	1	PB	1 yr	M * S
Cold Leg 2A Bend Instrument Root	RCS-PL-V173B	1	PB	1 yr	M * S
Cold Leg 2B Bend Instrument Root	RCS-PL-V174A	1	PB	1 yr	M * S
Cold Leg 2B Bend Instrument Root	RCS-PL-V174B	1	PB	1 yr	M * S
PZR Manual Vent	RCS-PL-V204	1	PB	1 yr	M * S
PZR Manual Vent	RCS-PL-V205	1	PB	1 yr	M * S
PZR Spray Bypass	RCS-PL-V210A	1	PB	1 yr	M * S
PZR Spray Bypass	RCS-PL-V210B	1	PB	1 yr	M * S
PZR Level Steam Space Instrument Root	RCS-PL-V225A	1	PB	1 yr	M * S
PZR Level Steam Space Instrument Root	RCS-PL-V225B	1	PB	1 yr	M * S
PZR Level Steam Space Instrument Root	RCS-PL-V225C	1	PB	1 yr	M * S
PZR Level Steam Space Instrument Root	RCS-PL-V225D	1	PB	1 yr	M * S
PZR Level Liquid Space Instrument Root	RCS-PL-V226A	1	PB	1 yr	M * S
PZR Level Liquid Space Instrument Root	RCS-PL-V226B	1	PB	1 yr	M * S
PZR Level Liquid Space Instrument Root	RCS-PL-V226C	1	PB	1 yr	M * S
PZR Level Liquid Space Instrument Root	RCS-PL-V226D	1	PB	1 yr	M * S
Pressurizer Level Reference Leg Tubing Instrument Root	RCS-PL-V227A	1	PB	1 yr	M *
Pressurizer Level Reference Leg Tubing Instrument Root	RCS-PL-V227B	1	PB	1 yr	M *
Pressurizer Level Reference Leg Tubing Instrument Root	RCS-PL-V227C	1	PB	1 yr	M *
Pressurizer Level Reference Leg Tubing Instrument Root	RCS-PL-V227D	1	PB	1 yr	M *
Pressurizer Liquid Sample Isolation	RCS-PL-V228	1	PB	1 yr	M * S
Wide Range PZR Level Liquid Space Instrument Root	RCS-PL-V229	1	PB	1 yr	M * S
Manual Head Vent	RCS-PL-V232	1	PB	1 yr	M * S
Head Vent Isolation	RCS-PL-V233	1	PB	1 yr	M * S
ADS Valve Discharge Header	RCS-PL-V241	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 43 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Drain Isolation					
ADS Discharge Line Isolation	RCS-PL-V250	1	PB	1 yr	M * S
RCP 1A Vent	RCS-PL-V260A	1	PB	1 yr	M * S
RCP 1B Vent	RCS-PL-V260B	1	PB	1 yr	M * S
RCP 2A Vent	RCS-PL-V260C	1	PB	1 yr	M * S
RCP 2B Vent	RCS-PL-V260D	1	PB	1 yr	M * S
RCP 1A Drain	RCS-PL-V261A	1	PB	1 yr	M * S
RCP 1B Drain	RCS-PL-V261B	1	PB	1 yr	M * S
RCP 2A Drain	RCS-PL-V261C	1	PB	1 yr	M * S
RCP 2B Drain	RCS-PL-V261D	1	PB	1 yr	M * S
RCS Pressure Boundary Valve Thermal Relief Isolation	RNS-PL-V004A	1	PB	1 yr	M * S
RCS Pressure Boundary Valve Thermal Relief Isolation	RNS-PL-V004B	1	PB	1 yr	M * S
RNS Pump A Suction Isolation	RNS-PL-V005A	6	PB	1 yr	M ** S
RNS Pump B Suction Isolation	RNS-PL-V005B	6	PB	1 yr	M ** S
RNS HX A Outlet Flow Control	RNS-PL-V006A	6	PB	1 yr	M ** S
RNS HX B Outlet Flow Control	RNS-PL-V006B	6	PB	1 yr	M ** S
RNS Pump A Discharge Isolation	RNS-PL-V007A	6	PB	1 yr	M ** S
RNS Pump B Discharge Isolation	RNS-PL-V007B	6	PB	1 yr	M ** S
RNS HX A Bypass Flow Control	RNS-PL-V008A	6	PB	1 yr	M ** S
RNS HX B Bypass Flow Control	RNS-PL-V008B	6	PB	1 yr	M ** S
RNS Discharge Containment Isolation Valve Test	RNS-PL-V010	6	PB	1 yr	M ** S
RNS Discharge Containment Isolation Valve Test Connection	RNS-PL-V014	1	PB	1 yr	M * S
RNS Discharge Containment Penetration Isolation Valves Test	RNS-PL-V016	1	PB	1 yr	M * S
RNS Discharge to IRWST Isolation	RNS-PL-V024	1	PB	1 yr	M * S
RNS Suction from IRWST – Bonnet Relief Isolation	RNS-PL-V025	1	PB	1 yr	M * S
RNS Suction from IRWST – Containment Isolation Test	RNS-PL-V026	1	PB	1 yr	M * S
RNS Discharge to CVS	RNS-PL-V029	1	PB	1 yr	M * S
RNS Train A Discharge Flow Instrument Isolation	RNS-PL-V031A	6	PB	1 yr	M ** S
RNS Train B Discharge Flow Instrument Isolation	RNS-PL-V031B	6	PB	1 yr	M ** S
RNS Train A Discharge Flow Instrument Isolation	RNS-PL-V032A	6	PB	1 yr	M ** S
RNS Train B Discharge Flow Instrument Isolation	RNS-PL-V032B	6	PB	1 yr	M ** S
RNS Pump A Suction Pressure Instrument Isolation	RNS-PL-V033A	6	PB	1 yr	M **
RNS Pump B Suction Pressure	RNS-PL-V033B	6	PB	1 yr	M **

Table 3.11-1 (Sheet 44 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Instrument Isolation					
RNS Pump A Discharge Pressure Instrument Isolation	RNS-PL-V034A	6	PB	1 yr	M ** S
RNS Pump B Discharge Pressure Instrument Isolation	RNS-PL-V034B	6	PB	1 yr	M ** S
RNS Pump A Suction Piping Drain Isolation	RNS-PL-V036A	6	PB	1 yr	M ** S
RNS Pump B Suction Piping Drain Isolation	RNS-PL-V036B	6	PB	1 yr	M ** S
RNS Pump Discharge Relief	RNS-PL-V045	6	PB	1 yr	M **
RNS Pump Seal Cooler A Vent Isolation	RNS-PL-V048A	6	PB	1 yr	M** S
RNS Pump Seal Cooler B Vent Isolation	RNS-PL-V048B	6	PB	1 yr	M** S
RNS Pump Seal Cooler A Drain Isolation	RNS-PL-V049A	6	PB	1 yr	M** S
RNS Pump Seal Cooler B Drain Isolation	RNS-PL-V049B	6	PB	1 yr	M** S
RNS Pump A Casing Drain Isolation	RNS-PL-V050	6	PB	1 yr	M ** S
RNS Pump B Casing Drain Isolation	RNS-PL-V051	6	PB	1 yr	M ** S
RNS Suction from SFP Isolation	RNS-PL-V052	6	PB	1 yr	M **
RNS Discharge to SFP Isolation	RNS-PL-V053	6	PB	1 yr	M **
RNS Suction from Cask Loading Pit Isolation Valve	RNS-PL-V055	6	PB	1 yr	M **
RNS Pump Suction to Cask Loading Pit Isolation	RNS-PL-V056	6	PB	1 yr	M **
RNS Train A Miniflow Isolation Valve	RNS-PL-V057A	6	PB	1 yr	M **
RNS Train B Miniflow Isolation Valve	RNS-PL-V057B	6	PB	1 yr	M ** S
RNS Pump Suction Containment Isolation Test Connection	RNS-PL-V059	6	PB	1 yr	M ** S
RNS Discharge Drain Valve	RNS-PL-V065	6	PB	1 yr	M** S
RNS Discharge to DVI Line A Drain	RNS-PL-V066A	1	PB	1 yr	M * S
RNS Discharge to DVI Line B Drain	RNS-PL-V066B	1	PB	1 yr	M * S
RNS Discharge to DVI Line A Drain	RNS-PL-V067A	1	PB	1 yr	M * S
RNS Discharge to DVI Line B Drain	RNS-PL-V067B	1	PB	1 yr	M * S
RNS Discharge to IRWST Drain	RNS-PL-V068	1	PB	1 yr	M * S
RNS HX A Channel Head Drain Isolation	RNS-PL-V071A	6	PB	1 yr	M**
RNS HX B Channel Head Drain Isolation	RNS-PL-V071B	6	PB	1 yr	M**
RNS HX A Channel Head Drain Isolation	RNS-PL-V072A	6	PB	1 yr	M**
RNS HX B Channel Head Drain Isolation	RNS-PL-V072B	6	PB	1 yr	M**
RNS HX A Channel Head Drain Isolation	RNS-PL-V073A	6	PB	1 yr	M**
RNS HX B Channel Head Drain Isolation	RNS-PL-V073B	6	PB	1 yr	M**
RNS HX A Channel Head Drain Isolation	RNS-PL-V074A	6	PB	1 yr	M**
RNS HX B Channel Head Drain Isolation	RNS-PL-V074B	6	PB	1 yr	M**
RNS HX A Channel Head Drain Isolation	RNS-PL-V075A	6	PB	1 yr	M**
RNS HX B Channel Head Drain Isolation	RNS-PL-V075B	6	PB	1 yr	M**
RNS Cask Loading Pit Suction Line Vent	RNS-PL-V081	6	PB	1 yr	M **
RNS Discharge Drain	RNS-PL-V082	1	PB	1 yr	M* S

Table 3.11-1 (Sheet 45 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
LT019A Root Isolation Valve	SFS-PL-V024A	6	PB	1 yr	M **
LT019B Root Isolation Valve	SFS-PL-V024B	6	PB	1 yr	M **
LT019C Root Isolation Valve	SFS-PL-V024C	6	PB	1 yr	M **
LT020 Root Isolation Valve	SFS-PL-V028	6	PB	1 yr	M **
SFS Refueling Cavity Drain to SGS Compartment Isolation	SFS-PL-V031	1	PB	1 yr	M * S
Limit Switch	SFS-PL-V031-L	1	PAMS	1 yr (Note 10)	E * S
SFS Refueling Cavity Suction Isolation	SFS-PL-V032	1	PB	1 yr	M * S
SFS Refueling Cavity Drain to Containment Sump Isolation	SFS-PL-V033	1	PB	1 yr	M * S
Limit Switch	SFS-PL-V033-L	1	PAMS	1 yr (Note 10)	E * S
SFS Suction Line from IRWST Isolation	SFS-PL-V039	1	PB	1 yr	M * S
SFS Fuel Transfer Canal Suction Isolation	SFS-PL-V040	6	PB	1 yr	M **
SFS Cask Loading Pit Suction Isolation	SFS-PL-V041	6	PB	1 yr	M **
Cask Loading Pit Level Transmitter Root Isolation Valve	SFS-PL-V043	6	PB	1 yr	M **
SFS Containment Penetration Test Connection	SFS-PL-V048	6	PB	1 yr	M **
SFS Containment Penetration Test Connection Isolation	SFS-PL-V056	1	PB	1 yr	M * S
SFS Containment Isolation Valve V034 Test	SFS-PL-V058	1	PB	1 yr	M * S
SFS Containment Floodup Isolation Valve	SFS-PL-V075	1	PB	1 yr	M * S
Limit Switch	SFS-PL-V075-L	1	PAMS	1 yr (Note 10)	E * S
Refueling Cavity Drain Line Test Connection	SFS-PL-V117	1	PB	1 yr	M * S
LT001, LT011 Root Isolation Valve	SGS-PL-V001A	1	PB	1 yr	M * S
LT005, LT013 Root Isolation Valve	SGS-PL-V001B	1	PB	1 yr	M * S
LT001 Root Isolation Valve	SGS-PL-V002A	1	PB	1 yr	M * S
LT005 Root Isolation Valve	SGS-PL-V002B	1	PB	1 yr	M * S
LT002, LT012 Root Isolation Valve	SGS-PL-V003A	1	PB	1 yr	M * S
LT006, LT014 Root Isolation Valve	SGS-PL-V003B	1	PB	1 yr	M * S
LT002 Root Isolation Valve	SGS-PL-V004A	1	PB	1 yr	M * S
LT006 Root Isolation Valve	SGS-PL-V004B	1	PB	1 yr	M * S
LT003, LT015, LT044 Root Isolation Valve	SGS-PL-V005A	1	PB	1 yr	M * S
LT007, LT017, LT046 Root Isolation Valve	SGS-PL-V005B	1	PB	1 yr	M * S
LT003 Root Isolation Valve	SGS-PL-V006A	1	PB	1 yr	M * S
LT007 Root Isolation Valve	SGS-PL-V006B	1	PB	1 yr	M * S
LT004, LT016, LT045 Root Isolation Valve	SGS-PL-V007A	1	PB	1 yr	M * S
LT008, LT018, LT047 Root Isolation Valve	SGS-PL-V007B	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 46 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
LT004 Root Isolation Valve	SGS-PL-V008A	1	PB	1 yr	M * S
LT008 Root Isolation Valve	SGS-PL-V008B	1	PB	1 yr	M * S
LT011 Root Isolation Valve	SGS-PL-V010A	1	PB	1 yr	M * S
LT013 Root Isolation Valve	SGS-PL-V010B	1	PB	1 yr	M * S
LT011 Root Isolation Valve	SGS-PL-V011A	1	PB	1 yr	M * S
LT013 Root Isolation Valve	SGS-PL-V011B	1	PB	1 yr	M * S
LT012 Root Isolation Valve	SGS-PL-V012A	1	PB	1 yr	M * S
LT014 Root Isolation Valve	SGS-PL-V012B	1	PB	1 yr	M * S
LT012 Root Isolation Valve	SGS-PL-V013A	1	PB	1 yr	M * S
LT014 Root Isolation Valve	SGS-PL-V013B	1	PB	1 yr	M * S
FT021 Root Isolation Valve	SGS-PL-V015A	1	PB	1 yr	M * S
FT023 Root Isolation Valve	SGS-PL-V015B	1	PB	1 yr	M * S
FT020 Root Isolation Valve	SGS-PL-V016A	1	PB	1 yr	M * S
FT022 Root Isolation Valve	SGS-PL-V016B	1	PB	1 yr	M * S
FT021 Root Isolation Valve	SGS-PL-V017A	1	PB	1 yr	M * S
FT023 Root Isolation Valve	SGS-PL-V017B	1	PB	1 yr	M * S
FT020 Root Isolation Valve	SGS-PL-V018A	1	PB	1 yr	M * S
FT022 Root Isolation Valve	SGS-PL-V018B	1	PB	1 yr	M * S
Main Steam Line Vent Isolation	SGS-PL-V019A	1	PB	1 yr	M * S
Main Steam Line Vent Isolation	SGS-PL-V019B	1	PB	1 yr	M * S
FT024 Root Isolation Valve	SGS-PL-V020A	1	PB	1 yr	M * S
FT025 Root Isolation Valve	SGS-PL-V020B	1	PB	1 yr	M * S
FT024 Root Isolation Valve	SGS-PL-V021A	1	PB	1 yr	M * S
FT025 Root Isolation Valve	SGS-PL-V021B	1	PB	1 yr	M * S
PT030 Root Isolation Valve	SGS-PL-V022A	1	PB	1 yr	M * S
PT034 Root Isolation Valve	SGS-PL-V022B	1	PB	1 yr	M * S
PT031 Root Isolation Valve	SGS-PL-V023A	2	PB	1 yr	M **
PT035 Root Isolation Valve	SGS-PL-V023B	2	PB	1 yr	M **
PT032 Root Isolation Valve	SGS-PL-V024A	1	PB	1 yr	M * S
PT036 Root Isolation Valve	SGS-PL-V024B	1	PB	1 yr	M * S
PT033 Root Isolation Valve	SGS-PL-V025A	2	PB	1 yr	M **
PT037 Root Isolation Valve	SGS-PL-V025B	2	PB	1 yr	M **
Steam Line 1 Nitrogen Supply Isolation	SGS-PL-V038A	5	PB	1 yr	M * S
Steam Line 2 Nitrogen Supply Isolation	SGS-PL-V038B	5	PB	1 yr	M * S
MSIV Bypass Control Isolation	SGS-PL-V042A	5	PB	1 yr	M * S
MSIV Bypass Control Isolation	SGS-PL-V042B	5	PB	1 yr	M * S
MSIV Bypass Control Isolation	SGS-PL-V043A	5	PB	1 yr	M * S
MSIV Bypass Control Isolation	SGS-PL-V043B	5	PB	1 yr	M * S
SG1 Condensate Pipe Drain Valve	SGS-PL-V045A	5	PB	1 yr	M * S
SG2 Condensate Pipe Drain Valve	SGS-PL-V045B	5	PB	1 yr	M * S
LT015 Root Isolation Valve	SGS-PL-V046A	1	PB	1 yr	M * S
LT017 Root Isolation Valve	SGS-PL-V046B	1	PB	1 yr	M * S

Table 3.11-1 (Sheet 47 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
LT015, LT044 Root Isolation Valve	SGS-PL-V047A	1	PB	1 yr	M * S
LT017, LT046 Root Isolation Valve	SGS-PL-V047B	1	PB	1 yr	M * S
LT016 Root Isolation Valve	SGS-PL-V048A	1	PB	1 yr	M * S
LT018 Root Isolation Valve	SGS-PL-V048B	1	PB	1 yr	M * S
LT016, LT045 Root Isolation Valve	SGS-PL-V049A	1	PB	1 yr	M * S
LT018, LT047 Root Isolation Valve	SGS-PL-V049B	1	PB	1 yr	M * S
LT044 Root Isolation Valve	SGS-PL-V050A	1	PB	1 yr	M * S
LT046 Root Isolation Valve	SGS-PL-V050B	1	PB	1 yr	M * S
LT044 Root Isolation Valve	SGS-PL-V051A	1	PB	1 yr	M * S
LT046 Root Isolation Valve	SGS-PL-V051B	1	PB	1 yr	M * S
LT045 Root Isolation Valve	SGS-PL-V052A	1	PB	1 yr	M * S
LT047 Root Isolation Valve	SGS-PL-V052B	1	PB	1 yr	M * S
LT045 Root Isolation Valve	SGS-PL-V053A	1	PB	1 yr	M * S
LT047 Root Isolation Valve	SGS-PL-V053B	1	PB	1 yr	M * S
PT062 Root Isolation Valve	SGS-PL-V056A	5	PB	1 yr	M * S
PT063 Root Isolation Valve	SGS-PL-V056B	5	PB	1 yr	M * S
Main Feedwater Check	SGS-PL-V058A	5	PB	1 yr	M * S
Main Feedwater Check	SGS-PL-V058B	5	PB	1 yr	M * S
FT055A Root Isolation Valve	SGS-PL-V062A	5	PB	1 yr	M * S
FT056A Root Isolation Valve	SGS-PL-V062B	5	PB	1 yr	M * S
FT055A Root Isolation Valve	SGS-PL-V063A	5	PB	1 yr	M * S
FT056A Root Isolation Valve	SGS-PL-V063B	5	PB	1 yr	M * S
FT055B Root Isolation Valve	SGS-PL-V064A	5	PB	1 yr	M * S
FT056B Root Isolation Valve	SGS-PL-V064B	5	PB	1 yr	M * S
FT055B Root Isolation Valve	SGS-PL-V065A	5	PB	1 yr	M * S
FT056B Root Isolation Valve	SGS-PL-V065B	5	PB	1 yr	M * S
FT055 Root Isolation Valve	SGS-PL-V066A	5	PB	1 yr	M * S
FT056 Root Isolation Valve	SGS-PL-V066B	5	PB	1 yr	M * S
FT055 Root Isolation Valve	SGS-PL-V068A	5	PB	1 yr	M * S
FT056 Root Isolation Valve	SGS-PL-V068B	5	PB	1 yr	M * S
SG 1 Blowdown Vent Line Isolation	SGS-PL-V076A	10	PB	1 yr	M *
SG 2 Blowdown Vent Line Isolation	SGS-PL-V076B	10	PB	1 yr	M *
SG1 Nitrogen Sparging Isolation	SGS-PL-V084A	1	PB	1 yr	M * S
SG2 Nitrogen Sparging Isolation	SGS-PL-V084B	1	PB	1 yr	M * S
Orifice Isolation Valve	SGS-PL-V093A	5	PB	1 yr	M * S
Orifice Isolation Valve	SGS-PL-V093B	5	PB	1 yr	M * S
Orifice Cleanout Line Isolation Valve	SGS-PL-V094A	5	PB	1 yr	M * S
Orifice Cleanout Line Isolation Valve	SGS-PL-V094B	5	PB	1 yr	M * S
Orifice Isolation Valve	SGS-PL-V095A	5	PB	1 yr	M * S
Orifice Isolation Valve	SGS-PL-V095B	5	PB	1 yr	M * S
Steam Line Condensate Drain Level Isolation Valve	SGS-PL-V096A	5	PB	1 yr	M * S
Steam Line Condensate Drain Level Isolation Valve	SGS-PL-V096B	5	PB	1 yr	M * S

Table 3.11-1 (Sheet 48 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Steam Line Condensate Drain Level Isolation Valve	SGS-PL-V097A	5	PB	1 yr	M * S
Steam Line Condensate Drain Level Isolation Valve	SGS-PL-V097B	5	PB	1 yr	M * S
Startup Feedwater Drain Isolation Valve	SGS-PL-V100A	5	PB	1 yr	M * S
Startup Feedwater Drain Isolation Valve	SGS-PL-V100B	5	PB	1 yr	M * S
Main Feedwater Drain Isolation Valve	SGS-PL-V101A	5	PB	1 yr	M * S
Main Feedwater Drain Isolation Valve	SGS-PL-V101B	5	PB	1 yr	M * S
Startup Feedwater Vent Isolation Valve	SGS-PL-V102A	5	PB	1 yr	M * S
Startup Feedwater Vent Isolation Valve	SGS-PL-V102B	5	PB	1 yr	M * S
Main Feedwater Vent Isolation Valve	SGS-PL-V103A	5	PB	1 yr	M * S
Main Feedwater Vent Isolation Valve	SGS-PL-V103B	5	PB	1 yr	M * S
Main Feedwater Drain Isolation Valve	SGS-PL-V104A	5	PB	1 yr	M * S
Main Feedwater Drain Isolation Valve	SGS-PL-V104B	5	PB	1 yr	M * S
Startup Feedwater Check Valve	SGS-PL-V256A	5	PB	1 yr	M * S
Startup Feedwater Check Valve	SGS-PL-V256B	5	PB	1 yr	M * S
SG 1 NR LT001 Upper Isolation Valve	SGS-PL-V300	1	PB	1 yr	M *
SG 1 NR LT001 Lower Isolation Valve	SGS-PL-V301	1	PB	1 yr	M *
SG 1 NR LT002 Upper Isolation Valve	SGS-PL-V302	1	PB	1 yr	M *
SG 1 NR LT002 Lower Isolation Valve	SGS-PL-V303	1	PB	1 yr	M *
SG 1 NR LT003 Upper Isolation Valve	SGS-PL-V304	1	PB	1 yr	M *
SG 1 NR LT003 Lower Isolation Valve	SGS-PL-V305	1	PB	1 yr	M *
SG 1 NR LT004 Upper Isolation Valve	SGS-PL-V306	1	PB	1 yr	M *
SG 1 NR LT004 Lower Isolation Valve	SGS-PL-V307	1	PB	1 yr	M *
SG 1 WR LT011 Lower Isolation Valve	SGS-PL-V308	1	PB	1 yr	M *
SG 1 WR LT012 Lower Isolation Valve	SGS-PL-V309	1	PB	1 yr	M *
SG 1 WR LT015 Lower Isolation Valve	SGS-PL-V310	1	PB	1 yr	M *
SG 1 WR LT016 Lower Isolation Valve	SGS-PL-V311	1	PB	1 yr	M *
SG 1 Main Steam FT020 Isolation Valve	SGS-PL-V312	1	PB	1 yr	M *
SG 1 Main Steam FT021 Isolation Valve	SGS-PL-V313	1	PB	1 yr	M *
SG 1 Main Steam FT024 Isolation Valve	SGS-PL-V314	1	PB	1 yr	M *
SG 2 NR LT005 Upper Isolation Valve	SGS-PL-V320	1	PB	1 yr	M *
SG 2 NR LT005 Lower Isolation Valve	SGS-PL-V321	1	PB	1 yr	M *
SG 2 NR LT006 Upper Isolation Valve	SGS-PL-V322	1	PB	1 yr	M *
SG 2 NR LT006 Lower Isolation Valve	SGS-PL-V323	1	PB	1 yr	M *
SG 2 NR LT007 Upper Isolation Valve	SGS-PL-V324	1	PB	1 yr	M *
SG 2 NR LT007 Lower Isolation Valve	SGS-PL-V325	1	PB	1 yr	M *
SG 2 NR LT008 Upper Isolation Valve	SGS-PL-V326	1	PB	1 yr	M *
SG 2 NR LT008 Lower Isolation Valve	SGS-PL-V327	1	PB	1 yr	M *
SG 2 WR LT013 Lower Isolation Valve	SGS-PL-V328	1	PB	1 yr	M *
SG 2 WR LT014 Lower Isolation Valve	SGS-PL-V329	1	PB	1 yr	M *
SG 2 WR LT017 Lower Isolation Valve	SGS-PL-V330	1	PB	1 yr	M *
SG 2 WR LT018 Lower Isolation Valve	SGS-PL-V331	1	PB	1 yr	M *
SG 2 Main Steam FT022 Isolation Valve	SGS-PL-V332	1	PB	1 yr	M *
SG 2 Main Steam FT023 Isolation Valve	SGS-PL-V333	1	PB	1 yr	M *

Table 3.11-1 (Sheet 49 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
SG 2 Main Steam FT025 Isolation Valve	SGS-PL-V334	1	PB	1 yr	M *
VBS-PDT-032A Isolation Valve	VBS-PL-V184A	3	PB	1 yr	M
VBS-PDT-032B Isolation Valve	VBS-PL-V184B	3	PB	1 yr	M
VBS-PDT-032C Isolation Valve	VBS-PL-V184C	3	PB	1 yr	M
Air Delivery Line Pressure Instrument Isolation Valve A	VES-PL-V006A	7	PB	1 yr	M **
Air Delivery Line Pressure Instrument Isolation Valve B	VES-PL-V006B	7	PB	1 yr	M **
Air Delivery Line Maintenance Isolation Valve A	VES-PL-V010A	7	PB	1 yr	M **
Air Delivery Line Maintenance Isolation Valve B	VES-PL-V010B	7	PB	1 yr	M **
Air Delivery Line Maintenance Isolation Valve A	VES-PL-V011A	7	PB	1 yr	M **
Air Delivery Line Maintenance Isolation Valve B	VES-PL-V011B	7	PB	1 yr	M **
Temporary Instrument Isolation Valve A	VES-PL-V016	7	PB	1 yr	M **
Temporary Instrument Isolation Valve B	VES-PL-V020	7	PB	1 yr	M **
Air Bank 1 Isolation Valve A	VES-PL-V024A	7	PB	1 yr	M **
Air Bank 2 Isolation Valve B	VES-PL-V024B	7	PB	1 yr	M **
Air Bank 3 Isolation Valve C	VES-PL-V024C	7	PB	1 yr	M **
Air Bank 4 Isolation Valve D	VES-PL-V024D	7	PB	1 yr	M **
Air Bank 1 Isolation Valve A	VES-PL-V025A	7	PB	1 yr	M **
Air Bank 2 Isolation Valve B	VES-PL-V025B	7	PB	1 yr	M **
Air Bank 3 Isolation Valve C	VES-PL-V025C	7	PB	1 yr	M **
Air Bank 4 Isolation Valve D	VES-PL-V025D	7	PB	1 yr	M **
Air Bank 1 Fill/Vent Isolation Valve A	VES-PL-V026A	7	PB	1 yr	M **
Air Bank 2 Fill/Vent Isolation Valve B	VES-PL-V026B	7	PB	1 yr	M **
Air Bank 3 Fill/Vent Isolation Valve C	VES-PL-V026C	7	PB	1 yr	M **
Air Bank 4 Fill/Vent Isolation Valve D	VES-PL-V026D	7	PB	1 yr	M **
DP Instrument Line Isolation Valve A	VES-PL-V043A	3	PB	1 yr	M
DP Instrument Line Isolation Valve B	VES-PL-V043B	3	PB	1 yr	M
Containment Isolation Test Connection	VFS-PL-V006	1	PB	1 yr	M *
RCS Ejector Discharge Isolation	VFS-PL-V007	1	PB	1 yr	M *
Containment Isolation Test Connection	VFS-PL-V008	6	PB	1 yr	M **
Containment Isolation Test Connection	VFS-PL-V012	1	PB	1 yr	M * S
Containment Isolation Test Connection	VFS-PL-V015	1	PB	1 yr	M * S
Containment Air Supply Line Test Connection	VFS-PL-V101	1	PB	1 yr	M *
Containment Atmosphere to Filtration Units Isolation	VFS-PL-V202	1	PB	1 yr	M *
Filtration Units to Containment Atmosphere Manual Isolation	VFS-PL-V587	1	PB	1 yr	M *
Main Equipment Hatch Test Connection	VUS-PL-V013	1	PB	1 yr	M *

Table 3.11-1 (Sheet 50 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Maintenance Equipment Hatch Test Connection	VUS-PL-V014	1	PB	1 yr	M *
Main Equipment Hatch Test Connection	VUS-PL-V015	1	PB	1 yr	M *
Maintenance Equipment Hatch Test Connection	VUS-PL-V016	1	PB	1 yr	M *
Personnel Hatch Test Connection	VUS-PL-V017	7	PB	1 yr	M **
Personnel Hatch Test Connection	VUS-PL-V018	7	PB	1 yr	M **
Personnel Hatch Test Connection	VUS-PL-V019	7	PB	1 yr	M **
Personnel Hatch Test Connection	VUS-PL-V020	7	PB	1 yr	M **
Personnel Hatch Test Connection	VUS-PL-V021	7	PB	1 yr	M **
Personnel Hatch Test Connection	VUS-PL-V022	7	PB	1 yr	M **
Fuel Transfer Tube Test Connection	VUS-PL-V023	1	PB	1 yr	M * S
Spare Penetration Test Connection	VUS-PL-V140	1	PB	1 yr	M *
Spare Penetration Test Connection	VUS-PL-V141	1	PB	1 yr	M *
Spare Penetration Test Connection	VUS-PL-V142	1	PB	1 yr	M *
VWS Supply Containment Penetration IRC Test Connection/Vent	VWS-PL-V424	1	PB	1 yr	M * S
VWS Return Containment Penetration ORC Test Connection/Vent	VWS-PL-V425	2	PB	1 yr	M **
WWS Main Control Room Isolation Valve	WWS-PL-V506	3	PB	1 yr	M
Heat Exchangers					
Normal Residual Heat Removal Heat Exchanger A	RNS-ME-01A	6	PB	1 yr	M **
Normal Residual Heat Removal Heat Exchanger B	RNS-ME-01B	6	PB	1 yr	M **
Tanks					
Spent Fuel Pool	FHS-MT-01	11	ESF	1 yr	M **
Fuel Transfer Canal	FHS-MT-02	11	ESF	1 yr	M **
Refueling Cavity	FHS-MT-03	11	ESF	1 yr	M **
Spent Fuel Cask Loading Pit	FHS-MT-05	6	ESF	1 yr	M **
Spent Fuel Cask Washdown Pit	FHS-MT-06	6	ESF	1 yr	M **
Spent Fuel Transfer Gate	FHS-MY-Y01	6, 11	ESF (Note 11)	1 wk	M ** S
Spent Fuel Cask Loading Pit Gate	FHS-MY-Y02	11	ESF (Note 11)	1 wk	M ** S
Passive Containment Cooling Water Storage Tank	PCS-MT-01	9 (Note 12)	ESF	1 yr	M **
Water Distribution Bucket	PCS-MT-03	9	ESF	1 yr	M **
Water Collection Troughs	PCS-MT-04	9	ESF	1 yr	M **
Passive RHR Heat Exchanger	PXS-ME-01	1	ESF	1 yr	M * S
Accumulator Tank A	PXS-MT-01A	1	ESF	1 yr	M * S
Accumulator Tank B	PXS-MT-01B	1	ESF	1 yr	M * S
Core Makeup Tank A	PXS-MT-02A	1	ESF	1 yr	M * S
Core Makeup Tank B	PXS-MT-02B	1	ESF	1 yr	M * S

Table 3.11-1 (Sheet 51 of 51)
Environmentally Qualified Electrical and Mechanical Equipment

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
In-Containment Refueling Water Storage Tank	PXS-MT-03	1	ESF	1 yr	M * S
Emergency Air Storage Tank 01	VES-MT-01	7	ESF	1 yr	M **
Emergency Air Storage Tank 02	VES-MT-02	7	ESF	1 yr	M **
Emergency Air Storage Tank 03	VES-MT-03	7	ESF	1 yr	M **
Emergency Air Storage Tank 04	VES-MT-04	7	ESF	1 yr	M **
Emergency Air Storage Tank 05	VES-MT-05	7	ESF	1 yr	M **
Emergency Air Storage Tank 06	VES-MT-06	7	ESF	1 yr	M **
Emergency Air Storage Tank 07	VES-MT-07	7	ESF	1 yr	M **
Emergency Air Storage Tank 08	VES-MT-08	7	ESF	1 yr	M **
Emergency Air Storage Tank 09	VES-MT-09	7	ESF	1 yr	M **
Emergency Air Storage Tank 10	VES-MT-10	7	ESF	1 yr	M **
Emergency Air Storage Tank 11	VES-MT-11	7	ESF	1 yr	M **
Emergency Air Storage Tank 12	VES-MT-12	7	ESF	1 yr	M **
Emergency Air Storage Tank 13	VES-MT-13	7	ESF	1 yr	M **
Emergency Air Storage Tank 14	VES-MT-14	7	ESF	1 yr	M **
Emergency Air Storage Tank 15	VES-MT-15	7	ESF	1 yr	M **
Emergency Air Storage Tank 16	VES-MT-16	7	ESF	1 yr	M **
Emergency Air Storage Tank 17	VES-MT-17	7	ESF	1 yr	M **
Emergency Air Storage Tank 18	VES-MT-18	7	ESF	1 yr	M **
Emergency Air Storage Tank 19	VES-MT-19	7	ESF	1 yr	M **
Emergency Air Storage Tank 20	VES-MT-20	7	ESF	1 yr	M **
Emergency Air Storage Tank 21	VES-MT-21	7	ESF	1 yr	M **
Emergency Air Storage Tank 22	VES-MT-22	7	ESF	1 yr	M **
Emergency Air Storage Tank 23	VES-MT-23	7	ESF	1 yr	M **
Emergency Air Storage Tank 24	VES-MT-24	7	ESF	1 yr	M **
Emergency Air Storage Tank 25	VES-MT-25	7	ESF	1 yr	M **
Emergency Air Storage Tank 26	VES-MT-26	7	ESF	1 yr	M **
Emergency Air Storage Tank 27	VES-MT-27	7	ESF	1 yr	M **
Emergency Air Storage Tank 28	VES-MT-28	7	ESF	1 yr	M **
Emergency Air Storage Tank 29	VES-MT-29	7	ESF	1 yr	M **
Emergency Air Storage Tank 30	VES-MT-30	7	ESF	1 yr	M **
Emergency Air Storage Tank 31	VES-MT-31	7	ESF	1 yr	M **
Emergency Air Storage Tank 32	VES-MT-32	7	ESF	1 yr	M **
Eductor Bypass Isol. Discharge Silencer	VES-PY-N02	3	ESF	2 wks	M
DVI-B Inline Expansion Joint	PXS-PY-E01	1	PB	1 yr	M *

Notes:

1. RT (Reactor Trip), ESF (Engineered Safeguards Feature), PAMS (Post-Accident Monitoring), ISOL (Isolation), PB (Pressure Boundary); all active valves in this table have “PB-1 yr” in addition to any other requirements.
2. Zones identified in Table 3D.5-1
3. Not required post-accident
4. IIS-JE-TE009, IIS-JE-TE013, IIS-JE-TE030, and IIS-JE-TE-034 are not safety-related and therefore excluded from this list.
5. Reference Table 3D.4-2. The operating time presented is a conservatively established qualification time enveloping the actual operating time for component function.
6. E = Electrical Equipment Program

M = Mechanical Equipment Program
* = Harsh Environment
** = Radiation-Harsh Environment (See Appendix 3D, Subsection 3D.4.3.)
\+ = Seismic Qualification not required
S = Qualified for submergence or operation with spray

7. The Protection and Safety Monitoring Cabinets will be qualified to meet the function operating times identified in this table.
8. Provides the function of floodup level indication to the operator in the main control room (MCR), including during a seismic event.
9. Operating time required while submerged is 4 months.
10. Operation while submerged is not required.
11. Not required unless irradiated fuel is stored in the spent fuel pool. ESF leakage prevention from the spent fuel pool may also be met by maintaining equivalent water pressure (level) on the opposite side of the gate seal.
12. Conservatively identified as Zone 9 due to adjacent rooms.

Appendix 3A HVAC Ducts and Duct Supports

This appendix provides the design criteria for seismic Category I and II HVAC ducts and their supports. These design criteria maintain structural integrity for seismic Category I and II ducts and functional capability for seismic Category I duct.

The structural components of a typical HVAC duct system include the sheet metal ducts, stiffeners for the ducts, duct supports, and other inline components such as duct heaters, dampers, etc.

3A.1 Codes and Standards

The design of the HVAC ducts and their supports conform to the following codes and standards:

- ASME N509-1989(R1996), Nuclear Power Plants Air Cleaning Units and Components
- ASME/ANSI AG-1-1997, Code on Nuclear Air and Gas Treatment
- American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, ANSI/AISC N690-1994. American Welding Society (AWS), Structural Welding Code - Steel, AWS D1.1-2000 provides an acceptable alternative for ANSI/AISC N690 for weld requirements as described in Subsections 3.8.3.2 and 3.8.4.2.
- American Iron and Steel Institute (AISI), Specification for the Design of Cold Formed Steel Structural Members, 1996 Edition and Supplement No. 1, July 30, 1999
- SMACNA, HVAC Duct Construction Standards, Metal and Flexible, Second Edition 1995.

3A.2 Loads and Load Combinations

3A.2.1 Loads

3A.2.1.1 Dead Load (D)

Dead load includes the weight of the duct sheet, stiffeners and inline components such as duct heaters and dampers. It also includes permanently attached items such as insulation and fireproofing, where applicable, and the weight of the duct supports. Temporary items used during construction or maintenance are removed prior to operation.

3A.2.1.2 Construction Live Load (L)

Live load consists of a load of 250 pounds to be applied only during construction or maintenance on an area of 10 square inches on the duct at a critical location to maximize flexural and shear stresses. This load is not combined with seismic loads.

3A.2.1.3 Pressure (P)

The duct metal thickness and stiffener requirements are based on maximum system design pressures. SMACNA or ASME guidelines, as applicable, are used in the design of duct metal thickness and stiffener requirements.

The pressure loads occur during normal plant operation, including plant start up testing, damper closure and normal airflow. Occasionally, overpressure transient loads such as rapid damper closure may also produce short duration pressure differential.

3A.2.1.4 Safe Shutdown Earthquake (E_s)

Seismic response of the HVAC ductwork and its support system are produced due to seismic excitation of the supports.

3A.2.1.5 Wind Loads (W)

Ductwork within partially or fully vented buildings is subject to wind effects. Design wind loads are discussed in Section 3.3.

3A.2.1.6 Tornado Loads (W_t)

Ductwork within partially or fully vented buildings is subject to tornado differential pressure effects. Tornado loads are discussed in Section 3.3. Seismic Category I HVAC ductwork is protected from impact by tornado missiles.

3A.2.1.7 External Pressure Differential Loads (P_A)

Seismic Category I HVAC ductwork and its supports are designed to withstand dynamic external pressure differential loads resulting from postulated accident conditions. Usually HVAC ducts are routed outside the areas of potential pipe break.

3A.2.1.8 Thermal (T_O/T_A)

Stresses on the supports resulting from the ductwork expansion due to temperature changes are avoided by designing the system to take care of the expansion or by utilizing expansion joints. For ducts of gasketed companion angle construction, thermal loads are negligible. For ducts exposed to higher temperatures during a postulated accident condition, an evaluation is performed on a case by case basis for its effect.

3A.2.2 Load Combinations

The load combinations for various service levels are as follows:

Service Level		Load Combination
A	(Construction / maintenance)	$D + L + P + T_O$
A	(Normal Operating Condition)	$D + P + T_O$
B	(Severe Condition)	$D + W + P + T_O$
C	(Extreme Condition)	$D + E_s + P + T_O$
C	(Extreme Condition)	$D + W_t + P + T_O$
D	(Abnormal Condition)	$D + P + P_A + E_s + T_A$

3A.3 Analysis and Design

The HVAC duct support system is designed to maintain structural integrity of the duct. Function is not required for the seismic Category II ductwork. The stresses are maintained within the allowable limits specified in Subsection 3A.3.4. Section properties and masses are calculated in accordance with SMACNA standard.

The damping values for seismic analysis are as follows:

- Welded HVAC Ductwork 4 percent
- Bolted HVAC Ductwork 7 percent

The duct design due to pressure loads is based on ASME/ANSI AG-1 for seismic Category I ducts and SMACNA for seismic Category II ducts.

The global behavior of the duct is determined from the overall bending of the duct between the supports. It is similar to the beam type bending. The dead load is combined with the seismic inertial load to determine the maximum bending moment. For determining the section modulus, the corners of the duct are considered effective. The corner length in each direction equals 32 times the thickness of the duct (t) for this purpose.

3A.3.1 Response Due to Seismic Loads

The methodology for seismic analysis is provided in Subsection 3.7.3. Seismic loads are determined by either using the equivalent static load method of analysis or by performing dynamic analysis.

Stresses are determined for the seismic excitation in two horizontal and one vertical direction. The stresses in the three directions are combined using the square root of sum of the squares (SRSS) method or the 100-40-40 method as described in Subsection 3.7.3.6.

3A.3.2 Deflection Criteria

Deflections for panels and stiffeners conform to the limits stated in the “Code on Nuclear Air and Gas Treatment.”

3A.3.3 Relative Movement

Clearances are provided for allowing relative movement between equipment, other commodities, and HVAC system.

3A.3.4 Allowable Stresses

The basic stress allowables for the HVAC ducts are in accordance with paragraph SA-4220 of ASME/ANSI AG-1.

The basic stress allowables for duct supports utilizing rolled structural shapes are in accordance with ANSI/AISC N690 and the supplemental requirements described in Subsection 3.8.4.5.2. The basic stress allowables for supports utilizing light gage cold rolled channel type sections are based on the manufacturer's published catalog values.

Service Level A and B	Basic Allowable
Service Level C and D	1.6 times basic allowable for tension and 1.4 times basic allowable for compression

3A.3.5 Connections

Connections are designed in accordance with the applicable codes and standards listed in Section 3A.1. For connections used with light gage cold rolled channel type sections, design is based on the manufacturer's published catalog values. Supports are attached to the building structure by bolted or welded connections. Fastening of the supports to concrete structures meets the supplemental requirements given in Subsection 3.8.4.5.1.

Appendix 3B Leak-Before-Break Evaluation of the AP1000 Piping

General Design Criterion 4 requires that structures, systems, and components important to safety be designed to accommodate the effects of conditions associated with normal operation, anticipated transients, and postulated accident conditions. However, the dynamic effects associated with pipe rupture may be excluded when analysis demonstrates that the probability of fluid system pipe rupture is extremely low. Dynamic effects are not considered for those segments of piping that are shown mechanistically, with a large margin, not to be susceptible to a pipe rupture.

The dynamic effects associated with pipe rupture include effects such as pipe break reaction loads, jets and jet impingement, subcompartment pressurization loads, and transient pipe rupture depressurization loads on other components.

The use of mechanistic pipe break to eliminate evaluation of dynamic effects of pipe rupture includes material selection, inspection, leak detection, and analysis. Subsection 3.6.3 outlines considerations relative to material selection, inspections, and leak detection. Subsection 5.2.5 describes the leak detection system inside containment. This appendix describes the analysis methods used to support the application of mechanistic pipe break to high-energy piping in the AP1000.

The analysis and criteria to eliminate dynamic effects of pipe breaks are encompassed in a methodology called leak-before-break (LBB). This methodology has been validated by theoretical investigations and test demonstrations sponsored by the industry and the NRC.

The primary regulatory documents for leak-before-break analyses are General Design Criterion No. 4 (GDC-4), Draft Standard Review Plan 3.6.3 (SRP 3.6.3) (Reference 1), and NUREG-1061, Volume 3 (Reference 2). Although SRP 3.6.3 has been issued only as a draft, its provisions are followed as guidelines to leak-before-break analyses.

Leak-before-break methodology has been applied to the reactor coolant loop and high-energy auxiliary line piping in operating nuclear power plants. The leak-before-break analysis used to support the piping design of the AP1000 is an application of the same methodology used in leak-before-beak evaluations previously accepted by the NRC.

In the AP1000, leak-before-break evaluations are performed for the reactor coolant loop, the surge line, selected other branch lines containing reactor coolant down to and including 6-inch diameter nominal pipe size, and portions of the main steam line. Those lines not qualified to the leak-before-break criteria are evaluated using the pipe rupture protection criteria outlined in Subsections 3.6.1 and 3.6.2.

This appendix provides a leak-before-break analysis for the applicable piping systems. Table 3B-1 provides a list of AP1000 leak-before-break piping systems.

3B.1 Leak-before-Break Criteria for AP1000 Piping

The methodology used for leak-before-break analysis is consistent with that set forth in GDC-4, SRP 3.6.3 (Reference 1) and NUREG-1061, Volume 3 (Reference 2). The steps are:

- Evaluate potential failure mechanisms
- Perform bounding analysis

3B.2 Potential Failure Mechanisms for AP1000 Piping

In high-energy piping, there are material degradation mechanisms that could adversely affect the integrity of the system as well as its suitability for leak-before-break analysis. The following lists potential degradation (or "failure") mechanisms:

- Erosion-corrosion induced wall thinning
- Stress corrosion cracking (SCC)
- Water hammer
- Fatigue
- Thermal aging
- Thermal stratification
- Other mechanisms

The stainless steel piping is fabricated of SA312TP316LN or SA312TP304L material. The type 304L material is used in the accumulator discharge lines. The main steam piping is fabricated of SA335 Grade P11. The welds are made by the gas tungsten arc welding (GTAW) method.

The various degradation mechanisms are discussed in the following subsections.

3B.2.1 Erosion-Corrosion Induced Wall Thinning

Primary Loop Piping

Wall thinning by erosion and erosion-corrosion effects does not occur in the primary loop piping because Series 300 austenitic stainless steel material is highly resistant to these effects. The coolant velocity in the AP1000 primary loop is about 76 feet per second. This flow velocity is not expected to create erosion-corrosion effects since stainless steels are considered to be virtually immune (Reference 3). A review of erosion-corrosion in nuclear power systems (Reference 4) reported that "stainless steels are increasingly being used due to their excellent resistance to erosion-corrosion, even at high water velocities, 40 m/s (131 ft/sec)." The bend radii in the AP1000 hot and cold legs are greater than the bend radii used in the crossover legs of operating plants. There is no record of erosion-corrosion induced wall thinning in the primary loops of operating plants.

Auxiliary Stainless Steel Piping

Wall thinning by erosion-corrosion effects does not occur in the auxiliary stainless steel piping because Series 300 austenitic stainless materials are highly resistant to these effects. The coolant velocity in these systems is lower than in comparable systems in operating Westinghouse-designed pressurized water reactors. There is no record of erosion-corrosion induced wall thinning in the stainless steel piping of operating plants.

Main Steam Line

Main steam lines in the AP1000 are fabricated from SA335 Grade P11 Alloy steel. Erosion-corrosion induced wall thinning is not expected in the main steam line. Extensive work has been done investigating erosion-corrosion in carbon steel pipes. The main steam line has low susceptibility to erosion due to the pipe material composition, which has sufficient levels of chromium to preclude erosion-corrosion material loss. Susceptibility is also low due to the relatively high operating temperature and the high quality steam in the main steam line.

Based on the above discussion, erosion-corrosion induced wall thinning does not have an adverse effect on the integrity of the AP1000 leak-before-break piping systems.

3B.2.2 Stress Corrosion Cracking

Stress corrosion cracking is not expected to occur in the AP1000 piping systems because the three conditions necessary for stress corrosion cracking to take place are not present. If any of these three conditions is not present, stress corrosion cracking will not take place. The three conditions are:

- There must be a corrosive environment.
- The material itself must be susceptible.
- Tensile stresses must be present in the material.

Primary Loop Piping

During plant operation, the reactor coolant water chemistry is monitored and maintained within specific limits (see Subsection 5.2.3 for a discussion of reactor coolant chemistry). Contaminant concentrations are kept below the thresholds known to be conducive to stress corrosion cracking. The major water chemistry control standards are included in the plant operating procedures as a condition for plant operation.

The key to avoidance of a corrosive environment is control of oxygen. During normal power operation, oxygen concentration in the reactor coolant system is controlled to extremely low levels by controlling charging flow chemistry and maintaining a hydrogen overpressure in the reactor coolant at specified concentrations. Halogen concentration is controlled by maintaining concentrations of chlorides and fluorides within the specified limits. During plant operations, the likelihood of stress corrosion cracking in the primary loop piping systems is very low.

The elements of a water environment known to increase the susceptibility of austenitic stainless steel to stress corrosion are oxygen, fluorides, chlorides, hydroxides, hydrogen peroxide, and reduced forms of sulfur (for example, sulfides, sulfites, and thionates). Pipe cleaning standards prior to operation and careful water chemistry control during plant operation are applied to prevent the occurrence of a corrosive environment. Before being placed in service the piping is cleaned. During flushes and preoperational testing, water chemistry is controlled according to written specifications. Standards on chlorides, fluorides, conductivity, and pH are included in the guidelines for water for cleaning the piping.

Series 300 stainless steel materials have been chosen for the AP1000 due to their proven operating experience. These materials have operated in low-oxygen or no-oxygen environments with no incidents for a number of years. The requirements of Regulatory Guide 1.44, with the exceptions as stated in Subsection 1.9.1, will be used to maintain the experiences of the PWR applications for the use of Series 300 stainless steel materials.

Design tensile stresses in the reactor coolant loop are within the ASME Code, Section III allowables. Residual tensile stresses are expected in the welds and such stresses are not considered when designing by the ASME Code, Section III because these stresses are self-equilibrating and do not affect the failure loads. The residual stresses should not be more severe than for the operating Westinghouse pressurized water reactor plants (which have not experienced stress corrosion cracking in the primary loop).

The material used for buttering nozzles at the stainless-to-carbon steel safe ends is a high nickel alloy. The nickel-chromium-iron alloy selected and qualified for this application is not susceptible to primary water stress corrosion cracking.

Auxiliary Stainless Steel Piping

The discussion above regarding the necessary conditions for primary loop piping stress corrosion cracking is also applicable to the other stainless steel piping of the primary system.

Series 300 stainless steel materials have been chosen for the AP1000 due to their proven operating experience. These materials have operated in low-oxygen or no-oxygen environments with no incidents for a number of years. The requirements of Regulatory Guide 1.44, with the exceptions as stated in Subsection 1.9.1, will be used to maintain the experiences of the PWR applications for the use of Series 300 stainless steel materials.

Design tensile stresses in the other stainless steel piping are within the ASME Code, Section III allowables. Residual tensile stresses are expected in the welds; however, the residual stresses should not be more severe than for the operating Westinghouse pressurized water reactor plants (which have not experienced stress corrosion cracking in the auxiliary stainless steel piping).

Main Steam Line

The main steam piping is constructed from ferritic steel. Stress corrosion cracking in ferritic steels commonly result from a caustic environment. A source of a caustic environment in the main steam piping would be moisture carryover from the steam generator. However, the secondary side water treatment utilizes all volatile treatment. All volatile treatment effectively precludes causticity in the steam generator bulk liquid environment. For some operating plants prior to implementing all volatile treatment, the phosphate water treatment caused a caustic chemical imbalance resulting in stress corrosion cracking of steam generator tubing. Under all volatile treatment water treatment conditions, there is no instance of caustic stress corrosion cracking on the ferritic steam lines indicating no significant caustic carryover. The operating secondary side chemistry precludes stress corrosion cracking on the ferritic main steam line.

Based on the above discussion, stress corrosion cracking does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.3 Water Hammer

Primary Loop Piping

The reactor coolant loop is designed to operate at a pressure greater than the saturation pressure of the coolant, thus precluding the voiding conditions necessary for water hammer to occur. The reactor coolant primary system is designed for Level A, B, C, and D (normal, upset, emergency, and faulted) service condition transients. The design requirements are conservative relative to both the number of transients and their severity. Relief valve actuation and the associated hydraulic transients following valve opening have been considered in the system design. Other valve and pump actuations cause relatively slow transients with no significant effect on the system dynamic loads.

To provide dynamic system stability, reactor coolant parameters are controlled. Temperature during normal operation is maintained within a narrow range by control rod positioning. Pressure is controlled within a narrow range for steady-state conditions by pressurizer heaters and pressurizer spray. The flow characteristics of the system remain constant during a fuel cycle. The operating transients of the reactor coolant system primary loop piping are such that significant water hammer loads are not expected to occur.

Auxiliary Stainless Steel Piping

The passive core cooling system and automatic depressurization system are designed to minimize the potential for water hammer induced dynamic loads. Design features include:

- Continuously sloping core makeup tank and passive residual heat exchanger inlet lines to eliminate local high points

- Inlet diffusers in the core makeup tanks to preclude adverse steam and water interactions

- Vacuum breakers in the discharge lines of the automatic depressurization valves connected to the pressurizer

The AP1000 pressurizer spray control valve is similar to what is used in the operating plants. There is no history of water hammer caused by the spray control valve.

The normal residual heat removal system isolation valves are slow closing valves, identical to operating plants, and therefore would not be a source of water hammer.

These features minimize the potential of water hammer in the auxiliary stainless steel piping system.

Main Steam Line

The steam lines are not subject to water hammer by the nature of the fluid transported. The following system design provisions address concerns regarding steam hammer within the main steam line and identify the significant dynamic loads included in the main steam piping design.

- Design features that prevent water slug formations are included in the system design and layout. In the main steam system, these include the use of drain pots and the proper sloping of lines.

- The operating and maintenance procedures that protect against a potential occurrence of steam hammer include system operating procedures that provide for slowly heating up (to avoid condensate formation from hotter steam on colder surfaces), operating procedures that caution against fast closing of the main steam isolation valves except when necessary, and operating and maintenance procedures that emphasize proper draining.

- The stress analyses for the safety-related portion of the main steam system piping and components include the dynamic loads from rapid valve actuations, including actuation of the main steam isolation valves and the safety valves.

Based on the above discussion, water hammer does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.4 Fatigue

Low-Cycle Fatigue

Low-cycle fatigue due to normal operation and anticipated transients is accounted for in the design of the piping system. The Class 1 piping systems comply with the fatigue usage requirements of the ASME Code, Section III. The Class 2 and 3 piping systems comply with the stress range reduction factors of the ASME Code, Section III.

Due to the nature of operating parameters, main steam line piping (Class 2) and the Class 3 portion of the accumulator piping, are not subjected to any significant transients to cause low-cycle fatigue.

Based on the above discussion, low-cycle fatigue is not a concern of AP1000 leak-before-break piping systems.

High-Cycle Fatigue

High-cycle fatigue loads in the system result primarily from pump vibrations. The steam generator is designed so that flow-induced vibrations in the tubes are avoided (see Subsection 5.4.2). The loads from reactor coolant pump vibrations are minimized by criteria for pump shaft vibrations during hot functional testing and operation. During operation, an alarm signals when the reactor coolant pump vibration is greater than the limits.

With these precautions taken, the likelihood of leakage due to fatigue in piping systems evaluated for leak-before-break is very small.

3B.2.5 Thermal Aging

Stainless Steel Piping

Piping used in the reactor coolant loop and other auxiliary lines are wrought stainless steel materials, rather than cast materials, so that thermal aging concerns are not expected for the AP1000 piping and fittings. The welds used in the assembly of the AP1000 are gas tungsten arc welds (GTAW). These welds are essentially as resistant to the effects of thermal aging as the base metal materials. This is due to the typically low ferrite content in welds which results in minimal impact from thermal aging. Based on this information, thermal aging of weld materials and piping used in the AP1000 is not an issue.

Main Steam Lines

The main steam piping system does not have cast materials. The welding process used on these lines is also gas tungsten arc weld (GTAW).

There are no thermal aging concerns for the carbon steel piping of the main steam line and the alloy steel of the main feedwater piping.

The material used for the main steam piping system is not susceptible to dynamic strain aging effects.

3B.2.6 Thermal Stratification

Leak-before-break analyses include consideration of the loads and stresses due to thermal stratification.

Thermal stratification occurs only in a pipe that has a susceptible geometry and low flow velocities. A temperature difference between the flowing fluid and stagnant fluid is also a prerequisite.

The design of piping and component nozzles in the AP1000 includes provisions to minimize the potential for and the effects of thermal stratification, cycling, and striping, pursuant to actions requested in several NRC bulletins, as discussed below.

Primary Loop Piping

Thermal stratification in the reactor coolant loops resulting from actuation of passive safety features is evaluated as a design transient. Stratification effects due to both Level B and Level D service conditions are considered. The criteria used in the evaluation of the stress in the loop piping due to stratification is the same as that applicable for other Level B and Level D service conditions.

Auxiliary Stainless Steel Piping

Pursuant to the actions requested in NRC Bulletin 88-11, the pressurizer surge line is analyzed to demonstrate that the applicable requirements of the ASME Code, Section III are met. This analysis includes consideration of plant operation, thermal stratification, and thermal striping using temperature distributions and transients developed from experience on existing plant monitoring programs.

Pursuant to the actions requested in NRC Bulletin 88-08 (cracking in piping connected to reactor coolant systems due to isolation valve leakage), a systems review of the AP1000 piping was performed in accordance with the criteria provided in Subsection 3.9.3.1.2.

The unisolable sections of the following lines which are evaluated for leak-before-break have been reviewed and are not susceptible to adverse stresses as described in NRC Bulletin 88-08:

Passive residual heat removal (PRHR) line from the hot leg, through the passive residual heat removal heat exchanger, and to the steam generator channel head
The potential for leakage through the isolation valves is not a concern for the piping extending from the reactor coolant system hot leg connection to the passive residual heat removal heat exchanger inlet, since hot leakage from the reactor coolant system would be entering a hot section of piping. Leakage exiting the passive residual heat removal heat exchanger would not be a concern since the cooled leakage would be entering a cold section of piping. This leakage would then heat up in the piping directly below the steam generator. Any amount of leakage is expected to be small, since the pressure differential across the isolation valves is about 50 psi (the difference between the hot leg and reactor coolant pump suction pressures). Activation of the passive residual heat removal system following a plant scram is not a concern, since stratification will not occur due to the high flow velocity in the passive residual heat removal return flow line.

Automatic depressurization stage 4 lines from the hot legs to the stage 4 depressurization valves
Leakage is not a concern since the squib valves are leaktight and other potential leakage flow paths have double isolation.

Pressurizer safety line from the pressurizer to the safety valve
This line is steam filled and will not experience stratified loadings.

Automatic depressurization stage 2 and 3 lines from the pressurizer to the depressurization valves
Leakage is not a concern since double isolation exists in all potential leakage flow paths.

Normal residual heat removal suction lines from the hot legs to the isolation valves
Thermal stratification in the normal residual heat removal suction lines, including leakage through the isolation valves, is considered in the ASME pipe stress and fatigue analysis of these lines.

Direct vessel injection lines
Thermal stratification in the direct vessel injection lines, including leakage through the isolation valves, is considered in the ASME Code pipe stress and fatigue analysis of these lines.

Main Steam Line

The steam lines are not subjected to thermal stratification by the nature of fluid transported.

Based on the above discussion, thermal stratification does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.7 Other Mechanisms

The pipe evaluated for leak-before-break does not operate at temperature for which creep fatigue must be considered. Creep fatigue is a concern for ferritic steel piping operation at temperatures above 700°F and for austenitic stainless steel operation above 800°F.

Pipe degradation or failure by indirect causes such as fires, missiles, and component support failures is precluded by criteria for design, fabrication, inspection, and separation of potential hazards in the vicinity of the safety-related piping. The structures, larger pipe, and components in the vicinity of pipe evaluated for leak-before-break are safety-related and seismically designed or are seismically supported if nonsafety-related.

Cleavage type failures are not a concern for systems operating temperature and material used in the stainless steel piping systems. The material used in the main steam line is highly ductile and resistant to cleavage type failure at operating temperatures. The resistance to failure have been demonstrated by material fracture toughness tests.

3B.3 Leak-before-Break Bounding Analysis

The methodology used for performing the bounding analysis is consistent with that set forth in GDC-4, SRP 3.6.3 (Reference 1) and NUREG-1061, Volume 3 (Reference 2).

Bounding leak-before-break analysis for the applicable AP1000 piping systems is performed. The analysis criteria and development techniques of the bounding analysis curves (BAC) are described below. The bounding analysis curve allows for the evaluation of the piping system in advance of the final piping analysis, incorporating leak-before-break considerations early in the piping design process. The leak-before-break bounding analysis curve is used to evaluate critical points in the piping system. A minimum of two points are required to develop the bounding analysis curve. One point for the low normal stress case and the other point for the high normal stress case. If variations in pipe size, material, pressure or temperature occur for a specific piping system, an additional bounding analysis curve is generated. These points meet the following margins for leak-before-break analysis: (References 1 and 2).

- Margin of 10 on leak detection capability
- Margin of 2 on flaw size
- Establish margin of 1 on load by using absolute combination method of maximum loads

The calculations to establish the bounding analysis curves use minimum values for wall thickness at the weld counterbore and ASME Code material properties. For the main steam line lower bound material property values determined from tests of the material are used. The use of the minimum values bounds the results of larger values. Since the piping is designed and analyzed using ASME Code minimum material properties, these are used conservatively in a consistent manner for evaluation of leak-before-break evaluations. The as-built material properties are expected to be higher than the ASME Code minimum properties. Using minimum thickness instead of a nominal thickness is conservative for the stability analysis and was also used for leak-before-break in operating plants. The use of one thickness (either nominal or minimum) for both leak rate and stability calculation gives comparable overall margins for typical plant loads. The bounding analysis curves are established using the axial load from internal pressure and neglecting other axial loads. This is an appropriate approximation because experience with leak-before-break calculations has shown that the axial load due to pressure is the dominant axial load.

3B.3.1 Procedure for Stainless Steel Piping

3B.3.1.1 Pipe Geometry, Material and Operating Conditions

The following information is identified for each of the lines:

- Piping materials - 316LN/304L, Type 304L is used for the accumulator discharge line
- Normal operating temperature
- Normal operating pressure
- Pipe outside diameter
- Pipe thickness

The number of bounding analysis curves needed for each analyzable piping system is determined by a review of the combinations of the following parameters:

- Pipe size
- Pipe schedule
- Operating pressures (100 percent power and maximum stress condition)
- Operating temperatures (100 percent power and maximum stress condition)

3B.3.1.2 Pipe Physical Properties

The physical and metallurgical properties for each of the lines are determined in the following manner

- Minimum wall thickness is calculated at the weld counterbore
- The area (A) and section modulus (Z) are calculated using minimum wall thickness
- The yield strength is the ASME Code, Section II (Reference 5) minimum value, at temperature of interest
- The ultimate strength is the ASME Code, Section II (Reference 5) minimum value, at temperature of interest
- The modulus of elasticity is the ASME Code, Section II (Reference 5) at temperature of interest

3B.3.1.3 Low Normal Stress Case (Case 1)

To determine the first point of the bounding analysis curve the following steps are used.

- Calculate axial force Fp (for normal operating pressure)
- Assume a lower magnitude of bending stress. The magnitude selected is a very small number that is lower than the expected minimum bending stress.
- Calculate bending moment = (bending stress) x (section modulus)
- Calculate the leakage flaw size at 100 percent power condition for 10 times the leak detection capability (for 0.5 gpm leak detection capability, this is 10 x 0.5 = 5 gpm)
- Perform the stability analysis using the limit load methodology to obtain the critical flaw size. For AP1000 piping systems, there is no cast material and the weld process is gas tungsten arc welds (Z factor is 1.0 since weld process is gas tungsten arc welds, Reference 1.)
  - Determine the maximum loads for a critical flaw size of twice the leakage flaw size. The margin of 2 on flaw size is satisfied.
- Calculate the low normal stress and corresponding maximum stress by using:

$$\text{Stress} = \frac{\text{Axial Force}}{\text{Area}} + \frac{\text{Bending Moment}}{\text{Section Modulus}} \qquad \text{(3B-1)}$$

3B.3.1.4 High Normal Stress Case (Case 2)

To determine the other endpoint of the bounding analysis curve the following steps are used.

- Axial force Fp is calculated as above for normal operating pressure

- Assume a higher magnitude of bending stress to get higher bending moment. The magnitude of bending is selected such that the corresponding maximum stress generated is close to the flow stress.

- Calculate bending moment = (bending stress) x (section modulus)

- Repeat leakage flaw size and stability calculations as outlined for the low normal stress case above

Note: For an intermediate point, calculation steps are the same as low normal or the high normal case.

3B.3.1.5 Develop the Bounding Analysis Curve

- For Case 1, normal and maximum stresses are established.

- For Case 2, normal and maximum stresses are established.

- Plot these two points with normal versus maximum stress. The curve is generated by joining these two points in a straight line. More than two points may be used if desired, to obtain a smooth curve fit between the calculated points. A typical curve is shown in Figure 3B-1.

3B.3.2 Procedure for Non-stainless Steel Piping

The procedure to develop the bounding analysis curve for the carbon steel for main steam lines is similar to that for the stainless steel and is described below.

3B.3.2.1 Pipe Geometry, Material and Operating Conditions

The following information is identified for each of the lines:

- Piping materials
- Normal operating temperature
- Normal operating pressure
- Pipe outside diameter
- Piping thickness

The number of bounding analysis curves needed for each analyzable piping system is determined by a review of the combinations of the following parameters:

  – Pipe size
  – Pipe schedule
  – Operating pressures (100 percent power and maximum stress condition)
  – Operating temperatures (100 percent power and maximum stress condition)

3B.3.2.2 Calculations Steps

- The minimum wall thickness is calculated at the weld counterbore

- The area (A) and section modulus (Z) are calculated using minimum wall thickness

- The material yield strength, ultimate strength, modulus of elasticity, stress-strain curves, and J-R curves are determined from the material tests

3B.3.2.3 Low Normal Stress Case (Case 1)

To determine the first point of the bounding analysis curve the following steps are used.

- Calculate axial force Fp (for normal operating pressure)
- Assume a lower magnitude of bending stress
- Calculate bending moment = (bending stress) x (section modulus)
- Calculate the leakage flaw size at 100 percent power condition for 10 times the leak detection capability (for 0.5 gpm leak detection capability, this is 10 x 0.5 = 5 gpm)
- Stability analysis
  - Perform J-integral analysis
  - Determine the maximum loads for a critical flaw size of twice the leakage flaw size by satisfying the stability criteria. The margin of 2 on flaw size is satisfied.
- Stability criteria
  - Japplied ≤ JIC
  - If Japplied > JIC, then Japplied < Jmax and Tapplied < Tmat
- Calculate the low normal stress and corresponding maximum stress by using:

$$\text{Stress} = \frac{\text{Axial Force}}{\text{Area}} + \frac{\text{Bending Moment}}{\text{Section Modulus}}$$

3B.3.2.4 High Normal Stress Case (Case 2)

To determine the other endpoint of the bounding analysis curve the following steps are used.

- Axial force Fp is calculated above (for normal operating pressure)
- Assume a higher magnitude of bending stress to get higher bending moment
- Calculate bending moment = (bending stress) x (section modulus)
- Repeat leakage flaw size and stability calculations as outlined for the low normal stress case above

Note: For an intermediate point, calculation steps are the same as low normal or the high normal case.

3B.3.2.5 Develop the Bounding Analysis Curve

Follow steps as outlined for the stainless steel case in Subsection 3B.3.1.5.

3B.3.3 Evaluation of Piping System Using Bounding Analysis Curves

To evaluate the applicability of leak-before-break, the results of the pipe stress analysis are compared to the bounding analysis curve. The critical location is the location of highest maximum stress as determined by the pipe stress results. A comparison is made with the applicable bounding analysis curves for the analyzable piping systems. As outlined in 3B.3.1.1 and 3B.3.2.1, bounding analysis curves are calculated for different combinations of pipe size, pipe schedule, operating pressures, operating temperatures.

The bounding analysis curves are used during the layout and design of the piping systems to provide a design that satisfies leak-before-break criteria. In addition, the results of the as-built piping analysis reconciliation to the bounding analysis curves to verify that the fabricated piping systems satisfy leak-before-break criteria. See Subsection 3.6.4 for the Combined License information item associated with this verification.

At the critical location, the load combination for the maximum stress calculation uses the absolute sum method. The load combination is as follows:

(1) |Pressure| + |Deadweight| + |Thermal (100% Power)*| + |Safe Shutdown Earthquake|

(2) |Pressure| + |Deadweight| + |Maximum Stratification| (Additional Case for Surge Line)

The normal stress is calculated using the algebraic sum method at critical location and the following load combination.

(1) Pressure + Deadweight + Thermal (100% Power*)

* Includes applicable 100% Power stratification loads.

3B.3.3.1 Calculation of Stresses

The stresses due to axial loads and moments are calculated by the following equation:

where:

$$\sigma = \frac{F}{A} + \frac{M}{Z} \qquad \text{(3B-2)}$$

σ = stress

F = axial load

M = moment

A = cross-sectional area

Z = section modulus

The moments for the desired loading combinations are calculated by the following equation:

$$M = \sqrt{M_X^2 + M_Y^2 + M_Z^2} \qquad \text{(3B-3)}$$

where,

M = moment for required loading

M_X = torsional moment

M_Y = Y component of bending moment

M_Z = Z component of bending moment

The Y and Z-axes are lateral axes to the X-axis which is the axial axis

The axial load and moments for the normal case and maximum case are computed by the methods shown below.

3B.3.3.2 Normal Loads

The normal operating loads are calculated by the following equations:

$$F = F_{DW} + F_{Th} + F_P \quad (3B\text{-}4)$$

$$M_X = (M_X)_{DW} + (M_X)_{Th} \quad (3B\text{-}5)$$

$$M_Y = (M_Y)_{DW} + (M_Y)_{Th} \quad (3B\text{-}6)$$

$$M_Z = (M_Z)_{DW} + (M_Z)_{Th} \quad (3B\text{-}7)$$

The subscripts of the above equations represent the following load cases:

DW = deadweight

Th = normal thermal expansion (100 percent power, including applicable stratification loads)

P = load due to internal pressure

The method of combining loads is often referred to as the algebraic sum method.

Calculate the normal stress at the critical location.

3B.3.3.3 Maximum Loads

For the maximum case, the absolute summation method of load combination is applied which results in higher magnitude of the combined loads. Since stability is demonstrated using these loads, the leak-before-break margin on loads is satisfied. An example of the absolute summation expressions are shown below:

$$F = |F_{DW}| + |F_{Th}| + |F_P| + |F_{SSEINERTIA}| + |F_{SSEAM}| \quad (3B\text{-}8)$$

$$M_X = |(M_X)_{DW}| + |(M_X)_{Th}| + |(M_X)_{SSEINERTIA}| + |(M_X)_{SSEAM}| \quad (3B\text{-}9)$$

$$M_Y = |(M_Y)_{DW}| + |(M_Y)_{Th}| + |(M_Y)_{SSEINERTIA}| + |(M_Y)_{SSEAM}| \quad (3B\text{-}10)$$

$$M_Z = |(M_Z)_{DW}| + |(M_Z)_{Th}| + |(M_Z)_{SSEINERTIA}| + |(M_Z)_{SSEAM}| \quad (3B\text{-}11)$$

where subscripts SSE, Inertia and AM mean safe shutdown earthquake, inertia and anchor motion respectively.

Note: For the surge line, see Subsection 3B.3.3 for additional case.

3B.3.3.4 Bounding Analysis Curve Comparison – LBB Criteria

To compare the stress results with the bounding analysis curve the following process is followed. The normal and maximum stress at the critical location are calculated by using the loads defined in Subsection 3B.3.3. Plot the normal stress versus maximum stress on the bounding analysis curve for the specified system. If the point is on or below the bounding analysis curve, the leak-before-break analysis and margins are satisfied. If the point falls above the bounding analysis curve, the leak-before-break analysis criteria are not satisfied and the pipe layout or support configuration needs to be revised to meet the leak-before-break bounding analysis. Figure 3B-1 shows a typical bounding analysis curve.

3B.3.4 Bounding Analysis Results

Table 3B-1 shows a summary of piping systems and corresponding bounding analysis figures. Figures 3B-1 to 3B-22 show the bounding analysis curves. The curves satisfy the margins as indicated in Section 3B.3.

3B.4 Differences in Leak-before-Break Analysis for Stainless Steel and Ferritic Steel Pipe

The significant difference between leak-before-break analysis performed for the stainless steel (Class 1 and Class 3) systems and the ferritic steel in the Class 2 systems is in the stability analysis. In the case of stainless steel systems, stability analyses are performed by limit load approach. In the ferritic steel systems, stability analyses are performed by J-integral approach.

3B.5 Differences in Inspection Criteria for Class 1, 2, and 3 Systems

Class 1, 2 and 3 systems are subjected to in-service inspection requirements from ASME Code, Section XI. For Class 1 piping, terminal ends and dissimilar metal welds are volumetrically inspected, along with other locations, to total 25 percent of the welds. For Class 2 piping, the requirement is to volumetrically inspect the terminal ends and other locations to total 7.5 percent of the welds. For Class 3 systems (the only Class 3 piping is in the accumulator line which is always at room temperature), the system receives periodic visual examinations in conjunction with pressure testing. These requirements were developed by ASME Code, Section XI consistent with the different safety classes of these systems.

The leak-before-break evaluations are based on the ability to detect a potential leaking crack; not the ability to find cracks by inservice inspections. The criteria or methods of the leak-before-break evaluations are the same for ASME Code Class 1, 2, and 3.

3B.6 Differences in Fabrication Requirements of ASME Class 1, Class 2, and Class 3 Piping

The significant difference among Class 1, 2 and 3 seamless pipe occurs in the nondestructive examination requirements. The Class 1 seamless pipe examination requirements include an ultrasonic testing examination, whereas Class 2 and 3 do not. In addition, the Class 1 examination requirements for a circumferential butt welded joint include radioagraphic testing and magnetic particle or liquid penetrant examination where Class 2 does not. The examination requirements for Class 2 pipe require radiographic examination of the welds and normally Class 3 pipe does not. As noted in Subsection 3.2.2.5, for Class 3 lines required for emergency core cooling functions, radiography will be conducted on a random sample of welds. The Class 3 leak-before-break lines are included in the lines that are radiographed. In addition see Subsection 3.6.3.2 for augmented inspection of Class 3 leak-before-break lines.

For the fabrication of welds in the Class 1, Class 2 and Class 3 pipes there is no significant differences.

The differences in fabrication and nondestructive examination requirements do not affect the leak-before-break analyses assumptions, criteria, or methods.

3B.7 Sensitivity Study for the Constraint Effect on LBB

Westinghouse performed a sensitivity study on a 6-inch diameter pipe to demonstrate that the leak-before-break evaluation margins are not significantly affected when constraint effects of pressure induced bending are included. The analysis used a finite element model of a 6-inch diameter pipe welded to a nozzle with a fixed end condition. This conservatively represents the bounding conditions for AP1000 piping. The normal and maximum stresses were used from a representative AP600 6-inch line bounding analysis curve. The material properties for the base metal and TIG weld were considered in the analysis. The stability analysis was performed using the J-integral method. This analysis was developed in consultation with the NRC.

The conclusion of this sensitivity study is that the leak-before-break margins for 6-inch and larger piping on AP1000 are not significantly affected by the constraint effect and application of leak-before-break to such piping is acceptable.

3B.8 References

1. Standard Review Plan 3.6.3, "Leak Before Break Evaluation Procedures," Federal Register, Volume 52, Number 167, Friday, August 28, 1987; Notice (Public Comment Solicited), pp. 32626-32633.

2. NUREG-1061, "Evaluation of Potential for Pipe Breaks, Report of the U.S. Nuclear Regulatory Commission Piping Review Committee," Volume 3, (prepared by the Pipe Break Task Group), November 1984.

3. "Erosion-Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines," EPRI NP-3944, April 1985.

4. G. Cragnolino, "Erosion-Corrosion in Nuclear Power Systems-An Overview," Corrosion '87, Paper No. 86, March 1987.

5. ASME Boiler and Pressure Vessel Code, Section II, "Materials," 1998 Edition through 2000 Addenda.

Table 3B-1 (Sheet 1 of 2)
AP1000 Leak-Before-Break Bounding Analysis Systems and Parameters

System	Subsystem	Line No(s).	Nominal Diameter (Inches)	Material	Temp (°F)	Pressure (psig)	Figure No.
RCS	Primary Loop Hot Leg	L001A, B	31 (ID)(1)	SA-376 TP316LN	610.0	2247.0	3B-2
RCS	Primary Loop Cold Leg	L002A, B, C, D	22 (ID)(1)	SA-376 TP316LN	537.2	2323.0	3B-3
SGS	Main Steam Line	L006A, B	38	SA-335 GR P11	523.0	821.0	3B-4
RCS	Normal Residual Heat Removal	L139	20	SA-312 TP316LN	610.0	2247.0	3B-5
RCS	Surge Line	L003	18	SA-312 TP316LN	653.0	2248.0	3B-6 (Sheet 1)
RCS	Surge Line	L003	18	SA-312 TP316LN	653.0(2) 455.0(2)	2248.0(2) 430.0(2)	3B-6 (Sheet 2)
RCS	Passive Residual Heat Removal Supply/ ADS 4	L135A,B; L136A,B	18	SA-312 TP316LN	610.0	2247.0	3B-7
RCS	Passive Removal Heat Removal Supply/ ADS 4	L133A, B; L137A, B; L134	14	SA-312 TP316LN	610.0	2247.0	3B-8
PXS	Passive Residual Heat Removal Supply to Cold Trap and Vent Line	L102, L107	14	SA-312 TP316LN	610.0	2235.0	3B-8
PXS	Passive Residual Heat Removal Supply after Cold Trap to PRHR HX	L102	14	SA-312 TP316LN	120.0	2235.0	3B-9
PXS	Return – PRHR HX to Isolation Valve	L103	14	SA-312 TP316LN	120.0	2235.0	3B-9
RCS	Automatic Depressurization System Stage 2, 3	L004A,B; L006A,B; L020A,B; L030A, B; L131	14	SA-312 TP316LN	653.0	2234.0	3B-10 (Sheets 1 and 2)
PXS	Passive Residual Heat Removal Return – after Isolation Valve	L104A, B; L105	14	SA-312 TP316LN	537.0	2202.0	3B-11

Table 3B-1 (Sheet 2 of 2)
AP1000 Leak-Before-Break Bounding Analysis Systems and Parameters

System	Subsystem	Line No(s).	Nominal Diameter (Inches)	Material	Temp (°F)	Pressure (psig)	Figure No.
RCS	Passive Residual Heat Removal Return	L113	14	SA-312 TP316LN	537.0	2202.0	3B-11
PXS	Passive Residual Heat Removal Vent Line	L107	12	SA-312 TP316LN	610.0	2248.0	3B-12 (Not Used)
PXS	Accumulator to Isolation Valve	L029A, B	8	SA-312 TP304L	120.0	700.0	3B-13
RCS	Balance Line from Cold Leg to CMT Isolation Valve	L118A, B	8	SA-312 TP316LN	537.0	2323.0	3B-14
PXS	Balance Line from CMT Isolation Valve to CMT	L007A, B; L070A, B	8	SA-312 TP316LN	537.0	2332.0	3B-14
PXS	Direct Vessel Injection Line to RV, IRWST Injection	L021A, B; L125A, B	8	SA-312 TP316LN	537.0	2332.0	3B-14
PXS	Core Makeup Tank (Injection Line, RV Side of Isolation Valve, Core Makeup Tank Side of Isolation Valve), Direct Vessel Injection (Accumulator Connection to Cold Trap), IRWST Injection	L015, L016, L017, L018, L020, L025, L123, L125, L127, L133, L134 (All A, B)	8	SA-312 TP316LN	120.0	2332.0	3B-15
PXS	Direct Vessel Injection Line to RV	L021A, B	8	SA-312-TP316LN	135.0	2332.0	3B-15
RCS	Automatic Depressurization System Stage 2, 3	L021A,B; L031A,B	8	SA-312 TP316LN	653.0	2235.0	3B-16 (Not Used)
PXS	Accumulator after Isolation Valve	L027A, B	8	SA-312 TP304L	120.0	700.0	3B-17
PXS	RNS Discharge	L019A, B	6	SA-312 TP316LN	120.0	2332.0	3B-18
RCS	Automatic Depressurization System Header to RCS Safety Valve	L005A, B	6	SA-312 TP316LN	653.0	2234.0	3B-19 (Sheets 1 and 2)
RCS	Normal Residual Heat Removal	L140	12	SA-312 TP316LN	610.0	2247.0	3B-20
RNS	Normal Residual Heat Removal	L001, L002A, B	10	SA-312 TP316LN	610.0	2235.0	3B-21
RCS	Automatic Depressurization System Stage 2, 3 (Cold Trap)	L021A, B; L031A, B	8	SA-312TP316LN	100.0	2234.0	3B-22

Note:
1. ID = Inside diameter
2. Temperature and Pressure at normal and maximum stress cases as indicated in Figure 3B-6 sheet 2.

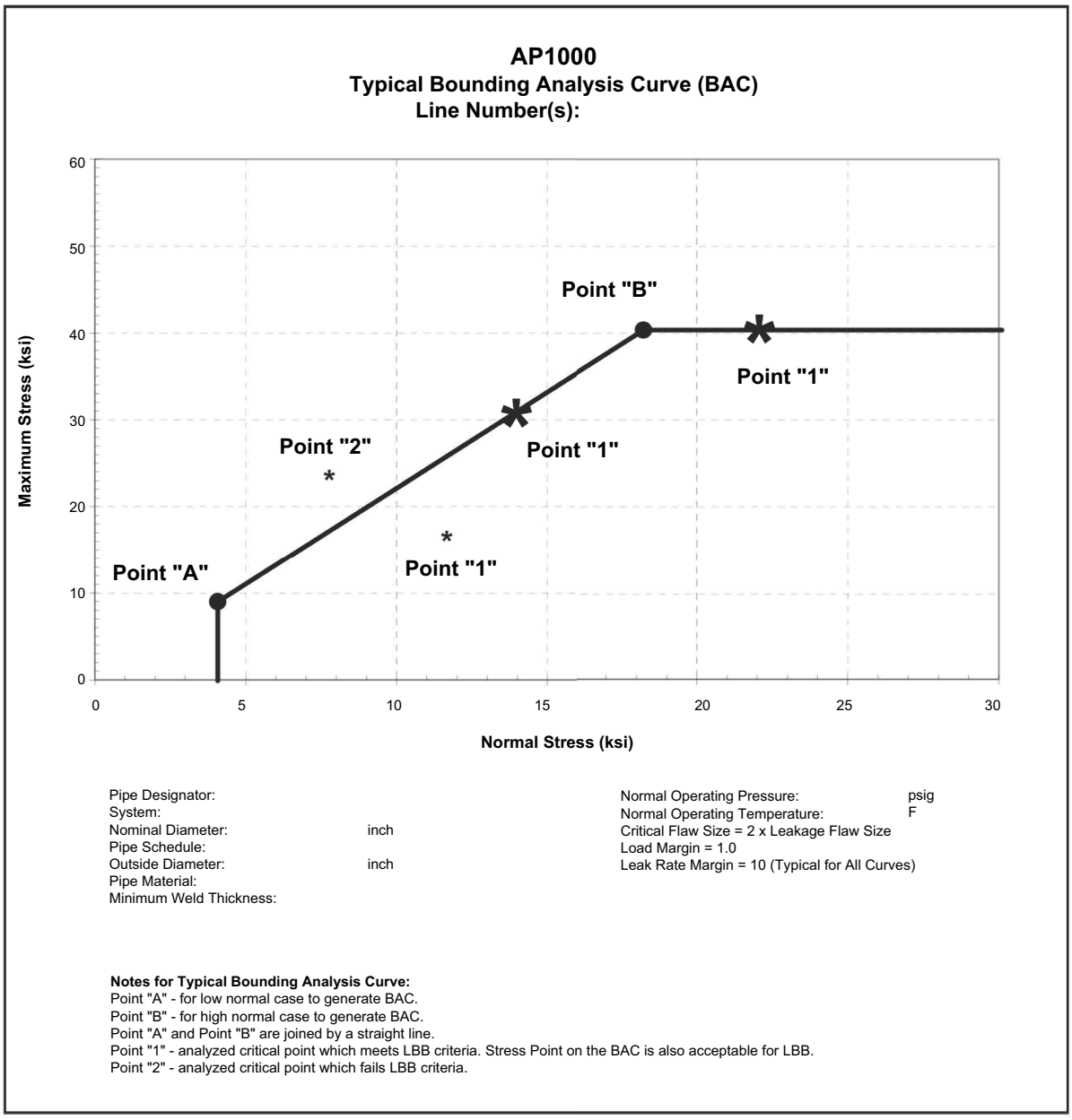

Figure 3B-1
Typical Bounding Analysis Curve (BAC)

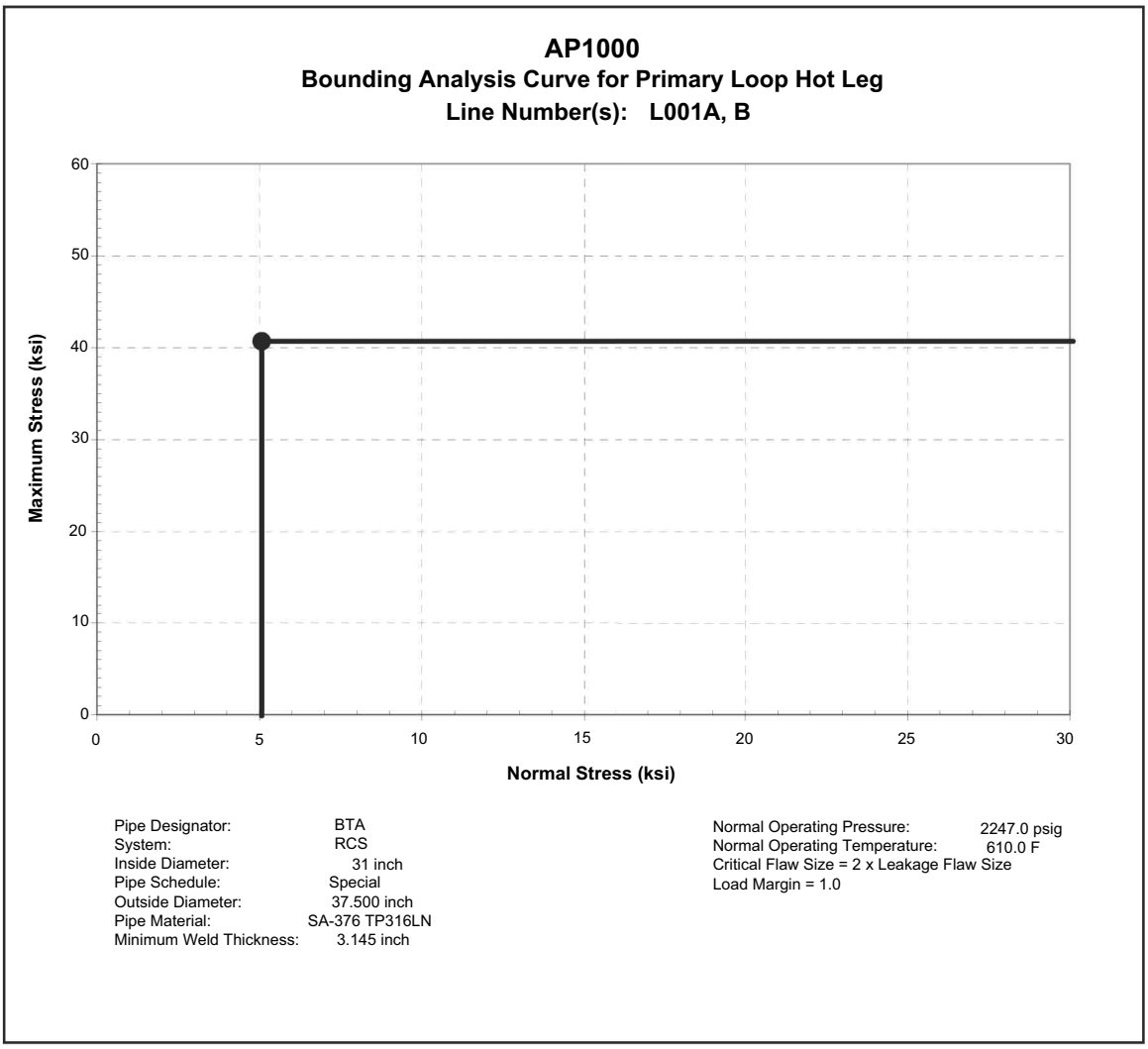

Figure 3B-2
Bounding Analysis Curve for Primary Loop Hot Leg

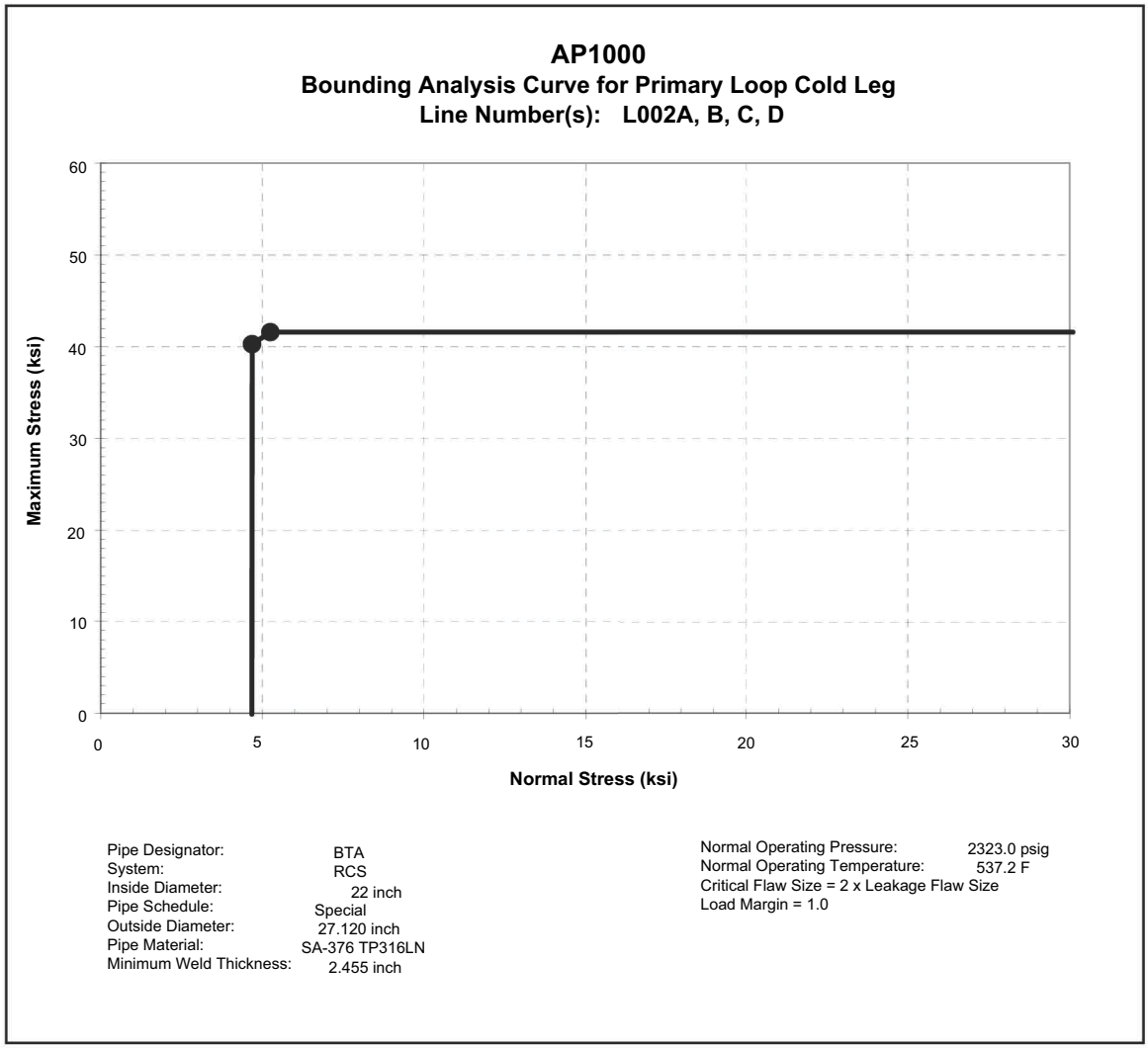

Figure 3B-3
Bounding Analysis Curve for Primary Loop Cold Leg

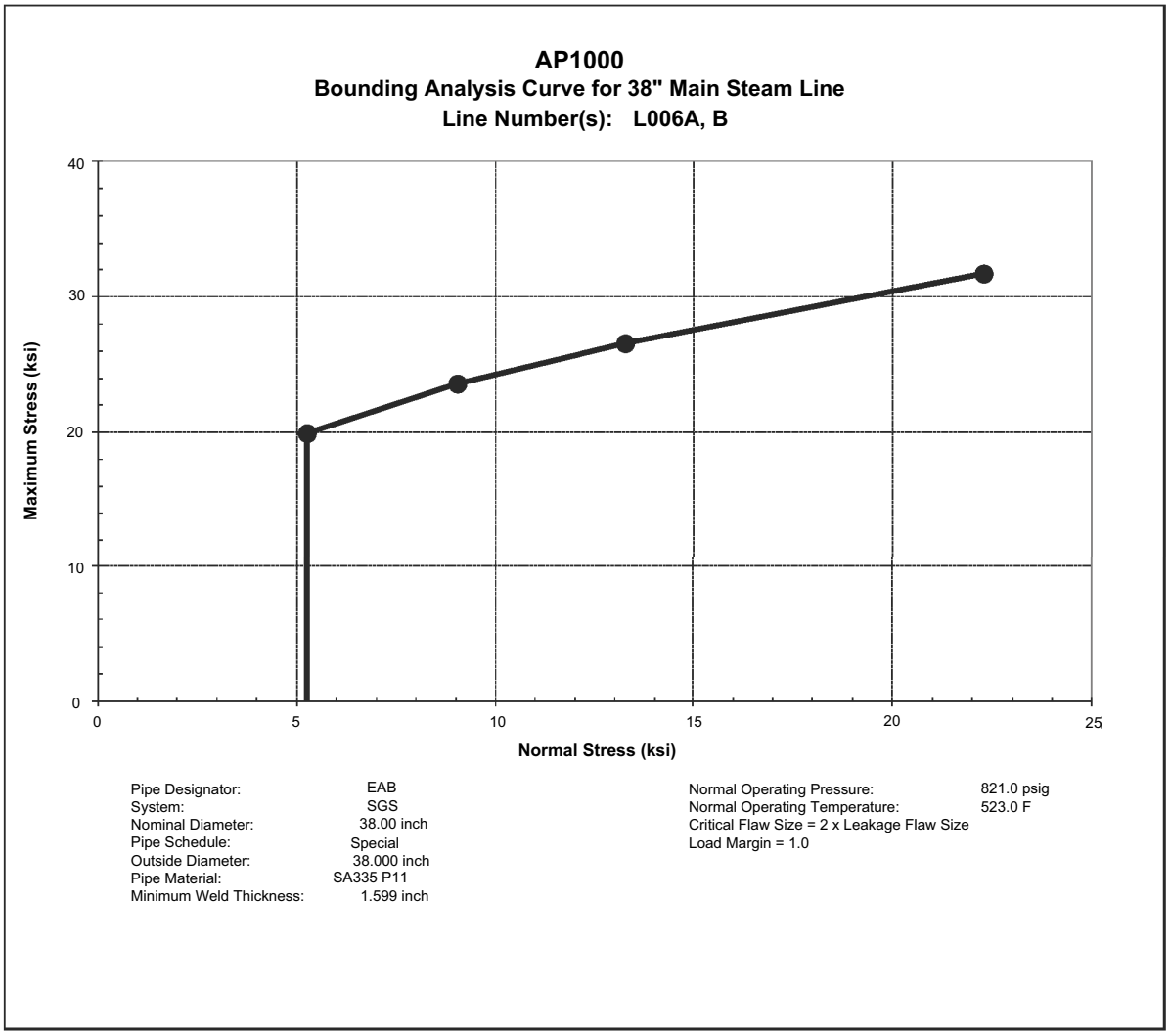

Figure 3B-4
Bounding Analysis Curve for 38″ Main Steam Line

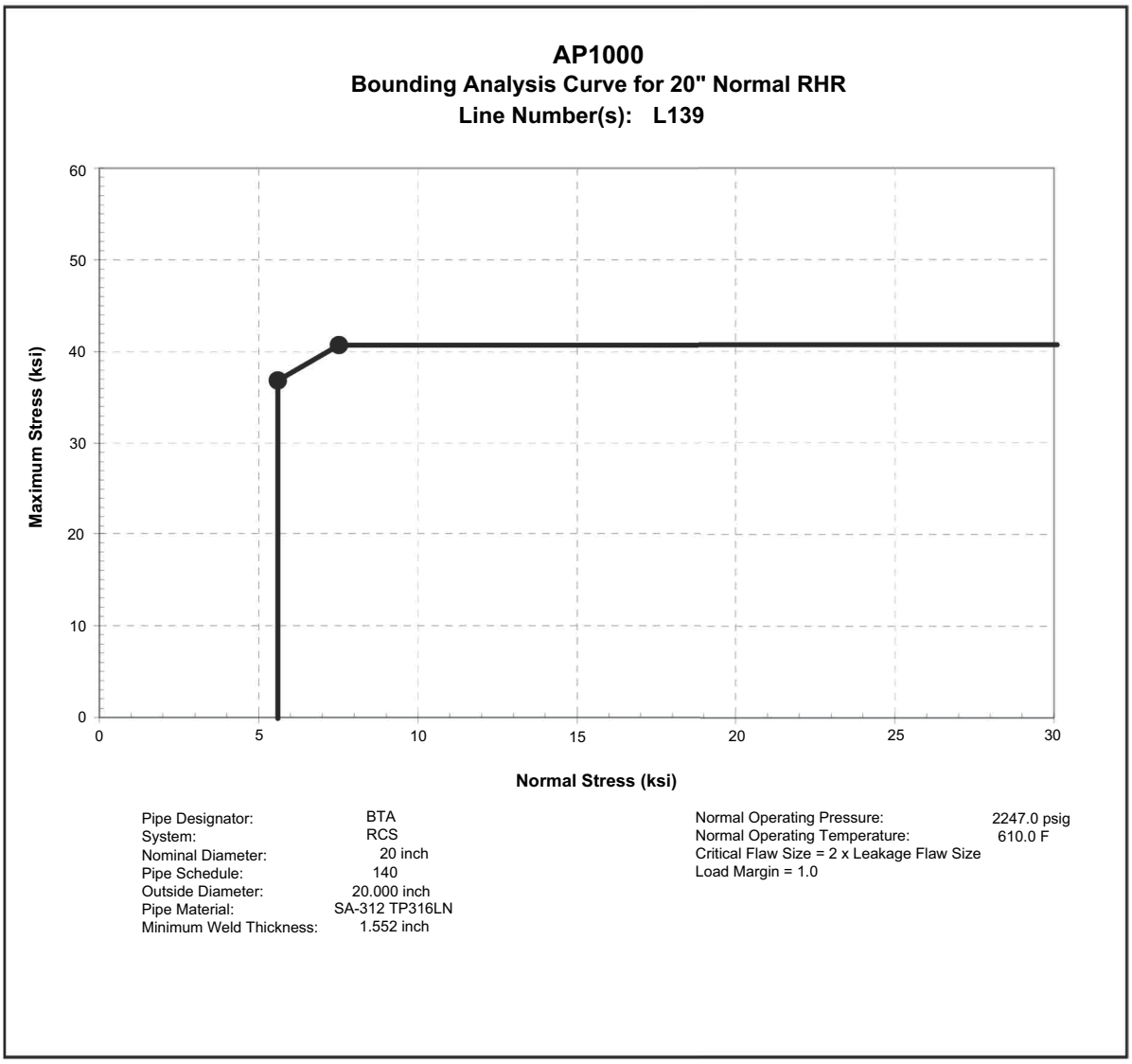

Figure 3B-5
Bounding Analysis Curve for 20″ Normal RHR

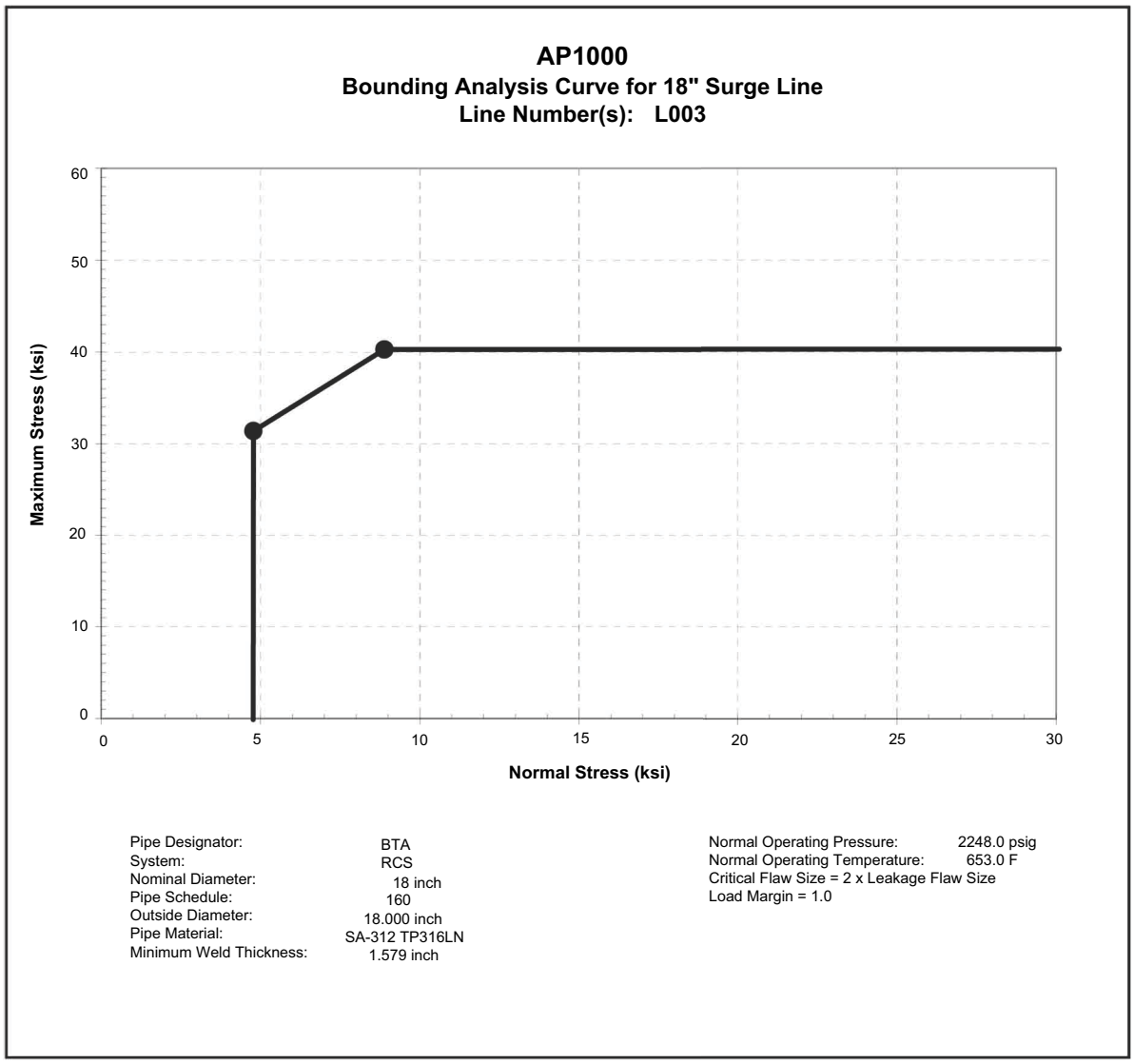

Figure 3B-6 (Sheet 1 of 2)
Bounding Analysis Curve for 18″ Surge Line

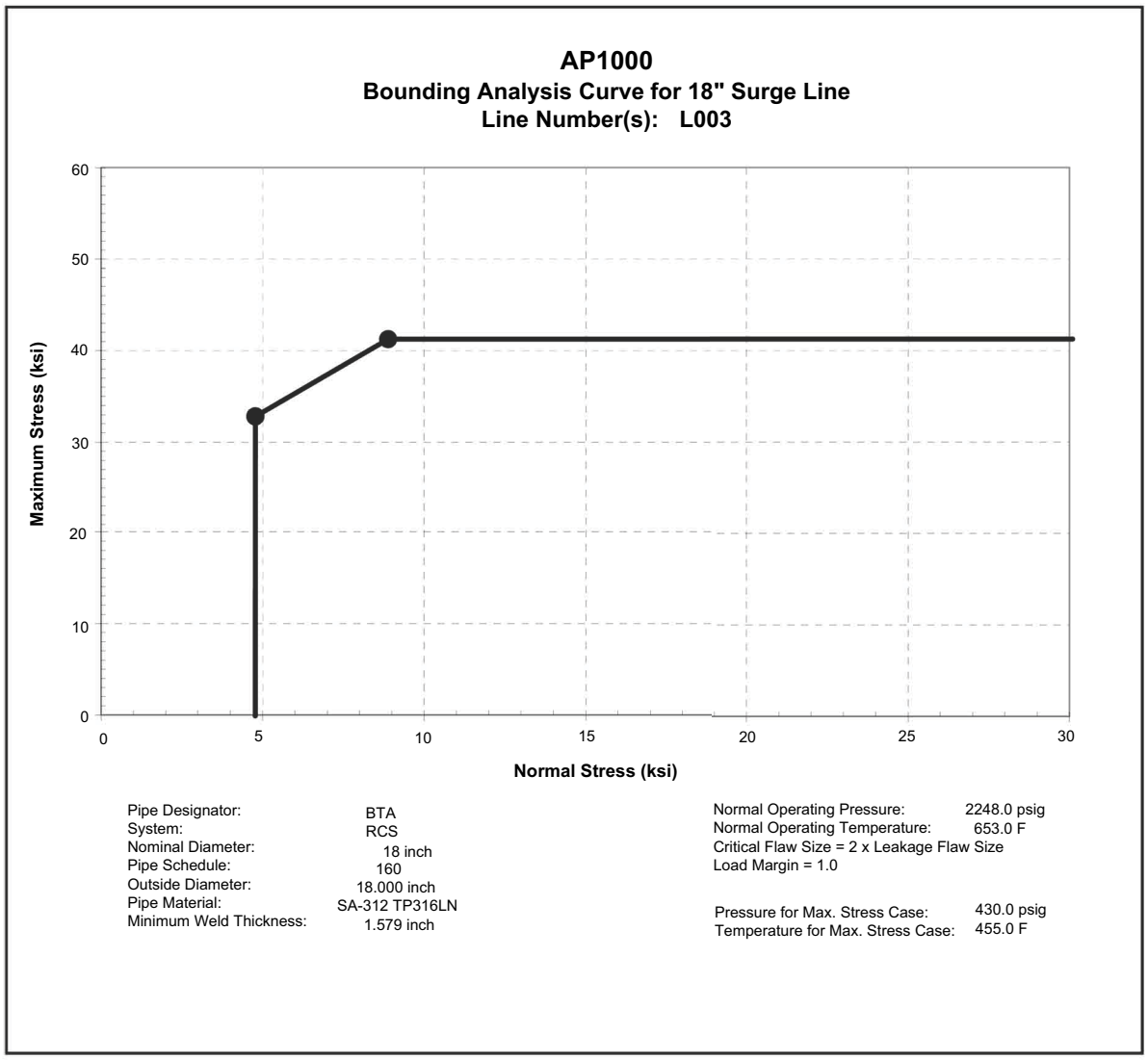

Figure 3B-6 (Sheet 2 of 2)
Bounding Analysis Curve for 18″ Surge Line

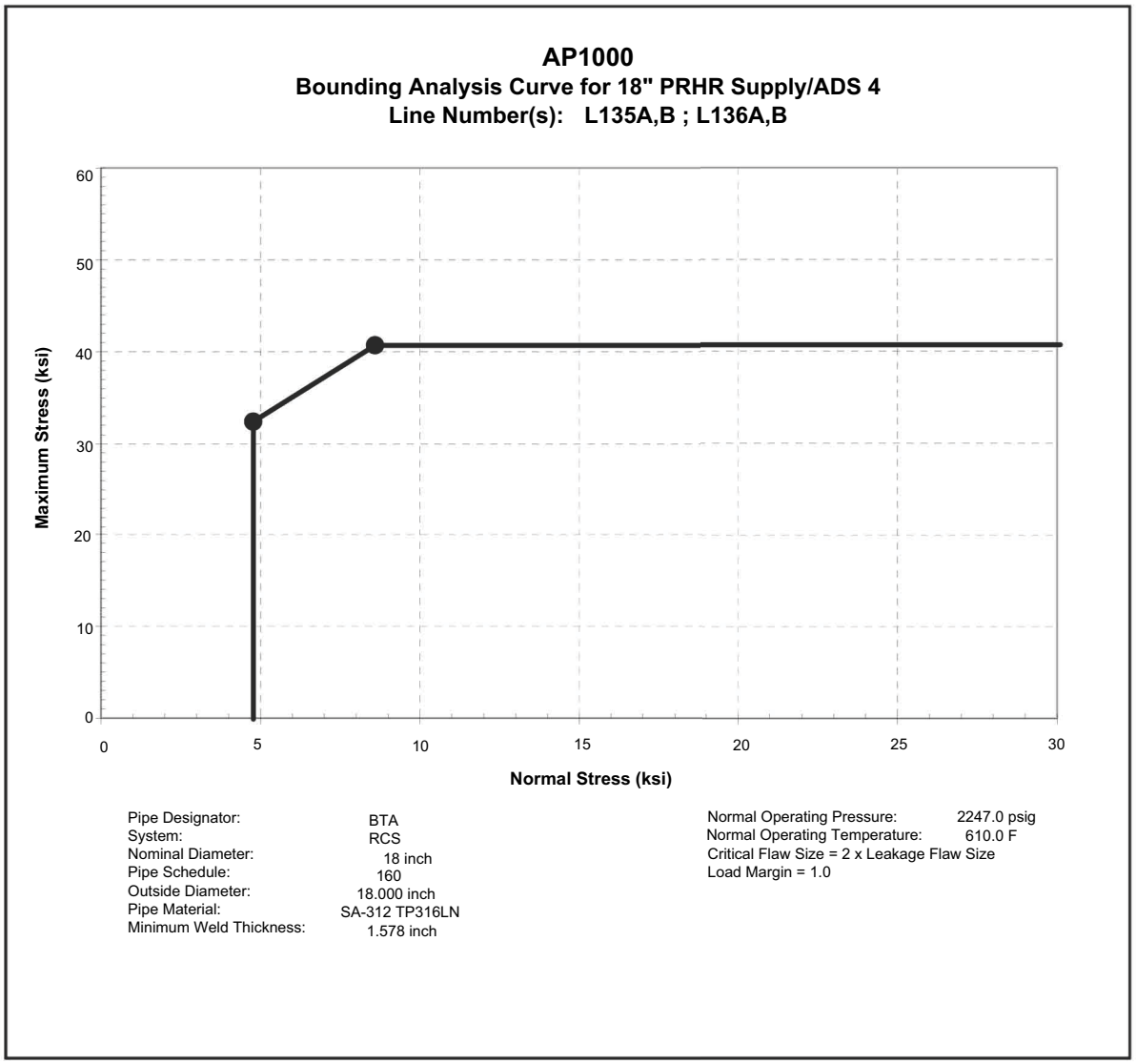

Figure 3B-7
Bounding Analysis Curve for 18″ PRHR Supply/ADS 4

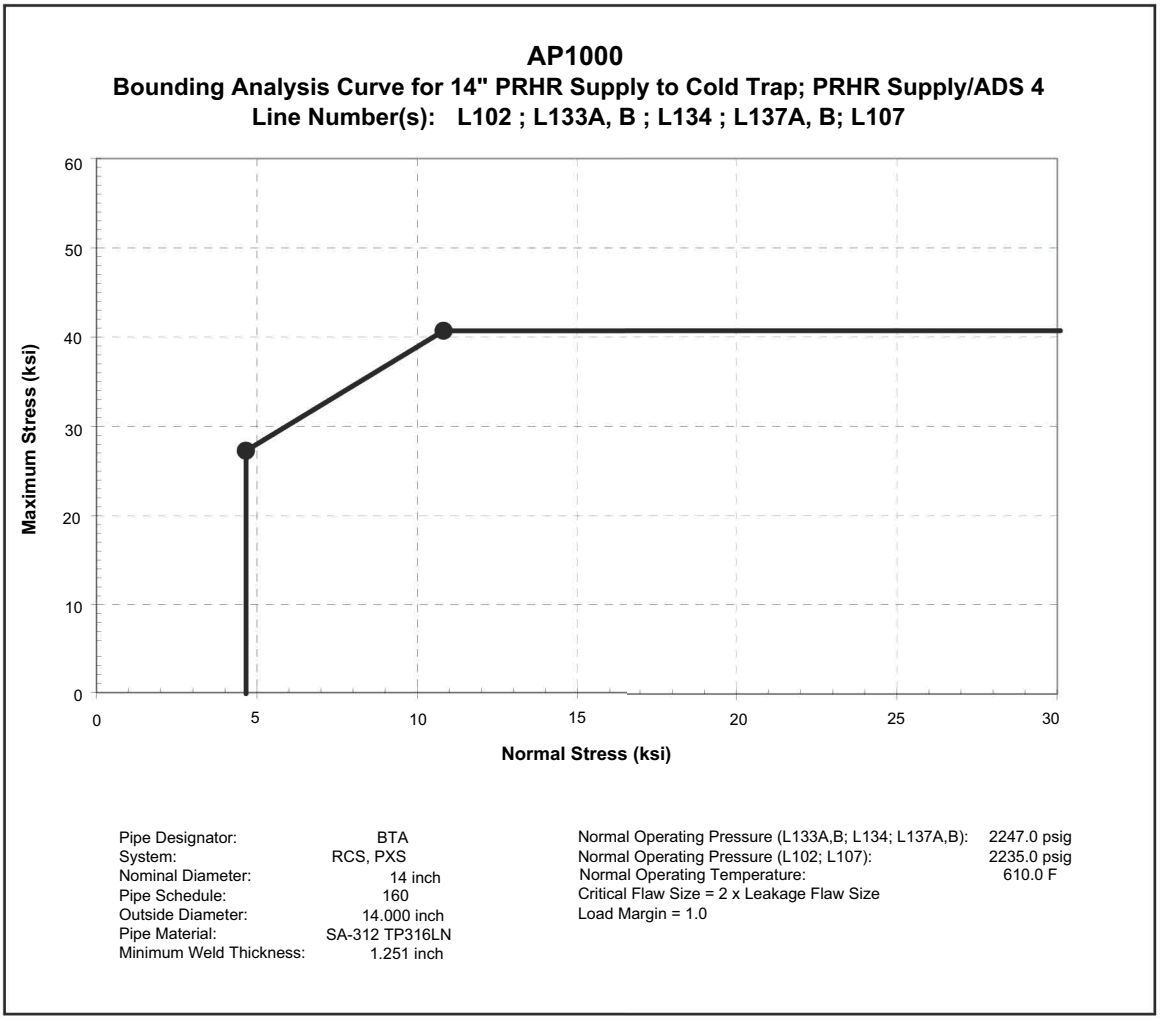

Figure 3B-8
Bounding Analysis Curve for 14″ PRHR Supply to Cold Trap, PRHR Supply/ADS4

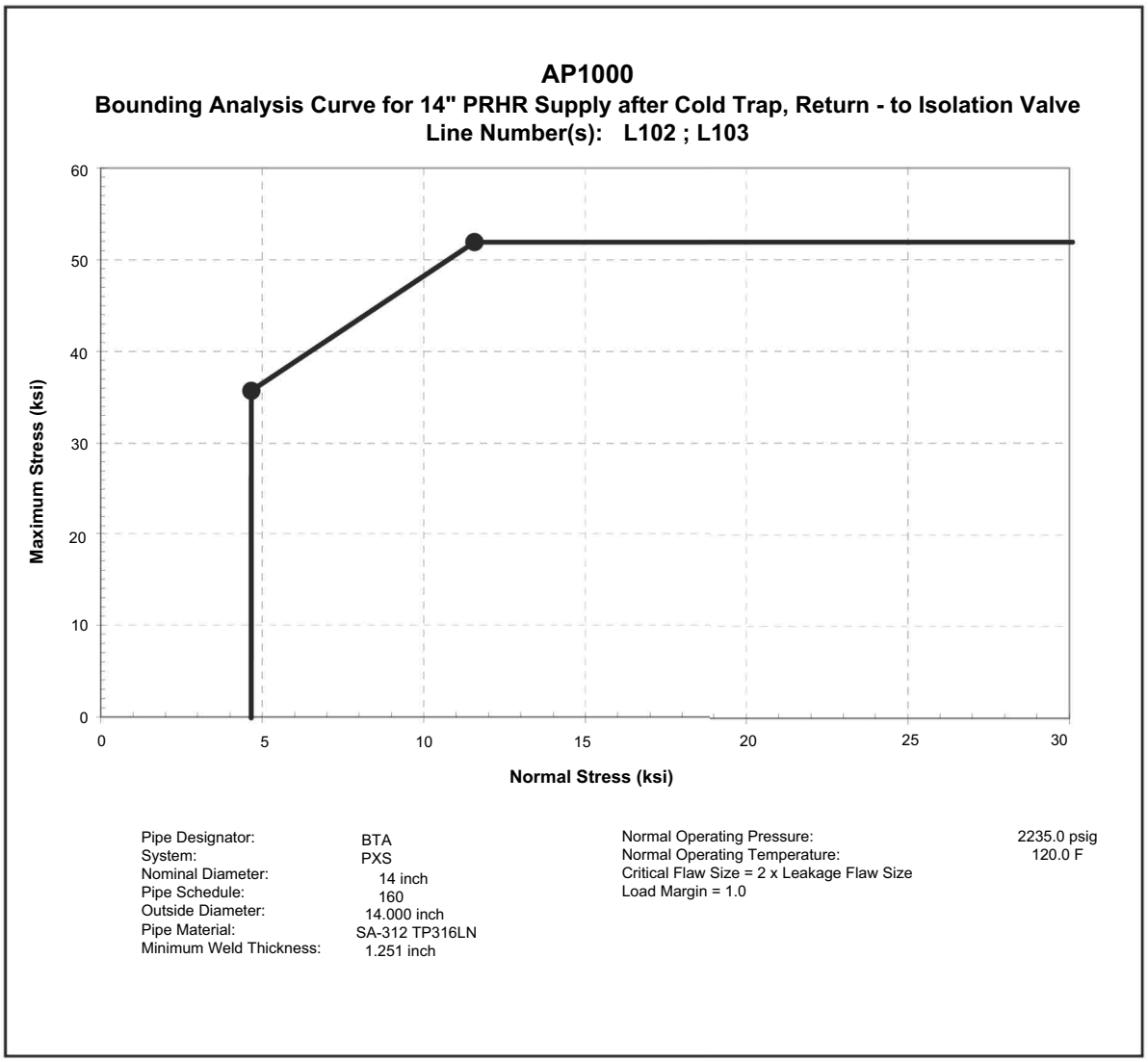

Figure 3B-9
Bounding Analysis Curve for 14″ PRHR Supply after Cold Trap, Return – to Isolation Valve

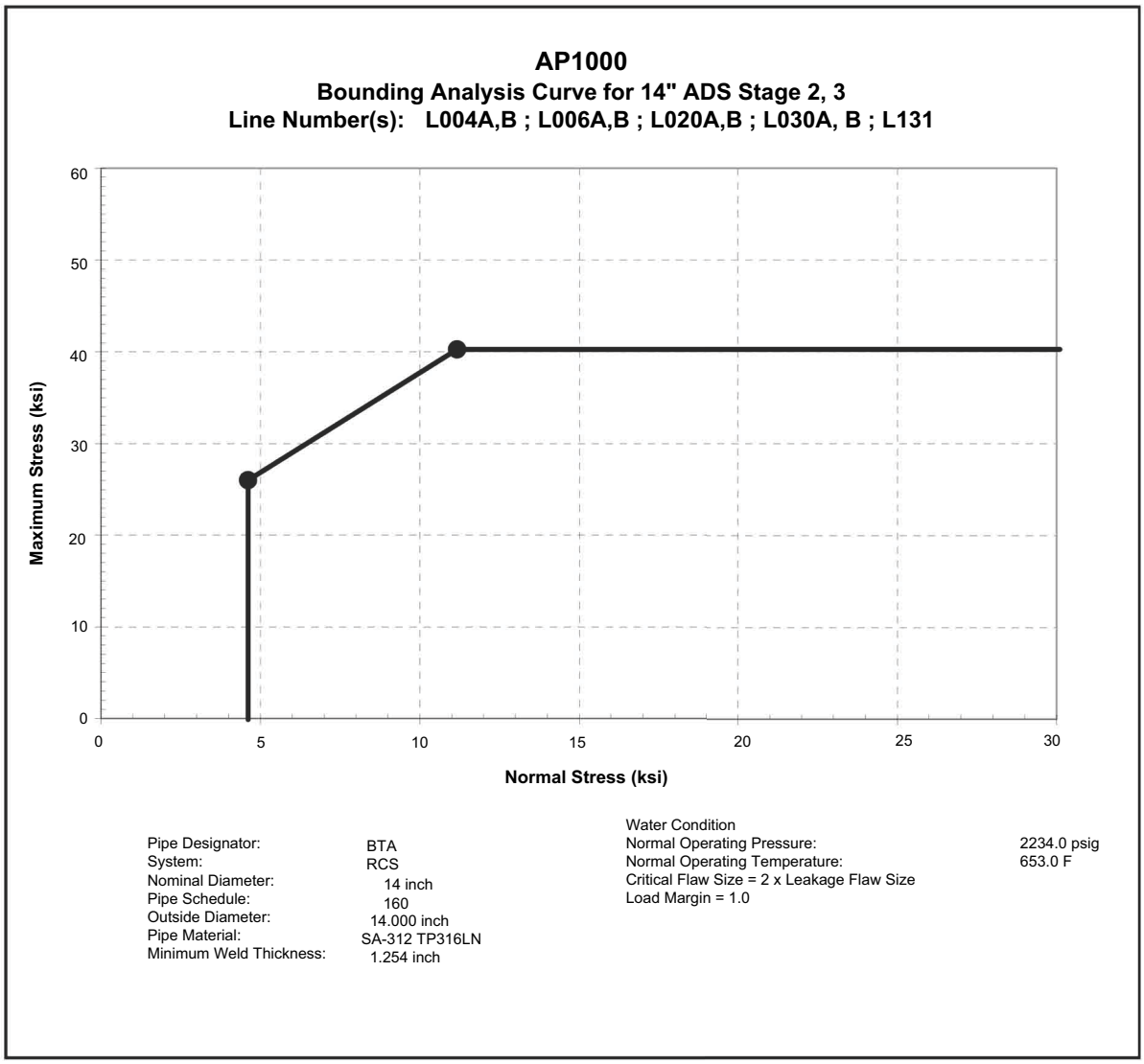

Figure 3B-10 (Sheet 1 of 2)
Bounding Analysis Curve for 14″ ADS Stage 2, 3

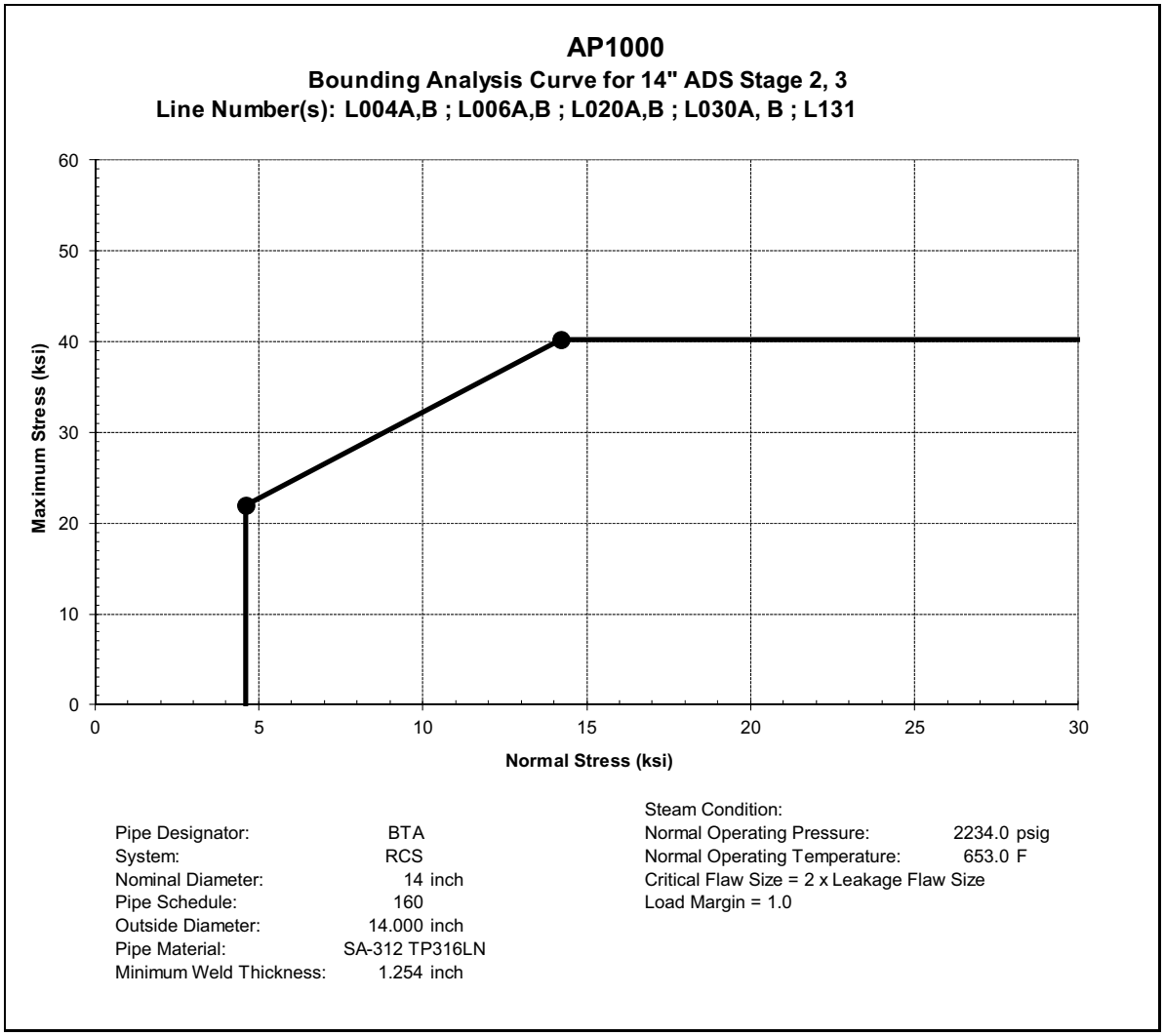

Figure 3B-10 (Sheet 2 of 2)
Bounding Analysis Curve for 14" ADS Stage 2, 3

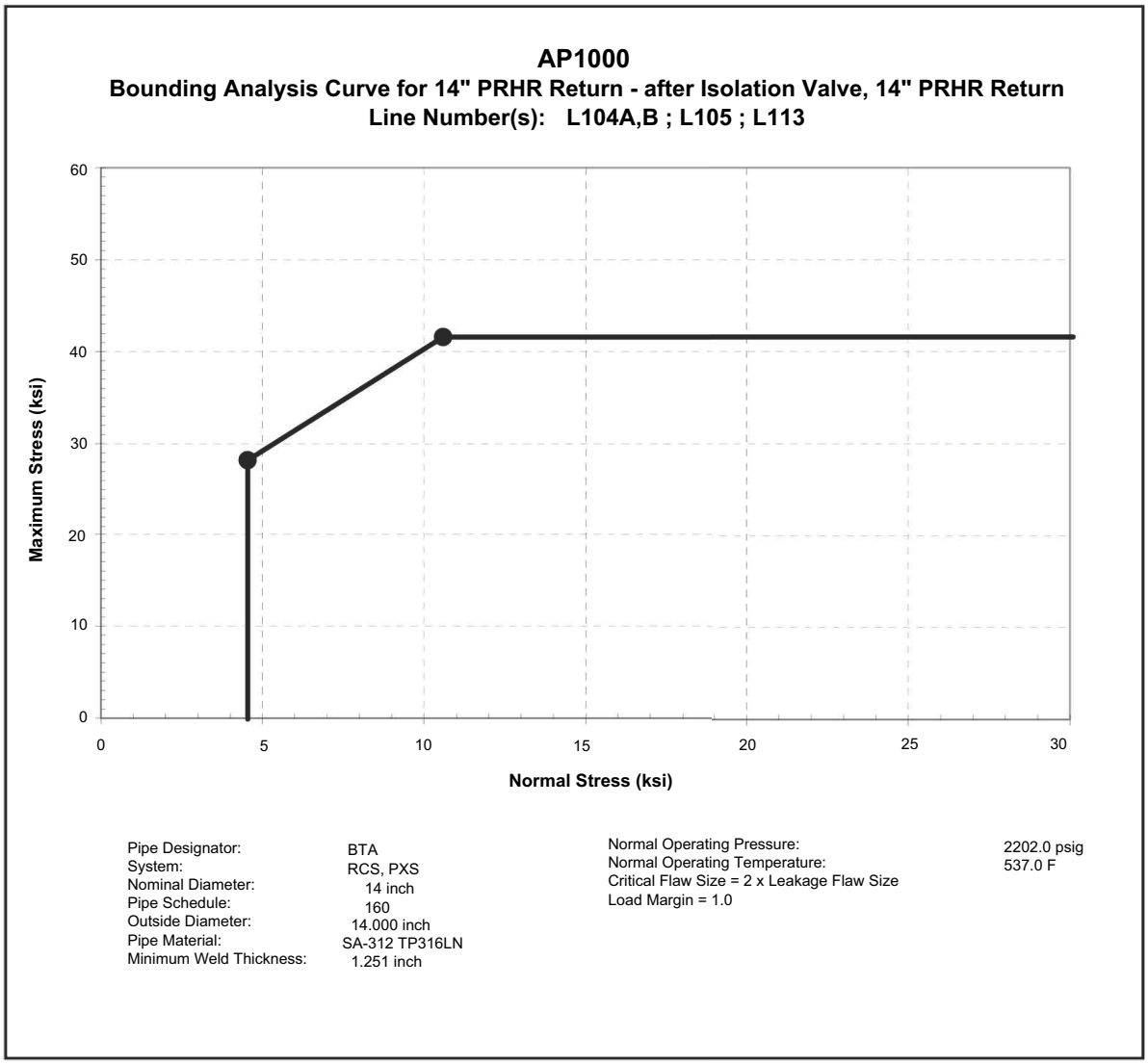

Figure 3B-11
Bounding Analysis Curve for 14″ PRHR Return – after Isolation Valve, 14″ PRHR Return

Figure 3B-12 Not Used

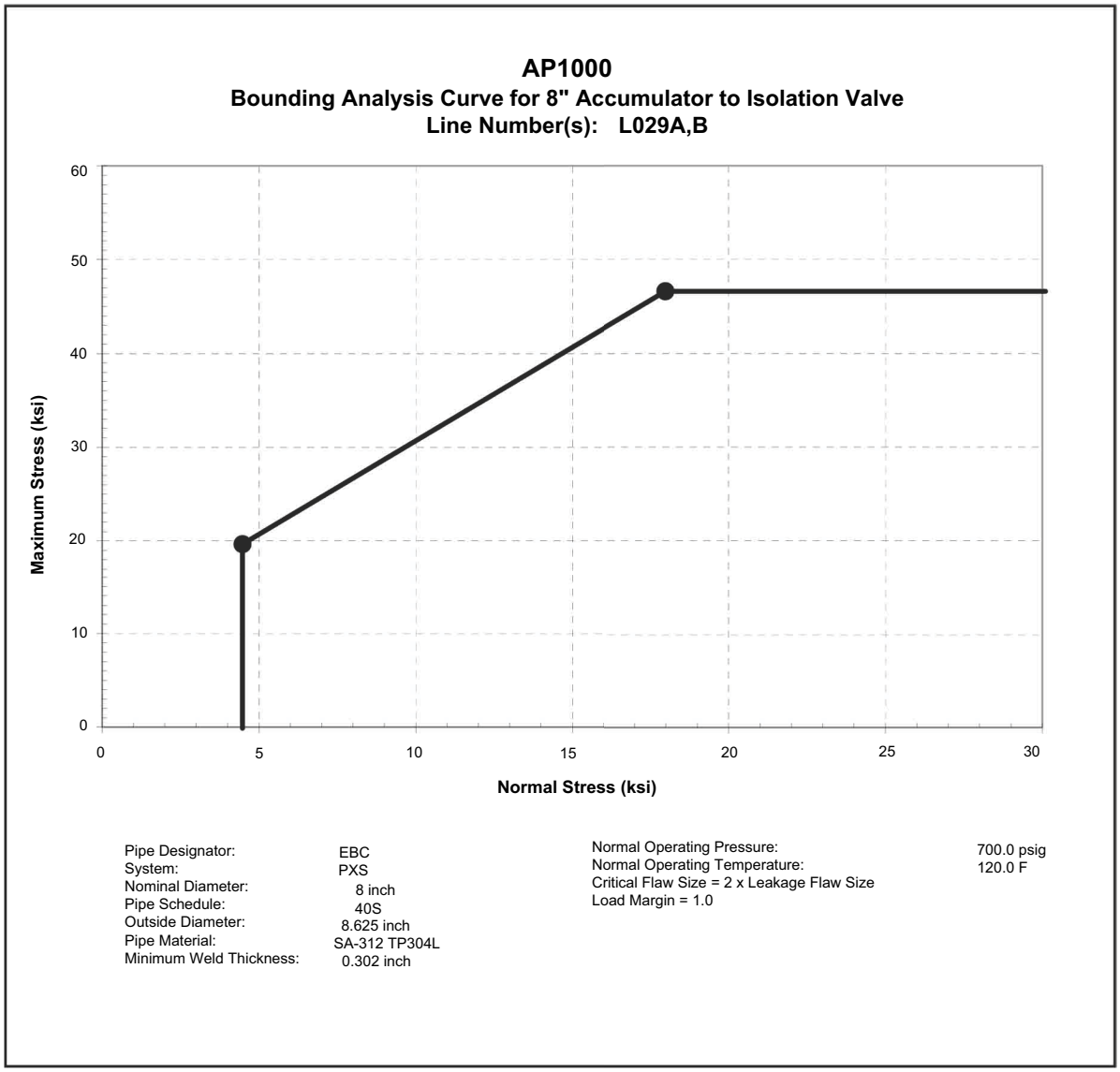

Figure 3B-13
Bounding Analysis Curve for 8″ Accumulator to Isolation Valve

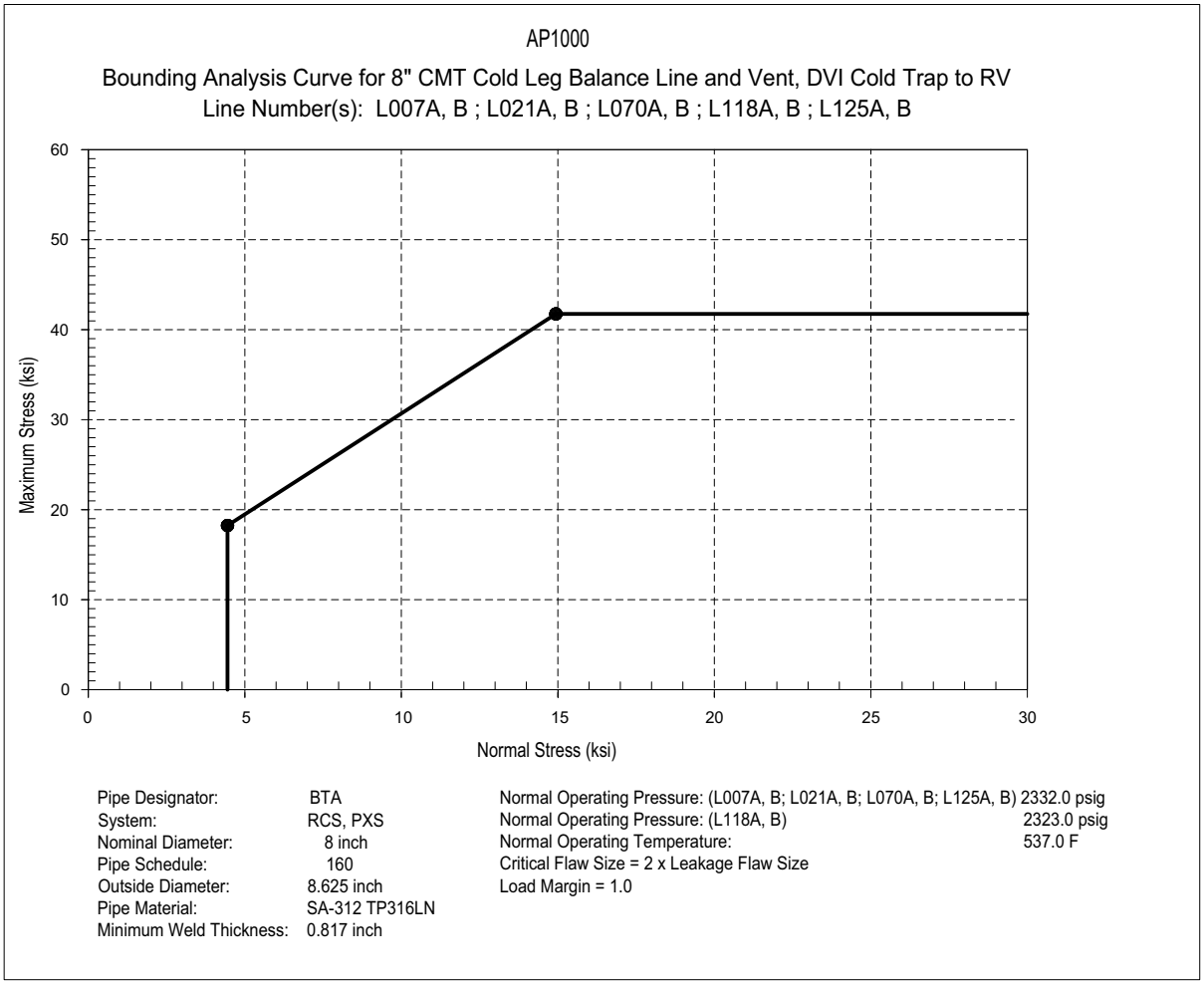

Figure 3B-14
Bounding Analysis Curve for 8″ CMT Cold Leg Balance Line and Vent, DVI Cold Trap to RV

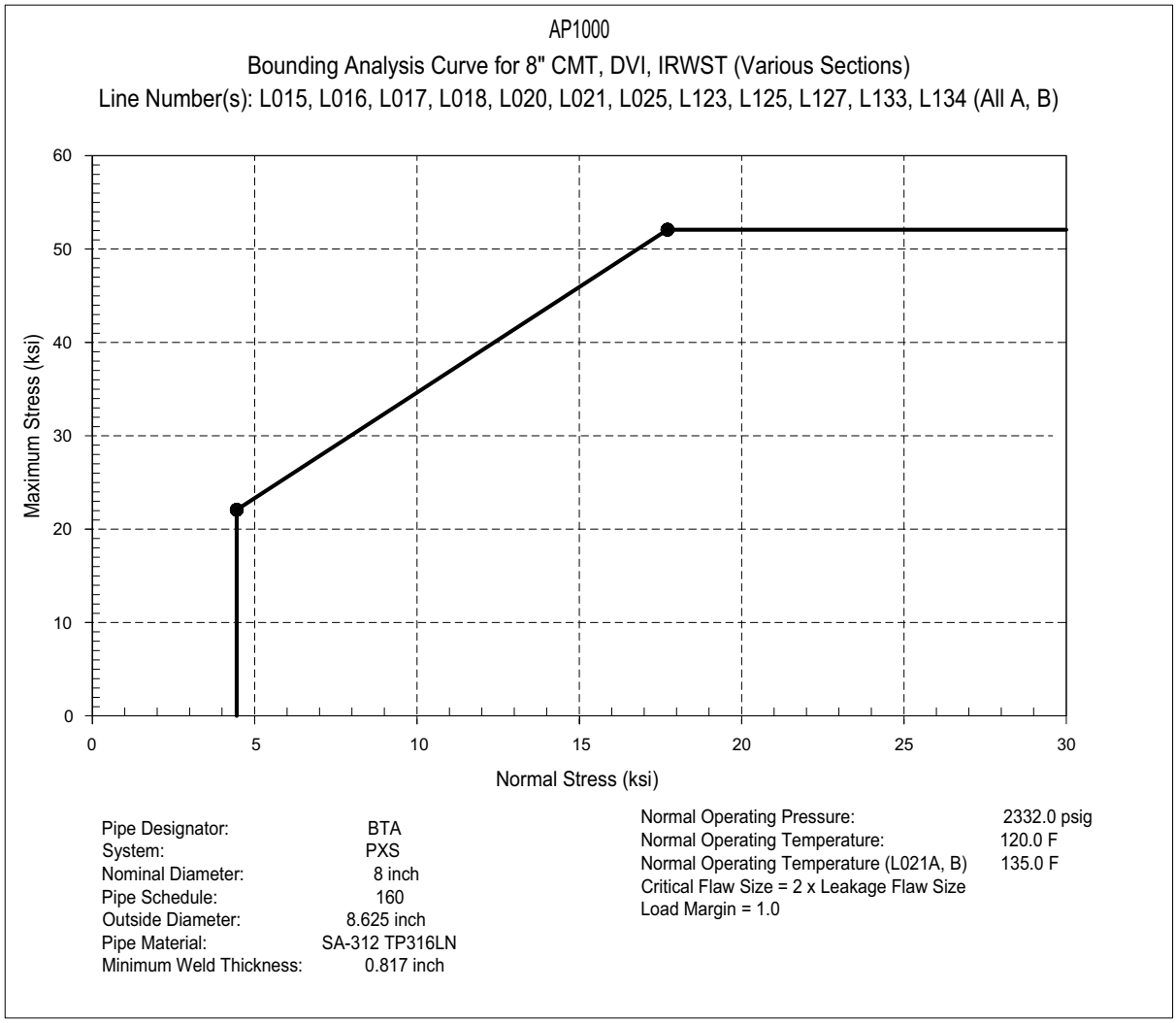

Figure 3B-15
Bounding Analysis Curve for 8″ CMT, DVI IRWST (Various Sections)

Figure 3B-16 Not Used

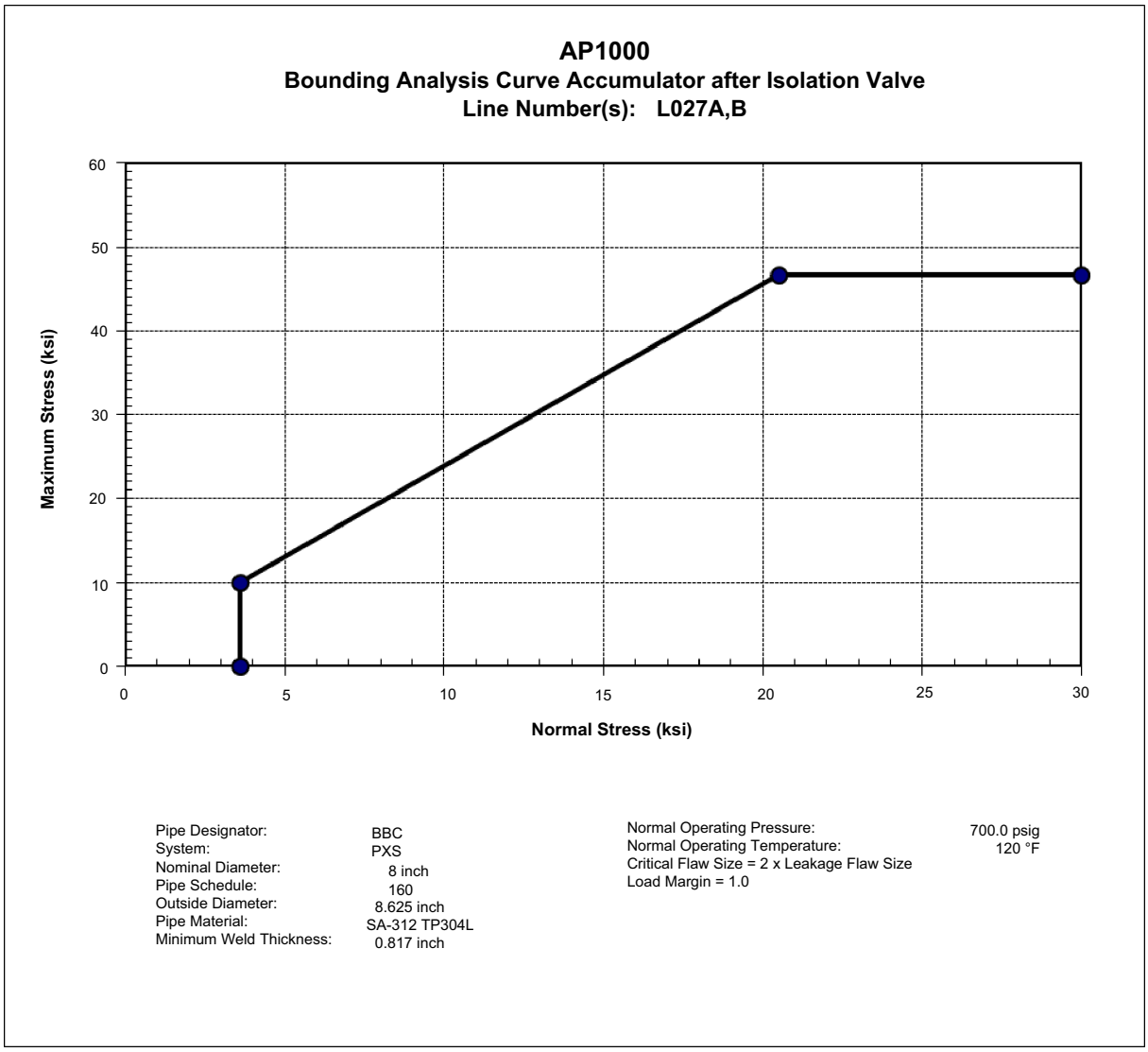

Figure 3B-17
Bounding Analysis Curve for Accumulator after Isolation Valve

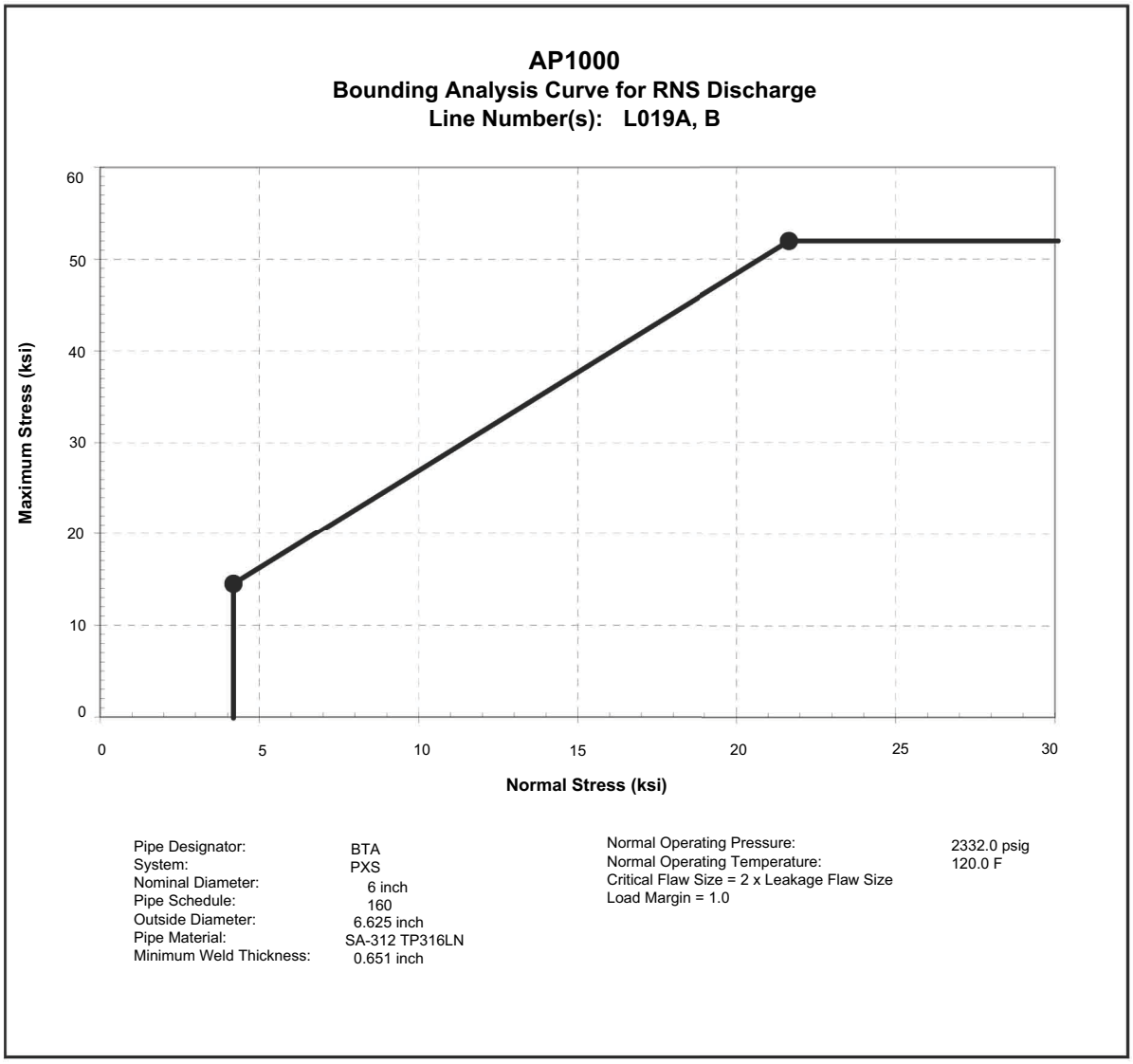

Figure 3B-18
Bounding Analysis Curve for RNS Discharge

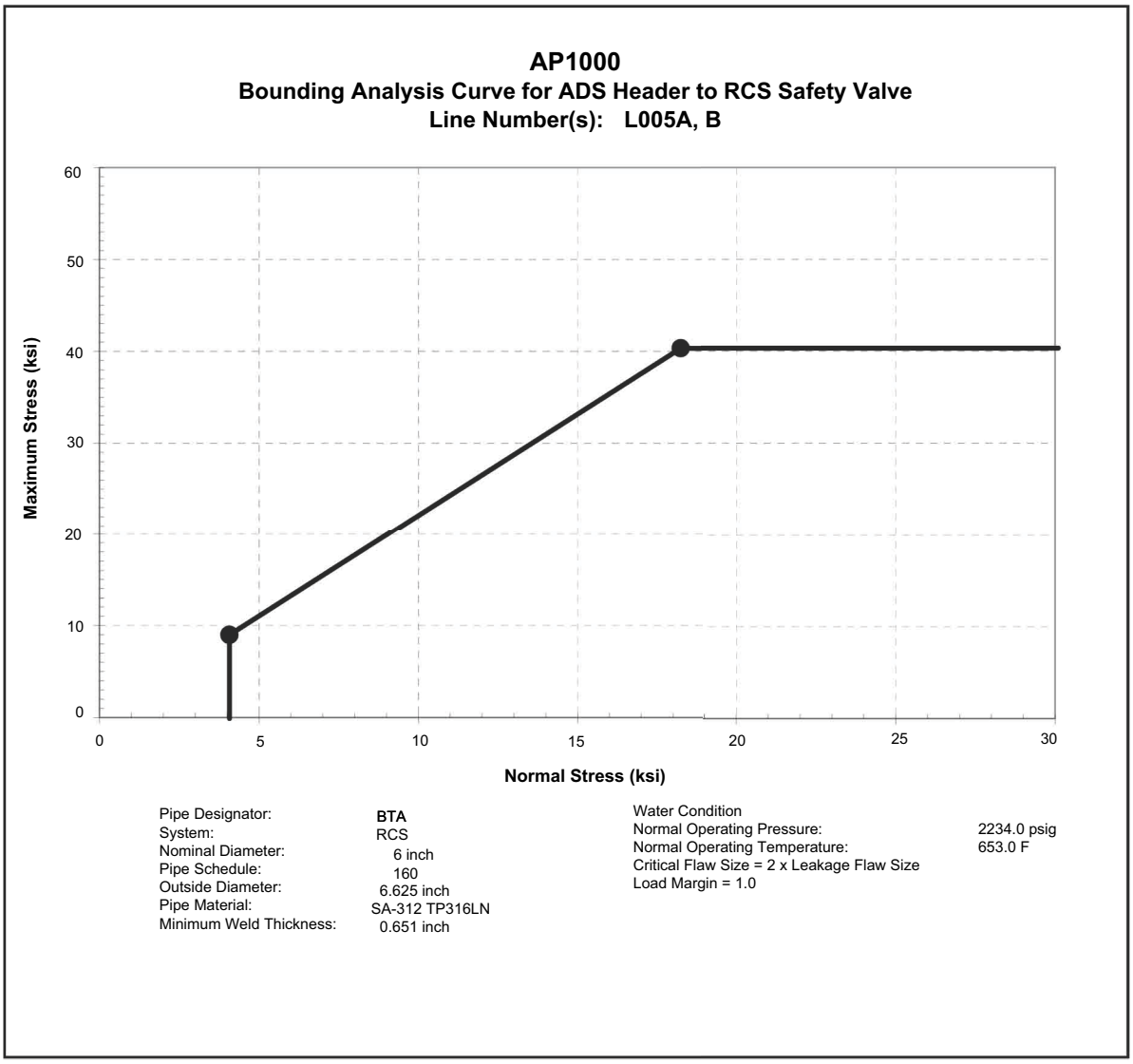

Figure 3B-19 (Sheet 1 of 2)
Bounding Analysis Curve for ADS Header to RCS Safety Valve

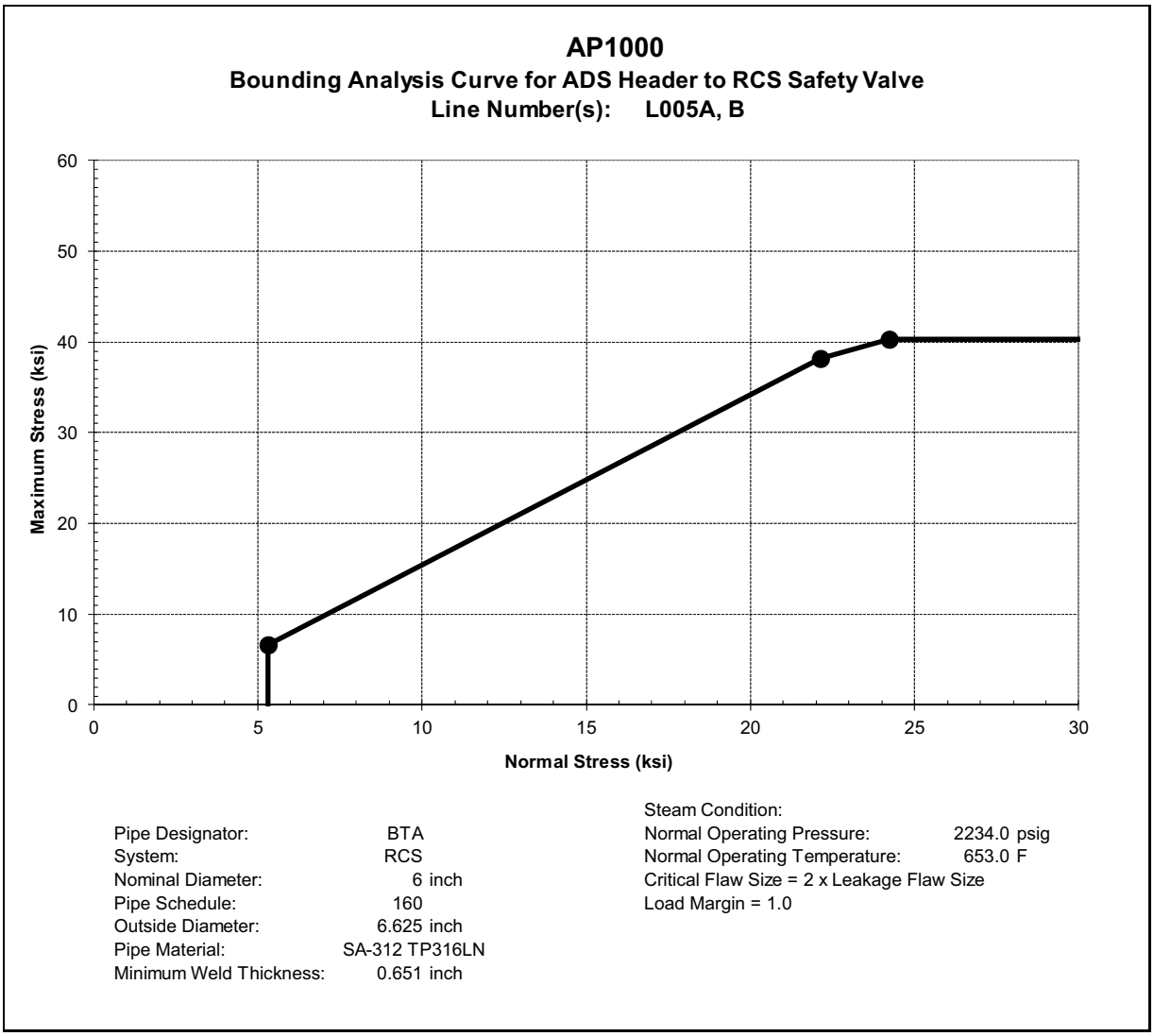

Figure 3B-19 (Sheet 2 of 2)
Bounding Analysis Curve for ADS Header to RCS Safety Valve

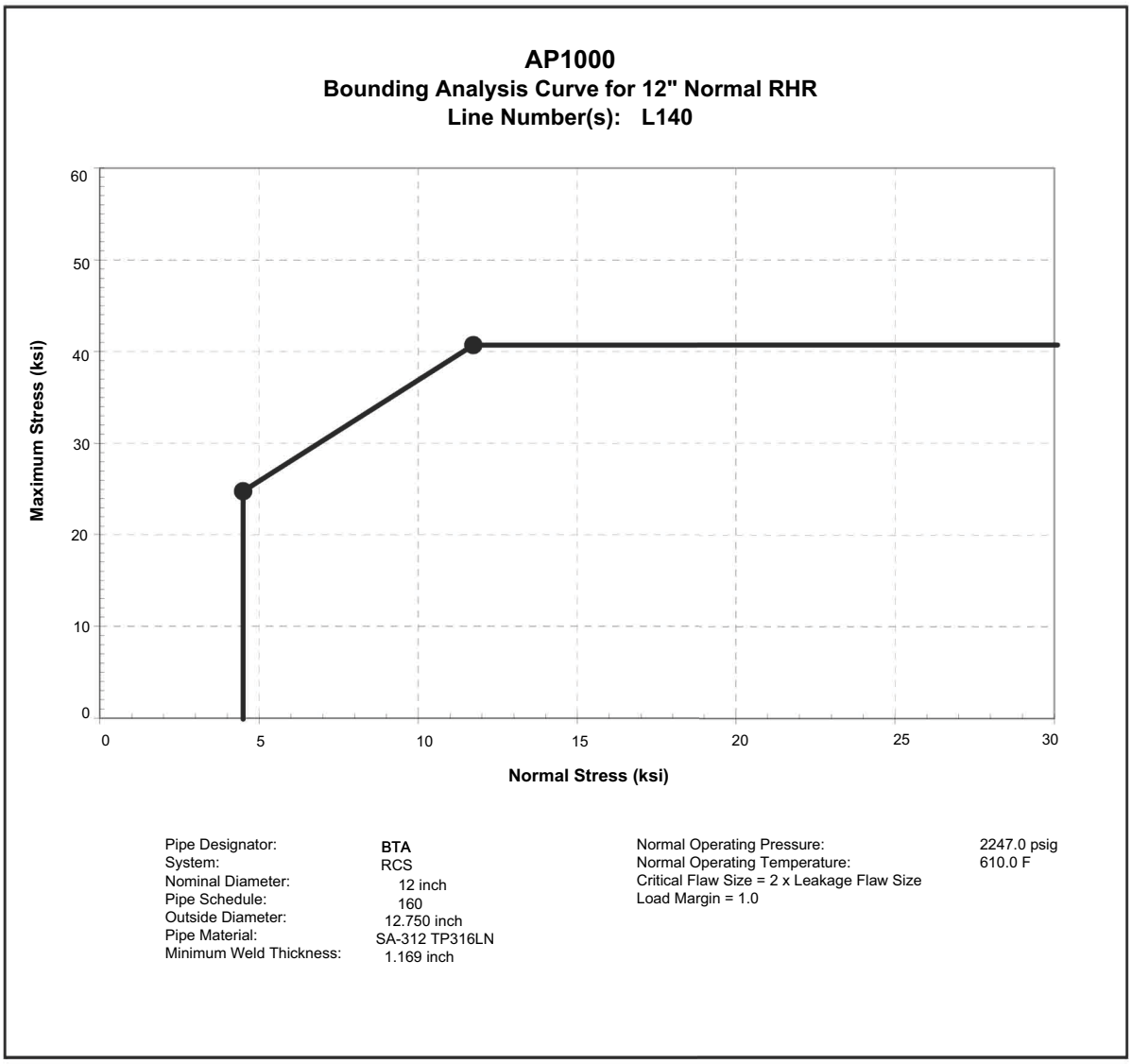

Figure 3B-20
Bounding Analysis Curve for 12″ Normal RHR

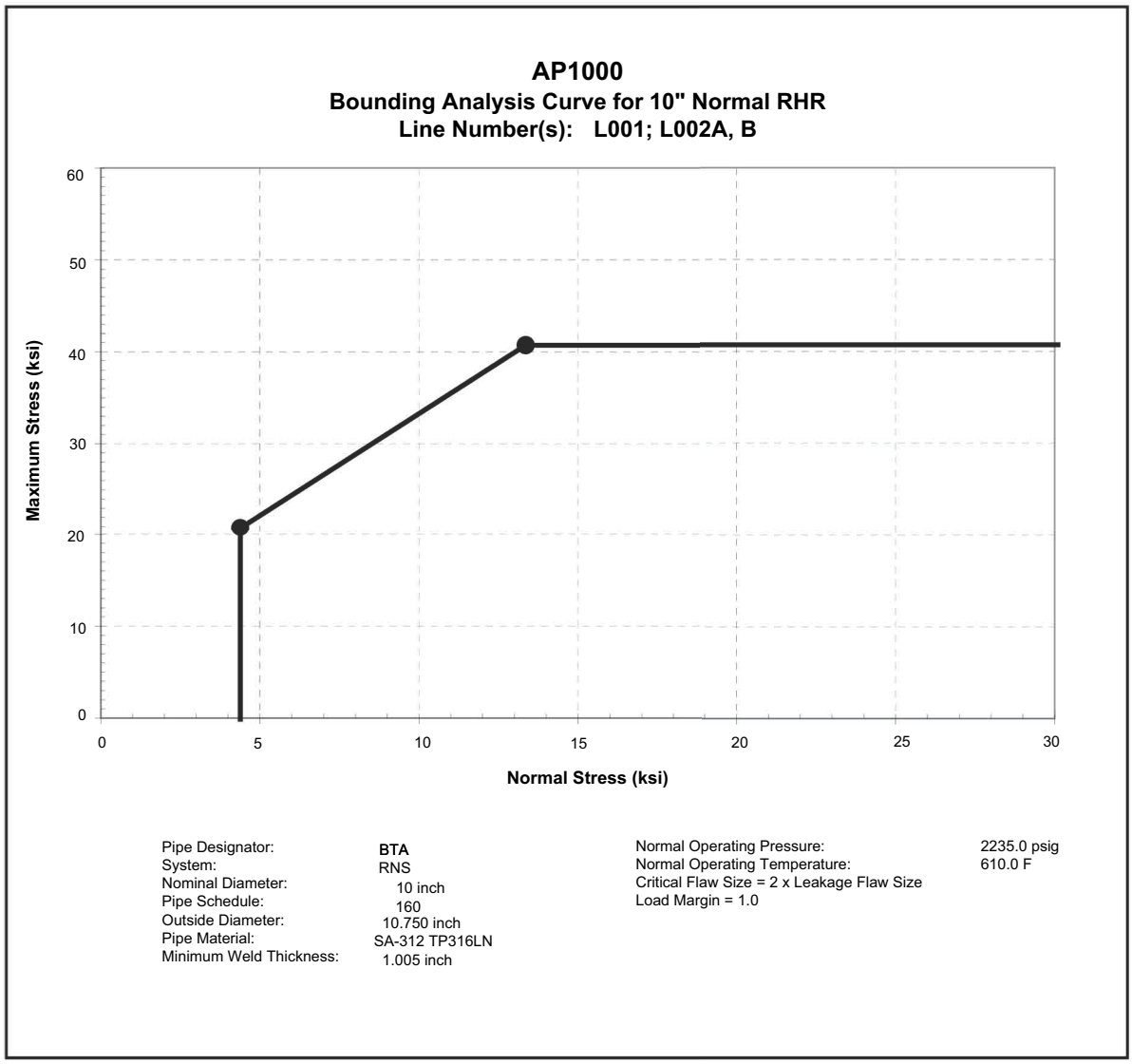

Figure 3B-21
Bounding Analysis Curve for 10″ Normal RHR

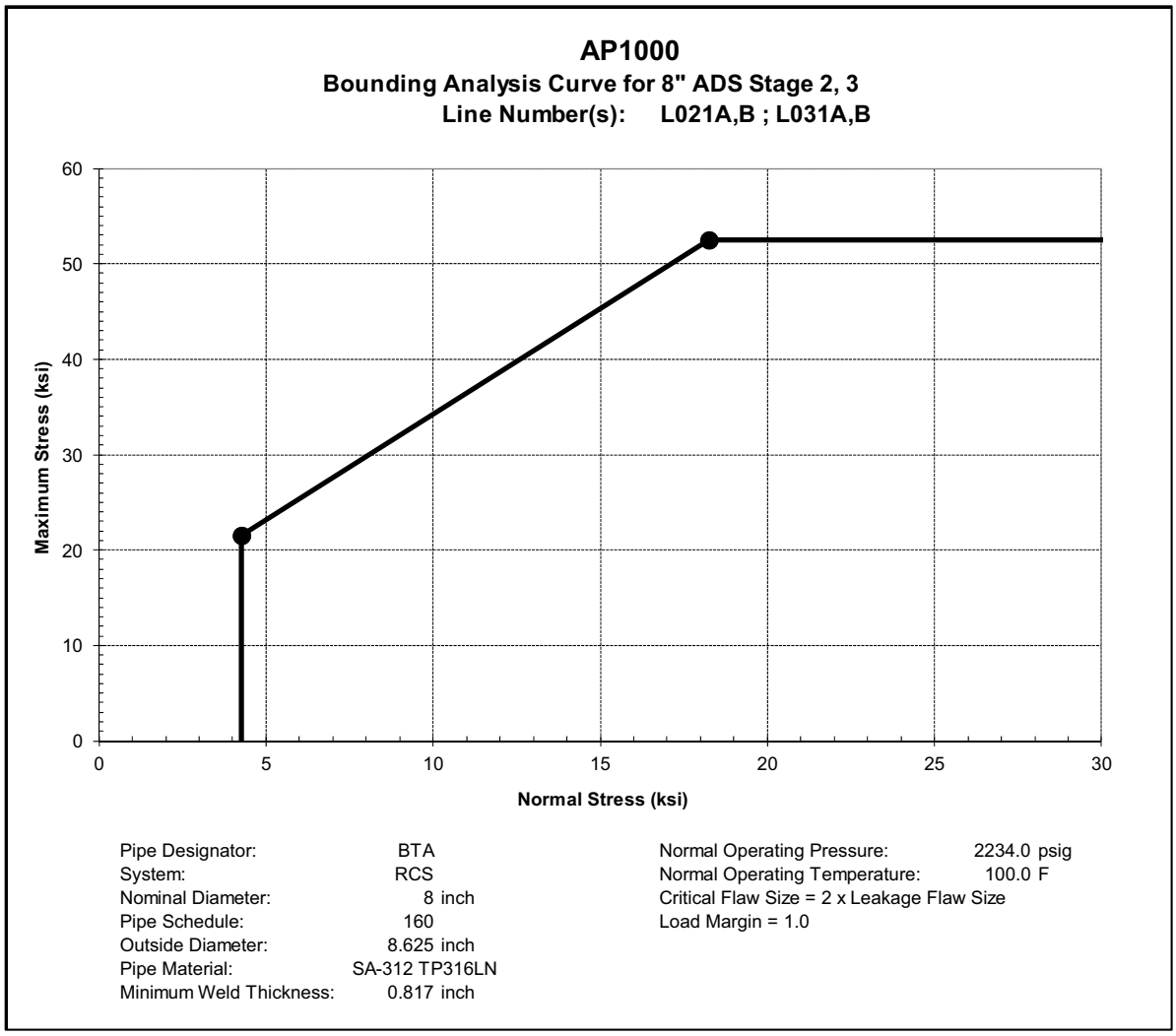

Figure 3B-22
Bounding Analysis Curve for 8″ ADS Stage 2, 3

Appendix 3C Reactor Coolant Loop Analysis Methods

The AP1000 reactor coolant loop (RCL) model consists of three-dimensional finite elements such as pipes, beams, elbows, masses, and springs. The structural model is subjected to internal pressure, thermal expansion, weight, seismic, and pipe break loadings with imposed boundary conditions. The finite element displacement method is used for the analysis. The stiffness matrix for each element is assembled into a system of simultaneous linear equations for the entire structure. This set of equations is then solved by a variation of the Gaussian elimination method, known as the wave-front technique. This technique makes it possible to solve systems of equations with a large number of degrees of freedom using a minimum amount of computer memory.

3C.1 Reactor Coolant Loop Model Description

The piping model of the reactor coolant loop consists of a number of elements of given dimensions, sizes, and physical properties that mathematically simulate the structural response of the physical system. The system model contains the reactor pressure vessel (RPV), two steam generators (SGs), four reactor coolant pumps (RCPs), the reactor coolant loop piping, and the primary equipment supports. A two-loop model is developed for the AP1000 reactor coolant loop system.

The stiffness and mass effects of branch piping connected to the primary loop piping are considered when significant (Subsection 3.7.3.8.1).

3C.1.1 Steam Generator Model

3C.1.1.1 Steam Generator Mass and Geometrical Model

The steam generator is represented by discrete masses. The geometry of the steam generator vessel is used to determine the properties of the equivalent piping elements that join the steam generator masses for sections of the steam generator above the tubesheet. For the steam generator channel head, a super element is used to represent the stiffness characteristics that link the steam generator lower shell with the steam generator supports and nozzles. The modulus of elasticity and coefficient of thermal expansion corresponding to the thermal conditions are applied to the steam generator equivalent piping elements.

3C.1.1.2 Steam Generator Supports

The values of the steam generator support stiffnesses and locations of the supports are determined from the finite element models of the support members. The stiffness of the upper lateral supports include the steam generator shell flexibility. The local concrete building flexibility is included in the support stiffness.

3C.1.2 Reactor Coolant Pump Model

3C.1.2.1 Static Model

The reactor coolant pump is represented by a super element to represent the mass and stiffness characteristics of the pump. For a thermal expansion analysis, rigid links are modeled in parallel with a super element with the thermal expansion coefficient incorporated.

3C.1.2.2 Seismic Model

The reactor coolant pump is represented by a super element to represent the mass and stiffness characteristics of the pump. The reactor coolant pump model is a detailed model similar to that used to qualify the pump.

3C.1.2.3 Reactor Coolant Pump Supports

There are no reactor coolant pump supports. Two reactor coolant pumps are attached to the steam generator channel head in each of the reactor coolant loops.

3C.1.3 Reactor Pressure Vessel Model

3C.1.3.1 Mass and Geometrical Model

The reactor pressure vessel model consists of equivalent pipe, stiffness, and mass elements. The elements represent the vessel shell, the vessel core barrel, the fuel assemblies, and the integrated head lift package.

The reactor pressure vessel is modeled with equivalent pipe elements and connecting stiffnesses. The equivalent pipe element properties of the vessel and barrel are those of the cylindrical structures. The beam properties of the reactor internals are adjusted to simulate their fundamental frequency. The appropriate modulus of elasticity and coefficient of thermal expansion are used for the equivalent pipe elements representing the reactor pressure vessel.

3C.1.3.2 Reactor Pressure Vessel Supports

The reactor pressure vessel is supported at the four reactor pressure vessel inlet nozzles. Each support consists of a vertical stiffness and a lateral tangential stiffness. The support is represented by a stiffness matrix. The reactor pressure vessel supports are active for the analyzed loading conditions. The reactor pressure vessel model includes the effects of the vessel shell flexibility at the inlet and outlet nozzles. The local concrete building flexibility is included in the support stiffness.

3C.1.4 Containment Interior Building Structure Model

A containment interior building structure finite element model is not required because the seismic inputs to the reactor coolant loop model are provided at all of the building attachments to the reactor coolant loop.

3C.1.5 Reactor Coolant Loop Piping Model

The reactor coolant loop piping model consists of piping elements and bends. Each reactor coolant loop has two cold legs and one hot leg. The straight runs and bends of the cold leg and hot leg are input with the nominal dimensions. Each reactor coolant loop branch connection is represented by a node point. The reactor coolant loop piping model contains distributed masses of the hot and cold leg piping for static deadweight analysis and lumped masses representing the hot and cold leg piping for dynamic analysis.

3C.2 Design Requirements

The reactor coolant piping is qualified to the requirements of the ASME Code as defined in Subsection 5.2.1.1.

The loadings for ASME Code, Section III, Class 1 components are defined in Subsection 3.9.3. The following loadings are considered in the reactor coolant loop piping analysis:

- Design pressure (P)
- Weight (DW)

- Thermal expansion during normal operating condition
- Thermal expansion during other transient conditions (not part of this appendix)
- Safe shutdown earthquake (SSE)
- Design basis pipe break (DBPB)
- Building motions due to automatic depressurization system sparger discharge into the IRWST
- Thermal stratification during transient conditions

In addition to the analyses of these loads, the reactor coolant piping is analyzed for the effect of cyclic fatigue due to the design transients and earthquakes smaller than SSE.

3C.3 Static Analyses

3C.3.1 Deadweight Analysis

The reactor coolant loop piping system is analyzed for the effect of deadweight. The deadweight analysis is performed without considering the dry weight of the directly supported equipment. The effects of the auxiliary branch piping on the reactor coolant loop are generally negligible by the design of the auxiliary supports. A deadweight analysis is performed to include the total weight of the reactor coolant loop piping and the water weight in the components.

The reactor coolant loop deadweight model includes the corresponding active reactor coolant loop supports - reactor pressure vessel supports, and the steam generator column and lower and intermediate lateral strut supports. The steam generator upper lateral snubber supports are considered as inactive.

3C.3.2 Internal Pressure Analysis

The effects of the internal primary coolant pipe pressure are used in the calculations of forces and moments for both the reactor coolant loop piping and equipment supports. The moment stress due to pressure is considered negligible for the ASME Code pipe stress equations.

3C.3.3 Thermal Expansion Analysis

The reactor coolant loop piping is analyzed for the effects of thermal expansion. The thermal expansion analysis model considers the expansion of the reactor coolant loop piping, reactor pressure vessel, steam generator, reactor coolant pump, and the equipment supports. The stiffness effects of the auxiliary piping on the reactor coolant loop expansion are generally negligible by the design of the auxiliary lines supports.

3C.4 Seismic Analyses

The reactor coolant loop piping is analyzed for the dynamic effects of a safe shutdown earthquake (SSE).

The model used in the static analysis is modified for the dynamic analysis by including the lumped mass characteristics of the piping and equipment. The effect of the equipment motion on the reactor coolant loop piping and support system is obtained by modeling the mass and stiffness characteristics of the equipment in the overall system model. The reactor coolant loop seismic

analysis is performed at normal full-power operation. This operating condition is considered based on the lower probability of occurrence of the earthquake at reactor coolant loop temperatures below full power.

The time history integration method of analysis is used for the reactor coolant loops. The seismic input considers the soil profiles described in Subsection 3.7.1. This input is obtained from the nuclear island seismic analysis with time history input generated from the enveloped basemat response spectra of the soil cases described in Subsection 3.7.1. The duration of the input is between 12 to 20 seconds, depending on the duration needed to envelop the design response spectra. Three runs were performed based on the envelope of the soil profiles, the building model at nominal stiffness, and at stiffness varied by + or - 30 percent to account for uncertainties. The reactor coolant loop uses separate time history displacement input from the building analysis at the primary support locations. Full direct integration is used with Rayleigh damping for loop components at 4 percent of critical damping. The steam generator snubbers have different stiffnesses in tension and compression. The mean value of the tension and compression stiffness is used in order to keep the model linear. The reactor pressure vessel vertical supports are acting downward only and are preloaded by deadweight, pressure, and thermal expansion loadings. The time history analysis is performed to evaluate the effect of lift-off of the vessel at the location of these supports.

3C.5 Reactor Coolant Loop Piping Stresses

To prevent gross rupture of the reactor coolant loop piping system, the general and local primary membrane stress criteria must be satisfied. This is accomplished by satisfying Equation (9) in paragraph NB-3652 of the ASME Code, Section III. The secondary stress caused by thermal expansion is qualified by satisfying Equation (12) in paragraph NB-3653 of the ASME Code, Section III. When the simplified requirements of ASME Section III, NB-3640 and NB-3650 are not satisfied, the more detailed methods of NB-3200 may be used as stated in NB-3630.

3C.6 Description of Computer Programs

This section provides a list of computer codes used for the AP1000 reactor coolant loop system analysis. Brief descriptions of the functions of each computer code are the following:

ANSYS – Performs Structural Analysis Using Finite Element Analysis Method. Displacements and loads are calculated at the pipe elements, supports, and equipment nozzles for pressure, deadweight, thermal, and seismic loadings.

Appendix 3D Methodology for Qualifying AP1000 Safety-Related Electrical and Mechanical Equipment

Safety-related electrical equipment is tested under the environmental conditions expected to occur in the event of a design basis event. This testing provides a high degree of confidence in the safety-related system performance under the limiting environmental conditions. Qualification criteria were revised by IEEE 323-1974 (Reference 1) and by Regulatory Guide 1.89, which endorses this IEEE standard. The concept of aging was highlighted in IEEE 323-1974, and interpretation of the scope of aging and implementation methods were subsequently developed. 10 CFR 50.49 provides the NRC requirements for qualification of equipment located in potentially harsh environments. Therefore, the guidance provided by IEEE 323-1974 is the evolutionary root of requirements, recommended methods, and qualification procedures described in this appendix.

Specific treatment of seismic qualification, part of the qualification test sequence recommended in IEEE 323-1974, is addressed in IEEE 344-1987 (Reference 2). This appendix bases technical guidance, recommendations, and requirements for seismic qualification on IEEE 344-1987.

The AP1000 Equipment Qualification methodology addresses the expanded scope of IEEE 627-1980 (Reference 3), which encompasses the qualification of Class 1E electrical and safety-related mechanical equipment. IEEE 627 generalizes the principles and technical guidance of IEEE 323 and 344. Compliance with the IEEE 323-1974 and 344-1987 is the specific means of compliance with the intent of IEEE 627-1980 for safety-related electrical and mechanical equipment.

Safety-related electrical and mechanical equipment is typically qualified using analysis, testing, or a combination of these methods. The specific method or methods used depend on the safety-related function of the equipment type to be qualified. Safety-related mechanical equipment, such as tanks and valves, is typically qualified by analysis, with supplementary functional testing when functional operability is demonstrated only through testing, as is the case for active valves. Either testing or testing combined with analysis is the method used for environmental and seismic qualification of safety-related (Class 1E) electrical equipment.

To the extent practical, the technical discussions of this appendix follow the format headings of the equipment qualification data packages (EQDPs) to be issued as specific qualification program documentation. This formatting (see Section 3D.7) permits easy cross-reference between the methodology defined in this report and the detailed plans contained in the equipment qualification data packages. Attachment A of this appendix is the format generally used for the equipment qualification data package.

Attachment B of this appendix, "Aging Evaluation Program," describes methods for addressing potential age-related, common-mode failure mechanisms used in AP1000 equipment qualification programs. The approach conforms with current industry positions and makes maximum use of available data and experience in the evaluation, test, and analysis of aging mechanisms.

Attachment C, "Effects of Gamma Radiation Doses Below 10^4 rads on the Mechanical Properties of Materials," provides the basis that radiation aging below 10^4 rads is not a significant factor in the ability of the equipment to perform properly during a seismic event. For some devices, electrical properties are degraded above 10^3 rads. Radiation aging for safety-related equipment which is subject to lifetime doses of less than 10^4 rads (10^3 rads for certain electrical components) and not subject to a high-energy line break environment is not required to be addressed in AP1000 qualification programs.

Attachment D, "Accelerated Thermal Aging Parameters," describes the methodology employed in calculating the accelerated thermal aging parameters used in this program.

Attachment E, "Seismic Qualification Techniques," discusses available methods for establishing a seismic qualification basis, by either test or analysis, and its application to the qualification of safety-related equipment for the AP1000.

3D.1 Purpose

The basic objectives of qualification of safety-related electrical and mechanical equipment follow:

- To reduce the potential for common cause failures due to specified environmental and seismic events
- To demonstrate that safety-related electrical and mechanical equipment is capable of performing its designated safety-related functions.

This appendix describes the methodology that has been adopted to qualify equipment according to IEEE 627-1980, "IEEE Standard for Design Qualification of Safety System Equipment Used in Nuclear Power Generating Stations." The two standards primarily used to demonstrate compliance with this standard are IEEE 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," and IEEE 344-1987, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

3D.2 Scope

The qualification criteria, methods, and environmental conditions described constitute the methodology that is adopted to comply with the standards for the AP1000. This methodology applies to safety-related, seismic Category I electrical and mechanical equipment and is also used for certain monitoring equipment. Seismic Category II equipment is also within the scope of this program. The criteria used for the design of seismic Category II structures, systems, and components are discussed in Section 3.7.

Performance during abnormal environmental conditions, while not specifically designated as an industry or a regulatory qualification requirement, is also addressed by this appendix. Performance during normal service conditions is demonstrated by tests and inspections addressed by the equipment specification. Electromagnetic interference (EMI) testing or analysis is not included in the qualification process and is addressed on an individual equipment basis, as necessary.

3D.3 Introduction

This appendix identifies qualification methods used for the AP1000 to demonstrate the performance of safety-related electrical and mechanical equipment when subjected to abnormal and accident environmental conditions including loss of ventilation systems, feedline, steam line and reactor coolant system breaks, and seismic events. This appendix provides the expected conditions for various locations in the AP1000. General requirements for the development of plans/procedures/reports are also provided. Section 3D.4 identifies the various industry and regulatory criteria upon which the program is based. Section 3D.5 defines the design specifications and applicable test environments. Section 3D.6 defines the basis for the qualification method selection. Section 3D.7 outlines the general format and content of the equipment qualification data packages.

3D.4 Qualification Criteria

The environmental requirements considered in the design of safety-related equipment are embodied in GDC 2, "Design Bases for Protection Against Natural Phenomena"; GDC 4, "Environmental and Missile Design Bases"; and GDC 23, "Protection System Failure Modes." GDC 1, "Quality Standards and Records," and Criterion III, "Design Control," Criterion XI, "Test Control," and Criterion XVII,

"Quality Assurance Record" of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to require that the environmental design of safety-related equipment is verified, documented, and controlled.

The qualification methods described in this appendix are used to verify the environmental design basis and capability of the safety-related electrical and mechanical equipment supplied for the AP1000. The results of the verification, as well as the design basis for each equipment, are documented in an equipment qualification data package (see Attachment A for sample format) and seismic analysis report for non-active mechanical equipment (with no environmental qualification requirements). Design control, test control, and quality assurance record keeping is performed through the AP1000 Quality Assurance Program. (See Chapter 17.)

3D.4.1 Qualification Guides

IEEE 323-1974 and 344-1987 serve as the basis upon which the AP1000 equipment qualification methodology demonstrates compliance with IEEE 627-1980. NRC regulations stated in 10 CFR 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," and NRC guidance provided in Regulatory Guide 1.89, and Regulatory Guide 1.100, endorse IEEE 323-1974 and IEEE 344-1987, respectively. The intent of the more general IEEE 627-1980 is addressed through conformance with IEEE 323 and 344.

3D.4.1.1 IEEE Standards

The following lists additional standards and guides used in developing the methodology:

- IEEE 98-1984, "IEEE Standard for the Preparation of Test Procedures for the Thermal Evaluation of Solid Electrical Insulating Materials"
- IEEE 100-1996, "IEEE Standard Dictionary of Electrical and Electronic Terms"
- IEEE 308-1991, "IEEE Standard Criteria for Class 1E Power System for Nuclear Power Generating Stations"
- IEEE 317-1983, "IEEE Standard for Electric Penetration Assemblies in Containment Structure for Nuclear Power Generating Stations"
- IEEE 381-1977, "IEEE Standard Criteria for Type Tests of Class 1E Modules Used in Nuclear Power Generating Stations"
- IEEE 382-1996, "IEEE Standard for Qualification of Actuators for Power-Operated Valve Assemblies with Safety-Related Functions for Nuclear Power Generating Stations"
- IEEE 383-1974, "IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations"
- IEEE 420-1982, "IEEE Standard Design and Qualification of Class 1E Control Boards, Panels, and Racks Used in Nuclear Powered Generating Stations"
- IEEE 494-1974, "IEEE Standard Method for Identification of Documents Related to Class 1E Equipment and Systems for Nuclear Power Generating Stations"
- IEEE 535-1986, "IEEE Standard for Qualification of Class 1E Lead Storage Batteries for Nuclear Power Generating Stations"

- IEEE 572-1985, "IEEE Standard for Qualification of Class 1E Connection Assemblies for Nuclear Power Generating Stations"
- IEEE 603-1991, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations"
- IEEE 649-1991, "IEEE Standard for Qualifying Class 1E Motor Control Centers for Nuclear Power Generating Stations"
- IEEE 650-1990, "IEEE Standard for Qualification of Class 1E Static Battery Chargers and Inverters for Nuclear Power Generating Stations"
- IEEE-741-1997, "IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations"
- ANSI/IEEE C37.98-1987, "IEEE Standard for Seismic Testing of Relays."

3D.4.1.2 NRC Regulatory Guides

In the area of seismic and environmental qualification of safety-related electrical and mechanical equipment, the NRC has issued the following Regulatory Guides:

Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)" – The guide endorses ANS and ANSI standards for quality assurance programs, but is considered here specifically for guidance in determining documentation adequacy. Appendix A of the guide, Item 9, "Procedures for Performing Maintenance," addresses procedural and documentation requirements for maintenance of safety-related equipment, preventive maintenance, repair, and replacement. This guide is a source in the development of qualification in the on-going qualification programs discussed in Subsection 3D.6.4.

Regulatory Guide 1.61, "Damping Values for Seismic Design of Nuclear Power Plants" – The guide prescribes acceptable values of damping used in elastic modal dynamic seismic analysis of seismic Category I structures, systems, and components. The AP1000 equipment qualification program is based on Regulatory Guide 1.61 and on values considered to be acceptable based on past NRC acceptances. The safe shutdown earthquake (SSE) damping values used for the qualification of mechanical and electrical equipment are listed in Table 3.7.1-1 of Chapter 3.

Regulatory Guide 1.63, "Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants" – The guide endorses, with certain qualifications, IEEE 317-1983. External circuit protection of electric penetration assemblies should meet the provisions of Section 5.4 of IEEE 741-1986, "Criteria for Protection of Class 1E Power Systems and Equipment in Nuclear Generating Stations," as these are beyond the scope of IEEE 317. The AP1000 design complies with IEEE 741-1997. The AP1000 equipment qualification program employs the recommendations of Regulatory Guide 1.63, Revision 3, in specifying qualification plans as a means of supplementing the guidance of IEEE 317 and 323.

Regulatory Guide 1.73, "Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants" – The guide endorses, with certain qualifications, IEEE 382-1972. The AP1000 equipment qualification program employs recommendations of Regulatory Guide 1.73, but gives preference to the guidance of IEEE 382-1996, where it is necessary to supplement the guidance of IEEE 323 or 344 in specifying qualification plans for electric valve operators.

Regulatory Guide 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants" – The guide provides guidance for conformance with 10 CFR 50.49, and endorses the procedures of IEEE 323-1974 as an acceptable means for qualifying Class 1E equipment. Implicit in the endorsement of IEEE 323 is the reference to seismic qualification methods of IEEE 344 as a part of the qualification test sequence. (See Regulatory Guide 1.100 later in this discussion.) The AP1000 equipment qualification methodology addresses the recommendations of Regulatory Guide 1.89 by the following:

- The recommendations of IEEE 323-1974 are met by the methods discussed in this appendix
- The radiation source terms used in qualification differ from those of Regulatory Guide 1.89, and are described in Section 3D.5 of this appendix
- The seismic qualification requirements employ the recommendations of IEEE 344-1987 as described in Attachment E of this appendix.

Regulatory Guide 1.92, "Combining Modal Responses and Spatial Components in Seismic Response Analysis" – The guide describes methods and procedures for the following:

- Combining the values of the response of individual modes in a response spectrum modal dynamic analysis to find the representative maximum value of a particular response of interest for each of the three orthogonal seismic spatial components
- Combining the maximum values (or representative maximum values) of the responses for a given element of a system or item of equipment, determined for each of the three orthogonal spatial components.

The AP1000 equipment qualification program employs methods consistent with the recommendations of Regulatory Guide 1.92 when combining individual modal response values or the response of three independent spatial components in seismic analyses.

Regulatory Guide 1.97, Revision 3, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident.” The guide describes a method acceptable to provide instrumentation to monitor plant variables and systems during and following an accident in a light-water-cooled nuclear power plant. The AP1000 program, identified as the post-accident monitoring instrumentation system (PAMS), provides the capability to monitor plant variables and systems operating status during and following an accident. PAMS includes those instruments provided to indicate system operating status and furnish information regarding the release of radioactive materials.

Regulatory Guide 1.100, "Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants" – The guide endorses IEEE 344-1987. Regulatory Guide 1.100 particularly notes that IEEE 344-1987 is applied in the qualification of safety-related mechanical equipment, as well as Class 1E electrical equipment. The AP1000 equipment qualification methodology employs the recommendations of Regulatory Guide 1.100, as described in Attachment E of this appendix.

Regulatory Guide 1.122, "Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components" – The guide describes specific methods for developing floor (and other equipment mounting locations) response spectra. Included are specific criteria for the broadening frequency amplitude peaks and smoothing of the frequency amplitude spectrum to incorporate conservatism in the seismic requirements. This is to compensate for other uncertainties of analysis. The AP1000 equipment qualification program employs methods consistent with the recommendations of Regulatory Guide 1.122.

Regulatory Guide 1.131, "Qualification Tests of Electrical Cables, Field Splices, and Connections for Light-Water Cooled Nuclear Power Plants" – The guide endorses IEEE 383-1974. The AP1000 equipment qualification program employs the recommendations of Regulatory Guide 1.131 in specifying the qualification program plans where this guide supplements the guidance of IEEE 383 and to further demonstrate conformance with the guidance of IEEE 323.

Regulatory Guide 1.156, "Environmental Qualification of Connection Assemblies for Nuclear Power Plants" – The guide endorses IEEE 572-1985. The AP1000 equipment qualification program employs the recommendations of Regulatory Guide 1.156 in specifying the qualification program plans where this guide supplements the guidance of IEEE 572 to demonstrate conformance with the guidance of IEEE 323.

Regulatory Guide 1.158, "Qualification of Safety-Related Lead Storage Batteries for Nuclear Power Plants" – The guide endorses IEEE 535-1986. The AP1000 equipment qualification program employs the recommendations of Regulatory Guide 1.158 in specifying the qualification program plans where this guide supplements the guidance of IEEE 535 to demonstrate conformance with the guidance of IEEE 323.

Regulatory Guide 1.180, “Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems.” Regulatory Guide 1.180 provides guidance to evaluate electromagnetic and radio-frequency interference in safety-related instrumentation and control systems. The AP1000 equipment qualification program employs methods consistent with the recommendations of Regulatory Guide 1.180, where applicable.

Regulatory Guide 1.183, “Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactor.” The radiation dose rates and integrated doses applicable for AP1000 following a design basis accident are determined based on the criteria of NUREG-1465 and this regulatory guide.

3D.4.2 Definitions

Definitions of terms used in this appendix are contained in the referenced standards and IEEE 100, "IEEE Standard Dictionary of Electrical and Electronic Terms, Sixth Edition." Subsection 3D.4.5 clarifies the definitions of "life" (that is, design, shelf, and qualified life) as used in this methodology. The terms "design life" and "qualified life" have the meanings set forth in IEEE 323 and are used in the context of that standard.

3D.4.3 Mild Versus Harsh Environments

Qualification requirements differ for equipment located in mild and harsh environments.

IEEE 323 defines a mild environment as an environment expected as a result of normal service conditions and the extremes of abnormal service conditions where a safe shutdown earthquake is the only design basis event of consequence or conditions where thresholds of material degradation are reached. The following limits are established as the delimiting environmental parameter values for mild and harsh environments.

Typically a mild environment conforms with the environmental parameter limits of Table 3D.4-1, though others may apply to specific equipment applications or locations.

The scope of 10 CFR 50.49 is limited exclusively to equipment located in a harsh environment. The AP1000 equipment qualification program conforms with the requirements of 10 CFR 50.49 for the qualification of harsh environment equipment. A radiation-harsh environment is defined for equipment designed to operate above certain radiation thresholds where other environmental

parameters remain bounded by normal or abnormal conditions. Any equipment that is above 10^4 rads gamma (10^3 for electronics) will be evaluated to determine if a sequential test which includes aging, radiation, and the applicable seismic event is required or if sufficient documentation exists to preclude such a test.

3D.4.4 Test Sequence

Where the test sequence deviates from that recommended by IEEE 323-1974, the deviation is justified. The test sequence employed for a given hardware item is specified in the equipment qualification data package Sections 2.1 and 3.6 (see Attachment A for example). Note that for this reference and subsequent references to Attachment A the information in Attachment A will be completed in accordance with Subsection 3.11.5. Clarifications to the IEEE 323-1974 recommended test sequence are discussed in the following:

1. Burn-In Test

   For electronic equipment, a burn-in test is completed, before operational testing of the equipment, to eliminate infant failures. The test consists of energizing the equipment for a minimum of 50 hours at nominal voltage and frequency under ambient temperature conditions. Any malfunction observed during these tests are repaired, and the 50-hour burn-in test is repeated for the repaired portion of the equipment.

2. Performance Extremes Test

   For equipment where seismic testing has previously been completed employing the recommended methods of IEEE 344-1987, seismic testing is not repeated. Testing of the equipment to demonstrate qualification at performance extremes is separately performed as permitted by IEEE 323-1974, Subsection 6.3.2(3). Additional discussion is provided in Subsection 3D.6.5.1.

3. Aging Simulation and Testing

   For equipment located in a mild environment, aging is addressed as described in Subsection 3D.6.4 and Attachment B. If there are no known aging mechanisms that significantly degrades the equipment during its service life, it is acceptable to perform seismic testing of unaged equipment. Separate testing or analysis (or both) is provided to demonstrate that the aging of components is not significant during the projected service or qualified life of the equipment.

4. Synergistic Effects

   An important consideration in the aging of equipment for harsh environment service is the possible existence of synergistic effects when multiple stress environments are applied simultaneously. This potential is addressed by conservatism inherent in the determination and use of the worst-case aging sequence and conservative accelerated aging parameters.

   The combination of effects from pressure, temperatures, humidity, and chemistry are addressed by the high-energy line break (HELB) tests. Since the test item is not exposed to radiation during this test, the effects of this parameter are conservatively addressed by subjecting the test items to the required total integrated dose before the high-energy line break. Specifically for instruments, the summing of errors for the irradiation and high-energy line break portions of the test sequence is a means of achieving conservatism.

5. Visual Inspections/Disassembly

   The results of post-test visual inspections are not necessarily documented unless problems are discovered. Disassembly is performed only when test results or visual inspections require further investigation.

3D.4.5 Aging

3D.4.5.1 Design Life

The AP1000 equipment qualification program relies on the IEEE 323 definition for design life, particularly its distinction with respect to qualified life.

Instead of determining a qualified life for mild environment equipment for which the seismic event is the exclusive design basis event to be addressed, a design life is determined. Design lives offered in manufacturers' literature are accepted cautiously, particularly where the equipment is typically used for applications outside the nuclear industry.

An application of the design life is substantiated by sound bases in reliability theory and relevant industry standards, or experience data sources within the nuclear industry. Analyses treat the applicability and similarity of the equipment and conditions relevant for the AP1000 safety-related application. These analyses, and documentation of such, conform with guidelines of IEEE standards, as applicable, and with Sections 3D.6 and 3D.7 of this appendix.

3D.4.5.2 Shelf Life

Based on recommended storage environments, the shelf life of an equipment item is not typically a significant portion of the defined qualified life. For example, ambient temperatures during storage are typically less than the operating temperatures assumed for aging calculations. Therefore, as long as equipment is in storage and is not energized (not experiencing self-heating), a reduction in qualified life is not appropriate. However, if storage conditions differ significantly from those recommended or the storage time becomes dramatically extended, the impact to the qualified life is determined by application of the Arrhenius time-temperature relationship.

3D.4.5.3 Qualified Life

A qualified life is established for each item of safety-related equipment that is exposed to a harsh environment based on the conditions postulated at the equipment location with consideration of the equipment operability requirements.

The determination of qualified life considers potential aging mechanisms resulting from significant in-service thermal, radiation, and vibration sources, and the effects of operational cycling (mechanical or electrical or both). Generally, all aging mechanisms do not apply to each item of equipment. Relevant aging mechanisms addressed or simulated are determined jointly with the identification of the equipment's critical components, functional modes, and material characteristics, and the assessment of tolerable limits in degradation of the components. An a priori consideration in selecting equipment to qualify is the evaluation of the equipment's inherent capability to survive and operate under the conditions for which it is qualified.

Since past qualification tests have provided a substantial basis for this assessment (indeed, some may provide sufficient basis to preclude any new testing as part of the AP1000 program) specific guidance on each equipment type is not provided here. Application of the lessons of past tests, insights provided in generic industry communications (for example, technical bulletins, NRC

Information Notices), and sound judgment in the development of test plans and analysis procedures are addressed in the documentation of qualification for each equipment type, as applicable.

Qualified life is established by the most limiting of the five aging mechanisms. Qualified life may be limited by the tolerable degradation of a single component or material critical to the equipment's capability to perform its safety function. Aging is subject to the requirement for margin. See Subsection 3D.4.8 of this appendix.

For some equipment, qualified life is established on the basis of periodic replacement of certain short-lived, age-sensitive components. The user complies with the mandatory replacement practices documented in the equipment qualification data packages (see Subsection 3D.7.2.5) to affirm the equipment qualified life.

The objective of thermal and irradiation qualified life testing is to simulate, according to the available empirical material data, the degradation effects such that the equipment is in its end-of-life condition before the application of the design basis event conditions testing.

Thermal qualified life is evaluated using the Arrhenius time-temperature relationship. (See more detailed discussions in Attachments B and D of this appendix.) The activation energy is the exclusive material-dependent parameter input into the Arrhenius time-temperature relationship. The activation energy is an empirically determined parameter indicative of the thermal degradation of a physical property of a material (for example, elasticity of silicone rubbers or insulation resistance of cross-linked polyethylene cable insulation). Each material may have more than one physical property that may be subject to thermal degradation over time. Consequently, it may have different activation energies with respect to each property. Thus, the selection of activation energy considers the material property most germane to the safety-related function of the material or component. (Also see Subsection 3D.4.5.4.)

Common practice for the evaluation of irradiation-induced degradation is to consider the sum of estimated life and the accident radiation doses before design basis event testing. When testing, the total dose is applied during the radiation aging simulation portion of the qualification test sequences. This is considered conservative because the equipment has accumulated an exposure, or total integrated dose, before the initiation of the seismic and accident environment testing. Further bases for test dose determination are provided in Subsection 3D.5.1.2. Sufficient margin must be included in test parameters (see Subsection 3D.4.8). The same margins are applied in an analysis of radiation life or design basis event radiation dosage.

The simulation of age also includes the effects of operational cycling, both electrical and mechanical. Generally, these considerations are applied specifically to electromechanical equipment such as valve operators, limit switches, motors, relays, switches, and circuit breakers. Furthermore, the simulation of these effects is waived where existing data demonstrates equipment durability greatly in excess of estimated number of operating cycles for Class 1E service. Analysis or justification is provided for any case where operational cycling is omitted in the test sequence.

It is not practicable to simultaneously simulate the aspects of aging. Development of each test plan considers known synergies and sequences the simulation of the various applicable aging mechanisms with regard for conservatism of the overall effect on the test specimens.

3D.4.5.4 Qualified Life Reevaluation

It may be possible to extend the qualified life of a particular piece of equipment at some future date by comparing the actual in-plant environments and conditions during the equipment's installed life to the values assumed for the AP1000 in establishing the qualified life. For example, the thermal qualified life might be extended by performing an analysis of actual internal or external temperatures

(or both) experienced. Continuous temperature monitoring or use of sample devices for testing and trending materials aging may be used. These efforts reveal the conservatism of the original thermal life calculation, which assumes that the maximum value specified for the normal plant operating environment endured at all times.

Although a strict Arrhenius calculation may yield an extended qualified life, care is taken in using this extrapolation because of uncertainties in the methodology. The Arrhenius time-temperature relationship relies on empirically determined activation energies of materials. This parameter has been determined for a number of materials to at least a good approximation for small temperature extrapolations. Extrapolation of the Arrhenius model to time periods of temperature beyond the range of materials test data is questionable and may result in large errors.

Calculated qualified lives based on this methodology should be limited to 20 years unless sound technical bases can be cited. This position is consistent with industry guidelines such as IEEE 98-1984, NUREG/CR-3156 (Reference 4), and EPRI NP-1558 (Reference 5).

3D.4.6 Operability Time

The post-accident operability times specified in Section 1.7 of each equipment qualification data package (see Attachment A) are conservatively established based on the safety-related function performed by that equipment for the spectrum of design basis event conditions. These include the following:

- Trip and/or monitoring functions of sensors and instruments
- Operability requirements for electromechanical equipment
- Duration of required operability for active valves.

This evaluation also considers what consequences the failure of the device has on the operator's action or decisions and the mitigation of the event. Table 3D.4-2 lists and explains typical operability times.

For monitoring functions, simulated aging techniques are employed to shorten the test time following a high-energy line break. These also comply with the margin guidelines of Subsection 3D.4.8.

Margins for trip function requirements are contained in the high-energy line break envelopes that encompass a full spectrum of break sizes. The defined margins are also justified by the fact that the signal generated by the sensor is locked in by the protection system and does not reset should the sensor fail after completion of its designated trip time requirement.

3D.4.7 Performance Criterion

The basic performance criterion is that the qualification test program demonstrates the capability of the equipment to meet the safety-related performance requirements defined in the equipment qualification data package, Section 1.7, while subjected to the environmental conditions specified in the equipment qualification data package, Section 1.8. Where three or more specimens are tested, failure of one of three may be considered a random failure, subject to an investigation concluding that the observed failure is not indicative of a common-mode occurrence.

For equipment for which aging is addressed by evaluation of appropriate mechanism(s) through a review of available material and component information, the basic acceptance criterion is that the evaluation of test data demonstrates that the effect of aging is minor and does not affect the capability of the aged equipment to perform specified functions.

3D.4.8 Margin

IEEE 323 (Subection 6.3.1.5) recommends that margin be applied to the most severe specified service conditions in order to establish the conditions for qualification. This margin is provided in order to account for normal variations in commercial production of equipment and for reasonable errors in defining satisfactory performance. Further guidance for determining the acceptability of margin with respect to application-specific or location-specific requirements is provided by the NRC in NUREG-0588 and Regulatory Guide 1.89, Revision 1. Margins are included in addition to conservatisms applied during the derivation of the local environmental conditions of the equipment, unless the conservatism is quantified and specifically shown to meet or exceed the guidance of IEEE 323, NUREG-0588, and Regulatory Guide 1.97.

Consistent with IEEE 323, margin is incorporated into the specification of the generic qualification parameters by either increasing the test levels, number of test cycles, test duration, or a combination of these options as appropriate. The AP1000 generic qualification parameters are selected to envelop a range of loss of coolant accident and high-energy line break sizes, and equipment locations. Margin in seismic conditions for test and analysis are addressed in Subsection 3D.4.8.4. The margins available for a specific application may be larger than the generic equipment qualification test objective for seismic events and some events outside containment and are verified on an application-specific basis.

In defining qualification parameters, the AP1000 equipment qualification program incorporates margin as described in the following subsections. Table 3D.4-3 lists margin requirements applied.

For generic testing, margin is applied at the time of testing to cover known safety-related applications of the equipment. Generally, this results in a worst-case test that provides substantial margin for applications where lesser environments apply. Application of margin for seismic qualification addresses several cases unique to the qualification approach. (See Subsection 3D.4.8.4.)

3D.4.8.1 Normal and Abnormal Extremes

As indicated in Section 7 of IEEE 323, the application of margin is directed at specifying adequate qualification requirements for the most severe service conditions represented by the design basis events (that is, high-energy line break accidents and seismic events). Consequently, the AP1000 equipment qualification methodology does not apply any systematic margin to the normal and abnormal environment parameters in defining the qualification conditions.

For electronic equipment not required to operate in a high-energy line break environment, additional margin is included by requiring that the equipment operate through the conservative normal and abnormal service conditions indicated in Figure 3D.5-1. The environmental parameters at least equal the specified range of service condition parameters. An exception occurs for transmitters where a performance verification is completed at 130°F on each transmitter to encompass the specified maximum abnormal conditions. For equipment to be qualified to operate in a high-energy line break environment, qualification to the severe high-energy line break conditions demonstrates ample margin for acceptable performance under certain specified normal and abnormal service conditions.

3D.4.8.2 Aging

No specific margin is applied to the time component in deriving appropriate aging parameters, if margin is included in deriving the accelerated aging parameters employed for simulating each applicable aging mechanism.

Margin may be addressed by demonstrating the adequacy of the aging simulated by test through the calculation of time-temperature equivalence (See Attachment B of this appendix) or the comparison

of simulated parameters with those applicable to the intended service of the equipment. The installed life of equipment must not exceed the thermal qualified life demonstrated by this calculation. Additionally, the selection and use of the thermal aging parameters both for test and subsequent calculations are subject to criteria, including the following:

- Test temperature must endure for at least 100 hours
- Test temperature must exceed any application temperature (that is, the normal or abnormal environment in which the equipment is to be used, and for which the life is calculated)
- Test temperature must be less than state-change temperature for materials critical to the equipment safety-related function or capability to endure the subsequent design basis event testing
- A conservative activation energy is used. Activation energies for materials critical to the equipment safety-related function or capability to endure the subsequent design basis event testing are considered. Materials may have several activation energies, each for a different material property. Relevant material properties are considered.

If margin is not demonstrated through conservatism in the aging parameters or calculation, then a +10 percent time margin is included.

A margin of 10 percent in the other parameters (for example, irradiation, operational cycling) applies to both the aging simulation and the post-accident simulated aging, with few exceptions.

For equipment required by design to perform its safety-related function within a short time period into the design basis event (that is, within seconds or minutes), and having completed its function, subsequent failure is shown not to be detrimental to plant safety, margin by percentage of additional time or equivalent time-temperature is not applied. Margins for trip function requirements are contained in the worst-case high-energy line break envelope. Test parameters are simulated on a real-time basis with the transient condition margins listed in Table 3D.4-3. Trip signals, once generated by the sensors, are locked in by the protection system and do not reset in the event of subsequent sensor failure.

3D.4.8.3 Radiation

An additional 10 percent is added to the calculated total integrated dose in specifying the test requirements.

3D.4.8.4 Seismic Conditions

Required response spectra included in Subsection 3.7.2 or other AP1000 program specifications are the conditions to be enveloped. No amplitude margin is added to these conditions. Peak broadening is also discussed in Subsection 3.7.2. Seismic qualification by analysis addresses margin requirements by other methods of conservatism while using the same sets of requirements - no amplitude margin is included. For qualification tests, the test facility increases the amplitude of seismic profiles by 10 percent to incorporate margin.

For most applications, considerable margin exists with respect to the acceleration levels employed and the width of the response spectra. Further details are addressed in Attachment E.

3D.4.8.5 High-Energy Line Break Conditions

The envelopes specified for high-energy line breaks are selected to encompass the transients resulting from a spectra of loss of coolant accidents and high-energy line break sizes and locations, and various nodes in the containment. As a consequence, these design envelopes already contain significant margin with respect to any transient corresponding to a single break.

The AP1000 equipment qualification methodology requires that the qualification envelopes be derived with a margin of 15°F and 10 psi with respect to the design envelopes in Figure 3D.5-8. The margin on dose is identified by comparing the location specific dose requirements and the AP1000 equipment qualification parameters.

Margin on chemistry is 10 percent on the bounding concentration of the chemical additives. For fluids with acidic pH, the margin is applied in chemicals that increase the acidity of the fluid. For fluids with basic pH, the margin is applied in chemicals that increase the alkalinity of the solution. Solutions simulating post-accident containment sump chemistry reflect the influence of the buffering agent and change over time from acidic to alkaline. Margin in the initial acidic sump chemistry does not have to be explicitly modeled because it is accomplished through continued low pH fluid injection. Required pH of chemistries is met or bounded in a conservative fashion.

3D.4.9 Treatment of Failures

The primary purpose of equipment qualification is to reduce the potential for common mode failures due to anticipated environmental and seismic conditions. The redundancy, diversity, and periodic testing of nuclear power plant safety-related equipment are designed to accommodate random failures of individual components.

Where an adequate test sample is available, the failure of one component or device together with a successful test of two identical components or devices indicates a random failure mechanism, subject to an investigation concluding that the observed failure is not common mode. Where insufficient test samples prevent such a conclusion, any failures are investigated to ascertain whether the failure mechanism is of common mode origin. Should a common mode failure mechanism be identified as causing the failure, either a design change is implemented to eliminate the problem or a repeat test completed to demonstrate compliance with the criteria.

For those mild environment equipment items that, through a review of available documentation, are subject to failure during a seismic event due to significant aging mechanisms, the material or component is replaced or monitored through a maintenance/surveillance program.

3D.4.10 Traceability

A system of baseline design documentation is instituted to control the design, procurement, and manufacturing of safety-related products. As part of this quality control program, critical parts are identified and assigned a level of control to reflect the estimate of potential qualification or procurement problems. In addition, levels of quality inspection are also assigned to each part. The baseline design documentation describes the equipment in sufficient detail (drawing number, part number, manufacturer) to establish traceability between equipment shipped and equipment tested in the qualification program.

3D.4.10.1 Auditable Link Document

The purchaser of equipment referencing this program requires an auditable link document that provides a tie between the specific equipment and documentation of qualification reviewed for

acceptance under this program. This auditable link document includes one or more of the following sections, as applicable.

3D.4.10.1.1 Equipment Link

This documentation certifies that the plant specific equipment is covered by the applicable equipment test reports. This link reflects a comparison of the as-built drawings, baseline design document or other documentation of the tested equipment to the specific equipment.

3D.4.10.1.2 Component Link

This documentation certifies that the components (for example, replacement parts) used in the specific equipment are represented in the applicable test reports or via analysis under a component aging program, such as that described in Attachment B. This link applies only to equipment whose equipment qualification data package references a component testing program. This link reflects a comparison of the as-built drawings, baseline design document, or other documentation of the specific equipment to the component program listing.

3D.4.10.1.3 Material Link

This documentation certifies that the materials used in the equipment are represented in a materials aging analysis, such as that described in Attachment B. This link applies only to equipment whose equipment qualification data package references the materials aging analysis and reflects a comparison of the as-built drawings, baseline design document, or other documentation of the plant specific equipment to the materials aging analysis listing.

3D.4.10.2 Similarity

Where differences exist between items of equipment, analysis may be employed to demonstrate that the test results obtained for one piece of equipment are applicable to a similar piece of equipment. Documentation of this analysis conforms with guidelines in IEEE 323 and 627, and Subsection 3D.6.2.1 and Section 3D.7 of this appendix.

3D.5 Design Specifications

The conditions and parameters considered in the environmental and seismic qualification of AP1000 safety-related equipment are separated into three categories: normal, abnormal, and design basis event. Normal conditions are those sets and ranges of plant conditions that are expected to occur regularly and for which plant equipment is expected to perform its safety-related function, as required, on a continuous, steady-state basis. Abnormal conditions refer to the extreme ranges of normal plant conditions for which the equipment is designed to operate for a period of time without any special calibration or maintenance effort. Design basis event conditions refers to environmental parameters to which the equipment may be subjected without impairment of its defined operating characteristics for those conditions.

The following subsections define the basis for the normal, abnormal, design basis event, and post-design basis event environmental conditions specified for the qualification of safety-related equipment in the AP1000 equipment qualification program. (These are cited in Section 1.7 of each equipment qualification data package; See Attachment A.)

The service conditions simulated by the test plan are identified in equipment qualification data package Section 3.7. (See Subsection 3D.7.4.6 and Attachment A.) In general, the parameters employed are selected to be equal to (normal and abnormal) or have margin (design basis event and post-design basis event) with respect to the specified service conditions of equipment qualification

data package, Section 1.7, as recommended by IEEE 323. These conditions are conservatively derived to allow for possible alternative locations of equipment within the plant.

3D.5.1 Normal Operating Conditions

Equipment not subject to high-energy line break environments is qualified for normal and abnormal conditions, as applicable, employing a cyclic test sequence of environmental and electrical extremes. A typical test profile, including voltage and frequency cycling, is shown in Figure 3D.5-1.

3D.5.1.1 Pressure, Temperature, Humidity

The calculated values for temperature, pressure, and humidity during normal operation are specified in Table 3D.5-1 as a function of in-plant location.

3D.5.1.2 Radiation Dose

The normal operating dose rates and consequent 60-year design expectation doses at various locations inside containment are specified in Table 3D.5-2. These values have been derived from theoretical calculations assuming an expected 60 years of continuous operation with a reactor power of 3468 MWth (including 2-percent power uncertainty) and steady-state operating conditions. Equivalent data at various locations outside containment are also specified in Table 3D.5-2.

The total integrated dose employed for testing is a combination of normal and accident doses (where applicable), and is defined to equal or exceed the maximum radiation dose contained in the equipment qualification data package. (See Section 3D.7 and Attachment A.) A margin of 10 percent is included in defining the total integrated doses for testing. Normal operating and accident gamma doses are simulated using a cobalt-60 or spent fuel source. The test dose is applied at a rate approximate to the maximum accident dose rate. Irradiation dose rates less than the maximum are considered where there is significant shielding (greater than two mm of steel) or where the peak in-containment design basis event dose rate is not expected to affect the equipment's electrical performance.

Low radiation dose rates encountered during normal operation for most equipment are not considered critical parameters because of the resultant low total integrated dose (10^4 to 10^5 rads) achieved. For equipment not required post-accident, material can be selected based on previous test results. Another test on the completed assembly is not required.

If equipment is located in an environment where the normal total integrated dose exceeds the threshold for radiation damage, then testing is required. For equipment required post-accident, the dose received during normal operation is usually an insignificant part of the total integrated dose, including accident conditions effects. The supposition that a concern over low dose rate effects diminishes as the total integrated dose decreases is supported by Sandia National Laboratories tests (References 6 and 7) on selected materials over a range of dose rates. These studies indicate that reduction in original properties is about the same (and not significant) for dose rates up to a total integrated dose in the megarad range. Although these tests were not performed at dose rates as low as those expected in a nuclear power plant and electrical properties were not evaluated, they do give some indication of the effect of varying the rate.

Based on results of research programs to date and low total integrated dose reached during normal operation, the AP1000 equipment qualification program does not consider degradation due to low dose rate effects to be a significant concern. Therefore, the program does not include any action other than inspecting organic material degradation in the plant through normal maintenance.

3D.5.2 Abnormal Operating Conditions

Abnormal environments are defined to recognize possible plant service abnormalities that lead to short-term changes in environments at various equipment locations.

For equipment located inside containment, several abnormal environment types are considered in Subsection 3D.5.2.1. Equipment located outside containment is addressed in Subsection 3D.5.2.2.

3D.5.2.1 Abnormal Environments Inside Containment

In the AP1000 equipment qualification program there are multiple events postulated at least once over the 60 year design expectation which cause abnormal environmental conditions in the containment. These are divided into two groups of events, based on peak containment temperatures expected.

Group 1: 150°F Events

- Loss of a fan cooler
- Loss of all ac for up to 2 hours
- Pressurizer safety valve open/close during reactor coolant system transient.

Group 2: 250°F Events

- Spurious automatic depressurization system (ADS) actuation
- Passive residual heat removal (PRHR) system use (long-term)
- Reactor coolant system depressurization via pressurizer safety valve
- Small loss of coolant accident.

Only the vapor conditions (containment air temperature, pressure, and humidity) associated with these events are considered in the abnormal, group 2 environmental conditions. Other environmental conditions resulting from these events (such as submergence, or radiation) are not included in the group 2 environmental conditions, but are part of or bounded by the accident condition qualification.

Table 3D.5-3 presents the conditions associated with these abnormal environments. Best estimate analyses of AP1000 plant behavior are used to determine abnormal environmental conditions. Plant recovery occurs after each event with varying degrees of time and maintenance efforts. Thus, the conditions resulting from these events are considered in the development of aging test parameters. Event frequency, conditions, and duration are accounted for within the context of the qualified life objective of each equipment type test program.

3D.5.2.2 Abnormal Environments Outside Containment

Figure 3D.5-1 represents the assumptions made in defining potential abnormal environments due to loss of air-conditioning or ventilation systems.

Table 3D.5-4 defines the abnormal environments as a function of equipment location. The assumed durations of the abnormal conditions specified in Table 3D.5-4 are consistent with operating practices and technical specification limits. For certain plant applications, qualification for abnormal environments is not necessary when equipment is located in environmental zones that do not exceed manufacturer's design limits for equipment operation, or — for flooding/wetting — if qualified in accordance with applicable criteria in Subsection 3.11.1.2.

3D.5.3 Seismic Events

See Attachment E.

3D.5.4 Containment Test Environment

The ASME Code, Section III, Paragraph NE-6321 specifies that containment integrity is demonstrated at not less than 1.1 times design pressure. The design pressure of the AP1000 containment is 59 psig. Consequently, the minimum pressure specified for the containment test is 59 x 1.1 = 64.9 psig. Other environmental parameters (such as temperature and humidity) of the containment test are adequately enveloped by the parameters specified for normal or abnormal plant conditions.

3D.5.5 Design Basis Event Conditions

Performance requirements are specified for those design basis events for which the equipment performs a safety-related function and which have a potential for changing the equipment environment due to increased temperature, pressure, humidity, radiation, or seismic effects. The environmental conditions for each applicable design basis event are summarized in Table 3D.5-5 and are defined in the equipment qualification data package (see Section 1.8 of Attachment A) based on considerations and assumptions described in the following subsections. The radiological conditions presented in Table 3D.5-5 represent the maximum one year TID expected to occur in that zone. Dosages used for equipment qualification will be evaluated on a room-by-room basis and may be less than this maximum dose.

3D.5.5.1 High-Energy Line Break Accidents Inside Containment

3D.5.5.1.1 Radiation Environment – Loss of Coolant Accident

The radiation dose rates and integrated doses following a design basis loss-of-coolant accident (LOCA) are determined based on the criteria and guidance provided in NUREG 1465, “Accident Source Terms for Light-Water Nuclear Power Plants – Final Report” (Reference 8) and Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors” (Reference 9).

The radiation exposure inside the containment is conservatively estimated by considering the dose in the middle of the AP1000 containment. Radioactive sources are assumed to be uniformly distributed throughout the containment atmosphere, and plate out of non-gaseous activity on containment surfaces is considered. No credit is taken for the shielding provided by internal structures and equipment.

Sources are based on the emergency safeguards system core thermal power rating and the following analytical assumptions:

- Power Level (including 2-percent power uncertainty) ..... 3,468 MWt
- Fraction of total core inventory released to the containment atmosphere:

  Noble Gases (Xe, Kr)..... 1.0

  Halogens (I, Br)..... 0.40

  Alkali Metals (Cs, Rb) 0.30

  Tellurium Group (Te, Sb, Se)..... 0.05

Barium, Strontium (Ba, Sr) 0.02

Noble Metals (Ru, Rh, Pd, Mo, Tc, Co) 0.0025

Lanthanides (La, Zr, Nd, Eu, Nb, Pm, Pr, Sm, Y, Cm, Am) 0.0002

Cerium Group (Ce, Pu, Np) 0.0005

The radionuclide groups and elemental release fractions listed above are consistent with the accident source term information presented in NUREG-1465 and Regulatory Guide 1.183.

The timing of the releases are based on NUREG-1465 assumptions. The release scenario assumed in the calculations is described below.

An initial release of activity from the gaps of a number of failed fuel rods at 10 minutes into the accident is considered. The release of 3 percent of the core inventory of the volatile species (defined as noble gases, halogens, and alkali metals) is assumed. An additional release period occurs over the next 30 minutes, that is, from 10 to 40 minutes into the accident. At this point, 5 percent of the total core inventory of volatile species has been considered to be released.

Over the next 1.3 hours, releases associated with an early in-vessel release period are assumed to occur, that is, from 40 minutes to 1.97 hours into the accident. This source term is a time-varying release in which the release rate is assumed to be constant during the duration time. Additional releases during the early in-vessel release period include 95 percent of the noble gases, 35 percent of the halogens, and 25 percent of the alkali metals, as well as the fractions of the tellurium group, barium and strontium, noble metals, lanthanides, and cerium group as listed above.

There is no additional release of activity to the containment atmosphere after the in-vessel release phase. Activity removal by natural mechanisms as described in Chapter 15 Subsection 15.6.5.3.2 and Appendix B are considered only during the first 24 hours following the accident.

The above source terms are consistent with the guidance provided by the NRC in Regulatory Guide 1.183 for design basis accident (DBA) loss-of-coolant accident (LOCA) evaluations.

Based on these assumptions the instantaneous and integrated gamma and beta doses for the containment atmosphere following a loss of coolant accident are shown in Figures 3D.5-2 and 3D.5-3, respectively.

The total integrated dose of radiation employed for testing is a combination of normal and design basis event dose, as applicable. It is defined to equal or exceed the maximum radiation dose contained in the specification (Attachment A, Section 1.8). A margin of 10 percent is included in defining the total integrated dose for testing. Normal operating and design basis event gamma doses are simulated using a cobalt-60 source. The test dose is applied at a rate approximate to the initial phase of the design basis event dose rate shown in Figure 3D.5-2 as modified by shielding effects (typically 0.2 to 0.25 Mr/hr).

Where exposed organic material is evaluated by test for the effect of (accident) beta radiation, a beta source is employed. Or a cobalt-60 or spent fuel source is used to impart the same dose using gamma radiation. When doing beta equivalent testing, the total integrated dose using gamma is conservatively equal to the beta total integrated dose, or the resulting bremsstrahlung is calculated and the test item is exposed to an equivalent gamma dose.

Radiation conditions for loss of coolant accident envelop other scenarios, such as rod ejection.

3D.5.5.1.2 Radiation Environment – Steam Line Break Accident

Sources associated with a steam line break accident are based on the release of reactor coolant system activity, assuming operation with the design basis fuel defect level of 0.25 percent. It is further assumed that an “event-initiated” iodine activity spike occurs, which increases the reactor coolant activity during the accident based on a rate of increase that is 500 times the normal activity appearance rate in the reactor coolant.

The activity inventory is instantaneously released into the containment atmosphere. The dose is conservatively estimated by considering the dose rate in the middle of the containment, with no credit for the shielding provided by the internal structures, components, and equipment. The instantaneous and integrated gamma and beta doses for the containment atmosphere following a steam line break are shown in Figures 3D.5-4 and 3D.5-5, respectively.

3D.5.5.1.3 Radiation Environment – Feedline Break

For convenience and simplicity, it is conservatively assumed that the radiation doses resulting from a feedline break are equal to the values specified in Figures 3D.5-4 and 3D.5-5 for a steam line break.

3D.5.5.1.4 Total Integrated Dose Specification

The applicable accident doses specified in equipment qualification data package Section 1.8 of Attachment A, have been derived based upon the time required to perform the specified safety function in the accident environment (Attachment A, Section 1.7) and the dose calculations described previously, subject to the following modifications:

- For equipment only required to provide trip or activation functions after accidents involving no release of radioactive material for at least one hour, the radiation dose is based on the normal dose rates (Table 3D.5-2).

3D.5.5.1.5 Temperature/Pressure Environments

The design basis events addressed are the loss of coolant accident, steam line break and feedwater line break. The WGOTHIC code is utilized to calculate the temperature and pressure conditions resulting from these breaks. To retain the option of qualifying equipment for each of these high-energy line break conditions, as applicable, separate environmental containment envelopes are specified for the higher irradiation/lower saturated temperature conditions of the loss of coolant accident as against the lower irradiation/short-term superheated temperature conditions associated with the steam line break. To limit the number of basic envelopes, this latter envelope is conservatively employed to define the containment environmental envelope following a feedline break.

Additionally, to facilitate AP1000 generic qualification and testing, the environmental envelopes have been combined to a single high-energy line break profile depicted in Figure 3D.5-8. This combined profile encompasses locations inside containment on the basis of the containment analyses for the AP1000 design. The profile, or a similar combined profile considering localized conditions resulting from the same events, is used to qualify equipment for any application or location for the AP1000 consistent with the NRC requirements in 10 CFR 50.49 and IEEE 308, 323, 603, and 627 when margin is added and via conformance with IEEE 323 guidelines.

Qualification tests to high-energy line break conditions are designed to address the applicable specified environment(s) with a margin of 15°F and 10 psi. Separate envelopes with margin are employed, or a combined loss of coolant accident/steam line break/feedwater line break envelope (Figure 3D.5-8, or its localized equivalent) may be employed for in-containment equipment

qualification tests. Figure 3D.5-8 does not include margin from IEEE 323-1974, which will be incorporated in the environmental qualification programs. The simulated post-design basis event aging time-temperature profile (Figure 3D.5-8, or its localized equivalent from 24 hours to test conclusion) is defined consistent with the smallest value of activation energy applicable to the thermal aging sensitive components composing the test equipment or by a demonstrably conservative activation energy, as described in Attachment D.

3D.5.5.1.6 Chemical Environment

The high-energy line break qualification test for safety-related components will include chemical injection during the first 24 hours of the test, as appropriate, to simulate the reactor coolant system fluid. Initial pH is from 4 to 4.5, with the solution consisting primarily of boric acid. Components situated in locations that will not be exposed to reactor coolant fluid are not required to be subjected to chemical injection during testing.

Since there is no caustic containment spray in the AP1000, subsequent adjustments in pH may not be necessary for all tests. Sump solution chemistry is adjusted by release of alkaline chemistry, which will rise to 7.0 to 9.5 within a few hours of containment flooding. Conditions, representative of expected sump solution chemistry, are simulated for submerged equipment.

Margin in low pH value is not included, but is addressed by the continued injection through the first 24 hours. Margin in alkaline pH, where adjustment is necessary, is incorporated by a 10 percent increase in alkalinity.

3D.5.5.1.7 Submergence

Performance of equipment in a submerged condition is verified by a test that replicates the actual conditions with appropriate margin.

3D.5.5.2 High-Energy Line Break Accidents Outside Containment

For the majority of equipment located outside containment, the normal operating environment remains unchanged by a high-energy line break accident. As a consequence, qualification for such events is covered by qualification for normal conditions.

A limited amount of equipment located outside containment, near high-energy lines, could be subject to local hostile environmental conditions because of a high-energy line break outside containment. In this case, the equipment is qualified for the conditions resulting from events affecting its location and for which it is required to operate. Figure 3D.5-9 shows the design conditions for equipment that is required to perform throughout postulated events. Figure 3D.5-9 does not include margin from IEEE 323-1974, which will be incorporated in the environmental qualification programs. The maximum pressure for any event outside containment is 6 psi, with the exception of the MSIV compartments, which are designed for a 6.5 psi pressurization load.

3D.6 Qualification Methods

The recognized methods available for qualifying safety-related electrical equipment are established in IEEE 323. These are type testing, analysis, on-going qualification, or a combination of these methods. The choice of qualification method for a particular item of equipment is based upon many factors. These factors include practicability, size and complexity of equipment, economics, and availability of previous qualification to earlier standards.

The qualification method employed for each equipment type included under the AP1000 equipment qualification program is identified in the individual equipment qualification data packages whether by

test (Attachment A, Section 3), analysis (Attachment A, Section 4), or by a combination of these methods. The AP1000 equipment qualification program may employ on-going qualification through the use of maintenance and surveillance. Guidance for such an approach is not included in this appendix.

3D.6.1 Type Test

The preferred method of environmental and seismic qualification of safety-related electrical and electromechanical equipment for the AP1000 equipment qualification program is type testing according to the guidelines and requirements of IEEE 323-1974 and 344-1987. Development of type test requirements are discussed in Section 3D.5. Documentation requirements and test plan development are addressed in Section 3D.7.

Additionally, qualification based on type tests performed according to IEEE 323 and 344, but not specifically for the AP1000, may be used as a qualification basis. Subsection 3D.6.5 of this appendix discusses the combination of qualification methods as they apply to the AP1000 equipment qualification program. (See Subsection 3D.6.5.1.)

3D.6.2 Analysis

The AP1000 equipment qualification program uses analysis for seismic qualification of equipment if the primary requirement is the demonstration of structural integrity during a seismic event. For equipment that performs an active or dynamic function, seismic qualification by analysis may also be used. (See Section E.3 of Attachment E.) However, the similarity between a qualified test unit and an as-supplied unit must be demonstrated unless otherwise justified. Subsection 3.9.2.2 describes the qualification requirements for safety-related mechanical equipment where a fluid pressure boundary is involved. For those mechanical components that are not pressure boundaries, analysis is performed in compliance with the applicable industry design standard. Where age-sensitive materials, such as gaskets and packing, are used in the assembly of mechanical equipment, the aging of these materials is normally evaluated based on an item-by-item review of the aging characteristics of the material. (See Subsection 3D.6.2.3.)

Requirements for documentation of the analysis are further treated in Section 3D.7.

3D.6.2.1 Similarity

Similarities among manufacturer's models provides several options for extending qualification to equipment without the need for a complete qualification test program.

A model series, such as that for a solenoid valve design, consists of numerous models that are identical in materials of construction and manufacturing process, but have minor variance in size, functional mode, operating voltage, electrical termination type, and mechanical interface sizing. Such variances in most cases have no impact on or relevance to the capability of the various models to perform acceptably under environmental or seismic (or both) qualification test conditions. Furthermore, the design basis document may apply equally to each member of the model series. In such cases, all members of the model series can be qualified by reference to the same testing or analysis.

There may be sufficient similarities between different model series to justify the case for similarity. A documented comparison addressing differences in the design for each, or apparent physical differences between members of each model series, may be sufficient to preclude the testing of one model series based on the testing of the other.

Similarly, different models of a manufacturer's transmitters may be identical in some respects but different in others. The justification of similarity addresses the degree of similarity for critical characteristics. Differences that are not significant to qualification are also addressed for completeness. The mechanical and electrical functional modes and configurations must be the same. The materials of construction may be different, but must demonstrate equivalent performance. Other means of assuring accuracy may be necessary. When the devices are sufficiently similar in all attributes affecting qualification, qualification testing of one item can adequately cover another.

3D.6.2.2 Substitution

The objectives are to establish a degree of similarity and equivalence of performance for parts and materials that are different and, ultimately, to preclude the need for testing. For example, a gasket material is changed or a new type of capacitor is used because the original is no longer available, economical, or inadequate. Substitution of parts and materials is acceptable if comparison or analysis supports the conclusion that equipment performance is the same or better as a result. Consideration is given to characteristics of materials and the relative degree to which each is affected (or degraded) by the environmental parameters of qualification.

3D.6.2.3 Analysis of Safety-Related Mechanical Equipment

Environmental qualification of safety-related mechanical equipment is required to preclude common mode failures due to environmental effects of a design basis accident. Requirements are based on GDC 4 and 10 CFR 50, Appendix B. These criteria mandate that safety-related structures, systems, and components be designed to accommodate both normal and accident environmental effects.

3D.6.2.3.1 Equipment Identification

Safety-related mechanical equipment to be qualified is identified through the review of design basis documentation or the requirements of each safety-related fluid system. Only nonmetallic parts or subcomponents within the safety-related mechanical equipment are addressed for the effects of the postulated environments. The principal scope is typically valve "soft parts" that are critical to the valve safety-related function or pressure boundary integrity.

The types of components most frequently encountered in the mechanical equipment evaluations are discussed in Subsection 3D.6.2.3.3. Properties of materials that are assessed to provide confidence in safety-related function performance are also identified.

3D.6.2.3.2 Safety-Related Function

Safety-related functions and performance criteria are identified based on system and component classification. Structure, system, and component design basis documentation is reviewed to determine the specific safety functions. Components and subcomponents not involved in the equipment's safety-related function(s) are excluded from the qualification process if it is shown that their failures have no effect on the safety-related functions.

3D.6.2.3.3 Performance Criteria

Comprehensive performance criteria are established to satisfy the fundamental qualification requirements. The criterion for qualification is that the property of the nonmetallic material with regard to its application is not degraded during the specified qualified life to the point that the component is unable to perform its intended safety-related function. Properties for the component types listed in Table 3D.6-1 are discussed as examples.

Gaskets and O-Rings

The capability of gaskets and O-rings to keep their shapes determines their ability to maintain pressure boundaries. When an O-ring or gasket loses its dimensional memory, it does not exert the necessary force on the confining surfaces. This could result in leakage. Compression set and elongation are good indicators of the dimensional memory of a material. They also reflect the extent of thermal aging and radiation-induced cross-linking. A compression set of 50 percent is chosen as a conservative end-of-life criterion even though leakage is unlikely to occur until the component takes a compression set of greater than 75 percent. When compression set data is not available for a gasket or O-ring, elongation at break is the material property evaluated because like compression set, it is an indication of dimensional memory and cross-link.

Diaphragms

Diaphragms must remain flexible yet maintain their dimensional memory throughout the estimated mechanical cycles. Retention of elongation or tensile strength is evaluated for radiation and thermal aging.

Diaphragm Support Sheets

The diaphragm support sheet prevents puncture and tearing of the diaphragm. It is not considered critical to the operability of diaphragm valves. The best indication of radiation damage and thermal aging to diaphragm support materials is retention of elongation.

Lubricants

One of the primary functions of oils and greases is to maintain a thin film barrier between moving parts to reduce friction and wear. Irradiation reduces the capability of a lubricant to perform this function by decreasing viscosity in oils and increasing penetration in greases and finally converting lubricants to hard, brittle solids if exposure is severe.

Worm Gears

Worm gears must be capable of transmitting forces without excessive deformation. Flexural strength is the material property chosen to evaluate radiation and thermal aging resistance of worm gears.

3D.6.2.3.4 Identification of Service Conditions

Service conditions are identified for the normal and accident conditions. The general design of equipment permits exemption of environmental parameters such as pressure and humidity. Where critical parts are totally enclosed and not directly exposed to potentially harsh environments, the effects of humidity and chemical spray are not addressed. The degradation of mechanical equipment due to thermal and radiation aging is typically more severe than the possible degradation due to other environments. Since most mechanical equipment interfaces with process fluid, the effect of the fluid on the environmental conditions (temperature, radiation, and chemical) is considered.

3D.6.2.3.5 Description of Potential Failure

Where applicable, potential failure modes are identified and assessed for the equipment. Assessment of equipment aging mechanisms is essential to determine if aging has a significant effect on operability. This assessment provides confidence that significant aging mechanisms are unlikely to contribute to common-mode failures adverse to the safety-related function of equipment.

3D.6.2.3.6 Qualification Procedure

The nonmetallic materials identified are evaluated to the normal and accident environmental parameters. The evaluation procedure includes the following steps:

- Identification of the environmental effect on the material properties
- Performance of a thermal aging analysis
- Determination of the environmental effects on the equipment safety-related function.

These are detailed in the equipment qualification data package of Attachment A, Section 4.

3D.6.2.3.7 Performance Criteria

The nonmetallic subcomponents of the mechanical equipment:

a. are acceptable for the plant environment by exhibiting threshold radiation values above the postulated environmental condition, and

b. are acceptable for the plant environment by exhibiting a maximum service temperature above the maximum postulated environmental, and

c. does exhibit a service life sufficient to survive the accident duration, or

d. instead of a, b, and c, are acceptable for the plant environment by analysis that demonstrates that the safety-related function of the component is not compromised.

The mechanical equipment is considered qualified if subcomponents important to the safety function are acceptable.

Nonmetallic subcomponents not meeting the criteria must have a replacement interval specified to maintain the qualification of the affected equipment. The replacement interval is determined by analysis and documented.

3D.6.2.3.8 Equipment Qualification Maintenance Requirements

The maintenance requirements resulting from the activities described herein are identified. The qualification maintenance requirements are based on the following:

- Qualification evaluation results (for example, periodic replacement of age-susceptible parts before the end of their qualified lives)
- Equipment qualification-related maintenance activities derived from the qualification report(s)
- Vendor recommended equipment qualification maintenance. Vendor recommended maintenance is included if it is required in order to maintain qualification.

3D.6.2.3.9 Qualification Documentation

The qualification of the mechanical equipment to the postulated environments is documented in an auditable form. See Section 3D.7.

3D.6.3 Operating Experience

Qualification by experience is not employed in the AP1000 equipment qualification program as a method of qualification.

3D.6.4 On-Going Qualification

The AP1000 equipment qualification program may employ on-going qualification through special maintenance and surveillance activities. However, this method of qualification is not suitable as a sole means for qualifying equipment for design basis event conditions. On-going qualification, as a method, is used exclusively for safety-related equipment located in a mild environment area. Such use requires supplementary test, or analysis to address equipment operability and performance during and after a seismic design basis event.

Documentation requirements for qualification that includes on-going qualification as a method are developed to conform with NRC guidance provided in Regulatory Guide 1.33, Revision 2.

3D.6.5 Combinations of Methods

Qualification by a combination of the preceding methods may be used under the AP1000 equipment qualification program.

3D.6.5.1 Use of Existing Qualification Reports

Pre-existing qualification programs and documents are used only if the seismic test program satisfies the guidelines of IEEE 344-1987 and the environmental qualification program satisfies the guidelines of IEEE 323-1974.

Qualification test and analysis reports conforming to those IEEE Standards, but not specifically performed to the AP1000 equipment qualification program parameters, may be acceptable as qualification bases. In such cases, supplementary qualification efforts described in Subsections 3D.6.2, 3D.6.3, and 3D.6.4 of this appendix may be required to validate acceptability under the AP1000 equipment qualification program. Justifications are documented as analyses, and appear in equipment qualification data package, Section 4. (See Attachment A.)

3D.6.5.1.1 Aging

Past qualification tests may provide sufficient basis to preclude new aging simulation testing as part of the AP1000 program. Also, simulation of both electrical and mechanical operational cycling may be waived where existing data demonstrates equipment durability greatly in the excess of the estimated number of operating cycles for Class 1E service. Application of past qualification and other tests is considered in the development of test plans and analysis procedures. The bases and justification is provided in qualification documentation for cases where applicable aging parameters are omitted from the test sequence.

3D.6.5.1.2 Seismic

Seismic qualification generally relies on analyses and justification to verify the adequacy or applicability of generic testing to a particular installed configuration of similar equipment. Analytical methods and documentation guidelines of IEEE 344-1987, as supplemented by Regulatory Guide 1.100, Revision 2, address these needs. Attachment E of this appendix provides the AP1000 equipment qualification program requirements regarding seismic qualification.

3D.6.5.1.3 High-Energy Line Break Conditions

Typically, existing qualification tests address conditions of high-energy line break environments occurring inside containment. These are used where it is demonstrated that the qualification envelops the applicable requirements.

3D.7 Documentation

The AP1000 equipment qualification program documentation consists principally of four types of documents:

- "Methodology for Qualifying AP1000 Safety-Related Electrical and Mechanical Equipment" is the generic program "parent" document. It describes the methods and practices employed in the AP1000 equipment qualification program.

- Equipment qualification data packages are "daughter" documents to the methodology. Each is a summary of the qualification program for a specific equipment type (for example, a particular model or design series of a manufacturer, an as-provided system, or a family of equipment tested as a set). The equipment qualification data package defines the qualification program objectives, methods, applicable equipment performance specifications, and the qualification plan. It provides a summary of the results. Other engineering tests that are outside the scope of 10 CFR 50.49, such as Electromagnetic Compatibility (EMC) testing and ASME QME-1 qualification testing of power-operated active valves, may be included in the EQDPs for convenience, but are not addressed further in this Appendix.

- Equipment Qualification Summary Reports (EQSRs) are the reports that present specific methods used during the qualification process and the results of that process.

- Seismic analysis reports for seismic Category I and Category II mechanical equipment that is qualified by analysis only are not required to be documented in the EQDP format. Environmental qualification of this equipment is not required due to non-existence of age-sensitive components as identified in Table 3D.6-1. The seismic qualification documentation is required to meet the documentation requirements of IEEE-344-1987 or applicable industry standard, which is the basis of qualification (i.e., ASME Section III). The seismic analysis documentation should include the purpose of the analysis, general equipment description, equipment mounting and interface requirements, analysis methods and codes, acceptance criteria, seismic loading conditions, assumptions, and conclusions.

The equipment qualification data packages are developed separate from the parent document. Similarly, the equipment qualification summary reports are developed separate from the equipment qualification data packages. Equipment qualification summary reports used in the AP1000 equipment qualification program may include existing reports of testing or analysis that comply with the relevant aspects of this methodology. Information necessary to demonstrate the equipment's capability to perform its intended safety-related function(s) while exposed to normal, abnormal, accident, and post-accident environments is provided in or referenced by the equipment qualification data package. If maintenance, refurbishment, or replacement of the equipment is necessary to provide confidence in the equipment's capability to perform its safety function, this information is also included in the equipment qualification data package. Data, in raw form, cited in the equipment qualification data packages or equipment qualification summary reports is available for audit for the life of the plant.

3D.7.1 Equipment Qualification Data Package

Attachment A contains a general example of the equipment qualification data package format. To the extent practical, each equipment qualification data package consists of the following elements:

Section 1 – Specifications
Section 2 – Qualification Program
Section 3 – Qualification by Test
Section 4 – Qualification by Analysis
Section 5 – Qualification Program Conclusions

Some organization and numbering differences are adopted where appropriate to accommodate the unique attributes of the equipment and the specific qualification requirements and methods to demonstrate the objective of the qualification program. The following paragraphs discuss the general content contained in the equipment qualification data packages.

3D.7.2 Specifications

Section 1 of Attachment A contains the performance specification of the equipment. This specification establishes the necessary parameters for which qualification is demonstrated. The basic criterion for qualification is that the safety-related functional requirements defined in Section 1 are successfully demonstrated, with margin, under the specified environmental conditions.

The following sections define the bases on which the parameters contained in Section 1 are selected.

3D.7.2.1 Equipment Identification

Equipment is identified in Section 1.1 of Attachment A by manufacturer, model or model series, and reference to other documents describing or depicting its construction, configuration, and modifications that are uniquely necessary after manufacture to its application in the AP1000 plant design. Model series (for example, a limit switch design family) and other pertinent details on items making up the equipment type qualified are compiled as a table and referenced from this section.

3D.7.2.2 Installation Requirements

So that the qualification represents the in-plant condition, the method of installation, as specified in Section 1.2 of Attachment A, is in accordance with the supplier's installation instructions. Differences unique to safety-related applications in the AP1000 design are included, with appropriate reference to drawings, technical manual supplements, or mandatory modification packages.

3D.7.2.3 Electrical Requirements

The pertinent electrical requirements are specified (for example, voltage, frequency, load) in this section. Also included is any variation in the defined parameters for which the equipment is to perform its specified functions (Section 1.3 of Attachment A).

3D.7.2.4 Auxiliary Devices

Sometimes the equipment qualified relies upon the operation of auxiliary devices in order to perform the specified safety-related functions. These devices are identified in Section 1.4 of Attachment A. Auxiliary devices include items such as electrical conductor seal assemblies that, in service, become part of the qualified equipment's pressure boundary. The applicable equipment qualification data package for the auxiliary device(s) is specified, if known.

3D.7.2.5 Preventive Maintenance

Preventive maintenance (Section 1.5 of Attachment A) to be performed includes maintenance or periodic activities assumed as part of the qualification program or necessary to support qualification. Only those activities that are required in order to support qualification or the qualified life are specified. The manufacturer's recommended maintenance activities are considered to determine that there is no adverse impact to qualification or the maintenance of qualified life. Likewise, manufacturer's recommendations for maintenance, replacement, or surveillance activities necessary to support operability are identified, or reference is made to the appropriate technical manual or supplements.

"None" means that maintenance is not essential to qualification or the qualified life of the equipment. However, this should not preclude development of a preventive maintenance program designed to enhance equipment performance and to identify unanticipated equipment degradation as long as such a program does not compromise the qualification status of the equipment. Surveillance activities may also be considered to support a basis for and a possible extension of the qualified life.

3D.7.2.6 Safety Functions

Section 1.6 of Attachment A addresses the known safety functions of the equipment, including summarizing the basis for the aspects of the safety functions that are relevant to demonstrating the equipment's qualification. This section should address the plant conditions under which the safety function is performed, the transients or accidents required for equipment performance, a characterization of the equipment function (e.g., how the safety function is performed, whether the equipment performs an active or passive function, etc.), and other information relevant to the qualification, as applicable.

3D.7.2.7 Performance Requirements

Section 1.7 of Attachment A contains a tabulation of performance requirements for each safety-related function for which the equipment is qualified. Several such sections or tables may be necessary when the equipment is qualified for applications where the performance requirements vary. Performance requirements are stated regarding the normal and abnormal environmental conditions applicable at the location where the equipment is installed. Similarly, each design basis event and the subsequent post-event period is included in the table.

Margin is not included in the performance requirements except by conservatism in their determination.

3D.7.2.8 Environmental Conditions

Within each set of performance requirements, a set of environmental parameters is specified in Section 1.8 of Attachment A, also in tabular form. Parameters are based on the equipment location and function and include those addressed in other sections of this appendix.

Margin is not included in the environmental parameters except by conservatism in their determination. The objective is to provide the baseline reference onto which margin is added.

3D.7.3 Qualification Program

An overview of the qualification program and its objective is presented in narrative form in Section 2. Attachment A includes a table to be completed as a graphic reference. As it is assumed that tests, analyses, or some combination of the two are the principal methods of qualification, columns are included for each. Other methods, when used, are summarized in brief notes appended to the table.

References to reports of testing, analysis, or other information considered in support of the qualification program are compiled in Section 2 of Attachment A. This includes any technical manuals, drawings, and supporting material cited or referenced by text throughout the equipment qualification data package.

3D.7.4 Qualification by Test

Qualification by test is selected as the primary method of qualification for complex equipment not readily amenable to analysis or for equipment required to perform a safety-related function in a high-energy line break environment. The proposed test plan is identified in Section 3 of Attachment A.

Where supportive analysis is claimed as an integral part of the qualification program, cross reference is provided to Attachment A, Section 4 for those aspects of the qualification not covered by the test plan. The following sections establish the basis on which the information specified in Section 3 is selected.

3D.7.4.1 Specimen Description

The equipment qualified is identified, including the baseline design document number/reference, where applicable, the equipment type, manufacturer and model number, in Section 3.1 of Attachment A. When testing a model series (or equipment families), the representative items tested are clearly identified. The basis of their representation should be included.

Section 3.1 is primarily intended to identify test specimens used in a test supporting the qualification program. But it also discusses the specimens considered for other methods used in the qualification program.

3D.7.4.2 Number Tested

The test program is based upon selectively testing a representative number of components according to type, size, or other appropriate classification, on a prototype basis. The number of items of equipment representative of the equipment type that are tested is defined in Section 3.2 of Attachment A.

3D.7.4.3 Mounting

The method of mounting the equipment for the test is identified in Section 3.3 of Attachment A. The in-plant installation requirements, as specified by the supplier under Section 1.2 of Attachment A, are fully represented.

3D.7.4.4 Connections

The equipment connections necessary to demonstrate safety-related functional operability during testing are identified in Section 3.4 of Attachment A. This includes items that are part of the installed configuration, but are not part of the test apparatus.

Particularly important are items that are included by "practice of good workmanship," such as pipe thread sealant. Another example is the use of electrical connection sealing materials. Where these items are included in the testing, they become factors in the performance of the equipment, especially under aggressive or adverse environmental conditions. Their thermal degradation and sensitivity to irradiation and chemistry environments are considered in the qualification program, both for impact to equipment performance under harsh conditions and for their contribution to equipment qualified life.

3D.7.4.5 Test Sequence

The preferred test sequence specified in Attachment A, Section 3.5 is the one recommended by IEEE 323-1974. The qualification test sequence used is specified in Section 3.6 of Attachment A. Justification for departures or additions to the preferred test sequence are included. Also, any portion of the test sequence that is supplemented by analysis or other methods is identified for completeness.

3D.7.4.6 Simulated Service Conditions

The service conditions simulated by the test plan are identified in Attachment A, Section 3.7. In general, the parameters employed are selected to be equal to (normal and abnormal) or have margin (accident and post-accident) with respect to the specified service conditions of Attachment A, Section 1.8. Criteria for margin is detailed in Subsection 3D.4.8.

3D.7.4.7 Measured Variables

The parameters measured during the specified test sequence in order to demonstrate qualification for the performance specification (Attachment A, Section 1) are individually listed in Section 3.8 of Attachment A. This section is formatted to include parameters relevant to the test environment and the electrical and mechanical characteristics of equipment operation. Other characteristics unique to a particular test or equipment type are included, when applicable.

3D.7.4.8 Type Test Summary

Section 3.9 of Attachment A provides a narrative summary of the qualification tests and results. The applicable test reports are provided as references in Attachment A, Section 2. Test data is available for audit throughout the operation of the plant.

Each test report referenced by the equipment qualification data package should contain information cited in the preceding section, as well as the following:

- The test facility, location, and a description of the test equipment used. Monitoring equipment should have current calibration traceable to the National Institute of Standards and Technology (NIST).
- Test setup and specimen installation details.
- Description of the mounting conditions simulated during the test program and any difference between them and the mounting details shown on the equipment drawings, with qualification of any differences found.
- Description of limitations on the use and mounting of the qualified equipment found as a result of the qualification test program.
- Description of the test method and the justification that the method meets the specification test requirements.
- Description of operational settings used to demonstrate functional operability and any limitation imposed on them.
- Test records (for example, test response spectra, time history; accident transient parameters - temperature, pressure). This includes performance and operability test results, inspection results, and the monitored test and specimen and calibration records of instruments used.
- Record of compliance of test results with the seismic qualification criteria.
- Description of anomalies found during the test program, and their resolution(s).

Potential aging mechanisms resulting from significant in-service thermal, electrical, mechanical, radiation, and vibration sources are identified in Section 3.9 of Attachment A. When aging is

addressed as part of the test sequence, the method employed for aging the equipment is indicated and is chosen to conservatively simulate the potential aging effects resulting from the operating cycles and environmental conditions specified in Attachment A, Section 1. The methods employed to address each of the potential aging mechanisms are discussed.

3D.7.5 Qualification by Analysis

Qualification by this methodology does not rely solely on analyses. Generally, analysis is permitted to support qualification testing or to establish that testing of other sufficiently similar equipment can be cited to establish or extend the qualification of equipment covered by the equipment qualification data package.

Section 4 of Attachment A is formatted to conform with the recommendations of IEEE 323-1974. Each subsection addresses a particular analysis if more than one is performed to support qualification. Not all subsections identified in the sample format apply to any particular analysis. Documentation of analyses demonstrating or supporting seismic qualification conforms with the guidelines of Attachment E and the recommendations of IEEE 344-1987.

3D.7.6 Qualification by Experience

This method of qualification is not used.

3D.7.7 Qualification Program Conclusions

Section 5 of Attachment A summarizes the conclusions of the qualification program, including and addressing methods employed and conditions upon which qualification of the equipment is based. Details regarding each aspect of simulated aging are addressed distinctly, with conclusions as to the life-limiting aspects clearly stated.

Conclusions for each design basis event are summarized. Generally, these are combined as either design basis event seismic and design basis event environmental.

3D.7.8 Combined License Information

Not used.

3D.8 References

1. IEEE-323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations."

2. IEEE-344-1987, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

3. IEEE-627-1980, "IEEE Standard for Design Qualification of Safety System Equipment Used in Nuclear Power Generating Stations."

4. NUREG/CR-3156, "A Survey of the State-of-the-Art in Aging of Electronics with Application to Nuclear Plant Instrumentation."

5. EPRI NP-1558, Project 890-1, "A Review of Equipment Aging Theory and Technology."

6. NUREG/CR 2156, "Radiation Thermal Degradation of PE and PVC: Mechanism of Synergism and Dose Rate Effects," Clough and Gillen, June 1981.

7. NUREG/CR 2157, "Occurrence and Implication of Radiation Dose Rate Effects for Material Aging Studies," Clough and Gillen, June 1981.

8. NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants – Final Report," L. Soffer, et al., February 1995.

9. Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” July 2000.

Note: See Subsection 3D.4.1.1 for other IEEE references.

Table 3D.4-1
Typical Mild Environment Parameter Limits

Parameter	Limit	Notes
Temperature	≤ 120°F	
Pressure	Atmospheric	(Nominal)
Humidity	30 – 65% ≤ 95%	(Typical) (Abnormal)
Radiation	≤ 10^4 rads gamma ≤ 10^3 rads gamma	 (IC electronics and microprocessors)
Chemistry	None	
Submergence	None	

Table 3D.4-2
Equipment Post-Accident Operability Times

Equipment	Required Post-Accident Operability	
Equipment necessary to perform trip functions	5 minutes	(Envelops trip time requirements)
Equipment located outside containment, is accessible, and can be repaired, replaced, or recalibrated	2 weeks	
Equipment located inside containment that is inaccessible and is required for post-accident monitoring	4 months	(This number is based on an acceptable amount of time to be repaired, replaced, or recalibrated, or for an equivalent indication to be obtained.)
Equipment located inside containment, is inaccessible, or cannot be repaired, replaced, recalibrated or equivalent indication cannot be obtained	1 year	(The required post-accident operability time during submergence may be shorter if the consequences of equipment failure after submergence are deemed acceptable and/or the monitored component is administratively controlled.)
Equipment in a location that will have a mild environment following an accident or equipment that does not provide information for a Type A, B, or C primary post-accident monitoring parameter	Various	(Specific as to function, maximum of 1 year)

Table 3D.4-3
AP1000 EQ Program Margin Requirements

Condition	Parameter	Required Margin	Notes
NORMAL:	Aging	+10%	+10% time margin, +10% radiation and/or selection of conservative test parameters. Comply with guidance of Subsection 3D.4.8.2
ABNORMAL:	Temperature/ Humidity		Margin is in "time" at abnormal test extremes.
	Pressure	None	Nominally atmospheric.
	Radiation	+10%	Include in aging doses, if applicable.
	Voltage & Frequency	+/- 10%	Simulated during temperature/humidity test.
ACCIDENT:	Transient Temperature and Pressure		Temperature (+15°F) and pressure (+10 psig peak) margins added to transient profile.
	Chemical effects	+10%	Bounding concentration of chemical additives +10%. Containment sump chemistry conditions reflect change over time from acidic to alkaline. (See Subsection 3D.4.8.5)
	Radiation	+10%	Added to calculated total integrated dose.
	Submergence	Note 1	Generally, precluded by design.
	Seismic/ Vibration	+10%	Of acceleration at equipment mounting point for either SSE or line-mounted equipment vibration. (See Subsection 3D.4.8.4.)
	Post-accident Aging	+10%	In time demonstrated via Arrhenius time/temperature relationship calculation.

Note:
1. Margin in submergence conditions is achieved by increases in temperature (+15°F), pressure (+10%), and chemistry.

Table 3D.5-1 (Sheet 1 of 3)
Normal Operating Environments

(Notes 1 and 2)

Location/Parameter	Normal Range	Notes
Zone 1 – Containment (Room numbers: 11000 through 11999)		
Temperature	50 - 120°F (All rooms except 11105 and 11205) 50 - 135°F (Rooms 11105 and 11205)	
Pressure	-0.2 - +1.0 psig	
Humidity	0 - 100%	
Radiation	see Table 3D.5-2	
Chemistry	None	
Zone 2 - Auxiliary Building - Non-Radiological - I&C, DC Equipment, RCP Switchgear & Battery rooms, etc. (Room numbers: 12101, 12102, 12103, 12104, 12105, 12111, 12112, 12113, 12201, 12202, 12203, 12204, 12205, 12207, 12211, 12212, 12213, 12300, 12301, 12302, 12303, 12304, 12305, 12311, 12312, 12313, 12405, 12411, 12412, 12501, Stairwell S05, and 12505)		
Temperature	67 - 77°F (All rooms except 12405, 12501, and 12505) 50 - 85°F (Rooms 12405, 12501, Stairwell S05, and 12505)	
Pressure	Slightly positive to slightly negative	
Humidity	10 - 60%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	
Zone 3 - Auxiliary Building - Non-Radiological - Main Control Room (Room number: 12400, 12401)		
Temperature	67 - 78°F	
Pressure	Slightly positive	
Humidity	25 - 60%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	
Zone 4 - Auxiliary Building - Non-Radiological - Accessible (Room numbers: 12321, 12421, 12422, 12423)		
Temperature	50 - 85°F (Rooms 12321, 12421) 50 - 105°F (Rooms 12422, 12423)	
Pressure	Slightly positive	
Humidity	10 - 60%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	

Table 3D.5-1 (Sheet 2 of 3)
Normal Operating Environments

(Notes 1 and 2)

Location/Parameter	Normal Range	Notes
Zone 5 - Auxiliary Building - Non-Radiological - MSIV Compartments (Room numbers: 12404, 12406, 12504, 12506)		
Temperature	50 - 130°F	
Pressure	Atmospheric	
Humidity	10 - 100%	
Radiation	$<10^4$ rads gamma	
Chemistry	None	
Zone 6 - Auxiliary Building - Radiological - Inaccessible (Room numbers: 12154, 12158, 12162, 12163, 12166, 12167, 12171, 12172, 12254, 12255, 12256, 12258, 12262, 12264, 12265, 12354, 12362, 12363, 12365, 12371, 12372, 12373, 12374, 12454, 12462, 12463)		
Temperature	50 - 130°F	
Pressure	Slightly negative to atmospheric	
Humidity	10 - 100%	
Radiation	See Table 3D.5-2	
Chemistry	None	
Zone 7 - Auxiliary Building - Radiological - Accessible (Room numbers: 12151, 12152, 12153, 12155, 12156, 12161, 12168, 12169, 12241, 12242, 12244, 12251, 12252, 12261, 12268, 12271, 12272, 12273, 12274, 12275, 12341, 12343, 12344, 12345, 12351, 12352, 12361, 12451, 12452, 12461, 12553, 12554, 12555, 12556, 12561, 12651)		
Temperature	50 - 104°F (All rooms except 12555) 60 - 80°F (Room 12555)	
Pressure	Slightly negative	
Humidity	10 - 100%	
Radiation	See Table 3D.5-2	
Chemistry	None	
Zone 8 - Turbine Building (Room numbers: 20300 through 20799)		
Temperature	50 - 105°F	
Pressure	Atmospheric	
Humidity	10 - 100%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	

Table 3D.5-1 (Sheet 3 of 3)
Normal Operating Environments

(Notes 1 and 2)

Location/Parameter	Normal Range	Notes
Zone 9 - Auxiliary Building - PCS Valve Room and Upper Annulus		
(Room number: 12541, 12701)		
Temperature	70 - 120°F (Room 12701) -40 - 115°F (Room 12541)	
Pressure	Atmospheric	
Humidity	10 - 100%	
Radiation	See Table 3D.5-2	
Chemistry	None	
Zone 10 - Auxiliary Building - Non-Radiological - Valve/Piping Penetration Room with SG Blowdown		
(Room number: 12306)		
Temperature	50 - 105°F	
Pressure	Slightly positive	
Humidity	10 - 60%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	
Zone 11 - Auxiliary Building - Radiological - Fuel Handling Area		
(Room numbers: 12472, 12562, 12563, 12564)		
Temperature	50 - 105°F	
Pressure	Slightly negative	
Humidity	10 - 100%	
Radiation	See Table 3D.5-2	
Chemistry	None	

Notes:

1. Room numbers - see Section 1.2, General Arrangement drawings.
2. Relative humidity is not controlled except in the main control room.

Table 3D.5-2
60-Year Normal Operating Doses

Location	Gamma Dose Rate (Rad air hour)	60-Year Gamma Dose (Rads air)
Inside Containment:		
RCS Pipe - Center	1.9×10^{3}	1.0×10^{9}
RCS Pipe - ID	1.1×10^{3}	5.7×10^{8}
RCS Pipe - OD (contact)	7.8×10^{1}	4.1×10^{7}
RCS Pipe - General Area(b)	4.0×10^{1}	2.1×10^{7}
Outside CA01 Excluding Rooms 11104 and 11204	<0.45	$<2.4 \times 10^{5}$
Adjacent to Reactor Vessel Wall	$\leq 3.6 \times 10^{4}$	$\leq 1.9 \times 10^{10}$(a)
Spent Resin and Spent Fuel Handling Areas(c)	--	$<1 \times 10^{9}$
IRWST	4.2×10^{1}	2.2×10^{7}
Outside Containment:		
Penetration Area	--	$<2 \times 10^{7}$
Pump Cubicles	--	$<2 \times 10^{7}$
Radioactive Waste Area	--	$<2 \times 10^{7}$
Radwaste Tank Cubicles	--	$<5 \times 10^{7}$
Other General Areas Not Under Radiation Control	--	$<1 \times 10^{4}$
Spent Resin and Spent Fuel Handling Areas(c)	--	$<1 \times 10^{9}$

Notes:

a. 60-year neutron fluence for E>1 MeV is 4.6×10^{18} n/cm^2

b. 12 inches from RCS pipe OD

c. Total gamma dose outside of tanks

Table 3D.5-3
Abnormal Operating Environments
Inside Containment

Conditions/Parameter	Abnormal Extreme	Duration	Notes
Group 1 (150°F) Abnormal Events			
Temperature	150°F	4 hours	Note 1
Pressure	2 psig	4 hours	Note 1
Humidity	100%	4 hours	Note 1
Radiation	Same as normal		
Chemistry	None		
Submergence	None		
Group 2 (250°F) Abnormal Events			
Temperature	250°F	30 days	Note 1
Pressure	18 psig	30 days	Note 1
Humidity	100%	30 days	Note 1
Radiation			Note 2
Chemistry	None		
Submergence	None		

Notes:
1. Parameter value is not maximum for full duration.
2. Minor increase over normal radiation conditions expected.

Table 3D.5-4 (Sheet 1 of 3)
Abnormal Operating Environments
Outside Containment

Conditions/Parameter	Abnormal Extreme	Duration	Notes
Zone 2			
Temperature (Rooms 12101, 12102, 12103, 12104, 12105, 12202, 12204)	120°F max	7 days	Note 3
Temperature (Rooms 12113, 12201, 12203, 12205, 12207, 12212, 12301, 12302, 12303, 12304, 12305, 12312, 12313, 12411, 12412)	120°F max	7 days	Note 3
Temperature (Rooms 12111, 12112, 12211, 12213, 12300, 12311)	120°F max	7 days	
Temperature (Rooms 12405, 12501, 12505, Stairwell S05)	120°F max	7 days	
Pressure	Atmospheric		
Humidity	40 – 95%		Note 2
Radiation	Same as normal		
Chemistry/Submergence	None		
Zone 3			
Temperature	Figure 3D.5-1 (Sheet 1)	7 days	
Pressure	Atmospheric		Note 1
Humidity	5 – 95%		Note 2
Radiation	Same as normal		
Chemistry/Submergence	None		
Zone 4			
Temperature	120°F max	10x4 hrs	
Pressure	Slightly positive		
Humidity	Same as normal		
Radiation	Same as normal		
Chemistry/Submergence	None		
Zone 5			
Temperature	150°F max	10x4 hrs	
Pressure	Atmospheric		
Humidity	Same as normal		
Radiation	Same as normal		
Chemistry/Submergence	None		
Piping Rupture			Note 6
Submergence and Spray	12504, 12506 0" 12404, 12406 36"	2 weeks	Notes 5, 7, 8

Table 3D.5-4 (Sheet 2 of 3)
Abnormal Operating Environments
Outside Containment

Conditions/Parameter	Abnormal Extreme	Duration	Notes
Zone 6			
Temperature	150°F max (Room 12256) 140°F max (Other Rooms)	10x4 hrs	
Pressure	Atmospheric		
Humidity	Same as normal		
Radiation	Same as normal		
Chemistry/Submergence	None		
Pipe Rupture			Note 6
Submergence and Spray	12259 3" 12255 36" 12258 132"	2 weeks	Notes 5, 7, 8
Submergence	12262 36" 12254 60" 12158 76.5" 12154, 12162, 12163, 12171, 12172 168" 12264 249" 12265 288"	2 weeks	Notes 7, 8
Zone 7			
Temperature	200°F max (Rooms 12241, 12341, 12343, 12344, 12345) 155°F max (Room 12252) 150°F max (Rooms 12451, 12554) 130°F max (Room 12561) 114°F max (Other Rooms)	10x4 hrs	
Pressure	Slightly negative		
Humidity	Same as normal		
Radiation	Same as normal		
Chemistry/Submergence	None		
Pipe Rupture			Note 6
Submergence and Spray	12241, 12244 36"	2 weeks	Notes 5, 7, 8
Submergence	12452 30" 12242, 12251, 12252, 12261, 12271, 12272, 12273, 12274, 12275 36" 12268 54" 12168 90" 12341 93" 12151, 12153, 12155 168" 12156 12169 173.5" 12152, 12161 180"	2 weeks	Notes 7, 8

Table 3D.5-4 (Sheet 3 of 3)
Abnormal Operating Environments
Outside Containment

Conditions/Parameter	Abnormal Extreme	Duration	Notes
Zones 8			
Temperature	Same as normal		
Pressure	Same as normal		
Humidity	Same as normal		
Radiation	Same as normal		
Chemistry/Submergence	None		
Zone 9			
Temperature (Room 12701)	40 to 120°F	3 days	
Temperature (Room 12541)	-40 to 150°F		
Pressure	Same as normal		
Humidity	Same as normal		
Radiation	Same as normal		
Chemistry/Submergence	None		
Zone 10			
Temperature	140°F max	10x4 hrs	
Pressure	Same as normal		
Humidity	Same as normal		
Radiation	Same as normal		
Chemistry/Submergence	None		
Pipe Rupture			Note 6
Submergence and Spray	12306 36"	2 weeks	Notes 5, 7, 8
Zone 11			
Temperature	212°F max	7 days	
Pressure	Atmospheric		Note 4
Humidity	100%		
Radiation	Same as normal		
Chemistry/Submergence	None		

Notes:

1. Main control room air pressure is maintained above a nominal value of atmospheric during accident conditions to prevent radioactive contaminant entry.
2. Figure 3D.5-1 Sheets 1 and 2 have two curves post-72 hours. The high curve represents the introduction of outside air that is high temperature, low humidity. The low curve represents the introduction of outside air that is low temperature, high humidity. The EQ Programs will include both of these extremes.
3. Test environments resulting from rooms with equipment supplied by 24- and 72-hour batteries are shown on Figure 3D.5-1, Sheet 2, for the dc equipment rooms 12203 and 12207 and for the I&C rooms 12302 and 12304. The 24-hour battery is disconnected at 24 hours. The 72-hour battery is not disconnected. Environments resulting from rooms with equipment supplied by 24-hour batteries only, – that is, dc equipment rooms 12201 and 12205 and I&C rooms 12301 and 12305 – are enveloped by the environments shown on Figure 3D.5-1, Sheet 2. The environments shown on Figure 3D.5-1, Sheet 2 also apply to the dc equipment rooms containing batteries (i.e., the IDS battery rooms 12101, 12102, 12103, 12104, 12105, 12202 and 12204).
4. A relief panel is designed to open when the fuel handling area temperature exceeds 165°F.
5. This room may also be subjected to spray or wetting above the submergence elevation as a result of pipe ruptures.
6. Equipment in these areas is addressed using the criteria outlined in Subsection 3.11.1.2.
7. Submergence in this table is specified for various rooms, and the distances tabulated represent the bounding flood height above the floor elevation in a given zone or room.
8. Spray and submergence as applicable, based upon the methods described in Subsection 3.4.1 and Section 3.6. Equipment affected by spray or submergence required to undergo qualification is reflected in the requirements contained in Table 3.11-1.

Table 3D.5-5
Accident Environments

(See Table 3D.5-1 for environmental zones)

Zone 1 – Inside Containment	
Temperature and pressure Submergence as applicable up to elevation 110'-6"	See Figure 3D.5-8 for most locations. Other locations may use a localized equivalent of this figure.
Radiation	See Figures 3D.5-2 through 3D.5-5.
Zones 2, 4 – Outside Containment	
Temperature (Zone 2)	Maximum: Same as Abnormal. See Table 3D.5-4. Rooms 12111, 12112, 12211, 12213, 12300, 12311 Minimum: 60°F
Temperature (Zone 4)	Same as Abnormal. See Table 3D.5-4.
Pressure	Same as Abnormal. See Table 3D.5-4.
Radiation	TID 1 year ≤ 1E+04 Rads maximum.
Zones 3, 8 – Outside Containment	
Temperature and pressure	Same as Abnormal. See Table 3D.5-4.
Radiation	TID 1 year ≤ 1E+03 Rads maximum.
Zone 5 – Outside Containment – MSIV Compartments	
Temperature	See Figure 3D.5-9.
Radiation	TID 1 year ≤ 3E+05 Rads maximum. See also Figures 3D.5-4 and 3D.5-5.
Zones 6, 11 – Outside Containment	
Temperature (Zone 6)	Same as Abnormal. See Table 3D.5-4.
Temperature (Zone 11)	Maximum: Same as Abnormal. See Table 3D.5-4. Minimum: 40°F
Pressure	Same as Abnormal. See Table 3D.5-4.
Radiation	Same as Abnormal. See Table 3D.5-4.
Zone 7 – Outside Containment	
Temperature	
Rooms 12241, 12341, 12343, 12344, and 12345	200°F max
Rooms 12156, 12244	135°F max
Other Rooms	Same as Abnormal with exceptions identified below. See Table 3D.5-4. Room 12555 Minimum: 50°F Room 12151 Maximum: 120°F
Pressure	Same as Abnormal. See Table 3D.5-4.
Radiation	TID 1 year ≤ 2E+07 Rads maximum.
Zone 9 – Outside Containment	
Pressure	Same as Abnormal. See Table 3D.5-4.
Temperature	
Room 12541	-40 - 180°F
Room 12701	40 - 125°F
Radiation	TID 1 year ≤ 6E+06 Rads maximum.
Zone 10 – Outside Containment	
Temperature	See Figure 3D.5-9.
Radiation	See Figures 3D.5-4 and 3D.5-5.

Table 3D.6-1
Mechanical Equipment Components Requiring
Environmental Qualification

Component	Material Property
Gaskets	Compression set/elongation
O-rings	Compression set/elongation
Diaphragms	Elongation/tensile strength
Diaphragm support sheets	Tensile strength/elongation
Lubricant	Viscosity/penetration
Worm gear	Flexural strength

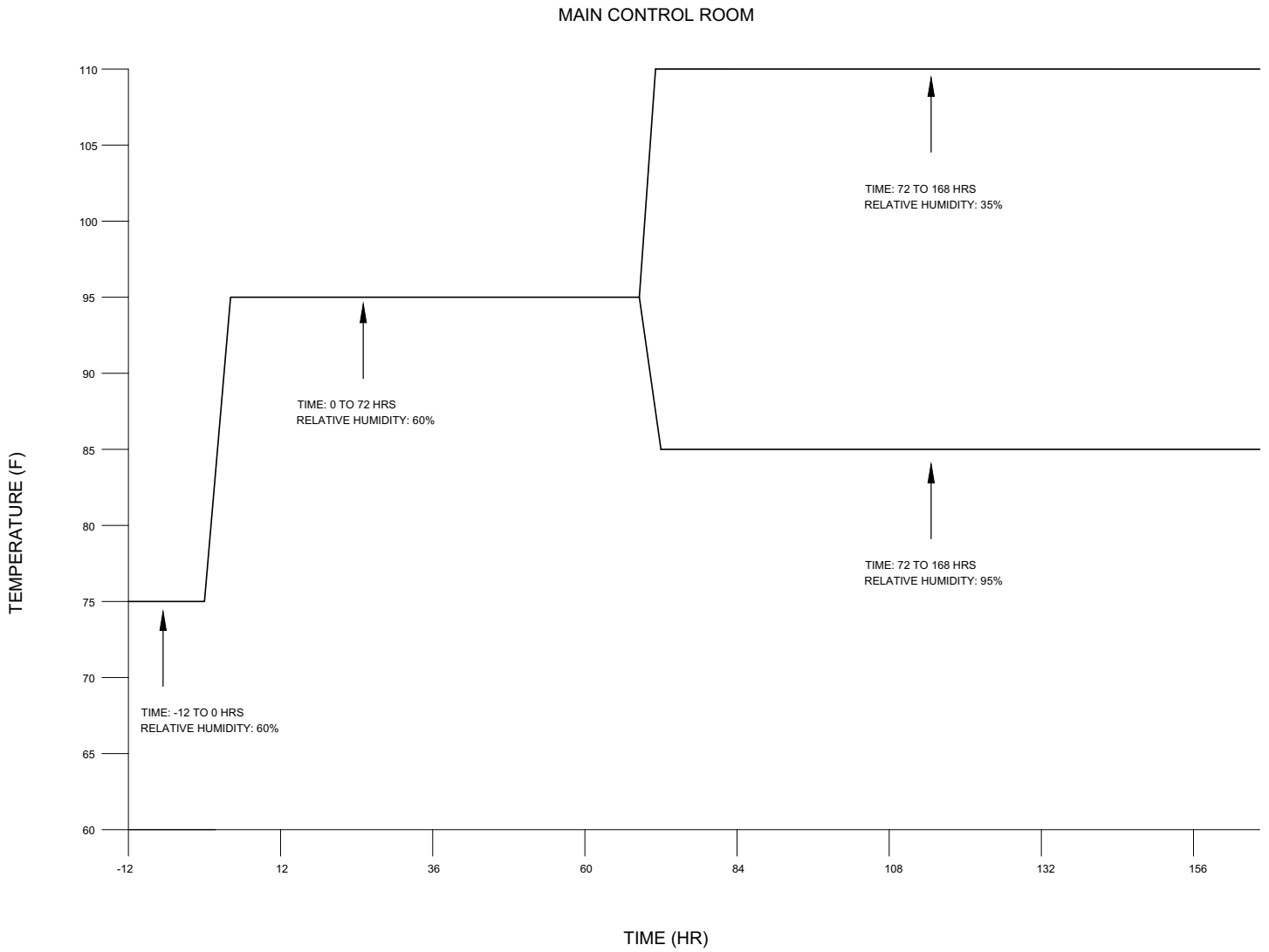

Figure 3D.5-1 (Sheet 1 of 3)
Typical Abnormal Environmental Test Profile: Main Control Room

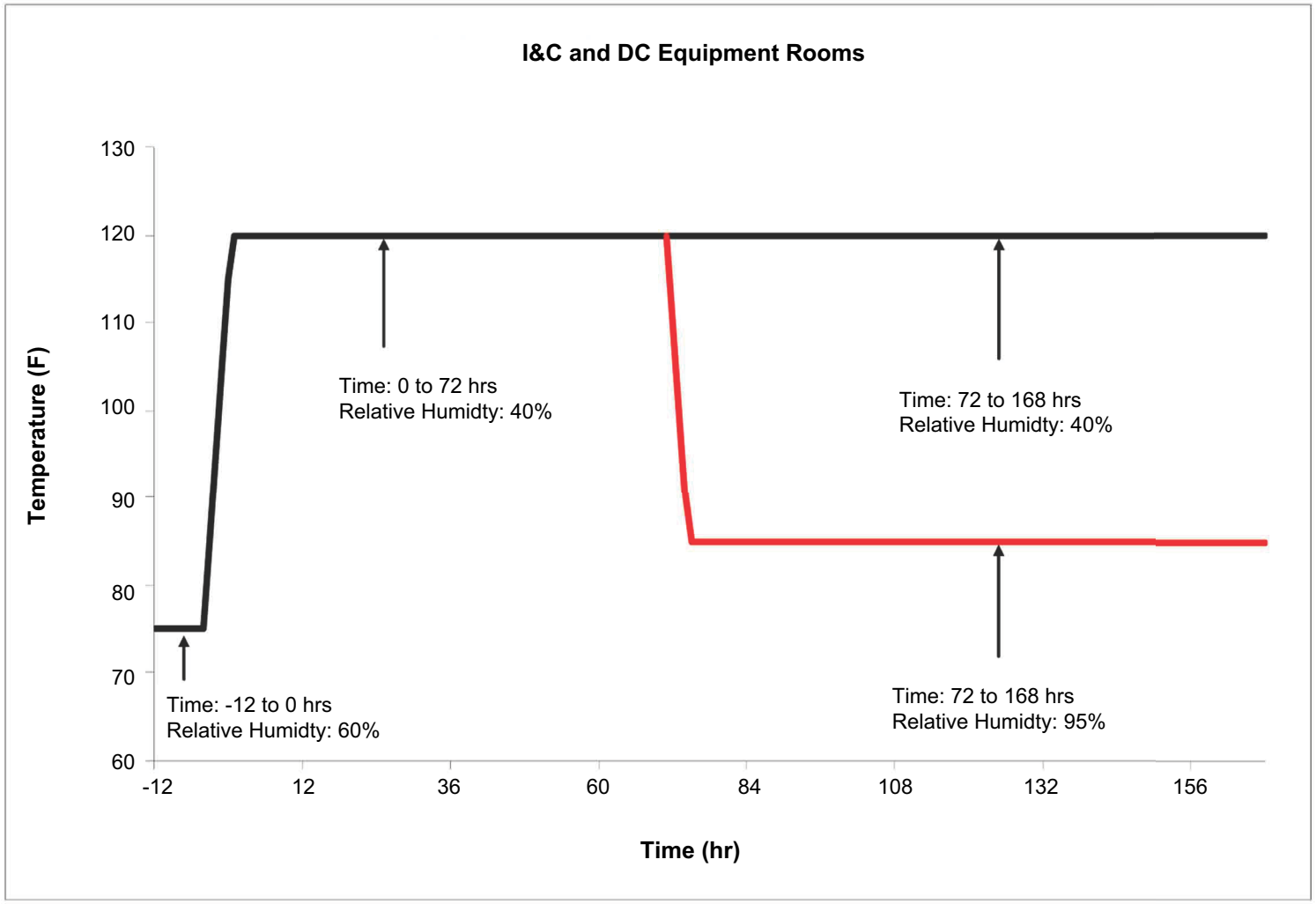

Figure 3D.5-1 (Sheet 2 of 3)
Typical Abnormal Environmental Test Profile:
I&C and DC Equipment Rooms

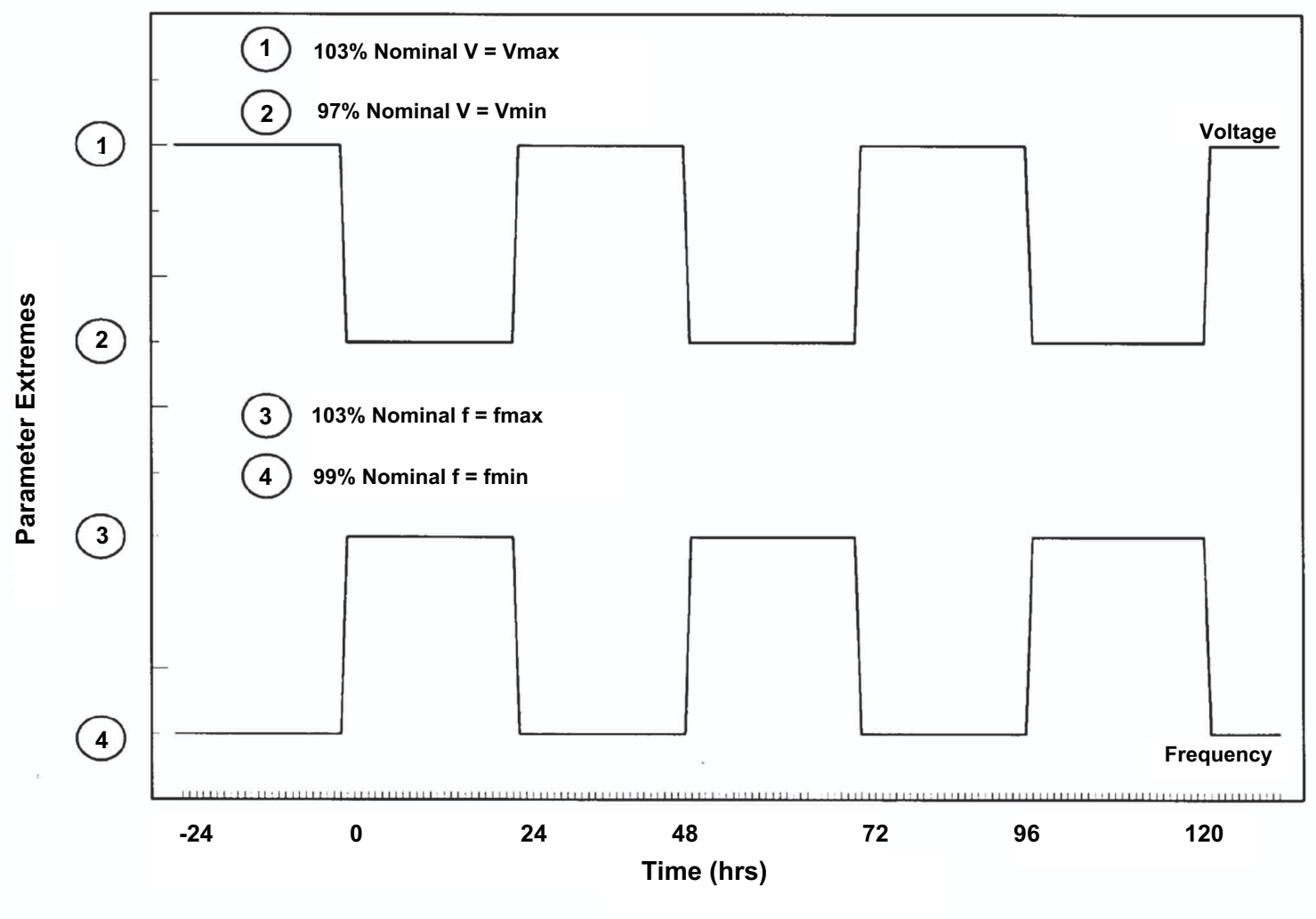

Figure 3D.5-1 (Sheet 3 of 3)
Typical Abnormal Environmental Test Profile:
Voltage and Frequency Variations

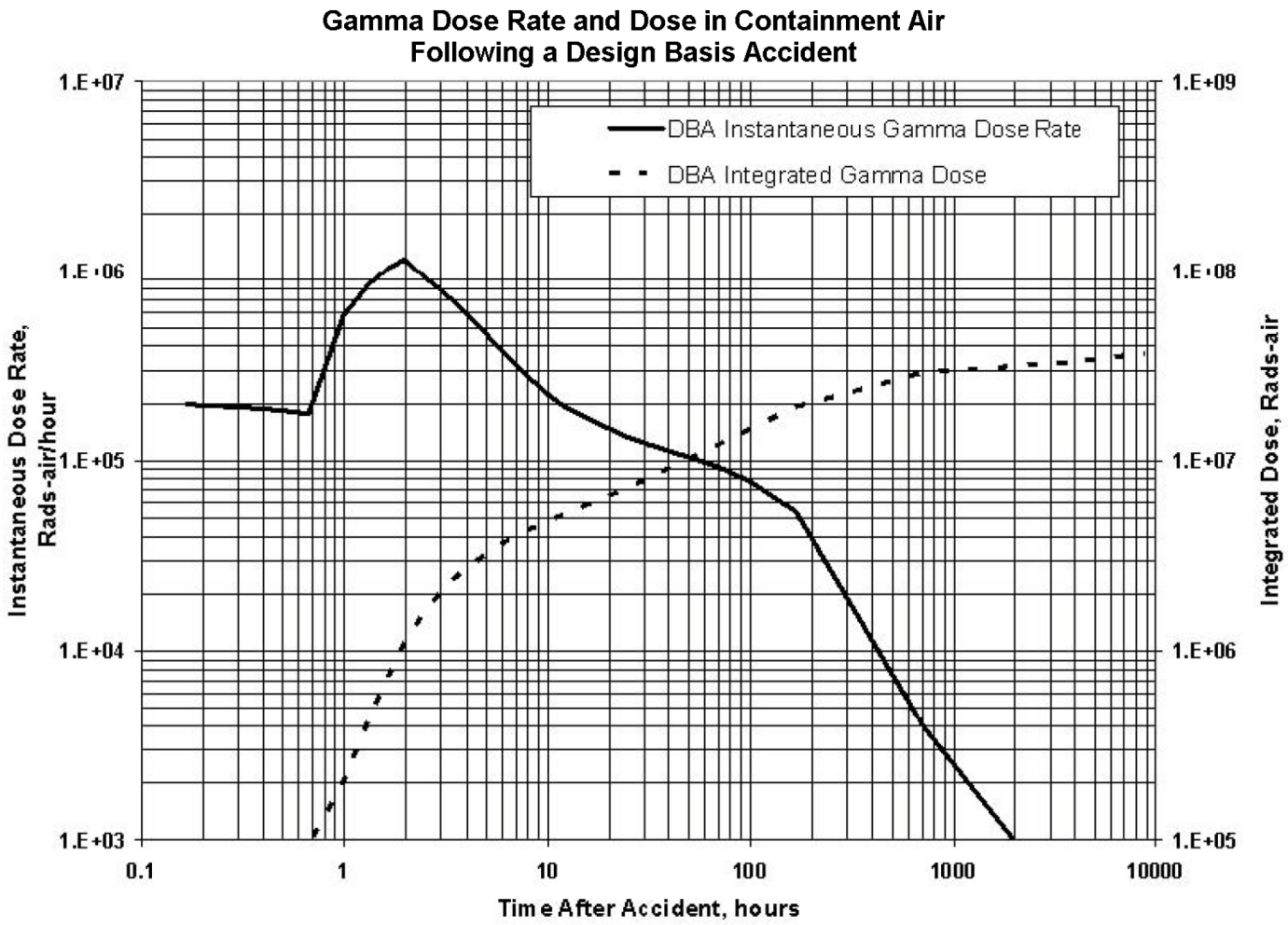

Figure 3D.5-2
Gamma Dose and Dose Rate Inside Containment After a LOCA

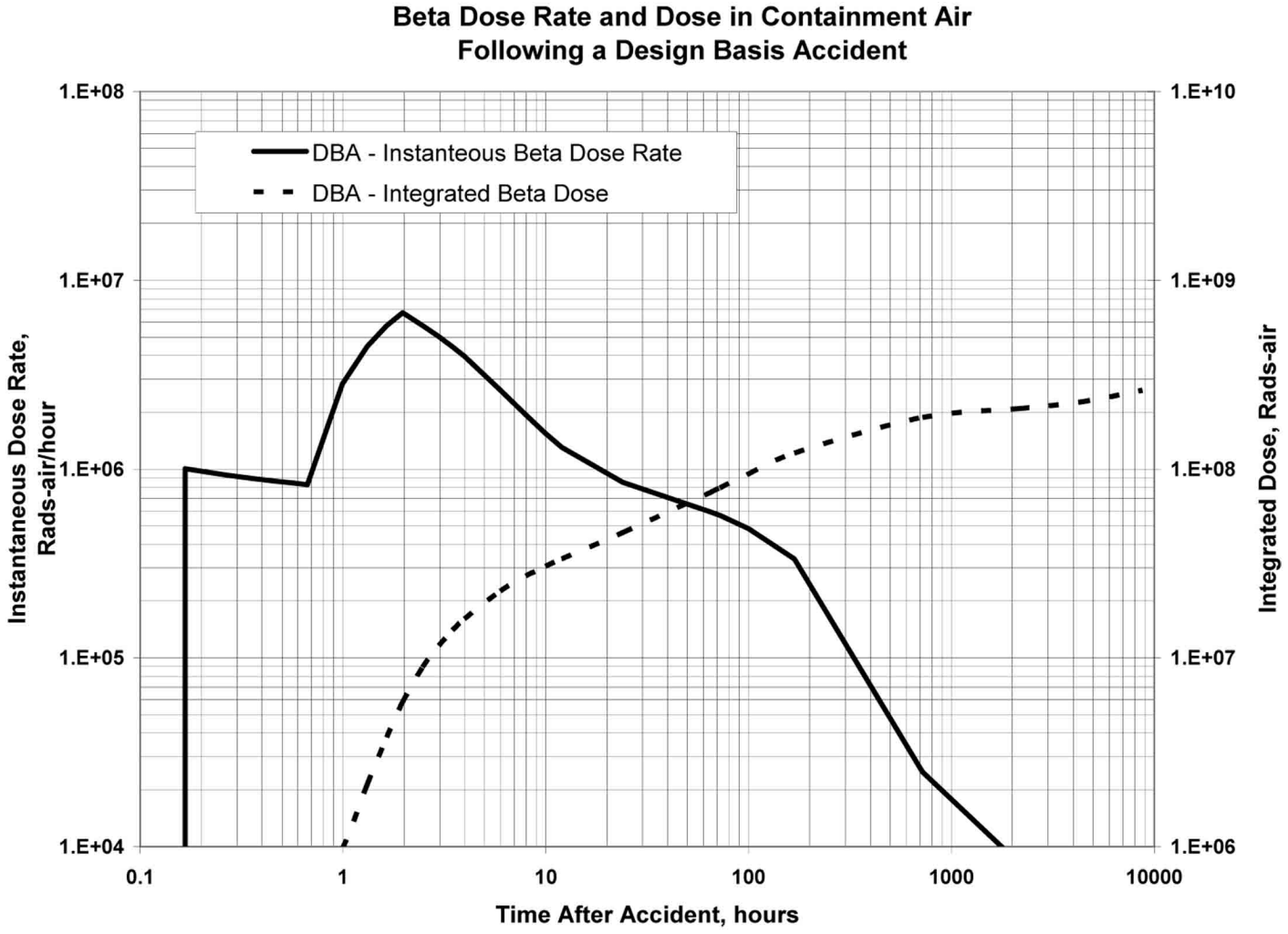

Figure 3D.5-3
Beta Dose and Dose Rate Inside Containment After a LOCA

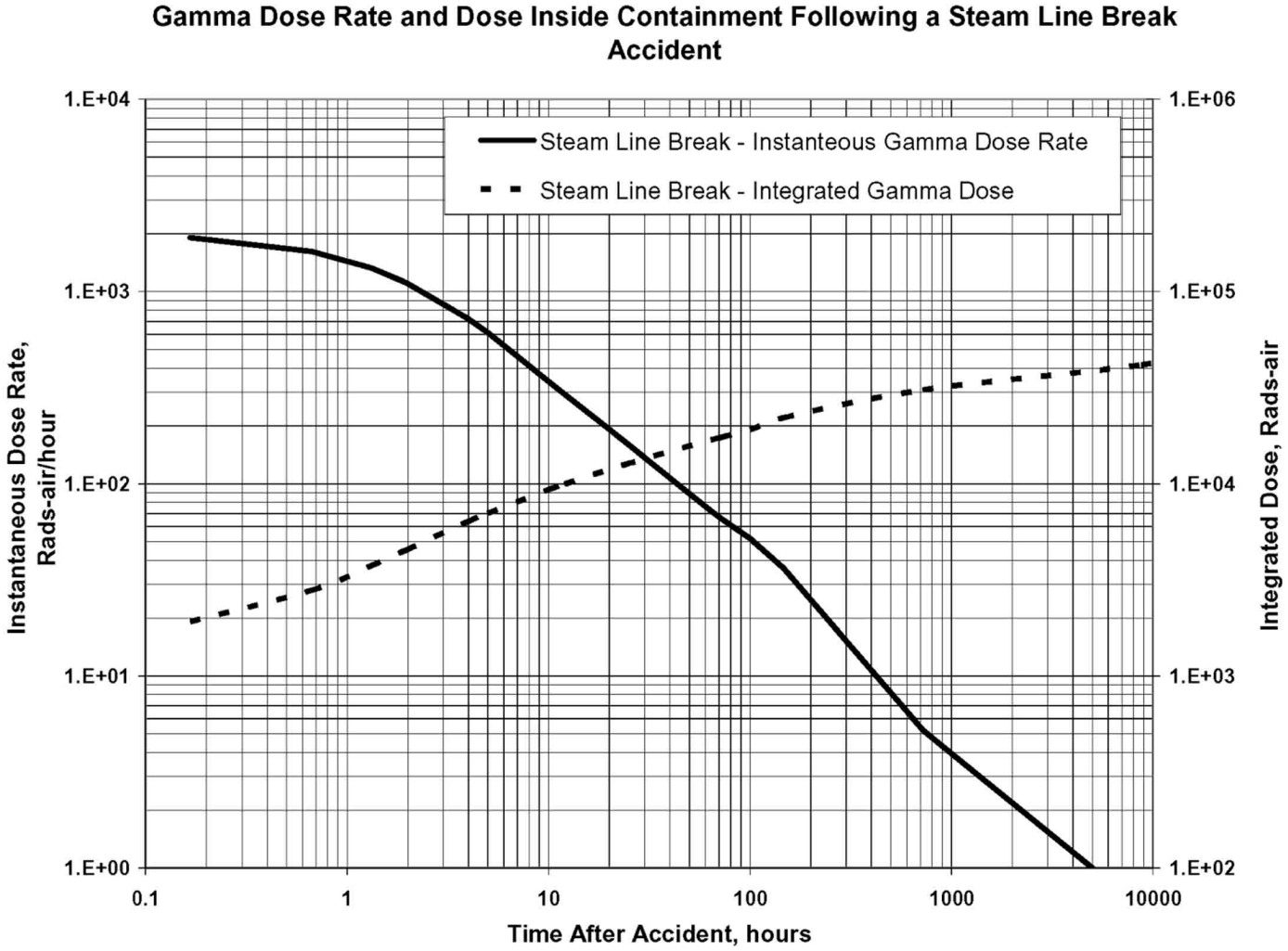

Figure 3D.5-4
Gamma Dose and Dose Rate Inside Containment After a Steam Line Break

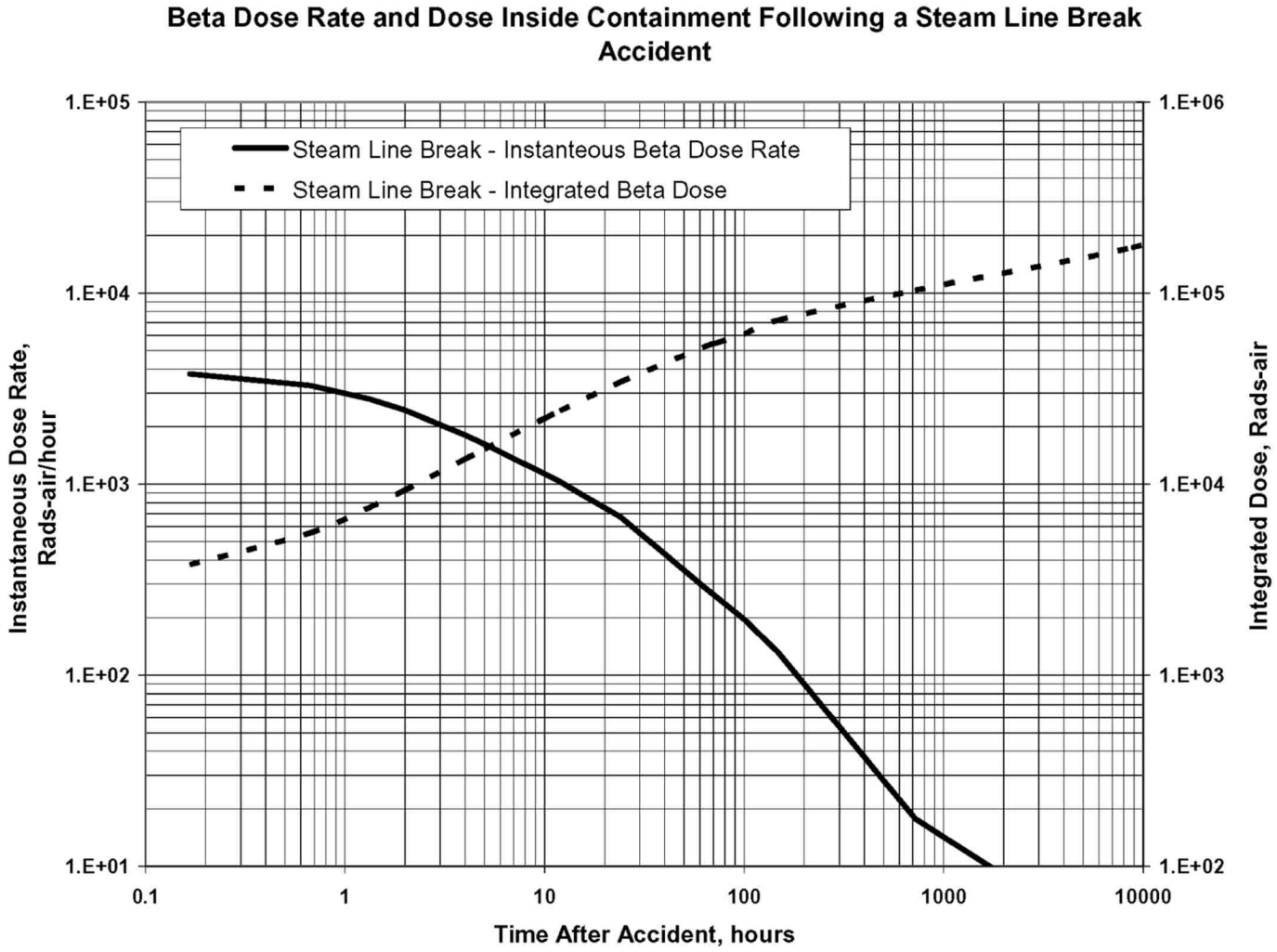

Figure 3D.5-5
Beta Dose and Dose Rate Inside Containment After a Steam Line Break

Figures 3D.5-6–3D.5-7 Not Used



Figure 3D.5-8 (Sheet 1 of 2)
Typical Combined LOCA/SLB/FLB EQ Design Envelope for Inside Containment Temperature(1)

Note:

1. Refer to Section 6.2 for detailed post-accident containment response. This figure represents only the Environmental Qualification profile, which bounds the actual containment response.

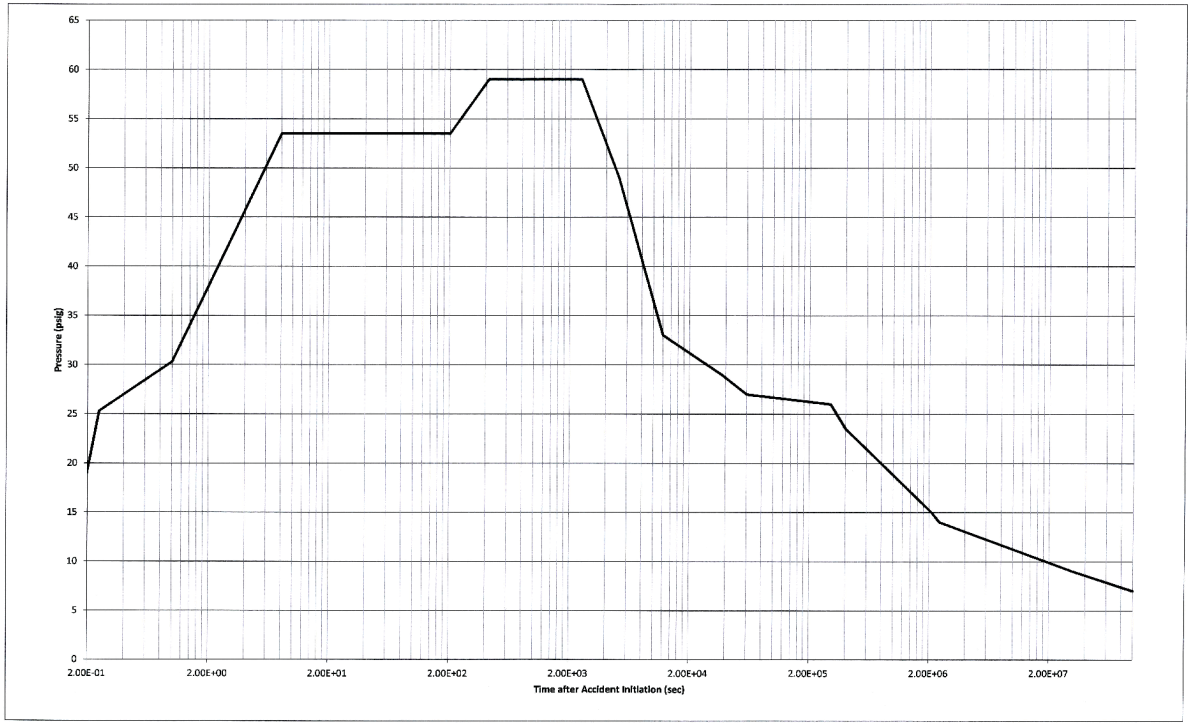

Figure 3D.5-8 (Sheet 2 of 2)
Typical Combined LOCA/SLB/FLB EQ Design Envelope for Inside Containment Pressure(1)

Note:

1. Refer to Section 6.2 for detailed post-accident containment response. This figure represents only the Environmental Qualification profile, which bounds the actual containment response.

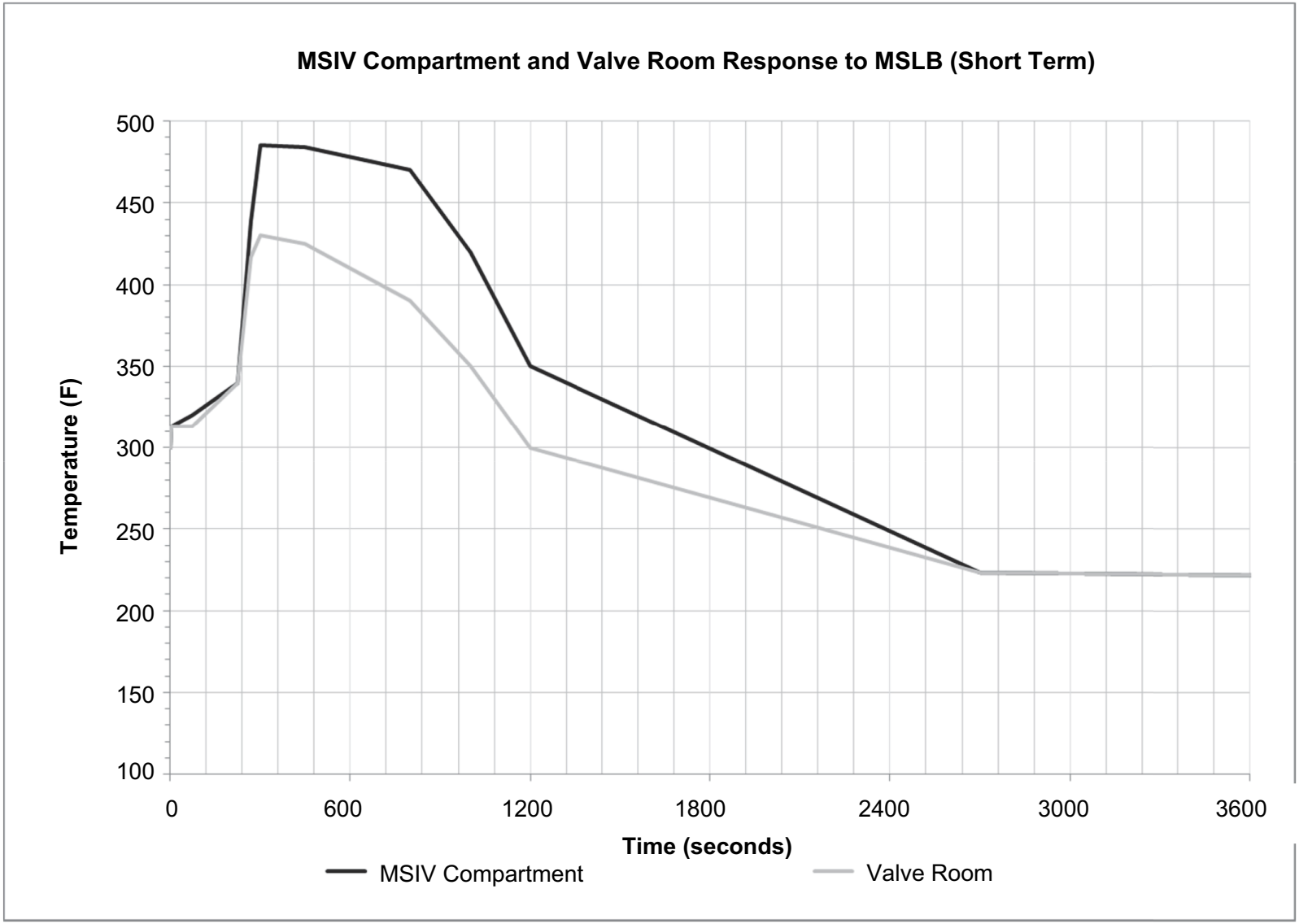

Figure 3D.5-9 (Sheet 1 of 2)
MSIV Compartment Response to MSLB (Short Term)

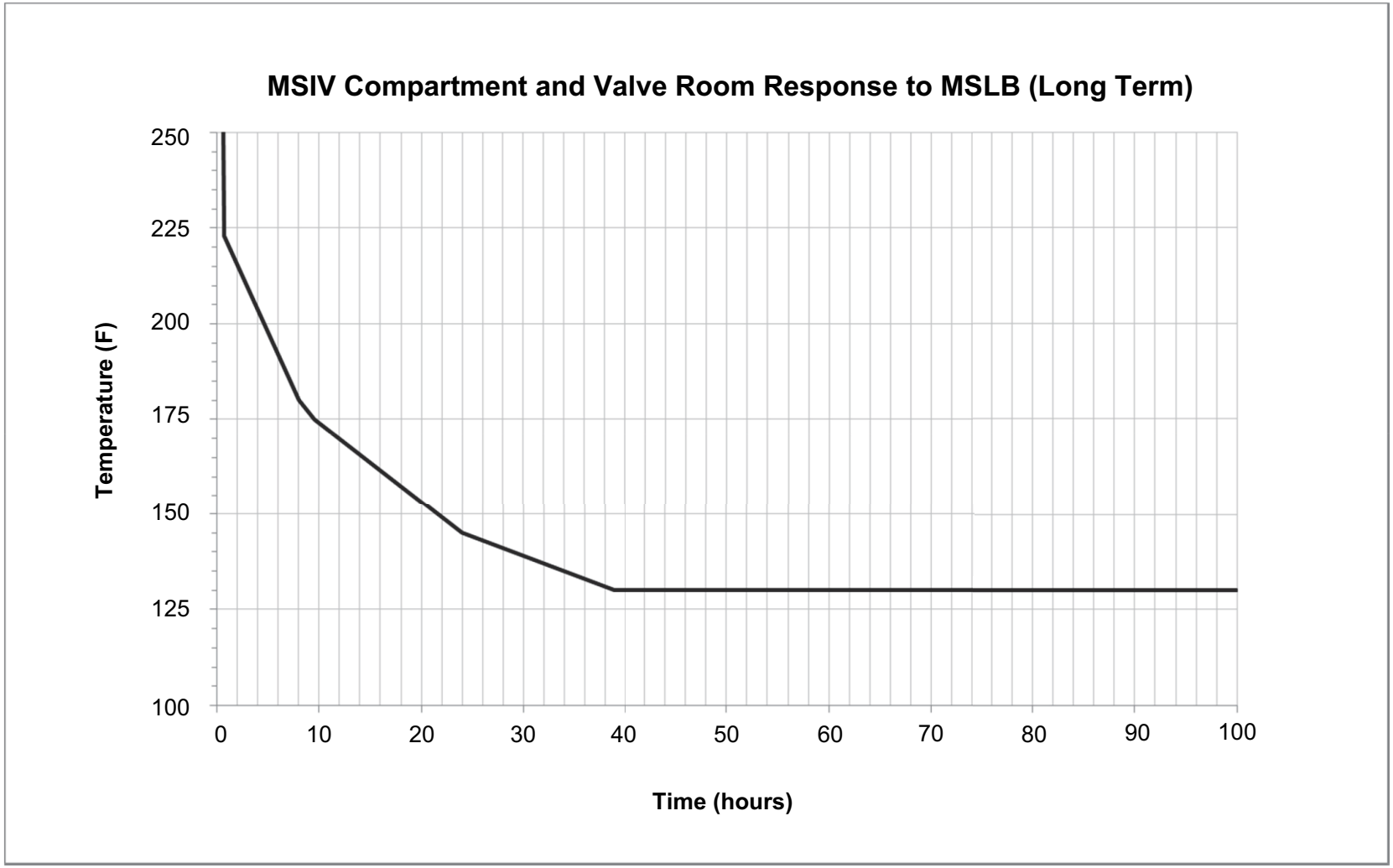

Figure 3D.5-9 (Sheet 2 of 2)
MSIV Compartment Response to MSLB (Long Term)

ATTACHMENT A

SAMPLE EQUIPMENT QUALIFICATION DATA PACKAGE (EQDP)

To the extent practical, the equipment qualification data packages consist of the following elements:

Section 1 – Specifications
Section 2 – Qualification Program
Section 3 – Qualification by Test
Section 4 – Qualification by Analysis
Section 5 – Qualification Program Conclusions

EQDP-_____
Rev. _____
{date issued}

EQUIPMENT QUALIFICATION DATA PACKAGE

Equipment _____

Manufacturer _____

Model _____

Application _____

Environment: ____ Harsh ____ Mild

Prepared by: _____
{name}

Reviewed by: _____
{name}

Approved by: _____
{name}

This document provides or summarizes the seismic and environmental qualification of the equipment identified above in accordance with the AP1000 EQ Program Methodology.

1 SPECIFICATIONS

1.1 EQUIPMENT IDENTIFICATION: {create table(s) for details if a model series is to be qualified.}

Manufacturer _____
Model _____
Technical Manual _____
Drawings _____
Specification No. _____
Modifications _____

1.2 INSTALLATION REQUIREMENTS: {Cite vendor technical manual; details of mounting used for seismic test specimen(s); include any special requirements unique to Class 1E service}

1.3 ELECTRICAL REQUIREMENTS

1.3.1	Voltage:	_____	
1.3.2	Frequency:	_____	{if powered by AC}
1.3.3	Load:	_____	{as applicable}
1.3.4	Other:	_____	{identify and address as needed}

1.4 AUXILIARY DEVICES: {These are devices required to be interfaced with the subject equipment to provide qualification or operability but not specifically included or addressed in this document.}

1.5 PREVENTATIVE MAINTENANCE: {Identify manufacturer recommended maintenance activities required as part of the qualification program. Identify activities that are required to support qualification or the qualified life. "None" shall mean that maintenance is not essential to qualification or the qualified life. The following statement may be used in cases where qualification is not contingent upon maintenance or surveillance activities:

"No preventive maintenance is required to support the equipment qualified life. This does not preclude development of a preventive maintenance program designed to enhance equipment performance and identify unanticipated equipment degradation as long as this program does not compromise the qualification status of the equipment. Surveillance activities may also be considered to support the basis for, and a possible extension, of the qualified life."}

1.6 SAFETY FUNCTIONS

{Specify known safety functions for which qualification is intended to apply.}

1.7 PERFORMANCE REQUIREMENTS[a] for: {RCS Loop RTDs}

			Containment Test	DBE[b] Conditions	
Parameter	Normal Conditions	Abnormal Conditions	Abnormal	Seismic	LOCA
1.7.1 Time requirement					
1.7.2 Performance					

1.8 ENVIRONMENTAL CONDITIONS[a] for Same Function

1.8.1 Temperature (°F)

1.8.2 Pressure (psig)

1.8.3 Humidity (%RH)

1.8.4 Radiation (Rads)

1.8.5 Chemicals

1.8.6 Vibration

1.8.7 Acceleration (g)

Notes: a: Test margin is not included in the parameters of this section.
b: DBE is the Design Basis Event.

{If more than one set of performance requirements and/or associated environmental conditions are to be specified, replicate these sections in pairs as "1.8 Performance ..." and "1.9 Environment ...", etc.}

2 QUALIFICATION PROGRAM

2.1 PROGRAM OBJECTIVE

The objective of this qualification program is to demonstrate, employing the recommended practices of Regulatory Guides 1.89 and 1.100 and IEEE 323-1974, 344-1987, {cite others as applicable} capability of the {Equipment description} to perform its/their safety related function(s) described in EQDP Section 1.7 while exposed to the applicable conditions and events defined in EQDP Section 1.8.

{Narrative should introduce an outline of the program plan. Table below to be completed as graphic reference. Table shall not be abbreviated; items must appear and be addressed by direct response.}

2.2 REFERENCES

{List test report(s) and information sources cited in this document}

	Qualification Method(s)		
CONDITION	**TEST**	**ANALYSIS**	**OTHER**
Aging:			
Thermal			
Radiation			
Vibrational			
Operational Cycling			
Electrical			
Mechanical			
Abnormal Environment			
Inadvertent ADS Actuation			
Seismic			
LOCA			
HELB Inside Containment			
HELB Outside Containment			
Post-accident Aging			

NOTES:

{All spaces above to be noted as "Yes," "No," or "Note #." Notes will be appended to the table. Notes will also include items "Not Applicable" with terse explanation and/or forwarding reference.}

3 QUALIFICATION BY TEST (TEST PLAN AND SUMMARY)

3.1 SPECIMEN DESCRIPTION

{Identify the item or items to be tested}

3.2 NUMBER TESTED

{If more than one type is to be tested, identify how many of each. Subsequent Sections should clarify specifics for each.}

3.3 MOUNTING

{Identify specific seismic mounting details, referencing applicable drawings, instructions, documents. Note existence of differences from manufacturer recommendations}

3.4 CONNECTIONS

{Identify interfaces, both electrical and mechanical, identify any connectors or sealing assemblies used which are not provided with the equipment, or are not covered by this qualification.

3.5 TEST SEQUENCE PREFERRED

This section identifies the preferred test sequences as specified in IEEE 323-1974.

3.5.1 Inspection of Test Item
3.5.2 Operation (Normal Condition)
3.5.3 Operation (Performance Specifications Extremes: Section 1)
3.5.4 Simulated Aging
3.5.5 Vibration/Seismic
3.5.6 Operation (Simulated High Energy Line Break Conditions)
3.5.7 Operation (Simulated Post-HELB Conditions)
3.5.8 Inspection

3.6 TEST SEQUENCE ACTUAL

This section identifies the actual test sequence which constitutes the qualification program for this equipment. A justification for anything other than the preferred sequence is provided.

Test Sequence (from Section 3.5):

{List and explain; provide forwarding references to subsequent subsections as necessary}

3.7 **SERVICE CONDITIONS TO BE SIMULATED BY TEST**(1)

	Normal	Abnormal	Seismic	HELB	Post-HELB
3.7.1 Temperature (°F)					
3.7.2 Pressure (psig)					
3.7.3 Humidity (% RH)					
3.7.4 Radiation (Rads)					
3.7.5 Chemicals					
3.7.6 Vibration					
3.7.7 Seismic (g)					

(1) Test parameter margins are included for the worst-case known requirements applicable to the equipment type. Margin for a specific parameter is dependent on the requirements of each application or location for the equipment; these may vary.

(2) Post-accident operability addressed through simulated thermal aging. Temperature and other parameters are selected to envelop the requirements.

3.8 MEASURED VARIABLES

This section tabulates the variables and parameters required to be measured during each of the following tests in the qualification test sequence.

Tests: {example}
A: Thermal Aging
B: Mechanical Cycling
C: Irradiation
D: Seismic Test
E: HELB Test

	Required	Not Required
3.8.1 Category I – Environment		
3.8.1.1 Temperature	...	...
3.8.1.2 Pressure	...	...
3.8.1.3 Moisture	...	...
3.8.1.4 Gas Composition	...	...
3.8.1.5 Vibration	...	...
3.8.1.6 Time	...	...
3.8.2 Category II – Input Electrical Characteristics		
3.8.2.1 Voltage	...	...
3.8.2.2 Current	...	...
3.8.2.3 Frequency	...	...
3.8.2.4 Power	...	...
3.8.2.5 Other	...	...
3.8.3 Category III – Fluid Characteristics		
3.8.3.1 Chemical Composition	...	...
3.8.3.2 Flowrate	...	...
3.8.3.3 Spray	...	...
3.8.3.4 Temperature	...	...
3.8.4 Category IV – Radiological Features		
3.8.4.1 Energy Type	...	...
3.8.4.2 Energy Level	...	...
3.8.4.3 Dose Rate	...	...
3.8.4.4 Integrated Dose	...	...
3.8.5 Category V – Electrical Characteristics		
3.8.5.1 Insulation Resistance	...	...
3.8.5.2 Output Voltage	...	...
3.8.5.3 Output Current	...	...
3.8.5.4 Output Power	...	...
3.8.5.5 Response Time	...	...
3.8.5.6 Frequency Characteristics	...	...
3.8.5.7 Simulated Load	...	...

	Required	Not Required
3.8.6 Category VI – Mechanical Characteristics		
3.8.6.1 Thrust	...	...
3.8.6.2 Torque	...	...
3.8.6.3 Time	...	...
3.8.6.4 Load Profile	...	...
3.8.7 Category VII – Auxiliary Equipment		
3.8.7.1 {as applicable, also see Section 1.4 of EQDP}	...	...

3.9 TYPE TEST SUMMARY

3.9.1 Normal Environment Testing

Operation of the {equipment} under normal conditions is demonstrated by {discuss test, checks, et. al. which provide baseline performance data} ... , as reported in Reference _.

3.9.2 Abnormal Environment Testing

Operation of the {equipment} under abnormal conditions is demonstrated by {discuss test, checks, et. al. which provide baseline performance data} ... , as reported in Reference _.

3.9.3 Aging Simulation Procedure

{Describe the aging mechanisms simulated and the sequence, including justifications as necessary.}

The test units were pre-conditioned to simulate an aged condition prior to subjecting them to the Design Basis Event (DBE) seismic and environmental conditions/simulation. The aged condition was achieved by separate phases of {accelerated thermal aging, thermal cycling, and radiation exposure to a total integrated gamma dose equivalent to a twenty-year normal dose plus the design basis accident dose, and accelerated flow induced and pipe vibration simulation}. Through all the pre-conditioning phases, the {equipment, performance} were monitored to verify {continuous operation}.

3.9.3.1 Design Life: {Also, justification of the bases for a design life goal should be provided, when used in mild-environment programs. Generally inapplicable to harsh-environment programs.}

3.9.3.2 Shelf Life: {Though not typically applicable, state any limitation in life, as well as conditions which may be detrimental if known.}

3.9.3.3 Thermal Aging: The qualified life is __ years based on an ambient temperature of {__°C (__°F) and a __°C temperature rise due to _____}. Calculations are based on a test temperature of __, test duration of ___ hours, and an activation of __ eV (See References x, et al.)}.

3.9.3.4 Radiation Aging: The qualified life is limited by the expected radiation during the __-year life and the Design Basis Event. {Subtract accident TID from qualified TID; account for margin, remainder is to be compared to normal/abnormal radiation requirements to yield life limits.}

3.9.3.5 Operating Cycles: {Expected number of electrical and/or mechanical cycles, or numbers of actuations, as applicable. Estimated on the basis of the expected for the design, qualified, installed life of the equipment. Specification may be on a per annum or a per fuel cycle basis. Compare to cycle life data from test.}

3.9.3.6 Vibration Aging: {present bases; refer to test profile and/or Subsection 3.9.4}.

3.9.4 Seismic Tests

The seismic testing reported in Reference x was completed on aged equipment employing {method(s)} in accordance with Regulatory Guide 1.100 and IEEE 344-1987. ... {Summarize equipment condition and/or performance versus the acceptance criteria.} ... Actual margin should be determined for each application/location throughout the plant and verified to meet or exceed the margin requirements.

{Discuss or reference discussion of test anomalies.}

3.9.5 High Energy Line Break/Post HELB Simulation

The {equipment} were subjected to the HELB simulation temperature/pressure profile of Figure x. Following the __°F temperature peak, the temperature gradually declines to __°F and is held at saturated steam conditions for _ days, simulating a _____ period of Post-HELB operation. The test data and activation energy specified in Subsection 3.9.3.3 can be used to determine margin in post-accident aging for each application/location of the equipment.

{Summarize equipment condition and/or performance versus the criteria}

{Discuss or reference discussion of test anomalies.}

4 QUALIFICATION BY ANALYSIS

The AP1000 EQ Program does permit qualification solely on the basis of analyses for equipment outside the scope of 10CFR50.49. The following subsections discuss each of the analyses preformed, its test basis and justification, and summarizes conclusions documented in References x; et. al., which provided detailed accounts of each analysis.

{Each subsection will address a particular analysis, if more than one is performed to support qualification.}

4.x (EXAMPLE)

{The purpose and objective will be identified here. Subsections will provide necessary details per the following format.}

4.x.1 {Equipment, Characteristic or Aspect} Analyzed

{A general description of the equipment and its function based on applicable equipment and mounting drawings, and purchase orders.}

4.x.2 Equipment Specification(s)

{The applicable design standards shall be documented including any limitations imposed by the equipment specification. Installation detail considered or represented are to be included.}

4.x.3 Methods and Codes

{Description of analytical methods or techniques, computer program, mathematical model(s) used, and the method(s) of verification}

4.x.4 Acceptance Criteria

{The specific safety function(s), postulated failure modes, or the failure effects to be demonstrated by analysis.}

4.x.5 Model

{Description of mathematical model of equipment or feature analyzed.}

4.x.6 Assumptions and Justifications

{EXAMPLES: Description of the loading conditions to be used. Summary of stresses to be considered.}

4.x.7 Impact to Safety Function

{Summarize analytically established performance characteristics and their acceptability. Discussion and summary of the analytical results which demonstrate equipment structural integrity and, where appropriate, operability. Particular to cabinets, critical deflections should be determined and included in mounting requirements for spacing with respect to other equipment and structures.}

4.x.8 Conclusions

{Descriptive summary, including any conditions imposed on qualification or use; qualified life, limitations, surveillance/maintenance requirements, et. al.} Further discussion of this analysis is presented in Reference x.

4.Y ENVIRONMENTAL QUALIFICATION ANALYSIS FOR {VALVE SOFT PARTS}

{purpose and objective}

4.Y.1 Equipment Identification

{Per Subsection 3D.6.2.3.1}

4.Y.2 Component Identification

{Per Subsection 3D.6.2.3.1}

4.Y.3 Safety Related Functions

{Per Subsection 3D.6.2.3.2}

4.Y.4 Component Acceptance Criteria

{Per Subsection 3D.6.2.3.3}

4.Y.5 Service Conditions

{Per Subsection 3D.6.2.3.4}

4.Y.6 Potential Failure Modes

{Per Subsection 3D.6.2.3.5}

4.Y.7 Identify the Environmental Effects on Material Properties

Each non-metallic, including lubricants, is evaluated to determine the effect of the environmental conditions on the material properties. For each non-metallic, a radiation threshold level and maximum service temperature is identified.

The radiation threshold level and the maximum service temperature are identified using materials handbooks, textbooks, government and industry reports, and laboratory data. If the evaluation indicates that the lowest levels may be exceeded for certain equipment, higher levels are identified at which varying degrees of material degradation may occur.

Mechanical equipment is highly resistive to degradation due to elevated humidity levels: therefore, relative humidity is not included as a parameter to be evaluated for environmental qualification. Pressure can be discounted for most equipment types, as there are no foreseen failures due to elevated pressure levels for most mechanical equipment. However, pressure must be addressed in the evaluation.

The susceptibility of the non-metallic material to the chemicals due to the design basis accident and exposure to the process fluid is evaluated. The material information in the chemical handbooks is an acceptable source of qualification documentation.

4.Y.7.1 Perform Thermal Aging Analysis

Aging analysis is performed for organic materials. Mineral-based subcomponents are not considered to be sensitive to thermal aging during the design life of a plant and, therefore, are not analyzed.

Aging in mechanical components is associated with corrosion, erosion, particle deposits and embrittlement. In new construction, corrosion and erosion are considered by providing additional material thickness as a corrosion or erosion allowance above the required design. The other aging phenomena are considered during inservice inspections of operating components in accordance with ASME Code, Section XI. Aging qualification of metallic parts of equipment except for corrosion and erosion is in compliance with ASME Code, Section XI, therefore aging effects on metallic components are not addressed herein.

The non-metallic material analysis for determining the expected qualified thermal life is performed using Arrhenius methodology. The thermal input during the operating time, as explained below, is deducted from the tested thermal aging of the material at service temperature to obtain the qualified life.

The component is evaluated for the specified post-accident operating time. The thermal input from the postulated accident profile (i.e., LOCA/MSLB) for the duration of the specified operating time is compared to the material thermal aging data. The Arrhenius model is used to perform this comparison. The component is evaluated for the maximum post-accident operating time unless a system analysis is performed to justify shorter operating times.

Analysis of the non-metallics should also take into account any degradation of the part due to its use in dynamic modes (i.e., moving part).

4.Y.7.2 Evaluate the Environmental Effects on Equipment Safety-Related Function

A conservative initial screening of the non-metallic subcomponents is made by comparison of the material capabilities (threshold radiation level and maximum service temperature) with the maximum postulated environmental conditions. If the threshold radiation values and the maximum service temperatures are above the maximum postulated environmental conditions, and if the material aging analysis demonstrates a service life sufficient to survive the accident duration, then the material is considered acceptable.

Those items which are not shown to be acceptable based on the above comparison are evaluated in further detail regarding:

- extent of material degradation
- material properties affected
- equipment/subcomponent function
- extent of equipment functional degradation
- location-specific environmental conditions

4.Y.8 Conclusions

{Per subsection 3D.6.2.3.7}

4.Y.9 EQ Maintenance Requirements

{Per subsection 3D.6.2.3.8}

5 QUALIFICATION PROGRAM CONCLUSIONS

5.1 AGING

{Discuss specifics and state on limitations or requirements; specifics with respect to:

- Design Life Goal
- Thermal Aging
- Radiation Aging
- Operating Cycles
- Vibration Aging}

5.2 DBE QUALIFICATIONS

5.3 PROGRAM CONCLUSIONS

The qualification of the {equipment} is demonstrated by the completion of the simulated aging and Design Basis Event testing described herein and reported in Reference {1}.

{State any conditions imposed on qualification or qualified life, cite any lessons learned which necessitate future user actions to preserve continued qualification}

{Refer to QUALFICATION SUMMARY TABLE}

QUALIFICATION SUMMARY TABLE

SYSTEM	{RPS}
CATEGORY	Category[1] {a}
LOCATION	{Containment bldg.}
STRUCTURE/AREA	{Zone Number}
EQUIPMENT TYPE	{pressure transmitter }
MANUFACTURER	{_____}
MODEL	{_____}

PARAMETER	QUAL METHOD[2]	ENVIRONMENTAL EXTREMES QUALIFIED[3]	SPECIFIED[4]	NOTES
NORMAL				
ABNORMAL				
QUALIFIED LIFE				{5}
SEISMIC	{Both}	Figure x	{Ref; Fig.}	
ACCIDENT		Figure x	{Ref; Fig.}	
Temperature	{Test}	___°F		
Pressure	{Test}	___ psig		
Rel. humidity	{Test}	___%		
Radiation	{Both}	___E+06 R(γ)		
	{Both}	___E+06 R(β)		
Chemistry	{Test}	{Note 6}		
Operability	{Both}			
Accuracy	{Test}			

NOTES:

1. Equipment category as per NUREG-0588, Appendix E, Section 2.
2. Qual. Methods are: Test, Analysis, Both (Test & Anal.), or Other.
3. Qualified values are test extremes which include margin.
4. Environmental parameters for the plant location are to be inserted. If more than one applicable, most extreme are to be cited
5. Qualified life estimated on basis of maximum normal temperature of ___°C (___°F) and a temperature rise of ___°C (____°F).
6. Chemistry Conditions: {pH and composition}.

ATTACHMENT B

AGING EVALUATION PROGRAM

B.1 Introduction

As stated in IEEE 323, aging of Class 1E equipment during normal service is considered as an integral part of the qualification program. The objective is not to address random age-induced failures that occur in-service and are detected by periodic testing and maintenance programs. The objective is to address the concern that some aging mechanisms, when considered in conjunction with the specified design basis events (DBE), may have the potential for common mode failure.

The AP1000 equipment qualification program addresses the aging concern and makes maximum use of available data and experience on aging mechanisms. This approach places primary emphasis on common mode failures due to enveloping design basis events. For example, reasonable assurance against common mode failures being induced because of a loss of heating, ventilation, and air conditioning (HVAC) is provided by adequate design, normal maintenance, and calibration procedures.

B.2 Objectives

The objectives of the aging evaluation program follow:

- To establish, where possible, the effects of the degradation due to aging mechanisms that occur before the occurrence of an accident, when safety-related equipment is called upon to function

- To provide increased confidence that safety-related equipment performs its safety-related function under the specified service condition.

B.3 Basic Approach

The general approach to addressing aging allocates equipment to one of two categories.

- Harsh environment includes electrical equipment required to perform a safety-related function in a high-energy line break (HELB) environment. For this equipment an aging simulation is included as part of the equipment qualification test sequence. The equipment is energized during the aging simulation.

- Mild environment includes equipment required to mitigate high-energy line breaks but which, due to its location, is isolated from any adverse external environment resulting from the accident. For equipment in a mild environment the single design basis event capable of producing an adverse environment at the equipment location is the seismic event. Aging, for mild environment, is not included in the equipment qualification test sequence. Significant aging mechanisms are determined by evaluation of available test data. Generally, this data is from separate programs conducted to demonstrate that aged components continue to meet manufacturer's performance specifications under applicable seismic design basis event conditions and that seismic testing of unaged equipment is not invalidated by anticipated aging mechanisms.

B.4 Harsh Environment

Electrical equipment required to perform a safety-related function in a high-energy line break (such as a loss of coolant accident, feed line break, or steam line break) environment is included in the

harsh environment category. This category provides for an aging simulation to be included in the equipment's qualification test sequence.

B.4.1 Scope

An example of equipment scope and the aging mechanisms applied under harsh environment are shown in Tables 3D.B-1 and 3D.B-2, respectively. The equipment selected is that Class 1E equipment qualified to operate in a high-energy line break environment. The aging mechanisms discussed next are those to which the equipment may be potentially sensitive in its installed location.

B.4.2 Aging Mechanisms

The aging mechanisms that could potentially affect electrical equipment in a harsh environment are discussed under the following headings:

Time, in conjunction with:

- Operational stresses (current, voltage, operating cycles, Joulean self-heating)
- (External stresses (thermal, vibration, radiation, humidity, seismic).

The aging mechanisms considered potentially significant and to be simulated are identified in Table 3D.B-2 for each item of equipment in a harsh environment. Where applied, the aging mechanisms are simulated as described in the following discussions.

B.4.3 Time

For equipment subject to high-energy line break conditions, the most significant in-service aging mechanisms (that is, radiation and thermal) come into effect during reactor operation. Consequently, it can be assumed that the "aging clock" starts on plant startup.

B.4.4 Operational Stresses

Electrical Cycling

Electrical supplies to safety-related equipment are, in general, highly stable. So aging effects due to supply cycling during service are not anticipated. Where the equipment is anticipated to experience multiple startup and shutdown cycles, the equipment is electrically cycled to simulate the number of anticipated startup and shutdown cycles plus 10 percent.

Mechanical Cycling

Aging effects resulting from anticipated mechanical cycling of the equipment are simulated by applying, as a minimum, the number of cycles estimated to occur during the target qualified life plus 10 percent. Mechanical cycling covers such operations as switching and relay actuation.

Joulean Self-Heating

Where the equipment is not aged in a live condition, the aging effects resulting from Joulean self-heating are recognized by employing the equipment operating temperature as the datum temperature for assessing the accelerated thermal aging parameters to be employed.

B.4.5 External Stresses

Thermal Effects

Thermal effects are considered one of the most significant aging mechanisms to address. The equipment is thermally aged to simulate an end-of-qualified-life condition using the Arrhenius model to establish the appropriate conditioning period at elevated temperature. Where data is not available to establish the model parameters for the materials employed, a verifiably conservative value of 0.5 eV is used for activation energy (Attachment D).

For each piece of equipment an appropriate normal and abnormal operating temperature and an associated time history are determined for inclusion in the Arrhenius model. The equipment temperature is determined by the addition of an appropriate equipment specific ΔT to the external ambient temperature. Attachment D also provides information concerning the determination of appropriate ambient temperatures and time-temperature histories for use in thermal aging evaluation of equipment. Post-accident thermal aging is included by recognizing the higher post-accident ambient temperatures in determining the parameters employed for the post-accident accelerated thermal aging simulation.

In-Service Vibration

The majority of safety-related electrical equipment has a proven history of in-plant service. Thus, it is unlikely that a significant, undetected, failure mechanism exists because of low-level, in-plant vibration. In addition, a simulation of earthquakes smaller than the safe shutdown earthquake (SSE) employed during equipment and component seismic testing give added confidence that this potential aging mechanism is covered (See Attachment E, Section 4.4). For line-mounted equipment, in-service pipe and flow induced vibration may be significant. As a consequence, an additional vibration aging step is included in the aging sequence as indicated for certain items of equipment in Table 3D.B-2. (See Attachment E, Subsection 5.2.2.)

Radiation

Radiation during normal operation is not considered an aging mechanism for equipment subject to in-service integrated doses less than 10^4 rads. Research has established that no aging mechanisms are measurable below 10^4 rads (Attachment C) for materials and most components supplied in safety-related electrical equipment. Some devices may have performance limitations below 10^4 rads. For radiation doses in excess of 10^4 rads, the equipment is irradiated using a gamma (γ) source to a dose equivalent to the estimated dose to be incurred during normal operation for the target qualified life. The estimated doses employed are specified in the equipment qualification data package, Subection 1.8.4, and are based on a 100 percent load factor, including appropriate margin. For harsh environment equipment, the equivalent accident dose is usually applied before design basis event testing.

Humidity

The use of materials significantly affected by humidity is avoided. For equipment subject to high energy line break environments, the aging effects due to humidity during normal operation are judged to be insignificant compared to the effects of the high-temperature steam accident simulation. Therefore, no additional humidity aging simulation is required.

Seismic Aging

The potential aging effects of low-level seismic activity and some low-level, in-plant vibration are addressed by employing a simulation of five earthquakes of 50 percent of the magnitude of a safe shutdown earthquake before seismic testing of the aged equipment.

B.4.6 Synergism

An important consideration in aging is the possible existence of synergistic effects when multiple stress environments are applied simultaneously. The potential for significant synergistic effects is addressed by the conservatisms inherent in using the "worst-case" aging sequence, conservative accelerated aging parameters and conservative, design basis event test levels which provide confidence that any synergistic effects are enveloped.

B.4.7 Design Basis Event Testing

Design basis event testing subsequent to equipment aging is discussed in Appendix 3D as to guidelines for defining high-energy line break environments and seismic conditions. Testing for equipment specific test environments and seismic parameters is discussed in Attachment A, Section 3.

B.4.8 Aging Sequence

The aging mechanisms applied to equipment subject to high-energy line break environments are determined by definition of the aging environments at the equipment location and by a subsequent evaluation of the sensitivity of the equipment to these environments. If the sensitivity of the equipment is not known, aging mechanisms are simulated by conservative methods as previously described. Those aging mechanisms that are simulated for example equipment subject to high-energy line break environments are shown in Table 3D.B-2.

The order in which each of the aging mechanisms is applied is as shown in Table 3D.B-2. This order is considered to be conservative, as no aging mechanism is anticipated to be capable of reducing the impact of the previously applied mechanisms. As an example, thermal aging is applied before radiation aging to preclude the annealing out of radiation-induced defects. Similarly, the effects of mechanical aging are considered more significant when applied to equipment that has already been preaged to address thermal and radiation phenomena.

B.4.9 Performance Criterion

The basic acceptance criterion is that the qualification tests demonstrate the capability of the aged equipment to perform prespecified, safety-related functions consistent with meeting the performance specification of Attachment A, Section 1.7 of the applicable equipment qualification data packages while exposed to the associated environmental conditions defined in Attachment A, Section 1.8.

B.4.10 Failure Treatment

When thermal aging is simulated at an equipment level, a conservative value for the activation energy is assumed for the components composing the equipment. As a consequence, many components are grossly overaged, and failure of some of the components is expected during the aging simulation. When three test units are preaged, in the event of such failure(s), one of the following options is selected.

- when a particular component fails in one of the three test units, the failure is considered random. The failed component is replaced by a new component, and the test is continued

- when a particular component fails in more than one of the three test units, either:

    1. the failed components are replaced by new identical components and the aging simulation continued. The claimed qualified life of the unit is consistent with the minimum aging period simulated by at least two of the three units; or

2. the failed components is replaced by identical components specifically aged to the qualified life by assuming for thermal aging a less conservative activation energy specifically determined for the component, or

3. the failed components are replaced by a different type of component which is aged for a period equal to the test units.

When less than three test samples prevent such a conclusion from being reached, any failures are investigated to ascertain whether the failure mechanism is of common mode origin. Should a common mode failure mechanism be identified as having caused the failure, a design change is implemented to eliminate the problem. Supplemental or repeat tests will be completed to demonstrate compliance with the acceptance criteria.

B.5 Mild Environment

A mild environment aging program includes Class 1E equipment not required to perform a safety related function in a high-energy line break environment. It involves a review of available information to demonstrate the absence of significant in-service aging mechanisms. For equipment allocated to this category, the single design basis event capable of producing an adverse environment at the equipment location is the seismic event. Seismic testing completed on unaged equipment is verified as valid by demonstrating that no available information suggests that aged materials and components would not continue to meet their design specification during a seismic event.

B.5.1 Scope

A mild environment aging program includes both a review of material analysis and the results of a component testing program for equipment not required to perform a safety-related function in a high-energy line break environment. Equipment is included that is required to mitigate high-energy line breaks but which, because of the equipment location, is isolated from the adverse environment resulting from the accident. An example of the equipment allocated to a mild environment is identified in Table 3D.B-1.

B.5.2 Performance Criteria

Available Material Analysis – For equipment and components for which aging is addressed by evaluation of appropriate mechanisms, the basic performance criterion is that the evaluation of test data demonstrates the effect of aging is minor and does not affect the capability of the aged equipment to perform prespecified functions. This is consistent with meeting the performance specification of Attachment A, Section 1.7 of the applicable equipment qualification data package while exposed to the associated environmental conditions defined in Attachment A, Section 1.8.

Available Component Aging Data – Random component failure or unacceptable performance due to aging is detected by routine maintenance and equipment calibration during service. The objective of a mild environment aging program is to provide reasonable assurance that a seismic event does not constitute a common mode failure mechanism capable of inducing unacceptable performance characteristics in aged components. Consequently, the single performance criterion for the aging portion of the qualification sequence requires that the component not fail to perform its general function, not that the component meets the original design and procurement specifications.

For the seismic event simulation, the component is considered acceptable if, during and after the simulation, it does not exhibit any temporary or permanent step change in performance characteristics. Failure of one of three components tested is considered a random failure, subject to an investigation concluding the observed failure is not common mode.

B.5.3 Failure Treatment

In the event of failure to demonstrate conformance to criteria, the following options are available for resolution of qualification with respect to age:

- Establish a maintenance and surveillance program
- Replace the materials or components with those constructed of materials of known acceptable characteristics.

Table 3D.B-1
Example Class 1E Equipment Scope and Category Allocation

Aging Method	Equipment
Harsh Environment	Valve Motor Operators Solenoid Valves Externally Mounted Limit Switches Pressure Transmitters Differential Pressure Transmitters Resistance Temperature Detectors Neutron Detectors Pressure Sensor Batteries*
Mild Environment	Pressure Transmitters Differential Pressure Transmitters Main Control Board Switch Modules Recorders (Post-Accident Monitoring) Indicators (Post-Accident Monitoring) Instrument Bus Distribution Panels Instrument Bus Power Supply (Static Inverter) Motor Control Centers Integrated Protection Cabinets (IPC) Engineered Safety Features Actuation Cabinets (ESFAC) Logic Cabinets Reactor Trip Switchgear Reactor Coolant Pump Switchgear

Note:
* To comply with R.G. 1.158

Table 3D.B-2
Aging Mechanism Sequence

Equipment	Location	Category	Burn-in	Aging Mechanisms						DBE	
				Thermal	Radiation	Mechanical	Vibration	Electrical	Seismic	Seismic	HELB
Safety-related Valve Motor Operators	I/C O/C	Harsh Harsh		X X	X X	X X	X X		X X	X X	X
Safety-related Solenoid Valves	I/C O/C	Harsh Harsh		X X	X X	X X	X X		X X	X X	X
Safety-related Externally Mounted Limit Switches	I/C O/C	Harsh Harsh		X X	X X	X X	X X		X X	X X	X
Pressure Transmitters	I/C&OC	Harsh	X	X	X				X	X	X
Differential Pressure Transmitters	I/C&OC	Harsh	X	X	X				X	X	X
Resistance Temperature Detectors: Well Mounted	I/C	Harsh		X	X		X		X	X	X
Excore Neutron Detectors	I/C	Harsh		X	X				X	X	X
Pressure Sensor	I/C	Harsh							X	X	X

ATTACHMENT C

EFFECTS OF GAMMA RADIATION DOSES BELOW 10^4 RADS ON THE MECHANICAL PROPERTIES OF MATERIALS

C.1 Introduction

One potential common-mode failure mechanism to consider in the qualification of safety-related equipment is gamma radiation. As part of a qualification program, the effect of gamma radiation dose is considered for two purposes: as a component of the high-energy line break environment and as a potential aging mechanism that could reduce the capability of safety-related equipment to perform safety-related functions under design basis event conditions (seismic or high-energy line break).

The scope of this attachment is limited to consideration of the effect of radiation for that substantial portion of equipment that does not experience an adverse change in external environment as a result of a high-energy line break, and for which, therefore, the only gamma radiation concern is an in-service aging mechanism.

This attachment assumes that the equipment contains devices that have been selected for performance through the total integrated dose expected in service. For example, devices such as integrated circuits may have a limit of 1000 rads established, in which case the following discussion applies for its installed life. The information in this attachment is not adequate to be applied to equipment that must perform its function in a high-energy line break.

The primary purpose of equipment qualification is to reduce the potential for common-cause failures due to environmental effects during the qualified life. Random failures that inevitably occur inservice are accommodated by the redundancy and diversity of the design of safety-related systems. Furthermore, in-service maintenance and testing programs are designed to detect such random failures. The chances of two identical components that perform identical functions failing during the same limited time period in between routine tests considered insignificant because of the following:

- General low failure rate of components used in nuclear equipment
- Minor differences in component material or geometric tolerances or both
- Minor differences in operating environment.

Therefore, failures that are induced in components by normal background gamma radiation below 10^4 rads (10^3 rads for some devices) alone are considered to be random. Thus, the only gamma radiation concern addressed for equipment not subject to an adverse high-energy line break environment is the potential for an aging mechanism resulting in a deterioration in component properties such that, when subject to seismic stress, a common-cause failure results. When considering such a failure mode, the aging mechanism of concern is not one that affects the electrical properties of components but one that reduces the mechanical strength and flexibility of components.

C.2 Scope

This report summarizes available information concerning the effects of gamma radiation on material mechanical properties. It justifies that for a gamma dose of less than 10^4 rads there are no observable radiation effects that impact material mechanical properties. Of the materials investigated, only Teflon (PTFE) is subject to an alteration of mechanical properties for a gamma dose of less than 10^5 rads. Information is drawn from several sources listed as references in Section C.5. They include various texts concerning radiation effects and damage and pertinent reports.

C.3 Discussion

The primary effects of gamma photons on materials are ionization, material heating (primarily at high dose rates, which is of negligible significance here), and some displacement damage caused by high-energy photons. Some other types of radiation have effects similar to those induced by gamma radiation. This allows the use of data obtained from exposure of material to an alternate radiation to provide limited information concerning the effects of exposure to gamma radiation.

For example, the primary consequence of fast-neutron bombardment of material is atom displacement. Therefore, if the effect of radiation on a material property is primarily dependent on atom displacement, it is inferred that for an equivalent dose (rads) of gamma and fast-neutron radiation, data obtained from neutron irradiation provides a conservative estimate of the effect of gamma irradiation in producing displacements.

The same type of inference is drawn for the ionization effect of charged particle (for example, electron, proton, alpha particle) irradiation. Charged particles do not have the penetration capability that gamma or neutron radiations exhibit as a result of extensive interaction between charged particles and atomic charge centers.

Table 3D.C-1 summarizes information derived from the listed references. The information relates to the effect of gamma radiation on material mechanical properties. Table 3D.C-1 presents either the threshold dose (that dose at which an effect on any mechanical property can first be detected) or, the dose that results in the identified effect. This provides a general indication of the susceptibility of material mechanical properties to gamma radiation.

An evaluation of the information available on inorganic materials summarized in Table 3D.C-1 shows that the mechanical damage threshold for gamma radiation is many orders of magnitude greater than 10^4 rads. For the organic materials listed in Table 3D.C-1, a histogram comparing threshold dose level and frequency of material susceptibility is provided. In instances for which a material threshold dose is not indicated in Table 3D.C-1, a threshold value is assumed which is one order of magnitude lower than the indicated damage dose. Where information is available, referenced documents indicate that the difference between threshold dose and 25 percent damage dose is about a factor of three. Thus, a factor of 10 supplies substantial margin in estimating the threshold dose level. Figure C-1 shows that any indications of mechanical property damage thresholds below 10^4 rads would be extremely unusual.

The references listed do not identify the existence of materials whose mechanical properties are deteriorated when exposed to a gamma radiation dose up to 10^4 rads. So it can be concluded that common-cause failures do not occur in electrical equipment during or after a seismic event as a result of radiation-induced degradation up to 10^4 rads.

This is supported by NRC documentation available as an attachment to "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," which provides further justification for the use of 10^4 rads as a threshold for mechanical damage. The NRC information appears to be consistent with the information provided in Table 3D.C-1.

C.4 Conclusions

For Class 1E equipment subject to a lifetime gamma dose of up to 10^4 rads, it is not necessary to address radiation aging for qualification purposes provided that the equipment is not required to perform a safety-related function in a high-energy line break environment.

As previously noted, this appendix does not apply to electrical properties of components in safety-related equipment.

C.5 References

1. Ricketts, L. W., "Fundamentals of Nuclear Hardening of Electronic Equipment," R. G. Krieger Publishing Co., 1986.

2. NASA Tech Brief Vol. 10, No. 5, Item #3, "Response of Dielectrics to Space Radiation," October 1986.

3. IRT Study 4331-006, "Design Guidelines for Transient Radiation Effects on Tactical Army Systems," Harry Diamond Labs, June 12, 1981.

4. Regulatory Guide 1.89, Rev. 1.

5. Hanks, C. L., and Hamman, D. J., "The Effect of Radiation on Electrical Insulating Materials," REIC Report No. 46, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, June 1969.

6. Kangilaski, M., "The Effects of Neutron Irradiation on Structural Materials," REIC Report No. 45, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, June 1967.

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8. Chapin, W. E., Drennan, J. E., and Hamman, D. J., "The Effect of Nuclear Radiation on Transducers," REIC Report No. 43, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, October 1966.

9. Drennan, J. E., and Hamman, D. J., "Space Radiation Damage to Electronic Components and Materials," REIC Report No. 39, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, January 1966.

10. Larin, F., "Radiation Effects in Semiconductor Devices," John Wiley and Sons, New York, 1968.

11. Billington, D. S., and Crawford, J. H., "Radiation Damage in Solids," Princeton University Press, Princeton, New Jersey, 1961.

12. Corbett, J. W., "Electron Radiation Damage in Semiconductors and Metals," Academic Press, New York, 1966.

13. Ricketts, L. W., "Fundamentals of Nuclear Hardening of Electronic Equipment," Wiley-Interscience, New York, 1972.

14. Kircher, J. F., and Bowman, Richard E., "Effect of Radiation on Materials and Components," Reinhold Publishing Corp., New York, 1964.

15. Bolt, R. O., and Carroll, J. G., "Radiation Effects on Organic Materials," Academic Press, New York, 1963.

16. Kaplan, Irvin, "Nuclear Physics," Addison-Wesley, 1962.

Table 3D.C-1 (Sheet 1 of 2)
Radiation-Induced Degradation
of Material Mechanical Properties

Material	Mechanical Damage	Threshold Dose for Comments
Structural Metals	10^{19} n/cm^2 (fast neutron spectrum)	Similar to cold work (10^{10} rads)
Inorganic Materials	~10^{17} n/cm^2 (fast neutron spectrum)	Borated materials have lower threshold values for neutron irradiation.
Elastomers		
Natural Rubber	2x10^6 rads(C)	
Polyurethane Rubber	9x10^5 rads(C)	
Styrene-Butadiene Rubber	2x10^6 rads(C)	
Nitrile Rubber	7x10^6 rads(C)	Compression set is 25% degraded
Neoprene Rubber	7x10^6 rads(C)	
Hypalon	~10^7 rads(C)	Variable
Acrylic Rubber	9x10^7 rads(C)	Variable
Silicone Rubber	10^7 rads(C)	~25% damage
Fluorocarbon Rubber	9x10^7 rads(C)	~25% hardness, 80% elongation
Polysulfate Rubber	10^8 rads(C)	
Butyl Rubber	10^7 rads(C)	~25% damage
One rad (C) is the field of radiation that will produce 100 ergs/gm in carbon.		
Plastic		
Teflon (PTFE)	1.7x10^4 rads(C)	
Kel-F	1.3x10^6 rads(C)	
Polyethylene	≥ 10^7 rads(C)	
Polystyrene	10^8 rads	
Mylar	10^6 rads(C)	Conservative
Polyamide (Nylon)	8.6x10^5 rads(C)	
Diallyl Phthalate	10^8 rads(C)	
Polypropylene	10^7 rads(C)	
Polyurethane	7x10^8 rads(C)	

Table 3D.C-1 (Sheet 2 of 2)
Radiation-Induced Degradation
of Material Mechanical Properties

Material	Mechanical Damage	Threshold Dose for Comments
Plastic (Continued)		
Kynar (400)	10^7 rads(C)	
Acrylics	$8.2x10^5$ rads	
Amino Resins	10^6 rads	
Aromatic Amide-Imide	10^7 rads	
Resins	10^7 rads	
Cellulose Derivatives	$3x10^7$ rads	25% damage
Polyester, Glass Filled	$8.7x10^8$ rads	
Phenolics	$3x10^8$ rads(C)	25% damage
Silicones	10^8 rads(C)	
Polycarbonate Resins	$5x10^7$ rads	25% damage to elongation
Polyesters	~ 10^5 - 10^6 rads	
Styrene Polymers	$4x10^7$ rads(C)	
Styrene Copolymers	$4x10^7$ rads(C)	25% damage
Vinyl Polymers	$1.4x10^6$ – $8.8x10^7$ rads(C)	
Vinyl Copolymers	$1.4x10^6$ – $8.8x10^7$ rads(C)	
Encapsulating Compounds		
RTV 501	$2x10^6$ rads	
Sylgard 182	$2x10^6$ rads	
Sylgard 1383	$2x10^6$ rads	
Polyurethane Foam	$2x10^6$ rads	
Epoxies	10^9 rads	

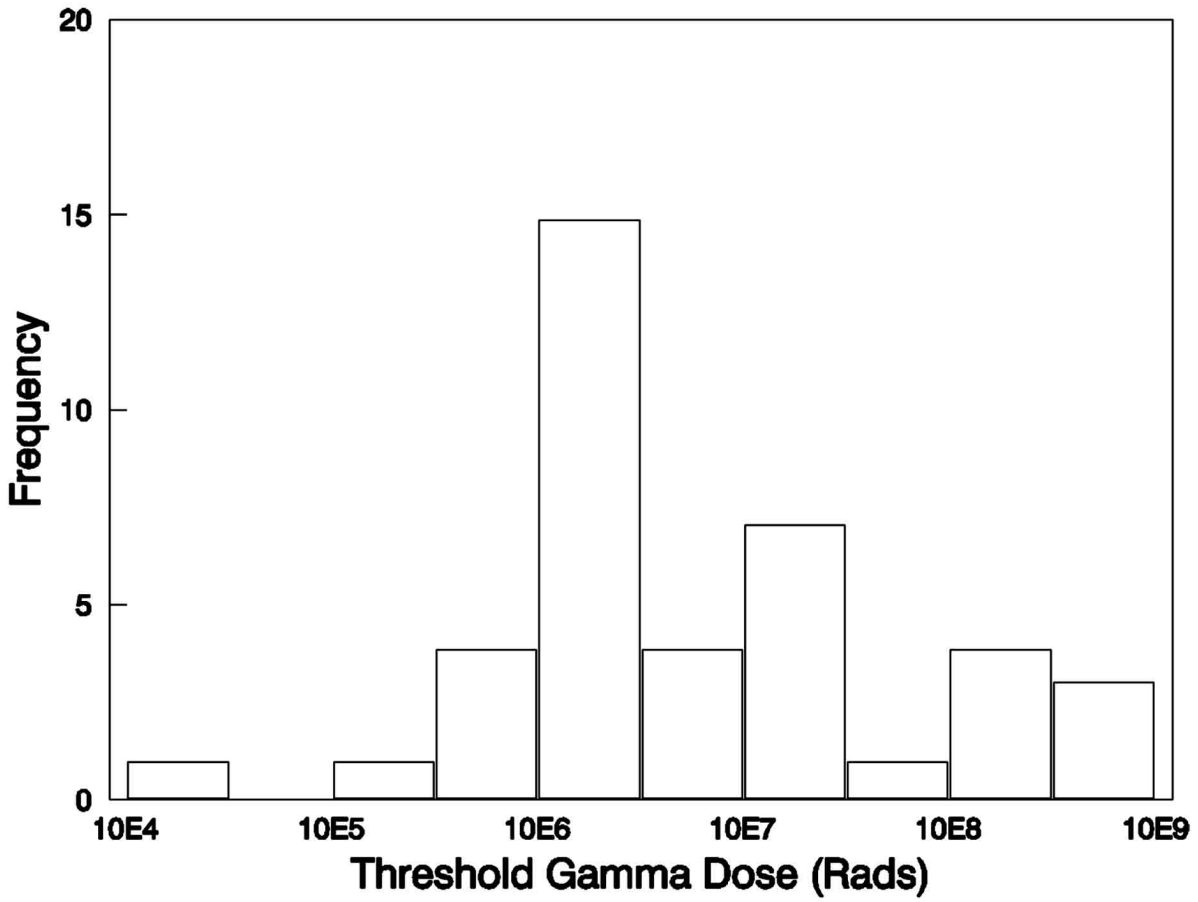


Figure 3D.C-1
Histogram of Threshold Gamma Dose for Mechanical Damage to Elastomers, Plastics, and Encapsulation Compounds

ATTACHMENT D

ACCELERATED THERMAL AGING PARAMETERS

D.1 Introduction

Attachment B describes the approach employed in the AP1000 equipment qualification program to address the aging requirement of IEEE 323. For equipment required to perform a safety-related function in a high-energy line break environment, the AP1000 equipment qualification program includes an aging simulation as part of its qualification test sequence (Harsh Environment of Attachment B).

For equipment not required to perform a safety related function in a high-energy line break environment, the single design basis event considered is a seismic event. Aging, in this case (Mild Environment of Attachment B) is not usually included in the test sequence. Aging, where significant, is addressed by separate qualification of aged components, using conservative testing under applicable seismic design basis event conditions.

Thermal effects are one of the primary aging mechanisms addressed by the AP1000 equipment qualification program described in Attachment B for equipment containing nonmetallic or nonceramic materials. When thermal aging effects are established as potentially significant to the capability of the component or equipment to perform its safety-related function under design basis event conditions, or in the absence of evidence to the contrary, the component or equipment is thermally aged to simulate an end-of-qualified-life condition before design basis event testing. Equipment required to operate in a high-energy line break environment is also thermally aged to simulate the post-accident conditions consistent with its established functional requirements.

This attachment defines the appropriate thermal environments considered for each item of equipment in the AP1000 equipment qualification program and establishes consequent accelerated thermal aging parameters for use in the qualification programs.

D.2 Arrhenius Model

If an aging mechanism is governed by a single chemical reaction, the rate of which is dependent on temperature alone, the Arrhenius equation can be used as the basis for establishing the accelerated aging parameters:

$$\frac{dR}{dt} = Ae^{\frac{-E}{kT}} \qquad (1)$$

where:

E = activation energy (eV)

k = Boltzmann's constant (8.617×10^{-5} eV/K)

A = constant factor

T = material temperature (K)

$\frac{dR}{dt}$ = reaction rate = aging rate

Integration gives:

$$\Delta R = Be^{\frac{-E}{kT}} \Delta t \quad (2)$$

where:

ΔR = change in measured property due to aging

Δt = time for aging effect ΔR to occur

B = constant factor

If the accelerated aging process employed correctly simulates the change in properties due to aging under normal operating or post-accident temperature conditions, then:

$$\Delta R_1 = \Delta R_0 \quad (3)$$

and

$$B\, t_1\, e^{\frac{-E}{kT_1}} = B\, t_o\, e^{\frac{-E}{kT_0}}$$

and

$$Ln\, t_1 = \frac{-E}{k} \frac{T_1 - T_0}{T_1 T_0} + Ln\, t_o$$

where:

T_1 = accelerated aging material temperature (K)

t_1 = time at temperature T_1

T_0 = material temperature under normal operating or post-accident conditions (K)

t_0 = time at temperature T_0

From Equation 3, given an activation energy (E) for the material, the time required at any selected elevated temperature can be calculated to simulate the ambient aging effects.

This model has been verified to represent the thermal aging characteristics of nonmetallic and non-ceramic materials and is employed in the AP1000 equipment qualification program to derive accelerated thermal aging parameters. The only material dependent parameter input into this model, when establishing the accelerated aging parameters, is the activation energy. This parameter is a direct measure of the chemical reaction rate governing the thermal degradation of the material.

D.3 Activation Energy

A single material may have more than one physical property that thermally degrades (for example, dielectric strength, flexural strength.) As a consequence, the material exhibits different activation energies with respect to each property. The activation energy selected is the one that reflects the physical property most significant to the safety-related function performed or the stresses applied to the material by the design basis fault(s) considered.

In actual practice, however, rarely is the choice so simple. Electrical components are invariably made up of more than one material. In many cases either the materials employed are not known in any chemical detail but just by a general organic or industrial trade name, or the appropriate activation energy is not known.

Where an activation energy is not available that reflects the material or component as well as the physical property of interest, a single conservative activation energy is used.

A distribution of activation energies (Figure 3D.D-1) was produced by EPRI (Reference 1) based on 170 materials. An independent review of materials used in Westinghouse-supplied equipment is summarized in Table 3D.D-1 and plotted in similar form in Figure 3D.D-2. A statistical analysis indicates that 95 percent of the activation energies exceed about 0.4 eV from the EPRI data and 0.6 eV from the Westinghouse data. Based on this information, a value of 0.5 eV is selected for use throughout this program whenever specific activation energies are not available. Employing a low value of activation energy in deriving the accelerated aging parameters causes materials having a high activation energy to be overaged with respect to the simulated conditions.

D.4 Thermal Aging (Normal/Abnormal Operating Conditions)

This section establishes the methodology employed and derives a typical set of accelerated aging parameters for equipment in various plant locations.

D.4.1 Normal Operation Temperature (T_0)

In determining the ambient operating temperature (T_0) of the component/material/equipment under investigation, the following is considered:

- External ambient temperature (T_a)
- Temperature rise in cabinet/enclosure (T_r)
- Self-heating effects (T_j)

where $T_o = T_a + T_r + T_j$

D.4.1.1 External Ambient Temperature (T_a)

a) For equipment located in areas supplied by an air-conditioning system, a typical value assumed for (T_a) throughout the qualified life is 68°F (20°C). For air-conditioning systems, two excursions per year to 91°F (33.3°C), each lasting 72 hours, has a negligible additional aging effect.

b) For equipment located in areas supplied by a ventilation system, a typical value assumed (T_a) throughout the qualified life is 77°F (25°C). Two excursions per year to 122°F (50°C), each lasting 72 hours, has a negligible additional aging effect.

D.4.1.2 Temperature Rise in Enclosure (T_r)

This temperature rise is estimated based on the heat generated (radiative and conductive) by equipment inside or attached to the enclosure. For example, limit switches may be affected by process heat through the valve. Temperatures measured during test runs may be available. A typical value for temperature rise inside an electronics cabinet is 10°C.

D.4.1.3 Self-Heating Effects (T_j)

For equipment that is energized during most of its life, a self-heating effect is measured or established. If the equipment is energized only for short durations, this effect may be determined to be negligible. Temperature effects due to the solenoid of an energized valve may be significant (over 40°C). In determining junction temperatures of semiconductor devices, known operating parameters along with the thermal impedance are used. If the power dissipation is not known, a 50 percent operating stress is assumed.

D.4.2 Accelerated Aging Temperature (T_i)

Temperatures used for actual accelerated thermal aging tests are determined based on the equipment or component specifications in an attempt to prevent damage from high temperature alone and second-order (non-Arrhenius) effects such as the glass transition temperature of plastics. A maximum of 130°C is typically used for electronic component aging, but this is evaluated on a case basis. If the device is energized during the accelerated aging process, the self-heating effect as determined in the preceding section is added to the oven temperature to determine the total aging temperature (T_1).

D.4.3 Examples of Arrhenius Calculations

D.4.3.1 For a Normally Energized Component Aged Energized – The Self-Heating Effect is Added to Both (T_o) and (T_1):

Conditions: T_a = 25°C, T_r = 10°C

T_j = 25°C, eV = 0.5,

Aging time = t_i

Oven temperature = 130°C

Qualified life goal = 10 years

Therefore T_o = 25 + 10 + 25 = 60°C = 333K

T_1 = 130 + 25 = 155°C = 428K

$$t_1 = 10e^{\frac{-0.5}{K}\frac{(428-333)}{(428 \times 333)}} * 8760 = 1831 \text{ hours}$$

D.4.3.2 For a Normally De-energized Component Aged Energized – the Self-heating Effect is Added Only to T_1:

Conditions: T_a = 25°C, T_r = 10°C

T_j = 25°C, eV = 0.5, Aging time = t_1

Oven temperature = 130°C

Qualified life goal = 10 years

Therefore T_o = 25 + 10 = 35°C = 308K

T_1 = 130 + 25 = 155°C = 428K

$$t_1 = 10e^{\frac{-0.5}{K}\frac{(428-308)}{(428 \times 308)}} * 8760 = 445 \text{ hours}$$

D.5 Post-Accident Thermal Aging

Most cases, some safety-related postaccident performance capability is specified by the functional requirements. As a consequence, to qualify equipment to IEEE 323, the effects of post-accident thermal aging must be simulated after the high-energy line break test. This section establishes the accelerated thermal aging parameters employed in performing this simulation.

D.5.1 Post-Accident Operating Temperatures

Assuming continuous operation of containment safeguards systems following an accident, the containment environment temperature is reduced to the external ambient temperature well within one year for any postulated high-energy line break. However, to allow for possible variations in plant operations following an accident, the design high-energy line break envelope extending to one year is indicated by Figure 3D.5-8 or an equivalent curve considering the location of the equipment.

For safety-related equipment located inside containment, either the self-heating effects of the operating unit, under post-accident conditions, may be insignificant compared to the heat input from the external environment (transmitters, RTDs), or the unit may not be in continuous operation during this phase (valve operators). So it may not be necessary to add a specific temperature increment to account for self-heating of these devices following an accident. The portion of Figure 3D.5-8 (or the localized equivalent) that is not addressed by DBA testing is then input at T_0 into the Arrhenius equation to calculate appropriate accelerated aging parameters for post-accident conditions. However, as noted in Section D.4, if the equipment is energized during the aging simulation period, the self-heating effect is added to both T_o and T_1.

D.5.2 Accelerated Thermal Aging Parameters for Post-Accident Conditions

The Arrhenius equation is used as the basis for establishing accelerated thermal aging. The aging temperature most often used for post-accident thermal simulation is 250°F (121°C). This temperature is selected as a maximum for electronic components and is generally used for tests. When applying the Arrhenius equation, conservative (lower bound) material activation energy is used that represents the equipment materials and material physical properties, and is essential to the safety function performance during the DBA. There are various ways to apply the Arrhenius equation to post-accident thermal aging. If the selected aging temperature is greater than the test temperature (including margin) at 24 hours, the Arrhenius equation is applied to the post-DBA temperature curve from the first day to the end of the post-accident operability time (e.g.; 72 hours, 2 weeks, 4 months or 1 year) in small time increments. The required aging times to simulate these small increments are then summed to yield a total test time. Another method is used if the selected aging temperature is less than the test temperature (including margin) after 24 hours, then the test temperature should be applied until the aging temperature is met. The Arrhenius equation is applied to the post-DBA temperature curve from the time the aging temperature is met to the end of the post-accident operability time.

D.6 References

1. EPRI NP-1558, Project 890-1, "A Review of Equipment Aging Theory and Technology," September 1980.

Table 3D.D-1 (Sheet 1 of 2)
Activation Energies From Westinghouse Reports

Material	Electron Volts
Melamine-Glass, G5	0.29
Epoxy B-725	0.48
Ester-Glass, GPO-3	0.57
RTV Silicone	0.60
Phenolic-Asbestos, A	0.61
Nylon 33 GF	0.70
Acetal	0.73
Mineral Phenolic	0.74
Silicone Varnish	0.74
Polypropylene	0.81
Polysulfone	0.83
Phenolic-Cotton, C	0.84
Formvar	0.85
Epoxy	0.88
Epoxy Adhesive	0.89
Nylon	0.90
Pressboard	0.91
Kapton	0.93
Silicone	0.94
Phenolic-Asbestos, A	0.94
Cast Epoxy	0.98
Urethane-Nylon	0.99
Phenolic-Glass, G-3	1.01
Polycarbonate	1.01
Phenolic-Paper, X	1.02
Epoxy Wire	1.05
Epoxy-Glass, FR-4	1.05
Varnish Cotton	1.06
PVC	1.08
Ester-Glass, GPO-1	1.09
Cellulose Phenolic	1.10
X-Link Ethylene	1.11
Urethane	1.12
Ester-Glass, GPO-2	1.13
Ester-Nylon	1.14

Table 3D.D-1 (Sheet 2 of 2)
Activation Energies From Westinghouse Reports

Material	Electron Volts
Ester-Glass, GPO-1	1.16
32102BK Varnish	1.16
Vulcanized Fiber	1.16
Cellulose Mineral Phenolic	1.17
Mylar	1.18
Cast Epoxy	1.18
32101EV Varnish	1.18
Epoxy	1.18
Silicone	1.18
Phenolic-Paper, XX	1.20
Vulanized Fiber	1.21
Cellulose Phenolic	1.24
Phenolic-Glass, G-3	1.24
Kraft Phenolic	1.25
Neoprene	1.26
Amide-Imide Varnish	1.31
Loctite 75	1.38
Acetyl. Cotton	1.39
Silicone-Asbestos	1.41
Epoxy-Glass, FR-4	1.50
Mylar	1.58
Nomex	1.59
Omega Varnish	1.59
Epoxy-Glass, G-11	1.64
Polythermaleze	1.64
Kraft Paper	1.67
Valox 310SE-0	1.75
Varnished Kraft	1.86
Nomex	1.91
Ester-Glass, GPO-3	2.03
Phenolic-Cotton, C	2.12
Melamine-Glass, G-5	2.18

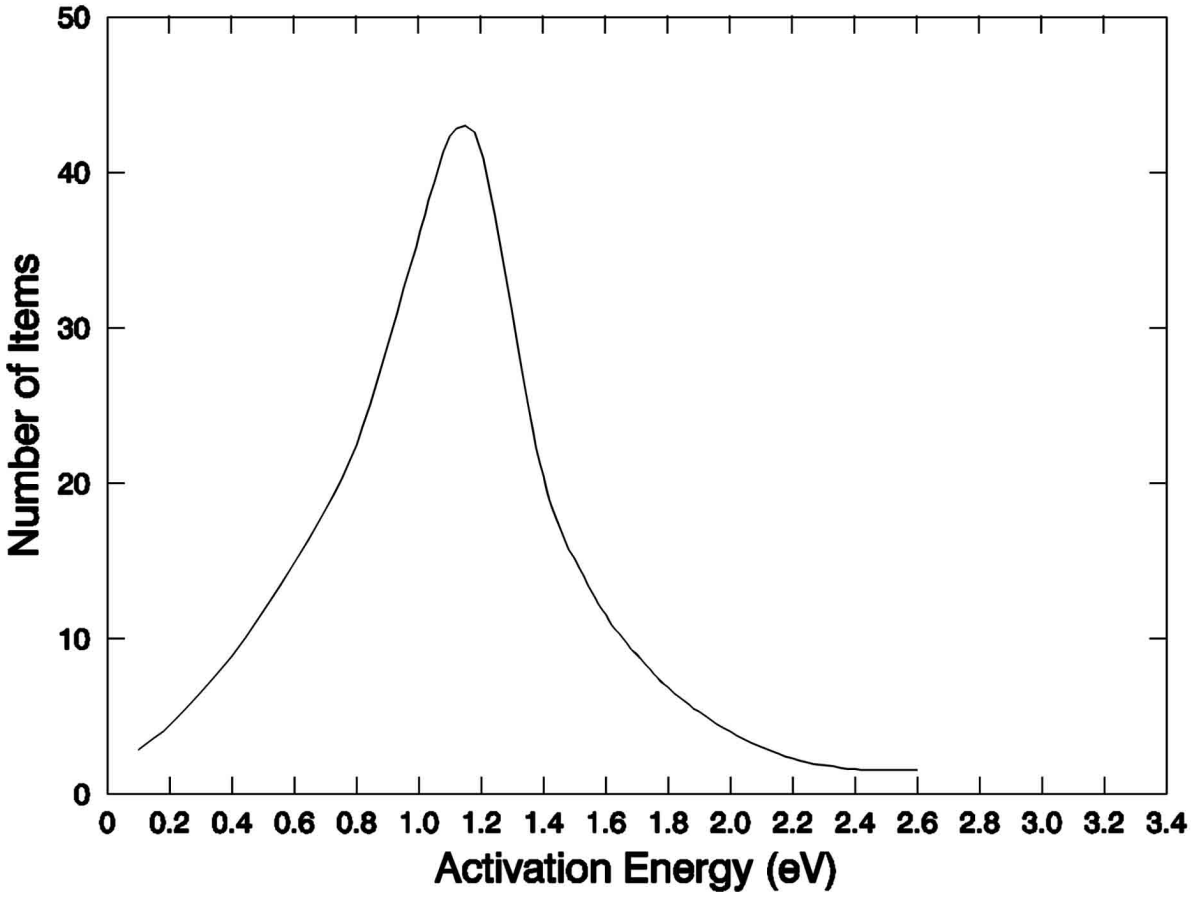


Figure 3D.D-1
Frequency Distribution of Activation Energies of Various Components/Materials (EPRI Data)

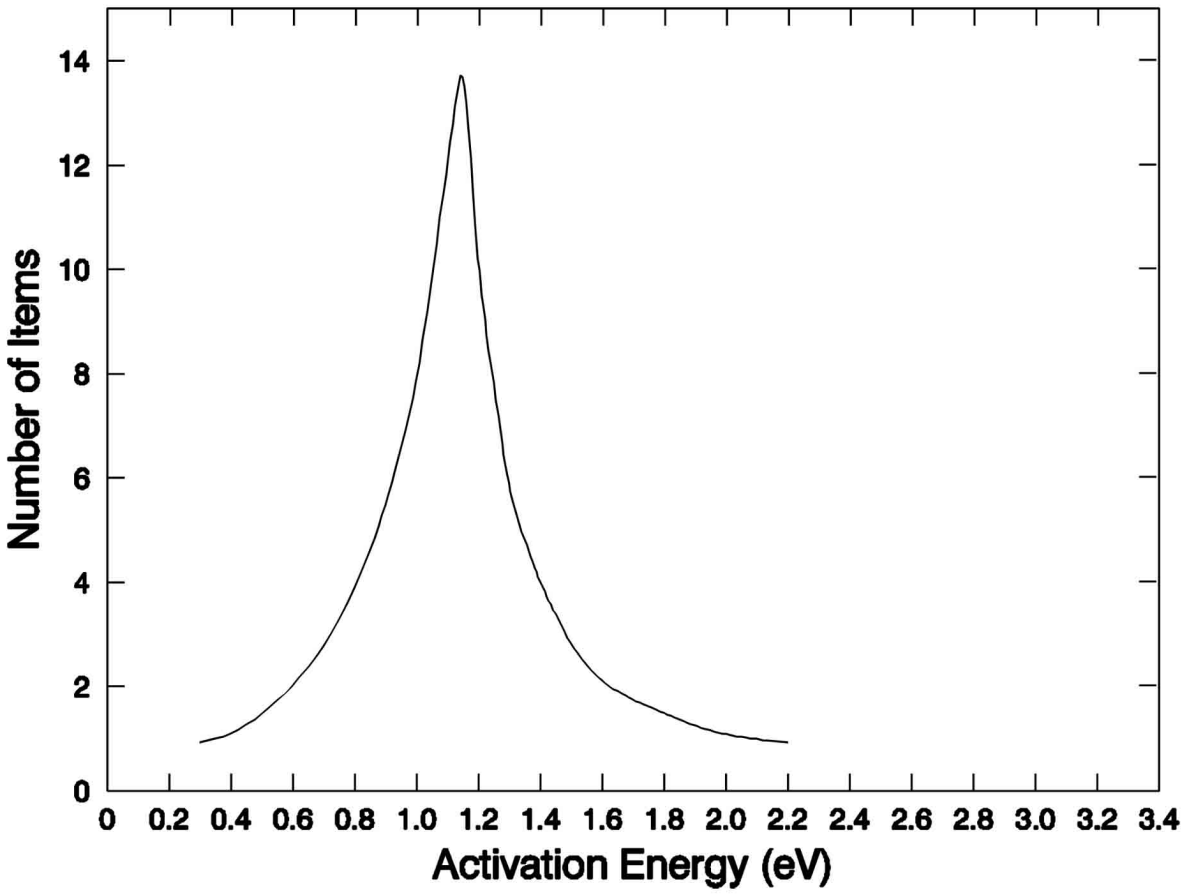


Figure 3D.D-2
Frequency Distribution of Activation Energies of Various Components/Materials
(Westinghouse Data)

Figure 3D.D-3 Not Used

ATTACHMENT E

SEISMIC QUALIFICATION TECHNIQUES

E.1 Purpose

The following is the methodology used to seismically qualify seismic Category I mechanical and electrical equipment for the AP1000 equipment qualification program. Qualification work covered by this appendix meets the applicable requirements of IEEE 344-1987 and 382-1996.

E.2 Definitions

The following are definitions of terms unique to or distinct from common industry usage. (See Section E.4.2.)

E.2.1 1/2 Safe Shutdown Earthquake

The 1/2 safe shutdown earth (SSE) is the earthquake level used during seismic testing to seismically age safety-related equipment before performing safe shutdown earthquake testing.

E.2.2 Seismic Category I Equipment

Seismic Category 1 equipment consists of structures, systems, and components required to withstand the effects of the safe shutdown earthquake and remain structurally intact, leak-tight (in case of pressurized systems), and functional to the extent required to perform their safety-related function.

E.2.3 Seismic Category II Equipment

Seismic Category II equipment is that equipment whose continued function is not required, but whose failure could reduce the functioning of seismic Category I structures, systems, and components to an unacceptable level. Seismic Category II equipment must be capable of maintaining structural integrity so that a seismic event up to and including an SSE would not cause such a failure.

E.2.4 Non-seismic Equipment

Equipment designated as non-seismic does not require seismic qualification.

E.2.5 Active Equipment

Equipment that must perform a mechanical or electrical operation during or after (or both) the safe shutdown earthquake in order to accomplish its safety-related function.

E.2.6 Passive Equipment

Equipment where maintenance of structural or pressure integrity is the only requirement necessary for accomplishing its safety-related function.

E.3 Qualification Methods

This section presents a general description of the seismic qualification methods used by AP1000 for the seismic qualification of seismic Category I safety-related mechanical and electrical equipment. Three methods are used: test, analysis, and a combination of the two. The approaches for qualification by testing and by analysis are discussed in Section E.5 and Section E.6, respectively. The following discussion covers the conditions under which each approach is used and the general

requirements applicable to the use of the methods. The qualification sequence is defined in Appendix 3D.

E.3.1 Use of Qualification by Testing

The preferred method for seismic qualification of safety-related Class 1E electrical and electromechanical equipment is seismic testing. The nature of the seismic and vibrational input used depends on where the equipment is used. For equipment mounted so that the seismic environment includes frequency content between 1 and 33 hertz (hard mounted), the seismic test input is multifrequency. For equipment mounted so that seismic ground motion is filtered to contain one predominant structural mode (line mounted), single frequency testing is appropriate. This is the case for equipment mounted on piping systems, ductwork, or cable trays.

E.3.2 Use of Qualification by Analysis

Analysis is used for seismic qualification when one of the following conditions is met:

- The equipment is too large or the interface support conditions cannot adequately be simulated on the test table.
- The only requirement is to maintain structural integrity during a postulated seismic event.
- The equipment represents a linear system, or the nonlinearities can conservatively be accounted for in the analysis. This approach is also applicable to the development of the seismic environment, required response spectrum curve, at the mounting location of a component attached to a larger structure when the device is seismically qualified by separate component testing.
- The analysis is used to document the seismic similarity of the equipment provided and that previously qualified by testing.

Seismic qualification of safety-related electrical equipment by analysis alone is not recommended for complex equipment that cannot be modeled to adequately predict its response. Analysis without testing may be acceptable provided structural integrity alone can ensure the design-intended function.

E.4 Requirements

E.4.1 Damping

Damping level of a component or system describes its capability to dissipate vibrational energy during a seismic event. The damping level used defines the response magnitude of an ideal single degree of freedom linear oscillator when subjected to the specified input as documented by the required response spectrum (RRS) curve. The significance of the damping value used depends on whether qualification is by testing or analysis.

E.4.1.1 Testing

Equipment qualification by testing involves subjecting the base of the equipment to a representative seismic acceleration time history. The response characteristics of the equipment are a function of the inherent damping present in the equipment. In this case the damping value used (typically five percent) serves as a convenient means of showing the compliance of the test response spectrum (TRS) with the required response spectrum.

E.4.1.2 Analysis

In the case of qualification by analysis, the damping level used is representative of the damping actually present in the equipment. Unless other documented equipment damping data is available, the values specified in Table 3.7.1-1 of Chapter 3 are used.

E.4.2 Interface Requirements

As part of the seismic qualification program, consideration is given to the definition of the clearances needed around the equipment mounted in the plant to permit the equipment to move during a postulated seismic event without causing impact between adjacent pieces of safety-related equipment. This is done as part of seismic testing by measuring the maximum dynamic relative displacement of the top and bottom of the equipment.

When performing qualification by analysis, the relative motion is obtained as part of the analytical results. These motions are reported in the seismic analysis report or qualification report and are used to determine the required clearance between adjacent pieces of equipment.

In addition, the qualification program takes into account the restraining effect of other interfaces, such as cables and conduits attached to the equipment, which may change the dynamic response characteristic of the equipment.

E.4.3 Mounting Simulation

The mounting conditions simulated by analysis or during seismic test are representative of the equipment as-installed mounting conditions used for the AP1000 equipment. When an interfacing structure exists between the safety-related equipment being qualified and the floor or wall at which the equipment mounting required response spectrum is specified, its flexibility is simulated as part of the qualification program. If this is not done, justification must be provided, demonstrating that the deviations in mounting conditions do not affect the applicability of qualification program.

E.4.4 1/2 Safe Shutdown Earthquake

The AP1000 makes use of a small earthquake having the intensity of one-half of the safe shutdown earthquake at the safety-related equipment mounting location to simulate the fatigue effects of smaller earthquakes that may occur before the postulated safe shutdown earthquake. These small earthquakes correspond to the operating basis earthquakes (OBEs) referenced in IEEE 344-1987. When qualification by testing is used, five of these small earthquakes are used to vibrationally age the equipment before the safe shutdown earthquake. When qualification by analysis is used, two safe shutdown earthquake events are used to simulate the fatigue aging effects. Each event contains 10 peak cycles. These stress cycles are used to verify that the equipment is not subject to failure due to low cycle fatigue.

E.4.5 Safe Shutdown Earthquake

The safe shutdown earthquake required response spectrum curve defines the seismic qualification basis for each piece of safety-related equipment. The seismic level varies according to the mounting location of the equipment. When equipment qualification is based on testing, an additional 10 percent test acceleration margin is added as specified in IEEE 323-1974.

E.4.6 Other Dynamic Loads

Hydrodynamic loads are considered as part of the qualification program, where applicable.

E.5 Qualification by Test

Seismic qualification testing is the preferred method for electrical, mechanical, and electromechanical equipment. Seismic testing shall be performed and input generated as specified in IEEE 344-1987. The nature of the test input used depends on whether the equipment is hard mounted or line mounted. The test program consists of the following elements, as applicable: environmental aging, mechanical aging, vibrational aging, and safe shutdown earthquake testing. For those cases where the equipment is also subject to a loss of coolant or a high-energy line break accident, these accidents are simulated on the same qualification specimen after completion of the testing previously discussed. (See Subsections 3D.4.4 and 3D.7.4.)

The characteristics of the required seismic and dynamic input motions should be specified by the response spectrum or time history methods. These characteristics, derived from the structures or systems seismic and dynamic analyses, should be representative of the input motions at the equipment mounting locations.

For seismic and dynamic loads, the actual test input motion should be characterized in the same manner as the required input motion, and the conservatism in amplitude and frequency content should be demonstrated (that is, the test response spectrum should closely resemble and envelop the required response spectrum over the critical frequency range).

Since seismic and the dynamic load excitation generally have a broad frequency content, multi-frequency vibration input motion should be used. However, single frequency input motion, such as sine beats, is acceptable provided the characteristics of the required input motion indicate that the motion is dominated by one frequency (for example, by structural filtering effects), or that the anticipated response of the equipment is adequately represented by one mode, or in the case of structural integrity assurance, that the input has sufficient intensity and duration to produce sufficiently high levels of stress for such assurance. Components that have been previously tested to IEEE-344-1971 should be reevaluated or retested to justify the appropriateness of the input motion used, and requalified if necessary.

For the seismic and dynamic portion of the loads, the test input motion should be applied to one vertical axis and one principal axis (or two orthogonal axes) simultaneously unless it can be demonstrated that the equipment response motion in the horizontal direction is not sensitive to the vibratory motion in the horizontal direction, and vice versa. The time phasing of the inputs in the vertical and horizontal directions must be such that a purely rectilinear resultant input is avoided. An acceptable alternative is to test with vertical and horizontal inputs in-phase, and then repeat the test with inputs 180 degrees out-of-phase. In addition, the test must be repeated with the equipment rotated 90 degrees horizontally.

E.5.1 Qualification of Hard-Mounted Equipment

Hard-mounted equipment is seismically tested mounted on a test table capable of producing multifrequency, multiaxis inputs. The waveform characteristics of the input are random and scaled in such a way that the test response spectrum equals or exceeds the required response spectrum (including margin). The input signal meets the requirements of Subsection 7.6.3 of IEEE 344-1987.

Furthermore, the test input simulates the multidirectional nature of the earthquake. The preferred method for meeting this requirement is to the use a triaxial test table capable of producing three statistically independent, orthogonal input motions. In this case the seismic testing consists of five 1/2 safe shutdown earthquake tests and one safe shutdown earthquake test in one orientation.

Using a biaxial test table is acceptable if it is justified that the horizontal and vertical test inputs conservatively simulate the three-dimensional nature of the seismic event. One acceptable approach

is to mount the equipment on the test table with its front-to-back axis oriented at 45 degrees to the horizontal drive axis and scale the horizontal component of the input by a factor of the square root of two. Statistically independent inputs are preferred and, if used, the test can be performed in two stages, with the equipment rotated 90 degrees about the vertical axis. In this case, the five 1/2 safe shutdown earthquake inputs need to be applied only in the first orientation.

If a dependent biaxial test table is used, the test is performed in four stages. The first stage involves five 1/2 safe shutdown earthquake tests and one safe shutdown earthquake test in the first orientation. The second, third, and fourth orientations are obtained by successively rotating the equipment 90 degrees clockwise from its previous position. One safe shutdown earthquake test is performed in each of the last three orientations.

Each multifrequency test has a minimum of 15 seconds of strong motion input. The strong motion portion is preceded and followed by a period of testing where the test input is ramped up and ramped down, respectively, so that the equipment is not subjected to impact loading. The adequacy of each test run is evaluated using the criteria set forth in Subsection 7.6.3.1 of IEEE 344-1987.

E.5.2 Qualification of Line-Mounted Equipment

Line-mounted equipment, because of the dynamic filtering characteristics of its mounting, is effectively subject to single frequency input. This condition is common for valves and sensors supported by piping systems, cable trays, and duct systems. This equipment is qualified consistent with the requirements of IEEE 382-1996.

In some cases this equipment may also be used in the hard-mounted condition. In this case multifrequency, multiaxis testing is also required unless justification is provided that the previous single frequency tests demonstrate the capability of the equipment to operate under the hard-mounted seismic conditions. Because of the large size of typical valves, it may be necessary to perform separate testing of the operators and valve assembly.

E.5.2.1 Seismic Qualification Test Sequence

The seismic qualification process is broken down into the following steps:

1. Mount the equipment on a rigid test fixture and perform a resonant search test to demonstrate that the equipment is structurally rigid (fundamental frequency greater than 33 hertz) and does not amplify the seismic motions acting at the equipment mounting interface.

2. Perform single frequency testing on the line-mounted equipment.

3. Perform multifrequency, multiaxis testing on the equipment, if appropriate.

4. If an active valve assembly is to be seismically qualified, additional testing is needed as follows:

    a. Perform a static pull test on the valve.

    b. Perform a static seismic analysis using a verified model of the valve and its extended structure to demonstrate that the valve has adequate structural strength to perform its safety-related function without exceeding the design allowable stresses specified in ASME Code, Section III, Subsection NB, NC, or ND for pressure-retaining parts, as

appropriate, and Subsection NF for non-pressure-retaining boundary parts. Limiting extended structure stress to material yield strength minimizes deflections, which could interfere with valve stroke function.

E.5.2.2 Line Vibration Aging

Line-mounted equipment may be subject to operational vibrations resulting from normal plant operations. The potential fatiguing effect of this vibrational aging is simulated as part of the qualification program. This requirement is satisfied by subjecting the equipment to a sine sweep from 5 to 100 to 5 hertz at an acceleration level of 0.75g or such reduced acceleration at low frequencies to limit the double amplitude to 0.025 inch as specified in Section 5.3.a, Part III of IEEE 382-1996.

E.5.2.3 Single Frequency Testing

The single frequency testing acceleration waveform is either sine beat or sine dwell applied at one-third octave frequency intervals as specified in IEEE 382-1996. Each dwell has a time length adequate to permit performance of functional testing, with a minimum time of 15 seconds. To account for the three-dimensional nature of the seismic event, the test input level is taken as the square root of two times the required input motion (RIM) level specified in IEEE 382. The level includes the 10 percent test margin. Each test series is performed using single axis input. The test series is performed successively in each of three orthogonal axes.

E.5.2.4 Seismic Aging

The aging effect of the five 1/2 safe shutdown earthquake earthquakes can be simulated by exposing the equipment to two sinusoidal sweeps at one-half of the safe shutdown earthquake required input motion level in each orthogonal axis. Each sweep shall go from 2 to 35 hertz to 2 hertz at a rate not to exceed one octave per minute. One sweep is performed with the equipment in its inactive mode, and the other with the equipment in its safety-related operational mode.

E.5.2.5 Static Deflection Testing of Active Valves

The seismic testing just discussed is normally performed only on the valve operator and the attached appurtenances. If the valve assembly is rigid, the operability of the valve assembly during a postulated seismic event may be demonstrated by performing a static pull test using a peak acceleration value equivalent to a triaxial acceleration of 6g. If the valve assembly is determined to be flexible, a supplemental analysis of the seismic response of the flexible valve and its supporting piping is performed to determine the actual acceleration level present at the center of gravity of the valve assembly.

The valve is placed in a suitable test fixture with the operator and appurtenances mounted and oriented as in the normal valve assembly installation. The valve is mounted so that the extended structure is freestanding and supported only by the valve nozzles. The valve is positioned so that the horizontal and vertical load components simulating the three-dimensional nature of the seismic event produce a worst-case stress condition in the valve extended structure.

During testing, the valve shall be internally pressurized and nozzle loads applied. Static loads simulating dead weight and seismic loads are applied to the extended structure. The tests are normally performed at ambient temperature. These loads simulate to the extent feasible the load distribution acting on critical parts of the valve assembly. The valve is actuated using the actuator system seismically qualified according to IEEE 382-1996. The valve assembly is cycled from its normal to the desired safety-related position within the time limits defined in the equipment specification. Leakage measurements are made, where required, and compared to the allowable values specified in the valve design specification.

E.5.3 Operational Conditions

When equipment being qualified performs a safety-related function during the safe shutdown earthquake, the equipment is operated and monitored to demonstrate that the equipment functions properly before, during, and after the seismic event. If the test time is not long enough to complete the required functional tests, the length of the strong motion test time is increased to permit completion of the required functional testing.

Where functional testing is dependent on external electrical supply, the testing is performed using the worst-case electrical supply conditions.

E.5.4 Resonant Search Testing

Resonant search testing is performed to provide data on the natural frequency and dynamic response characteristics of the equipment qualified. For hard-mounted equipment being qualified by seismic testing, resonant search testing is done to provide additional information but is not required for qualification of the equipment. This is an important consideration because frequency testing for hard-mounted equipment is normally performed with the equipment mounted on the test table, where dynamic interaction of the table and the equipment has a significant effect on the measured natural frequency.

For qualification of line-mounted valve assemblies, it is necessary that the assemblies be rigid. To meet this requirement, the assembly mounted to a rigid test fixture so that the frequencies measured are indeed representative of the valve assembly. If it is not feasible to provide a rigid fixture, as is likely the case when testing such very large valves, as the main steam and feedwater isolation valves, additional tests and analyses may be required to determine if the apparent flexibility measured is due to the test fixture or to the characteristic of the valve assembly itself.

If the resonant search test data is being generated to verify the accuracy of an analytical modeling technique, the test specimen mounting details must accurately simulate the boundary conditions used in the analytical model.

E.6 Qualification by Analysis

Section E.3.2 defines the limits on the use of analysis to demonstrate seismic qualification of safety-related equipment. The following sections describe the analytical methods to be employed for qualification of equipment. There are two techniques, static and dynamic, used to qualify equipment. The success of either method depends on the ability of the analytical model to describe the response of the system to seismic loads. Alternative methods of analysis are accepted if their conservatism is documented.

The analysis is used to demonstrate the structural adequacy of the equipment being qualified. This is done by showing that the calculated stresses do not exceed the design allowable stresses specified in ASME Code, Section III, Subsection NB, NC, or ND for pressure-retaining equipment and Subsection NF for nonpressure-retaining equipment.

E.6.1 Modeling

Analysis may be performed by hand calculations, finite element, or mathematical models that adequately represent the mass and stiffness characteristics of the equipment. The model contains enough degrees of freedom to adequately represent the dynamic behavior over the frequency range of interest. It includes the essential features of the equipment.

Dynamic properties reflect the in-service operating conditions, such as structural coupling, dynamic effects of contained liquids, and externally applied restraints (where appropriate). Where the modeled equipment exhibits some nonlinear behavior, this nonlinearity is modeled unless justification is provided that it is insignificant or that the linear model provides conservative results. The adequacy of the model or of the modeling techniques is shown by comparing the predicted responses to the responses predicted by benchmark problems or modal testing. Acceptable benchmark problems include hand calculations, analysis of the same problem using a comparable verified public-domain program, empirical data, or information from the technical literature.

In addition to documenting the modeling technique, a quality assurance program is in place that defines the requirements for the control, verification, and documentation for the computer programs used for qualification of safety-related equipment. The computer programs used in the qualification process are verified on the same computer on which the qualification analysis is performed.

E.6.2 Qualification by Static Analysis

For rigid equipment, the seismic forces resulting from one seismic input direction are calculated for each node point by multiplying the nodal mass in that direction by the appropriate zero period acceleration (ZPA) floor acceleration. The combined system response of the equipment to the simultaneous loads acting in all three directions is calculated by combining the three components, using the square root sum of the squares (SRSS) method. The square root sum of the squares method is used to account for the statistical independence of the individual orthogonal seismic components.

E.6.3 Qualification by Dynamic Analysis

If the lowest natural frequency of the equipment lies below the cutoff frequency, the response of the equipment to the seismic event in each orthogonal direction will be dynamically amplified and the equipment is said to be flexible. The analysis is performed in compliance with the guidelines set forth in the SSAR and in Regulatory Guides 1.92, 1.100, and 1.122.

The preferred method of analysis is the response spectrum method. In this method the responses in each equipment mode are calculated separately and combined by the square root sum of the squares method, provided the modes are not closely spaced. (Consecutive modes are said to be closely spaced if their frequencies differ from that of the first mode in the group by less than 10 percent.) The responses for each mode in a group are combined absolutely. The group response is then combined with the remaining modal responses using the square root sum of the squares method. The responses for each of the three orthogonal seismic components can then be combined as discussed in Section E.6.2. The applicable damping levels are noted in Table 3.7.1-1 of Chapter 3.

E.6.3.1 Response Spectrum Analysis

Modes up to and including the cutoff frequency are included in this summation. In some cases, the structure is basically rigid, with some of the flexible mode representing local effects. This situation is evaluated by reviewing the modal masses applicable to a given seismic input direction. If the sum of the effective modal masses used in the response spectrum analysis is greater than 0.9 times the total equipment mass, the model is assumed to adequately represent the total equipment mass. If this criterion is not satisfied, it means that a significant part of the equipment seismic response is due to the static seismic response of the higher equipment modes (above the cutoff frequency). If this situation occurs, the analyst determines the component of the response due to the higher modes and combines it with the flexible response component by square root sum of the squares. (This requirement is discussed in the SSAR, Subsection 3.7.2.)

E.6.3.2 Static Coefficient Method

As an alternative to the response spectrum method, the static coefficient method of analysis may be used. In this method the frequencies of the equipment are not determined, but a static analysis is performed, assuming that a peak acceleration equal to 1.5 times the peak spectral acceleration given in the applicable required response spectrum acts on the structure as described in Section E.6.2.

The static coefficient of 1.5 takes into account the combined effects of multifrequency excitation and multimode response for equipment and structures that can be represented by a simple model. A lower static coefficient may be used when it can be demonstrated that it will yield conservative results.

E.6.3.3 Time History Analysis

The time-history method of analysis is the preferred method of analysis when the equipment exhibits significant nonlinear behavior or when it is necessary to generate response spectra for specific component mounting locations in the equipment. The acceptable methods that are used to develop the seismic time histories are discussed in Regulatory Guide 1.122, ASME Code, Section III, Appendix N, and in Section 6.2 of IEEE 344-1987. Other analytical methods may be used to generate in-equipment response spectra provided that they are verified to produce accurate and/or conservative results.

E.7 Qualification by Test Experience

This method of qualification is not used.

E.8 Performance Criteria

E.8.1 Equipment Qualification by Test

The performance criterion for qualification of equipment is that the equipment successfully perform its safety-related function during and after the postulated seismic event. Acceptance requires, as a minimum, that:

- No spurious or unwanted outputs occur in the circuits that could impair the safety-related functional operability of the equipment;
- No gross structural damage of the equipment occur during the seismic event that could lead to the equipment or any part thereof becoming a missile. Local inelastic deformation of the equipment is permitted; and,
- Satisfactory completion of specified baseline tests are demonstrated before, during, and after the seismic test sequence.

E.8.2 Equipment Qualification by Analysis

E.8.2.1 Structural Integrity

The analysis verifies that the equipment, when subjected to the worst case combination of operating and seismic loads, maintains its structural integrity. In addition the analysis shows that the equipment is not subject to low cycle fatigue failure when subject to postulated seismic loading. Finally the analysis verifies that seismically induced equipment motion does not lead to impacting with other nearby equipment.

E.8.2.2 Operability

Analysis can be used to demonstrate equipment operability for those pieces of equipment where structural integrity or limitation of deformation guarantees operability. As an example the analysis of active equipment verifies that the combination of operating and postulated seismic loads do not produce stress levels or deformations that exceed established functional limits. The rationale for use of these limits is justified.

Appendix 3E High-Energy Piping in the Nuclear Island

This appendix identifies high-energy piping in the nuclear island with a diameter larger than 1 inch. Candidate leak-before-break piping is identified in Figures 3E-1 through 3E-5 along with other piping for which high-energy pipe failures are postulated. These figures also identify piping in the break exclusion zones inside and outside containment. These figures do not include piping of 1 inch size and smaller. These figures do not include the 6-inch diameter pipe segments on the high-energy reactor vessel head vent piping, or the 3-inch diameter high-energy lines for the reactor coolant pump heat exchangers which are evaluated in accordance with Subsection 3.6.2 and to which the leak-before-break methodology is not applied. Instrumentation and instrumentation lines are not included, except where a branch connection of greater than 1 inch is required.

The selection of the failure type is based on whether the system is high or moderate energy during normal operating conditions of the system. High-energy piping includes those systems or portions of systems in which the maximum normal operating temperature exceeds 200°F or the maximum normal operating pressure exceeds 275 psig. Piping systems or portions of systems pressurized above atmospheric pressure during normal plant conditions and not identified as high energy are considered moderate energy. Piping systems that exceed 200°F or 275 psig for 2 percent or less of the time during which the system is in operation or that experience high-energy pressures or temperatures for less than 1 percent of the plant operation time are considered moderate energy. In piping whose nominal diameter is greater than 1 inch but less than 4 inches, only circumferential breaks are postulated at each selected location. No breaks are postulated for piping whose nominal diameter is 1 inch or less.

The three-letter code included in the line numbering identifies the pipe specification. The letters define the pressure class, material specification, and AP1000 equipment classification, respectively. The symbols used in Figures 3E-1 through 3E-5 are the same as the P&ID figures. See Figure 1.7-2 for additional information on the drawing legend and for the key for the pipe specification. Section 3.2 includes additional information on the AP1000 equipment classification.

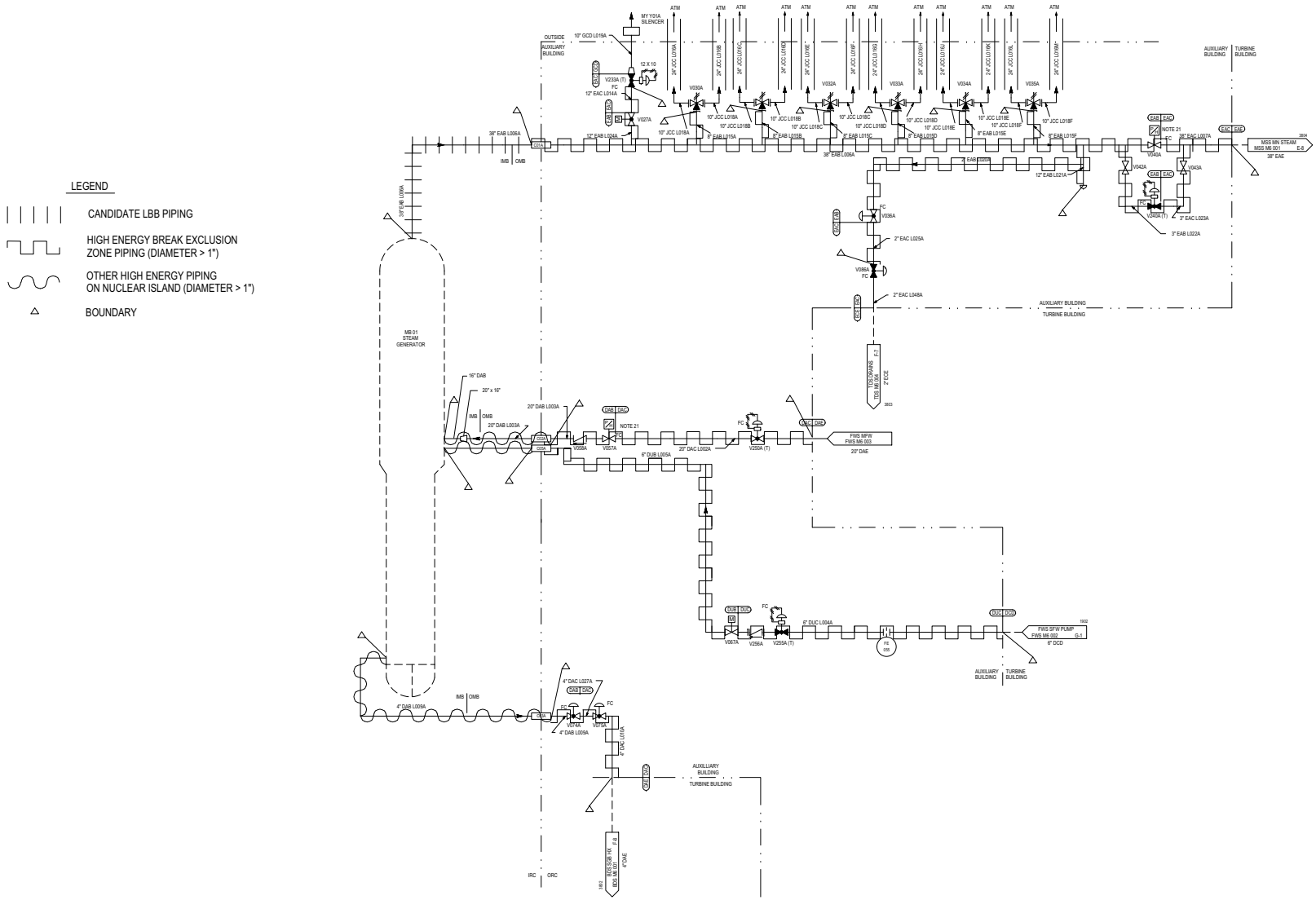


Figure 3E-1 (Sheet 1 of 2)
High Energy Piping – Steam Generator System

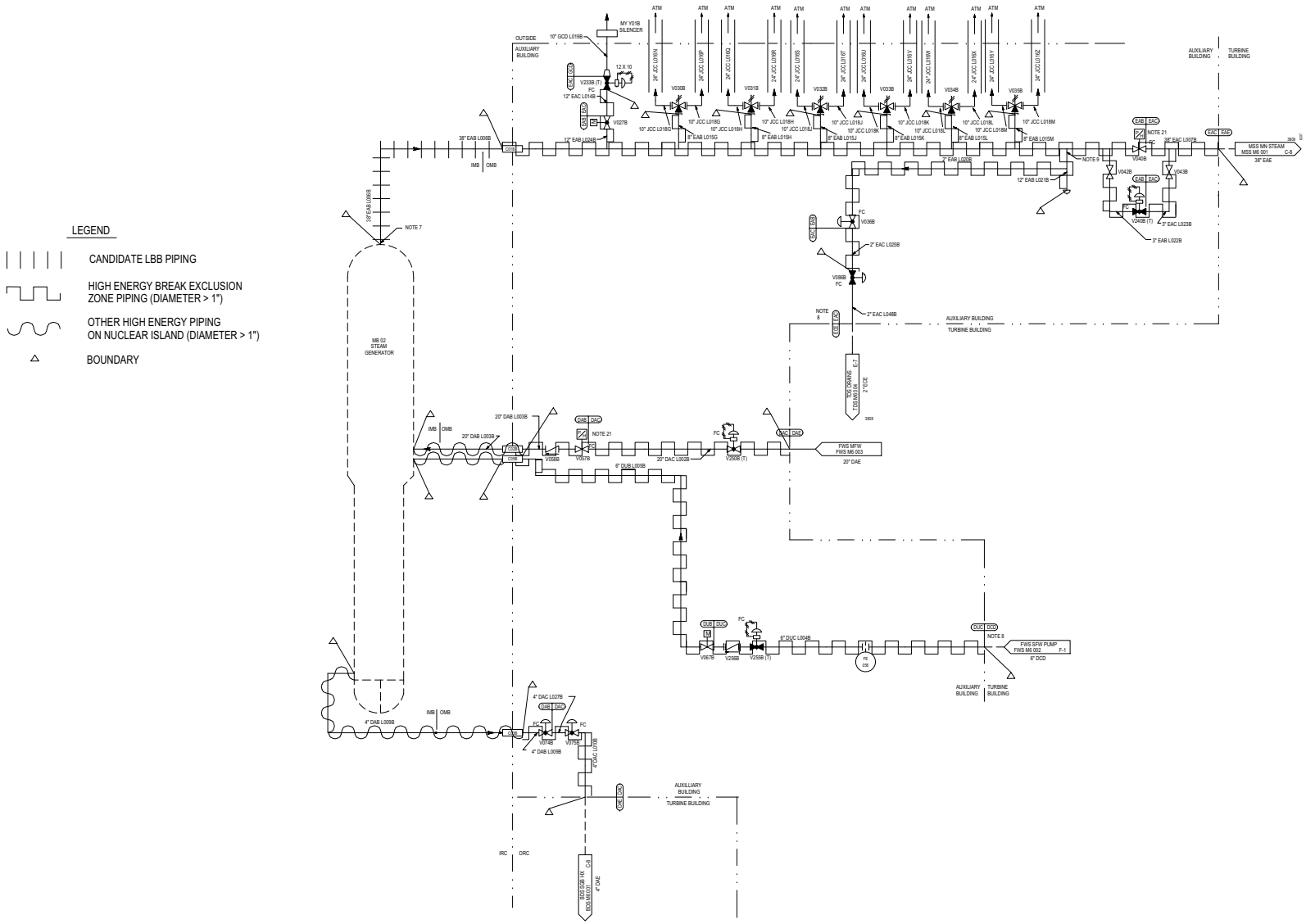


Figure 3E-1 (Sheet 2 of 2)
High Energy Piping – Steam Generator System

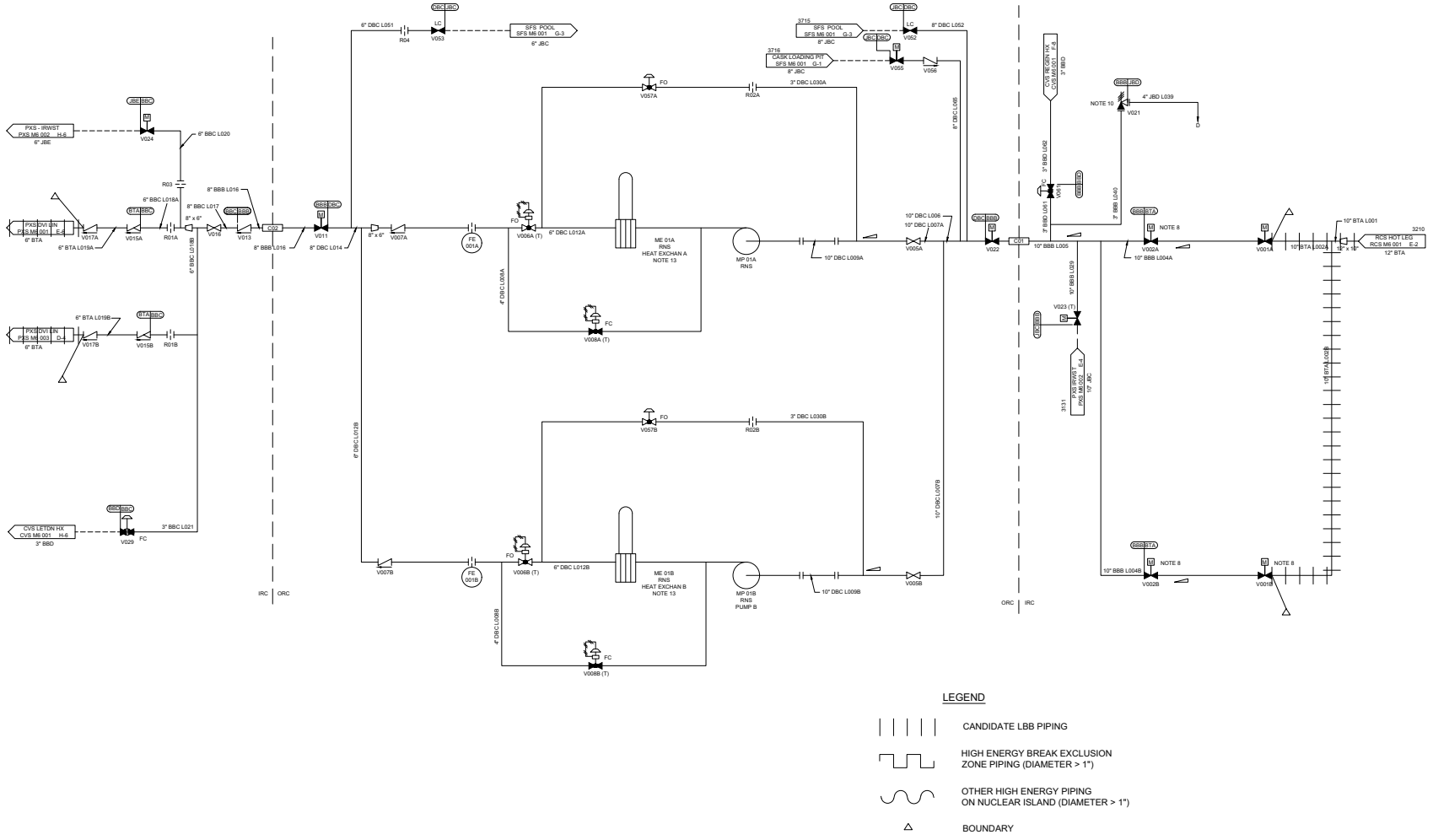
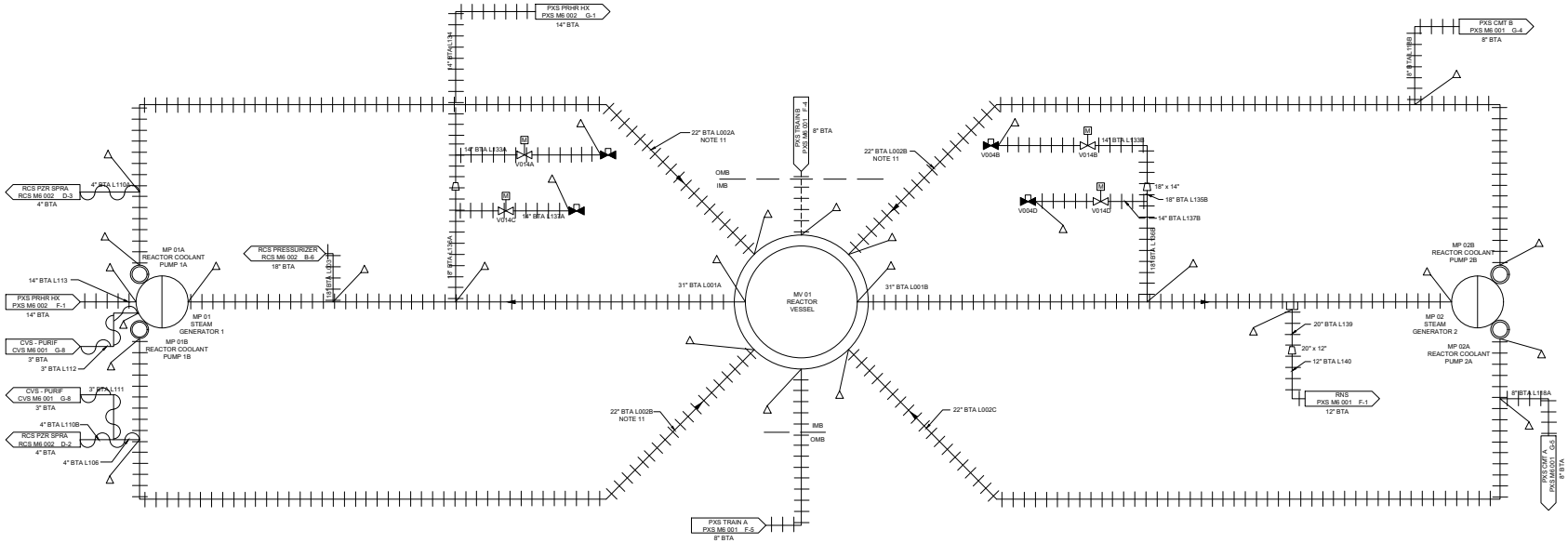


Figure 3E-2
High Energy Piping – Normal Residual Heat Removal System



LEGEND

CANDIDATE LBB PIPING

HIGH ENERGY BREAK EXCLUSION ZONE PIPING (DIAMETER > 1")

OTHER HIGH ENERGY PIPING ON NUCLEAR ISLAND (DIAMETER > 1")

BOUNDARY

Figure 3E-3 (Sheet 1 of 2)
High Energy Piping – Reactor Coolant System

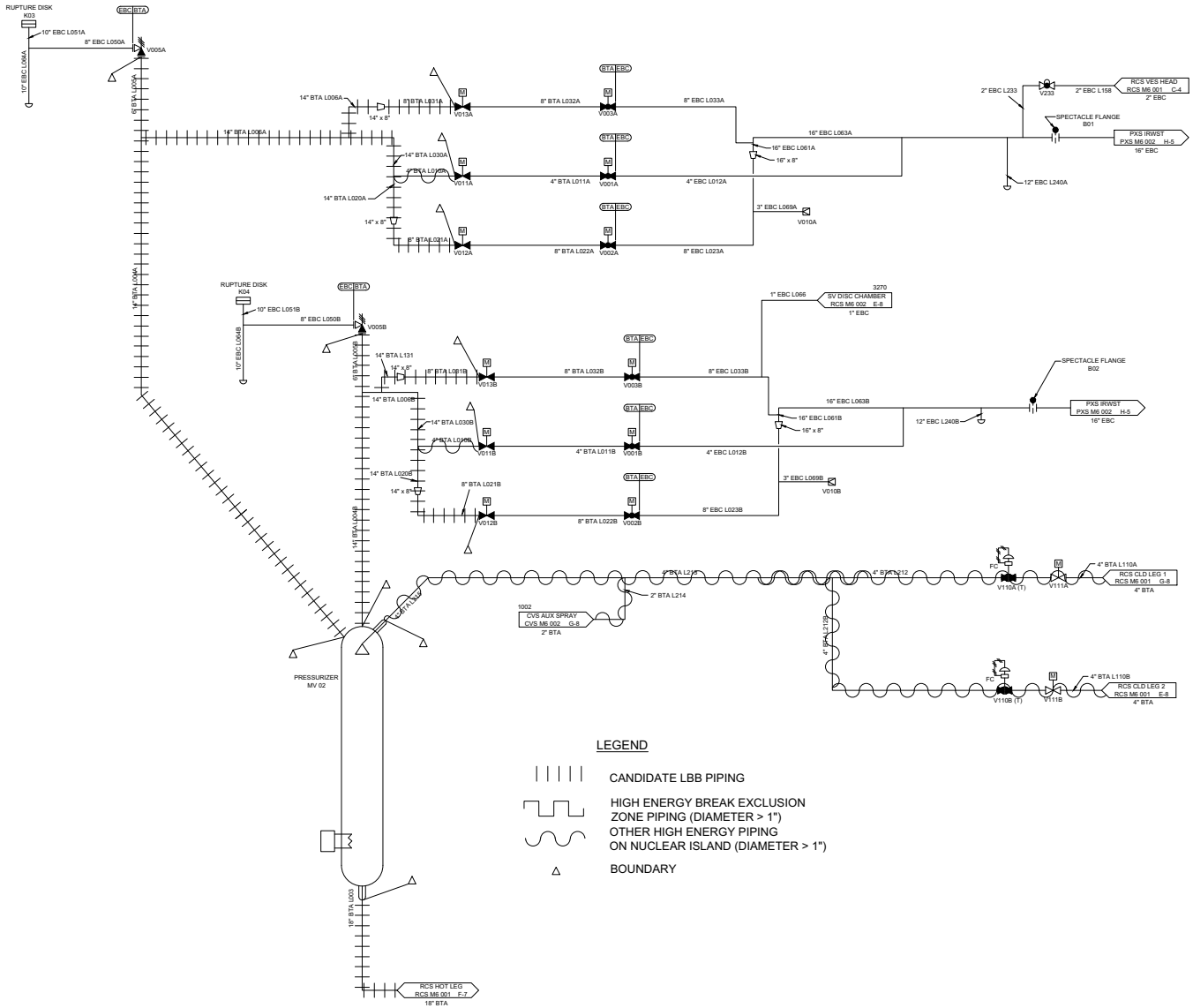


Figure 3E-3 (Sheet 2 of 2)
High Energy Piping – Reactor Coolant System

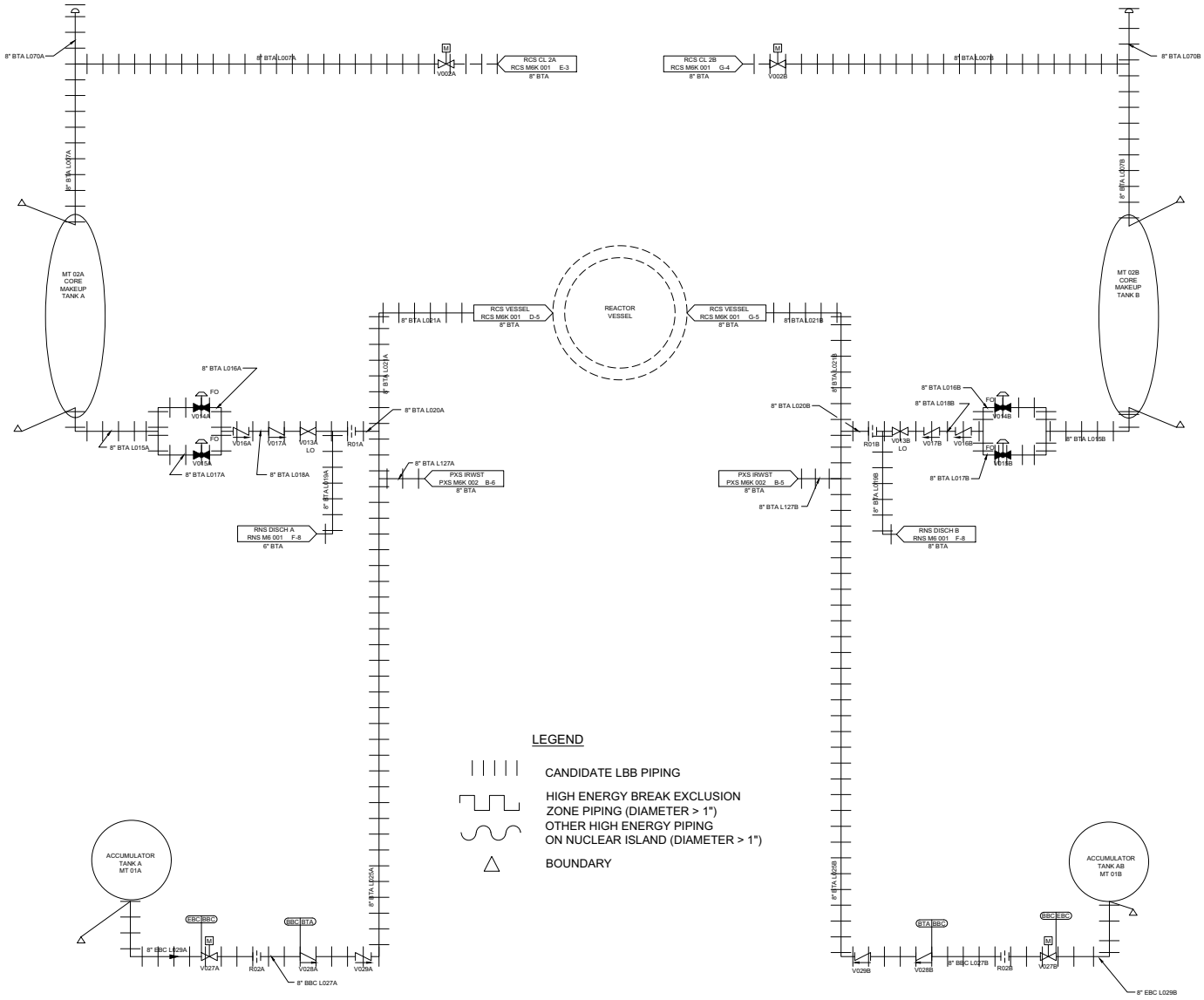


Figure 3E-4 (Sheet 1 of 2)
High Energy Piping – Passive Core Cooling System

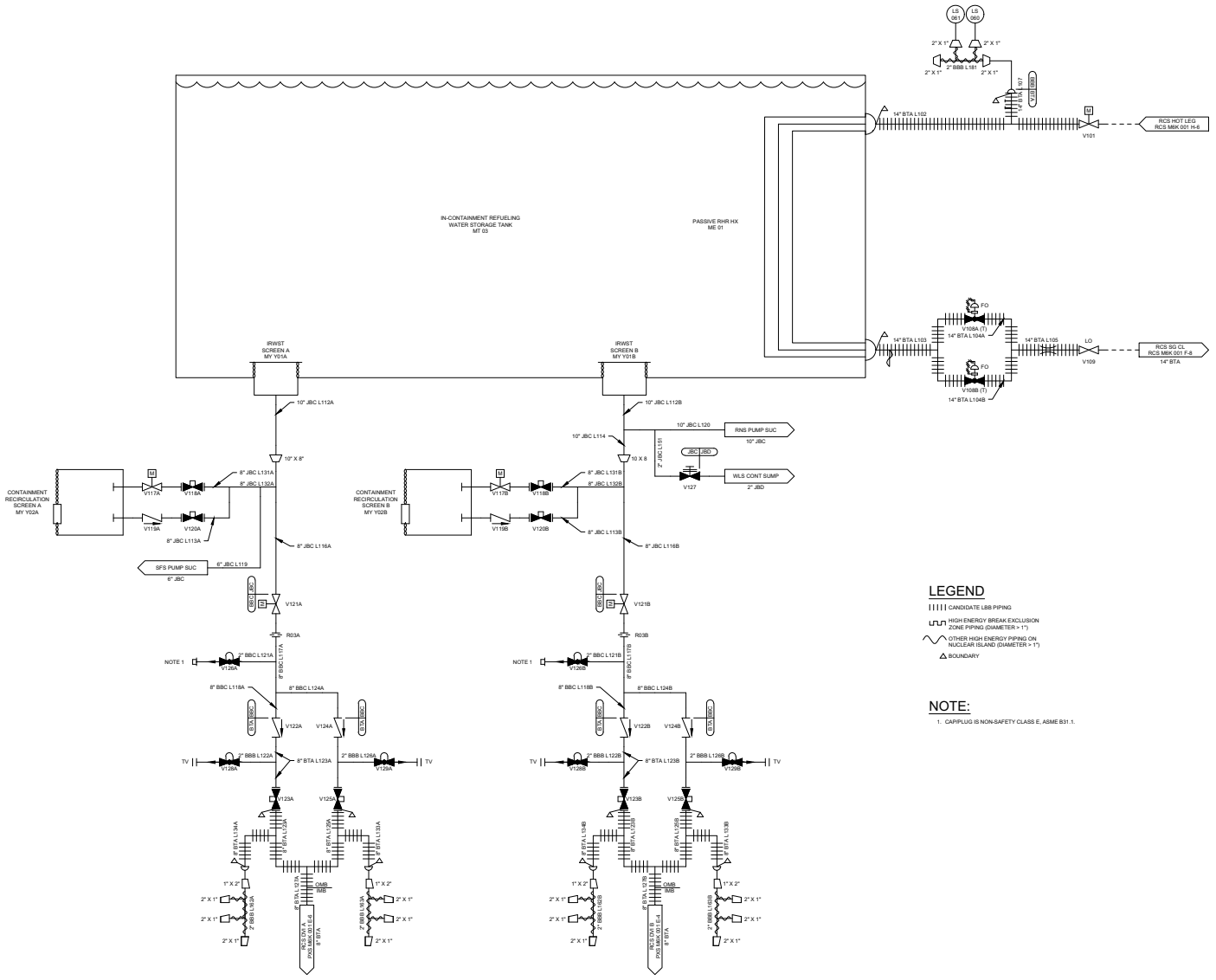


Figure 3E-4 (Sheet 2 of 2)
High Energy Piping – Passive Core Cooling System

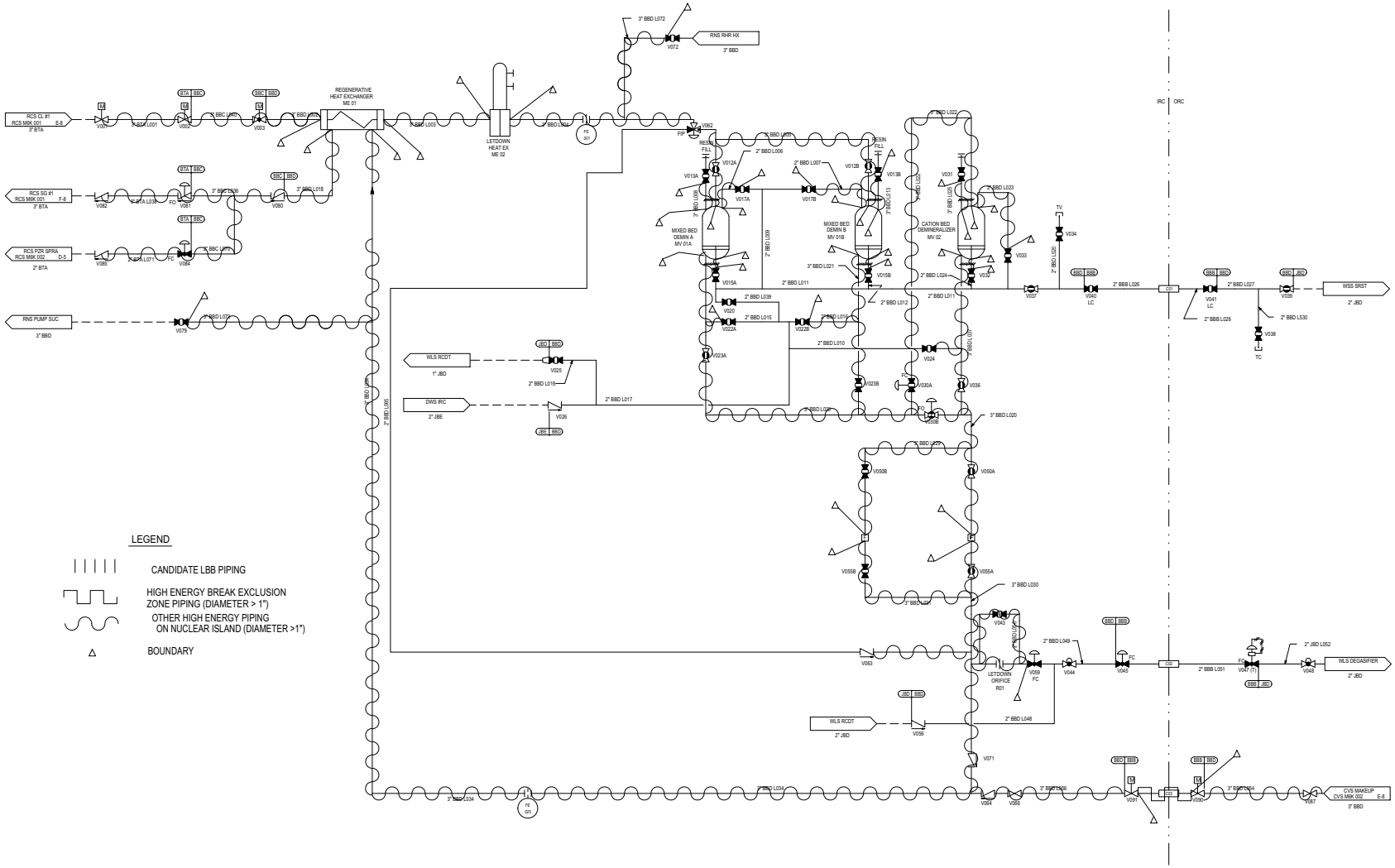


Figure 3E-5 (Sheet 1 of 2)
High Energy Piping – Chemical and Volume Control System

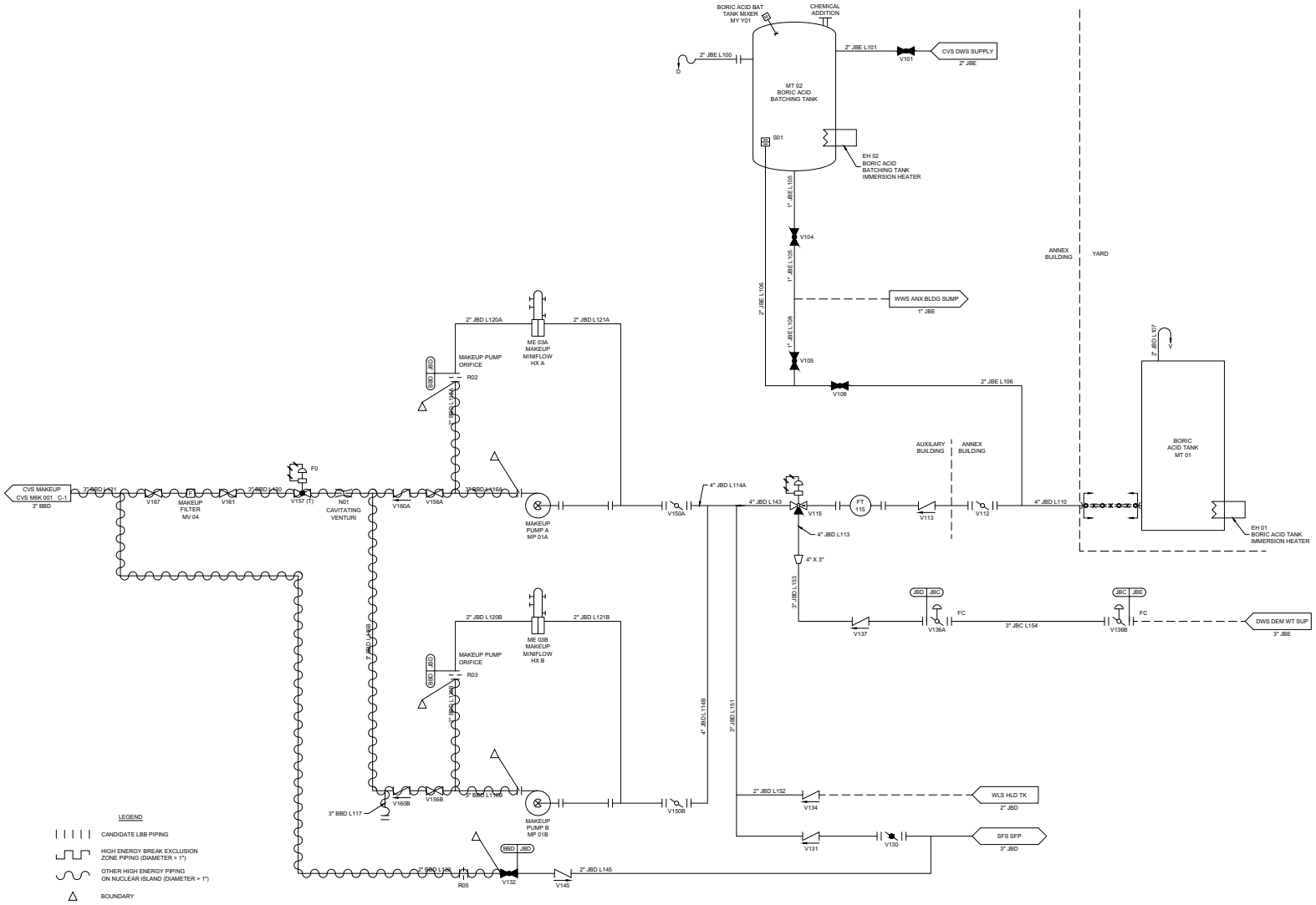


Figure 3E-5 (Sheet 2 of 2)
High Energy Piping – Chemical and Volume Control System

Appendix 3F Cable Trays and Cable Tray Supports

This appendix provides the design criteria for seismic Category I cable trays and their supports. Seismic Category II cable trays and their supports are also designed utilizing the design criteria of this appendix.

3F.1 Codes and Standards

The design of cable trays and their supports conform to the following codes and standards:

- American Iron and Steel Institute (AISI), Specification for the Design of Cold Formed Steel Structural Members, 1996 Edition and Supplement No. 1, July 30, 1999
- American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, ANSI/AISC N690-1994. American Welding Society (AWS), Structural Welding Code - Steel, AWS D1.1-2000 provides an acceptable alternative for ANSI/AISC N690 weld requirements as described in Subsections 3.8.3.2 and 3.8.4.2.
- Institute of Electrical and Electronic Engineers (IEEE), Standard 344-1987, IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations
- National Electrical Manufacturers Association (NEMA), Standard Publication No. VE 1-1998, Metallic Cable Tray Systems

3F.2 Loads and Load Combinations

3F.2.1 Loads

3F.2.1.1 Dead Load (D)

Dead load includes the weight of the cable trays, their supports and the cables inside the trays and any permanently attached items. Temporary items used during construction or maintenance are removed prior to operation.

It also includes the weight of

- Cable tray covers and
- Other components and fittings

3F.2.1.2 Construction Live Load (L)

Live load consists of a load of 250 pounds to be applied only during construction on the tray at a critical location to maximize flexural and shear stresses. This load is not combined with seismic loads.

3F.2.1.3 Safe Shutdown Earthquake (E_s)

Seismic response of the cable trays and their supports are produced due to seismic excitation of the supports.

3F.2.1.4 Thermal Load

These loads are usually not considered and trays are provided with expansion joints in accordance with NEMA.

3F.2.2 Load Combinations

The following load combinations are used for designing the cable trays and their supports:

(a) D + L

(b) D + E_s

3F.3 Analysis and Design

Cable tray systems are designed to maintain structural integrity which assures requirements for physical protection, cable separation, fire protection, and spatial interaction are met. The stresses are maintained within the allowable limits as specified in Subsection 3F.3.3. Section properties and weights of the trays are obtained from manufacturer's data.

3F.3.1 Damping

The maximum damping ratio is 10 percent unless the configuration is demonstrated to be similar to that of the tests described in (Reference 19) of Subsection 3.7.6.

As stated in Subsection 3.7.1.3, the damping ratio used for the AP1000 cable tray systems may be based on test results presented in Reference 19 (Subsection 3.7.6). The cable tray test program conducted by ANCO Engineers Inc. included more than 2000 dynamic tests of representative cable tray system design and construction. The test configurations included items such as various tray types on rigid supports, various tray hanger systems, effects of tray types, effects of strut connections and effects of bracing spacing, unbraced and braced tray systems. Cable ties were also used during the test program. Based on observations during the tests, the high damping values within the cable tray system are provided mainly by the movement, sliding or bouncing of the cables within the tray. The tests show that, for unloaded trays, the damping ratio closely approximates the 7 percent used for bolted structures, and a minimum damping value of 20 percent is maintained with cable ties at spacing greater than or equal to four feet. The tests show that for loaded trays, the damping ratio increases with increased cable loading, reaching a value of 30 percent at cable fill ratio of 50 percent to 100 percent. The major factors which affect the damping ratio of the cable tray systems are the input acceleration level, cable fill ratio, and the ability of the cables to move within the trays during a safe shutdown earthquake.

The AP1000 cable tray system design requires no sprayed-on material for fire protection. Cable ties are provided at spacing greater than 4 feet, thereby permitting cable movement within the trays. The damping ratio used for the cable tray system is dependent on the level of seismic input and the amount of cable fill within the trays. As shown in Figure 3.7.1-13, the 20 percent constant damping ratio may be used for trays loaded to more than 50 percent and subjected to input floor acceleration greater than 0.35g. For cable trays loaded to less than 50 percent and lower than 0.35g input floor acceleration, linearly interpolated lower damping values may be used.

3F.3.2 Seismic Analysis

The methodology for seismic analysis is provided in Subsection 3.7.3. Seismic loads are determined by either using the equivalent static load method of analysis or by performing dynamic analysis.

Stresses are determined for the seismic excitation in two horizontal and one vertical direction. The stresses in the three directions are combined using the square root of the sum of the squares (SRSS) method or the 100-40-40 method as described in Subsection 3.7.3.6.

3F.3.3 Allowable Stresses

The basic stress allowables for the cable trays are based on the American Iron and Steel Institute specification. The basic stress allowables for cable tray supports utilizing light gage cold rolled channel type sections are based on the manufacturer's published catalog values. The basic stress allowables for cable tray supports utilizing rolled structural shapes are in accordance with ANSI/AISC N690 and the supplemental requirements described in Subsection 3.8.4.5.2.

The allowable stresses for the load combinations are as follows:

D + L	Basic Allowable
D + E_s	1.6 times basic allowable for tension and 1.4 times basic allowable for compression

3F.3.4 Connections

Connections are designed in accordance with the applicable codes and standards listed in Section 3F.1. For connections used with light gage cold rolled channel type sections, design is based on the manufacturer's published catalog values. Supports are attached to the building structure by bolted or welded connections. Fastening of the supports to concrete structures meets the supplemental requirements given in Subsection 3.8.4.5.1.

Appendix 3G Nuclear Island Seismic Analyses

3G.1 Introduction

This appendix summarizes the seismic analyses of the nuclear island building structures performed to support the AP1000 design certification extension from just hard rock sites, to sites ranging from soft soils to hard rock. The seismic Category I building structures consist of the containment building (the steel containment vessel [SCV] and the containment internal structures [CIS]), the shield building, and the auxiliary building. These structures are founded on a common basemat and are collectively known as the nuclear island or nuclear island structures. Key dimensions of the seismic Category I building structures, such as thickness of the basemat, floor slabs, roofs and walls, are shown in Figures 3.7.1-14 and 3.7.2-12.

Analyses were performed in accordance with the criteria and methods described in Section 3.7. Section 3G.2 describes the development of the finite element models. Section 3G.3 describes the soil structure interaction analyses of a range of site parameters and the selection of the parameters used in the design analyses. Section 3G.4 describes the fixed base and soil structure interaction dynamic analyses and provides typical results from these dynamic analyses. References 3 and 6 provide a summary of dynamic and seismic analysis results (i.e., modal model properties, accelerations, displacements, response spectra) and the nuclear island liftoff analyses. The seismic analyses of the nuclear island are summarized in a seismic analysis summary report. Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Sections 3.7 and 3.8 provided the following acceptance criteria are met:

- The structural design meets the acceptance criteria specified in Section 3.8.
- The seismic floor response spectra (FRS) meet the acceptance criteria specified in Subsection 3.7.5.4.

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgment to performance of a revised analysis and design. The results of the evaluation will be documented in an as-built summary report by the Combined License applicant.

Table 3G.1-1 and Figure 3G.1-1 summarize the types of models and analysis methods that are used in the seismic analyses of the nuclear island, as well as the type of results that are obtained and where they are used in the design. Table 3G.1-2 summarizes the dynamic analyses performed and the methods used for combination of modal responses and directional input.

3G.2 Nuclear Island Finite Element Models

The AP1000 nuclear island consists of three distinct seismic Category I structures founded on a common basemat. The three building structures that make up the nuclear island are the coupled auxiliary and shield building (ASB), the SCV, and the CIS. The shield building and the auxiliary building are monolithically constructed with reinforced concrete and, therefore, considered one structure. The nuclear island is embedded approximately 40 feet with the bottom of basemat at elevation 60′-6″ and plant grade located at elevation 100′-0″. The SCV is described in Subsection 3.8.2, the CIS in Subsection 3.8.3, the ASB in Subsection 3.8.4, and the nuclear island basemat in Subsection 3.8.5.

Seismic systems are defined, according to SRP 3.7.2 (Reference 1), Section II.3.a, as the seismic Category I structures that are considered in conjunction with their foundation and supporting media to form a soil-structure interaction model. Fixed base seismic analyses are performed for the nuclear island at a rock site. Soil-structure interaction analyses are performed for soil sites. The analyses generate a set of in-structure responses (design member forces, nodal accelerations, nodal

displacements, and floor response spectra), which are used in the design and analysis of seismic Category I structures, components, and seismic subsystems. Concrete structures are modeled with linear elastic uncracked properties. However, the modulus of elasticity is reduced to 80% of the ACI code value to reduce stiffness to simulate cracking.

A seismic response spectrum analysis is performed to develop the seismic design loads for the design of the auxiliary building, shield building, and containment internal structure, and the loads generated include the amplified load due to flexibility and the distribution of this load to the surrounding structures. Equivalent static analyses are used to design the shield building roof and radial roof beams, tension ring, air inlet structure, and PCS tank.

3G.2.1 Individual Building and Equipment Models

3G.2.1.1 Coupled Auxiliary and Shield Building

The finite element shell dynamic model of the coupled ASB is a finite element model using primarily shell elements. The portion of the model up to the elevation of the auxiliary building roof is developed using the solid model features of ANSYS, which allow definition of the geometry and structural properties. The nominal element size in the auxiliary building model is about 9 feet so that each wall has two elements for the wall height of about 18 feet between floors. This mesh size, which is the same as that of the solid model, has sufficient refinement for global seismic behavior. It is combined with a finite element model of the shield building roof and cylinder above the elevation of the auxiliary building roof. This model is shown in Figure 3G.2-1. This finite element shell dynamic model is part of the NI10 model.

Since the water in the passive containment cooling system tank responds at a very low frequency (sloshing) and does not affect building response, the passive containment cooling system tank water mass is reduced to exclude the low frequency water sloshing mass. The wall thickness of the bottom portion of the shield building (elevation 63.5′ to 81.5′) is modeled as one half (1.5′) since the CIS model is connected to this portion and extends out to the mid-radius of the shield building cylindrical wall. Local portions of the ASB floors and walls are modeled with sufficient detail to give the response of the flexible areas.

3G.2.1.2 Containment Internal Structures

The finite element shell model of the containment internal structures is a finite element model using primarily shell elements for the walls and floors and solid elements for the mass concrete. It is developed using the solid model features of ANSYS, which allow definition of the geometry and structural properties. This model is used in both static and dynamic analyses. It models the inner and outer mass concrete basemats embedding the lower portion of the containment vessel, and the concrete structures above the mass concrete inside the containment vessel. The walls and basemat inside containment for this model are shown in Figure 3G.2-2. The basemat (dish) outside the containment vessel is shown in Figure 3G.2-3. This finite element shell dynamic model is part of the NI10 model. Static analyses are also performed on the model to obtain member forces in the walls. This model is also used in the 3D finite element basemat model (see Subsection 3.8.5.4.1).

3G.2.1.3 Containment Vessel

The SCV is a freestanding, cylindrical, steel shell structure with ellipsoidal upper and lower steel domes. The finite element model of the containment vessel is an axisymmetric model fixed at elevation 100′. Static analyses are performed with this model to obtain shell stresses as described in Subsection 3.8.2.4.1.1. The model is also used to develop modal properties (frequencies and mode shapes). The three-dimensional, lumped-mass stick model of the SCV is developed based on the

axisymmetric shell model. Figure 3G.2-4 presents the SCV stick model. In the stick model, the properties are calculated as follows:

- Members representing the cylindrical portion are based on the properties of the actual circular cross section of the containment vessel.

- Members representing the bottom head are based on equivalent stiffnesses calculated from the shell of revolution analyses for static 1.0g in vertical and horizontal directions.

- Shear, bending and torsional properties for members representing the top head are based on the average of the properties at the successive nodes, using the actual circular cross section. These are the properties that affect the horizontal modes. Axial properties, which affect the vertical modes, are based on equivalent stiffnesses calculated from the shell of revolution analyses for static 1.0g in the vertical direction.

The equivalent static acceleration analyses of the containment vessel use a finite element shell model with a refined mesh in the area adjacent to the large penetrations. Comparison of this with a time history analysis for the regions immediately surrounding the large penetrations verifies that the loads from equivalent static analysis are conservative to time history using a representative study.

The stick model is combined with the polar crane stick model as shown in Figure 3G.2-4. Modal properties of the containment vessel with and without the polar crane are shown in Table 3G.2-1. It is connected to nodes on the dish model. NI10 node numbers are shown in red and NI20 node numbers are shown in black.

The method used to construct a stick model from the axisymmetric shell model of the containment vessel is verified by comparison of the natural frequencies determined from the stick model and the shell of revolution model as shown in Table 3G.2-2. The shell of revolution vertical model (n = 0 harmonic) has a series of local shell modes of the top head above elevation 265′ between 23 and 30 hertz. These modes are predominantly in a direction normal to the shell surface and cannot be represented by a stick model. These local modes have small contribution to the total response to a vertical earthquake as they are at a high frequency where seismic excitation is small. The only seismic Category I components attached to this portion of the top head are the water distribution weirs of the passive containment cooling system. These weirs are designed such that their fundamental frequencies are outside the 23 to 30 hertz range of the local shell modes.

An evaluation was made of the connection of the bottom of the steel containment vessel stick model to the CIS finite element model. Comparisons were made between the unconstrained fully symmetric, radially constrained fully symmetric, and original asymmetric connectivity models. The response spectra at the elevation of the polar crane girder for the first two models are almost identical, and the third model had only minor differences. Based on this comparison, the unconstrained fully symmetric connectivity model is used.

3G.2.1.4 Polar Crane

The polar crane is supported on a ring girder, which is an integral part of the SCV at elevation 228′-0″, as shown in Figure 3.8.2-1. It is modeled as a multi-degree of freedom system attached to the steel containment shell at elevation 224′ (midpoint of ring girder) as shown in Figure 3G.2-4. The polar crane is modeled using a simplified and detailed model. The simplified model has five masses at the mid-height of the bridge at elevation 236′-6″ and one mass for the trolley, as shown in Figure 3G.2-5A. The polar crane model includes the flexibility of the crane bridge girders and truck assembly. The containment shell's local flexibility is considered when combined with the global model. When fixed at the center of containment, the model shows fundamental frequencies of 4.6 hertz transverse to the bridge, 6.9 hertz vertically, and 9.4 hertz along the bridge. The Detailed

Model of the polar crane consists of 76 nodes is defined having 96 dynamic degrees of freedom. It is used to verify the accuracy of the simplified model. This model is shown in Figure 3G.2-5B.

Nodes 425 to 428 are connected to 48 additional nodes. All 52 of these nodes are used to model the truck stiffnesses. The local SCV stiffness is considered when the detailed model of the polar crane is combined with the SCV model.

1. The elements connecting nodes 433, 431/477, 435, 436, 432/478, and 434 represent the trolley.

2. Nodes 437 to 454 are located on the polar crane bridge girders and cross beams. The end nodes (437, 443, 444, and 450) are used to connect the cross beams to the girders; these nodes are also attached to the trucks (nodes 425 to 428) by rigid links.

3. When the Detailed Model of the polar crane is combined with the SCV model, nodes 508 to 511, 528 to 531, 548 to 551, and 568 to 571 are merged to SCV nodes on the polar crane ring girder.

3G.2.1.5 Major Equipment and Structures Using Stick Models

The major equipment supported by the CIS is represented by stick models connected to the CIS. These stick models are the reactor coolant loop model shown in Figure 3G.2-6, the pressurizer model shown in Figure 3G.2-7, and the core makeup tank model shown in Figure 3G.2-8. The core makeup tank model is used only in the nuclear island fine (NI10) model; the core makeup tank is represented by mass in the nuclear island coarse model (NI20).

3G.2.2 Nuclear Island Dynamic Models

Finite element shell models (3D) of the nuclear island concrete structures are used for the time history seismic analyses. Stick models are coupled to the shell models of the concrete structures for the containment vessel, polar crane, the reactor coolant loop and pressurizer. Two models are used. The fine (NI10) model is used to define the seismic response for the hard rock site. The coarse (NI20) model is used for the soil structure interaction (SSI) analyses. It is similar to the NI10 model with the exception that the mesh size for the ASB and CIS is approximately 20 feet instead of 10 feet. This model is set up in both ANSYS and SASSI. The NI05 model is used to develop amplified seismic response for the envelope of soil profiles presented in Subsection 3.7.1.4 for flexible regions not captured by the coarser NI20 model. The NI05 model is also used in response spectrum analysis of the nuclear island to develop design seismic member forces and moments. The NI10, NI20, and NI05 models are described in the subsections below.

3G.2.2.1 NI10 Model

The large solid-shell finite element model of the AP1000 nuclear island shown in Figure 3G.2-9 combines the ASB solid-shell model described in Subsection 3G.2.1.1, and the CIS solid-shell model described in Subsection 3G.2.1.2. The containment vessel and major equipment that are supported by the CIS are represented by stick models and are connected to the CIS. These stick models are the SCV and the polar crane models, the reactor coolant loop model, core makeup tank models, and the pressurizer model. The stick models are described in Subsections 3G.2.1.3 and 3G.2.1.4. The CIS and attached sticks are shown in Figure 3G.2-10. This AP1000 nuclear island model is referred to as the NI10 or fine model. The ASB portion of this model has a mesh size of approximately 10 feet.

The SCV is connected to the CIS model using constraint equations. The SCV at the bottom of the stick at elevation 100′ (node 130401) is connected to CIS nodes at the same elevation. Figure 3G.2-4 shows the SCV stick model with the constraint equation nodes. The nodes are defined using a

cylindrical coordinate system whose origin coincides with the center of containment (node 130401). The CIS vertical displacement is tied rigidly (constrained) to the vertical displacement and RX and RY rotations of node 130401. The CIS tangential displacement is tied rigidly (constrained) to the horizontal displacement and RZ rotation of node 130401.

3G.2.2.2 NI20 Model

The NI20 coarse model has fewer nodes and elements than the NI10 model. It captures the essential features of the nuclear island configuration. The nominal shell and solid element dimension is about 20 feet. It is used in the soil-structure interaction analyses of the nuclear island performed using the program SASSI. The stick models are the same as used for the NI10 model except that the core makeup tank is not included. This model is shown in Figures 3G.2-11 and 3G.2-12. Results of fixed base analyses of the NI20 model were compared to those of the NI10 model to confirm the adequacy of the NI20 model for use in the soil-structure-interaction analyses.

3G.2.2.3 Nuclear Island Stick Model

The nuclear island lumped-mass stick model consists of the stick models of the individual buildings interconnected by rigid links. Each individual stick model is developed to match the modal properties of the finite element models described in Subsections 3G.2.1.1 and 3G.2.1.2 above. Modal analyses and seismic time history analyses were performed using this model for the hard rock design certification.

The nuclear island lumped-mass stick model has been replaced in the design analyses described in this appendix by the NI10 and NI20 finite element shell dynamic models of the nuclear island described in Subsections 3G.2.2.1 and 3G.2.2.2 above. A 2D stick model is used in the soil sensitivity analyses described in Section 3G.3.

3G.2.2.4 NI05 Model

The NI05 solid-shell finite element model of the AP1000 nuclear island is shown in Figures 3G.2-13 to 3G.2-15. The NI05 model is used for response spectrum analysis of the nuclear island auxiliary and shield building structures. The NI05 model is also used for the mode superposition time history analysis of the nuclear island for the amplified response at flexible floors. The NI05 model is used for the static analysis of the nuclear island for the basemat design. The NI05 model is a refined version of the NI10 model where the auxiliary and shield building mesh size is reduced from approximately 10 feet by 10 feet tetrahedral mesh to approximately 5 feet by 5 feet. The major equipment stick models supported by the CIS are the same as used for the NI10 model. The steel containment vessel stick model and connections are also the same as the NI10 model. The only difference between the NI05 CIS and NI10 CIS is the basemat (bowl) and dish region as shown in Figure 3G.2-15. The model is validated by a comparison of the mass participation by frequency of the fundamental modes to those of the NI10 model.

3G.2.2.5 Seismic Stability Model

The sliding stability of the nuclear island basemat is evaluated using a non-linear 2D East-West (EW) stick model of the nuclear island structures using the ANSYS program. Three concentric sticks represent ASB, CIS, and SCV, respectively. The reactor coolant loop is included as mass only. The basemat is modeled as a rigid beam, which is free in translation along the EW and vertical directions. The nuclear island combined sticks are attached to the rigid basemat at the nuclear island mass center.

Each node of the rigid basemat is connected with two spring elements in the horizontal and vertical directions, respectively. The spring elements only model the foundation media (rock or soil) damping,

not stiffness. A layer of contact elements is added along the rigid basemat bottom to simulate the friction forces between basemat bottom and foundation media as well as foundation media stiffnesses. The friction coefficient between the basemat bottom and the soil media is set at 0.55. Figure 3G.2-19 shows the schematic of this non-linear 2D EW nuclear island stick model. The contact elements are free to uplift when the upward force (normal force) is larger than the associated dead load component. When the tangential force is larger than the friction force, sliding occurs.

3G.2.3 Static Models

Member forces in the ASB are obtained from analyses of a model that is more refined than the finite element model described in Subsection 3G.2.1.1. This model is developed by meshing one area of the solid model with four finite elements. The nominal element size in this auxiliary building model is about 4.5 feet so that each wall has four elements for the wall height of about 18 feet between floors. This finite element shell model is referred to as the NI05 model. This refinement is used to calculate the design member forces and moments using response spectra analysis of the nuclear island models with seismic input enveloping all soil conditions. The finite element shell model of the containment internal structures described in Subsection 3G.2.1.2, which includes the basemat within the shield building and the containment vessel stick model, is also included.

Finite element solid/shell models were used for the equivalent static seismic analysis. For the detailed design of the shield building roof, a finite element model of one quadrant of the roof is used as described in Subsection 3G.2.3.1. For the detailed design of the steel containment vessel, a shell mesh finite element model with a much finer mesh in the areas surrounding the major penetrations is used as described in Subsection 3G.2.3.2. For the static analysis of the containment vessel, an axisymmetric model is used as described in Subsection 3G.2.3.3. The nuclear island basemat is evaluated using the NI05 finite element model described in Subsection 3G.2.2.4.

3G.2.3.1 Quadrant Model of Shield Building Roof

The one quadrant model of the shield building roof is shown in Figure 3G.2-16. The model is constructed with solid and shell elements and contains structures from the exposed shield wall through the top of the shield building roof. The quadrant model is used for the equivalent static analysis of the shield building roof. The results from the more detailed analysis are used in the design of the shield building roof and radial roof beams, tension ring, air inlet structure, and PCS tank.

3G.2.3.2 Containment Vessel 3D Finite Element Model

The 3D finite element model of the steel containment vessel is shown in Figure 3G.2-17. The finite element model for the steel containment vessel is used for the stress analysis of the large penetrations (personnel locks and equipment hatches) of the containment vessel.

3G.2.3.3 Containment Vessel Axisymmetric Model

The axisymmetric finite element model of the steel containment vessel is shown in Figure 3G.2-18. The axisymmetric model is a two-dimensional model with added mass for the stiffeners, crane girder, equipment hatches, and air locks.

3G.3 2D SASSI Analyses

This section describes the soil structure interaction analyses performed using 2D models in SASSI to select the design soil cases for the AP1000. The AP1000 footprint, or interface to the soil medium, is identical to the AP600. The AP1000 containment and shield building are 25′ 6″ and 20′ 6″ (Reference 4) respectively taller than AP600. Results and conclusions from the AP600 soil studies (Reference 2) are considered in establishing the design soil profiles for the AP1000.

Analyses were performed using 2D stick models of the AP1000 for horizontal seismic input with and without adjacent structures. The soil profiles included a hard rock site, a firm rock site, a soft rock site, a soft-to-medium soil site, an upper bound soft-to-medium site, and a soft soil site. Analyses were also performed without adjacent structures for a hard rock site, a firm rock site, a soft rock site, a soft-to-medium soil site, an upper bound soft-to-medium site, and a soft soil site. The soil damping and degradation curves are described in Subsection 3.7.1.4. The soil profiles selected for the AP1000 use the same parameters on depth to bedrock, depth to water table, and variation of shear wave velocity with depth as those used in the AP600 design analyses. The Poisson's ratio is 0.25 for rock sites (hard and firm rock) and 0.35 for soil sites (soft-to-medium soil, and upper bound soft-to-medium soil). For all the soil profiles defined, the base rock has been taken to be at 120 feet below grade level. The soil profiles are shown in Figure 3G.3-1. The shear wave velocity profiles and related governing parameters are as follows:

- For the hard rock site, an upper bound case for rock sites using a shear wave velocity of 8000 feet per second.

- For the firm rock site, a shear wave velocity of 3500 feet per second to a depth of 120 feet, and base rock at the depth of 120 feet.

- For the soft rock site, a shear wave velocity of 2400 feet per second at the ground surface, increasing linearly to 3200 feet per second at a depth of 240 feet, and base rock at the depth of 120 feet.

- For the upper bound soft-to-medium soil site, a shear wave velocity of 1414 feet per second at ground surface, increasing parabolically to 3394 feet per second at 240 feet, base rock at the depth of 120 feet, and ground water at grade level. The initial soil shear modulus profile is twice that of the soft-to-medium soil site.

- For the soft-to-medium soil site, a shear wave velocity of 1000 feet per second at ground surface, increasing parabolically to 2400 feet per second at 240 feet, base rock at the depth of 120 feet, and ground water is assumed at grade level.

- For the soft soil site, a shear wave velocity of 1000 feet per second at ground surface, increasing linearly to 1200 feet per second at 240 feet, base rock at the depth of 120 feet, and ground water is assumed at grade level.

The analyses with and without adjacent structures demonstrated that the effect of adjacent buildings on the nuclear island response is small. Based on this, the 3D SASSI analyses of the AP1000 nuclear island can be performed without adjacent buildings similar to those performed for the AP600.

The maximum acceleration values obtained from the AP1000 analyses without adjacent structures are given in Table 3G.3-1. The soil cases giving the maximum response are shown in bold. Floor response spectra associated with nodes 41, 120, 310, 411, and 535 for the six AP1000 soil cases are shown in Figures 3G.3-2 to 3G.3-11.

Based on review of the above results, five soil conditions were selected for 3D SASSI analyses in addition to the hard rock condition evaluated in the existing AP1000 Design Certification. Thus, the following five soil and rock cases identified in Subsection 3.7.1.4 are considered: hard rock, firm rock, soft rock, soft-to-medium soil, upper bound soft-to-medium, and soft soil.

3G.4 Nuclear Island Dynamic Analyses

3G.4.1 ANSYS Fixed Base Analysis

The NI10 model described in Subsection 3G.2.2.1 was analyzed by time history modal superposition. To perform the time history analysis of this large model, the ANSYS superelement (substructuring) techniques were applied. Substructuring is a procedure that condenses a group of finite elements into one element represented as a matrix. The reasons for substructuring are to reduce computer time of subsequent evaluations. Two sets of analyses were performed. To obtain the time history response of the ASB, the ASB finite element model was merged with the superelement of the CIS and its major components. To obtain the time history response of the CIS, the CIS finite element model was merged with the superelement of the ASB.

Deflection time history responses were obtained at selected representative locations. These locations included major wall and floor intersections and nodes at the cardinal orientations at key elevations of the shield building. Nodes were also selected at mid-span on flexible walls and floors. Typical locations are shown for the ASB at elevation 135′ on Figures 3G.4-1 and 3G.4-2. Figure 3G.4-1 shows the “rigid” locations, and Figure 3G.4-2 shows the “flexible” locations.

ANSYS is used to calculate the maximum relative deflection to the nuclear island for the envelope case that considers all of the soil and hard rock site cases. Synthesized displacement time histories are developed using the envelope seismic response spectra from the six site conditions (hard rock, firm rock, soft rock, upper-bound-soft-to-medium, soft-to-medium, and soft soil). Seismic response spectra at nine locations are used (four edge locations, one center location, and four corner locations). It is not necessary to adjust for drift since relative deflections to the basemat are calculated and the drift would be subtracted from the results.

3G.4.2 3D SASSI Analyses

The computer program SASSI 2000 is used to perform Soil-Structure Interaction analysis with the NI20 Coarse Finite Element Model. The SASSI Soil-Structure Interaction analyses are performed for the five soil conditions established from the AP1000 2D SASSI analyses. These soil conditions are firm rock, soft rock, soft-to-medium soil, upper bound soft-to-medium, and soft soil. The model includes a surrounding layer of excavated soil and the existing soil media as shown in Figures 3G.4-3 and 3G.4-4. Acceleration time histories and floor response spectra are obtained. Adjacent structures have a negligible effect on the nuclear island structures and, thus, are not considered in the 3D SASSI analyses.

Westinghouse has adopted the approach that calculates displacements internally within the ACS SASSI program based on an analytical complex frequency domain approach that uses inverse Fast-Fourier Transforms (FFT) to compute relative displacement histories instead of double numerical integration in the time domain that computes absolute displacement time histories from absolute acceleration time histories.

The relative displacement time history is calculated using ACS SASSI RELDISP module. The complex acceleration transfer functions (TF) are computed for reference and all selected output nodes. The relative acceleration transfer function is calculated by subtracting the reference node TF from the output node TF. The relative displacement transfer function is obtained by dividing the circular frequency square (ω^2) for each frequency data point. The relative displacement time history is obtained by taking the inverse FFT.

Relative displacements are calculated between adjacent buildings and the nuclear island using soft springs between the buildings. The spring stiffness is very small so that it does not affect the dynamic

response. These calculations are performed using 2D models and SASSI 2000. The relative deflection is calculated using the maximum compressive spring force and the stiffness value.

In these analyses, the three components of ground motions (N-S, E-W, and vertical direction) are input separately. Each design acceleration time history (N-S, E-W, and vertical) is applied separately, and the time history responses are calculated at the required nodes. The resulting co-linear time history responses at a node due to the three earthquake components are then combined algebraically.

3G.4.3 Seismic Analysis

3G.4.3.1 Response Spectrum Analysis

The response spectrum methodology used in the AP1000 design employs the Complete Quadratic Combination (CQC, Section 1.1 of Reference 5) grouping method for closely spaced modes with the Der Kiureghian Correlation Coefficient (Section 1.1.3 of Reference 5) used for correlation between modes. The Lindley-Yow (Section 1.3.2, Reference 5) spectra analysis methodology is employed for modes with both periodic and rigid response components. The modal analysis performed to develop composite modal participation is used to develop input for the response spectrum analysis. Modes ranging from 0 to 33 Hz or higher are considered. For modes above the cutoff frequency, the Lindley-Yow is used. The Static ZPA Method (Section 1.4.2, Reference 5) is employed for the residual rigid response component for each mode as outlined in NRC Regulatory Guide 1.92 (Reference 5). The complete solution is developed via Combination Method B (Section 1.5.2, Reference 5). The combined effects, considering three spatial components of an earthquake (N-S, E-W, and Vertical), are combined by square root sum of the squares method (Section 2.1, Reference 5).

In Subsection 3.7.2.6, “Three Components of Earthquake Motion,” the combination of three components of earthquake motion is discussed.

3G.4.3.2 Absolute Accelerations

The seismic analyses results, which include the new shield building configuration described in Section 3.8, are given in Reference 3.

3G.4.3.3 Seismic Response Spectra

The AP1000 plant floor response spectra for the six key locations are provided in Figure 3G.4-5X to 3G.4-10Z. The key locations are defined in Table 3G.4-1. The design seismic response spectra are conservatively adjusted in the low frequency range in anticipation of future sites having a slightly higher response at the lower frequency.

The in-structure response spectra at six key locations, as defined below, are used if a site-specific 3D dynamic analysis evaluation as outlined in Subsection 2.5.2 is required. The site is acceptable if the floor response spectra from the site-specific evaluation do not exceed the AP1000 spectra for each of the locations identified below or the exceedances are justified.

[*FRS Location*	*Figure Numbers*
Containment internal structures at elevation of reactor vessel support	*Figure 3G.4-5X to 3G.4-5Z*
Containment operating floor	*Figure 3G.4-6X to 3G.4-6Z*
Auxiliary building NE corner at elevation 116'-6"	*Figure 3G.4-7X to 3G.4-7Z*
Shield building at fuel building roof	*Figure 3G.4-8X to 3G.4-8Z*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Shield building roof *Figure 3G.4-9X to 3G.4-9Z*

Steel containment vessel at polar crane support *Figure 3G.4-10X to 3G.4-10Z*]*

Note:
See Table 3G.4-1 for locations of six key locations.

3G.4.3.4 Bearing Pressure Demand

Bearing pressure demand was calculated using both 2D and 3D analyses. Both linear and non-linear analyses are performed with the 2D nuclear island model. The maximum bearing pressures calculated include the effect of dead, live, and seismic loading.

The 2D model was used to evaluate the effect of liftoff on the bearing pressure. Since the largest bearing pressure will result from the east-west seismic excitation because of the smaller width of the basemat in this direction, liftoff was evaluated using an east-west stick model of the nuclear island structures, supported on a rigid basemat with non-linear springs. Direct integration time history analyses were performed. The bearing pressures calculated from these analyses are summarized in Table 3G.4-2. The pressures are at the edge of the basemat. Results are given for the three cases that result in the highest bearing pressure (hard rock [HR], upper bound soft to medium [UBSM] soil, and soft to medium [SM] soil). The linear results show maximum bearing pressures on the west side of 31 to 33 ksf. Liftoff increases the subgrade pressure close to the west edge by 4 percent to 6 percent with insignificant effect beneath most of the basemat.

The SASSI soil-structure interaction analyses are performed based on the nuclear island 3D SASSI model for the hard rock and five soil conditions established from the AP1000 2D SASSI analyses. The SASSI model of the nuclear island is based on the NI20 finite element model. The bearing pressures from the 3D SASSI analyses have been obtained by combining the time history results from the north-south, east-west, and vertical earthquakes. The maximum soil-bearing pressure demand is obtained from the hard rock (HR) case equal to 35 ksf. It is noted that a maximum localized peak is obtained on the west edge of 38 ksf; a limit of 35 ksf for maximum bearing seismic demand is obtained by averaging the soil pressure over 335 ft^2 of the west edge of the shield building where the maximum stress occurs.

3G.5 References

1. NUREG-800, Review of Safety Analysis Reports for Nuclear Power Plants, Section 3.7.2, Seismic System Analysis, Revision 2.

2. GW-GL-700, AP600 Design Control Document, Appendices 2A and 2B, Revision 4.

3. APP-GW-S2R-010, “Extension of Nuclear Island Seismic Analyses to Soil Sites,” Westinghouse Electric Company LLC.

4. APP-GW-GLN-112, “Structural Verification for Enhanced Shield Building,” Westinghouse Electric Company LLC.

5. U.S. NRC Regulatory 1.92, Revision 2, “Combining Modal Responses and Spatial Components in Seismic Analysis.”

6. APP-GW-GLR-044, “Nuclear Island Basemat and Foundation,” Westinghouse Electric Company LLC.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3G.1-1 (Sheet 1 of 4)
Summary of Models and Analysis Methods

Model	Analysis Method	Program	Type of Dynamic Response/Purpose
3D (ASB) solid-shell model	-	ANSYS	Creates the finite element mesh for the ASB finite element model.
3D (CIS) solid-shell model	-	ANSYS	Creates the finite element mesh for the CIS finite element model.
3D finite element model including shield building roof (ASB10)	-	ANSYS	ASB portion of NI10.
3D finite element model including dish below containment vessel	Response spectrum analysis	ANSYS	CIS portion of NI10.
3D finite element shell model of nuclear island [NI10] (coupled auxiliary and shield building shell model, containment internal structures, steel containment vessel, polar crane, RCL, pressurizer, and CMTs)	Mode superposition time history analysis	ANSYS	Performed for hard rock profile for ASB with CIS as superelement and for CIS with ASB as superelement. To develop time histories for generating plant design floor response spectra for nuclear island structures. To obtain maximum absolute nodal accelerations (ZPA) to be used in equivalent static analyses. To obtain maximum displacements relative to basemat.
3D finite element coarse shell model of auxiliary and shield building and containment internal structures [NI20] (including steel containment vessel, polar crane, RCL, and pressurizer)	Mode superposition time history analysis	ANSYS	Performed for hard rock profile for comparisons against more detailed NI10 model.

Table 3G.1-1 (Sheet 2 of 4)
Summary of Models and Analysis Methods

Model	Analysis Method	Program	Type of Dynamic Response/Purpose
Finite element lumped-mass stick model of nuclear island	Time history analysis	SASSI	Performed 2D parametric soil studies to help establish the bounding generic soil conditions and to develop adjustment factors to reflect all generic site conditions for seismic stability evaluation.
Finite element lumped-mass stick model of nuclear island	Direct integration time history analysis	ANSYS	Performed 2D linear and non-linear seismic analyses to evaluate effect of liftoff on Floor Response Spectra and bearing.
3D finite element coarse shell model of auxiliary and shield building and containment internal structures [NI20] (including steel containment vessel, polar crane, RCL, and pressurizer)	Time history analysis Complex frequency response analysis	SASSI	Performed for the five soil profiles of firm rock, soft rock, upper bound soft-to-medium soil, soft-to-medium soil, and soft soil. To develop time histories for generating plant design floor response spectra for nuclear island structures. To obtain maximum absolute nodal accelerations (ZPA) to be used in equivalent static analyses. To obtain maximum displacements relative to basemat. To obtain SSE bearing pressures for all generic soil cases. To obtain maximum member forces and moments in selected elements for comparison to equivalent static results.
3D shell model of auxiliary and shield building and containment internal structures [NI20] (including steel containment vessel)	Mode superposition time history analysis	ANSYS	Performed to develop loads for seismic stability evaluation.

Table 3G.1-1 (Sheet 3 of 4)
Summary of Models and Analysis Methods

Model	Analysis Method	Program	Type of Dynamic Response/Purpose
3D shell of revolution model of steel containment vessel	Modal analysis; equivalent static analysis using accelerations from time history analyses	ANSYS	To obtain dynamic properties. To obtain SSE stresses for the containment vessel.
3D lumped-mass stick model of the SCV	-	ANSYS	Used in the NI10 and NI20 models.
3D lumped-mass stick model of the RCL	-	ANSYS	Used in the NI10 and NI20 models.
3D lumped-mass stick model of the pressurizer	-	ANSYS	Used in the NI10 and NI20 models.
3D lumped-mass stick model of the CMT	-	ANSYS	Used in the NI10 model.
3D lumped mass detailed model of the polar crane	Modal analysis	ANSYS	To obtain dynamic properties. Used with 3D finite element shell model of the containment vessel.
3D lumped mass simplified (single beam) model of the polar crane	-	ANSYS	Used in the NI10 and NI20 models.
3D finite element shell model of containment vessel	Mode superposition time history analysis Equivalent static analysis	ANSYS	Used with detailed polar crane model to obtain acceleration response of equipment hatch and airlocks. To obtain shell stresses in vicinity of the large penetrations of the containment vessel.

Table 3G.1-1 (Sheet 4 of 4)
Summary of Models and Analysis Methods

Model	Analysis Method	Program	Type of Dynamic Response/Purpose
3D finite element refined shell model of nuclear island (NI05)	Equivalent static non-linear analysis using accelerations from time history analyses Mode superposition time history analysis for the wall and floor flexibility using synthetic time histories developed to match spectral envelopes applied at the base Response spectrum analysis with seismic input enveloping all soils cases	ANSYS	To obtain SSE member forces for the nuclear island basemat. To obtain floor and wall flexibility response characteristics. To obtain maximum displacements relative to basemat. To obtain SSE member forces for the auxiliary and shield building and the containment internal structures.
3D finite element coarse shell model of auxiliary and shield building and containment internal structures [NI20] (including steel containment vessel, polar crane, RCL, and pressurizer)	Mode superposition time history analysis with seismic input enveloping all soil cases	ANSYS	To obtain total basemat reactions for comparison to reactions in equivalent static linear analyses using NI05 model.
Quadrant model of shield building roof (See subsection 3.8.4.4.1 for information on use of the quadrant model.)	Equivalent static analysis The PCS tank is designed using the maximum accelerations at the applicable elevation resulting from time history dynamic analyses of the nuclear island. The tension ring and air inlet use maximum accelerations that are increased based on results of response spectrum analysis.	ANSYS	To obtain member forces for shield building roof and radial roof beams, air inlet structure, tension ring, and PCS tank.

Table 3G.1-2
Summary of Dynamic Analyses and Combination Techniques

Model	Analysis Method	Program	Three Components Combination	Modal Combination
3D finite element, fixed base models, coupled auxiliary and shield building shell model, with superelement of containment internal structures (NI10 and NI20)	Mode superposition time history analysis	ANSYS	Algebraic Sum	n/a
3D finite element nuclear island model (NI20)	Complex frequency response analysis	SASSI	Algebraic Sum	n/a
3D finite element, fixed base models, coupled auxiliary and shield building and containment internal structures including shield building roof (NI05)	Response spectrum analysis	ANSYS	SRSS or 100%, 40%, 40%	Lindley-Yow
3D finite element model of the nuclear island basemat (NI05)	Equivalent static analysis using nodal accelerations from shell model	ANSYS	100%, 40%, 40%	n/a
3D shell of revolution model of steel containment vessel	Equivalent static analysis using nodal accelerations from 3D stick model	ANSYS	SRSS or 100%, 40%, 40%	n/a
PCS valve room and miscellaneous steel frame structures, miscellaneous flexible walls, and floors	Response spectrum analysis	ANSYS	SRSS or 100%, 40%, 40%	Grouping or Lindley-Yow
2D stick model analyses with liftoff	Direct integration time history	ANSYS	Algebraic Sum	n/a

Table 3G.2-1 (Sheet 1 of 2)
Steel Containment
Vessel Lumped-Mass Stick Model (Without Polar Crane) Modal Properties

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
1	6.28	3.51	159.81	0.01
2	6.28	160.01	3.51	0.00
3	12.87	0.03	0.00	0.00
4	16.89	0.00	0.01	173.42
5	18.87	0.29	40.91	0.00
6	18.89	40.77	0.29	0.00
7	28.13	0.00	0.00	28.45
8	31.67	0.09	2.81	0.00
9	31.80	3.05	0.09	0.00
10	37.66	1.28	0.02	0.00
11	38.34	0.04	4.98	0.02
12	38.73	3.41	0.02	0.00
13	47.37	0.00	0.00	5.26
14	53.48	4.76	0.66	0.00
15	53.53	0.64	4.84	0.00
16	59.55	0.00	0.03	3.78
17	62.60	0.15	0.00	0.05
18	63.10	0.00	0.05	6.98
19	63.23	0.00	0.00	0.04
20	65.80	0.03	0.66	0.05
Sum of Effective Masses		218.06	218.69	218.05

Notes:
1. Fixed at Elevation 100′.
2. The total mass of the containment vessel is 229.16 kip-sec^2/ft.

Table 3G.2-1 (Sheet 2 of 2)
Steel Containment Vessel Lumped-Mass Stick Model (With Polar Crane)
Modal Properties

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
1	4.20	0.00	78.15	0.00
2	4.98	149.97	0.00	0.17
3	6.44	6.80	0.01	23.59
4	6.47	0.00	112.05	0.00
5	8.00	35.09	0.00	1.19
6	8.61	0.00	4.06	0.00
7	12.58	0.03	0.18	0.00
8	16.00	0.06	0.08	0.22
9	16.09	5.16	0.00	146.06
10	17.21	24.58	0.00	36.27
11	18.86	0.00	40.88	0.00
12	20.64	13.30	0.00	0.71
13	23.74	0.00	0.40	0.00
14	27.04	0.13	0.00	15.64
15	29.62	2.88	0.00	3.61
16	30.21	0.00	0.07	0.00
17	31.62	0.00	2.92	0.01
18	32.85	0.58	0.00	0.38
19	34.02	0.28	0.01	4.87
20	36.97	0.20	1.61	0.00
Sum of Effective Masses		239.04	240.42	232.72

Notes:
1. Fixed at Elevation 100′.
2. The total mass of the containment vessel with the polar crane is 261.02 kip-sec^2/ft.

Table 3G.2-2 Comparison of Frequencies for Containment Vessel Seismic Model

Mode No.	Vertical Model		Horizontal Model	
	Shell of Revolution Model	Stick Model	Shell of Revolution Model	Stick Model
1	16.51 hertz	16.97 hertz	6.20 hertz	6.31 hertz
2	23.26 hertz	28.20 hertz	18.58 hertz	18.96 hertz

Note:
1. Fixed at elevation 100′.

Table 3G.3-1
AP1000 ZPA for 2D SASSI Cases

	North-South		Hard Rock ZPA [g]	Firm Rock ZPA [g]	Soft Rock ZPA [g]	UBSM ZPA [g]	SM ZPA [g]	Soft Soil ZPA [g]
	Node	El. feet						
ASB	21	81.5	0.326	0.326	0.345	**0.358**	0.306	0.249
	41	99	0.348	0.327	0.347	**0.361**	0.308	0.227
	120	179.6	**0.571**	0.501	0.469	0.498	0.529	0.247
	150	242.5	0.803	0.795	0.816	**0.819**	0.787	0.29
	310	333.1	1.449	1.561	**1.567**	1.524	1.226	0.453
SCV	407	138.6	0.405	**0.424**	0.408	0.387	0.407	0.232
	411	200	0.82	**0.916**	0.672	0.541	0.484	0.263
	417	281.9	1.396	**1.465**	1.031	0.723	0.598	0.372
CIS	535	134.3	**0.548**	0.45	0.347	0.368	0.355	0.229
	538	169	**1.517**	0.874	0.45	0.441	0.397	0.317
	East-West		**Hard Rock ZPA [g]**	**Firm Rock ZPA [g]**	**Soft Rock ZPA [g]**	**UBSM ZPA [g]**	**SM ZPA [g]**	**Soft Soil ZPA [g]**
	Node	**El. feet**						
ASB	21	81.5	0.309	0.318	0.359	**0.376**	0.311	0.235
	41	99	0.318	0.336	0.367	**0.385**	0.317	0.237
	120	179.6	**0.607**	0.561	0.546	0.549	0.605	0.295
	150	242.5	0.84	0.823	0.854	0.912	**0.962**	0.557
	310	333.1	1.449	1.536	1.624	**1.74**	1.506	0.891
SCV	407	138.6	0.528	0.529	**0.535**	0.513	0.38	0.247
	411	200	0.817	**0.95**	0.816	0.741	0.515	0.429
	417	281.9	1.251	**1.503**	1.136	0.985	0.716	0.675
CIS	535	134.3	**0.52**	0.404	0.391	0.404	0.365	0.259
	538	169	**1.679**	1.052	0.755	0.553	0.526	0.441

Table 3G.4-1
Key Nodes at Location

Location	General Area	Elevation (feet)
CIS at Reactor Vessel Support Elevation	SCV Center	100.00
CIS at Operating Deck	SG West Compartment, NE	134.25
ASB NE Corner at Control Room Floor	NE Corner	116.50
ASB Corner of Fuel Building Roof at Shield Building	NW Corner of Fuel Bldg	179.19
ASB Shield Building Roof Area	South Side of Shield Bldg	327.41
SCV Near Polar Crane	SCV Stick Model	224.00

Table 3G.4-2
Maximum Bearing Pressure from 2D Time History Analyses

Soil Case	Analysis	East Edge (ksf)	West Edge (ksf)
Hard Rock	Linear	17.18	32.77
	Liftoff	17.38	34.85
Upper-bound Soft to Medium	Linear	19.46	31.69
	Liftoff	18.42	33.51
Soft to Medium	Linear	15.84	30.82
	Liftoff	17.06	32.18

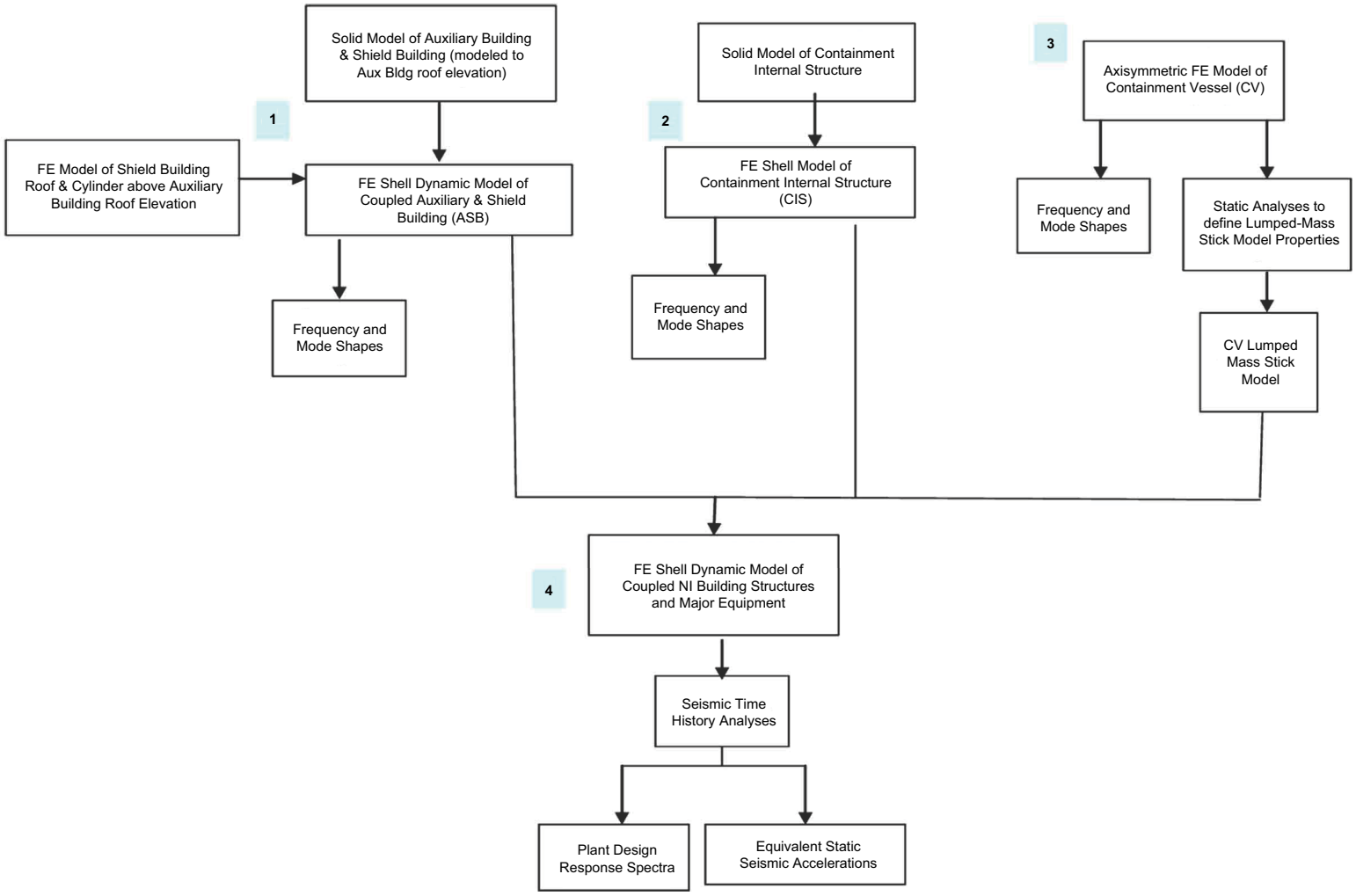


Figure 3G.1-1
Nuclear Island Seismic Analysis Models

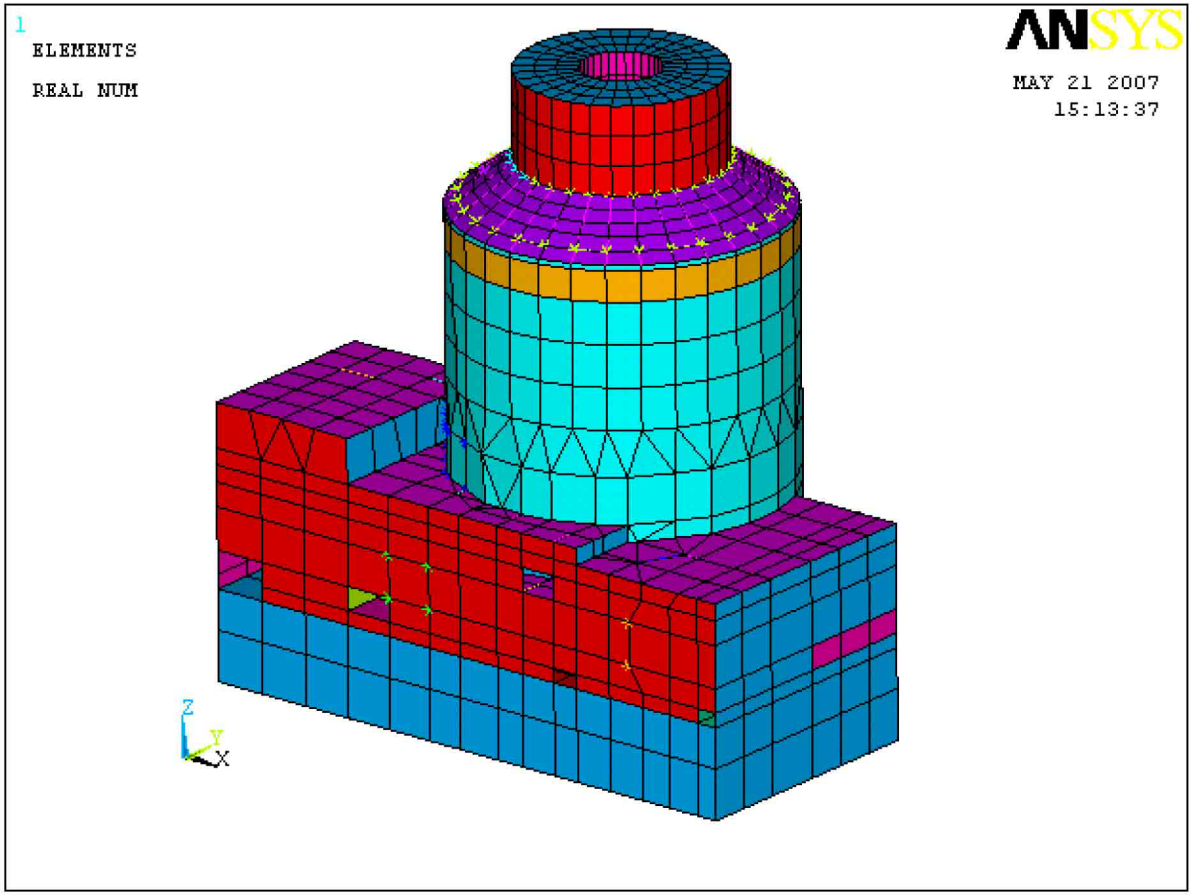
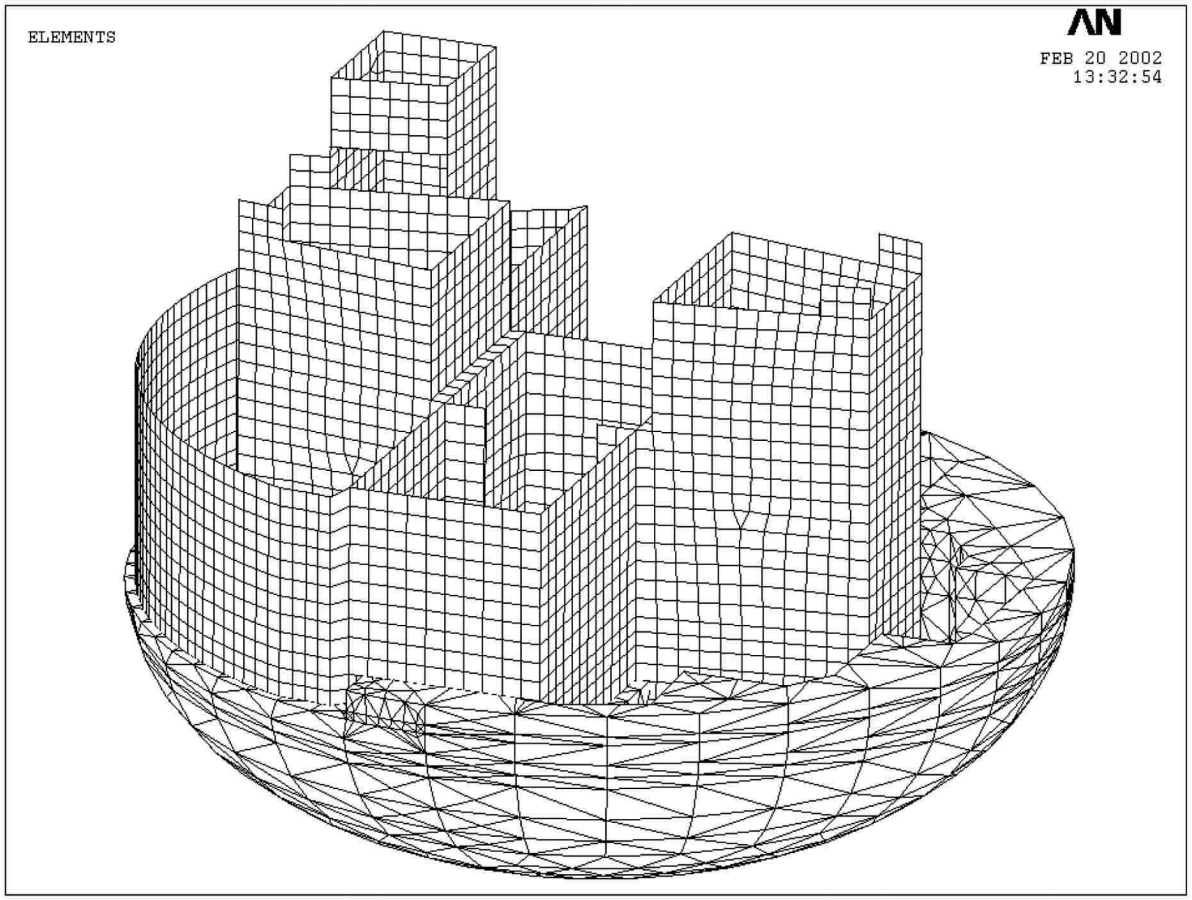


Figure 3G.2-1
3D Finite Element Model of
Coupled Shield and Auxiliary Building



Note: This figure shows the finite element model of walls and basemat inside containment. Floors are not shown.

Figure 3G.2-2
3D Finite Element Model of
Containment Internal Structures

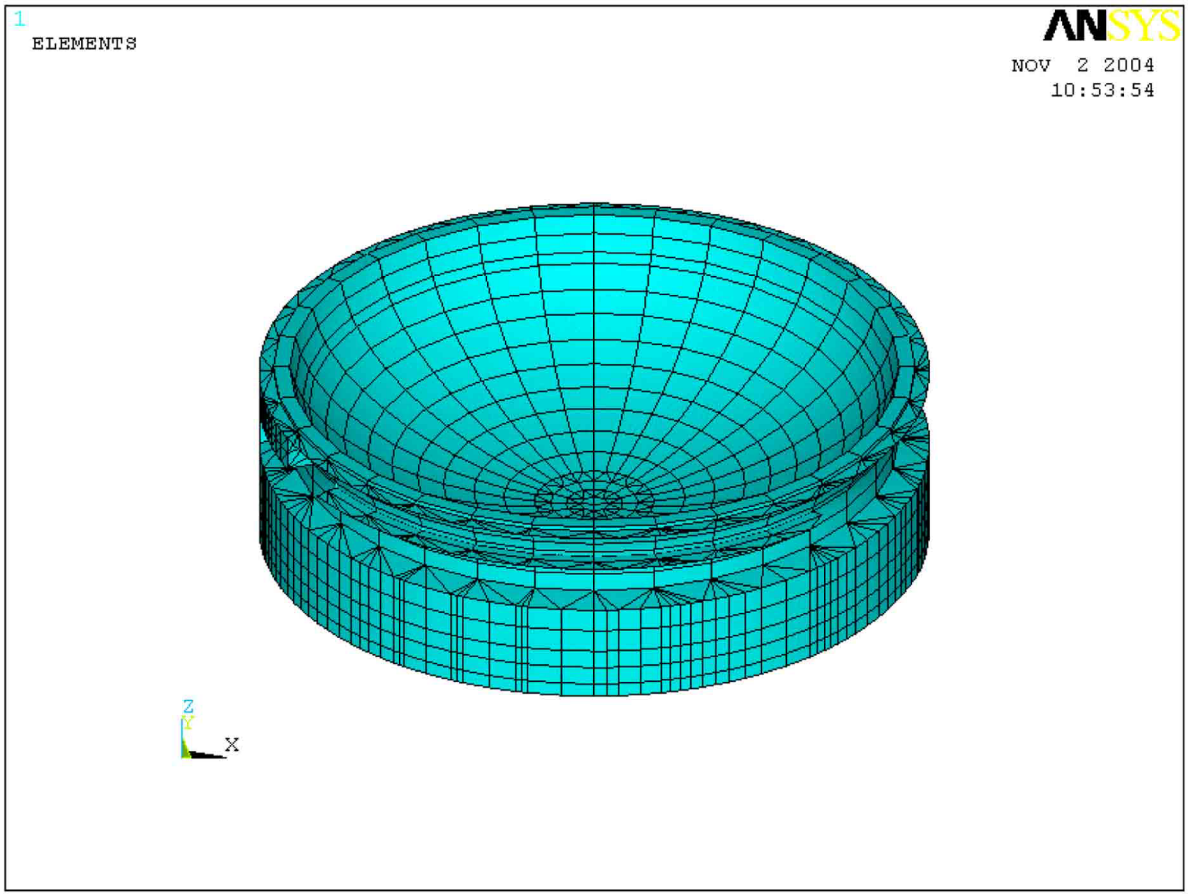


Figure 3G.2-3
3D Finite Element Model of
Containment Outer Basemat (Dish)

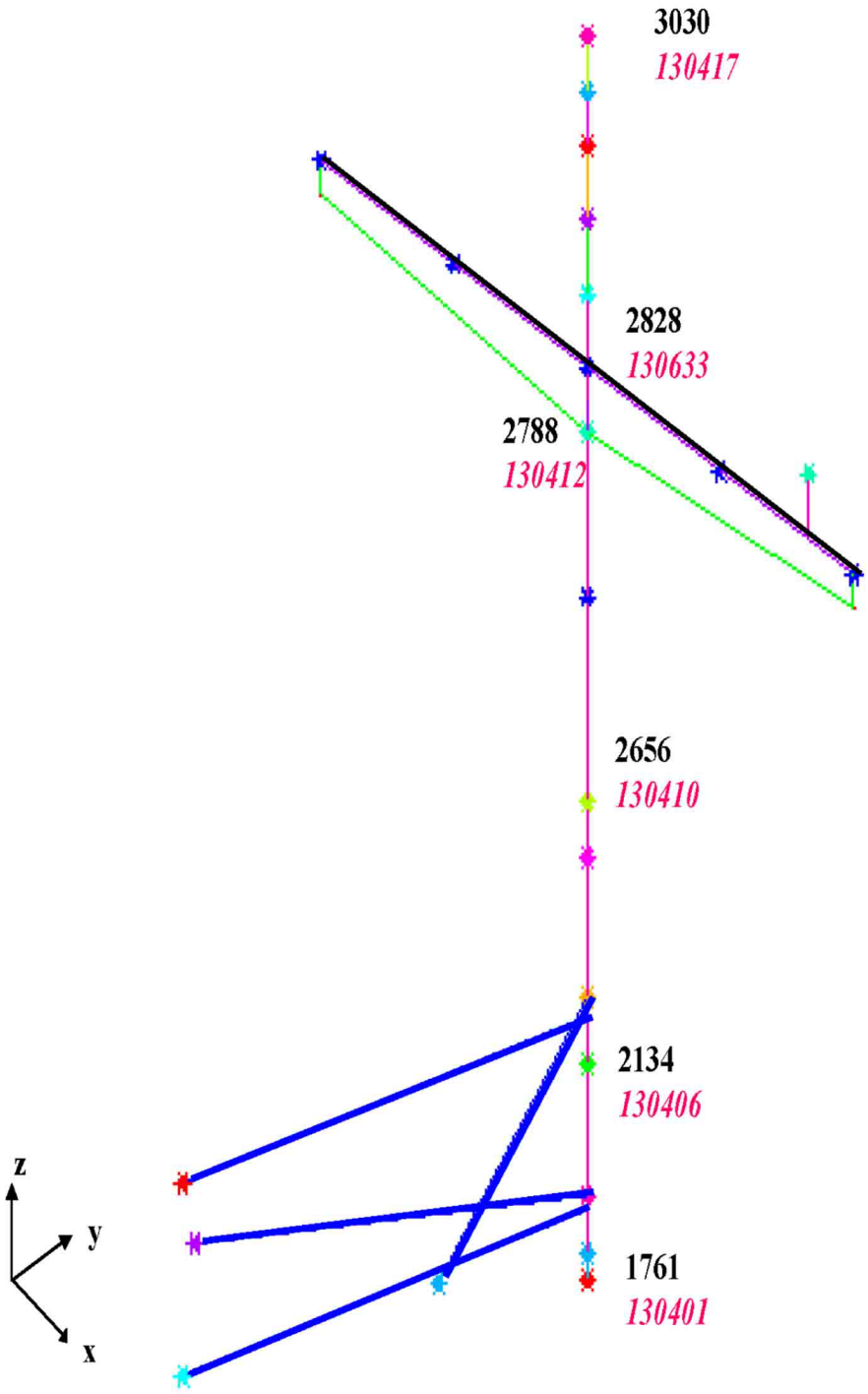
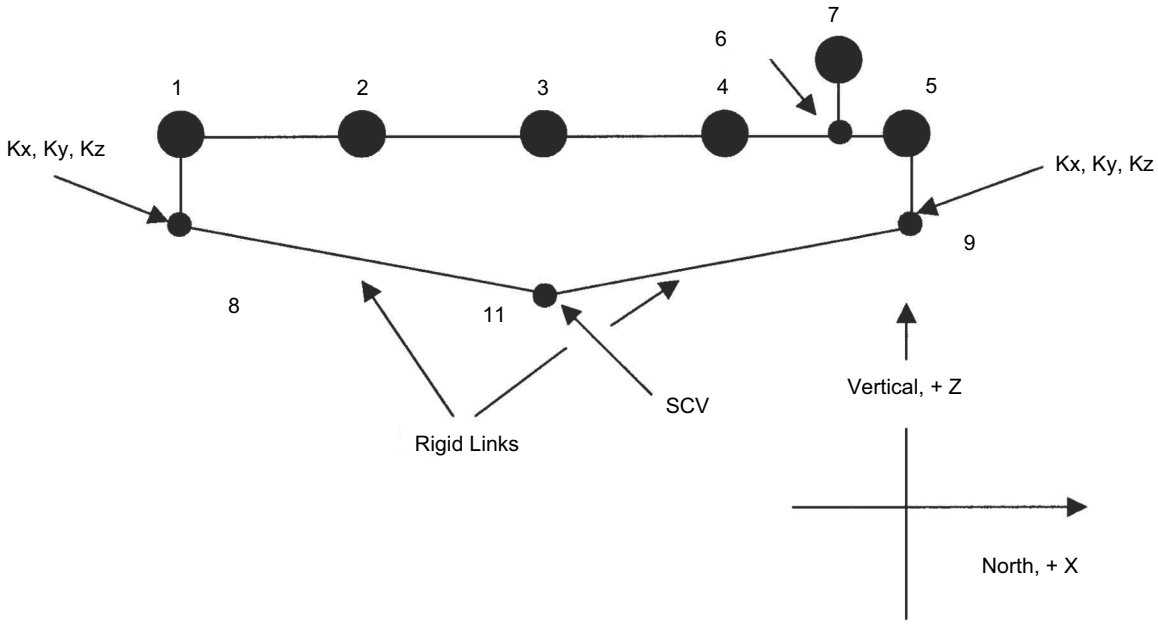


Figure 3G.2-4
Steel Containment Vessel and Polar Crane Models



Local SCV Stiffness are Kx, Ky, Kz

Dynamic Degrees of Freedom

- Masses at nodes 1, 2, 3, 4, 5, and 7
- All Mass nodes have DOFs in X, Y, and Z directions

Comments:

1. Cross Beams between girders are represented by rotation spring constants Kxx and Kzz
2. Cross Beam rotational spring constant Kyy is negligible compared to girder stiffness

Figure 3G.2-5A
Polar Crane Model Simplified Model

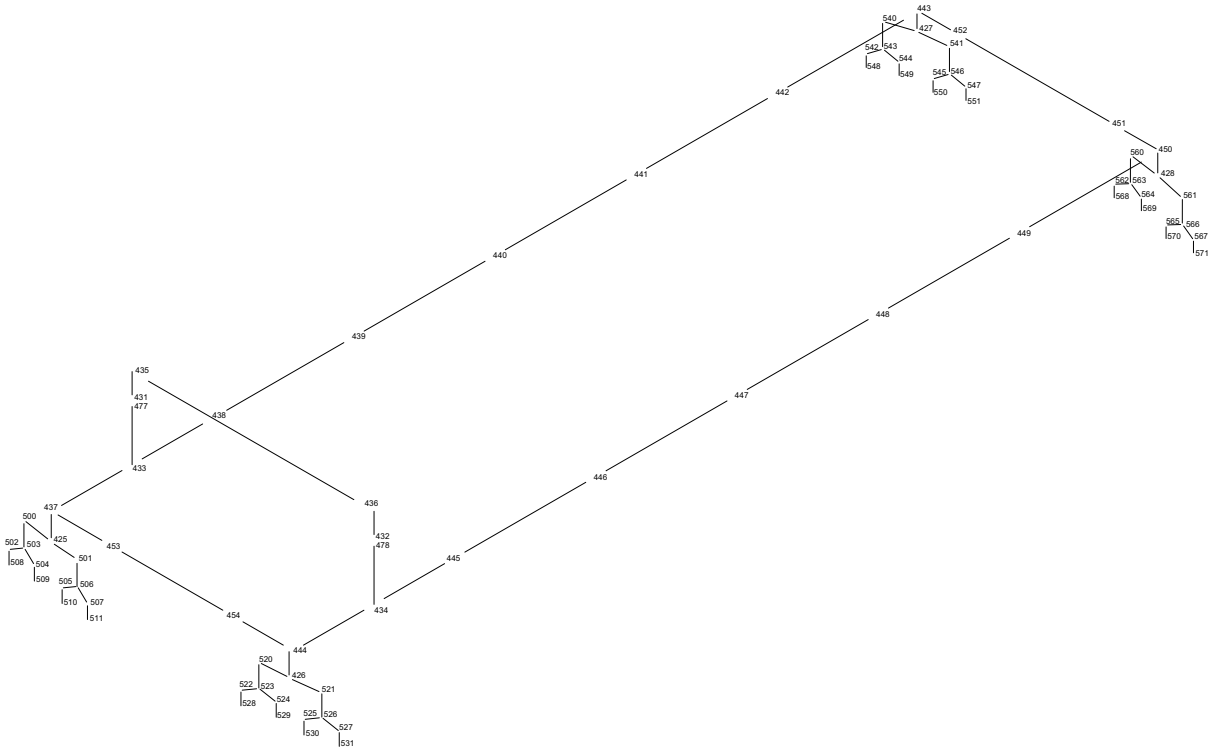


Figure 3G.2-5B
Polar Crane Model Detailed Model

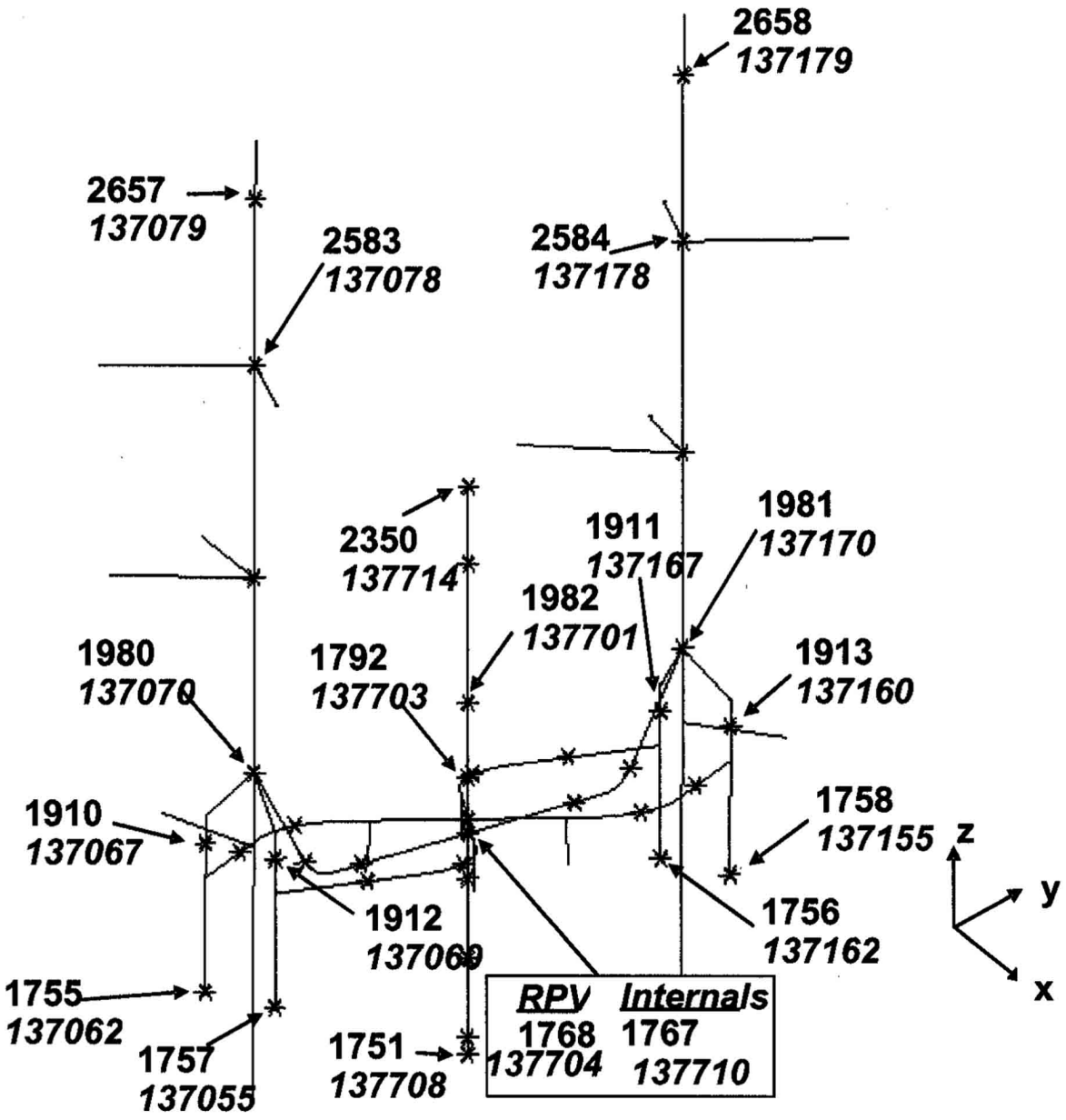


Figure 3G.2-6
Reactor Coolant Loop
Lumped-Mass Stick Model

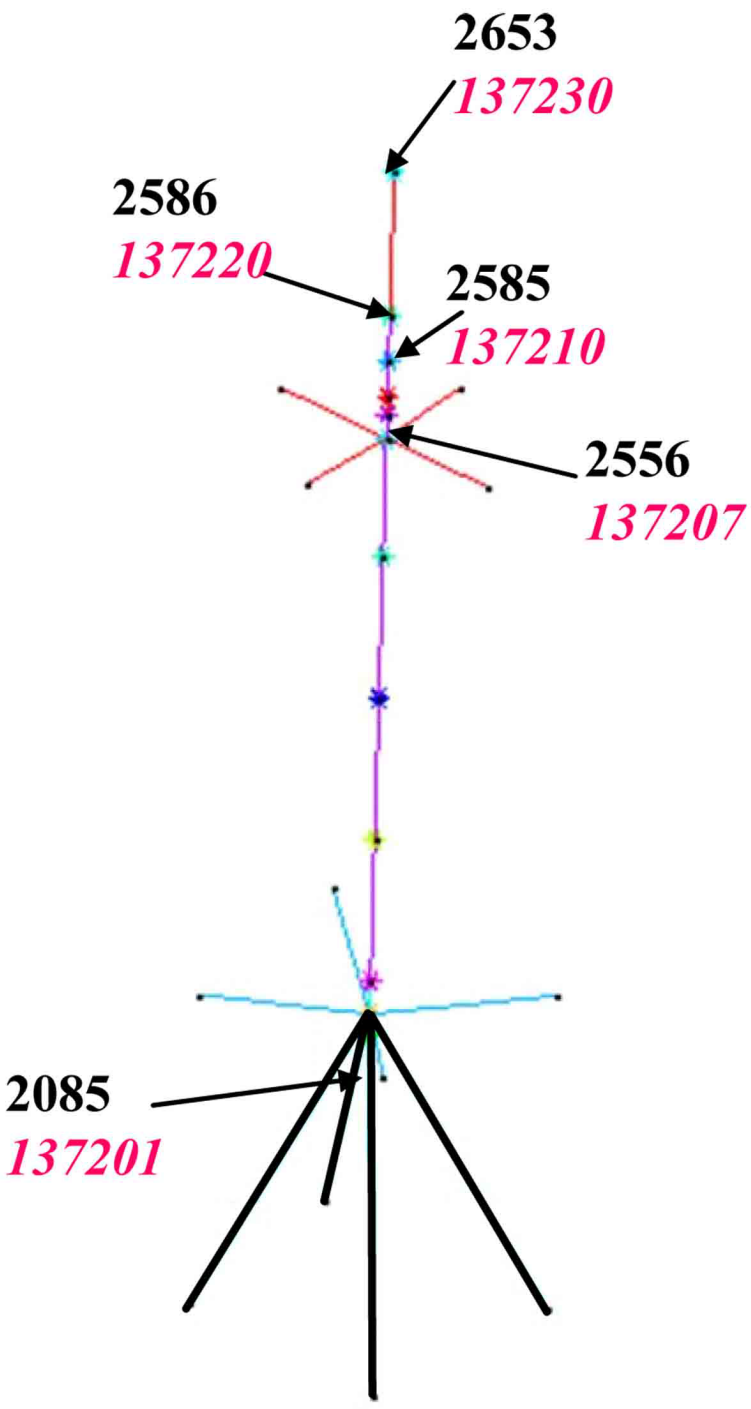


Figure 3G.2-7
Pressurizer Model

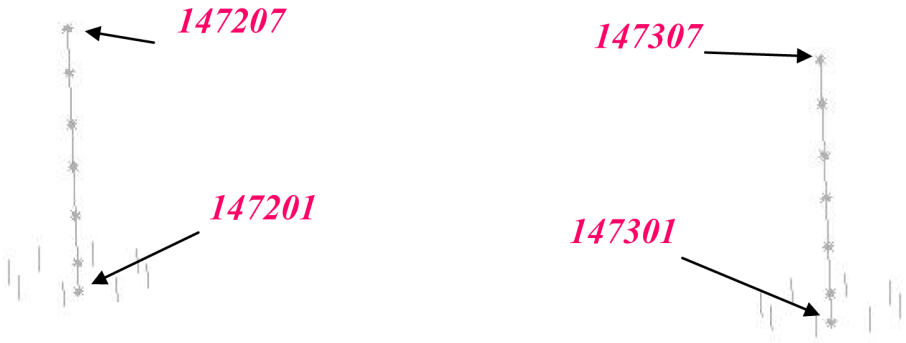


Figure 3G.2-8
Core Makeup Tank Models

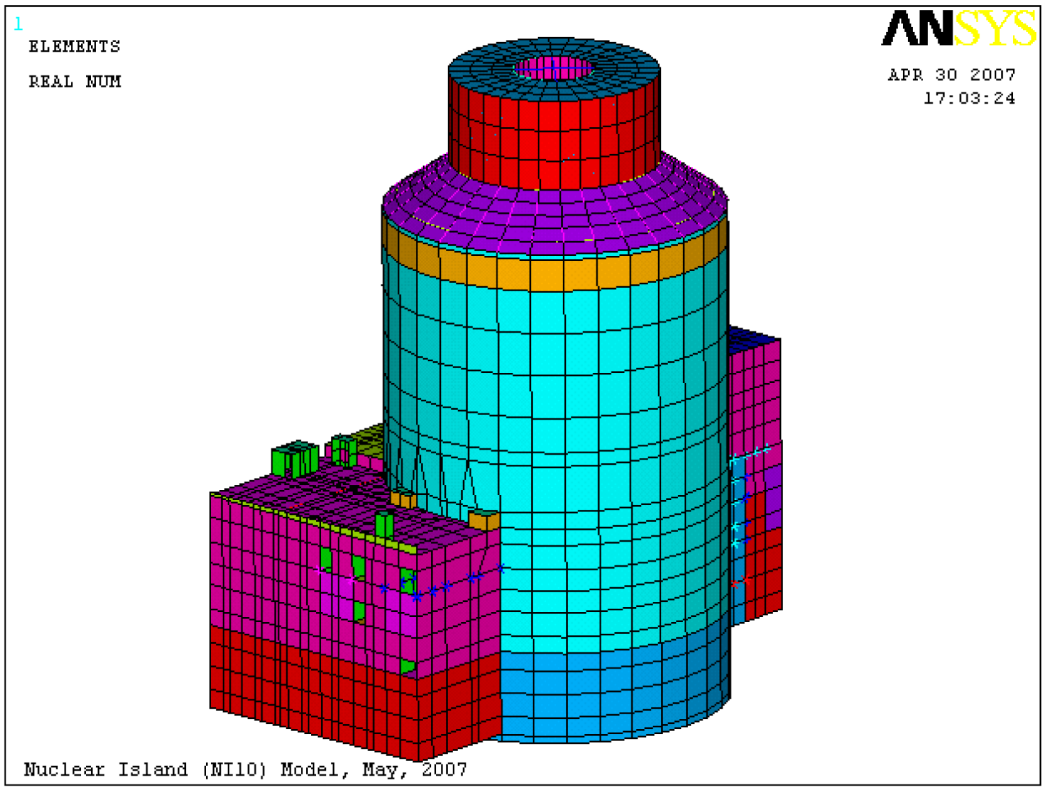


Figure 3G.2-9
AP1000 Nuclear Island Solid-Shell Model (NI10)

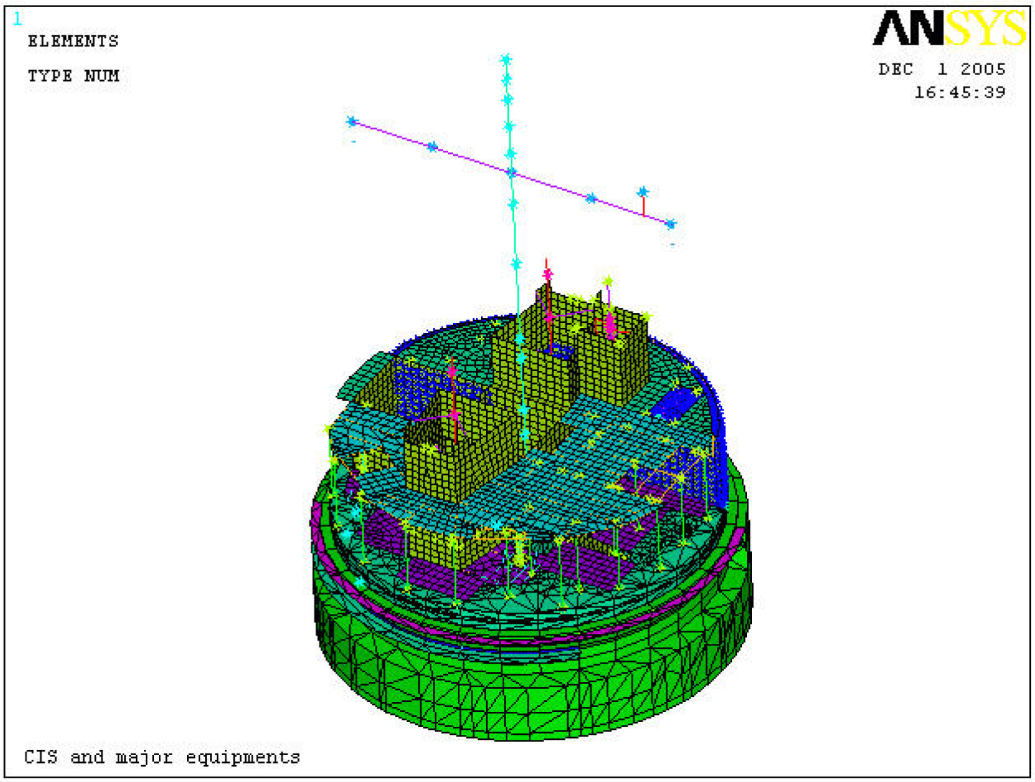
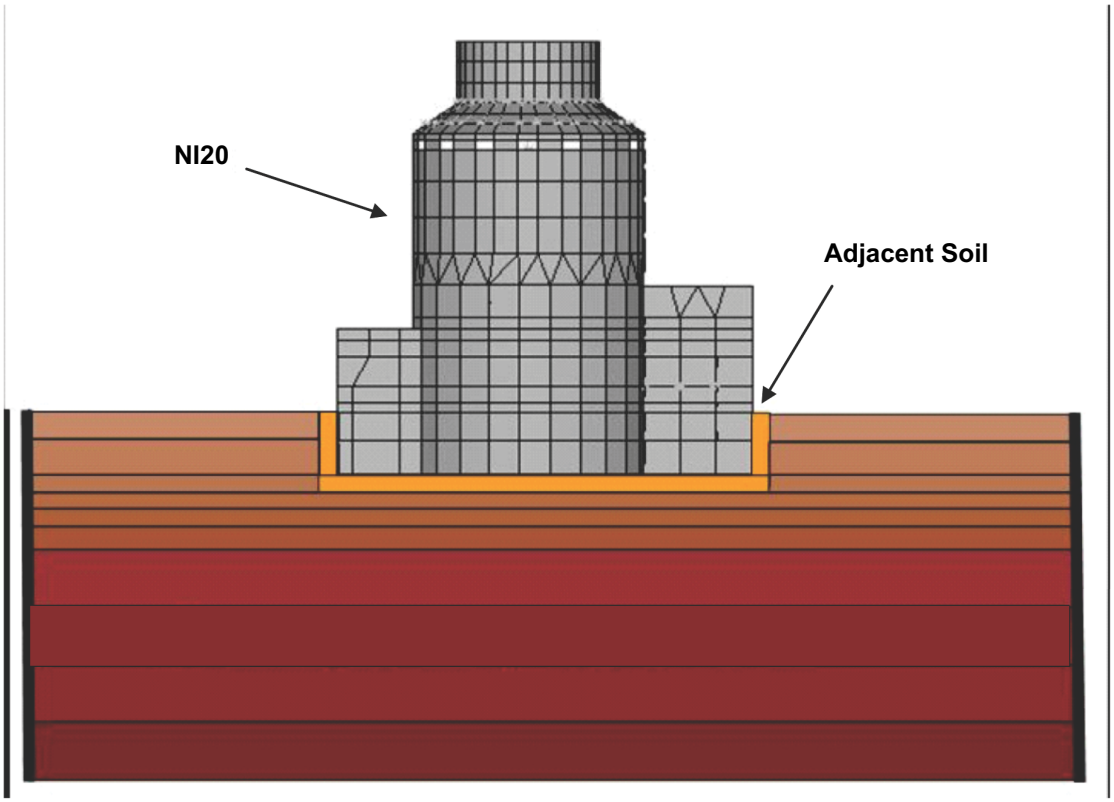


Figure 3G.2-10
Containment Internal Structure with the SCV, PC, Reactor Coolant Loop, and Pressurizer



Note: The adjacent soil elements are part of the structural portion of SASSI and have the same material properties as the soil. These elements are used to obtain soil lateral and bearing soil pressures.

Figure 3G.2-11
Soil Structure Interaction Model – NI20 Looking East

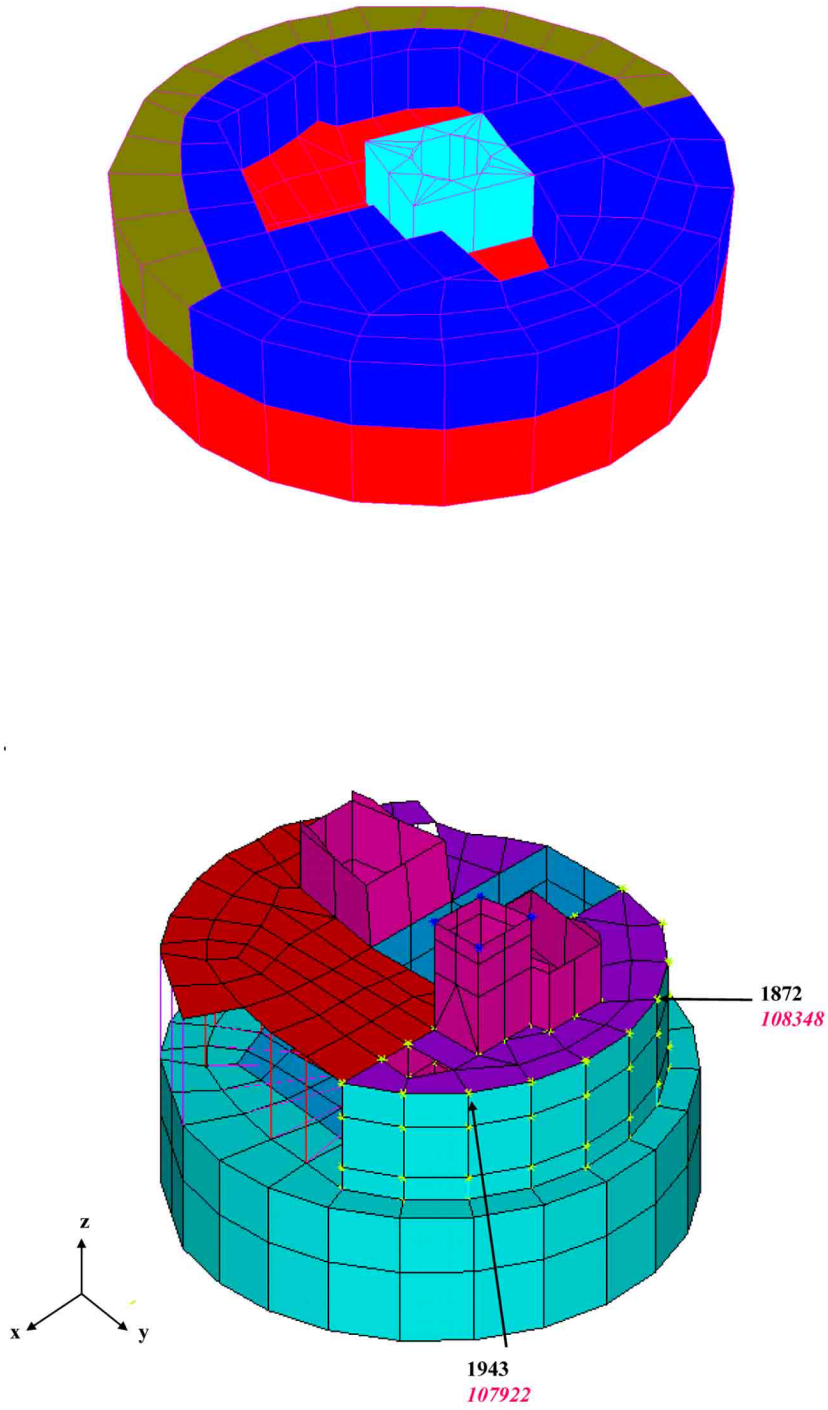


Figure 3G.2-12
Coarse Model of Containment Internal Structures

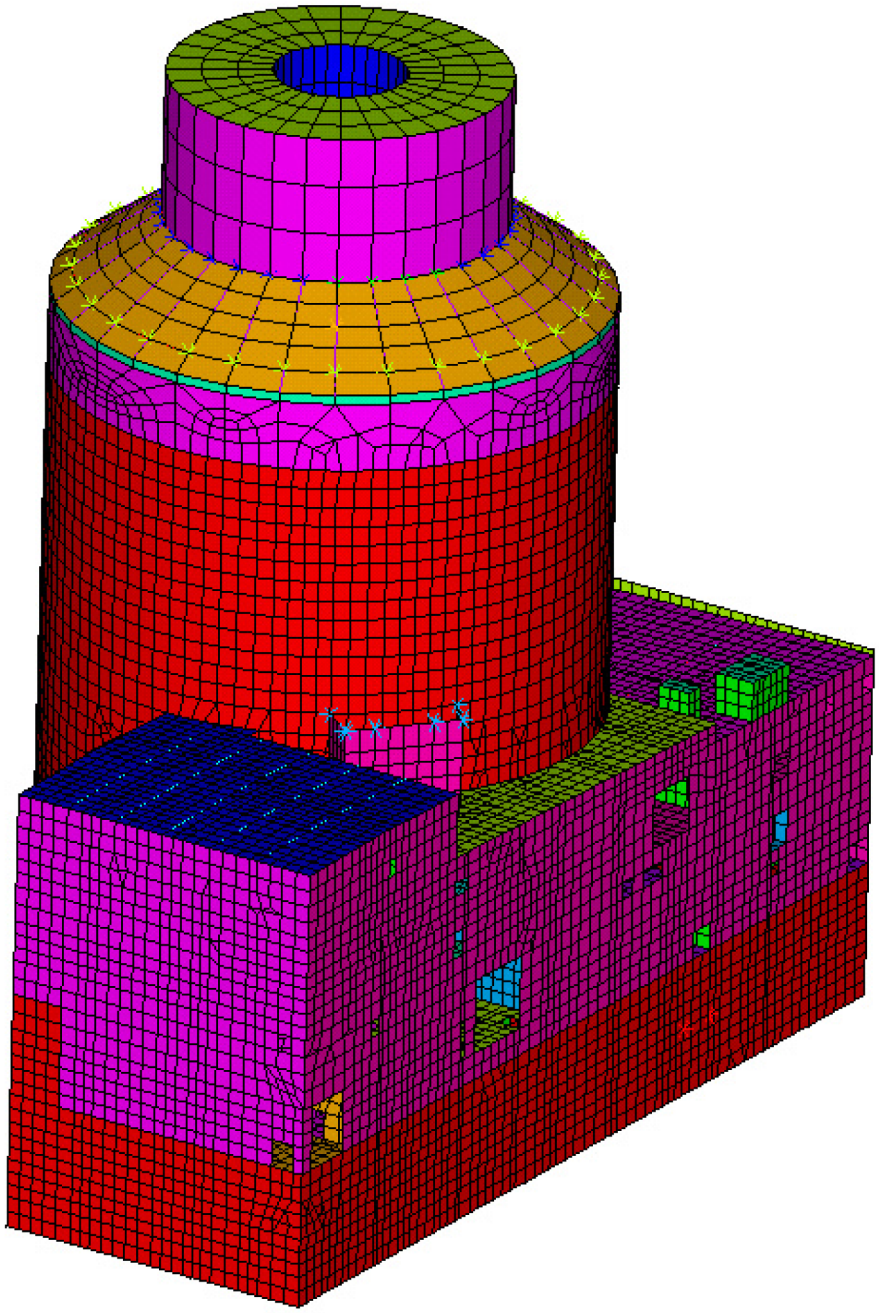


Figure 3G.2-13
Fine Mesh (NI05) Model of Auxiliary and Shield Building

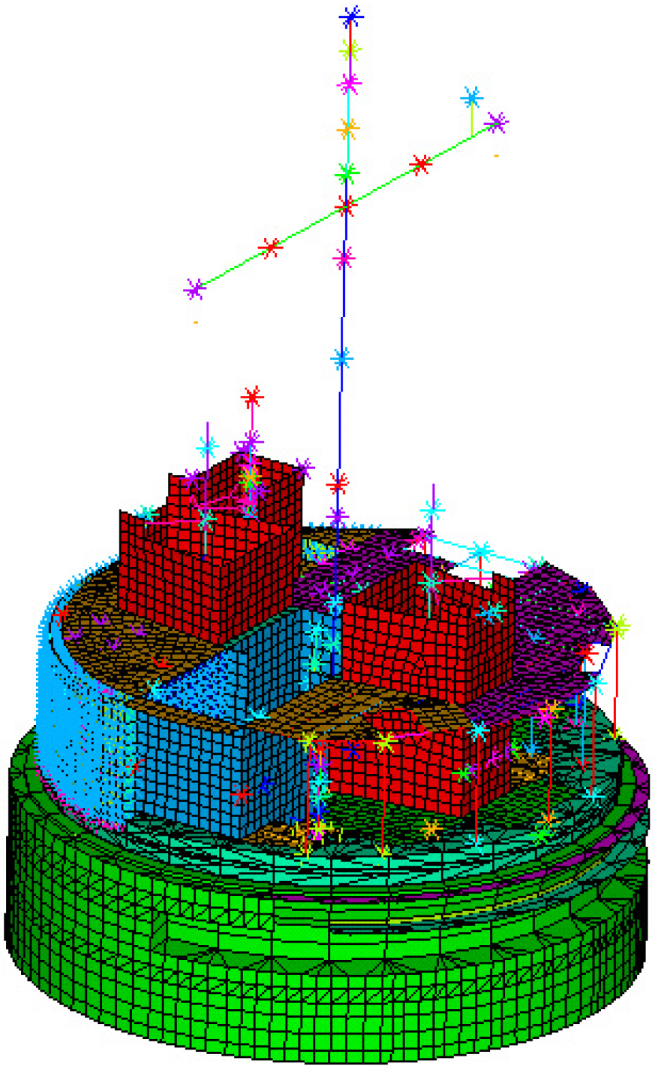


Figure 3G.2-14
NI05 Model of Containment Internal Structures

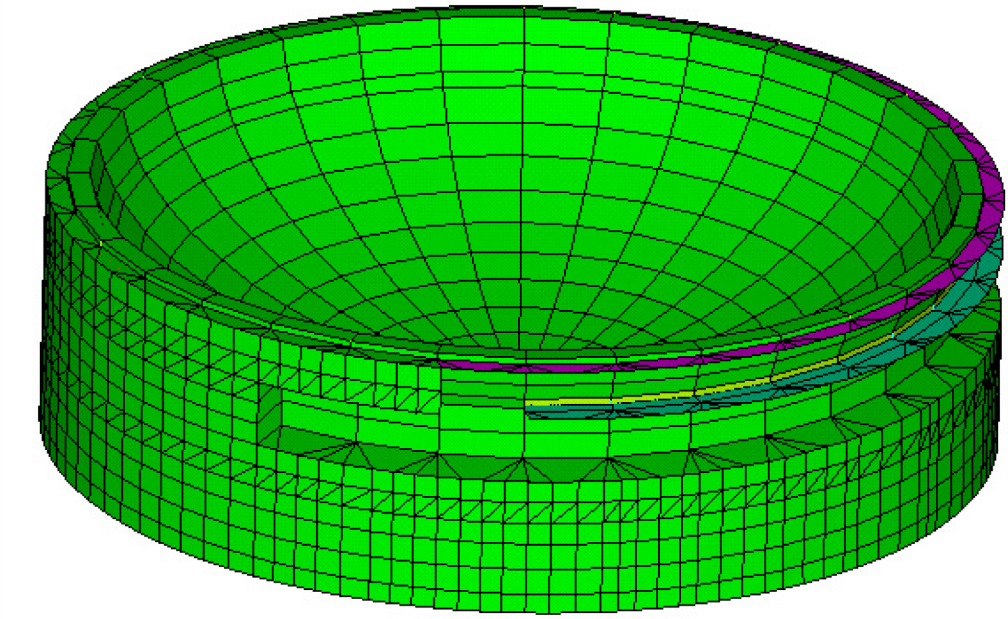


Figure 3G.2-15
3D NI05 Refined Mesh Model of Outer Containment Basemat (Dish)

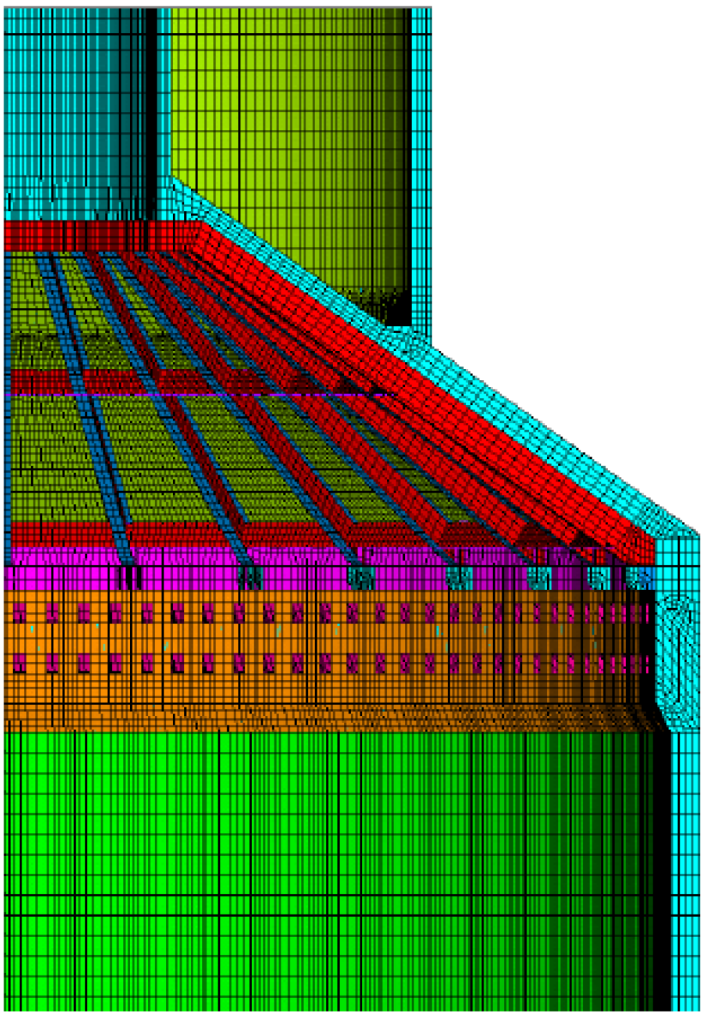
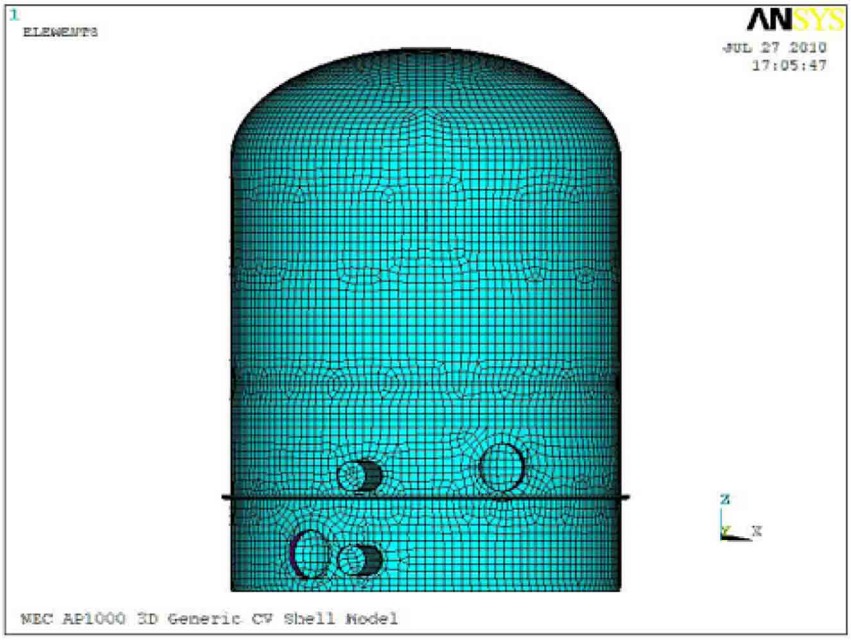


Figure 3G.2-16
Quadrant Model of Shield Building Roof



Mesh Size 37″ x 37″

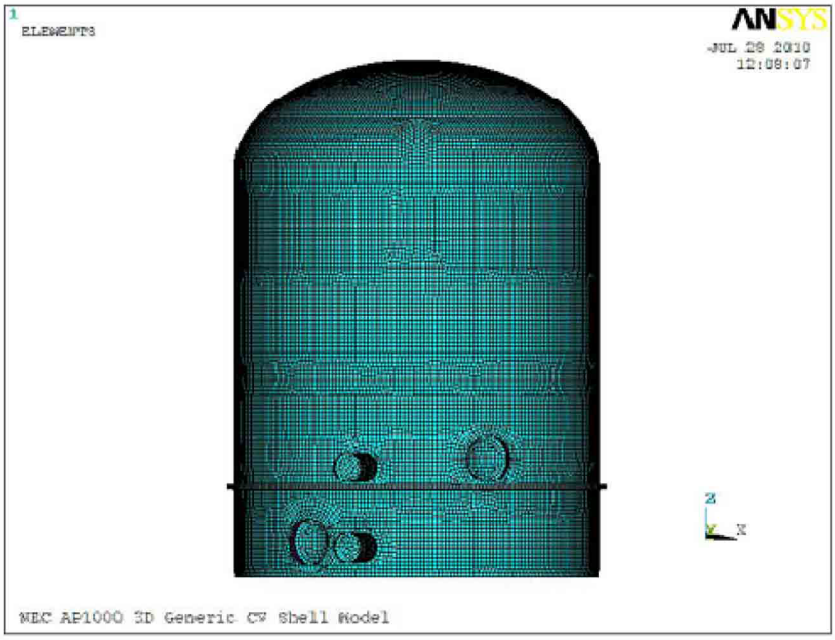


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Figure 3G.2-17
Detailed 3D Finite Element Model of Containment Vessel Including Large Penetrations

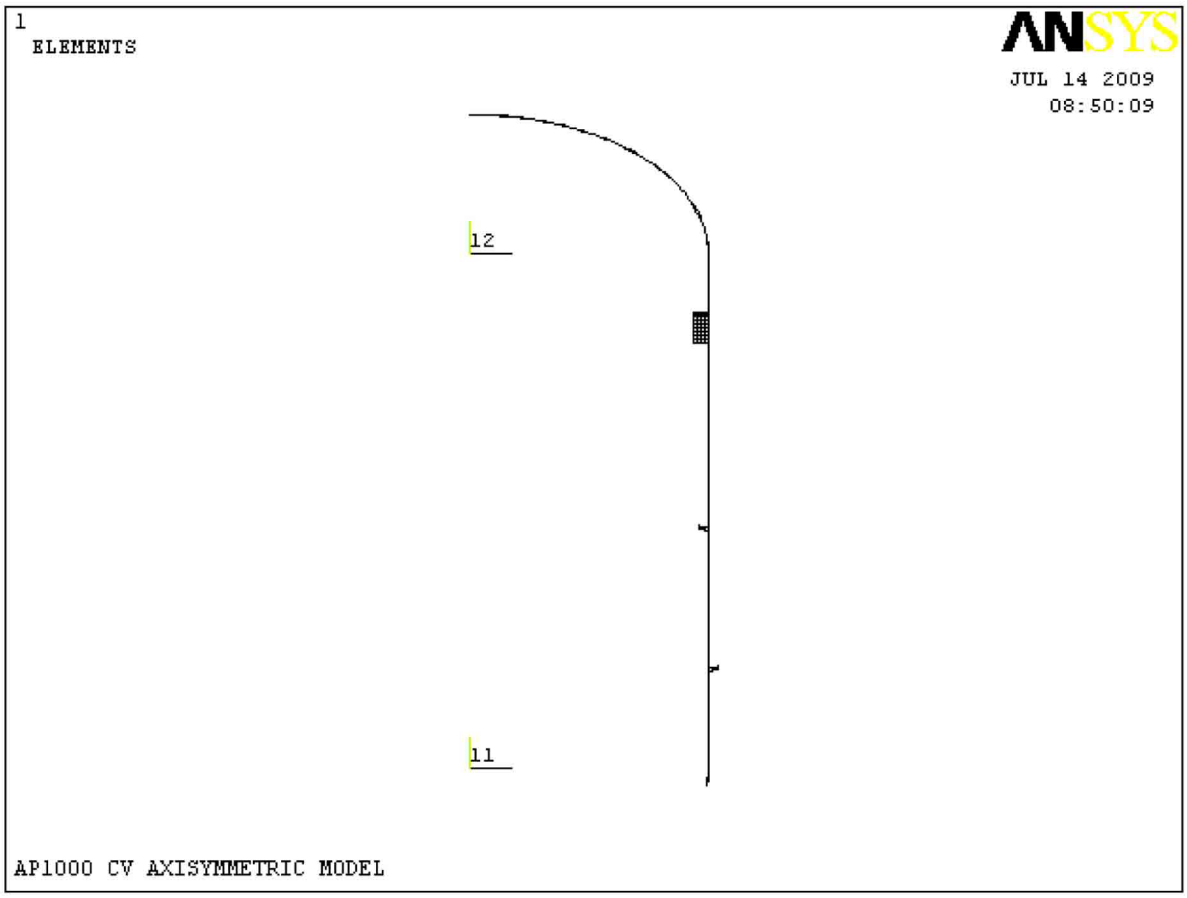


Figure 3G.2-18
Axisymmetric Model of Containment Vessel

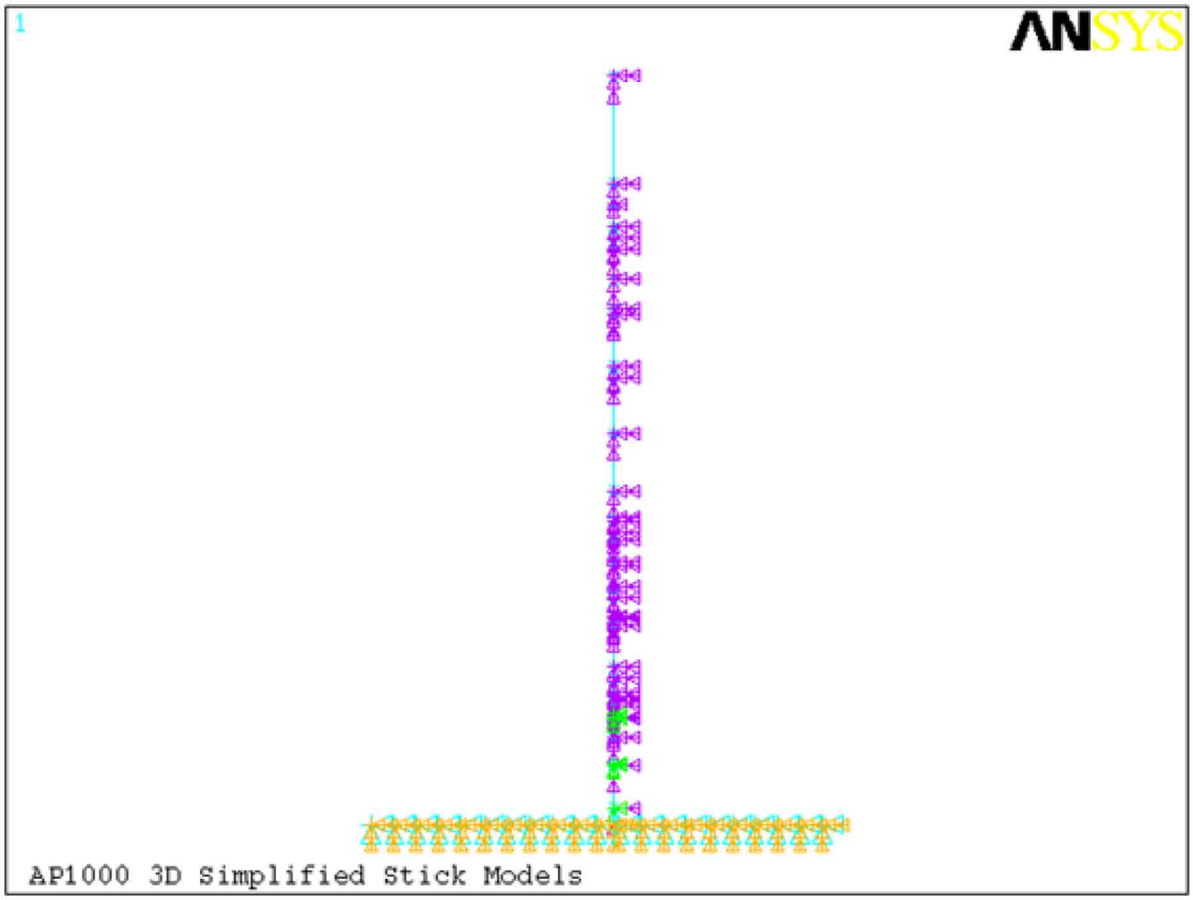
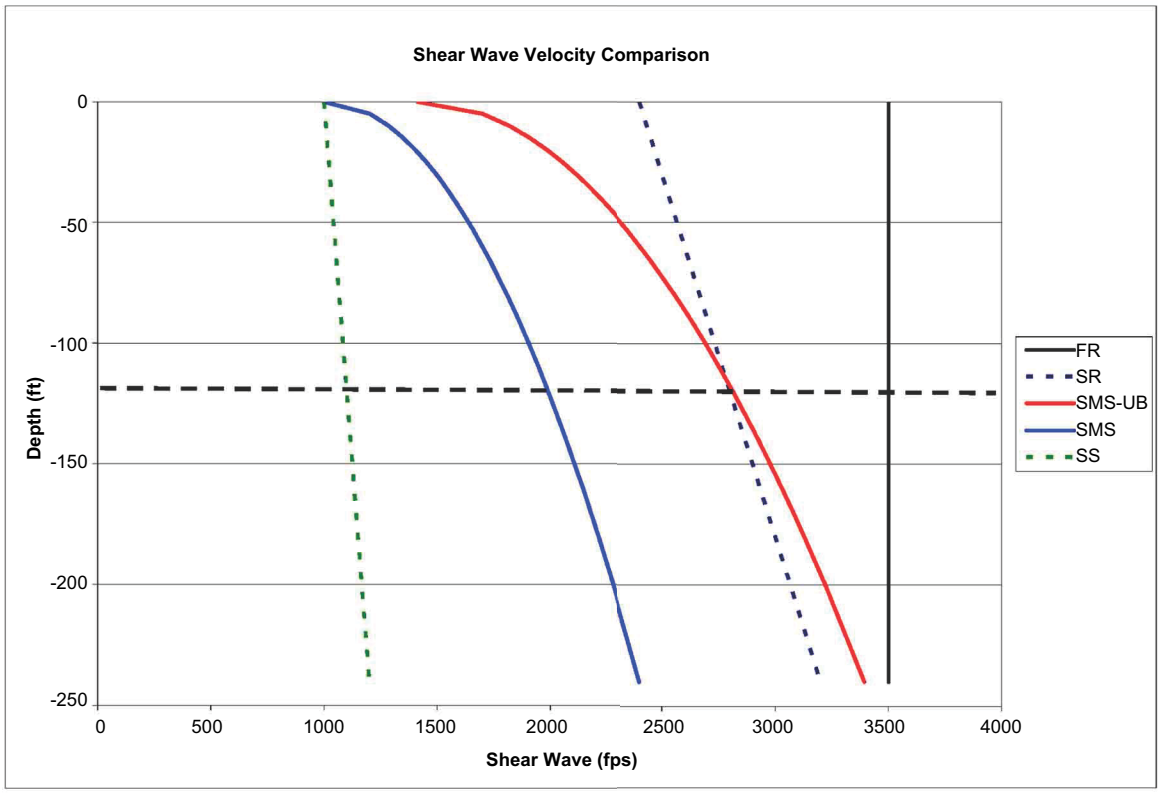


Figure 3G.2-19
Schematic of Non-linear 2D East-West Nuclear Island Stick Model Used for Stability Evaluation that Addresses Sliding and Overturning



Note: Fixed base analyses were performed for hard rock sites. These analyses are applicable for shear wave velocity greater than 8000 feet per second.

Figure 3G.3-1
Generic Soil Profiles

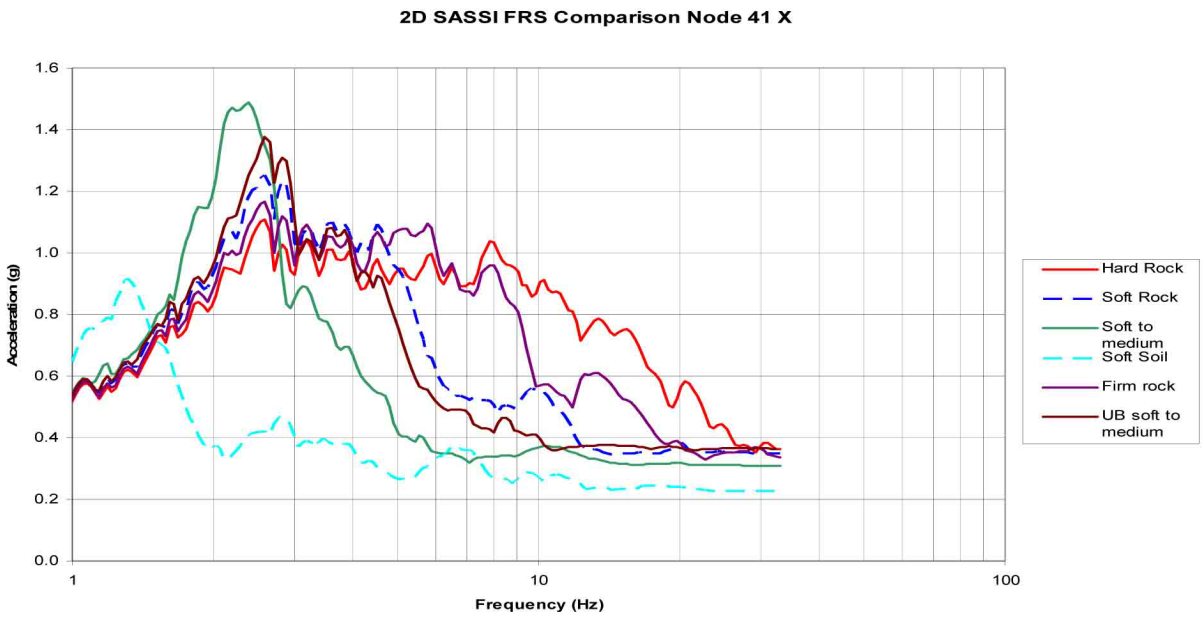


Figure 3G.3-2
2D SASSI FRS – Node 41 X (ASB El. 99')

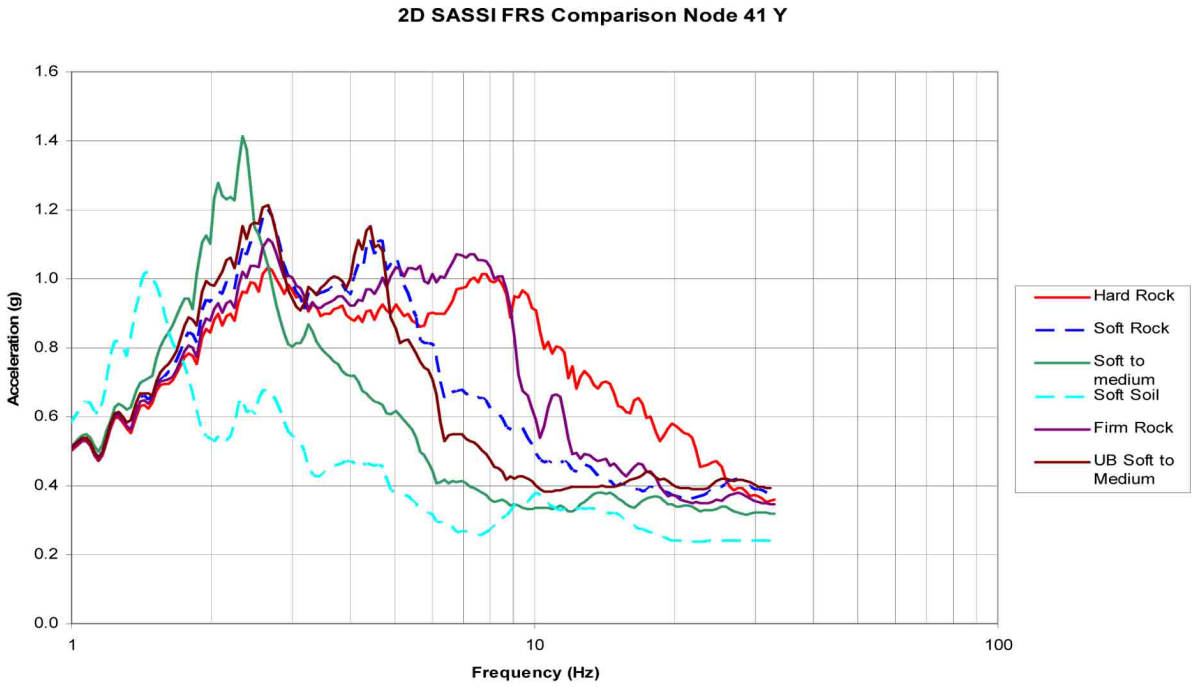


Figure 3G.3-3
2D SASSI FRS – Node 41 Y (ASB El. 99')

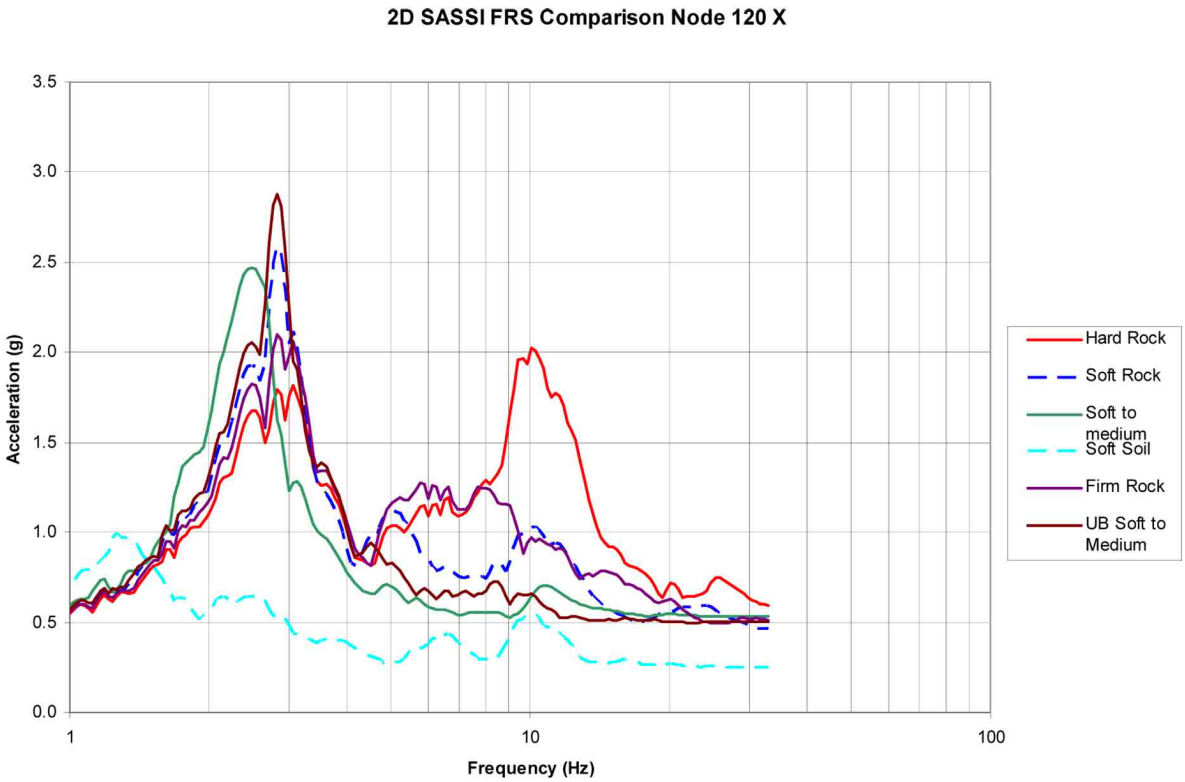


Figure 3G.3-4
2D SASSI FRS – Node 120 X (ASB El. 179.6')

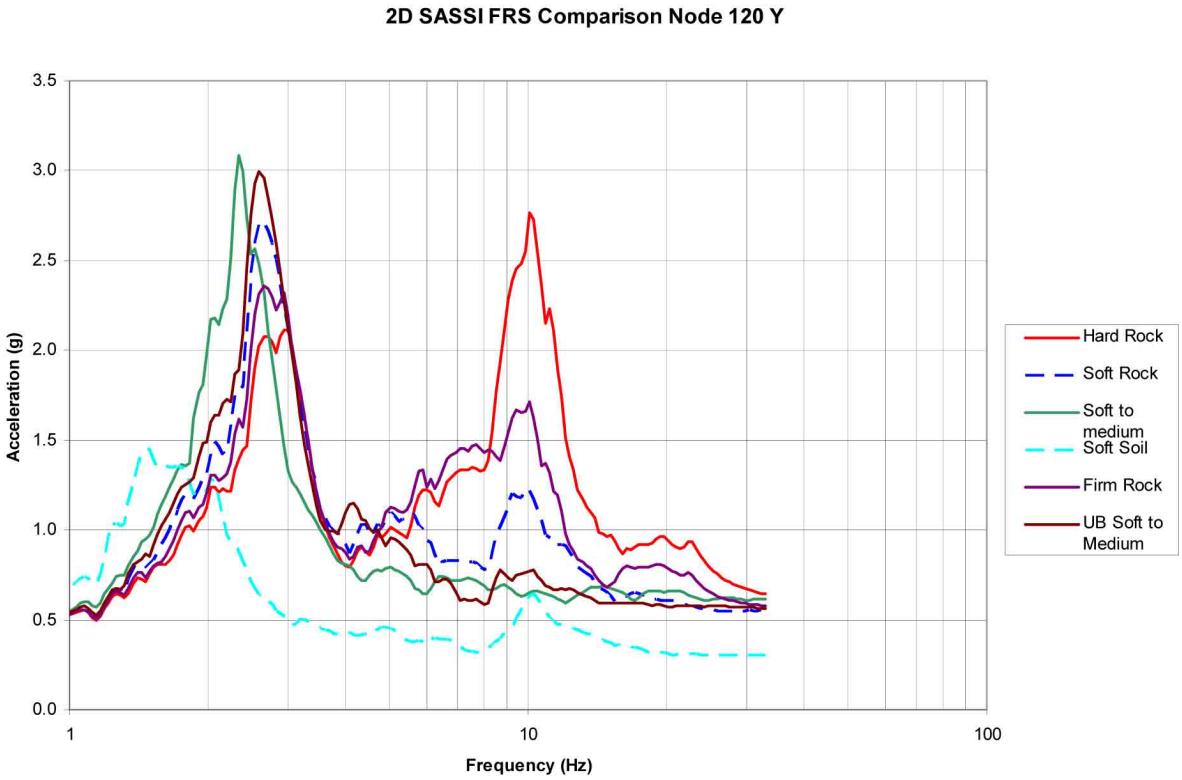


Figure 3G.3-5
2D SASSI FRS – Node 120 Y (ASB El. 179.6')

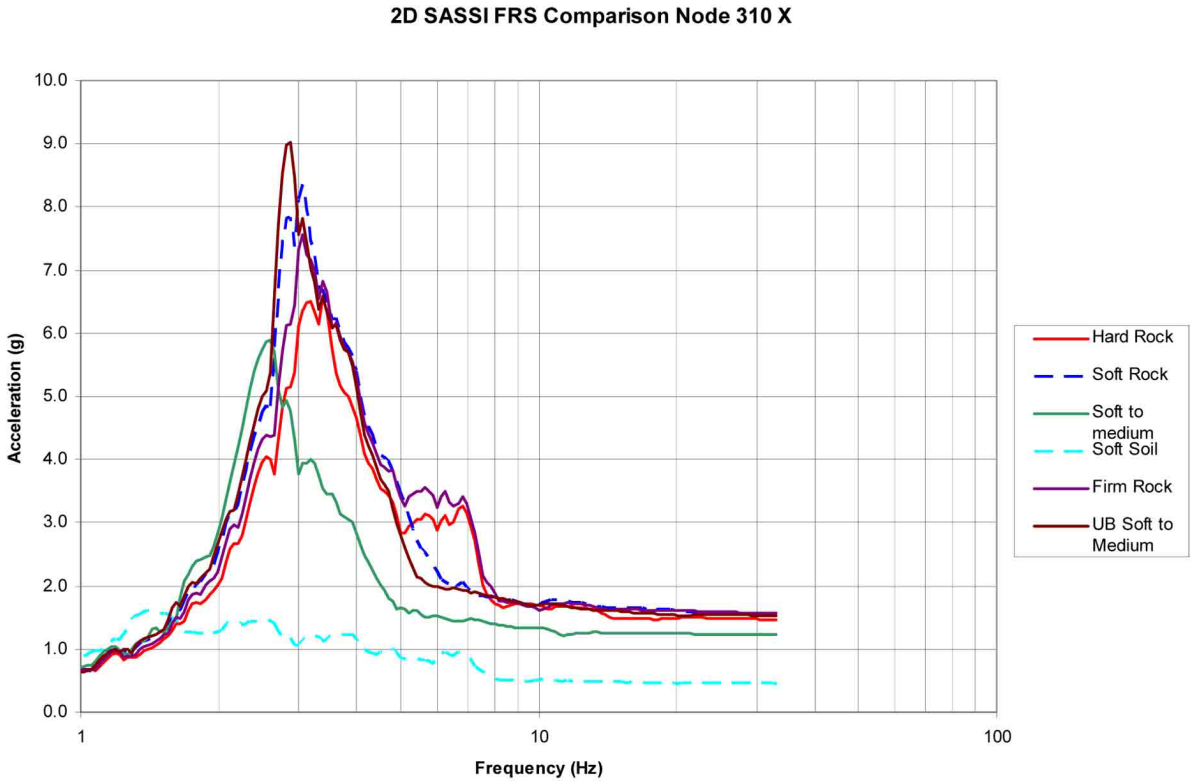


Figure 3G.3-6
2D SASSI FRS – Node 310 X (ASB El. 333.2')

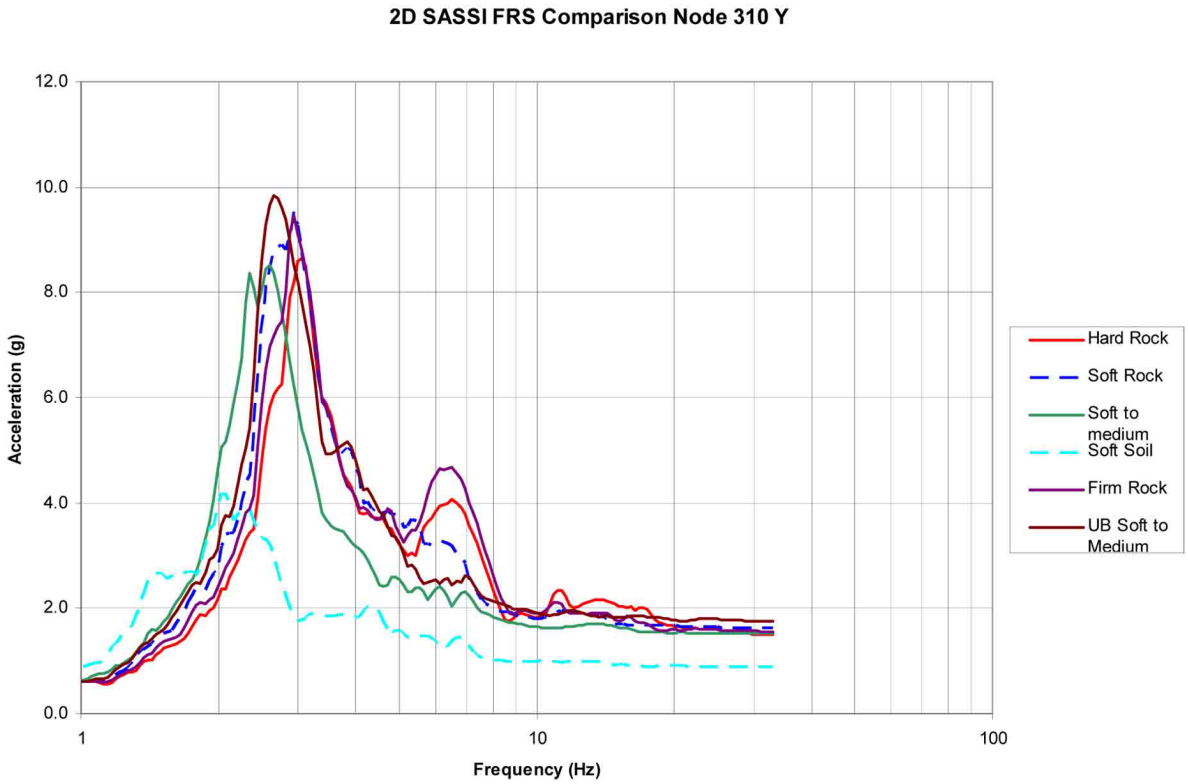


Figure 3G.3-7
2D SASSI FRS – Node 310 Y (ASB El. 333.2')

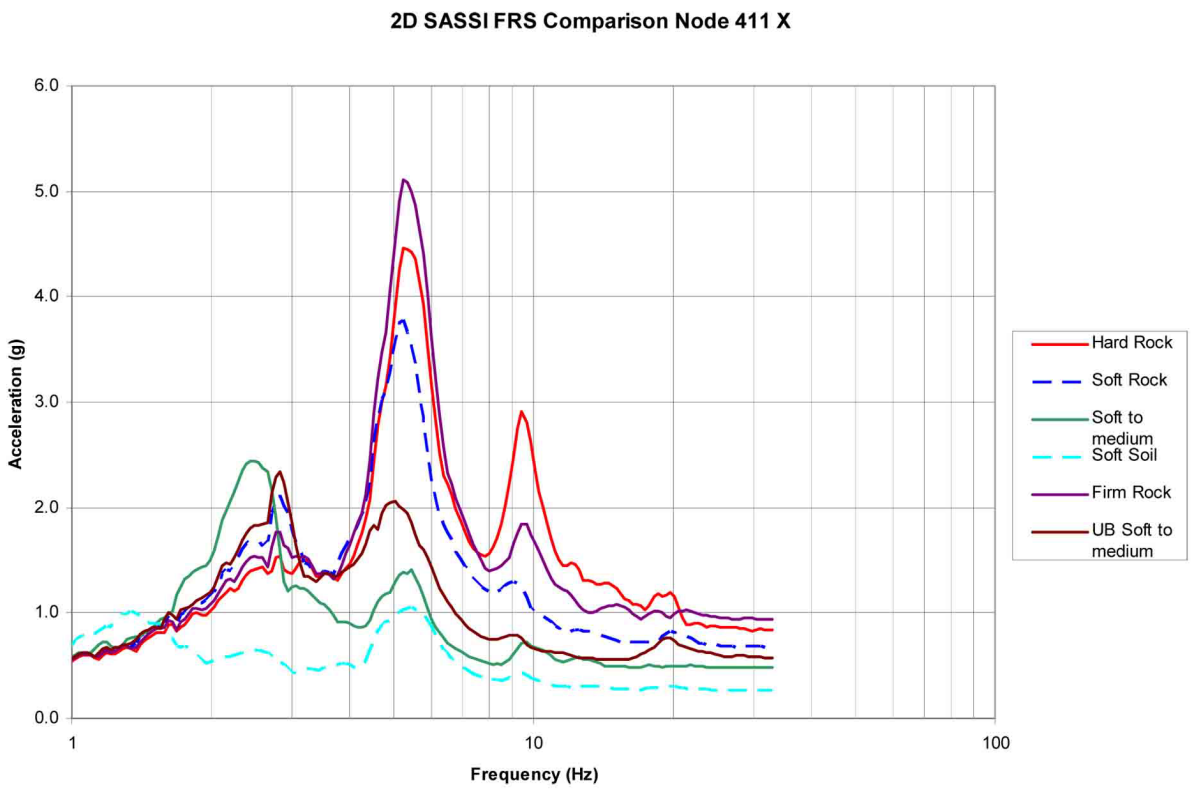


Figure 3G.3-8
2D SASSI FRS – Node 411 X (SCV El. 200.0')

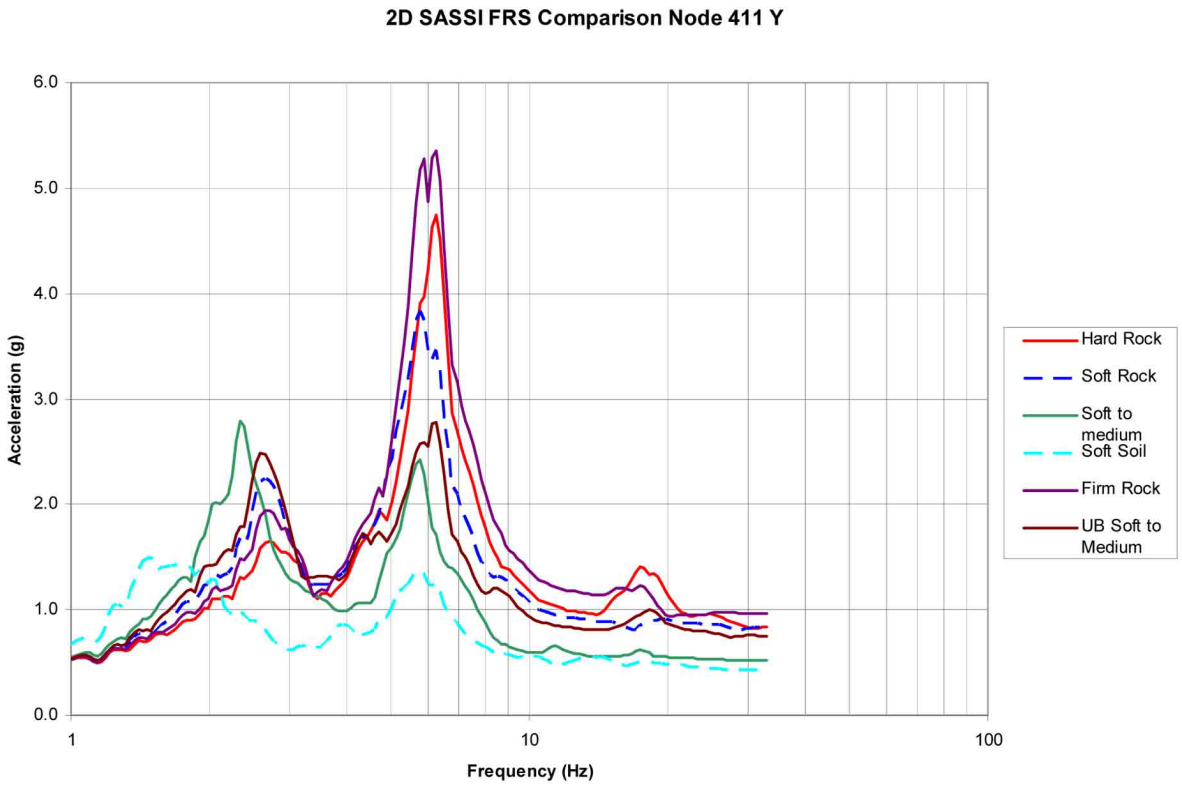


Figure 3G.3-9
2D SASSI FRS – Node 411 Y (SCV El. 200.0')

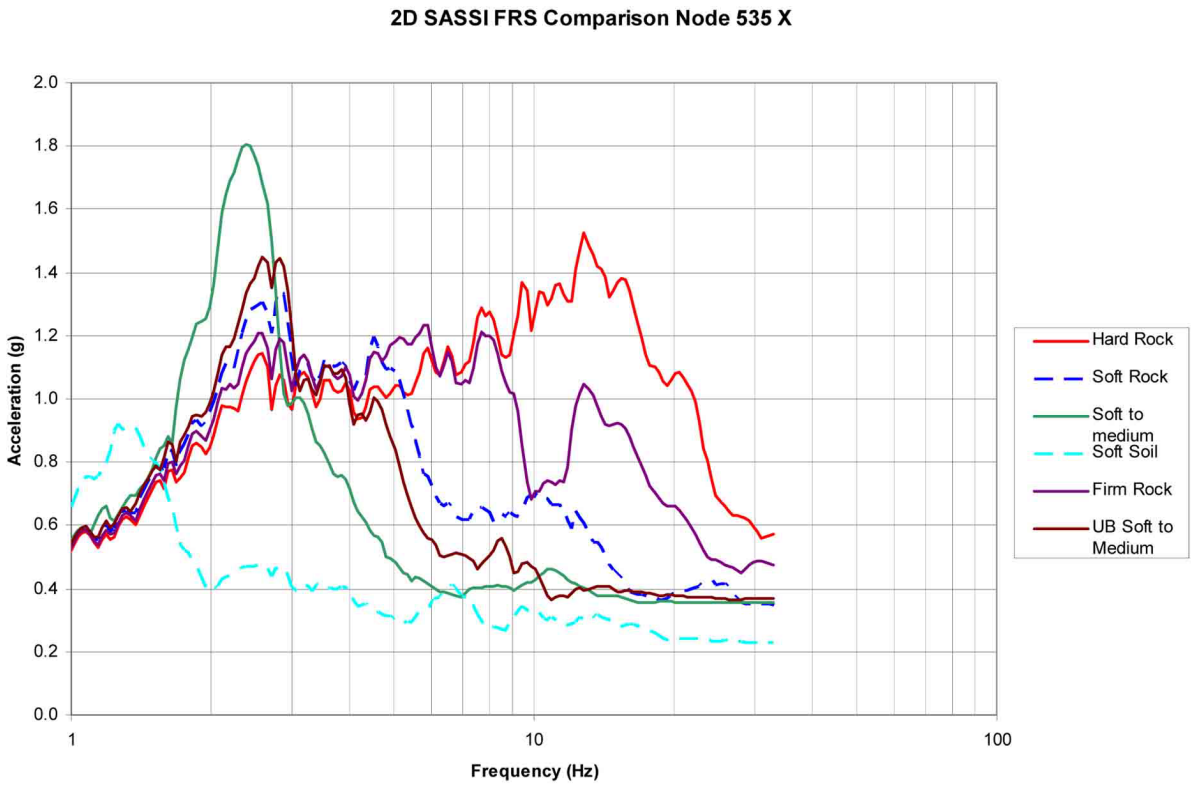


Figure 3G.3-10
2D SASSI FRS – Node 535 X (CIS El. 134.3')

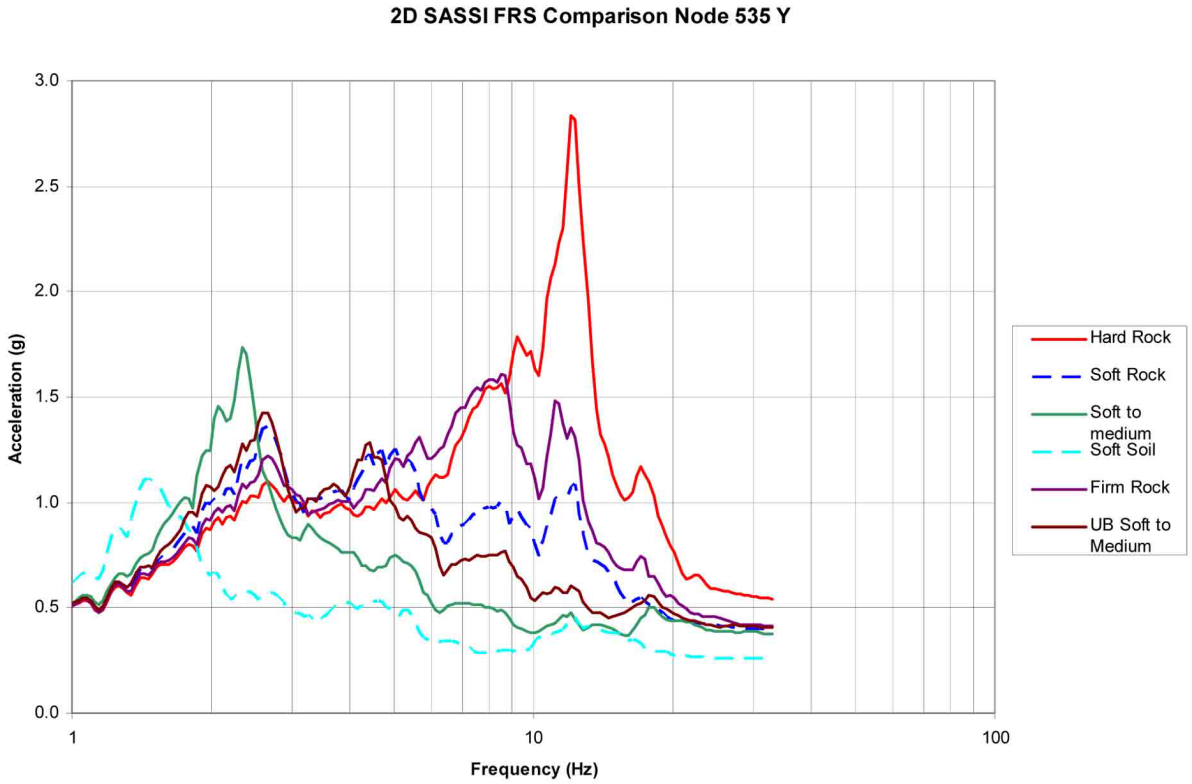


Figure 3G.3-11
2D SASSI FRS – Node 535 Y (CIS El. 134.3')

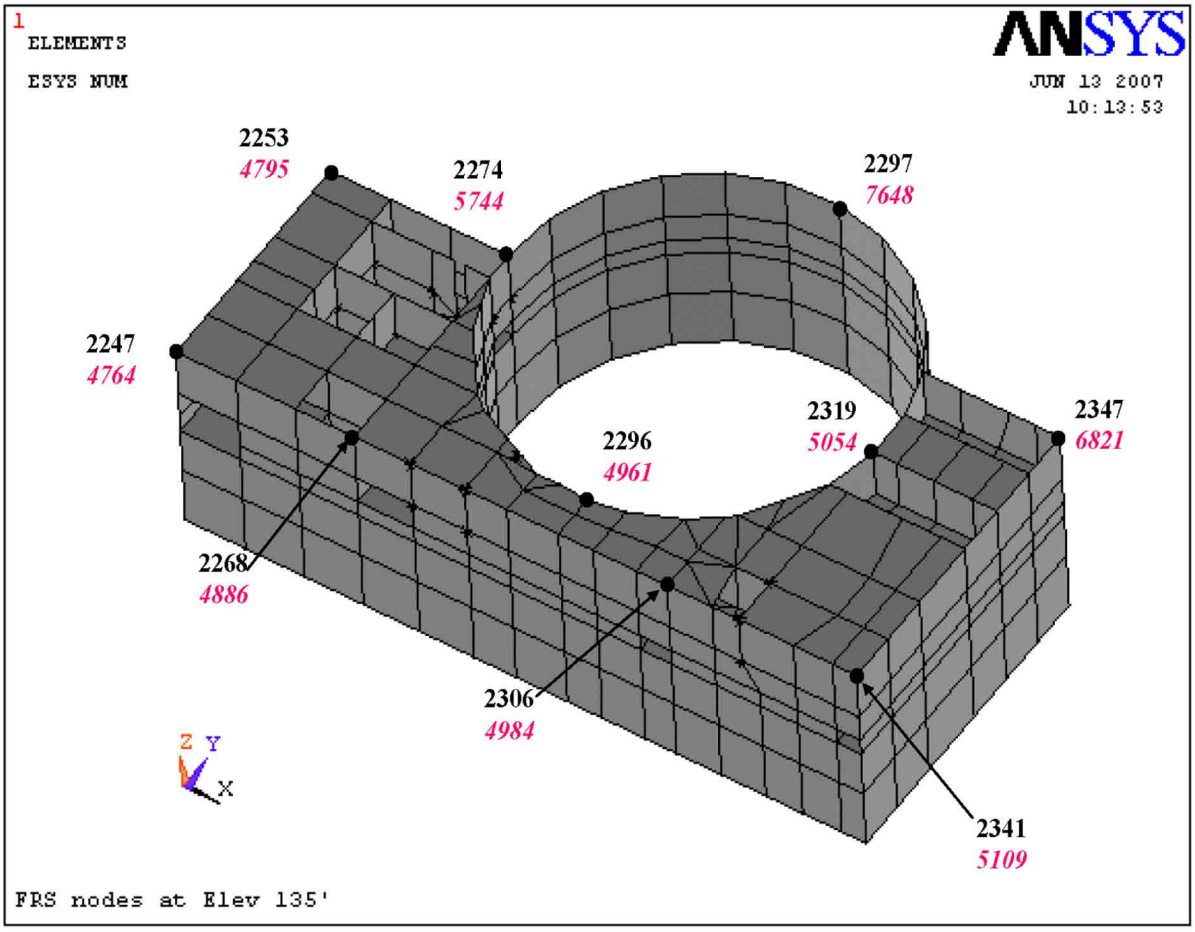


Figure 3G.4-1
Auxiliary Shield Building "Rigid" Nodes at El. 135'

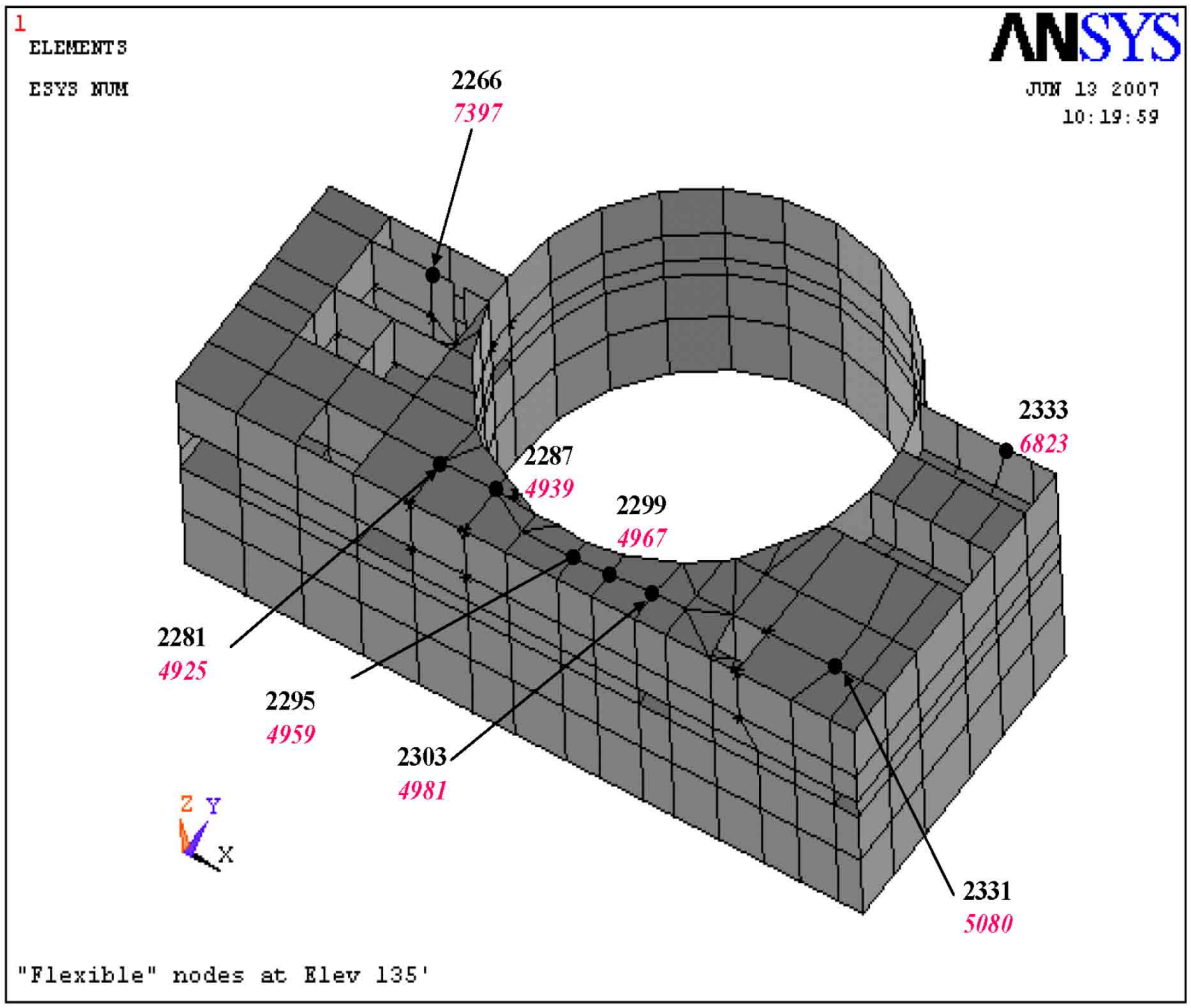


Figure 3G.4-2
Auxiliary Shield Building "Flexible" Nodes at El. 135'

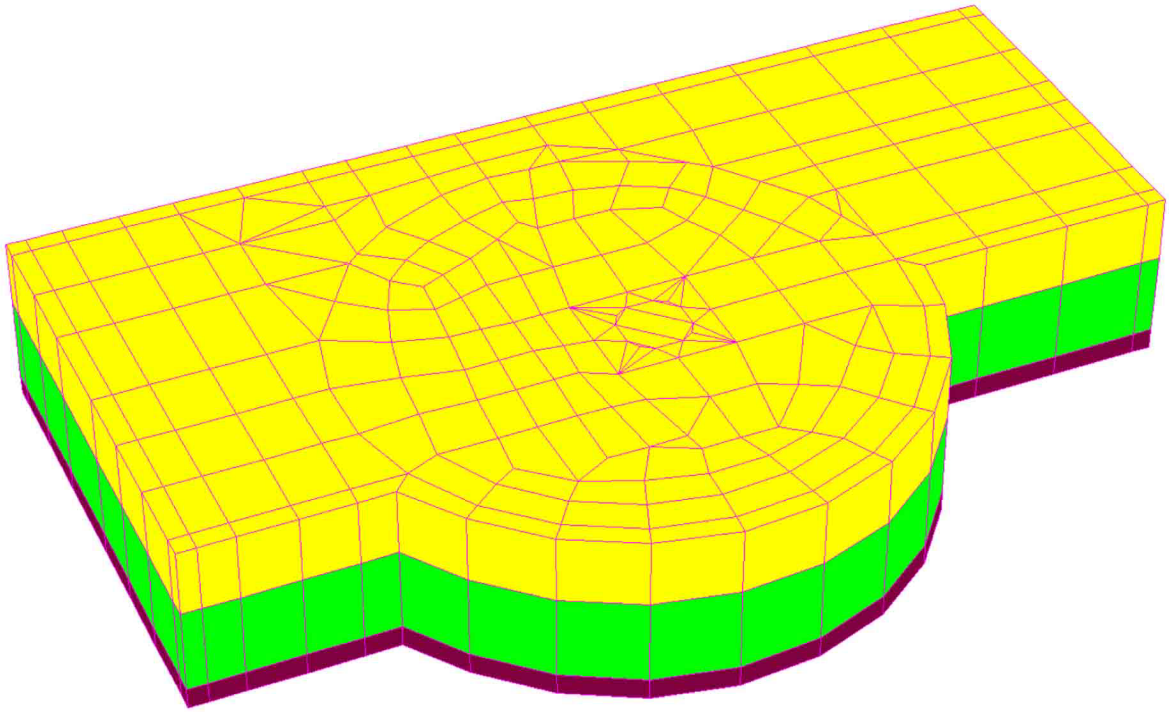


Figure 3G.4-3
Excavated Soil

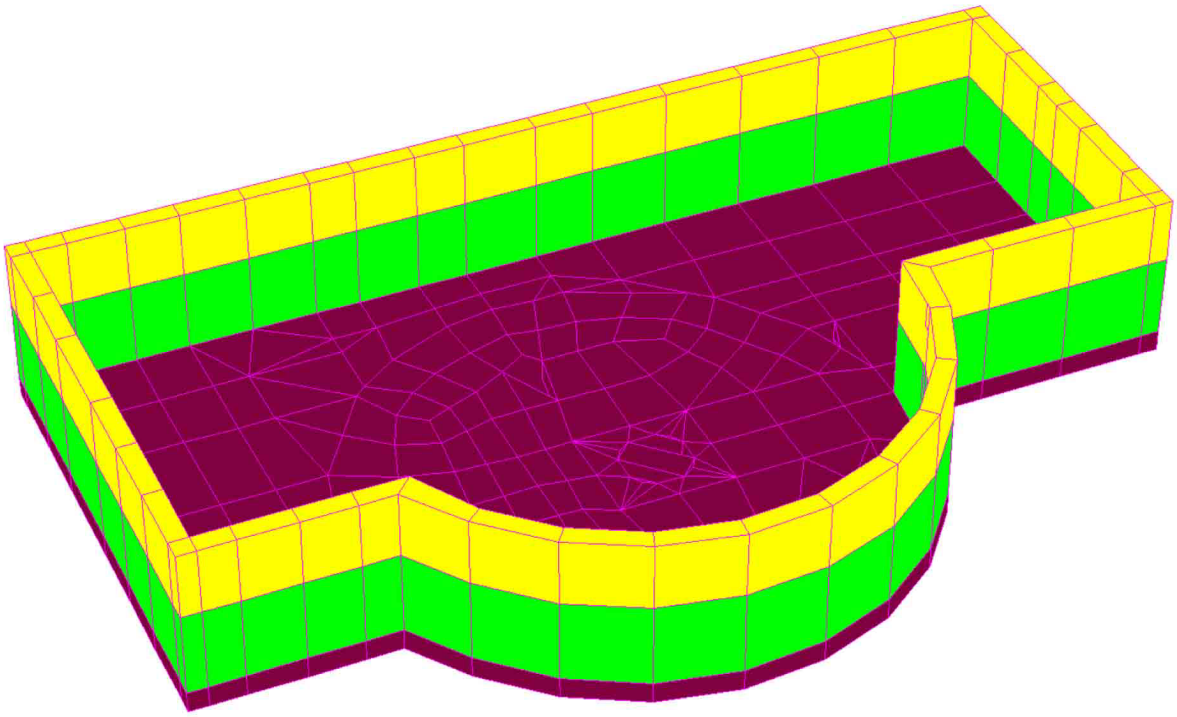
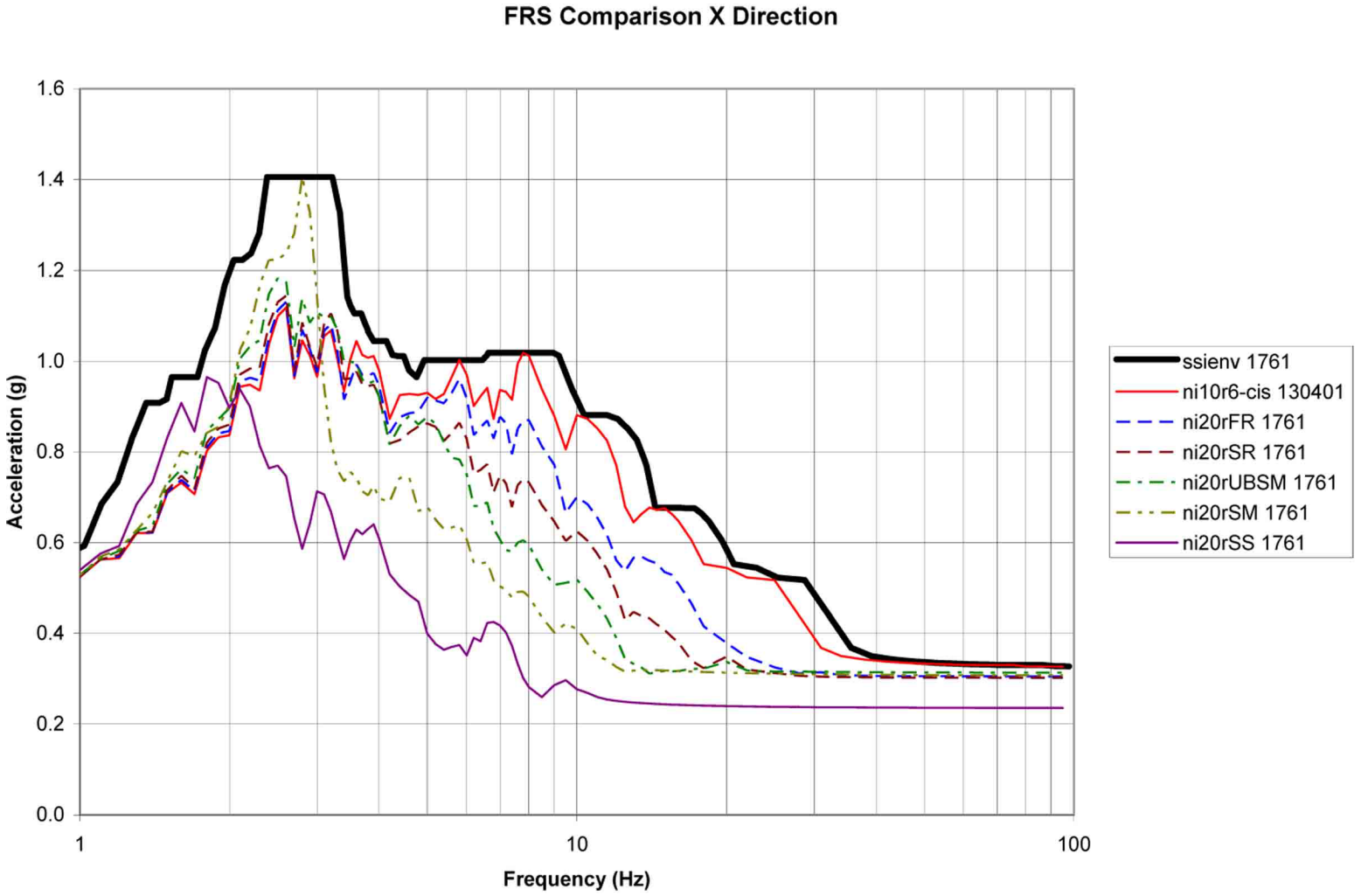
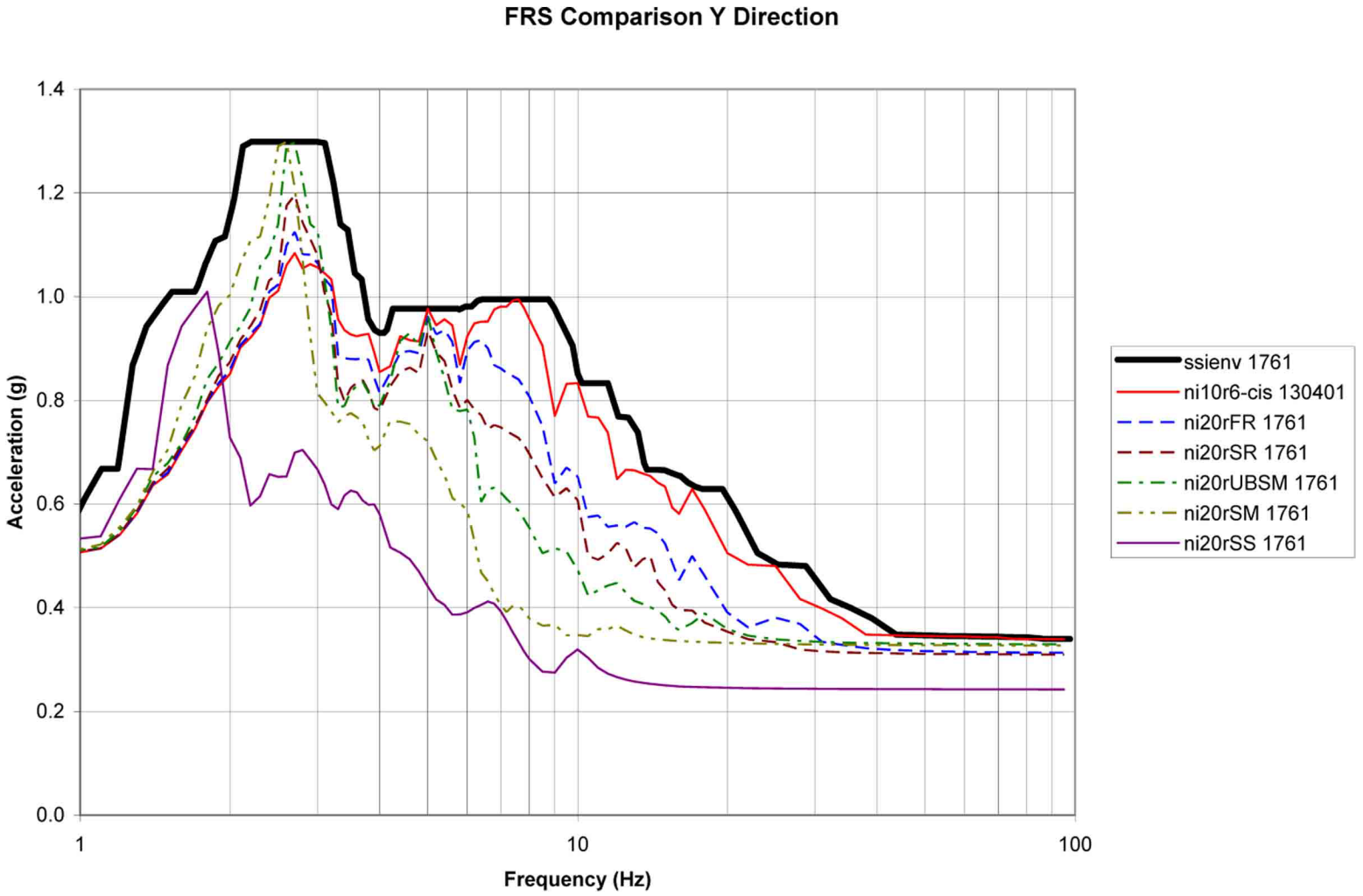


Figure 3G.4-4
Additional Elements for Soil Pressure Calculations



[*Figure 3G.4-5X*
X Direction FRS for Node 130401 (NI10) or 1761 (NI20) CIS at Reactor Vessel Support Elevation of 100']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



[*Figure 3G.4-5Y*
Y Direction FRS for Node 130401 (NI10) or 1761 (NI20) CIS at Reactor Vessel Support Elevation of 100']*

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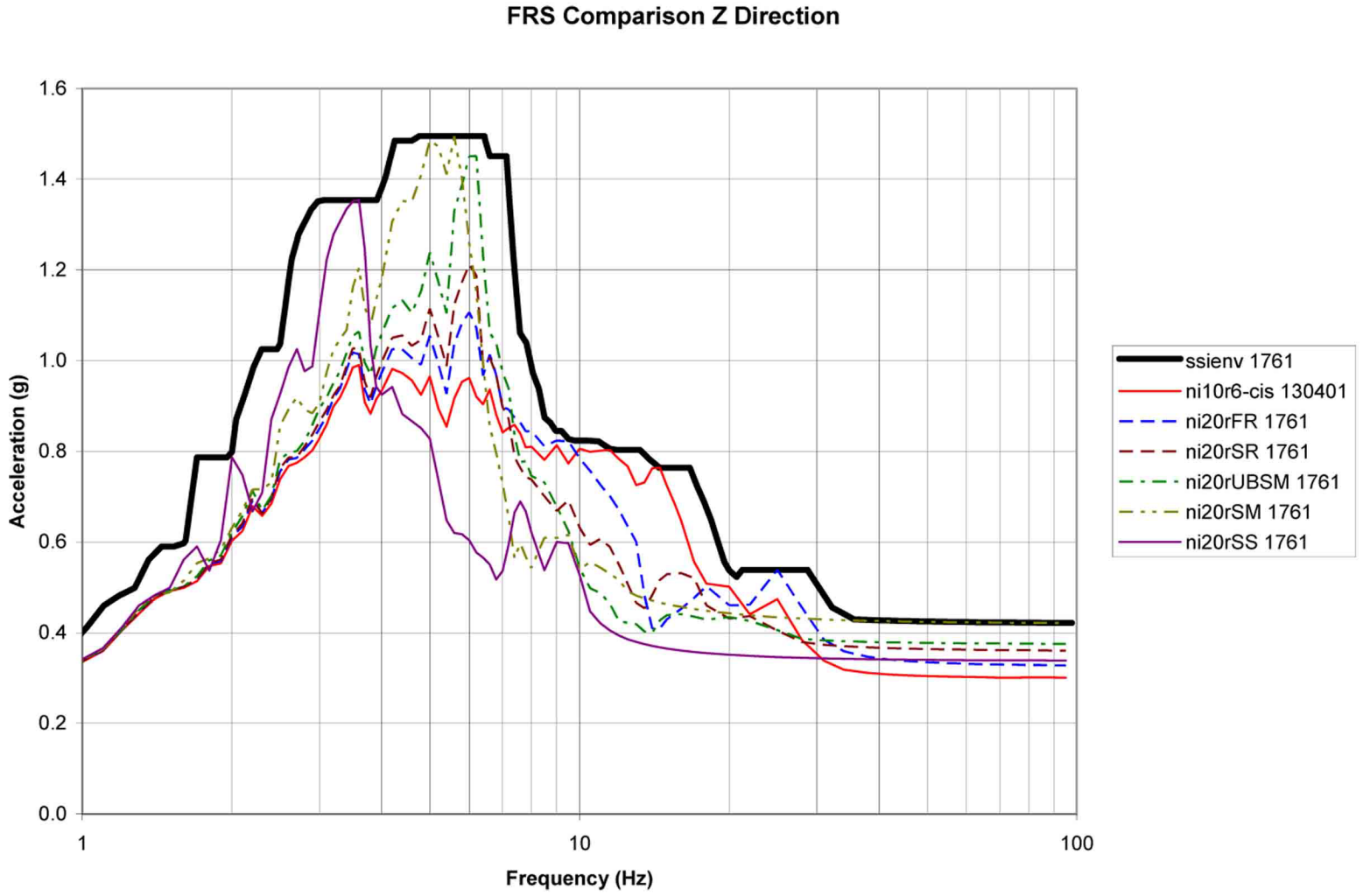
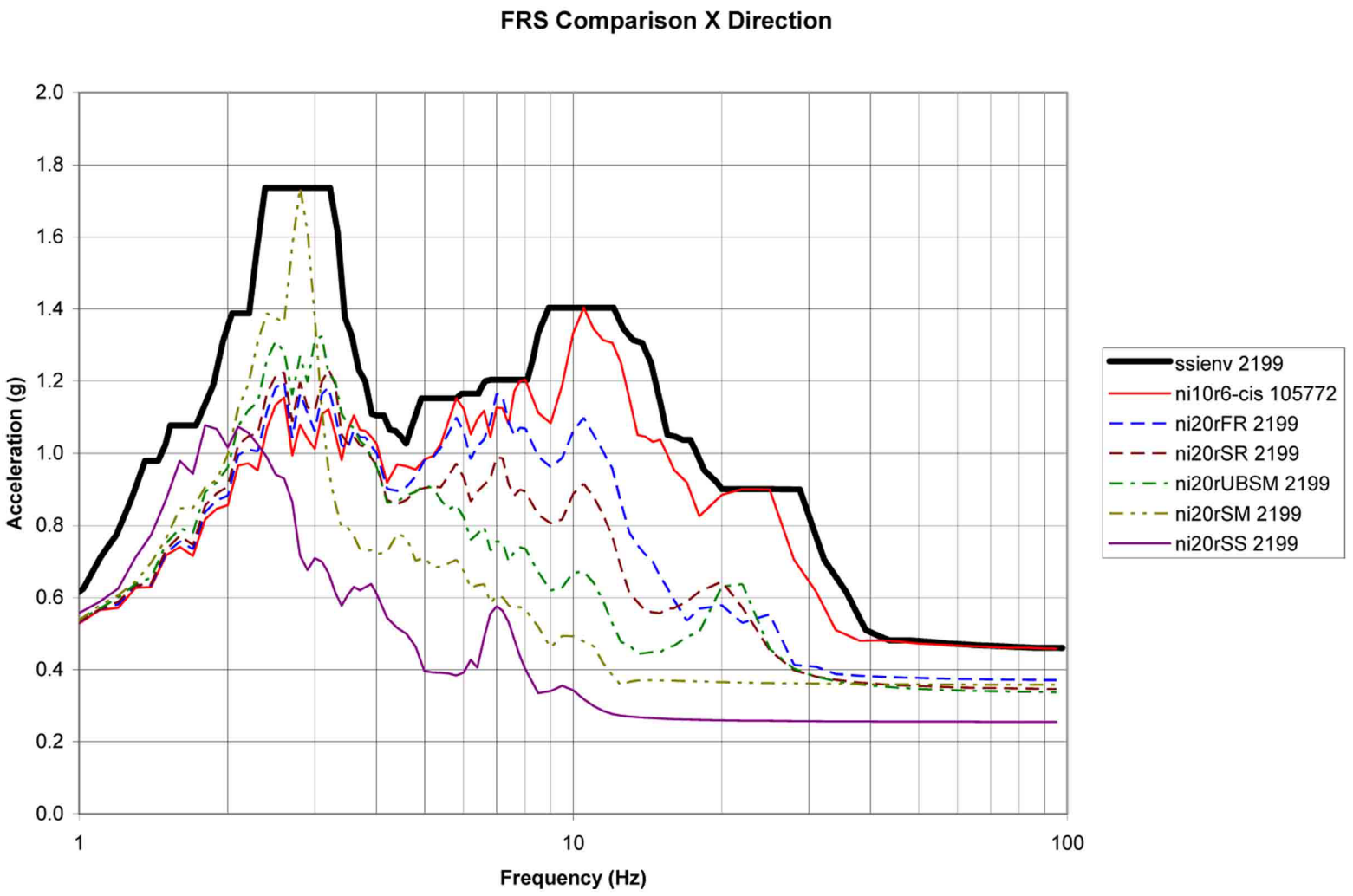


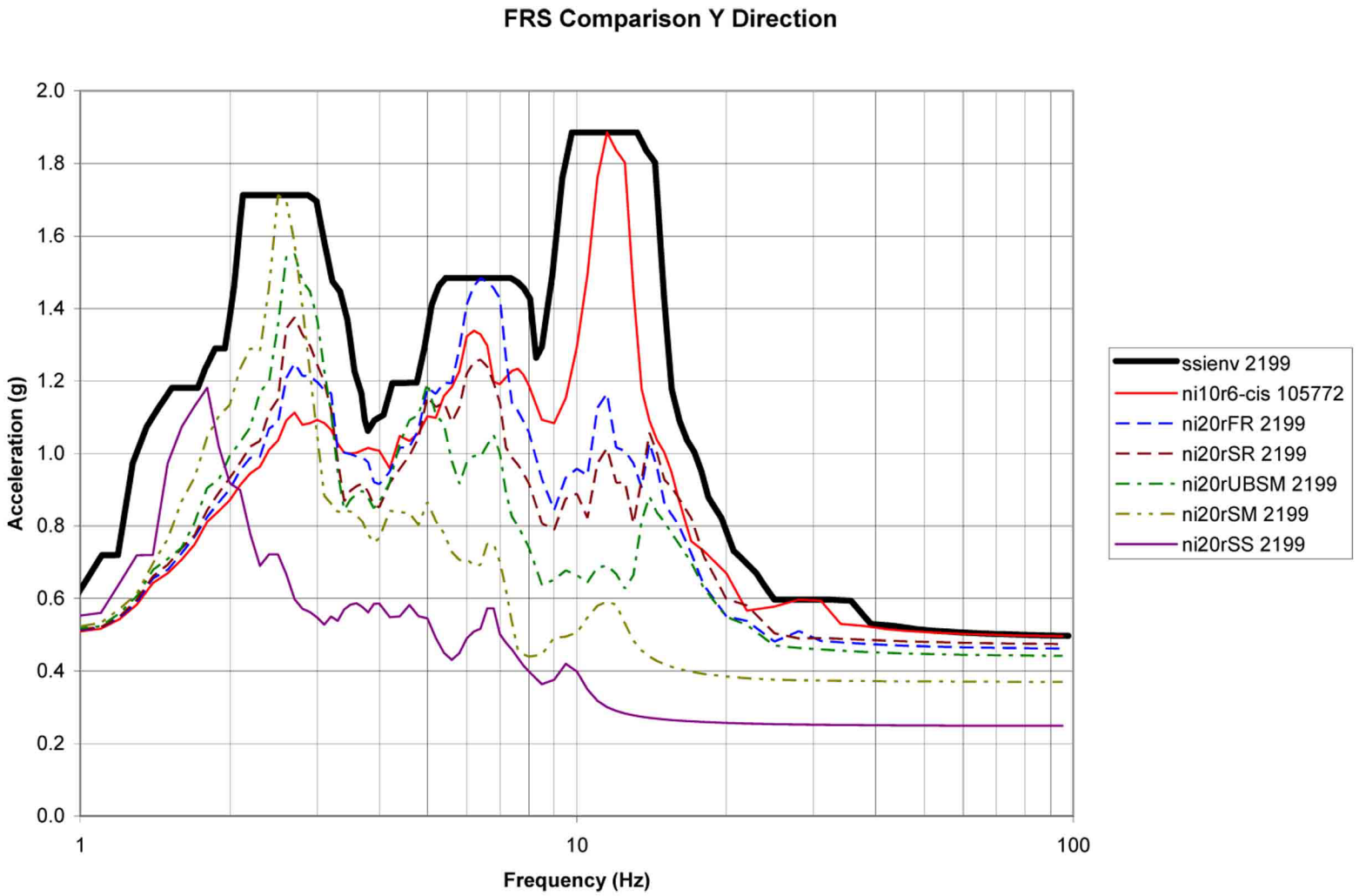
[*Figure 3G.4-5Z*
Z Direction FRS for Node 130401 (NI10) or 1761 (NI20) CIS at Reactor Vessel Support Elevation of 100']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



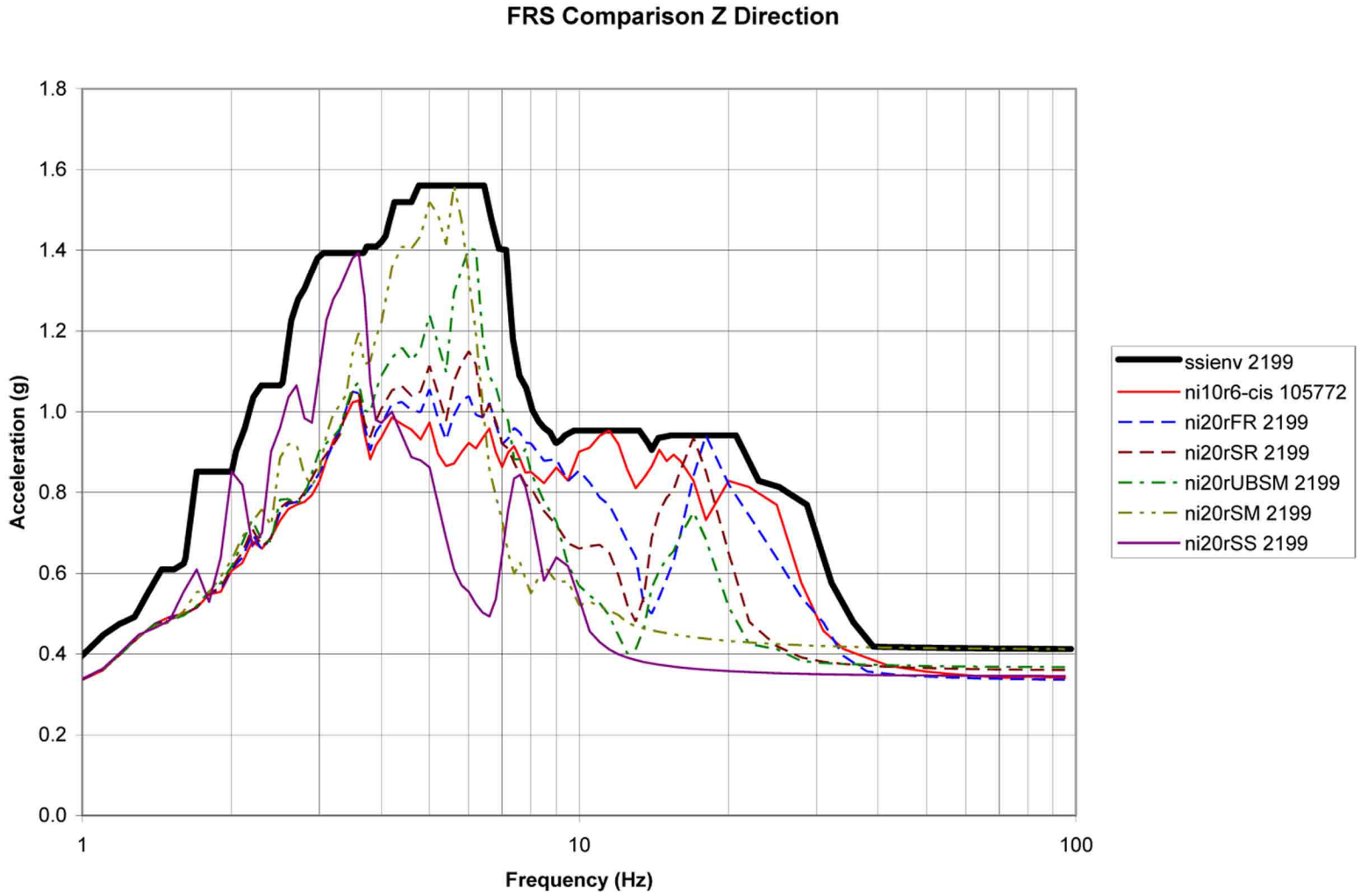
[*Figure 3G.4-6X*
X Direction FRS for Node 105772 (NI10) or 2199 (NI20) CIS at Operating Deck Elevation 134.25']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



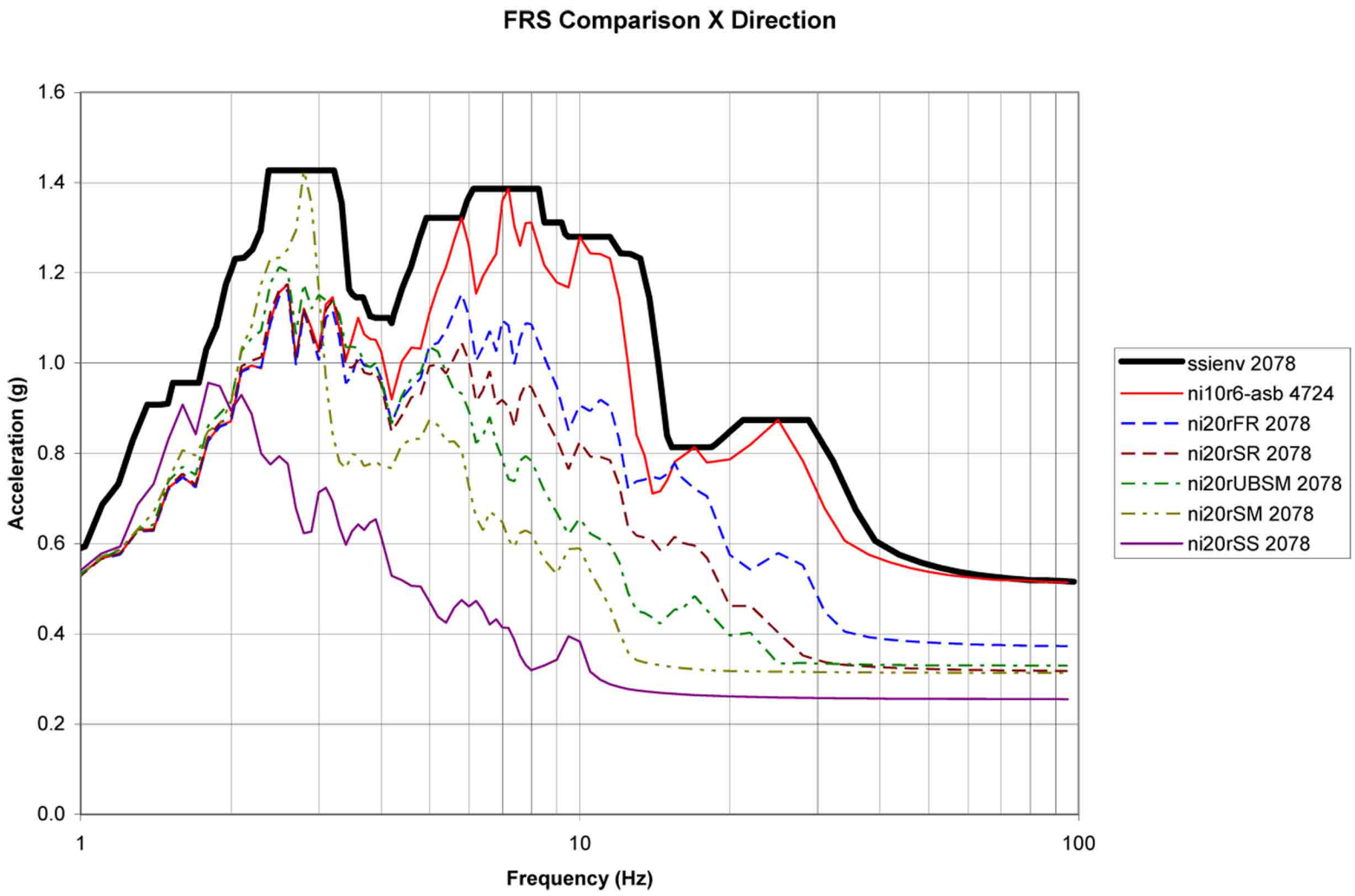
[*Figure 3G.4-6Y*
Y Direction FRS for Node 105772 (NI10) or 2199 (NI20) CIS at Operating Deck Elevation 134.25']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



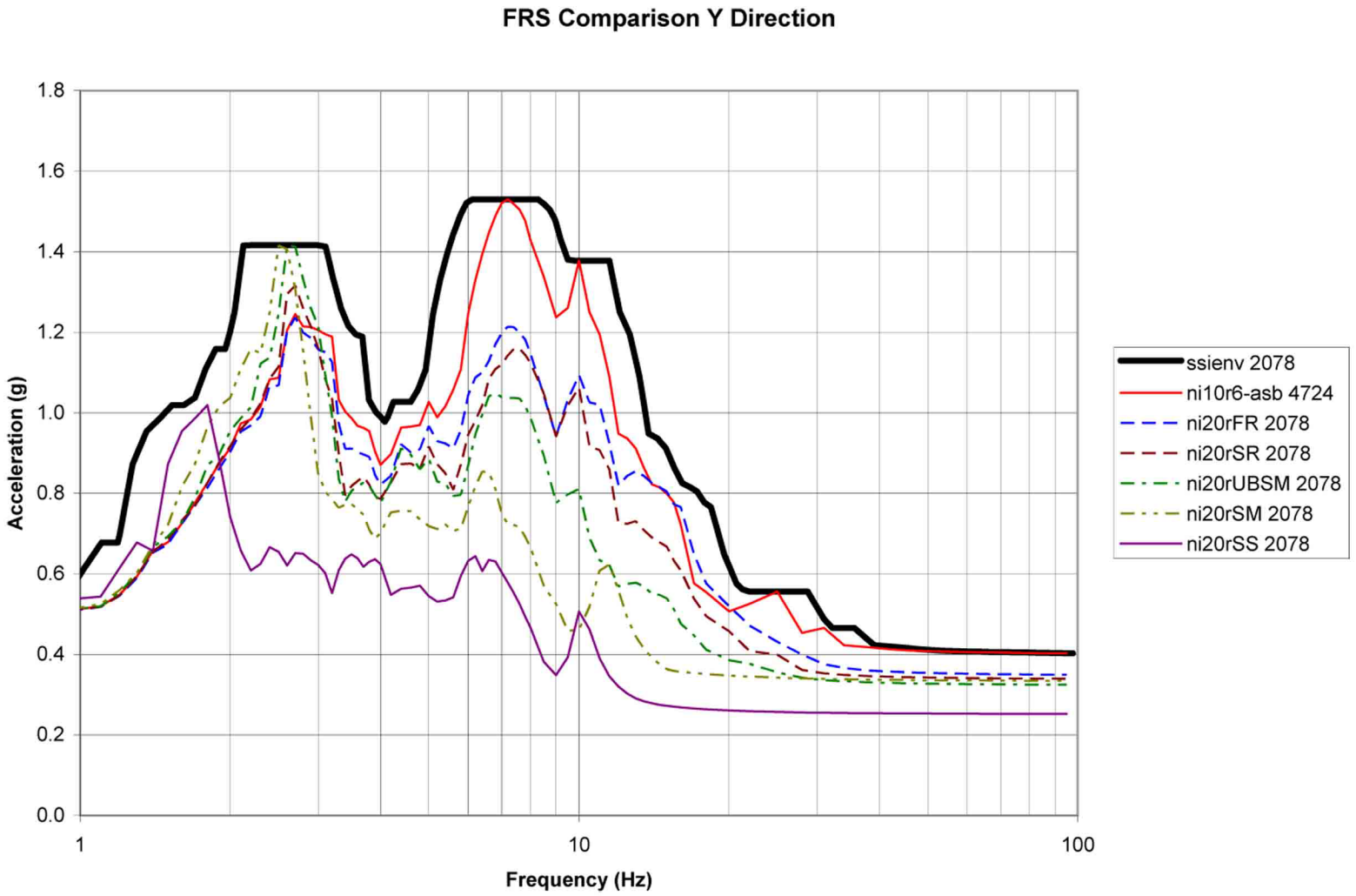
[*Figure 3G.4-6Z*
Z Direction FRS for Node 105772 (NI10) or 2199 (NI20) CIS at Operating Deck Elevation 134.25']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



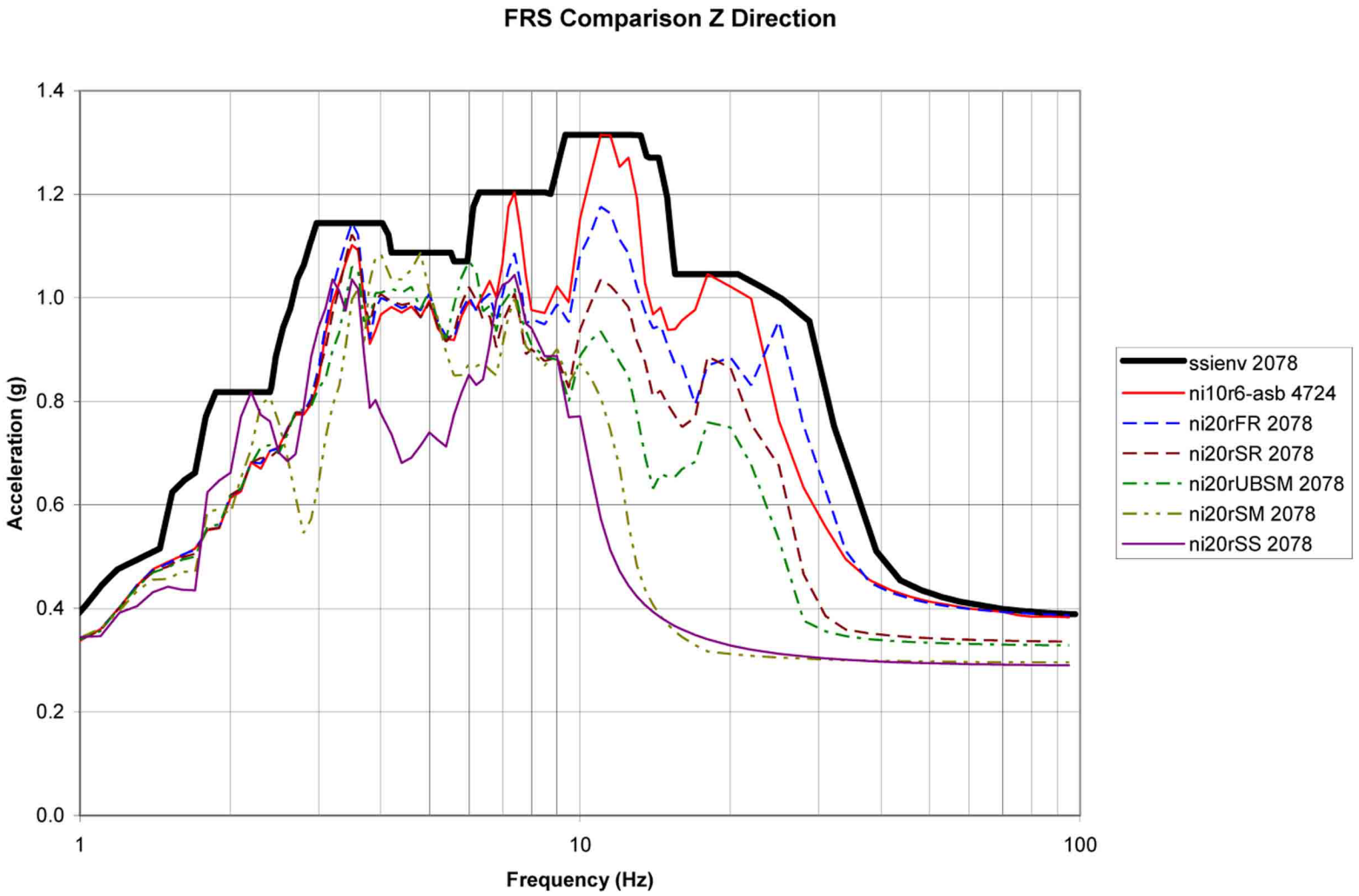
[*Figure 3G.4-7X*
X Direction FRS for Node 4724 (NI10) or 2078 (NI20)
ASB Control Room Side Elevation 116.50']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



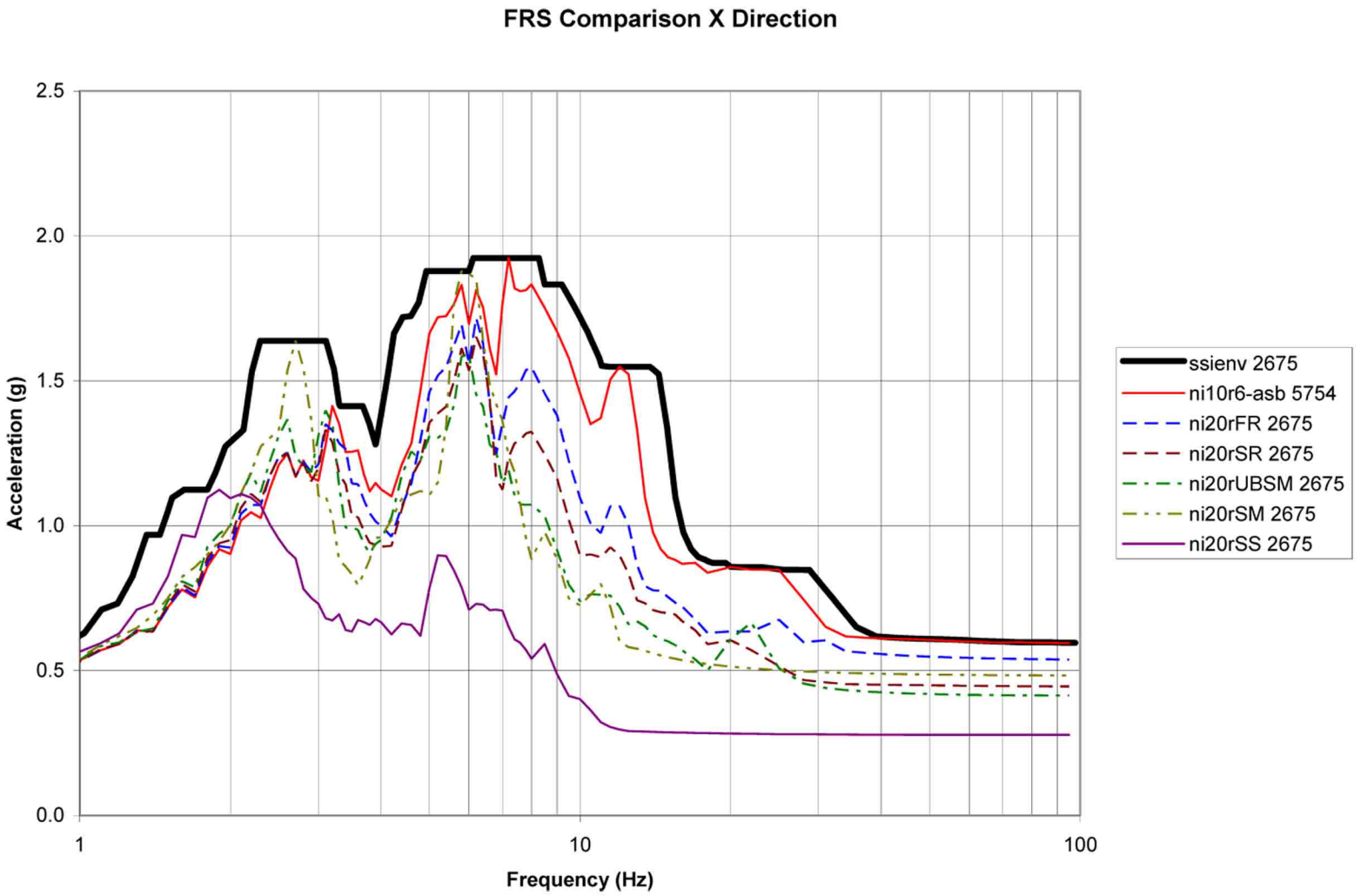
[*Figure 3G.4-7Y*
Y Direction FRS for Node 4724 (NI10) or 2078 (NI20)
ASB Control Room Side Elevation 116.50']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



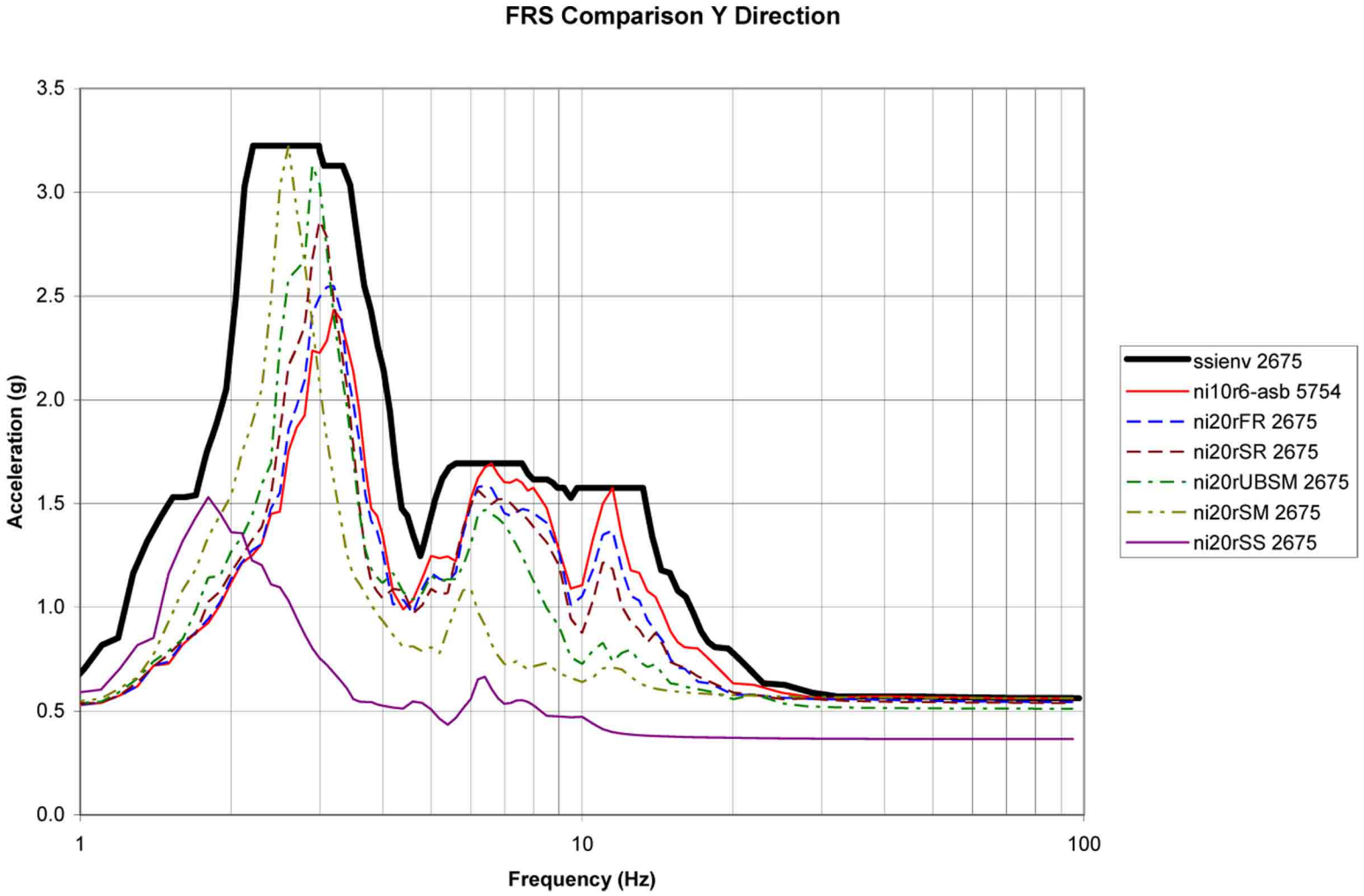
[*Figure 3G.4-7Z*
Z Direction FRS for Node 4724 (NI10) or 2078 (NI20)
ASB Control Room Side Elevation 116.50']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



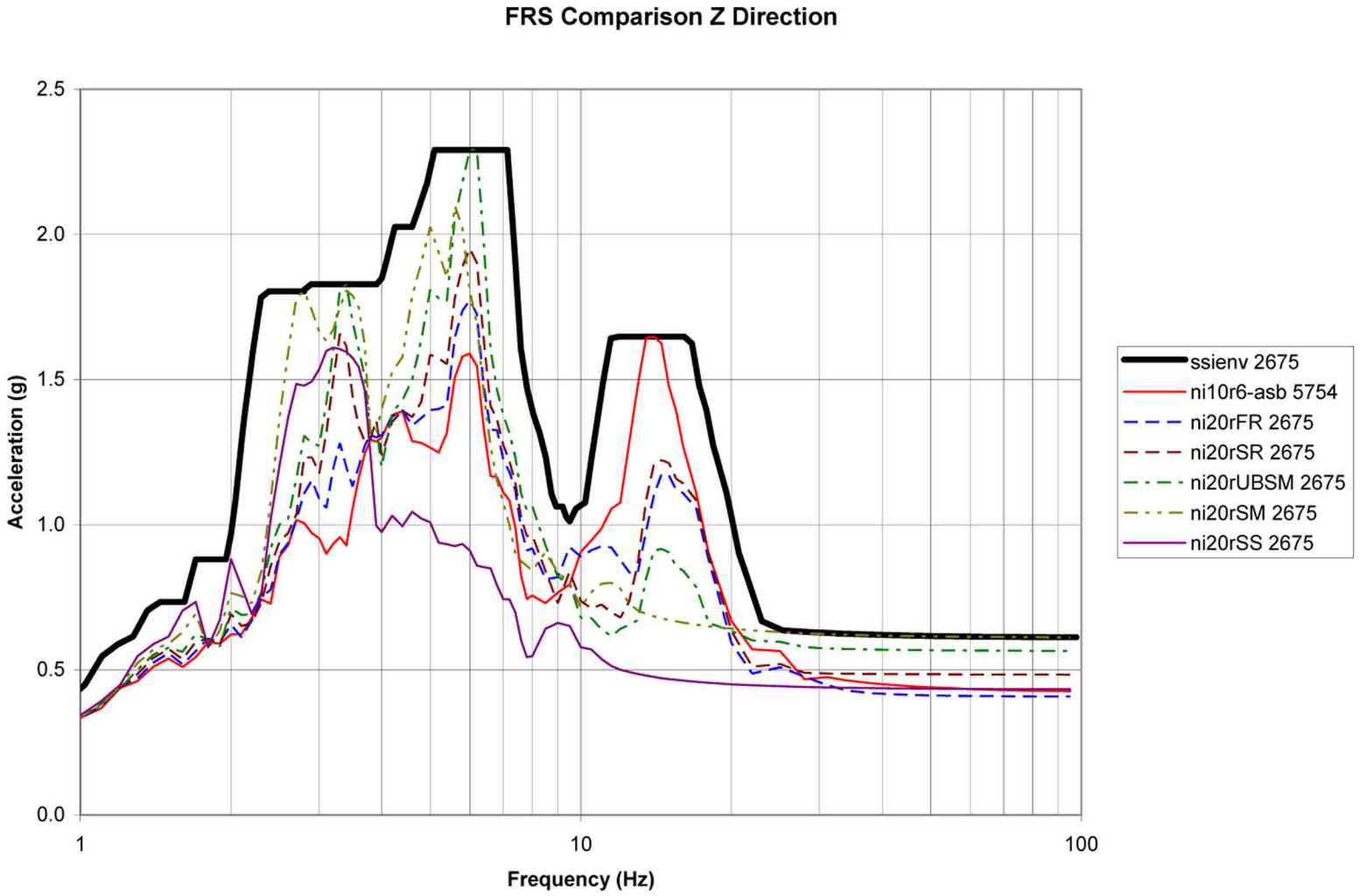
[*Figure 3G.4-8X*
X Direction FRS for Node 5754 (NI10) or 2675 (NI20)
ASB Fuel Building Roof Elevation 179.19']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



[*Figure 3G.4-8Y*
Y Direction FRS for Node 5754 (NI10) or 2675 (NI20)
ASB Fuel Building Roof Elevation 179.19']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



[*Figure 3G.4-8Z*
Z Direction FRS for Node 5754 (NI10) or 2675 (NI20)
ASB Fuel Building Roof Elevation 179.19']*

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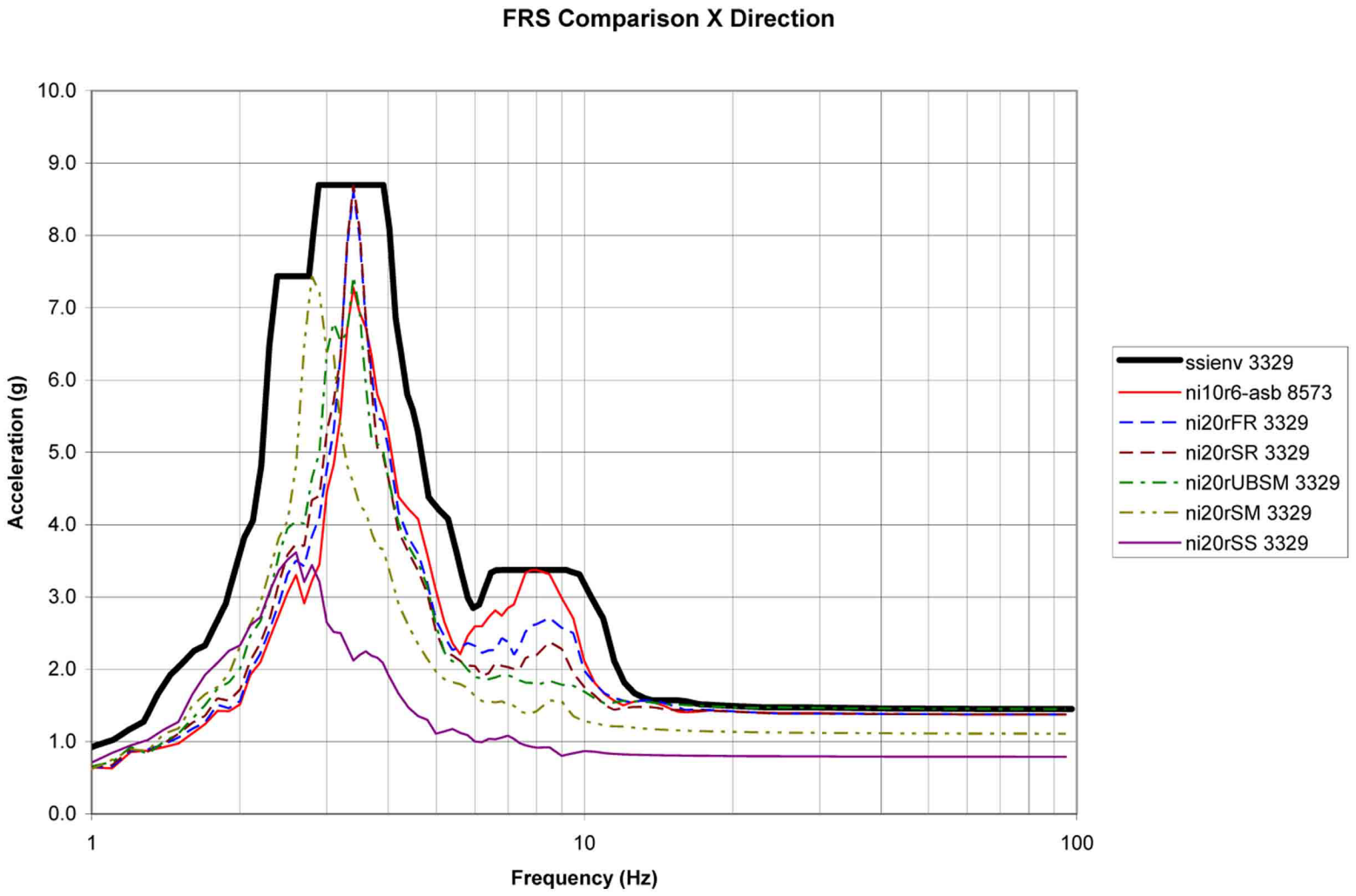
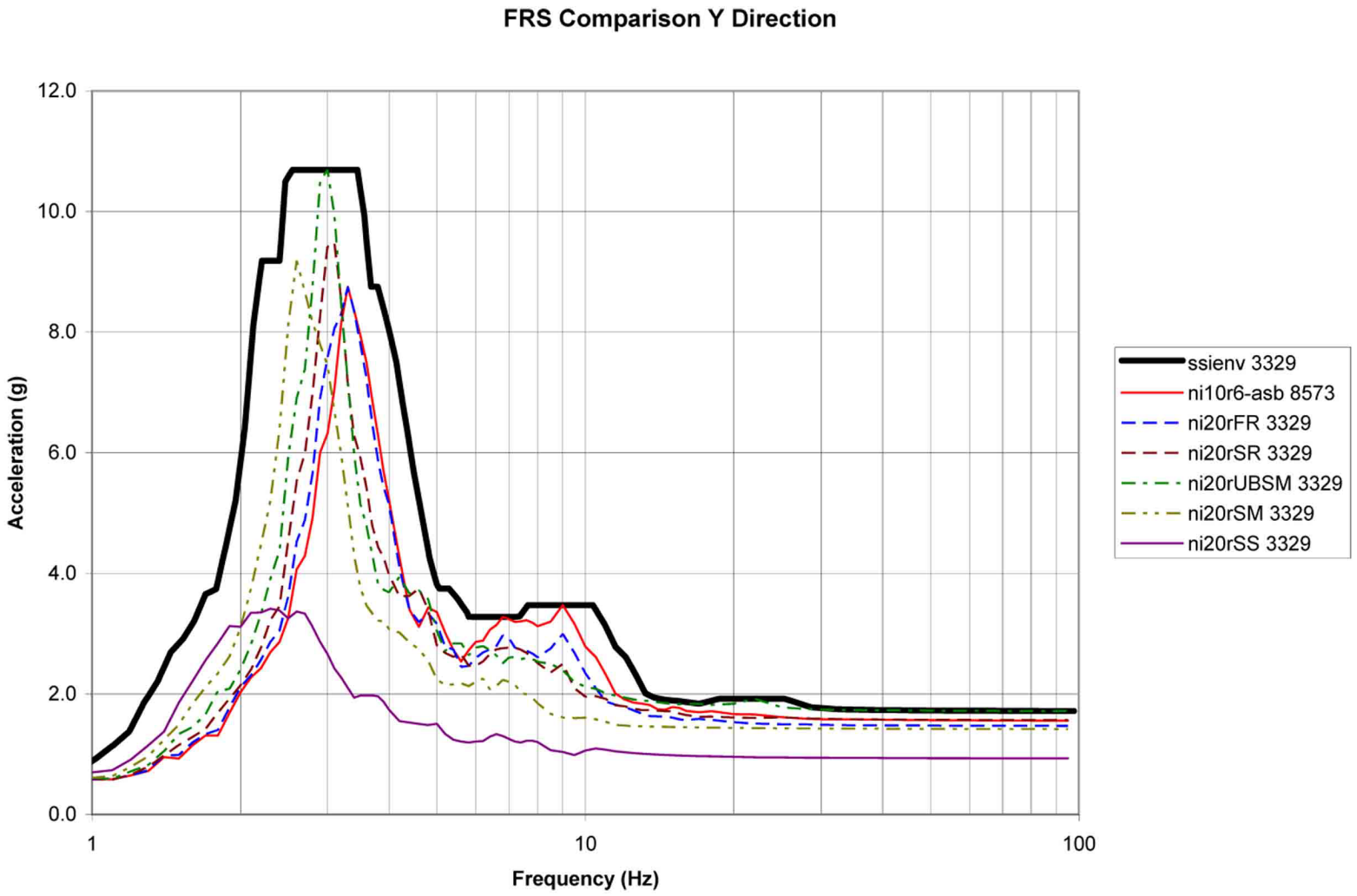


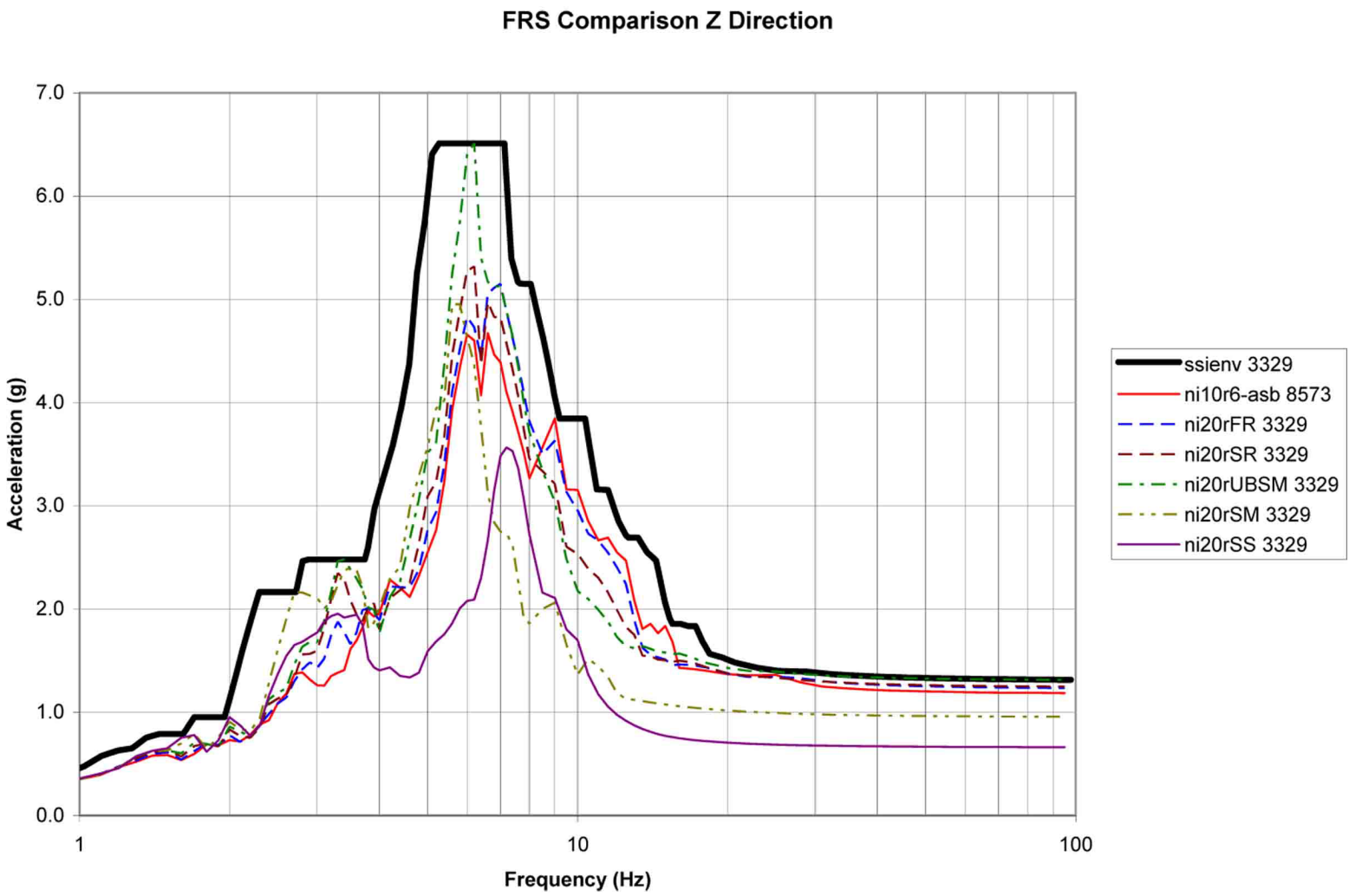
[*Figure 3G.4-9X*
X Direction FRS for Node 8573 (NI10) or 3329 (NI20)
ASB Shield Building Roof Elevation 327.41']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



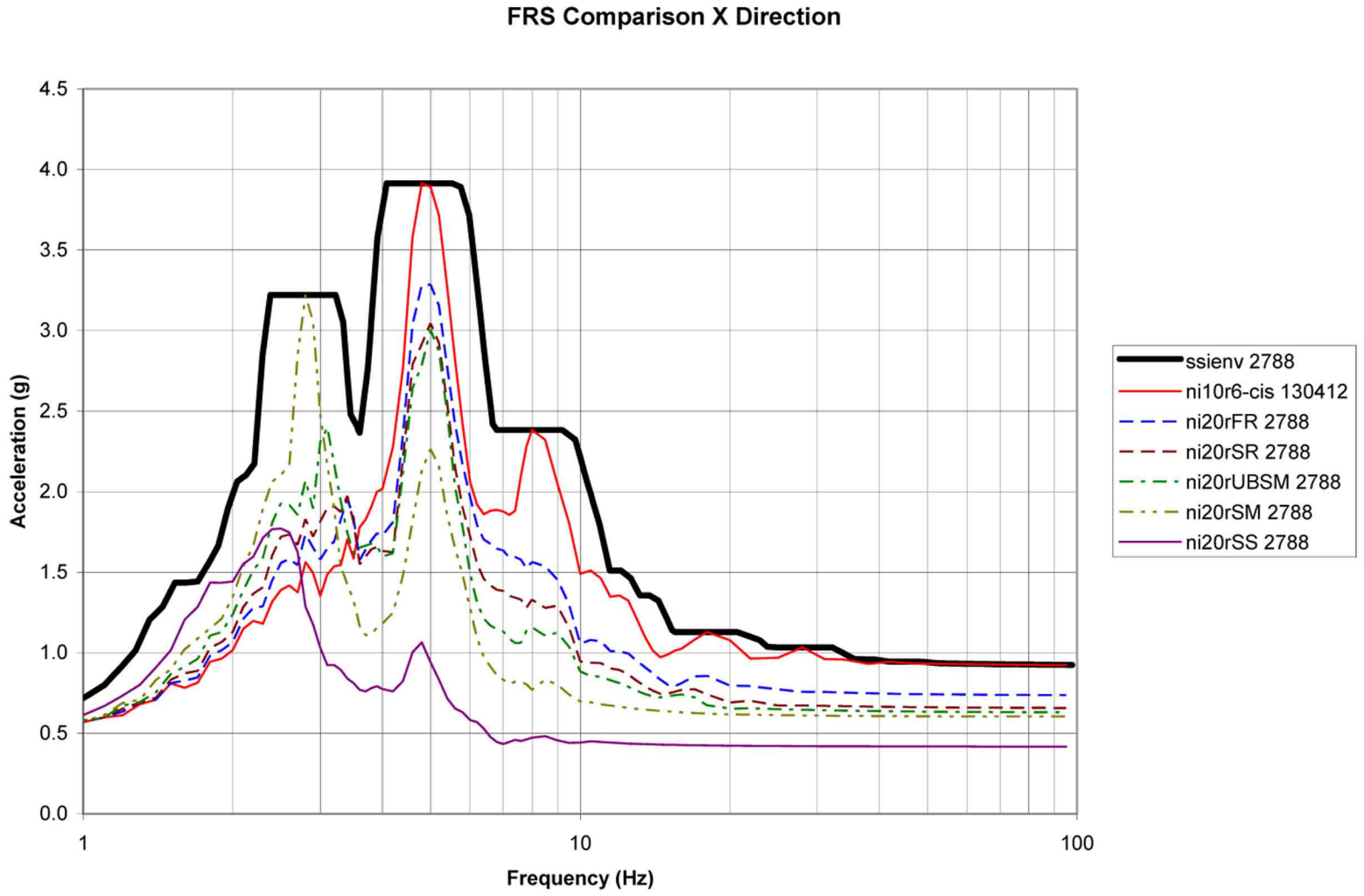
[*Figure 3G.4-9Y*
Y Direction FRS for Node 8573 (NI10) or 3329 (NI20)
ASB Shield Building Roof Elevation 327.41'*]

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



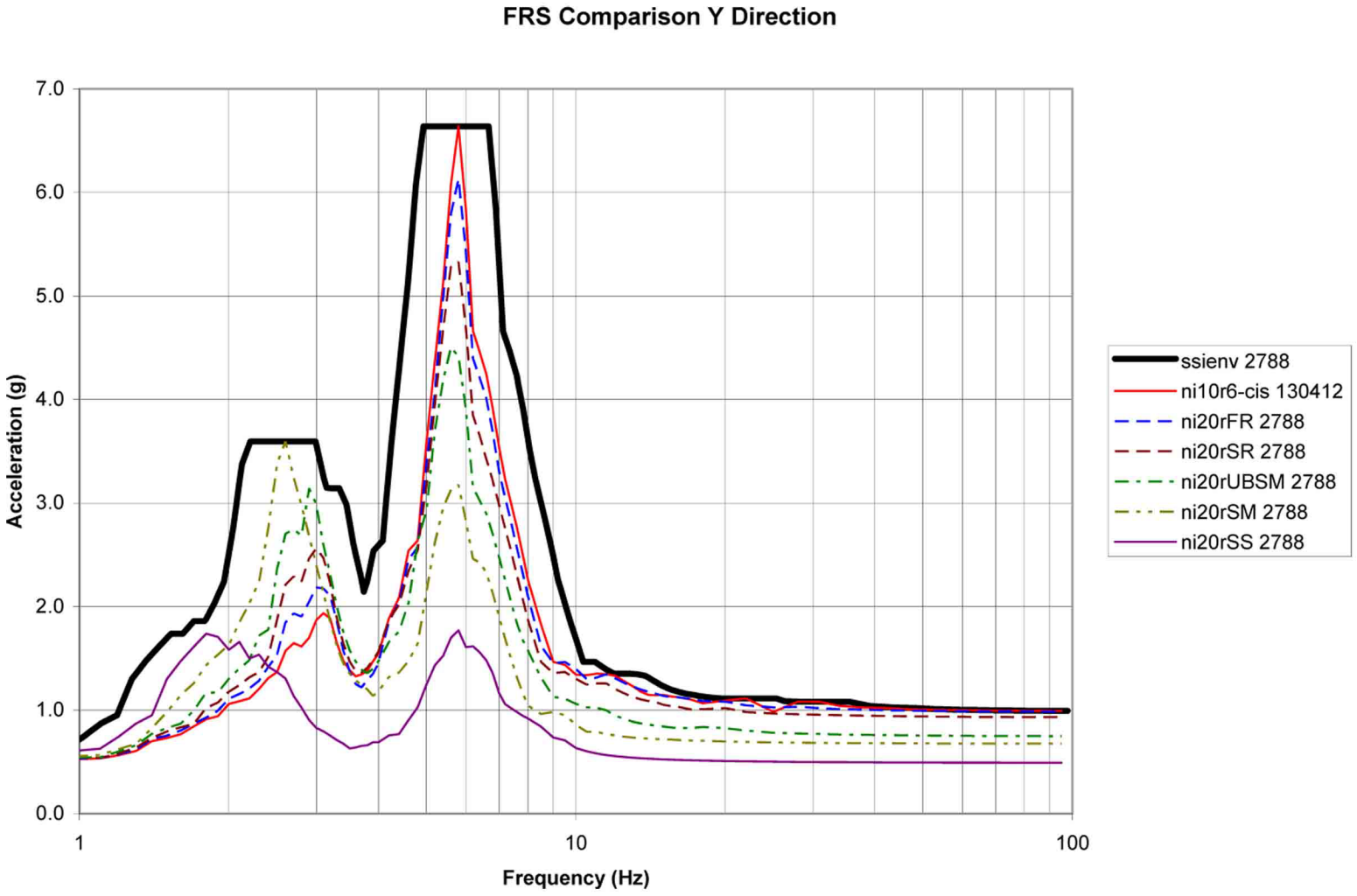
[*Figure 3G.4-9Z*
Z Direction FRS for Node 8573 (NI10) or 3329 (NI20)
ASB Shield Building Roof Elevation 327.41'*]

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



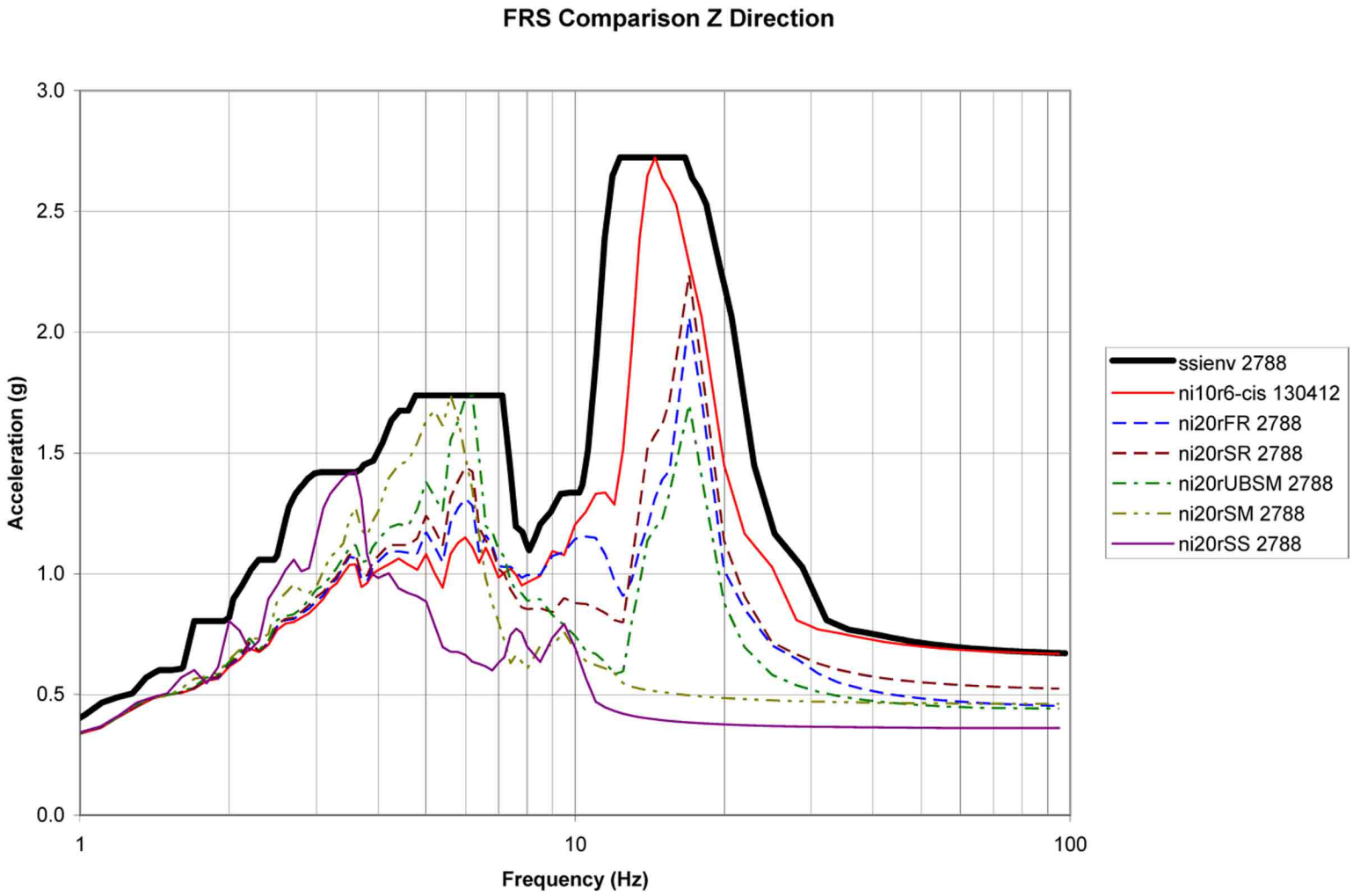
[*Figure 3G.4-10X*
X Direction FRS for Node 130412 (NI10) or 2788 (NI20) SCV Near Polar Crane Elevation 224.00']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



[*Figure 3G.4-10Y*
Y Direction FRS for Node 130412 (NI10) or 2788 (NI20)
SCV Near Polar Crane Elevation 224.00']*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



[*Figure 3G.4-10Z*
Z Direction FRS for Node 130412 (NI10) or 2788 (NI20) SCV Near Polar Crane Elevation 224.00'*]

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Appendix 3GG 3-D SSI Analysis of AP1000 at Vogtle Site Using NI15 Model

3-D SSI ANALYSIS OF AP1000 AT VOGTLE SITE USING NI15 MODEL

FOR

VEGP UNITS 3 AND 4

October 2010

Table of Contents

1. Introduction 4
2. Methodology 4
3. Vogtle Site Profile 4
4. Vogtle Site Specific Seismic Motion 8
   4.1 SSI Input Motion 9
5. Structural Model 12
6. SSI Analysis and Results 15
7. Conclusion 16
8. Reference 16

List of Tables

Table 1 Key Location for ISRS Comparison with DCD 16

List of Figures

Figure 1 Vogtle Strain-Compatible Soil Shear Wave Velocity Profiles Used in SSI Analysis 5
Figure 2 Vogtle Strain-Compatible Soil Damping Profiles Used in SSI Analysis 6
Figure 3 Vogtle Site-Specific and AP1000 Generic Strain-Compatible Soil Profiles 7
Figure 4 AP1000 CSDRS and Vogtle GMRS and FIRS - Horizontal Motion (5% Damping)..... 8
Figure 5 AP1000 CSDRS and Vogtle GMRS and FIRS - Vertical Motion (5% Damping) 9
Figure 6 Comparison of H1 Response Motion and GMRS at the Ground Surface Level (5% Damping) 10
Figure 7 Comparisons of the H2 Response Motions with the GMRS at the Ground Surface Level (5% Damping) 11
Figure 8 Comparisons of the Vertical Response Motions with the GMRS at the Ground Surface Level (5% Damping) 11
Figure 9 Comparisons of the Modified Vertical Response Motions with the GMRS at the Ground Surface Level (5% Damping) 12
Figure 10 NI15 Finite Element Model 14
Figure 11 NI15 CIS, RCL, and SCV Elements 15
Figure 12 Horizontal X Response Spectra at CIS at Reactor Vessel Support Elevation (El. 100.00 ft, Node 9007) 17
Figure 13 Horizontal Y Response Spectra at CIS at Reactor Vessel Support Elevation (El. 100.00 ft, Node 9007) 18

List of Figures (Cont.)

Figure 14 Vertical Z Response Spectra at CIS at Reactor Vessel Support Elevation (El. 100.00 ft, Node 9007) 19

Figure 15 Horizontal X Response Spectra at ASB NE Corner at Control Room Floor (El. 116.50 ft, Node 10115) 20

Figure 16 Horizontal Y Response Spectra at ASB NE Corner at Control Room Floor (El. 116.50 ft, Node 10115) 21

Figure 17 Vertical Z Response Spectra at ASB NE Corner at Control Room Floor (El 116.50 ft, Node 10115) 22

Figure 18 Horizontal X Response Spectra at CIS at Operating Deck (El. 134.25 ft, Node 10471) 23

Figure 19 Horizontal Y Response Spectra at CIS at Operating Deck (El. 134.25 ft, Node 10471) 24

Figure 20 Vertical Z Response Spectra at CIS at Operating Deck (El. 134.25 ft, Node 10471) 25

Figure 21 Horizontal X Response Spectra at ASB Corner of Fuel Building Roof at Shield Building (El. 179.19 ft, Node 11111) 26

Figure 22 Horizontal Y Response Spectra at ASB Corner of Fuel Building Roof at Shield Building (El. 179.19 ft, Node 11111) 27

Figure 23 Vertical Z Response Spectra at ASB Corner of Fuel Building Roof at Shield Building (El. 179.19 ft, Node 11111) 28

Figure 24 Horizontal X Response Spectra at SCV near Polar Crane (El. 224.00 ft, Node 11224) 29

Figure 25 Horizontal Y Response Spectra at SCV near Polar Crane (El. 224.00 ft, Node 11224) 30

Figure 26 Vertical Z Response Spectra at SCV near Polar Crane (El. 224.00 ft, Node 11224) 31

Figure 27 Horizontal X Response Spectra at ASB Shield Building Roof Area (El. 327.41 ft, Node 12052) 32

Figure 28 Horizontal Y Response Spectra at ASB Shield Building Roof Area (El. 327.41 ft, Node 12052) 33

Figure 29 Vertical Z Response Spectra at ASB Shield Building Roof Area (El. 327.41 ft, Node 12052) 34

1. Introduction

This report presents the results of the three-dimensional soil-structure interaction (SSI) analysis of the AP1000 plant at the Vogtle site to confirm the applicability of the AP1000 design to the site.

This report supplements the two-dimensional site-specific SSI analysis previously submitted as Appendix 2.5E in the Vogtle Early Site Permit Application.

Site-specific SSI analysis is required since the site specific design response spectra exceed the certified seismic design response spectra (CSDRS) at some limited frequency range and the Vogtle soil profile is significantly different than the AP1000 generic soil profiles in shear wave velocity versus depth and overall soil depth.

Reference 1 describes changes to the AP1000 NI20 SASSI model now identified as NI20r and provides revised AP1000 CSDRS broadened envelope ISRS. This report reflects those changes and consists of updating the Vogtle NI15 SASSI model, rerunning the Vogtle SASSI analyses using the updated Vogtle NI15 SASSI model to generate revised Vogtle ISRS at the six key locations for the Vogtle soil profile (Lower Bound, Best Estimate, and Upper Bound soil cases), and providing a comparison of the revised Vogtle ISRS to the new AP1000 CSDRS broadened envelope ISRS.

2. Methodology

The free-field analyses are performed using the Bechtel Computer Program SHAKE2000. The SSI analyses are performed using the Bechtel Computer Program SASSI2000

3. Vogtle Site Profile

A detailed description of the site geology and soil stratigraphy including the extent and characteristics of the backfill materials is contained in the Early Site Permit Application and is not repeated in this report. For the three-dimensional SSI analysis, the same soil profiles used for the two-dimensional SSI analysis are used. The strain-compatible soil shear-wave velocity and damping profiles for the three soil cases, (upper bound (UB), median (BE) and lower bound (LB)) are shown in Figure 1 and Figure 2. Note that the UB shear-wave velocity profile is combined with the LB damping profile to form the UB SSI soil profile. Likewise, the LB velocity profile is combined with the UB damping profile to form the LB SSI soil profile. The BE shear wave velocity and damping profiles are for the BE SSI soil profile. These profiles are obtained from the group of simulated soil profiles used for development of the soil amplification factors and site specific ground motions by considering the median and one standard deviation of the range of data and incorporating the NUREG-0800 requirement of the minimum soil shear modulus variation of 1.5. For SSI analysis, the rock was modeled at the depth of about 1000 ft corresponding to the approximate depth of the rock at the site.

For comparison purposes, the strain-compatible generic soil profiles used for certified design of AP1000 are compared with the strain-compatible Vogtle UB, BE and LB site-specific soil profiles in Figure 3. As shown, the Vogtle site-specific soil profiles are softer than the lower-bound generic Soft Soil profile in the upper 50 ft. In addition, the Vogtle site-specific soil profiles extend to the depth of about 1000 ft whereas the generic soil profiles are only 120 ft deep overlying a bedrock layer assumed to be a halfspace layer below 120 ft depth.

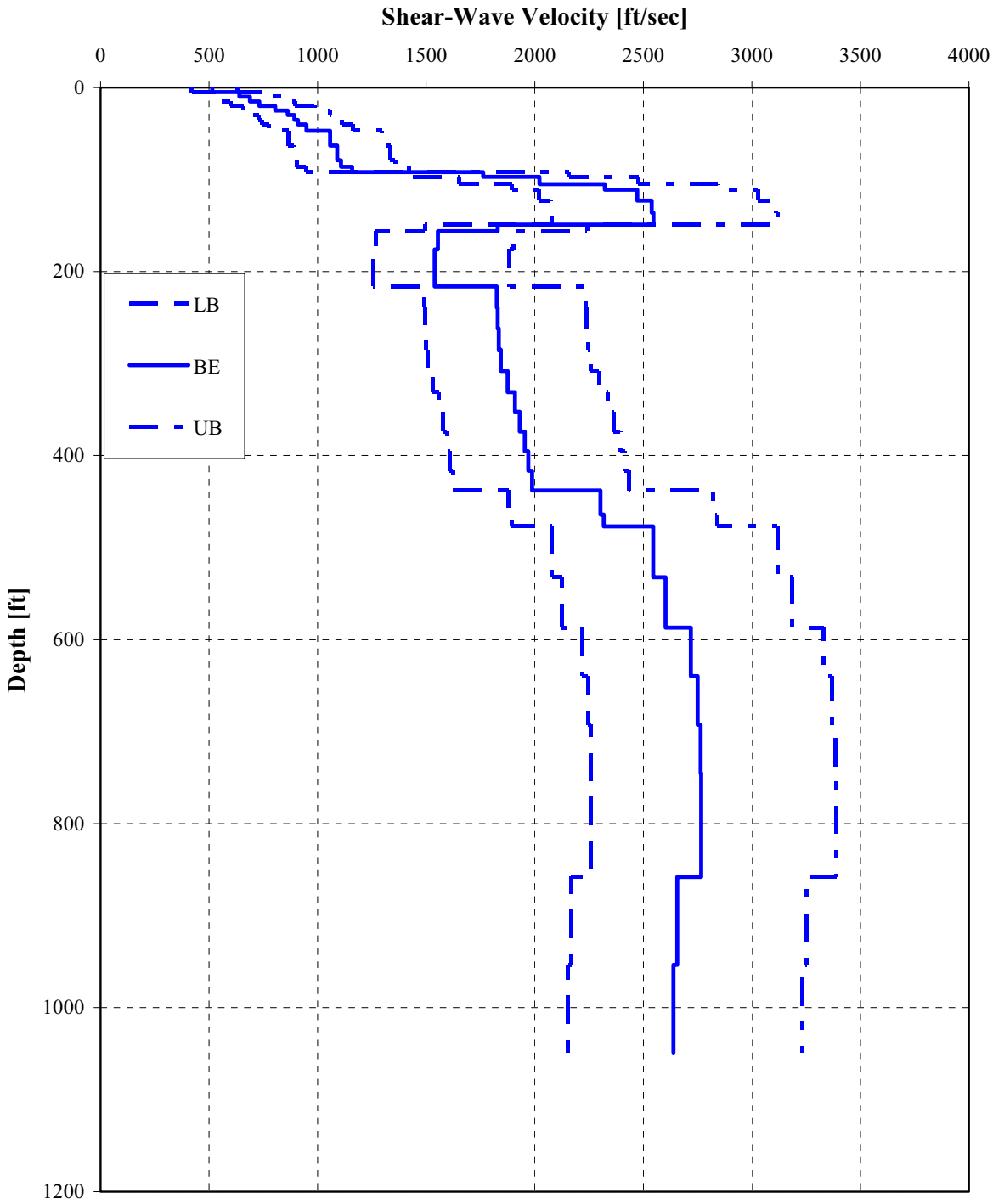


Figure 1 Vogtle Strain-Compatible Soil Shear Wave Velocity Profiles Used in SSI Analysis

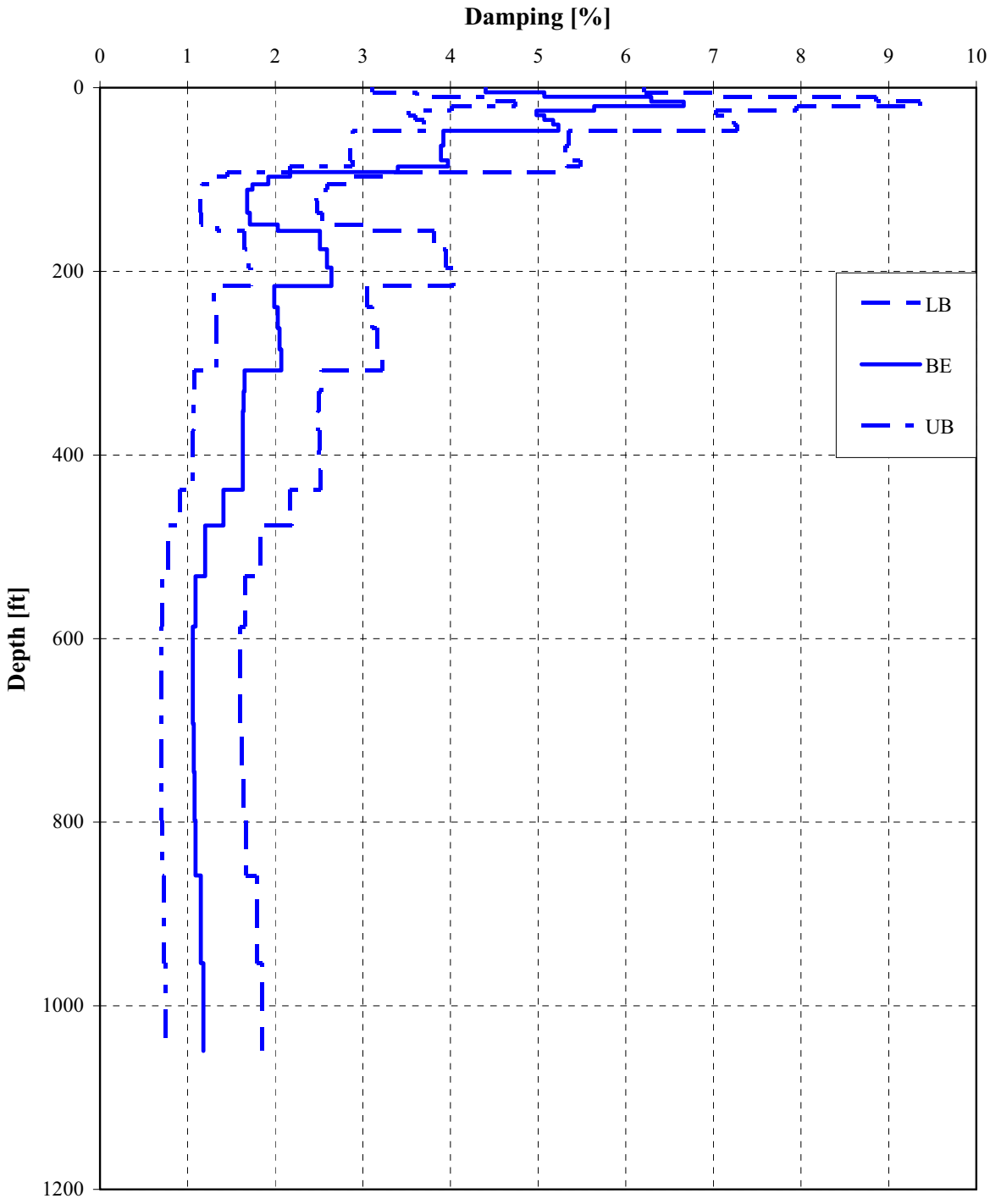


Figure 2 Vogtle Strain-Compatible Soil Damping Profiles Used in SSI Analysis

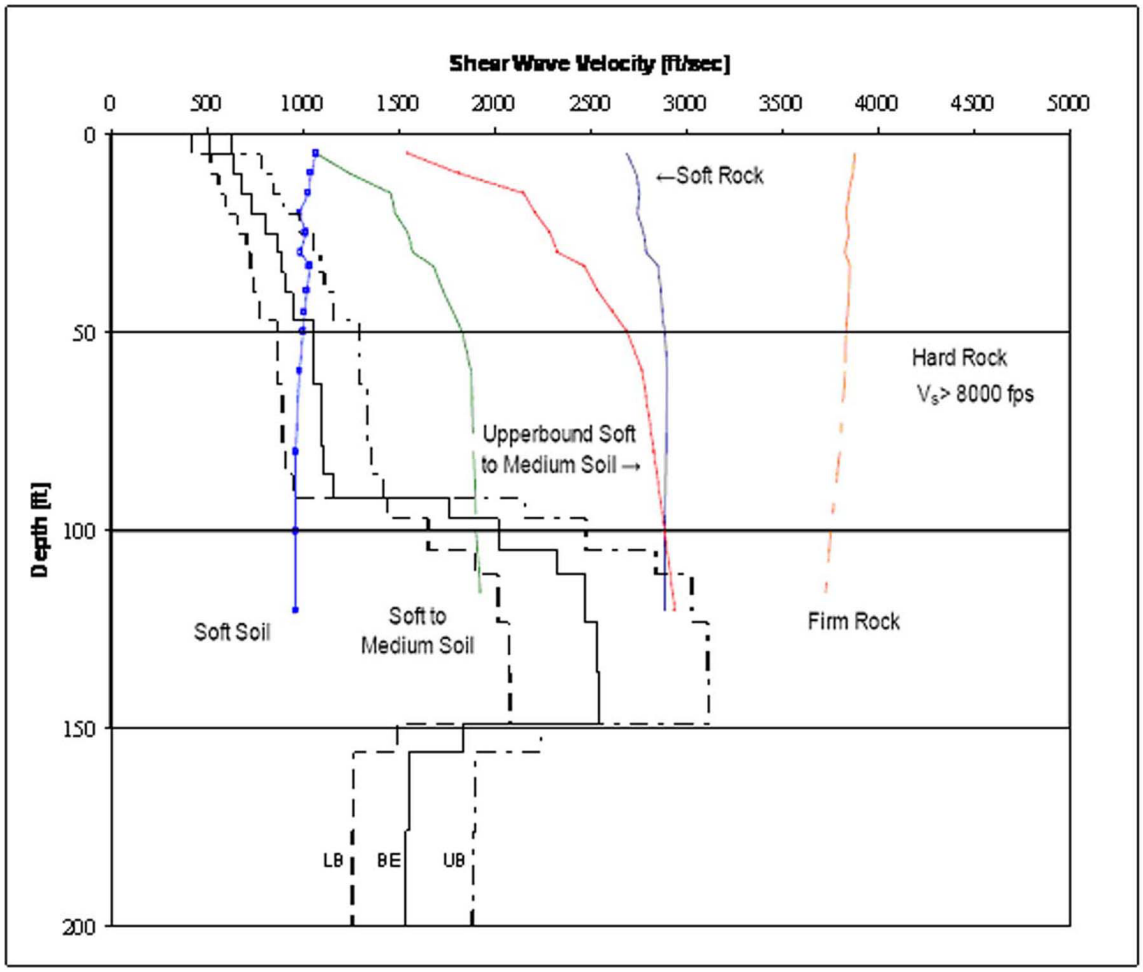


Figure 3 Vogtle Site-Specific and AP1000 Generic Strain-Compatible Soil Profiles

4. Vogtle Site Specific Seismic Motion

As described in the ESP application, the ground motion response spectra (GMRS) at the Vogtle site are defined at the finished grade at the top of the backfill. The foundation input response spectra (FIRS) is at the foundation horizon at the depth of 40 ft below the finished grade. FIRS and GMRS are compared with CSDRS in Figure 4 and Figure 5 for the horizontal and vertical motions, respectively. Note that the FIRS is an outcrop motion at the foundation level obtained from the soil column analysis of the site full soil column extending to the top of the backfill.

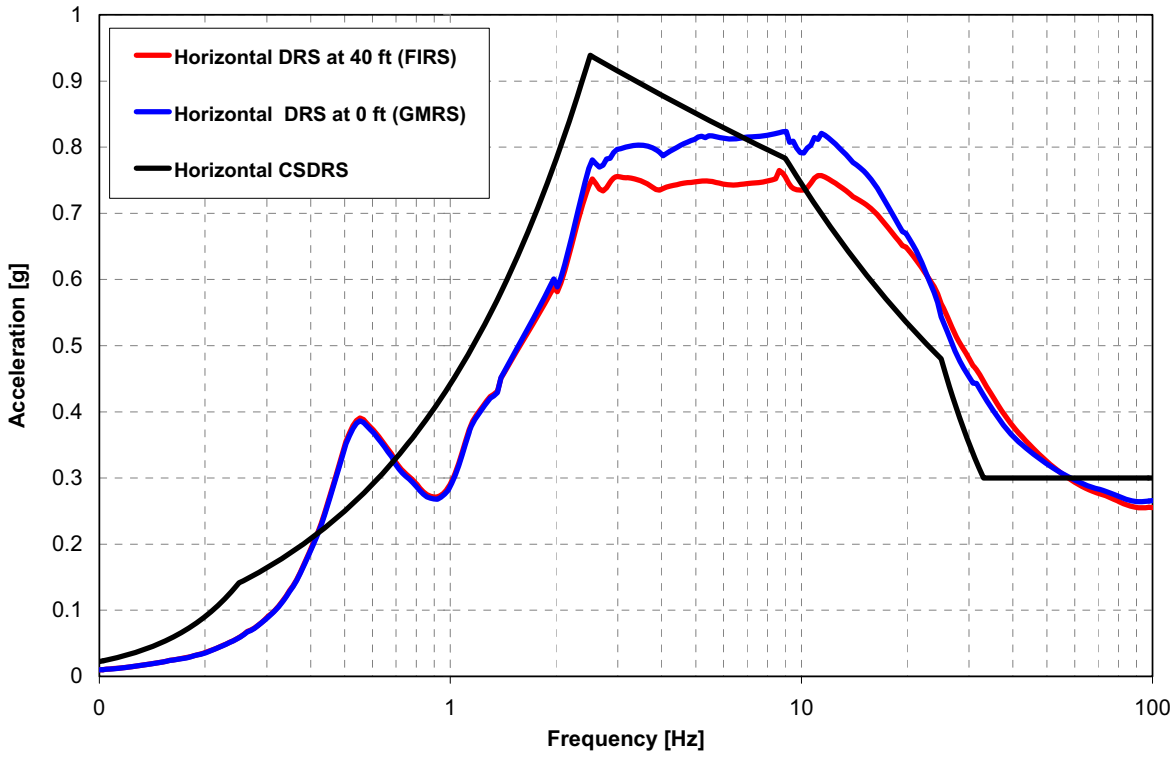


Figure 4 AP1000 CSDRS and Vogtle GMRS and FIRS - Horizontal Motion (5% Damping)

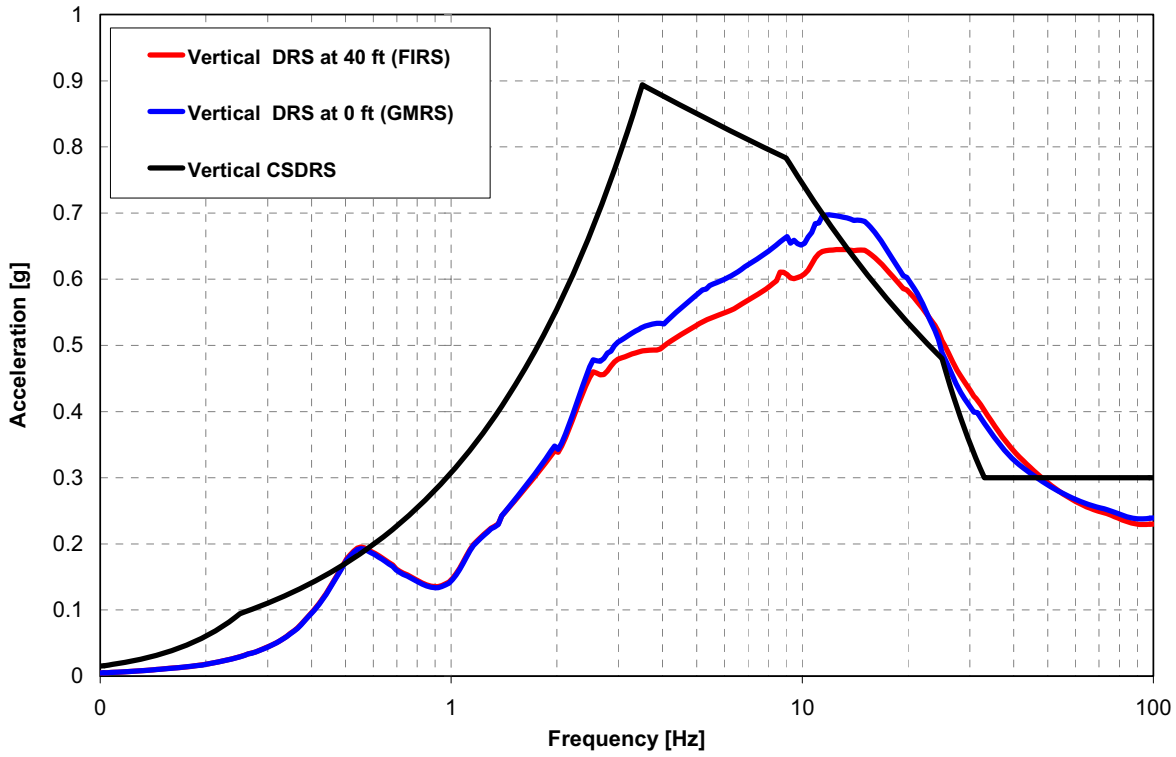


Figure 5 AP1000 CSDRS and Vogtle GMRS and FIRS - Vertical Motion (5% Damping)

As shown in the above figures, both the horizontal and vertical Design Response Spectra (DRS) at both GMRS and FIRS levels exceed the CSDRS at a limited frequency range.

4.1 SSI Input Motion

The development of SSI input motion follows the procedure outlined in the recent NRC position on this subject (ADAMS Accession Numbers ML083580072 and ML083020171). The development of SSI input motion is consistent with the development of FIRS and the required check has been made at the ground surface to evaluate the adequacy of the SSI input motion. Using the three SSI soil profiles defined above, acceleration time histories compatible with the FIRS are generated and applied as outcrop input motion at the depth of 40 ft, and the response motions at the surface are computed using Bechtel Program SHAKE2000. The resulting three spectra are compared with the surface design spectra (GMRS) in Figure 6 through Figure 8 for the horizontal H1, H2 and the Vertical component of the motion, respectively. As shown in these figures, the envelope of the three horizontal SSI input motions (LB, BE and UB) adequately envelops the GMRS in the two horizontal directions (H1 and H2) and no further modification of the horizontal motion is warranted, The vertical motions, however, are slightly less that the vertical GMRS in the frequency range 2.5 to 7 Hz. For this reason the vertical time history associated with the lower bound soil profile analysis was increased uniformly by a factor of 1.11. Figure 9 shows the comparison for the vertical motion confirming the enveloping spectra from the three soil profiles envelop the vertical GMRS at the ground surface.

For SASSI SSI analysis and for each SSI soil profile, the outcrop motions were converted to in-column motions at the depth of 40 ft and the in-column motions are subsequently used in the SSI analysis. For each of the three soil profiles, three in-column time histories are developed resulting in a total of nine incolumn time histories for SSI analysis. As described above, the vertical in-column time history corresponding to the LB soil profile was increased by a factor of 1.11 to meet the enveloping requirement at the surface.

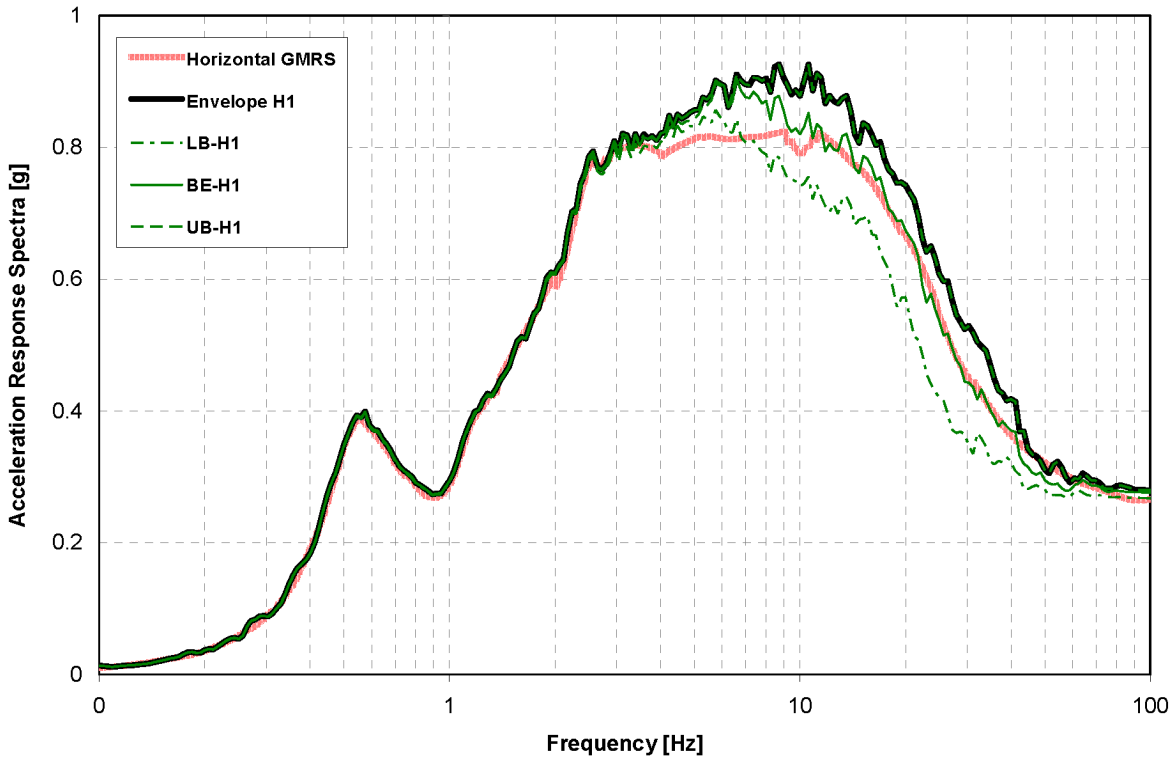


Figure 6 Comparison of H1 Response Motion and GMRS at the Ground Surface Level (5% Damping)

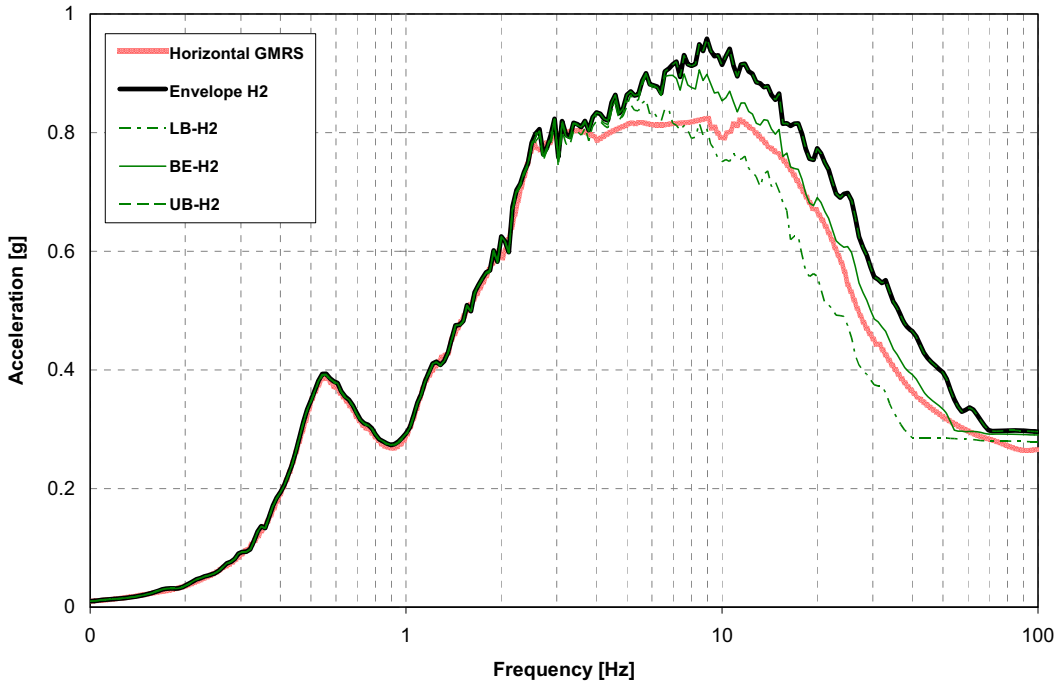


Figure 7 Comparisons of the H2 Response Motions with the GMRS at the Ground Surface Level (5% Damping)

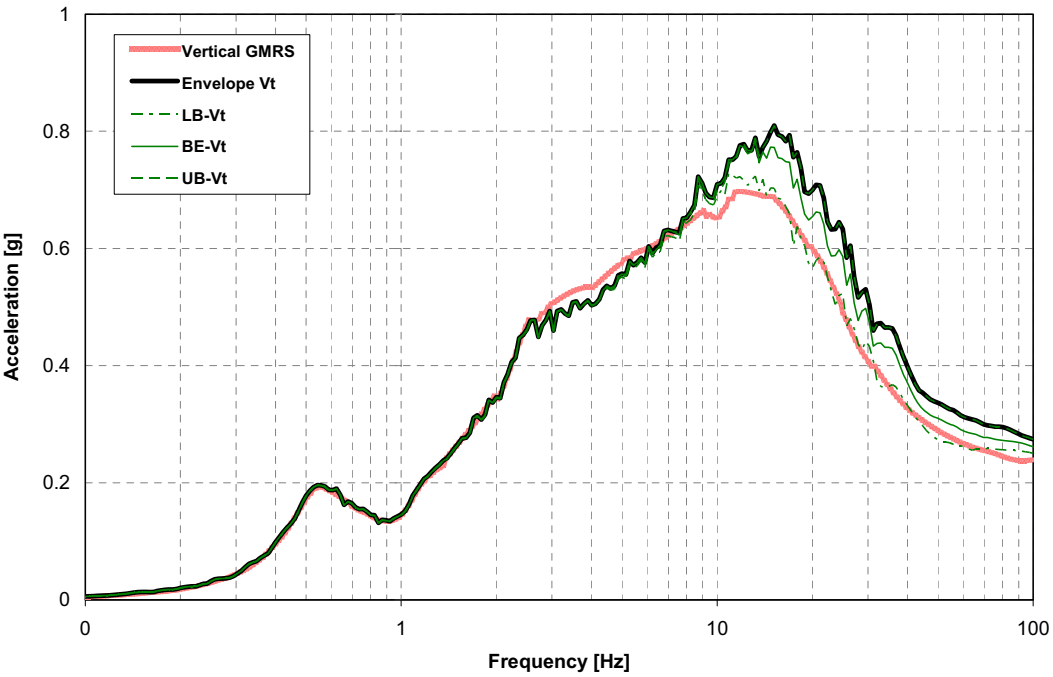


Figure 8 Comparisons of the Vertical Response Motions with the GMRS at the Ground Surface Level (5% Damping)

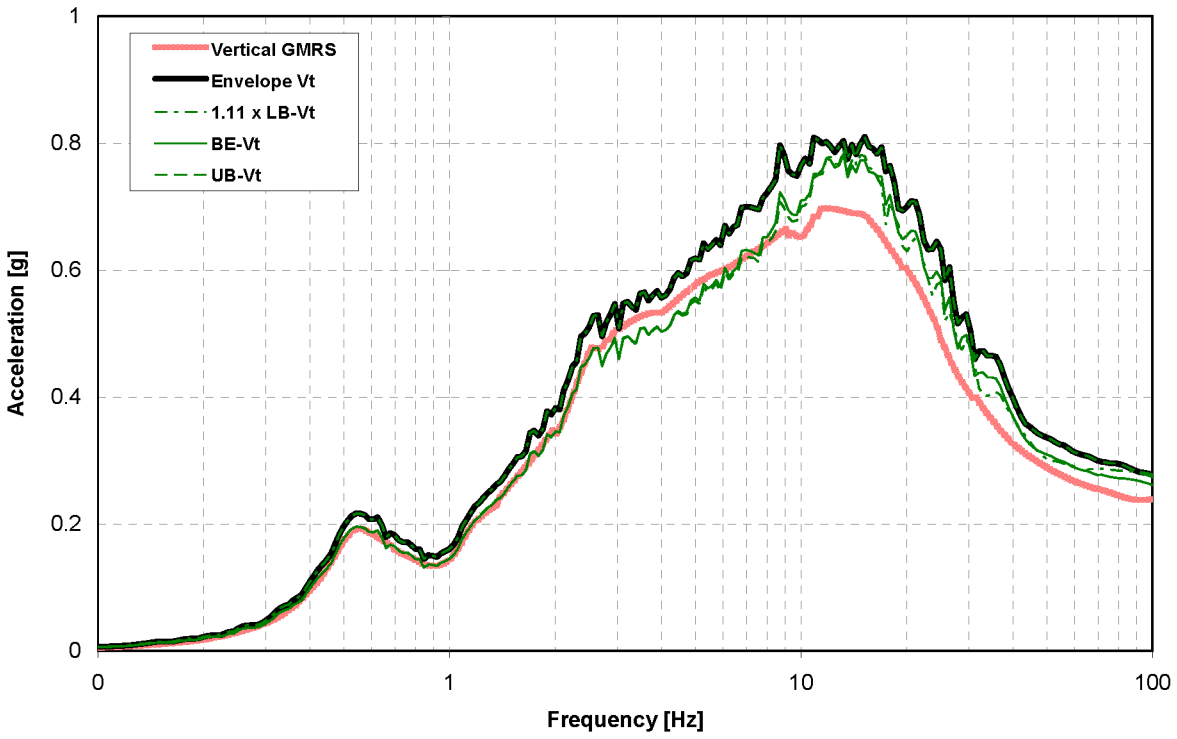


Figure 9 Comparisons of the Modified Vertical Response Motions with the GMRS at the Ground Surface Level (5% Damping)

5. Structural Model

The AP1000 model used for Vogtle site-specific SSI analysis is a three-dimensional finite element model defined as the NI15 model that is developed by Westinghouse. This model was developed specifically for the Vogtle site to incorporate additional refinement in order to capture the Vogtle high frequency exceedance beyond CSDRS as shown in Figure 4 and Figure 5. In addition as shown in Figure 3, the Vogtle soil profile is softer than the generic profiles in the upper 50 ft and significantly deeper with an inverted impedance mismatch below the Blue Bluff marl requiring site specific modeling and analysis to evaluate applicability of the design.

The AP1000 Nuclear Island consists of the Auxiliary and Shield building (ASB), Containment Internal Structure (CIS), Reactor Coolant Loop and Steel Containment Vessel (SCV). The ANSYS NI15 Model, averaging 15' by 15' for solid and shell elements in the ASB, is shown in Figure 10. The structure model has over 6300 nodes and 7500 elements. The embedded part of the NI is modeled with 5 layers of elements for a total embedment depth of 39.5 ft. Solid elements and Beam elements for SCV, CIS including Reactor Coolant Loop, Pressurizer, and polar crane are shown in Figure 11.

The NI15 was verified by Westinghouse by assuring that the mass distribution, the modal behavior and the floor response spectra results were consistent in ANSYS with WEC's most detailed model which is the model used for Hard Rock (NI10). The mass, centroid, and moment of inertia analysis determined the geometric and material properties were consistent with the

finite element model NI10. The dynamic behavior of the Nuclear Island building is identified by means of a modal analysis, and a floor response spectra comparison of the two models.

The ANSYS NI15 model is converted into the SASSI NI15 Model where excavated soil elements are added. The SASSI NI15 model is used in the Soil and Structure Interaction (SSI) analysis.

Due to the changes to the AP1000 NI20 SASSI model now identified as NI20r as described in Reference 1, the Vogtle NI15 SASSI model was revised from that described above as follows:

1. The properties of the Shield Building walls and air-inlet were updated to reflect the Shield Building design changes.

2. Modeling corrections to the Westinghouse AP1000 NI20 SASSI, as described in Reference 1, Section 4.2.3 “Corrections to NI20 SASSI Model”, were not required for the Vogtle NI15 SASSI model. These corrections to the SASSI NI20 model were to address modeling concerns with beam to solid element connectivity and improve the stress distribution in the basemat. The Vogtle NI15 SASSI model beam to solid element connectivity already properly modeled the connections between the solid elements and beam elements. Unlike the NI20 SASSI model that modeled the Auxiliary Building portion of the basemat of the Nuclear Island as shell elements, the Vogtle NI15 SASSI model used solid elements for the entire basemat. Therefore, there was no issue with the stress distribution at the basemat interface between the Auxiliary Building and the Containment Internal Structure (CIS).

3. The original NI20 SASSI model was revised to account for stiffness due to out-of-plane flexure where the walls, which are modeled as shell elements, connect to the floors, which are modeled as solid elements. Therefore, the Vogtle NI15 SASSI model was revised by extending the wall shell elements the depth of one solid element to capture the effects of out-of-plane flexural stiffness. This modeling change showed no significant effect on the response since in-plane wall stiffness was the controlling contributor to overall lateral structural stiffness.

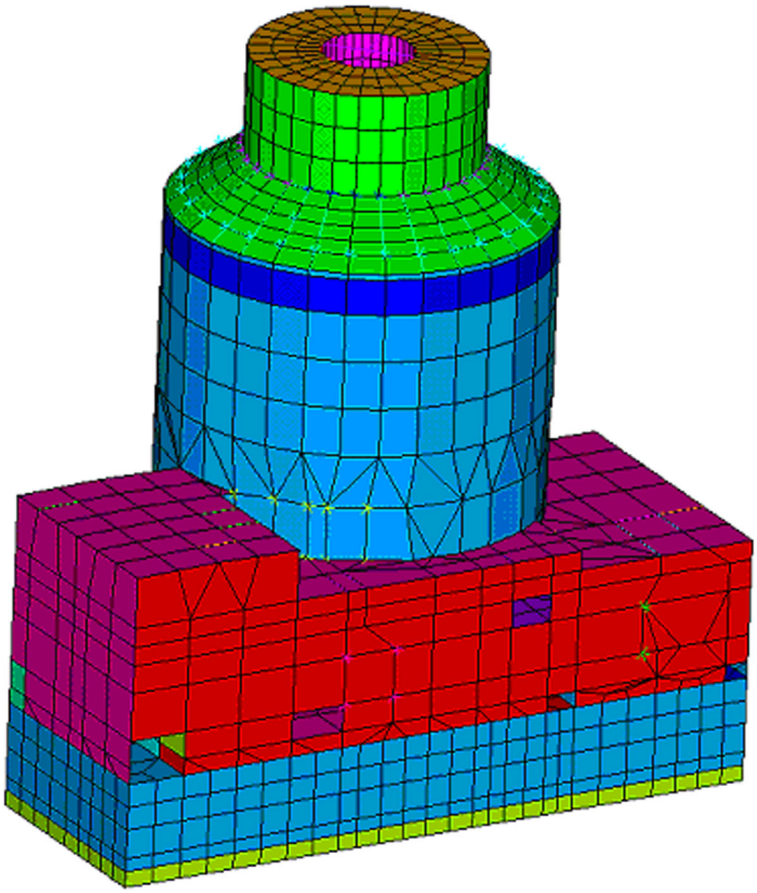


Figure 10 NI15 Finite Element Model

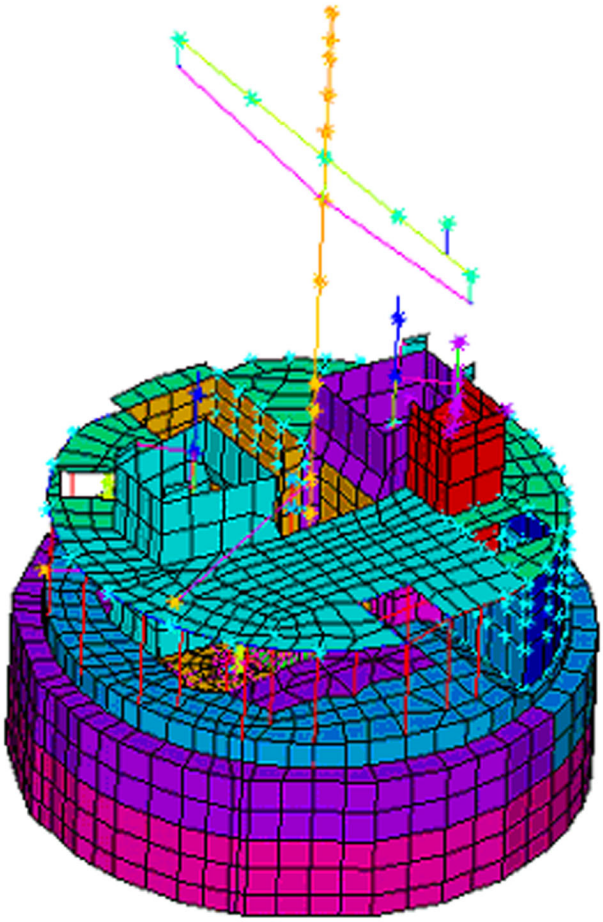


Figure 11 NI15 CIS, RCL, and SCV Elements

6. SSI Analysis and Results

Using the above structural model, the Vogtle site-specific SASSI SSI model of AP1000 was constructed by modeling the soil profile and the soil foundation model for the embedded part of the nuclear island (NI). For all structural members, 4% material damping was used. This damping is considered to be conservative and is representative of the lower bound value for damping compatible to structural response per RG 1.61. For each soil profile, the respective in-column motions were used as input at the depth of the foundation level with excitation in all three (North-South, East-West, and Vertical) directions. The results in terms of in-structure response spectra (ISRS) at 5% damping at the six key locations in the NI (Table 1) are computed. The coupling responses are combined using the SRSS method. The analyses are performed to 30 Hz (15 Hz for LB, 17 Hz for BE, 30 Hz for UB) to cover all frequencies of interest for the given design motion.

Table 1: Key Location for ISRS Comparison with DCD

Node	X* [ft]	Y* [ft]	Z [ft]	Location
10115	1116.5	948.5	116.5	ASB NE Corner at Control Room Floor
11111	929	1000	179.19	ASB Corner of Fuel Building Roof at Shield Building
12052	956.5	1000	327.41	ASB Shield Building Roof Area
10471	1008	1014	134.25	CIS Operating Deck
9007	1000	1000	100	CIS at Reactor Vessel Support Elevation
11224	1000	1000	224	SCV Near Polar Crane

*Note: X=Y=1000 ft at center of ASB and SCV

The results at these six locations are compared with the CSDRS-based design envelops in Figure 12 through Figure 29. In these figures, X denotes plant North, Y denotes plant West and, Z denotes vertical direction.

For a point of reference, the comparisons also include the original AP1000 CSDRS broadened envelope ISRS to aid in understanding the differences in the revised ISRS comparison.

As shown in these figures, the “design envelope” exceeds the site specific response motions basically over the entire range of frequencies and by a large margin. This margin is particularly large at the zero period acceleration level indicating a large margin for seismic member forces. At a very limited frequency range, small exceedances beyond the design envelops are observed. The exceedance at about 0.55 Hz is consistent with the previous two-dimensional SSI results and has no design consequence since there are no structural members at this frequency.

7. Conclusion

The results of the three dimensional SSI analysis of a refined AP1000 NI model at the Vogtle site show a large margin against the design envelops. This study confirms the applicability of the AP1000 design to the Vogtle site.

8. Reference

1. AP1000 Standard Combined License Technical Report: Extension of Nuclear Island Seismic Analyses to Soil Sites; APP-GW-S2R-010, Revision 4, March 2010, Docket No. 52-006, Westinghouse letter dated April 21, 2010 (DCP_NRC_002855).

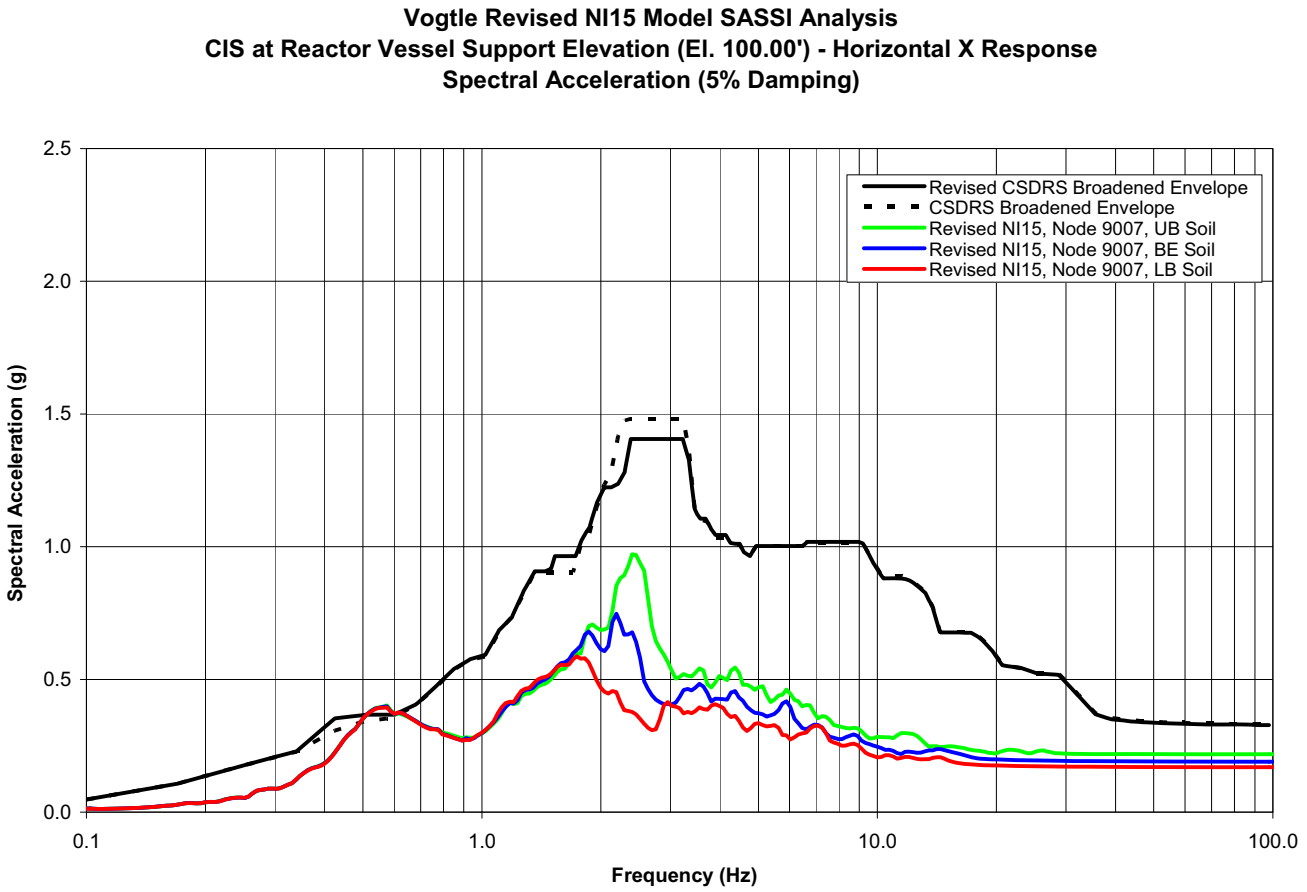


Figure 12 Horizontal X Response Spectra at CIS at Reactor Vessel Support Elevation (El. 100.00 ft, Node 9007)

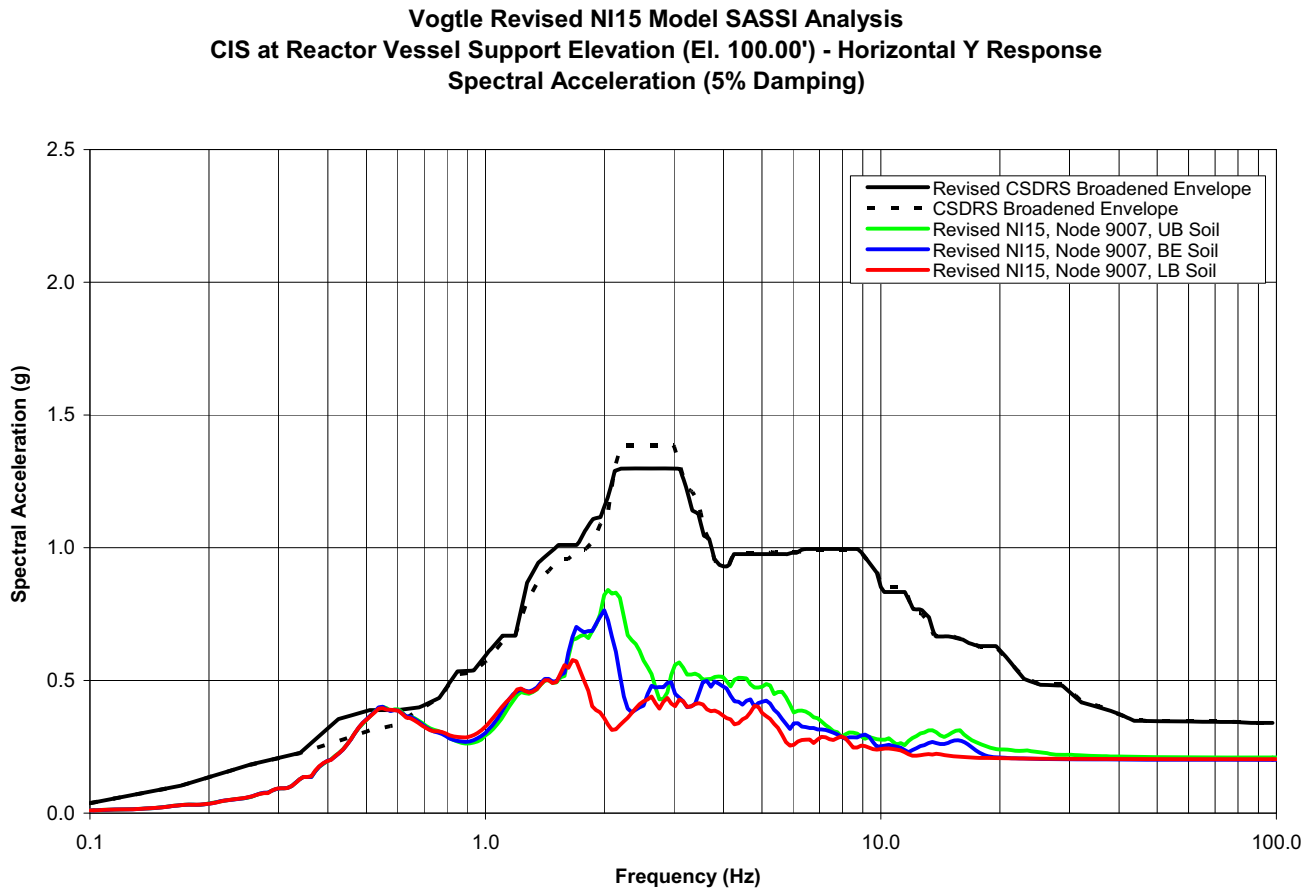


Figure 13 Horizontal Y Response Spectra at CIS at Reactor Vessel Support Elevation (El. 100.00 ft, Node 9007)

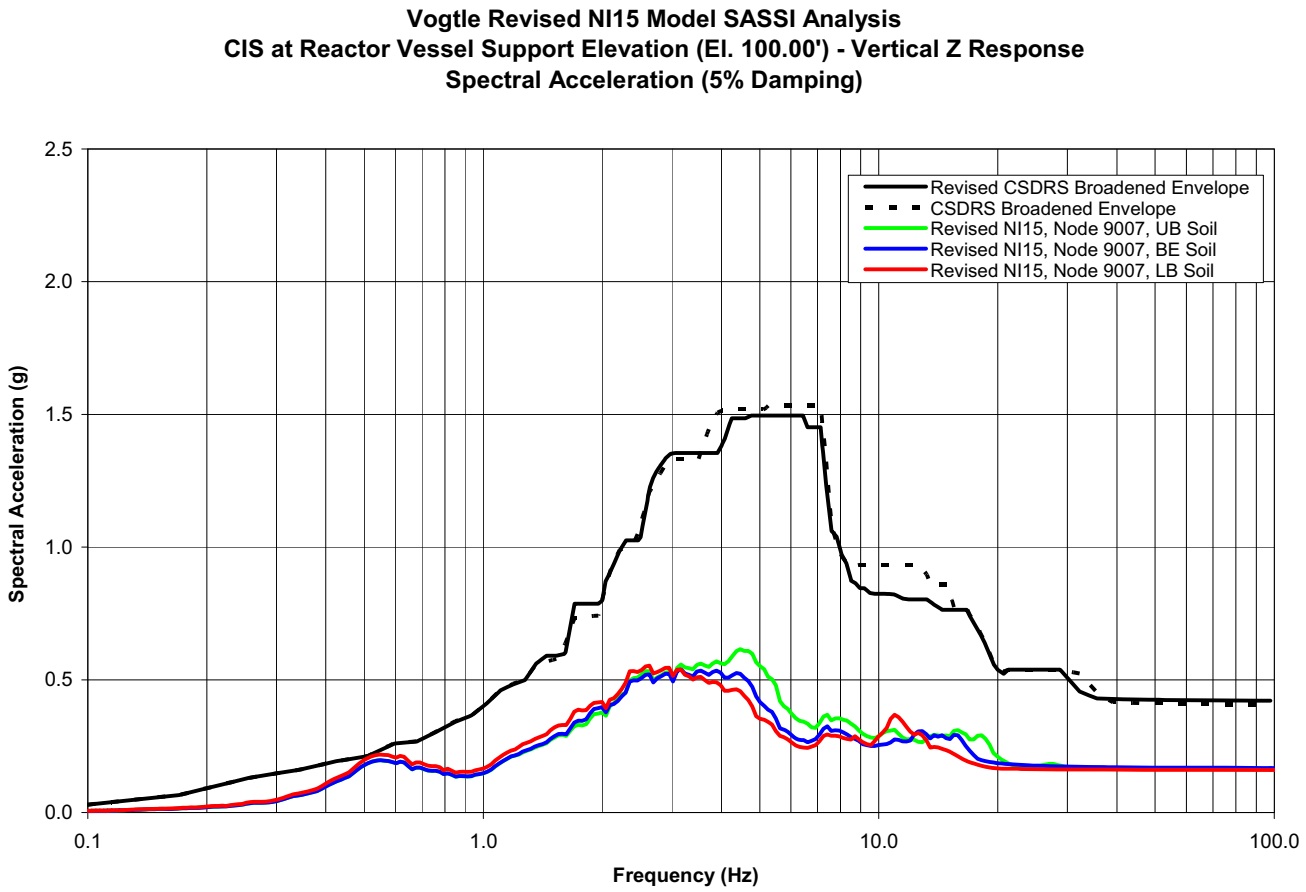


Figure 14 Vertical Z Response Spectra at CIS at Reactor Vessel Support Elevation (El. 100.00 ft, Node 9007)

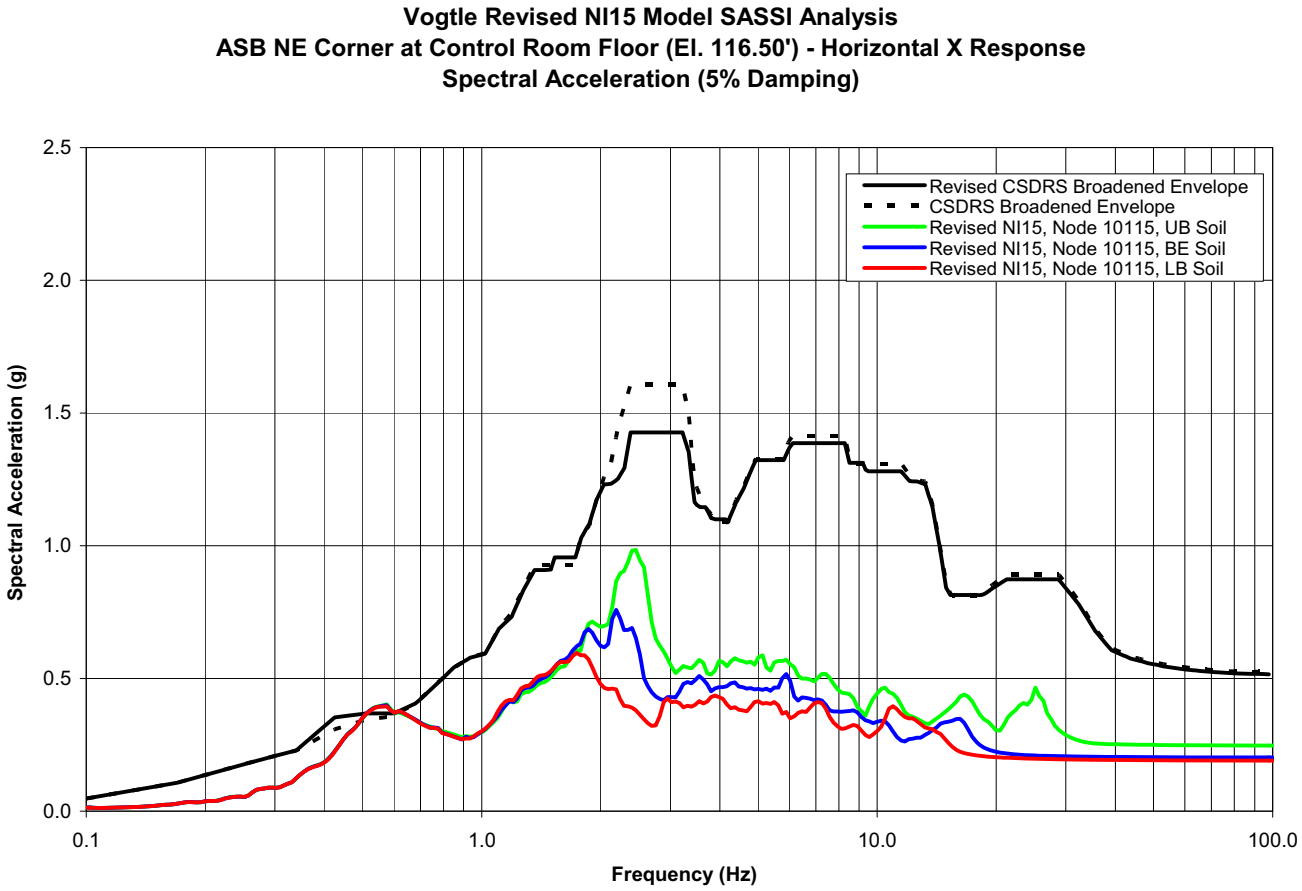


Figure 15 Horizontal X Response Spectra at ASB NE Corner at Control Room Floor (El. 116.50 ft, Node 10115)

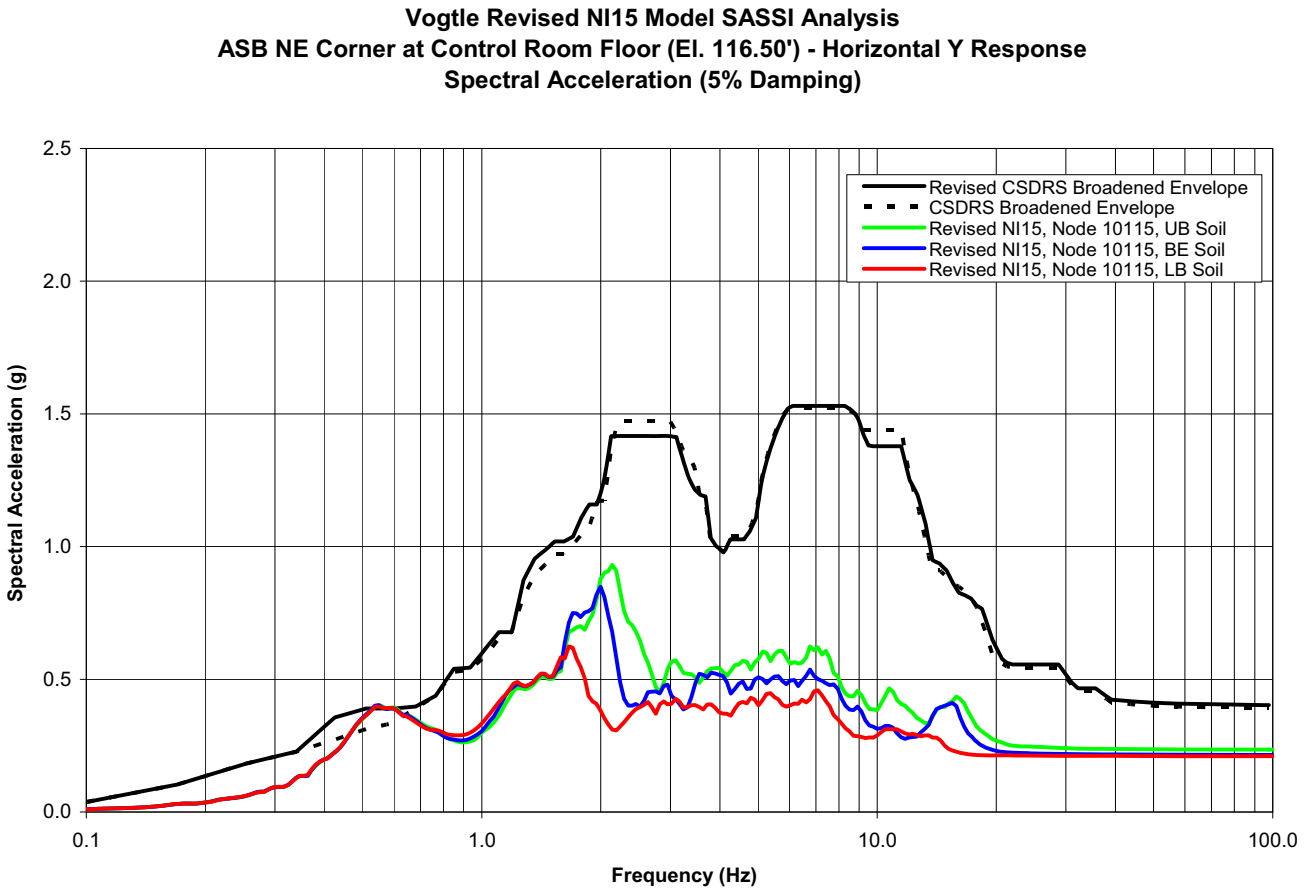


Figure 16 Horizontal Y Response Spectra at ASB NE Corner at Control Room Floor (El. 116.50 ft, Node 10115)

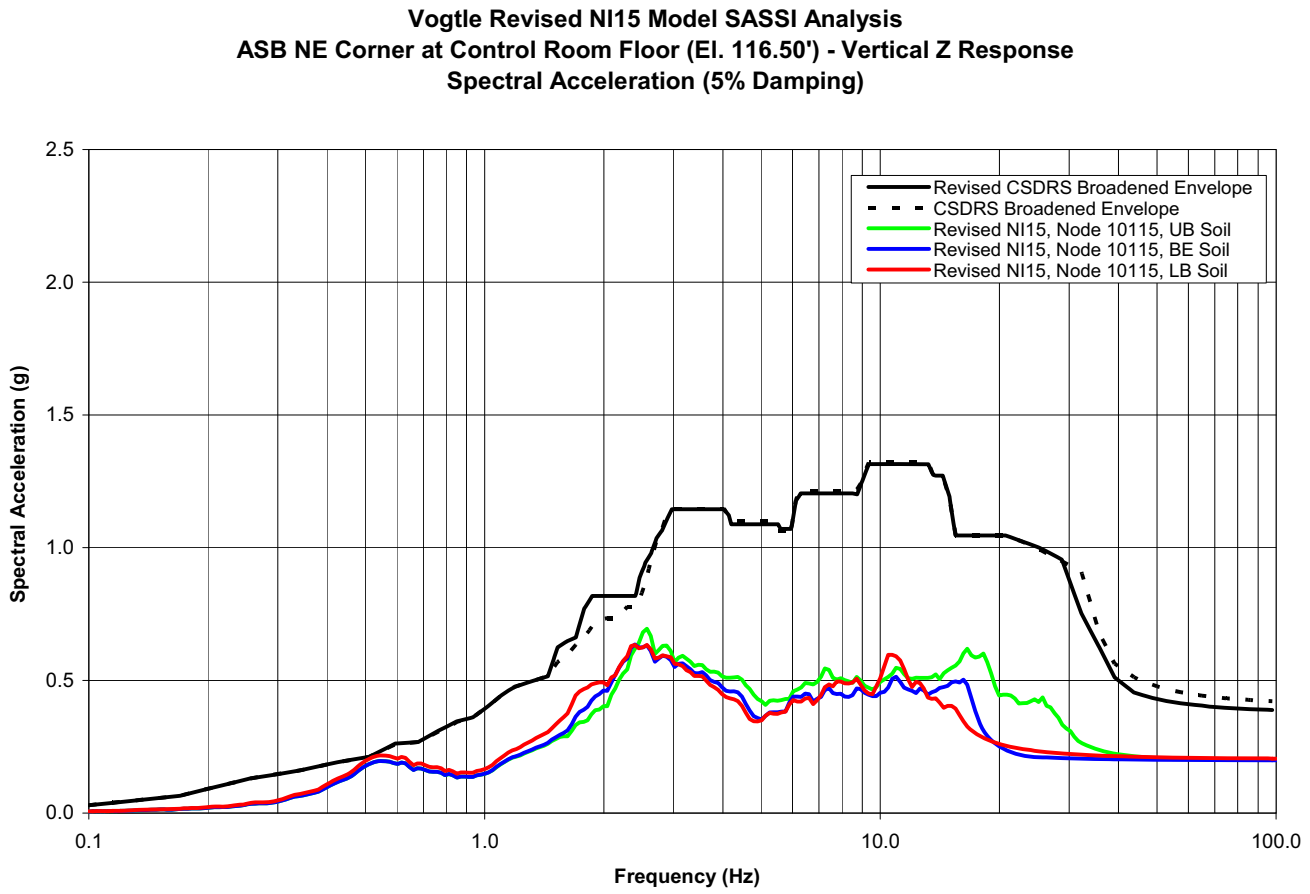


Figure 17 Vertical Z Response Spectra at ASB NE Corner at Control Room Floor (El. 116.50 ft, Node 10115)

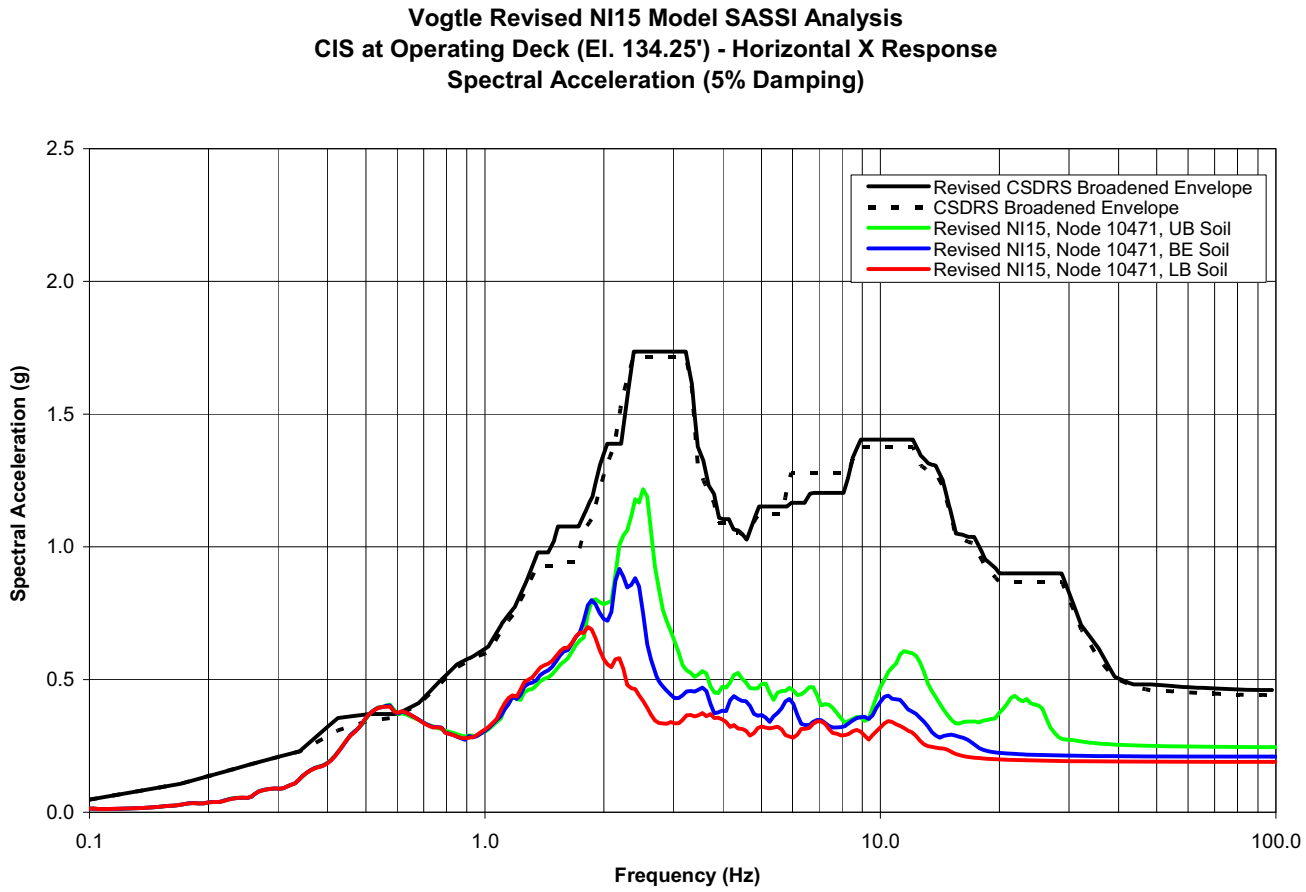


Figure 18 Horizontal X Response Spectra at CIS at Operating Deck (El. 134.25 ft, Node 10471)

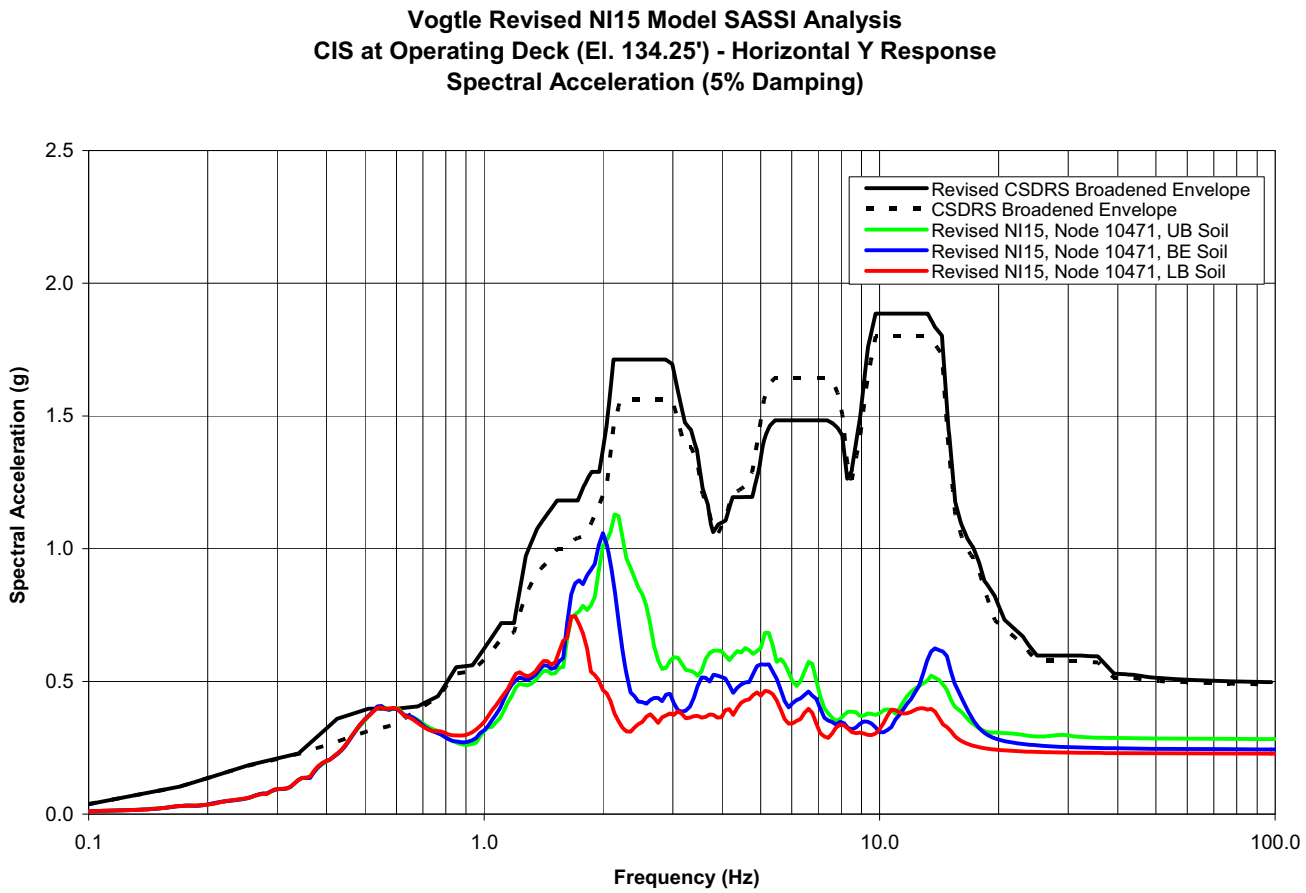


Figure 19 Horizontal Y Response Spectra at CIS at Operating Deck (El. 134.25 ft, Node 10471)

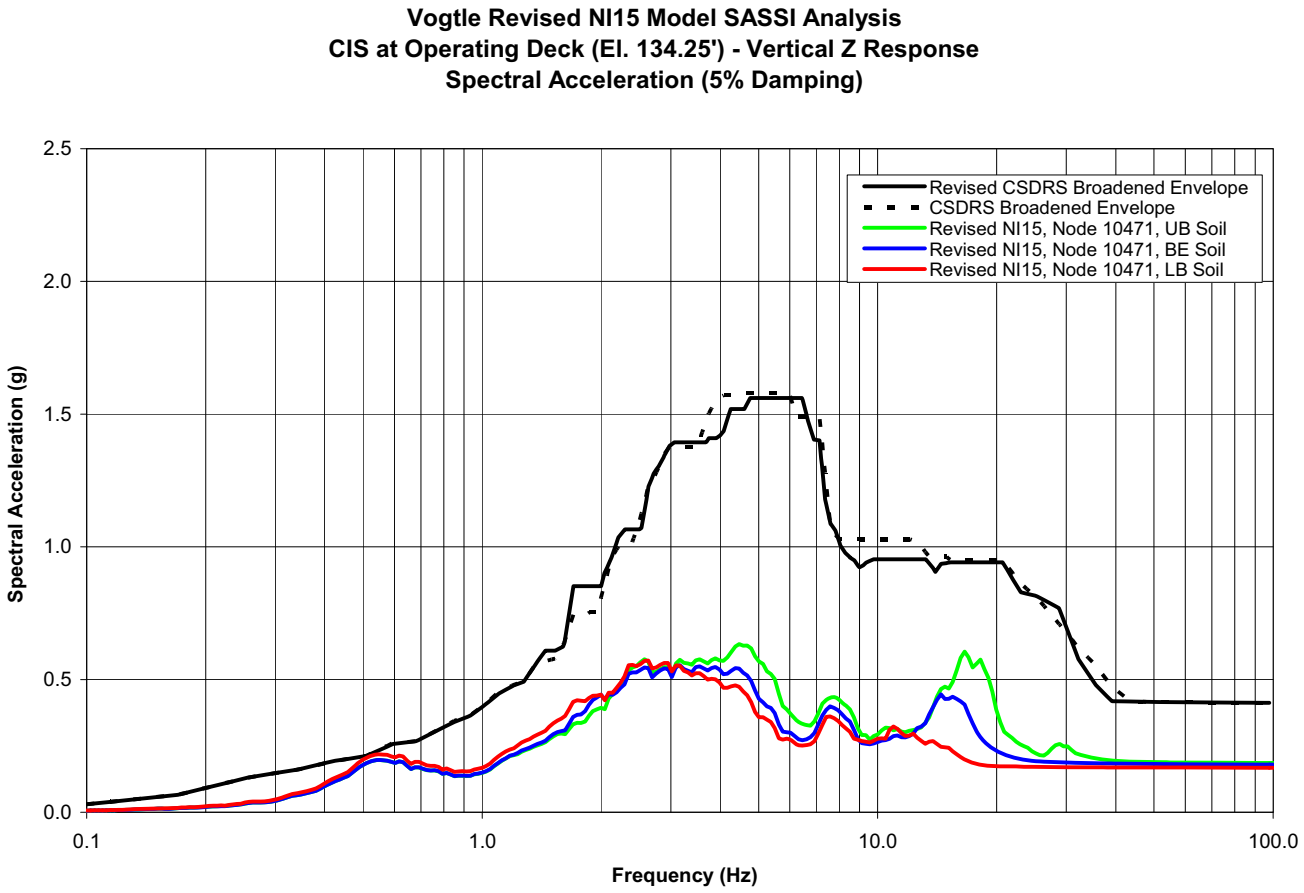


Figure 20 Vertical Z Response Spectra at CIS at Operating Deck (El. 134.25 ft, Node 10471)

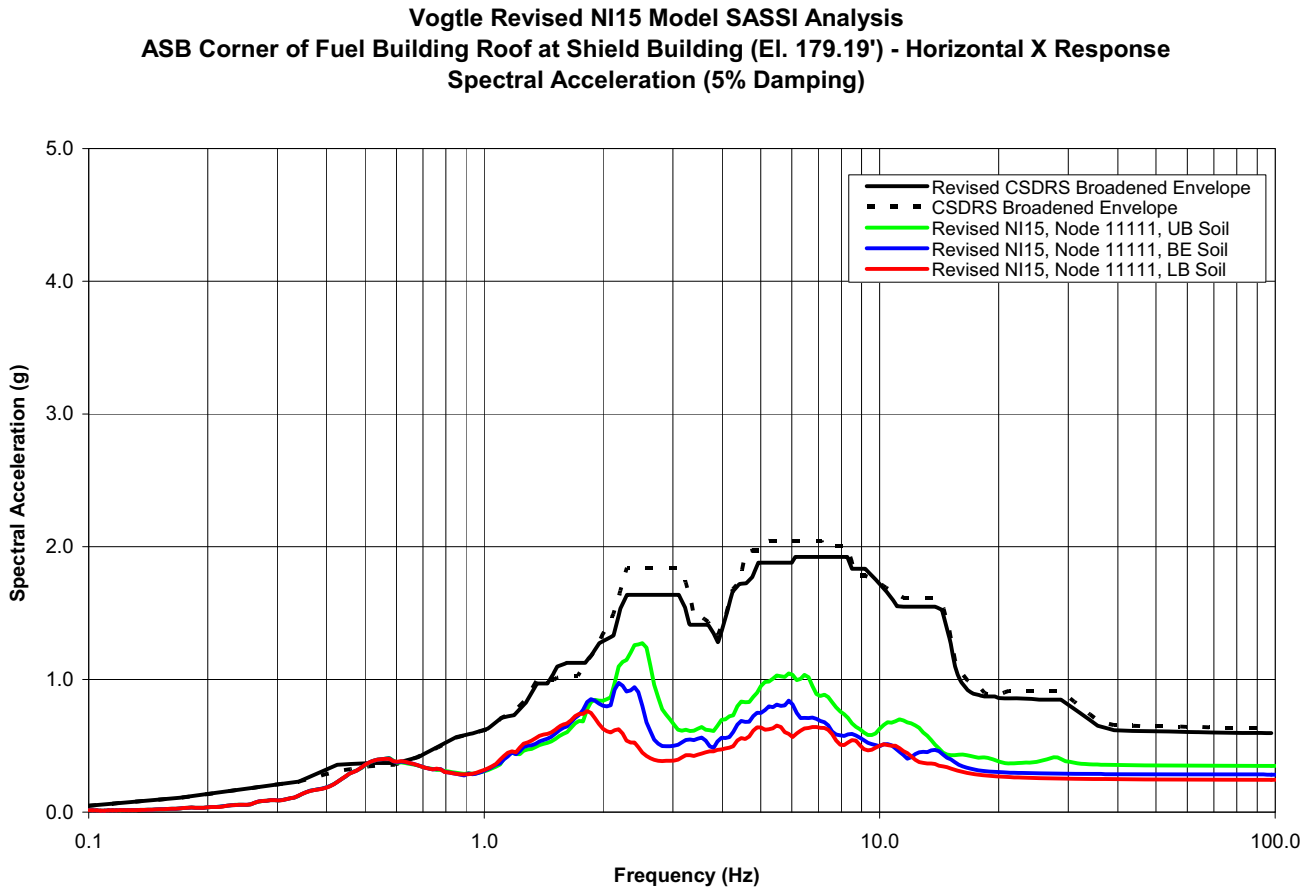


Figure 21 Horizontal X Response Spectra at ASB Corner of Fuel Building Roof at Shield Building (El. 179.19 ft, Node 11111)

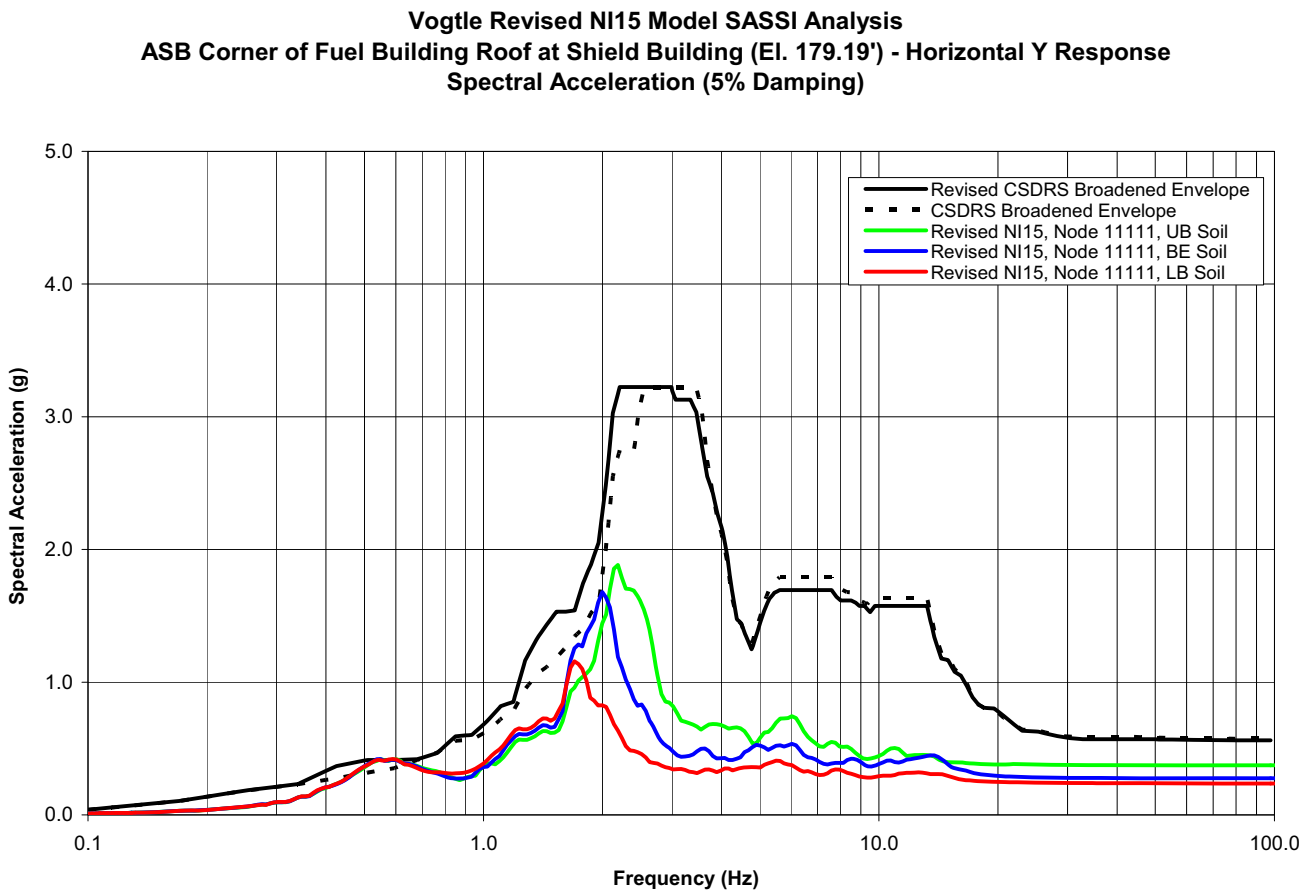


Figure 22 Horizontal Y Response Spectra at ASB Corner of Fuel Building Roof at Shield Building (El. 179.19 ft, Node 11111)

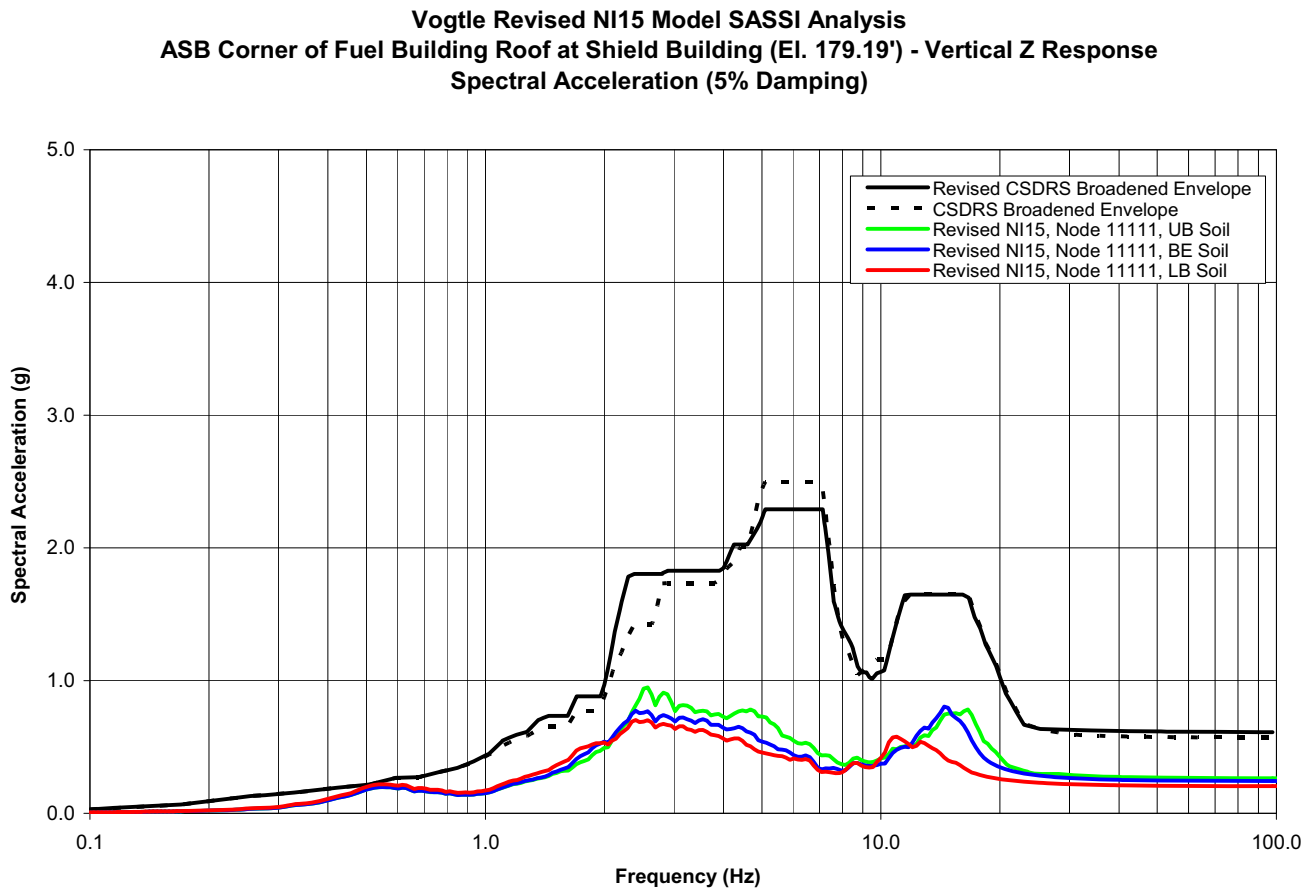


Figure 23 Vertical Z Response Spectra at ASB Corner of Fuel Building Roof at Shield Building (El. 179.19 ft, Node 11111)

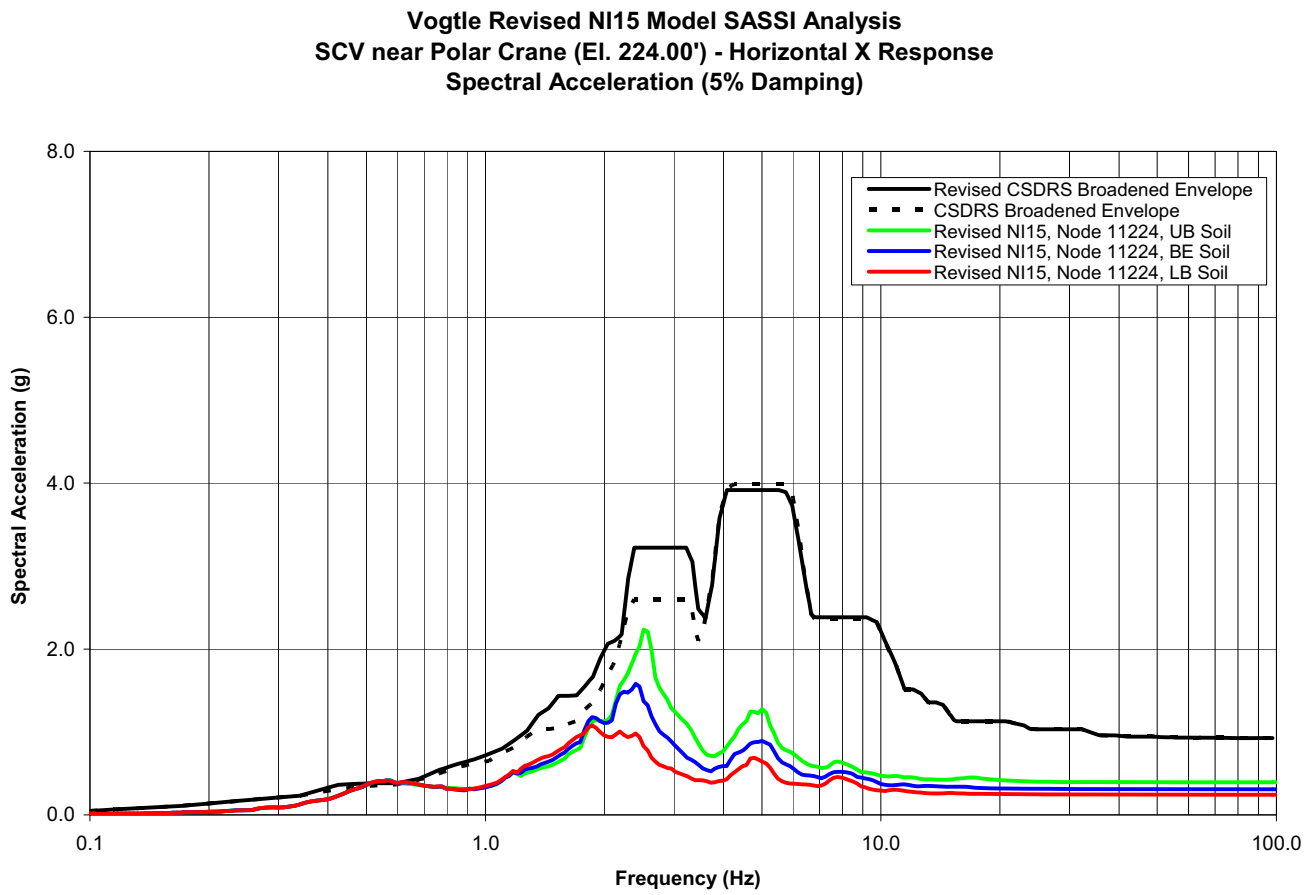


Figure 24 Horizontal X Response Spectra at SCV near Polar Crane (El. 224.00 ft, Node 11224)

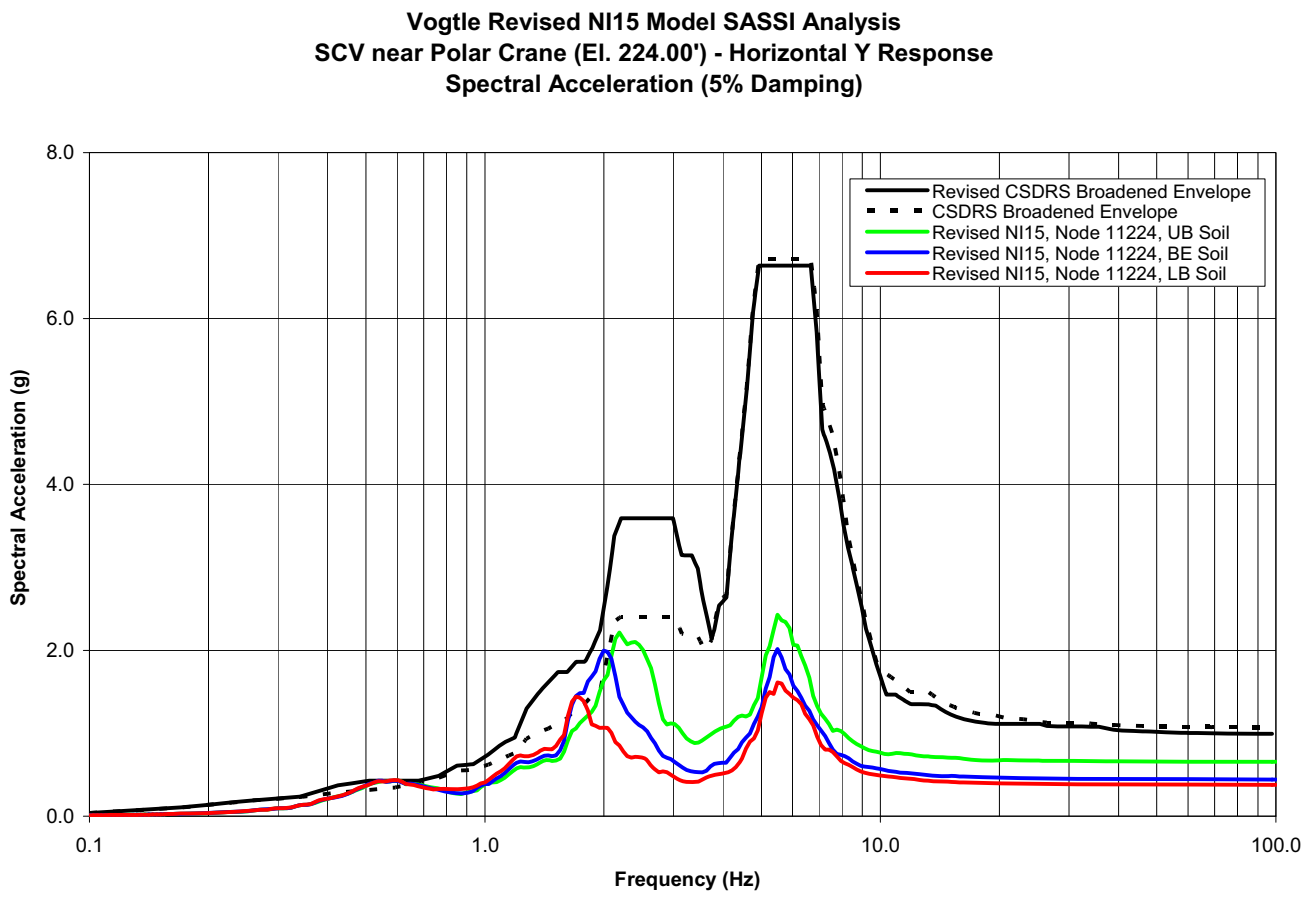


Figure 25 Horizontal Y Response Spectra at SCV near Polar Crane (El. 224.00 ft, Node 11224)

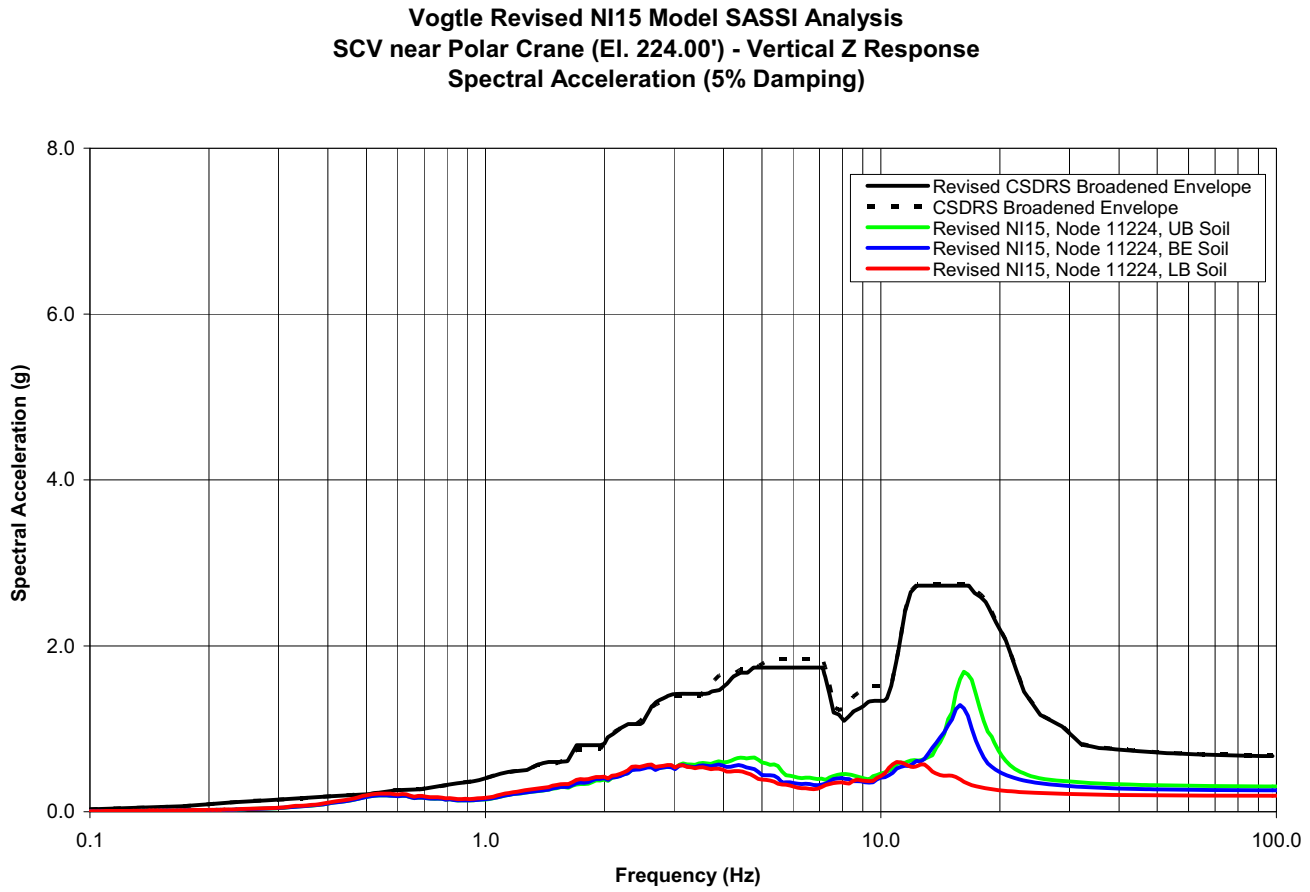


Figure 26 Vertical Z Response Spectra at SCV near Polar Crane (El. 224.00 ft, Node 11224)

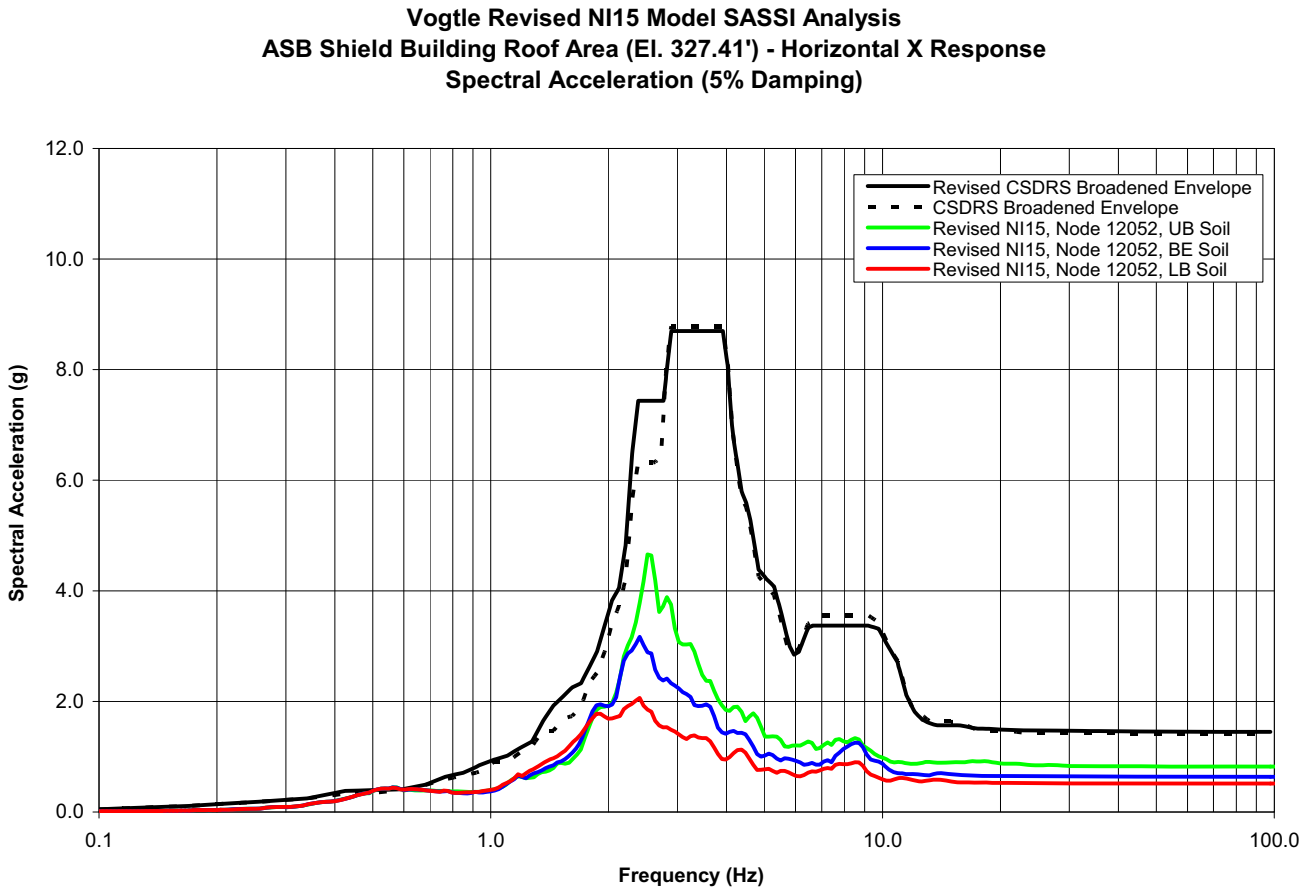


Figure 27 Horizontal X Response Spectra at ASB Shield Building Roof Area (El. 327.41 ft, Node 12052)

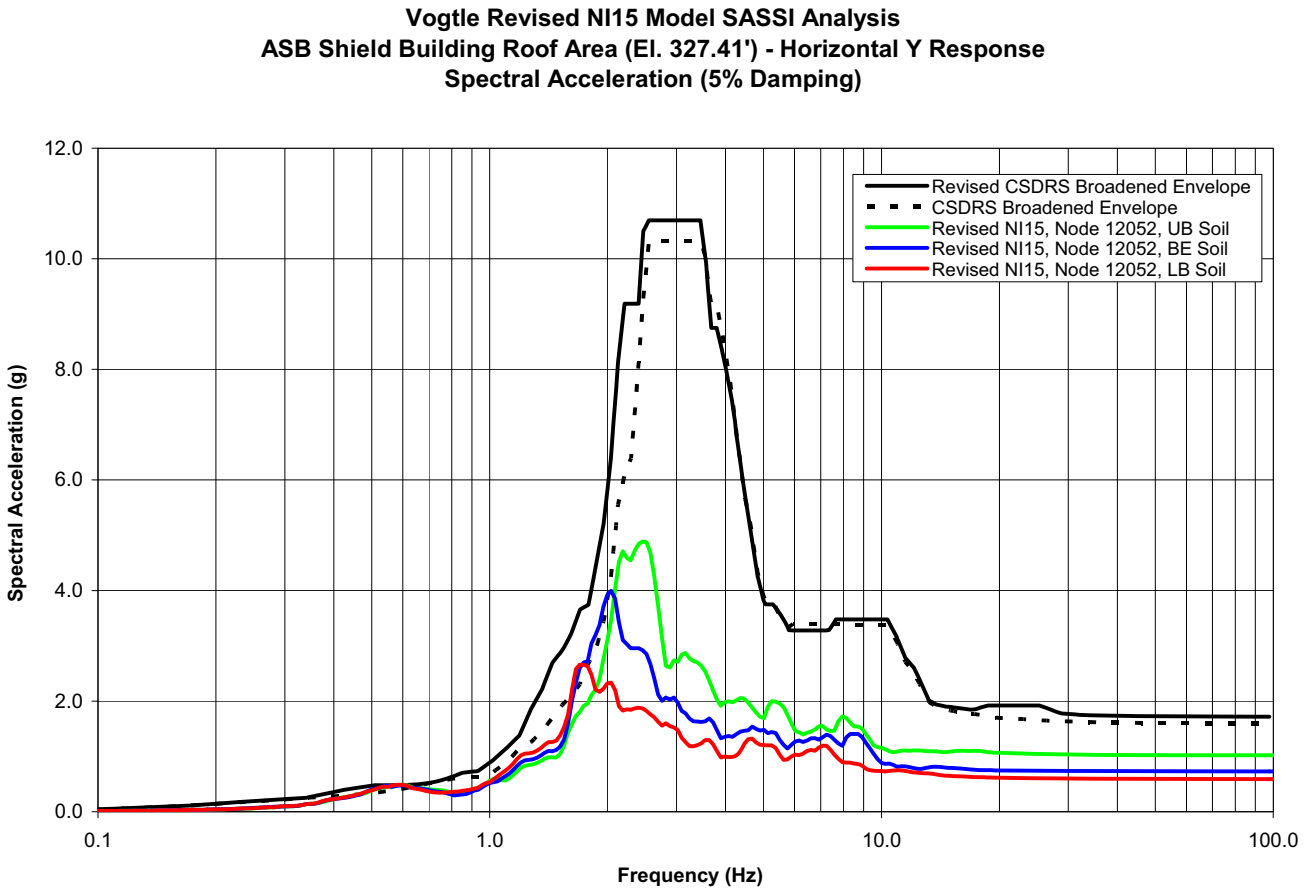


Figure 28 Horizontal Y Response Spectra at ASB Shield Building Roof Area (El. 327.41 ft, Node 12052)

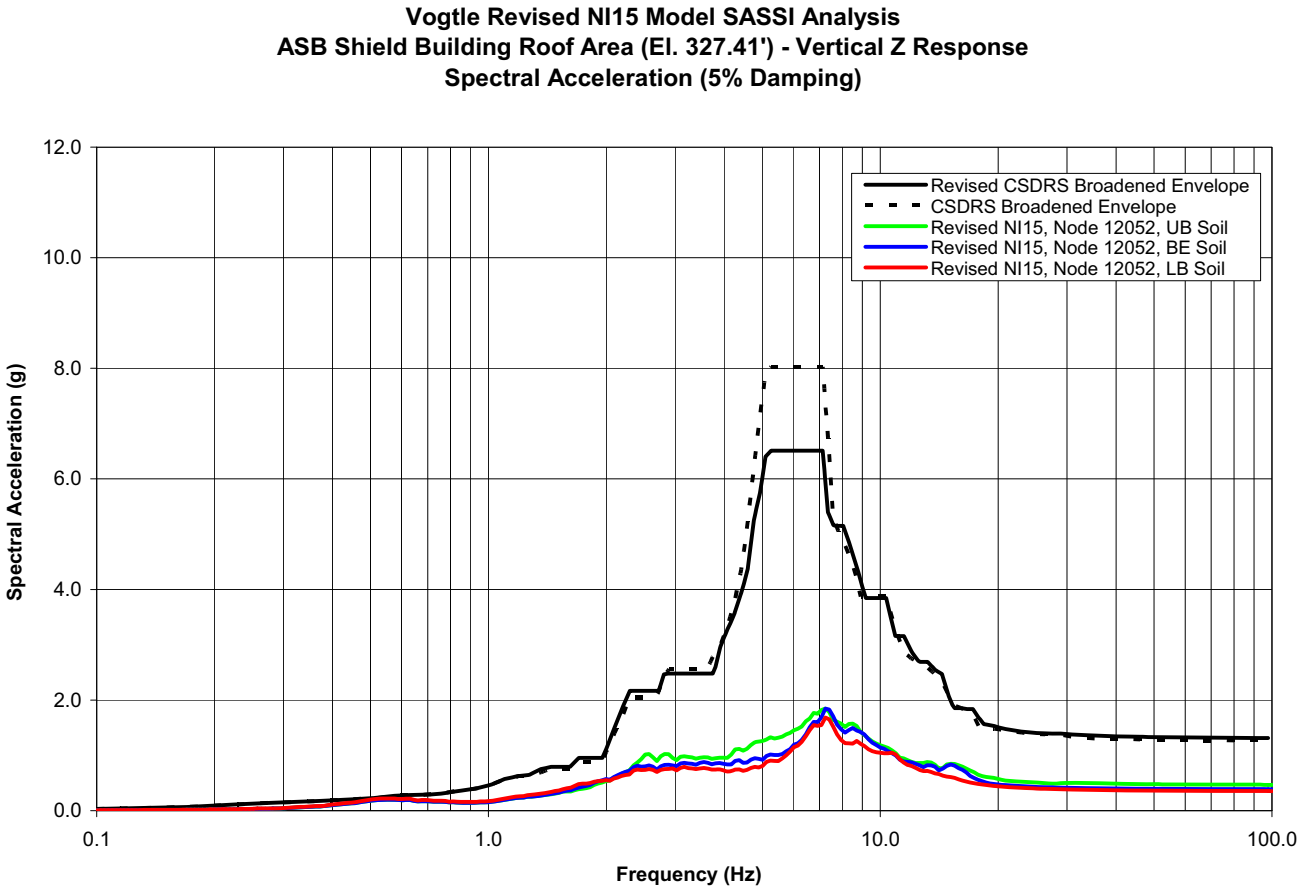


Figure 29 Vertical Z Response Spectra at ASB Shield Building Roof Area (El. 327.41 ft, Node 12052)

Appendix 3H Auxiliary and Shield Building Critical Sections

3H.1 Introduction

[*This appendix summarizes the structural design and analysis of structures identified as "Critical Sections" in the auxiliary and shield buildings. The design summaries include the following information:*

- *Description of buildings*
- *Governing codes and regulations*
- *Structural loads and load combinations*
- *Global analyses*
- *Structural design of critical structural elements*

Subsections 3H.2 through 3H.5 include a general description of the auxiliary building and shield building, a summary of the design criteria and the global analyses. The 3H.5 figures referenced in the descriptions show the structural designs for critical sections which are identified in subsection 3H.5 and shown in Figure 3H.5-1 (3 sheets). The exact locations of the critical sections related to the shield building cylinder are shown in Figure 3H.5-16. Representative design details are provided for these structures in subsection 3H.5.]*

3H.2 Description of Auxiliary and Shield Buildings

3H.2.1 Description of Auxiliary Building

[*The auxiliary building is a reinforced concrete structure. The auxiliary building is one of the three buildings that make up the nuclear island and shares a common basemat with the containment building and the shield building. The auxiliary building general layout is shown in Figure 3H.2-1. It is a C-shaped section of the nuclear island that wraps around approximately half of the circumference of the shield building. The building dimensions are shown on key structural dimension drawings, Figure 3.7.2-12.*

The auxiliary building is divided into six areas, which are identified in Figure 3H.2-1. It is a 5-story building; three stories are located above grade and two are located below grade. Areas 1 and 2 (Figure 3H.2-1) have five floors, including two floors below grade level. The lowest floor at elevation 66'-6" is used exclusively for housing battery racks. The next higher floor, at elevation 82'-6", also has battery racks and some electrical equipment. The floor at the grade level, elevation 100'-0", has electrical penetration areas, a remote shutdown workstation room, motor control centers, and some Division A and Division C equipment. The main control room is situated on the floor at elevation 117'-6", which also has rooms for the main steam and feedwater lines. The floor at elevation 135'-3" carries air filtration and air handling units, chiller pump equipment, and other mechanical and electrical equipment. The roof for areas 1 and 2 is at elevation 153'-0".

Areas 3 and 4 of the auxiliary building are the areas east of the containment shield building. Valve and piping areas, and some mechanical equipment, are located in the basement floor at elevation 66'-6". The floor at elevation 82'-6" has a piping penetration area, a radiation chemistry laboratory, makeup pumps, and other mechanical equipment. The floor at grade level elevation 100'-0" has an electrical penetration room, a staging area for the equipment hatch, and the access opening to the annex building. The electrical penetration area, trip switchgears, and other electrical equipment occupy most of the floor at elevation 117'-6". The floor at elevation 135'-3" is used for the

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storage of main control room air cylinders and provides access to the annex building. The roof for these areas is at elevation 160'-6".

Areas 5 and 6 include facilities for storage and handling of new and spent fuel. The spent fuel pool, fuel transfer canal, and cask loading and cask washdown pits have concrete walls and floors. They are lined on the inside surface with stainless steel plate for leak prevention. Interior structural walls and major floors are constructed using concrete filled steel plate modules, steel form modules, or reinforced concrete. The new fuel storage area is a separate reinforced concrete pit providing temporary dry storage for the new fuel assemblies. A 150-ton cask handling crane travels in the east-west direction. The location and travel of this crane prevents the crane from carrying loads over the spent fuel pool to preclude them from falling into the spent fuel pool. Mechanical equipment is also located in this area for spent fuel cooling, residual heat removal, and liquid waste processing. This equipment is generally nonsafety-related.]*

3H.2.2 Description of Shield Building

The shield building is the structure and annulus area that surrounds the containment building. It shares a common basemat with the containment building and the auxiliary building. The shield building uses concrete-filled steel plate construction (SC) as well as reinforced concrete (RC) structure. The figures in Section 1.2 show the layout of the shield building and its interface with the other buildings of the nuclear island.

Figure 3.8.4-5 shows the following significant features and the principal systems and components of the shield building:

- Shield building cylindrical structure
- Shield building roof structure
- RC/SC connections
- Air inlets and tension ring
- Passive containment cooling system (PCS) water storage tank (PCCWST)
- Knuckle region (connection to exterior wall of PCCWST)
- Compression ring (connection to interior wall of PCCWST)

The overall configuration of the shield building is established from functional requirements related to radiation shielding, missile barrier, passive containment cooling, tornado, and seismic event protection. These functional requirements led to establishing the design based on two primary design codes used for nuclear plant structures: 1) ACI 349 for reinforced concrete design, and 2) ANSI/AISC N690 for structural steel design.

The shield building SC walls are anchored to the RC basemat and shield building RC wall by mechanical connections. These RC-to-SC connections are also used in the other regions of the shield building, including:

- Auxiliary building RC roof connection to the shield building SC wall
- Auxiliary building RC wall connection to shield building SC wall
- Tension ring connection to the shield building RC roof

The connections provide for the direct transfer of forces from the RC reinforcing steel to the SC liner plates.

The cylindrical shield wall has an outside radius of 72.5 feet and a thickness of 36 inches. The cylindrical wall section that is a few feet below the auxiliary building roof line is a reinforced concrete (RC) structure. The section that is not protected by the auxiliary building is a steel concrete (SC) composite structure (see Figure 3H.5-16). The overall thickness of 36 inches is the same as the RC

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wall below. The concrete for the SC portion is standard concrete with compressive strength of 6000 psi. The SC portion is constructed with steel surface plates, which act as concrete reinforcement. The 0.75-inch tie bars are welded to the steel faceplates to develop composite behavior of the steel faceplates and concrete. The shear studs are welded to the inside surface of the steel plate. The tie bar spacing is reduced in the higher stress regions. A typical SC wall panel is shown in Figure 3H.5-13.

The tension ring is located at the interface of the shield building steel concrete composite air inlet structures and the shield building reinforced concrete roof. The top of the tension ring interfaces with the RC roof slab. The tension ring supports the roof girders that are located under the RC roof slab. The bottom of the tension ring is attached to the air inlets structure. The bottom of the air inlets structure is attached to the top of the cylindrical SC wall of the shield building. The connection of the tension ring to the roof is a mechanical connection design and is described above.

The primary function of the tension ring is to resist the thrust from the shield building roof. The air inlets structure is located directly below the tension ring and includes the air openings that provide for natural circulation of cooling air. Though its steel plates are connected to the concrete infill by studs and tie bars, the tension ring is conservatively designed as a hollow steel box girder. The concrete infill is credited only for out-of-plane shear transfer and for stability of the steel plates. The tension ring is designed to have high stiffness and to remain elastic under required load combinations.

The air inlets structure is a 4.5-foot-thick SC structure with through-wall openings for air flow. The air inlet openings consist of circular pipes at a downward inclination of 38 degrees from the vertical. Steel plates on each face, aligned with the inner and outer flanges of the tension ring, serve as primary reinforcement. The concrete infill is connected to the steel plates with tie bars and studs. The top of the air inlets structure is welded to the underside of the tension ring. The bottom of the air inlets structure is welded to the SC wall.

The shield building conical roof steel structure consists of 32 radial beams. Between each pair of radial beams there are circumferential beams. A steel plate is welded to the top flanges of each beam and forms a surface on which the concrete is placed. The steel structure forms a conical shell that spans the area from the compression ring to the tension ring.

The outside diameter of the PCS tank (passive containment cooling water storage tank) intersects with the shield building roof at the knuckle region. Outside of the PCS tank, the concrete roof slab thickness is 3 feet and at the bottom of the PCS tank, the concrete thickness is 2 feet. The wall from the PCS tank applies a load to the roof slab, and also provides stiffness and increases the strength of the roof in that region.

The inside diameter of the PCS tank intersects with the roof slab at the compression ring. The compression ring provides the compression support for the conical roof dome. It consists of a composite structure having a curved steel beam section, which supports the concrete roof directly above it. The inside wall of the PCS tank is located above the concrete roof. Studs are placed on the top flange of the steel girder to allow the steel and concrete sections to act as a composite unit. The curved girder is designed to provide support for the steel structure during construction and during the initial placement of the concrete roof before the concrete has hardened sufficiently.

The PCS tank sits on top of the shield building roof. It is supported by and acts integrally with the conical roof. The inside surface has a liner that functions to provide leak protection, but is not required to provide structural strength to the structure. Leak chase channels are provided over the liner welds. The top elevation of the water inside the tank for the PCS has sufficient freeboard to preclude impact on the roof during the SSE.

3H.3 Design Criteria

[*The auxiliary and shield building structures are reinforced concrete structures, structural modules, and horizontal concrete slabs supported by composite structural steel framing.*

- *Seismic forces are obtained from the response spectrum analysis of the three-dimensional finite element analysis models as described in subsection 3H.4. The shear wall and floor slab design also considers out-of-plane bending and shear forces due to loading, such as live load, dead load, seismic, lateral earth pressure, hydrostatic, hydrodynamic, and wind pressure.*

- *The shield building roof and the passive containment cooling water storage tank are analyzed using three-dimensional finite element models with the ANSYS computer code*]* as described in subsection 3.8.4.4.1. [*Loads and load combinations include construction, dead, live, thermal, wind, and seismic. The response spectrum analysis of the nuclear island is supplemented by equivalent static acceleration analysis of a more detailed model of a quadrant of the shield building roof. The results from the more detailed analysis are used in the evaluation of the tension ring, air inlets, and radial beams. The seismic response of the water in the tank is analyzed in a separate analysis with seismic input defined by the floor response spectrum.*

- *The structural steel framing is used primarily to support the concrete slabs and roofs. Metal decking, supported by the steel framing, is used as form work for the concrete slabs and roofs.*

- *The finned floors for the main control room and the instrumentation and control room ceilings are designed as reinforced concrete slabs in accordance with American Concrete Institute standard ACI 349. The steel panels are designed and constructed in accordance with American Institute of Steel Construction Standard ANSI/AISC N690. For positive bending, the steel plate is in tension and the steel plate with fin stiffeners serves as the bottom reinforcement. For negative bending, compression is resisted by the stiffened plate and tension by top reinforcement in the concrete.*]*

3H.3.1 Governing Codes and Standards

[*The primary codes and standards used in the design of the auxiliary and shield buildings are listed below:*

- *ACI 349-01, "Code Requirements for Nuclear Safety Related Concrete Structures" (refer to Subsection 3.8.4.5 for supplementary requirements and Subsection 3.8.4.4.1 for alternative requirements).*

- *ANSI/AISC N690-1994, "Specification for the Design, Fabrication and Erection of Safety-Related Steel Structures for Nuclear Facilities" (refer to subsection 3.8.4.5 for supplemental requirements). American Welding Society (AWS), Structural Welding Code - Steel, AWS D1.1-2000 provides an acceptable alternative for ANSI/AISC N690 weld requirements as described in Subsections 3.8.3.2 and 3.8.4.2.*]*

3H.3.2 Seismic Input

The SSE design response spectra are given in Figures 3.7.1-1 and 3.7.1-2. [*They are based on the Regulatory Guide 1.60 response spectra anchored to 0.30g, but are amplified at 25 Hertz to reflect larger high-frequency seismic energy content observed for eastern United States sites.*]* The nuclear island seismic analyses are summarized in Subsection 3.7.2.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3H.3.3 Loads

[*The auxiliary and shield buildings are seismic Category I structures. The loads listed in the following subsections are used for the design of the building structures. All the listed loads are not necessarily applicable to all structures and their elements. Loads for which each structural element is designed are based on the conditions to which that particular structural element is potentially subjected.*]*

Dead Load (D):

[*The weight of all permanent construction and installations, including fixed equipment, is included as the dead load during its normal operating condition.*

The weight of minor equipment (not specifically included in the dead load), piping, cables and cable trays, ducts, and their supports was included as equivalent dead load (EDL). A minimum of 50 pounds per square foot (psf) was used as EDL. For floors with a significant number of small pieces of equipment, the total weight of miscellaneous small pieces of equipment, divided by the floor area of the room plus an additional 50 psf was used as the equivalent dead load.]*

Earth Pressure (H):

[*The static earth pressure acting on the structures during normal operation is considered in the design of exterior walls. The dynamic soil pressure, induced during a safe shutdown earthquake (SSE), is included as a seismic load.*]*

Live Loads (L):

[*The load imposed by the use and occupancy of the building is included as the live load. Live loads include floor area loads, laydown loads, fuel transfer casks, equipment handling loads, trucks, railroad vehicles, and similar items. The floor area live load is not applied on areas occupied by equipment whose weight is specifically included in the dead load. Live load is applicable on areas under equipment where access is provided, for instance, the floor under an elevated tank supported on legs.*

Floor loading diagrams are prepared for areas for component laydown. The diagrams show the location of major pieces of equipment and their foot-print loads or equivalent uniformly distributed loads.

The following live load items are considered in design:

A. Building floor loads

The following minimum values for live loads are used.

– *Structural platforms and gratings*	*100 psf*
– *Ground floors*	*250 psf*
– *All other elevated floors*	*200 psf* *(This load is reduced if the equivalent dead load for the floor is more than 50 psf. The sum of the live load and the equivalent dead load is 250 psf.)*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

B. Roof loads

The roof is designed for a uniform snow load of 63 psf calculated in accordance with ASCE 7-98. This corresponds to ground snow load of 75 psf, exposure factor of 1.0, thermal factor of 1.0, and an importance factor of 1.2.

C. Concentrated loads for the design of local members

– *Concentrated load on beams and girders (in load combinations that do not include seismic load)*	*5,000 pounds so applied as to maximize moment or shear. This load is not carried to columns or walls. It is not applied in areas where no heavy equipment will be located or transported, such as the access control areas.*
– *Concentrated load on slabs (considered with dead load only)*	*5,000 pounds so applied as to maximize moment or shear. This load is not carried to columns or walls. It is not applied in access control areas.*

In design reconciliation analysis, if actual loads are established to be lower than the above loads, the actual loads are used for reconciliation.

D. Temporary exterior wall surcharge

When applicable, a minimum surcharge outside and adjacent to subsurface wall of 250 psf is applied.

E. Construction loads

The additional construction loads produced by cranes, trucks, and the like, with their pickup loads, are considered. For steel beams supporting concrete floors, the weight of the wet concrete plus 100 psf uniform load and 5,000 pounds concentrated load, distributed near points of maximum shear and moment, is applied. A one-third increase in allowable stress is permitted.

Metal decking and precast concrete panels, used as formwork for concrete floors are designed for the wet weight of the concrete plus a construction live load of 20 psf uniform or 150 pounds concentrated. The deflection during normal operation is limited to span in inches divided by 180, or 0.75 inch, whichever is less.

F. Crane loads

The impact allowance for traveling crane supports and runway horizontal forces is in accordance with ANSI/AISC N690.

G. Elevator loads

The impact allowance used for the elevator supports is 100 percent, applied to design capacity and weight of car plus appurtenances, unless otherwise specified by the equipment supplier.

H. Equipment laydown and major maintenance

Floors are designed for planned refueling and maintenance activities as defined on equipment laydown drawings.]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Wind Load

[*The wind loads are as follows:*

- *Design wind (W)*

  For the design of the exterior walls, wind loads are applied in accordance with ASCE 7-98 with a basic wind speed of 145 mph. The importance factor is 1.15, and the exposure category is C. Wind loads are not combined with seismic loads.

- *Tornado load (W_t)*

  The exterior walls of the auxiliary and shield buildings are designed for tornado. A maximum wind speed of 300 mph (maximum rotational speed: 240 mph, maximum translational speed: 60 mph) is used to design the structures.]*

Seismic Loads (E_s)

[*The SSE (E_s) is used for evaluation of the structures of the auxiliary and shield buildings. E_s is defined as the loads generated by the SSE specified for the plant, including the associated hydrodynamic loads and dynamic incremental soil pressure.*]*

Operating Thermal Loads (T_o)

[*Normal thermal loads for the exterior walls and roofs are addressed in the design. These correspond to positive and negative linear temperature gradients with the inside surface at an average 70°F and the outside air temperature at -40°F and +115°F, respectively. These loads are considered for the seismic Category I structures in combination with the SSE also. All exterior walls of the nuclear island above grade not protected by adjacent buildings are designed for these thermal loads. The thermal gradient is also applied to the portion of the shield building between the upper annulus and the auxiliary building.*

Normal thermal loads for the passive containment cooling system (PCS) tank design are calculated based on the outside air temperature extremes specified for the safety-related design. The PCS tank is assumed to be at 40°F when the outside air temperature is -40°F. The structural design of the PCS tank also conservatively assumes that the temperature on the inside of the PCS tank walls is at 40°F when the outside air temperature is postulated to be at 115°F.

Normal thermal loads due to a thermal gradient in the structures below the grade level (exterior walls and basemat) are small and are not considered in the design.]*

Effects of Pipe Rupture (Y)

[*The evaluations consider the following loads:*

- *Accident design pressure load, P_a, within or across a compartment and/or building generated by the postulated pipe rupture, including the dynamic effects due to the pressure time history.*

  The main steam isolation valve (MSIV) compartments are designed for a 6.5 pounds per square inch (psi) pressurization load. The steam generator blowdown valve compartment is designed for a 6 psi pressurization load.

- *Accident thermal loads, T_a, due to thermal conditions generated by the postulated pipe break and including T_o.*

Temperature gradients are based on an exterior air temperature of -40°F.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The structural integrity of the west wall of the main control room is also evaluated for the jet impingement (Y_j)]*

3H.3.4 Load Combinations and Acceptance Criteria

[*Concrete structures are designed in accordance with ACI 349 for the load combinations and load factors given in Table 3.8.4-2. Steel structures are designed in accordance with ANSI/AISC N690 for the load combinations and stress limit coefficients given in Table 3.8.4-1. The following supplemental requirements are applied for the use of ANSI/AISC N690:*

- *In Section Q1.0.2, the definition of secondary stress applies to stresses developed by temperature loading only.*
- *In Section Q1.3, where the structural effects of differential settlement are present, they are included with the dead load, D.*
- *In Table Q1.5.7.1, the stress limit coefficients for compression are as follows:*
  - *1.3 instead of 1.5 in load combinations 2, 5, and 6*
  - *1.4 instead of 1.6 in load combinations 7, 8, and 9*
  - *1.6 instead of 1.7 in load combination 11*
- *In Section Q1.5.8, for constrained members (rotation and/or displacement constraint such that a thermal load causes significant stresses) supporting safety-related structures, systems, or components, the stresses under load combinations 9, 10, and 11 are limited to those allowed in Table Q1.5.7.1 as modified above.*]*

3H.4 Seismic Analyses

[*A global seismic analysis of the AP1000 nuclear island structure is performed to obtain building seismic response for the seismic design of nuclear safety-related structures. The seismic loads for the design of the shear walls and the slabs in the auxiliary building are based on a response spectrum analysis of the auxiliary building and the shield building 3D finite element models.*]* This analysis is described in Subsection 3.7.2. [*For determining the out-of-plane seismic loads on flexible slabs and wall segments, spectral accelerations are obtained from time history analyses or from the relevant response spectra, using the 7 percent damping curve. Hand calculations are performed to estimate the out-of-plane seismic forces and the corresponding bending moment in each shear wall and floor slab element to supplement the loads obtained from the global seismic analysis.*]*

3H.4.1 Live Load for Seismic Design

[*Floor live loads, based on requirements during plant construction and maintenance activities, are specified varying from 50 to 250 pounds per square foot.*

For the local design of members, such as the floors and beams, seismic loads include the response due to masses equal to 25 percent of the specified floor live loads or 75 percent of the roof snow load, whichever is applicable. These seismic loads are combined with 100 percent of the specified live loads, or 75 percent of the roof snow load, whichever is applicable. These live and snow loads are included as mass in calculating the vertical seismic forces on the floors and roof. The mass of equipment and distributed systems is included in both the dead and seismic loads.]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3H.5 Structural Design of Critical Sections

[*This subsection summarizes the structural design of representative seismic Category I structural elements in the auxiliary building and shield building. Critical sections are listed below and the corresponding location numbers are shown on Figure 3H.5-1 for twelve of the critical sections. Items 13 and 14 in the list below are located in the shield building cylinder and are discussed in APP-GW-GLR-602 (Reference 1). The basis for their selection to this list is also provided for each* critical section.

(1) *South wall of auxiliary building (column line 1), elevation 66'-6" to elevation 180'-0". (This exterior wall illustrates typical loads such as soil pressure, surcharge, temperature gradients, seismic, and tornado.) – see subsection 3H.5.1.1 and Figures 3H.5-2 and 3H.5-3*

(2) *Interior wall of auxiliary building (column line 7.3), elevation 66'-6" to elevation 160'-6" (This is one of the most highly stressed shear walls.) – see subsection 3H.5.1.2 and Figure 3H.5-4*

(3) *West wall of main control room in auxiliary building (column line L), elevation 117'-6" to elevation 153'-0". (This illustrates design of a wall for subcompartment pressurization.) – see subsection 3H.5.1.3 and Figure 3H.5-12*

(4) *North wall of MSIV east compartment (column line 11 between column lines L and M), elevation 117'-6" to elevation 153'-0". (The main steam line is anchored to this wall segment.) – see subsection 3H.5.1.4 and Figure 3H.5-5*

(5) *Roof slab at elevation 180'-0" adjacent to shield building cylinder. (This is the connection between the two buildings at the highest elevation.) – see subsection 3H.5.2.1 and Figure 3H.5-7*

(6) *Floor slab on metal decking at elevation 135'-3". (This is a typical slab on metal decking and structural steel framing.) – see subsection 3H.5.2.2 and Figure 3H.5-6*

(7) *2'-0" slab in auxiliary building (operations work area (tagging room) ceiling) at elevation 135'-3". (This illustrates the design of a typical 2'-0" thick concrete slab.) – see subsection 3H.5.3.1 and Figure 3H.5-8. (Note: The 'Tagging Room' has been renamed as "Operations Work Area." However, to avoid changing the associated design and analysis documents, this room is referred to as the 'Tagging Room.')*

(8) *Finned floor in the main control room at elevation 135'-3". (This illustrates the design of the finned floors.) – see subsection 3H.5.4 and Figure 3H.5-9*

(9) *Shield building roof/exterior wall of PCS water storage tank. (This is a unique area of the roof and water tank.) – see subsection 3H.5.6.3*

(10) *Shield building roof/interior wall of PCS water storage tank. (This is a unique area of the roof and water tank.) – see subsection 3H.5.6.2*

(11) *Shield building roof, tension ring, and air inlet. (This is the junction between the shield building roof and the cylindrical wall of the shield building.) – see subsections 3H.5.6 and 3H.5.6.1*

(12) *Divider wall between the spent fuel pool and the fuel transfer canal. (This wall is subjected to thermal and seismic sloshing loads.) – see subsection 3H.5.5.1 and Figure 3H.5-10*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

(13) Shield building SC cylinder is the exposed portions of the shield building that are not protected by the Auxiliary Building and is a steel concrete composite structure – see subsection 3H.5.7.1, Figure 3H.5-16, and Figures 5 and 6 of APP-GW-GLR-602 (Reference 1)

(14) Shield building SC to RC connection is the region of the shield building that anchors the SC cylindrical wall modules to the RC basemat and wall of the shield building – see subsection 3H.5.7.2, Figure 3H.5-16, and Figures 1, 2, and 3 of APP-GW-GLR-602 (Reference 1)

The design implemented in fabrication and construction drawings and instructions will have the design shown, an equal design, or a better design for the key structural elements.]*

3H.5.1 Shear Walls

Structural Description

[*Shear walls in the auxiliary building vary in size, configuration, aspect ratio, and amount of reinforcement. The stress levels in shear walls depend on these parameters and the seismic acceleration level. The range of these parameters and the stress levels in various regions of the most severely stressed shear wall are described in the following paragraphs.*

The height of the major structural shear walls in the auxiliary building ranges between 30 to 120 feet. The length ranges between 40 and 260 feet. The aspect ratio of these walls (full height/full length) is generally less than 1.0 and often less than 0.25. The walls are typically 2 to 5 feet thick, and are monolithically cast with the concrete floor slabs, which are 9 inches to 2 feet thick. Exterior shear walls are several stories high and do not have many large openings. Interior shear walls, however, are discontinuous in both vertical and horizontal directions. The in-plane behavior of these shear walls, including the large openings, is adequately represented in the analytical models for the global seismic response. Where the refinement of these finite element models is insufficient for design of the reinforcement, for example in walls with a large number of openings, detailed finite element models are used.

The shear walls are used as the primary system for resisting the lateral loads, such as earthquakes. The auxiliary building shear walls are also evaluated for flexure and shear due to the out-of-plane loads.]*

Design Approach

[*The auxiliary building shear walls are designed to withstand the loads specified in subsection 3H.3.3. Beside dead, live, and other normal operating condition loads, the following loads are considered in the shear wall design:*

- *Seismic loads*
  - *The SSE loads for the wall are obtained from the seismic analyses of auxiliary/shield buildings that are described in subsection 3H.4.*
  - *Calculations are performed by considering shear wall segments bounded by the floors below and above the segment and the adjacent walls perpendicular to, on both sides of, the segment under consideration. Appropriate boundary conditions are assumed for the four edges of the segment. Natural frequencies of wall segments are determined using finite element models or text book formulas for the frequency of plate structures. Corresponding spectral acceleration is determined from the applicable response spectrum.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- *Exterior walls, below grade level, are also evaluated for dynamic earth pressure exerted during an SSE for two cases:*
  - *Dynamic earth pressure calculated in accordance with ASCE 4-98*
  - *Passive earth pressure*

- *Accident pressure load*
  - *Shear walls of the main steam isolation valves (MSIV) rooms are designed for 6.5 pounds per square inch (psi) differential pressure acting in conjunction with the seismic loads. Member forces due to accident pressure and SSE are combined by absolute sum.*
  - *The main control room wall of the east MSIV compartment is evaluated for the pressure and the jet load due to a postulated main steamline break.*

- *Tornado load*

  For exterior walls above grade level, tornado loads are considered.

The design temperatures for thermal gradient are included in Table 3H.5-1.

The shear walls are designed for the load combinations, as applicable, contained in Table 3.8.4-2. The wall sections are designed in accordance with the requirements of ACI 349-01.]*

3H.5.1.1 Exterior Wall at Column Line 1

[*The wall at column line 1 is the exterior wall at the south end of the nuclear island. The reinforced concrete wall extends from the top of the basemat at elevation 66'-6" to the roof at elevation 180'-0". It is 3'-0" thick below the grade. Above the grade, the wall thickness is as follows:*

- *2'-3", from column line I to 5'-7" west of column line K-2, from elevation 100'-0" to 109'-3";*
- *3'-0", from 5'-7" west of column line K-2 to column line N, from elevation 100'-0" to 109'-3";*
- *2'-3", from column line I to 5'-6" east of column line L-2, from elevation 109'-3" to 180'-0";*
- *3'-0", from 5'-6" east of column line L-2 to column line N, from elevation 109'-3" to 125'-0";*
- *2'-3", from 5'-6" east of column line L-2 to column line N, from elevation 125'-0" to 180'-0".*

The wall is designed for the applicable loads including dead load, live load, hydrostatic load, static and dynamic lateral soil pressure loads, seismic loads, and thermal loads. For various segments of this wall, Table 3H.5-2 provides the listing and magnitude of the various design loads under governing load combinations and Table 3H.5-3 presents the details of the wall reinforcement. The sections where the required reinforcement is calculated are shown in Figure 3H.5-2 (Sheet 1). Typical wall reinforcement is shown on Figure 3H.5-3.]*

3H.5.1.2 Wall at Column Line 7.3

[*The wall at column line 7.3 is a shear wall that connects the shield building and the nuclear island exterior wall at column line I. It extends from the top of the basemat at elevation 66'-6" to the top of the roof. The wall is 3 feet thick below the grade at elevation 100'-0" and 2 feet thick above the grade.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Out-of-plane lateral support is provided to the wall by the floor slabs on either side of it and the roof at the top.

The auxiliary building design loads are described in Section 3H.3.3, and the wall is designed for the applicable loads.

For various segments of this wall, the corresponding governing load combination and associated design loads are shown in Table 3H.5-4. Table 3H.5-5 presents the details of the wall reinforcement. The sections where the required reinforcement is calculated are shown in Figure 3H.5-2 (Sheet 2). Typical wall reinforcement is shown on Figure 3H.5-4]*

3H.5.1.3 Wall at Column Line L

[*The wall at column line L is a shear wall on the west side of the Main Control Room. It extends from the top of the basemat at elevation 66'-6" to the top of the roof. The wall is 2 feet thick. Out-of-plane lateral support is provided to the wall by the floor slabs on either side of it and the roof at the top. The segment of the wall that is a part of the main control room boundary is from elevation 117'-6" to elevation 135'-3".*

The auxiliary building design loads are described in subsection 3H.3.3, and the wall is designed for the applicable loads. In addition to the dead, live and seismic loads, the wall is designed to withstand a 6.5 pounds per square inch pressure load due to a pipe break in the MSIV room even though it is a break exclusion area. This wall segment is also designed to withstand a jet load due to the pipe break.

The governing load combination and associated design loads are those due to the postulated pipe rupture and are shown in Table 3H.5-6. Table 3H.5-7 and Figure 3H.5-12 present the details of the wall reinforcement. The sections where the required reinforcement is calculated are shown in Figure 3H.5-2 (Sheet 3).]*

3H.5.1.4 Wall at Column Line 11

[*The north wall of the MSIV east compartment, at column line 11 (Wall 11) between elevation 117'-6" and elevation 153'-0", has been identified as a critical section.*

The segment of the wall between elevation 117'-6" and elevation 135'-3" is 4 feet thick, and several pipes such as the main steam line, main feed water line, and the start-up feed water line are anchored to this wall at the interface with the turbine building.

The wall segment from elevation 135'-3" to elevation 153'-0" does not provide support to any high energy lines, and is 2 feet thick. This portion does not have to withstand reactions from high energy line breaks.

The wall (Wall 11) is designed to withstand loads such as the dead load, live load, seismic load and the thermal load. The MSIV compartments are break exclusion areas, but the design also considered the compartment pressurization load associated with a one square foot pipe rupture in the MSIV compartments. Wall 11 in the east MSIV compartment is also designed to withstand the jet loads and the reactions at the pipe anchors for main steam and main feedwater line breaks assumed to occur in the east MSIV compartment. Additionally, the Wall 11 design for both MSIV compartments considers loads from postulated breaks in the turbine building, which include turbine building first bay pressurization, jet loads, reactions at the Wall 11 pipe anchors, and pipe whip.

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The wall structure is analyzed using three dimensional finite element analyses supplemented by hand calculations. Analyses are performed for individual loads, and design loads are determined for applicable load combinations from Table 3.8.4-2.

Wall reinforcement for this location is shown in Figure 3H.5-5 illustrating conformance with ACI 349-01 requirements. The reinforcement detailing and development for the wall of the MSIV west compartment varies because the compartment is in the corner of the auxiliary building and the adjacent wall on column line Q (Wall Q) is oriented at 90 degrees to Wall 11.]*

3H.5.2 Composite Structures (Floors and Roof)

[*The floors consist of a concrete slab on metal deck, which rests on structural steel floor beams. Several floors in the auxiliary building are designed as one-way reinforced concrete slabs supported continuously on steel beams. Typically, the beams span between two reinforced concrete walls. The beams are designed as unshored, composite beams with formed metal deck spanning perpendicular to the members. For the floors, beams are predominately spaced at about 5- to 6-feet intervals and spans are between 15 feet and 25 feet. Based on local geometry considerations the intervals and spans are outside these ranges in a limited number of locations. The spacing between the beams or between beams and walls is as small as 3 feet and as large as 8 feet. The span of the beams is as small as 2 feet, 6 inches and as large as 38 feet, 6 inches. The designs of the beams satisfy the requirements in ANSI/AISC N690 for composite structures.*]*

Structural Description

[*A typical layout of these floors is shown in Figure 3H.5-6. The metal deck rests on the top flange of the structural steel floor beam, with the longitudinal axes of the metal deck ribs and floor beams placed perpendicular to each other. Figure 3H.5-6 shows the key structural elements in composite floors. The reinforcement size and spacing are based on loads and spans for this type of floor and are determined at each location based on the requirements in ACI 349 and ACI 318-11, Section 12.6. The development of the floor reinforcement in the walls can be either headed reinforcement or standard hooks. The beam size and spacing and beam support designs are based on loads and spans for this type of floor as noted on the figure. The beam support designs include beam seats or shear plates connected to the web of the beam. The detail design of the support for the beam, including the portion embedded in the concrete wall, is based on the load and structural system configuration as noted on the figure. The designs of these floors are in conformance with ANSI/AISC N690 and ACI 349. The depth of the ribs for 9-inch concrete floor slabs, 9.5-inch concrete floor slabs, 15-inch concrete floor slabs, and 15-inch deep concrete roof slabs are 3 inches, 2.5 inches, 3 inches, and 4.5 inches respectively. The concrete slab is tied to the structural steel floor beam by shear connectors, which are welded to the top flange of the floor beam. The concrete slab and the floor beams form a composite floor system. For the design loads after hardening of concrete, the transformed section is used to check the stresses.*

The construction sequence is as follows:

- *The structural steel floor (floor beam, metal deck, and shear connectors) is fabricated in the shop, brought to the floor location, and placed in position. In some cases, the beams and deck are preassembled and placed as a module.*

- *The metal deck is used as the formwork, and concrete is poured on the metal deck. Until concrete hardens, the load is carried by the metal deck and the steel floor beam.*

- *During concreting, no shoring is provided for the beams supporting the floors and roof. Local shoring of the metal deck at penetrations and other openings in the floor and supporting wall, or to act as temporary support at the location of an incomplete wall, is acceptable.*]*

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Design Approach

[*The floor design considers the dead, live, construction, extreme environmental, and other applicable loads identified in Section 3H.3.3. The design floor loading includes the equipment attached to the floor. The end condition for the steel beams is simply supported, or continuous. The seismic load is obtained using the applicable floor acceleration response spectrum (7 percent damping for the SSE loads).*

The load combinations applicable to the design of these floors are shown in Tables 3.8.4-1 and 3.8.4-2. The design of the floor system is performed in two parts:

- *Design of structural steel beams*
  - *The structural steel floor beams are evaluated to withstand the weight of wet concrete during the placement of concrete. The composite section is designed for the design loads during normal and extreme environment conditions. Shear connectors are also designed.*
- *Design of concrete slab*
  - *The concrete slab and the steel reinforcement of the composite section are evaluated for normal and extreme environmental conditions. The slab concrete and the reinforcement is designed to meet the requirements of American Concrete Institute standard ACI 349-01 "Code Requirements for Nuclear Safety Related Concrete Structures."*
  - *The slab design considers the in-plane and out-of-plane seismic forces. The global in-plane and out-of-plane forces are obtained from the response spectrum analysis of the 3D finite element model of the auxiliary and shield buildings. The out-of plane seismic forces due to floor self-excitation are determined by hand calculations using the applicable vertical seismic response spectrum and slab frequency.*]*

3H.5.2.1 Roof at Elevation 180′-0″, Area 6 (Critical Section is between Col. Lines N & K-2 and 3 & 4)

[*The layout of this segment of the roof is shown in Figure 3H.5-7 as Region "B." The concrete slab is 15 inches thick, plus 4.5-inch deep metal deck ribs. It is composite with 4 feet deep plate girders by using shear connectors. The girder spacing is a range of 13'-0" to 14'-2" center to center. The girder flanges are 26" x 2 1/2" and the web is 43" x 1". The girders span approximately 64 feet in the north-south direction and are designed as simply supported. The concrete slab between the girders behaves as a one-way slab and is designed to span between the girders.*

The roof girders are designed for dead and live loads, including construction loads (with wet concrete) with simple support end conditions. A one-third increase in allowable stress is permitted for the construction load combination.

The girders are also evaluated as part of the composite beam after drying of concrete. The composite roof structure is designed to withstand dead and live load / snow load, as well as the wind, tornado and seismic loads. The design summary for the critical section is shown in Table 3H.5-10. The design of the reinforcement and supporting beams, and girder and beam supports varies for other locations. The design is based on the loads and geometry for those sections.

A typical connection of the roof slab to the shield building is shown in Figure 3H.5-7. The figure shows the arrangement of reinforcement at the connection in the fuel building portion of the auxiliary building roof, the shield building cylindrical wall, and the walls of the auxiliary building just below the roof. The details of the connections between the auxiliary building roof and the shield building wall in other locations vary because of loads on the connection and the orientation of the wall to the roof

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reinforcement arrangement. These connection design details satisfy the requirements identified in Subsection 3.8.4.5.5.6.]*

3H.5.2.2 Floor at Elevation 135′-3″, Area 1 (Between Column Lines M and P)

[*The design of a typical composite floor is shown in Figure 3H.5-6. The design summary for the floor between column lines M and P at elevation 135'-3" is shown in Table 3H.5-11. The concrete slab is 9 inches thick, plus 3-inch deep metal deck ribs. The floor beam size is shown on the figure.*

- *The floor beams are designed for construction load (with wet concrete) with simple support end conditions. The design loads include the dead load and a construction live load of 100 pounds per square foot (psf) distributed load plus 5000 pounds concentrated load near the point of maximum shear and moment. A one-third increase in allowable stress is permitted.*

- *The floor beams are also designed as part of the composite beam after drying of the concrete. Because of continuity of rebars into the wall and the connection of the bottom flange to the support embedment, the end support condition is considered as fixed.*]*

3H.5.3 Reinforced Concrete Slabs

[*Reinforced concrete floors in auxiliary building are 24 inch or 36 inch thick. These floors are constructed with reinforced concrete placed on the top of 8 to 12 inch thick precast concrete panels. The precast concrete panels are installed at the bottom to serve as the formwork and withstand the load of wet concrete slab. The spans of the floors are predominately 13 feet to 20 feet, and the precast panels are predominately 7 to 14 feet wide. Based on local geometry considerations, the widths and spans are outside these ranges in a limited number of locations. The spans of the floor are as small as 5 feet and as large as 21 feet. The width of the precast panels is as small as 4 feet and as large as 19 feet. The number of side-by-side precast panels ranges from one to eight.*

Examples of such floors are the Operations Work Area (Tagging Room) ceiling slab at elevation 135 ft 3 inches in Area 2, and the Area 5/6 elevation 100'-0" slab between column lines 1 & 2.

Figure 3H.5-8 shows the key structural elements in reinforced concrete floor slabs. The precast panels and the cast-in-place concrete are designed to act together as a composite reinforced slab so that the floor dynamic response is consistent with the auxiliary building finite element analysis. However, the precast panels are neglected in determining floor strength and load carrying capacity. The reinforcement size and spacing are determined for each location, based on specific loads and spans, and satisfy the requirements in ACI 349 and ACI 318-11, Section 12.6. The floor thickness and precast panel thickness for this type of floor are based on specific loads and spans as noted on the figure. The type and thickness of adjacent walls and floors vary as noted on the figure. The main reinforcement is provided in the cast-in-place concrete. Reinforcement is placed in both the top and bottom layers of the cast-in-place concrete in both directions. For the design of the reinforcement in the cast-in-place floors, post-construction loads are conservatively assumed to be resisted only by the cast-in-place concrete and the reinforcement placed within it. The reinforcement in the cast-in-place portion is fully developed into supporting adjacent walls such that the connection is assumed to be a fixed connection. The development of the floor reinforcement in the walls is achieved using either headed reinforcement or standard hooks.

The precast panel reinforcement is designed to resist the weight of the panel and the wet weight of the cast-in-place concrete during construction. Reinforcement is placed within the precast panel portion in both top and bottom layers in both directions. The precast panel reinforcement is contained within the panel. The reinforcement is discontinuous with a design gap between adjacent precast panels and between precast panels and walls. The precast panels are connected to the concrete

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placed above them by shear reinforcement which satisfies the requirements of ACI 349 Chapter 17. The precast panels and the cast-in-place concrete are made to act together as a composite reinforced concrete slab by roughening the top surface of the precast panel and providing shear ties between the two elements. The detail designs of the supports for the precast panels are based on the loading and design requirements. The design of these floors is in conformance with ANSI/AISC N690 and ACI 349.

The finite element analysis model used for the auxiliary building seismic response assumes a homogenous thickness of concrete for the floor system, and includes floor-to-wall connections that are fixed over the full thickness of the reinforced concrete floor. The detailed design of the floor system includes a gap between the precast panel and the wall and between adjacent precast panels. Although the gap between the precast panels and the wall reduces the thickness of the floor in direct contact with the wall, the design of the floor system satisfies the requirements of ACI 349, including fully developing the floor reinforcement in the wall. The design of the floor system and the connection with the wall provide a fixed connection that transfers forces and moments from the floor to the wall.

Detailed analysis of the floor system connection design details, including the gap between the precast panel and wall is performed for the floor constructed with precast panels and is consistent with the nuclear island seismic model. The effects of stiffness, reinforcement anchorage, and concrete cracking are considered in the detailed analyses. The detailed analyses demonstrate that these floors have vertical response above 33 Hz and are rigid, which is consistent with the nuclear island seismic model.]*

3H.5.3.1 Operations Work Area (Tagging Room) Ceiling

The tagging room (room number 12401) location is shown on Figure 1.2-8. [*Figure 3H.5-8 shows the typical cross section and reinforcement. The design summary for this location is shown in Table 3H.5-12. Design dimensions of the Operations Work Area (Tagging Room) Ceiling are as follows:*

Room Size:	*16'-0" x 11'-10"*
Boundary Conditions:	*Fixed at Walls J and K*
Clear Span:	*16'-0"*
Slab Thickness:	*Total = 24 inches*
	Precast Panel = 8 inches
	Cast-in-Place = 16 inches

*The two precast concrete panels, each 6'-4½" wide and spanning over 16'-0" clear span, are installed to serve as the formwork.]**

3H.5.4 Concrete Finned Floors

[*The ceilings of the main control room and the instrumentation and control rooms in the auxiliary building are designed as finned-floor modules. A typical floor design is shown in Figure 3H.5-9. A finned floor consists of a 24-inch-thick concrete slab poured over a stiffened steel plate ceiling. The fins, welded to stiffen the steel plate, are half inch by 9 inch rectangular sections perpendicular to the plate. Shear studs are welded on the other side of the steel plate, and the steel and concrete act as a composite section. Figure 3H.5-9 shows the finned floor above the main control room and the connection of the floor to the wall on column line 11. The finned floors above the instrumentation and control rooms are similar, but differ with some design details, such as the size and spacing of reinforcement and the connecting dowels used in the connection of the floor to the wall. Penetrations and other interferences may cause localized variances with the design details shown in the figure.*

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The fins are exposed to the environment of the room and enhance the heat-absorbing capacity of the ceiling. Several shop-fabricated steel panels, cut to room width and placed side by side perpendicular to the room length, are used to construct the stiffened plate ceiling in a modularized fashion. The stiffened plate with fins is designed to withstand construction loads prior to concrete hardening.]*

The construction sequence for finned floors is as follows:

- Each panel (fins, steel plates, and shear connectors) is fabricated in the shop, brought to the floor location, and placed in position. In some cases, the panels are preassembled and placed as a module. The fins frame into steel shapes at the ends of the floors. The steel shapes are supported by intermittent brackets connected to the walls.

- The steel plate is used as the formwork for concrete placement. The wet concrete load is carried by the steel plates and the fins.

- During concrete placement, shoring may be provided for floors with longer spans. Local shoring of the steel plates at penetrations and other openings in the floor and supporting wall, or to act as temporary support at the location of an incomplete wall may also be provided.

[*The main control room ceiling fin floor is designed for the dead, live, and the seismic loads. The design summary is shown in Table 3H.5-13.*

The finned floor structure is evaluated for the load combinations listed in Tables 3.8.4-1 and 3.8.4-2.]*

Design Methodology

[*The finned floors are designed as reinforced concrete slabs in accordance with ACI Standard 349. For positive bending, the steel plate is in tension. The steel plate with fin stiffeners serves the function of bottom rebars. For negative bending, the potential for buckling due to compression in this element is checked by using the criteria of American National Standards Institute/American Institute of Steel Construction standards ANSI/AISC N690-94. Twisting, and therefore lateral buckling of the stiffener, is restrained by the concrete.*

The finned floors resist vertical and in-plane forces for both normal and extreme loading conditions. For positive bending, the concrete above the neutral axis carries compressive stresses and the stiffened steel plate resists tension. Negative bending compression is resisted by the stiffened plate and tension by top rebars in the concrete. The neutral axis for negative bending is located in the stiffened plate section, and the concrete in tension is assumed inactive. Horizontal in-plane forces are resisted by the stiffened plate and longitudinal rebars.

Minimum top reinforcement is provided in the slab in each direction for shrinkage and temperature crack control. In addition, top reinforcement located parallel to the stiffeners is used as tension reinforcement in negative bending. The stiffened plate provides crack control capability for the bottom of the slab in the transverse direction. Additional bottom layer reinforcing steel is provided in the finned floors at elevation 117'-6" where needed to maintain the structural integrity of the fire barrier during a fire event due to potential deterioration of mechanical properties of exposed steel fin plates during the fire.

Composite section properties, based on an all steel-transformed section, as detailed in Section Q1.11 of ANSI/AISC N690-94, are used to design the following:

- *Weld strength between stiffener and the steel plate*
- *Spacing of the shear studs for the composite action*

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The stiffened plate alone is designed to resist all construction loads prior to the concrete hardening. The plate is designed against the criteria for bending and shear, specified in ANSI/AISC N690-94, Sections Q1.5.1.4 and Q1.5.1.2. In addition, the weld between the stiffener and the steel plate is designed to satisfy the code requirements.]*

3H.5.5 Structural Modules

[*Structural modules are used for some of the structural elements on the south side of the auxiliary building. These structural modules are structural elements built up with welded steel structural shapes and plates. The modules consist of steel faceplates connected by steel trusses as shown in Figure 3.8.3-2. The primary purpose of the trusses is to stiffen and hold together the faceplates during handling, erection, and concrete placement. The thickness of the steel faceplates is 0.5 inch except in a few local areas. The nominal spacing of the trusses is 30 inches. Shear studs are welded to the inside faces of the steel faceplates. Faceplates are welded to adjacent faceplates with full penetration welds so that the weld is at least as strong as the plate. The structural wall modules are anchored to the concrete base by reinforcing steel dowels or other types of connections embedded in the reinforced concrete below. After erection, concrete is placed between the faceplates.*

These modules include the spent fuel pool, fuel transfer canal, and cask loading and cask washdown pits. The structural modules are similar to the structural modules for the containment internal structures (see description in subsection 3.8.3 and Figures 3.8.3-8, 3.8.3-14, 3.8.3-15 and 3.8.3-17). Figure 3.8.4-4 shows the location of the structural modules in the auxiliary building. The structural modules extend from elevation 66'-6" to elevation 135'-3".

The loads and load combinations applicable to the structural modules in the auxiliary building are the same as for the containment internal structures]* (Subsection 3.8.3.5.3) [*except that there are no ADS nor pressure loads due to pipe breaks.*

The design methodology of these modules in the auxiliary building is similar to the design of the structural modules in the containment internal structures]* described in Subsection 3.8.3.5.3.

3H.5.5.1 West Wall of Spent Fuel Pool

[*Figure 3H.5-10 shows an elevation of the west wall of the spent fuel pool (column line L-2), and element numbers in the finite element model. The wall is a 4 feet thick concrete filled structural wall module.*

A finite element analysis is performed for seismic, thermal, and hydrostatic loads with the following assumptions:

- *The seismic in-plane and out-of-plane forces are obtained from the response spectrum analysis of the 3D finite element model of the auxiliary and shield buildings.*
- *The thermal loads are applied as linearly varying temperatures between the inner and outer faces of the walls and floors.*
- *The hydrostatic loads are applied to the spent fuel pool walls and floors, which is considered full with water. This provides the loads for the design of the divider wall.*
- *The seismic sloshing is modeled in the spent fuel pool.*

The concrete filled structural wall modules are designed as reinforced concrete structures in accordance with the requirements of ACI-349. The face plates are treated as reinforcing steel.

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Methods of analysis are based on accepted principles of structural mechanics and are consistent with the geometry and boundary conditions of the structures. Both computer codes and hand calculations are used.

Table 3H.5-8 shows the required plate thickness for certain critical locations. The steel plates are half inch thick.]*

3H.5.6 Shield Building Roof and Connections

[*The shield building roof is a reinforced concrete shell (supporting the passive containment cooling system tank and air diffuser), which is supported on a structural steel module. The structural configuration is shown on sheets 7, 8, and 9 of Figure 3.7.2-12. Air intakes are located at the top of the cylindrical portion of the shield building. The conical roof supports the passive containment cooling system tank. The conical roof is constructed as a structural steel module and lifted into place during construction. Steel beams provide permanent structural support for steel liner and concrete. The concrete is cast in place. Connection between concrete and steel liner are made using shear studs.*

The design of the shield building is shown in Figure 3H.5-11 (Sheets 1-6). These figures show the typical details of the "Tension Ring," the "Air Inlet Structure," and the "Exterior Wall of the Passive Containment Cooling System Tank." Figure 3H.5-16, Sheets 1 and 2, also shows the typical dimensions of the surface plates and the SC to RC connections on the shield building cylindrical segment.]* The column line and auxiliary building roof information in Figure 3H.5-16 is shown for reference and is not Tier 2* information. Interferences such as penetrations; openings; and embedded pipe, conduit, and anchors can cause localized variances with design details shown in the figure.

[*A detailed ANSYS model was used to represent these components of the enhanced design. Analyses were performed to determine the response of the structures for the dead weight, hydrostatic load due to PCS water, snow load, wind load, tornado load, seismic load (including seismic-induced pressure on PCS wall), and thermal loads. The design was evaluated to comply with the requirements of ANSI/AISC N690-94 and of ACI 349-01.*

The design summaries of the components are included in Table 3H.5-9.

The steel frame for the shield building roof and the concrete placed directly thereon is designed to ANSI/AISC N690.

- *In the radial direction, the steel beams, the steel surface plate, and the concrete are evaluated as a composite section using the axial and bending member forces in the steel and concrete section from the finite element analyses. The steel stresses and the end connection are calculated assuming the steel alone resists all loads applied before the concrete has reached 75 percent of its required strength and the effective composite section resists all loads applied after that time.*

- *The concrete is evaluated using all member forces in the concrete and surface steel plate from the finite element analyses (in-plane and out-of-plane forces and moments). The circumferential channels are provided for construction only and are not modeled in the finite element analysis or credited for resisting permanent loads. The concrete section is evaluated by the strength method of ACI-349. The steel plate is not considered as reinforcement in the circumferential direction.*

Additional information is provided in Table 3H.5-15.]*

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3H.5.6.1 Air Inlets and Tension Ring

[*The configuration and plate size of the air inlets enhance their structural performance. The air inlets structure (as shown on Figure 3H.5-14) is located at the top of the cylindrical wall portion of the shield building, beginning at approximately elevation 251' and rising to approximately elevation 266'. The air inlets serve as the intake for air as part of the PCS.*

Above the air inlets, at approximately elevation 266', is the connection designated as the tension ring that connects and supports the conical roof. The tension ring also contains 32 radial beam seat connections where the radial beams for the conical roof are connected.

The air inlets region is 4.5-feet thick with steel plates on each face as the primary reinforcement, which are connected using tie bars. Near the bottom of the air inlet structure, the thickness transitions to 3 feet thick to connect with the shield building cylinder. The air inlet openings are formed using pipe at a downward inclination of 38 degrees from the vertical. The pipe spacing is approximately 2.81 degrees circumferentially with shear studs welded to the outside surface of the pipes. The tie bars are located with three bars between adjacent air inlets at each elevation at maximum design spacing of 8.5 inches vertically. At approximately the same elevations as the tie bars, two 3/4-inch by 6-inch (minimum) shear studs are located between the tie bars except at elevations where there is interference with the air inlet pipes. Tie bars and studs may be omitted in local areas due to design features and other obstructions, such as penetrations, embedments and embedded pipe, conduit, and anchors.]* In the vicinity of the opening through the air inlet region, pipes and other design elements are not provided and the design details can vary from that shown on the figures.

[*The tension ring is designed as a structural steel box structure with concrete infill and shear studs. Also the connection of the RC conical roof to the tension ring is designed to be a mechanical connection. The air inlets and tension ring design methodology is supported by linear analysis and benchmarked nonlinear analysis. The tension ring is designed to ANSI/AISC N690 and is a concrete-filled box girder, with two continuous 1.5-inch-thick steel plates top and bottom, which connect the inner liner plate to the outer liner plate, as shown in Figure 3H.5-15.*]* Interferences such as penetrations; embedments; openings for concrete placement; and embedded pipe, conduit, and anchors can cause localized variances with the design details shown in the figure.

3H.5.6.2 Compression Ring and Interior Wall of Passive Containment Cooling Water Storage Tank

[*The other areas of the shield building are designed to existing industry code requirements, and include the conical roof, the passive containment cooling water storage tank, the compression ring, the knuckle region, and their related attachments. These areas are designed as RC structures in accordance with ACI 349. The steel frame for the roof is designed for the applicable building code ANSI/AISC N690. The concrete roof is designed to ACI 349 requirements without credit for the steel plate on the bottom of the concrete. The configuration and reinforcement of the compression ring and the connection to the interior wall of the passive containment cooling water storage tank is shown in Figure 3H.5-11.*]* Interferences such as penetrations; leak chases; and embedded pipe, conduit, and anchors can cause localized variances with the reinforcement design details shown in the figure.

[*Additional information is provided in Table 3H.5-15.*]*

3H.5.6.3 Knuckle Region and Exterior Wall of Passive Containment Cooling Water Storage Tank

[*The exterior wall of the passive containment cooling water storage tank is two feet thick. The wall starts at the tank floor elevation of 293' 9". There is a stainless steel liner on the inside surface of the tank. The wall liner consists of a plate with stiffeners and welded studs on the concrete side of the*

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plate. Leak chase channels are provided over the liner welds. The reinforcement in the concrete wall is designed without taking credit for the strength provided by the liner. The governing loads for design of the exterior wall are the hydrostatic pressure of the water, the in-plane and out-of-plane seismic response, and the temperature gradient across the wall. The reinforcement is shown in Figure 3H.5-11.]* Interferences such as penetrations; leak chases; and embedded pipe, conduit, and anchors can cause localized variances with the reinforcement design details shown in the figure. [*The reinforcement required and the reinforcement provided is summarized in Table 3H.5-9.*

Additional information is provided in Table 3H.5-15.]*

3H.5.7 Shield Building Cylinder (SC)

3H.5.7.1 Shield Building Cylindrical Wall

[*The shield building surrounds the containment vessel and shares a common basemat with the containment vessel and the auxiliary building. The cylindrical shield wall has an outside radius of 72.5 feet and a thickness of 36 inches. The cylindrical wall section that is below the auxiliary building roof line is a reinforced concrete structure. The section that is not protected by the auxiliary building is a steel concrete composite structure, where two 0.75-inch plates act compositely with 34.5 inches of concrete via tie bars and shear studs. The steel plate modules are connected to the reinforced concrete basemat and walls by mechanical connectors as described below.*

A typical configuration of the SC wall is shown in Figure 3H.5-13. The overall thickness of 36 inches is the same as the RC wall below. The concrete for the SC portion is standard concrete with a compressive strength of 6000 psi. The SC portion is constructed with steel surface plates, which act as concrete reinforcement. The nominal thickness of the steel faceplates is 0.75 inches. The faceplates are thicker (up to 1.0-inch nominal thickness), as necessary, to address loads from connections and attachments in the areas of these local loads. In each module, tie bars are welded to the steel faceplates to develop composite behavior of the steel faceplates and concrete. The shear studs are welded to the inside surface of the steel plate to provide composite action. The tie bars are at closer spacing in the higher stress regions. The reinforcement detailing incorporates ACI 349 requirements.

The panels of the SC wall are welded together with a complete joint penetration weld.

The wall is designed for the applicable loads described in subsection 3H.3.3. A finite element analysis is performed to determine the design forces.

Table 3H.5-14 shows the design summary for the enhanced shield SC cylindrical wall. The three sheets represent locations in the shield building cylinder that have some of the largest demands due to mechanical loads. The element on the west side at grade near the RC/SC connection has large tension forces due to overturning of the cylinder under seismic demand. This area is one of the most stressed elements in tension. The element near the fuel handling building roof at elevation 180' is an element with high out-of-plane shear due to the interaction between the fuel handling building and the cylinder during an earthquake. This element is located close to the fuel building roof. The element above wall 7.3 at elevation 175' has the largest demand for out-of-plane shear in the general part of the cylindrical wall away from the SC/RC connection and the interface with the auxiliary building roof.

Additional discussion and information are provided in Section 4 and Figures 5 and 6 of APP-GW-GLR-602 (Reference 1).]*

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3H.5.7.2 Reinforced Concrete (RC)/Steel Concrete Composite (SC) Horizontal and Vertical Connections

[*The steel plate modules are anchored to the RC basemat and walls of the shield building by mechanical rebar connections. The connectors provide for the direct transfer of forces from the RC reinforcing steel to the SC liner plates.*

At the horizontal connection at the interface with the RC structure that occurs on the bottom of the lowest SC wall module, vertical reinforcing bars in the RC basemat wall are connected to the module with a mechanical connection. A similar vertical connection occurs on the vertical edges of SC wall modules that interface with the RC portion of the shield building wall. In the vertical connection, hoop reinforcing bars in the RC wall are connected to a mechanical connection and forces are transferred directly from the hoop bars to the SC liner plate. The mechanical connections are designed to the stress limits of ANSI/AISC N690 for loads in the reinforcing bars equivalent to 125 percent of the specified yield strength of the reinforcing bar and are proven components used in existing structures. This design basis exceeds the maximum demand that occurs on the west side of the shield building at grade and is summarized in Sheet 3 of Table 3H.5-14. This connection improves the overall ductility of the RC/SC connection.

Additional discussion and information are provided in Section 4 and Figures 1, 2, 3, and 4 of APP-GW-GLR-602 (Reference 1).]*

3H.5.8 References

1. [*APP-GW-GLR-602, Revision 5, October 2014, (Proprietary) and APP-GW-GLR-603, Revision 5* (Non-Proprietary), "AP1000 Shield Building Design Details for Select Wall and RC/SC *Connections," Westinghouse Electric Company LLC.*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-1
Nuclear Island: Design Temperatures for Thermal Gradient

Structure (See detail in Subsection 3H.3.3.)	Load	Temperature (°F)		Remark
PCS Tank Walls	Normal Thermal, T_o	[*(Outside)* *-40* *+115*	*(Inside)* *+40* *+40*]*	–
Roofs and Exterior Walls Above Grade Air Temperatures (Note 3)	Normal Thermal, T_o Accident Thermal, T_a	[*(Outside)* *-40* *+115* *-40* *-40*	*(Inside)* *+70* *+70* *+485* *+212*]*	– MSIV room Fuel handling area
Roofs and Exterior Walls Above Grade Concrete Temperatures (Note 3)	Normal Thermal, T_o Accident Thermal, T_a	[*(Outside)* *-21.6* *-22.8* *-25.4* *+3.2* *+109.1* *+108.0* *+107.5* *+98.6* *-40* *-40* *+63*	*(Inside)* *+47* *+48.4* *+51.5* *+46.6* *+79.2* *+80.7* *+81.3* *+81.3* *+222* *+212* *+212*]*	24″ thickness 27″ thickness 36″ thickness 15″ insulated roof 24″ thickness 27″ thickness 36″ thickness 15″ insulated roof MSIV room Fuel handling area Insulated roof (above fuel handling area)
Interior Walls/Slabs Concrete Temperatures	Normal Thermal, T_o Accident Thermal, T_a	[*(Side 1)* *N/R* *+70* *+70*	*(Side 2)* *N/R* *+222* *+212*]*	– MSIV room Fuel handling area
Exterior Walls Below Grade	Normal Thermal, T_o Accident Thermal, T_a	N/R +50	N/R +140	– Auxiliary Building
Basemat	Normal Thermal, T_o Accident Thermal, T_a	N/R +50	N/R +140	– Auxiliary Building
Shield Building (Between Upper Annulus and Auxiliary Building)	Normal Thermal, T_o Accident Thermal, T_a	[*(Outside)* *-40* *+115* *-40* *+70*	*(Inside)* *+70* *+70* *+222* *+165*]*	– MSIV room wall Rest of wall

Notes:
1. N/R means loads due to a thermal gradient are not required to be considered.
2. Based on ACI 349-01 (Appendix A), the base temperature for the construction is assumed to be 70°F.
3. For the auxiliary building exterior walls above ground, the temperature on the outside face of the walls can use 70°F instead of -40°F in winter or 115°F in summer when the exterior walls are adjacent to another building.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-2
Exterior Wall at Column Line 1 Forces and Moments in Critical Locations
(Units: kips, ft)

Load Combination	M_X	M_Y	M_{XY}	T_X	T_Y	T_{XY}
Elevation 180′-0″ to 135′-3″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		194.9	0.3		155.8	82.8
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym		266.4	18.4		27.2	34.0
D+F+L+H+Es+Pa+Ta+Ra+Yr+Yj+Ym	144.3		49.1	144.3		95.5
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	126.6		42.5	149.0		52.0
Elevation 135′-3″ to 100′-0″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		42.1	5.0		257.9	44.0
D+F+L+H+Es+Pa+Ta+Ra+Yr+Yj+Ym	59.7		1.9	149.7		47.3
D+F+L+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	83.4		37.0	72.2		53.0
Elevation 100′-0″ to 82′-6″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		16.4	13.8		194.4	130.8
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym		16.4	13.8		194.4	130.8
0.9D+0.9F+1.3L+1.2To+1.3H+1.3Ro	1.0		19.2	34.5		122.3
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	5.9		16.0	36.0		128.8
Elevation 82′-6″ to 66′-6″						
[*0.9D+F+H+Ro+To+Es*		18.1	2.3		204.2	83.4
0.9D+F+H+Ro+To+Es		105.7	22.8		230.6	25.6
0.9D+F+H+Ro+To+Es]*	24.4		2.3	11.4		83.4

Note:
X is along the horizontal direction, and Y is in the vertical direction.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-3
Exterior Wall on Column Line 1 Details of Wall Reinforcement (in ^{2}/ft)
(See Figure 3H.5-2 for Locations of Wall Sections.)

Wall Segment (See detail in Subsection 3H.5.1.1.)	Location	Required			*[Provided (Minimum)]**		
		Vertical	Horizontal	Shear(3)	*Vertical*	*Horizontal*	*Shear(3)*
Wall Section 1, 6							
Elevation 180′-0″ to 135′-3″				NR			None
	Outside Face	3.65(4)	3.08		[*3.91(4)*	*3.12*	
	Inside Face	2.76	2.51		*3.12*	*3.12*]*	
Wall Section 2, 3, 7							
Elevation 135′-3″ to 100′-0″				0.17			[*0.80*]*
	Outside Face	2.96	1.98		[*3.12*	*3.12*	
	Inside Face	2.96	2.10		*3.12*	*3.12*]*	
Wall Section 4, 8							
Elevation 100′-0″ to 82′-6″				0.03			[*0.44*]*
	Outside Face	3.04	1.55		[*3.12*	*1.56*	
	Inside Face	3.04	1.25		*3.12*	*1.27*]*	
Wall Section 5, 9							
Elevation 82′-6″ to 66′-6″				0.56			[*0.88*]*
	Outside Face	3.37	0.95		[*4.39*	*1.27*	
	Inside Face	2.68	0.95		*3.12*	*1.27*]*	

Notes:
1. NR = not required.
2. Not used.
3. Refer to Subsection 3.8.4.4.1 for the requirements for shear reinforcement.

[*4. For Vogtle Unit 3, the #8@12" vertical reinforcement bars are fully developed at elevation 137'-0" and above on the outside face with a headed reinforcement bar, effectively reducing the minimum provided area of steel in this wall to 3.12in^2/ft for the development length of the bars to elevation 137'-0". This reduction in minimum provided area does not change the performance of the existing structure under postulated loads and does not cause any excessive stress locally along the development length of the bar, as the required area of steel for elevation 135'-3" to 137'-0" is 3.09 in^2/ft. The arrangement of bars in the wall for both units is unchanged per Figure 3H.5-3.]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-4
Interior Wall at Column Line 7.3 Forces and Moments in Critical Locations
(Units: kips, ft)

Load Combination	M_X	M_Y	M_{XY}	T_X	T_Y	T_{XY}
From Roof to Elevation 155′-6″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		21.3	15.6		135.0	233.5
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	54.3		16.9	241.8		199.5
Elevation 155′-6″ to 135′-3″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		9.1	4.0		192.2	189.3
D+F+L+H+Ro+To+Es]*	23.5		2.5	39.1		215.9
Elevation 135′-3″ to 117′-6″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		9.3	3.7		177.9	161.6
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	11.3		0.6	46.3		184.3
Elevation 117′-6″ to 100′-0″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		7.8	2.7		133.8	199.0
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	4.7		1.2	178.9		116.4
Elevation 100′-0″ to 82′-6″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		31.0	8.5		166.2	91.5
D+F+L+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	12.8		0.0	6.4		164.8
Elevation 82′-6″ to 66′-6″						
[*0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym*		24.5	3.8		105.7	79.3
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	2.5		3.8	9.7		79.3

Note:
X is along the horizontal direction, and Y is in the vertical direction.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-5
Interior Wall on Column Line 7.3 Details of Wall Reinforcement
(See Figure 3H.5-2 for Locations of Wall Sections.)

Wall Segment (See detail in Subsection 3H.5.1.2.)	Location	Wall Section	Reinforcement on Each Face (in^2/ft)	
			Required	[*Provided (Min.)*]*
From Roof to Elevation 155′-6″	Horizontal	1	4.06	[*4.12*
	Vertical	7	3.52	*3.72*
Elevation 155′-6″ to 135′-3″	Horizontal	2	2.52	*3.12*
	Vertical	8	3.64	*3.72*
Elevation 135′-3″ to 117′-6″	Horizontal	3	2.10	*2.54*(4)
	Vertical	9	3.10	*3.12*
Elevation 117′-6″ to 100′-0″	Horizontal	4	2.34	*2.54*
	Vertical	10	2.97	*3.12*
Elevation 100′-0″ to 82′-6″	Horizontal	5	1.38	*2.54*
	Vertical	11	2.33	*3.12*(3)
Elevation 82′-6″ to 66′-6″	Horizontal	6	0.63	*1.27*
	Vertical	12	1.52	*1.56*
Shear Reinforcement(2) (in^2/ft^2)				
From Roof to Elevation 155′-6″	Standard hook or T headed bar	7	0.22	*0.80*]*

Notes:
1. Not used.
2. Refer to Subsection 3.8.4.4.1 for the requirements for shear reinforcement.

[*3. For Vogtle Unit 3, a single reinforcement bar is developed above elevation 82'-6" near the shield building with a headed reinforcement bar effectively reducing the minimum provided area of steel in this wall to 3.08in^2/ft. The provided minimum reinforcement is reduced along the development length of the single bar, though it does not change the performance of the existing structure under postulated loads and does not cause any excessive stress locally along the development length of the bar. The number of bars in the wall for both units is unchanged per Figure 3H.5-4.*]*

[*4. For Vogtle Unit 4, two horizontal reinforcement bars are terminated 2'-0" from the shield building vertical construction joint (CJ). These bars, one #10 on each face of the wall, are located directly below elevation 135'-3". This effectively reduces the minimum provided area of steel in this wall segment to 2.50 in^2/ft. This provided minimum reinforcement is reduced from the shield building CJ through the development length of the bars. However, it does not change the performance of the existing structure under postulated loads and does not cause any excessive stress locally along the development length of the bar.*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-6
Interior Wall at Column Line L Forces and Moments in Critical Locations
(Units: kips, ft)

Load Combination	M_X	M_Y	M_{XY}	T_X	T_Y	T_{XY}
Elevation 154′-2″ to 135′-3″						
[*0.9D+F+L+H+Ro+To+Es*		12.0	4.8		124.1	129.7
0.9D+F+H+Es+Pa+Ta+Ra+Yr+Yj+Ym]*	31.3		4.4	24.6		233.1
Elevation 135′-3″ to 117′-6″						
[*0.9D+F+L+H+Ro+To+Es*		4.5	5.0		124.8	127.5
0.9D+F+L+H+Ro+To+Es]*	26.1		6.2	9.3		132.6

Note:
X is along the horizontal direction, and Y is in the vertical direction.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-7
Interior Wall on Column Line L Details of Wall Reinforcement
(See Figure 3H.5-2, Sheet 3, for Locations of Wall Sections.)

Wall Segment (See detail in Subsection 3H.5.1.3.)	Location	Wall Section	Reinforcement on Each Face (in^2/ft)	
			Required	[*Provided (Min.)*]*
Elevation 154′-2″ to 135′-3″	Horizontal	1	2.09	[*2.27*
	Vertical	3	2.38	*3.12*
Elevation 135′-3″ to 117′-6″	Horizontal	2	1.46	*4.39*[3]
	Vertical	4	2.37	*5.66*[4]]*
Shear Reinforcement[2] **(in^2/ft^2)**				
Elevation 154′-2″ to 135′-3″	Standard hook or T headed bar	5	0.13	[*0.80*
Elevation 135′-3″ to 117′-6″	Standard hook or T headed bar	6	0.55	*1.76*]*

Notes:

1. Not used.
2. Refer to Subsection 3.8.4.4.1 for the requirements for shear reinforcement.

[*3. For Vogtle Unit 4, two #11 horizontal reinforcement bars (one on each face) are omitted directly above elevation 117′-6″ for the entire width of the wall. This effectively reduces the minimum provided area of steel in this wall segment to 4.36 in^2/ft. The provided minimum reinforcement is reduced for the entire width the wall segment. However, it does not change the performance of the existing structure under postulated loads and does not cause any excessive stress locally.*]*

[*4. For Vogtle Unit 4, three #11 and four #10 vertical reinforcement bars are omitted from elevation 117′-6″ to elevation 135′-3″. This effectively reduces the minimum provided area of steel in this wall segment to 5.55 in^2/ft. The provided minimum reinforcement is reduced for the entire width of the wall segment. However, it does not change the performance of the existing structure under postulated loads and does not cause any excessive stress locally.*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-8 (Sheet 1 of 7)
Design Summary of Spent Fuel Pool Wall Design Loads, Load Combinations, and Comparisons to Acceptance Criteria – Element No. 20477

Load/ Combination	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	Comments
Dead (D)	-15.54	-11.97	-19.88	0.12	0.10	-1.72	-0.36	
Live (L)	0.78	-0.04	-1.18	-0.24	-0.13	-0.01	0.02	
Hydro (F)	30.96	4.98	-3.82	-63.41	-5.35	43.84	-5.16	
Seismic (Es)	82.85	54.22	125.46	58.55	31.63	87.52	15.70	
Thermal (To)	-493.98	-241.71	-55.16	-494.28	-151.42	59.44	-31.16	
Thermal (Ta)	-863.45	-406.83	-143.22	-466.24	-453.18	196.15	-90.75	
LC(1a)	22.92	-9.85	-35.18	-89.01	-7.58	58.96	-7.69	[*1.4D+1.7L+1.4F*
LC(3a)	111.43	49.18	99.06	-30.33	24.10	147.17	8.14	*D+L+F+Es*
LC(3b)	111.43	49.18	-151.86	-147.44	-39.15	-27.87	-23.26	*D+L+F+E's*
LC(3e)	-197.31	-101.89	64.59	-339.26	-70.53	184.32	-11.34	*D+L+F+Es+To*
LC(3f)	-197.31	-101.89	-186.34	-456.36	-133.79	9.28	-42.73	*D+L+F+E's+To*
LC(3m)	112.20	50.42	102.23	-30.11	24.23	147.35	8.15	*0.9D+F+Es*
LC(3n)	112.20	50.42	-148.70	-147.21	-39.03	-27.69	-23.24	*0.9D+F+E's*
LC(3o)	-196.53	-100.65	67.75	-339.03	-70.41	184.50	-11.32	*0.9D+F+Es+To*
LC(3p)	-196.53	-100.65	-183.17	-456.13	-133.67	9.46	-42.72	*0.9D+F+E's+To*
LC(5a)	-523.45	-261.30	-114.39	-979.93	-288.62	164.71	-62.21	*D+L+F+Ta*
LC(5b)	-624.45	-326.96	-150.38	-10.07	8.26	60.09	-7.70	*D+L+F+Ta*
LC(6a)	-541.61	-272.74	-24.91	-921.37	-256.99	252.23	-46.51	*D+L+F+Es+Ta*
LC(6b)	-707.30	-381.18	-275.84	-1038.48	-320.25	77.19	-77.91	*D+L+F+E's+Ta*
LC(7a)	-353.28	-188.68	-67.78	-437.47	-119.25	88.80	-29.14	*1.05D+1.3L+1.05F+1.2To*]*

Notes:
x – direction is horizontal; y – direction is vertical.
See Figure 3H.5-10 for element location.

Plate thickness required for load combinations excluding thermal:	0.24 inches (Maximum)
[*Plate thickness provided:*	*0.50 -0.01 +0.10 inches*]*
Maximum principal stress for the load combinations including thermal:	35.8 ksi
[*Yield stress:*	*65.0 ksi (Minimum)*]*
Maximum stress intensity range for the load combinations including thermal:	74.2 ksi
Allowable stress intensity:	130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-8 (Sheet 2 of 7)
Design Summary of Spent Fuel Pool Wall Design Loads, Load Combinations, and Comparisons to Acceptance Criteria – Element No. 10529

Load/ Combination	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	Comments
Dead (D)	-17.41	-97.25	-17.82	-1.28	-0.78	-0.71	-1.27	
Live (L)	-0.49	-3.11	-0.65	-0.09	-0.29	0.00	0.03	
Hydro (F)	6.13	-6.31	3.61	-1.47	-51.56	11.49	13.08	
Seismic (Es)	75.07	320.60	80.95	15.40	78.74	18.35	26.14	
Thermal (To)	-196.00	-447.61	-134.64	-144.47	-333.40	8.42	-4.77	
Thermal (Ta)	-361.26	-827.41	-251.05	-409.00	-954.60	32.29	-7.21	
LC(1a)	-16.64	-150.28	-21.00	-3.99	-73.77	15.09	16.57	[*1.4D+1.7L+1.4F*
LC(3a)	65.74	211.40	67.54	11.98	5.48	33.73	43.20	*D+L+F+Es*
LC(3b)	65.74	211.40	-94.37	-18.82	-151.99	-2.98	-9.07	*D+L+F+E's*
LC(3e)	-56.76	-68.36	-16.61	-78.31	-202.89	38.99	40.22	*D+L+F+Es+To*
LC(3f)	-56.76	-68.36	-178.52	-109.11	-360.36	2.29	-12.05	*D+L+F+E's+To*
LC(3m)	67.98	224.24	69.97	12.20	5.85	33.80	43.31	*0.9D+F+Es*
LC(3n)	67.98	224.24	-91.94	-18.60	-151.62	-2.90	-8.97	*0.9D+F+E's*
LC(3o)	-54.52	-55.52	-14.18	-78.10	-202.53	39.06	40.33	*0.9D+F+Es+To*
LC(3p)	-54.52	-55.52	-176.09	-108.90	-360.00	2.36	-11.95	*0.9D+F+E's+To*
LC(5a)	-237.57	-623.81	-171.77	-258.46	-649.25	30.96	7.33	*D+L+F+Ta*
LC(5b)	-293.85	-862.10	-215.10	7.87	-109.50	11.32	19.92	*D+L+F+Ta*
LC(6a)	-218.78	-541.51	-134.14	-243.06	-570.52	49.31	33.47	*D+L+F+Es+Ta*
LC(6b)	-368.91	-1182.70	-296.05	-273.86	-727.99	12.60	-18.81	*D+L+F+E's+Ta*
LC(7a)	-159.49	-448.50	-116.74	-111.35	-305.38	17.63	8.86	*1.05D+1.3L+1.05F+1.2To*]*

Notes:
x – direction is horizontal; y – direction is vertical.
See Figure 3H.5-10 for element location.

Plate thickness required for load combinations excluding thermal:	0.26 inches (maximum)
[*Plate thickness provided:*	*0.50 -0.01 +0.10 inches*]*
Maximum principal stress for the load combinations including thermal:	48.2 ksi
[*Yield stress:*	*65.0 ksi (Minimum*]*
Maximum stress intensity range for the load combinations including thermal:	70.1 ksi
Allowable stress intensity:	130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-8 (Sheet 3 of 7)
Design Summary of Spent Fuel Pool Wall Design Loads, Load Combinations, and Comparisons to Acceptance Criteria – Element No. 10544

Load/ Combination	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	Comments
Dead (D)	-23.27	-59.59	-41.62	3.76	-0.81	0.28	-0.71	
Live (L)	-0.82	-2.01	-1.14	0.36	-0.04	0.04	-0.02	
Hydro (F)	-4.24	-1.67	-3.22	28.34	2.08	1.19	-2.90	
Seismic (Es)	75.42	145.64	111.14	44.70	4.30	5.79	4.07	
Thermal (To)	-103.44	-329.56	-196.76	87.54	-91.81	42.74	40.36	
Thermal (Ta)	-188.49	-561.47	-351.05	198.05	-247.04	118.07	126.02	
LC(1a)	-40.05	-89.18	-64.72	45.55	1.71	2.13	-5.10	[*1.4D+1.7L+1.4F*
LC(3a)	45.29	81.70	63.87	88.50	6.37	7.78	-0.73	*D+L+F+Es*
LC(3b)	45.29	81.70	-158.42	-0.91	-2.24	-3.80	-8.87	*D+L+F+E's*
LC(3e)	-19.36	-124.27	-59.11	143.21	-51.01	34.49	24.50	*D+L+F+Es+To*
LC(3f)	-19.36	-124.27	-281.39	53.80	-59.62	22.91	16.36	*D+L+F+E's+To*
LC(3m)	48.45	89.67	69.17	87.76	6.49	7.72	-0.63	*0.9D+F+Es*
LC(3n)	48.45	89.67	-153.12	-1.64	-2.12	-3.87	-8.78	*0.9D+F+E's*
LC(3o)	-16.20	-116.31	-53.81	142.48	-50.89	34.43	24.59	*0.9D+F+Es+To*
LC(3p)	-16.20	-116.31	-276.09	53.07	-59.50	22.84	16.45	*0.9D+F+E's+To*
LC(5a)	-146.24	-414.18	-265.39	156.24	-153.16	75.31	75.13	*D+L+F+Ta*
LC(5b)	-238.80	-668.77	-433.11	76.45	-23.63	2.24	-19.91	*D+L+F+Ta*
LC(6a)	-163.37	-523.13	-321.97	200.94	-148.86	81.10	-15.83	*D+L+F+Es+Ta*
LC(6b)	-314.22	-814.40	-544.25	31.75	-157.47	69.51	-23.98	*D+L+F+E's+Ta*
LC(7a)	-107.64	-314.11	-196.14	99.83	-67.57	33.65	26.45	*1.05D+1.3L+1.05F+1.2To*]*

Notes:
x – direction is horizontal; y – direction is vertical.
See Figure 3H.5-10 for element location.

Plate thickness required for load combinations excluding thermal:	0.16 inches (Maximum)
[*Plate thickness provided:*	*0.50 -0.01 +0.10 inches*]*
Maximum principal stress for the load combinations including thermal:	51.3 ksi
[*Yield stress:*	*65.0 ksi (Minimum)*]*
Maximum stress intensity range for the load combinations including thermal:	97.4 ksi
Allowable stress intensity:	130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-8 (Sheet 4 of 7)
Design Summary of Spent Fuel Pool Wall Design Loads, Load Combinations, and Comparisons to Acceptance Criteria – Element No. 10524

Load/ Combination	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	Comments
Dead (D)	-26.88	-136.36	-4.55	-2.71	8.30	-1.73	-2.55	
Live (L)	-0.57	-3.79	-0.78	-0.28	-0.56	0.01	0.10	
Hydro (F)	9.65	-2.30	3.42	20.28	15.30	2.96	-1.29	
Seismic (Es)	71.56	289.90	91.93	54.83	199.98	7.42	64.34	
Thermal (To)	-318.13	-400.37	145.44	-220.52	-146.44	-5.03	-40.60	
Thermal (Ta)	-622.23	-668.85	285.16	-561.88	-521.80	-9.38	-75.34	
LC(1a)	-25.08	-200.56	-2.90	24.13	32.08	1.74	-5.20	[*1.4D+1.7L+1.4F*
LC(3a)	57.62	146.53	91.38	80.24	229.14	9.85	60.09	*D+L+F+Es*
LC(3b)	57.62	146.53	-92.47	-29.42	-170.83	-5.00	-68.59	*D+L+F+E's*
LC(3e)	-141.21	-103.70	182.28	-57.58	137.61	6.71	34.72	*D+L+F+Es+To*
LC(3f)	-141.21	-103.70	-1.57	-167.25	-262.35	-8.14	-93.96	*D+L+F+E's+To*
LC(3m)	60.88	163.95	92.61	80.79	228.87	10.01	60.24	*0.9D+F+Es*
LC(3n)	60.88	163.95	-91.24	-28.87	-171.09	-4.84	-68.44	*0.9D+F+E's*
LC(3o)	-137.95	-86.28	183.51	-57.03	137.35	6.87	34.87	*0.9D+F+Es+To*
LC(3p)	-137.95	-86.28	-0.34	-166.70	-262.62	-7.98	-93.81	*0.9D+F+E's+To*
LC(5a)	-406.69	-560.48	176.31	-333.88	-303.09	-4.62	-50.82	*D+L+F+Ta*
LC(5b)	-633.03	-744.00	335.67	-9.66	68.94	-92.69	-84.33	*D+L+F+Ta*
LC(6a)	-561.47	-454.11	427.59	-279.05	-103.11	-85.27	-19.99	*D+L+F+Es+Ta*
LC(6b)	-704.58	-1033.90	243.74	-388.71	-503.08	-100.12	-148.67	*D+L+F+E's+Ta*
LC(7a)	-257.42	-450.80	106.88	-147.30	-85.78	-2.46	-34.34	*1.05D+1.3L+1.05F+1.2To*]*

Notes:
x – direction is horizontal; y – direction is vertical.
See Figure 3H.5-10 for element location.

Plate thickness required for load combinations excluding thermal:	0.27 inches (Maximum)
[*Plate thickness provided:*	*0.50 -0.01 +0.10 inches*]*
Maximum principal stress for the load combinations including thermal:	39.6 ksi
[*Yield stress:*	*65.0 ksi (Minimum)*]*
Maximum stress intensity range for the load combinations including thermal:	74.3 ksi
Allowable stress intensity:	130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-8 (Sheet 5 of 7)
Design Summary of Spent Fuel Pool Wall Design Loads, Load Combinations, and Comparisons to Acceptance Criteria – Element No. 20462

Load/ Combination	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	Comments
Dead (D)	-8.17	-30.95	-0.12	-1.17	0.10	-0.16	0.54	
Live (L)	-0.14	-0.57	0.14	-0.22	-0.79	0.00	0.07	
Hydro (F)	5.35	-0.40	-1.33	8.58	86.46	1.24	-22.66	
Seismic (Es)	24.18	33.34	30.34	23.64	161.73	3.85	15.90	
Thermal (To)	-242.25	-76.28	48.77	-202.47	-136.67	0.52	-1.81	
Thermal (Ta)	-542.05	-110.19	87.80	-643.16	-500.95	5.98	3.24	
LC(1a)	-4.18	-44.88	-1.79	10.01	119.85	1.52	-30.86	[*1.4D+1.7L+1.4F*
LC(3a)	23.37	1.25	28.50	34.27	282.09	5.44	-15.22	*D+L+F+Es*
LC(3b)	23.37	1.25	-32.18	-13.01	-41.37	-2.27	-47.03	*D+L+F+E's*
LC(3e)	-128.03	-46.43	58.98	-92.27	196.68	5.76	-16.35	*D+L+F+Es+To*
LC(3f)	-128.03	-46.43	-1.70	-139.55	-126.78	-1.94	-48.16	*D+L+F+E's+To*
LC(3m)	24.32	4.92	28.37	34.60	282.87	5.45	-15.34	*0.9D+F+Es*
LC(3n)	24.32	4.92	-32.31	-12.67	-40.59	-2.25	-47.15	*0.9D+F+E's*
LC(3o)	-127.08	-42.76	58.85	-91.94	197.45	5.78	-16.48	*0.9D+F+Es+To*
LC(3p)	-127.08	-42.76	-1.82	-139.21	-126.00	-1.93	-48.28	*0.9D+F+E's+To*
LC(5a)	-341.74	-100.80	53.57	-394.78	-227.32	4.82	-20.04	*D+L+F+Ta*
LC(5b)	-539.71	-94.05	58.98	41.54	179.68	-5.14	-28.12	*D+L+F+Ta*
LC(6a)	-515.53	-67.46	89.32	-371.14	-65.59	8.68	-12.22	*D+L+F+Es+Ta*
LC(6b)	-563.90	-134.15	28.64	-418.42	-389.05	-8.99	-44.03	*D+L+F+E's+Ta*
LC(7a)	-184.82	-90.88	35.24	-144.35	-12.63	1.53	-24.50	*1.05D+1.3L+1.05F+1.2To*]*

Notes:
x – direction is horizontal; y – direction is vertical.
See Figure 3H.5-10 for element location.

Plate thickness required for load combinations excluding thermal:	0.20 inches (Maximum)
[*Plate thickness provided:*	*0.50 -0.01 +0.10 inches*]*
Maximum principal stress for the load combinations including thermal:	18.0 ksi
[*Yield stress:*	*65.0 ksi (Minimum)*]*
Maximum stress intensity range for the load combinations including thermal:	23.0 ksi
Allowable stress intensity:	130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-8 (Sheet 6 of 7)
Design Summary of Spent Fuel Pool Wall Design Loads, Load Combinations, and Comparisons to Acceptance Criteria – Element No. 21402

Load/ Combination	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	Comments
Dead (D)	-1.52	-18.30	4.68	-0.37	0.72	0.00	-0.10	
Live (L)	-0.21	-0.93	0.42	0.28	-0.02	-0.02	-0.06	
Hydro (F)	4.03	-0.43	-1.50	92.82	12.95	-15.46	3.60	
Seismic (Es)	36.96	21.63	18.85	145.49	29.84	11.74	17.22	
Thermal (To)	-192.49	-155.43	84.14	-251.71	-207.93	11.21	8.20	
Thermal (Ta)	-334.80	-329.90	141.91	-762.50	-659.55	44.32	29.47	
LC(1a)	3.16	-27.81	5.16	129.90	19.09	-21.67	4.80	[*1.4D+1.7L+1.4F*
LC(3a)	40.88	1.79	21.85	275.34	48.66	-9.92	22.10	*D+L+F+Es*
LC(3b)	40.88	1.79	-15.86	-15.63	-11.02	-33.39	-12.34	*D+L+F+E's*
LC(3e)	-79.43	-95.35	74.44	118.02	-81.30	-2.92	27.23	*D+L+F+Es+To*
LC(3f)	-79.43	-95.35	36.73	-172.95	-140.98	-26.39	-7.21	*D+L+F+E's+To*
LC(3m)	41.24	4.55	20.97	275.10	48.61	-9.90	22.17	*0.9D+F+Es*
LC(3n)	41.24	4.55	-16.74	-15.87	-11.07	-33.38	-12.27	*0.9D+F+E's*
LC(3o)	-79.07	-92.59	73.55	117.78	-81.35	-2.90	27.29	*0.9D+F+Es+To*
LC(3p)	-79.07	-92.59	35.85	-173.19	-141.03	-26.37	-7.15	*0.9D+F+E's+To*
LC(5a)	-206.95	-225.85	92.29	-383.84	-398.58	12.22	21.86	*D+L+F+Ta*
LC(5b)	-234.63	-256.17	103.47	-397.15	-399.55	10.60	21.12	*D+L+F+Ta*
LC(6a)	-197.67	-234.54	122.33	-251.67	-369.71	23.96	38.35	*D+L+F+Es+Ta*
LC(6b)	-271.60	-277.80	84.62	-542.64	-429.39	0.49	3.90	*D+L+F+E's+Ta*
LC(7a)	-142.00	-137.45	66.99	-91.35	-141.63	-7.85	9.75	*1.05D+1.3L+1.05F+1.2To*]*

Notes:
x – direction is horizontal; y – direction is vertical.
See Figure 3H.5-10 for element location.

Plate thickness required for load combinations excluding thermal:	0.20 inches (Maximum)
[*Plate thickness provided:*	*0.50 -0.01 +0.10 inches*]*
Maximum principal stress for the load combinations including thermal:	28.2 ksi
[*Yield stress:*	*65.0 ksi (Minimum)*]*
Maximum stress intensity range for the load combinations including thermal:	34.2 ksi
Allowable stress intensity:	130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-8 (Sheet 7 of 7)
Design Summary of Spent Fuel Pool Wall Design Loads, Load Combinations, and Comparisons to Acceptance Criteria – Element No. 21414

Load/ Combination	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	Comments
Dead (D)	0.86	-10.93	-2.70	0.30	-0.02	-0.04	0.03	
Live (L)	0.15	0.06	-0.38	0.00	-0.13	-0.01	0.03	
Hydro (F)	3.53	0.73	-2.83	-24.72	-26.63	-1.07	1.12	
Seismic (Es)	23.63	12.73	32.11	21.80	30.03	2.52	5.47	
Thermal (To)	-66.65	-39.03	45.95	-118.96	-121.48	8.32	7.62	
Thermal (Ta)	-111.54	-58.96	50.88	-364.47	-375.75	24.84	24.99	
LC(1a)	6.38	-14.19	-8.39	-34.20	-37.54	-1.57	1.64	[*1.4D+1.7L+1.4F*
LC(3a)	29.57	2.87	25.06	-12.51	-7.41	0.97	7.08	*D+L+F+Es*
LC(3b)	29.57	2.87	-39.15	-56.11	-67.47	-4.06	-3.86	*D+L+F+E's*
LC(3e)	-12.09	-21.52	53.78	-86.86	-83.33	6.17	11.85	*D+L+F+Es+To*
LC(3f)	-12.09	-21.52	-10.43	-130.46	-143.39	1.14	0.91	*D+L+F+E's+To*
LC(3m)	29.34	3.91	25.72	-12.54	-7.28	0.98	7.06	*0.9D+F+Es*
LC(3n)	29.34	3.91	-38.50	-56.14	-67.33	-4.05	-3.88	*0.9D+F+E's*
LC(3o)	-12.32	-20.49	54.43	-86.89	-83.20	6.18	11.82	*0.9D+F+Es+To*
LC(3p)	-12.32	-20.49	-9.78	-130.49	-143.26	1.15	0.88	*0.9D+F+E's+To*
LC(5a)	-65.19	-47.00	25.89	-252.22	-261.63	14.41	16.78	*D+L+F+Ta*
LC(5b)	-88.36	-71.43	29.84	-36.01	-27.13	3.01	-2.28	*D+L+F+Ta*
LC(6a)	-64.73	-58.70	61.95	-230.42	-231.60	16.92	3.19	*D+L+F+Es+Ta*
LC(6b)	-111.99	-84.16	-2.27	-274.02	-291.66	11.89	-7.75	*D+L+F+E's+Ta*
LC(7a)	-45.20	-39.92	28.16	-114.86	-119.27	5.06	6.95	*1.05D+1.3L+1.05F+1.2To*]*

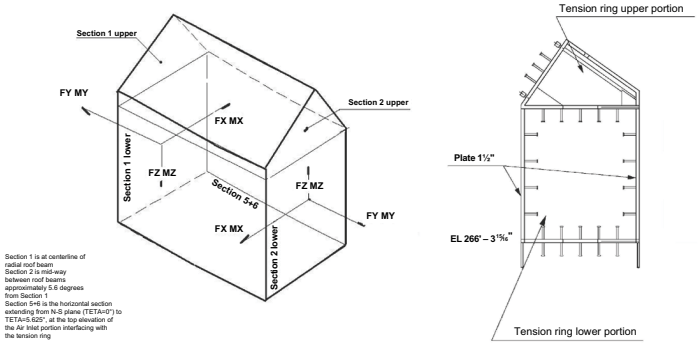
Notes:
x – direction is horizontal; y – direction is vertical.
See Figure 3H.5-10 for element location.

Plate thickness required for load combinations excluding thermal:	0.11 inches (Maximum)
[*Plate thickness provided:*	*0.50 -0.01 +0.10 inches*]*
Maximum principal stress for the load combinations including thermal:	27.2 ksi
[*Yield stress:*	*65.0 ksi (Minimum)*]*
Maximum stress intensity range for the load combinations including thermal:	35.0 ksi
Allowable stress intensity:	130.0 ksi (Minimum)

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-9 (Sheet 1 of 3)
Shield Building Roof Reinforcement Summary
(Tension Ring)

Tension Ring – Axial Force and Bending Verification								
Location		Seismic Maximum Stresses		Maximum Stresses ksi	F_y ksi	Maximum Steel Area Required (in^2/ft)	[*Steel Area Provided*]*	[*Design Limit for Ratio Max Required/ Provided*]*
Section	Angles	Seismic L/C	f_a ksi					
2 lower	5.625°	33	28.11	30.07	50	18.00	[*Liner 1 1/2" = 18 (in^2/ft) (Min)*]*	[*1.00*]*
	84.375°	41	27.59					
1 lower	0°	34	30.07					
	90°	43	29.48					
Tension Ring – Shear Force and Torsion Verification								
Location		Seismic Maximum Stresses		Maximum Stresses ksi	F_y ksi	Maximum Steel Area Required (in^2/ft)	[*Steel Area Provided*]*	[*Design Limit(1) for Ratio Max Required/ Provided*]*
Section	Angles	Seismic L/C	f_v ksi					
2 lower	5.625°	42	4.58	7.27	50	6.54	[*Liner 1 1/2" = 18 (in^2/ft) (Min.)*]*	[*0.36 + 2%*]*
	84.375°	35	4.24					
1 lower	0°	17	7.27					
	90°	9	6.78					



Notes:

1. [*The two percent of the ratio value that may be added to the design limit represents an allowance for minor variances in analysis results.*]*
2. Not used.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-9 (Sheet 2a of 3)
Shield Building Roof Reinforcement Summary
(Air Inlet)

AIS Reinforcement Summary – Horizontal Sections						
Locations (Figure 3H.5-11)		Steel Area (Vertical Direction – Z Local Dir.)				
		Required - Seismic Load Combinations (in^2/ft)		Maximum Required (in^2/ft)	[*Provided*]*	[*Design Limit*(1) *for Ratio Max Required/ Provided*]*
Sections	Angles	Seismic L/C	Values			
5+6	0°-5.625°	32	2.43	5.03	[*Liner 1" = 12 (in^2/ft) (Min.)*]*	[*0.42 + 2%*]*
	84.375°-90°	32	2.31			
7	0°-5.625°	16	4.19			
	84.375°-90°	24	4.27			
9	0°-5.625°	16	5.02			
	84.375°-90°	24	5.03			
11	0°-5.625°	16	3.55	3.57	[*Liner 1" = 12 (in^2/ft) (Min.)*]*	[*0.30 + 2%*]*
	84.375°-90°	24	3.57			

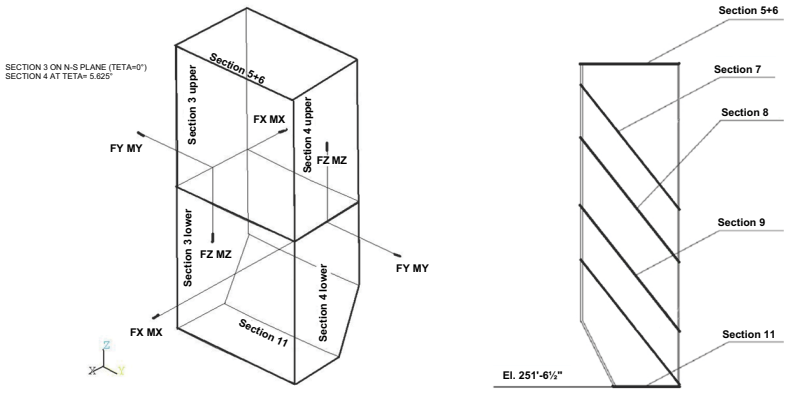
Notes:

1. [*The two percent of the ratio value that may be added to the design limit represents an allowance for minor variances in analysis results.*]*
2. Not used.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-9 (Sheet 2b of 3)
Shield Building Roof Reinforcement Summary
(Air Inlet)

AIS Reinforcement Summary – Vertical Sections						
Locations (Figure 3H.5-11)		**Steel Area (Hoop Direction – Y Local Dir.)**				
		Required - Seismic Load Combinations (in^2/ft)		**Maximum Required (in^2/ft)**	[***Provided***]*	[***Design Limit for Ratio Max Required/ Provided***]*
Sections	**Angles**	**Seismic L/C**	**Values**[3]			
3 Upper	0°	33	11.66	11.91	[*Liner 1" = 12 (in^2/ft) (Min.)*]*	[*0.99*]*
	90°	41	11.00			
3 Lower	0°	33	11.66			
	90°	41	11.00			
4 Upper	5.625°	33	11.91			
	84.375°	41	11.16			
4 Lower	5.625°	33	11.91			
	84.375°	41	11.16			



Notes:
1. Not used.
2. Not used.
3. The values reflect averaged results between the upper and lower sections.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-9 Sheet 2c of 3)
(Shield Building Roof Reinforcement Summary
(Air Inlet)

Out of Plane Shear Reinforcement Summary – AIS							
Locations (Figure 3H.5-11)		Required – Seismic Load Combinations (in^2/ft)			Maximum Required (in^2/ft)	[*Steel Area Provided*]*	[*Design Limit*(1) *for Ratio Max Required/ Provided*]*
Angles	Sections	Seismic L/C	Values	Sum			
0° - 5.625°	Max of Vertical Sections 3 upper - 4 upper	25	0.16	0.16	0.22	[*(3) 3/4" TIE BAR @2.8125° (41.36") (8 1/2" in vertical direction) = 0.50 (in^2/ ft) (Min.)*]*	[*0.68 + 2%*]*
	Circumferential Section 5+6		0.00				
84.375° - 90°	Max of Vertical sections 3 upper - 4 upper	25	0.16	0.16			
	Circumferential Section 5+6		0.00				
0° - 5.625°	Max of Vertical Sections 3 upper – 4 upper	25	0.16	0.16			
	Circumferential Section 7		0.00				
84.375° - 90°	Max of Vertical Sections 3 upper – 4 upper	25	0.16	0.16			
	Circumferential Section 7		0.00				
0° - 5.625°	Max of Vertical Sections 3 lower - 4 lower	18	0.22	0.22			
	Circumferential Section 9		0.00				
84.375° - 90°	Max of Vertical Sections 3 lower - 4 lower	11	0.22	0.22			
	Circumferential Section 9		0.00				
0° - 5.625°	Max of Vertical Sections 3 lower - 4 lower	18	0.22	0.22			
	Circumferential Section 11		0.00				
84.375° - 90°	Max of Vertical Sections 3 lower - 4 lower	11	0.22	0.22			
	Circumferential Section 11		0.00				

Notes:

1. [*The two percent of the ratio value that may be added to the design limit represents an allowance for minor variances in analysis results.*]*
2. Not used.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-9 (Sheet 3 of 3)
Shield Building Roof Reinforcement Summary
(Exterior Wall Of Passive Containment Cooling System Tank)

Wall Segment	Location (Figure 3H.5-11 Sheet 5 of 6)	Reinforcement on Each Face, in^2/ft			Ratio Required/ Provided
		Maximum Required	Provided (Minimum)		
Bottom	Vertical	1.53	1#8@1.125° & 1#11@1.125°	[*2.75*	0.56
	Hoop	1.22	1#9@6"	*2*	0.61
	Shear	0.11	1#4@0.5625°x6"	*0.94*	0.12
Mid-height	Vertical	0.69	1#8@1.125° & 1#11@1.125°	*2.75*	0.25
	Hoop	1.99	1#9@6"	*2*	0.99
Top	Vertical	0.34	1#8@1.125° & 1#11@1.125°	*2.75*	0.12
	Hoop	0.58	1#9@6"	*2*]*	0.29

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-10
Design Summary Of Roof At Elevation 180′-0″, Area 6
(Near Shield Building Interface)

Governing Load Combination (Roof Girder)	
Combination Number	7 – Abnormal Condition
Bending Moment	= 8028 kip-ft
Corresponding Stress	= 27.1 ksi
Allowable Stress	= 53.0 ksi
Shear Force	= 553 kips
Corresponding Stress	= 11.5 ksi
Allowable Stress	= 26.4 ksi
Governing Load Combination (Concrete Slab)	
Parallel to Girders	
Combination Numbers	7 – Abnormal Condition
Reinforcement (Each Face)	
Required	= 2.54 in^2/ft
[*Provided*	*= 2.54 in^2/ft (Minimum)*]*
Perpendicular to Girders	
Combination Numbers	3 – Extreme Environmental Condition
Reinforcement (Each Face)	
Required	= 2.37 in^2/ft
[*Provided*	*= 3.12 in^2/ft (Minimum)*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-11
Design Summary Of Floor At Elevation 135′-3″ Area 1 (Between Column Lines M And P)

Governing Load Combination (Steel Beam)	
Load Combination	3 – Extreme Environmental Condition Downward Seismic
Bending Moment	=(-) 41.1 kips-ft
Corresponding Stress	= 13.9 ksi
Allowable Stress	= 38.0 ksi
Shear Force	= 22.1 kips
Corresponding Stress	= 6.2 ksi
Allowable Stress	= 20.1 ksi
Governing Load Combination (Concrete Slab)	
Parallel to the Beams	
Load Combination	6 – Abnormal Condition
Bending Moment	=(-) 7.6 kips-ft/ft
In-plane Shear	= 31.0 kips (per foot width of the slab)
Reinforcement (Each Face)	
Required	= 0.43 in^2/ft
[*Provided*	*= 0.44 in^2/ft (Min.)*]*
Perpendicular to the Beams	
Combination Number	6 – Abnormal Condition
Bending Moment	=(-) 1.42 kips-ft (per foot width of the slab)
Reinforcement (Each Face)	
Required	= 0.43 in^2/ft
[*Provided*	*= 0.60 in^2/ft (Min.)*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-12
Design Summary Of Floor At Elevation 135′-3″
(Operations Work Area (Previously Known As 'Tagging Room') Ceiling))

Design of Precast Concrete Panels	
Governing Load Combination	Construction
Design Bending Moment (Midspan)	= 12.07 kip-ft/ft
Bottom Reinforcement (E/W Direction)	
Required(1)	= 0.49 in^2/ft
[*Provided*	*= 0.79 in^2/ft (Min.)*]*
Top Reinforcement (E/W Direction)	
Required(1)	= (Minimum required by Code)
[*Provided*	*= 0.20 in^2/ft (Min.)*]*
Top and Bottom Reinforcement (N/S Direction)	
Required(1)	= (Minimum required by Code)
[*Provided*	*= 0.20 in^2/ft (Min.)*]*
Design of 24-inch-Thick Slab	
Governing Load Combination	Abnormal Condition
Design Bending Moment (E/W Direction) Midspan	= 16.23 kips-ft/ft
Design In-plane Shear	= 30.19 kips/ft
Design In-plane Tension	= 37.1 kips/ft
Bottom Reinforcement (E/W Direction)	
Required(1)	= 0.71 in^2/ft
[*Provided*	*= 0.79 in^2/ft (Min.)*]*
Design Bending Moment (E/W Direction) at Support	= 17.75 kips-ft/ft
Design In-plane Shear	= 30.19 kips/ft
Design In-plane Tension	= 37.1 kips/ft
Top Reinforcement (E/W Direction)	
Required(1)	= 0.73 in^2/ft
[*Provided*	*= 1.00 in^2/ft (Min.)*]*
Design Bending Moment (N/S Direction)	= 21.55 kips-ft/ft
Design In-plane Shear	= 30.19 kips/ft
Design In-plane Tension	= 24.65 kip/ ft
Top and Bottom Reinforcement (N/S Direction)	
Required(1)	= 0.65 in^2/ft
[*Provided*	*= 0.79 in^2/ft (Min.)*]*

Note:

1. Thermal loads have been considered in the design of critical sections. The required reinforcement values shown do not include the load case where seismic and thermal loads are numerically combined as the thermal loads were assessed to be insignificant. When the seismic and thermal loads are numerically combined, the value of required reinforcement may increase; however, in all cases the required reinforcement is less than the provided reinforcement and thus the design of the critical section reinforcement is acceptable.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-13
Design Summary Of Floor At Elevation 135′-3″ Area 2 (Main Control Room Ceiling)

The design of the bottom plate with fins is governed by the construction (wet concrete) load.
For the composite floor, the design forces used for the evaluation of a 9-inch-wide strip of the slab are as follows: Maximum bending moment = +35.0 (-47.0) kips-ft Maximum shear force = 22.3 kips
The key structural capacities of a 9-inch wide strip of the slab are as follows: (1) • [*The actual area of the tension steel (bottom plate and fins) is 9.0 in^2 (Min.), except in the area of penetrations, openings, or other obstructions,*]* which provides a positive bending moment capacity of 518.5 kips-ft. • The minimum provided area of tension steel (top reinforcement) is 0.59 in^2, except in the area of penetrations, openings, or other obstructions, which provides a negative bending moment capacity of 56 kips-ft. • [*The design shear strength, not reduced for in-plane axial forces, is 23.22 kips.* • *The shear studs have a maximum design spacing of 9 inches c/c, in both directions except in the area of penetrations, openings, or other obstructions.*]*

Note:

1. Thermal loads have been considered in the design of critical sections. The required reinforcement values shown do not include the load case where seismic and normal thermal loads are numerically combined as the normal thermal loads were assessed to be insignificant. When the seismic and normal thermal loads are numerically combined, the value of required reinforcement may increase; however, in all cases the required reinforcement is less than the provided reinforcement and thus the design of the critical section reinforcement is acceptable.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-14 (Sheet 1 of 3)
Design Summary of Enhanced Shield Building Cylindrical Wall Load Combinations, and Comparison to Acceptance Criteria Elevation 180 Feet Near Fuel Handling Building Roof

Load/Combination	TX kip/ft	TY kip/ft	TXY kip/ft	MX k-ft/ft	MY k-ft/ft	MXY k-ft/ft	NX kip/ft	NY kip/ft	Comments
Dead	-7	-118	15	-25	-18	4	-6	-5	
Live	1	-1	1	0	0	0	0	0	
Seismic	157	390	163	301	211	35	71	33	
1	-8	-168	22	-35	-24	5	-8	-7	1.4 D + 1.7 L
2	152	270	179	276	194	38	66	28	D + L + Es
3	152	270	-148	-326	-228	-31	-77	-38	D + L + E's
4	-163	-509	-148	-326	-228	-31	-77	-38	D + L - Es
5	-163	-509	179	276	194	38	66	28	D + L - E's
6	152	283	177	278	195	38	66	28	0.9 D + Es
7	152	283	-150	-324	-227	-31	-77	-38	0.9 D + E's
35(2)	205	399	233	449	303	69	105	31	0.9 D + E's + αTo(W1)
37(2)	221	387	238	460	311	68	108	31	0.9 D + E's + αTo(W2)
x-direction is horizontal; y-direction is vertical.									
Element number:						12164			
[*Plate thickness required for load combinations excluding thermal:*						*0.50 inches + 2%(1)*]*			
[*Plate thickness required for load combinations including thermal:*						*0.65 inches + 2%(1)*]*			
[*Plate thickness provided:*						*0.75 inches*]*(3)			
[*Shear reinforcement required for load combinations excluding thermal:*						*0.72 in^2/ft^2 + 2%(1)*]*			
[*Shear reinforcement required for load combinations including thermal:*						*1.00 in^2/ft^2 + 2%(1)*]*			
Shear reinforcement provided:						See [*APP-GW-GLR-602, Section 4.*]*			

Notes:

1. [*The Tier 2* designation for "Plate thickness required" requires NRC approval if this value is exceeded as a result of design changes or detail design adjustments identified during preparation of fabrication or construction drawings or instructions.*]*
2. Load cases 35 and 37 are the two governing load combinations for element 12164 that include thermal and seismic loads combined numerically. W1 designates the winter conditions with the spent fuel pool at the normal operating temperature limit. W2 designates the winter conditions with the spent fuel pool and fuel transfer canal at the normal operating temperature limit. Es is SRSS (member forces are positive) of the SSE loads. E's is Es with all member forces except axial forces (TX, TY) reversed to negative.
3. The 0.75-inch plate thickness is the nominal plate size for the shield building away from connections, attachments, and other local loads. The plate may be thicker (up to 1.0-inch nominal thickness) in the area around these local loads.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-14 (Sheet 2 of 3)
Design Summary of Enhanced Shield Building Load Combinations, and Comparison to Acceptance Criteria Elevation 175 Feet Near Intersection With Wall 7.3

Load/Combination	TX kip/ft	TY kip/ft	TXY kip/ft	MX k-ft/ft	MY k-ft/ft	MXY k-ft/ft	NX kip/ft	NY kip/ft	Comments
Dead	-7	-106	12	-6	5	1	0	2	
Live	0	-1	0	0	0	0	0	0	
Seismic	34	327	178	38	25	13	2	8	
1	-9	-150	17	-9	7	1	0	3	1.4 D + 1.7 L
2	28	220	190	32	30	14	2	10	D + L + Es
3	28	220	-166	-45	-21	-12	-3	-6	D + L + E's
4	-40	-434	-166	-45	-21	-12	-3	-6	D + L - Es
5	-40	-434	190	32	30	14	2	10	D + L - E's
6	28	232	189	33	30	14	2	10	0.9 D + Es
7	28	232	-167	-44	-21	-12	-3	-7	0.9 D + E's
19(2)	75	251	168	-39	-107	-20	-2	-5	D + L + E's + αTo(W1)
37(2)	75	251	168	-39	-107	-20	-2	-5	0.9 D + E's + αTo(W2)
x-direction is horizontal; y-direction is vertical.									
Element number:						11514			
[*Plate thickness required for load combinations excluding thermal:*						*0.45 inches + 2%(1)*]*			
[*Plate thickness required for load combinations including thermal:*						*0.50 inches + 2%(1)*]*			
[*Plate thickness provided:*						*0.75 inches*]*(3)			
[*Shear reinforcement required for load combinations excluding thermal:*						*0.09 in^2/ft^2 + 2%(1)*]*			
[*Shear reinforcement required for load combinations including thermal:*						*0.12 in^2/ft^2 + 2%(1)*]*			
Shear reinforcement provided:						See [*APP-GW-GLR-602, Section 4.*]*			

Notes:

1. [*The Tier 2* designation for "Plate thickness required" requires NRC approval if this value is exceeded as a result of design changes or detail design adjustments identified during preparation of fabrication or construction drawings or instructions.*]*
2. Load cases 19 and 37 are the two governing load combinations for element 11514 that include thermal and seismic loads combined numerically. W1 designates the winter conditions with the spent fuel pool at the normal operating temperature limit. W2 designates the winter conditions with the spent fuel pool and fuel transfer canal at the normal operating temperature limit. Es is SRSS (member forces are positive) of the SSE loads. E's is Es with all member forces except axial forces (TX, TY) reversed to negative.
3. The 0.75-inch plate thickness is the nominal plate size for the shield building away from connections, attachments, and other local loads. The plate may be thicker (up to 1.0-inch nominal thickness) in the area around these local loads.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-14 (Sheet 3 of 3)
Design Summary of Enhanced Shield Building Load Combinations, and Comparison to Acceptance Criteria Elevation Grade on West Side

Load/Combination	TX kip/ft	TY kip/ft	TXY kip/ft	MX k-ft/ft	MY k-ft/ft	MXY k-ft/ft	NX kip/ft	NY kip/ft	Comments
Dead	-4	-129	0	2	16	0	0	-2	
Live	0	1	0	0	0	0	0	0	
Seismic	80	489	234	2	20	18	4	8	
1	-5	-179	0	3	23	0	0	-2	1.4 D + 1.7 L
2	77	362	234	5	36	19	4	7	D + L + Es
3	77	362	-234	0	-4	-18	-4	-10	D + L + E's
4	-84	-617	-234	0	-4	-18	-4	-10	D + L - Es
5	-84	-617	234	5	36	19	4	7	D + L - E's
6	77	374	234	5	34	19	4	7	0.9 D + Es
7	77	374	-235	0	-5	-18	-4	-10	0.9 D + E's
23(2)	202	377	-240	113	151	-18	-4	-32	D + L + E's + αTo(W1)
41(2)	203	393	-240	112	149	-17	-4	-32	0.9 D + E's + αTo(W2)
x-direction is horizontal; y-direction is vertical.									
Element number:						23752			
[*Plate thickness required for load combinations excluding thermal:*						*0.65 inches + 2%(1)*]*			
[*Plate thickness required for load combinations including thermal:*						*0.66 inches + 2%(1)*]*			
[*Plate thickness provided:*						*0.75 inches*]*(3)			
[*Shear reinforcement required for load combinations excluding thermal:*						*0.08 in^2/ft^2 + 2%(1)*]*			
[*Shear reinforcement required for load combinations including thermal:*						*0.26 in^2/ft^2 + 2%(1)*]*			
Shear reinforcement provided:						See [*APP-GW-GLR-602, Section 4.*]*			

Notes:

1. [*The Tier 2* designation for "Plate thickness required" requires NRC approval if this value is exceeded as a result of design changes or detail design adjustments identified during preparation of fabrication or construction drawings or instructions.*]*
2. Load cases 23 and 41 are the two governing load combinations for element 23752 that include thermal and seismic loads combined numerically. W1 designates the winter conditions with the spent fuel pool at the normal operating temperature limit. W2 designates the winter conditions with the spent fuel pool and fuel transfer canal at the normal operating temperature limit. Es is SRSS (member forces are positive) of the SSE loads. E's is Es with all member forces except axial forces (TX, TY) reversed to negative.
3. The 0.75-inch plate thickness is the nominal plate size for the shield building away from connections, attachments, and other local loads. The plate may be thicker (up to 1.0-inch nominal thickness) in the area around these local loads.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 3H.5-15
Shield Building Roof Reinforcement Ratio of Code Required Versus Provided

Critical Sections	Stress Component	Required in^2/ft	Provided (Minimum) in^2/ft	Reinforcement Ratio
[*Conical Roof Beams*]* (1)	Axial + Bending	-	[*Radial Beams W36 X 395*(2)]*	1.65
	Shear	-		3.85
[*Conical Roof Near Tension Ring*]*	Radial	1.81	[*2.34*]*	1.29
	Hoop	4.01	[4.68]*	1.16
[*Knuckle Region*]*	Vertical	1.53	[*2.75*]*	1.80
	Radial	3.48(3)	[*3.55*]*	1.02
	Hoop	2.67	[*3.12*]*	1.16
[*Compression Ring*]*	Vertical	1.09	[*2.40*]*	2.20
	Radial	2.08	[*3.56*]*	1.71
	Hoop	2.50	[*3.12*]*	1.25

Note:

1. Roof beams are not considered as reinforcement for the reinforced concrete roof. Ratio for conical roof beams is based on demand and allowable stresses in psi.
2. Built-up plate girders can be substituted for rolled shape. The section dimensions of the built-up plate girders are specified in Figure 3H.5-11 Sheet 1.
3. The value reflects averaged result between different angles of the stress line.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

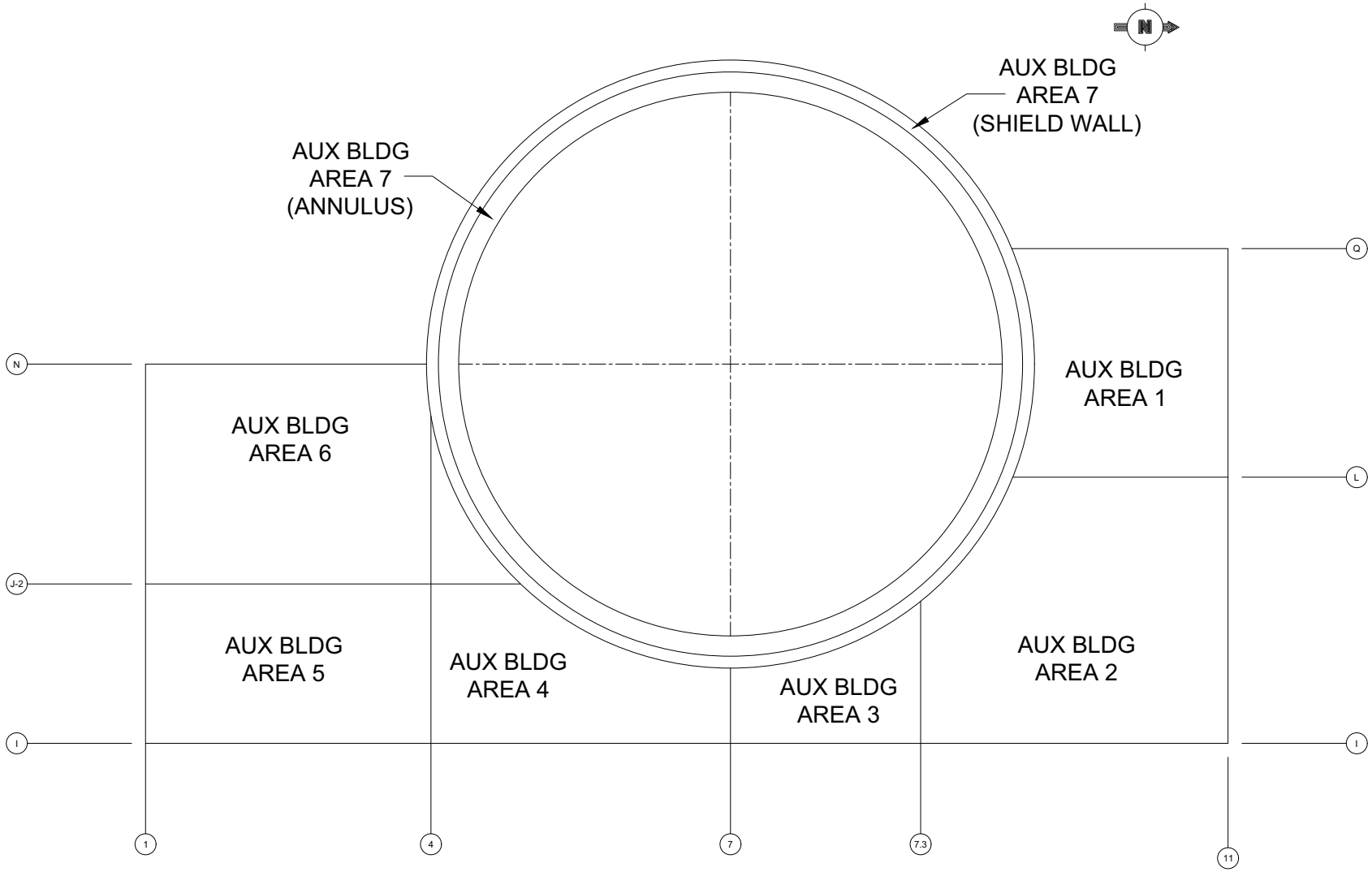


Figure 3H.2-1
[*General Layout of Auxiliary Building*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

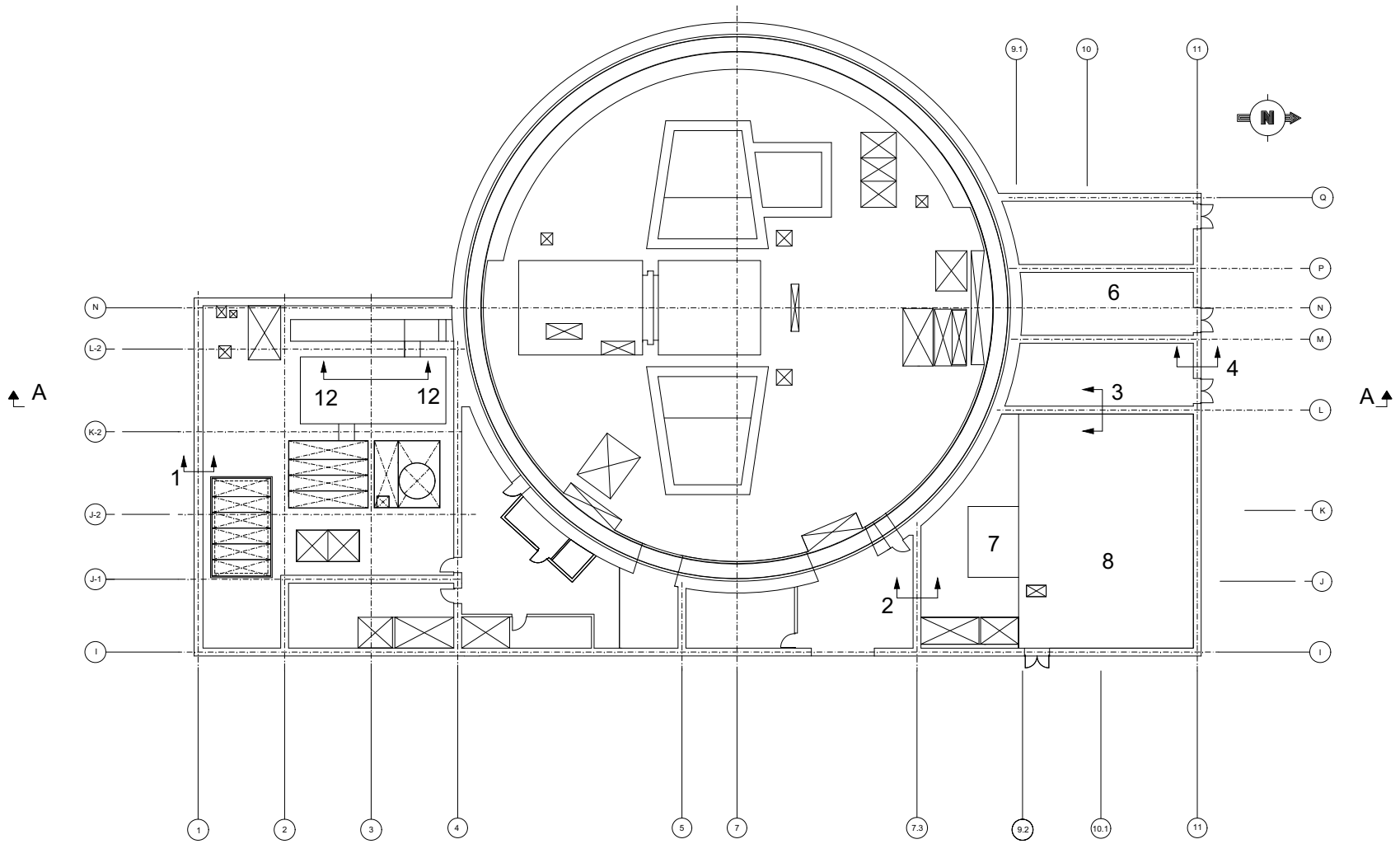


Figure 3H.5-1 (Sheet 1 of 3)
[*Nuclear Island Critical Sections Plan at El. 135'-3"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

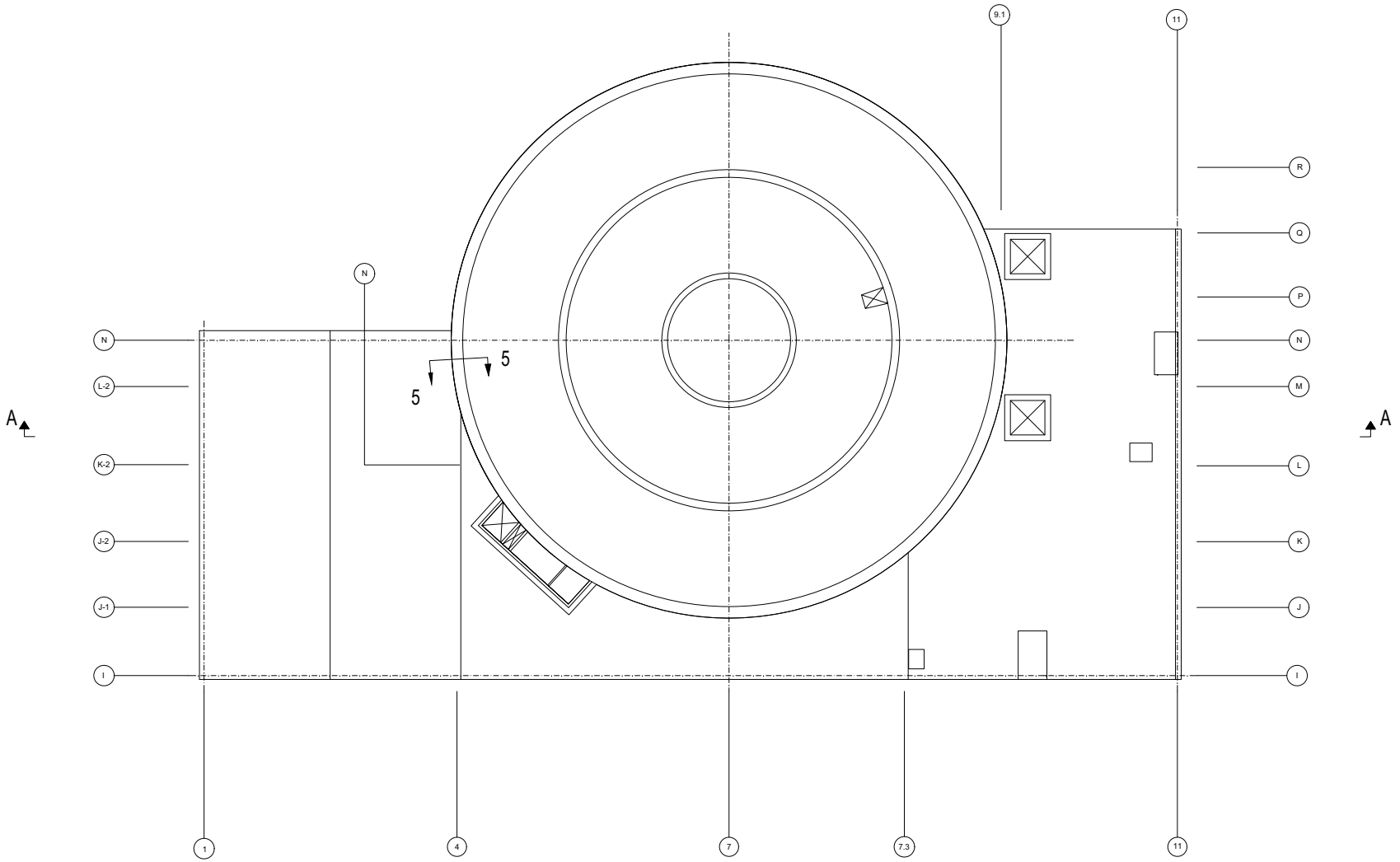


Figure 3H.5-1 (Sheet 2 of 3)
[*Nuclear Island Critical Sections Plan at El. 180'-0"*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3H.5-1 (Sheet 3 of 3)
[*Nuclear Island Critical Sections Section A-A*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

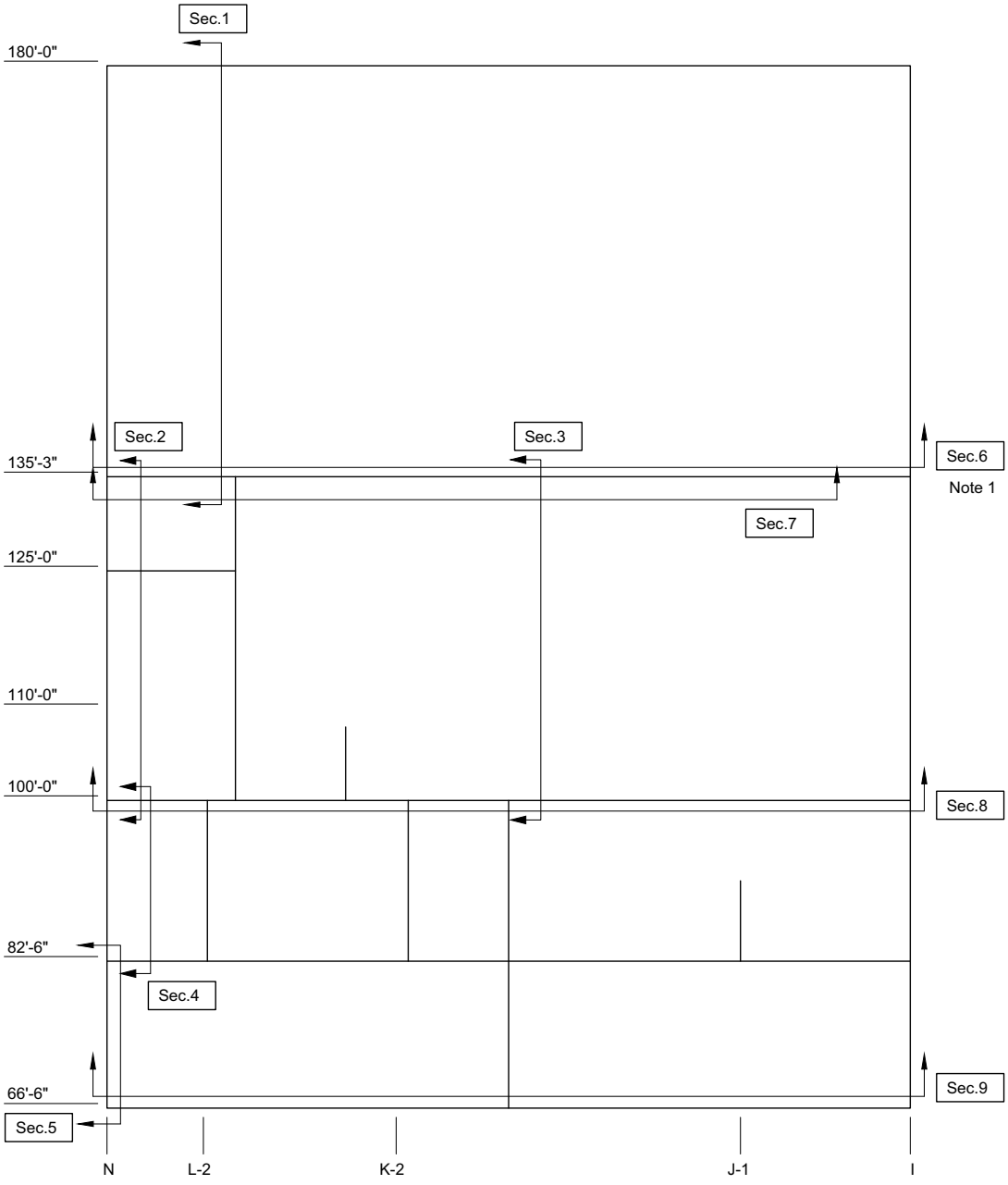


Figure 3H.5-2 (Sheet 1 of 3)
[*Wall on Column Line 1*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

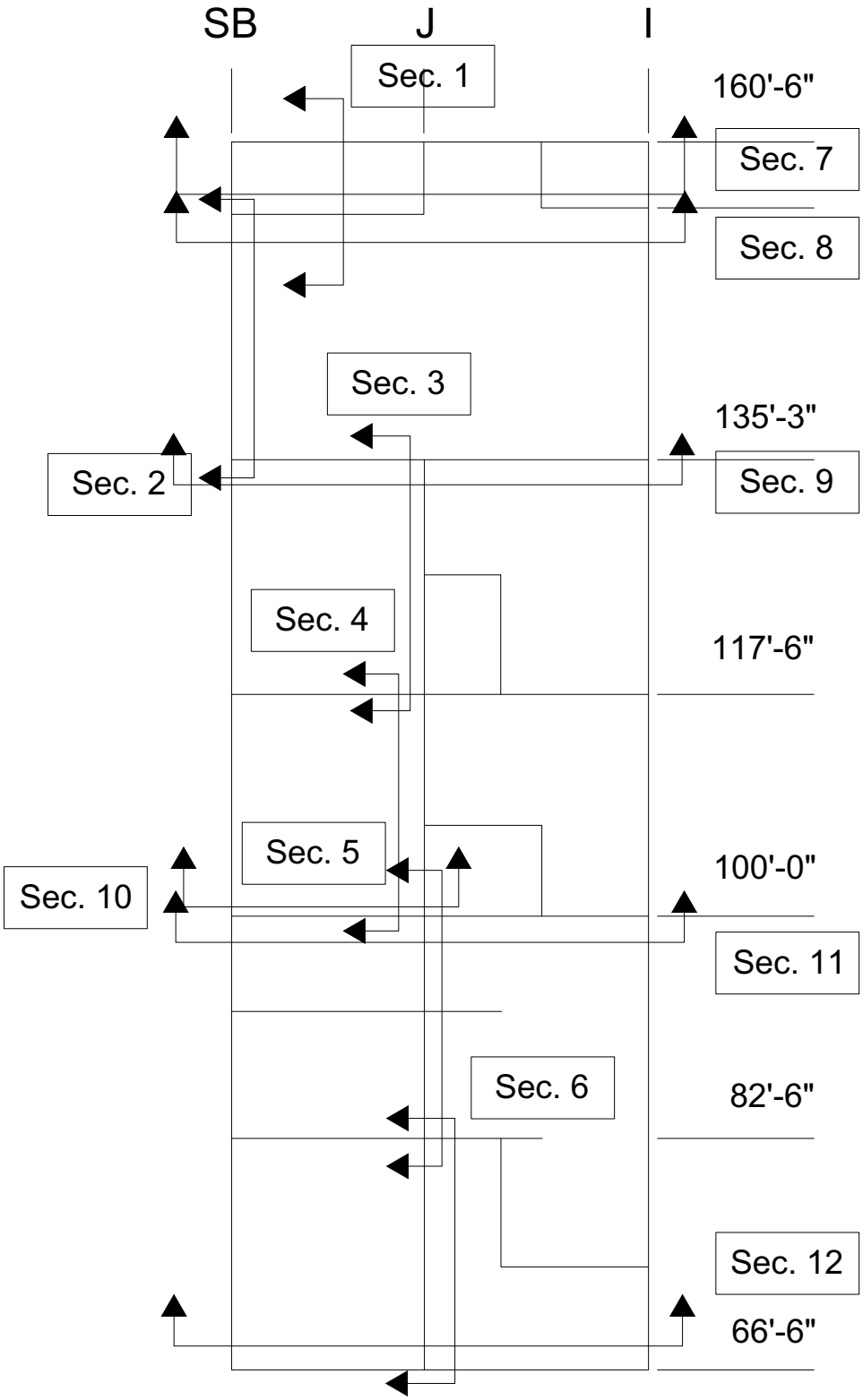


Figure 3H.5-2 (Sheet 2 of 3)
[*Wall on Column Line 7.3*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

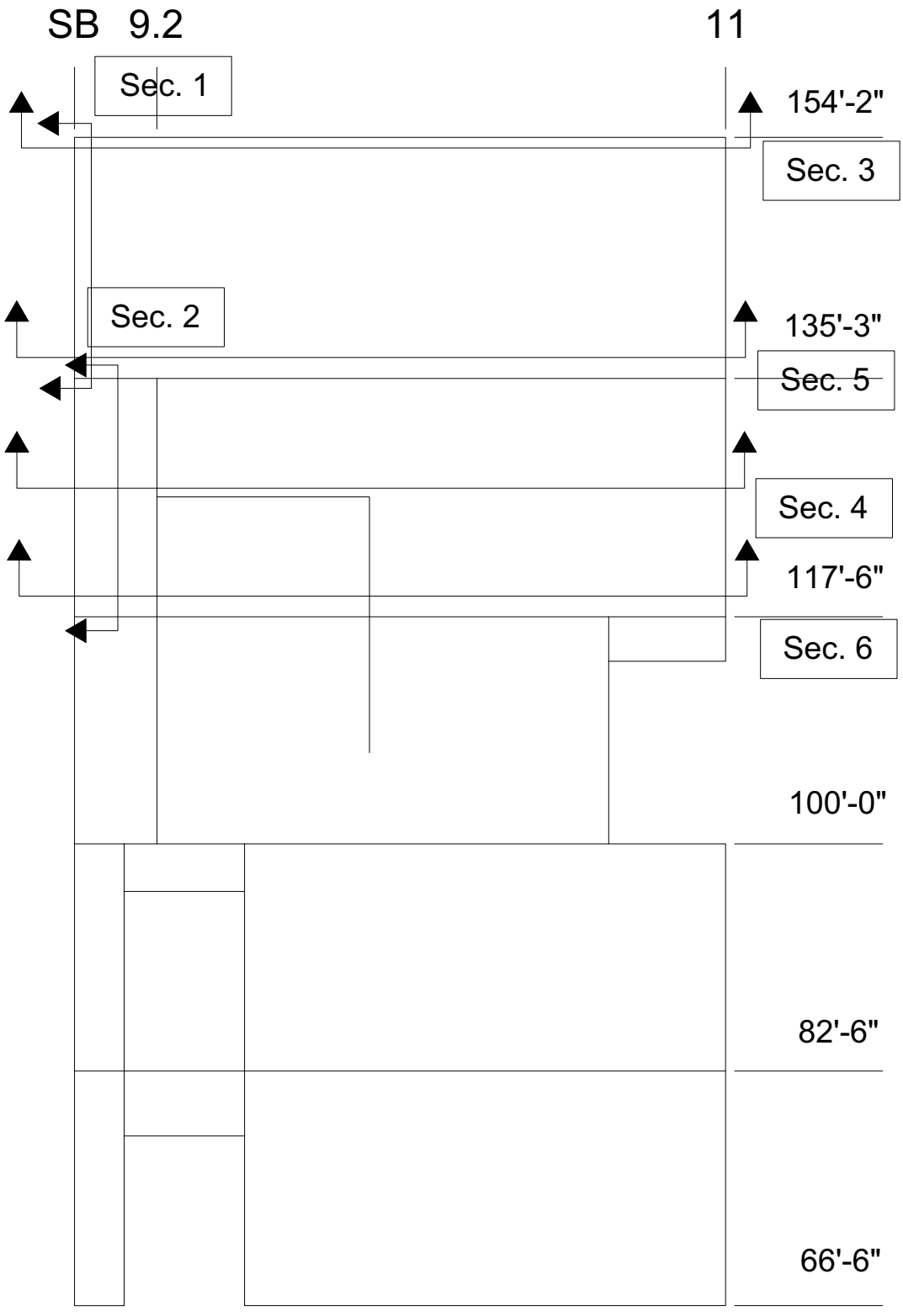
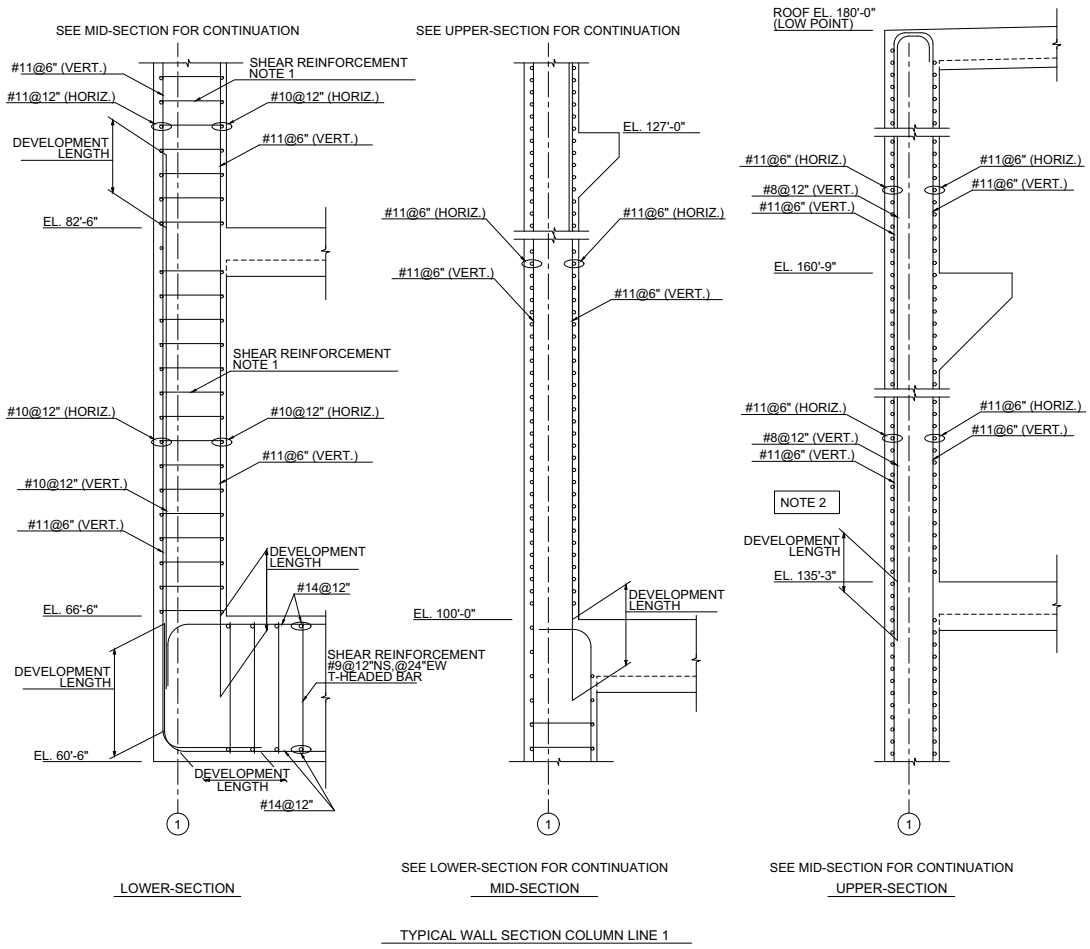


Figure 3H.5-2 (Sheet 3 of 3)
[*Wall on Column Line L*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

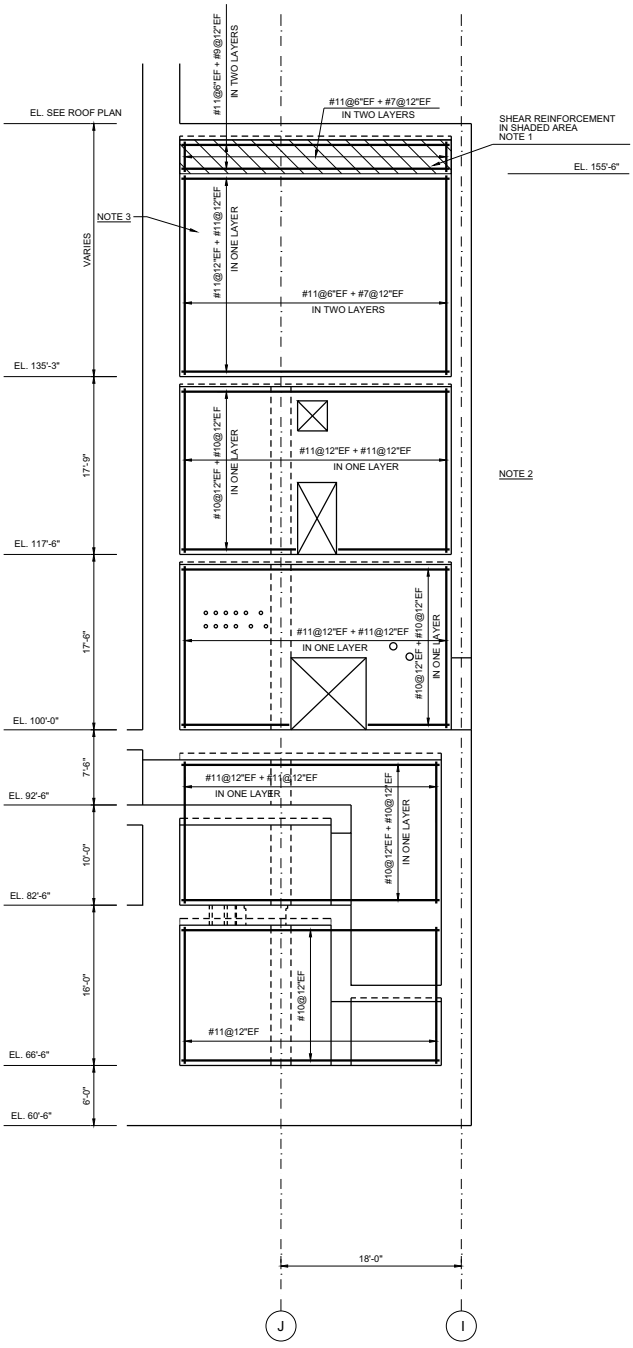


NOTE 1:
REFER TO SUBSECTION 3.8.4.4.1 FOR THE REQUIREMENTS FOR SHEAR REINFORCEMENT AND TABLE 3H.5-3 FOR SHEAR REINFORCEMENT PROVIDED.

NOTE 2:
FOR VOGTLE UNIT 3, THE DEVELOPMENT LENGTH FOR THE #8@12" VERTICAL REINFORCEMENT BARS IS SUCH THAT THE BARS ARE FULLY DEVELOPED AT ELEVATION 137'-0". SEE TABLE 3H.5-3 FOR ADDITIONAL DETAILS.

Figure 3H.5-3
[*Typical Reinforcement in Wall on Column Line 1*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



WALL 7.3

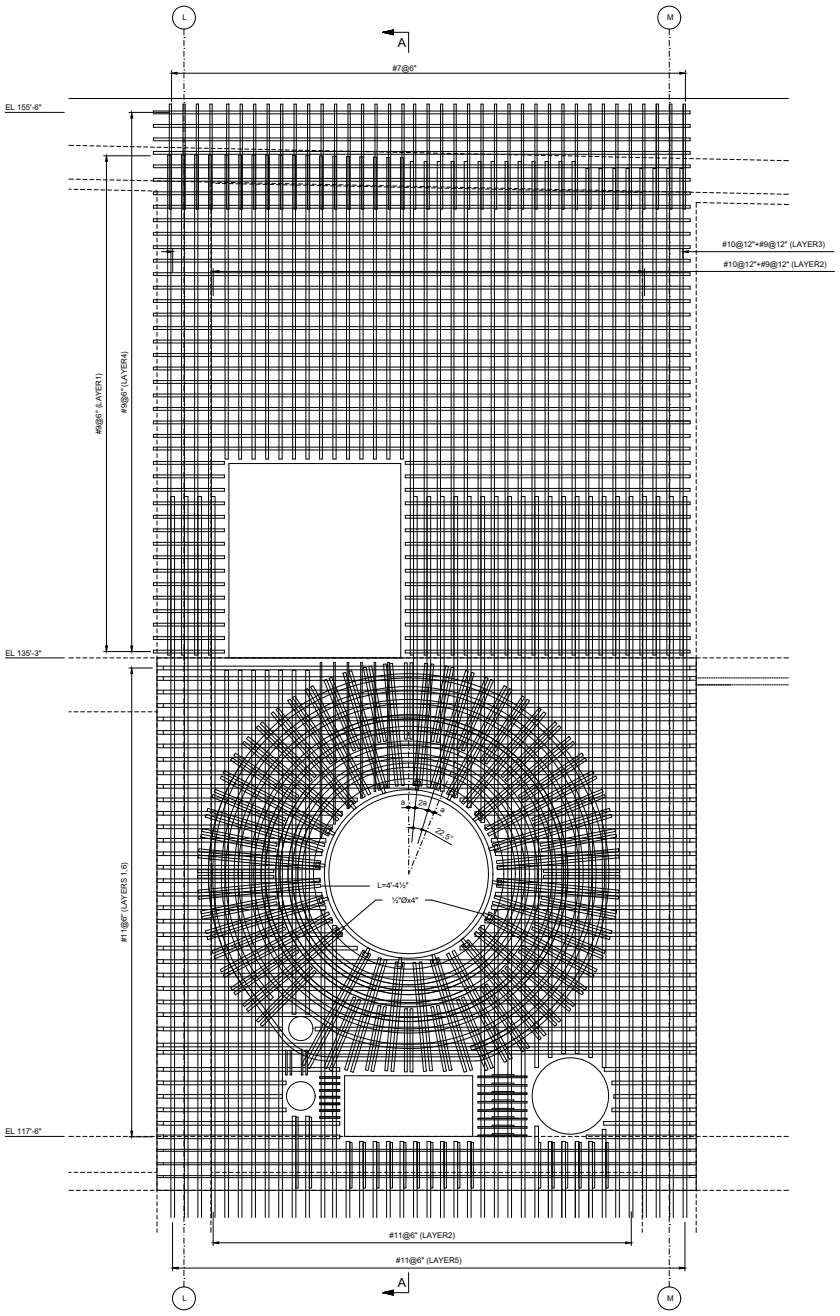
NOTE 1:
REFER TO SUBSECTION 3.8.4.4.1 FOR THE REQUIREMENTS FOR SHEAR REINFORCEMENT AND TABLE 3H.5-5 FOR SHEAR REINFORCEMENT PROVIDED.

NOTE 2:
FOR VOGTLE UNIT 4 TWO HORIZONTAL REINFORCEMENT BARS ARE TERMINATED 2'-0" FROM THE SHIELD BUILDING VERTICAL CONSTRUCTION JOINT. THESE BARS, ONE #10 ON EACH FACE OF THE WALL, ARE LOCATED DIRECTLY BELOW ELEVATION 135'-3". SEE TABLE 3H.5-5 FOR ADDITIONAL DETAILS.

NOTE 3:
FOR VOGTLE UNIT 4, THE HORIZONTAL REINFORCEMENT BETWEEN EL.135'-3" AND EL. 155'-6" TAKES CREDIT FOR ONE #9 BAR (EF) DEVELOPED IN THE SECOND LAYER AT 154'-9" IN PLACE OF ONE UNDEVELOPED #11 REINFORCEMENT BAR (EF) IN THE FIRST LAYER.

Figure 3H.5-4
[*Typical Reinforcement in Wall 7.3*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



NOTES:

1. DETAIL SHOWN IS SPECIFIC TO THE WALL BETWEEN COLUMN LINE L AND COLUMN LINE M. REFER TO SUBSECTION 3H.5.1.4 AND OTHER NOTES FOR ADDITIONAL INFORMATION ABOUT DESIGN DETAILS FOR THE OTHER WALL SECTION.
2. LAYER 1, 2, 5 AND 6 REINFORCEMENT TERMINATING WITHIN THE EXTENT OF THE RADIAL AND CIRCUMFERENTIAL REINFORCEMENT AROUND THE PENETRATION IS DEVELOPED USING STANDARD HOOKS OR HEADED REINFORCEMENT (NOT SHOWN). LAYER 3 AND 4 REINFORCEMENT TERMINATING WITHIN THE 4'-0" THICK SECTION IS DEVELOPED WITH EITHER A FULL STRAIGHT DEVELOPMENT ACCORDING TO CHAPTER 12 AND 21 OF ACI 349, OR A FULL STRAIGHT BAR DEVELOPMENT ACCORDING TO CHAPTER 12 OF ACI 349 WITH ADDITIONAL HEADED ANCHORAGE.
3. REFER TO SUBSECTION 3.8.4.4.1 FOR THE REQUIREMENTS FOR DEVELOPMENT OF HEADED REINFORCEMENT.
4. THE OTHER WALL SECTION FROM COLUMN LINE P TO Q CONTAINING A MAIN STEAM LINE PENETRATION IS ON THE CORNER OF THE AUXILIARY BUILDING, NOT DETAILED IN THIS FIGURE, AND THE DETAILING AND DEVELOPMENT OF THE REINFORCEMENT VARIES CONSISTENT WITH ACI 349 REQUIREMENTS FOR AN ADJACENT WALL AT A CORNER.
5. SOME DETAILING ASSOCIATED WITH REINFORCEMENT SPLICES AND DEVELOPMENT IS NOT PRESENTED IN THE FIGURE. THE DESIGN OF THIS DETAILING CONFORMS TO THE REQUIREMENTS OF ACI 349.
6. THE CRITICAL SECTION BOUNDARIES ARE DEFINED IN SUBSECTION 3H.5.1.4.
7. FOR CLARITY, NOT ALL REINFORCING BARS PROVIDED FOR THE PURPOSE OF CRACK CONTROL ARE DEPICTED IN THIS FIGURE. THE NUMBER, SIZE, AND PLACEMENT OF REINFORCING BARS FOR CRACK CONTROL MAY DEVIATE FROM THAT DEPICTED IN THIS FIGURE AS NEEDED TO FACILITATE CONSTRUCTION. PLACEMENT OF REINFORCING BARS FOR CRACK CONTROL SHALL BE IN ACCORDANCE WITH ACI 349-01.
8. FOR CLARITY, OUT-OF-PLANE SHEAR REINFORCEMENT IS NOT DEPICTED IN THIS FIGURE. OUT-OF-PLANE SHEAR REINFORCEMENT SHALL BE IN ACCORDANCE WITH ACI 349-01.

Figure 3H.5-5 (Sheet 1 of 3)
[*Concrete Reinforcement in Wall 11*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

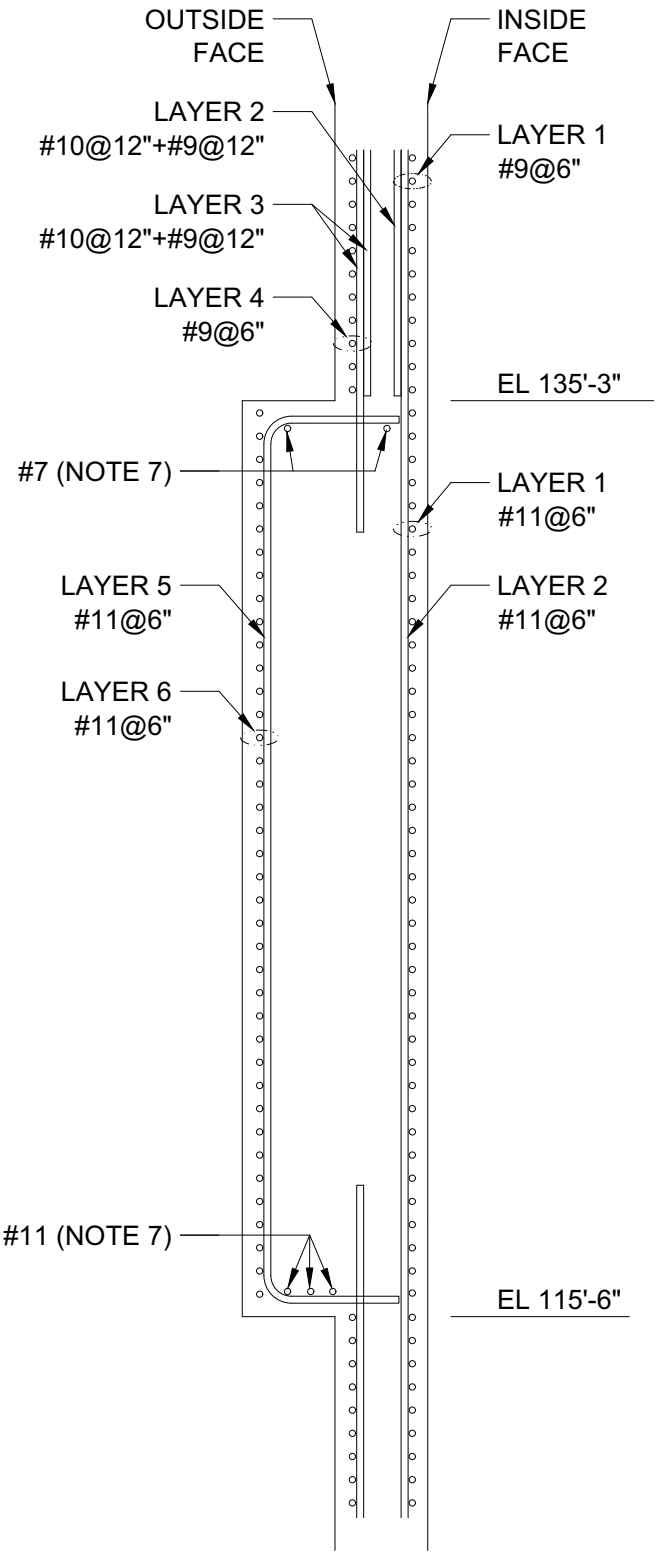


Figure 3H.5-5 (Sheet 2 of 3)
[*Concrete Reinforcement Layers in Wall 11 (Looking East)*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

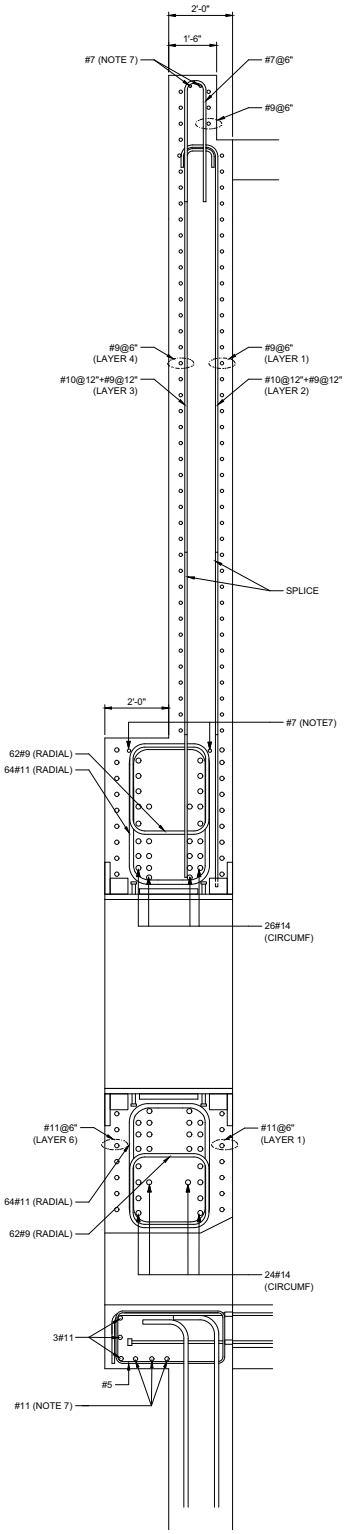
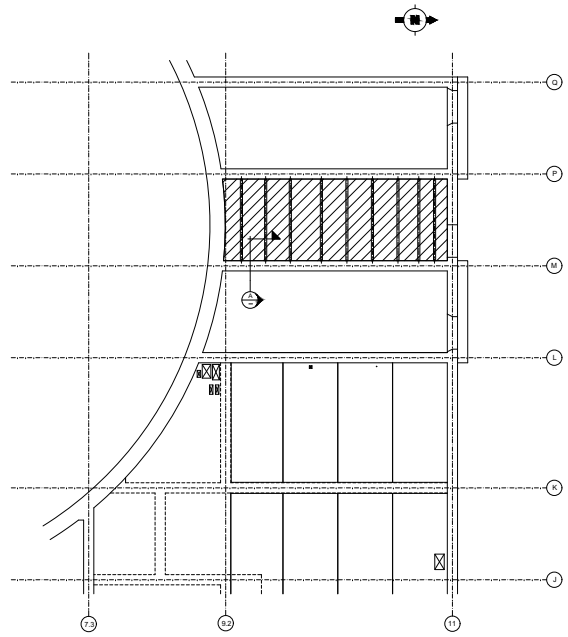
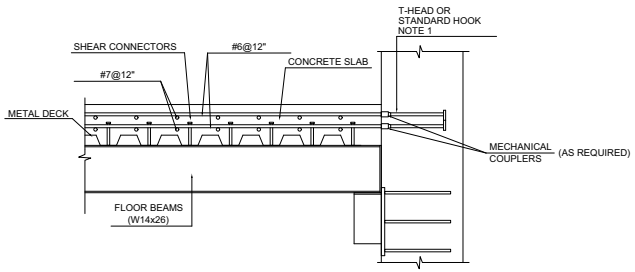


Figure 3H.5-5 (Sheet 3 of 3)
[*Wall 11 at Main Steamline Anchor Section A-A*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



PLAN VIEW
NOTES 1, 3, 6



SECTION A-A
NOTES 1,2,3,4,5,6, & 7

NOTES:

1. DETAIL SHOWN IS SPECIFIC TO THE COMPOSITE FLOOR AT EL. 135'-3" AT INTERSECTION WITH WALL M. REFER TO SUBSECTION 3H.5.2 AND OTHER NOTES FOR ADDITIONAL INFORMATION ABOUT DESIGN DETAILS FOR OTHER FLOOR SECTIONS.
2. REFER TO SUBSECTION 3.8.4.4.1 FOR THE REQUIREMENTS FOR DEVELOPMENT OF HEADED REINFORCEMENT.
3. FLOOR BEAM SIZE AND SPACING ARE DESIGNED BASED ON FLOOR LOAD AND GEOMETRY TO SATISFY AISC N690 REQUIREMENTS. THE BEAM SIZES USED ARE PREDOMINATELY W14x26 AND W14x48. THE RANGE OF BEAM SIZES USED IN OTHER LOCATIONS IS FROM W10 TO W44. THE SPACING BETWEEN THE BEAMS IS PREDOMINATELY IN A RANGE OF 5 TO 6 FEET.
4. THE REINFORCEMENT SHOWN IS FOR LOCATIONS AWAY FROM OPENINGS, PENETRATIONS, EMBEDMENTS, AND OTHER OBSTRUCTIONS.
5. REINFORCEMENT SIZE AND SPACING ARE BASED ON THE REQUIREMENTS IN ACI 349 AND ACI 318-11, SECTION 12.6.
6. THE ADJACENT WALL MAY BE DESIGNED AS A STRUCTURAL WALL MODULE.
7. THE DETAIL DESIGN, LOCATION, AND EMBEDMENT OF THE BEAM SUPPORTS ARE DESIGNED TO THE REQUIREMENTS OF AISC N690 AND ACI 349 AS APPLICABLE. SUPPORT CONFIGURATION, INCLUDING THE USE OF PLATES, STRUCTURAL SHAPES, AND STIFFENERS, IS BASED ON LOADING AND LOCAL GEOMETRY CONSIDERATIONS.THE DESIGN OF EMBEDMENT ANCHORAGE INCLUDING TYPE, SIZE, AND SPACING SATISFIES THE REQUIREMENTS OF APPENDIX B AS WELL AS OTHER APPLICABLE SECTIONS OF ACI 349.

Figure 3H.5-6
[*Auxiliary Building Typical Composite Floor*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

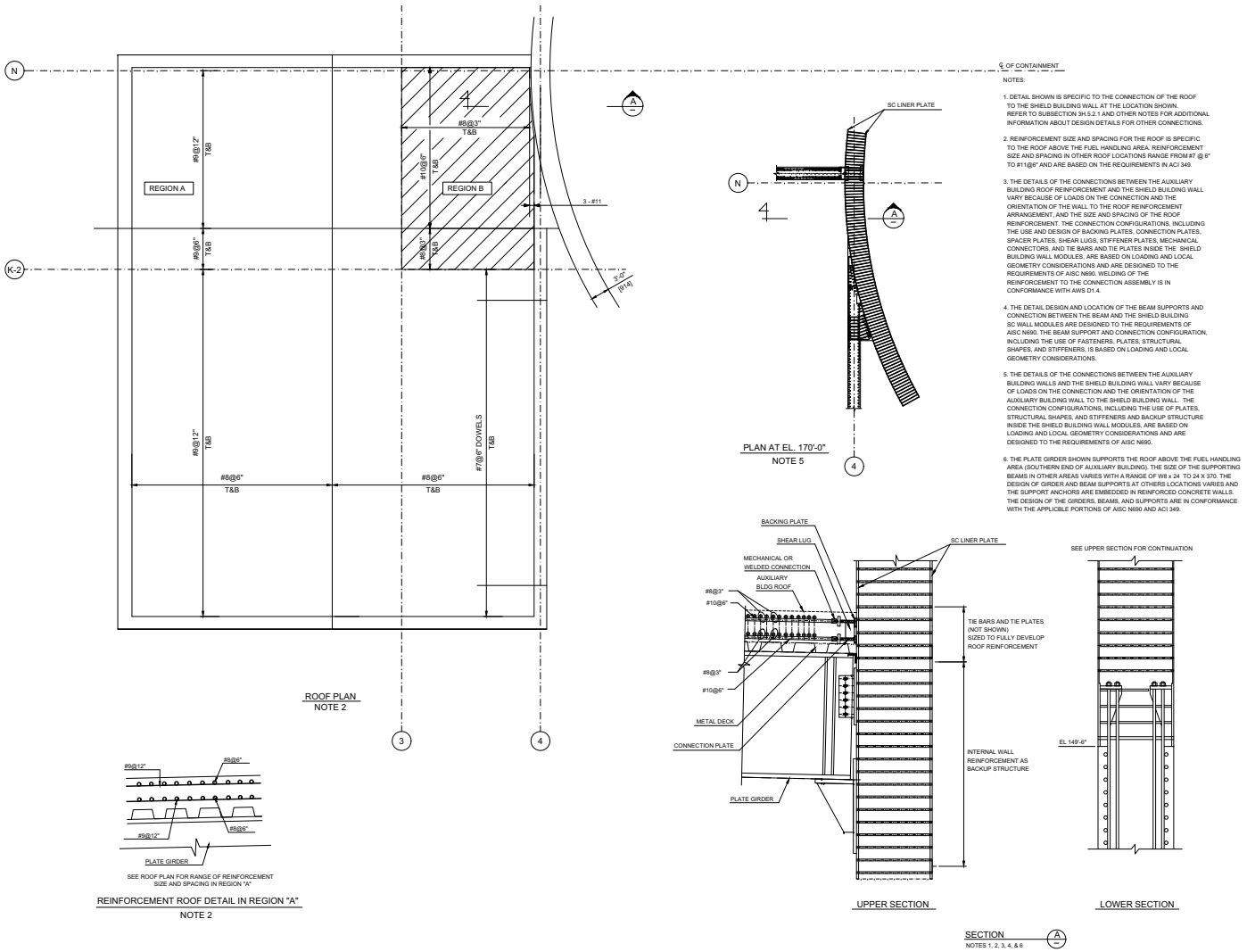
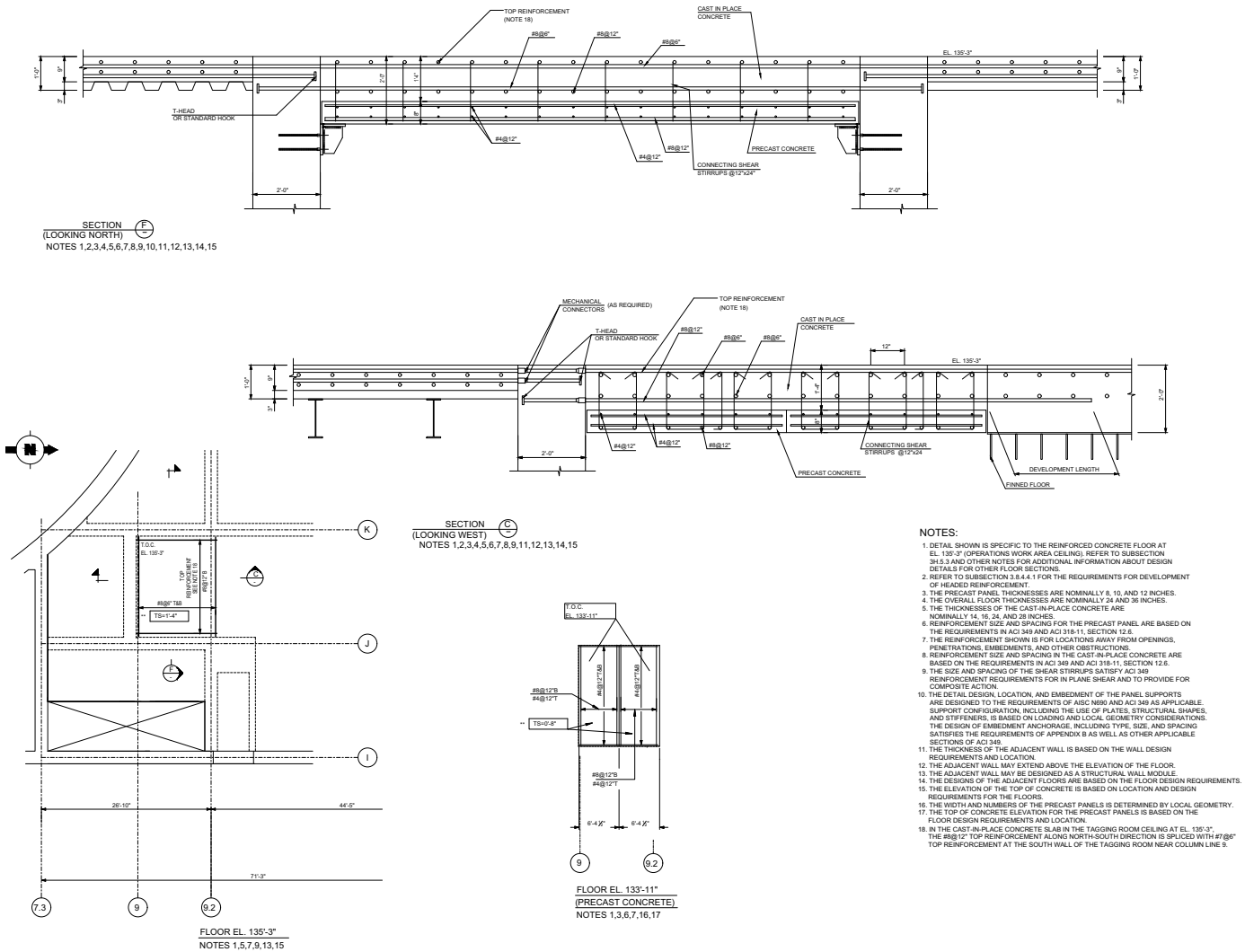


Figure 3H.5-7
[*Typical Reinforcement and Connection to Shield Building*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

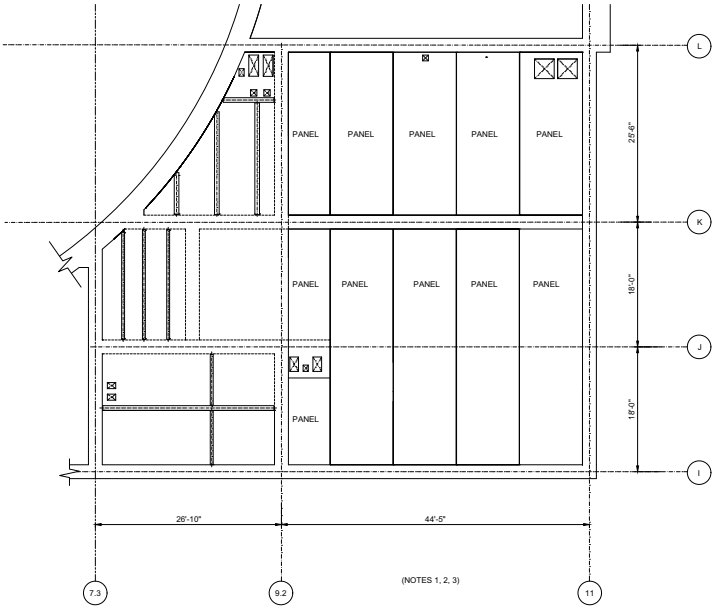


NOTES:

1. DETAIL SHOWN IS SPECIFIC TO THE REINFORCED CONCRETE FLOOR AT EL. 135'-3" (OPERATIONS WORK AREA CEILING). REFER TO SUBSECTION 3H.5.3 AND OTHER NOTES FOR ADDITIONAL INFORMATION ABOUT DESIGN DETAILS FOR OTHER FLOOR SECTIONS.
2. REFER TO SUBSECTION 3.8.4.4.1 FOR THE REQUIREMENTS FOR DEVELOPMENT OF HEADED REINFORCEMENT.
3. THE PRECAST PANEL THICKNESSES ARE NOMINALLY 8, 10, AND 12 INCHES.
4. THE OVERALL FLOOR THICKNESSES ARE NOMINALLY 24 AND 36 INCHES.
5. THE THICKNESSES OF THE CAST-IN-PLACE CONCRETE ARE NOMINALLY 14, 16, 24, AND 28 INCHES.
6. REINFORCEMENT SIZE AND SPACING FOR THE PRECAST PANEL ARE BASED ON THE REQUIREMENTS IN ACI 349 AND ACI 318-11, SECTION 12.6.
7. THE REINFORCEMENT SHOWN IS FOR LOCATIONS AWAY FROM OPENINGS, PENETRATIONS, EMBEDMENTS, AND OTHER OBSTRUCTIONS.
8. REINFORCEMENT SIZE AND SPACING IN THE CAST-IN-PLACE CONCRETE ARE BASED ON THE REQUIREMENTS IN ACI 349 AND ACI 318-11, SECTION 12.6.
9. THE SIZE AND SPACING OF THE SHEAR STIRRUPS SATISFY ACI 349 REINFORCEMENT REQUIREMENTS FOR IN PLANE SHEAR AND TO PROVIDE FOR COMPOSITE ACTION.
10. THE DETAIL DESIGN, LOCATION, AND EMBEDMENT OF THE PANEL SUPPORTS ARE DESIGNED TO THE REQUIREMENTS OF AISC N690 AND ACI 349 AS APPLICABLE. SUPPORT CONFIGURATION, INCLUDING THE USE OF PLATES, STRUCTURAL SHAPES, AND STIFFENERS, IS BASED ON LOADING AND LOCAL GEOMETRY CONSIDERATIONS. THE DESIGN OF EMBEDMENT ANCHORAGE, INCLUDING TYPE, SIZE, AND SPACING SATISFIES THE REQUIREMENTS OF APPENDIX B AS WELL AS OTHER APPLICABLE SECTIONS OF ACI 349.
11. THE THICKNESS OF THE ADJACENT WALL IS BASED ON THE WALL DESIGN REQUIREMENTS AND LOCATION.
12. THE ADJACENT WALL MAY EXTEND ABOVE THE ELEVATION OF THE FLOOR.
13. THE ADJACENT WALL MAY BE DESIGNED AS A STRUCTURAL WALL MODULE.
14. THE DESIGNS OF THE ADJACENT FLOORS ARE BASED ON THE FLOOR DESIGN REQUIREMENTS.
15. THE ELEVATION OF THE TOP OF CONCRETE IS BASED ON LOCATION AND DESIGN REQUIREMENTS FOR THE FLOORS.
16. THE WIDTH AND NUMBERS OF THE PRECAST PANELS IS DETERMINED BY LOCAL GEOMETRY.
17. THE TOP OF CONCRETE ELEVATION FOR THE PRECAST PANELS IS BASED ON THE FLOOR DESIGN REQUIREMENTS AND LOCATION.
18. IN THE CAST-IN-PLACE CONCRETE SLAB IN THE TAGGING ROOM CEILING AT EL. 135'-3", THE #8@12" TOP REINFORCEMENT ALONG NORTH-SOUTH DIRECTION IS SPLICED WITH #7@6" TOP REINFORCEMENT AT THE SOUTH WALL OF THE TAGGING ROOM NEAR COLUMN LINE 9.

Figure 3H.5-8
[*Auxiliary Building Operations Work Area (Tagging Room) Ceiling*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



NOTES:

1. DETAIL SHOWN IS SPECIFIC TO THE REINFORCED CONCRETE FLOOR AT EL. 135'-3" (MAIN CONTROL ROOM CEILING). REFER TO THIS AND OTHER NOTES FOR ADDITIONAL INFORMATION ABOUT DESIGN DETAILS FOR OTHER FLOOR SECTIONS AND FOR CONNECTIONS TO OTHER WALLS.
2. THE NUMBER OF STEEL PANELS USED TO CONSTRUCT THE FLOORS IS DETERMINED BY THE SIZE OF THE ROOM AND FABRICATOR CAPABILITIES.
3. THE OPENINGS FOR PIPING, HVAC DUCTS, OR CABLE TRAYS MAY VARY.
4. THE DEVELOPMENT OF THE FLOOR REINFORCEMENT IN THE WALLS CAN BE HEADED REINFORCEMENT INSTEAD OF STANDARD HOOKS. REFER TO SUBSECTION 3.8.4.4.1 FOR THE REQUIREMENTS FOR DEVELOPMENT OF HEADED REINFORCEMENT.
5. THE REINFORCEMENT AND CONNECTION DOWELS SHOWN ARE FOR LOCATIONS AWAY FROM OPENINGS, PENETRATIONS, EMBEDMENTS, AND OTHER OBSTRUCTIONS.
6. REINFORCEMENT SPACING AND SIZE FOR CONNECTING DOWELS ARE BASED ON THE REQUIREMENTS IN ACI 318-11 SECTION 12.6 AND ACI 349. THE RANGE OF SPACING AND SIZE OF THE CONNECTING DOWELS VARIES FROM 6" TO 12" AND FROM #8 TO #11, RESPECTIVELY. IN CERTAIN LOCATIONS SOME CONNECTING DOWELS ARE DEVELOPED INTO ADJACENT REINFORCEMENT CONCRETE FLOORS INSTEAD OF CONNECTING TO HOOKS OR HEADED REINFORCEMENT IN THE WALL. THE HOOK ORIENTATION IN CA20 FLOORS MAY VARY FROM THAT OF FINNED FLOORS.
7. DOWEL LENGTH IS THE LONGEST OF A) ACI 349 REQUIREMENTS FOR SPLICE LENGTH, B) LENGTH TO INCORPORATE SUFFICIENT SHEAR STUDS TO DEVELOP THE CAPACITY OF THE DOWEL, PER AISC N690 SHEAR STUD CAPACITIES, OR C) LENGTH TO INCORPORATE SUFFICIENT SHEAR STUDS TO DEVELOP THE DEMAND IN THE BOTTON PLATE, PER AISC N690 SHEAR STUD CAPACITIES.
8. ADDITIONAL BOTTOM LAYER REINFORCING STEEL IS PROVIDED IN THE FINNED FLOORS AT ELEVATION 117'-6" WHERE NEEDED TO MAINTAIN THE STRUCTURAL INTEGRITY OF THE FIRE BARRIER.
9. THE RANGE OF REINFORCEMENT SPACING AND SIZE VARIES FROM 6" TO 12" AND FROM #7 TO #11, RESPECTIVELY.
10. THE ELEVATION OF THE TOP OF CONCRETE IS BASED ON LOCATION AND DESIGN REQUIREMENTS FOR THE FLOOR PLATES.
11. THE DESIGN OF THE FINS VARIES AT LOCATIONS NEAR OPENINGS, PENETRATIONS, AND OTHER OBSTRUCTIONS AND DUE TO ATTACHMENTS TO THE FINS AND FLOOR PLATES.
12. THE CENTER LINE LOCATION OF THE SHEAR STUDS MAY VARY FROM THAT OF THE FINS.
13. THE GAP BETWEEN STEEL PLATE AND WALL, AND USE OF CONSTRUCTION JOINTS VARIES BASED ON FABRICATION AND CONSTRUCTION NEEDS.
14. THE NUMBER OF LAYERS OF TOP REINFORCEMENT AND TOP DOWELS ALONG EACH DIRECTION MAY VARY AS LONG AS THE MINIMUM REQUIRED REINFORCEMENT IS PROVIDED PER ACI 349.
15. THE SHEAR STUD DESIGN SHOWN IS FOR LOCATIONS AWAY FROM OPENINGS, PENETRATIONS, EMBEDMENTS, AND OTHER OBSTRUCTIONS.
16. THE DESIGN INFORMATION SHOWN ON SHEET 3 IS APPLICABLE TO FINNED FLOORS FOR LOCATIONS AWAY FROM OPENINGS, PENETRATIONS, EMBEDMENTS, AND OTHER OBSTRUCTIONS.

Figure 3H.5-9 (Sheet 1 of 3)
[*Auxiliary Building Finned Floor*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

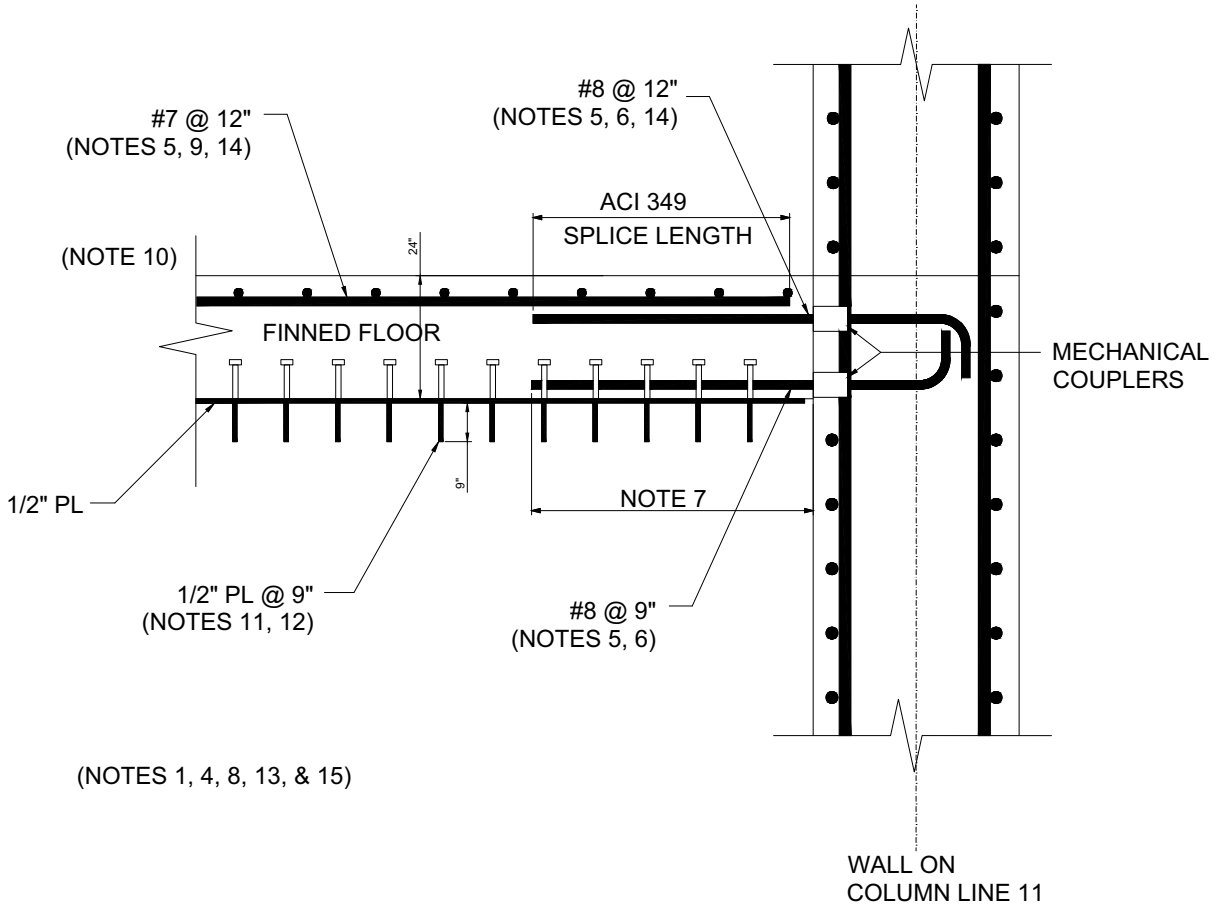


Figure 3H.5-9 (Sheet 2 of 3)
[*Auxiliary Building Finned Floor*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

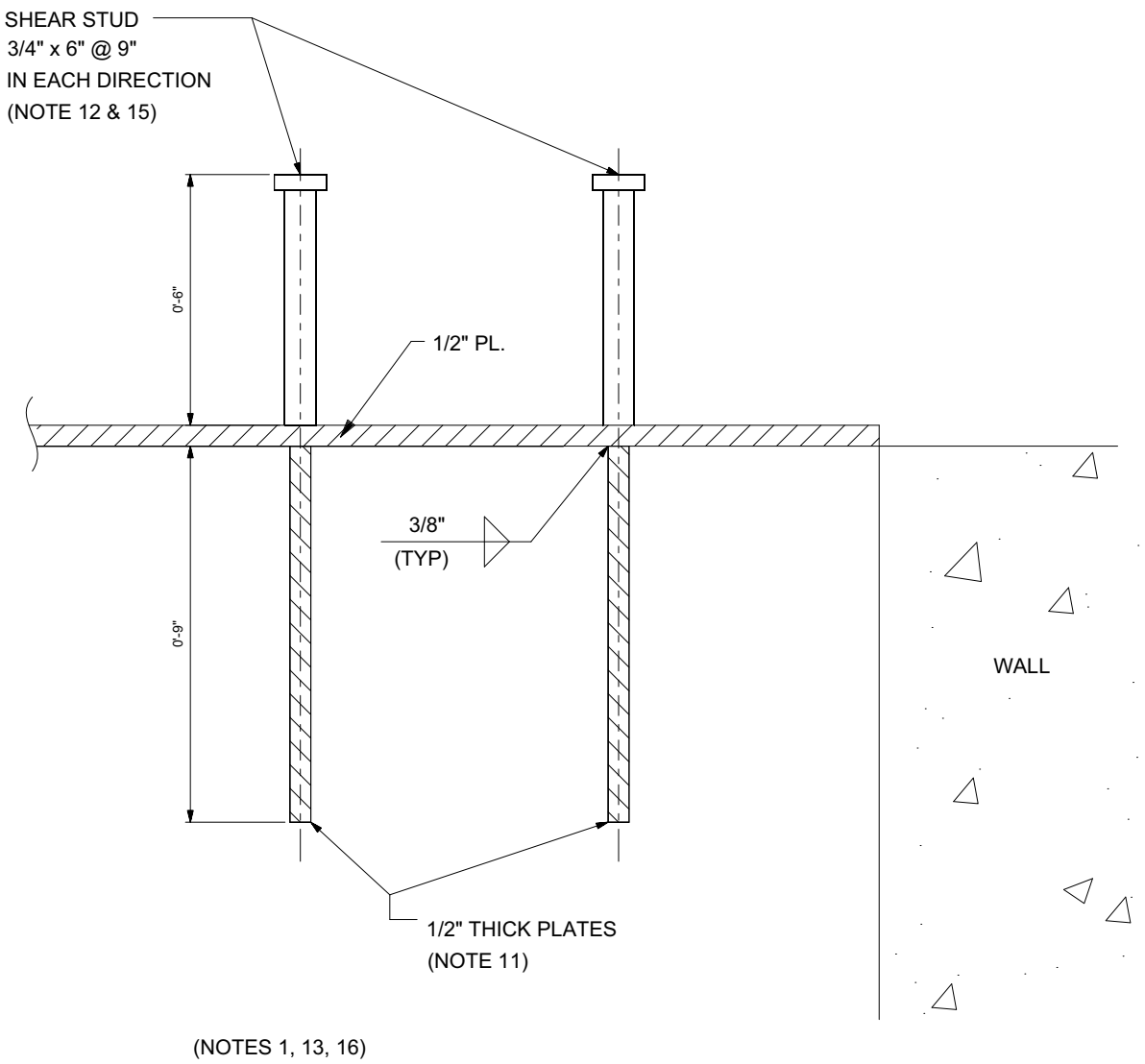


Figure 3H.5-9 (Sheet 3 of 3)
[*Auxiliary Building Finned Floor*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

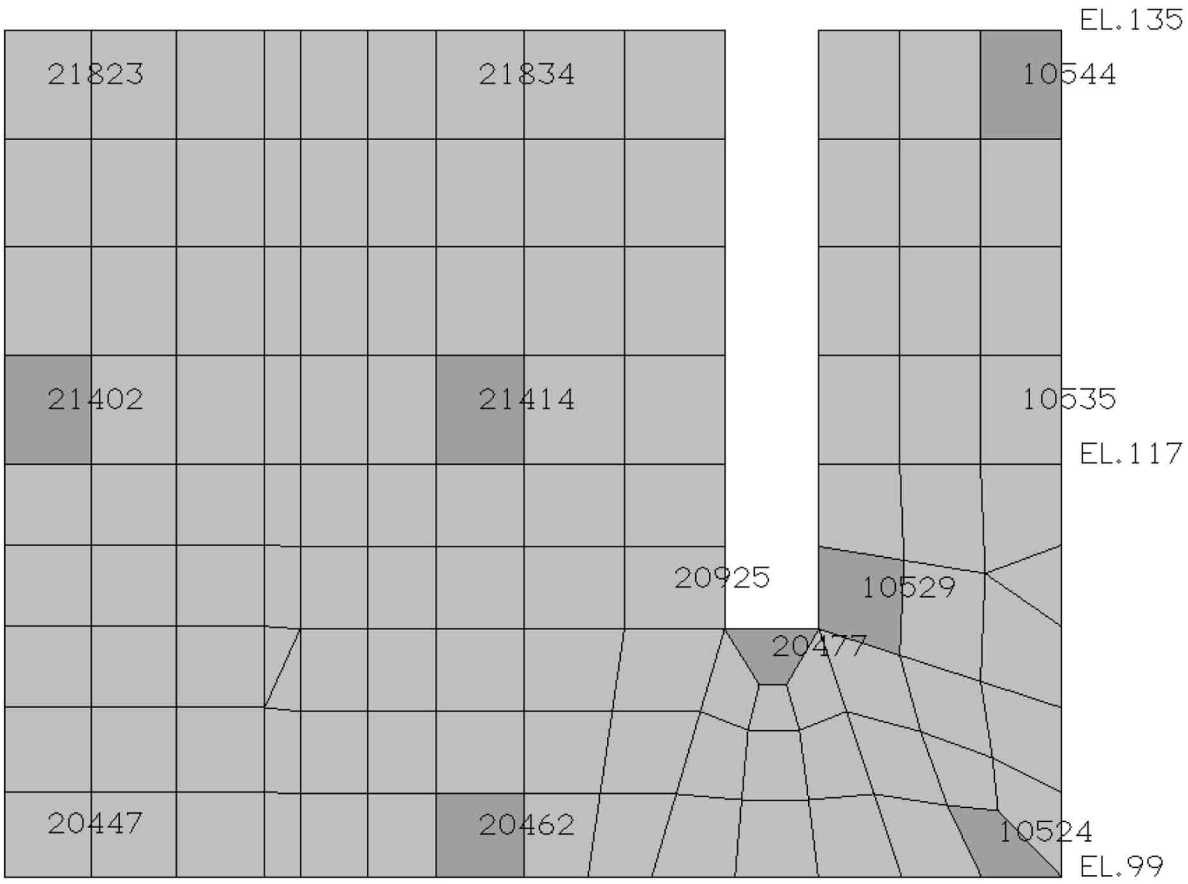


Figure 3H.5-10
[*Spent Fuel Pool Wall Divider Wall Element Locations*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3H.5-11 (Sheet 1 of 6)
[*Design of Shield Building: Roof and Air Inlets*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3H.5-11 (Sheet 2 of 6)
[*Design of Shield Building: Concrete Detail at Tension Ring*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3H.5-11 (Sheet 3 of 6)
[*Design of Shield Building: Roof/Air Inlet Interface*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3H.5-11 (Sheet 4 of 6)
[*Design of Shield Building at Air Inlets*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 3H.5-11 (Sheet 5 of 6)
[*Design of Shield Building: Tank/Roof Interface Reinforcement*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

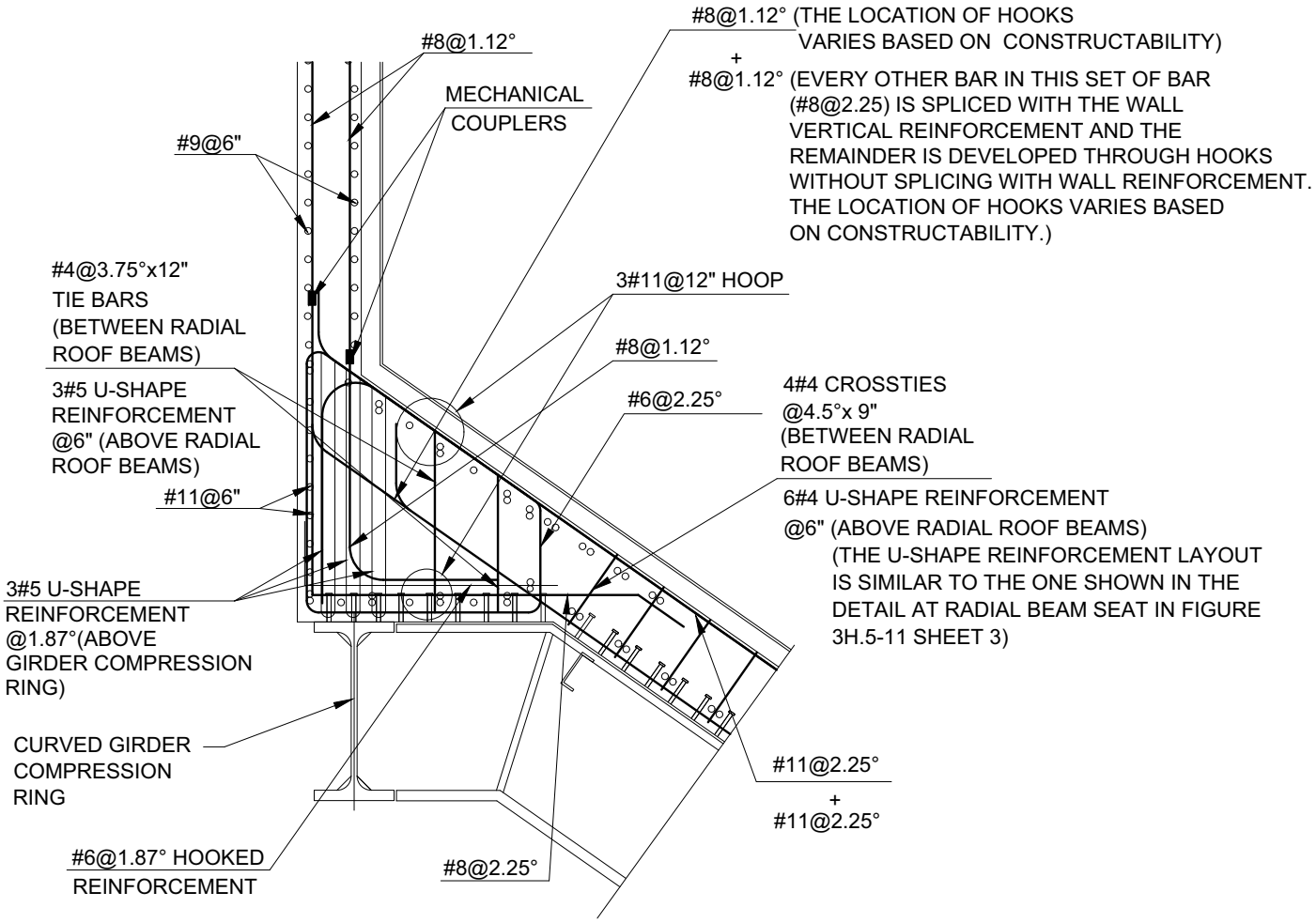
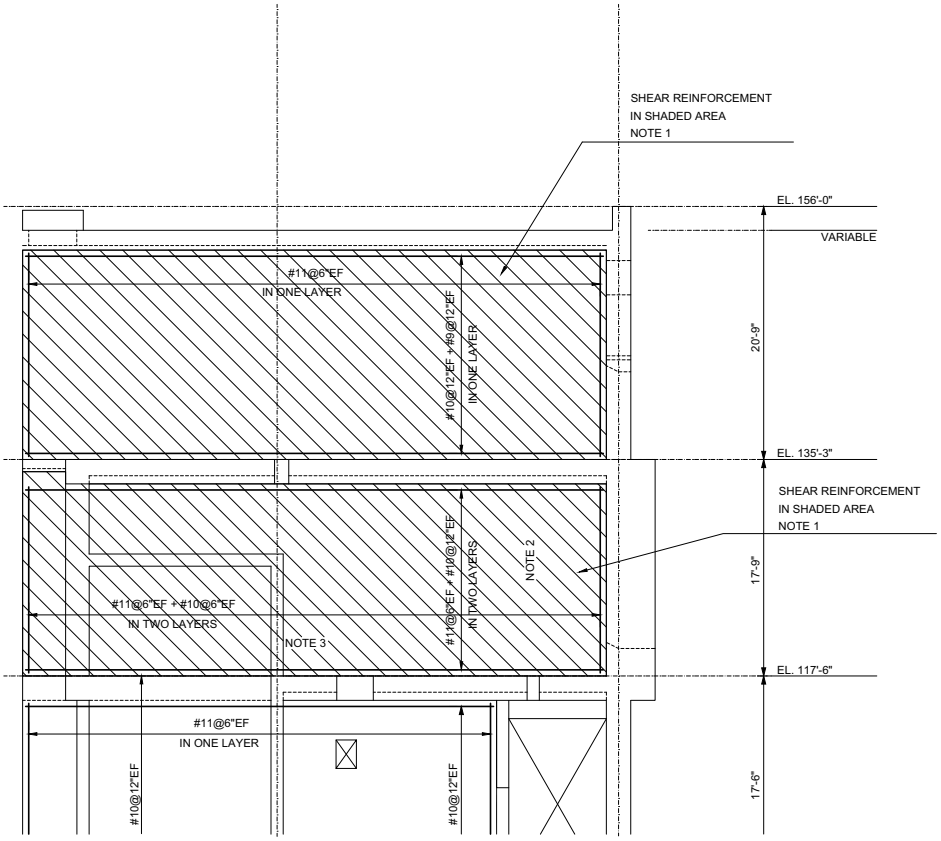


Figure 3H.5-11 (Sheet 6 of 6)
Design of Shield Building:
Tank/Compression Ring Roof Interface Reinforcement



NOTE 1:
REFER TO SUBSECTION 3.8.4.4.1 FOR THE REQUIREMENTS FOR SHEAR REINFORCEMENT AND TABLE 3H.5-7 FOR SHEAR REINFORCEMENT PROVIDED.

NOTE 2:
FOR VOGTLE UNIT 4, TWO #11 HORIZONTAL REINFORCEMENT BARS (ONE ON EACH FACE) ARE OMITTED DIRECTLY ABOVE ELEVATION 117'-6", FOR THE ENTIRE WIDTH OF THE WALL. SEE TABLE 3H.5-7 FOR ADDITIONAL DETAILS.

NOTE 3:
FOR VOGTLE UNIT 4, THREE #11 AND FOUR #10 VERTICAL REINFORCEMENT BARS ARE OMITTED FROM ELEVATION 117'-6" TO ELEVATION 135'-0". SEE TABLE 3H.5-7 FOR ADDITIONAL DETAILS.

Figure 3H.5-12
[*Typical Reinforcement in Wall L*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

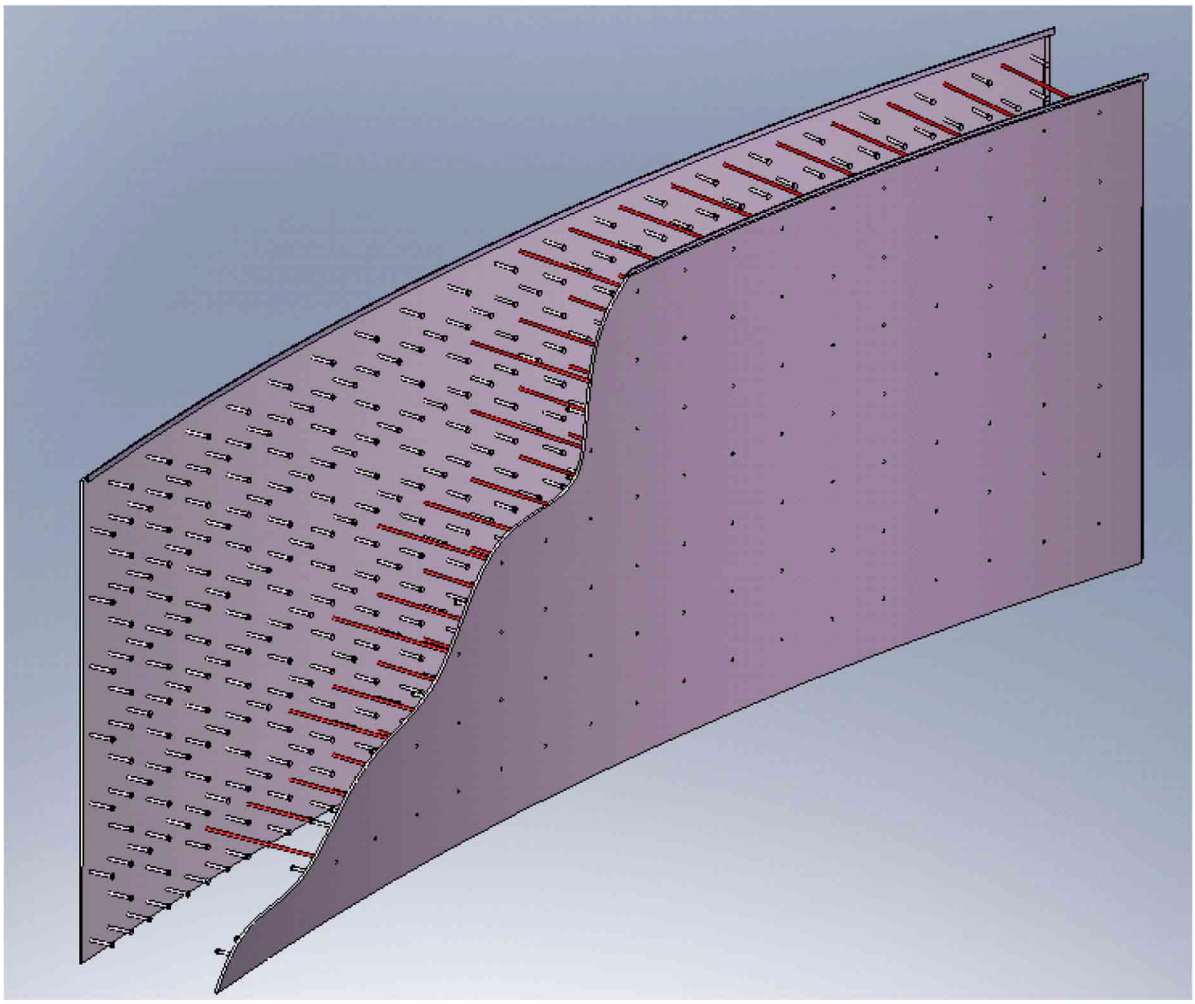


Figure 3H.5-13
Enhanced Shield Building Wall Panel Layout

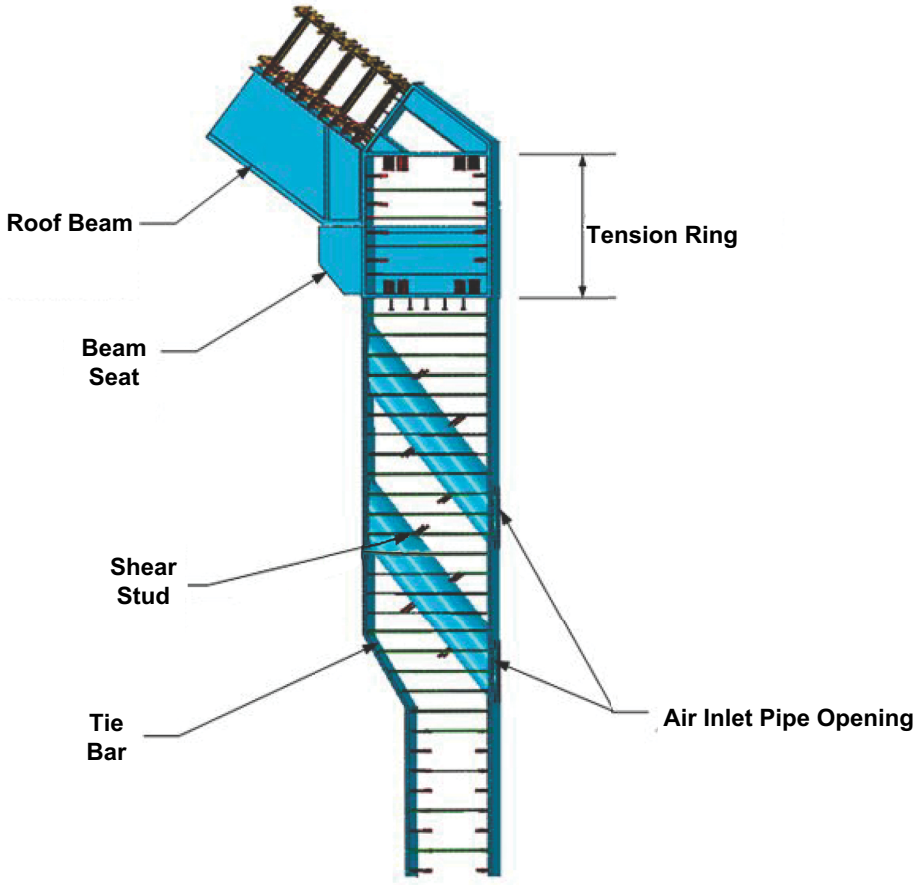


Figure 3H.5-14
Elevation View of Tension Ring and Air Inlets

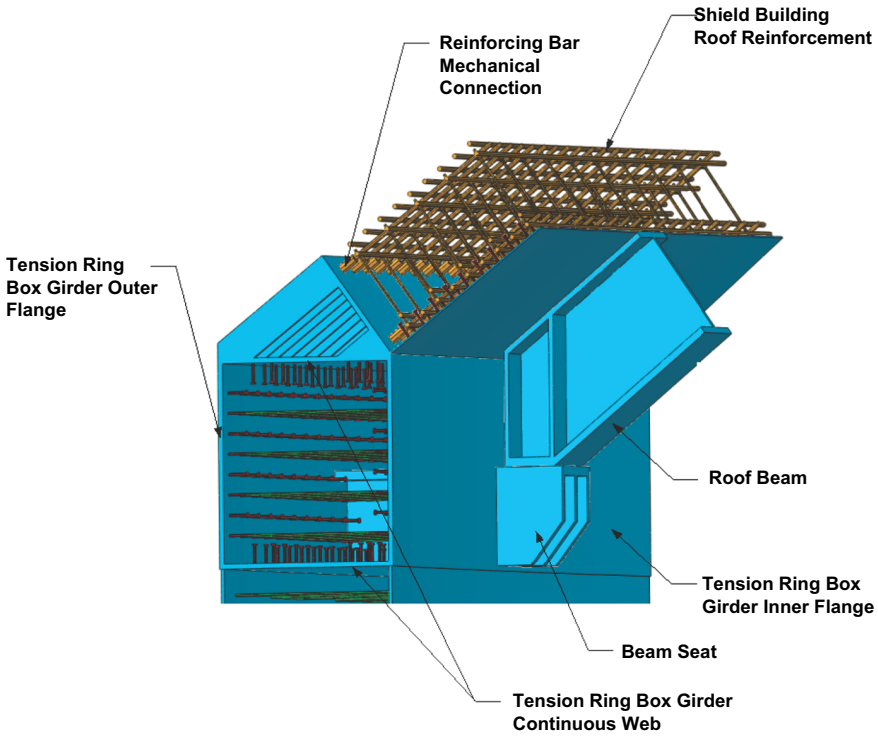


Figure 3H.5-15
Shield Building Tension Ring

Security-Related Information, Withheld Under 10 CFR 2.390d

For additional information, see Figure 6 of APP-GW-GLR-602 (Reference 1).

Figure 3H.5-16 (Sheet 1 of 2)
[*Design of Shield Building: Surface Plates on Cylindrical Section – Developed View 90-270 Degrees*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Security-Related Information, Withheld Under 10 CFR 2.390d

For additional information, see Figure 6 of APP-GW-GLR-602 (Reference 1).

Figure 3H.5-16 (Sheet 2 of 2)
[*Design of Shield Building: Surface Plates on Cylindrical Section – Developed View 270-90 Degrees*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Appendix 3I Evaluation for High Frequency Seismic Input

3I.1 Introduction

The seismic analysis and design of the AP1000 plant is based on the Certified Seismic Design Response Spectra (CSDRS) shown in Subsection 3.7.1.1. These spectra are based on Regulatory Guide 1.60 with an increase in the 25 hertz region. Ground Motion Response Spectra (GMRS) for some Central and Eastern United States rock sites show higher amplitude at high frequency than the CSDRS. Evaluations are described in this appendix for an envelope response spectra with high frequency for the seismic input. The resulting spectra of this site are shown in Figure 3I.1-1 and Figure 3I.1-2 and compare this hard rock high frequency (HRHF) envelope response spectra at the foundation level against the AP1000 CSDRS for both the horizontal and vertical directions for 5% damping. The HRHF envelope response spectra exceed the CSDRS for frequencies above about 15 Hz.

High frequency seismic input is generally considered to be non-damaging as described in Reference 1. The evaluation of the AP1000 nuclear island for the high frequency input is based on the analysis of a limited sample of structures, components, supports, and piping to demonstrate that the high frequency seismic response is non-damaging. The evaluation includes building structures, reactor pressure vessel and internals, primary component supports, primary loop nozzles, piping, and equipment.

This appendix describes the methodology and criteria used in the evaluation to confirm that the high frequency input is not damaging to equipment and structures qualified by analysis for the AP1000 CSDRS. It provides supplemental criteria for selection and testing of equipment whose function might be sensitive to high frequency. The results of the high frequency evaluation demonstrating that the AP1000 plant is qualified for this type of input are documented in a technical report (Reference 2). This report will provide a summary of the analysis and test results.

3I.2 High Frequency Seismic Input

Presented in Figures 3I.1-1 and 3I.1-2 is a comparison of the horizontal and vertical HRHF envelope response spectra and the AP1000 CSDRS. The HRHF envelope response spectra presented are calculated at foundation level (39.5' below grade), at the upper most competent material and treated as an outcrop for calculation purposes.

For each direction, the HRHF envelope response spectra exceed the design spectra in higher frequencies (greater than 15 Hz horizontal and 20 Hz vertical). The spectra are used for the HRHF envelope response spectra. If necessary, the HRHF envelope response spectra are enhanced at low frequencies so that HRHF envelope response spectra fully envelope all of the hard rock sites.

These HRHF envelope response spectra are further limited in that the shear wave velocity limitation is defined at the bottom of the basemat equal to or higher than 7,500 fps, while maintaining a shear wave velocity equal to or above 8,000 fps at the lower depths.

3I.3 NI Models Used To Develop High Frequency Response

The NI20 nuclear island model described in Appendix 3G is analyzed in ACS SASSI using the HRHF time histories applied at foundation level to obtain the motion at the base.

A modal analysis of the NI05 model for both the auxiliary and shield buildings and containment internal structure (CIS) has been performed for each of these regions. Specific areas within each wall or floor where out-of-plane modes, which may respond to either CSDRS or HRHF input (including structures with modes less than 33 Hz and between 33 Hz to 50 Hz), have been identified. The

survey reveals that some regions, typically in the middle of a floor or wall, exhibit amplified behavior compared to the critical nodes at the corner and edge building locations. The amplified FRS for these regions is generated in addition to the typical set of critical nodes for building analysis by a single time history analysis of the NI05 building model subject to the HRHF time history input. Seismic response spectra for each of the “flexible” nodes are considered when selecting the pre-existing “group” spectra, which is the envelope of the entire floor in that area.

Evaluation of incoherent HRHF spectra has been performed. The CSDRS and HRHF seismic responses were compared with coherent and incoherent considerations at a number of locations in the nuclear island. There are some exceedances, mostly above the 15 hertz region, and these are typical of the plant comparative responses. The steel containment vessel (SCV) was excluded from the evaluation because the HRHF spectra at the base of the SCV are enveloped by the AP1000 CSDRS spectra at the base of the SCV.

Structures designed to the CSDRS input are adequately designed for the HRHF input because the HRHF coherent results are enveloped by the CSDRS results.

3I.4 Evaluation Methodology

The demonstration that the AP1000 nuclear power plant is qualified for the high frequency seismic response does not require the analysis of the total plant. The evaluations made are of representative systems, structures, and components, selected by screening, as potentially sensitive to high frequency input in locations where there were exceedances in the high frequency region. Acceptability of this sample is considered sufficient to demonstrate that the AP1000 is qualified.

The high frequency seismic analyses that are performed use time history or broadened response spectra. The analysis is not performed using the combination spectra of the CSDRS and the HRHF envelope response spectra. Separate analyses with each spectra are used.

The high frequency seismic analyses used the soil-structure interaction code ACS SASSI. The results presented in this report are based on the stochastic (multiple, statistical analyses) seismic incoherent soil-structure interaction analysis approach referred herein as the simulation approach.

The evaluations performed assess the ability of the system, structure, or component to maintain its safety function.

Supplementary analyses are performed as needed to show that high frequency floor response spectra exceedances are not damaging. These analyses can include: gap nonlinearities; material inelastic behavior; multi point response spectra analyses where the high frequency response excites a local part of the system. Tests on equipment are specified as needed where function cannot be demonstrated by analysis, or analysis is not appropriate.

3I.5 General Selection Screening Criteria

The following general screening criteria are used to identify representative AP1000 systems, structures, and components (SSCs) for the samples to be evaluated to demonstrate acceptability of the AP1000 nuclear power plant for the high frequency motion.

- Select systems, structures, and components based on their importance to safety. This includes the review of component safety function for the SSE event and its potential failure modes due to an SSE. Those components whose failure modes would result in safe shutdown are excluded.

- Select systems, structures, and components that are located in areas of the plant that experience large high frequency seismic response.

- Select systems, structures, and components that have significant modal response within the region of high frequency amplification. Significance is defined by such items as modal mass; participation factor, stress and/or deflection.

- Select systems, structures, and components that have significant stress as compared to allowable when considering load combinations that include seismic.

3I.6 Evaluation

In this section the portions of structures, the components, and the systems that are evaluated for the high frequency seismic response are identified. The sample to be evaluated, based on the screening criteria applicable to the SSCs consists of the following:

- Building Structures
  - Auxiliary Building – 3 locations
  - Shield Building – 8 locations
  - CIS – 2 locations
- Primary Coolant Loop
  - Reactor Vessel and Internals
  - Primary Component Supports
  - Reactor Coolant Loop Primary Equipment Nozzles
- Piping Systems – ASME Class 1, 2, and 3 piping systems will be evaluated for the HRHF GMRS. This evaluation is within the scope of the piping DAC (see COL Information Item 3.9-7).
- Electro-Mechanical Equipment – Equipment that is potentially sensitive to high frequency input (see Table 3I.6-1)

These structures, systems, and equipment are discussed in more detail in the sections that follow.

3I.6.1 Building Structures

Maintaining the NI buildings structural integrity is important to the safety of the plant. Representative portions of the buildings that are evaluated for the effect of high frequency input are selected based on those areas that can experience high seismic shear and moment loads due to the seismic event. Areas chosen are at the base of the shield building, in the vicinity of auxiliary building floors that have fundamental frequencies in the high frequency region, and the corners of the auxiliary building. Three locations are selected on the auxiliary building that reflect the bottom of a wall where the shear and moment would be large, a wall in the vicinity of a floor that is influenced by high frequency response, and a corner intersection of walls. Eight locations are evaluated on the shield building. Four at elevation 107' and four at elevation 211'. These locations are located on the east, west, north and south sides. The south-west wall of the refueling canal is evaluated since it is a representative wall on

the refueling canal. The CA02 wall in the CIS building is evaluated since it is a representative wall associated with the IRWST.

The evaluation consists of a comparison of the loads from the high frequency input to those obtained from the AP1000 design spectra, shown in Figures 3I.1-1 and 3I.1-2, for these representative building structures. The NI building structures are considered qualified for the high frequency input if the seismic loads from the Regulatory Guide 1.60 (modified) envelope those from the high frequency input. If there is any exceedance, this is evaluated further to confirm that the existing design is adequate.

3I.6.2 Primary Coolant Loop

A failure within the reactor coolant loop could challenge the integrity of the reactor coolant pressure boundary. Therefore, it is chosen for evaluation. The components evaluated are as follows:

- Reactor vessel and internals
- Reactor vessel supports
- Steam generator supports
- Reactor coolant loop primary equipment nozzles

The reactor vessel and internals are selected since they are important to safety and their analysis is representative of major primary components. The building structure below the reactor vessel supports is fairly stiff and there may be significant vertical amplification at the supports of the reactor pressure vessel. Further, reactor vessel internals have relatively complex structural systems including gap nonlinearities and sliding elements. Also, they may be sensitive to high frequency input as summarized below:

- Vertical and horizontal modes of the upper internals and the reactor vessel modes are in the relatively high frequency range.

- Additional high frequencies are associated with nonlinear impact

The evaluation consists of a comparison of the loads from the high frequency input to those obtained from the Regulatory Guide 1.60 (modified) input. Qualification is shown for the high frequency input if the seismic loads from the Regulatory Guide 1.60 (modified) envelope those from the high frequency input. If there is exceedance, then comparison is made for the combination of the seismic with the design basis pipe break loads and steady state loads. Qualification is then shown if the high frequency loads are relatively insignificant compared to the other loads, or there are no required design changes.

Maintaining the integrity of the reactor vessel and steam generator supports is important to preserving the primary component safety function. They are representative of supports on components, and see high loads.

The reactor coolant loop nozzles at the cold and hot leg interfaces of the reactor pressure vessel, reactor coolant pumps, and steam generators are important to include in the evaluation since these are critical areas of components.

The evaluation of the primary component supports and reactor coolant loop nozzles consists of a comparison of the loads from the high frequency input to those obtained from the Regulatory Guide 1.60 (modified) input. These items are considered qualified for the high frequency input if the seismic loads from the Regulatory Guide 1.60 (modified) envelope those from the high frequency input. If there is any exceedance, then an evaluation is made combining the high frequency loads with the other load components (e.g., thermal, pressure, dead) and a comparison made to the design loads. If

the design loads envelope the load combinations that include the high frequency seismic input, then the nozzles and supports are considered qualified for the high frequency input.

3I.6.3 Piping Systems

ASME Class 1, 2, and 3 piping systems will be evaluated for the HRHF GMRS. This evaluation is within the scope of the piping DAC (see COL Information Item 3.9-7).

3I.6.4 Electrical and Electro-Mechanical Equipment

The groups of safety-related equipment considered for evaluation are those that may be sensitive to the high frequency input. This includes those cabinet-mounted equipment, field sensors, and appurtenants that may be sensitive to high frequency seismic inputs identified in Table 3I.6-1.

Sample safety-related cabinets have been identified that are typically sensitive to seismic input. Evaluations were performed to verify these cabinets do not have excessive seismic excitation on their mounted equipment, the cabinet designs do not require changes due to the high frequency input, and the cabinets will maintain their structural integrity during the high frequency input. Time history analyses of these cabinets were performed for both the Regulatory Guide 1.60 (modified) and the high frequency inputs so that comparisons can be made to their seismic response from both seismic inputs. This analytical study reported in APP-GW-GLR-115 (Reference 2) concluded that safety-related equipment may be screened.

The AP1000 HRHF screening program for determination and evaluation of potential high frequency sensitive equipment is in compliance with the NRC requirements in Section 4.0, “Identification and Evaluation of HF Sensitive Mechanical and Electrical Equipment/Components,” of COL/DC-ISG-1 (Reference 3). The AP1000 HRHF screening program is also consistent with the guidelines developed as part of an industry review document in the EPRI White Paper, “Seismic Screening of Components Sensitive to High Frequency Vibratory Motions” (Reference 4), transmitted to the NRC on June 28, 2007, for determining the safety-related equipment and components that may be HRHF sensitive, and screening procedures to ensure that any safety-related equipment and components sensitive to HRHF seismic excitation are screened out. This industry review of HF exceedance and further evaluations of SSCs performed by Westinghouse concluded that HRHF envelope response spectra are less harmful than the CSDRS except for the functionality of potential HRHF-sensitive components.

The AP1000 HRHF screening program is based on an HF evaluation study reported in APP-GW-GLR-115 (Reference 2). The HF evaluation study concluded that AP1000 In-Structure Response Spectra (ISRS) developed from the AP1000 CSDRS would, in the majority of cases, produce equipment stress results of the same magnitude or higher than the stress results produced from HRHF seismic excitation. The exception to this condition is when the dominant natural frequency of the equipment is in the HRHF exceedance range and there can be significantly more response because the frequency coincides with the input driving force. Under this condition, forces/stresses generated in the equipment could be due to the acceleration exceedance; therefore, the equipment will be subjected to HRHF seismic evaluation/testing to screen out equipment by verifying its performance and acceptability under HRHF excitation. Review of seismic test data for electrical and microprocessor based cabinets performed to generic and high frequency excitation concluded that seismic testing that peaks in the lower frequency range will produce larger displacements and velocities, and will result in higher stresses in the equipment.

The goal of the AP1000 HRHF screening program is to identify the potential safety-related equipment and components that have the potential to be HRHF-sensitive and show them to be acceptable for their specific application (screened-out). The AP1000 HRHF screening program is a two step process. The first step is an HRHF susceptibility review to identify potential high frequency sensitive

safety-related equipment. The second step is the screened-out equipment process to demonstrate its acceptability for the HRHF seismic excitation. Evaluation of screened-in equipment as defined in COL/DC-ISG-1 (Reference 3) is not performed because all safety-related equipment that is screened-in will be eliminated or shown to be acceptable through a design change process.

For the AP1000 HRHF screening program, the following conditions must exist:

1. Plant-specific HRHF GMRS exceeds the AP1000 CSDRS in the high frequency range at 5% critical damping.

2. Safety-related equipment has potential failure modes involving change of state, chatter, signal change/drift, and connection problems.

Table 3I.6-2 is a list of potential HRHF-sensitive AP1000 safety-related equipment developed based on Table 3.11-1 of Section 3.11, “Environmental Qualification of Mechanical and Electrical Equipment.” The equipment in Table 3.2-3 of Section 3.2, “AP1000 Classification of Mechanical and Fluid Systems, Components, and Equipment,” and Table 3I.6-3 is not HRHF-sensitive. The structural integrity and operability of equipment in Table 3.2-3 and Table 3I.6-3 will not be impacted by the high frequency excitation.

The HRHF susceptibility review of AP1000 safety-related equipment is not performed for potential failure modes associated with mounting, connections, fasteners, joints, and structural interface. These potential failure modes are addressed through the seismic qualification of the safety-related equipment to the AP1000 ISRS testing performed in compliance with IEEE Standard 344-1987. The AP1000 ISRS qualification testing generates higher displacements and velocities than those resulting from HRHF seismic excitation since the AP1000 ISRS is controlled by the lower frequency range. The higher displacement, velocities, and accelerations will detect these equipment structural failure modes if they exist.

At locations where HRHF response spectra show exceedance of the CSDRS and there is a likelihood of equipment damage, further evaluations would be performed to verify that the existing qualification is adequate for equipment not high frequency sensitive, as listed in Table 3I.6-3, under the following conditions:

- Safety-related equipment must have modes or natural frequencies in the range of interest.

- Evaluation will apply the same acceptance criteria and methodologies used in CSDRS qualification.

To demonstrate acceptability for both CSDRS and HRHF testing, the test response spectra must envelop the CSDRS and HRHF spectra, respectively, with margin over the frequency range of interest in compliance with IEEE Standard 344-1987. In the event that the CSDRS and/or HRHF response spectra would be revised after the qualification program has been completed, a reconciliation effort would be performed to verify that the CSDRS and HRHF testing is still valid. The reconciliation effort may result in requalification activities and qualification documentation revisions.

High Frequency Screening Process – Step 1

The potential failure modes of high frequency sensitive component types and assemblies are important considerations in the high frequency program. The following are potential failure modes of high frequency sensitive components/equipment:

- Inadvertent change of state
- Chatter
- Change in accuracy and drift in output signal or set-point

- Electrical connection failure or intermediacy (e.g., poor quality solder joints)
- Mechanical connection failure
- Mechanical misalignment/binding (e.g., latches, plungers)
- Fatigue failure (e.g., solder joints, ceramics, self-taping screws, spot welds)
- Improperly and unrestrained mounted components
- Inadequately secured/locked mechanical fasteners and connections

Components and equipment determined to have potential failure modes involve change of state, chatter, signal change/drift, and connection problems will be demonstrated to be acceptable through the performance of a supplemental high frequency screening test. Those high frequency sensitive components having failure modes associated with mounting, connections and fasteners, joints, and interface are considered to be acceptable as a result of the AP1000 ISRS qualification testing per IEEE Standard 344-1987 and/or require quality assurance inspection and process/design controls.

High Frequency Screening Process – Step 2

The HRHF susceptibility review is to verify that the subject equipment is capable of performing its safety-related function under HRHF seismic excitation. All AP1000 safety-related equipment will be qualified to the AP1000 ISRS, and the dominant natural frequencies of the equipment will be determined. The EPRI White Paper (Reference 4) identifies the following three evaluation methods to demonstrate that potential HRHF-sensitive safety-related equipment is not HRHF vulnerable:

1. Existing seismic qualification test data for potential high frequency sensitive equipment should be reviewed for applicability and adequacy of the test method to demonstrate sufficient high frequency content.

2. Systems/circuits containing potentially sensitive items should be reviewed for inappropriate/unacceptable system actions due to assumed change of state, contact chatter/intermittency, set point drifts, or loss of calibration.

3. HRHF vibration screening test is conducted to identify any HRHF sensitivities/abnormalities of the components. Several conventional test methods are recommended.

The first and third evaluation methods are part of the AP1000 HRHF screening program and are further detailed below. The AP1000 HRHF seismic screening evaluation will employ the AP1000 HRHF envelope response spectra as input in verifying potential HF sensitive safety-related equipment is not vulnerable to HRHF seismic excitation. Additional seismic test margin will be introduced into the HRHF seismic screening evaluation as needed.

Method 1: Review of Seismic Test Data

Available seismic test data can be used for AP1000 HRHF plant applications when:

- Seismic qualification testing performed on potential HRHF-sensitive safety-related equipment meets as a minimum the AP1000 ISRS in compliance with IEEE Standard 344-1987.

- Safe shutdown earthquake (SSE) test had sufficient energy content in the HRHF region to verify that the safety-related equipment is not vulnerable to HRHF seismic excitation.

No additional seismic testing is required for safety-related equipment previously tested and whose qualification level envelops the HRHF required response spectra (RRS).

IEEE Standard 344-1987 provides guidance to ensure that the seismic test input is generated and in compliance with the frequency range of interest. To demonstrate acceptability for frequency content, it is necessary to show that the frequency content of the test waveform is at least as broad as the

frequency content of the amplified region of the RRS except at the low frequencies where non-enveloping is permitted under certain conditions (refer to IEEE Standard 344-1987 subclauses 7.6.3.1(10) and 7.6.3.1(13)). An evaluation of the test input waveform should be conducted per IEEE Standard 344-1987 Annex B to verify the test data has sufficient content over the frequency range of interest throughout the input time history. If an evaluation of the test input is performed, and the data demonstrates sufficient frequency content in the high frequency range throughout the time history, then the data is acceptable.

Method 3: HRHF Screening Test

The HRHF screening test is a supplemental test to the required seismic qualification methods performed in accordance with IEEE Standard 344-1987 for those plants that have high frequency exceedance of the AP1000 CSDRS. The purpose of the HRHF screening test is to demonstrate that the potential HRHF-sensitive safety-related equipment will perform its safety-related function as required under HRHF seismic excitation. The HRHF screening test is performed in conjunction with the AP1000 ISRS seismic qualification testing, or it is performed as a supplemental test after completion of the AP1000 ISRS seismic qualification testing. The AP1000 ISRS and HRHF test input time histories have 30-second durations with frequency content up to the cutoff frequency developed in accordance with subclause 7.6.3 (Multiple-Frequency Tests) and Annex B (Frequency Content and Stationarity) of IEEE Standard 344-1987. During the AP1000 ISRS and HRHF testing, the equipment will be functional and monitored to verify the safety-related function was demonstrated. Screening testing will be performed using HRHF response spectra as defined in the EPRI White Paper (Reference 4) when AP1000 HRHF inputs are not available. The HRHF response spectra will be generated based on the 5g and 15g peak spectral acceleration at 5% critical damping in the 25 Hz to 50 Hz frequency range. If the HRHF screening test cannot demonstrate the equipment to be acceptable, then the safety-related equipment will be removed or modified and additional testing or justification will be required.

The AP1000 safety-related equipment will be seismic qualified to the AP1000 ISRS associated with the mounting location of the equipment as a minimum. Seismic qualification testing will consist of five AP1000 ISRS operating basis earthquakes (OBEs) followed by one SSE as a minimum. The OBE level will be at least one-half the SSE level. The OBE testing is used to vibration age and address low-cycle fatigue of equipment prior to SSE testing. Cyclic fatiguing of equipment for HRHF exceedance area is adequately addressed by performing five OBE (one-half the SSE) and a minimum of one SSE seismic test runs in compliance with IEEE Standard 344-1987 prior to performing the supplemental HRHF screening test. Additional OBE testing in the high frequency exceedance range is adequately addressed by the demonstration that the peak stress cycles required for five one-half SSE events using the AP1000 HRHF ISRS are equivalent to or enveloped by the peak stress cycles resulting from five one-half SSE events and one full SSE event using the AP1000 CSD ISRS (Reference 5).

The test results of AP1000 seismic qualification programs with multiple operational states (for example, relays have three possible operational states: de-energized, energized, and change of state) will be used to determine the most sensitive equipment electrical operational state. The HRHF test run is performed on the equipment in its most sensitive electrical operational state to demonstrate its safety-related function under HRHF seismic excitation. If this is not possible, additional HRHF screening tests will be performed as needed to address the other most sensitive electrical operation states.

3I.7 References

1. EPRI Draft White Paper, “Considerations for NPP Equipment and Structures Subjected to Response Levels Caused by High Frequency Ground Motions,” Transmitted to NRC March 19, 2007.

2. APP-GW-GLR-115, “Effect of High Frequency Seismic Content on SSCs,” Westinghouse Electric Company LLC.

3. COL/DC-ISG-1, “Interim Staff Guidance on Seismic Issues of High Frequency Ground Motion,” May 19, 2008.

4. EPRI White Paper, “Seismic Screening of Components Sensitive to High Frequency Vibratory Motions,” June 2007.

5. Letter, R. Sisk (Westinghouse) to NRC, “AP1000 Response to Request for Additional Information (SRP3),” DCP/NRC2396, March 5, 2009.

Table 3I.6-1
Potential High Frequency Sensitive Equipment List

- Equipment or components with moving parts and required to perform a switching function during the seismic event (e.g., circuit breakers, contactors, auxiliary switches, molded case circuit breakers, motor control center starters, and pneumatic control assemblies)
- Components with moving parts that may bounce or chatter such as relays and actuation devices (e.g., shunt trips)
- Unrestrained components
- Potentiometers
- Process switches and sensors (e.g., pressure/differential pressure, temperature, level, limit/position, and flow)
- Components with accuracy requirements that may drift due to seismic loading
- Interfaces such as secondary contacts
  - Connectors and connections (including circuit board connections for digital and analog equipment)

Table 3I.6-2 (Sheet 1 of 21)
List of Potential High Frequency Sensitive
AP1000 Safety-Related electrical and
Electro-mechanical Equipment

Description	AP1000 Tag Number
Batteries	
IDSA 125V 60 Cell Battery 1A	IDSA-DB-1A
IDSA 125V 60 Cell Battery 1B	IDSA-DB-1B
IDSB 125V 60 Cell Battery 1A	IDSB-DB-1A
IDSB 125V 60 Cell Battery 1B	IDSB-DB-1B
IDSB 125V 60 Cell Battery 2A	IDSB-DB-2A
IDSB 125V 60 Cell Battery 2B	IDSB-DB-2B
IDSC 125V 60 Cell Battery 1A	IDSC-DB-1A
IDSC 125V 60 Cell Battery 1B	IDSC-DB-1B
IDSC 125V 60 Cell Battery 2A	IDSC-DB-2A
IDSC 125V 60 Cell Battery 2B	IDSC-DB-2B
IDSD 125V 60 Cell Battery 1A	IDSD-DB-1A
IDSD 125V 60 Cell Battery 1B	IDSD-DB-1B
Spare 125V 60 Cell Battery 1A	IDSS-DB-1A
Spare 125V 60 Cell Battery 1B	IDSS-DB-1B
Battery Chargers	
IDSA Battery Charger	IDSA-DC-1
IDSB Battery Charger 1	IDSB-DC-1
IDSB Battery Charger 2	IDSB-DC-2
IDSC Battery Charger 1	IDSC-DC-1
IDSC Battery Charger 2	IDSC-DC-2
IDSD Battery Charger	IDSD-DC-1
Spare Battery Charger	IDSS-DC-1
Distribution Panels	
IDSA 250 Vdc Dist Panel	IDSA-DD-1
IDSB 250 Vdc Dist Panel	IDSB-DD-1
IDSC 250 Vdc Dist Panel	IDSC-DD-1
IDSD 250 Vdc Dist Panel	IDSD-DD-1
IDSA 120 Vac Dist Panel 1	IDSA-EA-1
IDSA 120 Vac Dist Panel 2	IDSA-EA-2
IDSB 120 Vac Dist Panel 1	IDSB-EA-1
IDSB 120 Vac Dist Panel 2	IDSB-EA-2
IDSB 120 Vac Dist Panel 3	IDSB-EA-3
IDSC 120 Vac Dist Panel 1	IDSC-EA-1
IDSC 120 Vac Dist Panel 2	IDSC-EA-2
IDSC 120 Vac Dist Panel 3	IDSC-EA-3
IDSD 120 Vac Dist Panel 1	IDSD-EA-1
IDSD 120 Vac Dist Panel 2	IDSD-EA-2

Table 3I.6-2 (Sheet 2 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Fuse Panels	
IDSA Fuse Panel	IDSA-EA-4
IDSA Battery Monitor Fuse Panel	IDSA-EA-5
IDSB Fuse Panel	IDSB-EA-4
IDSB Fuse Panel	IDSB-EA-5
IDSB Fuse Panel	IDSB-EA-6
IDSB Battery Monitor Fuse Panel	IDSB-EA-7
IDSB Battery Monitor Fuse Panel	IDSB-EA-8
IDSC Fuse Panel	IDSC-EA-4
IDSC Fuse Panel	IDSC-EA-5
IDSC Fuse Panel	IDSC-EA-6
IDSC Battery Monitor Fuse Panel	IDSC-EA-7
IDSC Battery Monitor Fuse Panel	IDSC-EA-8
IDSD Fuse Panel	IDSD-EA-4
IDSD Battery Monitor Fuse Panel	IDSD-EA-5
IDSS Battery Monitor Fuse Panel	IDSS-EA-1
Stand-alone Electrical Isolation Devices	
Current-to-Current Transmitter 1	WLS-JD-MISX01
Current-to-Current Transmitter 1	WLS-JD-MISX02
Current-to-Current Transmitter 1	WLS-JD-MISX03
Transfer Switches	
IDSA Fused Transfer Switch Box 1	IDSA-DF-1
IDSB Fused Transfer Switch Box 1	IDSB-DF-1
IDSB Fused Transfer Switch Box 2	IDSB-DF-2
IDSC Fused Transfer Switch Box 1	IDSC-DF-1
IDSC Fused Transfer Switch Box 2	IDSC-DF-2
IDSD Fused Transfer Switch Box 1	IDSD-DF-1
IDSS Fused Transfer Switch Box 1	IDSS-DF-1
IDSS Spare Battery Termination Box	IDSS–DF-3
Motor Control Centers	
IDSA 250 Vdc MCC	IDSA-DK-1
IDSB 250 Vdc MCC	IDSB-DK-1
IDSC 250 Vdc MCC	IDSC-DK-1
IDSD 250 Vdc MCC	IDSD-DK-1
Switchboards	
IDSA 250 Vdc Switchboard 1	IDSA-DS-1
IDSB 250 Vdc Switchboard 1	IDSB-DS-1
IDSB 250 Vdc Switchboard 2	IDSB-DS-2
IDSC 250 Vdc Switchboard 1	IDSC-DS-1
IDSC 250 Vdc Switchboard 2	IDSC-DS-2
IDSD 250 Vdc Switchboard 1	IDSD-DS-1

Table 3I.6-2 (Sheet 3 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Transformers	
IDSA Regulating Transformer 1	IDSA-DT-1
IDSB Regulating Transformer 1	IDSB-DT-1
IDSC Regulating Transformer 1	IDSC-DT-1
IDSD Regulating Transformer 1	IDSD-DT-1
Inverters	
IDSA Inverter	IDSA-DU-1
IDSB Inverter 1	IDSB-DU-1
IDSB Inverter 2	IDSB-DU-2
IDSC Inverter 1	IDSC-DU-1
IDSC Inverter 2	IDSC-DU-2
IDSD Inverter	IDSD-DU-1
Switchgear	
RCP 1A 6900V Switchgear 31	ECS-ES-31
RCP 1A 6900V Switchgear 32	ECS-ES-32
RCP 2A 6900V Switchgear 51	ECS-ES-51
RCP 2A 6900V Switchgear 52	ECS-ES-52
RCP 1B 6900V Switchgear 41	ECS-ES-41
RCP 1B 6900V Switchgear 42	ECS-ES-42
RCP 2B 6900V Switchgear 61	ECS-ES-61
RCP 2B 6900V Switchgear 62	ECS-ES-62
Junction Box Division A	PMS-EJ-001A
Junction Box Division B	PMS-EJ-001B
Junction Box Division C	PMS-EJ-001C
Junction Box Division D	PMS-EJ-001D
Junction Box Division A	PMS-EJ-002A
Junction Box Division B	PMS-EJ-002B
Junction Box Division C	PMS-EJ-002C
Junction Box Division D	PMS-EJ-002D
Reactor Trip Switchgear	PMS-JD-RTSA01
Reactor Trip Switchgear	PMS-JD-RTSA02
Reactor Trip Switchgear	PMS-JD-RTSB01
Reactor Trip Switchgear	PMS-JD-RTSB02
Reactor Trip Switchgear	PMS-JD-RTSC01
Reactor Trip Switchgear	PMS-JD-RTSC02
Reactor Trip Switchgear	PMS-JD-RTSD01
Reactor Trip Switchgear	PMS-JD-RTSD02

Table 3I.6-2 (Sheet 4 of 21)
List of Potential High Frequency Sensitive
AP1000 Safety-Related electrical and
Electro-mechanical Equipment

Description	AP1000 Tag Number
Level Transmitters	
Core Makeup Tank A Narrow Range	PXS-JE-LE011A / PXS-JE-LT011A
Core Makeup Tank A Narrow Range	PXS-JE-LE011B / PXS-JE-LT011B
Core Makeup Tank A Narrow Range	PXS-JE-LE011C / PXS-JE-LT011C
Core Makeup Tank A Narrow Range	PXS-JE-LE011D / PXS-JE-LT011D
Core Makeup Tank B Narrow Range	PXS-JE-LE012A / PXS-JE-LT012A
Core Makeup Tank B Narrow Range	PXS-JE-LE012B / PXS-JE-LT012B
Core Makeup Tank B Narrow Range	PXS-JE-LE012C / PXS-JE-LT012C
Core Makeup Tank B Narrow Range	PXS-JE-LE012D / PXS-JE-LT012D
Core Makeup Tank A Narrow Range	PXS-JE-LE013A / PXS-JE-LT013A
Core Makeup Tank A Narrow Range	PXS-JE-LE013B / PXS-JE-LT013B
Core Makeup Tank A Narrow Range	PXS-JE-LE013C / PXS-JE-LT013C
Core Makeup Tank A Narrow Range	PXS-JE-LE013D / PXS-JE-LT013D
Core Makeup Tank B Narrow Range	PXS-JE-LE014A / PXS-JE-LT014A
Core Makeup Tank B Narrow Range	PXS-JE-LE014B / PXS-JE-LT014B
Core Makeup Tank B Narrow Range	PXS-JE-LE014C / PXS-JE-LT014C
Core Makeup Tank B Narrow Range	PXS-JE-LE014D / PXS-JE-LT014D
Containment Floodup Level	PXS-JE-LE050 / PXS-JE-LT050
Containment Floodup Level	PXS-JE-LE051 / PXS-JE-LT051
Containment Floodup Level	PXS-JE-LE052 / PXS-JE-LT052
Neutron Detectors	
Source Range Neutron Detector	RXS-JE-NE001A
Source Range Neutron Detector	RXS-JE-NE001B
Source Range Neutron Detector	RXS-JE-NE001C
Source Range Neutron Detector	RXS-JE-NE001D
Intermediate Range Neutron Detector	RXS-JE-NE002A
Intermediate Range Neutron Detector	RXS-JE-NE002B
Intermediate Range Neutron Detector	RXS-JE-NE002C
Intermediate Range Neutron Detector	RXS-JE-NE002D
Power Range Neutron Detector (Lower)	RXS-JE-NE003A
Power Range Neutron Detector (Lower)	RXS-JE-NE003B
Power Range Neutron Detector (Lower)	RXS-JE-NE003C
Power Range Neutron Detector (Lower)	RXS-JE-NE003D
Power Range Neutron Detector (Upper)	RXS-JE-NE004A
Power Range Neutron Detector (Upper)	RXS–JE-NE004B
Power Range Neutron Detector (Upper)	RXS-JE-NE004C
Power Range Neutron Detector (Upper)	RXS-JE-NE004D

Table 3I.6-2 (Sheet 5 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Radiation Monitors	
Containment High Range Area Monitor	PXS-JE-RE160
Containment High Range Area Monitor	PXS-JE-RE161
Containment High Range Area Monitor	PXS-JE-RE162
Containment High Range Area Monitor	PXS-JE-RE163
Control Room Supply Air Area Radiation Monitor - Particulate Detector	VBS-JE-RE001A
Control Room Supply Air Area Radiation Monitor - Particulate Detector	VBS-JE-RE001B
Control Room Supply Air Area Radiation Monitor - Iodine Detector	VBS-JE-RE002A
Control Room Supply Air Area Radiation Monitor - Iodine Detector	VBS-JE-RE002B
Control Room Supply Air Area Radiation Monitor - Noble Gas Detector	VBS-JE-RE003A
Control Room Supply Air Area Radiation Monitor - Noble Gas Detector	VBS-JE-RE003B
Control Room Supply Air Area Radiation Monitor - Air Flow Transmitter	VBS-JE-FT011A
Control Room Supply Air Area Radiation Monitor - Air Flow Transmitter	VBS-JE-FT011B
Control Room Supply Air Area Radiation Monitor - Sample Pump	VBS-MP-01A
Control Room Supply Air Area Radiation Monitor - Sample Pump	VBS-MP-01B
Control Room Supply Air Area Radiation Monitor - Local Radiation Processors	VBS-JE-RY001A
Control Room Supply Air Area Radiation Monitor - Local Radiation Processors	VBS-JE-RY001B
Speed Sensors	
RCP 1A Pump Speed	RCS-JE-ST281
RCP 1B Pump Speed	RCS-JE-ST282
RCP 2A Pump Speed	RCS-JE-ST283
RCP 2B Pump Speed	RCS-JE-ST284
Speed Sensor Preamplifier	
RCP 1A Speed Sensor Preamplifier Enclosure	PMS-JD-MIS01A
RCP 1B Speed Sensor Preamplifier Enclosure	PMS-JD-MIS01B
RCP 2A Speed Sensor Preamplifier Enclosure	PMS-JD-MIS02A
RCP 2B Speed Sensor Preamplifier Enclosure	PMS-JD-MIS02B
Transmitters	
PCS Water Delivery Flow	PCS-JE-FT001
PCS Water Delivery Flow	PCS-JE-FT002
PCS Water Delivery Flow	PCS-JE-FT003
PCS Water Delivery Flow	PCS-JE-FT004
PCS Storage Tank Water Level	PCS-JE-LT010
PCS Storage Tank Water Level	PCS-JE-LT011
PRHR HX Flow	PXS-JE-FT049A
PRHR HX Flow	PXS-JE-FT049B
RCS Hot Leg 1 Flow	RCS-JE-FT101A
RCS Hot Leg 1 Flow	RCS-JE-FT101B
RCS Hot Leg 1 Flow	RCS-JE-FT101C
RCS Hot Leg 1 Flow	RCS-JE-FT101D
RCS Hot Leg 2 Flow	RCS-JE-FT102A

Table 3I.6-2 (Sheet 6 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
RCS Hot Leg 2 Flow	RCS-JE-FT102B
RCS Hot Leg 2 Flow	RCS-JE-FT102C
RCS Hot Leg 2 Flow	RCS-JE-FT102D
SG1 Startup Feedwater Flow	SGS-JE-FT055A
SG1 Startup Feedwater Flow	SGS-JE-FT055B
SG2 Startup Feedwater Flow	SGS-JE-FT-056A
SG2 Startup Feedwater Flow	SGS-JE-FT056B
MCR Air Delivery Line Flow Rate – A	VES-JE-FT003A
MCR Air Delivery Line Flow Rate – B	VES-JE-FT003B
IRWST Wide Range Level	PXS-JE-LT046
IRWST Wide Range Level	PXS-JE-LT047
IRWST Wide Range Level	PXS-JE-LT048
IRWST Lower Narrow Range Level	PXS-JE-LT066
IRWST Lower Narrow Range Level	PXS-JE-LT067
IRWST Lower Narrow Range Level	PXS-JE-LT068
IRWST Lower Narrow Range Level	PXS-JE-LT069
RCS Hot Leg Water Level	RCS-JE-LT160A
RCS Hot Leg Water Level	RCS-JE-LT160B
PZR Level	RCS-JE-LT195A
PZR Level	RCS-JE-LT195B
PZR Level	RCS-JE-LT195C
PZR Level	RCS-JE-LT195D
SG1 Narrow Range Level	SGS-JE-LT001
SG1 Narrow Range Level	SGS-JE-LT002
SG1 Narrow Range Level	SGS-JE-LT003
SG1 Narrow Range Level	SGS-JE-LT004
SG2 Narrow Range Level	SGS-JE-LT005
SG2 Narrow Range Level	SGS-JE-LT006
SG2 Narrow Range Level	SGS-JE-LT007
SG2 Narrow Range Level	SGS-JE-LT008
SG1 Wide Range Level	SGS-JE-LT011
SG1 Wide Range Level	SGS-JE-LT012
SG1 Wide Range Level	SGS-JE-LT015
SG1 Wide Range Level	SGS-JE-LT016
SG2 Wide Range Level	SGS-JE-LT013
SG2 Wide Range Level	SGS-JE-LT014
SG2 Wide Range Level	SGS-JE-LT017
SG2 Wide Range Level	SGS-JE-LT018

Table 3I.6-2 (Sheet 7 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Spent Fuel Pool Level	SFS-JE-LT019A
Spent Fuel Pool Level	SFS-JE-LT019B
Spent Fuel Pool Level	SFS-JE-LT019C
WLS Auxiliary Building RCA Floodup Level	WLS-JE-LT400A
WLS Auxiliary Building RCA Floodup Level	WLS-JE-LT400B
Containment Pressure Normal Range	PCS-JE-PT005
Containment Pressure Normal Range	PCS-JE-PT006
Containment Pressure Normal Range	PCS-JE-PT007
Containment Pressure Normal Range	PCS-JE-PT008
Containment Pressure Extended Range	PCS-JE-PT012
Containment Pressure Extended Range	PCS-JE-PT013
Containment Pressure Extended Range	PCS-JE-PT014
RCS Wide Range Pressure	RCS-JE-PT140A
RCS Wide Range Pressure	RCS-JE-PT140B
RCS Wide Range Pressure	RCS-JE-PT140C
RCS Wide Range Pressure	RCS-JE-PT140D
PZR Pressure	RCS-JE-PT191A
PZR Pressure	RCS-JE-PT191B
PZR Pressure	RCS-JE-PT191C
PZR Pressure	RCS-JE-PT191D
Main Steam Line SG1 Pressure	SGS-JE-PT030
Main Steam Line SG1 Pressure	SGS-JE-PT031
Main Steam Line SG1 Pressure	SGS-JE-PT032
Main Steam Line SG1 Pressure	SGS-JE-PT033
Main Steam Line SG2 Pressure	SGS-JE-PT034
Main Steam Line SG2 Pressure	SGS-JE-PT035
Main Steam Line SG2 Pressure	SGS-JE-PT036
Main Steam Line SG2 Pressure	SGS-JE-PT037
Main Control Room Differential Pressure	VES-JE-PDT004A
Main Control Room Differential Pressure	VES-JE-PDT004B
Protection and Safety Monitoring Systems	
Bistable Coincident Logic Cabinet 01 Division A	PMS-JD-BCCA01
Bistable Coincident Logic Cabinet 02 Division A	PMS-JD-BCCA02
Bistable Coincident Logic Cabinet 01 Division B	PMS-JD-BCCB01
Bistable Coincident Logic Cabinet 02 Division B	PMS-JD-BCCB02
Bistable Coincident Logic Cabinet 01 Division C	PMS-JD-BCCC01
Bistable Coincident Logic Cabinet 02 Division C	PMS-JD-BCCC02
Bistable Coincident Logic Cabinet 01 Division D	PMS-JD-BCCD01
Bistable Coincident Logic Cabinet 02 Division D	PMS-JD-BCCD02
Integrated Logic Cabinet 01 Division A	PMS-JD-ILCA01
Integrated Logic Cabinet 02 Division A	PMS-JD-ILCA02
Integrated Logic Cabinet 03 Division A	PMS-JD-ILCA03
Integrated Logic Cabinet 01 Division B	PMS-JD-ILCB01
Integrated Logic Cabinet 02 Division B	PMS-JD-ILCB02

Table 3I.6-2 (Sheet 8 of 21)
List of Potential High Frequency Sensitive
AP1000 Safety-Related electrical and
Electro-mechanical Equipment

Description	AP1000 Tag Number
Integrated Logic Cabinet 03 Division B	PMS-JD-ILCB03
Integrated Logic Cabinet 04 Division B	PMS-JD-ILCB04
Integrated Logic Cabinet 01 Division C	PMS-JD-ILCC01
Integrated Logic Cabinet 02 Division C	PMS-JD-ILCC02
Integrated Logic Cabinet 01 Division D	PMS-JD-ILCD01
Integrated Logic Cabinet 02 Division D	PMS-JD-ILCD02
Integrated Logic Cabinet 03 Division D	PMS-JD-ILCD03
Integrated Logic Cabinet 04 Division D	PMS-JD-ILCD04
Maintenance and Test Cabinet Division A	PMS-JD-MTCA01
Maintenance and Test Cabinet Division B	PMS-JD-MTCB01
Maintenance and Test Cabinet Division C	PMS-JD-MTCC01
Maintenance and Test Cabinet Division D	PMS-JD-MTCD01
Nuclear Instrumentation Cabinet Division A	PMS-JD-NICA01
Nuclear Instrumentation Cabinet Division B	PMS-JD-NICB01
Nuclear Instrumentation Cabinet Division C	PMS-JD-NICC01
Nuclear Instrumentation Cabinet Division D	PMS-JD-NICD01
Qualified Data Processing System Cabinet Division B	PMS-JD-QDPB01
Qualified Data Processing System Cabinet Division C	PMS-JD-QDPC01
Division A Squib Valve Controller Cabinet	PMS-JD-SVCA01
Division B Squib Valve Controller Cabinet	PMS-JD-SVCB01
Division C Squib Valve Controller Cabinet	PMS-JD-SVCC01
Division D Squib Valve Controller Cabinet	PMS-JD-SVCD01
Source Range Neutron Flux Preamplifier Panel A	PMS-JW-005A
Source Range Neutron Flux Preamplifier Panel B	PMS-JW-005B
Source Range Neutron Flux Preamplifier Panel C	PMS-JW-005C
Source Range Neutron Flux Preamplifier Panel D	PMS-JW-005D
Intermediate Range Neutron Flux Preamplifier Panel A	PMS-JW-006A
Intermediate Range Neutron Flux Preamplifier Panel B	PMS-JW-006B
Intermediate Range Neutron Flux Preamplifier Panel C	PMS-JW-006C
Intermediate Range Neutron Flux Preamplifier Panel D	PMS-JW-006D

Table 3I.6-2 (Sheet 9 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Main Control Room	
Operator Workstation A	N/A
Operator Workstation B	N/A
Supervisor Workstation	N/A
Primary Dedicated Safety Panel	OCS-JC-10
Secondary Dedicated Safety Panel	OCS-JC-11
MCR/RSR Transfer Switch Panel	OCS-JW-001
Qualified Safety Display Division A	PMS-JD-QSPA01
Qualified Safety Display Division B	PMS-JD-QSPB01
Qualified Safety Display Division C	PMS-JD-QSPC01
Qualified Safety Display Division D	PMS-JD-QSPD01
MCR Load Shed Panel 1	VES-EP-01
MCR Load Shed Panel 2	VES-EP-02
Active Valves	
Containment Isolation – Air Out	
Solenoid Valve	CAS-PL-V014-S
Limit Switch	CAS-PL-V014-L
Containment Isolation – Inlet	
Limit Switch	CCS-PL-V200-L
Motor Operator	CCS-PL-V200-M
Containment Isolation – Outlet	
Limit Switch	CCS-PL-V207-L
Motor Operator	CCS-PL-V207-M
Containment Isolation – Outlet	
Limit Switch	CCS-PL-V208-L
Motor Operator	CCS-PL-V208-M
RCS Purification Stop Valve	
Limit Switch	CVS-PL-V001-L
Motor Operator	CVS-PL-V001-M
RCS Purification Stop Valve	
Limit Switch	CVS-PL-V002-L
Motor Operator	CVS-PL-V002-M
RCS Letdown Stop Valve	
Limit Switch	CVS-PL-V003-L
Motor Operator	CVS-PL-V003-M
WLS Letdown IRC Isolation	
Limit Switch	CVS-PL-V045-L
Solenoid Valve	CVS-PL-V045-S1
Letdown Flow ORC Isolation	
Limit Switch	CVS-PL-V047-L
Solenoid Valve	CVS-PL-V047-S1
Auxiliary PZR Spray Isolation	
Limit Switch	CVS-PL-V084-L
Solenoid Valve	CVS-PL-V084-S

Table 3I.6-2 (Sheet 10 of 21)
List of Potential High Frequency Sensitive
AP1000 Safety-Related electrical and
Electro-mechanical Equipment

Description	AP1000 Tag Number
Makeup Line Containment Isolation	
Limit Switch	CVS-PL-V090-L
Motor Operator	CVS-PL-V090-M
Makeup Line Containment Isolation	
Limit Switch	CVS-PL-V091-L
Motor Operator	CVS-PL-V091-M
Zinc Addition Containment Isolation	
Limit Switch	CVS-PL-V092-L
Solenoid Valve	CVS-PL-V092-S
Zinc Addition IRC Isolation Valve	
Limit Switch	CVS-PL-V094-L
Solenoid Valve	CVS-PL-V094-S
Demineralizer Water System Isolation	
Limit Switch	CVS-PL-V136A-L
Solenoid Valve	CVS-PL-V136A-S
Demineralized Water System Isolation	
Limit Switch	CVS-PL-V136B-L
Solenoid Valve	CVS-PL-V136B-S
Hydrogen Injection Containment Isolation	
Limit Switch	CVS-PL-V219-L
Solenoid Valve	CVS-PL-V219-S
PCCWST Isolation Valve	
Limit Switch	PCS-PL-V001A-L
Solenoid Valve	PCS-PL-V001A-S1
PCCWST Isolation Valve	
Limit Switch	PCS-PL-V001B-L
Solenoid Valve	PCS-PL-V001B-S1
PCCWST Isolation Valve	
Limit Switch	PCS-PL-V001C-L
Motor Operator	PCS-PL-V001C-M
PCCWST Isolation Valve	
Limit Switch	PCS-PL-V002A-L
Motor Operator	PCS-PL-V002A-M
PCCWST Isolation Valve	
Limit Switch	PCS-PL-V002B-L
Motor Operator	PCS-PL-V002B-M
PCCWST Isolation Valve	
Limit Switch	PCS-PL-V002C-L
Motor Operator	PCS-PL-V002C-M

Table 3I.6-2 (Sheet 11 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Containment Isolation – Air Sample Line	
Limit Switch	PSS-PL-V008-L
Solenoid Operator	PSS-PL-V008-S
Voltage Control Box	PSS-DJ-05
Containment Isolation – Liquid Sample Line	
Limit Switch	PSS-PL-V010A-L
Solenoid Operator	PSS-PL-V010A-S
Voltage Control Box	PSS-DJ-03
Containment Isolation – Liquid Sample Line	
Limit Switch	PSS-PL-V010B-L
Solenoid Operator	PSS-PL-V010B-S
Voltage Control Box	PSS-DJ-04
Containment Isolation – Liquid Sample Line	
Limit Switch	PSS-PL-V011A-L
Solenoid Valve	PSS-PL-V011A-S
Containment Isolation – Liquid Sample Line	
Limit Switch	PSS-PL-V011B-L
Solenoid Valve	PSS-PL-V011B-S
Containment Isolation - Sample Return Line	
Limit Switch	PSS-PL-V023-L
Solenoid Valve	PSS-PL-V023-S
Containment Isolation – Sample Return Line	
Limit Switch	PSS-PL-V024-L
Solenoid Operator	PSS-PL-V024-S
Voltage Control Box	PSS-DJ-06
Containment Isolation - Air Sample Line	
Limit Switch	PSS-PL-V046-L
Solenoid Valve	PSS-PL-V046-S
Core Makeup Tank A Discharge Isolation	
Limit Switch	PXS-PL-V014A-L
Solenoid Valve	PXS-PL-V014A-S1
Core Makeup Tank B Discharge Isolation	
Limit Switch	PXS-PL-V014B-L
Solenoid Valve	PXS-PL-V014B-S1
Core Makeup Tank A Discharge Isolation	
Limit Switch	PXS-PL-V015A-L
Solenoid Valve	PXS-PL-V015A-S1
Core Makeup Tank B Discharge Isolation	
Limit Switch	PXS-PL-V015B-L
Solenoid Valve	PXS-PL-V015B-S1

Table 3I.6-2 (Sheet 12 of 21)
List of Potential High Frequency Sensitive
AP1000 Safety-Related electrical and
Electro-mechanical Equipment

Description	AP1000 Tag Number
Nitrogen Supply Outside Containment Isolation	
Limit Switch	PXS-PL-V042-L
Solenoid Valve	PXS-PL-V042-S
PRHR HX Discharge Isolation	
Limit Switch	PXS-PL-V108A-L
Solenoid Valve	PXS-PL-V108A-S1
PRHR HX Discharge Isolation	
Limit Switch	PXS-PL-V108B-L
Solenoid Valve	PXS-PL-V108B-S1
Recirc Sump A Isolation	
Limit Switch	PXS-PL–V118A-L
Squib Operator	PXS-PL–V118A-T
Recirc Sump B Isolation	
Limit Switch	PXS-PL-V118B-L
Squib Operator	PXS-PL-V118B-T
Recirc Sump A	
Limit Switch	PXS-PL-V120A-L
Squib Operator	PXS-PL-V120A-T
Recirc Sump B	
Limit Switch	PXS-PL-V120B-L
Squib Operator	PXS-PL-V120B-T
IRWST Injection A	
Limit Switch	PXS-PL-V123A-L
Squib Operator	PXS-PL-V123A-T
IRWST Injection B	
Limit Switch	PXS-PL-V123B-L
Squib Operator	PXS-PL-V123B-T
IRWST Injection A	
Limit Switch	PXS-PL-V125A-L
Squib Operator	PXS-PL-V125A-T
IRWST Injection B	
Limit Switch	PXS-PL-V125B-L
Squib Operator	PXS-PL-V125B-T
IRWST Gutter Drain Isolation A	
Limit Switch	PXS-PL-V130A-L
Solenoid Valve	PXS-PL-V130A-S1
IRWST Gutter Drain Isolation B	
Limit Switch	PXS-PL-V130B-L
Solenoid Valve	PXS-PL-V130B-S1

Table 3I.6-2 (Sheet 13 of 21)
List of Potential High Frequency Sensitive
AP1000 Safety-Related electrical and
Electro-mechanical Equipment

Description	AP1000 Tag Number
First Stage ADS	
Limit Switch	RCS-PL-V001A-L
Motor Operator	RCS-PL-V001A-M
First Stage ADS	
Limit Switch	RCS-PL-V001B-L
Motor Operator	RCS-PL-V001B-M
Second Stage ADS	
Limit Switch	RCS-PL-V002A-L
Motor Operator	RCS-PL-V002A-M
Second Stage ADS	
Limit Switch	RCS-PL-V002B-L
Motor Operator	RCS-PL-V002B-M
Third Stage ADS	
Limit Switch	RCS-PL-V003A-L
Motor Operator	RCS-PL-V003A-M
Third Stage ADS	
Limit Switch	RCS-PL-V003B-L
Motor Operator	RCS-PL-V003B-M
Fourth Stage ADS	
Limit Switch	RCS-PL-V004A-L
Squib Operator	RCS-PL-V004A-T
Fourth Stage ADS	
Limit Switch	RCS-PL-V004B-L
Squib Operator	RCS-PL-V004B-T
Fourth Stage ADS	
Limit Switch	RCS-PL-V004C-L
Squib Operator	RCS-PL-V004C-T
Fourth Stage ADS	
Limit Switch	RCS-PL-V004D-L
Squib Operator	RCS-PL-V004D-T
First Stage ADS Isolation	
Limit Switch	RCS-PL-V011A-L
Motor Operator	RCS-PL-V011A-M
First Stage ADS Isolation	
Limit Switch	RCS-PL-V011B-L
Motor Operator	RCS-PL-V011B-M
Second Stage ADS Isolation	
Limit Switch	RCS-PL-V012A-L
Motor Operator	RCS-PL-V012A-M

Table 3I.6-2 (Sheet 14 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Second Stage ADS Isolation	
Limit Switch	RCS-PL-V012B-L
Motor Operator	RCS-PL-V012B-M
Third Stage ADS Isolation	
Limit Switch	RCS-PL-V013A-L
Motor Operator	RCS-PL-V013A-M
Third Stage ADS Isolation	
Limit Switch	RCS-PL-V013B-L
Motor Operator	RCS-PL-V013B-M
Reactor Vessel Head Vent	
Limit Switch	RCS-PL-V150A-L
Solenoid Operator	RCS-PL-V150A-S
Voltage Control Box	RCS-DJ-01
Reactor Vessel Head Vent	
Limit Switch	RCS-PL-V150B-L
Solenoid Operator	RCS-PL-V150B-S
Voltage Control Box	RCS-DJ-02
Reactor Vessel Head Vent	
Limit Switch	RCS-PL-V150C-L
Solenoid Operator	RCS-PL-V150C-S
Voltage Control Box	RCS-DJ-03
Reactor Vessel Head Vent	
Limit Switch	RCS-PL-V150D-L
Solenoid Operator	RCS-PL-V150D-S
Voltage Control Box	RCS-DJ-04
RCS Inner Suction Isolation	
Limit Switch	RNS-PL-V001A-L
Motor Operator	RNS-PL-V001A-M
RCS Inner Suction Isolation	
Limit Switch	RNS-PL-V001B-L
Motor Operator	RNS-PL-V001B-M
RCS Outer Suction Isolation	
Limit Switch	RNS-PL-V002A-L
Motor Operator	RNS-PL-V002A-M
RCS Outer Suction Isolation	
Limit Switch	RNS-PL-V002B-L
Motor Operator	RNS-PL-V002B-M

Table 3I.6-2 (Sheet 15 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
RNS Discharge Containment Isolation Valve	
Limit Switch	RNS-PL-V011-L
Motor Operator	RNS-PL-V011-M
RNS Suction Header Containment Isolation	
Limit Switch	RNS-PL-V022-L
Motor Operator	RNS-PL-V022-M
IRWST Suction Line Isolation	
Limit Switch	RNS-PL-V023-L
Motor Operator	RNS-PL-V023-M
RNS – CVS Containment Isolation	
Limit Switch	RNS-PL-V061-L
Air Operator	RNS-PL-V061-S
SDS – MCR Vent Isolation Valve	
Limit Switch	SDS-PL-V001-L
Motor Operator	SDS-PL-V001-M
SDS – MCR Vent Isolation Valve	
Limit Switch	SDS-PL-V002-L
Motor Operator	SDS-PL-V002-M
SFS Suction Line Containment Isolation	
Limit Switch	SFS-PL-V034-L
Motor Operator	SFS-PL–V034-M
SFS Suction Line Containment Isolation	
Limit Switch	SFS-PL-V035-L
Motor Operator	SFS- PL-V035-M
SFS Discharge Line Containment Isolation	
Limit Switch	SFS-PL-V038-L
Motor Operator	SFS-PL-V038-M
PORV Block Valve	
Limit Switch	SGS-PL-V027A-L
Motor Operator	SGS-PL-V027A-M
PORV Block Valve	
Limit Switch	SGS-PL-V027B-L
Motor Operator	SGS-PL-V027B-M
Main Steam Safety Valve 1 Limit Switch	SGS-PL-V030A-L
Main Steam Safety Valve 1 Limit Switch	SGS-PL-V030B-L
Main Steam Safety Valve 2 Limit Switch	SGS-PL-V031A-L
Main Steam Safety Valve 2 Limit Switch	SGS-PL-V031B-L
Main Steam Safety Valve 3 Limit Switch	SGS-PL-V032A-L
Main Steam Safety Valve 3 Limit Switch	SGS-PL-V032B-L

Table 3I.6-2 (Sheet 16 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Main Steam Safety Valve 4 Limit Switch	SGS-PL-V033A-L
Main Steam Safety Valve 4 Limit Switch	SGS-PL-V033B-L
Main Steam Safety Valve 5 Limit Switch	SGS-PL-V034A-L
Main Steam Safety Valve 5 Limit Switch	SGS-PL-V034B-L
Main Steam Safety Valve 6 Limit Switch	SGS-PL-V035A-L
Main Steam Safety Valve 6 Limit Switch	SGS-PL-V035B-L
Steam Line Condensate Drain Isolation	
Limit Switch	SGS-PL-V036A-L
Solenoid Valve	SGS-PL-V036A-S
Steam Line Condensate Drain Isolation	
Limit Switch	SGS-PL-V036B-L
Solenoid Valve	SGS-PL-V036B-S
Main Steam Line Isolation	
Limit Switch	SGS-PL-V040A-L
Solenoid Valve	SGS-PL-V040A-S1
Solenoid Valve	SGS-PL-V040A-S2
Solenoid Valve	SGS-PL-V040A-S3
Solenoid Valve	SGS-PL-V040A-S4
Main Steam Line Isolation	
Limit Switch	SGS-PL-V040B-L
Solenoid Valve	SGS-PL-V040B-S1
Solenoid Valve	SGS-PL-V040B-S2
Solenoid Valve	SGS-PL-V040B-S3
Solenoid Valve	SGS-PL-V040B-S4
Main Feedwater Isolation	
Limit Switch	SGS-PL-V057A-L
Solenoid Valve	SGS-PL-V057A-S1
Solenoid Valve	SGS-PL-V057A-S2
Solenoid Valve	SGS-PL-V057A-S3
Solenoid Valve	SGS-PL-V057A-S4
Main Feedwater Isolation	
Limit Switch	SGS-PL-V057B-L
Solenoid Valve	SGS-PL-V057B-S1
Solenoid Valve	SGS-PL-V057B-S2
Solenoid Valve	SGS-PL-V057B-S3
Solenoid Valve	SGS-PL-V057B-S4
Startup Feedwater Isolation	
Limit Switch	SGS-PL-V067A-L
Motor Operator	SGS-PL-V067A-M

Table 3I.6-2 (Sheet 17 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Startup Feedwater Isolation	
Limit Switch	SGS-PL-V067B-L
Motor Operator	SGS-PL-V067B-M
SG Blowdown Isolation	
Limit Switch	SGS-PL-V074A-L
Solenoid Valve	SGS-PL-V074A-S
SG Blowdown Isolation	
Limit Switch	SGS-PL-V074B-L
Solenoid Valve	SGS-PL-V074B-S
SG Series Blowdown Isolation	
Limit Switch	SGS-PL-V075A-L
Solenoid Valve	SGS-PL-V075A-S
SG Series Blowdown Isolation	
Limit Switch	SGS-PL-V075B-L
Solenoid Valve	SGS-PL-V075B-S
Steam Line Condensate Drain Isolation	
Level Switch	SGS-PL-V086A-L
Solenoid Valve	SGS-PL-V086A-S
Steam Line Condensate Drain Isolation	
Limit Switch	SGS-PL-V086B-L
Solenoid Valve	SGS-PL-V086B-S
Power Operated Relief Valve	
Limit Switch	SGS-PL-V233A-L
Solenoid Valve	SGS-PL-V233A-S
Power Operated Relief Valve	
Limit Switch	SGS-PL-V233B-L
Solenoid Valve	SGS-PL-V233B-S
MSIV Bypass Isolation Valve	
Limit Switch	SGS-PL-V240A-L
Solenoid Valve	SGS-PL-V240A-S1
Solenoid Valve	SGS-PL-V240A-S2
MSIV Bypass Isolation Valve	
Limit Switch	SGS-PL-V240B-L
Solenoid Valve	SGS-PL-V240B-S1
Solenoid Valve	SGS-PL-V240B-S2
Main Feedwater Control Valve	
Limit Switch	SGS-PL-V250A-L
Solenoid Valve	SGS-PL-V250A-S

Table 3I.6-2 (Sheet 18 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Main Feedwater Control Valve	
Limit Switch	SGS-PL-V250B-L
Solenoid Valve	SGS-PL-V250B-S
Startup Feedwater Control Valve	
Limit Switch	SGS-PL-V255A-L
Solenoid Valve	SGS-PL-V255A-S
Startup Feedwater Control Valve	
Limit Switch	SGS-PL-V255B-L
Solenoid Valve	SGS-PL-V255B-S
MCR Isolation Valve	
Limit Switch	VBS-PL-V186-L
Motor Operator	VBS-PL-V186-M
MCR Isolation Valve	
Limit Switch	VBS-PL-V187-L
Motor Operator	VBS-PL-V187-M
MCR Isolation Valve	
Limit Switch	VBS-PL-V188-L
Motor Operator	VBS-PL-V188-M
MCR Isolation Valve	
Limit Switch	VBS-PL-V189-L
Motor Operator	VBS-PL-V189-M
MCR Isolation Valve	
Limit Switch	VBS-PL-V190-L
Motor Operator	VBS-PL-V190-M
MCR Isolation Valve	
Limit Switch	VBS-PL-V191-L
Motor Operator	VBS-PL-V191-M
Air Delivery Isolation Valve A	
Limit Switch	VES-PL-V005A-L
Solenoid Operator	VES-PL-V005A-S
Voltage Control Box	VES-DJ-01
Air Delivery Isolation Valve B	
Limit Switch	VES-PL-V005B-L
Solenoid Operator	VES-PL-V005B-S
Voltage Control Box	VES-DJ-02
Relief Isolation Valve A	
Limit Switch	VES-PL-V022A-L
Solenoid Valve	VES-PL-V022A-S

Table 3I.6-2 (Sheet 19 of 21)
List of Potential High Frequency Sensitive
AP1000 Safety-Related electrical and
Electro-mechanical Equipment

Description	AP1000 Tag Number
Relief Isolation Valve B	
Limit Switch	VES-PL-V022B-L
Solenoid Valve	VES-PL-V022B-S
Containment Purge Inlet Isolation	
Limit Switch	VFS-PL-V003-L
Solenoid Valve	VFS-PL-V003-S1
Containment Purge Inlet Isolation	
Limit Switch	VFS-PL-V004-L
Solenoid Valve	VFS-PL-V004-S1
Containment Purge Discharge Isolation	
Limit Switch	VFS-PL-V009-L
Solenoid Valve	VFS-PL-V009-S1
Containment Purge Discharge Isolation	
Limit Switch	VFS-PL-V010-L
Solenoid Valve	VFS-PL-V010-S1
Vacuum Relief Containment Isolation Valve A - ORC	
Limit Switch	VFS-PL-V800A-L
Motor Operator	VFS-PL-V800A-M
Vacuum Relief Containment Isolation Valve B - ORC	
Limit Switch	VFS-PL-V800B-L
Motor Operator	VFS-PL-V800B-M
Fan Cooler Supply Isolation	
Limit Switch	VWS-PL-V058-L
Solenoid Valve	VWS-PL-V058-S
Fan Cooler Return Isolation	
Limit Switch	VWS-PL-V082-L
Solenoid Valve	VWS-PL-V082-S
Fan Cooler Return Isolation	
Limit Switch	VWS-PL-V086-L
Solenoid Valve	VWS-PL-V086-S
Sump Containment Isolation IRC	
Limit Switch	WLS-PL-V055-L
Solenoid Valve	WLS-PL-V055-S1
Sump Containment Isolation ORC	
Limit Switch	WLS-PL-V057-L
Solenoid Valve	WLS-PL-V057-S1

Table 3I.6-2 (Sheet 20 of 21)
List of Potential High Frequency Sensitive
AP1000 Safety-Related electrical and
Electro-mechanical Equipment

Description	AP1000 Tag Number
RCDT Gas Containment Isolation	
Limit Switch	WLS-PL-V067-L
Solenoid Valve	WLS-PL-V067-S
RCDT Gas Containment Isolation	
Limit Switch	WLS-PL-V068-L
Solenoid Valve	WLS-PL-V068-S
Nonactive Valves	
Hot Leg 1 Sample Isolation	
Limit Switch	PSS-PL-V001A-L
Solenoid Valve	PSS-PL-V001A-S
Voltage Control Box	PSS-DJ-01
Hot Leg 2 Sample Isolation	
Limit Switch	PSS-PL-V001B-L
Solenoid Valve	PSS-PL-V001B-S
Voltage Control Box	PSS-DJ-02
Core Makeup Tank A CL Inlet Isolation	
Limit Switch	PXS-PL-V002A-L
Motor Operator	PXS-PL-V002A-M
Core Makeup Tank B CL Inlet Isolation	
Limit Switch	PXS-PL-V002B-L
Motor Operator	PXS-PL-V002B-M
Accumulator A N2 Vent Isolation	
Limit Switch	PXS-PL-V021A-L
Solenoid Valve	PXS-PL-V021A-S
Accumulator B N2 Vent Isolation	
Limit Switch	PXS-PL-V021B-L
Solenoid Valve	PXS-PL-V021B-S
Accumulator A Discharge Isolation	
Limit Switch	PXS-PL-V027A-L
Motor Operator	PXS-PL-V027A-M
Accumulator B Discharge Isolation	
Limit Switch	PXS-PL-V027B-L
Motor Operator	PXS-PL-V027B-M
PRHR HX Inlet Isolation	
Limit Switch	PXS-PL-V101-L
Motor Operator	PXS-PL-V101-M
Recirc Sump A Isolation	
Limit Switch	PXS-PL-V117A-L
Motor Operator	PXS-PL-V117A-M

Table 3I.6-2 (Sheet 21 of 21)
List of Potential High Frequency Sensitive AP1000 Safety-Related electrical and Electro-mechanical Equipment

Description	AP1000 Tag Number
Recirc Sump B Isolation	
Limit Switch	PXS-PL-V117B-L
Motor Operator	PXS-PL-V117B-M
IRWST Line A Isolation	
Limit Switch	PXS-PL-V121A-L
Motor Operator	PXS-PL-V121A-M
IRWST Line B Isolation	
Limit Switch	PXS-PL-V121B-L
Motor Operator	PXS-PL-V121B-M
Core Makeup Tank A Fill Isolation	
Limit Switch	PXS-PL-V230A-L
Solenoid Valve	PXS-PL-V230A-S
Core Makeup Tank B Fill Isolation	
Limit Switch	PXS-PL-V230B-L
Solenoid Valve	PXS-PL-V230B-S
Accumulator A Fill/Drain Isolation	
Limit Switch	PXS-PL-V232A-L
Solenoid Valve	PXS-PL-V232A-S
Accumulator B Fill/Drain Isolation	
Limit Switch	PXS-PL-V232B-L
Solenoid Valve	PXS-PL-V232B-S
Fourth Stage ADS Isolation	
Limit Switch	RCS-PL-V014A-L
Motor Operator	RCS-PL-V014A-M
Fourth Stage ADS Isolation	
Limit Switch	RCS-PL-V014B-L
Motor Operator	RCS-PL-V014B-M
Fourth Stage ADS Isolation	
Limit Switch	RCS-PL-V014C-L
Motor Operator	RCS-PL-V014C-M
Fourth Stage ADS Isolation	
Limit Switch	RCS-PL-V014D-L
Motor Operator	RCS-PL-V014D-M

Table 3I.6-3 (Sheet 1 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Resistance Temperature Detectors		
PRHR HX Outlet Temperature	RCS-JE-TE161	1
RCS Cold Leg 1A Narrow Range Temperature	RCS-JE-TE121A	1
RCS Cold Leg 1A Narrow Range Temperature	RCS-JE-TE121D	1
RCS Cold Leg 1B Narrow Range Temperature	RCS-JE-TE121B	1
RCS Cold Leg 1B Narrow Range Temperature	RCS-JE-TE121C	1
RCS Cold Leg 2A Narrow Range Temperature	RCS-JE-TE122B	1
RCS Cold Leg 2A Narrow Range Temperature	RCS-JE-TE122C	1
RCS Cold Leg 2B Narrow Range Temperature	RCS-JE-TE122A	1
RCS Cold Leg 2B Narrow Range Temperature	RCS-JE-TE122D	1
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE131A	1
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE131C	1
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE132A	1
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE132C	1
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE133C	1
RCS Hot Leg 1 Narrow Range Temperature	RCS-JE-TE133A	1
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE131B	1
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE131D	1
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE132B	1
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE132D	1
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE133B	1
RCS Hot Leg 2 Narrow Range Temperature	RCS-JE-TE133D	1
RCS Cold Leg 1A Dual Range Temperature	RCS-JE-TE125A	1
RCS Cold Leg 1B Dual Range Temperature	RCS-JE-TE125C	1
RCS Cold Leg 2A Dual Range Temperature	RCS-JE-TE125B	1
RCS Cold Leg 2B Dual Range Temperature	RCS-JE-TE125D	1
RCS Hot Leg 1 Wide Range Temperature	RCS-JE-TE135A	1
RCS Hot Leg 2 Wide Range Temperature	RCS-JE-TE135B	1
PZR Reference Leg Level Temperature	RCS-JE-TE193A	1
PZR Reference Leg Level Temperature	RCS-JE-TE193B	1
PZR Reference Leg Level Temperature	RCS-JE-TE193C	1
PZR Reference Leg Level Temperature	RCS-JE-TE193D	1

Table 3I.6-3 (Sheet 2 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
RCP 1A Bearing Water Temperature	RCS-JE-TE211A	1
RCP 1A Bearing Water Temperature	RCS-JE-TE211B	1
RCP 1A Bearing Water Temperature	RCS-JE-TE211C	1
RCP 1A Bearing Water Temperature	RCS-JE-TE211D	1
RCP 1B Bearing Water Temperature	RCS-JE-TE212A	1
RCP 1B Bearing Water Temperature	RCS-JE-TE212B	1
RCP 1B Bearing Water Temperature	RCS-JE-TE212C	1
RCP 1B Bearing Water Temperature	RCS-JE-TE212D	1
RCP 2A Bearing Water Temperature	RCS-JE-TE213A	1
RCP 2A Bearing Water Temperature	RCS-JE-TE213B	1
RCP 2A Bearing Water Temperature	RCS-JE-TE213C	1
RCP 2A Bearing Water Temperature	RCS-JE-TE213D	1
RCP 2B Bearing Water Temperature	RCS-JE-TE214A	1
RCP 2B Bearing Water Temperature	RCS-JE-TE214B	1
RCP 2B Bearing Water Temperature	RCS-JE-TE214C	1
RCP 2B Bearing Water Temperature	RCS-JE-TE214D	1
Thermocouples		1
Incore Thermocouples (Note 4)	IIS-JE-TE001-TE042	1
Penetrations		
Penetrations (Mechanical)		1
Penetrations (Electrical)		1
Active Valves		
Containment Isolation – Air Out	CAS-PL-V014	2
Containment Isolation – Air In	CAS-PL-V015	2
Containment Isolation – Inlet	CCS-PL-V200	2
Service Air Supply Inside Containment Isolation	CAS-PL-V205	2
Containment Isolation – Inlet	CCS-PL-V201	2
Containment Isolation – Outlet	CCS-PL-V207	2
Containment Isolation – Outlet	CCS-PL-V208	2
CCS Containment Isolation Relief	CCS-PL-V220	2
CCS IRC Relief Valve	CCS-PL-V270	2
CCS IRC Relief Valve	CCS-PL-V271	2
RCS Purification Stop Valve	CVS-PL-V001	2
RCS Purification Stop Valve	CVS-PL-V002	2
RCS Letdown Stop Valve	CVS-PL-V003	2
Demineralizer Flush Line Relief Valve	CVS-PL-V042	2

Table 3I.6-3 (Sheet 3 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
WLS Letdown IRC Isolation	CVS-PL-V045	2
Letdown Flow ORC Isolation	CVS-PL-V047	2
Letdown Line Containment Isolation Thermal Relief	CVS-PL-V058	2
CVS Makeup Line Bypass Check Valve	CVS-PL-V067	2
RCS Purification Check Valve	CVS-PL-V080	2
RCS Purification Stop Valve	CVS-PL-V081	2
RCS Purification Check Valve	CVS-PL-V082	2
Auxiliary PZR Spray Isolation	CVS-PL-V084	2
Auxiliary PZR Spray Isolation	CVS-PL-V085	2
Makeup Line Containment Isolation	CVS-PL-V090	2
Makeup Line Containment Isolation	CVS-PL-V091	2
Zinc Addition Containment Isolation	CVS-PL-V092	2
Zinc Addition Containment Isolation	CVS-PL-V094	2
Zinc Injection Containment Isolation Thermal Overpressurization Relief Valve	CVS-PL-V098	2
Makeup Containment Isolation	CVS-PL-V100	2
Demineralizer Water System Isolation	CVS-PL-V136A	2
Demineralized Water System Isolation	CVS-PL-V136B	2
Hydrogen Injection Containment Isolation Check Valve	CVS-PL-V217	2
Hydrogen Injection Containment Isolation	CVS-PL-V219	2
DWS Containment Penetration Thermal Relief Valve	DWS-PL-V241	2
Demin Water Supply Containment Isolation – Inside	DWS-PL-V245	2
Fuel Transfer Tube Gate Valve	FHS-PL-V001	2
Fire Water Containment Supply Isolation – Inside	FPS-PL-V052	2
FPS Containment Penetration Thermal Relief Valve	FPS-PL-V702	2
PCCWST Isolation Valve	PCS-PL-V001A	2
PCCWST Isolation Valve	PCS-PL-V001B	2
PCCWST Isolation Valve	PCS-PL-V001C	2
PCCWST Isolation Valve	PCS-PL-V002A	2
PCCWST Isolation Valve	PCS-PL-V002B	2
PCCWST Isolation Valve	PCS-PL-V002C	2
PCCWST Fire Protection Isolation	PCS-PL-V005	2
PCCWST Emergency Spent Fuel Pool Makeup Isolation	PCS-PL-V009	2
Water Bucket Makeup Line Drain Valve	PCS-PL-V015	2
Water Bucket Makeup Line Isolation Valve	PCS-PL-V020	2
PCS Recirculation Isolation	PCS-PL-V023	2
PCCWST Long-Term Makeup Check Valve	PCS-PL-V039	2
PCCWST Long Term Makeup Isolation Drain Valve	PCS-PL-V042	2
PCCWST Long Term Makeup Isolation Valve	PCS-PL-V044	2
Emergency Makeup to the Spent Fuel Pool Isolation Valve	PCS-PL-V045	2

Table 3I.6-3 (Sheet 4 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
PCCWST Recirculation Return Isolation Valve	PCS-PL-V046	2
Emergency Makeup to the Spent Fuel Pool Drain Isolation Valve	PCS-PL-V049	2
Spent Fuel Pool Long Term Makeup Isolation Valve	PCS-PL-V050	2
Spent Fuel Pool Emergency Makeup Lower Isolation Valve	PCS-PL-V051	2
Shutoff Valve for Leakage Sensor	PCS-PL-V060A	2
Shutoff Valve for Leakage Sensor	PCS-PL-V060B	2
Containment Isolation – Air Sample Line	PSS-PL-V008	2
Containment Isolation – Liquid Sample Line	PSS-PL-V010A	2
Containment Isolation – Liquid Sample Line	PSS-PL-V010B	2
Containment Isolation – Liquid Sample Line	PSS-PL-V011A	2
Containment Isolation – Liquid Sample Line	PSS-PL-V011B	2
Containment Isolation – Sample Return Line	PSS-PL-V023	2
Containment Isolation Sample Return	PSS-PL-V024	2
Containment Isolation – Air Sample Line	PSS-PL-V046	2
PWS MCR Isolation Valve	PWS-PL-V418	2
PWS MCR Isolation Valve	PWS-PL-V420	2
PWS MCR Vacuum Relief	PWS-PL-V498	2
Core Makeup Tank A Discharge Isolation	PXS-PL-V014A	2
Core Makeup Tank B Discharge Isolation	PXS-PL-V014B	2
Core Makeup Tank A Discharge Isolation	PXS-PL-V015A	2
Core Makeup Tank B Discharge Isolation	PXS-PL-V015B	2
Core Makeup Tank A Discharge	PXS-PL-V016A	2
Core Makeup Tank B Discharge	PXS-PL-V016B	2
Core Makeup Tank A Discharge	PXS-PL-V017A	2
Core Makeup Tank B Discharge	PXS-PL-V017B	2
Accumulator A Pressure Relief	PXS-PL-V022A	2
Accumulator B Pressure Relief	PXS-PL-V022B	2
Accumulator A Discharge	PXS-PL-V028A	2
Accumulator B Discharge	PXS-PL-V028B	2
Accumulator A Discharge	PXS-PL-V029A	2
Accumulator B Discharge	PXS-PL-V029B	2
Nitrogen Supply Outside Containment Isolation	PXS-PL-V042	2
Nitrogen Supply Containment Isolation IRC Check Valve	PXS-PL-V043	2
PRHR HX Discharge Isolation	PXS-PL-V108A	2
PRHR HX Discharge Isolation	PXS-PL-V108B	2

Table 3I.6-3 (Sheet 5 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Recirc Sump A Isolation	PXS-PL-V118A	2
Recirc Sump B Isolation	PXS-PL-V118B	2
Recirc Sump A Isolation	PXS-PL-V119A	2
Recirc Sump B Isolation	PXS-PL-V119B	2
Recirc Sump A Isolation	PXS-PL-V120A	2
Recirc Sump B Isolation	PXS- PL-V120B	2
IRWST Injection A	PXS-PL-V122A	2
IRWST Injection B	PXS-PL-V122B	2
IRWST Injection A	PXS-PL-V123A	2
IRWST Injection B	PXS-PL-V123B	2
IRWST Injection A	PXS-PL-V124A	2
IRWST Injection B	PXS-PL-V124B	2
IRWST Injection A	PXS-PL-V125A	2
IRWST Injection B	PXS-PL-V125B	2
IRWST Gutter Drain Isolation A	PXS-PL-V130A	2
IRWST Gutter Drain Isolation B	PXS-PL-V130B	2
First Stage ADS	RCS-PL-V001A	2
First Stage ADS	RCS-PL-V001B	2
Second Stage ADS	RCS-PL-V002A	2
Second Stage ADS	RCS-PL-V002B	2
Third Stage ADS	RCS-PL-V003A	2
Third Stage ADS	RCS-PL-V003B	2
Fourth Stage ADS	RCS-PL-V004A	2
Fourth Stage ADS	RCS-PL-V004B	2
Fourth Stage ADS	RCS-PL-V004C	2
Fourth Stage ADS	RCS-PL-V004D	2
PZR Safety Valve	RCS-PL-V005A	2
PZR Safety Valve	RCS-PL-V005B	2
ADS Discharge Header A Relief	RCS-PL-V010A	2
ADS Discharge Header B Relief	RCS-PL-V010B	2
First Stage ADS Isolation	RCS-PL-V011A	2
First Stage ADS Isolation	RCS-PL-V011B	2
Second Stage ADS Isolation	RCS-PL-V012A	2
Second Stage ADS Isolation	RCS-PL-V012B	2
Third Stage ADS Isolation	RCS-PL-V013A	2
Third Stage ADS Isolation	RCS-PL-V013B	2

Table 3I.6-3 (Sheet 6 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Reactor Vessel Head Vent	RCS-PL-V150A	2
Reactor Vessel Head Vent	RCS-PL-V150B	2
Reactor Vessel Head Vent	RCS-PL-V150C	2
Reactor Vessel Head Vent	RCS-PL-V150D	2
RCS Inner Suction Isolation	RNS-PL-V001A	2
RCS Inner Suction Isolation	RNS-PL-V001B	2
RCS Outer Suction Isolation	RNS-PL-V002A	2
RCS Outer Suction Isolation	RNS-PL-V002B	2
RCS Thermal Relief	RNS-PL-V003A	2
RCS Thermal Relief	RNS-PL-V003B	2
RNS Discharge Containment Isolation Valve	RNS-PL-V011	2
RNS Discharge Containment Isolation Valve Test Connection	RNS-PL-V012	2
RNS Discharge Containment Isolation	RNS-PL-V013	2
RNS Discharge RCS Pressure Boundary	RNS-PL-V015A	2
RNS Discharge RCS Pressure Boundary	RNS-PL-V015B	2
RNS Discharge RCS Pressure Boundary	RNS-PL-V017A	2
RNS Discharge RCS Pressure Boundary	RNS-PL-V017B	2
RNS Hot Leg Suction Relief	RNS-PL-V020	2
RNS Hot Leg Suction Relief	RNS-PL-V021	2
RNS Suction Header Containment Isolation	RNS-PL-V022	2
IRWST Suction Line Isolation	RNS-PL-V023	2
RNS Pump Discharge Relief	RNS-PL-V045	2
RNS – CVS Containment Isolation	RNS-PL-V061	2
SDS MCR Vent Isolation Valve	SDS-PL-V001	2
SDS MCR Vent Isolation Valve	SDS-PL-V002	2
SFS Suction Line Containment Isolation	SFS-PL-V034	2
SFS Suction Line Containment Isolation	SFS-PL-V035	2
SFS Discharge Containment Isolation	SFS-PL-V037	2
SFS Discharge Line Containment Isolation	SFS-PL-V038	2
SFS Cask Loading Pit to SFS Pump	SFS-PL-V042	2
SFS Pump to Cask Loading Pit	SFS-PL-V045	2
Cask Loading Pit to WLS	SFS-PL-V049	2
Spent Fuel Pool to Cask Washdown Pit Isolation	SFS-PL-V066	2
SFS Containment Isolation Relief	SFS-PL-V067	2
Cask Washdown Pit Drain Isolation	SFS-PL-V068	2
Refueling Cavity to SG Compartment	SFS-PL-V071	2
Refueling Cavity to SG Compartment	SFS-PL-V072	2
Refueling Cavity Drain Line Test Connection	SFS-PL-V117	2
PORV Block Valve	SGS-PL-V027A	2
PORV Block Valve	SGS-PL-V027B	2

Table 3I.6-3 (Sheet 7 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Steam Safety Valve SG01	SGS-PL-V030A	2
Steam Safety Valve SG02	SGS-PL-V030B	2
Steam Safety Valve SG01	SGS-PL-V031A	2
Steam Safety Valve SG02	SGS-PL-V031B	2
Steam Safety Valve SG01	SGS-PL-V032A	2
Steam Safety Valve SG02	SGS-PL-V032B	2
Steam Safety Valve SG01	SGS-PL-V033A	2
Steam Safety Valve SG02	SGS-PL-V033B	2
Steam Safety Valve SG01	SGS-PL-V034A	2
Steam Safety Valve SG02	SGS-PL-V034B	2
Steam Safety Valve SG01	SGS-PL-V035A	2
Steam Safety Valve SG02	SGS-PL-V035B	2
Steam Line Condensate Drain Isolation	SGS-PL-V036A	2
Steam Line Condensate Drain Isolation	SGS-PL-V036B	2
Main Steam Line Isolation	SGS-PL-V040A	2
Main Steam Line Isolation	SGS-PL-V040B	2
Main Feedwater Isolation	SGS-PL-V057A	2
Main Feedwater Isolation	SGS-PL-V057B	2
Startup Feedwater Isolation	SGS-PL-V067A	2
Startup Feedwater Isolation	SGS-PL-V067B	2
SG Blowdown Isolation	SGS-PL-V074A	2
SG Blowdown Isolation	SGS-PL-V074B	2
SG Series Blowdown Isolation	SGS-PL-V075A	2
SG Series Blowdown Isolation	SGS-PL-V075B	2
Steam Line Condensate Drain Isolation	SGS-PL-V086A	2
Steam Line Condensate Drain Isolation	SGS-PL-V086B	2
Power-Operated Relief Valve	SGS-PL-V233A	2
Power-Operated Relief Valve	SGS-PL-V233B	2
MSIV Bypass Isolation Valve	SGS-PL-V240A	2
MSIV Bypass Isolation Valve	SGS-PL-V240B	2
Main Feedwater Control Valve	SGS-PL-V250A	2
Main Feedwater Control Valve	SGS-PL-V250B	2
Startup Feedwater Control Valve	SGS-PL-V255A	2
Startup Feedwater Control Valve	SGS-PL-V255B	2
Main Feedwater Thermal Relief Valve	SGS-PL-V257A	2
Main Feedwater Thermal Relief Valve	SGS-PL-V257B	2
Startup Feedwater Thermal Relief Valve	SGS-PL-V258A	2
Startup Feedwater Thermal Relief Valve	SGS-PL-V258B	2
MCR Isolation Valve	VBS-PL-V186	2
MCR Isolation Valve	VBS-PL-V187	2
MCR Isolation Valve	VBS-PL-V188	2
MCR Isolation Valve	VBS-PL-V189	2
MCR Isolation Valve	VBS-PL-V190	2
MCR Isolation Valve	VBS-PL-V191	2

Table 3I.6-3 (Sheet 8 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Air Delivery Isolation Valve	VES-PL-V001	2
Pressure Regulator Valve A	VES-PL-V002A	2
Pressure Regulator Valve B	VES-PL-V002B	2
Air Delivery Isolation Valve A	VES-PL-V005A	2
Air Delivery Isolation Valve B	VES-PL-V005B	2
Temporary Instrument Isolation Valve A	VES-PL-V018	2
Temporary Instrument Isolation Valve B	VES-PL-V019	2
Relief Isolation Valve A	VES-PL-V022A	2
Relief Isolation Valve B	VES-PL-V022B	2
Air Tank Safety Relief Valve A	VES-PL-V040A	2
Air Tank Safety Relief Valve B	VES-PL-V040B	2
Air Tank Safety Relief Valve C	VES-PL-V040C	2
Air Tank Safety Relief Valve D	VES-PL-V040D	2
Main Air Flow Path Isolation Valve	VES-PL-V044	2
Containment Purge Inlet Isolation	VFS-PL-V003	2
Containment Purge Inlet Isolation	VFS-PL-V004	2
Containment Purge Discharge Isolation	VFS-PL-V009	2
Containment Purge Discharge Isolation	VFS-PL-V010	2
Vacuum Relief Containment Isolation Valve A - ORC	VFS-PL-V800A	2
Vacuum Relief Containment Isolation Valve B - ORC	VFS-PL-V800B	2
Vacuum Relief Containment Isolation Check Valve A - IRC	VFS-PL-V803A	2
Vacuum Relief Containment Isolation Check Valve B - IRC	VFS-PL-V803B	2
VWS Containment Penetration Thermal Relief Valve	VWS-PL-V053	2
VWS Containment Penetration Thermal Relief Valve	VWS-PL-V057	2
Fan Cooler Supply Isolation	VWS-PL-V058	2
Fan Coolers Supply Containment Isolation Check Valve	VWS-PL-V062	2
VWS Containment Isolation Relief	VWS-PL-V080	2
Fan Cooler Return Isolation	VWS-PL-V082	2
Fan Cooler Return Isolation	VWS-PL-V086	2
Sump Containment Isolation IRC	WLS-PL-V055	2
Sump Containment Isolation ORC	WLS-PL-V057	2
WLS Containment Isolation Relief	WLS-PL-V058	2
RCDT Gas Containment Isolation	WLS-PL-V067	2
RCDT Gas Containment Isolation	WLS-PL-V068	2
CVS To Sump	WLS-PL-V071 A	2
PXS A To Sump	WLS-PL-V071 B	2
PXS B To Sump	WLS-PL-V071 C	2
CVS To Sump	WLS-PL-V072 A	2
PXS A To Sump	WLS-PL-V072 B	2
PXS B To Sump	WLS-PL-V072 C	2

Table 3I.6-3 (Sheet 9 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Miscellaneous		
Nonactive Valves		
Containment Penetration Test Connection Isolation	CAS-PL-V027	2
Service Air Supply Outside Containment Isolation	CAS-PL-V204	2
Containment Penetration Test Connection Isolation	CAS-PL-V219	2
Containment Isolation Valve Test Connection – Outlet Line	CCS-PL-V209	2
CCS Supply Containment Isolation – IRC	CCS-PL-V214	2
CCS Supply Containment Isolation Valve Test Connection – IRC	CCS-PL-V215	2
Containment Leak Test Outlet Line – IRC	CCS-PL-V216	2
Containment Isolation Valve V207 Body Test Connection Valve	CCS-PL-V217	2
Containment Isolation Valve Test Connection – Inlet Line	CCS-PL-V257	2
Resin Flush IRC Isolation	CVS-PL-V040	2
Resin Flush ORC Isolation	CVS-PL-V041	2
Letdown PZR Instrument Root	CVS-PL-V046	2
Zinc Addition – IRC Shutoff	CVS-PL-V065	2
Zinc Add Cont Isolation Test Connection	CVS-PL-V095	2
Zinc Addition Containment Isolation Test Connection	CVS-PL-V096	2
Hydrogen Injection Containment Isolation Test Connection Valve	CVS-PL-V218	2
Demin Water Supply Containment Isolation – Outside	DWS-PL-V244	2
Containment Penetration Test Connection Isolation	DWS-PL-V248	2
Fire Water Containment Supply Isolation	FPS-PL-V050	2
Fire Water Containment Test Connection Isolation	FPS-PL-V051	2
Flow Transmitter FT001 Root Valve	PCS-PL-V010A	2
Flow Transmitter FT001 Root Valve	PCS-PL-V010B	2
Flow Transmitter FT002 Root Valve	PCS-PL-V011A	2
Flow Transmitter FT002 Root Valve	PCS-PL-V011B	2
Flow Transmitter FT003 Root Valve	PCS-PL-V012A	2
Flow Transmitter FT003 Root Valve	PCS-PL-V012B	2
Flow Transmitter FT004 Root Valve	PCS-PL-V013A	2
Flow Transmitter FT004 Root Valve	PCS-PL-V013B	2
PCCWST Drain Isolation Valve	PCS-PL-V016	2
Makeup to Distribution Bucket Isolation Valve	PCS-PL-V026	2
PCCWST Isolation Valve Leakage Detection Drain	PCS-PL-V029	2
PCCWST Isolation Valve Leakage Detection Crossconn	PCS-PL-V030	2
PCCWST Level Instrument Root Valve	PCS-PL-V031A	2
PCCWST Level Instrument Root Valve	PCS-PL-V031B	2
Recirculation Pump Suction from Long Term Makeup Isolation Valve	PCS-PL-V033	2
Spent Fuel Pool Emergency Makeup Isolation	PCS-PL-V052	2
Recirculation Header Discharge to SFS Pool Vent Isolation Valve	PCS-PL-V303	2
Recirculation Header Discharge to SFS Pool Drain Isolation Valve	PCS-PL-V304	2
PCCWST Recirculation Return Drain Isolation Valve	PCS-PL-V305	2

Table 3I.6-3 (Sheet 10 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Hot Leg 1 Sample Isolation	PSS-PL-V001A	2
Hot Leg 2 Sample Isolation	PSS-PL-V001B	2
Pressurizer Sample Isolation	PSS-PL-V003	2
PXS Accumulator Sample Isolation	PSS-PL-V004A	2
PXS Accumulator Sample Isolation	PSS-PL-V004B	2
PXS CMT A Sample Isolation	PSS-PL-V005A	2
PXS CMT B Sample Isolation	PSS-PL-V005B	2
PXS CMT A Sample Isolation	PSS-PL-V005C	2
PXS CMT B Sample Isolation	PSS-PL-V005D	2
Liquid Sample Isolation Valve	PSS-PL-V012A	2
Liquid Sample Check Valve	PSS-PL-V012B	2
RCS Pressurizer Sample Isolation Valve	PSS-PL-V013	2
RCS Hot Leg 1 Sample Isolation Valve	PSS-PL-V014A	2
RCS Hot Leg 2 Sample Isolation Valve	PSS-PL-V014B	2
PXS Accumulator Sample Isolation Valve	PSS-PL-V015A	2
PXS Accumulator Sample Isolation Valve	PSS-PL-V015B	2
PXS CMT A Sample Isolation Valve	PSS-PL-V016A	2
PXS CMT B Sample Isolation Valve	PSS-PL-V016B	2
PXS CMT A Sample Isolation Valve	PSS-PL-V016C	2
PXS CMT B Sample Isolation Valve	PSS-PL-V016D	2
Containment Testing Boundary Isolation Valve	PSS-PL-V076A	2
Containment Testing Boundary Isolation Valve	PSS-PL-V076B	2
Containment Isolation Test Connection Isolation Valve	PSS-PL-V082	2
Containment Isolation Test Connection Isolation Valve	PSS-PL-V083	2
Containment Isolation Test Connection Isolation Valve	PSS-PL-V085	2
Containment Isolation Test Connection Isolation Valve	PSS-PL-V086	2
PXS CMT A Sample Isolation Valve (Unit 3 Only)	PSS-PL-V902A	2
PXS CMT B Sample Isolation Valve (Unit 3 Only)	PSS-PL-V902B	2
PXS CMT B Sample Isolation Valve (Unit 3 Only)	PSS-PL-V903	2
Core Makeup Tank A CL Inlet Isolation	PXS-PL-V002A	2
Core Makeup Tank B CL Inlet Isolation	PXS-PL-V002B	2
Core Makeup Tank A Upper Sample	PXS-PL-V010A	2
Core Makeup Tank B Upper Sample	PXS-PL-V010B	2
Core Makeup Tank A Lower Sample	PXS-PL-V011A	2
Core Makeup Tank B Lower Sample	PXS-PL-V011B	2
Core Makeup Tank A Drain	PXS-PL-V012A	2
Core Makeup Tank B Drain	PXS-PL-V012B	2
Core Makeup Tank A Discharge Manual Isolation	PXS-PL-V013A	2
Core Makeup Tank B Discharge Manual Isolation	PXS-PL-V013B	2
RNS to CMT Injection Line A Drain	PXS-PL-V019A	2
RNS to CMT Injection Line B Drain	PXS-PL-V019B	2
IRWST Injection Line A Drain	PXS-PL-V020A	2
IRWST Injection Line B Drain	PXS-PL-V020B	2

Table 3I.6-3 (Sheet 11 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Accumulator A N_2 Vent	PXS-PL-V021A	2
Accumulator B N_2 Vent	PXS-PL-V021B	2
Accumulator A PZR Transmitter Isolation	PXS-PL-V023A	2
Accumulator B PZR Transmitter Isolation	PXS-PL-V023B	2
Accumulator A PZR Transmitter Isolation	PXS-PL-V024A	2
Accumulator B PZR Transmitter Isolation	PXS-PL-V024B	2
Accumulator A Sample	PXS-PL-V025A	2
Accumulator B Sample	PXS-PL-V025B	2
Accumulator A Drain	PXS-PL-V026A	2
Accumulator B Drain	PXS-PL-V026B	2
Accumulator A Discharge Isolation	PXS-PL-V027A	2
Accumulator B Discharge Isolation	PXS-PL-V027B	2
Core Makeup Tank A Highpoint Vent	PXS-PL-V030A	2
Core Makeup Tank B Highpoint Vent	PXS-PL-V030B	2
Core Makeup Tank A Highpoint Vent	PXS-PL-V031A	2
Core Makeup Tank B Highpoint Vent	PXS-PL-V031B	2
Accumulator A Check Valve Drain	PXS-PL-V033A	2
Accumulator B Check Valve Drain	PXS-PL-V033B	2
Accumulator N_2 Containment Penetration Test Connection	PXS-PL-V052	2
CMT A Wide Level Upper Root	PXS-PL-V080A	2
CMT B Wide Level Upper Root	PXS-PL-V080B	2
CMT A Wide Level Lower Root	PXS-PL-V081A	2
CMT B Wide Level Lower Root	PXS-PL-V081B	2
CMT A Upper Level A Isolation 1	PXS-PL-V082A	2
CMT B Upper Level A Isolation 1	PXS-PL-V082B	2
CMT A Upper Level A Isolation 2	PXS-PL-V083A	2
CMT B Upper Level A Isolation 2	PXS-PL-V083B	2
CMT A Upper Level A Vent	PXS-PL-V084A	2
CMT B Upper Level A Vent	PXS-PL-V084B	2
LT-011 A/C Drain Valve	PXS-PL-V085A	2
LT-012 A/C Drain Valve	PXS-PL-V085B	2
CMT A Upper Level B Isolation 1	PXS-PL-V086A	2
CMT B Upper Level B Isolation 1	PXS-PL-V086B	2
CMT A Upper Level B Isolation 2	PXS-PL-V087A	2
CMT B Upper Level B Isolation 2	PXS-PL-V087B	2
CMT A Upper Level B Vent	PXS-PL-V088A	2
CMT B Upper Level B Vent	PXS-PL-V088B	2
CMT A Upper Level B Drain	PXS-PL-V089A	2
CMT B Upper Level B Drain	PXS-PL-V089B	2

Table 3I.6-3 (Sheet 12 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
CMT A Lower Level A Isolation 1	PXS-PL-V092A	2
CMT B Lower Level A Isolation 1	PXS-PL-V092B	2
CMT A Lower Level A Isolation 2	PXS-PL-V093A	2
CMT B Lower Level A Isolation 2	PXS-PL-V093B	2
CMT A Lower Level A Vent	PXS-PL-V094A	2
CMT B Lower Level A Vent	PXS-PL-V094B	2
CMT A Lower Level A Drain	PXS-PL-V095A	2
CMT B Lower Level A Drain	PXS-PL-V095B	2
CMT A Lower Level B Isolation 1	PXS-PL-V096A	2
CMT B Lower Level B Isolation 1	PXS-PL-V096B	2
CMT A Lower Level B Isolation 2	PXS-PL-V097A	2
CMT B Lower Level B Isolation 2	PXS-PL-V097B	2
CMT A Lower Level B Vent	PXS-PL-V098A	2
CMT B Lower Level B Vent	PXS-PL-V098B	2
CMT A Lower Level B Drain	PXS-PL-V099A	2
CMT B Lower Level B Drain	PXS-PL-V099B	2
PRHR HX Inlet Isolation	PXS-PL-V101	2
PRHR HX Inlet Head Vent	PXS-PL-V102A	2
PRHR HX Inlet Head Drain	PXS-PL-V102B	2
PRHR HX Outlet Head Vent	PXS-PL-V103A	2
PRHR HX Outlet Head Drain	PXS-PL-V103B	2
PRHR HX Flow Transmitter A Isolation	PXS-PL-V104A	2
PRHR HX Flow Transmitter B Isolation	PXS-PL-V104B	2
PRHR HX Flow Transmitter A Isolation	PXS-PL-V105A	2
PRHR HX Flow Transmitter B Isolation	PXS-PL-V105B	2
Containment Recirculation A Highpoint Vent	PXS-PL-V106	2
Containment Recirculation A Highpoint Vent	PXS-PL-V107	2
PRHR HX/RCS Return Isolation	PXS-PL-V109	2
PRHR HX Highpoint Vent	PXS-PL-V111A	2
PRHR HX Highpoint Vent	PXS-PL-V111B	2
PRHR HX Pressure Transmitter Isolation	PXS-PL-V113	2
Containment Recirculation A Drain	PXS-PL-V115A	2
Containment Recirculation B Drain	PXS-PL-V115B	2
Containment Recirculation A Drain	PXS-PL-V116A	2
Containment Recirculation B Drain	PXS-PL-V116B	2
Recirc Sump A Isolation	PXS-PL-V117A	2
Recirc Sump B Isolation	PXS-PL-V117B	2
IRWST Line A Isolation	PXS-PL-V121A	2
IRWST Line B Isolation	PXS-PL-V121B	2

Table 3I.6-3 (Sheet 13 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
IRWST Injection Check Test	PXS-PL-V126A	2
IRWST Injection Check Test	PXS-PL-V126B	2
IRWST Injection Line A Drain	PXS-PL-V127	2
IRWST Injection Check Test	PXS-PL-V128A	2
IRWST Injection Check Test	PXS-PL-V128B	2
IRWST Injection Check Test	PXS-PL-V129A	2
IRWST Injection Check Test	PXS-PL-V129B	2
IRWST Injection Line A Drain	PXS-PL-V131A	2
IRWST Injection Line B Drain	PXS-PL-V131B	2
IRWST Injection Line A Drain	PXS-PL-V132A	2
IRWST Injection Line B Drain	PXS-PL-V132B	2
IRWST Injection Line A Highpoint Vent	PXS-PL-V133A	2
IRWST Injection Line B Highpoint Vent	PXS-PL-V133B	2
IRWST Injection Line A Highpoint Vent	PXS-PL-V134A	2
IRWST Injection Line B Highpoint Vent	PXS-PL-V134B	2
IRWST Injection Line A Highpoint Vent Isolation	PXS-PL-V135A	2
IRWST Injection Line B Highpoint Vent Isolation	PXS-PL-V135B	2
RNS Suction Pump Line Drain	PXS-PL-V149	2
IRWST Wide Range Level Transmitter B Isolation	PXS-PL-V151B	2
IRWST Wide Range Level Transmitter C Isolation	PXS-PL-V151C	2
IRWST Wide Range Level Transmitter D Isolation	PXS-PL-V151D	2
IRWST Lower Narrow Range Level Transmitter A Isolation	PXS-PL-V161A	2
IRWST Lower Narrow Range Level Transmitter B Isolation	PXS-PL-V161B	2
IRWST Lower Narrow Range Level Transmitter C Isolation	PXS-PL-V161C	2
IRWST Lower Narrow Range Level Transmitter D Isolation	PXS-PL-V161D	2
IRWST Lower Narrow Range Level Transmitter A Reference Leg Isolation	PXS-PL-V162A	2
IRWST Lower Narrow Range Level Transmitter B Reference Leg Isolation	PXS-PL-V162B	2
IRWST Lower Narrow Range Level Transmitter C Reference Leg Isolation	PXS-PL-V162C	2
IRWST Lower Narrow Range Level Transmitter D Reference Leg Isolation	PXS-PL-V162D	2
PRHR Flow Transmitter A Vent	PXS-PL-V170A	2
PRHR Flow Transmitter B Vent	PXS-PL-V170B	2
PRHR Flow Transmitter A Vent	PXS-PL-V171A	2
PRHR Flow Transmitter B Vent	PXS-PL-V171B	2
Accumulator A Leak Test	PXS-PL-V201A	2
Accumulator B Leak Test	PXS-PL-V201B	2
Accumulator A Leak Test	PXS-PL-V202A	2
Accumulator B Leak Test	PXS-PL-V202B	2
RNS Discharge Leak Test	PXS-PL-V205A	2
RNS Discharge Leak Test	PXS-PL-V205B	2
RNS Discharge Leak Test	PXS-PL-V206	2
RNS Suction Leak Test	PXS-PL-V207A	2
RNS Suction Leak Test	PXS-PL-V207B	2

Table 3I.6-3 (Sheet 14 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
RNS Suction Leak Test	PXS-PL-V208A	2
Core Makeup Tank A Fill Isolation	PXS-PL-V230A	2
Core Makeup Tank B Fill Isolation	PXS-PL-V230B	2
Core Makeup Tank A Fill Check	PXS-PL-V231A	2
Core Makeup Tank B Fill Check	PXS-PL-V231B	2
Accumulator A Fill/Drain Isolation	PXS-PL-V232A	2
Accumulator B Fill/Drain Isolation	PXS-PL-V232B	2
Accumulator A to PXS Test Header Iso Valve (Unit 3 Only)	PXS-PL-V233A	2
Accumulator B to PXS Test Header Iso Valve (Unit 3 Only)	PXS-PL-V233B	2
CMT A Check Valve Test Valve	PXS-PL-V250A	2
CMT B Check Valve Test Valve	PXS-PL-V250B	2
CMT A Check Valve Test Valve	PXS-PL-V251A	2
CMT B Check Valve Test Valve	PXS-PL-V251B	2
CMT A Check Valve Test Valve	PXS-PL-V252A	2
CMT B Check Valve Test Valve	PXS-PL-V252B	2
ADS Test Valve	RCS-PL-V007A	2
ADS Test Valve	RCS-PL-V007B	2
ADS Test Valve	RCS-PL-V007C	2
ADS Valve Leakage Check Valve	RCS-PL-V008	2
Fourth Stage ADS Isolation	RCS-PL-V014A	2
Fourth Stage ADS Isolation	RCS-PL-V014B	2
Fourth Stage ADS Isolation	RCS-PL-V014C	2
Fourth Stage ADS Isolation	RCS-PL-V014D	2
Hot Leg 2 Level Instrument Root	RCS-PL-V095	2
Hot Leg 2 Level Instrument Root	RCS-PL-V096	2
Hot Leg 1 Level Instrument Root	RCS-PL-V097	2
Hot Leg 1 Level Instrument Root	RCS-PL-V098	2
Hot Leg 1 Flow Instrument Root	RCS-PL-V101A	2
Hot Leg 1 Flow Instrument Root	RCS-PL-V101B	2
Hot Leg 1 Flow Instrument Root	RCS-PL-V101C	2
Hot Leg 1 Flow Instrument Root	RCS-PL-V101D	2
Hot Leg 1 Flow Instrument Root	RCS-PL-V101E	2
Hot Leg 1 Flow Instrument Root	RCS-PL-V101F	2
Hot Leg 2 Flow Instrument Root	RCS-PL-V102A	2
Hot Leg 2 Flow Instrument Root	RCS-PL-V102B	2
Hot Leg 2 Flow Instrument Root	RCS-PL-V102C	2
Hot Leg 2 Flow Instrument Root	RCS-PL-V102D	2
Hot Leg 2 Flow Instrument Root	RCS-PL-V102E	2
Hot Leg 2 Flow Instrument Root	RCS-PL-V102F	2
PRHR HX Outlet Line Drain	RCS-PL-V103	2
Hot Leg 1 Sample Isolation	RCS-PL-V108A	2
Hot Leg 2 Sample Isolation	RCS-PL-V108B	2
PZR Spray Valve	RCS-PL-V110A	2
PZR Spray Valve	RCS-PL-V110B	2

Table 3I.6-3 (Sheet 15 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
PZR Spray Block Valve	RCS-PL-V111A	2
PZR Spray Block Valve	RCS-PL-V111B	2
Cold Leg 1A Bend Instrument Root	RCS-PL-V171A	2
Cold Leg 1A Bend Instrument Root	RCS-PL-V171B	2
Cold Leg 1B Bend Instrument Root	RCS-PL-V172A	2
Cold Leg 1B Bend Instrument Root	RCS-PL-V172B	2
Cold Leg 2A Bend Instrument Root	RCS-PL-V173A	2
Cold Leg 2A Bend Instrument Root	RCS-PL-V173B	2
Cold Leg 2B Bend Instrument Root	RCS-PL-V174A	2
Cold Leg 2B Bend Instrument Root	RCS-PL-V174B	2
PZR Manual Vent	RCS-PL-V204	2
PZR Manual Vent	RCS-PL-V205	2
PZR Spray Bypass	RCS-PL-V210A	2
PZR Spray Bypass	RCS-PL-V210B	2
PZR Level Steam Space Instrument Root	RCS-PL-V225A	2
PZR Level Steam Space Instrument Root	RCS-PL-V225B	2
PZR Level Steam Space Instrument Root	RCS-PL-V225C	2
PZR Level Steam Space Instrument Root	RCS-PL-V225D	2
PZR Level Liquid Space Instrument Root	RCS-PL-V226A	2
PZR Level Liquid Space Instrument Root	RCS-PL-V226B	2
PZR Level Liquid Space Instrument Root	RCS-PL-V226C	2
PZR Level Liquid Space Instrument Root	RCS-PL-V226D	2
Pressurizer Level Reference Leg Tubing Instrument Root	RCS-PL-V227A	2
Pressurizer Level Reference Leg Tubing Instrument Root	RCS-PL-V227B	2
Pressurizer Level Reference Leg Tubing Instrument Root	RCS-PL-V227C	2
Pressurizer Level Reference Leg Tubing Instrument Root	RCS-PL-V227D	2
Pressurizer Liquid Sample Isolation	RCS-PL-V228	2
Wide Range PZR Level Liquid Space Instrument Root	RCS-PL-V229	2
Manual Head Vent	RCS-PL-V232	2
Head Vent Isolation	RCS-PL-V233	2
ADS Valve Discharge Header Drain Isolation	RCS-PL-V241	2
ADS Discharge Line Isolation Valve	RCS-PL-V250	2
RCP 1A Flush	RCS-PL-V260A	2
RCP 1B Flush	RCS-PL-V260B	2
RCP 2A Flush	RCS-PL-V260C	2
RCP 2B Flush	RCS-PL-V260D	2
RCP 1A Drain	RCS-PL-V261A	2
RCP 1B Drain	RCS-PL-V261B	2
RCP 2A Drain	RCS-PL-V261C	2
RCP 2B Drain	RCS-PL-V261D	2
RCS Pressure Boundary Valve Thermal Relief Isolation	RNS-PL-V004A	2
RCS Pressure Boundary Valve Thermal Relief Isolation	RNS-PL-V004B	2
RNS Pump A Suction Isolation	RNS-PL-V005A	2
RNS Pump B Suction Isolation	RNS-PL-V005B	2
RNS HX A Outlet Flow Control	RNS-PL-V006A	2

Table 3I.6-3 (Sheet 16 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
RNS HX B Outlet Flow Control	RNS-PL-V006B	2
RNS Pump A Discharge Isolation	RNS-PL-V007A	2
RNS Pump B Discharge Isolation	RNS-PL-V007B	2
RNS HX A Bypass Flow Control	RNS-PL-V008A	2
RNS HX B Bypass Flow Control	RNS-PL-V008B	2
RNS Discharge Containment Isolation Valve Test	RNS-PL-V010	2
RNS Discharge Containment Isolation Valve Test Connection	RNS-PL-V014	2
RNS Discharge Containment Penetration Isolation Valves Test	RNS-PL-V016	2
RNS Discharge to IRWST Isolation	RNS-PL-V024	2
RNS Suction from IRWST – Bonnet Relief Isolation	RNS-PL-V025	2
RNS Suction from IRWST – Containment Isolation Test	RNS-PL-V026	2
RNS Discharge to CVS	RNS-PL-V029	2
RNS Train A Discharge Flow Instrument Isolation	RNS-PL-V031A	2
RNS Train B Discharge Flow Instrument Isolation	RNS-PL-V031B	2
RNS Train A Discharge Flow Instrument Isolation	RNS-PL-V032A	2
RNS Train B Discharge Flow Instrument Isolation	RNS-PL-V032B	2
RNS Pump A Suction Pressure Instrument Isolation	RNS-PL-V033A	2
RNS Pump B Suction Pressure Instrument Isolation	RNS-PL-V033B	2
RNS Pump A Discharge Pressure Instrument Isolation	RNS-PL-V034A	2
RNS Pump B Discharge Pressure Instrument Isolation	RNS-PL-V034B	2
RNS Pump A Suction Piping Drain Isolation	RNS-PL-V036A	2
RNS Pump B Suction Piping Drain Isolation	RNS-PL-V036B	2
RNS Pump Seal Cooler A Vent Isolation	RNS-PL-V048A	2
RNS Pump Seal Cooler B Vent Isolation	RNS-PL-V048B	2
RNS Pump Seal Cooler A Drain Isolation	RNS-PL-V049A	2
RNS Pump Seal Cooler B Drain Isolation	RNS-PL-V049B	2
RNS Pump A Casing Drain Isolation	RNS-PL-V050	2
RNS Pump B Casing Drain Isolation	RNS-PL-V051	2
RNS Suction from SFP Isolation	RNS-PL-V052	2
RNS Discharge to SFP Isolation	RNS-PL-V053	2
RNS Suction from Cask Loading Pit Isolation Valve	RNS-PL-V055	2
RNS Pump Suction to Cask Loading Pit Isolation	RNS-PL-V056	2
RNS Train A Miniflow Isolation Valve	RNS-PL-V057A	2
RNS Train B Miniflow Isolation Valve	RNS-PL-V057B	2
RNS Pump Suction Containment Isolation Test Connection	RNS-PL-V059	2
RNS Discharge Drain Valve	RNS-PL-V065	2
RNS Discharge to DVI Line A Drain	RNS-PL-V066A	2
RNS Discharge to DVI Line B Drain	RNS-PL-V066B	2
RNS Discharge to DVI Line A Drain	RNS-PL-V067A	2
RNS Discharge to DVI Line B Drain	RNS-PL-V067B	2
RNS Discharge to IRWST Drain	RNS-PL-V068	2

Table 3I.6-3 (Sheet 17 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
RNS Pump A Miniflow Vent	RNS-PL-V069A	2
RNS Pump B Miniflow Vent	RNS-PL-V069B	2
RNS HX A Channel Head Drain Isolation	RNS-PL-V071A	2
RNS HX B Channel Head Drain Isolation	RNS-PL-V071B	2
RNS HX A Channel Head Drain Isolation	RNS-PL-V072A	2
RNS HX B Channel Head Drain Isolation	RNS-PL-V072B	2
RNS HX A Channel Head Drain Isolation	RNS-PL-V073A	2
RNS HX B Channel Head Drain Isolation	RNS-PL-V073B	2
RNS HX A Channel Head Drain Isolation	RNS-PL-V074A	2
RNS HX B Channel Head Drain Isolation	RNS-PL-V074B	2
RNS HX A Channel Head Drain Isolation	RNS-PL-V075A	2
RNS HX B Channel Head Drain Isolation	RNS-PL-V075B	2
IRWST Suction Line Vent	RNS-PL-V080	2
RNS Cask Loading Pit Suction Line Vent	RNS-PL-V081	2
RNS Discharge Drain	RNS-PL-V082	2
LT019A Root Isolation Valve	SFS-PL-V024A	2
LT019B Root Isolation Valve	SFS-PL-V024B	2
LT019C Root Isolation Valve	SFS-PL-V024C	2
LT020 Root Isolation Valve	SFS-PL-V028	2
SFS Refueling Cavity Drain To SGS Compartment Isolation	SFS-PL-V031	2
SFS Refueling Cavity Suction Isolation	SFS-PL-V032	2
SFS Refueling Cavity Drain to Containment Sump Isolation	SFS-PL-V033	2
SFS Suction Line from IRWST Isolation	SFS-PL-V039	2
SFS Fuel Transfer Canal Suction Isolation	SFS-PL-V040	2
SFS Cask Loading Pit Suction Isolation	SFS-PL-V041	2
Cask Loading Pit Level Transmitter Root Isolation Valve	SFS-PL-V043	2
SFS Containment Penetration Test Connection	SFS-PL-V048	2
SFS Containment Penetration Test Connection Isolation	SFS-PL-V056	2
SFS Containment Isolation Valve V034 Test	SFS-PL-V058	2
SFS Containment Floodup Isolation Valve	SFS-PL-V075	2
LT001, LT011 Root Isolation Valve	SGS-PL-V001A	2
LT005, LT013 Root Isolation Valve	SGS-PL-V001B	2
LT001 Root Isolation Valve	SGS-PL-V002A	2
LT005 Root Isolation Valve	SGS-PL-V002B	2
LT002, LT012 Root Isolation Valve	SGS-PL-V003A	2
LT006, LT014 Root Isolation Valve	SGS-PL-V003B	2
LT002 Root Isolation Valve	SGS-PL-V004A	2
LT006 Root Isolation Valve	SGS-PL-V004B	2
LT003, LT015, LT044 Root Isolation Valve	SGS-PL-V005A	2
LT007, LT017, LT046 Root Isolation Valve	SGS-PL-V005B	2

Table 3I.6-3 (Sheet 18 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
LT003 Root Isolation Valve	SGS-PL-V006A	2
LT007 Root Isolation Valve	SGS-PL-V006B	2
LT004, LT016, LT045 Root Isolation Valve	SGS-PL-V007A	2
LT008, LT018, LT047 Root Isolation Valve	SGS-PL-V007B	2
LT004 Root Isolation Valve	SGS-PL-V008A	2
LT008 Root Isolation Valve	SGS-PL-V008B	2
LT011 Root Isolation Valve	SGS-PL-V010A	2
LT013 Root Isolation Valve	SGS-PL-V010B	2
LT011 Root Isolation Valve	SGS-PL-V011A	2
LT013 Root Isolation Valve	SGS-PL-V011B	2
LT012 Root Isolation Valve	SGS-PL-V012A	2
LT014 Root Isolation Valve	SGS-PL-V012B	2
LT012 Root Isolation Valve	SGS-PL-V013A	2
LT014 Root Isolation Valve	SGS-PL-V013B	2
FT021 Root Isolation Valve	SGS-PL-V015A	2
FT023 Root Isolation Valve	SGS-PL-V015B	2
FT020 Root Isolation Valve	SGS-PL-V016A	2
FT022 Root Isolation Valve	SGS-PL-V016B	2
FT021 Root Isolation Valve	SGS-PL-V017A	2
FT023 Root Isolation Valve	SGS-PL-V017B	2
FT020 Root Isolation Valve	SGS-PL-V018A	2
FT022 Root Isolation Valve	SGS-PL-V018B	2
Main Steam Line Vent Isolation	SGS-PL-V019A	2
Main Steam Line Vent Isolation	SGS-PL-V019B	2
FT024 Root Isolation Valve	SGS-PL-V020A	2
FT025 Root Isolation Valve	SGS-PL-V020B	2
FT024 Root Isolation Valve	SGS-PL-V021A	2
FT025 Root Isolation Valve	SGS-PL-V021B	2
PT030 Root Isolation Valve	SGS-PL-V022A	2
PT034 Root Isolation Valve	SGS-PL-V022B	2
PT031 Root Isolation Valve	SGS-PL-V023A	2
PT035 Root Isolation Valve	SGS-PL-V023B	2
PT032 Root Isolation Valve	SGS-PL-V024A	2
PT036 Root Isolation Valve	SGS-PL-V024B	2
PT033 Root Isolation Valve	SGS-PL-V025A	2
PT037 Root Isolation Valve	SGS-PL-V025B	2
Steam Line 1 Nitrogen Supply Isolation	SGS-PL-V038A	2
Steam Line 2 Nitrogen Supply Isolation	SGS-PL-V038B	2
MSIV Bypass Control Isolation	SGS-PL-V042A	2
MSIV Bypass Control Isolation	SGS-PL-V042B	2
MSIV Bypass Control Isolation	SGS-PL-V043A	2
MSIV Bypass Control Isolation	SGS-PL-V043B	2

Table 3I.6-3 (Sheet 19 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
SG1 Condensate Pipe Drain Valve	SGS-PL-V045A	2
SG2 Condensate Pipe Drain Valve	SGS-PL-V045B	2
LT015 Root Isolation Valve	SGS-PL-V046A	2
LT017 Root Isolation Valve	SGS-PL-V046B	2
LT015, LT044 Root Isolation Valve	SGS-PL-V047A	2
LT017, LT046 Root Isolation Valve	SGS-PL-V047B	2
LT016 Root Isolation Valve	SGS-PL-V048A	2
LT018 Root Isolation Valve	SGS-PL-V048B	2
LT016, LT045 Root Isolation Valve	SGS-PL-V049A	2
LT018, LT047 Root Isolation Valve	SGS-PL-V049B	2
LT044 Root Isolation Valve	SGS-PL-V050A	2
LT046 Root Isolation Valve	SGS-PL-V050B	2
LT044 Root Isolation Valve	SGS-PL-V051A	2
LT046 Root Isolation Valve	SGS-PL-V051B	2
LT045 Root Isolation Valve	SGS-PL-V052A	2
LT047 Root Isolation Valve	SGS-PL-V052B	2
LT045 Root Isolation Valve	SGS-PL-V053A	2
LT047 Root Isolation Valve	SGS-PL-V053B	2
PT062 Root Isolation Valve	SGS-PL-V056A	2
PT063 Root Isolation Valve	SGS-PL-V056B	2
Main Feedwater Check	SGS-PL-V058A	2
Main Feedwater Check	SGS-PL-V058B	2
FT055A Root Isolation Valve	SGS-PL-V062A	2
FT056A Root Isolation Valve	SGS-PL-V062B	2
FT055A Root Isolation Valve	SGS-PL-V063A	2
FT056A Root Isolation Valve	SGS-PL-V063B	2
FT055B Root Isolation Valve	SGS-PL-V064A	2
FT056B Root Isolation Valve	SGS-PL-V064B	2
FT055B Root Isolation Valve	SGS-PL-V065A	2
FT056B Root Isolation Valve	SGS-PL-V065B	2
FT055 Root Isolation Valve	SGS-PL-V066A	2
FT056 Root Isolation Valve	SGS-PL-V066B	2
FT055 Root Isolation Valve	SGS-PL-V068A	2
FT056 Root Isolation Valve	SGS-PL-V068B	2
SG 1 Blowdown Vent Line Isolation	SGS-PL-V076A	2
SG 2 Blowdown Vent Line Isolation	SGS-PL-V076B	2
SG1 Nitrogen Sparging Isolation	SGS-PL-V084A	2
SG2 Nitrogen Sparging Isolation	SGS-PL-V084B	2
Orifice Isolation Valve	SGS-PL-V093A	2
Orifice Isolation Valve	SGS-PL-V093B	2
Orifice Cleanout Line Isolation Valve	SGS-PL-V094A	2
Orifice Cleanout Line Isolation Valve	SGS-PL-V094B	2
Orifice Isolation Valve	SGS-PL-V095A	2
Orifice Isolation Valve	SGS-PL-V095B	2

Table 3I.6-3 (Sheet 20 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Steam Line Condensate Drain Level Isolation Valve	SGS-PL-V096A	2
Steam Line Condensate Drain Level Isolation Valve	SGS-PL-V096B	2
Steam Line Condensate Drain Level Isolation Valve	SGS-PL-V097A	2
Steam Line Condensate Drain Level Isolation Valve	SGS-PL-V097B	2
Startup Feedwater Drain Isolation Valve	SGS-PL-V100A	2
Startup Feedwater Drain Isolation Valve	SGS-PL-V100B	2
Main Feedwater Drain Isolation Valve	SGS-PL-V101A	2
Main Feedwater Drain Isolation Valve	SGS-PL-V101B	2
Startup Feedwater Vent Isolation Valve	SGS-PL-V102A	2
Startup Feedwater Vent Isolation Valve	SGS-PL-V102B	2
Main Feedwater Vent Isolation Valve	SGS-PL-V103A	2
Main Feedwater Vent Isolation Valve	SGS-PL-V103B	2
Main Feedwater Drain Isolation Valve	SGS-PL-V104A	2
Main Feedwater Drain Isolation Valve	SGS-PL-V104B	2
Startup Feedwater Check Valve	SGS-PL-V256A	2
Startup Feedwater Check Valve	SGS-PL-V256B	2
SG 1 NR LT001 Upper Isolation Valve	SGS-PL-V300	2
SG 1 NR LT001 Lower Isolation Valve	SGS-PL-V301	2
SG 1 NR LT002 Upper Isolation Valve	SGS-PL-V302	2
SG 1 NR LT002 Lower Isolation Valve	SGS-PL-V303	2
SG 1 NR LT003 Upper Isolation Valve	SGS-PL-V304	2
SG 1 NR LT003 Lower Isolation Valve	SGS-PL-V305	2
SG 1 NR LT004 Upper Isolation Valve	SGS-PL-V306	2
SG 1 NR LT004 Lower Isolation Valve	SGS-PL-V307	2
SG 1 WR LT011 Lower Isolation Valve	SGS-PL-V308	2
SG 1 WR LT012 Lower Isolation Valve	SGS-PL-V309	2
SG 1 WR LT015 Lower Isolation Valve	SGS-PL-V310	2
SG 1 WR LT016 Lower Isolation Valve	SGS-PL-V311	2
SG 1 Main Steam FT020 Isolation Valve	SGS-PL-V312	2
SG 1 Main Steam FT021 Isolation Valve	SGS-PL-V313	2
SG 1 Main Steam FT024 Isolation Valve	SGS-PL-V314	2
SG 2 NR LT005 Upper Isolation Valve	SGS-PL-V320	2
SG 2 NR LT005 Lower Isolation Valve	SGS-PL-V321	2
SG 2 NR LT006 Upper Isolation Valve	SGS-PL-V322	2
SG 2 NR LT006 Lower Isolation Valve	SGS-PL-V323	2
SG 2 NR LT007 Upper Isolation Valve	SGS-PL-V324	2
SG 2 NR LT007 Lower Isolation Valve	SGS-PL-V325	2
SG 2 NR LT008 Upper Isolation Valve	SGS-PL-V326	2
SG 2 NR LT008 Lower Isolation Valve	SGS-PL-V327	2
SG 2 WR LT013 Lower Isolation Valve	SGS-PL-V328	2
SG 2 WR LT014 Lower Isolation Valve	SGS-PL-V329	2

Table 3I.6-3 (Sheet 21 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
SG 2 WR LT017 Lower Isolation Valve	SGS-PL-V330	2
SG 2 WR LT018 Lower Isolation Valve	SGS-PL-V331	2
SG 2 Main Steam FT022 Isolation Valve	SGS-PL-V332	2
SG 2 Main Steam FT023 Isolation Valve	SGS-PL-V333	2
SG 2 Main Steam FT025 Isolation Valve	SGS-PL-V334	2
Air Delivery Line Pressure Instrument Isolation Valve A	VES-PL-V006A	2
Air Delivery Line Pressure Instrument Isolation Valve B	VES-PL-V006B	2
Air Delivery Line Maintenance Isolation Valve A	VES-PL-V010A	2
Air Delivery Line Maintenance Isolation Valve B	VES-PL-V010B	2
Air Delivery Line Maintenance Isolation Valve A	VES-PL-V011A	2
Air Delivery Line Maintenance Isolation Valve B	VES-PL-V011B	2
Temporary Instrument Isolation Valve A	VES-PL-V016	2
Temporary Instrument Isolation Valve B	VES-PL-V020	2
Air Bank 1 Isolation Valve A	VES-PL-V024A	2
Air Bank 2 Isolation Valve B	VES-PL-V024B	2
Air Bank 3 Isolation Valve C	VES-PL-V024C	2
Air Bank 4 Isolation Valve D	VES-PL-V024D	2
Air Bank 1 Isolation Valve A	VES-PL-V025A	2
Air Bank 2 Isolation Valve B	VES-PL-V025B	2
Air Bank 3 Isolation Valve C	VES-PL-V025C	2
Air Bank 4 Isolation Valve D	VES-PL-V025D	2
Air Bank 1 Fill/Vent Isolation Valve A	VES-PL-V026A	2
Air Bank 2 Fill/Vent Isolation Valve B	VES-PL-V026B	2
Air Bank 3 Fill/Vent Isolation Valve C	VES-PL-V026C	2
Air Bank 4 Fill/Vent Isolation Valve D	VES-PL-V026D	2
DP Instrument Line Isolation Valve A	VES-PL-V043A	2
DP Instrument Line Isolation Valve B	VES-PL-V043B	2
Containment Isolation Test Connection	VFS-PL-V006	2
RCS Ejector Discharge Isolation	VFS-PL-V007	2
Containment Isolation Test Connection	VFS-PL-V008	2
Containment Isolation Test Connection	VFS-PL-V012	2
Containment Isolation Test Connection	VFS-PL-V015	2
Containment Isolation Test Connection	VFS-PL-V101	2
Containment Atmosphere to Filtration Units Isolation	VFS-PL-V202	2
Filtration Units to Containment Atmosphere Manual Isolation	VFS-PL-V587	2
Main Equipment Hatch Test Connection	VUS-PL-V013	2
Maintenance Equipment Hatch Test Connection	VUS-PL-V014	2
Main Equipment Hatch Test Connection	VUS-PL-V015	2

Table 3I.6-3 (Sheet 22 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Maintenance Equipment Hatch Test Connection	VUS-PL-V016	2
Personnel Hatch Test Connection	VUS-PL-V017	2
Personnel Hatch Test Connection	VUS-PL-V018	2
Personnel Hatch Test Connection	VUS-PL-V019	2
Personnel Hatch Test Connection	VUS-PL-V020	2
Personnel Hatch Test Connection	VUS-PL-V021	2
Personnel Hatch Test Connection	VUS-PL-V022	2
Fuel Transfer Tube Test Connection	VUS-PL-V023	2
Spare Penetration Test Connection	VUS-PL-V140	2
Spare Penetration Test Connection	VUS-PL-V141	2
Spare Penetration Test Connection	VUS-PL-V142	2
VWS Supply Containment Penetration IRC Test Connection/Vent	VWS-PL-V424	2
VWS Return Containment Penetration ORC Test Connection/Vent	VWS-PL-V425	2
WWS MCR Isolation Valve	WWS-PL-V506	2
VBS-PDT-032A Isolation Valve	VBS-PL-V184A	2
VBS-PDT-032B Isolation Valve	VBS-PL-V184B	2
VBS-PDT-032C Isolation Valve	VBS-PL-V184C	2
Heat Exchangers		
Normal Residual Heat Removal Heat Exchanger A	RNS-ME-01A	3
Normal Residual Heat Removal Heat Exchanger B	RNS-ME-01B	3
Tanks		
Spent Fuel Pool	FHS-MT-01	3
Fuel Transfer Canal	FHS-MT-02	3
Refueling Cavity	FHS-MT-03	3
Spent Fuel Cask Loading Pit	FHS-MT-05	3
Spent Fuel Cask Washdown Pit	FHS-MT-06	3
Passive Containment Cooling Water Storage Tank	PCS-MT-01	3
Water Distribution Bucket	PCS-MT-03	3
Water Collection Troughs	PCS-MT-04	3
Passive RHR Heat Exchanger	PXS-ME-01	3
Accumulator Tank A	PXS-MT-01A	3
Accumulator Tank B	PXS-MT-01B	3
Core Makeup Tank A	PXS-MT-02A	3
Core Makeup Tank B	PXS-MT-02B	3
In-Containment Refueling Water Storage Tank	PXS-MT-03	3
Emergency Air Storage Tank 01	VES-MT-01	3
Emergency Air Storage Tank 02	VES-MT-02	3
Emergency Air Storage Tank 03	VES-MT-03	3
Emergency Air Storage Tank 04	VES-MT-04	3
Emergency Air Storage Tank 05	VES-MT-05	3
Emergency Air Storage Tank 06	VES-MT-06	3
Emergency Air Storage Tank 07	VES-MT-07	3
Emergency Air Storage Tank 08	VES-MT-08	3

Table 3I.6-3 (Sheet 23 of 23)
List Of AP1000 Safety-Related Electrical and Mechanical Equipment Not High Frequency Sensitive

Description	AP1000 Tag Number	Comment
Emergency Air Storage Tank 09	VES-MT-09	3
Emergency Air Storage Tank 10	VES-MT-10	3
Emergency Air Storage Tank 11	VES-MT-11	3
Emergency Air Storage Tank 12	VES-MT-12	3
Emergency Air Storage Tank 13	VES-MT-13	3
Emergency Air Storage Tank 14	VES-MT-14	3
Emergency Air Storage Tank 15	VES-MT-15	3
Emergency Air Storage Tank 16	VES-MT-16	3
Emergency Air Storage Tank 17	VES-MT-17	3
Emergency Air Storage Tank 18	VES-MT-18	3
Emergency Air Storage Tank 19	VES-MT-19	3
Emergency Air Storage Tank 20	VES-MT-20	3
Emergency Air Storage Tank 21	VES-MT-21	3
Emergency Air Storage Tank 22	VES-MT-22	3
Emergency Air Storage Tank 23	VES-MT-23	3
Emergency Air Storage Tank 24	VES-MT-24	3
Emergency Air Storage Tank 25	VES-MT-25	3
Emergency Air Storage Tank 26	VES-MT-26	3
Emergency Air Storage Tank 27	VES-MT-27	3
Emergency Air Storage Tank 28	VES-MT-28	3
Emergency Air Storage Tank 29	VES-MT-29	3
Emergency Air Storage Tank 30	VES-MT-30	3
Emergency Air Storage Tank 31	VES-MT-31	3
Emergency Air Storage Tank 32	VES-MT-32	3

Notes:

1. Rugged AP1000 safety-related equipment with no moving parts required in demonstrating functional operability during a seismic event is considered to be not sensitive to HRHF seismic loadings. Seismic qualification is based on the seismic loads associated with the mounting location of the safety-related equipment as a minimum. AP1000 CSDRS seismic loads at the mounting location of the safety-related equipment produces comparable or higher equipment stresses and deflections than the HRHF seismic loadings based on the work reported in APP-GW-GLR-115, “Effect of High Frequency Seismic Content on SSCs.” For rugged safety-related line-mounted equipment being qualified by test, seismic testing will be performed in compliance with IEEE Standard 382-1996 with a required input motion (RIM) curve extended to 64 Hz typically to a peak acceleration of 6g.
2. AP1000 safety-related valves are seismic qualified in accordance with ASME code for structural integrity to a maximum acceleration of 6g in all three principal orthogonal axes. AP1000 CSDRS seismic loads at the mounting location of the safety-related equipment produce comparable or higher equipment stresses and deflections than the HRHF seismic loadings based on the work reported in APP-GW-GLR-115, “Effect of High Frequency Seismic Content on SSCs.” For rugged safety-related line-mounted equipment being qualified by test, seismic testing will be performed in compliance with IEEE Standard 382-1996 with a required input motion (RIM) curve extended to 64 Hz typically to a peak acceleration of 6g.
3. Seismic qualification is based on structural integrity alone to the seismic loadings associated with the mounting location of the safety-related equipment as a minimum. AP1000 CSDRS seismic loads at the mounting location of the safety-related equipment produce comparable or higher equipment stresses and deflections than the HRHF seismic loadings based on the work reported in APP-GW-GLR-115, “Effect of High Frequency Seismic Content on SSCs.”
4. IIS-JE-TE009, IIS-JE-TE013, IIS-JE-TE030, and IIS-JE-TE034 are not safety-related and therefore excluded from this list.

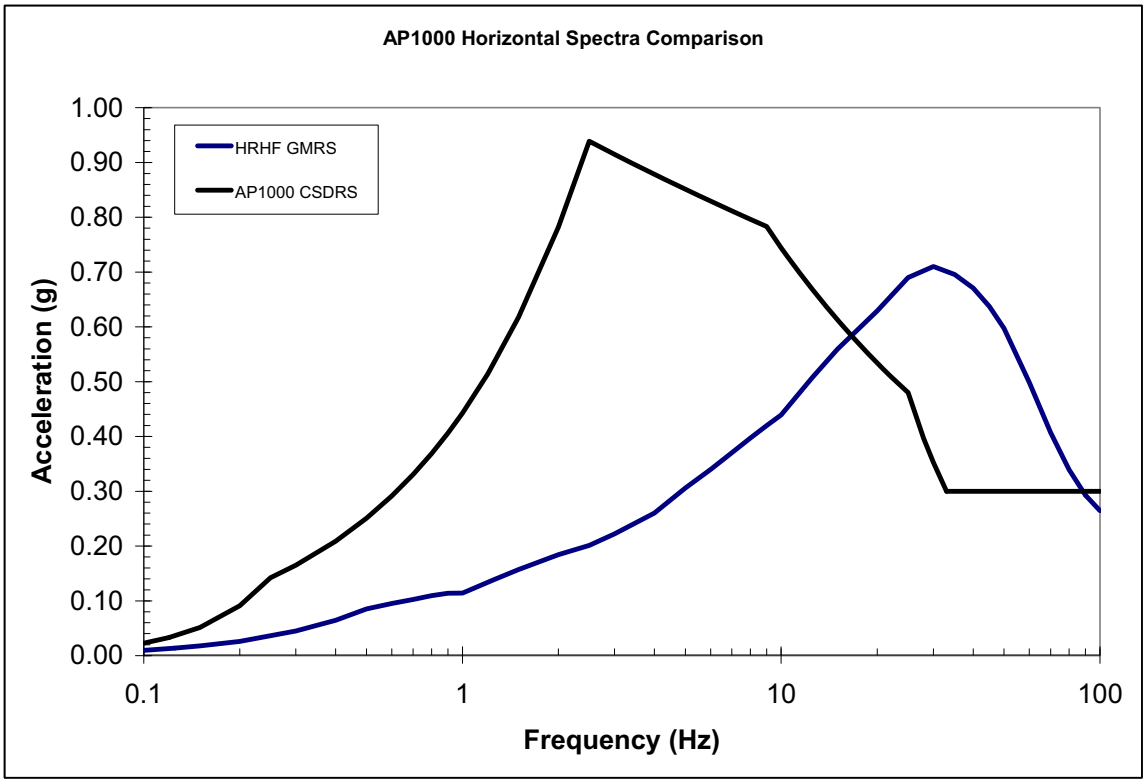


Figure 3I.1-1
Comparison of Horizontal AP1000 CSDRS and HRHF Envelope Response Spectra

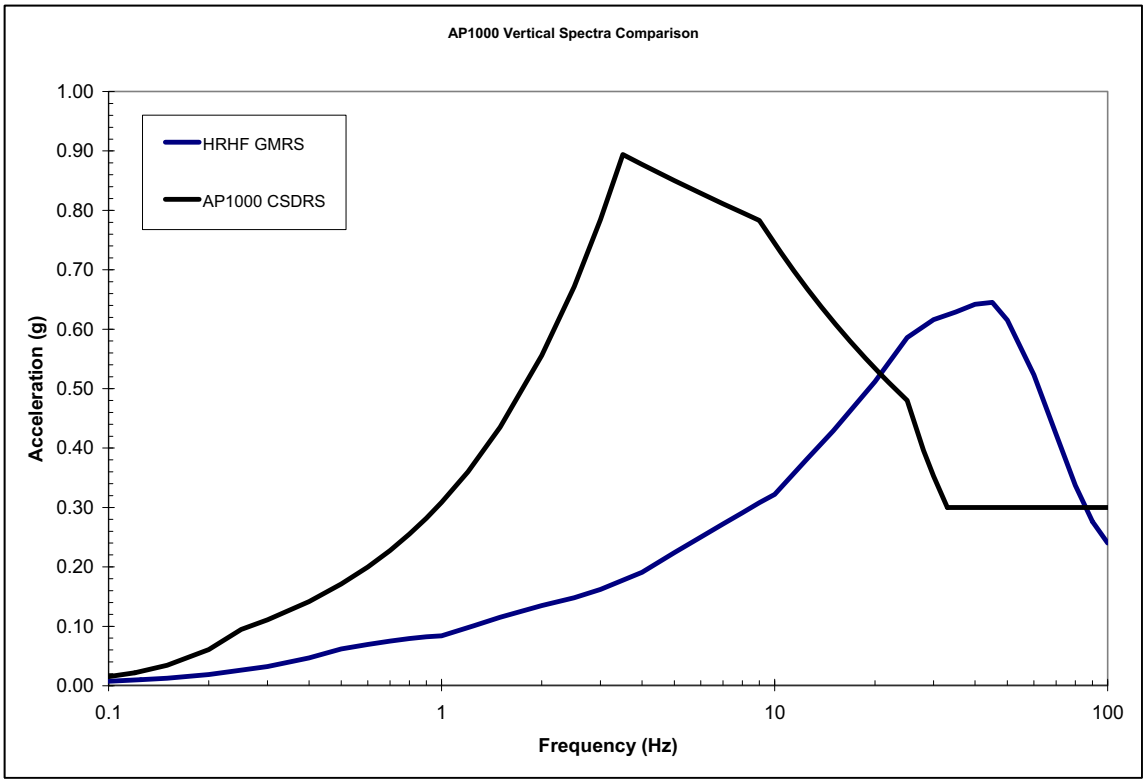


Figure 3I.1-2
Comparison of Vertical AP1000 CSDRS and HRHF Envelope Response Spectra

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 4	REACTOR	4.1-1
4.1	Summary Description	4.1-1
4.1.1	Principal Design Requirements	4.1-3
4.1.2	Combined License Information	4.1-4
4.1.3	References	4.1-4
4.2	Fuel System Design	4.2-1
4.2.1	Design Basis	4.2-2
4.2.1.1	Cladding	4.2-2
4.2.1.2	Fuel Material	4.2-3
4.2.1.3	Fuel Rod Performance	4.2-4
4.2.1.4	Spacer Grids	4.2-4
4.2.1.5	Fuel Assembly Structural Design	4.2-4
4.2.1.6	In-core Control Components	4.2-6
4.2.1.7	Surveillance Program	4.2-7
4.2.2	Description and Design Drawings	4.2-7
4.2.2.1	Fuel Rods	4.2-8
4.2.2.2	Fuel Assembly Structure	4.2-9
4.2.2.3	In-core Control Components	4.2-13
4.2.3	Design Evaluation	4.2-17
4.2.3.1	Cladding	4.2-17
4.2.3.2	Fuel Materials Considerations	4.2-19
4.2.3.3	Fuel Rod Performance	4.2-19
4.2.3.4	Spacer Grids	4.2-23
4.2.3.5	Fuel Assembly	4.2-23
4.2.3.6	Reactivity Control Assemblies and Burnable Absorber Rods	4.2-25
4.2.4	Testing and Inspection Plan	4.2-27
4.2.4.1	Quality Assurance Program	4.2-27
4.2.4.2	Quality Control	4.2-27
4.2.4.3	Letdown Radiation Monitoring	4.2-29
4.2.4.4	In-core Control Component Testing and Inspection	4.2-29
4.2.4.5	Tests and Inspections by Others	4.2-30
4.2.4.6	Inservice Surveillance	4.2-30
4.2.4.7	Onsite Inspection	4.2-30
4.2.5	Combined License Information	4.2-31
4.2.6	References	4.2-31
4.3	Nuclear Design	4.3-1
4.3.1	Design Basis	4.3-1
4.3.1.1	Fuel Burnup	4.3-2
4.3.1.2	Negative Reactivity Feedbacks (Reactivity Coefficients)	4.3-2
4.3.1.3	Control of Power Distribution	4.3-3
4.3.1.4	Maximum Controlled Reactivity Insertion Rate	4.3-3
4.3.1.5	Shutdown Margins	4.3-4
4.3.1.6	Stability	4.3-5
4.3.1.7	Anticipated Transients Without Scram (ATWS)	4.3-6
4.3.2	Description	4.3-6
4.3.2.1	Nuclear Design Description	4.3-6

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
4.3.2.2	Power Distribution	4.3-7
4.3.2.3	Reactivity Coefficients	4.3-16
4.3.2.4	Control Requirements	4.3-19
4.3.2.5	Control Rod Patterns and Reactivity Worth	4.3-24
4.3.2.6	Criticality of the Reactor During Refueling	4.3-25
4.3.2.7	Stability	4.3-27
4.3.2.8	Vessel Irradiation	4.3-30
4.3.3	Analytical Methods	4.3-31
4.3.3.1	Fuel Temperature (Doppler) Calculations	4.3-31
4.3.3.2	Macroscopic Group Constants	4.3-32
4.3.3.3	Spatial Few-Group Diffusion Calculations	4.3-33
4.3.4	Combined License Information	4.3-34
4.3.5	References	4.3-34
4.4	Thermal and Hydraulic Design	4.4-1
4.4.1	Design Basis	4.4-1
4.4.1.1	Departure from Nucleate Boiling Design Basis	4.4-1
4.4.1.2	Fuel Temperature Design Basis	4.4-2
4.4.1.3	Core Flow Design Basis	4.4-3
4.4.1.4	Hydrodynamic Stability Design Basis	4.4-3
4.4.1.5	Other Considerations	4.4-3
4.4.2	Description of Thermal and Hydraulic Design of the Reactor Core	4.4-3
4.4.2.1	Summary Comparison	4.4-3
4.4.2.2	Critical Heat Flux Ratio or DNBR and Mixing Technology	4.4-4
4.4.2.3	Linear Heat Generation Rate	4.4-8
4.4.2.4	Void Fraction Distribution	4.4-8
4.4.2.5	Core Coolant Flow Distribution	4.4-8
4.4.2.6	Core Pressure Drops and Hydraulic Loads	4.4-8
4.4.2.7	Correlation and Physical Data	4.4-9
4.4.2.8	Thermal Effects of Operational Transients	4.4-11
4.4.2.9	Uncertainties in Estimates	4.4-11
4.4.2.10	Flux Tilt Considerations	4.4-13
4.4.2.11	Fuel and Cladding Temperatures	4.4-14
4.4.3	Description of the Thermal and Hydraulic Design of the Reactor Coolant System	4.4-16
4.4.3.1	Plant Configuration Data	4.4-16
4.4.3.2	Operating Restrictions on Pumps	4.4-17
4.4.3.3	Power-Flow Operating Map (Boiling Water Reactor BWR)	4.4-17
4.4.3.4	Temperature-Power Operating Map (PWR)	4.4-17
4.4.3.5	Load Following Characteristics	4.4-17
4.4.3.6	Thermal and Hydraulic Characteristics Summary Table	4.4-17
4.4.4	Evaluation	4.4-17
4.4.4.1	Critical Heat Flux	4.4-17
4.4.4.2	Core Hydraulics	4.4-17
4.4.4.3	Influence of Power Distribution	4.4-18

TABLE OF CONTENTS (CONTINUED)

Section			Title	Page
		4.4.4.4	Core Thermal Response	4.4-20
		4.4.4.5	Analytical Methods	4.4-20
		4.4.4.6	Hydrodynamic and Flow Power Coupled Instability	4.4-21
		4.4.4.7	Fuel Rod Behavior Effects from Coolant Flow Blockage	4.4-23
	4.4.5		Testing and Verification	4.4-24
		4.4.5.1	Tests Prior to Initial Criticality	4.4-24
		4.4.5.2	Initial Power and Plant Operation	4.4-24
		4.4.5.3	Component and Fuel Inspections	4.4-24
	4.4.6		Instrumentation Requirements	4.4-24
		4.4.6.1	Incore Instrumentation	4.4-24
		4.4.6.2	Overtemperature and Overpower ΔT Instrumentation	4.4-26
		4.4.6.3	Instrumentation to Limit Maximum Power Output	4.4-26
		4.4.6.4	Digital Metal Impact Monitoring System	4.4-27
	4.4.7		Combined License Information	4.4-28
	4.4.8		References	4.4-28
4.5			Reactor Materials	4.5-1
	4.5.1		Control Rod and Drive System Structural Materials	4.5-1
		4.5.1.1	Materials Specifications	4.5-1
		4.5.1.2	Fabrication and Processing of Austenitic Stainless Steel Components	4.5-2
		4.5.1.3	Other Materials	4.5-2
		4.5.1.4	Contamination Protection and Cleaning of Austenitic Stainless Steel	4.5-2
	4.5.2		Reactor Internal and Core Support Materials	4.5-3
		4.5.2.1	Materials Specifications	4.5-3
		4.5.2.2	Controls on Welding	4.5-3
		4.5.2.3	Nondestructive Examination of Tubular Products and Fittings	4.5-3
		4.5.2.4	Fabrication and Processing of Austenitic Stainless Steel Components	4.5-4
		4.5.2.5	Contamination Protection and Cleaning of Austenitic Stainless Steel	4.5-4
	4.5.3		Combined License Information	4.5-4
4.6			Functional Design of Reactivity Control Systems	4.6-1
	4.6.1		Information for Control Rod Drive System	4.6-1
	4.6.2		Evaluations of the Control Rod Drive System	4.6-1
	4.6.3		Testing and Verification of the Control Rod Drive System	4.6-2
	4.6.4		Information for Combined Performance of Reactivity Systems	4.6-2
	4.6.5		Evaluation of Combined Performance	4.6-3
	4.6.6		Combined License Information	4.6-3

LIST OF TABLES

Table Number	Title	Page
4.1-1	Reactor Design Comparison Table	4.1-6
4.1-2	Analytical Techniques in Core Design	4.1-9
4.1-3	Design Loading Conditions for Reactor Core Components	4.1-10
4.3-1	Reactor Core Description (First Cycle)	4.3-39
4.3-2	Nuclear Design Parameters (First Cycle)	4.3-42
4.3-3	Reactivity Requirements for Rod Cluster Control Assemblies	4.3-44
4.3-4	Not Used	4.3-45
4.3-5	Stability Index for Pressurized Water Reactor Cores with a 12-Foot Height	4.3-46
4.3-6	Typical Neutron Flux Levels ($n/cm^2/s$) at Full Power	4.3-47
4.3-7	Comparison of Measured and Calculated Doppler Defects	4.3-48
4.3-8	Comparison of Measured and Calculated AG-in-CD Rod Worth	4.3-49
4.3-9	Comparison of Measured and Calculated Moderator Coefficients at HZP, BOL	4.3-50
4.4-1	Thermal and Hydraulic Comparison Table (AP1000, AP600 and a Typical Westinghouse XL Plant)	4.4-34
4.4-2	Void Fractions At Nominal Reactor Conditions With Design Hot Channel Factors	4.4-36

LIST OF FIGURES

Figure Number	Title	Page
4.2-1	Fuel Assembly Cross-Section	4.2-34
4.2-2	Fuel Assembly Outline	4.2-35
4.2-3	Fuel Rod Schematic	4.2-36
4.2-4	Top Grid Sleeve Detail	4.2-37
4.2-5	Intermediate Grid to Thimble Attachment Joint	4.2-38
4.2-6	Intermediate Flow Mixer Grid to Thimble Attachment	4.2-39
4.2-7	Grid Thimble to Bottom Nozzle Joint	4.2-40
4.2-8	Rod Cluster Control and Drive Rod Assembly With Interfacing Components	4.2-41
4.2-9	Rod Cluster Control Assembly	4.2-42
4.2-10	Absorber Rod Detail	4.2-43
4.2-11	Gray Rod Cluster Assembly	4.2-44
4.2-12	Wet Annular Burnable Absorber Assembly	4.2-45
4.2-13	Not Used	4.2-46
4.2-14	Primary Source Assembly	4.2-47
4.2-15	Secondary Source Assembly	4.2-48
4.3-1	Fuel Loading Arrangement for First Core	4.3-51
4.3-2	Typical Production and Consumption of Higher Isotopes	4.3-52
4.3-3	Cycle 1 Soluble Boron Concentration Versus Burnup	4.3-53
4.3-4a	(Sheet 1 of 4) Cycle 1 Assembly Integral and Wet Annular Burnable Absorber Patterns	4.3-54
4.3-4a	(Sheet 2 of 4) Cycle 1 Assembly Integral and Wet Annular Burnable Absorber Patterns	4.3-55
4.3-4a	(Sheet 3 of 4) Cycle 1 Assembly Integral and Wet Annular Burnable Absorber Patterns	4.3-56
4.3-4a	(Sheet 4 of 4) Cycle 1 Assembly Integral and Wet Annual Burnable Absorber Patterns	4.3-57
4.3-4b	Cycle 1 Assembly Integral and Wet Annular Burnable Absorber Axial Configurations	4.3-58
4.3-5	Cycle 1 Burnable Absorber, Primary, and Secondary Source Assembly Locations	4.3-59
4.3-6	Cycle 1 Normalized Power Density Distribution Near Beginning of Life, Unrodded Core, Hot Full Power, No Xenon	4.3-60
4.3-7	Cycle 1 Normalized Power Density Distribution Near Beginning of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon	4.3-61
4.3-8	Cycle 1 Normalized Power Density Distribution Near Beginning of Life, Gray Bank MA+MB Inserted, Hot Full Power, Equilibrium Xenon	4.3-62
4.3-9	Cycle 1 Normalized Power Density Distribution Near Middle of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon	4.3-63
4.3-10	Cycle 1 Normalized Power Density Distribution Near End of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon	4.3-64
4.3-11	Cycle 1 Normalized Power Density Distribution Near End of Life, Gray Bank MA+MB Inserted, Hot Full Power, Equilibrium Xenon	4.3-65
4.3-12	Rodwise Power Distribution in a Typical Assembly (M-5) Near Beginning of Life Hot Full Power, Equilibrium Xenon, Unrodded Core	4.3-66
4.3-13	Rodwise Power Distribution in a Typical Assembly (P-8) Near End of Life Hot Full Power, Equilibrium Xenon, Unrodded Core	4.3-67
4.3-14	Maximum F_Q x Power Versus Axial Height During Normal Operation	4.3-68

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
4.3-15	Typical Comparison Between Calculated and Measured Relative Fuel Assembly Power Distribution	4.3-69
4.3-16	Typical Calculated Versus Measured Axial Power Distribution	4.3-70
4.3-17	Measured F_Q Values Versus Axial Offset for Full Power Rod Configurations	4.3-71
4.3-18	Typical Doppler Temperature Coefficient at BOL and EOL	4.3-72
4.3-19	Typical Doppler-Only Power Coefficient at BOL and EOL	4.3-73
4.3-20	Typical Doppler-Only Power Defect at BOL and EOL	4.3-74
4.3-21	Typical Moderator Temperature Coefficient at BOL, Unrodded	4.3-75
4.3-22	Typical Moderator Temperature Coefficient at EOL	4.3-76
4.3-23	Typical Moderator Temperature Coefficient as a Function of Boron Concentration at BOL, Unrodded	4.3-77
4.3-24	Typical Hot Full Power Moderator Temperature Coefficient versus Cycle Burnup	4.3-78
4.3-25	Typical Total Power Coefficient at BOL and EOL	4.3-79
4.3-26	Typical Total Power Defect at BOL and EOL	4.3-80
4.3-27	Rod Cluster Control/Gray Rod Cluster Assembly (RCCA/GRCA) Assembly Pattern	4.3-81
4.3-28	Typical Accidental Simultaneous Withdrawal of Two Control Banks at EOL, HZP, Moving in the Same Plane	4.3-82
4.3-29	Typical Design Trip Curve	4.3-83
4.3-30	Typical Normalized Rod Worth Versus Percent Insertion All Rods Inserting Less Most Reactive Stuck Rod	4.3-84
4.3-31	X-Y Xenon Test Thermocouple Response Quadrant Tilt Difference Versus Time	4.3-85
4.3-32	Calculated and Measured Doppler Defect and Coefficients at BOL, 2-Loop Plant, 121 Assemblies, 12-foot Core	4.3-86
4.4-1	Thermal Diffusion Coefficient (TDC) as a Function of Reynolds Number	4.4-37
4.4-2	Thermal Conductivity of Uranium Dioxide (Data Corrected to 95% Theoretical Density)	4.4-38

Chapter 4 Reactor

4.1 Summary Description

This chapter describes the mechanical components of the reactor and reactor core, including the fuel rods and fuel assemblies, the nuclear design, and the thermal-hydraulic design.

The reactor contains a matrix of fuel rods assembled into mechanically identical fuel assemblies along with control and structural elements. The assemblies, containing various fuel enrichments, are configured into the core arrangement located and supported by the reactor internals. The reactor internals also direct the flow of the coolant past the fuel rods. The coolant and moderator are light water at a normal operating pressure of 2250 psia. The fuel, internals, and coolant are contained within a heavy walled reactor pressure vessel. An AP1000 fuel assembly consists of 264 fuel rods in a 17x17 square array. The center position in the fuel assembly has a guide thimble that is reserved for in-core instrumentation. The remaining 24 positions in the fuel assembly have guide thimbles. The guide thimbles are joined to the top and bottom nozzles of the fuel assembly and provide the supporting structure for the fuel grids.

The fuel grids consist of an egg-crate arrangement of interlocked straps that maintain lateral spacing between the rods. The grid straps have spring fingers and dimples that grip and support the fuel rods. The intermediate mixing vane grids also have coolant mixing vanes. In addition, there are four intermediate flow mixing (IFM) grids. The IFM grid straps contain support dimples and coolant mixing vanes only. The top and bottom grids and protective grid do not contain mixing vanes.

The AP1000 fuel assemblies are similar to the 17x17 Robust and 17x17 XL Robust fuel assemblies. The 17x17 Robust fuel assemblies have an active fuel length of 12 feet and three intermediate flow mixing grids in the top mixing vane grid spans. The 17x17 XL Robust fuel assemblies have an active fuel length of 14 feet (same as AP1000 fuel assemblies) and no intermediate flow mixing grids. The AP1000 fuel assemblies have four intermediate flow mixing grids in the top mixing vane grid spans.

There is substantial operating experience with the 17x17 Robust and 17x17 XL Robust fuel assemblies. The 17x17 Robust fuel assemblies are described in References 1, 2 and 3. The 17x17 XL Robust fuel assemblies are described in References 4 and 5.

The XL Robust fuel assembly evolved from the previous VANTAGE+, VANTAGE 5 and VANTAGE 5 HYBRID designs. The XL Robust fuel assembly is based on the substantial design and operating experience with those designs. The design is described and evaluated in References 2, 3, 6 through 10.

A number of proven design features have been incorporated in the AP1000 fuel assembly design. The AP1000 fuel assembly design includes: low pressure drop intermediate grids, four intermediate flow mixing (IFM) grids, a reconstitutable Westinghouse integral nozzle (WIN), and extended burnup capability. The bottom nozzle is a debris filter bottom nozzle (DFBN) that minimizes the potential for fuel damage due to debris in the reactor coolant. The AP1000 fuel assembly design also includes a protective grid for enhanced debris resistance.

The fuel rods consist of enriched uranium, in the form of cylindrical pellets of uranium dioxide, contained in ZIRLO®[1] (Reference 8) tubing. The tubing is plugged and seal welded at the ends to encapsulate the fuel. An axial blanket comprised of fuel pellets with reduced enrichment may be placed at each end of the enriched fuel pellet stack to reduce the neutron leakage and to improve fuel utilization.

1 ZIRLO® is a registered trademark in the United States of Westinghouse Electric Company LLC, its subsidiaries and/or its affiliates. This mark may also be used and/or registered in other countries throughout the world. All rights reserved. Unauthorized use is strictly prohibited. Other names may be trademarks of their respective owners.

Other types of fuel rods may be used to varying degrees within some fuel assemblies. One type uses an integral fuel burnable absorber (IFBA) containing a thin boride coating on the surface of the fuel pellets. The boride-coated fuel pellets provide a burnable absorber integral to the fuel.

Fuel rods are pressurized internally with helium during fabrication to reduce clad creepdown during operation and thereby prevent clad flattening. The fuel rods in the AP1000 fuel assemblies contain additional gas space below the fuel pellets, compared to the 17x17 Robust, 17x17 XL Robust and other previous fuel assembly designs to allow for increased fission gas production due to high fuel burnups.

Depending on the position of the assembly in the core, the guide thimbles are used for rod cluster control assemblies (RCCAs), gray rod cluster assemblies (GRCAs), neutron source assemblies, wet annular burnable absorber (WABA) assemblies, or thimble plugs.

For the initial core design, WABAs and IFBAs are used. Discrete burnable absorber designs, integral fuel burnable absorber designs or combinations may be used in subsequent reloads.

The bottom nozzle is a box-like structure that serves as the lower structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The size of flow passages through the bottom nozzle limits the size of debris that can enter the fuel assembly. The top nozzle assembly serves as the upper structural element of the fuel assembly and provides a partial protective housing for the rod cluster control assembly or other components.

The rod cluster control assemblies consist of 24 absorber rodlets fastened at the top end to a common hub, or spider assembly. Each absorber rod consists of an alloy of silver-indium-cadmium, which is clad in stainless steel. The rod cluster control assemblies are used to control relatively rapid changes in reactivity and to control the axial power distribution.

The gray rod cluster assemblies consist of 24 rodlets fastened at the top end to a common hub, or spider assembly (Reference 11). Geometrically, the gray rod cluster assembly is the same as a rod cluster control assembly except that the absorber rods consists of tungsten contained within a nickel-chromium-iron Alloy 718 sleeve. Stainless steel spacers are provided at the bottom of the rodlet between the bottom of the sleeve and the bottom end plug of the stainless steel cladding.

The gray rod cluster assemblies are used in base load operation and load follow maneuvering. The assemblies provide a mechanical shim reactivity mechanism to minimize the need for changes to the concentration of soluble boron.

The reactor core is cooled and moderated by light water at a pressure of 2250 psia. Soluble boron in the moderator/coolant serves as a neutron absorber. The concentration of boron is varied to control reactivity changes that occur relatively slowly, including the effects of fuel burnup. Burnable absorbers are also employed in the initial cycle to limit the amount of soluble boron required and, thereby maintain the desired negative reactivity coefficients.

The nuclear design analyses establish the core locations for control rods and burnable absorbers. The analyses define design parameters, such as fuel enrichments and boron concentration in the coolant.

The nuclear design establishes that the reactor core and the reactor control system satisfy design criteria, even if the rod cluster control assembly of the highest reactivity worth is in the fully withdrawn position.

The core has inherent stability against diametral and azimuthal power oscillations. Axial power oscillations, which may be induced by load changes, and resultant transient xenon may be suppressed by the use of the rod cluster control assemblies.

The control rod drive mechanisms used to withdraw and insert the rod cluster control assemblies and the gray rod cluster assemblies are described in Subsection 3.9.4.

The thermal-hydraulic design analyses establish that adequate heat transfer is provided between the fuel clad and the reactor coolant. The thermal design takes into account local variations in dimensions, power generation, flow distribution, and mixing. The mixing vanes incorporated in the fuel assembly spacer grid design and the fuel assembly intermediate flow mixers induce additional flow mixing between the various flow channels within a fuel assembly, as well as between adjacent assemblies.

The reactor internals direct the flow of coolant to and from the fuel assemblies and are described in Subsection 3.9.5.

The performance of the core is monitored by fixed neutron detectors outside the core, fixed neutron detectors within the core, and thermocouples at the outlet of selected fuel assemblies. The ex-core nuclear instrumentation provides input to automatic control functions.

Table 4.1-1 presents a summary of the principal nuclear, thermal-hydraulic, and mechanical design parameters of the AP1000 fuel. A comparison is provided to the fuel design used in AP1000, AP600 and in a licensed Westinghouse-designed plant using XL Robust fuel. For the comparison with a plant containing XL Robust fuel, a 193 fuel assembly plant is used, since no domestic, Westinghouse-designed 157 fuel assembly plants use 17x17 XL Robust fuel.

Table 4.1-2 tabulates the analytical techniques employed in the core design. The design basis must be met using these analytical techniques. Enhancements may be made to these techniques provided that the changes are bounded by NRC-approved methods, models, or criteria. In addition, application of the process described in WCAP-12488-A, (Reference 9) allows the Combined License holder to make fuel mechanical changes. Table 4.1-3 tabulates the mechanical loading conditions considered for the core internals and components. Specific or limiting loads considered for design purposes of the various components are listed as follows: fuel assemblies in Subsection 4.2.1.5; control rods (RCCAs and GRCAs), burnable absorber rods, and neutron source rods, in Subsection 4.2.1.6. The dynamic analyses, input forcing functions, and response loadings for the control rod drive system and reactor vessel internals are presented in Subsections 3.9.4 and 3.9.5.

4.1.1 Principal Design Requirements

The fuel and control rod mechanism are designed so the performance and safety criteria described in Chapter 4 and Chapter 15 are met. [*The mechanical design and physical arrangement of the reactor components, together with the corrective actions of the reactor control, protection, and emergency cooling systems (when applicable) are designed to achieve these criteria, referred to as Principal Design Requirements:*

- *Fuel damage, defined as penetration of the fuel cladding, is predicted not to occur during normal operation and anticipated operational transients.*
- *Materials used in the fuel assembly and in-core control components are selected to be compatible in a pressurized water reactor environment.*
- *For normal operation and anticipated transient conditions, the minimum DNBR calculated using the WRB-2M correlation is greater than or equal to 1.14.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- *Fuel melting will not occur at the overpower limit for Condition I or II events.*
- *The maximum fuel rod cladding temperature following a loss-of-coolant accident is calculated to be less than 2200°F.*
- *For normal operation and anticipated transient conditions, the calculated core average linear power, including densification effects, is less than or equal to 5.718 kw/ft for the initial fuel cycle.*
- *For normal operation and anticipated transient conditions, the calculated total heat flux hot channel factor, F_Q, is less than or equal to 2.60 for the initial fuel cycle.*
- *Calculated rod worths provide sufficient reactivity to account for the power defect from full power to zero power and provide the required shutdown margin, with allowance for the worst stuck rod.*
- *Calculations of the accidental withdrawal of two control banks using the maximum reactivity change rate predict that the peak linear heat rate and DNBR limits are met.*
- *The maximum rod cluster control assembly and gray rod speed (or travel rate) is 45 inches per minute.*
- *The control rod drive mechanisms are hydrotested after manufacture at a minimum of 125 percent of system design pressure.*
- *For the initial fuel cycle, the fuel rod temperature coefficient is calculated to be negative for power operating conditions.*
- *For the initial fuel cycle, the moderator temperature coefficient is calculated to be negative for power operating conditions.*]*

4.1.2 Combined License Information

This section contained no requirement for additional information.

4.1.3 References

1. Letter from N. J. Liparulo (Westinghouse) to J. E. Lyons (NRC), “Transmittal of Response to NRC Request for Information on Wolf Creek Fuel Design Modifications,” NSD-NRC-97-5189, June 30, 1997.

2. Letter from N. J. Liparulo (Westinghouse) to R. C. Jones (NRC), “Transmittal of Presentation Material for NRC/Westinghouse Fuel Design Change Meeting on April 15, 1996,” NSD-NRC-96-4964, April 22, 1996.

3. Letter from Westinghouse to NRC, “Fuel Criteria Evaluation Process Notification for the 17x17 Robust Fuel Assembly with IFM Grid Design,” NSD-NRC-98-5796, October 13, 1998.

4. Letter from H. A. Sepp (Westinghouse) to T. E. Collins (NRC), “Notification of FCEP Application for WRB-1 and WRB-2 Applicability to the 17x17 Modified LPD Grid Design for Robust Fuel Assembly Application,” NSD-NRC-98-5618, March 25, 1998.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

5. Letter from H. A. Sepp (Westinghouse) to T. E. Collins (NRC), “Fuel Criteria Evaluation Process Notification for the Revised Guide Thimble Dashpot Design for the 17x17 XL Robust Fuel Assembly Design,” NSD-NRC-98-5722, June 23, 1998.

6. Davidson, S. L., and Kramer, W. R., (Ed.), “Reference Core Report Vantage 5 Fuel Assembly,” WCAP-10444-P-A (Proprietary), September 1985 and WCAP-10445-A (Non-Proprietary), December 1983.

7. Davidson, S. L., (Ed.), “VANTAGE 5H Fuel Assembly,” Addendum 2-A, WCAP-10444-P-A (Proprietary) and WCAP-10445-NP-A (Non-Proprietary), February 1989.

8. Davidson, S. L., and Nuhfer, D. L., (Ed.), “VANTAGE+ Fuel Assembly Reference Core Report,” WCAP-12610-P-A (Proprietary) and WCAP-14342-A (Non-Proprietary), April 1995.

9. [*Davidson, S. L. (Ed.), “Fuel Criteria Evaluation Process,” WCAP-12488-A (Proprietary) and WCAP-14204-A (Non-Proprietary), October 1994.*]*

10. Letter, Peralta, J. D. (NRC) to Maurer, B. F. (Westinghouse), “Approval for Increase in Licensing Burnup Limit to 62,000 MWD/MTU (TAC No. MD1486),” May 25, 2006.

11. Conner, M. E., et al., “Enhanced GRCA Rodlet Design,” WCAP-16943-P-A (Proprietary) and WCAP-16943-NP-A (Non-Proprietary), September, 2012.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 4.1-1 (Sheet 1 of 3)
Reactor Design Comparison Table

Thermal and Hydraulic Design Parameters	AP1000[j]	AP600	Typical XL Plant
Reactor core heat output (MWt)	3400	1933	3800
Reactor core heat output (10^6 Btu/hr)	11,601	6596	12,969
Heat generated in fuel (%)	97.4	97.4	97.4
System pressure, nominal (psia)	2250	2250	2250
System pressure, minimum steady-state (psia)	2190	2200	2204
Minimum departure from nuclear boiling (DNBR) for design transients Typical flow channel Thimble (cold wall) flow channel	 >1.25[d] >1.25[d]	 >1.23 >1.22	 >1.26 >1.24
Departure from nucleate boiling (DNB) correlation[b]	WRB-2M[b]	WRB-2	WRB-1[a]
Coolant Flow[c]			
Total vessel thermal design flow rate (10^6 lbm/hr) Effective flow rate for heat transfer (10^6 lbm/hr) Effective flow area for heat transfer (ft^2) Average velocity along fuel rods (ft/s) Average mass velocity (10^6 lbm/hr-ft^2)	113.5 106.8 41.8 15.8 2.55	72.9 66.3 38.5 10.6 1.72	145.0 132.7 51.1 16.6 2.60
Coolant Temperature[c][e]			
Nominal inlet (°F) Average rise in vessel (°F) Average rise in core (°F) Average in core (°F) Average in vessel (°F)	535.0 77.2 81.4 578.1 573.6	532.8 69.6 75.8 572.6 567.6	561.2 63.6 68.7 597.8 593.0
Heat Transfer			
Active heat transfer surface area (ft^2) Avg. heat flux (BTU/hr-ft^2) Maximum heat flux for normal operation (BTU/hr-ft^2)[f] Average linear power (kW/ft)[g] Peak linear power for normal operation (kW/ft)[f][g] Peak linear power (kW/ft)[f][h] (Resulting from overpower transients/operator errors, assuming a maximum overpower of 118%)	56,700 199,300 518,200 5.72 14.9 ≤22.45	44,884 143,000 372,226 4.11 10.7 22.5	69,700 181,200 489,200 5.20 14.0 ≤22.45

Table 4.1-1 (Sheet 2 of 3)
Reactor Design Comparison Table

Thermal and Hydraulic Design Parameters	AP1000[j]	AP600	Typical XL Plant
Heat flux hot channel factor (F_Q)	2.60	2.60	2.70
Peak fuel center line temperature (°F) (For prevention of center-line melt)	4700	4700	4700
Fuel assembly design	17x17 XL Robust Fuel	17x17	17x17 XL Robust Fuel/ No IFM
Number of fuel assemblies	157	145	193
Uranium dioxide rods per assembly	264	264	264
Rod pitch (in.)	0.496	0.496	0.496
Overall dimensions (in.)	8.426 x 8.426	8.426 x 8.426	8.426 x 8.426
Fuel weight, as uranium dioxide (lb)	211,588	167,360	261,000
Clad weight (lb)	43,105	35,555	63,200
Number of grids per assembly Top and bottom - (Ni-Cr-Fe Alloy 718) Intermediate Intermediate flow mixing Protective Grid - (Ni-Cr-Fe Alloy 718)	 2[i] 8 ZIRLO 4 ZIRLO 1	 2[i] 7 Zircaloy-4 or 7 ZIRLO 4 Zircaloy-4 or 5 ZIRLO 1	 2 8 ZIRLO 0 1
Loading technique, first cycle	5 region nonuniform	3 region nonuniform	3 region nonuniform
Fuel Rods			
Number	41,448	38,280	50,952
Outside diameter (in.)	0.374	0.374	0.374
Diametral gap (non-IFBA) (in.)	0.0065	0.0065	0.0065
Clad thickness (in.)	0.0225	0.0225	0.0225
Clad material	ZIRLO	Zircaloy-4 or ZIRLO	Zircaloy-4/ ZIRLO
Fuel Pellets			
Material	UO_2 sintered	UO_2 sintered	UO_2 sintered
Density (% of theoretical)	95.5	95	95
Diameter (in.)	0.3225	0.3225	0.3225
Length (in.)	0.387	0.387	0.387

Table 4.1-1 (Sheet 3 of 3)
Reactor Design Comparison Table

Rod Cluster Control Assemblies	AP1000[j]	AP600	Typical XL Plant
Neutron Absorber			
RCCA GRCA	24 Ag-In-Cd rodlets 24 Tungsten rodlets	24 Ag-In-Cd rodlets 20 304 SS rodlets 4 Ag-In-Cd rodlets	24 Hafnium or Ag-In-Cd
Cladding material	Type 304 or 304L SS, cold-worked	Type 304 SS, cold-worked	Type 304 SS, cold-worked
Clad thickness (in.) - RCCA - GRCA	0.0185 0.0255	0.0185 0.0185	0.0185
Number of clusters	53 RCCAs 16 GRCAs	45 RCCAs 16 GRCAs	57 RCCAs 0 GRCAs
Core Structure			
Core barrel, ID/OD (in.)	133.75/137.75	133.75/137.75	148.0/152.5
Thermal shield	Neutron Panel	None	Neutron Panel
Baffle thickness (in.)	Core Shroud	Radial reflector	0.875
Structure Characteristics			
Core diameter, equivalent (in.)	119.7	115.0	132.7
Core height, cold, active fuel (in.)	168.0	144.0	168.0
Fuel Enrichment First Cycle (Weight Percent)			
Region 1	0.74 / --	1.90	Typical
Region 2	1.58 / --	2.80	3.8 to 4.4
Region 3	3.20 / 1.58	3.70	(5.0 Max)
Region 4	3.776 / 3.20		
Region 5	4.376 / 3.20		

Notes:
a. WRB-2M will be used in future reloads
b. See Subsection 4.4.2.2.1 for the use of the ABB-NV, WLOP, WRB-2 and WRB-2M correlations
c. Flow rates and temperatures are based on 10 percent steam generator tube plugging for the AP600 and AP1000 designs
d. The Design Limit DNBR is 1.25
e. Coolant temperatures based on thermal design flow (for AP600 and AP1000)
f. Based on FQ of 2.60 for AP600 and AP1000
g. Based on densified active fuel length. The value for AP1000 is rounded to 5.72 kW/ft.
h. See Subsection 4.3.2.2.6
i. The top grid will be fabricated of nickel-chromium-iron Alloy 718.
j. For the AP1000 design, the assembly average enrichments are given for the mid-zone and axial blanket regions.

Table 4.1-2
Analytical Techniques in Core Design

Analysis	Technique	Computer Code	Subsection Referenced
Mechanical design of core internals loads, deflections, and stress analysis	Static and dynamic modeling	BLOWDOWN code, FORCE, finite element structural analysis code, and others	3.7.2.1 3.9.2 3.9.3
Fuel rod design Fuel performance characteristics (such as, temperature, internal pressure, and clad stress)	Semi-empirical thermal model of fuel rod with considerations such as fuel density changes, heat transfer, and fission gas release.	Westinghouse fuel rod design model	4.2.1.1 4.2.3.2 4.2.3.3 4.3.3.1 4.4.2.11
Nuclear design Cross-sections and group constants	Microscopic data; macroscopic constants for homogenized core regions	Modified ENDF/B library with PHOENIX-P or PARAGON	4.3.3.2 4.3.3.3
X-Y and X-Y-Z power distributions, fuel depletion, critical boron concentrations, X-Y and X-Y-Z xenon distributions, reactivity coefficients	2-group diffusion theory, 2-group nodal theory	ANC (2-D or 3-D)	4.3.3.3
Axial power distributions, control rod worths, and axial xenon distribution	1-D, 2-group diffusion theory	APOLLO	4.3.3.3
Fuel rod power	Integral transport theory	LASER	4.3.3.1
Effective resonance temperature	Monte Carlo weighing function	REPAD	4.3.3.1
Criticality of reactor and fuel assemblies	3-D, Monte Carlo theory	MCNP4a	4.3.2.6.1
Vessel irradiation	Multigroup spatial dependent transport theory	DOT	4.3.2.8
Thermal-hydraulic design steady state	Subchannel analysis of local fluid conditions in rod bundles, including inertial and cross-flow resistance terms; solution progresses from core-wide to hot assembly to hot channel.	VIPRE-01	4.4.4.5.2
Transient departure from nucleate boiling	Subchannel analysis of local fluid conditions in rod bundles during transients by including accumulation terms in conservation equations; solution progresses from core-wide to hot assembly to hot channel.	VIPRE-01	4.4.4.5.4

Table 4.1-3
Design Loading Conditions for Reactor Core Components

- Fuel assembly weight and core component weights (burnable absorbers, sources, RCCA, GRCA, thimble plug)
- Fuel assembly holddown spring forces and core component spring forces
- Internals weight
- Control rod trip (equivalent static load)
- Differential pressure
- Spring preloads
- Coolant flow forces (static)
- Temperature gradients
- Thermal expansion
- Interference between components
- Vibration (mechanically or hydraulically induced)
- Operational transients listed in Table 3.9-1
- Pump overspeed
- Seismic loads (safe shutdown earthquake)
- Blowdown forces (due to pipe rupture)

4.2 Fuel System Design

The plant conditions for design are divided into four categories.

- Condition I - normal operation and operational transients
- Condition II - events of moderate frequency
- Condition III - infrequent incidents
- Condition IV - limiting faults

Chapter 15 describes bases and plant operation and events involving each condition.

The reactor is designed so that its components meet the following performance and safety criteria:

- The mechanical design and physical arrangement of the reactor core components, together with corrective actions of the reactor control, protection, and emergency cooling systems (when applicable) provide that:
  - Fuel damage, that is, breach of fuel rod clad pressure boundary, is not expected during Condition I and Condition II events. A very small amount of fuel damage may occur. This is within the capability of the plant cleanup system and is consistent with the plant design bases.
  - The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged. The fraction of fuel rods damaged must be limited to meet the dose guidelines identified in Chapter 15 although sufficient fuel damage might occur to preclude immediate resumption of operation.
  - The reactor can be brought to a safe state and the core kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.
- The fuel assemblies are designed to withstand non-operational loads induced during shipping, handling, and core loading without exceeding the criteria of Subsection 4.2.1.5.1.
- The fuel assemblies are designed to accept control rod insertions to provide the required reactivity control for power operations and reactivity shutdown conditions.
- The fuel assemblies have provisions for the insertion of in-core instrumentation.
- The reactor vessel and internals, in conjunction with the fuel assembly structure, directs reactor coolant through the core. Because of the resulting flow distribution and bypass flow, the heat transfer performance requirements are met for the modes of operation.

The following subsection provides the fuel system design bases and design limits. It is consistent with the criteria of the Standard Review Plan, Section 4.2.

Consistent with the growth in technology, Westinghouse modifies fuel system designs. These modifications utilize NRC approved methods. [*A set of design fuel criteria to be satisfied by new fuel designs was issued to the NRC in WCAP-12488-A and its addendums (Reference 1)*]* and also presented below in Subsection 4.2.1.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

4.2.1 Design Basis

The fuel rod and fuel assembly design bases are established to satisfy the general performance and safety criteria presented in Section 4.2 of the Standard Review Plan. [*The design bases and acceptance limits used by Westinghouse are also described in the Westinghouse Fuel Criteria Evaluation Process, WCAP-12488-A and its addendums (Reference 1).*]*

The fuel rods are designed to satisfy the fuel rod design criteria for rod burnup levels up to the design discharge burnup using the extended burnup design methods described in the Extended Burnup Evaluation report, WCAP-10125-P-A (Reference 2).

The AP1000 fuel rod design considers effects such as fuel density changes, fission gas release, clad creep, and other physical properties which vary with burnup. The integrity of the fuel rods is provided by designing to prevent excessive fuel temperatures as discussed in Subsection 4.2.1.2.1; excessive internal rod gas pressures due to fission gas releases as discussed in Subsections 4.2.1.3.1 and 4.2.1.3.2; and excessive cladding stresses, strains, and strain fatigue, as discussed in Subsections 4.2.1.1.2 and 4.2.1.1.3. The fuel rods are designed so that the conservative design bases of the following events envelope the lifetime operating conditions of the fuel. For each design basis, the performance of the limiting fuel rod, with appropriate consideration for uncertainties, does not exceed the limits specified by the design basis. The detailed fuel rod design also establishes such parameters as pellet size and density, clad/pellet diametral gap, gas plenum size, and helium pre-pressurization level.

Integrity of the fuel assembly structure is provided by setting limits on stresses and deformations due to various loads and by preventing the assembly structure from interfering with the functioning of other components. Three types of loads are considered:

- Non-operational loads, such as those due to shipping and handling
- Normal and abnormal loads, which are defined for Conditions I and II
- Abnormal loads, which are defined for Conditions III and IV

The design bases for the in-core control components are described in Subsection 4.2.1.6.

4.2.1.1 Cladding

4.2.1.1.1 Mechanical Properties

The ZIRLO cladding material combines neutron economy (low absorption cross-section); high corrosion resistance to coolant, fuel, and fission products; and high strength and ductility at operating temperatures. ZIRLO is an advanced zirconium based alloy that has the same or similar properties and advantages as Zircaloy-4 and was developed to support extended fuel burnup. WCAP-12610-P-A (Reference 5) provides a discussion of chemical and mechanical properties of the ZIRLO cladding material and a comparison to Zircaloy-4.

4.2.1.1.2 Stress-Strain Limits

Clad Stress

[*The volume average effective stress calculated with the Von Mises equation (considering interference due to uniform cylindrical pellet-clad contact, caused by pellet thermal expansion, pellet swelling and uniform clad creep, and pressure differences) is less than the 0.2 percent offset yield stress with due consideration to temperature and irradiation effects for Condition I and II events, WCAP-12488-A (Reference 1).*]* While the clad has some capability for accommodating plastic

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

strain, the yield stress has been accepted as a conservative design limit. The allowable stress limits due to Condition III and IV loadings, described in Subsection 4.2.1.5.3, are also applied to the fuel rod.

Clad Strain

[*The total plastic tensile creep strain due to uniform clad creep, and uniform cylindrical fuel pellet expansion associated with fuel swelling and thermal expansion is less than one percent from the unirradiated condition, WCAP-12488-A (Reference 1).*]* The acceptance limit for fuel rod clad strain during Condition II events is that the total tensile strain due to uniform cylindrical pellet thermal expansion is less than one percent from the pre-transient value. These limits are consistent with proven practice.

4.2.1.1.3 Fatigue and Vibration

Fatigue

[*The usage factor due to cycle fatigue is less than 1.0, WCAP-12488-A (Reference 1).*]* That is, for a given strain range, the number of strain fatigue cycles are less than those required for failure. The fatigue curve is based on a safety factor of two on the stress amplitude or a safety factor of 20 on the number of cycles, whichever is more conservative.

Vibration

Potential fretting wear due to vibration is prevented, giving confidence that the stress-strain limits are not exceeded during design life. Fretting of the clad surface can occur due to flow-induced vibration between the fuel rods and fuel assembly grid springs. Vibration and fretting forces may vary during the fuel life due to clad diameter creep down combined with grid spring relaxation.

4.2.1.1.4 Chemical Properties

Chemical properties of the ZIRLO cladding are discussed in WCAP-12610 (Reference 5).

4.2.1.2 Fuel Material

4.2.1.2.1 Thermal-Physical Properties

The center temperature of the hottest pellet is below the melting temperature of the uranium dioxide. The melting temperature of unirradiated uranium dioxide, 5080°F, decreases by 58°F per 10,000 megawatt days per metric ton of uranium, as discussed in WCAP-9179 (Reference 4). Fuel melting will not occur at the overpower limit for Condition I or II events. This provides sufficient margin for uncertainties as described in Subsection 4.4.2.9.

The nominal design density of the fuel is approximately 95.5 percent of the theoretical density. Additional information on fuel properties is provided in WCAP-9179 (Reference 4).

4.2.1.2.2 Fuel Densification and Fission Product Swelling

The design bases and models used for fuel densification and swelling are provided in WCAP-10851-P-A (Reference 7), and WCAP-15063-P-A, Revision 1 (Reference 21).

4.2.1.2.3 Chemical Properties

WCAP-9179 (Reference 4) and WCAP-12610 (Reference 5) provide the basis for justifying that no adverse chemical interactions occur between the fuel and its adjacent material.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

4.2.1.3 Fuel Rod Performance

4.2.1.3.1 Fuel Rod Models

The basic fuel rod models and the ability to predict fuel rod operating characteristics are given in WCAP-15063-P-A, Revision 1 (Reference 21) and Subsection 4.2.3.

4.2.1.3.2 Mechanical Design Limits

Cladding collapse is precluded during the fuel rod design lifetime. Current generation Westinghouse fuel is sufficiently stable with respect to fuel densification. Significant axial gaps in the pellet stack necessary for clad flattening do not occur and therefore, clad flattening will not occur. Clad flattening methodologies are described in WCAP-13589-A, (Reference 8) and WCAP-8377 (Reference 22).

The rod internal gas pressure remains below the value which causes the fuel/clad diametral gap to increase due to outward cladding creep during steady-state operation. Rod pressure is also limited such that extensive departure from nucleate boiling propagation does not occur as discussed in WCAP-8963-P-A (Reference 9).

4.2.1.4 Spacer Grids

4.2.1.4.1 Mechanical Limits and Materials Properties

The grid component strength criteria are based on experimental tests. The limit is established at the 95-percent confidence level on the true mean crush strength at operating temperature. This limit is sufficient to provide that, under worst-case combined seismic and pipe rupture event, the core will maintain a geometry amenable to cooling. As an integral part of the fuel assembly structure, the grids satisfy the applicable fuel assembly design bases and limits defined in Subsection 4.2.1.5.

The grid material and chemical properties are given in WCAP-9179 (Reference 4) and WCAP-12610 (Reference 5).

4.2.1.4.2 Vibration and Fatigue

The grids provide sufficient fuel rod support to limit fuel rod vibration and maintain clad fretting wear within acceptable limits (defined in Subsection 4.2.1.1).

4.2.1.5 Fuel Assembly Structural Design

As discussed in Subsection 4.2.1, the structural integrity of the fuel assemblies is provided by setting design limits on stresses and deformations due to various non-operational, operational, and accident loads. These limits are applied to the design and evaluation of the top and bottom nozzles, guide thimbles, grids, and thimble joints. [*Design changes to the fuel assembly structure qualify for evaluation in WCAP-12488-A (Reference 1).*]*

The design bases for evaluating the structural integrity of the fuel assemblies are discussed in Subsections 4.2.1.5.1 through 4.2.1.5.3.

4.2.1.5.1 Non-Operational

The non-operational load is a loading of 4 g axial (longitudinal) and 6 g lateral (transverse) with dimensional stability.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

4.2.1.5.2 Normal Operation and Operational Transients (Condition I) and Events of Moderate Frequency (Condition II)

For the normal operation (Condition I) and upset (Condition II) conditions, the fuel assembly component structural design criteria are established for the two primary material categories, austenitic steels and zirconium alloys. The stress categories and strength theory presented in the ASME Code, Section III, are used as a general guide. The maximum shear theory (Tresca criterion) for combined stresses is used to determine the stress intensities for the austenitic steel components. The stress intensity is defined as the largest numerical difference between the various principal stresses in a three-dimensional field. The design stress intensity value, S_m, for austenitic steels and zirconium alloys is given by the lowest of the following:

- One-third of the specified minimum tensile strength or two-thirds of the specified minimum yield strength at room temperature
- One-third of the tensile strength or 90 percent of the yield strength at temperature, but not to exceed two-thirds of the specified minimum yield strength at room temperature

The stress limits for the austenitic steel components are given below. Stress nomenclature follows the ASME Code, Section III.

Stress Intensity Limits

Categories	Limit
General primary membrane stress intensity	S_m
Local primary membrane stress intensity	1.5 S_m
Primary membrane plus bending stress intensity	1.5 S_m
Total primary plus secondary stress intensity	3.0 S_m

The zirconium alloy structural components, which consist of guide thimbles and fuel tubes, are in turn subdivided into two categories because of material difference and functional requirements. The fuel tube design criteria are covered separately in Subsection 4.2.1.1. The maximum shear theory is used to evaluate the guide thimble design. For conservative purposes, the zirconium alloy unirradiated properties are used to define the stress limits.

4.2.1.5.3 Infrequent Incidents (Condition III) and Limiting Faults (Condition IV)

Typical worse case abnormal loads during Conditions III and IV are represented by seismic and pipe rupture loadings. The design criteria for this category of loadings are as follows:

- Deflections or excessive deformation of components cannot interfere with capability of insertion of the control rods or emergency cooling of the fuel rods.
- The fuel assembly structural components stresses under faulted conditions are evaluated primarily using the methods outlined in Appendix F of the ASME Code, Section III. Since the current analytical methods use linear elastic analysis, the stress allowables are defined as the smaller value of 2.4 S_m or 0.70 S_u for primary membrane and 3.6 S_m or 1.05 S_u for primary membrane plus primary bending. For the austenitic steel fuel assembly components, the stress intensity is defined in accordance with the rules described in the previous section

for normal operating conditions. For the zirconium alloy components, the stress intensity limits are set at two-thirds of the material yield strength, S_y, at reactor operating temperature. This results in zirconium alloy stress limits being the smaller value of 1.6 S_y or 0.70 S_u for primary membrane and 2.4 S_y or 1.05 S_u for primary membrane plus bending.

- For conservative purposes, the zirconium alloy unirradiated properties are used to define the stress limits.

The material and chemical properties of the fuel assembly components are given in WCAP-9179 (Reference 4) and WCAP-12610 (Reference 5). Subsection 4.2.3.4 discusses the spacer grid crush testing.

Thermal-hydraulic design is discussed in Section 4.4.

4.2.1.6 In-core Control Components

The in-core control components are subdivided into permanent and temporary devices. The permanent components are the rod cluster control assemblies, gray rod cluster assemblies, thimble plugs and secondary neutron source assemblies. The temporary components are the primary neutron source assemblies (which are normally used only in the initial core), and the burnable absorber assemblies. For some reloads, the use of burnable absorbers may be necessary for power distribution control and/or to achieve an acceptable moderator temperature coefficient throughout core life (See Subsection 4.3.1.2.2). [*Design changes to the in-core control components qualify for evaluation using the criteria defined in WCAP-12488-A (Reference 1).*]*

Materials are selected for:

- Compatibility in a pressurized water reactor environment
- Adequate mechanical properties at room and operating temperatures
- Resistance to adverse property changes in a radioactive environment
- Compatibility with interfacing components

Material properties are given in WCAP-9179 (Reference 4).

The design bases for the in-core control components are given in Subsections 4.2.1.6.1 through 4.2.1.6.3.

4.2.1.6.1 Control Rods

For Conditions I and II, the stress categories and strength theory presented in the ASME Code, Section III, are used as a general guide in the design of the RCCA and GRCA structural parts in addition to absorber cladding.

Design conditions considered under the ASME Code, Section III, are as follows:

- External pressure equal to the reactor coolant system operating pressure with appropriate allowance for overpressure transients
- Wear allowance equivalent to 1000 reactor trips
- Bending of the rod due to a misalignment in the guide thimble

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- Forces imposed on the rods during rod drop
- Loads imposed by the accelerations of the control rod drive mechanism
- Radiation exposure during maximum core life. The RCCA absorber material temperature does not exceed its melting temperature (1454°F for silver-indium-cadmium [Ag-In-Cd]), (see WCAP-9179, Reference 4). Similarly, the GRCA absorber material temperature does not exceed its melting temperature (6116°F for tungsten), (see WCAP-16943-P-A, Reference 25).
- Temperature effects at operating conditions

4.2.1.6.2 Burnable Absorber Rods

For Conditions I and II, the stress categories and strength theory presented in the ASME Code, Section III, are used as a general guide in the design of the burnable absorber cladding. For abnormal loads during Conditions III and IV, code stresses are not considered limiting. Failures of the burnable absorber rods during these conditions must not interfere with reactor shutdown or emergency cooling of the fuel rods. The burnable absorber material is nonstructural. The structural elements of the burnable absorber rod are designed to maintain the absorber geometry even if the absorber material is fractured.

To reduce the dissolved boron requirement for control of excess reactivity, wet annular burnable absorber (WABA) rods have been incorporated in the first core design. The burnable absorber material is boron carbide contained in an alumina matrix. Thermal-physical and gas release properties of alumina-boron carbide are described in WCAP-9179 (Reference 4) and WCAP-10021-P-A (Reference 10). Discrete burnable absorber rods are designed so that the absorber temperature does not exceed 1200°F during normal operation or an overpower transient. The 1200°F maximum temperature helium gas release in a discrete burnable absorber rod will not exceed 30 percent of theoretical. See WCAP-10021-P-A (Reference 10).

4.2.1.6.3 Neutron Source Rods

The neutron source rods are designed to withstand the following:

- The external pressure equal to reactor coolant system operating pressure with appropriate allowance for overpressure transients
- An internal pressure equal to the pressure generated by released gases over the source rod life

4.2.1.7 Surveillance Program

Subsection 4.2.4.6 discusses the testing and fuel surveillance operation experience program that has been and is being conducted to verify the adequacy of the fuel performance and design bases. Fuel surveillance and testing results, as they become available, are used to improve fuel rod design and manufacturing processes and to confirm that the design bases and safety criteria are satisfied.

4.2.2 Description and Design Drawings

The fuel assembly, fuel rod, and in-core control component design data is given in Table 4.3-1.

Each fuel assembly consists of 264 fuel rods, 24 guide thimbles, and 1 instrumentation tube arranged within a supporting structure. The instrumentation thimble is located in the center position and

provides a channel for insertion of an in-core neutron detector, if the fuel assembly is located in an instrumented core position. The guide thimbles provide channels for insertion of either a rod cluster control assembly, a gray rod cluster assembly, a neutron source assembly, a burnable absorber assembly, or a thimble plug, depending on the position of the particular fuel assembly in the core. Figure 4.2-1 shows a cross-section of the fuel assembly array, and Figure 4.2-2 shows a fuel assembly full-length view.

The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles. The fuel rods are supported within the fuel assembly structure by fourteen grids (top grid (1), bottom grid (1), intermediate grids (8) and intermediate flow mixer (IFM) grids (4)), plus one protective grid. The top grid is fabricated from nickel-chromium-iron Alloy 718. The bottom grid is fabricated from nickel-chromium-iron Alloy 718. The intermediate grids and the IFM grids are fabricated from ZIRLO (see WCAP-12610-P-A, Reference 5). Top, bottom, and intermediate grids provide axial and lateral support to the fuel rods. In addition, the four IFM grids located near the center of the fuel assembly and between the intermediate grids provide additional fuel rod restraint. The protective grid, in combination with the debris filter bottom nozzle (DFBN), the protective zirconium oxide coated fuel cladding, and the long, solid fuel rod bottom end plug, provide debris failure mitigation.

Fuel assemblies are installed vertically in the reactor vessel and stand upright on the lower core plate, which is fitted with alignment pins to locate and orient each assembly. After the fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the fuel assemblies. The upper core plate then bears down against the hold-down springs on the top nozzle of each fuel assembly to hold the fuel assemblies in place.

Improper orientation of fuel assemblies within the core is prevented by the use of an indexing hole in one corner of the top nozzle top plate. The assembly is oriented with respect to the handling tool and the core by means of a pin inserted into this indexing hole. Visual confirmation of proper orientation is also provided by an engraved identification number on the opposite corner clamp.

4.2.2.1 Fuel Rods

The fuel rods consist of uranium dioxide ceramic pellets contained in cold-worked and stress relieved ZIRLO tubing, which is plugged and seal-welded at the ends to encapsulate the fuel. ZIRLO is an advanced zirconium based alloy selected for its mechanical properties and low neutron absorption cross-section (see WCAP-12610-P-A, Reference 5). Figure 4.2-3 shows a schematic of the fuel rod. The fuel pellets are right circular cylinders consisting of slightly enriched uranium dioxide powder which has been compacted by cold pressing and then sintered to the required density. The ends of each pellet are dished slightly, to allow greater axial expansion at the pellet centerline and to increase the void volume for fission gas release. The ends of each pellet also have a small chamfer at the outer cylindrical surface which improves manufacturability, and mitigates potential pellet damage due to fuel rod handling.

Void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the clad and the fuel, and fuel density changes during irradiation. To facilitate the extended burnup capability necessitated by longer operating cycles, the fuel rod is designed with two plenums (upper and lower) to accommodate the additional fission gas release. The upper plenum volume is maintained by a fuel pellet hold-down spring. The lower plenum volume is maintained by a standoff assembly.

Shifting of the fuel within the clad during handling or shipping, prior to core loading, is prevented by a stainless steel helical spring which bears on top of the fuel pellet stack. Assembly consists of plugging and welding the bottom of the cladding, installing the bottom plenum spacer assembly, fuel

pellets and top plenum spring, and then plugging and welding the top of the rod. The solid bottom end plug has an internal grip feature and tapered end to facilitate fuel rod loading during fuel assembly fabrication and reconstitution. Additionally, the bottom end plug is designed to be sufficiently long to extend through the protective grid. The bottom section of the fuel rod has a protective zirconium oxide coated surface feature. Use of the protective grid with a longer end plug and the debris filter bottom nozzle, in addition to the coated cladding surface, constitutes a three-level debris protection package, which enhances the fuel reliability performance against trapped debris. This precludes any breach in the fuel rod pressure boundary due to clad fretting wear induced by debris trapped at the bottom section of the fuel assembly.

The fuel rods are internally pressurized with helium during the welding process to minimize compressive clad stresses and prevent clad flattening under reactor coolant operating pressures. The fuel rods are pre-pressurized and designed so that:

- The internal gas pressure mechanical design limit referred to in Subsection 4.2.1.3 is not exceeded
- The cladding stress-strain limits (Subsection 4.2.1.1) are not exceeded for Condition I and II events
- Clad flattening will not occur during the fuel core life

The AP1000 fuel rod design may also include axial blankets. The axial blankets consist of fuel pellets of a reduced enrichment at each end of the fuel rod pellet stack. Axial blankets reduce neutron leakage axially and improve fuel utilization. The axial blankets use chamfered pellets that are longer than the enriched pellets to help prevent accidental mixing during manufacturing. Furthermore, axial blankets have no impact on the source range detector response, since the reduction in power from the axial blanket is limited to the top and bottom 0.67 feet of the core, while the source range detectors are centered typically about three feet from the bottom of the core.

The AP1000 fuel rod design may also include annular fuel pellets in the top and bottom 8 inches of the fuel stack. These pellets can be either fully enriched or partially enriched. The annular fuel pellets provide additional void volume in the fuel rod to accommodate fission gas release.

The AP1000 fuel rods include integral fuel burnable absorbers. The integral fuel burnable absorbers are boride-coated fuel pellets. The boride-coated fuel pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin boride coating less than 0.001 inch in thickness on the pellet cylindrical surface. Coated pellets occupy the central portion of the fuel column. The number and pattern of integral fuel burnable absorber rods within an assembly may vary depending on specific application. See WCAP-12610-P-A (Reference 5).

4.2.2.2 Fuel Assembly Structure

As shown in Figure 4.2-2, the fuel assembly structure consists of a bottom nozzle, top nozzle, fuel rods, guide thimbles, and grids.

4.2.2.2.1 Bottom Nozzle

The bottom nozzle serves as the bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The nozzle is fabricated from Type 304 and Grade CF-3 stainless steel and consists of a perforated plate, and casting which incorporates a skirt and four angle legs with bearing pads. Figure 4.2-2 illustrates this concept. The legs and skirt form a plenum to direct the inlet coolant flow to the fuel assembly. The perforated plate also prevents accidental downward ejection of the fuel rods from the fuel assembly. The bottom nozzle is fastened to the fuel

assembly guide thimbles by locked thimble screws, which penetrate through the nozzle and engage with a threaded plug in each guide thimble.

Coolant flows from the plenum in the bottom nozzle, upward through the penetrations in the plate, to the channels between the fuel rods. The penetrations in the plate are positioned between the rows of the fuel rods.

In addition to serving as the bottom structural element of the fuel assembly, the bottom nozzle also functions as a debris filter. The bottom nozzle perforated plate contains a multiplicity of flow holes which are sized to minimize passage of detrimental debris particles into the active fuel region of the core while maintaining sufficient hydraulic and structural margins. Furthermore, the skirt provides improved bottom nozzle structural stability and increased design margins to reduce damage due to abnormal handling.

Axial loads (from top nozzle hold-down springs) imposed on the fuel assembly and the weight of the fuel assembly are transmitted through the bottom nozzle to the lower core plate. Indexing and positioning of the fuel assembly is controlled by alignment holes in two diagonally opposite bearing pads that mate with locating pins in the lower core plate. Lateral loads on the fuel assembly are transmitted to the lower core plate through the locating pins.

The AP1000 bottom nozzle also has a reconstitution design feature which facilitates the easy removal of the nozzle from the fuel assembly. This design incorporates a thimble screw with a circular locking cup located around the screw head. The locking cup is crimped into a local spherical radius relief on the bottom nozzle. To remove the bottom nozzle, a counterclockwise torque is applied to the thimble screw until the locking cup (detents) is relaxed and the thimble screw is removed. This reconstitutable design permits the remote unlocking, the removal, and the relocking of the thimble screws, as the same or a new bottom nozzle is reattached to the fuel assembly.

4.2.2.2.2 Top Nozzle

The reconstitutable top nozzle functions as the upper structural component of the fuel assembly and, in addition, provides a partial protective housing for the rod cluster control assembly, discrete burnable absorber, or other core components. As shown in Figure 4.2-2, the top nozzle assembly includes four sets of hold-down springs, which are secured to the top nozzle top plate. The springs are made of nickel-chromium-iron Alloy 718. The other top nozzle components are made of Type 304L and Grade CF-3 stainless steel.

The adapter plate is provided with round penetrations and slots (with semicircular ends) to permit the flow of coolant upward through the top nozzle. Other round holes are provided in the adapter plate to accept (guide thimble) inserts which are mechanically locked to the adapter plate using a lock tube. The unique design of the insert joint and lock tube are the key design features of the reconstitutable top nozzle.

The ligaments in the adapter plate cover the top of the fuel rods precluding any upward ejection of the fuel rods from the fuel assembly. The enclosure is a box-like structure which establishes the distance between the adapter plate and the top plate. The top plate has a large square hole in the center to permit access for the rod cluster control assembly, burnable absorber assembly, or other components. Hold-down springs are mounted on the top plate and are retained by retaining pins located at diagonally opposite corners of the top plate.

The top plate also contains integral pads located on the two remaining top nozzle corners. The pads include alignment holes which, when fully engaged with the reactor internals upper core plate guide pins, provide proper alignment to the fuel assembly, reactor internals, and rod cluster control assembly.

As shown in Figure 4.2-4, to remove the top nozzle assembly a tool is first inserted through a lock tube and expanded radially to engage the bottom edge of the tube. An axial force is then exerted on the tool which overrides local lock tube deformations and withdraws the lock tubes from the inserts. After the lock tubes have been removed, the nozzle assembly is removed by raising it off the upper slotted ends of the nozzle inserts, which deflect inwardly under the axial lift load.

With the top nozzle assembly removed, direct access is provided for fuel rod examination or replacement. Reconstitution is completed by the remounting of the nozzle assembly and the insertion of lock tubes. Details of this design feature, the design bases and evaluation of the reconstitutable top nozzle are given in WCAP-10444-P-A (Reference 11).

4.2.2.2.3 Guide Thimbles and Instrument Tube

The guide thimbles are structural members that provide channels for the neutron absorber rods, burnable absorber rods, neutron source rods, or other assemblies. Each guide thimble is fabricated from Zircaloy-4 or ZIRLO with constant OD and ID over the entire length. Separate dashpot tubes, which are made from Zircaloy-4 or ZIRLO tubing, are inserted into the bottom portion of the guide thimble tubes. The larger tube diameter at the top section provides a relatively large annular area necessary to permit rapid control rod insertion during a reactor trip, as well as to accommodate the flow of coolant during normal operation. Holes are provided on the guide thimble above the dashpot to reduce the rod drop time. The lower portion of the guide thimble with the dashpot tube results in a dashpot action near the end of the control rod travel during normal trip operation. The dashpot is closed at the bottom by means of an end plug, which is provided with a small flow port to avoid fluid stagnation in the dashpot volume during normal operation.

As stated previously, the AP1000 fuel assembly includes a reconstitutable top nozzle as a standard feature. To accommodate the reconstitutable feature, the top end of the zirconium alloy guide thimble is fastened to a tubular sleeve, or insert, by a three tier expansion bulge joint. An expansion tool is inserted inside the nozzle insert and guide thimble to the proper elevation. The four lobes on the expansion tool force the guide thimble and insert outward locally to a predetermined diameter, therefore joining the two components.

Upon installation of the top nozzle assembly, the bulge near the top of the nozzle insert is captured in a corresponding groove in the hole of the top nozzle adapter plate. As shown in Figure 4.2-4, the mechanical connection between the nozzle insert-guide thimble and top nozzle is made by insertion of a lock tube into the insert. The design of the top grid sleeve-guide thimble and top nozzle insert-guide thimble bulge joint connections have been mechanically tested and found to meet applicable design criteria.

The fuel rod support grids are secured to the guide thimbles using a similar bulge joint connection to create an integral structure. Attachment of the intermediate mixing vane and intermediate flow mixer (IFM) zirconium alloy grids to the guide thimbles is performed using the fastening technique depicted in Figures 4.2-5 and 4.2-6.

The intermediate mixing vane and intermediate flow mixer grids employ a single tier bulge connection between the grid sleeve and guide thimble as compared to the two tier bulge connection used for the top grid. The design of the single tier bulge joint connection has also been mechanically tested and meets the design requirements.

The bottom nickel-chromium-iron Alloy 718 grid is secured to the guide thimble assembly by a double tier bulge connection between the grid sleeve and guide thimble. The design of the double tier bulge joint connection has also been mechanically tested and meets the design requirements.

The lower end of the guide thimble is fitted with a welded end plug. The nickel-chromium-iron Alloy 718 protective grid is secured to the guide thimble assembly by nickel-chromium-iron Alloy 718 spacers that are spot-welded to the grid. As shown in Figure 4.2-7, the spacer is captured between the guide thimble end plug and the bottom nozzle by means of a (thimble) locking screw.

The described methods of grid fastening are standard and have been used successfully since the introduction of zirconium alloy guide thimbles in 1969.

The central instrumentation tube in each fuel assembly is constrained by seating in counterbores located in both top and bottom nozzles. The instrumentation tube has a constant diameter and provides an unrestricted passageway for the in-core neutron detector which enters the fuel assembly from the top nozzle. Furthermore, the instrumentation tube is secured to the top, bottom, and mid-grids with bulge joint connections similar to those previously discussed for securing the grids to the guide thimbles.

4.2.2.2.4 Grid Assemblies

As shown in Figure 4.2-2, the fuel rods are supported at intervals along their lengths by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. Each fuel rod is given support at six contact points within each grid by the combination of support dimples and springs. The grid assembly consists of individual slotted straps assembled and interlocked into an egg-crate type arrangement with the straps permanently joined at their points of intersection. The straps may contain springs, support dimples, and mixing vanes; or any such combination.

Two types of structural grid assemblies are used on the AP1000 fuel assembly. One type, with mixing vanes projecting from the edges of the straps into the coolant stream, is used in the high heat flux region of the fuel assemblies to promote mixing of the coolant. The other type, located at the top and bottom of the assembly, does not contain mixing vanes on the internal straps. The outside straps on the grids contain mixing vanes that, in addition to their mixing function, aid in guiding the grids and fuel assemblies past projecting surfaces during handling or during loading and unloading of the core.

Because of its corrosion resistance and high strength properties, the bottom grid material chosen for the AP1000 fuel assembly design is nickel-chromium-iron Alloy 718. The top grid is fabricated from nickel-chromium-iron Alloy 718. The magnitude of the grid restraining force on the fuel rod is set high enough to minimize possible fretting, without overstressing the cladding at the points of contact between the grids and fuel rods. The grid assemblies are designed to allow axial thermal expansion of the fuel rods without imposing restraint sufficient to develop buckling or distortion of the fuel rods.

The eight intermediate (mixing vane), or structural grids on the AP1000 fuel assembly are made of ZIRLO. This material was selected to take advantage of the material's inherent low neutron capture cross-section. The zirconium alloy grids have thicker straps than the nickel-chromium-iron alloy grids. The zirconium alloy grid incorporates the same grid cell support configuration as the nickel-chromium-iron alloy grid. The zirconium alloy interlocking strap joints and grid/sleeve joints are fabricated by laser welding, whereas the nickel-chromium-iron alloy grid joints (except the protective grid) are brazed. The interlocking strap joints for the protective grid are also fabricated by laser welding. The mixing vanes incorporated in the zirconium alloy intermediate grids induce additional flow mixing among the various flow channels in a fuel assembly as well as between adjacent fuel assemblies. This additional flow mixing enhances thermal performance.

As shown in Figure 4.2-2, the intermediate flow mixer grids are located at selected spans between the zirconium alloy mixing vane structural grids and incorporate a similar mixing vane array. Their prime function is mid-span flow mixing in the hotter fuel assembly spans. Each intermediate flow mixer grid cell contains four dimples that are designed to prevent mid-span channel closure in the

spans containing intermediate flow mixers and fuel rod contact with the mixing vanes. This simplified cell arrangement allows short grid cells so that the intermediate flow mixer grid can accomplish its flow mixing objective with minimal pressure drop.

The intermediate flow mixer (IFM) grids, like the mixing vane grids, are fabricated from ZIRLO. The intermediate flow mixer grids are manufactured using the same basic techniques as the zirconium alloy structural grid assemblies and are joined to the guide thimbles via sleeves which are welded at the bottom of appropriate grid cells.

Grid impact testing has been performed on zirconium alloy structural grids and the intermediate flow mixer grids indicative of the AP1000 design. The purpose of the testing was to determine the dynamic buckling, or crush, strength of the grids. The grid impact testing was performed at an elevated temperature of 600°F. This temperature is a conservative value representing the core average temperature at the mid-grid locations.

The intermediate flow mixer grids are not intended to be structural members. The intermediate flow mixer grids do, however, share the loads of the structural grids during faulted loading and, as such, contribute to enhance the load carrying capability of the AP1000 fuel assembly.

The dynamic crush strength of the AP1000 structural grids and intermediate flow mixer grids envelope the calculated grid impact loading during combined seismic and pipe rupture events. A coolable geometry is, therefore, provided at the intermediate flow mixer grid elevations, as well as at the structural grid elevations.

4.2.2.3 In-core Control Components

Reactivity control is provided by neutron absorbing rods, gray rods, burnable absorber rods, and a soluble chemical neutron absorber (boric acid). The boric acid concentration is varied to control long-term reactivity changes such as:

- Fuel depletion and fission product buildup
- Cold to hot, zero power reactivity changes
- Reactivity change produced by intermediate-term fission products such as xenon and samarium
- Burnable absorber depletion

The chemical and volume control system, which is used to adjust the level of boron in the coolant, is discussed in Section 9.3.

The rod cluster control assemblies provide reactivity control for:

- Shutdown
- Reactivity changes due to coolant temperature changes in the power range
- Reactivity changes associated with the power coefficient of reactivity
- Reactivity changes due to void formation

A negative power coefficient is maintained at hot, full-power conditions throughout the entire cycle to reduce possible deleterious effects caused by a positive coefficient during pipe rupture or loss-of-flow

accidents. The first fuel cycle needs more excess reactivity than subsequent cycles due to the loading of fresh (unburned) fuel. Since soluble boron alone is insufficient to provide a negative moderator coefficient, burnable absorber assemblies are also used. Use of burnable absorber assemblies during reloads is discussed in Subsection 4.3.1.2.2.

The most effective reactivity control components are the rod cluster control assemblies and the corresponding drive rod assemblies, which along with the gray rod cluster assemblies, are the only kinetic parts in the reactor. Figure 4.2-8 identifies the rod cluster control and drive rod assembly, in addition to the arrangement of these components in the reactor relative to the interfacing fuel assembly, guide thimbles, and control rod drive mechanism. The arrangement for the gray rod cluster assemblies is the same.

As shown in Figure 4.2-8, the guidance system for the rod cluster control assembly is provided by the guide thimbles. The guide thimbles provide two regimes of guidance: first, in the lower section, a continuous guidance system provides support immediately above the core, which protects the rod against excessive deformation and wear caused by hydraulic loading. Second, the region above the continuous section provides support and guidance at uniformly spaced intervals.

As shown in Figure 4.2-9, the envelope of support is determined by the pattern of the control rod cluster. The guide thimbles provide alignment and support of the control rods, spider body, and drive rod while maintaining trip times at or below required limits.

Subsections 4.2.2.3.1 through 4.2.2.3.4 describe each reactivity control component in detail. The control rod drive mechanism assembly is described in Subsection 9.3.4. The neutron source assemblies provide a means of monitoring the core during periods of low neutron activity.

4.2.2.3.1 Rod Cluster Control Assemblies

The rod cluster control assemblies are divided into two categories: control and shutdown. The control groups compensate for reactivity changes due to variations in operating conditions of the reactor, that is, power and temperature variations. Two nuclear design criteria have been employed for selection of the control group. First, the total reactivity worth must be adequate to meet the nuclear requirements of the reactor. Second, in view of the fact that these rods may be partially inserted at power operation, the total power peaking factor should be low enough to confirm that the power capability is met. The control and shutdown groups provide adequate shutdown margin.

As illustrated in Figure 4.2-9, a rod cluster control assembly is comprised of a group of individual neutron absorber rods fastened at the top end to a common spider assembly.

The absorber material used in these rods is silver-indium-cadmium alloy, which is essentially “black” to thermal neutrons and has sufficient additional resonance absorption to significantly increase worth. As such, these rods are sometimes referred to as “black” rods. As shown in Figure 4.2-10, the absorber material is in the form of solid bars sealed in cold-worked stainless steel tubes. Sufficient diametral and end clearance is provided to accommodate relative thermal expansions.

The control rods have bottom plugs with bullet-like tips to reduce the hydraulic drag during reactor trip and to guide smoothly into the dashpot section of the fuel assembly guide thimbles.

The material used in the absorber rod end plugs is Type 308 or 308L stainless steel. The design stresses used for these materials are the same as those defined in the ASME B&PV Code for Type 304 or 304L stainless steel, which have essentially the same strength properties as Type 308 and 308L stainless steel, respectively.

The allowable stresses used as a function of temperature are listed in Table 2A of the ASME Code, Section II, Part D. The fatigue strength for the Type 308 or 308L material is based on the S-N curve for austenitic stainless steels in Figure I-9.2 of the ASME Code, Section III.

The spider assembly is in the form of a central hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Internal groove-like profiles to facilitate handling tool and drive rod assembly connection are machined into the upper end of the hub. Coil springs inside the spider body absorb the impact energy at the end of a trip insertion. The radial vanes may either be joined to the hub by welding and brazing, and the fingers joined to the vanes by brazing, or the vanes and fingers may be integral with the spider body. A bolt, which holds the springs and retainer, is threaded into the hub within the skirt and welded to prevent loosening while in service.

The components of the spider assembly are made from Types 304, 304L and/or CF-3 (casting equivalent of 304L) stainless steel except for the retainer, which is of Type 630 material, and the springs, which are nickel-chromium-iron Alloy 718.

The absorber rods are fastened securely to the spider. The rods are first threaded into the spider fingers and then secured with a locking device. The end plug below the thread is designed with a reduced section to permit flexing of the rods to correct for small operating or assembly misalignments.

The overall length of the rod cluster control assembly is such that, when the assembly is withdrawn through its full travel, the tips of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Since the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble.

4.2.2.3.2 Gray Rod Cluster Assemblies

Externally the mechanical design of the gray rod cluster assembly is identical to the rod cluster control assembly. In addition, the control rod drive mechanism and the interface with the fuel assemblies and guide thimbles are identical to those of the rod cluster control assembly.

As shown in Figure 4.2-11, the gray rod cluster assemblies consist of 24 rodlets fastened at the top end to a common hub or spider. Geometrically, the gray rod cluster assembly is the same as a rod cluster control assembly except that the absorber material consists of tungsten encapsulated in a nickel-chromium-iron Alloy 718 sleeve and clad with stainless steel cladding which has the same outer diameter as the rod cluster control assembly cladding. The lower portion of the rodlets consists of a stainless steel spacer.

The gray rod cluster assemblies are used in base load operation and load follow maneuvering and provide a mechanical shim to replace the use of changes in the concentration of soluble boron, that is, a chemical shim, normally used for this purpose. The AP1000 uses 53 rod cluster control assemblies and 16 gray rod cluster assemblies.

4.2.2.3.3 Burnable Absorber Assembly

Each burnable absorber assembly consists of discrete burnable absorber rods attached to a hold-down assembly. Figure 4.2-12 shows the burnable absorber assemblies. When needed for nuclear considerations, burnable absorber assemblies are inserted into selected thimbles within fuel assemblies.

The wet annular burnable absorber rods (WABA) consist of pellets of alumina-boron carbide material contained within zirconium alloy tubes. These zirconium alloy tubes, which form the outer clad for the burnable absorber rod, are plugged, pressurized with helium, and seal-welded at each end to

encapsulate the stack of absorber material. The absorber stack length, shown in Figure 4.2-12, is positioned axially within the burnable absorber rod by the use of a zirconium alloy bottom-end spacer as necessary.

The burnable absorber rods in each fuel assembly are grouped and attached together at the top end of the rods to a hold-down assembly by a flat, perforated retaining plate, which fits within the fuel assembly top nozzle and rests on the adapter plate.

The retaining plate and the burnable absorber rods are held down and restrained against vertical motion through a spring pack which is attached to the plate and is compressed by the upper core plate when the reactor upper internals assembly is lowered into the reactor. With this arrangement, the burnable absorber rods cannot be ejected from the core by flow forces. Each rod is attached to the baseplate by a nut that is crimped into place.

4.2.2.3.4 Neutron Source Assemblies

The purpose of a neutron source assembly is to provide a base neutron level to give confidence that the detectors are operational and responding to core multiplication neutrons. For the first core, neutron sources are placed in the reactor to provide a positive neutron count of at least two counts per second on the source range detectors attributable to core neutrons. The detectors, called source range detectors, are used primarily during subcritical modes of core operation.

The source assembly also permits detection of changes in the core multiplication factor during core loading, refueling, and approach to criticality. This can be done since the multiplication factor is related to an inverse function of the detector count rate. Changes in the multiplication factor can be detected during addition of fuel assemblies while loading the core, changes in control rod positions, and changes in boron concentration.

Both primary and secondary neutron source rods are used. The primary source rods, containing a radioactive material, spontaneously emit neutrons during initial core loading, reactor startup, and initial operation of the first core. After the primary source rods decay beyond the desired neutron flux level, neutrons are then supplied by the secondary source rods. The secondary source rods contain a stable material, which is activated during reactor operation. The activation results in the subsequent release of neutrons.

Four source assemblies are typically installed in initial load of the reactor core: two primary source assemblies and two secondary source assemblies. Each primary source assembly contains one primary source rod and a number of burnable absorber rods. Each secondary source assembly contains a symmetrical grouping of secondary source rodlets. Figure 4.2-14 shows the primary source assembly. Figure 4.2-15 shows the secondary source assembly.

Neutron source assemblies are employed at opposite sides of the core. The source assemblies are inserted into the rod cluster control guide thimbles in fuel assemblies at selected locations.

As shown in Figures 4.2-14 and 4.2-15, the source assemblies contain a hold-down assembly identical to that of the burnable absorber assembly.

The primary and secondary source rods both use the same cladding material as the absorber rods. The secondary source rods contain antimony-beryllium pellets stacked to a height of approximately 88 inches. The primary source rods contain capsules of californium (plutonium-beryllium possible alternate) source material and alumina spacers to position the source material within the cladding. The rods in each assembly are fastened at the top end to a hold-down assembly.

The other structural members, except for the springs, are constructed of Type 304, 304L, and 308L stainless steel. The springs exposed to the reactor coolant are nickel-chromium-iron Alloy 718.

4.2.3 Design Evaluation

[*The fuel assemblies, fuel rods, and in-core control components are designed to satisfy the performance and safety criteria of*]* Section 4.2 of the Standard Review Plan, the mechanical design bases of Subsection 4.2.1 and [*the Fuel Criteria Evaluation Process per WCAP-12488-A (Reference 1)*]*, and other interfacing nuclear and thermal and hydraulic design bases specified in Sections 4.3 and 4.4.

Effects of Conditions II, III, IV or anticipated transients without trip on fuel integrity are presented in Chapter 15.

The initial step in fuel rod design evaluation for a region of fuel is to determine the limiting rod(s). Limiting rods are defined as those rods whose predicted performance provides the minimum margin to each of the design criteria. For a number of design criteria, the limiting rod is the lead burnup rod of a fuel region. In other instances, it may be the maximum power or the minimum burnup rod. For the most part, no single rod is limiting with respect to all the design criteria.

After identifying the limiting rod(s), an analysis is performed to consider the effects of rod operating history, model uncertainties, and dimensional variations. To verify adherence to the design criteria, the evaluation considers the effects of postulated transient power changes during operation consistent with Conditions I and II. These transient power increases can affect both rod average and local power levels. Parameters considered include rod internal pressure, fuel temperature, clad stress, and clad strain. In fuel rod design analyses, these performance parameters provide the basis for comparison between expected fuel rod behavior and the corresponding design criteria limits.

Fuel rod and assembly models used for the performance evaluations are documented and maintained under an appropriate control system. Material properties used in the design evaluations are given in WCAP-12610 (Reference 5).

4.2.3.1 Cladding

4.2.3.1.1 Vibration and Wear

Fuel rod vibrations are flow induced. The effect of vibration on the fuel assembly and individual fuel rods is minimal. The cyclic stress range associated with deflections of such small magnitude is insignificant and has no effect on the structural integrity of the fuel rod.

The reaction force on the grid supports, due to rod vibration motions, is also small and is much less than the spring preload. Adequate fuel clad spring contact is maintained. No significant wear of the clad or grid supports is predicted during the life of the fuel assembly based on out-of-pile flow tests, performance of similarly designed fuel in operating reactors, and design analyses.

Clad fretting and fuel vibration has been experimentally investigated, as shown in WCAP-8278 (Reference 13).

4.2.3.1.2 Fuel Rod Internal Pressure and Cladding Stresses

A burnup-dependent fission gas release model (WCAP-15063-P-A, Revision 1 [Reference 21]) is used in determining the internal gas pressure as a function of irradiation time. The plenum volume of the fuel rod has been designed to provide that the maximum internal pressure of the fuel rod will not exceed the value which would cause:

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- The fuel/clad diametral gap to increase during steady-state operation
- Extensive departure from nucleate boiling propagation to occur (Reference 26)

The clad stresses at a constant local fuel rod power are low. Compressive stresses are created by the pressure differential between the coolant pressure and the rod internal gas pressure. Because of the pre-pressurization with helium, the volume average effective stresses are always less than approximately 14,000 psi at the pressurization level used in the AP1000 fuel rod design. Stresses due to the temperature gradient are not included in this average effective stress because thermal stresses are, in general, negative at the clad inside diameter and positive at the clad outside diameter, and their contribution to the clad volume average stress is small. Furthermore, the thermal stress decreases with time during steady-state operation due to stress relaxation. The stress due to pressure differential is highest in the minimum power rod at beginning-of-life due to low internal gas pressure and decreases as rod power increases. Thermal stresses are maximum in the maximum power rod due to the larger temperature gradient and decrease as the rod power is decreased.

The internal gas pressure at beginning-of-life ranges from approximately 200 to 750 psi for typical lead burnup fuel rods. The total tangential stress at the clad inside diameter at beginning-of-life is approximately 19,500 psi compressive (approximately 18,500 psi due to ΔP and approximately 1,000 due to ΔT) for a low-power rod operating at four kilowatts/foot. Total tangential stress is approximately 20,500 psi compressive (approximately 18,000 psi due to ΔP and approximately 2,500 psi due to ΔT) for a high-power rod operating at 10 kilowatts/foot. However, the volume average effective stress at beginning-of-life is between approximately 13,500 psi (high-power rod) and approximately 14,000 psi (low-power rod). These stresses are substantially below even the unirradiated clad yield strength (approximately 55,500 psi) at a typical clad mean operating temperature of 700°F.

Tensile stresses could be created once the clad has come in contact with the pellet. These stresses would be induced by the fuel pellet swelling during irradiation. Swelling of the fuel pellet can result in small clad strains (less than one percent) for expected discharge burnups, but the associated clad stresses are very low because of clad creep (thermal- and irradiation-induced creep). The one percent strain criterion is extremely conservative for fuel-swelling driven clad strain because the strain rate associated with solid fission products swelling is very slow. A detailed discussion of fuel rod performance is given in Subsection 4.2.3.3.

4.2.3.1.3 Material and Chemical Evaluation

ZIRLO clad has a high corrosion resistance to the coolant, fuel, and fission products. As shown in WCAP-8183 (Reference 3), there is considerable pressurized water reactor operating experience on the capability of Zircaloy-4 as a clad material. ZIRLO, an advanced zirconium based alloy, has equal or better corrosion resistance than Zircaloy-4 (see WCAP-12610-P-A, [Reference 5]). Controls on fuel fabrication specify maximum moisture levels to preclude clad hydriding.

Metallographic examination of irradiated commercial fuel rods has shown occurrences of fuel/clad chemical interaction. Reaction layers of less than one mil in thickness have been observed between fuel and clad at limited points around the circumference. Metallographic data indicates that this interface layer remains very thin even at high burnup. Thus, there is no indication of propagation of the layer and eventual clad penetration.

Stress corrosion cracking is another postulated phenomenon related to fuel/clad chemical interaction. Out-of-pile tests have shown that in the presence of high clad tensile stresses, large concentrations of iodine can chemically attack the zirconium alloy tubing and may lead to eventual clad cracking. Extensive post-irradiation examination has produced no evidence that this mechanism has been operative in Westinghouse commercial pressurized water reactor fuel.

4.2.3.1.4 Rod Bowing

WCAP-8691 (Reference 14) presents the model used for evaluation of AP1000 fuel rod bowing. This model has been used for bow assessment in 14x14, 15x15, and 17x17 type cores.

4.2.3.1.5 Consequences of Power Coolant Mismatch

Consequences of power coolant mismatch are discussed in Chapter 15.

4.2.3.1.6 Creep Collapse and Creepdown

This subject and the associated irradiation stability of cladding have been evaluated. In WCAP-13589-A (Reference 8), it is shown that current generation Westinghouse fuel is sufficiently stable with respect to fuel densification. Significant axial gaps do not form in the pellet stack, preventing clad collapse from occurring. The design basis of no clad collapse during planned core life is therefore satisfied. Cladding collapse analyses, if required, would be performed using the methods described in WCAP-8377 (Reference 22).

4.2.3.2 Fuel Materials Considerations

Sintered, high-density uranium dioxide fuel reacts only slightly with the clad at core operating temperatures and pressures. In the event of clad defects, the high resistance of uranium dioxide to attack by water protects against fuel deterioration, although limited fuel erosion can occur. The consequences of defects in the clad are greatly reduced by the ability of uranium dioxide to retain fission products, including those which are gaseous or highly volatile.

Observations from several early Westinghouse pressurized water reactors as discussed in WCAP-8218-P-A (Reference 6) have shown that fuel pellets can densify under irradiation to a density higher than the manufactured values. Fuel densification and subsequent settling of the fuel pellets can result in local and distributed gaps in the fuel rods. The densification process is related to the elimination of very small as-fabricated porosity in the fuel during irradiation. Early fuels were intentionally manufactured to low initial density and were undersintered, which resulted in a large fraction of very small pores. Densification behavior in current fuel is controlled by improved manufacturing process controls and by specifying a nominal 95.5 percent initial fuel density, which results in reduced levels of small, densifying porosity.

The evaluation of fuel densification effects and the treatment of fuel swelling and fission gas release are described in WCAP-13589-A (Reference 8) and WCAP-15063-P-A, Revision 1 (Reference 21).

4.2.3.3 Fuel Rod Performance

In the calculation of the steady-state performance of a nuclear fuel rod, the following interacting factors are considered:

- Clad creep and elastic deflection
- Pellet density changes, thermal expansion, gas release, and thermal properties as a function of temperature and fuel burnup
- Internal pressure as a function of fission gas release, rod geometry, and temperature distribution

These effects are evaluated using fuel rod design models, as discussed in WCAP-15063-P-A, Revision 1 (Reference 21), that include appropriate models for time dependent fuel densification. With these interacting factors considered, the model determines the fuel rod performance characteristics for a given rod geometry, power history, and axial power shape. In particular, internal gas pressure, fuel and clad temperatures, and clad deflections are calculated. The fuel rod is divided into several axial sections and radially into a number of annular zones. Fuel density changes are calculated separately for each segment. The effects are integrated to obtain the internal rod pressure.

The initial rod internal pressure is selected to delay fuel/clad mechanical interaction and to avoid the potential for clad flattening. It is limited, however, by the design criteria for the rod internal pressure, as discussed in Subsection 4.2.1.3.

The gap conductance between the pellet surface and the clad inner diameter is calculated as a function of the composition, temperature and pressure of the gas mixture, and the gap size or contact pressure between the clad and pellet. After computing the fuel temperature for each pellet zone, the fractional fission gas release is assessed using an empirical model derived from experimental data, as detailed in WCAP-15063-P-A, Revision 1 (Reference 21). The total amount of gas released is based on the average fractional release within each axial and radial zone and the gas generation rate, which, in turn, is a function of burnup. Finally, the gas released is summed over the zones, and the pressure is calculated.

The model shows close agreement in fit for a variety of published and proprietary data on fission gas release, fuel temperatures, and clad deflections, as detailed in WCAP-15063-P-A, Revision 1 (Reference 21). These data include variations in power, time, fuel density, and geometry.

4.2.3.3.1 Fuel/Cladding Mechanical Interaction

One factor in fuel element duty is potential mechanical interaction of the fuel and clad. This fuel/clad interaction produces cyclic stresses and strains in the clad, and these, in turn, reduce clad life. The reduction of fuel/clad interaction is therefore a goal of design. The technology for using pre-pressurized fuel rods in Westinghouse pressurized water reactors has been developed to further this objective.

The gap between the fuel and clad is initially sufficient to prevent hard contact between the two. However, during power operation a gradual compressive creep of the clad onto the fuel pellet occurs due to the external pressure exerted on the rod by the coolant. Clad compressive creep eventually results in fuel/clad contact. Once fuel/clad contact occurs, changes in power level result in changes in clad stresses and strains. By using pre-pressurized fuel rods to partially offset the effect of the coolant external pressure, the rate of clad creep toward the surface of the fuel is reduced. Fuel rod pre-pressurization delays the time at which fuel/clad contact occurs and, hence, significantly reduces the extent of cyclic stresses and strains experienced by the clad both before and after fuel/clad contact. These factors result in an increase in the fatigue life margin of the clad and lead to greater clad reliability.

A two-dimensional (r,θ) finite element model has been established to investigate the effects of radial pellet cracks on stress concentrations in the clad. Stress concentration herein is defined as the difference between the maximum clad stress in the θ direction and the mean clad stress. The first case has the fuel and clad in mechanical equilibrium; and, as a result, the stress in the clad is close to zero. In subsequent cases the pellet power is increased in steps and the resultant fuel thermal expansion imposes tensile stress in the clad.

In addition to uniform clad stresses, stress concentrations develop in the clad adjacent to radial cracks in the pellet. These radial cracks have a tendency to open during a power increase, but the frictional forces between fuel and clad oppose the opening of these cracks and result in localized increases in clad stress. As the power is further increased, large tensile stresses exceed the ultimate tensile strength of uranium dioxide and additional cracks in the fuel pellet are created, limiting the magnitude of the stress concentration in the clad.

As part of the standard fuel rod design analysis, the maximum stress concentration evaluated from finite element calculations is added to the volume-averaged effective stress in the clad as determined from one-dimensional stress/strain calculations. The resultant clad stress is then compared to the temperature-dependent cladding yield stress to confirm that the stress/strain criteria are satisfied.

The transient evaluation method is described in the following paragraphs.

Pellet thermal expansion due to power increases is considered the only mechanism by which significant stresses and strains can be imposed on the clad.

Power increases in commercial reactors can result from fuel shuffling (for example, a fuel assembly positioned near the core center for cycle 2 operation after operating near the periphery during cycle 1), reactor power escalation following extended reduced power operation, and full-length control rod movement. In the mechanical design model, lead rods are depleted using best-estimate power histories as determined by core physics calculations. During burnup, the amount of diametral gap closure is evaluated based upon the pellet expansion cracking model, clad creep model, and fuel swelling model. At various times during the depletion, the power is increased locally in the rod to the burnup-dependent attainable power density as determined by core physics calculations. The radial, tangential, and axial clad stresses resulting from the power increase are combined into a volume average effective clad stress.

The von Mises criterion is used to determine whether the clad yield stress has been exceeded. This criterion states that an isotropic material in multi-axial stress will begin to yield plastically when the effective stress exceeds the yield stress as determined by an axial tensile test. The yield stress correlation is that for irradiated cladding, since fuel/clad interaction occurs at high burnup. In applying this criterion, the effective stress is increased by an allowance which accounts for stress concentrations in the clad adjacent to radial cracks in the pellet, prior to the comparison with the yield stress. This allowance was evaluated using a two-dimensional (r,θ) finite element model.

Slow transient power increases can result in large clad strains without exceeding the clad yield stress because of clad creep and stress relaxation. Therefore, in addition to the yield stress criterion, a criterion on allowable clad strain is necessary. Based upon high strain rate burst and tensile test data on irradiated tubing, one percent strain was determined to be a conservative lower limit on irradiated clad ductility and that was adopted as a design criterion.

In addition to the mechanical design models and design criteria, the AP1000 fuel rod design relies on performance data accumulated through transient power test programs in experimental and commercial reactors, and through normal operation in commercial reactors.

It is recognized that a possible limitation to the satisfactory behavior of the fuel rods in a reactor subjected to daily load follow is the failure of the cladding by low-cycle strain fatigue. During their normal residence time in the reactor, the fuel rods may be subjected to on the order of 1000 load follow cycles, with typical changes in power level from 50 to 100 percent of their steady-state values.

The assessment of the fatigue life of the fuel rod cladding is subjected to considerable uncertainty because of the difficulty of evaluating the strain range which results from the cyclic interaction of the fuel pellets and cladding. This difficulty arises, for example, from such highly unpredictable

phenomena as pellet cracking, fragmentation, and relocation. Westinghouse investigated this particular phenomenon both analytically and experimentally. Strain fatigue tests on irradiated and nonirradiated hydrided Zircaloy-4 cladding were performed. These tests permitted the definition of a conservative fatigue-life limit and recommendation of a methodology to treat the strain fatigue evaluation of the Westinghouse-referenced fuel rod designs. (See WCAP-9500-P-A, Reference 15.)

Successful load follow operation has been performed on several reactors. There was no significant coolant activity increase that could be associated with the load follow mode of operation.

The Westinghouse analytical approach to strain fatigue is based on a comprehensive review of the available strain fatigue models. The review included the Langer-O'Donnell model (Reference 16) the Yao-Munse model, and the Manson-Halford model. Upon completion of this review, and using the results of the Westinghouse experimental programs as documented in WCAP-9500-P-A (Reference 15), it was concluded that the approach defined by Langer-O'Donnell would be retained and the empirical factors of their correlation modified to conservatively bound the results of the Westinghouse testing program.

The design equations followed the concept for the fatigue design criterion according to the ASME Code, Section III:

- The calculated pseudo stress amplitude (Sa) has to be multiplied by a factor of two to obtain the allowable number of cycles (Nf).
- The allowable cycles for a given Sa is five percent of Nf or a safety factor of 20 on cycles.

The lesser of the two allowable numbers of cycles is selected. The cumulative fatigue life fraction is then computed as:

$$\sum_{1}^{k} \frac{n_k}{N_{f\,k}} \leq 1$$

where:

n_k = number of diurnal cycles of mode k.

$N_{f\,k}$ = number of allowable cycles.

4.2.3.3.2 Irradiation Experience

Westinghouse fuel operational experience is presented in CENPD-404-P-A (Reference 27). Additional test assembly and test rod experience is given in WCAP-10125-P-A (Reference 2).

4.2.3.3.3 Fuel and Cladding Temperature

The methods used for evaluation of fuel rod temperatures are presented in Subsection 4.4.2.11.

4.2.3.3.4 Potentially Damaging Temperature Effects During Transients

The fuel rod experiences many operational transients (intentional maneuvers) during its residence in the core. A number of thermal effects must be considered when analyzing the fuel rod performance.

The clad can be in contact with the fuel pellet at some time in the fuel lifetime. Clad/pellet interaction occurs if the fuel pellet temperature is increased after the clad is in contact with the pellet. Clad/pellet interaction is discussed in Subsection 4.2.3.3.1.

Clad flattening has been observed in some operating power reactors. This is no longer a concern because clad flattening is precluded during the fuel residence in the core (Subsection 4.2.3.1) by the use of stable fuel.

Potential differential thermal expansion between the fuel rods and the guide thimbles during a transient is considered in the design. Excessive bowing of the fuel rods is precluded because the grid assemblies allow axial movement of the fuel rods relative to the grids. Specifically, thermal expansion of the fuel rods is considered in the grid design so that axial loads imposed on the fuel rods during a thermal transient will not result in excessively bowed fuel rods.

4.2.3.3.5 Fuel Element Burnout and Potential Energy Release

As discussed in Subsection 4.4.2.2, the core is protected from departure from nucleate boiling over the full range of possible operating conditions. In the extremely unlikely event that departure from nucleate boiling should occur, the clad temperature will rise due to the steam blanketing at the rod surface and the consequent degradation in heat transfer. During this time there is a potential for chemical reaction between the cladding and the coolant. However, because of the relatively good film boiling heat transfer following departure from nucleate boiling, the energy release resulting from this reaction is insignificant compared to the power produced by the fuel.

4.2.3.3.6 Coolant Flow Blockage Effects on Fuel Rods

The coolant flow blockage effects on fuel rods are presented in Subsection 4.4.4.7.

4.2.3.4 Spacer Grids

The coolant flow channels are established and maintained by the structure composed of grids and guide thimbles. The lateral spacing between fuel rods is provided and controlled by the support dimples of adjacent grid cells. Contact of the fuel rods on the dimples is maintained through the clamping force of the grid springs. Lateral motion of the fuel rods is opposed by the spring force and the internal moments generated between the spring and the support dimples. Grid testing is discussed in WCAP-8236 (Reference 17) and WCAP-10444-P-A (Reference 11).

4.2.3.5 Fuel Assembly

4.2.3.5.1 Stresses and Deflections

The fuel assembly component stress levels are limited by the design. For example, stresses in the fuel rod due to thermal expansion and zirconium alloy irradiation growth are limited by the relative motion of the rod as it slips over the grid spring and dimple surfaces. Clearances between the fuel rod ends and nozzles are provided so that zirconium alloy irradiation growth does not result in rod end interference. Stresses in the fuel assembly caused by tripping of the rod cluster control assembly have little influence on fatigue usage margin because of the small number of events during the life of an assembly. Assembly components and prototype fuel assemblies made from production parts have been subjected to structural tests to verify that the design bases requirements are met.

The fuel assembly design loads for shipping have been established at 4 g axial and 6 g lateral. Accelerometers are permanently placed in the shipping cask to monitor and detect fuel assembly accelerations that would exceed the criteria. Experience indicates that loads that exceed the allowable limits rarely occur. Exceeding the limits requires reinspection of the fuel assembly for damage. Tests on various fuel assembly components, such as the grid assembly, sleeves, inserts, and structure joints, have been performed to confirm that the shipping design limits do not result in impairment of fuel assembly function. Seismic analysis methodology of the fuel assembly

is presented in WCAP-8236 (Reference 17), WCAP-9401-P-A (Reference 18), and WCAP-10444-P-A (Reference 11).

To demonstrate that the fuel assemblies will maintain a geometry that is capable of being cooled under the worst-case accident Condition IV event, a plant specific or bounding seismic analysis is performed.

The fuel assembly response resulting from safe shutdown earthquake condition is analyzed using time-history numerical techniques. The vessel motion for this type of event primarily causes lateral loads on the reactor core. Consequently, the methodology and analytical procedures as described in WCAP-8236 (Reference 17) and WCAP-9401-P-A (Reference 18) are used to assess the fuel assembly deflections and impact forces.

The motions of the reactor internals upper and lower core plates and the core barrel at the upper core plate elevation, which are simultaneously applied to simulate the reactor core input motion, are obtained from the time-history analysis of the reactor vessel and internals. The fuel assembly response, namely the displacements and impact forces, is obtained with the reactor core model. Similar dynamic analyses of the core were performed using reactor internals motions indicative of the postulated pipe rupture. Scenarios regarding breaches in the pressure boundary are investigated to determine the most limiting structural loads for the fuel assembly. The application of leak-before-break limits the size of the pipe rupture loads for which the fuel assemblies must be analyzed. The pipe rupture used in the fuel assembly analysis is the largest pipe connected to the reactor coolant system which does not satisfy the leak-before-break criteria. Subsection 3.6.3 discusses mechanistic pipe break.

4.2.3.5.1.1 Grid Analyses

The maximum grid impact force obtained from seismic analyses is less than the allowable grid strength. With respect to the guidelines of Appendix A of the Standard Review Plan, Section 4.2, Westinghouse has demonstrated that a simultaneous safe shutdown earthquake and pipe rupture event is highly unlikely. The fatigue cycles, crack initiation, and crack growth due to normal operating and seismic events will not realistically lead to a pipe rupture. More information is available in WCAP-9283 (Reference 19).

Based on the deterministic fracture mechanics evaluation of small flaws in piping components, Westinghouse has demonstrated that the dynamic affects of a large pipe rupture in the primary coolant piping system for the AP1000 design does not have to be considered.

A design basis for the piping design in the AP1000 is that the reactor coolant loop and surge lines will satisfy the leak-before-break criteria for mechanistic pipe break. In addition, the piping connected to the reactor coolant system that is six inch nominal diameter or larger is evaluated for leak-before-break. The result of a pipe leakage event consistent with the mechanistic pipe break evaluation would be to impose insignificant asymmetric loadings on the reactor core system. Thus, fuel assembly grid loads due to large pipe ruptures are unrealistic and, as such, are not included in the analysis.

The pressure boundary integrity for numerous branch lines is analyzed to determine the most limiting break of a line not qualified for leak-before-break for the dynamic loading of the reactor core. Grid loads resulting from a combined seismic and pipe rupture event do not cause unacceptable grid deformation as to preclude a core coolable geometry.

4.2.3.5.1.2 Nongrid Analyses

The stresses induced in the various fuel assembly nongrid components are assessed based on the most limiting seismic condition. The fuel assembly axial forces resulting from the hold-down spring load together with its own weight distribution are the primary sources of the stresses in the guide thimbles and fuel assembly nozzles. The fuel rod accident induced stresses, which are generally very small, are caused by bending due to the fuel assembly deflections during a seismic event. The seismic-induced stresses are compared with the allowable stress limits for the fuel assembly major components. The component stresses, which include normal operating stresses, are below the established allowable limits. Consequently, the structural designs of the fuel assembly components are acceptable for the design basis accident conditions for the AP1000.

4.2.3.5.2 Dimensional Stability

Localized yielding and slight deformation in some fuel assembly components are allowed to occur during a Condition III or IV event. The maximum permanent deflection, or deformations, do not result in any violation of the functional requirements of the fuel assembly.

4.2.3.6 Reactivity Control Assemblies and Burnable Absorber Rods

4.2.3.6.1 Internal Pressure and Cladding Stresses during Normal, Transient, and Accident Conditions

The designs of the burnable absorber, source, and gray rods provide a sufficient cold void volume to accommodate the internal pressure increase during operation. This is not a concern for the rod cluster control assembly absorber rodlets because no significant amount of gas is released by the silver-indium-cadmium absorber material.

For the discrete burnable absorber rod, there is sufficient cold void volume to limit the internal pressure to a value, which satisfies the design criteria. For the source rods and gray rods, a void volume is provided within the rod to limit the maximum internal pressure increase at end-of-life. Figures 4.2-14 and 4.2-15 detail the primary and secondary source assemblies and Figure 4.2-11 details the gray rod cluster assembly.

During normal transient and accident conditions, the void volume limits the internal pressures to values that satisfy the criteria in Subsection 4.2.1.6. These limits are established not only to prevent the peak stresses from reaching unacceptable values, but also to limit the amplitude of the oscillatory stress component in consideration of the fatigue characteristics of the materials.

Rod, guide thimble, and dashpot flow analyses indicate that the flow is sufficient to prevent coolant boiling within the guide thimble. Therefore, clad temperatures at which the clad material has adequate strength to resist coolant operating pressures and rod internal pressures are maintained.

4.2.3.6.2 Thermal Stability of the Absorber Material, Including Changes and Thermal Expansion

The radial and axial temperature profiles within the source and absorber rods are determined by considering gap conductance, thermal expansion, neutron or gamma heating of the contained material as well as gamma heating of the clad.

The maximum temperatures of the silver-indium-cadmium RCCA or tungsten GRCA absorber materials are calculated and found to be significantly less than the material melting point and found to occur axially at only the highest flux region. The mechanical and thermal expansion properties of the silver-indium-cadmium absorber material are discussed in WCAP-9179 (Reference 4).

The mechanical and thermal expansion properties of the tungsten absorber material are discussed in WCAP-16943-P-A (Reference 25).

The wet annular burnable absorber (WABA) assemblies are used in the first core. The maximum temperature of the alumina-boron carbide burnable absorber pellet is expected to be less than 1200°F which takes place following the initial power ascent. As the operating cycle proceeds, the burnable absorber pellet temperature decreases due to a reduction in heat generation due to boron depletion and better gap conduction as the helium produced diffuses into the gap.

Sufficient diametral and end clearances have been provided in the neutron absorber, burnable absorber, and source rods to accommodate the relative thermal expansions between the enclosed material and the surrounding clad and end plug.

4.2.3.6.3 Irradiation Stability of the Absorber Material, Taking into Consideration Gas Release and Swelling

The irradiation stability of the silver-indium-cadmium absorber material is discussed in WCAP-9179 (Reference 4). Irradiation produces no deleterious effects in the absorber material. The irradiation stability of the tungsten absorber material is discussed in WCAP-16943-P-A (Reference 25).

As mentioned in Subsection 4.2.3.6.1, gas release is not a concern for the rod cluster control rod material because no gas is produced by the absorber material. Sufficient diametral and end clearances are provided to accommodate any potential expansion and/or swelling of the absorber material for both RCCA and GRCA absorber rods.

Irradiation produces no deleterious effects in the tungsten absorber material of the gray rodlets. Some minor cracking of the tungsten material may occur, but this cracking does not affect the absorber column geometric stability due to the small clearance between absorber and sleeve (Reference 25).

The alumina-boron carbide burnable absorber pellets are designed such that gross swelling or crumbling of the pellets is not predicted to occur during reactor operation. Some minor cracking of the pellets may occur, but this cracking should not affect the overall absorber and stack integrity.

4.2.3.6.4 Potential for Chemical Interaction, Including Possible Waterlogging Rupture

The structural materials selected have good resistance to irradiation damage and are compatible with the reactor environment.

Corrosion of the materials exposed to the coolant is quite low, and proper control of chloride and oxygen in the coolant minimizes potential for the occurrence of stress corrosion. The potential for the interference with rod cluster control assembly movement due to possible corrosion phenomena is very low.

Waterlogging rupture is not a failure mechanism associated with the AP1000 control rods. Furthermore, a breach of the cladding for any postulated reason does not result in serious consequences.

The silver-indium-cadmium absorber material is relatively inert and will remain inert even when subjected to high coolant velocity regions. Rapid loss of reactivity control material will not occur. Test results detailed in WCAP-9179 (Reference 4) concluded that additions of indium and cadmium to silver, in the amounts to form the silver-indium-cadmium absorber material composition, result in small corrosion rates.

In the unlikely event of GRCA rod cladding breach, loss of absorber material will not occur because the inner sleeve encapsulates the tungsten absorber (WCAP-16943-P-A, Reference 25).

For the discrete burnable absorber, in the unlikely event that the zirconium alloy clad is breached, the boron carbide in the affected rod(s) could be leached out by the coolant water. If this occurred early, in-core instruments could detect large peaking factor changes, and corrective action would be taken, if warranted. A postulated clad breach after substantial irradiation would have no significant effect on peaking factors since the boron will have been depleted. Breaching of the zirconium alloy clad by internal hydriding is not expected due to moisture controls employed during fabrication. Rods of this design have performed very well with no failures observed.

4.2.4 Testing and Inspection Plan

4.2.4.1 Quality Assurance Program

The Quality Assurance Program Plan of the Westinghouse Commercial Nuclear Fuel Division for the AP1000 is summarized in Chapter 17.

The program provides for control over activities affecting product quality, commencing with design and development and continuing through procurement, materials handling, fabrication, testing and inspection, storage, and transportation. The program also provides for the indoctrination and training of personnel and for the auditing of activities affecting product quality through a formal auditing program.

Westinghouse drawings and product, process, and material specifications identify the inspections to be performed.

4.2.4.2 Quality Control

Quality control philosophy is generally based on the following inspections being performed to a 95 percent confidence that at least 95 percent of the product meets specification, unless otherwise noted.

4.2.4.2.1 Fuel System Components and Parts

The characteristics inspected depend on the component parts. The quality control program includes dimensional and visual examinations, check audits of test reports, material certification, and nondestructive examination, such as X-ray and ultrasonic.

The material used in the AP1000 core is accepted and released by Quality Control.

4.2.4.2.2 Pellets

Inspection is performed for dimensional characteristics such as diameter, density, length, and squareness of ends. Additional visual inspections are performed for cracks, chips, and surface conditions according to approved standards.

Density is determined in terms of weight per unit length and is plotted on zone charts used in controlling the process. Chemical analyses are taken on a specified sample basis throughout pellet production.

4.2.4.2.3 Rod Inspection

Fuel rod, rod cluster control rod, discrete burnable absorber rod, and source rod inspections consists of the following nondestructive examination techniques and methods, as applicable:

- Each rod is leak tested using a calibrated mass spectrometer, with helium being the detectable gas.
- Rod welds are inspected by ultrasonic test or X-ray in accordance with a qualified technique and Westinghouse specifications meeting the requirements of ASTM-E-142-86 (Reference 20).
- Rods are dimensionally inspected prior to final release. The requirements include such items as length, camber, and visual appearance.
- Fuel rods are inspected by gamma scanning or other approved methods, as discussed in Subsection 4.2.4.5, to confirm proper plenum dimensions.
- Fuel rods are inspected by gamma scanning, or other approved methods, as discussed in Subsection 4.2.4.5, to confirm that no significant gaps exist between pellets.
- Fuel rods are actively and/or passively gamma scanned to verify enrichment control prior to acceptance for assembly loading.
- Traceability of rods and associated rod components is established by quality control.

4.2.4.2.4 Assemblies

Each fuel rod, control rod, burnable absorber rod and source rod assembly is inspected for compliance with drawing and/or specification requirements. Other in-core control component inspection and specification requirements are given in Subsection 4.2.4.4.

4.2.4.2.5 Other Inspections

The following inspections are performed as part of the routine inspection operation:

- Tool and gauge inspection and control, including standardization to primary and/or secondary working standards. Tool inspection is performed at prescribed intervals on serialized tools. Complete records are kept of calibration and conditions of tools.
- Audits are performed of inspection activities and records to confirm that prescribed methods are followed and that records are correct and properly maintained.
- Surveillance inspection, where appropriate, and audits of outside contractors are performed to confirm conformance with specified requirements.

4.2.4.2.6 Process Control

To prevent the possibility of mixing enrichments during fuel manufacture and assembly, strict enrichment segregation and other process controls are exercised.

The uranium dioxide powder is kept in sealed containers. The contents are fully identified both by descriptive tagging and unique barcode numbers. A quality control identification tag completely describing the contents is affixed to the containers before transfer to powder storage. Isotopic content is confirmed by analysis.

Powder withdrawal from storage can be made by only one authorized group, which directs the powder to the correct pellet production line. The pellet production lines are physically separated from each other, and pellets of only a single nominal enrichment and density are produced in a given production line at any given time.

Finished pellets are placed on trays identified with the same color code as the powder containers and transferred to segregated storage racks within the confines of the pelleting area. Samples from each pellet lot are tested for isotopic content and impurity levels prior to acceptance by quality control. Physical barriers are used to prevent mixing of pellets of different nominal densities and enrichments in the pellet storage area. Unused powder and substandard pellets are returned to storage in the original color-coded containers.

Loading of pellets into the clad is performed in isolated production lines; only one density and enrichment (with possible exception for top and bottom (axial blanket) zones) are loaded on a line at a time.

A serialized traceability code is placed on each fuel tube, which identifies the contract and enrichment. The end plugs are inserted and then welded (in an inert gas atmosphere) to seal the tube. The fuel tube remains coded and traceability identified until just prior to installation in the fuel assembly.

Similar traceability is provided for wet annular burnable absorber, source, and control rods, as required.

4.2.4.3 Letdown Radiation Monitoring

Radiation monitoring of the reactor coolant is made by grab samples and laboratory analysis of the primary coolant. Refer to information presented in Subsections 9.3.3 and 9.3.6, and Table 9.3.3-1.

4.2.4.4 In-core Control Component Testing and Inspection

Tests and inspections are performed on each reactivity control component to verify the mechanical characteristics. In the case of the rod cluster control assembly, prototype testing has been conducted. Manufacturing test/inspections and functional testing at the plant site are both performed.

During the component manufacturing phase, the following requirements apply to the reactivity control components to provide the proper functioning during reactor operation:

- Materials are procured to specifications to attain the desired standard of quality.
- Spider assemblies with brazed and welded vanes and fingers are proof-tested by applying a 5000-pound load to the spider body, so that approximately 310 pounds is applied to each vane. This proof load provides a bending moment at the spider body approximately equivalent to 1.4 times the load caused by the acceleration imposed by the control rod drive mechanism.
- Rods are checked for integrity by the applicable nondestructive methods described in Subsection 4.2.4.2.3.

- To confirm proper fit with the fuel assembly, the rod cluster control, discrete burnable absorber, and source assemblies are installed in the fuel assembly and checked for binding in the dry condition.

The rod cluster control assemblies and gray rod cluster assemblies are also functionally tested, following core loading but prior to criticality, to demonstrate reliable operation of the assemblies. Each assembly is operated (and tripped) one time at full-flow/hot conditions. In addition, any assembly that has a drop time greater than a two sigma limit from the average rod drop time is subjected to additional rod drops to confirm drop time. Thus, each assembly is sufficiently tested to confirm proper functioning and operation.

To demonstrate continuous free movement of the rod cluster control assemblies, and gray rod cluster assemblies, and to provide acceptable core power distributions during operations, partial movement checks are performed as required by the technical specifications. In addition, periodic drop tests of the rod cluster control assemblies are performed at each refueling shutdown to demonstrate continued ability to meet trip time requirements.

If a rod cluster control assembly and/or gray rod cluster assembly cannot be moved by its mechanism, and is determined to be untrippable, adjustments in the boron concentration of the coolant provide that adequate shutdown margin will be achieved following a trip. Thus, inability to move one assembly can be tolerated until the reactor can be safely taken to Mode 3.

4.2.4.5 Tests and Inspections by Others

For tests and inspections performed by others, Westinghouse reviews and approves the quality control procedures, and inspection plans to be utilized to confirm that they are equivalent to the description provided in Subsections 4.2.4.1 through 4.2.4.4 and are performed properly to meet Westinghouse requirements.

4.2.4.6 Inservice Surveillance

As detailed in CENPD-404-P-A (Reference 27), significant 17x17 fuel assembly operating experience has been obtained. A surveillance program is expected to be established for the AP1000 for inspection of post-irradiated fuel assemblies. This surveillance program will establish the schedule, guidelines, and inspection criteria for conducting visual inspection of post-irradiated fuel assemblies and/or insert components. The surveillance program includes a visual examination of some discharged fuel assemblies from each refueling. This program also includes criteria for additional inspection requirements for post-irradiated fuel assemblies if unusual characteristics are noticed in the visual inspection or if plant instrumentation and subsequent laboratory analysis indicates gross failed fuel. The post-irradiated fuel surveillance program will address disposition of fuel assemblies and/or insert components receiving an unsatisfactory visual inspection. Those post-irradiated fuel assemblies receiving an unsatisfactory visual inspection are not reinserted into the core until a more detailed inspection and/or evaluation can be performed.

4.2.4.7 Onsite Inspection

Written procedures are used for the post-shipment inspection of the new fuel assemblies in addition to reactivity control and source components. Fuel handling procedures specify the sequence in which handling and inspection take place.

Loaded fuel containers, when received onsite, are externally inspected to confirm that labels and markings are intact and security seals are unbroken. After the containers are opened, the shock indicators attached to the suspended internals are inspected to determine whether movement during transit exceeded design limitations.

Following removal of the fuel assembly from the container in accordance with detailed procedures, the fuel assembly plastic wrapper is examined for evidence of damage. The polyethylene wrapper is then removed, and a visual inspection of the entire fuel assembly is performed.

Control rod, gray rod, secondary source rod and discrete burnable absorber rod assemblies are usually shipped in fuel assemblies. They are inspected either prior to removal of the fuel assembly from the container or after the fuel assemblies are placed in the new fuel storage racks. The control rod assembly is withdrawn a few inches from the fuel assembly to confirm free and unrestricted movement, and the exposed section is visually inspected for mechanical integrity, replaced in the fuel assembly, and stored with the fuel assembly. Control rod, secondary source or discrete burnable absorber assemblies may be stored separately or within fuel assemblies in the new fuel storage area.

4.2.5 Combined License Information

Changes to the reference design of the fuel, burnable absorber rods, rod cluster control assemblies, or initial core design from that presented in the DCD are addressed in APP-GW-GLR-059 (Reference 24).

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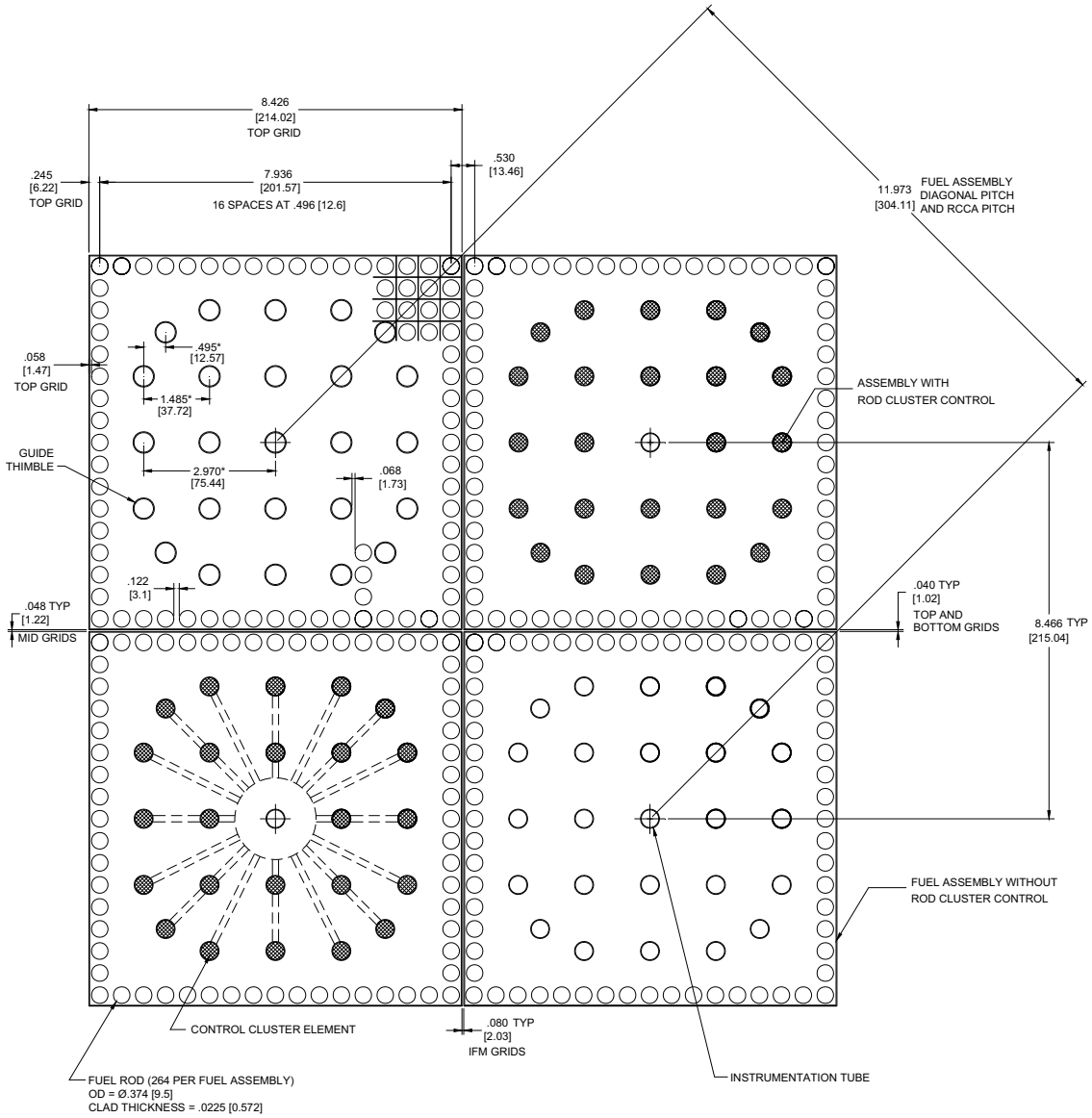
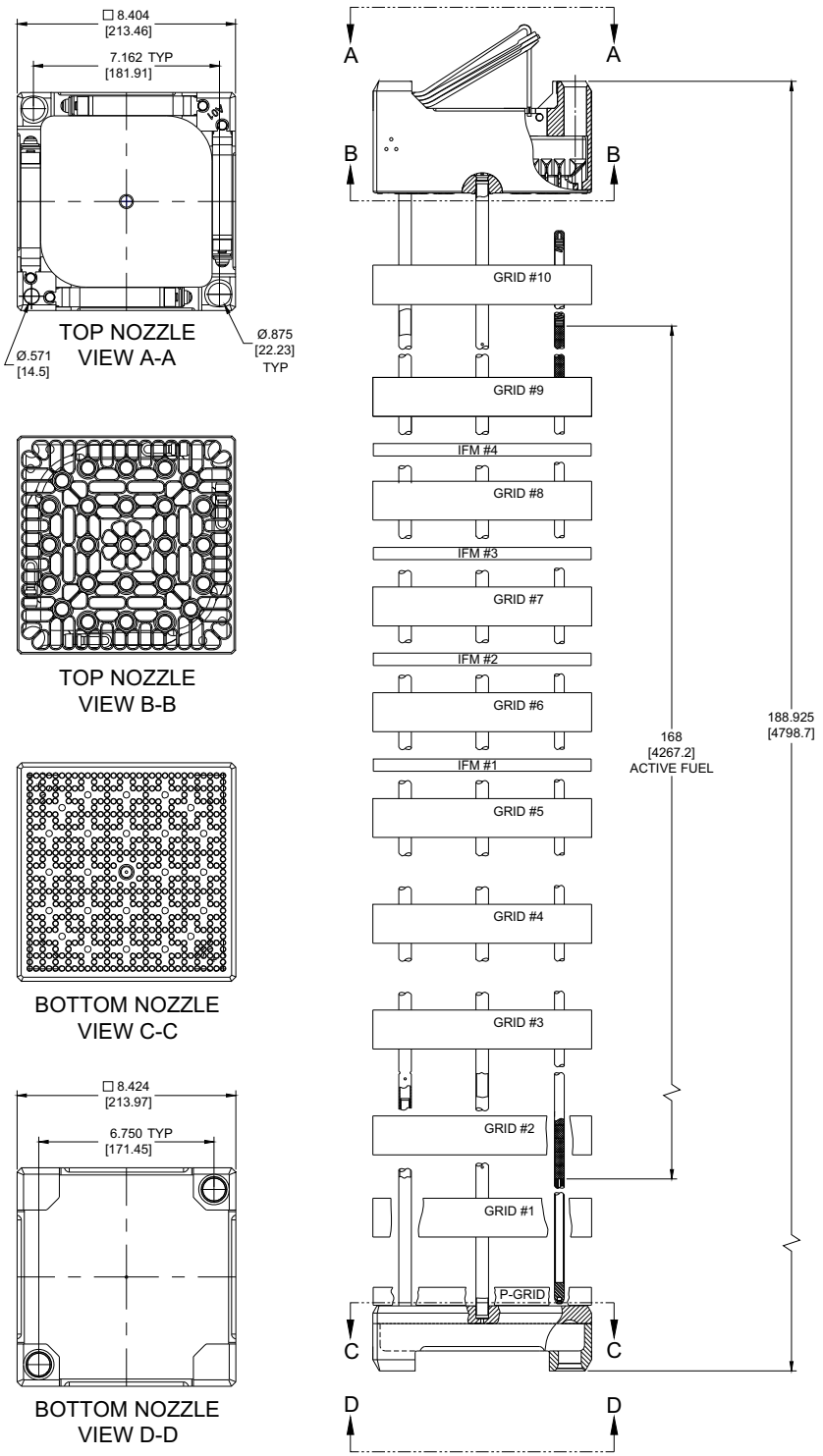


PRIMARY DIMENSIONS ARE IN INCHES (NOMINAL)
SECONDARY DIMENSIONS ARE IN MILLIMETERS

* GUIDE THIMBLE LOCATIONS
AT TOP NOZZLE ADAPTER PLATE

Figure 4.2-1
Fuel Assembly Cross-Section



PRIMARY DIMENSIONS ARE IN INCHES (NOMINAL)
SECONDARY DIMENSIONS ARE IN MILLIMETERS

Figure 4.2-2
Fuel Assembly Outline

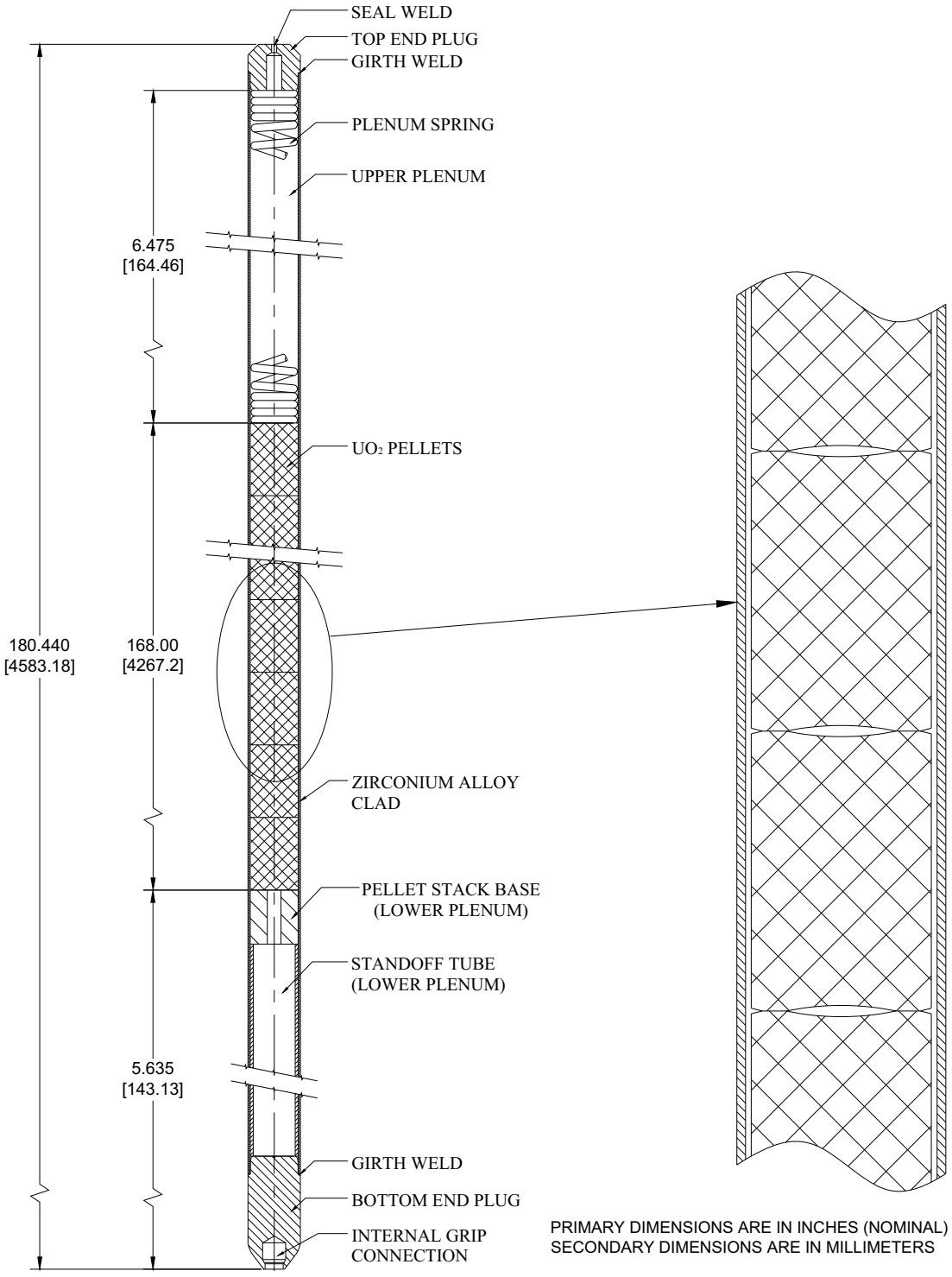


Figure 4.2-3
Fuel Rod Schematic

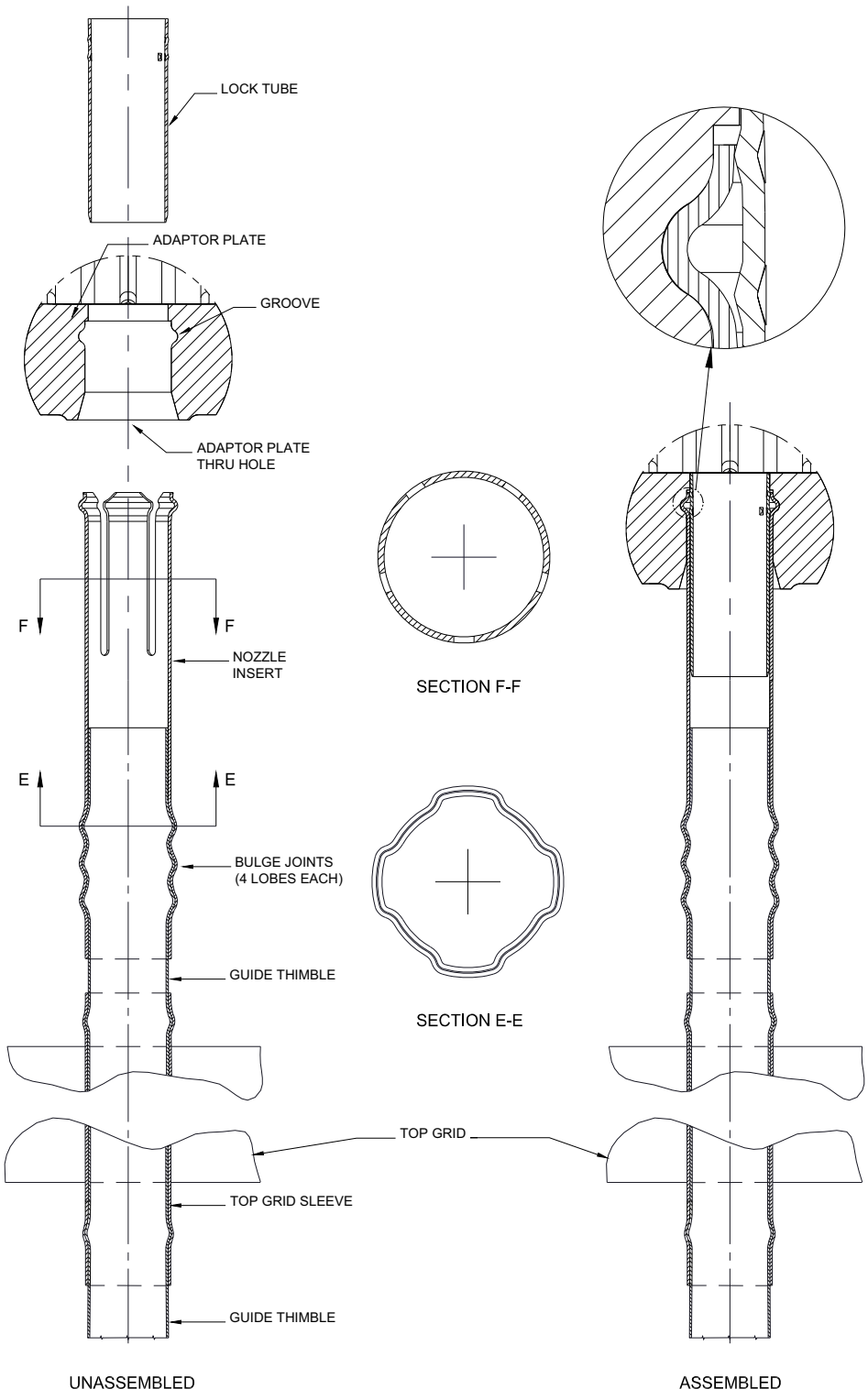


Figure 4.2-4
Top Grid Sleeve Detail

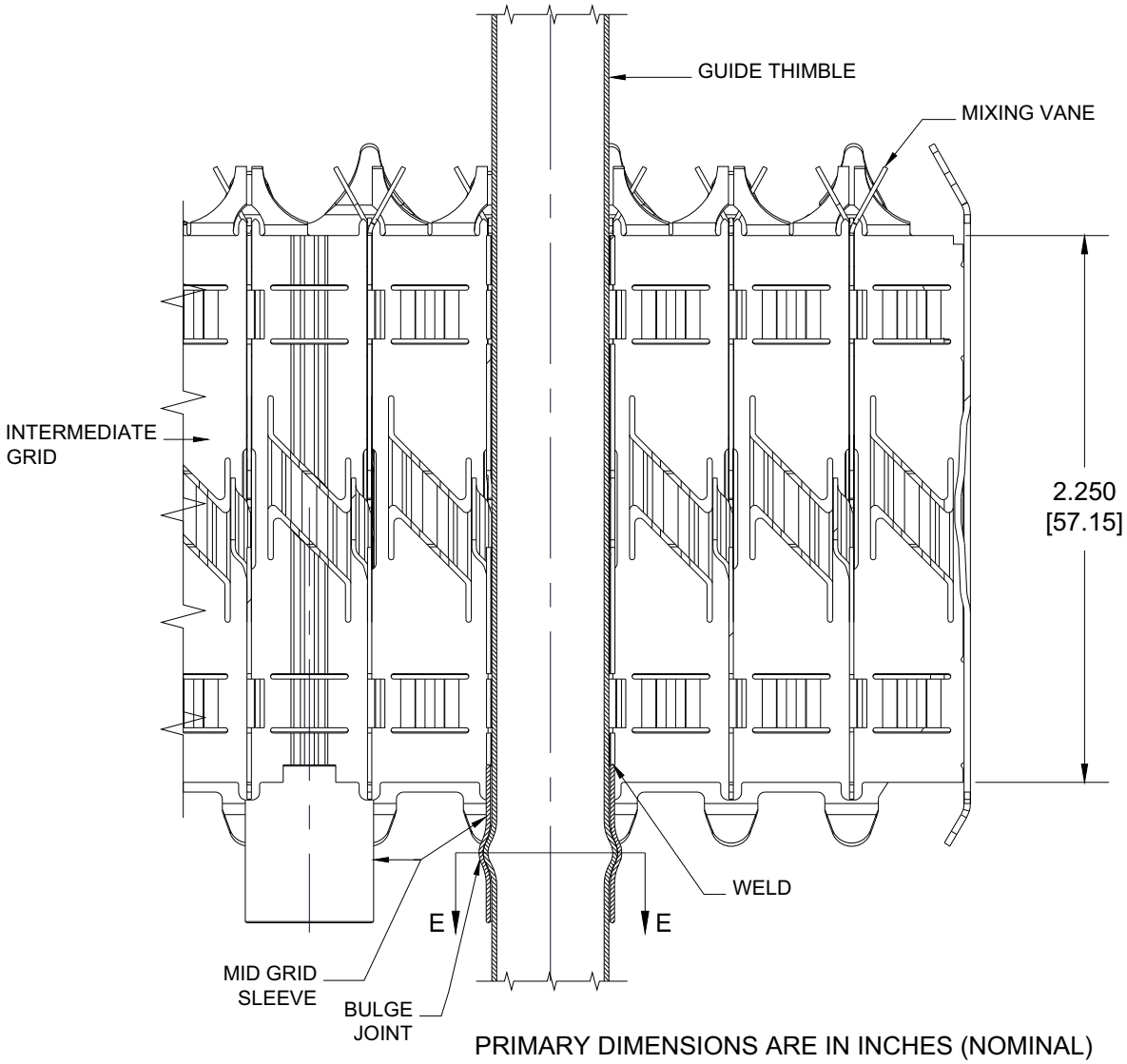


Figure 4.2-5
Intermediate Grid to Thimble Attachment Joint

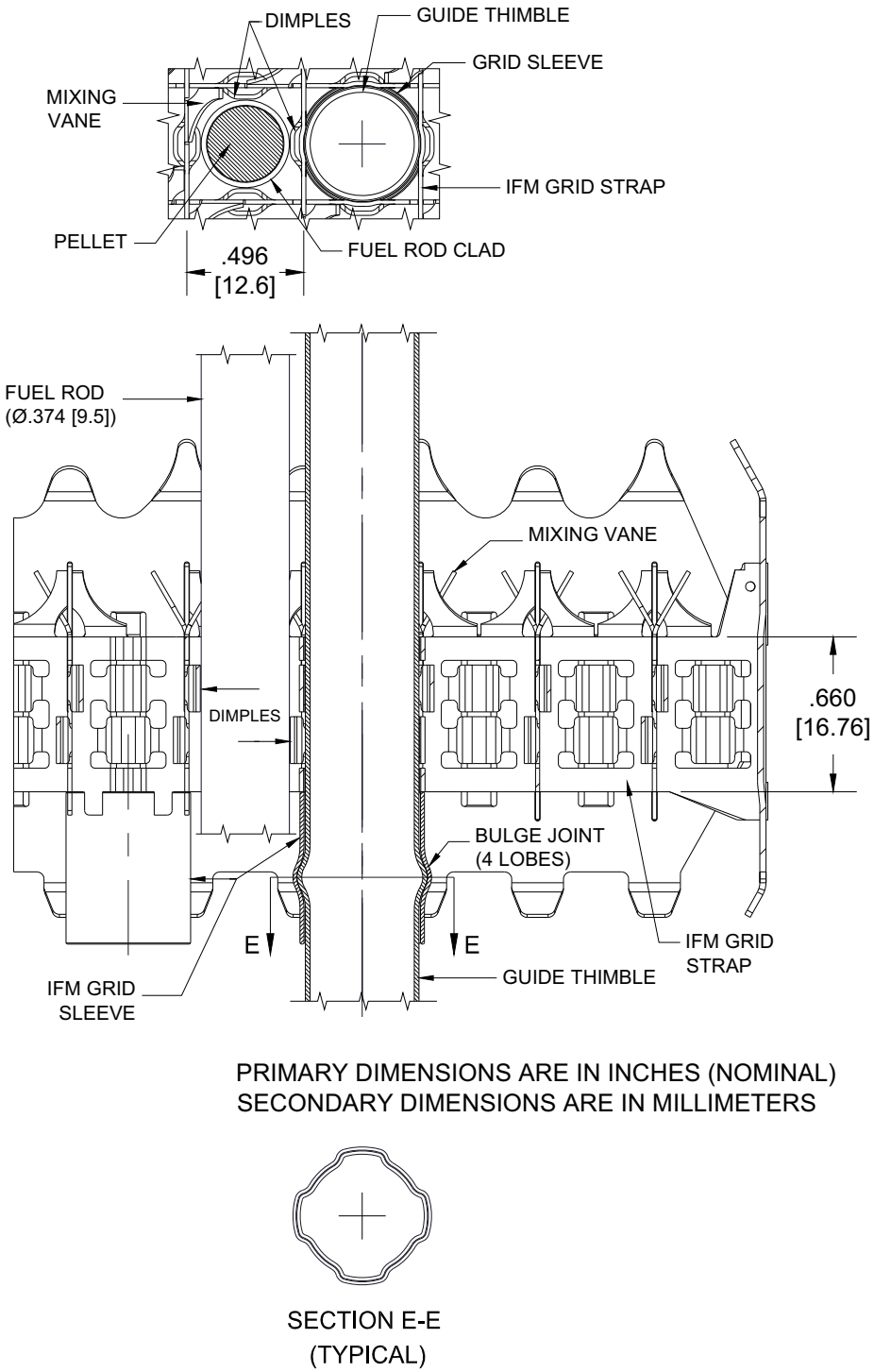


Figure 4.2-6
Intermediate Flow Mixer
Grid to Thimble Attachment

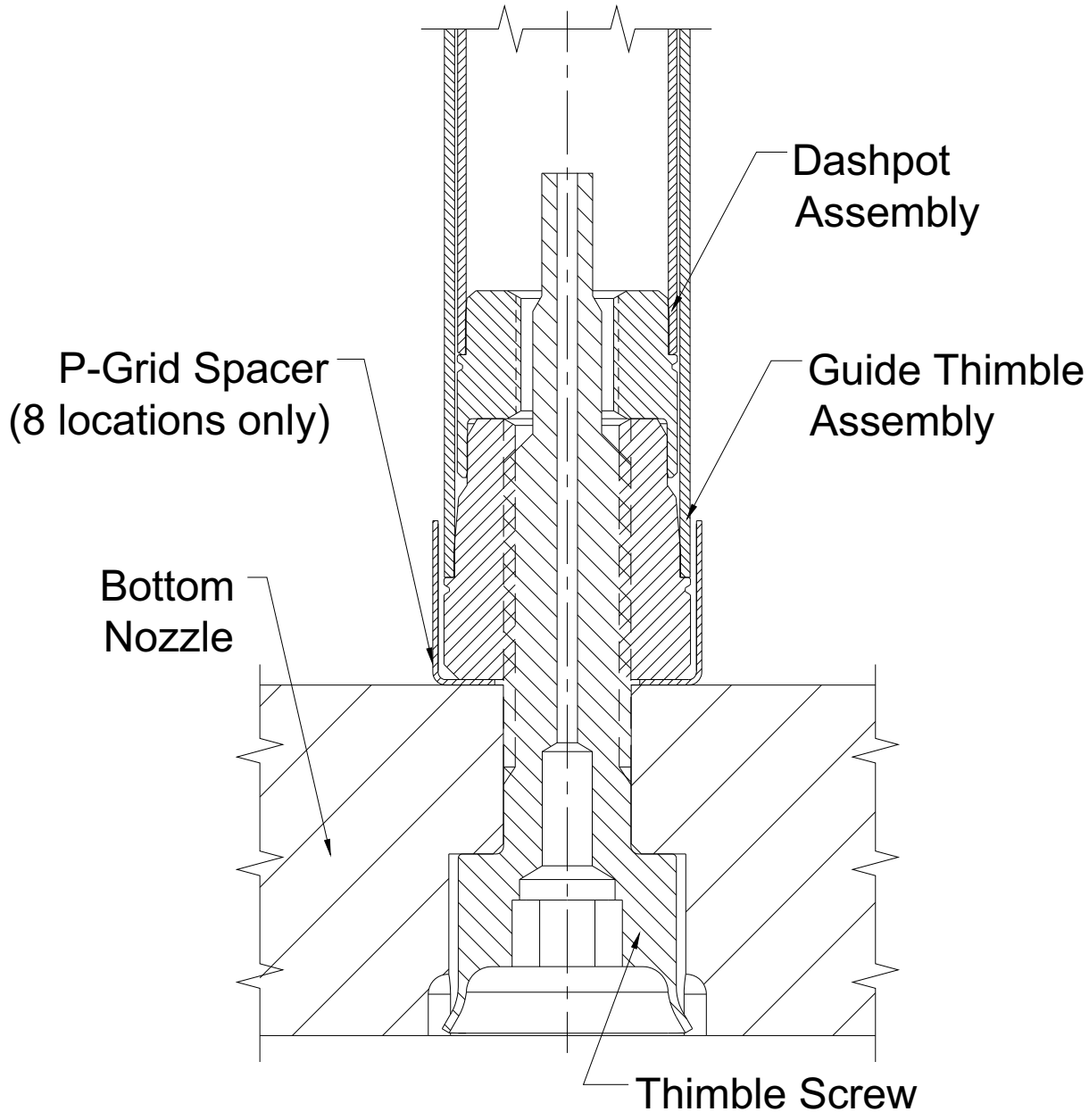


Figure 4.2-7
Grid Thimble to Bottom Nozzle Joint

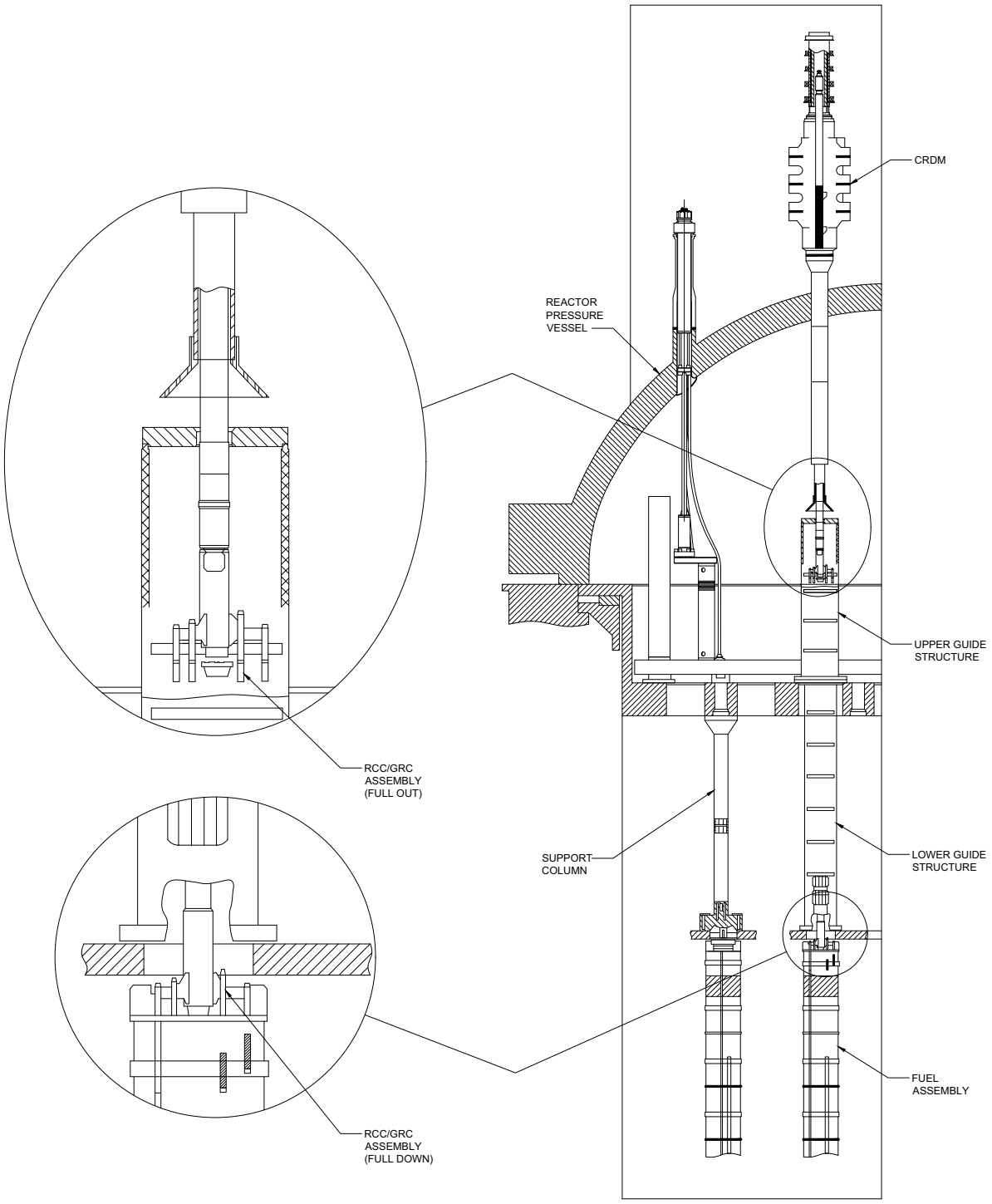


Figure 4.2-8
Rod Cluster Control and Drive Rod Assembly With Interfacing Components

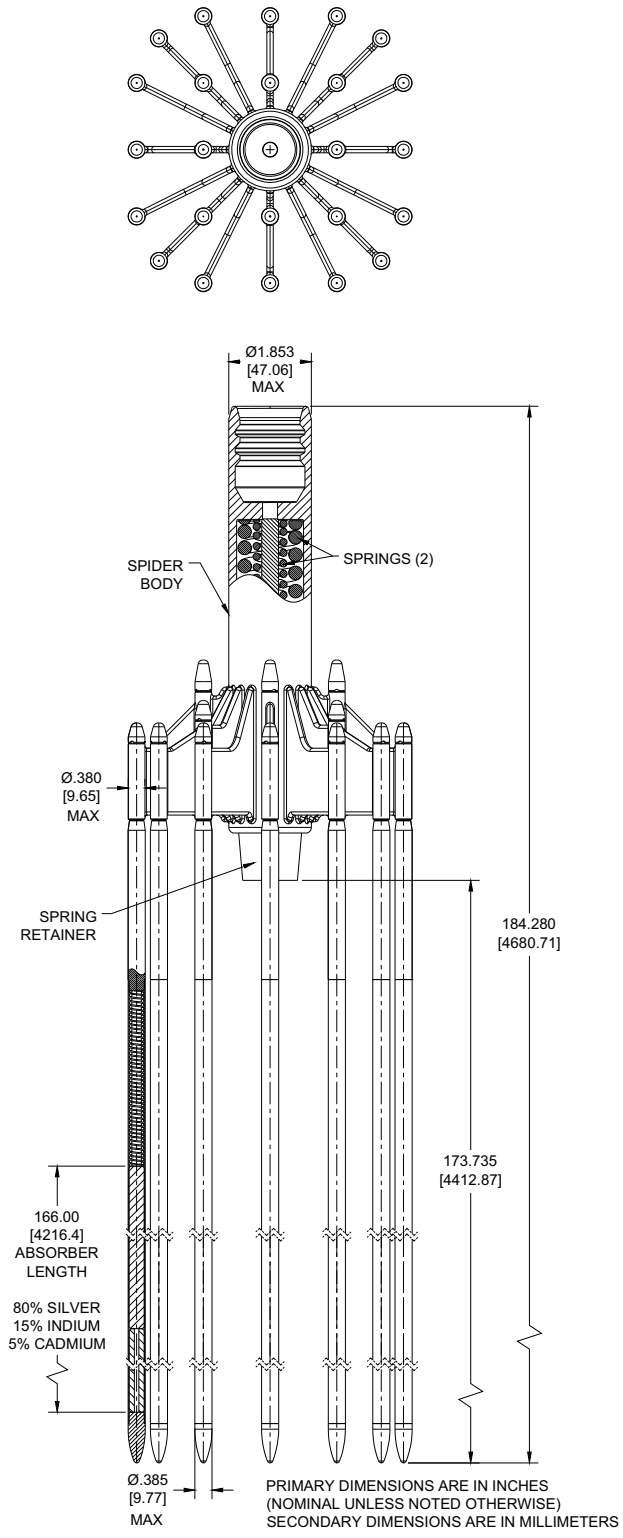
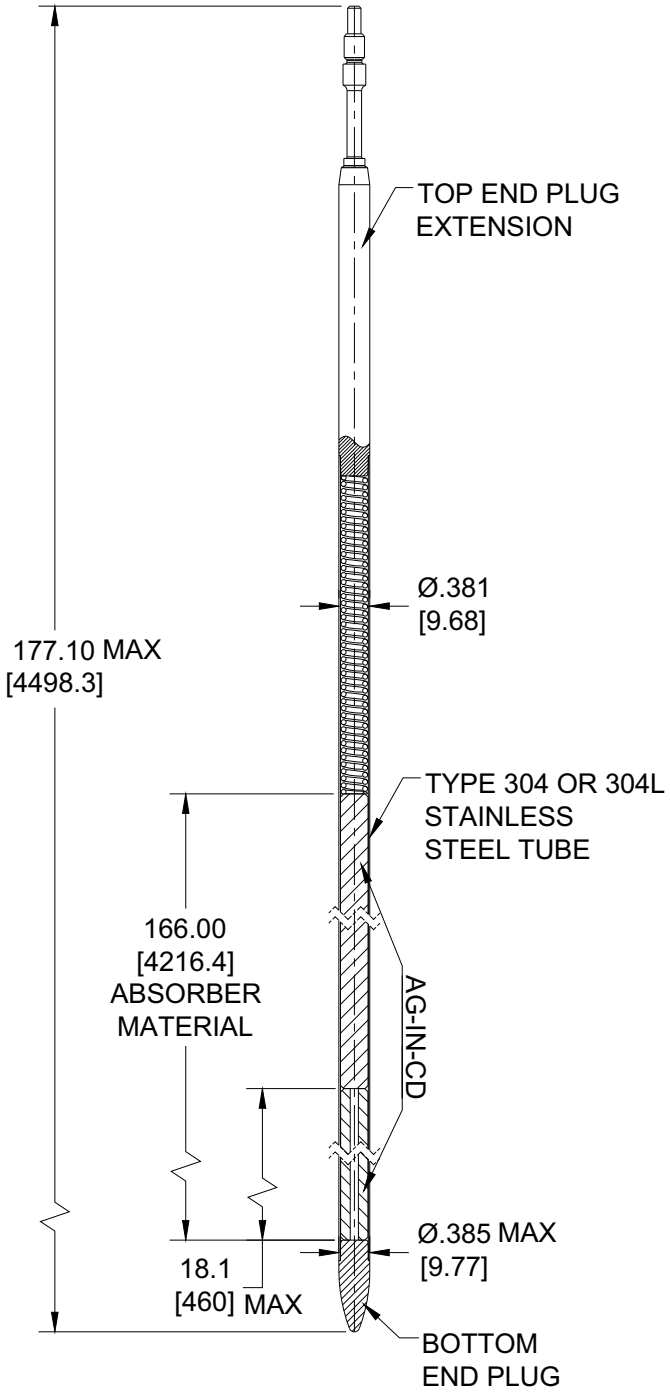


Figure 4.2-9
Rod Cluster Control Assembly



PRIMARY DIMENSIONS ARE IN INCHES
(NOMINAL UNLESS NOTED OTHERWISE)
SECONDARY DIMENSIONS ARE IN MILLIMETERS

Figure 4.2-10
Absorber Rod Detail

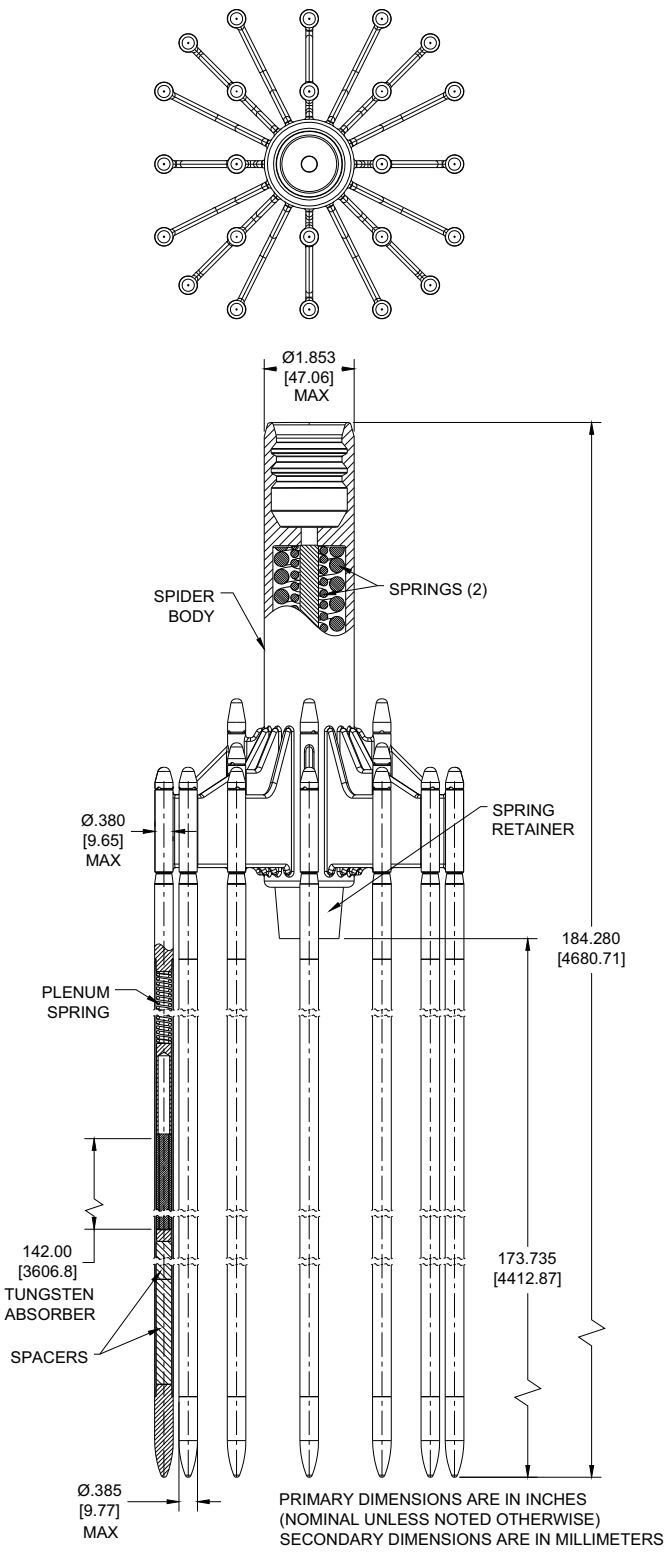


Figure 4.2-11
Gray Rod Cluster Assembly

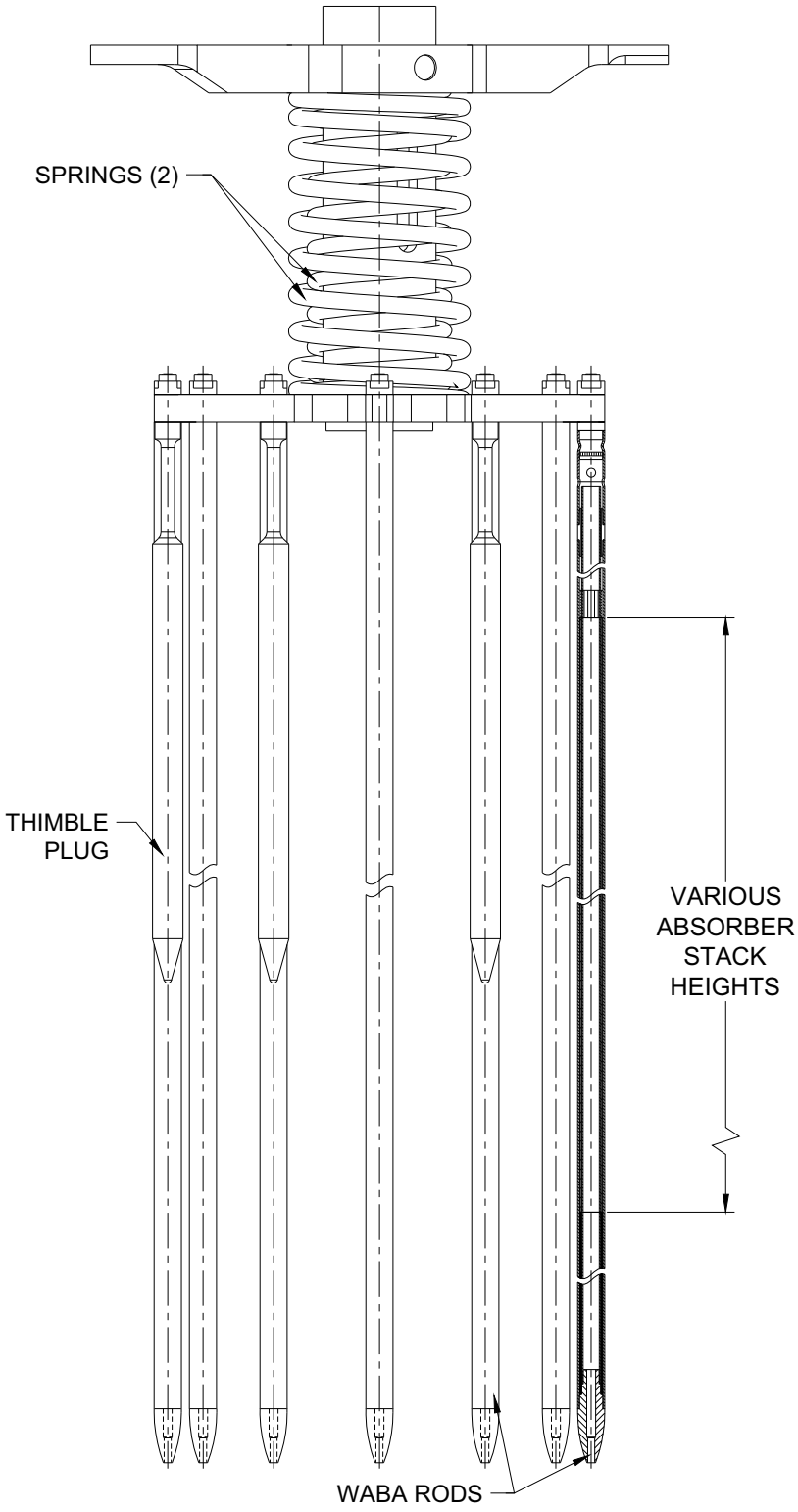


Figure 4.2-12
Wet Annular Burnable Absorber Assembly

Figure 4.2-13 Not Used

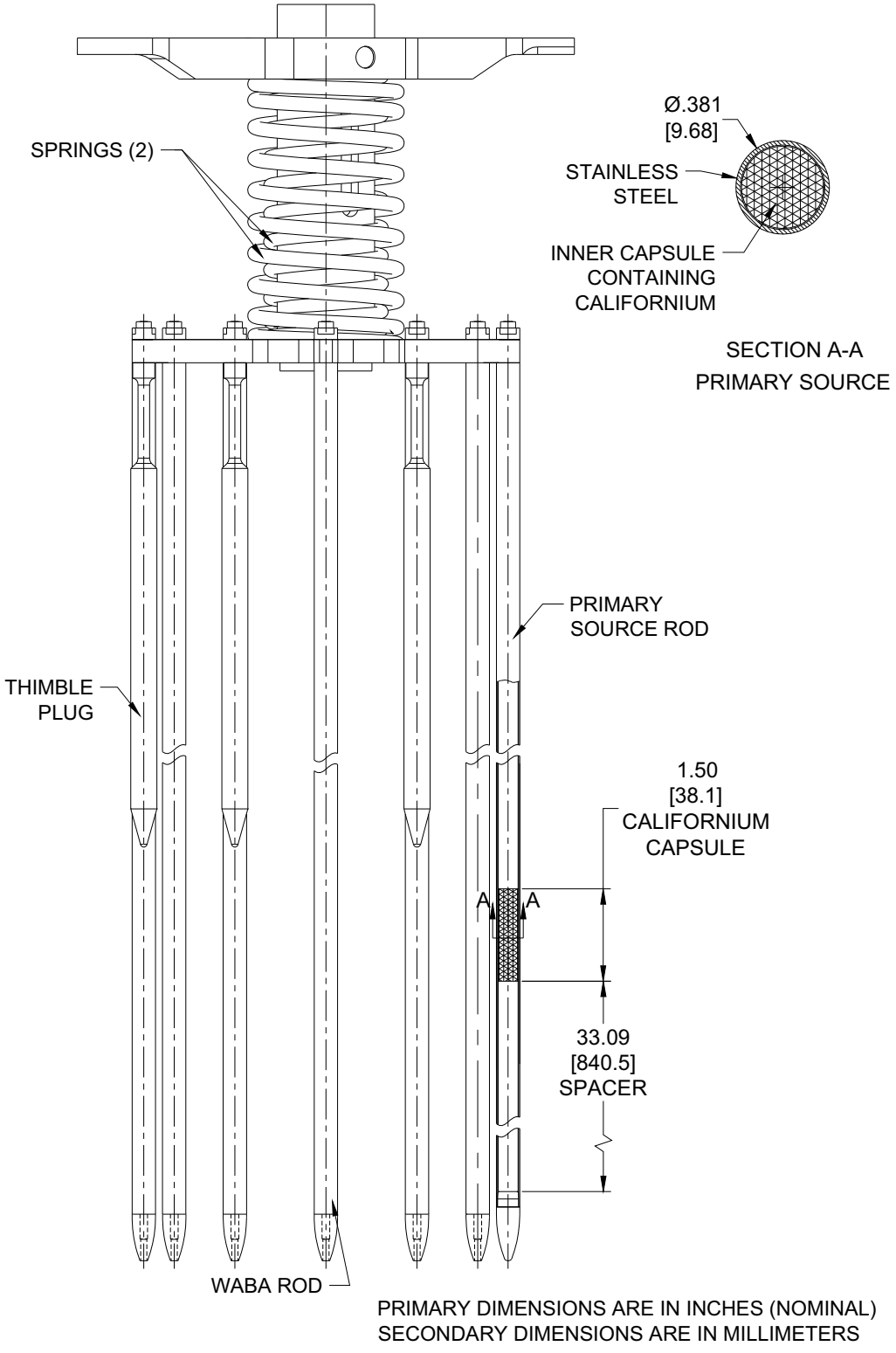
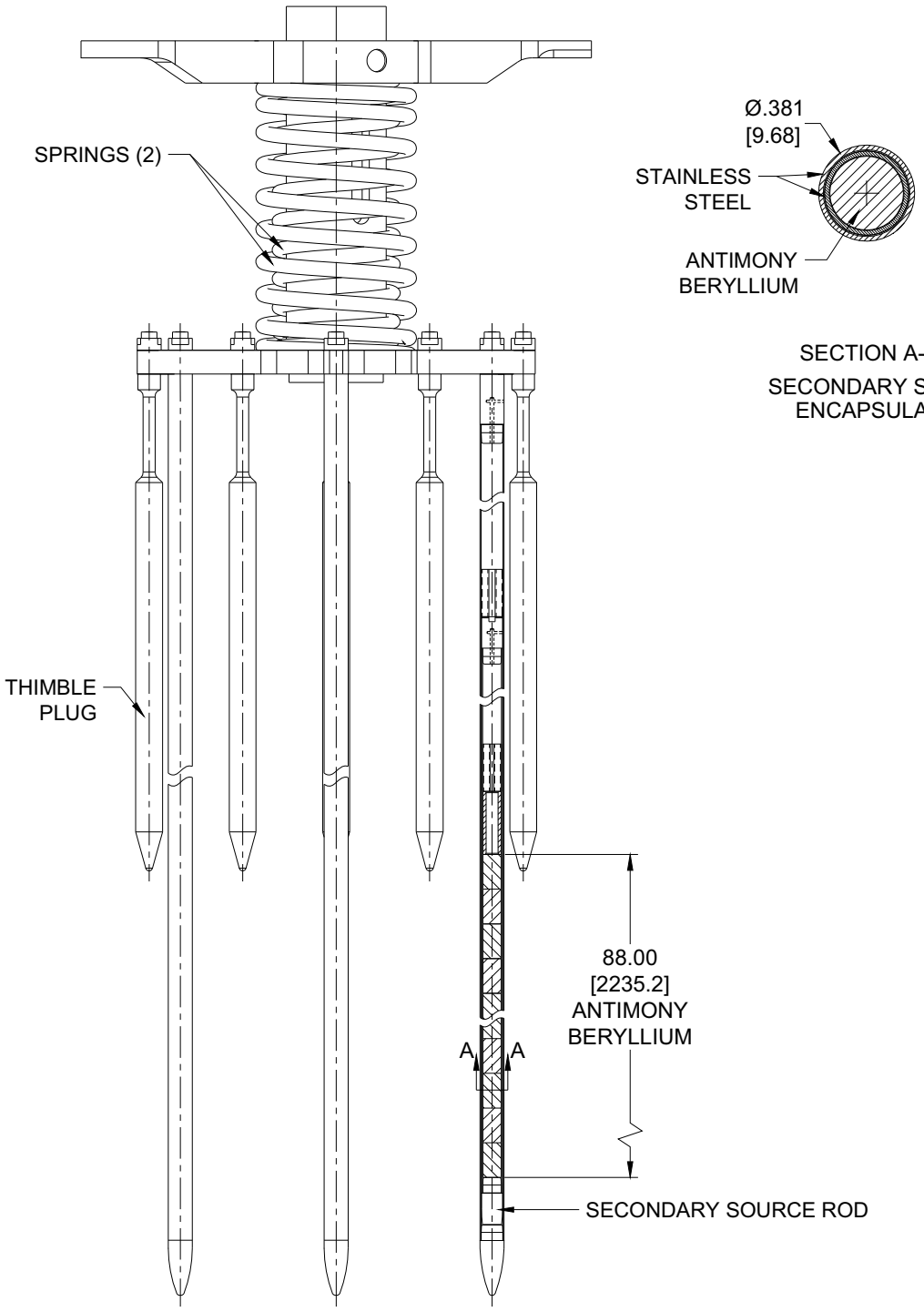


Figure 4.2-14
Primary Source Assembly



PRIMARY DIMENSIONS ARE IN INCHES (NOMINAL)
SECONDARY DIMENSIONS ARE IN MILLIMETERS

Figure 4.2-15
Secondary Source Assembly

4.3 Nuclear Design

4.3.1 Design Basis

This section describes the design bases and functional requirements used in the nuclear design of the fuel and reactivity control system and relates these design bases to the General Design Criteria (GDC). The design bases are the fundamental criteria that must be met using approved analytical techniques. [*Enhancements to these techniques may be made provided that the changes are founded by NRC approved methodologies as discussed in*]* WCAP-9272-P-A (Reference 1) and [*WCAP-12488-P-A (Reference 2).*]*

The plant conditions for design are divided into four categories:

- Condition I — Normal operation and operational transients
- Condition II — Events of moderate frequency
- Condition III — Infrequent incidents
- Condition IV — Limiting faults

The reactor is designed so that its components meet the following performance and safety criteria:

- In general, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action.
- Condition II occurrences are accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action.
- Fuel damage, that is, breach of fuel rod clad pressure boundary, is not expected during Condition I and Condition II occurrences. A very small amount of fuel damage may occur. This is within the capability of the chemical and volume control system (CVS) and is consistent with the plant design basis.
- Condition III occurrences do not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude immediate resumption of operation.
- The release of radioactive material due to Condition III occurrences is not sufficient to interrupt or restrict public use of those areas beyond the exclusion area boundary.
- A Condition III occurrence does not by itself generate a Condition IV occurrence or result in a consequential loss of function of the reactor coolant or reactor containment barriers.
- Condition IV faults do not cause a release of radioactive material that results in exceeding the dose limits identified in Chapter 15. Condition IV occurrences are faults that are not expected to occur but are defined as limiting faults which are included in the design.

The core design power distribution limits related to fuel integrity are met for Condition I occurrences through conservative design and are maintained by the action of the control system.

The requirements for Condition II occurrences are met by providing an adequate protection system which monitors reactor parameters.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The control and protection systems are described in Chapter 7.

The consequences of Condition II, III, and IV occurrences are described in Chapter 15.

4.3.1.1 Fuel Burnup

4.3.1.1.1 Basis

A limitation on initial installed excess reactivity or average discharge burnup is not required other than as is quantified in terms of other design bases, such as overall negative power reactivity feedback discussed below. [*The NRC has approved, in WCAP-12488-P-A (Reference 2), maximum fuel rod average burnup of 60,000 MWD/MTU. Extended burnup to 62,000 MWD/MTU has been established in Reference 61.*]*

4.3.1.1.2 Discussion

Fuel burnup is a measure of fuel depletion which represents the integrated energy output of the fuel in megawatt-days per metric ton of uranium (MWD/MTU) and is a useful means for quantifying fuel exposure criteria.

The core design lifetime, or design discharge burnup, is achieved by installing sufficient initial excess reactivity in each fuel region and by following a fuel replacement program (such as that described in Subsection 4.3.2) that meets the safety-related criteria in each cycle of operation.

Initial excess reactivity installed in the fuel, although not a design basis, must be sufficient to maintain core criticality at full-power operating conditions throughout cycle life with equilibrium xenon, samarium, and other fission products present. Burnable absorbers, control rod insertion, and/or chemical shim are used to compensate for the excess reactivity. The end of design cycle life is defined to occur when the chemical shim concentration is essentially zero with control rods present to the degree necessary for operational requirements. In terms of soluble boron concentration, this corresponds to approximately 10 ppm with the control and gray rods essentially withdrawn.

4.3.1.2 Negative Reactivity Feedbacks (Reactivity Coefficients)

4.3.1.2.1 Basis

For the initial fuel cycle, the fuel temperature coefficient will be negative, and the moderator temperature coefficient of reactivity will be negative for power operating conditions, thereby providing negative reactivity feedback characteristics. The design basis meets General Design Criterion 11.

4.3.1.2.2 Discussion

When compensation for a rapid increase in reactivity is considered, there are two major effects. These are the resonance absorption (Doppler) effects associated with changing fuel temperature and the neutron spectrum and reactor composition change effects resulting from changing moderator density. These basic physics characteristics are often identified by reactivity coefficients. The use of slightly enriched uranium results in a Doppler coefficient of reactivity that is negative. This coefficient provides the most rapid reactivity compensation. The initial core is also designed to have an overall negative moderator temperature coefficient of reactivity during power operation so that average coolant temperature changes or void content provides another, slower compensatory effect. For some core designs, if the compensation for excess reactivity is provided only by chemical shim, the moderator temperature coefficient could become positive. Nominal power operation is permitted only in a range of overall negative moderator temperature coefficient. The negative moderator temperature coefficient can be achieved through the use of discrete burnable absorbers (BAs) and/or

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

integral fuel burnable absorbers and/or control rods by limiting the reactivity controlled by soluble boron.

Burnable absorber content (quantity and distribution) is not stated as a design basis. However, for some reloads, the use of burnable absorbers may be necessary for power distribution control and/or to achieve an acceptable moderator temperature coefficient throughout core life. The required burnable absorber loading is that which is required to meet design criteria.

4.3.1.3 Control of Power Distribution

4.3.1.3.1 Basis

The nuclear design basis is that, with at least a 95 percent confidence level:

- The fuel will not operate with a power distribution that would result in exceeding the departure from nucleate boiling (DNB) design basis (i.e., the departure from nucleate boiling ratio (DNBR) shall be greater than the design limit departure from nucleate boiling ratio as discussed in Subsection 4.4.1) under Condition I and II occurrences, including the maximum overpower condition.

- Under abnormal conditions, including the maximum overpower condition, the peak linear heat rate (PLHR) will not cause fuel melting, as defined in Subsection 4.4.1.2.

- Fuel management will be such as to produce values of fuel rod power and burnup consistent with the assumptions in the fuel rod mechanical integrity analysis of Section 4.2.

- The fuel will not be operated at Peak Linear Heat Rate (PLHR) values greater than those found to be acceptable within the body of the safety analysis under normal operating conditions, including an allowance of one percent for calorimetric error (calorimetric uncertainty calculation will be provided per Subsection 15.0.15.1).

The above basis meets General Design Criterion 10.

4.3.1.3.2 Discussion

Calculation of extreme power shapes which affect fuel design limits are performed with proven methods. The conditions under which limiting power shapes are assumed to occur are chosen conservatively with regard to any permissible operating state. Even though there is close agreement between calculated peak power and measurements, a nuclear uncertainty is applied (Subsection 4.3.2.2.1) to calculated power distribution. Such margins are provided both for the analysis for normal operating states and for anticipated transients.

4.3.1.4 Maximum Controlled Reactivity Insertion Rate

4.3.1.4.1 Basis

The maximum reactivity insertion rate due to withdrawal of rod cluster control assemblies (RCCAs) or gray rod cluster assemblies (GRCAs) or by boron dilution is limited by plant design, hardware, and basic physics. During normal power operation, the maximum controlled reactivity insertion rate is limited. The maximum reactivity change rate for accidental withdrawal of two control banks is set such that PLHR and the departure from nucleate boiling ratio limitations are not challenged. This satisfies General Design Criterion 25.

The maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods are limited to preclude rupture of the coolant pressure boundary or disruption of the core internals to a degree which would impair core cooling capacity due to a rod withdrawal or an ejection accident. (See Chapter 15).

Following any Condition IV occurrence, such as rod ejection or steam line break, the reactor can be brought to the shutdown condition, and the core maintains acceptable heat transfer geometry. This satisfies General Design Criterion 28.

4.3.1.4.2 Discussion

Reactivity addition associated with an accidental withdrawal of a control bank (or banks) is limited by the maximum rod speed (or travel rate) and by the worth of the bank(s). For this reactor, the maximum control and gray rod speed is 45 inches per minute.

The reactivity change rates are conservatively calculated, assuming unfavorable axial power and xenon distributions. The typical peak xenon burnout rate is significantly lower than the maximum reactivity addition rate for normal operation and for accidental withdrawal of two banks.

4.3.1.5 Shutdown Margins

4.3.1.5.1 Basis

Minimum shutdown margin as specified in the technical specifications is required in all operating modes.

In analyses involving reactor trip, the single, highest worth rod cluster control assembly is postulated to remain untripped in its full-out position (stuck rod criterion). This satisfies General Design Criterion 26.

4.3.1.5.2 Discussion

Two independent reactivity control systems are provided: control rods and soluble boron in the coolant. The control rods provide reactivity changes which compensate for the reactivity effects of the fuel and water density changes accompanying power level changes over the range from full load to no load. The control rods provide the minimum shutdown margin under Condition I occurrences and are capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits (very small number of rod failures), assuming that the highest worth control rod is stuck out upon trip.

The boron system can compensate for xenon burnout reactivity changes and maintain the reactor in the cold shutdown condition. Thus, backup and emergency shutdown provisions are provided by mechanical and chemical shim control systems which satisfy General Design Criterion 26. Reactivity changes due to fuel depletion are accommodated with the boron system.

4.3.1.5.3 Basis

When fuel assemblies are in the pressure vessel and the vessel head is not in place, keff will be maintained at or below 0.95 with control rods and soluble boron. Further, the fuel will be maintained sufficiently subcritical that removal of the rod cluster control assemblies will not result in criticality.

4.3.1.5.4 Discussion

ANSI N18.2 (Reference 3) specifies a keff not to exceed 0.95 in spent fuel storage racks and transfer equipment flooded with pure water and a keff not to exceed 0.98 in normally dry new fuel storage racks, assuming optimum moderation. No criterion is given for the refueling operation. However, a five percent margin, which is consistent with spent fuel storage and transfer and the new fuel storage, is adequate for the controlled and continuously monitored operations involved.

The boron concentration required to meet the refueling shutdown criteria is specified in the Core Operating Limits Report (COLR). Verification that these shutdown criteria are met, including uncertainties, is achieved using standard design methods. The subcriticality of the core is continuously monitored as described in the technical specifications.

4.3.1.6 Stability

4.3.1.6.1 Basis

The core will be inherently stable to power oscillations at the fundamental mode. This satisfies General Design Criterion 12.

Spatial power oscillations within the core with a constant core power output, should they occur, can be reliably and readily detected and suppressed.

4.3.1.6.2 Discussion

Oscillations of the total power output of the core, from whatever cause, are readily detected by the loop temperature sensors and by the nuclear instrumentation. The core is protected by these systems; a reactor trip occurs if power increases unacceptably, thereby preserving the design margins to fuel design limits. The combined stability of the turbine, steam generator and the reactor power control systems are such that total core power oscillations are not normally possible. The redundancy of the protection circuits results in a low probability of exceeding design power levels.

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping; no operator action or control action is required to suppress them. The stability to diametral oscillations is so great that this excitation is highly improbable. Convergent azimuthal oscillations can be excited by prohibited motion of individual control rods.

Indications of power distribution anomalies are continuously available from an online core monitoring system. The online monitoring system processes information provided by the fixed in-core detectors, in-core thermocouples, and loop temperature measurements. Radial power distributions are therefore continuously monitored, thus power oscillations are readily observable and alarmed. The ex-core long ion chambers also provide surveillance and alarms of anomalous power distributions. In proposed core designs, these horizontal plane oscillations are self-damping by virtue of reactivity feedback effects inherent to the basic core physics.

Axial xenon spatial power oscillations may occur during core life, especially late in the cycle. The online core monitoring system provides continuous surveillance of the axial power distributions. The control rod system provides both manual and automatic control systems for controlling the axial power distributions.

Confidence that fuel design limits are not exceeded is provided by reactor protection system overpower ΔT ($OP\Delta T$) and overtemperature ΔT ($OT\Delta T$) trip functions, which use the loop temperature sensors, pressurizer pressure indication, and measured axial offset as an input. Detection and suppression of xenon oscillations are discussed in Subsection 4.3.2.7.

4.3.1.7 Anticipated Transients Without Scram (ATWS)

The AP1000 diverse reactor trip actuation system is independent of the reactor trip breakers used by the protection monitoring system. The diverse reactor trip reduces the probability and consequences of a postulated ATWS. The effects of anticipated transients with failure to trip are not considered in the design bases of the plant. Analysis has shown that the likelihood of such a hypothetical event is negligibly small. Furthermore, analysis of the consequences of a hypothetical failure to trip following anticipated transients has shown that no significant core damage would result, system peak pressures should be limited to acceptable values, and no failure of the reactor coolant system would result. (See WCAP-8330, Reference 5). The process used to evaluate the ATWS risk in compliance with 10 CFR 50.62 is described in Section 15.8.

4.3.2 Description

4.3.2.1 Nuclear Design Description

The reactor core consists of a specified number of fuel rods held in bundles by spacer grids and top and bottom fittings. The fuel rods are fabricated from cylindrical tubes made of zirconium based alloy(s) containing uranium dioxide fuel pellets. The bundles, known as fuel assemblies, are arranged in a pattern which approximates a right circular cylinder.

Each fuel assembly contains a 17 x 17 rod array composed nominally of 264 fuel rods, 24 rod cluster control thimbles, and an in-core instrumentation thimble. Figure 4.2-1 shows a cross-sectional view of a 17 x 17 fuel assembly and the related rod cluster control guide thimble locations. Detailed descriptions of the AP1000 fuel assembly design features are given in Section 4.2.

Both the initial and reload core loading patterns can employ various fuel management techniques including “low-leakage” designs, and are anticipated to operate approximately 18 months between refueling. For reload core loading patterns, the initial and final positions of assemblies, and the number of fresh assemblies and their placement are dependent on the energy requirement for the reload cycle and burnup and power histories of the previous cycles.

For the initial core loading, the fuel rods within certain assemblies contain varying uranium enrichments in both the radial and axial planes. Fuel containing up to five average enrichments will be used in the initial core load to establish a favorable radial power distribution simulating the reactivity distribution of a low leakage reload core. Figure 4.3-1 shows the fuel loading pattern used in the initial cycle. The higher enriched regions will be configured in the core interior consistent with the feed fuel placement in a reload core, and the lower enriched regions will approximate the reactivity of the burned fuel assemblies of a reload core. The enrichments for the initial cycle are shown in Table 4.3-1.

The core average enrichment is determined by the amount of fissionable material required to provide the desired energy requirements. The physics of the burnout process is such that operation of the reactor depletes the amount of fuel available due to the absorption of neutrons by the U-235 atoms and their subsequent fission. In addition, the fission process results in the formation of fission products, some of which readily absorb neutrons. These effects, the depletion and the buildup of fission products, are partially offset by the buildup of plutonium shown in Figure 4.3-2 for a typical 17 x 17 fuel assembly, which occurs due to the parasitic absorption of neutrons in U-238. Therefore, at the beginning of any cycle a reactivity reserve equal to the depletion of the fissionable fuel and the buildup of fission product poisons less the buildup of fissile fuel over the specified cycle life is built into the reactor. This excess reactivity is controlled by removable neutron-absorbing material in the form of boron dissolved in the primary coolant, control rod insertion, burnable absorber rods, and/or integral fuel burnable absorbers (IFBA). The stack length of the burnable absorber rods and/or integral absorber bearing fuel may vary for different core designs, with the optimum length

determined on a design specific basis. Figure 4.3-3 is a plot of the core soluble boron concentration versus core depletion for the first operating cycle.

The concentration of the soluble neutron absorber is varied to compensate for reactivity changes due to fuel burnup, fission product poisoning including xenon and samarium, burnable absorber depletion, and the cold-to-operating moderator temperature change. Throughout the operating range, the CVS is designed to provide changes in reactor coolant system (RCS) boron concentration to compensate for the reactivity effects of fuel depletion, peak xenon burnout and decay, and cold shutdown boration requirements.

Burnable absorbers are strategically located to provide a favorable radial power distribution and provide for negative reactivity feedback. Figures 4.3-4a and 4.3-4a show the burnable absorber distributions within a fuel assembly for the several patterns used in a 17 x 17 array. The initial core burnable absorber loading pattern is shown in Figure 4.3-5.

Tables 4.3-1 through 4.3-3 contain summaries of reactor core design parameters including reactivity coefficients, delayed neutron fraction, and neutron lifetimes. Sufficient information is included to permit an independent calculation of the nuclear performance characteristics of the core.

4.3.2.2 Power Distribution

The accuracy of power distribution calculations has been confirmed through approximately 1000 flux maps under conditions very similar to those expected. Details of this confirmation are given in WCAP-7308-L-P-A (Reference 7) and in Subsection 4.3.2.2.7.

4.3.2.2.1 Definitions

Relative power distributions within the reactor are quantified in terms of hot channel factors. These hot channel factors are normalized ratios of maximal absolute power generation rates and are a measure of the peak pellet power within the reactor core relative to the average pellet (F_Q) and the energy produced in a coolant channel relative to the core average channel ($F_{\Delta H}$). Absolute power generation rates are expressed in terms of quantities related to the nuclear or thermal design; more specifically, volumetric power density (qvol) is the thermal power produced per unit volume of the core (kW/liter).

Linear heat rate (LHR) is the thermal power produced per unit length of active fuel (kW/ft). Since fuel assembly geometry is standardized, LHR is the unit of absolute power density most commonly used. For practical purposes, LHR differs from qvol by a constant factor which includes geometry effects and the heat flux deposition fraction. The peak linear heat rate (PLHR) is defined as the maximum linear heat rate occurring throughout the reactor. PLHR directly impacts fuel temperatures and decay power levels thus being a significant safety analysis parameter.

Average linear heat rate (ALHR) is the total thermal power produced in the fuel rods expressed as heat flux divided by the total active fuel length of the rods in the core.

Local heat flux is the heat flux at the surface of the cladding (Btu/hr-ft^2). For nominal rod parameters, this differs from linear heat rate by a constant factor.

Rod power is the total power generated in one rod (kW).

Average rod power is the total thermal power produced in the fuel rods divided by the number of fuel rods (assuming the rods have equal length).

The hot channel factors used in the discussion of power distributions in this section are defined as follows:

F_Q, **heat flux hot channel factor**, is defined as the maximum local heat flux on the surface of a fuel rod divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

F^N_Q, **nuclear heat flux hot channel factor**, is defined as the maximum local fuel rod linear heat rate divided by the average fuel rod linear heat rate, assuming nominal fuel pellet and rod parameters.

F^E_Q, **engineering heat flux hot channel factor**, is the allowance on heat flux required for manufacturing tolerances. The engineering factor allows for local variations in enrichment, pellet density and diameter, burnable absorber content, surface area of the fuel rod, and eccentricity of the gap between pellet and clad. Combined statistically, the net effect is a factor of 1.03 to be applied to the fuel rod surface heat flux.

$F^N_{\Delta H}$, **nuclear enthalpy rise hot channel factor**, is defined as the ratio of the maximum integrated rod power within the core to the average rod power.

Manufacturing tolerances, hot channel power distribution, and surrounding channel power distributions are treated explicitly in the calculation of the departure from nucleate boiling ratio described in Section 4.4.

It is convenient for the purposes of discussion to define subfactors of F_Q. However, design limits are set in terms of the total peaking factor.

F_Q = total peaking factor or heat flux hot channel factor = $\frac{PLHR}{ALHR}$

Without densification effects:

$$F_Q = F^N_Q \times F^E_Q = F^N_{XY} \times F^N_Z \times F^N_U \times F^E_Q$$

where F^N_Q and F^E_Q are defined above and:

F^N_U = factor for calculational uncertainty, assumed to be 1.05.

F^N_{XY} = ratio of peak power density to average power density in the horizontal plane of peak local power.

F^N_Z = ratio of the power per unit core height in the horizontal plane of peak local power to the average value of power per unit core height. If the plane of peak local power coincides with the plane of maximum power per unit core height, then F^N_Z is the core average axial peaking factor.

4.3.2.2.2 Radial Power Distributions

The power shape in horizontal sections of the core at full power is a function of the fuel assembly and burnable absorber loading patterns, the control rod pattern, and the fuel burnup distribution. Thus, at any time in the cycle, a horizontal section of the core can be characterized as unrodded or with control rods. These two situations combined with burnup effects determine the radial power shapes which can exist in the core at full power. Typical first cycle values of $F^N_{\Delta H}$, the nuclear enthalpy rise hot channel factors from beginning of life (BOL) to end of life (EOL) are given in Table 4.3-2. The effects on radial power shapes of power level, xenon, samarium, and moderator density effects are

also considered, but these are quite small. The effect of nonuniform flow distribution is negligible. While radial power distributions in various planes of the core are often illustrated, since the moderator density is directly proportional to enthalpy, the core radial enthalpy rise distribution, as determined by the integral of power up each channel, is of greater interest. Figures 4.3-6 through 4.3-11 show typical normalized power density distributions for one-quarter of the core for representative operating conditions. These conditions are as follows:

- Hot full power (HFP) near beginning of life, unrodded, no xenon
- Hot full power near beginning of life, unrodded, equilibrium xenon
- Hot full power near beginning of life, gray bank MA+MB in, equilibrium xenon
- Hot full power near middle of life (MOL), unrodded equilibrium xenon
- Hot full power near end of life, unrodded, equilibrium xenon
- Hot full power near end of life, gray bank MA+MB in, equilibrium xenon

Since the position of the hot channel varies from time to time, a single-reference radial design power distribution is selected for departure from nucleate boiling calculations. This reference power distribution is chosen conservatively to concentrate power in one area of the core, minimizing the benefits of flow redistribution. Assembly powers are normalized to core average power. The radial power distribution within a fuel rod and its variation with burnup as utilized in thermal calculations and fuel rod design are discussed in Section 4.4.

4.3.2.2.3 Assembly Power Distributions

For the purpose of illustration, typical rodwise power distributions from the beginning of life and end of life conditions corresponding to Figures 4.3-7 and 4.3-10, are given for representative hot channel assemblies in Figures 4.3-12 and 4.3-13, respectively.

Since the detailed power distribution surrounding the hot channel varies from time to time, a conservatively flat radial assembly power distribution is assumed in the departure from nucleate boiling analysis, described in Section 4.4, with the rod of maximum integrated power artificially raised to the design value of $F^N_{\Delta H}$. Care is taken in the nuclear design of the fuel cycles and operating conditions to confirm that a flatter assembly power distribution does not occur with limiting values of $F^N_{\Delta H}$.

4.3.2.2.4 Axial Power Distributions

The distribution of power in the axial or vertical direction is largely under the control of the operator through either the manual operation of the control rods or the automatic motion of control rods in conjunction with manual operation of the chemical and volume control system. The automated mode of operation is referred to as mechanical shim (MSHIM) and is discussed in Subsection 4.3.2.4.16. The rod control system automatically modulates the insertion of the axial offset (AO) control bank controlling the axial power distribution simultaneous with the MSHIM gray and control rod banks to maintain programmed coolant temperature. Operation of the chemical and volume control system is initiated manually by the operator to compensate for fuel burnup and maintain the desired MSHIM bank insertion. Nuclear effects which cause variations in the axial power shape include moderator density, Doppler effect on resonance absorption, spatial distribution of xenon, burnup, and axial distribution of fuel enrichment and burnable absorber. Automatically controlled variations in total power output and rod motion are also important in determining the axial power shape at any time.

The online core monitoring system provides the operator with detailed power distribution information in both the radial and axial sense continuously using signals from the fixed in-core detectors. Signals are also available to the operator from the ex-core ion chambers, which are long ion chambers outside the reactor vessel running parallel to the axis of the core. Separate signals are taken from each ion chamber. The ion chamber signals are processed and calibrated against in-core measurements such that an indication of the power in the top of the core less the power in the bottom of the core is derived. The calibrated difference in power between the core top and bottom halves, called the flux difference (ΔI), is derived for each of the four channels of ex-core detectors and is displayed on the control panel. The principal use of the flux difference is to provide the shape penalty function to the OTΔT DNB protection and the OPΔT overpower protection.

4.3.2.2.5 Local Power Peaking

Fuel densification occurred early in the evolution of pressurized water reactor fuel manufacture under irradiation in several operating reactors. This caused the fuel pellets to shrink both axially and radially. The pellet shrinkage combined with random hang-up of fuel pellets can result in gaps in the fuel column when the pellets below the hung-up pellet settle in the fuel rod. The gaps vary in length and location in the fuel rod. Because of decreased neutron absorption in the vicinity of the gap, power peaking occurs in the adjacent fuel rods, resulting in an increased power peaking factor. A quantitative measure of this local peaking is given by the power spike factor S(Z), where Z is the axial location in the core. The power spike factor S(z) is discussed in References 8, 9, and 10.

Modern PWR fuel manufacturing practices have essentially eliminated significant fuel densification impacts on reactor design and operation. It has since been concluded and accepted that a densification power spike factor of 1.0 is appropriate for Westinghouse fuel as described in WCAP-13589-A (Reference 59).

4.3.2.2.6 Limiting Power Distributions

According to the ANSI classification of plant conditions (Chapter 15), Condition I occurrences are those expected frequently or regularly in the course of power operation, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Condition I occurrences are considered from the point of view of affecting the consequences of fault conditions (Conditions II, III, and IV). Analysis of each fault condition described is based on a conservative set of corresponding initial conditions.

The list of steady-state and shutdown conditions, permissible deviations, and operational transients is given in Chapter 15. Implicit in the definition of normal operation is proper and timely action by the reactor operator; that is, the operator follows recommended operating procedures for maintaining appropriate power distributions and takes any necessary remedial actions when alerted to do so by the plant instrumentation.

The online monitoring system evaluates the consequences of limiting power distributions based upon the conditions prevalent in the reactor at the current time. Operating space evaluations performed by the online monitoring system include the most limiting power distributions that can be generated by inappropriate operator or control system actions given the current core power level, xenon distribution, MSHIM or AO bank insertion and core burnup. Thus, as stated, the worst or limiting power distribution which can occur during normal operation is considered as the starting point for analysis of Conditions II, III, and IV occurrences.

Improper procedural actions or errors by the operator are assumed in the design as occurrences of moderate frequency (Condition II). Some of the consequences which might result are discussed in Chapter 15. Therefore, the limiting power shapes which result from such Condition II occurrences are

those power distributions which deviate from the normal operating condition within the allowable operating space as defined in the core operating limits; e.g., due to lack of proper action by the operator during a xenon transient following a change in power level brought about by control rod motion. Power distributions which fall in this category are used for determination of the reactor protection system setpoints to maintain margin to overpower or departure from nucleate boiling limits.

The means for maintaining power distributions within the required absolute power generation limits are described in the technical specifications. The online core monitoring system provides the operator with the current allowable operating space, detailed current power distribution information, thermal margin assessment and operational recommendations to manage and maintain required thermal margins. As such, the online monitoring system provides the primary means of managing and maintaining required operating thermal margins during normal operation.

In the unlikely event that the online monitoring system is out of service, power distribution controls based on bounding, precalculated analysis are also provided to the operator such that the online monitoring system is not a required element for short term reactor operation. Limits are placed on the axial flux difference so that the heat flux hot channel factor F_Q is maintained within acceptable limits. A discussion of precalculated power distribution control in Westinghouse pressurized water reactors (PWRs) is included in WCAP-7811 (Reference 11). Detailed background information on the design constraints on local power density in a Westinghouse PWR, on the defined operating procedures, and on the measures taken to preclude exceeding design limits is presented in the Westinghouse topical report on power distribution control and load following procedures WCAP-8385 (Reference 12) and the Westinghouse topical report on improved F_Q surveillance methodologies WCAP-17661 (Reference 15). The following paragraphs summarize these reports and describe the calculations used to establish the upper bound on peaking factors.

The calculations used to establish the upper bound on peaking factors, F_Q and $F_{\Delta H}^N$, include the nuclear effects which influence the radial and axial power distributions throughout core life for various modes of operation, including load follow, reduced power operation, and axial xenon transients.

Power distributions are calculated for the full-power condition. Fuel and moderator temperature feedback effects are included within these calculations in each spatial dimension. The steady-state nuclear design calculations are done for normal flow with the same mass flow in each channel and flow redistribution effects neglected. The effect of flow redistribution is calculated explicitly where it is important in the departure from nucleate boiling analysis of accidents. The effect of xenon on radial power distribution is small (compare Figures 4.3-6 and 4.3-7) but is included as part of the normal design process.

The core axial profile can experience significant changes, which can occur rapidly as a result of rod motion and load changes and more slowly due to xenon distribution. For the study of points of closest approach to thermal margin limits, several thousand cases are examined. Since the properties of the nuclear design dictate what axial shapes can occur, boundaries on the limits of interest can be set in terms of the parameters which are readily observed on the plant. Specifically, the nuclear design parameters significant to the axial power distribution analysis are as follows:

- Core power level
- Core height
- Coolant temperature and flow
- Coolant temperature program as a function of reactor power
- Fuel cycle lifetimes

- Rod bank worth
- Rod bank overlaps

Normal operation of the plant assumes compliance with the following conditions:

- Control rods in a single bank move together with no individual rod insertion differing from the bank demand position by more than the number of steps identified in the technical specifications.
- Control banks are sequenced with overlapping banks.
- The control bank insertion limits are not violated.
- Axial power distribution control procedures, which are given in terms of flux difference control and control bank position, are observed.

The axial power distribution procedures referred to above are part of the required operating procedures followed in normal operation with the online monitoring system out of service. In service, the online core monitoring system provides continuous indication of power distribution, shutdown margin, and margin to design limits.

Unit 3 only:

The constant axial offset control (CAOC) procedures described in WCAP-8385 (Reference 12) were developed to allow the use of a low upper bound on F_Q during normal operation (hence maximizing the margin to core safety limits) while permitting the maintenance of necessary load follow flexibility. The CAOC procedures require control of the AO at all power levels within a permissible operating band about a target value corresponding to the equilibrium full power value. Control to a target AO minimizes transient xenon effects on the axial power distributions.

The F_Q Surveillance Technical Specification responsible for providing assurance that F_Q will remain within the limits assumed in the plant safety analyses when the core is operated within its allowed operating space is based on the CAOC methodology presented in WCAP-8385 (Reference 12). The key operating space limits include RTP, control bank rod insertion limits (RILs), and the axial flux difference (AFD) limits. Together, these operating space limits restrict the range of potential non-equilibrium core power shapes during normal operation, thereby limiting the maximum non-equilibrium $F_Q(Z)$ and the maximum local power density.

The F_Q Surveillance formulation relies on a combination of analytical factors and periodic measurements to provide assurance that core operation within the allowed operating space will be acceptable. When an F_Q surveillance is performed, the equilibrium $F_Q(Z)$ is measured at or near steady-state conditions. This is then multiplied by an analytical factor, W(Z), which characterizes the increase in $F_Q(Z)$ for non-equilibrium operation. The result, when uncertainties are included, is the maximum postulated transient $F_Q(Z)$, which is then compared to the $F_Q(Z)$ limit.

WCAP-17661-P-A (Reference 15) improves upon the CAOC F_Q Surveillance formulation by permitting adjustment of the surveillance to the target AO core conditions. Also, the improved CAOC F_Q Surveillance formulation incorporates the concept of operating spaces by providing the option of implementing a more restrictive CAOC operating space, which is defined as a unique combination of AFD band and control bank RILs, if the F_Q limit is exceeded rather than having to reduce power.

The relaxed axial offset control (RAOC) procedures described in WCAP-10216-P-A (Reference 13) were developed to provide wide control band widths and consequently, more operating flexibility. These wide operating limits, particularly at lower power levels, increase plant availability by allowing quicker plant startup and increased maneuvering flexibility without trip. This procedure has been modified to accommodate AP1000 MSHIM operation. It is applied to analysis of axial power distributions under MSHIM control for the purpose of defining the allowed normal operating space such that Condition I thermal margin limits are maintained and Condition II occurrences are adequately protected by the reactor protection system when the online monitoring system is out of service.

The purpose of this analysis is to find the widest permissible ΔI versus power operating space by analyzing a wide range of achievable xenon distributions, MSHIM/AO bank insertion, and power level.

The bounding analyses performed off line in anticipation of the online monitoring system being out of service is similar to that based on the relaxed axial offset control analysis, which uses a xenon reconstruction model described in WCAP-10216-P-A (Reference 13). This is a practical method which is used to define the power operating space allowed with AP1000 MSHIM operation. Each resulting power shape is analyzed to determine if loss-of-coolant accident constraints are met or exceeded.

The online monitoring system evaluates the effects of radial xenon distribution changes due to operational parameter changes continuously and therefore eliminates the need for overly conservative bounding evaluations when the online monitoring system is available. A detailed discussion of this effect may be found in WCAP-8385 (Reference 12). The calculated values have been increased by a factor of 1.05 for method uncertainty and a factor of 1.03 for the engineering factor F^{E}_{Q}.

The envelope drawn in Figure 4.3-14 represents an upper bound envelope on local power density versus elevation in the core. This envelope is a conservative representation of the bounding values of local power density.

The online monitoring system measures the core condition continuously and evaluates the thermal margin condition directly in terms of peak linear heat rate and margin to departure from nucleate boiling limitations directly.

Allowing for fuel densification effects, the average linear power at 3400 MW is 5.72 kW/ft. From Figure 4.3-14, the conservative upper bound value of normalized local power density, including uncertainty allowances, is 2.60 corresponding to a peak linear heat rate of 15.0 kW/ft at each core elevation at 101 percent power.

To determine reactor protection system setpoints with respect to power distributions, three categories of events are considered: rod control equipment malfunctions and operator errors of commission or omission. In evaluating these three categories of events, the core is assumed to be operating within the four constraints described above.

The first category comprises uncontrolled rod withdrawal (with rods moving in the normal bank sequence) for both AO and MSHIM banks. Also included are motions of the AO and MSHIM banks below their insertion limits, which could be caused, for example, by uncontrolled dilution or primary coolant cooldown. Power distributions are calculated throughout these occurrences, assuming short-term corrective action; that is, no transient xenon effects are considered to result from the malfunction. The event is assumed to occur from typical normal operating situations, which include normal xenon transients. It is further assumed in determining the power distributions that total core power level would be limited by reactor trip to below the overpower protection setpoint of nominally

118 percent rated thermal power. Since the study is to determine protection limits with respect to power and axial offset, no credit is taken for OTΔT or OPΔT trip setpoint reduction due to flux difference. The peak power density which can occur in such events, assuming reactor trip at or below 118 percent, is less than that required for fuel centerline melt, including uncertainties and densification effects.

The second category assumes that the operator mispositions the AO and/or MSHIM rod banks in violation of the insertion limits and creates short-term conditions not included in normal operating conditions.

The third category assumes that the operator fails to take action to correct a power distribution limit violation (such as boration/dilution transient) assuming automatic operation of the rod control system which will maintain constant reactor power.

For each of the above categories, the trip setpoints are designed so as not to exceed fuel centerline melt criteria as well as fuel mechanical design criteria.

The appropriate hot channel factors F_Q and $F^N_{\Delta H}$ for peak local power density and for DNB analysis at full power are based on analyses of possible operating power shapes and are addressed in the technical specifications.

The maximum allowable F_Q can be increased with decreasing power, as shown in the technical specifications. Increasing $F^N_{\Delta H}$ with decreasing power is permitted by the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits, as described in Subsection 4.4.4.3. The allowance for increased $F^N_{\Delta H}$ permitted is addressed in the technical specifications.

This becomes a design basis criterion which is used for establishing acceptable control rod patterns and control bank sequencing. Likewise, fuel loading patterns for each cycle are selected with consideration of this design criterion. The worst values of $F^N_{\Delta H}$ for possible rod configurations occurring in normal operation are used in verifying that this criterion is met. The worst values generally occur when the rods are assumed to be at their insertion limits. Operation with rod positions above the allowed rod insertion limits provides increased margin to the $F^N_{\Delta H}$ criterion. As discussed in Section 3.2 of WCAP-7912-P-A (Reference 14), it has been determined that the technical specifications limits are met, provided the above conditions are observed. These limits are taken as input to the thermal-hydraulic design basis, as described in Subsection 4.4.4.3.1.

When a situation is possible in normal operation which could result in local power densities in excess of those assumed as the precondition for a subsequent hypothetical accident, but which would not itself cause fuel failure, administrative controls and alarms are provided for returning the core to a safe condition. These alarms are described in Chapter 7.

The independence of the various individual uncertainties constituting the uncertainty factor on F_Q enables the uncertainty (F^U_Q) to be calculated by statistically combining the individual uncertainties on the limiting rod. The standard deviation of the resultant distribution of F^U_Q is determined by taking the square root of the sum of the variances of each of the contributing distributions WCAP-7308-L-P-A (Reference 7). The values for F^E_Q and F^N_U are 1.03 and 1.05, respectively. The value for the rod bow factor, F^B_Q, is 1.056, which accounts for the maximum F_Q penalty as a function of burnup due to rod bow effects.

4.3.2.2.7 Experimental Verification of Power Distribution Analysis

This subject is discussed in WCAP-7308-L-P-A (Reference 7) and WCAP-12472-P-A (Reference 4). A summary of these reports and the extension to include the fixed in-core instrumentation system is

given below. Power distribution related measurements are incorporated into the evaluation of calculated power distribution information using the in-core instrumentation processing algorithms contained within the online monitoring system. The processing algorithms contained within the online monitoring system are functionally identical to those historically used for the evaluation of power distribution measurements in Westinghouse PWRs. Advances in technology allow a complete functional integration of reaction rate measurement algorithms and the expected reaction rate predictive capability within the same software package. The predictive software integrated within the online monitoring system supplies accurate, detailed information of current reactor conditions. The historical algorithms are described in detail in WCAP-12472-P-A (Reference 4).

The measured versus calculational comparison is performed continuously by the online monitoring system throughout the core life. The online monitoring system operability requirements are specified in the technical specifications.

In a measurement of the reactor power distribution and the associated thermal margin limiting parameters, with the in-core instrumentation system described in Subsections 7.7.1 and 4.4.6, the following uncertainties must be considered:

A. Reproducibility of the measured signal

B. Errors in the calculated relationship between detector current and local power generation within the fuel bundle

C. Errors in the detector current associated with the depletion of the emitter material, manufacturing tolerances and measured detector depletion

D. Errors due to the inference of power generation some distance from the measurement thimble

The appropriate allowance for category A has been accounted for through the imposition of strict manufacturing tolerances for the individual detectors. This approach is accepted industry practice and has been used in PWRs with fixed in-core instrumentation worldwide. Errors in category B above are quantified by calculation and evaluation of critical experiment data on arrays of rods with simulated guide thimbles, control rods, burnable absorbers, etc. These critical experiments provide the quantification of errors of categories A and D above. Errors in category C due to depletion of emitter material are accounted for by direct depletion of the detectors as modeled by the monitoring system. A bounding variability is used in the uncertainty calculation to account for the difference between the actual and the tracked detector depletion in the methodology.

WCAP-7308-L-P-A (Reference 7) describes critical experiments performed at the Westinghouse Reactor Evaluation Center and measurements taken on two Westinghouse plants with movable fission chamber in-core instrumentation systems. The measurement aspects of the movable fission chamber share the previous uncertainty categories less category C which is independent of the other sources of uncertainty. WCAP-7308-L-P-A (Reference 7) concludes that the uncertainty associated with peak linear heat rate (F_Q*P) is less than five percent at the 95 percent confidence level with only five percent of the measurements greater than the inferred value.

In comparing measured power distributions (or detector currents) with calculations for the same operating conditions, it is not possible to isolate the detector reproducibility. Thus, a comparison between measured and predicted power distributions includes some measurement error. Such a comparison is given in Figure 4.3-15 for one of the maps used in WCAP-7308-L-P-A (Reference 7). Since the first publication of WCAP-7308-L-P-A, hundreds of measurements have been taken on reactors all over the world. These results confirm the adequacy of the five percent uncertainty allowance on the calculated peak linear heat rate (ALHR*F_Q*P).

A similar analysis for the uncertainty in hot rod integrated power $F_{\Delta H}$*P measurements results in an allowance of four percent at the equivalent of a 95 percent confidence level.

A measurement in the fourth cycle of a 157-assembly, 12-foot core is compared with a simplified one-dimensional core average axial calculation in Figure 4.3-16. This calculation does not give explicit representation to the fuel grids.

The accumulated data on power distributions in actual operation are basically of three types:

- Much of the data is obtained in steady-state operation at constant power in the normal operating configuration.
- Data with unusual values of axial offset are obtained as part of the ex-core detector calibration exercise performed monthly.
- Special tests have been performed in load follow and other transient xenon conditions which have yielded useful information on power distributions.

These data are presented in detail in WCAP-7912-P-A (Reference 14). Figure 4.3-17 contains a summary of measured values of F_Q as a function of axial offset for five plants from that report.

4.3.2.2.8 Testing

A series of physics tests are planned to be performed on the first core. These tests and the criteria for satisfactory results are described in Chapter 14. Since not all limiting situations can be created at beginning of life, the main purpose of the tests is to provide a check on the calculational methods used in the predictions for the conditions of the test. Tests performed at the beginning of each reload cycle are limited to verification of the selected safety-related parameters of the reload design.

4.3.2.2.9 Monitoring Instrumentation

The adequacy of instrument numbers, spatial deployment, required correlations between readings and peaking factors, calibration, and errors are described in WCAP-12472-P (Reference 4). The relevant conclusions are summarized in Subsection 4.3.2.2.7 and Subsection 4.4.6.

Provided the limitations given in Subsection 4.3.2.2.6 on rod insertion and flux difference are observed, the in-core and ex-core detector systems provide adequate monitoring of power distributions when the online monitoring system is out of service. Further details of specific limits on the observed rod positions and flux difference are given in the technical specifications, together with a discussion of their bases.

Limits for alarms and reactor trip are given in the technical specifications. Descriptions of the systems provided are given in Section 7.7.

4.3.2.3 Reactivity Coefficients

The kinetic characteristics of the reactor core determine the response of the core to changing plant conditions or to operator adjustments made during normal operation, as well as the core response during abnormal or accidental transients. These kinetic characteristics are quantified in reactivity coefficients. The reactivity coefficients reflect the changes in the neutron multiplication due to varying plant conditions, such as thermal power, moderator and fuel temperatures, coolant pressure, or void conditions, although the latter are relatively unimportant. Since reactivity coefficients change during the life of the core, ranges of coefficients are employed in transient analysis to determine the

response of the plant throughout life. The results of such simulations and the reactivity coefficients used are presented in Chapter 15.

The reactivity coefficients are calculated with approved nuclear methods. The effect of radial and axial power distribution on core average reactivity coefficients is implicit in those calculations and is not significant under normal operating conditions. For example, a skewed xenon distribution which results in changing axial offset by five percent typically changes the moderator and Doppler temperature coefficients by less than 0.01 pcm/°F. An artificially skewed xenon distribution which results in changing the radial $F^{N}_{\Delta H}$ by three percent typically changes the moderator and Doppler temperature coefficients by less than 0.03 pcm/°F and 0.001 pcm/°F, respectively. The spatial effects are accentuated in some transient conditions, for example, in postulated rupture of the main steam line and rupture of a rod cluster control assembly mechanism housing described in Subsections 15.1.5 and 15.4.8, and are included in these analyses.

The analytical methods and calculational models used in calculating the reactivity coefficients are given in Subsection 4.3.3. These models have been confirmed through extensive qualification efforts performed for core and lattice designs.

Quantitative information for calculated reactivity coefficients including fuel-Doppler coefficient, moderator coefficients (density, temperature, pressure, and void), and power coefficient, is given in the following sections.

4.3.2.3.1 Fuel Temperature (Doppler) Coefficient

The fuel temperature (Doppler) coefficient is defined as the change in reactivity per degree change in effective fuel temperature and is primarily a measure of the Doppler broadening of U-238 and Pu-240 resonance absorption peaks. Doppler broadening of other isotopes is also considered, but their contribution to the Doppler effect is small. An increase in fuel temperature increases the effective resonance absorption cross sections of the fuel and produces a corresponding reduction in reactivity.

The fuel temperature coefficient is calculated using approved nuclear methods. Moderator temperature is held constant, and the power level is varied. Spatial variation of fuel temperature is taken into account by calculating the effective fuel temperature as a function of power density, as discussed in Subsection 4.3.3.1.

A typical Doppler temperature coefficient is shown in Figure 4.3-18 as a function of the effective fuel temperature (at beginning of life and end of life conditions). The effective fuel temperature is lower than the volume-averaged fuel temperature, since the neutron flux distribution is non-uniform through the pellet and gives preferential weight to the surface temperature. A typical Doppler-only contribution to the power coefficient, defined later, is shown in Figure 4.3-19 as a function of relative core power. The integral of the differential curve in Figure 4.3-19 is the Doppler contribution to the power defect and is shown in Figure 4.3-20 as a function of relative power. The Doppler temperature coefficient becomes more negative as a function of life as the Pu-240 content increases, thus increasing the Pu-240 resonance absorption. The upper and lower limits of Doppler coefficient used in accident analyses are given in Chapter 15.

4.3.2.3.2 Moderator Coefficients

The moderator coefficient is a measure of the change in reactivity due to a change in specific coolant parameters, such as density/temperature, pressure, or void. The coefficients obtained are moderator density/temperature, pressure, and void coefficients.

4.3.2.3.2.1 Moderator Density and Temperature Coefficients

The moderator temperature coefficient is defined as the change in reactivity per degree change in the moderator temperature. The moderator density coefficient is defined as the change in reactivity per unit change in moderator density. Generally, the effects of the changes in moderator density and the temperature are considered together.

The soluble boron used in the reactor as a means of reactivity control also has an effect on the moderator temperature and density coefficients, since the soluble boron density and the water density are decreased when the coolant temperature rises. A decrease in the soluble boron density introduces a positive component in the moderator density coefficient. If the concentration of soluble boron is large enough, the net value of the moderator temperature coefficient may be positive.

The initial core hot boron concentration is sufficiently low that the moderator temperature coefficient is negative at operating temperatures with the burnable absorber loading specified. Discrete or integral fuel burnable absorbers can be used in reload cores to confirm the moderator temperature coefficient is negative over the range of power operation. The effect of control rods is to make the moderator temperature coefficient more negative, since the thermal neutron mean free path, and hence the volume affected by the control rods, increase with an increase in temperature.

Except for a period early in the fuel cycle when boron density is increased briefly to compensate for burnable poison rod depletion, with burnup, the moderator temperature coefficient becomes more negative, primarily as a result of boric acid dilution, but also to a significant extent from the effects of the buildup of plutonium and fission products.

The moderator temperature and density coefficients are calculated for a range of plant conditions by performing two group two- or three-dimensional calculations, in which the moderator temperature is varied by about ±5°F about each of the mean temperatures, resulting in density changes consistent with the temperature change. The moderator temperature coefficient is shown as a function of core temperature and boron concentration for the core in Figures 4.3-21 through 4.3-23. The temperature range covered is from cold, about 70°F, to about 550°F. Figure 4.3-24 shows the unrodded hot full-power moderator temperature coefficient plotted as a function of burnup for the initial cycle. The temperature coefficient corresponds to the unrodded critical boron concentration present at hot full power operating conditions.

The moderator coefficients presented here are calculated to describe the core behavior in normal and accident situations when the moderator temperature changes can be considered to affect the entire core.

4.3.2.3.2.2 Moderator Pressure Coefficient

The moderator pressure coefficient relates the change in moderator density, resulting from a reactor coolant pressure change, to the corresponding effect on neutron production. This coefficient is of much less significance than the moderator temperature coefficient. A change of 50 psi in pressure has approximately the same effect on reactivity as a one half degree change in moderator temperature. This coefficient can be determined from the moderator temperature coefficient by relating change in pressure to the corresponding change in density. The typical moderator pressure coefficient may be negative over a portion of the moderator temperature range at beginning of life (BOL) (-0.004 pcm/psi) but is always positive at operating conditions and becomes more positive during life (+0.3 pcm/psi, at end of life).

4.3.2.3.2.3 Moderator Void Coefficient

The moderator void coefficient relates the change in neutron multiplication to the presence of voids in the moderator. In a PWR, this coefficient is not very significant because of the low void content in the coolant. The core void content is less than one-half of one percent and is due to local or statistical boiling. The typical void coefficient varies from 50 pcm/percent void at BOL and at low temperatures to minus 250 pcm/percent void at EOL and at operating temperatures. The void coefficient at operating temperature becomes more negative with fuel burnup.

4.3.2.3.3 Power Coefficient

The combined effect of moderator temperature and fuel temperature change as the core power level changes is called the total power coefficient and is expressed in terms of reactivity change per percent power change. Since a three-dimensional calculation is performed in determining total power coefficients and total power defects, the axial redistribution reactivity component described in Subsection 4.3.2.4.3 is implicitly included. A typical power coefficient at beginning of life (BOL) and end of life (EOL) conditions is given in Figure 4.3-25.

The total power coefficient becomes more negative with burnup, reflecting the combined effect of moderator and fuel temperature coefficients with burnup. The power defect (integral reactivity effect) at BOL and EOL is given in Figure 4.3-26.

4.3.2.3.4 Comparison of Calculated and Experimental Reactivity Coefficients

Subsection 4.3.3 describes the comparison of calculated and experimental reactivity coefficients in detail.

Experimental evaluation of the reactivity coefficients will be performed during the physics startup tests described in Chapter 14.

4.3.2.3.5 Reactivity Coefficients Used in Transient Analysis

Table 4.3-2 gives the limiting values as well as typical best-estimate values for the reactivity coefficients for the initial cycle. The limiting values are used as design limits in the transient analysis. The exact values of the coefficient used in the analysis depend on whether the transient of interest is examined at the BOL or EOL, whether the most negative or the most positive (least negative) coefficients are appropriate, and whether spatial non-uniformity must be considered in the analysis. Conservative values of coefficients, considering various aspects of analysis, are used in the transient analysis. This is described in Chapter 15.

The reactivity coefficients shown in Figures 4.3-18 through 4.3-26 are typical best-estimate values calculated for the initial cycle. Limiting values are chosen to encompass the best-estimate reactivity coefficients, including the uncertainties given in Subsection 4.3.3.3 over appropriate operating conditions. The most positive, as well as the most negative, values are selected to form the design basis range used in the transient analysis. A direct comparison of the best-estimate and design limit values for the initial cycle is shown in Table 4.3-2. In many instances the most conservative combination of reactivity coefficients is used in the transient analysis even though the extreme coefficients assumed may not simultaneously occur at the conditions assumed in the analysis. The need for a reevaluation of any accident in a subsequent cycle is contingent upon whether the coefficients for that cycle fall within the identified range used in the analysis presented in Chapter 15 with due allowance for the calculational uncertainties given in Subsection 4.3.3.3. Control rod requirements are given in Table 4.3-3 for the initial cycle and for a hypothetical equilibrium cycle, since these are markedly different. These latter numbers are provided for information only.

4.3.2.4 Control Requirements

To establish the required shutdown margin stated in the COLR under conditions where a cooldown to ambient temperature is required, concentrated soluble boron is added to the coolant. Boron concentrations for several core conditions are listed in Table 4.3-2 for the initial cycle. For core conditions including refueling, the boron concentration is well below the solubility limit. The rod cluster control assemblies are employed to bring the reactor to the shutdown condition. The minimum required shutdown margin is given in the COLR.

The ability to meet the shutdown margin requirements for hot conditions is demonstrated for the initial cycle and for an equilibrium reload cycle by performing a bounding calculation, the results of which are shown in Table 4.3-3. Table 4.3-3 compares the difference between the rod cluster control assembly reactivity available with an allowance for the worst stuck rod with that required for control and protection purposes. The shutdown margin includes an allowance of seven percent for analytic uncertainties which assumes the use of silver-indium-cadmium rod cluster control assemblies. Use of a seven percent uncertainty allowance on rod cluster control assembly worth is discussed and shown to be acceptable in WCAP-9217 (Reference 17). The largest reactivity control requirement appears at the EOL when the moderator temperature coefficient reaches its peak negative value as reflected in the larger power defect.

Any available negative reactivity insertion from withdrawn tungsten GRCAs is conservatively excluded when determining the available shutdown margin at hot operating conditions, even though all GRCAs are released into the core on a reactor trip (Reference 70). Only silver-indium-cadmium control rods are assumed to insert when the reactor is tripped for purposes of demonstrating that adequate shutdown margin is available at hot operating conditions. As such, the use of a seven percent uncertainty allowance for the credited trip rod worth remains appropriate in Table 4.3-3. After the reactor is brought to a shut down condition, the presence of GRCAs which are confirmed to be inserted and which have met the applicable physics testing acceptance criteria may be credited in confirming that the required shutdown margin is maintained during any cooldown period and as the result of long term xenon decay (Reference 70).

During plant operation, the available shutdown margin for hot operating conditions is continuously confirmed by the online monitoring system, by comparing the operating soluble boron concentration at current core conditions to the shutdown boron concentration that would be required immediately following a reactor trip from those conditions. The required shutdown boron concentration used in this type of calculation is conservatively determined at the target shutdown reactivity condition, assuming that all control rods insert except for the 16 tungsten GRCAs and the highest worth silver-indium-cadmium RCCA.

The control rods are required to provide sufficient reactivity to account for the power defect from full power to zero power and to provide the required shutdown margin. The reactivity addition resulting from power reduction consists of contributions from Doppler effect, moderator temperature, flux redistribution, and reduction in void content as discussed below.

4.3.2.4.1 Doppler Effect

The Doppler effect arises from the broadening of U-238 and Pu-240 resonance cross-sections with an increase in effective pellet temperature. This effect is most noticeable over the range of zero power to full power due to the large pellet temperature increase with power generation. The Doppler effect is implicitly included in the total power defects shown in Table 4.3-3.

4.3.2.4.2 Variable Average Moderator Temperature

When the core is shut down to the hot zero-power condition, the average moderator temperature changes from the equilibrium full-load value determined by the steam generator and turbine characteristics (such as steam pressure, heat transfer, tube fouling) to the equilibrium no-load value, which is based on the steam generator shell side design pressure. The design change in temperature is conservatively increased to account for the control system dead band and measurement errors.

When the moderator coefficient is negative, there is a reactivity addition with power reduction. The moderator coefficient becomes more negative as the fuel depletes because the boron concentration is reduced. This effect is the major contributor to the increased requirement at EOL. The change in average moderator temperature is implicitly included in the total power defects shown in Table 4.3-3.

4.3.2.4.3 Redistribution

During full-power operation, the coolant density decreases with core height. This, together with partial insertion of control rods, results in less fuel depletion near the top of the core. Under steady-state conditions, the relative power distribution will be slightly asymmetric toward the bottom of the core. On the other hand, at hot zero-power conditions, the coolant density is uniform up the core, and there is no flattening due to Doppler effect. The result will be a flux distribution which at zero power can be skewed toward the top of the core. Since a three-dimensional calculation is performed in determining total power defect, flux redistribution is implicitly included in this calculation. The three-dimensional total power defects specified in Table 4.3-3 were calculated including the use of a conservatively skewed adverse axial xenon distribution which increases the redistribution effect.

4.3.2.4.4 Void Content

A small void content in the core is due to nucleate boiling at full power. The void collapse coincident with power reduction makes a small positive reactivity contribution which has been added to the calculated total power defects shown in Table 4.3-3.

4.3.2.4.5 Rod Insertion Allowance

The MSHIM and AO banks are operated within a prescribed band of travel to compensate for changes in temperature and axial offset which are caused by fuel depletion and power maneuvers as described in Subsection 4.3.2.4.16. In calculating the available shutdown margin at hot operating conditions, the pre-trip control rod insertion can affect both the available trip rod worth and the total power defect control requirements. In addition, since the tungsten GRCAs are assumed not to insert on a reactor trip (Reference 70), the initial gray rod positions assumed prior to the trip can also have a small effect on the worth of the silver-indium-cadmium control rods that insert after the trip. In the bounding calculations shown in Table 4.3-3, the effect of the most limiting allowed control rod insertion is implicitly included in the calculated trip rod worth and total power defect values reported in the table. The most limiting allowed control rod insertion was determined by performing a series of three-dimensional shutdown margin calculations over the range of allowed control rod motion, and selecting the conditions which resulted in the minimum calculated shutdown margin.

4.3.2.4.6 Installed Excess Reactivity for Depletion

Excess reactivity is installed at the beginning of each cycle to provide sufficient reactivity to compensate for fuel depletion and fission product buildup throughout the cycle. This reactivity is controlled by the addition of soluble boron to the coolant, control rod insertion, and by burnable absorbers when necessary. The soluble boron concentration for several core configurations and the unit boron worth are given in Tables 4.3-1 and 4.3-2 for the initial cycle. Since the excess reactivity for

burnup is balanced during operation by negative reactivity from the above sources, it is not included in control rod requirements.

4.3.2.4.7 Xenon and Samarium Poisoning

Changes in xenon and samarium concentrations in the core occur at a sufficiently slow rate, even following rapid power level changes, that the resulting reactivity change can be controlled by changing the gray and/or control rod insertion. (Also see Subsection 4.3.2.4.16).

4.3.2.4.8 pH Effects

Changes in reactivity due to a change in coolant pH, if any, are sufficiently small in magnitude and occur slowly enough to be controlled by the boron system WCAP-3696-8 (Reference 18).

4.3.2.4.9 Experimental Confirmation

Following a normal shutdown, the total core reactivity change during cooldown with a stuck rod has been measured on a 121-assembly, 10-foot-high core and a 121-assembly, 12-foot-high core. In each case, the core was allowed to cool down until it reached criticality simulating the steam line break accident. For the 10-foot core, the total reactivity change associated with the cooldown is over predicted by about 0.3-percent $\Delta\rho$ with respect to the measured result. This represents an error of about five percent in the total reactivity change and is about half the uncertainty allowance for this quantity. For the 12-foot core, the difference between the measured and predicted reactivity change is an even smaller 0.2 percent $\Delta\rho$. These measurements and others demonstrate the capability of the methods described in Subsection 4.3.3.

4.3.2.4.10 Control

Core reactivity is controlled by means of a chemical poison dissolved in the coolant, rod cluster control assemblies, gray rod cluster assemblies and burnable absorbers as described below.

4.3.2.4.11 Chemical Shim

Boron in solution as boric acid is used to control relatively slow reactivity changes associated with:

- The moderator temperature defect in going from cold shutdown at ambient temperature to the hot operating temperature at zero power
- Transient xenon and samarium reactivity effects following power changes
- The reactivity effects of fissile inventory depletion and buildup of long-life fission products
- The depletion of the burnable absorbers

The boron concentrations for various core conditions are presented in Table 4.3-2 for the initial cycle.

4.3.2.4.12 Rod Cluster Control Assemblies

The number of rod cluster control assemblies is shown in Table 4.3-1. The rod cluster control assemblies are used for shutdown and control purposes to offset fast reactivity changes associated with:

- The required shutdown margin in the hot zero power, stuck rod condition

- The reactivity compensation as a result of an increase in power above hot zero power (power defect, including Doppler and moderator reactivity changes)
- Unprogrammed fluctuations in boron concentration, coolant temperature, or xenon concentration (with rods not exceeding the allowable rod insertion limits)
- Reactivity changes resulting from load changes

The allowed control bank reactivity insertion is limited at full power to maintain shutdown capability. As the power level is reduced, control rod reactivity requirements are also reduced, and more rod insertion is allowed. The control bank position is monitored, and the operator is notified by an alarm if the limit is approached. The determination of the insertion limit uses conservative xenon distributions and axial power shapes. In addition, the rod cluster control assembly withdrawal pattern determined from the analyses is used in determining power distribution factors and in determining the maximum worth of an inserted rod cluster control assembly ejection accident. For further discussion, refer to the technical specifications on rod insertion limits.

Power distribution, rod ejection, and rod misalignment analyses are based on the arrangement of the shutdown and control groups of the rod cluster control assemblies shown in Figure 4.3-27. Shutdown rod cluster control assemblies are withdrawn before withdrawal of the control and AO banks is initiated. The approach to critical is initiated by using the chemical and volume control system to establish an appropriate boron concentration based upon the estimated critical condition then withdrawing the AO bank above the zero power insertion limit and finally withdrawing the control banks sequentially. The limits of rod insertion and further discussion on the basis for rod insertion limits are provided in the COLR.

4.3.2.4.13 Gray Rod Cluster Assemblies

The rod cluster control assembly control banks include four gray rod banks consisting of gray rod cluster assemblies (GRCAs). Gray rod cluster assemblies consist of 24 rodlets fastened at the top end to a common hub or spider. Geometrically, it is the same as a rod cluster control assembly except that the GRCA design uses tungsten encapsulated in a nickel-chromium-iron Alloy 718 sleeve as an absorber. The term gray rod refers to the reduced reactivity worth relative to that of a rod cluster control assembly consisting of 24 silver-indium-cadmium rodlets. The gray rod cluster assemblies are used in base load operation and load follow maneuvering and provide a mechanical shim reactivity mechanism which reduces the need for changes to the concentration of soluble boron (that is, chemical shim).

4.3.2.4.14 Burnable Absorbers

Discrete burnable absorber rods and integral fuel burnable absorber rods will be used to provide partial control of the excess reactivity available during the first operating cycle. In doing so, the burnable absorber loading controls peaking factors and prevents the moderator temperature coefficient from being positive at normal operating conditions. The burnable absorbers perform this function by reducing the requirement for soluble boron in the moderator at the beginning of the fuel cycle, as described previously. For purposes of illustration, the initial cycle burnable absorber pattern is shown in Figure 4.3-5. Figures 4.3-4a and 4.3-4b show the burnable absorber distribution within a fuel assembly for several burnable absorber patterns used in the 17 x 17 array. The boron in the rods is depleted with burnup but at a slow rate so that the peaking factor limits are not exceeded and the resulting critical concentration of soluble boron is such that the moderator temperature coefficient remains within the limits stated above for power operating conditions.

4.3.2.4.15 Peak Xenon Startup

Compensation for the peak xenon buildup may be accomplished using the boron control system. Startup from the peak xenon condition is accomplished with a combination of rod motion and boron dilution. The boron dilution can be made at any time, including during the shutdown period, provided the shutdown margin is maintained.

4.3.2.4.16 Load Follow Control and Xenon Control

During load follow maneuvers, power changes are primarily accomplished using control rod motion alone, as required. Control rod motion is limited by the control rod insertion limits as provided in the COLR and discussed in Subsections 4.3.2.4.12 and 4.3.2.4.5. The power distribution is maintained within acceptable limits through limitations on control rod insertion. Reactivity changes due to the changing xenon concentration are also controlled by rod motion. The soluble boron concentration may also be changed during large load change maneuvers or during extended reduced power operation to maintain the control rods in a more optimum range for power distribution control.

Rapid power increases (five percent/min) from part power during load follow operation are accomplished with rod motion.

The rod control system is designed to automatically provide the power and temperature control described above 30 percent rated power for most of the cycle length without the need to change boron concentration as a result of the load maneuver. The automated mode of operation is referred to as mechanical shim (MSHIM) because of the usage of mechanical means to control reactivity and power distribution simultaneously. MSHIM operation allows load maneuvering without boron change because of the degree of allowed insertion of the control banks in conjunction with the independent power distribution control of the axial offset (AO) control bank. The worth and overlap of the MA, MB, MC, MD, M1, and M2 control banks are designed such that the AO control bank insertion will always result in a monotonically decreasing axial offset. MSHIM operation uses the MA, MB, MC, MD, M1, and M2 control banks to maintain the programmed coolant average temperature throughout the operating power range. The AO control bank is independently modulated by the rod control system to maintain a nearly constant axial offset throughout the operating power range. The target axial offset used during MSHIM operation is established at a more negative value than the axial offset associated with the all rods out condition. The negative bias is necessary to maintain both positive and negative axial offset control effectiveness by the AO-bank. Operation with gray control rod banks (MA, MB, MC, and MD) inserted has less of an effect on the core axial power distribution than insertion of the black control rods banks (M1 and M2) and results in a smaller negative bias in the target axial offset. Load change operations that are large enough to require a black control rod bank to enter the core may require a more negative target axial offset to accomplish. However, the boron system can optionally be used to maintain operation in the more optimum range of gray rod motion during such maneuvers. The degree of control rod insertion under MSHIM operation allows rapid return to power without the need to change boron concentration.

Extended base load operation is performed by controlling axial offset to the target value using the AO control bank, and by controlling the coolant average temperature to the programmed value with the M-banks. Boron concentration changes are made periodically as the fuel depletes to reposition the M-banks and allow for a periodic exchange of the gray rod bank insertion sequence. MSHIM load follow and base load operations (including the gray rod bank insertion sequence exchanges) are considered Condition I normal operations.

4.3.2.4.17 Burnup

Control of the excess reactivity for burnup is accomplished using soluble boron, control rod insertion, and/or burnable absorbers. The boron concentration is limited during operating conditions to

maintain the moderator temperature coefficient within its specified limits. A sufficient burnable absorber loading is installed at the beginning of a cycle to give the desired cycle lifetime, without exceeding the boron concentration limit. The end of a fuel cycle is reached when the soluble boron concentration approaches the practical minimum boron concentration in the range of 0 to 10 ppm.

4.3.2.4.18 Rapid Power Reduction System

The reactor power control system is designed with the capability of responding to full load rejection without initiating a reactor trip using the normal rod control system, reactor control system, and the rapid power reduction system. Load rejections requiring greater than a fifty percent reduction of rated thermal power or the loss of a main feedwater pump train as indicated by the pump motor breaker positions initiates the rapid power reduction system when above a predetermined power level. The rapid power reduction system utilizes selected (either automatically or manually) control rod banks which are intentionally tripped to rapidly reduce reactor power into a range where the rod control and reactor control systems are sufficient to maintain stable plant operation. The consequences of accidental or inappropriate actuation of the rapid power reduction system are included in the cycle specific safety analysis and licensing process.

4.3.2.5 Control Rod Patterns and Reactivity Worth

The rod cluster control assemblies are designated by function as the control groups and the shutdown groups. The terms group and bank are used synonymously to describe a particular grouping of control assemblies. The rod cluster control assembly patterns are displayed in Figure 4.3-27. The control banks are labeled MA, MB, MC, MD, M1, M2, and AO with the MA, MB, MC, and MD banks comprised of gray rod cluster assemblies; and the shutdown banks are labeled S1, S2, S3, and S4. Each bank of more than four rod cluster control assemblies, although operated and controlled as a unit, is composed of two or more subgroups. The axial position of the rod cluster control assemblies may be controlled manually or automatically. The rod cluster control assemblies are dropped into the core following actuation of reactor trip signals.

Two criteria have been employed for selection of the control groups. First, the total reactivity worth must be adequate to meet the requirements specified in Table 4.3-3. Second, in view of the fact that these rods may be partially inserted at power operation, the total power peaking factor should be low enough to meet the power capability requirements. Analyses indicate that the first requirement can be met either by a single group or by two or more banks whose total worth equals at least the required amount. The axial power shape is more peaked following movement of a single group of rods worth three to four percent $\Delta\rho$. Therefore, control bank rod cluster control assemblies have been separated into several bank groupings. Typical control bank worth for the initial cycle are shown in Table 4.3-2.

The position of control banks for criticality under any reactor condition is determined by the concentration of boron in the coolant. On an approach to criticality, boron is adjusted so that criticality will be achieved with control rods above the insertion limit set by shutdown and other considerations. (See the technical specifications and COLR). Early in the cycle, there may also be a withdrawal limit at low power to maintain the moderator temperature coefficient within the specified limits for that power level.

Ejected rod worths for several different conditions are given in Subsection 15.4.8.

Allowable deviations due to misaligned control rods are discussed in the technical specifications.

A representative differential rod worth calculation for two banks of control rods withdrawn simultaneously (rod withdrawal accident) is given in Figure 4.3-28.

Calculation of control rod reactivity worth versus time following reactor trip involves both control rod velocity and differential reactivity worth. A representative example of the rod position versus time of travel after rod release is given in Figure 4.3-29. The actual rod position versus time of travel used in the safety analysis is given in Chapter 15. For nuclear design purposes, the reactivity worth versus rod position is calculated by a series of steady-state calculations at various control positions, assuming the rods out of the core as the initial position in order to minimize the initial reactivity insertion rate. Also, to be conservative, the rod of highest worth is assumed stuck out of the core, and the flux distribution (and thus reactivity importance) is assumed to be skewed to the bottom of the core. A representative result of these calculations is shown in Figure 4.3-30.

The shutdown groups provide additional negative reactivity to establish adequate shutdown margin. Shutdown margin is the amount by which the core would be subcritical at hot shutdown if the rod cluster control assemblies were tripped, but assuming that the highest worth assembly remained fully withdrawn and no changes in xenon or boron took place. The loss of control rod worth due to the depletion of the absorber material is negligible.

The values given in Table 4.3-3 show that the available reactivity in withdrawn rod cluster control assemblies provides the design bases minimum shutdown margin, allowing for the highest worth cluster to be at its fully withdrawn position. An allowance for the uncertainty in the calculated worth of N-1 rods is made before determination of the shutdown margin.

4.3.2.6 Criticality of the Reactor During Refueling

The basis for maintaining the reactor subcritical during refueling is presented in Subsection 4.3.1.5, and a discussion of how control requirements are met is given in Subsections 4.3.2.4 and 4.3.2.5.

4.3.2.6.1 Criticality Design Method Outside the Reactor

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer, shipping, and storage facilities and by administrative control procedures. The two principal methods of preventing criticality are limiting the fuel assembly array size and limiting assembly interaction by fixing the minimum separation between assemblies and/or inserting neutron poisons between assemblies. The details of the methodology used for the new fuel rack and spent fuel rack criticality analysis are included in the Chapter 9.1 references.

The design criteria are consistent with General Design Criterion (GDC) 62, Reference 19, and NRC guidance given in Reference 20. The applicable 10 CFR Part 50.68 requirements are as follows:

1. The maximum K-effective value, including all biases and uncertainties, must be less than 0.95 with soluble boron credit and less than 1.0 with full density unborated water. Note this design criterion is provided in 10 CFR Part 50.68, Item 4 of Paragraph b. Note that the specific terminology is:

   “If no credit for soluble boron is taken, the k-effective of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with unborated water. If credit is taken for soluble boron, the k-effective of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with borated water, and the k-effective must remain below 1.0 (subcritical), at a 95 percent probability, 95 percent confidence level, if flooded with unborated water.”

2. The maximum enrichment of fresh fuel assemblies must be less than or equal to 5.0 weight-percent U-235. Note this design criterion is provided in 10 CFR Part 50.68, Item 7 of Paragraph b. Note that the specific terminology is:

"The maximum nominal U–235 enrichment of the fresh fuel assemblies is limited to five (5.0) percent by weight."

The following conditions are assumed in meeting this design bases:

- The fuel assembly contains the highest enrichment authorized without any control rods or non-integral burnable absorber(s) and is at its most reactive point in life.
- For flooded conditions, the moderator is pure water at the temperature within the design limits which yields the largest reactivity.
- The array is either infinite in lateral extent or is surrounded by a conservatively chosen reflector, whichever is appropriate for the design.
- Mechanical uncertainties are treated by combining both the worst-case bounding value and sensitivity study approaches.
- Credit is taken for the neutron absorption in structural materials and in solid materials added specifically for neutron absorption.

Fuel depletion analyses during core operation were performed with CASMO-4 (using the 70-group cross-section library), a two-dimensional multigroup transport theory code based on capture probabilities (Reference 53). CASMO-4 is used to determine the isotopic composition of the spent fuel. In addition, the CASMO-4 calculations are restarted in the storage rack geometry, yielding the two-dimensional infinite multiplication factor (k_{inf}) for the storage rack to determine the reactivity effect of fuel and rack tolerances, temperature variation, and to perform various studies.

The design method which determines the criticality safety of fuel assemblies outside the reactor uses the MCNP4a code (Reference 21), with continuous energy cross-sections based on ENDF/B-V and ENDF/B-VI.

A set of 62 critical experiments has been analyzed using the above method to demonstrate its applicability to criticality analysis and to establish the method bias and uncertainty. The benchmark experiments cover a wide range of geometries, materials, and enrichments, all of them adequate for qualifying methods to analyze light water reactor lattices (References 22 to 28, and 65 to 68).

The analysis of the 62 critical experiments results in an average K_{eff} of 0.9991. Comparison with the measured values results in a method bias of 0.0009. The standard deviation of the set of reactivities is 0.0011. The 95/95 tolerance factor is conservatively set to 2.0.

The analytical methods employed herein conform with ANSI N18.2 (Reference 3), Section 5.7, Fuel Handling System; ANSI N16.9 (Reference 29), NRC Standard Review Plan, Subsection 9.1.2, the NRC guidance, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications" (Reference 30).

4.3.2.6.2 Soluble Boron Credit Methodology

The minimum soluble boron requirement under normal and accident conditions must be determined to show that the reactivity of the spent fuel racks remains below 0.95. This is achieved by crediting a discrete amount of soluble boron and then determining by linear interpolation the appropriate amount of soluble boron necessary to reduce the maximum K_{eff} to 0.95 with all uncertainties and biases included.

4.3.2.7 Stability

4.3.2.7.1 Introduction

The stability of the PWR cores against xenon-induced spatial oscillations and the control of such transients are discussed extensively in References 11, 31, 32, and 33. A summary of these reports is given in the following discussion, and the design bases are given in Subsection 4.3.1.6.

In a large reactor core, xenon-induced oscillations can take place with no corresponding change in the total power of the core. The oscillation may be caused by a power shift in the core which occurs rapidly by comparison with the xenon-iodine time constants. Such a power shift occurs in the axial direction when a plant load change is made by control rod motion and results in a change in the moderator density and fuel temperature distributions. Such a power shift could occur in the diametral plane of the core as a result of abnormal control action.

Due to the negative power coefficient of reactivity, PWR cores are inherently stable to oscillations in total power. Protection against total power instabilities is provided by the control and protection system, as described in Section 7.7. Hence, the discussion on the core stability will be limited to xenon-induced spatial oscillations.

4.3.2.7.2 Stability Index

Power distributions, either in the axial direction or in the X-Y plane, can undergo oscillations due to perturbations introduced in the equilibrium distributions without changing the total core power. The harmonics and the stability of the core against xenon-induced oscillations can be determined in terms of the eigenvalue of the first flux harmonics. Writing the eigenvalue ξ of the first flux harmonic as:

$$\xi = b + ic \tag{1}$$

Then b is defined as the stability index and $T = 2\pi/c$ as the oscillation period of the first harmonic. The time dependence of the first harmonic $\delta\phi$ in the power distribution can now be represented as:

$$\delta\phi(t) = A\,e^{\xi t} = a\,e^{bt}\cos ct \tag{2}$$

where A and a are constants. The stability index can also be obtained approximately by:

$$b = \frac{1}{T}\ln\frac{A_{n+1}}{A_n} \tag{3}$$

where A_n and A_{n+1} are the successive peak amplitudes of the oscillation and T is the time period between the successive peaks.

4.3.2.7.3 Prediction of the Core Stability

The core described in this report has an active fuel length that is 24 inches longer (nominal) than that for previous Westinghouse PWRs licensed in the U.S. with 157 fuel assemblies. For this reason, it is expected that this core will be as stable as the 12-foot designs with respect to radial and diametral xenon oscillations since the radial core dimensions have not changed. This core will be slightly less stable than the 12-foot, 157 assembly cores with respect to axial xenon oscillations because the active core height has been increased by 24 inches. The effect of this increase will be to decrease the burnup at which the axial stability index becomes zero (Subsection 4.3.2.7.4 below). The moderator temperature coefficients and the Doppler temperature coefficients of reactivity will be similar to those of previous designs. Control banks included in the core design are sufficient to

dampen any xenon oscillations that may occur. Free axial xenon oscillations are not allowed to occur for a core of any height, except during special tests as described in Subsection 4.3.2.7.4.

4.3.2.7.4 Stability Measurements

4.3.2.7.4.1 Axial Measurements

Two axial xenon transient tests conducted in a PWR with a core height of 12 feet and 121 fuel assemblies are reported in WCAP-7964 (Reference 34) and are discussed here. The tests were performed at approximately 10 percent and 50 percent of cycle life.

Both a free-running oscillation test and a controlled test were performed during the first test. The second test at mid-cycle consisted of a free-running oscillation test only. In each of the free-running oscillation tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of the lead control bank and the subsequent oscillation period was monitored. In the controlled test conducted early in the cycle, the part-length rods were used to follow the oscillations to maintain an axial offset within the prescribed limits. The axial offset of power was obtained from the ex-core ion chamber readings (which had been calibrated against the in-core flux maps) as a function of time for both free-running tests, as shown in Figure 12 of WCAP-7964 (Reference 34).

The total core power was maintained constant during these spatial xenon tests, and the stability index and the oscillation period were obtained from a least-square fit of the axial offset data in the form of equation 2. The axial offset of power is the quantity that properly represents the axial stability in the sense that it essentially eliminates any contribution from even-order harmonics, including the fundamental mode. The conclusions of the tests follow:

- The core was stable against induced axial xenon transients, at the core average burnups of both 1550 MWD/MTU and 7700 MWD/MTU. The measured stability indices are -0.041 h^{-1} for the first test and - 0.014 h^{-1} for the second test. The corresponding oscillation periods are 32.4 and 27.2 hours, respectively.

- The reactor core becomes less stable as fuel burnup progresses, and the axial stability index is essentially zero at 12,000 MWD/MTU. However, the movable control rod systems can control axial oscillations, as described in Subsection 4.3.2.7.3.

4.3.2.7.4.2 Measurements in the X-Y Plane

Two X-Y xenon oscillation tests were performed at a PWR plant with a core height of 12 feet and 157 fuel assemblies. The first test was conducted at a core average burnup of 1540 MWD/MTU and the second at a core average burnup of 12,900 MWD/MTU. Both of the X-Y xenon tests show that the core was stable in the X-Y plane at both burnups. The second test shows that the core became more stable as the fuel burnup increased, and Westinghouse PWRs with 121 and 157 assemblies are stable throughout their burnup cycles. The results of these tests are applicable to the 157-assembly AP1000 core, as discussed in Subsection 4.3.2.7.3.

In each of the two X-Y tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of one rod cluster control unit located along the diagonal axis. Following the perturbation, the uncontrolled oscillation was monitored, using the movable detector and thermocouple system and the ex-core power range detectors. The quadrant tilt difference (QTD) is the quantity that properly represents the diametral oscillation in the X-Y plane of the reactor core in that the differences of the quadrant average powers over two symmetrically opposite quadrants essentially eliminates the contribution to the oscillation from the azimuthal mode. The quadrant tilt difference data were fitted in the form of equation 2 of Subsection 4.3.2.7.2 through a least-square

method. A stability index of - 0.076 hr^{-1} (per hour) with a period of 29.6 hr was obtained from the thermocouple data shown in Figure 4.3-31.

It was observed in the second X-Y xenon test that the PWR core with 157 fuel assemblies had become more stable due to an increased fuel depletion, and the stability index was not determined.

4.3.2.7.5 Comparison of Calculations with Measurements

The direct simulation of axial offset data was carried out using a licensed one-dimensional code (WCAP-7048-P-A (Reference 35)). The analysis of the X-Y xenon transient tests was performed in an X-Y geometry, using a licensed few group two-dimensional code (WCAP-7213-A (Reference 36)). Both of these codes solve the two-group, time-dependent neutron diffusion equation with time-dependent xenon and iodine concentrations. The fuel temperature and moderator density feedback is limited to a steady-state model. The X-Y calculations were performed in an average enthalpy plane.

The detailed experimental data during the tests, including the reactor power level, the enthalpy rise, and the impulse motion of the control rod assembly, as well as the plant follow burnup data, were closely simulated in the study.

The results of the stability calculation for the axial tests are compared with the experimental data in Table 4.3-5. The calculations show conservative results for both of the axial tests with a margin of approximately 0.01 hr^{-1} in the stability index.

An analytical simulation of the first X-Y xenon oscillation test shows a calculated stability index of - 0.081 hr^{-1}, in good agreement with the measured value of - 0.076 hr^{-1}. As indicated earlier, the second X-Y xenon test showed that the core had become more stable compared to the first test, and no evaluation of the stability index was attempted. This increase in the core stability in the X-Y plane due to increased fuel burnup is due mainly to the increased magnitude of the negative moderator temperature coefficient.

Previous studies of the physics of xenon oscillations, including three-dimensional analysis, are reported in a series of topical reports (References 31, 32, and 33). A more detailed description of the experimental results and analysis of the axial and X-Y xenon transient tests is presented in WCAP-7964 (Reference 34) and Section 1 of WCAP-8768 (Reference 37).

4.3.2.7.6 Stability Control and Protection

The online monitoring system provides continuous indication of current power distributions and provides guidance to the plant operator as to the timing and most appropriate action(s) to maintain stable axial power distributions. In the event the online monitoring system is out of service, the ex-core detector system is utilized to provide indications of xenon-induced spatial oscillations. The readings from the ex-core detectors are available to the operator and also form part of the protection system.

4.3.2.7.6.1 Axial Power Distribution

The rod control system automatically maintains axial power distribution within very tight axial offset bands as part of normal operation. The AO control bank is specifically designed with sufficient worth to be capable of maintaining essentially constant axial offset over the power operating range. The rod control system is also allowed to be operated in manual control in which case the operator is instructed to maintain an axial offset within a prescribed operating band, based on the ex-core detector readings. Should the axial offset be permitted to move far enough outside this band, the

protection limit is encroached, and the turbine power is automatically reduced or a reactor trip signal generated, or both.

As fuel burnup progresses, PWR cores become less stable to axial xenon oscillations. However, free xenon oscillations are not allowed to occur, except for special tests. The AO control bank is sufficient to dampen and control any axial xenon oscillations present. Should the axial offset be inadvertently permitted to move far enough outside the allowed band due to an axial xenon oscillation or for any other reason, the OTΔT and/or OPΔT protection setpoint including the axial offset compensation is reached and the turbine power is automatically reduced and/or a reactor trip signal is generated.

4.3.2.7.6.2 Radial Power Distribution

The core described herein is calculated to be stable against X-Y xenon-induced oscillations during the core life.

The X-Y stability of large PWRs has been further verified as part of the startup physics test program for PWR cores with 193 fuel assemblies. The measured X-Y stability of the cores with 157 and 193 assemblies was in close agreement with the calculated stability, as discussed in Subsections 4.3.2.7.4 and 4.3.2.7.5. In the unlikely event that X-Y oscillations occur, backup actions are possible and would be implemented, if necessary, to increase the natural stability of the core. This is based on the fact that several actions could be taken to make the moderator temperature coefficient more negative, which would increase the stability of the core in the X-Y plane.

Provisions for protection against non-symmetric perturbations in the X-Y power distribution that could result from equipment malfunctions are made in the protection system design. This includes control rod drop, rod misalignment, and asymmetric loss of coolant flow.

A more detailed discussion of the power distribution control in PWR cores is presented in WCAP-7811 (Reference 11) and WCAP-8385 (Reference 12).

4.3.2.8 Vessel Irradiation

A review of the methods and analyses used in the determination of neutron and gamma ray flux attenuation between the core and the pressure vessel is provided below. A more complete discussion on the pressure vessel irradiation and surveillance program is given in Section 5.3.

The materials that serve to attenuate neutrons originating in the core and gamma rays from both the core and structural components consist of the core shroud, core barrel and associated water annuli. These are within the region between the core and the pressure vessel.

In general, few group neutron diffusion theory codes are used to determine fission power density distributions within the active core, and the accuracy of these analyses is verified by in-core measurements on operating reactors. Region and rodwise power-sharing information from the core calculations is then used as source information in two-dimensional transport calculations which compute the flux distributions throughout the reactor.

The neutron flux distribution and spectrum in the various structural components vary significantly from the core to the pressure vessel. Representative values of the neutron flux distribution and spectrum are presented in Table 4.3-6.

As discussed in Section 5.3, the irradiation surveillance program utilizes actual test samples to verify the accuracy of the calculated fluxes at the vessel.

4.3.3 Analytical Methods

Calculations required in nuclear design consist of three distinct types, which are performed in sequence:

1. Determination of effective fuel temperatures
2. Generation of few-group cross sections
3. Space-dependent, few-group diffusion calculations

These calculations are carried out by computer codes which can be executed individually. Most of the codes required have been linked to form an automated design sequence which minimizes design time, avoids errors in transcription of data, and standardizes the design methods.

4.3.3.1 Fuel Temperature (Doppler) Calculations

Temperatures vary radially within the fuel rod, depending on the heat generation rate in the pellet; the conductivity of the materials in the pellet, gap, and clad; and the temperature of the coolant.

The fuel temperatures for use in most nuclear design Doppler calculations are obtained from a simplified version of the Westinghouse fuel rod design model described in Subsection 4.2.1.3, which considers the effect of radial variation of pellet conductivity, expansion coefficient and heat generation rate, elastic deflection of the clad, and a gap conductance which depends on the initial fill gas, the hot open gap dimension, and the fraction of the pellet over which the gap is closed. The fraction of the gap assumed closed represents an empirical adjustment used to produce close agreement with observed reactivity data at beginning of life. Further gap closure occurs with burnup and accounts for the decrease in Doppler defect with burnup which has been observed in operating plants. For detailed calculations of the Doppler coefficient, such as for use in xenon stability calculations, a more sophisticated temperature model is used, which accounts for the effects of fuel swelling, fission gas release, and plastic clad deformation.

Radial power distributions in the pellet as a function of burnup are obtained from LASER (WCAP-6073, Reference 38) calculations.

The effective U-238 temperature for resonance absorption is obtained from the radial temperature distribution by applying a radially dependent weighing function. The weighing function was determined from REPAD (WCAP-2048, Reference 39) Monte Carlo calculations of resonance escape probabilities in several steady-state and transient temperature distributions. In each case, a flat pellet temperature was determined which produced the same resonance escape probability as the actual distribution. The weighing function was empirically determined from these results.

The effective Pu-240 temperature for resonance absorption is determined by a convolution of the radial distribution of Pu-240 densities from LASER burnup calculations and the radial weighing function. The resulting temperature is burnup dependent, but the difference between U-238 and Pu-240 temperatures, in terms of reactivity effects, is small.

The effective pellet temperature for pellet dimensional change is that value which produces the same outer pellet radius in a virgin pellet as that obtained from the temperature model. The effective clad temperature for dimensional change is its average value.

The temperature calculational model has been validated by plant Doppler defect data, as shown in Table 4.3-7, and Doppler coefficient data, as shown in Figure 4.3-32. Stability index measurements also provide a sensitive measure of the Doppler coefficient near full power (Subsection 4.3.2.7).

4.3.3.2 Macroscopic Group Constants

PHOENIX-P (WCAP-11596-P-A, Reference 40) and PARAGON (WCAP-16045-P-A, Reference 69) have been used for generating the macroscopic cross sections needed for the spatial few group codes. PHOENIX-P, PARAGON, or other NRC approved lattice codes will be used for reload designs.

PHOENIX-P has been approved by the NRC as a lattice code for the generation of macroscopic and microscopic few group cross sections for PWR analysis. (See WCAP-11596-P-A, Reference 40). PHOENIX-P is a two-dimensional, multigroup, transport-based lattice code capable of providing necessary data for PWR analysis. Since it is a dimensional lattice code, PHOENIX-P does not rely on pre-determined spatial/spectral interaction assumptions for the heterogeneous fuel lattice and can provide a more accurate multigroup spatial flux solution than versions (ARK) of LEOPARD/CINDER.

The solution for the detailed spatial flux and energy distribution is divided into two major steps in PHOENIX-P (See References 40 and 41). First, a two-dimensional fine energy group nodal solution is obtained, coupling individual subcell regions (e.g., pellet, clad and moderator) as well as surrounding pins, using a method based on Carlvik's collision probability approach and heterogeneous response fluxes which preserve the heterogeneous nature of the pin cells and their surroundings. The nodal solution provides an accurate and detailed local flux distribution, which is then used to homogenize the pin cells spatially to few groups.

Then, a standard S_4 discrete ordinates calculation solves for the angular distribution, based on the group-collapsed and homogenized cross sections from the first step. These S_4 fluxes normalize the detailed spatial and energy nodal fluxes, which are then used to compute reaction rates, power distributions and to deplete the fuel and burnable absorbers. A standard B1 calculation evaluates the fundamental mode critical spectrum, providing an improved fast diffusion coefficient for the core spatial codes.

PHOENIX-P employs a 70 energy group library derived mainly from the ENDF/B-VI files (Reference 71). This library was designed to capture the integral properties of the multigroup data properly during group collapse and to model important resonance parameters properly. It contains neutronics data necessary for modelling fuel, fission products, cladding and structural materials, coolant, and control and burnable absorber materials present in PWRs.

Group constants for burnable absorber cells, RCCA cells, guide thimbles and instrumentation thimbles, or other non-fuel cells, can be obtained directly from PHOENIX-P without any adjustments such as those required in the cell or 1D lattice codes.

PHOENIX-P has been validated through an extensive qualification effort which includes calculation-measurement comparison of the Strawbridge-Barry critical experiments (See References 42 and 43), the KRITZ high temperature criticals (Reference 44), the AEC sponsored B&W criticals (References 45 through 47) and measured actinide isotopic data from fuel pins irradiated in the Saxton and Yankee Rowe cores (References 48 through 52). In addition, calculation-measurement comparisons have been made to operating reactor data measured during startup tests and during normal power operation.

Validation of the cross section method is based on analysis of critical experiments, isotopic data, plant critical boron concentration data, and control rod worth measurement data such as that shown in Table 4.3-8.

Confirmatory critical experiments on burnable absorber rods are described in WCAP-7806 (Reference 42).

Group constants for tungsten GRCAs are generated using the PARAGON lattice code. Like PHOENIX-P, PARAGON is a two-dimensional, multigroup, transport-based lattice code capable of providing necessary data for PWR analysis and is approved by the NRC in Reference 69. WCAP-16943-P-A (Reference 70) contains a description of the nuclear methods for modeling tungsten and PARAGON benchmark results to Monte-Carlo simulations for assemblies containing tungsten GRCAs.

The PARAGON lattice code is also capable of generating all of the group constants generated by PHOENIX-P, and has been benchmarked and qualified to the same degree as PHOENIX-P. The NRC has approved the use of PARAGON as an alternative method for generating all macroscopic and microscopic group constants for uranium fueled cores (Reference 69). The primary difference between PARAGON and PHOENIX-P is that PARAGON uses Collision Probability theory with the interface current method to solve the integral transport equation. PARAGON also allows increased flexibility in modeling the exact assembly and pin cell geometry. The group constants generated by PARAGON are coupled to the spatial few-group code using the NEXUS nuclear data methodology (Reference 72).

4.3.3.3 Spatial Few-Group Diffusion Calculations

The 3D ANC code (see WCAP-10965-P-A, References 57 and 73) permits the introduction of advanced fuel designs with axial heterogeneities, such as axial blankets and part-length burnable absorbers, and allows such features to be modeled explicitly. The three dimensional nature of this code provides both radial and axial power distribution. For some applications, the updated version APOLLO (see WCAP-13524 Reference 60) of the PANDA code (see WCAP-7048-P-A Reference 35) may be used for axial calculations, and a two-dimensional collapse of 3D ANC that properly accounts for the three-dimensional features of the fuel may be used for X-Y calculations.

Spatial few group calculations are carried out to determine the critical boron concentrations and power distributions. The moderator coefficient is evaluated by varying the inlet temperature in the same kind of calculations as those used for power distribution and reactivity predictions.

Validation of the reactivity calculations is associated with validation of the group constants themselves, as discussed in Subsection 4.3.3.2. Validation of the Doppler calculations is associated with the fuel temperature validation discussed in Subsection 4.3.3.1. Validation of the moderator coefficient calculations is obtained by comparison with plant measurements at hot zero power conditions, similar to that shown in Table 4.3-9.

Axial calculations may be used in place of the full three-dimensional nodal model to determine differential control rod worth curves (reactivity versus rod insertion) and to demonstrate load follow capability. Group constants are obtained from the three-dimensional nodal model by flux-volume weighing on an axial slicewise basis. Radial bucklings are determined by varying parameters in the buckling model while forcing the one-dimensional model to reproduce the axial characteristics (axial offset, midplane power) of the three-dimensional model.

Validation of the spatial codes for calculating power distributions involves the use of in-core and ex-core detectors and is discussed in Subsection 4.3.2.2.7.

As discussed in Subsection 4.3.3.2, calculation-measurement comparisons have been made to operating reactor data measured during startup tests and during normal power operation. These comparisons include a variety of core geometries and fuel loading patterns, and incorporate a reasonable extreme range of fuel enrichment, burnable absorber loading, and cycle burnup. Qualification data identified in References 40, 69, and 72 indicate small mean and standard deviations relative to measurement which are equal to or less than those found in previous reviews of

similar or parallel approved methodologies. For the reload designs the spatial codes described above, other NRC approved codes, or both are used.

4.3.4 Combined License Information

Changes to the reference design of the fuel, burnable absorber rods, rod cluster assemblies, or initial core design from that presented in the DCD are addressed in APP-GW-GLR-059 (Reference 64).

4.3.5 References

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Table 4.3-1 (Sheet 1 of 3)
[*REACTOR CORE DESCRIPTION (FIRST CYCLE)*]*

Active core	
Equivalent diameter (in.)	*119.7*
Active fuel height first core (in.), cold	*168*
Height-to-diameter ratio	*1.40*
Total cross section area (ft^2)	*78.14*
H_2O/U molecular ratio, cell, cold	*2.40*
Reflector thickness and composition	
Top - water plus steel (in.)	*~10*
Bottom - water plus steel (in.)	*~10*
Side - water plus steel (in.)	*~15*
Fuel assemblies	
Number	*157*
Rod array	*17 x 17*
Rods per assembly	*264*
Rod pitch (in.)	*0.496*
Overall transverse dimensions (in.)	*8.426 x 8.426*
Fuel weight, as UO_2 (lb)	*211,588*
Zircaloy clad weight (lb)	*43,105*
Number of grids per assembly	
Top and bottom - (Ni-Cr-Fe Alloy 718)	*2[(a)]*
Intermediate	*8 ZIRLO®*
Intermediate flow mixing (IFM)	*4 ZIRLO*
Protective	*1 (Ni-Cr-Fe Alloy 718)*
Number of guide thimbles per assembly	*24*
Composition of guide thimbles	*ZIRLO*
Diameter of guide thimbles, upper part (in.)	*0.442 ID x 0.482 OD*
Diameter of guide thimbles, lower part (in.)	*0.397 ID x 0.482 OD*
Diameter of instrument guide thimbles (in.)	*0.442 ID x 0.482 OD*

Note:
(a) The top and bottom grids will be fabricated of nickel-chromium-iron Alloy 718.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 4.3-1 (Sheet 2 of 3)
[*REACTOR CORE DESCRIPTION (FIRST CYCLE)*]*

Fuel rods	
Number	*41,448*
Outside diameter (in.)	*0.374*
Diameter gap (in.)	*0.0065*
Clad thickness (in.)	*0.0225*
Clad material	*ZIRLO*
Fuel pellets	
Material	*UO_2 sintered*
Density (% of theoretical) (nominal)	*95.5*
Fuel enrichments, first core (average weight %, midzone / blanket)	
Region 1	*0.74 / ---*
Region 2	*1.58 / ---*
Region 3	*3.20 / 1.58*
Region 4	*3.776 / 3.20*
Region 5	*4.376 / 3.20*
Diameter (in.)	*0.3225*
Length (in.)	*0.387*
Mass of UO_2 per ft of fuel rod (lb/ft)	*0.366*
Rod Cluster Control Assemblies	
Neutron absorber	*Ag-In-Cd*
Diameter (in.)	*0.341*
Density (lb/in.^{3})	*Ag-In-Cd 0.367*
Cladding material	*Type 304 or 304L, cold-worked SS*
Cladding OD (in.)	*0.381*
Cladding thickness (in.)	*0.0185*
Number of clusters, full-length	*53*
Number of absorber rods per cluster	*24*
Gray Rod Cluster Assemblies	
Neutron absorber	*Tungsten/Alloy 718*
Diameter (in.)	*Tungsten 0.197 / Alloy 718 0.310*
Density (lb/in.^{3})	*Tungsten 0.695 / Alloy 718 0.296*
Cladding material	*Type 304 or 304L, cold-worked SS*
Cladding OD (in.)	*0.381*
Cladding thickness (in.)	*0.0255*
Number of clusters, full-length	*16*
Number of absorber rods per cluster	*24*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 4.3-1 (Sheet 3 of 3)
[*REACTOR CORE DESCRIPTION (FIRST CYCLE)*]*

Discrete Burnable absorber rods (first core)
Number 592
Material ..... Alumina Boron-Carbide
OD (in.) 0.381
Inner tube, OD (in.) 0.267
Clad material ..... Zircaloy
Inner tube material ..... Zircaloy
B_{10} content (mg/cm) 6.03
Absorber length (in.) ..... See Figure 4.3-4b
Integral Fuel Burnable Absorbers (first core)
Number 5632
Type ..... IFBA
Material ..... Boride Coating
B_{10} Content (Mg/cm) 0.773
Absorber length (in.) 152
Excess reactivity
Maximum fuel assembly $K\infty$ (cold, clean, unborated water) 1.392
Maximum core reactivity K_{eff} (cold, zero power, beginning of cycle, zero soluble boron) 1.201

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 4.3-2 (Sheet 1 of 2)
[*NUCLEAR DESIGN PARAMETERS (FIRST CYCLE)*]*

Core average linear power, including densification effects (kW/ft)		*5.72*
Total heat flux hot channel factor, F_Q		*≤2.60*
Nuclear enthalpy rise hot channel factor, $F^N_{\Delta H}$		*≤1.72*
Reactivity coefficients [(a)]	*Design Limits*	*Typical Best Estimate*
Doppler-only power coefficients (see Figure 15.0.4-1) (pcm/% power)[(b)]		
Upper curve	*-19.4 to -12.6*	*-14.6 to -9.0*
Lower curve	*-10.2 to -6.7*	*-12.4 to -8.9*
Doppler temperature coefficient (pcm/°F)[(b)]	*-3.5 to -1.0*	*-2.1 to -1.4*
Moderator temperature coefficient (pcm/°F)[(b)]	*0 to -40*	*0 to -35*
Boron coefficient (pcm/ppm)[(b)]	*-13.5 to -5.0*	*-11.3 to -7.2*
Rodded moderator density coefficient (pcm/g/cm^3)[(b)]	*≤ 0.47x10^5*	*≤ 0.45x10^5*
Delayed neutron fraction and lifetime, β_{eff}		*0.0075(0.0044)[(c)]*
Prompt Neutron Lifetime, ℓ^*, μ s		*19.8*
Control rods		
Rod requirements		*See Table 4.3-3*
Maximum ejected rod worth		*See Chapter 15*
Typical Bank worth HZP no overlap (pcm)[(b)]	*BOL, Xe Free*	*EOL, Eq. Xe*
MA Bank	*238*	*257*
MB Bank	*248*	*327*
MC Bank	*232*	*194*
MD Bank	*239*	*271*
M1 Bank	*686*	*757*
M2 Bank	*1363*	*1031*
AO Bank	*1627*	*1544*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 4.3-2 (Sheet 2 of 2)
[*NUCLEAR DESIGN PARAMETERS (FIRST CYCLE)*]*

Typical Hot Channel Factors $F^N_{\Delta H}$ [(g)]	*BOL*	*EOL*
Unrodded	*1.44*	*1.38*
MA bank	*1.48*	*1.44*
MA + MB banks	*1.51*	*1.43*
MA + MB + MC banks	*1.51*	*1.42*
MA + MB + MC + MD banks	*1.54*	*1.47*
MA + MB + MC + MD + M1 banks	*1.63*	*1.53*
AO bank	*1.68*	*1.61*
Typical Boron concentrations (ppm)		
Zero power, k_{eff} = 0.99, cold[(d)] RCCAs out		*1427*
Zero power, k_{eff} = 0.99, hot[(e)] RCCAs out		*1429*
Design basis refueling boron concentration		*2700*
Zero power, $k_{eff} \leq 0.95$, cold[(d)] RCCAs in		*1061*
Zero power, k_{eff} = 1.00, hot[(e)] RCCAs out		*1321*
Full power, no xenon, k_{eff} = 1.0, hot RCCAs out		*1160*
Full power, equilibrium xenon, k = 1.0, hot RCCAs out		*844*
Reduction with fuel burnup		
First cycle (ppm/(GWD/MTU))[(f)]		*See Figure 4.3-3*
Reload cycle (ppm/(GWD/MTU))		*~40*

Notes:

(a) Uncertainties are given in Subsection 4.3.3.3.

(b) 1 pcm = 10^{-5} $\Delta\rho$ where $\Delta\rho$ is calculated from two statepoint values of k_{eff} by ln (k_1/k_2).

(c) Bounding lower value used for safety analysis.

(d) Cold means 68°F, 1 atm.

(e) Hot means 557°F, 2250 psia.

(f) 1 GWD = 1000 MWD. During the first cycle, a large complement of burnable absorbers is present which significantly reduce the boron depletion rate compared to reload cycles.

(g) Rodded hot channel factors reflect full insertion of each bank at hot full power conditions. Rod Insertion limits for the first cycle prohibit full insertion of the M1 and AO-banks during full power operation. The Rodded hot channel factors for these conditions are therefore not indicative of permitted operating conditions at full rated thermal power.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 4.3-3
[*REACTIVITY REQUIREMENTS FOR ROD CLUSTER CONTROL ASSEMBLIES*]*

Requirement	*First Cycle BOL Worths (%Δρ)*	*First Cycle EOL Worth (%Δρ)*	*Equilibrium Cycle EOL Representative Worths (%Δρ)*
(1) Total power defect (%Δρ)[(a)]	*1.66*	*3.14*	*3.50*
Trip rod worth[(b)]	*7.24*	*6.02*	*6.41*
(2) Less 7%[(c)]	*6.73*	*5.60*	*5.96*
Shutdown Margin			
Calculated margin (2) – (1)	*5.07*	*2.46*	*2.46*
Required shutdown margin[(d)]	*1.60*	*1.60*	*1.60*

Notes:

(a) Includes Doppler, Moderator Temperature, Redistribution, and Void collapse reactivity effects associated with reducing power from full power to zero. Also includes the effect of inserted control rods at the most limiting allowed insertion point on the total power defect.

(b) Negative reactivity inserted by RCCAs on the reactor trip. Assumes RCCAs start at most limiting allowed insertion point and fully insert on the reactor trip except for the highest worth stuck RCCA. Also conservatively excludes negative reactivity from withdrawn GRCAs which are designed to insert on the reactor trip.

(c) 7 percent adjustment to accommodate uncertainties (this assumes the use of Ag-In-Cd RCCAs).

(d) The design basis minimum shutdown margin is 1.60 percent.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 4.3-4 Not Used

Table 4.3-5
Stability Index for Pressurized Water Reactor Cores with a 12-Foot Height

Burnup (MWD/MTU)	F_Z	C_B (ppm)	Axial Stability Index (h^{-1})	
			Experiment	Calculated
1550	1.34	1065	-0.0410	-0.0320
7700	1.27	700	-0.0140	-0.0060
5090[a]			-0.0325	-0.0255
			Radial Stability Index (h^{-1})	
			Experiment	Calculated
2250[b]			-0.0680	-0.0700

Notes:
(a) Four-loop plant, 12-foot core in cycle 1, axial stability test
(b) Four-loop plant, 12-foot core in cycle 1, radial (X-Y) stability test

Table 4.3-6
Typical Neutron Flux Levels (n/cm^2/s) at Full Power

	E ≥ 1.0 MeV	1.00 MeV > E ≥5.53 KeV	5.53 KeV > E ≥0.625 eV	E < 0.625 eV
Core center	1.12×10^{14}	1.76×10^{14}	1.28×10^{14}	5.47×10^{13}
Core outer radius at midheight	3.86×10^{13}	6.08×10^{13}	4.42×10^{13}	1.83×10^{13}
Core top, on axis	3.02×10^{13}	4.75×10^{13}	3.46×10^{13}	2.17×10^{13}
Core bottom, on axis	2.92×10^{13}	4.59×10^{13}	3.34×10^{13}	2.40×10^{13}
Pressure vessel ID azimuthal peak	4.71×10^{10}	8.4×10^{10}	5.56×10^{10}	5.32×10^{10}

Table 4.3-7
Comparison of Measured and Calculated Doppler Defects

Plant	Fuel	Core Burnup (MWD/MTU)	Measured (pcm)[(a)]	Calculated (pcm)
1	Air filled	1800	1700	1710
2	Air filled	7700	1300	1440
3	Air and helium filled	8460	1200	1210

Note:
(a) pcm = $10^5 \times \ln (k_2/k_1)$

Table 4.3-8
Comparison of Measured and Calculated AG-in-CD Rod Worth

2-Loop Plant, 121 Assemblies, 10-ft Core		Measured (pcm)	Calculated (pcm)
Group B		1885	1893
Group A		1530	1649
Shutdown group		3050	2917
ESADA critical, 0.69-in. pitch[(a)] 2 w/o PuO_2, 8% Pu-240, 9 control rods			
6.21-in. rod separation		2250	2250
2.07-in. rod separation		4220	4160
1.38-in. rod separation		4100	4019
Benchmark Critical Experiment Hafnium Control Rod Worth			
Control Rod Configuration	**No. of Fuel Rods**	**Measured[(b)] Worth (Δppm B-10)**	**Calculated[(b)] Worth (Δppm B-10)**
9 hafnium rods	1192	138.3	141.0

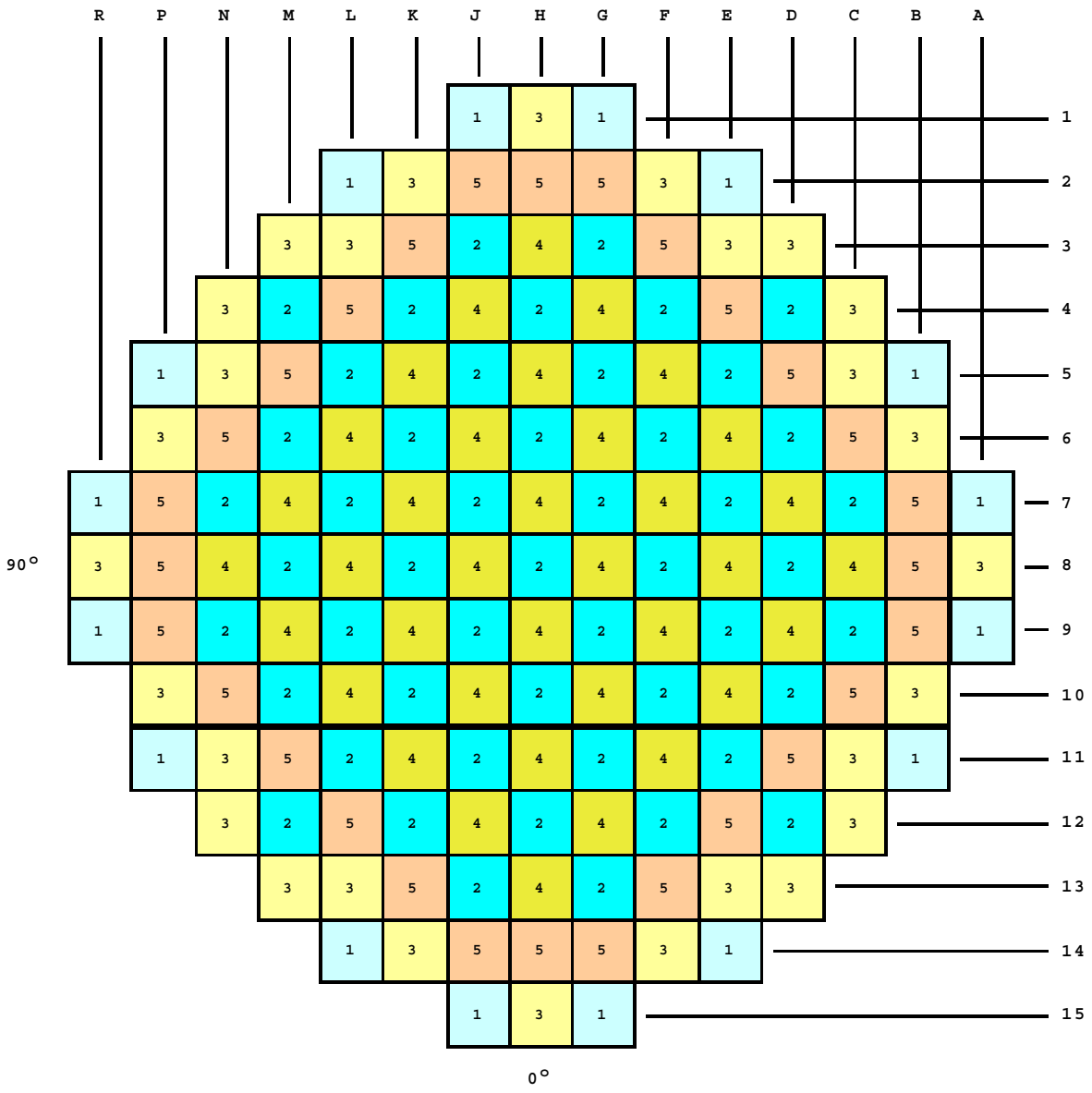
Notes:
(a) Report in WCAP-3726-1 (Reference 58).
(b) Calculated and measured worth are given in terms of an equivalent charge in B-10 concentration.

Table 4.3-9
Comparison of Measured and Calculated Moderator Coefficients at HZP, BOL

Plant Type/ Control Bank Configuration	Measured α_{iso} [(a)] (pcm/°F)	Calculated α_{iso} (pcm/°F)
3-loop, 157-assembly, 12-ft core		
D at 160 steps	-0.50	-0.50
D in, C at 190 steps	-3.01	-2.75
D in, C at 28 steps	-7.67	-7.02
B, C, and D in	-5.16	-4.45
2-loop, 121-assembly, 12-ft core		
D at 180 steps	+0.85	+1.02
D in, C at 180 steps	-2.40	-1.90
C and D in, B at 165 steps	-4.40	-5.58
B, C, and D in, A at 174 steps	-8.70	-8.12
4-loop, 193-assembly, 12-ft core		
ARO	-0.52	-1.2
D in	-4.35	-5.7
D and C in	-8.59	-10.0
D, C, and B in	-10.14	-10.55
D, C, B, and A in	-14.63	-14.45

Note:
(a) Isothermal coefficients, which include the Doppler effect in the fuel

$$\alpha_{iso} = 10^5 \ln \frac{k_2}{k_1} / \Delta T\,^{\circ}F$$



Region	Enrichment
1	0.74 w/o
2	1.58 w/o
3	3.20 w/o
4	3.776 w/o
5	4.376 w/o

Figure 4.3-1
Fuel Loading Arrangement for First Core

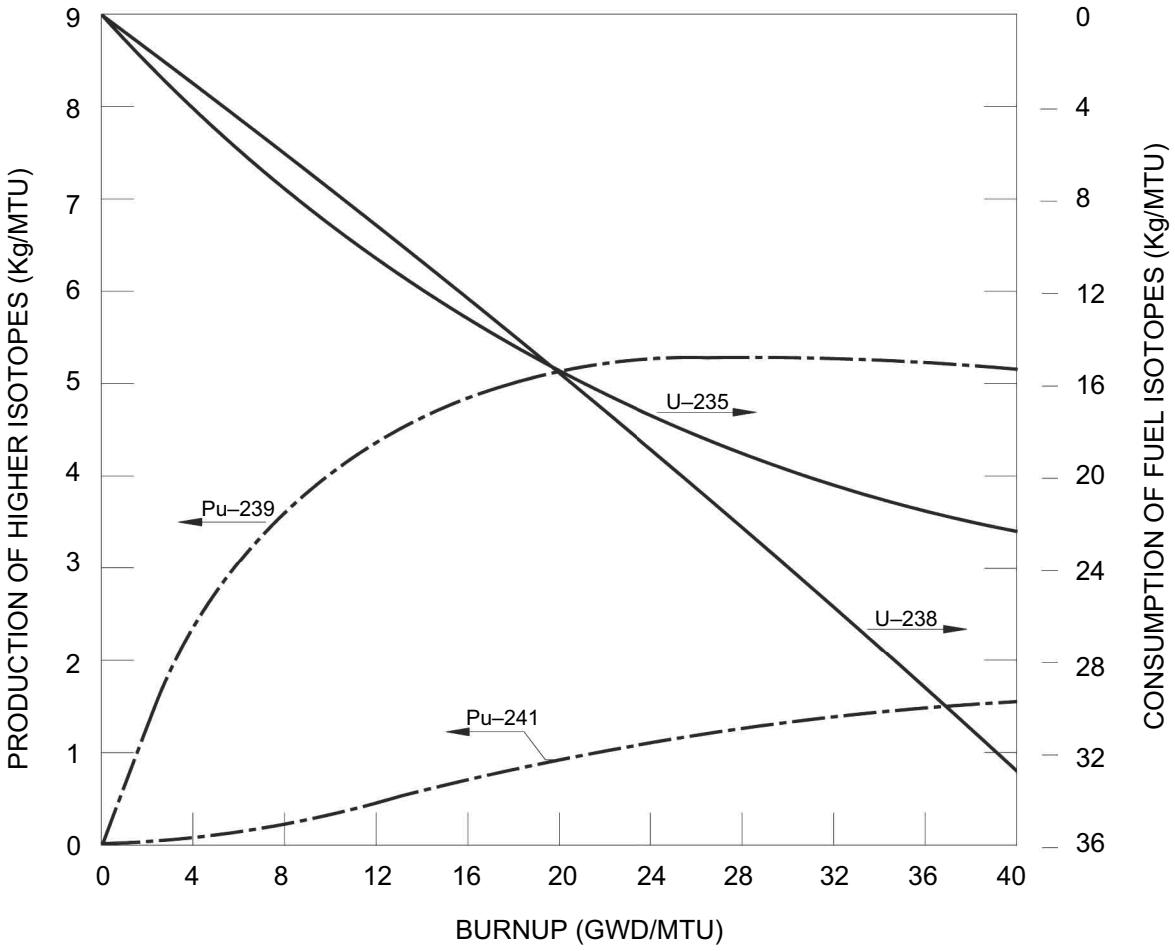


Figure 4.3-2
Typical Production and Consumption of Higher Isotopes

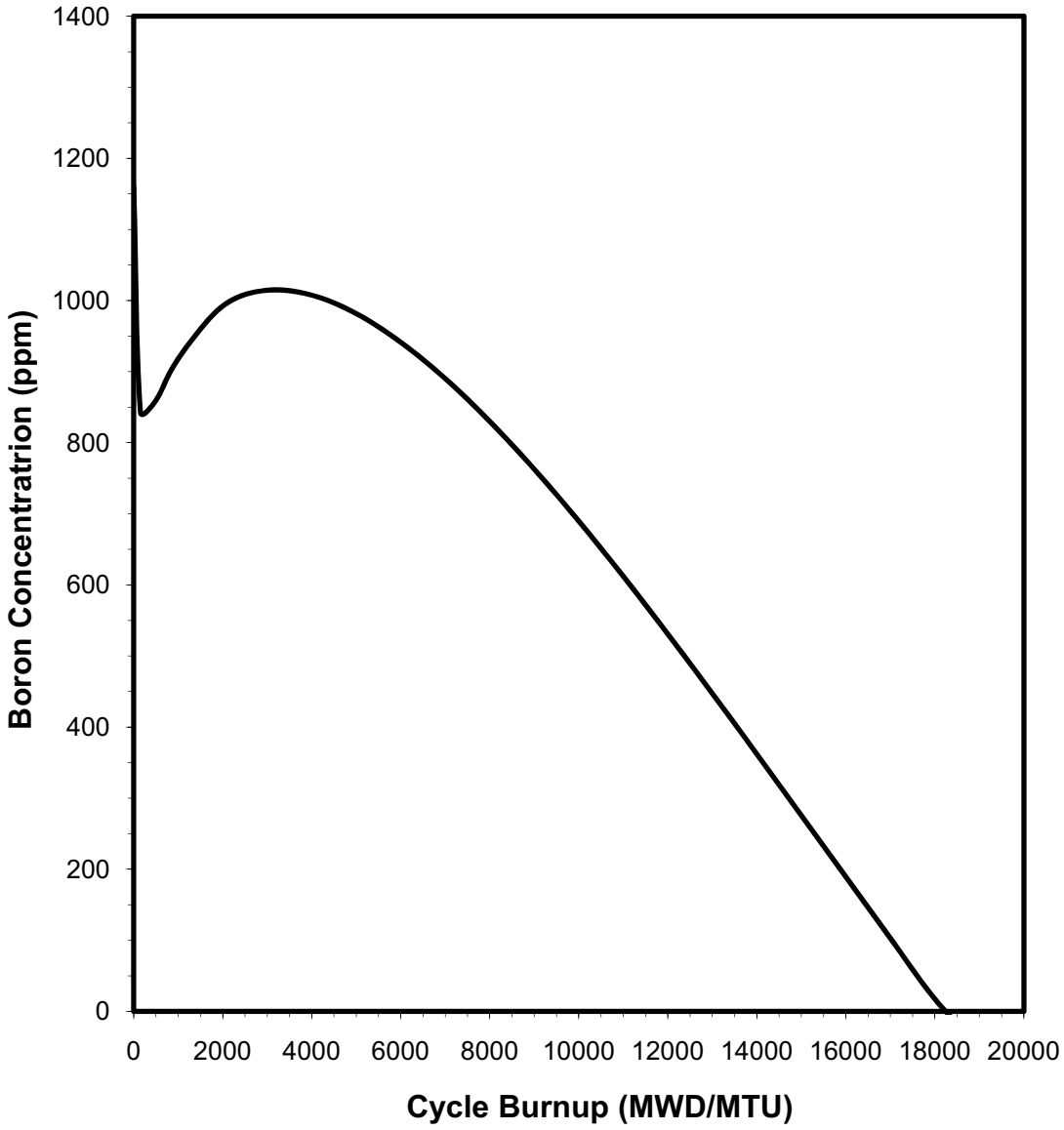


Figure 4.3-3
Cycle 1 Soluble Boron Concentration Versus Burnup

LI	L	LI	L	LI	L	LI	L	LI	L	LI	L	LI	L	LI	L	LI
L	MI	M	M	M	MI	M	M	M	M	M	MI	M	M	M	MI	L
LI	M	M	M	M	GT	M	M	LW	M	M	GT	M	M	M	M	LI
L	M	M	LW	M	M	HI	H	M	H	HI	M	M	LW	M	M	L
LI	M	M	M	M	M	HI	H	M	H	HI	M	M	M	M	M	LI
L	MI	GT	M	M	GT	M	M	SW	M	M	GT	M	M	GT	MI	L
LI	M	M	HI	HI	M	HI	H	M	H	HI	M	HI	HI	M	M	LI
L	M	M	H	H	M	H	HI	M	HI	H	M	H	H	M	M	L
LI	M	LW	M	M	SW	M	M	IT	M	M	SW	M	M	LW	M	LI
L	M	M	H	H	M	H	HI	M	HI	H	M	H	H	M	M	L
LI	M	M	HI	HI	M	HI	H	M	H	HI	M	HI	HI	M	M	LI
L	MI	GT	M	M	GT	M	M	SW	M	M	GT	M	M	GT	MI	L
LI	M	M	M	M	M	HI	H	M	H	HI	M	M	M	M	M	LI
L	M	M	LW	M	M	HI	H	M	H	HI	M	M	LW	M	M	L
LI	M	M	M	M	GT	M	M	LW	M	M	GT	M	M	M	M	LI
L	MI	M	M	M	MI	M	M	M	M	M	MI	M	M	M	MI	L
LI	L	LI	L	LI	L	LI	L	LI	L	LI	L	LI	L	LI	L	LI

Region D 68 IFBA + 12 WABA

	No. Pins	Enr.	BA
L	32	3.40	No BA
LI	32	3.40	IFBA
M	140	3.80	No BA
MI	12	3.80	IFBA
H	24	4.20	No BA
HI	24	4.20	IFBA
SW	4		WABA
LW	8		WABA
GT	12		
IT	1		

Figure 4.3-4a (Sheet 1 of 4)
Cycle 1 Assembly Integral and Wet Annular Burnable Absorber Patterns

L	LI	L	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	L	LI	L
LI	M	M	M	M	MI	MI	M	MI	M	MI	MI	M	M	M	M	LI
L	M	M	M	M	GT	M	M	GT	M	M	GT	M	M	M	M	L
LI	M	M	W	M	M	HI	H	M	H	HI	M	M	W	M	M	LI
LI	M	M	M	M	M	HI	H	M	H	HI	M	M	M	M	M	LI
LI	MI	GT	M	M	GT	M	M	GT	M	M	GT	M	M	GT	MI	LI
LI	MI	M	HI	HI	M	H	H	M	H	H	M	HI	HI	M	MI	LI
LI	M	M	H	H	M	H	H	M	H	H	M	H	H	M	M	LI
LI	MI	GT	M	M	GT	M	M	IT	M	M	GT	M	M	GT	MI	LI
LI	M	M	H	H	M	H	H	M	H	H	M	H	H	M	M	LI
LI	MI	M	HI	HI	M	H	H	M	H	H	M	HI	HI	M	MI	LI
LI	MI	GT	M	M	GT	M	M	GT	M	M	GT	M	M	GT	MI	LI
LI	M	M	M	M	M	HI	H	M	H	HI	M	M	M	M	M	LI
LI	M	M	W	M	M	HI	H	M	H	HI	M	M	W	M	M	LI
L	M	M	M	M	GT	M	M	GT	M	M	GT	M	M	M	M	L
LI	M	M	M	M	MI	MI	M	MI	M	MI	MI	M	M	M	M	LI
L	LI	L	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	L	LI	L

Region E 88 IFBA + 4 WABA

	No. Pins	Enr.	BA
L	12	4.00	No BA
LI	52	4.00	IFBA
M	132	4.40	No BA
MI	20	4.40	IFBA
H	32	4.80	No BA
HI	16	4.80	IFBA
W	4		WABA
GT	20		
IT	1		

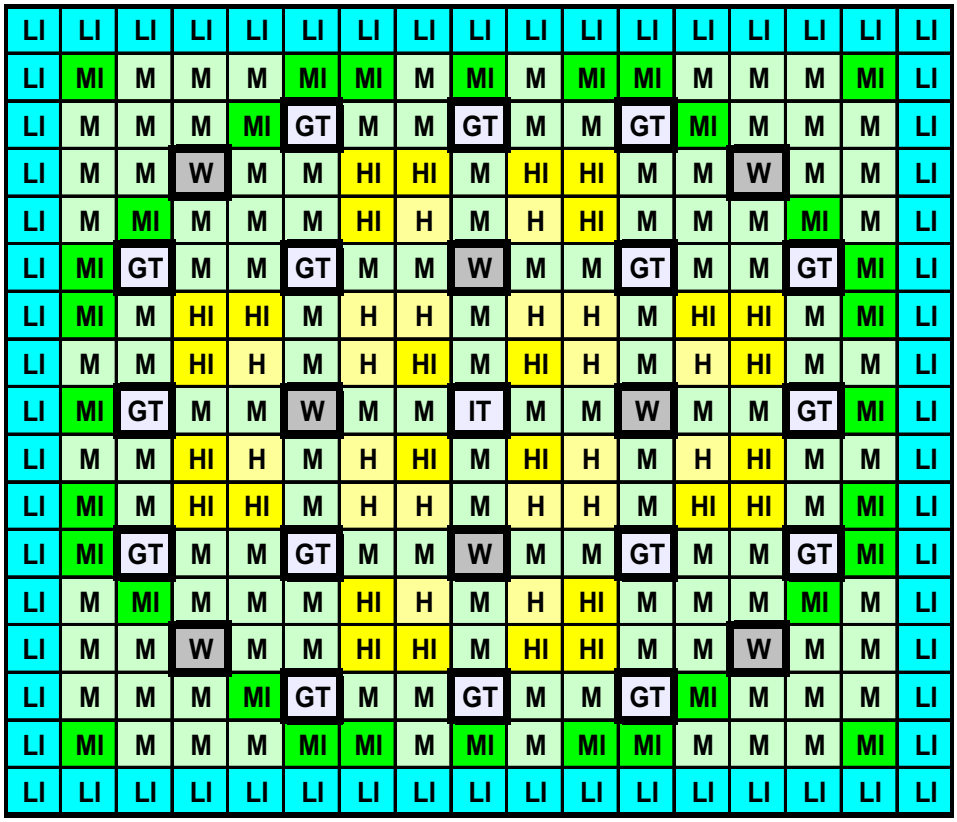
Figure 4.3-4a (Sheet 2 of 4)
Cycle 1 Assembly Integral and Wet Annular Burnable Absorber Patterns

LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI
LI	MI	M	M	M	MI	MI	M	MI	M	MI	MI	M	M	M	MI	LI
LI	M	M	M	MI	GT	M	M	GT	M	M	GT	MI	M	M	M	LI
LI	M	M	GT	M	M	HI	HI	M	HI	HI	M	M	GT	M	M	LI
LI	M	MI	M	M	M	HI	H	M	H	HI	M	M	M	MI	M	LI
LI	MI	GT	M	M	GT	M	M	GT	M	M	GT	M	M	GT	MI	LI
LI	MI	M	HI	HI	M	H	H	M	H	H	M	HI	HI	M	MI	LI
LI	M	M	HI	H	M	H	HI	M	HI	H	M	H	HI	M	M	LI
LI	MI	GT	M	M	GT	M	M	IT	M	M	GT	M	M	GT	MI	LI
LI	M	M	HI	H	M	H	HI	M	HI	H	M	H	HI	M	M	LI
LI	MI	M	HI	HI	M	H	H	M	H	H	M	HI	HI	M	MI	LI
LI	MI	GT	M	M	GT	M	M	GT	M	M	GT	M	M	GT	MI	LI
LI	M	MI	M	M	M	HI	H	M	H	HI	M	M	M	MI	M	LI
LI	M	M	GT	M	M	HI	HI	M	HI	HI	M	M	GT	M	M	LI
LI	M	M	M	MI	GT	M	M	GT	M	M	GT	MI	M	M	M	LI
LI	MI	M	M	M	MI	MI	M	MI	M	MI	MI	M	M	M	MI	LI
LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI	LI

Region E 124 IFBA

	No. Pins	Enr.	BA
L	0	4.00	No BA
LI	64	4.00	IFBA
M	120	4.40	No BA
MI	32	4.40	IFBA
H	20	4.80	No BA
HI	28	4.80	IFBA
W	0		WABA
GT	24		
IT	1		

Figure 4.3-4a (Sheet 3 of 4)
Cycle 1 Assembly Integral and Wet Annular Burnable Absorber Patterns



Region E 124 IFBA + 8 WABA

	No. Pins	Enr.	BA
L	0	4.00	No BA
LI	64	4.00	IFBA
M	120	4.40	No BA
MI	32	4.40	IFBA
H	20	4.80	No BA
HI	28	4.80	IFBA
W	8		WABA
GT	16		
IT	1		

Figure 4.3-4a (Sheet 4 of 4)
Cycle 1 Assembly Integral and Wet Annual Burnable Absorber Patterns

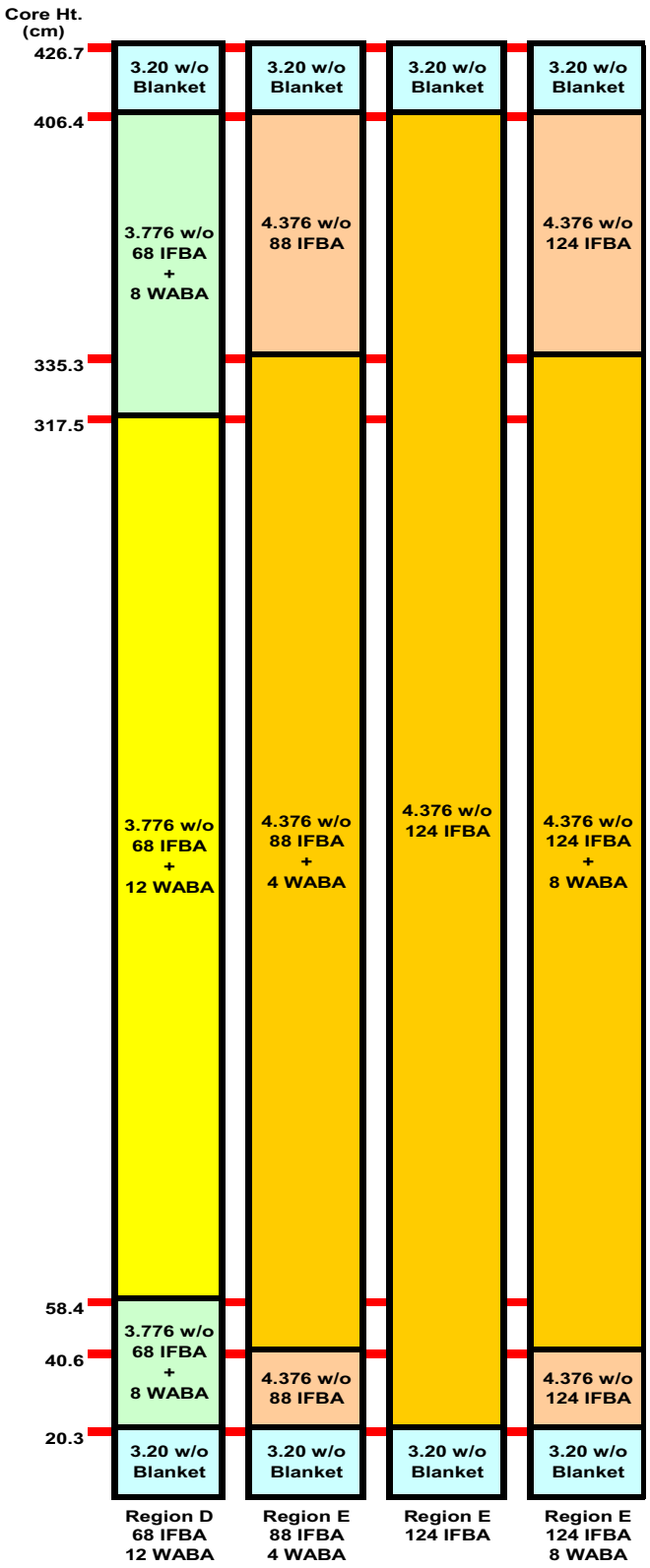
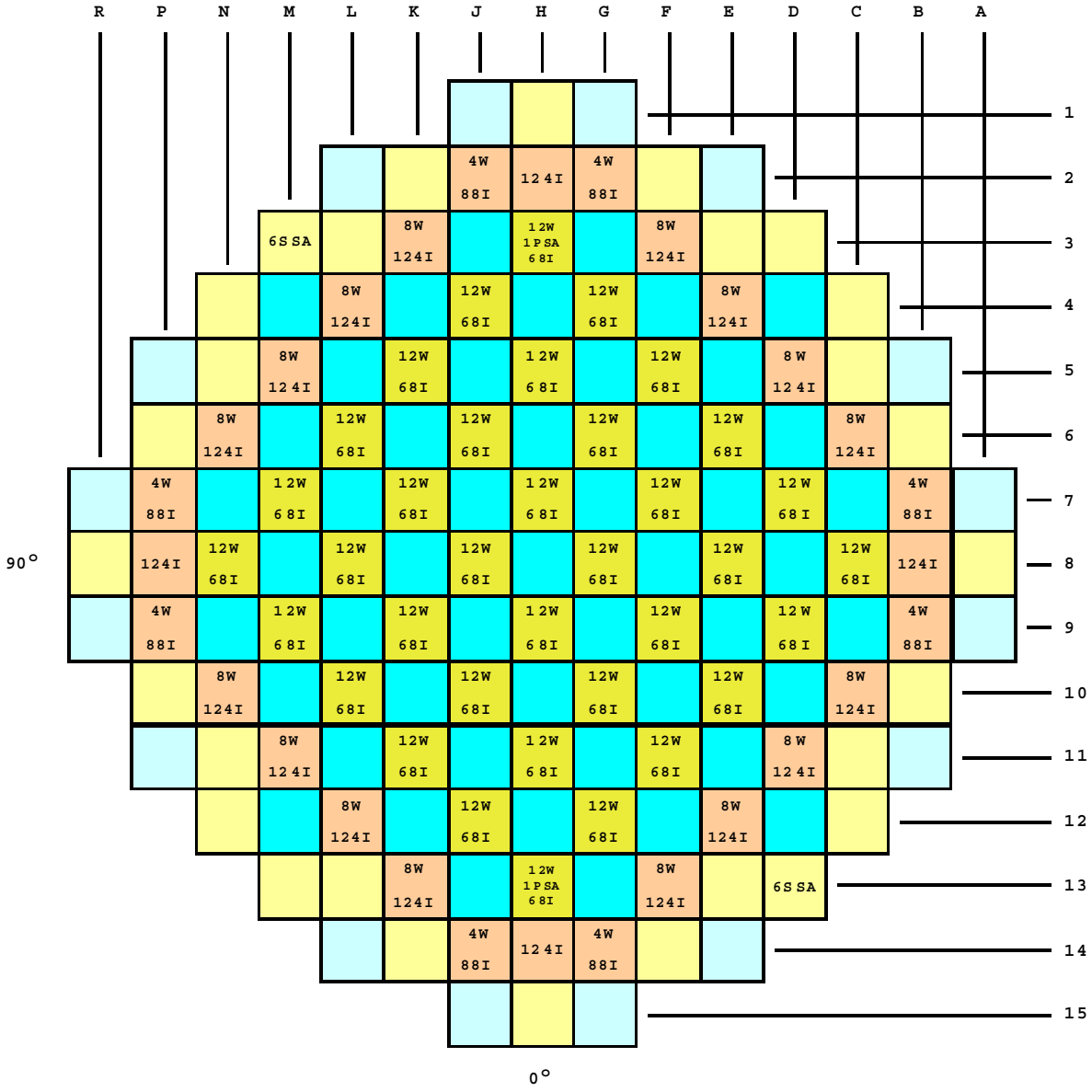


Figure 4.3-4b
Cycle 1 Assembly Integral and Wet Annular Burnable Absorber Axial Configurations



TYPE	TOTAL
##W...(NUMBER OF WABA RODLETS).....	592
##I...(TOTAL NUMBER OF FRESH IFBA RODS).....	5632
#SSA..(NUMBER OF SECONDARY SOURCE RODLETS)...	12
#PSA..(NUMBER OF PRIMARY SOURCE RODLETS).....	2

Figure 4.3-5
Cycle 1 Burnable Absorber, Primary, and Secondary Source Assembly Locations

0.962	1.296	0.964	1.299	0.966	1.277	1.205	0.653
1.296	0.963	1.299	0.967	1.301	0.947	1.149	0.201
0.964	1.299	0.967	1.307	0.970	1.290	0.874	
1.299	0.967	1.307	0.963	1.348	1.164	0.232	
0.966	1.301	0.970	1.348	0.829	0.765		
1.277	0.947	1.290	1.164	0.765			
1.205	1.149	0.874	0.232				
0.653	0.201						

Calculated $F_{\Delta H}^{N} = 1.460$

Key: Values Represent Assembly Relative Power

Figure 4.3-6
Cycle 1
Normalized Power Density Distribution
Near Beginning of Life, Unrodded Core,
Hot Full Power, No Xenon

1.002	1.327	0.998	1.316	0.982	1.258	1.171	0.647
1.327	1.001	1.323	0.992	1.300	0.947	1.119	0.207
0.998	1.323	0.996	1.314	0.977	1.262	0.856	
1.316	0.992	1.314	0.974	1.326	1.136	0.238	
0.982	1.300	0.977	1.326	0.829	0.752		
1.258	0.947	1.262	1.136	0.752			
1.171	1.119	0.856	0.238				
0.647	0.207						

Calculated $F^N_{\Delta H} = 1.441$

Key: Values Represent Assembly Relative Power

Figure 4.3-7
Cycle 1
Normalized Power Density Distribution
Near Beginning of Life, Unrodded Core,
Hot Full Power, Equilibrium Xenon

1.029	1.348	1.009	1.338	1.004	1.224	0.928	0.566
1.348	1.001	1.283	0.997	1.330	0.949	1.063	0.191
1.009	1.283	0.794	1.288	1.013	1.306	0.874	
1.338	0.997	1.288	0.995	1.391	1.204	0.253	
1.004	1.330	1.013	1.391	0.888	0.808		
1.224	0.949	1.306	1.204	0.808			
0.928	1.063	0.874	0.253				
0.566	0.191						

Calculated $F_{\Delta H}^{N} = 1.505$

Key: Values Represent Assembly Relative Power

Figure 4.3-8
Cycle 1
Normalized Power Density Distribution
Near Beginning of Life, Gray Bank MA+MB Inserted,
Hot Full Power, Equilibrium Xenon

1.017	1.350	1.017	1.349	1.014	1.339	1.260	0.660
1.350	1.017	1.349	1.014	1.338	0.979	1.144	0.275
1.017	1.349	1.013	1.338	0.991	1.269	0.790	
1.349	1.014	1.338	0.987	1.303	0.963	0.267	
1.014	1.338	0.991	1.303	0.756	0.599		
1.339	0.979	1.269	0.963	0.599			
1.260	1.144	0.790	0.267				
0.660	0.275						

Calculated $F^N_{\Delta H} = 1.428$

Key: Values Represent Assembly Relative Power

Figure 4.3-9
Cycle 1
Normalized Power Density Distribution
Near Middle of Life, Unrodded Core,
Hot Full Power, Equilibrium Xenon

0.984	1.253	0.990	1.266	1.006	1.293	1.263	0.738
1.253	0.987	1.260	0.997	1.278	0.998	1.170	0.366
0.990	1.260	0.995	1.272	1.001	1.266	0.832	
1.266	0.997	1.272	0.998	1.287	0.981	0.346	
1.006	1.278	1.001	1.287	0.814	0.645		
1.293	0.998	1.266	0.981	0.645			
1.263	1.170	0.832	0.346				
0.738	0.366						

Calculated $F_{\Delta H}^{N} = 1.378$

Key: Values Represent Assembly Relative Power

Figure 4.3-10
Cycle 1
Normalized Power Density Distribution
Near End of Life, Unrodded Core,
Hot Full Power, Equilibrium Xenon

1.017	1.284	1.006	1.296	1.027	1.253	0.989	0.645
1.284	0.993	1.234	1.006	1.310	0.997	1.106	0.335
1.006	1.234	0.802	1.258	1.039	1.312	0.848	
1.296	1.006	1.258	1.023	1.356	1.041	0.366	
1.027	1.310	1.039	1.356	0.872	0.695		
1.253	0.997	1.312	1.041	0.695			
0.989	1.106	0.848	0.366				
0.645	0.335						

Calculated $F^{N}_{\Delta H} = 1.431$

Key: Values Represent Assembly Relative Power

Figure 4.3-11
Cycle 1
Normalized Power Density Distribution
Near End of Life, Gray Bank MA+MB Inserted,
Hot Full Power, Equilibrium Xenon

1.215	1.187	1.200	1.215	1.228	1.234	1.239	1.258	1.265	1.273	1.265	1.269	1.269	1.261	1.251	1.250	1.310
1.139	1.194	1.279	1.296	1.312	1.277	1.248	1.345	1.310	1.355	1.267	1.304	1.348	1.341	1.338	1.272	1.263
1.133	1.258	1.260	1.255	1.246		1.347	1.360		1.368	1.362		1.273	1.295	1.317	1.350	1.274
1.143	1.270	1.250		1.283	1.343	1.281	1.281	1.322	1.287	1.290	1.360	1.307		1.305	1.364	1.293
1.159	1.288	1.245	1.286	1.317	1.356	1.287	1.339	1.258	1.343	1.294	1.369	1.336	1.317	1.293	1.381	1.311
1.170	1.261		1.353	1.363		1.341	1.266		1.269	1.347		1.378	1.380		1.345	1.320
1.181	1.239	1.359	1.298	1.301	1.349	1.396	1.365	1.278	1.367	1.400	1.355	1.311	1.317	1.402	1.315	1.325
1.203	1.339	1.378	1.304	1.359	1.279	1.371	1.309	1.354	1.311	1.374	1.284	1.369	1.321	1.417	1.417	1.342
1.213	1.307		1.348	1.280		1.287	1.358		1.361	1.292		1.290	1.366		1.378	1.345
1.220	1.354	1.392	1.317	1.372	1.291	1.383	1.319	1.364	1.321	1.384	1.293	1.377	1.329	1.425	1.424	1.349
1.213	1.269	1.389	1.325	1.327	1.374	1.421	1.388	1.299	1.388	1.420	1.374	1.328	1.333	1.418	1.329	1.338
1.217	1.306		1.397	1.405		1.379	1.300		1.300	1.377		1.406	1.405		1.367	1.340
1.218	1.350	1.302	1.343	1.373	1.411	1.337	1.389	1.303	1.388	1.335	1.409	1.373	1.350	1.324	1.412	1.338
1.212	1.345	1.323		1.353	1.413	1.344	1.342	1.382	1.342	1.342	1.411	1.353		1.346	1.404	1.329
1.208	1.344	1.347	1.341	1.329		1.431	1.440		1.440	1.429		1.329	1.348	1.368	1.399	1.319
1.217	1.284	1.381	1.400	1.416	1.376	1.341	1.440	1.398	1.441	1.341	1.376	1.418	1.407	1.401	1.330	1.320
1.294	1.282	1.305	1.326	1.341	1.346	1.348	1.362	1.364	1.365	1.351	1.349	1.345	1.334	1.322	1.322	1.388

Figure 4.3-12
Rodwise Power Distribution in a Typical Assembly (M-5)
Near Beginning of Life
Hot Full Power, Equilibrium Xenon, Unrodded Core

1.115	1.080	1.078	1.095	1.120	1.148	1.167	1.187	1.213	1.217	1.224	1.232	1.232	1.235	1.244	1.269	1.319
1.085	1.108	1.126	1.153	1.188	1.234	1.222	1.246	1.284	1.276	1.277	1.318	1.300	1.293	1.291	1.296	1.286
1.076	1.119	1.144	1.208	1.233		1.271	1.282		1.312	1.327		1.343	1.347	1.307	1.304	1.275
1.081	1.134	1.195		1.255	1.268	1.289	1.297	1.295	1.326	1.344	1.350	1.365		1.359	1.318	1.277
1.091	1.154	1.205	1.240	1.230	1.269	1.291	1.308	1.296	1.337	1.345	1.350	1.337	1.376	1.366	1.336	1.285
1.103	1.183		1.238	1.253		1.279	1.289		1.318	1.333		1.361	1.373		1.366	1.296
1.107	1.156	1.212	1.242	1.260	1.264	1.298	1.312	1.304	1.341	1.353	1.344	1.368	1.378	1.373	1.335	1.299
1.113	1.166	1.210	1.237	1.263	1.260	1.299	1.308	1.314	1.337	1.353	1.341	1.372	1.372	1.370	1.346	1.303
1.123	1.188		1.220	1.237		1.277	1.300		1.329	1.331		1.345	1.355		1.368	1.312
1.113	1.166	1.210	1.237	1.263	1.260	1.299	1.308	1.314	1.337	1.353	1.341	1.372	1.372	1.370	1.346	1.303
1.107	1.156	1.212	1.242	1.260	1.264	1.298	1.312	1.304	1.341	1.353	1.344	1.368	1.378	1.373	1.335	1.299
1.103	1.183		1.238	1.253		1.279	1.289		1.318	1.333		1.361	1.373		1.366	1.296
1.091	1.154	1.205	1.240	1.230	1.269	1.291	1.308	1.296	1.337	1.345	1.350	1.337	1.376	1.366	1.336	1.285
1.081	1.134	1.195		1.255	1.268	1.288	1.297	1.295	1.326	1.344	1.350	1.365		1.359	1.318	1.277
1.076	1.119	1.144	1.208	1.233		1.271	1.282		1.312	1.327		1.343	1.347	1.307	1.304	1.275
1.085	1.108	1.126	1.153	1.188	1.234	1.222	1.246	1.284	1.276	1.277	1.318	1.300	1.293	1.291	1.296	1.286
1.115	1.080	1.078	1.095	1.120	1.148	1.167	1.187	1.213	1.217	1.224	1.232	1.232	1.235	1.244	1.269	1.319

Figure 4.3-13
Rodwise Power Distribution in a Typical Assembly (P-8)
Near End of Life
Hot Full Power, Equilibrium Xenon, Unrodded Core

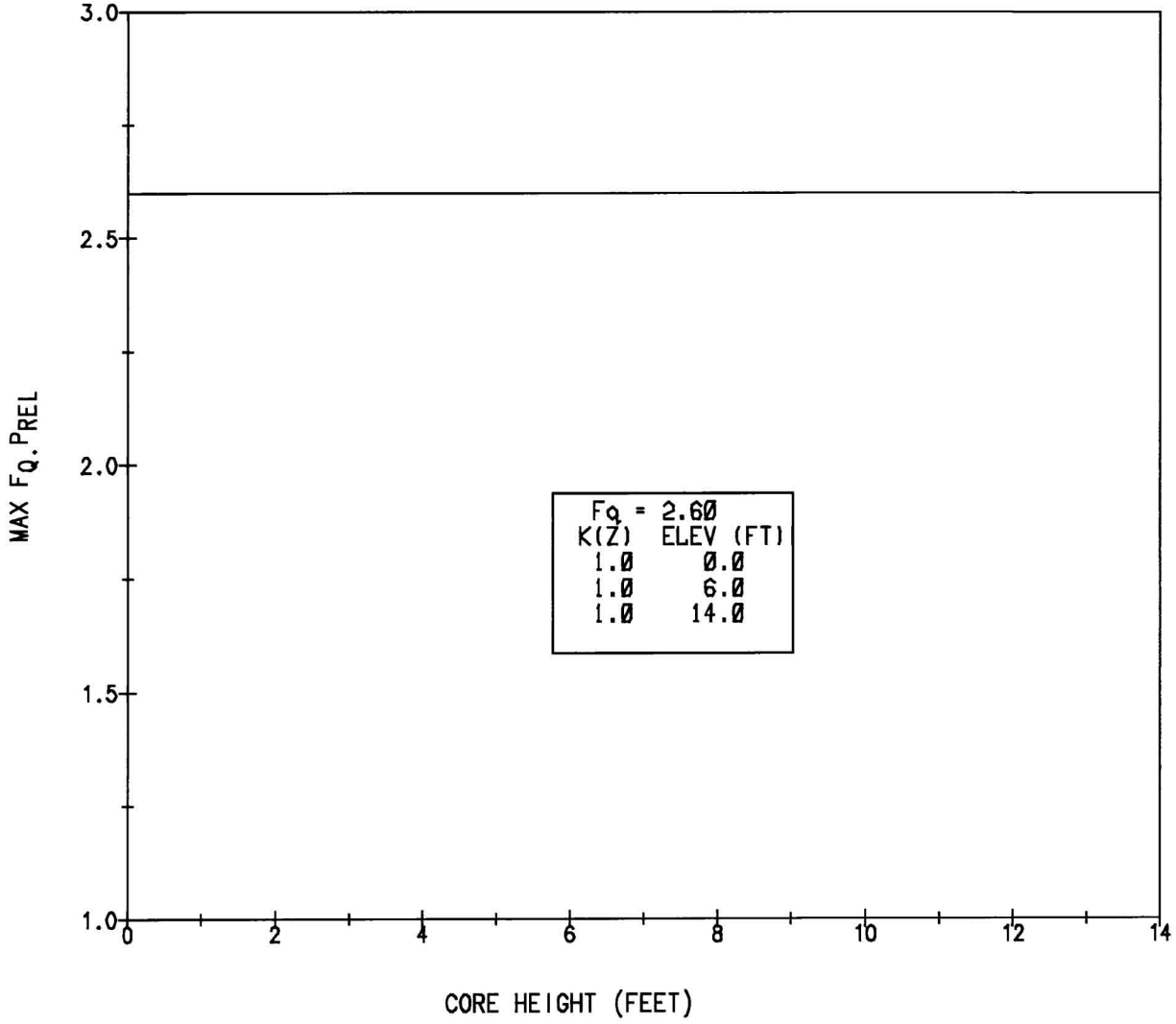


Figure 4.3-14
Maximum F_Q x Power Versus Axial Height
During Normal Operation

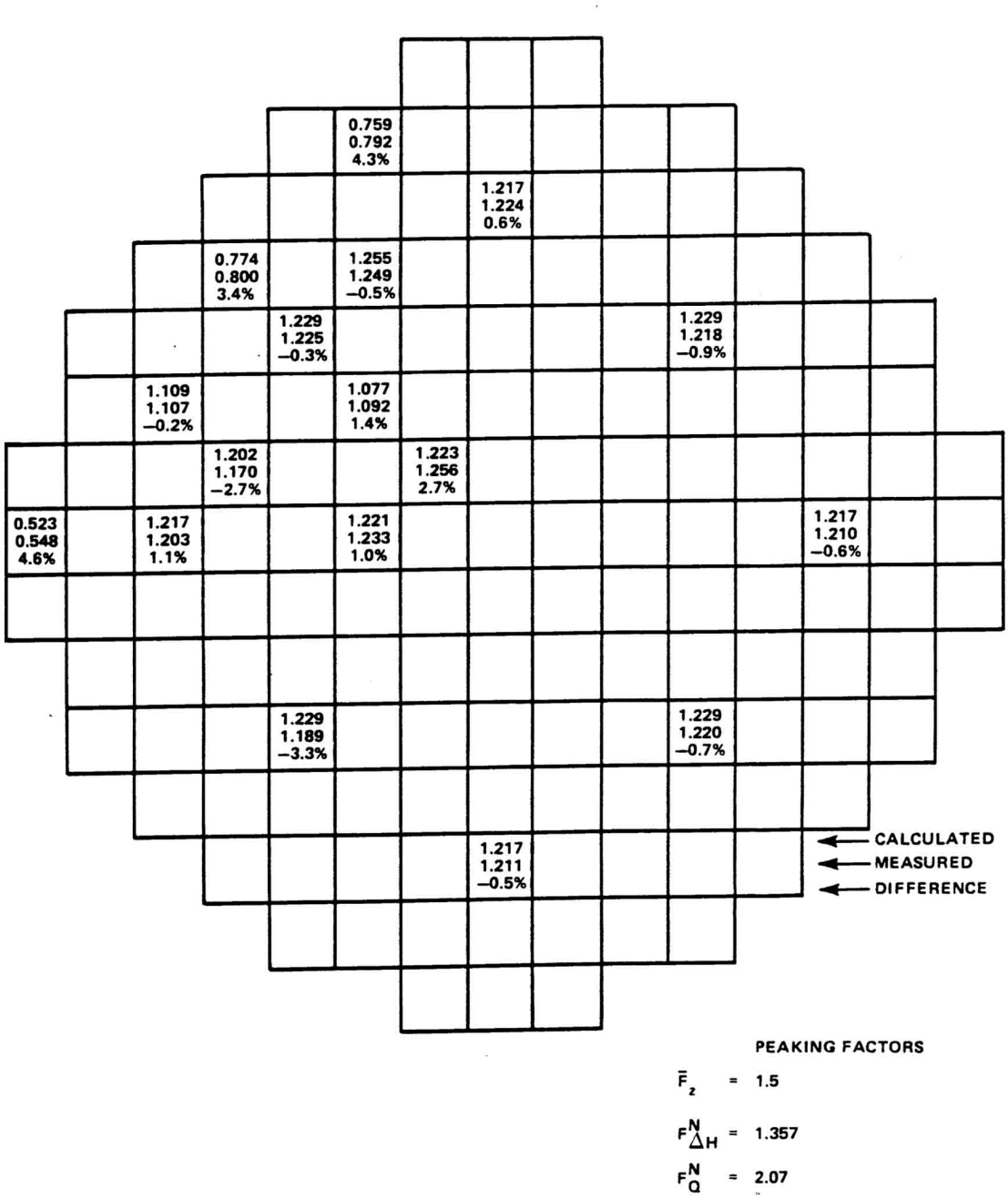


Figure 4.3-15
Typical Comparison Between Calculated and Measured Relative Fuel Assembly Power Distribution

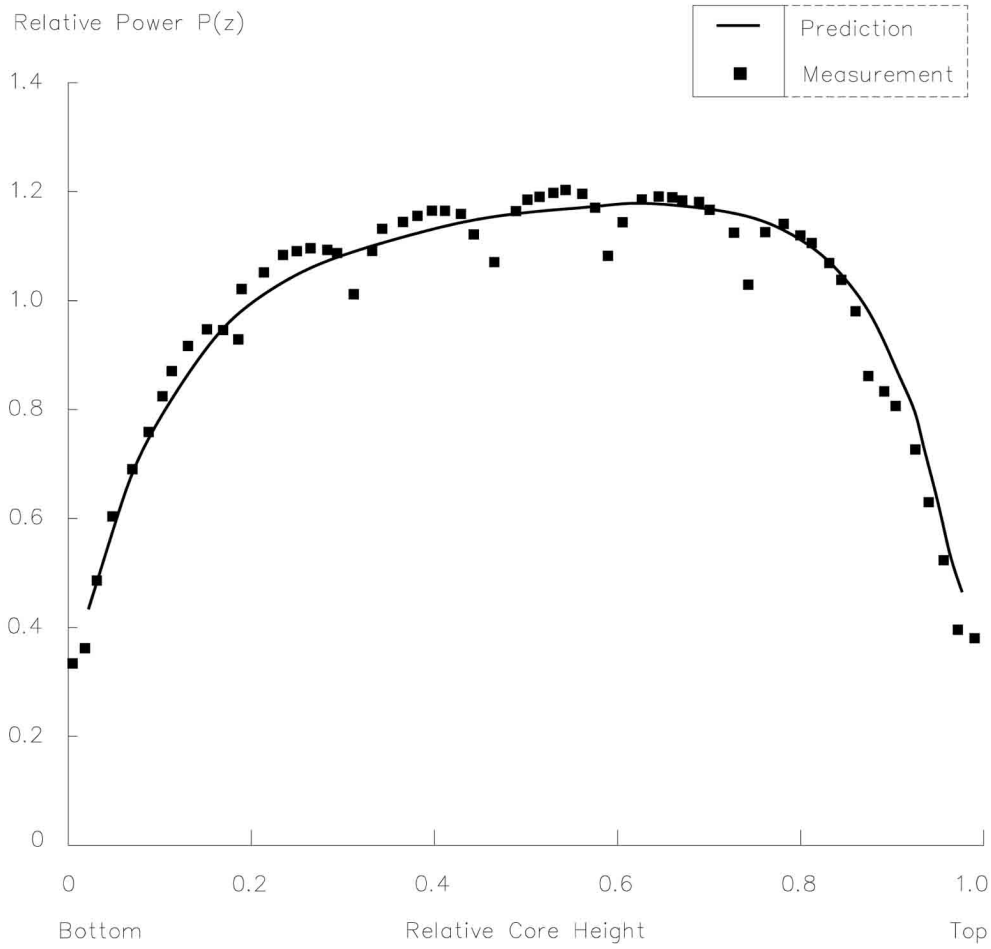


Figure 4.3-16
Typical Calculated Versus Measured Axial Power Distribution

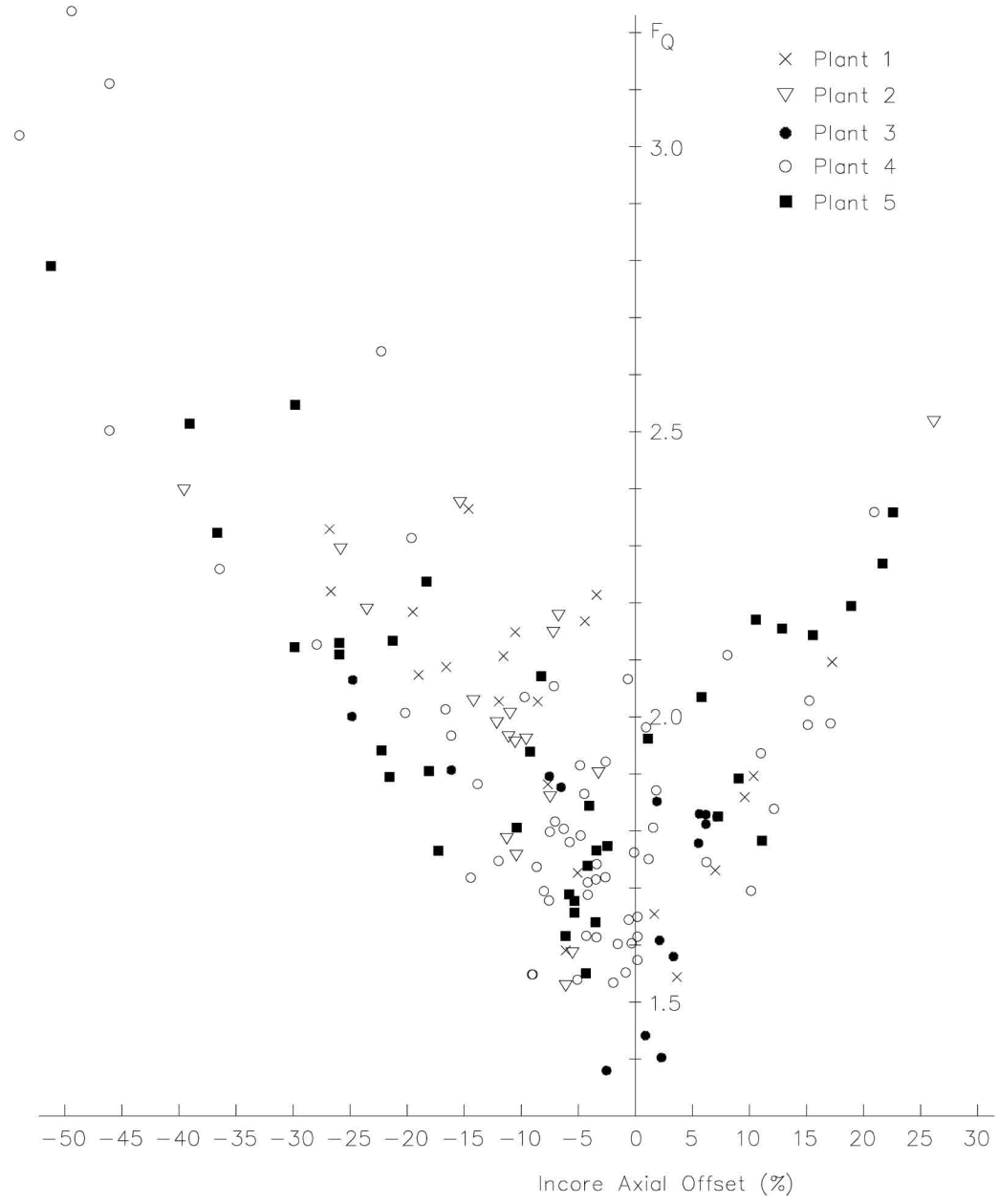


Figure 4.3-17
Measured F_Q Values Versus Axial Offset for Full Power Rod Configurations

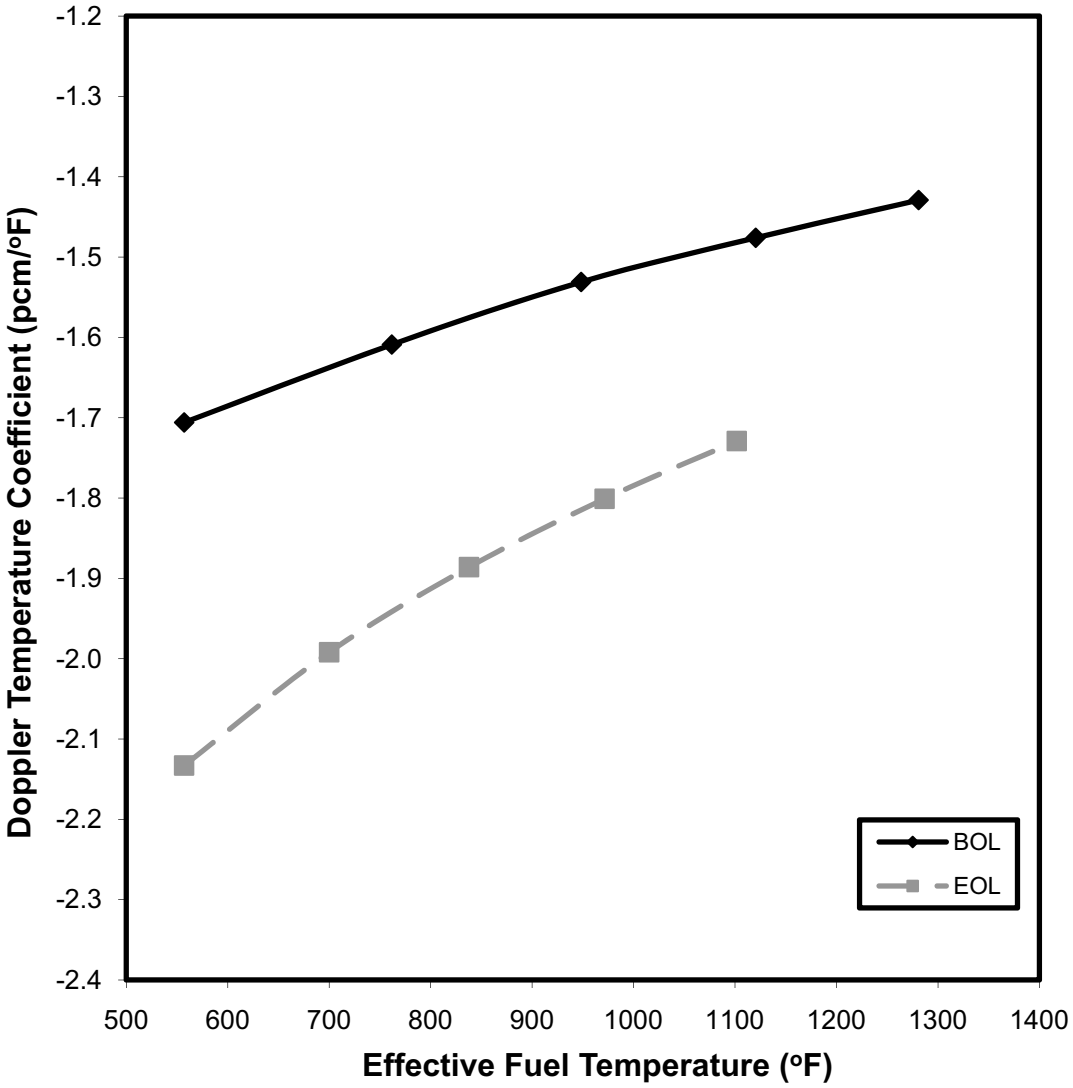


Figure 4.3-18
Typical Doppler Temperature Coefficient at BOL and EOL

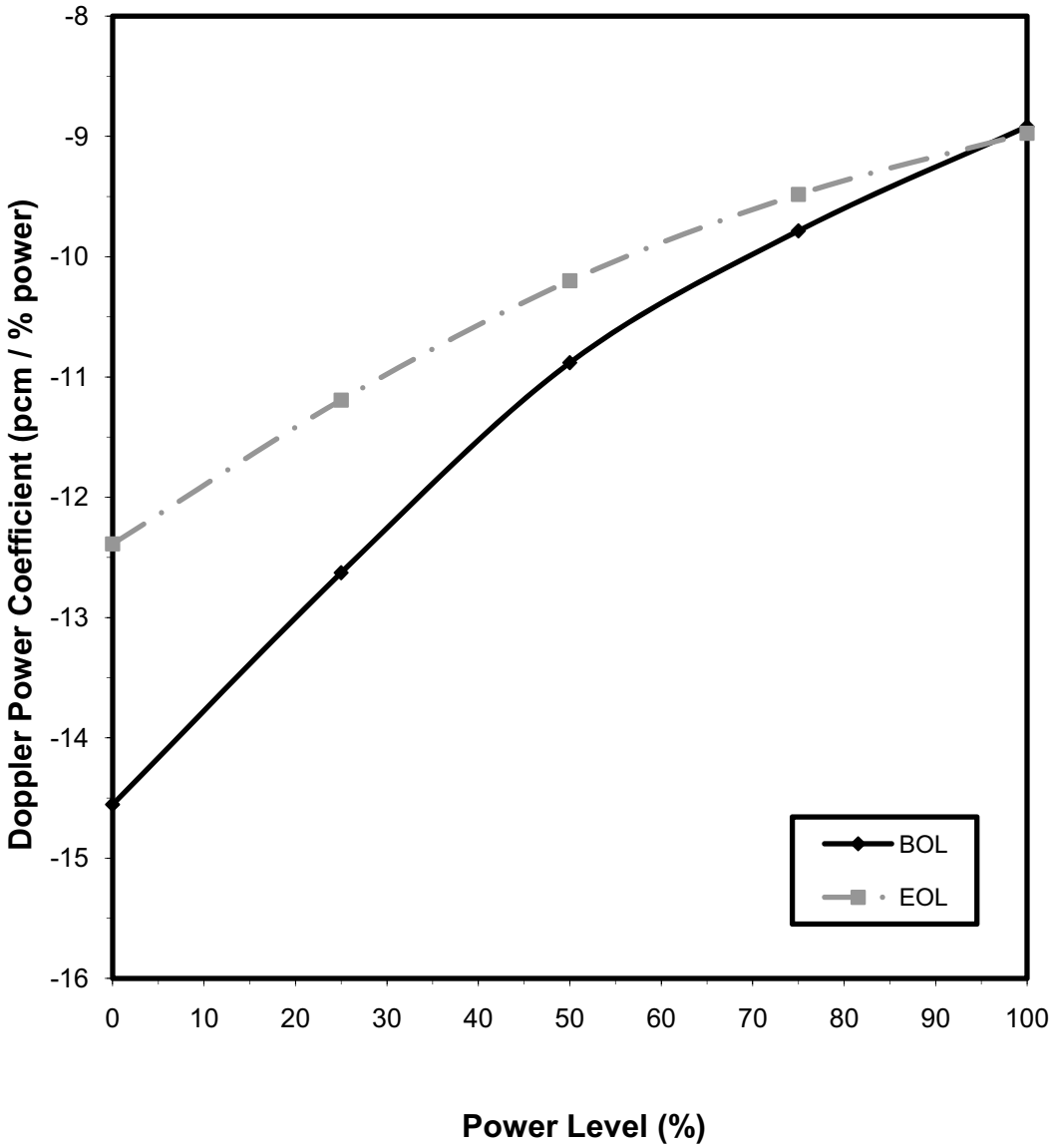


Figure 4.3-19
Typical Doppler-Only Power Coefficient at BOL and EOL

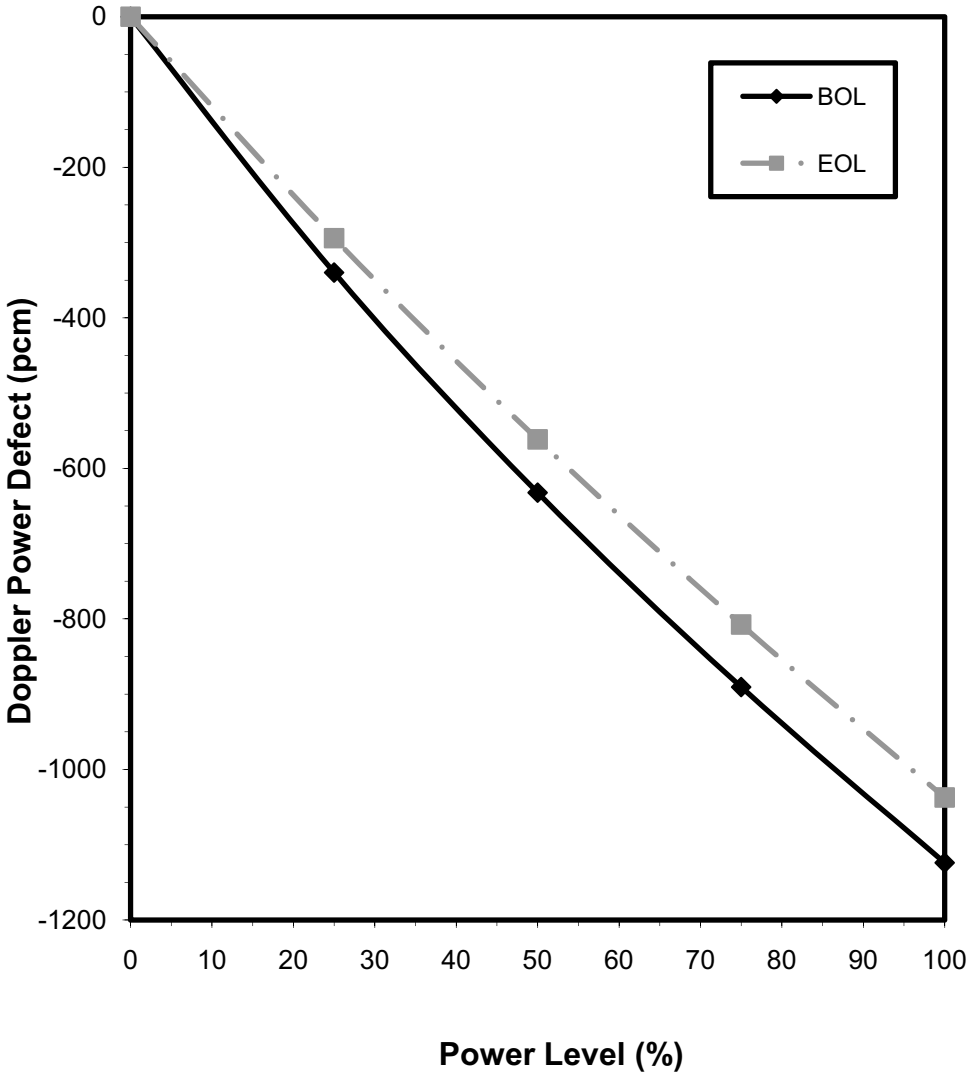


Figure 4.3-20
Typical Doppler-Only Power Defect at BOL and EOL

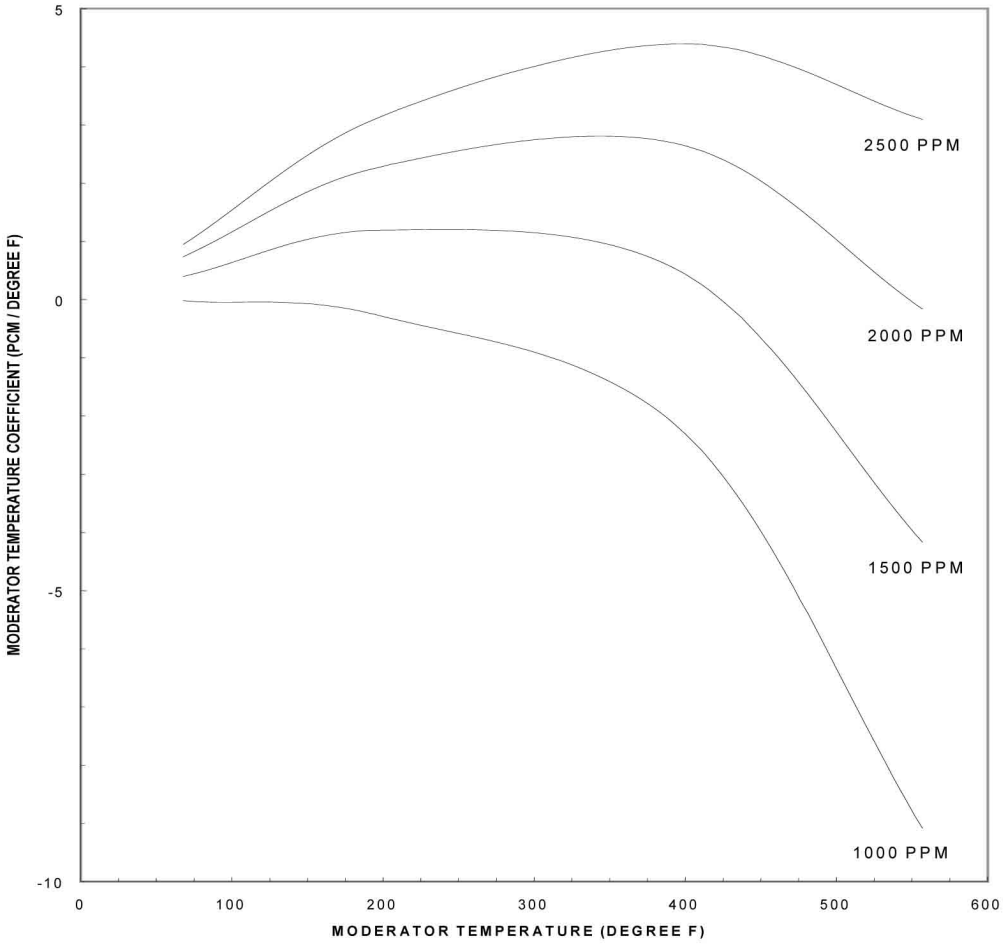


Figure 4.3-21
Typical Moderator Temperature Coefficient at BOL, Unrodded

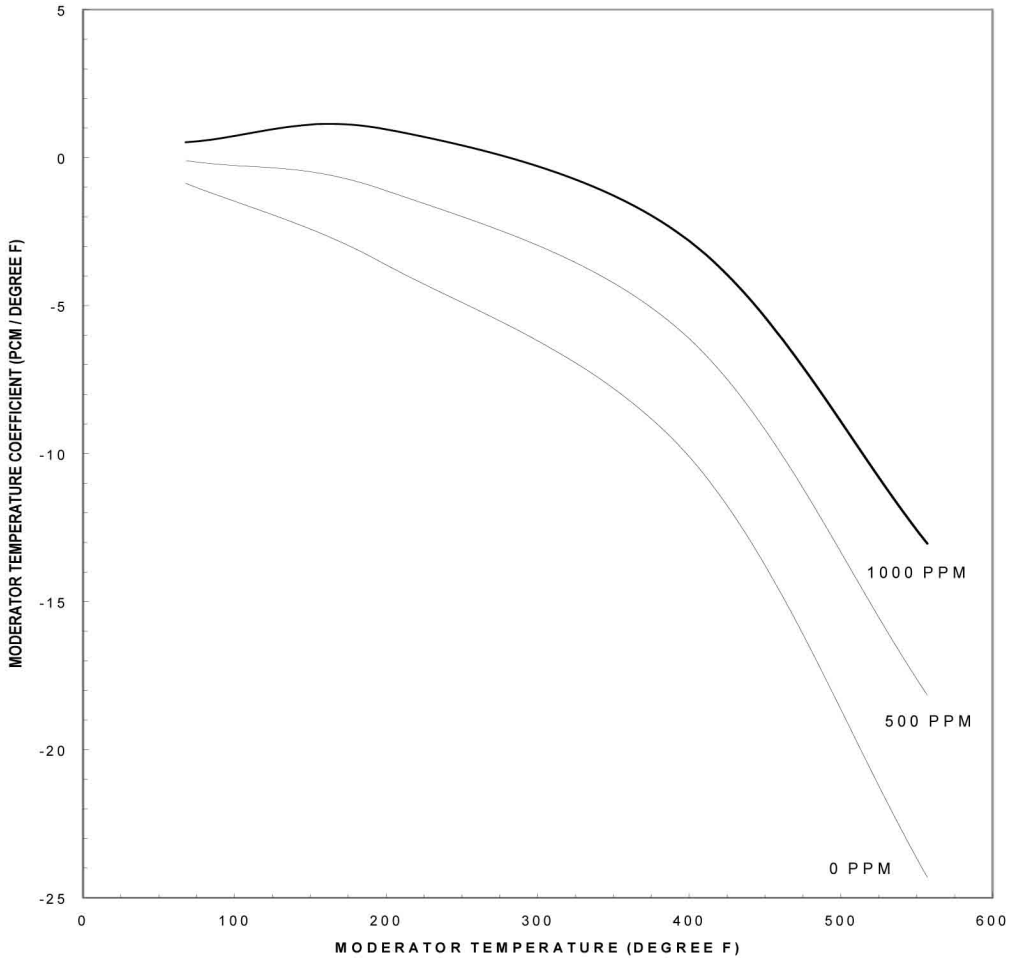


Figure 4.3-22
Typical Moderator Temperature Coefficient at EOL

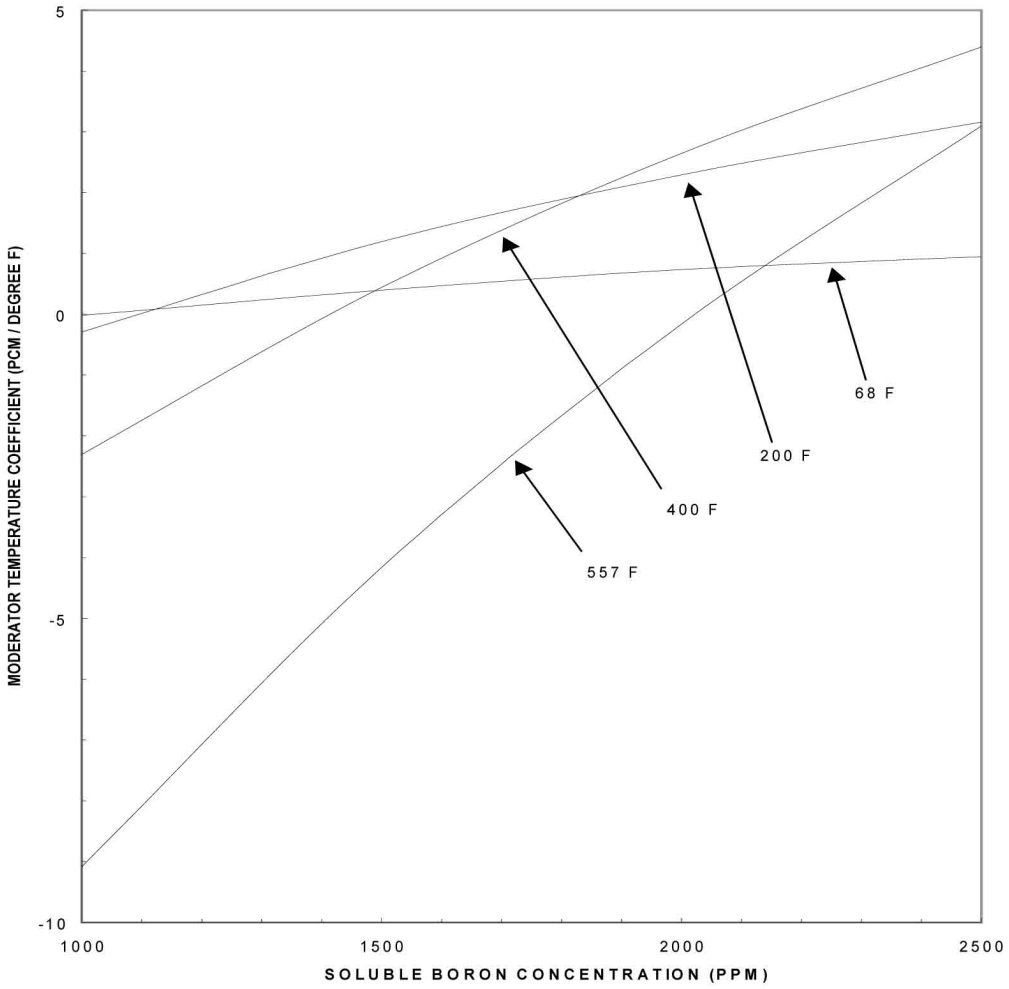


Figure 4.3-23
Typical Moderator Temperature Coefficient as a Function of Boron Concentration at BOL, Unrodded

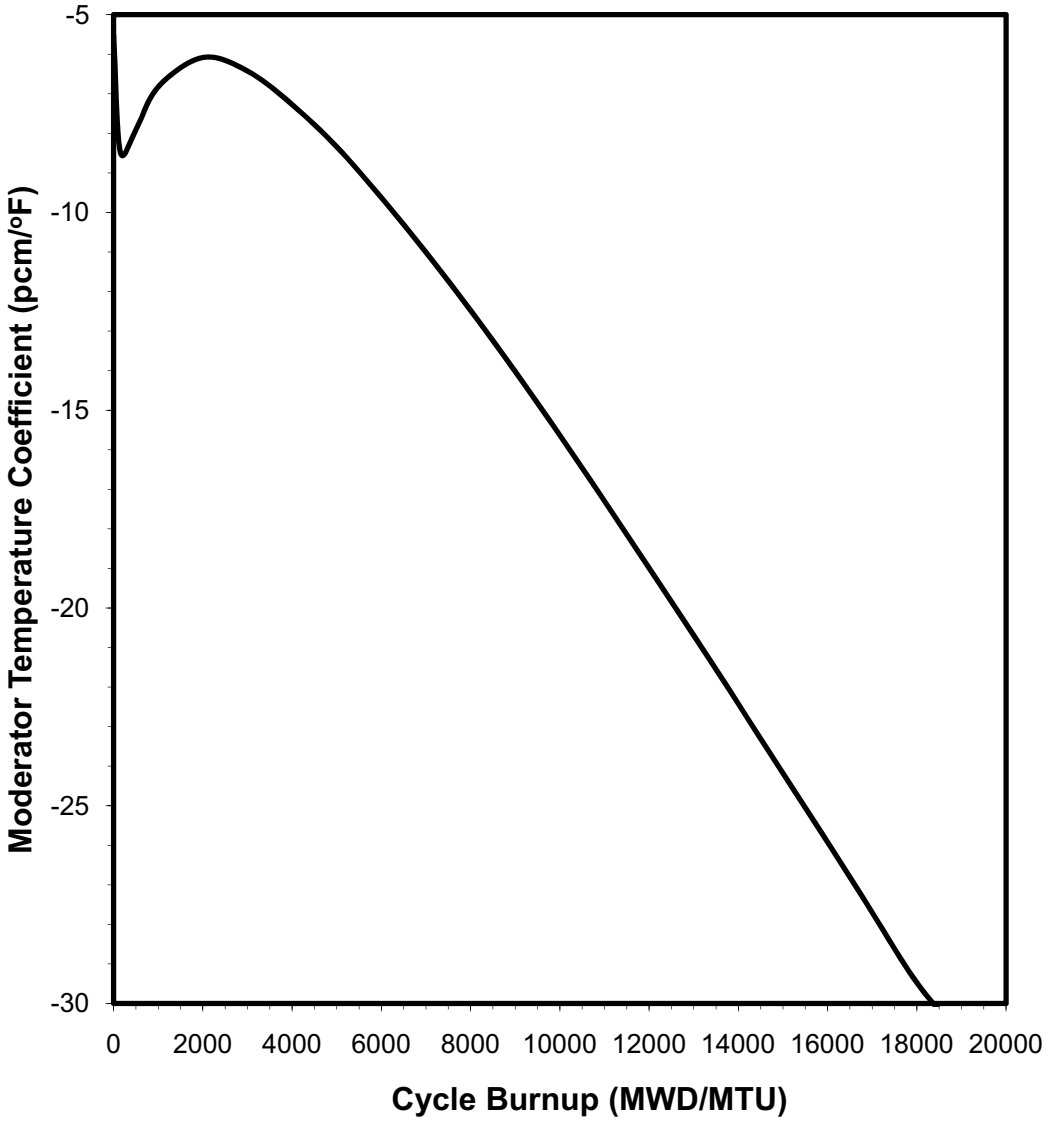


Figure 4.3-24
Typical Hot Full Power Moderator Temperature Coefficient versus Cycle Burnup

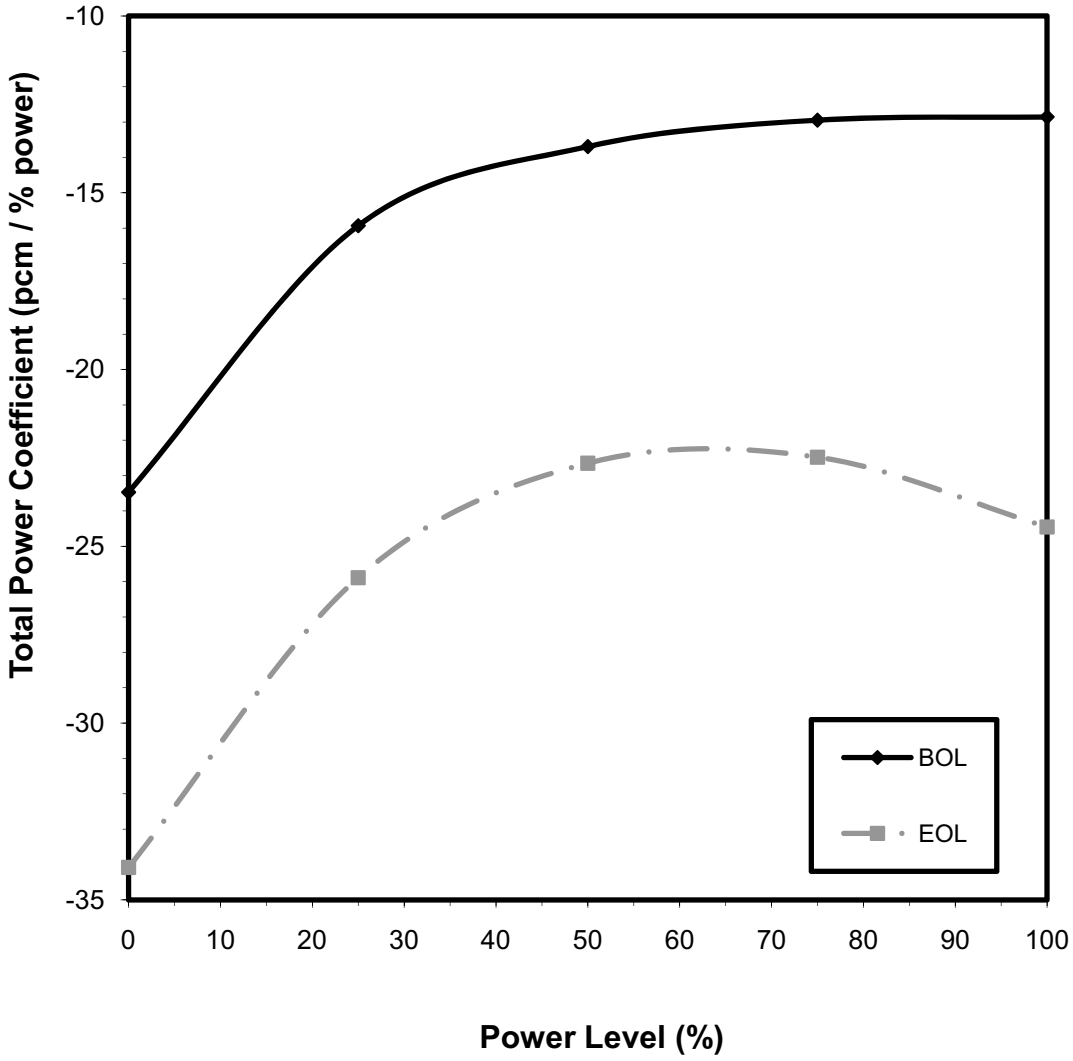


Figure 4.3-25
Typical Total Power Coefficient at BOL and EOL

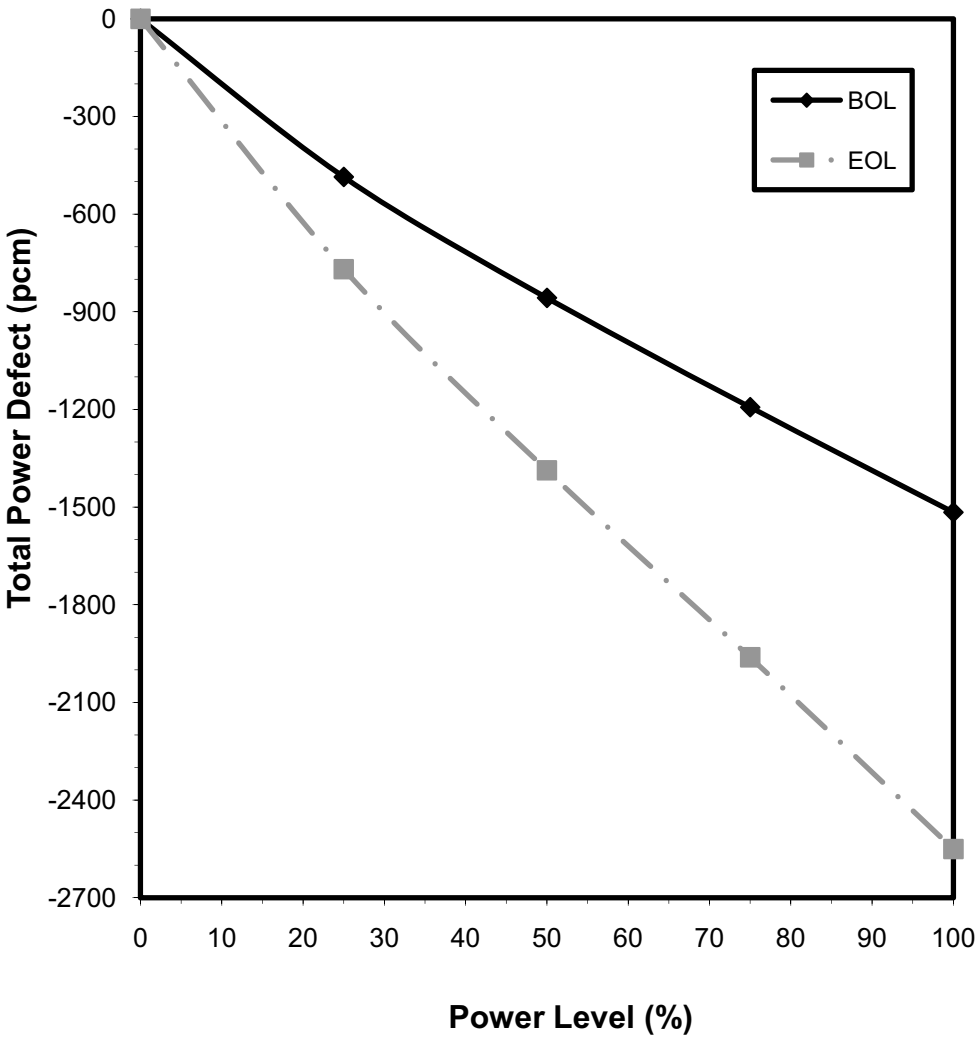
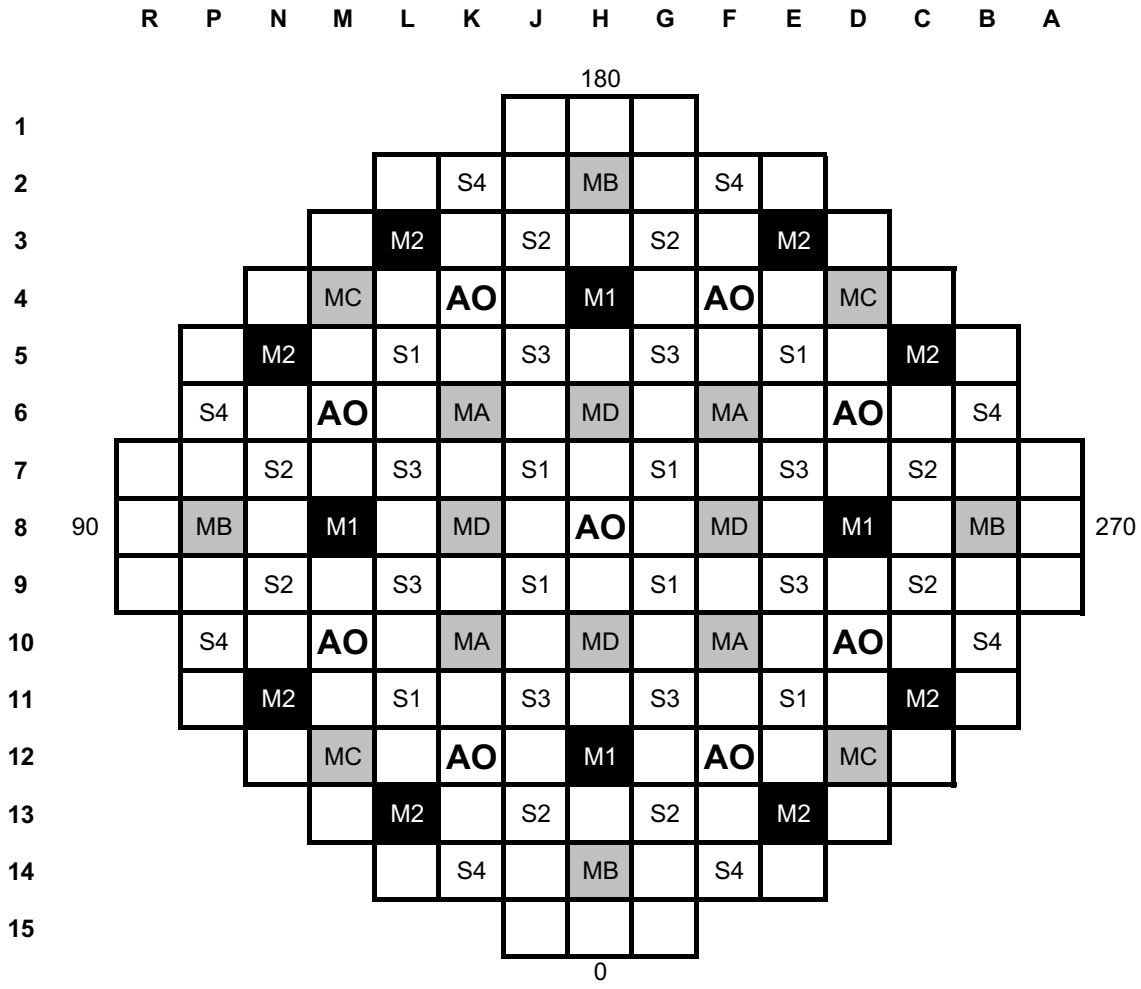


Figure 4.3-26
Typical Total Power Defect at BOL and EOL



Bank ID	Group Association	Cluster Design Type	# of Clusters
MA	MSHIM Control	Gray	4
MB	MSHIM Control	Gray	4
MC	MSHIM Control	Gray	4
MD	MSHIM Control	Gray	4
M1	MSHIM Control	Black	4
M2	MSHIM Control	Black	8
AO	Axial Offset Control	Black	9
S1	Shutdown	Black	8
S2	Shutdown	Black	8
S3	Shutdown	Black	8
S4	Shutdown	Black	8
Total			**69**

Figure 4.3-27
Rod Cluster Control/Gray Rod Cluster Assembly (RCCA/GRCA) Assembly Pattern

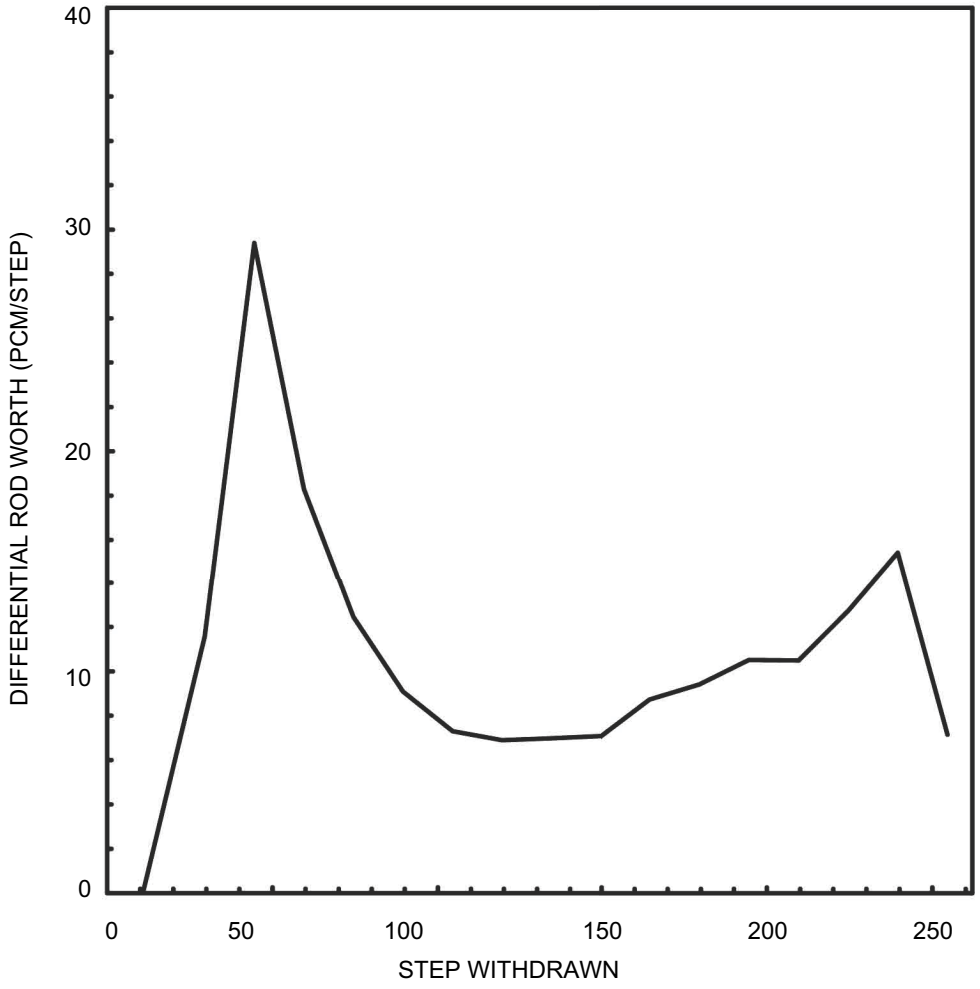


Figure 4.3-28
Typical Accidental Simultaneous Withdrawal of Two Control Banks at EOL, HZP, Moving in the Same Plane

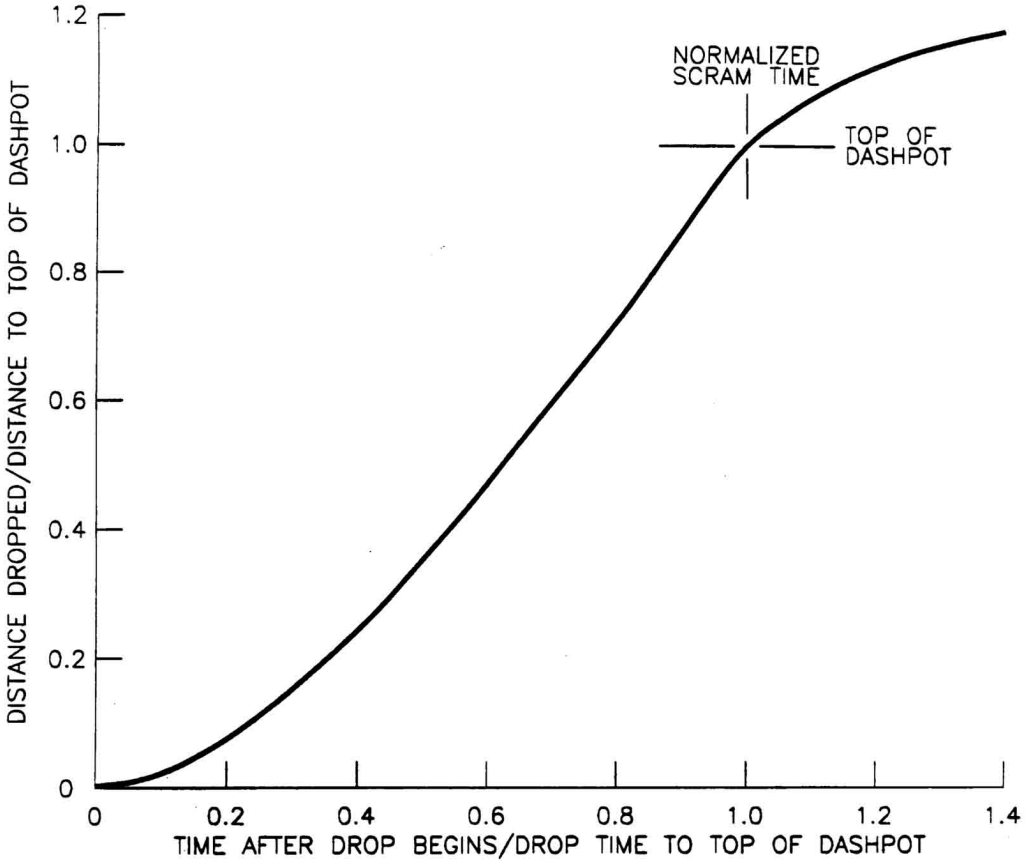


Figure 4.3-29
Typical Design Trip Curve

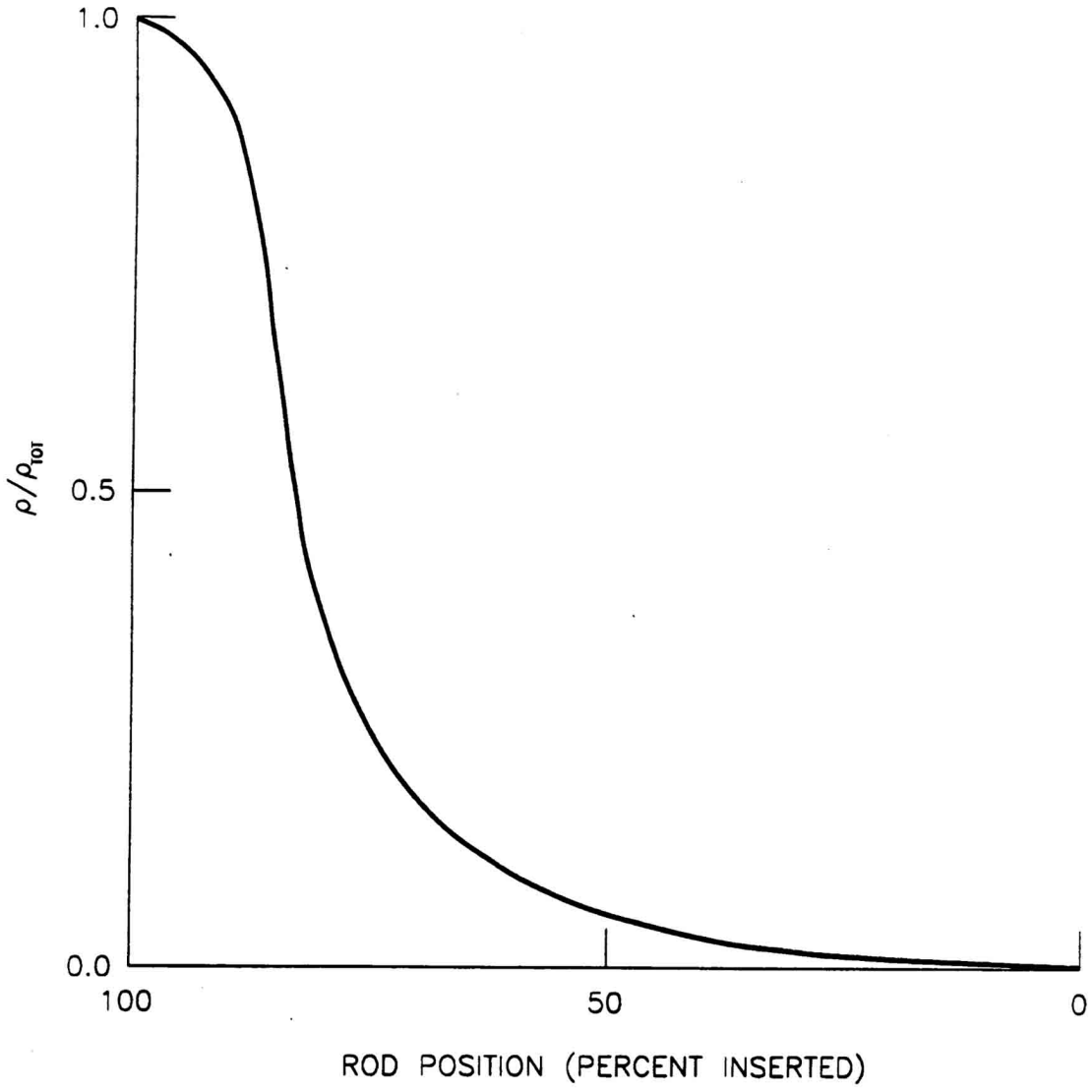


Figure 4.3-30
Typical Normalized Rod Worth Versus Percent Insertion
All Rods Inserting Less Most Reactive Stuck Rod

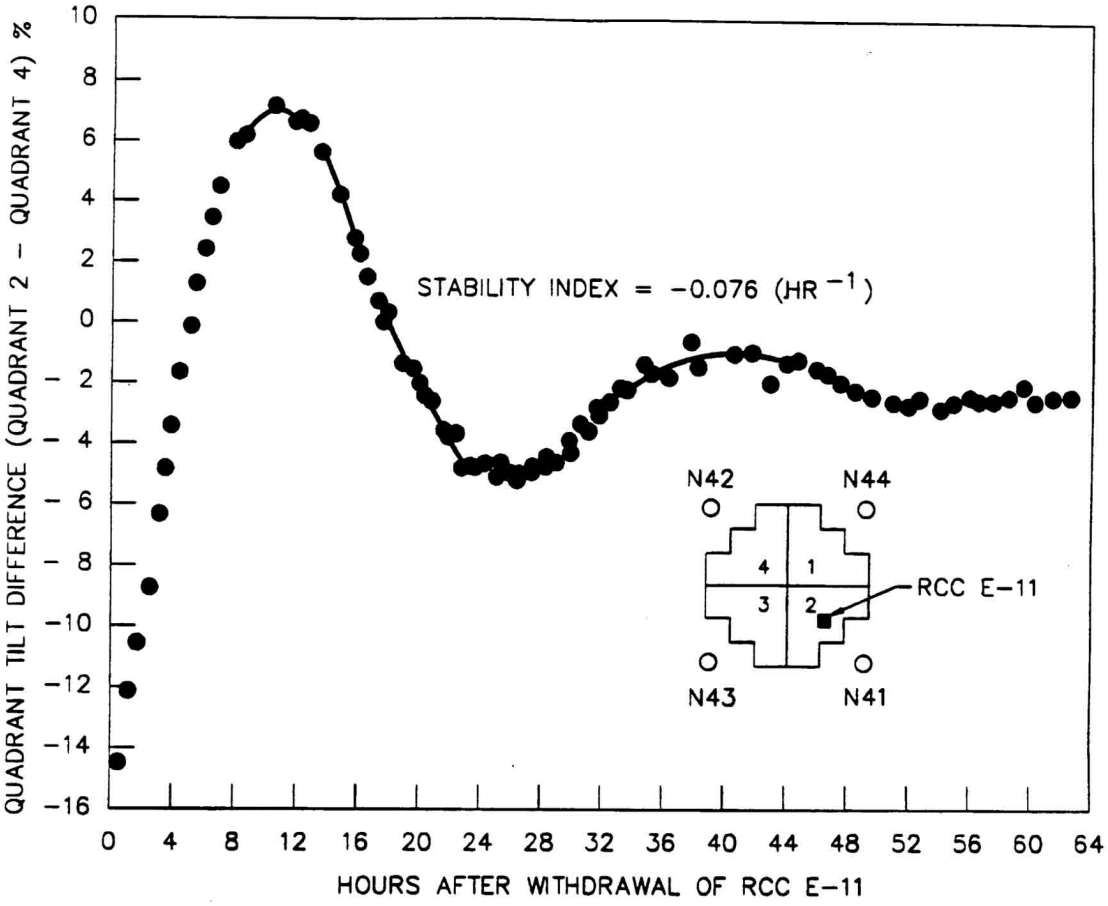


Figure 4.3-31
X-Y Xenon Test Thermocouple Response
Quadrant Tilt Difference Versus Time

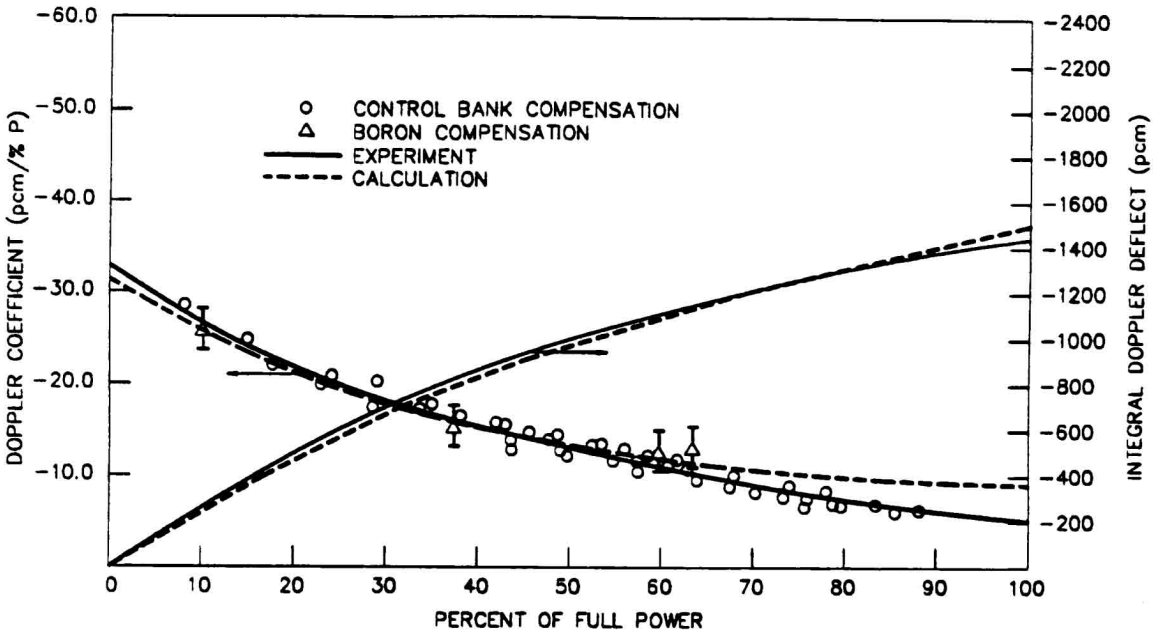


Figure 4.3-32
Calculated and Measured Doppler Defect and Coefficients at BOL, 2-Loop Plant, 121 Assemblies, 12-foot Core

4.4 Thermal and Hydraulic Design

The thermal and hydraulic design of the reactor core provides adequate heat transfer compatible with the heat generation distribution in the core. This provides adequate heat removal by the reactor coolant system, the normal residual heat removal system, or the passive core cooling system.

4.4.1 Design Basis

The following performance and safety criteria requirements are established for the thermal and hydraulic design of the fuel. Condition I, II, III, and IV transients and events through out this section are as defined in ANSI N18.2a-75 (Reference 1).

- Fuel damage (defined as penetration of the fission product barrier; that is, the fuel rod clad) is not expected during normal operation and operational transients (Condition I) or any transient conditions arising from faults of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the plant cleanup system and are consistent with the plant design bases.

- The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged (as defined in the above definition), although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.

- The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

To satisfy these requirements, the following design bases have been established for the thermal and hydraulic design of the reactor core.

4.4.1.1 Departure from Nucleate Boiling Design Basis

4.4.1.1.1 Design Basis

There is at least a 95-percent probability at a 95-percent confidence level that departure from nucleate boiling (DNB) does not occur on the limiting fuel rods during normal operation and operational transients and any transient conditions arising from faults of moderate frequency (Condition I and II events).

4.4.1.1.2 Discussion

The design method employed to meet the DNB design basis for the AP1000 fuel assemblies is the Revised Thermal Design Procedure, WCAP-11397-P-A (Reference 2). With the Revised Thermal Design Procedure methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, Revised Thermal Design Procedure design limits departure from nucleate boiling ratio (DNBR) values are determined such that there is at least a 95-percent probability at a 95-percent confidence level that DNB will not occur on the most limiting fuel rod during normal operation and operational transients and during transient conditions arising from faults of moderate frequency (Condition I and II events).

Assumed uncertainties in the plant operating parameters (pressurizer pressure, primary coolant temperature, reactor power, and reactor coolant system flow) are evaluated. Only the random portion of the plant operating parameter uncertainties is included in the statistical combination. Instrumentation bias is treated as a direct DNBR penalty. Since the parameter uncertainties are

considered in determining the Revised Thermal Design Procedure design limit DNBR values, the plant safety analyses are performed using input parameters at their nominal values.

For those transients that use the VIPRE-01 computer program (Subsection 4.4.4.5.2) and the WRB-2M correlation (Subsection 4.4.2.2.1), the Revised Thermal Design Procedure design limits are 1.25 for the typical cell and 1.25 for the thimble cell. These values may be revised (slightly) when plant specific uncertainties are available.

To maintain DNBR margin to offset DNB penalties such as those due to fuel rod bow (as described in Subsection 4.4.2.2.5), the safety analyses are performed to DNBR limits higher than the design limit DNBR values. The difference between the design limit DNBRs and the safety analysis limit DNBRs results in DNBR margin. A portion of this margin is used to offset rod bow and unanticipated DNBR penalties.

The Standard Thermal Design Procedure is used for those analyses where the Revised Thermal Design Procedure is not applicable. In the Standard Thermal Design Procedure method the parameters used in analysis are treated in a conservative way from a DNBR standpoint. The parameter uncertainties are applied directly to the plant safety analyses input values to give the lowest minimum DNBR. The DNBR limit for Standard Thermal Design Procedure is the appropriate DNB correlation limits increased to give sufficient margins to cover any DNBR penalties associated with the analysis.

By preventing DNB, adequate heat transfer is provided from the fuel clad to the reactor coolant, thereby preventing clad damage as a result of inadequate cooling. Maximum fuel rod surface temperature is not a design basis, since it is within a few degrees of coolant temperature during operation in the nucleate boiling region. Limits provided by the nuclear control and protection systems are such that this design basis is met for transients associated with Condition II events including overpower transients. There is an additional large DNBR margin at rated power operation and during normal operating transients.

4.4.1.2 Fuel Temperature Design Basis

4.4.1.2.1 Design Basis

During modes of operation associated with Condition I and Condition II events, there is at least a 95-percent probability at a 95-percent confidence level that the peak kW/ft fuel rods will not exceed the uranium dioxide melting temperature. The melting temperature of uranium dioxide is 5080°F (Reference 3) unirradiated and decreasing 58°F per 10,000 MWD/MTU. By precluding uranium dioxide melting, the fuel geometry is preserved and possible adverse effects of molten uranium dioxide on the cladding are eliminated. Design evaluations for Condition I and II events have shown that fuel melting will not occur for achievable local burnups up to 75,000 MWD/MTU (Reference 81). The NRC has approved design evaluations up to 60,000 MWD/MTU in Reference 81 and up to 62,000 MWD/MTU in References 9 and 88.

4.4.1.2.2 Discussion

Fuel rod thermal evaluations are performed at rated power, at maximum overpower, and during transients at various burnups. These analyses confirm that this design basis and the fuel integrity design bases given in Section 4.2 are met. They also provide input for the evaluation of Condition III and IV events given in Chapter 15.

The center-line temperature limit has been applied to reload cores with a lead rod average burnup of up to 60,000 MWD/MTU. For higher burnups, the peak kilowatt-per-foot experienced during Condition I and II events is limited to that maximum value which is sufficient to provide that the fuel

center-line temperatures remain below the melting temperature for the fuel rods. Thus, the fuel rod design basis that fuel rod damage not occur due to fuel melting continues to be met.

4.4.1.3 Core Flow Design Basis

4.4.1.3.1 Design Basis

Typical minimum value of 94.1 percent of the thermal flow rate is assumed to pass through the fuel rod region of the core and is effective for fuel rod cooling. Coolant flow through the thimble and instrumentation tubes and the leakage between the core barrel and core shroud, head cooling flow, and leakage to the vessel outlet nozzles are not considered effective for heat removal.

4.4.1.3.2 Discussion

Core cooling evaluations are based on the thermal flow rate (minimum flow) entering the reactor vessel. A typical maximum value of 5.9 percent of this value is allotted as bypass flow. This includes rod cluster control guide thimble and instrumentation tube cooling flow, leakage between the core barrel and the core shroud, head cooling flow, and leakage to the vessel outlet nozzles. The shroud core cavity flow is considered as active flow that is effective for fuel rod cooling.

The maximum bypass flow fraction of 5.9 percent assumes the use of thimble plugging devices in the rod cluster control guide thimble tubes that do not contain any other core components.

4.4.1.4 Hydrodynamic Stability Design Basis

Modes of operation associated with Condition I and II events do not lead to hydrodynamic instability.

4.4.1.5 Other Considerations

The design bases described in Subsections 4.4.1 through 4.4.1.4 together with the fuel clad and fuel assembly design bases given in Subsection 4.2.1 are sufficiently comprehensive that additional limits are not required.

Fuel rod diametral gap characteristics, moderator coolant flow velocity and distribution, and moderator void are not inherently limiting. Each of these parameters is incorporated into the thermal and hydraulic models used to confirm that the above-mentioned design criteria are met. For instance, the fuel rod diametral gap characteristics change with time, as described in Subsection 4.2.3, and the fuel rod integrity is evaluated on that basis. The effect of the moderator flow velocity and distribution described in Subsection 4.4.2.2 and the moderator void distribution described in Subsection 4.4.2.4 are included in the core thermal evaluation and thus affect the design basis.

Meeting the fuel clad integrity criteria covers the possible effects of clad temperature limitations. Clad surface temperature limits are imposed on Condition I and Condition II operation to preclude conditions of accelerated oxidation. A clad temperature limit is applied to the loss-of-coolant accident described in Subsection 15.6.5; control rod ejection accident described in Subsection 15.4.8; and locked rotor accident described in Subsection 15.3.3.

4.4.2 Description of Thermal and Hydraulic Design of the Reactor Core

4.4.2.1 Summary Comparison

Table 4.4-1 provides a comparison of the design parameters for the AP1000, the AP600, and a licensed Westinghouse-designed plant using XL Robust fuel. For the comparison with a plant

containing XL Robust fuel, a 193 fuel assembly plant is used, since no domestic Westinghouse designed 157 fuel assembly plants use 17x17 XL Robust fuel.

4.4.2.2 Critical Heat Flux Ratio or DNBR and Mixing Technology

The minimum DNBRs for the rated power and anticipated transient conditions are given in Table 4.4-1. The minimum DNBR in the limiting flow channel is typically downstream of the peak heat flux location (hotspot) due to the increased downstream enthalpy rise.

DNBRs are calculated by using the correlation and definitions described in Subsections 4.4.2.2.1 and 4.4.2.2.2. The VIPRE-01 computer code described in Subsection 4.4.4.5, is used to determine the flow distribution in the core and the local conditions in the hot channel for use in the DNB correlation. The use of hot channel factors is described in Subsections 4.4.4.3.1 (nuclear hot channel factors) and 4.4.2.2.4 (engineering hot channel factors).

4.4.2.2.1 DNB Technology

The primary DNB correlation used for the analysis of the AP1000 fuel is the WRB-2M correlation (References 82 and 82a). The WRB-2M correlation applies to the Robust Fuel Assemblies, which are planned to be used in the AP1000 core. This correlation applies to most AP1000 conditions.

A correlation limit of 1.14 is applicable for the WRB-2M correlation.

The applicable range of parameters for the WRB-2M correlation is:

Pressure	$1495 \le P \le 2425$ psia
Local mass velocity	$0.97 \le G_{loc}/10^6 \le 3.1$ lb/ft^2-hr
Local quality	$-0.1 \le X_{loc} \le 0.29$
Heated length, inlet to CHF location	$L_H \le 14$ feet
Grid spacing	$10 \le g_{sp} \le 20.6$ inches
Equivalent hydraulic diameter	$0.37 \le D_e \le 0.46$ inches
Equivalent heated hydraulic diameter	$0.46 \le D_h \le 0.54$ inches

The WRB-2 (Reference 4), ABB-NV (References 89 and 90), or WLOP (Reference 90) correlation is used wherever the WRB-2M correlation is not applicable. The WRB-2 correlation limit is 1.17.

The applicable range of parameters for the WRB-2 correlation is:

Pressure	$1440 \le P \le 2490$ psia
Local mass velocity	$0.9 \le G_{loc}/10^6 \le 3.7$ lb/ft^2-hr
Local quality	$-0.1 \le X_{loc} \le 0.3$
Heat length, inlet to DNB location	$L_h \le 14$ feet
Grid spacing	$10 \le g_{sp} \le 26$ inches
Equivalent hydraulic diameter	$0.37 \le D_e \le 0.51$ inches
Equivalent heated hydraulic diameter	$0.46 \le D_h \le 0.59$ inches

The WRB-2 correlation was developed based on mixing vane data and, therefore, is only applicable in the heated rod spans above the first mixing vane grid.

In the heated region below the first mixing vane grid, the ABB-NV correlation, References 89 and 90, which is based on CHF data from fuel assemblies without mixing vane grids, is used to calculate DNBR values. For system pressures and flow rates where the above correlations are not applicable, the WLOP correlation, Reference 90, is used to calculate DNBR values.

4.4.2.2.2 Definition of DNBR

The DNB heat flux ratio, DNBR, as applied to typical cells (flow cells with all walls heated) and thimble cells (flow cells with heated and unheated walls) is defined as:

$$\mathrm{DNBR} = \frac{q''_{\mathrm{DNB,\ predicted}}}{q''\mathrm{actual}}$$

where:

$$q''_{\mathrm{DNB,\ predicted}} = \frac{q''_{\mathrm{WRB-2M}}}{F} \quad \text{or} \quad q''_{\mathrm{DNB,\ predicted}} = \frac{q''_{\mathrm{WRB-2}}}{F}$$

q''_{WRB-2M} = the uniform DNB heat flux as predicted by the WRB-2M DNB correlation

q''_{WRB-2} = the uniform DNB heat flux as predicted by the WRB-2 DNB correlation

F = the flux shape factor to account for nonuniform axial heat flux distributions (Reference 10) with the term “C” modified as in Reference 5

$q''actual$ = the actual local heat flux

Adjusted F factors are used for WRB-2M, Reference 82a, ABB-NV, References 89 and 90, and WLOP, Reference 90.

4.4.2.2.3 Mixing Technology

The rate of heat exchange by mixing between flow channels is proportional to the difference in the local mean fluid enthalpy of the respective channels, the local fluid density, and the flow velocity. The proportionality is expressed by the dimensionless thermal diffusion coefficient (TDC) which is defined as:

$$\mathrm{TDC} = \frac{w'}{\rho V a}$$

where:

w' = flow exchange rate per unit length (lbm/ft-s)

ρ = fluid density (lbm/ft^3)

V = fluid velocity (ft/s)

a = lateral flow area between channels per unit length (ft^2/ft)

The application of the thermal diffusion coefficient in the VIPRE-01 analysis for determining the overall mixing effect or heat exchange rate is presented in Reference 83.

As discussed in WCAP-7941-P-A (Reference 12) those series of tests, using the “R” mixing vane grid design on 13-, 26-, and 32-inch grid spacing, were conducted in pressurized water loops at Reynolds numbers similar to that of a pressurized water reactor core under the following single- and two-phase (subcooled boiling) flow conditions:

- Pressure — 1500 to 2400 psia
- Inlet temperature — 332 to 642°F
- Mass velocity — 1.0 to 3.5 x 10^6 lbm/hr-ft^2
- Reynolds number — 1.34 to 7.45 x 10^5
- Bulk outlet quality — -52.1 to -13.5 percent

The thermal diffusion coefficient is determined by comparing the THINC code predictions with the measured subchannel exit temperatures. Data for 26-inch axial grid spacing are presented in Figure 4.4-1, where the thermal diffusion coefficient is plotted versus the Reynolds number. The thermal diffusion coefficient is found to be independent of the Reynolds number, mass velocity, pressure, and quality over the ranges tested. The two-phase data (local, subcooled boiling) falls within the scatter of the single-phase data. The effect of two-phase flow on the value of the thermal diffusion coefficient is demonstrated in WCAP-7941-P-A (Reference 12), by Rowe and Angle (References 13 and 14), and Gonzalez-Santalo and Griffith (Reference 15). In the subcooled boiling region, the values of the thermal diffusion coefficient are indistinguishable from the single-phase values. In the quality region, Rowe and Angle show that in the case with rod spacing similar to that in pressurized water reactor core geometry, the value of the thermal diffusion coefficient increased with quality to a point and then decreased, but never below the single-phase value. Gonzalez-Santalo and Griffith show that the mixing coefficient increased as the void fraction increased.

The data from these tests on the R-mixing vane grid show that a design thermal diffusion coefficient value of 0.038 (for 26-inch grid spacing) can be used in determining the effect of coolant mixing in the THINC analysis. An equivalent value of the mixing coefficient is used in the VIPRE-01 evaluations (Reference 83). A mixing test program similar to the one just described was conducted for the current 17 x 17 geometry and mixing vane grids on 26-inch spacing, as described in WCAP-8298-P-A (Reference 16). The mean value of the thermal diffusion coefficient obtained from these tests is 0.059.

The inclusion of intermediate flow mixer grids in the upper spans of the fuel assembly results in a grid spacing of approximately 10 inches giving higher values of the thermal diffusion coefficient. A conservative value of the thermal diffusion coefficient, 0.038, is used to determine the effect of coolant mixing in the core thermal performance analysis.

4.4.2.2.4 Hot Channel Factors

The total hot channel factors for heat flux and enthalpy rise are defined as the maximum-to-core-average ratios of these quantities. The heat flux hot channel factor considers the local maximum linear heat generation rate at a point (the hotspot), and the enthalpy rise hot channel factor involves the maximum integrated value along a channel (the hot channel).

Each of the total hot channel factors is composed of a nuclear hot channel factor, Subsection 4.4.4.3, describing the neutron power distribution and an engineering hot channel factor, which allows for

variations in flow conditions and fabrication tolerances. The engineering hot channel factors are made up of subfactors which account for the influence of the variations of fuel pellet diameter, density, enrichment, and eccentricity; inlet flow distribution; flow redistribution; and flow mixing.

Heat Flux Engineering Hot Channel Factor, F_Q^E

The heat flux engineering hot channel factor is used to evaluate the maximum linear heat generation rate in the core. This subfactor is determined by statistically combining the fabrication variations for fuel pellet diameter, density, and enrichment. As shown in WCAP-8174 (Reference 17), no DNB penalty needs to be taken for the short, relatively low-intensity heat flux spikes caused by variations in the above parameters, as well as fuel pellet eccentricity and fuel rod diameter variation.

Enthalpy Rise Engineering Hot Channel Factor, $F_{\Delta H}^E$

The effect of variations in flow conditions and fabrication tolerances on the hot channel enthalpy rise is directly considered in the VIPRE-01 core thermal subchannel analysis, described in Subsection 4.4.4.5.1 under any reactor operating condition. The following items are considered as contributors to the enthalpy rise engineering hot channel factor:

- Pellet diameter, density, and enrichment

  Variations in pellet diameter, density, and enrichment are considered statistically in establishing the limit DNBRs, described in Subsection 4.4.1.1.2, for the Revised Thermal Design Procedure (Reference 2). Uncertainties in these variables are determined from sampling of manufacturing data.

- Inlet flow maldistribution

  The consideration of inlet flow maldistribution in core thermal performances is described in Subsection 4.4.4.2.2. A design basis of five-percent reduction in coolant flow to the hot assembly is used in the VIPRE-01 analyses.

- Flow redistribution

  The flow redistribution accounts for the reduction in flow in the hot channel resulting from the high flow resistance in the channel due to the local or bulk boiling. The effect of the nonuniform power distribution is inherently considered in the VIPRE-01 analyses for every operating condition evaluated.

- Flow mixing

  The subchannel mixing model incorporated in the VIPRE-01 code and used in reactor design is based on experimental data, as detailed in WCAP-7667-P-A (Reference 18) and discussed in Subsections 4.4.2.2.3 and 4.4.4.5.1. The mixing vanes incorporated in the spacer grid design induce additional flow mixing between the various flow channels in a fuel assembly as well as between adjacent assemblies. This mixing reduces the enthalpy rise in the hot channel resulting from local power peaking or unfavorable mechanical tolerances. The VIPRE-01 mixing model is discussed in Reference 83.

4.4.2.2.5 Effects of Rod Bow on DNBR

The phenomenon of fuel rod bowing, as described in WCAP-8691 (Reference 19), is accounted for in the DNBR safety analysis of Condition I and Condition II events for each plant application. Applicable generic credits for margin resulting from retained conservatism in the evaluation of DNBR and/or margin obtained form measured plant operating parameters (such as $F_{\Delta H}^N$ or core flow), which are

less limiting than those required by the plant safety analysis, can be used to offset the effect of rod bow.

For the safety analysis of the AP1000, sufficient DNBR margin was maintained, as described in Subsection 4.4.1.1.2, to accommodate the full and low flow rod bow DNBR penalties identified in Reference 20. The referenced penalties are applicable to the analyses using the WRB-2M or WRB-2 DNB correlations.

The maximum rod bow penalties (less than about 2 percent DNBR) accounted for in the design safety analysis are based on an assembly average burnup of 24,000 MWD/MTU. At burnups greater than 24,000 MWD/MTU, credit is taken for the effect of $F^N_{\Delta H}$ burndown, due to the decrease in fissionable isotopes and the buildup of fission product inventory, and no additional rod bow penalty is required (Reference 21).

In the upper spans of the fuel assembly, additional restraint is provided with the intermediate flow mixer grids such that the grid-to-grid spacing in those spans with intermediate flow mixer grids is approximately 10 inches compared to approximately 20 inches in the other spans. Using the NRC approved scaling factor [see WCAP 8691 (Reference 19) and Reference 21], results in predicted channel closure in the limiting 10 inch spans of less than 50 percent closure. Therefore, no rod bow DNBR penalty is required in the 10 inch spans in the safety analyses.

4.4.2.3 Linear Heat Generation Rate

The core average and maximum linear heat generation rates are given in Table 4.4-1. The method of determining the maximum linear heat generation rate is given in Subsection 4.3.2.2.

4.4.2.4 Void Fraction Distribution

The calculated core average and the hot subchannel maximum and average void fractions are presented in Table 4.4-2 for operation at full power. The void models used in the VIPRE-W code are described in Subsection 4.4.2.7.3.

4.4.2.5 Core Coolant Flow Distribution

The VIPRE-01 code is used to calculate the flow and enthalpy distribution in the core for use in safety analysis. Extensive experimental verification of VIPRE-01 is presented in Reference 84.

4.4.2.6 Core Pressure Drops and Hydraulic Loads

4.4.2.6.1 Core Pressure Drops

The analytical model and experimental data used to calculate the pressure drops shown in Table 4.4-1 are described in Subsection 4.4.2.7. The core pressure drop includes the fuel assembly, lower core plate, and upper core plate pressure drops. The full-power operation pressure drop values shown in Table 4.4-1 are the unrecoverable pressure drops across the vessel, including the inlet and outlet nozzles, and across the core. These pressure drops are based on the best-estimate flow for actual plant operating conditions as described in Subsection 5.1.4. This subsection also defines and describes the thermal design flow (minimum flow) that is the basis for reactor core thermal performance and the mechanical design flow (maximum flow) that is used in the mechanical design of the reactor vessel internals and fuel assemblies. Since the best-estimate flow is that flow which is most likely to exist in an operating plant, the calculated core pressure drops in Table 4.4-1 are based on this best-estimate flow rather than the thermal design flow.

The uncertainties associated with the core pressure drop values are presented in Subsection 4.4.2.9.2.

4.4.2.6.2 Hydraulic Loads

Figure 4.2-2 shows the fuel assembly hold-down springs. These springs are designed to keep the fuel assemblies in contact with the lower core plate under Condition I and II events, except for the turbine overspeed transient associated with a loss of external load. The hold-down springs are designed to tolerate the possibility of an overdeflection associated with fuel assembly lift-off for this case and to provide contact between the fuel assembly and the lower core plate following this transient. More adverse flow conditions occur during a loss-of-coolant accident. These conditions are presented in Subsection 15.6.5.

Hydraulic loads at normal operating conditions are calculated considering the best-estimate flow, described in Section 5.1, and accounting for the minimum core bypass flow based on manufacturing tolerances. Core hydraulic loads at cold plant startup conditions are based on the cold best-estimate flow, but are adjusted to account for the coolant density difference. Conservative core hydraulic loads for a pump overspeed transient, which could possibly create a flow rate 18-percent greater than the best estimate flow, are evaluated to be approximately twice the fuel assembly weight.

Hydraulic verification tests for the fuel assembly are described in Reference 86.

4.4.2.7 Correlation and Physical Data

4.4.2.7.1 Surface Heat Transfer Coefficients

Forced convection heat transfer coefficients are obtained from the Dittus-Boelter correlation (Reference 24), with the properties evaluated at bulk fluid conditions:

$$\frac{hD_e}{K} = 0.023\left(\frac{D_e G}{\mu}\right)^{0.8}\left(\frac{C_p \mu}{K}\right)^{0.4}$$

where:

h = heat transfer coefficient (btu/h-ft^2-°F)

D_e = equivalent diameter (ft)

K = thermal conductivity (Btu/h-ft-°F)

G = mass velocity (lbm/h-ft^2)

μ = dynamic viscosity (lbm/ft-h)

C_p = heat capacity (Btu/lb-°F)

This correlation has been shown to be conservative (Reference 25) for rod bundle geometries with pitch-to-diameter ratios in the range used by pressurized water reactors.

The onset of nucleate boiling occurs when the clad wall temperature reaches the amount of superheat predicted by Thom's correlation (Reference 26). After this occurrence, the outer clad wall temperature is determined by:

$$\Delta T_{sat} = [0.072\exp(-P/1260)](q'')^{0.5}$$

where:

ΔT_{sat} = wall superheat, $T_W - T_{sat}$ (°F)

q'' = wall heat flux (Btu/h-ft^2)

P = pressure (psia)

T_w = outer clad wall temperature (°F)

T_{sat} = saturation temperature of coolant at pressure P (°F)

4.4.2.7.2 Total Core and Vessel Pressure Drop

Unrecoverable pressure losses occur as a result of viscous drag (friction) and/or geometry changes (form) in the fluid flow path. The flow field is assumed to be incompressible, turbulent, single-phase water. Those assumptions apply to the core and vessel pressure drop calculations for the purpose of establishing the primary loop flow rate. Two-phase considerations are neglected in the vessel pressure drop evaluation because the core average void is negligible, as shown in Table 4.4-2. Two-phase flow considerations in the core thermal subchannel analysis are considered and the models are described in Subsection 4.4.4.2.3. Core and vessel pressure losses are calculated by equations of the form:

$$\Delta P_L = (K + f\frac{L}{D_e})\frac{\rho V^2}{2 g_c (144)}$$

where:

ΔP_L = unrecoverable pressure drop (lb/in.^{2})

ρ = fluid density (lbm/ft^3)

L = length (ft)

D_e = equivalent diameter (ft)

V = fluid velocity (ft/s)

g_c = 32.174 (lbm-ft/lbf-s^2)

K = form loss coefficient (dimensionless)

f = friction loss coefficient (dimensionless)

Fluid density is assumed to be constant at the appropriate value for each component in the core and vessel. Because of the complex core and vessel flow geometry, precise analytical values for the form

and friction loss coefficients are not available. Therefore, experimental values for these coefficients are obtained from geometrically similar models.

Values are quoted in Table 4.4-1 for unrecoverable pressure loss across the reactor vessel, including the inlet and outlet nozzles, and across the core. The results of full-scale tests of core components and fuel assemblies are used in developing the core pressure loss characteristic.

Tests of the primary coolant loop flow rates are made prior to initial criticality as described in Subsection 4.4.5.1, to verify that the flow rates used in the design, which are determined in part from the pressure losses calculated by the method described here, are conservative. See Section 14.2 for preoperational testing.

4.4.2.7.3 Void Fraction Correlation

VIPRE-01 considers two-phase flow in two steps. First, a quality model is used to compute the flowing vapor mass fraction (true quality) including the effects of subcooled boiling. Then, given the true void quality, a bulk void model is applied to compute the vapor volume fraction (void fraction).

VIPRE-01 uses a profile fit model (Reference 83) for determining subcooled quality. It calculates the local vapor volumetric fraction in forced convection boiling by: 1) predicting the point of bubble departure from the heated surface and 2) postulating a relationship between the true local vapor fraction and the corresponding thermal equilibrium value.

The void fraction in the bulk boiling region is predicted by using homogeneous flow theory and assuming no slip. The void fraction in this region is therefore a function only of the thermodynamic quality.

4.4.2.8 Thermal Effects of Operational Transients

DNB core safety limits are generated as a function of coolant temperature, pressure, core power, and axial power imbalance. Steady-state operation within these safety limits provides that the DNB design basis is met. Subsection 15.0.6 discusses the overtemperature ΔT trip (based on DNBR limit) versus T_{avg}. This system provides protection against anticipated operational transients that are slow with respect to fluid transport delays in the primary system. In addition, for fast transients (such as uncontrolled rod bank withdrawal at power incident as described in Subsection 15.4.2), specific protection functions are provided as described in Section 7.2. The use of these protection functions is described in Chapter 15.

4.4.2.9 Uncertainties in Estimates

4.4.2.9.1 Uncertainties in Fuel and Clad Temperatures

As described in Subsection 4.4.2.11, the fuel temperature is a function of crud, oxide, clad, pellet-clad gap, and pellet conductances. Uncertainties in the fuel temperature calculation are essentially of two types: fabrication uncertainties, such as variations in the pellet and clad dimensions and the pellet density; and model uncertainties, such as variations in the pellet conductivity and the gap conductance. These uncertainties have been quantified by comparison of the thermal model to the in-pile thermocouple measurements (References 30 through 36), by out-of-pile measurements of the fuel and clad properties (References 37 through 48), and by measurements of the fuel and clad dimensions during fabrication. The resulting uncertainties are then used in the evaluations involving the fuel temperature. The effect of densification on fuel temperature uncertainties is also included in the calculation of the total uncertainty.

In addition to the temperature uncertainty described above, the measurement uncertainty in determining the local power and the effect of density and enrichment variations on the local power are considered in establishing the heat flux hot channel factor. These uncertainties are described in Subsection 4.3.2.2.1.

Reactor trip setpoints, as specified in the technical specifications, include allowance for instrument and measurement uncertainties such as calorimetric error, instrument drift and channel reproducibility, temperature measurement uncertainties, noise, and heat capacity variations.

Uncertainty in determining the cladding temperature results from uncertainties in the crud and oxide thicknesses. Because of the excellent heat transfer between the surface of the rod and the coolant, the film temperature drop does not appreciably contribute to the uncertainty.

4.4.2.9.2 Uncertainties in Pressure Drops

Core and vessel pressure drops based on the best-estimate flow, as described in Section 5.1, are quoted in Table 4.4-1. The uncertainties quoted are based on the uncertainties in both the test results and the analytical extension of these values to the reactor application.

A major use of the core and vessel pressure drops is to determine the primary system coolant flow rates, as described in Section 5.1. In addition, as described in Subsection 4.4.5.1, tests on primary system prior to initial criticality, are conducted to verify that a conservative primary system coolant flow rate has been used in the design and analysis of the plant.

4.4.2.9.3 Uncertainties Due to Inlet Flow Maldistribution

The effects of uncertainties in the inlet flow maldistribution criteria used in the core thermal analyses are described in Subsection 4.4.4.2.2.

4.4.2.9.4 Uncertainty in DNB Correlation

The uncertainty in the DNB correlation described in Subsection 4.4.2.2, is written as a statement on the probability of not being in DNB based on the statistics of the DNB data. This is described in Subsection 4.4.2.2.2.

4.4.2.9.5 Uncertainties in DNBR Calculations

The uncertainties in the DNBRs calculated by the VIPRE-01 analyses, discussed in Subsection 4.4.4.5.1, due to uncertainties in the nuclear peaking factors are accounted for by applying conservatively high values of the nuclear peaking factors. Measurement error allowances are included in the statistical evaluation of the limit DNBR described in Subsection 4.4.1.1 using the Revised Thermal Design Procedure. More information is provided in WCAP-11397-P-A (Reference 2). In addition, conservative values for the engineering hot channel factors are used as presented in Subsection 4.4.2.2.4. The results of a sensitivity study, WCAP-8054-P-A (Reference 22), with THINC-IV, a VIPRE-01 equivalent code, show that the minimum DNBR in the hot channel is relatively insensitive to variations in the core-wide radial power distribution (for the same value of $F^{N}_{\Delta H}$).

The ability of the VIPRE-01 computer code to accurately predict flow and enthalpy distributions in rod bundles is discussed in Subsection 4.4.4.5.1 and in Reference 83. Studies (Reference 84) have been performed to determine the sensitivity of the minimum DNBR to the void fraction correlation (see also Subsection 4.4.2.7.3) and the inlet flow distributions. The results of these studies show that the minimum DNBR is relatively insensitive to variation in these parameters. Furthermore, the VIPRE-01 flow field model for predicting conditions in the hot channels is consistent with that used in

the derivation of the DNB correlation limits including void/quality modeling, turbulent mixing and crossflow and two phase flow (Reference 83).

4.4.2.9.6 Uncertainties in Flow Rates

The uncertainties associated with reactor coolant loop flow rates are discussed in Section 5.1. A thermal design flow is defined for use in core thermal performance evaluations accounting for both prediction and measurement uncertainties. In addition, another 5.9 percent of the thermal design flow is assumed to be ineffective for core heat removal capability because it bypasses the core through the various available vessel flow paths described in Subsection 4.4.4.2.1.

4.4.2.9.7 Uncertainties in Hydraulic Loads

As described in Subsection 4.4.2.6.2, hydraulic loads on the fuel assembly are evaluated for a pump overspeed transient which creates flow rates 18 percent greater than the best estimate flow. The best estimate flow is the most likely flow rate value for the actual plant operating condition.

4.4.2.9.8 Uncertainty in Mixing Coefficient

A conservative value of the mixing coefficient, that is, the thermal diffusion coefficient, is used in the VIPRE-01 analyses.

4.4.2.10 Flux Tilt Considerations

Significant quadrant power tilts are not anticipated during normal operation since this phenomenon is caused by some asymmetric perturbation. A dropped or misaligned rod cluster control assembly could cause changes in hot channel factors. These events are analyzed separately in Chapter 15.

Other possible causes for quadrant power tilts include X-Y xenon transients, inlet temperature mismatches, enrichment variations within tolerances, and so forth.

In addition to unanticipated quadrant power tilts as described above, other readily explainable asymmetries may be observed during calibration of the ex-core detector quadrant power tilt alarm. During operation, in-core maps are taken at least one per month and additional maps are obtained periodically for calibration purposes. Each of these maps is reviewed for deviations from the expected power distributions.

Asymmetry in the core, from quadrant to quadrant, is frequently a consequence of the design when assembly and/or component shuffling and rotation requirements do not allow exact symmetry preservation. In each case, the acceptability of an observed asymmetry, planned or otherwise, depends solely on meeting the required accident analyses assumptions. In practice, once acceptability has been established by review of the incore maps, the quadrant power tilt alarms and related instrumentation are adjusted to indicate zero quadrant power tilt ratio as the final step in the calibration process. This action confirms that the instrumentation is correctly calibrated to alarm in the event an unexplained or unanticipated change occurs in the quadrant-to-quadrant relationships between calibration intervals.

Proper functioning of the quadrant power tilt alarm is significant. No allowances are made in the design for increased hot channel factors due to unexpected developing flux tilts, since likely causes are presented by design or procedures or are specifically analyzed.

Finally, in the event that unexplained flux tilts do occur, the Technical Specifications provide appropriate corrective actions to provide continued safe operation of the reactor.

4.4.2.11 Fuel and Cladding Temperatures

Consistent with the thermal-hydraulic design bases described in Subsection 4.4.1, the following discussion pertains mainly to fuel pellet temperature evaluation. A description of fuel clad integrity is presented in Subsection 4.2.3.1.

The thermal-hydraulic design provides that the maximum fuel temperature is below the melting point of uranium dioxide, Subsection 4.4.1.2. To preclude center melting and to serve as a basis for overpower protection system setpoints, a calculated center-line fuel temperature of 4700°F is selected as the overpower limit. This provides sufficient margin for uncertainties in the thermal evaluations, as described in Subsection 4.4.2.9.1. The temperature distribution within the fuel pellet is predominantly a function of the local power density and the uranium dioxide thermal conductivity. However, the computation of radial fuel temperature distributions combines crud, oxide, clad gap, and pellet conductances. The factors which influence these conductances, such as gap size (or contact pressure), internal gas pressure, gas composition, pellet density, and radial power distribution within the pellet, have been combined into a semi-empirical thermal model, discussed in Subsection 4.2.3.3, that includes a model for time-dependent fuel densification, as given in WCAP-10851-P-A (Reference 49) and WCAP-15063-P-A, Revision 1 (Reference 85). This thermal model enables the determination of these factors and their net effects on temperature profiles. The temperature predictions have been compared to in-pile fuel temperature measurements (References 30 through 36, 50 and 85) and melt radius data (References 51 and 52) with good results.

Fuel rod thermal evaluations (fuel centerline, average and surface temperatures) are performed at several times in the fuel rod lifetime (with consideration of time-dependent densification) to determine the maximum fuel temperatures.

The principal factors employed in the determination of the fuel temperature follow.

4.4.2.11.1 Uranium Dioxide Thermal Conductivity

The thermal conductivity of uranium dioxide was evaluated from data reported in References 37 through 48 and 53. At the higher temperatures, thermal conductivity is best obtained by using the integral conductivity to melt. From an examination of the data, it has been concluded that the best estimate is:

$$\int_{o}^{2800} K\,dt = 93\ W/cm$$

This conclusion is based on the integral values reported in References 51 and 53 through 57.

The design curve for the thermal conductivity is shown in Figure 4.4-2. The section of the curve at temperatures between 0° and 1300°C is in agreement with the recommendation of the International Atomic Energy Agency (IAEA) panel (Reference 58). The section of the curve above 1300°C is derived for an integral value of 93 W/cm. (References 51, 53, and 57).

Thermal conductivity for uranium dioxide at 95-percent theoretical density can be represented by the following equation:

$$K = \frac{1}{11.8 + 0.0238\,T} + 8.775 \times 10^{-13}\,T^3$$

where:

K = W/cm-°C

T = °C.

4.4.2.11.2 Radial Power Distribution in Uranium Dioxide Fuel Rods

An accurate description of the radial power distribution as a function of burnup is needed for determining the power level for incipient fuel melting and other important performance parameters, such as pellet thermal expansion, fuel swelling, and fission gas release rates. Radial power distribution in uranium dioxide fuel rods is determined with the neutron transport theory code, LASER. The LASER code has been validated by comparing the code predictions on radial burnup and isotopic distributions with measured radial microdrill data, as detailed in WCAP-6069 (Reference 59) and WCAP-3385-56 (Reference 60). A radial power depression factor, f, is determined using radial power distributions predicted by LASER. The factor, f, enters into the determination of the pellet centerline temperature, T_c, relative to the pellet surface temperature, T_g, through the expression:

$$\int_{T_i}^{T_c} K(T)\,dT = \frac{q'\,f}{4\pi}$$

where:

K(T) = the thermal conductivity for uranium dioxide with a uniform density distribution

q' = the linear power generation rate

The corresponding correlation for an annular fuel pellet is:

$$\int_{T_S}^{T_C} K(T)\,dT = \frac{q'\,f}{4\pi}\left[1 - \frac{2\ln(R_0/R_i)}{(R_0/R_i)^2 - 1}\right]$$

where:

R_0 = outer radius of fuel pellet

R_i = radius of the central void

4.4.2.11.3 Gap Conductance

The temperature drop across the pellet-clad gap is a function of the gap size and the thermal conductivity of the gas in the gap. The gap conductance model is selected so that when combined with the uranium dioxide thermal conductivity model, the calculated fuel center-line temperature reflect the in-pile temperature measurements. A more detailed description of the gap conductance model is presented in WCAP-10851-P-A (Reference 49) and WCAP-15063-P-A (Reference 85).

4.4.2.11.4 Surface Heat Transfer Coefficients

The fuel rod surface heat transfer coefficients during subcooled forced convection and nucleate boiling are presented in Subsection 4.4.2.7.1.

4.4.2.11.5 Fuel Clad Temperatures

The outer surface of the fuel rod at the hotspot operates at a temperature a few degrees above fluid temperature for steady-state operation at rated power throughout core life due to the onset of nucleate boiling. At beginning of life this temperature is the same as the clad metal outer surface.

During operation over the life of the core, the buildup of oxides and crud on the fuel rod surface causes the clad surface temperature to increase. Allowance is made in the fuel center melt evaluation for this temperature rise. Since the thermal-hydraulic design basis limits DNB, adequate heat transfer is provided between the fuel clad and the reactor coolant so that the core thermal output is not limited by considerations of clad temperature.

4.4.2.11.6 Treatment of Peaking Factors

The total heat flux hot channel factor, F_Q, is defined by the ratio of the maximum-to-core-average heat flux. The design value of F_Q, as presented in Table 4.3-2 and described in Subsection 4.3.2.2.6, is 2.6 for normal operation.

As described in Subsection 4.3.2.2.6, the peak linear power resulting from overpower transients/ operator errors (assuming a maximum overpower of 118 percent) is less than or equal to 22.45 kW/ft. The centerline fuel temperature must be below the uranium dioxide melt temperature over the lifetime of the rod, including allowances for uncertainties. The fuel temperature design basis is described in Subsection 4.4.1.2 and results in a maximum allowable calculated center-line temperature of 4700°F. The peak linear power for prevention of center-line melt is 22.5 kW/ft. The center-line temperature at the peak linear power resulting from overpower transients/operator errors (assuming a maximum overpower of 118 percent) is below that required to produce melting.

4.4.3 Description of the Thermal and Hydraulic Design of the Reactor Coolant System

4.4.3.1 Plant Configuration Data

Plant configuration data for the thermal-hydraulic and fluid systems external to the core are provided as appropriate in Chapters 5, 6, and 9. Areas of interest are as follows:

- Total coolant flow rates for the reactor coolant system and each loop are provided in Table 5.1-3. Flow rates employed in the evaluation of the core are presented throughout Section 4.4.

- Total reactor coolant system volume including pressurizer and surge line and reactor coolant system liquid volume, including pressurizer water at steady-state power conditions, are given in Table 5.1-2.

- The flow path length through each volume may be calculated from physical data provided in Table 5.1-2.
- Line lengths and sizes for the passive core cooling system are determined to provide a total system resistance which will provide, as a minimum, the fluid delivery rates assumed in the safety analyses described in Chapter 15.
- The parameters for components of the reactor coolant system are presented in Section 5.4.
- The steady-state pressure drops and temperature distributions through the reactor coolant system are presented in Table 5.1-1.

4.4.3.2 Operating Restrictions on Pumps

The minimum net positive suction head is established before operating the reactor coolant pumps. The operator verifies that the system pressure satisfies net positive suction head requirements prior to operating the pumps.

4.4.3.3 Power-Flow Operating Map (Boiling Water Reactor BWR)

This subsection is not applicable to AP1000.

4.4.3.4 Temperature-Power Operating Map (PWR)

The relationship between reactor coolant system temperature and power is a linear relationship between zero and 100-percent power.

The effects of reduced core flow due to inoperative pumps is described in Subsections 5.4.1 and 15.2.6 and Section 15.3. The AP1000 does not include power operation with one pump out of service. Natural circulation capability of the system is described in Subsection 5.4.2.3.2.

4.4.3.5 Load Following Characteristics

Load follow using control rod and gray rod motion is described in Subsection 4.3.2.4.16. The reactor power is controlled to maintain average coolant temperature at a value which is a linear function of load, as described in Section 7.7.

4.4.3.6 Thermal and Hydraulic Characteristics Summary Table

The thermal and hydraulic characteristics are given in Tables 4.1-1, 4.4-1, and 4.4-2.

4.4.4 Evaluation

4.4.4.1 Critical Heat Flux

The critical heat flux correlations used in the core thermal analysis are explained in Subsection 4.4.2.

4.4.4.2 Core Hydraulics

4.4.4.2.1 Flow Paths Considered in Core Pressure Drop and Thermal Design

The following flow paths for core bypass are considered:

A. Flow through the spray nozzles into the upper head for head cooling purposes

B. Flow entering into the rod cluster control and gray rod cluster guide thimbles

C. Leakage flow from the vessel inlet nozzle directly to the vessel outlet nozzle through the gap between the vessel and the barrel

D. Flow introduced through the core shroud for the purpose of cooling and not considered available for core cooling

The above contributions are evaluated to confirm that the design value of the core bypass flow is met.

Of the total allowance, one part is associated with the core and the remainder is associated with the internals (items A, C, and D above). Calculations have been performed using drawing tolerances in the worst direction and accounting for uncertainties in pressure losses. Based on these calculations, the core bypass is no greater than the 5.9 percent design value.

Flow model test results for the flow path through the reactor are described in Subsection 4.4.2.7.2.

4.4.4.2.2 Inlet Flow Distributions

A core inlet flow distribution reduction of five percent to the hot assembly inlet is used in the VIPRE-01 analyses of DNBR in the AP1000 core. Studies shown in WCAP-8054-P-A (Reference 22), made with THINC-IV, a VIPRE-01 equivalent code, show that flow distributions significantly more nonuniform than five percent have a very small effect on DNBR, which is accounted for in the DNB analysis.

4.4.4.2.3 Empirical Friction Factor Correlations

The friction factor for VIPRE-01 in the axial direction, parallel to the fuel rod axis, is evaluated using a correlation for a smooth tube (Reference 83). The effect of two-phase flow on the friction loss is expressed in terms of the single-phase friction pressure drop and a two-phase friction multiplier. The multiplier is calculated using the homogenous equilibrium flow model.

The flow in the lateral directions, normal to the fuel rod axis, views the reactor core as a large tube bank. Thus, the lateral friction factor proposed by Idel'chik (Reference 64) is applicable. This correlation is of the form:

$$F_L = A\, Re_L^{-0.2}$$

where:

A = a function of the rod pitch and diameter as given in Idel'chik (Reference 64)

Re_L = the lateral Reynolds number based on the rod diameter

The comparisons of predictions to data given in Reference 83 verify the applicability of the VIPRE-01 correlations in PWR design.

4.4.4.3 Influence of Power Distribution

The core power distribution, which is largely established at beginning of life by fuel enrichment, loading pattern, and core power level, is also a function of variables such as control rod worth and

position, and fuel depletion through lifetime. Radial power distributions in various planes of the core are often illustrated for general interest. However, the core radial enthalpy rise distribution, as determined by the integral of power up each channel, is of greater importance for DNBR analyses. These radial power distributions, characterized by $F_N^{\Delta H}$ (defined in Subsection 4.3.2.2.1), as well as axial heat flux profiles are discussed in the Subsections 4.4.4.3.1 and 4.4.4.3.2

4.4.4.3.1 Nuclear Enthalpy Rise Hot Channel Factor, $F_{\Delta H}^N$

Given the local power density q′ (kW/ft) at a point x, y, z in a core with N fuel rods and height H, then:

$$F_{\Delta H}^N = \frac{\text{hot rod power}}{\text{average rod power}} = \frac{\text{Max} \int_o^H q'(x_o, y_o, z_o)\, dz}{\frac{1}{N} \sum_{\text{all rods}} \int_o^H q'(x, y, z)\, dz}$$

The way in which $F_{\Delta H}^N$ is used in the DNBR calculation is important. The location of minimum DNBR depends on the axial profile, and the value of DNBR depends on the enthalpy rise to that point. Basically, the maximum value of the rod integral power is used to identify the most likely rod for minimum DNBR. An axial power profile is obtained that, when normalized to the design value of $F_{\Delta H}^N$, recreates the axial heat flux along the limiting rod. The surrounding rods are assumed to have the same axial profile with rod average powers which are typical distributions found in hot assemblies. In this manner, worst-case axial profiles can be combined with worst-case radial distributions for reference DNBR calculations.

It should be noted again that $F_{\Delta H}^N$ is an integral and is used as such in DNBR calculations. Local heat fluxes are obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal power shapes throughout the core.

For operation at a fraction of full power, the design $F_{\Delta H}^N$ used is given by:

$$F_{\Delta H}^N = F_{\Delta H}^{RTP}[1 + 0.3(1 - P)]$$

where:

$F_{\Delta H}^N$ is the limit at rated thermal power (RTP):

P is the fraction of rated thermal power and $F_{\Delta H}^{RTP}$ = 1.654 (= 1.72 / 1.04).

The permitted relaxation of $F_{\Delta H}^N$ is included in the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits, as detailed in WCAP-7912-P-A (Reference 65). This allows greater flexibility in the nuclear design.

4.4.4.3.2 Axial Heat Flux Distributions

As described in Subsection 4.3.2.2, the axial heat flux distribution can vary as a result of rod motion or power change or as a result of a spatial xenon transient which may occur in the axial direction. The ex-core nuclear detectors, as described in Subsection 4.3.2.2.7, are used to measure the axial power imbalance. The information from the ex-core detectors is used to protect the core from excessive axial power imbalance. The reference axial shape used in establishing core DNB limits (that is,

overtemperature ΔT protection system setpoints) is a chopped cosine with a peak-to-average value of 1.61. The reactor trip system provides automatic reduction of the trip setpoints on excessive axial power imbalance. To determine the magnitude of the setpoint reduction, the reference shape is supplemented by other axial shapes skewed to the bottom and top of the core.

The course of those accidents in which DNB is a concern is analyzed in Chapter 15 assuming that the protection setpoints have been set on the basis of these shapes. In many cases, the axial power distribution in the hot channel changes throughout the course of the accident due to rod motion, coolant temperature, and power level changes.

The initial conditions for the accidents for which DNB protection is required are assumed to be those permissible within the specified axial offset control limits described in Subsection 4.3.2.2. In the case of the loss-of-flow accident, the hot channel heat flux profile is very similar to the power density profile in normal operation preceding the accident. It is therefore possible to illustrate the calculated minimum DNBR for conditions representative of the loss-of-flow accident as a function of the flux difference initially in the core. The power shapes are evaluated with a full-power radial peaking factor ($F^{N}_{\Delta H}$) of 1.654 (= 1.72 / 1.04). The radial contribution to the hot rod power shape is conservative both for the initial condition and for the condition at the time of minimum DNBR during the loss-of-flow transient. The minimum DNBR is calculated for the design power shape for non-overpower/ overtemperature DNB events. This design shape results in calculated DNBR that bounds the normal operation shapes.

4.4.4.4 Core Thermal Response

A general summary of the steady-state thermal-hydraulic design parameters including thermal output and flow rates is provided in Table 4.4-1.

As stated in Subsection 4.4.1, the design bases of the application are to prevent DNB and to prevent fuel melting for Condition I and II events. The protective systems described in Chapter 7 are designed to meet these bases. The response of the core to Condition II transients is given in Chapter 15.

4.4.4.5 Analytical Methods

4.4.4.5.1 Core Analysis

The objective of reactor core thermal design is to determine the maximum heat removal capability in all flow subchannels and to show that the core safety limits, as presented in the technical specifications, are not exceeded while combining engineering and nuclear effects. The thermal design takes into account local variations in dimensions, power generation, flow redistribution, and mixing. The Westinghouse version of VIPRE-01, a three-dimensional subchannel code that has been developed to account for hydraulic and nuclear effects on the enthalpy rise in the core and hot channels, is described in Reference 83, VIPRE-01 modeling of a PWR core is based on a one-pass modeling approach (Reference 83). In the one-pass modeling, hot channels and their adjacent channels are modeled in detail, while the rest of the core is modeled simultaneously on a relatively coarse mesh. The behavior of the hot assembly is determined by superimposing the power distribution upon the inlet flow distribution while allowing for flow mixing and flow distribution between flow channels. Local variations in fuel rod power, fuel rod and pellet fabrication, and turbulent mixing are also considered in determining conditions in the hot channels. Conservation equations of mass, axial and lateral momentum, and energy are solved for the fluid enthalpy, axial flow rate, lateral flow, and pressure drop.

4.4.4.5.2 Steady State Analysis

The VIPRE-01 core model as approved by the NRC (Reference 83) is used with the applicable DNB correlations to determine DNBR distributions along the hot channels of the reactor core under all expected operating conditions. The VIPRE-01 code is described in detail in Reference 84, including discussions on code validation with experimental data. The VIPRE-01 modeling method is described in Reference 83, including empirical models and correlations used. The effect of crud on the flow and enthalpy distribution in the core is not directly accounted for in the VIPRE-01 evaluations. However, conservative treatment by the Westinghouse VIPRE-01 modeling method has been demonstrated to bound this effect in DNBR calculations (Reference 83).

Estimates of uncertainties are discussed in Subsection 4.4.2.9.

4.4.4.5.3 Experimental Verification

Extensive additional experimental verification of VIPRE-01 is presented in Reference 84.

The VIPRE-01 analysis is based on a knowledge and understanding of the heat transfer and hydrodynamic behavior of the coolant flow and the mechanical characteristics of the fuel elements. The use of the VIPRE-01 analysis provides a realistic evaluation of the core performance and is used in the thermal hydraulic analyses as described above.

4.4.4.5.4 Transient Analysis

VIPRE-01 is capable of transient DNB analysis. The conservation equations in the VIPRE-01 code contain the necessary accumulation terms for transient calculations. The input description can include one or more of the following time dependent arrays:

1. Inlet flow variation
2. Core heat flux variation
3. Core pressure variation
4. Inlet temperature or enthalpy variation

At the beginning of the transient, the calculation procedure is carried out as in the steady state analysis. The time is incremented by an amount determined either by the user or by the time step control options in the code itself. At each new time step the calculations are carried out with the addition of the accumulation terms which are evaluated using the information from the previous time step. This procedure is continued until a preset maximum time is reached.

At time intervals selected by the user, a complete description of the coolant parameter distributions as well as DNBR is printed out. In this manner the variation of any parameter with time can be readily determined.

4.4.4.6 Hydrodynamic and Flow Power Coupled Instability

Boiling flow may be susceptible to thermohydrodynamic instabilities (Reference 68). These instabilities are undesirable in reactors, since they may cause a change in thermohydraulic conditions that may lead to a reduction in the DNB heat flux relative to that observed during a steady flow condition or to undesired forced vibrations of core components. Therefore, a thermo-hydraulic design criterion was developed which states that modes of operation under Condition I and II events shall not lead to thermohydrodynamic instabilities.

Two specific types of flow instabilities are considered for AP1000 operation. These are the Ledinegg (or flow excursion) type of static instability and the density wave type of dynamic instability.

A Ledinegg instability involves a sudden change in flow rate from one steady state to another. This instability occurs (Reference 68) when the scope of the reactor coolant system pressure drop-flow rate curve:

$$\left(\frac{\partial \Delta P}{\partial G} \mid \text{internal}\right)$$

becomes algebraically smaller than the loop supply (pump head) pressure drop-flow rate curve:

$$\left(\frac{\partial \Delta P}{\partial G} \mid \text{external}\right)$$

The criterion for stability is thus:

$$\left(\frac{\partial \Delta P}{\partial G} \mid \text{internal} \geq \frac{\partial \Delta P}{\partial G} \mid \text{external}\right)$$

The reactor coolant pump head curve has a negative slope ($\partial\Delta P/\partial G$ external less than zero), whereas the reactor coolant system pressure drop-flow curve has a positive slope ($\partial\Delta P/\partial G$ internal greater than zero) over the Condition I and Condition II operational ranges. Thus, the Ledinegg instability does not occur.

The mechanism of density wave oscillations in a heated channel has been described by R. T. Lahey and F. J. Moody (Reference 69). Briefly, an inlet flow fluctuation produces an enthalpy perturbation. This perturbs the length and the pressure drop of the single-phase region and causes quality or void perturbations in the two-phase regions that travel up the channel with the flow. The quality and length perturbations in the two-phase region create two-phase pressure drop perturbations. However, since the total pressure drop across the core is maintained by the characteristics of the fluid system external to the core, then the two-phase pressure drop perturbation feeds back to the single-phase region. These resulting perturbations can be either attenuated or self-sustained.

A simple method has been developed by M. Ishii (Reference 70) for parallel closed-channel systems to evaluate whether a given condition is stable with respect to the density wave type of dynamic instability. This method had been used to assess the stability of typical Westinghouse reactor designs, including the design outlined in References 71, 72, and 73, under Condition I and II operation. The results indicate that a large margin-to-density wave instability exists. Increases on the order of 150 percent of rated reactor power would be required for the predicted inception of this type of instability.

The application of the Ishii method (Reference 70) to Westinghouse reactor designs is conservative due to the parallel open-channel feature of Westinghouse pressurized water reactor cores. For such cores, there is little resistance to lateral flow leaving the flow channels of high-power density. There is also energy transfer from channels of high-power density to lower power density channels. This

coupling with cooler channels leads to the conclusion that an open-channel configuration is more stable than the above closed-channel analysis under the same boundary conditions.

Flow stability tests (Reference 74) have been conducted where the closed channel systems were shown to be less stable than when the same channels were cross-connected at several locations. The cross-connections were such that the resistance to channel cross-flow and enthalpy perturbations would be greater than would exist in a pressurized water reactor core which has a relatively low resistance to cross-flow.

Flow instabilities that have been observed have occurred almost exclusively in closed-channel systems operating at low pressures relative to the Westinghouse pressurized water reactor operating pressures. H. S. Kao, T. D. Morgan, and W. B. Parker (Reference 75) analyzed parallel closed-channel stability experiments simulating a reactor core flow. These experiments were conducted at pressures up to 2200 psia. The results showed that, for flow and power levels typical of power reactor conditions, no flow oscillations could be induced above 1200 psia.

Additional evidence that flow instabilities do not adversely affect thermal margin is provided by the data from the rod bundle DNB tests. Many Westinghouse rod bundles have been tested over wide ranges of operating conditions with no evidence of premature DNB or inconsistent data which might be indicative of flow instabilities in the rod bundle.

In summary, it is concluded that thermohydrodynamic instabilities will not occur under Condition I and II for Westinghouse pressurized water reactor designs. A large power margin, greater than 150 percent of rated power, exists to predicted inception of such instabilities. Analysis has been performed which shows that minor plant-to-plant differences in Westinghouse reactor designs such as fuel assembly arrays, power-to-flow ratios, and fuel assembly length do not result in gross deterioration of the above power margins.

4.4.4.7 Fuel Rod Behavior Effects from Coolant Flow Blockage

Coolant flow blockages can occur within the coolant channels of a fuel assembly or external to the reactor core. The effects of fuel assembly blockage within the assembly on fuel rod behavior are more pronounced than external blockages of the same magnitude. In both cases, the flow blockages cause local reductions in coolant flow. The amount of local flow reduction, where the reduction occurs in the reactor, and how far along the flow stream the reduction persists are considerations which will influence the fuel rod behavior. The effects of coolant flow blockages in terms of maintaining rated core performance are determined both by analytical and experimental methods. The experimental data are usually used to augment analytical tools such as computer programs similar to the VIPRE-01 program. Inspection of the DNB correlation (Subsection 4.4.2.2 and References 4 and 5) shows that the predicted DNBR is dependent upon the local values of quality and mass velocity.

The VIPRE-01 code is capable of predicting the effects of local flow blockages on DNBR within the fuel assembly on a subchannel basis, regardless of where the flow blockage occurs. Reference 84 shows that, for a fuel assembly similar to the Westinghouse design, VIPRE-01 accurately predicts the flow distribution within the fuel assembly when the inlet nozzle is completely blocked. Full recovery of the flow was found to occur about 30 inches downstream of the blockage. With the reactor operating at the nominal full-power conditions specified in Table 4.4-1, the effects of an increase in enthalpy and decrease in mass velocity in the lower portion of the fuel assembly would not result in the fuel rods reaching the DNBR limit.

The open literature supports the conclusion that flow blockage in open-lattice cores, similar to the Westinghouse cores, causes flow perturbations which are local to the blockage. For example, A. Ohstubo and S. Uruwashi (Reference 76) show that the mean bundle velocity is approached asymptomatically about four inches downstream from the flow blockage in a single flow cell. Similar

results were also found for two and three cells completely blocked. P. Basmer, et al., (Reference 77) tested an open-lattice fuel assembly in which 41 percent of the subchannels were completely blocked in the center of the test bundle between spacer grids. Their results show that the stagnant zone behind the flow blockage essentially disappears after 1.65 L/De or about five inches for their test bundle. They also found that leakage flow through the blockage tended to shorten the stagnant zone or, in essence, the complete recovery length. Thus, local flow blockages within a fuel assembly have little effect on subchannel enthalpy rise. In reality, a local flow blockage would be expected to promote turbulence and, therefore would not likely affect DNBR at all.

Coolant flow blockages induce local cross-flows as well as promote turbulence. Fuel rod behavior is changed under the influence of a sufficiently high cross-flow component. Fuel rod vibration could occur, caused by this cross-flow component, through vortex shedding or turbulent mechanisms. If the cross-flow velocity exceeds the limit established for fluid elastic stability, large amplitude whirling results. The limits for a controlled vibration mechanism are established from studies of vortex shedding and turbulent pressure fluctuations. The cross-flow velocity required to exceed fluid elastic stability limits is dependent on the axial location of the blockage and the characterization of the cross-flow (jet flow or not). These limits are greater than those for vibratory fuel rod wear. Cross-flow velocity above the established limits can lead to mechanical wear of the fuel rods at the grid support locations. Fuel rod wear due to flow-induced vibration is considered in the fuel rod fretting evaluation as discussed in Section 4.2.

4.4.5 Testing and Verification

4.4.5.1 Tests Prior to Initial Criticality

A reactor coolant flow test is performed, as discussed in Chapter 14, following fuel loading but prior to initial criticality. Coolant loop pressure data is obtained in this test. This data allows determination of the coolant flow rates at reactor operating conditions. This test verifies that proper coolant flow rates have been used in the core thermal and hydraulic analysis.

4.4.5.2 Initial Power and Plant Operation

Core power distribution measurements are made at several core power levels, as discussed in Chapter 14. These tests are used to confirm that conservative peaking factors are used in the core thermal and hydraulic analysis.

Additional demonstration of the overall conservatism of the THINC analysis was obtained by comparing THINC predictions to in-core thermocouple measurements, as detailed WCAP-8453-A (Reference 78). VIPRE-01 has been confirmed to be as conservative as the THINC code in Reference 83.

4.4.5.3 Component and Fuel Inspections

Inspections performed on the manufactured fuel are described in Subsection 4.2.4. Fabrication measurements critical to thermal and hydraulic analysis are obtained to verify that the engineering hot channel factors in the design analyses (Subsection 4.4.2.2.4) are met.

4.4.6 Instrumentation Requirements

4.4.6.1 Incore Instrumentation

The primary function of the incore instrumentation system is to provide a three-dimensional flux map of the reactor core. This map is used to calibrate neutron detectors used by the protection and safety monitoring system as well as to optimize core performance. A secondary function of the incore

instrumentation system is to provide the protection and safety monitoring system with the signals necessary for monitoring core exit temperatures. This secondary function is the result of the mechanical design that groups the detectors used for generating the flux map in the same thimble as the core exit thermocouples.

The incore instrumentation system consists of incore instrument thimble assemblies, which house fixed incore detectors, core exit thermocouple assemblies contained within an inner and outer sheath assembly, and associated signal processing and data processing equipment. There are 42 incore instrument thimble assemblies: each is composed of multiple fixed incore detectors and one thermocouple.

The thimbles are inserted into the active core through the upper head and internals of the reactor vessel. The signals output from the fixed incore detectors are digitized inside containment and multiplexed out of the containment. The signal processing software integral to the incore instrumentation system allows the fixed incore detector signals to be used to calculate an accurate three-dimensional core power distribution suitable for developing calibration information for the excore nuclear instrumentation input to the overtemperature and overpower ΔT reactor trip setpoints. The system is also capable of accurately determining whether the reactor power distribution is currently within the operating limits defined in the technical specifications while the reactor is operating above approximately 20 percent of rated thermal power.

The incore instrument system data processor receives the transmitted digitized fixed incore detector signals from the signal processor and combines the measured data with analytically-derived constants, and certain other plant instrumentation sensor signals, to generate a full three-dimensional indication of nuclear power distribution in the reactor core. It also edits the three-dimensional indication of power distribution to extract pertinent power distribution parameters outputs for use by the plant operators and engineers. The data processor also generates hardcopy representations of the detailed three-dimensional nuclear power indications.

The hardware and software which perform the three-dimensional power distribution calculation are capable of executing the calculation algorithms and constructing graphical and tabular displays of core conditions at intervals of one minute or less. The software provides information to enable the reactor operator to ascertain how the measured peaking factor performance agrees with the peaking factor performance predicted by the design model used to determine the acceptability of the fuel loading pattern. The analysis software provides information required to activate a visual alarm display to alert the reactor operator about the current existence of, or the potential for, reactor operating limit violations. The calculation algorithms are capable of determining the three-dimensional reactor core power distribution using a minimum set of the total 42 in-core instrumentation thimble assemblies. Each in-core instrumentation thimble assembly consists of multiple fixed in-core detector elements that start at the top of the active fuel and have sequentially increasing lengths such that the longest element reaches the bottom of the active fuel in the fuel assembly. The calculation algorithms utilize the measured signal from detectors of different lengths within the assembly. The difference in signal from two operable detectors in the same assembly is defined as a detector segment. The minimum number of in-core monitor assemblies detectors required for operability of the system is at least 75% operating detector segments during the initial power distribution measurement required in each operating cycle; and at least 40% operating detector segments following the cycle initial power distribution measurement. A minimum of 15 operating detector segments in each quadrant with at least 6 detector segments in each quadrant below the core mid-plane and 6 detector segments per quadrant above the core midplane is required both prior to and following the cycle initial power distribution measurement. The hardware which performs the online power distribution monitoring is configured such that a single hardware failure will not necessitate a reactor maximum power reduction or restrict normal reactor operations.

During plant operation, the incore instrument thimble assembly is positioned within the fuel assembly and exits through the top of the reactor vessel QuickLoc seal connection. The fixed incore detector and core exit thermocouple signal exit the detector through a multipin connector to the incore instrument thimble tube cables. The fixed incore detector and core exit thermocouple cables are then routed to different data conditioning and processing stations. The data is processed and the results are available for display in the main control room.

4.4.6.2 Overtemperature and Overpower ΔT Instrumentation

The overtemperature ΔT trip protects the core against low DNBR. The overpower ΔT trip protects against excessive power (fuel rod rating protection).

As described in Subsection 7.2.1.1.3, factors included in establishing the overtemperature ΔT and overpower ΔT trip setpoints include the reactor coolant temperature in each loop and the axial distribution of core power as seen by excore neutron detectors.

4.4.6.3 Instrumentation to Limit Maximum Power Output

The signals from the three ranges (source, intermediate, and power) of neutron flux detectors, are used to limit the maximum power output of the reactor within their respective ranges.

There are twelve radial locations containing a total of twelve neutron flux detectors installed around the reactor between the vessel and the primary shield. Four proportional counters for the source range are located at the highest fluence portions of the core containing the primary startup sources at an elevation approximately one-fourth of the core height. Four pulse fission chambers for the intermediate range are positioned at an elevation corresponding to one-half of the core height. Four uncompensated ionization chamber assemblies for the power range are installed vertically at the four corners of the core. These assemblies are located equidistant from the reactor vessel along the length and, to minimize neutron flux pattern distortions, within approximately one foot of the reactor vessel. Each power range detector provides two signals corresponding to the neutron flux in the upper and in the lower sections of a core quadrant. The three ranges of detectors are used as inputs to monitor neutron flux from a completely shutdown condition to 120 percent of full power, with the capability of recording overpower excursions up to 200 percent of full power.

The output of the power range channels is used for:

- Protecting the core against the consequences of rod ejection accidents
- Protecting the core against the consequences of adverse power distributions resulting from dropped rods
- The rod speed control function
- Alerting the operator to an excessive power imbalance between the quadrants

The intermediate range detectors also provide signals for the post-accident monitoring system.

Details of the neutron detectors and nuclear instrumentation design and the control and trip logic are given in Chapter 7. The limits on neutron flux operation and trip setpoints are given in the technical specifications.

4.4.6.4 Digital Metal Impact Monitoring System

The digital metal impact monitoring system is the subsystem of the nonsafety-related special monitoring system that monitors the reactor coolant system for metallic loose parts. It consists of several active instrumentation channels, each comprising a piezoelectric accelerometer (sensor), signal conditioning, and diagnostic equipment. The digital metal impact monitoring system conforms with Regulatory Guide 1.133.

The digital metal impact monitoring system is designed to detect loose parts that weigh from 0.25 to 30 pounds, and can also detect impact with a kinetic energy of 0.5 foot-pounds on the inside surface of the reactor coolant system pressure boundary within three feet of a sensor.

The digital metal impact monitoring system consists of several redundant instrumentation channels, each comprised of a piezoelectric accelerometer (sensor), preamplifier, and signal conditioning equipment. The output signal from each accelerometer is amplified by the preamplifier and signal conditioning equipment before it is processed by a discriminator to eliminate noise and signals which are not indicative of loose part impacts. The system starts up and operates automatically.

The system facilitates performance tests, hardware integrity tests, and the recognition, location, replacement, repair and adjustment of malfunctioning components. System performance tests are made using a hammer as a tool to simulate an impact. Additional system performance testing is performed using special test modules. These modules simulate impacts and test performance of the signal processing equipment. Hardware integrity tests are also performed to verify equipment operation.

The impact detect algorithm, used by the signal processing equipment, is designed to minimize the number of false alarms. False impact detection, attributable to normal hydraulic, mechanical and electrical noise, is minimized by a number of techniques including:

- Utilizing a floating level within the impact detection algorithm. The floating level is based on signal levels not characteristic of an impact, and is generally a function of the background noise level.

- Comparing the impact event with the times and type of normally occurring plant operation events received from plant control system such as a control rod stepping.

- Comparing the number of events detected within a given time interval.

The sensors of the digital metal impact monitoring system are fastened mechanically to the reactor coolant system at potential loose part collection regions including the upper and lower head region of the reactor pressure vessel, and the reactor coolant inlet region of each steam generator.

The equipment inside the containment is designed to remain functional through an earthquake of a magnitude equal to 50 percent of the calculated safe shutdown earthquake and normal environments (radiation, vibration, temperature, humidity) anticipated during the operating lifetime. The instrument channels associated with the sensors at each reactor coolant system location are physically separated from each other starting at the sensor locations to a point in the plant that is always accessible for maintenance during full-power operation.

The digital metal impact monitoring system is calibrated prior to plant startup. Capabilities exist for subsequent periodic online channel checks and channel functional tests and for offline channel calibrations at refueling outages.

4.4.7 Combined License Information

4.4.7.1 Changes to the reference design of the fuel, burnable absorber rods, rod cluster control assemblies, or initial core design from that presented in the DCD are addressed in APP-GW-GLR-059 (Reference 87).

4.4.7.2 Following selection of the actual plant operating instrumentation and calculation of the instrumentation uncertainties of the operating plant parameters as discussed in Subsection 7.1.6, the design limit DNBR values will be calculated. The calculations will be completed using the RTDP with these instrumentation uncertainties and confirm that either the design limit DNBR values as described in this section remain valid or that the safety analysis minimum DNBR bounds the new design limit DNBR values plus DNBR penalties, such as rod bow penalty. This will be completed prior to fuel load.

4.4.8 References

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*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

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Table 4.4-1 (Sheet 1 of 2)
Thermal and Hydraulic Comparison Table
(AP1000, AP600 and a Typical Westinghouse XL Plant)

Design Parameters	AP1000[a]	AP600	Typical XL Plant
Reactor core heat output (MWt)	3400	1933	3800
Reactor core heat output (10^6 BTU/hr)	11601	6596	12,969
Heat generated in fuel (%)	97.4	97.4	97.4
System pressure, nominal (psia)	2250	2250	2250
System pressure, minimum (psia)	2190	2200	2204
Minimum DNBR at nominal conditions			
Typical flow channel	2.59	3.48	2.20
Thimble (cold wall) flow channel)	2.60	3.33	2.12
Minimum DNBR for design transients			
Typical flow channel	>1.25[b]	>1.23	>1.26
Thimble (cold wall) flow channel	>1.25[b]	>1.22	>1.24
DNB correlation[c]	WRB-2M	WRB-2	WRB-1
Coolant conditions[d]			
Vessel minimum measured flow rate (MMF)			
10^6 lbm/hr	115.55	74.4	148.9
gpm	301,670	193,200	403,000
Vessel thermal design flow rate (TDF)			
10^6 lbm/hr	113.5	72.9	145.0
gpm	296,000	189,600	392,000
Effective flow rate for heat transfer[e]			
10^6 lbm/hr	106.8	66.3	132.7
gpm	278,500	172,500	358,700
Effective flow area for heat transfer (ft^2)	41.8	38.5	51.1
Average velocity along fuel rods (ft/s)[e]	15.8	10.6	16.6
Average mass velocity, 10^6 lbm/hr-ft^2[e]	2.55	1.72	2.60
Coolant temperature[d][e]			
Nominal inlet (°F)	535.0	532.8	561.2
Average rise in vessel (°F)	77.2	69.6	63.6
Average rise in core (°F)	81.4	75.8	68.7
Average in core (°F)	578.1	572.6	597.8
Average in vessel (°F)	573.6	567.6	593.0

Table 4.4-1 (Sheet 2 of 2)
Thermal and Hydraulic Comparison Table
(AP1000, AP600 and a Typical Westinghouse XL Plant)

Design Parameters	AP1000[a]	AP600	Typical XL Plant
Heat transfer			
Active heat transfer surface area (ft^2)[f]	56,700	44,884	69,700
Average heat flux (BTU/hr-ft^2)	199,300	143,000	181,200
Maximum heat flux for normal operation (BTU/hr-ft^2)[g]	518,200	372,226	498,200
Average linear power (kW/ft)[f][m]	5.72	4.11	5.20
Peak linear power for normal operation (kW/ft)[g,h]	14.9	10.7	14.0
Peak linear power resulting from overpower transients/operator errors, assuming a maximum overpower of 118% (kW/ft)[h]	≤22.45	22.5	≤22.45
Peak Linear power for prevention of center-line melt (kW/ft)[i]	22.5	22.5	22.45
Power density (kW/liter of core)[j]	109.7	78.82	98.8
Specific power (kW/kg uranium)[j]	40.2	28.89	36.6
Fuel central temperature			
Peak at peak linear power for prevention of centerline melt (°F)	4700	4,700	4700
Pressure drop[k]			
Across core (psi)	38.7 ± 3.9[l]	17.5 ± 1.7	38.8 ± 3.9
Across vessel, including nozzle (psi)	64.8 ± 6.5[l]	45.3 ± 4.5	59.7 ± 6.0

Notes:

(a) Robust Fuel Assembly.
(b) The design limit DNBR is 1.25.
(c) WRB-2M is used for AP1000. WRB-2, ABB-NV, or WLOP is used for AP1000 where WRB-2M is not applicable. See Subsection 4.4.2.2.1 for use of ABB-NV, WLOP, WRB-2 and WRB-2M correlations.
(d) Based on vessel average temperature equal to 573.6°F. Flow rates and temperatures based on 10 percent steam generator tube plugging.
(e) Based on thermal design flow and 5.9 percent bypass flow.
(f) Based on densified active fuel length. The value for AP1000 is rounded to 5.72 kW/ft.
(g) Based on 2.60 F_Q peaking factor.
(h) See Subsection 4.3.2.2.6.
(i) See Subsection 4.4.2.11.6.
(j) Based on cold dimensions and 95.5 percent of theoretical density fuel for AP1000; 95 percent for others.
(k) These are typical values based on best-estimate reactor flow rate as discussed in Section 5.1.
(l) Inlet temperature = 536.8°F.
(m) The value for AP1000 is rounded to 5.72 kW/ft.

Table 4.4-2
Void Fractions At Nominal Reactor Conditions
With Design Hot Channel Factors
(Based On VIPRE-01)

	Average	Maximum
Core, %	0.0	-
Hot Subchannel, %	0.3	2.1

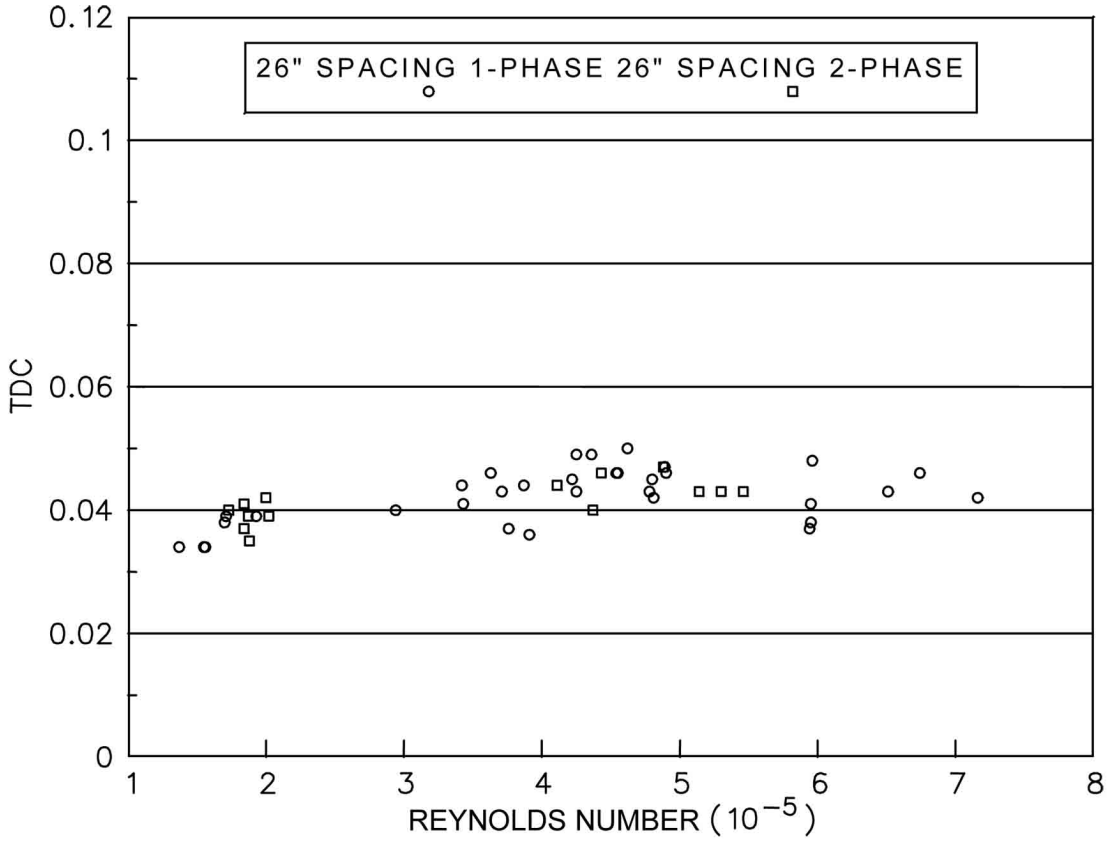

Figure 4.4-1
Thermal Diffusion Coefficient (TDC)
as a Function of Reynolds Number

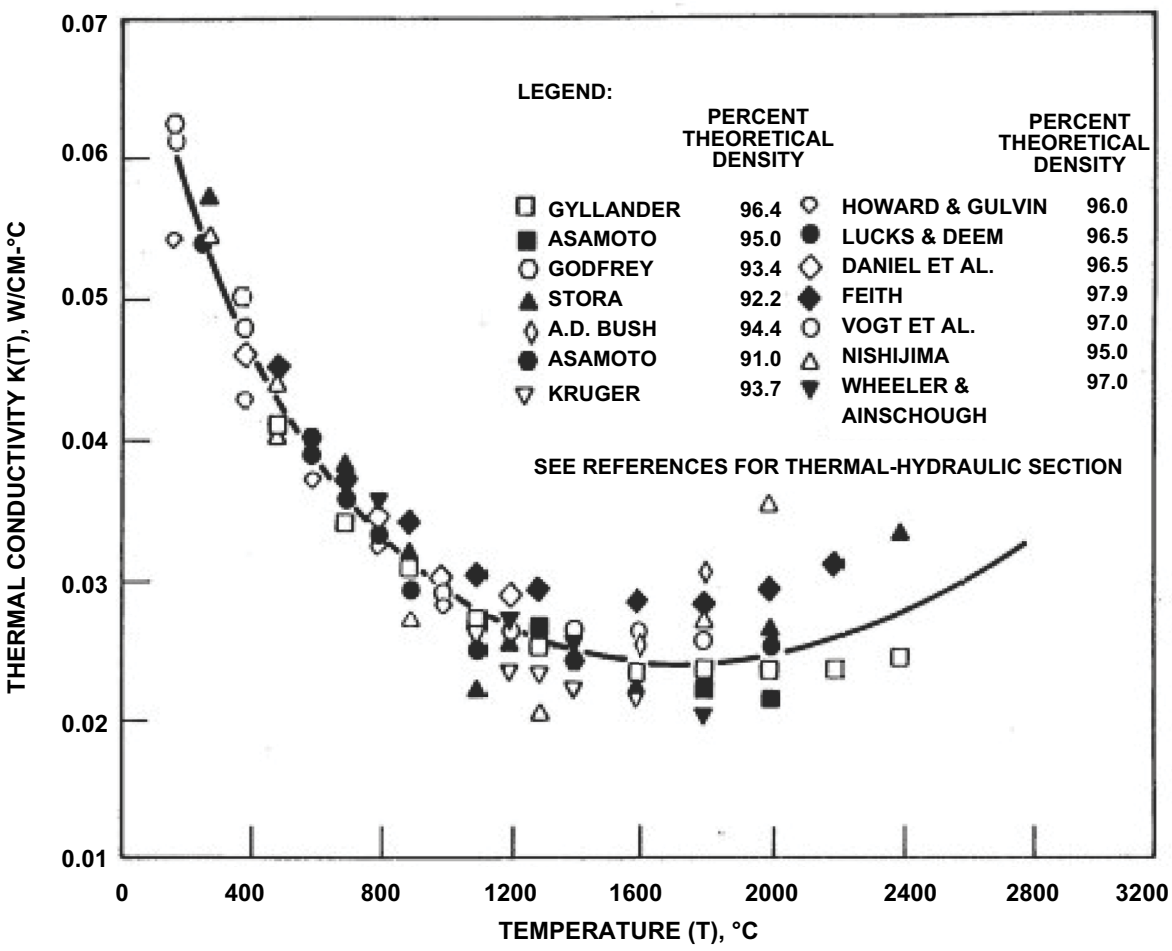

Figure 4.4-2
Thermal Conductivity of Uranium Dioxide
(Data Corrected to 95% Theoretical Density)

4.5 Reactor Materials

4.5.1 Control Rod and Drive System Structural Materials

4.5.1.1 Materials Specifications

The parts of the control rod drive mechanisms and control rod drive line exposed to reactor coolant are made of metals that resist the corrosive action of the coolant. Three types of metals are used exclusively: stainless steels, nickel-chromium-iron alloys, and, to a limited extent, cobalt-based alloys. These materials have provided many years of successful operation in similar control rod drive mechanisms. In the case of stainless steels, only austenitic and martensitic stainless steels are used.

Pressure-containing materials comply with the ASME Code, Section III. The material specifications for portions of the control rod drive mechanism that are reactor coolant pressure boundary are included in Table 5.2-1. These parts are fabricated from austenitic (Type 316, 316L, 316LN and Type 304, 304L, 304LN) stainless steel. Nickel-chromium-iron alloy (Alloy 690) is used for the reactor vessel head penetration. For pressure boundary parts, austenitic stainless steels are not used in the heat-treated conditions which can cause susceptibility to stress-corrosion cracking or accelerated corrosion in pressurized water reactor coolant chemistry and temperature environments. Pressure boundary parts and components made of stainless steel do not have specified minimum yield strength greater than 90,000 psi.

The material selection is based in part on the duty cycle specified for the control rod drive mechanisms and control rods. The materials are specified so that the components do not suffer adverse effects, such as excessive wear or galling, as a result of a minimum 300 trips from full power and 60 coupling and decoupling cycles of the drive rod coupling assembly. The material for the control rod drive mechanisms and the control rod assemblies are selected for acceptable performance. That is, the design goal is to achieve a service life of 9×10^6 full-step cycles. Inspection or changes in operation indicate the need for replacement or refurbishment. The worst case result of undetected wear of a control rod drive mechanism or drive rod is a rod assembly drop or a failure to drop an assembly during a trip. Both events are accounted for in safety analyses. The pressure boundary components are not subject to significant wear due to stepping cycles.

Internal latch assembly parts are fabricated of heat-treated martensitic and austenitic stainless steel. Heat treatment is such that stress-corrosion cracking is not initiated. Components and parts made of stainless steel do not have specified minimum yield strength greater than 90,000 psi. Magnetic pole pieces are immersed in the reactor coolant and are fabricated from Type 410 stainless steel. Nonmagnetic parts, except shims, pins, and springs, are fabricated from Type 304 stainless steel. A cobalt alloy or qualified substitute is used to fabricate the latch, link, and link pins. Springs and shims are made from nickel-chromium-iron alloy (Alloy X-750 and Alloy 625). Lock screws are fabricated of Type 316 stainless steel. Latch arm tips fabricated of stainless steel may be surfaced with a suitable hard facing material to provide improved resistance to wear. Hard chrome plate is used selectively for bearing and wear surfaces.

The drive rod assembly is also immersed in the reactor coolant and uses a Type 410 stainless steel drive rod. The drive rod coupling is machined from Type 403 or 410 stainless steel. The protective sleeve and disconnect button are also Type 410 stainless steel. The remaining parts are Type 304 or Type 304L stainless steel with the exception of the springs, button retainer, and locking button, which are fabricated of nickel-chromium-iron alloy.

The absorber rodlets in the rod cluster control assemblies and the gray rod cluster assemblies are closed stainless steel tubes (cladding) containing absorber material. The stainless steel cladding isolates from the reactor coolant, the absorber material, and other substances inside the tubes. The containment function of the control rod cladding and the effects of neutron flux in the control rod

materials are addressed in Section 4.2. The outside surface of the absorber rodlet is chromium plated or ion nitrided to enhance resistance to wear due to the stepping motion and vibration of the rods. The rods included in one rod cluster control assembly or gray rod cluster assembly are attached at the top to a common hub which connects with the drive rod of the control rod drive mechanism. The hub is fabricated from Type 304, Type 304L, or Grade CF-3 stainless steel.

The coil housing is exposed to containment atmosphere and requires a magnetic material. Low carbon cast steel and ductile iron are qualified by tests or other evaluations for this application. The finished housings are electroless nickel plated to provide resistance against general corrosion.

Coils are wound on composite bobbins, with double glass-insulated copper wire. Coils are vacuum impregnated with silicone varnish. A wrapping of mica sheet is secured to the coil outside diameter. The result is a well-insulated coil capable of sustained operation at 392°F (200°C).

4.5.1.2 Fabrication and Processing of Austenitic Stainless Steel Components

The discussions provided in Subsection 5.2.3.4 concerning the processes, inspections, and tests on austenitic stainless steel components to prevent increased susceptibility to intergranular corrosion caused by sensitization are applicable to the austenitic stainless steel pressure-housing components of the control rod drive mechanism. The discussions provided in Subsection 5.2.3.4, concerning the control of welding of austenitic stainless steels especially control of delta ferrite are also applicable. Subsection 5.2.3.4 discusses the compliance with the guidelines of Regulatory Guides 1.31, 1.34, and 1.44. The welded control rod drive mechanism austenitic stainless steels that come into contact with the primary reactor coolant meet the guidance of Regulatory Guide 1.44.

4.5.1.3 Other Materials

For the cobalt alloy used to fabricate the latch, link, and link pins in latch assemblies, stress-corrosion cracking has not been observed in this application. Where hardfacing material is used in the latch assembly, a cobalt base alloy equivalent to Stellite-6 is used.

The springs in the control rod drive mechanism are made from nickel-chromium-iron alloy (Alloy 750), ordered to Aerospace Material Specification (AMS) 5698 or AMS 5699 with additional restrictions on prohibited materials. Operating experience has shown that springs made of this material are not subject to stress-corrosion cracking in pressurized water reactor primary water environments. Alloy 750 is not used for bolting applications in the control rod drive mechanisms.

4.5.1.4 Contamination Protection and Cleaning of Austenitic Stainless Steel

The control rod drive mechanisms are cleaned prior to delivery in accordance with the guidance provided in NQA-1 (see Chapter 17). Process specifications in packaging and shipment are discussed in Subsection 5.2.3. Westinghouse personnel conduct surveillance of these operations to verify that manufacturers and installers adhere to appropriate requirements as described in Subsection 5.2.3.

Tools used in abrasive work operations on austenitic stainless steel, such as grinding or wire brushing, do not contain and are not contaminated with ferritic carbon steel or other materials that could contribute to intergranular cracking or stress-corrosion cracking.

4.5.2 Reactor Internal and Core Support Materials

4.5.2.1 Materials Specifications

The major core support material for the reactor internals is SA-182, SA-336, SA-376, SA-479, or SA-240 Types 304, 304L, 304LN, or 304H stainless steels. Fabricators performing welding of any of these materials are required to qualify the welding procedures for maximum carbon content and heat input for each welding process in accordance with Regulatory Guide 1.44. For threaded structural fasteners the material used is strain hardened Type 316 stainless steel (XM-19 as large diameter alternate) and for the clevis insert-to-vessel bolts either UNS N07718 or N07750. Remaining internals parts not fabricated from Types 304, 304L, 304LN, or 304H stainless steels typically include wear surfaces such as hardfacing on the radial keys, clevis inserts, alignment plates (Stellite™ 6 or 156 or low cobalt hardfaces); dowel pins (Type 316, XM-19 as large diameter alternate); and SB-166 for the clevis inserts.

Additional product forms that may be used by the reactor internals structures are SA-193, SA-213, SA-312, SA-358, and SB-637. Reactor internals structures materials that are not Types 304, 304L, 304LN, or 304H stainless steel are the guide bushings locating and support pins, instrumentation adapter, instrument tube tip, instrument tube sleeve top, guide stud (all UNS S21800), compression fitting (Type 316), hold down spring (SA-182, F6NM), irradiation specimen access plug springs and instrument stalk springs (UNS N07750), instrument tube sleeve spring (UNS N07718), and SB-168 for the flow skirt. Additionally, reactor internals structures will use either threaded structural fasteners of strain hardened Type 316 stainless steel, UNS N07718 or N07750 (XM-19 as large diameter alternate). ASTM A240 or ASTM A479 Type 300-series stainless steel may be used for small components classified as internal structures such as locking cups, locking caps, and shims.

Core support structure, internal structure, and threaded structural fastener materials are specified in the ASME Code, Section II, Part D, Subpart 1, Tables 2A, 2B, and 4 as supplemented by Code Case N-60, except for ASTM A240 and ASTM A479 which may be used for small components classified as internal structures. The qualification of cobalt free wear resistant alloys for use in reactor coolant is addressed in Subsection 4.5.1.3.

The use of cast austenitic stainless steel (CASS) is minimized in the AP1000 reactor internals. If used, CASS will be limited in carbon (low carbon grade: L grade) and ferrite contents and will be evaluated in terms of thermal aging effects.

The estimated peak neutron fluence for the AP1000 reactor internals has been considered in the design. Susceptibility to irradiation-assisted stress corrosion cracking or void swelling in reactor internals identified in the current pressurized water reactor fleet are being addressed in reactor internals material reliability programs. The selection of materials for the AP1000 reactor internals considers information developed by these programs. Ni-Cr-Fe Alloy 600 is not used in the AP1000 reactor internals.

4.5.2.2 Controls on Welding

The discussions provided in Subsection 5.2.3.4 are applicable to the welding of reactor internals and core support components.

4.5.2.3 Nondestructive Examination of Tubular Products and Fittings

The nondestructive examination and acceptance during fabrication of wrought seamless tubular products and fitting material are in accordance with ASME Code, Section III, Article NG-2500. The acceptance standards for welding post-assembly are in accordance with the requirements of ASME Code, Section III, Article NG-5300.

4.5.2.4 Fabrication and Processing of Austenitic Stainless Steel Components

The discussions provided in Subsection 5.2.3.4 and Section 1.9 describes the conformance of reactor internals and core support structures with Regulatory Guides 1.31 and 1.44.

The discussion provided in Section 1.9 describes the conformance of reactor internals with Regulatory Guides 1.34 and 1.71.

4.5.2.5 Contamination Protection and Cleaning of Austenitic Stainless Steel

The discussions provided in Subsection 5.2.3 and Section 1.9 are applicable to the reactor internals and core support structures describe the conformance of the process specifications with Regulatory Guide 1.37. The process specifications follow the guidance of NQA-1.

4.5.3 Combined License Information

This section contained no requirement for additional information.

4.6 Functional Design of Reactivity Control Systems

4.6.1 Information for Control Rod Drive System

The control rod drive mechanism (CRDM) and operation of the control rod drive system are described in Subsection 3.9.4. Figure 3.9-4 provides the details of the control rod drive mechanisms. Figure 4.2-8 provides the configuration of the driveline, including the control rod drive mechanism. No hydraulic system is associated with the functioning of the control rod drive system. The instrumentation and controls for the reactor trip system are described in Section 7.2. The reactor control system is described in Section 7.7.

The control rod drive mechanisms are contained within an integrated head package located on top of the reactor vessel head as described in Subsection 3.9.7. This assembly provides the support required for seismic restraint in conjunction with the attachment of the control rod drive mechanisms to the reactor vessel head. An outer shroud and the seismic restraint structure isolate the control rod drive mechanisms from the effects of ruptures of high-energy lines outside the shroud, and from missiles. The shroud also is used to direct air from the cooling fans past the control rod drive mechanisms. The cooling system maintains the temperatures of the coils in the control rod drive mechanisms below the design operating temperature. The integrated head package provides the proper support and required separation for electrical lines providing power to the control rod drive mechanisms and signals from the rod position sensors.

The line for the reactor head vent system is located among the control rod drive mechanisms and is supported by the integrated head package. This line is pressurized to reactor coolant system pressure and considered to be a high-energy line. This line is constructed to the appropriate requirements of the ASME Code. Figure 3.9-7 shows elements of the integrated head package surrounding the control rod drive mechanisms.

4.6.2 Evaluations of the Control Rod Drive System

Rod control systems of the type used in the AP1000 have been analyzed in detailed reliability studies. These studies include fault tree analysis and failure mode and effects analyses. These studies, and the analyses presented in Chapter 15, demonstrate that the control rod drive system performs its intended safety-related function – a reactor trip. The control rod drive system puts the reactor in a subcritical condition when a safety-related system setting is reached with an assumed credible failure of a single active component.

The essential elements of the control rod drive system (those required to provide reactor trip) are isolated from nonessential portions of the rod control system by the reactor trip switchgear, as described in Section 7.2. The essential portion of the control rod drive system is shielded from the direct effects of postulated moderate- and high-energy line breaks by the integrated head package. The dynamic effects of pipe ruptures do not have to be considered for those pipes that satisfy the requirements for mechanistic pipe break, as outlined in Subsection 3.6.3.

The reactor vessel head vent lines and instrumentation conduits are one inch nominal diameter or smaller. Breaks in lines of this size do not have to be postulated for dynamic effects, pressurization, and spray wetting. The pressure boundary housing of the control rod drive mechanisms is constructed to the requirements of the ASME Code and a break in this pressure boundary is not credible.

The only instrumentation required of the control rod drive mechanism and supporting systems to operate safely is the rod position indicator. A break in the cables connected to the rod position indicators would neither preclude a reactor trip, nor would it result in an unplanned withdrawal of a rod assembly. A break in the power cable to the control rod drive mechanism coils results in a drop of

the rod assembly. Information on the pressure and temperature of the control rod drive mechanisms and surrounding areas is not required for safe operation. The design pressure and temperature of the control rod drive mechanism housing is the same as the reactor coolant system, which is protected by safety valves. Overheating of the control rod drive mechanism coils due to a failure of the cooling system would in the worst case result in a drop of one or more rod assemblies. The reactor and reactor protection system is designed to accommodate and protect against rod drop events. Additional information is provided in Subsection 3.9.1, and Sections 7.2, and 15.4.

4.6.3 Testing and Verification of the Control Rod Drive System

The control rod drive system is extensively tested prior to its operation. These tests may be subdivided into five categories:

- Prototype tests of components
- Prototype control rod drive system tests
- Production tests of components following manufacture and prior to installation
- Onsite pre-operational and initial startup tests
- Periodic in-service tests

These tests, which are described in Subsection 3.9.4.4 and Sections 4.2 and 14.2, are conducted to verify the operability of the control rod drive system when called upon to function.

4.6.4 Information for Combined Performance of Reactivity Systems

As indicated in Chapter 15, there are only three postulated events that assume credit for reactivity control systems, other than a reactor trip to render the plant subcritical. These events are the steam-line break, feedwater line break, and small break loss of coolant accident. The reactivity control systems in these accidents are the reactor trip system and the passive core cooling system (PXS). Additional information on the control rod drive system is presented in Subsection 3.9.4. The passive core cooling system is discussed further in Section 6.3.

No credit is taken for the boration capabilities of the chemical and volume control system (CVS) as a system in the analysis of transients presented in Chapter 15. Information on the capabilities of the chemical and volume control system is provided in Subsection 9.3.6. The adverse boron dilution possibilities due to the operation of the chemical and volume control system are investigated in Subsection 15.4.6. Prior proper operation of the chemical and volume control system has been presumed as an initial condition to evaluate transients. Appropriate technical specifications promote the correct operation or remedial action.

The AP1000 instrumentation and control system includes a diverse actuation system (DAS). This system provides for automatic control rod insertion, turbine trip, passive residual heat removal heat exchanger start, core makeup tank start, isolation of critical containment penetrations, and start of the passive containment cooling system as appropriate upon conditions indicative of an anticipated transient without scram or other failure of the plant control and reactor protection system. This system is diverse and independent from the reactor trip system from the sensor through actuation devices.

In addition to the above, the AP1000 plant systems provide for operator response to an anticipated transient without scram (ATWS) event that includes core reactivity control followed by core decay heat removal. Core reactivity control is provided by a manual trip of the control rods, insertion of the

control rods, the chemical and volume control system, or by the core makeup tank injection. The decay heat removal can be performed by the startup feedwater system or the passive residual heat removal system.

4.6.5 Evaluation of Combined Performance

The evaluations of the steam-line break, the feedwater line break, and the small break loss of coolant accident, which presume the combined actuation of the reactor trip system and the control rod drive system and the passive safety injection, are presented in Subsections 15.1.5 and 15.2.8 and Section 15.6. Reactor trip signals and signals to actuate passive safety features for these events are generated from functionally diverse sensors. These signals actuate diverse means of reactivity control; that is, control rod insertion and injection of soluble neutron absorber.

Non-diverse but redundant types of equipment are used only in the processing of the incoming sensor signals into appropriate logic which initiates the protective action. This equipment is described in Sections 7.2 and 7.3. In particular, protection from equipment failures is provided by redundant equipment and periodic testing. Effects of failures of this equipment have been extensively investigated. Reliability studies, including failure mode and effects analysis for this type of equipment verify that a single failure does not have an adverse effect upon the engineered safety features actuation system. Adequacy of the passive core cooling system performance under faulted conditions is verified in Section 6.3.

In addition to the automatic actuations provided for by the diverse actuation system, that system also provides for manual actuation of the reactor trip.

The probability of a common mode failure impairing the ability of the reactor trip system to perform its safety-related function is extremely low. However, analyses are performed to demonstrate compliance with the requirements of 10 CFR 50.62. These analyses demonstrate that safety criteria would not be exceeded even if the control rod drive system were rendered incapable of functioning during anticipated transients for which its function would normally be expected. The evaluation demonstrates that borated water from the core makeup tank shuts down the reactor with no rods required, and the passive residual heat removal system provides sufficient core heat removal.

4.6.6 Combined License Information

This section contained no requirement for additional information.

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UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
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	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 5	REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS	5.1-1
5.1	Summary Description	5.1-1
5.1.1	Design Bases	5.1-1
5.1.2	Design Description	5.1-2
5.1.3	System Components	5.1-3
5.1.3.1	Reactor Vessel	5.1-3
5.1.3.2	AP1000 Steam Generator	5.1-4
5.1.3.3	Reactor Coolant Pumps	5.1-4
5.1.3.4	Primary Coolant Piping	5.1-5
5.1.3.5	Pressurizer	5.1-5
5.1.3.6	Pressurizer Safety Valves	5.1-5
5.1.3.7	Reactor Coolant System Automatic Depressurization Valves	5.1-6
5.1.4	System Performance Characteristics	5.1-6
5.1.4.1	Best-Estimate Flow	5.1-6
5.1.4.2	Minimum Measured Flow	5.1-6
5.1.4.3	Thermal Design Flow	5.1-7
5.1.4.4	Mechanical Design Flow	5.1-7
5.1.5	Combined License Information	5.1-7
5.2	Integrity of Reactor Coolant Pressure Boundary	5.2-1
5.2.1	Compliance with Codes and Code Cases	5.2-1
5.2.1.1	Compliance with 10 CFR 50.55a	5.2-1
5.2.1.2	Applicable Code Cases	5.2-3
5.2.1.3	Alternate Classification	5.2-3
5.2.2	Overpressure Protection	5.2-4
5.2.2.1	Design Bases	5.2-5
5.2.2.2	Design Evaluation	5.2-6
5.2.2.3	Piping and Instrumentation Diagrams	5.2-6
5.2.2.4	Equipment and Component Description	5.2-7
5.2.2.5	Mounting of Pressure Relief Devices	5.2-7
5.2.2.6	Applicable Codes and Classification	5.2-7
5.2.2.7	Material Specifications	5.2-7
5.2.2.8	Process Instrumentation	5.2-8
5.2.2.9	System Reliability	5.2-8
5.2.2.10	Testing and Inspection	5.2-8
5.2.3	Reactor Coolant Pressure Boundary Materials	5.2-8
5.2.3.1	Materials Specifications	5.2-8
5.2.3.2	Compatibility with Reactor Coolant	5.2-9
5.2.3.3	Fabrication and Processing of Ferritic Materials	5.2-11
5.2.3.4	Fabrication and Processing of Austenitic Stainless Steel	5.2-12
5.2.3.5	Threaded Fastener Lubricants	5.2-17
5.2.4	Inservice Inspection and Testing of Class 1 Components	5.2-17
5.2.4.1	System Boundary Subject to Inspection	5.2-18
5.2.4.2	Arrangement and Inspectability	5.2-19
5.2.4.3	Examination Techniques and Procedures	5.2-20
5.2.4.4	Inspection Intervals	5.2-22
5.2.4.5	Examination Categories and Requirements	5.2-22

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	5.2.4.6 Evaluation of Examination Results	5.2-22
	5.2.4.7 System Leakage and Hydrostatic Pressure Tests	5.2-22
	5.2.4.8 Relief Requests	5.2-22
	5.2.4.9 Preservice Inspection of Class 1 Components	5.2-22
	5.2.4.10 Program Implementation	5.2-22
	5.2.5 Detection of Leakage Through Reactor Coolant Pressure Boundary	5.2-23
	5.2.5.1 Collection and Monitoring of Identified Leakage	5.2-23
	5.2.5.2 Intersystem Leakage Detection	5.2-24
	5.2.5.3 Collection and Monitoring of Unidentified Leakage	5.2-25
	5.2.5.4 Safety Evaluation	5.2-30
	5.2.5.5 Tests and Inspections	5.2-30
	5.2.5.6 Instrumentation Applications	5.2-30
	5.2.5.7 Technical Specification	5.2-31
	5.2.6 Combined License Information Items	5.2-31
	5.2.6.1 ASME Code and Addenda	5.2-31
	5.2.6.2 Plant-Specific Inspection Program	5.2-31
	5.2.6.3 Response to Unidentified Reactor Coolant System Leakage Inside Containment	5.2-31
	5.2.7 References	5.2-31
5.3	Reactor Vessel	5.3-1
	5.3.1 Reactor Vessel Design	5.3-1
	5.3.1.1 Safety Design Bases	5.3-1
	5.3.1.2 Safety Description	5.3-1
	5.3.1.3 System Safety Evaluation	5.3-3
	5.3.1.4 Inservice Inspection/Inservice Testing	5.3-3
	5.3.2 Reactor Vessel Materials	5.3-3
	5.3.2.1 Material Specifications	5.3-3
	5.3.2.2 Special Processes Used for Manufacturing and Fabrication	5.3-3
	5.3.2.3 Special Methods for Nondestructive Examination	5.3-4
	5.3.2.4 Special Controls for Ferritic and Austenitic Stainless Steels	5.3-5
	5.3.2.5 Fracture Toughness	5.3-5
	5.3.2.6 Material Surveillance	5.3-5
	5.3.2.7 Reactor Vessel Fasteners	5.3-13
	5.3.3 Pressure-Temperature Limits	5.3-13
	5.3.3.1 Limit Curves	5.3-13
	5.3.3.2 Operating Procedures	5.3-14
	5.3.4 Reactor Vessel Integrity	5.3-14
	5.3.4.1 Design	5.3-14
	5.3.4.2 Materials of Construction	5.3-16
	5.3.4.3 Fabrication Methods	5.3-16
	5.3.4.4 Inspection Requirements	5.3-16
	5.3.4.5 Shipment and Installation	5.3-16
	5.3.4.6 Operating Conditions	5.3-17
	5.3.4.7 Inservice Surveillance	5.3-18
	5.3.5 Reactor Vessel Insulation	5.3-19

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
5.3.5.1	Reactor Vessel Insulation Design Bases	5.3-19
5.3.5.2	Description of Insulation	5.3-20
5.3.5.3	Description of External Vessel Cooling Flooded Compartments	5.3-21
5.3.5.4	Determination of Forces on Insulation and Support System	5.3-21
5.3.5.5	Design Evaluation	5.3-21
5.3.6	Combined License Information	5.3-22
5.3.6.1	Pressure-Temperature Limit Curves	5.3-22
5.3.6.2	Reactor Vessel Materials Surveillance Program	5.3-22
5.3.6.3	Surveillance Capsule Lead Factor and Azimuthal Location Confirmation	5.3-22
5.3.6.4	Reactor Vessel Materials Properties Verification	5.3-22
5.3.6.5	Reactor Vessel Insulation	5.3-22
5.3.6.6	Inservice Inspection of Reactor Vessel Head Weld Buildup	5.3-22
5.3.7	References	5.3-23
5.4	Component and Subsystem Design	5.4-1
5.4.1	Reactor Coolant Pump Assembly	5.4-1
5.4.1.1	Design Bases	5.4-1
5.4.1.2	Pump Assembly Description	5.4-1
5.4.1.3	Design Evaluation	5.4-3
5.4.1.4	Tests and Inspections	5.4-8
5.4.2	Steam Generators	5.4-9
5.4.2.1	Design Bases	5.4-9
5.4.2.2	Design Description	5.4-9
5.4.2.3	Design Evaluation	5.4-12
5.4.2.4	Steam Generator Materials	5.4-14
5.4.2.5	Steam Generator Inservice Inspection	5.4-17
5.4.2.6	Quality Assurance	5.4-18
5.4.3	Reactor Coolant System Piping	5.4-19
5.4.3.1	Design Bases	5.4-19
5.4.3.2	Design Description	5.4-20
5.4.3.3	Design Evaluation	5.4-22
5.4.3.4	Material Corrosion/Erosion Evaluation	5.4-22
5.4.3.5	Test and Inspections	5.4-23
5.4.4	Main Steam Line Flow Restriction	5.4-23
5.4.4.1	Design Bases	5.4-23
5.4.4.2	Design Description	5.4-24
5.4.4.3	Design Evaluation	5.4-24
5.4.4.4	Inspections	5.4-24
5.4.5	Pressurizer	5.4-24
5.4.5.1	Design Bases	5.4-24
5.4.5.2	Design Description	5.4-26
5.4.5.3	Design Evaluation	5.4-28
5.4.5.4	Tests and Inspections	5.4-30
5.4.6	Automatic Depressurization System Valves	5.4-30
5.4.6.1	Design Bases	5.4-31

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	5.4.6.2 Design Description	5.4-31
	5.4.6.3 Design Verification	5.4-32
	5.4.6.4 Inspection and Testing Requirements	5.4-32
5.4.7	Normal Residual Heat Removal System	5.4-32
	5.4.7.1 Design Bases	5.4-33
	5.4.7.2 System Description	5.4-36
	5.4.7.3 Component Description	5.4-39
	5.4.7.4 System Operation and Performance	5.4-41
	5.4.7.5 Design Evaluation	5.4-43
	5.4.7.6 Inspection and Testing Requirements	5.4-44
	5.4.7.7 Instrumentation Requirements	5.4-45
5.4.8	Valves	5.4-45
	5.4.8.1 Design Bases	5.4-45
	5.4.8.2 Design Description	5.4-48
	5.4.8.3 Design Evaluation	5.4-49
	5.4.8.4 Tests and Inspections	5.4-49
	5.4.8.5 Preoperational Testing	5.4-50
5.4.9	Reactor Coolant System Pressure Relief Devices	5.4-53
	5.4.9.1 Design Bases	5.4-53
	5.4.9.2 Design Description	5.4-53
	5.4.9.3 Design Evaluation	5.4-54
	5.4.9.4 Tests and Inspections	5.4-55
5.4.10	Component Supports	5.4-55
	5.4.10.1 Design Bases	5.4-55
	5.4.10.2 Design Description	5.4-56
	5.4.10.3 Design Evaluation	5.4-57
	5.4.10.4 Tests and Inspections	5.4-58
5.4.11	Pressurizer Relief Discharge	5.4-58
	5.4.11.1 Design Bases	5.4-58
	5.4.11.2 System Description	5.4-58
	5.4.11.3 Safety Evaluation	5.4-59
	5.4.11.4 Instrumentation Requirements	5.4-59
	5.4.11.5 Inspection and Testing Requirements	5.4-59
5.4.12	Reactor Coolant System High Point Vents	5.4-59
	5.4.12.1 Design Bases	5.4-60
	5.4.12.2 System Description	5.4-61
	5.4.12.3 Safety Evaluation	5.4-61
	5.4.12.4 Inspection and Testing Requirements	5.4-62
	5.4.12.5 Instrumentation Requirements	5.4-62
5.4.13	Core Makeup Tank	5.4-63
	5.4.13.1 Design Bases	5.4-63
	5.4.13.2 Design Description	5.4-63
	5.4.13.3 Design Evaluation	5.4-64
	5.4.13.4 Material Corrosion/Erosion Evaluation	5.4-64
	5.4.13.5 Test and Inspections	5.4-64
5.4.14	Passive Residual Heat Removal Heat Exchanger	5.4-64
	5.4.14.1 Design Bases	5.4-65
	5.4.14.2 Design Description	5.4-65

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	5.4.14.3 Design Evaluation	5.4-66
	5.4.14.4 Material Corrosion/Erosion Evaluation	5.4-66
	5.4.14.5 Testing and Inspections	5.4-67
5.4.15	Combined License Information	5.4-67
5.4.16	References	5.4-67

LIST OF TABLES

Table Number	Title	Page
5.1-1	Principal System Pressures, Temperatures, and Flow Rates	5.1-8
5.1-2	Nominal System Design and Operating Parameters	5.1-9
5.1-3	Thermal-Hydraulic Parameters	5.1-10
5.2-1	Reactor Coolant Pressure Boundary Materials Specifications	5.2-33
5.2-2	Reactor Coolant Water Chemistry Specifications	5.2-39
5.2-3	ASME Code Cases	5.2-40
5.2-201	NRC Authorized ASME Section III Requests for Alternative In Accordance with 10 CFR 50.55a(a)(3) or 10 CFR 50.55a(z)	5.2-41
5.3-1	Maximum Limits for Elements of the Reactor Vessel	5.3-24
5.3-2	Reactor Vessel Quality Assurance Program	5.3-25
5.3-3	End-of-Life RT_{NDT} and Upper Shelf Energy Projections	5.3-26
5.3-4	Reactor Vessel Material Surveillance Program	5.3-27
5.3-5	Reactor Vessel Design Parameters	5.3-28
5.4-1	Reactor Coolant Pump Design Parameters	5.4-69
5.4-2	Not Used	5.4-70
5.4-3	Reactor Coolant Pump Quality Assurance Program	5.4-71
5.4-4	Steam Generator Design Requirements	5.4-72
5.4-5	Steam Generator Design Parameters (Nominal Values)	5.4-73
5.4-6	Steam Generator Quality Assurance Program	5.4-74
5.4-7	Reactor Coolant System Piping Design	5.4-75
5.4-8	Reactor Coolant System Piping Quality Assurance Program	5.4-76
5.4-9	Pressurizer Design Data	5.4-77
5.4-10	Pressurizer Heater Group Parameters	5.4-78
5.4-11	Reactor Coolant System Design Pressure Settings	5.4-79
5.4-12	Pressurizer Quality Assurance Program	5.4-80
5.4-13	Design Bases for Normal Residual Heat Removal System Operation	5.4-81
5.4-14	Normal Residual Heat Removal System Component Data	5.4-82
5.4-15	Reactor Coolant System Valve Design Parameters	5.4-83
5.4-16	Reactor Coolant System Motor-operated Valves Design Opening and Closing Pressures	5.4-84
5.4-17	Pressurizer Safety Valves – Design Parameters	5.4-85
5.4-18	Reactor Vessel Head Vent System Design Parameters	5.4-86

LIST OF FIGURES

Figure Number	Title	Page
5.1-1	Reactor Coolant System Schematic Flow Diagram	5.1-11
5.1-2	Reactor Coolant Loops – Isometric View	5.1-12
5.1-3	Reactor Coolant System – Loop Layout	5.1-13
5.1-4	Reactor Coolant System – Elevation	5.1-14
5.1-5	(Sheet 1 of 3) Simplified Reactor Coolant System Piping and Instrumentation Diagram	5.1-15
5.1-5	(Sheet 2 of 3) Simplified Reactor Coolant System Piping and Instrumentation Diagram	5.1-16
5.1-5	(Sheet 3 of 3) Simplified Reactor Coolant System Piping and Instrumentation Diagram	5.1-17
5.2-1	Leak Detection Approach	5.2-44
5.3-1	Reactor Vessel	5.3-29
5.3-2	AP1000 Reactor Coolant System Heatup Limitations (Heatup Rate Up to 50° and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)	5.3-30
5.3-3	AP1000 Reactor Coolant System Cooldown Limitations (Cooldown Rates up to 50° and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)	5.3-31
5.3-4	AP1000 Reactor Vessel Surveillance Capsules Locations	5.3-32
5.3-5	Reactor Vessel Key Dimensions Plan View	5.3-33
5.3-6	Reactor Vessel Key Dimensions, Side View	5.3-34
5.3-7	Schematic of Reactor Vessel Insulation	5.3-35
5.3-8	RCS Flooded Compartments During Ex-Vessel Cooling	5.3-36
5.3-9	Door Between RCDT Room and Reactor Cavity Compartment	5.3-37
5.4-1	Reactor Coolant Pump	5.4-87
5.4-2	Steam Generator	5.4-88
5.4-3	Support Plate Geometry (Trifoil Holes)	5.4-89
5.4-4	Surge Line	5.4-90
5.4-5	Pressurizer	5.4-91
5.4-6	Normal Residual Heat Removal System	5.4-92
5.4-7	Simplified Normal Residual Heat Removal System Piping and Instrument Diagram	5.4-93
5.4-8	Reactor Vessel Head Vent System	5.4-94

Chapter 5 Reactor Coolant System and Connected Systems

5.1 Summary Description

This section describes the reactor coolant system (RCS) and includes a schematic flow diagram of the reactor coolant system (Figure 5.1-1), an isometric view of the reactor coolant loops and major components (Figure 5.1-2), a sketch of the loop layout (Figure 5.1-3), and a sketch of the elevation of the reactor coolant system (Figure 5.1-4). The piping and instrumentation diagram (Figure 5.1-5, sheets 1, 2, and 3) shows additional details of the design of the reactor coolant system.

5.1.1 Design Bases

The performance and safety design bases of the reactor coolant system and its major components are interrelated. These design bases are listed as follows:

- The reactor coolant system transfers to the steam and power conversion system the heat produced during power operation as well as the heat produced when the reactor is subcritical, including the initial phase of plant cooldown.

- The reactor coolant system transfers to the normal residual heat removal system the heat produced during the subsequent phase of plant cooldown and cold shutdown.

- During power operation and normal operational transients (including the transition from forced to natural circulation), the reactor coolant system heat removal maintain fuel condition within the operating bounds permitted by the reactor control and protection systems.

- The reactor coolant system provides the water used as the core neutron moderator and reflector conserving thermal neutrons and improving neutron economy. The reactor coolant system also provides the water used as a solvent for the neutron absorber used in chemical shim reactivity control.

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

- The reactor coolant system pressure boundary accommodates the temperatures and pressures associated with operational transients.

- The reactor vessel supports the reactor core and control rod drive mechanisms.

- The pressurizer maintains the system pressure during operation and limits pressure transients. During the reduction or increase of plant load, the pressurizer accommodates volume changes in the reactor coolant.

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

- The steam generators provide high-quality steam to the turbine. The tubes and tubesheet boundary prevent the transfer of radioactivity generated within the core to the secondary system.

- The reactor coolant system piping contains the coolant under operating temperature and pressure conditions and limits leakage (and activity release) to the containment atmosphere. The reactor coolant system piping contains demineralized and borated water that is circulated at the flow rate and temperature consistent with achieving the reactor core thermal and hydraulic performance.

- The reactor coolant system is monitored for loose parts, as described in Subsection 4.4.6.

- Applicable industry standards and equipment classifications of reactor coolant system components are identified in Tables 3.2-1 and 3.2-3 of Subsection 3.2.2.

- The reactor vessel head is equipped with suitable provisions for connecting the head vent system, which meets the requirements of 10 CFR 50.34 (f)(2)(vi) (TMI Action Item II.B.1). (See Subsection 5.4.12.)

- The pressurizer surge line and each loop spray line connected with the reactor coolant system are instrumented with resistance temperature detectors (RTDs) attached to the pipe to detect thermal stratification.

5.1.2 Design Description

Figure 5.1-1 shows a schematic of the reactor coolant system. Table 5.1-1 provides the principal pressures, temperatures, and flow rates of the system at the locations noted in Figure 5.1-1 under normal steady-state, full-power operating conditions. These parameters are based on the best-estimate flow at the pump discharge. Table 5.1-2 contains a summary of nominal system design and operating parameters under normal steady-state, full-power operating conditions. These parameters are based on the best-estimate conditions at nominal full power. The reactor coolant system volume under these conditions is also provided.

The reactor coolant system consists of two heat transfer circuits, each with a steam generator, two reactor coolant pumps, and a single hot leg and two cold legs for circulating reactor coolant. In addition, the system includes the pressurizer, interconnecting piping, valves, and instrumentation for operational control and safeguards actuation. All reactor coolant system equipment is located in the reactor containment.

During operation, the reactor coolant pumps circulate pressurized water through the reactor vessel then the steam generators. The water, which serves as coolant, moderator, and solvent for boric acid (chemical shim control), is heated as it passes through the core. It is transported to the steam generators where the heat is transferred to the steam system. Then it is returned to the reactor vessel by the pumps to repeat the process.

The reactor coolant system pressure boundary provides a barrier against the release of radioactivity generated within the reactor and is designed to provide a high degree of integrity throughout operation of the plant.

The reactor coolant system pressure is controlled by operation of the pressurizer, where water and steam are maintained in equilibrium by the activation of electrical heaters or a water spray, or both. Steam is formed by the heaters or condensed by the water spray to control pressure variations due to expansion and contraction of the reactor coolant.

Spring-loaded safety valves are installed above and connected to the pressurizer to provide overpressure protection for the reactor coolant system. These valves discharge into the containment atmosphere. Three stages of reactor coolant system automatic depressurization valves are also connected to the pressurizer. These valves discharge steam and water through spargers to the

in-containment refueling water storage tank (IRWST) of the passive core cooling system (PXS). Most (initially all) of the steam and water discharged to the spargers is condensed and cooled by mixing with the water in the tank.

The fourth-stage automatic depressurization valves are connected by two redundant paths to each reactor coolant loop hot leg and discharge directly to the containment atmosphere.

The reactor coolant system is also served by a number of auxiliary systems, including the chemical and volume control system (CVS), the passive core cooling system (PXS), the normal residual heat removal system (RNS), the steam generator system (SGS), the primary sampling system (PSS), the liquid radwaste system (WLS), and the component cooling water system (CCS).

The reactor coolant system includes the following:

- The reactor vessel, including control rod drive mechanism housings.
- The reactor coolant pumps, consisting of four sealless pumps that pump fluid through the entire reactor coolant and reactor systems. Two pumps are coupled with each steam generator.
- The portion of the steam generators containing reactor coolant, including the channel head, tubesheet, and tubes.
- The pressurizer which is attached by the surge line to one of the reactor coolant hot legs. With a combined steam and water volume, the pressurizer maintains the reactor system within a narrow pressure range.
- The safety and automatic depressurization system valves.
- The reactor vessel head vent isolation valves.
- The interconnecting piping and fittings between the preceding principal components.
- The piping, fittings, and valves leading to connecting auxiliary or support systems.

The piping and instrumentation diagram of the reactor coolant system (Figure 5.1-5) shows the extent of the systems located within the containment and the interface between the reactor coolant system and the secondary (heat utilization) system.

Figures 5.1-3 and 5.1-4 show the plan and section of the reactor coolant loops. These figures show reactor coolant system components in relationship to supporting and surrounding steel and concrete structures. The figures show the protection provided to the reactor coolant system by its physical layout.

5.1.3 System Components

The major components of the reactor coolant system are described in the following subsections. Additional details of the design and requirements of these components are found in other sections of this safety analysis report.

5.1.3.1 Reactor Vessel

The reactor vessel is cylindrical, with a hemispherical bottom head and removable, flanged, hemispherical upper head. The vessel contains the core, core support structures, control rods, and

other parts directly associated with the core. The vessel interfaces with the reactor internals, the integrated head package, and reactor coolant loop piping and is supported on the containment building concrete structure.

The design of the AP1000 reactor vessel closely matches the existing vessel designs of Westinghouse three-loop plants. New features for the AP1000 have been incorporated without departing from the proven features of existing vessel designs.

The vessel has inlet and outlet nozzles positioned in two horizontal planes between the upper head flange and the top of the core. The nozzles are located in this configuration to provide an acceptable cross-flow velocity in the vessel outlet region and to facilitate optimum layout of the reactor coolant system equipment. The inlet and outlet nozzles are offset, with the inlet positioned above the outlet, to allow mid-loop operation for removal of a main coolant pump without discharge of the core.

Coolant enters the vessel through the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom, and flows up through the core to the outlet nozzles.

5.1.3.2 AP1000 Steam Generator

The AP1000 steam generator (SG) is a vertical shell and U-tube evaporator with integral moisture separating equipment. The basic steam generator design and features have been proven in tests and in previous steam generators including replacement steam generator designs.

Design enhancements include nickel-chromium-iron Alloy 690 thermally treated tubes on a triangular pitch, improved antivibration bars, single-tier separators, enhanced maintenance features, and a primary-side channel head design that allows for easy access and maintenance by robotic tooling. The AP1000 steam generator employs tube supports utilizing a broached hole support plate design. All tubes in the steam generator are accessible for sleeving, if necessary. The design enhancements are based on proven technology.

The basic function of the AP1000 steam generator is to transfer heat from the single-phase reactor coolant water through the U-shaped heat exchanger tubes to the boiling, two-phase steam mixture in the secondary side of the steam generator. The steam generator separates dry, saturated steam from the boiling mixture, and delivers the steam to a nozzle from which it is delivered to the turbine. Water from the feedwater system replenishes the steam generator water inventory by entering the steam generator through a feedwater inlet nozzle and feedring.

In addition to its steady-state performance function, the steam generator secondary side provides a water inventory which is continuously available as a heat sink to absorb primary side high temperature transients.

5.1.3.3 Reactor Coolant Pumps

The AP1000 reactor coolant pumps are high-inertia, high-reliability, low-maintenance, sealless pumps of canned motor design that circulate the reactor coolant through the reactor vessel, loop piping, and steam generators. The pumps are integrated into the steam generator channel head.

The integration of the pump suction into the bottom of the steam generator channel head eliminates the cross-over leg of coolant loop piping; reduces the loop pressure drop; simplifies the foundation and support system for the steam generator, pumps, and piping; and reduces the potential for uncovering of the core by eliminating the need to clear the loop seal during a small loss of coolant accident.

The AP1000 design uses four pumps. Two pumps are coupled with each steam generator.

Each AP1000 reactor coolant pump is a vertical, single-stage centrifugal pump designed to pump large volumes of main coolant at high pressures and temperatures. Because of its sealless design, it is more tolerant of off-design conditions that could adversely affect shaft seal designs. The main impeller attaches to the rotor shaft of the driving motor, which is an electric induction motor. The stator and rotor of the motor are both encased in corrosion-resistant cans constructed and supported to withstand full system pressure.

Primary coolant circulates between the stator and rotor which obviates the need for a seal around the motor shaft. Additionally, the motor bearings are lubricated by primary coolant. The motor is thus an integral part of the pump. The basic pump design has been proven by many years of service in other applications.

The pump motor size is minimized through the use of a variable frequency drive to provide speed control in order to reduce motor power requirements during pump startup from cold conditions. The variable frequency drive is used only during heatup and cooldown when the reactor trip breakers are open. During power operations, the drive is isolated and the pump is run at constant speed.

To provide the rotating inertia needed for flow coast-down, bi-metallic flywheel assemblies are attached to the pump shaft.

5.1.3.4 Primary Coolant Piping

Reactor coolant system piping is configured with two identical main coolant loops, each of which employs a single 31-inch inside diameter hot leg pipe to transport reactor coolant to a steam generator. The two reactor coolant pump suction nozzles are welded directly to the outlet nozzles on the bottom of the steam generator channel head. Two 22-inch inside diameter cold leg pipes in each loop (one per pump) transport reactor coolant back to the reactor vessel to complete the circuit.

The loop configuration and material have been selected such that pipe stresses are sufficiently low for the primary loop and large auxiliary lines to meet the requirements to demonstrate "leak-before-break." Thus, pipe rupture restraints are not required, and the loop is analyzed for pipe ruptures only for small auxiliary lines that do not meet the leak-before-break requirements.

5.1.3.5 Pressurizer

The AP1000 pressurizer is a principal component of the reactor coolant system pressure control system. It is a vertical, cylindrical vessel with hemispherical top and bottom heads, where liquid and vapor are maintained in equilibrium saturated conditions.

One spray nozzle and two nozzles for connecting the safety and depressurization valve inlet headers are located in the top head. Electrical heaters are installed through the bottom head. The heaters are removable for replacement. The bottom head contains the nozzle for attaching the surge line. This line connects the pressurizer to a hot leg, and provides for the flow of reactor coolant into and out of the pressurizer during reactor coolant system thermal expansions and contractions.

5.1.3.6 Pressurizer Safety Valves

The pressurizer safety valves are spring loaded, self-actuated with back-pressure compensation. Their set pressure and combined capacity is based on not exceeding the reactor coolant system maximum pressure limit during the Level B service condition loss of load transient.

5.1.3.7 Reactor Coolant System Automatic Depressurization Valves

Some of the functions of the AP1000 passive core cooling system (PXS) are dependent on depressurization of the reactor coolant system. This is accomplished by the automatically actuated depressurization valves. The automatic depressurization valves connected to the pressurizer are arranged in six parallel sets of two valves in series opening in three stages.

A set of fourth-stage automatic depressurization valves is connected to each reactor coolant hot leg. Each set of valves consists of two parallel paths of two valves in series.

To mitigate the consequences of the various accident scenarios, the controls are arranged to open the valves in a prescribed sequence based on core makeup tank level and a timer as described in Section 6.3.

5.1.4 System Performance Characteristics

Table 5.1-3 lists the nominal thermal hydraulic parameters of the reactor coolant system. The system performance parameters are also determined for an assumed 10 percent uniform steam generator tube plugging condition.

Reactor coolant flow is established by a detailed design procedure supported by operating plant performance data and component hydraulics experimental data. The procedure establishes a best-estimate flow and conservatively high and low flows for the applicable mechanical and thermal design considerations. In establishing the range of design flows, the procedure accounts for the uncertainties in the component flow resistances and the pump head-flow capability, established by analysis of the available experimental data. The procedure also accounts for the uncertainties in the technique used to measure flow in the operating plant.

Definitions of the four reactor coolant flows applied in various plant design considerations are presented in the following paragraphs.

5.1.4.1 Best-Estimate Flow

The best-estimate flow is the most likely value for the normal full-power operating condition. This flow is based on the best estimate of the fuel, reactor vessel, steam generator, and piping flow resistances, and on the best estimate of the reactor coolant pump head and flow capability. The best-estimate flow provides the basis for the other design flows required for the system and component design. The best-estimate flow and head also define the performance requirement for the reactor coolant pump. Table 5.1-1 lists system parameters based on best-estimate flow.

The best-estimate flow analysis is based on extensive experimental data, including accurate flow and pressure drop data from an operating plant, flow resistance measurements from several fuel assembly hydraulics tests, and hydraulic performance measurements from several pump impeller model tests. Since operating plant flow measurements are in close agreement with the calculated best-estimate flows, the flows established with this design procedure can be applied to the plant design with a high level of confidence.

Although the best-estimate flow is the most likely value to be expected in operation, more conservative flow rates are applied in the thermal and mechanical designs.

5.1.4.2 Minimum Measured Flow

The minimum measured flow is specified in the technical specifications as the flow that must be confirmed or exceeded by the flow measurements obtained during plant startup. This is the flow used

in reactor core departure from nucleate boiling (DNB) analysis for the thermal design procedure used in the AP1000. In the thermal design procedure methodology for DNB analysis, flow measurement uncertainties are combined statistically with fuel design and manufacturing uncertainties.

The measured reactor coolant flow will most likely differ from the best-estimate flow because of uncertainties in the hydraulics analysis and the inaccuracies in the instrumentation used to measure flow. The measured flow is expected to fall within a range around the best-estimate flow. The magnitude of the expected range is established by statistically combining the system hydraulics uncertainty with the total flow rate within the expected range, less any excess flow margin that may be provided to account for future changes in the hydraulics of the reactor coolant system.

5.1.4.3 Thermal Design Flow

The thermal design flow is the conservatively low value used for thermal-hydraulic analyses where the design and measurement uncertainties are not combined statistically, and additional flow margin must therefore be explicitly included. The thermal design flow is derived by subtracting the plant flow measurement uncertainty from the minimum measured flow. The thermal design flow is approximately 4.5 percent less than the best-estimate flow. The thermal design flow is confirmed when the plant is placed in operation. Table 5.1-3 provides tabulations of important design parameters based on the thermal design flow.

5.1.4.4 Mechanical Design Flow

Mechanical design flow is the conservatively high flow used as the basis for the mechanical design of the reactor vessel internals, fuel assemblies, and other system components. Mechanical design flow is established at 104 percent of best-estimate flow.

5.1.5 Combined License Information

This section contained no requirement for additional information.

Table 5.1-1
Principal System Pressures, Temperatures, and Flow Rates
(Nominal Steady-State, Full Power Operating Conditions)

Location (Fig. 5.1-1)	Description	Fluid	Pressure (psig)	Nominal Temp. (°F)	Flow[(a)] (gpm)
1	Hot Leg 1	Reactor Coolant	2247	610	177,645
2	Hot Leg 2	Reactor Coolant	2247	610	177,645
3	Cold Leg 1A	Reactor Coolant	2323	537.2	78,750
4	Cold Leg 1B	Reactor Coolant	2323	537.2	78,750
5	Cold Leg 2A	Reactor Coolant	2323	537.2	78,750
6	Cold Leg 2B	Reactor Coolant	2323	537.2	78,750
7	Surge Line Inlet	Reactor Coolant	2248	610	-
8	Pressurizer Inlet	Reactor Coolant	2241	653.0	-
9	Pressurizer Liquid	Reactor Coolant	2235	653.0	-
10	Pressurizer Steam	Steam	2235	653.0	-
11	Pressurizer Spray 1A	Reactor Coolant	2317	537.2	1 - 2
12	Pressurizer Spray 1B	Reactor Coolant	2317	537.2	1 - 2
13	Common Spray Line	Reactor Coolant	2317	537.2	2 - 4
14	ADS Valve Inlet	Steam	2234	653.0	-
15	ADS Valve Inlet	Steam	2234	653.0	-

Note:
(a) At the conditions specified.

Table 5.1-2
Nominal System Design and Operating Parameters

General	
Plant design objective, years	60
NSSS power, MWt	3415
Reactor coolant pressure, psia	2250
Reactor coolant liquid volume at power conditions (including 1000 ft^3 pressurizer liquid), ft^3	9600
Loops	
Number of cold legs	4
Number of hot legs	2
Hot leg ID, in.	31
Cold leg ID, in.	22
Reactor Coolant Pumps	
Type of reactor coolant pumps	Sealless
Number of reactor coolant pumps	4
Estimated motor rating, hp	7300
Effective pump power to coolant, MWt	15
Pressurizer	
Number of units	1
Total volume, ft^3	2100
Water volume, ft^3	1000
Spray capacity, gpm	700
Inside diameter, in.	100
Height, in.	503
Steam Generator	
Steam generator power, MWt/unit	1707.5
Type	Vertical U-tube Feedring-type
Number of units	2
Surface area, ft^2/unit	123,540
Shell design pressure, psia	1200
Zero load temperature, °F	557
Feedwater temperature, °F	440
Exit steam pressure, psia	836
Steam flow, lb/hr per steam generator	7.50×10^6
Total steam flow, lb/hr	14.99×10^6

Table 5.1-3
Thermal-Hydraulic Parameters
(Nominal)

Detailed Thermal-Hydraulic Parameters		
Best-Estimate Flow (BEF)	**Without Plugging**	**With 10% Tube Plugging**
Flow rate, gpm/loop	157,500	155,500
Reactor vessel outlet temperature, °F	610.0	610.4
Reactor vessel inlet temperature, °F	537.2	536.8
Minimum Measured Flow (MMF)		
Flow rate, gpm/loop	152,775	150,835
Thermal Design Flow (TDF)		
Flow rate, gpm/loop	149,940	148,000
Reactor vessel outlet temperature, °F	611.7	612.2
Reactor vessel inlet temperature, °F	535.5	535.0
Mechanical Design Flow (MDF)		
Flow rate, gpm/flow	163,800	
Best-Estimate Reactor Core and Vessel Thermal-Hydraulic Parameters		**Without Plugging**
NSSS power, MWt		3415
Reactor power, MWt		3400
Best-Estimate loop flow, gpm/loop		157,500
Best-Estimate vessel flow, lb/hr		120.5×10^6
Best-Estimate core flow, lb/hr		113.4×10^6
Reactor coolant pressure, psia		2250
Vessel/core inlet temperature, °F		537.2
Vessel average temperature, °F		573.6
Vessel outlet temperature, °F		610.0
Average core outlet temperature, °F		615.9
Total core bypass flow, (percent of total flow)		5.9
Core barrel nozzle flow		1.0
Head cooling flow		1.5
Thimble flow		1.9
Core shroud cooling flow		0.5
Unallocated bypass flow		1.0

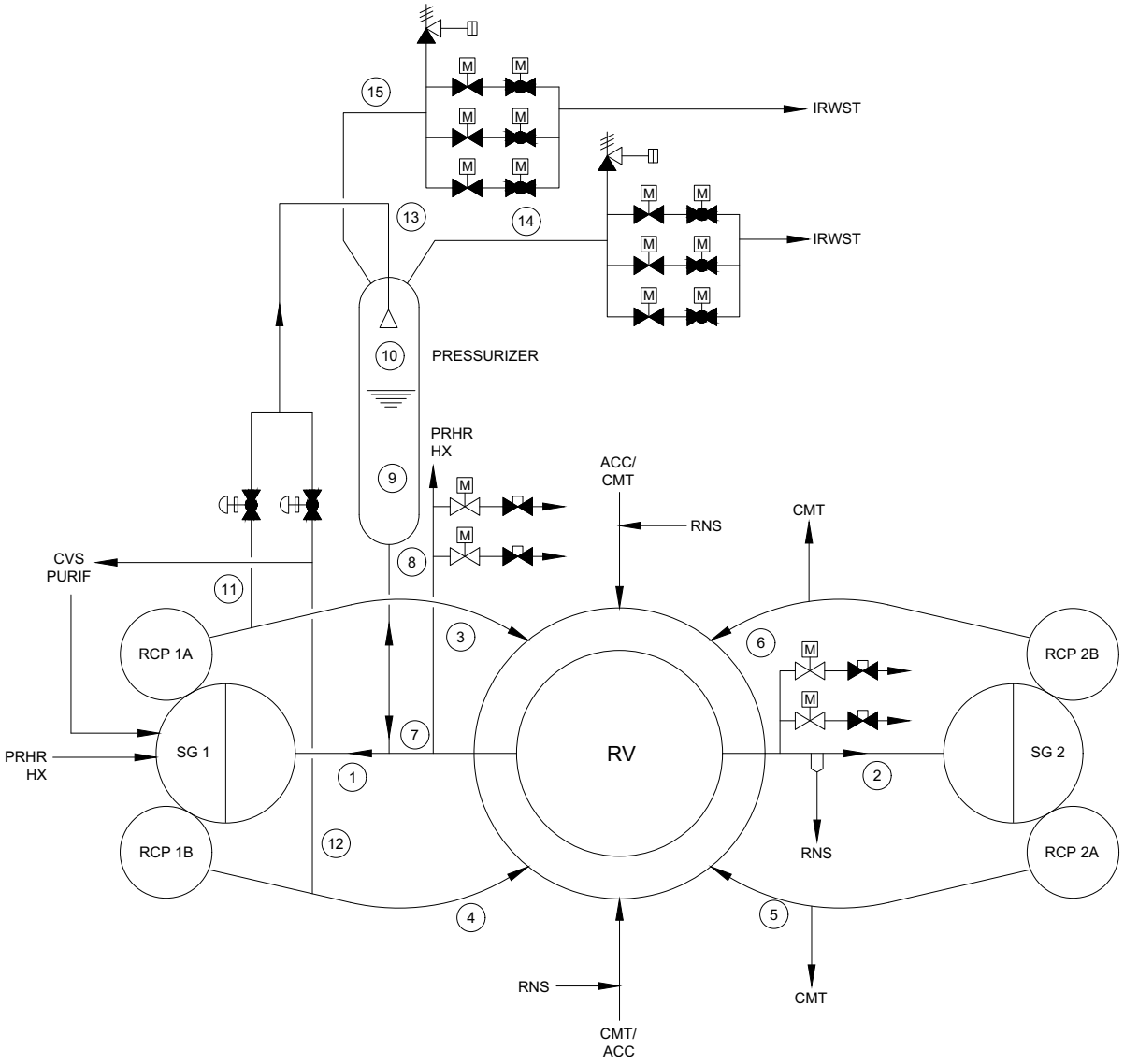


Figure 5.1-1
Reactor Coolant System Schematic Flow Diagram

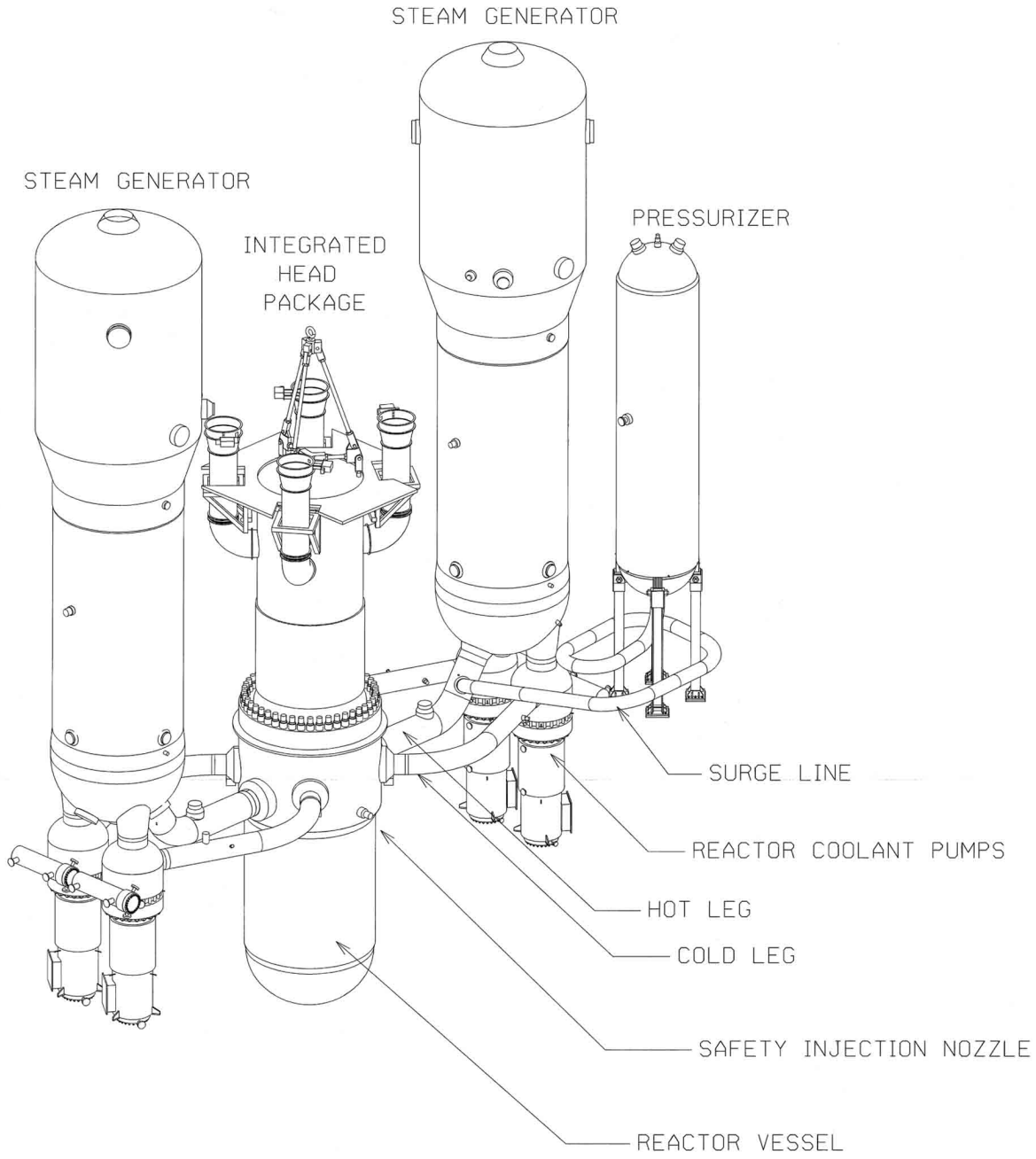


Figure 5.1-2
Reactor Coolant Loops – Isometric View

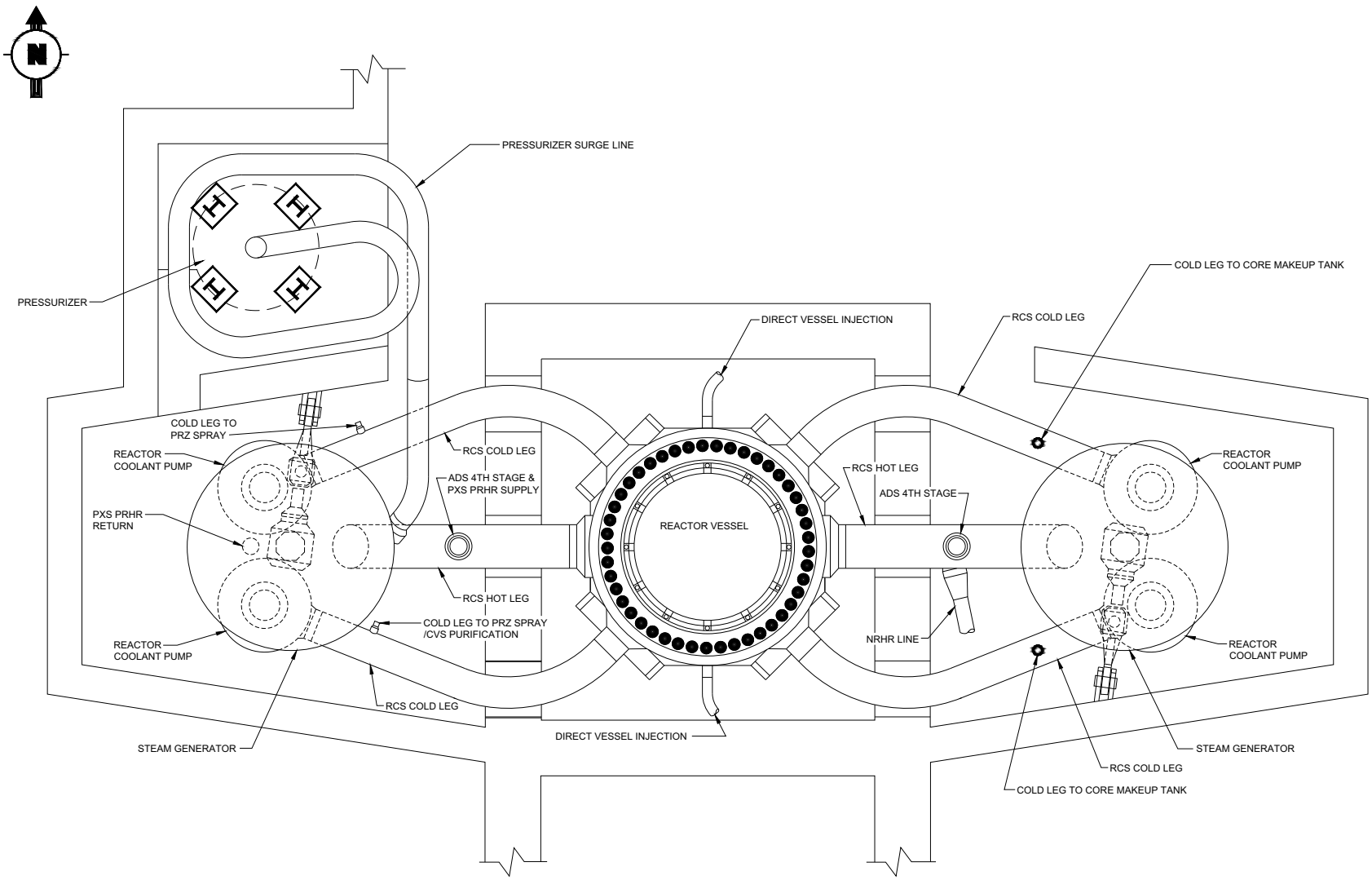
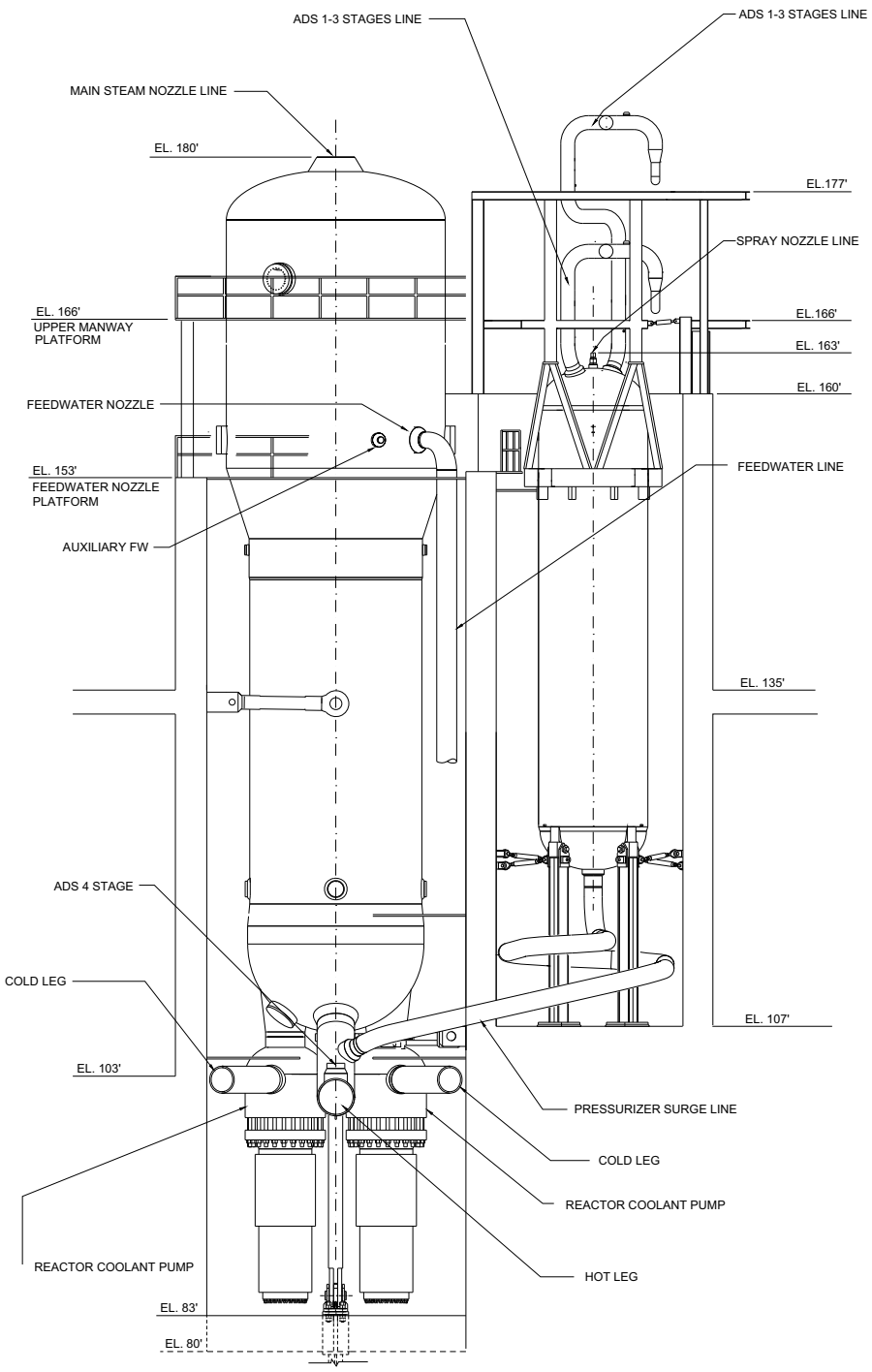
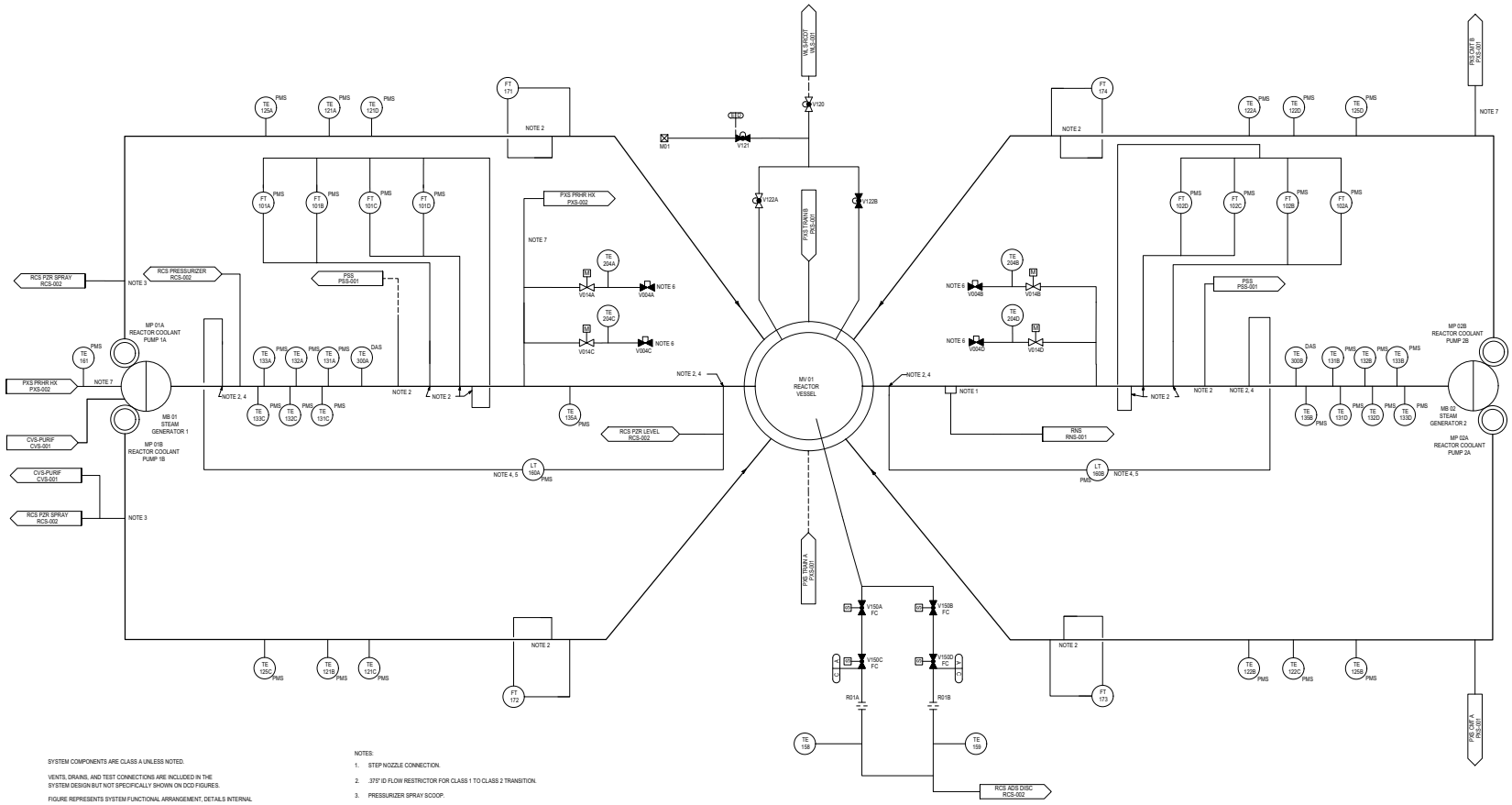


Figure 5.1-3
Reactor Coolant System – Loop Layout



NOTE: THE ELEVATIONS INCLUDED IN THIS FIGURE
ARE ROUNDED TO THE NEAREST FOOT.

Figure 5.1-4
Reactor Coolant System – Elevation



SYSTEM COMPONENTS ARE CLASS A UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

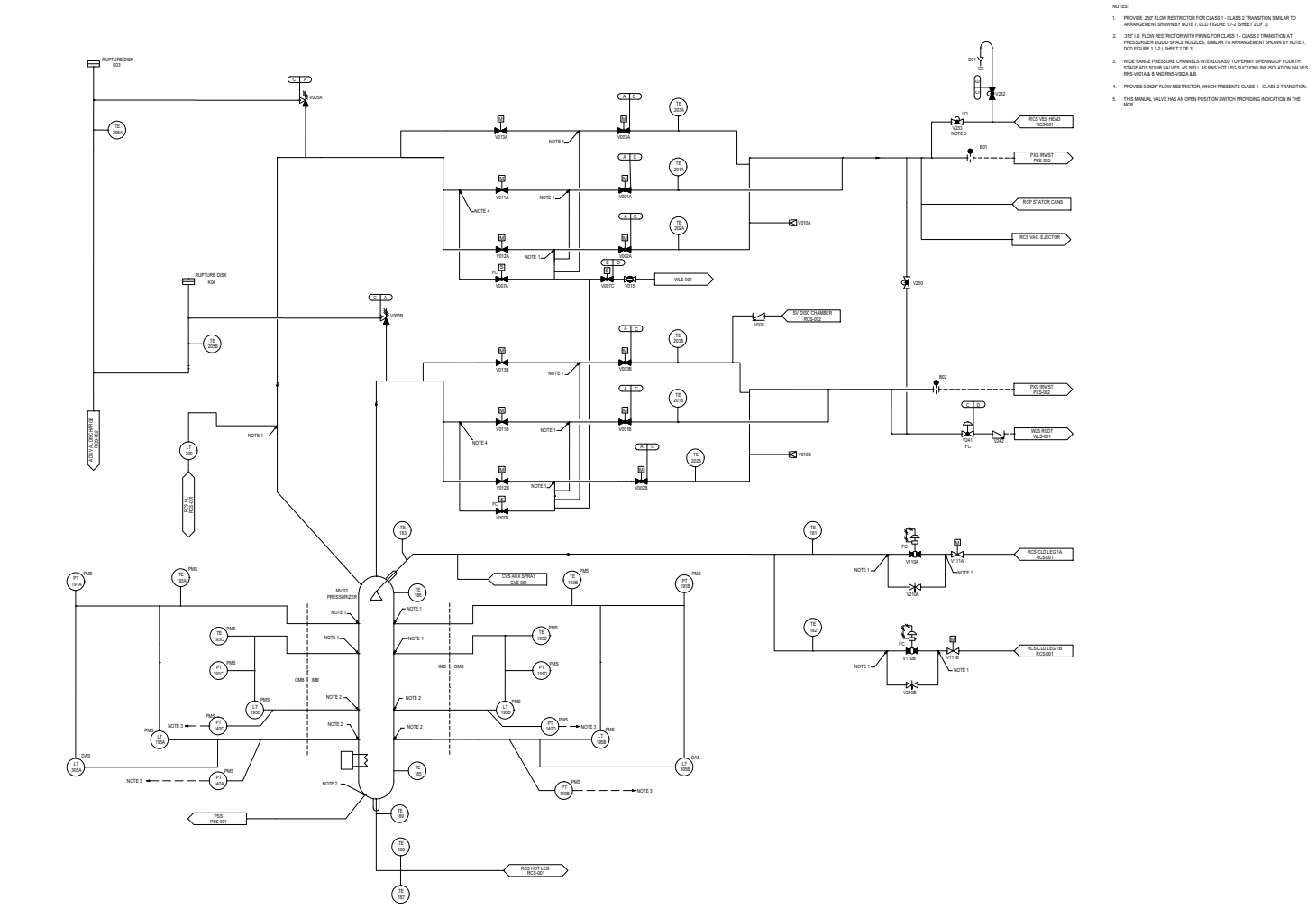
FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

NOTES:

1. STEP NOZZLE CONNECTION.
2. .375" ID FLOW RESTRICTOR FOR CLASS 1 TO CLASS 2 TRANSITION.
3. PRESSURIZER SPRAY SCOOP.
4. LEVEL INSTRUMENTATION PROVIDED TO MONITOR RCS WATER LEVEL DURING MID-LOOP OPERATION FOLLOWING SHUTDOWN.
5. PMS - OPENS IRWST INJECTION VALVES ON LOW-4 (EMPTY) HOT LEG LEVEL PLUS 30 MINUTE TIME DELAY.
6. THE 4TH STAGE ADS VALVES DISCHARGE TO THE STEAM GENERATOR COMPARTMENTS AT AN ELEVATION GREATER THAN 110'.
7. ROUTE ALL ASSOCIATED PIPING TO HIGH POINT VENT WITHOUT ANY LOCAL DOWNWARD SLOPING SECTIONS. NO LOCAL LOW OR HIGH POINTS ARE ALLOWED THAT WOULD PREVENT ASSOCIATED PIPING FROM VENTING PROPERLY TO THE VENT LOCATION FOR THOSE PIPING SEGMENTS.

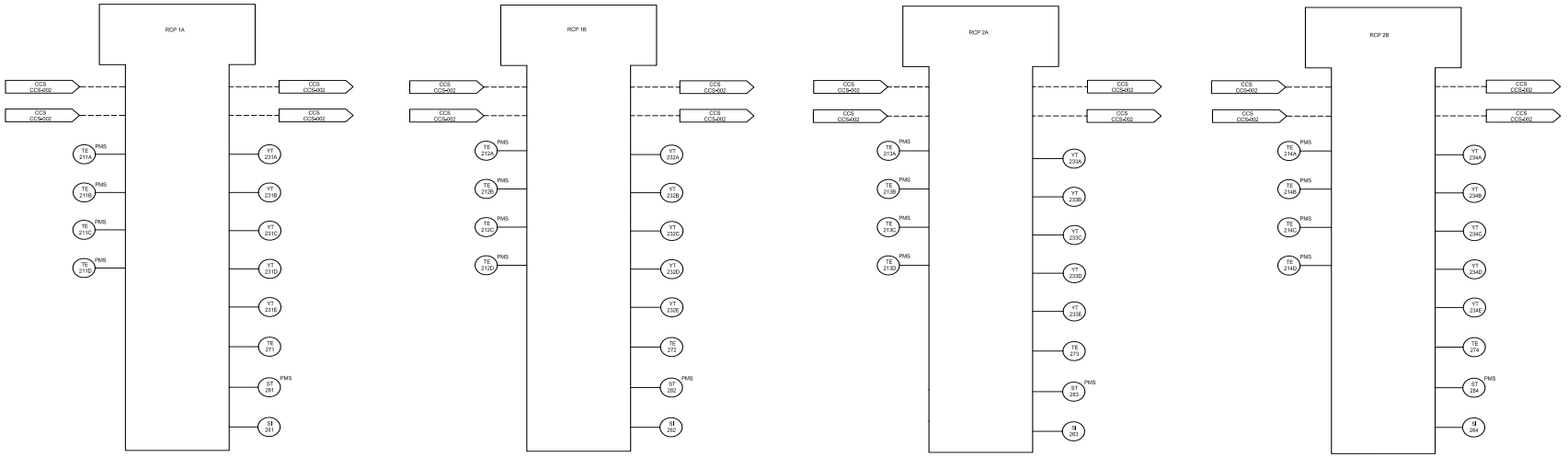
Inside Reactor Containment

Figure 5.1-5 (Sheet 1 of 3)
Simplified Reactor Coolant System Piping and Instrumentation Diagram (REF) RCS 001



Inside Reactor Containment

Figure 5.1-5 (Sheet 2 of 3)
Simplified Reactor Coolant System Piping and Instrumentation Diagram
(REF) RCS 002



VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Reactor Containment

Figure 5.1-5 (Sheet 3 of 3)
Simplified Reactor Coolant System Piping and Instrumentation Diagram (REF) RCS 003

5.2 Integrity of Reactor Coolant Pressure Boundary

This section discusses the measures to provide and maintain the integrity of the reactor coolant pressure boundary (RCPB) during plant operation. Section 50.2 of 10 CFR 50 defines the reactor coolant pressure boundary as vessels, piping, pumps, and valves that are part of the reactor coolant system (RCS), or that are connected to the reactor coolant system up to and including the following:

- The outermost containment isolation valve in system piping that penetrates the containment
- The second of two valves closed during normal operation in system piping that does not penetrate containment
- The reactor coolant system overpressure protection valves

The design transients used in the design and fatigue analysis of ASME Code Class 1 and Class CS components, supports, and reactor internals are provided in Subsection 3.9.1. The loading conditions, loading combinations, evaluation methods, and stress limits for design and service conditions for components, core support structures, and component supports are discussed in Subsection 3.9.3.

The term reactor coolant system, as used in this section, is defined in Section 5.1. The AP1000 reactor coolant pressure boundary is consistent with that of 10 CFR 50.2.

5.2.1 Compliance with Codes and Code Cases

5.2.1.1 Compliance with 10 CFR 50.55a

The regulations in 10 CFR 50.55a require that ASME Section III Class 1, 2, and 3 components of the AP1000 meet the requirements of the ASME Section III Code, except where alternatives to the requirements have been authorized by the Commission pursuant to paragraph (a)(3), prior to December 5, 2014, or paragraph (z) of 10 CFR 50.55a. These authorized alternatives are very similar to ASME Section III Code Cases, as they provide an alternative to existing Code rules, and also reflect how the plant was constructed. Authorized NRC ASME Section III Requests for Alternatives used in the AP1000 are listed in Table 5.2-201.

Reactor coolant pressure boundary components are designed and fabricated in accordance with the ASME Boiler and Pressure Vessel Code, Section III. A portion of the chemical and volume control system inside containment that is defined as reactor coolant pressure boundary uses an alternate classification in conformance with the requirements of 10 CFR 50.55a(z). Systems other than the reactor coolant system connecting to the chemical and volume control system have required isolation and are not classified as reactor coolant pressure boundary. The alternate classification is discussed in Subsection 5.2.1.3. The quality group classification for the reactor coolant pressure boundary components is identified in Subsection 3.2.2. The quality group classification is used to determine the appropriate sections of the ASME Code or other standards to be applied to the components.

The edition and addenda of the ASME Code applied in the design and manufacture of each component are the edition and addenda established by the requirements of the Design Certification. The use of editions and addenda issued subsequent to the Design Certification is permitted or required based on the provisions in the Design Certification. If a later Code edition/addenda than the Design Certification Code edition/addenda is used by the material and/or component supplier, then a code reconciliation to determine acceptability is performed as required by the ASME Code, Section III, NCA-1140. The later Code edition/addenda must be authorized in 10 CFR 50.55a or in a specific authorization as provided in 50.55a(z). Code Cases to be used in design and construction are identified in this document.

Inservice inspection of the reactor coolant pressure boundary is conducted in accordance with the applicable edition and addenda of the ASME Boiler and Pressure Vessel Code Section XI, as described in Subsection 5.2.4. Inservice testing of the reactor coolant pressure boundary components is in accordance with the edition and addenda of the ASME OM Code as discussed in Subsection 3.9.6 for pumps and valves, and as discussed in Subsection 3.9.3.4.4 for dynamic restraints. The baseline used for the evaluations done to support this safety analysis report and the Design Certification is the 1998 Edition, 2000 Addenda, [*with an additional restriction for piping design.*

The restriction on piping design is that the treatment of dynamic loads, including seismic loads, in pipe stress analysis will satisfy the requirements of the ASME Code, Section III, Subarticles NB-3210, NB-3220, NB-3620, NB-3630, NB-3650, NC-3620, NC-3650, ND-3620, and ND-3650 1989 Edition, 1989 Addenda. The requirements shown below for fillet welds are also applicable.

The criteria below are used in place of those in paragraph NB-3683.4(c)(1) and Footnote 11 to Figures NC/ND-3673.2(b)-1 of the 1989 Addenda to the 1989 Edition of ASME Code, Section III. This criteria is based on the criteria included in the 1989 Edition of the ASME Code, Section III.

For girth fillet welds between the piping and socket welded fittings, valves and flanges, and slip on flanges in ASME III Class 1, 2, and 3 piping, the primary stress indices and stress intensification factors are as follows:

Primary Stress Indices

B_1 = *0.75*

B_2 = *1.5*

Stress Intensification Factor

i = $2.1*(t_n/C_x)$, *but not less than 1.3*

C_x = *fillet weld leg length based on ASME III 1989 Edition, Figures NC/ND-4427-1, sketches (c-1), (c-2), and (c-3). For unequal leg length, use smaller leg length for* C_x.]*

Seismic Integrity of the CVS System Inside Containment

To provide for the seismic integrity and pressure boundary [*integrity of the nonsafety-related (ASME B31.1, Piping Class D) CVS piping located inside containment, a seismic analysis will be performed and a CVS Seismic Analysis Report prepared with a faulted stress limit equal to the smaller of 4.5* S_h *and 3.0* S_y *and based on the following additional criteria:*

Additional loading combinations and stress limits for nonsafety-related chemical and volume control system piping systems and components inside containment]*

Condition	***Loading Combination(3)***	***[Equations (ND3650)***	***Stress Limit***
Level D	*PMAX(1) + DW + SSE + SSES*	*9*	*Smaller of* $4.5\ S_h$ *or* $3.0\ S_y$
	SSES	F_{AM}/A_M(4)	$1.0\ S_h$
	TNU + SSES	*i (M1 + M2)/Z(2)*	$3.0\ S_h$

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Notes:

1. *For earthquake loading, PMAX is equal to normal operating pressure at 100% power.*
2. *Where: M1 is range of moments for TNU, M2 is one half the range of SSES moments, M1 + M2 is larger of M1 plus one half the range of SSES, or full range of SSES.*
3. *See Table 3.9-3 for description of loads.*
4. *F_{AM} is amplitude of axial force for SSES; A_M is nominal pipe metal area.*]*

Component supports, equipment, and structural steel frame are evaluated to demonstrate that they do not fail under seismic loads. Design methods and stress criteria are the same as for corresponding Seismic Category I components. The functionality of the chemical and volume control system does not have to be maintained to insure structural integrity of the components.

[*Dimensional fabrication, assembly, erection, inspection, examination, and testing requirements as defined in Chapters IV, V, and VI of the ASME B31.1 Code are applicable and used for the ASME B31.1 (Piping Class D) CVS piping systems, valves, and equipment inside containment.*]*

5.2.1.2 Applicable Code Cases

[*ASME Code Cases used in the AP1000 are listed in Table 5.2-3.*]* In addition, other ASME Code Cases found in Regulatory Guide 1.84, as discussed in Section 1.9 and Appendix 1A, in effect at the time of the Design Certification may be used for pressure boundary components. Use of Code Cases approved in revisions of the Regulatory Guides issued subsequent to the Design Certification may be used as discussed in Subsection 5.2.6.1 by using the process outlined above for updating the ASME Code edition and addenda. Use of any Code Case not approved in Regulatory Guide 1.84 on Class 1 components is authorized as provided in 50.55a(z) and the requirements of the Design Certification.

The use of any Code Case conditionally approved in Regulatory Guide 1.84 used on Class 1 components meets the conditions established in the Regulatory Guide.

ASME Code Cases required for Section XI inspections will be identified in Plant Owner provided Inspection Plans as referenced in Subsection 5.2.6.2. See Subsection 5.2.4, “Inservice Inspection and Testing of Class 1 Components,” and Section 6.6, “Inservice Inspection of Class 2, 3, and MC Components,” for discussion of inservice examinations and procedures.

5.2.1.3 Alternate Classification

The Code of Federal Regulations, Section 10 CFR 50.55a requires the reactor coolant pressure boundary be class A (ASME Boiler and Pressure Vessel Code Section III, Class 1). Components which are connected to the reactor coolant pressure boundary that can be isolated from the reactor coolant system by two valves in series (both closed, both open, or one closed and the other open) with automatic actuation to close can be classified as class C (ASME Section III, class 3) according to 50.55a.

A portion of the chemical and volume control system inside containment is not classified as safety-related. The classification of the AP1000 reactor coolant pressure boundary deviates from the requirement that the reactor coolant pressure boundary be classified as safety related and be constructed using the ASME Code, Section III as provided in 10 CFR 50.55a. The safety-related classification of the AP1000 reactor coolant pressure boundary ends at the third isolation valve between the reactor coolant system and the chemical and volume control system. The nonsafety-related portion of the chemical and volume control system inside containment provides purification of the reactor coolant and includes heat exchangers, demineralizers, filters and connecting piping. For a description of the chemical and volume control system, refer to

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Subsection 9.3.6. The portion of the chemical and volume control system between the inside and outside containment isolation valves is classified as Class B and is constructed using the ASME Code, Section III.

The nonsafety-related portion of the chemical and volume control system is designed using ASME B31.1 and ASME Code, Section VIII for the construction of the piping, valves, and components. The nonsafety-related portion of the CVS inside containment is analyzed seismically. The methods and criteria used for the seismic analysis are similar to those used of seismic Category II pipe and are defined in the Subsection 5.2.1.1. The chemical and volume control system components are located inside the containment which is a seismic Category I structure.

The alternate classification of the nonsafety-related purification subsystems satisfies the purpose of 10 CFR 50.55a that structures, systems, and components of nuclear power plants which are important to safety be designed, fabricated, erected, and tested to quality standards that reflect the importance of the safety functions to be performed.

The AP1000 chemical and volume control system is not required to perform safety-related functions such as emergency boration or reactor coolant makeup. Safety-related core makeup tanks are capable of providing sufficient reactor coolant makeup for shutdown and cooldown without makeup supplied by the chemical and volume control system. Safe shutdown of the reactor does not require use of the chemical and volume control system makeup. AP1000 safe shutdown is discussed in Section 7.4.

The isolation valves between the reactor coolant system and the chemical and volume control system are active safety-related valves that are designed, qualified, inspected and tested for the isolation requirements. These isolation valves also function to isolate the reactor coolant system in the event of a break in the nonsafety portion of the chemical and volume control system purification loop. The isolation valves between the reactor coolant system and chemical and volume control system are designed and qualified for design conditions that include closing against blowdown flow with full system differential pressure. These valves are qualified for adverse seismic and environmental conditions. The valves are subject to inservice testing including operability testing.

The potential for release of activity from a break or leak in the chemical and volume control system is minimized by the location of the purification subsystem inside containment and the design and test of the isolation valves. Chemical and volume control system leakage inside containment is detectable by the reactor control leak detection function as potential reactor coolant pressure boundary leakage. This leakage must be identified before the reactor coolant leak limit is reached. The nonsafety-related classification of the system does not impact the need to identify the source of a leak inside containment.

5.2.2 Overpressure Protection

Reactor coolant system and steam system overpressure protection during power operation are provided by the pressurizer safety valves and the steam generator safety valves, in conjunction with the action of the reactor protection system. Combinations of these systems provide compliance with the overpressure protection requirements of the ASME Boiler and Pressure Vessel Code, Section III, Paragraphs NB-7300 and NC-7300, for pressurized water reactor systems.

Low temperature overpressure protection is provided by relief valves in the suction line of the normal residual heat removal (RNS) system. The sizing and use of the relief valves for low temperature overpressure protection is consistent with the guidelines of Branch Technical Position RSB 5-2.

5.2.2.1 Design Bases

Overpressure protection during power operation is provided for the reactor coolant system by the pressurizer safety valves. This protection is afforded for the following events to envelop those credible events that could lead to overpressure of the reactor coolant system if adequate overpressure protection were not provided:

- Loss of electrical load and/or turbine trip
- Uncontrolled rod withdrawal at power
- Loss of reactor coolant flow
- Loss of normal feedwater
- Loss of offsite power to the station auxiliaries

The sizing of the pressurizer safety valves is based on the analysis of a complete loss of steam flow to the turbine, with the reactor operating at 102 percent of rated power. In this analysis, feedwater flow is also assumed to be lost. No credit is taken for operation of the pressurizer level control system, pressurizer spray system, rod control system, steam dump system, or steam line power-operated relief valves. The reactor is maintained at full power (no credit for direct reactor trip on turbine trip and for reactivity feedback effects), and steam relief through the steam generator safety valves is considered. The total pressurizer safety valve capacity is required to be at least as large as the maximum surge rate into the pressurizer during this transient.

This sizing procedure results in a safety valve capacity well in excess of the capacity required to prevent exceeding 110 percent of system design pressure for the events previously listed. The discharge of the safety valve is routed through a rupture disk to containment atmosphere. The rupture disk is to contain leakage past the valve. The rupture disk pressure rating is substantially less than the set pressure of the safety valve. See Subsection 5.4.11 for additional information on the safety valve discharge system. Subsection 5.4.5 describes the connection of the safety valves to the pressurizer.

Administrative controls and plant procedures aid in controlling reactor coolant system pressure during low-temperature operation. Normal plant operating procedures maximize the use of a steam or gas bubble in the pressurizer during periods of low pressure, low-temperature operation. For those low-temperature modes of operation when operation with a water solid pressurizer is possible, relief valves in the residual heat removal system provide low-temperature overpressure protection for the reactor coolant system. The valves are sized to prevent overpressure during the following credible events with a water-solid pressurizer:

- Makeup/letdown flow mismatch
- Inadvertent actuation of the pressurizer heaters
- Loss of residual heat removal with reactor coolant system heatup due to decay heat and pump heat
- Inadvertent start of one reactor coolant pump
- Inadvertent hydrogen addition

Of those events the makeup/letdown flow mismatch is the limiting mass input condition. Inadvertent start of an inactive reactor coolant pump is the limiting heat input condition to size the relief valves. The flow rate postulated for mass input condition is based on the flow from one or both makeup pumps at the set pressure of the relief valves. The heat input condition is based on a 50-degree temperature difference between the reactor coolant system and the steam generator secondary side.

The set pressures for the normal residual heat removal system relief valves are established based on the lower value of the normal residual heat removal system design pressure and the low-temperature pressure limit for the reactor vessel based on ASME Code, Section III, Appendix G, analyses. The pressure-temperature limits for the reactor vessel, based on expected material properties and the vessel design, are discussed in Subsection 5.3.3.

The capacity of the residual heat removal relief valves can maintain the pressure in the reactor coolant system and the residual heat removal system to a pressure less than the lesser of 110 percent of the design pressure of the normal residual heat removal system or the pressure limit from the Appendix G analyses for the limiting event.

Overpressure protection for the steam system is provided by steam generator safety valves. The capacity of the steam system safety valves limits steam system pressure to less than 110 percent of the steam generator shell side design pressure. See Section 10.3 for details.

Section 10.3 discusses the steam generator relief valves and connecting piping.

5.2.2.2 Design Evaluation

The relief capacities of the pressurizer safety valves, steam generator safety valves, and the normal residual heat removal system relief valves are determined from the postulated overpressure transient conditions in conjunction with the action of the reactor protection system. An overpressure protection report is prepared according to Article NB-7300 of Section III of the ASME Code. WCAP-7907 (Reference 1) describes the analytical model used in the analysis of the overpressure protection system and the basis for its validity.

Chapter 15 includes a design description of certain initiating events and describes assumptions made, method of analysis, conclusions, and the predicted response of the AP1000 to those events. The performance characteristics of the pressurizer safety valves are included in the analysis of the response. The incidents evaluated include postulated accidents not included in the compilation of credible events used for valve sizing purposes.

Subsection 5.4.9 discusses the capacities of the pressurizer safety valves and residual heat removal system relief valves used for low temperature overpressure protection. The setpoints and reactor trip signals which occur during operational overpressure transients are discussed in Subsection 5.4.5. With the current AP1000 pressure-temperature limits (Subsection 5.3.3), the set pressures for the relief valves in the normal residual heat removal system are based on a sizing analysis performed to prevent the reactor coolant system pressure from exceeding the applicable low temperature pressure limit for the reactor vessel based on ASME Code, Section III, Appendix G. The limiting mass and energy input transients are assumed for the sizing analysis.

5.2.2.3 Piping and Instrumentation Diagrams

The connection of the pressurizer safety valves to the pressurizer is incorporated into the pressurizer safety and relief valve module and is discussed in Subsection 5.4.9. The pressurizer safety and relief valve module configuration appears in the piping and instrumentation drawing for the reactor coolant system (Figure 5.1-5). The normal residual heat removal system (Subsection 5.4.7) incorporates the relief valves for low-temperature overpressure protection. The valves which isolate the normal

residual heat removal system from the reactor coolant system do not have an autoclosure interlock. Figure 5.4-6 shows a simplified sketch of the normal residual heat removal system. Figure 5.4-7 shows the piping and instrumentation drawing for the residual heat removal system.

Section 10.3 discusses the safety valves for the main steam system. Figure 10.3.2-1 shows the piping and instrumentation drawing for the main steam system.

5.2.2.4 Equipment and Component Description

Subsection 5.4.9 discusses the design and design parameters for the safety valves providing operating and low-temperature overpressure protection. The pressurizer safety valves are ASME Boiler and Pressure Vessel Code Class 1 components. These valves are tested and analyzed using the design transients, loading conditions, seismic considerations, and stress limits for Class 1 components as described in Subsections 3.9.1, 3.9.2, and 3.9.3.

The relief valves included in the normal residual heat removal system provide containment boundary function since they are connected to the piping between the containment isolation valves for the system. Containment isolation requirements are discussed in Subsection 6.2.3. Based on the containment boundary function, the relief valves are ASME Code Class 2 components and are analyzed to the appropriate requirements.

In addition to the testing and analysis required for ASME Code requirements, the pressurizer safety valves are of a type which has been verified to operate during normal operation, anticipated transients, and postulated accident conditions. The verification program (Reference 2) was established by the Electric Power Research Institute to address the requirements of 10 CFR 50.34 (f)(2)(x). These requirements do not apply to relief valves of the size and type represented by the relief valves on the normal residual heat removal system.

Section 10.3 discusses the equipment and components that provide the main steam system overpressure protection.

5.2.2.5 Mounting of Pressure Relief Devices

Subsection 5.4.9 describes the design and installation of the pressure relief devices for the reactor coolant system. Section 3.9 describes the design basis for the assumed loads for the primary- and secondary-side pressure relief devices. Subsection 10.3.2, discusses the main steam safety valves and the power-operated atmospheric steam relief valves.

5.2.2.6 Applicable Codes and Classification

The requirements of the ASME Boiler and Pressure Vessel Code, Section III, Paragraphs NB-7300 (Overpressure Protection Report) and NC-7300 (Overpressure Protection Analysis), are met.

Piping, valves, and associated equipment used for overpressure protection are classified according to the classification system discussed in Subsection 3.2.2. These safety-class designations are delineated in Table 3.2-3.

5.2.2.7 Material Specifications

See Subsection 5.2.3 for the material specifications for the pressurizer safety valves. The piping in the pressurizer safety and relief valve module up to the safety valve is considered reactor coolant system. See Subsection 5.2.3 for material specifications. The discharge piping is austenitic stainless steel. Subsection 5.4.7 specifies the materials used in the normal residual heat removal system.

5.2.2.8 Process Instrumentation

Each pressurizer safety valve discharge line incorporates a main control room temperature indicator and alarm to notify the operator of steam discharge due to either leakage or actual valve operation.

5.2.2.9 System Reliability

ASME Code safety valves and relief valves have demonstrated a high degree of reliability over many years of service. The in-service inspection and testing required of safety valves and relief valves (Subsections 3.9.6 and 5.2.4 and Section 6.6) provides assurance of continued reliability and conformance to setpoints. The assessment of reliability, availability, and maintainability which is done to evaluate the estimated availability for the AP1000 includes estimates for the contribution of safety valves and relief valves to unavailability. These estimates were based on experience for operating units.

5.2.2.10 Testing and Inspection

Subsections 3.9.6 and 5.4.8 and Section 6.6 discuss the preservice and in-service testing and inspection required for the safety valves and relief valves. The testing and inspection requirements are in conformance with industry standards, including Section XI of the ASME Code.

5.2.3 Reactor Coolant Pressure Boundary Materials

5.2.3.1 Materials Specifications

Table 5.2-1 lists material specifications used for the principal pressure-retaining applications in Class 1 primary components and reactor coolant system piping. Material specifications with grades, classes or types are included for the reactor vessel components, steam generator components, reactor coolant pump, pressurizer, core makeup tank, and the passive residual heat removal heat exchanger. Table 5.2-1 lists the application of nickel-chromium-iron alloys in the reactor coolant pressure boundary. The use of nickel-chromium-iron alloy in the reactor coolant pressure boundary is limited to Alloy 690, or its associated weld metals Alloys 52, 52M, and 152, and similar alloys developed for improved weldability as allowed by ASME Boiler and Pressure Vessel Code rules. Steam generator tubes use Alloy 690 in the thermally treated form. Nickel-chromium-iron alloys are used where corrosion resistance of the alloy is an important consideration and where the use of nickel-chromium-iron alloy is the choice because of the coefficient of thermal expansion. Subsection 5.4.3 defines reactor coolant piping. See Subsection 4.5.2 for material specifications used for the core support structures and reactor internals. See appropriate sections for internals of other components. Engineered safeguards features materials are included in Subsection 6.1.1. The nonsafety-related portion of the chemical and volume control system inside containment in contact with reactor coolant is constructed of or clad with corrosion resistant material such as Type 304 or Type 316 stainless steel or material with equivalent corrosion resistance. The materials are compatible with the reactor coolant. The nonsafety-related portion of the chemical and volume control system is not required to conform to the process requirements outlined below.

Table 5.2-1 material specifications are the materials used in the AP1000 reactor coolant pressure boundary. The materials used in the reactor coolant pressure boundary conform to the applicable ASME Code rules. Cast austenitic stainless steel does not exceed a ferrite content of 20 FN. Calculation of ferrite content is based on Hull's equivalent factors.

The welding materials used for joining the ferritic base materials of the reactor coolant pressure boundary conform to or are equivalent to ASME Material Specifications SFA 5.1, 5.5, 5.17, 5.18, 5.20, 5.23, 5.28, 5.29, and 5.30. They are qualified to the requirements of the ASME Code, Section III.

The welding materials used for joining the austenitic stainless steel base materials of the reactor coolant pressure boundary conform to ASME Material Specifications SFA 5.4, 5.9, 5.22, and 5.30. They are qualified to the requirements of the ASME Code, Section III.

The welding materials used for joining nickel-chromium-iron alloy in similar base material combination and in dissimilar ferritic or austenitic base material combination conform to ASME Material Specifications SFA 5.11 and 5.14, or are similar welding alloys to those in SFA-5.11 or SFA-5.14 developed for improved weldability as allowed by the ASME Boiler and Pressure Vessel Code rules. They are qualified to the requirements of the ASME Code, Section III.

The fabrication and installation specifications for partial penetration welds with Alloy 52/52M/152, within the ASME Class 1 reactor coolant pressure boundary, require successive dye penetrant examinations after the first pass and after every 1/4-inch of weld metal. The specifications for J-groove welds, which join ASME Class 1 reactor coolant pressure boundary penetrations require ultrasonic examination of the interface where the weld joins the penetration tube. The specifications for butt welds used for nozzle safe-end welds require these welds to be radiographically inspected. These weld specifications are applicable to the ASME Class 1 reactor coolant pressure boundary portions of the reactor vessel (Section 5.3), the reactor coolant pumps (Subsection 5.4.1), the steam generators (Subsection 5.4.2), the reactor coolant system piping (Subsection 5.4.3), the pressurizer (Subsection 5.4.5), the core makeup tanks (Subsection 5.4.13), and the passive residual heat removal heat exchanger (Subsection 5.4.14).

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Chemistry of Reactor Coolant

The reactor coolant system chemistry specifications conform to the recommendation of Regulatory Guide 1.44, with exceptions as stated in Subsection 1.9.1, and are shown in Table 5.2-2. The values presented in Table 5.2-2 are bounding for chemistry operational control of primary fluids that are in contact with primary systems' materials and nuclear fuel. The operational chemistry program may apply stricter limits as deemed appropriate.

The reactor coolant system water chemistry is selected to minimize corrosion. Routinely scheduled analyses of the coolant chemical composition are performed to verify that the reactor coolant chemistry meets the specifications. Other additions, such as those to reduce activity transport and deposition, may be added to the system.

The chemical and volume control system (CVS) provides a means for adding chemicals to the reactor coolant system. The chemicals perform the following functions:

- Control the pH of the coolant during prestartup testing and subsequent operation
- Scavenge oxygen from the coolant during heatup
- Control radiolysis reactions involving hydrogen, oxygen, and nitrogen during power operations following startup

Table 5.2-2 shows the normal limits for chemical additives and reactor coolant impurities for power operation.

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

hydroxide is introduced into the reactor coolant system via the charging flow. The concentration of lithium-7 hydroxide in the reactor coolant system is maintained in the range specified for pH control.

During reactor startup from the cold condition, hydrazine is used as an oxygen-scavenging agent. The hydrazine solution is introduced into the reactor coolant system in the same manner as described for the pH control agent.

The reactor coolant is treated with dissolved hydrogen to control the net decomposition of water by radiolysis in the core region. The hydrogen reacts with oxygen introduced into the reactor coolant system by the radiolysis effect of radiation on molecules. Hydrogen makeup is supplied to the reactor coolant system by direct injection of high pressure gaseous hydrogen, which can be adjusted to provide the correct equilibrium hydrogen concentration. Subsection 1.9.1 indicates the degree of conformance with Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," with the exceptions as stated in Subsection 1.9.1.

Boron, in the chemical form of boric acid, is added to the reactor coolant system for long-term reactivity control of the core.

Suspended solid (corrosion product particulates) and other impurity concentrations are maintained below specified limits by controlling the chemical quality of makeup water and chemical additives and by purification of the reactor coolant through the chemical and volume control system.

The water chemistry program is based on industry guidelines as described in EPRI “Pressurized Water Reactor Primary Water Chemistry” (Reference 201). The program includes periodic monitoring and control of chemical additives and reactor coolant impurities listed in Table 5.2-2. Detailed procedures implement the program requirements for sampling and analysis frequencies, and corrective actions for control of reactor water chemistry.

The frequency of sampling water chemistry varies (e.g. continuous, daily, weekly, or as needed) based on plant operating conditions and the EPRI water chemistry guidelines. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions. When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range and within the time period specified in the EPRI water chemistry guidelines. Following corrective actions, additional samples are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants to within the specified range.

Chemistry procedures will provide guidance for the sampling and monitoring of primary coolant properties.

5.2.3.2.2 Compatibility of Construction Materials with Reactor Coolant

Ferritic low-alloy and carbon steels used in principal pressure-retaining applications have corrosion-resistant cladding on surfaces exposed to the reactor coolant. The corrosion resistance of the cladding material is at least equivalent to the corrosion resistance of Types 304 and 316 austenitic stainless steel alloys or nickel-chromium-iron alloy, martensitic stainless steel, and precipitation-hardened stainless steel. These clad materials may be subjected to the ASME Code-required postweld heat treatment for ferritic base materials.

Ferritic low-alloy and carbon steel nozzles have safe ends of stainless steel-wrought materials welded to nickel-chromium-iron alloy-weld metal F-number 43 buttering. The safe end is welded to the F 43 buttering after completion of postweld heat treatment of the buttering when the nozzle is larger than a 4-inch nominal inside diameter and/or the wall thickness is greater than 0.531 inch.

Austenitic stainless steel and nickel-chromium-iron alloy base materials with primary pressure-retaining applications are used in the solution-annealed or thermally treated conditions. These heat treatments are as required by the material specifications.

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

Components using stainless steel sensitized in the manner expected during component fabrication and installation operate satisfactorily under normal plant chemistry conditions in pressurized water reactor (PWR) systems because chlorides, fluorides, and oxygen are controlled to very low levels. Subsection 1.9.1 indicates the degree of conformance with Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," with the exceptions as stated in Subsection 1.9.1.

The use of cobalt base alloy is minimized. Restrictions on the use of cobalt in the base metal for material in contact with reactor coolant are discussed in Subsection 12.3.1.1.1.

5.2.3.2.3 Compatibility with External Insulation and Environmental Atmosphere

In general, materials that are used in principal pressure-retaining applications and are subject to elevated temperature during system operation are in contact with thermal insulation that covers their outer surfaces.

The thermal insulation used on the reactor coolant pressure boundary is reflective stainless steel-type.

The compounded materials in the form of blocks, boards, cloths, tapes, adhesives, cements, etc., are silicated to provide protection of austenitic stainless steels against stress corrosion that may result from accidental wetting of the insulation by spillage, minor leakage, or other contamination from the environmental atmosphere. Subsection 1.9.1 indicates the degree of conformance with Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel."

In the event of coolant leakage, the ferritic materials will show increased general corrosion rates. Where minor leakage is considered possible based on service experience (such as valve packing, pump seals, etc.), only materials compatible with the coolant are used. Table 5.2-1 shows examples. Ferritic materials exposed to coolant leakage can be readily observed as part of the inservice visual and/or nondestructive inspection program to confirm the integrity of the component for subsequent service.

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

The fracture toughness properties of the reactor coolant pressure boundary components meet the requirements of the ASME Code, Section III, Subarticle NB-2300. Those portions of the reactor coolant pressure boundary that meet the requirements of ASME Code, Section III, Class 2 per the criteria of 10 CFR 50.55a, meet the fracture toughness requirements of the ASME Code, Section III, Subarticle NC-2300. The fracture toughness properties of the reactor coolant pressure boundary components also meet the requirements of Appendix G of 10 CFR 50.

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

Limiting steam generator and pressurizer reference temperatures for a nil ductility transition (RT_{NDT}) temperatures are guaranteed at 10°F for the base materials and the weldments.

These materials meet the 50-foot-pound absorbed energy and 35-mils lateral expansion requirements of the ASME Code, Section III, at 70°F. The actual results of these tests are provided in the ASME material data reports which are supplied for each component and submitted to the owner at the time of shipment of the component.

Temperature instruments and Charpy impact test machines are calibrated to meet the requirements of the ASME Code, Section III, Paragraph NB-2360.

Westinghouse has conducted a test program to determine the fracture toughness of low-alloy ferritic materials with specified minimum yield strengths greater than 50,000 psi to demonstrate compliance with Appendix G of the ASME Code, Section III. In this program, fracture toughness properties were determined and shown to be adequate for base metal plates and forgings, weld metal, and heat-affected zone metal for higher-strength ferritic materials used for components of the reactor coolant pressure boundary. WCAP-9292 (Reference 3) documents the program results.

5.2.3.3.2 Control of Welding

Welding is conducted using procedures qualified according to the rules of Sections III and IX of the ASME Code. Control of welding variables (as well as examination and testing) during procedure qualification and production welding is performed according to ASME Code requirements.

The practices for storing and handling welding electrodes and fluxes comply with ASME Code, Section III, Paragraphs NB-2400 and NB-4400.

Subsection 1.9.1 indicates the degree of conformance of the ferritic materials components of the reactor coolant pressure boundary with Regulatory Guides 1.31, "Control of Ferrite Content in Stainless Steel Welds"; 1.34, "Control of Electroslag Weld Properties"; 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components"; 1.50, "Control of Preheat Temperature for Welding of Low-Alloy Steel"; and 1.71, "Welder Qualification for Areas of Limited Accessibility."

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

Subsections 5.2.3.4.1 through 5.2.3.4.5 address Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," and present the methods and controls to avoid sensitization and to prevent intergranular attack (IGA) of austenitic stainless steel components. Also, Subsection 1.9.1 indicates the degree of conformance with Regulatory Guide 1.44.

5.2.3.4.1 Cleaning and Contamination Protection Procedures

Austenitic stainless steel materials used in the fabrication, installation, and testing of nuclear steam supply components and systems are handled, protected, stored, and cleaned according to recognized, accepted methods designed to minimize contamination that could lead to stress corrosion cracking. The procedures covering these controls are stipulated in process specifications. Tools used in abrasive work operations on austenitic stainless steel, such as grinding or wire brushing, do not contain and are not contaminated with ferritic carbon steel or other materials that could contribute to intergranular cracking or stress-corrosion cracking.

These process specifications supplement the equipment specifications and purchase order requirements of every individual austenitic stainless steel component or system procured for the AP1000, regardless of the ASME Code classification.

The process specifications define these requirements and follow the guidance of ASME NQA-1.

Subsection 1.9.1 indicates the degree of conformance of the austenitic stainless steel components of the reactor coolant pressure boundary with Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants."

5.2.3.4.2 Solution Heat Treatment Requirements

The austenitic stainless steels listed in Table 5.2-1 are used in the final heat-treated condition required by the respective ASME Code, Section II, materials specification for the particular type or grade of alloy.

5.2.3.4.3 Material Testing Program

Austenitic stainless steel materials of product forms with simple shapes need not be corrosion-tested provided that the solution heat treatment is followed by water quenching. Simple shapes are defined as plates, sheets, bars, pipe, and tubes, as well as forgings, fittings, and other shaped products that do not have inaccessible cavities or chambers that would preclude rapid cooling when water-quenched. This characterization of cavities or chambers as inaccessible is in relation to the entry of water during quenching and is not a determination of the component accessibility for inservice inspection.

When testing is required, the tests are performed according to a process specification following the guidelines of ASTM A 262, Practice A or E.

5.2.3.4.4 Prevention of Intergranular Attack of Unstabilized Austenitic Stainless Steels

Unstabilized stainless steels can be subject to intergranular attack if the steels are sensitized, if certain species are present, such as chlorides and oxygen, and if they are exposed to a stressed condition. In the reactor coolant system, reliance is placed on the elimination or avoidance of these conditions. This is accomplished by the following:

- Control of primary water chemistry to provide a benign environment
- Use of materials in the final heat-treated condition and the prohibition of subsequent heat treatments from 800°F to 1500°F
- Control of welding processes and procedures to avoid heat-affected zone sensitization
- Confirmation that the welding procedures used for the manufacture of components in the primary pressure boundary and the reactor internals do not result in the sensitization of heat-affected zones

Further information on each of these steps is provided in the following paragraphs.

The water chemistry in the reactor coolant system is controlled to prevent the intrusion of aggressive elements. In particular, the maximum permissible oxygen and chloride concentrations are 0.005 ppm and 0.15 ppm, respectively. Table 5.2-2 lists the recommended reactor coolant water chemistry specifications.

The precautions taken to prevent the intrusion of chlorides into the system during fabrication, shipping, and storage are stipulated in the appropriate process specifications. The use of hydrogen overpressure precludes the presence of oxygen during operation.

The effectiveness of these controls has been demonstrated by both laboratory tests and operating experience. The long-term exposure of severely sensitized stainless steels to reactor coolant environments in early Westinghouse pressurized water reactors has not resulted in any sign of intergranular attack. WCAP-7477 (Reference 4) describes the laboratory experimental findings and reactor operating experience. The additional years of operations since Reference 4 was issued have provided further confirmation of the earlier conclusions that severely sensitized stainless steels do not undergo any intergranular attack in Westinghouse pressurized water reactor coolant environments.

Although there is no evidence that pressurized water reactor coolant water attacks sensitized stainless steels, it is good metallurgical practice to avoid the use of sensitized stainless steels in the reactor coolant system components.

Accordingly, measures are taken to prohibit the use of sensitized stainless steels and to prevent sensitization during component fabrication. The wrought austenitic stainless steel stock used in the reactor coolant pressure boundary is used in one of the following conditions:

- Solution-annealed and water-quenched
- Solution-annealed and cooled through the sensitization temperature range within less than about 5 minutes

Westinghouse has verified that these practices will prevent sensitization by performing corrosion tests on wrought material as it was received.

The heat-affected zones of welded components must, of necessity, be heated into the sensitization temperature range (800°F to 1500°F). However, severe sensitization (that is, continuous grain boundary precipitates of chromium carbide, with adjacent chromium depletion) can be avoided by controlling welding parameters and welding processes. The heat input and associated cooling rate through the carbide precipitation range are of primary importance. Westinghouse has demonstrated this by corrosion-testing a number of weldments.

The heat input in austenitic pressure boundary weldments is controlled by the following:

- Limiting the maximum interpass temperature to 350°F
- Exercising approval rights on welding procedures
- Requiring qualification of processes

5.2.3.4.5 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitization Temperatures

If during the course of fabrication, steel is inadvertently exposed to the sensitization temperature range, the material may be tested according to a process specification, following the guidelines of ASTM A 262, to verify that it is not susceptible to intergranular attack. Testing is not required for the following:

- Cast metal or weld metal with a ferrite content of 5 percent or more
- Material with a carbon content of 0.03 percent or less
- Material exposed to special processing, provided the following:

– Processing is properly controlled to develop a uniform product

– Adequate documentation exists of service experience and/or test data to demonstrate that the processing will not result in increased susceptibility to intergranular attack

If such material is not verified to be not susceptible to intergranular attack, the material is resolution-annealed and water-quenched or rejected.

5.2.3.4.6 Control of Welding

The following paragraphs address Regulatory Guide 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal." They present the methods used, and the verification of these methods, for austenitic stainless steel welding.

The welding of austenitic stainless steel is controlled to mitigate the occurrence of microfissuring, or hot cracking, in the weld.

Also, it has been well documented that delta ferrite is one of the mechanisms for reducing the susceptibility of stainless steel welds to hot cracking. The minimum delta ferrite level below which the material will be prone to hot cracking lies between 0 and 3 percent delta ferrite.

The following paragraphs discuss welding processes used to join stainless steel parts in components designed, fabricated, or stamped according to the ASME Code, Section III, Classes 1 and 2, and core support components. Delta ferrite control is appropriate for the preceding welding requirements, except where no filler metal is used or where such control is not applicable, such as the following: electron beam welding; autogenous gas shielded tungsten arc welding; explosive welding; welding using fully austenitic welding materials.

The fabrication and installation specifications require welding procedures and welder qualification according to Section III of the ASME Code. They also include the delta ferrite determinations for the austenitic stainless steel welding materials used for welding qualification testing and for production processing.

Specifically, the undiluted weld deposits of the "starting" welding materials must contain at least 5 percent delta ferrite. (The equivalent ferrite number may be substituted for percent delta ferrite.) This is determined by chemical analysis and calculation using the appropriate weld metal constitution diagrams in Section III of the ASME Code or magnetic measurement by calibrated instruments.

When new welding procedure qualification tests are evaluated for these applications, including repair welding of raw materials, they are performed according to the requirements of Sections III and IX of the ASME Code.

The results of the destructive and nondestructive tests are recorded in the procedure qualification record, in addition to the information required by Section III of the ASME Code.

The welding materials used for fabrication and installation welds of austenitic stainless steel materials and components meet the requirements of Section III of the ASME Code. For applications using austenitic stainless steel welding material, the material conforms to ASME weld metal analysis A-8, Type 308, 308L, 309, 309L, 316, or 316L.

Delta ferrite determinations of austenitic stainless steel weld filler materials to be used with gas tungsten arc welding (GTAW) and plasma arc welding (PAW) processes and any other welding material to be used with any GTAW, PAW, or gas metal arc welding (GMAW) process, including consumable insert material, shall be made using a magnetic measuring instrument and weld deposits

made in accordance with ASME Code, Section III, NB-2432.1(c) or (d) or, alternatively, the delta ferrite determinations for welding materials may be performed by the use of chemical analysis performed either on the filler metal or on an undiluted weld deposit made in accordance with NB-2432. The allowable delta ferrite range shall be 5 FN to 20 FN for the weld material with low molybdenum content, and 5 FN to 16 FN for weld materials with higher molybdenum content such as Types 316/316L, which contain 2.0 to 3.0% molybdenum.

Delta ferrite determinations of austenitic stainless steel weld filler materials to be used with flux welding processes, such as shielded metal arc welding (SMAW), submerged arc welding (SAW) or for electro-slag weld (ESW) deposited cladding and other welding material to be used with other than the GTAW, PAW, or GMAW process shall be made using a magnetic measuring instrument and weld deposits made in accordance with ASME Code, Section III, B-2432.1(c) or (d) or, alternatively, the delta ferrite determinations may be performed by the use of chemical analysis of the undiluted weld deposit of NB-2432 in conjunction with Figure NB-2433.1-1. The allowable delta ferrite range shall be 5 FN to 20 FN for the weld material with low molybdenum content, and 5 FN to 16 FN for weld materials with higher molybdenum content such as types 316/316L, which contain 2.0 to 3.0% molybdenum.

Welding materials are tested using the welding energy inputs employed in production welding.

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

- Quality assurance audit, including calibration of gauges and instruments
- Identification of welding materials
- Welder and procedure qualifications
- Availability and use of approved welding and heat-treating procedures
- Documentary evidence of compliance with materials, welding parameters, and inspection requirements

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

To verify the reliability of these controls, Westinghouse has completed a delta ferrite verification program, described in WCAP-8324-A (Reference 5). This program has been approved as a valid approach to verify the Westinghouse hypothesis and is considered an acceptable alternative for conformance with the NRC Interim Position on Regulatory Guide 1.31. The regulatory staff's acceptance letter and topical report evaluation were received on December 30, 1974. The program results, which support the hypothesis presented in WCAP-8324-A (Reference 5), are summarized in WCAP-8693 (Reference 6).

Subsection 1.9.1 indicates the degree of conformance of the austenitic stainless steel components of the reactor coolant pressure boundary with Regulatory Guides 1.34, "Control of Electroslag Weld Properties," and 1.71, "Welder Qualification for Areas of Limited Accessibility."

5.2.3.4.7 Control of Cold Work in Austenitic Stainless Steels

The use of cold worked austenitic stainless steels is limited to small parts including pins and fasteners where proven alternatives are not available and where cold worked material has been used successfully in similar applications. Cold work control of austenitic stainless steels in pressure boundary applications is provided by limiting the hardness of austenitic stainless steel raw material and controlling the hardness during fabrication by process control of bending, cold forming, straightening or other similar operation. Grinding of material in contact with reactor coolant is controlled by procedures. Ground surfaces are finished with successively finer grit sizes to remove the bulk of cold worked material.

5.2.3.5 Threaded Fastener Lubricants

The lubricants to be used on threaded fasteners which maintain pressure boundary integrity in the reactor coolant and related systems and in the steam, feed, and condensate systems; threaded fasteners used inside those systems; and threaded fasteners used in component structural support for those systems are specified in the design specification. Field selection of thread lubricants is not permitted. The thread lubricants are selected based on experience and test data which show them to be effective, but not to cause or accelerate corrosion of the fastener. Where leak sealants are used on threaded fasteners or can be in contact with the fastener in service, their selection is based on satisfactory experience or test data. Selection considers possible adverse interaction between sealants and lubricants. Lubricants containing molybdenum sulphide are prohibited.

5.2.4 Inservice Inspection and Testing of Class 1 Components

Preservice and inservice inspection and testing of ASME Code Class 1 pressure-retaining components (including vessels, piping, pumps, valves, bolting, and supports) within the reactor coolant pressure boundary are performed in accordance with Section XI of the ASME Code including addenda according to 10 CFR 50.55a(g). This includes all ASME Code Section XI mandatory appendices.

The specific edition and addenda of the Code used to determine the requirements for the inspection and testing plan for the initial and subsequent inspection intervals is to be delineated in the inspection program. The Code includes requirements for system pressure tests and functional tests for active components. The requirements for system pressure tests are defined in Section XI, IWA-5000 and IWB-5000. These tests verify the pressure boundary integrity in conjunction with inservice inspection. Section 6.6 discusses Classes 2 and 3 component examinations.

Subsection 3.9.6 discusses the in-service functional testing of valves for operational readiness. Since none of the pumps in the AP1000 are required to perform an active safety function, the operational readiness test program for pumps is controlled administratively.

In conformance with ASME Code and NRC requirements, the preparation of inspection and testing programs is discussed in Subsection 5.2.6. A preservice inspection program (nondestructive examination) for the AP1000 will be developed and submitted to the NRC. The in-service inspection program will be submitted to the NRC as discussed in Subsection 5.2.6. These programs will comply with applicable in-service inspection provisions of 10 CFR 50.55a(b)(2).

The preservice program provides details of areas subject to examination, as well as the method and extent of preservice examinations. The in-service program details the areas subject to examination and the method, extent, and frequency of examinations. Additionally, component supports and examination requirements are included in the inspection programs.

5.2.4.1 System Boundary Subject to Inspection

ASME Code Class 1 components (including vessels, piping, pumps, valves, bolting, and supports) are designated AP1000 equipment Class A (see Subsection 3.2.2). Class 1 pressure-retaining components and their specific boundaries are included in the equipment designation list and the line designation list. Both of these lists are contained in the inspection programs.

The Class 1 system boundary for both preservice and inservice inspection programs and the system pressure test program includes those items within the Class 1 and Quality Group A (Equipment Class A per Subsection 3.2.2 and Table 3.2-3) boundary. Based on 10 CFR Part 50 and Regulatory Guide 1.26, the Class 1 boundary includes the following:

- Reactor pressure vessel;
- Portions of the Reactor System (RXS);
- Portions of the Chemical and Volume Control System (CVS);
- Portions of the Incore Instrumentation System (IIS);
- Portions of the Passive Core Cooling System (PXS);
- Portions of the Reactor Coolant System (RCS); and
- Portions of the Normal Residual Heat Removal System (RNS).

Those portions of the above systems within the Class 1 boundary are those items that are part of the reactor coolant pressure boundary as defined in Section 5.2.

Exclusions

Portions of the systems within the reactor coolant pressure boundary (RCPB), as defined above, that are excluded from the Class 1 boundary in accordance with 10 CFR Part 50, Section 50.55a, are as follows:

- Those components where, in the event of postulated failure of the component during normal reactor operation, the reactor can be shut down and cooled down in an orderly manner, assuming makeup is provided by the reactor coolant makeup system only; or
- Components that are or can be isolated from the reactor coolant system by two valves in series (both closed, both open, or one closed and the other open). Each open valve is capable of automatic actuation and, assuming the other valve is open, its closure time is such that, in the event of postulated failure of the component during normal reactor operation, each valve remains operable and the reactor can be shut down and cooled down in an orderly manner, assuming makeup is provided by the reactor coolant makeup system only.

The description of portions of systems excluded from the RCPB does not address Class 1 components exempt from inservice examinations under ASME Code Section XI rules. The Class 1 components exempt from inservice examinations are defined by ASME Section XI, IWB-1220, except as modified by 10 CFR 50.55a.

The inservice inspection program is augmented for reactor vessel top head inspections by use of the ASME Code Case(s) as specified in 10 CFR 50.55a(g).

Boric acid corrosion control procedures require inspection of the reactor coolant pressure boundary subject to leakage that can cause boric acid corrosion of the reactor coolant pressure boundary materials. The procedures determine the principal locations where leaks can cause degradation of the primary pressure boundary by boric acid corrosion. Potential paths of the leaking coolant are established. The boric acid corrosion control procedures also contain methods for conducting examinations and performing engineering evaluations to establish the impact on the reactor coolant pressure boundary when leakage is located.

The boric acid corrosion control procedures consist of:

1. Visual inspections of component surfaces that are potentially exposed to borated water leakage.

2. Discovery of leak path and removal of boric acid residue.

3. Assessment of the corrosion.

4. Follow-up inspection for adequacy of corrective actions, as appropriate.

The inservice inspection program, along with the boric acid corrosion control procedures, provides guidance for inspecting the integrity of bolting and threaded fasteners.

The in-service inspection program is augmented to include the performance of a 100 percent volumetric examination of the weld build-up on the reactor vessel head for the instrumentation penetrations (Quickloc) conducted once during each 120-month inspection interval in accordance with the ASME Code, Section XI. The weld build-up acceptance standards are those provided in ASME Code, Section XI, IWB-3514. Personnel performing examinations and the ultrasonic examination systems are qualified in accordance with ASME Code, Section XI, Appendix VIII. Alternatively, an alternative inspection may be developed in conjunction with the voluntary consensus standards bodies (i.e., ASME) and submitted to the NRC for approval.

5.2.4.2 Arrangement and Inspectability

ASME Code Class 1 components are designed so that access is provided in the installed condition for visual, surface, and volumetric examinations specified by the ASME Code Section XI (1998 Edition) and mandatory appendices. Design provisions, in accordance with Section XI, Article IWA-1500, are incorporated in the design processes for Class 1 components.

The AP1000 design activity includes a design for inspectability program. The goal of this program is to provide for the inspectability access and conformance of component design with available inspection equipment and techniques. Factors such as examination requirements, examination techniques, accessibility, component geometry and material selection are used in evaluating component designs. Examination requirements and examination techniques are defined by inservice inspection personnel. Inservice inspection review as part of the design process provides component designs that conform to inspection requirements and establishes recommendations for enhanced inspections.

Considerable experience is utilized in designing, locating, and supporting pressure-retaining components to permit preservice and in-service inspection required by Section XI of the ASME Code. Factors such as examination requirements, examination techniques, accessibility, component geometry, and material selections aid in establishing the designs. The inspection design goals are to eliminate uninspectable components, reduce occupational radiation exposure, reduce inspections times, allow state-of-the-art inspection system, and enhance flaw detection and the reliability of flaw characterization.

As one example of component geometry that reduces inspection requirements, the reactor pressure vessel has no longitudinal welds requiring in-service inspection. No Quality Group A (ASME Code Class 1) components require in-service inspection during reactor operation.

Removable insulation and shielding are provided on those piping systems requiring volumetric and surface examination. Removable hangers and pipe whip restraints are provided as necessary and practical to facilitate inservice inspection. Working platforms are provided in areas requiring inspection and servicing of pumps and valves. Permanent or temporary working platforms, scaffolding, and ladders facilitate access to piping and component welds. The components and welds requiring in-service inspection allow for the application of the required in-service inspection methods. Such design features include sufficient clearances for personnel and equipment, maximized examination surface distances, two-sided access (except for valve to pipe welds), favorable materials, weld-joint simplicity, elimination of geometrical interferences, and proper weld surface preparation.

Some of the ASME Class 1 components are included in modules fabricated offsite and shipped to the site. (See Subsection 3.9.1.5.) The modules are designed and engineered to provide access for in-service inspection and maintenance activities. The attention to detail engineered into the modules before construction provides the accessibility for inspection and maintenance. Relief from Section XI requirements should not be required for Class 1 pressure retaining components in the AP1000. Future unanticipated changes in the ASME Code, Section XI requirements could, however, necessitate relief requests. Relief from the inspection requirements of ASME Code, Section XI will be requested when full compliance is not practical according to the requirements of 10 CFR 50.55a(g)(5)(iv). In such cases, specific information will be provided which identifies the applicable Code requirements, justification for the relief request, and the inspection method to be used as an alternative.

Space is provided to handle and store insulation, structural members, shielding, and other materials related to the inspection. Suitable hoists and other handling equipment, lighting, and sources of power for inspection equipment are installed. The integrated head package provides for access to inspect the reactor vessel head and the weld of the control rod drive mechanisms to the reactor vessel head. Closure studs, nuts, and washers are removed to a dry location for direct inspection.

5.2.4.3 Examination Techniques and Procedures

The visual, surface, and volumetric examination techniques and procedures agree with the requirements of Subarticle IWA-2200 and Table IWB-2500-1 of the ASME Code, Section XI. Qualification of the ultrasonic inspection equipment, personnel and procedures is in compliance with Appendix VII of the ASME Code, Section XI. Approved Code Cases listed in Regulatory Guide 1.147 are applied as the need arises during the pre-service inspection. Approved Code Cases determined as necessary to accomplish pre-service inspection activities are used. The liquid penetrant method or the magnetic particle method is used for surface examinations. Radiography, ultrasonic, or eddy current techniques (manual or remote) are used for volumetric examinations.

The reactor vessel is designed so that the reactor pressure vessel (RPV) inspections can be performed primarily from the vessel internal surfaces. These inspections can be done remotely using existing inspection tool designs to minimize occupational radiation exposure and to facilitate the inspections. Access is also available for the application of inspection techniques from the outside of the complete reactor pressure vessel. Reactor pressure vessel welds are examined to meet the requirements of Appendix VIII of ASME Code, Section XI, which has been incorporated into the guidance of Regulatory Guide 1.150, as defined in Subsection 1.9.1.

5.2.4.3.1 Examination Methods

Ultrasonic Examination of the Reactor Vessel

Ultrasonic examination for the RPV is conducted in accordance with the ASME Code, Section XI. The design of the RPV considered the requirements of the ASME Code Section XI with regard to performance of preservice inspection. For the required preservice examinations, the reactor vessel meets the acceptance standards of Section XI, IWB-3510. The RPV shell welds are designed for 100% accessibility for both preservice and inservice inspection. RPV shell welds may be examined from the inside or outside diameter surfaces (or a combination of those techniques) using automated ultrasonic examination equipment. The RPV nozzle-to-shell welds are 100% accessible for preservice inspection but might have limited areas that may not be accessible from the outer surface for inservice examination techniques. If accessibility is limited, an inservice inspection program relief request is prepared and submitted for review approval by the NRC.

Inner radius examinations are performed from inside the nozzle using two opposing circumferential beam directions to obtain complete coverage of the required examination volume. Alternatively, nozzle inner radius examinations may be performed using enhanced visual techniques, as allowed by 10 CFR 50.55a(b)(2)(xxi).

Visual Examination

Visual examination methods VT-1, VT-2 and VT-3 are conducted in accordance with ASME Section XI, IWA-2210. In addition, VT-2 examinations meet the requirements of IWA-5240.

Where direct visual VT-1 examinations are conducted without the use of mirrors or with other viewing aids, clearance is provided where feasible for the head and shoulders of a man within a working arm's length of the surface to be examined.

Surface Examination

Examination methods are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

Volumetric Ultrasonic Direct Examination

Examination methods are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

Alternative Examination Techniques

Examination methods are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

5.2.4.3.2 Qualification of Personnel and Examination Systems for Ultrasonic Examination

Personnel performing examinations shall be qualified in accordance with ASME Section XI, Appendix VII. Ultrasonic examination systems shall be qualified in accordance with industry accepted programs for implementation of ASME Section XI, Appendix VIII. Qualification to ASME Section XI, Appendix VIII, is in compliance with the provisions of 10 CFR 50.55a. Alternatively, qualification of personnel and examination systems may use other methods when authorized in accordance with 10 CFR 50.55a(z).

5.2.4.4 Inspection Intervals

Inspection intervals are established as defined in Subarticles IWA-2400 and IWB-2400 of the ASME Code, Section XI. The interval may be extended by as much as one year so that inspections are concurrent with plant outages. It is intended that in-service examinations be performed during normal plant outages such as refueling shutdowns or maintenance shutdowns occurring during the inspection interval.

5.2.4.5 Examination Categories and Requirements

The examination categories and requirements are established according to Subarticle IWB-2500 and Table IWB-2500-1 of the ASME Code, Section XI. Class 1 piping supports will be examined in accordance with ASME Section XI, IWF-2500. Preservice examinations required by design specification and preservice documentation are in accordance with ASME Section III, NB-5280. Components exempt from preservice examination are described in ASME Section III, NB-5283.

The preservice examinations comply with IWB-2200. The preservice examination is performed once in accordance with ASME XI, IWB-2200, on all of the items selected for inservice examination, with the exception of the examinations specifically excluded by ASME Section XI from preservice requirements, such as VT-3 examination of valve body and pump casing internal surfaces (B-M-2 and B-L-2 examination categories, respectively) and the visual VT-2 examinations for category B-P.

5.2.4.6 Evaluation of Examination Results

Evaluation of examination results are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

System pressure tests comply with IWA-5000 and IWB-5000 of the ASME Code, Section XI. These system pressure tests are included in the design transients defined in Subsection 3.9.1. This subsection discusses the transients included in the evaluation of fatigue of Class 1 components due to cyclic loads.

5.2.4.8 Relief Requests

The specific areas where the applicable ASME Code requirements cannot be met are identified after the initial examinations are performed. Should relief requests be required, they will be developed through the regulatory process and submitted to the NRC for approval in accordance with 10 CFR 50.55a(z) or 50.55a(g)(5). The relief requests include appropriate justifications and proposed alternative inspection methods.

5.2.4.9 Preservice Inspection of Class 1 Components

Preservice examinations required by design specification and preservice documentation are in accordance with ASME Section III, NB-5281. Volumetric and surface examinations are performed as specified in ASME Section III, NB-5282. Components described in ASME Section III, NB-5283 are exempt from preservice examination.

5.2.4.10 Program Implementation

The milestones for preservice and inservice inspection program implementation are identified in Table 13.4-201.

5.2.5 Detection of Leakage Through Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary (RCPB) leakage detection monitoring provides a means of detecting and to the extent practical, identifying the source and quantifying the reactor coolant leakage. The detection monitors perform the detection and monitoring function in conformance with the requirements of General Design Criteria 2 and 30 and the recommendations of Regulatory Guide 1.45. Leakage detection monitoring is also maintained in support of the use of leak-before-break criteria for high-energy pipe in containment. See Subsection 3.6.3 for the application of leak-before-break criteria.

Leakage detection monitoring is accomplished using instrumentation and other components of several systems. Diverse measurement methods including level, flow, and radioactivity measurements are used for leak detection. The equipment classification for each of the systems and components used for leak detection is generally determined by the requirements and functions of the system in which it is located. There is no requirement that leak detection and monitoring components be safety-related. See Figure 5.2-1 for the leak detection approach. The descriptions of the instrumentation and components used for leak detection and monitoring include information on the system.

To satisfy position 1 of Regulatory Guide 1.45, reactor coolant pressure boundary leakage is classified as either identified or unidentified leakage. Identified leakage includes:

- Leakage from closed systems such as reactor vessel seal or valve leaks that are captured and conducted to a collecting tank

- Leakage into auxiliary systems and secondary systems (intersystem leakage) (This leakage is considered to be part of the 10 gpm limit identified leakage in the bases of the technical specification 3.4.7. This additional leakage must be considered in the evaluation of the reactor coolant inventory balance.)

Other leakage is unidentified leakage.

5.2.5.1 Collection and Monitoring of Identified Leakage

Identified leakage other than intersystem leakage is collected in the reactor coolant drain tank. The reactor coolant drain tank is a closed tank located in the reactor cavity in the containment. The tank vent is piped to the gaseous radwaste system to prevent release of radioactive gas to the containment atmosphere. For positions 1 and 7 of Regulatory Guide 1.45, the liquid level in the reactor coolant drain tank and total flow pumped out of the reactor coolant drain tank are used to monitor the identified leakage rate. The identified leakage rate is automatically calculated by the data display and processing system using the liquid level in the reactor coolant drain tank. A leak as small as 0.1 gpm can be detected in one hour. The design leak of 10 gpm will be detected in less than a minute. These parameters are available in the main control room. The reactor coolant drain tank, pumps, and sensors are part of the liquid radwaste system. The following sections outline the various sources of identified leakage other than intersystem leakage.

5.2.5.1.1 Valve Stem Leakoff Collection

Valve stem leakoff connections are not provided in the AP1000.

5.2.5.1.2 Reactor Head Seal

The reactor vessel flange and head flange are sealed by two concentric seals. Seal leakage is detected by two leak-off connections: one between the inner and outer seal, and one outside the

outer seal. These lines are combined in a header before being routed to the reactor coolant drain tank. An isolation valve is installed in the common line. During normal plant operation, the leak-off valves are aligned so that leakage across the inner seal drains to the reactor coolant drain tank.

A surface-mounted resistance temperature detector installed on the bottom of the common reactor vessel seal leak pipe provides an indication and high temperature alarm signal in the main control room indicating the possibility of a reactor pressure vessel head seal leak. The temperature detector and drain line downstream of the isolation valve are part of the liquid radwaste system.

The reactor coolant pump closure flange is sealed with a welded canopy seal and does not require leak-off collection provisions.

Leakage from other flanges is discussed in Subsection 5.2.5.3, Collection and Monitoring of Unidentified Leakage.

5.2.5.1.3 Pressurizer Safety Relief and Automatic Depressurization Valves

Temperature is sensed downstream of each pressurizer safety relief valve and each automatic depressurization valve mounted on the pressurizer by a resistance temperature detector on the discharge piping just downstream of each globe valve. High temperature indications (alarms in the main control room) identify a reduction of coolant inventory as a result of seat leakage through one of the valves. These detectors are part of the reactor coolant system. This leakage is drained to the reactor coolant drain tank during normal plant operation and vented to containment atmosphere or the in-containment refueling water storage tank during accident conditions. This identified leakage is measured by the change in level of the reactor coolant drain tank.

5.2.5.1.4 Other Leakage Sources

In the course of plant operation, various minor leaks of the reactor coolant pressure boundary may be detected by operating personnel. If these leaks can be subsequently observed, quantified, and routed to the containment sump, this leakage will be considered identified leakage.

5.2.5.2 Intersystem Leakage Detection

Substantial intersystem leakage from the reactor coolant pressure boundary to other systems is not expected. However, possible leakage points across passive barriers or valves and their detection methods are considered. In accordance with position 4 of Regulatory Guide 1.45, auxiliary systems connected to the reactor coolant pressure boundary incorporate design and administrative provisions that limit leakage. Leakage is detected by increasing auxiliary system level, temperature, flow, or pressure, by lifting the relief valves or increasing the values of monitored radiation in the auxiliary system.

The normal residual heat removal system and the chemical and volume control system, which are connected to the reactor coolant system, have potential for leakage past closed valves. For additional information on the control of reactor coolant leakage into these systems, see Subsections 5.4.7 and 9.3.6 and the intersystem LOCA discussion in Subsection 1.9.5.1.

5.2.5.2.1 Steam Generator Tubes

An important potential identified leakage path for reactor coolant is through the steam generator tubes into the secondary side of the steam generator. Identified leakage from the steam generator primary side is detected by one, or a combination, of the following:

- High condenser air removal discharge radioactivity, as monitored and alarmed by the turbine island vent discharge radiation monitor
- Steam generator secondary side radioactivity, as monitored and alarmed by the steam generator blowdown radiation monitor
- Secondary side radioactivity, as monitored and alarmed by the main steam line radiation monitors
- Radioactivity, boric acid, or conductivity in condensate as indicated by laboratory analysis

Details on the radiation monitors are provided in Section 11.5, Radiation Monitoring.

5.2.5.2.2 Component Cooling Water System

Leakage from the reactor coolant system to the component cooling water system is detected by high component cooling water system radiation, by increasing surge tank level, by high flow downstream of selected components, by a high temperature condition at reactor coolant pump bearing water temperature RTDs, or by some combination of the preceding. Refer to Section 11.5, Radiation Monitoring, and Subsection 9.2.2, Component Cooling Water System.

5.2.5.2.3 Passive Residual Heat Removal Heat Exchanger Tubes

A potential identified leakage path for reactor coolant is through the passive residual heat removal heat exchanger into the in-containment refueling water storage tank. Identified leakage from the passive residual heat removal heat exchanger tubes is detected as follows:

- High temperature in the passive residual heat removal heat exchanger, as monitored and alarmed by a temperature detector in the heat exchanger inlet cold trap, alerts the operators to potential leakage. The location of the instrument is selected to provide early indication of leakage considering the potential for thermal stratification. The alarm setpoint is selected to provide early indication of leakage.
- With the increase in temperature in the passive residual heat removal heat exchanger inlet cold trap coinciding with an increase in the reactor coolant system inventory balance leakage rate and no corresponding increase in containment sump level, containment pressure, temperature or humidity, or containment atmosphere radiation, then passive residual heat removal heat exchanger leakage is confirmed. If no increase in reactor coolant system inventory balance is present, then the increase in passive residual heat removal cold trap temperature is indicative of leakage through the outlet isolation valves.
- If residual heat removal heat exchanger tube leakage is present the operator then compares the current reactor coolant system inventory leakage to the reactor coolant inventory leakage before passive residual heat removal heat exchanger tube leakage was present. The difference in the reactor coolant system leakage is the passive residual heat removal heat exchanger tube leakage rate.

5.2.5.3 Collection and Monitoring of Unidentified Leakage

Position 3 of Regulator Guide 1.45 identifies three diverse methods of detecting unidentified leakage. AP1000 use two of these three and adds a third method. To detect unidentified leakage inside containment, the following diverse methods may be utilized to quantify and assist in locating the leakage:

- Containment Sump Level
- Reactor Coolant System Inventory Balance
- Containment Atmosphere Radiation

Other methods that can be employed to supplement the above methods include:

- Containment Atmosphere Pressure, Temperature, and Humidity
- Containment Water Level
- Visual Inspection

The reactor coolant system is an all-welded system, except for the connections on the pressurizer safety valves, reactor vessel head, explosively actuated fourth stage automatic depressurization system valves, pressurizer and steam generator manways, reactor vessel head vent, the RCP drain, the RCP heat exchanger piping, and the RCP heat exchanger vent, which are flanged. During normal operation, variations in airborne radioactivity, containment pressure, temperature, or specific humidity above the normal level signify a possible increase in unidentified leakage rates and alert the plant operators that corrective action may be required. Similarly, increases in containment sump level signify an increase in unidentified leakage. The following sections outline the methods used to collect and monitor unidentified leakage.

These methods also allow for identification of main steam line leakage inside containment. The primary method of identifying steam line leakage is redundant containment sump level monitoring. A diverse backup method is provided by containment water level monitoring. The safety-related class 1E containment water level sensors use a different measuring process than the containment sump level sensors.

5.2.5.3.1 Containment Sump Level Monitor

In conformance with position 2 of Regulatory Guide 1.45, leakage from the reactor coolant pressure boundary and other components not otherwise identified inside the containment will condense and flow by gravity via the floor drains and other drains to the containment sump.

A leak in the primary system would result in reactor coolant flowing into the containment sump. Leakage is indicated by an increase in the sump level. The containment sump level is monitored by three seismic Category I level sensors. Position 6 of Regulatory Guide 1.45 requires two sensors. The third sensor is provided for redundancy in detecting main steam line leakage. The level sensors are powered from a safety-related Class 1E electrical source. These sensors remain functional when subjected to a safe shutdown earthquake and are considered the primary method of RCPB leakage detection in containment after an SSE. This provides conformance to position 6 of Regulatory Guide 1.45 although using different technology than envisioned in that guidance (sump level rather than airborne radioactivity). The containment sump level and sump total flow sensors located on the discharge of the sump pump are part of the liquid radwaste system.

Failure of two of the level sensors will still allow the calculation of a 0.5 gpm in-leakage rate within 1 hour. The data display and processing system (DDS) computes the leakage rate and the plant control system (PLS) provides an alarm in the main control room if the average change in leak rate for any given measurement period exceeds 0.5 gpm for unidentified leakage. The minimum detectable leak rate is no greater than 0.19 gpm. Unidentified leakage is the total leakage minus the identified leakage. The leakage rate algorithm subtracts the identified leakage directed to the sump.

Control room display and functionality for the level sensors is not seismically qualified; however, local readout (outside containment) of the instrumentation is provided and is qualified to be operable post-SSE.

To satisfy positions 2 and 5 of Regulatory Guide 1.45, the measurement interval must be long enough to permit the measurement loop to adequately detect the increase in level that would correspond to 0.5 gpm leak rate, and yet short enough to ensure that such a leak rate is detected within an hour. The measurement interval is less than or equal to 1 hour.

When the sump level increases to the high level setpoint, one of the sump pumps automatically starts to pump the accumulated liquid to the waste holdup tanks in the liquid radwaste system. The sump discharge flow is integrated and available for display in the control room, in accordance with position 7 of Regulatory Guide 1.45.

Procedures to identify the leakage source upon a change in the unidentified leakage rate into the sump include the following:

- Check for changes in containment atmosphere radiation monitor indications,
- Check for changes in containment humidity, pressure, and temperature,
- Check makeup rate to the reactor coolant system for abnormal increases,
- Perform an RCS inventory balance,
- Check for changes in water levels and other parameters in systems which could leak water into the containment, and
- Review records for maintenance operations which may have discharged water into the containment.

This procedure allows identification of main steam line leakage as well as RCS leakage.

5.2.5.3.2 Reactor Coolant System Inventory Balance

Reactor coolant system inventory monitoring provides an indication of system leakage. Net level change in the pressurizer is indicative of system leakage. Monitoring net makeup from the chemical and volume control system and net collected leakage provides an important method of obtaining information to establish a water inventory balance. An abnormal increase in makeup water requirements or a significant change in the water inventory balance can indicate increased system leakage.

The reactor coolant system inventory balance is a quantitative inventory or mass balance calculation. This approach allows determination of both the type and magnitude of leakage. Steady-state operation is required to perform a proper inventory balance calculation. Steady-state is defined as stable reactor coolant system pressure, temperature, power level, pressurizer level, and reactor coolant drain tank and in-containment refueling water storage tank levels. The reactor coolant inventory balance is done on a periodic basis and when other indication and detection methods indicate a change in the leak rate. The minimum detectable leak is 0.13 gpm.

The mass balance involves isolating the reactor coolant system to the extent possible and observing the change in inventory which occurs over a known time period. This involves isolating the systems connected to the reactor coolant system. System inventory is determined by observing the level in the pressurizer. Compensation is provided for changes in plant conditions which affect water density.

The change in the inventory determines the total reactor coolant system leak rate. Identified leakages are monitored (using the reactor coolant drain tank) to calculate a leakage rate and by monitoring the intersystem leakage. The unidentified leakage rate is then calculated by subtracting the identified leakage rate from the total reactor coolant system leakage rate.

Since the pressurizer inventory is controlled during normal plant operation through the level control system, the level in the pressurizer will be reasonably constant even if leakage exists. The mass contained in the pressurizer may fluctuate sufficiently, however, to have a significant effect on the calculated leak rate. The pressurizer mass calculation includes both the steam and water mass contributions.

Changes in the reactor coolant system mass inventory are a result of changes in liquid density. Liquid density is a strong function of temperature and a lesser function of pressure. A range of temperatures exists throughout the reactor coolant system all of which may vary over time. A simplified, but acceptably accurate, model for determining mass changes is to assume all of the reactor coolant system is at $T_{Average}$.

The inventory balance calculation is done by the data display and processing system with additional input from sensors in the protection and safety monitoring system, chemical and volume control system, and liquid radwaste system. The use of components and sensors in systems required for plant operation provides conformance with the regulatory guidance of position 6 in Regulatory Guide 1.45 that leak detection should be provided following seismic events that do not require plant shutdown.

5.2.5.3.3 Containment Atmosphere Radioactivity Monitor

Leakage from the reactor coolant pressure boundary will result in an increase in the radioactivity levels inside containment. The containment atmosphere is continuously monitored for airborne particulate radioactivity. Air flow through the monitor is provided by the suction created by a vacuum pump. An F18 particulate concentration monitor indicates radiation concentrations in the containment atmosphere.

F18 particulate is a neutron activated product, which is proportional to power levels. An increase in activity inside containment would, therefore, indicate a leakage from the reactor coolant pressure boundary. Based on the concentration of F18 in particulate form and the power level, reactor coolant pressure boundary leakage can be estimated.

The F18 particulate monitor is seismic Category I. The remaining tubing is not seismically qualified, and safety-related Class 1E power is not provided. The leakage detection system can be reasonably expected to remain functional following seismic events of lesser severity than the SSE. However, no special qualification program is used to ensure operability under such conditions. Conformance to the intent of position 6 guidance of Regulatory Guide 1.45 — that is, leak detection should be provided following seismic events that do not require plant shutdown — is provided by the seismic Category I containment sump level monitor leakage detection system.

The F18 particulate monitor is operable when the plant is above 20-percent power, and can detect a 0.5 gpm leak within 1 hour when the plant is at full power.

Radioactivity concentration indication and alarms for loss of sample flow, high radiation, and loss of indication are provided. Sample collection connections permit sample collection for laboratory analysis. The radiation monitor can be calibrated during power operation.

5.2.5.3.4 Containment Pressure, Temperature and Humidity Monitors

Reactor coolant pressure boundary leakage increases containment pressure, temperature, and humidity, values available to the operator through the plant control system.

An increase in containment pressure is an indication of increased leakage or a high energy line break. Containment pressure is monitored by redundant Class 1E pressure transmitters. For additional discussion see Subsection 6.2.2, Passive Containment Cooling System.

The containment average temperature is monitored using temperature instrumentation at the inlet to the containment fan cooler as an indication of increased leakage or a high energy line break. This instrumentation as well as temperature instruments within specific areas, including steam generator areas, pressurizer area, and containment compartments, are part of the containment recirculation cooling system.

An increase in the containment average temperature combined with an increase in containment pressure indicate increased leakage or a high energy line break. The individual compartment area temperatures can assist in identifying the location of the leak.

Containment humidity is monitored using temperature-compensated humidity detectors which determine the water-vapor content of the containment atmosphere. An increase in the containment atmosphere humidity indicates release of water vapor within the containment. The containment humidity monitors are part of the containment leak rate test system.

The humidity monitors supplement the containment sump level monitors and are most sensitive under conditions when there is no condensation. A rapid increase of humidity over the ambient value by more than 10 percent is indication of a probable leak.

Containment pressure, temperature and humidity can assist in identifying and locating a leak. They are not relied on to quantify a leak.

5.2.5.3.5 Response to Reactor Coolant System Leakage

Operating procedures specify operator actions in response to prolonged low level unidentified reactor coolant leakage conditions that exist above normal leakage rates and below the Technical Specification (TS) limits to provide operators sufficient time to take action before the TS limit is reached. The procedures include identifying, monitoring, trending, and addressing prolonged low level leakage. The procedures for effective management of leakage, including low level leakage, are developed including the following operations related activities:

- Trends in the unidentified leakage rates are periodically analyzed. When the leakage rate increases noticeably from the baseline leakage rate, the safety significance of the leak is evaluated. The rate of increase in the leakage is determined to verify that plant actions can be taken before the plant exceeds TS limits.

- Procedures are established for responding to leakage. These procedures address the following considerations to prevent adverse safety consequence results from the leakage:

  – Plant procedures specify operator actions in response to leakage rates less than the limits set forth in the Technical Specifications. The procedures include actions for confirming the existence of a leak, identifying its source, increasing the frequency of monitoring, verifying the leakage rate (through a water inventory balance), responding to trends in the leakage rate, performing a walkdown outside containment, planning a

containment entry, adjusting alarm setpoints, limiting the amount of time that operation is permitted when the sources of the leakage are unknown, and determining the safety significance of the leakage.

– Plant procedures specify the amount of time the leakage detection and monitoring instruments (other than those required by Technical Specifications) may be out of service to effectively monitor the leakage rate during plant operation (i.e., hot shutdown, hot standby, startup, transients, and power operation).

- The output and alarms from leakage monitoring systems are provided in the main control room. Procedures are readily available to the operators for converting the instrument output to a common leakage rate. (Alternatively, these procedures may be part of a computer program so that the operators have a real-time indication of the leakage rate as determined from the output of these monitors.) Periodic calibration and testing of leakage monitoring systems are conducted. The alarm(s), and associated setpoint(s), provide operators an early warning signal so that they can take corrective actions, as discussed above, i.e., before the plant exceeds TS limits.

- During maintenance and refueling outages, actions are taken to identify the source of any unidentified leakage that was detected during plant operation. In addition, corrective action is taken to eliminate the condition resulting in the leakage.

The procedures described above will be available prior to fuel load.

5.2.5.4 Safety Evaluation

Leak detection monitoring has no safety-related function. Therefore, the single failure criterion does not apply and there is no requirement for a nuclear safety evaluation. The containment sump level monitors and the containment atmosphere monitor are seismic Category I. The components used to calculate reactor coolant system inventory balance are both safety-related and nonsafety-related components. The containment sump level monitors are powered from the Class 1E dc and UPS system (IDS). Measurement signals are processed by the data display and processing system and the plant control system (PLS).

5.2.5.5 Tests and Inspections

To satisfy position 8 of Regulatory Guide 1.45, periodic testing of leakage detection monitors verifies the operability and sensitivity of detector equipment. These tests include installation calibrations and alignments, periodic channel calibrations, functional tests, and channel checks in conformance with regulatory guidance.

5.2.5.6 Instrumentation Applications

The parameters tabulated below satisfy position 7 of Regulatory Guide 1.45 and are provided in the main control room to allow operating personnel to monitor for indications of reactor coolant pressure boundary leakage. The containment sump level, containment atmosphere radioactivity, reactor coolant system inventory balance, and the flow measurements are provided as gallon per minute leakage equivalent.

Parameter	System(s)	Alarm or Indication
Containment sump level and sump total flow	WLS	Both
Reactor coolant drain tank level and drain tank total flow	WLS	Both

Containment atmosphere radioactivity	PSS	Both
Reactor coolant system inventory balance parameters	CVS, PCS, PXS, RCS, WLS	Both
Containment humidity	VUS	Indication
Containment atmospheric pressure	PCS	Both
Containment atmosphere temperature	VCS	Both
Containment water level	PXS	Both
Reactor vessel head seal leak temperature	WLS	Both
Pressurizer safety relief valve leakage temperature	RCS	Both
Reactor coolant pump bearing water RTDs	RCS	Both
Steam generator blowdown radiation	BDS	Both
Turbine island vent discharge radiation	TDS	Both
Component cooling water radiation	CCS	Both
Main steam line radiation	SGS	Both
Component cooling water surge tank level	CCS	Both

5.2.5.7 Technical Specification

Limits which satisfy position 9 of Regulatory Guide 1.45 for identified and unidentified reactor coolant leakage are identified in the Technical Specifications. LCO 3.4.7 addresses RCS leakage limits. LCO 3.7.8 addresses main steam line leakage limits. LCO 3.4.9 addresses leak detection instrument requirements.

5.2.6 Combined License Information Items

5.2.6.1 ASME Code and Addenda

The ASME Code editions and addenda to be used are addressed in Subsection 5.2.1.1.

5.2.6.2 Plant-Specific Inspection Program

The plant-specific preservice inspection and inservice inspection program is addressed in Subsections 5.2.4, 5.2.4.1, 5.2.4.3.1, 5.2.4.3.2, 5.2.4.4, 5.2.4.5, 5.2.4.6, 5.2.4.8, 5.2.4.9, and 5.2.4.10.

5.2.6.3 Response to Unidentified Reactor Coolant System Leakage Inside Containment

Prolonged low-level unidentified reactor coolant leakage inside containment is addressed in Subsection 5.2.5.3.5.

5.2.7 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), and WCAP-7907-A (Nonproprietary), April 1984.

2. EPRI PWR Safety and Relief Valve Test Program, Safety and Relief Valve Test Report, Interim Report, April 1982.

3. Logsdon, W. A., Begley, J. A., and Gottshall, C. L., "Dynamic Fracture Toughness of ASME SA-508 Class 2a and ASME SA-533 Grade A Class 2 Base and Heat-Affected Zone Material and Applicable Weld Metals," WCAP-9292, March 1978.

4. Golik, M. A., "Sensitized Stainless Steel in Westinghouse PWR Nuclear Steam Supply Systems," WCAP-7477-L (Proprietary), March 1970, and WCAP-7735 (Nonproprietary), August 1971.

5. Enrietto, J. F., "Control of Delta Ferrite in Austenitic Stainless Steel Weldments," WCAP-8324-A, June 1975.

6. Enrietto, J. F., "Delta Ferrite in Production Austenitic Stainless Steel Weldments," WCAP-8693, January 1976.

201. EPRI, “Pressurized Water Reactor Primary Water Chemistry Guidelines.”

Table 5.2-1 (Sheet 1 of 6)
Reactor Coolant Pressure Boundary Materials Specifications

Component	Material Specification	Class, Grade, or Type
Reactor Vessel Components		
Head plates (other than core region)	SA-533 SA-508	Type B, CL 1 GR 3 CL 1
Shell courses	SA-508	GR 3 CL 1
Shell, flange, and nozzle forgings	SA-508	GR 3 CL 1
Nozzle safe ends	SA-182	F316, F316L, F316LN
CRDM latch housing head penetration nozzle	SB-167 SB-166	N06690 N06690
Instrumentation nozzles, upper head	SB-167 SB-166 SA-182 SA-479	N06690 N06690 F304, F304L, F304LN, F316, F316L, F316LN 304, 304L, 304LN 316, 316L, 316LN, S21800
Closure studs	SA-540	GR B23 CL 3, GR B24 CL 3
Monitor tubes	SA-312(1) SA-376 SA-182	TP304, TP304L, TP304LN, TP316, TP316L, TP316LN TP304, TP304LN, TP316, TP316LN F304, F304L, F304LN, F316, F316L, F316LN
Vent pipe	SB-166 SB-167 SA-312(1) SA-376	N06690 N06690 TP304, TP304L, TP304LN, TP316, TP316L, TP316LN TP304, TP304LN, TP316, TP316LN

Table 5.2-1 (Sheet 2 of 6)
Reactor Coolant Pressure Boundary Materials Specifications

Component	Material Specification	Class, Grade, or Type
Steam Generator Components		
Pressure plates	SA-533	Type B, CL 1 or CL 2
Pressure forgings (including primary side nozzles and tube sheet)	SA-508	GR 3, CL 2
Nozzle safe ends	SA-182 SA-336 SB-564	F316, F316L, F316LN F316LN N06690
Channel heads	SA-508	GR 3, CL 2
Tubes	SB-163	N06690
Manway studs/ Nuts	SA-193 SA-194	GR B7 GR 7
Pressurizer Components		
Pressure plates	SA-533	Type B, CL 1
Pressure forgings	SA-508	GR 3, CL 2
Nozzle safe ends	SA-182 SA-336 SB-564 SB-163	F316, F316L, F316LN F316, F316L, F316LN N06690 N06690
Manway studs/ Nuts	SA-193 SA-194	GR B7 GR 7

Table 5.2-1 (Sheet 3 of 6)
Reactor Coolant Pressure Boundary Materials Specifications

Component	Material Specification	Class, Grade, or Type
Reactor Coolant Pump		
Pressure forgings	SA-182	F304, F304L, F304LN, F304N F316, F316L, F316LN, F316N, F6 per Code Case N-4-11
	SA-508	GR1[4]
	SA-336	F304, F304L, F304LN, F316, F316L, F316LN, F316N
Pressure casting	SA-351	CF3A or CF8A
Tube and pipe	SA-213	TP304, TP304L, TP304LN, TP316, TP316L, TP316LN
	SA-376	TP304, TP304LN, TP316, TP316LN
	SA-312[1]	TP304, TP304L, TP304LN, TP316, TP316L, TP316LN
	SA-403	316LN
Pressure bar stock	SA-479	304
Pressure plates	SA-240	304, 304L, 304LN, 304N 316, 316L, 316LN
Closure bolting	SA-193	GR B7
	SA-194	GR 2H or 7
	SA-540	GR B24, CL2 & CL 4, or GR B23, CL 2, CL 3 & 4
Reactor Coolant Piping		
Reactor coolant pipe	SA-376	TP304, TP304LN, TP316, TP316LN
	SA-182[2]	F304, F304L, F304LN, F316, F316L, F316LN
Reactor coolant fittings, branch nozzles	SA-376	TP304, TP304LN, TP316, TP316LN
	SA-182	F304, F304L, 304LN, F316, F316L, F316LN
Surge line	SA-376	TP304, TP304LN, TP316, TP316LN
	SA-312[1]	TP304, TP304L, TP304LN, TP316, TP316L, TP316LN

Table 5.2-1 (Sheet 4 of 6)
Reactor Coolant Pressure Boundary Materials Specifications

Component	Material Specification	Class, Grade, or Type
RCP piping other than loop and surge line	SA-312(1)	TP304, TP304L, TP304LN, TP316, TP316L, TP316LN
	SA-376	TP304, TP304L, TP304LN, TP316, TP316L, TP316LN
CRDM		
Latch housing except for head penetration nozzle	SA-336	F304, F304L, F304LN, F316, F316L, F316LN
	SA-182	F304, F304L, F304LN, F316, F316L, F316LN
Rod travel housing	SA-336	F304, F304L, F304LN, F316, F316L, F316LN
	SA-182	F304, F304L, F304LN, F316, F316L, F316LN
Valves		
Bodies	SA-182	F304, F304L F316, F316L
	SA-240	304, 304L 316, 316L
	SA-479	304, 304L 316, 316L
	SA-351	CF3A, CF3M, CF8, CF3, CF8M
Bonnets	SA-182	F304, F304L F316, F316L
	SA-240	304, 304L 316, 316L
	SA-351	CF3A, CF3M, CF8, CF3, CF8M
	SA-479	304, 304L 316, 316L XM-19

Table 5.2-1 (Sheet 5 of 6)
Reactor Coolant Pressure Boundary Materials Specifications

Component	Material Specification	Class, Grade, or Type
Discs	SA-182	F304, F304L, F304LN, F316, F316L, F316LN
	SA-240	304, 304L 316, 316L
	SA-479	XM-19 304, 304L 316, 316L
	SB-637	N07750 (limited application)(9) N07718 (limited application)(9)
	SA-564	Type 630 (H1100 or H1150),
	SB-564	N06690
	A-565	GR 616 (limited application)(10)
	SA-351	CF3A, CF3M, CF8, CF3, CF8M
Stems(11)		
Pressure retaining bolting	SA-453	GR 660
	SA-564	Type 630 (H1100)
	SB-637	N07718
Pressure retaining nuts	SA-453	GR 660
	SA-194	GR 6 or 8
Core Makeup Tank		
Pressure plates	SA-533	Type B, CL 1
	SA-240	304, 304L, 304LN, 316, 316L, 316LN
Pressure forgings	SA-508	GR 3 CL 1
	SA-182	F304, F304L, F316, F316L
	SA-336	F304, F304L, F316, F316L
Passive Residual Heat Removal Heat Exchanger		
Pressure plates	SA-533	Type B CL1
	SA-240	304, 304L, 304LN

Table 5.2-1 (Sheet 6 of 6)
Reactor Coolant Pressure Boundary Materials Specifications

Component	Material Specification	Class, Grade, or Type
Pressure forgings	SA-508	GR 3 CL 2
	SA-336	F304, F304L, F304LN
Tubing	SB-163	N06690
Welding Consumables		
Austenitic stainless steel corrosion-resistant cladding, buttering, and welds(5)	SFA 5.4	E308, E308L, E309, E309L, E316, E316L
	SFA 5.9(6)	ER308, ER308L, ER309, ER309L, ER316, ER316L, EQ308L, EQ309L
	SFA 5.22(3)	E308LTX-Y, E308TX-Y, E309LTX-Y, E309TX-Y, E316LTX-Y, E316TX-Y
	SFA 5.30	IN308, IN308L, IN316, IN316L
Ni-Cr-Fe corrosion-resistant cladding, buttering, and welds(7)	SFA 5.11	ENiCrFe-7
	SFA 5.14	ERNiCrFe-7, ERNiCrFe-7A, EQNiCrFe-7, EQNiCrFe-7A
Carbon steel pressure boundary welds(8)(4)	SFA 5.1, 5.17, 5.18, 5.20, 5.30	To be compatible with base material
Low alloy pressure boundary welds(8)	SFA 5.5, 5.23, 5.28, 5.29	To be compatible with base material

Notes:

1. Limited to seamless form only.
2. Subject to manufacturing sequence and final finish condition review.
3. Only gas-shielded electrodes for use with the FCAW process are permitted. These electrodes shall not be used for root passes except for joints welded from two sides where the root is back-gouged to sound metal as evidenced by magnetic particle or liquid penetrant testing.
   X=Position, acceptable values 0 (flat and horizontal) and 1 (all positions)
   Y=Shield Gas, acceptable values 1 (100% CO_2) and 4 (75-80% Argon, remainder CO_2)
4. GR1 material (carbon steel) and associated filler material is used only for reactor coolant pump components that are not exposed to the reactor coolant. These components are limited to the stator main flange, stator shell, and external heat exchanger supports.
5. Austenitic stainless steel filler metals that are exposed to temperatures within the 800°F to 1500°F temperature range after welding, and are not subsequently solution annealed, do not contain more than 0.03% or 0.04% carbon by weight (depending on the maximum carbon content of the corresponding low-carbon classification in the SFA specification), or have demonstrated nonsensitization per Regulatory Guide 1.44.
6. In addition to ER, EC (composite) rod/electrodes may also be used.
7. These materials are UNS N06052, N06054, and W86152, where F43 grouping is allowed by codes cases 2143-1 and 2142-2. Note that UNS N06054 is only in ASME Section II part C 2004 with 2006 addenda and later. Similar welding alloys developed for improved weldability may be used as allowed by ASME Boiler and Pressure Vessel Code rules.
8. These weld metals are compatible with the base metal mechanical requirements and meet applicable ASME Section III, Section II part C, and Section IX requirements. Their use is limited to applications in which the welds are not exposed to reactor coolant. These weld metals used with a flux bearing welding process are also not used for root passes of single-sided welds.
9. Valve material is limited by valve component per NB-2121(c)(1).
10. Valve material is limited by valve size per NB-2121(c)(3).
11. Stems are not pressure boundary material per NB-2121(b).

Table 5.2-2
Reactor Coolant Water Chemistry Specifications

Electrical conductivity	Determined by the concentration of boric acid and alkali present. Expected range is <1 to 40 μmhos/cm at 25°C.
Solution pH	Determined by the concentration of boric acid and alkali present. Expected values range between 4.2 (high boric acid concentration) and 10.5 (low boric acid concentration) at 25°C. Values will be 5.0 or greater at normal operating temperatures.
Oxygen(1)	0.1 ppm, maximum
Chloride(2)	0.15 ppm, maximum
Fluoride(2)	0.15 ppm, maximum
Hydrogen(3)	25 to 50 cm^3 (STP)/kg H_2O
Suspended solids(4)	0.2 ppm, maximum
pH control agent (Li7OH)(5)	Lithium is coordinated with boron per fuel warranty contract.
Boric acid	Variable from 0 to 4000 ppm as boron
Silica(6)	1.0 ppm, maximum
Aluminum(6)	0.05 ppm, maximum
Calcium(6) + magnesium	0.05 ppm, maximum
Magnesium(6)	0.025 ppm, maximum
Zinc(7)	0.04 ppm, maximum

Notes:

1. Oxygen concentration must be controlled to less than 0.1 ppm in the reactor coolant by scavenging with hydrazine prior to plant operation above 250°F. During power operation with the specified hydrogen concentration maintained in the coolant, the residual oxygen concentration will not exceed 0.005 ppm.
2. Halogen concentrations must be maintained below the specified values regardless of system temperature.
3. Hydrogen must be maintained in the reactor coolant for plant operations with nuclear power above 1 MW. The normal operating range should be 30-40 cm^3 (STP) H_2/kg H_2O.
4. Solids concentration determined by filtration through filter having 0.45-μm pore size.
5. The specified lithium concentrations must be established for startup testing prior to heatup beyond 150°F. During cold hydrostatic testing and hot functional testing in the absence of boric acid, the reactor coolant limits for lithium hydroxide must be maintained to inhibit halogen stress corrosion cracking.
6. These limits are included in the table of reactor coolant specifications as recommended standards for monitoring coolant purity. Establishing coolant purity within the limits shown for these species is judged desirable with the current data base to minimize fuel clad crud deposition, which affects the corrosion resistance and heat transfer of the clad.
7. Specification is applicable during power operation when zinc is being injected. The zinc concentration is maintained at the lower of 0.04 ppm or that specified in the reload safety analyses.

Table 5.2-3
ASME Code Cases

Code Case Number	Title
N-4-11	Special Type 403 Modified Forgings or Bars, Section III, Division 1, Class 1 and Class CS
N-20-4	SB-163 Nickel-Chromium-Iron Tubing (Alloys 600 and 690) and Nickel-Iron-Chromium Alloy 800 at a Specified Minimum Yield Strength of 40.0 ksi and Cold Worked Alloy 800 at Yield Strength of 47.0 ksi, Section III, Division 1, Class 1
N-60-5	Material for Core Support Structures, Section III, Division 1(a)
N-71-18	Additional Material for Subsection NF, Class 1, 2, 3 and MC Component Supports Fabricated by Welding, Section III Division 1
[*N-122-2*	*Procedure for Evaluation of the Design of Rectangular Cross Section Attachments on Class 1 Piping Section III, Division 1*]*
N-192-3	Use of Braided Flexible Connectors, Section III, Division 1, Class 2 and 3
N-249-14	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Supports Fabricated Without Welding, Section III, Division 1(b)
[*N-284-1*	*Metal Containment Shell Buckling Design Methods, Section III, Division 1 Class MC*]*
[*N-318-5*	*Procedure for Evaluation of the Design of Rectangular Cross Section Attachments on Class 2 or 3 Piping Section III, Division*]*
[*N-319-3*	*Alternate Procedure for Evaluation of Stresses in Butt Welding Elbows in Class 1 Piping Section III, Division 1*]*
[*N-391-2*	*Procedure for Evaluation of the Design of Hollow Circular Cross Section Welded Attachments on Class 1 Piping Section III, Division 1*]*
[*N-392-3*	*Procedure for Valuation of the Design of Hollow Circular Cross Section Welded Attachments on Class 2 and 3 Piping Section III, Division 1(c)*]*
N-405-1	Socket Welds, Section III, Division 1
N-474-2	Design Stress Intensities and Yield Strength Values for UNS06690 With a Minimum Yield Strength of 35 ksi, Class 1 Components, Section III, Division 1
2142-2	F-Number Grouping for Ni-Cr-Fe Filler Metals, Section IX (Applicable to all Sections, including Section III, Division 1, and Section XI)
2143-1	F-Number Grouping for Ni-Cr-Fe, Classification UNS W86152 Welding Electrode, Section IX
N-655-1	Use of SA-738, Grade B, for Metal Containment Vessels, Class MC, Section III, Division 1
N-757-1	Alternative Rules for Acceptability for Class 2 and 3 Valves, NPS 1 (DN25) and Smaller with Welded and Nonwelded End Connections other than Flanges, Section III, Division 1(d)
N-759-2	Alternative Rules for Determining Allowable External Pressure and Compressive Stresses for Cylinders, Cones, Spheres, and Formed Heads, Class 1, 2, and 3, Section III, Division 1
N-782	Use of Code Editions, Addenda, and Cases Section III, Division 1
N-801	Rules for Repair of N-Stamped Class 1, 2, and 3 Components by Organization Other Than the N Certificate Holder That Originally Stamped the Component Being Repaired, Section III, Division 1(e)
N-802	Rules for Repair of Stamped Components by the N Certificate Holder That Originally Stamped the Component, Section III, Division 1(e)

Notes:

(a) Use of this code case will meet the conditions for Code Case N-60-4 in Reg. Guide 1.85 Revision 30.
(b) Use of this code case will meet the conditions for Code Case N-249-10 in Reg. Guide 1.85 Revision 30.
(c) Use of this code case will meet the conditions for Code Case N-392-1 in Reg. Guide 1.84 Revision 30.
(d) Use of this code case is subject to the condition that the design provisions of ASME Code, Section III, Division I, Appendix XIII not be used for the design of Code Class 3 (ND) valves.
(e) Use of this code case is acceptable per Reg. Guide 1.84 Revision 37.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 5.2-201 (Sheet 1 of 3)
NRC Authorized ASME Section III Requests for Alternative
In Accordance with 10 CFR 50.55a(a)(3)[a] or 10 CFR 50.55a(z)[a]

Requests for Alternative Number	Title	Description
STPD-DSN/FAB-ALT-01	Safety Related Air Gas Storage Tanks Design and Fabrication Code Requirements [b]	Pursuant to the requirements of 10 CFR 50.55a(a)(3)(i), the use of the rules of ASME Code, Section VIII, Appendix 22 for the design and construction of the air gas storage tanks in the main control room (MCR) emergency habitability system has been authorized by the NRC in lieu of the required ASME Section III requirements for design and construction.
STPD-DSN/FAB-ALT-02	Permission to use ASME Section III Code Case N-655-1[c]	Pursuant to the requirements of 10 CFR 50.55a(a)(3)(i), the use of Code Case N-655-1, “Use of SA-738, Grade B, for Metal Containment Vessels, Class MC” has been authorized by the NRC.
STPD-DSN/FAB-ALT-03	Permission to use ASME Section III Code Case N-757-1[c]	Pursuant to the requirements of 10 CFR 50.55a(a)(3)(i), the use of Code Case N-757-1, “Alternative Rules for Acceptability for Class 2 and 3 Valves, NPS 1 (DN 25) and Smaller With Welded and Nonwelded End Connections Other Than Flanges” has been authorized by the NRC.
STPD-DSN/FAB-ALT-04	Permission to use ASME Section III Code Case N-759-2 [c]	Pursuant to the requirements of 10 CFR 50.55a(a)(3)(i), the use of Code Case N-759-2, “Alternative Rules for Determining Allowable External Pressure and Compressive Stresses for Cylinders, Cones, Spheres, and Formed Heads, Class 1, 2, and 3” has been authorized by the NRC.
STPD-DSN/FAB-ALT-05	Permission to use ASME Section III Code Case N-782 [c]	Pursuant to the requirements of 10 CFR 50.55a(a)(3)(i), the use of Code Case N-782, “Use of Code Editions, Addenda, and Cases” has been authorized by the NRC.
STPD-DSN/FAB-ALT-06	“Alternate Classification,” of the portion of the CVS inside containment that is defined as part of the RCPB [d]	Pursuant to the requirements of 10 CFR 50.55a(a)(3)(i), changing the safety classification of the RCPB portion of CVS inside containment to non-safety, Class D has been authorized by the NRC.
VEGP 3&4-PSI/ISI-ALT-01	Reactor Vessel Flow Skirt ASME Code Jurisdictional Boundary [e]	Pursuant to the requirements of 10 CFR 50.55a(a)(3)(ii), allows the Reactor Vessel flow skirt to support pad weld to be excluded from the Reactor Vessel ASME Section III jurisdictional boundary.

Table 5.2-201 (Sheet 2 of 3)
NRC Authorized ASME Section III Requests for Alternative
In Accordance with 10 CFR 50.55a(a)(3)[a] or 10 CFR 50.55a(z)[a]

Requests for Alternative Number	Title	Description
VEGP 3&4-PSI/ISI-ALT-02	ASME Certification Marks [f]	Pursuant to the requirements of 10 CFR 50.55a(a)(3)(i), allows the use of ASME Section III Code certification marks with certification designators and class designators interchangeably with the currently authorized ASME Section III Code symbol stamps.
VEGP 3&4-PSI/ISI-ALT-03	ASME NPT Code Symbol Stamps[g]	Pursuant to the requirements of 10 CFR 50.55a(z)(1), allows the use of horizontal ASME NPT Symbol Stamp that is currently not specified in the ASME Code. The horizontal ASME NPT Code Symbol Stamp would be applied to the nameplate or parts, appurtenances, piping subassemblies, and tubular products welded with filler metal from February 2012 through December 2016.
VEGP 3&4-PSI/ISI-ALT-08	Counterboring of Class 1 Piping, Components and Fittings with Weld End Transitions[h]	Pursuant to the requirements of 10 CFR 50.55a(z)(1), allows the use of alternative counterbore configurations to those shown in ASME Section III Figures NB-4250-2 and NB-4250-3 for Class 1 piping, components, and fittings when the alternative weld joint configuration can be inspected.
VEGP 3&4-PSI/ISI-ALT-09	Elimination of External Surface Defects on Class 1, 2, and 3 Piping, Pumps, or Valves After Component Stamping and Prior to Completion of the N-3 Data Report[i]	Pursuant to the requirements of 10 CFR 50.55a(z)(1), allows removal of external surface defects on previously stamped piping, pumps, or valves by an N or NA Certificate Holder at a location authorized by their certificate in accordance with their Quality Assurance Program provided specific requirements are met.
VEGP 3&4-PSI/ISI-ALT-10R1	Alternative Requirements for Preservice Examination Volumetric Surface Configuration Requirements	Pursuant to the requirements of 10 CFR 50.55a(z)(1), allows the use of alternate requirements for surface finish and distance, and distance for a hanger or nearest attachment (or any other interference) to those required by ASME Section III NB-4424.2(a) for performance of preservice ultrasonic examinations.

Table 5.2-201 (Sheet 3 of 3)
NRC Authorized ASME Section III Requests for Alternative In Accordance with 10 CFR 50.55a(a)(3)[a] or 10 CFR 50.55a(z)[a]

Requests for Alternative Number	Title	Description
VEGP 3&4-PSI/ISI-ALT-12	ASME Pressure Tests Conducted Following the Completion of ASME Section III Construction Activities[k]	Pursuant to the requirements of 10 CFR 50.55a(z)(2), allows ASME Section III pressure conducted following the completion of ASME Section III Construction activities and application of the ASME certification marking to be performed in accordance with ASME Section XI.
VEGP 3-ALT-16	Alternative Requirements for ASME Section III Remediation of Containment Vessel Unistrut Welding[l]	Pursuant to the requirements of 10 CFR 50.55a(z)(1), allows remediation activities for Unistrut brackets welded on the inner diameter of the Containment Vessel shell by a contractor that is not the N-Certificate Holder for the Containment Vessel, with trace amounts of remnant weld material remaining in place for the life of the plant.

Notes:

(a) 10 CFR 50.55a(a)(3) or 10 CFR 50.55a(z), Requests for Alternatives authorized for ASME Section XI inspections and ASME OM testing will be identified in Plant Owner provided Inspection and Testing Plans.

(b) The Request for Alternative was authorized for use by NRC NUREG-1793, “Final Safety Evaluation Report Related to Certification of the AP1000 Standard Design” September 2004, Page 3-4 (NRC ADAMS Accession Number ML043450344) and incorporated by reference by NRC NUREG-2124, “Final Safety Evaluation Report Related to the Combined Licenses for Vogtle Electric Generating Plant, Units 3 and 4” September 2012 (NRC ADAMS Accession Number ML12271A045).

(c) This ASME Section III Code Case has not been authorized for use in Regulatory Guide 1.84. Therefore, a 10 CFR 50.55a(a)(3) Request for Alternative was submitted asking for authorization to use the Case. The Request for Alternative was authorized for use by NRC NUREG-1793, “Final Safety Evaluation Report Related to Certification of the AP1000 Standard Design” September 2011, Pages 5-4 thru 5-6 (NRC ADAMS Accession Number ML11293A199) and incorporated by reference by NRC NUREG-2124, “Final Safety Evaluation Report Related to the Combined Licenses for Vogtle Electric Generating Plant, Units 3 and 4” September 2012 (NRC ADAMS Accession Number ML12271A045).

(d) The Request for Alternative was authorized for use by NRC NUREG-1793, “Final Safety Evaluation Report Related to Certification of the AP1000 Standard Design” September 2004, Page 5-9 (NRC ADAMS Accession Number ML043450344) and incorporated by reference by NRC NUREG-2124, “Final Safety Evaluation Report Related to the Combined Licenses for Vogtle Electric Generating Plant, Units 3 and 4” September 2012, (NRC ADAMS Accession Number ML12271A045).

(e) Request for Alternative VEGP 3&4-PSI/ISI-ALT-01 (SNC ND Licensing Letter Number ND-12-1388) was authorized for use by NRC SER on August 30, 2012 (NRC ADAMS Accession Number ML12216A349).

(f) Request for Alternative VEGP 3&4-PSI/ISI-ALT-02 (SNC ND Licensing Letter Number ND-12-1993) was authorized for use by NRC SER on November 29, 2012 (NRC ADAMS Accession Number ML12331A309).

(g) Request for Alternative VEGP 3&4-PSI/ISI-ALT-03 (SNC ND Licensing Letter Number ND-15-0773) was authorized for use by NRC SER on November 4, 2015 (NRC ADAMS Accession Number ML15289A161).

(h) Request for Alternative VEGP 3&4-PSI/ISI-ALT-08 (SNC ND Licensing Letter Number ND-17-1698) was authorized for use by NRC SER on March 20, 2018 (NRC ADAMS Accession Number ML18071A359).

(i) Request for Alternative VEGP 3&4-PSI/ISI-ALT-09 (SNC ND Licensing Letter Number ND-17-1697) was authorized for use by NRC SER on March 5, 2018 (NRC ADAMS Accession Number ML18054A068).

(j) Request for Alternative VEGP 3&4-PSI/ISI-ALT-10R1 (SNC ND Licensing Letter Number ND-18-1158) was authorized for use by NRC SER on November 20, 2018 (NRC ADAMS Accession Number ML 18305B416).

(k) Request for Alternative VEGP 3&4-PSI/ISI-ALT-12 (SNC ND Licensing Letter Number ND-18-1460) was authorized for use by NRC SER on April 9, 2019 (NRC ADAMS Accession Number ML19018A130).

(l) Request for Alternative VEGP 3-ALT-16 (SNC ND Licensing Letter Number ND-21-0392) was authorized for use by NRC SER on July 25, 2021 (NRC ADAMS Accession Number ML21203A317).

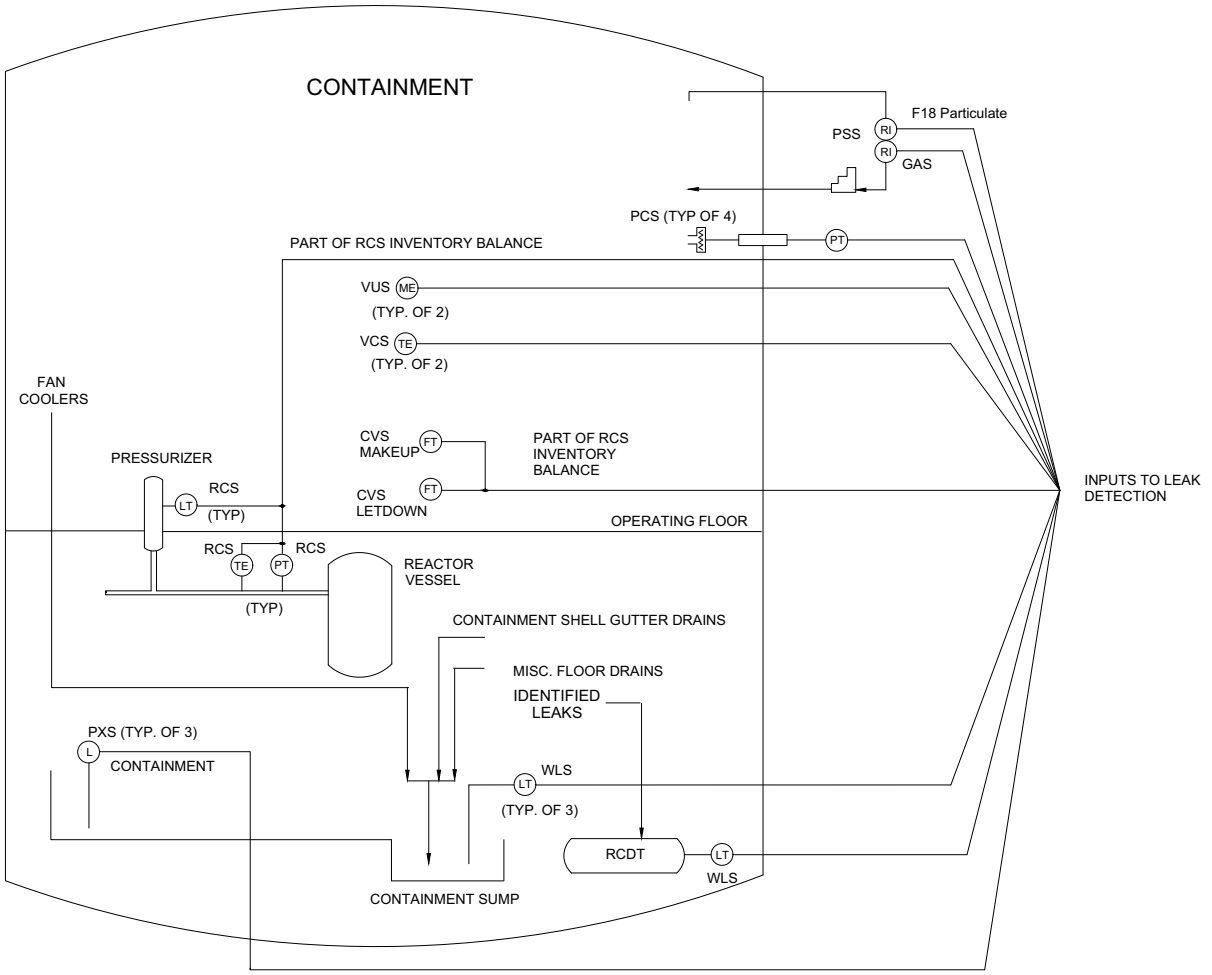


Figure 5.2-1
Leak Detection Approach

5.3 Reactor Vessel

5.3.1 Reactor Vessel Design

5.3.1.1 Safety Design Bases

The reactor vessel, as an integral part of the reactor coolant pressure boundary will be designed, fabricated, erected and tested to quality standards commensurate with the requirements set forth in 10 CFR 50, 50.55a and General Design Criterion 1. Design and fabrication of the reactor vessel is carried out in accordance with ASME Code, Section III, Class 1 requirements. Subsections 5.2.3 and 5.3.2 provide further details.

The performance and safety design bases of the reactor vessel follow:

- The reactor vessel provides a high integrity pressure boundary to contain the reactor coolant, heat generating reactor core, and fuel fission products. The reactor vessel is the primary pressure boundary for the reactor coolant and the secondary barrier against the release of radioactive fission products.
- The reactor vessel provides support for the reactor internals, flow skirt, and core to ensure that the core remains in a coolable configuration.
- The reactor vessel directs main coolant flow through the core by close interface with the reactor internals and flow skirt.
- The reactor vessel provides for core internals location and alignment.
- The reactor vessel provides support and alignment for the control rod drive mechanisms and in-core instrumentation assemblies.
- The reactor vessel provides support and alignment for the integrated head assembly.
- The reactor vessel provides an effective seal between the refueling cavity and sump during refueling operations.
- The reactor vessel supports and locates the main coolant loop piping.
- The reactor vessel provides support for safety injection flow paths.
- The reactor vessel serves as a heat exchanger during core meltdown scenario with water on the outside surface of the vessel.

5.3.1.2 Safety Description

The reactor vessel consists of a cylindrical section with a transition ring, hemispherical bottom head, and a removable flanged hemispherical upper head (Figure 5.3-1). Key dimensions are shown in Figures 5.3-5 and 5.3-6. The cylindrical section consists of two shells, the upper shell and the lower shell. The upper and lower shells and the lower hemispherical head are fabricated from low alloy steel and clad with austenitic stainless steel. The upper shell forging is welded to the lower shell forging, and the lower shell is welded to the transition ring, which is welded to the hemispherical bottom head. The removable flanged hemispherical upper head consists of a single forging, which includes the closure head flange and the closure head dome. The closure head is fabricated from a low alloy steel forging and clad with austenitic stainless steel. Specifics of the processes used in base materials, clad material, and weld materials are discussed in Subsection 5.2.3. The removable

flanged hemispherical closure head is attached to the vessel (consisting of the upper shell-lower shell-transition ring-bottom hemispherical head dome) by studs. Two metal o-rings are used for sealing the two assemblies. Inner and outer monitor tubes are provided through the upper shell to collect any leakage past the o-rings. Details of the head gasket monitoring connections are included in Subsection 5.2.5.1.2.

The reactor vessel supports the internals. An internal ledge is machined into the top of the upper shell section. The core barrel flange rests on the ledge. A large circumferential spring is positioned on the top surface of the core barrel flange. The upper support plate rests on the top surface of the spring. The spring is compressed by installation of the reactor vessel closure head and the upper and lower core support assemblies are restrained from any axial movements.

Four core support pads are located on the bottom hemispherical head just below the transition ring-to-lower shell circumferential weld. The core support pads function as a clevis. At assembly, as the lower internals are lowered into the vessel, the keys at the bottom of the lower internals engage the clevis in the axial direction. With this design, the internals are provided with a lateral support at the furthest extremity and may be viewed as a beam supported at the top and bottom.

The interfaces between the reactor vessel and the lower internals core barrel are such that the main coolant flow enters through the inlet nozzle and is directed down through the annulus between the reactor vessel and core barrel and through the flow skirt and flows up through the core. The annulus is designed such that the core remains in a coolable configuration for all design conditions.

Prior to installation of the internals into the reactor vessel, guide studs are assembled into the upper shell. Dimensional relationships are established between the guide studs and the core support pads such that when the lower internals lifting rig engages the guide studs, the keys at the bottom of the lower internals are in relative circumferential position to enter the core support pads.

There are 69 penetrations in the removable flanged hemispherical upper head (closure head) that are used to provide access for the control rod drive mechanisms. Each control rod drive mechanism is positioned in its opening and welded to the closure head penetration. In addition there are eight penetrations in the closure head used to provide access for in-core and core exit instrumentation.

Lugs are welded to the outside surface of the closure head along the outer periphery of the dome section. The purpose of these lugs is to provide support and alignment for the integrated head package.

Attached to the top surface and along the outer periphery of the upper shell is a permanent cavity seal ring. During field assembly the permanent cavity seal ring is welded to the refueling cavity liner. This permanent cavity seal ring provides an effective water seal between the refueling cavity and sump during refueling operations.

A support pad is integral to each of the four inlet nozzles. The reactor vessel is supported by the pads. The pads rest on steel base pads atop a support structure, which is attached to the concrete foundation wall. Thermal expansion and contraction of the vessel are accommodated by sliding surfaces between the support pads and the base plates. Side stops on these plates keep the vessel centered and resist lateral loads.

The reactor vessel primary and direct vessel injection (DVI) nozzles are located in the upper shell. These nozzles are either forged as part of the upper shell forging or are fabricated by “set in” construction such that the welding is through the vessel shell forging. A stainless steel safe end is shop welded to each of the four inlet, two outlet and two DVI nozzles to facilitate field welding without heat treatment to the stainless steel reactor coolant piping system. The primary coolant nozzles

support one end of the primary coolant system. Reaction loads are transferred into the nozzles and eventually into the support pads. The inlet and outlet elevation nozzles are offset in different planes by 17.5 inches. This allows pump maintenance without discharging the core.

There are no penetrations in the reactor vessel below the core. This eliminates the possibility of a loss-of-coolant accident by leakage from the reactor vessel that would allow the core to be uncovered.

5.3.1.3 System Safety Evaluation

The reactor vessel is part of the reactor coolant system. Load and stress evaluation for operating loads and mechanical transients of safe shutdown earthquake (SSE), and pipe ruptures appear in Subsection 3.9.3.

5.3.1.4 Inservice Inspection/Inservice Testing

Inservice surveillance is discussed in Subsection 5.3.4.7.

5.3.2 Reactor Vessel Materials

5.3.2.1 Material Specifications

Material specifications are in accordance with the ASME Code requirements and are given in Subsection 5.2.3. All ferritic reactor vessel materials comply with the fracture toughness requirements of Section 50.55a and Appendices G and H of 10 CFR 50.

The ferritic materials of the reactor vessel beltline are restricted to the maximum limits shown in Table 5.3-1. Copper, nickel, and phosphorus content is restricted to reduce sensitivity to irradiation embrittlement in service.

5.3.2.2 Special Processes Used for Manufacturing and Fabrication

The reactor vessel is classified as AP1000 Class A. Design and fabrication of the reactor vessel is carried out in accordance with ASME Code, Section III, Class 1 requirements. The shell sections, flange, and nozzles are manufactured as forgings. The hemispherical heads are made from dished plates or forgings. The reactor vessel parts are joined by welding, using the single or multiple wire submerged arc and the shielded metal arc processes. Gas metal arc welding and plasma arc welding are acceptable methods of applying buttering for dissimilar metal welds.

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

At locations in the reactor vessel where stainless steel and nickel-chromium-iron alloy are joined, the final joining beads are nickel-chromium-iron alloy weld metal in order to prevent cracking.

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

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

Freedom from underclad cracking is provided by special evaluation of the procedure qualification for cladding applied on low-alloy steel (SA-508, GR 3 CL 1).

Minimum preheat requirements have been established for pressure boundary welds using low-alloy material. The preheat is maintained until either a low temperature (400°F – 500°F) post heat treatment, an intermediate postweld heat treatment or a full postweld heat treatment is performed.

A field weld is made, after the reactor vessel has been set, to install the permanent cavity seal ring. This stainless steel filler weld joins the permanent cavity seal ring to the reactor vessel seal ledge. A minimum preheat is specified for this weld in compliance with the ASME Code requirements.

The flow skirt is also welded to support lugs in the field after the reactor vessel/internals system is set.

5.3.2.3 Special Methods for Nondestructive Examination

The nondestructive examination (NDE) of the reactor vessel and its appurtenances is conducted in accordance with ASME Code, Section III requirements; also, numerous examinations are performed in addition to ASME Code, Section III requirements. The nondestructive examination of the vessel is discussed in the following paragraphs, and the reactor vessel quality assurance program is given in Table 5.3-2.

5.3.2.3.1 Ultrasonic Examination

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

In addition to the ASME Code, Section III nondestructive examination, the full penetration ferritic pressure boundary welds in the reactor vessel, the nozzle to safe end welds, the primary and direct vessel injection (DVI) nozzle inner radii and inner protrusions, the Quickloc instrument nozzle (QIN) weld buildups, and the QIN dissimilar metal welds are ultrasonically examined during fabrication. These tests are performed upon completion of the welding and intermediate heat treatment but prior to the final postweld heat treatment.

After hydrotesting, the full penetration ferritic pressure boundary welds in the reactor vessel, the nozzle to safe end welds, the primary and DVI nozzle inner radii and inner protrusions, the QIN weld buildups, and the QIN dissimilar metal welds are ultrasonically examined. These inspections are performed in addition to the ASME Code, Section III nondestructive examination requirements.

5.3.2.3.2 Penetrant Examinations

The partial penetration welds between the control rod drive mechanism latch housing nozzle and reactor vessel closure head are inspected by dye penetrant after the root pass, in addition to ASME code requirements. The QIN full penetration dissimilar metal weld is examined by dye penetrant on the back chip and final surfaces to ASME code requirements. Core support block attachment welds are inspected by dye penetrant after the first layer of weld metal and after each 0.5 inch of weld metal. Clad surfaces and other vessel and head internal surfaces are inspected by dye penetrant after the hydrostatic test.

5.3.2.3.3 Magnetic Particle Examination

Magnetic particle examination requirements below are in addition to the magnetic particle examination requirements of Section III of the ASME Code. All magnetic particle examinations of materials and welds are performed in accordance with the following:

- Prior to the final postweld heat treatment, by the prod, coil, direct contact, or yoke method

- After the final postweld heat treatment, only by the yoke method

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

Surface Examinations

- Magnetic particle examination of exterior vessel and head surfaces after the hydrostatic test.
- Magnetic particle examination of exterior closure stud surfaces and all nut surfaces after final machining or rolling. Continuous circular and longitudinal magnetization is used.
- Magnetic particle examination of inside diameter surfaces of carbon and low alloy steel products that have their properties enhanced by accelerated cooling. Liquid (dye) penetrant examination may be used as an alternative method, in accordance with ASME B&PV, Section III, NB-2541(a), when the inspection surface and surrounding geometry do not permit effective use of magnetic particle examination equipment. Both dye penetrant examination and magnetic particle examination are capable to detect surface flaws in carbon and low alloy steels regardless of the cooling process of the material. This inspection is performed after forming and machining and prior to cladding.

Weld Examination

Magnetic particle examination of the welds attaching the closure head lifting lugs and refueling seal ledge to the reactor vessel after the first layer and each 0.5 inch of weld metal is deposited. All pressure boundary welds are examined after back-chipping or back-grinding operations.

5.3.2.4 Special Controls for Ferritic and Austenitic Stainless Steels

Welding of ferritic steels and austenitic stainless steels is discussed in Subsection 5.2.3. Subsection 5.2.3 includes discussions on the degree of conformance with Regulatory Guide 1.44. Section 1.9 discusses the degree of conformance with Regulatory Guides, including 1.31 and 1.34 (if applicable), as well as 1.37, 1.43, 1.50, 1.71, and 1.99.

5.3.2.5 Fracture Toughness

Assurance of adequate fracture toughness of ferritic materials in the reactor vessel (ASME Code, Section III, Class 1 component) is provided by compliance with the requirements for fracture toughness testing included in NB-2300 to Section III of the ASME Code and Appendix G of 10 CFR 50.

The initial Charpy V-notch minimum upper shelf fracture energy levels for the reactor vessel beltline base metal transverse direction and welds are 75 foot-pounds, as required by Appendix G of 10 CFR 50. The vessel fracture toughness data are given in Table 5.3-3. The AP1000 end-of-life RT_{NDT} and upper shelf energy projections were estimated using Regulatory Guide 1.99 for the end-of-life neutron fluence at the 1/4-thickness (T) and ID reactor vessel locations.

5.3.2.6 Material Surveillance

In the surveillance program, the evaluation of radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens and postirradiation testing of Charpy V-notch, tensile, and 1/2-T compact tension (CT) fracture mechanics test specimens. The program is directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach. The program conforms to ASTM E-185 (Reference 1) and 10 CFR 50, Appendix H.

Surveillance test materials are prepared from the actual materials used in fabricating the beltline region of the reactor vessel. Records are maintained of the chemical analyses, fabrication history, mechanical properties and other essential variables pertinent to the fabrication process of the shell forging and weld metal from which the surveillance test materials are prepared. The test materials are processed so that they are representative of the material in the completed reactor vessel.

Three metallurgically different materials prepared from sections of reactor vessel shell forging are used for test specimens. These include base metal, weld metal and heat affected zone (HAZ) material.

Base metal test material is manufactured from a section of ring forging, either the intermediate shell course, the lower shell course, or the transition ring of the reactor pressure vessel. Selection is based on an evaluation of initial toughness (characterized by the reference temperature (RT_{NDT}) and Upper Shelf Energy (USE)), and the predicted effect of chemical composition (nickel and residual copper) and neutron fluence on the toughness (RT_{NDT} shift and decrease in USE) during reactor operation. The ring forging with the highest predicted adjusted RT_{NDT} temperature (initial RT_{NDT} plus RT_{NDT} shift) or that with USE predicted to approach close to the minimum limit of 50 ft-lb at end-of-license (EOL) is selected as the surveillance base metal test material. The means for measuring initial toughness and for predicting irradiation induced toughness changes is consistent with applicable procedures in force at the time the material is being selected. The section of shell forging used for the base metal test block is adjacent to the test material used for fracture toughness tests.

Weld metal and HAZ test material is produced by welding together sections of the forgings from the beltline of the reactor vessel. The HAZ test material is manufactured from a section of the same shell course forging used for base metal test material. The sections of shell course forging used for weld metal and HAZ test material are adjacent to the test material used for fracture toughness tests. The heat of wire or rod and lot of flux are from the same heat and lot used in making the beltline region welds. Welding parameters duplicate those used for the beltline region welds. The procedures for inspection of the reactor vessel welds are followed for the inspection of the welds in test materials. The surveillance weld and HAZ material are heat-treated to metallurgical conditions which are representative of the final metallurgical conditions of similar materials in the completed reactor vessel.

Test Specimens are marked to identify the type of materials and the orientation with respect to the test materials. Drawings specify the identification system to be used and include plant identification, type of material, orientation of specimen and sequential number.

Baseline test specimens are provided for establishing the baseline (unirradiated) properties of the reactor vessel materials. The data from tests of these specimens provides the basis for determining the radiation induced property changes of the reactor vessel materials.

Drop weight test specimens of each of base metal, weld metal, and HAZ metal are provided for establishing the nil-ductility transition temperature (NDTT) of the unirradiated surveillance materials. These data form the basis for RT_{NDT} determination from which subsequent radiation induced changes are determined.

Standard Charpy impact test specimens each of base metal (longitudinal (tangential) and transverse (axial)), weld metal, and HAZ material are provided for developing a Charpy impact energy transition curve from fully brittle to fully ductile behavior for defining specific index temperatures for these materials. These data, together with the drop weight NDTT, are used to establish an RT_{NDT} for each material.

Tensile test specimens each of base metal (longitudinal (tangential) and transverse (axial)), weld metal, and HAZ metal are provided to permit a sufficient number of tests for accurately establishing

the tensile properties for these materials at a minimum of three test temperatures (e.g., ambient, operating and one intermediate temperature) to define the strength of the material.

The above described test specimens are to be used for determining changes in the strength and toughness of the surveillance materials resulting from neutron irradiation. Sufficient Charpy impact, compact tension and tensile test specimens are provided for establishing the changes in the properties of the surveillance materials over the lifetime of the reactor vessel. The type, quantity, and storage conditions (e.g., surveillance capsules backfilled with inert gas) of test specimens meet or exceed the minimum requirements of ASTM E-185.

Reactor materials do not begin to be affected by neutron fluence until the reactor begins critical operation. Table 13.4-201 provides milestones for reactor vessel material surveillance program implementation.

The reactor vessel surveillance program incorporates eight specimen capsules. The capsules are located in guide baskets bolted to the outside of the core barrel as shown in Figure 5.3-4 and positioned directly opposite the center portion of the core. The capsules can be removed when the vessel head is removed. To meet the guidelines of ASTM E-185 (lead factors less than three), the specimen guide baskets are located azimuthally near the lowest fluence locations at 135, 225, and 315 degrees. The 45 degree location is also a low fluence azimuthal location; however, there is a Roto-Lock insert for the internals lifting rig, which would prevent access for removal of the capsules from the baskets. Therefore, there are no guide baskets at the 45 degree location. Eight specimen capsules are provided by including three guide baskets at the 135 and 315 degree azimuthal locations and two baskets at the 225 degree location.

The capsules contain reactor vessel weld metal, base metal, and heat-affected zone metal specimens. The base metal specimens are oriented both parallel and normal (longitudinal and transverse) to the principal rolling direction of the limiting base material located in the core region of the reactor vessel. The 8 capsules contain 72 tensile specimens, 480 Charpy V-notch specimens, and 48 compact tension specimens. Archive material sufficient for two additional capsules and heat-affected-zone (HAZ) materials is retained.

Dosimeters, as described below, are placed in filler blocks drilled to contain them. The dosimeters permit evaluation of the flux seen by the specimens and the vessel wall. In addition, thermal monitors made of low melting point alloys are included to monitor the maximum temperature of the specimens. The specimens are enclosed in a tight-fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule is helium leak tested. As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01 percent is made for surveillance material and as deposited weld metal. Each of the eight capsules contains the specimens shown in Table 5.3-4.

The following dosimeters and thermal monitors are included in each of the eight capsules:

- Dosimeters
  - Iron
  - Copper
  - Nickel
  - Niobium-93 (cadmium shielded)
  - Cobalt-aluminum (0.15-percent cobalt)

  - Cobalt-aluminum (cadmium shielded)

- Thermal Monitors
  - 97.5-percent lead, 2.5-percent silver, (579°F melting point)
  - 97.5-percent lead, 1.75-percent silver, 0.75-percent tin (590°F melting point)

The fast neutron exposure of the specimens occurs at a faster rate than that experienced by the vessel wall, with the specimens being located between the core and the vessel. Since these specimens experience accelerated exposure and are actual samples from the materials used in the vessel, the transition temperature shift measurements are representative of the vessel at a later time in life. The lead factors for the eight specimen capsule locations based on the reference neutron flux distribution (flux distribution that results in the maximum fluence on the reactor vessel inner surface) vary between approximately 1.8 and 2.3. These lead factors will change over the life of the plant due to changes in core design and operating parameters. Data from CT fracture toughness specimens are expected to provide additional information for use in determining allowable stresses for irradiated material.

Correlations between the calculations and measurements of the irradiated samples in the capsules, assuming the same neutron spectrum at the samples and the vessel inner wall, are described in Subsection 5.3.2.6.1. The anticipated degree to which the specimens perturb the fast neutron flux and energy distribution is considered in the evaluation of the surveillance specimen data. Verification and possible readjustment of the calculated wall exposure is made by the use of data on capsules withdrawn. The recommended program schedule for removal of the capsules for post-irradiation testing includes five capsules to be withdrawn instead of four as specified in ASTM E-185 (Reference 1) and Appendix H of 10 CFR 50. The following is the recommended withdrawal schedule of capsules for AP1000.

Capsule	Withdrawal Time
1st	When the accumulated neutron fluence of the capsule is 5×10^{18} n/cm^2.
2nd	When the accumulated neutron fluence of the capsule corresponds to the approximate end of life fluence at the reactor vessel 1/4T location.
3rd	When the accumulated neutron fluence of the capsule corresponds to the approximate end of life fluence at the reactor vessel inner wall location.
4th	When the accumulated neutron fluence of the capsule corresponds to a fluence not less than once or greater than twice the peak end of vessel life fluence.
5th	End of plant design objective of 60 years
6th	Standby
7th	Standby
8th	Standby

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

The use of passive neutron sensors such as those included in the internal surveillance capsule dosimetry sets does not yield a direct measure of the energy dependent neutron flux level at the measurement location. Rather, the activation or fission process is a measure of the integrated effect that the time and energy dependent neutron flux has on the target material over the course of the irradiation period. An accurate estimate of the average neutron flux level, and hence, time integrated exposure (fluence) experienced by the sensors may be derived from the activation measurements only if the parameters of the irradiation are well known. In particular, the following variables are of interest:

- The measured specific activity of each sensor
- The physical characteristics of each sensor
- The operating history of the reactor
- The energy response of each sensor
- The neutron energy spectrum at the sensor location

The procedures used to determine sensor specific activities, to develop reaction rates for individual sensors from the measured specific activities and the operating history of the reactor, and to derive key fast neutron exposure parameters from the measured reaction rates are described below.

5.3.2.6.1.1 Determination of Sensor Reaction Rates

The specific activity of each of the radiometric sensors is determined using established ASTM procedures. Following sample preparation and weighing, the specific activity of each sensor is determined by means of a high purity germanium gamma spectrometer. In the case of the surveillance capsule multiple foil sensor sets, these analyses are performed by direct counting of each of the individual wires or, as in the case of niobium monitors, by appropriate methods as described in ASTM E 1297.

The irradiation history of the reactor over its operating lifetime is determined from plant power generation records. In particular, operating data are extracted on a monthly basis from reactor startup to the end of the capsule irradiation period. For the sensor sets utilized in the surveillance capsule irradiations, the half-lives of the product isotopes are long enough that a monthly histogram describing reactor operation has proven to be an adequate representation for use in radioactive decay corrections for the reactions of interest in the exposure evaluations.

Having the measured specific activities, the operating history of the reactor, and the physical characteristics of the sensors, reaction rates referenced to full power operation are determined from the following equation:

$$R = \frac{A}{N_0 F Y \sum_j \frac{P_j}{P_{ref}} C_j [1 - e^{-\lambda t_j}] e^{-\lambda t_d}}$$

where:

A = measured specific activity provided in terms of disintegrations per second per gram of target material (dps/gm).

R = reaction rate averaged over the irradiation period and referenced to operation at a core power level of P_{ref} expressed in terms of reactions per second per nucleus of target isotope (rps/nucleus).

N_0 = number of target element atoms per gram of sensor.

F = weight fraction of the target isotope in the sensor material.

Y = number of product atoms produced per reaction.

P_j = average core power level during irradiation period j (MW).

P_{ref} = maximum or reference core power level of the reactor (MW).

C_j = calculated ratio of $\phi(E > 1.0\ MeV)$ during irradiation period j to the time weighted average $\phi(E > 1.0\ MeV)$ over the entire irradiation period.

λ = decay constant of the product isotope (sec-1).

t_j = length of irradiation period j (sec).

t_d = decay time following irradiation period j (sec).

and the summation is carried out over the total number of monthly intervals comprising the total irradiation period.

In the above equation, the ratio P_j/P_{ref} accounts for month-by-month variation of power level within a given fuel cycle. The ratio C_j is calculated for each fuel cycle and accounts for the change in sensor reaction rates caused by variations in flux level due to changes in core power spatial distributions from fuel cycle to fuel cycle. Since the neutron flux at the measurement locations within the surveillance capsules is dominated by neutrons produced in the peripheral fuel assemblies, the change in the relative power in these assemblies from fuel cycle to fuel cycle can have a significant impact on the activation of neutron sensors. For a single-cycle irradiation, $C_j = 1.0$. However, for multiple-cycle irradiations, particularly those employing low leakage fuel management, the additional C_j correction must be utilized in order to provide accurate determinations of the decay corrected reaction rates for the dosimeter sets contained in the surveillance capsules.

5.3.2.6.1.2 Least Squares Adjustment Procedure

Least squares adjustment methods provide the capability of combining the measurement data with the neutron transport calculation resulting in a Best Estimate neutron energy spectrum with associated uncertainties. Best Estimates for key exposure parameters such as neutron fluence (E > 1.0 MeV) or iron atom displacements (dpa) along with their uncertainties are then easily obtained from the adjusted spectrum. The use of measurements in combination with the analytical results reduces the uncertainty in the calculated spectrum and acts to remove biases that may be present in the analytical technique.

In general, the least squares methods, as applied to pressure vessel fluence evaluations, act to reconcile the measured sensor reaction rate data, dosimetry reaction cross-sections, and the calculated neutron energy spectrum within their respective uncertainties. For example,

$$R_i \pm \delta_{R_i} = \sum_g (\sigma_{ig} \pm \delta_{\sigma_{ig}})(\phi_g \pm \delta_{\phi_g})$$

relates a set of measured reaction rates, Ri, to a single neutron spectrum, ϕg, through the multigroup dosimeter reaction cross-section, σig, each with an uncertainty δ.

The use of least squares adjustment methods in LWR dosimetry evaluations is not new. The American Society for Testing and Materials (ASTM) has addressed the use of adjustment codes in ASTM Standard E944, “Application of Neutron Spectrum Adjustment Methods in Reactor Surveillance” and many industry workshops have been held to discuss the various applications. For example, the ASTM-EURATOM Symposia on Reactor Dosimetry holds workshops on neutron spectrum unfolding and adjustment techniques at each of its bi-annual conferences.

The primary objective of the least squares evaluation is to produce unbiased estimates of the neutron exposure parameters at the location of the measurement. The analytical method alone may be deficient because it inherently contains uncertainty due to the input assumptions to the calculation. Typically these assumptions include parameters such as the temperature of the water in the peripheral fuel assemblies, by-pass region, and downcomer regions, component dimensions, and peripheral core source. Industry consensus indicates that the use of calculation alone results in overall uncertainties in the neutron exposure parameters in the range of 15-20% (1σ).

The application of the least squares methodology requires the following input:

1. The calculated neutron energy spectrum and associated uncertainties at the measurement location.

2. The measured reaction rate and associated uncertainty for each sensor contained in the multiple foil set.

3. The energy dependent dosimetry reaction cross-sections and associated uncertainties for each sensor contained in the multiple foil sensor set.

For a given application, the calculated neutron spectrum is obtained from the results of plant specific neutron transport calculations applicable to the irradiation period experienced by the dosimetry sensor set. This calculation is performed using the benchmarked transport calculational methodology described in Subsection 5.3.2.6.2. The sensor reaction rates are derived from the measured specific activities obtained from the counting laboratory using the specific irradiation history of the sensor set to perform the radioactive decay corrections. The dosimetry reaction cross-sections and uncertainties that are utilized in LWR evaluations comply with ASTM Standard E1018, “Application of ASTM Evaluated Cross-Section Data File, Matrix E 706 (IIB).”

The uncertainties associated with the measured reaction rates, dosimetry cross-sections, and calculated neutron spectrum are input to the least squares procedure in the form of variances and covariances. The assignment of the input uncertainties also follows the guidance provided in ASTM Standard E 944.

5.3.2.6.2 Calculation of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

A generalized set of guidelines for performing fast neutron exposure calculations within the reactor configuration, and procedures for analyzing measured irradiation sample data that can be correlated to these calculations, has been promulgated by the Nuclear Regulatory Commission (NRC) in

Regulatory Guide 1.190, or RG-1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence” [Reference 2]. Since different calculational models exist and are continuously evolving along with the associated model inputs, e.g., cross-section data, it is worthwhile summarizing the key models, inputs, and procedures that the NRC staff finds acceptable for use in determining fast neutron exposures within the reactor geometry. This material is highlighted in the subsection of material that is provided below.

5.3.2.6.2.1 Calculation and Dosimetry Measurement Procedures

The selection of a particular geometric model, the corresponding input data, and the overall methodology used to determine fast neutron exposures within the reactor geometry are based on the needs for accurately determining a solution to the problem that must be solved and the data/ resources that are currently available to accomplish this task. Based on these constraints, engineering judgment is applied to each problem based on an analyst’s thorough understanding of the problem, detailed knowledge of the plant, and due consideration to the strengths and weaknesses associated with a given calculational model and/or methodology. Based on these conditions, RG-1.190 does not recommend using a singular calculational technique to determine fast neutron exposures. Instead, RG-1.190 suggests that one of the following neutron transport tools be used to perform this work.

- Discrete Ordinates Transport Calculations
  - Adjoint calculations benchmarked to a reference-forward calculation, or stand-alone forward calculations.
  - Various geometrical models utilized with suitable mesh spacing in order to accurately represent the spatial distribution of the material compositions and source.
  - In performing discrete ordinates transport calculations, RG-1.190 also suggests that a P_3 angular decomposition of the scattering cross-sections be used, as a minimum.
  - RG-1.190 also recommends that discrete ordinates transport calculations utilize S_8 angular quadrature, as a minimum.
  - RG-1.190 indicates that the latest version of the Evaluated Nuclear Data File, or ENDF/B, should be used for determining the nuclear cross-sections; however, cross-sections based on earlier or equivalent nuclear data sets that have been thoroughly benchmarked are also acceptable.
- Monte Carlo Transport Calculations

  A complete description of the Westinghouse pressure vessel neutron fluence methodology, which is based on discrete ordinates transport calculations, is provided in Reference 3. The Westinghouse methodology adheres to the guidelines set forth in Regulatory Guide 1.190.

5.3.2.6.2.2 Plant-Specific Calculations

The location, selection, and evaluation of neutron dosimetry and the associated radiometric monitors, as well as fast (E > 1.0 MeV) neutron fluence assessments of the AP1000 reactor pressure vessel, are conducted in accordance with the guidelines that are specified in Regulatory Guide 1.190.

5.3.2.6.3 Report of Test Results

A summary technical report for each capsule withdrawn with the test results is submitted, as specified in 10 CFR 50.4, within one year of the date of capsule withdrawal unless an extension is granted by the Director, Office of Nuclear Reactor Regulation.

The report includes the data required by ASTM E185-82, as specified in paragraph III.B.1 of 10 CFR Part 50, Appendix H, and includes the results of the fracture toughness tests conducted on the beltline materials in the irradiated and unirradiated conditions.

If the test results indicate a change in the Technical Specifications is required, either in the pressure-temperature limits or in the operating procedures required to meet the limits, the expected date for submittal of the revised Technical Specification is provided with the report.

5.3.2.7 Reactor Vessel Fasteners

The reactor vessel closure studs, nuts, and washers are designed and fabricated in accordance with the requirements of the ASME Code, Section III. The closure studs are fabricated of SA-540. The closure stud material meets the fracture toughness requirements of the ASME Code, Section III, and 10 CFR 50, Appendix G. Conformance with Regulatory Guide 1.65, Materials and Inspections for Reactor Vessel Closure Studs, is discussed in Section 1.9. Nondestructive examinations are performed in accordance with the ASME Code, Section III. See Subsection 5.2.3 for restrictions on lubricants.

Refueling procedures require that the reactor vessel closure studs, nuts, and washers are lifted out of their respective holes and a stud support collar be put in place prior to the lift of the integrated head assembly during preparation for refueling. In this way the studs are lifted with and stored on the head. An alternative method is to remove the reactor vessel closure studs, nuts, and washers from the reactor closure and place them in storage racks during preparation for refueling. In this method, the storage racks are removed from the refueling cavity and stored at convenient locations on the containment operating deck prior to removal of the reactor closure head and refueling cavity flooding. In either case, the reactor closure studs are not exposed to the borated refueling cavity water. Additional protection against the possibility of incurring corrosion effects is provided by the use of a manganese base phosphate surfacing treatment.

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

5.3.3 Pressure-Temperature Limits

5.3.3.1 Limit Curves

Heatup and cooldown pressure-temperature limit curves are required as a means of protecting the reactor vessel during startup and shut down to minimize the possibility of fast fracture. The methods outlined in Appendix G of Section III of the ASME Code are employed in the analysis of protection against nonductile failure. Beltline material properties degrade with radiation exposure, and this degradation is measured in terms of the adjusted reference nil ductility temperature, which includes a reference nil ductility temperature shift (ΔRT_{NDT}), initial RT_{NDT} and margin. The extent of the RT_{NDT} shift is enhanced by certain chemical elements (such as copper and nickel).

Predicted ΔRT_{NDT} values are derived considering the effect of fluence and copper and nickel content for the reactor vessel steels exposed to 550°F temperature. U.S. NRC Regulatory Guide 1.99 is used in calculating adjusted reference temperature. Since the cold leg temperature exceeds 525°F (minimum steady-state temperature is 535°F at 100% power, thermal design flow, and 10% tube

plugging), the procedures of Regulatory Guide 1.99 for nominal embrittlement apply. The heatup and cooldown curves are developed considering a sufficient magnitude of radiation embrittlement so that no unirradiated ferritic materials in other components of the reactor coolant system will be limiting in the analysis.

The pressure-temperature curves are developed considering a radiation embrittlement of up to 54 effective full power years (EFPY) consistent with the plant design objective of 60 years with 90 percent availability. As validated in Reference 12, the AP1000 PTLR (Reference 9) limits bound the VEGP 3&4 PTLR limits that utilize VEGP 3&4 inputs to determine the VEGP 3&4 P/T limit curves. However, the VEGP 3&4 PTLRs (References 10 and 11) continue to use the more conservative generic AP1000 PTLR limits. Copper, nickel contents and initial RT_{NDT} for materials in the reactor vessel beltline region and the reactor vessel flange and the closure head flange region are shown in Tables 5.3-1 and 5.3-3. The operating curves are developed with the methodology given in Reference 6, which is in accordance with 10 CFR 50, Appendix G.

The curves are applicable up to 54 effective full-power years. These curves, shown in Figures 5.3-2 and 5.3-3, are the curves for the VEGP 3&4 reactor vessel design and they are limiting curves based on copper and nickel material composition (References 10 and 11). These curves are applicable as long as the following criteria are met:

- 10 CFR 50, Appendix G as related to pressure-temperature remains unchanged,
- Adjusted Reference Temperatures at 1/4T and 3/4T locations remain below the bases of Figures 5.3-2 and 5.3-3

The results of the material surveillance program described in Subsection 5.3.2.6 were used to verify the validity of ΔRT_{NDT} used in the calculation for the development of heatup and cooldown curves. The projected fluence, copper, and nickel contents along with the RT_{NDT} calculation will be adjusted if necessary, from time to time using the surveillance capsule results. This may require the development of new heatup and cooldown curves.

Higher rates of temperature changes when the reactor coolant system pressure is at or above the operating pressure do not impact the determination of the proper curve to use. Figure 5.3-2 also includes a curve for the leak test limit at steady-state temperature and curves for the criticality limit for nuclear heatup.

Temperature limits for core operation, inservice leak and hydrotests are calculated in accordance with the ASME Code, Section III, Appendix G.

5.3.3.2 Operating Procedures

Plant operating procedures are developed and maintained to prevent exceeding the pressure-temperature limits identified in reactor coolant system pressure and temperature limits report, as required by Technical Specification 5.6.4, during normal and abnormal operating conditions and system tests.

5.3.4 Reactor Vessel Integrity

5.3.4.1 Design

The reactor vessel is the high pressure containment boundary used to support and enclose the reactor core. It provides flow direction with the reactor internals through the core and maintains a volume of coolant around the core. The vessel is cylindrical, with a transition ring, hemispherical bottom head, and removable flanged hemispherical upper head. The vessel is fabricated by welding

together the lower head dome, the transition ring, the lower shell, and the upper shell. The upper shell contains the penetrations from the inlet and outlet nozzles and direct vessel injection nozzles. The closure head is fabricated with a head dome and bolting flange. The upper head has penetrations for the control rod drive mechanisms, the incore instrumentation, head vent, and support lugs for the integrated head package.

The reactor vessel (including closure head) is approximately 40 feet long and has an inner diameter at the core region of 159 inches. The total weight of the vessel (including closure head and CRDMs) is approximately 417 tons. Surfaces which can become wetted during operation and refueling are clad to a nominal 0.22 inches of thickness with stainless steel welded overlay which includes the upper shell top surface but not the stud holes. The AP1000 reactor vessel's design objective is to withstand the design environment of 2500 psi and 650°F for 60 years. The major factor affecting vessel life is radiation degradation of the lower shell.

As a safety precaution, there are no penetrations below the top of the core. This eliminates the possibility of a loss of coolant accident by leakage from the reactor vessel which could allow the core to be uncovered. The core is positioned as low as possible in the vessel to limit reflood time in an accident. The main radial support system of the lower end of the reactor internals is accomplished by key and keyway joints to the vessel wall. At equally spaced points around the circumference, a clevis block is located on the reactor vessel inner diameter. A permanent cavity seal ring is attached to the top of the vessel shell for welding to the refueling cavity liner. To decrease outage time during refueling, access to the stud holes is provided to allow stud hole plugging with the head in place. By the use of a ring forging with an integral flange, the number of welds is minimized to decrease inservice inspection time.

The lower head has an approximate 6.5 feet inner spherical radius. The lower radial supports are located on the head at the elevation of the lower internals lower core support plate. The transition ring is welded to the lower shell course with the weld located outside the highest fluence area of the beltline region of the reactor vessel. The lower shell is a ring forging about 8 inches thick with an inner diameter of 159 inches. The length of the shell is greater than 168 inches to place the upper shell weld outside of the active fuel region. The upper shell is a large ring forging. Included in this forging are four 22-inch inner diameter inlet nozzles, two 31-inch inner diameter outlet nozzles and two 6.81-inch inner diameter direct vessel injection nozzles (8-inch schedule 160 pipe connections). These nozzles are forged into the ring or are fabricated by "set in" construction. The inlet and outlet nozzles are offset axially in different planes by 17.5 inches. The injection nozzles are 100 inches down from the main flange and the outlet nozzles are 80 inches down and the inlet nozzles are 62.5 inches below the mating surface.

The closure head has a 77.5-inch inner spherical radius and a 188.0-inch O.D. outer flange. Cladding is extended across the bottom of the flange for refueling purposes. Forty-five, seven-inch diameter studs attach the head to the lower vessel (which consists of the lower shell, transition ring, and bottom head) and two metal o-rings are used for sealing. The upper head has sixty-nine 4-inch outer diameter penetrations for the control rod drive mechanism housings and eight penetrations for the incore instrumentation tubes.

The eight penetrations for the incore instrumentation tubes are Quickloc instrument nozzles, which are welded to the reactor vessel head. Up to six instrument thimble assemblies pass through each Quickloc instrument nozzle. The reactor vessel head penetration diameter is approximately 4.75 inches to the cladding. The material of the pressure boundary parts of the Quickloc are SA-182 – Type F304, SA-479 – Type 304 and Type 316, and UNS S21800. The Quickloc instrument nozzle is welded to the Ni-Cr-Fe buttering on the weld buildup on the reactor vessel closure head. The Quickloc provides two pressure boundaries: 1) between the Quickloc plug and the incore instrument thimble assemblies (this pressure boundary is disassembled only when the instrument thimble is replaced) and 2) between the Quickloc plug and the instrument nozzle (this pressure boundary is

disassembled when the reactor vessel closure head is removed). The Quickloc instrument nozzle pressure boundary parts are designed and fabricated to the requirements of the ASME Code, Section III Division 1, Subsection NB. The Quickloc internal, non-pressure boundary parts are designed to Subsection NG. The Quickloc assembly is a proven design, which was first installed in an operating plant in 1995. Since then, it has been installed on four additional operating plants.

The vessel is manufactured from low alloy steel plates and forgings to minimize size. The chemical content of the core region base material is specifically controlled. A surveillance program is used to monitor the radiation damage to the vessel material.

The four vessel supports are located beneath the inlet nozzles and the internals support ledge is machined into the top of the upper shell. The top of the upper shell contains the stud holes and has the sealing surface for the closure head. Inner and outer monitor tubes are provided through the shell to collect any leakage past the closure region o-rings.

The reactor vessel is designed and fabricated in accordance with the quality standards set forth in 10 CFR 50, General Design Criteria 1, 14, 30, and 31, and 50.55a; and the requirements of the American Society of Mechanical Engineers (ASME) Code, Section III. Principal design parameters of the reactor vessel are given in Table 5.3-5. The vessel design and construction enables inspection in accordance with the ASME Code, Section XI.

Cyclic loads are introduced by normal power changes, reactor trips, and startup and shutdown operations. These design base cycles are selected for fatigue evaluation and constitute a conservative design envelope for the design life. Thermal stratification during passive core cooling system operation and natural circulation cooldown is considered by performing a thermal/flow analysis using computational fluid dynamics techniques. This analysis includes thermally-induced fluid buoyancy, heat transfer between the coolant and the metal of the vessel and internals and uses thermal/flow boundary conditions based on an existing thermal/hydraulic transient analysis of the primary reactor coolant system. This analysis provides temperature maps that are used to evaluate thermal stresses.

Analysis proves that the vessel is in compliance with the fatigue and stress limits of the ASME Code, Section III. The loadings and transients specified for the analysis are based on the most severe conditions expected during service. The heatup and cooldown rates imposed by plant operating limits are 100°F per hour for normal operations.

5.3.4.2 Materials of Construction

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

5.3.4.3 Fabrication Methods

The fabrication methods used in the construction of the reactor vessel are discussed in Subsection 5.3.2.2.

5.3.4.4 Inspection Requirements

The nondestructive examinations performed on the reactor vessel are described in Subsection 5.3.2.3.

5.3.4.5 Shipment and Installation

The reactor vessel is shipped in a horizontal position on a shipping skid with a vessel-lifting truss assembly. All vessel openings are sealed to prevent the entrance of moisture, and an adequate

quantity of desiccant bags is placed inside the vessel. These are usually placed in a wire mesh basket attached to the vessel cover. All carbon steel surfaces are protected with a temporary protective covering before shipment.

The closure head is also shipped with a shipping cover and skid. An enclosure attached to the reactor vessel closure head flange protects the control rod mechanism housings. All head openings are sealed to prevent the entrance of moisture, and an adequate quantity of desiccant bags is placed inside the head. These are placed in a wire mesh basket attached to the head cover. All carbon steel surfaces are protected with a temporary protective covering before shipment.

5.3.4.6 Operating Conditions

Operating limitations for the reactor vessel are presented in Subsection 5.3.3 and in the technical specifications.

In addition to the analysis of primary components discussed in Subsection 3.9.1.4, the reactor vessel is further qualified to ensure against unstable crack growth under faulted conditions. Safeguard actuation following a loss-of-coolant, tube rupture or other similar emergency or faulted event produces relatively high thermal stresses in regions of the reactor vessel which come into contact with water from the passive core cooling system. Primary consideration is given to these areas, including the reactor vessel beltline region and the reactor vessel primary coolant nozzles, to ensure the integrity of the reactor vessel under these severe postulated transients. TMI Action Item II.K.2.13, is satisfied upon submittal of RT_{NDT} values which are below the pressurized thermal shock (PTS) rule screening values. The results given in Table 5.3-3 show that the issue is resolved.

For the beltline region, the NRC staff concluded that conservatively calculated screening criterion values of RT_{NDT} less than 270°F for plate material and axial welds, and less than 300°F for circumferential welds, present an acceptably low risk of vessel failure from pressurized thermal shock events. These values were chosen as the screening criterion in the pressurized thermal shock rule for 10 CFR 50.34 (new plants) and 10 CFR 50.61 (operating plants). The conservative methods chosen by the NRC staff for the calculation of RT_{PTS} for the purpose of comparison with the screening criterion is presented in paragraph (b)(2) of 10 CFR 50.61. Details of the analysis method and the basis for the pressurized thermal shock rule can be found in SECY-82-465 (Reference 4).

The revised pressurized thermal shock rule, (10 CFR 50.61), effective June 14, 1991 makes the procedure for calculating RT_{PTS} values consistent with the methods given in Regulatory Guide 1.99.

The reactor vessel beltline materials are specified in Subsection 5.3.2. Evaluation of the AP1000 reactor vessel material showed that even at the fluence level which results in the highest RT_{PTS} value, this value is well below the screening criteria of 270°F. RT_{PTS} is RT_{NDT}, the reference nil ductility transition temperature as calculated by the method chosen by the NRC staff as presented in paragraph (b)(2) of 10 CFR 50.61, and the pressurized thermal shock rule. The pressurized thermal shock rule states that this method of calculating RT_{PTS} should be used in reporting values used to compare pressurized thermal shock to the above screening criterion set in the pressurized thermal shock rule. The screening criteria will not be exceeded using the method of calculation prescribed by the pressurized thermal shock rule for the vessel design objective. The material properties, and initial RT_{NDT} and end-of-life RT_{PTS} requirements and predictions are in Tables 5.3-1 and 5.3-3. The materials that are exposed to high fluence levels at the beltline region of the reactor vessel are subject to the pressurized thermal shock rule. These materials are a subset of the reactor vessel materials identified in Subsection 5.3.2.

The principles and procedures of linear elastic fracture mechanics (LEFM) are used to evaluate thermal effects in the regions of interest. The linear elastic fracture mechanics approach to the design against failure is basically a stress intensity consideration in which criteria are established for fracture

instability in the presence of a crack. Consequently, a basic assumption employed in linear elastic fracture mechanics is that a crack or crack-like defect exists in the structure. The essence of the approach is to relate the stress field developed in the vicinity of the crack tip to the applied stress on the structure, the material properties, and the size of defect necessary to cause failure.

5.3.4.7 Inservice Surveillance

The internal surfaces of the reactor vessel are accessible for periodic inspection. Visual and/or nondestructive techniques are used. During refueling, the vessel cladding is capable of being inspected in certain areas of the upper shell above the primary coolant inlet nozzles, and if deemed necessary, the core barrel is capable of being removed, making the entire inside vessel surface accessible.

Reactor vessel closure head examination is performed periodically as required by 10 CFR 50.55a. Optical devices permit a selective inspection of the cladding, control rod drive mechanism nozzles, and the gasket seating surface. Access to the top head surface is provided by 7 ports around the circumference of the integrated head package shroud and by multiple removable insulation panels, which interface with the head under the integrated head package shroud. Both the ports and the insulation panels provide access to the bare vessel head, and CRDM and instrumentation penetrations for use of a remote, mobile visual inspection manipulator to perform a 360° inspection around each penetration. The head insulation is a stand-off design with a minimum offset from the head surface of 3 inches.

The knuckle transition piece, which is the area of highest stress of the closure head, is accessible on the outer surface for visual inspection, dye penetrant or magnetic particle testing, and ultrasonic testing. The closure studs and nuts can be inspected periodically using visual, magnetic particle, and ultrasonic techniques.

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

- Vessel shell, from the inside surface.
- Primary coolant nozzles, from the inside surface. Only partial outside diameter coverage is provided.
- Closure head, from the inside surface; bottom head, from the inside surface.
- Field welds between the reactor vessel nozzle safe ends and the main coolant piping, from the inside surface.

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

- Reactor internals are completely removable. The tools and storage space required to permit removal of the reactor internals are provided.
- The closure head is stored on a stand on the reactor operating deck during refueling to facilitate direct visual inspection.
- Reactor vessel studs, nuts, and washers can be removed to dry storage during refueling.

- Access is provided to the reactor vessel nozzle safe ends. The insulation covering the nozzle-to-pipe welds may be removed.

Because radiation levels and remote underwater accessibility limits access to the reactor vessel, several steps have been incorporated into the design and manufacturing procedures in preparation for the periodic nondestructive tests which are required by the ASME Code inservice inspection requirements. These are as follows:

- Shop ultrasonic examinations are performed on internally clad surfaces to an acceptance and repair standard to provide an adequate cladding bond to allow later ultrasonic testing of the base metal from the inside surface. The size of cladding bond defect allowed is 0.25 inch by 0.75 inch with the greater direction parallel to the weld in the region bounded by 2T (T = wall thickness) on both sides of each full-penetration pressure boundary weld. Unbounded areas exceeding 0.442 square inches (0.75-inch diameter) in other regions are rejected.

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

- The weld-deposited clad surface on both sides of the welds to be inspected is specifically prepared to ensure meaningful ultrasonic examinations.

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

- After the shop hydrostatic testing, full-penetration ferritic pressure boundary welds (with the exception of the closure head welds), as well as the nozzles to safe end welds, are ultrasonically examined from both the inside and outside diameters in addition to ASME Code, Section III requirements.

- Preservice examinations for the closure head will include a baseline top-of-the head visual examination; ultrasonic examinations of the inside diameter surface of each vessel head penetration; eddy current examinations of the surface of head penetration welds, the outside diameter surface of the vessel penetrations, and the inside diameter surface of the penetrations; and post-hydro liquid penetrant examinations of accessible surfaces that have undergone preservice inspection eddy current examinations.

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

5.3.5 Reactor Vessel Insulation

5.3.5.1 Reactor Vessel Insulation Design Bases

Reactor vessel insulation is provided to minimize heat losses from the primary system. Nonsafety-related reflective (or suitable equivalent, as described within Subsection 6.3.2.2.7) insulation similar to that in use in current pressurized water reactors is utilized. The AP1000 reactor vessel insulation contains design features to promote in-vessel retention following severe accidents. In the unlikely event of a beyond design basis accident, the reactor cavity is flooded with water, and the reactor vessel insulation allows heat removal from core debris via boiling on the outside surface of the reactor vessel. The reactor vessel insulation permits a water layer next to the reactor vessel to promote heat transfer from the reactor vessel. This is accomplished by providing:

- A means of allowing water free access to the region between the reactor vessel and insulation.

- A means to allow steam generated by water contact with the reactor vessel to escape from the region surrounding the reactor vessel.

- The insulation support frame and the insulation panels form a structurally reliable flowpath for the water and steam.

The reactor vessel insulation and its supports are designed to withstand bounding pressure differentials across the reactor vessel insulation panels during the period that the reactor vessel is externally flooded with water and the core heat is removed from the vessel wall by water and generated steam is vented. This is accomplished by providing steam vents with a minimum flow area of 12 ft^2 from the vessel insulation annular space. The flow path from the reactor loop compartment to the reactor cavity provides an open flow path for water to flood the reactor cavity. The reactor vessel insulation water inlets are designed to minimize the pressure drop during ex-vessel cooling to permit water inflow to cool the vessel.

5.3.5.2 Description of Insulation

A schematic of the reactor vessel, the vessel insulation and the reactor cavity is shown in Figure 5.3-7. The insulation is mounted on a structural frame that is supported from the wall and floor of the reactor cavity. The insulation panels are designed to have a minimum gap between the insulation and reactor vessel not less than 2 inches when subjected to the dynamic loads in the direction towards the vessel that result during ex-vessel cooling.

The bottom portion of the vessel insulation is constructed to provide a flow channel conducive for heat removal.

The structural frame supporting the insulation is designed to withstand the bounding severe accident loads while maintaining the flow path. The fasteners holding the insulation panels to the frame are also designed for these loads.

At the bottom of the insulation are water inlet assemblies. Each water inlet assembly is normally closed to prevent an air circulation path through the vessel insulation. The inlet assemblies are self-actuating passive devices. The inlet assemblies open when the cavity is filled with water. This permits ingress of water during a severe accident, while preventing excessive heat loss during normal operation.

The total flow area of the water inlet assemblies has sufficient margin to preclude significant pressure drop during ex-vessel cooling during a severe accident. The minimum total flow area for the water inlets assemblies is 6 ft^2. Due to the relatively low approach velocities in the flow paths leading to the reactor cavity, the grating over the vertical access tunnel, the design of the doorway between the reactor coolant drain tank compartment and the reactor cavity, the low flow velocities approaching the water inlet assemblies, and the relatively large minimum flow area through each water inlet assembly, at least 7 in^2, the water inlet assemblies and the steam flow path are not susceptible to clogging from debris inside containment.

Multiple steam vents in the nozzle gallery provide a flow path for the steam/water within the reactor vessel/insulation annular space to flow back to the containment flood-up region. The steam vents provide 12 ft^2 minimum flow area for steam/water to exit the annular space. Each of the steam vents has a door that will be opened by the steam/water flow generated under the insulation with the cavity filled with water, but which remains in place when only normal air cooling flow is operating.

Extensive maintenance of the vessel insulation is not normally required. Periodic verification of the vessel insulation moving parts can be performed during refueling outages.

5.3.5.3 Description of External Vessel Cooling Flooded Compartments

Ex-vessel cooling during a severe accident is provided by flooding the reactor coolant system loop compartment including the vertical access tunnel, the reactor coolant drain tank room, and the reactor cavity. Water from these compartments replenishes the water that comes in contact with the reactor vessel and is boiled and vented to containment. The opening between the vertical access tunnel and the reactor coolant drain tank room is approximately 100 ft^2. Removable steel grating is provided over the inlet to the vertical access tunnel to restrict access to the lower compartments. This grating precludes large debris from being transported into the reactor cavity during ex-vessel cooling scenarios. Figure 5.3-8 depicts the flooded compartments that provide the water for ex-vessel cooling. The doorway between the reactor cavity compartment and the reactor coolant drain tank room consists of a normally closed door and a damper above the door. The door and damper arrangement, shown in Figure 5.3-9, maintains the proper air flow through the reactor cavity during normal operation. The damper prevents air from flowing into the reactor coolant drain tank compartment, but opens to permit flooding of the reactor cavity from the reactor coolant drain tank compartment. The damper opening has a minimum flow area of 8 ft^2 and is not susceptible to clogging from debris that can pass through the grating over the inlet to the vertical access tunnel. It is constructed of light-weight material to minimize the force necessary to open the damper and permit flooding and continued water flow through the opening during ex-vessel cooling. The damper provides an acceptable pressure drop through the opening during ex-vessel cooling.

Subsection 6.3.2.1.3 discusses post-accident operation of the passive core cooling system, which operates to flood the reactor cavity following an accident. Subsection 9.1.3 discusses the connections from the refueling cavity to the steam generator compartment that facilitate flooding of the reactor cavity following an accident.

5.3.5.4 Determination of Forces on Insulation and Support System

The forces that may be expected in the reactor cavity region of the AP1000 plant during a core damage accident in which the core has relocated to the lower head and the reactor cavity is reflooded can be based on test results from the ULPU test program (Reference 5). The particular configuration (Configuration V) reviewed closely models the full-scale AP1000 geometry of water in the region near the reactor vessel, between the reactor vessel and the reactor vessel insulation. The ULPU tests provide data on the pressure generated in the region between the reactor vessel and reactor vessel insulation. These data, along with observations and conclusions from heat transfer studies, are used to develop the functional requirements with respect to in-vessel retention for the reactor vessel insulation and support system. Interpretation of data collected from ULPU Configuration V experiments in conjunction with the static head of water that would be present in the AP1000 is used to estimate forces acting on the rigid sections of insulation. The ULPU V test results indicate that the pressure variations in the flow channel between the vessel and the insulation are on the order of plus/minus 0.5 meters of water. Fast Fourier Transform analysis of the ULPU V pressure data is also included in the ULPU V test report. This analysis shows that the dominant frequency of the pressure variations is less than about 2 Hz. The natural frequency of the insulation structure is expected to be well above 2 Hz.

5.3.5.5 Design Evaluation

A structural analysis of the AP1000 reactor cavity insulation system was performed that demonstrates that it meets the functional requirements discussed above. The analysis encompasses the insulation and support system and includes a determination of the stresses in support members, bolts, insulation panels and welds, as well as deflection of support members and insulation panels.

Loads on the insulation and the support structure include hydrostatic loads and dynamic loads from boiling. These loads are of the same order as those analyzed for AP600, and the results of the

AP1000 analysis show that the insulation is able to meet its functional requirements. The reactor vessel insulation provides an engineered pathway for water-cooling the vessel and for venting steam from the reactor cavity. These results were also compared to the available test data.

The reactor vessel insulation is purchased equipment. The purchase specification for the reactor vessel insulation design required confirmatory static load analyses.

5.3.6 Combined License Information

5.3.6.1 Pressure-Temperature Limit Curves

The pressure-temperature curves shown in Figures 5.3-2 and 5.3-3 have been substantiated as the curves for VEGP 3&4 reactor vessel design, and they are the limiting curves based on copper and nickel material composition.

5.3.6.2 Reactor Vessel Materials Surveillance Program

The reactor vessel reactor material surveillance program is addressed in Subsections 5.3.2.6 and 5.3.2.6.3.

5.3.6.3 Surveillance Capsule Lead Factor and Azimuthal Location Confirmation

The surveillance capsule lead factors and azimuthal locations are addressed in APP-GW-GLR-023 (Reference 7), and the applicable changes are incorporated into the UFSAR.

5.3.6.4 Reactor Vessel Materials Properties Verification

5.3.6.4.1 The verification of plant-specific belt line material properties consistent with the requirements in Subsection 5.3.3.1 and Tables 5.3-1 and 5.3-3 will be completed prior to fuel load. The verification will include a pressurized thermal shock evaluation based on as procured reactor vessel material data and the projected neutron fluence for the plant design objective of 60 years. This evaluation report will be submitted for NRC staff review.

5.3.6.4.2 The structural analysis of the AP1000 reactor vessel insulation and support structure is addressed in APP-GW-GLR-060 (Reference 8), and the applicable changes are incorporated into the UFSAR.

5.3.6.5 Reactor Vessel Insulation

The verification that the reactor vessel insulation is consistent with the design bases established for in-vessel retention is addressed in Reference 8 (APP-GW-GLR-060).

5.3.6.6 Inservice Inspection of Reactor Vessel Head Weld Buildup

The inservice inspection program of the weld buildup on the reactor vessel head for the instrumentation penetrations (Quickloc) is addressed in Subsection 5.2.4.1.

5.3.7 References

1. ASTM E-185-82, “Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels.”

2. Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” United States Nuclear Regulatory Commission, Office of Nuclear Reactor Research, March, 2001.

3. WCAP-15557, “Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology,” S. L. Anderson, August 2000.

4. NRC Policy Issue, “Pressurized Thermal Shock,” SECY-82-465, November 23, 1982.

5. Theofanous, T.G., et al., “Limits of Coolability in the AP1000-Related ULPU-2400 Configuration V Facility,” CRSS-03/06, June 2003.

6. WCAP-14040-NP-A, Revision 4, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” May 2004.

7. APP-GW-GLR-023, “Surveillance Capsule Lead Factor and Azimuthal Location Confirmation,” Westinghouse Electric Company LLC.

8. APP-GW-GLR-060, “Reactor Vessel Insulation System – Verification of In-Vessel Retention Design Bases,” Westinghouse Electric Company LLC.

9. APP-RXS-Z0R-001, Revision 3, “AP1000 Generic Pressure Temperature Limits Report,” April 2018.

10. Vogtle Electric Generating Plant (VEGP) Unit 3 Pressure and Temperature Limits Report (PTLR), Rev. 0.

11. Vogtle Electric Generating Plant (VEGP) Unit 4 Pressure and Temperature Limits Report (PTLR), Rev. 0.

12. SV0-RXS-GLR-001, Validation of the AP1000 Pressure-Temperature Limits Report (PTLR) for Use at Vogtle Units 3 and 4.

Table 5.3-1
Maximum Limits for Elements of the Reactor Vessel

Element	Beltline Forging (percent)	As Deposited Weld Metal (percent)
Copper	0.06	0.06
Phosphorus	0.01	0.01
Vanadium	0.05	0.05
Sulfur	0.01	0.01
Nickel	0.85	0.85

Table 5.3-2
Reactor Vessel Quality Assurance Program

	RT[a]	UT[a]	PT[a]	MT[a][b]
Forgings				
Flanges		Yes		Yes
Studs and nuts		Yes		Yes
CRDM latch housing nozzle		Yes	Yes	
Quickloc instrument nozzle (QIN)		Yes	Yes	
Main nozzles		Yes		Yes
Nozzle safe ends		Yes	Yes	
Shell sections		Yes		Yes
Heads		Yes		Yes
Plates		Yes		Yes
Weldments				
Head and shell	Yes	Yes		Yes
CRDM latch housing nozzle to closure head connection			Yes	
QIN to QIN weld buildup connection	Yes	Yes	Yes	
QIN weld buildup		Yes		Yes
Main nozzle	Yes	Yes		Yes
Cladding		Yes	Yes	
Nozzle to safe ends	Yes	Yes	Yes	
All full-penetration ferritic pressure boundary welds accessible after hydrotest		Yes		Yes
Full-penetration nonferritic pressure boundary welds accessible after hydrotest a. Nozzle to safe ends		Yes	Yes	
Seal ledge				Yes
Head lift lugs				Yes
Core pad welds			Yes	
Flow skirt support lugs weld buildup		Yes	Yes	

Notes:

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

b. Dye penetrant (PT) examination may be used in lieu of magnetic particle (MT) examination in accordance with Subsection 5.3.2.3.3.

Base metal weld repairs as a result of UT, MT, RT, and/or PT indications are cleared by the same nondestructive examination technique/procedure by which the indications were found. The repairs meet applicable Section III requirements.

In addition, UT examination in accordance with the in process/posthydro UT requirements is performed on base metal repairs in the core region and base metal repairs in the inservice inspection zone (1/2 T).

Table 5.3-3
End-of-Life RT_{NDT} and Upper Shelf Energy Projections

	Unirradiated		End-of-life (54 EFPY)	
	RT_{NDT} (°F)	**USE (ft-lb)**	**USE (ft-lb) 1/4T**	**RT_{PTS} (°F)**
Beltline Forging	-10	> 75	> 50	< 270(2)
Head	10	N/A	N/A	N/A
Flange	10	N/A	N/A	N/A
Weld	10	N/A	N/A	N/A
Beltline Weld	-20	> 75	> 50	< 300(2)

Notes:

1. The minimum unirradiated upper shelf energy for beltline base metal is for the transverse direction.
2. End-of-Life RT_{PTS} requirements shown. End-of-Life RT_{PTS} (also equals RT_{NDT}) will be determined for as-built material. The preliminary RT_{PTS} for the AP1000 reactor vessel beltline forging and beltline weld are 94°F and 148°F, respectively.

Table 5.3-4
Reactor Vessel Material Surveillance Program

Capsules S, T, U, V, W, X, Y, and Z			
Material	**Charpy Specimens**	**Tensile Specimens**	**1/2T-CT Specimens**
Forging (tangential)	15	3	2
Forging (axial)	15	3	2
Weld Metal	15	3	2
Heat Affected Zone (HAZ)	15	–	–

Table 5.3-5
Reactor Vessel Design Parameters

(approximate values)	
Design pressure (psig)	2485
Design temperature (°F)	650
Overall height of vessel and closure head, bottom head outside diameter to the control rod drive mechanism rod position indicator mating surface	45-9
Number of reactor closure head studs	45
Diameter of reactor closure head/studs, (in.)	7
Outside diameter of closure head flange (in.)	188
Inside diameter of flange (in.)	148.81
Outside diameter at shell (in.)	176
Inside diameter at shell (in.)	159
Inlet nozzle inside diameter (in.)	22
Outlet nozzle inside diameter (in.)	31
Clad thickness, nominal (in.)	0.22
Lower head thickness, minimum (in.)	6
Vessel beltline thickness, minimum (in.)	8
Closure head thickness (in.)	6.25

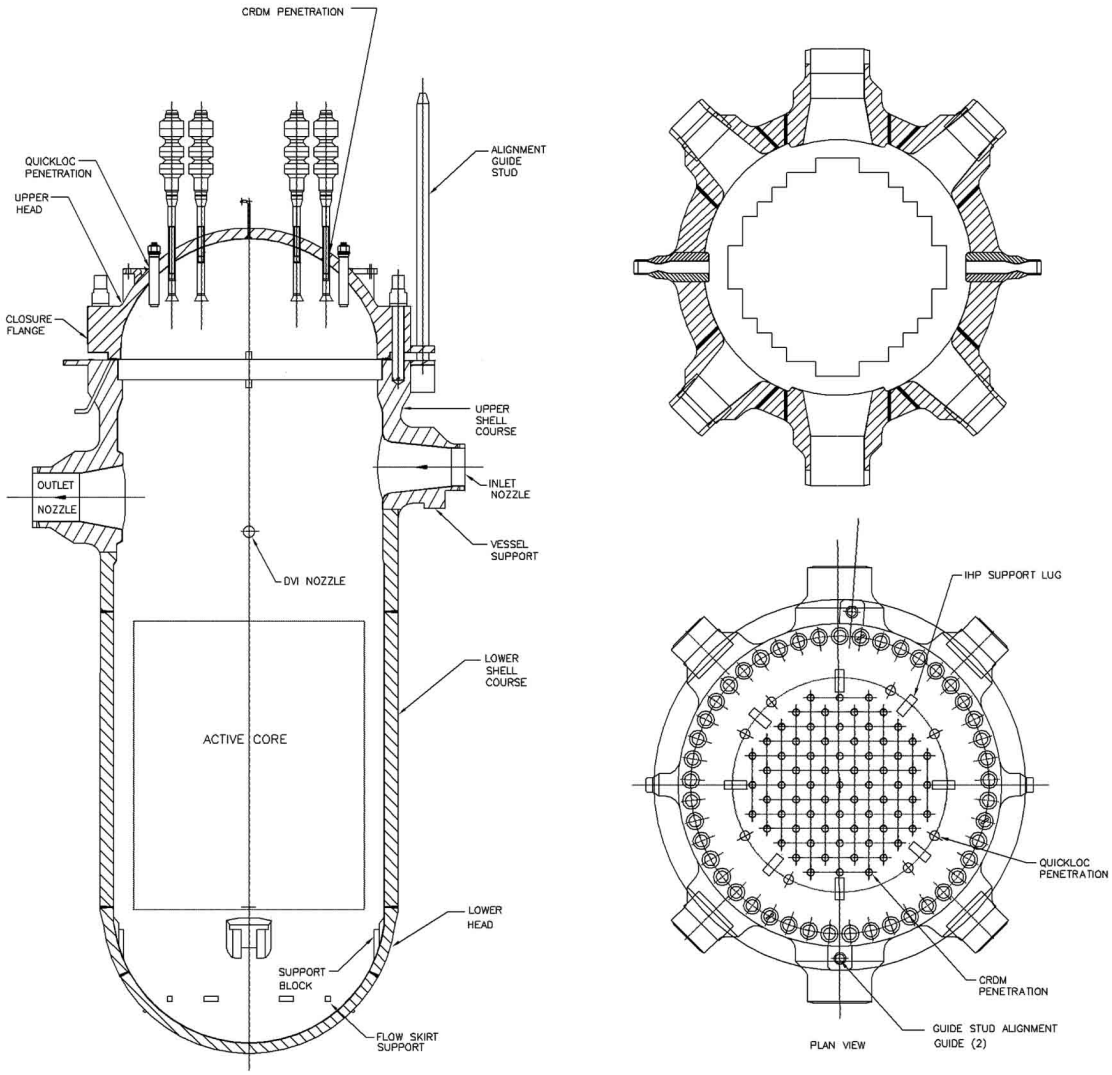


Figure 5.3-1
Reactor Vessel

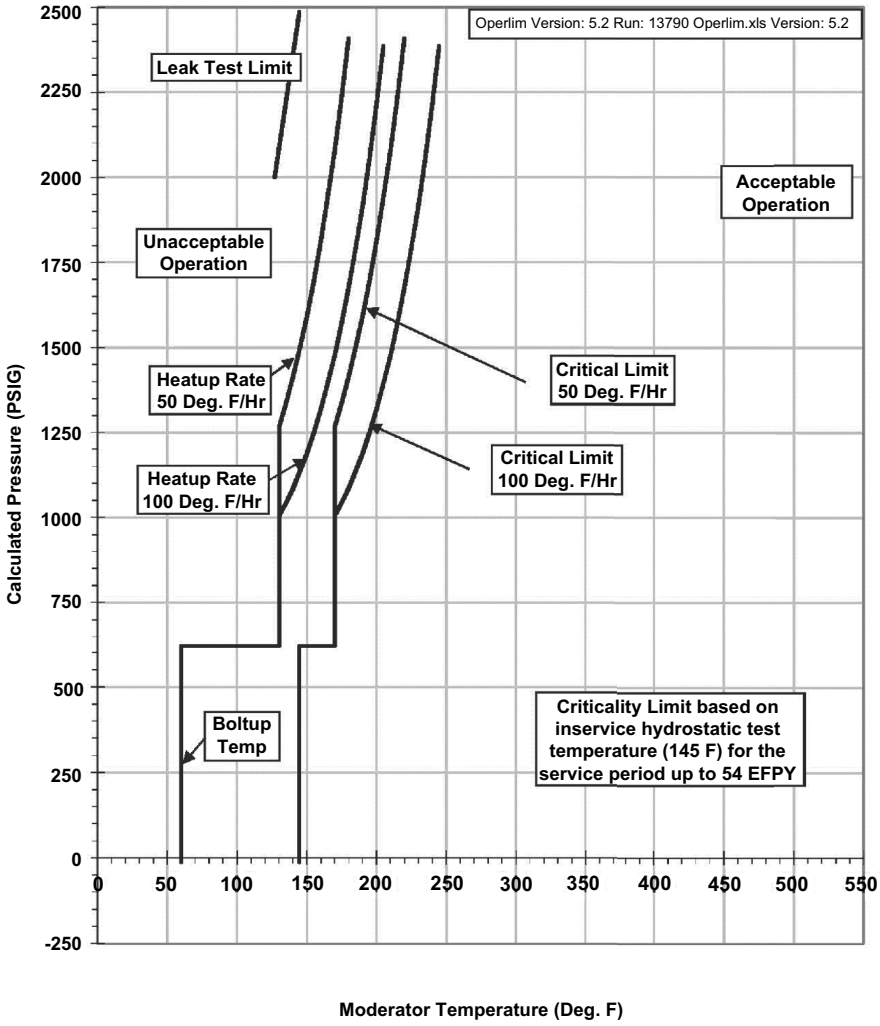


Figure 5.3-2
AP1000 Reactor Coolant System Heatup Limitations (Heatup Rate Up to 50° and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)

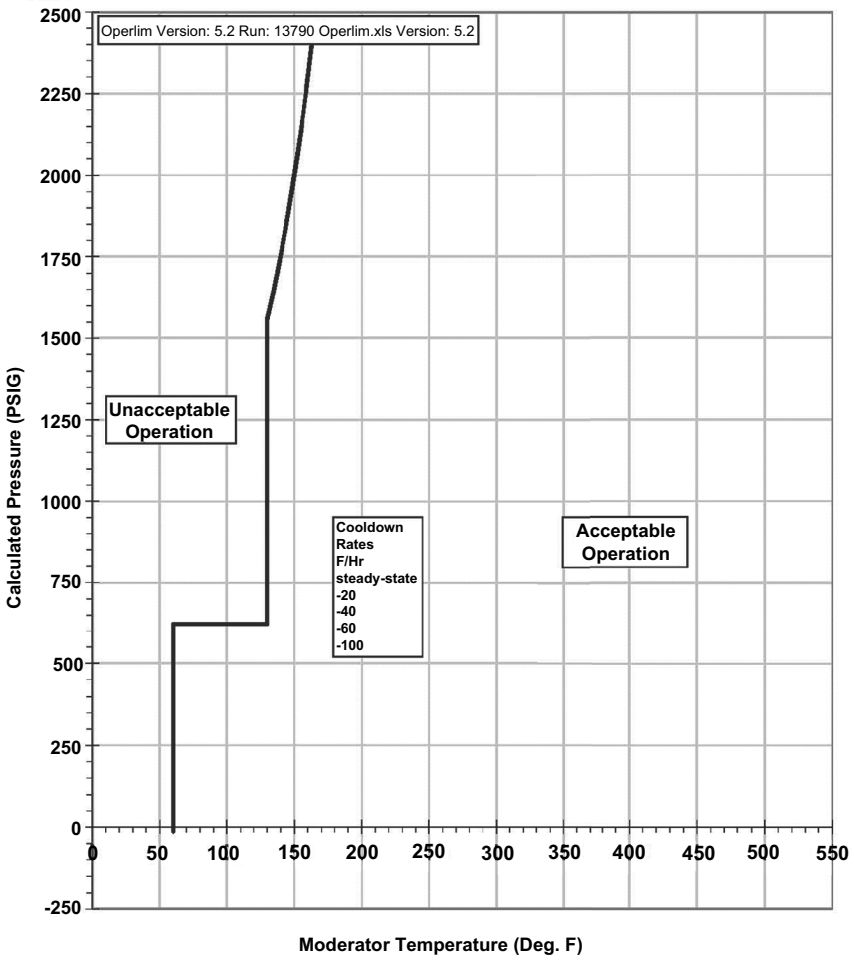


Figure 5.3-3
AP1000 Reactor Coolant System Cooldown Limitations (Cooldown Rates up to 50° and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)

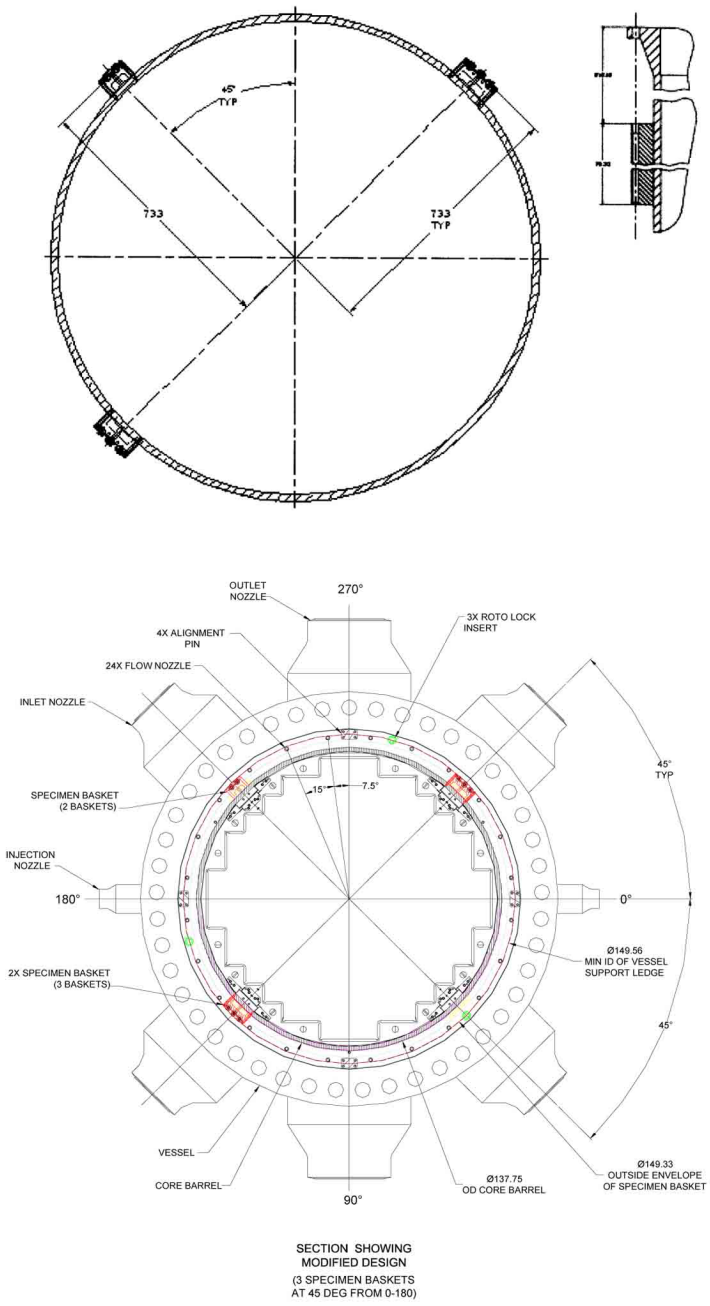


Figure 5.3-4
AP1000 Reactor Vessel Surveillance Capsules Locations

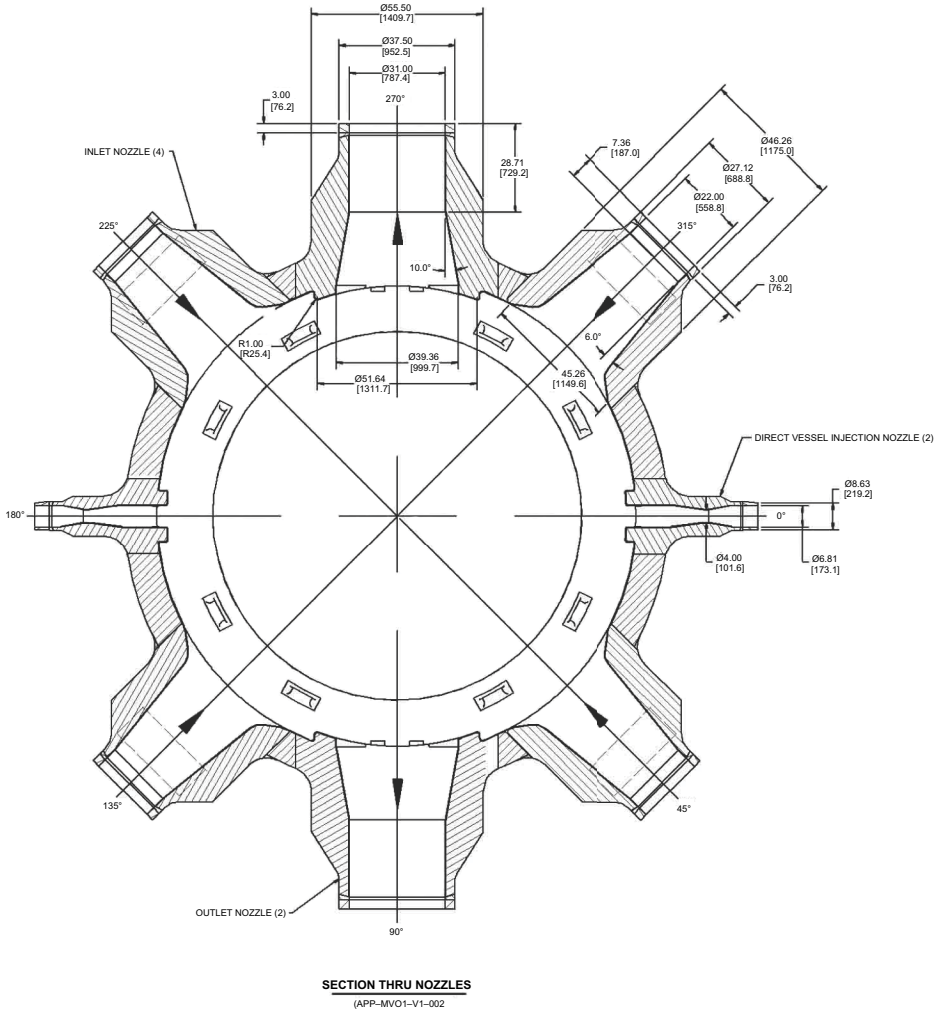


Figure 5.3-5
Reactor Vessel Key Dimensions
Plan View

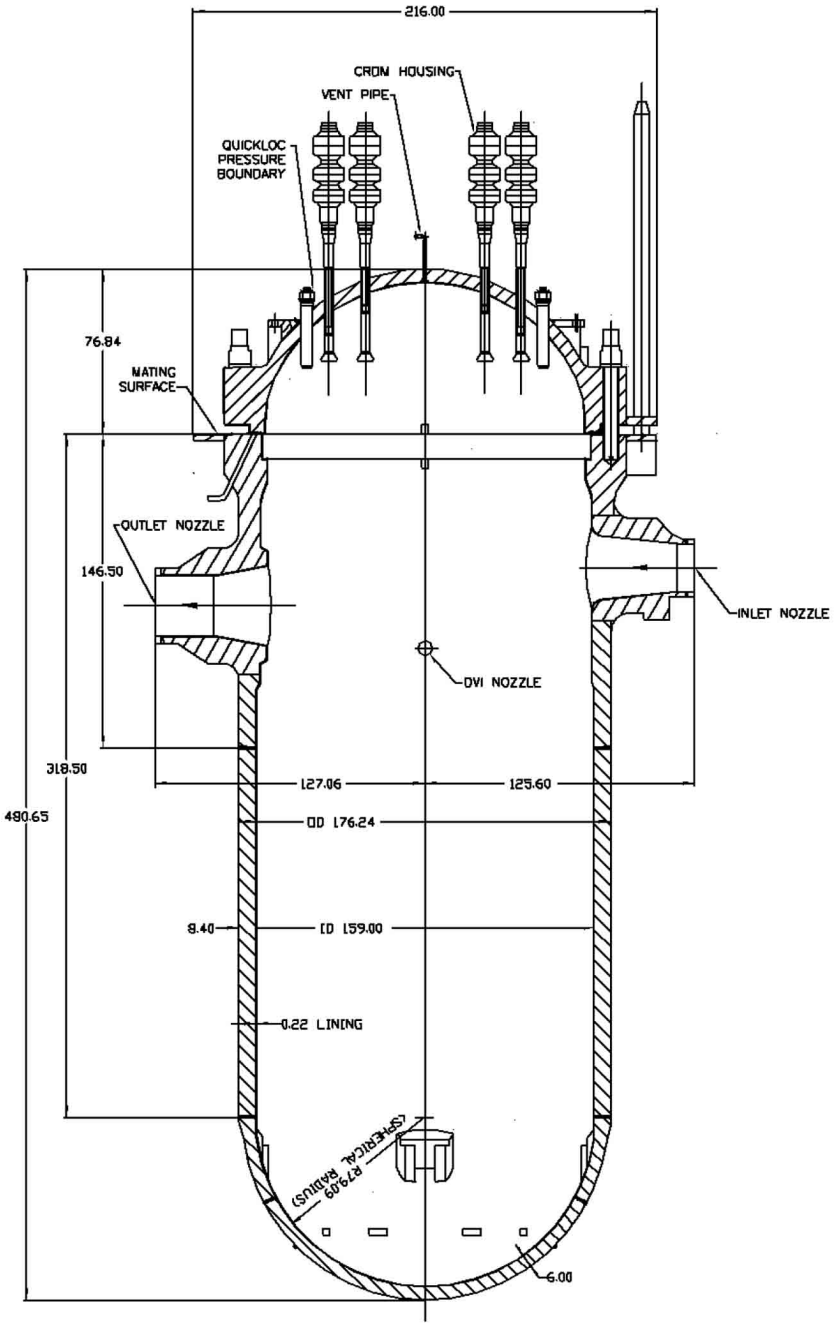


Figure 5.3-6
Reactor Vessel Key Dimensions, Side View

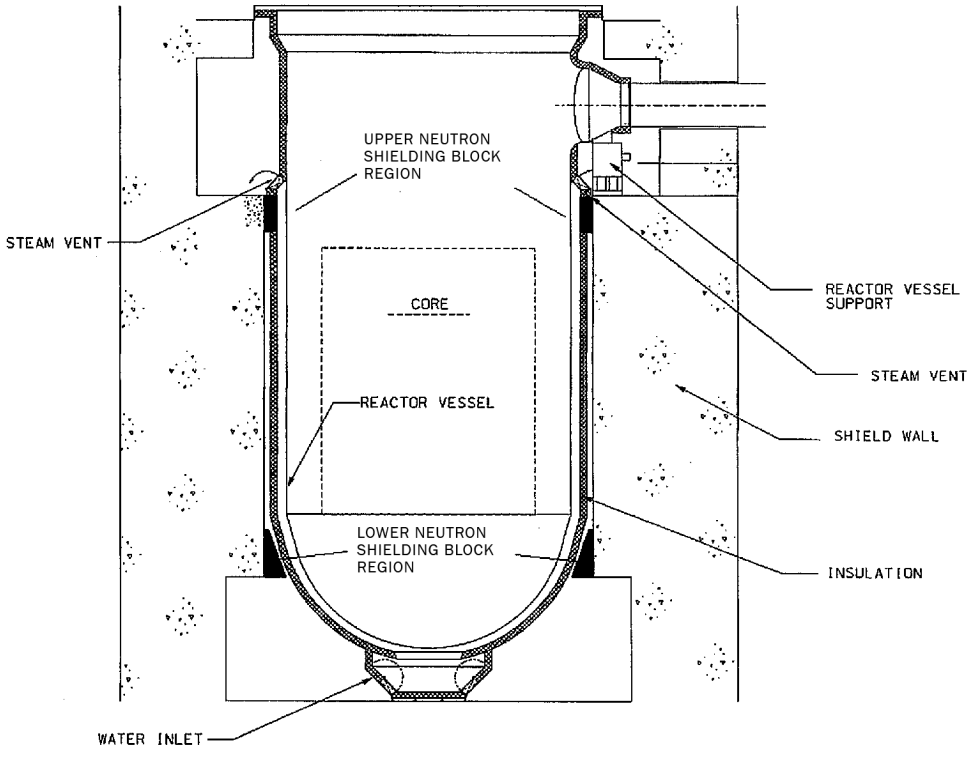


Figure 5.3-7
Schematic of Reactor Vessel Insulation

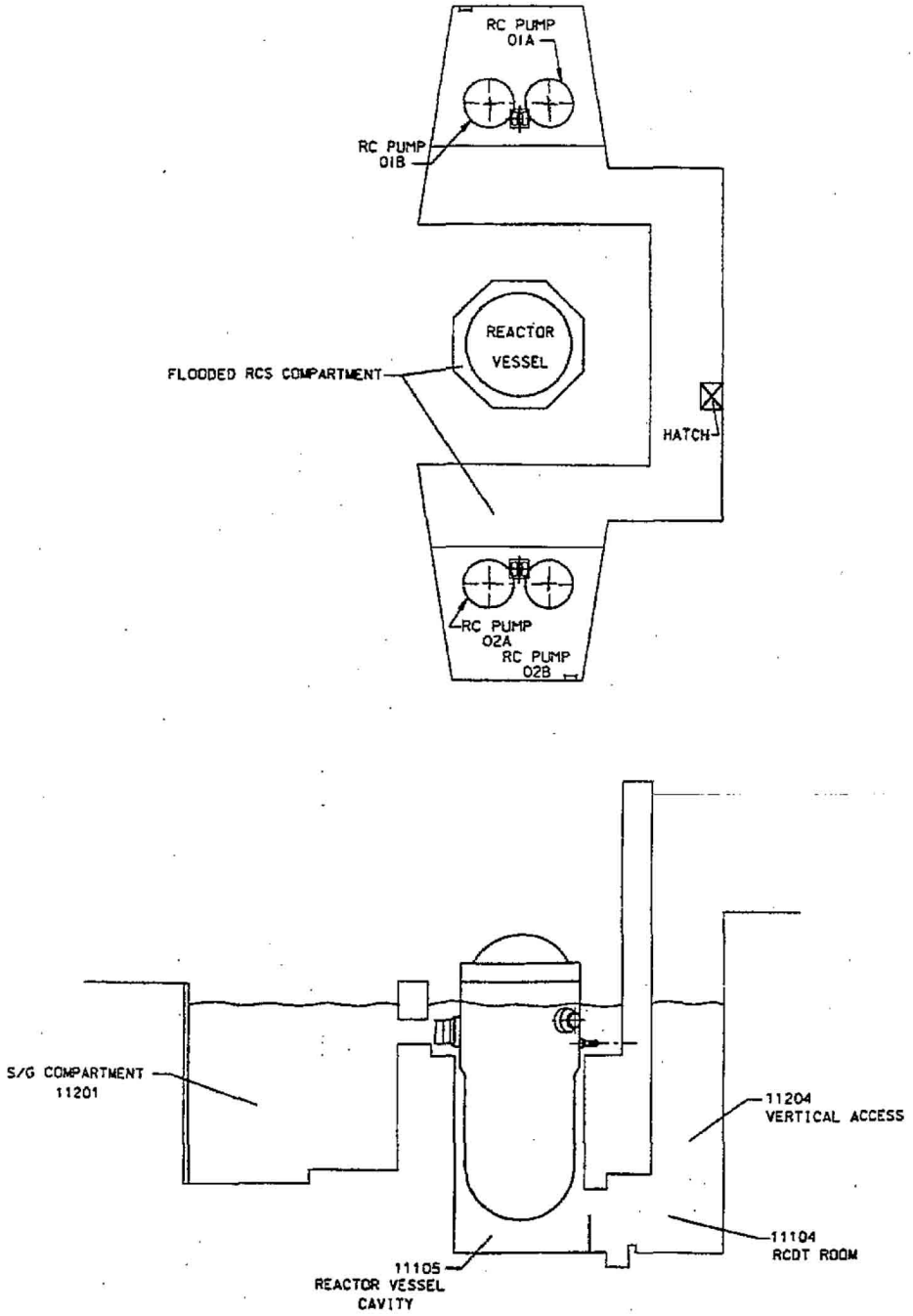


Figure 5.3-8
RCS Flooded Compartments During Ex-Vessel Cooling

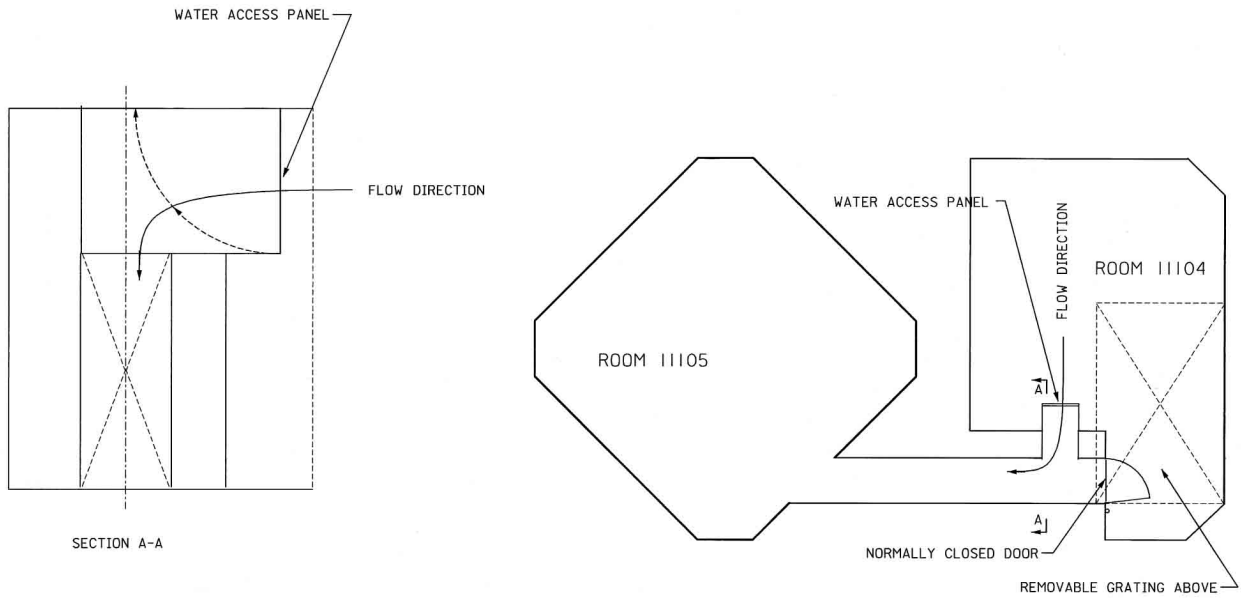


Figure 5.3-9
Door Between RCDT Room and Reactor Cavity Compartment

5.4 Component and Subsystem Design

5.4.1 Reactor Coolant Pump Assembly

5.4.1.1 Design Bases

The reactor coolant pump (RCP) is an integral part of the reactor coolant pressure boundary. It is designed, fabricated, erected, and tested to quality standards consistent with the requirements set forth in 10 CFR 50, 50.55a and General Design Criterion 1. The reactor coolant pump casing and stator shell provide a barrier to the release of reactor coolant and other radioactive materials to the containment atmosphere.

The reactor coolant pump provides an adequate core cooling flow rate for sufficient heat transfer to maintain a departure from nucleate boiling ratio (DNBR) greater than the limit established in the safety analysis. Pump assembly rotational inertia is provided by a flywheel (inside the pump pressure boundary) motor rotor, and other rotating parts. This rotational inertia provides flow during coastdown conditions. This forced flow following an assumed loss of electrical power and the subsequent natural circulation effect in the reactor coolant system (RCS) adequately cools the core. The net positive suction head (NPSH) required for operation is by conservative pump design always less than that available by system design and operation.

The reactor coolant pump pressure boundary shields the balance of the reactor coolant pressure boundary from theoretical worst-case flywheel failures. The reactor coolant pump pressure boundary is analyzed to demonstrate that a fractured flywheel cannot breach the reactor coolant system boundary (impacted pressure boundary components are stator closure, stator main flange, and lower stator flange) and impair the operation of safety-related systems or components. This meets the requirements of General Design Criteria 4. The reactor coolant pump flywheel is designed, manufactured, and inspected to minimize the potential for the generation of high-energy fragments (missiles) under any anticipated operating or accident condition consistent with the intent of the guidelines set forth in Standard Review Plan Subsection 5.4.1.1 and Regulatory Guide 1.14. Each flywheel is tested at an overspeed condition to verify the flywheel design and construction.

5.4.1.2 Pump Assembly Description

5.4.1.2.1 Design Description

[*The reactor coolant pump is a single-stage, hermetically sealed, high-inertia, centrifugal sealless pump of canned motor design.*]* It pumps large volumes of reactor coolant at high pressures and temperature. Figure 5.4-1 shows a reactor coolant pump. Table 5.4-1 gives the design parameters.

A reactor coolant pump is directly connected to each of two outlet nozzles on the steam generator channel head. The two pumps on a steam generator turn in the same direction.

A sealless pump contains the motor and all rotating components inside a pressure vessel. The pressure vessel consists of the pump casing, stator closure, stator main flange, stator shell, stator lower flange, and stator cap, which are designed for full reactor coolant system pressure. In a canned motor pump, the stator and rotor are encased in corrosion-resistant cans that prevent contact of the rotor bars and stator windings by the reactor coolant. Because the shaft for the impeller and rotor is contained within the pressure boundary, seals are not required to restrict leakage out of the pump into containment. The connection between the pump casing and the stator closure is provided with a welded canopy type seal assembly, which provides definitive leak protection for the pump closure. Access to the internals of the pump and motor is by severing the canopy seal weld. When the pump is reassembled, a canopy seal is rewelded. Canned motor reactor coolant pumps have a long history of safe, reliable performance in military and commercial nuclear plant service.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The reactor coolant pump driving motor is a vertical, water-cooled, squirrel-cage induction motor with a canned rotor and stator. It is designed for removal from the casing for inspection, maintenance, and replacement, if required. The stator can protects the stator (windings and insulation) from the controlled portion of the reactor coolant circulating inside the motor and bearing cavity. The can on the rotor isolates the copper rotor bars from the system and minimizes the potential for the copper to plate out in other areas.

The motor is cooled by primary reactor coolant system coolant circulating through the motor cavity and by component cooling water circulating through a cooling jacket on the outside of the motor housing. Primary coolant used to cool the motor enters the lower end of the rotor and passes axially through the motor cavity to remove heat from the rotor and stator. An auxiliary impeller provides the motive force for circulating the coolant. Heat from the primary coolant is transferred to component coolant water in an external heat exchanger.

Each pump motor is driven by a variable speed drive, which is used for pump startup and operation when the reactor trip breakers are open. When the reactor trip breakers are closed, the variable frequency drives are bypassed and the pumps run at constant speed.

Flywheel assemblies provide rotating inertia that increases the coastdown time for the pump. Each flywheel assembly is of bi-metallic design consisting of a tungsten heavy metal alloy for mass with Type 403 stainless steel and 18Mn-18Cr alloy steel structural components. The upper flywheel assembly is located between the motor and pump impeller. The lower assembly is located below the canned motor, with the thrust bearing. Surrounding the flywheel assemblies are the heavy walls of the stator closure, casing, thermal barrier, or stator lower flange.

The materials in contact with the reactor coolant and cooling water (with the exception of the bearing material) are austenitic stainless steel, nickel-chromium-iron alloy, or equivalent corrosion-resistant material.

There are two journal bearings, one at the bottom of the rotor shaft and the other between the upper flywheel assembly and the motor. The bearings are a hydrodynamic film-riding design. During rotor rotation, a thin film of water forms between the journal and pads, providing lubrication.

The thrust bearing assembly is at the bottom of the rotor shaft. The pivoted pad hydrodynamic bearing provides positive axial location of the rotating assembly regardless of operating conditions.

The reactor coolant pump is equipped with a vibration monitoring system that continuously monitors pump structure (frame) vibrations. Five vibration monitors provide pump vibration information. The readout equipment includes warning alarms and high-vibration level alarms, as well as output for analytical instruments.

Four resistance temperature detectors (RTDs) monitor motor cooling circuit water temperature. These detectors provide indication of anomalous bearing or motor operation, as well as leakage through the pump labyrinth seal into the stator cavity as a result of a leak in the pump external heat exchanger. They also provide a system for automatic shutdown in the event of a prolonged loss of component cooling water or a large tube leak from the external heat exchanger into the CCS.

A speed sensor monitors rotor rpm’s. Additionally, voltage and current sensors provide information on motor load and electrical input.

5.4.1.2.2 Description of Operation

Reactor coolant is pumped by the main impeller. It is drawn through the eye of the impeller and discharged via the diffuser out through the radial discharge nozzle in the side of the casing. Once the

motor housing is filled with coolant, the labyrinth seals around the shaft between the impeller and the thermal barrier minimize the flow of coolant into the motor during operation.

An auxiliary impeller at the lower part of the rotor shaft circulates a controlled volume of the primary coolant through the motor cavity and external heat exchanger. The coolant is cooled to about 150°F by component cooling water circulating on the shell side of the external heat exchanger. The cooled reactor coolant then passes through the motor cavity, where it removes heat from the rotor and stator and lubricates the motor's hydrodynamic bearings.

The variable frequency drives enable the startup of the reactor coolant pumps at slow speeds to decrease the power required from the pump motor during operation at cold conditions. The variable frequency drive provides operational flexibility during pump startup and reactor coolant system heatup. During a plant startup, the general startup procedure for the pumps is for the operator to start the pumps at a low speed. During reactor coolant system heatup, the pumps are run at the highest speed that is within the allowable motor current limits. As the reactor coolant temperature increases, the allowable pump speed also increases. Before the reactor trip breakers are closed, the variable frequency controllers are bypassed and the pumps run at constant speed.

During all power operations (Modes 1 and 2), the variable frequency drives are bypassed and the pumps run at constant speed.

5.4.1.3 Design Evaluation

5.4.1.3.1 Pump Performance

The reactor coolant pump is sized to deliver a flow rate that equals or exceeds the required flow rate. Testing prior to plant startup confirms the total delivery capability of the reactor coolant pump. See Section 14.2. Thus, adequate forced circulation coolant flow is confirmed prior to initial plant operation.

The required net positive suction head is provided with ample margin to provide operational integrity and minimize the potential for cavitation. The AP1000 does not require reactor coolant pump operation to achieve safe shut down. Minimum net positive suction head requirements are not required to provide safe operation of the AP1000.

5.4.1.3.2 Overspeed Conditions

Reactor coolant pump overspeed can be postulated for either a fault in the connected electrical system that results in an increase in the frequency of the supplied current or due to a pipe rupture which results in an increase in the flow through the pump as the coolant exits the pipe.

For grid disconnect transients or turbine trips actuated by either the reactor trip system or the turbine protection system, the turbine overspeed control system acts to limit the reactor coolant pump overspeed. The turbine control system acts to rapidly close the turbine governor and intercept valves.

An electrical fault requiring immediate generator trip (with resulting turbine trip) will result in an overspeed condition in the electrically coupled reactor coolant pump no greater than that described previously for the grid disconnect/turbine trip transient.

Pump overspeed from high coolant flow rates associated with pipe rupture events are mitigated by the inertia of the pump, flywheel, and motor and by the connection of the motor to the electrical grid. Because of the application of mechanistic pipe break criteria, dynamic effects such as pump overspeed are not evaluated for breaks in piping in which leak-before-break is demonstrated.

5.4.1.3.3 Pressure Boundary Integrity

The pressure boundary integrity is verified for normal, anticipated transients, and postulated accident conditions. The pressure boundary components (pump casing, stator closure, stator main flange, stator shell, stator lower flange, stator cap, and external piping and tube side of the external heat exchanger) meet the requirements of the ASME Boiler and Pressure Vessel Code, Section III. These components are designed, analyzed, and tested according to the requirements in Paragraph NB-3400 of the ASME Code, Section III. Wells provided for resistance temperature detectors and a phase reference sensor, and speed sensor penetrations also satisfy the requirements of the ASME Code, Section III.

The motor terminals form part of the pressure boundary in the event of a stator-can failure. The ASME Code does not include criteria or methods for completely designing or analyzing such terminals. Motor terminals are designed, analyzed, and tested using criteria established and validated based on many years of service. Where applicable, ASME Code requirements and criteria are used. Individual terminals are hydrostatically tested to test the integrity prior to performance testing.

5.4.1.3.4 Coastdown Capability

It is important to reactor protection that the reactor coolant continues to flow for a time after reactor trip and loss of electrical power. To provide this flow, each reactor coolant pump has a high-density flywheel and high-inertia rotor. The rotating inertia of the pump, motor, and flywheel is used during the coastdown period to continue the reactor coolant flow. The reactor coolant pump is designed for the safe shutdown earthquake. The coastdown capability of the pump is maintained even for the case of loss of offsite and onsite electrical power coincident with the safe shutdown earthquake. Core flow transients and figures are provided in Subsections 15.3.1 and 15.3.2.

A loss of component cooling water has no impact on coastdown capability. The reactor coolant pump can operate without cooling water until a reactor coolant pump trip occurs on High-2 bearing water temperature. This prevents damage that could potentially affect coastdown.

The reactor trip system maintains the pump operation within the assumptions used for loss of coolant flow analyses. This also provides that adequate core cooling is provided to permit an orderly reduction in power if flow from a reactor coolant pump is lost during operation.

The reactor coolant pump coastdown occurs on a power loss to the plant. The following conditions are assumed to occur simultaneously:

- Reactor coolant system at normal operation temperature and pressure,
- Loss of cooling water,
- Loss of pump power,
- Reactor trip

If the stator can should leak during operation, the reactor coolant may cause a short in the stator windings. In such a case, the result would be the same as a loss of power to that pump. With either a rotor or a stator can failure, no fluid would be lost to the containment.

5.4.1.3.5 Bearing Integrity

The design requirements for the reactor coolant pump bearings provide long life with negligible wear. The vibration warning level and high-vibration level alarm set-points are, in part, based on evaluation of the effect of vibration on bearing life.

The bearings provide adequate stiffness to control shaft motion, protect the pump impeller and shaft labyrinths from wear, and avoid contact between the motor stator and rotor. The bearing loads are maintained within the load capabilities of hydrodynamic journal bearings even under the severe conditions experienced during seismic events. The bearing/shaft design and loadings are established by analysis and testing.

The frame vibration detectors provide indication of bearing performance. Control room indicators and alarms provide indication for operator action.

The bearing cooling provisions include a temperature monitoring system. The system operates continuously and has at least four redundant indicators per pump. Upon initiation of failure, the system indicates and alarms in the control room as a high bearing water temperature. All of the pumps trip when the High-2 temperature setpoint is reached.

5.4.1.3.6 Integrity of Rotating Components

The rotating components of the pump and motor are analyzed for dynamic characteristics, including natural frequencies, stability, and forced responses to normal operation loads, and for several postulated fault conditions associated with the rotating masses. The fault conditions include seized rotor events, and integrity of the rotating components, including the flywheel.

5.4.1.3.6.1 Natural Frequency and Critical Speeds

The damped natural frequency of the reactor coolant pump rotating assembly is greater than 120 percent of the normal operating speed.

Determination of the damped natural frequency of the reactor coolant pump rotor bearing system model includes the effects of the bearing films, can annular fluid interaction, motor magnetic phenomena, and pump structure. The damped natural frequencies for the AP1000 reactor coolant pump exhibit sufficient energy dissipation to be stable. The high degree of damping provides smooth pump operation.

The pump is analyzed for the response of the rotor and stator to external forcing functions. The support and connection of the pump to the steam generator and piping are considered in the analysis. The responses are evaluated using criteria including critical loads, stress deformation, wear, and displacement limits to establish the actual system critical speeds.

5.4.1.3.6.2 Rotor Seizure

The design of the pump is such as to preclude the instantaneous stopping of any rotating component of the pump or motor. The rotating inertia and power supplied to the motor would overcome interference between the impeller, bearings, flywheel assemblies, motor rotor, or rotor can and the surrounding components for a period of time. A change in the condition of any of the components sufficient to cause an interference would be indicated by the instrumentation monitoring speed, vibration, temperature, or current.

The reactor coolant system and reactor coolant pump are analyzed for a locked rotor event. To analyze the mechanical and structural effects of a rapid slow down of the rotating assembly, a failure

of the rotating assembly is postulated that results in deformation that causes an interference with the surrounding reactor coolant pump components. For such an interference, the pump and motor are postulated to come to a complete stop in a very short time period. This assumption bounds other postulated mechanisms for a rapid slowdown of the rotor, including impeller rub and rotor or stator can failure. The connection of the pump with the steam generator and discharge piping is analyzed for the vibration of the pump, hydraulic effects, and the torque due to the rapid slow down of the rotating assembly. The stresses in the pump casing, motor housing, steam generator channel head, and piping are analyzed using ASME Code, Section III, Service Level D limits for this condition.

The transient analysis of thermal and hydraulic effects of a postulated locked rotor event is based on a nonmechanistic, instantaneous stop of the impeller. This conservative assumption bounds any slower stop and provides a comparison with the same analysis done for other nuclear power plants. The transient analysis considers the effect of the locked rotor on the reactor core and the reactor coolant system pressure. The results of the transient analysis are found in Subsection 15.3.3 and show that the peak reactor coolant system pressure does not exceed the licensed safety analysis RCS pressure limit.

5.4.1.3.6.3 Flywheel Integrity

The reactor coolant pump in the AP1000 complies with the requirement of General Design Criterion (GDC) Number 4. That Criterion states that components important to safety be protected against the effects of missiles.

The flywheel assemblies are located within and surrounded by the heavy walls of the stator closure, stator main flange, casing, thermal barrier, or lower stator flange. In the event of a postulated worst-case flywheel assembly failure, the surrounding structure can, by a large margin, contain the energy of the fragments without causing a rupture of the pressure boundary. The analysis in Reference 10 of the capacity of the housing to contain the fragments of the flywheel is done using the energy absorption equations of Hagg and Sankey (Reference 2).

Compliance with the requirement of GDC 4 related to missiles can be demonstrated without reference to flywheel integrity, nevertheless, the intent of the guidelines of Regulatory Guide 1.14 is followed in the design and fabrication of the flywheel. The guidelines in Regulatory Guide 1.14 apply to steel flywheels. Since the bi-metallic design of the AP1000 reactor coolant pump flywheel does not respond in the same manner as homogeneous steel, many of the guidelines in the Regulatory Guide are not directly applicable.

The reactor coolant pump flywheel assemblies are fabricated from a tungsten heavy alloy, Type 403 stainless steel, and 18Mn-18Cr alloy steel (ASTM A289, Grade 8). Heavy alloy segments (ASTM B777, Class 4) are fitted to a stainless steel hub modified (ASTM A336, Grade F6); these segments are not relied upon structurally. The modifications to the ASTM A336, Grade F6 specification consist of allowing slightly more carbon and sulfur content. The segments are held into place by an interference fit retainer cylinder of 18Mn-18Cr alloy steel placed over the outside of the assembly. The assembly is hermetically sealed from primary coolant by endplates and an outer thin shell of Alloy 625. Ni/Fe/Cr Alloy 600 base material is not used in the flywheel assembly; however, Alloy 600 type weld filler material may be used for welds on the thin Alloy 625 enclosure.

The bi-metallic flywheel design will be manufactured using multiple processes and materials. In accordance with Regulatory Guide 1.14, each structural component of the bi-metallic flywheel will be inspected prior to final assembly according to its fabrication and the procedures outlined below. The Type 403 stainless steel inner hub material will be subject to impact testing using one Charpy V-notch test (three specimens) in accordance with Section III, NB-2300 of the ASME Code, magnetic particle examination, and ultrasonic examination in accordance with Section III, NB-2500 of the ASME Code. The retainer ring will be subject to one Charpy V-notch test (three specimens) per material

specification ASTM A289, Supplemental Requirement S1, liquid penetrant examination, and ultrasonic examination in accordance with Section III, NB-2500 of the ASME Code. Following finishing operations on the flywheel assembly, the outside circumference of the retainer ring and the inside surface of the inner hub are subject to liquid penetrant inspections in accordance with Section III, NB-2500 of the ASME Code.

The design speed of the flywheel is defined as 125 percent of the synchronous speed of the motor. The design speed envelopes all expected overspeed conditions. At the normal speed the calculated maximum primary stress in the flywheel assemblies is less than one third of minimum yield strength. At the design speed the calculated maximum primary stress in the flywheel assemblies is less than two thirds of minimum yield strength.

An analysis of the flywheel failure modes of ductile failure, nonductile failure and excessive deformation of the flywheel is performed to evaluate the flywheel design. The analysis is performed to determine that the critical flywheel failure speeds, based on these failure modes, are greater than the design speed. The critical flywheel failure speeds are not the same as the critical speed identified for the rotor. The critical flywheel failure speeds are greater than the design speed. The overspeed condition for a postulated pipe rupture accident is less than the critical flywheel failure speeds.

The flywheel assemblies are sealed within a welded nickel-chromium-iron alloy enclosure to prevent contact with the reactor coolant or any other fluid. The enclosure minimizes the potential for corrosion of the flywheel and contamination of the reactor coolant. The enclosure material specifications are ASTM-B-443 and ASTM-B-564. Even though the welds of the flywheel enclosure are not external pressure boundary welds, these welds are made using procedures and specifications that follow the rules of the ASME Code. A dye penetrant test of the enclosure welds is performed in conformance with these requirements. The final assemblies are leak tested using a leak test hole located in the inner hub.

No credit is taken in the analysis of the flywheel missile generation for the retention of the fragments by the enclosure. A leak in the enclosure during operation could result in an out-of-balance flywheel assembly. An out-of-balance flywheel exhibits an increase in vibration, which is monitored by vibration instrumentation.

The flywheel enclosure contributes only a small portion of the energy in a rotating flywheel assembly.

The stress in the welds of the flywheel enclosure components for normal and design speeds are within the criteria in subsection NG of the ASME Code, which is used as a guideline.

Pipe rupture overspeed is based on a break of the largest branch line pipe connected to the reactor coolant system piping that is not qualified for leak-before-break criteria. The exclusion of the reactor coolant loop piping and branch line piping of 6 inches or larger size from the basis of the pump loss of coolant accident overspeed condition is based on the provision in GDC 4 to exclude dynamic effects of pipe rupture when a leak-before-break analysis demonstrates that appropriate criteria are satisfied. See Subsection 3.6.3 for a discussion of leak-before-break analyses. The criteria of Subsection 3.6.2 are used to determine pipe break size and location for those piping systems that do not satisfy the requirements for mechanistic pipe break criteria.

In addition to material specification and non destructive testing requirement, each flywheel is subject to a spin test at 125 percent overspeed, followed by visual inspection, during manufacture. This demonstrates quality of the flywheel. Since the basis for the safety of the flywheel is retention of the fragments within the reactor coolant pump pressure boundary, periodic inservice inspections of the flywheel assemblies are not required to ensure that the basis for safe operation is maintained.

Because of the configuration of the flywheel assemblies, inservice inspection of the flywheel assemblies may not result in significant inspection results. Inspection of the flywheel assemblies would require removal of the assemblies from the shaft, removal of the enclosures, rewelding of the enclosure, reassembly, and balancing of the pump shaft. Opening of the pump assembly for a periodic inspection of the enclosure would result in an increased occupational radiation exposure and would not be consistent with goals relative to maintaining exposure as low as reasonably achievable. Also, opening the pump may increase the potential for entry of foreign objects into the motor area. For these reasons, routine, periodic inspection of the flywheel assemblies in the AP1000 reactor coolant pump is not recommended.

5.4.1.3.6.4 Other Rotating Components

The rotating components (other than the flywheel), including the impeller, auxiliary impeller, rotor, and rotor can, are evaluated for potential missile generation. In the event of fracture, the fragments from these components are contained by the surrounding pressure housing. The impeller is contained by the pump casing. The rotor and rotor can are contained by the stator, stator can, and motor housing. The auxiliary impeller is contained by the motor housing. In each case, the energy of the postulated fragments is less than that required to penetrate through the pressure boundary.

5.4.1.4 Tests and Inspections

Reactor coolant pump construction is subject to a quality assurance program. The pressure boundary components meet requirements established by the ASME Code. In addition, the flywheel is subject to quality assurance requirements. Table 5.4-3 outlines the inspection included in the reactor coolant pump quality assurance program.

The reactor coolant pump inservice inspection program is according to the ASME Code, Section XI.

The design enables removal of the pump internals for inspection of the pump casing, if required. As noted earlier, routine inspections of the impeller, flywheel, and motor internals are not required for safe operation of the pump.

5.4.1.4.1 Reactor Coolant System Flow Rate Verification

Initial verification of the reactor coolant system flow rate is made during the plant initial test program. Reactor coolant system flow rates are measured during the pre-core load hot functional tests, and during the startup tests. The objective of these tests is to verify that the reactor coolant system flow rate meets the flow rate range of Technical Specification 3.4.1.

After the pre-core reactor coolant system flow rate measurement is taken, analytical adjustments are made to the pre-core measured reactor coolant system flow rate to predict a post-core reactor coolant system flow rate. Calculations of the reactor coolant system flow rate with and without the core are performed. The calculation of the pre-core load reactor coolant system flow rate is compared with results of the pre-core load flow testing, and this information will be used in the calculation of the post-core load reactor coolant system flow rate as appropriate. The predicted post-core load reactor coolant system flow rate is checked to verify that it satisfies Technical Specification 3.4.1. Verifications are also made that the post-core load reactor coolant system flow rates satisfy Technical Specification 3.4.1 flow limits during startup testing.

5.4.2 Steam Generators

5.4.2.1 Design Bases

The steam generator channel head, tubesheet, and tubes are a portion of the reactor coolant pressure boundary. The tubes transfer heat to the steam system while retaining radioactive contaminants in the primary system. The steam generator removes heat from the reactor coolant system during power operation and anticipated transients and under natural circulation conditions. The steam generator heat transfer function and associated secondary water and steam systems are not required to provide a safety-related safe shutdown of the plant.

The steam generator secondary shell functions as containment boundary during operation and during shutdown when access opening closures are in place.

Tables 5.4-4 and 5.4-5 give steam generator design data. AP1000 equipment, seismic and ASME Boiler and Pressure Vessel Code classifications of the steam generator components are discussed in Section 3.2. ASME Code and Code Case compliance are discussed in Subsection 5.2.1. The ASME Code classification for the secondary side is specified as Class 2. The pressure-retaining parts of the steam generator, including the primary and secondary pressure boundaries, are designed to satisfy the criteria specified in Section III of the ASME Code for Class 1 components.

Subsection 3.9.3 discusses the design stress limits, loads, and combined loading conditions. Subsection 3.9.1 discusses the transient conditions applicable to the steam generator. The number of transients is based on 60 years of operation.

In addition to the loading conditions associated with pressure and temperature variations for transient and anticipated accident conditions, the steam generator is evaluated for fluid borne and structural vibration originating with the reactor coolant pump. The steam generator is also evaluated for the load on the primary outlet nozzles resulting from a postulated locked reactor coolant pump rotor. See Subsection 5.4.1.3.6 for a discussion of the locked rotor postulation.

Chapter 11 gives estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation and the bases for the estimates. Chapter 15 discusses the accident analysis of a steam generator tube rupture.

The water chemistry on the primary side, selected to provide the necessary boron content for reactivity control, should minimize corrosion of reactor coolant system surfaces. The effectiveness of the water chemistry in the control of the secondary side corrosion is discussed in Chapter 10. Compatibility of steam generator tubing with both primary and secondary coolants is discussed further in Subsection 5.4.2.4.3.

The steam generator is designed to minimize the potential for mechanical or flow-induced vibration. Tube support adequacy is discussed in Subsection 5.4.2.3.3. The tubes and tubesheet are analyzed and confirmed to withstand the maximum accident loading conditions defined in Subsection 3.9.3. Further consideration is given in Subsection 5.4.2.3.4 to the effect of tube-wall thinning on accident condition stresses.

5.4.2.2 Design Description

The AP1000 steam generator is a vertical-shell U-tube evaporator with integral moisture separating equipment. Figure 5.4-2 shows the steam generator, indicating several of its design features.

The design of the Model Delta-125 steam generator, except for the configuration of the channel head, is similar to an upgraded Model Delta-75 steam generator. The Delta-75 steam generator has been placed in operation as a replacement steam generator.

Steam generator design features are described in the following paragraphs.

On the primary side, the reactor coolant flow enters the primary chamber via the hot leg nozzle. The lower portion of the primary chamber is elliptical and merges into a cylindrical portion, which mates to the tubesheet. This arrangement provides enhanced access to all tubes, including those at the periphery of the bundle, with robotics equipment. This feature enhances the ability to inspect, replace and repair portions of the AP1000 unit compared to the more spherical primary chamber of earlier designs. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the apex of the head to the tubesheet.

The reactor coolant flow enters the inverted U-tubes, transferring heat to the secondary side during its traverse, and returns to the cold leg side of the primary chamber. The flow exits the steam generator via two cold leg nozzles to which the reactor coolant pumps are directly attached. A high-integrity, nickel-chromium-iron (Alloy 690) weld is made to the nickel-chromium-iron alloy buttered ends of these nozzles.

A passive residual heat removal (PRHR) nozzle attaches to the bottom of the channel head of the loop 1 steam generator on the cold leg portion of the head. This nozzle provides recirculated flow from the passive residual heat removal heat exchanger to cool the primary side under emergency conditions. A separate nozzle on one of the steam generator channel heads is connected to a line from the chemical and volume control system. The nozzle provides for purification flow and makeup flow from the chemical and volume control system to the reactor coolant system.

The AP1000 steam generator channel head has provisions to drain the head. To minimize deposits of radioactive corrosion products on the channel head surfaces and to enhance the decontamination of these surfaces, the channel head cladding is machined or electropolished for a smooth surface. The primary manways provide enhanced primary chamber access compared to previous model steam generators.

Should steam generator replacement using a channel head cut be required, the arrangement of the AP1000 steam generator channel head facilitates steam generator replacement in two ways. It is completely unobstructed around its circumference for mounting cutting equipment. And is long enough to permit post-weld heat treatment with minimal effect of tubesheet acting as a heat sink.

The tubes are fabricated of nickel-chromium-iron Alloy 690. The tubes undergo thermal treatment following tube-forming operations. The tubes are tack-expanded, welded, and expanded over the full depth of the tubesheet. Full depth expansion was selected because of its capability to minimize secondary water access to the tube-to-tube-sheet crevice. The method by which the tubes are expanded into the tubesheet is determined based on consideration of the residual stresses and the resultant susceptibility of the tube to degradation. Residual stresses (and the expanded tube's susceptibility to degradation) are limited, in part, through tight control of the pre-expansion clearance between the tube and tubesheet hole.

Support of the tubes is provided by ferritic stainless steel tube support plates. The holes in the tube support plates are broached with a hole geometry to promote flow along the tube and to provide an appropriate interface between the tube support plate and the tube. Figure 5.4-3 shows the support plate hole geometry. Anti-vibration bars installed in the U-bend portion of the tube bundle minimize the potential for excessive vibration.

Steam is generated on the shell side, flows upward, and exits through the outlet nozzle at the top of the vessel. Feedwater enters the steam generator at an elevation above the top of the U-tubes through a feedwater nozzle. The feedwater enters a feedring via a welded thermal sleeve connection and leaves it through nozzles attached to the top of the feedring. The nozzles are fabricated of an alloy that is very resistant to erosion and corrosion with the expected secondary water chemistry and flow rate through the nozzles. After exiting the nozzles, the feedwater flow mixes with saturated water removed by the moisture separators. The flow then enters the downcomer annulus between the wrapper and the shell.

Fluid instabilities and water hammer phenomena are important considerations in the design of steam generators. Water level instabilities can occur from density wave instabilities which could affect steam generator performance. Density wave instability is avoided in the AP1000 steam generator by including appropriate pressure losses in the downcomer and the risers that lead to negative damping factors.

Steam generator bubble collapse water hammer has occurred in certain early pressurized water reactor steam generator designs having feedrings equipped with bottom discharge holes. Prevention and mitigation of feedline-related water hammer has been accomplished through an improved design and operation of the feedwater delivery system. The AP1000 steam generator and feedwater system incorporate features designed to eliminate the conditions linked to the occurrence of steam generator water hammer. The steam generator features include introducing feedwater into the steam generator at an elevation above the top of the tube bundle and below the normal water level by a top discharge feedring. The top discharge of the feedring helps to reduce the potential for vapor formation in the feedring. This minimizes the potential for conditions that can result in water hammer in the feedwater piping. The feedwater system features (Subsection 10.4.7 discusses in more detail) designed to prevent and mitigate water hammer include a short, horizontal or downward sloping feedwater pipe at steam generator inlet.

These features minimize the potential for trapping pockets of steam which could lead to water hammer events.

Stratification and striping are reduced by an upturning elbow inside the steam generator which raises the feedring relative to the feedwater nozzle. The elevated feedring reduces the potential for stratified flow by allowing the cooler, more dense feedwater to fill the nozzle/elbow arrangement before rising into the feedring.

The potential for water hammer, stratification, and striping is additionally reduced by the use of a separate startup feedwater nozzle. The startup feedwater nozzle is located at an elevation that is the same as the main feedwater nozzle and is rotated circumferentially away from the main feedwater nozzle. A startup feedwater spray system independent of the main feedwater feedring is used to introduce startup feedwater into the steam generator. The layout of the startup feedwater piping includes the same features as the main feedwater line to minimize the potential for waterhammer. The startup feedwater system is used to introduce water into the secondary side of the steam generator as described in Subsection 10.4.7.2.3.

At the bottom of the wrapper, the water is directed toward the center of the tube bundle by the lowest tube support plate. This recirculation arrangement serves to minimize the low-velocity zones having the potential for sludge deposition.

As the water passes the tube bundle, it is converted to a steam-water mixture. Subsequently, the steam-water mixture from the tube bundle rises into the steam drum section, where centrifugal moisture separators remove most of the entrained water from the steam. The steam continues to the secondary separators, or dryers, for further moisture removal, increasing its quality to a designed minimum of 99.75 percent (0.25 percent by weight maximum moisture). Water separated from the

steam combines with entering feedwater and recirculates through the steam generator. A sludge collector located amidst the inner primary separator risers provides a preferred region for sludge settling away, from the tubesheet and tube support plates. The dry, saturated steam exits the steam generator through the outlet nozzle, which has a steam-flow restrictor. (See Subsection 5.4.4.)

5.4.2.3 Design Evaluation

Integrity of the pressure retaining function of the steam generator is provided by compliance with the ASME Code. The evaluation of the stress levels and fatigue usage for the steam generator pressure boundary is calculated for the specified loading conditions and demonstrates that the values are less than the allowable limits. These calculations are documented in a stress report as required by the ASME Code. Corrosion allowances which are consistent with material erosion/corrosion resistance and service environment (velocity, chemistry, etc.) are employed throughout the design.

Meeting the heat transfer requirements and tube vibration and tube wall integrity requirements in addition to the ASME Code requirements is discussed in the following subsections:

5.4.2.3.1 Forced Convection

The steam generator transfers to the secondary coolant loop the heat generated during power operation in the reactor and by the reactor coolant pumps. The evaluation of the steam generator thermal performance, including required heat transfer area and steam flow, uses conservative assumptions for parameters such as primary flow rates and heat transfer coefficients. The effective heat transfer coefficient is determined by the physical characteristics of the AP1000 steam generator and the fluid conditions in the primary and secondary systems for the nominal 100 percent design case. It includes a conservative allowance for fouling and uncertainty. Tables 5.4-4 and 5.4-5 show the nominal design requirements and parameters. Table 5.1-1 lists additional parameters used to evaluate the steam generator design.

5.4.2.3.2 Natural Circulation Flow

When the normal feedwater supply is not available, water may be supplied to the steam generators by the startup feedwater system. The startup feedwater system is a nonsafety-related system that provides a nonsafety-related source of decay heat removal. In addition, the system is used during startup and shutdown and other times when the normal feedwater system is not available.

When the steam generator is supplied with water from the startup feedwater system, the steam generator has enough surface area and a small enough primary-side hydraulic resistance to remove decay heat from the reactor coolant by natural circulation without operation of the reactor coolant pumps.

If the passive residual heat removal system activates, the passive residual heat removal nozzle connection to the steam generator passes coolant flow from the passive residual heat removal heat exchanger into the cold leg side of the channel head. Coolant is drawn through the reactor coolant pumps into the cold legs and then into the reactor vessel.

5.4.2.3.3 Mechanical and Flow-Induced Vibration under Normal Operating Conditions

Potential sources of tube excitation are considered, including primary fluid flow within the U-tubes, mechanically induced vibration, and secondary fluid flow on the outside of the U-tubes. The effects of primary fluid flow and mechanically induced vibration, including those developed by the reactor coolant pump, are acceptable during normal operation. The primary source of potential tube degradation due to vibration is the hydrodynamic excitation of the tubes by the secondary fluid. This

area has been emphasized in both analyses and tests, including evaluation of steam generator operating experience.

Three potential tube vibration mechanisms related to hydrodynamic excitation of the tubes have been identified and evaluated. These include potential flow-induced vibrations resulting from vortex shedding, turbulence, and fluid-elastic vibration mechanisms.

Nonuniform, two-phase turbulent flow exists throughout most of the tube bundle. Therefore, vortex shedding is possible only for the outer few rows of the inlet region. Moderate tube response caused by vortex shedding is observed in some carefully controlled laboratory tests on idealized tube arrays. However, no evidence of tube response caused by vortex shedding is observed in steam generator scale model tests simulating the inlet region. Bounding calculations consistent with laboratory test parameters confirmed that vibration amplitudes would be acceptably small, even if the carefully controlled laboratory conditions were unexpectedly reproduced in the steam generator.

Flow-induced vibrations due to flow turbulence are also small: Root mean square amplitudes are less than allowances used in tube sizing. These vibrations cause stresses that are two orders of magnitude below fatigue limits for the tubing material. Therefore, neither unacceptable tube wear nor fatigue degradation due to secondary flow turbulence is anticipated.

Tube fluid elastic excitation is potentially more significant than either vortex shedding or turbulence. Relatively large tube amplitudes can feed back proportionally large tube driving forces if an instability threshold is exceeded. Tube support spacing, in both the tube support plates in the straight leg region and the anti-vibration bars in the U-bend region, provides tube response frequencies such that the instability threshold is not exceeded. This approach provides large margins against initiation of fluid elastic vibration for tubes effectively supported by the tube support system.

Small clearances between the tubes and the supporting structure are required for steam generator fabrication. These clearances introduce the potential that any given tube support location may not be totally effective in restraining tube motion if there is a finite gap around the tube at that location. Fluid-elastic tube response within available support clearances is therefore theoretically possible if secondary flow conditions exceed the instability threshold when no support is assumed at the location with a gap around the tube. This potential has been investigated both with tests and analyses for both the U-bend and straight leg regions.

AP1000 steam generator tube wear potential is expected to be within available design margins even for limiting tube fit-up conditions, based on previous experience. The AP1000 steam generator includes a number of features that minimize the potential for tube wear at tube supports and antivibration bars. Provisions to minimize the potential for wear include optimal spacing between the tube supports and the configuration of the anti-vibration bar assemblies. Tube wear is minimized in the tube support plate design by the configuration of the broached hole through the support plate, the surface finish of the broached hole in the tube support plate, the clearance between the tube and the hole in the tube support plate, and tube support plate material selection.

Tube bending stresses corresponding to tube vibration response remain more than two orders of magnitude below fatigue limits as a consequence of vibration amplitudes constrained by the tube supports. These analyses and tests for limiting postulated fit-up conditions include simultaneous contributions from flow turbulence.

As outlined, analyses and tests demonstrate that unacceptable tube degradation resulting from tube vibration is not expected for the AP1000 steam generators. Operating experience with steam generators having the same size tubes and similar flow conditions supports this conclusion.

The U-bend fatigue (discussed in NRC Bulletin 88-02) is not a consideration in the AP1000 steam generators. The mechanism considered in Bulletin 88-02 requires denting of the top tube support plate. But this is not expected with the stainless steel tube support plates in the AP1000 steam generator. Additionally, the location of anti-vibration bars is controlled by in-process dimensional inspection.

5.4.2.3.4 Allowable Tube Wall Thinning under Accident Conditions

An evaluation determined the extent of tube wall thinning that can be tolerated under accident conditions. The worst-case loading conditions are assumed to be imposed upon uniformly thinned tubes at the most critical location in the steam generator. Under such a postulated design basis accident, vibration is short enough duration that there is no endurance issue to be considered.

The steam generator tubes, existing originally at their minimum wall thickness and reduced by a conservative general corrosion and erosion loss, provide an adequate safety margin (sufficient wall thickness) in addition to the minimum required for a maximum stress less than the allowable stress limit, as defined by the ASME Code.

Studies have been made on AP1000 sized tubing under accident loadings. The results show that the maximum Level D Service condition stress due to combined pipe rupture and safe shutdown earthquake loads is less than the allowable limit. The tube thickness required to achieve the acceptable stress is less than the minimum AP1000 steam generator tube wall thickness, which is reduced to account for assumed general corrosion and erosion rate. Thus, an adequate safety margin is exhibited. The general corrosion rate is based on a conservative weight-loss rate for Alloy 690 TT tubing in flowing, 650°F primary-side reactor coolant fluid. The estimated weight loss, based on testing when equated to a thinning rate and projected over a 60-year design objective, is much less than the assumed corrosion allowance of 3 mils. This leaves the remainder of the general corrosion allowance for thinning on the secondary side.

5.4.2.4 Steam Generator Materials

5.4.2.4.1 Selection and Fabrication of Materials

The pressure boundary materials used in the steam generator are selected and fabricated in accordance with the requirements of Section II and III of the ASME Code. Subsection 5.2.3 contains a general discussion of material specifications. Table 5.2-1 lists the types of materials. Fabrication of reactor coolant pressure boundary materials is also discussed in Subsection 5.2.3, particularly in Subsections 5.2.3.3 and 5.2.3.4.

Industry-wide corrosion testing and specification development programs have justified the selection of thermally treated Alloy 690, a nickel-chromium-iron alloy (ASME SB-163), for the steam generator tubes. The channel head divider plate is also Alloy 690 (ASME SB-168). The interior surfaces of the reactor coolant channel head, nozzles, and manways are clad with austenitic stainless steel. The primary side of the tubesheet is weld clad with nickel-chromium-iron alloy (ASME SFA-5.14). The tubes are then seal welded to the tubesheet cladding. These fusion welds, comply with Sections III and IX of the ASME Code. The welds are dye-penetrant inspected and leak-tested before each tube is expanded the full depth of the tubesheet bore.

Nickel-chromium-iron alloy in various forms is used for parts where high velocities could otherwise lead to erosion/corrosion. These include the nozzles on the feedwater ring and startup feedwater sparger.

Subsection 5.2.1 discusses authorization for use of ASME Code cases used in material selection. Subsection 1.9.1 discusses the extent of conformance with Regulatory Guides 1.84, Design and Fabrication Code Case Acceptability ASME Section III, Division 1.

During manufacture, the primary and secondary sides of the steam generator are cleaned according to written procedures following the guidance of Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants, and ASME NQA-1 Part II. Onsite cleaning and cleanliness control also follow the guidance of Regulatory Guide 1.37 (discussed in Subsection 1.9.1). Cleaning process specifications are discussed in Subsection 5.2.3.4.

Subsection 5.2.3.3 discusses the fracture toughness of the materials. Adequate fracture toughness of ferritic materials in the reactor coolant pressure boundary is provided by compliance with 10 CFR 50, Appendix G, Fracture Toughness Requirements, and Paragraph NB-2300 of Section III of the ASME Code.

The heat and lot of tubing material for each steam generator tube is recorded and documented as part of the quality assurance records. Archive samples of each heat and lot of steam generator tubing material are provided for use in future materials testing programs or as inservice inspection calibration standards. A minimum of 7 feet of tubing in the final heat treat condition is supplied.

The exterior of the steam generator surface may be submerged following a postulated actuation of the automatic depressurization system (ADS). During this event, water may be present on the outside of the steam generator without affecting the heat transfer or pressure boundary capabilities of the AP1000 steam generator.

5.4.2.4.2 Steam Generator Design Effects on Materials

Several features in the AP1000 steam generator minimize crevice areas and the deposition of contaminants from the secondary-side flow. Such crevices and deposits could otherwise produce a local environment allowing potential chemical concentration and material corrosion.

The portion of the tube within the tubesheet is expanded to close the crevice between the tube and tubesheet. The length of the expansion is carefully controlled to minimize the potential of an over-expanded condition above the tubesheet and to minimize the extent of unexpanded tube at the top of the tubesheet.

The tube support plates are made of corrosion resistant Type 405 stainless steel alloy. A three-lobed, or trifoil, tube hole design provides flow adjacent to the tube outer surface. This provides high sweeping velocities at the tube and tube support plate intersections. The trifoil tube support plate provides in-plane and out-of-plane strength. The sweeping velocities through the support plate reduce sludge accumulation in the tube-to-tube support crevices. Figure 5.4-3 shows the trifoil broached holes. This support plate design contributes to a high circulation ratio. The increased flow from a high circulation ratio circulation results in increased flow in the interior of the bundle, as well as horizontal velocity across the tubesheet, which reduces the tendency for sludge deposition.

The effect of the total bundle flow on the vibrational stability of the tube bundle has been analyzed, with consideration given to flow-induced excitation frequencies. The maximum unsupported span length of tubing in the U-bend region and the optimal number of anti-vibration bars has been determined, using advanced statistical techniques and vibration modeling. The anti-vibration bars are fabricated from Type 405 stainless steel. The construction minimizes the gaps between the anti-vibration bars and tubes.

Additional measures in the AP1000 steam generator design minimize areas of dryout in the steam generator and sludge accumulations in low-velocity areas. The wrapper design results in significant water velocities across the tubesheet.

A high capacity blowdown system is capable of continuous blowdown of the steam generators at a moderate volume and intermittent flow. The intakes of the blowdown system are located on the top surface (secondary side) of the tubesheet.

A passive sludge collector, which provides a low flow settling zone, is in the upper shell region located among the inner primary moisture separator risers. The sludge collector, or mud drum, provides a location for particulate to settle remote from the tubesheet and tube support plates. The mud drum can be cleaned during a plant shutdown.

Several methods can be used to clean operating steam generators of secondary-side deposits. Sludge lancing is a procedure in which a hydraulic jet inserted through an access opening (handhole) loosens deposits and the loose material is flushed out of the steam generator. A minimum of four 6-inch access ports are provided for sludge lancing, inspection of the tube bundle by portable inspection equipment, and retrieval of loose objects. They are located above the tubesheet 90° apart (two on the tubelane and two at 90° from the tube lane) to provide access to the secondary face of the tubesheet. Also, a minimum of two 4-inch ports located on the secondary shell in line with the tubelane and above the top tube support plate provide access to the U-Bend area. A blowdown hole, located at the bottom of the secondary side drain channel permits continuous blowdown and monitoring of secondary water chemistry. The materials of the secondary side of the steam generator are also compatible with chemical cleaning.

5.4.2.4.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants

The industry corrosion tests mentioned in Subsection 5.4.2.4.1, subjected the steam generator tubing material thermally treated Alloy 690 ASME SB-163, to simulated steam generator water chemistry. These tests indicated that the loss due to general corrosion over the 60-year operating design objective is small compared to the tube wall thickness. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions indicate that Alloy 690 TT provides as good or better corrosion resistance as either Alloy 600 TT or nickel-iron-chromium Alloy 800. Alloy 690 TT also resists general corrosion in severe operating water conditions.

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

The all volatile treatment (AVT) control program minimizes the possibility of the tube wall thinning phenomenon. Successful AVT operation requires maintenance of low concentrations of impurities in the steam generator water. This reduces the potential for formation of highly concentrated solutions in low-flow zones, which is a precursor of corrosion. By restricting the total alkalinity in the steam generator and prohibiting extended operation with free alkalinity, the all volatile treatment program minimizes the possibility for intergranular corrosion in localized areas due to excessive levels of free caustic.

Laboratory testing shows that Alloy 690 TT tubing is compatible with the AVT environment. Isothermal corrosion testing in high-purity water shows that Alloy 690 TT exhibiting normal microstructure tested at normal engineering stress levels is not susceptible to intergranular stress

corrosion cracking in extended exposure to high-temperature water. These tests also show that no general type corrosion occurred. Field experience with Alloy 690 TT tubing in operation since 1989 has been excellent.

Model boiler tests evaluate similar AVT chemistry guidelines adopted by Westinghouse and EPRI. Conformance to the guidelines enhances tube corrosion performance. The secondary water chemistry guidelines for AP1000 are found in Chapter 10. Action levels for secondary side water chemistry during power operation are addressed in Subsection 10.3.5.5. Extensive operating data has been accumulated for all volatile treatment chemistry.

A comprehensive program of steam generator inspections, including the recommendations of Regulatory Guide 1.83, Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes, with the exceptions as stated in Subsection 1.9.1, provides for detection of any degradation that might occur in the steam generator tubing.

Included with the standard operating condition water chemistry controls are chemistry controls during zero power (including shutdown, no-load, heatup, cooldown, and refueling operations). The startup feedwater nozzle may be used to supply hydrazine, ammonia, and other chemicals to control secondary pH and oxygen during wet layup. Sparging the steam generator with nitrogen through the blowdown line also promotes secondary recirculation at zero power. This recirculation can be used, in conjunction with the addition of cleaning agents into the secondary side, to remove magnetite, copper, or other deposited contaminants. The AP1000 steam generator is also configured for pressure pulse cleaning and water slap methods to remove deposits on the secondary side.

High margins against primary water stress corrosion cracking exist with the specification of thermally treated Alloy 690 tubing. Alloy 690 TT is resistant to primary water stress corrosion cracking over the range of anticipated operating environments. The tubing is thermally treated according to a laboratory-derived treatment process and is generally consistent with industry-accepted and EPRI procedures.

The tube support plates are fabricated of ferritic stainless steel. Laboratory tests show that this material is resistant to corrosion in the AVT environment. If corrosion of ferritic stainless steel were to occur because of the concentration of contaminants, the volume of the corrosion products is essentially equivalent to the volume of the parent material consumed. This would be expected to preclude denting. The support plates are also designed with trifoil tube holes rather than cylindrical holes. The trifoil tube hole (see Figure 5.4-3) design promotes high velocity flow along the tube and is expected to minimize the accumulation of impurities at the support plate location.

5.4.2.5 Steam Generator Inservice Inspection

The steam generator is designed to permit inspection of pressure boundary parts, including individual tubes. Preservice inspection of the AP1000 steam generators is performed according to the ASME Code. Inservice inspection complies with the requirements of 10 CFR 50.55a.

The design includes a number of openings to provide access to both the primary and secondary sides of the steam generator. The openings include four 18-inch diameter manways, one for access to each chamber of the reactor coolant channel head and two in the steam drum for inspection and maintenance of the upper shell internals. In addition, there are a minimum of four 6-inch diameter handholes in the shell, located just above the tubesheet secondary surface are provided. A minimum of two 4-inch diameter inspection openings are provided at each end of the tubelane between the upper tube support plate and the row 1 tubes. Additional access to the tube bundle U-bend is provided through the internal deck plate at the bottom of the primary separators. For proper functioning of the steam generator, some of the deck-plate openings are covered with hatch plates welded in place that are removable by grinding, gouging, or other methods to cut off the welds.

Regulatory Guide 1.83 provides recommendations on the inspection of tubes. The recommendations cover inspection equipment, baseline inspections, tube selection, sampling and frequency of inspection, methods of recording, and required actions based on findings. Any eddy current inspection performed in the manufacturing facility is conducted by personnel qualified to the requirements for inspectors performing inservice inspection of operating units. The manufacturing facility inspection is conducted using the same equipment as, or equipment similar to, that used during inservice inspection of operating units. Exceptions to Regulatory Guide 1.83 are noted in Subsection 1.9.1.

The steam generators permit access to tubes for inspection, repair, or plugging, if necessary, per the guidelines described in Regulatory Guide 1.83. Tooling to install mechanical and welded plugs, tube repair sleeves, or effect other repair processes remotely can be delivered robotically. The AP1000 steam generator includes features to enhance robotics inspection of steam generator tubes. These include a cylindrical section of the channel head and primary manways. Computer simulation using designs of existing robotically delivered inspection and maintenance equipment verifies that tubes can be accessed. To facilitate tube identification for manual activities, the tube location for a fraction of the tubes is scribed on the tubesheet.

The minimum requirements for inservice inspection of steam generators, including tube repair criteria, are discussed in Subsection 5.4.15 considering NRC requirements and industry recommendations. The steam generator tube integrity is verified in accordance with a Steam Generator Tube Surveillance Program. The Steam Generator Tube Surveillance Program is discussed in Subsection 5.4.15. Section XI of the ASME Code provides general acceptance criteria for indications of tube degradation in the steam generator.

A steam generator tube surveillance program is implemented in accordance with the recommendations and guidance of Nuclear Energy Institute (NEI) 97-06, “Steam Generator Program Guidelines” (Reference 201). A program for periodic monitoring of degradation of steam generator internals is also implemented in accordance with NEI 97-06. Applicable Electric Power Research Institute (EPRI) Steam Generator Management Program (SGMP) guidelines are followed as described in the NEI 97-06. The Programs are in compliance with applicable sections of ASME Section XI.

NEI 97-06 and the referenced EPRI SGMP guidelines provide recommendations concerning the inspection of tubes, which cover inspection equipment, baseline inspections, tube selection, sampling and frequency of inspection, methods of recording, required actions based on findings, and tube plugging. The minimum requirements for inservice inspection of steam generators, including plugging criteria, are established in Technical Specification 5.5.4.

The tube surveillance and degradation monitoring programs include provisions to maintain the compatibility of steam generator tubing with primary and secondary coolant to limit the steam generators’ susceptibility to corrosion. These provisions are in accordance with NEI 97-06.

5.4.2.6 Quality Assurance

The steam generator is constructed to a quality assurance program that meets the requirements of the ASME Code and ASME NQA-1. Table 5.4-6 outlines the testing included in the steam generator quality assurance program.

The radiographic inspection and acceptance standard comply with the requirements of Section III of the ASME Code per applicable Code Year and Addenda.

Liquid penetrant inspection and acceptance standards comply with the requirements of Section III of the ASME Code per applicable Code Year and Addenda. Liquid penetrant inspection is performed on

weld-deposited tubesheet cladding, channel head cladding, divider-plate-to-tubesheet and to channel head weldments, tube-to-tubesheet weldments, and weld-deposit cladding.

Magnetic particle inspection and acceptance standards comply with the requirements of Section III of the ASME Code per applicable Code Year and Addenda. Magnetic particle inspection is performed on the tubesheet forging, channel head forging, nozzle forging, and the following weldments:

- Nozzle to shell (if not integral)
- Support brackets
- Instrument connection (secondary)
- Temporary attachments, after removal
- Accessible pressure retaining welds after hydrostatic test

Ultrasonic inspection and acceptance standards comply with the requirements of Section III of the ASME Code per applicable Code Year and Addenda. Ultrasonic tests are performed on the tubesheet forgings, tubesheet cladding, secondary shells and heads plates and forgings, and nozzle forgings.

The heat transfer tubing is subjected to eddy current testing and ultrasonic examination.

Hydrostatic tests comply with Section III of the ASME Code.

Non-destructive examination of pressure boundary and associated weldments will be performed in accordance with the applicable Code Year and Addenda of ASME Section III, Subsections NB and NC.

5.4.3 Reactor Coolant System Piping

5.4.3.1 Design Bases

The reactor coolant system piping accommodates the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. The piping in the reactor coolant system is AP1000 equipment Class A (ANS Safety Class 1, Quality Group A) (see Subsection 3.3.2) and is designed and fabricated according to ASME Code, Section III, Class 1 requirements. Lines with a 3/8-inch or less flow restricting orifice qualify as AP1000 equipment Class B (ANS Safety Class 2, Quality Group B) and are designed and fabricated with ASME Code, Section III, Class 2 requirements. If one of these lines breaks, the chemical and volume control system charging pumps are capable of providing makeup flow while maintaining pressurizer water level. Stresses are maintained within the limits of Section III of the ASME Code. Code and material requirements are provided in Section 5.2. Inservice inspection of Class 1 components is discussed in Subsection 5.2.4.

Materials of construction are specified to minimize corrosion/erosion and to provide compatibility with the operating environment including the expected radiation level. The welding, cutting, heat treating and other processes used to minimize sensitization of stainless steel are discussed in Subsection 5.2.3.

The thickness of reactor coolant system piping satisfies the design requirements of the ASME Code, Section III, Subsection NB. The analysis of piping of nominal pipe size of 6 inches or greater which demonstrates leak-before-break characteristics, as outlined in Subsection 3.6.3, does not include

loads due to the dynamic effects of pipe rupture. The minimum pipe bend radius is 1.5-nominal pipe diameters, and ovality meets the requirements of the ASME Code.

Butt welds, branch connection nozzle welds, and boss welds are of a full-penetration design. Flanges conform to ANSI B16.5. Socket weld fittings and socket joints conform to ANSI B16.11.

5.4.3.2 Design Description

5.4.3.2.1 Piping Elements

The reactor coolant system piping includes those sections of reactor coolant hot leg and cold leg piping interconnecting the reactor vessel, steam generators, and reactor coolant pumps. It also includes piping connected to the reactor coolant loop piping and primary components. Figure 5.1-5 shows the Piping and Instrumentation Drawing (P&ID) of the reactor coolant system. The boundary of the reactor coolant system includes the second of two isolation or shut off valves and the piping between those valves. A single ASME Code safety valve may also represent the boundary of the reactor coolant system. The connected piping in the reactor coolant system includes the following:

- Chemical and volume control system (CVS) purification return line from the system isolation valve up to a nozzle on the steam generator channel head
- Chemical and volume control system purification line from the branch connection on the pressurizer spray line to the system isolation valve
- Pressurizer spray lines from the reactor coolant cold legs up to the spray nozzle on the pressurizer vessel
- Normal residual heat removal system (RNS) pump suction line from one reactor coolant hot leg up to the designated isolation valve
- Normal residual heat removal system discharge line from the designated check valve to the connection to the core makeup tank return lines to the reactor vessel direct injection nozzle
- Accumulator lines from the designated check valve to the reactor vessel direct injection nozzle
- Passive core cooling system (PXS) lines from the cold legs to the core make-up tanks and back to the reactor vessel direct injection nozzles
- Drain, sample and instrument lines to the designated isolation valve.
- Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel surge nozzle
- Pressurizer spray scoop, reactor coolant temperature element installation boss, and the temperature element well itself
- All branch connection nozzles attached to reactor coolant loops
- Pressure relief lines in the pressurizer safety and relief valve module from nozzles on top of the pressurizer vessel up to and including the pressurizer safety valves
- Automatic depressurization system (ADS) lines from the pressurizer relief lines to the stages 1, 2, and 3 automatic depressurization system valves

- Automatic depressurization system lines from the connection with the hot leg up to the fourth stage valves
- Auxiliary spray line from the isolation valve up to the main pressurizer spray line
- Passive core cooling system lines from the hot leg to the passive residual heat removal heat exchanger, and back to the nozzle on the steam generator channel head
- Vent line from the reactor vessel head to the system isolation valves
- In-containment refueling water storage tank injection lines from the designated valves to the reactor vessel direct injection nozzle

Table 5.4-7 gives principal design data for the reactor coolant piping.

A discussion of the codes used in the fabrication of reactor coolant piping and fittings appears in Section 5.2.

Reactor coolant system piping is fabricated of austenitic stainless steel. The piping is forged seamless without longitudinal or electroslag welds. It complies with the requirements of the ASME Code, Section II (Parts A and C), Section III, and Section IX. The reactor coolant system piping does not contain any cast fittings. Changes in direction are accomplished in most cases using bent pipe instead of elbows to minimize the number of welds, fittings, and short radius turns.

5.4.3.2.2 Piping Connections

Joints and connections are welded, except for the pressurizer safety valves, the reactor head vent line, miscellaneous vents and drains, orifice flanges, and the RCP heat exchanger piping, where flanged joints are used. Fillet welds may be used to connect small instrument lines to socket weld connections. RCS loop piping branch lines and penetrations are above the horizontal centerline of the reactor coolant loop piping, except for the following:

- The residual heat removal pump suction line, which is located at the bottom of a hot leg pipe. This enables the water level in the reactor coolant system to be lowered in the reactor coolant loop pipe while continuing to operate the residual heat removal system, should this be required for maintenance.
- The pressurizer level channel nozzles with a 0.375-inch or less flow restrictor and the hot leg level channel nozzle with a 0.375-inch flow restrictor located in the hot leg piping.
- Eight of twelve cold leg-narrow range thermowells.
- Three of the six narrow-range thermowell taps in each hot leg.
- Two pressurizer spray scoop nozzles, one each located in cold legs L002A and L002B.
- One flow measurement tap on the outside bend of each hot leg elbow (total of two).
- One flow measurement tap on the inside and outside of each cold leg elbow (total of eight).

5.4.3.2.3 Encroachment into Coolant Flow

Parts encroaching into the primary coolant loop flow path are limited to the following:

- The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force.

- The narrow-range and wide-range temperature detectors are in resistance temperature detector wells that extend into both the hot and cold legs of the reactor coolant loop piping.

5.4.3.3 Design Evaluation

The loading combinations, stress limits, and analytical methods for the structural evaluation of the reactor coolant system piping and supports for design conditions, normal conditions, anticipated transients, and postulated accident conditions are discussed in Subsection 3.9.3. The requirements for dynamic testing and analysis are discussed in Subsection 3.9.2. The reactor coolant system design transients for normal operation, anticipated transients and postulated accident conditions are discussed in Subsection 3.9.1.

The pressurizer surge line has been specifically designed and instrumented to minimize the potential for thermal stratification that could increase cyclic stresses and fatigue usage. At the connection of the surge line to the hot leg, the surge line is sloped 24 degrees from horizontal. The connection to the reactor coolant hot leg is in the portion of the loop piping that is at an angle with horizontal and adjacent to the steam generator inlet nozzle. The run between the hot leg and pressurizer continuously slopes up. The surge line has an angle of at least 2.5 degrees to horizontal. The pressurizer surge line is shown in Figure 5.4-4. Changes of direction in the surge line are made using pipe bends instead of elbow fittings.

The surge line temperature is monitored for indication of thermal stratification. The temperature is monitored at three locations using strap-on resistance temperature detectors. One location is on the vertical section of pipe directly under the pressurizer. The other two locations are on the top and bottom of the pipe at the same diameter on a more horizontal section of pipe near the pressurizer.

Temperatures in the spray lines from the cold legs of one loop are measured and indicated. Alarms from these signals actuate to warn the operator of low spray water temperature or to indicate insufficient flow in the spray lines.

5.4.3.4 Material Corrosion/Erosion Evaluation

The pipe material is selected to minimize corrosion in the reactor coolant water chemistry. (See Subsection 5.2.3.) A periodic analysis of the coolant chemistry is performed to verify that the reactor coolant water quality meets the specifications. Water quality is maintained to minimize corrosion by using the chemical and volume control system and sampling system, described in Chapter 9.

Contamination of stainless steel and nickel-chromium-iron alloys by copper, low-melting-temperature alloys, mercury, and lead is prohibited during fabrication, installation, and operation.

The austenitic stainless steel surfaces are cleaned to an appropriate halogen limit. The austenitic stainless steel piping is very resistant to erosion due to single-phase fluid flow. The flow rate in the reactor coolant loop piping and branch connections during normal operation and anticipated transients is significantly below the threshold value for erosion due to water for austenitic stainless steel.

The material selection, water chemistry specification, and residual stress in the piping minimize the potential for stress corrosion cracking. (See Subsection 5.2.3.) Reactor coolant system piping is stress-relieved subsequent to bending or other fabrication operations which could result in significant residual stress in the pipe. Processes such as welding or heat treating which apply heat to stainless steel are controlled to minimize the potential for sensitization of the stainless steel.

Pressure boundary welds out to the second valve that delineates the reactor coolant system boundary are accessible for inservice examination as required by ASME Code, Section XI, and are fitted with removable insulation. Reactor coolant system piping is seamless and does not have any longitudinal welds.

5.4.3.5 Test and Inspections

The reactor coolant system piping construction is subject to a quality assurance program. The pressure boundary components meet requirements established by the ASME Code and ASME NQA-1. The testing included in the reactor coolant system piping quality assurance program is outlined in Table 5.4-8.

A transverse tension test conforming with the supplementary requirements S2 of material specification ASME SA-376 applies to each heat of pipe material.

Ultrasonic examination is performed throughout 100 percent of the wall volume of each pipe, fitting, and other forgings according to the applicable requirements of Section III of the ASME Code for reactor coolant system piping. Unacceptable defects are eliminated according to the requirements of the ASME Code. The surfaces of weld areas are smooth enough to permit preservice and inservice non-destructive examination.

The ends of pipe sections and branch ends are machined to provide a smooth weld transition adjacent to the weld.

A liquid penetrant examination is performed on accessible surfaces, including weld surfaces, of each finished pipe and fitting according to the criteria of the ASME Code, Section III. Acceptance standards are according to the applicable requirements of the ASME Code, Section III. Liquid penetrant examinations are done on the area of pipe bends before the bending operation and after the subsequent heat treatment. Since reactor coolant system piping is austenitic stainless steel, magnetic particle testing for surface examination is not an option. Fillet weld joints are examined by liquid penetrant examination method.

Radiographic examination is performed on circumferential butt welds and on branch connection nozzle welds exceeding 4-inch nominal pipe size.

The examination of a weld repair is repeated as required for the original weld. Except, when the defect was originally detected by the liquid penetrant method, and when the repair cavity does not exceed the lesser of 0.38 inch or 10 percent of the thickness, it need be re-examined only by the liquid penetrant method.

5.4.4 Main Steam Line Flow Restriction

5.4.4.1 Design Bases

The outlet nozzle of the steam generator has a flow restrictor that limits steam flow in the unlikely event of a break in the main steam line. A large increase in steam flow results in choked flow in the restrictor which limits further increase in flow. In a steam line qualified for mechanistic pipe break, a sudden rupture resulting in a large increase in steam flow is not expected. The flow restrictor performs the following functions:

- Limits rapid rise in containment pressure
- Limits the rate of heat removal from the reactor to keep the cooldown rate within acceptable limits

- Reduces thrust forces on the main steam line piping
- Limits pressure differentials on internal steam generator components, particularly the tube support plates

The restrictor is configured to minimize the unrecovered pressure loss across the restrictor during normal operation.

5.4.4.2 Design Description

The flow restrictor consists of seven nickel-chromium-iron Alloy 690 (ASME SB-564) venturi inserts which are installed in holes in an integral steam outlet nozzle forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle, and the other six are equally spaced around it. After insertion into the nozzle forging holes, the venturi inserts are welded to the nickel-chromium-iron alloy buttering on the inner surface of the forging.

5.4.4.3 Design Evaluation

The flow restrictor design has been analyzed to determine its structural adequacy. The equivalent throat area of the steam generator outlet is 1.4 square feet. The resultant pressure drop through the restrictor at 100 percent steam flow is approximately 20 psi. This is based on a design flow rate of 7.50×10^6 pounds per hour. The flow restrictor is AP1000 Equipment Class B, ANS Safety Class 2, and seismic Category I; but is constructed to ASME Code, Section III, Class 1 requirements. Materials of construction of the flow restrictor are in accordance with Section II of the ASME Code. The material of the inserts is not an ASME Code pressure boundary, nor is it welded to an ASME Code pressure boundary. The method for seismic analysis is dynamic.

5.4.4.4 Inspections

Since the restrictor is not part of the steam system pressure boundary, inservice inspections are not required.

5.4.5 Pressurizer

The pressurizer provides a point in the reactor coolant system where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control of the reactor coolant system during steady-state operations and transients. The pressurizer provides a controlled volume from which level can be measured.

The pressurizer contains the water inventory used to maintain reactor coolant system volume in the event of a minor system leak for a reasonable period without replenishment. The pressurizer surge line connects the pressurizer to one reactor coolant hot leg. This allows continuous coolant volume and pressure adjustments between the reactor coolant system and the pressurizer.

5.4.5.1 Design Bases

The pressurizer is sized to meet following requirements:

- The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.
- The water volume is sufficient to prevent a reactor trip during a step-load increase of 10 percent of full power, with automatic reactor control.

- The water volume is sufficient to prevent uncovering of the heaters following reactor trip and turbine trip, with normal operation of control systems and no failures of nuclear steam supply systems.

- The steam volume is large enough to accommodate the surge resulting from a step load reduction from 100 percent power to house loads without reactor trip, assuming normal operation of control systems.

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

- A Low-3 pressurizer pressure engineered safety features actuation signal will not be activated because of a reactor trip and turbine trip, assuming normal operation of control and makeup systems and no failures of the nuclear steam supply systems.

The pressurizer is sized to have sufficient volume to accomplish the preceding requirements without power-operated relief valves. The AP1000 pressurizer has approximately 40 percent more volume than the pressurizers for previous plants with similar power levels. This increased volume provides plant operating flexibility and minimizes challenges to the safety relief valves.

The pressurizer and surge line provide the connection of the reactor coolant system to the safety relief valves and the automatic depressurization system valves. The safety relief valves provide overpressure protection for the reactor coolant system. The automatic depressurization system is provided to reduce reactor coolant system pressure in stages to allow stored water in the in-containment refueling water storage tank to flow into the reactor coolant system to provide cooling.

The pressurizer surge nozzle and the surge line between the pressurizer and one hot leg are sized to maintain the pressure drop between the reactor coolant system and the safety valves within allowable limits during a design discharge flow from the safety valves or the valves of the automatic depressurization system. Requirements for the surge line and piping connecting the pressurizer to safety and automatic depressurization valves is discussed in Subsection 5.4.3.

Section 3.2 discusses the AP1000 equipment classification, seismic category and ASME Code classification of the pressurizer. ASME Code and Code Case compliance is discussed in Subsection 5.2.1.

The design stress limits, loads, and combined loading conditions are discussed in Subsection 3.9.3. Design transients for the components of the reactor coolant system are discussed in Subsection 3.9.1. The pressurizer surge nozzle and surge line are designed to withstand the thermal stresses resulting from volume surges occurring during operation. The evaluation of design transients for the pressurizer addresses the potential for thermal stratification at the surge nozzle.

The pressurizer provides a location for high point venting of noncondensable gases from the reactor coolant system. The gas accumulations in the pressurizer can be removed by remote manual operation of the first-stage automatic depressurization system valves following an accident. Degassing of the pressurizer using the automatic depressurization valves will not be required on a routine basis for normal and moderate frequency events. See Subsection 5.4.12 for a discussion of high-point vents.

5.4.5.2 Design Description

5.4.5.2.1 Pressurizer

The pressurizer is a vertical, cylindrical vessel having hemispherical top and bottom heads constructed of low alloy steel. Internal surfaces exposed to the reactor coolant are clad austenitic stainless steel. Material specifications are provided in Table 5.2-1 for the pressurizer.

The general configuration of the pressurizer is shown in Figure 5.4-5. The design data for the pressurizer are given in Table 5.4-9. Codes and material requirements are provided in Section 5.2. Nickel-chromium-iron alloys are not used for heater wells or instrument nozzles.

The spray line nozzles and the automatic depressurization and safety valve connections are located in the top head of the pressurizer vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves can also be operated manually from the control room. In the bottom head at the connection of the surge line to the surge nozzle a thermal sleeve protects the nozzle from thermal transients.

A retaining screen above the surge nozzle prevents passage of any foreign matter from the pressurizer to the reactor coolant system. A baffle in the lower section of the pressurizer prevents an insurge of cold water from flowing directly to the steam/water interface. The baffle also assists in mixing the incoming water with the water in the pressurizer. The retaining screen and baffle also act as a diffuser. The baffle also supports the heaters to limit vibration.

Electric direct-immersion heaters are installed in vertically oriented heater wells located in the pressurizer bottom head. The heater wells are welded to the bottom head and form part of the pressure boundary. The heaters can be removed for maintenance or replacement.

The heaters are grouped into a control group and backup groups. The heaters in the control group are proportional heaters which are supplied with continuously variable power to match heating needs. The heaters in the backup group are either off or at full power. The power supply to the heaters is a 480-volt 60 Hz three-phase circuit. Each heater is connected to one leg of a delta-connected circuit and is rated at 460 volts with one-phase current. The capacity of the control and backup groups is defined in Table 5.4-10.

A manway in the upper shell provides access to the internal space of the pressurizer in order to inspect or maintain the spray nozzle. The manway closure is a gasketed cover held in place with threaded fasteners. Periodic planned inspections of the pressurizer interior are not required.

Brackets on the upper shell attach the structure (a ring girder) of the pressurizer safety and relief valve (PSARV) module. The pressurizer safety and relief valve module includes the safety valves and the first three stages of automatic depressurization system valves. The support brackets on the pressurizer represent the primary vertical load path to the building structure. Sway struts between the ring girder and pressurizer compartment walls also provide lateral support to the upper portion of the pressurizer. See Subsection 5.4.10 for additional details.

Four steel columns attach to pads on the lower head to provide vertical support for the vessel. The columns are based at elevation 107'-2". Lateral support for the lower portion of the vessel is provided by sway struts between the columns and compartment walls.

The AP1000 pressurizer has metallic reflective insulation (MRI) installed on the external surfaces; the insulation is designed to minimize heat losses from the pressurizer, to reduce heat load on the containment cooling system, and to limit temperatures in nearby concrete or components. During

normal operating conditions, the insulation has an average maximum heat transfer rate of 65 Btu/hr-ft^2 at a containment design temperature of 120°F.

5.4.5.2.2 Instrumentation

Instrument connections are provided in the pressurizer shell to measure important parameters. Eight level taps are provided for four channels of level measurement. Level taps are also used for connection to the pressure measurement instrumentation. Two temperature taps monitor water/steam temperature. A sample tap connection is provided for connection to the sampling system to monitor coolant chemistry. The instrument and sample taps are constructed of stainless steel and designed for a socket weld of the connecting lines to the taps. The sample and instrument taps incorporate an integral flow restrictor with a diameter of 0.38 inch or smaller.

See Chapter 7 for details of the instrumentation associated with pressurizer pressure, level, and temperature.

5.4.5.2.3 Operation

During steady-state operation at 100 percent power, approximately 50 percent of the pressurizer volume is water and 50 percent is steam. Electric immersion heaters in the bottom of the vessel keep the water at saturation temperature. The heaters also maintain a constant operating pressure.

A small continuous spray flow is provided through a manual bypass valve around each power-operated spray valve to minimize the boron concentration difference between the pressurizer liquid and the reactor coolant. This continuous flow also prevents excessive cooling of the spray piping. Proportional heaters in the control group are continuously on during normal operation to compensate for the continuous introduction of cooler spray water and for losses to ambient.

These conditions result in a continuous outsurge in most cases during normal operation and anticipated transients. The outsurge minimizes the potential for thermal stratification in the surge line.

During an outsurge of water from the pressurizer, flashing of water to steam and generation of steam by automatic actuation of the heaters keep the pressure above the Low-3-pressure engineered safety features actuation setpoint. During an insurge from the reactor coolant system, the spray system (which is fed from two cold legs) condenses steam in the pressurizer. This prevents the pressurizer pressure from reaching the High-2-pressure reactor trip setpoint.

During heatup and cooldown of the plant, when the potential for thermal stratification in the pressurizer is the greatest, the pressurizer may be operated with a continuous outsurge of water from the pressurizer. This is achieved by continuous maximum spray flow and energizing of all of the backup pressurizer heater groups. The temperature difference between the pressurizer and hot leg is minimized by maintaining the lowest reactor coolant system pressure possible consistent with operation of a reactor coolant pump. This mode of operation minimizes the frequency and magnitude of thermal shock to the surge line nozzle and lower pressurizer head, and the potential for stratification in the pressurizer and surge line. The design analyses of the pressurizer include consideration of transients on the lower head and shell regions to account for these possible insurge/outsurge events.

The pressurizer is the initial source of water to keep the reactor coolant system full of water in the event of a small loss of coolant. Pressurizer level and pressure measurements indicate if other sources of water, including the chemical and volume control system and passive safety systems, must be used to supply additional reactor coolant.

Power to the pressurizer heaters is blocked when the core makeup tanks are actuated. This action reduces the potential for steam generator overfill for a steam generator tube rupture accident.

5.4.5.3 Design Evaluation

5.4.5.3.1 System Pressure Control

The reactor coolant system pressure is controlled by the pressurizer whenever a steam volume is present in the pressurizer.

A design basis safety limit has been set so that the reactor coolant system pressure does not exceed the maximum transient value based on the design pressure as allowed under the ASME Code, Section III. Evaluation of plant conditions of operation considered for design indicates that this safety limit is not reached. The safety valves provide overpressure protection. See Subsection 5.2.2.

During startup and shutdown, the rate of temperature change in the reactor coolant system is controlled automatically by the steam dump system. Heatup rate is controlled by energy input from the reactor coolant pumps and by the modulation of the steam dump valves. Pressurizer heatup rate is controlled by the electrical heaters in the pressurizer.

When the pressurizer is filled with water, i.e., during initial system heatup or near the end of the second phase of plant cooldown, reactor coolant system pressure is controlled by the letdown flowrate.

The AP1000 pressurizer heaters are powered from the 480 V ac system. During loss of offsite power events concurrent with a turbine trip, selected pressurizer heater buses are capable of being powered from the onsite diesel generators via manual alignment. This permits use of the pressurizer for control purposes when power is supplied by the diesel-generators. The power supplied by the diesel-generators is sufficient to establish and maintain natural circulation in hot standby condition in conformance with the requirement of 10 CFR 50.34 (f)(2)(xiii).

If loss of offsite power occurs and onsite power is available, the pressurizer heaters and startup feedwater pumps can operate to provide natural circulation and cooling through the steam generators.

Should the onsite diesel generators not be available during loss of offsite power events, core decay heat is removed from the reactor coolant system using the passive residual heat removal heat exchanger. The decay heat is transferred to the in-containment refueling water storage tank (IRWST) water. The passive core cooling system does not require the use of pressurizer heaters to maintain pressure control. The passive containment cooling system functions to maintain the plant in a safe condition.

NUREG-0737, Action Item II.E.3.1, outlines four requirements for emergency power supply to the pressurizer heaters for purposes of establishing natural circulation in the reactor coolant system during a loss of offsite power. NUREG-0737 does not address scenarios involving natural circulation cooling for a loss of all ac power, which is a design basis for the AP1000. Under these circumstances, cooling is provided by the passive residual heat removal system. Upon a loss of all ac power, the heaters are not available to maintain the pressurizer inventory in a saturated condition. That condition is not needed for the plant to be maintained in a safe condition. On this basis, compliance with the requirements of the action item is not required to provide for the safety of the AP1000. Nevertheless, AP1000 compliance with the intent of these requirements is summarized in the following paragraphs.

The heaters are powered from separate electrical buses for each heater group. Two groups of heaters can be administratively loaded onto the non-Class 1E diesel-generator-backed buses (Figure 8.3.1-1).

Analysis of AP1000 steady-state heat losses indicates that a heater capacity of about 166 kW is sufficient to provide saturated conditions in the pressurizer. Each AP1000 heater group has a capacity greater than 166 kW (see Table 5.4-10). One group alone can maintain control over reactor coolant system pressure and subcooling.

Established administrative procedures are followed for re-energizing groups. Associated actions can be controlled from either the main control room or the shutdown panel. It is not necessary to shed other loads in order to manually load a heater group.

Based on analysis of other pressurizer water reactors, the reactor coolant system sensible heat capacity is such that adequate subcooling can be maintained in the reactor coolant system for four hours without heat input from the pressurizer heaters. Thus, the time required to accomplish connection of the heaters to the emergency buses is consistent with timely initiation of natural circulation conditions.

Since the buses supplying the heaters for the diesel generators are not Class 1E, the 480 V breakers supplying the heaters are not required to be “qualified in accordance with safety-related requirements.”

5.4.5.3.2 Pressurizer Level Control

The normal operating water volume at full-load conditions is approximately 50 percent of the free internal vessel volume. Under part-load conditions the water volume in the pressurizer is reduced proportionally with reductions in plant load to approximately 25 percent of the free internal vessel volume at the zero-power condition.

5.4.5.3.3 Pressure Setpoints

The reactor coolant system design and operating pressure, together with the safety valve setpoints, heater actuation setpoints, pressurizer spray valve setpoints, and protection system pressure setpoints, are listed in Table 5.4-11. When operating in load regulation mode, the pressurizer spray and backup heaters are on continuously. This continuous operation decreases the number of actuations of the backup heaters and spray valves, thereby extending the component lifetimes.

The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics. The design pressure allows for operating transient pressure changes.

The Low-3 pressurizer pressure engineered safety features actuation signal does not require a coincident low pressurizer water level signal.

5.4.5.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote manual overrides are used to initiate pressurizer spray.

In parallel with each spray valve is a manual throttle valve. The throttle permits a small, continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open. Flow through this valve helps to maintain uniform water chemistry and temperature in the

pressurizer. Temperature sensors with low temperature alarms are located in each spray line to alert the operator to insufficient bypass flow.

The layout of the common spray line piping routed to the pressurizer forms a water seal that prevents steam buildup back to the control valves. The design spray rate is selected to prevent the pressurizer pressure from reaching the reactor trip setpoint during a step reduction in power level of 10 percent of full load.

The pressurizer spray lines and valves are large enough to provide the required spray flowrate under the driving force of the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop in order to use the velocity head of the reactor coolant loop flow to add to the spray driving force. The spray line also assists in equalizing the boron concentration between the reactor coolant loops and the pressurizer.

A flowpath from the chemical and volume control system to the pressurizer spray line is also provided. This path provides auxiliary spray to the vapor space of the pressurizer during cooldown, hot standby, and hot shutdown when the reactor coolant pumps are not operating. The pressurizer spray connection and the spray piping can withstand the thermal stresses resulting from the introduction of cold spray water.

5.4.5.4 Tests and Inspections

The pressurizer construction is subject to a quality assurance program. The pressure boundary components meet requirements established by the ASME Code and ASME NQA-1. Table 5.4-12 outlines the testing included in the pressurizer quality assurance program.

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

- Surge nozzle to the lower head
- Safety and spray nozzles to the upper head
- Nozzle to safe end attachment welds
- The girth full-penetration welds

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

Peripheral support rings are furnished for the removable insulation modules.

5.4.6 Automatic Depressurization System Valves

The automatic depressurization system (ADS) valves are part of the reactor coolant system and interface with the passive core cooling system (PXS). Twenty valves are divided into four depressurization stages. These stages connect to the reactor coolant system at three different locations. The automatic depressurization system first, second, and third stage valves are included as part of the pressurizer safety and relief valve (PSARV) module and are connected to nozzles on top of the pressurizer. The fourth stage valves connect to the hot leg of each reactor coolant loop. The reactor coolant system P&ID, Figure 5.1-5, shows the arrangement of the valves.

Opening of the automatic depressurization system valves is required for the passive core cooling system to function as required to provide emergency core cooling following postulated accident conditions. Operation of the passive core cooling system, including setpoints for the opening of the automatic depressurization system valves is discussed in Section 6.3.

The first stage valves may also be used, as required following an accident, to remove noncondensable gases from the steam space of the pressurizer. (See Subsection 5.4.11.)

5.4.6.1 Design Bases

Subsection 5.4.8 discusses the general design basis, design evaluation, and testing and inspection for reactor coolant system valves, including the automatic depressurization system valves. The automatic depressurization system valves are seismic Category 1, AP1000 equipment Class A components. (See Subsection 3.2.2.) The fourth stage valves are interlocked so that they can not be opened until reactor coolant system pressure has been substantially reduced. The design criteria and bases, functional requirements, mechanical design, and testing and inspection of the passive core cooling system are included in Section 6.3. The design requirements for the passive core cooling system also apply to automatic depressurization valves except where the requirements for reactor coolant system valves are more restrictive.

5.4.6.2 Design Description

The first stage automatic depressurization system valves are motor-operated 4-inch valves. The second and third stage automatic depressurization system valves are motor-operated 8-inch valves. The fourth stage automatic depressurization system valves are 14 inch squib valves arranged in series with normally-open, dc powered, motor-operator valves. See Section 6.3 for a discussion of the sizing of the automatic depressurization system valves.

The control system for the opening of the automatic depressurization system valves, as part of the passive core cooling system, has an appropriate level of diverse and redundant features to minimize the inadvertent opening of the valves.

For each stage 1-3 discharge path a pair of valves are placed in series to minimize the potential for an inadvertent discharge of the automatic depressurization system valves. The fourth stage valves are interlocked so that they cannot be opened until reactor coolant system pressure has been substantially reduced.

The first, second, and third stage valves are located on the pressurizer safety and relief valve module clustered into two groups. Each group has one pair of valves for each stage. The two groups are on different elevations and are separated by a steel plate.

Vacuum breakers are provided in the AP1000 ADS discharge lines to help prevent water hammer following ADS operation. The vacuum breakers limit the pressure reduction that could be caused by steam condensation in the discharge line and thus limit the potential for liquid backflow from the in-containment refueling water storage tank following ADS operation.

A bypass test line is connected to the inlet and outlet of the first, second, and third stage upstream isolation valves. This bypass line can control the differential pressure across the upstream valves during inservice testing. The bypass test solenoid valves do not have a safety-related function to open.

5.4.6.3 Design Verification

The automatic depressurization system valves are verified to meet their safety-related functional requirements by the following:

- Valve equipment qualification
- Pre-operational valve operational verification
- In-service valve operational verification

Automatic depressurization system valve qualification is addressed in Subsection 5.4.8.1.2 for the stage 1/2/3 motor operated valves and in Subsection 5.4.8.1.3 for the stage 4 squib valves. The equipment qualification includes type testing which verifies the automatic depressurization system valve operability and flow capacity. Automatic depressurization system valve pre-operational valve operational verification is addressed in Subsection 14.2.9.1. Automatic depressurization system valve in-service valve operational verification is addressed in Subsection 3.9.6.

5.4.6.4 Inspection and Testing Requirements

The requirements for tests and inspections for reactor coolant system valves is found in Subsection 5.4.8.4. In addition, tests for the automatic depressurization system valves and piping are conducted during preoperational testing of the passive core cooling system, as discussed in Sections 6.3 and 14.2.

5.4.6.4.1 Flow Testing

Initial verification of the resistance of the automatic depressurization system piping and valves is performed during the plant initial test program. A low pressure flow test and associated analysis is conducted to determine the total piping flow resistance of each automatic depressurization system valve group connected to the pressurizer (i.e. stages 1-3) from the pressurizer through the outlet of the downstream valve. The reactor coolant system shall be at cold conditions with the pressurizer full of water. The normal residual heat removal pumps will be used to provide injection flow into the reactor coolant system, discharging through the ADS valves.

Inspections and associated analysis of the piping flow paths from the discharge of the automatic depressurization system valve groups connected to the pressurizer (i.e., stages 1-3) to the spargers are conducted to verify the line routings are consistent with the line routings used for design flow resistance calculations. The calculated piping flow resistances from the pressurizer through the sparger, with valves of each group open are bounded by the resistances used in the Chapter 15 safety analysis.

Inspection of the piping flow paths from each hot leg through the automatic depressurization stage 4 valves is conducted. The calculated flow resistances with valves in each group open are bounded by the resistances used in the Chapter 15 safety analysis.

5.4.7 Normal Residual Heat Removal System

The normal residual heat removal system (RNS) performs the following major functions:

- **Reactor Coolant System Shutdown Heat Removal** - Remove heat from the core and the reactor coolant system during shutdown operations.

- **Shutdown Purification** - Provide reactor coolant system and refueling cavity purification flow to the chemical and volume control system during refueling operations.
- **In-containment Refueling Water Storage Tank Cooling** - Provide cooling for the in-containment refueling water storage tank.
- **Reactor Coolant System Makeup** - Provide low pressure makeup to the reactor coolant system.
- **Post-Accident Recovery** - Remove heat from the core and the reactor coolant system following successful mitigation of an accident by the passive core cooling system.
- **Low Temperature Overpressure Protection** - Provide low temperature overpressure protection (LTOP) for the reactor coolant system during refueling, startup, and shutdown operations.
- **Long-Term, Post-Accident Containment Inventory Makeup Flowpath** - Provide long-term, post-accident makeup flowpath to the containment inventory.
- **Spent Fuel Pool Cooling** - Provide backup for cooling the spent fuel pool.

5.4.7.1 Design Bases

5.4.7.1.1 Safety Design Bases

The safety-related functions provided by the normal residual heat removal system include containment isolation of normal residual heat removal system lines penetrating containment, preservation of the reactor coolant system pressure boundary and a flow path for long term post-accident makeup to the containment inventory. The containment isolation valves perform the containment isolation function according to the criteria specified in Subsection 6.2.3. The system preserves the reactor coolant system pressure boundary according to the criteria specified in Subsection 5.4.8.

The normal residual heat removal system piping and components outside containment are an AP1000 Class C, Seismic Category I pressure boundary. This classification recognizes the importance of pressure boundary integrity even though these components have no safety-related functions.

5.4.7.1.2 Nonsafety Design Bases

Subsection 5.4.7 outlines the principal functions of the normal residual heat removal system. The normal residual heat removal system is designed to be reliable. This reliability is achieved by using redundant equipment and a simplified system design. The normal residual heat removal system is not a safety-related system. It is not required to operate to mitigate design basis events.

The normal residual heat removal system is designed for a single nuclear power unit and is not shared between units. The normal residual heat removal system is operated from the main control room.

The normal residual heat removal system provides the capability to cool the spent fuel pool during times when it is not needed for removing heat from the reactor coolant system.

5.4.7.1.2.1 Shutdown Heat Removal

The normal residual heat removal system removes both residual and sensible heat from the core and the reactor coolant system. It reduces the temperature of the reactor coolant system during the second phase of plant cooldown. The first phase of cooldown is accomplished by transferring heat from the reactor coolant system via the steam generators to the main steam system (MSS).

Following cooldown, the normal residual heat removal system removes heat from the core and the reactor coolant system during the plant shutdown, until the plant is started up.

The normal residual heat removal system reduces the temperature of the reactor coolant system from 350° to 125°F within 96 hours after shutdown. The system maintains the reactor coolant temperature at or below 125°F for the plant shutdown. The system performs this function based on the following:

- Operation of the system with both subsystems of normal residual heat removal system pumps and heat exchangers available.

- Initiation of normal residual heat removal system operation at four hours following reactor shutdown, after the first phase of cooldown by the main steam system has reduced the reactor coolant system temperature to less than or equal to 350°F and 450 psig.

- The component cooling water system supply temperature to the normal residual heat removal system heat exchangers is based on maximum normal ambient wet bulb temperature as defined in Chapter 2, Table 2.0-201. The maximum normal ambient temperature is assumed for shutdown cooling.

- Operation of the system is consistent with reactor coolant system cooldown rate limits and consistent with maintaining the component cooling water below design limits during cooldown.

- Core decay heat generation is based on the decay heat curve for a three-region core having burnups consistent with a 24-month or 18-month refueling schedule and based on the ANSI/ANS-5.1-1994 decay heat curve (Reference 5).

- A failure of an active component during normal cooldown does not preclude the ability to cool down, but lengthens the time required to reach 125°F. Furthermore, if such a single failure occurs while the reactor vessel head is removed, the reactor coolant temperature remains below boiling temperature.

- The system operates at a constant normal residual heat removal flow rate throughout refueling operations. This includes the time when the level in the reactor coolant system is reduced to a midloop level to facilitate draining of the steam generators or removal of a reactor coolant pump. Operation of the system at the minimum level that the reactor coolant system can attain using the normal reactor coolant system draining connections and procedures results in no incipient vortex formation which would cause air entrainment into the pump suction.

- The pump suction line is self-venting to a condition acceptable for RNS pump operation such that no manual venting is required to start the pumps if stopped on cavitation due to excessive air entrainment. This is achieved by sloping most of the RNS pump suction piping upward from the RNS pump suction to the reactor coolant system hot leg. In the level portions of piping, there are no local high points. This arrangement minimizes entrapment of air and system venting efforts for startup.

- Features are included that permit mid-loop operations to be performed from the main control room.

5.4.7.1.2.2 Shutdown Purification

The normal residual heat removal system provides reactor coolant system flow to the chemical and volume control system during refueling operations. The purification flow rate is consistent with the purification flow rate specified in Table 9.3.6-1.

5.4.7.1.2.3 In-Containment Refueling Water Storage Tank Cooling

The normal residual heat removal system provides cooling for the in-containment refueling water storage tank during operation of the passive residual heat removal heat exchanger or during normal plant operations when required. The system is manually initiated by the operator. The normal residual heat removal system limits the in-containment refueling water storage tank water temperature to less than boiling temperature during extended operation of the passive residual heat removal system and not greater than 120°F during normal operation. The system performs this function based on the following:

- Operation of the system with both subsystems of normal residual heat removal system pumps and heat exchangers available.

- The component cooling water system supply temperature to the normal residual heat removal system heat exchangers is based on an ambient design wet bulb temperature of no greater than 86.1°F (0 percent exceedance). The 86.1°F value is assumed for normal conditions and transients that start at normal conditions.

Since the normal residual heat removal system is not a safety-related system, its operation is not credited in Chapter 15 Accident Analyses.

5.4.7.1.2.4 Low Pressure Reactor Coolant System Makeup and Cooling

The normal residual heat removal system provides low pressure makeup from the cask loading pit to the reactor coolant system. The system is manually initiated by the operator following receipt of an automatic depressurization signal. If the system is available, it provides reactor coolant system makeup once the pressure in the reactor coolant system falls below the shutoff head of the normal residual heat removal system pumps. The system provides makeup from the cask loading pit to the reactor coolant system and provides additional margin for core cooling. The normal residual heat removal system is not required to mitigate design basis accidents, and therefore its operation is not considered in Chapter 15 Accident Analyses.

5.4.7.1.2.5 Low Temperature Overpressure Protection

The normal residual heat removal system provides a low temperature overpressure protection function for the reactor coolant system during refueling, startup, and shutdown operations. The system is designed to limit the reactor coolant system pressure to the lower of either the limits specified in 10 CFR 50, Appendix G, or 110 percent of the normal residual heat removal system design pressure.

5.4.7.1.2.6 Spent Fuel Pool Cooling

The normal residual heat removal system has the capability to supplement or take over the cooling of the spent fuel pool when it is not needed for normal shutdown cooling.

5.4.7.2 System Description

Figure 5.4-6 shows a simplified sketch of the normal residual heat removal system. Figure 5.4-7 shows the piping and instrumentation diagram for the normal residual heat removal system. Table 5.4-13 gives the important system design parameters.

The inside containment portions of the system from the reactor coolant system up to and including the containment isolation valves outside containment are designed for full reactor coolant system pressure. The portion of the system outside containment, including the pumps, valves and heat exchangers, has a design pressure and temperature such that full reactor coolant system pressure is below the ultimate rupture strength of the piping.

The normal residual heat removal system consists of two mechanical trains of equipment. Each train includes one residual heat removal pump and one residual heat removal heat exchanger. The two trains of equipment share a common suction line from the reactor coolant system and a common discharge header. The normal residual heat removal system includes the piping, valves and instrumentation necessary for system operation.

The normal residual heat removal system suction header is connected to a reactor coolant system hot leg with a single step-nozzle connection. The step-nozzle connection is employed to minimize the likelihood of air ingestion into the residual heat removal pumps during reactor coolant system mid-loop operations. The suction header then splits into lines with two parallel sets of two normally closed, motor-operated isolation valves in series. This arrangement allows for normal residual heat removal system operation following a single failure of an isolation valve to open and also allows for normal residual heat removal system isolation following a single failure of an isolation valve to close.

The lines join into a common suction line inside containment. A single line from the in-containment refueling water storage tank is connected to the suction header before it leaves containment.

Once outside containment, the suction header contains a single normally closed, motor-operated isolation valve. Downstream of the suction header isolation valve, the header branches into two separate lines, one to each pump. Each branch line has a normally open, manual isolation valve upstream of the residual heat removal pumps. These valves are provided for pump maintenance.

The normal residual heat removal system suction header is designed to be self-venting to a condition acceptable for RNS pump operation such that no manual venting is required to start the pumps if stopped on cavitation due to excessive air entrainment. This is achieved by sloping most of the RNS pump suction piping upward from the RNS pump suction to the reactor coolant system hot leg. In the level portions of piping, there are no local high points. This eliminates any locations where a sufficient volume of air could collect to cause low net positive suction head, pump binding, and a loss of residual heat removal capability.

The discharge of each residual heat removal pump is directed to its respective residual heat removal heat exchanger. The outlet of each residual heat removal heat exchanger is routed to the common discharge header, which contains a normally closed, motor-operated isolation valve. For pump protection, a miniflow line with an orifice is included from downstream of the residual heat removal heat exchanger to upstream of the residual heat removal pump suction. This line is sized to provide sufficient pump flow when the pressure in the reactor coolant system is above the residual heat removal pump shutoff head.

Once inside containment, the common discharge header contains a check valve that acts as a containment isolation valve. Downstream of the check valve, the discharge header branches into two lines, one to each passive core cooling system direct vessel injection nozzle. These branch lines each contain a stop check valve and check valve in series that serve as the reactor coolant system

pressure boundary. A line to the chemical and volume control system demineralizers branches from one of the direct vessel injection lines. This line is used for shutdown purification of the reactor coolant system. Another line branches from the same direct vessel injection line to the in-containment refueling water storage tank which is used when cooling the tank.

Two relief valves are located on the normal residual heat removal system suction header inside containment. These valves provide low temperature overpressure protection of the reactor coolant system. Subsection 5.4.9 describes the sizing basis of these valves. Another relief valve outside of containment provides protection against excess pressure for the piping and components.

When the normal residual heat removal system is in operation, the water chemistry is the same as that of the reactor coolant. Sampling may be performed using the normal residual heat removal heat exchangers channel head drain connections. Sampling of the reactor coolant system using these connections is available at shutdown. Sampling of the in-containment refueling water storage tank is available during normal plant operation.

5.4.7.2.1 Design Features Addressing Shutdown and Mid-Loop Operations

The following is a summary of the specific AP1000 design features that address Generic Letter (GL) 88-17 regarding mid-loop operations. In addition, these features support improved safety during shutdown.

Loop Piping Offset - As shown in Figure 5.3-6, the reactor coolant system hot legs and cold legs are vertically offset. This permits draining of the steam generators for nozzle dam insertion with hot leg level much higher than traditional designs. The reactor coolant system must be drained to a level which is sufficient to provide a vent path from the pressurizer to the steam generators. This is nominally 80 percent level in the hot leg. This loop piping offset also allows a reactor coolant pump to be replaced without removing a full core.

Step-nozzle Connection - The normal residual heat removal system employs a step-nozzle connection to the reactor coolant system hot leg. The step-nozzle connection has two effects on mid-loop operation. One effect is to substantially lower the RCS hot leg level at which a vortex occurs in the residual heat removal pump suction line due to the lower fluid velocity in the hot leg nozzle. This increases the margin from the nominal mid-loop level to the level where air entrainment into the pump suction begins.

Another effect of the step-nozzle is that, if a vortex should occur, the maximum air entrainment into the pump suction has been shown experimentally to be no greater than 5 percent. This level of air ingestion will make air binding of the pump much less likely.

Normal Residual Heat Removal Throttling During Mid-Loop - The normal residual heat removal pumps are designed to minimize susceptibility to cavitation. Normally, the normal residual heat removal system operates without the need for throttling a residual heat removal control valve when the level in the reactor coolant system is reduced to a mid-loop level. If the reactor coolant system is at saturated conditions and mid-loop level, some throttling of a flow control valve is necessary to maintain adequate net positive suction head.

Self-Venting Suction Line - The residual heat removal pump suction line is designed to be self-venting to a condition acceptable for RNS pump operation such that no manual venting is required to restart the pumps if stopped on cavitation due to excessive air entrainment. This is achieved by sloping most of the RNS pump suction piping, upward from the RNS pump to the reactor coolant system hot leg. In the level portions of piping, there are no local high points. This eliminates potential problems with refilling the pump suction line if a residual heat removal pump is stopped when cavitating due to excessive air entrainment. With the self-venting suction line, the line will refill

without manual venting and the pumps can be immediately (no additional operator action required) restarted once an adequate level in the hot leg is re-established.

Wide Range Pressurizer Level - A nonsafety-related independent pressurizer level transmitter, calibrated for low temperature conditions, provides water level indication during startup, shutdown, and refueling operations in the main control room and at the remote shutdown workstation. The upper level tap is connected to an ADS valve inlet header above the top of the pressurizer. The lower level tap is connected to the bottom of the hot leg. This provides level indication for the entire pressurizer and a continuous reading as the level in the pressurizer decreases to mid-loop levels during shutdown operations.

Hot Leg Level Instrumentation - The AP1000 reactor coolant system contains level instrumentation in each hot leg with indication in the main control room. In addition to the wide-range pressurizer level instrumentation (used during cold plant operation) which provides continuous level indication in the main control room from the normal level in the pressurizer, two narrow-range hot leg level instruments are available. Alarms are provided to alert the operator when the reactor coolant system hot leg level is approaching a low level. The isolation valves in the line used to drain the reactor coolant system close on a low reactor coolant system level during shutdown operations. Operations required during mid-loop are performed by the operator in the main control room. The level monitoring and control features significantly improve the reliability of the AP1000 during mid-loop operations.

Reactor Vessel Outlet Temperature - Reactor coolant system hot leg wide range temperature instruments are provided in each hot leg for normal residual heat removal system operation with normal inventory. The normal residual heat removal temperature instruments, upstream of the heat exchangers, indicate reactor coolant system hot leg temperature when in reduced inventory conditions. In addition, at least two incore thermocouple channels are available to measure the core exit temperature during midloop residual heat removal operation. These two thermocouple channels are associated with separate electrical divisions.

ADS Valves - The automatic depressurization system first-, second-, and third-stage valves, connected to the top of the pressurizer, are open whenever the core makeup tanks are blocked during shutdown conditions while the reactor vessel upper internals are in place. This provides a vent path that, when combined with actuation of the automatic depressurization system fourth-stage valves, sufficient steam venting area is provided to reduce reactor coolant system pressure after decay heat removal is lost. Actuation of ADS stage 4, either automatically or manually (as described in Subsection 19E.4.8.3) allows the in-containment water storage tank to provide injection flow following a loss of decay heat removal.

The capability to restore containment integrity during shutdown conditions is provided. The containment equipment hatches are equipped with guide rails that allow reinstallation of the hatches to re-establish containment integrity. The containment design also includes penetrations for temporary cables and hoses needed for shutdown operations.

Procedures direct the operator in the proper conduct of midloop operation and aid in identifying and correcting abnormal conditions that might occur during shutdown operations.

5.4.7.2.2 Design Features Addressing Intersystem LOCA

The AP1000 has addressed the intersystem LOCA section of SECY 90-016 with a number of design features. These design features are:

Codes and Standards/Seismic Protection - The portions of the normal residual heat removal system located outside containment (that serve no active safety functions) are classified as AP1000

Equipment Class C so that the design, manufacture, installation, and inspection of this pressure boundary is in accordance with the following industry codes and standards and regulatory requirements: 10 CFR 50, Appendix B; Regulatory Guide 1.26 Quality Group C; and ASME Boiler and Pressure Vessel Code, Section III, Class 3. The pressure boundary is classified as Seismic Category I.

Increased Design Pressure - The portions of the normal residual heat removal system from the reactor coolant system to the containment isolation valves outside containment are designed to the operating pressure of the reactor coolant system. The portions of the system downstream of the suction line containment isolation valve and upstream of the discharge line containment isolation valve are designed so that its ultimate rupture strength is not less than the operating pressure of the reactor coolant system. Specifically, the piping is designed as schedule 80S, and the flanges, valves, and fittings are specified to be greater than or equal to ANS class 900. The design pressure of the normal residual heat removal system is 900 psi, which is approximately 40 percent of operating reactor coolant system pressure.

Reactor Coolant System Isolation Valve - The AP1000 normal residual heat removal system contains an isolation valve in the pump suction line from the reactor coolant system. This motor-operated containment isolation valve is designed to the reactor coolant system pressure. It provides an additional barrier between the reactor coolant system and lower pressure portions of the normal residual heat removal system.

Normal Residual Heat Removal System Relief Valves - The inside containment AP1000 normal residual heat removal system relief valves are connected to the residual heat removal pump suction line. These valves are designed to provide low-temperature overpressure protection of the reactor coolant system as described in Subsection 5.2.2. They are connected to the high pressure portion of the pump suction line and reduces the risk of overpressurizing the low pressure portions of the system.

Features Preventing Inadvertent Opening of Isolation Valves - The reactor coolant system isolation valves are interlocked to prevent their opening at reactor coolant system pressures above 450 psig. Section 7.6 discusses this interlock. The power to these valves is administratively blocked during normal power operation.

RCS Pressure Indication and High Alarm - The AP1000 Normal residual heat removal system contains an instrumentation channel that indicates pressure in each normal residual heat removal pump suction line. A high pressure alarm is provided in the main control room to alert the operator to a condition of rising RCS pressure that could eventually exceed the design pressure of the normal residual heat removal system.

Closed valves connecting to spent fuel pool - The cross-connecting piping between the normal residual heat removal system and the spent fuel pool cooling system is isolated by normally closed valves.

5.4.7.3 Component Description

The descriptions of the normal residual heat removal system components are provided in the following subsections. Table 5.4-14 lists the key equipment parameters for the normal residual heat removal system components.

5.4.7.3.1 Normal Residual Heat Removal Pumps (MP01 A&B)

Two residual heat removal pumps are provided. These pumps are single stage, vertical in-line, bottom suction centrifugal pumps. They are coupled with a motor shaft driven by an ac powered induction motor.

Each pump is sized to provide the flow required by its respective heat exchanger for removal of its design basis heat load. Redundant pumps and heat exchangers provide sufficient cooling to prevent RCS boiling if one subsystem is inoperative. A continuously open miniflow line is also provided to protect the pump from operation at low flow conditions.

5.4.7.3.2 Normal Residual Heat Removal Heat Exchangers (ME01 A&B)

Two residual heat removal heat exchangers are installed to provide redundant residual heat removal capability. These heat exchangers are vertically mounted, shell and U-tube design. Reactor coolant flow circulates through the stainless steel tubes while component cooling water circulates through the carbon steel shell. The tubes are welded to the tubesheet.

5.4.7.3.3 Normal Residual Heat Removal Valves

The normal residual heat removal system packed valves designated for radioactive service are provided with stem packing designs that provide enhanced resistance to leakage. Leakage to the atmosphere is essentially zero for these valves.

Manual and motor-operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. The basic material of construction for valves is stainless steel.

Two manually operated valves that individually isolate each of the RNS trains are locked-open to prevent thermal overpressurization of the RNS piping in the auxiliary building. There is one additional valve locked-open to maintain a path for the RNS discharge containment isolation check valve to provide overpressure protection for the containment penetration piping and provide a flow path for post-accident makeup to passive core cooling.

5.4.7.3.3.1 Reactor Coolant System Inner/Outer Isolation Valves (V001 A&B, V002 A&B)

There are two parallel sets of two valves in series for a total of four valves. These valves are normally closed, motor-operated valves and are located inside the containment. These valves form the reactor coolant pressure boundary. They are opened only for normal cooldown after reactor coolant system depressurization to 450 psig. They are controlled from the main control room and fail in the “as-is” position. These valves are protected from inadvertently opening when the reactor coolant system pressure is above 450 psig by an interlock. Power to these valves is administratively blocked during normal power operations. The outer isolation valves, V002A & V002B, also act as containment isolation valves.

5.4.7.3.3.2 In-Containment Refueling Water Storage Tank Suction Line Isolation Valve (V023)

There is one motor-operated valve located inside containment in the line from the in-containment refueling water storage tank to the pump suction header. This valve is designed for full reactor coolant system pressure. It also acts as a containment isolation valve.

5.4.7.3.3.3 Residual Heat Removal Isolation Valve (V011)

There is one motor-operated valve in the pump discharge header outside of containment. This valve is designed for full reactor coolant system pressure. It also acts as a containment isolation valve.

5.4.7.3.3.4 In-Containment Refueling Water Storage Tank Return Isolation Valve (V024)

There is one normally closed motor-operated valve located inside containment in the discharge line to the in-containment refueling water storage tank. This valve is aligned for full-flow testing of the residual heat removal pumps or for operations involving cooling of the in-containment refueling water storage tank.

5.4.7.3.3.5 Cask Loading Pit Isolation Valve (V055)

There is one normally closed motor-operated valve in the line between the cask loading pit and the residual heat removal pump suction line. This valve can be opened by the operator to provide low pressure injection from the cask loading pit to the reactor coolant system during an accident.

5.4.7.3.3.6 Normal Residual Heat Removal Pump Miniflow Isolation Valves (V057A&B)

There is one normally open air-operated valve in each of the residual heat removal pump miniflow lines. During plant cooldown the operator can close these valves to increase the circulating flow rate of the reactor coolant through the residual heat removal heat exchangers to decrease the reactor coolant system cooldown time. These valves automatically open on low flow in the residual heat removal heat exchanger discharge line.

5.4.7.4 System Operation and Performance

Operation of the normal residual heat removal system is described in the following sections. System operations are controlled and monitored from the main control room, including mid-loop operations. The reactor coolant system is equipped with mid-loop level instrumentation with remote readout in the main control room. This instrumentation is used for monitoring mid-loop operations from the main control room.

5.4.7.4.1 Plant Startup

Plant startup includes the operations that bring the reactor plant from a cold shutdown condition to no-load operating temperature and pressure, and subsequently to power operation.

During cold shutdown conditions, both residual heat removal pumps and heat exchangers operate to circulate reactor coolant and remove decay heat. The residual heat removal pumps are switched off when plant startup begins. The normal residual heat removal system remains aligned to the reactor coolant system to maintain a low pressure letdown path to the chemical and volume control system. This alignment provides reactor coolant system purification flow and low temperature over-pressure protection of the reactor coolant system. As the reactor coolant pumps are started, their thermal input begins heating the reactor coolant inventory. Once the pressurizer steam bubble formation is complete, the normal residual heat removal system suction header isolation valve and the discharge header isolation valve are closed and tested for leakage. The valve arrangement is then set for normal operation, as shown in Figure 5.4-6.

5.4.7.4.2 Plant Cooldown

Plant cooldown is the operation that brings the reactor plant from normal operating temperature and pressure to refueling conditions.

The initial phase of plant cooldown consists of reactor coolant cooldown and depressurization. Heat is transferred from the reactor coolant system via the steam generators to the main steam system. Depressurization is accomplished by spraying reactor coolant into the pressurizer, which cools and condenses the pressurizer steam bubble.

When the reactor coolant temperature and pressure have been reduced to 350°F and 450 psig, respectively (approximately four hours after reactor shutdown), the second phase of plant cooldown is initiated with the normal residual heat removal system being placed in service.

Before starting the residual heat removal pumps, the in-containment refueling water storage tank isolation valve is closed. Then the normal residual heat removal system suction header isolation valve and the discharge header isolation valve are opened. When the pressure in the reactor coolant system has been reduced to below 450 psig, the inner/outer isolation valves are opened.

Once the proper valve alignment has been performed and component cooling water flow has been initiated to both residual heat removal heat exchangers, normal residual heat removal system operation may begin. The pumps are started and the cooldown proceeds. The cooldown rate is controlled by throttling the flow through the heat exchanger based on reactor coolant temperature.

This mode of operation continues for the duration of the cooldown until the reactor coolant system temperature is reduced to 140°F and the system is depressurized. The reactor coolant system may then be opened for either maintenance or refueling. Cooldown continues until the reactor coolant system temperature is lowered to 125°F (about 96 hours after reactor shutdown).

During the cooldown operations, the reactor coolant system water level is drained to a “mid-loop” level to facilitate steam generator draining and maintenance activities. For normal refuelings, the level to which the reactor coolant system is drained is that which allows air to be vented into the steam generators from the pressurizer. This level is nominally an 80 percent water level in the hot leg. The design of the AP1000 normal residual heat removal system is such that throttling of the residual heat removal pump flow during mid-loop operations to avoid air-entrainment into the pump suction is not required.

At the appropriate time during the cooldown, the operator lowers the water level in the reactor coolant system by manually positioning the chemical and volume control system letdown control valve. At this time the makeup pumps are turned off; and the letdown flow control valve controls the drain rate to the liquid waste processing system. The drain rate proceeds initially at the maximum letdown rate and is substantially reduced as the level in the reactor coolant system is lowered to the top of the hot leg. The letdown flow control valve as well as the letdown line containment isolation valve receives a signal to automatically close once the appropriate level is attained. Alarms actuate in the main control room if the level continues to drop to alert the operator to manually isolate the letdown line.

5.4.7.4.3 Refueling

Both residual heat removal pumps and heat exchangers remain operating during refueling. Water transfers from the in-containment refueling water storage tank to the refueling cavity are performed by the spent fuel pool cooling system (SFS). This function has traditionally been performed by residual heat removal systems. That capability still exists if the need arises. To improve clarity in the refueling cavity and reduce operational radiation exposure, the spent fuel pool cooling system is used to flood the refueling cavity without flooding through the reactor vessel.

As decay heat decreases and as fuel is moved to the spent fuel pool, one residual heat removal pump and heat exchanger may be taken out of service. However, the valves remain aligned should the need arise to start this pump quickly in case of a failure of the operating residual heat removal pump.

5.4.7.4.4 Accident Recovery Operations

Upon actuation of automatic depressurization, the normal residual heat removal system can be employed to provide low-pressure reactor coolant system makeup. Provided that radiation levels inside containment are below a high radiation value and after resetting the safeguards actuation signal to the valves as necessary, the operator may open the cask loading pit suction valves and the residual heat removal discharge isolation valve and start the residual heat removal pumps. Water is pumped from the cask loading pit to the direct vessel injection lines. Operation of the normal residual heat removal system will not prevent the passive core cooling system from performing its safety functions.

5.4.7.4.5 Spent Fuel Pool Cooling

The normal residual heat removal system has the capability of being connected to supplement or take over the cooling function of the spent fuel pool cooling system. The normally closed valves in the cross-connecting piping are opened. One normal residual heat removal pump is started. Spent fuel pool water is drawn through the pump, passed through a heat exchanger and returned to the pool.

This mode of cooling is available when the normal residual heat removal system is not needed for normal shutdown cooling. The spent fuel pool water flow path between the spent fuel pool and the normal residual heat removal system is independent of the flow path used for spent fuel pool cooling by the spent fuel pool cooling system.

5.4.7.4.6 Fire Leading to MODE 5, Cold Shutdown

In the event of loss of normal component cooling system function where it is desired to transfer to MODE 5, Cold Shutdown, to facilitate maintenance, the fire protection system can provide the source of cooling water for a normal residual heat removal system pump and heat exchanger as described in Subsection 9.2.2.4.5.5.

5.4.7.5 Design Evaluation

Since the normal residual heat removal system is connected to the reactor coolant system, portions of the system that create the reactor coolant system pressure boundary are designed according to ANSI/ANS 51.1 (Reference 6) with regards to maintaining the reactor coolant system pressure boundary integrity.

Since the normal residual heat removal system penetrates the containment boundary, the containment penetration lines are designed according to the containment isolation criteria identified in Subsection 6.2.3.

Makeup water can be provided through the normal residual heat removal system for long-term post-accident containment makeup. This makeup is provided through the manual containment isolation test connection valve in the discharge of the normal residual heat removal system. This test connection provides a containment-inventory makeup flow path to be used after a loss-of-coolant accident (LOCA). With the maximum allowable containment leak rate, makeup to containment is not needed for about one month.

The normal residual heat removal system components and piping are compatible with the radioactive fluids they contain.

The design of the normal residual heat removal system has been compared with the acceptance criteria set forth in Subsection 5.4.7, “Residual Heat Removal System,” Revision 3, of the NRC’s Standard Review Plan. The specific General Design Criteria identified in the Standard Review Plan

section are General Design Criteria 2, 4, 5, 19, and 34. Additionally, positions of Regulatory Guides 1.1, 1.29, and 1.68 were also reviewed to determine the degree of compliance between the AP1000 and the acceptance criteria. Branch Technical Position RSB 5-1 was also reviewed as appropriate.

Discussions of the conformance with Regulatory Guides and Branch Technical Positions are found in Section 1.9. Compliance with General Design Criteria is found Section 3.1.

5.4.7.6 Inspection and Testing Requirements

5.4.7.6.1 Preoperational Inspection and Testing

Preoperational tests are conducted to verify proper operation of the normal residual heat removal system (RNS). The preoperational tests include valve inspection and testing, flow testing, and verification of heat removal capability.

5.4.7.6.1.1 Valve Inspection and Testing

The inspection requirements of the normal residual heat removal system valves that constitute the reactor coolant pressure boundary are consistent with those identified in Subsection 5.2.4. The inspection requirements of the normal residual heat removal system valves that isolate the lines penetrating containment are consistent with those identified in Section 6.6.

The low temperature overpressure protection relief valves, RNS-V020 and RNS-V021, located on the normal residual heat removal system suction relief lines, are bench tested with water. Each valve's set pressure is verified to be less than or equal to the value assumed in the low temperature overpressure protection analysis. Relieving capacity of each valve is certified in accordance with the ASME code, Section III, NC-7000.

5.4.7.6.1.2 Flow Testing

Each installed normal residual heat removal system pump is tested to measure the flow through the normal residual heat removal system heat exchangers when aligned to cool the reactor coolant system. Testing will be performed with the pump suction aligned to the reactor coolant system hot leg and the discharge aligned to the passive core cooling system direct vessel injection lines. Flow will be measured using instrumentation in the pump discharge line. Testing will confirm that each pump provides at least the required flow rate shown in Table 5.4-14. This is the minimum flow rate required to ensure that the normal residual heat removal system can meet its functional requirement of cooling the reactor during shutdown operations.

Each installed normal residual heat removal system pump is also tested to measure the flow when aligned to deliver low pressure makeup to the reactor coolant system. Testing will be performed with the pump suction aligned to the cask loading pit and the discharge aligned to the passive core cooling system direct vessel injection lines. Flow will be measured using instrumentation in the pump discharge line. The reactor coolant system will be at atmospheric pressure for this test. Testing will confirm that each pump provides at least the required flow rate shown in Table 5.4-14. This is the minimum flow rate required to ensure that the normal residual heat removal system can meet its functional requirement to prevent 4th stage ADS actuation for small breaks.

5.4.7.6.1.3 Heat Removal Capability Analysis

Heat exchanger manufacturer's heat exchanger data will be used to perform an analysis to verify that the heat removal capability of each normal residual heat removal system heat exchanger, as calculated by the product of the heat transfer coefficient and the effective heat transfer area, UA, is equal to or greater than the required value shown in Table 5.4-14. This is the minimum value required

to ensure that the normal residual heat removal system can meet its functional requirement of cooling the reactor during shutdown operations.

5.4.7.6.2 System Gas Accumulation Assessment and Mitigation

Subsection 6.3.6.3.1 describes the assessment method to address the potential for gas intrusion for the passive core cooling system in response to Interim Staff Guidance (ISG-019) and Generic Letter 2008-01. The same assessment methodology was used to assess the normal residual heat removal system.

The normal residual heat removal system locations equipped with manual vent valves will be inspected according to the system surveillance and venting procedures described in Subsection 6.3.6.3 to eliminate identified gas accumulations.

5.4.7.7 Instrumentation Requirements

The normal residual heat removal system contains instrumentation to monitor system performance. System parameters necessary for system operation are monitored in the main control room including the following:

- Residual heat removal flow;
- Residual heat removal heat exchanger inlet and system outlet temperatures; and,
- Residual heat removal pump discharge pressure.

In addition, the reactor coolant system contains instrumentation to control and monitor the operations of the normal residual heat removal system. These include the following:

- Reactor coolant system wide range pressure; and,
- Reactor coolant system hot leg level.

Instrumentation is also provided to enable mid-loop operations to be performed from the main control room.

The motor-operated valves connected to the reactor coolant system hot leg are interlocked to prevent them from opening when reactor coolant system pressure exceeds 450 psig. These valves are also interlocked to prevent their being opened unless the isolation valve from the in-containment refueling water storage tank to the residual heat removal pump suction header is closed. Section 7.6 describes this interlock.

5.4.8 Valves

Valves in the reactor coolant system and safety-related valves in connecting systems provide the primary means for the flow of water into and out of the reactor coolant system. In the following paragraphs the design basis, description, evaluation and testing of ASME Code Class 1, 2 and 3 valves is discussed. This discussion includes safety-related valves not in the reactor coolant system because the valve requirements are independent of the system.

5.4.8.1 Design Bases

Valves within the reactor coolant system and safety-related valves in connected systems are designed, manufactured, and tested to meet the requirements of the ASME Code, Section III. As

noted in Section 5.2, valves out to and including the second valve that is normally closed or capable of automatic or remote closure are part of the reactor coolant system. The reactor coolant pressure boundary valves are manufactured to the ASME Code Class 1 requirements. Valves of 1 inch and smaller in lines connected to the reactor coolant system are manufactured to Class 2 requirements when the flow is limited by a flow-limiting orifice.

Containment isolation valves are manufactured to ASME Code, Class 2 requirements. Other AP1000 equipment Class C safety-related valves are manufactured to ASME Code, Class 3 requirements. Safety-related valves in auxiliary systems are manufactured to ASME Code Class 2 and 3 requirements depending on their function and classification as outlined in Subsection 3.2.2.

Table 5.4-15 provides design data for the reactor coolant pressure boundary valves. Valves and operators are sized to provide valve operation under the full range of design basis flow and pressure drop conditions, including recovery from potential mispositioning of the valves. Operating modes, normal operating and worst-case differential pressures, fluid temperature ranges, and environmental effects are considered in sizing valves and valve operators. Table 5.4-16 gives the normal and maximum differential pressure expected during opening and closing of motor-operated valves in the reactor coolant pressure boundary. Check valves considered part of the reactor coolant system are located inside the containment.

5.4.8.1.1 Check Valves Design and Qualification

Design basis and required operating conditions for safety-related check valves are established based on design conditions including the required system operating cycles to be experienced by the valve, environmental conditions under which the valve is required to function, and severe transient loadings expected during the life of the valve. The design conditions considered may include water hammer and pipe break transients, sealing and leakage requirements, operating fluid conditions (including flow, velocity, temperature, and temperature gradient), maintenance requirements, time between major refurbishments, corrosion requirements, vibratory loading, planned testing methods, and test frequency, and periods of idle operation. Design conditions may include other requirements identified during plant detail design. The maximum loading resulting from the design conditions and transients are evaluated in accordance with the ASME Code, Section III Class 1 design requirements.

Active safety-related check valves include the capability to verify the movement of each check valve's obturator during inservice testing by observing a direct instrumentation indication of the valve position or by using non-intrusive test methods. This instrumentation provides nonintrusive check valve indication and may be either permanently or temporarily installed.

Check valve model and size selection are based on the systems flow conditions, installed location of the valve with respect to flow disturbance, and orientation of the valve in the piping system. Design features, surface finish, and materials can accommodate provisions for nonintrusive determination of disk position and potential valve degradation over time. Valve internal parts are designed with self-aligning features for the purpose of assured alignment after each valve opening. Qualification testing provides for the adequacy of the safety-related check valves under design conditions. This testing includes test data from the manufacturer, field test data and empirical test data supported by test or test (such as prototype) of similar valves where similarity is justified by technical data. Sampling size for the qualification test is justified by technical data.

For safety-related active check valves with extended structures functional qualification will be performed to demonstrate by test, by analysis or by a combination thereof, the ability to operate at the safety-related design conditions. This functional qualification will demonstrate the valve operability during and after loads representative of the maximum seismic and vibratory event. Check valve internal parts are analyzed for maximum design basis loading conditions in accordance with the requirements in ASME Code, Section III.

5.4.8.1.2 Motor-Operated Valves Design and Qualification

[*Design basis and required operating conditions are established for active safety-related motor-operated valves. Based on the design conditions the motor-operated valves will have a structural analysis performed to demonstrate their components are within the structural limits at the design conditions. The motor-operated valves are designed for a range of conditions up to the design conditions which includes fluid flow, differential pressure (including line break, if necessary), system pressure and temperature, ambient temperature, operating voltage range and stroke time. The sizing of the motor operators on the valves take into account diagnostic equipment accuracies, changes in output capability for increasing differential pressures and flow and ambient temperature and reduction in motor voltage, control switch repeatability, friction variations and other changes in parameters that could result in an increase in operating loads or a decrease in operator output.*]* Valves that are subjected to large temperature changes during operation and can have water or high pressure fluid trapped in the bonnet cavity are evaluated for pressure locking. Provisions are provided, as required to reduce the susceptibility to bonnet overpressurization, pressure locking, and thermal binding.

[*The motor-operated valves have a functional qualification performed to demonstrate by test, by analysis or by a combination thereof, the ability to operate over a range up to the design conditions. This functional qualification will demonstrate the motor-operated valve capability during and after loads representative of the maximum seismic or vibratory event (as required to perform their intended function), demonstrate the valve sealing capability, demonstrate capability under cold and hot operating conditions, demonstrate capability under maximum pipe end loads and demonstrate flow interruption and functional capability. The testing includes test data provided by the manufacturer, field test data, empirical data supported by testing or analysis of prototype tests of similar motor-operated valves that support the qualification where similarity must be justified by technical data. The qualification must be used for validating the required thrust and torque as applicable to operate the valve and the output capability of the motor operator.*]*

Motor-operated valves are designed to be able to change their position from an improper position (mis-positioned) either prior to or during accidents. The recovery from mis-positioning is considered a nonsafety-related function. The nonsafety-related capability to recover from valve mis-positioning is provided for plant operational availability considerations. Systems with safety-related functions that contain motor-operated valves are designed to tolerate mis-positioning as a single failure or redundant features are provided to preclude mis-positioning. These features include multiple position indicators and alarms, technical specification surveillance, power lock-out, and confirmatory open or close signals.

Since recovery from mis-positioning is a nonsafety-related function, equipment qualification testing and inservice testing is not required for the recovery from mis-position function.

Provisions are made, where possible, for in-situ testing of motor-operated valves at a range of conditions up to the maximum design basis operating conditions in the safety-related design direction (open or close). Where an alternative to in-situ testing is required, the justification of the alternative method to design condition differential testing is documented as part of the valve test program.

5.4.8.1.3 Other Power-Operated Valves Including Explosively Actuated Valves Design and Qualification

Design basis and required operating conditions are established for power-operated (POV) and explosively actuated valve assemblies with an active safety-related function. Power-operated valve assemblies include pneumatic-hydraulic-, air piston-, and solenoid-operated assemblies. Explosively-actuated valves have shear caps and are actuated by an explosive charge fired by an electrical signal.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

[*The power-operated safety related valves will have a structural analysis performed to demonstrate their components are within the structural limits at the design conditions. Power operated valve assemblies and explosively actuated valves are designed to accept the maximum compression, tension, and torsional loads which the assembly is capable of producing in combination with other loads such as pressure, thermal, or externally applied loads. The maximum loading resulting from the design conditions and transients is evaluated in accordance with the ASME Code, Section III Class 1 design requirements. Packing adjustment limits are identified to reduce the potential for stem binding.*

The power-operated valves are designed to operated at design operating conditions which include fluid flow, differential pressure (including pipe break, if necessary), system pressure, fluid temperature, ambient temperature, fluid supply conditions (or electrical power supply), spring force and stroke time requirements. The power operated valves, depending on their design and actuation mode, have the operators sized to account for diagnostic equipment accuracies, changes in output capability for increasing differential pressures and flow, friction variations and changes in other parameters that could result in an increase in operating loads or a decrease in operator output.

The power-operated, safety-related valves have a functional qualification performed to demonstrate by test, by analysis or by a combination thereof, the ability to operate at the design conditions. Qualification testing of each size, type, and model is performed under a range of differential pressures and maximum achievable flow conditions up to the design conditions. This functional qualification will demonstrate the power-operated valves capability during and after loads representative of the maximum seismic or vibratory event (as required to perform their intended function), demonstrate the valve sealing capability, demonstrate capability under cold and hot operating conditions, demonstrate capability under maximum pipe end loads and demonstrate flow interruption and functional capability. The testing includes test data from the manufacturer, field test data, empirical data supported by test, or analysis of prototype tests of similar power-operated valves that support qualification of the power-operated valve. Similarity must be justified by technical data. Solenoid-operated valves are verified to satisfy the applicable requirements for Class 1E components. Solenoid-operated valves are verified to perform their safety-related design requirements over a range of electrical power supply conditions including minimum and maximum voltage.]*

5.4.8.2 Design Description

The materials of construction are selected to minimize the effects of corrosion and erosion and are compatible with the environment. The valves in contact with reactor coolant fluid shall be constructed of stainless steel materials or alloys acceptable for the fluid chemistry.

Safety-related valves do not have full penetration welds within the valve body walls except that explosive actuated valves may be fabricated using full penetration welds of the valve bodies.

Valves and actuators are furnished as a matched system capable of operating over the entire range of design basis conditions. The function of the valve and operator including switch settings for motor-operated valves are qualified by testing, analysis or a combination thereof.

Valves that have stem packing are constructed with packing material compatible with the system fluid and stem material. Valves greater than 2 inch diameter may have live load packing to maintain a compressive packing force. Variations in valve packing configurations are bounded in occupational radiation exposure dose assessments. Valves supplied with stem packing are supplied with a backseat which may be utilized to minimize stem leakage. The backseat capability does not rely on system pressure to achieve a satisfactory seal. Valve designs such as main steam isolation valves, safety relief valves, packless valves and small solenoid valves by nature of the design of these valves do not have backseat capability. Motor operated valves are not backseated during normal operation. The backseating of the valve must not compromise the structural integrity of the valve and

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

the backseats are capable of retaining the valve stem against full system pressure and maximum thrust produced by the actuator.

Gate valves at the interface with the reactor coolant system and connected safety-related systems are either of the wedge or parallel disc design and have essentially straight through flow. The wedge design is flex-wedge; solid wedge designs are not used. Gate valves have backseats. Gate valves that are susceptible to overpressurization as the result of the heatup of trapped fluid shall be provided with venting capability to alleviate the issue. The valve shall be of outside screw and yoke design. Gate valves are not used in flow regulation or throttling service.

Globe valves are either T or Y type of either a standard or balanced plug design. Valves that are used for throttling service are designed with a disc or disc/cage assembly that will provide the required flow characteristic. Motor operated and manual valves are of the outside screw and yoke design.

Check valves are typically swing type, but tilt disk, nozzle check, and lift check may be used. Check valves containing radioactive fluid are fabricated of stainless steel. These valves do not have body penetration other than the inlet, outlet and bonnet. The check hinge is serviced through the bonnet. Operating parts are contained within the body. The disc of swing check valves has limited rotation to provide a change of seating surface and alignment after each valve opening.

5.4.8.3 Design Evaluation

ASME Code, Class 1 valves meet the design requirements of ASME Code, Section III, Article NB-3000. ASME Code, Class 2 valves meet the design requirements of ASME Code, Section III, Article NC-3000. ASME Code Class 3 valves meet the design requirements of ASME Code, Section III, Article ND-3000. The AP1000 equipment Classes A, B, and C valves, which are manufactured to ASME Code Classes 1, 2, and 3 respectively, meet established functional requirements. The functional requirements include operability, differential pressure during opening or closure, and seat leakage. The functional requirements are based on ASME QME-1 (Reference 8).

The design transients for the valves including the number and the duration of each type of cycle are identified in Subsection 3.9.1.1.

Valves with extended structures have testing or analysis performed to demonstrate that the natural frequency is greater than 33 hz. In addition, a structural analysis is performed to verify the design loading will not effect the intended operation of the valve.

Qualification testing of each power operated valve which includes motor-operated, air operated, hydraulic operated, solenoid operated and explosive actuated valves demonstrates the capability of the operator to operate over the full range of expected plant operating conditions. Qualification testing also demonstrates the closing, opening, and seating capability of the valve against the maximum pressure differential and flow within a specified time over the entire operating range. Requirements for qualification testing of power-operated active valves are based on ASME QME-1 (Reference 8). The testing programs in Section 3.10 demonstrate the capability of the valves to operate, as required, during anticipated and postulated plant conditions.

Reactor coolant chemistry parameters are compatible with valve construction materials.

5.4.8.4 Tests and Inspections

The nondestructive examinations for the reactor coolant pressure boundary valves meet the more stringent requirements of the ASME Code, Section III, and ASME B16.34 (Reference 9). The nondestructive examination required is evaluated for each type and class of valve. The examinations consist of the following:

- **Radiographic Examination** - Classes 1 and 2 valve bodies, bonnets, and discs which are made of cast material are radiographically examined in accordance with the ASME Code, Section III. The procedure and acceptance standards are according to the requirements for Class 1 in the ASME Code, Section III.

- **Ultrasonic Examination -** Classes 1 and 2 valve bodies, bonnets, and discs and Classes 1, 2, and 3 valve stems of 1 inch nominal diameter or larger fabricated of wrought or forged material are ultrasonically examined, except for stems for valves with inlet pipe connections of 2 inches nominal pipe size and less. The procedures and acceptance standards are according to the requirements for Class 1 in the ASME Code, Section III.

- **Liquid Penetrant Examination** - Bodies, bonnets, discs, and stems, including machined surfaces on these parts, are liquid-penetrant examined in accordance with the ASME Code, Section III. The procedures and acceptance standards are according to the requirements for Class 1 in the ASME Code, Section III.

Hydrostatic pressure boundary test and seat leakage are performed on the reactor coolant pressure boundary valves. The valves are subjected to the following tests as appropriate following manufacture: hydrostatic pressure boundary test, disc hydrostatic test, backseat leakage test, packing leakage test, stem leakage test, and main seat leakage test. Valves used for containment isolation are subjected to a pneumatic seat leakage test. Each diaphragm actuator assembly is subjected to a pneumatic leakage test.

Preoperational testing is performed on the valves to verify operability during design basis operating conditions. The preoperational testing is described in the following sections. The requirements of NRC Generic Letter 89-10 are used as guidelines to develop the preservice test program for valve operability. Except when test alternatives are justified, design conditions are used for the operability testing.

Subsection 5.2.4 discusses inservice inspection for ASME Code Class 1 valves. Section 6.6 discusses inservice inspection for ASME Code Class 2 and 3 components. Valves are accessible for disassembly and internal visual inspection to the extent practical. Subsection 3.9.6 discusses the inservice testing program for active valves.

5.4.8.5 Preoperational Testing

Results of preoperational testing will be used to demonstrate that the results of testing under in situ or installed conditions can be used to confirm the capacity of the valve to operate under design conditions as discussed in Section 14.4.

5.4.8.5.1 Check Valves

Active check valves are tested in the open and close direction. Testing a check valve confirms the valve operability to move to the position to fulfill the safety-related mission during applicable plant modes. The test shows that the check valve opens in response to flow and closes when the flow is stopped. Operability testing of the valves is described in Subsection 3.9.3.2.2. Full-flow testing during applicable plant modes of check valves or sufficient flow to fully open the check valve to demonstrate valve operability under design conditions is permitted in most cases by the system design. Where this testing cannot be accomplished, an alternate method of demonstrating operability is developed, and justified. A demonstration of reverse-flow isolation of the check valves that is that the check valve closes when the flow is stopped is performed using direct means or diagnostics. The testing includes the effects of rapid pump starts and stops as required by expected system operating conditions.

The valves to be tested, the safety-related functions of the valves, and the type of testing to be done to verify the capability of the valves to perform the safety-related functions are outlined in valve inservice test requirements found in Subsection 3.9.6. The valves to be tested, safety-related functions, and test requirements for preoperational testing are the same as outlined in inservice test requirements.

During pre-operational testing the following is verified to demonstrate the acceptability of the functional performance.

- The valves are verified to fully open or fully closed under design flow conditions.
- The disc movement from full open to full close is free.
- The valve leakage when fully closed is within established limits, as applicable.
- The disc is stable in the full open position at the system operating flow, conditions.
- The valve disc position can be verified without disassembly of the valve.
- The valve design features, surface finish and materials can accommodate nonintrusive diagnostic testing methods.
- The testing requirements in the inservice test plan can be accommodated in the piping system design.

5.4.8.5.2 Motor-Operated Valves

[*Active safety-related motor-operated valves are tested to verify that the valves open and close under static and safety-related design conditions. Where the safety-related design conditions cannot be achieved, the testing is performed at the maximum achievable dynamic conditions. During the testing critical parameters needed to determine the required closing and opening loads are measured These parameters include thrust, torque, travel, differential pressure, system pressure, fluid flow, voltage, temperature, operating time and thrust/torque at seating, unwedging and at control switch trip. The data collected during the testing on the parameters is used to determine the required operator loads and output capability for the design operating conditions in conjunction with the diagnostic equipment inaccuracies, load changes for increasing differential pressures and flow and ambient temperature and reduction in motor voltage, control switch repeatability, friction variations and changes in other parameters that could result in an increase in operating loads or decrease in operator output capability. The resulting operating loads including uncertainties are then compared to the structural capabilities of the motor-operated valve.*]* Active safety-related motor-operated valves are tested prior to operation for operability as described in Subsection 3.9.3.2.2.

Pre-operational testing and evaluation is used to demonstrate the acceptability of the valves functional performance including the following.

- The valves are verified to open and close as applicable at a range of safety-related conditions up to the design conditions to perform their safety function.
- The control switch settings must be adequate to provide margin for diagnostic accuracy, control switch repeatability, load sensitive behavior and degradation.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- The motor operator capability at degraded voltage must exceed the required operating loads and the loads at the control switch settings including diagnostic equipment inaccuracies, load changes for increasing differential pressures and flow, control switch repeatability, friction variations and other parameters that could result in an increase in operating loads or decrease in operator output capability.

- The maximum operating loads including diagnostic equipment inaccuracies, load changes for increasing differential pressures and flow, control switch repeatability, friction variations and other parameters that could result in an increase in operating loads or decrease in operator output capability are verified not to exceed the allowable structural capability limits of the motor-operated valve components.

- The stroke time measurements during opening and closing must be within the design requirements if stroke time is important to the safety function.

- The remote position indication is verified against the local position indication.

- The valve leakage when fully closed is within established limits, as applicable.

5.4.8.5.3 Power-Operated Valves

[*Active safety related power-operated valve assemblies are tested to verify that the valve opens and closes under static and design conditions. Where the design conditions cannot be achieved, the testing is performed at the maximum achievable dynamic conditions. During the testing, critical parameters needed to determine the required closing and opening loads are measured. These parameters include seat load, torque or thrust, travel, spring rate, differential pressure, system pressure, fluid flow, temperature, power supply, operating time and minimum supply pressure. The data collected during the testing on the parameters is used to determine the required operating loads for the design operating conditions in conjunction with the diagnostic equipment inaccuracies and other parameters that could result in an increase in operating loads or decrease in operator output capability. The resulting operating loads including uncertainties are then compared to the structural capabilities of the power-operated valve.*]*

During pre-operational testing the following are verified to demonstrate the acceptability of the functional performance.

- The valves are verified to open and close as applicable at a range of conditions up to the design conditions to perform its safety function.

- For air-operated valves and hydraulically-operated valves the operator capability at minimum supply pressure, power supply or loss of motive force exceed the required operating loads including diagnostic equipment inaccuracies and other parameters that could result in an increase in operating loads or decrease in operator output capability.

- For solenoid-operated valves the valve must be capable of opening or closing the valve at the minimum power supply.

- For air-operated valves and hydraulically-operated valves the maximum operating loads including diagnostic equipment inaccuracies and other parameters that could result in an increase in operating loads are verified not to exceed the allowable structural capability limits of the power-operated valve components.

- The stroke time measurements during opening and closing must be within the design requirements for safety-related functions.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- The remote position indication is verified against the local position indication.
- The valve leakage when fully closed is within established limits, as applicable.

5.4.9 Reactor Coolant System Pressure Relief Devices

Safety valves connected to the pressurizer provide overpressure protection for the reactor coolant system during power operation. The relief valves on the suction line of the normal residual heat removal system (RNS) provide low temperature overpressure protection consistent with the guidelines of NRC Branch Technical Position RSB 5-2. The following discusses the requirements for the valves. Sizing of the safety and relief valves is discussed in Subsection 5.2.2.

Power-operated relief valves are not provided in the AP1000 reactor coolant system. Non-reclosing pressure relief devices are not used for pressure relief on the AP1000 reactor coolant system. Section 10.3 discusses safety valves for the main steam system. The automatic depressurization valves which are also connected to the pressurizer and are the interface with the passive core cooling system, are not pressure relief devices. (See Subsection 5.4.6.)

5.4.9.1 Design Bases

The combined capacity of the pressurizer safety valves can accommodate the maximum pressurizer surge resulting from complete loss of load. The relief valves on the suction line of the normal residual heat removal system can accommodate the flow from one or both makeup pumps with no letdown and a water-solid reactor coolant system during low-temperature modes. Table 5.4-17 gives design parameters for the pressurizer safety valves and the residual heat removal system relief valves.

Use of the pressurizer safety valves and the normal residual heat removal relief valves at elevated temperatures in post-accident environments is not anticipated.

5.4.9.2 Design Description

The pressurizer safety valves and the normal residual heat removal system relief valves are spring loaded, self-actuated by direct fluid pressure, and have backpressure compensation features. These valves are designed to reclose and prevent further flow of fluid after normal conditions have been restored. The pressurizer safety valves are of the totally enclosed pop type. The normal residual heat removal relief valves are designed for water relief.

The pressurizer safety valves are incorporated in the pressurizer safety and relief valve (PSARV) module, which provides the connection to the pressurizer nozzles. The routing of pipe between the pressurizer and the safety valves does not include a loop seal. Any condensation of steam in the connecting pipe up to the valve rains back to the pressurizer. Condensate does not collect as a slug of water to be discharged during the initial opening of the valve. The discharge of the safety valve is routed through a rupture disk to containment atmosphere. The rupture disk is provided to contain leakage past the valve, is designed for a substantially lower set pressure than the safety valve set pressure, and does not function as a relief device. Because the rupture disks have relatively low set pressures and the header directing the safety valve discharge to the rupture disk also drains into the ADS discharge, with ADS discharge having a potential rupture disk breaking pressure, for economic reasons being to reduce rupture disk replacement costs, a check valve is installed in the safety valve discharge drain line to reduce the potential for ADS backpressure actuating the rupture disks while ADS is discharging. The reactor coolant system Piping and Instrumentation Drawing (Figure 5.1-5) shows the arrangement of the safety valves, rupture disks, and check valve.

The relief valves in the normal residual heat removal system are located between the suction line of the pump and the valve that isolates the residual heat removal system from the reactor coolant

system. The discharge from the valves is directed to the containment sump. Subsection 5.4.7 discusses the residual heat removal system. Figure 5.4-6 shows a simplified sketch of the normal residual heat removal system.

In accordance with the requirements of 10 CFR 50.34(f)(2)(xi), positive position indication is provided for the pressurizer safety valves and the normal residual heat removal system relief valves, which provide overpressure protection for the reactor coolant pressure boundary.

Temperatures in the safety valve discharge lines are measured, and an indication and a high temperature alarm are provided in the control room. An increase in a discharge line temperature is an indication of leakage or relief through the associated valve. Leakage past the pressurizer safety valve during normal operation is collected and directed to the reactor coolant drain tank. Section 7.5 discusses the functional requirements for the instrumentation required to monitor the safety valves.

Temperature in the common relief valve discharge line is measured, and an indication and a high alarm are provided in the control room. A rate of change in the discharge line temperature is an indication of leakage or relief through the associated valves. Leakage past the RNS relief valves is directed to the containment sump.

5.4.9.3 Design Evaluation

The pressurizer safety valves prevent reactor coolant system pressure from exceeding 110 percent of system design pressure, in compliance with the ASME Code, Section III. The relief valves on the suction line of the normal residual heat removal system protect that system from exceeding 110 percent of the design pressure of the system and from exceeding the pressure-temperature limits determined from ASME Code, Appendix G, analyses.

The reactor coolant system pressure transients are described in Subsection 15.2.3 and are the basis for the ASME Code Overpressure Protection Report. In the analysis of overpressure events, the pressurizer safety valves are assumed to actuate at 2500 psia. The safety valve flowrate assumed is based on full flow at 2575 psia, assuming 3 percent accumulation.

In certain design basis events described in Chapter 15, including the inadvertent CMT actuation, loss of normal feedwater, and CVS malfunction events, the reactor coolant system experiences slow pressurization rates up to the pressurizer safety valve lift setpoint and pressure is relieved through the safety valves for an extended period of time. For these events, the reactor coolant system pressure is slowly increasing as a result of the mismatch between the decay heat removal rate from the passive residual heat removal heat exchanger and the core decay heat. This slow pressurization of the reactor coolant system may be relieved through a small amount of steam flow through the safety valves without either safety valve fully opening. However, the pressurizer safety valves are designed to minimize leakage at pressures approaching lift pressure. These valves are qualified to relieve pressure for the duration of the anticipated transients assuming the valves fully open when their lift setpoint is reached. Operation of the safety valves under these conditions could result in small leakage from the valve (much less than the capacity of the normal makeup system), but does not impair the valve overpressure protection capability.

The relief valves on the normal residual heat removal system have an accumulation of 10 percent of the set pressure. The set pressures are the lower of the pressure based on the design pressure of the residual heat removal system and the pressure based on the reactor vessel low temperature pressure limit. The pressure limit determined based on the design pressure includes the effect of the pressure rise across the pump. The set pressures in Table 5.4-17 are based on the reactor vessel low temperature pressure limit. The lowest permissible set pressure is based on the required net positive suction head for the reactor coolant pump.

5.4.9.4 Tests and Inspections

The safety and relief valves are the subject of a variety of tests to validate the design and to verify pressure boundary and functional integrity. For valves that are required to function during a Service Level D condition, static deflection tests are performed to demonstrate operability. Section 3.10 describes these tests.

Safety valves similar to those connected to the pressurizer have been tested within the Electric Power Research Institute (EPRI) safety and relief valve test program. Capacity data for the specific AP1000 safety valve size has been correlated with the EPRI test data to demonstrate that the valve is adequate for steam flow and water flow, even though water flow is not anticipated through the pressurizer safety valves. The completion of this program addresses the requirements of 10 CFR 50.34(f)(2)(x) as related to reactor coolant system relief and safety valve testing. The normal residual heat removal system relief valves are designed for water relief and are not reactor coolant system pressure relief devices since each valve has a set pressure less than reactor coolant system design pressure. Therefore, the valves selected for the normal residual heat removal system relief valves are independent from the Electric Power Research Institute safety and relief valve test program.

Reactor coolant system pressure relief devices are subjected to preservice and inservice hydrostatic tests, seat leakage tests, operational tests, and inspections, as required. The preservice and inservice inspection and testing programs for valves are described in Subsections 3.9.6 and 5.2.4 and Section 6.6. The test program for the safety valves complies with the requirements of ASME Appendix I of the OM Code.

The pressure boundary portion of the valves are required to be inservice inspected according to the rules of Section XI of the ASME Code. There are no full-penetration welds within the valve body walls. Valves are accessible for disassembly and internal visual inspection.

Type testing of the pressurizer safety valves is performed to verify that the pressurizer safety valves operate stably during slow pressurization transients at pressures near the valve set pressure. The valve full-open pressure is the pressure at which the safety valve opens with significant blowdown flow. The duration of the testing need not duplicate the times indicated in the accident analysis results but should last for a sufficient time to demonstrate stable valve operation. Stable valve performance which may include extended periods of valve simmering or typical valve opening (popping fully open) without excessive valve cycling or chattering for a 15 minute time duration is sufficient. The testing is performed to verify the pressurizer safety valves are capable of performing their intended design function throughout the duration of the slow pressurization transients by either simmering or popping fully open. Following this testing, the valve integrity is demonstrated, and the valve leakage is required to be less than the makeup capability of the chemical and volume control system makeup pumps.

5.4.10 Component Supports

5.4.10.1 Design Bases

Component supports provide deadweight support for the piping and equipment, allow lateral thermal movement of the loop during plant operation, and restrain the loops and components during accident and seismic conditions. Subsection 3.9.3 discusses the loading combinations and design stress limits. Support design is according to the ASME Code, Section III, Subsection NF.

The design provides for the integrity of the reactor coolant pressure boundary for normal, seismic, and accident conditions. The design also maintains the piping stresses less than ASME Code limits and less than the limits required to support mechanistic pipe break discussed in Subsection 3.6.3.

Section 3.9 presents the results of piping and supports stress evaluations. The loads associated with the dynamic effects of postulated pipe rupture for pipes 6" and larger, which satisfied the requirements for mechanistic pipe break, are not included. See Subsection 3.6.3.

The edition of the ASME code, Section III, subsection NF, which is used as the baseline requirement, address the guidance of Regulatory Guides 1.124 and 1.130. The plant design is in conformance with these requirements of the ASME Code. Conformance with Regulatory Guides 1.124 and 1.130 is discussed in detail in Section 1.9. The embedded portions of the component supports are designed according to AISC N690 and ACI 349, as discussed in Subsection 3.8.3.

5.4.10.2 Design Description

The support structures are welded, structural steel sections. Linear structures (tension and compression struts, columns, and beams) are used except for the reactor vessel supports, which are plate-and-shell-type structures. Attachments to the supported equipment are either integral (welded to the component) or non-integral (pinned to, bolted to, or borne against the components). The supports-to-concrete attachments are either brackets welded to heavy embedded plates or anchor bolts or are embedded fabricated assemblies.

The supports permit thermal growth of the supported systems but restrain vertical and lateral movement resulting from seismic and pipe-break loadings. This is accomplished by using pinned ends in the vertical support columns, girders, bumper pedestals, and hydraulic snubbers, and lateral struts.

Because of manufacturing and construction tolerances, ample adjustment for the support structures provides proper erection alignment and fit-up. This is accomplished by shimming or grouting at the supports-to-concrete interface and by shimming at the supports-to-equipment interface.

The supports for the various components are described in the following paragraphs.

5.4.10.2.1 Reactor Pressure Vessel

The reactor vessel supports consist of four individual, air-cooled steel box structures located beneath the inlet nozzles (See Figure 3.8.3-4). The boxes are air-cooled to achieve a concrete design temperature of 200°F. To reduce heat transfer from the nozzle to the concrete, cooled air is baffled vertically through the support, and the heated air is vented at the top.

Vertical and horizontal loads are transmitted from the reactor vessel nozzle pad to the box structure through an integral recessed “pocket” at the top of the box. The nozzle pad bears on permanently lubricated wear plates that allow radial thermal movements of the nozzle with minimal friction resistance to the movement. The vessel support boxes transfer loads from the reactor pressure vessel to vertical and horizontal embedments in the primary shield wall concrete.

5.4.10.2.2 Steam Generator

As shown in Figure 3.8.3-5, each steam generator support consists of the following:

Vertical Support

The vertical support consists of a single vertical column extending from the steam generator compartment floor to the bottom of each steam generator channel head. The column is constructed of a heavy wide flange section, and is pinned at both ends to permit thermal movement of each steam generator during plant heatup and cooldown. The column is located so that it allows full access to the steam generator for routine maintenance activities. It is located far enough from the reactor coolant pump motors to permit pump maintenance and inservice inspection.

Lower Lateral Support

The lower horizontal support is located at the bottom of the channel head. It consists of a tension/compression link bar and extension bar oriented nearly perpendicular to the hot leg. The link bar/extension bar is pinned at both the wall bracket and the steam generator channel head to permit movement of the steam generator during plant heatup and cooldown.

Upper Lateral Support

The upper horizontal support in the direction of the hot leg is located on the upper shell just above the transition cone. It consists of two large hydraulic snubbers oriented parallel with the hot leg centerline. One snubber is mounted on each side of the generator on top of the steam generator compartment wall. The hydraulic snubbers are valved to permit relatively unrestricted steam generator movement during thermal transient conditions, and to “lock up” and act as a rigid strut under dynamic loads.

The upper steam generator horizontal support in the direction normal to the hot leg is located on the lower shell just below the transition cone. It consists of two rigid struts oriented perpendicular to the hot leg. The two rigid struts are mounted on the steam generator compartment wall at the elevation of the operating deck. The steam generator loads are transferred to the struts and snubbers through trunnions on the generator shell.

5.4.10.2.3 Reactor Coolant Pump

The reactor coolant pumps are supported entirely by the steam generators; consequently, there are no reactor coolant pump supports.

5.4.10.2.4 Pressurizer

The supports for the pressurizer, as shown in Figure 3.8.3-6, consist of the following:

- Four steel columns attached to the lower head to provide vertical support for the pressurizer. Struts connected to the lower head and surrounding walls provide lateral support.

- The upper lateral support consists of a box-type ring girder that surrounds the pressurizer. The support connects to the corners of the pressurizer cubicle walls with eight standard sway struts. The girder rests on and is supported vertically by the pressurizer valve support brackets. The pressurizer upper support also supports the pressurizer safety relief piping and valve module, in addition to providing lateral support to the pressurizer.

5.4.10.2.5 Control Rod Drive Mechanism Supports

The support for the control rod drive mechanism is provided by the integrated head package, as described in Subsection 3.9.7.

5.4.10.3 Design Evaluation

An evaluation verifies the design adequacy and structural integrity of the reactor coolant loop and the primary equipment supports system. This evaluation compares the analytical results with established criteria for acceptability. Structural analyses demonstrate design adequacy for safety and reliability of the plant in case of a seismic disturbance, and/or loss of coolant accident conditions. Loads that the system is expected to encounter during its lifetime (thermal, weight, and pressure) are applied, and stresses are compared to allowable values. Subsection 3.9.3 discusses the modeling and analysis methods.

5.4.10.4 Tests and Inspections

Nondestructive examinations are performed according to the procedures of the ASME Code, Section V, except as modified by the ASME Code, Section III, Subsection NF.

5.4.11 Pressurizer Relief Discharge

The AP1000 does not have a pressurizer relief discharge system. The AP1000 has neither power operated pressurizer relief valves nor a pressurizer relief discharge tank. Some of the functions provided by the pressurizer relief discharge system in previous nuclear power plants are provided by portions of other systems in the AP1000.

The safety valves connected to the top of the pressurizer provide for overpressure protection of the reactor coolant system. First-, second-, and third-stage automatic depressurization system valves provide for depressurization of the reactor coolant system and venting of noncondensable gases in the pressurizer following an accident. These functions are discussed in Subsections 5.2.2, 5.4.12, and in Section 6.3. The AP1000 does not have power operated relief valves connected to the pressurizer.

The discharge of the safety valves is directed through a rupture disk to containment atmosphere.

The discharge of the first-, second-, and third-stage automatic depressurization system valves is directed to the in-containment refueling water storage tank. For the automatic depressurization system valves, the following discussion considers only the gas venting function. Only the first stage automatic depressurization valves are used to vent non-condensible gases following an accident. The sizing considerations and design basis for the in-containment refueling water storage tank for the depressurization function are discussed throughout Section 6.3. The provisions to minimize the differential pressure between the containment atmosphere and the interior of the in-containment refueling water storage tank are also discussed in Subsection 6.3.2.

The relief valves on the normal residual heat removal system, which provide low temperature overpressure protection, discharge into the containment sump. See Subsection 5.4.7 for a discussion of the connections to and location of the relief valves in the normal residual heat removal system.

5.4.11.1 Design Bases

The containment has the capability to absorb the pressure increase and heat load resulting from the discharge of the safety valves to containment atmosphere. The in-containment refueling water storage tank has the capability to absorb the pressure increase and heat load from the discharge, including the water seal, steam and gases, from a first-stage automatic depressurization system valve when used to vent noncondensable gases from the pressurizer following an accident. The venting of noncondensable gases from the pressurizer following an accident is not a safety-related function.

5.4.11.2 System Description

Each safety valve discharge is directed to a rupture disk at the end of the discharge piping. A small pipe is connected to the discharge piping to drain away condensed steam leaking past the safety valve. The discharge is directed away from any safety related equipment, structures, or supports that could be damaged to the extent that emergency plant shutdown is prevented by such a discharge.

The discharge from each of two groups of automatic depressurization system valves is connected to a separate sparger below the water level in the in-containment refueling water storage tank. The piping and instrumentation diagram for the connection between the automatic depressurization

system valves and the in-containment refueling water storage tank is shown in Figure 6.3-1. The in-containment refueling water storage tank is a stainless steel lined compartment integrated into the containment interior structure. The discharge of water, steam, and gases from the first-stage automatic depressurization system valves when used to vent noncondensable gases does not result in pressure in excess of the in-containment refueling water storage tank design pressure. Additionally, vents on the top of the tank protect the tank from overpressure, as described in Subsection 6.3.2.

Overflow provisions prevent overfilling of the tank. The overflow is directed into the refueling cavity. The in-containment refueling water storage tank does not have a cover gas and does not require a connection to the waste gas processing system. The normal residual heat removal system provides nonsafety-related cooling of the in-containment refueling water storage tank.

5.4.11.3 Safety Evaluation

The design of the control for the reactor coolant system and the volume of the pressurizer is such that a discharge from the safety valves is not expected. The containment design pressure, which is based on loss of coolant accident considerations, is greatly in excess of the pressure that would result from the discharge of a pressurizer safety valve. The heat load resulting from a discharge of a pressurizer safety valve is considerably less than the capacity of the passive containment cooling system or the fan coolers. See Section 6.2.

Venting of noncondensable gases, including entrained steam and water from the loop seals in the lines to the automatic depressurizations system valves, from the pressurizer into spargers below the water line in the in-containment refueling water storage tank does not result in a significant increase in the pressure or water temperature. The in-containment refueling water storage tank is not susceptible to vacuum conditions resulting from the cooling of hot water in the tank, as described in Subsection 6.3.2. The in-containment refueling water storage tank has capacity in excess of that required for venting of noncondensable gases from the pressurizer following an accident.

5.4.11.4 Instrumentation Requirements

The instrumentation for the safety valve discharge pipe, containment, and in-containment refueling water storage tank are discussed in Subsections 5.2.5, 5.4.9, and in Sections 6.2 and 6.3, respectively. Separate instrumentation for the monitoring of the discharge of noncondensable gases is not required.

5.4.11.5 Inspection and Testing Requirements

Sections 6.2 and 6.3 discuss the requirements for inspection and testing of the containment and in-containment refueling water storage tank, including operational testing of the spargers. Separate testing is not required for the noncondensable gas venting function.

5.4.12 Reactor Coolant System High Point Vents

The requirements for high point vents are provided for the AP1000 by the reactor vessel head vent valves and the automatic depressurization system valves. The primary function of the reactor vessel head vent is for use during plant startup to properly fill the reactor coolant system and vessel head. Both reactor vessel head vent valves and the automatic depressurization system valves may be activated and controlled from the main control room. The AP1000 does not require use of a reactor vessel head vent to provide safety-related core cooling following a postulated accident.

The reactor vessel head vent valves (Figure 5.4-8) can remove noncondensable gases or steam from the reactor vessel head to mitigate a possible condition of inadequate core cooling or impaired

natural circulation through the steam generators resulting from the accumulation of noncondensable gases in the reactor coolant system. The design of the reactor vessel head vent system is in accordance with the requirements of 10 CFR 50.34 (f)(2)(vi).

The reactor vessel head vent valves can be operated from the main control room to provide an emergency letdown path which is used to prevent pressurizer overfill following long-term loss of heat sink events. An orifice is provided downstream of each set of head vent valves to limit the emergency letdown flow rate.

The first stage valves of the automatic depressurization system are attached to the pressurizer and provide the capability of removing noncondensable gases from the pressurizer steam space following an accident. Venting of noncondensable gases from the pressurizer steam space is not required to provide safety-related core cooling following a postulated accident. Gas accumulations are removed by remote manual operation of the first stage automatic depressurization system valves.

The discharge of the automatic depressurization system valves is directed to the in-containment refueling water storage tank. Subsection 5.4.6 and Section 6.3 discuss the automatic depressurization system valves and discharge system.

The passive residual heat removal heat exchanger piping and the core makeup tank inlet piping in the passive core cooling system include high point vents that provide the capability of removing noncondensable gases that could interfere with heat exchanger or core makeup tank operation. These gases are normally expected to accumulate when the reactor coolant system is refilled and pressurized following refueling shutdown. Any noncondensable gases that collect in these high points can be manually vented.

The discharge of the passive residual heat removal heat exchanger high point vent is directed to the in-containment refueling water storage tank. The discharge of the core makeup tank high point vent is directed to the reactor coolant drain tank. Section 6.3 discusses the passive residual heat removal heat exchanger and venting capability, which is part of the passive core cooling system.

5.4.12.1 Design Bases

The reactor vessel head vent arrangement is designed to remove noncondensable gases or steam from the reactor coolant system via remote manual operations from the main control room through a pair of valves. The system discharges to the in-containment refueling water storage tank (IRWST).

The reactor vessel head vent system is designed to provide an emergency letdown path that can be used to prevent long-term pressurizer overfill following loss of heat sink events. The reactor vessel head vent is designed to limit the emergency letdown flow rate to within the capabilities of the normal makeup system. The reactor vessel head vent system can also vent noncondensable gases from the reactor head in case of a severe accident.

The system vents the reactor vessel head by using only safety-related equipment. The reactor vessel head vent system satisfies applicable requirements and industry standards, including ASME Code classifications, safety classifications, single-failure criteria, and environmental qualification.

The piping and equipment from the vessel head vent up to and including the second isolation valve are designed and fabricated according to ASME Codes Section III, Class 1 requirements. The remainder of the piping and equipment are design and fabricated in accordance with ASME Code, Section III, Class 3 requirements.

The supports and support structures conform with the applicable requirements of the ASME Code.

The Class 1 piping used for the reactor vessel head vent is 1-inch schedule 160 and 6-inch schedule 160. In accordance with ASME Section III it is analyzed following the procedures of NC-3600 for Class 2 piping.

The piping stresses meet the requirements of ASME Code, Section III, NC-3600, with a design temperature of 650°F and a design pressure of 2485 psig.

The automatic depressurization system functions as a part of the passive core cooling system. The first stage automatic depressurization system valves are connected to the pressurizer. The valves are designed, constructed, and inspected to ASME Code Class 1 and seismic Category I requirements. Subsection 5.4.6 and Section 6.3 discuss the design bases for the automatic depressurization system and automatic depressurization system valves.

The primary function of the passive residual heat removal heat exchanger and core makeup tank high point vents is to prevent accumulation of noncondensable gases from the reactor coolant system that could interfere with operation of the passive core cooling system. Section 6.3 discusses the design bases for the passive residual heat removal heat exchanger, the core makeup tanks, and their vent lines.

5.4.12.2 System Description

The reactor vessel head vent arrangement consists of two flow paths, each with redundant isolation valves. Orifices are located downstream of each set of head vent isolation valves to limit the reactor vessel head vent flow rate. Table 5.4-18 lists the equipment design parameters. The reactor vessel head vent arrangement is shown on the reactor coolant system piping and instrumentation diagram (Figure 5.1-5).

The head vent arrangement consists of two parallel paths of two 1-inch, open/close, solenoid-operated isolation valves connected to a 1-inch vent pipe located near the center of the reactor vessel head and two sections of 6-inch pipe along this pipe. The system design with two valves in series in each flow path minimizes the possibility of reactor coolant pressure boundary leakage. The solenoid-operated isolation valves are powered by the safety-related Class 1E DC and UPS system. The solenoid-operated isolation valves are fail-closed, normally closed valves. The valves are included in the valve operability program and are qualified to IEEE-323, IEEE-344, and IEEE-382.

The vent system piping is supported such that the resulting loads and stresses on the piping and on the vent connection to the vessel head are acceptable.

The automatic depressurization system valves are included as part of the pressurizer safety and relief valve module attached to the top of the pressurizer and are connected to the pressurizer nozzles. The automatic depressurization system includes a group of valves attached to the reactor coolant system hot leg that are not used to vent noncondensable gases. The pressurizer safety and relief valve module is supported by an attachment to the top of the pressurizer and provides support for the automatic depressurization system valves. The automatic depressurization system valves are active valves required to provide safe shutdown or to mitigate the consequences of postulated accidents. Subsection 5.4.6 discusses the function control and power requirements for the automatic depressurization system valves.

5.4.12.3 Safety Evaluation

The reactor vessel head vent system is designed so that a single failure of the remotely operated vent valves, power supply, or control system does not prevent isolation of the vent path. The two isolation valves in the active flow path provide a redundant method of isolating the venting

system. With two valves in series, the failure of any one valve does not inadvertently open a vent path or prevent isolation of a flow path. The Chapter 15 accident analysis and supporting analyses are performed consistent with the reactor vessel head vent system design parameters provided in Table 5.4-18.

The reactor vessel head vent system has two normally de-energized valves in series in each flow path. This arrangement eliminates the possibility of opening a flow path due to the spurious movement of one valve.

A break of the reactor vessel head vent system line would result in a small loss of coolant accident of not greater than one-inch diameter. Such a break is similar to those analyzed in Subsection 15.6.5. Since a break in the head vent line would behave similarly to the hot leg break case presented in Subsection 15.6.5, the results presented therein apply to a reactor vessel head vent system line break. This postulated vent line results in no calculated core uncovery.

Subsection 5.4.6 and Section 6.3 discuss the evaluation of the automatic depressurization system valves. Inadvertent opening of an automatic depressurization system valve is included in the transients considered for mechanical system and component design in Subsection 3.9.1.

Section 6.3 discusses the evaluation of the passive residual heat removal heat exchanger and core makeup tanks. These high point vent lines contain two manual isolation valves in series, so that a single failure of either valve to reclose following venting operation does not prevent isolation of the flow path. The high point vent line from the passive residual heat removal heat exchanger to the in-containment refueling water storage tank contains a flow-restricting orifice such that postulated break flow is within the makeup capability of the chemical and volume control system and therefore would not normally require actuation of the passive safety systems.

5.4.12.4 Inspection and Testing Requirements

Inservice inspection of ASME Code Classes 2 and 3 components is conducted according to Section 6.6. Subsection 3.9.6 discusses inservice testing and inspection of valves. Subsection 5.2.4 discusses inservice inspection and testing of ASME Code, Class 1 components that are part of the reactor coolant pressure boundary.

The requirements for tests and inspections for reactor coolant system valves is found in Subsection 5.4.8.4. In addition, tests for the reactor vessel head vent valves and piping are conducted during preoperational testing of the reactor coolant system, as discussed in Section 14.2.

5.4.12.4.1 Flow Testing

Initial verification of the capacity of the reactor vessel head vent valves is performed during the plant initial test program. A low pressure flow test and associated analysis is conducted to determine the capacity of each reactor vessel head vent flow path. The reactor coolant system is at cold conditions with the pressurizer full of water. The normal residual heat removal pumps are used to provide injection flow into the reactor coolant system, discharging through the reactor vessel head vent valves. The measured flow rate at low pressure is such that the head vent flow capacity is at least 9.0 lbm/sec at an RCS pressure of 2500 psia.

5.4.12.5 Instrumentation Requirements

The reactor head vent valves can be operated from the control room or the remote shutdown workstation. The isolation valves in the vent line and automatic depressurization system valves have position sensors. The position indication from each solenoid-operated isolation valve is monitored in the control room.

5.4.13 Core Makeup Tank

The core makeup tank (CMT) in the passive core cooling system stores cold borated water under system pressure for high pressure reactor coolant makeup. See Section 6.3 for a discussion of the operation of the core makeup tank in the passive core cooling system and the connections to the core makeup tank.

5.4.13.1 Design Bases

The core makeup tank is designed and fabricated according to the ASME Code, Section III as a Class 1 component. See Subsection 5.2.1. The boundaries of the ASME Code include the pressure-containing materials up to, but excluding, the circumferential welds at nozzle safe ends. The manway cover and bolting materials are included within this boundary. The core makeup tank is AP1000 equipment Class A (ANS Safety Class 1, Quality Group A). Stresses are maintained within the limits of the ASME Code, Section III. Section 5.2 provides the ASME Code and material requirements. Subsection 5.2.4 discusses inservice inspection.

Materials of construction are specified to minimize corrosion/erosion and to provide compatibility with the operating environment, including the expected radiation level. Subsection 5.2.3 discusses the welding, cutting, heat treating and other processes used to minimize sensitization of stainless steel.

Instrumentation nozzles are welded to the clad inside wall of the vessel according to ASME Code, Section III. Butt welds, branch connection nozzle welds, and boss welds are of a full-penetration design. Flanges conform to ANSI B16.5.

The transients used to evaluate the core makeup tank are based on the system design transients described in Subsection 3.9.1.1. In addition to normal reactor coolant system transients, two additional Service Level B transients affect only the core makeup tank. There are an assumed 30 occurrences of the first transient, leakage at power, in the plant lifetime. This event covers situations which a small leak draws in hot reactor coolant system fluid. There are an assumed 10 occurrences in the plant lifetime of the second transient, increase in containment temperature above normal operating range.

5.4.13.2 Design Description

The core makeup tank is a low-alloy steel vessel with 308L stainless steel internal cladding. The minimum free internal volume for the core makeup tank is 2487 cubic feet. The normal full-power temperature and pressure in the core makeup tank are 70° to 120°F and 2250 psia, respectively. The tank is designed to withstand the design environment of 2500 psia and 650°F. The core makeup tank is a vertically mounted, cylindrical pressure vessel with hemispherical top and bottom heads.

The core makeup tank is supported on columns. One nozzle on the lower head connects the tank to the reactor vessel direct vessel injection (DVI) piping. One nozzle in the center of the upper head connects the tank to a line connected to one of the RCS cold legs. The top nozzle incorporates a diffuser inside the tank. The diffuser has the same diameter and thickness as the connecting piping. The bottom of the diffuser is plugged (with the exception of a small drain hole) and holes are drilled in the side. The diffuser forces the steam flow to turn 90 degrees which limits the steam penetration into the coolant in the core makeup tank. The core makeup tank includes a manway and cover in the shell to allow access to the tank interior.

To maintain system pressure, the flowpath from the reactor coolant system cold leg to the upper head of the core makeup tank is normally open. The core makeup tank discharge piping flow path from the lower head to the reactor vessel is blocked by two normally closed, fail-open, parallel isolation valves. See Section 6.3 for a description of the system operation.

The tank includes nozzles and flanges for connection to level detection instrumentation.

Two sample lines, one in the upper head and the other in the lower head, are provided for sampling the solution in the core makeup tank for Unit 4 only. Three sample lines, one in the upper head and the other in the lower head, one in the vessel shell, are provided for sampling the solution in the core makeup tank for Unit 3 only. A fill connection is provided for core makeup tank make up water from the chemical and volume control system.

5.4.13.3 Design Evaluation

Subsection 3.9.3 discusses the loading combinations, stress limits, and analytical methods for the structural evaluation of the reactor coolant system core makeup tank for design conditions, normal conditions, anticipated transients, and postulated accident conditions. Subsection 3.9.2 discusses the requirements for dynamic testing and analysis. The reactor coolant system design transients for normal operation, anticipated transients and postulated accident conditions are discussed in Subsection 3.9.1.

Stress intensities resulting from design loads do not exceed the limits specified in ASME Code, Section III. The rules for the evaluation of the faulted conditions are defined in Appendix F of the ASME Code, Section III. Only those stress limits applicable for an elastic system analysis are used for the external load analysis.

5.4.13.4 Material Corrosion/Erosion Evaluation

Those portions of the core makeup tank in contact with reactor coolant are fabricated from or clad with stainless steel. The water chemistry of the core makeup tank, comparable to reactor coolant, causes minimal corrosion of the stainless steel. Erosion is not an issue, since there is normally no flow. A periodic analysis of the coolant chemical composition verifies that the reactor coolant quality meets the specifications, as discussed in Subsection 5.2.3.

Contamination of stainless steel and nickel-chromium-iron alloys by copper, low-melting-temperature alloys, mercury, and lead is prohibited. The material selection, water chemistry specification, and residual stress in the piping minimize the potential for stress corrosion cracking, as discussed in Subsection 5.2.3.

5.4.13.5 Test and Inspections

Charpy V-notch tests and drop-weight fracture toughness tests are performed as required. Orientation of test specimens is according to the ASME Code, Section III, except that the material is not considered to be subjected to high irradiation.

Compliance with the sensitization requirement is demonstrated by passing the susceptibility to intergranular attack test of ASTM A-262, Practice A or E. Inservice inspection requirements for Class 1 are discussed in Subsection 5.2.4.

In addition, materials and welds are inspected according to the requirements of the ASME Code, Section III Class 1.

5.4.14 Passive Residual Heat Removal Heat Exchanger

The passive residual heat removal heat exchanger (PRHR HX) is the component of the passive core cooling system that removes core decay heat for any postulated non-loss of coolant accident event where a loss of cooling capability via the steam generators occurs. Section 6.3 discusses the operation of the passive residual heat removal heat exchanger in the passive core cooling system.

5.4.14.1 Design Bases

The passive residual heat removal heat exchanger automatically actuates to remove core decay heat for 72 hours as discussed in Section 6.3, assuming the condensate from steam generated in the in-containment refueling water storage tank (IRWST) is returned to the tank. The passive residual heat removal heat exchanger is designed to withstand the design environment of 2500 psia and 650°F.

The passive residual heat removal heat exchanger and the in-containment refueling water storage tank are designed to delay significant steam release to the containment for at least one hour. The passive residual heat removal heat exchanger will prevent water relief from the pressurizer and remove sufficient decay heat from the reactor coolant system to satisfy the applicable post-accident safety evaluation criteria detailed in Chapter 15 for at least 72 hours. In addition, the passive residual heat removal heat exchanger will cool the reactor coolant system, with reactor coolant pumps operating or in the natural circulation mode, so that the reactor coolant system pressure can be lowered to reduce stress levels in the system if required. See Section 6.3 for a discussion of the capability of the passive core cooling system.

The passive residual heat removal heat exchanger is designed and fabricated according to the ASME Code, Section III, as a Class 1 component. Those portions of the passive residual heat exchanger that support the primary-side pressure boundary and falls under the jurisdiction of ASME Code, Section III, Subsection NF are AP1000 equipment Class A (ANS Safety Class 1, Quality Group A). Stresses for ASME Code, Section III equipment and supports are maintained within the limits of Section III of the Code. Section 5.2 provides ASME Code, Section III and material requirements. Subsection 5.2.4 discusses inservice inspection.

Materials of construction are specified to minimize corrosion/erosion and to provide compatibility with the operating environment, including the expected radiation level. Subsection 5.2.3 discusses the welding, cutting, heat treating and other processes used to minimize sensitization of stainless steel.

5.4.14.2 Design Description

The passive residual heat removal heat exchanger consists of an upper and lower tubesheet mounted through the wall of the in-containment refueling water storage tank. A series of 0.75-inch outer diameter C-shaped tubes connect the tubesheets shown in Figure 6.3-5. The primary coolant passes through the tubes, which transfer decay heat to the in-containment refueling water storage tank water and generate enough thermal driving head to maintain the flow through the heat exchanger during natural circulation. The design minimizes the diameter of the tubesheets and allows ample flow area between the tubes in the in-containment refueling water storage tank.

The horizontal lengths of the tubes and lateral support spacing in the vertical section allow for the potential temperature difference between the tubes at cold conditions and the tubes at hot conditions. The tubes are supported in the in-containment refueling water storage tank interior with a frame structure.

The passive residual heat removal heat exchanger is welded to the in-containment refueling water storage tank.

The design of the passive residual heat removal heat exchanger incorporates a flexible member at the heat exchanger to in-containment refueling water storage tank interface to minimize the load imposed on the wall of the in-containment refueling water storage tank resulting from thermal expansion on the tubesheet.

5.4.14.3 Design Evaluation

Subsection 3.9.3 discusses the loading combinations, stress limits, and analytical methods for the structural evaluation of the passive residual heat removal heat exchanger for design conditions, normal conditions, anticipated transients, and postulated accident conditions. Operation of passive residual heat removal heat exchanger is evaluated using Service Levels B, C, and D plant conditions. In addition to loads due to conditions in the reactor coolant system and operation of the passive residual heat removal heat exchanger, the passive residual heat removal heat exchanger is evaluated for hydraulic loads due to discharge of steam from the automatic depressurization system valves into a sparger in the in-containment refueling water storage tank. These loads are evaluated using Service Level B limits and are not combined with any other Service Level C or D conditions.

Seismic, loss of coolant accident, sparger activation and flow-induced vibration loads are derived using dynamic models of the passive residual heat removal heat exchanger. The dynamic analysis considers the hydraulic interaction between the coolant (steam or water) and the system structural elements.

Subsection 3.9.2 discusses the requirements for dynamic testing and analysis. Subsection 3.9.1 discusses the reactor coolant system design transients for normal operation, anticipated transients, and postulated accident conditions. In addition to reactor coolant system design transients, there are two additional Service Level B transients that affect only the passive residual heat removal heat exchanger. In the plant lifetime, there are an assumed 30 occurrences of the first transient, leakage at power. This event covers situations in which a small leak in the manway cover draws in hot reactor coolant system fluid. There are an assumed 10 occurrences in the plant lifetime of the second transient, increase in in-containment refueling water storage tank temperature, due an event which activates passive core cooling.

Stress intensities resulting from design loads do not exceed the limits specified in ASME Code, Section III. The rules evaluating the Service Level D conditions are defined in Appendix F of the ASME Code, Section III. Only those stress limits applicable for an elastic system analysis are used for the external load analysis.

During normal plant operation the system is pressurized to the reactor coolant system hot leg pressure at the temperature of the in-containment refueling water storage tank. The pressure transients during normal plant operation are the same as those for the reactor coolant system hot leg. There is no flow through the passive residual heat removal heat exchanger during normal plant operation. The tubesheet temperatures are calculated to provide sufficient temperature drop between the tubesheet and the attachment to the tank. Section 6.3 describes the passive residual heat removal heat exchanger performance characteristics.

5.4.14.4 Material Corrosion/Erosion Evaluation

Those portions of the passive residual heat removal heat exchanger in contact with reactor coolant are fabricated from or clad with corrosion-resistant material. The use of severely sensitized austenitic stainless steel in the pressure boundary of the reactor coolant system is prohibited. A periodic analysis of the coolant chemical composition verifies that the reactor coolant quality meets the specifications discussed in Subsection 5.2.3.

Sulphur, lead, copper, mercury, aluminum, antimony, arsenic, and other low-melting-point elements and their alloys and compounds are restricted in their use as construction materials, erection aids, cleaning agents, and coatings for finished surfaces of the passive residual heat removal heat exchanger that are in contact with reactor coolant system fluid or in-containment refueling water storage tank. Contamination of stainless steel and nickel-chromium-iron alloys by copper, low-melting-temperature alloys, mercury, and lead is prohibited. The material selection, water chemistry

specification, and residual stress in the piping minimize the potential for stress corrosion cracking, as discussed in Subsection 5.2.3.

Stainless steel and nickel-chromium-iron alloys used in the passive residual heat removal heat exchanger are procured to ASME specifications.

5.4.14.5 Testing and Inspections

The passive residual heat removal heat exchanger is designed and manufactured to permit inservice testing and examination as specified in the ASME Code, Section XI. Methods and techniques developed for steam generator tube eddy current inspection can be used for the passive residual heat removal heat exchanger tubes.

Preservice and inservice inspection of the PRHR HX is performed according to Subsection 5.2.4. PRHR HX tube integrity is verified using inspection procedures that consider the methods and techniques developed for steam generator tube eddy current inspection.

Access for inspection and maintenance is possible through manways in the top and bottom channel heads without draining the in-containment refueling water storage tank.

Hydrostatic tests are performed in accordance with the requirements of the ASME Code, Section III, using working fluids meeting the appropriate water chemistry specifications.

5.4.15 Combined License Information

The Steam Generator Tube Surveillance Program is addressed in Subsection 5.4.2.5.

5.4.16 References

1. Not used.

2. Hagg, A. C. and Sankey, G. O., “The Containment of Disk Burst Fragments by Cylindrical Shells,” ASME Journal of Engineering for Power, April 1974, pp. 114-123.

3. Not used.

4. Not used.

5. ANSI/ANS-5.1-1994, “Decay Heat Power in Light Water Reactors.”

6. ANSI/ANS-51.1-1983, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

7. Not used.

8. ASME QME-1-2007 Edition, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants.”

9. ASME B16.34-1996, “Valves – Flanged, Threaded, and Welding End.”

10. Curtiss-Wright Electro-Mechanical Corporation Report AP1000RCP-06-009-P, Revision 3 (Proprietary), and AP1000RCP-06-009-NP, Revision 3 (Non-Proprietary), “Structural Analysis Summary for the AP1000 Reactor Coolant Pump High Inertia Flywheel,” APP-MP01-GLR-001P (Proprietary) and APP-MP01-GLR-001NP (Non-Proprietary), November 2016.

201. Nuclear Energy Institute, “Steam Generator Program Guidelines,” NEI 97-06.

Table 5.4-1
Reactor Coolant Pump Design Parameters

Unit design pressure (psia)	2500
Unit design temperature (°F)	650
Estimated Unit overall height (ft)	22
Component cooling water flow (gpm)	650
Maximum continuous component cooling water inlet temperature (°F)(1)	95
Total estimated weight motor and casing, dry (lb)	200,000
Pump	
Design flow (gpm)	78,750
Developed head (feet)	365
Pump discharge nozzle, inside diameter (inches)	22
Pump suction nozzle, inside diameter (inches)	26
Speed (synchronous)(rpm)	1800
Motor	
Type	Squirrel Cage Induction
Voltage (V)	6900
Phase	3
Frequency (Hz)	60
Insulation class	Class H or N
Current (amp)	
Starting	Variable
Nominal input, cold reactor coolant	Variable
Motor/pump rotor minimum required moment of inertia	Sufficient to provide flow coastdown as given in Figure 15.3.2-1

Note:
1. An elevated component cooling water supply temperature of up to 110°F may occur for a 6-hour period.

Table 5.4-2 Not Used

Table 5.4-3
Reactor Coolant Pump Quality Assurance Program

	RT[(a)]	UT[(a)]	PT[(a)]	MT[(a)]
Castings – Casing (or pressure boundary)	X		X	
Flywheel		X	X	X
Forgings		X		X
Plate			X	
Weldments				
Circumferential	X[(c)]		X	
Instrument connections			X	
Motor terminals[(b)]		X	X	

Notes:
(a) RT - radiographic, UT - ultrasonic, PT - dye penetrant, MT - magnetic particle
(b) See Subsection 5.4.1.3.3.
(c) RT does not apply to flywheel enclosure.

Table 5.4-4
Steam Generator Design Requirements

Type	Vertical U-tube Feedring-type
Design pressure, reactor coolant side (psia)	2500
Design pressure, steam side (psia)	1200
Design pressure, primary to secondary (psi)	1650
Design temperature, reactor coolant side (°F)	650
Design temperature, steam side (°F)	600
S/G Power, MWt/unit	1707.5
Total heat transfer surface area (ft^2)	123,538
Steam nozzle outlet pressure, psia	836
Steam flow, lb/hr per S/G	$7.50x10^6$
Total steam flow, lb/hr	$14.99x10^6$
Maximum moisture carryover (weight percent) maximum	0.25[(a)]
No load temperature, °F	557
Feedwater temperature, °F	440
Number of tubes per unit	10,025
Tube outer diameter, inch	0.688
Tube wall thickness, inch	0.040
Tube pitch, inches	0.980 (triangular)

Note:
a. Moisture content at the outlet of the steam generator secondary separators (dryers).

Table 5.4-5
Steam Generator Design Parameters
(Nominal Values)

Tube pitch, inches	0.980 (triangular)
Overall length, inches	884.29*
Upper shell I.D., inches	210
Lower shell I.D., inches	165
Tubesheet thickness, inches	31.417**
Primary water volume, ft^3	2077
Water volume in tubes, ft^3	1489
Water volume in plenums, ft^3	588
Secondary water volume, ft^3	3517.3
Secondary steam volume, ft^3	5543.4
Secondary water mass, lbm	169,251
Design fouling factor, hr-°F-ft^2/BTU	9.0×10^{-5}

Notes:
* Measured from steam nozzle to the flat, exterior portion of the channel head.
** Base metal thickness.

Table 5.4-6
Steam Generator Quality Assurance Program

	RT[(a)]	UT[(a)]	PT[(a)]	MT[(a)]	ET[(a)]
Base Metals					
Tubesheet Forging		Yes		Yes	
Channel Head Forging Plate Casting	 Yes	 Yes Yes 		 Yes Yes	
Secondary Shell and Head Forgings Plate		 Yes Yes		 Yes	
Tubes		Yes			Yes
Nozzles (Forgings)		Yes		Yes	
Safe ends		Yes	Yes		
Welds					
Channel head if fabricated	Yes			Yes	
Pressure boundary, longitudinal if fabricated	Yes			Yes	
Pressure boundary, circumferential	Yes			Yes	
Primary nozzles to fabricated head	Yes			Yes	
Primary nozzles to forged head	Yes			Yes	
Manways to fabricated head or shell	Yes			Yes	
Manways to forged head or shell	Yes			Yes	
Steam and feedwater nozzles to fabricated shell	Yes			Yes	
Steam and feedwater nozzles to forged shell	Yes			Yes	
Support brackets				Yes	
Tube to tubesheet			Yes		
Instrument connections (secondary)				Yes	
Temporary attachments after removal				Yes	
After hydrostatic test (all major pressure boundary welds and complete cast channel head where accessible)				Yes	
Weld deposit on primary nozzles	Yes		Yes		
Safe end to nozzle	Yes		Yes		
Cladding					
Tubesheet		Yes[(b)]	Yes		
Channel head		Yes	Yes		
Cladding (channel head-tubesheet joint cladding restoration)		Yes	Yes		

Notes:
(a) RT – Radiographic, UT – Ultrasonic, PT – Dye penetrant, MT – Magnetic particle, ET – Eddy current.
(b) Flat surfaces only

Table 5.4-7
Reactor Coolant System Piping Design

Reactor Coolant Loop Piping	
Design Pressure (psig)	2485
Design Temperature (°F)	650
Reactor Inlet Piping	
Inside Diameter (ID)	22
Nominal Wall Thickness	2.56
Reactor Outlet Piping	
Inside Diameter (ID)	31
Nominal Wall Thickness	3.25
Pressurizer Surge Line	
Design Pressure (psig)	2485
Design Temperature (°F)	680
Pressurizer Surge Line Piping	
Nominal Pipe Size	18
Nominal Wall Thickness	1.78
Pressurizer Safety Valve and ADS Valve Inlet Line	
Design Pressure (psig)	2485
Design Temperature (°F)	680
Other Rector Coolant Branch Lines	
Design Pressure (psig)	2485
Design Temperature (°F)	650

Table 5.4-8
Reactor Coolant System Piping Quality Assurance Program

	RT[(a)]	UT[(a)]	PT[(a)]
Pipe (Forged Seamless)		Yes	Yes
Fittings		Yes	Yes
Weldments			
Circumferential Butt Welds	Yes		Yes
Branch Nozzle Connections	Yes[(b)]		Yes
Fillet Weld Instrument Connections			Yes

Notes:
(a) RT - Radiographic; UT - Ultrasonic; PT - Dye Penetrant
(b) No RT is required for branch nozzle connections of 4 inch nominal size smaller.

Table 5.4-9
Pressurizer Design Data

Design pressure (psig)	2485
Design temperature (°F)	680
Surge line nozzle nominal diameter (in.)	18
Spray line nozzle nominal diameter (in.)	4
Safety valve nozzle nominal diameter (in.)	14
Internal volume (ft^3)	2100

Table 5.4-10
Pressurizer Heater Group Parameters

Power Supply Voltage (Vac)	480
Heater Rated Voltage (Vac)	460
Frequency (Hz.)	60
Power Capacity (kW)	
Control Group	369
Backup Group A	246
Backup Group B	246
Backup Group C	369
Backup Group D	369

Table 5.4-11
Reactor Coolant System Design Pressure Settings

	Base Load Mode (Psig)
Hydrostatic test pressure	3106
Design pressure	2485
Safety valves (begin to open)	2485
High pressure reactor trip	2405
High pressure alarm	2335
Pressurizer spray valves (full open)	2310
Pressurizer spray valves (begin to open)	2260
Proportional heaters (begin to operate)	2250
Operating pressure	2235
Proportional heater (full operation)	2220
Backup heaters on	2210
Low pressure alarm	2085
Low pressure safeguards actuation	1855

Table 5.4-12
Pressurizer Quality Assurance Program

	RT[(a)]	UT[(a)]	PT[(a)]	MT[(a)(c)]
Heads				
Forged head		Yes		Yes
Cladding		Yes	Yes	
Shell				
Forgings		Yes		Yes
Cladding		Yes	Yes	
Heaters				
Tubing		Yes[(b)]	Yes	
Centering of element	Yes			
Nozzle (Forgings)		Yes	Yes[(c)]	Yes[(c)]
Weldments				
Shell, circumferential	Yes			Yes
Nozzle to head (if fabricated)	Yes			Yes
Cladding		Yes	Yes	
Nozzle safe end	Yes		Yes	
Instrument nozzle			Yes	
Temporary attachments (after removal)				Yes
Boundary welds (after shop hydrostatic tests)				Yes
Support brackets				Yes

Notes:
(a) RT - Radiographic, UT - Ultrasonic, PT - Dye Penetrant, MT - Magnetic Particle.
(b) Eddy current testing can be used in lieu of UT.
(c) Dye penetrant (PT) examination is acceptable when accessibility limitations prohibit the use of magnetic particle (MT) test equipment.

Table 5.4-13
Design Bases for Normal Residual Heat Removal System Operation

RNS initiation, hours after reactor shutdown	4
RCS initial pressure (psig)	450
RCS initial temperature (°F)	350
CCS Design Temperature (°F)[(a)]	95
Cooldown time, (hours after shutdown)	96
RCS temperature at end of cooldown (°F)	125

Note:
(a) The maximum CCS temperature during cooldown is 110°F.

Table 5.4-14
Normal Residual Heat Removal System Component Data

Normal RHR Pumps (per pump)		
Minimum Flow Required for Shutdown Cooling (gpm)	1400	
Minimum Flow Required for Low Pressure Makeup (gpm)	1100	
Design Flow (gpm)	1500	
Design Head (ft)	360	
Normal RHR Heat Exchangers		
Minimum UA Required for Shutdown Cooling (BTU/hr-°F)	2.2×10^6	
Design Heat Removal Capacity (BTU/hr)(1)	23×10^6	
	Tube Side	**Shell Side**
Design Flow (lb/hr)	750,000	1,405,000
Inlet Temperature (°F)	125	87.5
Outlet Temperature (°F)	94	104
Fluid	Reactor Coolant	CCS

Note:
(1) Design heat removal capacity is based on decay heat at 96 hours after reactor shutdown.

Table 5.4-15
Reactor Coolant System Valve Design Parameters

Design pressure (psig)	2485
Preoperational plant hydrotest (psig)	3106
Design temperature (°F)	
Reactor coolant system	650
Pressurizer safety valves and ADS valves	680

Table 5.4-16
Reactor Coolant System Motor-operated Valves Design Opening and Closing Pressures

	Normal ΔP (PSIG)[a]		Design ΔP (PSIG)	
	OPEN	**CLOSE**	**OPEN**	**CLOSE**
First Stage ADS Valves (RCS-PL-V001A & B)	2235	2235[b,c]	2485	2485
First Stage ADS Isolation Valves (RCS-PL-V011A & B)	2235	2235	2485	2485
Second Stage ADS Valves (RCS-PL-V002A & B)	1200	100[b]	2485	1200
Second Stage ADS Isolation Valves (RCS-PL-V012A & B)	1200	100	2485	1200
Third Stage ADS Valves (RCS-PL-V003A & B)	500	100	2485	1200
Third Stage ADS Isolation Valves (RCS-PL-V013A & B)	500	100	2485	1200
Fourth Stage ADS Isolation Valves (RCS-PL-V014A & B)	N/A[e]	0	200[e]	200
CVS Purification Isolation Valves (CVS-PL-V001,-V002,-003)	2235	2235	2485	2485
Normal RHR Inner/Outer Isolation Valves (RNS-PL-V001A,B -V002A,B)[d]	450	450	600	600

Notes:
(a) Normal expected operating pressures.
(b) Valves are prevented from closing until ADS signal is reset.
(c) First stage ADS valve can be manually actuated for controlled depressurizations or gas venting.
(d) Valves are administratively blocked from opening at the motor control center.
(e) Fourth stage ADS block valves are normally open.

Table 5.4-17
Pressurizer Safety Valves – Design Parameters

Number	2
Minimum required relieving capacity per valve (lb/hr)	750,000 at 3% accumulation
Set pressure (psig)	2485 ±25 psi
Design temperature (°F)	680
Fluid	Saturated steam
Backpressure	
Normal (psig)	3 to 5
Expected maximum during discharge (psig)	500
Environmental conditions	
Ambient temperature (°F)	50 to 120
Relative humidity (percent)	0 to 100
Residual Heat Removal Relief Valve - Design Parameters	
Number	2 (RNS-V021/RNS-V020)
Required relieving capacity per valve, Reactor Vessel Low Temperature Overpressure Protection (LTOP) flowrate (gpm)	1061/50
Required relieving capacity per valve, Normal Residual Heat Removal System (RNS) ASME Section III Overpressure Event flowrate (gpm)	944/50
Nominal set pressure (psig)	500*/470*
Full-open pressure, with accumulation (psig)	550*/517*
RNS design temperature (°F)	400
Fluid	Reactor coolant
Pressure-Relieving Temperature LTOP (°F)	300
Pressure-Relieving Temperature RNS ASME Section III Overpressure Protection (°F)	400
Backpressure	
Normal (psig)	3 to 5
Expected maximum during LTOP event discharge (psig)	40.2
Expected maximum during RNS ASME Section III overpressure event discharge (psig)	203
Environmental conditions	
Ambient temperature (°F)	50 to 120
Relative humidity (percent)	0 to 100

Note:
* See text (Subsection 5.4.9.3) for discussion of set pressure

Table 5.4-18
Reactor Vessel Head Vent System Design Parameters

System design pressure, psig	2485
System design temperature, °F	650
Number of remotely-operated valves	4
Vent line, nominal diameter, inches	1
Head vent capacity, lbm/sec (assuming a single failure, RCS pressure at 2500 psia)	9.0

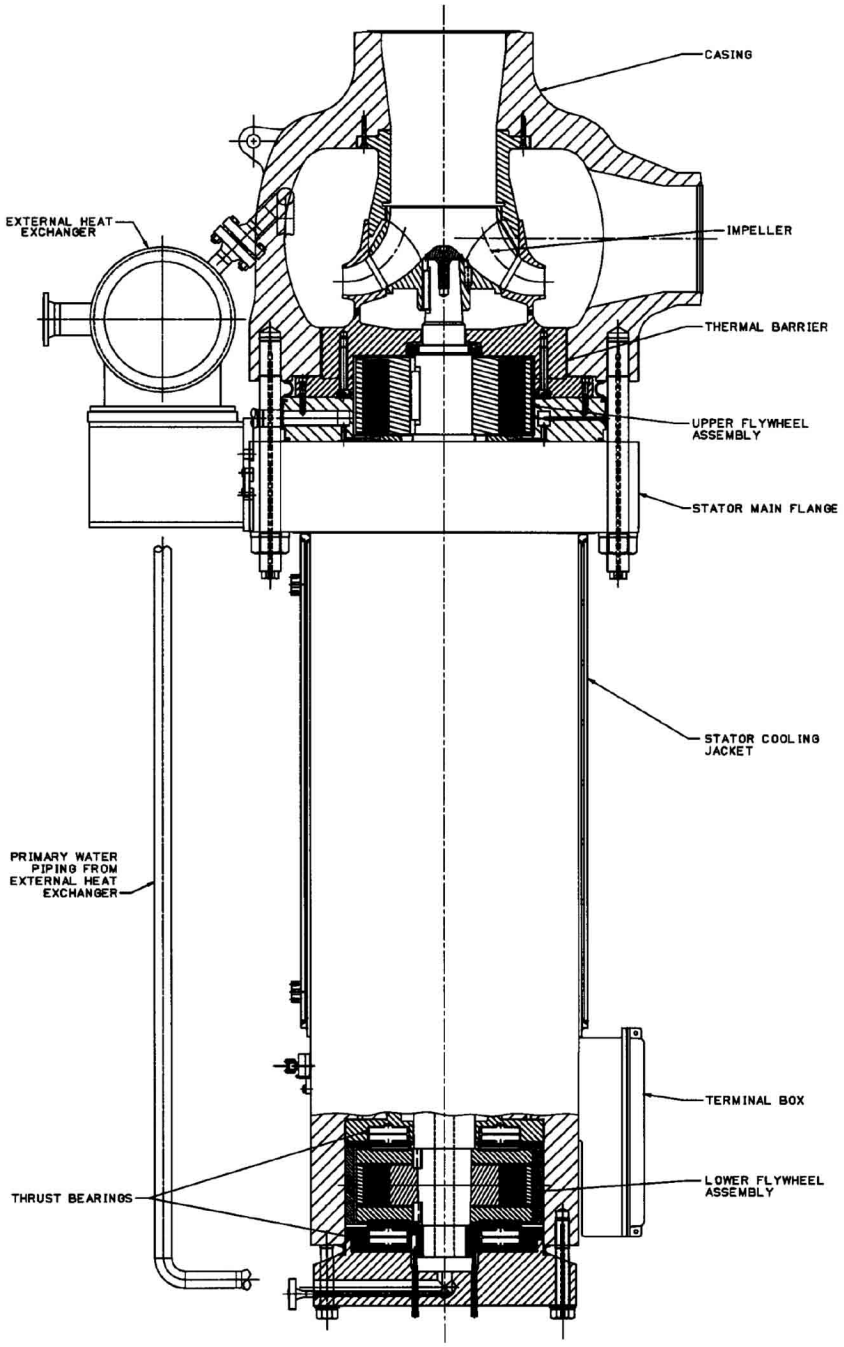


Figure 5.4-1
Reactor Coolant Pump

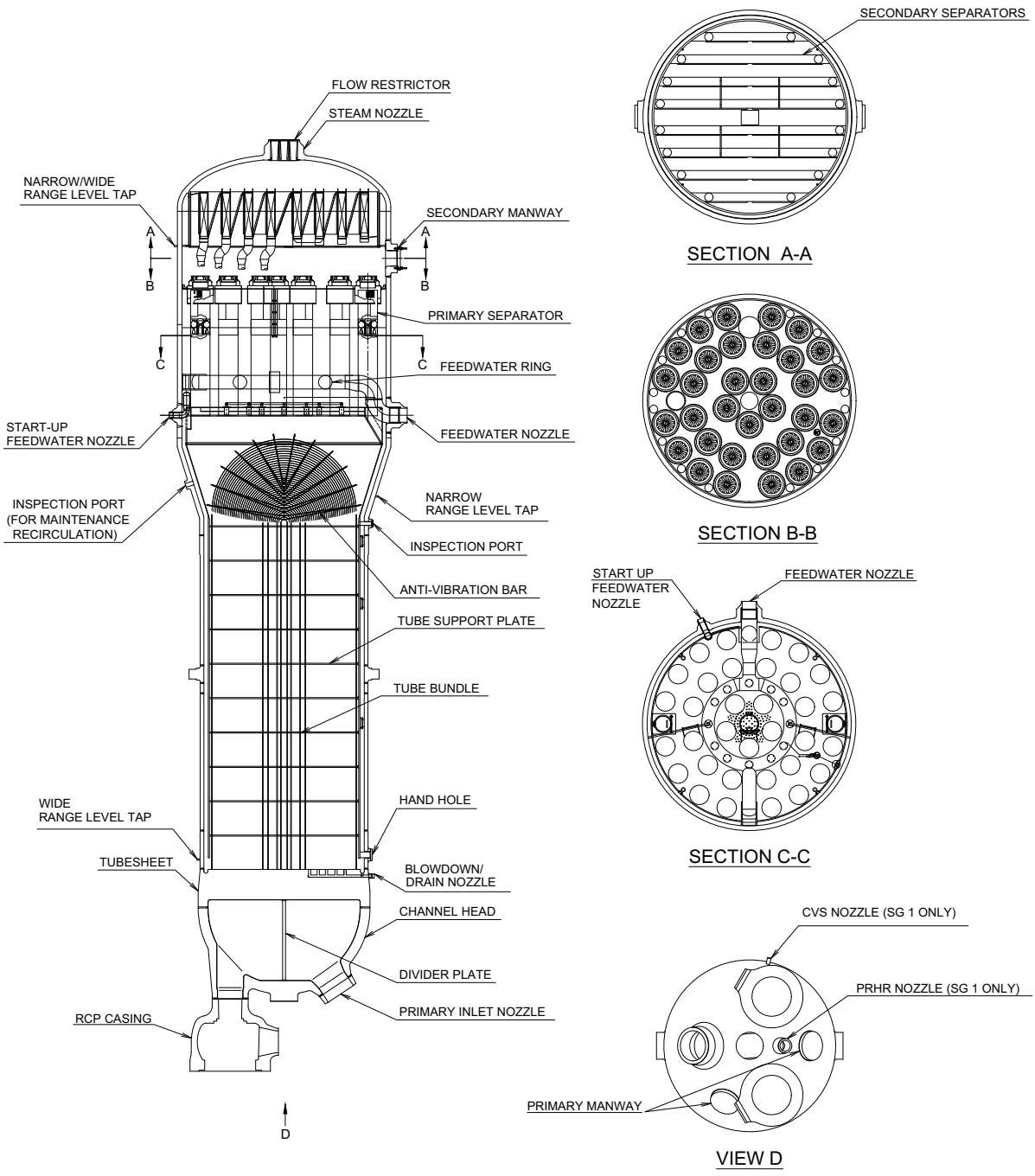


Figure 5.4-2
Steam Generator

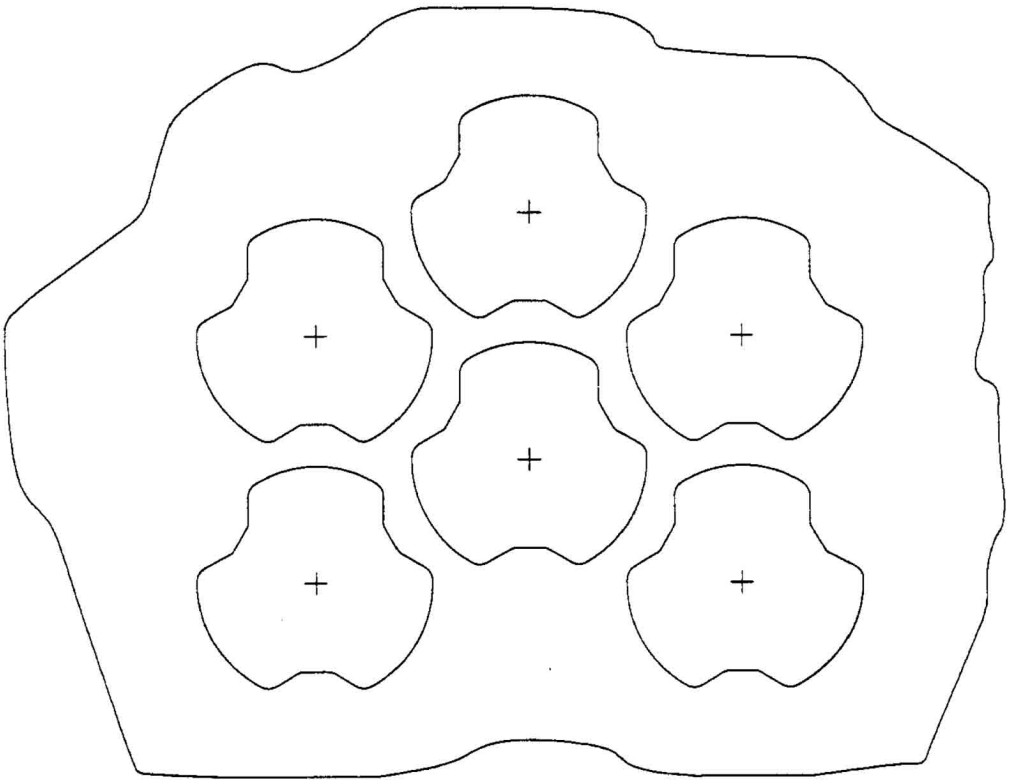


Figure 5.4-3
Support Plate Geometry
(Trifoil Holes)

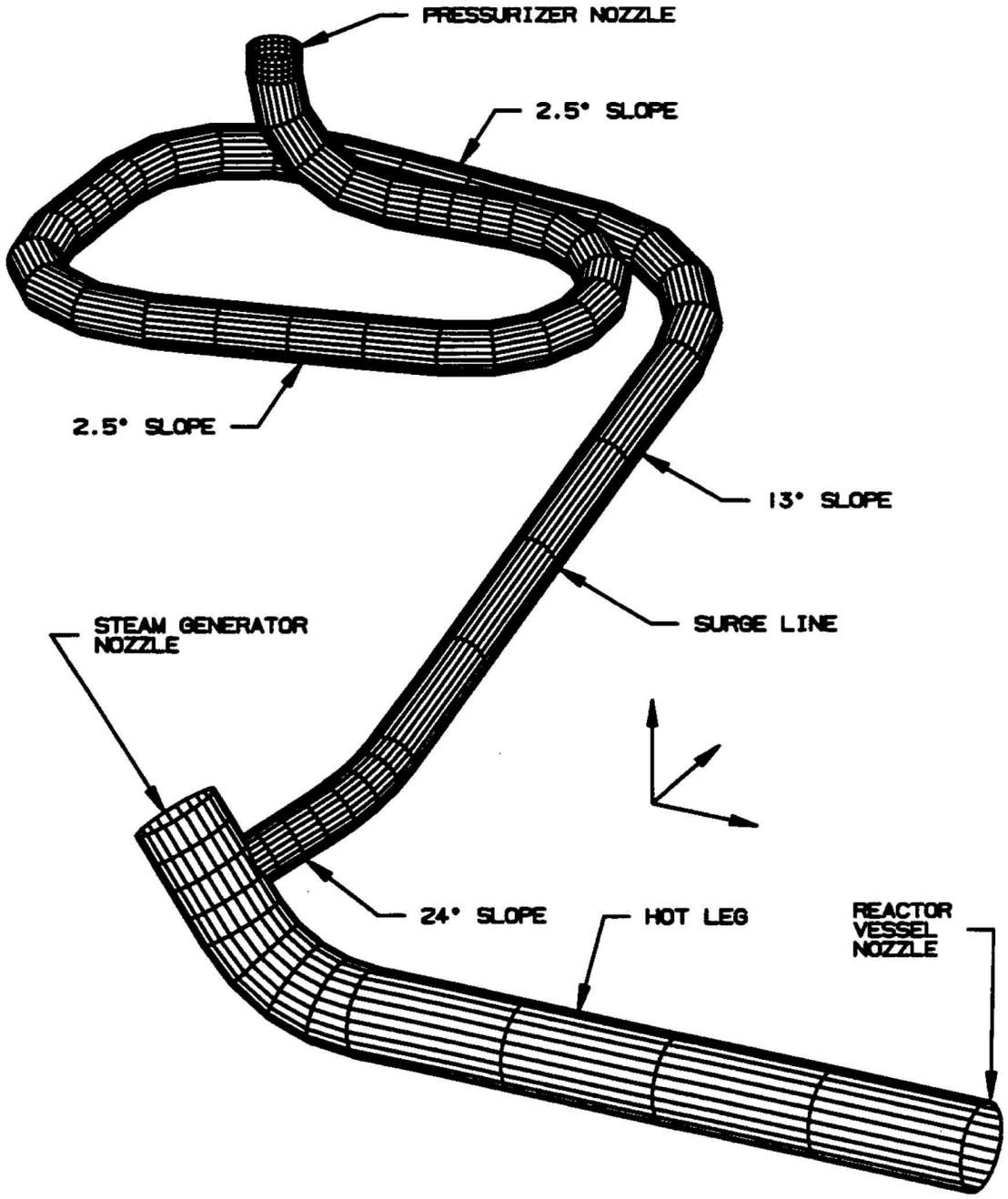


Figure 5.4-4
Surge Line

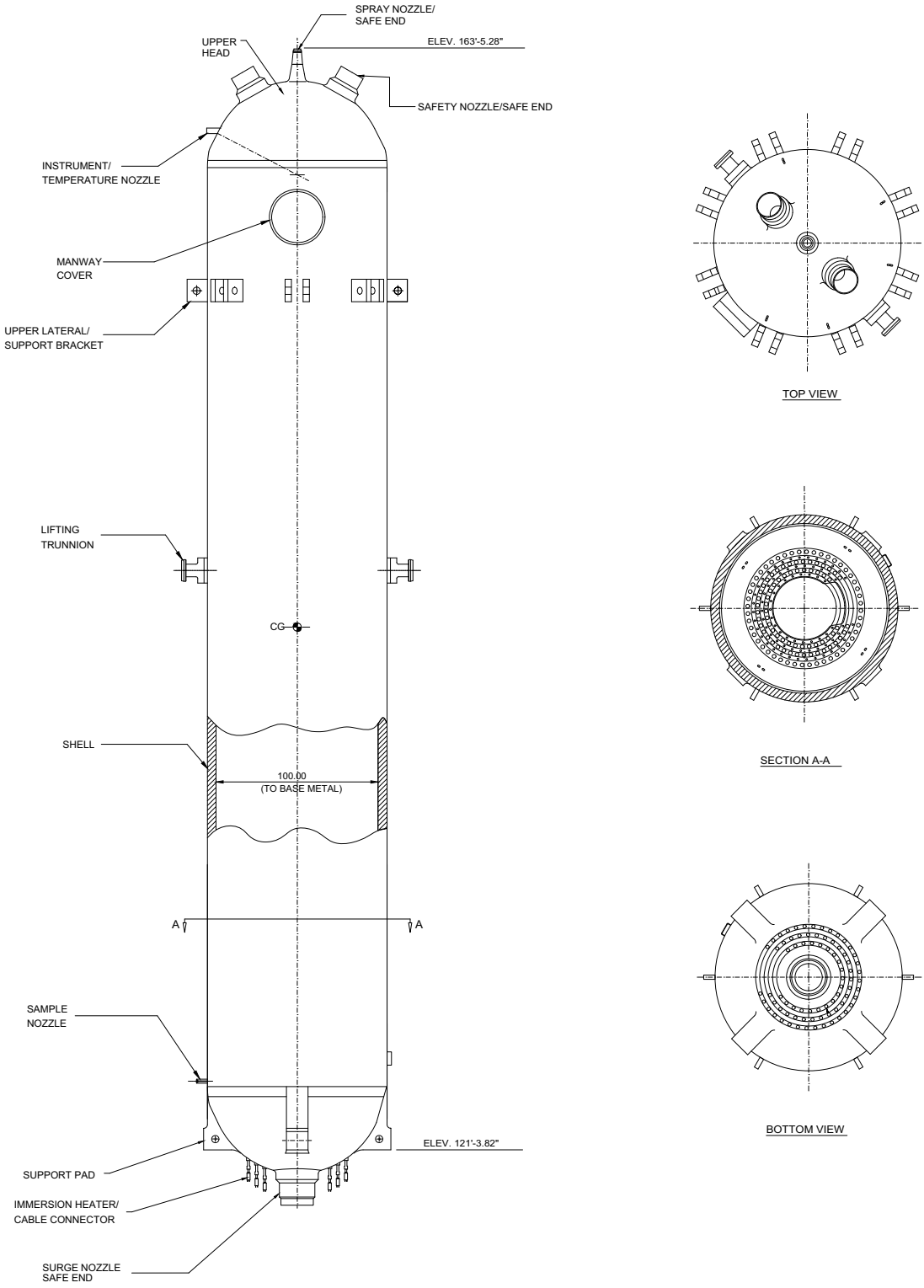


Figure 5.4-5
Pressurizer

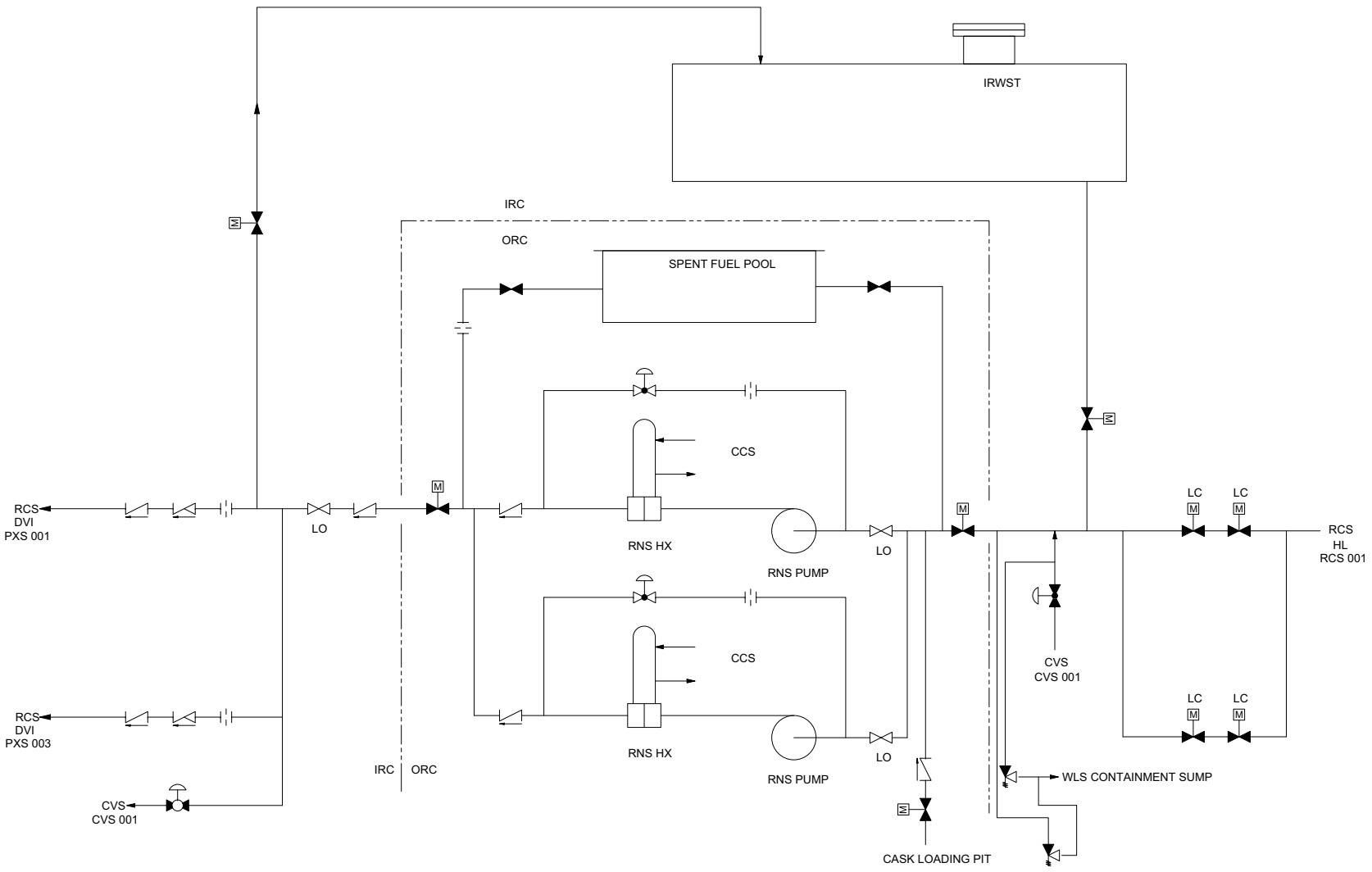
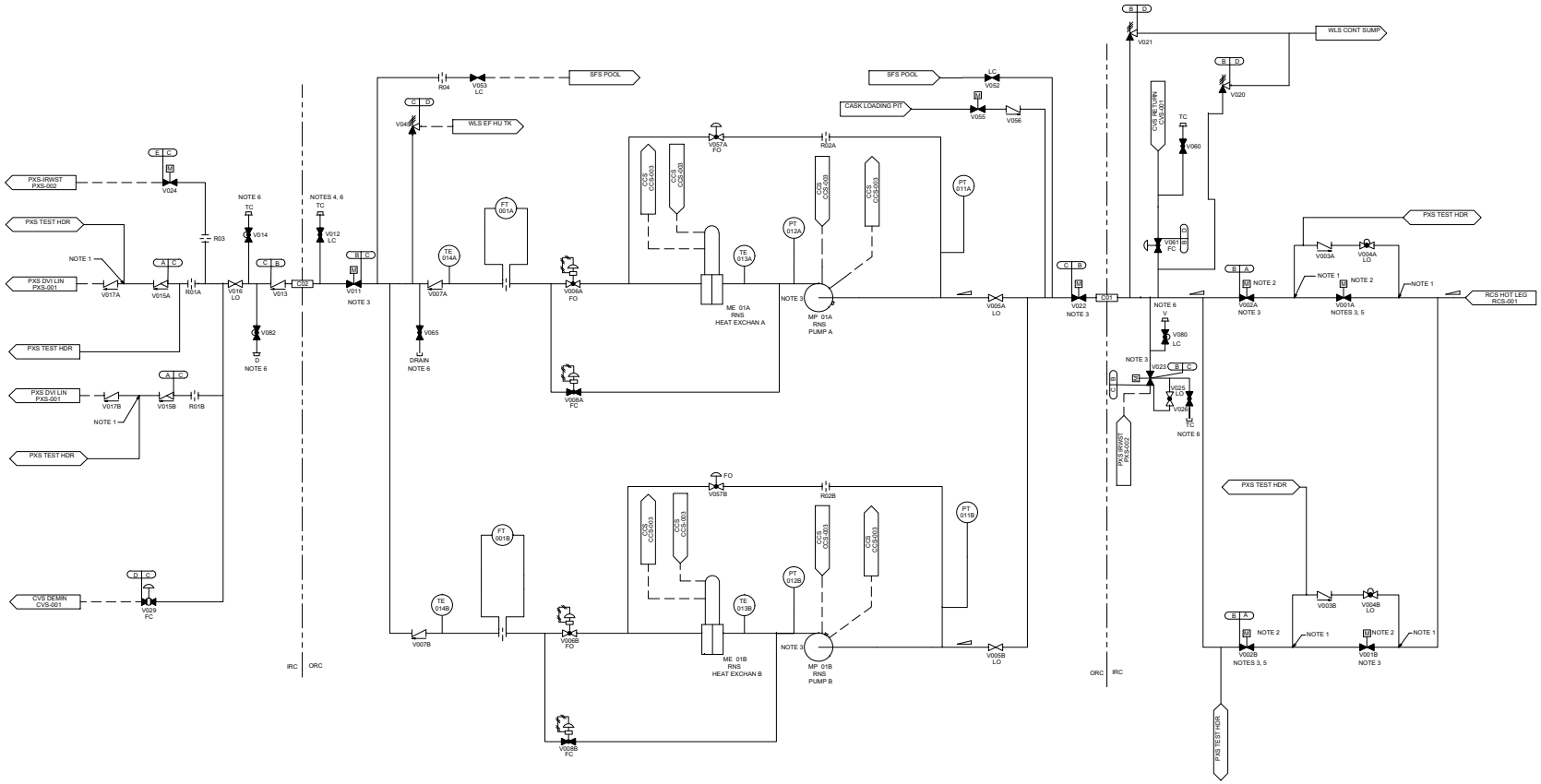


Figure 5.4-6
Normal Residual Heat Removal System



VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

NOTES:

1. PROVIDE .375' ID FLOW RESTRICTOR FOR CLASS 1 AND CLASS 2 TRANSITION
2. POWER TO VALVE LOCKED OUT AT THE MOTOR CONTROL CENTER.
3. VALVES CLOSE AND PUMPS STOP ON HIGH CONTAINMENT RADIATION, SAFEGUARDS ACTUATION SIGNAL, OR ADS STAGE 4 ACTUATION SIGNAL.
4. POST-ACCIDENT CONTAINMENT MAKEUP IS ADDED THROUGH TEST CONNECTION.
5. VALVE TO BE ACTUATED ON TIME DELAY AFTER PMS ACTUATION SIGNAL.
6. CAP/PLUG IS NON-SAFETY CLASS E, ASME B31.1.

Figure 5.4-7
Simplified Normal Residual Heat Removal System Piping and Instrument Diagram (REF) RNS 001

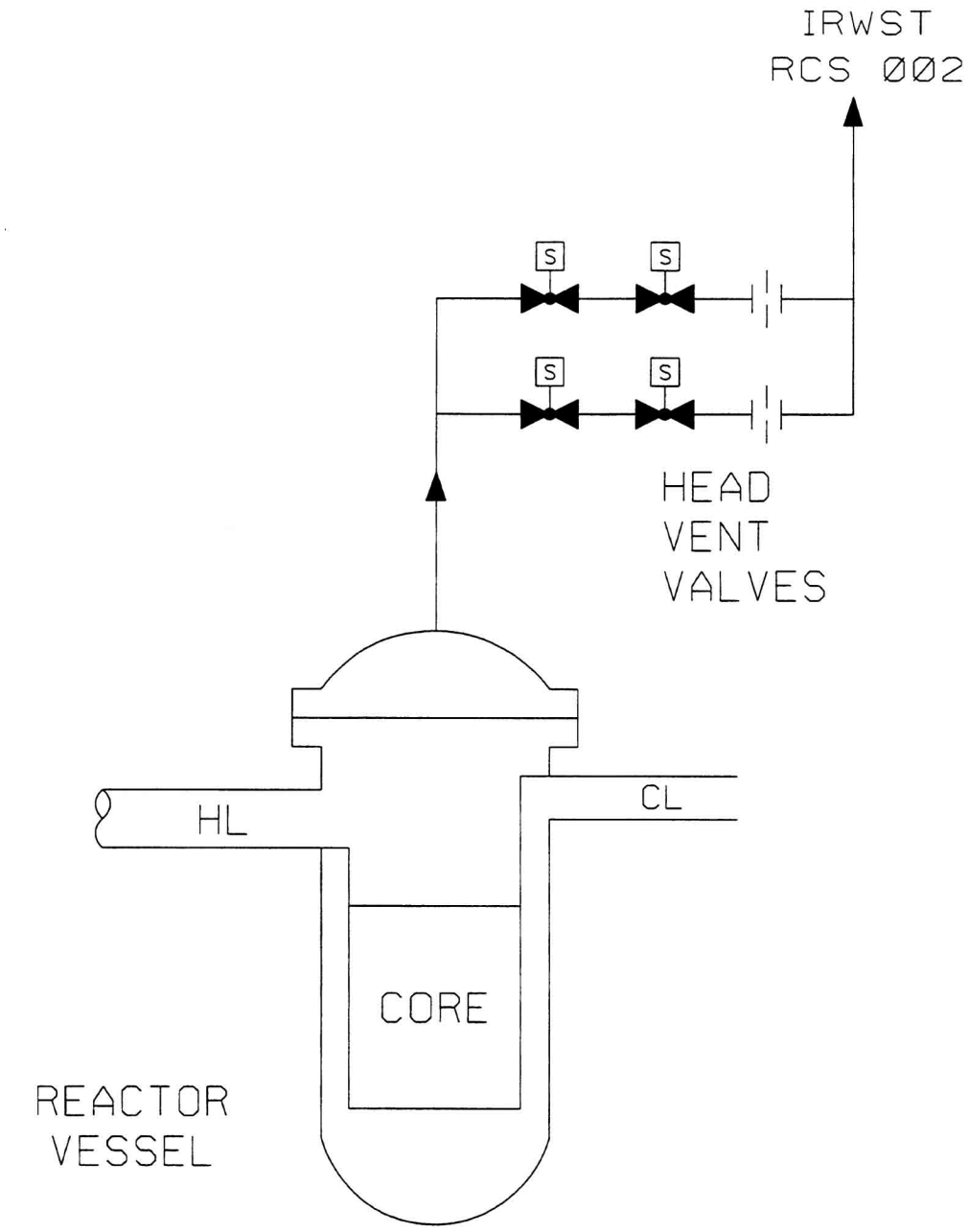


Figure 5.4-8
Reactor Vessel Head Vent System

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UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 6	ENGINEERED SAFETY FEATURES	6.0-1
6.0	Engineered Safety Features	6.0-1
6.1	Engineered Safety Features Materials	6.1-1
6.1.1	Metallic Materials	6.1-1
6.1.1.1	Specifications for Principal Pressure-Retaining Materials	6.1-1
6.1.1.2	Fabrication Requirements	6.1-2
6.1.1.3	Specifications for Nonpressure-Retaining Materials	6.1-3
6.1.1.4	Material Compatibility with Reactor Coolant System Coolant and Engineered Safety Features Fluids	6.1-3
6.1.1.5	Integrity of Safety-Related Components	6.1-4
6.1.1.6	Thermal Insulation	6.1-4
6.1.1.7	Component and System Cleaning	6.1-4
6.1.2	Organic Materials	6.1-4
6.1.2.1	Protective Coatings	6.1-4
6.1.2.2	Other Organic Materials	6.1-9
6.1.3	Combined License Information Items	6.1-10
6.1.3.1	Procedure Review	6.1-10
6.1.3.2	Coating Program	6.1-10
6.1.4	References	6.1-10
6.2	Containment Systems	6.2-1
6.2.1	Containment Functional Design	6.2-1
6.2.1.1	Containment Structure	6.2-1
6.2.1.2	Containment Subcompartments	6.2-4
6.2.1.3	Mass and Energy Release Analyses for Postulated Pipe Ruptures	6.2-7
6.2.1.4	Mass and Energy Release Analysis for Postulated Secondary-System Pipe Rupture Inside Containment	6.2-11
6.2.1.5	Minimum Containment Pressure Analysis for Performance Capability Studies of Emergency Core Cooling System (PWR)	6.2-14
6.2.1.6	Testing and Inspection	6.2-15
6.2.1.7	Instrumentation Requirements	6.2-16
6.2.2	Passive Containment Cooling System	6.2-16
6.2.2.1	Safety Design Basis	6.2-17
6.2.2.2	System Design	6.2-17
6.2.2.3	Safety Evaluation	6.2-22
6.2.2.4	Testing and Inspection	6.2-23
6.2.2.5	Instrumentation Requirements	6.2-25
6.2.3	Containment Isolation System	6.2-25
6.2.3.1	Design Basis	6.2-26
6.2.3.2	System Description	6.2-29
6.2.3.3	Design Evaluation	6.2-30
6.2.3.4	Tests and Inspections	6.2-33
6.2.3.5	Instrumentation and Control Application	6.2-34
6.2.4	Containment Hydrogen Control System	6.2-35
6.2.4.1	Design Basis	6.2-35

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
6.2.4.2	System Design	6.2-37
6.2.4.3	Design Evaluation (Design Basis Accident)	6.2-39
6.2.4.4	Design Evaluation (Severe Accident)	6.2-39
6.2.4.5	Tests and Inspections	6.2-40
6.2.4.6	Combined License Information	6.2-41
6.2.5	Containment Leak Rate Test System	6.2-41
6.2.5.1	Design Basis	6.2-41
6.2.5.2	System Description	6.2-42
6.2.5.3	Safety Evaluation	6.2-47
6.2.5.4	Inservice Inspection/Inservice Testing	6.2-47
6.2.6	Combined License Information for Containment Leak Rate Testing	6.2-48
6.2.7	References	6.2-48
6.3	Passive Core Cooling System	6.3-1
6.3.1	Design Basis	6.3-1
6.3.1.1	Safety Design Basis	6.3-2
6.3.1.2	Nonsafety Design Basis	6.3-5
6.3.1.3	Power Generation Design Basis	6.3-5
6.3.2	System Design	6.3-6
6.3.2.1	Schematic Piping and Instrumentation Diagrams	6.3-6
6.3.2.2	Equipment and Component Descriptions	6.3-11
6.3.2.3	Applicable Codes and Classifications	6.3-27
6.3.2.4	Material Specifications and Compatibility	6.3-27
6.3.2.5	System Reliability	6.3-28
6.3.2.6	Protection Provisions	6.3-30
6.3.2.7	Provisions for Performance Testing	6.3-31
6.3.2.8	Manual Actions	6.3-31
6.3.3	Performance Evaluation	6.3-31
6.3.3.1	Increase in Heat Removal by the Secondary System	6.3-34
6.3.3.2	Decrease in Heat Removal by the Secondary System	6.3-35
6.3.3.3	Decrease in Reactor Coolant System Inventory	6.3-37
6.3.3.4	Shutdown Events	6.3-40
6.3.4	Post-72 Hour Actions	6.3-43
6.3.5	Limits on System Parameters	6.3-43
6.3.6	Inspection and Testing Requirements	6.3-44
6.3.6.1	Preoperational Inspection and Testing	6.3-44
6.3.6.2	In-Service Testing and Inspection	6.3-45
6.3.6.3	Mitigation of Gas Accumulation	6.3-45
6.3.7	Instrumentation Requirements	6.3-48
6.3.7.1	Pressure Indication	6.3-48
6.3.7.2	Temperature Indication	6.3-48
6.3.7.3	Passive Residual Heat Removal Heat Exchanger Outlet Flow Indication	6.3-49
6.3.7.4	Level Indication	6.3-49
6.3.7.5	Containment Radiation Level	6.3-50
6.3.7.6	Valve Position Indication and Control	6.3-50

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	6.3.7.7 Automatic Depressurization System Actuation at 24 Hours	6.3-51
	6.3.8 Combined License Information	6.3-51
	6.3.8.1 Containment Cleanliness Program	6.3-51
	6.3.8.2 Verification of Water Sources for Long-Term Recirculation Cooling Following a LOCA	6.3-53
	6.3.9 References	6.3-53
6.4	Habitability Systems	6.4-1
	6.4.1 Safety Design Basis	6.4-1
	6.4.1.1 Main Control Room Design Basis	6.4-1
	6.4.1.2 Instrumentation and Control Room/DC Equipment Rooms Design Basis	6.4-2
	6.4.2 System Description	6.4-2
	6.4.2.1 Definition of the Main Control Room Pressure Boundary	6.4-2
	6.4.2.2 General Description	6.4-3
	6.4.2.3 Component Description	6.4-4
	6.4.2.4 Leaktightness	6.4-6
	6.4.2.5 Interaction with Other Zones and Pressurized Equipment	6.4-7
	6.4.2.6 Shielding Design	6.4-7
	6.4.3 System Operation	6.4-8
	6.4.3.1 Normal Mode	6.4-8
	6.4.3.2 Emergency Mode	6.4-8
	6.4.4 System Safety Evaluation	6.4-10
	6.4.4.1 Dual Unit Analysis	6.4-12
	6.4.4.2 Toxic Chemical Habitability Analysis	6.4-13
	6.4.5 Inservice Inspection/Inservice Testing	6.4-13
	6.4.5.1 Preoperational Inspection and Testing	6.4-13
	6.4.5.2 Inservice Testing	6.4-14
	6.4.5.3 Air Quality Testing	6.4-14
	6.4.5.4 Main Control Room Envelope Habitability	6.4-14
	6.4.6 Instrumentation Requirements	6.4-15
	6.4.7 Combined License Information	6.4-15
	6.4.8 References	6.4-15
6.5	Fission Product Removal and Control Systems	6.5-1
	6.5.1 Engineered Safety Feature (ESF) Filter Systems	6.5-1
	6.5.2 Containment Spray System	6.5-1
	6.5.2.1 System Description	6.5-1
	6.5.2.2 Design Evaluation	6.5-3
	6.5.3 Fission Product Control Systems	6.5-5
	6.5.3.1 Primary Containment	6.5-5
	6.5.3.2 Secondary Containment	6.5-5
	6.5.4 Combined License Information	6.5-5
	6.5.5 References	6.5-5
6.6	Inservice Inspection of Class 2, 3, and MC Components	6.6-1
	6.6.1 Components Subject to Examination	6.6-1
	6.6.2 Accessibility	6.6-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
6.6.3	Examination Techniques and Procedures	6.6-2
6.6.3.1	Examination Methods	6.6-2
6.6.3.2	Qualification of Personnel and Examination Systems for Ultrasonic Examination	6.6-3
6.6.3.3	Relief Requests	6.6-3
6.6.4	Inspection Intervals	6.6-3
6.6.5	Examination Categories and Requirements	6.6-3
6.6.6	Evaluation of Examination Results	6.6-4
6.6.7	System Pressure Tests	6.6-4
6.6.8	Augmented Inservice Inspection to Protect against Postulated Piping Failures	6.6-4
6.6.9	Combined License Information Items	6.6-4
6.6.9.1	Inspection Programs	6.6-4
6.6.9.2	Construction Activities	6.6-4
APPENDIX 6A	FISSION PRODUCT DISTRIBUTION IN THE AP1000 POST-DESIGN BASIS ACCIDENT CONTAINMENT ATMOSPHERE	6A-1
6A.1	Design Basis Sequence Assumptions	6A-1
6A.1.1	Break Size and Fission Product Release Location in Containment	6A-1
6A.1.1.1	Releases From Depressurization System Lines	6A-2
6A.1.1.2	Releases From Coolant Loop Breaks	6A-2
6A.1.1.3	Direct Vessel Injection Line Breaks	6A-2
6A.1.1.4	Core Makeup Tank Balance Line Breaks	6A-3
6A.1.1.5	Chemical and Volume Control System Line Breaks	6A-3
6A.1.1.6	Fission Product Release Location Conclusion	6A-3
6A.2	Containment Natural Circulation and Mixing	6A-3
6A.3	Insights From the Passive Containment Cooling System Large Scale Test and AP1000 Stratification Studies	6A-6
6A.4	Conclusions	6A-7
6A.5	References	6A-7

LIST OF TABLES

Table Number	Title	Page
6.1-1	Engineered Safety Features Pressure-Retaining Materials	6.1-11
6.1-2	AP1000 Coated Surfaces, Containment Shell and Surfaces Inside Containment	6.1-13
6.2.1.1-1	Summary of Calculated Peak Containment Pressures and Vapor Temperatures	6.2-51
6.2.1.1-2	Containment Integrity Analysis Initial Conditions	6.2-51
6.2.1.1-3	Postulated Containment Accident Analyses Relative to GDC	6.2-52
6.2.1.1-4–6.2.1.1-7	Not Used	6.2-53
6.2.1.1-8	Material Properties Used in the WGOTHIC Containment Evaluation Model	6.2-54
6.2.1.1-9	Containment External Pressure Analysis Major Assumptions	6.2-55
6.2.1.1-10	Plant Requirements for Metal Heat Sinks Inside Containment	6.2-56
6.2.1.1-11	Heat Sinks Credited in the Peak Containment Pressure Analyses	6.2-57
6.2.1.2-1	Calculated Maximum Differential Pressures of High Energy Line Breaks for Short-Term Subcompartment Pressurization	6.2-59
6.2.1.3-1	Short-term Mass and Energy Inputs	6.2-62
6.2.1.3-2	Short-term Mass and Energy Releases - 3" Purification Line from RHX Tube Outlet to LHX Tube Inlet	6.2-63
6.2.1.3-3	Short-term Mass and Energy Releases - 3" Purification Line from CVS-PL-V003 Outlet to RHX Tube Inlet	6.2-64
6.2.1.3-4	Short-term Mass and Energy Releases - 3" Purification Return Line from RHX Shell Outlet to Check Valve CVS-PL-V080 Inlet	6.2-65
6.2.1.3-5	Short-term Mass and Energy Releases - 3" CVS Purification Return Line	6.2-66
6.2.1.3-6	Short-term Mass and Energy Releases - 4" Cold Leg Pressurizer Spray Line	6.2-67
6.2.1.3-7	Short-term Mass and Energy Releases - 4" Steam Generator Blowdown Line	6.2-68
6.2.1.3-8	Parameters for LOCA Long-Term Containment Analysis	6.2-69
6.2.1.3-9	Long-Term DECL Break Mass and Energy Releases	6.2-70
6.2.1.3-10	Blowdown DEHL Break Mass and Energy Releases	6.2-77
6.2.1.3-11	Short-term Mass and Energy Releases - 3" CVS-PL-V081 Inlet to CVS-PL-V082 Outlet	6.2-80
6.2.1.3-12	Short-term Mass and Energy Releases - 3" CVS Purification Return Line	6.2-81
6.2.1.3-13	Short-term Mass and Energy Releases - 4" Auxiliary Spray Piping to Pressurizer Spray Nozzle	6.2-82
6.2.1.3-14	Short-term Mass and Energy Releases - 2" Auxiliary Spray Piping to Pressurizer Spray Nozzle	6.2-83
6.2.1.4-1	Not Used	6.2-84
6.2.1.4-2	Main Steam Line Double Ended Rupture Mass and Energy Releases from 30% Power Level	6.2-85
6.2.1.4-3	Main Steam Line Double Ended Rupture Mass and Energy Releases from Full Power Level	6.2-87
6.2.1.4-4	Parameters for Steam Line Break Mass and Energy Releases Inside Containment Analysis	6.2-89
6.2.1.5-1	Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA	6.2-90

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
6.2.2-1	Passive Containment Cooling System Performance Parameters	6.2-102
6.2.2-2	Component Data Passive Containment Cooling System (Nominal)	6.2-103
6.2.2-3	Failure Mode and Effects Analysis - Passive Containment Cooling System Components	6.2-104
6.2.3-1	Containment Mechanical Penetrations and Isolation Valves	6.2-105
6.2.4-1	Component Data - Hydrogen Monitors (Nominal)	6.2-109
6.2.4-2	Component Data - Hydrogen Recombiner (Nominal)	6.2-110
6.2.4-3	Component Data - Hydrogen Igniter (Nominal)	6.2-111
6.2.4-4–6.2.4-5	Not Used	6.2-112
6.2.4-6	Igniter Location	6.2-113
6.2.4-7	Subcompartment/Area Igniter Coverage	6.2-116
6.3-1	Passive Core Cooling System - Remote Actuation Valves	6.3-54
6.3-2	Component Data - Passive Core Cooling System	6.3-55
6.3-3	Failure Mode and Effects Analysis - Passive Core Cooling System Components	6.3-57
6.4-1	Onsite Chemicals	6.4-17
6.4-2	Main Control Room Habitability Indications and Alarms	6.4-18
6.4-3	Loss of AC Power Heat Load Limits	6.4-19
6.4-201	Main Control Room Habitability Evaluations of Onsite Toxic Chemicals	6.4-20
6.5.3-1	Primary Containment Operation Following a Design Basis Accident	6.5-7

LIST OF FIGURES

Figure Number	Title	Page
6.2.1.1-1	AP1000 Containment Pressure Response for Full DER MSLB – 30% Power	6.2-117
6.2.1.1-2	AP1000 Containment Temperature Response for Full DER MSLB – 101% Power	6.2-118
6.2.1.1-3–6.2.1.1-4	Not Used	6.2-119
6.2.1.1-5	AP1000 Containment Pressure Response for DECLG LOCA – 5000 sec	6.2-120
6.2.1.1-6	AP1000 Containment Temperature Response to DECLG LOCA – 5000 sec	6.2-121
6.2.1.1-7	AP1000 Containment Pressure Response for DECLG LOCA – 3 Days	6.2-122
6.2.1.1-8	AP1000 Containment Temperature Response for DECLG LOCA – 3 Days	6.2-123
6.2.1.1-9	AP1000 Containment Pressure Response – DEHLG LOCA	6.2-124
6.2.1.1-10	AP1000 Containment Temperature Response for DEHLG LOCA	6.2-125
6.2.1.1-11	AP1000 Design External Pressure Analysis Containment Pressure vs. Time	6.2-126
6.2.1.3-1	AP1000 DECLG Integrated Break Flow	6.2-127
6.2.1.3-2	AP1000 DECLG LOCA Integrated Energy Released	6.2-128
6.2.1.3-3	AP1000 DEHLG Integrated Break Flow	6.2-129
6.2.1.3-4	AP1000 DEHLG LOCA Integrated Energy Released	6.2-130
6.2.1.5-1	AP1000 Minimum Containment Pressure for DECLG LOCA	6.2-131
6.2.2-1	(Sheet 1 of 2) Simplified Passive Containment Cooling System Piping and Instrumentation Diagram	6.2-132
6.2.2-1	(Sheet 2 of 2) Simplified Passive Containment Cooling System Piping and Instrumentation Diagram	6.2-133
6.2.2-2	Simplified Sketch of Passive Containment Cooling System	6.2-134
6.2.4-1–6.2.4-4	Not Used	6.2-135
6.2.4-5	Hydrogen Igniter Locations – Section View	6.2-136
6.2.4-6	Hydrogen Igniter Locations Plan View Elevation 82′-6″	6.2-137
6.2.4-7	Hydrogen Igniter Locations – Section View	6.2-138
6.2.4-8	Hydrogen Igniter Locations Plan View Elevation 96′-6″	6.2-139
6.2.4-9	Hydrogen Igniter Locations Plan View Elevation 118′-6″	6.2-140
6.2.4-10	Hydrogen Igniter Locations Plan View Elevation 135′-3″	6.2-141
6.2.4-11	Hydrogen Igniter Locations Plan View Elevation 162′-0″	6.2-142
6.2.4-12	Hydrogen Igniter Locations Plan View Elevation 210′-0″	6.2-143
6.2.4-13	Hydrogen Igniter Locations Section A-A	6.2-144
6.2.5-1	Simplified Containment Leak Rate Test System Piping and Instrumentation Diagram	6.2-145
6.3-1	(Sheet 1 of 3) Simplified Passive Core Cooling System Piping and Instrumentation Diagram	6.3-61
6.3-1	(Sheet 2 of 3) Simplified Passive Core Cooling System Piping and Instrumentation Diagram	6.3-62
6.3-1	(Sheet 3 of 3) Simplified Passive Core Cooling System Piping and Instrumentation Diagram	6.3-63
6.3-2	Not Used	6.3-64
6.3-3	Passive Safety Injection	6.3-65
6.3-4	Passive Decay Heat Removal	6.3-66

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
6.3-5	Passive Heat Removal Heat Exchanger	6.3-67
6.3-6	IRWST Screen Plan Location	6.3-68
6.3-7	IRWST Screen Section Location	6.3-69
6.3-8	Containment Recirculation Screen Location Plan	6.3-70
6.3-9	Containment Recirculation Screen Location Elevation	6.3-71
6.4-1	Main Control Room Envelope	6.4-24
6.4-2	(Sheet 1 of 2) Simplified Main Control Room Habitability System Piping and Instrumentation Diagram	6.4-25
6.4-2	(Sheet 2 of 2) Simplified Main Control Room Habitability System Piping and Instrumentation Diagram	6.4-26
6.5-1	Containment Spray Coverage at Operating Deck	6.5-8
6A-1	RCS Release Locations	6A-9
6A-2	Containment Natural Circulation	6A-10

Chapter 6 Engineered Safety Features

6.0 Engineered Safety Features

Engineered safety features (ESF) protect the public in the event of an accidental release of radioactive fission products from the reactor coolant system. The engineered safety features function to localize, control, mitigate, and terminate such accidents and to maintain radiation exposure levels to the public below applicable limits and guidelines, such as 10 CFR 50.34. The following are defined as engineered safety features:

Containment

The containment vessel, discussed in Subsection 6.2.1, is a free standing cylindrical steel vessel with ellipsoidal upper and lower heads. It is surrounded by a seismic Category I shield building. The function of the containment vessel, as part of the overall containment system, is to contain the release of radioactivity following postulated design basis accidents. The containment vessel also functions as the safety-related ultimate heat sink by transferring the heat associated with accident sources to the surrounding environment. The following paragraph details this safety-related feature.

Passive Containment Cooling System

The function of the passive containment cooling system, discussed in Subsection 6.2.2, is to maintain the temperature below a maximum value and to reduce the containment temperature and pressure following a postulated design-basis event. The passive containment cooling system removes thermal energy from the containment atmosphere. The passive containment cooling system also serves as the safety-related ultimate heat sink for other design basis events and shutdowns. The passive containment cooling system limits the release of radioactive material to the environment by reducing the pressure differential between the containment atmosphere and the external environment. This diminishes the driving force for leakage of fission products from the containment to the atmosphere.

Containment Isolation System

The major function of the containment isolation system of the AP1000, discussed in Subsection 6.2.3, is to provide containment isolation to allow the normal or emergency passage of fluids through the containment boundary while preserving the integrity of the containment boundary, if required. This prevents or limits the escape of fission products that may result from postulated accidents. Containment isolation provisions are designed so that fluid lines penetrating the primary containment boundary are isolated in the event of an accident. This minimizes the release of radioactivity to the environment.

Passive Core Cooling System

The primary function of the passive core cooling system, discussed in Section 6.3, is to provide emergency core cooling following postulated design-basis events. The passive core cooling system provides reactor coolant system makeup and boration during transients or accidents where the normal reactor coolant system makeup supply from the chemical and volume control system is lost or is insufficient. The passive core cooling system provides safety injection to the reactor coolant system to provide adequate core cooling for the complete range of loss of coolant accident events up to, and including, the double ended rupture of the largest primary loop reactor coolant system piping. The passive core cooling system provides core decay heat removal during transients, accidents, or whenever the normal heat removal paths are lost.

Main Control Room Emergency Habitability System

The main control room emergency habitability system, discussed in Section 6.4, is designed so that the main control room remains habitable following a postulated design basis event. With a loss of all

ac power sources, the habitability system will maintain an acceptable environment for continued operating staff occupancy.

Fission Product Control

Post-accident safety-related fission product control for the AP1000, discussed in Section 6.5, is provided by natural removal processes inside containment, the containment boundary, and the containment isolation system. The natural removal processes, including various aerosol removal processes and pool scrubbing, remove airborne particulates and elemental iodine from the containment atmosphere following a postulated design basis event.

6.1 Engineered Safety Features Materials

This section provides a description of the materials used in the fabrication of engineered safety features components and of the provisions to avoid material interactions that could potentially impair the operation of the engineered safety features. A list of engineered safety features was given previously in Section 6.0. Reactor coolant system materials, including branch piping connected to the reactor coolant system, are described in Subsection 5.2.3.

6.1.1 Metallic Materials

Materials for use in engineered safety features are selected for their compatibility with the reactor coolant system and refueling water.

The edition and addenda of the ASME Code applied in the design and manufacture of each component are the edition and addenda established by the requirements of the Design Certification. The use of editions and addenda issued subsequent to the Design Certification is permitted or required based on the provisions in the Design Certification. The baseline used for the evaluations done to support this safety analysis report and the Design Certification is the 1998 Edition, through the 2000 Addenda. When material is procured to later editions or addenda, the design of the component is reconciled to the new material properties in accordance with the rules of the ASME Code, provided that the later edition and addenda are authorized in 10 CFR 50.55a or in a specific authorization as provided in 50.55a(z).

6.1.1.1 Specifications for Principal Pressure-Retaining Materials

The pressure-retaining materials in engineered safety features system components comply with the corresponding material specification permitted by the ASME Code, Section III, Division 1. The material specifications used for pressure-retaining valves in contact with reactor coolant are the specifications used for reactor coolant pressure boundary valves and piping. See Table 5.2-1 for a listing of these specifications. The material specifications for pressure-retaining materials in each component of an engineered safety features system meet the requirements of Article NC-2000 of the ASME Code, Section III, Class 2, for Quality Group B; Article ND-2000 of the ASME Code, Section III, Class 3, for Quality Group C components; and Article NE-2000 of the ASME Code, Section III for containment pressure boundary components.

Containment penetration materials meet the requirements of Articles NC-2000 or NE-2000 of the ASME Code, Section III, Division 1. The quality groups assigned to each component are given in Section 3.2. The pressure-retaining materials are indicated in Table 6.1-1. Materials for ASME Class 1 equipment are provided in Subsection 5.2.3.

The following subsection provides information on the selection and fabrication of the materials in the engineered safety features of the plant.

Components in contact with borated water are fabricated of, or clad with, austenitic stainless steel or equivalent corrosion-resistant material. The use of nickel-chromium-iron alloy in the engineered safety features is limited to Alloy 690 or its associated weld metals Alloys 52, 52M, 152, and similar alloys developed for improved weldability as allowed by ASME Boiler and Pressure Vessel Code rules. Nickel-chromium-iron alloy is used where the corrosion resistance of the alloy is an important consideration and where the use of nickel-chromium-iron alloy is the choice because of the coefficient of thermal expansion.

The material for the air storage tanks in the main control room emergency habitability system is tested for lateral expansion by the Charpy V-Notch impact testing method per supplementary requirement S3 of material specification SA-372. The lateral expansion shall be 20 mils or greater

from an average of three tests at or below the lowest service temperature. The lowest expansion value of the three tests shall be 15 mils or greater. The material is not permitted to be weld repaired.

6.1.1.2 Fabrication Requirements

The welding materials used for joining the ferritic base materials of the pressure-retaining portions of the engineered safety features conform to, or are equivalent to, ASME Material Specifications SFA 5.1, 5.5, 5.17, 5.18, 5.20, 5.23, 5.28, 5.29, and 5.30. The welding materials used for joining nickel-chromium-iron alloy in similar base material combination, and in dissimilar ferritic or austenitic base material combination, conform to ASME Material Specifications SFA 5.11 and 5.14, or are similar welding alloys to those in SFA-5.11 or SFA-5.14 developed for improved weldability as allowed by the ASME Boiler and Pressure Vessel Code rules.

The welding materials used for joining the austenitic stainless steel base materials for the pressure-retaining portions of engineered safety features conform to, or are equivalent to, ASME Material Specifications SFA 5.4, 5.9, 5.22, and 5.30. These materials are qualified to the requirements of the ASME Code, Section III and Section IX, and are used in procedures qualified to these same rules. The methods used to control delta ferrite content in austenitic stainless steel weldments in engineered safety features components are the same as those for ASME Code Class 1 components, described in Subsection 5.2.3.4.

The integrity of the safety-related components of the engineered safety features is maintained during component manufacture. Austenitic stainless steel is used in the final heat-treated condition as required by the respective ASME Code, Section II, material specification for the particular type or grade of alloy. Also, austenitic stainless steel materials used in the engineered safety features components are handled, protected, stored, and cleaned according to recognized and accepted methods designed to minimize contamination, which could lead to stress corrosion cracking. These controls for engineered safety features components are the same as those for ASME Code Class 1 components, discussed in Subsection 5.2.3.4. Sensitization avoidance, intergranular attack prevention, and control of cold work for engineered safety features components are the same as the ASME Code Class 1 components discussed in Subsection 5.2.3.4. Cold-worked austenitic stainless steels having a minimum specified yield strength greater than 90,000 psi are not used for pressure boundary components of the engineered safety features in contact with reactor coolant.

Information is provided in Section 1.9 concerning the degree of conformance with the following Regulatory Guides:

- Regulatory Guide 1.31, Control of Ferrite Content in Stainless Steel Weld Metal
- Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel

Lead, antimony, cadmium, indium, mercury, and tin metals and their alloys are not allowed to come in contact with engineered safety features component parts made of stainless steel or high alloy metals during fabrication or operation. Bearing alloys containing greater than 1 percent of lead, antimony, cadmium, or indium are not used in contact with reactor coolant.

In accordance with Appendix B to 10 CFR Part 50, the quality assurance program establishes measures to provide control of special processes. One element of control is the review and acceptance of vendor procedures that pertain to the fabrication, welding, and other quality assurance methods for safety related component to determine both code and regulatory conformance. Included in this review and acceptance process are those vendor procedures necessary to provide conformance with the requirements of Regulatory Guides 1.31 and 1.44 for engineered safety features components as discussed in Section 6.1 and reactor coolant system components as discussed in Subsection 5.2.3.

6.1.1.3 Specifications for Nonpressure-Retaining Materials

Materials for nonpressure-retaining portions of engineered safety features in contact with borated water or other fluids may be procured under ASTM designation. The principle examples of these items are the in-containment refueling water storage tank liner and the passive containment cooling system storage tank liner.

The wetted plate walls of the in-containment refueling water storage tank are fabricated of ASTM A240 UNS S32101. ASTM A240 UNS S32101 is a chromium, manganese, and nitrogen-strengthened duplex stainless steel with higher ultimate tensile and yield strengths than type 304 and 316 stainless steel. This material can be welded using a matching Duplex 2101 (2304 or 2209) filler metal by any of the commonly used stainless steel welding methods, including shielded metal arc welding (SMAW), gas tungsten arc welding TIG (GTAW), gas metal arc welding MIG (GMAW), flux-cored arc welding (FCW), plasma arc welding (PAW), and submerged arc welding (SAW). This material is used for applications where the higher strength allows reductions in weight and material costs. The material has a resistance to intergranular stress corrosion cracking similar to or better than type 304 and 304L stainless steel.

6.1.1.4 Material Compatibility with Reactor Coolant System Coolant and Engineered Safety Features Fluids

Engineered safety features components materials are manufactured primarily of stainless steel or other corrosion-resistant material. Protective coatings are applied on carbon steel structures and equipment located inside the containment, as discussed in Subsection 6.1.2.

Austenitic stainless steel plate conforms to ASME SA-240. Austenitic stainless steel is confined to those areas or components which are not subject to post-weld heat treatment. Carbon steel forgings conform to ASME SA-350. Austenitic stainless steel forgings conform to ASME SA-182. Nickel-chromium-iron alloy pipe conforms to ASME SB-167. Carbon steel castings conform to ASME SA-352. Austenitic stainless steel castings conform to ASME SA-351.

The use of cobalt-base alloys is minimized. Restrictions on the use of cobalt in the base metal for material in contact with reactor coolant are discussed in Subsection 12.3.1.1.1.

In post-accident situations where the containment is flooded with water containing boric acid, pH adjustment is provided by the release of trisodium phosphate into the water. The trisodium phosphate is held in baskets located in the floodable volume that includes the steam generator compartments and contains the reactor coolant loop. The addition of trisodium phosphate to the solution is sufficient to raise the pH of the fluid to above 7.0. This pH is consistent with the guidance of NRC Branch Technical Position MTEB-6.1 for the protection of austenitic stainless steel from chloride-induced stress corrosion cracking. Section 6.3 describes the design of the trisodium phosphate baskets.

In the post-accident environment, both aluminum and zinc surfaces in the containment are subject to chemical attack resulting in the production of hydrogen and/or chemical precipitants that can affect long-term core cooling. The amount of aluminum allowed in the containment below the maximum flood level of a design basis loss-of-coolant accident (LOCA) (refer to Subsection 6.3.2.2.7.1, item 3) will be limited to less than 40 pounds with a surface area of no more than 13.33 square feet during operating conditions. A large potential source of aluminum in the AP1000 containment are the excore detectors described in Subsection 7.1.2.7.2. To avoid sump water contact with the excore detectors, they are enclosed in stainless steel or titanium housings. The non-flooded surfaces would be wetted by condensing steam, but they would not be subjected to the boric acid or trisodium phosphate solutions since there is no containment spray. For this reason, the amount of aluminum in the excore detectors is not applied to the 40-pound weight limit restriction as they are not subject to the post-design basis accident (DBA) environment as a result of stainless steel or titanium encasement.

Furthermore, other aluminum, within containment encased in stainless steel/titanium that can ensure interaction with the boric acid or trisodium phosphate solutions does not occur, should not be applied to the 40-pound weight limit. Nonsafety-related passive autocatalytic recombiners are provided to limit hydrogen buildup inside containment.

6.1.1.5 Integrity of Safety-Related Components

The pH adjustment baskets provide for long-term pH control. In the case of inadvertent short-term flooding when the pH adjustment baskets remain above the flood level, the condition of the material in contact with the fluid is evaluated prior to return to operation. Based on previous industry testing and experience, the behavior of austenitic stainless steels in the post-design basis accident environment is acceptable. Cracking is not anticipated, provided that the core cooling pH is maintained at an adequate level.

6.1.1.6 Thermal Insulation

The majority of the engineered safety features insulation used in the AP1000 containment is reflective metallic insulation. Fibrous insulation may be used if it is enclosed in stainless steel cans. The selection, procurement, testing, storage, and installation of nonmetallic thermal insulation provides confidence that the leachable concentrations of chloride, fluoride, and silicate are in conformance with Regulatory Guide 1.36. Conformance with Regulatory Guide 1.36 is summarized in Section 1.9.

6.1.1.7 Component and System Cleaning

See Subsection 1.9.1 for a discussion on the provisions of Regulatory Guide 1.37 for the cleaning of components and systems.

6.1.2 Organic Materials

6.1.2.1 Protective Coatings

6.1.2.1.1 General

The AP1000 is divided into four areas with respect to the use of protective coatings. These four areas are:

- Inside containment
- Exterior surfaces of the containment vessel
- Radiologically controlled areas outside containment
- Remainder of plant

The considerations for protective coatings differ for these four areas and the coatings selection process accounts for these differing considerations. The AP1000 design considers the function of the coatings, their potential failure modes, and their requirements for maintenance. Table 6.1-2 lists different areas and surfaces inside containment and on the containment shell that have coatings, their functions, and to what extent their coatings are related to plant safety.

Coatings used outside containment do not provide functions related to plant safety except for the coating on the outside of the containment shell. The coating on the outside of the containment shell

above elevation 135′ 3″ shell supports passive containment cooling system heat transfer and is classified as a Service Level III coating.

The coating used on the inside surface of the containment shell supports the transfer of thermal energy from the post-accident atmosphere inside containment to the containment shell. Passive containment cooling system testing and analysis have been performed with a coating. This coating is classified as a Service Level I coating.

Coatings are not used in the vicinity of the containment recirculation screens to minimize the possibility of debris clogging the screens. Subsection 6.3.2.2.7.3 defines the area in the vicinity of the recirculation screens where coatings are not used.

Coatings used inside containment, except for inorganic zinc used on the inside surface of the containment shell and on other components, and epoxy top coat used on the inside surface of the containment shell are classified as Service Level II coatings because their failure does not prevent functioning of the engineered safety features. If the Service Level I epoxy or Service Level II coatings delaminate, the solid debris they may form will not have a negative impact on the performance of safety-related post-accident cooling systems. See Subsection 6.1.2.1.5 for a discussion of the factors including plant design features and low water flows that permit the use of Service Level II coatings inside containment. Protective coatings are maintained to provide corrosion protection for the containment pressure boundary and for other system components inside containment.

The corrosion protection of the containment shell is a safety-related function. Good housekeeping and decontamination functions of the coatings are nonsafety-related functions.

For information on coating design features, quality assurance, material and application requirements, and performance monitoring requirements, see Subsection 6.1.2.1.6.

6.1.2.1.2 Inside Containment

Carbon Steel

Inorganic zinc is the basic coating applied to the containment vessel. Below the operating floor, most of the inorganic zinc coating is top coated with epoxy where enhanced decontamination is desired. Where practical, carbon steel and structural modules within the containment are coated with self-priming high solids epoxy (SPHSE). When coating use is not practical, carbon steel items (such as items with threaded surfaces, bolted connections, surfaces that could wear due to moving parts, and surfaces with temperature or radiation conditions that exceed the coatings' qualification) are left uncoated or use a rust preventative. Where practical, miscellaneous carbon steel items (such as stairs, ceilings, gratings, ladders, railings, conduit, duct, and cable tray) are hot-dip galvanized. Steel surfaces subject to immersion during normal plant operation (such as sumps and gutters) are stainless steel or are coated with SPHSE applied directly to the carbon steel without an inorganic zinc primer. Carbon steel structures and equipment are assembled in modules, and the modules are coated in the fabrication shop under controlled conditions.

Concrete

Concrete surfaces inside containment are coated primarily to prevent concrete from dusting, to protect it from chemical attack, and to enhance decontaminability. In keeping with ALARA goals, the exposed concrete surfaces are made as decontaminable as practical in areas of frequent personnel access and areas subject to liquid spray, splash, spillage, or immersion.

Exposed concrete surfaces inside containment are coated with epoxy. Concrete floors inside containment are coated. Exposed concrete walls inside containment are coated to a minimum height of 7 feet.

6.1.2.1.3 Exterior of Containment Vessel

The exterior of the containment vessel is coated with the same inorganic zinc as is used inside of the containment vessel. The inorganic zinc coating enhances heat transfer by providing good heat conduction and by enhancing surface wetting of the exterior surface of the containment vessel. The inorganic zinc also provides corrosion protection.

6.1.2.1.4 Radiologically Controlled Areas Outside Containment and Remainder of Plant

The coatings used in the radiologically controlled areas outside containment and in the remainder of the plant are also classified as Service Level II coatings. However, these coatings are selected, specified, and applied in a manner that optimizes performance and standardization within the AP1000 design. Therefore, wherever practical, the same coating systems are used in radiologically controlled areas outside containment as are used inside containment. The ALARA concept is carried through in areas subject to radiation exposure and possible radiological contamination. Consistent with ALARA goals, the surfaces are made as decontaminable as practical in areas of frequent personnel access and areas subject to liquid spray, splash, spillage, or immersion. The remainder of the plant coating systems are commercial grade materials that are selected and applied according to the expected conditions in the specific areas where the coatings are applied.

6.1.2.1.5 Safety Evaluation

This subsection describes the basis for classifying coatings as Service Level I, II, or III. Table 6.1-2 identifies which coatings are classified as Service Level I and Service Level III.

The inorganic zinc coating on the outside of the containment shell above elevation 135' 3" supports passive containment cooling system heat transfer and is classified as a Service Level III coating.

The inorganic zinc coating used on the inside surface of the containment shell supports the transfer of thermal energy from the post-accident atmosphere inside containment to the containment shell. Passive containment cooling system testing and analysis have been performed with an inorganic zinc coating. This coating is classified as Service Level I coating.

The AP1000 has a number of design features that facilitate the use of Service Level II coatings inside containment. These features include a passive safety injection system that provides a long delay time between a LOCA and the time recirculation starts. This time delay provides time for settling of debris. These passive systems also flood the containment to a high level which allows the use of containment recirculation screens that are located well above the floor and are relatively tall. Significant volume is provided for the accumulation of coating debris without affecting screen plugging. These screens are protected by a plate located above the screens that extends out in front and to the side of the screens. Coatings are not used under this plate in the vicinity of the screens. The protective plate, together with low recirculation flow, approach velocity and the screen size preclude postulated coating debris above the plate from reaching the screens. Refer to Subsection 6.3.2.2.7.3 for additional discussion of these screens, the protective plate and the areas where coatings are prohibited from being used.

The recirculation inlets are screened enclosures located near the northwest and southwest corners of the east steam generator compartment (refer to the figures in Subsection 6.3.2.2.7.3). The enclosure bottoms are located above the surrounding floor, which prevent ingress of heavy debris (density ≥ 100 lb_m/ft^3). Additionally, the screens are oriented vertically and are protected by a large plate located above the screens, further enhancing the capability of the screens to function with debris in the water. The screen mesh size and the surface area of the containment recirculation screens in the AP1000, in conjunction with the large floor area for debris to settle on, can accommodate failure of

coatings inside containment during a design basis accident even though the residue of such a failure is unlikely to be transported to the vicinity of the enclosures.

The AP1000 does not have a safety-related containment spray system. The containment spray system provided in the AP1000 is only used for beyond design basis events. This reduces the chance that coatings will peel off surfaces inside containment because the thermal shock of cold spray water on hot surfaces combined with the rapid depressurization following spray initiation are recognized as contributors to coating failure. Parts of the containment below elevation 110′ are flooded and water is recirculated through the passive core cooling system. However, the volume of water moved in this manner is relatively small and the flow velocity is very low.

The coating systems used inside containment also include epoxy and/or self-priming high solids epoxy coatings. These are applied to concrete substrates, as top coats over the inorganic zinc coating, and directly to steel, as noted in Subsection 6.1.2.1.2. The failure modes of these systems could include delamination or peeling if the epoxy coatings are not properly applied (References 1, 2, 3). The epoxies applied to concrete and carbon steel surfaces are sufficiently heavy (dry film density greater than or equal to 100 lb/ft^3) so that transport of small chips with the low water velocity in the AP1000 containment is limited.

Inside containment, there are components coated with various manufacturers' standard coating systems. These coating systems are generally not required to have Class I or III safety classification as delineated in Table 6.1-2; however, those located below the maximum flood level of a design basis LOCA, or where there is sufficient water flow to transport debris, are required to be sufficiently heavy (dry film density greater than or equal to 100 lb/ft^3) so that transport of small chips with the low water velocity in the AP1000 containment is limited.

If a coating on walls, structures, or components has a dry film density less than 100 lb/ft^3, then testing and/or analysis must be performed to demonstrate that the debris is not transported to an AP1000 screen or into the core through a flooded break. The testing and/or analysis must be approved by the NRC.

In addition, inorganic zinc should be used only on surfaces that may be exposed to temperatures that are above the limits of epoxy coatings during normal operating conditions; inorganic zinc coatings used in such applications are required to be Safety – Service Level I to prevent detachment during a LOCA since such debris is not likely to settle out.

Requirements related to production of hydrogen as a result of zinc corrosion in design basis accident conditions, including the zinc in paints applied inside containment, were eliminated by the final rule, effective October 16, 2003, amending 10 CFR 50.44, "Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors."

Nonconforming coatings that cannot be qualified as Service Level I are evaluated on a case basis relative to impact on plant safety. The total inventory of unqualified coatings (coatings which cannot be qualified as Safety-Service Level I) within Service Level I areas combined with the total amount of coating debris fines that can be generated by a LOCA jet is restricted to the limits established in Subsection 6.3.2.2.7.1.

6.1.2.1.6 Quality Assurance Features

A number of quality assurance features provide confidence that the coating systems inside the containment, on the exterior of the containment vessel and in potentially contaminated areas outside containment will perform as intended. These features enhance the ALARA program and enhance corrosion resistance. The features are discussed in the following paragraphs.

Service Level I and Service Level III Coatings

The quality assurance program for Service Level I and Service Level III coatings conforms to the requirements of ASME NQA-1 as identified in the position statement of Regulatory Guide 1.28 provided in Appendix 1A. Safety related coatings meet the pertinent provisions of 10CFR Part 50 Appendix B to 10CFR Part 50. The service level classification of coatings is consistent with the positions given in Regulatory Guide 1.54 (revision and exceptions as specified in Appendix 1A), "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." Service Level I and Service Level III coatings used in the AP1000 are tested for radiation tolerance and for performance under design basis accident conditions. Where decontaminability is desired, the coatings are evaluated for decontaminability. The coating applicator submits and follows acceptable procedures to control surface preparation, application of coatings and inspection of coatings. The painters are qualified and certified, and the inspectors are qualified and certified.

The inorganic zinc coating used on the inside surface (Service Level I coatings) and outside surface (Service Level III coatings) of the containment shell is inspected using a non-destructive dry film thickness test and a MEK rub test. These inspections are performed after the initial application and after recoating. Long term surveillance of the coating is provided by visual inspections performed during refueling outages. Other inspections are not required.

During the design and construction phase, the coatings program associated with selection, procurement and application of safety related coatings is performed to applicable quality standards. The requirements for the coatings program are contained in certified drawings and/or standards and specifications controlling the coating processes of the designer (Westinghouse) (these design documents will be available prior to the procurement and application of the coating material by the constructor of the plant). Regulatory Guide 1.54 and ASTM D5144 (Reference 201) form the basis for the coating program.

During the operations phase, the coatings program is administratively controlled in accordance with the quality assurance program implemented to satisfy 10 CFR Part 50, Appendix B, and 10 CFR Part 52 requirements. The coatings program provides direction for the procurement, application, inspection, and monitoring of safety related coating systems. Prior to initial fuel loading, a consolidated plant coatings program will be in place to address procurement, application, and monitoring (maintenance) of those coating system(s) for the life of the plant.

Coating system monitoring requirements for the containment coating systems are based on ASTM D5163 (Reference 202), "Standard Guide for Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant," and ASTM D7167 (Reference 203), "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant." Any anomalies identified during coating inspection or monitoring are resolved in accordance with applicable quality assurance requirements. Management of unqualified coatings inside containment is performed in accordance with the guidance of ASTM D7491 (Reference 204), "Standard Guide for Management of Non-Conforming Coatings in Coating Service Level I Areas of Nuclear Power Plants."

Refer to Table 6.1-2 for identification of Service Level I and Service Level III coating applications in the AP1000.

Service Level II Coatings

The use of Service Level II coatings inside containment is based on the use of selected types of coatings and the properties of the coatings. To preclude the use of inappropriate coatings, the procurement of Service Level II coatings used inside containment is considered a safety-related activity whereas the Service Level II coatings used outside the containment are nonsafety-related.

Such Service Level II coatings used inside containment are procured to the same standards as Service Level I coatings with regard to radiation tolerance and performance under design basis accident conditions as discussed below.

Service Level II coatings used on manufactured components are not subject to the procurement under 10 CFR 50, Appendix B, because their high density limits the transport with the low water velocity in the AP1000 containment.

Service Level II coatings used inside containment are tested for radiation tolerance and for performance under design basis accident conditions to the standards referenced in Appendix 1A. Service Level II coating application configurations such as variations in substrate, surface preparation, cleanliness, profile, color, and dry film thickness are not required to be qualified by DBA testing. Delamination of Service Level II coatings during DBA testing is acceptable if the Service Level II coating meets the criteria identified in Subsection 6.1.2.1.1. Where decontaminability is desired, the coatings are selected to be as decontaminable as practical.

Service Level II coatings used inside containment on internal structures, including walls, floor slabs, structural steel, and the polar crane are subject to procurement and DBA testing under 10 CFR 50 Appendix B, except in the following areas: a) surfaces located inside the chemical and volume control system room # 11209, and b) the area outside of the annular wall of the IRWST. Service Level II coatings used in the chemical and volume control system room are not subject to procurement under 10 CFR 50, Appendix B and DBA testing, because the room is connected to the containment in a limited way through a drain line. In addition, the drain line is routed to the waste liquid processing system sump which is located well below and separate from the recirculation screens. Service Level II coatings used on the outside of the annular wall of the IRWST are not subject to procurement under 10 CFR 50, Appendix B and DBA testing, because their high density and location limit the transportation in the accident conditions of the low water velocity in the AP1000 containment.

The Service Level II coatings used inside containment are as shown in Table 6.1-2. Coating system application, inspection and monitoring requirements for the Service Level II coatings used inside containment will be performed in accordance with a program based on ASTM D5144 (Reference 201), “Standard Guide for Use of Protective Coating Standards in Nuclear Power Plants,” and the guidance of ASTM D5163 (Reference 202), “Standard Guide for Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant.” Application anomalies identified during coating inspection or monitoring are resolved in accordance with applicable quality requirements.This program is not subject to 10 CFR 50, Appendix B, quality assurance requirements.

Due to the use of modularized construction, a significant portion of the containment coatings are shop applied to the containment vessel and to piping, structural and equipment modules. This application of coatings under controlled shop conditions provides additional confidence that the coatings will perform as designed and as expected.

The coatings used in radiologically controlled areas outside containment, consistent with ALARA goals, are selected to be as decontaminable as practical; they are not specified to be radiation tolerance tested or design basis accident tested, and they are not procured to Appendix B to 10 CFR 50. Where practical, the same coating materials are used in radiologically controlled areas outside containment as are used inside containment. This provides a high level of quality and optimizes maintenance painting over the life of the plant.

6.1.2.2 Other Organic Materials

A listing of other organic materials in the containment is developed based on the specific type of equipment and the supplier selected to provide it. Materials are evaluated for potential interaction

with engineered safety features to provide confidence that the performance of the engineered safety features is not unacceptably affected.

6.1.3 Combined License Information Items

6.1.3.1 Procedure Review

The review of vendor fabrication and welding procedures or other quality assurance methods to judge conformance of austenitic stainless steels with Regulatory Guides 1.31 and 1.44 is addressed in Subsection 6.1.1.2.

6.1.3.2 Coating Program

The programs to control procurement, application, inspection, and monitoring of Service Level I, Service Level II, and Service Level III coatings are addressed in Subsection 6.1.2.1.6.

6.1.4 References

1. NUREG-0797, “Safety Evaluation Report related to the operation of Comanche Peak Steam Electric Station, Units 1 and 2.”

2. Bolt, R. O. and J. G. Carroll, “Radiation Effects on Organic Materials,” Academic Press, New York, 1963, Chapter 12.

3. Parkinson, W. W. and O. Sisman, “The Use of Plastics and Elastomers in Nuclear Radiation,” Nuclear Engineering and Design 17 (1971), pp 247-280, North-Holland Publishing Co., Amsterdam.

201. ASTM D5144-08, “Standard Guide for Use of Protective Coating Standards in Nuclear Power Plants.”

202. ASTM D5163-05a, “Standard Guide for Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant.”

203. ASTM D7167-05, “Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant.”

204. ASTM D7491-08, “Standard Guide for Management of Non-Conforming Coatings in Coating Service Level I Areas of Nuclear Power Plants.”

Table 6.1-1 (Sheet 1 of 2)
Engineered Safety Features Pressure-Retaining Materials

Component	Materials
Passive Core Cooling System (safety-related portion)	
Core makeup tank	Refer to Subsection 5.2.3
Passive residual heat removal heat exchanger	Refer to Subsection 5.3.4, Table 5.2-1
In-containment refueling water storage tank	ASTM A240 S32101 or TP304L (or dual grade TP-304/304L)
Accumulators	Refer to Subsections 6.1.1, 6.3.2.2, and 6.3.2.4
Spargers	
Piping	SA-358 Grade 304 or 316 or SA-312 Grade TP304 or TP316
Fittings	SA-182 Grade F304 or SA-403 Grade WP304 or WP316
Tube and piping, valves, and fittings	Refer to Subsections 6.1.1 and 6.3.2.4
Passive containment cooling system (safety-related portion)	
Passive containment cooling system water storage tank	ASTM A240 TP304
PCCWST Discharge Path	
Valves	SA-182 Grade F304 or F304L or F316 or F316L or SA-351 Grade CF3 or CF3A or CF3M or CF8 or CF8M
Tube and piping	SA-312 Grade TP304L or SA-213 Grade TP316
Fittings	SA-182 Grade F304L or F316 or F316L or dual-marked F304/F304L or F316/F316L or SA-403 Grade WP304L or SA-479 Type 316
PCS Recirculation Subsystem	
Valves	SA-217 Grade WC6 or SA-182 Grade F304 or F304L or F316 or F316L or F11 Class 2 or SA-351 Grade CF8M
Piping	SA-335 Grade P11 or SA-312 Grade TP304L
Fittings	SA-234 Grade WP11 Class 1 or SA-182 Grade F304L or F316L or dual-marked F304/F304L or F316/F316L or F11 Class 2 or SA-403 Grade WP304L or SA-479 Type 316
Containment vessel and penetrations	Refer to Subsection 3.8.2.1
Valves in contact with borated water	Refer to Subsection 5.2.3, Table 5.2-1

Table 6.1-1 (Sheet 2 of 2)
Engineered Safety Features Pressure-Retaining Materials

Component	Materials
Main control room emergency habitability system	
Valves	SA-182 Grade F11 or F304 or F316 or F304L or F316L, or SA-217 Grade WC6
Pipe	SA-335 Grade P11
Air storage tanks	SA-372

Table 6.1-2 (Sheet 1 of 2)
AP1000 Coated Surfaces, Containment Shell and Surfaces Inside Containment

Surface	Boundary	Surface Material	Coating	Coating Functions/Safety Classifications		Coating Classification (1)
Containment Shell, Outside Surface	Shell surfaces above elevation 135′ 3″	Carbon Steel	Inorganic Zinc Coating	1 Promote wettability 2 Heat conduction 3 Nondetachable 4 Inhibit corrosion	1 Safety 2 Safety 3 Safety 4 Safety	Safety – Service Level III
Containment Shell, Inside Surface	Shell surfaces above the operating floor	Carbon Steel	Inorganic Zinc Coating	1 Promote wettability 2 Heat conduction 3 Nondetachable 4 Inhibit corrosion	1 Safety (2) 2 Safety 3 Safety 4 Safety	Safety – Service Level I
	Shell surfaces below the operating floor	Carbon Steel	Inorganic Zinc Coating with Epoxy Top Coat	1 Nondetachable (inorganic zinc only) 2 Inhibit corrosion 3 Enhance radioactive decontamination (epoxy only) 4 Ensure settling (epoxy only)	1 Safety 2 Safety 3 Nonsafety 4 Safety	Safety – Service Level I
Components Inside Containment	(6)	Material of Component (6)	NA (6)	1 Ensure settling 2 Inhibit corrosion	1 Safety (7) 2 Non-safety	Non-safety (7) Service Level II
Inside Containment	Areas surrounding the containment recirculation screens (3)	NA	NA	NA	NA	NA
	Concrete walls, ceilings and floors (4)	Concrete	Epoxy	1 Ensure settling 2 Prevent dusting 3 Protect from chemical attack 4 Enhance radioactive decontamination 5 Heat conduction	1 Safety (5) 2 Nonsafety 3 Nonsafety 4 Nonsafety 5 Safety (5)	Nonsafety (5) Service Level II

Table 6.1-2 (Sheet 2 of 2)
AP1000 Coated Surfaces, Containment Shell and Surfaces Inside Containment

Surface	Boundary	Surface Material	Coating	Coating Functions/Safety Classifications		Coating Classification (1)
	Steel walls, ceilings, floors, columns, beams, braces, plates (4)	Carbon Steel	Self-Priming High Solid Epoxy	1 Ensure settling 2 Inhibit corrosion 3 Enhance radioactive decontamination 4 Heat conduction	1 Safety (5) 2 Nonsafety 3 Nonsafety 4 Safety (5)	Nonsafety (5) Service Level II

Notes:

1. The applicability of 10 CFR 50, Appendix B, and other codes and standards to coatings and their application are discussed in Subsection 6.1.2.1.6.
2. An inorganic zinc coating on the inside of the containment shell is not required to promote wettability, however it has been included in PCS testing and analysis and as a result is considered safety-related.
3. Areas around PXS recirculation screens do not require coatings as defined in Subsection 6.3.2.2.7.3.
4. 10 CFR 50, Appendix B, does not apply to DBA testing and procurement of coatings in the CVS room inside containment as discussed in Subsection 6.1.2.1.6.
5. 10 CFR 50, Appendix B, applies to DBA testing and procurement of these Service Level II coatings as discussed in Subsection 6.1.2.1.6.
6. The explicit coating material is not required to be specified. However, the coating material must comply with the restrictions set forth in Subsection 6.1.2.1.5 and Table 6.1-2 for components located below the maximum flood level for a design basis LOCA or where there is sufficient water flow to transport debris. If a coating on walls, structures, or components has a dry film density less than 100 lb/ft^3, then testing and/or analysis must be performed to demonstrate that the debris is not transported to an AP1000 screen or into the core through a flooded break. The testing and/or analysis must be approved by the NRC. Inorganic zinc should be used only on surfaces that may be exposed to temperatures that are above the limits of epoxy coatings during normal operating conditions; inorganic zinc coatings used in such applications are required to be Safety – Service Level I to prevent detachment during a LOCA since such debris is not likely to settle out.
7. 10 CFR 50, Appendix B does not apply to DBA testing and procurement of coatings used on manufactured components as discussed in Subsection 6.1.2.1.6.

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.1 Containment Structure

6.2.1.1.1 Design Basis

The containment system is designed such that for all break sizes, up to and including the double-ended severance of a reactor coolant pipe or secondary side pipe, the containment peak pressure is below the design pressure. A summary of the results is presented in Table 6.2.1.1-1.

This capability is maintained by the containment system assuming the worst single failure affecting the operation of the passive containment cooling system (PCS). For primary system breaks, loss of offsite power (LOOP) is assumed. For secondary system breaks, offsite power is assumed to be available when it maximizes the mass and energy released from the break. Additional discussion of the assumptions made for secondary side pipe breaks may be found in Subsection 6.2.1.4.

The single failure postulated for the containment pressure/temperature calculations is the failure of one of the valves controlling the cooling water flow for the PCS. Failure of one of these valves would lead to cooling water flow being delivered to the containment vessel through two of three delivery headers. This results in reduced cooling flow for PCS operation. However, as stated in Table 6.2.2-3, only one flowpath is necessary to meet the minimum containment cooling requirements, and only one flowpath is assumed in the containment integrity analysis.

The containment integrity analyses for the AP1000 employ a multivolume lumped parameter model to study the long-term containment response to postulated Loss of Coolant Accidents (LOCA) and Main Steam Line Break (MSLB) accidents.

The analyses presented in this section are based on assumptions that are conservative with respect to the containment and its heat removal systems, such as minimum heat removal, and maximum initial containment pressure.

The containment design for the Safe Shutdown Earthquake (SSE) is discussed in Subsection 3.8.2.

The minimum containment backpressure used in the Passive Core Cooling System (PXS) analysis is discussed in Subsection 6.2.1.5.

6.2.1.1.2 Design Features

The operation of the PCS is discussed in Subsection 6.2.2. The arrangement of the containment and internal structures is described in Section 1.2.

The reactor coolant loop is surrounded by structural walls of the containment internal structures. These structural walls are a minimum of 2-feet - 6-inches thick and enclose the reactor vessel, steam generators, reactor coolant pumps, and the pressurizer.

The containment vessel is designed and constructed in accordance with the ASME Code, Section III, Subsection NE, Metal Containment, as described in Subsection 3.8.2.

Structural steel non-pressure retaining parts such as ladders, walkways, and handrails are designed to the requirements for steel structures defined in Subsection 3.8.4.

The design features provide adequate containment sump levels following a design basis event as described in Section 3.4.

Containment and subcompartment atmospheres are maintained during normal operation within prescribed pressure, temperature, and humidity limits by means of the containment air recirculation system (VCS), and the central chilled water system (VWS). The recirculation system cooling coils are provided with chilled water for temperature control. The filtration supply and exhaust subsystem can be utilized periodically to purge the containment air for pressure control. Periodic inspection and maintenance verify functional capability.

6.2.1.1.3 Design Evaluation

The Westinghouse-GOTHIC (WGOTHIC) computer code (Reference 20) is a computer program for modeling multiphase flow in a containment transient analysis. It solves the conservation equations in integral form for mass, energy, and momentum for multicomponent flow. The momentum conservation equations are written separately for each phase in the flow field (drops, liquid pools, and atmosphere vapor). The following terms are included in the momentum equation: storage, convection, surface stress, body force, boundary source, phase interface source, and equipment source.

To model the passive cooling features of the AP1000, several assumptions are made in creating the plant decks. The external cooling water does not completely wet the containment shell, therefore, both wet and dry sections of the shell are modeled in the WGOTHIC analyses. The analyses use conservative coverage fractions to determine evaporative cooling as explained in Chapter 7 of Reference 20. The analyses conservatively assume that the external cooling water is not initiated until 400 seconds (Chapter 7, Reference 20) into the transient, allowing time to initiate the signal and to fill the headers and weirs and to develop the flow down the containment side walls. The effects of water flowing down the shell from gravitational forces are explicitly considered in the analysis.

The containment initial conditions of pressure, temperature, and humidity are provided in Table 6.2.1.1-2.

For the LOCA events, two double-ended guillotine reactor coolant system pipe breaks are analyzed. The breaks are postulated to occur in either a hot or a cold leg of the reactor coolant system. The hot leg break is limiting during the blowdown phase of the accident, and is only analyzed for this time period. The cold leg break is the most limiting scenario after the blowdown, and is analyzed for the long term containment response. The cold leg break analysis includes the long term contribution to containment pressure from the sources of stored energy, such as the steam generators. The LOCA mass and energy releases described in Subsection 6.2.1.3 are used for these calculations.

For the MSLB event, a double-ended pipe rupture is analyzed at several power levels with the WGOTHIC code. The MSLB mass and energy releases described in Subsection 6.2.1.4 are used for these calculations.

Table 6.2.1.1-10 summarizes the required volume of steel inside containment to validate the heat sink input and methodology for the WGOTHIC containment analyses. It includes requirements for analyses that minimize heat sinks (the peak containment pressure analyses) and ones that maximize heat sinks (the minimum containment pressure analyses).

The methodology for calculating the internal containment heat sink data used in the WGOTHIC analyses is presented in Reference 20, Section 13. Heat sinks include both metallic and concrete structures. Table 6.2.1.1-11 lists the heat sinks that are credited for heat transfer in the containment evaluation model for peak containment pressure analyses. The physical properties of the heat sink materials are presented in Table 6.2.1.1-8. These properties are inputs to the containment peak

pressure evaluation, consistent with the methodology specified in Reference 20 Section 13, including:

- The thermal conductivity and volumetric heat capacity of the steel materials are reduced by 10% per the ASME standard to account for variability of alloy content.
- The thermal conductivity of inorganic zinc is reduced by a factor of two relative to the minimum test requirement. The conditions for use of this reduction factor identified in Section 4 of Reference 37 are met.
- Emissivity is reduced by 10% and is only credited on the outer surface of the containment vessel, baffle, and shield building. Emissivity inside containment is ignored.

Carbon steel and concrete heat sinks inside containment are modeled with a coating of epoxy on the exposed surface. The containment vessel is modeled with an inorganic zinc coating inside and outside containment. The containment vessel below the operating deck has both inorganic zinc coating and an epoxy top coating.

The free volume inside the containment is calculated using nominal, cold dimensions. This conservatively neglects the thermal expansion of the containment vessel at elevated temperatures.

The containment pressure and temperature responses to a double-ended cold leg guillotine break are presented in Figures 6.2.1.1-5 and 6.2.1.1-6 for the first 5000 seconds, which shows the peak portion of the containment transients and Figures 6.2.1.1-7 and 6.2.1.1-8 for the 3-day transients. The containment pressure and temperature response to a double-ended hot leg guillotine break are presented in Figures 6.2.1.1-9 and 6.2.1.1-10. A separate analysis for the double-ended cold leg guillotine LOCA event, without considering heat conduction from the dry to wet section, results in somewhat higher containment pressure in the long term, but still below 50 percent of design pressure at 24 hours. This separate analysis confirms the assumption in Subsection 15.6.3.3.3 of reducing the containment leakage to half its design value at 24 hours as shown in Table 6.2.1.1-3.

The peak containment pressure and temperature results of the LOCA and MSLB postulated accidents are provided in Table 6.2.1.1-1. The peak value is the maximum of any location within the multi-node WGOTHIC model. A comparison of the containment integrity acceptance criteria to General Design Criteria is provided in Table 6.2.1.1-3.

The containment pressure response for the peak pressure steam line break case is provided in Figure 6.2.1.1-1. The containment temperature response for the peak temperature steam line break case is provided in Figure 6.2.1.1-2.

The instrumentation provided outside containment to monitor and record the containment pressure and the instrumentation provided inside containment to monitor and record temperature are found in Section 7.5.

6.2.1.1.4 External Pressure Analysis

Certain design basis events and credible inadvertent systems actuation have the potential to result in containment external pressure loads. Evaluations of these events show that a loss of all ac power sources during cold ambient conditions has the potential for creating the worst-case external pressure load on the containment vessel. This event leads to a reduction in the internal containment heat loads from the reactor coolant system and other active components, thus resulting in a temperature reduction within the containment and an accompanying pressure reduction. Evaluations are performed to determine the maximum external pressure to which the containment may be

subjected, and to develop the operating differential air temperature limit presented in LCO 3.6.9 of the Technical Specifications.

The bounding scenario results from a postulated loss of ac power sources (station blackout). This scenario, along with bounding assumptions and initial conditions, are used to determine the maximum expected external pressure transient. The containment pressure response from the bounding transient is used for sizing the containment vacuum relief system and verifies that the vacuum relief system is capable of mitigating the most bounding external pressure scenario.

The evaluation assumes a 25°F ambient temperature with no outside wind blowing to maximize the containment internal temperature and corresponding containment vessel shell temperatures. The initial internal containment temperature is in equilibrium at the maximum allowable value of 120°F. A 25°F outside temperature coupled with a 120°F internal temperature exceeds the maximum allowable internal/external temperature differential depicted in the AP1000 Technical Specifications (LCO 3.6.9). However, this is conservative and bounding as described below. Once the equilibrium temperature and humidity values are determined, the bounding analysis is performed with an initial containment internal relative humidity set to a value that is higher than the equilibrium conditions. A conservatively large value for humidity coupled with the assumed maximum containment internal temperature creates the largest potential for external pressure as this maximizes the partial pressure of steam vapor, vapor concentration, and corresponding condensation rate. These parameters represent the dominant effect for the determination of the bounding external pressure scenario. A negative 0.2 psig initial containment pressure is used for this evaluation. At transient initiation, the external wind is assumed to instantaneously accelerate to 48 mph (24.9 ft/s in annulus riser region) and the external temperature is assumed to begin decreasing at a rate of 30°F/hr. It is also conservatively assumed that no air leakage occurs into the containment during the transient. The key assumptions for containment initial conditions and containment transient conditions are listed in Table 6.2.1.1-9.

The external pressure evaluations are performed using WGOTHIC with conservatively low estimates of the containment heat loads and conservatively high heat removal through the containment vessel consistent with the limiting assumptions stated above. Results of these evaluations are used to develop the maximum depressurization rate of containment to determine the adequacy of the active safety grade containment vacuum relief system. Figure 6.2.1.1-11 shows that the performance of the vacuum relief system is sufficient to mitigate the maximum expected external pressure scenario.

6.2.1.2 Containment Subcompartments

6.2.1.2.1 Design Basis

Subcompartments within containment are designed to withstand the transient differential pressures of a postulated pipe break. These subcompartments are vented so that differential pressures remain within structural limits. The subcompartment walls are challenged by the differential pressures resulting from a break in a high energy line. Therefore, a high energy line is postulated, with a break size chosen consistent with the position presented in Section 3.6, for analyzing the maximum differential pressures across subcompartment walls.

Section 3.6 describes the application of the mechanistic pipe break criteria, commonly referred to as leak-before-break (LBB), to the evaluation of pipe ruptures. This eliminates the need to consider the dynamic effects of postulated pipe breaks for pipes which qualify for LBB. However, the LBB leakage cracks are considered for subcompartment pressurization. The LBB evaluation of leakage from a crack (10 times larger than the minimum leakage the detection system is capable of sensing) determined that the flow magnitude of an LBB leakage crack would not challenge the structural integrity of any of the walls evaluated for subcompartment pressurization. The analyses of containment pressure and temperature, emergency core cooling, and environmental qualification of

equipment are based on double-ended guillotine (DEG) reactor coolant system breaks and through-wall cracks.

6.2.1.2.1.1 Summary of Subcompartment Pipe Break Analyses

Each subcompartment is analyzed for effects of differential pressures resulting from the break of the most limiting line in the subcompartment which has not been evaluated for LBB.

The subcompartment analysis demonstrates that the wall differential pressures resulting from the most limiting high energy line break within the subcompartments are within the design capability.

Table 6.2.1.2-1 provides the design and maximum calculated subcompartment differential pressures for the breaks considered for short-term subcompartment pressurization.

6.2.1.2.2 Design Features

The plant general arrangement drawings shown in Section 1.2 include descriptions of the containment sub-compartments and surrounding areas. The general arrangement drawings are used in assembling the subcompartment analysis model.

Vent paths considered in the analyses are shown in the general arrangement drawings and consist of floor gratings and openings through walls. In the AP1000 subcompartment analyses, no credit is taken for vent paths that become available only after the occurrence of the postulated break (such as blowout panels, doors, hinged panels and insulation collapsing).

6.2.1.2.3 Design Evaluation

The Transient Mass Distribution (TMD) computer code (Reference 2) is used in the subcompartment analysis to calculate the differential pressures across subcompartment walls. The TMD code has been reviewed by the NRC and approved for use in subcompartment differential pressure analyses.

Specific information relative to details on the analysis, such as noding diagrams, volumes, vent areas, and initial conditions, are provided in Reference 26. The nodalization has been chosen so that substantial pressure gradients do not exist within a node, and 100 percent entrainment is assumed. Vent flow is based on homogeneous mixture in thermal equilibrium with 100 percent water entrainment. In order to model the various compartments of containment, a control volume technique is used to spatially represent these regions. The conservations of mass, momentum, energy, and equation of state are solved within each control volume as a function of time and space. The model includes moisture entrainment effects in the momentum and energy equations. The peak pressures in each element, and the peak differential pressures across structures within the containment, are determined from these calculations. The pressure differentials occur because of the propagation of the pressure disturbance around the containment subsequent to the pipe break.

The methodology used to generate the short term mass and energy releases is described in Subsection 6.2.1.3.1.

The initial atmospheric conditions used in the TMD subcompartment analysis are selected so that the calculated differential pressures are maximized. These conditions are chosen according to criteria identified in Subsection 6.2.1.2 of NUREG-0800. Preliminary runs were included on a case by case basis to justify the initial conditions selected to maximize differential pressures.

The containment and subcompartment atmospheres during normal operating conditions are maintained within prescribed pressure, temperature, and humidity limits by means of the containment air recirculation system (VCS), and the central chilled water system (VWS). The recirculation system

cooling coils are provided with chilled water to provide sufficient temperature control. The filtration supply and exhaust subsystem can be utilized to purge the containment air for pressure control. Periodic inspection and maintenance are performed to verify functional capability.

6.2.1.2.3.1 Flow Equation

The flow equations used by the TMD code to calculate the flow between nodes are described in Reference 2. These flow equations are based on the unaugmented critical flow model, which demonstrate conservatively low critical flow velocity predictions compared to experimental test data. Due to the TMD calculation methods presented in Subsection 1.3.1 of Reference 2, 100 percent entrainment results in the highest calculated differential pressures and therefore this degree of entrainment is conservatively assumed in the subcompartment analysis.

6.2.1.2.3.2 Pipe Breaks

Subcompartment pressurization analyses were performed for break locations found within various subcompartments inside the containment. Table 6.2.1.2-1 provides the locations that were analyzed. Break locations were excluded if:

- A pair of train specific breaks occurs in the same location.
- They occur in a subcompartment that cannot pressurize.
- They do not contain high energy fluid capable of pressurizing subcompartment.
- They are bounded by another break in the same subcompartment.

The subcompartment analysis for the steam generator compartments (Rooms 11201, 11301, 11401 and 11402) is performed assuming double-ended ruptures in the chemical and volume control system (CVS) 3-inch purification return line, 4-inch steam generator blowdown line, or 4-inch pressurizer spray line. The breaks can be assumed to occur between the 83-foot elevation and the 135-foot, 3-inch elevation of the steam generator compartment. Because the TMD code assumes homogeneous mixtures within a node, the specific location of the break within the node is not critical to the differential pressure calculation. No flow restrictions exist that limit the flow out of the break.

The analysis for the steam generator vertical access area (Room 11204) is performed assuming double-ended ruptures in the 3-inch purification line between the CVS-PL-V003 outlet to the regenerative heat exchanger (RHX) tube inlet, or the 3-inch purification line between the RHX shell outlet to the CVS-PL-V080 check valve inlet. These breaks are assumed to occur between the 83-foot elevation and the 103-foot, 5.5-inch elevation of the steam generator vertical access area compartment.

The analysis for the main CVS room (Room 11209) is performed assuming double-ended ruptures in the 3-inch purification line from the RHX tube outlet to the letdown heat exchanger (LHX) inlet (center and south locations), the 3-inch purification line between the CVS-PL-V003 outlet and the RHX tube inlet, or the 3-inch purification line from the RHX shell outlet to the CVS-PL-V080 check valve inlet. These breaks can be assumed to occur between the 80-foot, 6-inch elevation and the 105-foot, 2-inch elevation of the CVS room compartment.

The analysis for the pipe tunnel in the CVS compartment (Room 11209) is performed assuming double-ended ruptures in the 3-inch purification line from the CVS-PL-V003 outlet to RHX tube inlet, the 3-inch purification return line between the RHX shell outlet and the CVS-PL-V080 check valve inlet, or the 4-inch steam generator blowdown line. The breaks can be assumed to occur between the 100-foot elevation and the 105-foot, 5-inch elevation of the CVS room pipe tunnel.

The analysis for the steam generator access room (Room 11304) is performed for immediate break ruptures in the CVS return line piping assembly from the regenerative heat exchanger, bypass of CVS-PL-V081, 3-inch by 1-inch weldolet, downstream of CVS-PL-V081 and in the CVS return line piping assembly from the regenerative heat exchanger, valve transition, CVS-PL-V081 and CVS-PL-V082. The break at the downstream side of CVS-PL-V082 is a double-ended rupture break; the others are single-ended ruptures. The breaks can be assumed to occur between the 107-foot, 2-inch elevation and the 116-foot, 6-inch elevation of the steam generator access room.

The analysis for the pressurizer spray valve room (Room 11403) is performed for immediate break ruptures in the pressurizer spray piping valve module, 4-inch by 2-inch schedule 160 reducing tee to the auxiliary spray line. These breaks are double-ended ruptures and are assumed to occur between the 118-foot, 6-inch elevation and the 133-foot, 3-inch elevation of the pressurizer spray valve room.

6.2.1.2.3.3 Node Selection

The nodalization for the sub-compartments is analyzed in sufficient detail such that nodal boundaries are at the location of flow obstructions or geometrical changes within the subcompartment. These discontinuities create pressure differentials between adjoining nodes. There are no significant discontinuities within each node, and hence the pressure gradient is negligible within any node.

6.2.1.2.3.4 Vent Flowpath Flow Conditions

The flow characteristics for each of the subcompartments are such that, at no time during the transient does critical flow exist through vent paths.

6.2.1.3 Mass and Energy Release Analyses for Postulated Pipe Ruptures

Mass and Energy releases are documented in this section for two different types of transients.

The first section describes the methodology used to calculate the releases for the subcompartment differential pressure analysis using the TMD code (referred to as the short term analysis). These releases are used for the subcompartment response in Subsection 6.2.1.2.

The second section describes the methodology used to determine the releases for the containment pressure and temperature calculations using the WGOTHIC code (Reference 20) (referred to as the long term analysis). These releases are used for the containment integrity analysis in Subsection 6.2.1.1.

The short term analysis considers only the initial stages of the blowdown transient, and takes into consideration the application of LBB methodology. LBB is discussed in Subsection 3.6.3. Since LBB is applicable to reactor coolant system piping that is 6 inches in diameter and greater, the mass and energy release analysis for sub-compartments postulates the complete DEG severance of 3-inch and 4-inch pipe. The mass and energy release postulated for a ruptured steam line is for a one square foot break.

Conversely, the limiting break size for containment integrity analysis considers as its LOCA design basis the complete DEG severance of the largest reactor coolant system pipe.

The containment system receives mass and energy releases following a postulated rupture of the reactor coolant system. The release rates are calculated for pipe failure at two locations: the hot leg and the cold leg. These break locations are analyzed for both the short-term and the long-term transients. Because the initial operating pressure of the reactor coolant system is approximately 2250 psi, the mass and energy are released extremely rapidly when the break occurs. As the water exits from the broken pipe, a portion of it flashes to steam because of the differences in pressure and

temperature between the reactor coolant system and containment. The reactor coolant system depressurizes rapidly since break flow exits from both sides of the pipe in a DEG severance.

6.2.1.3.1 Short Term Mass and Energy Release Data

The AP1000 short term LOCA mass and energy releases are predicted for the first ten seconds of the blowdown from a postulated DEG break of the largest non-LBB high energy line in each compartment. The density of the fluid released from a postulated pipe rupture has a direct effect on the magnitude of the differential pressures that results across subcompartment walls.

Short-term transients are characterized by a peak mass and energy release rate that occurs during a subcooled condition. The modified Zaloudek correlation (Reference 3), which models this condition, is used to calculate the critical mass flux for the LOCA breaks analyzed for subcompartment pressurization. Using this correlation maximizes the mass released, which is conservative for the subcompartment analysis. This is the same critical flow correlation utilized from the short-term LOCA SATAN-VI computer program.

The Moody correlation (Reference 34), a model developed for predicting the maximum flow rate of a single component two-phase mixture, is used to calculate the critical mass flow for the steam generator blowdown line breaks analyzed for subcompartment pressurization. No reduction in break flow is credited due to the depressurization of the system. The limiting plant condition in terms of initial secondary-system pressure is obtained when the plant is at hot zero power.

The initial conditions and inputs used for the LOCA mass and energy releases are given in Table 6.2.1.3-1. The limiting plant condition in terms of initial secondary-system pressure used for the steam generator blowdown line break mass and energy releases are obtained when the plant is at hot zero power. The short term LOCA mass and energy releases are affected by the initial density of the fluid. A lower density yields a more conservative maximum compartment differential pressure. The break specific mass and energy releases used in the TMD code for calculating subcompartment pressurization are identified in Table 6.2.1.2-1.

6.2.1.3.2 LOCA Long Term Mass and Energy Release Data

A long term LOCA analysis calculational model is typically divided into four phases: blowdown, which includes the period from the accident initiation (when the reactor is in a steady-state full power operation condition) to the time that the broken loop pressure equalizes to the containment pressure; refill, which is the time from the end of the blowdown to the time when the passive core cooling system (PXS) refills the vessel lower plenum; reflood, which begins when the water starts to flood the core and continues until the core is completely quenched; and post-reflood, which is the period after the core has been quenched and energy is released to the reactor coolant system primary system by the reactor coolant system metal, core decay heat, and the steam generators.

The long-term analysis considers the blowdown, reflood, and post-reflood phases of the transient. The refill period is conservatively neglected so that the releases to the containment are conservatively maximized.

The AP1000 long-term LOCA mass and energy releases are predicted for the blowdown phase for postulated DECLG and DEHLG breaks. The blowdown phase mass and energy releases are calculated using the NRC approved SATAN-VI computer code (Reference 4). The post blowdown phase mass and energy releases for the postulated DECLG break are calculated considering the energy released from the available energy sources described below. The energy release rates are conservatively modeled so that the energy is released quickly. The higher release rates result in a conservative containment pressure calculation. The releases are provided in Tables 6.2.1.3-9 and 6.2.1.3-10.

6.2.1.3.2.1 Mass and Energy Sources

The following are accounted for in the long-term LOCA mass and energy calculation:

- Decay heat
- Core stored energy
- Reactor coolant system fluid and metal energy
- Steam Generator fluid and metal energy
- Accumulators, core make-up tanks (CMTs), and the in-containment refueling water storage tank (IRWST) fluid energy
- Zirconium-water reaction

The methods and assumptions used to release the various energy sources during the blowdown phase are given in Reference 4.

The following parameters are used to conservatively analyze the energy release for maximum containment pressure (calorimetric uncertainty calculation will be provided per Subsection 15.0.15.1):

- Maximum expected operating temperature
- Allowance in temperature for instrument error and dead band
- Margin in volume (+1.4 percent)
- Allowance in volume for thermal expansion (+1.6 percent)
- 100 percent full power operation
- Allowance for calorimetric error (+1.0 percent of full power)
- Conservatively modified coefficients of heat transfer
- Allowance in core stored energy for effect of fuel densification
- Margin in core stored energy (+15.0 percent)
- Allowance in pressure for instrument error and dead band
- Margin in steam generator mass inventory (+10.0 percent)
- One percent of the Zirconium surrounding the fuel is assumed to react

6.2.1.3.2.2 Description of Blowdown Model

A description of the SATAN-VI model that is used to determine the mass and energy released from the reactor coolant system during the blowdown phase of a postulated LOCA is provided in Reference 4. Significant correlations are discussed in this reference. The only exception to the Reference 4 methodology is that the overall heat transfer coefficient between the primary side of the

reactor coolant system metal and the fluid will be adjusted when there is no liquid in the system to prevent an unrealistically high temperature for the steam release.

6.2.1.3.2.3 Description of Post-Blowdown Model

The remaining reactor coolant system and SG mass and energy inventories at the end of blowdown are used to define the initial conditions for the beginning of the reflood portion of the transient. The broken and unbroken loop SG inventories are kept separate to account for potential differences in the cooldown rate between the loops. In addition, the mass added to the reactor coolant system from the IRWST is returned to containment as break flow so that no net change in system mass occurs.

Energy addition due to decay heat is computed using the 1979 ANS standard (plus 2 sigma) decay heat table from Reference 4. The energy release rates from the reactor coolant system metal and steam generators are modelled using exponential decay rates. This modelling is consistent with analyses for current generation design analyses that are performed with the models described in Reference 4.

The accumulator, CMT, and IRWST mass flow rates are computed from the end of blowdown to the time the tanks empty. The rate of reactor coolant system mass accumulation is assumed to decrease exponentially during the reflood phase. More CMT and accumulator flow is spilled from the break as the system refills. The break flow rate is determined by subtracting the reactor coolant system mass addition rate from the sum of the accumulator, CMT and IRWST flow rates.

Mass which is added to, and which remains in, the vessel is assumed to be raised to saturation. Therefore, the actual amount of energy available for release to the containment for a given time period is determined from the difference between the energy required to raise the temperature of the incoming flow to saturation and the sum of the decay heat, core stored energy, reactor coolant system metal energy and SG mass and metal energy release rates. The energy release rate for the available break flow is determined from a comparison of the total energy available release rate and the energy release rate assuming that the break flow is 100-percent saturated steam following IRWST draindown. Saturated steam releases maximize the calculated containment pressurization.

6.2.1.3.2.4 Single Failure Analysis

The assumptions for the containment mass and energy release analysis are intended to maximize the calculated release. A single failure could reduce the flow rate of water to the RCS, but would not disable the passive core cooling function. The effects of a single failure are taken into account in the containment analysis of Subsection 6.2.1.1.

6.2.1.3.2.5 Metal-Water Reaction

Consistent with 10 CFR 50, Appendix K criteria, the energy release associated with the zirconium-water exothermic reaction has been considered. The LOCA peak cladding temperature analysis, presented in Chapter 15, demonstrates compliance with the Appendix K criteria demonstrates that no appreciable level of zirconium oxidation occurs. This level of reaction has been bounded in the containment mass and energy release analysis by incorporating the heat of reaction from 1 percent of the zirconium surrounding the fuel. This exceeds the level predicted by the LOCA analysis and results in additional conservatism in the mass and energy release calculations.

6.2.1.3.2.6 Energy Inventories

The amount of mass and energy released to containment during a postulated LOCA is provided in summary Tables 6.2.1.3-9 and 6.2.1.3-10.

6.2.1.3.2.7 Additional Information Required for Confirmatory Analysis

System parameters and hydraulic characteristics needed to perform confirmatory analysis are provided in Table 6.2.1.3-8 and Figures 6.2.1.3-1 through 6.2.1.3-4.

6.2.1.4 Mass and Energy Release Analysis for Postulated Secondary-System Pipe Rupture Inside Containment

Steam line ruptures occurring inside a reactor containment structure may result in significant releases of high-energy fluid to the containment environment, possibly resulting in high containment temperatures and pressures. The quantitative nature of the releases following a steam line rupture is dependent upon the configuration of the plant steam system, the containment design as well as the plant operating conditions and the size of the rupture. This section describes the methods used in determining the containment responses to a variety of postulated pipe breaks encompassing variations in plant operation.

6.2.1.4.1 Significant Parameters Affecting Steam Line Break Mass and Energy Releases

Four major factors influence the release of mass and energy following a steam line break: steam generator fluid inventory, primary-to-secondary heat transfer, protective system operation and the state of the secondary fluid blowdown. The following is a list of those plant variables which have significant influence on the mass and energy releases:

- Plant power level
- Main feedwater system design
- Startup feedwater system design
- Postulated break type, size, and location
- Availability of offsite power
- Safety system failures
- Steam generator reverse heat transfer and reactor coolant system metal heat capacity.

The following is a discussion of each of these variables.

6.2.1.4.1.1 Plant Power Level

Steam line breaks are postulated to occur with the plant in any operating condition ranging from hot shutdown to full power. Since steam generator mass decreases with increasing power level, breaks occurring at lower power generally result in a greater total mass release to the containment. Because of increased energy storage in the primary plant, increased heat transfer in the steam generators and additional energy generation in the nuclear fuel, the energy released to the containment from breaks postulated to occur during power operation may be greater than for breaks occurring with the plant in a hot shutdown condition. Additionally, steam pressure and the dynamic conditions in the steam generators change with increasing power. They have significant influence on the rate of blowdown from the break following a steam break event.

Because of the opposing effects of changing power level on steam line break releases, no single power level can be pre-defined as a worst case initial condition for a steam line break event.

Therefore, several different power levels (101%, 70%, 30%, 0%) spanning the operating range as well as the hot shutdown condition are analyzed.

6.2.1.4.1.2 Main Feedwater System Design

The rapid depressurization that occurs following a rupture may result in large amounts of water being added to the steam generators through the main feedwater system. Rapid closing isolation valves are provided in the main feedwater lines to limit this effect. The piping layout downstream of the isolation valves determine the volume in the feedwater lines that cannot be isolated from the steam generators. As the steam generator pressure decreases, some of the fluid in this volume will flash into the steam generator, providing additional secondary fluid that may exit out the rupture. This unisolated feedwater mass between the steam generator and isolation valve is accounted for within the results in Subsection 6.2.1.4.3.2. The assumed unisolable volume bounds the volume to either the feedwater control valve or the feedwater isolation valve on the faulted loop, so that no additional feedwater mass could be postulated due to a single failure of one of the valves.

The feedwater addition that occurs prior to closing of the feedwater line isolation valves is conservatively calculated based on the depressurization of the faulted steam generator, and assuming that the feedwater control valve is fully open in response to the increased steam flow rate.

6.2.1.4.1.3 Startup Feedwater System Design

Within the first minute following a steam line break, the startup feedwater system may be initiated on a low steam generator water level signal in combination with low main feedwater flow. The addition of startup feedwater to the steam generators would increase the secondary mass available for release to the containment through the steam line break if the actuation signal occurs. Maximum startup feedwater flow to the faulted steam generator is conservatively assumed after the main feedwater flow is isolated until the startup feedwater is automatically terminated on a Low-2 RCS Tcold signal.

6.2.1.4.1.4 Postulated Break Type, Size and Location

The steam line break is postulated as a full double-ended pipe rupture immediately downstream of the integral flow restrictor on the faulted steam generator. The forward break flow from the faulted steam generator is limited by the flow restrictor area (1.4 ft^2). The faulted steam generator is unisolable from the break location, and the forward break flow continues until the steam generator is empty. The reverse break flow consists of the initial steam within the steam line piping and steam that comes from the intact steam generator. The reverse break flow continues until main steam line isolation valve (MSIV) closure. The modeling of the reverse break flow does not differentiate the location of the MSIVs, and all steam that has exited the intact steam generator prior to MSIV closure is assumed to be released out the break. This bounds the possible effects of an MSIV failed open.

No liquid entrainment is credited in the break effluent from the double-ended pipe rupture. The release of dry saturated steam from the largest possible break size maximizes the mass and energy release to the containment.

6.2.1.4.1.5 Availability of Offsite Power

The effects of the assumption of the availability of offsite power are enveloped in the analysis.

Offsite power is assumed to be available where it maximizes the mass and energy released from the break because of the following:

- The continued operation of the reactor coolant pumps until automatically tripped as a result of core makeup tank (CMT) actuation. This maximizes the energy transferred from the reactor coolant system to the steam generator.

- The continued operation of the feedwater pumps and actuation of the startup feedwater system until they are automatically terminated. This maximizes the steam generator inventories available for release.

- The AP1000 is equipped with the passive safeguards system including the CMT and the passive residual heat removal (PRHR) heat exchanger. Following a steam line rupture, these passive systems are actuated when their setpoints are reached. This decreases the primary coolant temperatures. The actuation and operation of these passive safeguards systems do not require the availability of offsite power.

  When the PRHR is in operation, the core-generated heat is dissipated to the in-containment refueling water storage tank (IRWST) via the PRHR heat exchanger. This causes a reduction of the heat transfer from the primary system to the steam generator secondary system and causes a reduction of mass and energy releases via the break.

Thus, the availability of ac power maximizes the mass and energy releases via the break. Therefore, blowdown occurring with the availability of offsite power is more limiting than cases where offsite power is not available.

6.2.1.4.1.6 Safety System Failures

The calculation of the mass and energy release following a steam line rupture is done to conservatively bound the possible increase of mass release due to safety system failures. Two failures, which are bounded are:

- Failure of one main steam isolation valve, as discussed in Subsection 6.2.1.4.1.4

- Failure of one main feedwater isolation valve, as discussed in Subsection 6.2.1.4.1.2

6.2.1.4.1.7 Steam Generator Reverse Heat Transfer and Reactor Coolant System Metal Heat Capacity

Once steam line isolation is complete, the steam generator in the intact steam loop becomes a source of energy that can be transferred to the steam generator with the broken line. This energy transfer occurs through the primary coolant. As the primary plant cools, the temperature of the coolant flowing in the steam generator tubes drops below the temperature of the secondary fluid in the intact unit, resulting in energy being returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steam line.

Similarly, the heat stored in the metal of the reactor coolant piping, the reactor vessel, and the reactor coolant pumps is transferred to the primary coolant as the plant cooldown progresses. This energy also is available to be transferred to the steam generator with the broken line. Energy from the metal of the faulted steam generator is also transferred to the fluid in the faulted steam generator as the fluid temperature drops below the metal temperature.

The effects of the reactor coolant system metal, the steam generator metal, and the energy in the fluid from the intact steam generator are included in the results presented.

6.2.1.4.2 Description of Blowdown Model

The steam line blowdown is calculated with the LOFTRAN code (Reference 6) which has been modified to include simulation of the AP1000 passive residual heat removal heat exchanger, core makeup tanks, and associated protection and safety monitoring system actuation logic. Documentation of the code changes for the passive models is provided in Reference 31. The methodology for the steam line break analysis is based on Reference 5. The applicability of the LOFTRAN code to AP1000, and the applicability of the methodology used to analyze the steam line break blowdown are discussed in Reference 32.

6.2.1.4.3 Containment Response Analysis

The WGOTHIC Computer Code (Reference 20) is used to determine the containment responses following the steam line break, which is described in Subsection 6.2.1.1.

6.2.1.4.3.1 Initial Conditions

The initial containment conditions are discussed in Subsection 6.2.1.1.3.

6.2.1.4.3.2 Mass and Energy Release Data

Using References 5, 6, 31 and 32 as a basis, mass and energy release data are developed to determine the containment pressure-temperature response for the cases analyzed. Table 6.2.1.4-2 provides the mass and energy release analysis results for the steam line break case that produces the highest containment pressure and Table 6.2.1.4-3 provides the mass and energy release analysis results for the steam line break case that produces the highest containment temperature. Table 6.2.1.4-4 provides nominal plant data used in the steam line break mass and energy releases determination.

6.2.1.4.3.3 Containment Pressure-Temperature Results

The results of the containment pressure-temperature analyses for the postulated secondary system pipe ruptures that produce the highest peak containment pressure and temperature are presented in Subsection 6.2.1.1.3.

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies of Emergency Core Cooling System (PWR)

An analysis is performed to establish a minimum containment pressure boundary condition applied to the WCOBRA/TRAC code for the cold leg guillotine break for the emergency core cooling system (ECCS) analysis presented in Subsection 15.6.5.4A. A single-node containment model is used with the WGOTHIC computer code to assess the containment pressure response. The calculated containment backpressure is provided in Figure 6.2.1.5-1. Results of the WCOBRA/TRAC analyses demonstrate that the AP1000 meets 10 CFR 50.46 requirements (Reference 7).

Minimum containment pressure analyses are also performed to provide the containment backpressure boundary condition for small break LOCA (Subsection 15.6.5.4B) and post-LOCA long-term cooling analyses (Subsection 15.6.5.4C). A multi-node WGOTHIC containment model described in WCAP-15846 (Reference 20) is used.

6.2.1.5.1 Mass and Energy Release Data

The mass and energy releases to the containment for the double-ended cold-leg guillotine break (DECLG) transient are presented in Table 6.2.1.5-1, as computed by the WCOBRA/TRAC code.

The mathematical models which calculate the mass and energy releases to the containment are described in Subsection 15.6.5. A break spectrum analysis is performed (see references in Subsection 15.6.5) that considers various break sizes and Moody discharge coefficients for the double-ended cold leg guillotines and splits. Mixing of steam and accumulator water injected into the vessel reduces the available energy released to the containment vapor space, thereby minimizing calculated containment pressure.

6.2.1.5.2 Initial Containment Internal Conditions

Initial containment conditions were biased for the emergency core cooling system backpressure analysis to predict a conservatively low containment backpressure. Initial containment conditions include an initial pressure of 14.5 psia, initial containment temperature of 50°F, and a relative humidity of 100 percent. An air annulus temperature of 0°F is assumed. The initial through-thickness metal temperature of the containment shell is assumed to also be 0°F.

6.2.1.5.3 Other Parameters

Containment parameters, such as containment volume and passive heat sinks, are biased to predict a conservative low containment backpressure. The containment volume used in the calculation is conservatively set to 1.1 times the free volume of the AP1000 containment Evaluation Model. Containment internal heat sinks used heat transfer correlations of 4 times Tagami (Reference 9) during the blowdown phase followed by 1.2 times Uchida (Reference 10) for the post-blowdown phase. Passive heat sink surface areas were increased by a factor of 1.35 relative to the heat sinks developed for the peak containment evaluation model described in Reference 20. The thermal conductivity and volumetric heat capacity of the steel materials were increased by 10% from the ASME standard to increase heat removal. No air gap was modeled between the steel liner and base concrete of jacketed concrete heat sinks. The outside surface of the containment shell was maintained at 0°F throughout the calculation. To further minimize containment pressure, containment purge was assumed to be in operation at time zero and air is vented through both the containment purge supply and exhaust lines until the isolation valves have fully closed. These valves were modeled to close after the High-2 containment pressure setpoint was reached and after an associated delay to account for valve closure time.

6.2.1.6 Testing and Inspection

This section describes the functional testing of the containment vessel. Testing and in-service inspection of the containment vessel are described in Subsection 3.8.2.6. Isolation testing and leak testing are described in Subsection 6.2.5. Testing and inspection are consistent with regulatory requirements and guidelines.

The valves of the passive containment cooling system are stroke tested periodically. Subsection 6.2.2 provides a description of testing and inspection.

The baffle between the containment vessel and the shield building is equipped with removable panels to allow for inspection of the containment surface. See Subsection 3.8.2 for the requirements for in-service inspection of the steel containment vessel. Subsection 6.2.2 provides a description of testing and inspection to be performed.

Testing is not required on any subcompartment vent or on the collection of condensation from the containment shell. The collection of condensate from the containment shell and its use in leakage detection are discussed in Subsection 5.2.5.

6.2.1.7 Instrumentation Requirements

Instrumentation is provided to monitor the conditions inside the containment and to actuate the appropriate engineered safety features, should those conditions exceed the predetermined levels. The instruments measure the containment pressure, containment atmosphere radioactivity, and containment hydrogen concentration. Instrumentation to monitor reactor coolant system leakage into containment is described in Subsection 5.2.5.

The containment pressure is measured by four independent pressure transmitters. The signals are fed into the engineered safety features actuation system, as described in Subsection 7.3.1. Upon detection of high pressure inside the containment, the appropriate safety actuation signals are generated to actuate the necessary safety-related systems. Low pressure is alarmed but does not actuate the safety-related systems.

The physically separated pressure transmitters are located outside the containment. Section 7.3 provides a description.

The containment atmosphere radiation level is monitored by four independent area monitors located above the operating deck inside the containment building. The measurements are continuously fed into the engineered safety features actuation system logic. Section 11.5 provides information on the containment area radiation monitors. The engineered safety features actuation system operation is described in Section 7.3.

The containment hydrogen concentration is measured by hydrogen monitors, as described in Subsection 6.2.4. Hydrogen concentrations are monitored by three sensors located in the upper containment dome to provide a representative indication of bulk containment hydrogen concentration.

These indications are used by the plant operators to monitor hydrogen concentrations. High hydrogen concentration is alarmed in the main control room.

6.2.2 Passive Containment Cooling System

The passive containment cooling system (PCS) is an engineered safety features system. Its functional objective is to reduce the containment temperature and pressure following a loss of coolant accident (LOCA) or main steam line break (MSLB) accident inside the containment by removing thermal energy from the containment atmosphere. The passive containment cooling system also serves as the means of transferring heat to the safety-related ultimate heat sink for other events resulting in a significant increase in containment pressure and temperature.

The passive containment cooling system limits releases of radioactivity (post-accident) by reducing the pressure differential between the containment atmosphere and the external environment, thereby diminishing the driving force for leakage of fission products from the containment to the atmosphere. This subsection describes the safety design bases of the safety-related containment cooling function. Nonsafety-related containment cooling, a function of the containment recirculation cooling system, is described in Subsection 9.4.6.

The passive containment cooling system also provides a source of makeup water to the spent fuel pool in the event of a prolonged loss of normal spent fuel pool cooling.

6.2.2.1 Safety Design Basis

- The passive containment cooling system is designed to withstand the effects of natural phenomena such as ambient temperature extremes, earthquakes, winds, tornadoes, or floods.

- Passive containment cooling system operation is automatically initiated upon receipt of a High-2 containment pressure signal.

- The passive containment cooling system is designed so that a single failure of an active component, assuming loss of offsite or onsite ac power sources, will not impair the capability of the system to perform its safety-related function.

- Active components of the passive containment cooling system are capable of being tested during plant operation. Provisions are made for inspection of major components in accordance with the intervals specified in the ASME Code, Section XI.

- The passive containment cooling system components required to mitigate the consequences of an accident are designed to remain functional in the accident environment and to withstand the dynamic effects of the accident.

- The passive containment cooling system is capable of removing sufficient thermal energy including subsequent decay heat from the containment atmosphere following a design basis event resulting in containment pressurization such that the containment pressure remains below the design value with no operator action required for 72 hours.

- The passive containment cooling system is designed and fabricated to appropriate codes consistent with Regulatory Guides 1.26 and 1.32 and in accordance with Regulatory Guide 1.29 as described in Section 1.9.

6.2.2.2 System Design

6.2.2.2.1 General Description

The passive containment cooling system and components are designed to the codes and standards identified in Section 3.2; flood design is described in Section 3.4; missile protection is described in Section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is described in Section 3.6. Seismic and environmental design and equipment qualification are described in Sections 3.10 and 3.11. The actuation system is described in Section 7.3.

6.2.2.2.2 System Description

The passive containment cooling system is a safety-related system which is capable of transferring heat directly from the steel containment vessel to the environment. This transfer of heat prevents the containment from exceeding the design pressure and temperature following a postulated design basis accident, as identified in Chapters 6 and 15. The passive containment cooling system makes use of the steel containment vessel and the concrete shield building surrounding the containment. The major components of the passive containment cooling system are: the passive containment cooling water storage tank (PCCWST) which is incorporated into the shield building structure above the containment; an air baffle, located between the steel containment vessel and the concrete shield building, which defines the cooling air flowpath; air inlets and an air exhaust, also incorporated into the shield building structure; and a water distribution system, mounted on the outside surface of the steel containment vessel, which functions to distribute water flow on the containment. A passive containment cooling ancillary water storage tank and two recirculation pumps are provided for onsite

storage of additional passive containment cooling system cooling water, to transfer the inventory to the passive containment cooling water storage tank, and to provide a back-up supply to the fire protection system (FPS) seismic standpipe system as discussed in Subsection 9.5.1.

A normally isolated, manually-opened flow path is available between the passive containment cooling system water storage tank and the spent fuel pool.

The passive containment cooling water outlet valves are located in the PCS valve room. Due to the unique location of this room, insulation is required to allow the room to passively keep PCS valve room components and piping above freezing for 72 hours following loss of AC power in cold weather. Following seismic and environmental design basis events, the safety related function of the insulation is the R-value. The insulation is supported as seismic Category I.

A recirculation path is provided to control the passive containment cooling water storage tank water chemistry and to provide heating for freeze protection. Passive containment cooling water storage tank filling operations and normal makeup needs are provided by the demineralized water transfer and storage system discussed in Subsection 9.2.4.

The system piping and instrumentation diagram is shown in Figure 6.2.2-1. System parameters are shown in Table 6.2.2-1. A simplified system sketch is included as Figure 6.2.2-2.

6.2.2.2.3 Component Description

The mechanical components of the passive containment cooling system are described in this subsection. Table 6.2.2-2 provides the component design parameters.

Passive Containment Cooling Water Storage Tank – The passive containment cooling water storage tank is incorporated into the shield building structure above the containment vessel. The inside wetted walls of the tank are lined with stainless steel plate. It is filled with demineralized water and has the minimum required useable volume for the passive containment cooling function as defined in Table 6.2.2-2. The passive containment cooling system functions as the safety-related ultimate heat sink. The passive containment cooling water storage tank is seismically designed and missile protected.

The surrounding reinforced concrete supporting structure is designed to ACI 349 as described in Subsection 3.8.4.3. The welded seams of the plates forming part of the leak tight boundary are examined by liquid penetrant after fabrication to confirm that the boundary does not leak.

The tank also has redundant level measurement channels and alarms for monitoring the tank water level and redundant temperature measurement channels to monitor and alarm for potential freezing. To maintain system operability, a recirculation loop that provides chemistry and temperature control is connected to the tank.

The tank is constructed to provide sufficient thermal inertia and insulation such that draindown can be accomplished without heater operation.

In addition to its containment heat removal function, the passive containment cooling water storage tank also serves as a source of makeup water to the spent fuel pool and a seismic Category I water storage reservoir for fire protection following a safe shutdown earthquake.

The PCCWST suction pipe for the fire protection system is configured so that actuation of the fire protection system will not infringe on the usable capacity allocated to the passive containment cooling function as defined in Table 6.2.2-2.

Passive Containment Cooling Water Storage Tank Isolation Valves – The passive containment cooling system water storage tank outlet piping is equipped with three sets of redundant isolation valves. In two sets, air-operated butterfly valves are normally closed and open upon receipt of a High-2 containment pressure signal. These valves fail-open, providing a fail-safe position, on the loss of air or loss of 1E dc power. In series with these valves are normally-open motor-operated gate valves located upstream of the butterfly valves. They are provided to allow for testing or maintenance of the butterfly valves. A third set of motor-operated gate valves is provided. One valve is normally closed, and the other is normally open. Based on PRA insights, diversity requirements are adopted for these valves to minimize the consequences of common-mode failure of motor-operated valves to cause a loss of containment cooling in multiple failure scenarios.

The storage tank isolation valves, along with the passive containment cooling water storage tank discharge piping and associated instrumentation between the passive containment cooling water storage tank and the downstream side of the isolation valves, are contained within a temperature-controlled valve room to prevent freezing. Valve room heating is provided to maintain the room temperature above 70°F to prevent freezing for 72 hours following a loss of ac power during seismic and design basis events.

Flow Control Orifices – Orifices are installed in each of the four passive containment cooling water storage tank outlet pipes. They are used, along with the different elevations of the outlet pipes, to control the flow of water from the passive containment cooling water storage tank as a function of water level. The orifices are located within the temperature-controlled valve room.

Water Distribution Bucket – A water distribution bucket is provided to deliver water to the outer surface of the containment dome. The redundant passive containment cooling water delivery pipes and auxiliary water source piping discharge into the bucket, below its operational water level, to prevent excessive splashing. A set of circumferentially spaced distribution slots are included around the top of the bucket. The bucket is hung from the shield building roof and suspended just above the containment dome for optimum water delivery. The structural requirements for safety-related structural steel identified in Subsection 3.8.4 apply to the water distribution bucket. ANSI/ASCE-8-90 (Reference 24) is used for design and analysis of stainless steel cold formed parts. The water distribution bucket is fabricated from one or more of the materials included in Table 3.8.4-6, ASTM-A240 austenitic stainless steel, or ASTM-A276 austenitic stainless steel.

Water Distribution Weir System – A weir-type water delivery system is provided to optimize the wetted coverage of the containment shell during passive containment cooling system operation. The water delivered to the center of the containment dome by the water distribution bucket flows over the containment dome, being distributed evenly by slots in the distribution bucket. Vertical divider plates are attached to the containment dome and originate at the distribution bucket extending radially along the surface of the dome to the first distribution weir. The divider plates limit maldistribution of flow which might otherwise occur due to variations in the slope of the containment dome. At the first distribution weir set, the water in that sector is collected and then redistributed onto the containment utilizing channeling walls and collection troughs equipped with distribution weirs. A second set of weirs are installed on the containment dome at a greater radius to again collect and then redistribute the cooling water to enhance shell coverage. The system includes channeling walls and collection troughs, equipped with distribution weirs. The distribution system is capable of functioning during extreme low- or high-ambient temperature conditions. The structural requirements for safety-related structural steel and cold formed steel structures identified in Subsection 3.8.4 apply to the water distribution weir system. ANSI/ASCE-8-90, (Reference 24) is used for design and analysis of stainless steel cold formed parts. The water distribution weir system is fabricated from one or more of the materials included in Table 3.8.4-6, ASTM-A240 austenitic stainless steel, or ASTM-A276 austenitic stainless steel.

Air Flow Path – An air flow path is provided to direct air along the outside of the containment shell to provide containment cooling. The air flow path includes a screened shield building inlet, an air baffle that divides the outer and inner flow annuli, and a chimney to increase buoyancy. Subsection 3.8.4.1.3 includes information regarding the air baffle. The general arrangement drawings provided in Section 1.2 provide layout information of the air flow path.

Passive Containment Cooling Ancillary Water Storage Tank – The passive containment cooling ancillary water storage tank is a cylindrical steel tank located at ground level near the auxiliary building. It is filled with demineralized water and has a volume of greater than required for makeup to the passive containment cooling water storage tank and the spent fuel pool as defined in Table 6.2.2-2. The PCCAWST volume includes the base amount of water needed to maintain PCCWST and spent fuel pool makeup inventory by providing 135 gpm for four days (780,000 gal.) plus an additional volume intended to provide margin for potential instrument inaccuracies, flow control valve mis-positioning, and makeup inventory for the fire protection system. The tank is analyzed, designed and constructed using the method and criteria for Seismic Category II components defined in Subsections 3.2.1 and 3.7.2, except that 3D SASSI models are used for the tank due to its location relative to the Nuclear Island. The tank is designed and analyzed for Category 5 hurricanes including the effects of sustained winds, maximum gusts, and associated wind-borne missiles.

The tank has a level measurement, an alarm for monitoring the tank water level and a temperature measurement channel to monitor and alarm for potential freezing. To maintain system operability, an internal heater, controlled by the temperature instrument, is provided to maintain water contents above freezing. Chemistry can be adjusted by passive containment cooling water storage tank recirculation loop.

The tank is insulated to assure sufficient thermal inertia of the contents is available to prevent freezing for 7 days without heater operation. The transfer piping is maintained dry also to preclude freezing.

Chemical Addition Tank – The chemical addition tank is a small, vertical, cylindrical tank that is sized to inject a solution of hydrogen peroxide to maintain a passive containment cooling water storage tank concentration for control of algae growth.

Recirculation Pumps – Each recirculation pump is a 100 percent capacity centrifugal pump with wetted components made of austenitic stainless steel. The pump is sized to recirculate the entire volume of PCCWST water once every week. Each pump is capable of providing makeup flow to both the PCCWST and the spent fuel pool simultaneously. Both pumps are operated in parallel to meet fire protection system requirements.

Recirculation Heater – The recirculation heater is provided for freeze protection. The heater is sized based on heat losses from the passive containment cooling water storage tank and recirculation piping at the minimum site temperature, as defined in Section 2.3.

6.2.2.2.4 System Operation

Operation of the passive containment cooling system is initiated upon receipt of two out of four High-2 containment pressure signals. Manual actuation by the operator is also possible from either the main control room or remote shutdown workstation. System actuation consists of opening the passive containment cooling water storage tank isolation valves. This allows the passive containment cooling water storage tank water to be delivered to the top, external surface of the steel containment shell. The flow of water, provided entirely by the force of gravity, forms a water film over the dome and side walls of the containment structure.

The flow of water to the containment outer surface is initially established for short-term containment cooling following a design basis loss of coolant accident. The flow rate is reduced over a period of not less than 72 hours. This flow provides the desired reduction in containment pressure over time and removes decay heat. The flow rate change is dependent only upon the decreasing water level in the passive containment cooling water storage tank. Prior to 72 hours after the event, operator actions are taken to align the passive containment cooling ancillary water storage tank to the suction of the passive containment cooling system recirculation pumps to replenish the cooling water supply to the passive containment cooling water storage tank. Sufficient inventory is available within the passive containment cooling ancillary water storage tank to maintain the minimum flow rate for an additional 4 days. The passive containment cooling system performance parameters are identified in Table 6.2.2-1.

To adequately wet the containment surface, the water is delivered to the distribution bucket above the center of the containment dome which subsequently delivers the water to the containment surface. A weir-type water distribution system is used on the dome surface to distribute the water for effective wetting of the dome and vertical sides of the containment shell. The weir system contains radial arms and weirs located considering the effects of tolerances of the containment vessel design and construction. A corrosion-resistant paint or coating for the containment vessel is specified to enhance surface wetability and film formation.

The cooling water not evaporated from the vessel wall flows down to the bottom of the inner containment annulus into annulus drains. The redundant annulus drains route the excess water out of the upper annulus. The annulus drains are located in the shield building wall slightly above the floor level to minimize the potential for clogging of the drains by debris. The drains are horizontal or have a slight slope to promote drainage. The drains are always open (without isolation valves) and each is sized to accept maximum passive containment cooling system flow. The outside ends of the drains are located above catch basins or other storm drain collectors.

A path for the natural circulation of air upward along the outside walls of the containment structure is always open. The natural circulation air flow path begins at the shield building inlet, where atmospheric air is turned upward from the horizontal by louvers outside the concrete structure. Air flows past the set of fixed louvers and is forced to turn downward into an outer annulus. This outer shield building annulus is encompassed by the concrete shield building on the outside and a removable baffle on the inside. This inner annulus is encompassed by the baffle wall on the outside and the steel containment vessel on the inside. Air flows up through the inner annulus to the top of the containment vessel and then exhausts through the shield building chimney.

As the containment structure heats up in response to high containment temperature, heat is removed from within the containment via conduction through the steel containment vessel, convection from the containment surface to the water film, convection and evaporation from the water film to the air, and radiation from the water film to the air baffle. As heat and water vapor are transferred to the air space between the containment structure and air baffle, the air becomes less dense than the air in the outer annulus. This density difference causes an increase in the natural circulation of the air upward between the containment structure and the air baffle, with the air finally exiting at the top center of the shield building.

The passive containment cooling water storage tank provides water for containment wetting for at least 72 hours following system actuation. Operator action can be taken to replenish this water supply from the passive containment cooling ancillary water storage tank or to provide an alternate water source directly to the containment shell through an installed safety-related seismic piping connection. In addition, water sources used for normal filling operations can be used to replenish the water supply.

The arrangement of the air inlet and air exhaust in the shield building structure has been selected so that wind effects aid the natural air circulation. The air inlets are placed at the top, outside of the shield building, providing a symmetrical air inlet that reduces the effect of wind speed and direction or adjacent structures. The air/water vapor exhaust structure is elevated above the air inlet to provide additional buoyancy and reduces the potential of exhaust air being drawn into the air inlet. The air flow inlet and chimney regions are both designed to protect against ice or snow buildup and to prevent foreign objects from entering the air flow path.

Inadvertent actuation of the passive containment cooling system is terminated through operator action by closing either of the series isolation valves from the main control room. Subsection 6.2.1.1.4 provides a discussion of the effects of inadvertent system actuation.

The passive containment cooling system provides for makeup water to the spent fuel pool to provide for continued spent fuel pool inventory and heat removal. The passive containment cooling water storage tank provides makeup to the spent fuel pool when the inventory is not required for passive containment cooling system operation. An installed long term makeup connection for the passive containment cooling system and the spent fuel pool is provided as a part of the passive containment cooling system. The passive containment cooling ancillary water storage tank and the passive containment cooling system recirculation pumps may also be utilized for makeup to the spent fuel pool.

The passive containment cooling system provides spray water to the spent fuel pool spray header. Use of the PCCWST to provide water to the spent fuel pool spray header is controlled by the Extensive Damage Mitigation Guidelines (EDMG) per NEI 06-12 (Reference 33).

6.2.2.3 Safety Evaluation

The safety-related portions of the passive containment cooling system are located within the shield building structure. This building (including the safety-related portions of the passive containment cooling system) is designed to withstand the effects of natural phenomena such as earthquakes, winds, tornadoes, or floods. Components of the passive containment cooling system are designed to withstand the effects of ambient temperature extremes.

The portions of the passive containment cooling system which provide for long term (post 72-hour) water supply for containment wetting are located in Seismic Category I or Seismic Category II structures excluding the passive containment cooling ancillary water storage tank and associated valves located outside of the auxiliary building. The water storage tank and the anchorage for the associated valves are Seismic Category II. The features of these structures which protect this function are analyzed and designed for Category 5 hurricanes including the effects of sustained winds, maximum gusts, and associated wind-borne missiles. The resistance of the full-scale, as-designed passive containment cooling air flow path is verified by scale testing and analysis (Reference 38).

Operation of the containment cooling system is initiated automatically following the receipt of a High-2 containment pressure signal. The use of this signal provides for system actuation during transients, resulting in mass and energy releases to containment, while avoiding unnecessary actuations. System actuation requires the opening of any of the three normally closed isolation valves, with no other actions required to initiate the post-accident heat removal function since the cooling air flow path is always open. Operation of the passive containment cooling system may also be initiated from the main control room and from the remote shutdown workstation. A description of the actuation system is contained in Section 7.3.

The active components of the passive containment cooling system, the isolation valves, are located in three redundant pipe lines. Failure of a component in one train does not affect the operability of the

other mechanical train or the overall system performance. The fail-open, air-operated valves require no electrical power to move to their safe (open) position. The normally open motor-operated valves are powered from separate redundant Class 1E dc power sources. Table 6.2.2-3 presents a failure modes and effects analysis of the passive containment cooling system.

Capability is provided to periodically test actuation of the passive containment cooling system. Active components can be tested periodically during plant operation to verify operability. The system can be inspected during unit shutdown. Additional information is contained in Subsections 3.9.6 and 6.2.2.4, as well as in the Technical Specifications.

There are four instrument lines that penetrate containment and are required to remain functional following an accident. The lines are used to sense the pressure of the containment atmosphere and convey it to pressure transmitters outside containment. The pressure transmitters, tubing, and pressure sensors inside containment comprise a sealed, fluid-filled assembly forming a double barrier between inside and outside containment. If the instrument line breaks outside containment, leakage of containment atmosphere is prevented by the pressure sensor and the sealed tubing boundary inside containment. If a break occurs inside containment, leakage is prevented by the transmitter and tubing boundary outside containment. The pressure sensors, tubing, and pressure transmitters are designed and tested for seismic Category I service.

The containment pressure analyses are based on an ambient air temperature of 115°F dry bulb and 86.1°F coincident wet bulb. The passive containment cooling water storage tank water temperature basis is 120°F. Results of the analyses are provided in Subsection 6.2.1.

The shield building air inlets were changed as part of the enhanced shield building design. The impact of these changes on the containment pressure analyses is small, and the conclusions remain valid. The analyses provided in Subsection 6.2.1 include the air inlet changes.

6.2.2.4 Testing and Inspection

6.2.2.4.1 Inspections

The passive containment cooling system is designed to permit periodic testing of system readiness as specified in the Technical Specifications.

The portions of the passive containment cooling system from the isolation valves to the passive containment cooling water storage tank are accessible and can be inspected during power operation or shutdown for leaktightness. Examination and inspection of the pressure retaining piping welds is performed in accordance with ASME Code, Section XI. The design of the containment vessel and air baffle retains provisions for the inspection of the vessel during plant shutdowns.

6.2.2.4.2 Preoperational Testing

Preoperational testing of the passive containment cooling system is verified to provide adequate cooling of the containment. The flow rates are confirmed at the minimum initial tank level, an intermediate step with all but one standpipe delivering flow and at a final step with all but two standpipes delivering to the containment shell. The flow rates are measured utilizing the differential pressure across the orifices within each standpipe and will be consistent with the flow rates specified in Table 6.2.2-1.

The containment coverage will be measured at the base of the upper annulus in addition to the coverage at any elevation between elevation 266 ft. and the spring line for the full flow case using the PCS water storage tank delivering to the containment shell and a lower flow case with both PCS recirculation pumps delivering to the containment shell. For the low flow case, a throttle valve is used

to obtain a low flow rate less than the full capacity of the PCS recirculation pumps. This flow rate is then re-established for subsequent tests using the throttle valve. These benchmark values will be used to develop acceptance criteria for the Technical Specifications. The full flow condition is selected since it is the most important flow rate from the standpoint of peak containment pressure and the lower flow rate is selected to verify wetting characteristics at less than full flow conditions.

The standpipe elevations are verified to be at the values specified in Table 6.2.2-2.

The inventory within the tank is verified to provide 72 hours of operation from the minimum initial operating water level with a minimum flow rate over the duration in excess of 100.7 gpm or a report exists and concludes that the as-measured flow rates bound the 72 hours containment peak pressure and temperature results. The flow rates are measured utilizing the differential pressure across the orifices within each standpipe.

The containment vessel exterior surface is verified to be coated with an inorganic zinc coating.

The passive containment cooling air flow path will be verified at the following locations:

- Air inlets
- Base of the outer annulus
- Base of the inner annulus
- Discharge structure

With either a temporary water supply or the passive containment cooling ancillary water storage tank connected to the suction of the recirculation pumps and with either of the two pumps operating, flow must be provided simultaneously to the passive containment cooling water storage tank and to the spent fuel pool for the following cases:

- Greater than or equal to 100 gpm to the passive containment cooling water storage tank and greater than or equal to 35 gpm to the spent fuel pool
- Greater than or equal to 80 gpm to the passive containment cooling water storage tank and greater than or equal to 50 gpm to the spent fuel pool
- Greater than or equal to 50 gpm to the passive containment cooling water storage tank and greater than or equal to 80 gpm to the spent fuel pool

The passive containment cooling water storage tank provides makeup water to the spent fuel pool. When aligned to the spent fuel pool the flow rate is verified to exceed 118 gpm. Installed instrumentation will be utilized to verify the flow rate. The volume of the passive containment cooling water storage tank is verified to exceed the minimum usable volume defined in Table 6.2.2-2.

Additional details for preoperational testing of the passive containment cooling system are provided in Chapter 14.

6.2.2.4.3 Operational Testing

Operational testing is performed to:

- Demonstrate that the sequencing of valves occurs on the initiation of High-2 containment pressure and demonstrate the proper operation of remotely operated valves.

- Verify valve operation during plant operation. The normally open motor-operated valves, in series with each normally closed air-operated isolation valve, are temporarily closed. This closing permits isolation valve stroke testing without actuation of the passive containment cooling system.

- Verify water flow delivery and containment water coverage, consistent with the accident analysis.

- Verify visually that the path for containment cooling air flow is not obstructed by debris or foreign objects.

- Test frequency is consistent with the plant Technical Specifications and inservice testing program (Subsection 3.9.6).

6.2.2.4.4 System Gas Accumulation Assessment and Mitigation

Subsection 6.3.6.3.1 describes the assessment method to address the potential for gas intrusion for the passive core cooling system in response to Interim Staff Guidance (ISG-019) and Generic Letter 2008-01. The same assessment methodology was used to assess the passive containment cooling system.

The passive containment cooling system locations equipped with manual vent valves will be inspected according to the system surveillance and venting procedures described in Subsection 6.3.6.3 to eliminate identified gas accumulations.

6.2.2.5 Instrumentation Requirements

The status of the passive containment cooling system is displayed in the main control room. The operator is alerted to problems with the operation of the equipment within this system during both normal and post-accident conditions.

Normal operation of the passive containment cooling system is demonstrated by monitoring the recirculation pump discharge pressure, flow rate, water storage tank level and temperature, and valve room temperature. Post-accident operation of the passive containment cooling system is demonstrated by monitoring the passive containment cooling water storage tank level, passive containment cooling system cooling water flow rate, containment pressure, and external cooling air discharge temperature.

The information on the activation signal-generating equipment is found in Chapter 7.

The protection and safety monitoring system providing system actuation is discussed in Chapter 7.

6.2.3 Containment Isolation System

The major function of the containment isolation system of the AP1000 is to provide containment isolation to allow the normal or emergency passage of fluids through the containment boundary while preserving the integrity of the containment boundary, if required. This prevents or limits the escape of fission products that may result from postulated accidents. Containment isolation provisions are designed so that fluid lines which penetrate the primary containment boundary are isolated in the event of an accident. This minimizes the release of radioactivity to the environment.

The containment isolation system consists of the piping, valves, and actuators that isolate the containment. The design of the containment isolation system satisfies the requirements of NUREG 0737, as described in the following paragraphs.

6.2.3.1 Design Basis

6.2.3.1.1 Safety Design Basis

A. The containment isolation system is protected from the effects of natural phenomena, such as earthquakes, tornadoes, hurricanes, floods, and external missiles (General Design Criterion 2).

B. The containment isolation system is designed to remain functional after a safe shutdown earthquake (SSE) and to perform its intended function following the postulated hazards of fire, internal missiles, or pipe breaks (General Design Criteria 3 and 4).

C. The containment isolation system is designed and fabricated to codes consistent with the quality group classification, described in Section 3.2. Conformance with Regulatory Guide 1.26, 1.29, and 1.32 is described in Section 1.9.

D. The containment isolation system provides isolation of lines penetrating the containment for design basis events requiring containment integrity.

E. Upon failure of a main steam line, the containment isolation system isolates the steam generators as required to prevent excessive cooldown of the reactor coolant system or overpressurization of the containment.

F. The containment isolation system is designed in accordance with General Design Criterion 54.

G. Each line that penetrates the containment that is either a part of the reactor coolant pressure boundary or that connects directly to the containment atmosphere, and does not meet the requirements for a closed system (as defined in paragraph H below), satisfies the requirements of General Design Criteria 55 and 56. For most lines, the safety design basis is isolation valve(s) in one of the configurations described in GDC 55 and GDC 56. The acceptable basis for isolation of instrument lines for containment pressure measurements is as specified in NUREG-0800, Standard Review Plan, Subsection 6.2.4:

   “Regulatory Guide (RG) 1.11 describes acceptable containment isolation provisions for instrument lines. In addition, instrument lines closed both inside and outside containment are designed to withstand pressure and temperature conditions following a loss-of-coolant accident (LOCA) and dynamic effects are acceptable without isolation valves.”

H. Each line that penetrates the containment, that is neither part of the reactor coolant pressure boundary nor connected directly to the atmosphere of the containment, and that satisfies the requirements of a closed system is provided with a containment isolation valve according to General Design Criterion 57. A closed system is not a part of the reactor coolant pressure boundary and is not connected directly to the atmosphere of the containment. A closed system also meets the following additional requirements:

   - The system is protected against missiles and the effects of high-energy line break.
   - The system is designed to Seismic Category I requirements.
   - The system is designed to ASME Code, Section III, Class 2 requirements.
   - The system is designed to withstand temperatures at least equal to the containment design temperature.

- The system is designed to withstand the external pressure from the containment structural acceptance test.

- The system is designed to withstand the design basis accident transient and environment.

I. The containment isolation system is designed so that no single failure in the containment isolation system prevents the system from performing its intended functions.

J. Fluid penetrations supporting the engineered safety features functions have remote manual isolation valves. These valves can be closed from the main control room or from the remote shutdown workstation, if required.

K. The containment isolation system is designed according to 10 CFR 50.34, so that the resetting of an isolation signal will not cause any valve to change position.

6.2.3.1.2 Power Generation Design Basis

The containment isolation system has no power generation design basis. Power generation design bases associated with individual components of the containment isolation system are discussed in the section describing the system of which they are an integral part.

6.2.3.1.3 Additional Requirements

The AP1000 containment isolation system is designed to meet the following additional requirements:

A. The containment isolation elements are designed to minimize the number of isolation valves which are subject to Type C tests of 10 CFR 50, Appendix J. Specific requirements are the following:

- The number of pipe lines which provide a direct connection between the inside and outside of primary containment during normal operation are minimized.

- Closed systems outside of containment that may be open to the containment atmosphere during an accident are designed for the same conditions as the containment itself, and are testable during Type A leak tests.

- The total number of penetrations requiring isolation valves are minimized by appropriate system design. For example:

  – In the component cooling system, a single header with branch lines inside of containment is employed instead of providing a separate penetration for each branch line.

  – Consistent with other considerations, such as containment arrangement and exposure of essential safety equipment to potentially harsh environments, the equipment is located inside and outside of containment so as to require the smallest number of penetrations.

- Consistent with current practice, Type C testing is not required for pressurized water reactor main steam, feedwater, startup feedwater, or steam generator blowdown isolation valves. The steam generator tubes are considered to be a suitable boundary to prevent

release of radioactivity from the reactor coolant system following an accident. The steam generator shell and pipe lines, up to and including the first isolation valve, are considered a suitable boundary to prevent release of containment radioactivity.

B. Personnel hatches and equipment hatches are sealed by closures with double gaskets. The fuel transfer tube is sealed with a hatch/blind flange inside containment.

C. Containment isolation is actuated on a two-out-of-four logic from within the protection and safety monitoring system. The safeguards signals provided to each isolation valve are selected to enhance plant safety. Provisions are provided for manual containment isolation from the main control room.

D. Penetration lines with automatic isolation valves are isolated by engineered safety features actuation signals.

E. Isolation valves are designed to provide leaktight service against the medium to which the valves are exposed in the short and long-term course of any accident. For example, a valve is gas-tight if the valve is exposed to the containment atmosphere.

F. Isolation valves are designed to have the capacity to close against the conditions that may exist during events requiring containment isolation.

G. Isolation valve closure times are designed to limit the release of radioactivity to within regulation and are consistent with standard valve operators, except where a shorter closure time is required.

H. The position of each power-operated isolation valve (fully closed or open), whether automatic or remote manual, is indicated in the main control room and is provided as input to the data display and processing system. Such position indication is based on actual valve position, for example, by a limit switch which directly senses the actual valve stem position, rather than demanded valve position.

I. Normally closed manual containment isolation valves have provisions for locking the valves closed. Locking devices are designed such that the valves can be locked only in the fully closed position. Administrative control provides verification that manual isolation valves are maintained locked closed during normal operation. Position locks provide confidence that valves are placed in the correct position prior to locking.

J. Automatic containment isolation valves are powered by Class 1E dc power. Air-operated valves fail in the closed position upon loss of a support system, such as instrument air or electric power.

K. Valve alignments used for fluid system testing during operation are designed so that either: containment bypass does not occur during testing, assuming a single failure; or exceptions are identified, and remotely operated valves provide timely isolation from the control room. Containment isolation provisions can be relaxed during system testing. The intent of the design is to provide confidence that operators are aware of any such condition and have the capability to restore containment integrity.

L. A diverse method of initiating closure is provided for those containment isolation valves associated with penetrations representing the highest potential for containment bypass. Diverse actuation is discussed in Section 7.7.

M. Containment penetrations with leaktight barriers, both inboard and outboard, are designed to limit pressure excursion between the barriers due to heatup of fluid between the barriers. The penetration will either be fitted with relief or check valves to relieve internal pressure or one of the valves has been designed or oriented to limit pressures to an acceptable value. For example, a penetration which incorporates two air-operated globe valves –one of the globe valves will be oriented such that pressure between the two valves will lift the plug from the seat to relieve the pressure, then reseat.

6.2.3.2 System Description

6.2.3.2.1 General Description

Piping systems penetrating the containment have containment isolation features. These features serve to minimize the release of fission products following a design basis accident. SRP Subsection 6.2.4 provides acceptable alternative arrangements to the explicit arrangements given in General Design Criteria 55, 56 and 57. Table 6.2.3-1 lists each penetration and provides a summary of the containment isolation characteristics. For isolation valves outside containment, Table 6.2.3-1 also lists the nominal length of pipe between the containment penetration and the isolation valve. The Piping and Instrumentation Diagrams of the applicable systems show the functional arrangement of the containment penetration, isolation valves, test and drain connections. Section 1.7 contains a list of the Piping and Instrumentation Diagrams.

As discussed in Subsection 6.2.3.1, the AP1000 containment isolation design satisfies the NRC requirements including post-Three Mile Island requirements. Two barriers are provided -- one inside containment and one outside containment. Usually these barriers are valves, but in some cases they are closed piping systems not connected to the reactor coolant system or to the containment atmosphere.

The AP1000 has fewer mechanical containment penetrations (including hatches) and a higher percentage of normally closed isolation valves than current plants. The majority of the penetrations that are normally open incorporate fail closed isolation valves that close automatically with the loss of support systems such as instrument air. Table 6.2.3-1 lists the AP1000 containment mechanical penetrations and the isolation valves associated with them. Provisions for leak testing are discussed in Subsection 6.2.5.

For those systems having automatic isolation valves or for those provided with remote-manual isolation, Subsection 6.2.3.5 describes the power supply and associated actuation system. Power-operated (air, motor, or pneumatic) containment isolation valves have position indication in the main control room.

The actuation signal that occurs directly as a result of the event initiating containment isolation is designated in Table 6.2.3-1. If a change in valve position is required at any time following primary actuation, a secondary actuation signal is generated which places the valve in an alternative position. The closure times for automatic containment isolation valves are provided in Table 6.2.3-1.

The containment air filtration system is used to purge the containment atmosphere of airborne radioactivity during normal plant operation. The containment vacuum relief system is a safety grade system, used to mitigate a containment external pressure scenario, and is part of the containment air filtration system. The containment air filtration system is designed in accordance with Branch Technical Position CSB 6-4. The purge component of the air filtration system uses 16-inch supply and exhaust lines and containment isolation valves. The vacuum relief component of the air filtration system uses 6-inch supply lines and containment isolation valves. These valves close automatically on a containment isolation signal. The entire containment air filtration system is described in Subsection 9.4.7.

Section 3.6 describes dynamic effects of pipe rupture. Section 3.5 discusses missile protection, and Section 3.8 discusses the design of Category I structures including any structure used as a protective device. Lines associated with those penetrations that are considered closed systems inside the containment are protected from the effects of a pipe rupture and missiles. The actuators for power-operated isolation valves inside the containment are either located above the maximum containment water level or in a normally nonflooded area. The actuators are designed for flooded operation or are not required to function following containment isolation and designed and qualified not to spuriously open in a flooded condition.

Other defined bases for containment isolation are provided in SRP Subsection 6.2.4.

6.2.3.2.2 Component Description

Codes and standards applicable to the piping and valves associated with containment isolation are those for Class B components, as discussed in Section 3.2. Containment penetrations are classified as Quality Group B and Seismic Category I.

Section 3.11 provides the normal, abnormal, and post-loss-of-coolant accident environment that is used to qualify the operability of power-operated isolation valves located inside the containment.

The containment penetrations which are part of the main steam system and the feedwater system are designed to meet the stress requirements of NRC Branch Technical Position MEB 3-1, and the classification and inspection requirements of NRC Branch Technical Position ASB 3-1, as described in Section 3.6. Section 3.8 discusses the interface between the piping system and the steel containment.

As discussed in Subsection 6.2.3.5, the instrumentation and control system provides the signals which determine when containment isolation is required. Containment penetrations are either normally closed prior to the isolation signal or the valves automatically close upon receipt of the appropriate engineered safety features actuation signal.

6.2.3.2.3 System Operation

During normal system operation, approximately 25 percent of the penetrations are not isolated. These lines are automatically isolated upon receipt of isolation signals, as described in Subsections 6.2.3.3 and 6.2.3.4 and Chapter 7. Lines not in use during power operation are normally closed and remain closed under administrative control during reactor operation.

6.2.3.3 Design Evaluation

A. Engineered safeguards and containment isolation signals automatically isolate process lines which are normally open during operation. The containment isolation system uses diversity in the parameters sensed for the initiation of redundant train-oriented isolation signals. The majority of process lines are closed upon receipt of a containment isolation signal. This safeguards signal is generated by any of the following initiating conditions.

- Low-3 pressurizer pressure
- Low-2 steam-line pressure
- Low-2 T_{cold}
- High-2 containment pressure

- Manual containment isolation actuation

The component cooling water lines penetrating containment provide cooling water to the reactor coolant pumps and chemical and volume control system and liquid radwaste system heat exchangers. The reactor coolant pumps are interlocked to trip following a safeguards actuation (S) signal but will continue to operate (if in service) following a containment isolation (T) signal. In order to provide reliable cooling to the reactor coolant pumps the component cooling lines are isolated on a safeguards actuation signal rather than on a containment isolation signal. The safeguards actuation signal is generated by any of the following conditions.

- Low-3 pressurizer pressure
- Low-2 steam line pressure
- Low-2 reactor coolant inlet temperature
- High-2 containment pressure
- Manual initiation

The chemical and volume control system charging line, normal residual heat removal system reactor coolant and IRWST cooling lines, and containment air filtration system containment purge lines are isolated on high containment radiation signals. Closure of the containment air filtration system isolation valves is based on providing rapid response to elevated activity conditions in containment to limit offsite doses and is initiated on either a high radiation signal or a containment isolation signal consistent with the requirements of NUREG-0737 (Reference 22) and NUREG-0718 Rev 2 (Reference 23). The isolation of the chemical and volume control system charging line on a High-2 radiation signal and normal residual heat removal system cooling lines on a High-2 radiation or safeguards actuation signal with provisions to reset safeguards actuation signal for the normal residual heat removal system valves permits a defense in depth response to a postulated accident by providing for normal residual heat removal system and chemical and volume control system operation unless there is a high radiation level present.

The remainder of the containment isolation valves are closed on parameters indicative of the need to isolate.

B. Upon failure of a main steam line, the steam generators are isolated, and the main steam-line isolation valves, main steam-line isolation bypass valves, power operated relief block valves, and the main steam-line drain are closed to prevent excessive cooldown of the reactor coolant system or overpressurization of the containment.

The two redundant train-oriented steam-line isolation signals are initiated upon receipt of any of the following signals:

- Low-2 steam-line pressure
- High steam pressure negative rate
- High-2 containment pressure
- Manual actuation
- Low-2 T_{cold}

The main steam-line isolation valves, main steam line isolation valve bypass valves, main feedwater isolation valves, steam generator blowdown system isolation valves, and piping are designed to prevent uncontrolled blowdown from more than one steam generator. The main steam-line isolation valves and main feedwater isolation valves close fully within 5 seconds after an isolation is initiated. The blowdown rate is restricted by steam flow restrictors located within the steam generator outlet steam nozzles in each blowdown path. For main steam-line breaks upstream of an isolation valve, uncontrolled blowdown from more than one steam generator is prevented by the main steam-line isolation valves on each main steam line.

Failure of any one of these components relied upon to prevent uncontrolled blowdown of more than one steam generator does not permit a second steam generator blowdown to occur. No single active component failure results in the failure of more than one main steam isolation valve to operate. Redundant main steam isolation signals, described in Section 7.3, are fed to redundant parallel actuation vent valves to provide isolation valve closure in the event of a single isolation signal failure.

The effects on the reactor coolant system after a steam-line break resulting in single steam generator blowdown and the offsite radiation exposure after a steam line break outside containment are discussed in Chapter 15. The containment pressure transient following a main steam-line break inside containment is discussed in Section 6.2.

C. The containment isolation system is designed according to General Design Criterion 54. Leakage detection capabilities and leakage detection test program are discussed in Subsection 6.2.5. Valve operability tests are also discussed in Subsection 3.9.6. Redundancy of valves and reliability of the isolation system are provided by the other safety design bases stated in Section 6.2. Redundancy and reliability of the actuation system are covered in Section 7.3.

   The use of motor-operated valves that fail as-is upon loss of actuating power in lines penetrating the containment is based upon the consideration of what valve position provides the plant safety. Furthermore, each of these valves, is provided with redundant backup valves to prevent a single failure from disabling the isolation function. Examples include: a check valve inside the containment and motor-operated valve outside the containment or two motor-operated valves in series, each powered from a separate engineered safety features division.

D. Lines that penetrate the containment and which are either part of the reactor coolant pressure boundary, connect directly to the containment atmosphere, or do not meet the requirements for a closed system are provided with one of the following valve arrangements conforming to the requirements of General Design Criteria 55 and 56, as follows:

   - One locked-closed isolation valve inside and one locked-closed isolation valve outside containment
   - One automatic isolation valve inside and one locked-closed isolation valve outside containment
   - One locked-closed isolation valve inside and one automatic isolation valve outside containment. (A simple check valve is not used as the automatic isolation valve outside containment.)
   - One automatic isolation valve inside and one automatic isolation valve outside containment. (A simple check valve is not used as the automatic isolation valve outside containment).

Isolation valves outside containment are located as close to the containment as practical. Upon loss of actuating power, air-operated automatic isolation valves fail closed.

In accordance with GDC 56, isolation of instrument lines for containment pressure transmitters is demonstrated on a different basis. The lines are closed inside and outside containment, and are designed to withstand pressure and temperature conditions following a loss-of-coolant accident (LOCA) and dynamic effects.

E. Each line penetrating the containment that is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere, and that satisfies the requirements of a closed system, has at least one containment isolation valve. This containment isolation valve is either automatic, locked-closed, or capable of remote-manual operation. The valve is outside the containment and located as close to the containment as practical. A simple check valve is not used as the automatic isolation valve. This design is in compliance with General Design Criterion 57.

F. The containment isolation system is designed according to seismic Category I requirements as specified in Section 3.2. The components (and supporting structures) of any system, equipment, or structure that are non-seismic and whose collapse could result in loss of a required function of the containment isolation system through either impact or resultant flooding are evaluated to confirm that they will not collapse when subjected to seismic loading resulting from a safe shutdown earthquake.

Air-operated isolation valves fail in the closed position upon loss of air or power. Containment isolation system valves required to be operated after a design basis accident or safe shutdown earthquake are powered by the Class 1E dc electric power system.

6.2.3.4 Tests and Inspections

6.2.3.4.1 Preoperational Testing

Preoperational testing is described in Chapter 14. The containment isolation system is testable through the operational sequence that is postulated to take place following an accident, including operation of applicable portions of the protection system and the transfer between normal and standby power sources.

The safety related function of containment boundary integrity is verified by an integrated leakage rate test. The integrated leakage rate is verified to be less than L_a as defined in Table 6.5.3-1. The integrated containment leakage rate system is utilized to measure the containment leak rate for determination of the integrated leakage rate. The containment isolation valves are verified to close within the time specified in Table 6.2.3-1.

The piping and valves associated with the containment penetration are designed and located to permit pre-service and in-service inspection according to ASME Section XI, as discussed in Subsection 3.9.6 and Section 6.6.

6.2.3.4.2 In-service Testing

Each line penetrating the containment is provided with testing features to allow containment leak rate tests according to 10 CFR 50, Appendix J, as discussed in Subsection 6.2.5.

6.2.3.5 Instrumentation and Control Application

Instrumentation and control necessary for containment isolation, and the sensors used to determine that containment isolation is required, are described in Section 7.3.

Engineered safeguards actuation signals which initiate containment isolation will be initiated using two out of four logic. Containment isolation signals can also be initiated manually from the main control room. Containment isolation valves requiring isolation close automatically on receipt of a safeguards actuation signal.

Containment isolation valves that are equipped with power operators and are automatically actuated may also be controlled individually from the main control room. Also, a manual override of an automatic isolation signal is installed to permit manual control of the associated valve. For all valves except the vacuum relief containment isolation valves, the override control function can be performed only subsequent to resetting of the actuation signal. That is, deliberate manual action is required to change the position of containment isolation valves in addition to resetting the original actuation signal. Resetting of the actuation signal does not cause any valve to change position. The design does not allow ganged reopening of the containment isolation valves. Reopening of the isolation valves is performed on a valve-by-valve basis, or on a line-by-line basis. Safeguards actuation signals take precedence over manual overrides of other isolation signals. For example, a containment isolation signal causes isolation valve closure even though the high containment radiation signal is being overridden by the operator. Containment isolation valves with power operators are provided with open/closed indication, which is displayed in the main control room. The valve mechanism also provides a local mechanical indication of valve position.

As discussed in Subsection 9.4.7.2.3, the containment vacuum relief path includes normally closed motor-operated isolation valves, which are located outside the containment and open automatically to provide a flow path to allow atmospheric air into the containment to equalize differential pressure across the containment vessel shell. These valves also perform a containment isolation function when vacuum relief is not required. As discussed in Subsection 7.6.2.4, an interlock ensures the availability of the engineered safety features for the vacuum relief isolation valves to perform their vacuum relief and containment isolation functions.

If a negative containment pressure condition occurs that causes the vacuum relief isolation valves to automatically actuate open, there will not be a simultaneous need to close for containment isolation. The negative pressure inside the containment prevents expulsion of air from inside the containment when vacuum relief is actuated so that there are no challenges to the offsite dose limits or main control room habitability. Passive cooling system operations with low core decay heat may significantly delay containment pressurization.

Containment isolation is typically required for events that pressurize the containment with steam, such as a primary system or steam generator system line break, or operation of the passive core cooling systems. An event that causes containment pressurization precludes the need for vacuum relief actuation.

If containment conditions change following vacuum relief actuation so that the containment pressure increases, then the vacuum relief actuation signal (which is not latched) would clear and allow the containment isolation signal to automatically close the vacuum relief isolation valves. Since these valves would have recently opened for vacuum relief actuation during the event, it is expected that they would close. A relatively low containment pressure differential and mild containment conditions would be expected when the valves close for containment isolation during this event. Additionally, there are self-actuated vacuum relief valves inside the containment that are in series with the vacuum relief isolation valves, which provide single failure protection in the event that one of the motor-operated valves fails to close.

There is a valve interlock between the inside containment purge exhaust isolation valve and the vacuum relief isolation valves, which limits the potential release of radioactivity from the containment while the containment isolation valves are being closed.

The valve interlock prevents having two parallel vent paths out of the containment in the event of an accident where a negative pressure condition inside the containment does not exist.

The valve interlock preserves the assumptions of the dose analyses, which are bounded by closure of the normal containment purge isolation valves. Having the vacuum relief flow path open, in parallel with the normal containment purge isolation valves without a negative pressure condition in the containment, would provide simultaneous air flow discharge paths. The valve interlock prevents both paths from being open simultaneously. The potential radioactivity release out through the larger containment purge system piping bounds the potential radioactivity release out of the smaller vacuum relief piping during the closure of the vacuum relief isolation valves.

Power supplies and control functions necessary for containment isolation are Class 1E, as described in Chapters 7 and 8.

6.2.4 Containment Hydrogen Control System

The containment hydrogen control system is provided to limit the hydrogen concentration in the containment so that containment integrity is not endangered.

Following a severe accident, it is assumed that 100 percent of the fuel cladding reacts with water. Although hydrogen production due to radiolysis and corrosion occurs, the cladding reaction with water dominates the production of hydrogen for this case. The hydrogen generation from the zirconium-steam reaction could be sufficiently rapid that it may not be possible to prevent the hydrogen concentration in the containment from exceeding the lower flammability limit. The function of the containment hydrogen control system for this case is to promote hydrogen burning soon after the lower flammability limit is reached in the containment. Initiation of hydrogen burning at the lower level of hydrogen flammability prevents accidental hydrogen burn initiation at high hydrogen concentration levels and thus provides confidence that containment integrity can be maintained during hydrogen burns and that safety-related equipment can continue to operate during and after the burns.

The containment hydrogen control system serves the following functions:

- Hydrogen concentration monitoring
- Hydrogen control during and following a degraded core or core melt scenarios (provided by hydrogen igniters). In addition, two nonsafety-related passive autocatalytic recombiners (PARs) are provided for defense-in-depth protection against the buildup of hydrogen following a loss of coolant accident.

6.2.4.1 Design Basis

A. The hydrogen control system is designed to provide containment atmosphere cleanup (hydrogen control) in accordance with General Design Criterion 41, 42 and 43.

B. The hydrogen control system is designed in accordance with the requirements of 10 CFR 50.44 and meets the NRC staff's position related to hydrogen control of SECY-93-087.

C. The hydrogen control system is designed in compliance with the recommendations of NUREG 0737 and 0660 as detailed in Section 1.9.

D. The hydrogen control system is designed in accordance with the recommendations of Regulatory Guide 1.7 as discussed in Appendix 1A. The containment recirculation system discussed in Subsection 9.4.7 provides the controlled purge capability for the containment as specified in position C.4 of Regulatory Guide 1.7

E. The hydrogen control system is designed and fabricated to codes consistent with the quality group classification, described in Section 3.2. Conformance with Regulatory Guide 1.26, 1.29, and 1.32 is described in Section 1.9.

F. The hydrogen control system complies with the intent of Regulatory Guide 1.82 “The Water Sources For Long-Term Recirculation Cooling Following A Loss-Of-Coolant Accident” as it could be applied to concerns for blockage of recombiner air flow paths.

6.2.4.1.1 Containment Mixing

Containment structures are arranged to promote mixing via natural circulation. The physical mechanisms of natural circulation mixing that occur in the AP1000 are discussed in Appendix 6A and summarized below. For a postulated break low in the containment, buoyant flows develop through the lower compartments due to density head differences between the rising plume and the surrounding containment atmosphere, tending to drive mixing through lower compartments and into the region above the operating deck. There is also a degree of mixing within the region above the operating deck, which occurs due to the introduction of and the entrainment into the steam-rich plume as it rises from the operating deck openings. Thus, natural forces tend to mix the containment atmosphere.

Two general characteristics have been incorporated into the design of the AP1000 to promote mixing and eliminate dead-end compartments. The compartments below deck are large open volumes with relatively large interconnections, which promote mixing throughout the below deck region. All compartments below deck are provided with openings through the top of the compartment to eliminate the potential for a dead pocket of high-hydrogen concentration. In addition, if forced containment air-circulation is operated during post-accident recovery, then nonsafety-related fan coolers contribute to circulation in containment.

In the event of a hydrogen release to the containment, passive autocatalytic recombiners act to recombine hydrogen and oxygen on a catalytic surface (see Subsection 6.2.4.2.2). The enthalpy of reaction generates heat within a passive autocatalytic recombiner, which further drives containment mixing by natural circulation. Catalytic recombiners reduce hydrogen concentration at very low hydrogen concentrations (less than 1 percent) and very high steam concentrations, and may also promote convection to complement passive containment cooling system natural circulation currents to inhibit stratification of the containment atmosphere (Reference 17). The implementation of passive autocatalytic recombiners has a favorable impact on both containment mixing and hydrogen mitigation.

For events involving actuation of ADS Stages 1-3, hydrogen has the potential to accumulate in the IRWST airspace where concentrations will be at elevated levels for a limited timeframe and may exceed detonation limits. A detonation in the IRWST has a low probability of occurrence because there are no credible ignition sources in the IRWST airspace during the timeframe of the elevated hydrogen concentration. In the event a hydrogen detonation does occur within the IRWST airspace, the structure and safety-related components within the IRWST maintain their ability to perform their safety-related function. After ADS Stages 1-3 blowdown is complete, the containment hydrogen control system contains design features to address the remaining hydrogen, if needed.

6.2.4.1.2 Validity of Hydrogen Monitoring

The hydrogen monitoring function monitors bulk containment hydrogen concentration.

6.2.4.1.3 Hydrogen Control for Severe Accident

The containment hydrogen concentration is limited by operation of the distributed hydrogen ignition subsystem. Ignition causes deflagration of hydrogen (burning of the hydrogen with flame front propagation at subsonic velocity) at hydrogen concentrations between the flammability limit and 10 volume percent and thus prevents the occurrence of hydrogen detonation (burning of hydrogen with supersonic flame front propagation).

6.2.4.2 System Design

6.2.4.2.1 Hydrogen Concentration Monitoring Subsystem

The hydrogen concentration monitoring subsystem consists of three hydrogen sensors, each paired with a pressure sensor. The sensors are placed in the upper dome where bulk hydrogen concentration can be monitored. The paired pressure sensors are used for pressure compensation for the hydrogen sensors.

The subsystem is comprised of three hydrogen concentration monitors, one corresponding to each pair of hydrogen and pressure sensors, designated as non-Class 1E serving to provide a post accident monitoring function. See Section 7.5 for additional information.

The hydrogen monitors are powered by the Non-Class 1E dc and UPS System. Monitor parameters are provided in Table 6.2.4-1. Hydrogen concentration is continuously indicated in the main control room. Additionally, high hydrogen concentration alarms are provided in the main control room.

6.2.4.2.2 Hydrogen Recombination Subsystem

The hydrogen recombination subsystem is designed to accommodate the hydrogen production rate anticipated for loss of coolant accident. The hydrogen recombination subsystem consists of two nonsafety-related passive autocatalytic recombiners installed inside the containment above the operating deck at approximate elevations of 170 feet and 181 feet respectively, each a minimum of 13 feet inboard from the containment shell. The locations provide placement within a homogeneously mixed region of containment as supported by Subsection 6.2.4.1.1 and Appendix 6A. The location is in a predominately upflow natural convection region. Additionally, the PARs are located azimuthally away from potential high upflow regions such as the direct plume above the loop compartment.

The passive autocatalytic recombiners are simple and passive in nature without moving parts and independent of the need for electrical power or any other support system. The recombiners require no power supply and are self-actuated by the presence of the reactants (hydrogen and oxygen).

Normally, oxygen and hydrogen recombine by rapid burning only at elevated temperatures (greater than about 1100°F [600°C]). However, in the presence of catalytic materials such as the palladium group, this “catalytic burning” occurs even at temperatures below 32°F (0°C). Adsorption of the oxygen and hydrogen molecules occurs on the surface of the catalytic metal because of attractive forces of the atoms or molecules on the catalyst surface. Passive autocatalytic recombiner devices use palladium or platinum as a catalyst to combine molecular hydrogen with oxygen gases into water vapor. The catalytic process can be summarized by the following steps (Reference 15):

1. Diffusion of the reactants (oxygen and hydrogen) to the catalyst

2. Reaction of the catalyst (chemisorption)

3. Reaction of intermediates to give the product (water vapor)

4. Desorption of the product

5. Diffusion of the product away from the catalyst

The reactants must get to the catalyst before they can react and subsequently the product must move away from the catalyst before more reactants will be able to react.

The passive autocatalytic recombiner device consists of a stainless steel enclosure providing both the structure for the device and support for the catalyst material. The enclosure is open on the bottom and top and extends above the catalyst elevation to provide a chimney to yield additional lift to enhance the efficiency and ventilation capability of the device. The catalyst material is either constrained within screen cartridges or deposited on a metal plate substrate material and supported within the enclosure. The spaces between the cartridges or plates serve as ventilation channels for the throughflow. During operation, the air inside the recombiner is heated by the recombination process, causing it to rise by natural convection. As it rises, replacement air is drawn into the recombiner through the bottom of the passive autocatalytic recombiner and heated by the exothermic reaction, forming water vapor, and exhausted through the chimney where the hot gases mix with containment atmosphere. The device is a molecular diffusion filter and thus the open flow channels are not susceptible to fouling.

Passive autocatalytic recombiners begin the recombination of hydrogen and oxygen almost immediately upon exposure to these gases when the catalyst is not wetted. If the catalyst material is wet, then a short delay is experienced in passive autocatalytic recombiner startup (References 19 and 29). The delay is short with respect to the time that the PARs have to control hydrogen accumulation rates (days to weeks) following a design basis accident. The recombination process occurs at room or elevated temperature during the early period of accidents prior to the buildup of flammable gas concentrations. Passive autocatalytic recombiners are effective over a wide range of ambient temperatures, concentrations of reactants (rich and lean, oxygen/hydrogen less than 1 percent) and steam inerting (steam concentrations greater than 50 percent). Although the passive autocatalytic recombiner depletion rate reaches peak efficiency within a short period of time, the rate varies with hydrogen concentration and containment pressure, (Reference 19).

Passive autocatalytic recombiners have been shown to be effective at minimizing the buildup of hydrogen inside containment following loss of coolant accidents (Reference 16). They are provided in the AP1000 as defense-in-depth protection against the buildup of hydrogen following a loss of coolant accident. A summary of component data for the hydrogen recombiners is provided in Table 6.2.4-2.

6.2.4.2.3 Hydrogen Ignition Subsystem

The hydrogen ignition subsystem is provided to address the possibility of an event that results in a rapid production of large amounts of hydrogen such that the rate of production exceeds the capacity of the recombiners. Consequently, the containment hydrogen concentration will exceed the flammability limits. This massive hydrogen production is postulated to occur as the result of a degraded core or core melt accident (severe accident scenario) in which up to 100 percent of the zirconium fuel cladding reacts with steam to produce hydrogen.

The hydrogen ignition subsystem consists of 66 hydrogen igniters strategically distributed throughout the containment. Since the igniters are incorporated in the design to address a low-probability severe accident, the hydrogen ignition system is not Class 1E. Although not class 1E, the igniter coverage,

distribution and power supply has been designed to minimize the potential loss of igniter protection globally for containment and locally for individual compartments. The igniters have been divided into two power groups. Power to each group will be normally provided by offsite power, however should offsite power be unavailable, then each of the power groups is powered by one of the onsite non-essential diesels and finally should the diesels fail to provide power then approximately 4 hours of igniter operation is supported by the non-Class 1E batteries for each group through the use of appropriate load shedding. Assignment of igniters to each group is based on providing coverage for each compartment or area by at least one igniter from each group.

The locations of the igniters are based on evaluation of hydrogen transport in the containment and the hydrogen combustion characteristics. Locations include compartmented areas in the containment and various locations throughout the free volume, including the upper dome.

For enclosed areas of the containment at least two igniters are installed. The separation between igniter locations is selected to prevent the velocity of a flame front initiated by one igniter from becoming significant before being extinguished by a similar flame front propagating from another igniter. The number of hydrogen igniters and their locations are selected considering the behavior of hydrogen in the containment during severe accidents. The likely hydrogen transport paths in the containment and hydrogen burn physics are the two important aspects influencing the choice of igniter location.

The primary objective of installing an igniter system is to promote hydrogen burning at a low concentration and, to the extent possible, to burn hydrogen more or less continuously so that the hydrogen concentration does not build up in the containment. To achieve this goal, igniters are placed in the major regions of the containment where hydrogen may be released, through which it may flow, or where it may accumulate. The criteria utilized in the evaluation and the application of the criteria to specific compartments is provided in Table 6.2.4-6. The location of igniters throughout containment is provided in Figures 6.2.4-5 through 6.2.4-13. The location of igniters is also summarized in Table 6.2.4-7 identifying subcompartment/regions and which igniters by power group provide protection. The locations identified are considered approximations (± 2.5 feet) with the final locations governed by the installation details.

The igniter assembly is designed to reach a minimum surface temperature of 1700°F in the anticipated containment environment following a loss of coolant accident. A spray shield is provided to protect the igniter from falling water drops (resulting from condensation of steam on the containment shell and on nearby equipment and structures). Design parameters for the igniters are provided in Table 6.2.4-3.

6.2.4.2.4 Containment Purge

Containment purge is not part of the containment hydrogen control system. The purge capability of the containment air filtration system (see Subsection 9.4.7) can be used to provide containment venting prior to post-loss of coolant accident cleanup operations.

6.2.4.3 Design Evaluation (Design Basis Accident)

A design basis accident evaluation is not required.

6.2.4.4 Design Evaluation (Severe Accident)

Although a severe accident involving major core degradation or core melt is not a design basis accident, the containment hydrogen control system contains design features to address this potential occurrence. The hydrogen monitoring subsystem has sufficient range to monitor concentrations up to 20 percent hydrogen. The hydrogen ignition subsystem is provided so that hydrogen is burned off in

a controlled manner, preventing the possibility of deflagration with supersonic flame front propagation which could result in large pressure spikes in the containment.

It is assumed that 100 percent of the active fuel cladding zirconium reacts with steam. This reaction may take several hours to complete. The igniters initiate hydrogen burns at concentrations less than 10 percent by volume and prevent the containment hydrogen concentration from exceeding this limit. Further evaluation of hydrogen control by the igniters is presented in the AP1000 Probabilistic Risk Assessment.

6.2.4.5 Tests and Inspections

6.2.4.5.1 Preoperational Inspection and Testing

Hydrogen Monitoring Subsystem

Pre-operational testing is performed either before or after installation but prior to plant startup to verify performance.

Hydrogen Recombination Subsystem

The performance of the autocatalytic recombiner plates (or cartridges) is tested by the manufacturer for each lot or batch of catalyst material. The number of plates tested is based on the guidance provided in ANSI/ASQC Z1.4-1993, “Sampling Procedures and Tables for Inspection by Attributes,” (formerly Military Standard 105), required to achieve Inspection Level III quality level.

Hydrogen Ignition Subsystem

Pre-operational testing and inspection is performed after installation of the hydrogen ignition system and prior to plant startup to verify operability of the hydrogen igniters. It is verified that 66 igniter assemblies are installed at the locations defined by Figures 6.2.4-5 through 6.2.4-11. Operability of the igniters is confirmed by verification of the surface temperature in excess of the value specified in Table 6.2.4-3. This temperature is sufficient to ensure ignition of hydrogen concentrations above the flammability limit.

Pre-operational inspection is performed to verify the location of openings through the ceilings of the passive core cooling system valve/accumulator rooms with respect to the containment pressure boundary. The primary openings are those that constitute at least 98% of the opening area. The primary openings in Room 11206 that vent to Room 11300 are the equipment access opening and CMT-A opening. These openings are verified to be a minimum distance of 24.3 feet and 9.4 feet, respectively, from the containment shell. The primary opening in Room 11207 that vents to Room 11300 is the CMT-B opening, which is verified to be a minimum distance of 24.6 feet from the containment shell. Other openings must be at least 3 feet from the containment shell.

Pre-operational inspection is performed to verify the orientation of the vents from the IRWST that are located along the side of the IRWST next to the containment. The discharge of each of these IRWST vents must be oriented generally away from the containment shell.

6.2.4.5.2 In-service Testing

Hydrogen Monitoring Subsystem

The system is normally in service. Periodic testing and calibration are performed to provide ongoing confirmation that the hydrogen monitoring function can be reliably performed.

Hydrogen Recombination Subsystem

Periodic inspection and testing are performed on the passive autocatalytic recombiners. The testing is performed by testing a sample of the catalyst plates as specified in Subsection 6.2.4.5.1.

Hydrogen Ignition Subsystem

Periodic inspection and testing are performed to confirm the continued operability of the hydrogen ignition system. Operability testing consists of energizing the igniters and confirming the surface temperature as specified in Table 6.2.4-3.

6.2.4.6 Combined License Information

This section contained no requirement for additional information.

6.2.5 Containment Leak Rate Test System

The reactor containment, containment penetrations and isolation barriers are designed to permit periodic leak rate testing in accordance with General Design Criteria 52, 53, and 54. The containment leak rate test system is designed to verify that leakage from the containment remains within limits established in the Technical Specifications.

6.2.5.1 Design Basis

Leak rate testing requirements are defined by 10 CFR 50 Appendix J, “Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors,” (Reference 14) which classifies leak tests as Types A, B and C. The system design provides testing capability consistent with the testing requirements of ANSI-56.8 (Reference 13). The system design accommodates the test methods and frequencies consistent with requirements of 10 CFR 50 Appendix J, Option A or Option B.

The Containment Leak Rate Test Program using 10 CFR Part 50, Appendix J Option B is established in accordance with NEI 94-01 (Subsection 6.2.7, Reference 30), as modified and endorsed by the NRC in Regulatory Guide 1.163 and any exceptions identified in Technical Specification 5.5.8. Table 13.4-201 provides milestones for containment leak rate testing implementation.

6.2.5.1.1 Safety Design Basis

The containment leak rate test system serves no safety-related function other than containment isolation, and therefore has no nuclear safety design basis except for containment isolation. See Subsection 6.2.3 for the containment isolation system.

6.2.5.1.2 Power Generation Design Basis

The containment leak rate test system is designed to verify the leak tightness of the reactor containment. The specified maximum allowable containment leak rate is 0.10 weight percent of the containment air mass per day at the calculated peak accident pressure, P_a, identified in Subsection 6.2.1. The system is specifically designed to perform the following tests in accordance with the provisions of ANSI-56.8 (Reference 13):

- Containment integrated leak rate testing (Type A): The containment is pressurized with clean, dry air to a pressure of P_a. Measurements of containment pressure, dry bulb temperature, and dew point temperature are used to determine the decrease in the mass of air in the containment over time, and thus establish the leak rate.

- Local leak rate testing of containment penetrations with a design that incorporates features such as resilient seals, gaskets, and expansion bellows (Type B): The leakage limiting boundary is pressurized with air or nitrogen to a pressure of P_a and the pressure decay or the leak flow rate is measured.

- Local leak rate testing of containment isolation valves (Type C): The piping test volume is pressurized with air or nitrogen to a pressure of P_a and pressure decay or the leak flow rate is measured. For valves sealed with a fluid such as water, the test volume is pressurized with the seal fluid to a pressure of not less than 1.1 P_a.

The containment leak rate test system piping is also designed for use during the performance of the containment structural integrity test. The instrumentation used for the structural integrity test may be different than that used for the integrated leak rate test.

6.2.5.1.3 Codes and Standards

The containment leak rate test system is designed to conform to the applicable codes and standards listed in Section 3.2. The containment leak testing program satisfies 10 CFR 50, Appendix J requirements.

6.2.5.2 System Description

6.2.5.2.1 General Description

The containment leak rate test system is illustrated on Figure 6.2.5-1. Unless otherwise indicated on the figure, piping and instrumentation is permanently installed. Fixed test connections used for Type C testing of piping penetrations are not shown on Figure 6.2.5-1. These connections are not part of the containment leak rate test system and are shown on the applicable system piping and instrument diagram figure.

Air compressor assemblies used for Type A testing are temporarily installed and are connected to the permanent system piping. The number and capacity of the compressors is sufficient to pressurize the containment with air to a pressure of P_a at a maximum containment pressurization rate of about 5 psi/hour. The compressor assemblies include additional equipment, such as air coolers, moisture separators and air dryers to reduce the moisture content of the air entering containment.

Temperature and humidity sensors are installed inside containment for Type A testing. Data acquisition hardware and instrumentation is available outside containment. Instrumentation not required during normal plant operation may be installed temporarily for the Type A tests.

The system is designed to permit depressurization of the containment at a maximum rate of 10 psi/hour.

Portable leak rate test panels are used to perform Type C containment isolation valve leak testing using air or nitrogen. The panels are also used for Type B testing of penetrations, for which there is no permanently installed test equipment. The panels include pressure regulators, filters, pressure gauges and flow instrumentation, as required to perform specific tests.

6.2.5.2.2 System Operation

Containment Integrated Leak Rate Test (Type A)

An integrated leak rate test of the primary reactor containment is performed prior to initial plant operation, and periodically thereafter, to confirm that the total leakage from the containment does not

exceed the maximum allowable leak rate. The allowable leak rate specified in the test criteria is less than the maximum allowable containment leak rate, in accordance with 10 CFR 50, Appendix J.

Following construction of the containment and satisfactory completion of the structural integrity test, described in Subsection 3.8.2.7, a preoperational Type A test is performed as described in Chapter 14. Additional Type A tests are conducted during the plant life, at intervals in accordance with the Technical Specifications.

- Pretest Requirements

Prior to performing an integrated leak rate test, a number of pretest requirements must be satisfied as described in this subsection.

A general inspection of the accessible interior and exterior surfaces of the primary containment structure and components is performed to uncover any evidence of structural deterioration that could affect either the containment structural integrity or leak tightness. If there is evidence of structural deterioration, corrective action is taken prior to performing the Type A test. The structural deterioration and corrective action are reported in accordance with 10 CFR 50, Appendix J. Except as described above, during the period between the initiation of the containment inspection and the performance of the Type A test, no repairs or adjustments are made so that the containment can be tested in as close to the “as-is” condition as practical.

Containment isolation valves are placed in their post-accident positions, identified in Table 6.2.3-1, unless such positioning is impractical or unsafe. Test exceptions to post-accident valve positioning are identified in Table 6.2.3-1 or are discussed in the test report. Closure of containment isolation valves is accomplished by normal operation and with no preliminary exercising or adjustments (such as tightening of a valve by manual handwheel after closure by the power actuator). Valve closure malfunctions or valve leakage that requires corrective action before the test is reported in conjunction with the Type A test report.

Those portions of fluid systems that are part of the reactor coolant pressure boundary and are open directly to the containment atmosphere under post-accident conditions and become an extension of the boundary of the containment, are opened or vented to the containment atmosphere prior to and during the test.

Portions of systems inside containment that penetrate containment and could rupture as a result of a loss of coolant accident are vented to the containment atmosphere and drained of water to the extent necessary to provide exposure of the containment isolation valves to containment air test pressure and to allow them to be subjected to the full differential test pressure, except that:

- Systems that are required to maintain the plant in a safe condition during the Type A test remain operable and are not vented.

- Systems that are required to establish and maintain equilibrium containment conditions during Type A testing remain operable and are not vented.

- Systems that are normally filled with water and operating under post-accident conditions are not vented.

Systems not required to be vented and drained for Type A testing are identified in Table 6.2.3-1. The leak rates for the containment isolation valves in these systems, measured by Type C testing, are reported in the Type A test report.

Tanks inside the containment are vented to the containment atmosphere as necessary to protect them from the effects of external test pressure and/or to preclude leakage which could affect the accuracy of the test results. Similarly, instrumentation and other components that could be adversely affected by the test pressure are vented or removed from containment.

The containment atmospheric conditions are allowed to stabilize prior to the start of the Type A test consistent with the guidance of ANSI-56.8. The containment recirculation cooling system and central chilled water system are operated as necessary prior to, and during, the test to maintain stable test conditions.

- Test Method

The Type A test is conducted in accordance with ANSI-56.8, using the absolute method. The test duration is established consistent with ANSI-56.8 following the stabilization period. Periodic measurements of containment pressure, dry bulb temperatures and dew point temperatures (water vapor pressure) are used to determine the decrease in the mass of air in the containment over time. A standard statistical analysis of the data is conducted consistent with recommendations of ANSI-56.8.

The accuracy of the Type A test results is then verified by a supplemental verification test. The supplemental verification test is performed using methodology consistent with the recommendations described in ANSI-56.8.

Test criteria for the Type A test are given in the technical specifications. If any Type A test fails to meet the criteria, the test schedule for subsequent tests is adjusted in accordance with 10 CFR 50, Appendix J as defined in the Containment Leakage Rate Testing Program.

During the period between the completion of one Type A test and the initiation of the containment inspection for the subsequent Type A test, repairs or adjustments are made to components identified as exceeding individual leakage limits, as soon as practical after such leakage is identified.

Containment Penetration Leak Rate Tests (Type B)

The following containment penetrations receive preoperational and periodic Type B leak rate tests in accordance with ANSI-56.8 with test intervals as defined by NEI 94-01 (Reference 30):

- Penetrations whose design incorporates resilient seals, gaskets or sealant compounds
- Air locks and associated door seals
- Equipment and access hatches and associated seals
- Electrical penetrations
- Expansion bellows for main steam and feedwater piping penetrations

Figure 6.2.5-1 provides the piping and instrumentation diagram for the containment leak rate test system and illustrates examples of containment penetrations subject to Type B tests.

The fuel transfer tube penetration is sealed with a blind flange inside containment. The flanged joint is fitted with testable seals as shown in Figure 3.8.2-4. The two expansion bellows used on the fuel transfer tube penetration are not part of the leakage-limiting boundary of the containment.

The personnel hatches (airlocks) are designed to be tested by internal pressurization. The doors of the personnel hatches have testable seals as shown in Figure 3.8.2-3. Mechanical and electrical

penetrations on the personnel hatches are also equipped with testable seals. The hatch cover flanges for the main equipment and maintenance hatches have testable seals as shown in Figure 3.8.2-2. Containment electrical penetrations have testable seals as shown in Figure 3.8.2-4.

Type B leak tests are performed by local pressurization using the test connections shown on Figure 6.2.5-1. Unless otherwise noted in Table 6.2.3-1, the test pressure is not less than the calculated containment peak accident pressure, P_a. Either the pressure decay or the flowmeter test method is used. These test methods and the test criteria are presented below for Type C tests.

Containment Isolation Valve Leak Rate Tests (Type C)

Containment isolation valves receive preoperational and periodic Type C leak rate tests in accordance with ANSI-56.8 with test intervals as defined by NEI 94-01 (Reference 30). A list of containment isolation valves subject to Type C tests is provided in Table 6.2.3-1. Containment isolation valve arrangement and test connections provided for Type C testing are illustrated on the applicable system piping and instrument diagram figure.

Type C leak tests are performed by local pressurization. Each valve to be tested is closed by normal means without any preliminary exercising or adjustments. Piping is drained and vented as needed and a test volume is established that, when pressurized, will produce a differential pressure across the valve. Table 6.2.3-1 identifies the direction in which the differential pressure is applied.

Isolation valves whose seats may be exposed to the containment atmosphere subsequent to a loss of coolant accident are tested with air or nitrogen at a pressure not less than P_a. Valves in lines which are designed to be, or remain, filled with a liquid for at least 30 days subsequent to a loss of coolant accident are leak rate tested with that liquid at a pressure not less than 1.1 times P_a. Isolation valves tested with liquid are identified in Table 6.2.3-1.

Isolation valves are tested using either the pressure decay or flowmeter method. For the pressure decay method the test volume is pressurized with air or nitrogen. The rate of decay of pressure in the known volume is monitored to calculate the leak rate. For the flowmeter method pressure is maintained in the test volume by supplying air or nitrogen through a calibrated flowmeter. The measured makeup flow rate is the isolation valve leak rate.

The leak rates of penetrations and valves subject to Type B and C testing are combined in accordance with 10 CFR 50, Appendix J. As each Type B or C test, or group of tests, is completed the combined total leak rate is revised to reflect the latest results. Thus, a reliable summary of containment leaktightness is maintained current. Leak rate limits and the criteria for the combined leakage results are described in the technical specifications.

Scheduling and Reporting of Periodic Tests

Schedules for the performance of periodic Type A, B, and C leak rate tests are in accordance with the Technical Specifications as specified in the Containment Leakage Rate Testing Program. Provisions for reporting test results are described in the Containment Leakage Rate Testing Program.

Type B and C tests may be conducted at any time that plant conditions permit, provided that the time between tests for any individual penetration or valve does not exceed the maximum allowable interval specified in the Containment Leakage Rate Testing Program.

Schedules for the performance of periodic Type A, B, and C leak rate tests are in accordance with NEI 94-01, as endorsed and modified by Regulatory Guide 1.163, and described below:

Type A Tests

A preoperational Type A test is conducted prior to initial fuel load. If initial fuel load is delayed longer than 36 months after completion of the preoperational Type A test, a second preoperational Type A test shall be performed prior to initial fuel load. The first periodic Type A test is performed within 48 months after the successful completion of the last preoperational Type A test. Periodic Type A tests are performed at a frequency of at least once per 48 months, until acceptable performance is established. The interval for testing begins at initial reactor operation. Each test interval begins upon completion of a Type A test and ends at the start of the next test. The extension of the Type A test interval is determined in accordance with NEI 94-01.

Type A testing is performed during a period of reactor shutdown at a frequency of at least once per 10 years based on acceptable performance history. Acceptable performance history is defined as successful completion of two consecutive Type A tests where the calculated performance leakage rate was less than 1.0 L_a. A preoperational Type A test may be used as one of the two Type A tests that must be successfully completed to extend the test interval, provided that an engineering analysis is performed to document why a preoperational Type A test can be treated as a periodic test. Elapsed time between the first and last tests in a series of consecutive satisfactory tests used to determine performance shall be at least 24 months.

Schedular exceptions to the above and to NEI 94-01 are identified in Technical Specification 5.5.8.

Type B Tests (Except Containment Airlocks)

Type B tests are performed prior to initial entry into Mode 4. Subsequent periodic Type B tests are performed at a frequency of at least once per 30 months, until acceptable performance is established. The test intervals for Type B penetrations may be increased based upon completion of two consecutive periodic as-found Type B tests where results of each test are within allowable administrative limits. Elapsed time between the first and last tests in a series of consecutive satisfactory tests used to determine performance shall be 24 months or the nominal test interval (e.g., refueling cycle) for the component prior to implementing Option B of 10 CFR Part 50, Appendix J. An extended test interval for Type B tests may be increased to a specific value in a range of frequencies from greater than once per 30 months up to a maximum of once per 120 months. The extension of specific test intervals for Type B penetrations is determined in accordance with NEI 94-01.

Type B Tests (Containment Airlocks)

Containment airlock(s) are tested at an internal pressure of not less than P_{ac}. (Prior to a preoperational Type A test P_{ac}= P_a.) Subsequent periodic tests are performed at a frequency of at least once per 30 months. In addition, equalizing valves, door seals, and penetrations with resilient seals (i.e., shaft seals, electrical penetrations, view port seals and other similar penetrations) that are testable, are tested at a frequency of once per 30 months.

For periods of multiple containment entries where the airlock doors are routinely used for access more frequently than once every seven days (e.g., shift or daily inspection tours of the containment), door seals may be tested once per 30 days during this time period.

Airlock door seals are tested prior to a preoperational Type A test. When containment integrity is required, airlock door seals are tested within seven days after each containment access.

Type C Tests

Type C tests are performed prior to initial entry into Mode 4. Subsequent periodic Type C tests are performed at a frequency of at least once per 30 months, until adequate performance has been established. Test intervals for Type C valves may be increased based upon completion of two

consecutive periodic as-found Type C tests where the result of each test is within allowable administrative limits. Elapsed time between the first and last tests in a series of consecutive passing tests used to determine performance shall be 24 months or the nominal test interval (e.g., refueling cycle) for the valve prior to implementing Option B of 10 CFR Part 50, Appendix J. Intervals for Type C testing may be increased to a specific value in a range of frequencies from 30 months up to a maximum of 60 months. Test interval extensions for Type C valves are determined in accordance with NEI 94-01.

Reporting

A post-outage report is prepared presenting results of the previous cycle's Type B and Type C tests, and Type A, Type B and Type C tests, if performed during that outage. The report is available on-site for NRC review. The report shows that the applicable performance criteria are met, and serves as a record that continuing performance is acceptable.

Special Testing Requirements

AP1000 does not have a subatmospheric containment or a secondary containment. There are no containment isolation valves which rely on a fluid seal system. Thus, there are no special testing requirements.

Acceptance Criteria

Acceptance criteria for Type A, B and C Tests are established in Technical Specification 5.5.8.

6.2.5.2.3 Component Description

The system pressurization equipment is temporarily installed for Type A testing. In addition to one or more compressors, this hardware includes components such as aftercoolers, moisture separators, filters and air dryers. The hardware characteristics may vary from test to test.

The flow control valve in the pressurization line is a leaktight valve capable of throttling to a low flow rate.

6.2.5.2.4 Instrumentation Applications

For Type A testing, instruments are provided to measure containment absolute pressure, dry bulb temperature, dew point temperature, air flow rate, and atmospheric pressure. Data acquisition equipment scans, processes and records data from the individual sensors. For Type B and C testing, instruments are provided to measure pressure, dry bulb temperature, and flow rate.

The quantity and location of Type A instrumentation and permanently installed Type B instrumentation, is indicated on Figure 6.2.5-1. The type, make and range of test instruments may vary from test to test. The instrument accuracy must meet the criteria of Reference 13.

6.2.5.3 Safety Evaluation

The containment leak rate test system has no safety-related function, other than containment isolation and therefore requires no nuclear safety evaluation, other than containment isolation which is described in Subsection 6.2.3.

6.2.5.4 Inservice Inspection/Inservice Testing

There are no special inspection or testing requirements for the containment leak rate test system. Test equipment is inspected and instruments are calibrated in accordance with ANSI-56.8 criteria and the requirements of the test procedure.

6.2.6 Combined License Information for Containment Leak Rate Testing

The Containment Leakage Rate Testing Program is addressed in Subsections 6.2.5.1 and 6.2.5.2.2.

6.2.7 References

1. Not used.

2. "Ice Condenser Containment Pressure Transient Analysis Methods," WCAP-8077, March, 1973 (Proprietary), WCAP-8078 (Non-Proprietary).

3. Shepard, R. M., et al., "Westinghouse Mass and Energy Release Data for Containment Design," WCAP-8264-P-A, June 1975 (Proprietary), and WCAP-8312-A, Revision 2, August 1975 (Non-Proprietary).

4. "Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version," WCAP-10325-P-A (Proprietary) and WCAP-10326-A (Non-Proprietary), May 1983.

5. Land, R. E., "Mass and Energy Releases Following a Steam Line Rupture," WCAP-8822 (Proprietary) and WCAP-8860 (Non-Proprietary), September 1976; "Supplement 1 - Calculations of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture," WCAP-8822-P-S1 (Proprietary), January 1985; "Supplement 2 - Impact of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture for Dry and Subatmospheric Containment Designs," WCAP-8822-S2-P-A (Proprietary), September 1986.

6. Burnett, T. W. T., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), April 1984.

7. 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Cooled Nuclear Power Reactors," and Appendix K to 10 CFR 50, "ECCS Evaluation Model."

8. Not used.

9. T. Tagami, "Interim Report on Safety Assessment and Facilities Established Project in Japan for Period Ending June 1965 (No. 1)," prepared for the National Reactor Testing Station, February 28, 1966 (unpublished work).

10. H. Uchida, A. Oyama, and Y. Toga, "Evaluation of Post-Incident Cooling Systems of Light-Water Power Reactors," Proc. Third International Conference on the Peaceful Uses of Atomic Energy, Volume 13, Session 3.9, United Nations, Geneva (1964).

11. Not used.

12. Not used.

13. ANSI/ANS-56.8-1994, "Containment System Leakage Testing Requirements."

14. 10 CFR 50, Appendix J, "Containment Leak Rate Testing," September 26, 1995.

15. Thomas C. L. Catalytic Processes and Proven Catalysts, Academic Press, 1970.

16. AP600 Standard Safety Analysis Report, Section 6.2.

17. J. Rohde, et al., “Hydrogen Mitigation by Catalytic Recombiners and Ignition During Severe Accidents,” Third International Conference on Containment Design and Operation, Canadian Nuclear Society, Toronto, Ontario, October 19-21, 1994.

18. Not used.

19. EPRI Report, “NIS passive autocatalytic recombiner Depletion Rate Equation for Evaluation of Hydrogen Recombination During AP600 Design Basis Accident,” EPRI ALWR Program, November 15, 1995.

20. WCAP-15846 (Proprietary) and WCAP-15862 (Non-Proprietary) “WGOTHIC Application to AP600 and AP1000,” Revision 5, September 2016.

21. Not used.

22. NUREG-737, “Clarification of TMI Action Plan Requirements,” October, 1980

23. NUREG-718. Rev. 2, “Licensing Requirements for Pending Applications for Construction Permits and Manufacturing License,” January, 1982.

24. ANSI/ASCE-8-90, Specification for the Design of Cold Formed Stainless Steel Structural Members

25. Not used.

26. WCAP-15965-P (Proprietary) and WCAP-15965-NP (Non-Proprietary), “AP1000 Subcompartment Models,” Revision 1, September 2014.

27. Not used.

28. Not used.

29. EPRI Report TR-107517, Volumes 1, 2, and 3, “Generic Model Tests of Passive Autocatalytic Recombiners (PARs) for Combustible Gas Control in Nuclear Power Plants,” June 1997.

30. Nuclear Energy Institute Report, NEI 94-01, “Industry Guidelines for Implementing Performance Based Option of 10 CFR 50, Appendix J,” Revision 0.

31. Carlin, E. L. and U. Bachrach, “LOFTRAN and LOFTTR2 AP600 Code Applicability Document,” WCAP-14234, Revision 1 (Proprietary) and WCAP-14235, Revision 1 (Non-Proprietary), August 1997.

32. WCAP-15644-P (Proprietary) and WCAP-15644-NP (Non-Proprietary), “AP1000 Code Applicability Report,” Revision 2, March 2004.

33. NEI 06-12, “B.5.b Phase 2 & 3 Submittal Guidelines,” Revision 2.

34. Moody, F. J., “Maximum Flow Rate of a Single Component, Two-Phase Mixture,” Journal of Heat Transfer, Transactions of the ASME, Series C, Vol. 87, February 1965.

35. Not used.

36. Not used.

37. WCAP-15846-P (Proprietary), Addendum 1 and WCAP-15846-NP (Non-Proprietary) Addendum 1, “Effective Thermal Conductivity Model of Inorganic Zinc Coating for Application to AP1000,” Revision 0, October 2013.

38. APP-PCS-M3C-033, “AP1000 Passive Containment Cooling System (PCS) Air Flow Path Resistance Analysis by Using Computational Fluid Dynamics (CFD).”

Table 6.2.1.1-1
Summary of Calculated Peak Containment Pressures and Vapor Temperatures

Break	Peak Pressure (psig)	Available[1] Margin (psi)	Peak Temperature (°F)
Double-ended hot leg guillotine	49.8	9.2	385.8
Double-ended cold leg guillotine	58.1	0.9	357.8
Full main steam line DER, 30% power, MSIV failure	57.2	1.8	381.8
Full main steam line DER, 101% power, MSIV failure	54.4	4.6	383.6

Note:
1. Design Pressure is 59 psig

Table 6.2.1.1-2
Containment Integrity Analysis Initial Conditions

Internal Temperature (°F)	120
Pressure (psia)	15.7
Internal Relative Humidity (%)	0
Net Free Volume (ft^3)	2.06E+06
External Temperature (°F)	115 dry bulb 86.1 wet bulb

Table 6.2.1.1-3
Postulated Containment Accident Analyses Relative to GDC

Criterion	Acceptance Criterion Value	Lumped DEHLG LOCA Value	Lumped DECLG LOCA Value	30% Power MSLB Value	External Pressurization Value
GDC 16 & GDC 50 Design Pressure	<59.0 psig	49.8 psig	58.1 psig	57.2 psig	
GDC 38 Rapidly Reduce Containment Pressure	< 29.5 psig		< 27 psig after 24 hrs(1)		
GDC 38 & 50 External Pressure	< 1.7 psid				1.63
GDC 38 & GDC 50 Containment Heat Removal Single Failure	Most Severe	Two of Three PCS Water Supply Flowpaths(2)	Two of Three PCS Water Supply Flowpaths(2)	Two of Three PCS Supply Flowpaths(2)	

Notes:
1. Analysis without crediting heat conduction from dry to wet sections on containment shell.
2. Table 6.2.2-3 notes that operation of only one of three flowpaths is necessary to meet minimum containment cooling requirements.

Tables 6.2.1.1-4–6.2.1.1-7 Not Used

Table 6.2.1.1-8
Material Properties Used in the WGOTHIC Containment Evaluation Model

Material		Thermal Conductivity (BTU/hr-ft-°F)	Volumetric Heat Capacity (BTU/ft^3-°F)	Emissivity
Epoxy		0.1875	26.25	N/A
Inorganic zinc		0.302	22.825	0.54(1)
Baffle aluminum		13.4	28.443	0.81(1)
Concrete		0.83	26.6	0.81(1)
Air	0°F	0.0131	0.020736	N/A
	250°F	0.0192	0.020988	N/A
	500°F	0.0246	0.021427	N/A
Group A Carbon Steel	70°F	31.4	44.9	N/A
	100°F	31.2	46.2	N/A
	150°F	30.8	48.0	N/A
	200°F	30.3	49.6	N/A
	250°F	29.7	50.8	N/A
	300°F	29.1	51.9	N/A
Group B Carbon Steel	70°F	24.6	46.4	N/A
	100°F	24.8	47.8	N/A
	150°F	25.0	49.6	N/A
	200°F	25.0	51.4	N/A
	250°F	24.8	52.7	N/A
	300°F	24.6	54.0	N/A
Group C Carbon Steel	70°F	21.3	46.5	N/A
	100°F	21.2	47.1	N/A
	150°F	21.2	48.4	N/A
	200°F	21.2	49.9	N/A
	250°F	21.1	51.1	N/A
	300°F	21.1	52.5	N/A
Group D Carbon Steel	70°F	18.9	46.3	N/A
	100°F	18.9	47.1	N/A
	150°F	19.1	48.7	N/A
	200°F	19.2	49.9	N/A
	250°F	19.3	51.1	N/A
	300°F	19.4	52.2	N/A
Group J Stainless Steel	70°F	7.7	51.3	N/A
	100°F	7.8	51.5	N/A
	150°F	8.1	52.6	N/A
	200°F	8.4	53.7	N/A
	250°F	8.6	54.7	N/A
	300°F	8.8	55.1	N/A
Group K Stainless Steel	70°F	7.5	53.1	N/A
	100°F	7.5	53.4	N/A
	150°F	7.7	54.5	N/A
	200°F	7.9	54.6	N/A
	250°F	8.2	55.7	N/A
	300°F	8.4	55.8	N/A

Notes:
1. Emissivity is only credited outside containment

Table 6.2.1.1-9
Containment External Pressure Analysis Major Assumptions

Initial	
Parameter	**Value**
Containment External Temperature	25°F
Containment Wind Speed	Natural convection
Containment Internal Temperature	120°F
Containment Initial Humidity	72%
IRWST Temperature	120°F
Containment Internal Pressure	14.5 psia
Transient Conditions	
Containment External Temperature	Decreasing at 30°F/hr
Containment Wind Speed	Forced convection at 24.9 ft/s in the riser region
Containment Heat Rate	Sensible heat from Mode 3 with 0 decay heat considered
Safety Analysis Limit Assumed for Vacuum Relief System Actuation	-1.2 psig

Table 6.2.1.1-10
[*Plant Requirements for Metal Heat Sinks Inside Containment*]*

Region	*Metal Volume (ft^3) (minimum – maximum)*
Above the operating deck	*4973 – 7279*
Inside SG/Pressurizer compartments	*1002 – 1677*
Below the operating deck	*5246 – 8255*
Total	*11,811(3) – 17,211*

Notes:

1. *Does not include the containment vessel.*
2. *Only includes structures and equipment that are typically less than or equal to containment ambient temperature.*
3. *The total minimum volume includes an additional 590 ft^3 of metal inside containment.*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 6.2.1.1-11 (Sheet 1 of 2)
Heat Sinks Credited in the Peak Containment Pressure Analyses

Description	Material	Surface Area (ft^2)	Metal Volume (ft^3)	Metal Effective Thickness (in)
Above the Operating Deck				
Containment vessel above the operating deck	Carbon Steel C	62,988	8,986	1.625 and 1.750
Polar crane bridge and trolley	Carbon Steel B	9,000	1,936	2.581
Crane girder	Carbon Steel C	11,509	1,190	1.241
Circular walkway at 162’	Carbon Steel B	11,903	349	0.351
Upper manway platforms at 166’ above SG rooms and ADS platform at 166’ and 176.88’ over pressurizer compartment	Carbon Steel B	13,060	238	0.219
Internal stiffener	Carbon Steel C	2,320	232	1.198
Integrated head stands	Carbon Steel B	692	170	2.940
Recirculation unit platforms at 153’ (CH53, CH57)	Carbon Steel B	9,056	176	0.242
Outer SG compartment walls (loop B)	Carbon Steel B, Concrete	1,808	139	0.922
Outer SG compartment walls (loop A)	Carbon Steel B, Concrete	1,572	105	0.800
Outer pressurizer walls	Carbon Steel B, Concrete	1,117	77	0.832
Stairs outside SG compartments	Carbon Steel B	4,394	74	0.201
Attachment plates above the operating deck	Carbon Steel C	678	62	1.090
Ring duct	Carbon Steel A	9,024	117	0.155
Recirculation duct and supports	Carbon Steel A	3,823	53	0.166
ADS module	Carbon Steel C	1,856	58	0.373
Inside SG Compartments and Pressurizer Compartment				
Inner SG room walls (loop B)	Carbon Steel B, Concrete	6,838	364	0.639
Inner SG room walls (loop A)	Carbon Steel B, Concrete	5,738	314	0.656
Inner pressurizer compartment walls	Carbon Steel B, Concrete	2,958	150	0.608
Lower manway platforms at 104’-7” in SG compartments	Carbon Steel B	3,631	113	0.375
Tubesheet platforms at 116’-6” in SG compartments	Carbon Steel B	3,979	33	0.100
Steel plate at 95’-6” in SG compartment (loop B)	Stainless Steel K	239	27	1.370
Flow-Through Compartments Below the Operating Deck				
Containment vessel below operating deck	Carbon Steel C	10,381	1,514	1.750
CMTs	Carbon Steel C	2,109	1,187	6.754
Floor framing below operating deck	Carbon Steel A	9,236	495	0.643
Platform at 118’-6” between maintenance floor and maintenance floor mezzanine	Carbon Steel B	27,703	439	0.190
Columns in maintenance floor room	Carbon Steel B	2,255	330	1.754
Curved IRWST wall	Stainless Steel K	4,110	219	0.639
Walls in maintenance floor and maintenance floor mezzanine	Carbon Steel B, Concrete	9,029	372	0.493

Table 6.2.1.1-11 (Sheet 2 of 2)
Heat Sinks Credited in the Peak Containment Pressure Analyses

Description	Material	Surface Area (ft^2)	Metal Volume (ft^3)	Metal Effective Thickness (in)
Walls in reactor coolant drain tank (RCDT) room and vertical access (VA) room	Carbon Steel B, Concrete	2,966	133	0.538
Platforms at 83' and 107', and stairs in VA room	Carbon Steel B	3,131	37	0.140
Ceiling of maintenance floor mezzanine, Q-deck	Carbon Steel B, Concrete	5,552	28	0.060
Ceiling of maintenance floor mezzanine, steel plate (south)	Carbon Steel A, Concrete	514	13	0.293
Ceiling of pressurizer spray valve room	Carbon Steel B, Concrete	199	8	0.500
Dead-end Compartments Below the Operating Deck				
Accumulators	Carbon Steel C	1,616	264	1.959
PXS compartments walls	Carbon Steel B, Concrete	5,492	261	0.569
Upper refueling room walls	Stainless Steel K, Concrete	5,191	218	0.503
Platforms in PXS compartments	Carbon Steel B	6,404	158	0.296
CVS compartment walls	Carbon Steel B, Concrete	2,869	120	0.500
Demineralizers, reactor coolant filters in CVS compartment	Stainless Steel J	364	109	3.599
IRWST ceiling	Stainless Steel K, Concrete	2,174	87	0.479
PXS compartments ceiling	Carbon Steel A, Concrete	1,668	70	0.500
Lower refueling room walls	Stainless Steel K, Concrete	1,164	66	0.681
CVS compartment ceiling	Carbon Steel A, Concrete	679	28	0.500
Hatches over PXS, CVS Rooms	Carbon Steel D	62	17	3.294

Table 6.2.1.2-1 (Sheet 1 of 3)
Calculated Maximum Differential Pressures of High Energy Line Breaks for Short-Term Subcompartment Pressurization[3]

AP1000 Room #	Possible[1] Pipe Rupture	Design Differential Pressure (psi)	Maximum Differential Pressure (psi)	Table for Mass and Energy Data
11104	None	5.0	NA	NA
11105	None	5.0	NA	NA
11201	4" Cold Leg 1A Pressurizer Spray Line	5.0	<4.0	6.2.1.3-6
	4" Cold Leg 1B Pressurizer Spray Line	5.0	<4.0	6.2.1.3-6
11202	None	5.0	NA	NA
11204	3" Purification Line from CVS-PL-V003 Outlet to RHX Tube Inlet	5.0	<2.0	6.2.1.3-3
	3" Purification Return Line from RHX Shell Outlet to Check Valve CVS-PL-V080 Inlet	5.0	<2.0	6.2.1.3-4
11205	None	5.0	NA	NA
11206	None	5.0	NA	NA
11207	None	5.0	NA	NA
11208	None	5.0	NA	NA
11209 North	None	5.0	NA	NA
11209 Center	3" Purification Line from RHX Tube Outlet to LHX Tube Inlet	5.0	<4.0	6.2.1.3-2
	3" Purification Line from CVS-PL-V003 Outlet to RHX Tube Inlet	5.0	<4.9	6.2.1.3-3
	3" Purification Return Line from RHX Shell Outlet to Check Valve CVS-PL-V080 Inlet	5.0	<3.5	6.2.1.3-4
11209 South	3" Purification Line from RHX Tube Outlet to LHX Tube Inlet	5.0	<3.5	6.2.1.3-2

Table 6.2.1.2-1 (Sheet 2 of 3)
Calculated Maximum Differential Pressures of High Energy Line Breaks for Short-Term Subcompartment Pressurization[3]

AP1000 Room #	Possible[1] Pipe Rupture	Design Differential Pressure (psi)	Maximum Differential Pressure (psi)	Table for Mass and Energy Data
11209 Pipe Tunnel	3" Purification Line from CVS-PL-V003 Outlet to RHX Tube Inlet	7.5[2]	<5.5	6.2.1.3-3
	3" Purification Return Line from RHX Shell Outlet to Check Valve CVS-PL-V080 Inlet	7.5[2]	<5.0	6.2.1.3-4
	4" Blowdown Line of SG2 to SGS-PL-V074B	7.5[2]	<5.5	6.2.1.3-7
11300	None	5.0	NA	NA
11301	3" CVS Purification Return Line	5.0	<4.0	6.2.1.3-5
11302	None	5.0	NA	NA
11303	None	5.0	NA	NA
11304	3" CVS-PL-V081 Inlet to CVS-PL-V082 Outlet	5.0	<2.5	6.2.1.3-11
	3" CVS Purification Return Line	5.0	<3.0	6.2.1.3-12
11305	None	5.0	NA	NA
11400	None	5.0	NA	NA
11401	4" Line to Outlet Nozzle of SG1	5.0	<3.0	6.2.1.3-7
11402	4" Blowdown Line to Outlet Nozzle of SG2	5.0	<3.0	6.2.1.3-7
11403	2" Aux Spray Piping to Pressurizer Spray Nozzle	5.0	<2.5	6.2.1.3-14
	4" Aux Spray Piping to Pressurizer Spray Nozzle	5.0	<4.8	6.2.1.3-13
11500	None	5.0	NA	NA
11501	None	5.0	NA	NA
11502	None	5.0	NA	NA
11503	None	5.0	NA	NA

Table 6.2.1.2-1 (Sheet 3 of 3)
Calculated Maximum Differential Pressures of High Energy Line Breaks for Short-Term Subcompartment Pressurization[3]

AP1000 Room #	Possible[1] Pipe Rupture	Design Differential Pressure (psi)	Maximum Differential Pressure (psi)	Table for Mass and Energy Data
11504	None	5.0	NA	NA
11601	None	5.0	NA	NA
11602	None	5.0	NA	NA
11603	None	5.0	NA	NA
11701	None	5.0	NA	NA
11702	None	5.0	NA	NA
11703	None	5.0	NA	NA

Notes:

1. "None" indicates that there are no breaks analyzed within that specific subcompartment with respect to the break criteria provided in Subsection 6.2.1.2.3.2.
2. Structures are designed to a differential pressurization load of 5.0 psi except the CVS room pipe tunnel is designed to a differential pressurization load of 7.5 psi as discussed in Subsection 3.8.3.5.
3. "NA" indicates that no calculation was performed because no rupture was postulated or that the line was postulated to rupture in a region with a large free volume so compartment differential pressures would be negligible.

Table 6.2.1.3-1
Short-term Mass and Energy Inputs

Analyzed Break	Pressure (psia)	Temperature (°F)
3" CVS Purification Return Line	2266.7	462
4" Cold Leg 1A Pressurizer Spray Line	2381.7	537
4" Cold Leg 1B Pressurizer Spray Line	2381.7	537
3" Purification Line from CVS-PL-V003 outlet to RHX tube inlet	2376.4	537
3" Purification Return Line from RHX shell outlet to check valve CVS-PL-V080 inlet	2254.9	441
3" Purification Return Line from RHX tube outlet to LHX tube inlet	2366.7	240
3" CVS-PL-V081 inlet to CVS-PL-V082 outlet	2183.1	441
3" CVS Purification Return Line	2183.1	441
4" Auxiliary Spray Piping to Pressurizer Spray Nozzle	2317	537
2" Auxiliary Spray Piping to Pressurizer Spray Nozzle	2317	537

Table 6.2.1.3-2
Short-term Mass and Energy Releases - 3" Purification Line from RHX Tube Outlet to LHX Tube Inlet

Break Location	Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
RHX Tube Outlet	0.00	0.00	0.00
	0.001	1926.0	6.810E+05
	0.4385	1926.0	6.810E+05
	0.4386	860.9	4.589E+05
	End	860.9	4.589E+05
LHX Tube Inlet	0.00	0.00	0.00
	0.001	2130.2	4.442E+05
	0.0290	2130.2	4.442E+05
	0.0291	1926.0	6.810E+05
	0.4094	1926.0	6.810E+05
	0.4095	860.9	4.589E+05
	End	860.9	4.589E+05

Table 6.2.1.3-3
Short-term Mass and Energy Releases - 3" Purification Line from CVS-PL-V003 Outlet to RHX Tube Inlet

Break Location	Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
Penetration between Rooms 11204 and 11209	0.00	0.00	0.00
	0.001	1721.8	9.178E+05
	0.3611	1721.8	9.178E+05
	0.3612	1926.0	6.810E+05
	0.7998	1926.0	6.810E+05
	0.7999	860.9	4.589E+05
	End	860.9	4.589E+05
RHX Tube Inlet	0.00	0.00	0.00
	0.001	1721.8	9.178E+05
	0.2895	1721.8	9.178E+05
	0.2896	1926.0	6.810E+05
	0.7281	1926.0	6.810E+05
	0.7282	860.9	4.589E+05
	End	860.9	4.589E+05

Table 6.2.1.3-4
Short-term Mass and Energy Releases - 3" Purification Return Line from RHX Shell Outlet to Check Valve CVS-PL-V080 Inlet

Break Location	Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
Penetration between Rooms 11204 and 11209	0.00	0.00	0.00
	0.001	1921.8	8.074E+05
	0.0231	1921.8	8.074E+05
	0.0232	960.9	4.037E+05
	0.6614	960.9	4.037E+05
	0.6615	0.000	0.000
	End	0.000	0.000
RHX Shell Outlet	0.00	0.00	0.00
	0.001	1921.8	8.074E+05
	0.0867	1921.8	8.074E+05
	0.0868	960.9	4.037E+05
	0.5978	960.9	4.037E+05
	0.5979	0.000	0.000
	End	0.000	0.000

Table 6.2.1.3-5
Short-term Mass and Energy Releases - 3" CVS Purification Return Line

Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
0.00	0.000	0.000
0.001	2341.5	1.134E+06
End	2341.5	1.134E+06

Table 6.2.1.3-6
Short-term Mass and Energy Releases - 4" Cold Leg Pressurizer Spray Line

Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
0.00	0.000	0.000
0.001	4282.0	2.282E+06
End	4282.0	2.282E+06

Table 6.2.1.3-7
Short-term Mass and Energy Releases - 4" Steam Generator Blowdown Line

Break Location	Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
At Steam Generator Outlet Nozzle	0.00	0.00	0.00
	0.001	1479.88	8.303E+05
	4.49	1479.88	8.303E+05
	4.50	739.94	4.152E+05
	End	739.94	4.152E+05
In Penetration of Pipe Tunnel	0.00	0.00	0.00
	0.001	1479.88	8.303E+05
	0.71	1479.88	8.303E+05
	0.72	1257.89	7.058E+05
	3.78	1257.89	7.058E+05
	3.79	517.96	2.906E+05
	End	517.96	2.906E+05

Table 6.2.1.3-8
Parameters for LOCA Long-Term Containment Analysis

Number of Loops	2
Active Core Length (ft)	14.0
Core Power, license application (MWt)	3400
Nominal Vessel Inlet Temperature (°F)	535.5
Nominal Vessel Outlet Temperature (°F)	612.2
Steam Pressure (psia)	870.0
Rod Array	17 x 17
Accumulator Temperature (°F)	120.0
Containment Design Pressure (psia)	73.7

Table 6.2.1.3-9 (Sheet 1 of 7)
Long-Term DECL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Enthalpy (Btu/lbm)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
0.00000	0.00	0.00	0.00	1172.85
0.00108	40052.87	533.75	0.00	1172.85
0.10110	59368.22	536.62	0.00	1172.85
0.20117	66300.29	536.89	0.00	1172.85
0.30142	66447.67	536.95	0.00	1172.85
0.40126	65675.65	537.00	0.00	1172.85
0.50145	65274.95	537.18	0.00	1172.85
0.60133	65290.12	537.55	0.00	1172.85
0.70130	65183.67	538.11	0.00	1172.85
0.80144	64916.35	538.88	0.00	1172.85
0.90103	64703.12	539.95	0.00	1172.85
1.00122	64778.19	541.41	0.00	1172.85
1.10107	63859.23	543.18	0.00	1172.85
1.20134	62704.81	545.26	0.00	1172.85
1.30148	61608.59	547.41	0.00	1172.85
1.40117	60696.70	549.57	0.00	1172.85
1.50101	59585.89	551.90	0.00	1172.85
1.60141	58359.48	554.43	0.00	1172.85
1.70131	56787.10	556.83	0.00	1172.85
1.80125	55305.59	558.86	0.00	1172.85
1.90137	54805.09	560.74	0.00	1172.85
2.00120	53523.86	562.60	0.00	1172.85
2.10115	51899.58	564.36	0.00	1172.85
2.20135	50470.83	566.26	0.00	1172.85
2.30124	48836.67	568.63	0.00	1172.85
2.40170	46760.05	570.30	0.00	1172.85
2.50110	45835.40	570.67	0.00	1172.85
2.60114	45719.77	570.44	0.00	1172.85
2.70114	43403.61	570.20	0.00	1172.85
2.80148	42788.61	571.01	0.00	1172.85
2.90154	41342.36	571.84	0.00	1172.85
3.00113	40211.11	572.79	0.00	1172.85
3.10107	38847.30	573.56	0.00	1172.85
3.20165	37459.63	574.16	0.00	1172.85
3.30125	36707.64	574.64	0.00	1172.85
3.40140	35554.13	574.74	0.00	1172.85
3.50164	33912.53	574.51	0.00	1172.85
3.60102	32445.79	574.15	0.00	1172.85
3.70124	31442.01	573.68	0.00	1172.85
3.80133	30850.86	573.12	0.00	1172.85
3.90137	30538.16	572.52	0.00	1172.85
4.00213	30402.98	572.04	0.00	1172.85
4.20089	30215.90	571.36	0.00	1172.85

Table 6.2.1.3-9 (Sheet 2 of 7)
Long-Term DECL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Enthalpy (Btu/lbm)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
4.40010	29884.56	570.88	0.00	1172.85
4.60029	29237.21	569.91	0.00	1172.85
4.80091	28863.69	569.12	0.00	1172.85
5.00095	28500.04	568.75	0.00	1172.85
5.20029	27991.45	568.29	0.00	1172.85
5.40047	27617.14	567.86	0.00	1172.85
5.60072	26880.06	567.43	0.00	1172.85
5.80010	25514.01	567.46	0.00	1172.85
6.00037	24438.77	568.10	0.00	1172.85
6.20107	23755.47	568.80	0.00	1172.85
6.40077	23353.56	570.18	0.00	1172.85
6.60037	24088.35	574.19	0.00	1172.85
6.80035	22164.93	578.28	0.00	1172.85
7.00004	22614.22	581.76	0.00	1172.85
7.20050	22660.07	587.32	0.00	1172.85
7.40063	21703.27	593.51	0.00	1172.85
7.60053	21990.12	598.58	0.00	1172.85
7.80031	21794.29	601.95	0.00	1172.85
8.00010	20967.93	606.91	0.00	1172.85
8.20042	20881.43	612.68	0.00	1172.85
8.40037	20555.65	617.72	0.00	1172.85
8.60062	20196.66	623.44	0.00	1172.85
8.80051	19882.25	628.99	0.00	1172.85
9.00018	19753.14	632.83	0.00	1172.85
9.20122	19392.43	635.04	0.00	1172.85
9.40127	18955.06	636.58	0.00	1172.85
9.60057	18125.94	643.16	0.00	1172.85
9.80034	17308.72	655.66	0.00	1172.85
10.00008	16528.22	674.84	0.00	1172.85
10.20015	15595.19	700.74	0.00	1172.85
10.40041	15312.81	707.39	0.00	1172.85
10.40102	15311.00	707.41	0.00	1172.85
10.40164	15309.15	707.43	0.00	1172.85
10.60060	14926.83	708.59	0.00	1172.85
10.80003	14921.74	707.14	0.00	1172.85
11.00059	14498.78	713.57	0.00	1172.85
11.20005	14065.62	725.27	0.00	1172.85
11.40030	13746.99	726.15	0.00	1172.85
11.60079	13378.70	725.68	0.00	1172.85
11.80077	13108.47	723.62	0.00	1172.85
12.00002	12817.73	725.37	0.00	1172.85
12.20002	12608.56	728.61	0.00	1172.85
12.40202	12228.65	731.29	0.00	1172.85
12.60080	11936.85	732.84	0.00	1172.85

Table 6.2.1.3-9 (Sheet 3 of 7)
Long-Term DECL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Enthalpy (Btu/lbm)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
12.80058	11684.11	734.81	0.00	1172.85
13.00048	11398.79	742.13	0.00	1172.85
13.20050	11185.74	745.24	0.00	1172.85
13.40083	10918.00	748.36	0.00	1172.85
13.60040	10702.65	750.83	0.00	1172.85
13.80071	10588.34	754.34	0.00	1172.85
14.00069	10461.08	753.58	0.00	1172.85
14.20110	10350.79	748.85	0.00	1172.85
14.40163	10338.33	743.29	0.00	1172.85
14.60172	10339.87	739.95	0.00	1172.85
14.80216	10168.76	736.39	0.00	1172.85
15.00154	10107.50	731.33	0.00	1172.85
15.20132	10037.27	730.64	0.00	1172.85
15.40209	9805.80	731.18	0.00	1172.85
15.60198	9668.46	729.18	0.00	1172.85
15.80174	9572.84	729.82	0.00	1172.85
16.00165	9332.89	732.42	0.00	1172.85
16.20099	9168.69	732.14	0.00	1172.85
16.40111	9045.69	733.75	0.00	1172.85
16.60064	8823.68	736.75	0.00	1172.85
16.80135	8656.43	737.69	0.00	1172.85
17.00245	8501.97	740.04	0.00	1172.85
17.20278	8305.69	743.04	0.00	1172.85
17.40007	8132.45	745.16	0.00	1172.85
17.60291	7951.18	748.11	0.00	1172.85
17.80012	7753.09	751.70	0.00	1172.85
18.00106	7538.37	755.57	0.00	1172.85
18.20078	7305.90	759.71	0.00	1172.85
18.40101	7057.74	763.21	0.00	1172.85
18.60187	6816.10	765.94	0.00	1172.85
18.80066	6587.07	768.24	0.00	1172.85
19.00116	6420.48	774.60	0.00	1172.85
19.20154	6201.37	780.97	0.00	1172.85
19.40130	5931.44	787.59	0.00	1172.85
19.60026	5703.61	791.54	0.00	1172.85
19.80112	5474.96	795.15	0.00	1172.85
20.00183	5247.80	797.78	0.00	1172.85
20.20207	5037.97	798.71	0.00	1172.85
20.40037	4844.34	796.50	0.00	1172.85
20.60103	4673.24	792.34	0.00	1172.85
20.80154	4507.68	785.42	0.00	1172.85
21.00033	4359.90	775.95	0.00	1172.85
21.20061	4213.90	765.34	0.00	1172.85
21.40038	4075.02	753.86	0.00	1172.85

Table 6.2.1.3-9 (Sheet 4 of 7)
Long-Term DECL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Enthalpy (Btu/lbm)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
21.60041	3941.72	741.54	0.00	1172.85
21.80051	3813.73	728.79	0.00	1172.85
22.00092	3691.21	715.52	0.00	1172.85
22.20055	3573.81	702.02	0.00	1172.85
22.40015	3460.34	688.27	0.00	1172.85
22.60085	3349.67	674.29	0.00	1172.85
22.80028	3240.79	660.43	0.00	1172.85
23.00123	3134.87	646.66	0.00	1172.85
23.20025	3032.48	632.75	0.00	1172.85
23.40130	2934.25	618.77	0.00	1172.85
23.60062	2839.94	605.26	0.00	1172.85
23.80059	2785.80	590.53	0.00	1172.85
24.00032	2738.35	576.48	0.00	1172.85
24.20023	2690.76	563.10	0.00	1172.85
24.40037	2646.22	550.81	0.00	1172.85
24.60079	2595.15	538.42	0.00	1172.85
24.80099	2539.13	526.24	0.00	1172.85
25.00086	2484.05	514.43	0.00	1172.85
25.20027	2428.62	503.09	0.00	1172.85
25.40063	2373.34	492.10	0.00	1172.85
25.60067	2316.52	481.47	0.00	1172.85
25.80048	2260.36	471.09	0.00	1172.85
26.00093	2204.96	461.22	0.00	1172.85
26.20012	2150.27	451.77	0.00	1172.85
26.40032	2095.19	442.78	0.00	1172.85
26.60063	2041.33	433.95	0.00	1172.85
26.80110	1987.93	425.53	0.00	1172.85
27.00110	1932.88	417.43	0.00	1172.85
27.20147	1875.86	409.77	0.00	1172.85
27.40054	1816.27	402.49	0.00	1172.85
27.60094	1763.81	394.91	0.00	1172.85
27.80020	1734.80	386.34	0.00	1172.85
28.00090	1703.80	378.17	0.00	1172.85
28.20081	1659.91	370.23	0.00	1172.85
28.40000	1602.77	362.72	0.00	1172.85
28.60056	1529.80	355.96	0.00	1172.85
28.80117	1438.61	351.27	0.00	1172.85
29.00084	1301.55	331.87	0.00	1172.85
29.20008	1046.95	320.22	0.00	1172.85
29.40028	846.42	293.61	0.00	1172.85
29.60048	740.78	369.07	0.00	1172.85
29.80038	390.68	290.99	0.00	1172.85
30.00017	76.52	291.27	0.00	1172.85
30.20022	0.00	291.27	0.00	1172.85

Table 6.2.1.3-9 (Sheet 5 of 7)
Long-Term DECL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Enthalpy (Btu/lbm)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
30.30000	0.00	1172.85	0.00	1172.85
30.70000	0.00	1172.85	0.00	1172.85
31.60000	0.00	1172.85	110.15	1172.85
39.98990	0.00	1172.85	277.76	1172.85
44.26170	44.77	332.98	309.91	1172.85
51.11270	151.51	201.99	306.69	1172.85
55.33040	206.47	188.62	304.53	1172.85
60.08680	260.73	181.68	302.04	1172.85
64.61610	303.35	178.72	300.29	1172.85
69.75980	344.91	177.00	298.26	1172.85
75.64790	383.82	176.25	295.90	1172.85
79.69800	404.01	176.38	294.29	1172.85
86.42560	430.39	177.08	292.30	1172.85
91.00040	444.22	177.71	290.93	1172.85
95.00040	453.98	178.34	289.72	1172.85
101.00040	464.97	179.37	287.88	1172.85
105.00040	474.33	179.63	286.81	1172.85
111.00040	474.91	181.29	285.44	1172.85
119.00040	479.52	182.62	283.41	1172.85
132.23300	471.78	185.81	280.19	1172.85
150.00000	458.14	189.29	275.62	1172.85
153.03100	452.32	190.28	274.92	1172.85
159.50000	446.63	191.35	273.67	1172.85
185.00000	407.43	197.56	269.12	1172.85
190.00000	397.85	199.07	268.28	1172.85
192.00000	210.98	247.43	277.12	1172.85
201.00000	336.81	1172.85	178.25	1172.85
210.10000	0.00	1172.85	203.18	1172.85
215.04000	0.00	1172.85	306.42	1172.85
225.14500	5.35	1172.85	294.70	1172.85
251.34600	0.00	1172.85	290.12	1172.85
262.10700	0.00	1172.85	301.34	1172.85
278.62500	0.00	1172.85	288.52	1172.85
299.44900	78.64	339.18	272.67	1172.85
319.81500	0.00	1172.85	282.61	1172.85
341.55800	0.00	1172.85	288.11	1172.85
357.38100	0.00	1172.85	281.99	1172.85
380.08900	0.00	1172.85	213.98	1172.85
401.34000	66.05	333.10	206.10	1172.85
422.89000	101.14	289.75	207.95	1172.85
439.29700	60.86	337.13	198.55	1172.85
461.72200	111.06	277.12	199.40	1172.85
482.52000	70.43	317.00	197.45	1172.85
503.31800	58.46	333.71	192.82	1172.85

Table 6.2.1.3-9 (Sheet 6 of 7)
Long-Term DECL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Enthalpy (Btu/lbm)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
518.91600	75.95	305.41	189.44	1172.85
539.71400	76.76	302.01	188.86	1172.85
560.51200	54.02	335.33	183.08	1172.85
581.30900	76.29	297.85	179.47	1172.85
602.10700	81.14	289.73	173.60	1172.85
648.90200	76.26	290.30	166.19	1172.85
701.67700	82.14	277.68	160.57	1172.85
749.38800	79.12	275.91	154.02	1172.85
801.38200	84.06	264.97	149.41	1172.85
848.61900	78.26	266.39	143.76	1172.85
898.37400	85.11	253.96	139.52	1172.85
947.83100	76.92	257.74	133.90	1172.85
1002.89100	83.57	245.17	122.89	1172.85
1150.00000	72.37	243.43	112.79	1172.85
1201.00000	303.14	146.76	112.79	1172.85
1251.00000	314.82	157.69	111.17	1172.85
1300.00000	314.73	155.46	108.24	1172.85
1310.00000	314.96	154.98	107.65	1172.85
1531.16000	321.76	145.34	95.87	1172.85
1750.00000	330.97	137.47	86.56	1172.85
1984.63000	332.53	131.38	78.21	1172.85
3997.77000	321.57	112.70	47.86	1172.85
6009.01000	294.32	110.59	39.01	1172.85
6512.70000	284.52	110.60	37.89	1172.85
7518.20000	270.41	110.58	35.95	1172.85
8022.81000	262.54	110.62	35.06	1172.85
9980.83000	232.36	111.06	32.69	1172.85
10000.00000	232.06	111.06	32.67	1172.85
10500.00000	224.18	111.25	32.30	1172.85
11000.00000	216.31	111.46	31.95	1172.85
11500.00000	208.39	111.69	31.59	1172.85
11756.12000	204.33	111.81	31.42	1172.85
11806.12000	198.63	207.23	36.30	1172.85
11856.12000	0.00	1171.70	36.26	1171.70
13000.00000	0.00	1171.70	35.35	1171.70
15005.00000	0.00	1171.70	33.78	1171.70
20005.80000	0.00	1171.70	31.27	1171.70
26007.30000	0.00	1171.70	29.77	1171.70
30007.90000	0.00	1171.70	28.77	1171.70
36008.10000	0.00	1171.70	27.11	1171.70
40000.00000	0.00	1171.70	26.02	1171.70
60000.00000	0.00	1171.70	23.27	1171.70
1000000.00	0.00	1171.70	8.63	1171.70
1500000.00	0.00	1171.70	7.25	1171.70

Table 6.2.1.3-9 (Sheet 7 of 7)
Long-Term DECL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Enthalpy (Btu/lbm)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
2000000.00	0.00	1171.70	6.39	1171.70
4000000.00	0.00	1171.70	4.53	1171.70

Table 6.2.1.3-10 (Sheet 1 of 3)
Blowdown DEHL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Average Enthalpy (Btu/lbm)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
0.00000	0.00	0.00	0.00	1172.85
0.00109	105,570.69	640.36	0.00	1172.85
0.10123	84,276.91	643.74	0.00	1172.85
0.20147	69,536.27	648.87	0.00	1172.85
0.30212	66,459.53	648.51	0.00	1172.85
0.40115	63,767.37	647.50	0.00	1172.85
0.50117	61,780.84	646.07	0.00	1172.85
0.60163	60,568.67	644.59	0.00	1172.85
0.70199	59,836.05	643.37	0.00	1172.85
0.80156	59,097.35	642.66	0.00	1172.85
0.90127	58,145.00	642.15	0.00	1172.85
1.00142	57,238.52	642.77	0.00	1172.85
1.10124	56,197.23	644.53	0.00	1172.85
1.20146	55,077.32	645.55	0.00	1172.85
1.30111	54,566.21	646.09	0.00	1172.85
1.40180	54,386.15	647.10	0.00	1172.85
1.50106	53,769.79	647.80	0.00	1172.85
1.60162	52,685.67	647.41	0.00	1172.85
1.70104	51,506.02	645.71	0.00	1172.85
1.80114	50,609.82	644.03	0.00	1172.85
1.90174	50,184.90	643.59	0.00	1172.85
2.00150	49,725.24	643.29	0.00	1172.85
2.10118	49,161.41	643.89	0.00	1172.85
2.20155	48,229.62	645.79	0.00	1172.85
2.30103	47,263.74	647.48	0.00	1172.85
2.40113	46,518.36	648.54	0.00	1172.85
2.50111	46,092.72	648.26	0.00	1172.85
2.60141	45,621.89	646.13	0.00	1172.85
2.70168	45,100.39	643.63	0.00	1172.85
2.80172	44,605.49	641.15	0.00	1172.85
2.90173	44,144.54	638.98	0.00	1172.85
3.00164	43,675.82	637.47	0.00	1172.85
3.10145	43,218.53	636.62	0.00	1172.85
3.20168	42,709.16	636.15	0.00	1172.85
3.30109	42,224.10	635.20	0.00	1172.85
3.40161	41,851.30	633.69	0.00	1172.85
3.50202	41,572.59	632.18	0.00	1172.85
3.60144	41,230.11	631.98	0.00	1172.85
3.70164	40,821.18	633.63	0.00	1172.85
3.80150	40,275.80	635.07	0.00	1172.85
3.90150	39,842.81	638.19	0.00	1172.85
4.00100	39,426.69	638.75	0.00	1172.85
4.20138	39,081.20	636.41	0.00	1172.85

Table 6.2.1.3-10 (Sheet 2 of 3)
Blowdown DEHL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Average Enthalpy (Btu/lbm)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
4.40048	39,248.60	629.12	0.00	1172.85
4.60221	39,552.56	621.60	0.00	1172.85
4.80261	40,044.99	614.28	0.00	1172.85
5.00037	34,131.29	647.30	0.00	1172.85
5.20026	34,081.91	641.02	0.00	1172.85
5.40054	34,072.49	632.55	0.00	1172.85
5.60033	33,996.78	628.40	0.00	1172.85
5.80062	33,868.08	624.58	0.00	1172.85
6.00047	33,694.00	621.26	0.00	1172.85
6.20044	33,486.38	619.01	0.00	1172.85
6.40091	32,744.20	620.51	0.00	1172.85
6.60074	32,303.09	621.00	0.00	1172.85
6.80014	31,604.74	621.00	0.00	1172.85
7.00181	31,339.32	618.53	0.00	1172.85
7.20150	30,952.43	616.40	0.00	1172.85
7.40211	30,470.86	615.61	0.00	1172.85
7.60157	30,019.92	614.03	0.00	1172.85
7.80114	29,402.10	613.35	0.00	1172.85
8.00274	28,766.97	613.62	0.00	1172.85
8.20091	28,022.33	614.27	0.00	1172.85
8.40064	27,170.14	616.22	0.00	1172.85
8.60026	26,248.56	618.43	0.00	1172.85
8.80142	25,251.81	623.03	0.00	1172.85
9.00012	24,695.39	624.65	0.00	1172.85
9.20300	23,232.10	632.39	0.00	1172.85
9.40008	22,325.42	638.48	0.00	1172.85
9.60128	21,729.93	641.25	0.00	1172.85
9.80116	20,355.91	652.80	0.00	1172.85
10.00109	19,420.14	662.24	0.00	1172.85
10.20236	18,471.76	672.91	0.00	1172.85
10.40117	17,602.76	682.03	0.00	1172.85
10.60151	16,610.39	694.91	0.00	1172.85
10.80100	15,628.61	713.20	0.00	1172.85
11.00240	14,721.95	731.75	0.00	1172.85
11.20062	13,821.05	752.20	0.00	1172.85
11.40229	12,889.32	775.73	0.00	1172.85
11.60122	11,975.66	802.31	0.00	1172.85
11.80212	11,077.56	833.25	0.00	1172.85
12.00010	10,210.87	868.52	0.00	1172.85
12.20059	9,346.99	910.42	0.00	1172.85
12.40039	8,498.21	955.06	0.00	1172.85
12.60095	7,826.42	977.10	0.00	1172.85
12.80059	7,371.91	986.44	0.00	1172.85
13.00077	6,967.45	997.64	0.00	1172.85

Table 6.2.1.3-10 (Sheet 3 of 3)
Blowdown DEHL Break
Mass and Energy Releases

Time (sec)	Two-Phase		Steam	
	Mass (lbm/sec)	Average Enthalpy (Btu/lbm)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
13.20054	6,562.39	1,014.23	0.00	1172.85
13.40073	6,181.01	1,032.01	0.00	1172.85
13.60048	5,830.31	1,047.88	0.00	1172.85
13.80018	5,505.98	1,060.91	0.00	1172.85
14.00022	5,206.85	1,065.11	0.00	1172.85
14.20054	4,944.17	1,065.64	0.00	1172.85
14.40083	4,611.19	1,078.60	0.00	1172.85
14.60032	4,336.69	1,092.23	0.00	1172.85
14.80049	4,095.19	1,103.57	0.00	1172.85
15.00012	3,818.80	1,124.39	0.00	1172.85
15.20081	3,569.39	1,147.25	0.00	1172.85
15.40035	3,336.41	1,165.94	0.00	1172.85
15.60040	3,120.28	1,182.81	0.00	1172.85
15.80093	2,913.39	1,199.27	0.00	1172.85
16.00065	2,726.75	1,211.13	0.00	1172.85
16.20058	2,526.63	1,204.33	0.00	1172.85
16.40032	2,350.66	1,209.98	0.00	1172.85
16.60035	2,222.36	1,210.26	0.00	1172.85
16.80092	2,096.17	1,205.95	0.00	1172.85
17.00019	1,946.13	1,201.30	0.00	1172.85
17.20081	1,797.79	1,203.22	0.00	1172.85
17.40079	1,663.12	1,206.03	0.00	1172.85
17.60039	1,531.49	1,205.92	0.00	1172.85
17.80081	1,399.92	1,209.32	0.00	1172.85
18.00075	1,246.94	1,214.97	0.00	1172.85
18.20019	1,095.75	1,222.13	0.00	1172.85
18.40124	984.45	1,219.68	0.00	1172.85
18.60070	850.38	1,218.35	0.00	1172.85
18.80042	687.47	1,216.49	0.00	1172.85
19.00044	535.47	1,222.79	0.00	1172.85
19.20009	426.42	1,231.82	0.00	1172.85
19.40032	269.60	1,236.30	0.00	1172.85
19.60049	0.00	0.00	0.00	1172.85

Table 6.2.1.3-11
Short-term Mass and Energy Releases - 3" CVS-PL-V081 Inlet to CVS-PL-V082 Outlet

Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
0.00	1110.9	5.838E+05
End	1110.9	5.838E+05

Table 6.2.1.3-12
Short-term Mass and Energy Releases - 3" CVS Purification Return Line

Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
0.00	2367.7	1.114E+06
End	2367.7	1.114E+06

Table 6.2.1.3-13
Short-term Mass and Energy Releases - 4" Auxiliary Spray Piping to Pressurizer Spray Nozzle

Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
0.00	4282.0	2.282E+06
End	4282.0	2.282E+06

Table 6.2.1.3-14
Short-term Mass and Energy Releases - 2" Auxiliary Spray Piping to Pressurizer Spray Nozzle

Time (sec)	Total Mass Release Rate (lbm/sec)	Total Energy Release Rate (Btu/sec)
0.000	951.6	5.072E+05
0.0362	951.6	5.072E+05
0.0363	475.8	2.536E+05
End	475.8	2.536E+05

Table 6.2.1.4-1 Not Used

Table 6.2.1.4-2 (Sheet 1 of 2)
Main Steam Line Double Ended Rupture
Mass and Energy Releases from 30% Power Level

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
0.00	11468.30	1188.58
0.01	17637.10	1188.60
0.50	11865.20	1189.62
0.60	10839.60	1189.81
2.39	9088.22	1192.77
4.76	6977.98	1195.62
7.10	4973.83	1197.61
7.11	2402.15	1197.62
9.51	2311.41	1198.55
19.01	1881.93	1202.24
23.81	1699.56	1203.37
28.61	1543.11	1204.06
33.31	1411.22	1204.38
39.41	1267.86	1204.47
44.61	1169.42	1204.38
49.81	1084.97	1204.18
55.11	1009.94	1203.88
60.31	945.58	1203.51
65.51	889.21	1203.10
70.71	839.97	1202.66
81.11	759.10	1201.75
91.51	694.97	1200.81
101.91	642.42	1199.87
112.31	598.45	1198.95
122.81	560.75	1198.06
133.21	528.62	1197.22
143.61	500.83	1196.42
164.41	455.33	1194.93
185.31	419.91	1193.56
206.11	391.98	1192.33
226.91	369.44	1191.27
247.81	350.46	1190.33
289.41	319.78	1188.67
331.11	295.40	1187.26
372.81	276.49	1186.05
414.51	260.24	1184.91
456.21	246.00	1183.82
539.51	222.09	1181.80
622.81	201.03	1179.82
706.21	183.96	1178.08
753.51	167.56	1180.19
770.01	160.58	1181.96
786.61	151.83	1184.83
796.21	145.40	1187.30
803.21	139.83	1189.63

Table 6.2.1.4-2 (Sheet 2 of 2)
Main Steam Line Double Ended Rupture
Mass and Energy Releases from 30% Power Level

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
815.61	128.28	1195.13
823.81	117.54	1199.98
828.01	110.64	1202.88
836.21	94.84	1209.36
844.51	77.41	1216.98
848.71	60.78	1221.36
850.51	46.64	1223.19
851.41	38.93	1224.05
852.01	32.47	1224.58
852.71	19.65	1225.19
852.81	11.58	1225.30
852.91	2.62	1150.35
1000.01	2.62	1150.35

Table 6.2.1.4-3 (Sheet 1 of 2)
Main Steam Line Double Ended Rupture
Mass and Energy Releases from Full Power Level

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
0.00	9488.34	1195.03
0.01	14673.17	1195.04
0.49	10265.53	1195.51
0.53	10146.34	1195.54
2.12	8728.07	1196.69
7.11	4914.85	1197.03
7.12	2470.30	1196.90
9.11	2431.47	1197.32
11.11	2344.55	1198.22
18.91	1939.20	1201.83
22.91	1767.69	1202.99
26.91	1621.85	1203.75
30.81	1499.85	1204.20
40.31	1267.30	1204.47
45.31	1173.99	1204.39
50.11	1097.11	1204.22
59.81	975.89	1203.69
69.61	882.49	1203.04
79.41	809.49	1202.35
89.21	751.10	1201.65
99.01	702.44	1200.93
118.61	624.39	1199.51
138.21	564.93	1198.16
157.81	518.99	1196.95
177.31	483.30	1195.89
196.91	454.74	1194.91
236.11	411.54	1193.20
275.31	379.33	1191.74
314.41	353.51	1190.48
353.61	331.84	1189.34
376.81	305.86	1191.91
388.41	289.54	1194.76
400.01	269.11	1199.84
405.81	256.10	1203.69
411.61	240.27	1208.68
417.41	220.56	1215.05
423.21	196.05	1222.95
429.01	167.41	1232.28
437.51	119.88	1248.03
439.11	98.02	1251.23
439.81	90.27	1252.49
440.61	82.50	1253.87
443.51	57.13	1258.36
444.31	49.36	1259.44
445.01	41.86	1260.34

Table 6.2.1.4-3 (Sheet 2 of 2)
Main Steam Line Double Ended Rupture
Mass and Energy Releases from Full Power Level

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
445.71	33.21	1261.19
446.01	28.91	1261.54
446.21	25.55	1261.78
446.31	23.51	1261.89
446.41	20.64	1262.01
446.51	2.62	1150.35
500.01	2.62	1150.35

Table 6.2.1.4-4
Parameters for Steam Line Break Mass and Energy Releases Inside Containment Analysis

Plant data for all cases:	
Power, Nominal Rating (MWt)	3415
Nominal RCS Flow (GPM)	299,880
Nominal Full Load T_{avg} (°F)	573.6
Nominal RCS Pressure (psia)	2250
Nominal Steam Temperature (°F)	525.5
Nominal Feedwater Enthalpy (BTU/lbm)	419.4

Table 6.2.1.5-1 (Sheet 1 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
0.00	0.00	0
0.01	7942.87	4197068
0.51	57956.40	30282500
1.01	56472.40	29608220
1.51	54084.40	28449280
2.01	48999.30	25903610
2.51	44669.40	23773360
3.01	40136.20	21554050
3.51	36059.80	19555650
4.01	32343.80	17726170
4.51	30080.20	16651800
5.01	28154.80	15805980
5.51	26326.81	15014160
6.01	24527.91	14256040
6.51	22846.03	13563570
7.01	21582.36	13025710
7.51	20192.85	12407740
8.01	18986.50	11890100
8.51	17871.42	11359050
9.01	17076.27	10930030
9.51	16328.68	10479370
10.01	15748.25	10165630
10.51	15138.17	9823398
11.01	14561.62	9486835
11.51	13474.22	9024197
12.01	13680.55	8910145
12.51	13179.21	8612196
13.01	12104.41	8178315
13.51	11928.12	7962325
14.01	11331.71	7630674
14.51	10285.89	7140065
15.01	9612.06	6800880
15.51	8890.77	6437936
16.01	8397.32	6117610
16.51	8110.99	5827232
17.01	7989.51	5551450
17.51	7776.17	5249230
18.01	7400.69	4907268
18.51	7127.20	4601066
19.01	6709.37	4279012
19.51	6386.74	3978181
20.01	6115.01	3705914
20.51	5776.52	3425902
21.01	5517.91	3180462
21.51	5273.02	2963178

Table 6.2.1.5-1 (Sheet 2 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
22.01	4939.00	2748973
22.51	4605.24	2551896
23.01	4470.27	2376817
23.51	3941.49	2159592
24.01	3651.01	2028490
24.51	3112.96	1831021
25.01	2948.30	1674552
25.51	2559.77	1528877
26.01	2458.65	1408223
26.51	2948.44	1371068
27.01	2746.30	1290115
27.51	1786.07	1043598
28.01	2712.07	1012782
28.51	2910.33	1083228
29.01	2233.45	918945
29.51	1450.78	729919
30.01	1211.72	620407
30.51	1589.06	589646
31.01	2324.34	657795
31.51	511.11	385601
32.01	327.07	257183
32.51	229.93	170637
33.01	138.97	118111
33.51	38.78	49703
34.01	30.85	39557
34.51	24.61	28213
35.01	32.26	28358
35.51	24.41	20639
36.01	7.67	6232
36.51	63.33	50679
37.01	17.81	22853
37.51	13.02	16607
38.01	9.73	12441
38.51	0.00	0
39.01	3.26	2928
39.51	65.55	53687
40.01	67.34	72602
40.51	62.30	67887
41.01	49.03	58542
41.51	43.45	52364
42.01	17.96	22932
42.51	15.20	19131
43.01	33.83	37590
43.51	25.45	21467
44.01	29.94	24662
44.51	33.10	29509

Table 6.2.1.5-1 (Sheet 3 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
45.01	28.30	26896
45.51	24.91	23758
46.01	72.50	78140
46.51	56.34	68242
47.01	40.06	48849
47.51	106.92	118490
48.01	26.54	28205
48.51	57.76	61793
49.01	166.99	188706
49.51	142.10	153683
50.01	122.34	133270
50.51	104.57	118432
51.01	94.50	106009
51.51	114.97	125648
52.01	304.27	327915
52.51	438.18	353398
53.01	217.91	238944
53.51	208.85	243504
54.01	196.84	229968
54.51	170.84	200237
55.01	143.16	168668
55.51	108.35	123758
56.01	96.07	110132
56.51	145.71	166951
57.01	184.00	199601
57.51	148.14	159282
58.01	111.16	129618
58.51	103.14	115094
59.01	59.11	70920
59.51	121.13	133279
60.01	192.10	221407
60.51	274.36	259082
61.01	217.48	222919
61.51	140.77	164224
62.01	113.46	131276
62.51	81.97	95753
63.01	125.53	146907
63.51	277.75	267057
64.01	279.66	259800
64.51	202.16	222185
65.01	181.19	194112
65.51	125.69	141746
66.01	97.86	111750
66.51	155.16	176333
67.01	224.14	242392
67.51	230.40	234200

Table 6.2.1.5-1 (Sheet 4 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
68.01	180.98	207383
68.51	155.58	181044
69.01	129.63	148391
69.51	134.89	158826
70.01	179.41	202659
70.51	189.19	217939
71.01	189.94	212600
71.51	200.16	215380
72.01	155.87	182233
72.51	144.58	165043
73.01	152.39	171976
73.51	193.73	218892
74.01	213.02	246071
74.51	207.90	243728
75.01	285.04	276724
75.51	218.60	234337
76.01	174.99	194687
76.51	168.67	191156
77.01	230.41	262908
77.51	220.33	257748
78.01	328.67	299957
78.51	269.62	271423
79.01	194.11	220457
79.51	190.95	218188
80.01	213.99	244892
80.51	236.23	267305
81.01	260.53	279713
81.51	223.30	258393
82.01	217.44	254964
82.51	205.88	242910
83.01	238.23	259684
83.51	243.58	275560
84.01	234.26	269102
84.51	228.11	268944
85.01	220.56	262949
85.51	211.33	251832
86.01	218.36	259571
86.51	248.80	284213
87.01	260.76	296727
87.51	262.52	299547
88.01	264.89	298182
88.51	820.35	304725
89.01	1658.45	387314
89.51	419.25	332530
90.01	465.12	307753
90.51	798.98	323657

Table 6.2.1.5-1 (Sheet 5 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
91.01	1564.18	392925
91.51	1681.45	488011
92.01	524.80	328926
92.51	715.87	302892
93.01	916.00	331695
93.51	1609.64	395641
94.01	1483.75	445986
94.51	796.83	367070
95.01	567.18	323061
95.51	846.66	343109
96.01	1008.32	354410
96.51	1583.02	418731
97.01	846.20	359939
97.51	559.47	324035
98.01	651.65	321456
98.51	736.91	339803
99.01	916.43	329098
99.51	1519.14	410810
100.01	720.12	338623
100.51	508.98	313605
101.01	751.29	332987
101.51	709.66	337150
102.01	1026.40	342413
102.51	1501.55	485867
103.01	1509.55	443226
103.51	1615.99	389899
104.01	709.60	343936
104.51	298.47	290818
105.01	405.18	307500
105.51	236.00	257365
106.01	214.57	244634
106.51	196.03	225879
107.01	211.49	243737
107.51	209.45	241604
108.01	212.12	244237
108.51	211.72	243033
109.01	231.93	255782
109.51	221.98	254250
110.01	230.22	261121
110.51	221.28	253187
111.01	220.14	254614
111.51	219.87	253850
112.01	222.09	256551
112.51	228.52	255866
113.01	225.70	254820
113.51	230.06	256396

Table 6.2.1.5-1 (Sheet 6 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
114.01	232.07	259134
114.51	221.75	256236
115.01	220.54	255640
115.51	208.33	246119
116.01	217.96	249376
116.51	203.44	239316
117.01	233.75	262602
117.51	231.74	261453
118.01	212.96	251032
118.51	945.18	291332
119.01	1704.73	351147
119.51	1072.30	370636
120.01	805.66	318168
120.51	1629.05	366554
121.01	1601.92	368274
121.51	876.85	344974
122.01	953.84	345943
122.51	1061.37	345113
123.01	2077.05	361856
123.51	1155.47	400824
124.01	735.68	308794
124.51	1068.45	328982
125.01	1486.66	389182
125.51	1532.30	376918
126.01	1054.35	378053
126.51	355.16	300169
127.01	985.78	370905
127.51	1033.92	331664
128.01	1622.16	383545
128.51	1509.10	437329
129.01	886.90	351995
129.51	335.52	289093
130.01	567.94	261593
130.51	1353.63	358127
131.01	1597.91	353608
131.51	250.38	256082
132.01	183.70	215997
132.51	182.98	211803
133.01	188.64	218584
133.51	189.25	220139
134.01	187.08	215705
134.51	208.59	225750
135.01	189.82	213258
135.51	186.80	214116
136.01	182.34	209390
136.51	183.58	209779

Table 6.2.1.5-1 (Sheet 7 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
137.01	181.74	207033
137.51	176.95	201679
138.01	195.32	207464
138.51	169.57	191895
139.01	199.69	206952
139.51	175.63	196657
140.01	174.02	195324
140.51	169.66	190497
141.01	154.86	176102
141.51	166.87	176534
142.01	142.95	162974
142.51	145.92	165928
143.01	142.22	163605
143.51	140.98	163470
144.01	135.00	157359
144.51	130.69	152796
145.01	143.00	154391
145.51	129.44	150373
146.01	131.26	152180
146.51	126.54	149938
147.01	120.20	146381
147.51	121.14	147390
148.01	118.77	145198
148.51	137.33	152053
149.01	125.19	149500
149.51	125.34	151325
150.01	123.63	151903
150.51	121.18	149714
151.01	123.87	153456
151.51	142.83	161818
152.01	123.52	152431
152.51	137.71	164398
153.01	138.42	165917
153.51	143.37	169283
154.01	144.04	170853
154.51	146.94	172510
155.01	157.46	180972
155.51	182.18	194506
156.01	182.68	199083
156.51	240.23	226854
157.01	186.17	201397
157.51	188.78	207869
158.01	177.53	197204
158.51	182.14	199744
159.01	170.94	193739
159.51	175.02	193991

Table 6.2.1.5-1 (Sheet 8 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
160.01	183.89	202184
160.51	178.53	200576
161.01	180.58	202006
161.51	176.12	199661
162.01	178.24	202356
162.51	183.29	206040
163.01	187.97	205289
163.51	192.60	207365
164.01	188.51	207204
164.51	180.04	204996
165.01	177.20	203222
165.51	177.24	203394
166.01	179.82	205213
166.51	191.01	210737
167.01	202.91	222624
167.51	185.70	209773
168.01	201.58	219384
168.51	700.89	213031
169.01	1432.73	284625
169.51	722.96	282295
170.01	575.47	275907
170.51	705.57	272191
171.01	1397.11	321115
171.51	1406.78	306333
172.01	1180.97	318445
172.51	1451.68	326298
173.01	847.43	302801
173.51	751.32	271505
174.01	1484.65	298434
174.51	1442.95	361325
175.01	306.30	258039
175.51	754.45	290941
176.01	1234.32	321950
176.51	1756.73	314456
177.01	846.52	320401
177.51	750.78	285970
178.01	1352.84	375378
178.51	1523.54	329154
179.01	1610.91	489664
179.51	539.67	286078
180.01	747.77	308665
180.51	1370.97	351393
181.01	1627.21	324214
181.51	355.67	296933
182.01	748.64	299398
182.51	1313.10	372028

Table 6.2.1.5-1 (Sheet 9 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
183.01	1602.96	368136
183.51	1550.98	345203
184.01	1200.60	358644
184.51	1566.80	362057
185.01	567.66	310741
185.51	759.46	306641
186.01	1582.28	358212
186.51	805.19	309261
187.01	1606.31	377818
187.51	753.33	326692
188.01	848.18	318199
188.51	1765.10	384565
189.01	754.14	309859
189.51	1345.61	397944
190.01	1756.46	369226
190.51	925.16	368732
191.01	670.60	329144
191.51	784.74	311315
192.01	2049.53	372920
192.51	1470.02	508289
193.01	611.38	320418
193.51	756.78	328536
194.01	879.90	312220
194.51	1098.97	378667
195.01	1744.50	365532
195.51	701.02	343283
196.01	662.32	323679
196.51	832.72	334816
197.01	1646.10	379766
197.51	893.81	335562
198.01	1714.79	373751
198.51	611.19	333258
199.01	609.68	320394
199.51	859.92	338769
200.01	1607.56	389751
200.51	847.96	336163
201.01	1726.12	374152
201.51	469.76	312506
202.01	487.49	317122
202.51	613.81	324092
203.01	833.89	325131
203.51	1259.87	410487
204.01	1625.88	385435
204.51	1483.54	513440
205.01	334.19	297833
205.51	254.25	275754

Table 6.2.1.5-1 (Sheet 10 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
206.01	251.45	276027
206.51	240.26	268651
207.01	242.13	267065
207.51	245.12	268164
208.01	243.47	265902
208.51	237.91	263708
209.01	234.71	258062
209.51	231.02	257222
210.01	226.45	253802
210.51	232.31	254552
211.01	223.84	249586
211.51	216.30	243441
212.01	213.96	238951
212.51	215.87	240067
213.01	215.05	237629
213.51	219.00	238554
214.01	226.80	244094
214.51	223.98	241160
215.01	214.93	234096
215.51	210.14	230933
216.01	202.37	225065
216.51	196.68	219516
217.01	200.69	219035
217.51	184.67	208066
218.01	185.29	209360
218.51	181.72	207222
219.01	186.53	210264
219.51	193.14	213581
220.01	190.57	208299
220.51	178.65	199749
221.01	175.16	196941
221.51	164.34	188476
222.01	163.08	188061
222.51	158.73	183780
223.01	160.78	186829
223.51	167.31	185445
224.01	160.04	181597
224.51	154.22	179787
225.01	152.87	177243
225.51	163.79	186478
226.01	159.82	182491
226.51	169.10	190870
227.01	166.42	186909
227.51	169.19	189283
228.01	167.97	188685
228.51	162.80	183799

Table 6.2.1.5-1 (Sheet 11 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
229.01	163.17	183882
229.51	166.72	185166
230.01	163.60	183083
230.51	166.08	185501
231.01	185.01	198040
231.51	171.17	190371
232.01	170.02	189413
232.51	167.32	187192
233.01	165.87	187133
233.51	162.23	184680
234.01	162.12	184239
234.51	163.65	185256
235.01	170.11	190998
235.51	172.03	191517
236.01	176.57	195559
236.51	177.90	195105
237.01	179.11	196781
237.51	177.36	194796
238.01	184.55	203196
238.51	175.43	193499
239.01	180.92	198347
239.51	186.38	201952
240.01	187.65	204156
240.51	206.22	215759
241.01	189.12	203103
241.51	193.57	210875
242.01	193.46	207113
242.51	198.81	213650
243.01	201.22	217114
243.51	197.74	212561
244.01	206.62	221578
244.51	203.31	217715
245.01	208.59	223702
245.51	203.91	219671
246.01	208.89	222208
246.51	212.31	225805
247.01	212.32	225398
247.51	214.35	227594
248.01	214.15	226651
248.51	217.36	228825
249.01	222.31	234267
249.51	217.86	229171
250.01	223.83	235041
250.51	220.16	231207
251.01	240.82	243903
251.51	253.81	247226

Table 6.2.1.5-1 (Sheet 12 of 12)
Minimum Containment Pressure Mass and Energy Releases for Large Break LOCA

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
252.01	436.89	265598
252.51	276.84	260077
253.01	829.62	316490
253.51	314.26	270224
254.01	236.27	246359
254.51	314.74	268735
255.01	272.12	261657
255.51	252.32	253658
256.01	277.28	262941
256.51	342.11	256883
257.01	755.60	308477
257.51	411.16	280874
258.01	646.77	293049
258.51	592.41	299836
259.01	276.26	264083
259.51	697.14	280918
260.01	1081.61	351122
260.51	708.00	303184
261.01	917.67	334397
261.51	542.69	321954
262.01	249.78	263198
262.51	347.78	287660
263.01	560.89	302627
263.51	682.74	309234
264.01	837.97	332817

Table 6.2.2-1
Passive Containment Cooling System Performance Parameters

PCCWST[1] useable capacity for PCS (gal) - Minimum	756,700
PCCWST useable capacity for FPS[2] (gal) - Minimum	18,000
Flow duration from PCCWST (days) - Minimum	3
PCCWST minimum temperature (°F)	40
PCCWST maximum temperature (°F)	120
Upper annulus drain rate (per drain) - Minimum	525 gpm
PCCAWST[4] long-term makeup rate to containment - Minimum[7]	100 gpm
PCCAWST long-term makeup to spent fuel pool – Minimum[7]	35 gpm
PCCAWST long-term makeup duration - Minimum	4 days
PCCWST long-term makeup to spent fuel pool – Minimum	118 gpm

PCCWST Water Elevation (Note 3) (feet)	Nominal Flow (Note 5) (gpm)	Minimum Flow (Note 6) (gpm)	Safety Analysis Flow (gpm)	Wetted Coverage (Note 3) (% of circumference)
At initiating height	489	484	N/A	N/A
27.5	484	N/A	469.1	90
24.1	242	241	226.6	90
20.3	186	187	176.3	72.9
16.8	153	154	144.2	59.6
At 72 hours	105	102	100.7 @ 72 hours	41.7

Notes:

1. PCCWST = passive containment cooling water storage tank
2. FPS = fire protection system
3. PCCWST Water Elevation corresponds to the nominal standpipe elevations in feet above the tank floor (Reference Plant Elevation 293′-9″, see Figure 3.8.4-2). Wetted coverage is measured as the linear percentage of the containment shell circumference wetted measured at any elevation between elevation 266 ft. and the upper spring line for the safety analysis flow rate conditions.
4. PCCAWST = passive containment cooling ancillary water storage tank
5. The nominal flow is based on a nominal PCCWST water elevation between the overflow and the minimum useable level.
6. The minimum flow is based on initiating the system at the PCCWST minimum useable capacity.
7. These flow rates apply when the plant is not refueling. The minimum makeup flow rates are adjusted following a design basis loss of normal spent fuel pool cooling that occurs during a refueling because more decay heat is located in the spent fuel pool and less decay heat is located in the reactor. See Subsections 6.2.2.4.2 and 9.1.3 for additional details.

Table 6.2.2-2
Component Data
Passive Containment Cooling System
(Nominal)

Passive Containment Cooling Water Storage Tank	
Volume (gal) - Minimum	756,700
Design temperature (°F)	125
Design pressure (psig)	Atmospheric
Material	Concrete with stainless steel liner
Standpipe Elevations Above Bottom of Tank Floor (Plant Elevation 293′-9″)	
Overflow (ft) – Nominal	28.5
Top standpipe (ft) - Nominal	24.1
Second standpipe (ft) - Nominal	20.3
Third standpipe (ft) - Nominal	16.8
Bottom standpipe (ft)	0.5
Passive Containment Ancillary Cooling Water Storage Tank	
Volume (gal) - Nominal	885,000
Design temperature (°F)	125
Design pressure (psig)	Atmospheric
Material	Carbon steel
Water Distribution Bucket	
Volume (gal) - Nominal	42
Design temperature (°F)	300
Design pressure (psig)	Atmospheric
Material	Stainless steel
Water Distribution Collection Troughs and Weirs	
Design temperature (°F)	N/A
Design pressure (psig)	Atmospheric
Material	Stainless steel
Passive Containment Cooling Recirculation Pump	
Quantity	2
Type	Centrifugal
Design capacity (gpm)	135
Design total differential head (ft) at 135 gpm	308 to 341

Table 6.2.2-3
Failure Mode and Effects Analysis -
Passive Containment Cooling System Components

Component	Failure Mode	PCS Operation Phase	Effect on System Operation	Failure Detection Method	Remarks
Air-operated butterfly valve PCS-PL-V001A (PCS-PL-V001B and motor-operated valve PCS-PL-V001C analogous)	Failure to open on demand	Passive containment cooling water delivery to containment	Failure blocks flow of containment cooling water through one path of PCS which reduces system redundancy. No safety effect on system operation. Minimum containment cooling requirements will be met by the flow of cooling water through operation of one of three flowpaths.	Valve position indication (closed to open position change) in main control room and at the remote shutdown workstation	Valve is normally closed during power operations. Valve opens on actuation by a High-2 containment pressure signal or loss of air or loss of 1E power.
Motor-operated gate valve PCS-PL-V002A (PCS-PL-V002B and PCS-PL-V002C analogous)	Spurious valve closure	Passive containment cooling water delivery to containment	Spurious closure blocks flow of containment cooling water through associated flowpath of PCS which reduces system redundancy. No safety effect on system operation. Minimum containment cooling requirements will be met by the flow of cooling water through operation of one of three flowpaths.	Valve position indication (open to closed position change) in main control room and at the remote shutdown workstation	Valve is normally open during power operations. Valve receives confirmatory open signal on High-2.
Air-operated butterfly valve PCS-PL-V001A (PCS-PL-V001B and motor-operated valve PCS-PL-V001C analogous)	Spurious valve opening	Normal idle condition	Failure initiates flow of containment cooling water through associated flow path of PCS when not required. No safety effect on system operation. Flow will be terminated through operator action by closing the series isolation valves via the main control room.	Valve position indication (closed to open) in main control room or at the remote shutdown workstation. Also by PCS flow indication and decreasing PCCWST level.	Valve is normally closed during power operations to isolate PCS water.

Table 6.2.3-1 (Sheet 1 of 4)
Containment Mechanical Penetrations and Isolation Valves

	Containment Penetration			Isolation Device						Test		
System	Line	Flow	Closed Sys IRC	Valve/Hatch Identification	Pipe Length	DCD Subsection	Position N-S-A	Signal	Closure Times	Type[1, 14] & Note	Medium	Direction
CAS	Service air in	In	No	CAS-PL-V204 CAS-PL-V205	11 -	9.3.1	C-O-C C-O-C	None None	N/A N/A	C	Air or N2	Forward
	Instrument air in	In	No	CAS-PL-V014 CAS-PL-V015	8 -	9.3.1	O-O-C O-O-C	T None	std. N/A	C	Air or N2	Forward
CCS	IRC loads in	In	No	CCS-PL-V200 CCS-PL-V201	9 -	9.2.2	O-O-C O-O-C	S, HRCP2 None	std. N/A	C	Air or N2	Forward
	IRC loads out	Out	No	CCS-PL-V208 CCS-PL-V207 CCS-PL-V220	8 - -	9.2.2	O-O-C O-O-C C-C-C	S, HRCP2 S, HRCP2 None	std. std. N/A	C	Air or N2	Forward Forward Reverse
CVS	Spent resin flush out	Out	No	CVS-PL-V041 CVS-PL-V040 CVS-PL-V042	19 - -	9.3.6	C-C-C C-C-C C-C-C	None None None	N/A N/A N/A	C	Air or N2	Forward Forward Reverse
	Letdown	Out	No	CVS-PL-V047 CVS-PL-V045 CVS-PL-V058	38 - -	9.3.6	C-O-C C-O-C C-C-C	T, DAS T, DAS None	std. std. N/A	C C, 13 C	Air or N2	Forward Forward Reverse
	Makeup	In	No	CVS-PL-V090 CVS-PL-V091 CVS-PL-V100	31 - -	9.3.6	O-O-C O-O-C C-C-C	HR2, PL2, S+PL1, SGL3, R+SGL HR2, PL2, S+PL1, SGL3, R+SGL None	30 sec. 30 sec. N/A	C	Air or N2	Forward
	Zinc injection to RCS	In	No	CVS-PL-V092 CVS-PL-V094 CVS-PL-V098	22 -	9.3.6	O-C-C O-C-C C-C-C	T, LPL1 T, LPL1 None	std. std. N/A	C	Air or N2	Forward Forward Reverse
	Hydrogen Injection to RCS	In	No	CVS-PL-V219 CVS-PL-V217	38	9.3.6	O-C-C O-C-C	T, LPL1 None	std. N/A	C	Air or N2	Forward
DWS	Demin. water supply	In	No	DWS-PL-V244 DWS-PL-V245	29 -	9.2.4	C-O-C C-O-C	None None	N/A N/A	C	Air or N2	Forward
FHS	Fuel transfer	N/A	No	FHS-FT-01	-	6.2.5	C-O-C	None	N/A	B	Air or N2	Forward
FPS	Fire protection standpipe sys.	In	No	FPS-PL-V050 FPS-PL-V052	58 -	9.5.1	C-C-C C-C-C	None None	N/A N/A	C	Air or N2	Forward
PSS	RCS/PXS/CVS samples out	Out	No	PSS-PL-V010A PSS-PL-V010B PSS-PL-V011A PSS-PL-V011B	- - 19 15	9.3.3	O-C-C C-C-C O-C-C C-C-C	T T T T	std. std. std. std.	C	Air or N2	Forward
	Cont. air samples out	Out	No	PSS-PL-V046 PSS-PL-V008	13 -	9.3.3	O-C-C O-C-C	T T	std. std.	C	Air or N2	Forward
	RCS/Cont. air sample return	In	No	PSS-PL-V023 PSS-PL-V024	16 -	9.3.3	O-C-C O-C-C	T T	std. std.	C	Air or N2	Forward

Table 6.2.3-1 (Sheet 2 of 4)
Containment Mechanical Penetrations and Isolation Valves

	Containment Penetration			Isolation Device						Test		
System	Line	Flow	Closed Sys IRC	Valve/Hatch Identification	Pipe Length	DCD Subsection	Position N-S-A	Signal	Closure Times	Type[1, 14] & Note	Medium	Direction
PXS	N_2 to accumulators	In	No	PXS-PL-V042 PXS-PL-V043	9 -	6.3	O-O-C C-C-C	T None	std. N/A	C	Air or N2	Forward
RNS	RCS to RHR pump	Out	No	RNS-PL-V002A RNS-PL-V002B RNS-PL-V023 RNS-PL-V022 RNS-PL-V020 RNS-PL-V021 RNS-PL-V061 PXS-PL-V208A	- - - 46 - - - -	5.4.7 5.4.7 5.4.7 5.4.7 5.4.7 5.4.7 5.4.7 6.3	C-O-C C-O-C C-O-C C-O-C C-C-C C-C-C C-O-C C-C-C	HR2, S, ADS4 HR2, S, ADS4 HR2, S, ADS4 HR2, S, ADS4 None None T None	std. std. (see Note 12) std. std. N/A N/A std. N/A	C C C C,4 C C C C	Air or N2	Forward Forward Forward Forward Reverse Reverse Forward Forward
	RHR pump to RCS	In	No	RNS-PL-V011 RNS-PL-V012 RNS-PL-V013	26 -	5.4.7	C-O-C C-C-C (11) C-O-C	HR2, S, ADS4 None None	std. N/A N/A	C,4 C,4 C,4	Air or N2	Forward
SFS	IRWST/Ref. cav. SFP pump discharge	In	No	SFS-PL-V038 SFS-PL-V037	20 -	9.1.3	C-O-C C-O-C	T None	std. N/A	C	Air or N2	Forward
	IRWST/Ref. cav. purif. out	Out	No	SFS-PL-V035 SFS-PL-V034 SFS-PL-V067	30 - -	9.1.3	C-O-C C-O-C C-C-C	T T None	std. std. N/A	C	Air or N2	Forward Forward Reverse
SGS	Main steam line 01	Out	Yes	SGS-PL-V040A SGS-PL-V027A(7) SGS-PL-V030A,31A,32A, 33A,34A,35A SGS-PL-V036A SGS-PL-V240A	29 26 13, 16, 20, 23, 26, 29 40 47	10.3	O-C-C O-O-C C-C-C O-O-C C-C-C	MS LSL2 None MS MS	5 sec std. N/A std. std.	A,2	N2	Forward
	Main steam line 02	Out	Yes	SGS-PL-V040B SGS-PL-V027B(7) SGS-PL-V030B,31B,32B, 33B,34B,35B SGS-PL-V036B SGS-PL-V240B	29 26 13, 16, 20, 23, 26, 29 40 47	10.3	O-C-C O-O-C C-C-C O-O-C C-C-C	MS LSL2 None MS MS	5 sec std. N/A std. std.	A,2	N2	Forward
	Main feedwater 01	In	Yes	SGS-PL-V057A SGS-PL-V101A SGS-PL-V103A	28 - -	10.3	O-C-C C-C-C C-C-C	MF None None	5 sec N/A N/A	A,2	H2O	Forward
	Main feedwater 02	In	Yes	SGS-PL-V057B SGS-PL-V101B SGS-PL-V103B	28 - -	10.3	O-C-C C-C-C C-C-C	MF None None	5 sec N/A N/A	A,2	H2O	Forward
	SG blowdown 01	Out	Yes	SGS-PL-V074A	13	10.3	O-O-C	PRHR, T, LSGL	std.	A,2	H2O	Forward
	SG blowdown 02	Out	Yes	SGS-PL-V074B	19	10.3	O-O-C	PRHR, T, LSGL	std.	A,2	H2O	Forward
	Startup feedwater 01	In	Yes	SGS-PL-V067A	29	10.3	O-O-C	LTC2, SGL3, R+SGL	std.	A,2	H2O	Forward
	Startup feedwater 02	In	Yes	SGS-PL-V067B	27	10.3	O-O-C	LTC2, SGL3, R+SGL	std.	A,2	H2O	Forward

Table 6.2.3-1 (Sheet 3 of 4)
Containment Mechanical Penetrations and Isolation Valves

System	Containment Penetration			Isolation Device						Test		
	Line	Flow	Closed Sys IRC	Valve/Hatch Identification	Pipe Length	DCD Subsection	Position N-S-A	Signal	Closure Times	Type[1, 14] & Note	Medium	Direction
VFS	Cont. air filter supply	In	No	VFS-PL-V003 VFS-PL-V004	33 -	9.4.7	C-O-C C-O-C	T,HR1,DAS T,HR1,DAS	10 sec 10 sec	C	Air or N2	Forward Forward
	Cont. air filter exhaust	Out	No	VFS-PL-V010 VFS-PL-V009 VFS-PL-V008 VFS-PL-V800A VFS-PL-V800B VFS-PL-V803A VFS-PL-V803B	85 - - 99 102 - -	9.4.7	C-O-C C-O-C C-C-C C-C-C C-C-C C-C-C C-C-C	T,HR1,DAS T,HR1,DAS N/A T, HR1 (Note 8) T, HR1 (Note 8) None None	10 sec 10 sec N/A 30 sec 30 sec N/A N/A	C C N/A C C C C	Air or N2	Forward
VWS	Fan Coolers out	Out	No	VWS-PL-V086 VWS-PL-V082 VWS-PL-V080	9 - -	9.2.7	O-O-C O-O-C C-C-C	T T None	std. std. N/A	C,3,4	Air or N2	Forward Forward Reverse
	Fan coolers in	In	No	VWS-PL-V058 VWS-PL-V062	8 -	9.2.7	O-O-C O-O-C	T N/A	std. N/A	C,3,4	Air or N2	Forward
WLS	Reactor coolant drain tank gas	Out	No	WLS-PL-V068 WLS-PL-V067	49 -	11.2	C-C-C C-C-C	T T	std. std.	C	Air or N2	Forward
	Normal cont. sump	Out	No	WLS-PL-V057 WLS-PL-V055 WLS-PL-V058	39 - -	11.2	C-C-C C-C-C C-C-C	T,DAS T,DAS None	std. std. N/A	C, 13 C, 13 C	Air or N2	Forward Forward Reverse
SPARE		N/A	No	P40	-	6.2.5	C-C-C	N/A	N/A	B	Air or N2	Forward
SPARE		N/A	No	P41	-	6.2.5	C-C-C	N/A	N/A	B	Air or N2	Forward
SPARE		N/A	No	P42	-	6.2.5	C-C-C	N/A	N/A	B	Air or N2	Forward
CNS	Main equipment hatch	N/A	No	CNS-MY-Y01	-	6.2.5	C-C-C	None	N/A	B	Air or N2	Forward
	Maintenance hatch	N/A	No	CNS-MY-Y02	-	6.2.5	C-C-C	None	N/A	B	Air or N2	Forward
	Upper Personnel Hatch	N/A	No	CNS-MY-Y03	-	6.2.5	C-C-C	None	N/A	B	Air or N2	Forward
	Lower Personnel Hatch	N/A	No	CNS-MY-Y04	-	6.2.5	C-C-C	None	N/A	B	Air or N2	Forward
PCS	Containment pressure instrumentation lines (four)	N/A	Yes	P46, P47, P48, P49	-	6.2.3.1	N/A	N/A	N/A	A,10	Capillary Fluid	Forward

Table 6.2.3-1 (Sheet 4 of 4)
Containment Mechanical Penetrations and Isolation Valves

Explanation of Heading and Acronyms for Table 6.2.3-1

System:	Fluid system penetrating containment
Containment Penetration:	These fields refer to the penetration itself
Line:	Fluid system line
Flow:	Direction of flow in or out of containment
Closed Sys IRC:	Closed system inside containment as defined in Subsection 6.2.3.1.1
Isolation Device:	These fields refer to the isolation devices for a given penetration
Valve/Hatch ID:	Identification number on P&ID or system figure
Pipe Length:	Nominal length of pipe to outboard containment isolation valve, feet
Subsection Containing Figure:	Safety analysis report containing the system P&ID or figure
Position N-S-A:	Device position for N (normal operation)
	S (shutdown)
	A (post-accident)
Signal:	Device closure signal
	MS: Main steam line isolation
	ADS4: ADS Stage 4 Actuation
	LSL2: Low-2 steam line pressure
	MF: Main feedwater isolation
	LTC2: Low-2 T_{cold}
	PRHR: Passive residual heat removal actuation
	T: Containment isolation
	S: Safeguards actuation signal
	R: Reactor Trip signal
	HR1: High-1 containment radiation
	HR2: High-2 containment radiation
	DAS: Diverse actuation system signal
	PL2: High 2 pressurizer level signal
	S+PL1: Safeguards actuation signal plus high 1 pressurizer level
	R+SGL: Reactor trip plus High steam generator level
	SGL3: High-3 steam generator level
	HRCP2: High-2 reactor coolant pump bearing water temperature trip
	LSGL: Low steam generator level
	LPL1: Low-1 Pressurizer Water Level
Closure Time:	
	Required valve closure stroke time
	std: Industry standard for valve type (≤ 60 seconds)
	N/A: Not Applicable
Test:	These fields refer to the penetration testing requirements
Type:	Required test type
	A: Integrated Leak Rate Test
	B: Local Leak Rate Test -- penetration
	C: Local Leak Rate Test -- fluid systems
Note:	See notes below
Medium:	Test fluid on valve seat
Direction:	Pressurization direction
	Forward: High pressure on containment side
	Reverse: High pressure on outboard side

Notes:

1. Containment leak rate tests are designated Type A, B, or C according to 10CFR50, Appendix J.
2. The secondary side of the steam generator, including main steam, feedwater, startup feedwater, blowdown and sampling piping from the steam generators to the containment penetration, is considered an extension of the containment. These systems are not part of the reactor coolant pressure boundary and do not open directly to the containment atmosphere during post-accident conditions. During Type A tests, the secondary side of the steam generators is vented to the atmosphere outside containment to ensure that full test differential pressure is applied to this boundary.
3. The central chilled water system remains water-filled and operational during the Type A test in order to maintain stable containment atmospheric conditions.
4. The containment isolation valves for this penetration are open during the Type A test to facilitate testing. Their leak rates are measured separately.
5. Not used.
6. Deleted.
7. Refer to Table 15.0-4b for PORV block valve closure time.
8. These valves also receive a signal to open on Low-2 containment pressure.
9. Not used.
10. The containment pressure instrumentation lines are sealed, fluid-filled, and closed inside and outside the containment, without containment isolation valves. They are not vented or drained during Type A testing.
11. Valve is opened and administratively controlled for post-72-hour accident actions to permit long-term containment makeup.
12. A 60-second time delay is imposed on the actuation signal for RNS-PL-V002B. This is not a radiological concern since the valve is normally closed with power removed in normal plant operation, only in service during shutdown conditions, and is flooded during post-accident operation. Once the time delay expires, the stroke time of the valve from receipt of the actuation signal is <60 seconds.
13. A closure time of less than or equal to 150 seconds is required when actuated from DAS.
14. Alternate Type tests can be conducted for repair / modification activities as applicable in accordance with regulatory guidance.

Table 6.2.4-1
Component Data - Hydrogen Monitors
(Nominal)

Number	3
Range (% hydrogen)	0 - 20
Response time	90% in 180 seconds

Table 6.2.4-2
Component Data - Hydrogen Recombiner
(Nominal)

Number Full Size PAR	2
Average efficiency (percent)	85
Depletion rate	Reference 19

Table 6.2.4-3
Component Data - Hydrogen Igniter
(Nominal)

Number	66
Surface Temperature (°F)	≥1700

Tables 6.2.4-4–6.2.4-5 Not Used

Table 6.2.4-6 (Sheet 1 of 3)
Igniter Location

Criteria

- A sufficient number of igniters are placed in the major transport paths (including dominant natural circulation pathways) of hydrogen so that hydrogen can be burned continuously close to the release point. This prevents hydrogen from preferentially accumulating in a certain region of the containment.
- Igniters (minimum of 2) are located in major regions or compartments where hydrogen may be released, through which it may flow, or where it may accumulate.
- It is preferable to ignite a hydrogen-air mixture at the bottom so that upward flame propagation can be promoted at lean hydrogen concentrations. Igniters within each subcompartment are located in the vicinity of, and above, the highest potential release location within the subcompartment.
- In compartments with relatively small openings in the ceiling, the potential may exist for the hydrogen-air mixture to rise and to collect near the ceiling. Therefore, one or more igniters are placed near the ceiling of such compartments. Igniter coverage is provided within the upper 10 percent of the vertical height subcompartments or 10 feet from the ceiling whichever is less. In cases where the highest potential release point is low in the compartment, both this and the previous criteria are considered.
- To the extent possible, igniters are placed away from walls and other large surfaces so that a flame front created by ignition at the bottom of a compartment can travel unimpeded up to the top.
- A sufficient number of igniters are installed in long, narrow compartments (corridors) so that the flame fronts created by the igniters need to travel only a limited distance before they merge. This limits the potential for significant flame acceleration.
- Igniter coverage is provided to control combustion in areas where oxygen rich air may enter into an inerted region with combustible hydrogen levels during an accident scenario.
- Igniters are located above the flood level, if possible. Those which may be flooded have redundant fuses to protect the power supply.
- In locations where the potential hydrogen release location can be defined, i.e. above the IRWST spargers, at IRWST vents, etc igniter coverage is provided as close to the source as feasible.
- Provisions for installation, maintenance, and testing are to be considered.

Table 6.2.4-6 (Sheet 2 of 3)
Igniter Location

Implementation

Note: The igniter locations and power groups are delineated in Table 6.2.4-7. For each subcompartment/area, the igniters are split between the two power groups and provide backup control for each other.

- **Reactor Cavity –** Hydrogen releases within the reactor cavity will flow either through the vertical access tunnel, through the opening around the RCS hot and cold legs into the loop compartments or if the permanent cavity seal ring fails then potentially through the refueling cavity. The potential flow paths have igniters. No igniters have been located within the reactor cavity since this region would always be flooded, adequate igniter coverage is available in hydrogen pathways from the reactor cavity and any maintenance or inspection would result in elevated personnel exposure.
- **Loop Compartments –** Hydrogen releases from the hot or cold legs or from the reactor cavity would flow up through the loop compartment to the dome region. Igniter coverage provided within the loop compartment consists of igniters at different elevations covering the perimeter of the compartment. Additional igniter coverage is provided above each loop compartment.
- **Pressurizer Compartment –** Hydrogen releases within the pressurizer compartment would flow up through the compartment toward the dome region. Igniter coverage provided within the compartment consists of igniters at different elevations covering the perimeter of the compartment. Additional igniter coverage is provided above the pressurizer compartment.
- **Tunnel Connection Loop Compartments –** The tunnel between the loop compartments and extending downward into the reactor coolant drain tank cavity is provided with igniters for hydrogen control. Releases within the reactor cavity or from the loop compartment may flow through this vertical access tunnel. Igniter coverage is provided over the width of the tunnel at separate elevations.
- **Refueling Cavity –** Hydrogen releases from the reactor cavity or potentially from the reactor coolant loops may flow up past the permanent cavity seal ring and through the refueling cavity to the dome region. Igniter coverage provided within the refueling cavity consists of igniters at different elevations covering the perimeter of the compartment. Additional igniter coverage is provided above the refueling cavity.
- **Southeast Valve and Accumulator Rooms –** Hydrogen releases within the southeast valve or accumulator rooms will rise with the mass and energy releases to near the ceiling and exit either through the opening on the west wall or through piping penetration holes in the ceiling. The hydrogen control protection is provided by igniters, located near the ceiling of each of the adjoining rooms.

Table 6.2.4-6 (Sheet 3 of 3)
Igniter Location

- **East Valve, Northeast Accumulator, and Northeast Valve Room –** Hydrogen releases within the east valve, northeast accumulator or valve rooms will rise with the mass and energy releases to near the ceiling and exit either through the enlarged vent area surrounding the discharge piping from the core makeup tank and through other piping penetration holes in the ceiling. The hydrogen control protection is provided by igniters, located near the ceiling of each of the adjoining rooms.
- **North CVS Equipment Room –** Hydrogen releases within the CVS equipment room will rise from the piping or equipment located on the CVS module to near the ceiling, pass over the outer barrier wall and flow up through the stairwell or ceiling grating. Hydrogen control is provided by igniters located near the ceiling of the equipment room between the equipment module and the major relief paths from the compartment.
- **IRWST –** Hydrogen releases into the IRWST are controlled by the distribution of igniters internal to the IRWST and near the vents from and into the IRWST.
  - IRWST Sparger Side – Igniters are located within the IRWST just below the tank roof of the IRWST and near the spargers. In the event of hydrogen releases via the spargers, the igniters near the release points will provide the most immediate point of recombination.
  - IRWST Roof Vents – Should the environment within the IRWST be inerted or otherwise not be ignited by the assemblies near the sparger, the hydrogen will be ignited as it exhausts from the IRWST at any of the vents with igniter assemblies. The igniters are located in the upper compartment just above the vents.
  - IRWST Vacuum Breaker Vents – In the event that the IRWST is hydrogen rich and air is drawn into the IRWST the mixture will become flammable. In order to provide this recombination, the two inlet vents on the other side of the IRWST from the sparger side are fitted with an igniter.
  - IRWST Hooded Vents – Should the environment within the IRWST be inerted or otherwise not be ignited by the assemblies near the sparger side, the hydrogen will be ignited as it exhausts from the IRWST by the igniters at the vent hoods. The igniters are located in the upper compartment just outside the vent hoods.
- **Lower Compartment Area –** Hydrogen releases within the lower compartment will rise with the mass and energy releases to near the ceiling and exit either through the north stairwell or along the circumferential gap between the operating deck and the containment shell. The hydrogen control protection is provided by igniters spread over the potential release areas and located either near the mezzanine deck elevation or near the ceiling. This approach provides wide coverage over the entire compartment area at two separate elevations.
- **Upper Compartment –** Hydrogen control is provided at three separate regions within the upper compartment. At the lower region, igniters are distributed over the area primarily above the major release flow paths including the loop compartments, refueling cavity, pressurizer compartment and above the stairwell from the lower compartment area. An igniter is provided in each quadrant at the mid region of the upper compartment. At the upper region, igniters are located to initiate recombination of hydrogen not ignited at either the source or along its flow path.

Table 6.2.4-7
Subcompartment/Area Igniter Coverage

	Igniter Coverage (Elevation)[1]	
Subcompartment	**Power Group 1**	**Power Group 2**
Reactor Cavity	1 (El 89'-3") 3 (El 95') 13 (El 121'-6"), 5, 55 (El 120') 58 (El 132') 8, 12 (El 139')	4 (El 96'-6") 2 (El 99') 11, 7 (El 119'), 56 (El 120') 57 (El 132') 6, 14 (El 139')
Loop Compartment 01	13 (El 121'-6") 12 (El 139')	11 (El 120') 14 (El 139')
Loop Compartment 02	5 (El 120') 8 (El 139')	7 (El 119') 6 (El 139')
Pressurizer Compartment	49 (El 154'-3") 60 (El 135')	50 (El 154') 59 (El 135')
Tunnel connecting Loop Compartments	1 (El 89'-3") 3 (El 95') 31 (El 120')	4 (El 96'-6") 2 (El 99') 30 (El 132'-8")
Southeast Valve Room	21 (El 105'-2")	20 (El 105'-2")
Southeast Accumulator Room	21 (El 105'-2")	20 (El 105'-2")
East Valve Room	18 (El 105'-2")	19 (El 105'-2")
Northeast Accumulator Room	18 (El 105'-2")	17, 19 (El 105'-2")
Northeast Valve Room	18 (El 105'-2")	17 (El 105'-2")
North CVS Equipment Room	34 (El 105'-2")	33 (El 105'-2")
Lower Compartment Area (CMT and Valve area)	22 (El 134') 27 (El 117'-3") 28 (El 118'-11") 29, 31, 32 (El 120')	23, 24, 25 (El 134') 26 (El 119'-6") 30 (El 132'-8")
IRWST Hooded Vents	35, 37 (El 137'-6")	36, 38 (El 137'-6")
IRWST Sparger Side	9 (El 133'-3")	10 (El 133'-3")
IRWST Vacuum Breaker Vents	16 (El 132'-7")	15 (El 132'-7")
IRWST Roof Vents	65 (El 137')	66 (El 137')
Refueling Cavity	55 (El 120') 58 (El 132')	56 (El 120') 57 (El 132')
Upper Compartment		
Lower Region	39, 42, 44, 43 (El 167'-7"), 47 (El 166'-9")	40, 41, 45 (El 161'-11"), 46, 48 (El 166'-9")
Mid Region	51, 54 (El 218')	52, 53 (El 218')
Upper Region	61, 63 (El 258')	62, 64 (El 258')

Note:
1. Elevations are approximate (± 2.5 feet).

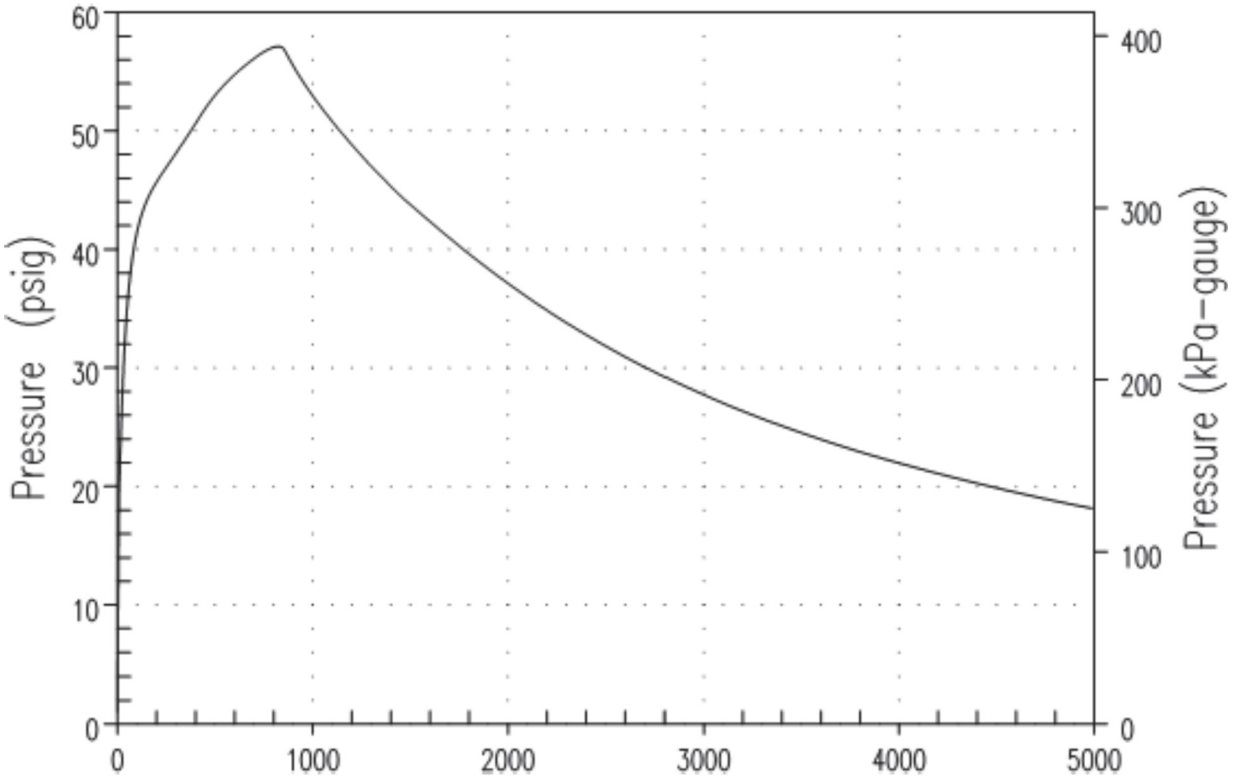


Figure 6.2.1.1-1
AP1000 Containment Pressure Response for Full DER MSLB – 30% Power

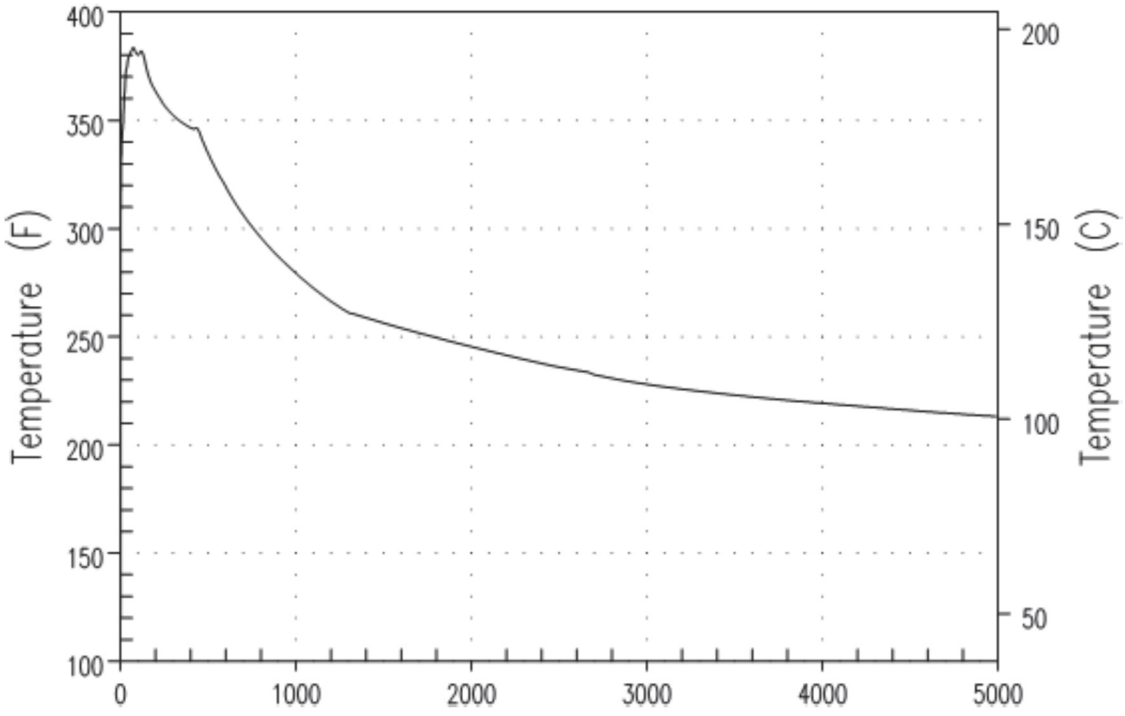


Figure 6.2.1.1-2
AP1000 Containment Temperature Response for Full DER MSLB – 101% Power

Figures 6.2.1.1-3–6.2.1.1-4 Not Used

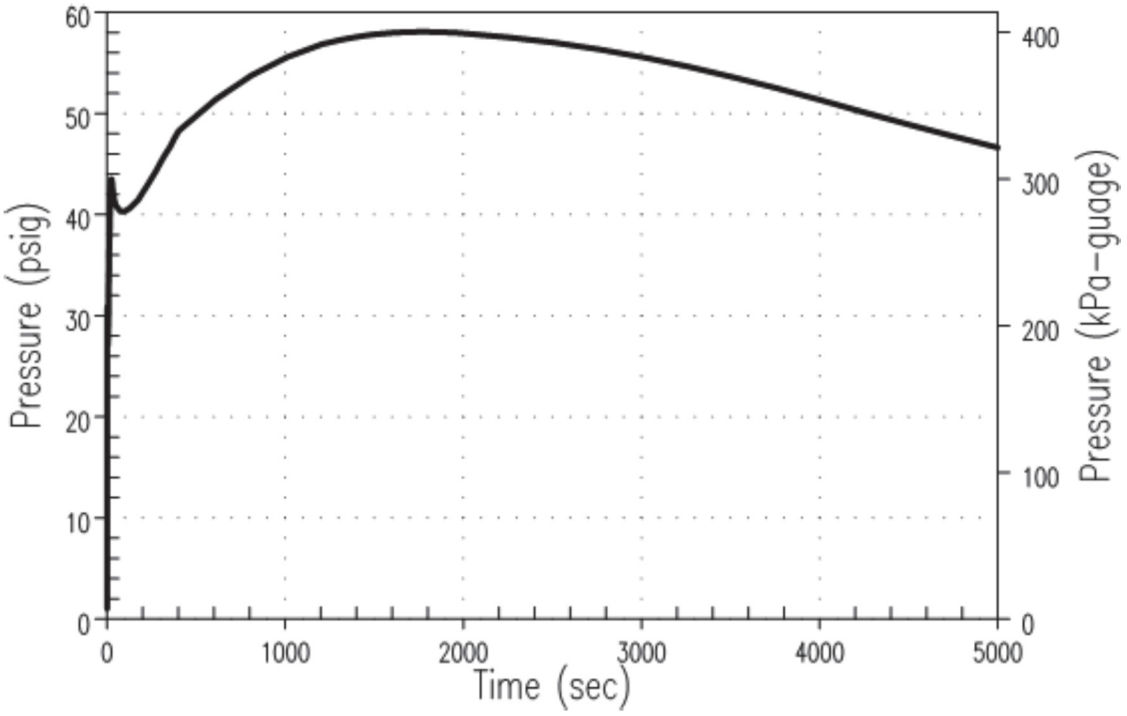


Figure 6.2.1.1-5
AP1000 Containment Pressure Response for DECLG LOCA – 5000 sec

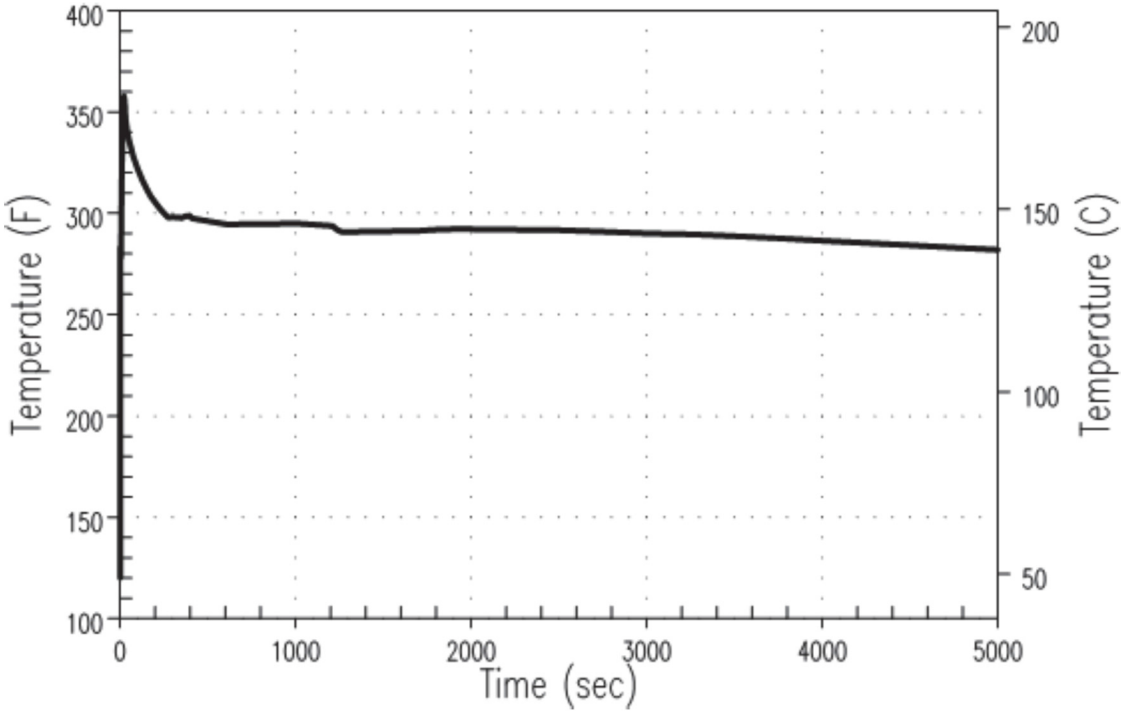


Figure 6.2.1.1-6
AP1000 Containment Temperature Response to DECLG LOCA – 5000 sec

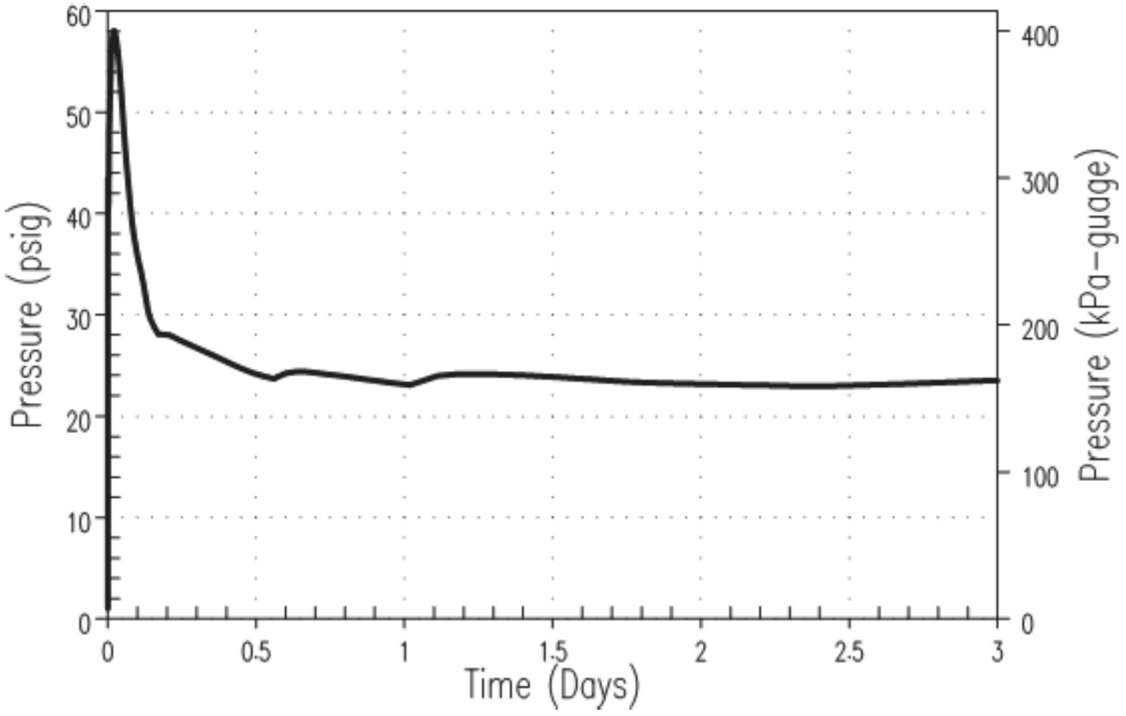


Figure 6.2.1.1-7
AP1000 Containment Pressure Response for DECLG LOCA – 3 Days

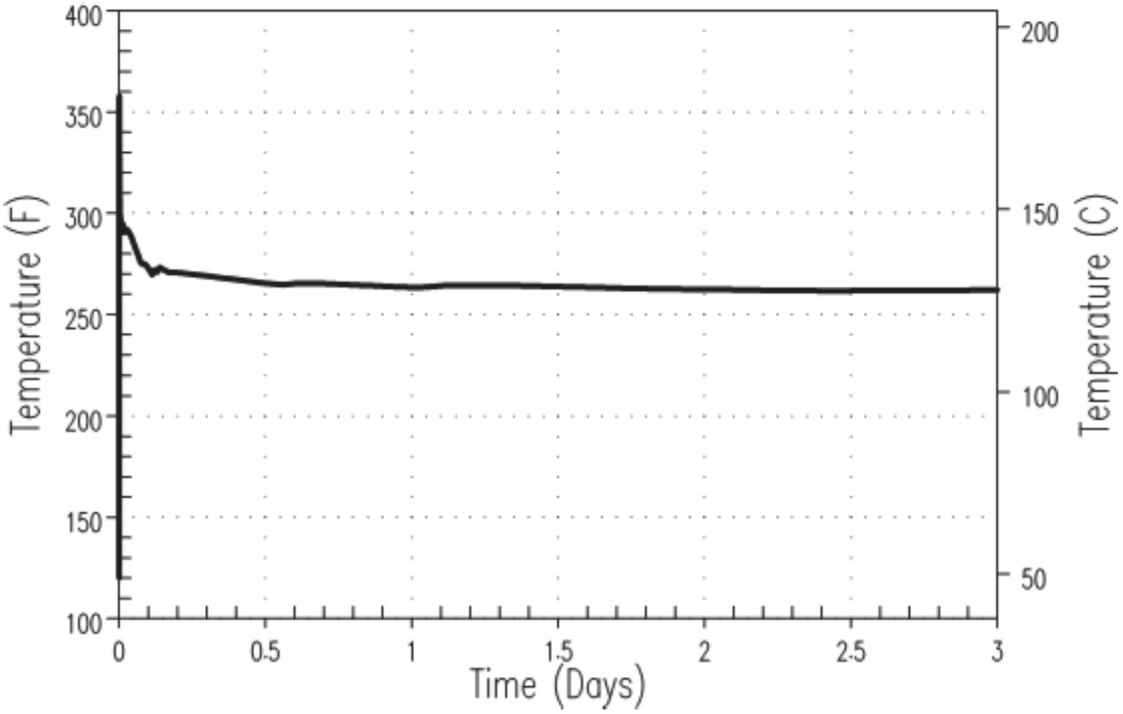


Figure 6.2.1.1-8
AP1000 Containment Temperature Response for DECLG LOCA – 3 Days

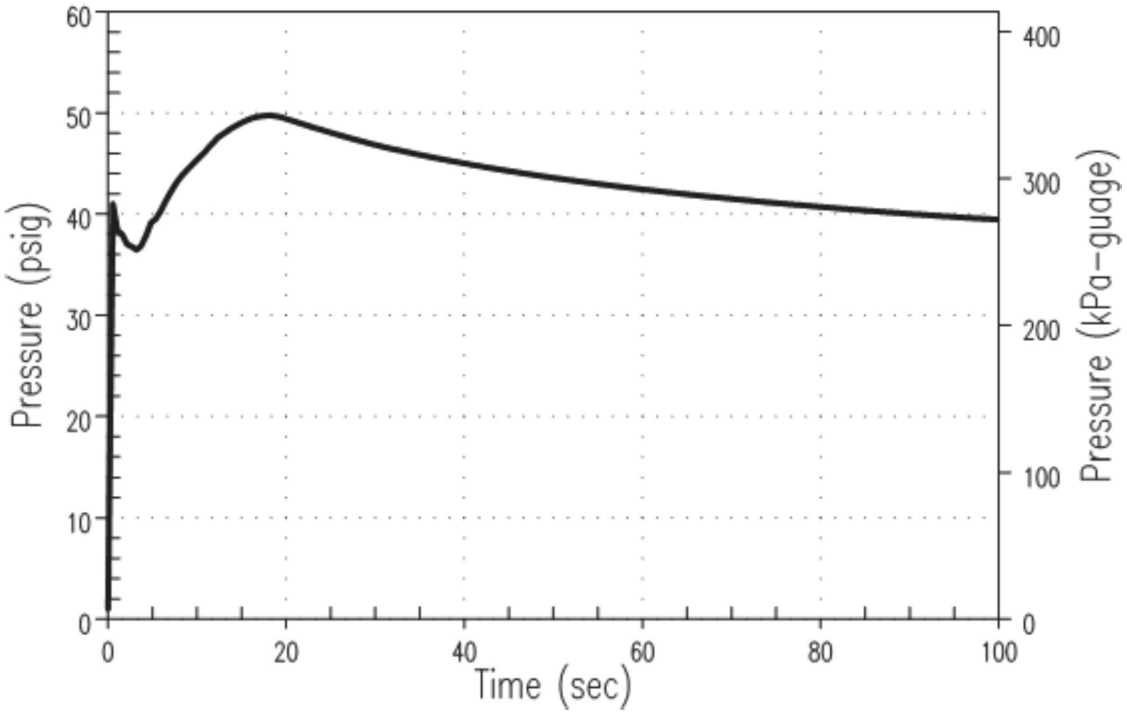


Figure 6.2.1.1-9
AP1000 Containment Pressure Response – DEHLG LOCA

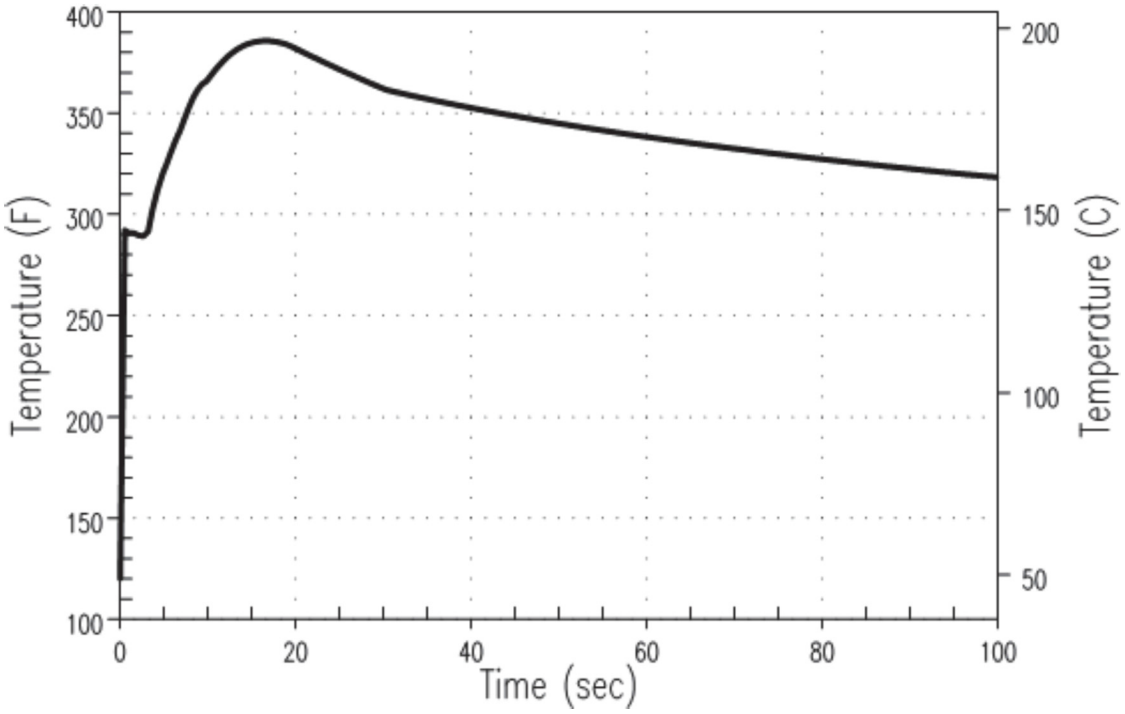


Figure 6.2.1.1-10
AP1000 Containment Temperature Response for DEHLG LOCA

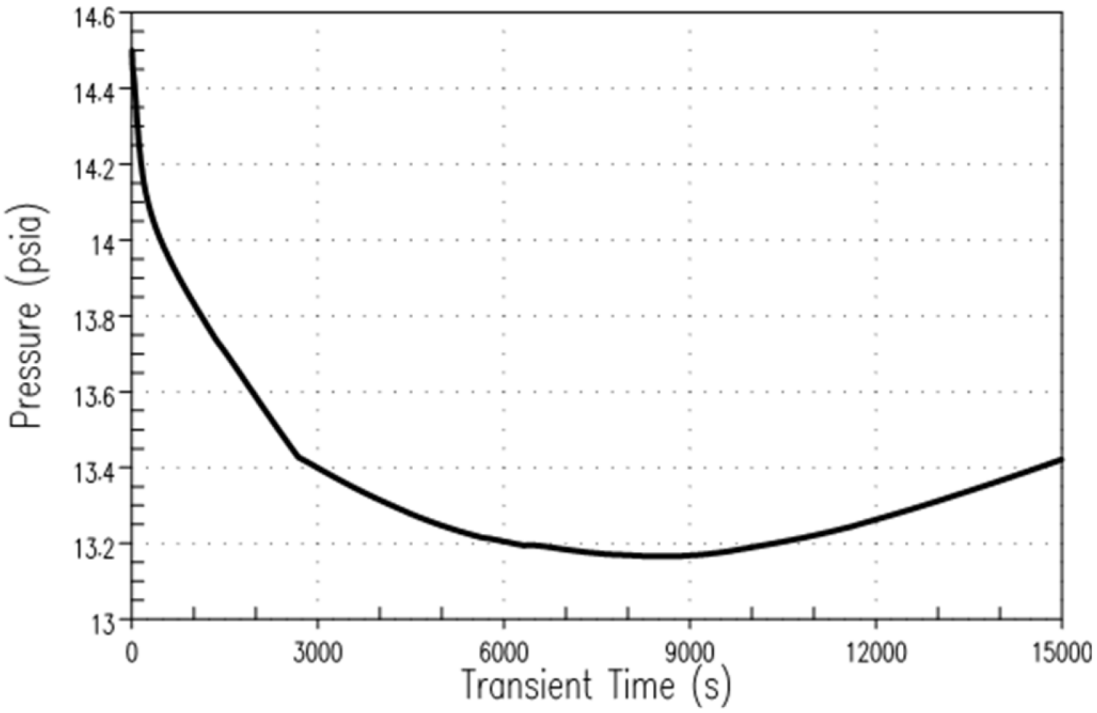


Figure 6.2.1.1-11
AP1000 Design External Pressure Analysis
Containment Pressure vs. Time

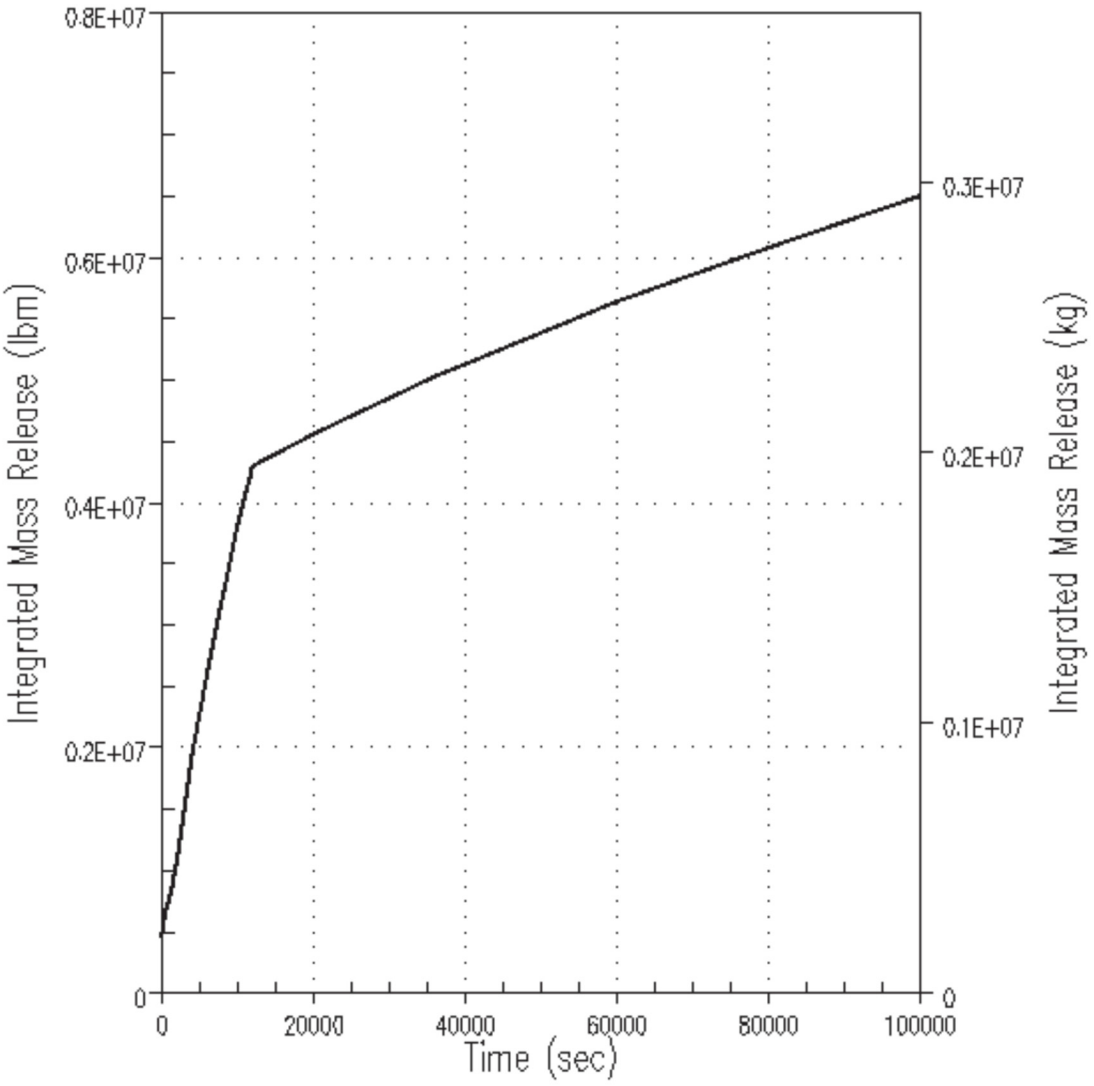


Figure 6.2.1.3-1
AP1000 DECLG Integrated Break Flow

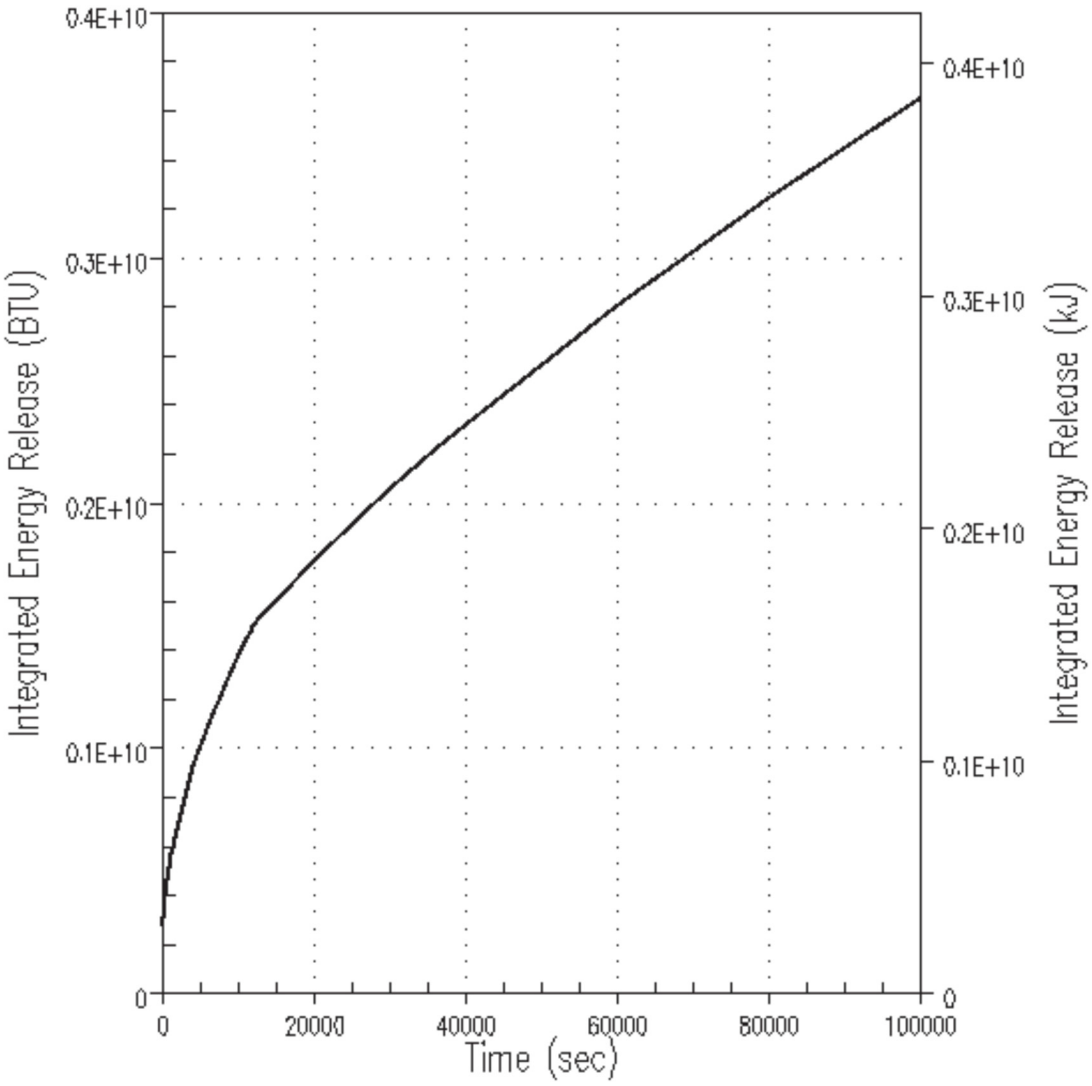


Figure 6.2.1.3-2
AP1000 DECLG LOCA Integrated Energy Released

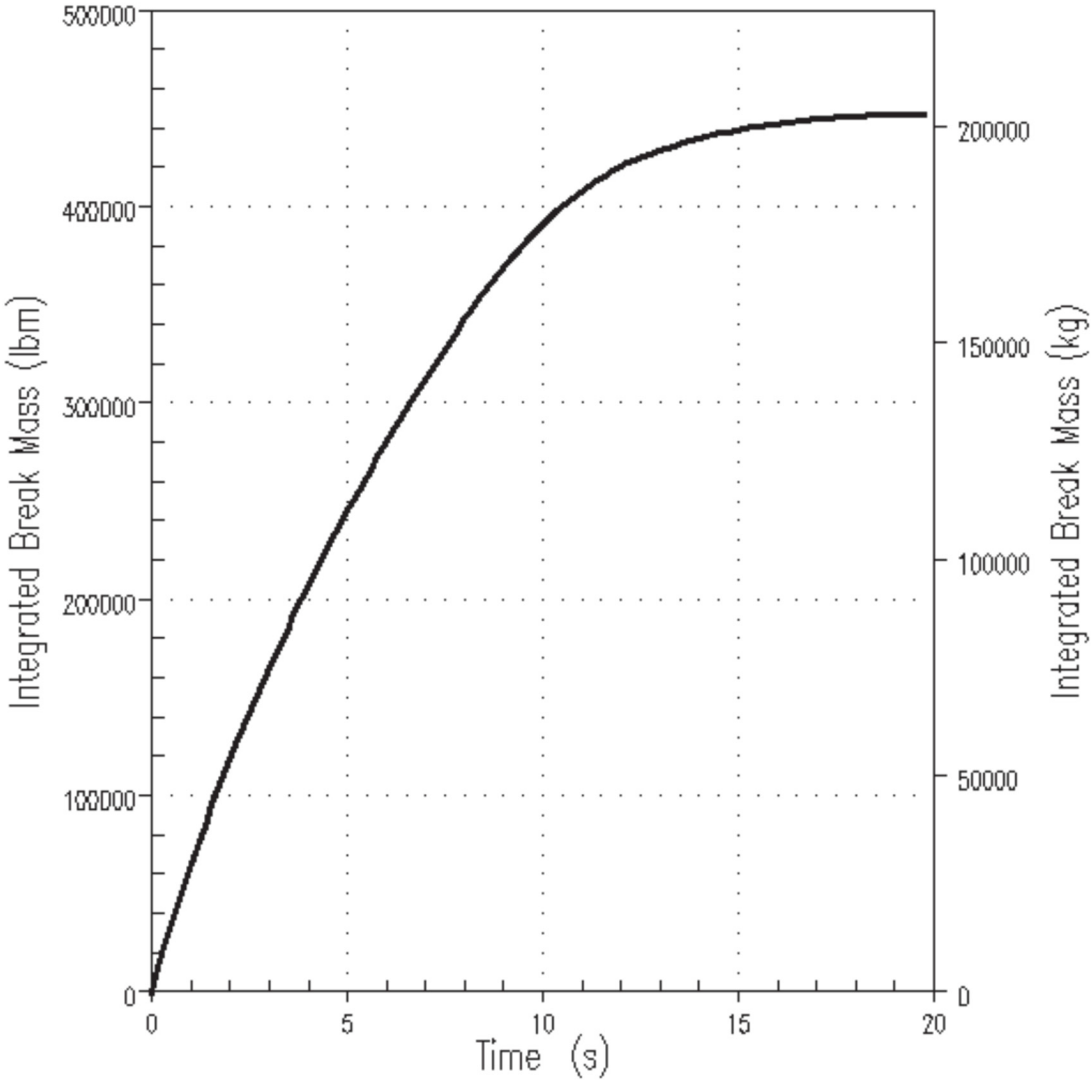


Figure 6.2.1.3-3
AP1000 DEHLG Integrated Break Flow

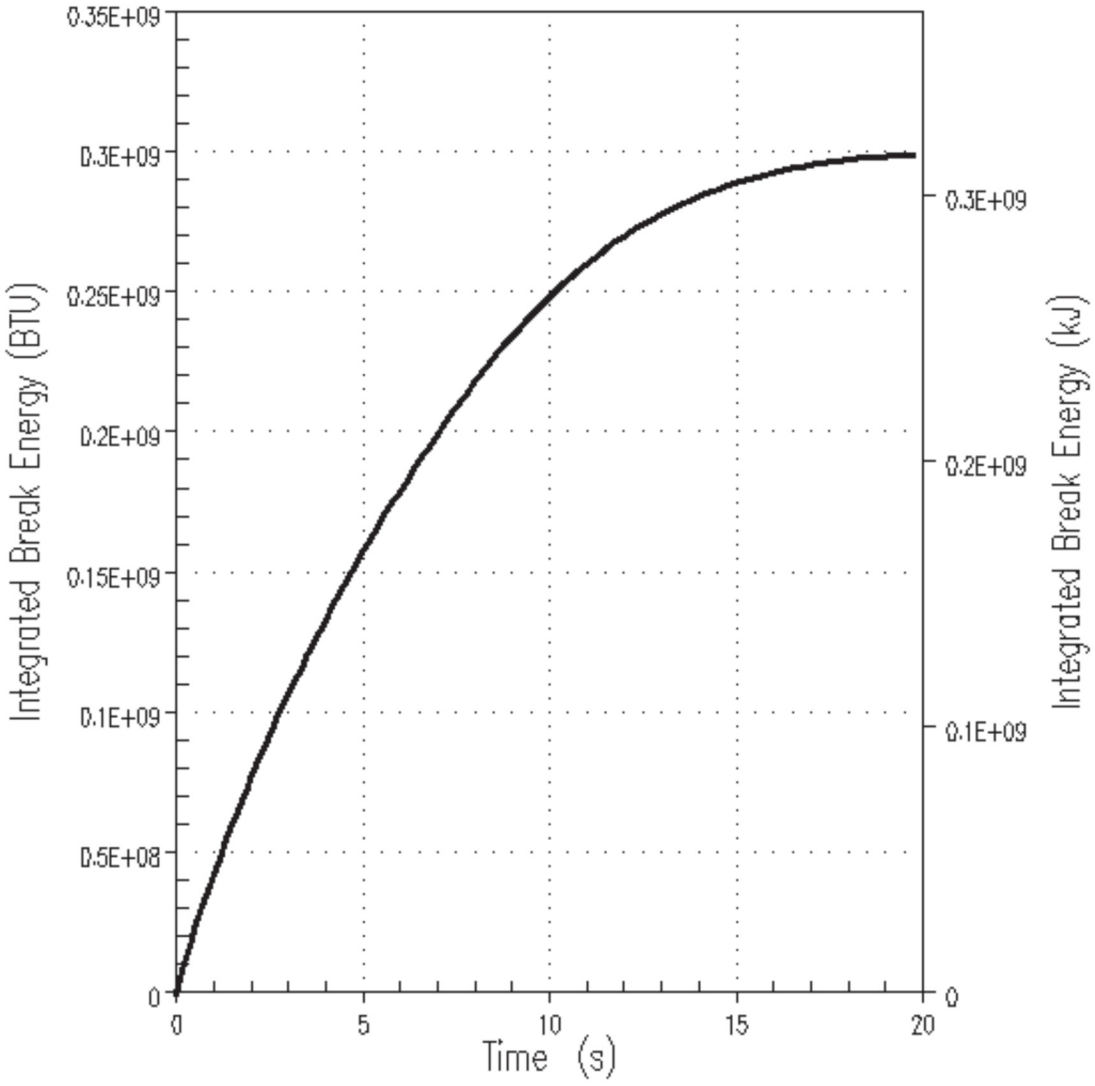


Figure 6.2.1.3-4
AP1000 DEHLG LOCA Integrated Energy Released

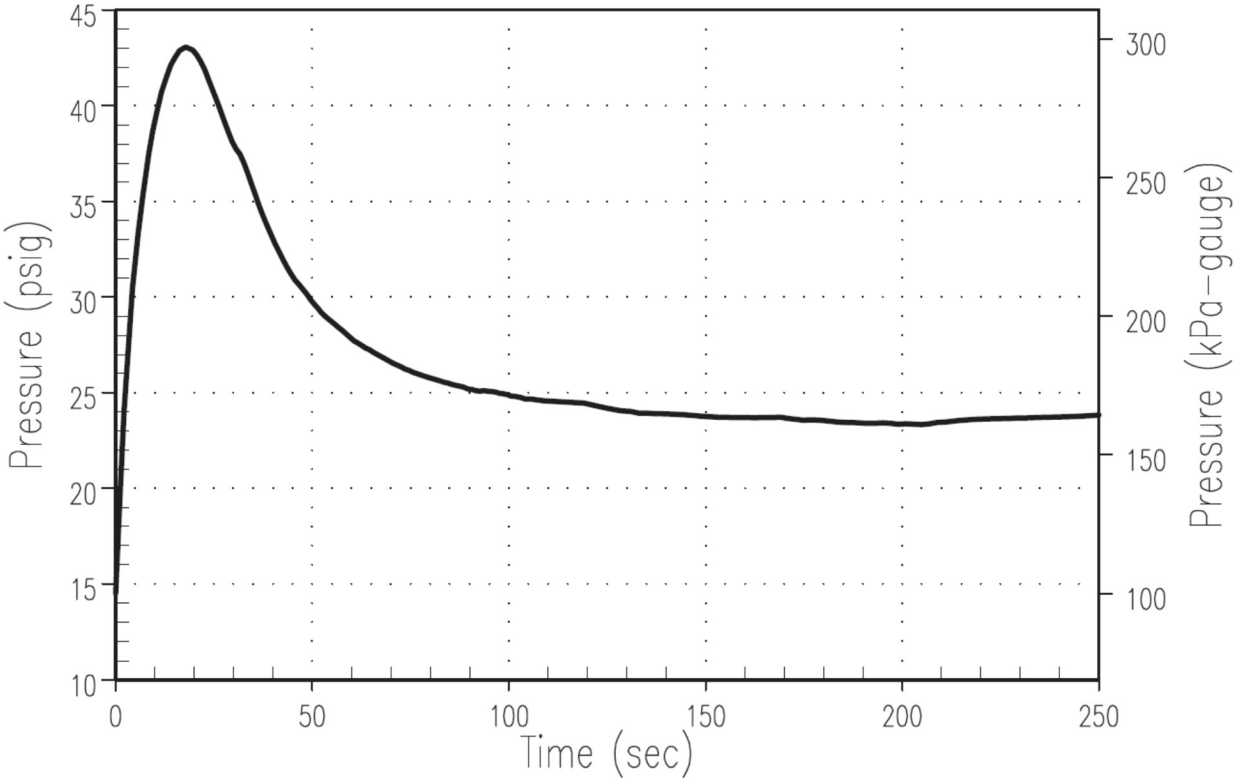


Figure 6.2.1.5-1
AP1000 Minimum Containment Pressure for DECLG LOCA

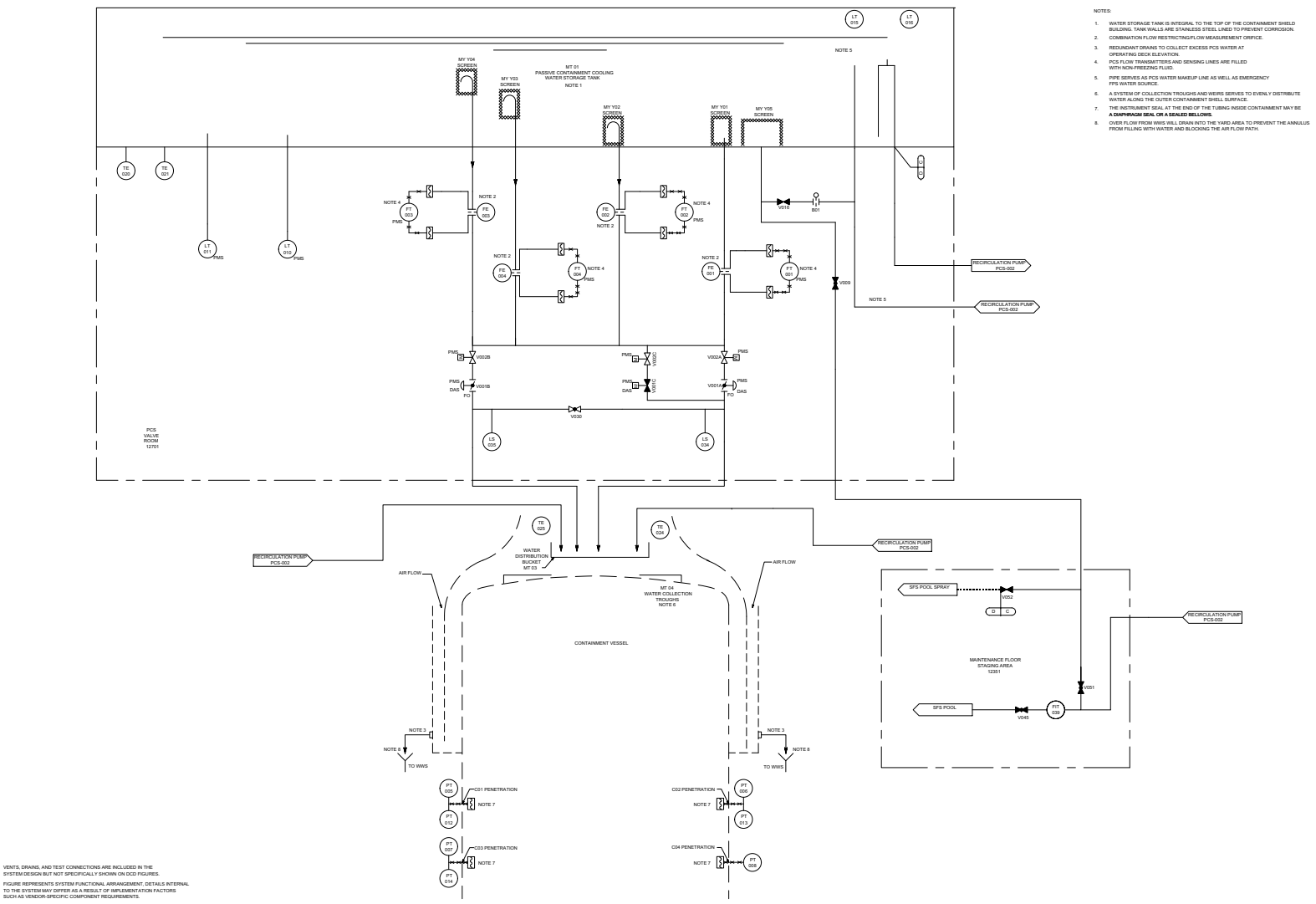
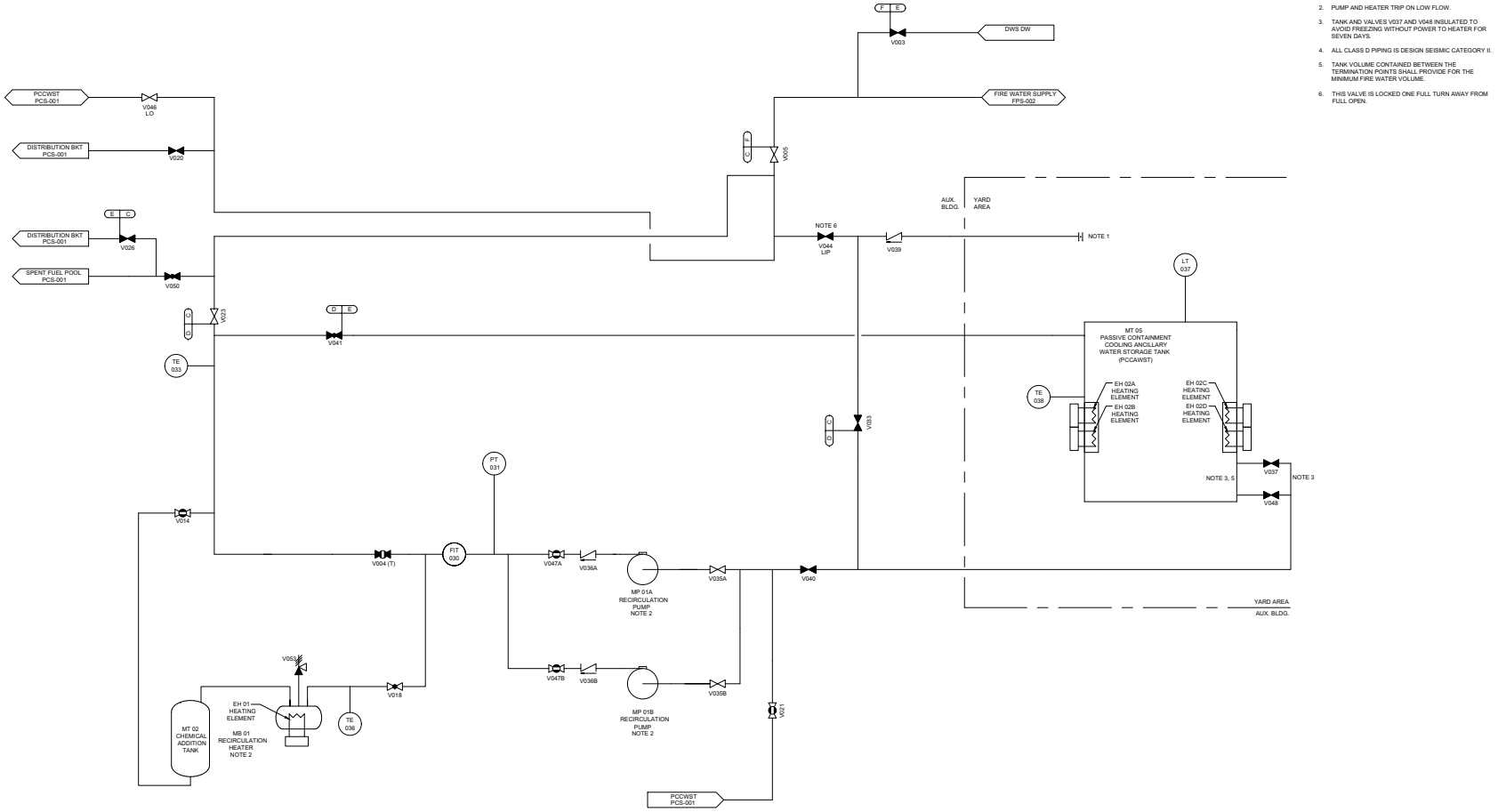


Figure 6.2.2-1 (Sheet 1 of 2)
Simplified Passive Containment Cooling System Piping and Instrumentation Diagram (REF) PCS 001



VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT, DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 6.2.2-1 (Sheet 2 of 2)
Simplified Passive Containment Cooling System Piping and Instrumentation Diagram (REF) PCS 002

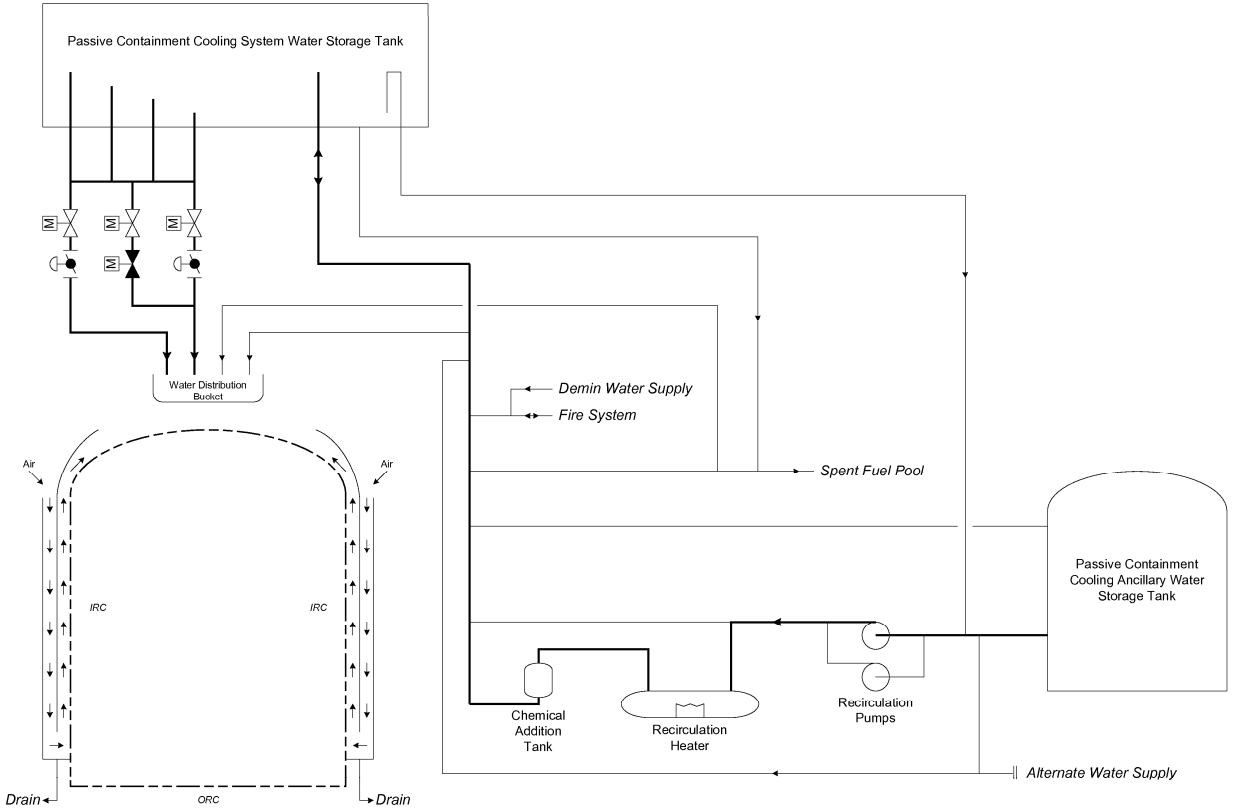


Figure 6.2.2-2
Simplified Sketch of Passive Containment Cooling System

Figures 6.2.4-1–6.2.4-4 Not Used

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-5
Hydrogen Igniter Locations – Section View

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-6
Hydrogen Igniter Locations
Plan View Elevation 82′-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-7
Hydrogen Igniter Locations – Section View

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-8
Hydrogen Igniter Locations
Plan View Elevation 96′-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-9
Hydrogen Igniter Locations
Plan View Elevation 118′-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-10
Hydrogen Igniter Locations
Plan View Elevation 135′-3″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-11
Hydrogen Igniter Locations
Plan View Elevation 162′-0″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-12
Hydrogen Igniter Locations
Plan View Elevation 210′-0″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.2.4-13
Hydrogen Igniter Locations Section A-A

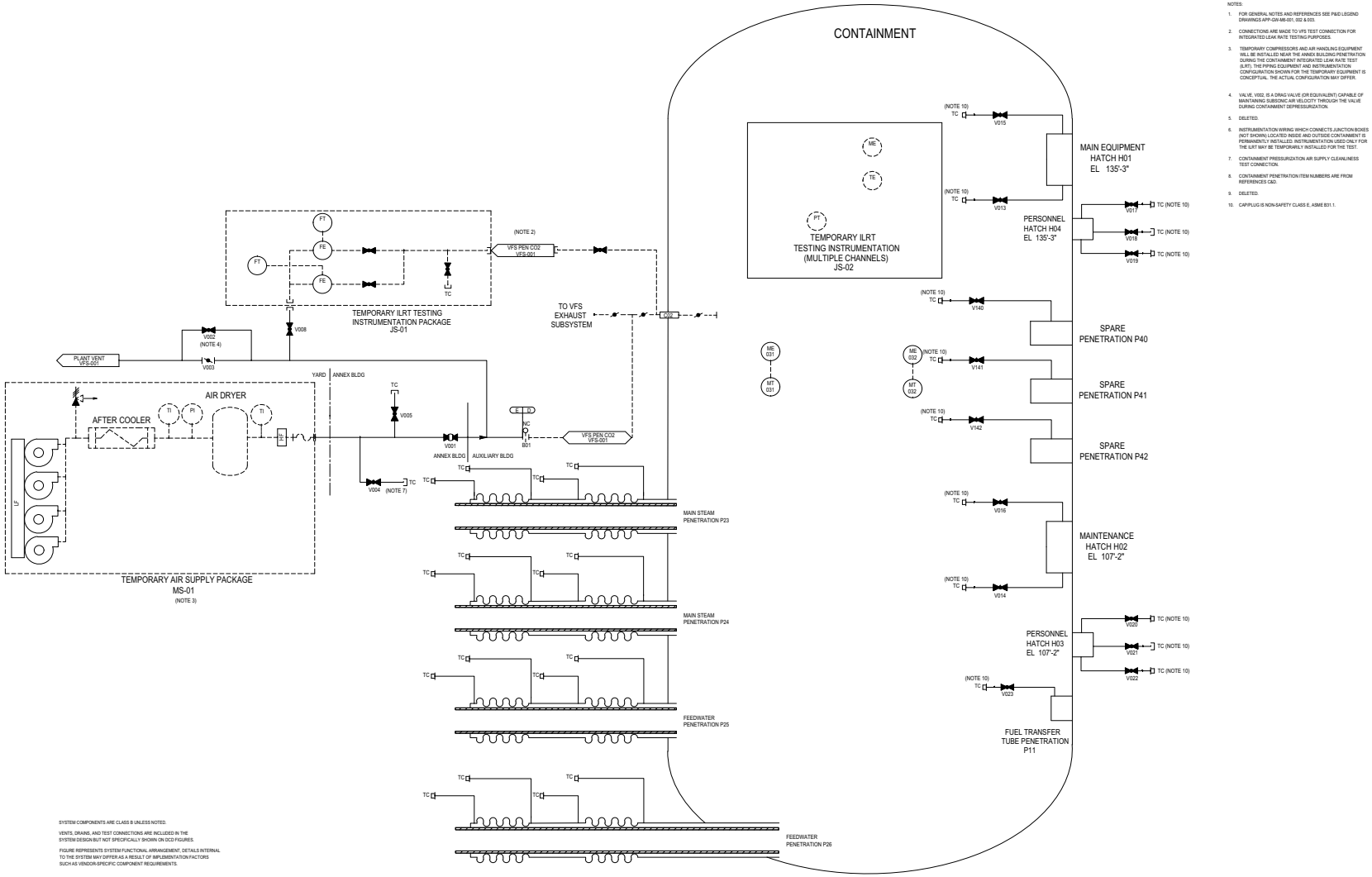


Figure 6.2.5-1
Simplified Containment Leak Rate Test System Piping and Instrumentation Diagram (REF) VUS 001

6.3 Passive Core Cooling System

The primary function of the passive core cooling system is to provide emergency core cooling following postulated design basis events. To accomplish this primary function, the passive core cooling system is designed to perform the following functions:

- Emergency core decay heat removal

  Provide core decay heat removal during transients, accidents or whenever the normal heat removal paths are lost. This heat removal function is available at reactor coolant system conditions including shutdowns. During refueling operations, when the IRWST is drained into the refueling cavity, other passive means of core decay heat removal are utilized. Subsection 6.3.3.4.4 provides a description of how this is accomplished.

- Reactor coolant system emergency makeup and boration

  Provide reactor coolant system makeup and boration during transients or accidents when the normal reactor coolant system makeup supply from the chemical and volume control system is unavailable or is insufficient.

- Safety injection

  Provide safety injection to the reactor coolant system to provide adequate core cooling for the complete range of loss of coolant accidents, up to and including the double-ended rupture of the largest primary loop reactor coolant system piping.

- Containment pH control

  Provide for chemical addition to the containment during post-accident conditions to establish floodup chemistry conditions that support radionuclide retention with high radioactivity in containment and to prevent corrosion of containment equipment during long-term floodup conditions.

The passive core cooling system is designed to operate without the use of active equipment such as pumps and ac power sources. The passive core cooling system depends on reliable passive components and processes such as gravity injection and expansion of compressed gases. The passive core cooling system does require a one-time alignment of valves upon actuation of the specific components.

6.3.1 Design Basis

The passive core cooling system is designed to perform its safety-related functions based on the following considerations:

- It has component redundancy to provide confidence that its safety-related functions are performed, even in the unlikely event of the most limiting single failure occurring coincident with postulated design basis events.

- Components are designed and fabricated according to industry standard quality groups commensurate with its intended safety-related functions.

- It is tested and inspected at appropriate intervals, as defined by the ASME Code, Section XI, and by technical specifications.

- It performs its intended safety-related functions following events such as fire, internal missiles or pipe breaks.
- It is protected from the effects of external events such as earthquakes, tornadoes, and floods.
- It is designed to be sufficiently reliable, considering redundancy and diversity, to support the plant core melt frequency and significant release frequency goals.

6.3.1.1 Safety Design Basis

The passive core cooling system is designed to provide emergency core cooling during events involving increases and decreases in secondary side heat removal and decreases in reactor coolant system inventory. Subsection 6.3.3 provides a description of the design basis events. The performance criteria are provided in Subsection 6.3.1 and also described in Chapter 15, under the respective event sections.

6.3.1.1.1 Emergency Core Decay Heat Removal

For postulated non-LOCA events, where a loss of capability to remove core decay heat via the steam generators occurs, the passive core cooling system is designed to perform the following functions for at least 72 hours:

- The passive residual heat removal heat exchanger automatically actuates to provide reactor coolant system cooling and to prevent water relief through the pressurizer safety valves.
- The passive residual heat removal heat exchanger, in conjunction with the in-containment refueling water storage tank, the condensate collection features, and the passive containment cooling system, is designed to remove decay heat following a design basis event. Automatic depressurization actuation is not expected, but may occur depending on the amount of reactor coolant system leakage and when normal systems are recovered (refer to Subsection 6.3.1.1.4).
- The passive residual heat removal heat exchanger is designed to maintain acceptable reactor coolant system conditions following a non-LOCA event. The applicable post-accident safety evaluation criteria are discussed in Chapter 15.
- The passive residual heat removal heat exchanger is capable of performing its post-accident safety functions, assuming the steam generated in the in-containment refueling water storage tank is condensed on the containment vessel and returned by gravity via the in-containment refueling water storage tank condensate return gutter and downspouts.
- During a steam generator tube rupture event, the passive residual heat removal heat exchanger removes core decay heat and reduces reactor coolant system temperature and pressure, equalizing with steam generator pressure and terminating break flow, without overfilling the steam generator.

System operation beyond 72 hours is described in Subsection 6.3.1.2.1.

6.3.1.1.2 Reactor Coolant System Emergency Makeup and Boration

For postulated non-LOCA events, sufficient core makeup water inventory is automatically provided to keep the core covered and to allow for decay heat removal. In addition, this makeup prevents actuation of the automatic depressurization system for a significant time.

For postulated events resulting in an inadvertent cooldown of the reactor coolant system, such as a steam line break, sufficient borated water is automatically provided to makeup for reactor coolant system shrinkage. The borated water also counteracts the reactivity increase caused by the resulting system cooldown.

For a Condition III steam line break described in Chapter 15, return to power is acceptable if there is no core damage. For this event, the automatic depressurization system is not actuated.

For a large steam line break, the peak return to power is limited so that the offsite dose limits are satisfied. Following either of these events, the reactor is automatically brought to a subcritical condition.

For safe shutdown, the passive core cooling system is designed to supply sufficient boron to the reactor coolant system to maintain the technical specification shutdown margin for cold, post-depressurization conditions, with the most reactive rod fully withdrawn from the core. The automatic depressurization system is not expected to actuate for these events.

6.3.1.1.3 Safety Injection

The passive core cooling system provides sufficient water to the reactor coolant system to mitigate the effects of a loss of coolant accident. In the event of a large loss of coolant accident, up to and including the rupture of a hot or cold leg pipe, where essentially all of the reactor coolant volume is initially displaced, the passive core cooling system rapidly refills the reactor vessel, refloods the core, and continuously removes the core decay heat. A large break is a rupture with a total cross-sectional area equal to or greater than one square foot. Although the criteria for mechanistic pipe break are used to limit the size of pipe rupture considered in the design and evaluation of piping systems, as described in Subsection 3.6.3, such criteria are not used in the design of the passive core cooling system.

Sufficient water is provided to the reactor vessel following a postulated loss of coolant accident so that the performance criteria for emergency core cooling systems, described in Chapter 15, are satisfied.

The automatic depressurization system valves, provided as part of the reactor coolant system, are designed so that together with the passive core cooling system they:

- Satisfy the small loss of coolant accident performance requirements
- Provide effective core cooling for loss of coolant accidents from when the passive core cooling system is actuated through the long-term cooling mode.

6.3.1.1.4 Safe Shutdown

The functional requirements for the passive core cooling system specify that the plant be brought to a safe, stable condition using the passive residual heat removal heat exchanger for events not involving a loss of coolant. As stated in Subsection 6.3.1.1.1, the passive residual heat removal heat exchanger in conjunction with the passive containment cooling system provides sufficient heat removal to satisfy the post-accident safety evaluation criteria for at least 72 hours. Additionally, the passive core cooling system, in conjunction with the passive containment cooling system and the automatic depressurization system, has the capability to establish long-term safe shutdown conditions in the reactor coolant system as identified in Subsection 7.4.1.1.

The core makeup tanks automatically provide injection to the reactor coolant system after they are actuated on low reactor coolant temperature or low pressurizer pressure or level. The passive core

cooling system can maintain stable plant conditions for a long time in this mode of operation, depending on the reactor coolant leakage and the availability of normal systems. For example, with a technical specification leak rate of 10 gpm, stable plant conditions can be maintained for at least 10 hours. With a smaller leak a longer time is available.

In scenarios when ac power sources are unavailable for approximately 22 hours, the automatic depressurization system automatically actuates. However, after the initial plant cooldown following a non-LOCA event, operators assess plant conditions and have the option to perform recovery actions to further cool and depressurize the reactor coolant system in a closed-loop mode of operation, i.e., without actuation of the automatic depressurization system. After verifying the reactor coolant system is in an acceptable, stable condition such that automatic depressurization is not needed, the operators may take action to extend the passive residual heat removal heat exchanger operation by de-energizing the loads on the 24-hour Class 1E dc batteries powering the protection and monitoring system actuation cabinets. After operators have taken action to extend its operation, the passive residual heat removal heat exchanger, in conjunction with the passive containment cooling system, has the capability to maintain safe, stable conditions for at least 72 hours. The automatic depressurization system remains available to maintain safe shutdown conditions at a later time.

In most sequences, the operators would return the plant to normal system operations and terminate passive system operation within several hours in accordance with the plant emergency operating procedures. For loss of coolant accidents, when the core makeup tank level reaches the automatic depressurization system actuation setpoint and other postulated events where the passive residual heat removal heat exchanger operation is not extended or is exhausted, the automatic depressurization system may be initiated. This results in injection from the accumulators and subsequently from the in-containment refueling water storage tank, once the reactor coolant system is nearly depressurized. For these conditions, the reactor coolant system depressurizes to saturated conditions at about 250°F within 24 hours. The passive core cooling system can maintain this safe shutdown condition indefinitely for the plant as identifed in Subsection 7.4.1.1.

The passive core cooling system functional requirements are met over the range of anticipated events and single failure assumptions. The primary function of the passive core cooling system during a safe shutdown using only safety-related equipment is to provide a means for boration, injection, and core cooling. Details of the safe shutdown design bases are presented in Subsection 5.4.7 and Section 7.4. The performance of the passive residual heat removal exchanger to bring the plant to 420°F in 36 hours is summarized in Subsection 19E.4.10.2.

6.3.1.1.5 Containment pH Control

The passive core cooling system is capable of maintaining the desired post-accident pH conditions in the recirculation water after containment floodup. The pH adjustment is capable of maintaining containment pH within a range of 7.0 to 9.5, to enhance radionuclide retention in the containment and to prevent stress corrosion cracking of containment components during long-term containment floodup.

6.3.1.1.6 Reliability Requirements

The passive core cooling system satisfies a variety of reliability requirements, including redundancy (such as for components, power supplies, actuation signals, and instrumentation), equipment testing to confirm operability, procurement of qualified components, and provisions for periodic maintenance. In addition, the system provides protection in a number of areas including:

- Single active and passive component failures
- Spurious failures

- Physical damage from fires, flooding, missiles, pipe whip, and accident loads
- Environmental conditions such as high-temperature steam and containment floodup

Subsection 6.3.1.3 includes specific nonsafety-related design requirements that help to confirm satisfactory system reliability.

6.3.1.2 Nonsafety Design Basis

6.3.1.2.1 Post Accident Core Decay Heat Removal

The passive residual heat removal heat exchanger is designed to cool the reactor coolant system to 420°F in 36 hours, with or without reactor coolant pumps operating. This allows the reactor coolant system to be depressurized and the stress in the reactor coolant system and connecting pipe to be reduced to low levels. This non-bounding, conservative evaluation is discussed in Subsection 19E.4.10.2.

The passive residual heat removal heat exchanger, in conjunction with the in-containment refueling water storage tank, the condensate return features, and the passive containment cooling system, has the capability to maintain the reactor coolant system in the specified, long-term safe shutdown condition of 420°F for greater than 14 days in a closed-loop mode of operation. The automatic depressurization system can be manually actuated by the operators during the extended passive residual heat removal heat exchanger operation to initiate open-loop cooling. The operator actions necessary to achieve safe shutdown using the passive residual heat removal heat exchanger in a closed-loop mode of operation involve preventing unnecessary actuation of the automatic depressurization system as detailed in Subsection 7.4.1.

Eventually, if pressurizer heaters are not available, the pressurizer subcools due to ambient heat loss. When this happens, the steam void within the pressurizer is transferred to the reactor coolant system. It has been determined that this condition is safe as long as the passive residual heat removal performance is not affected.

If passive residual heat removal performance is affected by subcooling (or other plant conditions) and non-safety systems to control core cooling are not reestablished, then the final, long-term safe shutdown conditions may be achieved and maintained using the automatic depressurization system as discussed in Subsection 7.4.1.1.

6.3.1.3 Power Generation Design Basis

The passive core cooling system is designed to be sufficiently reliable to support the probabilistic risk analysis goals for core damage frequency and severe release frequency. In assessing the reliability for probabilistic risk analysis purposes, more realistic analysis is used for both the passive core cooling system performance and for plant response.

In the event of a small loss of coolant accident, the passive core cooling system limits the increase in peak clad temperature and core uncovery with design basis assumptions. For pipe ruptures of eight-inch nominal diameter size and less, the passive core cooling system is designed to prevent core damage with best estimate assumptions.

The passive residual heat removal heat exchanger and the in-containment refueling water storage tank are designed to delay significant steam release to the containment for at least one hour.

The frequency of automatic depressurization system actuation is limited to a low probability to reduce safety risks and to minimize plant outages. Equipment is located so that it is not flooded or it is

designed so that it is not damaged by the flooding. Major plant equipment is designed for multiple occurrences without damage.

The pH control equipment is designed to minimize the potential for and the impact of inadvertent actuation.

The passive core cooling system is capable of supporting the required testing and maintenance, including capabilities to isolate and drain equipment.

6.3.2 System Design

The passive core cooling system is a seismic Category I, safety-related system. It consists of two core makeup tanks, two accumulators, the in-containment refueling water storage tank, the passive residual heat removal heat exchanger, pH adjustment baskets, and associated piping, valves, instrumentation, and other related equipment. The automatic depressurization system valves and spargers, which are part of the reactor coolant system, also provide important passive core cooling functions.

The passive core cooling system is designed to provide adequate core cooling in the event of design basis events. The redundant onsite safety-related class 1E dc and UPS system provides power such that protection is provided for a loss of ac power sources, coincident with an event, assuming a single failure has occurred.

6.3.2.1 Schematic Piping and Instrumentation Diagrams

Figure 6.3-1 shows the piping and instrumentation drawings of the passive core cooling system. Simplified flow diagrams are shown in Figures 6.3-3 and 6.3-4. The accident analysis results of events analyzed in Chapter 15 provide a summary of the expected fluid conditions in the passive core cooling system for the various locations shown on the simplified flow diagrams, for the specific plant conditions identified -- safety injection and decay heat removal.

The passive core cooling system is designed to supply the core cooling flow rates to the reactor coolant system specified in Chapter 15 for the accident analyses. The accident analyses flow rates and heat removal rates are calculated by assuming a range of component parameters, including best estimate and conservatively high and low values.

The passive core cooling system design is based on the six major components, listed in Subsection 6.3.2.2, that function together in various combinations to support the four passive core cooling system functions:

- Emergency decay heat removal
- Emergency reactor makeup/boration
- Safety injection
- Containment pH control

6.3.2.1.1 Emergency Core Decay Heat Removal at High Pressure and Temperature Conditions

For events not involving a loss of coolant, the emergency core decay heat removal is provided by the passive core cooling system via the passive residual heat removal heat exchanger. The heat exchanger consists of a bank of C-tubes, connected to a tubesheet and channel head arrangement

at the top (inlet) and bottom (outlet). The passive residual heat removal heat exchanger connects to the reactor coolant system through an inlet line from one reactor coolant system hot leg (through a tee from one of the fourth stage automatic depressurization lines) and an outlet line to the associated steam generator cold leg plenum (reactor coolant pump suction).

The inlet line is normally open and connects to the upper passive residual heat removal heat exchanger channel head. The inlet line is connected to the top of the hot leg and is routed continuously upward to the high point near the heat exchanger inlet. The normal water temperature in the inlet line will be hotter than the discharge line.

The outlet line contains normally closed air-operated valves that open on loss of air pressure or on control signal actuation. The alignment of the passive residual heat removal heat exchanger (with a normally open inlet motor-operated valve and normally closed outlet air-operated valves) maintains the heat exchanger full of reactor coolant at reactor coolant system pressure. The water temperature in the heat exchanger is about the same as the water in the in-containment refueling water storage tank, so that a thermal driving head is established and maintained during plant operation.

The heat exchanger is elevated above the reactor coolant system loops to induce natural circulation flow through the heat exchanger when the reactor coolant pumps are not available. The passive residual heat removal heat exchanger piping arrangement also allows actuation of the heat exchanger with reactor coolant pumps operating. When the reactor coolant pumps are operating, they provide forced flow in the same direction as natural circulation flow through the heat exchanger. If the pumps are operating and subsequently trip, then natural circulation continues to provide the driving head for heat exchanger flow.

The heat exchanger is located in the in-containment refueling water storage tank, which provides the heat sink for the heat exchanger.

Although gas accumulation is not expected, there is a vertical pipe stub on the top of the inlet piping high point that serves as a gas collection chamber. Level detectors indicate when gases have collected in this area. There are provisions to allow the operators to open manual valves to locally vent these gases to the in-containment refueling water storage tank.

The passive residual heat removal heat exchanger, in conjunction with the in-containment refueling water storage tank, the condensate return features, and the passive containment cooling system, can provide core cooling for at least 72 hours. After the in-containment refueling water storage tank water reaches its saturation temperature (in several hours), the process of steaming to the containment initiates. Containment pressure increases as steam is released from the in-containment refueling water storage tank. As containment temperature increases, condensation begins to form on the subcooled metal and concrete surfaces inside containment. Condensation on these heat sink surfaces transfers energy to the bulk metal and concrete until they come into equilibrium with the containment atmosphere. Condensation that is not returned to the incontainment refueling water storage tank drains to the containment sump.

Condensation occurs on the steel containment vessel, which is cooled by the passive containment cooling system. Most of the condensate formed on the containment vessel wall is collected in a safety-related gutter arrangement. A gutter is located near the operating deck elevation, and a downspout piping system is connected at the polar crane girder and internal stiffener, to collect steam condensate inside the containment during passive containment cooling system operation and return it to the in-containment refueling water storage tank. The gutter normally drains to the containment sump, but when the passive residual heat removal heat exchanger actuates, safety-related isolation valves in the gutter drain line shut and the gutter overflow returns directly to the in-containment refueling water storage tank. Recovery of the condensate maintains the passive residual heat removal heat exchanger heat sink for greater than 14 days.

The passive residual heat removal heat exchanger is used to maintain an acceptable, stable reactor coolant system condition. It transfers decay heat and sensible heat from the reactor coolant system to the in-containment refueling water storage tank, the containment atmosphere, the containment vessel, and finally to the ultimate heat sink–the atmosphere outside of containment. This occurs after in-containment refueling water storage tank saturation is reached and steaming to containment initiates.

The duration the passive residual heat removal heat exchanger can continue to remove decay heat is affected by the efficiency of the return of condensate to the in-containment refueling water storage tank. The in-containment refueling water storage tank water level is affected by the amount of steam that leaves the tank and does not return. Resources are typically recovered within 72 hours, which allows the operators to place active, defense-in-depth systems into service and to terminate passive system operation. If resources are not recovered within this time frame, cooling can be extended as described in Subsection 7.4.1.1 to maintain a safe, stable condition after a design basis event.

6.3.2.1.2 Reactor Coolant System Emergency Makeup and Boration

The core makeup tanks provide reactor coolant system makeup and boration during events not involving loss of coolant when the normal makeup system is unavailable or insufficient. There are two core makeup tanks located inside the containment at an elevation slightly above the reactor coolant loops. During normal operation, the core makeup tanks are completely full of cold, borated water. The boration capability of these tanks provides adequate core shutdown margin following a steam line break.

The core makeup tanks are connected to the reactor coolant system through a discharge injection line and an inlet pressure balance line connected to a cold leg. The discharge line is blocked by two normally closed, parallel air-operated isolation valves that open on a loss of air pressure or electrical power, or on control signal actuation. The core makeup tank discharge isolation valves are diverse from the passive residual heat removal heat exchanger outlet isolation valves discussed above. They use different valve body styles and different air operator types.

The pressure balance line from the cold leg is normally open to maintain the core makeup tanks at reactor coolant system pressure, which prevents water hammer upon initiation of core makeup tank injection.

The cold leg pressure balance line is connected to the top of the cold leg and is routed continuously upward to the high point near the core makeup tank inlet. The normal water temperature in this line will be hotter than the discharge line.

The outlet line from the bottom of each core makeup tank provides an injection path to one of the two direct vessel injection lines, which are connected to the reactor vessel downcomer annulus. Upon receipt of a safeguards actuation signal, the two parallel valves in each discharge line open to align the associated core makeup tank to the reactor coolant system.

There are two operating processes for the core makeup tanks, steam-compensated injection and water recirculation. During steam-compensated injection, steam is supplied to the core makeup tanks to displace the water that is injected into the reactor coolant system. This steam is provided to the core makeup tanks through the cold leg pressure balance line. The cold leg line only has steam flow if the cold legs are voided.

During water recirculation, hot water from the cold leg enters the core makeup tanks, and the cold water in the tank is discharged to the reactor coolant system. This results in reactor coolant system boration and a net increase in reactor coolant system mass.

The operating process for the core makeup tanks depends on conditions in the reactor coolant system, primarily voiding in the cold leg. When the cold leg is full of water, the cold leg pressure balance line remains full of water and the injection occurs via water recirculation. If reactor coolant system inventory decreases sufficiently to cause cold leg voiding, then steam flows through the cold leg balance lines to the core makeup tanks.

Following an event such as steam-line break, the reactor coolant system experiences a decrease in temperature and pressure due to an increase of energy removed by the secondary system as a consequence of the break. The cooldown results in a reduction of the core shutdown margin due to the negative moderator temperature coefficient. There is a potential return to power, assuming the most reactive rod cluster control assembly is stuck in its fully withdrawn position. The actuation of the core makeup tanks following this event provides injection of borated water via water recirculation to mitigate the reactivity transient and provide the required shutdown margin.

In case of a steam generator tube rupture, core makeup tank injection together with the steam generator overfill prevention logic terminates the reactor coolant system leak into the steam generator. This occurs without actuation of the automatic depressurization system and without operator action. In a steam generator tube rupture, the core makeup tanks operate in the water recirculation mode to provide borated water to compensate for reactor coolant system inventory losses and to borate the reactor coolant system. In case of a leak rate of 10 gallons per minute, the passive core cooling system can delay the automatic depressurization system actuation for at least 10 hours while providing makeup water to the reactor coolant system. After the actuation of the automatic depressurization system, the passive core cooling system provides sufficient borated water to compensate for reactor coolant system shrinkage and to provide the reactor coolant system boration.

6.3.2.1.3 Safety Injection During Loss of Coolant Accidents

The passive core cooling system uses four different sources of passive injection during loss of coolant accidents.

- Accumulators provide a very high flow for a limited duration of several minutes.
- The core makeup tanks provide a relatively high flow for a longer duration.
- The in-containment refueling water storage tank provides a lower flow, but for a much longer time.
- The containment is the final long-term source of water. It becomes available following the injection of the other three sources and floodup of containment.

The operation of the core makeup tanks is described in the Subsection 6.3.2.1.2. During a loss of coolant accident, they provide injection rates commensurate with the severity of the loss of coolant accident. For a larger loss of coolant accident, and after the automatic depressurization system has been actuated, the cold legs are expected to be voided. In this situation, the core makeup tanks operate at their maximum injection rate with steam entering the core makeup tanks through the cold leg pressure balance lines.

Downstream of the parallel discharge isolation valves, the core makeup tank discharge line contains two check valves, in series, that normally remain open with or without flow in the line. These valves prevent reverse flow through this line, from the accumulator, that would bypass the reactor vessel in the event of a larger loss of coolant accident in the cold leg or the cold leg pressure balance line.

For smaller loss of coolant accidents the core makeup tanks initially operate in the water recirculation mode since the cold legs are water filled. During this water recirculation, the core makeup tanks remain full, but the cold, borated water is purged with hot, less borated cold leg water. The water recirculation provides reactor coolant system makeup and also effectively borates the reactor coolant system. As the accident progresses, when the cold legs void, the core makeup tanks switch to the steam displacement mode which provides higher flow rates.

The two accumulators contain borated water and a compressed nitrogen cover gas to provide rapid injection. They are located inside the reactor containment and the discharge from each tank is connected to one of the direct vessel injection lines. These lines connect to the reactor vessel downcomer. A deflector in the annulus directs the water flow downward to minimize core bypass flow. The water and gas volumes and the discharge line resistance provide several minutes of injection in a large loss of coolant accident.

The in-containment refueling water storage tank is located in the containment at an elevation slightly above the reactor coolant system loop piping. Reactor coolant system injection is possible only after the reactor coolant system has been depressurized by the automatic depressurization system or by a loss of coolant accident. Squib valves in the in-containment refueling water storage tank injection lines open automatically on a 4th stage automatic depressurization signal. Check valves, arranged in series with the squib valves, open when the reactor pressure decreases to below the in-containment refueling water storage tank injection head.

After the accumulators, core makeup tanks, and the in-containment refueling water storage tank inject, the containment is flooded up to a level sufficient to provide recirculation flow through the gravity injection lines back into the reactor coolant system.

The time that it takes until the initiation of containment recirculation flow varies greatly, depending on the specific event. With a break in a direct vessel injection line, the in-containment refueling water storage tank spills out through the break and floods the containment, along with reactor coolant system leakage, and recirculation can occur in several hours. In the event of automatic depressurization without a reactor coolant system break and with condensate return, the in-containment refueling water storage tank level decreases very slowly. Recirculation may not initiate for 72 hours. Containment recirculation may be impacted by shutdown maintenance activities which remove access hatches or curbs located at the 107'-2" plant elevation. Subsection 3.4.1.2.2.1 discusses containment flooding events in further detail.

Containment recirculation initiates when the recirculation line valves are open and the containment floodup level is sufficiently high. When the in-containment refueling water storage tank level decreases to the Low-3 level, the containment recirculation squib valves automatically open to provide redundant flow paths from the containment to the reactor.

These recirculation flow paths can also provide a suction flow path from the containment to the normal residual heat removal pumps, when they are operating after containment flood up. In addition, the squib valves in the recirculation paths containing normally open motor-operated valves can be manually opened to intentionally drain the in-containment refueling water storage tank to the reactor cavity during severe accidents. This action is modeled in the AP1000 probabilistic risk assessment.

A range of break sizes and locations are analyzed to verify the adequacy of passive core cooling system injection. These events include a no-break case, a complete severance of one (eight-inch) direct vessel injection line case, and other smaller break cases. Successful reactor coolant system depressurization to in-containment refueling water storage tank injection is achieved, as shown in Chapter 15.

In larger loss of coolant accidents, including double ended ruptures in reactor coolant system piping, the passive core cooling system can provide a large flow rate, from the accumulators, to quickly refill the reactor vessel lower plenum and downcomer. The accumulators provide the required injection flow during the first part of the event including refilling the downcomer and lower plenum and partially reflooding the core. After the accumulators empty, the core makeup tanks complete the reflooding of the core. The subsequent in-containment refueling water storage tank injection and recirculation provide long-term cooling. Both injection lines are available since the injection lines are not the source of a large pipe break.

6.3.2.1.4 Containment pH Control

Control of the pH in the containment sump water post-accident is achieved through the use of pH adjustment baskets containing granulated trisodium phosphate (TSP). The baskets are located below the minimum post-accident floodup level, and chemical addition is initiated passively when the water reaches the baskets. The baskets are placed at least a foot above the floor to reduce the chance that water spills in containment will dissolve the TSP.

The TSP is designed to maintain the pH of the containment sump water in a range from 7.0 to 9.5. This chemistry reduces radiolytic formation of elemental iodine in the containment sump, consequently reducing the aqueous production of organic iodine, and ultimately reducing the airborne iodine in containment and offsite doses.

The chemical addition also helps to reduce the potential for stress corrosion cracking of stainless steel components in a post floodup condition, where chlorides can leach out of the containment concrete and potentially affect these components during a long-term floodup event.

6.3.2.1.5 Passive Core Cooling System Actuation

Table 6.3-1 lists the remotely actuated valves used by the various passive core cooling system components. The engineered safeguards features actuation signals used for these valves are described in Section 7.3. Table 6.3-1 shows the normal valve position, the valve position to actuate the associated component, and the failure position of the valve. The failed position represents the position that the valve fails upon loss of electrical power or other motive sources, such as instrument air.

Table 6.3-3 contains the failure mode and effects analysis of the passive core cooling system.

6.3.2.2 Equipment and Component Descriptions

Table 6.3-2 contains a summary of equipment parameters for major components of the passive core cooling system.

6.3.2.2.1 Core Makeup Tanks

The two core makeup tanks are vertical, cylindrical tanks with hemispherical upper and lower heads. They are made of carbon steel, clad on the internal surfaces with stainless steel. The core makeup tanks are AP1000 Equipment Class A and are designed to meet seismic Category I requirements. They are located inside containment on the 107-foot floor elevation. The core makeup tanks are located above the direct vessel injection line connections to the reactor vessel, which are located at an elevation near the bottom of the hot leg.

During normal operation the core makeup tanks are completely filled with borated water and are maintained at reactor coolant system pressure by the cold leg pressure balance line. The

temperature of the borated water in the core makeup tanks is about the same as the containment ambient temperature since the tanks are not insulated or heated.

The inlet line from the cold leg is sized for loss of coolant accidents, where the cold legs become voided and higher core makeup tank injection flows are required. The discharge line from each core makeup tank contains a flow-tuning orifice that provides a mechanism for the field adjustment of the injection line resistance. The orifice is used to establish the required flow rates assumed in the core makeup tank design. The core makeup tanks provide injection for an extended time after core makeup tank actuation. The duration of injection will be much longer when the core makeup tanks operate in the water recirculation mode as compared to the steam condensation mode.

Connections are provided for remotely adjusting the boron concentration of the borated water in each core makeup tank during normal plant operation, as required. Makeup water for the core makeup tank is provided by the chemical and volume control system. Samples from the core makeup tanks are taken periodically to check boron concentration.

Each core makeup tank has an inlet diffuser which is designed to reduce steam velocities entering the core makeup tank; thereby minimizing potential water hammer and reducing the amount of mixing that occurs during initial core makeup tank operation. The inlet diffuser flow area is ≥ 165 in^2.

The core makeup tanks are located inside the containment but outside the secondary shield wall. This facilitates maintenance and inspection.

Core makeup tank level and inlet and outlet line temperatures are monitored by indicators and alarms. The operator can take action as required to meet the technical specification requirements for core makeup tank operability. Core makeup tank temperature is monitored and trended to investigate potential leaks prior to alarm setpoints.

6.3.2.2.2 Accumulators

The two accumulators are spherical tanks made of carbon steel and clad on the internal surfaces with stainless steel. The accumulators are AP1000 Equipment Class C and are designed to meet seismic Category I requirements. They are located inside the containment on the floor just below the core makeup tanks.

The accumulators are mostly filled with borated water and pressurized with nitrogen gas. The temperature of the borated water in the accumulators is about the same as the containment ambient temperature since the tanks are not insulated or heated. Each accumulator is connected to one of the direct vessel injection lines. During normal operation, the accumulator is isolated from the reactor coolant system by two check valves in series. When the reactor coolant system pressure falls below the accumulator pressure, the check valves open and borated water is forced into the reactor coolant system by the gas pressure. Mechanical operation of the check valves is the only action required to open the injection path from the accumulators to the core.

The accumulators are designed to deliver a high flow of borated water to the reactor vessel in the event of a large loss of coolant accident. This large flow rate is used to quickly establish core cooling following the large loss of reactor coolant system inventory.

The injection line from each accumulator contains a flow-tuning orifice that provides a mechanism for the field adjustment of the injection line resistance. The orifice is used to establish the required flow rates assumed in the accumulator design. The accumulator provides injection for several minutes after reactor coolant system pressure drops below the static accumulator pressure.

Connections are provided for remotely adjusting the level and boron concentration of the borated water in each accumulator during normal plant operation, as required. Accumulator water level may be adjusted either by draining or by pumping borated water from the chemical and volume control system to the accumulator. Samples from the accumulators are taken periodically to check the boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas and can be adjusted as required during normal plant operation. However, the accumulators are normally isolated from the nitrogen supply. Gas relief valves on the accumulators protect them from overpressurization. The system also includes the capability to remotely vent gas from the accumulator, if required.

The accumulators are located inside the containment and outside the secondary shield wall. This facilitates maintenance and inspection.

Accumulator level and pressure are monitored by indication and alarms. The operator can take action, as required, to meet the technical specification requirements for accumulator operability.

6.3.2.2.3 In-Containment Refueling Water Storage Tank

The in-containment refueling water storage tank is a large, stainless-steel lined tank located underneath the operating deck inside the containment. The in-containment refueling water storage tank is AP1000 Equipment Class C and is designed to meet seismic Category I requirements. The tank is constructed as an integral part of the containment internal structures, and is isolated from the steel containment vessel except for the bottom portion of the tank wall, separated from the containment vessel by concrete. See Subsection 3.8.3 for additional information.

The bottom of the in-containment refueling water storage tank is above the reactor coolant system loop elevation so that the borated refueling water can drain by gravity into the reactor coolant system after it is sufficiently depressurized. The in-containment refueling water storage tank is connected to the reactor coolant system through both direct vessel injection lines. The in-containment refueling water storage tank contains borated water, at the existing temperature and pressure in containment.

Vents are installed in the roof of the in-containment refueling water storage tank. These vents are provided with normally closed covers in order to contain water vapor and radioactive gases within the tank during normal operation and to prevent debris from entering the tank from the containment operating deck. The vent covers open with a slight pressurization of the in-containment refueling water storage tank. These vents provide a path to vent steam released by the spargers or generated by the passive residual heat removal heat exchanger, into the containment atmosphere. Other vent covers also open on small pressure differentials to allow air/steam to enter the in-containment refueling water storage tank from containment, such as during a loss of coolant accident, to prevent damage to the tank. Overflow weirs with covers are provided from the in-containment refueling water storage tank to the refueling cavity to accommodate volume and mass increases during passive residual heat removal heat exchanger or automatic depressurization system operation, while minimizing the floodup of the containment.

The IRWST is stainless steel lined and does not contain material either in the tank or the recirculation path that could plug the outlet screens.

The in-containment refueling water storage tank contains one passive residual heat removal heat exchanger and two depressurization spargers. The top of the passive residual heat removal heat exchanger tubes are located underwater and extend down into the in-containment refueling water storage tank. The spargers are also submerged in the in-containment refueling water storage tank, with the spargers midarms located below the normal water level.

The in-containment refueling water storage tank is sized to provide the flooding of the refueling cavity for normal refueling, the post-loss of coolant accident flooding of the containment for reactor coolant system long-term cooling mode, and to support the passive residual heat removal heat exchanger operation. Flow out of the in-containment refueling water storage tank during the injection mode includes conservative allowances for spill flow during a direct vessel injection line break.

The in-containment refueling water storage tank can provide sufficient injection until the containment sump floods up high enough to initiate recirculation flow. The injection duration varies greatly, depending upon the specific event. A direct vessel injection line break more rapidly drains the in-containment refueling water storage tank and speeds containment floodup.

The containment floodup volume for a LOCA in PXS room B is less than 71,960 ft^3 (excluding the in-containment refueling water storage tank) below a containment elevation of 107.68 feet.

Connections to the in-containment refueling water storage tank provide for transfer to and from the reactor coolant system/refueling cavity via the normal residual heat removal system, purification and sampling via the spent fuel pool cooling system, and remotely adjusting boron concentration to the chemical and volume control system. Also, the normal residual heat removal system can provide cooling of the in-containment refueling water storage tank.

In-containment refueling water storage tank level and temperature are monitored by indicators and alarms. The operator can take action, as required, to meet the technical specification requirements for in-containment refueling water storage tank operability.

The protection and safety monitoring system isolates the spent fuel pool cooling system by closing the spent fuel pool cooling system containment isolation valves on low IRWST wide range level to prevent loss of inventory in the event of a leak in the nonsafety spent fuel pool cooling system.

The actuation can be manually blocked while the plant is in Mode 6, below P-9, to allow the spent fuel pool cooling system to transfer the IRWST to the refueling cavity and perform cooling and purification of the refueling cavity. A manual block can also be used during other modes when the plant is below P-9 so that if required, operators can continue to use the spent fuel pool cooling system to cool, purify, sample, or transfer water to the IRWST when the level is below the low setpoint.

6.3.2.2.4 pH Adjustment Baskets

The passive core cooling system utilizes pH adjustment baskets for control of the pH level in the containment sump. The baskets are made of stainless steel with a mesh front that readily permits contact with water. The baskets are designated AP1000 Equipment Class C, and are designed to meet seismic Category I requirements.

The total weight of TSP contained in the baskets is at least 26,460 pounds. The TSP, in granular form, is provided to raise the pH of the borated water in the containment following an accident to at least 7.0. After extended plant operation, the granular TSP may cake into a solid form as it absorbs moisture. Assuming that the TSP has caked, the dissolution time of the TSP is approximately 3 hours. Good mixing with the sump water is expected due to both basket construction and because the baskets are placed in locations conducive to recirculation flows post-accident. The baskets are designed for ease of replacement of the TSP.

6.3.2.2.5 Passive Residual Heat Removal Heat Exchanger

The passive residual heat removal exchanger consists of inlet and outlet channel heads connected together by vertical C-shaped tubes. The tubes are supported inside the in-containment refueling water storage tank. The top of the tubes is several feet below the in-containment refueling water

storage tank water surface. The component data for the passive residual heat removal heat exchanger is shown in Table 6.3-2. The passive residual heat removal heat exchanger is AP1000 Equipment Class A and is designed to meet seismic Category I requirements.

The heat exchanger inlet piping connects to an inlet channel head located near the outside top of the tank. The inlet channel head and tubesheet are attached to the tank wall via an extension flange. The heat exchanger is supported by a frame which is attached to the IRWST floor and ceiling. The heat exchanger supports are designed to ASME Code, Section III, subsection NF. The extended flange is designed to accommodate thermal expansion. Figure 6.3-5 illustrates the relationship between these parts and the boundaries of design code jurisdiction. The heat exchanger outlet piping is connected to the outlet channel head, which is vertically below the inlet channel head, near the tank bottom. The outlet channel head has an identical structural configuration to the inlet channel head. Both channel head tubesheets are similar to the steam generator tubesheets and they have manways for inspection and maintenance access.

The passive residual heat removal heat exchanger is designed to remove sufficient heat so that its operation, in conjunction with available inventory in the steam generators, provide reactor coolant system cooling and prevents water relief through the pressurizer safety valves during loss of main feedwater or main feedline break events.

Passive residual heat removal heat exchanger flow and inlet and outlet line temperatures are monitored by indicators and alarms. The operator can take action, as required, to meet the technical specification requirements or follow emergency operating procedures for control of the passive residual heat removal heat exchanger operation.

6.3.2.2.6 Depressurization Spargers

Two reactor coolant depressurization spargers are provided. Each one is connected to an automatic depressurization system discharge header (shared by three automatic depressurization system stages) and submerged in the in-containment refueling water storage tank. Each sparger has four branch arms inclined downward. The connection of the sparger branch arms to the sparger hub are submerged below the in-containment refueling water storage tank overflow level by ≤11.5 feet. The component data for the spargers is shown in Table 6.3-2. The spargers are AP1000 Equipment Class C and are designed to meet seismic Category I requirements.

The spargers perform a nonsafety-related function -- minimizing plant cleanup and recovery actions following automatic depressurization. They are designed to distribute steam into the in-containment refueling water storage tank, thereby promoting more effective steam condensation.

The first three stages of automatic depressurization system valves discharge through the spargers and are designed to pass sufficient depressurization venting flow, with an acceptable pressure drop, to support the depressurization system performance requirements. The installation of the spargers prevents undesirable and/or excessive dynamic loads on the in-containment refueling water storage tank and other structures.

Each sparger is sized to discharge at a flow rate that supports automatic depressurization system performance, which in turn, allows adequate passive core cooling system injection.

6.3.2.2.7 IRWST and Containment Recirculation Screens

The passive core cooling system has two different sets of screens that are used to prevent debris from entering the reactor and blocking core cooling passages during a LOCA: IRWST screens and containment recirculation screens. The screens are AP1000 Equipment Class C and are designed to meet seismic Category I requirements. The structural frames, attachment to the building structure,

and attachment of the screen modules use the criteria of ASME Code, Section III Subsection NF. The screen modules are fabricated of sheet metal and are designed and fabricated to a manufacturer's standard. The IRWST screens and containment recirculation screens are designed to comply with applicable licensing regulations including:

- GDC 35 of 10 CFR 50 Appendix A
- Regulatory Guide 1.82
- NUREG-0897

The operation of the passive core cooling system following a LOCA is described in Subsection 6.3.2.1.3. Proper screen design, plant layout, and other factors prevent clogging of these screens by debris during accident operations.

6.3.2.2.7.1 General Screen Design Criteria

The IRWST screens and containment recirculation screens are designed with the following criteria.

1. Screens are designed to Regulatory Guide 1.82, including:
    - Separate, large screens are provided for each function.
    - Containment recirculation screens are located well below containment floodup level. Each screen provides the function of a trash rack and a fine screen. A debris curb is provided for the containment recirculation screens to prevent high density debris from being swept along the floor to the screen face. The IRWST screens are arranged such that the lowest screening surface is 6 inches above the floor of the IRWST to prevent debris on the floor from entering the lowest levels of the screen face.
    - Floors slope away from screens (not required for AP1000).
    - Drains do not impinge on screens.
    - Screens can withstand accident loads and credible missiles.
    - Screens have conservative flow areas to account for plugging. Operation of the non-safety-related normal residual heat removal pumps with suction from the IRWST and the containment recirculation lines is considered in sizing screens.
    - System and screen performance are evaluated.
    - Screens have solid top cover. Containment recirculation screens have a protective plate that is located no more than 1 foot, 3 inches above the top of the face of the screens, which extends at least 8 feet, 3 inches perpendicular to the front and at least 7 feet to the side of the face of the screens. The plate dimensions are relative to the portion of the screens where water flow enters the screen openings. The protective plate maximum height dimension is the distance between the top of the screens and the underside of the protective plate module top plate at the exposed edges of the protective plate, which extend into the containment recirculation water flow (east toward steam generator 2, and north toward the corridor). Coating debris, from coatings located outside of the ZOI, is not transported to the containment recirculation screens, to the IRWST screens, or into a

direct vessel injection or a cold leg LOCA break that becomes submerged during recirculation considering the use of high density coatings discussed in Subsection 6.1.2.1.5.

- Screens are seismically qualified.
- Screen openings are sized to prevent blockage of core cooling.
- Screens are designed for adequate pump performance. AP1000 has no active ASME Section III safety-related pumps.
- Corrosion resistant materials are used for screens.
- Access openings in screens are provided for screen inspection.
- Screens are inspected each refueling.

2. Low screen approach velocities limit the transport of heavy debris even with operation of normal residual heat removal pumps.

3. [*Metal reflective insulation is used on ASME class 1 lines because they are subject to loss-of-coolant accidents. Metal reflective insulation is also used on the reactor vessel, the reactor coolant pumps, the steam generators, and on the pressurizer because they have relatively large insulation surface areas and they are located close to large ASME class 1 lines. As a result, they are subject to jet impingement during loss-of-coolant accidents.*]* A suitable equivalent insulation to metal reflective may be used. A suitable equivalent insulation is one that is encapsulated in stainless steel that is seam welded so that LOCA jet impingement does not damage the insulation and generate debris. Another suitable insulation is one that may be damaged by LOCA jet impingement as long as the resulting insulation debris is not transported to the containment recirculation screens, to the IRWST screens, or into a direct vessel injection or a cold leg LOCA break that becomes submerged during recirculation. In order to qualify as a suitable equivalent insulation, testing must be performed that subjects the insulation to conditions that bound the AP1000 conditions and demonstrates that debris would not be generated. If debris is generated, testing and/or analysis must be performed to demonstrate that the debris is not transported to an AP1000 screen or into the core through a flooded break. It would also have to be shown that the material used would not generate chemical debris. In addition, the testing and/or analysis must be approved by the NRC.

   [*In order to provide additional margin, metal reflective insulation is used inside containment where it would be subject to jet impingement during loss-of-coolant accidents that are not otherwise shielded from the blowdown jet.*]* As a result, fibrous debris is not generated by loss-of-coolant accidents. Insulation located within the zone of influence (ZOI), which is a spherical region within a distance equal to 29 inside diameters (for Min-K, Koolphen-K, or rigid cellular glass insulation) or 20 inside diameters (for other types of insulation) of the LOCA pipe break is assumed to be affected by the LOCA when there are intervening components, supports, structures, or other objects.

   [*The ZOI in the absence of intervening components, supports, structures, or other objects includes insulation in a cylindrical area extending out a distance equal to 45 inside diameters from the break along an axis that is a continuation of the pipe axis and up to 5 inside diameters in the radial direction from the axis.*]* A suitable equivalent insulation to metal reflective may be used as discussed in the previous paragraph.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

[*Insulation used inside the containment, outside the ZOI, but below the maximum post-DBA LOCA floodup water level (plant elevation 110.2 feet), is metal reflective insulation, jacketed fiberglass, or a suitable equivalent.*]* A suitable equivalent insulation is one that would be restrained so that it would not be transported by the flow velocities present during recirculation and would not add to the chemical precipitates. In order to qualify as a suitable equivalent insulation, testing must be performed that subjects the insulation to conditions that bound the AP1000 conditions and demonstrates that debris would not be generated. If debris is generated, testing and/or analysis must be performed to demonstrate that the debris is not transported to an AP1000 screen or into the core through a flooded break. It would also have to be shown that the material used would not generate chemical debris. In addition, the testing and/or analysis must be approved by the NRC.

[*Insulation used inside the containment, outside the ZOI, but above the maximum post-design basis accident (DBA) LOCA floodup water level, is jacketed fiberglass, rigid cellular glass, or a suitable equivalent.*]* A suitable equivalent insulation is one that when subjected to dripping of water from the containment dome would not add to the chemical precipitates; suitable equivalents include metal reflective insulation.

The non-metallic insulation used in the AP1000 reactor vessel neutron shield blocks and the water inlet doors have been determined to be a suitable equivalent for the locations bounded by testing and analysis (Reference 5).

4. Coatings are not used on surfaces located close to the containment recirculation screens. The surfaces considered close to the screens are defined in Subsection 6.3.2.2.7.3. Refer to Subsection 6.1.2.1.6. These surfaces are constructed of materials that do not require coatings.

5. The IRWST is enclosed which limits debris egress to the IRWST screens.

6. Containment recirculation screens are located above lowest levels of containment.

7. Long settling times are provided before initiation of containment recirculation.

8. Air ingestion by safety-related pumps is not an issue in the AP1000 because there are no active ASME Section III safety-related pumps. The normal residual heat removal system pumps are evaluated to show that they can operate with minimum water levels in the IRWST and in the containment.

9. A commitment for cleanliness program to limit debris in containment is provided in Subsection 6.3.8.1.

10. [*Other potential sources of fibrous material, such as ventilation filters or fiber-producing fire barriers, are not located in jet impingement damage zones or below the maximum post-DBA LOCA floodup water level.*]*

11. Other potential sources of transportable material, such as caulking, signs, and equipment tags installed inside the containment are located:

    - Below the maximum flood level, or
    - Above the maximum flood level and not inside a cabinet or enclosure.

    Tags and signs in these locations are made of stainless steel or another metal that has a density ≥ 100 lbm/ft^3. Caulking in these locations is a high density (≥ 100 lbm/ft^3).

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The use of high-density metal prevents the production of debris that could be transported to the containment recirculation screens, to the IRWST screens, or into a direct vessel injection or a cold leg LOCA break location that is submerged during recirculation. If a high-density material is not used for these components, then the components must be located inside a cabinet or other enclosure, or otherwise shown not to transport; the enclosures do not have to be watertight, but need to prevent water dripping on them from creating a flow path that would transport the debris outside the enclosure. For light-weight (< 100 lb_m/ft^3) caulking, signs or tags that are located outside enclosures, testing must be performed that subjects the caulking, signs, or tags to conditions that bound the AP1000 conditions and demonstrates that debris would not be transported to an AP1000 screen or into the core through a flooded break. Note that in determining if there is sufficient water flow to transport these materials, consideration needs to be given as to whether they are within the ZOI (for the material used) because that determines whether they are in their original geometry or have been reduced to smaller pieces. It would also have to be shown that the material used would not generate chemical debris. In addition, the testing must be approved by the NRC.

12. An evaluation consistent with Regulatory Guide 1.82, Revision 3, and subsequently approved NRC guidance, has been performed (Reference 3) to demonstrate that adequate long-term core cooling is available considering debris resulting from a LOCA together with debris that exists before a LOCA. As discussed in Subsection 6.3.2.2.7.1, a LOCA in the AP1000 does not generate fibrous debris due to damage to insulation or other materials included in the AP1000 design. The evaluation considered resident fibers and particles that could be present considering the plant design, location, and containment cleanliness program. The determination of the characteristics of such resident debris was based on sample measurements from operating plants. The evaluation also considered the potential for the generation of chemical debris (precipitants). The potential to generate such debris was determined considering the materials used inside the AP1000 containment, the post-accident water chemistry of the AP1000, and the applicable research/testing.

    The evaluation considered the following conservative considerations:

    - [*The COL cleanliness program will limit the total amount of resident debris inside the containment to ≤ 130 pounds and the amount of the total that might be fiber to ≤ 6.6 pounds.*]*

    - In addition to the resident debris, the LOCA blowdown jet may impinge on coatings and generate coating debris fines, which because of their small size, might not settle. The amount of coating debris fines that can be generated in the AP1000 by a LOCA jet will be limited to less than 70 pounds for double-ended cold leg and double-ended direct vessel injection LOCAs. In evaluating this limit, a ZOI of 4 IDs for epoxy and 10 IDs for inorganic zinc will be used. A DEHL LOCA could generate more coating debris; however, with the small amount of fiber available in the AP1000 following a LOCA, the additional coating debris fines that may be generated in a DEHL LOCA are not limiting.

    - For ZOIs used in the debris evaluation, the diameter can be determined from the double ended guillotine break of primary system piping or the alternate debris generation size (Reference 5) developed in accordance with the alternate evaluation approach from NEI 04-07 (Reference 6).

    - The total resident and ZOI coating debris available for transport following a LOCA is ≤ 193.4 pounds of particulate and ≤ 6.6 pounds of fiber. The percentage of this debris that could be transported to the screens or to the core is as follows:

        – Containment recirculation screens is ≤ 100 percent fiber and particles

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

  - IRWST screens is ≤ 50 percent fiber and 100 percent particles
  - Core (via a direct vessel injection or a cold leg LOCA break that becomes submerged) is ≤ 90 percent fiber and 100 percent particles
- Fibrous insulation debris is not generated and transported to the screens or into the core as discussed in item 3.
- Metal reflective insulation, including accident generated debris, is not transported to the screens or into the core.
- Coating debris is not transported to the screens or into the core as discussed in item 1.
- Debris from other sources, including caulking, signs, and tags, is not generated and transported to the screens or into the core as discussed in item 11.
- A ZOI radius of 4 IDs is applicable to the AP1000 in-containment cables bounded by testing and analysis, consistent with Reference 5.
- The total amount of chemical precipitates that could form in 30 days is ≤ 57 pounds.
- The percentage of the chemical precipitates that could be transported to the:
  - Containment recirculation screens is ≤ 100 percent.
  - IRWST screens is ≤ 100 percent.
  - Core is ≤ 100 percent.
- The range of flow rates during post-LOCA injection and recirculation is as follows:
  - CR screens: 2600 to 539 gpm
  - IRWST screens: 2600 to 464 gpm
  - Core: 2012 to 484 gpm

These flows bound operation of the PXS and the RNS. Note that if the RNS operates during post-LOCA injection or recirculation, the RNS flow is limited to 2600 gpm. This limit ensures that the operation of the plant is consistent with screen head loss testing. In addition, the screens will be designed structurally to withstand much higher flow rates and pressure losses to provide appropriate margin during PXS and RNS operation.

No chemical precipitates are expected to enter the IRWST because the primary water input to the IRWST is steam condensed on the containment vessel. However, during a direct vessel injection LOCA, recirculation can transport chemical debris through the containment recirculation screens and to the IRWST screens. As a result, 100 percent of the chemical debris is conservatively assumed to be transported to the IRWST screens.

The AP1000 containment recirculation screens and IRWST screens have been shown to have acceptable head losses. The head losses for these screens were determined in testing performed using the above conservative considerations. It has been shown that a head loss of 0.25 psi at the maximum screen flows is acceptable based on long-term core cooling sensitivity analysis.

Considering downstream effects as well as potential bypass through a cold leg LOCA, the core was shown to have acceptable head losses. The head losses for the core were determined in testing performed using the above conservative considerations. It has been shown that a head loss of 4.1 psi at these flows is acceptable based on long-term core cooling sensitivity analysis.

6.3.2.2.7.2 IRWST Screens

The IRWST screens are located inside the IRWST at the bottom of the tank. Figure 6.3-6 shows a plan view and Figure 6.3-7 shows a section view of these screens. Three separate screens are provided in the IRWST, one at either end of the tank and one in the center. A cross-connect pipe connects all three IRWST screens to distribute flow. The IRWST is closed off from the containment; its vents and overflow weirs are normally closed by louvers. The potential for introducing debris inadvertently during plant operations is limited. A cleanliness program (refer to Subsection 6.3.8.1) controls foreign debris from being introduced into the tank during maintenance and inspection operations. The Technical Specifications require visual inspections of the screens during every refueling outage.

The IRWST design eliminates sources of debris from inside the tank. Insulation is not used in the tank. Air filters are not used in the IRWST vents or overflow weirs. Wetted surfaces in the IRWST are corrosion resistant such as stainless steel or nickel alloys; the use of these materials prevents the formation of significant amounts of corrosion products. In addition, the water is required to be clean because it is used to fill the refueling cavity for refueling; filtering and demineralizing by the spent fuel pool cooling system is provided during and after refueling.

During a LOCA, steam vented from the reactor coolant system condenses on the containment shell and drains down the shell to the polar crane girder or internal stiffener where it is drained via downspouts to the IRWST. Steam that condenses below the internal stiffener drains down the shell and is collected in a gutter near the operating deck elevation. It is very unlikely that debris generated by a LOCA can reach the downspouts or the gutter because of their locations. Each downspout inlet is covered with a coarse screen that prevents larger debris from entering the downspout. The gutter is covered with a trash rack which prevents larger debris from clogging the gutter or entering the IRWST through the two 4-inch drain pipes. The inorganic zinc coating applied to the inside surface of the containment shell is safety – Service Level I, and will stay in place and will not detach.

The design of the IRWST screens reduces the chance of debris reaching the screens. The screens are oriented vertically such that debris that settles out of the water does not fall on the screens. The lowest screening surface of the IRWST screens is located 6 inches above the IRWST floor to prevent debris on the floor from entering the lowest levels of the IRWST screens. The screen design provides the trash rack function. This is accomplished by the screens having a large surface area to prevent a single object from blocking a large portion of the screen and by the screens having a robust design to preclude an object from damaging the screen and causing by-pass. The screen prevents debris larger than 0.0625 inch from being injected into the reactor coolant system and blocking fuel cooling passages. The screen is a type that has sufficient surface area to accommodate debris that could be trapped on the screen. The design of the IRWST screens is described further in APP-GW-GLN-147 (Reference 4).

The screen flow area is conservatively designed considering the operation of the nonsafety-related normal residual heat removal system pumps which produce a higher flow than the safety-related gravity driven IRWST injection/recirculation flows. As a result, when the normal residual heat removal system pumps are not operating, there is a large margin to screen clogging.

6.3.2.2.7.3 Containment Recirculation Screens

The containment recirculation screens are oriented vertically along walls above the loop compartment floor (elevation 83 feet). Figure 6.3-8 shows a plan view and Figure 6.3-9 shows a section view of these screens. Two separate screens are provided as shown in Figure 6.3-3. The loop compartment floor elevation is significantly above (11.5 feet) the lowest level in the containment, the reactor vessel cavity. A two-foot-high debris curb is provided in front of the screens.

During a LOCA, the reactor coolant system blowdown will tend to carry debris created by the accident (pipe whip/jets) into the cavity under the reactor vessel which is located away from and below the containment recirculation screens. As the accumulators, core makeup tanks and IRWST inject, the containment water level will slowly rise above the 108 foot elevation. The containment recirculation line opens when the water level in the IRWST drops to the Low-3 level setpoint a few feet above the final containment floodup level. When the recirculation lines initially open, the water level in the IRWST is higher than the containment water level and water flows from the IRWST backwards through the containment recirculation screen. This back flow tends to flush debris located close to the recirculation screens away from the screens. A flow connection between Screen A and Screen B is provided so that both recirculation screens will operate. This connection increases the reliability of the PXS in a PRA sequence where there are multiple failures of valves in one of the PXS subsystems.

The water level in the containment when recirculation begins is well above (~ 10 feet) the top of the recirculation screens. During the long containment floodup time, floating debris does not move toward the screens and heavy materials settle to the floors of the loop compartments or the reactor vessel cavity. During recirculation operation, the containment water level will not change significantly nor will it drop below the top of the screens.

The amount of debris that may exist following an accident is limited. Reflective insulation (or a suitable equivalent, as demonstrated per the criteria in Subsection 6.3.2.2.7.1) is used to preclude fibrous debris that can be generated by a loss of coolant accident and be postulated to reach the screens during recirculation. The nonsafety-related coatings used in the containment are designed to withstand the post accident environment. The containment recirculation screens are protected by a plate located above them. The protective plate prevents debris from the failure of nonsafety-related coatings from getting into the water close to the screens (closer than 8 feet, 3 inches from the front of the face of the screens and 7 feet from the side of the face of the screens) where the recirculation flow could cause the debris to be swept to the screens before it settles to the floor. The north edge of the north containment recirculation screen face is located at least 3 feet, 6 inches from the north corner of the west wall of steam generator compartment 2 (Room 11202), to which the containment recirculation screens are attached. Placement of the north containment recirculation screen prevents debris falling into the vertical access corridor (Room 11204) from entering the water closer than 3 feet, 6 inches from the face of the north containment recirculation screen. Stainless steel is used on the underside of the plate and on surfaces located below the plate, above the bottom of the screen face, extending at least 8 feet, 3 inches perpendicular to the front and at least 7 feet to the side of the face of the screens to prevent coating debris from reaching the screens.

A cleanliness program (refer to Subsection 6.3.8.1) controls foreign debris introduced into the containment during maintenance and inspection operations. The Technical Specifications require visual inspections of the screens during every refueling outage.

The design of the containment recirculation screens reduces the chance of debris reaching the screens. The screens are orientated vertically such that debris settling out of the water will not fall on the screens. The protective plate described above provides additional protection to the screens from debris. A 2-foot-high debris curb is provided to prevent high density debris from being swept along the floor by water flow to the containment recirculation screens. The screen design provides the trash

rack function. This is accomplished by the screens having a large surface area to prevent a single object from blocking a large portion of the screen and by the screens having a robust design to preclude an object from damaging the screen and causing by-pass. The screen prevents debris larger than 0.0625 inch from being injected into the reactor coolant system and blocking fuel cooling passages. The screen is a type that has more surface area to accommodate debris that could be trapped on the screen. The design of the containment recirculation screens is further described in APP-GW-GLN-147 (Reference 4).

The screen flow area is conservatively designed, considering the operation of the normal residual heat removal system pumps, which produce a higher flow than the gravity driven IRWST injection/ recirculation flows. As a result, when the normal residual heat removal system pumps are not operating there is even more margin in screen clogging.

6.3.2.2.8 Valves

Design features used to minimize leakage for valves in the passive core cooling system include:

- Hermetically sealed valves are used for manual isolation valves that are 2 inches or smaller, except for some valves in the passive core cooling system test header, which have stems that are not normally pressurized.

- Valves which are normally open, except check valves and those which perform control function, are provided with back seats to limit stem leakage.

6.3.2.2.8.1 Manual Globe, Gate, and Check Valves

Gate valves have backseats and external screw and yoke assemblies.

Globe valves, both “T” and “Y” styles, are full-ported with external screw and yoke construction.

Stainless steel check valves have no penetration welds other than the inlet, outlet, and bonnet. The check valve hinge is serviced through the bonnet.

The gasket of the stainless steel manual globe and gate valves is similar to those described in Subsection 6.3.2.2.8.3 for motor-operated valves.

6.3.2.2.8.2 Manual Valves

Manual valves are generally used as maintenance isolation valves. When used for this function they are under administrative control. They are located so that no single valve can isolate redundant passive core cooling system equipment or they are provided with alarms in the main control room to indicate mispositioning.

To help preclude the possibility of passive core cooling system degradation due to valve mispositioning, line connections such as vent and drain lines, test connections, pressure points, flow element test points, flush connections, local sample points, and bypass lines are provided with double isolation or sealed barriers. The isolation is provided by one of the following methods:

- Two valves in series

- A single valve with a blind flange or pipe/tubing plug

- A single locked-closed valve

- A blind flange

6.3.2.2.8.3 Motor-Operated Valves

The motor operators for gate valves are conservatively sized, considering the frictional component of the hydraulic unbalance on the valve disc, the disc face friction, and the packing box friction. For motor-operated valves, the valve disc is guided throughout the full disc travel to prevent chattering and to provide ease of gate movement. The seating surfaces are hard-faced to prevent galling and to reduce wear.

Where a gasket is employed for the body to bonnet joint, it is either a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding or it is of the pressure seal design with provisions for seal welding.

6.3.2.2.8.4 Motor-Operated Valve Controls

Remotely operated valves which do not receive a safeguards actuation signal, have their positions indicated on the main control board. When one of these valves is not in the ready position for injection during plant operation, this condition is indicated and alarmed in the main control room.

Spurious movement of a motor-operated valve due to an electrical fault in the motor actuation circuitry, coincident with loss of coolant accident, has been analyzed (Reference 1) and found to be an acceptably low probability event. In addition, power lockout in accordance with Branch Technical Position ICSB-18 is provided for those valves whose spurious movement could result in degraded passive core cooling system performance.

Table 6.3-1 provides a list of the remotely operated isolation valves in the passive core cooling system. These valves have various interlocks, automatic features, and position indication. Some valves have their control power locked out during normal plant operation. Periodic visual inspection and operability testing of the motor-operated valves in the passive core cooling system confirm valve operability. In addition, the location of the motor-operated valves within the containment, which are identified in Table 6.3-1, has been examined to identify remotely operated valves which may be submerged following a postulated loss of coolant accident.

See Section 3.4 for additional information on containment flooding effects.

6.3.2.2.8.5 Automatic Depressurization Valves

The automatic depressurization system consists of four different stages of valves. The first three stages each have two lines and each line has two valves in series; both normally closed. The fourth stage has four lines with each line having two valves in series; one normally open and one normally closed. The four stages, therefore, include a total of 20 valves. The four valve stages open sequentially.

The first stage, second-stage and third-stage valves have dc motor operators. The stage 1/2/3 control valves are normally closed globe valves; the isolation valves are normally closed gate valves. The fourth-stage valves are interlocked so that they can not open until reactor coolant system pressure has been substantially reduced. The fourth stage control valves are squib valves. There is a normally open motor-operated gate valve in series with each squib valve.

The first three stages have a common inlet header connected to the top of the pressurizer. The outlet of the first to third stages then combine to a common discharge line to one of the spargers in the in-containment refueling water storage tank. There is a second identical group of first- to third-stage valves with its own inlet and outlet line and sparger.

The fourth-stage valves connect directly to the top of the reactor coolant hot leg and vent directly to the steam generator compartment. There are also two groups of fourth stage valves, with one group in each steam generator compartment.

The automatic depressurization valves are designed to automatically open when actuated and to remain open for the duration of an automatic depressurization event. Valve stages 1 and 4 actuate at discrete core makeup tank levels, as either tank's level decreases during injection or from spilling out a broken injection line. Valve stages 2 and 3 actuate based upon a timed delay after actuation of the preceding stage. This opening sequence provides a controlled depressurization of the reactor coolant system. The valve opening sequence prevents simultaneous opening of more than one stage, to allow the valves to sequentially open. The valve actuation logic is based on two-of-four level detectors, in either core makeup tank for automatic depressurization system stages 1 and 4.

The stage 1/2/3 automatic depressurization control valves are designed to open relatively slowly. During the actuation of each stage, the isolation valve is sequenced open before the control valve. Therefore, there is some time delay between stage actuation and control valve actuation.

The operators can manually open the first-stage valves to a partially open position to perform a controlled depressurization of the reactor coolant system. Additional information on the automatic depressurization valves is provided in Subsection 5.4.6.

6.3.2.2.8.6 Low Differential Pressure Opening Check Valves

Several applications in the passive core cooling system gravity injection piping use check valves that open with low differential pressures. These check valves are installed in the following locations:

- The gravity injection line flow paths from the in-containment refueling water storage tank
- The containment recirculation lines that connect to the gravity injection lines

The check valves selected for these applications incorporate a simple swing-check design with a stainless steel body and hardened valve seats. The passive core cooling system check valves are safety-related, designed with their operating parts contained within the body, and with a low pressure drop across each valve. The valve internals are exposed to low temperature reactor coolant or borated refueling water.

During normal plant operation, these check valves are closed, with essentially no differential pressure across them. Confidence in the check valve operability is provided by operation at no differential pressure clean/cold fluid environment, the simple valve design, and the specified seat materials.

The check valves normally remain closed, except for testing or when called upon to open following an event to initiate passive core cooling system operation. The valves are not subject to the degradation from flow operation or impact loads caused by sudden flow reversal and seating, and they do not experience significant wear of the moving parts.

These check valves are periodically tested during shutdown conditions to demonstrate valve operation. These check valves are equipped with nonintrusive position sensors to indicate when the valves are open or closed.

6.3.2.2.8.7 Accumulator Check Valves

The accumulator check valve design is similar to the accumulator check valves in current pressurized water reactor applications. It is also similar to the low differential pressure opening check valve

design described in Subsection 6.3.2.2.8.6. The accumulator check valves are diverse from the core makeup tank valves because they use different check valve types.

During normal operation, the check valves are in the closed position with a nominal differential pressure across the disc of about 1550 psid. The valves remain in this position, except for testing or when called upon to open following an event. They are not subject to the degradation from flow operation or impact loads caused by sudden flow reversal and seating. They do not experience significant wear of the moving parts and they are expected to function with minimal backleakage.

The accumulators can accept some inleakage from the reactor coolant system without affecting availability. Continuous inleakage requires that the accumulator water volume and boron concentration be adjusted periodically to meet technical specification requirements.

The AP1000 accumulator check valves are periodically tested during shutdown conditions to demonstrate their operation.

6.3.2.2.8.8 Relief Valves

Relief valves are installed for passive core cooling system accumulators to protect the tanks from overpressure.

The passive core cooling system piping is reviewed to identify those lengths of piping that are isolated by normally closed valves and that do not have pressure relief protection in the piping section between the valves.

These piping sections include:

- Portions of in-containment passive core cooling system test lines that are not passive core cooling system accident mitigation flow paths and are not needed to achieve safe shutdown
- Piping vents, drains, and test connections that typically have two closed valves or one closed valve and a blind flange, or pipe/tubing plug
- Check valve test lines with sections isolated by two normally closed valves.

The piping vents, drains, test connections, and check valve lines have design pressure/ temperature conditions compatible with the process piping to which they connect. Valve leakage does not overpressurize the isolated piping sections and pressure relief provisions are not required.

6.3.2.2.8.9 Explosively Opening (Squib) Valves

Squib valves are used in several passive core cooling system lines in order to provide the following:

- Zero leakage during normal operation
- Reliable opening during an accident
- Reduced maintenance and associated personnel radiation exposure

Squib valves are used to isolate the incontainment refueling water storage tank injection lines and the containment recirculation lines. In these applications, the squib valves are not expected to be opened during normal operation and anticipated transients. In addition, after they are opened it is not necessary that they re-close.

In the incontainment refueling water storage tank injection lines, the squib valves are in series with normally closed check valves. Inadvertent opening of the injection squib valves is considered beyond design basis. However, the consequence of this inadvertent opening could lead to a loss of reactor coolant. Therefore, a blocking device, as described in Subsection 7.3.1.2.4.1, is utilized to preclude the inadvertent opening of the injection squib valves. In the containment recirculation lines, the squib valves are in series with normally closed check valves in two lines and with normally open motor operated valves in the other two lines. Inadvertent opening of these recirculation squib valves is a beyond design basis event that will not result in loss of reactor coolant but will drain the incontainment refueling water storage tank. In the event of inadvertent actuation, the operator would manage the plant in accordance with the appropriate operating procedures.

The type of squib valve used in these applications provides zero leakage in both directions. It also allows flow in both directions. A valve open position sensor is provided for these valves. The IRWST injection squib valves and the containment recirculation squib valves in series with check valves are diverse from the other containment recirculation squib valves. They are designed to different design pressures. The IRWST injection and the containment recirculation squib valves are qualified to operate after being submerged; this capability adds margin to the performance of the PXS in handling debris during long-term core cooling following a LOCA.

Squib valves are also used to isolate the fourth stage automatic depressurization system lines. These squib valves are in series with normally open motor operated gate valves. Actuation of these squib valves requires signals from two separate protection logic cabinets. This helps to prevent spurious opening of these squib valves. The type of squib valve used in this application provides zero leakage of reactor coolant out of the reactor coolant system. The reactor coolant pressure acts to open the valve. A valve open position sensor is provided for these valves.

See Section 13.6 with regard to the use of these special explosive devices on-site.

6.3.2.3 Applicable Codes and Classifications

Sections 5.2 and 3.2 list the equipment ASME Code and seismic classification for the passive core cooling system. Most of the piping and components of the passive core cooling system within containment are AP1000 Equipment Class A, B, or C and are designed to meet seismic Category I requirements. Equipment Class C components and piping, that provide an emergency core cooling function, have augmented weld inspection requirements (see Subsection 3.2.2.5). Some system piping and components that do not perform safety-related functions are nonsafety-related.

The requirements for the control, actuation, and Class 1E devices are presented in Chapters 7 and 8.

6.3.2.4 Material Specifications and Compatibility

Materials used for engineered safety feature components are given in Section 6.1. Materials for passive core cooling system components are selected to the meet the applicable material requirements of the codes in Section 5.2, as well as the following additional requirements:

- Parts of components in contact with borated water are fabricated of, or clad with, austenitic stainless steel or an equivalent corrosion-resistant material.

- Internal parts of components in contact with containment emergency sump solution during recirculation are fabricated of austenitic stainless steel or an equivalent corrosion resistant material.

- Valve seating surfaces are hard-faced to prevent failure and to reduce wear.

- Valve stem materials are selected for their corrosion resistance, high-tensile properties, and their resistance to surface scoring by the packing.

Section 6.1 summarizes the materials used for passive core cooling system components.

6.3.2.5 System Reliability

The reliability of the passive core cooling system is considered including periodic testing of the components during plant operation. The passive core cooling system is a redundant, safety-related system. The system is designed to withstand credible single active or passive failures.

The initiating signals for the passive core cooling system are derived from independent sources as measured from process parameters (pressurizer Low-3 pressure) or environmental (containment High-2 pressure) variables. Redundant, as well as functionally independent variables, are measured to initiate passive core cooling system operation.

Redundant passive core cooling system components are physically separated and protected so that a single event cannot initiate a common failure.

Power sources for the passive core cooling system are divided into four independent divisions that are supplied from the Class 1E dc and UPS system. Sufficient battery capacity is maintained to provide required power to the emergency loads when onsite and offsite ac power sources are not available. Section 8.3 provides additional information.

The preoperational testing program confirms that the systems, as designed and constructed meet the functional design requirements. Section 14.2 provides additional information. The passive core cooling system is designed with the capability for on-line testing of its active components so the availability and operation status can be readily determined. Testing of passive components such as check valves, tanks, heat exchanger, and flow paths can be conducted during shutdown conditions. In addition, the integrity of the passive core cooling system is verified through examination of critical components during the routine in-service inspection. Subsection 3.9.6 provides additional information.

The reliability assurance program described in Section 16.2, extends to the procurement of passive core cooling system components. The procurement quality assurance program is described in Chapter 17.

The passive core cooling system is a redundant, safety-related system. During the long-term cooling period following a loss of coolant accident, once the passive core cooling system equipment has actuated, there is no long-term maintenance required. Components actuate to the safeguards actuation alignment and do not need subsequent position changes for long-term operation.

For long-term cooling, the reactor coolant system is depressurized to containment ambient pressure following a loss of coolant accident. During this period, the heat generated in the reactor core is the residual decay heat and the passive core cooling system provides the required decay heat removal.

Proper initial filling and venting of the passive core cooling system prevents water hammer from occurring in the passive core cooling system lines. In addition, the head of water provided by the various tanks keeps system lines full. The arrangement of the core makeup tank pressure equalization line design also reduces the potential for water hammer. High-point vents in the passive core cooling system lines are provided as a means for venting of lines. Fill and venting procedures for the passive core cooling system provide for the removal of air from the system.

The existence of high-point vents and the positive head of water provide means by which the operator can confirm water-solid passive core cooling system lines, where required.

6.3.2.5.1 Response to Active Failure

Treatment of active failures is described in Subsection 15.0.12.

An active failure is the failure of a powered component, a component of the electrical supply system, or instrumentation and control equipment to act on command to perform its function. One example is the failure of a motor-operated valve to move to its intended safeguards actuation position.

One change in the definition of active failures has been incorporated into the passive core cooling system design. The system has been specifically designed to treat check valve failures to reposition as active failures. More specifically, it is assumed that normally closed check valves may fail to open and normally open check valves may fail to close. Check valves that remain in the same position before and after an event are not considered active failures.

There are two exceptions to this treatment of check valve failures in the passive core cooling system. One exception is made for the accumulator check valves, which is consistent with the treatment of these specific check valves in currently licensed plant designs. The other exception is made for the core makeup tank check valves failure to re-open after they have closed during an accident. The valves are normally open, biased-opened check valves. This exception is based on the low probability of these check valves not re-opening within a few minutes after they have cycled closed during accumulator operation.

The failure mode and effects analysis provided in Table 6.3-3 provides a summary of the passive core cooling system response to single failure of the various components.

The following passive core cooling system motor-operated valves are not included in this analysis:

- Both accumulator discharge line motor-operated valves
- Both in-containment refueling water storage tank gravity injection line motor-operated valves
- Both containment recirculation line motor-operated valves
- Both core makeup tank inlet line motor-operated valves
- The passive residual heat removal heat exchanger inlet line motor-operated valve

These valves are normally in the required position for actuation of the associated component, they have redundant position indications and alarms, and they also receive confirmatory open actuation signals. The accumulator, incontainment refueling water storage tanks and passive residual heat removal heat exchanger valves have their power removed and locked out. The core makeup tank line has redundant series controllers. Therefore, these valves are not considered in the failure modes and effects analysis.

The analysis illustrates that the passive core cooling system can sustain an active failure in either the short-term or long-term and meet the required level of performance for core cooling. The short-term operation of the active components of the passive core cooling system following a steam line rupture or a steam generator tube rupture is similar to that following a loss of coolant accident. The same analysis is applicable and the passive core cooling system can sustain the failure of a single active component and meet the level of performance for the addition of shutdown reactivity.

Portions of the passive core cooling system are also relied upon to provide boration and makeup during a safety-related shutdown. The passive core cooling system can sustain an active failure and perform the required functions necessary to establish safe shutdown conditions. Safe shutdown operation of the passive core cooling system is described in Section 7.4.

6.3.2.5.2 Response to Passive Failure

Treatment of passive failures is described in Subsection 15.0.12.

A passive failure is the structural failure of a static component which limits the component's effectiveness in carrying out its design function. Examples include cracking of pipes, sprung flanges, or valve packing leaks. The passive core cooling system can sustain a single passive failure during the long-term phase and still retain an intact flow path to the core to supply sufficient flow to keep the core covered and to remove decay heat.

Since the passive core cooling system equipment is inside the containment, offsite dose caused by passive failures is not a concern. Also, with actuation of the automatic depressurization system, the reactor coolant system pressure is very close to containment pressure. Therefore, it is not necessary to isolate or realign the passive core cooling system following a passive failure.

The passive core cooling system flow paths are separated into redundant lines, either of which can provide minimum core cooling functions and return spilled water from the floor of the containment back to the reactor coolant system. For the long-term passive core cooling system function, adequate core cooling capacity exists with one of the two redundant flow paths.

6.3.2.5.3 Lag Times

Lag times for initiation and operation of the passive core cooling system are controlled by repositioning of valves. Some valves are normally in the position required for safety-related system function and therefore, their valve operation times are not considered. For those valves that reposition to initiate safety-related system functions, the valve repositioning times are less than the times assumed in the accident analyses. These lag times refer to the time after initiation of the safeguards actuation signal.

6.3.2.5.4 Potential Boron Precipitation

Boron precipitation in the reactor vessel is prevented by sufficient flow of passive core cooling system water through the core to limit the increase in boron concentration of the water remaining in the reactor vessel. Water along with steam leaves the core and exits the RCS through the fourth stage ADS lines. These valves connect to the hot leg and open in about 20 minutes after a loss of coolant accident or an automatic depressurization system actuation.

6.3.2.5.5 Safe Shutdown

During a safe shutdown, the passive core cooling system provides redundancy for boration, makeup, and heat removal functions. Section 7.4 provides additional information about safe shutdown.

6.3.2.6 Protection Provisions

The measures taken to protect the system from damage that might result from various events are described in other sections, as listed below.

- Protection from dynamic effects is presented in Section 3.6.

- Protection from missiles is presented in Section 3.5.
- Protection from seismic damage is presented in Sections 3.7, 3.8, 3.9, and 3.10.
- Protection from fire is presented Subsection 9.5.1.
- Environmental qualification of equipment is presented in Section 3.11.
- Thermal stresses on the reactor coolant system are presented in Section 5.2.

6.3.2.7 Provisions for Performance Testing

The passive core cooling system includes the capability for determination of the integrity of the pressure boundary formed by series passive core cooling system check valves. Additional information on testing can be found in Subsection 6.3.6.

6.3.2.8 Manual Actions

The passive core cooling system is automatically actuated for those events as presented in Subsection 6.3.3. Following actuation, the passive core cooling system continues to operate in the injection mode until the transition to recirculation initiates automatically following containment floodup.

Although the passive core cooling system operates automatically, operator actions would be beneficial, in some cases, in reducing the consequences of an event. For example, in a steam generator tube rupture with no operator action, the protection and safety monitoring system automatically terminates the leak, prevents steam generator overfill, and limits the offsite doses. However, the operator can initiate actions, similar to those taken in current plants, to identify and isolate the faulted steam generator, cool down and depressurize the reactor coolant system to terminate the break flow to the steam generator, and stabilize plant conditions.

The operator can take action to avoid actuation of the automatic depressurization system when it is not needed. For non-LOCA events during which ac power has been lost for more than 22 hours, the protection and safety monitoring system will automatically open the automatic depressurization system valves to begin a controlled depressurization of the reactor coolant system and, eventually, containment floodup and recirculation prior to depletion of the 24-hour Class 1E actuation batteries. However, the operators can take action to block actuation of the automatic depressurization system should actuation be deemed unnecessary based on reactor coolant system conditions. This action allows closed loop passive residual heat removal heat exchanger operation to continue as long as acceptable reactor coolant system conditions are maintained.

Section 7.4 describes the anticipated operator actions to block the unnecessary automatic depressurization system actuation and to achieve recovery using available systems to remove decay heat. Section 7.5 describes the post-accident monitoring instrumentation available to the operator in the main control room following an event.

6.3.3 Performance Evaluation

The events described in Subsection 6.3.1 result in passive core cooling system actuation and are mitigated within the performance criteria. For the purpose of evaluation in Chapters 15 and 19, the events that result in passive core cooling system actuation are categorized as follows:

A. Increase in heat removal by the secondary system

1. Inadvertent opening of a steam generator power-operated atmospheric steam relief or safety valve

2. Steam system piping failure

B. Decrease in heat removal by the secondary system

1. Loss of Main Feedwater Flow

2. Feedwater system piping failure

C. Decrease in reactor coolant system inventory

1. Steam generator tube rupture

2. Loss of coolant accident from a spectrum of postulated reactor coolant system piping failures

3. Loss of coolant due to a rod cluster control assembly ejection accident

   (This event is enveloped by the reactor coolant system piping failures.)

D. Shutdown Events (Chapter 19)

1. Loss of Startup Feedwater

2. Loss of normal residual heat removal system with reactor coolant system pressure boundary intact

3. Loss of normal residual heat removal system during mid-loop operation

4. Loss of normal residual heat removal system with refueling cavity flooded

The events listed in groups A and B are non-LOCA events where the primary protection is provided by the passive core cooling system passive residual heat removal heat exchanger. For these events, the passive residual heat removal heat exchanger is actuated by the protection and monitoring system for the following conditions:

- Low-2 steam generator narrow range water level, coincident with startup feedwater Low-2 flow
- Low-2 steam generator wide range water level
- Core makeup tank actuation
- Automatic depressurization actuation
- Pressurizer water level - High 3
- Manual actuation

The events listed in group C above are events involving the loss of reactor coolant where the primary protection is by the core makeup tanks and accumulators. For these events the core makeup tanks are actuated by the protection and monitoring system for the following conditions:

- Pressurizer Low-3 pressure
- Pressurizer Low-2 level
- Steam line Low-2 pressure
- Containment High-2 pressure
- Cold leg Low-2 temperature
- Low-2 steam generator wide range water level, coincident with reactor coolant system high hot leg temperature
- Manual actuation

In addition to initiating passive core cooling system operation, these signals initiate other safeguards automatic actions including reactor trip, reactor coolant pump trip, feedwater isolation, and containment isolation. The passive core cooling system actuation signals are described in Section 7.3.

The core makeup tanks and passive residual heat removal heat exchangers are also actuated by the Diverse Actuation System as described in Subsection 7.7.1.11.

Upon receipt of an actuation signal, the actions described in Subsection 6.3.2.1 are automatically initiated to align the appropriate features of the passive core cooling system.

For non-LOCA events, the passive residual heat removal heat exchanger is actuated so that it can remove core decay heat. The passive residual heat removal heat exchanger can operate for at least 72 hours after initiation of a design basis event to satisfy Condition I, II, III, and IV safety evaluation criteria described in the relevant safety analyses. Subsection 6.3.3.2.1.1 provides an evaluation of the duration of the passive residual heat removal heat exchanger operation using the LOFTRAN code described in Subsection 15.0.11.2. In this evaluation, it is assumed that the operators power down the protection and safety monitoring actuation cabinets in the 22-hour time frame prior to the automatic timer actuating the automatic depressurization system.

In addition to mitigating the initiating events, the passive residual heat removal heat exchanger is capable of cooling the reactor coolant system to the specified safe shutdown condition of 420°F within 36 hours as described in Subsection 19E.4.10.2. A non-bounding, conservative analysis of the plant response during operator-initiated, extended operation of the passive residual heat removal heat exchanger is demonstrated in the shutdown temperature evaluation of Subsection 19E.4.10.2. The closed-loop cooling mode allows the reactor coolant system pressure to decrease and reduces the stress in the reactor coolant system and connecting pipe.

For loss of coolant accidents, the core makeup tanks deliver borated water to the reactor coolant system via the direct vessel injection nozzles. The accumulators deliver flow to the direct vessel injection line whenever reactor coolant system pressure drops below the tank static pressure. The in-containment refueling water storage tank provides gravity injection once the reactor coolant system pressure is reduced to below the injection head from the in-containment refueling water storage tank. The passive core cooling system flow rates vary depending upon the type of event and its characteristic pressure transient.

As the core makeup tanks drain down, the automatic depressurization system valves are sequentially actuated. The depressurization sequence establishes reactor coolant pressure conditions that allow injection from the accumulators, and then from the in-containment refueling water storage tank and

the containment recirculation path. Therefore, an injection source is continually available. If onsite or offsite ac power has not been restored after 72 hours, the post-72 hour support actions described in Subsection 1.9.5.4 maintain this mode of core cooling and provide adequate decay heat removal for an unlimited time.

The transient analyses summarized in Chapter 15 are extended long enough to demonstrate the applicable safety evaluation criteria are met. It is expected that normal systems would be available such that operators could terminate the passive safety systems and proceed with an orderly shutdown. However, as discussed in Subsection 6.3.1.1.4, the passive systems are capable of bringing the plant to a safe, stable condition for at least 72 hours in closed loop cooling mode and for longer in an open loop mode.

The events listed in group D occur during shutdown conditions that are characterized by slow plant responses and mild thermal-hydraulic transients. In addition, some of the passive core cooling system features need to be isolated to allow the plant to be in these conditions or to perform maintenance on the system. The protection and monitoring system automatically actuates gravity injection from the IRWST to provide core cooling during shutdown conditions prior to refueling cavity floodup. In addition, the operator can also manually actuate other passive core cooling system equipment, such as the passive residual heat removal heat exchanger, to provide core cooling during shutdown conditions when the equipment does not automatically actuate.

6.3.3.1 Increase in Heat Removal by the Secondary System

A number of events that could result in an increase in heat removal from the reactor coolant system by the secondary system have been postulated. For each event, consideration has been given to operation of nonsafety-related systems that could affect the event results. The operation of the startup feedwater system and the chemical and volume control system makeup pumps can affect these events. Analyses of these events, both with and without these nonsafety-related systems operating, are presented in Section 15.1. For those events resulting in passive core cooling system actuation, the following summarizes passive core cooling system performance.

6.3.3.1.1 Inadvertent Opening of a Steam Generator Relief or Safety Valve

Subsection 15.1.4 provides a description of an inadvertent opening of a steam generator relief or safety valve, including criteria and analytical results.

For this event, upon generation of a safeguards actuation signal the reactor is tripped, the core makeup tanks are actuated, and the reactor coolant pumps are tripped. Since the core makeup tanks are actuated, the passive residual heat removal heat exchanger is also actuated. The main steam lines are also isolated to prevent blowdown of more than one steam generator. The core makeup tanks operate with water recirculation injection to provide borated water to the reactor vessel downcomer plenum for reactor coolant system inventory and reactivity control. The trip of the reactor initially brings the reactor sub-critical. The rapid reactor coolant system cool down may result in the reactor returning to critical because the rate of positive reactivity addition (reactor coolant system temperature reduction) exceeds the rate of negative reactivity addition (boron from the core makeup tank). As the event continues, the reactor coolant system cooldown will slow down such that the continued core makeup tank boration will return the reactor sub-critical. The departure from nucleate boiling design basis is met, thereby preventing fuel damage.

During this event, the startup feedwater system is assumed to malfunction so that it injects water at the maximum flow rate. This injection continues until feedwater isolation occurs on low reactor coolant system temperature. The feedwater isolation signal terminates the feedwater addition from the startup feedwater system. The passive residual heat removal heat exchanger is also assumed to function in this event. This heat removal mechanism continues throughout the duration of the event.

For this event, the core makeup tanks operate in the water recirculation mode, providing boration and injection flow without draining. Therefore, the automatic depressurization system is not actuated on the lowering of the core makeup tank level.

Subsequent to stabilizing plant conditions and satisfying passive core cooling system termination criteria, the operator terminates passive core cooling system operation and initiates normal plant shutdown operations.

6.3.3.1.2 Steam System Pipe Failure

The most severe core conditions resulting from a steam system piping failure are associated with a double-ended rupture of a main steam line, occurring at zero power. Effects of smaller piping failures at higher power levels are bounded by the double-ended rupture at zero power. Subsection 15.1.5 provides a description of this event, including criteria and analytical results.

For this event, the passive core cooling system functions as described in Subsection 6.3.3.1.1 for the inadvertent opening of a steam generator relief or safety valve. However, this piping failure constitutes a more severe cooldown transient. The malfunctioning of the startup feedwater system is considered as it was in the inadvertent steam generator depressurization. The trip of the reactor initially brings the reactor sub-critical. The rapid reactor coolant system cool down may result in the reactor returning to critical because the rate of positive reactivity addition (reactor coolant system temperature reduction) exceeds the rate of negative reactivity addition (boron from the core makeup tank). As the event continues, the reactor coolant system cooldown will slow down such that the continued core makeup tank boration will return the reactor sub-critical. The departure from nucleate boiling design basis is met.

For this event, the reactor coolant system may depressurize sufficiently to permit the accumulators to deliver makeup water to the reactor coolant system. The core makeup tanks inject via water recirculation without draining. Therefore, the automatic depressurization system is not actuated on the lowering of the core makeup tank level. Subsequent to stabilizing plant conditions and satisfying passive core cooling system termination criteria, the operator terminates passive core cooling system operation and initiates a normal plant shutdown.

6.3.3.2 Decrease in Heat Removal by the Secondary System

A number of events have been postulated that could result in a decrease in heat removal from the reactor coolant system by the secondary system. For each event, consideration has been given to operation of nonsafety-related systems that could affect the consequences of an event. The operation of the startup feedwater system and the chemical and volume control system makeup pumps can affect these events. Analyses of these events, both with and without these nonsafety-related systems operating, are presented in Section 15.2. For those events resulting in passive core cooling system actuation, the following summarizes passive core cooling system performance.

6.3.3.2.1 Loss of Main Feedwater

The most severe core conditions resulting from a loss of main feedwater system flow are associated with a loss of flow at full power. The heat-up transient effects of loss of flow at reduced power levels are bounded by the loss of flow at full power. Subsection 15.2.7 provides a description of this event, including criteria and analytical results.

For this event, the passive residual heat removal heat exchanger is actuated. If the core makeup tanks are not initially actuated, they actuate later when passive residual heat exchanger cooling sufficiently reduces pressurizer level. The passive residual heat removal heat exchanger serves to remove core decay heat and the core makeup tanks inject a borated water solution directly into the

reactor vessel downcomer annulus. Since the reactor coolant pumps are tripped on actuation of the core makeup tanks, the passive residual heat removal heat exchanger operates under natural circulation conditions. The core makeup tanks operate via water recirculation, without draining, to maintain reactor coolant system inventory. Therefore, the automatic depressurization system is not actuated on the lowering of the core makeup tank level. Since the event is characterized by a heat-up transient, the injection of negative reactivity is not required and is not taken credit for in the analysis to control core reactivity.

The reactor coolant system does not depressurize to permit the accumulators to deliver makeup water to the reactor coolant system. Subsequent to stabilizing plant conditions and satisfying passive core cooling system termination criteria, the operator terminates passive core cooling system operation and initiates a normal plant shutdown.

6.3.3.2.1.1 Loss of AC Power to Plant Auxiliaries

The most severe conditions resulting from a loss of ac power to the plant auxiliaries are associated with loss of offsite power with a loss of main feedwater system flow at full power. A loss of main feedwater with a loss of ac power lasting longer than a few hours presents the highest demand on passive residual heat removal heat exchanger operation. Subsection 15.2.6 provides a description of this short-term event, including criteria and analytical results.

During most events, the passive systems would be terminated in hours. When an ac power source is restored and passive core cooling system termination criteria are satisfied, the operator terminates passive core cooling system operation and initiates normal plant shutdown operations (as discussed in Subsection 6.3.1.2.1).

However, if normal systems are not recovered as expected, the passive residual heat removal heat exchanger removes core decay heat and maintains acceptable reactor coolant system conditions for at least 72 hours. For a non-LOCA event where ac power is lost, the automatic depressurization system will actuate in approximately 22 hours if operators do not act to avoid actuation when it is not needed. For this long-term transient, it is assumed operators extend passive residual heat exchanger operation as described in the Subsection 7.4.1.1.

The loss of main feedwater with loss of ac power event is analyzed for a 72-hour period, assuming operators extend closed-loop cooling beyond the time the automatic depressurization system would be actuated by the protection and safety monitoring system. This event mirrors the loss of ac power to the plant auxiliaries as described in Subsection 15.2.6, but the loss of ac power extends to 72 hours. In this event, operation of the passive residual heat removal heat exchanger continues for 72 hours and maintains acceptable reactor coolant system conditions such that the applicable Condition II safety evaluation criteria are met. If non-safety systems capable of removing decay heat are not recovered, operator action to actuate automatic depressurization system is eventually required. This condition would then be bounded by the Condition III event of inadvertent automatic depressurization system actuation.

Reactor coolant system leakage could limit closed-loop capacity. A reactor coolant system leak could produce conditions that would preclude the operators from de-energizing the loads on the 24-hour Class 1E batteries, or could require the operators to re-energize the buses powered by the Class 1E batteries before 72 hours so that the automatic depressurization system valves could be actuated.

6.3.3.2.2 Feedwater System Pipe Failure

The most severe core conditions resulting from a feedwater system piping failure are associated with a double-ended rupture of a feed line at full power. Depending on break size and power level, a feedwater system pipe failure could cause either a reactor coolant system cooldown transient or a

reactor coolant system heat-up transient. Only the reactor coolant system heat-up transient is evaluated as a feedwater system pipe failure, since the spectrum of cooldown transients is bounded by the steam system pipe failure analyses. The heat-up transient effects of smaller piping failures at reduced power levels are bounded by the double-ended feed line rupture at full power. Subsection 15.2.8 provides a description of this event, including criteria and analytical results.

For this event, the passive residual heat removal heat exchanger and the core makeup tanks are actuated. The passive residual heat removal heat exchanger serves to remove core decay heat, and the core makeup tanks inject a borated water solution directly into the reactor vessel downcomer. Since the reactor coolant pumps are tripped on actuation of the core makeup tanks, the passive residual heat removal heat exchanger operates under natural circulation conditions. The core makeup tanks operate via water recirculation to maintain reactor coolant system inventory. Since the event is characterized by a heat-up transient, the injection of negative reactivity is not required and is not taken credit for in the analysis to control core reactivity.

The reactor coolant system does not depressurize to permit the accumulators to deliver makeup water to the reactor coolant system. Subsequent to stabilizing plant conditions and satisfying passive core cooling system termination criteria, the operator terminates passive core cooling system operation and initiates normal plant shutdown operations.

6.3.3.3 Decrease in Reactor Coolant System Inventory

A number of events have been postulated that could result in a decrease in reactor coolant system inventory. For each event, consideration has been given to operation of nonsafety-related systems that could affect the consequences of the event. The operation of the startup feedwater system and the chemical and volume control system makeup pumps can affect these events. Analyses of these events, both with and without these nonsafety-related systems operating, are presented in Section 15.6. For those events which result in passive core cooling system actuation, the following summarizes passive core cooling system performance.

6.3.3.3.1 Steam Generator Tube Rupture

Although a steam generator tube rupture is an event that results in a decrease in reactor coolant system inventory, severe core conditions do not result from a steam generator tube rupture. The event analyzed is a complete severance of a single steam generator tube that occurs at power with the reactor coolant contaminated with fission products, corresponding to continuous operation with a limited amount of defective fuel rods. Effects of smaller breaks are bounded by the complete severance. Subsection 15.6.3 provides a description of this event, including criteria and analytical results.

For this event, the nonsafety-related makeup pumps are automatically actuated when reactor coolant system inventory decreases and a reactor trip occurs, followed by actuation of the startup feedwater pumps. The startup feedwater flow initiates on low steam generator level following the reactor trip and automatically throttles feedwater flow to maintain programmed steam generator level, limiting overfill of the faulted steam generator. The makeup pumps automatically function to maintain the programmed pressurizer level. The operators are expected to take actions similar to those in current plants to identify and isolate the faulted steam generator, cooldown and depressurize the reactor coolant system to terminate the break flow into the steam generator, and stabilize plant conditions.

If the operator fails to take timely or correct actions in response to the leak, or if the makeup pumps and/or the startup feedwater pumps malfunction with excessive flow, then the water level in the faulted steam generator continues to increase. This actuates safety-related overfill protection and automatically isolates the startup feedwater pumps and the chemical and volume control system makeup pumps. The core makeup tanks subsequently actuate on Low-2 pressurizer level, if they are

not already actuated. Actuation of the core makeup tanks automatically actuates the passive residual heat removal system heat exchanger.

The core makeup tanks operate via water recirculation to provide borated water directly into the reactor vessel downcomer to maintain reactor coolant system inventory. The passive residual heat removal heat exchanger serves to remove core decay heat. Since the reactor coolant pumps are automatically tripped on actuation of the core makeup tanks, the passive residual heat removal heat exchanger operates under natural circulation flow conditions. The passive residual heat removal heat exchanger, in conjunction with the core makeup tanks, remove core decay heat and reduce reactor coolant system temperature. As the reactor coolant system cools and the inventory contracts, pressurizer level and pressure decrease, equalizing with steam generator pressure and terminating break flow.

If the nonsafety-related systems fail to start, the core makeup tanks and the passive residual heat removal heat exchangers automatically actuate. Their response is similar to that previously described, except that the faulted steam generator level is lower.

In these events, the plant conditions are stabilized without actuating the automatic depressurization system. Once plant conditions are stable, the operator completes a normal plant shutdown.

6.3.3.3.2 Loss of Coolant Accident

A loss of coolant accident is a rupture of the reactor coolant system piping or branch piping that results in a decrease in reactor coolant system inventory that exceeds the flow capability of the normal makeup system. Ruptures resulting in break flow within the capability of the normal makeup system do not result in decreasing reactor coolant system pressure and actuation of the passive core cooling system. The maximum break size for which the normal makeup system can maintain reactor coolant system pressure is obtained by comparing the calculated flow from the reactor coolant system through the postulated break with the charging pump makeup flow at a reactor coolant system pressure that is above the low pressure safeguards actuation setpoint. The makeup flow rate from one makeup pump is adequate to maintain pressurizer pressure for a break through a 0.375-inch diameter hole. Therefore, the normal makeup system can maintain reactor coolant system pressure and permit the operator to execute an orderly shutdown.

For the purpose of evaluation, the spectrum of postulated piping breaks in the reactor coolant system is divided into major pipe breaks (large break) and minor pipe breaks (small breaks). The large break is a rupture with a total cross-sectional area equal to or greater than one square foot. The small break is defined as a rupture with a total cross-sectional area less than one square foot. Section 15.6 provides a description of this event, including criteria and analytical results.

For either event, the core makeup tanks are actuated upon receipt of a safeguards actuation signal. These tanks provide high-pressure injection. For large breaks, or after the automatic depressurization system is actuated, the accumulators also provide injection. After automatic depressurization system actuation, the in-containment refueling water storage tank, and the containment recirculation sump, provide low pressure injection.

The core makeup tanks can operate via water recirculation or steam-compensated injection during LOCAs. For smaller loss of coolant accidents, the reactor coolant system inventory is sufficient to establish water recirculation. For larger break sizes, when the pressurizer empties and voiding occurs in the cold legs steam-compensated injection initiates. When the cold legs void, the core makeup tank flow increases.

As the core makeup tanks drain, their level sequences the automatic depressurization system valve stages. As the level drops in the core makeup tank, the first-stage actuates. The first-stage valves are

connected to the top of the pressurizer and discharge to the in-containment refueling water storage tank via the automatic depressurization system spargers. After a time delay, the second-stage is actuated. The second stage valves are connected with the same flow path as the first-stage valves. After an additional time delay, the third-stage is actuated. The third stage valves are identical to the second-stage valves. As the core makeup tank drops to a low level the fourth-stage is actuated. The fourth stage valves are connected to both hot legs and they discharge directly to the reactor coolant system loop compartments at an elevation just above the maximum containment floodup level.

The in-containment refueling water storage tank line squib valves are opened on the fourth stage actuation signal. Check valves arranged in series with the squib valves remain closed until the reactor depressurizes. After depressurization, the in-containment refueling water storage tank provides injection flow. The flow continues until containment floodup initiates containment recirculation.

For large breaks or following automatic depressurization system initiation, the accumulators provide rapid injection to the reactor vessel through the same connections used by the core makeup tanks and the in-containment refueling water storage tank injection. The accumulators begin to inject when the reactor coolant system depressurizes to about 700 psig. During the loss of coolant accident transient, flow to the reactor coolant system is dependent on the reactor coolant system pressure transient. The passive core cooling system water injected into the reactor coolant system provides for heat transfer from the core, prevents excessive core clad temperatures, and refloods the core (for large loss of coolant accidents) or keeps the core covered (for small loss of coolant accidents).

For small loss of coolant accidents, the control rods provide the initial core shutdown and the boron in the passive core cooling system tanks add negative reactivity to provide adequate shutdown at low temperatures.

Following the initial thermal-hydraulic transient for a loss of coolant accident event, the passive core cooling system continues to supply water to the reactor coolant system for long-term cooling. When the water level in the in-containment refueling water storage tank drops to the Low-3 level, the water level in the containment has increased to a sufficient level to provide recirculation flow. The in-containment refueling water storage tank Low-3 level signal opens the squib valves in the lines between the containment and the gravity injection line. Initially, some of the water remaining in the tank drains to the containment until the water levels equalize. During this drain, injection to the core continues. The redundant flow paths provide continued cooling of the core by recirculation of the water in the containment. Figure 6.3-3 provides process flow information illustrating passive core cooling system performance for the various modes of system operation.

6.3.3.3.3 Passive Residual Heat Removal Heat Exchanger Tube Rupture

Although a passive residual heat removal heat exchanger tube rupture is an event that results in a decrease in reactor coolant system inventory, severe core conditions do not result from this event. There is a spectrum of heat exchanger tube leak sizes that are possible. For a small initiating leak, the passive core cooling system temperature instrumentation for the heat exchanger is used to identify that this is a heat exchanger leak. If the leak rate is less than the Technical Specification limits, plant operation can continue indefinitely. If the leak rate exceeds the Technical Specification limits the plant would be shut down to repair the heat exchanger.

If a severe tube leak occurs, the operators can use available instrumentation to identify the leak source. Action can then be taken to remotely isolate the heat exchanger by closing the motor-operated inlet isolation valve, which is normally open. The plant would be shut down to repair the heat exchanger.

This event is addressed in Section 15.6.

6.3.3.4 Shutdown Events

The passive core cooling system components are available whenever the reactor is critical and when reactor coolant energy is sufficiently high to require passive safety injection. During low-temperature physics testing, the core decay heat levels are low and there is a negligible amount of stored energy in the reactor coolant. Therefore, an event comparable in severity to events occurring at operating conditions is not possible and passive core cooling system equipment is not required. The possibility of a loss of coolant accident during plant startup and shutdown has been considered.

During shutdown conditions, some of the passive core cooling system equipment is isolated. In addition, since the normal residual heat removal system is not a safety-related system, its loss is considered. Containment recirculation may be impacted by shutdown maintenance activities which remove access hatches or curbs located at the 107'-2" plant elevation. Subsection 3.4.1.2.2.1 discusses containment flooding events in further detail.

As a result, gravity injection is automatically actuated when required during shutdown conditions prior to refueling cavity floodup, as discussed in Subsection 6.3.3.3.2. The operator can also manually actuate other passive core cooling system equipment, such as the passive residual heat removal heat exchanger, if required for accident mitigation during shutdown conditions when the equipment does not automatically actuate.

6.3.3.4.1 Loss of Startup Feedwater During Hot Standby, Cooldowns, and Heat-ups

During normal cooldowns, the steam generators are supplied by the startup feedwater pumps and steam from the steam generator is directed to either the main condenser or to the atmosphere. There are two nonsafety-related startup feedwater pumps, each of which is capable of providing sufficient feedwater flow to both steam generators to remove decay heat. These pumps are also automatically loaded on the nonsafety-related diesel-generators in the event normal ac power and offsite power are lost. Since these pumps are nonsafety-related, their failure is considered.

In the event of a loss of startup feedwater, the passive residual heat removal heat exchanger is automatically actuated on Low-2 steam generator narrow range water level and provides safety-related heat removal. The passive residual heat removal heat exchanger can maintain the reactor coolant system temperature, as well as provide for reactor coolant system cooldown to conditions where the normal residual heat removal system can be operated.

Since the chemical and volume control system makeup pumps are nonsafety-related, they may not be available. In this case, the core makeup tanks automatically actuate as the cooldown continues and the pressurizer level decreases. The core makeup tanks operate in a water recirculation mode to maintain reactor coolant system inventory while the passive residual heat removal heat exchanger is operating.

The in-containment refueling water storage tank provides the heat sink for the passive residual heat removal heat exchanger. Initially, the heat addition increases the water temperature. Within one to two hours, the water reaches saturation temperature and begins to boil. The steam generated in the in-containment refueling water storage tank discharges to containment. Because the containment integrity is maintained during cooldown Modes 3 and 4, the passive containment cooling system provides the safety-related ultimate heat sink. Therefore, most of the steam generated in the in-containment refueling water storage tank is condensed on the inside of the containment vessel and drains back into the in-containment refueling water storage tank via the condensate return gutter arrangement. This allows it to function as a heat sink for greater than 14 days, as discussed in Subsection 6.3.1.2.1.

6.3.3.4.2 Loss of Normal Residual Heat Removal Cooling With The Reactor Coolant System Pressure Boundary Intact

During normal shutdown conditions, the normal residual heat removal system is placed into service at about 350°F to accomplish reactor coolant system cooldown to refueling temperatures. The normal residual heat removal system piping is safety-related and meets seismic Category I requirements to prevent pipe breaks that could result in a significant loss of reactor coolant during system operation. The pump motors and the electrical power supplies are nonsafety-related.

The system is designed so that with single failure of an active system component, it can maintain the plant in a hot shutdown condition (<350°F). It is also possible to perform a reactor coolant system cooldown, but at a slower rate than with full system capability. Heat removed by the normal residual heat removal system is transferred to the component cooling water system and then to the service water system. The heat removal path is powered by the nonsafety-related diesel-generators in the event that normal ac power and offsite power are lost.

Since the normal residual heat removal pumps are nonsafety-related, they may not be available. In this case, the reactor coolant system pressure boundary remains intact and the passive residual heat removal heat exchanger provides the safety-related heat removal flow path.

The normal residual heat removal system is operated once the reactor coolant system temperature is too low to support sufficient steam production for decay heat removal. With a loss of shutdown cooling, the reactor coolant system temperature does not increase sufficiently to initiate steam generator steaming and to reduce steam generator level. This is because the steam generators are normally filled, with a nitrogen purge established, during shutdown conditions. The loss of cooling would result in the heat up of the reactor coolant system and a pressure increase resulting in one or both of the normal residual heat removal system relief valves opening. This loss of fluid would result in a decrease in the pressurizer level; a Low-2 pressurizer level signal automatically actuates the core makeup tanks and the passive residual heat removal heat exchanger. The passive residual heat removal heat exchanger could also be manually actuated.

The passive residual heat removal heat exchanger is capable of functioning at low reactor coolant system temperatures and pressures, but it may not be able to maintain the initial reactor coolant system temperature. It can remove sufficient heat to maintain the reactor coolant system within the normal residual heat removal system design limits (400°F). This permits the normal residual heat removal system to be placed back in operation when it becomes available.

For this event, the reactor coolant system temperature is expected to increase and expand into the pressurizer. Reactor coolant system injection should not be required. The makeup pumps are aligned for automatic operation in the event that pressurizer level decreases, due to leakage. However, since they are nonsafety-related, they are considered unavailable for reactor coolant system makeup. Therefore should safety-related makeup be required, the core makeup tanks would automatically actuate and operate via water recirculation injection. For some scenarios, the core makeup tanks could drain down and actuate the automatic depressurization system valves. This would lead to injection via the in-containment refueling water storage tank and containment recirculation paths.

6.3.3.4.3 Loss of Normal Residual Heat Removal Cooling During Reduced Inventory

During reactor coolant system maintenance, the most limiting shutdown condition anticipated is with the reactor coolant level reduced and the reactor coolant system pressure boundary opened. It is normal practice to open the steam generator channel head manway covers to install the hot leg and cold leg nozzle dams during a refueling outage. In this situation, the normal residual heat removal system is used to cool the reactor coolant system. The AP1000 incorporates many features to reduce the probability of losing the normal residual heat removal system. However, since the normal residual

heat removal system is nonsafety-related, its failure has been considered. The normal residual heat removal system is described Subsection 5.4.7.

In reduced inventory operation with the reactor coolant system depressurized and the pressure boundary opened, the passive residual heat removal heat exchanger is unable to remove the decay heat because the reactor coolant system cannot heat sufficiently above the in-containment refueling water storage tank temperature.

In this situation, core cooling is provided by the safety-related passive core cooling system, using gravity injection from the in-containment refueling water storage tank, while venting through the automatic depressurization system valves (and possibly through other openings in the reactor coolant system).

Prior to draining the reactor coolant system inventory below the no-load pressurizer level, the core makeup tanks are isolated to preclude inadvertent draining into the reactor coolant system while preparing for midloop operation. During plant shutdown, at 1000 psig, the accumulators are isolated to prevent inadvertent injection. In this configuration, the core makeup tanks and accumulators are isolated from the reactor coolant system, however these valves can be remotely opened with operator action to provide additional makeup water injection, if required.

Before the core makeup tanks are isolated, the automatic depressurization first-, second-, and third-stages valves are opened manually be the operators. The automatic depressurization system first-, second- and third-stage valves are required to remain open whenever the reactor coolant inventory is reduced or the upper core internals are in place. During an extended loss of normal residual heat removal system operation the stage one, two and three vent paths may not provide sufficient vent capability to allow gravity injection of water from the in-containment refueling water storage tank because of pressurizer surge line flooding. As a result, the automatic depressurization stage four paths are required. The stage four valves are opened manually as described in Subsection 19E.4.8.3 or automatically by a signal from the protection and monitoring system on a Low-4 hot leg level signal following a time delay.

The in-containment refueling water storage tank injection squib valves automatically open via the same Low-4 hot leg level signal that opens the automatic depressurization stage four valves. The operators can also open these injection and depressurization valves via the diverse actuation system. Once these valves open, injection from the in-containment refueling water storage tank provides gravity injection for core cooling. When the in-containment refueling water storage tank level drops to the Low-3 level, the squib valves in the containment recirculation line automatically open. This action initiates containment recirculation flow, with flow passing through the in-containment refueling water storage tank gravity injection lines, which provides long-term core cooling.

This arrangement provides automatic core cooling protection, while in reduced inventory operation while also providing protection (an evacuation alarm and sufficient time to evacuate) for maintenance personnel in containment during midloop operation. The time delay also provides the operators with time to take actions to restore nonsafety-related decay heat removal prior to actuating the passive core cooling system.

During reduced inventory conditions the capability of closing the containment is required. After the containment is closed, containment recirculation can continue indefinitely, with the decay heat generating steam which condenses on the containment vessel and drains back into the in-containment refueling water storage tank.

6.3.3.4.4 Loss of Normal Residual Heat Removal Cooling During Refueling

The normal residual heat removal system is normally used for decay heat removal during refueling operation. Its failure is considered because it is not a safety-related system. In this case, it is assumed that the reactor vessel head is removed and the water from the in-containment refueling water storage tank has been transferred to the refueling cavity, which is flooded to its high level condition. The passive residual heat removal heat exchanger is not available and containment integrity is expected to be relaxed with air locks and/or equipment hatches open.

Assuming that the refueling cavity was just flooded when the normal residual heat removal system fails, the refueling cavity water heats up to saturation temperature in about nine hours. With the slow heat-up of the refueling cavity water, there is ample time to close containment before significant steaming to the containment begins. The Technical Specifications require that containment closure capability be maintained during refueling MODES such that closure of the containment can be assumed. With the containment closed, water will not be lost from containment and long-term cooling can be maintained without subsequent need for cooling water makeup. Without closing the containment, boiling would reduce the water level to the top of the fuel assemblies in about five days.

6.3.4 Post-72 Hour Actions

The AP1000 passive core cooling system design includes safety-related equipment that is sufficient to automatically establish and maintain safe shutdown conditions for the plant following design basis events. The passive core cooling system can maintain safe shutdown conditions for 72 hours after an event without operator action and without both nonsafety-related onsite and offsite power.

There is only one action that may be required to provide long-term core cooling. There is a potential need for containment inventory makeup. The need for makeup to containment is directly related to the leakrate from the containment. With the maximum allowable containment leakrate, makeup to containment is not needed for about one month. A safety-related connection is available in the normal residual heat removal system to align a temporary makeup source to containment.

6.3.5 Limits on System Parameters

The analyses show that the design basis performance of the passive core cooling system is sufficient to meet the core cooling requirements following an event, with the minimum engineered safety features equipment operating. To provide this capability in the event of the single failure of components, technical specifications are established for reactor operation.

The passive core cooling system equipment is not required to operate to support either normal power operation or shutdown operation of the plant. This reduces the probability that the passive core cooling system equipment is unavailable due to maintenance. Planned maintenance on the passive core cooling system equipment is accomplished during shutdown operations when the core temperatures are low, decay heat levels are low, and the Technical Specifications do not require availability of the equipment.

The principal system parameters and the number of components that may be out of operation during testing, quantities and concentrations of coolant available, and allowable time for operation in a degraded status are provided in the technical specifications.

If efforts to restore the operable status of the passive core cooling system equipment are not accomplished within technical specification requirements, the plant is required to be placed in a lower operational mode.

6.3.6 Inspection and Testing Requirements

6.3.6.1 Preoperational Inspection and Testing

Preoperational inspections and tests of the passive core cooling system are performed to verify the operability of the system prior to loading fuel. This testing includes valve inspection and testing, flow testing, and verification of heat removal capability.

Preoperational testing of the passive core cooling system is completed in conjunction with testing of the reactor coolant system following flushing and hydrostatic testing, with the system cold and the reactor vessel head removed. The passive core cooling system is aligned for normal power operation. This testing provides the following information:

- Satisfactory safeguards actuation signal generation and transmission
- Valve operating times
- Injection starting times
- Injection delivery rates

The preoperational testing program includes testing of the following passive core cooling system components:

- Core makeup tanks
- Accumulators
- In-containment refueling water storage tank
- Containment recirculation
- Passive residual heat removal heat exchanger

Conformance with the recommendations of Regulatory Guide 1.79 is described in Subsection 1.9.1. Preoperational testing of the passive core cooling system is conducted in accordance with the requirements presented in Subsection 14.2.9.1.3.

6.3.6.1.1 Flow Testing

Initial verification of the resistance of the passive core cooling injection lines is performed by conducting a series of flow tests for the core makeup tanks, accumulators, in-containment refueling water storage tank, and containment recirculation piping. The calculated flow resistances are bounded by the resistances used in the Chapter 15 safety analyses.

6.3.6.1.2 Heat Transfer Testing

Initial verification of the heat transfer capability of the passive residual heat removal heat exchanger is performed by conducting a forced flow test. This test is conducted during hot functional testing of the reactor coolant system and performed as described in Subsection 14.2.9.1.3 item g).

6.3.6.1.3 Preoperational Inspections

Preoperational inspections are performed to verify that important elevations associated with the passive core cooling system components are consistent with the accident analyses presented in Chapter 15. The following elevations are verified:

- The bottom inside surface of each core makeup tank is at least 7.5 feet above the direct vessel injection nozzle centerline.
- The bottom inside surface of the in-containment refueling water storage tank is at least 3.4 feet above the direct vessel injection nozzle centerline.
- The centerline of the upper passive residual heat removal heat exchanger channel head is at least 26.3 feet above the hot leg centerline.
- The pH baskets are located below plant elevation 107 feet, 2 inches.

Inspections of the passive core cooling system tanks and pH adjustment baskets are conducted to verify that the actual tank volumes are greater than or equal to volume assumed in the Chapter 15 accident analyses. Inspections to determine dimensions of the core makeup tanks, accumulators, in-containment refueling water storage tank, and pH adjustment baskets are conducted, and calculations are performed to verify that actual volume is not less than the corresponding minimum required volume listed in Table 6.3-2.

6.3.6.2 In-Service Testing and Inspection

In-service testing and inspection of the passive core cooling system components and the associated support systems are planned. The passive core cooling system components and systems are designed to meet the intent of the ASME Operations and Maintenance (OM) Code, for in-service testing. A description of the in-service testing program is provided in Subsection 3.9.6.

Two basic types of in-service testing are performed on the passive core cooling system components:

- Periodic exercise testing of active components during power operation (for example, cycling of specific valves)
- Operability testing of specific passive core cooling system features during plant shutdown (for example, accumulator injection flow to the reactor vessel or leak testing of containment isolation valves during selected plant shutdown.

The passive core cooling system includes specific features to support in-service test performance:

- Remotely operated valves can be exercised during routine plant maintenance
- Level, pressure, flow, and valve position instrumentation is provided for monitoring required passive core cooling system equipment during plant operation and testing
- Permanently installed test lines and connections are provided for operability testing

6.3.6.3 Mitigation of Gas Accumulation

Periodic system surveillance and venting procedures, in addition to specific design features, are implemented that aim to prevent gas accumulation and minimize or eliminate gas whenever found. Locations identified by the gas accumulation assessment have been equipped with manual vent

valves or continuously monitored and alarmed pipe stubs with manual vent valves. These locations are specified within the periodic system surveillance and venting procedures as locations of high importance. Locations outfitted with pipe stub collection and alarm features have Technical Specifications including Surveillance Requirements to continuously monitor for gas accumulation and Required Actions subsequent to identifying gas accumulation in those locations to vent the identified gas accumulation. Plant startup and operational procedures include venting and surveillance steps that provide a means to track and trend accumulated gas such that problem areas can be systematically identified, monitored, and corrected.

6.3.6.3.1 System Gas Accumulation Assessment

Reviews of pipe layout and routing drawings to identify high-point vent and low-point drain locations are included as part of system design finalization activities. This existing design activity was expanded for the AP1000 passive safety systems, to integrate the draft Interim Staff Guidance (ISG) document ISG-019 regarding gas intrusion assessment guidance into the design process, helping to confirm that the potential issues identified in Generic Letter 2008-01 have been addressed within the design. Westinghouse also performed a comprehensive assessment for gas intrusion within the passive safety systems, consistent with the methodology in NEI 09-10 as applied in current operating plants, and consistent with the additional guidance in the ISG.

6.3.6.3.2 System Design Features to Mitigate Gas Intrusion

The gas intrusion assessment described in Subsection 6.3.6.3.1 helped to identify:

- Potential gas accumulation locations in the passive core cooling system piping.
- Potential gas intrusion mechanisms during various plant conditions (including plant startup, shutdown, post-maintenance system restoration and filling, power operation, and accident conditions).
- Passive core cooling system design features to provide the capability to perform system high-point venting and to continuously monitor several high-point locations.

These passive core cooling system design features help to eliminate the potential for significant gas accumulation in specific passive safety system injection lines that could adversely impact passive safety system operation. System venting capabilities are provided for the following passive safety system locations:

- IRWST injection line squib valve inlet lines
  - Vents located at the piping high points upstream of the parallel paths in both IRWST safety injection lines
  - Vents located between the check and squib valves in each line of the parallel paths in both IRWST safety injection lines
- Core makeup tank outlet lines
  - Vents located on bodies of both in-series check valves in both core makeup tank outlet lines
- Containment recirculation Line A

– Vents located at the high points in the common containment recirculation Line A path between the recirculation squib valves and the IRWST injection line (before and after the spent fuel system connection tee)

The potential for gas accumulation in passive safety system IRWST injection lines following accumulator injection is precluded by connecting the accumulator injection line in the direct vessel injection line riser section vertically above the IRWST injection line connection to the direct vessel injection line riser.

In addition, passive safety system design features are provided to monitor for gas accumulation at several specific locations. These design features include pipe stub gas collection chambers with redundant instrumentation at each high point, are continuously monitored and alarmed, have hard piped vent lines, are accessible during power operation, and include Technical Specifications and Surveillance Requirements specifically intended to identify unintended gas accumulations that could potentially challenge passive safety system operability for the following locations:

- Core makeup tank inlet highpoints
- Passive residual heat removal heat exchanger inlet high point
- IRWST injection line squib valve outlet high points

To ensure that all of the vent locations identified above function properly, notes are included on the system piping and instrumentation diagrams that specify layout sloping requirements. The intent of the layout requirements is to help ensure that the installed vents can effectively vent accumulated gases from the associated line segments. These notes also appear on the isometric drawings to make certain that the layout sloping requirements are observed during fabrication, construction, and installation.

The continuously monitored and alarmed pipe stub gas collection chamber, including Technical Specifications and Surveillance Requirements, was not utilized for the high points in the containment recirculation Line A because there are no credible postulated gas intrusion mechanisms by which gas is expected to migrate into these lines (except in the event of improper venting during line filling operations such as after maintenance). This isolated piping section is maintained in a standby condition prior to passive safety system actuation. This local high point is located between the containment recirculation squib valves and the IRWST injection line squib valves, and it remains connected to the IRWST so that the tank water elevation head maintains the pressure in this line prior to actuation.

Passive safety system locations equipped with manual vent valves will be inspected according to the system surveillance and venting procedures to eliminate any identified gas accumulation. Locations equipped with pipe stub gas collection and alarm features will be continuously monitored via alarm indications in the main control room. Because the locations with pipe stub collection and alarm features are continuously monitored and have Surveillance Requirements and Required Actions, the potential exists that these locations will be vented at RCS pressure. Consequently, these locations have manual vent valves and are hard-piped to either the IRWST or the reactor coolant drain tank for potential venting at RCS pressure.

For the AP1000, the structures, systems, and components (SSCs) of the passive safety systems that are used to establish and maintain safe shutdown conditions for the plant are identified and discussed in Subsections 7.4.1.1 and 7.4.2, and listed in Table 7.4-1. These same SSCs that provide the AP1000 safe shutdown capability also provide the passive, safety-related accident mitigation functions, including those that are equivalent to the emergency core cooling system, decay heat removal, and containment spray system functions for active plants specified in the generic letter.

6.3.7 Instrumentation Requirements

Instrumentation channels employed for actuation of passive core cooling system operation are described in Section 7.3. This subsection describes the instrumentation provided for monitoring passive core cooling system components during normal plant operation and also during passive core cooling system post-accident operation. Alarms are annunciated in the main control room.

6.3.7.1 Pressure Indication

6.3.7.1.1 Accumulator Pressure

Two pressure channels are installed on each accumulator. The pressure indications are used to confirm that accumulator pressure is within bounds of the assumptions used in the safety analysis. Each channel provides pressure indication in the main control room and also provides high-pressure and low-pressure alarms.

6.3.7.1.2 Passive Residual Heat Removal Heat Exchanger Pressure

One pressure indicator is installed on the passive residual heat removal heat exchanger inlet line. The instrument provides pressure indication in the main control room.

6.3.7.2 Temperature Indication

6.3.7.2.1 Core Makeup Tank Inlet Line Temperature

Individual temperature channels are installed on the inlet line for each core makeup tank. The temperature indication is used to determine if there is a sufficient thermal gradient for system operation. Each channel provides temperature indication in the main control room and also provides a low-temperature alarm.

6.3.7.2.2 Passive Residual Heat Removal Heat Exchanger Inlet Temperature

One temperature channel is installed on the inlet line to the passive residual heat removal heat exchanger. The temperature indication is used to detect reactor coolant system leakage into the passive residual heat removal heat exchanger, either through the discharge valves or from tube leakage into the in-containment refueling water storage tank, and to identify the leakage path. The channel provides temperature indication in the main control room and also provides a high-temperature alarm.

6.3.7.2.3 In-Containment Refueling Water Storage Tank Temperature

Four temperature channels are installed on the in-containment refueling water storage tank. The temperature indications are used to confirm that in-containment refueling water storage tank temperature is within the bounds of the assumptions used in the safety analysis. The temperature indications are also used to monitor in-containment refueling water storage tank temperature during passive core cooling system operation. Each channel provides temperature indication and high-temperature alarms in the main control room.

6.3.7.2.4 Core Makeup Tank Outlet Line Temperature

Two temperature channels are installed, one on each core makeup tank outlet line. The temperature indication is used to detect reactor coolant system leakage into the core makeup tanks. Each channel provides temperature indication in the main control room and also provides a high-temperature alarm.

6.3.7.2.5 Direct Vessel Injection Line Temperature

Two temperature channels are installed, one on each direct vessel injection line. The temperature indication is used to detect reactor coolant system leakage back through the direct vessel injection lines to the core makeup tanks, accumulator, or in-containment refueling water storage tank. Each channel provides temperature indication in the main control room.

6.3.7.2.6 Passive Residual Heat Removal Heat Exchanger Inlet High Point Temperature

One temperature channel is installed on the passive residual heat removal heat exchanger inlet line. The temperature indication is used to determine that the temperature in the inlet is within the bounds of the assumptions used in the safety analysis. The channel provides temperature indication and a low temperature alarm in the main control room.

6.3.7.3 Passive Residual Heat Removal Heat Exchanger Outlet Flow Indication

Two flow channels are installed on the passive residual heat removal outlet line. The flow indications are used to monitor and control passive residual heat removal heat exchanger operation. Each channel provides flow indication in the main control room.

6.3.7.4 Level Indication

6.3.7.4.1 Core Makeup Tank Level

Ten level channels are installed on each core makeup tank. There are 2 wide range level channels which are used to confirm that the core makeup tanks are maintained at full water level during normal operation. There are four narrow range level channels which are used to control the actuation of the automatic depressurization system stages 1, 2, and 3 valves. There are four narrow range level channels which are used to control the actuation of the automatic depressurization system stage 4 valves. Each wide range channel provides level indication and alarms in the main control room. Each narrow range channel provides level indication and alarms in the main control room and actuation of the automatic depressurization system. Each set of two narrow range channels share upper and lower level tap connections with the core makeup tanks; a failure modes and effects analysis confirms the ability of this arrangement to tolerate single failures (Reference 2). Each upper level tap line has a downward slope of ≥ 2.4 degrees from the centerline of the connection to the core makeup tank to the centerline of the connection to the standpipe.

6.3.7.4.2 Accumulator Level

Two level channels are installed on each accumulator. The level indications are used to confirm that accumulator level is within bounds of the assumptions used in the safety analysis. Each channel provides level indication and both high and low level alarms in the main control room.

6.3.7.4.3 In-Containment Refueling Water Storage Tank Level

Nine level channels are installed on the in-containment refueling water storage tank. There are two upper narrow range level channels. These level indications are used to confirm that in-containment refueling water storage tank normal level is within the bounds of the assumptions used in the safety analysis. There are three wide range level channels. Two of these level indications are used to provide refueling cavity and spent fuel pool cooling system isolation. There are four lower narrow range level channels. These level indications are used to provide containment recirculation valve repositioning. Each channel provides level indication in the main control room and provides level alarms.

The in-containment refueling water storage tank is sized and the level alarm setpoints selected to provide adequate in-containment refueling water storage tank injection (and spill flow to containment for a direct vessel injection line break) until containment floodup is sufficient to provide recirculation flow.

6.3.7.4.4 Containment Level

Three level channels are installed on the containment. The level indications are used to monitor containment level from the reactor vessel cavity up to the maximum containment floodup elevation. Each channel provides level indication and alarms in the main control room.

6.3.7.5 Containment Radiation Level

Four channels are installed for the containment radiation. The radiation indications are used to monitor containment conditions. Each channel provides radiation indication and high radiation alarms in the main control room. Section 11.5 provides additional information.

6.3.7.6 Valve Position Indication and Control

6.3.7.6.1 Valve Position Indication

Individual valve position is provided for the safety-related, remotely actuated valves listed in Table 6.3-1. In addition, valve position is provided for certain manually operated valves, as described in Subsection 6.3.2.2.8.2, that can isolate redundant passive core cooling equipment, if mispositioned. The incontainment refueling water injection check valves and containment recirculation check valves have nonintrusive position indication.

For certain passive core cooling system valves with position indication, alarms in the main control room are provided to alert the operators to valve mispositioning. For the passive residual heat removal heat exchanger discharge valves, valve position indication is used to initiate a reactor trip upon opening of these valves while the reactor is at power.

6.3.7.6.2 Valve Position Control

Valve controls are provided for remotely operated passive core cooling system valves. Table 6.3-1 provides a list of the passive core cooling system remotely operated valves. These remotely operated valves have controls in the main control room.

6.3.7.6.2.1 Accumulator Motor-Operated Valve Controls

As part of the plant shutdown procedures, the operator is required to close the accumulator motor-operated valves. This prevents a loss of accumulator water inventory to the reactor coolant system when the reactor coolant system is depressurized. The valves are closed after the reactor coolant system has been depressurized to below the setpoint to block the safeguards actuation signal. The redundant pressure and level alarms on each accumulator function to alert the operator to close these valves, if any are inadvertently left open. Power is locked out after the valves are closed. During plant startup, the operator is directed by plant procedures to energize and open these valves prior to reaching the reactor coolant system pressure setpoint that unblocks the safeguards actuation signal. Redundant indication and alarms are available to alert the operator if a valve is inadvertently left closed once the reactor coolant system pressure increases beyond the setpoint. Power is also locked out after these valves are opened.

The accumulator isolation valves are not required to move during power operation. For a description of limiting conditions for operation and surveillance requirements of these valves, refer to the

technical specifications. The accumulator isolation valves receive a safeguards actuation signal to confirm that they are open in the event of an accident. As a result of the power lock out, technical specifications, and the redundant position indication and alarms, the valve controls are nonsafety-related.

6.3.7.6.2.2 In-Containment Refueling Water Storage Tank Injection Motor-Operated Valve Controls

The motor-operated valves in each in-containment refueling water storage tank injection line are normally open during all modes of normal plant operation. Power to these valves is locked out. Redundant valve position indication and alarms are provided to alert the operator if a valve is inadvertently closed. The technical specifications specify surveillances to show that these valves are open. These valves also receive a safeguards actuation signal to confirm that they are open in the event of an accident. As a result of the power lock out, the redundant position indication and alarms and the technical specifications the valve controls are nonsafety-related.

6.3.7.6.2.3 Passive Residual Heat Removal Heat Exchanger Inlet Motor-Operated Valve Control

The motor-operated valve in the passive residual heat removal heat exchanger inlet line is normally open during normal plant operation. Power to this valve is locked out. Redundant valve position indications and alarms are provided to alert the operator if the valve is open. This valve also receives an actuation signal to confirm that it is open in the event of an accident.

6.3.7.7 Automatic Depressurization System Actuation at 24 Hours

A timer is used to automatically actuate the automatic depressurization system if offsite and onsite power are lost for about 24 hours. This prevents discharging the Class 1E dc power sources such that they are no longer able to operate the automatic depressurization system valves. If power becomes available to the dc batteries and they are no longer discharging prior to activation of the timer, then the automatic depressurization system actuation would be delayed. If the plant does not need actuation of the automatic depressurization system based on having stable pressurizer level, full core makeup tanks, and high and stable in-containment refueling water storage tank levels, the operators are directed to de-energize all loads on the 24-hour batteries. This action will block actuation of the automatic depressurization system and allow for its actuation later should the plant conditions unexpectedly degrade.

6.3.8 Combined License Information

6.3.8.1 Containment Cleanliness Program

A program to limit the amount of debris that might be left in the containment following refueling and maintenance outages is described below. The cleanliness program will limit the storage of outage materials (such as temporary scaffolding and tools) inside containment during power operation to items that do not produce debris (physical or chemical), which could be transported to the containment recirculation screens, to the IRWST screens, or into a direct vessel injection or a cold leg LOCA break that becomes submerged during recirculation. The cleanliness program shall limit the amount of latent debris and fibrous material located within the containment, as identified in Subsection 6.3.2.2.7.1, item 12.

Administrative procedures implement the containment cleanliness program. Implementation of the program minimizes the amount of debris left in containment following personnel entry and exits. The program includes, as a minimum, the following:

Responsibilities

The program defines the organizational responsibilities for implementing the program; defines personnel and material controls; and defines the inspection and reporting requirements.

Implementation

Containment Entry/Exit

- Controls to account for the quantities and types of materials introduced into the containment.
- Limits on the types and quantities of materials, including scaffolding and tools, to ensure adequate accountability controls. This may be accomplished by the work management process. Storage of aluminum is prohibited without engineering authorization. Cardboard boxes or miscellaneous packing material is not brought into containment without approval.
- If entries are made at power, prohibited materials and limits on quantities of materials that may generate hydrogen are established.
- Controls for loose items, such as keys and pens, which could be inadvertently left in containment.
- Methods and controls for securing any items and materials left unattended in containment.
- Administrative controls for accounting for tools, equipment and other material are established.
- Administrative controls for accounting of the permanent removal of materials previously introduced into the containment.
- Limits on the types and quantities of materials, including scaffolding and tools, that may be left unattended in containment during outages and power operation. Types of materials considered are tape, labels, plastic film, and paper and cloth products.
- Requirements and actions to be taken for unaccounted for material.
- Requirements for final containment cleanliness inspections.
- Record keeping requirements for entry/exit logs.

Housekeeping

Housekeeping procedures require that work areas be maintained in a clean and orderly fashion during work activities and returned to original conditions (or better) upon completion of work.

Sampling Program

A sampling program is implemented consistent with NEI Guidance Report 04-07, “Pressurized Water Reactor Sump Performance Evaluation Methodology” as supplemented by the NRC in the “Safety Evaluation by The Office of Nuclear Reactor Regulation Related to NRC Generic Letter 2004-02, Nuclear Energy Institute Guidance Report (Proposed Document Number NEI 04-07), ‘Pressurized Water Reactor Sump Performance Evaluation Methodology.’” Latent debris sampling is implemented before startup. The sampling is conducted after containment exit cleanliness inspections to provide reasonable assurance that the plant latent debris design bases are met. Sampling frequency and

scope may be adjusted based on sampling results. Results are evaluated post-start up and any nonconforming results will be addressed in the Corrective Action Program.

6.3.8.2 Verification of Water Sources for Long-Term Recirculation Cooling Following a LOCA

The long-term core cooling considering debris resulting from a LOCA together with debris that exists before a LOCA is addressed in APP-GW-GLR-079 (Reference 3), and the applicable changes are incorporated into the UFSAR.

6.3.9 References

1. WCAP-8966, “Evaluation of Mispositioned ECCS Valves,” September 1977.

2. WCAP-13594 (P), WCAP-13662 (NP), “FMEA of Advanced Passive Plant Protection System,” Revision 1, June 1998.

3. APP-GW-GLR-079, “AP1000 Verification of Water Sources for Long-Term Recirculation Cooling Following a LOCA,” Westinghouse Electric Company LLC.

4. APP-GW-GLN-147, “AP1000 Containment Recirculation and IRWST Screen Design,” Westinghouse Electric Company LLC.

5. WCAP-17938 (P-A/NP-A), “AP1000 In-Containment Cables and Non-Metallic Insulation Debris Assessment,” Revision 3, June 2018.

6. NEI 04-07, “Pressurized Water Reactor Sump Performance Evaluation Methodology,” Revision 0.

Table 6.3-1
Passive Core Cooling System - Remote Actuation Valves

	Normal Position	Actuation Position	Failed Position	Notes
Core Makeup Tanks				
CMT inlet isolation MOV (V002A/B)	Open	Open	As is	(1,4)
CMT outlet isolation AOV (V014A/B,V015A/B)	Closed	Open	Open	
CMT fill/drain isolation AOV (V230A/B)	Closed	N/A	Closed	(4)
Accumulators				
Accumulators vent isolation SOV (V021A/B)	Closed	N/A	Closed	(4)
Accumulator discharge MOV (V027A/B)	Open	Open	As is	(2,4)
Nitrogen supply isolation AOV (V042)	Open	Closed	Closed	
Accumulator fill/drain isolation AOV (V232A/B)	Closed	N/A	Closed	(4)
In-Containment Refueling Water Storage Tank				
IRWST injection line MOV (V121A/B)	Open	Open	As is	(2,4)
IRWST injection line squib (V123A/B, V125A/B)	Closed	Open	As is	
Containment Recirculation Sump Valves				
Recirculation line MOVs (V117A/B)	Open	Open	As is	(3,4)
Recirculation line squib valves (V118A/B, V120A/B)	Closed	Open	As is	
Passive Residual Heat Removal Heat Exchanger				
PRHR HX inlet MOV (V101)	Open	Open	As is	(2,4)
PRHR HX outlet AOVs (V108A/B)	Closed	Open	Open	
IRWST gutter isolation AOVs (V130A/B)	Open	Closed	Closed	
Automatic Depressurization System Valves				
ADS Stage 1 MOVs (V001A/B, V011A/B)	Closed	Open	As is	
ADS Stage 2 MOVs (V002A/B, V012A/B)	Closed	Open	As is	
ADS Stage 3 MOVs (V003A/B, V013A/B)	Closed	Open	As is	
ADS Stage 4 MOVs (V014A/B/C/D)	Open	Open	As is	(3,4)
ADS Stage 4 squib valves (V004A/B/C/D)	Closed	Open	As is	

Notes:

(1) These valves are normally in the correct post-accident position, but receive confirmatory actuation signals to redundant controllers.

(2) These valves are normally in the correct post-accident position with their power locked out. They also receive confirmatory actuation signals.

(3) These valves are normally in the correct post-accident position, but receive confirmatory actuation signals.

(4) The operation of these valves is not safety-related.

Table 6.3-2 (Sheet 1 of 2)
Component Data - Passive Core Cooling System

Passive RHR HX			
Number		1	
Type		Vertical C-Tube	
Case		Design	
Heat transfer (BTU/hr)		2.01 E+08	
		Tube side	Shell side
Fluid		Reactor coolant	IRWST water
Design flow (lb/hr)		5.03 E+05	N/A
Temperature	in (°F)	567	120
	out (°F)	199	N/A
Design pressure (psig)		2485	N/A
Design temperature (°F)		650	N/A
Material		Alloy 690	N/A
AP1000 equipment class		A	N/A
Core Makeup Tanks			
Number		2	
Type		Vertical, cylindrical, hemispherical heads	
Minimum volume (cubic feet)		2487	
Design pressure (psig)		2485	
Design temperature (°F)		650	
Material		Carbon-steel, stainless steel clad	
AP1000 equipment class		A	
Accumulators			
Number		2	
Type		Spherical	
Volume (cubic feet)		2000	
Design pressure (psig)		800	
Design temperature (°F)		300	
Material		Carbon-steel, stainless steel clad	
AP1000 equipment class		C	

Table 6.3-2 (Sheet 2 of 2)
Component Data - Passive Core Cooling System

IRWST		
Number	1	
Type	Integral to containment internal structure	
Volume, minimum water (cubic feet)	73,100	
Design pressure (psig)	5	
Design temperature (°F)	150 *	
Material	Wetted surfaces are stainless steel	
AP1000 equipment class	C	
Spargers		
Number	2	
Type	Cruciform	
Flow area of holes (in^2)	274	
Design pressure (psig)	600	
Design temperature (°F)	500	
Material	Stainless Steel	
AP1000 equipment class	C	
pH Adjustment Baskets		
Number	4 Total	
Type	Rectangular	
Volume minimum total (cubic feet)	560	
Material	Stainless steel	
AP1000 equipment class	C	
Screens	IRWST	Containment Recirculation
Number	3	2
Surface area, screen (square feet)	IRWST Screens A and B: ≥ 575 per screen IRWST Screen C: ≥ 1150	≥ 2,500 per screen
Material	Stainless steel	Stainless steel
AP1000 equipment class	C	C

Note:
* Several times during plant life, the refueling water could reach 250°F.

Table 6.3-3 (Sheet 1 of 4)
Failure Mode and Effects Analysis -
Passive Core Cooling System Components

Component	Failure Mode	Plant Condition	Effect on System Operation	Failure Detection Method	Remarks
CMT outlet isolation AOVs V014A/B, V015A/B Normally closed/ fail open	Failure to open on demand	All design basis events	No safety-related effect since each valve has a redundant, parallel isolation AOV, actuated by a separate division, which provides flow through a parallel branch line for the affected CMT. The other CMT is unaffected.	Valve position indication alarm in MCR and at RSW	
CMT discharge line check valves V016A/B, V017A/B Normally open	Failure to close on reverse flow	All design basis events	No safety-related effect since each valve has a redundant, series check valve which closes to prevent reverse flow, during a cold leg (large) LOCA or cold leg balance line break, preventing accumulator flow from bypassing the reactor vessel.	No valve position indication	
Accumulator nitrogen supply/ vent valves V021A/B, V045 Normally closed/ fail closed	Spurious opening	All design basis events	No safety-related effect since each valve has either a normally closed redundant, series isolation SOV or a check valve in each vent flow path, that prevents accumulator nitrogen from leaking out of the accumulator, which could degrade accumulator injection.	Valve position indication in MCR and at RSW Accumulator low pressure alarm in MCR and at RSW	
Accumulator nitrogen supply containment isolation AOV V042 Normally open/ fail closed	Failure to close on demand	All design basis events	No safety-related effect since each valve has a redundant, series isolation check valve which independently closes on reverse flow in the line, preventing reactor coolant from leaking out of containment.	Valve position indication alarm in MCR and at RSW	
Accumulator nitrogen supply containment isolation check valve V043 Normally open	Failure to close on reverse flow	All design basis events	No safety-related effect since each valve has a redundant, series isolation AOV, actuated by a separate division, which closes to prevent reactor coolant from leaking out of containment.	No valve position indication	

Table 6.3-3 (Sheet 2 of 4)
Failure Mode and Effects Analysis -
Passive Core Cooling System Components

Component	Failure Mode	Plant Condition	Effect on System Operation	Failure Detection Method	Remarks
PRHR HX outlet line isolation AOVs V108A/B Normally closed/ fail open	Failure to open	All design basis events	No safety-related effect since each valve has a redundant, parallel isolation AOV, actuated by a separate division, which opens to provide PRHR HX flow through a parallel branch line.	Valve position indication alarm in MCR and at RSW PRHR HX flow indication in MCR & RSW	
IRWST gravity injection line check valves V122A/B, V124A/B Normally closed	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a check valve and a squib valve that open to provide gravity injection through a parallel branch line. The other IRWST gravity injection line is unaffected.	Valve position indication in MCR and at RSW	
IRWST gravity injection line squib valves V123A/B, V125A/B Normally closed/ fail as is	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a check valve and a squib valve that open to provide gravity injection through a parallel branch line. The other IRWST gravity injection line is unaffected.	Valve position indication in MCR and at RSW	
IRWST gutter isolation valves V130A/B Normally open/ fail closed	Failure to close	All design basis events	No safety-related effect since each valve has a redundant, series isolation AOV, actuated by a separate division, which closes to divert the gutter flow into the IRWST.	Valve position indication alarm in MCR and at RSW	
Containment recirculation line check valves V119A/B Normally closed	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a MOV and a squib valve, actuated by separate divisions, that open to provide recirculation through a parallel branch line. The other containment recirculation line is unaffected.	Valve position indication in MCR and at RSW	

Table 6.3-3 (Sheet 3 of 4)
Failure Mode and Effects Analysis -
Passive Core Cooling System Components

Component	Failure Mode	Plant Condition	Effect on System Operation	Failure Detection Method	Remarks
Containment recirculation line squib valves V120A/B Normally closed/ fail as is	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a MOV and a squib valve, actuated by separate divisions, that open to provide recirculation through a parallel branch line. The other containment recirculation line is unaffected.	Valve position indication in MCR and at RSW	
Containment recirculation line squib valves V118A/B Normally closed/ fail as is	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a check valve and a squib valve, actuated by separate divisions, that independently open to provide recirculation through a parallel branch line. The other containment recirculation line is unaffected.	Valve position indication in MCR and at RSW	
Accumulator fill/ drain line isolation AOVs V232A/B Normally closed/ fail closed	Spurious opening	All design basis events	No safety-related effect since each valve has a normally closed redundant, series isolation valve in each drain flow path, which prevents draining water from the accumulator.	Valve position indication alarm in MCR and at RSW	
CMT fill line isolation AOVs V230A/B Normally closed/ fail closed	Spurious opening	All design basis events	No safety-related effect since each valve has a redundant, series check valve that closes on reverse flow and prevents draining water from the CMT.	Valve position indication alarm in MCR and at RSW	
CMT fill line check valves V231A/B Normally closed	Failure to close on reverse flow	All design basis events	No safety-related effect since each valve has a normally closed redundant, series AOV that prevents draining water from the CMT.	No valve position indication CMT low level indication alarm in MCR and at RSW	

Table 6.3-3 (Sheet 4 of 4)
Failure Mode and Effects Analysis -
Passive Core Cooling System Components

Component	Failure Mode	Plant Condition	Effect on System Operation	Failure Detection Method	Remarks
ADS Stage 1 to 3 MOVs V001A/B, V011A/B, V002A/B, V012A/B, V003A/B, V013A/B, and ADS Stage 4 squib valves V004A/B/C/D Normally closed/ fail as is applies to all of the above	Failure to open on demand	All design basis events	Failure to open blocks reactor coolant system vent flow through the one of two parallel branch lines of the affected ADS valve stage. Failure of a Stage 4 ADS valve is the most limiting single valve failure from the standpoint of ADS performance, based on this stage being the largest valve size. With the failure of ADS path, the ADS vent flow capacity is reduced, but safety analysis has demonstrated that the limiting Stage 4 ADS valve failure still meets design basis reactor coolant system venting requirements.	ADS Stage 1 to 3 MOVs have valve position indication alarm in the MCR and at RSW. ADS Stage 4 squib valves have valve position indication in the MCR and at RSW.	
Class 1E direct current and UPS system distribution switchgear division IDSA DS 1 IDSB DS 1 IDSC DS 1 IDSD DS 1	Failure of a dc power source	All design basis events	Failure of a single dc power source from either Division A or Division B is the most limiting dc failure. The limiting PXS components are the IRWST injection/containment recirc. valves and the ADS valves. Failure of either of these dc power sources can prevent actuation of the ADS Stage 1 and Stage 3 MOVs in one group of ADS valves. The other ADS valves are unaffected by this failure. This dc power failure can also cause failure of one (of 4) IRWST injection squib valves and one (of 4) squib recirculation valves. The ADS vent flow and IRWST injection/containment recirculation capacity is reduced, but safety analysis has demonstrated that this limiting valve failure combination still meets design basis reactor coolant system venting/injection requirements.	Valves position indication alarm in MCR and at RSW	For other PXS components, the loss of a Class 1E division either actuates the affected AOVs to a fail-safe position, or does not affect MOVs which are already in appropriate positions

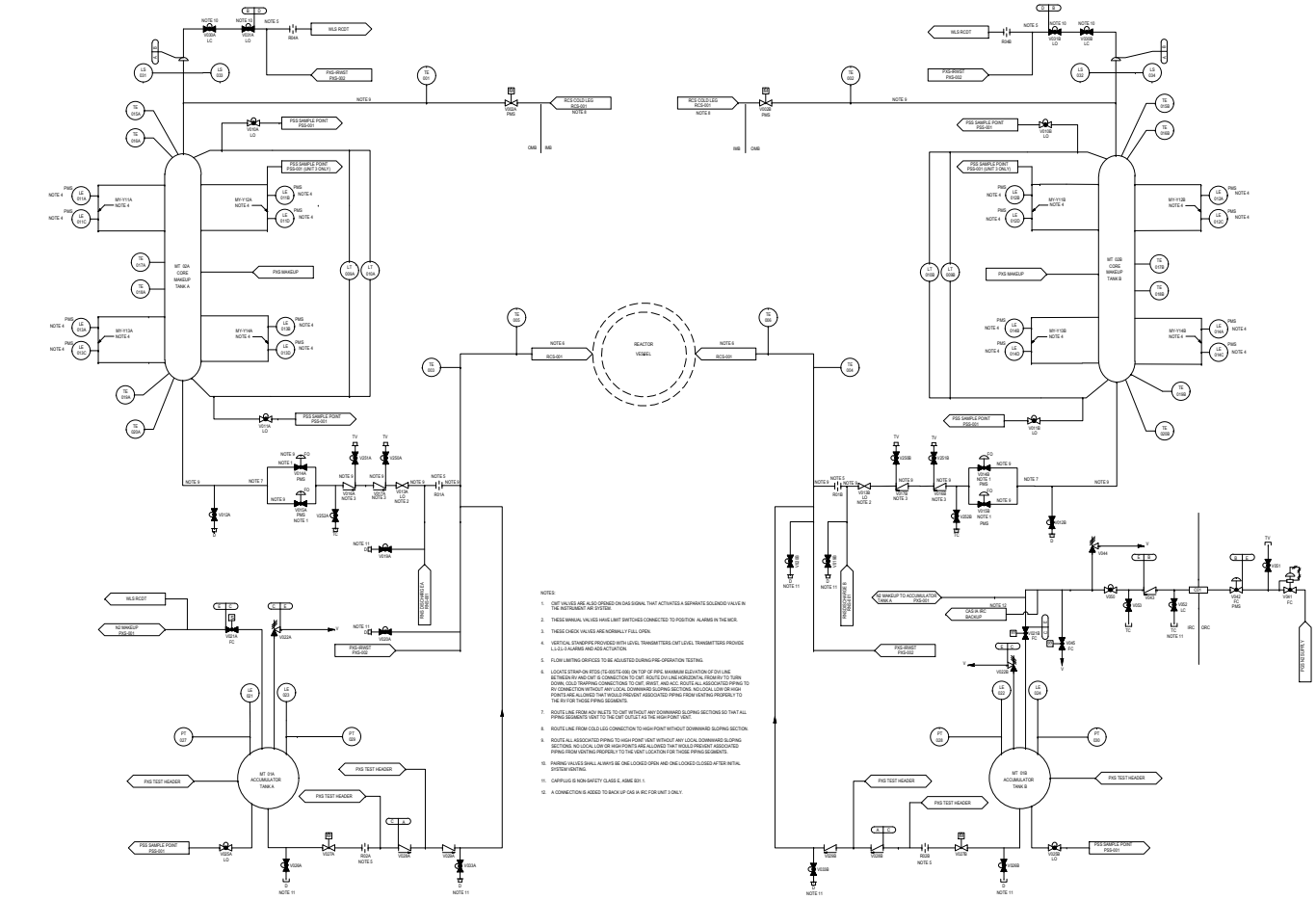


Figure 6.3-1 (Sheet 1 of 3)
Simplified Passive Core Cooling System Piping and Instrumentation Diagram (REF) PXS 001

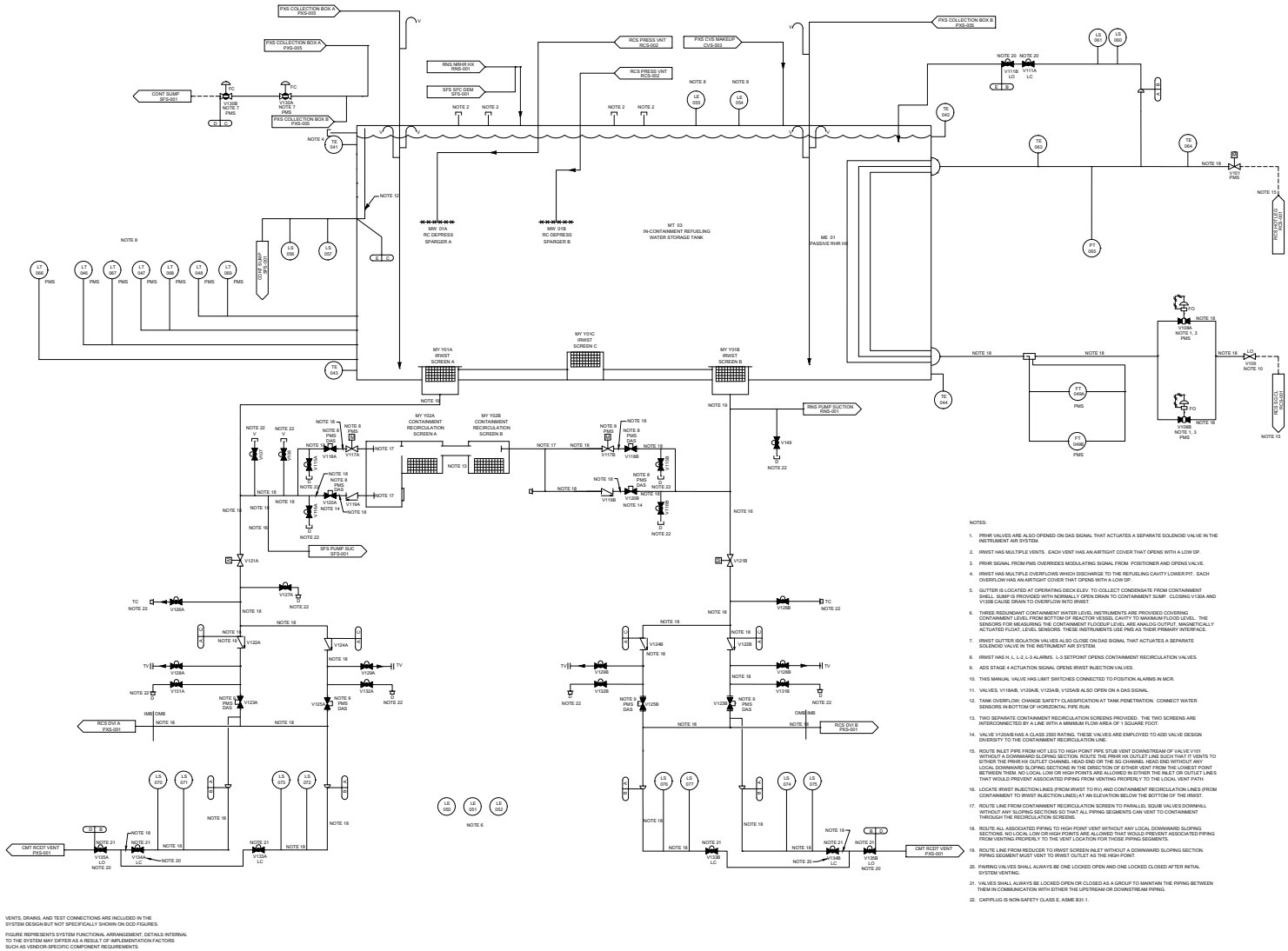


Figure 6.3-1 (Sheet 2 of 3)
Simplified Passive Core Cooling System Piping and Instrumentation Diagram (REF) PXS 002

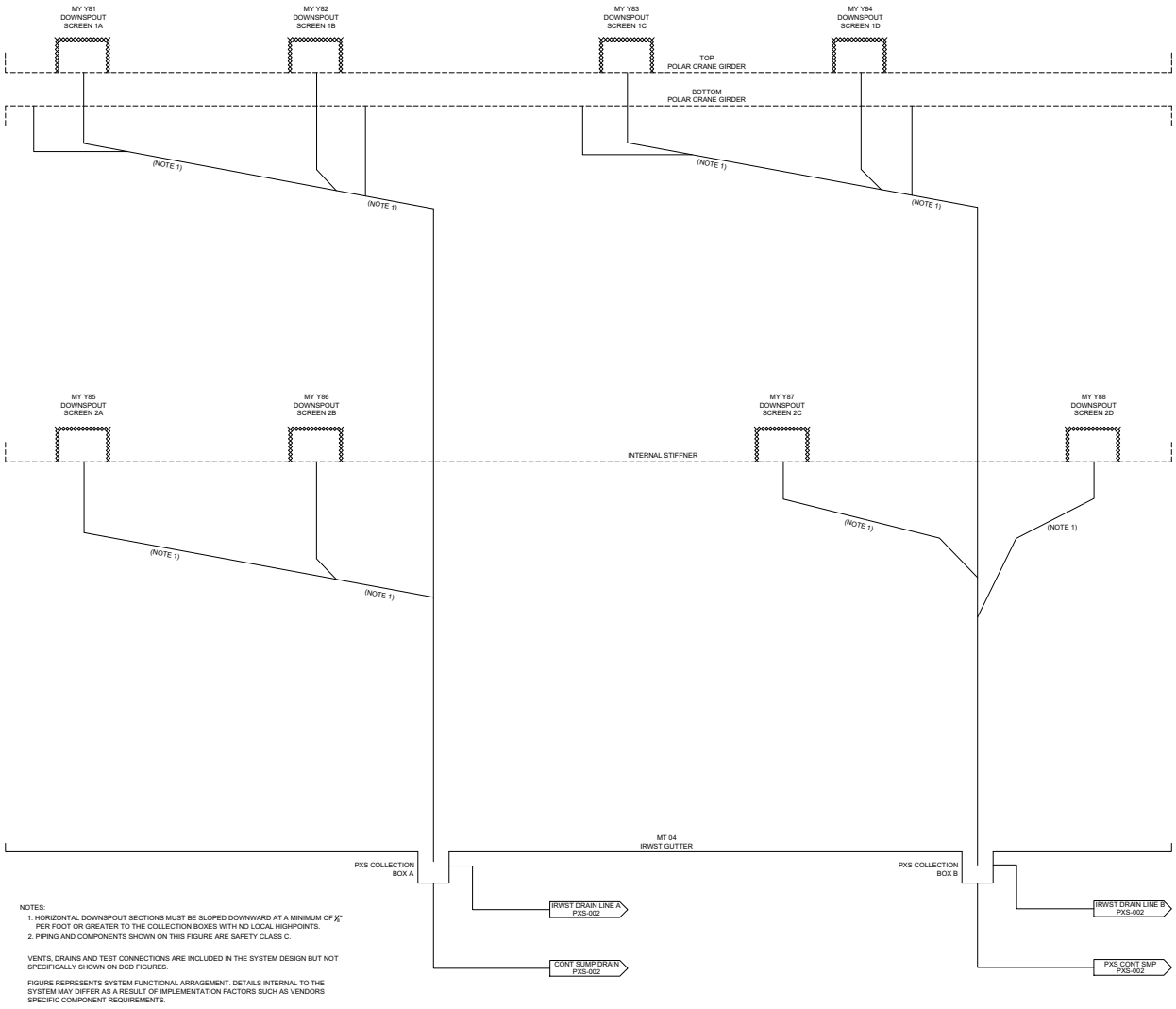
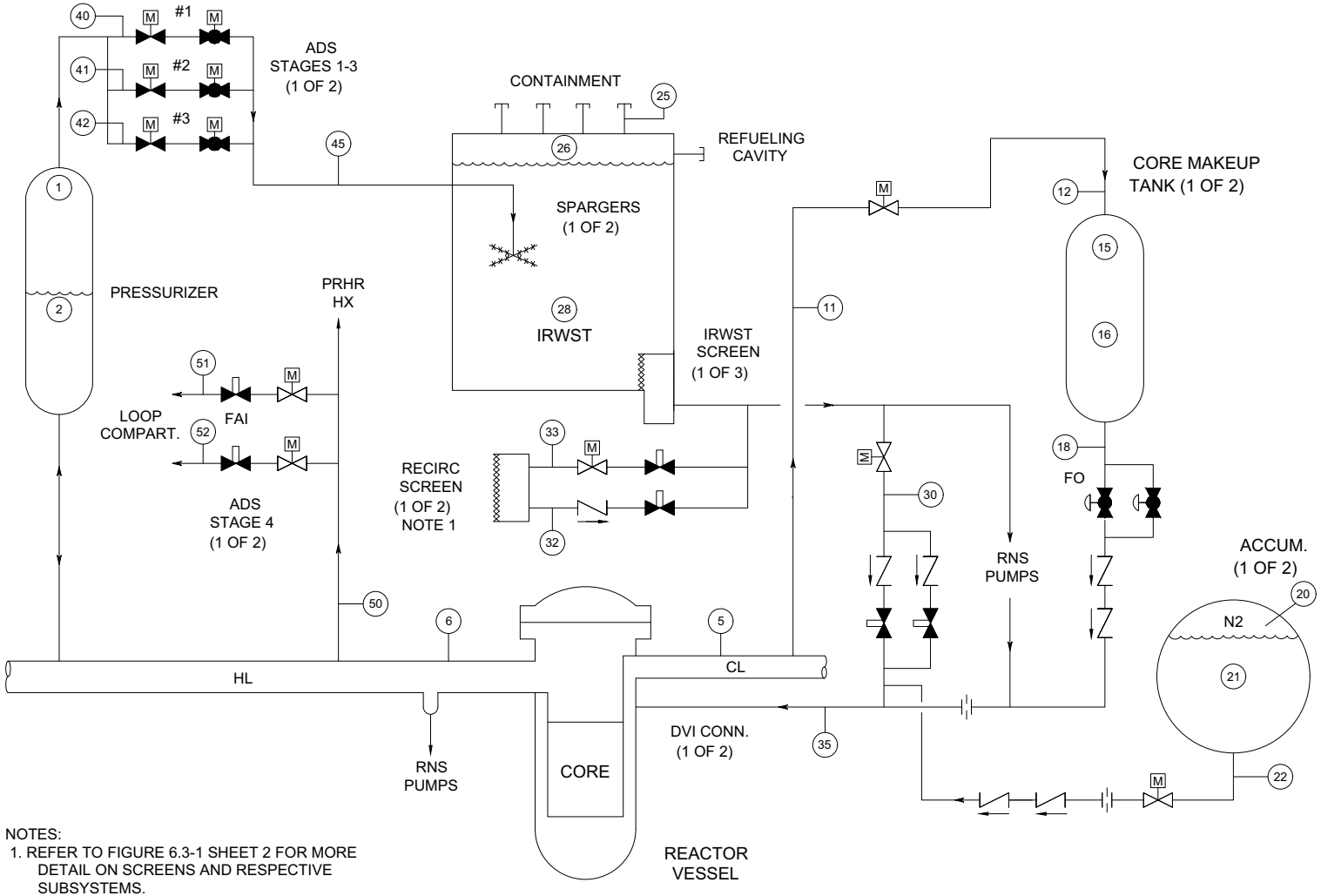
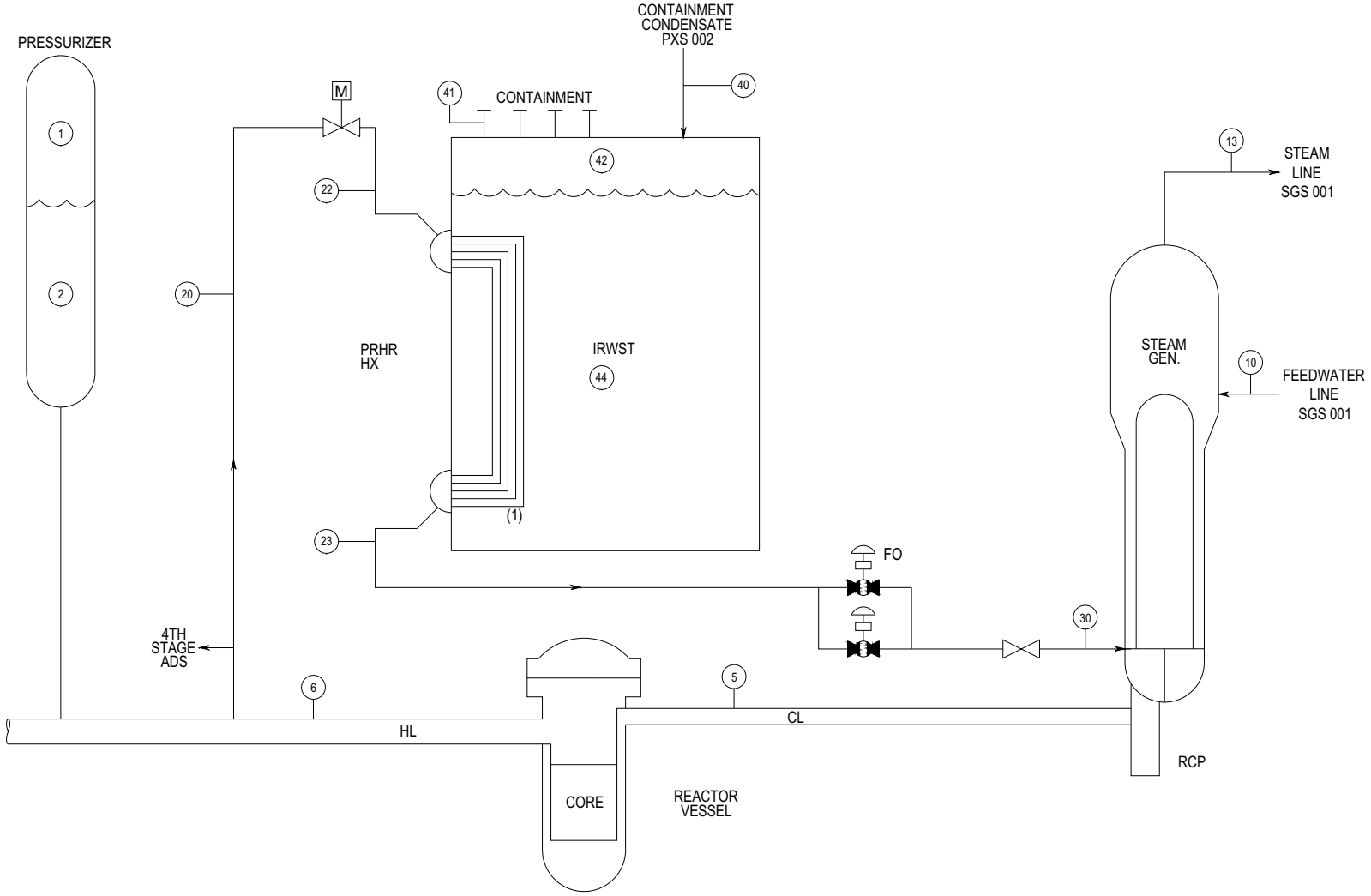


Figure 6.3-1 (Sheet 3 of 3)
Simplified Passive Core Cooling System
Piping and Instrumentation Diagram
(REF) PXS 003

Figure 6.3-2 Not Used



Inside Reactor Containment
Figure 6.3-3
Passive Safety Injection
(REF) RCS & PXS



Inside Reactor Containment
Figure 6.3-4
Passive Decay Heat Removal
(REF) RCS & PXS

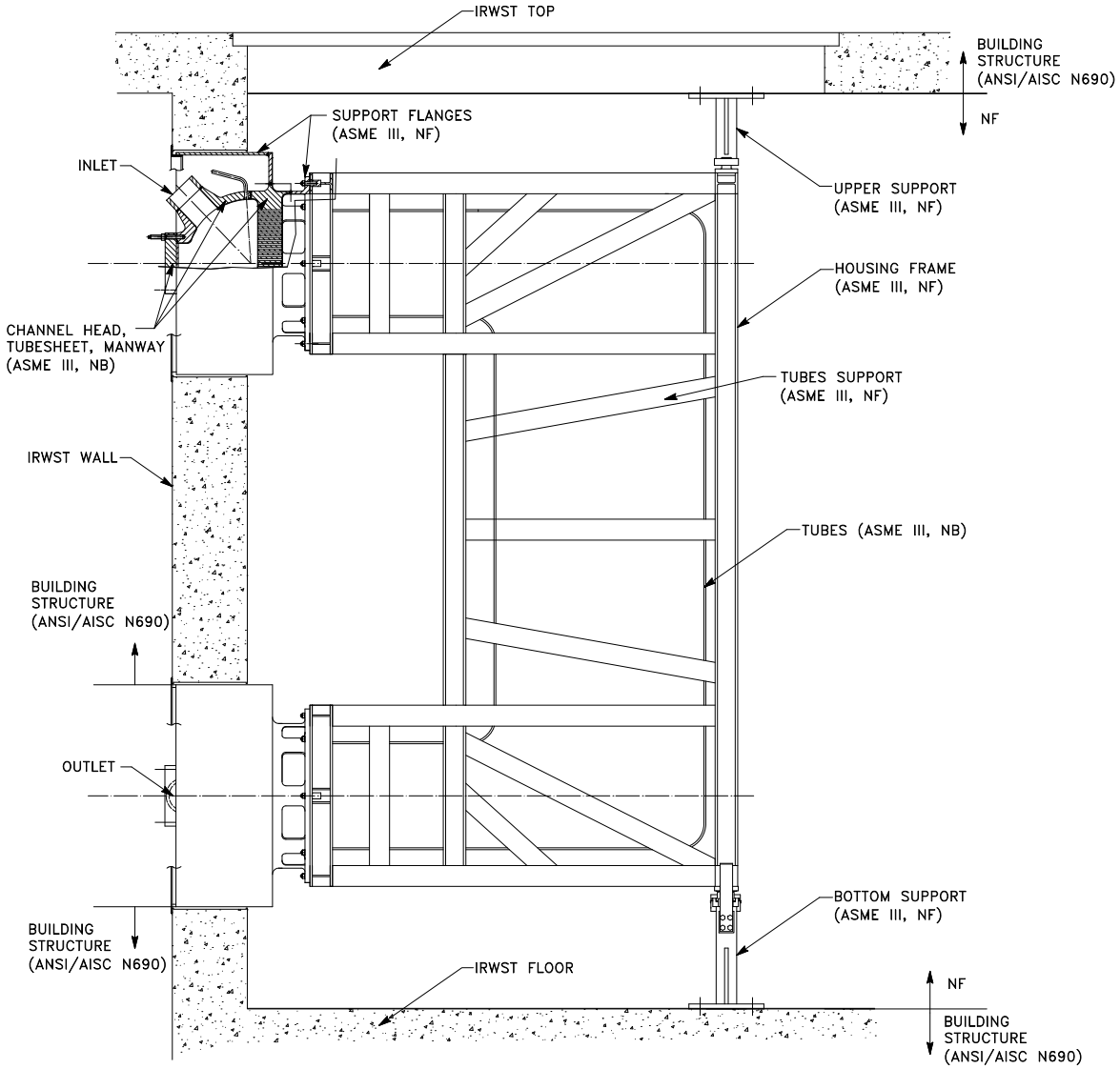


Figure 6.3-5
Passive Heat Removal Heat Exchanger

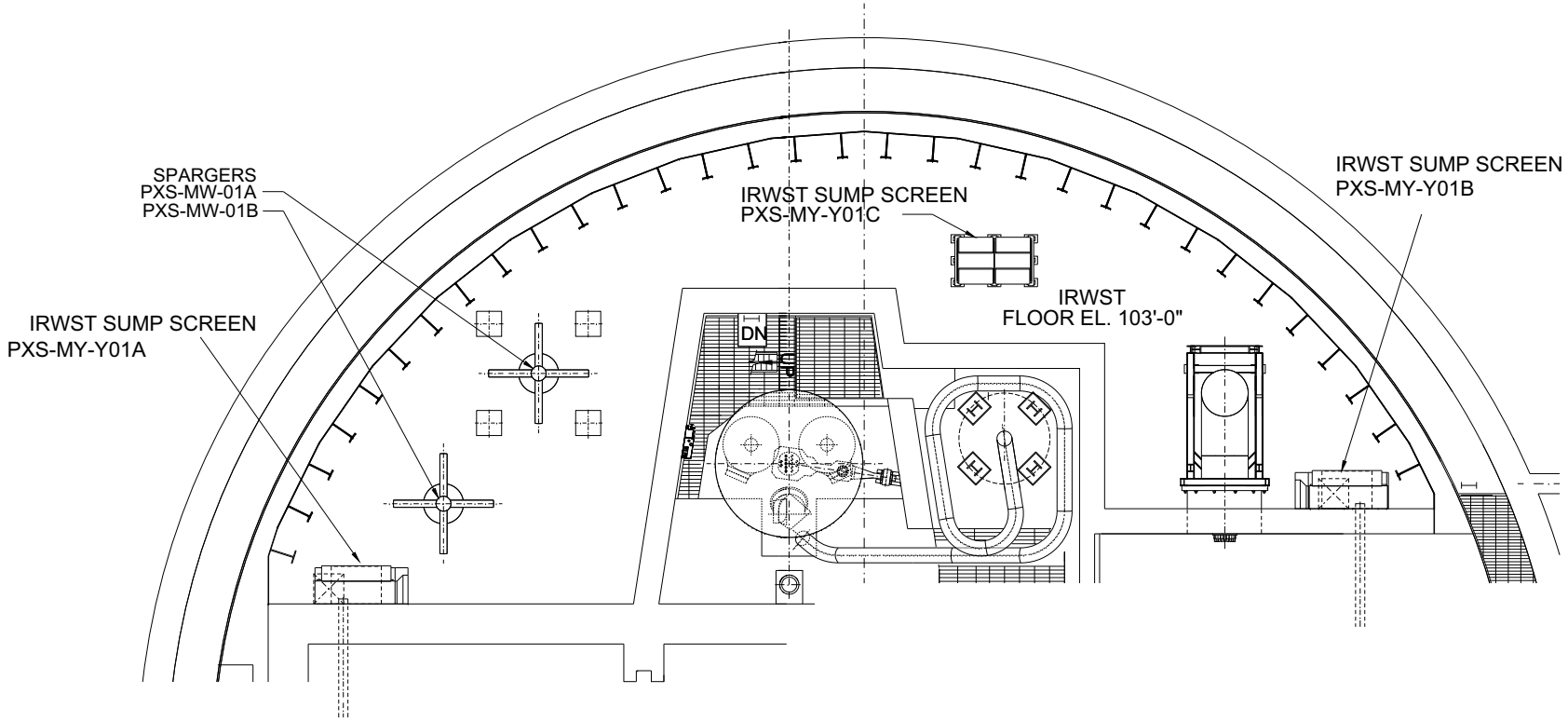


Figure 6.3-6
IRWST Screen Plan Location

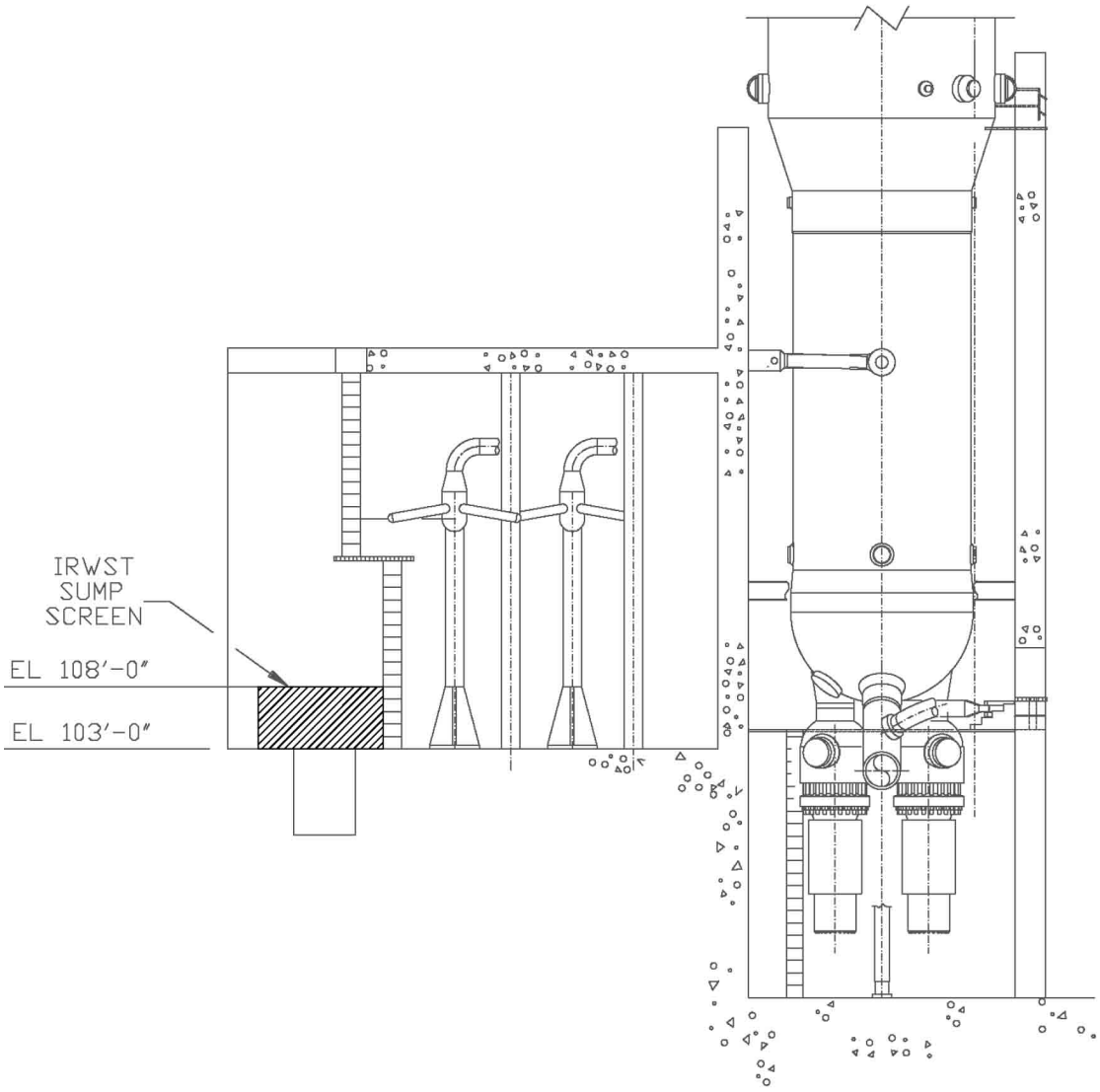
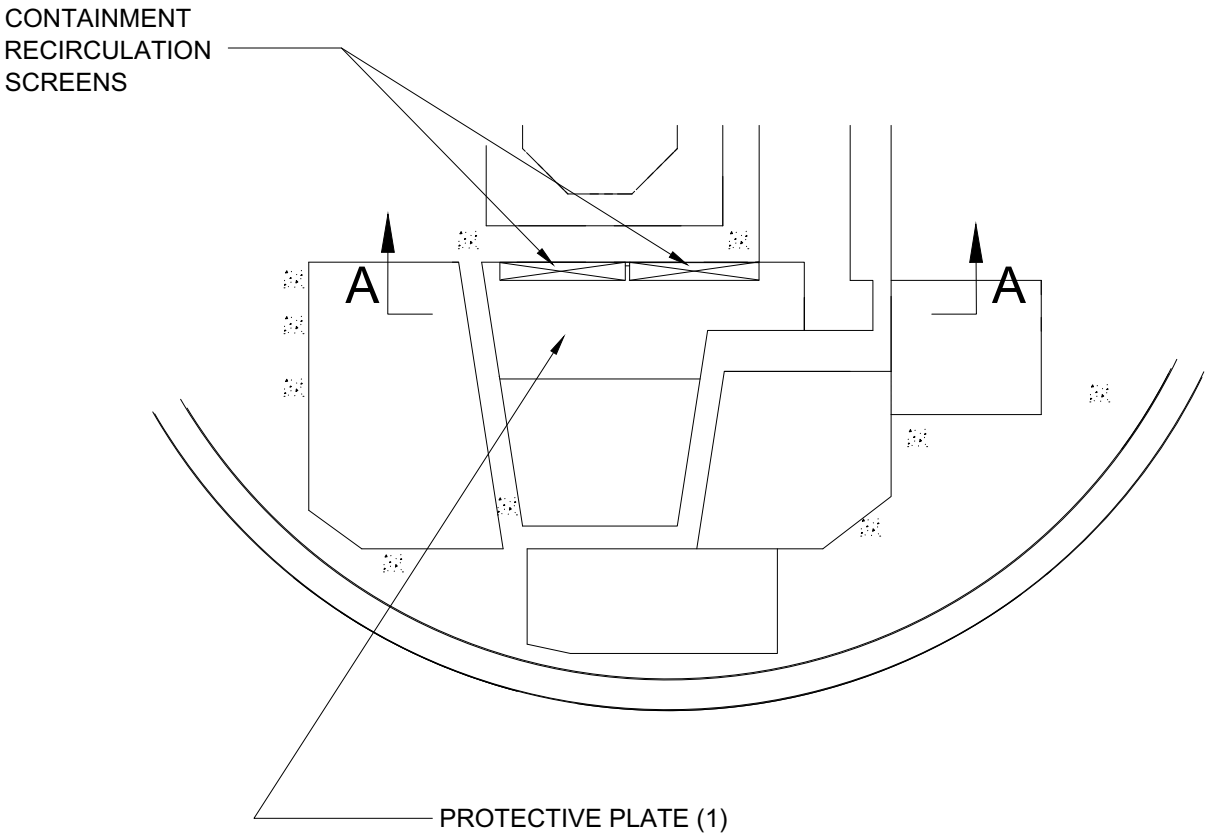
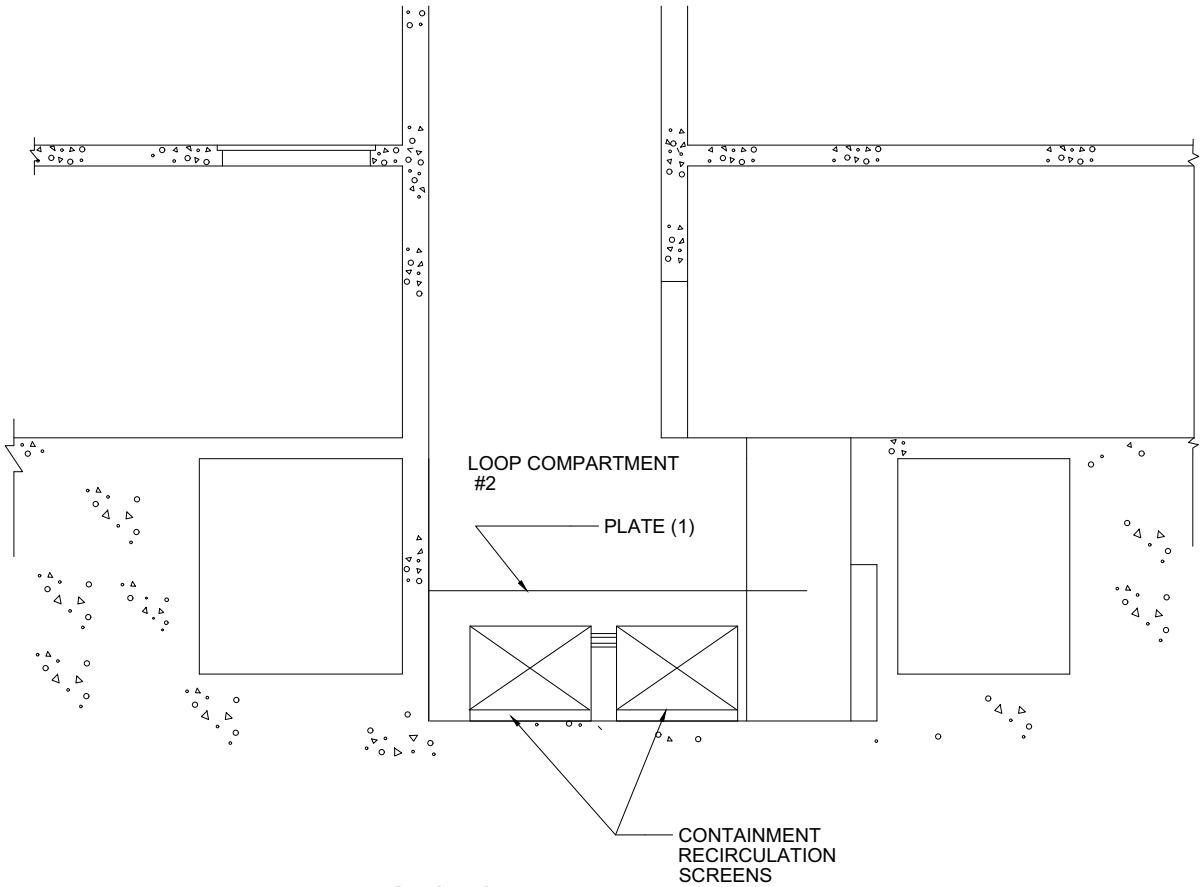


Figure 6.3-7
IRWST Screen Section Location



NOTE 1 - MINIMUM PLATE SIZE AND ELEVATION LIMITS
ARE DEFINED IN SUBSECTION 6.3.2.2.7.1.

Figure 6.3-8
Containment Recirculation Screen Location Plan



SECTION A-A

NOTE 1 - MINIMUM PLATE SIZE AND ELEVATION LIMITS
ARE DEFINED IN SUBSECTION 6.3.2.2.7.1.

Figure 6.3-9
Containment Recirculation Screen Location Elevation

6.4 Habitability Systems

The habitability systems are a set of individual systems that collectively provide the habitability functions for the plant. The systems that make up the habitability systems are the:

- Nuclear island nonradioactive ventilation system (VBS)
- Main control room emergency habitability system (VES)
- Radiation monitoring system (RMS)
- Plant lighting system (ELS)
- Fire Protection System (FPS)

When a source of ac power is available, the nuclear island nonradioactive ventilation system (VBS) provides normal and abnormal HVAC service to the main control room (MCR), control support area (CSA), instrumentation and control rooms, dc equipment rooms, battery rooms, and the nuclear island nonradioactive ventilation system equipment room as described in Subsection 9.4.1.

If ac power is unavailable for more than 10 minutes or if main control room differential pressure is below the “Low” setpoint for more than 10 minutes or if “High-2” particulate or iodine radioactivity is detected in the main control room supply air duct, which may lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The main control room emergency habitability system is capable of providing emergency ventilation and pressurization for the main control room. The main control room emergency habitability system also provides emergency passive heat sinks for the main control room, instrumentation and control rooms, and dc equipment rooms.

Radiation monitoring of the main control room environment is provided by the radiation monitoring system. Smoke detection is provided in the VBS system. Emergency lighting is provided by the plant lighting system. Storage capacity is provided in the main control room for personnel support equipment. Manual hose stations outside the MCR and portable fire extinguishers are provided to fight MCR fires.

6.4.1 Safety Design Basis

The safety design bases discussed here apply only to the portion of the individual system providing the specified function. The range of applicability is discussed in Subsection 6.4.4.

6.4.1.1 Main Control Room Design Basis

The habitability systems provide coverage for the main control room pressure boundary as defined in Subsection 6.4.2.1. The following discussion summarizes the safety design bases with respect to the main control room:

- The habitability systems are capable of maintaining the main control room environment suitable for prolonged occupancy throughout the duration of the postulated accidents discussed in Chapter 15 that require protection from the release of radioactivity. Refer to Section 3.1 and Subsections 6.4.4 and 15.6.5.3 for a discussion on conformance with General Design Criterion 19 and to Section 1.9 for a discussion on conformance with Generic Issue B-66.

- The main control room is designed to withstand the effects of an SSE and a design-basis tornado.
- A maximum main control room occupancy of up to 11 persons can be accommodated.
- The radiation exposure of main control room personnel throughout the duration of the postulated limiting faults discussed in Chapter 15 does not exceed the limits set by General Design Criterion 19.
- The emergency habitability system maintains CO_2 concentration to less than 0.5 percent for up to 11 main control room occupants.
- The habitability systems provide the capability to detect and protect main control room personnel from external fire, smoke, and airborne radioactivity.
- Automatic actuation of the individual systems that perform a habitability systems function is provided. Smoke detectors, radiation detectors, and associated control equipment are installed at various plant locations as necessary to provide the appropriate operation of the systems.
- The habitability system provides the capability to provide passive air filtration for the main control room during VES operation. The filtration portion of the systems meets the intent of Regulatory Guide 1.52 (Reference 10).

6.4.1.2 Instrumentation and Control Room/DC Equipment Rooms Design Basis

The habitability systems are also designed to service the instrumentation and control rooms and dc equipment rooms. The habitability systems are capable of maintaining the temperature in the instrumentation and control rooms and dc equipment rooms below the equipment qualification temperature limit throughout the duration of the postulated accidents discussed in Chapter 15, an SSE, or design-basis tornado.

6.4.2 System Description

Only the main control room emergency habitability system is discussed in this subsection. The remaining systems are described only as necessary to define their functions in meeting the safety-related design bases of the habitability systems. Descriptions of the nuclear island nonradioactive ventilation system, fire protection system, plant lighting system, and radiation monitoring system are found in Subsections 9.4.1, 9.5.1, 9.5.3, and Section 11.5, respectively.

6.4.2.1 Definition of the Main Control Room Pressure Boundary

The main control room pressure boundary is located on elevation 117′-6″ in the auxiliary building, on the nuclear island. As shown in Figure 6.4-1, the pressure boundary encompasses the main control area, operations work area, operations break room, shift supervisor's office, kitchen, and toilet facilities. The pressure boundary is represented by the line around the periphery of the boundary in the figure. The stairwell leading down to elevation 100′ and the area within the vestibule are specifically excluded from the boundary.

The areas, equipment, and materials to which the main control room operator requires access during a postulated accident are shown in Figure 6.4-1. This figure is a subset of Figure 1.2-8. Areas adjacent to the main control room are shown in Figures 1.2-19 and 1.2-24. The layout, size, and ergonomics of the operator workstations and wall panel information system depicted in Figure 6.4-1 do not reflect the results of the design process described in Chapter 18. The actual size, shape,

ergonomics, and layout of the operator workstations and wall panel information system is an output of the design process in Chapter 18.

6.4.2.2 General Description

The main control room emergency habitability system air storage tanks are sized to deliver the required air flow to the main control room and induce sufficient air flow through the passive filtration line to meet the ventilation and pressurization requirements for 72 hours based on the performance requirements of Subsection 6.4.1.1. Normal system makeup is provided by a connection to the breathable quality air compressor in the compressed and instrument air system (CAS). See Subsection 9.3.1 for a description of the CAS. A connection for refilling operation is provided in the CAS.

Flow from the air storage tanks induces a filtration flow of at least 600 cfm. Testing was conducted to validate that the passive filtration line is capable of inducing a filtration flow of at least 600 cfm greater than the design flow rate from the VES emergency air storage tanks. The testing is documented in TR-SEE-III-09-03 (Reference 12). The filtration flow passes through a series of silencers to maintain acceptable main control room noise levels. The passive filtration portion of the system includes a HEPA filter, a charcoal adsorber, and a downstream postfilter. The filters are configured to satisfy the guidelines of Regulatory Guide 1.52 (Reference 10). The air intake to the passive filtration ductwork is located near the operations work area. The ductwork is routed behind the main control area through the operations break room to reduce the overall noise level in the main control area. The filtered air supply is then distributed to three supply locations that are sufficiently separated from the air intake to avoid short circuiting of the air flow. Two of the supply locations are located inside the main control area. Flow dampers ensure the filtered air is properly distributed throughout the main control room envelope.

The function of providing passive heat sinks for the main control room, instrumentation and control rooms, and dc equipment rooms is part of the main control room emergency habitability system. The heat sinks for each room are designed to limit the temperature rise inside each room during the 72-hour period following a loss of nuclear island nonradioactive ventilation system operation. The heat sinks consist primarily of the thermal mass of the concrete that makes up the ceilings and walls of these rooms.

To enhance the heat-absorbing capability of the ceilings, a metal form is attached to the interior surface of the concrete at selected locations. Metallic plates are attached perpendicular to the form. These plates extend into the room and act as thermal fins to enhance the heat transfer from the room air to the concrete. The specifics of the fin construction for the main control room and I&C room ceilings are described in Subsection 3.8.4.1.2.

The normal operating temperatures in the main control room, instrumentation and control rooms, dc equipment rooms, and adjacent rooms are kept within a specified range by the nuclear island nonradioactive ventilation system in order to maintain a design basis initial heat sink capacity of each room. See Subsection 9.4.1 for a description of the nuclear island nonradioactive ventilation system.

In the unlikely event that power to the nuclear island nonradioactive ventilation system is unavailable for more than 72 hours, MCR habitability is maintained by operating one of the two MCR ancillary fans to supply outside air to the MCR such that the maximum average Wet Bulb Globe Temperature (WBGT) Index for the MCR is less than 90°F. See Subsection 9.4.1 for a description of this cooling mode of operation. Doors and ducts may be opened to provide a supply pathway and an exhaust pathway. Likewise, outside air is supplied to division B and C instrumentation and control rooms in order to maintain the ambient temperature below the qualification temperature of the equipment.

The main control room emergency habitability system piping and instrumentation diagram is shown in Figure 6.4-2.

6.4.2.3 Component Description

The main control room emergency habitability system compressed air supply contains a set of storage tanks connected to a main and an alternate air delivery line and equipment to provide electrical load de-energization. Components common to both lines include a manual isolation valve and a pressure regulating valve. Single active failure protection is provided by the use of redundant, remotely operated isolation valves, which are located within the MCR pressure boundary. In the event of insufficient or excessive flow in the main delivery line, the main delivery line is isolated and the alternate delivery line is manually actuated. The alternate delivery line contains the same components as the main delivery line with the exception of the remotely operated isolation valves, and thus is capable of supplying compressed air to the MCR pressure boundary at the required air flowrate. The VES piping and penetrations for the MCR envelope are designated as equipment Class C. Additional details on Class C designation are provided in Subsection 3.2.2.5. The classification of VES components is provided in Table 3.2-3, as appropriate.

- Emergency Air Storage Tanks

  There are a total of 32 air storage tanks. The air storage tanks are constructed of forged, seamless pipe, with no welds, and conform to Section VIII and Appendix 22 of the ASME Code. The design pressure of the air storage tanks is 4000 psi. The storage tanks collectively contain a minimum storage capacity of 327,574 scf.

- MCR Load Shed Panels

  The de-energization of the MCR electrical loads is performed using Class 1E equipment. Equipment within each of the two electrical panels is actuated from the “main control room isolation, air supply initiation, and electrical load de-energization” engineered safety feature. The de-energization is separated into two stages to provide operators with the maximum available nonsafety-related equipment while maintaining the MCR heat load within the requirements of the VES.

  Each electrical panel has redundant relays and timers controlled by both protection and safety monitoring system (PMS) Division A and PMS Division C. Either division is capable of actuating the timers and relays associated with each electrical panel independent of one another. This configuration prevents routine maintenance or single failures of a PMS cabinet from creating a spurious loss of MCR electrical loads while still providing for single failure protection. To accomplish the De-energize MCR Electrical Loads function, one set of Stage 1 and Stage 2 timers in each electrical panel must receive the PMS command.

  Relays in both electrical panels must be actuated to carry out the overall function. However, overall actuation may occur via different combinations of Division A and Division C commands.

- Pressure Regulating Valve

  Each compressed air supply line contains a pressure regulating valve located downstream of the common header. The pressure at the outlet of the valve is controlled via a two-staged self-contained pressure control operator. A failure of either stage of the pressure regulating valve will not cause the valve to fail completely open. A failure of the second stage of the pressure regulating valve will increase flow from the emergency air storage tanks. There is adequate margin in the emergency air storage tanks such that an operator has time to isolate the line and manually actuate the alternate delivery line.

- Flow Metering Orifice

  The flow rate of air delivered to the main control room pressure boundary is limited by an orifice located downstream of the pressure regulating valve in the eductor and in the eductor bypass line. The orifice is sized to provide the required air flow rate to the main control room pressure boundary.

- Air Delivery Main Isolation Valve

  The pressure boundary of the compressed air storage tanks is maintained by normally closed remotely operated isolation valves in the main supply line. These valves are located within MCR pressure boundary downstream of the pressure regulating valve and automatically initiate air flow upon receipt of a signal to open (see Subsection 6.4.3.2).

- Pressure Relief Isolation Valve

  To limit the pressure increase within the main control room, isolation valves are provided, one in each of redundant flowpaths, which open on a time delay after receipt of an emergency habitability system actuation signal. The valves provide a leak tight seal to protect the integrity of the main control room pressure boundary during normal operation, and are normally closed to prevent interference with the operation of the nonradioactive ventilation system.

- Main Air Flowpath Isolation Valve

  The main air flowpath contains a normally open, manually operated valve located within the MCR pressure boundary, downstream of the remotely operated air delivery main isolation valves. The valve is provided as a means of isolating and preserving the air storage tank's contents in the event of a pressure regulating valve malfunction.

- Air Delivery Alternate Isolation Valve

  The alternate air delivery flowpath contains a normally closed, manually operated valve, located within the MCR pressure boundary. The valve is provided as a means of manually activating the alternate air delivery flowpath in the event the main air delivery flowpath is inoperable.

- Pressure Relief Damper

  Pressure relief dampers are located downstream of the butterfly isolation valves, and are set to open on a differential pressure of at least 1/8-inch water gauge with respect to the surrounding areas. The differential pressure between the control room and the surrounding area location is monitored to ensure that a positive pressure is maintained in the control room with respect to its surroundings.

  The pressure relief dampers discharge through the MCR vestibule in order to reduce the amount of radioactivity that can be transported into the MCR when operators enter. Two vestibule discharge openings provide a purge flow path from the vestibule to the electrical penetration room division A (room 12412).

- Eductor

  An eductor is connected to the discharge of the VES makeup line from the emergency air storage tanks and to ductwork located inside the main control room envelope that comprises the passive filtration portion of the VES. The eductor works by directing compressed air from the VES storage tanks through a specially designed nozzle to create a powerful vacuum that draws air from the

main control room through the surrounding ductwork into the passive air filtration line. The eductor is designed to create a vacuum capable of drawing at least 600 scfm of flow into the passive air filtration system. This flow rate is based on a VES makeup flow of 65 ± 5 scfm at an approximate pressure of 110 psig at the discharge of the bottled air supply to the eductor. The eductor has no electrical power requirements, contains no moving parts, and requires no maintenance such as adjusting setpoints or lubricating bearings.

- High-Efficiency Particulate (HEPA) Filter, Charcoal Adsorber, and Postfilter

  The main control room passive filtration flowpath contains a HEPA filter in series with a charcoal adsorber and a postfilter. They work to remove particulate and iodine from the air to reduce potential control room dose during VES operation.

  HEPA filters are constructed, qualified, and tested in accordance with UL-586 (Reference 9) and ASME AG-1 (Reference 7), Section FC. Each HEPA filter cell is individually shop tested to verify an efficiency of at least 99.97 percent using a monodisperse 0.3-µm aerosol in accordance with ASME AG-1 (Reference 7), Section TA.

  The charcoal adsorber is designed, constructed, qualified, and tested in accordance with ASME AG-1 (Reference 7), Section FD; and Regulatory Guide 1.52. Each charcoal adsorber is an assembly with 2-inch deep Type II adsorber cells, conforming to IE Bulletin 80-03 (Reference 8).

  Postfilters downstream of the charcoal filters have a minimum DOP efficiency of 95 percent. The filters are UL listed in accordance with UL 900 (Reference 11).

- Silencers

  Two silencers are located in the passive air filtration line. One silencer is located downstream of the eductor, and the other silencer is located upstream of the eductor. The silencers are designed to reduce the noise created by the passive air filtration line.

- Control Room Access Doors

  Two sets of doors, with a vestibule between, are provided at the access to the main control room.

- Breathing Apparatus

  Self-contained portable breathing equipment with air bottles is stored inside the main control room pressure boundary. The amount of stored air is sufficient to provide a 6-hour supply of breathable air for up to 11 main control room occupants. This is backup protection to the permanently installed habitability systems.

6.4.2.4 Leaktightness

The main control room pressure boundary is designed for low leakage. It consists of cast-in-place reinforced concrete walls and slabs, and is constructed to minimize leakage through construction joints and penetrations. The following features are applied as needed in order to achieve this objective:

- The outside surface of penetrations sleeves in contact with concrete are sealed with a crack sealer. The piping and electrical cable penetrations are sealed with qualified pressure-resistant material compatible with penetration materials and/or cable jacketing.

- The interior or exterior surfaces of the main control room envelope (walls, floor, and ceiling) are coated with low permeability paint/epoxy sealant.

- Inside surfaces of penetrations and sleeves in contact with commodities (i.e., pipes and conduits, etc.) are sealed. Main control room pressure boundary HVAC isolation valves are qualified to shut tight against control room pressure.

- Penetration sealing materials are designed to withstand at least 1/4-inch water gauge pressure differential in an air pressure barrier. Penetration sealing material is a silicone-based material or equivalent.

- There is no HVAC duct that penetrates the main control room pressure boundary. Ventilation flow paths that pass through the main control room pressure boundary consist of safety-related cast sleeves and attached piping, including redundant safety-related seismic Category I isolation valves that are physically located within the main control room envelope.

The piping, conduits, and electrical cable trays penetrating through any combination of main control room pressure boundary are sealed with seal assembly compatible with the materials of penetration commodities. Penetration sealing materials are selected to meet barrier design requirements and are designed to withstand specific area environmental design requirements and remain functional and undamaged during and following an SSE. There are no adverse environmental effects on the MCR sealant materials resulting from postulated spent fuel pool boiling events.

The main control room pressure boundary main entrance is designed with a double-door vestibule, which is purged by the pressure relief damper discharge flow during main control room emergency habitability system operation. The emergency exit door (stairs to elevation 100′) is normally closed, and remains closed under design basis source term conditions. Administrative controls prohibit the emergency exit door to the remote shutdown workstation from being used for normal ingress and egress during VES operation.

When the main control room pressure boundary is isolated in an accident situation, there is no direct communication with the outside atmosphere, nor is there communication with the normal ventilation system. Leakage from the main control room pressure boundary is the result of an internal pressure of at least 1/8-inch water gauge provided by emergency habitability system operation.

The exfiltration and infiltration analysis for nuclear island nonradioactive ventilation system operation is discussed in Subsection 9.4.1.

6.4.2.5 Interaction with Other Zones and Pressurized Equipment

The main control room emergency habitability system is a self-contained system. There is no interaction between other zones and pressurized equipment.

For a discussion of the nuclear island nonradioactive ventilation system, refer to Subsection 9.4.1.

6.4.2.6 Shielding Design

The design basis loss-of-coolant accident (LOCA) dictates the shielding requirements for the main control room. Main control room shielding design bases are discussed in Section 12.3. In addition to shielding provided by building structural features, consideration is given to shielding provided by the VES filter shielding. Descriptions of the design basis LOCA source terms, main control room shielding parameters, and evaluation of doses to main control room personnel are presented in Section 15.6.

The main control room and its location in the plant are shown in Figure 12.3-1.

6.4.3 System Operation

This subsection discusses the operation of the main control room emergency habitability system.

Generic Issue 83 addresses the importance of maintaining control room habitability following an accidental release of external toxic or radioactive material or smoke and the capability of the control room operators to safely control the reactor. Procedures and training for control room habitability are written in accordance with Section 13.5 for control room operating procedures, and Section 13.2 for operator training. The procedures and training are verified to be consistent to the intent of Generic Issue 83.

The procedures and training address the toxic chemical events addressed in Sections 2.2 and 6.4 consistent with the guidance provided in regulatory position C.5 of Regulatory Guide 1.78, including arrangements with Federal, State, and local agencies or other cognizant organizations for the prompt notification of the nuclear power plant when accidents involving hazardous chemicals occur within five miles of the plant. The procedures include the conduct of periodic surveys of stationary and mobile sources of hazardous chemicals affecting the evaluations consistent with the guidance provided in regulatory position 2.5 of Regulatory Guide 1.196. The procedures include appropriate reviews of the configuration of the control room envelope and habitability systems consistent with the guidance provided in regulatory position 2.2.1 of Regulatory Guide 1.196. The procedures also include periodic assessments of the control room habitability systems' material condition, configuration controls, safety analyses, and operating and maintenance procedures consistent with the guidance provided in regulatory position 2.2.1 of Regulatory Guide 1.196.

Procedures for testing and maintenance are consistent with the design requirements of the DCD including the guidance provided in regulatory position 2.7.1 of Regulatory Guide 1.196.

6.4.3.1 Normal Mode

The main control room emergency habitability system is not required to operate during normal conditions. The nuclear island nonradioactive ventilation system maintains the air temperature of a number of rooms within a predetermined temperature range. The rooms with this requirement include the rooms with a main control room emergency habitability system passive heat sink design and their adjacent rooms.

6.4.3.2 Emergency Mode

Operation of the main control room emergency habitability system is automatically initiated by either of the following conditions:

- "High-2" particulate or iodine radioactivity in the main control room supply air duct
- Loss of ac power for more than 10 minutes
- "Low" main control room differential pressure for more than 10 minutes

Operation can also be initiated by manual actuation.

The nuclear island nonradioactive ventilation system is isolated from the main control room pressure boundary by automatic closure of the isolation devices located in the nuclear island nonradioactive ventilation system ductwork if radiation levels in the main control room supply air duct exceed the "High-2" setpoint or if ac power is lost for more than 10 minutes or if main control room differential

pressure is below the “Low” setpoint for more than 10 minutes. At the same time, the main control room emergency habitability system begins to deliver air from the emergency air storage tanks to the main control room by automatically opening the isolation valves located in the supply line. The relief damper isolation valves also open allowing the pressure relief dampers to function and discharge the damper flow to purge the vestibule.

After the main control room emergency habitability system isolation valves are opened, the air supply pressure is regulated by a self-contained regulating valve. This valve maintains a constant downstream pressure regardless of the upstream pressure. Downstream of the pressure regulating valve, a constant air flow rate is maintained by the flow metering orifice in the eductor and in the eductor bypass line. This flow rate is sufficient to maintain the main control room pressure boundary at least 1/8-inch water gauge positive differential pressure with respect to the surroundings and induce a flow rate of at least 600 cfm into the passive air filtration line. The main control room emergency habitability system air flow rate is also sufficient to maintain the carbon dioxide levels below 0.5 percent concentration for 11 occupants and to maintain air quality within the guidelines of Table 1 and Appendix C, Table C-1, of Reference 1.

The emergency air storage tanks are sized to provide the required air flow to the main control room pressure boundary for 72 hours. After 72 hours, the main control room is cooled by drawing in outside air and circulating it through the room, as discussed in Subsection 6.4.2.2.

The temperature and humidity in the main control room pressure boundary following a loss of the nuclear island nonradioactive ventilation system remain within limits for reliable human performance (Reference 14) over a 72-hour period. The bounding initial values of temperature/relative humidity in the MCR are 75°F/60 percent, the relative humidity in the MCR varies between 5% and 95% with a corresponding dry bulb temperature variance between 75°F to under 95°F. The temperature/relative humidity values calculated during the 72 hours following a design basis accident equate to a maximum average WBGT Index for the MCR of less than 90°F. The 90°F WBGT Index is the design limit for minimizing performance decrements and potential harm, and preserving well-being and effectiveness of the MCR staff for an unlimited duration (Reference 14). Non-Class 1E MCR heat loads are de-energized by PMS automatic actions, and the 24-hour battery heat loads are terminated or exhausted at 24 hours to maintain the occupied zone of the MCR and the zones containing qualified safety-related equipment within the constraints of the heat loads in Table 6.4-3 (to maintain temperature below the WBGT limit) at 72 hours after VES actuation. The occupied zone is considered to be the area between the raised floor and 7 feet above the floor, which encompasses the reactor operator and the senior reactor operator consoles.

Sufficient thermal mass is provided in the walls and ceiling of the main control room to absorb the heat generated by the equipment, lights, and occupants. The temperature in the instrumentation and control rooms and dc equipment rooms following a loss of the nuclear island nonradioactive ventilation system remains below acceptable limits as discussed in Subsection 6.4.4. As in the main control room, sufficient thermal mass is provided surrounding these rooms to absorb the heat generated by the equipment. After 72 hours, the instrumentation and control rooms will be cooled by drawing in outside air and circulating it through the room, as discussed in Subsection 6.4.2.2.

In the event of a loss of ac power or “Low” main control room differential pressure for more than 10 minutes, the nuclear island nonradioactive ventilation system isolation valves automatically close and the main control room emergency habitability system isolation valves automatically open. These actions protect the main control room occupants from a potential radiation release. In instances in which there is no radiological source term present, the compressed air storage tanks are refilled via a connection to the breathable quality air compressor in the compressed and instrument air system (CAS). The compressed air storage tanks can also be refilled from portable supplies by an installed connection in the CAS.

6.4.4 System Safety Evaluation

In the event of an accident involving the release of radioactivity to the environment, the nuclear island nonradioactive ventilation system (VBS) is expected to switch from the normal operating mode to the supplemental air filtration mode to protect the main control room personnel. Although the VBS is not a safety-related system, it is expected to be available to provide the necessary protection for realistic events. However, the design basis accident doses reported in Chapter 15 utilize conservative assumptions, and the main control room doses are calculated based on operation of the safety-related emergency habitability system (VES) since this is the system that is relied upon to limit the amount of activity the personnel are exposed to. The analyses assume that the VBS is initially in operation, but fails to enter the supplemental air filtration mode on a High-1 radioactivity indication in the main control room atmosphere. VES operation is then assumed to be initiated once the “High-2” level for control room atmosphere iodine or particulate radioactivity is reached.

Doses are also calculated assuming that the VBS does operate in the supplemental air filtration mode as designed, but with no switchover to VES operation. This VBS operating case demonstrates the defense-in-depth that is provided by the system and also shows that, in the event of an accident with realistic assumptions, the VBS is adequate to protect the control room operators without depending on VES operation.

Doses were determined for the following design basis:

	VES Operating	VBS Operating
Large Break LOCA	4.33 rem TEDE	4.84 rem TEDE
Fuel Handling Accident	1.5 rem TEDE	1.1 rem TEDE
Steam Generator Tube Rupture		
(Pre-existing iodine spike)	3.5 rem TEDE	2.8 rem TEDE
(Accident-initiated iodine spike)	1.0 rem TEDE	0.8 rem TEDE
Steam Line Break		
(Pre-existing iodine spike)	1.1 rem TEDE	0.6 rem TEDE
(Accident-initiated iodine spike)	1.4 rem TEDE	1.6 rem TEDE
Rod Ejection Accident	3.6 rem TEDE	2.2 rem TEDE
Locked Rotor Accident		
(Accident without feedwater available)	0.4 rem TEDE	0.5 rem TEDE
(Accident with feedwater available)	0.2 rem TEDE	0.6 rem TEDE
Small Line Break Outside Containment	0.4 rem TEDE	0.2 rem TEDE

For all events the doses are within the dose acceptance limit of 5.0 rem TEDE. The details of analysis assumptions for modeling the doses to the main control room personnel are delineated in the LOCA dose analysis discussion in Subsection 15.6.5.3 for VES operating cases. The analysis assumptions are provided in Subsection 9.4.1.2.3.1 for the VBS operating case.

No radioactive materials are stored or transported near the main control room pressure boundary (this does not apply to installed equipment, such as radiation monitors described in Section 11.5, nor to portable equipment that is in use, such as calibration equipment, survey instrumentation, tools, and other such transient items).

As discussed and evaluated in Subsection 9.5.1, the use of noncombustible construction and heat and flame resistant materials throughout the plant reduces the likelihood of fire and consequential

impact on the main control room atmosphere. Operation of the nuclear island nonradioactive ventilation system in the event of a fire is discussed in Subsection 9.4.1.

The exhaust stacks of the onsite standby power diesel generators are located in excess of 150 feet away from the fresh air intakes of the main control room. The onsite standby power system fuel oil storage tanks are located in excess of 300 feet from the main control room fresh air intakes. These separation distances reduce the possibility that combustion fumes or smoke from an oil fire would be drawn into the main control room.

The protection of the operators in the main control room from offsite toxic gas releases is discussed in Section 2.2. The sources of onsite chemicals are described in Table 6.4-1, and their locations are shown on Figure 1.2-2. Analysis of these sources is in accordance with Regulatory Guide 1.78 (Reference 5) and the methodology in NUREG-0570, “Toxic Vapor Concentrations in the Control Room Following a Postulated Accidental Release” (Reference 6), and the analysis shows that these sources do not represent a toxic or flammability hazard to control room personnel.

Table 6.4-201 provides additional details regarding the evaluated onsite chemicals.

A supply of protective clothing, respirators, and self-contained breathing apparatus adequate for 11 persons is stored within the main control room pressure boundary.

The main control room emergency habitability system components discussed in Subsection 6.4.2.3 are arranged as shown in Figure 6.4-2. The location of components and piping within the main control room pressure boundary provides the required supply of compressed air to the main control room pressure boundary, as shown in Figure 6.4-1.

During emergency operation, the main control room emergency habitability system passive heat sinks are designed to limit the temperature inside the main control room to remain within limits for reliable human performance (Reference 14) over 72 hours. The passive heat sinks limit the air temperature inside the instrumentation and control rooms to 120°F and dc equipment rooms to 120°F. The walls and ceilings that act as the passive heat sinks contain sufficient thermal mass to accommodate the heat sources from equipment, personnel, and lighting for 72 hours.

The main control room emergency habitability system nominally provides 65 scfm of ventilation air to the main control room from the compressed air storage tanks. Sixty scfm of supplied ventilation flow is sufficient to induce a filtration flow of at least 600 cfm into the passive air filtration line located inside the main control room envelope. This ventilation flow is also sufficient to pressurize the control room to at least positive 1/8-inch water gauge differential pressure with respect to the surrounding areas in addition to limiting the carbon dioxide concentration below one-half percent by volume for a maximum occupancy of 11 persons and maintaining air quality within the guidelines of Table 1 and Appendix C, Table C-1, of Reference 1.

Automatic transfer of habitability system functions from the main control room/control support area HVAC subsystem of the nuclear island nonradioactive ventilation system to the main control room emergency habitability system is initiated by any of the following conditions:

- “High-2” particulate or iodine radioactivity in MCR air supply duct
- Loss of ac power for more than 10 minutes
- “Low” main control room differential pressure for more than 10 minutes

The airborne fission product source term in the reactor containment following the postulated LOCA is assumed to leak from the containment and airborne fission products are assumed to result from

spent fuel pool steaming. The concentration of radioactivity, which is assumed to surround the main control room, after the postulated accident, is evaluated as a function of the fission product decay constants, the containment leak rate, and the meteorological conditions assumed. The assessment of the amount of radioactivity within the main control room takes into consideration the radiological decay of fission products and the infiltration/exfiltration rates to and from the main control room pressure boundary.

A single active failure of a component of the main control room emergency habitability system or nuclear island nonradioactive ventilation system does not impair the capability of the systems to accomplish their intended functions. The Class 1E components of the main control room emergency habitability system are connected to independent Class 1E power supplies. Both the main control room emergency habitability system and the portions of the nuclear island nonradioactive ventilation system which isolates the main control room are designed to remain functional during an SSE or design-basis tornado.

In accordance with SECY-77-439 (Reference 13), a single passive failure of a component in the passive filtration line in the main control room emergency habitability system does not impair the capability of the system to accomplish its intended function. There is no source that could create line blockage in the VES line from the air bottles to the eductor. Thus potential blockage in the filtration line does not preclude breathable air from the emergency air storage tanks from being delivered to the main control room envelope for 72 hours during VES operation. Passive filtration using the main control room habitability system is not required to maintain operator dose rates below the acceptance limit of 5.0 rem TEDE 24 hours after the initiation of a design basis event. The dose rates for the following limiting cases were determined to demonstrate that passive filtration is not required 24 hours after the initiation of a design basis event. The following cases are evaluated since they involve releases that extend beyond 24 hours after the initiation of the event:

Large Break LOCA	4.4 rem TEDE
Steam Line Break	
(Pre-existing iodine spike)	1.2 rem TEDE
(Accident-initiated iodine spike)	2.0 rem TEDE

For all events, the doses are within the dose acceptance limit of 5.0 rem TEDE. The details of analysis assumptions for modeling the doses to the main control room personnel are the same as those delineated in the LOCA dose analysis discussion in Subsection 15.6.5.3 assuming a passive failure disables the passive filtration flow path after 24 hours. Potential blockage in the filtration line does not preclude breathable air from the emergency air storage tanks from being delivered to the main control room envelope for 72 hours during VES operation. An eductor bypass line with a flow control orifice provides the operators with the ability to ensure that the breathable air from the emergency air storage tanks is delivered to the MCR.

6.4.4.1 Dual Unit Analysis

Credible events that could put the control room operators at risk from a dose standpoint at a single AP1000 unit have been evaluated and addressed in the DCD. The dose to the control room operators at an adjacent AP1000 unit due to a radiological release from another unit is bounded by the dose to control room operators on the affected unit. While it is possible that a unit may be downwind in an unfavorable location, the dose at the downwind unit would be bounded by what has already been evaluated for a single unit AP1000. Simultaneous accidents at multiple units at a common site are not considered to be a credible event.

The hazard due to the effects of a Design Basis Accident (DBA) from Units 1 and 2 is discussed in Subsection 2.2.3.4.

6.4.4.2 Toxic Chemical Habitability Analysis

Offsite chemicals are evaluated in Subsection 2.2.3. Site-specific onsite chemicals are evaluated in Subsection 2.2.3. Evaluation results show that there are no toxic hazards to Units 3 and 4 control room personnel.

During a toxic gas emergency, the control room operators have the option of manually actuating the emergency habitability system (Subsection 1.9.4.2.3, Issue 83). This action activates isolation dampers for the control room and supplies positive internal pressure and breathing air via bottled gas. Because the emergency habitability system isolates and pressurizes the control room, the activation of the system stabilizes and begins to decrease the concentration of toxic gas in the control room at the actuation value.

Normal HVAC operation would resume after the gas cloud passes the site, rapidly dropping the remaining elevated levels of toxic gas in the control room to non-detectable levels.

6.4.5 Inservice Inspection/Inservice Testing

A program of preoperational and inservice testing requirements is implemented to confirm initial and continued system capability. The VES system is tested and inspected at appropriate intervals, as defined by the technical specifications. Emphasis is placed on tests and inspections of the safety-related portions of the habitability systems.

6.4.5.1 Preoperational Inspection and Testing

Preoperational testing of the main control room emergency habitability system is performed to verify that the air flow rate of 65 ± 5 scfm is sufficient to induce a flow rate of at least 600 cfm into the passive air filtration line and maintain pressurization of the main control room envelope of at least 1/8-inch water gauge with respect to the adjacent areas. The positive pressure within the main control room is confirmed via the differential pressure transmitters within the control room. The installed flow meters are utilized to verify the system flow rates. The preoperational testing also verifies that the VES pressure regulating valves are capable of maintaining the VES flow rate of 65 ± 5 scfm over the operating range of expected valve inlet pressures. The pressurization of the control room limits the ingress of radioactivity, and the recirculation through the passive air filtration line maintains operator dose limits below regulatory limits. Air quality within the MCR environment is confirmed to be within the guidelines of Table 1 and Appendix C, Table C-1, of Reference 1 by analyzing air samples taken during the pressurization test.

The storage capacity of the compressed air storage tanks is verified to be in excess of 327,574 scf of compressed air. This amount of compressed air will assure 72 hours of air supply to the main control room.

Temperatures within the MCR are verified by analysis and/or testing to remain within the limits for reliable human performance (Reference 14) for a 72-hour period following a bounding scenario with MCR isolation and nonsafety-related ac power available (see Table 6.4-3 for heat loads) and a station blackout (battery-backed loads only).

Preoperational testing of the main control room isolation valves in the nuclear island nonradioactive ventilation system is performed to verify the leaktightness of the valves.

Preoperational testing for main control room envelope habitability during VES operation will be conducted in accordance with ASTM E741 (Reference 4). Where possible, inleakage testing is performed in conjunction with the VES system level operability testing since the VES must be in operation to perform the inleakage testing.

Testing and inspection of the radiation monitors is discussed in Section 11.5. The other tests noted above are discussed in Chapter 14.

6.4.5.2 Inservice Testing

Inservice testing of the main control room emergency habitability system and nuclear island nonradioactive ventilation system is conducted in accordance with the surveillance requirements specified in the Technical Specifications.

ASTM E741 testing of the main control room pressure boundary is conducted in accordance with the frequency specified in the technical specifications.

6.4.5.3 Air Quality Testing

Connections are provided for sampling the air supplied from the compressed and instrument air system and for periodic sampling of the air stored in the storage tanks. Air samples of the compressed air storage tanks are taken quarterly and analyzed for acceptable air quality within the guidelines of CGA G-7.1-1997, “Commodity Specification for Air,” Grade E (Reference 15), with a pressure dew point of 40°F or lower at 3,400 psig or greater.

6.4.5.4 Main Control Room Envelope Habitability

Testing for main control room envelope habitability during VES operation will be conducted in accordance with ASTM E741 (Reference 4).

The main control room envelope must undergo an analysis of inleakage into the control room envelope to determine the integrity of the control room envelope boundary during a design basis accident, hazardous chemical release, or smoke event. Baseline control room envelope habitability testing will be performed as discussed in Subsection 6.4.5.1, followed by a self-assessment at three (3) years after successful baseline testing, and a periodic test at six (6) years in conjunction with other ASME inservice testing requirements. The self-assessment of the ability to maintain main control room habitability includes a review of procedures, boundaries, design changes, maintenance activities, safety analyses, and other related determinations.

If periodic testing is successful, then the assessment/testing cycle continues with a self-assessment three (3) years later and periodic testing three (3) years after the self-assessment. If a periodic testing is unsuccessful, then a periodic test is required three (3) years after repair and successful re-testing, following the unsuccessful periodic testing, to ensure there is no accelerated degradation of the main control room boundary or discrepancies in control of the main control room habitability.

In addition to periodic tests, control room envelope testing will also be performed when changes are made to structures, systems, and components that could impact control room envelope integrity, including systems internal and external to the control room envelope. The tests must be commensurate with the types and degrees of modifications and repairs and the potential impact upon integrity. Additional control room envelope testing will also be performed if a new limiting condition or alignment arises for which no inleakage data is available. Test failure is considered to be inleakage in excess of the licensing basis value for the particular challenge to control room envelope integrity.

Where possible, inleakage testing is performed in conjunction with the VES system level operability testing since the VES must be in operation to perform the inleakage testing.

6.4.6 Instrumentation Requirements

The indications in the main control room used to monitor the main control room emergency habitability system and nuclear island nonradioactive ventilation system are listed in Table 6.4-2.

Instrumentation required for actuation of the main control room emergency habitability system and nuclear island nonradioactive ventilation system are discussed in Subsection 7.3.1.

Details of the radiation monitors used to provide the main control room indication of actuation of the nuclear island nonradioactive ventilation system supplemental filtration mode of operation and actuation of main control room emergency habitability system operation are given in Section 11.5.

A description of initiating circuits, logic, periodic testing requirements, and redundancy of instrumentation relating to the habitability systems is provided in Section 7.3.

6.4.7 Combined License Information

The amount and location of possible sources of hazardous chemicals in or near the plant and for seismic Category I Class 1E hazardous chemical monitoring, are addressed in Subsections 2.2.3.2.3.1, 2.2.3.2.3.2, 2.2.3.3, 6.4.4, and 6.4.4.2. Regulatory Guide 1.78 (Reference 5) addresses control room protection for hazardous chemicals and evaluation of offsite hazardous chemical releases (including the potential for hazardous chemical releases beyond 72 hours) in order to meet the requirements of TMI Action Plan Item III.D.3.4 and GDC 19.

Procedures and training for control room envelope habitability consistency with the intent of Generic Issue 83 (see Section 1.9) are addressed in Subsection 6.4.3.

The testing frequency for the main control room envelope habitability is discussed in Subsection 6.4.5.4.

6.4.8 References

1. “Ventilation for Acceptable Indoor Air Quality,” ASHRAE Standard 62 - 1989.

2. “Human Engineering Design Guidelines,” MIL-HDBK-759C, 31 July 1995.

3. “Human Engineering,” MIL-STD-1472, Revision F, 23 August 1999.

4. “Standard Test Methods for Determining Air Change in a Single Zone by Means of a Tracer Gas Dilution,” ASTM E741, 2000.

5. “Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release,” Regulatory Guide 1.78, Revision 1, December 2001.

6. NUREG-0570, “Toxic Vapor Concentrations in the Control Room Following a Postulated Accidental Release,” June 1979.

7. “Code on Nuclear Air and Gas Treatment,” ASME/ANSI AG-1-1997.

8. “Loss of Charcoal Adsorber Cells,” IE Bulletin 80-03, 1980.

9. “High-Efficiency, Particular, Air-Filter Units,” UL 586, 9th Edition.

10. “Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants,” Regulatory Guide 1.52, Revision 3, 2001.

11. “Standard for Air Filter Units,” UL 900, 8th Edition.

12. “AP1000 VES Air Filtration System Test Report,” TR-SEE-III-09-03.

13. “Single Failure Criterion,” SECY-77-439.

14. NUREG-0700, “Human-System Interface Design Review Guidelines,” Revision 2, 2002.

15. “Commodity Specification for Air,” CGA G-7.1-1997.

Table 6.4-1
Onsite Chemicals[b]

Material	State	Location
Hydrogen	Liquid/Gas	Gas storage/Yard at Turbine Building
Nitrogen	Liquid/Gas	Gas storage
CO_2	Liquid/Gas	Gas storage
Oxygen Scavenger	Liquid	SWS chemical treatment building/area
pH Addition	Liquid	Turbine building[a], SWS chemical treatment building/area
Sulfuric Acid	Liquid	CWS area, SWS chemical treatment building/area
Sodium Hydroxide	Liquid	Turbine building
Dispersant	Liquid	Turbine building[a], CWS area[a], SWS chemical treatment building/area
Fuel Oil	Liquid	DG fuel oil storage tank/DG building/Annex building/FPS Pump Enclosure/Yard West of Turbine Building
Corrosion Inhibitor	Liquid	Turbine building[a], CWS area[a], SWS chemical treatment building/area
Scale Inhibitor	Liquid	Turbine building
Biocide/Disinfectant	Liquid	Turbine building[a], CWS area[a], SWS chemical treatment building/area
Nonoxidizing Biocide	Liquid	SWS chemical treatment building/area
Sodium Bisulfite	Liquid	Turbine building

Note:
a. Site-specific
b. Table 6.4-201 supplements Table 6.4-1.

Table 6.4-2
Main Control Room Habitability Indications and Alarms

VES emergency air storage tank pressure (indication and low and low-low alarms)
VES MCR pressure boundary differential pressure (indication and high and low alarms)
VES air delivery line flowrate (indication and high and low alarms)
VES passive filtration flow rate (indication and high and low alarms)
VBS main control room supply air radiation level (“High-1” and “High-2” alarms)
VBS outside air intake smoke level (high alarm)
VBS isolation valve position
VBS MCR pressure boundary differential pressure

Table 6.4-3
Loss of AC Power Heat Load Limits

Room Name	Room Numbers	Heat Load 0 to 24 Hours (Btu/sec)	Heat Load 24 to 72 Hours (Btu/sec)
MCR Envelope	12401	23.5 (Hour 0 to 0.5) 14.5 (Hour 0.5 to 3.5) 4.75 (Hour 3.5 through 24)	3.95
I&C Rooms	12301	3.50	1.10
	12302	3.20	2.50
	12304	4.30	3.20
	12305	4.20	1.50
dc Equipment Rooms	12201	2.00	2.00
	12203	3.30	3.30
	12205	2.40	2.40
	12207	3.45	3.45

Table 6.4-201 (Sheet 1 of 4)
Main Control Room Habitability Evaluations of Onsite Toxic Chemicals(1)

A — Standard Onsite Toxic Chemicals

Evaluated Material(2)	Evaluated State	Evaluated Maximum Quantity	Evaluated Minimum Distance to MCR Intake	Evaluated Location	MCR Habitability Impact Evaluation
Hydrogen	Gas	2200 scf	126.3 ft	Yard at turbine building	MCR
Hydrogen	Liquid(3)	1500 gal	577 ft	Gas storage	MCR
Nitrogen	Liquid/Gas(3)	3000 gal	577 ft	Gas storage	MCR
Carbon Dioxide (CO_2)	Liquid/Gas(3)	6 tons	577 ft	Gas storage	MCR
Oxygen Scavenger [Hydrazine, or Carbohydrazide]	Liquid	1600 gal	203 ft	SWS chemical treatment building	IH
pH Addition [Ammonium Hydroxide, Morpholine, Ethanolamine or Methoxypropylamine]	Liquid	1600 gal	203 ft	SWS chemical treatment building	IH
Sulfuric Acid	Liquid	800 gal	203 ft	SWS chemical treatment building	IH
Sulfuric Acid	Liquid	20,000 gal	436 ft	CWS area	IH
Sodium Hydroxide	Liquid	800 gal	203 ft	Turbine building	S
Sodium Bisulfite	Liquid	450 gal	203 ft	Turbine Building	S
Fuel Oil	Liquid	94,000 gal	197 ft	DG fuel oil storage tank, DG building, Annex building	IH

Table 6.4-201 (Sheet 2 of 4)
Main Control Room Habitability Evaluations of Onsite Toxic Chemicals[1]

A — Standard Onsite Toxic Chemicals

Evaluated Material[2]	Evaluated State	Evaluated Maximum Quantity	Evaluated Minimum Distance to MCR Intake	Evaluated Location	MCR Habitability Impact Evaluation
Corrosion Inhibitor/Silt Dispersant [Nalco Trasar 3DT187 or Nalco Trasar 3DT487]	Liquid	800 gal	203 ft	SWS chemical treatment building	S
Scale Inhibitor [Polyacrylic Acid]	Liquid	800 gal	203 ft	Turbine building	S
Biocide/Disinfectant [Sodium Hypochlorite or Nalco Stabrex™ ST70]	Liquid	800 gal	203 ft	SWS chemical treatment building	S
Biocide/Disinfectant [Sodium hypochlorite]	Liquid	10,000 gal	436 ft	CWS area	S
Nonoxidizing Biocide [Nalco 77352NA or Ammonium Chloride]	Liquid	800 gal	203 ft	SWS chemical treatment building	S

Table 6.4-201 (Sheet 3 of 4)
Main Control Room Habitability Evaluations of Onsite Toxic Chemicals(1)

B — Site Specific Onsite Toxic Chemicals

Evaluated Material(2)	Evaluated State	Evaluated Maximum Quantity	Evaluated Minimum Distance to MCR Intake	Evaluated Location	MCR Habitability Impact Evaluation
pH Control [Methoxypropylamine (MPA]	Liquid	800 gal	211 ft	Turbine building	IH, MCR
Silt dispersant [Proprietary tagged high strength polymer]	Liquid	800 gal	211 ft	Turbine building	S
Silt dispersant [Proprietary tagged high strength polymer]	Liquid	10,000 gal	802 ft	CWS area	S
Corrosion inhibitor [Proprietary blend of Phosphonate, Phosphinosuccinic Oligomer (PSO), and Phosphoric Acid]	Liquid	800 gal	211 ft	Turbine building	S
Corrosion inhibitor [Proprietary blend of Phosphonate, Phosphinosuccinic Oligomer (PSO), and Phosphoric Acid]	Liquid	10,000 gal	802 ft	CWS area	S
Biocide [Stabilized Bromine]	Liquid	800 gal	211 ft	Turbine building	S
Biocide [Stabilized Bromine]	Liquid	10,000 gal	802 ft	CWS area	S

Table 6.4-201 (Sheet 4 of 4)
Main Control Room Habitability Evaluations of Onsite Toxic Chemicals(1)

B — Site Specific Onsite Toxic Chemicals

Evaluated Material(2)	Evaluated State	Evaluated Maximum Quantity	Evaluated Minimum Distance to MCR Intake	Evaluated Location	MCR Habitability Impact Evaluation
Biocide [Sodium Bromide]	Liquid	800 gal	211 ft	Turbine building	S
Biocide [Sodium Bromide]	Liquid	10,000 gal	802 ft	CWS area	S
Detoxification agent [Ammonium Bisulfite]	Liquid	1000 gal	211 ft	Turbine building	IH, MCR
Propane	Liquid	8000 gal	3400 ft	Fire Training Facility	MCR

Notes:

1) This table supplements Table 6.4-1. Quantities are by largest evaluated container content for the evaluated location per unit. Quantities and distances are bounding evaluation values and may not be actual amounts and distances. Smaller quantities of a chemical at further distances from the MCR air intake are not shown on this table. Actual site locations are confirmed to be at or beyond the evaluated distance.

S - Chemicals with an Impact Evaluation designation of “S” for the MCR Habitability Impact Evaluation were evaluated and screened out based on the chemical properties, distance, and quantities.

IH - Chemicals with an Impact Evaluation designation of “IH” indicates the evaluation of this chemical considered the design detail of the main control room intake height.

MCR - Chemicals with an Impact Evaluation designation of “MCR” indicates the evaluation of this chemical considered design details of the main control room such as volume, envelope boundaries, ventilation systems, and occupancy factor.

2. Evaluated chemicals listed in [brackets] are typical of the class of compounds evaluated. The exact chemicals vary based on site needs and technology available. The bracketed chemicals are substituted for similar chemical performing a similar function only after review by site personnel to ensure the new chemical does not impact the previous MCR Habitability Impact Evaluation.

3. Evaluated state is analyzed as mass. Equivalent mass of gas is bounded by liquid.

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 6.4-1
Main Control Room Envelope

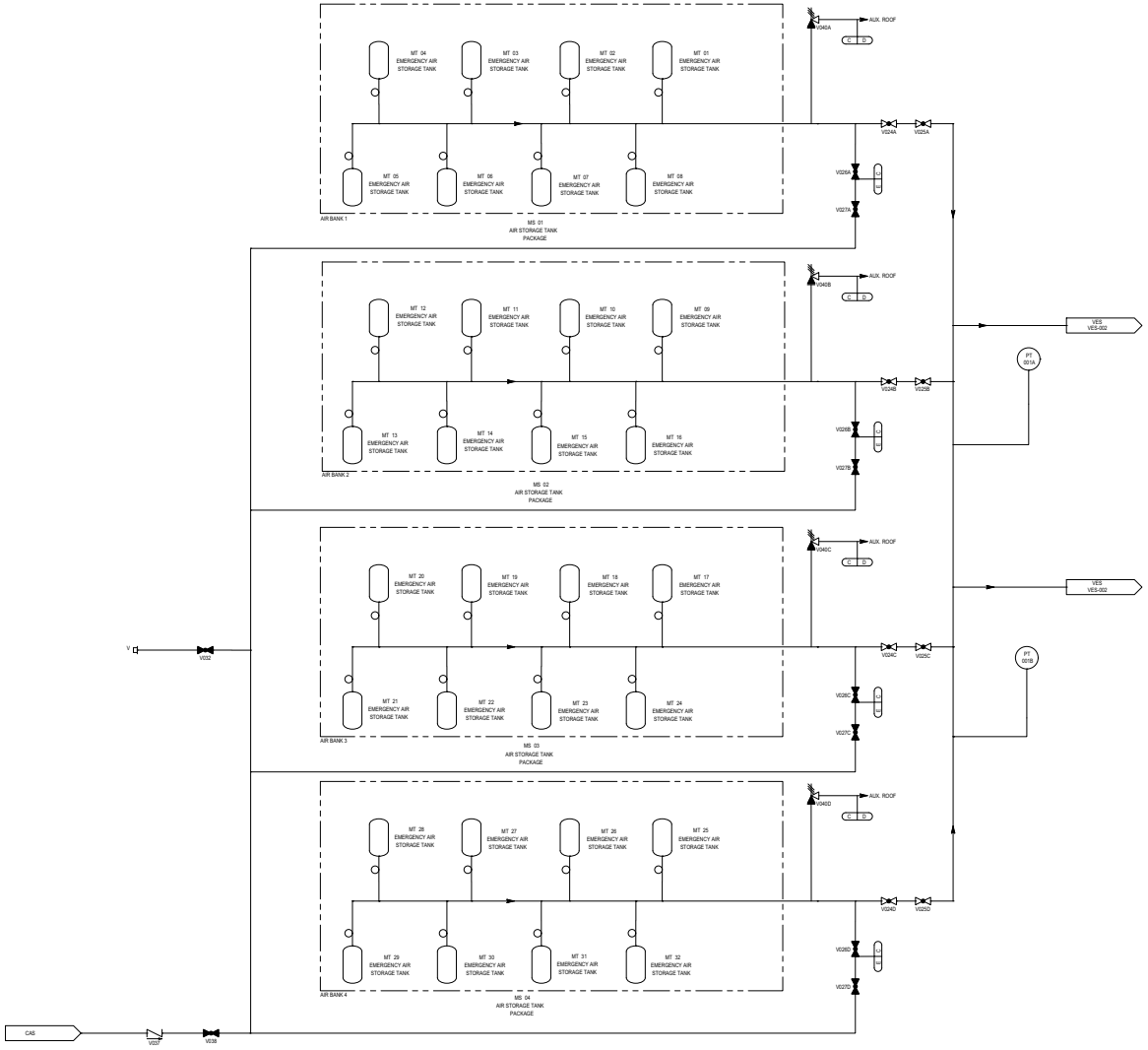


Figure 6.4-2 (Sheet 1 of 2)
Simplified Main Control Room Habitability System Piping and Instrumentation Diagram (REF) VES 001

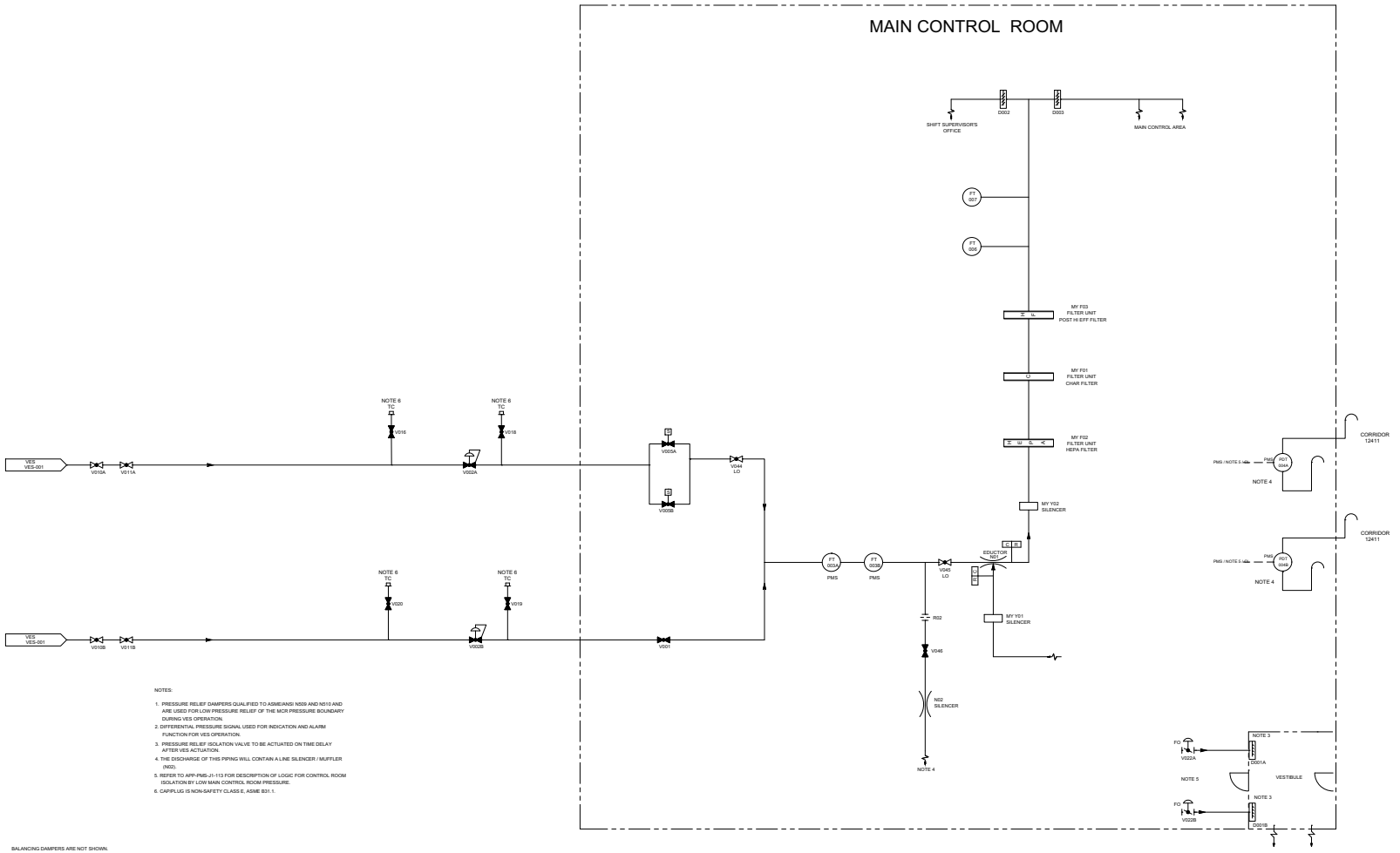


Figure 6.4-2 (Sheet 2 of 2)
Simplified Main Control Room Habitability System Piping and Instrumentation Diagram (REF) VES 002

6.5 Fission Product Removal and Control Systems

6.5.1 Engineered Safety Feature (ESF) Filter Systems

This subsection is not applicable to the AP1000.

6.5.2 Containment Spray System

In the event of a design basis LOCA there is an assumed core degradation that results in a significant release of radioactivity to the containment atmosphere. This activity would consist of noble gases, particulates, and a small amount of elemental and organic iodine (as discussed in Subsection 15.6.5.3, most of the iodine would be in the particulate form). The AP1000 does not include a safety-related containment spray system to remove airborne particulates or elemental iodine. Removal of airborne activity is by natural processes that do not depend on sprays (that is sedimentation, diffusiophoresis, and thermophoresis). These removal mechanisms are discussed in Appendix 15B.

Much of the non-gaseous airborne activity would eventually be deposited in the containment sump solution. Long-term retention of iodine in the containment sump following design basis accidents requires adjustment of the sump solution pH to 7.0 or above. This pH adjustment is accomplished by the passive core cooling system and is discussed in Subsection 6.3.2.1.4.

In accordance with Reference 1, the fire protection system provides a nonsafety-related containment spray function for accident management following a severe accident. This design feature is not safety-related and is not credited in any accident analysis including the dose analysis provided in Subsection 15.6.5. Dose reduction following a severe accident may be enhanced over the natural removal mechanisms via the nonsafety-related containment spray. Subsection 15.6.5.3.2 provides additional discussion of the natural removal mechanisms. The following subsections provide a discussion of the nonsafety-related containment spray function provided by the fire protection system.

6.5.2.1 System Description

The fire protection system provides a nonsafety-related containment spray function for severe accident management. Subsection 9.5.1 provides a description of the fire protection system including equipment and valves that support the containment spray function such as the fire pumps and fire main header. This section provides the description of the portion of the fire protection system designed specifically to provide the containment spray function.

The source of water for the containment spray function is provided by the secondary fire protection system water tank. Either the motor driven or diesel driven fire protection system pump may be used to deliver fire water to the containment spray header. The flow path to containment is via the normal fire main header as shown in Figure 9.5.1-1, sheets 1 through 3. The containment spray flow path is from the fire main extension, through the fire protection system line that penetrates containment, to the containment spray riser that connects to the fire protection system header inside containment. This riser supplies two ring headers located above the containment polar crane.

6.5.2.1.1 Valves

The containment spray flow path from the fire main header contains one normally open manual valve (FPS-V048), one normally closed manual valve (FPS-V101), one locked closed manual containment isolation valve outside containment (FPS-V050), a containment isolation check valve inside containment (FPS-V052), a normally open manual isolation valve in the spray riser (FPS-V700), and

a normally closed remotely-operated valve (FPS-V701) downstream of the manual isolation valve in the spray riser.

Containment spray is initiated by first closing the passive containment cooling water system fire header isolation valve (PCS-V005) isolating the passive containment cooling water storage tank, opening the manual valves outside containment, and by opening the remotely-operated valve inside containment. The manual valves outside containment are located in valve / piping penetration room 12306. The valves are located close to the entrance door such that radiation exposures to an individual required to enter the room and align the valves would not exceed the prescribed post-accident dose limits discussed in Subsection 12.4.1.8.

Valve FPS-V701 is a fail-open air-operated valve such that the containment spray flow path can be opened following a loss of the nonsafety-related compressed and instrument air system. During shutdown operations, the fire protection system header inside containment is pressurized from the passive containment cooling water storage tank for fire protection and manual isolation valve FPS-V700 is closed.

6.5.2.1.2 Containment Spray Header and Nozzles

The containment spray header consists of a single header that feeds two ring headers located above the containment polar crane. The containment spray ring headers and spray nozzles are oriented to maximize containment volume coverage. A lower ring header is located at plant elevation 260 feet, and contains 44 spray nozzles. An upper ring header is located at plant elevation 275 feet, and contains 24 spray nozzles.

The nozzles within the spray ring header are conventional containment spray nozzles utilized in past Westinghouse pressurized water reactors. The spray nozzles are selected on the basis of drop size to provide adequate absorption of fission products from the containment atmosphere.

6.5.2.1.3 Applicable Codes and Classifications

The containment spray function is not safety-related, and therefore the valves and piping in the containment spray flow path are not required to be safety-related for the containment spray function. However, the containment isolation piping and valves are safety-related (AP1000 Equipment Class B) to perform the safety-related function of containment isolation. The classification of the remaining portions of the fire header are nonsafety-related, and are classified as Class F as discussed in Subsections 3.2.2.7 and 9.5.1. The containment spray header and valve, downstream of the manual isolation valve inside containment is nonsafety-related and classified as Class E. The containment spray header is classified as Seismic category II.

6.5.2.1.4 System Operation

During normal operation, the fire protection system header inside containment is isolated from the fire main header by closed isolation valves, including a locked closed containment isolation valve. The containment spray piping is therefore not pressurized during normal operation. During plant shutdown modes, personnel access to containment is required, and as such, the fire protection system standby header inside containment is pressurized by the water in the passive containment cooling water storage tank. During these modes, the manual isolation valve located between the header and the spray ring is closed to further isolate the containment spray header from the passive containment cooling water storage tank. Inadvertent actuation of the containment spray system during power operation and shutdown is not credible. Inadvertent actuation of the containment spray would require multiple failures of closed valves.

Severe accident management guidelines provide the operator with guidance to initiate the containment spray feature of the fire protection system. Operator action to open two manual isolation valves outside of containment followed by remotely opening the containment spray isolation valve within containment from either the main control room or the remote shutdown workstation will initiate the spray function. Containment spray may be terminated at any time by closing the remotely operated isolation valve within containment, or by closing any of the manual valves in the containment spray flow path outside containment. Operation of the containment spray will have no effect on the availability of the remainder of the fire protection system other than the loss of inventory from the secondary fire water tank due to the sprayed water. To preserve inventory for firefighting, the primary fire water tank is isolated during containment spray operation. Since the fire protection system operates in the active standby mode, i.e. the supply piping is kept full and pressurized, once the remotely operated isolation valve is opened the system will perform the containment spray function.

When water pressure in the fire main begins to fall, due to a demand for water from containment spray, the motor-driven pump starts automatically on a low-pressure signal. If the motor-driven pump fails to start, the diesel-driven pump starts upon a lower pressure signal. The pump continues to run until it is stopped manually.

6.5.2.2 Design Evaluation

6.5.2.2.1 Containment Coverage

The containment spray nozzles are the Lechler (SPRACO Company) spray nozzles or equivalent, which provide a drop size distribution which has been established by testing and found suitable for fission product removal. The fire protection system header provides a containment spray nozzle differential pressure of 40 psid, which fixes the drop size distribution. The mass mean drop size produced at this differential pressure is conservatively assumed to be 1000 microns.

The fire protection system header can provide the design flow rate of 15.2 gpm to each spray nozzle at a containment backpressure of 20 psig for a total containment spray flow of approximately 1034 gpm. Analyses of severe accident sequences show that containment backpressure is less than 20 psig after containment spray flow is initiated.

Figure 6.5-1 is a diagram of containment which shows the developed spray patterns for the containment spray ring headers. The overlay of the spray patterns on the containment is useful in illustrating the completeness of spray coverage in the sprayed region. Furthermore, as discussed in Reference 2, there is significant momentum exchange between the spray droplets and the closed air volume of the containment, which provides far greater mixing within the sprayed region than the idealized spray patterns would indicate. Therefore, even though small areas of the sprayed region are not directly sprayed by the developed spray patterns, the sprayed region of the containment is well-mixed.

The sprayed regions of containment include the region of containment above the operating deck, and the refueling cavity, which is open at the operating deck. The total free volume of the sprayed region is approximately 1.7×10^6 cubic feet which represents approximately 84% of the total containment free volume.

6.5.2.2.2 Aerosol Removal Effectiveness of Sprays

The removal of aerosol activity from the containment atmosphere by sprays is simply described by:

$$C_t = C_o e^{-\lambda t}$$

where:

C_t = concentration of aerosols at time "t"

C_o = initial concentration of aerosols

λ = aerosol removal coefficient for sprays (hr^{-1})

t = elapsed time (hr)

However, to fully model the removal of aerosols from the containment atmosphere in a severe accident, the analysis also needs to take into account mixing between the sprayed and unsprayed regions and the rate of release of activity from the core into the containment atmosphere.

6.5.2.2.3 Aerosol Removal Coefficient for Sprays

The aerosol removal coefficient for sprays is calculated by the following equation from the Standard Review Plan (Reference 2):

$$\lambda = 3hfE / 2Vd$$

where:

h = average spray drop fall height (ft)

f = spray flow rate (ft^3/hr)

E = collection efficiency

V = volume of the containment exposed to sprays

d = average spray drop diameter (ft)

Reference 2 identifies a value for E/d of 10 m^{-1} (3.05 ft^{-1}) as being conservative until the air concentration is reduced by a factor of 50. Using this together with a nominal spray fall height of 125 feet and a nominal flow rate of 1000 gpm (8022 ft^3/hr), the aerosol removal coefficient for the containment sprays is approximately 2.7 hr^{-1} in the sprayed volume. This spray removal coefficient is significantly greater than that associated with the natural removal mechanisms assumed in the design basis analysis (see Appendix 15B) and would enhance dose reduction following a severe accident.

The decontamination factor (DF) that would be achieved at any point in time is dependent on the timing of spray operation. Additionally, the continuing release of activity must be factored into the determination of DF (i.e., the DF would be based on the integrated activity release to the containment at a point in time, not on the amount of activity present in the containment atmosphere at the time spray operation is initiated). After a DF of 50 is reached, the value of E/D would be reduced by a factor of ten (Reference 2) and the aerosol removal coefficient would also be reduced by the same factor to a value of 0.27 hr^{-1}. Based on an assumed spray actuation shortly after the onset of core melt and a nominal spray duration of three hours, the DF of 50 would not be reached until after spray operation was terminated.

6.5.3 Fission Product Control Systems

The containment atmosphere is depleted of elemental iodine and particulates as a result of the passive removal processes discussed in Appendix 15B. No active fission product control systems are required in the AP1000 design to meet regulatory requirements. The passive removal processes and the limited leakage from the containment of less than L_a as defined in the Containment Leakage Rate Testing Program, result in doses less than the regulatory guideline limits. (See Subsection 15.6.5.3.)

6.5.3.1 Primary Containment

The containment consists of a freestanding cylindrical steel vessel with ellipsoidal heads. The containment structural design is presented in Subsection 3.8.2.

The containment vessel, penetrations, and isolation valves function to limit the release of radioactive materials following postulated accidents. The resulting offsite doses are less than regulatory guideline limits. Containment parameters affecting fission product release accident analyses are given in Table 6.5.3-1.

Long-term containment pressure and temperature response to the design basis accident are presented in Section 6.2.

The containment air filtration system may be operated for personnel access to the containment when the reactor is at power, as presented in Subsection 9.4.7. For this reason, the radiological assessment of a loss-of-coolant accident assumes that both trains of the air filtration system are in service at the initiation of the event. The isolation valves receive automatic signals to close from diverse parameters. The valves are designed to close automatically as described in Subsection 6.2.3.

Containment hydrogen control systems are presented in Subsection 6.2.4.

6.5.3.2 Secondary Containment

There is no secondary containment provided for the fission product control following design basis accident.

The annulus between containment and shield building from the elevation 100′-0″ to the elevation 132′-3″ acts as a holdup volume to limit the spread of fission products following severe accident. Most containment penetrations are located within this holdup volume. It is served by the radiologically controlled area ventilation system (VAS) described in Subsection 9.4.3. Isolation dampers are provided to reduce the air interchange between the holdup volume and environment. Fission product control via holdup within the annulus is considered in severe accident dose analysis but excluded from consideration for design basis accident dose evaluations presented in Chapter 15.

6.5.4 Combined License Information

This section contained no requirement for additional information.

6.5.5 References

1. SECY-97-044, "Policy and Key Technical Issues Pertaining to the Westinghouse AP600 Standardized Passive Reactor Design," June 30, 1997.

2. NUREG-0800, Section 6.5.2, Revision 2, "Containment Spray as a Fission Product Cleanup System."

Table 6.5.3-1
Primary Containment Operation
Following a Design Basis Accident

Type of structure	Freestanding cylindrical steel vessel with ellipsoidal heads
Containment free volume (ft^3)	2.06×10^6
Design basis containment leak rate	0.10% containment air weight per day

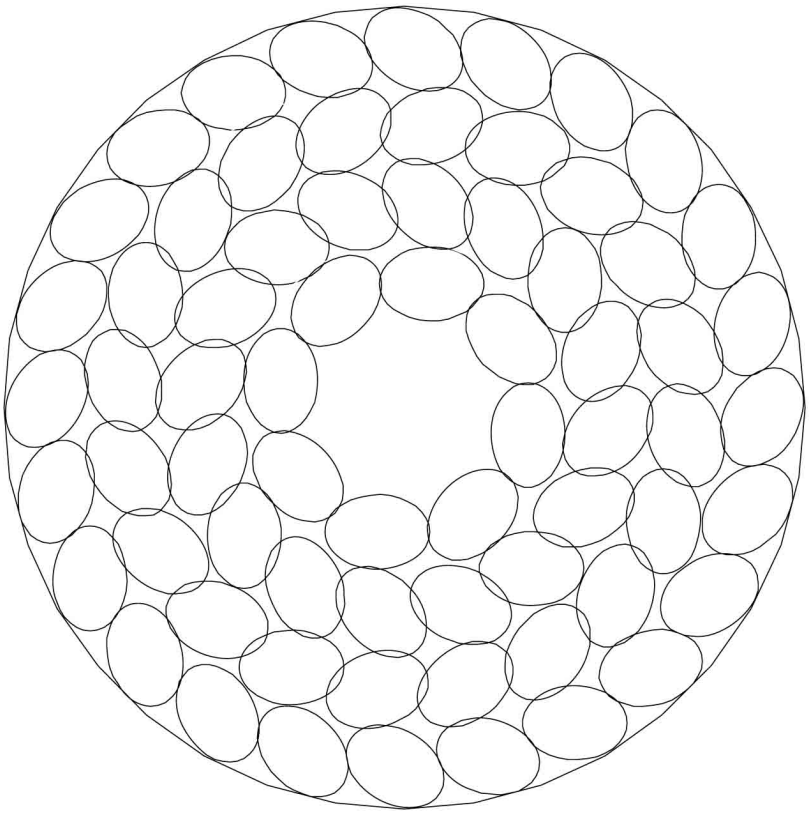


Figure 6.5-1
Containment Spray Coverage at Operating Deck

6.6 Inservice Inspection of Class 2, 3, and MC Components

The inservice inspection program incorporates the ASME Boiler and Pressure Vessel Code approved in 10 CFR 50.55a(b) subject to the limitations and modifications listed in 10 CFR 50.55a(b).

6.6.1 Components Subject to Examination

Preservice and inservice inspections of Quality Group B and C pressure retaining components (ASME Code, Section III Class 2 and 3 components) such as vessels, piping, pumps, valves, bolting, and supports as identified in Subsection 3.2.2 are performed in accordance with the ASME Code, Section XI, as required by 10 CFR 50.55a(g). This includes the ASME Code Section XI Mandatory Appendices. Preservice and inservice inspections of Quality Group B components that are ASME Class MC (metallic containment) pressure-retaining components and integral attachments are performed in accordance with the ASME Code, Section XI, as required by 10 CFR 50.55a. Refer to Subsection 3.8.2, “Steel Containment” for design details, including accessibility of primary containment.

The responsibility for preparation of the pre-service inspection program (nondestructive examination) is described in Subsection 6.6.9. The responsibility for the inservice inspection program that is required prior to commercial operation is described in Subsection 6.6.9. These programs will address applicable inservice inspection provisions of 10 CFR 50.55a(g). The pre-service program will provide details of areas subject to inspection, as well as the method and extent of pre-service inspection. The inservice inspection program will detail the areas subject to inspection and method, extent, and frequency of inspection.

Class 2 and 3 components are included in the equipment designation list and the line designation list contained in the inservice inspection program.

6.6.2 Accessibility

ASME Code Class 2, 3, and MC components are designed so that access is provided in the installed condition for visual, surface and volumetric examinations specified by the ASME Code. See Subsection 5.2.1.1 for a discussion of the baseline ASME Code edition and Addenda. Design provisions, in accordance with Section XI, IWA-1500, are formally implemented in the Class 2, 3, and MC component design processes.

The goal of designing for inspectability is to provide for the inspectability access and conformance of component design with available inspection equipment and techniques. Factors such as examination requirements, examination techniques, accessibility, component geometry and material selection are used in evaluating component designs. Examination requirements and examination techniques are defined by inservice inspection personnel. Inservice inspection review as part of the design process provides component designs that conform to inspection requirements and establishes recommendations for enhanced inspections.

Considerable experience has been drawn on in designing, locating, and supporting Quality Group B and C (ASME Class 2 and 3) and Class MC pressure-retaining components to permit pre-service and inservice inspection required by Section XI of the ASME Code. Factors such as examination requirements, examination techniques, accessibility, component geometry, and material selections are used in establishing the designs. The inspection design goals are to eliminate uninspectable components, reduce occupational radiation exposure, reduce inspection times, allow state-of-the-art inspection systems, and enhance detection and the reliability of flaw characterization. There are no Quality Group B and C components or Class MC components, which require inservice inspection during reactor operation.

Removable insulation is provided on piping systems requiring volumetric and surface inspection. Removable hangers and pipe whip restraints are provided, as necessary and practical, to facilitate inservice inspection. Working platforms are provided in areas requiring inspection and servicing of pumps and valves. Temporary or permanent platforms, scaffolding, and ladders are provided to facilitate access to piping welds. The components and welds requiring inservice inspection are designed to allow for the application of the required inservice inspection methods, that is, sufficient clearances for personnel and equipment, maximized examination surface distances, two-sided access (except for valve to pipe welds), favorable materials, weld joint simplicity, elimination of geometrical interferences, and proper weld surface preparation.

Many of the ASME Code, Section III, Class 2 and 3 components are included in modules which are fabricated offsite and shipped to the site, as described in Subsection 3.9.1.5. The modules are designed and engineered to provide access for in-service inspection and maintenance activities. The attention to detail that is engineered into the modules prior to construction improves the accessibility for inspection and maintenance.

Future unanticipated changes in the Section XI requirements could, however, necessitate relief requests. Relief from the inspection requirements of Section XI will be requested when full compliance is not practical according to the requirements of 10 CFR 50.55a. In such cases, specific information will be provided to identify the applicable ASME Code requirements, justification for the relief request, and the inspection method to be used as an alternative.

Space is provided to handle and store insulation, structural members, shielding, and other material related to the inspection. Suitable hoists and other handling equipment, lighting, and sources of power for inspection equipment are installed at appropriate locations.

During the construction phase of the project, anomalies and construction issues are addressed using change control procedures. Modifications reviewed following design certification adhere to the same level of review as the certified design per 10 CFR Part 50, Appendix B as implemented by the Westinghouse Quality Management System (QMS). The QMS requires that changes to approved design documents, including field changes, are subject to the same review and approval process as the original design. This explicitly requires the field change process to follow the same level of review that was required during the design process. Accessibility and inspectability are key components of the design process.

Control of accessibility for inspectability and testing during post-design certification activities is provided via procedures for design control and plant modifications.

6.6.3 Examination Techniques and Procedures

The visual, surface, and volumetric examination techniques and procedures are in accordance with the requirements of ASME Code, Section XI, Article IWA-2000. Approved Code Cases listed in Regulatory Guide 1.147 are applied as the need arises during the pre-service inspection. Approved Code Cases determined as necessary to accomplish pre-service inspection activities are used.

6.6.3.1 Examination Methods

Visual Examination

Examination methods are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

Surface Examination

Examination methods are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

Ultrasonic Examination

Examination methods are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

Alternative Examination Techniques

Examination methods are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

6.6.3.2 Qualification of Personnel and Examination Systems for Ultrasonic Examination

Personnel performing examinations shall be qualified in accordance with ASME Section XI, Appendix VII. Ultrasonic examination systems shall be qualified in accordance with industry accepted programs for implementation of ASME Section XI, Appendix VIII.

6.6.3.3 Relief Requests

The specific areas where the applicable ASME Code requirements cannot be met are identified after the examinations are performed. Should relief requests be required, they will be developed through the regulatory process and submitted to the NRC for approval in accordance with 10 CFR 50.55a(z) or 50.55a(g)(5). The relief requests include appropriate justifications and proposed alternative inspection methods.

6.6.4 Inspection Intervals

Inspection intervals included in the inspection program are as defined in Subarticles IWA-2400, IWC-2400, IWD-2400, IWE-2400, and IWF-2400 of the ASME Code, Section XI. The periods within each inspection interval may be extended by as much as one year to permit inspections to be concurrent with plant outages. It is intended that inservice examinations be performed during normal plant outages, such as refueling shutdown or maintenance shutdowns occurring during the inspection interval.

Inspection intervals meet the requirements of ASME Section XI as specified in 10 CFR 50.55a.

6.6.5 Examination Categories and Requirements

Examination categories and examination requirements (examination methods, acceptance criteria, extent of examination, and frequency of examination) for Class 2 components are in accordance with Subsection IWC and Table IWC-2500-1 of the ASME Code, Section XI. Similar information for Class 3 components is in conformance with Subsection IWD and Table IWD-2500-1. For component supports, examination categories and examination requirements are in conformance with Subsection IWF and Table IWF-2500-1; and for Class MC components, examination categories and examination requirements are in conformance with Subsection IWE and Table IWE-2500-1 of ASME Code, Section XI.

The pre-service examination of Class 2 components is according to the requirements of Subarticle IWC-2200. The pre-service examination of Class MC components is in accordance with the requirements of Subarticle IWE-2200. The pre-service examination requirements for component

supports are in accordance with the requirements of Subarticle IWF-2200. The pre-service examination of Class 3 components is according to the requirements of Subarticle IWD-2200.

As provided in ASME Section XI, IWC-1220, IWD-1220, and IWE-1220, certain portions of Class 2, 3, and MC systems are exempt from the volumetric, surface, and visual examination requirements of IWC-2500, IWD-2500, and IWE-2500. Supports associated with Class 2, 3, and MC components are also exempt in accordance with the requirements of IWF-1230.

6.6.6 Evaluation of Examination Results

Examination results are evaluated per the acceptance standards found in IWA-3000, IWC-3000, IWD-3000, IWE 3000, and IWF-3000 of the ASME Code, Section XI. Repair and replacement procedures are in accordance with ASME Code, Section XI, Article IWA-4000.

Evaluation of examination results are conducted in accordance with ASME Section XI, as modified or required by 10 CFR 50.55a.

6.6.7 System Pressure Tests

System pressure tests comply with IWA-5000, IWC-5000, IWD-5000, and IWE-5000 of the ASME Code, Section XI, for Class 2, 3, and MC components. Pressure testing of Class MC components is performed per the 10 CFR 50 Appendix J “Containment Leak Rate Testing” Program.

6.6.8 Augmented Inservice Inspection to Protect against Postulated Piping Failures

An augmented inspection program is developed for high-energy fluid systems piping between containment isolation valves. Such a program is also developed where no isolation valve is used inside containment between the first rigid pipe connection to the containment penetration or the first pipe whip restraint inside containment and the outside isolation valve. This program provides for 100 percent volumetric examination of welds in the affected piping during each inspection interval, conducted according to the ASME Code, Section XI. The program covers the break exclusion portion of high-energy fluid systems described in Subsections 3.6.1 and 3.6.2.

There is no requirement for an augmented inspection of ASME Code, Section III Class 1, 2, or 3 pipe to address erosion-corrosion-induced pipe wall thinning. Class 1, 2, and 3 pipe containing single-phase water or two-phase steam and water is fabricated of erosion-corrosion resistant material. See Section 10.1 for information on monitoring of nonsafety-related pipe for erosion-corrosion.

6.6.9 Combined License Information Items

6.6.9.1 Inspection Programs

The pre-service inspection program (nondestructive examination) and an inservice inspection program for ASME Code, Section III Class 2, 3, and MC systems, components, and supports are addressed in Section 6.6 introduction, and in Subsections 6.6.1, 6.6.3.1, 6.6.3.2, 6.6.3.3, 6.6.4, and 6.6.6.

6.6.9.2 Construction Activities

The controls to preserve accessibility and inspectability for ASME Code, Section III, Class 2, 3, and MC components and piping during construction or other post design certification activities are addressed in Subsection 6.6.2.

Appendix 6A Fission Product Distribution in the AP1000 Post-Design Basis Accident Containment Atmosphere

The AP1000 design-basis analyses for hydrogen control (Subsection 6.2.4.3) and natural aerosol removal coefficient (Appendix 15B) assume that the fission products and hydrogen released to the containment following a postulated design basis loss of coolant accident (LOCA) are homogeneously distributed in the containment atmosphere within the open compartments that participate in natural circulation. The purpose of this discussion is to justify the homogeneous assumption for aerosol natural deposition calculations.

The following evaluation includes:

- Identification of the accident sequence assumptions and boundary conditions in the reactor coolant system and containment prior to the fission product and hydrogen releases
- Identification of the limiting steam and fission product release location from the reactor coolant system to the containment
- Discussion of containment natural circulation in quasi-steady conditions
- Discussion of AP1000 passive containment cooling system (PCS) large-scale test (LST) insights that support the well-mixed assumption

6A.1 Design Basis Sequence Assumptions

The design-basis fission product source term (Subsection 15.6.5.3.1) is superimposed onto thermal-hydraulic conditions of the design-basis accident sequence for the evaluation of fission product deposition. The following assumptions define the design basis conditions. The AP1000 design-basis sequence consists of a LOCA which drains the reactor coolant system (RCS) and core makeup tanks (CMTs) sufficiently to activate the automatic depressurization system (ADS). Both trains of all four stages of automatic depressurization system open sequentially. During the depressurization, the core makeup tanks and accumulators inject into the reactor vessel downcomer. The final reactor coolant system pressure is essentially equal to the containment pressure which allows gravity injection of the IRWST water. Steam is produced in the vessel at the rate dictated by decay heat minus the heat in the volatile fission products which have been released from the core. The passive containment cooling system water flow is initiated based on High-2 containment pressure from the blowdown or the automatic depressurization system prior to the release of fission products.

Fission product release occurs from a fully depressurized reactor coolant system. The aerosols are carried into the containment in a buoyancy-driven steam flow. The earliest time of fission product release from core degradation is well past the time of the blowdown and automatic depressurization. The containment condition during and following the release is quasi-steady-state. Internal heat sinks are assumed to be essentially thermally-saturated and no longer effective, and the condensation rate of steam on the containment dome and shell is equivalent to the decay heat steaming rate.

6A.1.1 Break Size and Fission Product Release Location in Containment

This section discusses each of the postulated fission product release locations from the reactor coolant system, the containment location for each, the size limitations and the phenomena associated with the break locations. It is shown that it is appropriate to assume that the steam and fission products are released from the reactor coolant system hot leg to the containment above the maximum water flood-up elevation in the steam generator compartment gas space.

6A.1.1.1 Releases From Depressurization System Lines

Any design-basis LOCA which can be postulated to produce a large core activity release to containment will actuate the four stages of the automatic depressurization system. The stage 1, 2 and 3 automatic depressurization system lines, which relieve from the top of the pressurizer (see Figure 6A-1), deliver flow to the containment through the in-containment refueling water storage tank (IRWST). This is not considered to be a major fission product release pathway because the IRWST is a cold, effectively closed system with no leakage pathway to the environment. The IRWST is nearly full of water during the depressurization blowdown which would trap any postulated fission products released to the IRWST. At the time the water is drained below the spargers, the reactor coolant system is depressurized with stage 4 automatic depressurization system open, and the IRWST vents, which are closed with flappers, are not expected be significantly opened by the small buoyancy-driven flows. Aerosols released from stages 1, 2 and 3, either before or after the draining of the IRWST, would essentially be trapped in the water or in the IRWST compartment. Therefore, this pathway is conservatively neglected as a release pathway from the reactor coolant system to maximize the activity entering the containment atmosphere.

Stage 4 automatic depressurization system lines relieve reactor coolant system coolant, steam, and fission products from the hot legs (see Figure 6A-1) to the steam generator compartments above the maximum water flood-up level. The stage 4 lines consist of four 14-inch schedule 160 lines. Two lines are connected to each of the two hot legs. Each of these trains relieves at the 112-foot elevation to a steam generator compartment.

Of the postulated release locations in the reactor coolant system, openings in the hot-side piping, such as the stage 4 automatic depressurization system, provide the lowest resistance pathway for fission product releases to the containment because of the large flow area, high temperatures, short resident time and low surface area for aerosol deposition in the reactor coolant system. To reach openings in the cold side piping when stage 4 automatic depressurization system valves are open, the reactor coolant system low-pressure natural circulation flow must pass through the steam generator tubes (see Figure 6A-1). At the superheated steam temperature of the gas which accompanies the fission product flow, significant heat transfer would take place in the steam generator tubes which are cooled on the secondary side by water. Aerosol deposition to the tubes would remove fission products from the release before the flow reached the containment. Therefore, releases from cold-side breaks are less severe than hot side breaks with the stage 4 automatic depressurization system open.

6A.1.1.2 Releases From Coolant Loop Breaks

Breaks in the reactor coolant system loop piping (hot legs or cold legs) relieve primary coolant, steam and fission products to the steam generator compartments. Assuming double-ended guillotine breaks, the hot-leg break has a diameter of 31 inches (78.7 cm) and the cold-leg break has a diameter of 22 inches (55.9 cm). Breaks in the hot leg piping are more limiting than breaks in the cold leg with respect to the fission product releases to the containment because of the larger break area, higher temperatures, shorter resident time and lower surface area for aerosol deposition in the reactor coolant system. Therefore, of the coolant loop breaks, hot leg breaks to the steam generator compartment provide the more conservative magnitude of fission product release to the containment. Because of the similar fission product flow path, release magnitude and release location, the hot leg breaks can be lumped with the stage 4 automatic depressurization system releases.

6A.1.1.3 Direct Vessel Injection Line Breaks

A break in one of the two direct vessel injection lines can relieve steam and fission products outside the steam generator compartments to one of the two dead-ended accumulator compartments below the core makeup tank room. The piping is 8-inch diameter schedule 160 piping, but an orifice at the

reactor vessel wall limits the break size to a 4-inch diameter. The nozzle connects to the reactor vessel downcomer (see Figure 6A-1), so all direct vessel injection line breaks relieve from the cold-side of the reactor coolant system. The accumulator compartments have significant heat sink surfaces (equipment, grating, support structures and compartment walls) for aerosol deposition to trap fission products within the dead-ended compartment. Given the small break size, cold-side location of the break, the compartment retention capacity, and the large relief flow area associated with the open stage 4 automatic depressurization system valves, very little fission product release is expected from the direct vessel injection line. The steam release to an accumulator compartment is negligible with respect to that from the stage 4 automatic depressurization system.

6A.1.1.4 Core Makeup Tank Balance Line Breaks

Breaks in the core makeup tank balance lines can relieve steam and fission products to the core makeup tank room. The balance line piping is 8-inch diameter schedule 160 piping. The balance line nozzle is attached to a cold leg (see Figure 6A-1). Given the small break size, cold-side location of the break, the compartment retention capacity, and the large relief flow area associated with the open stage 4 automatic depressurization system valves, very little fission product release is expected from the balance line. The steam, hydrogen and fission product releases to the core makeup tank room is negligible with respect to the release from the stage 4 automatic depressurization system.

6A.1.1.5 Chemical and Volume Control System Line Breaks

A break in the chemical and volume control system (CVS) line relieves to the dead-ended chemical and volume control system compartment below the core makeup tank room. The chemical and volume control system piping is 3-inch diameter schedule 160 piping. The inlet of the chemical and volume control system draws from the cold leg and the outlet discharges to the reactor coolant pump suction, both on the cold-side of the reactor coolant system (see Figure 6A-1). Given the small break size, cold-side location of the break, the compartment retention capacity, and the large relief flow area associated with the open stage 4 automatic depressurization system valves, very little fission product release is expected from the chemical and volume control system piping. The steam release to the chemical and volume control system compartment is negligible with respect to that from the stage 4 automatic depressurization system.

6A.1.1.6 Fission Product Release Location Conclusion

The fission product releases are expected to discharge mainly from the stage 4 automatic depressurization system lines, which relieve from the hot legs to the steam generator compartments. Stage 4 automatic depressurization system is open in all design-basis LOCA sequences that can be postulated to produce large core activity releases to the containment. For a coolant loop break, the release would also go to the steam generator compartments along with the releases from the stage 4 automatic depressurization system lines. Fission products released to other postulated containment locations are negligible by comparison because the releases are from the cold-side of the reactor coolant system through comparatively long and narrow piping pathways. Therefore, the bounding release pathway is a hot-side break into the steam generator compartments with fission product and steam releases through the break and stage 4 automatic depressurization system.

6A.2 Containment Natural Circulation and Mixing

This section describes the natural circulation flow path and the entrainment processes in the containment atmosphere. Figure 6A-2 graphically depicts the containment natural circulation flow paths and the entrainment processes.

The steam plume, rising from a point low in the containment, and the condensation on the containment surface and wall entrainment rates provide the driving forces for natural circulation in the

containment. Based on the sequence timing, the containment conditions at the time of the fission product releases are quasi-steady-state. Therefore, it is assumed:

$Q_{st} \approx$ constant

$Q_{cond} = Q_{st}$

where:

Q_{st} = steam volumetric flowrate

Q_{cond} = condensation volumetric flowrate.

Steam and fission products are released low in the containment through stage 4 automatic depressurization system at the 112-foot elevation as hot, buoyant plumes from the low pressure primary system into the steam generator compartments. Entrainment into the rising plume drives circulation of surrounding atmosphere into the bottom of the steam generator compartment through the openings to the core makeup tank room. The fission products are released from the reactor coolant system with the steam plumes. The plumes rise through the steam generator compartments, mix with the flow entrained from below and are released into the upper compartment at the top of the steam generator doghouses (153-foot elevation). The plumes rise unconstrained for over 100 feet in the containment. As the plumes rise, the surrounding upper compartment gas mixture is entrained. The steam, fission products and any non-condensable gases (e.g. hydrogen and air) in the plumes are mixed with a large volume of entrained atmosphere in the rising plume.

An estimate of the volume entrained into the plume above the operating deck is made conservatively neglecting entrainment into the lower steam generator compartment, and assuming the plumes from the two steam generator compartments behave as one:

$Q_{ent} = 0.15 * B^{1/3} * Z^{5/3}$ (Reference 1)

where:

Q_{ent} = volumetric flowrate of entrained gas in the rising plume above the operating deck

Z = height of rising plume

B = $g * Q_{ST} * (\rho_{amb} - \rho_{st})/\rho_{amb}$

g = gravitational acceleration

The fission product releases occur at approximately 1 hour when the best estimate (no uncertainty) 1979 ANS decay heat rate is 1.4%. At one hour, the volatile fission products which are released from the core contribute 30% of the decay heat, so the decay heat fraction is 1.0% and 34 MW of steam is generated in the reactor vessel. At a containment pressure of approximately 50 psia, the source flow is approximately 295 ft^3/sec and $\Delta\rho/\rho$ is approximately 1/4. Thus, $B^{1/3} = 13.3\ ft^{4/3}$/sec. For a release into the upper compartment where Z = 125 ft, $Q_{ent} = 6250\ ft^3$/sec and $Q_{ent}/Q_{st} = 21.2$.

At 24 hours, best estimate (no uncertainty) 1979 ANS decay heat is 0.6%, and the volatile fission products released from the core contribute 15% of the decay heat. The heat generated in the vessel, generating steam is 17.3 MW, assuming the containment pressure is 34 psia and $\Delta\rho/\rho = 0.32$. So the source flow is approximately 216 ft^3/sec, $B^{1/3} = 13.1\ ft^{4/3}$/sec, $Q_{ent} = 6142\ ft^3$/sec and $Q_{ent}/Q_{st} = 28.4$.

Therefore, for the AP1000 height above the operating deck, a conservative entrainment ratio for times greater than 1 hour after accident initiation is:

$$Q_{ent}/Q_{st} > 20$$

The application of water to the external surface of the containment shell maintains the containment shell at a cool temperature. The condensation of steam on the containment shell creates a heavy, air-rich downward flowing gas boundary layer on the wall. Fission products are carried along in the wall layer flow. As it flows downward along the wall, the wall layer also entrains surrounding mixture. Thus, the circulation flow rate in the above-deck volume generates significant circulation flow.

A review of literature on circulation within enclosures (appendix 9.C of (Reference 2) shows that as long as there is cooling on the inner surface of the containment shell, there are no regions of stratification in the containment including under the containment dome. There are significant recirculation flows in the stratified regions between the plume and the wall layer. Thus concentration gradients are small and there are no stagnant regions above the operating deck.

The circulation time constant due to entrainment above the operating deck for the AP1000 can be estimated by $V/(20*Q_{st})$, where V is the containment volume above the operating deck, and the steam generator compartments and core makeup tank room above the 108′ elevation, $2.0x10^6$ ft^3. Therefore, the circulation time constant at 1 hour is approximately 340 seconds. At 24 hours it is 462 seconds. The time constant is estimated to be conservatively large as it does not include entrainment into the downward flowing wall layer. At 1 hour, during the fission product release, the time constant of 340 seconds is very short compared to the 1.3 hour fission product release duration. Therefore, the fission products can be assumed to be homogeneous within the gas volume as soon as they are released. There is no stagnant region in the upper compartment as the entire volume participates in the rising plume, entrainment flow and wall layer. Stratification exists in the form of a relatively shallow, continuous vertical steam gradient as discussed in section 3.0.

Over the time period of interest, no mechanisms exist to separate the non-condensable gases (air and hydrogen) once they are mixed in the rising plumes. The molecular weight difference is so overwhelmed by natural circulation it does not lead to gravitational separation. The terminal gravitational settling rate of hydrogen in air at 1 atm and 25°C is less than 10^{-6} cm/sec (Reference 4). Over the height of the upper compartment, 125 ft, the average separation length is 62.5 ft (1588 cm) so the time for gravitational separation of the hydrogen and air is $1.6x10^9$ seconds. By comparing the separation time to the time constant for the plume entrainment circulation (463 seconds) it is determined that the separation rate is orders of magnitude less effective than the convective mixing forces. Thus gravity effects do not lead to separation of hydrogen from the non-condensable mixture.

As the downward boundary layer flow reaches the operating deck (135-foot elevation), it has been cooled and somewhat depleted of steam. The air, hydrogen and fission products remain well-mixed in the flow. Vents in the operating deck (135′ elevation, see Figure 6A-2) and a gap between the operating deck and the containment wall allow the denser gases to “drain” down into the maintenance floor area and vertical access tunnel through two large vertical openings which empty to the steam generator compartments. Little condensation is expected below the operating deck in the quasi-steady-state condition as the metal heat sinks are essentially thermally-saturated. The condensation on heat sinks below the operating deck is small compared to that on the steel shell. The maintenance floor area and vertical access tunnel communicates with the steam generator compartments such that air flow will freely pass to the steam generator compartments. In the steam generator compartment, the circulation flow is entrained by the initial steam source, and the circuit begins again.

The accumulator and chemical and volume control system compartments and the reactor cavity, including the reactor coolant drain tank room, do not participate in the large-scale natural circulation

flow as they are dead-ended or filled with water. The IRWST compartment is essentially sealed at the vents by flappers after blowdown. The accumulator and chemical and volume control system compartments, IRWST, reactor cavity and reactor coolant drain tank compartments are not considered in the calculation of the aerosol deposition.

6A.3 Insights From the Passive Containment Cooling System Large Scale Test and AP1000 Stratification Studies

The AP600 passive containment cooling system Large Scale Test (LST) provides insight into the circulation and stratification behavior in the AP1000 containment. The following results are consistent with international test data from various scales (Reference 2, Appendix 9.C). Since the large scale test did not include a flow path into the simulated steam generator compartment, the degree of mixing of injected light non-condensable gases with the existing air throughout the test vessel is conservatively underestimated. This is because the extra flow path would allow density-driven circulation through the path into the compartment, introducing an additional mixing mechanism which exists in AP1000.

In the large scale test rising plume, large amounts of surrounding air-steam mixture were entrained with the released gases. Estimates of entrainment above the deck in large scale test show that about one times the break volumetric flow is entrained. In several large scale test tests, 217.1, 218.1, 219.1, and 221.1, in which helium (a hydrogen simulant) was released in an amount equal to 10-20 volume percent, non-condensable gas concentrations were measured (Reference 3). The helium fraction was reduced from 100% at the release point to 50% of the non-condensable gas in the dome during the initial period of injection. For design basis hydrogen releases, the hydrogen concentration as a fraction of the non-condensable gas in the dome would be much less due to the increased height for entrainment.

The existence of circulation under the dome in the large scale test can be seen based on the reduction of helium non-condensable fraction over time after the helium release stops. The mixing of helium above the deck establishes homogeneous concentrations in only a few minutes in the large scale test. Note that it was seen to take hours for the circulation to mix the injected helium with the non-condensable gases in the compartment below the deck, however, this was due to a lack of a flow path in the simulated steam generator compartments. Because of the additional height for entrainment in the AP1000, circulation is about 10 times greater than in the large scale test based on plume entrainment alone. Wall layer entrainment and circulation through the steam generator compartment would further increase the circulation in AP1000. This result indicates that in the AP1000 circulation distributes the injected non-condensable gases with the air throughout the containment quickly compared to the rate of release.

The effect of external cooling on non-condensable gas distributions was studied in large scale test 219.1 which started out with a dry external shell, injected helium, and then initiated the external water cooling. Non-condensable gas data showed that the application of external cooling acts to accelerate the mixing of non-condensable gases, which is probably due to the higher wall layer entrainment rate from the higher condensation rate on the cooler shell.

As discussed above, the fluid dynamics of entrainment into a buoyant plume and wall boundary layers generate large amounts of circulation within the above deck region. Thus, the region is not a static, layered stratification, and there are no stagnant pockets of gases that do not participate in the circulation. The physics do, however, lead to a standing vertical steam density gradient in the circulating stratified region, which will tend to be slightly richer in steam at the top due to the lower density of the injected steam.

Based on the above, at quasi-steady conditions, the decay heat steaming and heat and mass transfer to the steel shell create natural circulation in the containment that mixes the fission products

and hydrogen quickly throughout the circulating volume. Circulation time constants indicate that it is reasonable to assume non-condensable gases and fission products can be assumed to be homogeneous in the volumes participating in the circulation. The rising plume and the cooling of the shell create a vertical steam density gradient and a vertical temperature gradient in the upper compartment circulating stratified region. The density and temperature gradients result from a balance between the forces that drive the natural circulation. In the evaluation, no credit is taken for cold plumes falling from the containment dome which cause further circulation above the operating deck.

In Reference 5, studies were performed to demonstrate that the AP1000 containment is at least as well-mixed as the AP600 containment. Studies performed indicate the increase in containment height slightly improves the steady state mixing for the AP1000 when compared to the AP600, and therefore the conclusions regarding the mixing characteristics of the AP600 containment can be applied to the AP1000 containment.

Based on the above, condensation and sensible heat transfer occur over the entire steel shell, albeit at different rates over the height of the shell. As shown in Appendix 15B, thermophoresis and diffusiophoresis are directly related to the heat and mass transfer. Fission products are present at all sites of steam condensation and sensible heat transfer in the containment. In Appendix 15B, the processes are modeled by assuming homogeneous aerosol mass distribution throughout the circulating volume and averaging the steam condensation and sensible heat transfer over the entire upper shell. This treatment provides a valid estimate of the aerosol deposition rates.

6A.4 Conclusions

Based on first principal arguments and insight from testing at various scales, the following conclusions are made with respect to mixing in the AP1000 containment during quasi-steady conditions:

- As long as there is cooling on the inner surface of the containment shell, downward wall flow will prevent stagnation under the dome
- No unmixed pockets develop as the doorways extend to the floor and vents are in the ceiling. For the rooms participating in the natural circulation flow, the entire volume participates in the circulation
- The rising plume, condensation of steam on the containment shell, and downward flowing wall layer create vertical steam density and temperature gradients above the operating deck
- Fission products and hydrogen are quickly and uniformly mixed, relative to the duration of the release, in the containment volumes participating in the natural circulation
- For the purpose of calculating long-term aerosol deposition, it is reasonable to assume that aerosols and non-condensable gases are homogeneous throughout the major compartments participating in the containment natural circulation: the steam generator compartments, upper compartment and core makeup tank room.

6A.5 References

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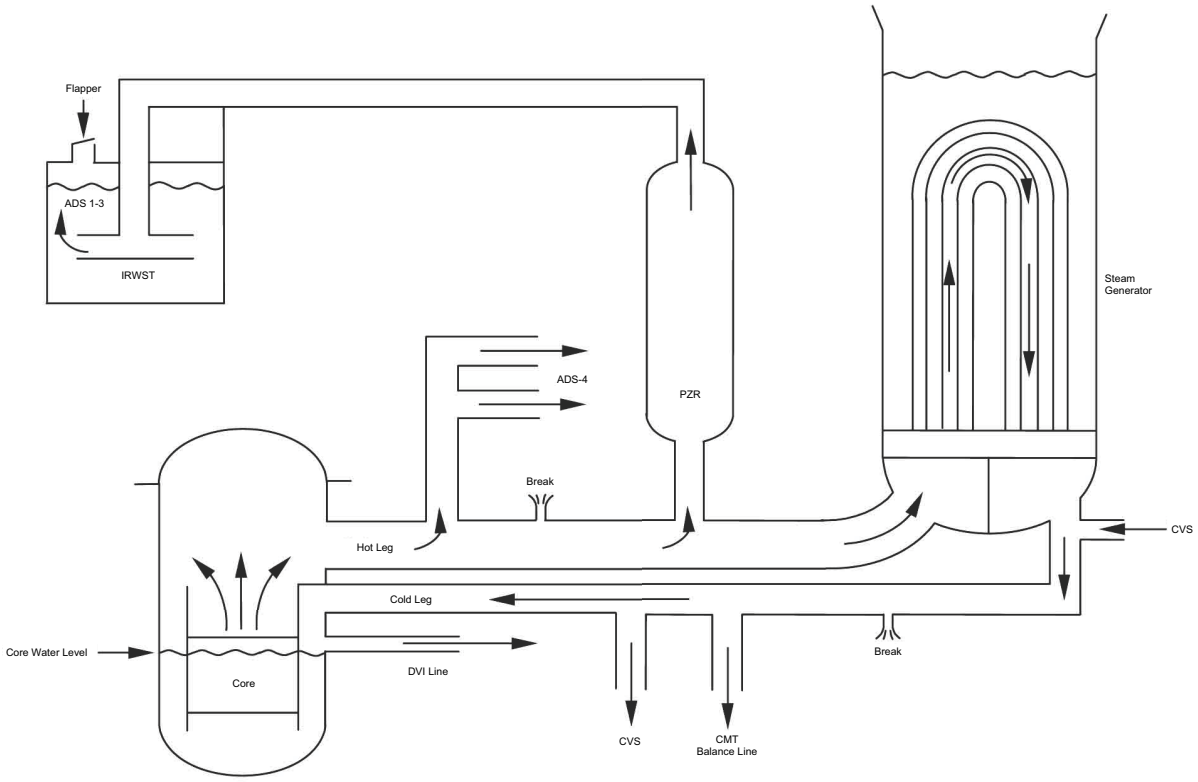

Figure 6A-1
RCS Release Locations

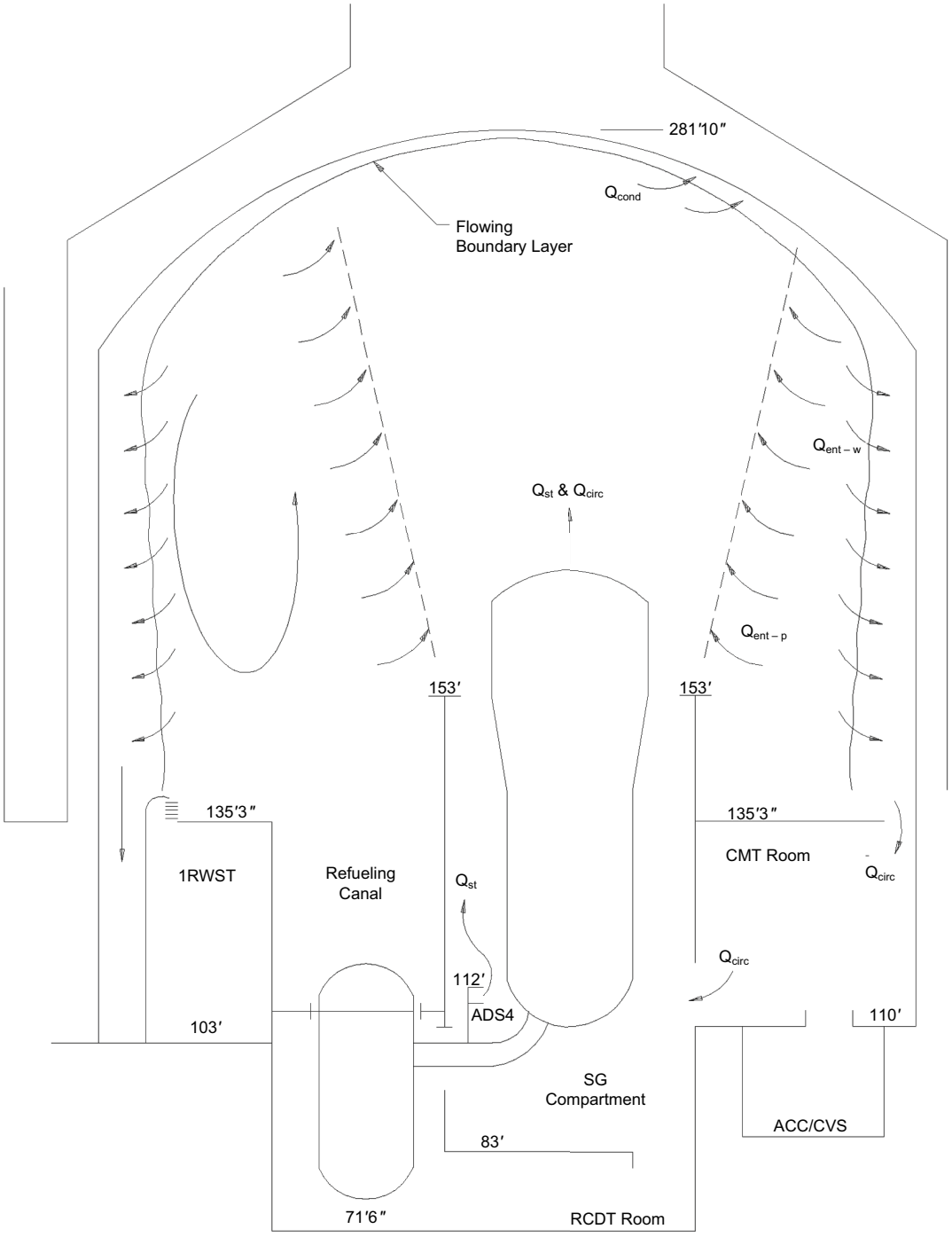

Figure 6A-2
Containment Natural Circulation

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 7	INSTRUMENTATION AND CONTROLS	7.1-1
7.1	Introduction	7.1-1
7.1.1	The AP1000 Instrumentation and Control Architecture	7.1-2
7.1.2	Protection and Safety Monitoring System	7.1-4
7.1.2.1	Plant Protection Subsystems	7.1-4
7.1.2.2	Engineered Safety Features Coincidence Logic	7.1-5
7.1.2.3	Engineered Safety Features Actuation Subsystems	7.1-5
7.1.2.4	Reactor Trip Switchgear	7.1-5
7.1.2.5	Qualified Data Processing System	7.1-5
7.1.2.6	Main Control Room Multiplexers	7.1-5
7.1.2.7	Sensors	7.1-5
7.1.2.8	Communication Functions	7.1-6
7.1.2.9	Fault Tolerance, Maintenance, Test, and Bypass	7.1-6
7.1.2.10	Isolation Devices	7.1-7
7.1.2.11	Test Subsystem	7.1-7
7.1.2.12	Safety-Related Display Instrumentation	7.1-7
7.1.2.13	Auxiliary Supporting Systems	7.1-7
7.1.2.14	Verification and Validation	7.1-7
7.1.3	Plant Control System	7.1-9
7.1.3.1	Distributed Controllers	7.1-10
7.1.3.2	Signal Selector Algorithms	7.1-10
7.1.3.3	Operator Controls and Indication	7.1-11
7.1.3.4	Real-Time Data Network	7.1-11
7.1.3.5	Rod Control System	7.1-12
7.1.3.6	Rod Position Indication	7.1-12
7.1.3.7	Rod Drive Motor-Generator Sets	7.1-12
7.1.4	Identification of Safety Criteria	7.1-12
7.1.4.1	Conformance of the Safety System Instrumentation to Applicable Criteria	7.1-12
7.1.4.2	Conformance With Industry Standards	7.1-13
7.1.5	AP1000 Protective Functions	7.1-14
7.1.6	Combined License Information	7.1-14
7.1.7	References	7.1-14
7.2	Reactor Trip	7.2-1
7.2.1	Description	7.2-1
7.2.1.1	Functional Description	7.2-2
7.2.1.2	Design Basis for Reactor Trips	7.2-10
7.2.1.3	System Drawings	7.2-12
7.2.2	Analyses	7.2-12
7.2.2.1	Failure Modes and Effects Analysis (FMEA)	7.2-12
7.2.2.2	Conformance of the Reactor Trip Function to Applicable Criteria	7.2-12
7.2.3	Combined License Information	7.2-15
7.2.4	References	7.2-15
7.3	Engineered Safety Features	7.3-1
7.3.1	Description	7.3-1
7.3.1.1	Safeguards Actuation (S) Signal	7.3-2
7.3.1.2	Engineered Safety Feature Descriptions	7.3-3

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	7.3.1.3 Blocks, Permissives, and Interlocks for Engineered Safety Features Actuation	7.3-21
	7.3.1.4 Bypasses of Engineered Safety Features Actuation	7.3-21
	7.3.1.5 Design Basis for Engineered Safety Features Actuation	7.3-21
	7.3.1.6 System Drawings	7.3-23
	7.3.2 Analysis for Engineered Safety Features Actuation	7.3-23
	7.3.2.1 Failure Modes and Effects Analyses	7.3-23
	7.3.2.2 Conformance of Engineered Safety Features to the Requirements of IEEE 603-1991	7.3-23
	7.3.3 Combined License Information	7.3-25
	7.3.4 References	7.3-25
7.4	Systems Required for Safe Shutdown	7.4-1
	7.4.1 Safe Shutdown	7.4-2
	7.4.1.1 Safe Shutdown Using Safety-Related Systems	7.4-2
	7.4.1.2 Safe Shutdown Using Safety-Related and Nonsafety-Related Systems	7.4-5
	7.4.1.3 Safe Shutdown Using Nonsafety-Related Systems	7.4-5
	7.4.2 Safe Shutdown Systems	7.4-8
	7.4.2.1 Passive Core Cooling System	7.4-8
	7.4.2.2 Passive Containment Cooling System	7.4-9
	7.4.2.3 Containment Isolation	7.4-9
	7.4.2.4 Reactor Coolant System Circulation	7.4-9
	7.4.2.5 Other Systems Required for Safe Shutdown	7.4-9
	7.4.3 Safe Shutdown from Outside the Main Control Room	7.4-9
	7.4.3.1 Description	7.4-9
	7.4.3.2 Analysis	7.4-12
	7.4.4 Combined License Information	7.4-12
	7.4.5 References	7.4-12
7.5	Safety-Related Display Information	7.5-1
	7.5.1 Introduction	7.5-1
	7.5.2 Variable Classifications and Requirements	7.5-1
	7.5.2.1 Variable Types	7.5-2
	7.5.2.2 Variable Categories	7.5-4
	7.5.3 Description of Variables	7.5-8
	7.5.3.1 Type A Variables	7.5-8
	7.5.3.2 Type B Variables	7.5-8
	7.5.3.3 Type C Variables	7.5-8
	7.5.3.4 Type D Variables	7.5-8
	7.5.3.5 Type E Variables	7.5-9
	7.5.3.6 Type F Variables	7.5-9
	7.5.4 Processing and Display Equipment	7.5-9
	7.5.5 Combined License Information	7.5-10
7.6	Interlock Systems Important to Safety	7.6-1
	7.6.1 Prevention of Overpressurization of Low-Pressure Systems	7.6-1
	7.6.1.1 Description of Normal Residual Heat Removal Isolation Valve Interlocks	7.6-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
7.6.1.2	Analysis of Normal Residual Heat Removal Valve Interlocks	7.6-1
7.6.2	Availability of Engineered Safety Features	7.6-2
7.6.2.1	Passive Residual Heat Removal Heat Exchanger Inlet Isolation Valve	7.6-2
7.6.2.2	Core Makeup Tank Cold Leg Balance Line Isolation Valves	7.6-3
7.6.2.3	Interlocks for the Accumulator Isolation Valve and IRWST Discharge Valve	7.6-4
7.6.2.4	Interlock for Containment Vacuum Relief Isolation Valves	7.6-4
7.6.3	Combined License Information	7.6-5
7.7	Control and Instrumentation Systems	7.7-1
7.7.1	Description	7.7-1
7.7.1.1	Reactor Power Control System	7.7-2
7.7.1.2	Rod Control System	7.7-4
7.7.1.3	Control Rod Position Monitoring	7.7-5
7.7.1.4	Control Rod Insertion Limits	7.7-6
7.7.1.5	Control Rod Stops	7.7-7
7.7.1.6	Pressurizer Pressure Control System	7.7-7
7.7.1.7	Pressurizer Water Level Control System	7.7-7
7.7.1.8	Feedwater Control System	7.7-8
7.7.1.9	Steam Dump Control System	7.7-9
7.7.1.10	Rapid Power Reduction System	7.7-10
7.7.1.11	Diverse Actuation System	7.7-11
7.7.1.12	Signal Selector Algorithm	7.7-16
7.7.2	Analysis	7.7-17
7.7.3	Combined License Information	7.7-18
7.7.4	References	7.7-18
APPENDIX 7A	NOT USED	7A-1
APPENDIX 7B	PROTECTION AND SAFETY MONITORING SYSTEM FAILURE MODES AND EFFECTS ANALYSIS	7B-1
7B.1	BPL Process Station	7B-3
7B.2	LCL Process Station	7B-7
7B.3	Reactor Trip Interface	7B-12
7B.4	ILP Process Station	7B-13
7B.5	NIS Subsystem	7B-17
7B.6	ICP Process Station	7B-19
7B.7	ITP Process Station	7B-21
7B.8	MTP Process Station	7B-24
7B.9	Safety Display Subsystem	7B-25
7B.10	QDPS Process Station	7B-26
7B.11	Power Distribution	7B-28
7B.12	ADS and IRWST Blocking Device	7B-33
7B.13	Squib Valve Control Termination Unit	7B-34
7B.14	Acronyms	7B-35

LIST OF TABLES

Table Number	Title	Page
7.2-1	Reactor Trip Variables, Limits, and Ranges (Design Basis for Reactor Trip) (Nominal)	7.2-16
7.2-2	Reactor Trips	7.2-19
7.2-3	Reactor Trip Permissives and Interlocks	7.2-21
7.2-4	System-Level Manual Inputs to the Reactor Trip Functions	7.2-23
7.2-5	Figure 7.2-1 Cross References	7.2-24
7.3-1	Engineered Safety Features Actuation Signals	7.3-26
7.3-2	Interlocks for Engineered Safety Features Actuation System	7.3-35
7.3-3	System-Level Manual Input to the Engineered Safety Features Actuation System	7.3-42
7.3-4	Engineered Safety Features Actuation, Variables, Limits, and Ranges (Nominal)	7.3-44
7.4-1	Systems Required for Safe Shutdown	7.4-13
7.5-1	Post-Accident Monitoring System	7.5-11
7.5-2	Summary of Selection of Criteria	7.5-23
7.5-3	Summary of Qualification, Design, and Interface Requirements	7.5-24
7.5-4	Summary of Type A Variables	7.5-25
7.5-5	Summary of Type B Variables	7.5-26
7.5-6	Summary of Type C Variables	7.5-27
7.5-7	Summary of Type D Variables	7.5-28
7.5-8	Summary of Type E Variables	7.5-33
7.5-9	Summary of Type F Variables	7.5-34
7.5-201	Not Used	7.5-37
7.5-202	Not Used	7.5-37
7.7-1	Rod Control System Interlocks - Power Control Subsystem	7.7-19
7.7-2	Rod Control System Interlocks – Axial Offset Control Subsystem	7.7-20
7.7-3	Cross Reference Table for Defense-in-Depth Functions Supported by the Plant Control System	7.7-21
7B-1	Failure Criticality Classes	7B-1
7B-2	Failure Detectability Classes	7B-2

LIST OF FIGURES

Figure Number	Title	Page
7.1-1	Instrumentation and Control Architecture	7.1-16
7.1-2	Common Q Standard Process and AP1000 Project-Specific Documents	7.1-17
7.1-3–7.1-11	Not Used	7.1-18
7.2-1	(Sheet 1 of 21) Functional Diagram Index and Symbols	7.2-25
7.2-1	(Sheet 2 of 21) Functional Diagram Reactor Trip Functions	7.2-26
7.2-1	(Sheet 3 of 21) Functional Diagram Nuclear Startup Protection	7.2-27
7.2-1	(Sheet 4 of 21) Functional Diagram Nuclear Overpower Protection	7.2-28
7.2-1	(Sheet 5 of 21) Functional Diagram Core Heat Removal Protection and Reactor Coolant Pump Trip	7.2-29
7.2-1	(Sheet 6 of 21) Functional Diagram Primary Overpressure & Loss of Heat Sink Protection	7.2-30
7.2-1	(Sheet 7 of 21) Functional Diagram Loss of Heat Sink Protection	7.2-31
7.2-1	(Sheet 8 of 21) Functional Diagram Loss of Heat Sink Protection	7.2-32
7.2-1	(Sheet 9 of 21) Functional Diagram Steam Line Isolation	7.2-33
7.2-1	(Sheet 10 of 21) Functional Diagram Feedwater Isolation	7.2-34
7.2-1	(Sheet 11 of 21) Functional Diagram Safeguards Actuation	7.2-35
7.2-1	(Sheet 12 of 21) Functional Diagram Core Makeup Tank Actuation	7.2-36
7.2-1	(Sheet 13 of 21) Functional Diagram Containment and Other Protection	7.2-37
7.2-1	(Sheet 14 of 21) Functional Diagram Turbine Trip and Refueling Cavity and SFS Isolation	7.2-38
7.2-1	(Sheet 15 of 21) Functional Diagram Automatic RCS Depressurization Valve Sequencing	7.2-39
7.2-1	(Sheet 16 of 21) Functional Diagram In-containment Refueling Water Storage Tank Actuations	7.2-40
7.2-1	(Sheet 17 of 21) Not Used	7.2-41
7.2-1	(Sheet 18 of 21) Functional Diagram Normal Residual Heat Removal System Isolation Valve Interlocks	7.2-42
7.2-1	(Sheet 19 of 21) Functional Diagram Containment Vacuum Relief Protection	7.2-43
7.2-1	(Sheet 20 of 21) Functional Diagram Diverse Actuation System Logic Automatic Actuations	7.2-44
7.2-1	(Sheet 21 of 21) Functional Diagram Diverse Actuation System Logic, Manual Actuations	7.2-45

Chapter 7 Instrumentation and Controls

7.1 Introduction

The instrumentation and control systems presented in this chapter provide protection against unsafe reactor operation during steady-state and transient power operations. They initiate selected protective functions to mitigate the consequences of design basis events. This chapter relates the functional performance requirements, design bases, system descriptions, and safety evaluations for those systems. The safety evaluations show that the systems can be designed and built to conform to the applicable criteria, codes, and standards concerned with the safe generation of nuclear power.

Because of the rapid changes that are taking place in the digital computer and graphic display technologies employed in a modern human system interface, design certification of the AP1000 focuses upon the process used to design and implement instrumentation and control systems for the AP1000, rather than on the specific implementation. The design specifics provided here are included as an example for illustration.

Chapter 7 for the AP1000 has been written to describe the protection system hardware utilizing the Common Qualified Platform (Common Q) described in Reference 8 (which includes the NRC SER). The I&C functional requirements of the AP600, which has received Design Certification, have been retained to the maximum extent compatible with the Common Q hardware and software.

The terminology used for Chapter 7 is intended to be independent of any product, but when this is not possible, Common Q terminology is used.

This chapter also discusses the instrumentation portions of the safety-related systems which function to achieve the system responses assumed in the accident analysis, and those needed to shutdown the plant. Section 7.1 describes the AP1000 instrumentation and control architecture, with specific emphasis on the protection and safety monitoring system. The plant control system is discussed briefly. Other systems are discussed in more detail in relevant sections or chapters. Section 7.2 discusses the reactor trip function, and Section 7.3 addresses the engineered safety features (ESF). Systems required for safe shutdown are discussed in Section 7.4 in support of other chapters. Safety-related display instrumentation is discussed in Section 7.5 and interlocks important to safety are presented in Section 7.6. Control systems and the diverse actuation system are discussed in Section 7.7.

Definitions

Terminology used in this chapter reflects an interdisciplinary approach to safety-related systems similar to that proposed in IEEE 603 (Reference 1).

Safety System – The aggregate of electrical and mechanical equipment necessary to mitigate the consequences of design basis events.

Protection and Safety Monitoring System – The aggregate of electrical and mechanical equipment which senses generating station conditions and generates the signals to actuate reactor trip and ESF, and which provides the equipment necessary to monitor plant safety-related functions during and following designated events.

Protective Function – Any one of the functions necessary to mitigate the consequences of a design basis event. Protective functions are initiated by the protection and safety monitoring system logic and will be accomplished by the trip and actuation subsystems. Examples of protective functions are reactor trip and engineered safety features (such as valve alignment and containment isolation).

Actuated Equipment – The assembly of prime movers and driven equipment used to accomplish a protective function (such as solenoids, shutdown rods, and valves).

Actuation Device – A component that directly controls the motive power for actuated equipment (such as circuit breakers, relays, and pilot valves).

Division – One of the four redundant segments of the safety system. A division includes its associated sensors, field wiring, cabinets, and electronics used to generate one of the redundant actuation signals for a protective function. It also includes the power source and actuation signals.

Channel – One of the several separate and redundant measurements of a single variable used by the protection and safety monitoring system in generating the signal to initiate a protective function. A channel can lose its identity when it is combined with other inputs in a division.

Degree of Redundancy – The number of redundant channels monitoring a single variable, or the number of redundant divisions which can initiate a given protective function or accomplish a given protective function. Redundancy is used to maintain protection capability when the safety-related system is degraded by a single random failure.

System-Level Actuation – Actuation of a sufficient number of actuation devices to effect a protective function.

Component-Level Actuation – Actuation of a single actuation device (component).

7.1.1 The AP1000 Instrumentation and Control Architecture

Figure 7.1-1 illustrates the instrumentation and control architecture for the AP1000. The figure shows two major sections separated by the real-time data network. Figure 7.1-1 depicts the real-time data highway as a single network.

The lower portion of the figure includes the plant protection, control, and monitoring functions. At the lower right-hand side is the protection and safety monitoring system. It performs the reactor trip functions, the engineered safety features (ESF) actuation functions, and the Qualified Data Processing (QDPS) functions. The I&C equipment performing reactor trip and ESF actuation functions, their related sensors, and the reactor trip switchgear are, for the most part, four-way redundant. This redundancy permits the use of bypass logic so that a division or individual channel out of service can be accommodated by the operating portions of the protection system.

The ESF coincidence logic performs system-level logic calculations, such as initiation of the passive residual heat removal system. It receives inputs from the plant protection subsystem bistables and the main control room.

The ESF actuation subsystems provide the capability for on-off control of individual safety-related plant loads. They receive inputs from the ESF coincidence logic, remote shutdown workstation and the main control room.

The plant control system performs nonsafety-related instrumentation and control functions using both discrete (on/off) and modulating (analog) type actuation devices.

The nonsafety-related real-time data network, which horizontally divides Figure 7.1-1, is a high speed, redundant communications network that links systems of importance to the operator. Safety-related systems are connected to the network through gateways and qualified isolation devices so that the safety-related functions are not compromised by failures elsewhere. Plant

protection, control, and monitoring systems feed real-time data into the network for use by the control room and the data display and processing system.

The upper portion of the figure depicts the control rooms and data display and processing system. The main control room is implemented as a set of compact operator consoles featuring color graphic displays and soft control input devices. The graphics are supported by a set of graphics workstations that take their input from the real-time data network. An advanced alarm system, implemented in a similar technology, is also provided.

The data display and processing system is implemented in a distributed architecture. The working elements of the distributed computer system are graphics workstations, although their graphics capability is secondary to their computing performance. The distributed computer system obtains its input from the real-time data network and delivers its output over the network to other users.

WCAP-15775 (Reference 7), Sections 1 through 5, describes the diversity and defense-in-depth features of the AP1000 instrumentation and control architecture.

Protection and Safety Monitoring System

The protection and safety monitoring system provides detection of off-nominal conditions and actuation of appropriate safety-related functions necessary to achieve and maintain the plant in a safe shutdown condition. The protection and safety monitoring system controls safety-related components in the plant that are operated from the main control room or remote shutdown workstation. Secure development and operational environments for the protection and safety monitoring system are used during design as described in Section 2 of APP-GW-J0R-012 (Reference 22).

In addition, the protection and safety monitoring system provides the equipment necessary to monitor the plant safety-related functions during and following an accident as required by Regulatory Guide 1.97.

Special Monitoring System

The special monitoring system does not perform any safety-related or defense-in-depth functions. The special monitoring system consists of specialized subsystems that interface with the instrumentation and control architecture to provide diagnostic and long-term monitoring functions.

The digital metal impact monitoring system is the subsystem of the special monitoring system that detects the presence of metallic debris in the reactor coolant system when the debris impacts against the internal parts of the reactor coolant system. The digital metal impact monitoring system is composed of digital circuit boards, indicators, power supplies and remotely located sensors and related signal processing devices. A minimum of two sensors are located at each natural collection region, connected to separate instrumentation channels, to maintain the impact monitoring function if a sensor fails in service. The digital metal impact monitoring system is described in Subsection 4.4.6.4.

Plant Control System

The plant control system provides the functions necessary for normal operation of the plant from cold shutdown through full power. The plant control system controls nonsafety-related components in the plant that are operated from the main control room or remote shutdown workstation.

The plant control system contains nonsafety-related control and instrumentation equipment to change reactor power, control pressurizer pressure and level, control feedwater flow, and perform other plant functions associated with power generation. The plant control system is described in Subsections 7.1.3 and 7.7.1.

Diverse Actuation System

The diverse actuation system is a nonsafety-related, diverse system that provides an alternate means of initiating reactor trip and actuating selected engineered safety features, and providing plant information to the operator. The diverse actuation system is described in Subsection 7.7.1.11.

Operation and Control Centers System

The operation and control centers system includes the main control room, the technical support center, the remote shutdown room, emergency operations facility, local control stations and associated workstations for these centers. With the exception of the control console structures, the equipment in the control room is part of the other systems (for example, protection and safety monitoring system, plant control system, data display and processing system).

The boundaries of the operation and control centers system for the main control room and the remote shutdown workstation are the signal interfaces with the plant components. These interfaces are via the plant protection and safety monitoring system processor and logic circuits, which interface with the reactor trip and ESF plant components; the plant control system processor and logic circuits, which interface with the nonsafety-related plant components; and the plant real-time data network, which provides plant parameters, plant component status, and alarms.

Data Display and Processing System

The data display and processing system provides the equipment used for processing data that result in nonsafety-related alarms and displays for both normal and emergency plant operations, generating these displays and alarms, providing analysis of plant data, providing plant data logging and historical storage and retrieval, and providing operational support for plant personnel. DDS also provides the manual actuation switches in the remote shutdown room (RSR).

The data display and processing system also contains the real-time data network, which is a redundant data highway that links the elements of the AP1000 instrumentation and control architecture.

Incore Instrumentation System

The primary function of the incore instrumentation system is to provide a three-dimensional flux map of the reactor core. This map is used to calibrate neutron detectors used by the protection and safety monitoring system, as well as to optimize core performance. A secondary function of the incore instrumentation system is to provide the protection and safety monitoring system with the thermocouple signals necessary for the post-accident inadequate core cooling monitor. The incore instrument assemblies house both fixed incore flux detectors and core exit thermocouples. The incore instrumentation system is described in Subsection 4.4.6.1.

7.1.2 Protection and Safety Monitoring System

Reference 19, Section 2.1 provides an overview description of the protection and safety monitoring system.

7.1.2.1 Plant Protection Subsystems

Reference 19, Section 2.2 describes the plant protection subsystems.

7.1.2.1.1 Reactor Trip Functions

Section 7.2 describes the reactor trip functions.

7.1.2.1.2 Reactor Trip Switchgear Interface and Logic

Reference 19, Subsection 2.2.3.1.1 describes the reactor trip switchgear interface and logic.

7.1.2.1.3 Manual Reactor Trip

Reference 19, Subsection 2.2.3.1.3 describes the manual reactor trip.

7.1.2.2 Engineered Safety Features Coincidence Logic

Reference 19, Subsection 2.2.3.2.1 describes the Engineered Safety Features Coincidence Logic.

7.1.2.3 Engineered Safety Features Actuation Subsystems

Reference 19, Subsection 2.2.3.2.2 describes the Engineered Safety Features Actuation Subsystems.

7.1.2.4 Reactor Trip Switchgear

Reference 19, Subsection 2.2.3.1.2 describes the reactor trip switchgear, which is also referred to as the reactor trip circuit breaker (RTCB).

7.1.2.5 Qualified Data Processing System

Reference 19, Section 4.2 describes the Qualified Data Processing System (QDPS).

7.1.2.6 Main Control Room Multiplexers

The protection and safety monitoring system does not use multiplexers to provide a signal path between the protection system equipment and the main control room. Each division's safety display communicates with the protection system equipment via that division's communications network as shown in Figure 2-2 of Reference 19.

7.1.2.7 Sensors

The protection and safety monitoring system monitors key variables related to equipment mechanical limitations, and variables directly affecting the heat transfer capability of the reactor. Some limits, such as the overtemperature ΔT setpoint, are calculated in the plant protection subsystem from other parameters because direct measurement of the variable is not possible. This subsection provides a description of the sensors which monitor the variables for the protection and safety monitoring system. For convenience the discussions are grouped into the following three categories:

- Process sensors
- Nuclear instrumentation detectors
- Status inputs from field equipment

The inputs described are those required to generate the initiation signals for the protective functions. The use of each parameter is discussed in the sections that deal with each protective function. For example, reactor trip is discussed in Section 7.2 and ESF actuation is described in Section 7.3.

7.1.2.7.1 Process Sensors

The process sensors are devices which measure temperature, pressure, fluid flow, and fluid level. Process instrumentation excludes nuclear and radiation measurements.

Additional information on these process variables is included as part of the description of each process system provided in other chapters. The process variables measured by the protection and safety monitoring system are listed in Sections 7.2, 7.3, and 7.5.

7.1.2.7.2 Nuclear Instrumentation Detectors

Three types of neutron detectors are used to monitor the leakage neutron flux from a completely shutdown condition to 120 percent of full power. The intermediate range channels are capable of measuring overpower excursions up to 200 percent of full power.

The lowest range (source range) covers six decades of leakage neutron flux. The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This generally is greater than two counts per second. The next range (intermediate range) covers eight decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the power range. The highest range of instrumentation (power range) covers approximately two decades of the total instrumentation range. This is a linear range that overlaps the higher portion of the intermediate range. The neutron detectors are installed in tubes located around the reactor vessel in the primary shield. Detector types for these three ranges are:

- Source range – proportional counter or pulse fission chamber
- Intermediate range – pulse fission chamber
- Power range – uncompensated ionization chamber

7.1.2.7.3 Equipment Status Inputs

Some inputs to the protection system are not measurements of process or nuclear variables, but are discrete indications of the status of certain equipment. Examples include manual switch positions, contact status inputs, and indications provided by valve limit switches.

7.1.2.8 Communication Functions

Reference 19, Section 3, and Reference 25, Sections 1 through 8, describe the communication functions.

7.1.2.9 Fault Tolerance, Maintenance, Test, and Bypass

Reference 19, Section 7 describes the fault tolerance features, and Section 6 describes the maintenance, test, and bypass features of the protection and safety monitoring system.

7.1.2.10 Isolation Devices

Isolation devices are used to maintain the electrical independence of divisions, and to prevent interaction between nonsafety-related systems and the safety-related system.

Isolation devices are incorporated into selected interconnections to maintain division independence. Isolation devices serve to prevent credible faults (such as open circuits, short circuits, or applied credible voltages) in one circuit from propagating to another circuit.

7.1.2.11 Test Subsystem

Reference 19, Section 6 describes the test subsystem.

The automatic continuous self-diagnostic features of the PMS and application software provide sufficient assurance of PMS component operability where diagnostics are credited. The faults detected by diagnostics are alarmed and displayed in the Main Control Room. Operators assess operability of the PMS using the plant alarm response and abnormal operating procedures.

7.1.2.12 Safety-Related Display Instrumentation

Safety-related display (PMS safety display subsystem) instrumentation provides the operator with information to determine the effect of automatic and manual actions taken following reactor trip due to a Condition II, III, or IV event as defined in Chapter 15. This instrumentation also provides for operator display of the information necessary to meet Regulatory Guide 1.97. A description of the equipment used to provide this function is provided in Reference 19, Section 4.1. A description of the data provided to the operator by this instrumentation is provided in Section 7.5. A description of the equipment used to provide data to the safety-related display instrumentation is provided in Subsection 7.1.2.5.

In addition to the functions of the PMS and the post-accident monitoring identified above, the PMS provides water level indication for the flooding events as discussed in Sections 3.4 and 11.2. The two sensors used for water level indication provide input into the bistable processor logic (BPL) subsystem and then into the integrated communications processor (ICP) subsystem. The information is then sent to the safety displays. These sensors are categorized as Class 1E and are on the safety-related displays for flood indication, but do not perform any safety-related function.

7.1.2.13 Auxiliary Supporting Systems

The safety-related system equipment is supported by the supply of uninterruptible electrical power. This electrical power is supplied by the Class 1E dc and UPS system discussed in Chapter 8.

7.1.2.14 Verification and Validation

[*Adequacy of the hardware and software is demonstrated for the protection and safety monitoring system through a verification and validation (V&V) program. Details on the verification and validation program for the Common Q portion of the protection and safety monitoring system are provided in WCAP-16096-P-A (Reference 9).*]* WCAP-16096-P-A defines a software development process consistent with appropriate industry standards.

7.1.2.14.1 Design Process

[*WCAP-16096-P-A (Reference 9) provides a planned design process for Common Q software development during life cycle stages:*

- *Conceptual phase (may also be referred to as design requirements phase)*
- *Requirements phase (may also be referred to as system definition phase)*
- *Design phase (may also be referred to as hardware and software development phase)*

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- *Implementation phase (may also be referred to as hardware and software development phase)*
- *Test phase (may also be referred to as system integration and test phase)*
- *Installation and checkout phase (may also be referred to as installation phase)*

WCAP-16096-P-A (Reference 9), WCAP-15927 (Reference 20), and NRC-approved Westinghouse Quality Management System (Reference 21) describe design processes that will be used for the Common Q portion of the AP1000 protection and safety monitoring system.]*

Reference 22 describes how the protection and safety monitoring system meets the control of access requirements of IEEE 603.

The planning (or design requirements) phase documents are listed below. Figure 7.1-2 shows the relationship of the same documents.

Document 1: WNA-PD-00206-WAPP, “AP1000 Engineering Project Execution Program”

Document 2: WNA-PD-00051-WAPP, “AP1000 I&C Programs Plan”

Document 3: WNA-PQ-00283-WAPP, “AP1000 I&C Programs Project Quality Plan”

Document 4: WNA-PD-00283-WAPP, “U.S. AP1000 I&C Protection and Safety Monitoring System”

Document 5: WNA-PD-00042-WAPP, “AP1000 Protection and Safety Monitoring System Software Development Plan”

Document 6: WCAP-16096-P-A, “Software Program Manual for Common Q™ Systems”

Document 7: NABU-DP-00014-GEN, “Design Process for Common Q Safety Systems”

Document 8: WNA-PV-00009-GEN, “Verification & Validation Process for the Common Q Safety Systems”

Document 9: WNA-PT-00058-GEN, “Testing Process for Common Q Safety Systems”

Document 10: NABU-DP-00015-GEN, “Common Q Software Configuration Management Guidelines”

Document 11: 00000-ICE-3889, “Coding Standards & Guidelines for Common Q Systems”

Document 12: APP-PMS-GER-020, “Protection and Safety Monitoring System Concept Phase V&V Summary Report”

Document 13: APP-PMS-T5-001, “AP1000 Protection and Safety Monitoring System Test Plan”

Document 14: WCAP-15927, “Design Process for AP1000 Common Q Safety Systems”

Document 15: APP-GW-J0R-012, “AP1000™ Protection and Safety Monitoring System Computer Security Plan”

Document 16: WCAP-17179 (APP-GW-GLR-143), “AP1000 Component Interface Module Technical Report,” Revision 6

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

7.1.2.14.2 Commercial Dedication

[*WCAP-16097-P-A (Reference 8) provides for the use of commercial off-the-shelf hardware and software through a commercial dedication process.*]* Control of the hardware and software during the operational and maintenance phase is the responsibility of the Combined License applicant as described in Subsection 13.5.3.

7.1.2.14.3 Operational Process

The protection and safety monitoring system has a software operations plan or procedure. The software operations plan addresses the secure operating environment of the protection and safety monitoring system. This includes precluding unauthorized changes to hardware, software, and system parameters. The software operations plan requires monitoring to detect penetration, or attempted penetration, of the system. There are also provisions on how to respond to unauthorized access.

The software operations plan includes administrative controls for changing setpoints in the PMS. The controls include declaring the channel associated with the setpoint change inoperable and not relying on its function until declared operable again. The controls for an inoperable channel would then comply with any applicable Technical Specification action. A software operations plan also includes administrative controls to require that the PMS is in the proper configuration and room environmental conditions are acceptable for cabinet access prior to making setpoint changes. The administrative controls prevent the protection and safety monitoring system division room environment from interfering with protection and safety monitoring system equipment when plant personnel are making setpoint changes. The administrative controls account for local emissions from nearby equipment and activities (e.g., welding) while the maintenance test cabinet (MTC) door is open.

7.1.3 Plant Control System

The plant control system is a nonsafety-related system that provides control and coordination of the plant during startup, ascent to power, power operation, and shutdown conditions. The plant control system integrates the automatic and manual control of the reactor, reactor coolant, and various reactor support processes for required normal and off-normal conditions. The plant control system also provides control of the nonsafety-related decay heat removal systems during shutdown. The plant control system accomplishes these functions through use of the following:

- Rod control
- Pressurizer pressure and level control
- Steam generator water level control
- Steam dump (turbine bypass) control
- Rapid power reduction

The plant control system provides automatic regulation of reactor and other key system parameters in response to changes in operating limits (load changes). The plant control system acts to maximize margins to plant safety limits and maximize the plant transient performance. The plant control system also provides the capability for manual control of plant systems and equipment. Redundant control logic is used in some applications to increase single-failure tolerance.

The plant control system includes the equipment from the process sensor input circuitry through to the modulating and nonmodulating control outputs as well as the digital signals to other plant

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systems. Modulating control devices include valve positioners, pump speed controllers, and the control rod equipment. Nonmodulating devices include motor starters for motor-operated valves and pumps, breakers for heaters, and solenoids for actuation of air-operated valves. The plant control system cabinets contain the process sensor inputs and the modulating and nonmodulating outputs. The plant control system also includes equipment to monitor and control the control rods.

The functions of the plant control system are performed by system assemblies including:

- Distributed controllers
- Signal selector algorithms
- Operator controls and indication
- Real-time data network
- Rod control system
- Rod position indication
- Rod drive motor-generator sets

7.1.3.1 Distributed Controllers

Each distributed controller processes inputs, performs system-level and component-level control calculations, provides capability for an operator interface to the controlled components, transmits control signals to discrete, modulating, and networked interfaced control components, and provides plant status and plant parameter information to the real-time data network.

The distributed controllers receive process inputs and implement the system-level logic and control algorithms appropriate for the plant operating mode. The distributed controllers receive process inputs from, and transmit process control outputs to, the actuated components. The distributed controller also transmits and receives process signals via the real-time data network. The real-time data network also provides for two-way communication between the distributed controllers and between the distributed controllers and the main control room and remote shutdown workstation.

Control functions are distributed across multiple distributed controllers so that single failures within a controller do not degrade the performance of control functions performed by other controllers. The major control functions which are implemented in different distributed controllers include reactor power control, feedwater control, pressurizer control, and turbine control.

7.1.3.2 Signal Selector Algorithms

Signal selector algorithms provide the plant control system with the ability to obtain inputs from the protection and safety monitoring system. The signal selector algorithms select those protection system signals that represent the actual status of the plant and reject erroneous signals. Therefore, the control system does not cause an unsafe control action to occur even if one of four redundant protection channels is degraded by random failure simultaneous with another of the four channels bypassed for test or maintenance.

Each signal selector algorithm receives data from each of the redundant divisions of the protection and safety monitoring system. The data is received from each division through an isolation device.

The signal selector algorithms provide validated process values to the plant control system. They also provide the validation status; the average, the median, or an individual input value of the valid process values; the number of valid process values; an alarm (if one process value has been rejected); and another alarm (if the algorithm is not able to provide a valid process value).

For the logic values received from the protection and safety monitoring system, such as permissives, two-out-of-four (2/4) voting is used to provide a valid logic value to the plant control system.

The signal selection algorithm is executed in the PLS, and the results are not available to PMS or DAS. Therefore, PMS and DAS performance, controls, and displays are independent of the signal selector algorithm.

7.1.3.3 Operator Controls and Indication

The plant control system operator interface is a set of soft control devices that replace conventional switch/light or potentiometer/meter assemblies used for operator interface with control systems. These soft control devices provide consistent operator interfaces for the plant control system. The soft controls are accessible from the visual display unit (VDU) based operator workstations in the main control room and the remote shutdown room. Soft control devices are used to control safety-related and nonsafety-related equipment.

The implementation of the soft controls is consistent with the following functional requirements:

- The soft control function does not affect the electrical or functional isolation of the safety-related and nonsafety-related equipment. This isolation is maintained upon a single failure of any equipment performing or supporting the soft control function.

- Failure of the operator displays does not prevent an operator from being able to safely shutdown the plant.

Section 18.8 presents the design implementation plan for the human system interfaces, including the soft controls. When the operator desires to operate a component from the nonsafety interface, the graphical operator display, which represents the component status, is selected by the operator on the VDU-based workstation. The operator then selects the component symbol to open the soft control template. The operator then selects the desired control action on the template via placing the cursor over the desired action. After the operator verifies that the desired control action is properly selected, the operator then actuates the control action, causing the selected control action to be transmitted to the component.

7.1.3.4 Real-Time Data Network

The real-time data network is a redundant data highway that supports both periodic and aperiodic data transfers of nonsafety-related signals and data. Periodic transfers consist of process data that is broadcast over the network at fixed intervals and is available to all destinations. Aperiodic data transfer is generally used for messages or file transfers.

The real-time data network provides communications among the distributed controllers, the plant protection and safety monitoring system gateways, the incore instrumentation, and the special monitoring system.

7.1.3.5 Rod Control System

The primary means of regulating the reactor power and power distribution is to position clusters of control rods in the reactor core using the rod control system.

The control rods are moved into and out of the reactor core by means of electromagnetic jacking mechanisms, called control rod drive mechanisms, located on the reactor vessel head. Each control rod drive mechanism consists of two gripper mechanisms, one stationary and one movable, that hold a notched driveline attached to the upper end of the control rod. The grippers and the lift armature are controlled by coils mounted external to the mechanism, concentric with the rod driveline. By controlling the sequence of energizing these coils, the mechanism can be made to step into, or out of, the reactor in increments. The rod control equipment provides this sequence control.

The control rods are arranged into symmetrical groups. The groups of control rods are divided into two categories: shutdown rods that are normally held fully withdrawn from the reactor, and control rods that are positioned to some intermediate insertion. In addition, there is a subcategory of control rods (low worth gray rods). If a rapid shutdown is necessary, the control, shutdown, and gray rods are dropped into the reactor by de-energizing their drive mechanisms.

Interlocks are provided to prevent the motion of the control rods outside of planned sequences.

7.1.3.6 Rod Position Indication

The position of each control rod is continuously monitored by the rod position indication system. This information is detected by the rod position detector assemblies. The signals from the detectors are processed by the data cabinets and transmitted to the distributed controllers. The distributed controllers further process the rod position information and transmit this information to the real-time data network.

7.1.3.7 Rod Drive Motor-Generator Sets

The rod drive motor-generator sets provide the power to the control rod drive mechanisms through the reactor trip switchgear. The rod drive motor-generator sets are included in the plant control system. The safety-related reactor trip switchgear is included in the plant protection and safety monitoring system.

There are two motor-generator sets with flywheels and two control cabinets. Each motor-generator is a three-phase induction motor, direct-coupled to a flywheel, and a synchronous generator.

During normal operating conditions, both motor generator sets are operating in parallel and equally sharing the total load demand. Each motor-generator set is capable of supplying the entire load requirements when the other set is out of service.

7.1.4 Identification of Safety Criteria

7.1.4.1 Conformance of the Safety System Instrumentation to Applicable Criteria

The safety-related system instrumentation described in Subsection 7.1.1 is designed and built to conform to the applicable criteria, codes, and standards concerned with the safe generation of nuclear power. Applicable General Design Criteria are listed in Section 3.1, NRC Regulatory Guides in Subsection 1.9.1, and Branch Technical Positions in Subsection 1.9.2. Industry Standards are cited as references.

The instrumentation and control portion of the safety-related system meets the requirements of IEEE 603-1991 as discussed in WCAP-15776 (Reference 12) Sections 1 through 5. The references to WCAP-15776 in UFSAR Section 7.2 and Section 7.3 include Sections 1 through 5. Therefore, only these sections are incorporated by reference. The topics are listed in the same order as they appear in Sections 4 through 8 of IEEE 603-1991. IEEE 603 provides the design bases of the

instrumentation and control portion of the safety system. Other criteria related to the IEEE 603-1991 requirements are also identified.

7.1.4.2 Conformance With Industry Standards

The instrumentation and control systems are designed in accordance with guidance provided in applicable portions of the following standards. The portions of the standards which are considered to be applicable are the portions of the standards which apply to instrumentation and control systems performing protection and control functions in an industrial environment:

- IEEE 323-1974; “IEEE Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations”
- IEEE 344-1987; “IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations”
- IEEE 379-2000; “IEEE Standard Application of the Single-Failure Criterion to Nuclear Power Generating Station Safety Systems”
- IEEE 383-1974; “IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations”
- IEEE 384-1981; “IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits” (See discussion for Regulatory Guide 1.75 in Appendix 1A)
- IEEE 420-1982; “IEEE Standard for the Design and Qualification of Class 1E Control Boards, Panels, and Racks Used in Nuclear Power Generating Stations”
- IEEE 603-1991; “IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations”
- IEEE 627-1980; “IEEE Standard for Design Qualification of Safety Systems Equipment Used in Nuclear Power Generating Stations”
- IEEE 1050-1996; “IEEE Guide for Instrumentation and Control Equipment Grounding in Generating Stations”
- IEEE 1074-1995; “IEEE Standard for Developing Software Life Cycle Processes” (See Discussion for Regulatory Guide 1.173 in Appendix 1A)
- Regulatory Guide 1.180, Revision 1, “Guidelines For Evaluating Electromagnetic and Radio-Frequency Interference In Safety-Related Instrumentation And Control Systems”

7.1.5 AP1000 Protective Functions

Protective functions are those necessary to achieve the system responses assumed in the safety analyses, and those needed to shut down the plant safely. The protective functions are grouped into two classes, reactor trip and ESF actuation. The software associated with these functions is considered a basic component as defined in 10 CFR 21 (Reference 6).

Reactor trip is discussed in Section 7.2. ESF actuation is discussed in Section 7.3.

7.1.6 Combined License Information

7.1.6.1 The calculation of setpoints for protective functions is addressed in WCAP-16361-P (Reference 17), and the applicable changes are incorporated into the UFSAR.

The Setpoint Program described in Technical Specifications Section 5.5 provides the appropriate controls for update of the instrumentation setpoints following completion of the calculation of setpoints for protective functions and the reconciliation of the setpoints against the final design.

7.1.6.2 Common Q Platform generic open items and plant specific action items identified during AP1000 design certification are addressed in APP-GW-GLR-017 (Reference 18), and the applicable changes are incorporated into the UFSAR.

7.1.7 References

1. IEEE 603-1991, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations."

2. Not used.

3. Not used.

4. Not used.

5. Not used.

6. 10 CFR 21, "Reporting of Defects and Noncompliance."

7. WCAP-15775, "AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report," Revision 8, May 2017.[1]

8. [*WCAP-16097-P-A (Proprietary) and WCAP-16097-NP-A (Non-Proprietary), Revision 3, "Common Qualified Platform Topical Report," February 2013. (Note: as modified by the Topical Report alternative in WCAP-15927, Revision 8).*]*

9. [*WCAP-16096-P-A (Proprietary) and WCAP-16096-NP-A (Non-Proprietary), Revision 4, "Software Program Manual for Common Q™ Systems," February 2013. (Note: as modified by the Software Program Manual alternatives in WCAP-15927, Revision 8)*]*

10. Not used.

11. Not used.

12. WCAP-15776, "Safety Criteria for the AP1000 Instrument and Control Systems," Revision 1, July 2019.

13. Not used.

14. Not used.

1. The UFSAR text incorporates by reference portions or all of this document.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

15. IEEE 7-4.3.2-1993, “IEEE Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations.”

16. Not used.

17. WCAP-16361-P (Proprietary) and WCAP-16361-NP (Non-Proprietary), “Westinghouse Setpoint Methodology for Protection Systems – AP1000,” February 2011.

18. {HISTORICAL — APP-GW-GLR-017, AP1000 Standard Combined License Technical Report, “Resolution of Common Q NRC Items,” Revision 0, Westinghouse Electric Company LLC. — HISTORICAL}

19. WCAP-16675-P (Proprietary) and WCAP-16675-NP (Non-Proprietary), “AP1000 Protection and Safety Monitoring System Architecture Technical Report,” Revision 10, September 2020.[1]

20. [*WCAP-15927-P (Proprietary) and WCAP-15927-NP (Non-Proprietary), Revision 8, September 2020 “Design Process for AP1000 Common Q Safety Systems.”*]*

21. Westinghouse Electric Company Quality Management System (QMS), Revision 7 (Non-Proprietary), October 1, 2013.

22. APP-GW-J0R-012, “AP1000 Protection and Safety Monitoring System Computer Security Plan,” Revision 5, September 2020, Westinghouse Electric Company LLC.[1]

23. Not used.

24. [*WCAP-17179-P (Proprietary) and WCAP-17179-NP (Non-Proprietary), “AP1000 Component Interface Module Technical Report,” Revision 6, April 2016.*]*

25. WCAP-16674-P (Proprietary) and WCAP-16674-NP (Non-Proprietary), “AP1000 I&C Data Communication and Manual Control of Safety Systems and Components,” Revision 9, June 2019.[1]

1. The UFSAR text incorporates by reference portions or all of this document.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

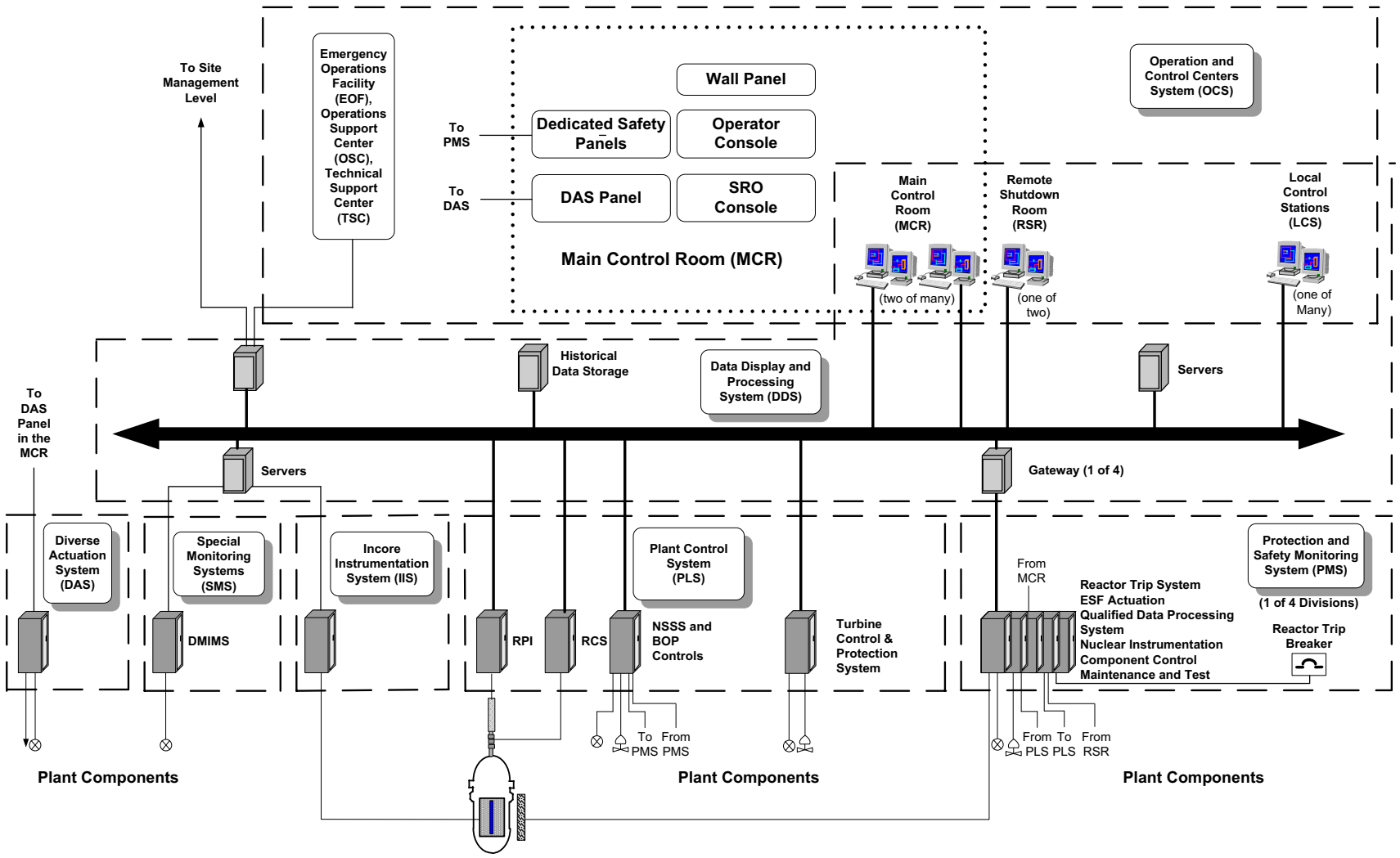


Figure 7.1-1
Instrumentation and Control Architecture

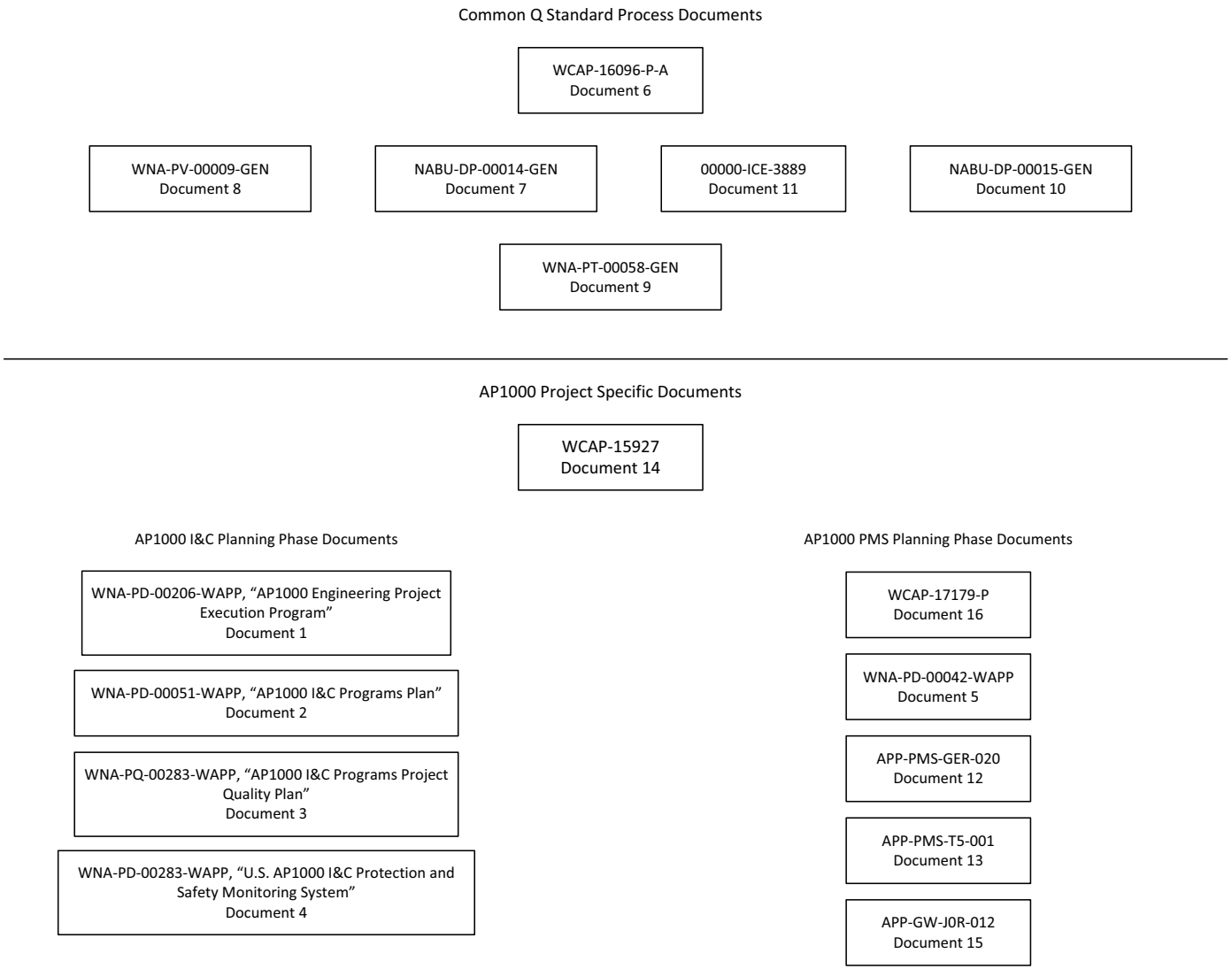


Figure 7.1-2
Common Q Standard Process and AP1000 Project-Specific Documents

Figures 7.1-3–7.1-11 Not Used

7.2 Reactor Trip

7.2.1 Description

Considerations, such as mechanical or hydraulic limitations on equipment or heat transfer requirements on the reactor core, define a safe operating region for the plant. Maneuvering of the plant within this safe operating region is permitted in response to normal power generation demands. The plant design provides margin to the safety limits so that an unsafe condition is not caused by the transients induced by normal operating changes. The plant control system attempts to keep the reactor operating away from any safety limit. Excursions toward a limit occur because of abnormal demands, malfunctions in the control system, or by severe transients induced by occurrence of a Condition II or III event, as discussed in Chapter 15. Hypothetical events (Condition IV) are analyzed with respect to plant safety limits. The safety system keeps the reactor within the safe region by shutting down the reactor whenever safety limits are approached. Reactor trip is a protective function performed by the protection and safety monitoring system when it anticipates an approach of a parameter to its safety limit. Reactor shutdown occurs when electrical power is removed from the rod drive mechanism coils, allowing the rods to fall by gravity into the reactor core.

Section 7.1 provides a description of the reactor trip equipment. The equipment involved is:

- Sensors and manual inputs
- Protection and safety monitoring system cabinets
- Reactor trip switchgear

The plant protection subsystems maintain surveillance of key process variables directly related to equipment mechanical limitations (such as pressure), and of variables which directly affect the heat transfer capability of the reactor (such as flow and temperature). Some limits, such as the overtemperature ΔT setpoint, are calculated in the protection and safety monitoring system from other parameters when direct measurement of the variable is not possible. Table 7.2-1 lists variables monitored for reactor trip.

Four redundant measurements, using four separate sensors, are made for each variable used for reactor trip. Analog signals are converted to digital form by analog-to-digital converters within the protection and safety monitoring system. Signal conditioning is applied to selected inputs following the conversion to digital form. Following necessary calculations and processing, the measurements are compared against the applicable setpoint for that variable. Steam generator level, pressurizer level, power range neutron flux, and reactor coolant flow are compensated per Subsection 7.2.1.2.2. A partial trip signal for a parameter is generated if one channel's measurement exceeds its predetermined or calculated limit. Processing of variables for reactor trip is identical in each of the four redundant divisions of the protection system. Each division sends its partial trip status to each of the other three divisions over isolated data links. Each division is capable of generating a reactor trip signal if two or more of the redundant channels of a single variable are in the partial trip state.

The reactor trip signal from each of the four divisions of the protection and safety monitoring system is sent to the corresponding reactor trip switchgear breakers.

Each of the four reactor trip actuation divisions consists of two reactor trip circuit breakers. The reactor is tripped when two or more actuation divisions output a reactor trip signal. This automatic trip demand initiates the following two actions. It deenergizes the under-voltage trip attachments on the reactor trip breakers, and it energizes the shunt trip devices on the reactor trip breakers. Either action causes the breakers to trip. Opening the appropriate trip breakers removes power to the rod drive mechanism coils, allowing the rods to fall into the core. This rapid negative reactivity insertion causes the reactor to shutdown.

Bypasses of parameter channels used to generate reactor trip signals and of reactor trip actuation divisions are permitted as described in Subsection 7.2.1.1.13. Single failure criterion is met even when one channel or division is bypassed. Bypassing two or more redundant channels or divisions is not allowed.

Subsection 7.2.1.1 provides a description of each of the reactor trip functions. Figure 7.2-1 shows the functional diagrams for reactor trips, as well as functional diagrams for other related plant functions. Figure 7.2-1 sheets are derived from the APP-PMS-J1 drawings and the references shown on Figure 7.2-1 sheets are tied to these parent drawings and not the sheets. Table 7.2-5 provides a cross reference to match the APP-PMS-J1 drawing to its corresponding Figure 7.2-1 sheet.

7.2.1.1 Functional Description

The following subsections describe the specific reactor trip functions and are grouped according to the following 11 conditions:

- Subsection 7.2.1.1.1 Nuclear Startup Trips
- Subsection 7.2.1.1.2 Nuclear Overpower Trips
- Subsection 7.2.1.1.3 Core Heat Removal Trips
- Subsection 7.2.1.1.4 Primary Overpressure Trips
- Subsection 7.2.1.1.5 Loss of Heat Sink Trips
- Subsection 7.2.1.1.6 Feedwater Isolation Trip
- Subsection 7.2.1.1.7 Automatic Depressurization Systems Actuation Reactor Trip
- Subsection 7.2.1.1.8 Core Makeup Tank Injection Trip
- Subsection 7.2.1.1.9 Reactor Trip on Passive Residual Heat Removal Actuation
- Subsection 7.2.1.1.10 Reactor Trip on Safeguards Actuation
- Subsection 7.2.1.1.11 Manual Reactor Trip

Table 7.2-2 lists the reactor trips and summarizes the coincidence logic to trip. Table 7.2-3 provides the interlocks for each trip. Table 7.2-4, lists system level manual inputs to reactor trip functions.

7.2.1.1.1 Nuclear Startup Trips

Source Range High Neutron Flux Trip

Source range high neutron flux trips the reactor when two of the four source range channels exceed the trip setpoint. This trip provides protection during reactor startup and plant shutdown. This function is delayed from actuating each time the source range detector's high voltage power is energized to prevent a spurious trip due to the short term instability of the processed source range values. This trip function may be manually blocked and the high voltage source range detector power supply de-energized when the intermediate range neutron flux is above the P-6 setpoint value. It is automatically blocked and the high voltage source range detector power supply is automatically de-energized by the power range neutron flux interlock above the P-10 setpoint value. The block may be manually reset when neutron flux is between P-6 and P-10. The reset and energization of the high voltage source range detector power supply both occur automatically when the intermediate range flux decreases below P-6. The channels can be individually bypassed to permit channel testing during plant shutdown or prior to startup. This bypass action is indicated in the main control room.

Figure 7.2-1, sheet 3 shows the logic for this trip. This sheet also shows the development of permissive P-6 while P-10 is shown in Figure 7.2-1, sheet 4.

Intermediate Range High Neutron Flux Trip

Intermediate range high neutron flux trips the reactor when two of the four intermediate range channels exceed the trip setpoint. This trip, which provides protection during reactor startup, can be

manually blocked if the power range channels are above approximately 10-percent power (P-10). The block is automatically reset when the power range channels indicate less than 10-percent power. The intermediate range channels, including detectors, are separate from the power range channels. The intermediate range channels can be individually bypassed to permit channel testing during plant shutdown or prior to startup. This bypass action is indicated in the main control room.

Figure 7.2-1, sheet 3 shows the logic for this trip. The development of permissive P-10 is shown in Figure 7.2-1, sheet 4.

Power Range High Neutron Flux Trip (Low Setpoint)

Power range high neutron flux (low setpoint) trips the reactor when two of the four power range channels exceed the trip setpoint. The flux level is compensated for cold leg density, using cold leg temperature and pressurizer pressure as inputs.

The trip, which provides protection during startup, can be manually blocked when the power range channels are above approximately 10-percent power (P-10). The block is automatically reset when the power range channels indicate less than 10-percent power.

Figure 7.2-1, sheet 3 shows the logic for this trip. The development of permissive P-10 is shown on Figure 7.2-1, sheet 4.

7.2.1.1.2 Nuclear Overpower Trips

Power Range High Neutron Flux Trip (High Setpoint)

Power range high neutron flux (high setpoint) trips the plant when two of the four power range channels exceed the trip setpoint. The flux level is compensated for cold leg density, using cold leg temperature and pressurizer pressure as inputs. It provides a backup trip to the overtemperature ΔT, overpower ΔT, and power range high positive flux rate trips for protection against excessive core power generation during normal operation and is always active. Figure 7.2-1, sheet 4 shows the logic for this trip.

Power Range High Positive Flux Rate Reactor Trip

This trip protects the reactor against a rapid increase in core power generation during normal operation and is always active. The flux level is compensated for cold leg density, using cold leg temperature and pressurizer pressure as inputs. The reactor is tripped when nuclear flux increases rapidly in excess of a predetermined setpoint in two out of the four power range channels.

Figure 7.2-1, sheet 4 shows the logic for this trip.

7.2.1.1.3 Core Heat Removal Trips

Overtemperature ΔT Reactor Trip

The overtemperature ΔT trip provides core protection to prevent departure from nucleate boiling for combinations of pressure, power, coolant temperature, and axial power distribution. The protection is provided if the transient is slow with respect to piping transient delays from the core to the temperature detectors and pressure is within the range between the high and low pressure reactor trips. This setpoint includes corrections for changes in density and heat capacity of water with temperature and dynamic compensation for piping delays from the core to the loop temperature detectors. With normal axial power distribution, this reactor trip limit is always below the core safety limit. If axial peaks are greater than design, as indicated by the difference between upper and lower power range nuclear detectors, the reactor trip limit is automatically reduced. Two hot leg

temperature measurements per loop are combined with individual cold leg temperature measurements to form four ΔT power signals, $q_{\Delta T}$.

The ΔT power signal, $q_{\Delta T,}$ is the calculated core power based on the properties of compressed water at the measured hot leg T_H, cold leg temperature, T_C, and pressurizer pressure, P_{PZR}:

$q_{\Delta T} = f(T_H, T_C, P_{PZR})$

$q_{\Delta T} = \rho(T_C, P_{ZR})[h(T_H, P_{ZR}) - h(T_C, P_{ZR}) - C]/\Delta T°$

Where:

T_C = $(1+\tau_1 s)/[(1+\tau_2 s)(1+\tau_3 s)]T_{COLD}$, where T_{COLD} is the measured cold leg temperature (lead/lag compensation with time constants τ_1, τ_2, and τ_3 applied to compensate for cold leg-to-core transit time)

T_H = $(1+\tau_4 s)/[(1+\tau_5 s)(1+\tau_6 s)]T_{HOT}$, where T_{HOT} is the measured hot leg temperature (lead/lag compensation with time constants τ_4, τ_5, and τ_6 applied to compensate for core-to-hot leg transit time)

$\rho(T_C,P_{PZR})$ = density of water at cold leg temperature in the cold leg (T_C) and pressurizer pressure, P_{PZR}

$h(T,P_{PZR})$ = enthalpy of water at the specified temperature (T_H or T_C) and pressurizer pressure P_{PZR}

ΔT° = a conversion factor, such that the value of $q_{\Delta T}$ is 100 percent at normal rated thermal power

C = a bias coefficient that permits zeroing $q_{\Delta T}$ at zero power (to compensate for small errors in RTD calibration)

s = Laplace transform operator

The ΔT setpoint for the overtemperature trip is continuously calculated, with one set of temperature measurements per loop by interpolating from tabulated core safety limits, with correction, (if needed) for adverse axial power distribution.

$OT\Delta T_{SP} = OT\Delta T_{SP}^{\circ} - f_1(\Delta I)$

Where:

$f_1(\Delta I)$ = the penalty associated with an adverse axial power distribution

$OT\Delta T_{SP}^{\circ}$ = the core DNB thermal design limit with design axial power distribution

$OT\Delta T_{SP}^{\circ}$ = $f(P_{PZR}, TC)$. The function, f(P,T), is determined by interpolation from specified tables of allowable core thermal power as a function of core inlet temperature at various pressures.

P_{PZR} and T_C, pressurizer pressure and cold leg temperature, are as defined previously.

A reactor trip is initiated if $q_{\Delta T} \geq OT\Delta T_{SP}$ in two of the four divisions.

Two separate ionization chambers supply the upper and lower flux signal for each overtemperature ΔT channel.

Increases in ΔI beyond a predefined deadband results in a decrease in trip setpoint.

The required one pressurizer pressure parameter per loop is obtained from four separate sensors connected to pressure taps at the top of the pressurizer.

Figure 7.2-1, sheet 5, shows the logic for the overtemperature ΔT trip function.

A more detailed description of the Overtemperature ΔT reactor trip is provided in Reference 5.

Overpower ΔT Trip

The Overpower ΔT reactor trip provides confidence of fuel integrity during overpower conditions and limits the required range for overtemperature ΔT protection.

A reactor trip is initiated if the ΔT power signal, $q_{\Delta T}$, exceeds the setpoint in two of the four divisions; that is, if:

$$q_{\Delta T} \geq OP\Delta T_{SP} = C_{OP}^{\circ} - f_2(\Delta I),$$

Where:

$q_{\Delta T}$ is the same ΔT power signal used for the Overtemperature ΔT reactor trip

C_{OP}° = A preset bias

$f_2(\Delta I)$ = A function of the neutron flux difference between upper and lower ionization chamber flux signals; to correct, if necessary, for an adverse axial flux shape.

Increases in ΔI beyond a predefined deadband results in a decrease in trip setpoint.

The source of temperature and neutron flux information is identical to that of the overtemperature ΔT trip, and the resultant ΔT setpoint is compared to the same measured ΔT power signal. Figure 7.2-1, sheet 5, shows the logic for this trip function.

A more detailed description of the Overpower ΔT reactor trip is provided in Reference 5.

Reactor Trip on Low-2 Pressurizer Pressure

This trip protects against low pressure, which could lead to departure from nucleate boiling. The parameter sensed is reactor coolant pressure as measured in the pressurizer. This trip is automatically blocked when reactor power is below the P-10 permissive setpoint to allow control rod testing during cold, depressurized conditions. The block is automatically reset when reactor power is above the P-10 setpoint.

Figure 7.2-1, sheet 5, shows the logic for this trip. The development of the P-10 permissive is shown in Figure 7.2-1, sheet 4.

Reactor Trip on Low-2 Reactor Coolant Flow

This trip protects against departure from nucleate boiling in the event of Low-2 reactor coolant flow. Flow in each hot leg is measured at the hot leg elbow. Two first-order lag filters in series are used to reduce noise on the input signals. Each flow signal is compensated for changes in reactor coolant density using the ΔT power signal. The trip on Low-2 flow in the hot legs is automatically blocked

when reactor power is below the P-10 permissive setpoint. This enhances reliability by preventing unnecessary reactor trips. The block function is automatically reset when reactor power is above the P-10 setpoint.

Figure 7.2-1, sheet 5 shows the logic for this trip. The development of permissive P-10 is shown in Figure 7.2-1, sheet 4.

Reactor Trip on Low-2 Reactor Coolant Pump Speed

This trip protects the reactor core from departure from nucleate boiling in the event of a loss of flow in more than one loop. This protection is provided by tripping the reactor when the speed on two out of the four reactor coolant pumps falls below the setpoint. Loss of flow in more than one loop could be caused by a voltage or frequency transient in the plant power supply such as would occur during a station blackout. It could be caused by inadvertent opening of more than one reactor coolant pump circuit breaker. There is one speed detector mounted on each reactor coolant pump. The trip is automatically blocked when reactor power is below the P-10 permissive setpoint to enhance reliability by preventing unnecessary reactor trips. The block is automatically reset when reactor power is above the P-10 setpoint.

Figure 7.2-1, sheet 5, shows the logic for this trip. The development of P-10 is shown in Figure 7.2-1, sheet 4.

Reactor coolant pump speed is detected by a probe mounted on the reactor coolant pump frame. The speed signal is transmitted to the protection and safety monitoring system to provide the input to the trip logic function.

The Low-2 reactor coolant pump speed trip provides a direct measurement of the parameter of interest. It permits the plant to ride through many postulated voltage or frequency dip transients without reactor trip if safety limits are not violated. Selection of the Low-2 reactor coolant pump speed trip setpoint and time response provide for the timely initiation of reactor trip during the complete loss of flow accident and the limiting frequency decay event, consistent with the analysis results reported in Chapter 15.

The reactor coolant pump speed sensor response time is not dependent on moving parts and produces a nearly instantaneous response delayed only by the transit time for the flow of electric current in the sensor. The preamplifier also provides a prompt response compared to the overall channel response time and is designed such that there are no components that can contribute to changes in the response time. The response time for the reactor coolant pump speed sensor and preamplifier is allocated in lieu of direct measurement. This is conservative with respect to the response time identified through benchmark testing (Reference 6).

The reactor coolant pump speed detectors perform their protective function (during the complete loss of flow accident and the limiting frequency decay event) in an environment (temperature, humidity, pressure, chemical, and radiation) that is not changed by the event. Therefore, it is not necessary to impose environmental qualification requirements on these detectors more restrictive than those imposed for use under rated conditions. The reactor coolant pump speed detectors are qualified for use under rated conditions with their performance verified by operation in the plant. The reactor coolant pump speed detectors are qualified to the most limiting vibrations experienced by pump operation.

Reactor Trip on High-2 Reactor Coolant Pump Bearing Water Temperature

This trip is an anticipatory trip and is lead-lag compensated based on the expectation of a complete loss of reactor coolant flow if cooling water is lost to any of the reactor coolant pumps. This trip occurs before the reactor coolant pumps are tripped on the same measurement.

Figure 7.2-1, sheet 5, shows the logic for this trip.

7.2.1.1.4 Primary Overpressure Trips

Pressurizer High-2 Pressure Reactor Trip

This trip protects the reactor coolant system against system overpressure. The same sensors used for the pressurizer Low-2 pressure reactor trip are used for the High-2 pressure trip except that separate setpoints are used. The High-2 pressurizer pressure protection trips the reactor when two out of the four pressurizer pressure channels exceed the trip setpoint. There are no interlocks or permissives associated with this trip function.

Figure 7.2-1, sheet 6, shows the logic for this trip.

High-3 Pressurizer Water Level Reactor Trip

This trip is provided as backup to the High-2 pressurizer pressure reactor trip and serves to prevent water relief through the pressurizer safety valves. The high-3 pressurizer water level protection trips the reactor when two out of the four pressurizer water level channels exceed the trip setpoint. The level signal is compensated for pressurizer reference leg temperature, pressurizer pressure, and RCS wide range pressure. The trip is automatically blocked when reactor power is below the P-10 permissive setpoint. This permits control rod testing with the plant cold and the pressurizer water solid. The block is automatically reset when reactor power is above the P-10 setpoint.

Figure 7.2-1, sheet 6, shows the logic for the trip. The development of P-10 is shown in Figure 7.2-1, sheet 4.

7.2.1.1.5 Loss of Heat Sink Trip

Reactor Trip on Low-2 Steam Generator Narrow Range Water Level in any Steam Generator

This trip protects the reactor from loss of heat sink in the event of a loss of feedwater to the steam generators. The reactor is tripped when two out of the four narrow range water level sensors in any steam generator produce signals below the setpoint value. The level signal is compensated for steam line pressure. This trip can be manually blocked when the reactor coolant average temperature is below the P-9 permissive setpoint. This block is automatically reset when reactor coolant average temperature is above the P-9 permissive setpoint.

Figure 7.2-1, sheet 7, shows the logic for the trip. The development of the P-9 permissive is shown on Figure 7.2-1, sheet 7.

7.2.1.1.6 Feedwater Isolation Trip

High-3 Steam Generator Water Level in Any Steam Generator

This function is an anticipatory trip based on the expectation that a reactor trip would occur after steam generator feedwater is isolated. The plant control system uses a lower steam generator water level setpoint, High-1, to close the feedwater control valves. This provides an interval for operator action to prevent total isolation of the steam generator and a reactor trip before the High-3 setpoint is exceeded. The level signal is compensated for steam line pressure. The trip on High-3 steam generator water level may be manually blocked below the P-11 permissive setpoint to allow control rod testing. The block is automatically reset when the pressurizer pressure is above the P-11 setpoint.

Figure 7.2-1, sheet 10, shows the logic for this trip function.

7.2.1.1.7 Automatic Depressurization Systems Actuation Reactor Trip

A reactor trip is initiated if an automatic depressurization system actuation occurs either automatically or manually. This provides a reactor trip if the system is depressurized and a trip is not initiated from another source. The automatic depressurization system actuation function is discussed in Subsection 7.3.1.2.4.

Manual automatic depressurization system actuation is initiated from either of two sets of controls in the main control room. Operating either of the two sets of controls also sends a reactor trip signal to the reactor trip switchgear breakers. Outputs on the control sets, physically and electrically separated, send their position status to the protection and safety monitoring system. These outputs de-energize the interposing relays and the undervoltage trip attachments and energize the shunt trip attachments on the reactor trip breakers. Either action causes the breakers to open. The shunt trip attachment provides a backup to the undervoltage trip of the breakers.

Figure 7.2-1, sheet 15 shows the logic for this trip function. There are no interlocks or bypasses associated with this trip.

7.2.1.1.8 Core Makeup Tank Injection Trip

A reactor trip is initiated if core makeup injection occurs either automatically or manually. Since core makeup tank injection results in a trip of the reactor coolant pumps, providing a reactor trip upon core makeup tank injection maximizes the margin to DNB at all power levels. The core makeup tank injection function is discussed in Subsection 7.3.1.2.3.

Manual core makeup tank injection is initiated from either of two controls in the main control room. Operating either of the two controls also sends a reactor trip signal to the reactor trip switchgear breakers. Outputs on each control, physically and electrically separated, send their position status to the protection and safety monitoring system. These outputs de-energize the interposing relays and the undervoltage trip attachments and energize the shunt trip attachments on the reactor trip breakers. Either action causes the breakers to open. The shunt trip attachment provides a backup to the undervoltage trip of the breakers.

Figure 7.2-1, sheets 2 and 12 show the logic for this trip function. There are no interlocks or bypasses associated with this trip.

7.2.1.1.9 Reactor Trip on Passive Residual Heat Removal System Actuation

A reactor trip is initiated when either of the passive residual heat removal (PRHR) system's discharge valves is not closed, allowing flow through the PRHR heat exchanger (PRHR HX). This reactor trip will prevent the fuel design limits from being exceeded in the event the PRHR HX is inadvertently aligned to allow flow when the reactor is being operated at power conditions. The PRHR HX alignment is discussed in Subsection 7.3.1.2.7.

Figure 7.2-1, sheets 2 and 4 show the logic for this trip function. There are no interlocks or bypasses associated with this trip.

7.2.1.1.10 Reactor Trip on Safeguards Actuation

A reactor trip is initiated with any signal that causes a safeguards actuation. This reactor trip occurs whether the safeguards actuation is commanded automatically or manually. The means for actuating safeguards automatically are described in Section 7.3. This trip protects the core against a loss of reactor coolant or a steam line rupture.

Manual safeguards actuation is initiated from either of two controls in the main control room. Operating either of the two controls also sends a reactor trip signal to the reactor trip switchgear breakers. Outputs on each control, physically and electrically separated, send their position status to the protection and safety monitoring system. These outputs de-energize the interposing relays and the undervoltage trip attachments and energize the shunt trip attachments on the reactor trip breakers. Either action causes the breakers to open. The shunt trip attachment provides a backup to the undervoltage trip of the breakers.

Figure 7.2-1, sheets 2 and 11, show the logic for this trip function. There are no interlocks or bypasses associated with this trip.

7.2.1.1.11 Manual Reactor Trip

The manual reactor trip consists of 2 controls in the main control room, either of which trip all 8 of the reactor trip switchgear breakers. The reactor trip circuit breakers contain both undervoltage and shunt trip attachments. The shunt trip acts as a diverse backup to the undervoltage trip in the breakers. Contacts on each control, physically and electrically separated, are in series with the undervoltage trip attachment on the reactor trip breakers, the shunt trip attachment, and the power outputs at the protection and safety monitoring system cabinet. Actuating either control interrupts power from the voting logic to the interposing relays and undervoltage trip attachments, releasing them. It also supplies power to shunt trip attachments, actuating the shunt trip attachments. The breakers trip when either the shunt trip attachments are energized or the undervoltage trip attachments are de-energized. Actuating either manual trip control causes each breaker to trip by initiating both of these actions.

Figure 7.2-1, sheets 2 and 13, show the logic for the manual trip. There are no interlocks or bypasses associated with this trip.

7.2.1.1.12 Reactor Trip System Interlocks

The interlocks used in the reactor trip functions are designated as P-xx permissives. Table 7.2-3 provides a listing of these interlocks. These permissives are implemented at the channel level rather than at the logic level because plant availability has been determined to be improved using this technique of integrating permissives into each channel.

Manual blocks to reactor trip are listed on Table 7.2-4 and are described in the following subsections. The source, intermediate, power (low setpoint), and steam generator water level manual blocks, when used in conjunction with the applicable permissives, are implemented during startup.

Source Range Block (One Control for each Division)

The source range reactor trip may be manually blocked upon the occurrence of the P-6 permissive and the block is automatically reset when the permissive condition is not met. The channel is automatically blocked upon the occurrence of the P-10 permissive. The block of the trip function also de-energizes the source range neutron flux detectors. Figure 7.2-1, sheet 3, shows these blocks.

Intermediate Range Block (One Control for each Division)

The intermediate range reactor trip may be manually blocked upon the occurrence of the P-10 permissive and the block is automatically reset when the permissive condition is not met. Figure 7.2-1, sheet 3, shows this block.

Power Range (Low Setpoint) Block (One Control for each Division)

The power range low setpoint reactor trip may be manually blocked upon the occurrence of the P-10 permissive and the block is automatically reset when the permissive condition is not met. Figure 7.2-1, sheet 3, shows this block.

Steam Generator Low-2 Water Level Block (One Control for each Division)

The steam generator Low-2 reactor trip may be manually blocked upon the occurrence of the P-9 permissive and the block is automatically reset when the permissive condition is not met.

Steam Generator High-3 Water Level Block (One Control for each Division)

The steam generator High-3 reactor trip may be manually blocked upon the occurrence of the P-11 permissive. This block function is automatically reset when the permissive condition is not met. Figure 7.2-1, sheets 9, 10, and 11, illustrates the functional logic relating to this function.

7.2.1.1.13 Bypasses of Reactor Trip Functions

Each channel used in reactor trip can be bypassed, as discussed in Subsection 7.1.2.9, except for reactor trips resulting from manual initiations. One channel can be bypassed for an indefinite period of time with the normal two-out-of-four trip logic automatically reverting to a two-out-of-three trip logic. Bypassing two or more channels is not allowed.

7.2.1.2 Design Basis for Reactor Trips

This section provides the design bases information on the reactor trip function, including the information required by Section 4 of IEEE-603-1991. Reactor trip is a protective function generated as part of the protection and safety monitoring system. Those design bases relating to the equipment that initiates and accomplishes reactor trips are contained in WCAP-15776 (Reference 2). The design bases presented here concern the variables monitored for reactor trips, the minimum performance requirements in generating the trips, and the requirements placed on reactor trips during various reactor operating modes.

7.2.1.2.1 Design Basis: Generating Station Conditions Requiring Reactor Trip (Paragraph 4.1 of IEEE-603-1991)

The generating station conditions requiring protective actions are analyzed in Chapter 15. Conditions that result in a reactor trip are listed in Table 15.0-6. This table correlates the accident conditions (II, III, or IV events) to each reactor trip.

7.2.1.2.2 Design Basis: Variables, Levels, Ranges, and Accuracies Used in Reactor Trip Functions (Paragraphs 4.1, 4.2, and 4.4 of IEEE-603-1991)

The variables monitored for reactor trips are:

- Neutron flux (with cold leg temperature and pressurizer pressure compensation)
- Reactor coolant pump bearing water temperature
- Pressurizer pressure
- Water level in the pressurizer (with pressurizer reference leg temperature, pressurizer pressure, and RCS wide range pressure compensation)
- Reactor coolant flow in each loop (with thermal power compensation)
- Speed of each reactor coolant pump
- Water level in each steam generator (with steam line pressure compensation)
- Cold leg temperature (T_{cold}) in each loop
- Hot leg temperature (T_{hot}) in each loop

- Status of each manual reactor trip control
- Status of PRHR HX discharge valves

The ranges and response times for each variable are listed on Table 7.2-1. Channel accuracies are accounted for in the setpoint methodology. Some PMS response times are allocated rather than measured (Reference 3 and Reference 6).

A discussion on levels that require reactor trip is contained in Subsection 7.2.1.1.

The reactor trip setpoints are maintained by the setpoint program, which is described in the Technical Specifications.

7.2.1.2.3 Design Basis: Spatially Dependent Parameters Used in Reactor Trip (Paragraph 4.6 of IEEE-603-1991)

The hot and cold leg temperature signals required for input to the protection and control functions are obtained using thermowell-mounted RTDs installed in each reactor coolant loop. The hot leg temperature measurement in each loop is accomplished using six fast-response, narrow-range RTDs each in its own thermowell; three thermowells are RTDs for each of the two divisions monitoring that hot leg. The three thermowells for each division are mounted approximately 120 degrees apart in the cross-sectional plane of the piping, to obtain a representative temperature sample. The temperatures measured by the three RTDs are different due to hot leg temperature streaming and vary as a function of thermal power. Therefore, these signals are averaged using electronic weighting to generate a hot leg average temperature. Provisions are incorporated into the process electronics to allow for operation with only two RTDs in service. The two RTD measurements can be biased to compensate for the loss of the third RTD.

Radially varying cold leg temperature is not a concern since the resistance temperature detectors are located downstream of the reactor coolant pumps. The pumps provide mixing of the coolant so that radial temperature variations do not exist.

Radial neutron flux is not a spatially dependent concern because of core radial symmetry. Axial variation in neutron flux is used for calculations involving overtemperature and overpower ΔT. Excore detectors furnish this axially-dependent information to the overtemperature and overpower calculators. See Subsection 7.2.1.1.3.

7.2.1.2.4 Design Basis: Operational Limits for Variables in Various Reactor Operating Modes (Paragraph 4.3 of IEEE-603-1991)

During startup or shutdown, reactor trips are provided for three ranges of neutron flux (source, intermediate, and power range). The source range, intermediate range, and power range (low setpoint) trips are manually blocked when the appropriate power escalation permissives are present. The blocks are automatically reset during power de-escalation. Subsection 7.2.1.1.1 describes these reactor trips. Their interlocks are described in Subsection 7.2.1.1.12.

During testing or maintenance, functions are provided to bypass a channel monitoring a variable for reactor trip. Although no setpoints need to be changed for bypassing, the coincidence logic is automatically adjusted as described in Subsection 7.2.1.1.13. The logic provides that the remaining redundant channels for that variable meet the single failure criterion. The two-out-of-four logic is automatically reinstated when the bypass is removed.

7.2.1.2.5 Design Basis: Reactor Trips for Malfunctions, Accidents, Natural Phenomena, or Credible Events (Paragraph 4.7 and 4.8 of IEEE-603-1991)

There are no reactor trip functions that directly shutdown the reactor on occurrence of either natural phenomena (such as seismic flood or wind) or internal events (such as fire or pipe whip). The operator can trip the reactor at any time by actuating the manual reactor trip.

Functional diversity is used to determine the reactor trips for accident conditions. Generally, two or more reactor trips occur for the transients analyzed in the accident analyses.

For example, protection is provided for the complete loss of coolant flow event by Low-2 reactor coolant pump speed and by Low-2 coolant flow reactor trips. Complete reliance is not made on a single reactor trip terminating a given event. Table 15.0-6 lists the reactor trips and the conditions which normally result in each trip.

Redundancy provides confidence that reactor trips are generated on demand, even when the protection system is degraded by a single failure. Reactor trips are four-way redundant. The single failure criterion is met even if one channel is bypassed, as discussed in Subsection 7.2.1.1.13. More than one bypass is not allowed.

7.2.1.3 System Drawings

Functional diagrams of the reactor trip function are provided in Figure 7.2-1.

7.2.2 Analyses

7.2.2.1 Failure Modes and Effects Analysis (FMEA)

A failure modes and effects analysis was performed on the AP1000 protection and safety monitoring system. Through the process of examining the feasible failure modes, it was concluded that the AP1000 protection system maintains safety functions during single point failures. The AP1000 failure modes and effects analysis is documented in Appendix 7B.

7.2.2.2 Conformance of the Reactor Trip Function to Applicable Criteria

Reactor trip is a protective function generated by the AP1000 protection and safety monitoring system. Requirements addressing equipment in the protection and safety monitoring system are presented in WCAP-15776 (Reference 2). The discussions presented in this subsection address only the functional aspects of reactor trip.

7.2.2.2.1 Conformance to the General Functional Requirements for Reactor Trip (Section 5 of IEEE-603-1991, GDC-13, GDC-20)

The protection and safety monitoring system initiates a reactor trip whenever a condition monitored by the system reaches a preset level. The reactor trips are listed in Table 7.2-2 and are discussed in Subsection 7.2.1.1. The variables which are monitored for these trips are listed in Subsection 7.2.1.2.2. Table 7.2-1 lists the ranges and response times for these variables. Channel accuracies are accounted for in the setpoint methodology. The reactor trip setpoints are maintained by the setpoint program, which is described in the Technical Specifications.

As discussed in WCAP-15776 (Reference 2), the setpoints set into the protection and safety monitoring system equipment provide a margin to the safety limits which are assumed in the accident analyses. The safety limits are based on mechanical or hydraulic limitations of equipment or on heat transfer characteristics of the reactor core. While most setpoints used for reactor trip are fixed, there

are continuously calculated setpoints for the overtemperature and overpower ΔT trips. Setpoints for reactor trip are selected on the basis of engineering design and safety studies. The setpoints provide a margin to allow for uncertainties and instrument errors.

The overtemperature and overpower conditions are not directly measurable quantities. However, the process variables that determine overtemperature and overpower conditions are sensed and evaluated. Small isolated changes in various process variables may not individually result in reaching a core safety limit. However, the combined variations over time may cause the overtemperature or overpower limit to be exceeded. The design concept for reactor trips takes cognizance of this situation by providing reactor trips associated with individual process variables in addition to the overtemperature and overpower ΔT safety limit trips. Process variable trips prevent reactor operation when a monitored value reaches a core or safety limit. Overtemperature and overpower ΔT trips provide protection for slow transients. Other trips, such as low flow or high flux, trip the reactor for rapid changes in flow or flux respectively.

Table 15.0-6 summarizes events which normally result in reactor trips.

7.2.2.2.2 Conformance to the Single Failure Criterion for Reactor Trip (Paragraph 5.1 of IEEE 603-1991, IEEE 379-2000)

A single failure in the protection and safety monitoring system or the reactor trip actuation divisions does not prevent a reactor trip, even when a reactor trip channel is bypassed for test or maintenance. Conformance of the equipment to this requirement is discussed in WCAP-15776 (Reference 2). In addition to the redundancy of equipment, diversity of reactor trip functions is incorporated. Most Condition II, III, or IV events requiring a reactor trip are protected by trips from diverse parameters. For example, reactor trip, because of an uncontrolled rod cluster control assembly bank withdrawal at power, may occur on power range high neutron flux, overtemperature, overpower, pressurizer High-2 pressure or pressurizer High-3 water level. Reactor trip on complete loss of reactor coolant flow may occur on Low-2 flow or from the diverse parameter of Low-2 reactor coolant pump speed.

7.2.2.2.3 Conformance to the Requirements Covering Control and Reactor Trip Interactions (Paragraphs 5.6 and 6.3 of IEEE 603-1991, GDC-24)

The AP1000 is designed to permit maneuvering of the plant in response to normal power generation demands without causing a reactor trip. The plant control system attempts to keep the reactor operating away from any safety limit. However, the selection of the reactor trip setpoints does not take credit for such control actions. The accident analyses in Chapter 15 assume that the plant is at normal operation commensurate with the operating mode at the onset of the accident. If a control system action leads to more conservative results, that assumption is made. If failure of a control system to work leads to more conservative results, that assumption is made. In this way, reactor trips do not depend on control system actions.

As stated in Subsection 7.7.1.12, it is considered advantageous to use certain protection data for control functions. Isolation devices are incorporated into the protection system to prevent control system failures from degrading the performance of the protection system.

Failures in a protection channel monitoring a variable that is also used for control do not result in control system actions requiring protection by the redundant channels monitoring that variable. This is discussed in WCAP-15776 (Reference 2).

7.2.2.2.4 Conformance to Requirements on the Derivation of System Inputs for Reactor Trip (Paragraph 6.4 of IEEE 603-1991)

To the extent feasible, inputs used for reactor trip are derived from signals that are direct measurements of the desired variables. Two exceptions exist, overtemperature and overpower, which cannot be directly measured. The process variables that do affect these parameters can be measured and they are used to continuously calculate the setpoints.

The overtemperature ΔT trip setpoint is calculated from pressurizer pressure, reactor coolant temperature, and nuclear axial power shape. The setpoint is compared against the measured ΔT power signal.

Overpower ΔT is calculated from reactor coolant temperature and the nuclear axial power shape in the core. This value is compared against the measured ΔT power signal.

The overtemperature and overpower ΔT trips are described in Subsection 7.2.1.1.3.

7.2.2.2.5 Conformance to Requirements on Bypassing of Reactor Trip Functions (Paragraph 5.8, 5.9, 6.6, and 6.7 of IEEE 603-1991)

With the exception of the manual reactor trips, reactor trip channels and the reactor trip actuation divisions are permitted to be bypassed as described in WCAP-15776 (Reference 2).

Operating bypasses for reactor trips are described in Subsection 7.2.1.1.13.

7.2.2.2.6 Conformance to Requirements on Multiple Setpoints Used for Reactor Trips (Paragraph 6.8.2 of IEEE 603-1991)

For monitoring neutron flux, multiple setpoints are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protection and safety monitoring system hardware and software are designed to provide positive means or administrative control to ensure that the more restrictive trip setpoint is used. The hardware and software used to prevent improper use of less restrictive trip settings are considered part of the protection and safety monitoring system.

7.2.2.2.7 Conformance to the Requirement for Completion of Reactor Trip Once Initiated (Paragraph 5.2 of IEEE 603-1991, Regulatory Guide 1.62)

Once initiated, reactor trips proceed to completion. Return to operation requires deliberate operator action to reset the reactor trip circuit breakers that are opened by the reactor trip signal. The circuit breakers cannot be closed while the reactor trip signals are present from the respective protection and safety monitoring system division. A manual control is provided in the main control room to reset (close) the reactor trip breakers when all reactor trip signals have been cleared. The reset feature is not a safety function. Refer also to WCAP-15776 (Reference 2).

7.2.2.2.8 Conformance to the Requirement to Provide for Manual Initiation of Reactor Trip (Paragraph 6.2 of IEEE 603-1991, Regulatory Guide 1.62)

The reactor is tripped by actuating one of two manual reactor trip controls from the main control room. The reactor is also tripped upon manual actuation of the automatic depressurization system, manual core makeup tank injection, or upon manual safeguards actuation. These reactor trips are described in Subsections 7.2.1.1.7, 7.2.1.1.8, 7.2.1.1.10, and 7.2.1.1.11. Refer also to WCAP-15776 (Reference 2).

7.2.3 Combined License Information

The FMEA for the protection and safety monitoring system is addressed in WCAP-16438-P (Reference 1) and WCAP-16592-P (Reference 4), and the applicable changes are incorporated into the UFSAR.

7.2.4 References

1. WCAP-16438-P (Proprietary), WCAP-16438-NP (Non-Proprietary), “FMEA of AP1000 Protection and Safety Monitoring System,” Revision 3, February 2011.

2. WCAP-15776, “Safety Criteria for the AP1000 Instrument and Control Systems,” Revision 1, July 2019.

3. Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment Nos. 168 and 166 to the Combined License Nos. NPF-91 and NPF-92, respectively, Vogtle Electric Generating Plant Units 3 and 4, Docket Nos. 52-025 and 52-026, dated November 21, 2019 [ML19297C988 (Proprietary) and ML19297D159 (non-proprietary)].

4. WCAP-16592-P (Proprietary), WCAP-16592-NP (Non-Proprietary), “Software Hazards Analysis of AP1000 Protection and Safety Monitoring System,” Revision 2.

5. APP-GW-GLR-137, “Bases of Digital Overpower and Overtemperature Reactor Trips,” Revision 1.

6. APP-GW-GLR-804, “AP1000® Technical Report to Support Modification to Response Time and Channel Calibration Testing Requirements for Reactor Coolant Pump Speed,” Revision 0, Westinghouse Electric Company, LLC.

Table 7.2-1 (Sheet 1 of 3)
Reactor Trip Variables, Limits, and Ranges
(Design Basis for Reactor Trip)
(Nominal)

Protective Functions	Variable	Range of Variables	Response Time Assumed in Accident Analysis (Sec)[1]
Source Range High Neutron Flux	Neutron flux	6 decades of neutron flux: 1 to 10^6 counts per second	N/A[2]
Intermediate Range High Neutron Flux	Neutron flux	8 decades of neutron flux overlapping source range by 2 decades and including 100% power	N/A[2]
Power Range Neutron Flux (Low Setpoint)	Neutron flux	1 to 120% of full power	0.9
Power Range Neutron Flux (High-Setpoint)	Neutron flux	1 to 120% of full power	N/A[2]
Power Range High Positive Flux Rate	Neutron flux	1 to 120% of full power	0.9
Overtemperature ΔT	Cold leg temp. (T_{cold})	490° to 610°F	2.0[3]
	Hot leg temp. (T_{hot})	530° to 650°F	2.0[3]
	Pressurizer pressure	1500 to 2500 psig	2.0
	Neutron flux (difference between top and bottom power range detectors)	-60 to +60% (Δφ)	N/A[2]
Overpower ΔT	Cold leg temp. (T_{cold})	490° to 610°F	1.0[3]
	Hot leg temp. (T_{hot})	530° to 650°F	1.0[3]
	Pressurizer pressure	1500 to 2500 psig	1.0
	Neutron flux (difference between top and bottom power range detectors)	-60 to +60% (Δφ)	N/A[2]
Pressurizer Low Pressure	Pressurizer pressure	1500 to 2500 psig	2.0

Table 7.2-1 (Sheet 2 of 3)
Reactor Trip Variables, Limits, and Ranges
(Design Basis for Reactor Trip)
(Nominal)

Protective Functions	Variable	Range of Variables	Response Time Assumed in Accident Analysis (Sec)[1]
Pressurizer High Pressure	Pressurizer pressure	1500 to 2500 psig	2.0
Pressurizer High Water Level	Pressurizer water level	0-100% of entire cylindrical portion of pressurizer	2.0
Low Reactor Coolant Flow	Coolant flow	0 to 120% of rated flow	1.451
Low Reactor Coolant Pump Speed	Pump speed	0 to 120% of rated speed	0.65
Low Steam Generator Water Level	Steam generator water level	0-100% of span (narrow range taps)	2.0
High Steam Generator Water Level	Steam generator water level	0-100% of span (narrow range taps)	2.0
Reactor Coolant Pump High Bearing Water Temperature	Reactor coolant pump bearing water temperature	50° to 400°F	N/A[2]

Table 7.2-1 (Sheet 3 of 3)
Reactor Trip Variables, Limits, and Ranges
(Design Basis for Reactor Trip)
(Nominal)

Protective Functions	Variable	Range of Variables	Response Time Assumed in Accident Analysis (Sec)(1)
Automatic or Manual Safeguards Actuation	See Table 7.3-4	See Table 7.3-4	2.0(3)
Manual Reactor Trip	Control status	N/A	N/A
Automatic or Manual Depressurization System Actuation	See Table 7.3-4	See Table 7.3-4	N/A(4)
Automatic or Manual Core Makeup Tank Injection	See Table 7.3-4	See Table 7.3-4	N/A(4)
Automatic or Manual PRHR Actuation	PRHR discharge valve position	Valve closed/valve not-closed	1.25

Notes:

1. Delay from the time that the process variable exceeds the setpoint until the time that the control rods are free to fall into the core (includes reactor trip breaker opening delay and control rod drive mechanism gripper release delay). This response time reflects the total delay from both the PMS equipment and the associated sensor.
2. The following functions are not explicitly assumed to initiate a reactor trip in the accident analysis. However, they are subject to response time test surveillance requirements in the technical specifications. Therefore, the following maximum allowable response times are allocated:

   Source Range High Neutron Flux = 2.0 seconds
   Intermediate Range High Neutron Flux = 2.0 seconds
   Power Range Neutron Flux (High-Setpoint) = 2.0 seconds
   Neutron flux (difference between top and bottom power range detectors) for Overtemperature ΔT = 2.0 seconds
   Neutron flux (difference between top and bottom power range detectors) for Overpower ΔT = 2.0 seconds
   Reactor Coolant Pump High Bearing Water Temperature = 8.5 seconds

3. In addition to the response time given, a 4.0 second lag time is used in the accident analysis for this function to account for the associated RTDs. For automatic safeguards actuation, the 4.0 second lag time is only used for the temperature inputs.
4. This function is not explicitly assumed to initiate a reactor trip in the accident analysis and does not have any response time test requirements in the technical specifications.

Table 7.2-2 (Sheet 1 of 2)
Reactor Trips

Reactor Trip[1]	No. of Channels	Division Trip Logic	Bypass Logic	Permissives and Interlocks (See Table 7.2-3)
Source Range High Neutron Flux Reactor Trip	4	2/4	Yes[2]	P-6, P-10
Intermediate Range High Neutron Flux Reactor Trip	4	2/4	Yes[2]	P-10
Power Range High Neutron Flux (Low Setpoint) Trip	4	2/4	Yes[2]	P-10
Power Range High Neutron Flux (High Setpoint) Trip	4	2/4	Yes[2]	----
High Positive Flux Rate Trip	4	2/4	Yes[2]	----
High-2 Reactor Coolant Pump Bearing Water Temperature	16 (4/pump)	2/4 in any single pump	Yes[2]	----
Overtemperature ΔT	4 (2/loop)	2/4	Yes[2]	----
Overpower ΔT	4 (2/loop)	2/4	Yes[2]	----
Pressurizer Low-2 Pressure Trip	4	2/4	Yes[2]	P-10
Pressurizer High-2 Pressure Trip	4	2/4	Yes[2]	----
High-3 Pressurizer Water Level Trip	4	2/4	Yes[2]	P-10
Low-2 Reactor Coolant Flow	8 (4/hot leg)	2/4 in either hot leg	Yes[2]	P-10
Low-2 Reactor Coolant Pump speed	4 (1/pump)	2/4	Yes[2]	P-10
Low-2 Steam Generator Narrow Range Water Level	4/steam generator	2/4 in any steam generator	Yes[2]	P-9
High-3 Steam Generator Water Level	4/steam generator	2/4 in any steam generator	Yes[2]	P-11

Table 7.2-2 (Sheet 2 of 2)
Reactor Trips

Reactor Trip[1]	No. of Channels	Division Trip Logic	Bypass Logic	Permissives and Interlocks (See Table 7.2-3)
Automatic Safeguards Actuation	4	2/4	Yes[2]	—
Automatic Depressurization System Actuation	4	2/4	Yes[2]	—
Automatic Core Makeup Tank Injection	4	2/4	Yes[2]	—
PRHR Actuation	4	2/4	Yes[2]	—
Manual Safeguards Actuation	2 controls	1/2 controls	No	—
Manual Depressurization System Actuation	4 controls	2/4 controls	No	—
Manual Core Makeup Tank Injection	2 controls	1/2 controls	No	—
Manual Reactor Trip	2 controls	1/2 controls	No	—

Notes:
1. Reactor Trip divisions are also bypassed with the logic as defined in 2. below.
2. Bypass Logic = 2/4 with no bypasses; 2/3 with 1 bypass; more than one bypass is not allowed.

— No permissive or interlock.

Table 7.2-3 (Sheet 1 of 2)
Reactor Trip Permissives and Interlocks

Designation	Derivation	Function
P-6	Intermediate range neutron flux above setpoint	Allows manual block of source range reactor trip
$\overline{\text{P-6}}$	Intermediate range neutron flux below setpoint	Automatically resets source range reactor trip
P-9	Reactor coolant average temperature above setpoint	Prevents the block of Low-2 steam generator narrow range water level reactor trip
$\overline{\text{P-9}}$	Reactor coolant average temperature below setpoint	Allows manual block of Low-2 steam generator narrow range water level reactor trip
P-10	Power range nuclear power above setpoint	(a) Allows manual block of power range (low setpoint) reactor trip (b) Allows manual block of intermediate range reactor trip (c) Automatically blocks source range reactor trip (back-up to P-6) (d) Allows reactor trip on Low-2 coolant flow (e) Allows reactor trip on Low-2 reactor coolant pump speed (f) Allows reactor trip on High-3 pressurizer water level (g) Allows reactor trip on Low-2 pressurizer pressure

Table 7.2-3 (Sheet 2 of 2)
Reactor Trip Permissives and Interlocks

Designation	Derivation	Function
$\overline{\text{P-10}}$	Power range nuclear power below setpoint	(a) Prevents the block of power range (low setpoint) reactor trip (b) Prevents the block of intermediate range reactor trip (c) Permits manual reset of each source range channel reactor trip (d) Blocks reactor trip on Low-2 coolant flow (e) Blocks reactor trip on Low-2 reactor coolant pump speed (f) Blocks reactor trip on High-3 pressurizer water level (g) Blocks reactor trip on Low-2 pressurizer pressure
P-11	Pressurizer pressure below setpoint	Allows manual block of High-3 steam generator water level reactor trip
$\overline{\text{P-11}}$	Pressurizer pressure above setpoint	Automatically resets High-3 steam generator water level reactor trip

Table 7.2-4
System-Level Manual Inputs to the Reactor Trip Functions

Manual Control	To Divisions				Figure 7.2-1 Sheet
Manual Reactor Trip Control #1	A	B	C	D	13
Manual Reactor Trip Control #2	A	B	C	D	13
Source Range High Neutron Flux Block, Division A	A				3
Source Range High Neutron Flux Block, Division B		B			3
Source Range High Neutron Flux Block, Division C			C		3
Source Range High Neutron Flux Block, Division D				D	3
Intermediate Range High Neutron Flux Block, Division A	A				3
Intermediate Range High Neutron Flux Block, Division B		B			3
Intermediate Range High Neutron Flux Block, Division C			C		3
Intermediate Range High Neutron Flux Block, Division D				D	3
Power Range High Neutron Flux Block (Low Setpoint), Division A	A				3
Power Range High Neutron Flux Block (Low Setpoint), Division B		B			3
Power Range High Neutron Flux Block (Low Setpoint), Division C			C		3
Power Range High Neutron Flux Block (Low Setpoint), Division D				D	3
Low Steam Generator Level PRHR Actuation Block, Division A	A				7
Low Steam Generator Level PRHR Actuation Block, Division B		B			7
Low Steam Generator Level PRHR Actuation Block, Division C			C		7
Low Steam Generator Level PRHR Actuation Block, Division D				D	7
Manual Safeguards Actuation Control #1	A	B	C	D	11
Manual Safeguards Actuation Control #2	A	B	C	D	11
Manual Core Makeup Tank Injection Control #1	A	B	C	D	12
Manual Core Makeup Tank Injection Control #2	A	B	C	D	12
Manual Depressurization System Stages 1, 2 & 3 Actuation Controls #1 & 2	A	B	C	D	15
Manual Depressurization System Stages 1, 2 & 3 Actuation Controls #3 & 4	A	B	C	D	15
Steam Line/Feedwater Isolation and Safeguards Block, Division A	A				9
Steam Line/Feedwater Isolation and Safeguards Block, Division B		B			9
Steam Line/Feedwater Isolation and Safeguards Block, Division C			C		9
Steam Line/Feedwater Isolation and Safeguards Block, Division D				D	9

Note:
Controls are located in the main control room except as noted on the applicable sheet of Figure 7.2-1.

Table 7.2-5
Figure 7.2-1 Cross References

APP-PMS-J1 Drawing Number	Figure 7.2-1 Sheet Number
APP-PMS-J1-101	1
APP-PMS-J1-102	2
APP-PMS-J1-103	3
APP-PMS-J1-104	4
APP-PMS-J1-105	5
APP-PMS-J1-106	6
APP-PMS-J1-107	7
APP-PMS-J1-108	8
APP-PMS-J1-109	9
APP-PMS-J1-110	10
APP-PMS-J1-111	11
APP-PMS-J1-112	12
APP-PMS-J1-113	13
APP-PMS-J1-114	14
APP-PMS-J1-115	15
APP-PMS-J1-116	16
Not Used	17
APP-PMS-J1-119	18
APP-PMS-J1-120	19
APP-DAS-J1-102	20
APP-DAS-J1-103	21

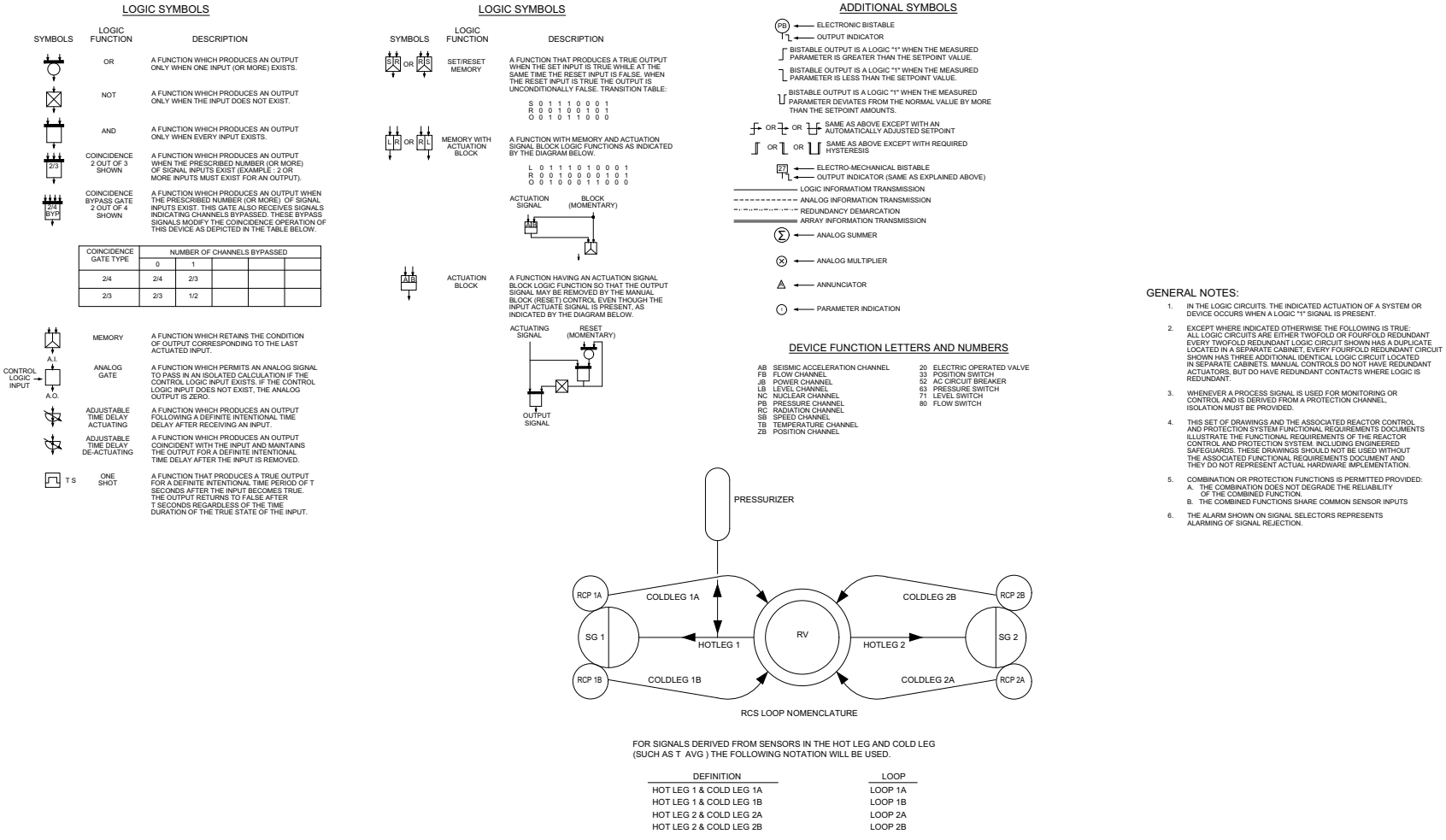
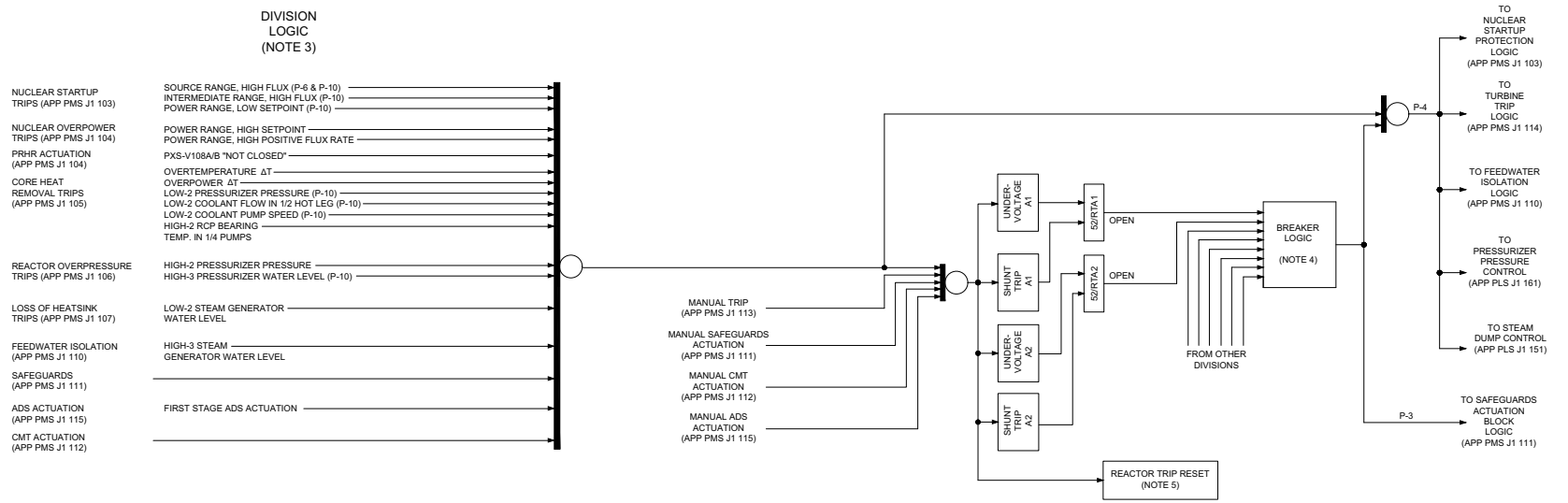
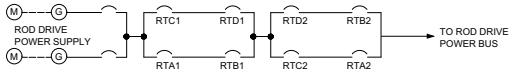


Figure 7.2-1 (Sheet 1 of 21)
Functional Diagram
Index and Symbols



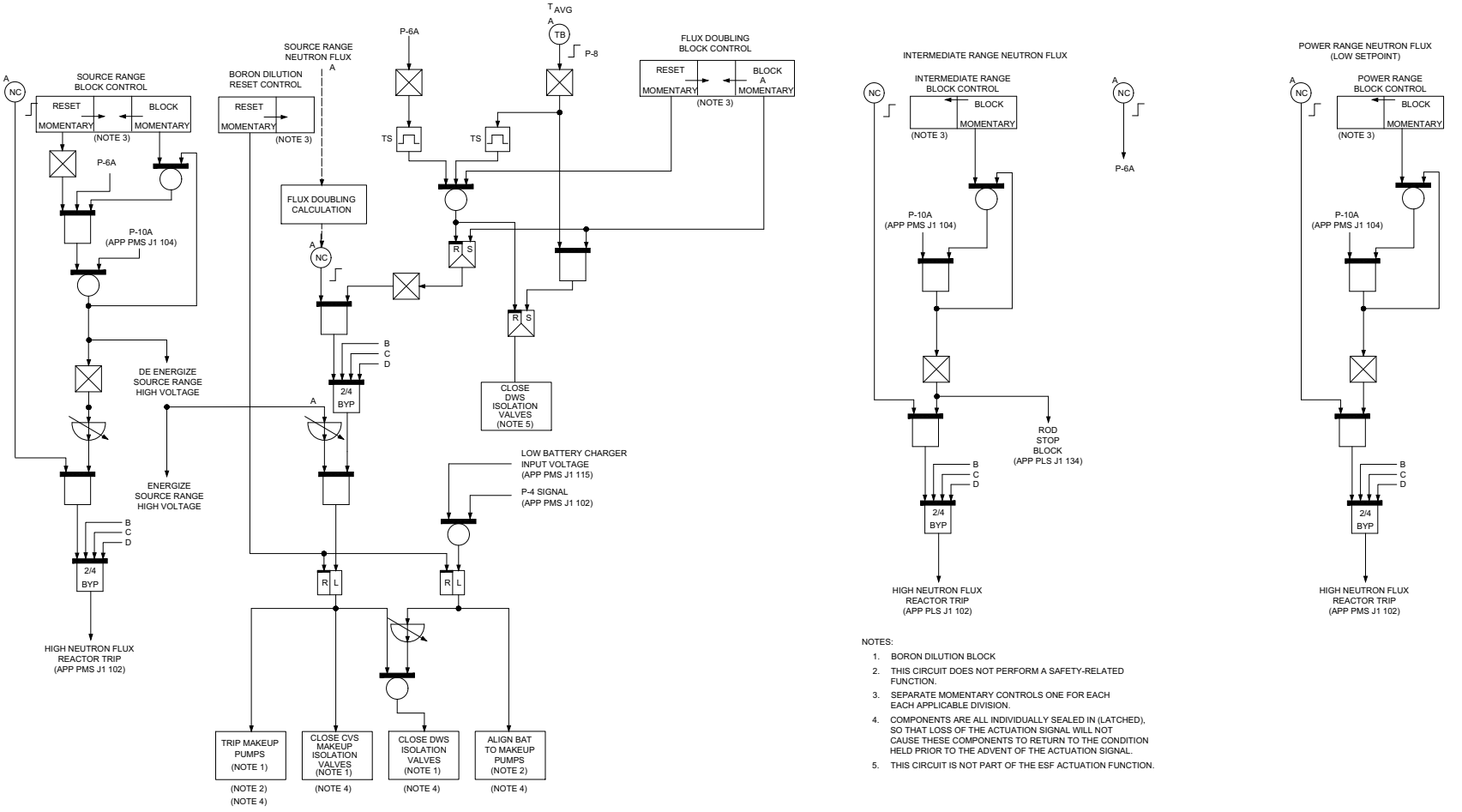
REACTOR TRIP BREAKER ARRANGEMENT
ONE LINE DIAGRAM
(NOTE 1)



NOTES:

1. TRIPPING ANY TWO OR MORE BREAKER SETS, BOTH 1 AND 2 BREAKERS DE-ENERGIZE THE ROD DRIVES. THE FULL LENGTH CONTROL RODS AND SHUTDOWN RODS ARE THEREBY RELEASED FOR GRAVITY INSERTION INTO THE REACTOR CORE.
2. DELETED.
3. THIS CIRCUITRY IS FOURFOLD REDUNDANT. ONLY ONE DIVISION IS SHOWN WHICH IS TYPICAL OF THE OTHER DIVISIONS.
4. REACTOR TRIP LOGIC PRODUCES A TRUE (LOGIC "1") OUTPUT IF THE FOLLOWING BREAKER OPEN STATUS CONDITIONS ARE MET:
   [(A1+B1) . (C1+D1)] + [(A2+C2) . (B2+D2)]
5. PERFORMED IN PLS.

Figure 7.2-1 (Sheet 2 of 21)
Functional Diagram
Reactor Trip Functions



NOTES:

1. BORON DILUTION BLOCK
2. THIS CIRCUIT DOES NOT PERFORM A SAFETY-RELATED FUNCTION.
3. SEPARATE MOMENTARY CONTROLS ONE FOR EACH EACH APPLICABLE DIVISION.
4. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
5. THIS CIRCUIT IS NOT PART OF THE ESF ACTUATION FUNCTION.

Figure 7.2-1 (Sheet 3 of 21)
Functional Diagram
Nuclear Startup Protection

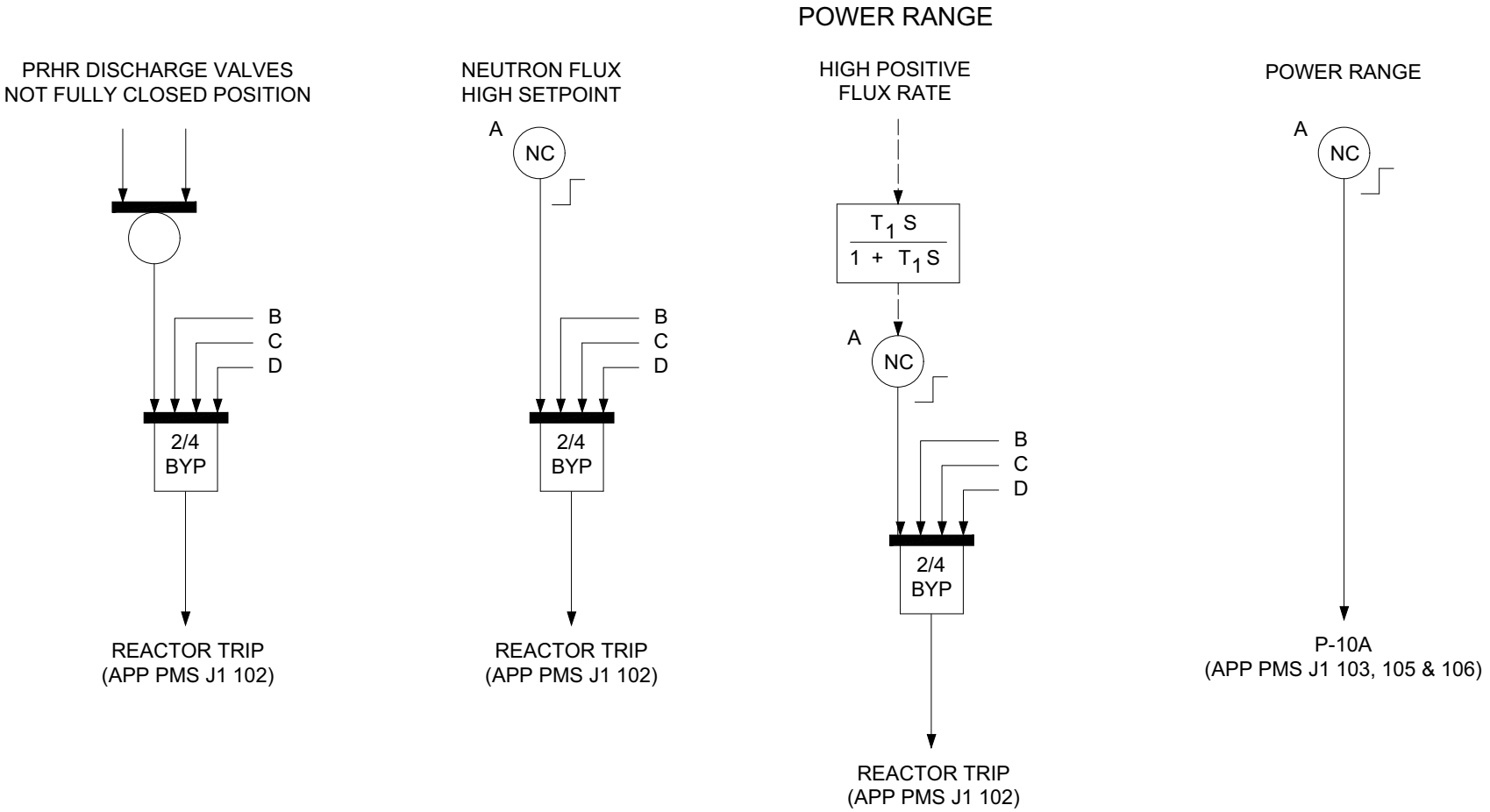


Figure 7.2-1 (Sheet 4 of 21)
Functional Diagram
Nuclear Overpower Protection

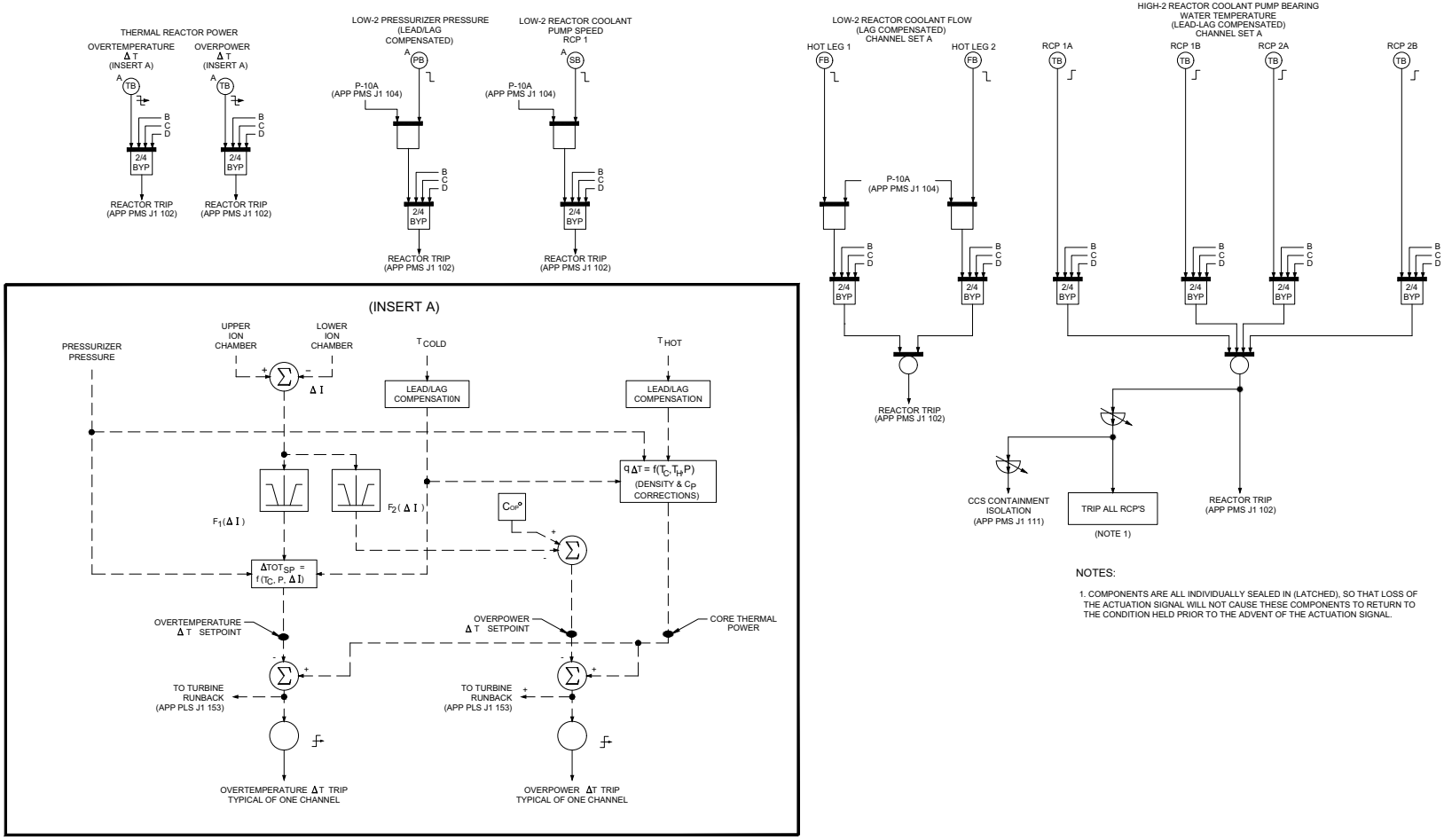


Figure 7.2-1 (Sheet 5 of 21)
Functional Diagram
Core Heat Removal Protection and Reactor Coolant Pump Trip

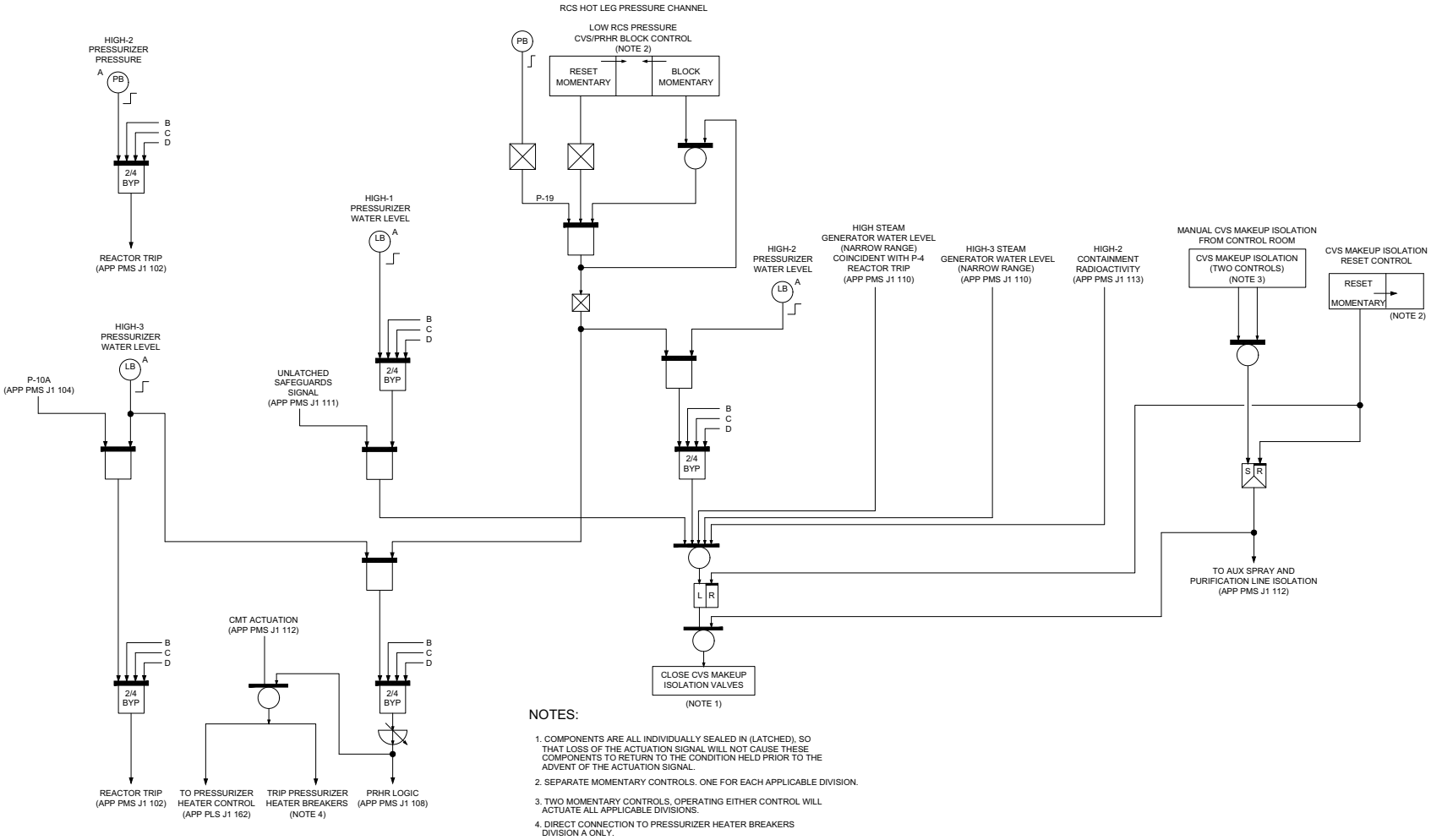


Figure 7.2-1 (Sheet 6 of 21)
Functional Diagram
Primary Overpressure & Loss of Heat Sink Protection

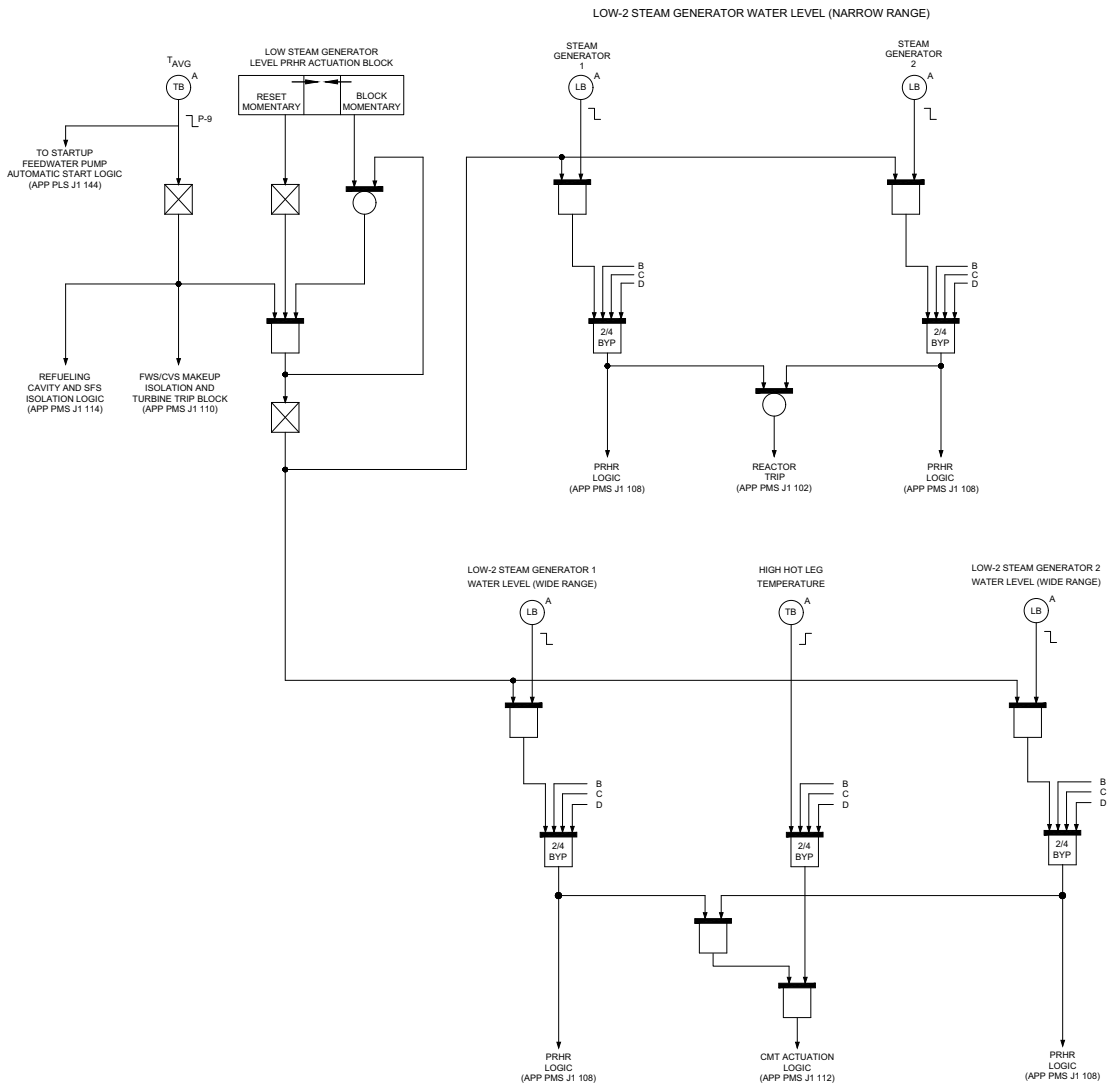


Figure 7.2-1 (Sheet 7 of 21)
Functional Diagram
Loss of Heat Sink Protection

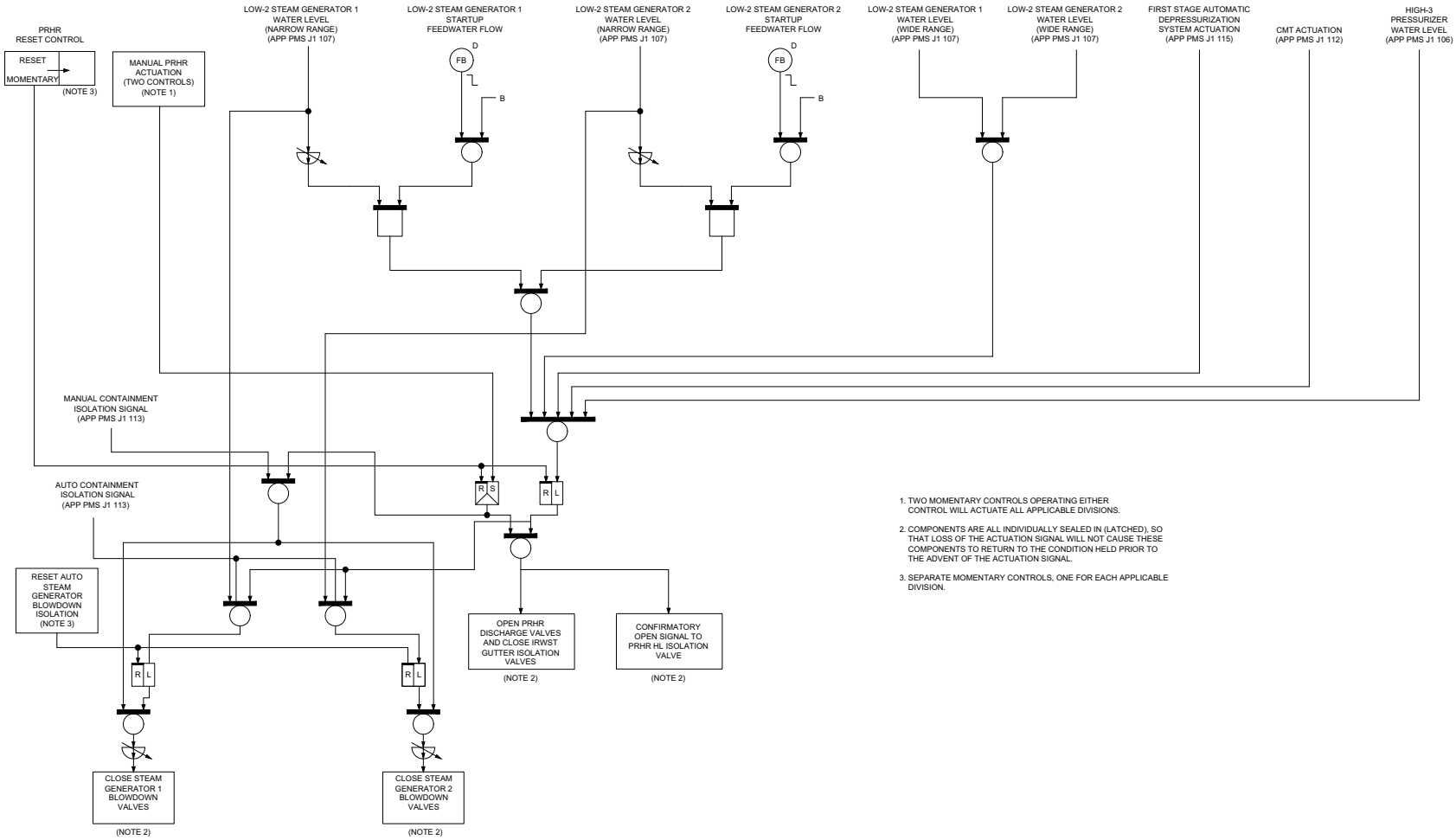


Figure 7.2-1 (Sheet 8 of 21)
Functional Diagram
Loss of Heat Sink Protection

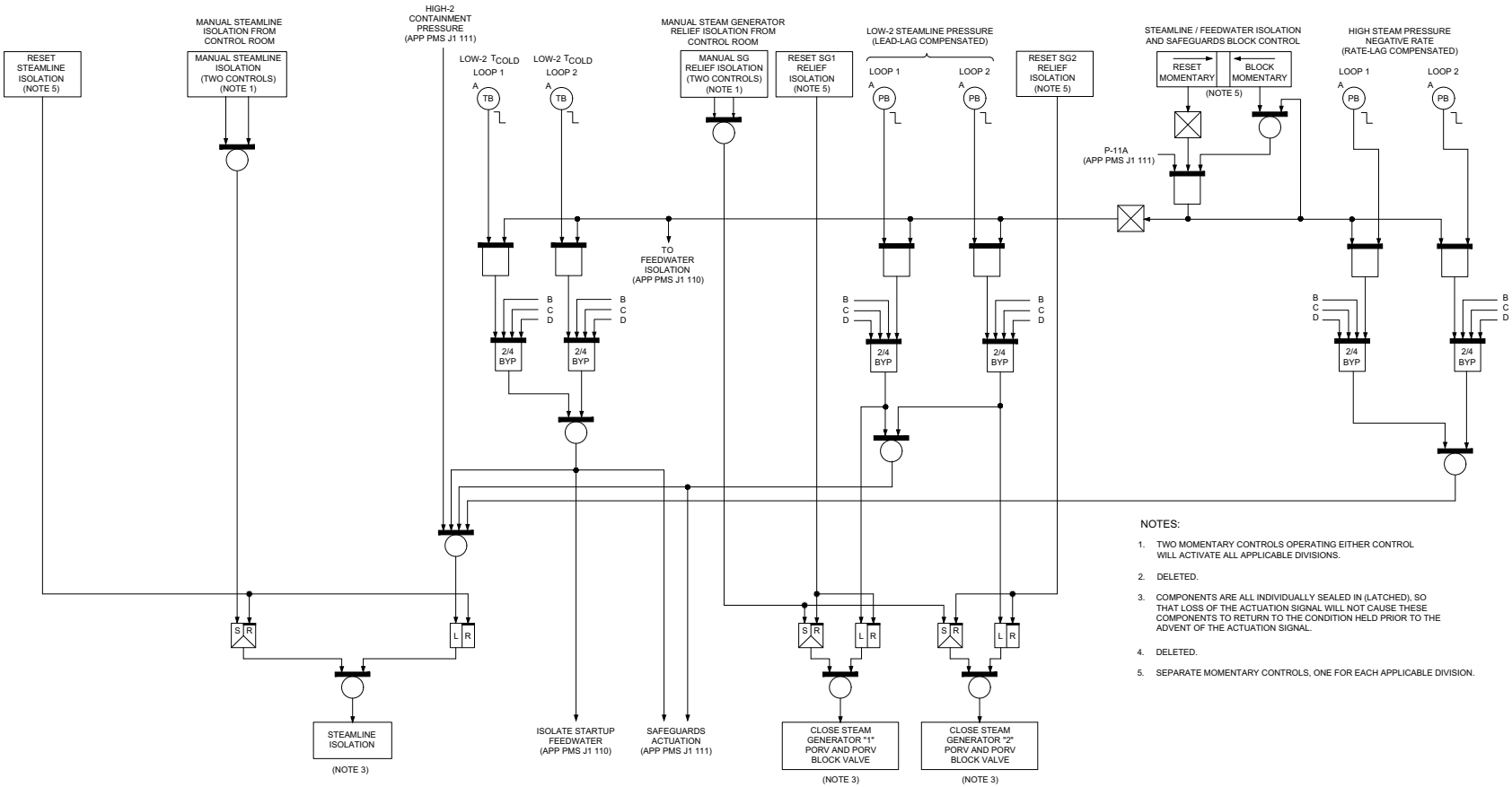


Figure 7.2-1 (Sheet 9 of 21)
Functional Diagram
Steam Line Isolation

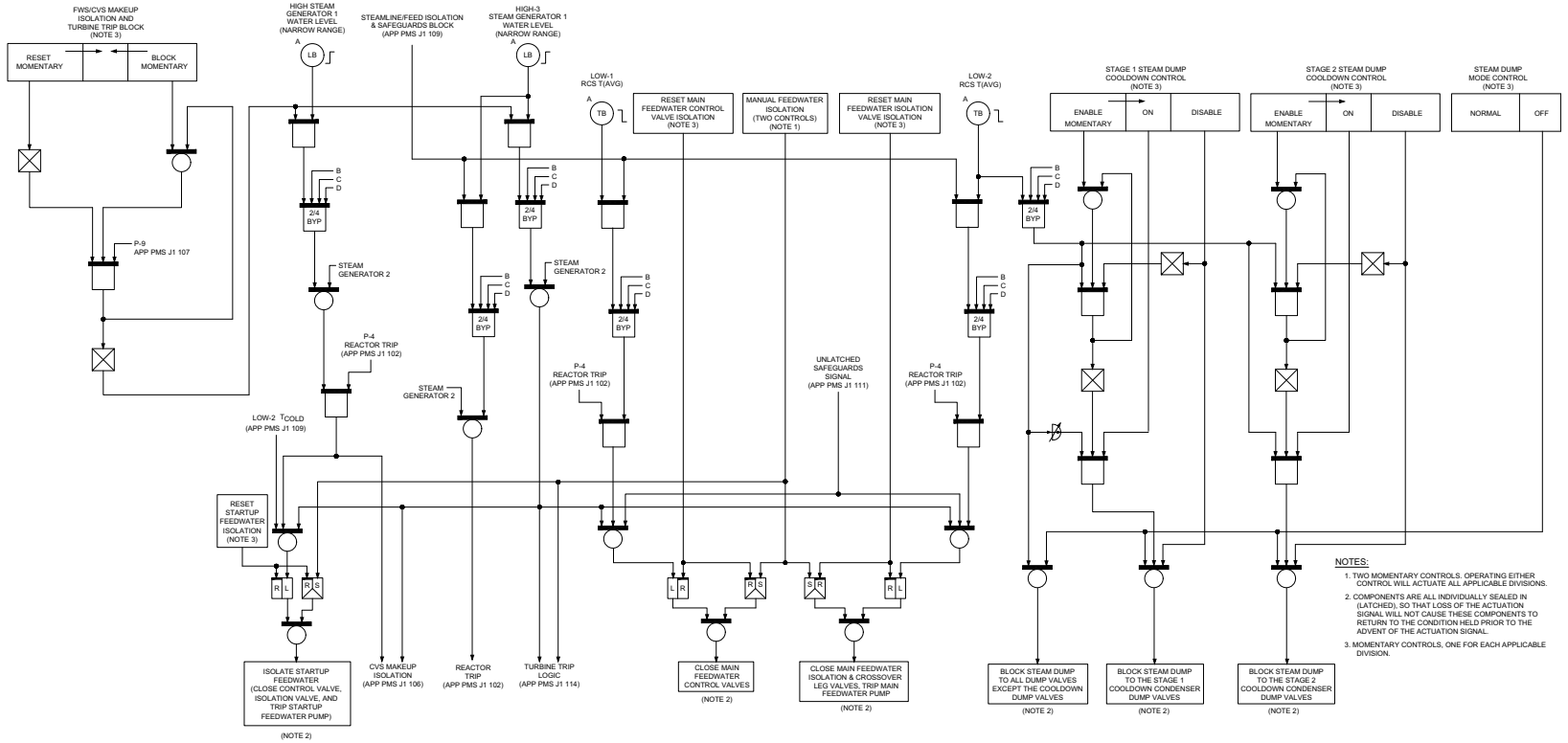
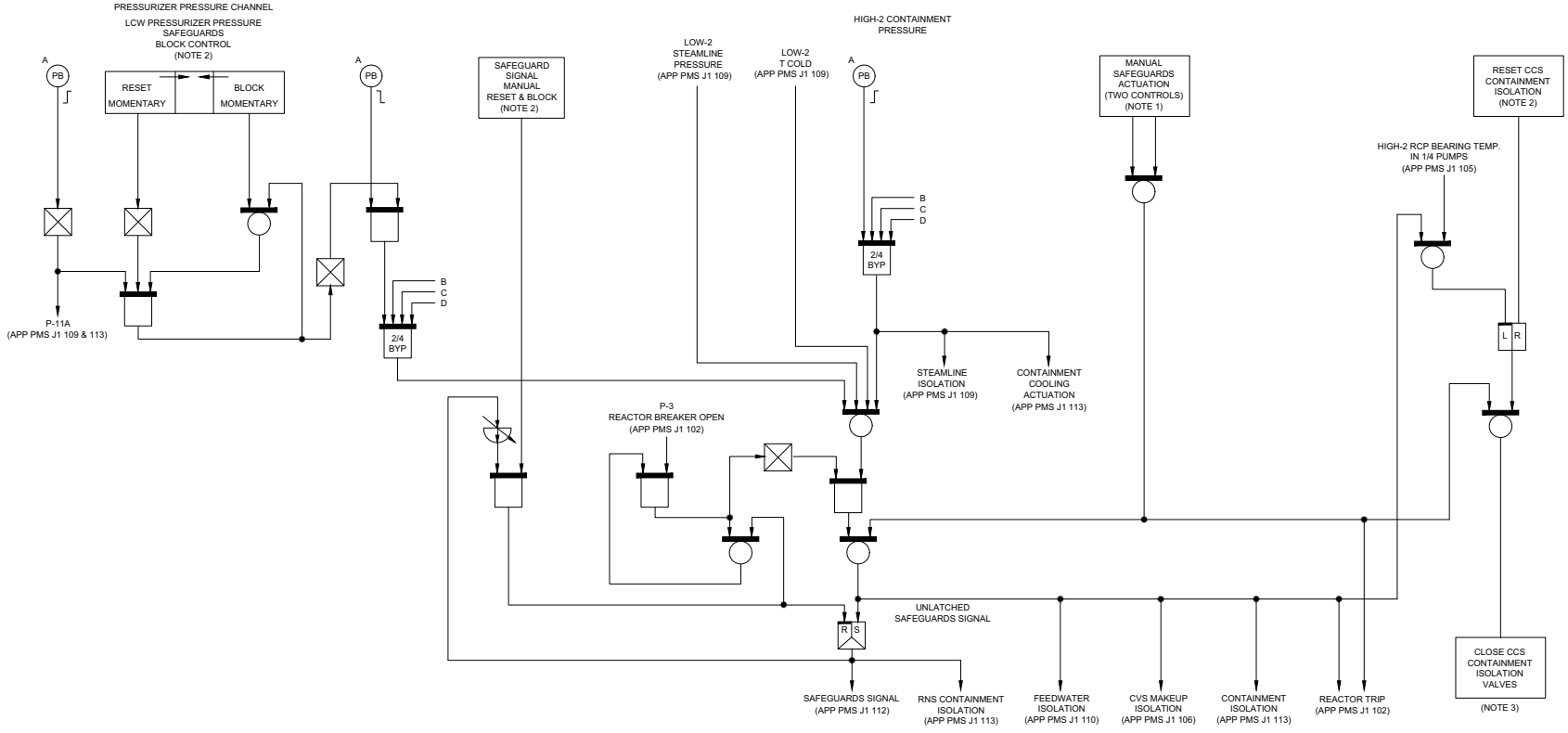


Figure 7.2-1 (Sheet 10 of 21)
Functional Diagram
Feedwater Isolation



NOTES:

1. TWO MOMENTARY CONTROLS. OPERATING EITHER CONTROL WILL ACTUATE ALL APPLICABLE DIVISIONS.
2. SEPARATE MOMENTARY CONTROLS. ONE FOR EACH APPLICABLE DIVISION.
3. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED) SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.

Figure 7.2-1 (Sheet 11 of 21)
Functional Diagram
Safeguards Actuation

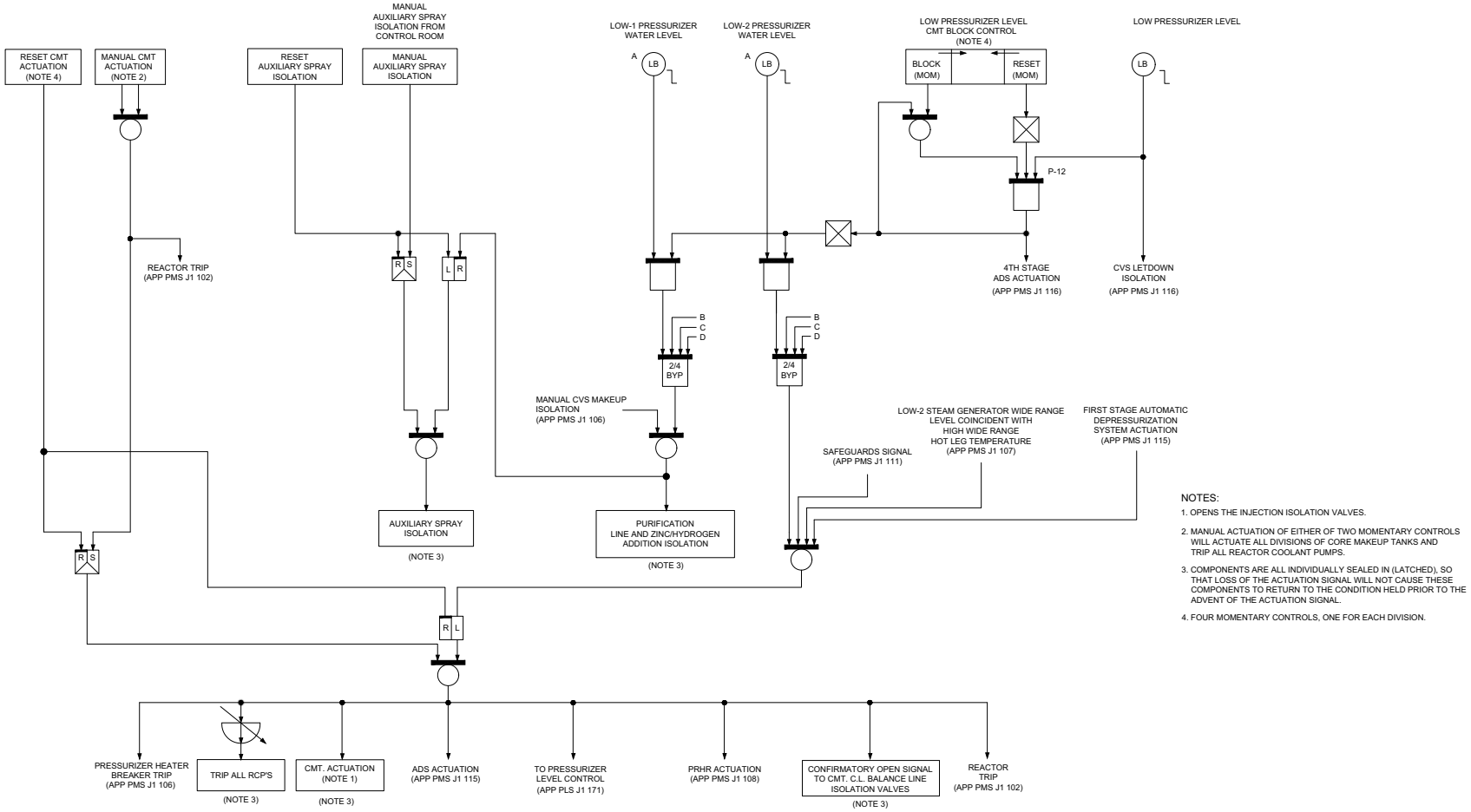


Figure 7.2-1 (Sheet 12 of 21)
Functional Diagram
Core Makeup Tank Actuation

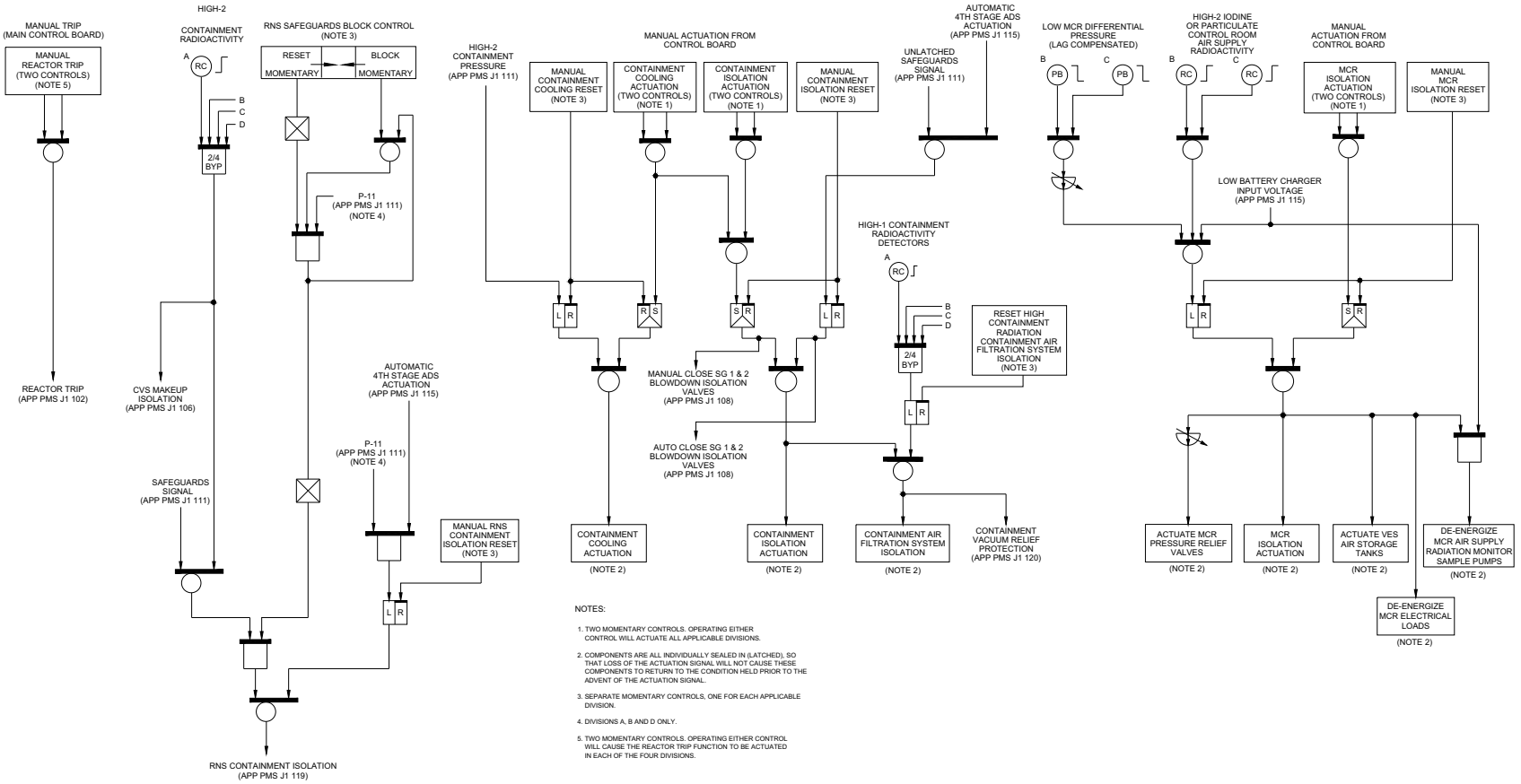
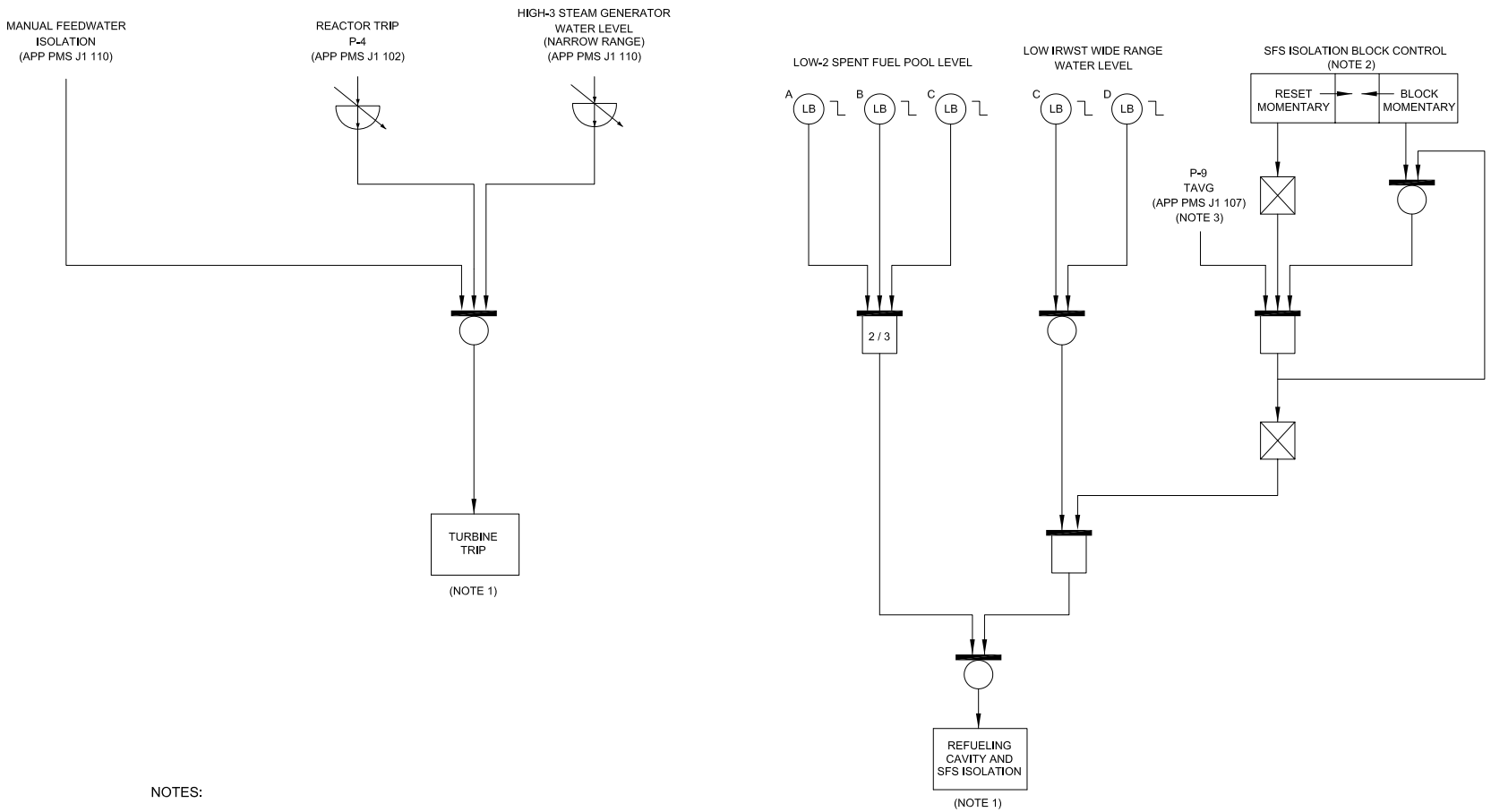


Figure 7.2-1 (Sheet 13 of 21)
Functional Diagram
Containment and Other Protection



NOTES:

1. COMPONENTS ARE INDIVIDUALLY SEALED IN (LATCHED) SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
2. SEPARATE MOMENTARY CONTROLS, ONE FOR EACH APPLICABLE DIVISION.
3. DIVISIONS A AND B ONLY.

Figure 7.2-1 (Sheet 14 of 21)
Functional Diagram
Turbine Trip and Refueling Cavity and SFS Isolation

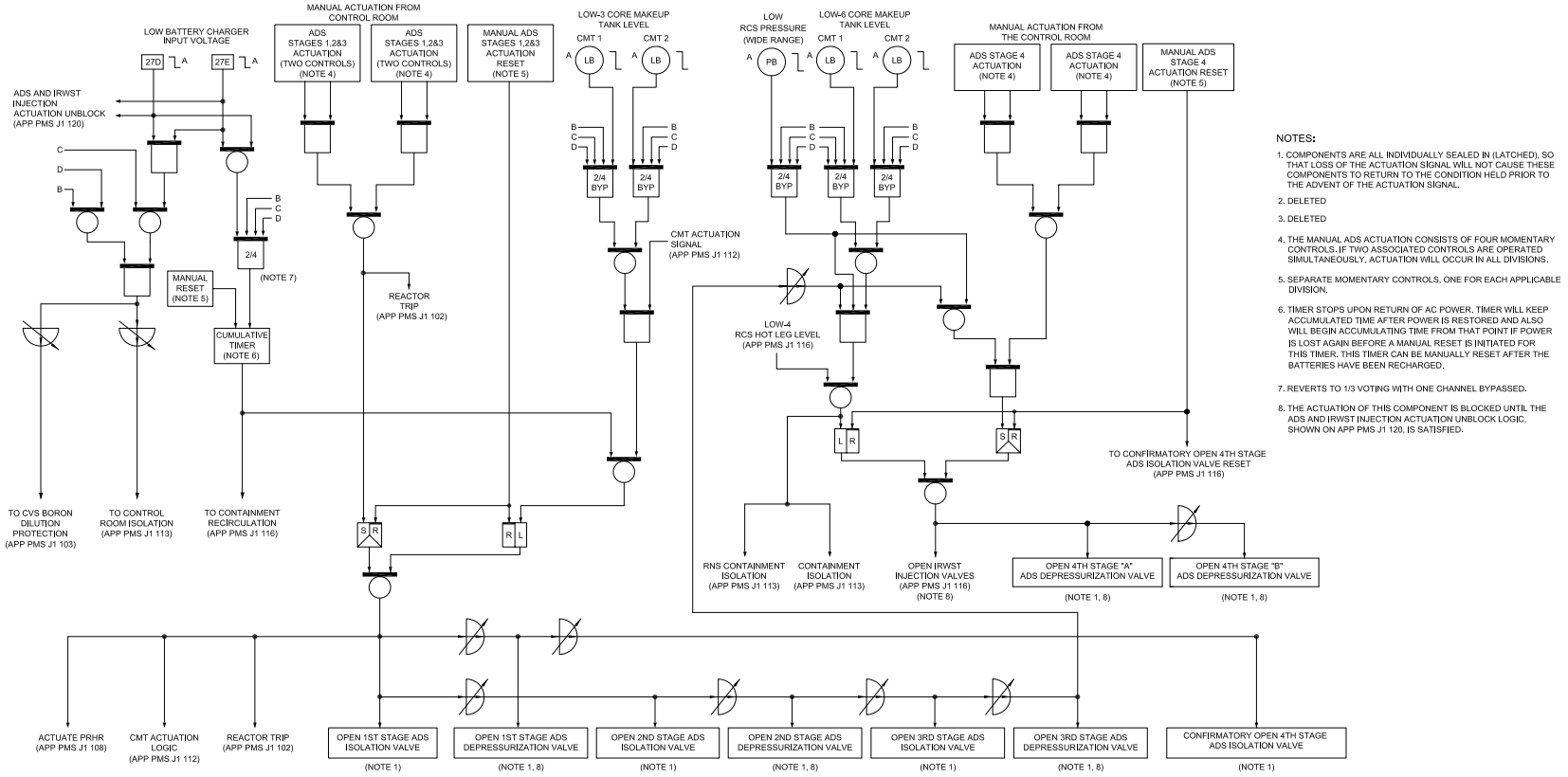
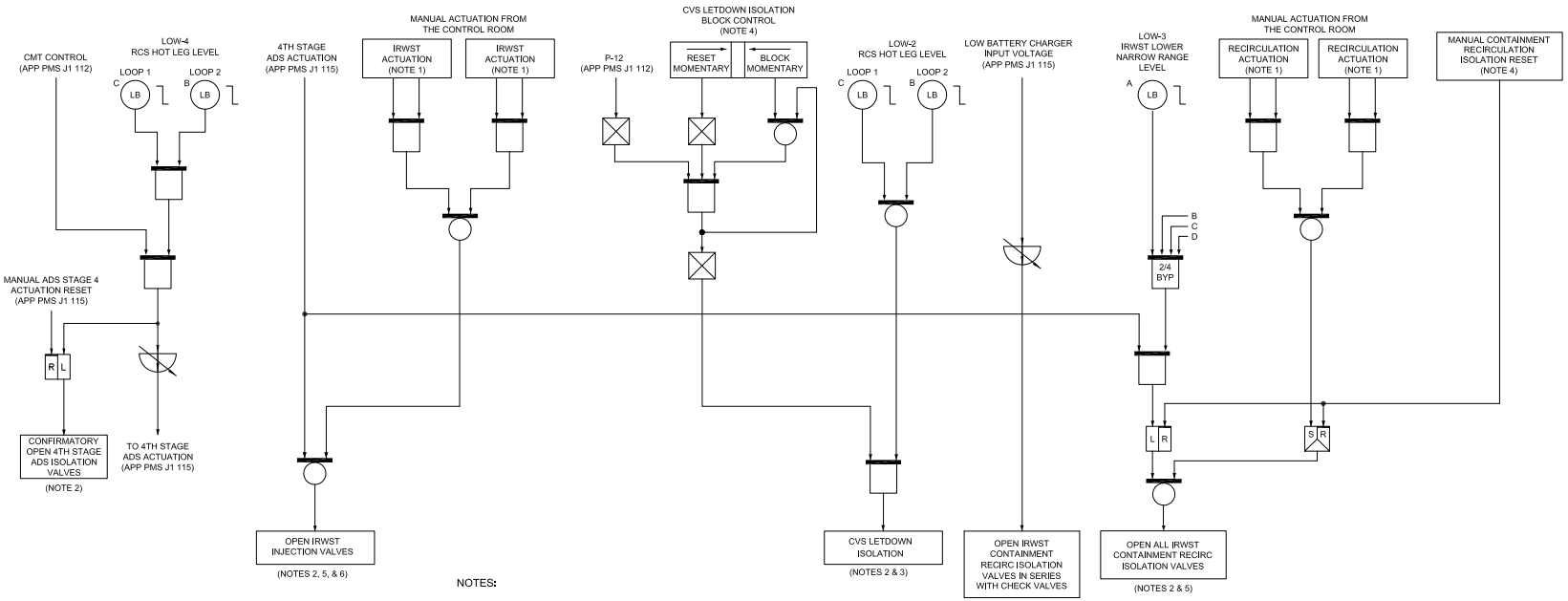


Figure 7.2-1 (Sheet 15 of 21)
Functional Diagram
Automatic RCS Depressurization Valve Sequencing



NOTES:

1. THE MANUAL ACTUATION CONSISTS OF FOUR MOMENTARY CONTROLS. IF TWO ASSOCIATED CONTROLS ARE OPERATED SIMULTANEOUSLY, ACTUATION WILL OCCUR IN ALL APPLICABLE DIVISIONS.

2. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.

3. CVS LETDOWN ISOLATION ALSO OCCURS DURING CONTAINMENT ISOLATION. SEE APP PMS J1 113.

4. SEPARATE MOMENTARY CONTROLS, ONE FOR EACH APPLICABLE DIVISION.

5. FOR REDUNDANT COMPONENTS IN A PARALLEL CONFIGURATION, BOTH COMPONENTS USE DIFFERENT TIME DELAYS TO HELP PREVENT ACTUATING THEM SIMULTANEOUSLY.

6. THE ACTUATION OF THIS COMPONENT IS BLOCKED UNTIL THE ADS AND IRWST INJECTION ACTUATION LOGIC, SHOWN ON APP-PMS-J1-120, IS SATISFIED.

Figure 7.2-1 (Sheet 16 of 21)
Functional Diagram
In-containment Refueling Water Storage Tank Actuations

Figure 7.2-1 (Sheet 17 of 21) Not Used

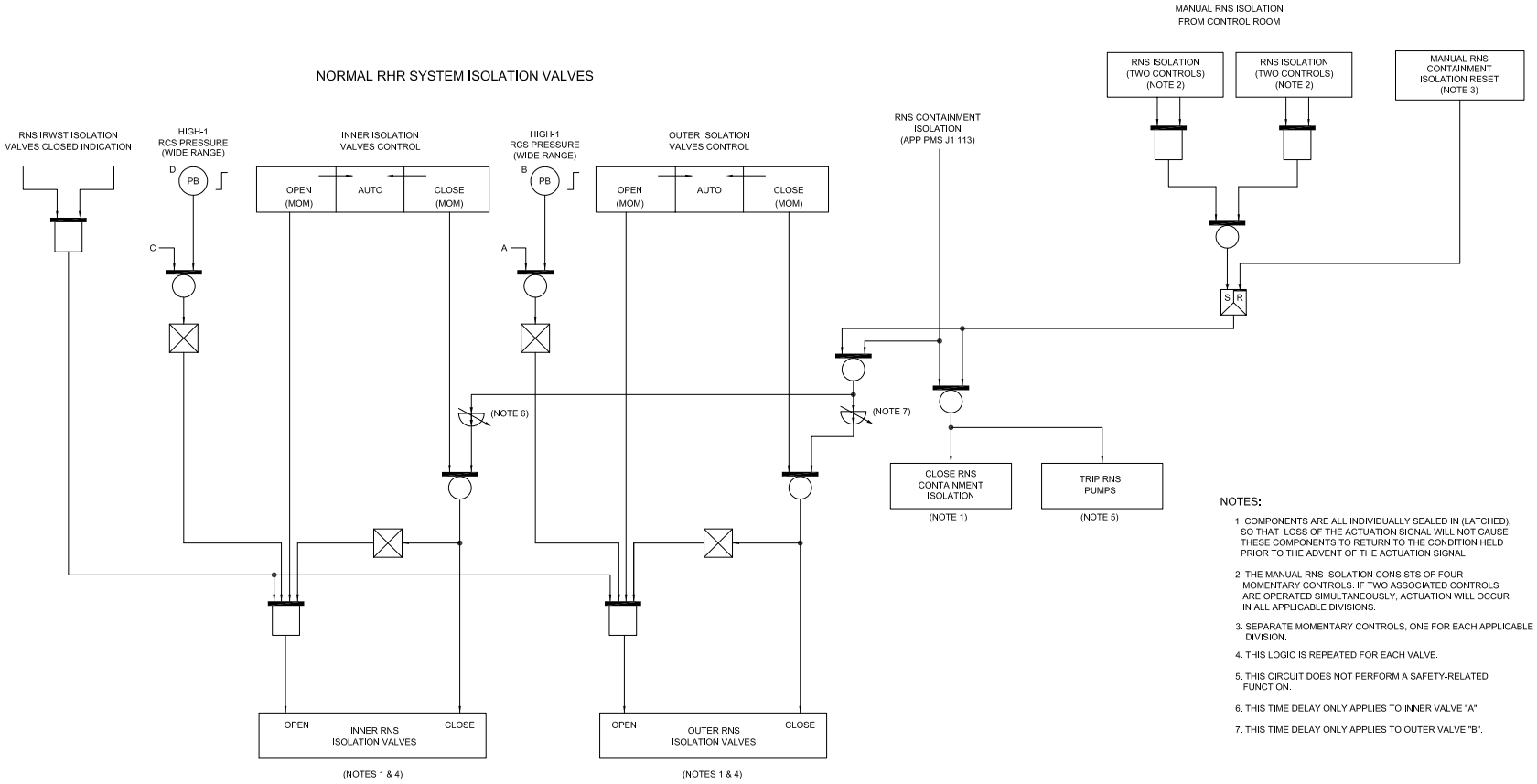
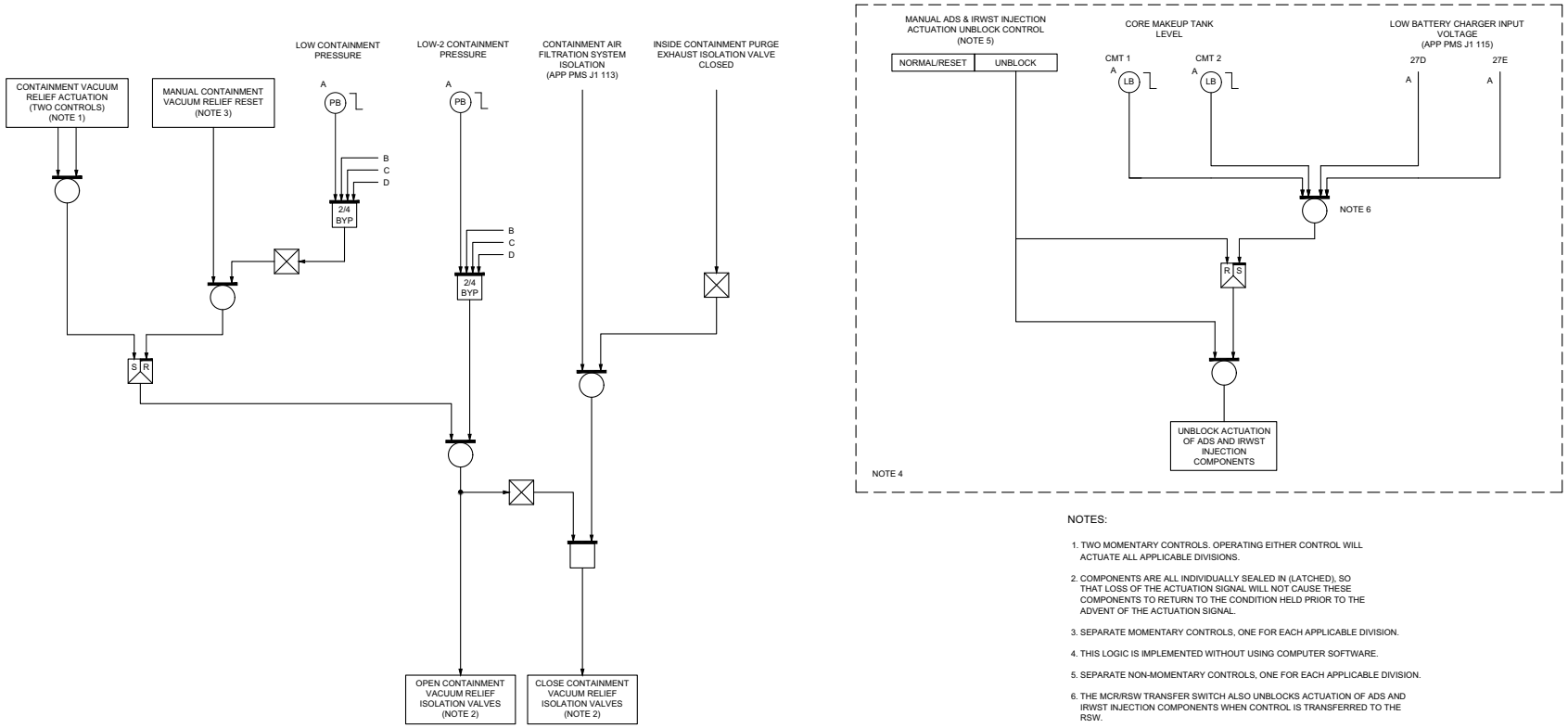


Figure 7.2-1 (Sheet 18 of 21)
Functional Diagram
Normal Residual Heat Removal System Isolation Valve Interlocks



NOTES:

1. TWO MOMENTARY CONTROLS. OPERATING EITHER CONTROL WILL ACTUATE ALL APPLICABLE DIVISIONS.
2. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
3. SEPARATE MOMENTARY CONTROLS, ONE FOR EACH APPLICABLE DIVISION.
4. THIS LOGIC IS IMPLEMENTED WITHOUT USING COMPUTER SOFTWARE.
5. SEPARATE NON-MOMENTARY CONTROLS, ONE FOR EACH APPLICABLE DIVISION.
6. THE MCR/RSW TRANSFER SWITCH ALSO UNBLOCKS ACTUATION OF ADS AND IRWST INJECTION COMPONENTS WHEN CONTROL IS TRANSFERRED TO THE RSW.

Figure 7.2-1 (Sheet 19 of 21)
Functional Diagram
Containment Vacuum Relief Protection

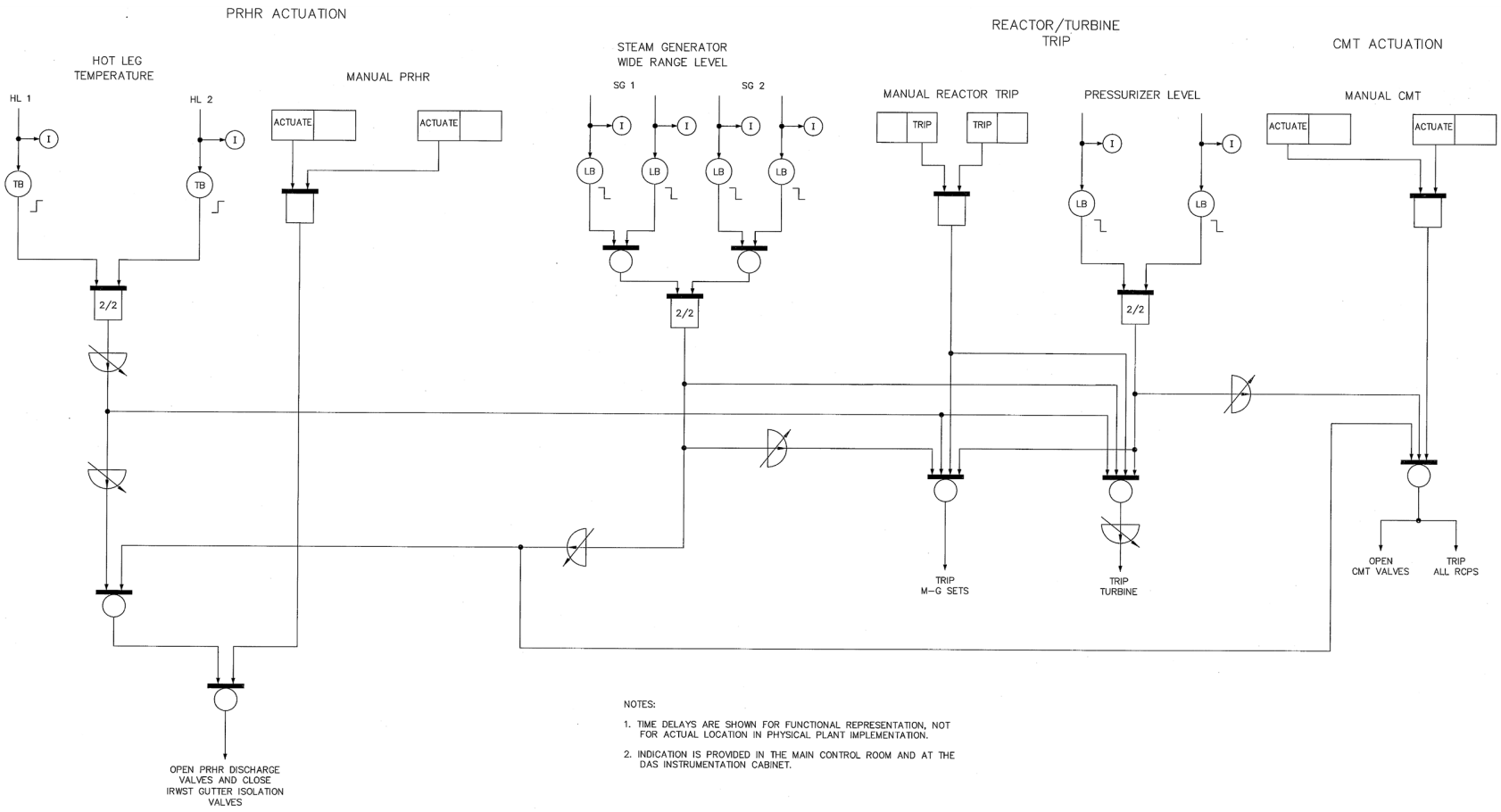


Figure 7.2-1 (Sheet 20 of 21)
Functional Diagram
Diverse Actuation System Logic Automatic Actuations

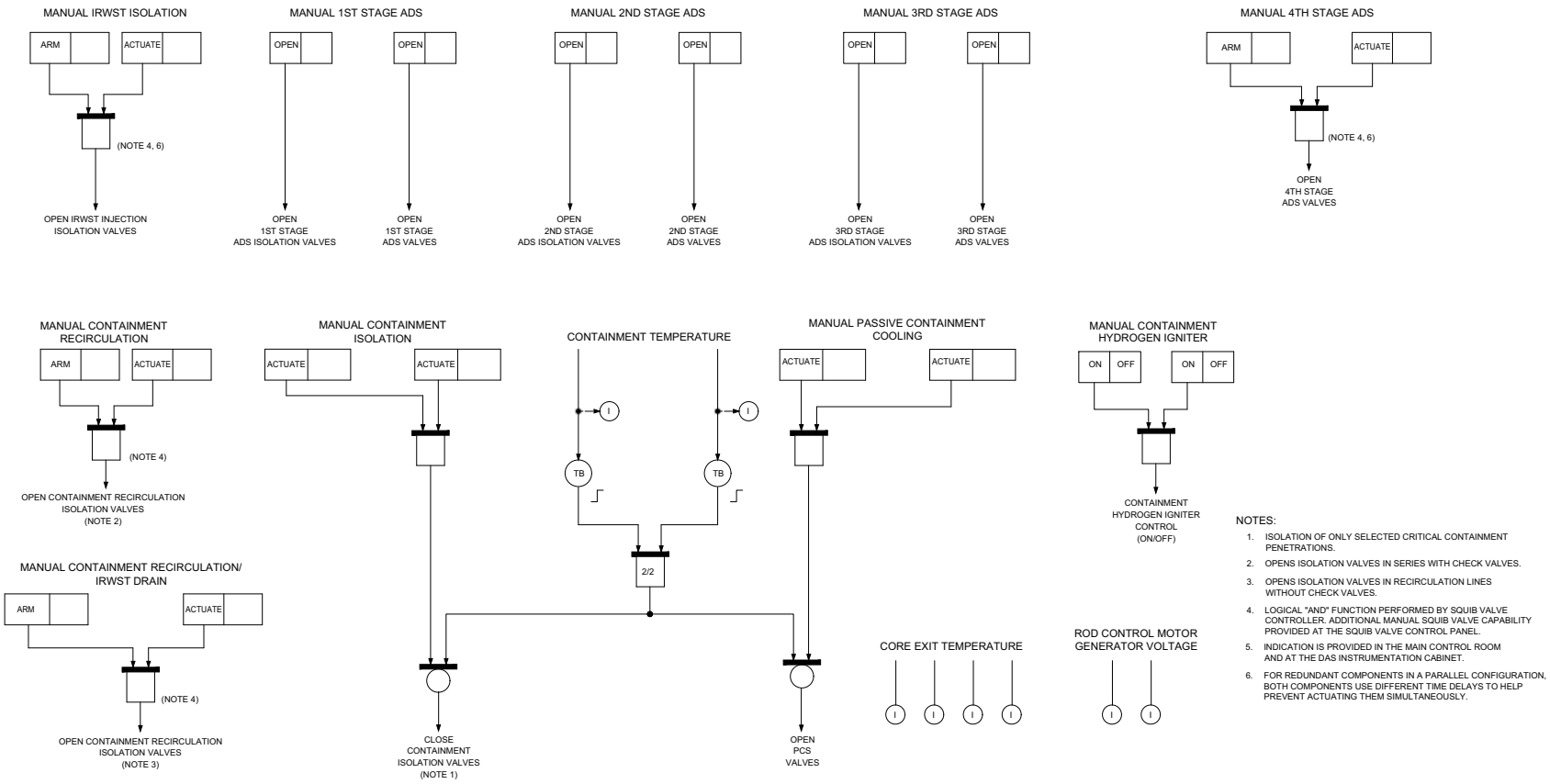


Figure 7.2-1 (Sheet 21 of 21)
Functional Diagram
Diverse Actuation System Logic, Manual Actuations

7.3 Engineered Safety Features

AP1000 provides instrumentation and controls to sense accident situations and initiate engineered safety features (ESF). The occurrence of a limiting fault, such as a loss of coolant accident or a secondary system break, requires a reactor trip plus actuation of one or more of the engineered safety features. This combination of events prevents or mitigates damage to the core and reactor coolant system components, and provides containment integrity.

7.3.1 Description

The protection and safety monitoring system is actuated when safety system setpoints are reached for selected plant parameters. The selected combination of process parameter setpoint violations is indicative of primary or secondary system boundary ruptures. Once the required logic combination is generated, the protection and safety monitoring system equipment sends the signals to actuate appropriate engineered safety features components.

The following paragraphs summarize the major functional elements of the protection and safety monitoring system that are involved in generating an actuation signal to an engineered safety features component.

Four sensors normally monitor each variable used for an engineered safety feature actuation. (These sensors may monitor the same variable for a reactor trip function.) Analog measurements are converted to digital form by analog-to-digital converters within each of the four divisions of the protection and safety monitoring system. Following required signal conditioning or processing, the measurements are compared against the setpoints for the engineered safety feature to be generated. Steam generator level and pressurizer level are compensated per Subsection 7.3.1.5.2. When the measurement exceeds the setpoint, the output of the comparison results in a channel partial trip condition. The partial trip information is transmitted to the ESF coincidence logic to form the signals that result in an engineered safety features actuation. The voting logic is performed twice within each division. Each voting logic element generates an actuation signal if the required coincidence of partial trips exists at its inputs.

The signals are combined within each division of ESF coincidence logic to generate a system-level signal. System-level manual actions are also processed by the logic in each division.

The system-level signals are then broken down to the individual actuation signals to actuate each component associated with a system-level engineered safety feature. For example, a single safeguards actuation signal must trip the reactor and the reactor coolant pumps, align core makeup tank and in-containment refueling water storage tank valves, and initiate containment isolation. The interposing logic accomplishes this function and also performs necessary interlocking so that components are properly aligned for safety. Component-level manual actions are also processed by this interposing logic. The power interface transforms the low level signals to voltages and currents commensurate with the actuation devices they operate. The actuation devices, in turn, control motive power to the final engineered safety feature component.

Subsection 7.3.1.2 provides a functional description of the signals and initiating logic for each of the engineered safety features. Figure 7.2-1 presents the functional diagrams for engineered safety features actuation.

Table 7.3-1 summarizes the signals and initiating logic for each of the engineered safety features initiated by the protection and safety monitoring system. Most of the functions provide protection against design basis events which are analyzed in Chapter 6 and Chapter 15. However, not all the functions listed in Table 7.3-1 are necessary to meet the assumptions used in performing the safety analysis. For example, the design provides features which provide automatic actuations which are

not required for performing the safety analysis. In addition, some functions are provided to support assumptions used in the probabilistic risk assessment, but are not used to mitigate a design basis accident. Only those functions which meet the 10 CFR 50.36(c)(2)(ii) criteria are included in the Technical Specifications. This accounts for any difference between functions listed in Table 7.3-1 and functions which are included in the Technical Specifications.

7.3.1.1 Safeguards Actuation (S) Signal

A safeguards actuation (S) signal is used in the initiation logic of many of the engineered safety features discussed in Subsection 7.3.1.2. In addition, as described in Section 7.2, the safeguards actuation signal also initiates a reactor trip. The variables that are monitored and used to generate a safeguards actuation signal are typically those that provide indication of a significant plant transient that requires a response by several engineered safety features.

The safeguards actuation signal is generated from any of the following initiating conditions:

1. Low-3 pressurizer pressure
2. Low-2 lead-lag compensated steam line pressure
3. Low-2 cold leg temperature
4. High-2 containment pressure
5. Manual initiation

Condition 1 results from the coincidence of pressurizer pressure below the Low-3 setpoint in any two of the four divisions.

Condition 2 results from the coincidence of two of the four divisions of compensated steam line pressure below the Low-2 setpoint in either of the two steam lines. The steam line pressure signal is lead-lag compensated to improve system response.

Condition 3 results from the coincidence of two of the four divisions of reactor coolant system cold leg temperature below the Low-2 setpoint in any loop.

Condition 4 results from the coincidence of two of the four divisions of containment pressure above the High-2 setpoint.

Condition 5 consists of two momentary controls. Manual actuation of either of the two controls will trip the reactor and generate a safeguards actuation signal.

To permit startup and cooldown, the safeguards actuation signals generated from Low-3 pressurizer pressure, Low-2 steam line pressure, or Low-2 reactor coolant inlet temperature can be manually blocked when pressurizer pressure is below the P-11 setpoint. The signal is automatically unblocked when the pressurizer pressure is above the P-11 setpoint.

Separate momentary controls are provided, each of which will manually reset the safeguards actuation signal in a single division. Manual reset of a safeguards actuation signal in coincidence with reactor trip breaker open (P-3) blocks the safeguards actuation signal. Absence of P-3 automatically resets the blocking function. The safeguards actuation signal is manually reset based on a preset delay following initiation. Resetting the signal does not reposition any safeguards actuated equipment, since individual components are required to latch in and seal on the safeguards actuation signal.

The logic relating to the development of the safeguards actuation signal is illustrated in Figure 7.2-1, sheets 9 and 11.

7.3.1.2 Engineered Safety Feature Descriptions

The following subsections provide a functional description of the signals and initiating logic for each engineered safety feature. Table 7.3-1 lists the signals and summarizes the coincidence logic used to generate the safeguards actuation signal or initiate each engineered safety feature. Table 7.3-2 describes the permissives and interlocks relating to the engineered safety features. Table 7.3-3 lists the system-level manual input to the engineered safety features.

7.3.1.2.1 Containment Isolation

A signal to actuate containment isolation is generated from any of the following conditions:

1. Automatic or manual safeguards actuation signal (Subsection 7.3.1.1)
2. Automatic fourth stage ADS actuation (Subsection 7.3.1.2.4)
3. Manual initiation
4. Manual actuation of passive containment cooling (Subsection 7.3.1.2.12)

Conditions 1, 2, and 4 are discussed in other subsections as noted.

Condition 3 consists of the manual actuation of either of two momentary controls in the main control room. Either control actuates all divisions and closes the nonessential fluid system paths from the containment.

Manual reset is provided to block the automatic actuation signal for containment isolation. Separate momentary controls are provided for resetting each division.

No other interlocks or permissive signals apply directly to the containment isolation function. Automatic actuation originates from a safeguards actuation (S) signal that does contain interlock and permissive inputs.

The functional logic that actuates containment isolation is illustrated in Figure 7.2-1, sheets 11, 13, and 15.

7.3.1.2.2 In-Containment Refueling Water Storage Tank Injection

Signals to align the in-containment refueling water storage tank for injection are generated from the following conditions:

1. Actuation of the fourth stage of the automatic depressurization system (Subsection 7.3.1.2.4)

2. Coincidence loop 1 and loop 2 hot leg levels below Low-4 setpoint for a duration exceeding an adjustable time delay

3. Manual initiation

Each of the above conditions opens the in-containment refueling water storage tank injection valves, thereby providing a flow path to the reactor coolant system. As described in Subsection 7.3.1.2.4.1, a blocking device prevents ADS spurious actuation as well as in-containment refueling water storage tank injection.

In addition to initiating in-containment refueling water storage tank injection, condition 2 also initiates the opening sequence of the fourth stage of the automatic depressurization system. This is discussed in Subsection 7.3.1.2.4.

Condition 3 consists of two sets of two momentary controls. Manual actuation of both controls of either of the two control sets generates signals that open the in-containment refueling water storage tank injection valves. A two-control simultaneous actuation prevents inadvertent actuation.

In-containment refueling water storage tank injection on Low-4 hot leg level is automatically blocked when the pressurizer water level is above the P-12 setpoint. This reduces the probability of a spurious injection. This block is removed when the core makeup tank actuation on Low-2 pressurizer level function is manually blocked to allow mid-loop operation. As described in Subsection 7.3.1.2.3, this core makeup tank actuation function can be manually blocked when the pressurizer water level is below the P-12 setpoint.

The functional logic relating to in-containment refueling water storage tank injection is illustrated in Figure 7.2-1, sheets 12 and 16.

7.3.1.2.3 Core Makeup Tank Injection

Signals to align the core makeup tanks for injection are generated from the following conditions:

1. Automatic or manual safeguards actuation (Subsection 7.3.1.1)

2. Automatic or manual actuation of the first stage of the automatic depressurization system (Subsection 7.3.1.2.4)

3. Low-2 pressurizer level

4. Low-2 steam generator wide range water level coincident with High hot leg temperature

5. Manual initiation

Conditions 1 through 5 initiate a block of the pressurizer heaters; trip the reactor and reactor coolant pumps; initiate alignment of the core makeup tank isolation valves for passive injection to the reactor coolant system; and provide a confirmatory open signal to the cold leg balance line isolation valves. The balance line isolation valves are normally open but can be closed by the operator. The confirmatory open signal automatically overrides any cases when the cold leg balance line isolation valves are closed for short periods of time. The motive force for core makeup tank injection is provided by density differences between the fluids in the cold leg balance line and the core makeup tank water.

Condition 3 results from the coincidence of pressurizer level below the Low-2 setpoint in any two of the four divisions. This function can be manually blocked when the pressurizer water level is below the P-12 setpoint. This function is automatically unblocked when the pressurizer water level is above the P-12 setpoint.

Condition 4 is derived from a coincidence of:

- Both steam generator 1 and steam generator 2 wide range level below the Low-2 setpoint (derived from two of the four wide range water level measurement divisions for each steam generator), and

- Two of the four divisions of hot leg temperature above the High (T_{hot}) setpoint

Low-2 steam generator wide range water level can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint, and is automatically unblocked when the reactor coolant average temperature is above the P-9 permissive.

Condition 5 consists of two momentary controls. Manual actuation of either of the two controls will align the core makeup tanks for injection.

The functional logic relating to core makeup tank injection is illustrated in Figure 7.2-1, sheets 7, 12 and 15. The development of the P-9 permissive is shown on Figure 7.2-1, sheet 7.

7.3.1.2.4 Automatic Depressurization System Actuation

A signal to actuate the first stage of the automatic depressurization system is generated from any of the following conditions:

1. Core makeup tank injection alignment signal (Subsection 7.3.1.2.3) coincident with core makeup tank level less than the Low-3 setpoint in either core makeup tank in two of the four divisions

2. Extended loss of ac power sources (low Class 1E battery charger input voltage)

3. Manual initiation

Any actuation of the first stage of the automatic depressurization system also trips the reactor and reactor coolant pumps, align the core makeup tanks for injection, and actuates the passive residual heat removal heat exchanger.

The automatic depressurization system is arranged to sequentially open four parallel stages of valves. Each of the first three stages consists of two parallel paths with each path containing an isolation valve and a depressurization valve. The first three stages are connected to the pressurizer and discharge into the in-containment refueling water storage tank. The fourth stage paths are connected to the hot legs of the reactor coolant system and discharge to containment.

The first stage isolation valves open on any actuation of the first stage of the automatic depressurization system. The first stage depressurization valves are opened following a preset time delay after the isolation valves are sent a signal to open. No interlocks or permissive signals apply directly to the first stage depressurization. However, some safeguards actuation signals, from which the core makeup tank injection actuation signal is derived, do contain interlock and permissive inputs.

The second stage isolation valves are sent a signal to open following a preset time delay after the first stage isolation valves are sent a signal to open. The second stage depressurization valves are sent a signal to open following a preset time delay after the second stage isolation valves are sent a signal to open, similar to stage one.

Similar to the second stage, the third stage isolation valves are sent a signal to open following a preset time delay after the second stage depressurization valves are sent a signal to open. The third stage depressurization valves are sent a signal to open following a preset time delay after the third stage isolation valves are sent a signal to open.

The fourth stage of the automatic depressurization system consists of four parallel paths. Each of these paths consists of a normally open isolation valve and a depressurization valve. The four paths are divided into two redundant groups with two paths in each group. Within each group, one path is designated to be substage A and the second path is designated to be substage B.

The fourth stage isolation valves receive a confirmatory open signal (nonsafety-related function) following a preset time delay after the first stage depressurization valves are sent a signal to open.

The fourth stage is actuated upon the coincidence of a Low-6 core makeup tank level and Low reactor coolant system pressure following a preset time delay after the third stage depressurization valves are sent a signal to open. The Low-6 core makeup tank level input is based on the core makeup tank level being less than the Low-6 setpoint in two of the four divisions in either core makeup tank. Upon a fourth stage actuation signal, the substage-A depressurization valves are opened. The signal to open the substage-B depressurization valve is provided following a preset time delay after the substage-A depressurization valves are sent a signal to open. The net effect is to provide a controlled depressurization of the reactor coolant system. In addition to initiating this controlled depressurization sequence, the fourth stage actuation signal also provides a signal that aligns the in-containment refueling water storage tank for injection, as discussed in Subsection 7.3.1.2.2.

A signal to initiate the opening sequence of the fourth stage is also generated upon the occurrence of coincident loop 1 and loop 2 hot leg levels below the Low-4 setpoint. First, the fourth stage isolation valves receive a confirmatory open signal (a nonsafety-related function) following a preset time delay after the first stage depressurization valves are sent a signal to open. Then, the depressurization valves receive an open signal if the coincident loop 1 and loop 2 hot leg levels remain below this setpoint for a duration exceeding a preset time delay. This signal also initiates in-containment refueling water storage tank injection. As discussed in Subsection 7.3.1.2.2, this signal is automatically blocked when the pressurizer water level is above the P-12 setpoint. This reduces the probability of a spurious signal. The block is removed when the core makeup tanks actuation on Low-2 pressurizer level function is manually blocked to allow mid-loop operation.

The automatic actuation of fourth stage ADS isolates the containment and when pressurizer pressure is below the P-11 permissive setpoint also isolates the RNS, as discussed in Subsections 7.3.1.2.1 and 7.3.1.2.20. This function isolates a potential break in the RNS when it is in service.

The fourth stage can also be manually initiated. In this case the manual initiation signal is interlocked to prevent actuation until either the reactor coolant system pressure has decreased below a preset setpoint, or until the signals which control the opening sequence of the first, second, and third stage valves have been generated. As discussed above, the signals to the first, second, and third stage valves are generated based on preset time delays.

The core makeup tank injection alignment signal, which is part of condition 1, is latched-in upon its occurrence. A deliberate operator action is required to reset this latch. This feature is provided so that an automatic depressurization system actuation signal is not cleared by the reset of the safeguards actuation signal as discussed in Subsection 7.3.1.1.

Condition 2 results from the loss of all ac power for a period of time that approaches the 24-hour Class 1E dc battery capability to activate the automatic depressurization system valves. The timed output holds upon restoration of ac power and is manually reset after the batteries are recharged. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. Two sensors are connected to each of the four battery charger inputs. The loss of ac power signal is based on the detection of an undervoltage condition by either of the two sensors connected to two of the four battery chargers.

Condition 3 is achieved via either of two sets of two momentary controls. If both controls of either set are operated simultaneously, actuation of the automatic depressurization system occurs. A two-control simultaneous actuation prevents inadvertent actuation.

The functional logic relating to automatic depressurization operation is illustrated in Figure 7.2-1, sheet 15.

7.3.1.2.4.1 Block to Prevent ADS and IRWST Injection Spurious Actuation

A number of measures have been taken to reduce the likelihood of spurious actuation of ESF functions in the AP1000 Protection and Safety Monitoring System (PMS) design. Special attention has been given to prevention of spurious Automatic Depressurization System (ADS) and In-containment Refueling Water Storage Tank (IRWST) Injection valve action, since a spurious actuation could result in a release of reactor coolant to containment. In order to prevent such spurious actuations, an ADS and IRWST Injection blocking device is provided that is independent of PMS processor hardware and software. Each division of the PMS contains an independent blocking device that prevents the following ADS Stage 1-4 valves and IRWST Injection valves from actuating unless there is a confirmatory process condition separate from the PMS ADS and IRWST Injection actuation logic:

ADS Stage 1: Depressurization Valve for Stage 1A Valve Set and Depressurization Valve for Stage 1B Valve Set

ADS Stage 2: Depressurization Valve for Stage 2A Valve Set and Depressurization Valve for Stage 2B Valve Set

ADS Stage 3: Depressurization Valve for Stage 3A Valve Set and Depressurization Valve for Stage 3B Valve Set

ADS Stage 4: Block “ARM” signal for all squib valves

IRWST Injection Isolation Valves: Block “ARM” signal for all squib valves

Independence

The ADS and IRWST Injection blocking device is a Class 1E module physically located within each of the PMS divisions. The blocking device is diverse from the PMS processor hardware and software that is used to create the automatic ADS and IRWST Injection actuation signal, which provides the input to the component interface modules for the ADS and IRWST Injection valves. There are no inter-divisional connections between the blocking devices nor will there be any coincidence voting among the blocking devices.

Removing the ADS and IRWST Injection Block

The ADS and IRWST injection blocking device uses Core Makeup Tank (CMT) level and Class 1E Battery Charger (IDS) input voltage to automatically remove this block. The ADS and IRWST injection block in each division receives an input from a level sensor on each CMT that removes the block if the water level in either CMT is below a predetermined setpoint. CMT level is also used to actuate the ADS, therefore the unblock CMT level setpoint is set at a level with enough margin, including instrument uncertainty, to ensure the unblock function occurs prior the need for ADS actuation. Similarly, the block is removed if either of the two undervoltage relay inputs indicates that the voltage has dropped below a predetermined setpoint. The use of two CMT level sensors and two IDS undervoltage inputs in each ADS and IRWST injection blocking device ensures that the blocking device does not significantly affect the reliability of ADS and IRWST injection to actuate when required. In addition, the main control room (MCR)/remote shutdown workstation (RSW) switch unblocks actuation of the ADS and IRWST injection signal when control is transferred to the remote shutdown room (RSR) by the main control room (MCR)/remote shutdown workstation (RSW) switch. The MCR also contains one switch for each division that allows operators to manually remove the ADS and IRWST injection blocks. The logic for the ADS blocking device is shown on Figure 7.2-1 (Sheet 19). The ADS and IRWST injection block must be manually removed if less than two CMTs are allowed to be operable.

7.3.1.2.5 Reactor Coolant Pump Trip

A signal to trip reactor coolant pumps is generated from any one of the following conditions:

1. Automatic or manual safeguards actuation signal (Subsection 7.3.1.1)
2. Automatic or manual actuation of the first stage of the automatic depressurization system (Subsection 7.3.1.2.4)
3. Low-2 pressurizer level
4. Low-2 steam generator wide range water level coincident with High hot leg temperature
5. Manual initiation of core makeup tank injection (Subsection 7.3.1.2.3)
6. High-2 reactor coolant pump bearing water temperature

Once a signal to trip the reactor coolant pump is generated, the actual tripping of the pump is delayed by a preset time delay.

Condition 3 results from the coincidence of pressurizer level below the Low-2 setpoint in any two of the four divisions. This function can be manually blocked when the pressurizer water level is below the P-12 setpoint. This function is automatically unblocked when the pressurizer water level is above the P-12 setpoint.

Condition 4 is derived from a coincidence of:

- Both steam generator 1 and steam generator 2 wide range level below the Low-2 setpoint (derived from two of the four wide range water level measurement divisions for each steam generator), and
- Two of the four divisions of hot leg temperature above the High (T_{hot}) setpoint

Condition 4 can be manually blocked when reactor coolant system average temperature is below the P-9 setpoint. This function is automatically unblocked when the reactor coolant system average temperature is above the P-9 setpoint.

Condition 6 is derived from a coincidence of two of the four divisions of High-2 reactor coolant pump bearing water temperature for any reactor coolant pump. All of the reactor coolant pumps are tripped simultaneously if Condition 6 is met for the bearing water temperature of any reactor coolant pump. This function is included for equipment protection. The high temperature setpoint and dynamic compensation are the same as used in the High-2 reactor coolant pump bearing water temperature reactor trip (Subsection 7.2.1.1.3) but with the inclusion of preset time delay.

The functional logic relating to the tripping of the reactor coolant pumps is illustrated in Figure 7.2-1, sheets 5, 7, 12, and 15.

7.3.1.2.6 Main Feedwater Isolation

Signals to isolate the main feedwater supply to the steam generators are generated from any of the following conditions:

1. Automatic or manual safeguards actuation (Subsection 7.3.1.1)
2. Manual initiation

3. High-3 steam generator narrow range water level
4. Low-1 reactor coolant system average temperature coincident with P-4 permissive
5. Low-2 reactor coolant system average temperature coincident with P-4 permissive

Conditions 1, 2, and 3 isolate the main feedwater supply by tripping the main feedwater pumps and closing the main feedwater control, isolation and crossover valves. These conditions also initiate a turbine trip.

Condition 2 consists of two momentary controls. Manual actuation of either of the two controls will trip the turbine and isolate the main feedwater supply. This action also initiates isolation of startup feedwater (Subsection 7.3.1.2.13).

Condition 3 is derived from a coincidence of two of the four divisions of narrow range steam generator water level above the High-3 setpoint for either steam generator. In addition to tripping the turbine and isolating the main feedwater supply, condition 3 also initiates a reactor trip, isolates the startup feedwater supply (Subsection 7.3.1.2.13), and isolates the chemical and volume control system. The functions of turbine trip, main feedwater supply isolation, startup feedwater supply isolation, and chemical volume control system isolation can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint. This function is automatically unblocked when the reactor coolant system average temperature is above the P-9 permissive setpoint.

Condition 4 results from a coincidence of two of the four divisions of reactor loop average temperature (T_{avg}) below the Low-1 setpoint coincident with the P-4 permissive (reactor trip). This condition results in the closure of the main feedwater control valves. The feedwater isolation resulting from this condition may be manually blocked when the pressurizer pressure is below the P-11 setpoint. The block is automatically removed when the pressurizer pressure is above the P-11 setpoint.

Condition 5 results from a coincidence of two of the four divisions of reactor loop average temperature (T_{avg}) below the Low-2 setpoint coincident with the P-4 permissive (reactor trip). This condition results in the tripping of the main feedwater pumps and closure of the main feedwater isolation and crossover valves. The feedwater isolation resulting from this condition may be manually blocked when the pressurizer pressure is below the P-11 setpoint. The block is automatically removed when the pressurizer pressure is above the P-11 setpoint.

The functional logic relating to the isolation of the main feedwater is illustrated in Figure 7.2-1, sheet 10.

7.3.1.2.7 Passive Residual Heat Removal Heat Exchanger Alignment

A signal to align the passive heat removal heat exchanger to passively remove core heat is generated from any of the following conditions:

1. Core makeup tank injection alignment signal (Subsection 7.3.1.2.3)
2. First stage automatic depressurization system actuation (Subsection 7.3.1.2.4)
3. Low-2 steam generator wide range water level
4. Low-2 steam generator narrow range water level coincident with Low-2 startup feedwater flow
5. High-3 pressurizer water level
6. Manual initiation

Each of these conditions opens the passive residual heat removal discharge isolation valves, closes the in-containment refueling water storage tank gutter isolation valves, and provides a confirmatory

open signal to the inlet isolation valve. The inlet isolation valve is normally open but can be closed by the operator. These conditions override any closure signal to this valve and also close the blowdown isolation valves in both steam generators.

Condition 3 results from the coincidence of two of the four divisions of steam generator wide range water level below the Low-2 setpoint in either of the two steam generators. Low-2 steam generator wide range water level can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint, and is automatically unblocked when the reactor coolant average temperature is above the P-9 permissive.

Condition 4 results from the coincidence of two of the four divisions of steam generator narrow range water level below the Low-2 setpoint, after a preset time delay, coincident with a Low-2 startup feedwater flow in a particular steam generator. This function is provided for each of the two steam generators. The Low-2 steam generator narrow range water level also isolates blowdown in the affected steam generator. Low-2 steam generator narrow range water level can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint, and is automatically unblocked when the reactor coolant average temperature is above the P-9 permissive.

Condition 5 results from the coincidence of pressurizer level above the High-3 setpoint in any two of four divisions. This function can be manually blocked when the reactor coolant system pressure is below the P-19 permissive setpoint to permit pressurizer water solid conditions with the plant cold. This function is automatically unblocked when reactor coolant system pressure is above the P-19 setpoint. In addition to actuating the passive residual heat removal heat exchanger, condition 5 initiates a block of the pressurizer heaters.

Condition 6 consists of two momentary controls. Manual actuation of either of the two controls will align the passive residual heat removal heat exchanger initiating heat removal by this path.

The functional logic relating to alignment of the passive residual heat removal heat exchanger is illustrated in Figure 7.2-1, sheet 8. The development of the P-9 permissive is shown on Figure 7.2-1, sheet 7.

7.3.1.2.8 Turbine Trip

A signal to initiate turbine trip is generated from any of the following conditions:

1. Reactor trip (Table 7.3-2, interlock P-4)
2. High-3 steam generator narrow-range water level
3. Manual feedwater isolation (Subsection 7.3.1.2.6)

Each of these conditions initiates a turbine trip to prevent or terminate an excessive cooldown of the reactor or minimizes the potential for equipment damage caused by loss of steam supply to the turbine.

Condition 2 results from a coincidence of two of the four divisions of narrow range steam generator water level above the High-3 setpoint for either steam generator. This function can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint. This function is automatically unblocked when the reactor coolant system average temperature is above the P-9 permissive setpoint.

The functional logic relating to the tripping of the turbine is illustrated in Figure 7.2-1, sheet 14.

7.3.1.2.9 Containment Recirculation

Signals to align the containment recirculation isolation valves are generated from the following conditions:

1. Low-3 in-containment refueling water storage tank water level in coincidence with fourth stage automatic depressurization system actuation (Subsection 7.3.1.2.4)

2. Manual initiation

3. Extended loss of ac power sources

There are four parallel containment recirculation paths provided to permit the recirculation of the water provided by the in-containment refueling water storage tank. Two of these paths are provided with two isolation valves in series while the remaining two paths are provided with a single isolation valve in series with a check valve.

Conditions 1 and 2 result in the opening of all isolation valves in all four parallel paths. Condition 3 results in the opening of the two isolation valves that are in series with the check valves.

Condition 1 results from the coincidence of two of the four divisions of in-containment refueling water storage tank water level below the Low-3 setpoint, coincident with an automatic fourth stage automatic depressurization system signal.

Condition 2 consists of two sets of two momentary controls. Manual actuation of both controls of either of the two control sets initiates recirculation in all four parallel paths. A two-control simultaneous actuation prevents inadvertent actuation.

Condition 3 results from the loss of all ac power for a period of time that approaches the 24-hour Class 1E dc battery capability to activate the in-containment refueling water storage tank containment recirculation isolation valves. The timed output holds on restoration of ac power and is manually reset after the batteries are recharged. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. Two sensors are connected to each of the four battery charger inputs. The loss of ac power signal is based on the detection of an undervoltage condition by either of the two sensors connected to two of the four battery chargers.

The functional logic relating to activation of the containment recirculation isolation valves is illustrated in Figure 7.2-1, sheets 15 and 16.

7.3.1.2.10 Steam Line Isolation

A signal to isolate the steam line is generated from any one of the following conditions:

1. Manual initiation
2. High-2 containment pressure
3. Low-2 lead-lag compensated steam line pressure
4. High steam line pressure negative rate
5. Low-2 cold leg temperature

The steam line isolation signal closes the main steam line isolation valves and the stop and bypass valves. In addition to manual system-level steam line isolation, steam line isolation valves can be closed individually via the non-safety plant control system.

Condition 1 consists of two momentary controls. Manual actuation of either of the two controls initiates steam line isolation for both steam generators.

Condition 2 results from the coincidence of two of the four divisions of containment pressure above the High-2 setpoint.

Condition 3 results from the coincidence of two of the four divisions of compensated steam line pressure below the Low-2 setpoint. The steam line pressure signal is lead-lag compensated to improve system response. If the pressure is below this setpoint, in either steam line, both main steam lines are isolated.

Condition 4 results from the coincidence in either steam line of two of the four divisions of rate-lag compensated steam line pressure exceeding the High negative rate setpoint.

Condition 5 results from the coincidence of reactor coolant system cold leg temperature below the Low-2 T_{cold} setpoint in any loop.

Steam line isolation for conditions 3 and 5 may be manually blocked when pressurizer pressure is below the P-11 setpoint and is automatically unblocked when pressurizer pressure is above P-11. Steam line isolation on condition 4 is automatically blocked when pressurizer pressure is above P-11 and is automatically unblocked on the manual blocking of the steam line isolation for conditions 3 and 5. Under all plant conditions, steam line isolation is automatically provided on either Condition 3 or 5, or Condition 4.

The functional logic relating to main steam isolation is illustrated in Figure 7.2-1, sheet 9.

7.3.1.2.11 Steam Generator Blowdown System Isolation

Signals to close the isolation valves of the steam generator blowdown system in both steam generators are generated from the following conditions:

1. Passive residual heat removal heat exchanger alignment signal (Subsection 7.3.1.2.7)
2. Low-2 steam generator narrow range water level
3. Manual and automatic containment isolation (Subsection 7.3.1.2.1)

Condition 2 results from the coincidence of two of the four divisions of steam generator narrow range water level below the Low-2 setpoint. This condition only closes the blowdown system isolation valves of the affected steam generator. Low-2 steam generator narrow range water level can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint, and is automatically unblocked when the reactor coolant average temperature is above the P-9 permissive.

The functional logic relating to steam generator blowdown isolation is illustrated in Figure 7.2-1, sheets 7 and 8. The development of the P-9 permissive is shown on Figure 7.2-1, sheet 7.

7.3.1.2.12 Passive Containment Cooling Actuation

A signal to actuate the passive containment cooling system is generated from either of the following conditions:

1. Manual initiation
2. High-2 containment pressure

The passive containment cooling actuation signal opens valves that initiate gravity flow of cooling water from the passive containment cooling system water storage tank to the top of the containment shell. The evaporation of the water on the containment shell provides the passive cooling.

Condition 1 consists of two momentary controls. Manual actuation of either of the two controls results in manual actuation of the passive containment cooling system. This action also initiates containment isolation (Subsection 7.3.1.2.1) and isolation of the containment air filtration system (Subsection 7.3.1.2.19).

Condition 2 results from a coincidence of two of the four divisions of containment pressure above the High-2 setpoint. Manual reset is provided to block this actuation signal for passive containment cooling. Separate momentary controls are provided for resetting each division.

The functional logic relating to actuation of the passive containment cooling system is illustrated in Figure 7.2-1, sheet 13.

7.3.1.2.13 Startup Feedwater Isolation

Signals to isolate the startup feedwater supply to the steam generators are generated from either of the following conditions:

1. Low-2 cold leg temperature
2. High-3 steam generator narrow range water level
3. Manual actuation of main feedwater isolation (Subsection 7.3.1.2.6)
4. High steam generator narrow range water level (coincident with P-4 permissive)

Any of these conditions isolates the startup feedwater supply by tripping the startup feedwater pumps and closing the startup feedwater isolation and control valves.

Condition 1 results from the coincidence of reactor coolant system cold leg temperature below the Low-2 T_{cold} setpoint in any loop. Startup feedwater isolation on this condition may be manually blocked when the pressurizer pressure is below the P-11 setpoint. This function is automatically unblocked when the pressurizer pressure is above the P-11 setpoint.

Condition 2 results from a coincidence of two of the four divisions of narrow range steam generator water level above the High-3 setpoint for either steam generator. This function can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint. This function is automatically unblocked when the reactor coolant system average temperature is above the P-9 permissive setpoint.

Condition 3 is discussed in other subsections as noted.

Condition 4 results from a coincidence of two of the four divisions of narrow range steam generator water level above the High setpoint for either steam generator coincident with the P-4 permissive (reactor trip). This function can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint. This function is automatically unblocked when the reactor coolant system average temperature is above the P-9 permissive setpoint.

The functional logic relating to the isolation of the startup feedwater is illustrated in Figure 7.2-1, sheets 9 and 10.

7.3.1.2.14 Boron Dilution Block

Signals to block boron dilution are generated from any of the following conditions:

1. Excessive increasing rate of source range flux doubling signal
2. Loss of ac power sources (low Class 1E battery charger input voltage)
3. Reactor trip (Table 7.3-2, interlock P-4)

In the event of an excessive increasing rate of source range flux doubling signal, the block of boron dilution is accomplished by closing the chemical and volume control system makeup isolation valves and closing the makeup pump suction valves to the demineralized water storage tanks. This signal also provides a non-safety trip of the makeup pumps. These actions terminate the supply of potentially unborated water to the reactor coolant system as quickly as possible.

In the event of a loss of ac power sources or a reactor trip (as indicated by P-4), the block of boron dilution is accomplished by closing the makeup pump suction valves to the demineralized water storage tanks and aligning the boric acid tank to the suction of the makeup pumps. This permits makeup as needed but ensures that it will be from a borated source that will not reduce the available shutdown margin in the reactor core.

Condition 1 is an average of the source range count rate, sampled at least N times over the most recent time period T_1, compared to a similar average taken at time period T_2 earlier. If the ratio of the current average count rate to the earlier average count rate is greater than a preset value, a partial trip is generated in the division. On a coincidence of excessively increasing source range neutron flux in two of the four divisions, boron dilution is blocked. The Flux Doubling function is also delayed from actuating each time the source range detector's high voltage power is energized to prevent a spurious dilution block due to the short term instability of the processed source range values. This source range flux doubling signal may be manually blocked to permit plant startup and normal power operation when reactor coolant average temperature is above the P-8 setpoint. It is automatically reinstated when reactor power is decreased below the P-6 power level during shutdown or reactor coolant average temperature decreases below the P-8 setpoint.

Below the P-6 setpoint, the source range neutron flux detectors are automatically energized and the Source Range Neutron Flux Doubling actuation of the Boron Dilution Block and CVS isolation Functions is automatically reinstated. Above the P-10 setpoint, the Source Range Neutron Flux Doubling actuation of the Boron Dilution Block and CVS isolation is automatically blocked and the source range neutron flux detectors are de-energized. Above the P-6 setpoint and below the P-10 setpoint, automatic Source Range Neutron Flux Doubling actuation of the Boron Dilution Block and CVS isolation Functions can be manually blocked or manually unblocked.

The source range flux doubling function can also be manually blocked during shutdown conditions when below the P-8 setpoint. Prior to manually blocking the source range flux doubling function, the operator isolates unborated water source flow paths. When blocked during shutdown conditions, an automatic close signal is also sent to the CVS demineralized water system isolation valves to prevent boron dilution.

Condition 2 results from the loss of ac power. A short, preset time delay is provided to prevent actuation upon momentary power fluctuations; however, actuation occurs before ac power is restored by the onsite diesel generators. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. Two sensors are connected to each of the four battery charger inputs. The loss of ac power signal is based on the detection of an undervoltage condition by each of the two sensors connected to two of the four battery chargers. The two-out-of-four logic is based on an undervoltage to the battery chargers for divisions A or C coincident with an undervoltage to the battery chargers for divisions B or D.

Condition 3 results from a reactor trip as indicated by the P-4 interlock.

The functional logic relating to the boron dilution block is illustrated in Figure 7.2-1, sheets 3 and 15.

7.3.1.2.15 Chemical and Volume Control System Makeup Isolation

A signal to close the makeup line containment isolation valves of the chemical and volume control system is generated from any of the following conditions:

1. High-2 pressurizer level
2. High-3 steam generator narrow range water level
3. Automatic or manual safeguards actuation signal (Subsection 7.3.1.1) coincident with High-1 pressurizer level
4. High-2 containment radioactivity
5. Manual initiation
6. High steam generator narrow range water level (coincident with P-4 permissive)
7. Excessive increasing rate of source range flux doubling signal

Condition 1 results from the coincidence of pressurizer level above the High-2 setpoint in any two of the four divisions. This function can be manually blocked when the reactor coolant system pressure is below the P-19 permissive setpoint to permit pressurizer water solid conditions with the plant cold and to permit pressurizer level makeup during plant cooldowns. This function is automatically unblocked when reactor coolant system pressure is above the P-19 setpoint.

Condition 2 results from a coincidence of two of the four divisions of narrow range steam generator water level above the High-3 setpoint for either steam generator. This function can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint. This function is automatically unblocked when the reactor coolant system average temperature is above the P-9 permissive setpoint.

Condition 3 results from the coincidence of two of the four divisions of pressurizer level above the High-1 setpoint, coincident with an automatic or manual safeguards actuation.

Condition 4 results from the coincidence of containment radioactivity above the High-2 setpoint in any two of the four divisions.

Condition 5 consists of two momentary controls. This action also initiates auxiliary spray and purification line and zinc/hydrogen addition isolation (Subsection 7.3.1.2.18).

Condition 6 results from a coincidence of two of the four divisions of narrow range steam generator water level above the High setpoint for either steam generator coincident with the P-4 permissive (reactor trip). This function can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint. This function is automatically unblocked when the reactor coolant system average temperature is above the P-9 permissive setpoint.

Condition 7 is an average of the source range count rate, sampled at least N times over the most recent time period T_1, compared to a similar average taken at time period T_2 earlier. If the ratio of the current average count rate to the earlier average count rate is greater than a preset value, a partial trip is generated in the division. On a coincidence of excessively increasing source range neutron flux in two of the four divisions, chemical and volume control system makeup is isolated. The flux doubling function is also delayed from actuating each time the source range detector's high voltage power is energized to prevent a spurious chemical and volume control system makeup isolation due

to the short-term instability of the processed source range values. This source range flux doubling signal may be manually blocked to permit plant startup and normal power operation when reactor coolant average temperature is above the P-8 setpoint. It is automatically reinstated when reactor power is decreased below the P-6 power level during shutdown or reactor coolant average temperature decreases below the P-8 setpoint. The source range flux doubling function can also be manually blocked during shutdown conditions when below the P-8 setpoint. Prior to manually blocking the source range flux doubling function, the operator isolates unborated water source flow paths. When blocked during shutdown conditions, an automatic close signal is also sent to the CVS demineralized water system isolation valves to prevent inadvertent boron dilution.

Below the P-6 setpoint, the source range neutron flux detectors are automatically energized and the Source Range Neutron Flux Doubling actuation of the Boron Dilution Block and CVS isolation Functions is automatically reinstated. Above the P-10 setpoint, the Source Range Neutron Flux Doubling actuation of the Boron Dilution Block and CVS isolation is automatically blocked and the source range neutron flux detectors are de-energized. Above the P-6 setpoint and below the P-10 setpoint, automatic Source Range Neutron Flux Doubling actuation of the Boron Dilution Block and CVS isolation Functions can be manually blocked or manually unblocked.

The functional logic relating to chemical and volume control system isolation is illustrated in Figure 7.2-1, sheets 3, 6, and 11.

7.3.1.2.16 Steam Dump Block

Signals to block steam dump (turbine bypass) are generated from either of the following conditions:

1. Low-2 reactor coolant system average temperature
2. Manual initiation

Condition 1 results from a coincidence of two of the four divisions of reactor loop average temperature (T_{avg}) below the Low-2 setpoint. This blocks the opening of the steam dump valves. This signal also becomes an input to the steam dump interlock selector switch for unblocking the steam dump valves used for plant cooldown.

Condition 2 consists of three sets of controls. The first set of two controls selects whether the steam dump system has its normal manual and automatic operating modes available or is turned off. The second set of two controls enables or disables the operations of the Stage 1 cooldown steam dump valves if the reactor coolant average temperature (T_{avg}) is below the Low-2 setpoint. The third set of two controls enables or disables the operation of the Stage 2 cooldown steam dump valves.

The functional logic relating to the steam dump block is illustrated in Figure 7.2-1, sheet 10.

7.3.1.2.17 Main Control Room Isolation, Air Supply Initiation, and Electrical Load De-energization

Signals to initiate isolation of the main control room, to initiate the air supply, to open the main control room pressure relief isolation valves, and to de-energize nonessential main control room electrical loads are generated from any of the following conditions:

1. High-2 main control room air supply radioactivity level
2. Loss of ac power sources (low Class 1E battery charger input voltage)
3. “Low” main control room differential pressure
4. Manual initiation

Condition 1 is the occurrence one of two main control room air supply radioactivity monitors detecting the iodine or particulate radioactivity level above the High-2 setpoint.

Condition 2 results from the loss of normal control room ventilation due to a loss of all ac power sources. A preset time delay is provided to permit the restoration of ventilation and ac power from the offsite sources or from the onsite diesel generators before initiation. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. Two sensors are connected to each of the four battery charger inputs. The loss of ac power signal is based on the detection of an undervoltage condition by each of the two sensors connected to two of the four battery chargers. The logic is based on an undervoltage to the battery chargers for divisions A or C coincident with an undervoltage to the battery chargers for divisions B or D.

Condition 3 results from the loss of main control room differential pressure as detected by the pressure boundary differential sensors. One out of two logic is based on main control room differential pressure below the “Low” setpoint for greater than 10 minutes.

In addition, the loss of all ac power sources coincident with main control room isolation will de-energize the main control room air supply radiation monitor sample pumps in order to conserve the battery capacity, maintain room temperature below the equipment qualification limitation, and maintain the assumed heat load for MCR habitability.

Condition 4 consists of two momentary controls. Manual actuation of either of the two controls will result in main control room isolation, air supply initiation, and electrical load de-energization.

The functional logic relating to main control room isolation, air supply initiation, and electrical load de-energization is illustrated in Figure 7.2-1, Sheet 13.

7.3.1.2.18 Auxiliary Spray and Purification Line and Zinc/Hydrogen Addition Isolation

A signal to isolate the auxiliary spray purification, zinc addition, and hydrogen addition lines is generated upon the coincidence of pressurizer level below the Low-1 setpoint in any two of four divisions. This helps to maintain reactor coolant system inventory. This function can be manually blocked when the pressurizer water level is below the P-12 setpoint. This function is automatically unblocked when the pressurizer water level is above the P-12 setpoint. The automatic auxiliary spray isolation signal can be reset by the operator, after actuation of the auxiliary spray isolation valve, by using the reset control. This will allow the operators to use the auxiliary spray to rapidly depressurize the reactor coolant system. The operator can also manually initiate auxiliary spray isolation. The functional logic relating to this is illustrated in Figure 7.2-1, sheet 12.

The auxiliary spray and purification line and zinc/hydrogen addition isolation signal is also generated upon manual actuation of chemical and volume control system makeup isolation (Subsection 7.3.1.2.15).

The zinc addition and hydrogen addition isolation valves are also closed by the containment isolation function as described in Subsection 7.3.1.2.1.

7.3.1.2.19 Containment Air Filtration System Isolation

A signal to isolate the containment air filtration system is generated from any of the following conditions:

1. Automatic or manual safeguards actuation signal (Subsection 7.3.1.1)
2. Manual actuation of containment isolation (Subsection 7.3.1.2.1)
3. Manual actuation of passive containment cooling (Subsection 7.3.1.2.12)

4. High-1 containment radioactivity

Conditions 1, 2, and 3 are discussed in other subsections as noted.

Condition 4 results from the coincidence of containment radioactivity above the High-1 setpoint in any two of the four divisions.

The manual reset which is provided to block the automatic actuation signal for containment isolation (Subsection 7.3.1.2.1) also resets the containment air filtration system isolation signal generated as a result of condition 1.

No other interlocks or permissive signals apply directly to the containment air filtration system isolation function. Automatic actuation originates from a safeguards actuation (S) signal that does contain interlock and permissive inputs.

The functional logic relating to air filtration system isolation is illustrated in Figure 7.2-1, sheets 11 and 13.

7.3.1.2.20 Normal Residual Heat Removal System Isolation

Signals for isolating the normal residual heat removal system lines are generated from any of the following conditions:

1. Automatic or manual safeguards actuation signal (Subsection 7.3.1.1)
2. High-2 containment radioactivity
3. Automatic fourth stage ADS actuation (Subsection 7.3.1.2.4)
4. Manual initiation

The isolation signal generated as a result of Condition 1 can be manually reset to block the isolation of the normal heat removal system lines. This is done to permit the normal residual heat removal system to operate after the occurrence of a safeguards actuation signal. Separate momentary controls are provided for resetting each division.

Condition 2 results from the coincidence of containment radioactivity above the High-2 setpoint in any two of the four divisions.

Actuation signals for conditions 1 and 2 can be manually blocked when pressurizer pressure is below the P-11 permissive setpoint and can be manually reset to allow use of the system in accident mitigation and plant recovery if desired. These signals are automatically unblocked when the pressurizer pressure is above the P-11 permissive setpoint.

The condition 3 actuation signal is automatically enabled when pressurizer pressure is below the P-11 permissive setpoint and can be manually reset to assist with accident mitigation and plant recovery processes.

Condition 4 consists of two sets of two momentary controls. Manual actuation of both controls of either of two control sets initiates closure of RNS isolation valves. A two-control simultaneous actuation prevents inadvertent actuation.

The functional logic relating to normal residual heat removal system isolation is illustrated in Figure 7.2-1, sheets 13, 15, and 18.

7.3.1.2.21 Refueling Cavity and Spent Fuel Pool Cooling System Isolation

Signals for isolating the spent fuel pool cooling system lines by closing the spent fuel pool cooling system containment isolation valves are generated from either of the following conditions:

1. Low-2 spent fuel pool level
2. Low IRWST wide range level

Condition 1 results from the coincidence of spent fuel pool level below the Low-2 setpoint in two of three divisions. This helps to maintain the water inventory in the refueling cavity due to line leakage.

Condition 2 results from IRWST wide range level below the Low setpoint in one of two divisions. This helps to maintain the water inventory in the IRWST in the event of a leak in the nonsafety-related spent fuel pool cooling system. Low IRWST wide range level can be manually blocked when the reactor coolant system average temperature is below the P-9 permissive setpoint and the plant is in Mode 6, to allow the spent fuel pool cooling system to transfer the IRWST inventory to the refueling cavity and perform cooling and purification of the refueling cavity. A manual block can also be used when the reactor coolant system average temperature is below the P-9 permissive setpoint to use the spent fuel pool cooling system to cool, purify, sample, or transfer water to or from the IRWST when the level is below the Low IRWST wide range level setpoint. Low IRWST wide range level is automatically unblocked when the reactor coolant average temperature is above the P-9 permissive.

The functional logic relating to refueling cavity and spent fuel pool cooling system isolation is illustrated in Figure 7.2-1, sheet 14. The development of the P-9 permissive is shown on Figure 7.2-1, sheet 7.

7.3.1.2.22 Chemical and Volume Control System Letdown Isolation

A signal to isolate the letdown valves of the chemical and volume control system is generated upon the occurrence of a Low-2 hot leg level in either of the two hot leg loops. This helps to maintain reactor coolant system inventory during mid-loop operation. This signal may be manually blocked by the operator when pressurizer level is above the P-12 setpoint. The functional logic relating to this is illustrated in Figure 7.2-1, sheet 16. These letdown valves are also closed by the containment isolation function as described in Subsection 7.3.1.2.1.

7.3.1.2.23 Pressurizer Heater Trip

Signals for disabling the operation of the pressurizer heaters are generated from any of the following conditions:

1. Core makeup tank injection alignment signal (Subsection 7.3.1.2.3)
2. High-3 pressurizer water level

Division A of the protection and safety monitoring system provides actuation signals to five load center circuit breakers which provide the power feed to five pressurizer heater electrical control centers. When these five power feed breakers are opened, the electrical power is removed from the pressurizer heaters. In addition, each division of the protection and safety monitoring system provides a separate signal to the plant control system. Within the plant control system, these signals are voted two-out-of four and the result is used to open the pressurizer heater circuits at the motor control center. This arrangement provides for complete disabling of the pressurizer heaters, even if a single component failure occurs. Pressurizer heater trip on condition 2 may be manually blocked when wide range RCS pressure is below the P-19 setpoint.

The functional logic relating to the pressurizer heater block is illustrated in Figure 7.2-1, sheets 6 and 12.

7.3.1.2.24 Steam Generator Relief Isolation

A signal for closing the steam generator power operated relief valves and their block valves is generated from any of the following conditions:

1. Manual initiation
2. Low-2 lead-lag compensated steam line pressure

Condition 2 results from the coincidence of two of the four divisions of compensated steam line pressure below the Low-2 setpoint. The steam line pressure signal is lead-lag compensated to improve system response. The signal closes the steam generator power-operated relief valve and the associated block valve for the affected steam generator. Steam generator relief isolation for condition 2 may be manually blocked when pressurizer pressure is below the P-11 setpoint and is automatically unblocked when pressurizer pressure is above P-11.

The functional logic relating to steam generator relief isolation is illustrated in Figure 7.2-1, sheet 9.

7.3.1.2.25 Component Cooling System Containment Isolation Valve Closure

A closure signal for the component cooling system containment isolation valves is generated from the following:

1. Safeguards actuation signal
2. Reactor coolant pump High-2 bearing water temperature

For condition 1, the safeguards acutation signal is generated based on the incidence of any of the following conditions:

- Automatic or manual safeguards actuation (Subsection 7.1.3.1)

For condition 2, a signal to close the component cooling system containment isolation valves is derived from a coincidence of two of the four divisions of High-2 reactor coolant pump bearing water temperature for any reactor coolant pump. The high temperature setpoint and dynamic compensation are the same as used in the High-2 reactor coolant pump bearing water temperature reactor coolant pump trip (Subsection 7.3.1.2.5, condition 6), but with the inclusion of preset time delay.

The functional logic relating to the tripping of the reactor pumps and the closure of the component cooling system isolation valves is illustrated in Figure 7.2-1, Sheets 5 and 11.

7.3.1.2.26 Containment Vacuum Relief

A signal for opening the containment vacuum relief valves is generated from the following conditions:

- Low-2 containment pressure
- Manual initiation coincident with low containment pressure

Condition 1 results from the incidence of containment pressure reaching the Low-2 setpoint in any two of the four divisions.

Condition 2 consists of two momentary controls. Manual actuation of either of the two controls will result in opening of the containment vacuum relief valves. Manual containment vacuum relief valve actuation for Condition 2 is interlocked to prevent actuation until the Containment Pressure Low setpoint is reached in any two of the four divisions. After manual containment vacuum relief is initiated, the signal is automatically reset when containment pressure rises above the Low setpoint. Following signal reset, the valves will remain open until closed by a manual or automatic actuation signal.

Either signal will actuate two motor-operated containment isolation valves to break the containment vacuum.

The functional logic relating to containment vacuum relief is illustrated in Figure 7.2-1, Sheet 19.

7.3.1.3 Blocks, Permissives, and Interlocks for Engineered Safety Features Actuation

The interlocks used for engineered safety features actuation are designated as "P-xx" permissives and are listed in Table 7.3-2.

7.3.1.4 Bypasses of Engineered Safety Features Actuation

The channels used in engineered safety features actuation that can be manually bypassed are indicated in Table 7.3-1. A description of this bypass capability is provided in Subsection 7.1.2.9. The actuation logic is not bypassed for test. During tests, the actuation logic is fully tested by blocking the actuation logic output before it results in component actuation.

7.3.1.5 Design Basis for Engineered Safety Features Actuation

The following subsections provide the design bases information for engineered safety features actuation, including the information required by Section 4 of IEEE 603-1991. Engineered safety features are initiated by the protection and safety monitoring system. Those design bases relating to the equipment that initiates and accomplishes engineered safety features are given in WCAP-15776 (Reference 1). The design bases presented here concern the variables monitored for engineered safety features actuation and the minimum performance requirements in generating the actuation signals.

7.3.1.5.1 Design Basis: Generating Station Conditions Requiring Engineered Safety Features Actuation (Paragraph 4.1 of IEEE 603-1991)

The generating station conditions requiring protective action are identified in Table 15.0-6, which summarizes the engineered safety features as they relate to the Condition II, III, or IV events analyzed in Chapter 15.

7.3.1.5.2 Design Basis: Variables, Ranges, Accuracies, and Response Times Used in Engineered Safety Features Actuation (Paragraphs 4.1, 4.2, and 4.4 of IEEE 603-1991)

The variables monitored for engineered safety features actuation are:

- Pressurizer pressure
- Pressurizer water level (with reference leg temperature, pressurizer pressure, and RCS wide range pressure compensation)
- Reactor coolant temperature (T_{hot} and T_{cold}) in each loop
- Containment pressure
- Containment radioactivity level

- Steam line pressure in each steam line
- Water level in each steam generator (narrow and wide ranges) (with steam line pressure compensation)
- Source range neutron flux
- Core makeup tank level
- Reactor coolant level in each of the two hot legs
- Loss of ac power sources (low Class 1E battery charger input voltage)
- In-containment refueling water storage tank level
- Main control room supply air radioactivity level
- Main control room differential pressure
- Reactor coolant pump bearing water temperature
- Startup feedwater flow
- Spent fuel pool level
- Reactor coolant pressure in each of the two hot legs

Subsections 7.3.1.1 and 7.3.1.2 discuss levels that result in engineered safety features actuation. The engineered safety features actuation and trip setpoints are maintained by the setpoint program, which is described in the Technical Specifications.

Ranges and response times for the variables used in engineered safety features actuation are listed in Table 7.3-4. Channel accuracies are accounted for in the setpoint methodology. The time response is the maximum allowable time for an actuation signal to reach the necessary components. Any intentional time delays in the system are accounted for separately in the accident analyses. Some PMS response times are allocated rather than measured (Reference 2).

7.3.1.5.3 Design Basis: Spatially Dependent Variables Used for Engineered Safety Features Actuation (Paragraph 4.6 of IEEE 603-1991)

Spatially dependent variables are discussed in Subsection 7.2.1.2.3.

7.3.1.5.4 Design Basis: Limits for Engineered Safety Features Parameters in Various Reactor Operating Modes (Paragraph 4.3 of IEEE 603-1991)

During startup or shutdown, various engineered safety features actuation can be manually blocked. These functions are listed in Table 7.3-1.

During testing or maintenance of the protection and safety monitoring system, certain channels used for engineered safety features may be bypassed. Although no setpoints are changed for bypassing, the logic is automatically adjusted, as described in Subsection 7.3.1.4. The safeguards channels that can be bypassed in the protection and safety monitoring system are listed in Table 7.3-1.

7.3.1.5.5 Design Basis: Engineered Safety Features for Malfunctions, Accidents, Natural Phenomena, or Credible Events (Paragraph 4.7 and 4.8 of IEEE 603-1991)

The accidents that the various engineered safety features are designed to mitigate are detailed in Chapter 6 and Chapter 15. Table 15.0-6 contains a summary listing of the engineered safety features actuated for various Condition II, III, or IV events. It relies on provisions made to protect equipment against damage from natural phenomena and credible internal events. Consequently, there are no engineered safety features actuated by the protection and safety monitoring system to mitigate the consequences of events such as fires.

Functional diversity is used in determining the actuation signals for engineered safety features. For example, a safeguards actuation signal is generated from High-2 containment pressure, Low-3

pressurizer pressure, and Low-2 compensated steam line pressure. Engineered safety features are not normally actuated by a single signal. The extent of this diversity is seen from the initiating signals presented in Subsections 7.3.1.1 and 7.3.1.2. Table 7.3-1 also lists the engineered safety features signals and the conditions that result from their actuation.

Redundancy provides confidence that engineered safety features are actuated on demand, even when the protection and safety monitoring system is degraded by a single random failure. The single-failure criterion is met even when engineered safety features channels are bypassed.

7.3.1.6 System Drawings

Functional diagrams are provided in Figure 7.2-1.

7.3.2 Analysis for Engineered Safety Features Actuation

7.3.2.1 Failure Modes and Effects Analyses

The AP1000 failure modes and effects analysis (Appendix 7B) examines failures of the protection and safety monitoring system. This analysis concludes that the protection system maintains safety functions during single point failures.

7.3.2.2 Conformance of Engineered Safety Features to the Requirements of IEEE 603-1991

The discussions presented in this subsection address only the functional aspects of actuating engineered safety features. Requirements addressing equipment in the protection and safety monitoring system are presented in WCAP-15776 (Reference 1).

7.3.2.2.1 Conformance to the General Functional Requirements for Engineered Safety Features Actuation (Section 5 of IEEE 603-1991)

The protection and safety monitoring system automatically generates an actuation signal for an engineered safety feature whenever a monitored condition reaches a preset value. The specific engineered safety features actuation functions are listed in Table 7.3-1 and are discussed in Subsection 7.3.1.2.

Table 7.3-4 lists the ranges and response times of the parameters monitored. Channel accuracies are accounted for in the setpoint methodology. The engineered safety features, in conjunction with a reactor trip, protect against damage to the core and reactor coolant system components, as well as maintain containment integrity following a Condition II, III, or IV event. Table 15.0-6 summarizes the events that normally result in the initiation of engineered safety features. The setpoints that actuate engineered safety features are maintained by the setpoint program, which is described in the Technical Specifications.

7.3.2.2.2 Conformance to the Single Failure Criterion for Engineered Safety Features Actuation (Paragraph 5.1 of IEEE 603-1991)

A single failure in the protection and safety monitoring system does not prevent an actuation of the engineered safety features when the monitored condition reaches the preset value that requires the initiation of an actuation signal. The single failure criterion is met even when one division of the ESF coincidence logic is being tested, as discussed in Subsection 7.1.2.9, or when there is a bypass condition in connection with test or maintenance of the protection and safety monitoring system.

7.3.2.2.3 Conformance to the Requirements for Channel Independence of the Engineered Safety Features Actuation (Paragraph 5.6.1 of IEEE 603-1991)

A discussion of channel independence is presented in WCAP-15776 (Reference 1). The signals to initiate division A of the engineered safety features are electrically isolated from the signals to initiate the redundant divisions (B, C, and D). Divisions of the safeguards actuation system are electrically independent and redundant, as are the power supplies for the divisions up to and including the final actuated equipment.

7.3.2.2.4 Conformance to the Requirements Governing Control and Protection System Interaction of the Engineered Safety Features Actuation (Paragraphs 5.6.3.1, 5.6.3.3, and 6.3.1 of IEEE 603-1991)

Discussions on this subject are presented in WCAP-15776 (Reference 1).

7.3.2.2.5 Derivation of System Input for Engineered Safety Features Actuation (Paragraph 6.4 of IEEE 603-1991)

To the extent feasible and practical, the protection and safety monitoring system inputs used to actuate engineered safety features are derived from signals that are direct measures of the desired parameters. The parameters are listed in Table 7.3-4.

7.3.2.2.6 Capability for Sensor Checks and Equipment Test and Calibration of the Engineered Safety Features Actuation (Paragraphs 5.7 and 6.5 of IEEE 603-1991)

The discussion of system testability provided in Section 7.1 is applicable to the sensors, signal processing, and actuation logic that initiate engineered safety features actuation.

The testing program meets Regulatory Guide 1.22 as discussed in WCAP-15776 (Reference 1). The program is as follows:

- Prior to initial plant operations, engineered safety features tests are conducted.
- Subsequent to initial startup, engineered safety features tests are conducted during each regularly scheduled refueling outage.
- During operation of the reactor, the protection and safety monitoring system is tested as described in Subsection 7.1.2.11. In addition, the engineered safety features final actuators, whose operation is compatible with continued plant operation, are tested periodically at power.
- Continuity of the wiring is verified for devices that cannot be tested at power without damaging or upsetting the plant. Operability of the final actuated equipment is demonstrated at shutdown.

During reactor operation, the basis for acceptability of engineered safety features actuation includes the successful completion of the tests performed on the protection and safety monitoring system. Process indications are used to verify operability of sensors.

7.3.2.2.7 Conformance to Requirements on Bypassing Engineered Safety Features Actuation Functions (Paragraph 5.8, 5.9, 6.6, and 6.7 of IEEE 603-1991)

Discussions on bypassing are provided in WCAP-15776 (Reference 1) and Subsection 7.3.1.4.

7.3.2.2.8 Conformance to the Requirement for Completion of Engineered Safety Features Actuation Once Initiated (Paragraph 5.2 of IEEE 603-1991)

Once initiated, engineered safety features proceed to completion.

Equipment actuated on a safeguards actuation signal cannot be returned to its previous position for a predetermined time period following initiation of the safeguards actuation signal. A block of the automatic safeguards signal is permitted at this time, if the reactor is tripped. This interlock is shown in Figure 7.2-1, sheet 11.

Resetting a system-level safeguards signal does not terminate any safeguards function. Rather, it permits the operator to individually reposition equipment. Equipment cannot be reset until the system-level signal is reset.

7.3.2.2.9 Conformance to the Requirement to Provide Manual Initiation at the System-Level for All Safeguards Actuation (Paragraph 6.2 of IEEE 603-1991)

Manual initiation at the system-level exists for the engineered safety features actuation. These system-level manual initiations are discussed in Subsections 7.3.1.1 and 7.3.1.2.

As a minimum, two controls are provided for each system-level manual initiation so that the protective function can be manually initiated at the system-level, despite a single random failure in one control. In certain applications, such as automatic depressurization, two pairs of controls are provided. One pair must be actuated simultaneously. This reduces the likelihood of inadvertent actuation while providing a design that meets the single failure criterion.

7.3.3 Combined License Information

This section contained no requirement for information.

7.3.4 References

1. WCAP-15776, “Safety Criteria for the AP1000 Instrument and Control Systems,” Revision 1, July 2019.

2. Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment Nos. 168 and 166 to the Combined License Nos. NPF-91 and NPF-92, respectively, Vogtle Electric Generating Plant Units 3 and 4, Docket Nos. 52-025 and 52-026, dated November 21, 2019 [ML19297C988 (Proprietary) and ML19297D159 (non-proprietary)].

Table 7.3-1 (Sheet 1 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
1. Safeguards Actuation Signal (Figure 7.2-1, Sheets 9 and 11)			
a. Low-3 pressurizer pressure	4	2/4-BYP[1]	Can be manually blocked on presence of P-3 Block automatically removed on absence of P-3 Manual block permitted below P-11 Automatically unblocked above P-11
b. Low-2 lead-lag compensated steam line pressure	4/steam line	2/4-BYP[1] in either steam line	Can be manually blocked on presence of P-3 Block automatically removed on absence of P-3 Manual block permitted below P-11 Automatically unblocked above P-11
c. Low-2 cold leg temperature (Low-2 T_{cold})	4/loop	2/4-BYP[1] either loop[6]	Can be manually blocked on presence of P-3 Block automatically removed on absence of P-3 Manual block permitted below P-11 Automatically unblocked above P-11
d. High-2 containment pressure	4	2/4-BYP[1]	Can be manually blocked on presence of P-3 Block automatically removed on absence of P-3
e. Manual safeguards initiation	2 controls	1/2 controls	None
2. Containment Isolation (Figure 7.2-1 Sheets 11, 13, and 15)			
a. Automatic or manual safeguards actuation signal	(See items 1a through 1e)		
b. Automatic fourth stage ADS actuation[(8)]	(See items 3d through 3f)		
c. Manual initiation	2 controls	1/2 controls	None
d. Manual initiation of passive containment cooling	(See item 10a)		

Table 7.3-1 (Sheet 2 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
3. Automatic Depressurization System[9] (Figure 7.2-1, Sheets 15 and 19) **(Initiate Stages 1, 2, and 3)**			
a. Core makeup tank injection coincident with	(See items 6a through 6e)		
Core makeup tank level less than Low-3 setpoint	4/tank	2/4-BYP[1] either tank[2]	None
b. Extended undervoltage to Class 1E battery chargers[8]	2/charger	1/2 per charger and 2/4 chargers	None
c. Stages 1, 2, and 3 manual initiation	4 controls	2/4 controls[3]	None
(Initiate Stage 4)			
d. Stage 4 manual initiation coincident with one of the following two conditions:	4 controls	2/4 controls[3]	None
Low[10] reactor coolant system pressure or	4	2/4 BYP[1]	None
3rd stage depressurization			
e. Core makeup tank level less than Low-6 setpoint coincident with	4/tank	2/4 BYP[1] either tank[2]	None
Low[10] reactor coolant system pressure and coincident with	4	2/4 BYP[1]	None
3rd stage depressurization			
f. Coincident loop 1 and loop 2 Low-4 hot leg level (after delay)	1 per loop	2/2[1]	Manual unblock permitted below P-12 Automatically blocked above P-12

Table 7.3-1 (Sheet 3 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
4. Main Feedwater Isolation (Figure 7.2-1, Sheet 10) (Closure of Control Valves)			
a. Safeguards actuation signal (automatic or manual)	(See items 1a through 1e)		
b. Manual initiation	2 controls	1/2 controls	None
c. High-3 steam generator narrow range level	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
d. Low[10] reactor coolant temperature (Low T_{avg}) coincident with	2/loop	2/4 -BYP[1]	Manual block permitted below P-11 Automatically unblocked above P-11
Reactor trip (P-4)	1/division	2/4	None
(Trip of Main Feedwater Pumps and Closure of Isolation and Crossover Valves)			
a. Safeguards actuation signal (automatic or manual)	(See items 1a through 1e)		
b. Manual initiation	2 controls	1/2 controls	None
c. High-3 steam generator narrow range level	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
d. Low reactor coolant temperature (Low-2 T_{avg}) coincident with	2/loop	2/4 - BYP[1]	Manual block permitted below P-11 Automatically unblocked above P-11
Reactor trip (P-4)	1/division	2/4	None
5. Reactor Coolant Pump Trip (Figure 7.2-1, Sheets 5, 7, 12, and 15) **(Trips All Reactor Coolant Pumps)**			
a. Safeguards actuation signal (automatic or manual)	(See items 1a through 1e)		
b. Automatic reactor coolant system depressurization (first stage)	(See items 3a through 3c)		
c. Low-2 pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-12 Automatically unblocked above P-12
d. Low-2 steam generator wide range water level coincident with	4/steam generator	2/4-BYP[1] in both steam generators	Manual block permitted below P-9 Automatically unblocked above P-9
High hot leg temperature (High T_{hot})[(8)]	2/loop	2/4-BYP[1]	None
e. Manual core makeup tank initiation	(See item 6e)		
f. High-2 (lead-lag compensated) reactor coolant pump bearing water temperature	4/pump	2/4-BYP[1] in affected pump	None

Table 7.3-1 (Sheet 4 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
6. Core Makeup Tank Injection (Figure 7.2-1, Sheets 7, 12 and 15)			
a. Safeguards actuation signal (automatic or manual)	(See items 1a through 1e)		
b. Automatic reactor coolant system depressurization (first stage)	(See items 3a through 3c)		
c. Low-2 pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-12 Automatically unblocked above P-12
d. Low-2 steam generator wide range water level coincident with	4/steam generator	2/4-BYP[1] in both steam generators	Manual block permitted below P-9 Automatically unblocked above P-9
High hot leg temperature (High T_{hot})[(8)]	2/loop	2/4-BYP[1]	None
e. Manual initiation	2 controls	1/2 controls	None
7. Turbine Trip (Figure 7.2-1, Sheet 14)			
a. Manual feedwater isolation	(See item 4b)		
b. Reactor trip (P-4)	1/division	2/4	None
c. High-3 steam generator narrow range level	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
8. Steam Line Isolation (Figure 7.2-1, Sheet 9)			
a. Manual initiation	2 controls	1/2 controls	None
b. High-2 containment pressure	4	2/4-BYP[1]	None
c. Low-2 lead-lag compensated steam line pressure[4]	4/steam line	2/4-BYP[1] in either steam line	Manual block permitted below P-11 Automatically unblocked above P-11
d. High steam line negative pressure rate	4/steam line	2/4-BYP[1] in either steam line[7]	Manual unblock permitted below P-11 Automatically blocked above P-11
e. Low-2 cold leg temperature (Low-2 T_{cold})	4/loop	2/4-BYP[1] either loop[6]	Manual block permitted below P-11 Automatically unblocked above P-11
9. Steam Generator Blowdown System Isolation (Figure 7.2-1 Sheets 7 and 8)			
a. Passive residual heat removal heat exchanger actuation	(See items 12a through 12f)		
b. Low-2 steam generator narrow range water level	4/steam generator	2/4 BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
c. Containment isolation	(See items 2a through 2c)		
10. Passive Containment Cooling Actuation (Figure 7.2-1, Sheet 13)			
a. Manual initiation	2 controls	1/2 controls	None
b. High-2 containment pressure	4	2/4-BYP[1]	None

Table 7.3-1 (Sheet 5 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
11. Startup Feedwater Isolation (Figure 7.2-1, Sheets 9 and 10)			
a. Low-2 cold leg temperature (Low-2 T_{cold})	4/loop	2/4-BYP[1] either loop[6]	Manual block permitted below P-11 Automatically unblocked above P-11
b. High-3 steam generator narrow range water level	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
c. Manual initiation of main feedwater isolation		(See item 4b)	
d. High[10] steam generator narrow range level coincident with	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
Reactor trip (P-4)	1/division	2/4	None
12. Passive Residual Heat Removal (Figure 7.2-1, Sheet 8)			
a. Manual initiation	2 controls	1/2 controls	None
b. Low-2 steam generator narrow range water level coincident with	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
Low-2 startup feedwater flow	2/feedwater line	1/2[1] in either feedwater line	None
c. Low-2 steam generator wide range water level	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
d. Core makeup tank injection	(See Items 6a through 6e)		
e. Automatic reactor coolant system depressurization (first stage)	(See items 3a through 3c)		
f. High-3 pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-19 Automatically unblocked above P-19
13. Block of Boron Dilution (Figure 7.2-1, Sheets 3 and 15)			
a. Flux doubling calculation	4	2/4-BYP[1]	Manual block permitted above P-6 and above P-8 Automatically unblocked below P-6 or below P-8 Manual block permitted below P-8; demineralized water system isolation valves signaled closed when blocked below P-8
b. Undervoltage to Class 1E battery chargers(8)	2/charger	2/2 per charger and 2/4 chargers[5]	None
c. Reactor trip (P-4)	1/division	2/4	None

Table 7.3-1 (Sheet 6 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
14. Chemical and Volume Control System Makeup Isolation (See Figure 7.2-1, Sheets 3, 6, and 11)			
a. High-2 pressurizer water level	4	2/4-BYP[1]	Automatically unblocked above P-19 Manual block permitted below P-19
b. High-3 steam generator narrow range level	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
c. Automatic or manual safeguards actuation signal coincident with	(See items 1a through 1e)		
High[10] pressurizer water level	4	2/4-BYP[1]	None
d. High-2 containment radioactivity	4	2/4-BYP[1]	None
e. Manual initiation	2 controls	1/2 controls	None
f. Flux doubling calculation	4	2/4-BYP[1]	Manual block permitted above P-6 and above P-8 Automatically unblocked below P-6 or below P-8 Manual block permitted below P-8; demineralized water system isolation valves signaled closed when blocked below P-8
g. High[10] steam generator narrow range level coincident with	4/steam generator	2/4-BYP[1] in either steam generator	Manual block permitted below P-9 Automatically unblocked above P-9
Reactor trip (P-4)	1/division	2/4	None
15. Steam Dump Block (Figure 7.2-1, Sheet 10)[(8)]			
a. Low reactor coolant temperature (Low-2 T_{avg})	2/loop	2/4-BYP[1]	None
b. Mode control	2 controls	1/division	None
c. Manual stage 1 cooldown control	2 controls	1/division	None
d. Manual stage 2 cooldown control	2 controls	1/division	None
16. Main Control Room Isolation, Air Supply Initiation, and Electrical Load De-energization (Figure 7.2-1, Sheet 13)[(13)]			
a. High-2 main control room air supply iodine or particulate radiation	2	1/2[1]	None
b. Extended undervoltage to Class 1E 24-hour battery chargers[(13)]	2/charger	2/2 per charger and 2/4 chargers[5]	None
c. Extended Low main control room differential pressure	2	1/2[1]	None
d. Manual initiation[(8)]	2 controls	1/2 controls	None

Table 7.3-1 (Sheet 7 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
17. Auxiliary Spray and Purification Line and Zinc/Hydrogen Addition Isolation (Figure 7.2-1, Sheet 12)			
a. Low[10] pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-12 Automatically unblocked above P-12
b. Manual initiation of chemical and volume control system makeup isolation	(See item 14e)		
c. Manual initiation of auxiliary spray isolation[(8,12)]	1	1/1	None
d. Containment isolation[(11)]	(See Items 2a through 2c)		
18. Containment Air Filtration System Isolation (Figure 7.2-1, Sheets 11 and 13)			
a. Containment isolation	(See items 2a through 2c)		
b. High[10] containment radioactivity	4	2/4-BYP[1]	None
c. N/A	2	N/A	For containment vacuum relief valves only – close on inside containment purge isolation valve not closed
19. Normal Residual Heat Removal System Isolation (Figure 7.2-1, Sheets 13, 15, and 18)			
a. Automatic or manual safeguards actuation signal	(See items 1a through 1e)		
b. High-2 containment radioactivity	4	2/4-BYP[1]	Manual block permitted below P-11 Automatically unblocked above P-11
c. Automatic fourth stage ADS actuation[(8)]	4	2/4-BYP[1]	Automatically enabled below P-11 Automatically blocked above P-11
d. Manual initiation	4 controls	2/4 controls[3]	None
20. Refueling Cavity and SFS Isolation (Figure 7.2-1, Sheet 14)			
a. Low-2 spent fuel pool level	3	2/3[1]	None
b. Low IRWST wide range level	2	1/2[1]	Manual block permitted below P-9 Automatically unblocked above P-9
21. Open In-Containment Refueling Water Storage Tank (IRWST) Injection Line Valves[(9)] (Figure 7.2-1, Sheets 12, 16, and 19)			
a. Automatic reactor coolant system depressurization (fourth stage)	(See items 3d and 3e)		
b. Manual initiation	4 controls	2/4 controls[3]	None

Table 7.3-1 (Sheet 8 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
22. Open Containment Recirculation Valves In Series with Check Valves (Figure 7.2-1, Sheet 15 and 16)			
a. Extended undervoltage to Class 1E battery chargers(8)	2/charger	1/2 per charger and 2/4 chargers	None
23. Open All Containment Recirculation Valves (Figure 7.2-1, Sheet 16)			
a. Automatic reactor coolant system depressurization (fourth stage) coincident with		(See items 3d through 3f)	
Low IRWST lower narrow range level (Low-3 setpoint)	4	2/4-BYP[1]	None
b. Manual initiation	4 controls	2/4 controls[3]	None
24. Chemical and Volume Control System Letdown Isolation (Figure 7.2-1, Sheet 16)			
a. Low-2 hot leg level	1 per loop	1/2[1]	Manual block permitted above P-12 Automatically unblocked below P-12
25. Pressurizer Heater Trip (Figure 7.2-1, Sheets 6 and 12)			
a. Core makeup tank injection	(See items 6a through 6e)		
b. High-3 pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-19 Automatically unblocked above P-19
26. Steam Generator Relief Isolation (Figure 7.2-1, Sheet 9)			
a. Manual initiation	2 controls	1/2 controls	None
b. Low-2 lead-lag compensated steam line pressure[4]	4/steam line	2/4-BYP[1] in either steam line	Manual block permitted below P-11 Automatically unblocked above P-11
27. Close Component Cooling System Containment Isolation Valves (Figure 7.2-1, Sheets 5 and 11)			
a. High-2 (lead-lag compensated) reactor coolant pump bearing water temperature	4/pump	2/4-BYP[1] in affected pump	None
b. Safeguards actuation signal (automatic or manual)	(See items 1.a through 1.e)		

Table 7.3-1 (Sheet 9 of 9)
Engineered Safety Features Actuation Signals

Actuation Signal	No. of Divisions/ Controls	Actuation Logic	Permissives and Interlocks
28. Containment Vacuum Relief (Figure 7.2-1, Sheet 19)			
a. Low-2 containment pressure	4	2/4-BYP[1]	None
b. Manual initiation coincident with the following condition:	2 controls	1/2 controls	None
Low containment pressure	4	2/4-BYP[1]	None

Notes:

1. Capable of bypass (examples: The 2 out of 4 logic becomes 2 out of 3, the 2 out of 3 logic becomes 2 out of 2, and the 1 out of 2 logic is 1 out of 1 with one bypass. Note that 2 out of 2 logic becomes 2 out of 1 which renders the function inoperable). 2/4-BYP, where identified, indicates bypass logic specifically for 2/4 coincidence logic functions.
2. Any two channels from either tank not in same division.
3. Two associated controls must be actuated simultaneously.
4. Also, closes power-operated relief block valve of respective steam generator.
5. The logic is based on undervoltage to the battery chargers for divisions A or C coincident with an undervoltage to the battery chargers for divisions B or D.
6. Any two channels from either loop not in same division.
7. Any two channels from either line not in same division.
8. This function does not meet the 10 CFR 50.36(c)(2)(ii) criteria and is not included in the Technical Specifications.
9. Spurious ADS and IRWST injection actuations, both automatic and manual, are blocked as described in Subsection 7.3.1.2.4.1.
10. Low and Low-1 are considered to be equivalent terms when referring to the first low setpoint designator. High and High-1 are considered to be equivalent terms when referring to the first high setpoint designator.
11. Applies to only the Zinc/Hydrogen Addition Isolation.
12. Applies to only the Auxiliary Spray Isolation.
13. De-energization of Main Control Room air supply radiation monitor sample pumps occurs on an extended undervoltage to Class 1E 24-hour battery chargers as shown in Figure 7.2-1, Sheet 13.

Table 7.3-2 (Sheet 1 of 7)
Interlocks for Engineered Safety Features Actuation System

Designation	Derivation	Function
P-3	Reactor trip breaker open	Permits manual reset of safeguards actuation signal to block automatic safeguards actuation
$\overline{\text{P-3}}$	Reactor trip breakers closed	Automatically resets the manual block of automatic safeguards actuation
P-4	Reactor trip initiated or reactor trip breakers open	(a) Permits closing of the main feedwater control valves on low reactor coolant temperature (b) Permits closing of the main feedwater isolation valves, closing of the crossover leg valves, and tripping of the main feedwater pumps on Low-2 reactor coolant temperature (c) Trips turbine (d) Blocks boron dilution (e) Permits isolation of the startup feedwater valves on high narrow range water level in either steam generator (f) Permits isolation of the CVS makeup valves on high narrow range water level in either steam generator
$\overline{\text{P-4}}$	No reactor trip initiated and reactor trip breakers closed	(a) Prevents closing of the main feedwater control valves on low reactor coolant temperature (b) Prevents closing of the main feedwater isolation valves, closing of the crossover leg valves, and tripping of the main feedwater pumps on Low-2 reactor coolant temperature (c) Removes demand for turbine trip (d) Removes demand for boron dilution block (e) Prevents isolation of the startup feedwater valves on high narrow range water level in either steam generator (f) Prevents isolation of the CVS makeup valves on high narrow range water level in either steam generator
P-6	Intermediate range neutron flux channels above setpoint	Permits manual block of flux doubling actuation of the boron dilution block and CVS isolation Functions
$\overline{\text{P-6}}$	Intermediate range neutron flux channels below setpoint	Automatically resets the manual block of flux doubling actuation of the boron dilution block and CVS isolation Functions
P-8	Reactor coolant average temperature above setpoint	Permits manual block of flux doubling actuation of the boron dilution block and CVS isolation Functions

Table 7.3-2 (Sheet 2 of 7)
Interlocks for Engineered Safety Features Actuation System

Designation	Derivation	Function
$\overline{\text{P-8}}$	Reactor coolant average temperature below setpoint	(a) Automatically resets the manual block of flux doubling actuation of the boron dilution block and CVS isolation Functions (b) Permits manual block of flux doubling actuation of the boron dilution block and CVS isolation Functions; signals the demineralized water system isolation valves closed if flux doubling actuation of the boron dilution block is blocked below P-8
P-9	Reactor coolant average temperature above setpoint	(a) Prevents manual block of core makeup tank actuation on Low-2 steam generator wide range water level and automatically unblocks (b) Prevents manual block of steam generator blowdown system isolation on Low-2 steam generator narrow range water level and automatically unblocks (c) Prevents manual block of passive residual heat removal actuation on Low-2 steam generator wide range water level and on Low-2 steam generator narrow range water level and automatically unblocks (d) Prevents manual block of refueling cavity and spent fuel pool cooling system isolation on low IRWST wide range level and automatically unblocks (e) Prevents manual block of startup feedwater isolation on high narrow range steam generator level coincident with reactor trip (P-4) and automatically unblocks (f) Prevents manual block of CVS isolation on high narrow range steam generator level coincident with reactor trip (P-4) and automatically unblocks (g) Prevents manual block of startup feedwater isolation on High-3 narrow range steam generator level and automatically unblocks (h) Prevents manual block of CVS isolation on High-3 narrow range steam generator level and automatically unblocks (i) Prevents manual block of main feedwater isolation on High-3 narrow range steam generator level and automatically unblocks (j) Prevents manual block of turbine trip on High-3 narrow range steam generator level and automatically unblocks (k) Prevents manual block of reactor coolant pump trip on Low-2 steam generator wide range water level and automatically unblocks

Table 7.3-2 (Sheet 3 of 7)
Interlocks for Engineered Safety Features Actuation System

Designation	Derivation	Function
$\overline{\text{P-9}}$	Reactor coolant average temperature below setpoint	(a) Permits manual block of core makeup tank actuation on Low-2 steam generator wide range water level (b) Permits manual block of steam generator blowdown system isolation on Low-2 steam generator narrow range water level (c) Permits manual block of passive residual heat removal actuation on Low-2 steam generator wide range water level and on Low-2 steam generator narrow range water level (d) Permits manual block of refueling cavity and spent fuel pool cooling system isolation on low IRWST wide range level (e) Permits manual block of startup feedwater isolation on high narrow range steam generator level coincident with reactor trip (P-4) (f) Permits manual block of CVS isolation on high narrow range steam generator level coincident with reactor trip (P-4) (g) Permits manual block of startup feedwater isolation on High-3 narrow range steam generator level (h) Permits manual block of CVS isolation on High-3 narrow range steam generator level (i) Permits manual block of main feedwater isolation on High-3 narrow range steam generator level (j) Permits manual block of turbine trip on High-3 narrow range steam generator level (k) Permits manual block of reactor coolant pump trip on Low-2 steam generator wide range water level

Table 7.3-2 (Sheet 4 of 7)
Interlocks for Engineered Safety Features Actuation System

Designation	Derivation	Function
P-11	Pressurizer pressure below setpoint	(a) Permits manual block of safeguards actuation on Low-3 pressurizer pressure, Low-2 compensated steam line pressure, or Low-2 reactor coolant inlet temperature (b) Permits manual block of steam line isolation on Low-2 reactor coolant inlet temperature (c) Permits manual block of steam line isolation and steam generator power-operated relief valve block valve closure on Low-2 compensated steam line pressure (d) Coincident with manual actions of (b) or (c), automatically unblocks steam line isolation on high negative steam line pressure rate (e) Permits manual block of main feedwater control valve isolation on low reactor coolant temperature coincident with reactor trip (P-4) (f) Permits manual block of main feedwater isolation actuation, crossover leg valve isolation, and main feedwater pump trip on Low-2 reactor coolant temperature coincident with reactor trip (P-4) (g) Permits manual block of startup feedwater isolation on Low-2 reactor coolant inlet temperature (h) Permits manual block of normal residual heat removal system isolation on High-2 containment radioactivity. (i) Permits RNS containment isolation on automatic ADS stage 4 actuation.

Table 7.3-2 (Sheet 5 of 7)
Interlocks for Engineered Safety Features Actuation System

Designation	Derivation	Function
$\overline{\text{P-11}}$	Pressurizer pressure above setpoint	(a) Prevents manual block of safeguards actuation on Low-3 pressurizer pressure, Low-2 compensated steam line pressure, or Low-2 reactor coolant inlet temperature (b) Prevents manual block of steam line isolation on Low-2 reactor coolant inlet temperature (c) Prevents manual block of steam line isolation and steam generator power-operated relief valve block valve closure on Low-2 compensated steam line pressure (d) Automatic block of steam line isolation on high negative steam line pressure rate (e) Prevents manual block of main feedwater control valve isolation on low reactor coolant temperature coincident with reactor trip (P-4) (f) Prevents manual block of main feedwater isolation actuation, crossover leg valve isolation, and main feedwater pump trip on Low-2 reactor coolant temperature coincident with reactor trip (P-4) (g) Prevents manual block of startup feedwater isolation on Low-2 reactor coolant inlet temperature (h) Prevents manual block of normal residual heat removal system isolation on High-2 containment radioactivity (i) Prevents RNS containment isolation on automatic ADS stage 4 actuation.

Table 7.3-2 (Sheet 6 of 7)
Interlocks for Engineered Safety Features Actuation System

Designation	Derivation	Function
P-12	Pressurizer level below setpoint	(a) Permits manual block of core makeup tank actuation on Low-2 pressurizer level to allow mid-loop operation (b) Permits manual block of reactor coolant pump trip on Low-2 pressurizer level to allow mid-loop operation (c) Permits manual block of auxiliary spray and purification line isolation, and zinc and hydrogen addition isolation valves isolation on low pressurizer level to allow mid-loop operation (d) Coincident with manual action of (a), automatically unblocks fourth stage automatic depressurization system initiation on Low-4 hot leg level to provide protection during mid-loop operation. (e) Automatically unblocks chemical and volume control system letdown isolation on Low-2 hot leg level
$\overline{\text{P-12}}$	Pressurizer level above setpoint	(a) Prevents manual block of core makeup tank actuation on Low-2 pressurizer level (b) Prevents manual block of reactor coolant pump trip on Low-2 pressurizer level (c) Prevents manual block of auxiliary spray and purification line isolation, and zinc and hydrogen addition isolation valves isolation on low pressurizer level (d) Automatically blocks fourth stage automatic depressurization system initiation on Low-4 hot leg level to reduce the probability of spurious actuation. (e) Permits manual block of chemical and volume control system letdown isolation on Low-2 hot leg level

Table 7.3-2 (Sheet 7 of 7)
Interlocks for Engineered Safety Features Actuation System

Designation	Derivation	Function
P-19	Reactor coolant system pressure below setpoint	(a) Permits manual block of chemical and volume control system makeup isolation on High-2 pressurizer water level (b) Permits manual block of passive residual heat removal heat exchanger alignment on High-3 pressurizer water level (c) Permits manual block of the pressurizer heater trip on High-3 pressurizer water level
$\overline{\text{P-19}}$	Reactor coolant system pressure above setpoint	(a) Prevents manual block of chemical and volume control system makeup isolation on High-2 pressurizer water level (b) Prevents manual block of passive residual heat removal heat exchanger alignment on High-3 pressurizer water level (c) Prevents manual block of the pressurizer heater trip on High-3 pressurizer water level

Table 7.3-3 (Sheet 1 of 2)
System-Level Manual Input to the
Engineered Safety Features Actuation System

Manual Control	To Divisions				Figure 7.2-1 Sheet
Manual safeguards actuation #1	A	B	C	D	11
Manual safeguards actuation #2	A	B	C	D	11
Manual chemical and volume control system makeup isolation #1	A		C	D	6
Manual chemical and volume control system makeup isolation #2	A		C	D	6
Manual passive residual heat removal heat exchanger alignment #1	A	B		D	8
Manual passive residual heat removal heat exchanger alignment #2	A	B		D	8
Manual steam line isolation #1		B		D	9
Manual steam line isolation #2		B		D	9
Manual steam generator relief isolation #1		B		D	9
Manual steam generator relief isolation #2		B		D	9
Steam/feedwater isolation and safeguards block control #1	A				9
Steam/feedwater isolation and safeguards block control #2		B			9
Steam/feedwater isolation and safeguards block control #3			C		9
Steam/feedwater isolation and safeguards block control #4				D	9
Manual feedwater isolation #1		B		D	10
Manual feedwater isolation #2		B		D	10
Manual steam dump mode control #1		B			10
Manual steam dump mode control #2				D	10
Manual Stage 1 steam dump cooldown control #1		B			10
Manual Stage 1 steam dump cooldown control #2				D	10
Manual Stage 2 steam dump cooldown control #1		B			10
Manual Stage 2 steam dump cooldown control #2				D	10
Pressurizer pressure safeguards block control #1	A				11
Pressurizer pressure safeguards block control #2		B			11
Pressurizer pressure safeguards block control #3			C		11
Pressurizer pressure safeguards block control #4				D	11
Manual auxiliary spray isolation			C		12
Manual core makeup tank injection actuation #1	A	B	C	D	12
Manual core makeup tank injection actuation #2	A	B	C	D	12
Core makeup tank injection actuation block control #1	A				12
Core makeup tank injection actuation block control #2		B			12
Core makeup tank injection actuation block control #3			C		12
Core makeup tank injection actuation block control #4				D	12
Manual passive containment cooling actuation #1	A	B	C	D	13
Manual passive containment cooling actuation #2	A	B	C	D	13
Manual passive containment isolation actuation #1	A	B	C	D	13
Manual passive containment isolation actuation #2	A	B	C	D	13
Manual depressurization system stages 1, 2, and 3 actuation #1 & #2	A	B	C	D	15

Table 7.3-3 (Sheet 2 of 2)
System-Level Manual Input to the
Engineered Safety Features Actuation System

Manual Control	To Divisions				Figure 7.2-1 Sheet
Manual depressurization system stages 1, 2, and 3 actuation #3 & #4	A	B	C	D	15
Manual depressurization system stage 4 actuation #1 & #2	A	B	C	D	15
Manual depressurization system stage 4 actuation #3 & #4	A	B	C	D	15
Manual IRWST injection actuation #1 & #2	A	B	C	D	16
Manual IRWST injection actuation #3 & #4	A	B	C	D	16
Manual containment recirculation actuation #1 & #2	A	B	C	D	16
Manual containment recirculation actuation #3 & #4	A	B	C	D	16
Manual main control room isolation, air supply initiation, and electrical load de-energization #1	A	B	C		13
Manual main control room isolation, air supply initiation, and electrical load de-energization #2	A	B	C		13
RCS pressure CVS/PRHR block control #1	A				6
RCS pressure CVS/PRHR block control #2		B			6
RCS pressure CVS/PRHR block control #3			C		6
RCS pressure CVS/PRHR block control #4				D	6
SFS isolation block control #1	A				14
SFS isolation block control #2		B			14
Normal residual heat removal system isolation safeguards block control #1	A				13
Normal residual heat removal system isolation safeguards block control #2		B			13
Boron dilution block control #1	A				3
Boron dilution block control #2		B			3
Boron dilution block control #3			C		3
Boron dilution block control #4				D	3
Manual RNS isolation #1 & #3	A	B		D	18
Manual RNS isolation #2 & #4	A	B		D	18
CVS letdown isolation block control #1	A				16
CVS letdown isolation block control #2				D	16
Manual containment vacuum relief actuation #1	A		C		19
Manual containment vacuum relief actuation #2	A		C		19
FWS/CVS isolation and turbine trip block control #1	A				10
FWS/CVS isolation and turbine trip block control #2		B			10
FWS/CVS isolation and turbine trip block control #3			C		10
FWS/CVS isolation and turbine trip block control #4				D	10

Table 7.3-4 (Sheet 1 of 2)
Engineered Safety Features Actuation, Variables, Limits, and Ranges (Nominal)

Variable	Range of Variable	Response Time Assumed in Accident Analysis (Sec)(1)
Pressurizer pressure	1500 to 2500 psig	2.0
Steam line pressure	500 to 1300 psig	2.0
Steam line negative pressure rate	0 to 1300 psig	N/A(2)
Cold leg temperature (T_{cold})	490 to 610°F	2.0(3)
Hot leg temperature (T_{hot})	530 to 650°F	N/A(4)
Containment pressure	-5 to 10 psig	2.0
Reactor coolant system hot leg level	0 to 100% of span	N/A(2)
In-containment refueling water storage tank level	0 to 100% of span	N/A(2)
Undervoltage on input of 1E battery charger	0 to 500 V	N/A(4)
Steam generator narrow range water level	0 to 100% of span (narrow range taps)	2.0
Steam generator wide range water level	0 to 100% of span (wide range taps)	2.0
Core makeup tank narrow range upper water level	0 to 100% of span	2.0
Core makeup tank narrow range lower water level	0 to 100% of span	2.0
Reactor coolant pump bearing temperature	50 to 400°F	N/A(2)
Spent fuel pool level	0 to 26 feet	N/A(2)
Reactor coolant system wide range pressure	0 to 3300 psig	N/A(2)

Table 7.3-4 (Sheet 2 of 2)
Engineered Safety Features Actuation, Variables, Limits, and Ranges (Nominal)

Variable	Range of Variable	Response Time Assumed in Accident Analysis (Sec)(1)
Pressurizer water level	0 to 100% of cylindrical portion of pressurizer	2.0
Startup feedwater flow	0 to 600 gpm	2.0
Neutron flux (flux doubling calculation)	1 to 10^6 c/sec	80.0(5)
Control room supply air radiation level	Particulate: 10^{-12} to 10^{-7} μ Ci/cc Iodine: 10^{-11} to 10^{-5} μ Ci/cc	200
Control room differential pressure	+1.00 to -1.00 in. w.g.	N/A(2)
Containment radioactivity	10^0 to 10^7 R/hr	N/A(2)

Notes:

1. Delay from the time that the process variable exceeds the setpoint until the time that an output is provided to the actuated device. This response time reflects the total delay from both the PMS equipment and the associated sensor.
2. The following functions are not explicitly assumed to initiate an ESF in the accident analysis. However, they are subject to response time test surveillance requirements in the technical specifications. Therefore, the following maximum allowable response times are allocated:

   Steam line negative pressure rate = 2.0 seconds
   Reactor coolant system hot leg level = 3.0 seconds
   In-containment refueling water storage tank level (Narrow Range) = 3.0 seconds
   In-containment refueling water storage tank level (Wide Range) = 3.0 seconds
   Reactor coolant pump bearing temperature = 8.5 seconds
   Spent Fuel Pool Level = 2.0 seconds
   Reactor coolant system wide range pressure = 2.0 seconds
   Control room differential pressure = 3.0 seconds
   Containment Radioactivity = 25.0 seconds

3. In addition to the response time given, a 4.0 second lag time is used in the accident analysis for this function to account for the associated RTDs.
4. This function is not explicitly assumed to initiate an ESF in the accident analysis and does not have any response time test requirements in the technical specifications.
5. Response time depends on flux doubling calculation.

7.4 Systems Required for Safe Shutdown

Systems to establish safe shutdown conditions perform two basic functions. First, they provide the necessary reactivity control to maintain the core in a subcritical condition. Boration capability is provided to compensate for xenon decay and to maintain the required core shutdown margin. Second, these systems must provide residual heat removal capability to maintain adequate core cooling.

The designation of systems required for safe shutdown depends on identifying those systems that provide the following capabilities for maintaining a safe shutdown:

- Decay heat removal
- Reactor coolant system inventory control
- Reactor coolant system pressure control
- Reactivity control

There are two different safe shutdown conditions that are expected following a transient or accident condition. Short-term safe shutdown refers to the plant conditions from the start of an event until about 36 hours later. Long-term safe shutdown refers to the plant conditions after this 36-hour period.

The short-term safe shutdown conditions include maintaining the reactor subcritical, the reactor coolant average temperature less than or equal to no load temperature, and adequate coolant inventory and core cooling. These shutdown conditions shall be achieved following any of the design basis events using safety-related equipment. The specific safe shutdown condition achieved is a function of the particular accident sequence.

The long-term safe shutdown conditions are the same as the short-term conditions except that the core average temperature shall be less than 420°F. This long-term condition must be achieved within 36 hours following a non-LOCA event using the passive residual heat removal heat exchanger as shown in Appendix 19E. These safe shutdown conditions can be maintained by the passive residual heat removal heat exchanger for greater than 14 days based on a non-bounding, conservative analysis that only credits using safety-related equipment. In addition, these safe shutdown conditions can be maintained indefinitely using the automatic depressurization system and passive injection/ recirculation as discussed in Subsection 7.4.1.1.

There are no systems specifically and solely dedicated as safe shutdown systems. However, there are a number of plant systems that are available to establish and maintain safe shutdown conditions. Normally, in the event of a turbine or reactor trip, nonsafety-related plant systems automatically function to place the plant in short-term safe shutdown, as described in Subsection 7.4.1.2. During the short-term safe shutdown condition, an adequate heat sink is provided to remove reactor core residual heat and boration control is available. Redundancy of systems and components is provided to enable continued maintenance of the short-term safe shutdown condition. Additional redundant nonsafety-related systems are normally available to manually perform a plant depressurization and cooldown.

The engineered safety systems are designed to establish and maintain safe shutdown conditions for the plant. Nonsafety-related systems are not required for safe shutdown of the plant.

This section focuses on safety-related systems used to establish and maintain safe shutdown conditions. The discussion of safe shutdown does not include accident response and/or mitigation since the standard review plan for this section addresses safe shutdown not related to accident

mitigation. However, safe shutdown conditions are also established and maintained by these safety-related systems following accident conditions. For example, the control rods are released to initially place the plant in a shutdown condition to mitigate the consequences of various accidents. The passive core cooling system, on the other hand, is used to provide core cooling in an accident, but it is also one of the principal systems used for safe shutdown. Only those specific engineered safety systems listed in Table 7.4-1 are used to establish and maintain safe shutdown of the plant. These engineered safety systems automatically function to place the plant in a safe shutdown condition without operator action.

The instrumentation functions necessary for safe shutdown are available through instrumentation channels associated with the safety-related systems in the primary plant. These channels automatically actuate the protective functions provided by the safety-related systems. Manual actuation of the associated safety-related systems is also provided.

The instrumentation systems discussed in this section are those which are required during nonaccident conditions to align the safety-related systems and perform the specified safe shutdown functions.

The specific systems available for safe shutdown are discussed in Subsection 7.4.2 and are listed in Table 7.4-1.

Maintenance of safe shutdown conditions with these systems, and the associated instrumentation and controls, includes consideration of the accident consequences that might challenge safe shutdown conditions. The accident consequences that are germane are those that tend to degrade the capabilities for coolant circulation, boration, heat removal, and depressurization. Safe shutdown is achieved following any of the accidents analyzed in Chapter 15. The specific safe shutdown condition reached is a function of the particular accident sequence.

The instrumentation and controls discussed in Subsection 7.4.1 are used to control and/or monitor shutdown. These safety-related systems allow the maintenance of safe shutdown, even under accident conditions that tend toward a return to criticality or a loss of heat sink.

In addition to the operation of safety-related systems used for safe shutdown, as described in Subsection 7.4.1, the following are part of the safe shutdown provisions:

- The turbine is tripped. (This can be accomplished at the turbine as well as from the main control room.)
- The reactor is tripped. (This can be accomplished at the reactor trip switchgear as well as from the main control room.)
- Support of engineered safety systems actuation is provided by safety-related onsite dc power.

7.4.1 Safe Shutdown

7.4.1.1 Safe Shutdown Using Safety-Related Systems

The following describes the process that establishes safe shutdown conditions for the plant, based on a conservative, non-bounding analysis using the safety-related systems, and no operator action. The reactor coolant system is assumed to be intact for this discussion of safe shutdown.

Since this discussion only considers the use of safety-related systems, offsite electrical power sources are assumed to be lost at the start of the event. This results in a loss of the reactor coolant

pumps. Even though the reactor coolant pumps are tripped during the initiation of certain engineered safety system actuation, it is assumed that no engineered safety system actuation signal is generated for this initiating event. With loss of the reactor coolant pumps, reactor coolant system natural circulation flow initiates and transfers core heat to the steam generators. Since feedwater flow is lost, the existing steam generator water inventory provides initial decay heat removal capability.

The initial loss of main ac power results in the Class 1E dc batteries automatically supplying power to the Class 1E dc power distribution network and the four Class 1E 120 Vac instrumentation divisions via the inverters.

The initial response of the passive safety systems is to actuate the passive residual heat removal heat exchanger due to Low-2 steam generator wide range water level. The passive residual heat removal heat exchanger removes decay heat from the core by transferring this heat to the in-containment refueling water storage tank.

The passive residual heat removal heat exchanger removes core decay heat, cooling the reactor coolant system. As reactor coolant system cooldown continues, the reactor coolant system pressure decreases due to contraction of the reactor coolant system inventory since the pressurizer heaters are de-energized. An engineered safety system actuation signal occurs when reactor coolant system pressure decreases below a setpoint. This actuates the core makeup tanks, if they had not been previously actuated due to Low-2 pressurizer level. The core makeup tanks provide borated water injection to the reactor coolant system.

The engineered safety system actuation signal generated on Low-3 pressurizer pressure also actuates containment isolation. This prevents loss of water inventory from containment and permits operation of the passive residual heat removal heat exchanger and the in-containment refueling water storage tank for greater than 14 days.

The in-containment refueling water storage tank starts to boil about one to two hours after passive residual heat removal operation is initiated. Once boiling occurs, the in-containment refueling water storage tank begins steaming to containment, transferring heat to the air flowing on the outside of the containment shell. As steaming to containment continues, containment pressure slowly increases. As containment pressure slowly increases, an engineered safety system actuation signal is generated on containment High-2 pressure, resulting in the initiation of passive containment cooling. This provides water flow on the outside of the containment shell to improve the heat removal performance from containment through evaporative cooling to the outside air.

A gutter located at the operating deck elevation collects condensate from the inside of the containment shell. Valves located in drain lines from the gutter to the containment waste sump close on a passive residual heat removal heat exchanger actuation signal. This action diverts the condensate to the in-containment refueling water storage tank. The system provides core decay heat removal in this configuration for greater than 14 days with a limited increase in the containment water level.

Once the reactor coolant system and the safety systems are in this configuration, the plant is in a safe, stable shutdown condition. The reactor coolant system temperatures and pressures continue to slowly decrease. The passive residual heat removal heat exchanger has the capacity to maintain a safe, stable reactor coolant system condition during a design basis event for at least 72 hours in a closed-loop mode of operation. A non-bounding, conservative analysis of extended operation in this mode shows the passive residual heat removal heat exchanger cools the reactor coolant system to 420°F in 36 hours.

Operation in this configuration may be limited in time duration by reactor coolant system leakage. The core makeup tanks can only supply a limited amount of makeup in the event there is reactor

coolant system leakage. Eventually the volume of the water in the core makeup tanks will decrease to the first stage automatic depressurization setpoint. The time to reach this setpoint depends upon the reactor coolant system leak rate and the reactor coolant cooldown.

The 24-hour Class 1E dc batteries that power the automatic depressurization system valves provide power for at least 24 hours. There is a timer that measures the time that ac power sources are unavailable. This timer provides for automatic actuation of the automatic depressurization system before the 24-hour Class 1E dc batteries are discharged. The emergency response guidelines direct the operator to assess the need for automatic depressurization before the timer completes its count (approximately 22 hours). The operator assessment considers core makeup tank levels, reactor coolant system hot leg level, temperature, and pressure. If automatic depressurization is not needed, the operator is directed to de-energize all loads on the 24-hour Class 1E dc batteries. This action preserves the capability for the operator to initiate automatic depressurization at a later time based on assessment of the same parameters.

The automatic depressurization system can be manually initiated by the operator at any time, but no operator action is needed to provide safe shutdown conditions. Once the automatic depressurization system sequence initiates, the plant automatically transitions to lower pressure and temperature conditions that establish and maintain long-term safe shutdown of the plant.

When the automatic depressurization system is actuated, the first stage depressurization valves open and the reactor coolant system depressurization starts. The second and third stage depressurization valves open in sequence, based on automatic timers that are started upon the actuation of the first stage depressurization valves. As reactor coolant inventory continues to be lost, the core makeup tanks continue to inject. If the volume of the water in the core makeup tanks decrease to the fourth stage automatic depressurization setpoint, the fourth stage depressurization valves open. The water and steam vented from the reactor coolant system initially flows into the in-containment refueling water storage tank and overflows into the refueling canal. Eventually this overflows into the reactor vessel cavity, where any moisture from the fourth stage automatic depressurization system valves also collects from discharge in the loop compartments. This overflow initiates the floodup of containment, along with condensate from the containment shell and other cool surfaces in containment.

As the reactor coolant system pressure decreases, the accumulators inject borated water into the reactor coolant system. After the fourth stage automatic depressurization system valves open, the reactor coolant system pressure is reduced sufficiently so that in-containment refueling water storage tank injection can begin as the core makeup tanks empty.

The drain down of the in-containment refueling water storage tank is relatively slow, depending on the injection rates and the reactor coolant system pressure. As the in-containment refueling water storage tank continues to inject, the containment floodup also continues and eventually the floodup volume is sufficient to initiate flow from the recirculation sump.

As the reactor coolant system voids during the cooldown and depressurization process, water flow through the passive residual heat removal heat exchanger is replaced by steam flow, which also provides core cooling. As the in-containment refueling water storage tank empties and uncovers the passive residual heat removal heat exchanger, heat transfer via this path decreases. Eventually, the passive residual heat removal heat exchanger is uncovered, heat removal by the passive residual heat removal heat exchanger stops, and decay heat is removed by automatic depressurization system venting.

The final long-term safe shutdown plant conditions are maintained with the reactor coolant system depressurized to about 10 psig at saturated conditions, venting steam through the automatic depressurization system valves to containment, with heat transferred to the outside atmosphere via

the passive containment cooling system. With containment isolation established, the water inventory inside containment provides an indefinite cooling water supply for core decay heat removal.

7.4.1.2 Safe Shutdown Using Safety-Related and Nonsafety-Related Systems

This subsection describes situations where nonsafety-related features of the plant are used together with safety-related systems to establish safe shutdown conditions. As discussed in Subsection 7.4.1.1, the AP1000 can be placed in a safe shutdown condition and maintained there using safety-related systems and no operator actions. Section 6.3 provides additional discussion of these situations.

Following passive residual heat removal heat exchanger actuation, the in-containment refueling water storage tank heats up and starts to boil after several hours of operation. If normal steam generator heat removal is not re-established, the operators align the normal residual heat removal system to cool the in-containment refueling water storage tank. This operation prevents significant steaming to the containment.

In case the automatic depresurization system is actuated, the operators align the normal residual heat removal system to provide injection to the reactor coolant system. This action causes the core makeup tank level to remain above the fourth stage valve actuation setpoint and prevents significant steaming to and flooding of the containment.

7.4.1.3 Safe Shutdown Using Nonsafety-Related Systems

This subsection describes the process to establish and maintain safe shutdown conditions using the nonsafety-related systems. As discussed in Section 7.4, the review of the plant safe shutdown capability, including the capabilities provided by the nonsafety-related systems, does not include accident response or mitigation. The nonsafety-related systems normally used to support plant shutdown operations are expected to be available. Offsite power is also expected to be available to support safe shutdown operations, although the nonsafety-related systems can establish and maintain safe shutdown conditions using only onsite electrical power.

For the purposes of this discussion, the nonsafety-related system operation following a reactor trip is described. As assumed in the discussion in Subsection 7.4.1.1 on safe shutdown using safety-related systems, the reactor coolant system is assumed to be intact during plant safe shutdown operations.

The nonsafety-related systems and equipment used to establish and maintain safe shutdown conditions are the same systems and equipment that are operated during normal plant startup and shutdown evolutions. The safe shutdown capability using the safety-related systems, described in Subsection 7.4.1.1, is only expected to be used in the event that the nonsafety-related systems are not available.

The nonsafety-related systems operate to establish and maintain safe shutdown conditions by providing the safe shutdown functions described in Section 7.4, except that reactivity control is only needed for long-term safe shutdown. If offsite power is available, the operation of these nonsafety-related systems is automatic.

The nonsafety-related systems actuate to establish and maintain the short-term safe shutdown conditions. The systems can also establish and maintain long-term safe shutdown conditions within the time limits discussed in Section 7.4. The operational philosophy following any event is to maintain appropriate safe shutdown conditions based on the duration of the shutdown, until the plant is able to re-start.

Cold shutdown conditions would only be established if it becomes necessary for equipment repair or due to limitations of the nonsafety-related systems in maintaining safe shutdown conditions (such as feedwater system water inventory). This philosophy reduces unnecessary challenges to plant safety due to the transition from operating systems to infrequently-operated standby systems.

Normally, offsite electrical power is available and the nonsafety-related systems automatically maintain short-term safe shutdown conditions as follows:

- Reactor coolant system forced flow to the steam generators by the reactor coolant pumps
- Feedwater from the main or startup feedwater systems
- Heat removal by the steam generators to the main condenser using turbine bypass valves
- Condenser heat removal provided by the main circulating water system
- Reactor coolant system inventory and boration control by the chemical and volume control system
- Reactor coolant system pressure control using pressurizer heaters and normal spray

If offsite power is not available, the reactor coolant pumps, main feedwater pumps, and main circulating water pumps will not be operating. However, the nonsafety-related systems maintain short-term safe shutdown conditions without offsite electrical power as follows:

- Electrical power provided to the required nonsafety-related systems by the diesel-generators of the onsite standby power system
- Heat removal by the steam generators directly to the atmosphere through the power-operated relief valves
- Feedwater from the startup feedwater system
- Reactor coolant system flow to the steam generators via natural circulation
- Reactor coolant system inventory and boration control by the chemical and volume control system
- Reactor coolant system pressure control using pressurizer heaters and auxiliary spray

In case the main feedwater is unavailable, the initial response of the nonsafety-related systems following a reactor trip is to automatically actuate the startup feedwater system, on low steam generator water level, to provide decay heat removal. The steam generators can remove decay heat from the core by either forced or natural circulation in the reactor coolant system. If offsite electrical power is available, the reactor coolant pumps continue to provide forced circulation in the reactor coolant system and the circulating water system continues to operate to provide a heat sink for the steam discharged from the steam generators to the main condenser.

With offsite power and the main condenser available, the turbine bypass valves automatically actuate after the reactor trip to control reactor coolant system temperature, based on the pre-set steam generator pressure control set point that is normally established for standby turbine bypass valve operation. The main feedwater system or the startup feedwater system automatically maintains steam generator water level as the turbine bypass valves continue to throttle steam flow to match the

decreasing core decay heat levels. The pressurizer heaters and spray automatically maintain reactor coolant system subcooling with pressure at normal reactor coolant system conditions.

The chemical and volume control system makeup pumps automatically actuate as required to provide borated makeup water to maintain pressurizer level in the programmed band for no-load conditions. The makeup source is the boric acid tank which provides long-term reactivity control. The makeup pumps are expected to operate infrequently during these conditions to compensate for normal reactor coolant system inventory losses such as valve leakage.

Operation of the nonsafety-related systems in this mode maintains short-term safe shutdown conditions and reactor coolant system temperature and pressure remain near no-load conditions. If it becomes necessary to perform a plant cooldown and depressurization to establish long-term safe shutdown conditions, the nonsafety-related systems are used, following the normal plant cooldown procedures. Manual boration to the cold shutdown boron concentration is provided by the chemical and volume control system by initiating reactor coolant system letdown in combination with makeup pump operation. After the boration is completed and letdown is secured, the makeup pumps automatically maintain reactor coolant system inventory throughout the remainder of the cooldown process.

After the required boration is completed the turbine bypass valves are used to initiate the cooldown, with manual control of pressurizer heaters and spray to maintain the reactor coolant system pressure, temperature, and cooldown rate within the limits specified in the technical specifications. The main feedwater system automatically provides feedwater and maintains steam generator level throughout the cooldown process.

When the reactor coolant system temperature and pressure are reduced to within the capabilities of the normal residual heat removal system, at approximately 350°F and 400 psig, the system is manually aligned to the reactor coolant system and started to continue the cooldown process. The final long-term safe shutdown conditions established would be dependent upon the specific maintenance required.

The use of the nonsafety-related systems and equipment for both short-term and long-term safe shutdown also requires the operation of associated support systems. These normally operating support systems include component cooling water, chilled water, compressed air, area ventilation, and nonsafety-related instrumentation and control power. These systems are started as required following a loss of offsite power, once the nonsafety-related diesel-generators are started.

If offsite electrical power is unavailable, the nonsafety-related systems actuate to establish and maintain safe shutdown conditions. There are some differences in the decay heat discharge flow path and the reactor coolant system remains at a slightly higher temperature resulting from the natural circulation flow conditions. With the loss of offsite electrical power, the nonsafety-related diesel-generators provide electrical power for the required nonsafety-related equipment. However, the reactor coolant pumps, main feedwater pumps, and main circulating water pumps are not available. Therefore, core decay heat is transferred to the steam generators using natural circulation in the reactor coolant system, the startup feedwater pumps supply the steam generators, and the steam generators discharge directly to the atmosphere to remove decay heat.

When offsite electrical power is unavailable, reactor coolant temperature is automatically maintained by the steam generator atmospheric power-operated relief valves instead of the turbine bypass valves. The steam generator power-operated relief valves maintain a pre-set steam generator pressure by throttling the steam discharged directly from the steam generators to the atmosphere. The relief valve operation maintains a slightly higher steam generator pressure than the pressure maintained with turbine bypass valve standby operation, resulting in a slight increase in the reactor coolant system temperature. The automatic operation of the startup feedwater subsystem maintains

steam generator inventory with the pumps powered from the diesel-generators. In addition, the direct discharge of steam to the atmosphere prevents condensate recovery, which limits the water inventory for the startup feedwater system.

Following a loss of offsite power, the reactor coolant system temperature is slightly higher than for a reactor trip when offsite electrical power is available, resulting from natural circulation flow and steam generator power-operated relief valve operation. Since the transition to natural circulation flow is relatively slow, the reactor coolant system pressure remains stable without operator action. Operator action is not required to maintain reactor coolant system pressure.

Without offsite electrical power, the pressurizer heaters are manually re-energized after the diesel-generators start. Without reactor coolant pump operation, normal pressurizer spray is unavailable to counteract system pressure increases. Therefore, auxiliary spray provided by the chemical and volume control system makeup pumps is manually initiated to decrease reactor coolant system pressure, if necessary. The operation of the chemical and volume control system makeup pumps to maintain reactor coolant system inventory is similar to their operation when offsite power is available, except that the pumps are manually controlled and powered from the diesel-generators.

The nonsafety-related systems are normally expected to maintain short-term safe shutdown conditions when offsite power is not available. If it is required to establish long-term safe shutdown conditions for equipment maintenance, the cooldown would normally be delayed until offsite power is recovered.

However, the nonsafety-related systems can be used to perform a natural circulation cooldown, if necessary. When performing a natural circulation plant cooldown and depressurization, the operation of the nonsafety-related systems is similar to the normal cooldown operation except that they are powered from the diesel-generators. The primary difference in operation is the use of the steam generator power-operated relief valves to control the cooldown process.

7.4.2 Safe Shutdown Systems

To effect a safe shutdown, with safety-related systems, the plant is initially brought to a stable condition with heat removal provided by the passive residual heat removal heat exchanger. For safe shutdown conditions, control is possible from either the main control room or the remote shutdown workstation. To accomplish a safe shutdown, the functions required are: coolant circulation, boration, heat removal, and depressurization. The portions of the protection and safety monitoring system required to achieve the safe shutdown condition are described in Sections 7.2 and 7.3. The minimum systems required to maintain safe shutdown conditions under a nonaccident condition are listed and discussed in the following paragraphs.

7.4.2.1 Passive Core Cooling System

A description of the passive core cooling system and its operation is provided in Section 6.3. The passive residual heat removal heat exchanger, the core makeup tanks, the in-containment refueling water storage tank, the containment recirculation, and the automatic depressurization system actuate automatically. They can also be manually initiated. Actuation controls are located at the remote shutdown workstation as well as in the main control room.

The safety injection flow from the accumulators, initiates automatically by the reactor coolant system depressurization process. The operation of the accumulator is integrated with the automatic actuation of the other passive core cooling subsystems.

7.4.2.2 Passive Containment Cooling System

A description of the passive containment cooling system and its operation is provided in Subsection 6.2.2. The passive containment cooling system actuates automatically. It also can be manually initiated. Actuation controls are located at the remote shutdown workstation as well as in the main control room.

7.4.2.3 Containment Isolation

A description of containment isolation valves and their operation is provided in various subsections. Each system that has piping that penetrates the containment vessel and therefore, requires containment isolation valves is discussed in its own subsection. Most of these systems are nonsafety-related; however, the containment isolation valves and the associated piping are safety-related and automatically close on a safeguards actuation (S) signal. The containment isolation system is discussed in Subsection 6.2.3.

7.4.2.4 Reactor Coolant System Circulation

The preferred method of coolant circulation is forced circulation with the reactor coolant pumps supplying the driving head. Upon the loss of main ac power, or when the reactor coolant pumps are tripped during engineered safety system actuation, the reactor coolant pumps are not available. However, the reactor coolant system is designed to provide sufficient natural circulation to achieve safe shutdown conditions with the steam generators and passive residual heat removal heat exchanger removing decay heat. Natural circulation flow is verified by monitoring the reactor coolant system temperatures.

7.4.2.5 Other Systems Required for Safe Shutdown

The other safety-related equipment and systems used to maintain the plant in safe shutdown are identified in Table 7.4-1. They are also listed below, with a reference to the respective section or subsection which discusses their operation in more detail:

- Protection and safety monitoring system — Sections 7.2, 7.3, and 7.5
- Class 1E dc and UPS system — Subsection 8.3.2

These systems are either normally operating or they start automatically when required. The instrumentation for these systems is described in the particular section containing the system description.

The monitoring instrumentation available in the main control room for safe shutdown is safety-related and is part of the protection and safety monitoring system. The instrumentation available for safe shutdown monitoring is listed in Section 7.5.

7.4.3 Safe Shutdown from Outside the Main Control Room

7.4.3.1 Description

If temporary evacuation of the main control room is required because of some abnormal main control room condition, the operators can establish and maintain safe shutdown conditions for the plant from outside the main control room through the use of controls and monitoring located at the remote shutdown workstation. Safe shutdown is a stable plant condition that can be maintained for an extended period of time. In the event that access to the main control room is restricted, the plant is maintained in safe shutdown until the main control room can be re-entered.

7.4.3.1.1 Remote Shutdown Room/Remote Shutdown Workstation

Safe shutdown can be established and maintained from the remote shutdown room. The I&C equipment in the room is collectively referred to as the remote shutdown workstation. The workstation is designed to allow control of a shutdown following an evacuation of the control room, coincident with the loss of offsite power and a single active failure. No other design basis event is postulated. Subsection 9.5.1 provides a discussion of shutdown in the event of a fire. The design basis for the remote shutdown workstation does not require safety-related displays, alarms, and controls.

The remote shutdown workstation contains nonsafety controls, displays, and alarms for the safety-related equipment required to establish and maintain safe shutdown. Additionally, control of nonsafety-related components is available.

The remote shutdown workstation includes operator workstations that are similar to the operator workstations in the main control room and are designed to the same standards. The remote shutdown workstation also includes dedicated nonsafety controls that provide the minimum inventory of controls listed in Table 18.12.2-1. The dedicated nonsafety controls interface to the plant safety and monitoring system via qualified isolators within that system.

The operator workstations have the same capabilities as the reactor operator's workstation in the main control room. The displays and alarms listed in Table 18.12.2-1 are retrievable from the operator workstations. Subsection 18.12.3 provides more discussion on the remote shutdown workstation displays, alarms, and controls.

The remote shutdown workstation is provided for use only following an evacuation of the main control room. No actions are anticipated from the remote shutdown workstation during normal, routine shutdown, refueling, or maintenance operations.

The remote shutdown workstation has sufficient communication circuits to allow the operator to effectively establish safe shutdown conditions. As detailed in Subsection 9.5.2, communication is available between the following stations:

- Main control room
- Remote shutdown workstation
- Onsite technical support center
- Diesel generator local control station

Operator control capability at the remote shutdown workstation is normally disabled, and operator control functions are normally performed from workstations located inside the main control room; however, operator control capability can be transferred from the main control room workstations to the remote shutdown workstation if the control room requires evacuation. Procedures will instruct the operator to trip the reactor prior to evacuating the control room and transferring control to the remote shutdown workstation. This operator control transfer capability cannot be disabled by any single active failure coincident with the loss of offsite power.

The control transfer function is implemented by multiple transfer switches. Each individual transfer switch is associated with only a single safety-related or single nonsafety-related group. These switches are located behind an unlocked access panel. Entry into this access panel will result in alarms at the main control room and remote shutdown workstation. The access panel is located within a fire zone which is separate from the main control room. Actuation of these transfer switches

results in additional alarms at the main control room and remote shutdown workstation, the activation of operator control capability from the remote workstation, and the deactivation of operator control capability from the main control room workstations. This deactivation of operator control capability includes deactivation of all operator control capability provided by the soft control devices described in Subsection 7.1.3.3 and deactivation of all operator control capability provided by dedicated switches. This includes deactivation of operator control capability using manual actuation functions provided by the diverse actuation system as described in Subsection 7.7.1.11. The manual reactor trip switches located in the main control room are not affected by this control transfer function. The operator displays, located in the main control room and on the remote shutdown workstation, are also not affected by this control transfer function. The displays on the remote shutdown workstation are operational during normal operation (from the main control room) so that they can be used with no delay if transfer to the remote shutdown workstation is required.

7.4.3.1.2 Controls at Other Locations

In addition to the controls and indicators provided at the remote shutdown workstation, the following controls are provided outside the main control room:

- Reactor trip capability at the reactor trip switchgear
- Turbine trip capability at the turbine
- Start/stop controls for the diesel generators, located at each diesel generator local control panel
- Local control at motor control centers and electrical switchgear.

7.4.3.1.3 Design Bases Information

According to GDC 19, the capability of establishing a shutdown condition and maintaining the station in a safe status in that mode is an essential function. The controls and indications necessary for this function are identified in Subsection 7.4.2. To provide the availability of the remote shutdown workstation after control room evacuation, the following design features are provided:

- The remote shutdown workstation conforms with the guidelines provided by ANSI 58.6 1996 (Reference 1).
- The remote shutdown workstation achieves and maintains safe shutdown conditions from full power conditions and maintains safe shutdown conditions thereafter.
- The remote shutdown workstation achieves safe shutdown when offsite power is available and when offsite power is not available.
- The remote shutdown workstation operates safety-related systems, independent from the main control room.
- The remote shutdown workstation is designed with redundancy. When a random event, such as a fire, or an allowable technical specification maintenance results in one safety-related division being unavailable, a single failure in a redundant division is not postulated. When a random event other than fire causes a main control room evacuation, a coincident single failure in the safety systems controlled from the remote shutdown workstation is considered.
- Access to the remote shutdown workstation is under administrative control.

7.4.3.2 Analysis

The analysis of the systems required for safe shutdown is provided in Subsection 7.4.1. The following discussion is limited to the remote shutdown workstation.

Conformance to NRC General Design Criteria

General Design Criterion 19 – The remote shutdown workstation provides adequate controls and indications located outside the main control room to establish and maintain the reactor and the reactor coolant system in a safe shutdown condition in the event that the main control room must be evacuated.

Conformance to NRC Regulatory Guides

Regulatory Guide 1.22 – The remote shutdown workstation is tested periodically during station operation.

Regulatory Guide 1.29 – The remote shutdown workstation is designed as seismic Category II to prevent compromising the function of safety-related devices during or after a safe shutdown earthquake.

Conformance to IEEE 603-1991

The remote shutdown workstation and the design features which provide for the transfer of control capability from the main control room to the remote shutdown workstation conform to applicable portions of IEEE 603-1991. The circuits which perform the control transfer function are designed so that a single failure does not prevent maintaining safe shutdown. This is accomplished by redundant components in the systems required for safe shutdown, using independent safety-related power divisions.

To prevent interaction between the redundant systems, the redundant control channels are wired independently and are separated from each other. Nonsafety-related circuits available for (but not required for) safe shutdown are electrically isolated from safety-related circuits.

7.4.4 Combined License Information

This section contained no requirement for information.

7.4.5 References

1. ANSI 58.6 1996, "Criteria for Remote Shutdown for Light Water Reactors."

Table 7.4-1
Systems Required for Safe Shutdown

Protection and Safety Monitoring System
Passive Core Cooling System
Passive Residual Heat Removal Heat Exchanger
Core Makeup Tanks
Accumulators
In-Containment Refueling Water Storage Tank
Containment Sump Recirculation
Automatic Depressurization Valves
Passive Containment Cooling System
Class 1E dc and UPS System
Containment Isolation Valves
Reactor System
Control Rods

7.5 Safety-Related Display Information

7.5.1 Introduction

An analysis is conducted to identify the appropriate variables and to establish the appropriate design bases and qualification criteria for instrumentation employed by the operator for monitoring conditions in the reactor coolant system, the secondary heat removal system, the containment, and the systems used for attaining a safe shutdown condition. This selection of monitored variables is based on the guidance provided in Regulatory Guide 1.97. The variables and instrument design criterion selected for the AP1000 is described in Subsections 7.5.2 and 7.5.3.

The safety-related display information is used by the operator to monitor and maintain the safety of the AP1000 throughout operating conditions that include anticipated operational occurrences and accident and post-accident conditions. The equipment which processes the safety-related display information and makes it available to the operator is discussed in Subsection 7.5.4.

7.5.2 Variable Classifications and Requirements

Accident monitoring instrumentation is necessary to permit the operator to take actions to address design basis accident situations and for unforeseen situations (should plant conditions evolve differently than predicted by the safety analyses, the control room operating staff has sufficient information to evaluate and monitor the course of the event). Additional instrumentation is needed to indicate to the operating staff whether the integrity of the fuel cladding, the reactor coolant pressure boundary, or the reactor containment has degraded beyond the prescribed limits defined in the plant safety analyses and other evaluations.

Six types of variables are classified to provide this instrumentation:

- Variables that provide information needed by the operator to perform manual actions associated with design basis accident events, for which no automatic control is provided and that are required for the safety systems to accomplish their safety function, are designated as Type A.

- Variables needed to assess that the plant critical safety functions are accomplished or maintained, as identified in the plant safety analysis and other evaluations, are designated as Type B.

- Variables used to monitor for the gross breach or the potential for gross breach of the fuel cladding, the reactor coolant pressure boundary, or the containment are designated as Type C.

- Variables needed to assess the operation of individual safety-related systems are designated as Type D.

- Variables used in determining the magnitude of the postulated releases and continually assessing releases of radioactive materials are designated as Type E.

- Variables that provide information to manually actuate and to monitor the performance of nonsafety-related systems to prevent unnecessary actuation of safety-related systems following plant events are designated as Type F.

The six classifications of variables are not mutually exclusive. When a variable is included in one or more of the six classifications, the equipment monitoring this variable meets the requirements of the highest category identified.

Three categories of design and qualification criteria are used. This classification is made to identify the importance of the information and to specify the requirements placed on the accident monitoring instrumentation. Category 1 instrumentation has the highest performance requirements and is used for information that cannot be lost. Category 2 and Category 3 instruments are of lesser importance in determining the state of the plant and do not require the same level of operational assurance.

The primary differences between category requirements are in qualification, application of single failure, power supply, and display requirements. Category 1 requires seismic and environmental qualification, the application of a single-failure criterion, use of emergency power, and an immediately accessible display. Category 2 requires environmental qualification commensurate with the required function. It may require emergency power, but does not require the single failure criterion or an immediately accessible display. Category 2 requires a rigorous performance verification for a single instrument channel. Category 3, which is high quality commercial grade, does not require qualification, single failure criterion, emergency power, or an immediately accessible display.

The results of the post-accident monitoring system analysis are summarized in Table 7.5-1, which lists the variables selected for accident monitoring and reflects design requirements imposed on the instrumentation to satisfy post-accident monitoring guidance in accordance with the variable type and category. The instruments used for accident monitoring may have other design functions that impose requirements more stringent than those identified by the post-accident monitoring system.

Table 7.5-1 summarizes the following information for each variable identified:

- Instrument range or status
- Type and category
- Environmental qualification
- Seismic qualification
- Number of required channels
- Power supply
- Qualified data processing system (QDPS) indication

Table 7.5-1 also provides variable data shown as "site specific."

7.5.2.1 Variable Types

Accident monitoring variables and information display channels are those that enable the control room operating staff to perform the functions defined by the Types A, B, C, D, E, and F classifications.

Type A

Type A variables provide the primary information to permit the control room operating staff to:

- Perform the diagnosis in the AP1000 emergency operating instructions

- Take the specified, preplanned, manually-controlled actions, for which automatic controls are not provided, and that are required for safety-related systems to mitigate design basis accidents

There are no specific preplanned, manually-controlled actions for safety-related systems to mitigate design basis accidents in the AP1000 design. This includes the diagnosis of plant conditions required to take preplanned manual action. Variables used for contingency actions and additional variables that might be utilized are Types B, C, D, E, and F.

Type B

Type B variables provide the control room operating staff with information to assess the process of accomplishing or maintaining critical integrity safety-related functions (that is, reactivity control, reactor coolant system integrity, reactor coolant system inventory control, reactor core cooling, heat sink maintenance, and reactor containment environment).

Type C

Type C variables provide the control room operating staff information to monitor:

- The extent to which variables that indicate the potential for causing a gross breach of a fission product barrier have exceeded the design basis values
- The in-core fuel cladding, the reactor coolant pressure boundary, or the primary reactor containment that may have been subject to gross breach

These variables include those required to initiate the early phases of an emergency plan. Excluded are those associated with monitoring of radiological release from the plant that are included in Type E.

Type C variables used to monitor the potential for breach of a fission product barrier have an extended range. The extended range is chosen to minimize the probability of instrument saturation even if conditions exceed those predicted by the safety analysis.

Although variables selected to fulfill Type C functions may rapidly approach the values that indicate an actual gross failure, it is the final steady-state value reached that is important. Therefore, a high degree of accuracy and a rapid response time are not necessary for Type C instrument channels.

Type D

Type D variables provide the control room operating staff with sufficient information to:

- Monitor the performance of plant safety-related systems used for mitigating the consequences of an accident and subsequent plant recovery to attain a safe shutdown condition, including verification of the automatic actuation of safety-related systems
- Take specified, preplanned, manually controlled actions using safety-related systems for establishing and maintaining a safe shutdown condition

Type E

Type E variables provide the control room operating staff with information to:

- Monitor the plant areas where access may be required to service equipment necessary to monitor or mitigate the consequences of an accident
- Estimate the magnitude of release of radioactive material through identified pathways and continually assess such releases
- Monitor radiation levels and radioactivity in the environment surrounding the plant
- Monitor the habitability of the main control room

Type F

Type F variables provide the information that allows the control room operating staff to:

- Take specified, preplanned, manually controlled actions using nonsafety-related systems to prevent the unnecessary actuation of safety-related systems

- Monitor the performance of plant nonsafety-related systems used for mitigating the consequences of an accident and subsequent plant recovery to establish shutdown conditions, including verification of the automatic actuation of nonsafety-related systems

- Operate other nonsafety-related systems normally used for plant cooldown and to maintain plant shutdown conditions

7.5.2.2 Variable Categories

The qualification requirements of the Types A, B, C, D, E, and F accident monitoring instrumentation are subdivided into three categories. Descriptions of the three categories are given below. Table 7.5-2 summarizes the selection criteria for Types A, B, C, D, E, and F variables into each of the three categories. Table 7.5-3 summarizes the design and qualification requirements of the three designated categories.

7.5.2.2.1 Category 1

Selection Criteria for Category 1

The selection criteria for Category 1 variables are subdivided according to the variable type. For Type A, those primary variables used for providing information for preplanned operator action, required for the safety-related systems to accomplish their safety function for design basis accidents, are designated as Category 1. For Type B, those primary variables used for monitoring the process of accomplishing or maintaining critical safety functions are designated Category 1. For Type C, those primary variables used for monitoring the potential for breach of a fission product barrier are designated as Category 1. There are no Types D, E, or F Category 1 variables.

Qualification Criteria for Category 1

The Category 1 instrumentation is seismically and environmentally qualified as described in Sections 3.10 and 3.11. Instrumentation continues to read within the required accuracy following, but not necessarily during, a seismic event.

Each instrumentation channel is qualified from the sensor up to, and including, the display. Subsection 7.5.2.2.4 details the extended range instrumentation qualification.

Design Criteria for Category 1

The following design criteria apply to Category 1:

- No single failure (within either the accident monitoring instrumentation, its auxiliary supporting features, or its power sources), concurrent with the failures that are a cause of or result from a specific accident, prevents the control room operating staff from receiving the required information. Where failure of one accident monitoring channel results in information ambiguity (that is, the redundant displays disagree), additional information is provided to allow the control room operating staff to analyze the actual conditions in the plant. This is accomplished by providing additional independent channels of information of the same variable (an identical channel), or by providing independent channels which monitor different variables which bear known relationships to the channels (a diverse channel(s)). Redundant or diverse channels are electrically independent and physically separated from each other and from equipment not classified as safety-related.

If ambiguity does not result from failure of the channel, then a redundant or diverse channel is not provided.

- The instrumentation is energized from the uninterruptible power supply inverter subsystem from the Class 1E dc system.
- Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between shutdowns, a capability for testing during power operation is provided.
- The design provides administrative control of the access for removing channels from service.
- The design provides administrative control of the access to setpoint adjustments, module calibration adjustments, and test points.
- The monitoring instrumentation design minimizes the development of conditions that cause displays to give anomalous indications that are potentially confusing to the control room operating staff.
- The instrumentation is designed to promote the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.
- To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it is shown by analysis to provide unambiguous information.
- Periodic checking, testing, calibration, and calibration verification is performed.
- The range selected for the instrumentation encompasses the expected operating range of the monitored variable.

Information Processing and Display Interface Criteria for Category 1

The following interface criteria are implemented in the processing and displaying of the information:

- The control room operating staff has immediate access to the information from redundant or diverse channels in familiar units of measure. For example, degrees are used, not volts, for temperature readings. Where two or more instruments are needed to cover a particular range, overlapping instrument spans are provided.
- Continuous recording of these channels is provided following an accident until continuous recording of such information is not necessary. The term continuous recording does not exclude the use of discrete time sample data storage systems. This recording is available when required and does not need to be immediately accessible. The recording function is provided by the non-Class 1E data display and processing system.

7.5.2.2.2 Category 2

Selection Criteria for Category 2

The selection criteria for Category 2 variables are subdivided according to the variable type. For Types A, B, and C, some variables that provide backup information are designated Category 2. For Type D, those primary variables that are used for monitoring the performance of safety systems are designated as Category 2. For Type E, those primary parameters monitored for use in determining

the magnitude of the release of radioactive materials and for continuously assessing such releases are designated as Category 2. For Type F, those primary parameters monitored for use in implementing preplanned actions using nonsafety-related systems or for monitoring the status of nonsafety-related system operation are designated as Category 2.

Qualification Criteria for Category 2

Category 2 instrumentation is qualified from the sensor up to, and including, the channel isolation device for the environment in which it operates to serve its intended function.

Design Criteria for Category 2

The following design criteria apply to Category 2:

- Category 2 instrumentation that is required for operation of a safety-related component is energized from the Class 1E dc uninterruptible power supply system. Otherwise, the instrumentation is energized from the non-Class 1E dc uninterruptible power system.

- The out-of-service interval is based on the technical specification requirements on out-of-service for the system the instrument serves where applicable.

- Servicing, testing, and calibration programs are implemented to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the time interval between shutdowns, a capability for testing during power operation is provided.

- The design provides administrative control of the access for removing channels from service.

- The design provides administrative control of the access to setpoint adjustments, module calibration adjustments, and test points.

- The monitoring instrumentation design minimizes the potential for the development of conditions that cause displays to give anomalous indications that are potentially confusing to the control room operating staff.

- The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

- To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

- Periodic checking, testing, calibration, and calibration verification is performed.

- The range selected for the instrumentation encompasses the expected operating range of the monitored variable.

Information Processing and Display Interface Criteria for Category 2

The instrumentation signal is processed for display on demand. Recording requirements are determined on a case-by-case basis.

7.5.2.2.3 Category 3

Selection Criteria for Category 3

The selection criteria for Category 3 variables are subdivided according to the variable type. Types B, C, D, E, and F variables which provide backup information are designated as Category 3.

Qualification Criteria for Category 3

The instrumentation is high quality, commercial grade which is not required to provide information when exposed to a post-accident adverse environment.

Design Criteria for Category 3

The following design criteria apply to Category 3:

- Servicing, testing, and calibration programs are implemented to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between plant shutdowns, a capability for testing during power operation is provided.
- The design provides administrative control of the access for removing channels from service.
- The design provides administrative control of the access to setpoint adjustments, module calibration adjustments, and test points.
- The monitoring instrumentation design minimizes the potential for the development of conditions that cause displays to give anomalous indications that are potentially confusing to the control room operating staff.
- The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.
- To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

Information Processing and Display Interface Criteria for Category 3

The instrumentation signal is processed for display on demand. Recording requirements are determined on a case-by-case basis.

7.5.2.2.4 Extended Range Instrumentation Qualification Criteria

The qualification environment for extended range instrumentation is based on the design basis accident events. The qualification value of the monitored variable is equal to the maximum range for the variable. The monitored variable is assumed to approach this peak by extrapolating the most severe initial ramp associated with the design basis accident events. The decay is considered proportional to the decay for this variable associated with the design basis accidents. No additional qualification margin is added to the extended range variable. Since extended variable ranges are nonmechanistically determined, extension of associated parameter levels is not justifiable and is, therefore, not implemented. For example, a sensor measuring containment pressure is qualified for the measured process variable range (that is, four times design pressure for steel containments), but the corresponding ambient temperature is not mechanistically linked to that pressure. Rather, the ambient temperature value is the bounding value for design basis accident events analyzed in

Chapter 15. The extended range instrument provides information if conditions degrade beyond those postulated in the safety analysis.

7.5.3 Description of Variables

7.5.3.1 Type A Variables

Type A variables provide primary information to permit the control room operating staff to:

- Perform the diagnosis in the AP1000 emergency operating procedures.
- Take specified preplanned, manually-controlled actions, for which automatic controls are not provided, and that are required for safety-related systems to mitigate design basis accidents.

There are no specific preplanned, manually-controlled actions for safety-related systems to mitigate design basis accidents in the AP1000 design. This includes the diagnosis of plant conditions required to take preplanned manual action. Therefore, as reflected in Table 7.5-4, there are no Type A variables.

7.5.3.2 Type B Variables

Type B variables provide information to the control room operating staff to assess the process of accomplishing or maintaining critical safety functions, including the following:

- Reactivity control
- Reactor coolant system integrity
- Reactor coolant system inventory control
- Reactor core cooling
- Heat sink maintenance
- Containment environment.

Variables which provide the most direct indication (primary variable) to assess each of the six critical safety functions are designated as Category 1. Backup variables are designated as Category 2 or Category 3. These variables are listed in Table 7.5-5.

7.5.3.3 Type C Variables

Type C variables provide the control room operating staff with information to monitor the potential for breach or the actual gross breach of:

- Incore fuel cladding
- Reactor coolant system boundary
- Containment boundary.

Variables associated with monitoring radiological release from the plant are included in Type E.

Those Type C variables that provide the most direct measure of the potential for breach of one of the three fission product boundaries are designated as Category 1. Backup information that indicates potential for breach or actual breach is designated as Category 2 or Category 3. These variables are listed in Table 7.5-6.

7.5.3.4 Type D Variables

Type D variables provide sufficient information to the control room operating staff to:

- Monitor the performance of plant safety-related systems used for mitigating the consequences of an accident and subsequent plant recovery to attain a safe shutdown condition, including verification of the automatic actuation of safety-related systems

- Take specified, preplanned, manually controlled actions using safety-related systems used for establishing and maintaining a safe shutdown condition

Primary Type D variables are designated as Category 2. Backup information is designated as Category 3. These variables are listed in Table 7.5-7.

7.5.3.5 Type E Variables

Type E variables provide the control room operating staff with information to:

- Monitor the plant areas where access may be required to service equipment to monitor or mitigate the consequences of an accident

- Estimate the magnitude of release of radioactive materials through identified pathways

- Monitor radiation levels and radioactivity in the environment surrounding the plant

- Monitor the habitability of the main control room

Primary Type E variables are designated as Category 2. Backup variables are designated as Category 3. These variables are listed in Table 7.5-8.

Table 7.5-8 also provides variable data shown as "site specific."

7.5.3.6 Type F Variables

Type F variables provide the control room operating staff with information to:

- Take preplanned manual actions using nonsafety-related systems to prevent unnecessary actuation of the safety-related systems

- Monitor the performance of the nonsafety-related systems used to mitigate the consequences of an accident

- Operate other nonsafety-related systems normally used for plant cooldown and to maintain plant shutdown conditions

Primary Type F variables are designated as Category 2. Backup variables are designated as Category 3. These variables are listed in Table 7.5-9.

7.5.4 Processing and Display Equipment

The AP1000 processing and display function is performed by equipment which is part of the protection and safety monitoring system, plant control system, and the data display and processing system. A description of each of these processing systems is provided in Section 7.1.

The protection and safety monitoring system provides signal conditioning, communications, and display functions for Category 1 variables and for Category 2 variables that are energized from the Class 1E dc uninterruptible power supply system. The plant control system and the data display and processing system provides signal conditioning, communications and display functions for Category

3 variables and for Category 2 variables that are energized from the non-Class 1E dc uninterruptible power system. The data display and processing system also provides an alternate display of the variables which are displayed by the protection and safety monitoring system. Electrical separation of the data display and processing system and the protection and safety monitoring system is maintained through the use of isolation devices in the interconnections connecting the two systems, as discussed in Subsection 7.1.2.10. The portion of the protection and safety monitoring system which is dedicated to providing post-accident monitoring is referred to as the qualified data processing system and is discussed in Subsection 7.1.2.5. Post-accident information is displayed in the MCR on the four divisions of safety displays of the PMS safety display subsystem.

The qualified data processing system is divided into two separate electrical divisions. Each of the two electrical divisions is connected to a Class 1E dc uninterruptible power system with sufficient battery capacity to provide necessary electrical power for at least 72 hours. If all ac power sources are lost for a period of time that exceeds 72 hours, the power supply system will be energized from the ancillary diesel generator or from ac power sources which are brought to the site from other locations. See Section 8.3.

Instrumentation associated with primary variables that are energized from the Class 1E dc uninterruptible power supply system are powered from one of the two electrical divisions with 72 hour battery capacity. Instrumentation associated with other variables that are energized from the Class 1E dc uninterruptible power supply system are powered from one of four electrical divisions with 24 hour battery capacity. If a variable exists only to provide a backup to a primary variable, it may be powered by an electrical division with a 24 hour battery capacity. In such cases, provisions are provided to enable this variable to be powered by an alternate source if it is needed to resolve a discrepancy between two primary variables in the event that all ac power sources are lost for a period in excess of 24 hours.

Class 1E position indication signals for valves and electrical breakers may be powered by an electrical division with 24 hour battery capacity. This is necessary to make full use of all four Class 1E electrical divisions to enhance fire separation criteria. The power associated with the actuation signal for each of these valves or electrical breakers is provided by an electrical division with 24 hour battery capacity, so there is no need to provide position indication beyond this period. The operator will verify that the valves or electrical breakers have achieved the proper position for long-term stable plant operation before position indication is lost. Once the position indication is lost, there is no need for further monitoring since the operator does not have any remote capability for changing the position of these components.

Electrically operated valves, which have the electrical power removed to meet the single failure criterion, are provided with redundant valve position sensors. Each of the two position sensors is powered from a different non-Class 1E power source.

7.5.5 Combined License Information

The site specific variables are addressed in Subsection 7.5.2 and Table 7.5-1, and in Subsection 7.5.3.5 and Table 7.5-8.

Table 7.5-1 (Sheet 1 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
RCS wide range pressure	0-3300 psig	B1, D2, C1, F2	Harsh	Yes	3 (Note 4)	1E	Yes	Located inside containment
RCS T_H (Wide Range)	50-700°F	B1, B2, D2, F2	Harsh	Yes	2	1E	Yes	Diverse Measurement: Core exit temperature
RCS T_C (Wide Range)	50-700°F	B1, B2, D2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
Steam generator wide range water level	0-100% of span	D2, F3	Harsh	Yes	1/steam generator	1E	Yes	
Steam generator narrow range water level	0-100% of span	D2, F2	Harsh	Yes	1/steam generator	1E	Yes	
Pressurizer level (Note 11)	0-100% of span	B1, D2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
Pressurizer reference leg temperature	50-420°F	B1, D2	Harsh	Yes	3 (Note 4)	1E	Yes	
Neutron flux	10^{-6}-200% power	B1	Harsh	Yes	3 (Note 4)	1E	Yes	
Control rod position	0-264 steps	B3, D3	None	None	1/control rod	Non-1E	No	
Containment water level	El. 72'-11" to 112'-2 1/2" in discrete steps	B1, C1, F2	Harsh	Yes	3 (Note 4)	1E	Yes	

Table 7.5-1 (Sheet 2 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Core exit temperature	200-2300°F	B1, C1, F2	Harsh	Yes	2/quadrant per Division	1E	Yes	
PRHR HX inlet temperature	50-650°F	D3	None	None	1	Non-1E	No	Primary indication is RCS T_H
PRHR HX outlet temperature	50-500°F	B2, D2	Harsh	Yes	1	1E	Yes	
PRHR flow	700-3000 gpm	B1, D2, F2	Harsh	Yes	2	1E	Yes	Diverse measurement: PRHR HX inlet isolation valve status together with PRHR HX control valve status
IRWST wide range water level	0-100% of span	B1, D2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
IRWST lower narrow range water level	0-100% of span	D2	Harsh	Yes	1	1E	No	
RCS subcooling (Note 6)	200°F Sub-cooling to 35°F super heat	B1, F2	Harsh	Yes	2 calculated variables	1E	Yes	
Passive containment cooling water flow	0-150 gpm	B1, D2	Mild	Yes	1 (Note 1)	1E	Yes	
PCS storage tank water level	5-100% of tank height	B1, D2	Mild	Yes	2	1E	Yes	Diverse measurement: PCS flow
IRWST surface temperature	50-300°F	D3	None	None	1	Non-1E	No	
IRWST bottom temperature	50-300°F	D3	None	None	1	Non-1E	No	
Steam line pressure	0-1300 psig	F2	Harsh/ Mild (Note 8)	Yes	1/steam generator	1E	Yes	

Table 7.5-1 (Sheet 3 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Startup feedwater flow	0-600 gpm	F2	Mild	Yes	1/steam generator	1E	Yes	
Startup feedwater control valve status	Open/Closed	D2, F3	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Containment pressure	-5 to 10 psig	B1, C2, D2, F2	Mild	Yes	3 (Note 4)	1E	Yes	
Containment pressure (extended range)	0 to 240 psig	C1	Mild	Yes	3 (Note 4)	1E	Yes	
Containment area radiation (high range)	10^0-10^7 R/hr	C1, E2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
Reactor vessel hot leg water level	0-100% of span	B2, B3	Harsh	Yes	1	1E	Yes	Two instruments are provided
Plant vent noble gas radiation level	10^{-7} to 10^5 µCi/cc	C2, E2	Mild	None	1	Non-1E	No	Several instruments can fulfill range
Plant vent particulate and iodine radiation level	(Note 3)	E3	Mild	None	1/detector type	Non-1E	No	
Remotely operated containment isolation valve status (Note 13)	Open/Closed	B1, D2	Harsh/Mild/ Radiation Harsh	Yes	1/valve (Note 7)	1E	Yes	Separate divisions on series valves
Containment vacuum relief valve status	Open/Closed	B1, D2	Mild	Yes	1/valve (Note 7)	1E	Yes	Input to remotely operated containment isolation valve status variable
Boundary environs radiation/Plant Environs radiation levels and airborne radioactivity • Airborne Radiohalogens and Particulates (portable sampling with onsite analysis capability)	10^{-9} to 10^{-3} µCi/cc	C3, E3	None	None	N/A	Non-1E	No	Conforms to Regulatory Guide 1.97, Revision 3

Table 7.5-1 (Sheet 4 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
• Radiation (portable instrumentation) • Radioactivity (portable instrumentation)	10^{-3} to 10^{4} R/hr, photons 10^{-3} to 10^{4} rads/hr, beta and low-energy photons Multichannel gamma ray spectrometer							
Hydrogen concentration	0-20%	C3	None	None	1	Non-1E	No	Three instruments are provided
Class 1E dc switchboard voltages	0-300 Vdc	D2	Mild	Yes	1/ switchboard	1E	Yes	
Diesel generator status	On/Off	F3	None	None	1/diesel generator	Non-1E	No	
Diesel generator ready to pick up load	On/Off	F3	None	None	1/generator	Non-1E	No	
Diesel generator load	0-6000 kW	F3	None	None	1/diesel generator	Non-1E	No	
Voltage for diesel-backed buses	0-8600V	F3	None	None	3/bus	Non-1E	No	
Power supply to diesel-backed buses	On/Off	F3	None	None	1/supply source/bus	Non-1E	No	
RCP bearing water temperature	50-400°F	F3	None	None	1/RCP (Note 10)	Non-1E	No	
RCP breaker status	Open/Closed	D2, F3	Mild	Yes	1/breaker (Note 10)	1E	No	
Reactor trip breaker status	Open/Closed	D2	Mild	Yes	1/breaker (Note 10)	1E	No	
MCR air storage bottle pressure	0-5000 psig	D2	Mild	None	1	Non-1E	No	Two instruments are provided
Turbine stop valve status	Open/Closed	D2	None (Note 12)	None	1/valve	Non-1E	No	
Turbine control valve status	Open/Closed	D2	None (Note 12)	None	1/valve	Non-1E	No	
Pressurizer pressure	1500-2500 psig	B1, D2	Harsh	Yes	3 (Note 4)	1E	Yes	
Pressurizer safety valve status	Open/Closed	D2	Harsh	None	1/valve	Non-1E	No	

Table 7.5-1 (Sheet 5 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Pressurizer heater power (current)	0-800 amps	F3	None	None	1/group	Non-1E	No	
Steam generator PORV status	Open/Closed	D2, F3	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Steam generator PORV block valve status	Open/Closed	D2, F3	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Steam generator safety valve status	Open/Closed	D2	Harsh	None	1/valve	Non-1E	No	
Main feedwater isolation valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Main feedwater flow	0-9x10^6 lb/hr	F3	None	None	1/feedline	Non-1E	No	
Main feedwater control valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Steam generator blowdown isolation valve status	Open/Closed	B1, D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	Input to remotely operated containment isolation valve status variable
Steam flow	0-9x10^6 lb/hr	F3	None	None	1/steam generator	Non-1E	No	
Main steam line isolation valve status	Open/Closed	D2, F3	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Main steam line isolation bypass valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Main feedwater pump status	On/Off	D2, F3	Mild	None	1/pump	Non-1E	No	
Main to startup feedwater crossover valve status	Open/Closed	D2, F3	Mild	None	1	Non-1E	No	
Startup feedwater pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Circulating water pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Condenser backpressure	0-30 in. Hg(A)	F3	None	None	1	Non-1E	No	
Steam line condensate drain control valve status	Open/Closed	D2, F3	Harsh	Yes	1/valve (Note 7)	1E	Yes	

Table 7.5-1 (Sheet 6 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Steam line condensate drain isolation valve status	Open/Closed	D2, F3	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Startup feedwater Isolation valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Condenser steam dump valve status	Open/Closed	D2, F3	Mild	None	1/valve	Non-1E	No	
Condensate storage tank water level	0-100% of span	F3	None	None	1	Non-1E	No	
PCS water storage tank isolation valve status (AOV)	Open/Closed	D2	Radiation Harsh	Yes	1/valve (Note 7)	1E	Yes	
PCS water storage tank isolation valve status (MOV)	Open/Closed	D2	Radiation Harsh	Yes	1 (Note 7)	1E	Yes	
PCS water storage tank series isolation valve status (MOV)	Open/Closed	D2	Radiation Harsh	Yes	1/valve (Note 7)	1E	Yes	
Containment temperature	32-400°F	D2, F3	Harsh	None	1	Non-1E	No	
CCS surge tank level	0-100% of span	F3	None	None	1	Non-1E	No	
CCS flow	0-20,000 gpm	F3	None	None	1	Non-1E	No	
CCS pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
CCS flow to RNS valve status	Open/Closed	F3	None	None	1/valve	Non-1E	No	
CCS containment isolation valve status	Open/Closed	D2	Mild/Harsh	Yes	1/valve (Note 7)	1E	Yes	Harsh applies only to the valve located inside containment
CCS flow to RCPs valve status	Open/Closed	F3	None	None	1/valve	Non-1E	No	
CCS pump inlet temperature	50-200°F	F3	None	None	1	Non-1E	No	
CCS heat exchanger outlet temperature	50-130°F	F3	None	None	1	Non-1E	No	
Containment fan cooler status	On/Off	F3	None	None	1/fan	Non-1E	No	

Table 7.5-1 (Sheet 7 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Water-cooled chiller status	On/Off	F3	None	None	1/chiller	Non-1E	No	
Water-cooled chilled water pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Water-cooled chilled water valve status	Open/Closed	F3	None	None	1/valve	Non-1E	No	
Spent fuel pool pump flow	0-1500 gpm	F3	None	None	1/pump	Non-1E	No	
Spent fuel pool temperature	50-250°F	F3	None	None	1	Non-1E	No	
Spent fuel pool water level	0-100% of span	D2, F3	Radiation Harsh	Yes	3 (Note 4)	1E	Yes	
SFS to SGS compartment valve status	Open/Closed	D2	Harsh	Yes	1 (Note 7)	1E	Yes	
SFS to cont. sump valve status	Open/Closed	D2	Harsh	Yes	1 (Note 7)	1E	Yes	
SFS floodup valve status	Open/Closed	D2	Harsh	Yes	1 (Note 7)	1E	Yes	
SFS suction and discharge line isolation valve status	Open/Closed	B1, D2	Radiation Harsh/Harsh	Yes	1/valve (Note 7)	1E	Yes	Input to remotely operated containment isolation valve status variable. Harsh applies only to the valve located inside containment
CMT discharge isolation valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
CMT inlet isolation valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
CMT upper water level	0%-100% of span	D2, F2	Harsh	Yes	1/tank	1E	Yes	
CMT lower water level	0%-100% of span	D2, F2	Harsh	Yes	1/tank	1E	Yes	
IRWST injection isolation valve (Squib)	Open/Not Open	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
IRWST line isolation valve status (MOV)	Open/Closed	D3	None	None	1/valve	Non-1E	No	

Table 7.5-1 (Sheet 8 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
ADS: first, second and third stage valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
ADS fourth stage valve status (Squib)	Open/Not Open	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
ADS fourth stage valve status (MOV)	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Pressurizer spray valve status	Open/Closed	F3	None	None	1/valve	Non-1E	No	
PRHR HX inlet isolation valve status	Open/Closed	B1, D2	Harsh	Yes	1 (Note 7)	1E	Yes	Together with PRHR HX control valve status as diverse variables to PRHR flow
PRHR HX control valve status	Open/Closed	B1, D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	Together with PRHR HX inlet isolation valve status as diverse variables to PRHR flow
IRWST gutter bypass isolation valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Accumulator pressure	100-800 psig	D2	Harsh	None	1/tank	Non-1E	No	
Accumulator isolation valve status	Open/Closed	D3	None	None	1/valve	Non-1E	No	
Accumulator vent valve status	Open/Closed	F3	None	None	1/valve	Non-1E	No	
Auxiliary spray line isolation valve status	Open/Closed	D2, F3	Harsh	Yes	1 (Note 7)	1E	Yes	
Purification stop valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Purification line containment isolation valve status	Open/Closed	B1, D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	Input to remotely operated containment isolation valve status variable

Table 7.5-1 (Sheet 9 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Containment recirculation isolation valve status (Squib)	Open/Not Open	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Containment recirculation isolation valve status (MOV)	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Boric acid tank level	0-100%	F3	None	None	1	Non-1E	No	
Demineralized water isolation valve status	Open/Closed	D2	Radiation Harsh	Yes	1/valve (Note 7)	1E	Yes	
Boric acid flow	0-175 gpm	F3	None	None	1	Non-1E	No	
Demineralized water flow	0-175 gpm	F3	None	None	1	Non-1E	No	
Makeup blend valve status	Position	F3	None	None	1	Non-1E	No	
Makeup flow	0-175 gpm	F3	None	None	1	Non-1E	No	
Makeup pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Makeup flow control valve status	Position	F3	None	None	1	Non-1E	No	
CVS makeup line containment isolation valve status	Open/Closed	D2	Radiation Harsh/Harsh	Yes	1/valve (Note 7)	1E	Yes	Harsh applies only to the valve located inside containment
Letdown flow	0-120 gpm	F3	None	None	1	Non-1E	No	
RNS hot leg suction isolation valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
RNS pump discharge isolation valve status	Open/Closed	D2	Radiation Harsh	Yes	1 (Note 7)	1E	Yes	
RNS flow	0-3000 gpm	F3	None	None	1/pump	Non-1E	No	
RCS sampling line isolation valve status	Open/Closed	E3	Harsh	None	1/valve	Non-1E	No	

Table 7.5-1 (Sheet 10 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
IRWST to RNS suction valve status	Open/Closed	B1, D2, F3	Harsh/Radiation Harsh	Yes	1/valve (Note 7)	1E	Yes	Harsh applies only to the valve located inside containment
RNS discharge to IRWST valve status	Open/Closed	F3	None	None	1	Non-1E	No	
RNS pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Reactor vessel head vent valve status	Open/Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
MCR return air isolation valve status	Open/Closed	D2, F3	Mild	Yes	1/valve (Note 7)	1E	Yes	
MCR toilet exhaust isolation valve status	Open/Closed	D2	Mild	Yes	1/valve (Note 7)	1E	Yes	
MCR supply air isolation valve status	Open/Closed	D2, F3	Mild	Yes	1/valve (Note 7)	1E	Yes	
MCR differential pressure	-1" to +1" wg	D2	Mild	Yes	1	1E	Yes	
MCR air delivery flowrate	0-80 cfm	D2	Mild	Yes	1	1E	Yes	
MCR pressure relief isolation valve status	Open/Closed	D2	Mild	Yes	1/valve	1E	Yes	
MCR vent isolation valve status	Open/Closed	D2	Mild	Yes	1/valve (Note 7)	1E	Yes	
MCR air delivery isolation valve status	Open/Closed	D2	Mild	Yes	1/valve (Note 7)	1E	Yes	
MCR electrical load status	Open/Closed	D2	Mild	Yes	1/contactor	1E	Yes	
Instrument air header pressure	0-125 psig	F3	None	None	1	Non-1E	No	
Service water flow	0-15,000 gpm	F3	None	None	1/pump	Non-1E	No	
Service water pump status	On/Off	F3	None	None	1/pump	Non-1E	No	

Table 7.5-1 (Sheet 11 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Service water pump discharge valve status	Open/Closed	F3	None	None	1/valve	Non-1E	No	
Service water pump discharge temperature	50-150°F	F3	None	None	1/pump	Non-1E	No	
Main control room supply air radiation	Note 5	E3, F3	Mild	Yes	2 (Note 9)	1E	Yes	
Plant vent air flow	0-110% design flow	E2	Mild	None	1	Non-1E	No	
Turbine island vent discharge radiation level	10^{-6}-10^{+5} µCi/cc	C2, E2	Mild	None	1	Non-1E	No	
Turbine island vent flow	0-6,500 scfm	C2, E2	Mild	None	1	Non-1E	No	
Steam generator blowdown discharge radiation	10^{-7} to 10^{-2} µCi/cc	C2	Mild	None	1	Non-1E	No	
Steam generator blowdown electrodeionization reject flow radiation level	10^{-7} to 10^{-2} µCi/cc	C2	Mild	None	1	Non-1E	No	
Main steam line radiation level	10^{-1}-10^{3} µCi/cc	C2, E2	Mild	None	1/line	Non-1E	No	
Control support area radiation	10^{-1}-10^{4} mR/hr	E3	None	None	1	Non-1E	No	
Meteorological parameters		E3	None	None		Non-1E	No	
• Wind Speed	0–112 mph				2 (1@ 10 m and 1 @ 60 m)			Conforms to Regulatory Guide 1.97, Revision 3
• Wind Direction	0°–360°				2 (1@ 10 m and 1 @ 60 m)			
• Differential Temperature	-10°F to +20°F				1 (10–60 m)			

Table 7.5-1 (Sheet 12 of 12)
Post-Accident Monitoring System

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Primary sampling station area radiation level	10^{-1}-10^{7} mR/hr	E3	None	None	1	Non-1E	No	
VES passive air filtration flow	0-2000 cfm	E3	None	None	1	Non-1E	No	

Notes:

1. The flow instrument on the lowest standpipe is the Category 1 instrument; and is diverse indication for PCS storage tank water level.
2. The same information is available in the control support area via the monitor bus. Information available on the qualified data processing system is also available at the remote shutdown workstation.
3. Extended range fixed particulate and iodine sample filters are provided for removal for onsite laboratory analysis meeting range 10^{-3} to 10^{2} µCi/cc. This extended range radiation level is not displayed in the control room. Radiation level from the normal range particulate monitor (range: 10^{-12} to 10^{-7} µCi/cc) and normal range iodines monitor (range: 10^{-11} to 10^{-6} µCi/cc) is indicated in the control room.
4. The number of instruments required after stable plant conditions is two. A third channel is available through temporary connections to resolve information ambiguity if necessary (See Subsection 7.5.4).
5. Noble gas: 10^{-7} to 10^{-1} µCi/cc
   Particulate: 10^{-12} to 10^{-7} µCi/cc
   Iodines: 10^{-11} to 10^{-5} µCi/cc
6. Degree of subcooling is calculated from RCS wide range pressure and core exit temperature.
7. This instrument is only required to be provided with 24 hour battery capacity.
8. Two steam line pressure instruments per SG are located inside containment, and are qualified for a harsh environment. Two steam line pressure instruments per SG are located outside containment (not in MSIV compartment), and are qualified for a mild environment.
9. MCR supply air radiation monitoring is not required after MCR has been isolated.
10. This instrument is only required when non-safety power is available.
11. The pressurizer level signal is compensated by pressurizer reference leg temperature, pressurizer pressure, and RCS wide range pressure.
12. These devices are backup verification to QDPS status parameters. These devices are purchased to perform in their anticipated service environments for the plant conditions for which they must function.
13. Remotely operated containment isolation valve status applies to components that receive the ESF containment isolation signal (T signal). SGS-PL-V075A/B are not containment isolation valves, but are conservatively included because they receive the T signal. SGS-PL-V075A/B are in series with containment isolation valves SGS-PL-V074A/B that also receive the T signal, and are functionally equivalent.

Table 7.5-2
Summary of Selection of Criteria

Type	Category 1	Category 2	Category 3
A	Primary variables that are used for diagnosis or providing information necessary for operator action	Variables that provide backup information	None
B	Primary variables that are used for monitoring the process of accomplishing or maintaining critical safety functions	Variables that provide backup information	Variables that provide backup information
C	Primary variables that are used for monitoring the potential for breach of a fission product barrier	Variables that provide backup information	Variables that provide backup information
D	None	Primary variables used for monitoring the performance of plant safety-related systems	Variables that provide backup information and monitor the performance of plant safety-related systems
E	None	Primary variables to be monitored in determining the magnitude of the release of radioactive materials and for continuously assessing such releases.	Variables that provide backup information in determining the magnitude of the release of radioactive materials and for continuously assessing such releases
F	None	Primary variables to be monitored to implement preplanned manual actions using nonsafety-related systems	Variables that provide backup information and for monitoring the performance of nonsafety-related systems

Table 7.5-3
Summary of Qualification, Design, and Interface Requirements

	Category 1	Category 2	Category 3
Qualification			
Environmental	Yes	Yes	No
Seismic	Yes	As appropriate (See Subsection 7.5.2.2.2.)	No
Design			
Single failure	Yes	No	No
Power supply	Class 1E dc battery	Class 1E dc or Non-Class 1E dc battery onsite (As appropriate, see Subsection 7.5.2.2.2.)	Non-Class 1E
Channel out of service	Technical Specifications	As appropriate (See Subsection 7.5.2.2.2.)	No specific requirement
Interface			
Minimum indication	Immediately accessible	On demand	On demand
Recording	Yes	As required (See Subsection 7.5.2.2.2.)	As required (See Subsection 7.5.2.2.3.)

Table 7.5-4
Summary of Type A Variables

There are no Type A variables for AP1000.

Table 7.5-5
Summary of Type B Variables

Function Monitored	Variable	Type/Category
Reactivity Control	Neutron flux Control rod position	B1 B3
Reactor Coolant System Integrity	RCS wide range pressure RCS wide range T_{hot} RCS wide range T_{cold} Containment water level Containment pressure	B1 B1 B1 B1 B1
Reactor Coolant Inventory Control	Pressurizer level Pressurizer reference leg temperature Pressurizer pressure RCS wide range pressure Reactor vessel - hot leg water level	B1 B1 B1 B1 B3
Reactor Core Cooling	Core exit temperature RCS subcooling RCS wide range pressure RCS wide range T_{hot} RCS wide range T_{cold} Reactor vessel - hot leg water level	B1 B1 B1 B2 B2 B2
Heat Sink Maintenance	IRWST wide range water level PRHR flow PRHR HX outlet temperature PRHR HX inlet isolation valve status PRHR HX control valve status PCS storage tank water level Passive containment cooling water flow IRWST to RNS suction valve status	B1 B1 B2 B1 B1 B1 B1 B1
Containment Environment	Containment pressure Remotely operated containment isolation valve status Containment water level	B1 B1 B1

Table 7.5-6
Summary of Type C Variables

Function Monitored	Variable	Type/Category
Incore Fuel Clad	Core exit temperature	C1
RCS Boundary	RCS wide range pressure Containment pressure Containment water level Containment area radiation (high range) Turbine island vent discharge radiation level Turbine island vent flow Steam generator blowdown discharge radiation Steam generator blowdown electrodeionization reject flow radiation level Main steam line radiation level	C1 C2 C1 C1 C2 C2 C2 C2 C2
Containment Boundary	Containment pressure (extended range) Plant vent noble gas radiation level Hydrogen concentration Boundary environs radiation/Plant Environs radiation levels and airborne radioactivity	C1 C2 C3 C3

Table 7.5-7 (Sheet 1 of 5)
Summary of Type D Variables

System	Variable	Type/Category
Reactivity Control System	Reactor trip breaker status	D2
	Control rod position	D3
Pressurizer Level and Pressure Control	Pressurizer safety valve status	D2
	Pressurizer level	D2
	RCS wide range pressure	D2
	Pressurizer pressure	D2
	Pressurizer reference leg temperature	D2
RCS Loops	RCS wide range T_{hot}	D2
	RCS wide range T_{cold}	D2
	RCP breaker status	D2
Secondary Pressure and Level Control	Steam generator PORV status	D2
	Steam generator PORV block valve status	D2
	Steam generator safety valve status	D2
	Main feedwater isolation valve status	D2
	Steam generator wide range water level	D2
	Steam generator narrow range water level	D2
	Steam generator blowdown isolation valve status	D2

Table 7.5-7 (Sheet 2 of 5)
Summary of Type D Variables

System	Variable	Type/Category
Secondary Pressure and Level Control (continued)	Main feedwater pump status	D2
	Main feedwater control valve status	D2
	Main steam line isolation valve status	D2
	Main steam line isolation bypass valve status	D2
Startup Feedwater	Startup feedwater control valve status	D2
	Startup feedwater isolation valve status	D2
	Main to startup feedwater crossover valve status	D2
Safeguards	Containment pressure	D2
	Accumulator pressure	D2
	Core makeup tank upper water level	D2
	Core makeup tank lower water level	D2
	IRWST/line isolation valve status (MOV)	D3
	IRWST/injection isolation valve status (Squib)	D2
	ADS: first, second, and third stage valve status	D2
	ADS fourth stage valve status (MOV)	D2
	ADS fourth stage valve status (Squib)	D2
	PRHR heat exchanger inlet isolation valve status	D2
	PRHR heat exchanger control valve status	D2
	Reactor vessel head vent valve status	D2
	CMT discharge isolation valve status	D2
	CMT inlet isolation valve status	D2

Table 7.5-7 (Sheet 3 of 5)
Summary of Type D Variables

System	Variable	Type/Category
Safeguards (continued)	Accumulator isolation valve status	D3
	PRHR flow	D2
	Containment recirculation isolation valve status (MOV)	D2
	Containment recirculation isolation valve status (Squib)	D2
	PRHR HX inlet temperature	D3
	PRHR HX outlet temperature	D2
	IRWST surface temperature	D3
	IRWST bottom temperature	D3
	IRWST wide range water level	D2
	IRWST lower narrow range water level	D2
	IRWST gutter bypass isolation valve status	D2
	CCS containment isolation valve status	D2
	Remotely operated containment isolation valve status	D2
Chemical and Volume Control	Auxiliary spray line isolation valve status	D2
	Purification stop valve status	D2
	Purification line containment isolation valve status	D2
	Demineralized water isolation valve status	D2
	CVS makeup line containment isolation valve status	D2
Normal Residual Heat Removal	RNS hot leg suction isolation valve status	D2
	RNS pump discharge isolation valve status	D2
	IRWST to RNS suction valve status	D2

Table 7.5-7 (Sheet 4 of 5)
Summary of Type D Variables

System	Variable	Type/Category
Electric Power	Class 1E dc switchboard voltage	D2
Spent Fuel Pool	Spent fuel pool water level	D2
	SFS to SGS compartment valve status	D2
	SFS to containment valve status	D2
	SFS floodup valve status	D2
	SFS suction and discharge line isolation valve status	D2
Containment Cooling	Containment temperature	D2
	PCS water storage tank series isolation valve status (MOV)	D2
	PCS water storage tank isolation valve status (MOV)	D2
	PCS water storage tank isolation valve status (AOV)	D2
	Passive containment cooling water flow	D2
	PCS storage tank water level	D2
Containment	Containment vacuum relief valve status	D2

Table 7.5-7 (Sheet 5 of 5)
Summary of Type D Variables

System	Variable	Type/Category
HVAC System Status	MCR return air isolation valve status	D2
	MCR toilet exhaust isolation valve status	D2
	MCR supply air isolation valve status	D2
	MCR air delivery isolation valve status	D2
	MCR pressure relief isolation valve status	D2
	MCR electrical load status	D2
	MCR vent isolation valve status	D2
	MCR air storage bottle pressure	D2
	MCR differential pressure	D2
	MCR air delivery flowrate	D2
Main Steam	Turbine stop valve status	D2
	Turbine control valve status	D2
	Condenser steam dump valve status	D2
	Steam line condensate drain control valve status	D2
	Steam line condensate drain isolation valve status	D2

Table 7.5-8
Summary of Type E Variables

Function Monitored	Variable	Type/Category
Containment Radiation	Containment area radiation (high level)	E2
Area Radiation	Control support area radiation	E3
	Primary sampling station area radiation level	E3
Airborne Radioactivity Released from Plant	Turbine island vent discharge radiation level	E2
	Turbine island vent flow	E2
	Plant vent noble gas radiation level	E2
	Plant vent air flow	E2
	Main steam line radiation level	E2
	Plant vent particulate and iodine radiation level	E3
	Main control room supply air radiation level	E3
Environs Radiation and Radioactivity	Boundary environs radiation/ Plant Environs radiation levels and airborne radioactivity	E3
Meteorology	Wind speed, wind direction, and estimation of atmospheric stability (based on vertical temperature difference)	E3
Accident Sampling	RCS sampling line isolation valve status	E3
	Containment air (grab sample analysis)	E3
MCR Filtration Flow	VES passive air filtration flow	E3

Table 7.5-9 (Sheet 1 of 3)
Summary of Type F Variables

Variable	Type/Category
Monitoring for preplanned manual nonsafety-related system actions	
RCS wide range pressure	F2
RCS wide range T_{hot}	F2
RCS wide range T_{cold}	F2
Steam generator narrow range water level	F2
Pressurizer level	F2
Containment pressure	F2
Steam line pressure	F2
Containment water level	F2
IRWST wide range water level	F2
Startup feedwater flow	F2
Containment area radiation (high range)	F2
Core exit temperature	F2
RCS subcooling	F2
PRHR flow	F2
Core makeup tank upper water level	F2
Core makeup tank lower water level	F2
Monitoring for nonsafety-related system performance	
Pressurizer heater power (current)	F3
Steam generator PORV status	F3
Steam generator PORV block valve status	F3
Startup feedwater control valve status	F3
Main feedwater flow	F3
Steam generator wide range water level	F3
Steam flow	F3
Main steam line isolation valve status	F3
Main feedwater pump status	F3
Startup feedwater pump status	F3
Condenser steam dump valve status	F3
Condensate storage tank water level	F3
Pressurizer spray valve status	F3

Table 7.5-9 (Sheet 2 of 3)
Summary of Type F Variables

Variable	Type/Category
Auxiliary spray line isolation valve status	F3
Makeup flow	F3
Makeup pump status	F3
Letdown flow	F3
Circulating water pump status	F3
Condenser backpressure	F3
Accumulator vent valve status	F3
Boric acid tank level	F3
Boric acid flow	F3
Demineralized water flow	F3
Makeup blend valve status	F3
Makeup flow control valve status	F3
RNS flow	F3
RNS pump status	F3
IRWST to RNS suction valve status	F3
RNS discharge to IRWST valve status	F3
CCS surge tank level	F3
CCS flow	F3
CCS pump status	F3
CCS flow to RNS valve status	F3
CCS flow to RCPs valve status	F3
CCS pump inlet temperature	F3
CCS heat exchanger outlet temperature	F3
Diesel generator status	F3
Diesel generator ready to pick up load	F3
Diesel generator load	F3
Voltage for diesel-backed buses	F3
Power supply to diesel-backed buses	F3
RCP bearing water temperature	F3
RCP breaker status	F3
Containment fan cooler status	F3
Water-cooled chiller status	F3

Table 7.5-9 (Sheet 3 of 3)
Summary of Type F Variables

Variable	Type/Category
Water-cooled chilled water pump status	F3
Water-cooled chilled water valve status	F3
Containment temperature	F3
MCR supply air isolation valve status	F3
MCR return air isolation valve status	F3
Main control room supply air radiation	F3
Service water flow	F3
Service water pump status	F3
Service water pump discharge valve status	F3
Service water pump discharge temperature	F3
Instrument air header pressure	F3
Spent fuel pool pump flow	F3
Spent fuel pool temperature	F3
Spent fuel pool water level	F3
Main to startup feedwater crossover valve status	F3
Steam line condensate drain control valve status	F3
Steam line condensate drain isolation valve status	F3

Table 7.5-201
Not Used

Table 7.5-202
Not Used

7.6 Interlock Systems Important to Safety

This section discusses interlock systems which operate to reduce the probability of occurrence of specific events or to verify the state of a safety system. These include interlocks to prevent overpressurization of low-pressure systems and interlocks to verify availability of engineered safety features.

7.6.1 Prevention of Overpressurization of Low-Pressure Systems

7.6.1.1 Description of Normal Residual Heat Removal Isolation Valve Interlocks

An interlock is provided for the normally closed, motor-operated normal residual heat removal system (RNS) inner and outer suction isolation valves. The interlock prevents the suction valves for the normal residual heat removal system from being opened by operator action unless the reactor coolant system pressure is less than a preset pressure and both the suction and discharge valves for the in-containment refueling water storage tank are in a closed position.

There are two parallel sets of two motor-operated valves in series in the normal residual heat removal system pumps suction line from the reactor coolant system hot leg. The two valves nearest the reactor coolant system are designated as the inner isolation valves. The two valves nearest the normal residual heat removal system pumps are designated as the outer isolation valves. Logic for the outer valves is similar to that provided for the inner isolation valves, except that equipment diversity is provided by virtue of the fact that the pressure transmitters used for valve interlocks on the inner valves are diverse from the pressure transmitters used for the outer valve interlocks. Typically, this diversity is achieved by procuring wide range pressure transmitters either with similar measurement principles from different vendors, or with different measurement principles (from either the same or different vendors).

Each valve is interlocked so that it cannot be opened unless the reactor coolant system pressure is below a preset pressure. This interlock prevents the valve from being opened when the reactor coolant system pressure is above the normal residual heat removal system design pressure.

Figure 7.2-1, Sheet 18 illustrates the interlock logic that applies to these valves. The logic, shown on Sheet 18, is replicated twice, once for each parallel path. This interlock logic prevents the two series isolation valves from being opened while the reactor coolant system is pressurized above a set pressure.

The valves may be closed by operator action from the main control room at any time. To prevent an inadvertent closure of these valves, no auto-closure interlock that would close the valves on high reactor coolant system pressure is included.

The normal residual heat removal system relief valves provide adequate system pressure protection for conditions after the valves have been opened. (This is discussed in Subsection 5.2.2.1). Alarms are provided in the main control room and on the remote shutdown workstation to alert the operator if reactor coolant system pressure exceeds the normal residual heat removal system design pressure after the valves are opened.

7.6.1.2 Analysis of Normal Residual Heat Removal Valve Interlocks

IEEE 603-1991 and IEEE 338-1987 criteria do not apply to the normal residual heat removal isolation valve interlocks. Their function is not required during, or after, a design basis event. However, because of the possible severity of the consequences of loss of function, the requirements of IEEE 603-1991 are applied with the following comments:

- For the purpose of applying IEEE 603-1991, the protection system is the two parallel sets of two valves in series and the components of their interlock circuitry. The inner valve is powered by a separate power supply from the outer valve of each series combination.

- Online testability; IEEE 603-1991, Paragraph 5.7: The pressure interlock signals and logic are tested on line to the maximum extent possible without adversely affecting safety. This test includes the initiating signals for the interlocks from the protection and safety monitoring system cabinets.

- IEEE 603-1991, Paragraph 6.8.2: This requirement does not apply, as the setpoints are independent of mode of operation and are not changed.

7.6.2 Availability of Engineered Safety Features

7.6.2.1 Passive Residual Heat Removal Heat Exchanger Inlet Isolation Valve

The passive core cooling system passive residual heat removal heat exchanger inlet line includes a normally open motor-operated isolation valve that can be manually controlled from either the main control room or the remote shutdown workstation. The generation of the confirmatory open signal to this valve is described in Subsection 7.3.1.2.7.

The use of a confirmatory open signal to this valve provides a means to automatically override cases when this isolation valve is closed for short periods of time.

The operation of the valve is controlled by an actuation control circuit that functions in the following manner:

- The protection and safety monitoring system provides a confirmatory open signal that will automatically open the valve in the case of a passive residual heat removal heat exchanger actuation signal if power is available to the valve.

- The plant control system provides control features to allow the valve to be operated from the normal operator workstations.

- The control circuit has a valve close actuation function that closes the valve when a control on the operator workstation is manually actuated. This function is required when performing periodic inservice testing of the passive residual heat removal heat exchanger discharge valves when the reactor is shut down. The automatic confirmatory open signal makes the passive residual heat exchanger available during inservice testing of the discharge valves.

- The maximum permissible time that a passive residual heat removal heat exchanger inlet isolation valve can be closed is specified in technical specifications.

The valve is interlocked so that:

- If the valve is closed and power not removed, it opens automatically on receipt of a confirmatory open signal.

- It cannot be manually closed when a confirmatory open signal is present.

When the passive residual heat removal heat exchanger is required to be functional, the inlet isolation valve is open with power removed to prevent inadvertent closure due to a fire.

This normally open motor-operated valve has alarms, indicating valve mispositioning (with regard to its passive core cooling function). The alarm actuates in the main control room and the remote shutdown workstation. Redundant valve position sensors are used to generate the alarm when the valve is not fully open.

7.6.2.2 Core Makeup Tank Cold Leg Balance Line Isolation Valves

Each core makeup tank has a cold leg balance line which is provided with a normally open, motor-operated, isolation valve. The balance line isolation valves, for each core makeup tank, may be manually controlled from either the main control room or the remote shutdown workstation. The generation of the confirmatory open signal to these valves is described in Subsection 7.3.1.2.3.

A confirmatory open signal to these valves automatically overrides any cases when the balance line isolation valve is closed for short periods of time. As a result of the confirmatory open signal, isolation of the core makeup tank cold leg balance line to permit inservice testing of the core makeup tank discharge valves, is acceptable.

The operation of each valve is controlled by an actuation control circuit that functions in the following manner:

- The protection and safety monitoring system provides a confirmatory open signal from automatic or manual core makeup tank actuation for cases when a balance line isolation valve is closed to support testing, maintenance, or outage related activities.
- The plant control system provides control features to allow the valve to be operated from the normal operator workstations.
- The control circuit has a valve close actuation function that closes the valve when a control on the operator workstation is manually actuated. This function is provided for performing periodic operability tests of the core makeup tank discharge valves when the reactor is operating. The automatic confirmatory open signal makes the balance line isolation valves available during operability testing of the valves.
- An administrative procedure can be invoked to maintain the valve in the closed position. This administrative procedure allows the valve to be maintained closed if needed for leakage isolation. The maximum permissible time that a core makeup tank cold leg balance line isolation valve can be closed is specified in technical specifications.

Each valve is interlocked so that:

- It receives a confirmatory open signal on a core makeup tank actuation signal.
- It cannot be manually closed when a confirmatory open signal is present.
- There is an additional control circuit that will automatically open the valve when the pressurizer water level increases above the P-12 interlock.

During power and shutdown operations, the core makeup tank cold leg balance line isolation valve remains open. To prevent an inadvertent closure of the valve, redundant output cards are used in the protection and safety monitoring system cabinet. As a result, it is not necessary to lock out control circuit power during normal operation. However, motive power is removed from this valve for risk reduction purposes noted in Chapter 19.

These normally open motor-operated valves have alarms, indicating valve mispositioning (with regard to their passive core cooling function). The alarms actuate in the main control room and the remote shutdown workstation. Redundant position sensors are used to generate the alarm when the valve is not fully open.

7.6.2.3 Interlocks for the Accumulator Isolation Valve and IRWST Discharge Valve

The accumulator isolation and in-containment refueling water storage tank injection isolation valves are safety-related in order to retain their pressure boundary and remain in their open position. The accumulator isolation and in-containment refueling water storage tank injection valve operators are nonsafety-related since the valves are not required to change position to mitigate an accident. The Chapter 15 safety analyses assume that these valves are not subject to valve mispositioning (prior to an accident) or spurious closure (during an accident). Valve mispositioning and spurious closure are prevented by the following:

- The Technical Specifications require these valves to be open and power locked out whenever these injection paths are required to be available. The accumulators are required to be available when the reactor coolant system pressure is above 1000 psig. Both in-containment refueling water storage tank injection lines are required to be available in Modes 1, 2, 3, and 4. One in-containment refueling water storage tank injection line is required to be available in Mode 5 and in Mode 6.

- The Technical Specifications require verification that the motor-operated valves are open every 12 hours. They also require verification that power is removed every 31 days.

- With power locked out, redundant (nonsafety-related) valve position indication is provided in the main control room and remote shutdown workstation. Valve position indication and alarm are provided to alert the operator if these valves are mispositioned. These indications are powered by different nonsafety-related power supplies.

In addition, the valves have a confirmatory open signal during an accident (safeguards actuation signal for accumulator motor-operated valves and automatic depressurization system stage 4 signal for in-containment refueling water storage tank motor-operated valves). The valves also have an automatic open signal when their close permissives (P-11 for accumulator motor-operated valves and P-12 for in-containment refueling water storage tank motor-operated valves) clear during plant startup. The confirmatory open and the automatic open control signals are provided to the valve operator by the nonsafety-related plant control system.

7.6.2.4 Interlock for Containment Vacuum Relief Isolation Valves

The containment vacuum relief path includes normally closed motor-operated isolation valves, which are located outside the containment and open automatically to provide a flow path to allow atmospheric air into the containment to equalize a negative differential pressure across the containment vessel shell. These valves also perform a containment isolation function when vacuum relief is not required. An interlock ensures the availability of the engineered safety features for the vacuum relief isolation valves to perform their vacuum relief and containment isolation functions. The opening of these valves at any time other than the mitigation of a negative pressure condition or for required testing is controlled by the following:

- Technical Specifications for containment isolation valves require verification every 31 days that the containment purge isolation valves are closed with a few appropriate exceptions.

- Safety-related position indication is available in the main control room and in the remote shutdown workstation on the non-safety-related operator work stations for the containment vacuum relief isolation valves and for the containment purge exhaust containment isolation valves. An alarm is provided if these valves are incorrectly positioned.

There is also a valve interlock between the inside containment purge exhaust isolation valve and the vacuum relief isolation valves, which limits the potential release of radioactivity from the containment while the containment isolation valves are being closed. The purge and vacuum relief valve interlock automatically closes the vacuum relief isolation valves any time that the inside containment purge exhaust valve is not fully closed and a coincident vacuum relief actuation signal is not present. If a vacuum relief actuation signal is present, it takes priority over the valve closure interlock.

As discussed in Subsections 6.2.3.5 and 9.4.7.2.3, the vacuum relief subsystem is used to mitigate a condition where the atmospheric air pressure outside is higher than the reactor containment air pressure (so that a negative containment pressure condition exists). The valves can be opened either automatically or manually when an excessively low containment pressure exists to mitigate the event. The actuation signal includes a control interlock provided by the protection and safety monitoring system. The interlock is a part of the logic for the control of the valves shown on Figure 7.2-1 (Sheet 19 of 21).

7.6.3 Combined License Information

This section contained no requirement for information.

7.7 Control and Instrumentation Systems

The function of the AP1000 control systems is to establish and maintain the plant operating conditions within prescribed limits. The control system improves plant safety by minimizing the number of situations for which some protective response is initiated and relieves the operator from routine tasks.

The AP1000 control systems share a common hardware design and implementation philosophy. They are also functionally integrated to enhance responsiveness during plant transients. Specific design requirements are imposed that limit the impact of individual equipment failures. (See Subsection 7.1.3).

The control systems regulate the operating conditions in the plant automatically in response to changing plant conditions and changes in plant load demand. These operating conditions include the following:

Reactor Coolant System Temperature - The control systems function to maintain the reactor coolant system temperature at or near a programmed value. This value is a function of plant load or other operating conditions. Steam conditions for the turbine depend on the temperature maintained in the reactor coolant. Reactor coolant system temperature is also used for controlling core reactivity.

Nuclear Power Distribution - Operating limits include the distribution of nuclear energy production within the core as well as its average value. The axial distribution of the nuclear power is controlled within prescribed limits.

Reactor Coolant System Pressure - The reactor coolant system is pressurized to prevent significant boiling at operating temperatures. This pressure is controlled within limits that prevent reductions which expose the fuel to possible departure from nucleate boiling or from increases that would challenge the reactor coolant system design pressure.

Pressurizer Water Level - To provide a sufficient buffer for plant transients, the reactor coolant system pressurizer contains a prescribed volume of water and steam which depends on plant load and operating temperature.

Steam Generator Water Level - The steam generator water level is maintained within limits to provide adequate energy removal capability and to avoid moisture carryover.

Steam Dump (Turbine Bypass) - For fast and large transients such as load rejections, an additional thermal load (designated steam dump or turbine bypass) functions until nuclear power is reduced. This steam dump is also used to maintain hot no-load or hot low-load conditions prior to turbine loading. It provides a means for plant cooldown.

7.7.1 Description

The plant control and instrumentation systems described in this section perform the following functions:

Reactor Power Control System - The reactor power control system coordinates the responses of the various reactivity control mechanisms. The system enables daily load follow operation with a minimum of manual control by the operator. Load regulation and frequency control are compatible with the reactor power control system operation. Axial nuclear power distribution control is also performed by the reactor power control system.

Rod Control System - The rod control system, in conjunction with the reactor power control system, maintains nuclear power and reactor coolant temperature, without challenges to the protection systems, during normal operating transients.

Pressurizer Pressure Control - The pressurizer pressure control system maintains or restores the pressurizer pressure to the nominal operating value following normal operating transients. The control system reacts to avoid challenges to the protection systems during these operating transients.

Pressurizer Water Level Control - The pressurizer water level control system establishes, and maintains or restores pressurizer water level to its programmed operating region. The required water level operating region is programmed as a function of reactor coolant system temperature to minimize charging and letdown requirements. No challenges to the protection system result from normal operational transients.

Feedwater Control System - The feedwater control system maintains the steam generator water level at a predetermined setpoint during steady-state operation. It also maintains the water level within operating limits during normal transient operation. The feedwater control system restores normal water level following a unit trip. The various modes of feedwater addition are automated to require a minimum of operator involvement.

Steam Dump Control - The steam dump control system reacts to prevent a reactor trip following a sudden loss of electrical load. The steam dump control system also removes stored energy and residual heat following a reactor trip so that the plant can be brought to equilibrium no-load conditions without actuation of the steam generator safety valves. The steam dump control system also provides for maintaining the plant at no-load or low-load conditions to facilitate a controlled cooldown of the plant.

Rapid Power Reduction - For large, rapid load rejections (turbine trip or grid disconnect from 50-percent power or greater) or the loss of a main feedwater pump train, a rapid nuclear power cutback is implemented. This results in a reduction of thermal power to a level that can be handled by the steam dump system in conjunction with the reactor power control system for the large load rejection. For a loss of main feedwater pump transient, the actuation of the rapid power reduction reduces power to a level that can be handled by the remaining feedwater pumps.

Defense-In-Depth Control - The plant control system provides control of systems performing defense-in-depth functions. Table 7.7-3 provides a listing of the defense-in-depth functions that are supported by the plant control system and provides a cross reference to the applicable information located in other sections of this document.

7.7.1.1 Reactor Power Control System

Automatic reactor power and power distribution control are the basic functions of the reactor power control system. They are achieved by varying the position of the control rods. Separate control rod banks are used to regulate reactor power and power distribution.

The reactor power control system enables the plant to respond to the following load change transients:

- Step load changes of plus or minus 10 percent
- Ramp load increases and decreases of 5 percent per minute

- Daily load follow operations with the following profile:
  - Power ramps from 100 percent to 50 percent in 2 hours
  - Power remains at 50 percent for 2 to 10 hours
  - Power ramps back up to 100 percent in 2 hours
  - Power remains at 100 percent for the remainder of the 24-hour cycle
- Grid frequency response (denoted load regulation) resulting in a maximum of 10-percent power change at 2 percent per minute

These capabilities are accomplished without a reactor trip or steam dump actuation. During daily load follow and load regulation transients, automatic control of axial offset is provided. The system restores coolant average temperature to a value which is within the programmed temperature band following a change in load. Manual control of either the power control rods (M banks) or the axial offset control rods (AO bank) is performed within the range of defined insertion limits.

The reactor power control system uses a different control strategy for the rods used to regulate core power (M banks) from the control strategy used to regulate axial offset (AO bank). Reactor coolant system boron concentration is adjusted by the operator to account for long-term core burnup. The adjustment also inserts the gray M banks to targeted positions with both black M banks (M1 and M2) remaining in a near fully withdrawn position and the AO bank within its normal operating range. During load follow or load regulation response transients, the power control and the axial offset control subsystems jointly function to control both core power and axial offset. The following two subsections provide a description of each control subsystem.

7.7.1.1.1 Power Control

The power control subsystem controls the reactor coolant average temperature by regulating the M control rod bank positions. The reactor coolant loop average temperatures are determined from hot and cold leg measurements in each reactor coolant loop. The average coolant temperature (T_{avg}) is computed for each loop, where:

$$T_{avg} = \frac{T_{hot} + T_{cold}}{2}$$

The error between the programmed reference temperature (based on turbine first stage pressure) and the highest of the T_{avg} measured temperatures from each of the reactor coolant loops constitutes the primary control signal (for Unit 3). The error between the programmed reference temperature (based on turbine first stage pressure) and the measured signal selected medium loop T_{avg} constitutes the primary control signal (for Unit 4). The programmed coolant temperature increases linearly with turbine load from the zero-power to the full-power condition.

The temperature input signals for the power control subsystem are fed from protection channels via isolation devices and the signal selector function.

An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks.

The deviation of the reactor coolant temperature from the programmed value is the basic control variable for reactor power control. A deadband is included in the power control subsystem so that no rod motion is demanded if the temperature error is within the deadband. As the temperature error becomes greater, the demanded rod speed becomes greater.

Separate reactor control deadbands are used for various modes of control. If the plant is in a load regulation mode of operation, then the deadband is widened from that used for base load or load follow operation. This allows the core reactivity feedbacks to assist in stabilizing the plant at the conclusion of the maneuver and reduces the total control rod movement and subsequent wear on the control rods.

A different control strategy is used at low-power levels, principally when the turbine is off-line and the steam dump system is used to regulate coolant temperature. In this mode, nuclear power is controlled directly. For this mode, a nuclear power setpoint calculator allows the operator to enter a desired power level above or below the current power level along with a desired rate of change (limited to fixed predetermined maximum limits). The nuclear power setpoint calculator then supplies a changing setpoint that provides for a linear ramp change in core power at the selected rate.

7.7.1.1.2 Axial Offset Control

The axial offset control subsystem controls the core axial offset (power difference between the top and bottom halves of the core) to a value that is within the desired control range for load follow and grid frequency change transients. This is accomplished by using a control rod bank separate from those used for the reactor power control described in Subsection 7.7.1.1.1. Measurements of axial offset are input into the axial offset control subsystem and then compared to an axial offset control "window." This window is calculated from measurements of ΔT power, along with operator inputs for the desired axial offset target value and target bandwidth. If the plant is in a load regulation mode of control, then lag compensation is applied to both the ΔT power and the axial offset signals. This provides smoothed input to the axial offset controller to avoid unnecessary axial offset control. When the axial offset error is outside the acceptable control window, the axial offset rods are actuated until the axial offset error is back inside the control window.

In order to minimize the potential for adverse interactions and optimize coordination between the power and axial offset rod control subsystems, an interface rule is established such that control of T_{avg} always takes precedence over control of power distribution.

7.7.1.2 Rod Control System

The rod control system receives rod speed and direction signals from the power control and axial offset control subsystems. The portion of the rod control system associated with the power and axial offset control subsystems each operate their own sets of control rod banks as follows:

- The power control portion operates the MA, MB, MC, MD, M1 and M2 control rod banks.
- The axial offset control portion operates the AO control rod bank.

For power control, the rod speed demand signals vary over the range of 5 to 45 inches per minute (8 to 72 steps per minute), depending on the magnitude of the input signal and the need for axial offset control. Manual control is provided to move a bank in or out at a prescribed fixed speed. In the automatic mode, the rods are withdrawn (or inserted) in a predetermined sequence within the limits imposed by the control interlocks as shown in Table 7.7-1.

For axial offset control, the rod speed demand signals are set to a fixed constant speed of approximately 5 inches per minute (8 steps per minute). Manual control is provided to move a bank in

or out at a prescribed fixed speed. In the automatic mode, the rods are withdrawn (or inserted) within the limits imposed by the control interlocks, as shown in Table 7.7-2.

The shutdown control rod banks are always in the fully withdrawn position during normal operation and are moved to this position at a constant speed by manual control prior to criticality. A reactor trip signal causes them to fall by gravity into the core. There are four shutdown control rod banks.

The power and axial offset control rod banks are the only rods that can be manipulated under automatic control. Each bank contains one or more groups of four control rod assemblies with the exception of the axial offset control rod bank, which contains an additional group with a single assembly. Each control rod assembly in a group is electrically paralleled to move simultaneously. There is individual position indication for each control rod assembly.

Power to the rod drive mechanisms is supplied by two motor-generator sets operating from two separate 480-volt, 3-phase busses. Each generator is the synchronous type, and is driven by an induction motor. The ac power is distributed to the rod control system cabinets through the reactor trip switchgear.

The variable speed rod drive programmer used in the power control subsystem inserts small amounts of reactivity at low speed. This permits fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing control at high speed for transients such as load rejections. A summary of the control rod assembly sequencing characteristics is given below:

- The control rod groups within the same bank are stepped so that the relative position of the groups do not differ by more than one step.

- The control rod banks are programmed so that withdrawal of the banks is sequenced in a prescribed order. The programmed insertion sequence is the opposite of the withdrawal sequence. That is, the last control bank withdrawn is the first control bank inserted.

- The control bank withdrawals are programmed so that, when the first bank reaches a preset position, the next bank begins to move out simultaneously with the first bank. This preset position is determined by the maximum allowable overlap between banks (approximately 50 to 100 steps). This withdrawal sequence continues until the control banks reach the fully withdrawn position. The control bank insertion sequence is the opposite of the withdrawal sequence.

- Overlap between successive control banks is adjustable between 0 to 50 percent (0 to 135 steps), with an accuracy of ±1 step.

The constant rod speed used in the axial offset control subsystem provides a slow stable control of core axial offset. This is acceptable since axial offset changes for the design basis load follow transients generally occur over several hours and rapid response is not needed. The slow response of the axial offset control system also allows the rods used by the power control subsystem to counteract the core power reactivity changes that are induced by the axial offset rods.

7.7.1.3 Control Rod Position Monitoring

Digital Rod Position - The digital rod position indication system measures the position of each control rod assembly using a detector consisting of discrete coils mounted concentric with the rod drive pressure housing. The coils are located axially along the pressure housing and magnetically sense the entry and presence of the rod drive shaft through its center line.

Demand Position System - The demand position system counts the pulses generated in the rod control system to provide a digital readout of the demanded bank position. The demanded and measured rod position signals are displayed in the main control room. An alarm is generated whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm is set with appropriate allowance for instrument error and within sufficiently narrow limits to prevent exceeding core design hot channel factors.

Alarms are also generated if any shutdown rod is detected to have left its fully withdrawn position, or if any M bank control rods are detected at the bottom position, except as part of the normal insertion sequence.

7.7.1.4 Control Rod Insertion Limits

With the reactor critical, the normal indication of reactivity status in the core is the position of the control rod bank in relation to reactor power (as indicated by the ΔT power monitors). The ΔT power signal is used to calculate insertion limits for the banks. The following two alarms are provided for each bank.

- A "low" alarm alerts the operator of an approach to the M bank or AO bank insertion limits. Further approach is avoided by following appropriate plant procedure.

- A "low-low" alarm alerts the operator to take immediate action to restore margin to the M bank or AO bank insertion limits. Interlocks will terminate automatic AO bank withdrawal (to prevent further insertion of the M banks) or insertion (to avoid the AO bank insertion limits).

The purpose of the control bank rod insertion alarms and interlocks is to provide warning to the operator of excessive rod insertion and to terminate the insertion. The insertion limit maintains sufficient core reactivity shutdown margin following reactor trip. It also provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection. Insertion limits provide confidence that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits are decreased (the rods must be withdrawn further) with increasing power. The insertion limits for the M banks and the AO bank are calculated from the reactor power, as measured by the ΔT power monitor, according to the following equations:

$$Z_{LL}^{M} = A + B \cdot P_{EF} + C \cdot Z_{AO} + D \cdot P_{EF} \cdot Z_{AO}$$

$$Z_{LL}^{AO} = E + F \cdot P_{EF}$$

where:

Z_{LL}^{M} = Maximum permissible insertion limit for the affected M control bank

Z_{LL}^{AO} = Maximum permissible insertion limit for the affected AO control bank

Z_{AO} = Current AO bank position (fraction inserted)

P_{EF} = $Max(P_{TH},P^{LP})$, effective power for each bank

P_{TH} = ΔT Power (thermal power)

P^{LP} = Low power threshold for each bank

A,B,C,D,E,F = Constants chosen to maintain Z_{LL} ≥ the actual limit based on physics calculations

The control rod bank demand position (Z) for the M banks and the AO bank is compared to the respective Z_{LL} as follows:

- If $Z - Z_{LL} \leq G$, a low alarm is actuated.
- If $Z - Z_{LL} \leq H$, a low-low alarm and interlock is actuated.

Since nuclear peaking factors can be aggravated by the opposite movement of the M banks and the AO bank, the interlocks on the AO bank are different, depending on whether the M bank or the AO bank insertion limit setpoint is actuated. If an M bank insertion limit is reached, this stops AO bank withdrawal and reduces the increases in the core peaking factor. If an AO bank insertion limit is reached, this stops AO bank insertion. If the M banks are at their C-18 withdrawal limit, AO bank automatic insertion is blocked.

7.7.1.5 Control Rod Stops

Rod stops are provided to prevent abnormal power conditions that could result from excessive control rod withdrawal initiated by either a control system malfunction or operator violation of administrative procedures.

7.7.1.6 Pressurizer Pressure Control System

The primary system pressure is closely regulated during operation to prevent pressure from increasing to the point where an engineered safety features actuation is required to prevent overstressing the pressure boundary; or from decreasing to a condition where engineered safety features actuation is required to prevent the possibility of departure from nucleate boiling. Fine control of pressure to the desired setpoint is accomplished by regulating the power to a bank of heaters located in the pressurizer. Large decreases in pressure are accommodated by turning on additional heater banks and by the inherent flashing from the water mass in the pressurizer, which is at saturation. Large pressure increases are controlled by actuating pressurizer spray to condense steam.

Pressurizer pressure control is designed to provide stable and accurate control of pressure to its predetermined setpoint. Automatic pressure control is available from the point at which nominal pressure is established in the startup cycle to 100-percent power. During steady-state operating conditions, the pressurizer heater output is regulated to compensate for pressurizer heat loss and a small continuous pressurizer spray. During normal transient operation, the pressure is regulated to provide adequate margin to safety systems actuation or reactor trip. The pressurizer pressure control system is designed to minimize equipment duty (such as spray nozzle thermal cycling due to spray actuation) due to load regulation operation.

Small changes in pressure are regulated by modulation of the variable heater control. Reset (integral) action is included to maintain pressure at its setpoint. Decreases in pressure larger than that which can be accommodated by the variable heater control results in the actuation of the backup heaters. The backup heaters are deactivated when the variable heaters alone are capable of restoring pressure.

7.7.1.7 Pressurizer Water Level Control System

The pressurizer water inventory, or level control, provides a reservoir for the reactor coolant system inventory changes that occur due to changes in reactor coolant system density. As the reactor coolant system temperature is increased from hot zero-load to full-load values, the reactor coolant system fluid expands. The pressurizer level is programmed to absorb this change. A deadband is provided around the nominal pressurizer level program to intermittently control charging and letdown. When the pressurizer water level reaches the lower limit of the deadband, it actuates the charging system. The charging system continues to operate until the level is restored to a limit above the nominal program value. When the pressurizer water level reaches the upper limit of the deadband, it actuates letdown to the liquid waste processing system.

Pressurizer water level control provides stable and accurate control of pressurizer level within a prescribed deadband around the programmed setpoint value, as derived from the plant operating parameters. Automatic level control is supplied from the point in the startup cycle where the hot zero-load level is established through 100-percent power.

7.7.1.8 Feedwater Control System

The feedwater control system consists of those controllers and associated hardware whose primary function is to regulate the flow of feedwater into the steam generator. The feedwater control system consists of two separate subsystems. The feedwater control subsystem regulates the flow of feedwater into the steam generators via the main feedwater line. The startup feedwater control subsystem regulates the flow of feedwater into the steam generators via the startup feedwater line. Flow to the startup feedwater line may be supplied by either the main or startup feedwater pump. The following two subsections provide a description of each control subsystem.

7.7.1.8.1 Feedwater Control

The feedwater control subsystem maintains a programmed water level in the shell side of the steam generator during steady-state operation, and limits the water level shrink and swell during normal plant transients. This prevents an undesirable reactor trip actuation. Indication is provided for monitoring system operation. Alarms and indications are provided to alert the plant operator of control system malfunctions or abnormal operating conditions.

Two modes of feedwater control are incorporated in the feedwater control subsystem. In the high-power control mode, the feedwater flow is regulated in response to changes in steam flow and proportional plus integral (PI)-compensated steam generator narrow range water level deviation from setpoint. In the low-power control mode, the feedwater flow is regulated in response to changes in steam generator wide-range water level and PI-compensated steam generator narrow range water level deviation from setpoint.

The transition from the low to the high-power control mode is initiated on the basis of the filtered high range feedwater flow signal. The transition point is set at a feedwater flow corresponding to a power at which reliable steam flow indication is expected. The transition point is also low enough to allow effective feedforward control using wide range water level. Tracking is provided to allow a smooth transition between control modes and between manual and automatic control.

A high steam generator water level signal reduces the feedwater flow demand signal and closes the feedwater control valves.

7.7.1.8.2 Startup Feedwater Control

During no-load or very low power conditions, the main feedwater control subsystem is not intended to be used for automatic control of the steam generator water level. The startup feedwater control subsystem performs this function.

The startup feedwater control subsystem maintains a programmed water level in the shell side of the steam generator during low power (below approximately 10 percent of plant rated thermal power), no-load, and plant heatup and cooldown modes. During low feedwater flow demand, feedwater is controlled by the startup feedwater control subsystem. Transition between the main and startup feedwater line is automatically controlled based on flow measurements within the respective lines. The startup feedwater is also automatically actuated on signals which indicate a loss of water inventory or heat sink in the secondary side of the steam generator and will attempt to recover the inventory loss and return the steam generator water level to the programmed value. If the startup feedwater cannot recover the inventory deficit, reactor cooling is initiated by the passive residual heat removal system.

The startup feedwater control subsystem regulates the flow of feedwater in a manner which is similar to the way (main) feedwater is controlled in the low-power control mode. Feedwater flow is regulated in response to changes in steam generator wide-range water level and PI-compensated steam generator narrow range water level deviation from setpoint. Tracking is provided to allow a smooth transition between control modes and between manual and automatic control.

7.7.1.9 Steam Dump Control System

The AP1000 is designed to sustain a 100-percent load rejection, or a turbine trip from 100-percent power, without generating a reactor trip, requiring atmospheric steam relief, or actuating a pressurizer or steam generator safety valve. The automatic steam dump control system, in conjunction with other control systems, is provided to accommodate this abnormal load rejection and to reduce the effects of the transient imposed on the reactor coolant system. By bypassing main steam to the condenser, an artificial load is maintained on the primary system. This artificial load makes up the difference between the reactor power and the turbine load for load rejections and turbine trips. It also removes latent and decay heat following a reactor trip.

The steam dump system is sized to pass up to 40 percent of rated main steam flow. This capacity, in conjunction with the performance of the reactor power control system, is sufficient to handle reactor trips from any power level, turbine trips from up to a predetermined power level, and load rejections up to a predetermined magnitude. For turbine trips above a threshold power level, or load rejections exceeding a given magnitude, the steam dump system operates in conjunction with the rapid power reduction system described in Subsection 7.7.1.10 to meet the performance described in the previous paragraph.

The steam dump control system has two main modes of operation:

- The T_{avg} mode uses the difference between measured signal selected median loop T_{avg} and a reference temperature derived from turbine first-stage pressure, to generate a steam dump demand signal. This mode is largely used for at-power transients requiring steam dump, such as load rejections and turbine trips (where the load rejection T_{avg} mode is used). The load rejection controller is discussed in Subsection 7.7.1.9.1.

- The pressure mode uses the difference between measured steam header pressure and a pressure setpoint to generate a steam dump demand signal. This mode is used for low-power conditions (up through turbine synchronization), plant cooldown, and reactor trip. It is described in Subsection 7.7.1.9.3.

The Class 1E process variable input signals to the steam dump control system are fed from protection channels via isolation devices and the signal selector function. Each input (T_{avg}, turbine load, and steam header pressure) is obtained from multiple transmitters of the same parameter. The signal selector rejects any signal which is bad in comparison with the remaining transmitter outputs and allows only valid measurements to be used by the control system. This makes the steam dump system tolerant of single transmitter failures or input signal failures and eliminates interaction between the control and the protection system.

To prevent actuation of steam dump on small load perturbations, an independent load rejection sensing circuit is provided. This circuit senses the rate of decrease in the turbine load as detected by the turbine first stage pressure. It unblocks the dump valves when the rate of a load rejection exceeds a preset value corresponding to a 10-percent step load decrease or a sustained ramp load decrease of greater than 5 percent per minute.

7.7.1.9.1 Load Rejection Steam Dump Controller

This controller prevents a large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead-lag compensated selected T_{avg} and the selected reference T_{avg} (designated T_{ref}), based on turbine first stage pressure.

The T_{avg} input signals are the same as those used in the reactor power control system, although a signal selector algorithm in a separate controller is employed. The lead-lag compensation for the T_{avg} signal compensates for lags in the plant thermal response and in valve positioning. The lead-lag compensation in the T_{ref} signal is used to compensate for hangup effects noted in the turbine first stage pressure measurement on turbine trips and grid disconnects. It allows for a decrease in gain in the steam dump controller, thereby increasing stability. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase. This generates an immediate demand signal for steam dump. Following the initial steam dump opening, the reactor power control system in conjunction with the rod control system commands the control rods to insert in a controlled manner to reduce the reactor power to match turbine load. On a load rejection resulting in a turbine runback, the steam dump terminates when the reactor power matches the turbine load and the temperature error is within the maneuvering capability of the control rods. On a grid disconnect, the steam dump modulates closed in response to the control rods reducing nuclear power to match the steam demand of plant auxiliaries. At this point, rod insertion stops and the plant stabilizes in preparation for a turbine/generator restart and/or grid synchronization with the steam dumps partially open. On a turbine trip the steam dump and reactor power control system reduce the plant to hot zero power conditions.

7.7.1.9.2 Not Used

7.7.1.9.3 Steam Header Pressure Controller

Decay heat removal between hot standby and residual heat removal system cut-in conditions is maintained by the steam header pressure controller. This controller uses the difference between steam header pressure and a pressure setpoint to control the steam flow to the condensers. Reset action is used to eliminate steady-state error. This controller uses the same steam dump valves as the load rejection controller described in Subsection 7.7.1.9.1. Following a reactor trip, the steam dump control system automatically switches to steam header pressure control mode with a fixed pressure setpoint. Otherwise, the steam header pressure control mode is manually selected by the operator. The pressure setpoint is manually adjusted by the operator based on the desired reactor coolant system temperature. In addition, the controller has a feature that allows automatically controlled plant cooldowns at a chosen rate (within limits). The operator can enter the desired cooldown rate and the desired target reactor coolant system temperature. The control system then dumps the required steam to achieve the setpoint cooldown rate and stops at the target setpoint.

7.7.1.10 Rapid Power Reduction System

The rapid power reduction system rapidly reduces the nuclear power to a level capable of being handled by the steam dump system for a large load rejection (greater than 50-percent power reduction at a rapid rate). Upon the detection of a large and rapid turbine power reduction (via a rate/lag circuit, similar to that used for steam dump control), the circuit provides a signal demanding the release of a selected number of control rods when power is above a predetermined level.

The large load rejection also actuates the steam dump system and the reactor power control system. Following the initiation of the load rejection, the power control rods insert in a controlled manner due to the mismatch between the programmed reference average coolant temperature (based on turbine first stage pressure) and the compensated average coolant temperature measured in the reactor coolant loops. In a similar manner, the load rejection steam dump controller controls the steam dump valves to prevent a large increase in reactor coolant temperature. Following the release of the selected control rods, the power control system continues to insert the remaining control rods to reduce power (by temperature control channel trying to match T_{avg} to T_{ref}). Following the initial opening, the steam dump valves modulate closed based upon the (T_{avg} - T_{ref}) signal.

Following rapid power reduction actuation, controlled rod insertion, steam dump modulation, and/or additional turbine runbacks continue as necessary until the plant is stabilized at a reduced power level. At this time, the operators can then recover the released control rods to restore normal overlap. The system can then be returned to automatic, and a normal power escalation will be performed to the desired power level. The rapid power reduction system is also used to rapidly reduce the nuclear power in conjunction with a turbine runback upon loss of one of the three operating main feedwater pumps as indicated by motor breaker positions when power is above a predetermined level. Power reduction is achieved in the same manner as described above.

7.7.1.10.1 Rod Block Interlock

To avoid the potential for a withdrawal of the normally functioning power control rods following the rod release by the rapid power reduction system, a rod withdrawal block (P-17) is actuated. The P-17 interlock is actuated by the rapid reduction in nuclear power caused by the insertion of power control rods (M banks) into the core after the initiation of the rapid power reduction system as discussed in Subsection 7.7.1.10. The rod withdrawal block does not adversely impact the performance of the rapid power reduction system. The demand of the power control subsystem is a continuous rod insertion. Rod withdrawal during the power reduction phase is not required.

7.7.1.10.2 Rapid Power Reduction Rod Selection

The number of rods needed to obtain the required power reduction is dependent on the initiating transient and the transient initial conditions, including the core burnup during the fuel cycle, the initial power level, and the initial position of the M-banks. Therefore, bank selection logic is provided to automatically determine which rods will be released by the rapid power reduction system based on these factors. Alternatively, the operator can override the automatic selection and manually select the rods for release.

7.7.1.11 Diverse Actuation System

The diverse actuation system is a nonsafety-related system that provides a diverse backup to the protection and safety monitoring system. This backup is included to support the aggressive AP1000 risk goals by reducing the probability of a severe accident which potentially results from the unlikely coincidence of postulated transients and postulated common mode failure in the protection and control systems.

The protection and safety monitoring system is designed to prevent common mode failures. However, in the low probability case where a common mode failure does occur, the diverse actuation system provides diverse protection. The specific functions performed by the diverse actuation system are selected based on the PRA evaluation. The diverse actuation system functional requirements are based on an assessment of the protection system instrumentation common mode failure probabilities combined with the event probability. The plant-specific PRA model reflects DAS functionality testing at the frequency specified in the TRM.

The functional logic for the diverse actuation system is shown in Figure 7.2-1, sheets 20 and 21.

The DAS is developed using a planned design process, which provides for specific design documentation during the following life cycle stages:

- Design Requirements Phase
- System Definition Phase

These life cycle stages are completed by developing a number of specific design documents. The following documents are developed to address the Design Requirements and System Definition Phases:

- WCAP-17184-P, "AP1000™ Diverse Actuation System Planning and Functional Design Summary Technical Report," including Appendix A, "DAS Setpoint Methodology Description," and Appendix B, "PRA Performance Requirements Associated with DAS Manual Actuation."

  WCAP-17184-P, "AP1000™ Diverse Actuation System Planning and Functional Design Summary Technical Report," (Reference 1) identifies the DAS architecture and associated licensing basis at the functional design level. The overall DAS detailed design is not identified in the report. Select design details are identified only for the purpose of architectural completeness or licensing compliance. The content of WCAP-17184 Sections 1 through 11, and Appendices A and B are incorporated by reference into the UFSAR. Appendix A of the Technical Report describes the DAS setpoint methodology and provides a representative basis for DAS nominal trip setpoints. Appendix B addresses operator actions taken through DAS that are modeled in the "AP1000 Probabilistic Risk Assessment" (PRA). These manual actions are not required to mitigate design basis accidents but instead are modeled in the PRA to provide insights into sequences that involve multiple failures. This appendix lists the operator actions used in the PRA for manual DAS actions from the control room DAS actuation panel.

- WCAP-15775, "AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report"

  Diversity is a principle in instrumentation of sensing different variables, using different technology, using different logic or algorithms, or using different actuation means to provide different ways of responding to postulated plant conditions. NUREG/CR-6303 segregates the types of diversity into six different areas: human, design, software, functional, signal, and equipment. WCAP-15775, "AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report," (Reference 2) describes the type of diversity that exists among the four echelons of defense for AP1000 and identifies dependencies among the echelons. The content of WCAP-15775 Sections 1 through 5 is incorporated by reference into the UFSAR.

A number of additional design process documents are submitted to the U.S. NRC for review and audit. They include the following:

1. "AP1000 Diverse Actuation System Logic Drawings"

2. “AP1000 Diverse Actuation System Sub-System Requirements”

3. “DAS Requirements Traceability Report”

Automatic Actuation Function

The automatic actuation signals provided by the diverse actuation system are generated in a functionally diverse manner from the protection system actuation signals. The common-mode failure of sensors of a similar design is also considered in the selection of these functions.

The automatic actuation function is accomplished by redundant logic subsystems. Input signals are received from the sensors by an input signal conditioning block, which consists of one or more electronic modules. This block converts the signals to standardized levels, provides a barrier against electromagnetic and radio frequency interference, and presents the resulting signal to the input signal conversion block. The conversion block continuously performs analog to digital signal conversions and stores the value for use by the signal processing block.

The signal processing block polls the various input signals, evaluates the input signals against stored setpoints, executes the logic when thresholds are exceeded, and issues actuation commands.

The resulting output signals are passed to the output signal conversion block, whose function is to convert logic states to parallel, low-level dc signals. These signals are passed to the output signal conditioning block. This block provides high-level signals capable of switching the traditional power plant loads, such as breakers and motor controls. It also provides a barrier against electromagnetic and radio frequency interference.

The DAS automatic actuation signals are generated in a functionally diverse manner from the PMS signals. Diversity between DAS and PMS is achieved by the use of different architectures, different hardware implementations, and different software, if any.

Software diversity between the DAS and PMS will be achieved through the use of different algorithms, logic, program architecture, executable operating system, and executable software/logic.

The AP1000 plant Component Interface Module (CIM) provides the priority logic between PMS and plant control for component control. Section 2.9 of WCAP-17179, “AP1000 Component Interface Module Technical Report,” (Reference 3) identifies how diversity is maintained between the DAS and the CIM.

The diverse automatic actuations are:

- Trip rods via the motor generator set, trip turbine, initiate the passive residual heat removal, actuate core makeup tanks, close the in-containment refueling water storage tank gutter isolation valves, and trip the reactor coolant pumps on low wide-range steam generator water level

- Trip rods via the motor generator set, trip turbine, open the passive heat removal discharge isolation valves, and close the in-containment refueling water storage tank gutter isolation valves on high hot leg temperature

- Trip rods via the motor generator set, trip turbine, actuate the core makeup tanks, and trip the reactor coolant pumps on low pressurizer water level

- Isolate selected containment penetrations and start passive containment cooling water flow on high containment temperature

The selection of setpoints and time responses determine that the automatic functions do not normally actuate unless the protection and safety monitoring system has failed to actuate to control plant conditions. Capability is provided for testing and calibrating the channels of the diverse actuation system.

Manual Actuation Function

[*The manual actuation function of the diverse actuation system is implemented by hard-wiring the controls located in the main control room directly to the final loads in a way that completely bypasses the normal path through the protection and safety monitoring system cabinets, and the diverse actuation system automatic logic.*]*

The diverse manual functions are:

- Reactor and turbine trip
- Passive containment cooling actuation
- Core makeup tank actuation and reactor coolant pump trip
- Open stage 1 automatic depressurization system valves
- Open stage 2 automatic depressurization system valves
- Open stage 3 automatic depressurization system valves
- Open stage 4 automatic depressurization system valves
- Open the passive residual heat removal discharge isolation valves and close the in-containment refueling water storage tank gutter isolation valves
- Selected containment penetration isolation
- Containment hydrogen igniter actuation
- Initiate in-containment refueling water storage tank injection
- Initiate containment recirculation
- Initiate in-containment refueling water storage tank drain to containment

In addition to the above functions, a redundant method of actuating the following components is provided at DAS Processor Cabinet 1, Processor Cabinet 2, and the Squib Valve Control Cabinet:

- Open stage 4 automatic depressurization system valves
- Initiate in-containment refueling water storage tank injection
- Initiate containment recirculation
- Initiate in-containment refueling water storage tank drain to containment

The specific DAS controls were selected based on PRA risk importance (Reference 4). Although the DAS manual controls are non-Class 1E, they have been shown to be PRA risk-important (Reference 4).

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Actuation Logic Function

There are two actuation logic modes, automatic and manual. The automatic actuation logic mode functions to logically combine the automatic signals from the two redundant automatic subsystems in a two-out-of-two basis. The combined signal operates a power switch with an output drive capability that is compatible, in voltage and current capacity, with the requirements of the final actuation devices. The two-out-of-two logic is implemented by connecting the outputs in series. The manual actuation mode operates in parallel to independently actuate the final devices.

Actuation signals are output to the loads in the form of normally de-energized, energize-to-actuate signals. The normally de-energized output state, along with the dual, two out of two redundancy reduces the probability of inadvertent actuation.

After an actuation signal is output to a load, subsequent return to operation requires deliberate operator action.

Indication

To support the diverse manual actuations, sensor outputs are displayed in the main control room in a manner that is diverse from the protection system display functions. The instrument sensor output displayed in the main control room is repeated at DAS Processor Cabinet 1. The indications that are provided from at least two sensors per function are:

- Steam generator water level – for reactor trip and passive residual heat removal actuations, and for overfill prevention by manual actuation of the automatic depressurization system valves
- Hot leg temperature – for passive residual heat removal actuation and reactor trip
- Core exit temperature – for automatic depressurization system actuation and subsequent initiation of in-containment refueling water storage tank injection and also containment hydrogen igniter actuation
- Pressurizer level – for core makeup tank actuation and reactor coolant pump trip
- Containment temperature – for containment isolation and passive containment cooling system actuation
- Rod control motor generator voltage – for confirmation of reactor trip

Isolation

The diverse actuation system uses sensors that are separate from those being used by the protection and safety monitoring system and the plant control system. This prohibits failures from propagating to the other plant systems through the use of shared sensors.

There is signal isolation between the two subsystems within the diverse actuation system, one for each input and output path. These isolators are characterized by a high common mode voltage withstand capability to provide the necessary isolation against faults. The configuration is set up such that the isolation devices are capable of protecting against fault propagation between the diverse actuation system subsystems.

Actuation interfaces are shared between the diverse actuation system and the protection and safety monitoring system. The diverse actuation system actuation devices are isolated from the protection and safety monitoring system actuation devices, so as to avoid adverse interactions between the two systems. The actuation devices of each system are capable of independent operation that is not

affected by the operation of the other. The diverse actuation system is designed to actuate components only in a manner that initiates the safety function. This type of interface also prevents the failure of an actuation device in one system from propagating a failure into the other system.

The diverse actuation system and the protection and safety monitoring system use independent and separate uninterruptible power supplies.

Operability, Availability, and Testing

The diverse actuation system is designed to provide protection under all plant operating conditions in which the reactor vessel head is in place and non-Class 1E UPS power is available. The automatic actuation processors, in each of the two redundant automatic subsystems of the diverse actuation system, are provided with the capability for channel calibration and testing while the plant is operating. To prevent inadvertent DAS actuations during online calibration, testing activities or maintenance, the normal activation function is bypassed. Testing of the diverse actuation system is performed on a periodic basis.

Equipment Qualification and Quality Standards

The diverse actuation system is located in a controlled environment, but is capable of functioning during and after normal and abnormal events and conditions that include:

- Wide temperature range of 40° to 120°F
- Noncondensing relative humidity up to 95 percent
- Radio frequency and electromagnetic interference

The diverse actuation system processor cabinets are located in the seismic Category I Auxiliary Building. The diverse actuation system equipment, including actuated devices, is designed and tested in accordance with industry standards. The adequacy of the hardware and software (if any) is demonstrated through a diverse form of the verification and validation program discussed in Subsection 7.1.2.14. This program provides for the use of commercial off-the-shelf hardware and software. As the diverse actuation system performs many of the protection functions associated within the ATWS systems used in existing plants, the diverse actuation system is designed to meet the quality guidelines established by Generic Letter 85-06, "Quality Assurance Guidelines for ATWS Equipment that is not Safety-Related."

7.7.1.12 Signal Selector Algorithm

The plant control system for the AP1000 derives some of its control inputs from signals that are also used in the protection and safety monitoring system. The advantages of this design are:

- The nonsafety-related plant systems are controlled from the same measurements which provide protection. This permits the control system to function in a manner which maintains margin between operating conditions and safety limits, and reduces the likelihood of spurious trips.
- Reducing the number of redundant measurements for any single process variable reduces the overall plant complexity at critical pressure boundary penetrations. This leads to a reduction in separation requirements within the containment, as well as to a decrease in plant cost and maintenance requirements.

To obtain these advantages, measures are taken to provide the independence of the protection and control systems. The criteria for these measures are contained in IEEE 603-1991, Section 5.6.3.

Isolation devices are provided to guard the protection system against possible electrical faults in the control system.

To avoid a single component failure or spurious signal causing an inadvertent plant trip while a channel is in test or maintenance, the protection and safety monitoring system uses the bypass logic discussed in Subsection 7.1.2.9. This necessitates a different mechanism for achieving the functional independence of control and protection.

Functional independence of control and protection is obtained by signal selector algorithms. The purpose of the signal selector algorithm is to prevent a failed signal, caused by the failure of a protection channel, from initiating a control action that could lead to a plant condition requiring that protective action. The signal selector function provides this capability by comparing the redundant signals and automatically eliminating an aberrant signal from use in the control system. This capability exists for bypassed sensors or for sensors whose signals have diverged from the expected error tolerance.

The operation of the signal selector algorithm is described in Subsection 7.1.3.2.

7.7.2 Analysis

The control system is capable of maneuvering the plant through certain reference transients. This maneuvering is done without the need for manual intervention and without violating plant protection or component limits. The plant control systems provide high reliability during these anticipated operational occurrences and meet the following objectives:

- The capability to accept 10-percent step load decreases from an initial power level between 100-percent and 25-percent of full power, and step load increase of 10-percent from an initial power level between 15-percent and 90-percent of full power without reactor trip or steam dump actuation.

- The capability to accept ramp load changes at 5-percent power per minute while operating in the range of 15-percent to 100-percent of full power without reactor trip or steam dump system actuation, subject to core power distribution limits.

- The capability to accept the design full-load rejection without reactor trip.

- The capability to accept a turbine trip from full-power operation without reactor trip. This capability is provided with the normally available systems (such as steam dump and feedwater control).

- The capability to follow the design basis network load follow pattern for 90-percent of the fuel cycle. The design basis load follow pattern is defined as the daily (24-hour period) cycle consisting of 10 to 18 hours of operation at 100-percent power, followed by a 2-hour linear ramp to 50-percent power, followed by 2 to 10 hours of operation at 50-percent power and then a 2-hour linear ramp back to 100-percent power.

- The capability to satisfy a 20-percent power increase or decrease within 10 minutes.

- The capability of handling grid frequency changes equivalent to 10-percent peak-to-peak power changes at a two percent per minute rate. This capability is provided over a 15- to 100-percent power range throughout the plant operating life. A total of 35 peak-to-peak swings per day are allowed.

The control system permits maneuvering the plant through the transients without actuation of the following:

- Steam generator safety valves
- Steam generator power operated relief valves
- Pressurizer safety valves

In addition, these valves are not actuated during a normal plant trip.

7.7.3 Combined License Information

This section contained no requirement for information.

7.7.4 References

1. WCAP-17184-P (Proprietary) and WCAP-17184-NP (Non-Proprietary), “AP1000™ Diverse Actuation System Planning and Functional Design Summary Technical Report,” Revision 13, May 2019.[1]

2. WCAP-15775, “AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report,” Revision 8, May 2017.[1]

3. [*WCAP-17179-P (Proprietary) and WCAP-17179-NP (Non-Proprietary), “AP1000 Component Interface Module Technical Report,” Revision 6, April 2016.*]*[1]

4. WCAP-15985, "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process," Revision 2. August 2003.

1. The UFSAR text incorporates by reference portions or all of this document.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 7.7-1
Rod Control System Interlocks - Power Control Subsystem

Designation	Derivation	Function
C-1	Intermediate range neutron flux (output of signal selector) above setpoint (when 2/4 intermediate range neutron flux is not blocked)	Blocks automatic and manual control rod withdrawal
C-2	Nuclear power (output of signal selector) above setpoint	Blocks automatic and manual control rod withdrawal
C-3	Margin to overtemperature ΔT (output of signal selector) below setpoint	Blocks automatic and manual control rod withdrawal
		Actuates turbine runback via load reference
C-4	Margin to overpower ΔT (output of signal selector) below setpoint	Blocks automatic and manual control rod withdrawal
		Actuates turbine runback via load reference
C-5	Turbine first stage pressure (output of signal selector) below setpoint (blocked if in low-power rod control mode)	Blocks automatic control rod withdrawal
C-11	1/1M bank control rod position above setpoint	Blocks automatic rod withdrawal
C-16	Reactor coolant system T_{avg} or (T_{avg} minus T_{ref}) signal (output of signal selector) below setpoint	Stops automatic turbine loading until condition clears
P-17	Negative flux rate (calculated from signal selected nuclear power) below setpoint	Blocks automatic rod withdrawal

Table 7.7-2
Rod Control System Interlocks – Axial Offset Control Subsystem

Designation	Derivation	Function
C-1	Intermediate range neutron flux (output of signal selector) above setpoint (when 2/4 intermediate range neutron flux is not blocked)	Blocks automatic and manual axial offset control rod withdrawal
C-2	Nuclear power (output of signal selector) above setpoint	Blocks automatic and manual axial offset control rod withdrawal
C-5	Turbine first stage pressure (output of signal selector) below setpoint	Blocks automatic axial offset control rod withdrawal and insertion
C-15	1/1 bank AO control rod position below setpoint	Blocks automatic axial offset control rod insertion
C-17	1/6M bank control rod positions below setpoint	Blocks automatic axial offset control rod withdrawal
C-18	1/1M bank control rod position above setpoint	Blocks automatic axial offset control rod insertion
---	Power control rods moving in	Blocks automatic axial offset control rod withdrawal
---	Power control rods moving out	Blocks automatic axial offset control rod insertion
P-17	Negative flux rate (calculated from signal selected nuclear power) below setpoint	Blocks automatic axial offset control rod withdrawal

Table 7.7-3 (Sheet 1 of 3)
Cross Reference Table for Defense-in-Depth Functions Supported by the Plant Control System

Supported System	Defense-in-Depth Function	DCD Section	DCD Figure
Component Cooling Water (CCS)	Provides cooling for normal residual heat removal system heat exchangers and pumps when the reactor coolant system pressure and temperature are below 450 psig and 350°F.	9.2.2.1.2.2 9.2.2.4.3	9.2.2-2
Component Cooling Water (CCS)	Provides cooling for the miniflow heat exchangers of the chemical and volume control system makeup pumps.	9.3.6.3.1	9.2.2-2
Component Cooling Water (CCS)	Provides cooling for the spent fuel pool heat exchangers for heat removal from the spent fuel pool.	9.2.2.1.2.3	9.2.2-2
Chemical and Volume Control (CVS)	Supply makeup and boration to the reactor coolant system.	9.3.6.7	9.3.6-1
Chemical and Volume Control (CVS)	Supply coolant to the pressurizer auxiliary spray line.	9.3.6.4.5	9.3.6-1
Standby Diesel Fuel Oil (DOS)	Supply fuel to the onsite standby power diesel generators.	9.5.4	9.5.4-1
Main and Startup Feedwater (FWS)	Provide startup feedwater for heat removal from the reactor coolant system (startup feedwater).	10.4.9.1.2	10.4.7-1 10.3.2-1
Normal Residual Heat Removal (RNS)	Remove heat from the reactor coolant system during shutdown operation at reduced pressure and temperature.	5.4.7.1.2.1	5.4-7
Normal Residual Heat Removal (RNS)	Provide low temperature overpressure protection for the reactor coolant system.	5.4.7.1.2.5	5.4-7
Normal Residual Heat Removal (RNS)	Provide low-pressure makeup to the reactor coolant system and remove heat from the reactor coolant system following actuation of the automatic depressurization system.	5.4.7.1.2.4 5.4.7.4.4	5.4-7

Table 7.7-3 (Sheet 2 of 3)
Cross Reference Table for Defense-in-Depth Functions Supported by the Plant Control System

Supported System	Defense-in-Depth Function	DCD Section	DCD Figure
Spent Fuel Pool Cooling (SFS)	Provide for heat removal from the spent fuel stored in the spent fuel pool by pumping the water from the pool through a heat exchanger, and then returning the water to the pool.	9.1.3.2	9.1-8
Steam Generator (SGS)	Provide decay heat removal capability during shutdown operations by delivery of startup feedwater flow to the steam generator and venting of steam from the steam generators to the atmosphere via the power-operated relief valves.	10.4.9 10.3	10.4.7-1 10.3.2-1
Service Water (SWS)	Provide the capability for removing heat from the component cooling water system.	9.2.1.1.2	9.2.1-1
Service Water (SWS)	Provide the capability for removing heat from the spent fuel pool via the spent fuel cooling and component cooling water systems.	9.2.2 and Table 9.2.2-2	9.2.2-1 9.2.2-2
Service Water (SWS)	Provide the capability for decay heat removal at shutdown conditions through the normal residual heat removal and component cooling systems.	9.2.2 and Table 9.2.2-2	9.2.2-1 9.2.2-2
Nuclear Island Nonradioactive Ventilation (VBS)	Provide ventilation and cooling to the main control room envelope, Class 1E instrumentation and control rooms, Class 1E dc equipment rooms, and Class 1E battery rooms.	9.4.1	9.4.1-1 all sheets
Containment Hydrogen Control (VLS)	Provide hydrogen igniters to control hydrogen concentration in excess of the recombiner capability.	6.2.4	N/A
Central Chilled Water (VWS)	Provide chilled water to support the nuclear island nonradioactive ventilation system cooling of the main control room envelope, Class 1E instrumentation and control rooms, Class 1E dc equipment rooms, and the Class 1E battery rooms.	9.2.7	9.2.7-1 sheet 2
Central Chilled Water (VWS)	Provide chilled water to support the cooling functions of the compartment unit coolers for the normal residual heat removal system pump.	9.2.7	9.2.7-1 sheet 2

Table 7.7-3 (Sheet 3 of 3)
Cross Reference Table for Defense-in-Depth Functions
Supported by the Plant Control System

Supported System	Defense-in-Depth Function	DCD Section	DCD Figure
Central Chilled Water (VWS)	Provide chilled water to support the cooling functions of the compartment unit coolers for the chemical and volume control system makeup pump.	9.2.7	9.2.7-1 sheet 2
Annex/Auxiliary Building Nonradioactive Heating and Ventilation (VXS)	Provide ventilation of the electrical switchgear rooms that contain the diesel bus switchgear. Provide ventilation of the equipment room that contains the switchgear room air-handling units.	9.4.2	9.4.2-1 sheets 3, 4, 5, and 6
Diesel Generator Building Heating and Ventilation (VZS)	Provide ventilation and cooling of the diesel generator building, and ventilation and heating of the diesel oil transfer module enclosure to support operation of the onsite standby power system.	9.4.10	9.4.10-1
Onsite Standby Power (ZOS)	Supply ac power to the Class 1E dc and UPS system.	8.3 and Table 8.3.1-2	8.3.1-2
Onsite Standby Power (ZOS)	Supply ac power to selected electrical components of the plant defense-in-depth, nonsafety-related systems.	8.3 and Table 8.3.1-2	8.3.1-2

APPENDIX 7A NOT USED

Proprietary Information, Withheld Under 10 CFR 2.390d

APPENDIX 7B PROTECTION AND SAFETY MONITORING SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

The protection and safety monitoring system failure modes and effect analysis is provided in Sections 7B.1 through 7B.13.

Each failure mode identified in the failure modes and effect analysis is assigned a failure classification to facilitate identification of significant failures with regard to their criticality to the ability of the system to accomplish its required safety functions and to the effectiveness of diagnostics and/or surveillance tests to reveal the failures. The first part of this classification will be a number indicating criticality, as defined in Table 7B-1. The second part of the classification identifies the detectability of the failure, according to the definitions provided in Table 7B-2.

Based on this analysis, it is concluded that the AP1000 protection system maintains safety functions during single point failures.

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Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.1 BPL PROCESS STATION

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

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Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.2 LCL PROCESS STATION

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[ ]a,c

Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.3 REACTOR TRIP INTERFACE

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Proprietary Information, Withheld Under 10 CFR 2.390d

7B.4 ILP PROCESS STATION

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

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Proprietary Information, Withheld Under 10 CFR 2.390d

[ ] a,c

Proprietary Information, Withheld Under 10 CFR 2.390d

[ ] a,c

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.5 NIS SUBSYSTEM

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.6 ICP PROCESS STATION

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.7 ITP PROCESS STATION

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[ ] a,c

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.8 MTP PROCESS STATION

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.9 SAFETY DISPLAY SUBSYSTEM

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.10 QDPS PROCESS STATION

[a,c]

Proprietary Information, Withheld Under 10 CFR 2.390d

[ ]a,c

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.11 POWER DISTRIBUTION

[a,c]

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Proprietary Information, Withheld Under 10 CFR 2.390d

7B.12 ADS AND IRWST BLOCKING DEVICE

[ ]a,c

Proprietary Information, Withheld Under 10 CFR 2.390d

7B.13 SQUIB VALVE CONTROL TERMINATION UNIT

[a,c]

7B.14 ACRONYMS

ADS	Automatic Depressurization System
AF100	Advant Fieldbus 100
ASIC	Application Specific Integrated Circuit
BCC	Bistable Coincidence Cabinet
BIOB	Backplane Input Output Bus
BPL	Bistable Processor Logic
CB	Circuit Breaker
CI	Communications Interface
CIM	Component Interface Module
CS	Communication Section (of the PM646A Module)
DO	Digital Output
ESF	Engineered Safeguards Features
FPGA	Field Programmable Gate Array
HIM	HSL Interface Module
HSL	High Speed Link
HV	High Voltage
I/O	Input/Output
I&C	Instrumentation and Control
ICP	Interface Communication Processor
ILC	Interposing Logic Cabinet
ILP	Integrated Logic Processor
IR	Intermediate Range
IRWST	In-containment Refueling Water Storage Tank
ITP	Interface and Test Processor
LCL	Local Coincidence Logic
LCO	Limiting Condition for Operation
MCR	Main Control Room
MOV	Motor Operated Valve
MSV	Mean Square Voltage
MTP	Maintenance and Test Processor
NIS	Nuclear Instrumentation Subsystem
NISPA	Nuclear Instrumentation Signal Processing Assembly
PC	Personal Computer
PLS	Plant Control System
PM	Processor Module
PMS	Protection and Safety Monitoring System
PR	Power Range
PS	Processor Section (of the PM Module)
QDP	Qualified Data Processor
QDPS	Qualified Data Processing System
RCP	Reactor Coolant Pump
RSR	Remote Shutdown Room
SIR	Shunt Trip Interface Relay
SR	Source Range
SRNC	Safety Remote Node Controller
STA	Shunt Trip Attachment
TU	Termination Unit

UIR	Undervoltage Interface Relay
UVTA	Undervoltage Trip Attachment
WDT	Watchdog Timer
XIR	Auxiliary Interposing Relay

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 8	ELECTRIC POWER	8.1-1
8.1	Introduction	8.1-1
8.1.1	Utility Grid Description	8.1-1
8.1.2	Onsite Power System Description	8.1-1
8.1.3	Safety-Related Loads	8.1-3
8.1.4	Design Basis	8.1-3
8.1.4.1	Offsite Power System	8.1-3
8.1.4.2	Onsite Power System	8.1-3
8.1.4.3	Design Criteria, Regulatory Guides, and IEEE Standards	8.1-4
8.1.5	Combined License Information	8.1-5
8.2	Offsite Power System	8.2-1
8.2.1	System Description	8.2-1
8.2.1.1	Transmission Switchyard	8.2-3
8.2.1.2	Transformer Area	8.2-6
8.2.1.3	Switchyard Control Building	8.2-7
8.2.1.4	Switchyard and Transmission Lines Testing and Inspection	8.2-7
8.2.2	Grid Stability	8.2-8
8.2.3	Conformance to Criteria	8.2-10
8.2.4	Standards and Guides	8.2-11
8.2.5	Combined License Information for Offsite Electrical Power	8.2-11
8.2.6	References	8.2-11
8.3	Onsite Power Systems	8.3-1
8.3.1	AC Power Systems	8.3-1
8.3.1.1	Description	8.3-1
8.3.1.2	Analysis	8.3-12
8.3.1.3	Raceway/Cable	8.3-12
8.3.1.4	Inspection and Testing	8.3-13
8.3.2	DC Power Systems	8.3-14
8.3.2.1	Description	8.3-14
8.3.2.2	Analysis	8.3-19
8.3.2.3	Physical Identification of Safety-Related Equipment	8.3-20
8.3.2.4	Independence of Redundant Systems	8.3-21
8.3.2.5	Inspection and Testing	8.3-24
8.3.3	Combined License Information for Onsite Electrical Power	8.3-26
8.3.4	References	8.3-26

LIST OF TABLES

Table Number	Title	Page
8.1-1	Criteria and Guidelines for Electric Power Systems	8.1-6
8.1-201	Not Used	8.1-10
8.2-201	Grid Stability Interface Evaluation	8.2-12
8.3.1-1	Onsite Standby Diesel Generator ZOS MG 02A Nominal Loads	8.3-28
8.3.1-2	Onsite Standby Diesel Generator ZOS MG 02B Nominal Loads	8.3-33
8.3.1-3	Component Data - Main AC Power System (Nominal Values)	8.3-38
8.3.1-4	Post-72 Hours Nominal Load Requirements	8.3-39
8.3.1-5	Indication and Alarm Points Standby Diesel Generators	8.3-40
8.3.2-1	250V DC Class 1E Division A Battery Nominal Load Requirements	8.3-41
8.3.2-2	250V DC Class 1E Division B Battery Nominal Load Requirements	8.3-42
8.3.2-3	250V DC Class 1E Division C Battery Nominal Load Requirements	8.3-43
8.3.2-4	250V DC Class 1E Division D Battery Nominal Load Requirements	8.3-44
8.3.2-5	Component Data - Class 1E DC System (Nominal Values)	8.3-45
8.3.2-6	Component Data - Non-Class 1E DC System EDS1 – EDS4 (Nominal Values)	8.3-46
8.3.2-7	Class 1E 250V DC and Class 1E Uninterruptible Power Supplies Failure Modes and Effects Analysis	8.3-49

LIST OF FIGURES

Figure Number	Title	Page
8.2-201	Offsite Power System One-Line Diagram	8.2-13
8.2-202	Switchyard General Arrangement	8.2-14
8.3.1-1	AC Power Station One Line Diagram	8.3-54
8.3.1-2	Onsite Standby Diesel Generator Initiating Circuit Logic Diagram	8.3-55
8.3.1-3	Ancillary Diesel Generator One Line Diagram	8.3-56
8.3.1-4	(Sheet 1 of 2) Simplified Diesel Generator System Piping and Instrumentation Diagram	8.3-57
8.3.1-4	(Sheet 2 of 2) Simplified Diesel Generator System Piping and Instrumentation Diagram	8.3-58
8.3.1-5	(Sheet 1 of 2) Diesel Engine Skid Mounted System	8.3-59
8.3.1-5	(Sheet 2 of 2) Diesel Engine Skid Mounted System	8.3-60
8.3.2-1	(Sheet 1 of 2) Class 1E DC System One Line Diagram	8.3-61
8.3.2-1	(Sheet 2 of 2) Class 1E DC System One Line Diagram	8.3-62
8.3.2-2	Class 1E 208y/120V UPS One Line Diagram	8.3-63
8.3.2-3	(Sheet 1 of 3) Non-Class 1E DC & UPS System One Line Diagram	8.3-64
8.3.2-3	(Sheet 2 of 3) Non-Class 1E DC & UPS System One Line Diagram	8.3-65
8.3.2-3	(Sheet 3 of 3) Non-Class 1E DC & UPS System One Line Diagram	8.3-66

Chapter 8 Electric Power

8.1 Introduction

8.1.1 Utility Grid Description

VEGP is interconnected to the Southern Balancing Authority Area (SBAA) transmission grid operated by Southern Company Transmission (SCT). The SBAA transmission grid consists of transmission facilities owned by Alabama Power Company, Georgia Power Company, and Mississippi Power Company, all subsidiaries of the Southern Company and Georgia Transmission Corporation, the Municipal Electric Authority of Georgia and Dalton Utilities, who along with Georgia Power Company are participants in and make up the Georgia Integrated Transmission System. The SBAA transmission grid is interconnected with Duke Power Company, South Carolina Electric and Gas Company, South Carolina Public Service Authority (Santee Cooper), Florida Power and Light Company, Progress Energy, City of Tallahassee, Entergy Gulf States, Entergy Louisiana, Mississippi Power and Light, and the Tennessee Valley Authority. The SBAA transmission grid interconnects hydro plants, fossil-fueled plants, and nuclear plants supplying electric energy over a transmission grid consisting of various voltages up to 500 kV.

VEGP Units 3 and 4 are located in eastern Burke County, Georgia, approximately 26 miles southeast of Augusta, Georgia and 100 miles northwest of Savannah, Georgia, directly across the Savannah River from the US Department of Energy's Savannah River Site in Barnwell County, South Carolina. VEGP Units 1 and 2, which are two Westinghouse Electric Company, LLC (Westinghouse) pressurized water reactors (PWRs), have been in commercial operation since 1987 and 1989, respectively. Plant Wilson, a six-unit oil-fueled combustion turbine facility owned by Georgia Power Company (GPC), is also located on the VEGP site. VEGP Units 3 and 4 are adjacent to and west of VEGP Units 1 and 2. VEGP Units 1 and 2 are co-owned by Georgia Power Company, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia. Southern Nuclear Operating Company (SNC) is the licensed operator of the nuclear facilities at the VEGP site, with control of the nuclear facilities, including complete authority to regulate any and all access and activity within the plant exclusion area boundary. GPC and SNC are subsidiaries of Southern Company.

VEGP Unit 3 is connected to the Units 1, 2 and 3, 230/500 kV switchyard at the 230 kV level. The 230 kV and 500 kV levels of the Units 1, 2 and 3, 230/500 kV switchyard are arranged in a breaker-and-a-half configuration and are interconnected through two, 230/500 kV autotransformers. VEGP Unit 4 is connected to the Unit 4, 500 kV switchyard. This switchyard is also arranged in a breaker-and-a-half configuration. The Unit 4, 500 kV switchyard is connected to the 500 kV section of the Units 1, 2 and 3, 230/500 kV switchyard by overhead lines. The Reserve Auxiliary Transformers (RATs) for Units 3 and 4 are supplied by two overhead lines from a 230 kV switching station (i.e., switchyard) with a ring bus configuration. A portion of Unit 3 RAT “A” supply line is underground between Unit 4 and Unit 3. Five, 230 kV and three, 500 kV transmission lines connect the VEGP high voltage switchyards to the remainder of the SBAA transmission grid.

8.1.2 Onsite Power System Description

The onsite power system is comprised of the main ac power system and the dc power system. The main ac power system is a non-Class 1E system. The dc power system consists of two independent systems: Class 1E dc system and non-Class 1E dc system. The ac and dc onsite power system configurations are shown on Figures 8.3.1-1 and 8.3.2-1, 8.3.2-2 and 8.3.2-3, respectively.

The normal ac power supply to the main ac power system is provided from the station main generator. When the main generator is not available, plant auxiliary power is provided from the switchyard by backfeeding through the main stepup and unit auxiliary transformers. This is the

preferred power supply. When neither the normal or the preferred power supply (see Subsection 8.2.1) is available due to an electrical fault, fast bus transfer is initiated to transfer the loads to the reserve auxiliary transformers powered by maintenance sources of power. Both the normal and the preferred power supply will be unavailable due to an electrical fault at either the main stepup transformer, unit auxiliary transformer, AC portion of the excitation system, isophase bus, 6.9kv nonsegregated bus duct, or switchyard zone including the switchyard leads and grid breakers to the high side of the main stepup transformer. In addition, two non-Class 1E onsite standby diesel generators supply power to selected loads in the event of loss of the normal, preferred, and maintenance power sources. The reserve auxiliary transformers also serve as a source of maintenance power. The maintenance sources are as described.

The main generator is connected to the offsite power system by three single-phase stepup transformers. The normal power source for the plant auxiliary ac loads comes from the generator bus through two unit auxiliary transformers of identical rating and a third unit auxiliary transformer of lesser rating. In the event of a loss of the main generator, the power is maintained without interruption from the preferred power supply by an autotrip of the main generator breaker. Power then flows from the switchyard to the auxiliary loads through the main and unit auxiliary transformers.

A spare single-phase main stepup transformer is provided in the transformer area. The spare can be placed in service upon failure of one phase of the main stepup transformers.

The onsite standby power system, powered by the two onsite standby diesel generators, supplies power to selected loads in the event of loss of other ac power sources. Loads that are priority loads for investment protection due to their specific functions (permanent nonsafety loads) are selected for access to the onsite standby power supply. Availability of the standby power source is not required to accomplish any safety function.

The maintenance power supplies are provided at the medium voltage (6.9 kV) buses through normally open circuit breakers. Bus transfer to maintenance source either is automatic under fast bus transfer logic or may be initiated manually.

Four independent divisions of Class 1E 250 Vdc battery systems are provided for the Class 1E dc and UPS system. Divisions B and C have two battery banks; one battery bank is sized to supply power to safety-related loads for at least 24 hours and the other battery bank is sized to supply power to a second set of safety-related loads for at least 72 hours following a design basis event (including the loss of all ac power). Divisions A and D have one 24-hour battery bank. The loads are assigned to each battery bank, depending on their required function, during the 72 hour coping period so that no manual or automatic load shedding is required for the first 24 hours. Two ancillary diesel generators are provided for power for Class 1E post-accident monitoring, MCR lighting, MCR and I&C room ventilation, and power to refill the PCS water storage tank and spent fuel pool if no other sources of ac power are available.

An IDS spare battery bank (IDSS-DB-1A and IDSS-DB-1B) with a spare charger (IDSS-DC-1) is provided for the Class 1E battery system. In order to preserve independence of each Class 1E dc system division, plug-in locking type disconnects are permanently installed to prevent connection of more than one battery bank to the spare. In addition, kirk-key interlock switches are provided to prevent transfer operation of more than one switchboard at a time. The spare battery bank is located in a separate room and is capable of supplying power to the required loads on any battery being temporarily replaced with the spare.

The non-Class 1E 125 Vdc power system provides continuous, reliable power to the plant nonsafety-related dc loads. Operation of the non-Class 1E dc system is not required to accomplish any safety function.

Uninterruptible power supplies (UPS) to the four independent divisions of the Class 1E 120 Vac instrument buses are included in the Class 1E dc system. The normal power to the uninterruptible power supply comes from the respective Class 1E 250 Vdc bus. The backup power comes from the main ac power system through Class 1E 480-208Y/120V voltage regulating transformers. The same configuration applies for the uninterruptible power to the non-divisional, non-Class 1E 120 Vac instrument buses. The normal power to the non-Class 1E uninterruptible power supply comes from the non-Class 1E 125 Vdc bus and the backup power comes from the main ac power system through a voltage regulating transformer.

8.1.3 Safety-Related Loads

The safety-related loads requiring Class 1E power are listed in Tables 8.3.2-1, 8.3.2-2, 8.3.2-3 and 8.3.2-4. Safety-related loads are powered from the Class 1E 250 Vdc batteries and the associated Class 1E 120 Vac instrument buses.

8.1.4 Design Basis

8.1.4.1 Offsite Power System

Offsite power has no safety-related function due to the passive design of the AP1000. Therefore, redundant offsite power supplies are not required. The design provides a reliable offsite power system that minimizes challenges to the passive safety system.

8.1.4.2 Onsite Power System

8.1.4.2.1 Safety Design Basis

- The Class 1E dc and UPS power system meets the single failure criterion (GDC 17).
- The Class 1E dc and UPS system has sufficient capacity to achieve and maintain safe shutdown of the plant for 72 hours following a complete loss of all ac power sources without requiring load shedding for the first 24 hours.
- The Class 1E dc and UPS system is divided into four independent divisions. Any three-out-of-four divisions can shut down the plant safely and maintain it in a safe shutdown condition.
- Separation criteria preserve the independence of redundant Class 1E circuits as described in Subsection 8.3.2.4 and no single credible event is capable of disabling redundant safety-related systems.
- Special identification criteria are applied for Class 1E equipment, Class 1E cabling, and raceways that route Class 1E cables as described in Subsection 8.3.2.3.
- The Class 1E systems and equipment are designed to permit periodic inspection and testing (GDC-18).
- The Class 1E dc and UPS power system permits connection of any one 250 Vdc switchboard at a time to the spare battery and the spare battery charger. The spare battery and charger have sufficient capacity to permit continuous plant operation at 100-percent power in case of a failure or unavailability of one Class 1E battery bank and the associated battery charger, as described in Subsection 8.3.2.1.1.

- Two ancillary diesel generators provide ac power for Class 1E post-accident monitoring, MCR lighting, MCR and I&C room ventilation, and power to refill the PCS water storage tank and spent fuel pool if no other sources of power are available. The equipment used to perform this function is not safety-related because it is not needed for a prolonged period following a loss of ac and it is easily replaced with transportable generators.

8.1.4.2.2 Power Generation Design Basis

- The main ac power system is a non-Class 1E system and nonsafety-related. The normal power supply to the main ac power system comes from the station main generator through two identically rated unit auxiliary transformers and an additional unit auxiliary transformer for the electric auxiliary boiler and as described site-specific loads.

- The onsite standby power system supplies ac power to the selected permanent nonsafety loads in the event of a main generator trip concurrent with the loss of preferred power source and maintenance power source when under fast bus transfer conditions. The onsite standby diesel generators are automatically connected to the associated 6.9 kV buses upon loss of bus voltage only after the generator rated voltage and frequency is established. Loads that are important for orderly plant shutdown are sequentially connected as shown in Subsection 8.3.1 during this event.

  The permanent nonsafety loads are not required for the plant safe shutdown; therefore, the onsite standby power system is a nonsafety-related system and non-Class 1E.

- For continued operation of the plant, a spare single-phase main transformer can be placed in service upon failure of one phase of the main stepup transformers.

8.1.4.3 Design Criteria, Regulatory Guides, and IEEE Standards

Refer to Table 8.1-1 for guidelines, and their applicability to Chapter 8.

The offsite and onsite ac power systems have no safety function and, therefore, their conformance to General Design Criteria, Regulatory Guides and IEEE Standards is not required, except as indicated in Table 8.1-1.

The Class 1E dc power system design is based on the following:

- General Design Criteria (GDC)

  See Section 3.1 for a discussion of conformance to the General Design Criterion.

- Nuclear Regulatory Commission (NRC) Regulatory Guides

  See Section 1.9 for the list and details of conformance to the regulatory guides.

- IEEE Standards.

  The Class 1E dc power system design is based on the following IEEE Standards that are generally acceptable to the NRC as stated in the referenced Regulatory Guides:

  – IEEE 308-1991, IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.32.

- IEEE 317-1983, IEEE Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.63.

- IEEE 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.89.

- IEEE 338-1987, IEEE Standard Criteria for the Periodic Surveillance Testing of Nuclear Power Generating Station Safety Systems. Refer to Regulatory Guide 1.118.

- IEEE 344-1987, IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.100.

- IEEE 379-2000, IEEE Standard Application of the Single Failure Criterion to Nuclear Power Generating Station Safety Systems. Refer to Regulatory Guide 1.53.

- IEEE 382-1996, IEEE Standard for Qualification of Actuators for Power Operated Valve Assemblies with Safety Related Functions for Nuclear Power Plants. Refer to Regulatory Guide 1.73.

- IEEE 383-1974, IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.131.

- IEEE 384-1981, IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits. Refer to Regulatory Guide 1.75.

- IEEE 450-1995, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications. Refer to Regulatory Guide 1.32.

- IEEE 484-1996, IEEE Recommended Practice for Installation Design and Installation of Vented Lead-Acid Batteries for Stationary Applications. Refer to Regulatory Guide 1.128.

- IEEE 741-1997, IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations. Refer to Regulatory Guide 1.63.

- IEEE 1202-1991, IEEE Standard for Flame Testing of Cables for Use in Cable Tray in Industrial and Commercial Occupancies.

8.1.5 Combined License Information

This section contained no requirement for information.

Table 8.1-1 (Sheet 1 of 5)
Criteria and Guidelines for Electric Power Systems

Criteria			Applicability ([a] Section/Subsection)			Remarks
			8.2	8.3.1	8.3.2	
1.	10CFR50 Appendix A – General Design Criteria (GDC) (See Section 3.1 for a discussion of conformance to each of the GDC).					
a.	GDC 2	Design Bases for Protection Against Natural Phenomena			A	
b.	GDC 4	Environmental and Missile Design Basis			A	
c.	GDC 5	Sharing of Structures, Systems, and Components				not applicable
d.	GDC 17	Electric Power Systems			A	
e.	GDC 18	Inspection and Testing of Electric Power Systems			A	
f.	GDC 50	Containment Design Basis		A	A	applicable to penetration design

Note:
(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2 (except for those guidelines that are site-specific, which are defined in NUREG-0800, Rev. 3), Table 8-1 (SRP). No letter denotes "Not Applicable."

Table 8.1-1 (Sheet 2 of 5)
Criteria and Guidelines for Electric Power Systems

Criteria			Applicability ([a] Section/Subsection)			Remarks
			8.2	8.3.1	8.3.2	
2.	Regulatory Guide (See Section 1.9 for list and discussion of conformance to the Regulatory Guides).					
a.	RG 1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems			G	
b.	RG 1.9	Selection, Design, and Qualification of Diesel Generator Units Used as Stand-by (Onsite) Electric Power Systems at Nuclear Power Plants				not applicable
c.	RG 1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Generating Stations			G	
d.	RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems			G	
e.	RG 1.63	Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants		G	G	
f.	RG 1.75	Physical Independence of Electric Systems			G	
g.	RG 1.81	Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants				not applicable

Note:
(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2 (except for those guidelines that are site-specific, which are defined in NUREG-0800, Rev. 3), Table 8-1 (SRP). No letter denotes "Not Applicable."

Table 8.1-1 (Sheet 3 of 5)
Criteria and Guidelines for Electric Power Systems

Criteria			Applicability ([a] Section/Subsection)			Remarks
			8.2	8.3.1	8.3.2	
h.	RG 1.106	Thermal Overload Protection for Electric Motors on Motor-Operated Valves			G	
i.	RG 1.108	Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants				not applicable
j.	RG 1.118	Periodic Testing of Electric Power and Protection Systems			G	
k.	RG 1.128	Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants			G	
l.	RG 1.129	Maintenance, Testing, and Replacement of Vented Lead-Acid Storage Batteries for Nuclear Power Plants			G	Battery maintenance, testing, and replacement is in accordance with approved Technical Specifications which are based on IEEE Std. 450-1995.
m.	RG 1.131	Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants			G	The insulating and jacketing material for electrical cables are selected to meet the fire and flame test requirements of IEEE Standard 1202, IEEE Standard 383, or the standards for the corresponding test types as listed in Tables K-1 and K-2 in NEI 04-02, Rev 3 excluding the option to use the alternate flame source, oil or burlap.
n.	RG 1.155	Station Blackout				Not applicable[b]
o.	RG 1.204	Guidelines for Lightning Protection of Nuclear Power Plants	G	G		Implemented via IEEE 665.
p.	RG 1.206	Combined License Applications for Nuclear Power Plants (LWR Edition)	G	G	G	

Note:
(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2 (except for those guidelines that are site-specific, which are defined in NUREG-0800, Rev. 3), Table 8-1 (SRP). No letter denotes "Not Applicable."
(b) Station Blackout and the associated guidelines are addressed as a design issue in Subsection 1.9.5.1.5.

Table 8.1-1 (Sheet 4 of 5)
Criteria and Guidelines for Electric Power Systems

Criteria			Applicability ([a] Section/Subsection)			Remarks
			8.2	8.3.1	8.3.2	
3.	Branch Technical Position (BTP)					
a.	BTP ICSB 4 (PSB)	Requirements on Motor-Operated Valves in the ECCS Accumulator Lines			G	see 1.9.2
b.	BTP ICSB 8 (PSB)	Use of Diesel-Generator Sets for Peaking				not applicable
c.	BTP 8-3 ICSB 11 (PSB)	Stability of Offsite Power Systems	G			site-specific Stability Analysis of the Offsite Power System is performed in accordance with the BTP.
d.	BTP ICSB 18 (PSB)	Application of the Single Failure Criterion to Manually Controlled Electrically-Operated Valves			G	see 1.9.2
e.	BTP ICSB 21	Guidance for Application of Regulatory Guide 1.47			G	see also 7.5
f.	BTP PSB 1	Adequacy of Station Electric Distribution System Voltages				not applicable
g.	BTP PSB 2	Criteria for Alarms and Indications Associated with Diesel-Generator Unit Bypassed and Inoperable Status				not applicable

Note:
(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2 (except for those guidelines that are site-specific, which are defined in NUREG-0800, Rev. 3), Table 8-1 (SRP). No letter denotes "Not Applicable."

Table 8.1-1 (Sheet 5 of 5)
Criteria and Guidelines for Electric Power Systems

Criteria	Applicability ([a] Section/Subsection)			Remarks
	8.2	8.3.1	8.3.2	
4. NUREG Reports				
a. NUREG CR0660 Enhancement of Onsite Diesel Generator Reliability				not applicable

Note:
(a) "A" denotes applicable to AP1000, and "G" denotes guidelines as defined in NUREG-0800, Rev. 2 (except for those guidelines that are site-specific, which are defined in NUREG-0800, Rev. 3), Table 8-1 (SRP). No letter denotes "Not Applicable."

Table 8.1-201
Not Used

8.2 Offsite Power System

8.2.1 System Description

The normal ac power supply to the main ac power system is provided from the main generator. When the main generator is not available, plant auxiliary power is provided from the switchyard by backfeeding through the main stepup and unit auxiliary transformers. This is the preferred power supply. When neither the normal or the preferred power supply is available due to an electrical fault, the loads are transferred to onsite sources as identified in Subsection 8.1.2. In addition, two non-Class 1E onsite standby diesel generators supply power to selected plant loads in the event of loss of the normal, preferred, and maintenance power sources. The reserve auxiliary transformers also serve as a source of maintenance power.

Maintenance power is provided at the medium voltage level (6.9 kV) through normally open circuit breakers. Bus transfer to the maintenance source is automatic under fast bus transfer logic or may be initiated manually.

The Southern Balancing Authority Area (SBAA) transmission grid supplies the off-site AC power (preferred and maintenance power) for Vogtle Electric Generating Plant (VEGP) Units 3 and 4 via three, high voltage switchyards located north of the facility. The three, high voltage switchyards are defined as follows:

- Units 1, 2 and 3, 230/500 kV switchyard
- Unit 4, 500 kV switchyard
- Units 3 and 4, Reserve Auxiliary Transformer (RAT) supply, 230 kV switching station

The interconnection of the three switchyards, and the 230 kV and 500 kV transmission lines are shown on Figures 8.2-201 and 8.2-202.

VEGP Units 3 and 4 are connected into a transmission grid supplying large load centers. Unit 3 is tied into the 230 kV transmission grid via the Units 1, 2 and 3, 230/500 kV switchyard. Unit 4 is tied into the 500 kV transmission grid via the Unit 4, 500 kV switchyard.

The Units 3 and 4, RAT supply, 230 kV switching station, consists of 5 breakers installed in a ring bus configuration. The Augusta Newsprint transmission line and the Units 1, 2 and 3, 230/500 kV switchyard are connected to the Units 3 and 4, RAT supply, 230kV switching station.

230 kV Overhead Transmission Lines

Five, 230 kV overhead transmission lines connect the Units 1, 2 and 3, 230/500 kV switchyard to other substations throughout the transmission grid. Each 230 kV transmission line is connected to a Georgia Integrated Transmission System or a South Carolina Electric and Gas (SCEG) substation. The five, 230 kV transmission lines originate at the VEGP switchyards and connect to various substations as shown below.

230 kV Line	Termination Point	Length (miles)	Thermal Rating (MVA)
Switching Station/Augusta Newsprint	Augusta Newsprint Sub	20	596
Goshen White	Goshen Sub	19	866
Augusta Corporate Park	Augusta Corporate Park Sub	14	866
SCEG	Savannah River Plant Sub	22	1020

230 kV Line	Termination Point	Length (miles)	Thermal Rating (MVA)
Plant Wilson	Plant Wilson Sub	1	718

The Switching Station/Augusta Newsprint, Goshen White and Augusta Corporate Park 230 kV lines are on a common right-of-way for the first 14.19 miles from the plant. The lines exit the north side of the switchyard and leave the plant site to the northwest. Approximately 0.5 miles from the plant, the Units 3 and 4, RAT supply, 230 kV switching station is installed along the Switching Station/Augusta Newsprint transmission line.

The SCEG 230 kV line exits the north side of the switchyard, crosses the Savannah River and continues to the Savannah River Plant Substation in South Carolina.

The 230 kV transmission line from the Unit 3 generator to the Units 1, 2 and 3, 230/500 kV switchyard travels under these four transmission lines. All high voltage equipment and conductors are designed to meet the requirements of the National Electrical Safety Code (NESC) and Georgia Power Company (GPC) engineering standards. Electrical clearances phase-to-phase and phase-to-ground are determined by NESC and engineering requirements.

The Plant Wilson 230 kV line exits the north side of the switchyard traveling southeast to the Wilson switchyard less than 1 mile away.

500 kV Overhead Transmission Lines

Three 500 kV overhead transmission lines connect the Units 1, 2 and 3, 230/500 kV switchyard and the Unit 4, 500 kV switchyard to other substations throughout the SBAA transmission grid. Each 500 kV transmission line is connected to a Georgia Integrated Transmission System substation. The three, 500 kV transmission lines originate at the VEGP switchyards and connect to various substations as shown below.

500kV Line	Termination Point	Length (miles)	Thermal Rating (MVA)
West McIntosh	West McIntosh Sub	69	2439
Warthen	Warthen Sub	154	2701
Thomson	Thomson Sub	52	2701

The Thomson 500 kV line exits the switchyard to the north and crosses over the 230 kV transmission line from the Unit 3 generator and then west over the 230 kV transmission lines to the Units 3 and 4 RATs. All high voltage equipment and conductors are designed to meet the requirements of the National Electrical Safety Code (NESC) and GPC engineering standards. After leaving the plant, the Thomson and Warthen 500 kV lines are on a common right-of-way for approximately the first 5 miles. The lines exit the north side of the switchyard and leave the plant site to the west.

The West McIntosh 500 kV line exits the north side of the switchyard and leaves the plant site traveling to the west before changing direction to the southeast.

All transmission lines connected to the VEGP switchyards are suspended from steel, lattice-type towers designed to provide clearances consistent with NESC and GPC engineering standards. Electrical clearances phase-to-ground are determined by NESC and engineering requirements, but are not less than 27 feet for 230 kV transmission lines and 32 feet for 500 kV transmission lines. Transmission towers include overhead ground wires. All towers are grounded with either ground rods or a counterpoise system.

A transformer area containing the generator step-up transformers (GSU), the unit auxiliary transformers (UATs), and reserve auxiliary transformers (RATs) is located north of each turbine building.

The main generator is connected to the offsite power system via three single-phase main stepup transformers. The normal power source for the plant auxiliary ac loads is provided from the isophase generator bus through the two unit auxiliary transformers of identical ratings and a third unit auxiliary transformer of lesser rating. In the event of a loss of the main generator, the power is maintained without interruption from the preferred power supply by an auto-trip of the main generator breaker. Power then flows from the transformer area to the auxiliary loads through the main and unit auxiliary transformers.

The transmission line structures associated with the plant are designed to withstand standard loading conditions for the specific-site as provided in Reference 1.

Automatic load dispatch is not used at the plant and does not interface with safety-related action required of the reactor protection system.

8.2.1.1 Transmission Switchyard

A 230 kV air insulated switching station, installed along the Switching Station/Augusta Newsprint transmission line, supplies power to the Units 3 and 4 RATs and the retail power supply. The switching station is located approximately 3500 feet to the north of Units 3 and 4. This arrangement provides the power supply to the RATs from the Units 1, 2 and 3, 230/500 kV switchyard or directly from the Augusta Newsprint transmission line. The switching station also provides power to the 13.8 kV retail power supply. Two overhead transmission lines connect the Units 3 and 4, RAT supply, 230 kV switching station to the two RATs for Unit 3 and the two RATs for Unit 4. One overhead transmission line supplies RAT “A” for Units 3 and 4 and the other overhead transmission line supplies RAT “B” for Units 3 and 4. A portion of Unit 3 RAT “A” supply line is underground between Unit 4 and Unit 3. The RATs may be used to distribute power for plant auxiliaries when the GSUs or UATs are out of service. The Units 1, 2 and 3, 230/500 kV switchyard is used to transmit electrical power output from Unit 3 to the SBAA transmission grid. The 230 kV section of the switchyard is interconnected to the 500 kV section through two, 230/500 kV autotransformers.

A 500 kV air insulated switchyard is located 500 feet north of Unit 4 and 1500 feet to the west of the Units 1, 2 and 3, 230/500 kV switchyard. The Unit 4, 500kV switchyard is interconnected to the 500 kV section of the Units 1, 2 and 3, 230/500 kV switchyard by two overhead lines. These two lines cross over the 230 kV lines for the Unit 3 generator and the supply line for the Units 3 and 4 RAT “B”. The Unit 4, 500 kV switchyard is used to transmit electrical power output from Unit 4 to the SBAA transmission grid.

The Unit 3 generator is connected to the Units 1, 2 and 3, 230/500 kV switchyard by overhead tie lines that exit the north side of the switchyard and travel west, and then south to the GSU. The Unit 4 generator is connected to the Unit 4, 500kV switchyard by overhead tie lines that exit the south side of the switchyard and travel south to the GSU.

The high voltage circuit breakers in all three switchyards are sized with sufficient continuous current carrying capacity and fault interrupting capability to perform their intended function. The switchyard disconnect switches are rated equal to or greater than the continuous current basis of their associated circuit breakers. The Units 1, 2 and 3, 230/500 kV switchyard, the Unit 4, 500 kV switchyard and the Units 3 and 4, RAT supply, 230 kV switching station are shown on the offsite power system one-line diagram and the switchyard general arrangement, Figures 8.2-201 and 8.2-202 respectively.

Failure Analysis

The design of the offsite power system provides for a robust system that supports reliable power production. Offsite power is not required to meet any safety function, and physical independence is not necessary. The certified design has been granted a partial exemption to GDC 17 by the NRC. Multiple, reliable transmission circuits are provided to support operation of the facility. Neither the accident analysis nor the Probabilistic Risk Assessment has identified the non-safety related offsite power system as risk significant for normal plant operation.

VEGP Units 3 and 4 are supplied with off-site power from the SBAA 230 kV and 500 kV transmission grid via two separate switchyard buses and backfed through the GSUs. The VEGP switchyards are connected to eight transmission lines. No single transmission line is designated as the preferred circuit, but analysis shows that with any one of these transmission lines out of service, the transmission grid can supply the switchyard with sufficient power for the safety related systems and other auxiliary loads for normal, abnormal and accident conditions on Units 3 and 4.

For the portions of the switchyards associated with VEGP Units 3 and 4, a failure modes and effects analysis (FMEA) confirmed that a single initiating event, such as a transmission line fault, plus a single breaker not operating, does not cause failure of more than one single transmission line, or a loss of offsite power to either Unit 3 or 4 via the GSU. This evaluation recognizes that a single failure of some switchyard components could directly cause the loss of the switchyard feed to the GSU, such as a fault on this feed. Evaluated events include a breaker not operating during a fault condition; a fault on a switchyard bus; a spurious relay trip; and a loss of control power supply. In summary:

- In the event of a fault on a 230 kV or 500 kV transmission line, the associated line breakers trip and both buses stay energized and both units continue operation.

- In the event of a fault on a 230 kV or 500 kV transmission line concurrent with a stuck bus breaker, the affected bus differential relays cause circuit breakers on the affected bus to trip and thereby isolate the affected bus. Both units continue operation through the non-affected bus.

- In the event of a 230 kV or 500 kV bus fault, bus differential relays sense the fault and the breakers associated with the affected bus trip, thereby isolating the faulted bus. In this event, both units continue normal operation through the non-affected bus.

- In the event of a 230 kV or 500 kV bus fault concurrent with a stuck breaker, the adjacent breaker senses the fault and trips, which isolates the faulted bus. If the stuck breaker is associated with the output of either the Unit 3 or Unit 4 GSU, opening of the adjacent breaker interrupts power to the associated GSU and UATs resulting in a reactor trip. The unaffected unit continues operation through the non-affected bus.

- In the event of transmission line relay mis-operation, both associated switchyard breakers trip, isolating one of the transmission lines from the yard. In this event, both switchyard buses stay energized and both units continue normal operation.

- In the case of a loss of DC control power, the loss of control power to a breaker or to a transmission line primary relay is compensated for by redundant trip coils powered from a different source which allows the protective function to occur. Both units continue normal operation.

- In the event of a fault on either the 230 kV Switching Station or Augusta Newsprint line concurrent with a stuck breaker, power will be lost to either the Units 3 and 4 RAT “A” or Units 3 and 4 RAT “B” by tripping the adjacent circuit breaker with the stuck breaker relay protection schemes. In this event, both units continue normal operation and the maintenance power supply to the “A” or “B” RATs will be lost.

The results of the analysis show that a single fault in any section of one 230 kV or 500 kV bus is cleared by the adjacent breakers and does not interrupt operation of the remaining switchyard bus or the connection of the unaffected transmission lines. A bus fault with a stuck breaker associated with the output of either the Unit 3 or Unit 4 GSU causes the loss of power to, and a reactor trip in the associated unit. A bus fault concurrent with any other stuck breaker does not cause a loss of power to either unit.

An analysis was performed of transmission line crossings within the area of the Vogtle site. Sixteen line crossings were evaluated to demonstrate that offsite power would be available to both Unit 3 and Unit 4 from at least one of the three available offsite power supplies to each unit. A nonmechanistic failure was assumed for each of the 16 transmission lines (a line is considered to be any one of the three phases) allowing it to fall on the line or lines immediately below it. In three cases, the falling line was assumed to contact two lines below. In all, 13 separate cases of falling transmission lines were evaluated. No single failures of protective relaying or breakers were assumed in this evaluation. The evaluation demonstrated that, in each case, at least one offsite power supply remained available to both Unit 3 and Unit 4.

Transmission System Operator (TSO)

Southern Company Transmission (SCT) is the TSO within the SBAA and is responsible for the safe and reliable operation of the SBAA transmission grid. The SBAA is located within the SERC Reliability Corporation, one of the regional corporations within the North American Electric Reliability Corporation (NERC). SCT has responsibility for Transmission Planning and Operation of the bulk power transmission system. The Operation is performed by the Georgia Control Center (GCC) in Atlanta, Georgia and Bulk Power Operations (BPO) organization. The BPO control center is also known as the Power Coordination Center (PCC) and is located in Birmingham, Alabama.

SCT and VEGP have an agreement and protocols in place to provide safe and reliable operation of the transmission grid and equipment at VEGP Units 3 and 4. Elements of this agreement are implemented in accordance with the procedures of both parties.

The TSO establishes a voltage schedule for the 230 kV and 500 kV switchyards. VEGP Units 3 and 4, while generating, are expected to supply or absorb reactive power to help regulate voltage in the 230 kV and 500 kV switchyards in accordance with TSO voltage schedule criteria. VEGP maintains switchyard voltage such that steady state voltage on the 26 kV generator terminals is within 0.95 – 1.05 per unit (p.u.) of its nominal value.

VEGP provides the TSO with a nuclear plant interface agreement that specifies the detailed voltage and other requirements necessary to ensure safe and reliable operation of VEGP. The minimum and maximum switchyard voltage at VEGP is maintained in accordance with this interface agreement. These voltage levels are maintained without any reactive power support from VEGP Units 3 and 4.

The agreement between VEGP and SCT demonstrates protocols in place for the plant to remain cognizant of grid vulnerabilities so that they can make informed decisions regarding maintenance activities critical to the electrical system. As part of its operational responsibilities, the PCC continuously monitors real-time power flows and assesses contingency impacts through the use of a state-estimator tool. The PCC/GCC continuously monitors and evaluates grid reliability and switchyard voltages, and informs plant operations of any potential grid instability or voltage inadequacies. They also work to maintain local voltage requirements as required by VEGP

Operational planning studies are also performed using offline power flow study tools to assess near term operating conditions under varying load, generation, and transmission topology patterns. If a condition arises where the SBAA transmission grid cannot supply adequate offsite power, plant operators are notified and appropriate actions are taken.

VEGP plant operations reviews input from the GCC/PCC to make informed decisions regarding plant activities that may affect plant reliability or impacts to the transmission grid. In addition, plant operators inform the PCC/GCC of changes in generation ramp rates and notify them of any developing problems that may impact generation.

An agreement between VEGP and SCT sets the requirements for transmission grid studies and analyses. These analyses demonstrate the capability of the offsite power system to support plant start up and shutdown.

SCT conducts planning studies of the transmission grid on an ongoing basis. Model data used to perform simulation studies of projected future conditions is maintained and updated as load forecasts and future generation/transmission changes evolve. Studies are updated periodically to assess future system performance in accordance with NERC Reliability Standards. These studies form a basis for identifying future transmission expansion needs.

8.2.1.2 Transformer Area

The transformer area contains the main stepup transformers, the unit auxiliary transformers, and the reserve auxiliary transformers. Protective relaying and metering required for this equipment is located in the turbine building. The necessary power sources (480 Vac, 120 Vac, and 125 Vdc) to the equipment are supplied from the turbine building. See Subsection 9.5.1 for a discussion of fire protection associated with plant transformers.

The transformer area for each unit contains the main stepup transformer (the GSU), (3 single phase transformers plus one spare), three unit auxiliary transformers (the UATs), and two reserve auxiliary transformers (the RATs). The two RATs are connected to the Units 3 and 4 RAT supply 230 kV switching station via overhead tie lines, with a portion of Unit 3 RAT “A” supply line being underground between Unit 4 and Unit 3. The secondary windings (230 kV side) of the Unit 3 GSU are connected in a wye configuration and connected to the Units 1, 2 and 3, 230/500 kV switchyard. The secondary windings (500 kV side) of the Unit 4 GSU are connected in a wye configuration and connected to the Unit 4, 500 kV switchyard.

One feeder connects the transformer area with the switchyard to supply power to/from the main stepup transformers for the unit. An arrangement is shown in Figure 8.3.1-1.

Each transformer is connected to the switchyard by an offsite circuit beginning at the switchyard side of the breaker(s) within the switchyard and ending at the high voltage terminals of the GSU and RATs.

8.2.1.2.1 Switchyard Protection Relay Scheme

The switchyards are designed to provide high speed fault clearing while also maintaining high reliability and operational flexibility. The arrangement of the switchyards allow for isolation of components and buses, while preserving VEGP’s connection to the grid.

Under normal operating conditions all 230 kV and 500 kV circuit breakers (with the exception of the 500 kV breakers for the switchyard line reactors) and all bus sectionalizing motor operated disconnect switches are closed and all bus sections are energized.

Each 230 kV and 500 kV transmission line is protected by two independent protection schemes (primary and secondary) to achieve high speed clearing for a fault anywhere on the line and to provide remote back-up protection for remote faults. Each scheme has a pilot protection package and a stand alone step distance line protection package. The breaker failure scheme is initiated by either of the primary or secondary protection schemes and operates through a timing relay, and should a breaker fail to trip within the time setting of its timing relay, the associated breaker failure trip relay will trip and lock out all necessary breakers to isolate the faulted area.

The protective devices controlling the switchyard breakers are set with consideration given to preserving the plant grid connection following a turbine trip.

8.2.1.3 Switchyard Control Building

A separate control building is provided to serve the requirements of each of the three high voltage switchyards. Each control building houses switchyard batteries (redundant battery systems are housed in separate battery rooms and appropriately ventilated) and accommodates a sufficient number of relay/control panels.

The 230 kV and 500 kV switchyard breakers associated with the GSU are under the functional control of the plant, and the 230 kV breakers associated with the RATs are under the control of the GCC. Transmission line circuit breakers and switches in the switchyards are under the control of the GCC. The 230 kV and 500 kV disconnect switches associated with the GSU and RATs are under the control of the plant. All plant switchyard switching is coordinated between the GCC and the VEGP control room operators.

8.2.1.4 Switchyard and Transmission Lines Testing and Inspection

An agreement between VEGP and SCT for development, maintenance, calibration, testing and modification of transmission lines, switchyards, transformer yards and associated transmission equipment, provides the procedure, policy and organization to carry out maintenance, calibration, testing and inspection of transmission lines and switchyards.

This agreement defines the interfaces and working relationship between VEGP and SCT. As a service to VEGP, SCT performs maintenance, calibration, and testing of VEGP transformer assets at Southern Company nuclear sites. VEGP and SCT are responsible for control of plant/grid interface activities. For reliability, VEGP and SCT coordinate maintenance and testing of off-site power systems. SCT and GPC establish communication and coordination protocols for restoration of external power supply to the nuclear plant on a priority basis.

For performance of maintenance, testing, calibration and inspection, SCT follows its own field test manuals, vendor manuals and drawings, and industry maintenance practices to comply with applicable NERC Reliability Standards.

SCT verifies that these test results demonstrate compliance with design requirements and takes corrective actions as necessary. SCT plans and schedules maintenance activities, notifying the plant and PCC/GCC in advance. SCT also procures and stores necessary spare parts prior to the commencement of inspection, testing, and maintenance activities.

Transmission lines are currently inspected through aerial inspection. Inspections focus on conductor, hardware and structure condition assessment, with some having a specific focus on right of way encroachments and vegetation management. An integrated vegetation management program, consisting of periodic mechanical mowing or hand clearing, and herbicide application, is used to control vegetation within the boundaries of the transmission line rights of way. Patrols to identify and

remove danger trees beyond the formal right-of-way, which could adversely affect the operation of the transmission line, are performed twice per year.

In addition to the aerial patrols, each transmission line structure is inspected every six years by ground crew personnel. These crews perform an in-depth, on-site assessment of the structure, conductor, and hardware. Any maintenance work required is noted and scheduled for a follow-up crew if the inspection crew cannot complete the task while on-site.

The interconnecting switchyard, as well as other substation facilities, has multiple levels of inspection and maintenance, including the following:

- Walk throughs and visual inspections of the entire substation facility.
- Relay functional tests.
- Oil sampling of large power transformers. Oil samples are evaluated through the use of gas chromatography and dielectric breakdown analysis.
- Power circuit breakers are subjected to several levels of inspection and maintenance. The frequency of each is a function of the number of operations and the length of time in service. Maintenance leverages the use of external visual inspection of all functional systems, an external test, and an internal inspection. Frequency of the various maintenance/inspection efforts is based on a combination of operating history of the type of breaker, industry practice and manufacturer's recommended maintenance requirements.
- A power factor test (Doble Test) is typically performed on oil filled equipment.
- Thermography is used to identify potential thermal heating issues on buses, conductors, connectors and switches.

8.2.2 Grid Stability

The AP1000 is designed with passive safety-related systems for core cooling and containment integrity and, therefore, does not depend on the electric power grid for safe operation. This feature of the AP1000 significantly reduces the importance of the grid connection and the requirement for grid stability. The AP1000 safety analyses assume that the reactor coolant pumps can receive power from either the main generator or the grid for a minimum of 3 seconds following a turbine trip.

The AP1000 main generator is connected to the generator bus through the generator circuit breaker. The grid is connected to the generator bus through the main step-up transformers and the grid breakers. The reactor coolant pumps are connected to the generator bus through the reactor coolant pump breakers, the 6.9 kV switchgear, and the unit auxiliary transformers. During normal plant operation the main generator supplies power to the generator bus. Some of this power is used by the plant auxiliary systems (including the reactor coolant pumps); the rest of the power is supplied to the grid.

If, during power operation of the plant, a turbine trip occurs, the motive power (steam) to the turbine will be removed. The generator will attempt to keep the shaft rotating at synchronous speed (governed by the grid frequency) by acting like a synchronous motor. The reverse-power relay monitoring generator power will sense this condition and, after a time delay of at least 15 seconds, open the generator breaker. During this delay time the generator will be able to provide voltage support to the grid if needed. The reactor coolant pumps will receive power from the grid for at least 3 seconds following the turbine trip. A grid stability analysis to show that, with no electrical system failures, the grid will remain stable and the reactor coolant pump bus voltage will remain above the

voltage required to maintain the flow assumed in the Chapter 15 analyses for a minimum of 3 seconds following a turbine trip is as addressed in Subsection 8.2.5. In the Chapter 15 analyses, if the initiating event is an electrical system failure (such as failure of the isophase bus), the analyses do not assume operation of the reactor coolant pumps following the turbine trip. The responsibility for setting the protective devices controlling the switchyard breakers with consideration given to preserving the plant grid connection following a turbine trip is discussed in Subsection 8.2.5.

If the turbine trip occurs when the grid is not connected (generator supplying plant house loads only), the main turbine-generator shaft will begin to slow down as the energy stored in the rotational inertia of the shaft is used to supply the house loads (including reactor coolant pumps). The system will coast down until the generator exciter can no longer maintain generator terminal voltage and the generator breaker is tripped on either generator under-voltage or exciter over-current. This coast down will last at least 3 seconds before the generator breaker trips.

The sequence of events following a loss-of-offsite-power event is the same as those described for grid-disconnected operation.

SCT Transmission Planning has performed a transmission system study of the offsite power system. In order to maintain Reactor Coolant Pump (RCP) operation for three seconds following a turbine trip as specified in Subsection 8.2.2, the grid voltage at the high-side of the GSU, and RATs cannot dip more than 0.15 p.u. from the pre-trip steady-state voltage.

The study analyzes transient stability utilizing an appropriate load flow case while considering various fault contingencies. In order to complete the forward looking study, the following assumptions are made:

- Grid voltage is 235 kV and 517 kV
- Unit 3 GSU voltage ratio 230/26 kV with a 1.05 p.u. tap setting
- Unit 4 GSU voltage ratio 525/26 kV with a 1.0 p.u. tap setting
- The 2015 summer off-peak case was used as a starting point for the study. The SBAA load was scaled down to a valley load condition of ~38% of peak and the generation was re-dispatched. Valley load conditions provide the most conservative stability results for nuclear units.

The computer analysis was performed using the Siemens Power Technology International Software PSS/E. The analysis examines two conditions:

- Normal Running
- Turbine Trip

Other conditions (i.e. startup and normal shutdown) are bounded by these analyses.

Table 8.2-201 confirms that the interface requirements for steady state load, inrush kVA for motors, nominal voltage, allowable voltage regulation, nominal frequency, allowable frequency fluctuation, maximum frequency decay rate, and limiting under frequency value for RCP have been met.

In addition to turbine trip, the grid stability analysis also considered normally-cleared three-phase faults on the transmission system and three-phase faults followed by breaker failure at the VEGP 500 kV and 230 kV switchyards. A 500 kV line out for maintenance with a normally cleared fault on another 500 kV line was also studied. The results demonstrate that the grid remains stable for the

loss of the most critical transmission line, the loss of the largest load, and the loss of the largest generating unit. For these contingencies, the generator bus voltages and switchyard voltages (after fault clearing) remain within acceptable steady state voltage limits.

From January 1, 1992 to November 30, 2007, the average grid availability for the two transmission voltages is as follows:

500 kV Transmission Voltage: The West McIntosh and Warthen 500 kV transmission lines for VEGP have an availability of 99.9% with 25 forced outages. The 500 kV Thomson transmission line is not in service during this time period. The average frequency of forced line outages since 1992 is less than two per year. The leading cause of forced outages of significant duration is lightning and the resulting damage. Other failures of significant line outage duration are substation equipment problems and storms not associated with lightning.

230 kV Transmission Voltage: The five 230 kV transmission lines for VEGP have an availability of 99.6% with 26 forced outages. The average frequency of forced line outages since 1992 is less than two per year. The leading cause of forced outages of significant duration is a line structure failure (which only occurred once). Other failures of significant line outage duration are substation equipment problems.

8.2.3 Conformance to Criteria

The offsite sources are not Class 1E. Commercial equipment is manufactured to the industrial standards listed in Subsection 8.2.6. The design meets General Design Criterion 1. Unit trips occur at the generator breaker and do not cause the loss of the preferred power source to the plant electrical systems. The AP1000 does not require ac power sources for mitigating design basis events; Chapter 15.0 describes the design bases assumptions utilized for analysis of these events.

The AP1000 plant design supports an exemption to the requirement of GDC 17 for two physically independent offsite circuits by providing safety-related passive systems for core cooling and containment integrity, and multiple nonsafety-related onsite and offsite electric power sources for other functions. See Section 6.3 for additional information on the systems for core cooling.

A reliable dc power source supplied by batteries provides power for the safety-related valves and instrumentation during transient and accident conditions.

The Class 1E dc and UPS system is the only safety-related power source required to monitor and actuate the safety-related passive systems. Otherwise, the plant is designed to maintain core cooling and containment integrity, independent of nonsafety-related ac power sources indefinitely. The only electric power source necessary to accomplish these safety-related functions is the Class 1E dc and UPS power system which includes the associated safety-related 120V ac distribution switchgear.

Although the AP1000 is designed with reliable nonsafety-related offsite and onsite ac power that are normally expected to be available for important plant functions, nonsafety-related ac power is not relied upon to maintain the core cooling or containment integrity.

The nonsafety-related ac power system is designed such that plant auxiliaries can be powered from the grid under all modes of operation. During loss of normal ac power and offsite power, the ac power is supplied by the onsite standby diesel-generators. Preassigned loads and equipment are automatically loaded on the diesel-generators in a predetermined sequence. Additional loads can be manually added as required. The onsite standby power system is not required for safe shutdown of the plant.

Conformance with General Design Criterion 18 is provided by the test and inspection capability of the system.

8.2.4 Standards and Guides

In addition to the General Design Criteria, the industry guides and standards listed as Reference 2 through 4 are used as guides in the design and procurement of the offsite power system.

8.2.5 Combined License Information for Offsite Electrical Power

The design of the ac power transmission system and its testing and inspection plan is addressed in Subsections 8.2.1, 8.2.1.1, 8.2.1.2, 8.2.1.3, and 8.2.1.4.

The technical interfaces for ac power requirements from offsite and the analysis of the offsite transmission system and the setting of protective devices are addressed in Subsections 8.2.1.2.1 and 8.2.2.

8.2.6 References

1. ANSI C2-1997, “National Electrical Safety Code.”

2. ANSI C37.010-1999, “IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.”

3. ANSI C37.90-1989, “IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.”

4. ANSI C57.12.00-2000, “IEEE Standard General Requirements for Liquid-Immersed Distribution, Power and Regulating Transformers.”

Table 8.2-201
Grid Stability Interface Evaluation

Table 1.8-1 Item 8.2 Parameter	Westinghouse Offsite AC Requirement	VEGP 3 & 4 Value Assumed
Steady-state load	"normal running values provided as input to grid stability"	(78.2 + j 41.7) MVA
Inrush kVA for motors	56,712 kVA*	56,712 kVA @ locked rotor power factor (lrpf) = 0.15 pu
Nominal voltage	Not provided	1.03 pu (517 kV) 1.02 pu (235 kV)
Allowable voltage regulation	0.95–1.05 pu steady state 0.15 pu transient dip**	0.95–1.05 pu steady state 0.15 pu transient dip**
Nominal frequency	60 Hz	60 Hz
Allowable frequency fluctuation	± 1/2 Hz indefinite	± 1/2 Hz indefinite
Maximum frequency decay rate	5 Hz/sec	5 Hz/sec

*Based on the inrush of a single 10,000 HP feedwater pump assuming efficiency = 0.95, pf = 0.9, and inrush = 6.5 x FLA

** Applicable to Turbine Trip Only. The maximum allowable voltage dip from the pre-event steady state voltage value during the 3 second turbine trip event transient as measured at the point of connection to the high side of the generator step-up transformer and the reserve auxiliary transformer.

Table 1.8-1 Item 8.2 Parameter	Westinghouse Offsite AC Requirement	VEGP 3 & 4 Value Calculated
Limiting under frequency value for RCP	$\geq$ 57.7 Hz	> 59.85 Hz

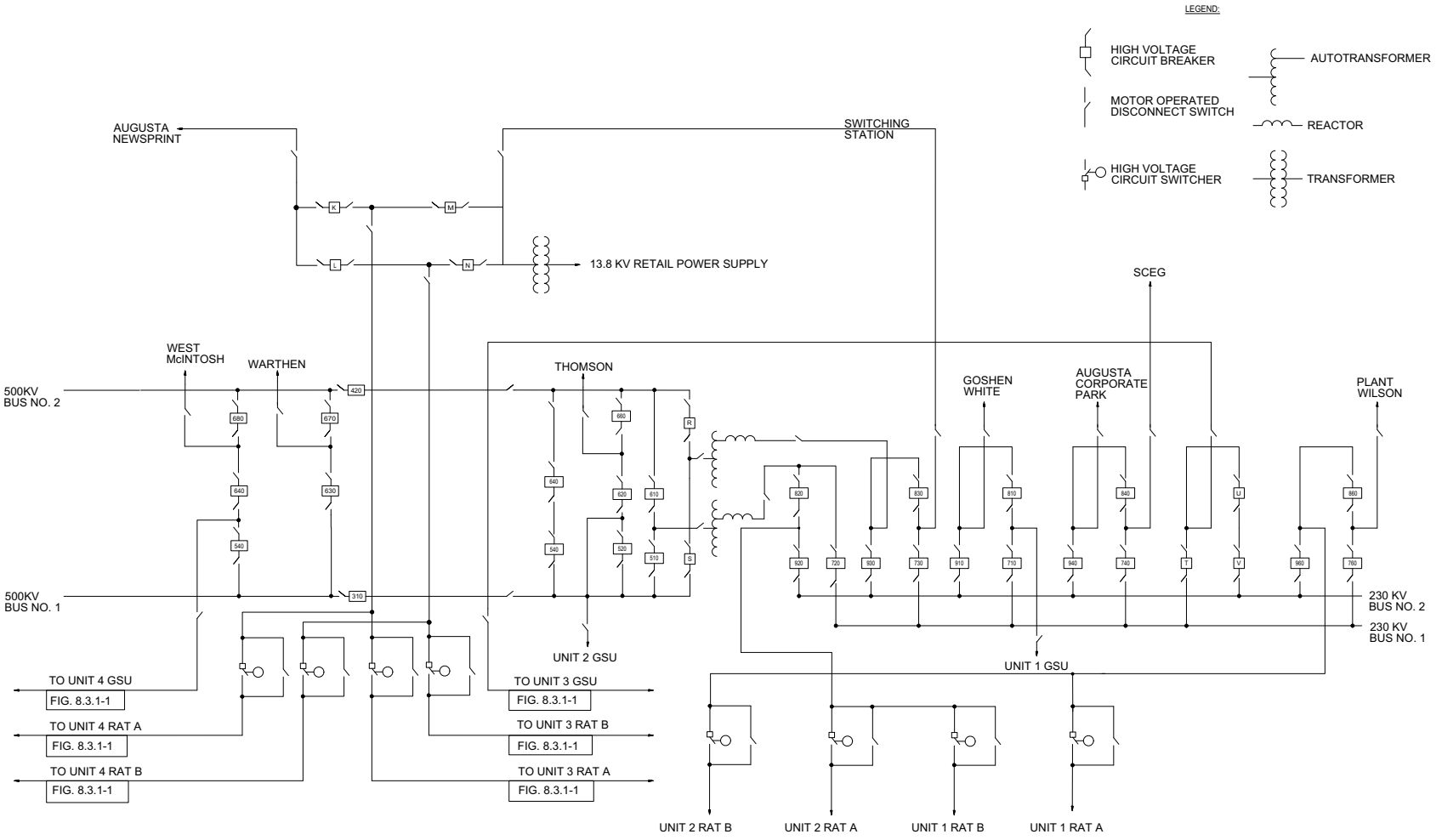


Figure 8.2-201
Offsite Power System One-Line Diagram

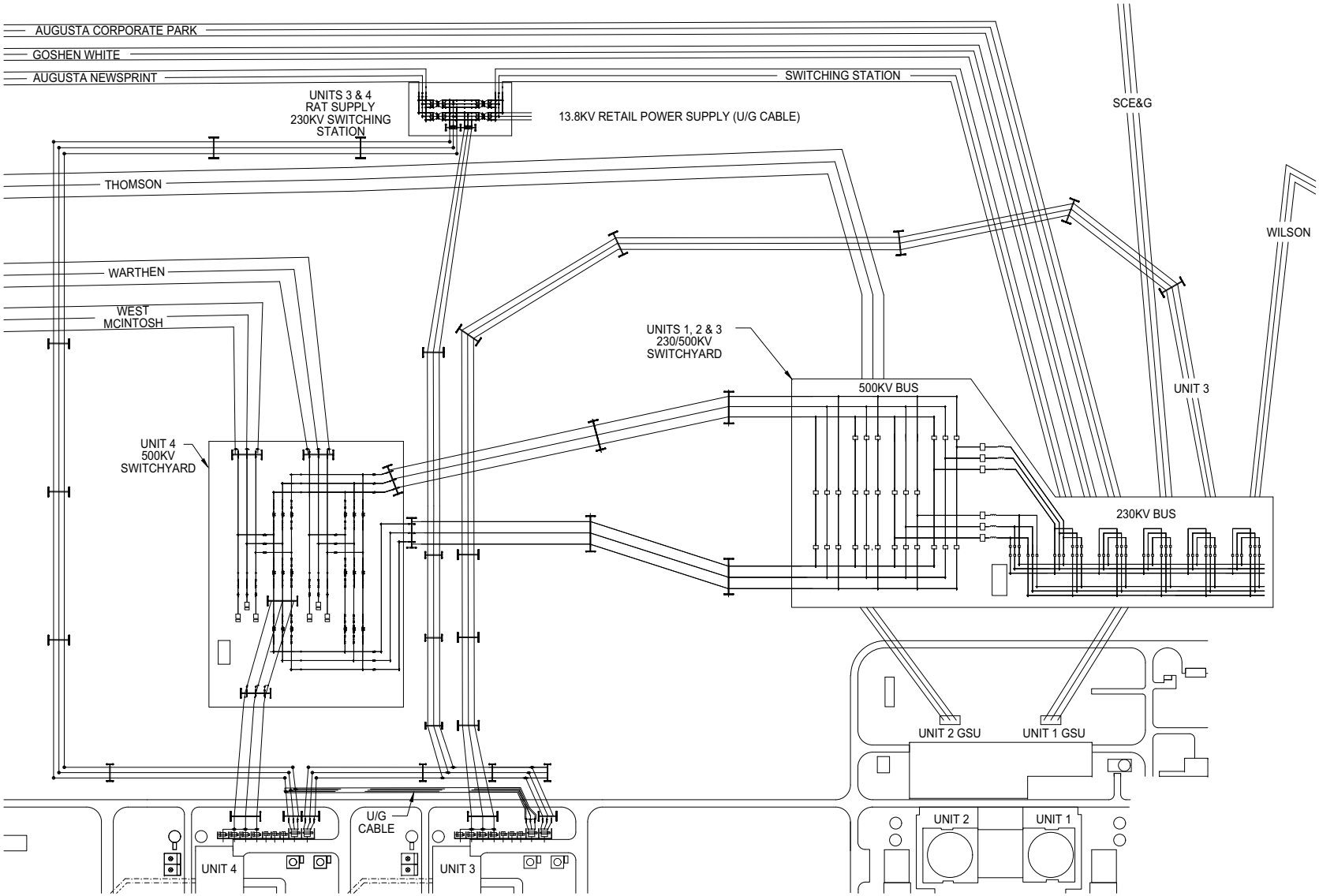


Figure 8.2-202
Switchyard General Arrangement

8.3 Onsite Power Systems

8.3.1 AC Power Systems

8.3.1.1 Description

The onsite ac power system is a non-Class 1E system comprised of a normal, preferred, maintenance and standby power supplies. The normal, preferred, and maintenance power supplies are included in the main ac power system. The standby power is included in the onsite standby power system. The Class 1E and non-Class 1E 208/120 Vac instrumentation power supplies are described in Subsection 8.3.2 as a part of uninterruptible power supply in the dc power systems.

8.3.1.1.1 Onsite AC Power System

The main ac power system is a non-Class 1E system and does not perform any safety-related functions (other than tripping the reactor coolant pumps (RCPs) as noted below). It has nominal bus voltage ratings of 6.9 kV, 480 V, 277 V, 208 V, and 120 V.

Figure 8.3.1-1 shows the main generator, transformers, feeders, buses, and their connections. The ratings of major ac equipment are listed in Table 8.3.1-3.

During power generation mode, the turbine generator normally supplies electric power to the plant auxiliary loads through the unit auxiliary transformers. The plant is designed to sustain a load rejection from 100 percent power with the turbine generator continuing stable operation while supplying the plant house loads. The load rejection feature does not perform any safety function.

During plant startup, shutdown, and maintenance the generator breaker remains open. The main ac power is provided by the preferred power supply from the high-voltage switchyard (switchyard voltage is site-specific) through the plant main stepup transformers and three unit auxiliary transformers. Two of the unit auxiliary transformers each supply power to about 50 percent of the principal plant loads. A third auxiliary transformer is provided to power the electric boiler and other nonsafety-related loads as described below. The site specific switchyard and transformer voltage is shown in Figure 8.2-201.

A maintenance source is provided to supply power through two reserve auxiliary transformers. The maintenance source and the associated reserve auxiliary transformers primary voltage are site specific. The reserve auxiliary transformers are sized so that it can be used in place of the unit auxiliary transformers.

Two unit auxiliary transformers (UAT 2A, 2B) are three winding transformers with two identically rated 6.9 kV secondary windings. The third unit auxiliary transformer (UAT 2C) is a two winding transformer sized to accommodate the electric boiler, the turbine turning gear, a portion of the turbine building space heating loads, and nonsafety-related site-specific loads. Secondaries of the auxiliary transformers are connected to the 6.9 kV switchgear buses by nonsegregated phase buses. The primary of the unit auxiliary transformer is connected to the main generator isolated phase bus duct tap. The 6.9 kV switchgear designation, location, connection, and connected loads are shown in Figure 8.3.1-1. The buses tagged with odd numbers (ES1, ES3, etc.) are connected to one unit auxiliary transformer and the buses tagged with even numbers (ES2, ES4, etc.) are connected to the other unit auxiliary transformer. ES7 is connected to the third unit auxiliary transformer. 6.9 kV buses ES1-ES6 are provided with an access to the maintenance source through normally open circuit breakers connecting the bus to the reserve auxiliary transformer. ES7 is not connected to the maintenance source. Bus transfer to the maintenance source is manual or automatic through a fast bus transfer scheme.

The arrangement of the 6.9 kV buses permits feeding functionally redundant pumps or groups of loads from separate buses and enhances the plant operational flexibility. The 6.9 kV switchgear powers large motors and the load center transformers. There are two switchgear (ES1 and ES2) located in the annex building, and five (ES3, ES4, ES5, ES6, and ES7) in the turbine building.

The main stepup transformers have protective devices for sudden pressure, neutral overcurrent, and differential current. The unit auxiliary transformers have protective devices for sudden pressure, overcurrent, differential current, and neutral overcurrent. The excitation transformer has ground fault protection. The isophase bus duct has ground fault protection. If these devices sense a fault condition the following actions will be automatically taken:

- Trip high-side (grid) breaker
- Trip generator breaker
- Trip exciter field breaker
- Trip the 6.9 kV buses connected to the faulted transformer
- Initiate a fast bus transfer of ES1-ES6 6.9kV buses ES1-ES6.

The reserve auxiliary transformers have protective devices for sudden pressure, overcurrent, differential current and neutral overcurrent. The reserve auxiliary transformers protective devices trip the reserve supply breaker and any 6.9 kV buses connected to the reserve auxiliary transformers.

The onsite standby power system powered by the two onsite standby diesel generators supplies power to selected loads in the event of loss of normal ac power and offsite power supplies followed by a fast bus transfer to the reserve auxiliary transformers. Those loads that are priority loads for defense-in-depth functions based on their specific functions (permanent nonsafety loads) are assigned to buses ES1 and ES2. These plant permanent nonsafety loads are divided into two functionally redundant load groups (degree of redundancy for each load is described in the sections for the respective systems). Each load group is connected to either bus ES1 or ES2. Each bus is backed by a non-Class 1E onsite standby diesel generator. In the event of a loss of voltage on these buses, the diesel generators are automatically started and connected to the respective buses. In the event where a fast bus transfer initiates but fails to complete, the diesel generator will start on an undervoltage signal; however, if a successful residual voltage transfer occurs, the diesel generator will not be connected to the bus because the successful residual voltage transfer will provide power to the bus before the diesel connection time of 2 minutes. The source incoming breakers on switchgear ES1 and ES2 are interlocked to prevent inadvertent connection of the onsite standby diesel generator and preferred/maintenance ac power sources to the 6.9 kV buses at the same time. The diesel generator, however, is capable of being manually paralleled with the preferred or reserve power supply for periodic testing. Design provisions protect the diesel generators from excessive loading beyond the design maximum rating, should the preferred power be lost during periodic testing. The control scheme, while protecting the diesel generators from excessive loading, does not compromise the onsite power supply capabilities to support the defense-in-depth loads. See Subsection 8.3.1.1.2 for starting and load sequencing of standby diesel generators.

The reactor coolant pumps (RCPs) are powered from the four switchgear buses located in the turbine building, one RCP per bus. Variable-speed drives are provided for RCP startup and for RCP operation when the reactor trip breakers are open. During normal power operation (reactor trip breakers are closed), 60 Hz power is provided directly to the RCPs and the variable-speed drives are not connected.

Each RCP is powered through two Class 1E circuit breakers connected in series. These are the only Class 1E circuit breakers used in the main ac power system for the specific purpose of satisfying the safety-related tripping requirement of these pumps. The reactor coolant pumps connected to a common steam generator are powered from two different unit auxiliary transformers. The bus assignments for the reactor coolant pumps are shown in Figure 8.3.1-1.

The 480 V load centers supply power to selected 460 V motor loads and to motor control centers. Bus tie breakers are provided between two 480 V load centers each serving predominantly redundant loads. This intertie allows restoration of power to selected loads in the event of a failure or maintenance of a single load center transformer. The bus tie breakers are interlocked with the corresponding bus source incoming breakers so that one of the two bus source incoming breakers must be opened before the associated tie breaker is closed. Load center 71, associated with ES-7, does not have an equivalent match.

The 480 V motor control centers supply power to 460 V motors not powered directly from load centers, while the 480/277 V, and 208/120 V distribution panels provide power for miscellaneous loads such as unit heaters, space heaters, and lighting system. The motor control centers also provide ac power to the Class 1E battery chargers for the Class 1E dc power system as described in Subsection 8.3.2.

Two ancillary ac diesel generators, located in the annex building, provide ac power for Class 1E post-accident monitoring, MCR lighting, MCR and I&C room ventilation, and pump power to refill the PCS water storage tank and the spent fuel pool, when all other sources of power are not available.

Each ancillary ac generator output is connected to a distribution panel. The distribution panel is located in the room housing the diesel generators. The distribution panel has incoming and outgoing feeder circuit breakers as shown on Figure 8.3.1-3. The outgoing feeder circuit breakers are connected to cables which are routed to the divisions B and C voltage regulating transformers and to the PCS pumps. Each distribution panel has the following outgoing connections:

- Connection for Class 1E voltage regulating transformer to power the post-accident monitoring loads, the lighting in the main control room, and ventilation in the main control room and divisions B and C I&C rooms.
- Connection for PCS recirculation pump to refill the PCS water storage tank and the spent fuel pool.
- Connection for local loads to support operation of the ancillary generator (lighting and fuel tank heating).
- Temporary connection for a test load device (e.g., load resistor).
- The connection from the ancillary diesel generators to the voltage regulating transformers includes a transfer switch to allow the regulating transformers to be powered by post-72 hour portable equipment.

  See Figure 8.3.1-3 for connections to post-72-hour loads.

8.3.1.1.1.1 Electric Circuit Protection

Protective relay schemes and direct acting trip devices on circuit breakers:

- Provide safety of personnel
- Minimize damage to equipment
- Minimize system disturbances
- Isolate faulted equipment and circuits from unfaulted equipment and circuits
- Maintain (selected) continuity of the power supply

Major types of protection systems employed for AP1000 include the following:

Medium Voltage Switchgear

Differential Relaying

Each medium voltage switchgear bus is provided with a bus differential relay (device 87B) to protect against a bus fault. The actuation of this relay initiates tripping of the source incoming circuit breaker and all branch circuit load breakers. The differential protection scheme employs high-speed relays.

Motors rated 1500 hp and above are generally provided with a high dropout overcurrent relay (device 50D) for differential protection.

Overcurrent Relaying

To provide backup protection for the buses, the source incoming circuit breakers are equipped with an inverse time overcurrent protection on each phase and a residually connected inverse time ground overcurrent protection.

Each medium voltage motor feeder breaker is equipped with a motor protection relay which provides protection against various types of faults (phase and ground) and abnormal conditions such as locked rotor and phase unbalance. Motor overload condition is annunciated in the main control room.

Each medium voltage power feeder to a 480 V load center has a multifunction relay. The relay provides overcurrent protection on each phase for short circuit and overload, and an instantaneous overcurrent protection for ground fault.

Undervoltage Relaying

Medium voltage buses are provided with a set of three undervoltage relays (device 27B) which trip motor feeder circuit breakers connected to the bus upon loss of bus voltage using two-out-of-three logic to prevent spurious actuation. In addition, a protective device is provided on the line side of incoming supply breakers of buses ES1 and ES2 to initiate an alarm in the main control room if a sustained low or high voltage condition occurs on the utility supply system. The alarm is provided so that the operator can take appropriate corrective measures.

480-V Load Centers

Each motor-feeder breaker in load centers is equipped with a trip unit which has long time, instantaneous, and ground fault tripping features. Overload condition of motors is annunciated in the main control room.

The circuit breakers feeding the 480V motor control centers and other non-motor loads have long time, short time, and ground fault tripping features.

Each load center bus has an undervoltage relay which initiates an alarm in the main control room upon loss of bus voltage.

Load center transformers have transformer winding temperature relays (device 49T) which give an alarm on transformer overload.

480-V Motor Control Center

Motor control center feeders for low-voltage (460 V) motors have molded case circuit breakers (magnetic or motor circuit protectors) and motor starters. Motor starters are provided with thermal units (overload heaters) or current sensors. Other feeders have molded case circuit breakers with thermal and magnetic trip elements for overload and short circuit protection.

Non-Class 1E ac motor-operated valves are protected by thermal overload devices. Thermal overload devices are selected and sized so as to provide the necessary protection while minimizing the probability of spurious interruptions of valve actuation.

8.3.1.1.2 Standby AC Power Supply

8.3.1.1.2.1 Onsite Standby Diesel Generators

Two onsite standby diesel generator units, each furnished with its own support subsystems, provide power to the selected plant nonsafety-related ac loads. Power supplies to each diesel generator subsystem components are provided from separate sources to maintain reliability and operability of the onsite standby power system. These onsite standby diesel generator units and their associated support systems are classified as AP1000 Class D, defense-in-depth systems.

The onsite standby diesel generator function to provide a backup source of electrical power to onsite equipment needed to support decay heat removal operation during reduced reactor coolant system inventory, midloop, operation is identified as an important nonsafety-related function. The standby diesel generators are included in the Investment Protection Short-Term Availability Controls described in Section 16.3 and the Design Reliability Assurance Program described in Section 17.4.

Each of the generators is directly coupled to the diesel engine. Each diesel generator unit is an independent self-contained system complete with necessary support subsystems that include:

- Diesel engine starting subsystem
- Combustion air intake and engine exhaust subsystem
- Engine cooling subsystem
- Engine lubricating oil subsystem
- Engine speed control subsystem
- Generator, exciter, generator protection, monitoring instruments, and controls subsystems

The diesel-generator starting air subsystem consists of an ac motor-driven, air-cooled compressor, a compressor inlet air filter, an air-cooled aftercooler, in-line air filters, a refrigerant dryer (with dew point at least 10°F less than the lowest normal diesel generator room temperature), and an air receiver with sufficient storage capacity for three diesel engine starts. The starting air subsystem is consistent with manufacturer's recommendations regarding the devices to crank the engine, duration of the cranking cycle, the number of engine revolutions per start attempt, volume and design pressure of the air receivers, and compressor size. The interconnecting stainless steel piping from the compressor to the diesel engine dual air starter system includes air filters, moisture drainers, and pressure regulators to provide clean dry compressed air at normal diesel generator room temperature for engine starting.

The diesel-generator combustion air intake and engine exhaust subsystem provides combustion air directly from the outside to the diesel engine while protecting it from dust, rain, snow and other environmental particulates. It then discharges exhaust gases from the engine to the outside of the diesel generator building more than 20 feet higher than the air intake. The combustion air circuit is separate from the ventilation subsystems and includes weather protected dry type inlet air filters piped directly to the inlet connections of the diesel engine-mounted turbochargers. The combustion air filters are capable of reducing airborne particulate material, assuming the maximum expected airborne particulate concentration at the combustion air intake. Each engine is provided with two

filters as shown in Figure 8.3.1-4. A differential pressure gauge is installed across each filter to determine the need for filter replacement. The engine exhaust gas circuit consists of the engine exhaust gas discharge pipes from the turbocharger outlets to a single vertically mounted outdoor silencer which discharges to the atmosphere. Manufacturer's recommendations are considered in the design of features to protect the silencer module and other system components from possible clogging due to adverse atmospheric conditions, such as dust storms, rain, ice, and snow.

The diesel-generator engine cooling system is an independent closed loop cooling system, rejecting engine heat through two separate roof-mounted, fan-cooled radiators. The system consists of two separate cooling loops each maintained at a temperature required for optimum engine performance by separate engine-driven coolant water circulating pumps. One circuit cools the engine cylinder block, jacket, and head area, while the other circuit cools the oil cooler and turbocharger aftercooler. The cooling water in each loop passes through a three-way self-contained temperature control valve which modulates the flow of water through or around the radiator, as necessary, to maintain required water temperature. The temperature control valve has an expanding wax-type temperature-sensitive element or equivalent. The cooling circuit, which cools the engine cylinder blocks, jacket, and head areas, includes a keep-warm circuit consisting of a temperature controlled electric heater and an ac motor-driven water circulating pump.

The diesel-generator engine lubrication system is contained on the engine skid and includes an engine oil sump, a main engine-driven oil pump and a continuous engine prelube system consisting of ac and dc motor-driven pumps, an air-driven pump, and a keep warm circuit consisting of a motor driven pump and an electric heater. The prelube system maintains the engine lubrication system in service when the diesel engine is in standby mode. The lube oil is circulated through the engine and various filters and a cooler to maintain the lube oil properties suitable for engine lubrication.

The diesel generator engine fuel oil system consists of two engine-mounted, engine-driven fuel oil pumps that take fuel from the fuel oil day tank, and pump through inline oil filters to the engine fuel injectors and a separate recirculation circuit with a fuel oil cooler. The recirculation circuit discharges back to the fuel oil day tank that is maintained at the proper fuel level by the diesel fuel oil storage and transfer system.

The onsite standby diesel generators are provided with necessary controls and indicators for local or remote monitoring of the operation of the units. Essential parameters are monitored and alarmed in the main control room via the plant data display and processing system as described in Chapter 7. Indications and alarms that are available locally and in the main control room are listed in Table 8.3.1-5.

The design of the onsite standby diesel generators does not ensure functional operability or maintenance access or support plant recovery following design basis events. Maintenance accessibility is provided consistent with the system nonsafety-related functions and plant availability goals.

The simplified piping and instrumentation diagrams for the onsite standby diesel generator units and the associated subsystems are shown on Figures 8.3.1-4 and 8.3.1-5.

The onsite standby power supply system is shown schematically on one line diagram, Figure 8.3.1-1.

The onsite diesel generators were procured in accordance with an equipment specification which includes requirements based upon the manufacturer's standards and applicable recommendations from documents such as NUREG/CR-0660 (Reference 15). Capability to detect system leakage and to prevent crankcase explosions will be based upon manufacturer's recommendations. Control of moisture in the starting air system by the equipment described above will be based upon manufacturer's recommendations. Dust and dirt in the diesel generator room is controlled by the

diesel generator building ventilation system described in Subsection 9.4.10. Personnel training is addressed as part of overall plant training in Subsection 13.2.6. Automatic engine prelube by the equipment described above will be based upon manufacturer's recommendations. Testing, test loading and preventive maintenance is addressed as part of overall plant testing and maintenance in Chapter 13. Instrumentation to support diagnostics during operation is shown on Figure 8.3.1-4. The overall diesel building ventilation design is described in Subsection 9.4.10 and the combustion air systems are described above. The fuel oil storage and handling system is described in Subsection 9.5.4. High temperature insulation will be based upon manufacturer's recommendations. Response to the effects of engine vibration will be based upon manufacturer's recommendations. Diesel building floor coatings are described in Subsections 6.1.2.1.4 and 6.1.3.2. The diesel generator building HVAC system, as described in Subsection 9.4.10, will function to provide adequate heating, ventilation, and cooling to support the operation of the diesel generators.

8.3.1.1.2.2 Generator

Each generator is a direct-shaft driven, air-cooled self ventilated machine. The generator enclosure is open drip-proof type that facilitates free movement of ventilation air. The generator component design is in compliance with the NEMA MG-1 (Reference 1) requirements.

Each generator produces its rated power at 6900 V, 60 Hz. Each generator continuous rating is based on supplying the electrical ac loads listed in Tables 8.3.1-1 or 8.3.1-2. The loads shown on Tables 8.3.1-1 and 8.3.1-2 represent a set of nonsafety-related loads which provide shutdown capability using nonsafety-related systems. The generators can also provide power for additional investment protection ac loads. The plant operator would normally provide power to these loads by de-energizing one of those system components that are redundantly supplied by both the diesel generators. The diesel generator design is compatible with the step loading requirements identified in Tables 8.3.1-1 and 8.3.1-2. The generator exciter and voltage regulator systems are capable of providing full voltage control during operating conditions including postulated fault conditions.

Each generator has a set of potential and current transformers for protective relaying and metering purposes.

The following generator protection functions are provided via relays that are mounted on the local generator control panel:

Differential (87), overcurrent (50/51), reverse power (32), underfrequency (81), under/over voltage (27/59), loss of excitation (40), ground fault (59N), negative sequence (46), synchronization check (25), voltage balance (60).

Note: The number in the parentheses identifies the ANSI device designation.

8.3.1.1.2.3 Onsite Standby Power System Performance

The onsite standby power system provides reliable ac power to the various plant system electrical loads shown on Tables 8.3.1-1 and 8.3.1-2. These loads represent system components that enhance an orderly plant shutdown under emergency conditions. Additional loads that are for investment protection can be manually loaded on the standby power supply after the loads required for orderly shutdown have been satisfied. The values listed in the "Operating Load (kW)" column of Tables 8.3.1-1 and 8.3.1-2 represent nominal values of the actual plant loads.

Both the diesel engine and the associated generator are rated based on 104°F ambient temperature at 1000 ft elevation as standard site conditions. The selected unit rating has a design margin to accommodate possible derating resulting from other site conditions.

The VEGP site conditions provided in Section 2.3 are bounded by the standard site conditions used to rate both the diesel engine and the associated generator in Subsection 8.3.1.1.2.3.

The diesel generator unit is able to reach the rated speed and voltage and be ready to accept electrical loads within 120 seconds after a start signal.

Each generator has an automatic load sequencer to enable controlled loading on the generator. The automatic load sequencer connects selected loads at predetermined intervals (i.e., load blocks). This feature allows recuperation of generator voltage and frequency to rated values prior to the connection of the next load.

For sequential and manual loading of the onsite standby diesel generator, see Tables 8.3.1-1 and 8.3.1-2.

To enable periodic testing, each generator has synchronizing equipment at a local panel as well as in the main control room.

The logic diagram for diesel generator initiating circuit is shown in Figure 8.3.1-2.

8.3.1.1.2.4 Operation, Inspection, and Maintenance

Operation, inspection and maintenance (including preventive, corrective, and predictive maintenance) procedures consider both the diesel generator manufacturer's recommendations and industry diesel working group recommendations.

8.3.1.1.3 Ancillary Diesel Generators

Power for Class 1E post-accident monitoring, MCR lighting, MCR and divisions B and C I&C room ventilation and for refilling the PCS water storage tank and the spent fuel pool when no other sources of power are available is provided by two ancillary diesel generators located in the annex building. The ancillary diesel generators are not needed for refilling the PCS water storage tank, spent fuel pool makeup, post-accident monitoring or lighting for the first 72 hours following a loss of all other ac sources.

The generators are classified as AP1000 Class D. The generators are commercial, skid-mounted, packaged units and can be easily replaced in the event of a failure. Generator control is manual from a control integral with the diesel skid package. These generators are located in the portion of the Annex Building that is a seismic Category II structure.

For these systems and components, the design of equipment anchorages is consistent with the SSE design of equipment anchorages of seismic Category I items and there should be no spatial interaction with any other non-seismic SSC that could adversely interact to prevent the functioning of the post-72 hour SSCs following an SSE; no dynamic qualification of the active equipment is necessary. Features of this structure which protect the function of the ancillary diesel generators are analyzed and designed for Category 5 hurricanes, including the effects of sustained winds, maximum gusts, and associated wind-borne missiles. The function of the ancillary diesel generators can be maintained through a temporary hose to exhaust fumes in the event of loss of ancillary diesel generator stacks.

The fuel for the ancillary generators is stored in a tank located in the same room as the generators. The fuel tank, piping, and valves are analyzed to show that they withstand an SSE. The tank includes provisions for venting to the outside atmosphere and for refilling from a truck or other mobile source of fuel. The tank is seismic Category II and holds sufficient fuel for 4 days of operation.

Each ancillary diesel generator output is connected to a distribution panel located in the same room as the generators. Each distribution panel has an incoming circuit breaker and outgoing feeder circuit breakers. The outgoing feeder circuit breakers are connected to cables that are routed to the divisions B and C voltage regulating transformers and to the passive containment cooling system recirculation pumps (see Figure 8.3.1-3).

8.3.1.1.4 Electrical Equipment Layout

The main ac power system distributes ac power to the reactor, turbine, and balance of plant (BOP) auxiliary electrical loads for startup, normal operation, and normal/emergency shutdown.

The medium voltage switchgear ES1 and ES2 are located in the electrical switchgear rooms 1 and 2 of the annex building. The incoming power is supplied from the unit auxiliary transformers ET2A and ET2B (X windings) via nonsegregated buses. The nonsegregated buses are routed from the transformer yard to the annex building in the most direct path practical.

The switchgear ES3, ES4, ES5, and ES6 are located in the turbine building electrical switchgear rooms. The incoming power is supplied from the unit auxiliary transformers ET2A and ET2B (Y windings) via nonsegregated buses to ES3 and ES4 and from ET2A and ET2B (X windings) to ES5 and ES6. Switchgear ES7 is located in the auxiliary boiler room in the turbine building.

The Class 1E medium voltage circuit breakers, ES31, ES32, ES41, ES42, ES51, ES52, ES61, and ES62, for four reactor coolant pumps are located in the auxiliary building.

The 480 V load centers are located in the turbine building electrical switchgear rooms 1 and 2 and in the annex building electrical switchgear rooms 1 and 2 based on the proximity of loads and the associated 6.9 kV switchgear. Load center 71 is located in the auxiliary boiler room in the turbine building.

The 480 V motor control centers are located throughout the plant to effectively distribute power to electrical loads. The load centers and motor control centers are free standing with top or bottom cable entry and front access. The number of stacks/cubicles varies for each location.

8.3.1.1.5 Heat Tracing System

The electric heat tracing system is nonsafety-related and provides electrical heating where temperature above ambient is required for system operation and freeze protection.

The electric heat tracing system is part of the AP1000 permanent nonsafety-related loads and is powered from the diesel backed 480 V ac motor control centers through 480 V - 208Y/120V transformers and distribution panels.

8.3.1.1.6 Containment Building Electrical Penetrations

The electrical penetrations are in accordance with IEEE 317 (Reference 2).

The penetrations conform to the same functional service level as the cables, (for example, low-level instrumentation is in a separate nozzle from power and control). The same service class separation requirements apply within inboard/outboard terminal boxes.

Individual electrical penetrations are provided for each electrical service level and follow the same raceway voltage grouping described in Subsection 8.3.1.3.4. Optical fibers are installed in instrumentation and control or low voltage power electric penetrations.

The electrical penetrations conductor modules are in penetrations of the same Service Class. Modules for instrumentation signals will be in instrumentation penetrations; modules for control power (e.g., 120/125/250V) will be in control power penetrations; modules for low voltage power (e.g., 600 Vac) will be in low voltage power penetrations.

It is possible to combine low voltage power with control power in the same electrical penetration assembly.

Penetrations carrying medium voltage power cables have thermocouples to monitor the temperature within the assembly at the spot expected to have the hottest temperature.

Electrical circuits passing through electrical penetrations have primary and backup protective devices. These devices coordinate with the thermal capability curves (I^2t) of the penetration assemblies. The penetrations are rated to withstand the maximum short-circuit currents available either continuously without exceeding their thermal limit, or at least longer than the field cables of the circuits so that the fault or overload currents are interrupted by the protective devices prior to a potential failure of a penetration. Penetrations are protected for the full range of currents up to the maximum short circuit current available.

Primary and backup protective devices protecting Class 1E circuits are Class 1E in accordance with IEEE 741 (Reference 10). Primary and backup protective devices protecting non-Class 1E circuits are non-Class 1E.

Penetration overcurrent protection coordination curves are generated based on the protection requirements specified by the penetration equipment manufacturer. When necessary, penetrations are protected for instantaneous overcurrent by current limiting devices such as current-limiting fuses, current-limiting breakers, or reactors.

Procedures implement periodic testing of protective devices that provide penetration overcurrent protection. A sample of each different type of overcurrent device is selected for periodic testing during refueling outages. Testing includes:

- Verification of thermal and instantaneous trip characteristics of molded case circuit breakers.
- Verification of long time, short time, and instantaneous trips of medium voltage vacuum circuit breakers.
- Verification of long time, short time, and instantaneous trips of low voltage air circuit breakers.
- Verification of Class 1E and non-Class 1E dc protective device characteristics (except fuses) per manufacturer recommendations, including testing for overcurrent interruption and/or fault current limiting.

Penetration protective devices are maintained and controlled under the plant configuration control program. A fuse control program, including a master fuse list, is established based on industry operating experience.

8.3.1.1.7 Grounding System

The AP1000 grounding system complies with the guidelines provided in IEEE 665 (Reference 18) and IEEE 1050 (Reference 20). The grounding system consists of the following four subsystems:

- Station grounding grid
- Electrical system grounding (neutral grounding)

- Equipment grounding
- Instrument/computer grounding

The station grounding grid subsystem consists of buried, interconnected bare copper conductors and ground rods forming a plant ground grid matrix. The subsystem maintains a uniform ground potential and limits the step and touch potentials to safe values under all fault conditions.

The electrical system grounding (neutral grounding) subsystem provides grounding of the neutral points of the main generator, main step-up transformers, auxiliary transformers, load center transformers, and onsite standby diesel generators. The main and diesel generator neutrals are grounded through grounding transformers providing high-impedance grounding. The main step-up and load center transformer neutrals are grounded solidly. The auxiliary (unit and reserve) transformer secondary winding neutrals are resistance grounded except for the auxiliary transformer UAT 2C, which is solidly grounded to meet the requirements of the electrode type auxiliary boiler.

The equipment grounding subsystem provides grounding of the equipment enclosures, metal structures, metallic tanks, ground bus of switchgear assemblies, load centers, MCCs, and control cabinets. The equipment grounding subsystem is connected to the station grounding grid.

The instrument/computer grounding subsystem provides plant instrument/computer grounding through separate radial grounding systems consisting of isolated instrumentation ground buses and insulated cables. The radial grounding systems are connected to the station grounding grid at one point only and are insulated from all other grounding circuits.

A station grounding grid subsystem design within the plant boundary includes step and touch potentials near equipment that are within the acceptable limit for personnel safety. Actual resistivity measurements from soil samples taken at the plant site were analyzed to create a soil model. The ground grid conductor size was then determined using the methodology outlined in IEEE 80, “IEEE Guide for Safety in AC Substation Grounding” (Reference 201) and a grid configuration for the site was created. The grid configuration was modeled in conjunction with the soil model. The resulting step and touch potentials are within the acceptable limits.

8.3.1.1.8 Lightning Protection

The lightning protection system, consisting of air terminals and ground conductors, is provided for the protection of exposed structures and buildings housing safety-related and fire protection equipment in accordance with NFPA 780 (Reference 19). Also, lightning arresters are provided in each phase of the transmission lines and at the high-voltage terminals of the outdoor transformers. The isophase bus connecting the main generator and the main transformer and the medium-voltage switchgear is provided with lightning arresters. In addition, surge suppressors are provided to protect the plant instrumentation and monitoring system from lightning-induced surges in the signal and power cables connected to devices located outside.

Direct-stroke lightning protection for facilities is accomplished by providing a low-impedance path by which the lightning stroke discharge can enter the earth directly. The direct-stroke lightning protection system, consisting of air terminals, interconnecting cables, and down conductors to the ground grid, are provided external to the facility in accordance with the guidelines included in NFPA 780. The system is connected to the station grounding grid subsystem to facilitate dissipation of the large current of a direct lightning stroke. The lightning arresters and the surge suppressors connected directly to ground provide a low-impedance path to ground for the surges caused or induced by lightning. Thus, fire or damage to facilities and equipment resulting from a lightning stroke is avoided.

In accordance with IEEE 665, "IEEE Standard for Generating Station Grounding" (Section 8.3 Reference 18), a lightning protection risk assessment for the buildings comprising the VEGP Units 3

and 4 was performed based on the methodology in NFPA 780 (Section 8.3 Reference 19). The tolerable lightning frequency for each of the buildings was determined to be less than the expected lightning frequency; therefore, lightning protection is required for the VEGP Units 3 and 4 buildings based on the design in accordance with NFPA 780. The zone of protection is based on the elevations and geometry of the structures. It includes the space covered by a rolling sphere having a radius sufficient enough to cover the building to be protected. The zone of protection method is based on the use of ground masts, air terminals and shield wires. Either copper or aluminum is used for lightning protection. Lightning protection grounding is interconnected with the station grounding grid subsystem or switchyard grounding system.

8.3.1.2 Analysis

The ac power system is non-Class 1E and is not required for safe shutdown. Compliance with existing regulatory guides and General Design Criteria is covered in Table 8.1-1 of Section 8.1.

8.3.1.3 Raceway/Cable

8.3.1.3.1 General

The raceway system for non-Class 1E ac circuits complies with IEEE 422 (Reference 3) in respect to installation and support of cable runs between electrical equipment including physical protection. A raceway system is the complete assembly of raceways (e.g., conduit, cable tray, or wireway) and raceway supports.

8.3.1.3.2 Load Groups Segregation

There are two nonsafety-related load groups associated with different transformers, buses, and onsite standby diesel generators. No physical separation is required as these two ac load groups are non-Class 1E and nonsafety-related.

8.3.1.3.3 Cable Derating and Conduit and Cable Tray Fill

Cable Derating

The power and control cable insulation is designed for a conductor temperature of 90°C during normal operation. The allowable current carrying capacity of the cable is based on the insulation design temperature while the surrounding air is at an ambient temperature of 65°C for the containment and 40 to 50°C for other areas. The power and control cables in the integrated head package (IHP) CRDM cable tray are designed to an ambient air temperature of 50°C. Power cables, feeding loads from switchgear, load centers, motor control centers, and distribution panels are sized at 125 percent of the full-load current at a 100-percent load factor. Temperature and full-load current conditions for high-temperature cables, specialty cables, and cables within interfacing commodities are determined based on application-specific conditions.

The power cable ampacities are in accordance with the Insulated Cable Engineers Association publications (Reference 4 and 11), and National Electric Code (Reference 5). The derating is based on the type of installation, the conductor and ambient temperature, the number of cables in a raceway, and the grouping of the raceways. A further derating of the cables is applied for those cables which pass through a fire barrier. The method of calculating these derating factors is determined from the Insulated Cable Engineers Association publications and other applicable standards.

Instrumentation cable insulation is also designed for a conductor temperature of 90°C during normal operation. The operating power of these cables is low (usually mV or mA) and does not cause cable overheating at the maximum design ambient temperature.

For circuits that are routed partly through conduit and partly through trays or underground ducts, the cable size is based on the ampacity in that portion of the circuit with the lowest indicated current carrying capacity.

Conduit and Cable Tray Fill

Cable tray design is based on random cable fill of 40 percent of usable tray depth. Conduit fill design is in compliance with Chapter 9 of National Electrical Code (Reference 5). If tray or conduit fill exceeds the above stated maximum fill, the fill will be analyzed and the acceptability documented.

8.3.1.3.4 Raceway and Cable Routing

When cable trays are arranged in a vertical array they are arranged physically from top to bottom, in accordance with the function and voltage class of the cables as follows:

- Medium voltage power (6.9 kV)
- Low voltage power (480 Vac, 208Y/120 Vac, 125 Vdc/250 Vdc)
- 120 Vac/125 Vdc/250 Vdc signal and control (if used)
- Instrumentation (analog and digital)

480 Vac, 208Y/120 Vac, 125 Vdc/250 Vdc power cables may be mixed with 120 Vac/125 Vdc/ 250 Vdc signal and control cables in random fill cable trays, subject to the following additional criteria:

- Insulation ratings are the same voltage level
- Respective sizes do not differ greatly
- Operating temperatures are compatible
- The fault current on any cable prior to the breaker or fuse clearing time is not sufficient to heat the cable insulation to the ignition point
- The signal or control function served by the Y cable is not susceptible to EMI/RFI levels generated in the low voltage power trays (XA)
- The “Y” cable does not directly interface with any inputs/outputs of a core digital control system

Separate raceways are provided for medium voltage power, low voltage power and control, as well as instrumentation cables.

Raceways that route non-Class 1E cables and their supports installed in seismic Category I structures are designed and/or physically arranged so that the safe shutdown earthquake could not cause unacceptable structural interaction or failure of seismic Category I components.

Raceways are kept at a reasonable distance from heat sources such as steam piping, steam generators, boilers, high and low pressure heaters, and any other actual or potential heat source. Cases of heat source crossings are evaluated and supplemental heat shielding is used if necessary.

See Subsection 8.3.2 for raceway and cable routing for Class 1E cables.

8.3.1.4 Inspection and Testing

Preoperational tests are conducted to verify proper operation of the ac power system. The preoperational tests include operational testing of the diesel load sequencer and diesel generator capacity testing.

Procedures are established for periodic verification of proper operation of the Onsite AC Power System capability for automatic and manual transfer from the preferred power supply to the

maintenance power supply and return from the maintenance power supply to the preferred power supply.

8.3.1.4.1 Diesel Load Sequencer Operational Testing

The load sequencer for each standby diesel generator is tested to verify that it produces the appropriate sequencing signals within five (5) seconds of the fixed duration portion of the intervals specified in Tables 8.3.1-1 and 8.3.1-2. The five second margin is sufficient for proper diesel generator transient response.

The time sequence values defined in UFSAR Tables 8.3.1-1 and 8.3.1-2 are the allowable initiation times for individual load blocks (starting from the maximum 120 seconds allowed for the DG to start and be ready to pickup load). The tables reflect the allowable interval that each load block has to initiate the subsequent load block. This interval is the time difference between the load blocks identified in UFSAR Tables 8.3.1-1 and 8.3.1-2. For example, if the load block 0 interval begins at 120 seconds, it ends at 140 seconds with the initiation of load block 1, thus the table establishes the allowable load block 0 interval to be 20 seconds.

The automatic load sequencer produces a load block initiation signal for each load block. The active load block duration is terminated by the initiation of the subsequent load block. The subsequent load block initiation requires the active load block signal to be available for a fixed duration (less than or equal to the intervals in UFSAR Tables 8.3.1-1 and 8.3.1-2) and the DG ready to pickup load signal to be present after the fixed duration. The "ready to pickup load" signal can extend the interval beyond the fixed duration to allow the DG to recover from the current load block transient response. Testing verifies that each load block initiates within ± 5 seconds of the fixed duration in each interval (i.e., the predetermined interval).

8.3.1.4.2 Standby Diesel Generator Capacity Testing

Each standby diesel generator is tested to verify the capability to provide 4000 kW while maintaining the output voltage and frequency within the design tolerances of 6900±10% Vac and 60±5% Hz. The 4000 kW capacity is sufficient to meet the loads listed in Tables 8.3.1-1 and 8.3.1-2. The test duration will be the time required to reach engine temperature equilibrium plus 2.5 hours. This duration is sufficient to demonstrate long-term capability.

8.3.1.4.3 Ancillary Diesel Generator Capacity Testing

Each ancillary diesel generator is tested to verify the capability to provide 35 kW while maintaining the output voltage and frequency within the design tolerances of 480±10% Vac and 60±5% Hz. The 35 kW capacity is sufficient to meet the loads listed in Table 8.3.1-4. The test duration will be the time required to reach engine temperature equilibrium plus 2.5 hours. This duration is sufficient to demonstrate long-term capability.

8.3.2 DC Power Systems

8.3.2.1 Description

The plant dc power system is comprised of independent Class 1E and non-Class 1E dc power systems. Each system consists of ungrounded stationary batteries, dc distribution equipment, and uninterruptible power supply (UPS).

The Class 1E dc and UPS system provides reliable power for the safety-related equipment required for the plant instrumentation, control, monitoring, and other vital functions needed for shutdown of the

plant. In addition, the Class 1E dc and UPS system provides power to the normal and emergency lighting in the main control room and at the remote shutdown workstation.

The Class 1E dc and UPS system is capable of providing reliable power for the safe shutdown of the plant without the support of battery chargers during a loss of all ac power sources coincident with a design basis accident (DBA). The system is designed so that no single failure will result in a condition that will prevent the safe shutdown of the plant.

The non-Class 1E dc and UPS system provides continuous, reliable electric power to the plant non-Class 1E control and instrumentation loads and equipment that are required for plant operation and investment protection and to the hydrogen igniters located inside containment. Operation of the non-Class 1E dc and UPS system is not required for nuclear safety. See Subsection 8.3.2.1.2.

The batteries for the Class 1E and non-Class 1E dc and UPS systems are sized in accordance with IEEE 485 (Reference 6). The operating voltage range of the Class 1E batteries and of the EDS5 turbine generator motor load support batteries is 210 to 280 Vdc. The maximum equalizing charge voltage for the Class 1E and EDS5 batteries is 280 Vdc. The nominal system voltage is 250 Vdc. The operating voltage range of non-Class 1E EDS1 through EDS4 batteries is 105 to 140 Vdc. The maximum equalizing charge voltage for non-Class 1E EDS1 through EDS4 batteries is 140 Vdc. The nominal system voltage is 125 Vdc for non-Class 1E EDS1 through EDS4.

The qualification test program for AP1000 24-hour and 72-hour class 1E batteries meets or exceeds the requirements of IEEE Standard 323, IEEE Standard 344, and IEEE Standard 535, including required and recommended margins, and it is in regulatory compliance with Regulatory Guides 1.89, 1.100, and 1.158. The test program requires that the battery be subjected to accelerated thermal aging and discharge cycling (wear aging) in accordance with IEEE Standard 323 and IEEE Standard 535 over its qualified life objective followed by the DBE seismic event performed in accordance with IEEE Standard 344. In addition, following the aging process, the test specimens shall be subjected to environmental testing to verify the equipment's ability to operate in postulated abnormal environmental conditions during plant operation. Discharge cycling will be performed as a potential aging mechanism prior to seismic testing using Type 3 modified performance test method in accordance with IEEE Standard 450-2002 at intervals representative of the AP1000 surveillance test requirements of the batteries with 10% margin in the number of discharge cycles, which establishes margin for the expected life of the battery. Thus, magnitude/duration (modified performance test versus service and performance tests) and test interval envelop the AP1000 and industry cycling requirements. If new battery failure modes are detected during the qualification testing, these failure modes will be evaluated for any potential changes to the technical specification's surveillance requirements and revision to maintenance procedures required to ensure identification of degradation prior to reaching those failure modes during plant operation. Following the qualification process, a report that uniquely describes step-by-step the tests performed and results, and addresses any deficiencies and repairs, including photographs, drawings, and other materials, will be maintained for records.

8.3.2.1.1 Class 1E DC and UPS System

8.3.2.1.1.1 Class 1E DC Distribution

The Class 1E dc distribution is in compliance with applicable General Design Criteria, IEEE standards, and Regulatory Guides listed in Subsection 8.1.4.3. The scope of compliance encompasses physical separation, electrical isolation, equipment qualification, effects of single active component failure, capacity of battery and battery charger, instrumentation and protective devices, and surveillance test requirements. The Class 1E dc components are housed in seismic Category I structures. For system configuration and equipment rating, see Class 1E dc one-line diagram, Figure 8.3.2-1. Nominal ratings of major Class 1E dc equipment are listed in Table 8.3.2-5.

There are four independent, Class 1E 250 Vdc divisions, A, B, C, and D. Divisions A and D are each comprising one battery bank, one switchboard, and one battery charger. The battery bank is connected to Class 1E dc switchboard through a set of fuses and a disconnect switch. Divisions B and C are each composed of two battery banks, two switchboards, and two battery chargers. The first battery bank in the four divisions, designated as 24-hour battery bank, provides power to the loads required for the first 24 hours following an event of loss of all ac power sources concurrent with a design basis accident (DBA). The battery charger for each 24-hour division battery bank provides two Class 1E battery charger input voltage status signals to the protection and safety monitoring system for actuation of engineered safety features. The second battery bank in divisions B and C, designated as 72-hour battery bank, is used for those loads requiring power for 72 hours following the same event. Each switchboard connected with a 24-hour battery bank supplies power to an inverter, a 250 Vdc distribution panel, and a 250 Vdc motor control center. Each switchboard connected with a 72-hour battery bank supplies power to an inverter. No load shedding or load management program is needed to maintain power during the required 24-hour safety actuation period.

A single spare battery bank with a spare battery charger is provided for the Class 1E dc and UPS system. In the case of a failure or unavailability of the normal battery bank and the battery charger, permanently installed cable connections allow the spare to be connected to the affected bus by plug-in locking type disconnect along with kirk-key interlock switches. The plug-in locking type disconnect and kirk-key interlock switches permit connection of only one battery bank and battery charger at a time so that the independence of each battery division is preserved. The spare battery and the battery charger can also be utilized as a substitute when offline testing, maintenance, and equalization of an operational battery bank are desired. If the spare battery charger is substituted for a 24-hour division battery charger and the 24-hour division battery charger is disconnected from its normal power supply, the two undervoltage relays on the 24-hour division battery charger each provide a low input voltage signal to the protection and safety monitoring system for the division.

Each 250 Vdc Class 1E battery division and the spare battery bank are separately housed as described in Subsection 8.3.2.1.3.

Each battery bank, including the spare, has a battery monitor system that detects battery open-circuit conditions and monitors battery voltage. The battery monitor provides a trouble alarm in the main control room. The battery monitors are not required to support any safety-related function. The battery monitor connection to the Class 1E batteries are provided with safety-related fuse isolation panels that provide the required isolation between non-Class 1E and Class 1E circuits and equipment. The fuse panels are qualified as isolation devices in accordance with IEEE 384 (Reference 7) and Regulatory Guide 1.75, with the exceptions noted in Appendix 1A. Monitoring and alarming of dc current and voltages are through the plant control system which includes a battery discharge rate alarm. AP1000 generally uses fusible disconnect switches in the Class 1E dc system. If molded-case circuit breakers are used for dc applications, they will be sized to meet the dc interrupting rating requirements.

The Class 1E dc switchboards employ fusible disconnect switches and have adequate short circuit and continuous-current ratings. The main bus bars are braced to withstand mechanical forces resulting from a short-circuit current. Fused transfer switch boxes, equipped with double pole single throw transfer switches, are provided to facilitate battery testing, and maintenance.

Battery chargers are connected to dc switchboard buses. The input ac power for the Class 1E dc battery chargers is supplied from non-Class 1E 480 Vac diesel generator backed motor control centers. The battery chargers provide the required isolation between the non-1E ac and the Class 1E dc electrical systems. The battery chargers are qualified as isolation devices in accordance with IEEE 384 (Reference 7) and Regulatory Guide 1.75. Each battery charger has an input ac and output dc circuit breaker for the purpose of power source isolation and required protection. Each battery

charger prevents the ac supply from becoming a load on the battery due to a power feedback as a result of the loss of ac power to the chargers. Each battery charger has a built-in current limiting circuit, adjustable between 110 to 125 percent of its rating to hold down the output current in the event of a short circuit or overload on the dc side. The output of the charger is ungrounded and filtered. The output float and equalizing voltages are adjustable. The battery chargers have an equalizing timer and a manual bypass switch to permit periodic equalizing charges. Each charger is capable of providing the continuous demand on its associated dc system while providing sufficient power to charge a fully discharged battery (as indicated by the nominal load requirements in Tables 8.3.2-1 through 8.3.2-4) within a 24-hour period. The battery chargers are provided with a common failure/trouble alarm.

The Class 1E dc motor control centers operate at 250 Vdc nominal two wire, ungrounded system. The dc motor control centers provide branch circuit protection for the dc motor-operated valves. Motor-operated valves are protected by thermal overload devices in accordance with Regulatory Guide 1.106. Motor overload condition is annunciated in the main control room. The loads fed from the motor control centers are protected against a short-circuit fault by fusible disconnect switches.

The Class 1E dc distribution panels provide power distribution and tripping capability between the 250 Vdc power sources and the assigned safeguard loads indicated on Figure 8.3.2-1.

No site-specific non-Class 1E dc loads are connected to the Class 1E dc system.

8.3.2.1.1.2 Class 1E Uninterruptible Power Supplies

The Class 1E UPS provides power at 208 Y/120 Vac to four independent divisions of Class 1E instrument and control power buses. Divisions A and D each consist of one Class 1E inverter associated with an instrument and control distribution panel and a backup voltage regulating transformer with a distribution panel. The inverter is powered from the respective 24-hour battery bank switchboard. Divisions B and C each consist of two inverters, two instrument and control distribution panels, and a voltage regulating transformer with a distribution panel. One inverter is powered by the 24-hour battery bank switchboard and the other, by the 72-hour battery bank switchboard. For system configuration and equipment rating, see Figures 8.3.2-1 and 8.3.2-2. The nominal ratings of the Class 1E inverters and the voltage regulating transformers are listed in Table 8.3.2-5. Under normal operation, the Class 1E inverters receive power from the associated battery bank. If an inverter is inoperable or the Class 1E 250 Vdc input to the inverter is unavailable, the power is transferred automatically to the backup ac source by a static transfer switch featuring a make-before-break contact arrangement. The backup power is received from the diesel generator backed non-Class 1E 480 Vac bus through the Class 1E voltage regulating transformer. In addition, a manual mechanical bypass switch is provided to allow connection of backup power source when the inverter is removed from service for maintenance.

In order to supply power during the post-72-hour period following a design basis accident, provisions are made to connect a ancillary ac generator to the Class 1E voltage regulating transformers (divisions B and C only). This powers the Class 1E post-accident monitoring systems and the lighting in the main control room and ventilation in the MCR and divisions B and C I&C rooms. See Subsection 8.3.1.1.1 for post-72-hour power distribution details, Subsection 9.4.1 for post-72-hour ventilation, and Subsection 9.5.3 for post-72-hour lighting details respectively.

8.3.2.1.1.2 Non-Class 1E DC and UPS System

The non-Class 1E dc and UPS system consists of the electric power supply and distribution equipment that provide dc and uninterruptible ac power to the plant non-Class 1E dc and ac loads that are critical for plant operation and investment protection and to the hydrogen igniters located inside containment. The non-class 1E dc and UPS system is comprised of two subsystems

representing two separate power supply trains. The subsystems are located in separate rooms in the annex building. Figure 8.3.2-3, non-Class 1E dc and UPS system one line diagram represents the distribution configuration.

Each of the EDS1 and 3, and 2 and 4 subsystems consists of separate dc distribution buses. These two buses can be connected by a normally open circuit breaker to enhance the power supply source availability.

Each dc subsystem includes battery chargers, stationary batteries, dc distribution equipment, and associated monitoring and protection devices.

DC buses 1, 2, 3, and 4 (See Figure 8.3.2-3) provide 125 Vdc power to the associated inverter units that supply the ac power to the non-Class 1E uninterruptible power supply ac system. An alternate regulated ac power source for the UPS buses is supplied from the associated regulating transformers. DC bus 5 supplies large dc motors. This configuration isolates the large motors.

The onsite standby diesel generator backed 480 Vac distribution system provides the normal ac power to the battery chargers. Industry standard stationary batteries that are similar to the Class 1E design are provided to supply the dc power source in case the battery chargers fail to supply the dc distribution bus system loads. The batteries are sized to supply the system loads for a period of at least two hours after loss of all ac power sources. Hydrogen igniter power requirements as stated in Subsection 6.2.4.2.3 are provided through the use of appropriate load shedding.

The dc distribution switchboard houses the dc feeder protection device, dc bus ground fault detection, and appropriate metering. The component design and the current interrupting device selection follow the circuit coordination principles.

The non-Class 1E dc and UPS system is designed to meet the quality guidelines established by Generic Letter 85-06, "Quality Assurance Guidance for ATWS Equipment that is not Safety-Related."

An EDS spare battery bank (EDSS-DB-1A and EDSS-DB-1B) with spare battery chargers (EDSS-DC-1 and EDSS-DC-2), is provided for the non-Class1E dc and UPS system (Figure 8.3.2-3). This 125/250 Vdc EDS spare battery and the EDS buses are completely independent of and not connectable to the IDS buses. In the case of an EDS failure or unavailability of the normal battery bank and the battery charger, permanently installed cable connections allow the spare to be connected to the affected bus with kirk-key interlock switches. The kirk-key interlock switches permit connection of only one battery bank and battery charger at a time. The spare battery bank and the battery chargers can also be utilized as a substitute when offline testing, maintenance, and equalization of an operational battery bank is desired. A center tap bus arrangement consisting of a +125 Vdc bus, a 0 bus, and a -125 Vdc bus is used in the spare fused transfer switchbox (EDSS-DF-1) in order to obtain either 125 Vdc or 250 Vdc. Spare battery EDSS-DB-1A and spare battery charger EDSS-DC-1 are connected to the +125 Vdc bus and 0 bus, which feed EDS2 and EDS4. Spare battery EDSS-DB-1B and spare battery charger EDSS-DC-2 are connected to the 0 bus and -125 Vdc bus, which feed EDS1 and EDS3. EDS5 is connected to the +125 Vdc and -125 Vdc bus, which puts the two battery strings in series, providing 250 Vdc.

8.3.2.1.3 Separation and Ventilation

For the Class 1E dc system, the 24-hour and the 72-hour battery banks are housed in the auxiliary building in ventilated rooms apart from chargers and distribution equipment. The battery rooms are ventilated to limit hydrogen accumulation. Subsection 9.4.1 describes the ventilation system in the battery rooms. Each of the four divisions of dc systems are electrically isolated and physically separated to prevent an event from causing the loss of more than one division.

8.3.2.1.4 Maintenance and Testing

Components of the 125 Vdc and 250 Vdc systems undergo periodic maintenance tests to determine the condition of the system. Batteries are checked for electrolyte level, specific gravity, and cell voltage, and are visually inspected.

The surveillance testing of the Class 1E 250 Vdc system is performed as required by the Technical Specifications.

The inverter DC input protection will be set at least 10% higher than the battery charger trip setpoints to prevent the inverter tripping before the battery charger. The time delay for the inverter high dc input voltage trip will be set higher than the time delay for the battery charger to prevent the inverter tripping before the battery charger.

Procedures are established for inspection and maintenance of Class 1E and non-Class 1E batteries. Class 1E battery maintenance, testing, and replacement are performed in conformance with approved Technical Specifications. Batteries are inspected periodically to verify proper electrolyte levels, specific gravity, cell temperature and battery float voltage. Cells are inspected in conformance with IEEE 450 and vendor recommendations.

The clearing of ground faults on the Class 1E dc system is also addressed by procedure. The battery testing procedures are written in conformance with IEEE 450 and the Technical Specifications.

Procedures are established for periodic testing of the Class 1E battery chargers and Class 1E voltage regulating transformers in accordance with the manufacturer recommendations.

- Circuit breakers in the Class 1E battery chargers and Class 1E voltage regulating transformers that are credited for an isolation function are tested through the use of breaker test equipment. This verification confirms the ability of the circuit to perform the designed coordination and corresponding isolation function between Class 1E and non-Class 1E components. Circuit breaker testing is done as part of the Maintenance Rule program and testing frequency is determined by that program.

- Fuses / fuse holders that are included in the isolation circuit are visually inspected.

- Class 1E battery chargers are tested to verify current limiting characteristic utilizing manufacturer recommendation and industry practices. Testing frequency is in accordance with that of the associated battery.

8.3.2.2 Analysis

Compliance with General Design Criteria (GDC) and Regulatory Guides is discussed in Sections 3.1 and 1.9, respectively. Refer to Table 8.1-1 of Section 8.1 for guidelines and applicability of GDC, Regulatory Guides and IEEE Standards. A failure modes and effects analysis for the Class 1E dc and UPS system is provided in Table 8.3.2-7.

In the event of a loss of offsite power coincident with a main generator trip, ac power to the battery charger is provided from two separate non-Class 1E onsite standby diesel generators. Divisions A and C chargers receive their ac power from one diesel generator, ZOS MG 02A, and division B and D chargers from the second diesel generator, ZOS MG 02B. Provisions are also made to power the post accident monitoring systems and the main control room lighting loads in divisions B and C from ancillary ac generators during the post 72-hour period as described in Subsection 8.3.2.1.1.2.

The Class 1E battery chargers are designed to limit the input (ac) current to an acceptable value under faulted conditions on the output side, however, the voltage regulating transformers do not have active components to limit current; therefore, the Class 1E voltage regulating transformer maximum current is determined by the impedance of the transformer. They have built-in circuit breakers at the input and output sides for protection and isolation. The circuit breakers are coordinated and periodically tested to verify their current-limiting characteristics. They are qualified as isolation devices between Class 1E and non-Class 1E circuits in accordance with IEEE 384 and Regulatory Guide 1.75.

The four divisions are independent, located in separate rooms, cannot be interconnected, and their circuits are routed in dedicated, physically separated raceways. This level of electrical and physical separation prevents the failure or unavailability of a single battery, battery charger, or inverter from affecting adversely a redundant division.

The Class 1E dc and UPS system is designed in accordance with IEEE 308 (Reference 8) and IEEE 946 (Reference 9). Important system component failures are annunciated. The battery monitoring system detects battery open circuit condition and monitors battery voltage. The Class 1E 208Y/120Vac distribution panels are equipped with undervoltage protection. The set of fuses located in the 250 Vdc switchboards provide selective tripping of circuits for a fault to limit the effects of the abnormal condition, minimize system disturbance and protect the battery from complete accidental discharge through a short circuit fault. The Class 1E dc system is ungrounded, thus, a single ground fault does not cause immediate loss of the faulted system. Ground detections with alarms are provided for each division of power so that ground faults can be located and removed before a second ground fault could disable the affected circuit. A spare battery bank and charger enables testing, maintenance, and equalization of battery banks offline. This configuration provides the capability for each battery bank or battery charger to be separately tested and maintained (including battery discharge tests, battery cell replacement, battery charger replacement) without limiting continuous plant operation at 100-percent power. Substitution of the spare battery charger for a division 24-hour division battery charger sends two low Class 1E battery charger input voltage signals to the protection and safety monitoring system from the division removed from service if the division 24-hour division battery charger is disconnected from the normal power supply. The low Class 1E battery charger input voltage signal removes the automatic depressurization system and in-containment refueling water storage tank injection block in the affected division and generates a partial trip for other engineered safety features supported by the signal as described in Subsection 7.3.1.2.

Short circuit analyses will be performed in accordance with IEEE 946 (Reference 9) and/or other acceptable industry standards or practices to determine fault currents. Circuit interrupting device coordination analyses will be performed in accordance with IEEE 141, 242 (References 16 and 17), and/or other acceptable industry standards or practices.

8.3.2.3 Physical Identification of Safety-Related Equipment

Each safety-related circuit and the raceway that routes it is given a unique identification number to distinguish between circuits and raceways of different voltage level or separation groups. Each raceway is color coded with indelible ink, paint (consistent with the considerations identified in Subsection 6.1.2.1.1), or adhesive markers (adhesive markers are not used in the containment) at intervals of 15 feet or less along the length of the raceway and on both sides of floor or wall penetrations. Each cable is color coded at a maximum of 5 feet intervals along the length of the cable and cable markers showing the cable identification number are applied at each end of the cable.

The following color coding is used for identification purposes:

Separation Group	Color Code
A	Brown
B	Green
C	Blue
D	Yellow
S	Orange
N	Black

8.3.2.4 Independence of Redundant Systems

8.3.2.4.1 General

The routing of cable and the design of raceways prevents a single credible event from disabling a redundant safety-related plant function.

8.3.2.4.2 Raceway and Cable Routing

There are six separation groups for the cable and raceway system: group A, B, C, D, S, and N. Separation group A contains safety-related circuits from division A. Similarly, separation group B contains safety-related circuits from division B; group C from division C; group D from division D; group S from the spare separation group; and group N from nonsafety-related circuits.

Cables of one separation group are run in separate raceway and physically separated from cables of other separation groups. Group N raceways are separated from safety-related groups A, B, C and D. Separation between safety-related groups, and between safety-related groups and nonsafety-related cables, are routed according to spatial separation stipulated in Regulatory Guide 1.75 and IEEE 384 with the exceptions listed below.

Note: If not explicitly specified below, “enclosed raceway” and “enclosed configuration” refer to conduit, enclosed trays or transition boxes designed and used for supporting or enclosing wires, cables or busbars. “Open configuration” refers to free air cable and open cable trays. The exceptions are limited to low-voltage power system applications and below (instrumentation and control).

Non-hazard Area Exceptions

- The minimum vertical separation is 3 inches and the minimum horizontal separation is 1 inch between open to enclosed configurations for configurations involving low-voltage power cables.
- The minimum vertical separation is 1 inch and the minimum horizontal separation is 1 inch between open configurations, and between open to closed configurations, for configurations that involve exclusively limited energy content cables (instrumentation and control).
- For configurations involving low-voltage power cables within an enclosed raceway and an open raceway, the minimum vertical separation is 1 inch if the enclosed raceway is below the open raceway.

- Within panels and control switchboards, the minimum horizontal separation between components or cables of different separation groups (both field-routed and vendor-supplied internal wiring) is 1 inch, and the minimum vertical separation is 1 inch.

Limited Hazard Area Exceptions

- The minimum vertical separation is 1 inch and the minimum horizontal separation is 1 inch with configurations that involve exclusively limited energy content cables (instrumentation and control).

- The minimum vertical separation is 12 inches and the minimum horizontal separation is 6 inches with configurations that involve low-voltage power cables for cable sizes less than and equal to 2/0 AWG. The minimum vertical separation may be reduced to 3 inches for the configuration with a conduit above and crossing an open tray at an angle equal to or greater than 45 degrees.

- The minimum vertical separation is 12 inches and the minimum horizontal separation is 6 inches between a conduit and an open configuration for low-voltage power cables greater than 2/0 AWG but not greater than 750 kcmil. The vertical separation may be reduced to 3 inches if the conduit is above and crossing an open tray at an angle equal to or greater than 45 degrees.

- The minimum vertical separation is 1 inch if the enclosed raceway is below the open raceway for low-voltage power cables.

- The minimum vertical separation is 1 inch and the minimum horizontal separation is 1 inch for configurations with a non-safety conduit and a free air safety cable with low-voltage power cables and below.

- Within panels and control switchboards, the minimum horizontal separation between components or cables of different separation groups (both field-routed and vendor-supplied internal wiring) is 1 inch, and the minimum vertical separation is 1 inch.

Hazard Area Exceptions

- Within hazard areas, the minimum spatial separation between safety-related groups, and between safety-related groups and nonsafety-related cables is the same as the spatial separation applicable in limited hazard areas, unless otherwise specified by IEEE 384 for an external hazard.

The exceptions to the guidance in Regulatory Guide 1.75 are based on test results used to support exceptions to the separation guidance for operating nuclear power plants. A summary of test results from ten electrical separation test programs is documented in Reference 13. These test programs support the AP1000 exceptions.

In addition to the listed exceptions, other cable configurations with lesser separation distances than those specified in IEEE 384 Sections 6.1.3, 6.1.4, and 6.1.5 can be established by appropriate analysis of the proposed cable installation, per IEEE 384 Section 6.1.1.3. Additional exceptions where separation by analysis has been established are documented in Reference 202.

Fiber optic cables are not capable of generating a fire due to an internally generated fault. Therefore, they do not require separation from other fiber optic cables or from current carrying cables when the fiber optic cable is considered the source of a potential fire.

Non-Class 1E circuits are electrically isolated from Class 1E circuits, and Class 1E circuits from different separation groups are electrically isolated by isolation devices, shielding and wiring techniques, physical separation (in accordance with Regulatory Guide 1.75 for circuits in raceways), or an appropriate combination thereof.

When isolation devices are used to isolate Class 1E circuits from non-Class 1E circuits, the circuits within or from the Class 1E equipment or devices are identified as Class 1E and are treated as such. Beyond the isolation device(s) these circuits are identified as non-Class 1E and are separated from Class 1E circuits in accordance with the above separation criteria.

Power and control cables are installed in conduits, solid bottom trays, or ventilated bottom trays (ladder-type). Solid tray covers are used in outdoor locations and indoors where trays run in areas where falling debris is a problem. Instrumentation cables are routed in conduit or solid bottom cable tray with solid tray covers as required. The cables are derated for specific application in the location where they are installed as stated in Subsection 8.3.1.3.3. The environmental design of electrical equipment including Class 1E cables under normal and abnormal operating conditions is discussed in Section 3.11.

Separate trays are provided for each voltage service level: 6.9 kV, low voltage power (480 Vac, 208Y/120 Vac, 125 Vdc, 250 Vdc), high-level signal and control (120 Vac, 125 Vdc, 250 Vdc), and low level signal (instrumentation). A tray designed for a single class of cables shall contain only cables of the same class except that low voltage power cables may be routed in raceways with high level signal and control cables if their respective sizes do not differ greatly and if they have compatible operating temperatures. When this is done in trays, the power cable ampacity is calculated as if all cables in the tray are power cable. Low voltage power cable and high level signal and control cable will not be routed in common raceways if the fault current, within the breaker or fuse clearing time, is sufficient to heat the insulation to the ignition point. Vertically stacked trays are arranged from top to bottom as stated in Subsection 8.3.1.3.4. In general, a minimum of 12 inches vertical spacing is maintained between trays of different service levels within the stack.

The electrical penetrations are in accordance with IEEE 317 (Reference 2). Class 1E and non-Class 1E electrical penetration assemblies are maintained in a separate nozzle. The physical separation of the Class 1E electrical penetration assemblies are in accordance with Regulatory Guide 1.75. The containment building penetrations are described in Subsection 8.3.1.1.6.

A raceway system is the complete assembly of raceways (e.g., conduit, cable tray, or wireway) and raceway supports. Raceways installed in seismic Category I structures have seismically designed supports or are shown not to affect safety-related equipment should they fail. Trays are not attached rigidly to seismic Category I equipment. Conduits may be attached to seismic Category I equipment with flexible type connections.

8.3.2.4.3 Hazard Protection

See Subsection 8.3.2.4.2 for separation requirements in hazard areas.

Where hazards to safety-related raceway systems are identified, a predetermined minimum separation is maintained between the break and/or missile source and any safety-related raceway systems, or a barrier designed to withstand the effects of the hazard is placed to prevent damage to raceway of redundant systems. For details of missile protection and high-energy line break protection, see Sections 3.5 and 3.6, respectively.

Where redundant circuits, devices, or equipment (different separation groups) are exposed to the same external hazard(s), predetermined spatial separation is provided. Where the spatial separation cannot be met, qualified barriers are installed. For details on fire protection, see Subsection 9.5.1.

See Section 3.4 for protection of raceways and the associated equipment against flooding.

8.3.2.4.4 Control of Compliance with Separation Criteria during Design and Installation

The separation group identification described in Subsection 8.3.2.3 provides for the maintenance of separation in the routing of cables and the connection of control boards and panels. The separation group designation on the cable or raceway is assigned to maintain compatibility with a single line diagram channel designation and other cables or raceways routed. The routing is verified during installation. Color identification of equipment and cabling (discussed in Subsection 8.3.2.3) assist field personnel in this effort.

8.3.2.5 Inspection and Testing

Preoperational tests are conducted to verify proper operation of the dc power systems. The preoperational tests include MOV terminal voltage testing and capacity testing of the batteries, chargers, inverters, and regulating transformers.

8.3.2.5.1 Class 1E 24-Hour Battery Capacity Testing

Each Class 1E 24-hour battery is tested to verify the capability to provide its load for 24 hours while maintaining the battery terminal voltage above the minimum voltage specified in Table 8.3.2-5. Analysis will be performed based on the design duty cycle, and testing will be performed with loads which envelope the analyzed battery bank design duty cycle. Each battery is connected to a charger maintained at 270±2 V for a period of at least 24 hours prior to the test to assure the battery is fully charged.

8.3.2.5.2 Class 1E 72-Hour Battery Capacity Testing

Each Class 1E 72-hour battery is tested to verify the capability to provide its load for 72 hours while maintaining the battery terminal voltage above the minimum voltage specified in Table 8.3.2-5. Analysis will be performed based on the design duty cycle, and testing will be performed with loads which envelope the analyzed battery bank design duty cycle. Each battery is connected to a charger maintained at 270±2 V for a period of at least 24 hours prior to the test to assure the battery is fully charged.

8.3.2.5.3 Class 1E Spare Battery Capacity Testing

The Class 1E spare battery is tested to the same requirements as the most severe of the six division batteries.

8.3.2.5.4 Class 1E 24-Hour Inverter Capacity Testing

Each Class 1E 24-hour inverter is tested to verify the capability to provide 12 kW while maintaining the output voltage and frequency within the tolerances specified in Table 8.3.2-5. The 12 kW capacity is sufficient to meet the 24-hour inverter loads listed in Tables 8.3.2-1, 8.3.2-2, 8.3.2-3, and 8.3.2-4. The inverter input voltage will be no more than 210 Vdc during the test to represent the conditions at the battery end of life.

8.3.2.5.5 Class 1E 72-Hour Inverter Capacity Testing

Each Class 1E 72-hour inverter is tested to verify the capability to provide 7 kW while maintaining the output voltage and frequency within the tolerances specified in Table 8.3.2-5. The 7 kW capacity is sufficient to meet the 72-hour inverter loads listed in Tables 8.3.2-2 and 8.3.2-3. The inverter input

voltage will be no more than 210 Vdc during the test to represent the conditions at the battery end of life.

8.3.2.5.6 Class 1E 24-Hour Charger Capacity Testing

Each Class 1E 24-hour charger is tested to verify the capability to provide 150 A while maintaining the output voltage within the range specified in Table 8.3.2-5. The 150 A is sufficient to meet the 24-hour loads listed in Tables 8.3.2-1, 8.3.2-2, 8.3.2-3, and 8.3.2-4 while maintaining the corresponding battery charged.

8.3.2.5.7 Class 1E 72-Hour Charger Capacity Testing

Each Class 1E 72-hour charger is tested to verify the capability to provide 125 A while maintaining the output voltage within the range specified in Table 8.3.2-5. The 125 A is sufficient to meet the 72-hour loads listed in Tables 8.3.2-2 and 8.3.2-3 while maintaining the corresponding battery charged.

8.3.2.5.8 Class 1E Regulating Transformer Capacity Testing

Each Class 1E regulating transformer is tested to verify the capability to provide 30 kW while maintaining the output voltage within the tolerance specified in Table 8.3.2-5. The 30 kW capacity is sufficient to meet the inverter loads listed in Tables 8.3.2-1, 8.3.2-2, 8.3.2-3 and 8.3.2-4.

8.3.2.5.9 Class 1E Motor-Operated Valves Terminal Voltage Testing

As-built testing and analysis representing design conditions are used to verify that a voltage is provided from the IDS batteries to the Class 1E motor-operated valve motor terminals that is greater than or equal to the minimum design voltage necessary for the valves to operate. Class 1E motor-operated valves are tested by measuring the voltage during motor starting at both the IDS battery and motor-operated valve motor terminals while each motor-operated valve is stroked. The results are compared in a voltage analysis which verifies that the voltage at the motor-operated valve motor terminals is greater than or equal to the minimum design voltage of each motor-operated valve with an IDS battery terminal voltage of 210 Vdc.

8.3.2.5.10 Non-Class 1E Battery Capacity Testing

Each load group 1, 2, 3, and 4 non-Class 1E battery is tested to verify the capability to provide 850 A for two hours while maintaining the battery terminal voltage above the minimum voltage specified in Table 8.3.2-6. The 850 A is sufficient to meet the loads described in Subsection 8.3.2.1.2. Each battery is connected to a charger maintained at 135±1 V for a period of at least 24 hours prior to the test to assure the battery is fully charged.

8.3.2.5.11 Non-Class 1E Inverter Capacity Testing

Each load group 1, 2, 3, and 4 non-Class 1E inverter is tested to verify the capability to provide 55 kW while maintaining the output voltage and frequency within the tolerances specified in Table 8.3.2-6. The 55 kW capacity is sufficient to meet the loads described in Subsection 8.3.2.1.2.

8.3.2.5.12 Non-Class 1E Charger Capacity Testing

Each load group 1, 2, 3, and 4 non-Class 1E charger is tested to verify the capability to provide 900 A while maintaining the output voltage within the range specified in Table 8.3.2-6. The 900 A is sufficient to meet the loads described in Subsection 8.3.2.1.2 while maintaining the corresponding battery charged.

8.3.3 Combined License Information for Onsite Electrical Power

The design of grounding and lightning protection is addressed in Subsections 8.3.1.1.7 and 8.3.1.1.8.

The plant procedures for the following are addressed in Subsections 8.3.1.1.2.4, 8.3.1.1.6 and 8.3.2.1.4.

- Clearing ground fault on the Class 1E dc system
- Checking sulfated battery plates or other anomalous conditions through periodic inspections
- Battery maintenance and surveillance (for battery surveillance requirements, refer to the Technical Specifications, Section 3.8)
- Periodic testing of penetration protective devices
- Diesel generator operation, inspection, and maintenance in accordance with manufacturers' recommendations.
- Periodic testing on the battery chargers and voltage regulating transformers.

8.3.4 References

1. NEMA MG-1, "Motors and Generators," 1998.

2. IEEE Standard 317, "Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations," 1983.

3. IEEE Standard 422, "Guide for the Design and Installation of Cable Systems in Power Generating Stations," 1986.

4. ICEA Standard Publication P-54-440, "Ampacities of Cables in Open-Top Cable Trays," 1986.

5. NFPA 70, "National Electrical Code (NEC)," 1999.

6. IEEE Standard 485, "IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications," 1997.

7. IEEE Standard 384, "IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits," 1981.

8. IEEE Standard 308, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations," 1991.

9. IEEE Standard 946, "IEEE Recommended Practice for the Design of dc Auxiliary Power Systems for Generating Stations," 1992.

10. IEEE Standard 741, "IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations," 1997.

11. IPCEA Standard Publication P-46-426-1962, "Power Cable Ampacities, Volume I - Copper Conductors."

12. IEEE Standard 450, "IEEE Recommended Practice for Maintenance, Testing and Replacement of Vented Lead-Acid Batteries for Stationary Applications," 1995.

13. DeYoung, G. L. et al., "Cable Separation - What Do Industry Programs Show?," IEEE Transactions of Energy Conversion, September 1990, Volume 5, Number 3, pp 585-602.

14. Not used.

15. NUREG/CR-0660, "Enhancement of On-Site Emergency Diesel Generator Reliability," February 1979.

16. IEEE Standard 141, "IEEE Recommended Practice for Electric Power Distribution for Industrial Plants" (IEEE Red Book), 1993.

17. IEEE Standard 242, "IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems" (IEEE Buff Book), 1986.

18. IEEE Standard 665, "IEEE Guide for Generating Station Grounding," 1995.

19. NFPA 780, "Standard for the Installation of Lightning Protection Systems," 2000.

20. IEEE Standard 1050, "IEEE Guide for Instrumentation and Control Equipment Grounding in Generating Stations," 1996

201. Institute of Electrical and Electronics Engineers (IEEE), “IEEE Guide for Safety in AC Substation Grounding,” IEEE Std 80-2000, August 4, 2000.

202. APP-GW-EOR-006, "IEEE 384 Design Compliance Description."

Table 8.3.1-1 (Sheet 1 of 5)
Onsite Standby Diesel Generator ZOS MG 02A Nominal Loads

Automatic Loads (Notes 1 and 2)					
Item No.	Time Seq. (sec) (Note 3)	Event or Load Description	Rating (hp/kW)	Operating Load (kW) (Note 4)	
				At Power (Note 10)	Shutdown (Note 10)
1.	0	D/G Start Signal is Initiated	-	-	-
2.		Not used.	-	-	-
3.		Not used.	-	-	-
4.	120	D/G Breaker Closes, Load Sequencer Starts (Note 6)	-	-	-
5.	120	Load Center Transformer EK11 (Note 7)	2500 kVA	7.5	7.5
6.	120	Load Center Transformer EK12 (Note 7)	2500 kVA	7.5	7.5
7.	120	Load Center Transformer EK14 (Note 7)	2500 kVA	7.5	7.5
8.	120	Annex Bldg Lighting Panels (Note 8)	120 kVA	22	22
9.	120	Aux Bldg Lighting Panels (Note 8)	270 kVA	23	23
10.	120	Turbine Bldg Lighting Panels (Note 8)	120 kVA	30.5	30.5
11.	120	D/G Bldg Lighting Panel (Note 8)	30 kVA	8	8
12.	120	D/G 2A AC/OC Radiator Fan	30 hp	25	25
13.	120	Diesel Oil Transfer Module Unit Heater A	4 kW	4	4

Table 8.3.1-1 (Sheet 2 of 5)
Onsite Standby Diesel Generator ZOS MG 02A Nominal Loads

Automatic Loads (Notes 1 and 2)					
Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW) (Note 4)	
				At Power (Note 10)	Shutdown (Note 10)
14.	120	Diesel Oil Transfer Module Exhaust Fan A	0.5 hp	0.5	0.5
15.	120	D/G A Jacket Water Radiator Fans	60 hp	50	50
16.	120	Class 1E Div. A Regulating XFMR 1	45 kVA	0	0
17.	120	Class 1E Div. C Regulating XFMR 1	45 kVA	4	4
18.	120	Class 1E Div. A Battery Charger 1	81.8 kVA	6.5	6.5
19.	120	Class 1E Div. C Battery Charger 1	81.8 kVA	4	4
20.	120	Class 1D Div. C Battery Charger 2	81.8 kVA	4.5	4.5
21.	120	Motor-Operated Valves (Note 5)	-	-	-
22.	120	D/G A Fuel Oil Transfer Pump	5 hp	4	4
23.	120	D/G A Bldg Stdby Exhaust Fan 1A	7.5 hp	5.6	5.6
24.	120	D/G A Bldg Stdby Exhaust Fan 2A	7.5 hp	5.6	5.6
25.	120	D/G A Bldg Primary AHU MS 01A Fan	5 hp	4	4
26.	120	D/G A Fuel Oil Cooler Fan	7.5 hp	6.2	6.2
27.	120	D/G Bldg Engine AHU MS 03A Fan	15 hp	11.2	11.2
28.	120	Load Center Transformer EK13 (Note 7)	2500 kVA	7.5	7.5
29.	120	ECS Panel Transformers	330 kVA	50	50
30.	120	D/G A Lube Oil Cooling Motor - Front	0.5 hp	0.5	0.5
31.	120	D/G A Lube Oil Cooling Motor - Rear	0.5 hp	0.5	0.5
32.	120	D/G A Transformer	45 kVA	2	2
33.	120	Air Cooled Chiller #2 Piping Heat Trace	0.5 kW	0.5	0.5
34.	120	Air Cooled Chiller #2 Control and Heat Trace (Notes 11 and 14)	6 kW	6	6
35.	140	Start-up Feed Water Pump A	800 hp	665	0
36.	160	Fuel Oil Day Tank Vault Exhaust Fan A	1 hp	0.8	0.8
37.	160	Diesel Fuel Oil Transfer Heater A	90 kW	90	90
38.	160	Service Water Pump A	500 hp	350	350
39.	180	Service Water Cooling Tower Cell Fan A	200 hp	122	122
40.	200	Component Cooling Water Pump A	800 hp	580	580

Table 8.3.1-1 (Sheet 3 of 5)
Onsite Standby Diesel Generator ZOS MG 02A Nominal Loads

Automatic Loads (Notes 1 and 2)					
Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW) (Note 4)	
				At Power (Note 10)	Shutdown (Note 10)
41.	240	Normal Residual Heat Removal Pump A	250 hp	0	207
42.	240	RNS Pump Room Fan A	1.5 hp	0	1.5
43.	240	Annex Bldg Equipment Room Return/Exhaust Fan A (Note 12)	15 hp	12.4	12.4
44.	240	Annex Bldg Equipment Room AHU MS02A Supply Fan (Note 12)	30 hp	25.0	25.0
45.	240	Annex Bldg Swgr Rm AHU MS 05A Supply Fan (Note 12)	25 hp	21.0	21.0
46.	240	Annex Bldg Swgr Rm Ret/Exhaust Fan 06A (Note 12)	15 hp	12.4	12.4
47.	240	Instrument Air Compressor A (Note 15)	250 hp	185	185
48.	240	Instrument Air Dryer Package A	0.008 kW	0.008	0.008
49.	300	Non-1E Battery Charger EDS1-DC-1	204.4 kVA	72	72
50.	300	Non 1E Battery Room A Exhaust Fan	1 hp	0.8	0.8
51.	300	Day Tank Heater Pad A	4 kW	4	4
52.	300	Containment Recirculation Fan A	200 hp	149	149
53.	360	Containment Recirculation Fan D	200 hp	149	149
54.	360	Non-1E Battery Charger EDS3-DC-1	204.4 kVA	60	60
		Total Automatically Sequenced Loads (kW)		**2806.5**	**2350**

Table 8.3.1-1 (Sheet 4 of 5)
Onsite Standby Diesel Generator ZOS MG 02A Nominal Loads

Manual Loads (Notes 1 and 2)				
Item No.	**Time Seq. (sec)**	**Event or Load Description**	**Rating (hp/kW)**	**Operating Load (kW)**
55.	--	Supplemental Air Filtration System Fan A	15 hp	12.4
56.	--	Supplemental Air Filtration System Electric Heater A	20 kW	20
57.	--	Backup Group 4A Pressurizer Heaters	246 kW	246
58.	--	CRDM Fan 01A	75 hp	62
59.	--	CRDM Fan 01B	75 hp	62
60.	--	Spent Fuel Cooling Pump A	150 hp	124
61.	--	CVS Make-Up Pump A	600 hp	498
62.	--	Non-1E Regulating XFMR EDS1-DT-1	100 kVA	17
63.	--	Non-1E Regulating XFMR EDS3-DT-1	100 kVA	17
64.	--	Main Control Room AHU Supply Fan A (Note 11)	40 hp	34
65.	--	Main Control Room AHU Return Fan A (Note 11)	20 hp	17
66.	--	Div A/C Class 1E Electrical Room AHU Supply Fan A (Note 11)	40 hp	34
67.	--	Div A/C Class 1E Electrical Room Return Fan A (Note 11)	25 hp	21
68.	--	Div. A/C Class 1E Battery Room Exhaust Fan A	1.5 hp	1.2
69.	--	So. Bay Eq. Area AHU MS03A Supply Fan	40 hp	33

Table 8.3.1-1 (Sheet 5 of 5)
Onsite Standby Diesel Generator ZOS MG 02A Nominal Loads

Manual Loads (Notes 1 and 2)				
Item No.	**Time Seq. (sec)**	**Event or Load Description**	**Rating (hp/kW)**	**Operating Load (kW)**
70.	--	Div B/D Class 1E Electrical Room AHU Supply Fan D (Note 11)	20 hp	17
71.	--	Div B/D Class 1E Electrical Room Return Fan D (Note 11)	10 hp	8
72.	--	Div. B/D Class 1E Battery Room Exhaust Fan D	1.5 hp	1.2
73.	--	Air Cooled Chiller Pump 2 (Note 11)	20 hp	17
74.	--	Air Cooled Chiller 2 (Notes 11 and 14)	444 kW	444
75.	--	CVS Pump Room Fan A (Note 11)	1.5 hp	1.5
		Total Manually Sequenced Loads (kW)		**1687.3**

Notes:

1. Loads listed are for diesel generator ZOS MG 02A.
2. Loads identified in the first portion of the table (AUTOMATIC LOADS) will be loaded without operator action. Loads identified in the second portion of the table (MANUAL LOADS) will be energized at operator discretion based on system needs. Automatic loads may not be started until there is a system need. Not all manually sequenced loads will be operated simultaneously.
3. Time Sequence is counted from the time a diesel generator receives the start signal and represents the end of the previous load block interval and the beginning of the following load block interval.
4. The "Operating Load" column shows the load input power requirement from the diesel generator.
5. Motor-operated valves (MOVs) pertaining to various systems will be energized in the first load block interval. Normally the MOV power requirement is for a very short duration (a few seconds); hence, the MOV load will not affect the diesel generator capacity rating.
6. On receipt of the diesel generator start signal, the engine accelerates to a set idle speed. The engine operates at the idle speed for a time to allow bearing oil pressure buildup, proper lubrication of the moving parts, and engine warmup. The engine ramps up to the rated operating speed and is ready to accept electrical loads within 120 seconds.
7. On restoring the power supply to the diesel backed bus ES1 by closing the diesel generator incoming breaker, the associated unit substation ECS EK 11, 12, 13, and 14 load center transformers are energized in the first load block interval. The transformers draw magnetizing current and the no load losses (approx. 0.3 percent of the rating) from the bus.
8. Only a part of the building lighting load is automatically connected to the diesel generator bus. The remaining lighting load is connected via manual action at the operator's discretion.
9. Not used.
10. The ‘At Power’ loads are those loads that would be automatically sequenced on the diesel generator following a loss of offsite power and reactor trip from power; i.e., reactor coolant pressure above the residual heat removal system operating pressure. The ‘Shutdown’ loads are those loads that would be automatically sequenced on the diesel generator following a loss of offsite power during a plant shutdown; i.e., reactor coolant pressure below the residual heat removal system operating pressure and the RNS isolation valves open.
11. Air cooled chiller VWS MS 03 is automatically loaded on diesel generator ZOS MG 02B along with the VAS and VBS fans associated with the cooling coils served by this chiller. The redundant air cooled chiller VWS MS 02 and its associated VAS and VBS fans can be manually loaded on diesel generator ZOS MG 02A in case of failures of VWS MS 03 or ZOS MG 02B.
12. Annex building ventilation fans are automatically loaded on diesel generator ZOS MG 02A. The redundant fans can be manually loaded on diesel generator ZOS MG 02B in case of diesel generator or fan failures.
13. Not used.
14. To support operation of Air Cooled Chiller VWS-MS-02 at very cold conditions, the breaker to the package is loaded automatically in order to energize the skid mounted heat tracing and motor-heaters for the package.The chiller compressor will not be started. Start of the chiller compressor is a manual operator action. The skid control power and heat trace load for the chiller is 6 kW and is included in the Auto Load section of the table and is thus subtracted from the 450 kW total chiller load in the Manual Load section of the table.
15. Feeder breaker for instrument air compressor package to be closed in the first load block interval and PLS enable/disable command used to delay actual start of compressor to a later load block interval to allow instrument air compressor package programmable logic controller (PLC) time to initialize.

Table 8.3.1-2 (Sheet 1 of 5)
Onsite Standby Diesel Generator ZOS MG 02B Nominal Loads

Automatic Loads (Notes 1 and 2)					
Item No.	Time Seq. (sec) (Note 3)	Event or Load Description	Rating (hp/kW)	Operating Load (kW)	
				At Power (Note 10)	Shutdown (Note 10)
1.	0	D/G Start Signal is Initiated	-	-	-
2.		Not used.	-	-	-
3.		Not used.	-	-	-
4.	120	D/G Breaker Closes, Load Sequencer Starts (Note 6)	-	-	-
5.	120	Load Center Transformer EK21 (Note 7)	2500 kVA	7.5	7.5
6.	120	Load Center Transformer EK22 (Note 7)	2500 kVA	7.5	7.5
7.	120	Load Center Transformer EK24 (Note 7)	2500 kVA	7.5	7.5
8.	120	Annex Bldg Lighting Panels (Note 8)	120 kVA	33	33
9.	120	Radwaste Bldg Lighting Panel (Note 8)	30 kVA	8.5	8.5
10.	120	Aux Bldg Lighting Panels (Note 8)	270 kVA	20.5	20.5
11.	120	Turbine Bldg Lighting Panels (Note 8)	120 kVA	27	27
12.	120	D/G Bldg Lighting Panel (Note 8)	30 kVA	8	8
13.	120	D/G 2B AC/OC Radiator Fan	30 hp	25	25
14.	120	Diesel Oil Transfer Module Unit Heater B	4 kW	4	4
15.	120	Diesel Oil Transfer Module Exhaust Fan B	0.5 hp	0.5	0.5
16.	120	D/G B Jacket Water Radiator Fans	60 hp	50	50

Table 8.3.1-2 (Sheet 2 of 5)
Onsite Standby Diesel Generator ZOS MG 02B Nominal Loads

Automatic Loads (Notes 1 and 2)					
Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW)	
				At Power (Note 10)	Shutdown (Note 10)
17.	120	Class 1E Div. B Regulating XFMR 1	45 kVA	4	4
18.	120	Class 1E Div. D Regulating XFMR 1	45 kVA	0	0
19.	120	Class 1E Div. B Battery Charger 1	81.8 kVA	7.3	7.3
20.	120	Class 1E Div. B Battery Charger 2	81.8 kVA	4.5	4.5
21.	120	Class 1E Div. D Battery Charger 1	81.8 kVA	8.2	8.2
22.	120	Motor-Operated Valves (Note 5)	-	-	-
23.	120	D/G B Fuel Oil Transfer Pump	5 hp	4	4
24.	120	D/G B Bldg Stdby Exhaust Fan 1B	7.5 hp	5.6	5.6
25.	120	D/G B Bldg Stdby Exhaust Fan 2B	7.5 hp	5.6	5.6
26.	120	D/G B Bldg. Primary AHU MS 01B Fan	5 hp	4	4
27.	120	D/G B Fuel Oil Cooler Fan	7.5 hp	6.2	6.2
28.	120	D/G Bldg Engine AHU MS 03B Fan	15 hp	11.2	11.2
29.	120	Load Center Transformer EK23 (Note 7)	2500 kVA	7.5	7.5
30.	120	ECS Panel Transformers	420 kVA	60	60
31.	120	D/G B Lube Oil Cooling Motor - Front	0.5 hp	0.5	0.5
32.	120	D/G B Lube Oil Cooling Motor - Rear	0.5 hp	0.5	0.5
33.	120	D/G B Transformer	45 kVA	2	2
34.	120	Air Cooled Chiller #3 Piping Heat Trace	0.5 kW	0.5	0.5
35.	120	Unit 4 only - Air Cooled Chiller 3 Control and Heat Trace (Note 15)	6 kW	6	6
36.	140	Start-up Feed Water Pump B	800 hp	665	0
37.	160	Fuel Oil Day Tank Vault Exhaust Fan B	1 hp	0.8	0.8
38.	160	Diesel Fuel Oil Transfer Heater B	90 kW	90	90
39.	160	Service Water Pump B	500 hp	350	350
40.	180	Service Water Cooling Tower Cell Fan B	200 hp	122	122
41.	180	Main Control Room AHU Supply Fan B	40 hp	34	34
42.	180	Main Control Room AHU Return Fan B	20 hp	17	17
43.	180	Div. B/D Class 1E Electrical Room AHU Supply Fan B	20 hp	17	17

Table 8.3.1-2 (Sheet 3 of 5)
Onsite Standby Diesel Generator ZOS MG 02B Nominal Loads

Automatic Loads (Notes 1 and 2)					
Item No.	Time Seq. (sec)	Event or Load Description	Rating (hp/kW)	Operating Load (kW)	
				At Power (Note 10)	Shutdown (Note 10)
44.	180	Div B/D Class 1E Electrical Room Return Fan B	10 hp	8	8
45.	180	Div A/C Class 1E Electrical Room AHU Supply Fan C	40 hp	34	34
46.	180	Div A/C Class 1E Electrical Room Return Fan C	25 hp	21	21
47.	180	Air Cooled Chiller Pump 3	20 hp	17	17
48.	200	Component Cooling Water Pump B	800 hp	580	580
49.	220	Unit 3 only - Air Cooled Chiller 3 (Note 15)	450 kW	450	450
50.	220	Unit 4 only - Air Cooled Chiller 3 (Note 15)	444 kW	444	444
51.	240	CVS Pump Room Fan B	1.5 hp	1.5	1.5
52.	240	Instrument Air Compressor B (Note 14)	250 hp	185	185
53.	240	Instrument Air Dryer Package B	0.008 kW	0.008	0.008
54.	300	Normal Residual Heat Removal Pump B	250 hp	0	207
55.	300	RNS Pump Room Fan B	1.5 hp	0	1.5
56.	300	Non-1E Battery Charger EDS2-DC-1	204.4 kVA	80	80
57.	300	Non-1E Battery Room B Exhaust Fan 09B	1 hp	0.8	0.8
58.	300	Day Tank Heater Pad B	4 kW	4	4
59.	360	Containment Recirculation Fan B	200 hp	149	149
60.	360	Containment Recirculation Fan C	200 hp	149	149
61.	360	Non-1E Battery Charger EDS4-DC-1	204.4 kVA	50	50
62.	420	Div. B/D Class 1E Battery Room Exhaust Fan B	1.5 hp	1.5	1.5
63.	420	Div. A/C Class 1E Battery Room Exhaust Fan C	1.5 hp	1.4	1.4
		Total Automatically Sequenced Loads (kW)		**3358.6**	**2902.1**

Table 8.3.1-2 (Sheet 4 of 5)
Onsite Standby Diesel Generator ZOS MG 02B Nominal Loads

Manual Loads (Notes 1 and 2)				
Item No.	**Time Seq. (sec)**	**Event or Load Description**	**Rating (hp/kW)**	**Operating Load (kW)**
64.	--	Supplemental Air Filtration System Fan B	15 hp	12.4
65.	--	Supplemental Air Filtration System Electric Heater B	20 kW	20
66.	--	Backup Group 4B Pressurizer Heaters	246 kW	246
67.	--	CRDM Fan 01C	75 hp	62
68.	--	CRDM Fan 01D	75 hp	62
69.	--	Spent Fuel Cooling Pump B	150 hp	124
70.	--	CVS Make-Up Pump B	600 hp	498
71.	--	Non-1E Regulating XFMR EDS2-DT-1	100 kVA	17
72.	–	Non-1E Regulating XFMR EDS4-DT-1	100 kVA	17
73.	--	Annex Bldg Equipment Room Return/Exhaust Fan B	15 hp	12.4
74.	--	Annex Bldg Equipment Room AHU MS02B Supply Fan	30 hp	25.0
75.	--	Annex Bldg Swgr Rm AHU MS 05B Supply Fan	25 hp	21.0
76.	--	Annex Bldg Swgr Rm Ret/Exhaust Fan 06B	15 hp	12.4
77.	--	So. Bay Eq. Area AHU MS03B Supply Fan	40 hp	33
		Total Manually Sequenced Loads (kW)		**1162.2**

Table 8.3.1-2 (Sheet 5 of 5)
Onsite Standby Diesel Generator ZOS MG 02B Nominal Loads

Notes:

1. Loads listed are for diesel generator ZOS MG02B.
2. Loads identified in the first portion of the table (AUTOMATIC LOADS) will be loaded without operator action. Loads identified in the second portion of the table (MANUAL LOADS) will be energized at operator discretion based on system needs. Automatic loads may not be started until there is a system need. Not all manually sequenced loads will be operated simultaneously.
3. Time Sequence is counted from the time a diesel generator receives the start signal and represents the end of the previous load block interval and the beginning of the following load block interval.
4. The "Operating Load" column shows the load input power requirement from diesel generator.
5. Motor-operated valves (MOVs) pertaining to various systems will be energized in the first load block interval. Normally the MOV power requirement is for a very short duration (few seconds); hence the MOV load will not affect the diesel generator capacity rating.
6. On receipt of the diesel generator start signal, the engine accelerates to a set idle speed. Engine operates at the idle speed for a time period to allow bearing oil pressure build up, proper lubrication of the moving parts, and engine warmup. The engine ramps up to the rated operating speed and is ready to accept electrical loads within 120 seconds.
7. On restoring the power supply to the diesel backed bus ES2 by closing diesel generator incoming breaker, the associated unit substation ECS EK 21, 22, 23, and 24 load center transformers are energized in the first load block interval. The transformers draw magnetizing current and the no load losses (approx. 0.3 percent of the rating) from the bus.
8. Only a part of the building lighting load is automatically connected to the diesel generator bus. The remaining lighting load is connected via manual action at the operator's discretion.
9. Not used.
10. The ‘At Power’ loads are those loads that would be automatically sequenced on the diesel generator following a loss of offsite power and reactor trip from power; i.e., reactor coolant pressure above the residual heat removal system operating pressure. The ‘Shutdown’ loads are those loads that would be automatically sequenced on the diesel generator following a loss of offsite power during a plant shutdown; i.e., reactor coolant pressure below the residual heat removal system operating pressure and the RNS isolation valves open.
11. Air cooled chiller VWS MS 03 is automatically loaded on diesel generator ZOS MG 02B along with the VAS and VBS fans associated with the cooling coils served by this chiller. The redundant air cooled chiller VWS MS 02 and its associated VAS and VBS fans can be manually loaded on diesel generator ZOS MG 02A in case of failures of VWS MS 03 or ZOS MG 02B.
12. Annex building ventilation fans are automatically loaded on diesel generator ZOS MG 02A. The redundant fans can be manually loaded on diesel generator ZOS MG 02B in case of diesel generator or fan failures.
13. Not used.
14. Feeder breaker for instrument air compressor package to be closed in the first load block interval and PLS enable/disable command used to delay actual start of compressor to a later load block interval to allow instrument air compressor package programmable logic controller (PLC) time to initialize.
15. Unit 4 only. To support operation of Air Cooled Chiller VWS-MS-03 at very cold conditions, the breaker to the package is closed automatically at Load Step 0 in order to energize the skid mounted heat tracing and motor-heaters for the package. The chiller compressor is not started until Load Step 5.

Table 8.3.1-3
Component Data - Main AC Power System
(Nominal Values)

1.	**Main Stepup Transformer**	
		3 single phase, FOA, 65°C rise, liquid filled
2.	**Unit Auxiliary Transformers (UAT 2A/2B)**	
		3 phase, 3 winding H = 76 MVA, OA, 65°C X = 38 MVA, OA, 65°C Y = 38 MVA, OA, 65°C
	Unit Auxiliary Transformer (UAT 2C)	
		3 phase, 2 winding 33 MVA, OA, 65°C
	Reserve Auxiliary Transformers (RAT)	
		3 phase, 3 winding H = 76 MVA, OA, 65°C X = 38 MVA, OA, 65°C Y = 38 MVA, OA, 65°C
3.	**6.9 kV Switchgear**	
		medium voltage metal-clad switchgear Interrupting current rating – 63kA vacuum-type circuit breaker
4.	**480 V Load Centers**	
	Transformers - Indoor, Air-Cooled Ventilated Dry-Type, Fire Retardant:	2500 kVA, AA 3 phase, 60 Hz 6900 - 480 V
		3000/4000 kVA, AA/FA (Load Centers 31 and 41) 3 phase, 60 Hz 6900 - 480 V
		1500 kVA, AA (Load Center 71) 3 phase, 60 Hz 6900 - 480 V
	Main Bus Ampacity	4000 amperes continuous
		5000 amperes continuous (Load Centers 31 and 41)
		3200 amperes continuous (Load Center 71)
	480V Breakers	metal enclosed draw-out circuit breaker or motor-starter (contactor) 65,000 A RMS symmetrical interrupting rating
5.	**480 V Motor Control Centers**	
	Horizontal Bus	800 A and 1200 A continuous rating 65,000 A RMS symmetrical bracing
	Vertical Bus	300 A continuous rating
		65,000 A RMS symmetrical bracing
	Breakers (molded case)	65,000 A RMS symmetrical interrupting rating

Table 8.3.1-4
Post-72 Hours Nominal Load Requirements

Item No.	Description of Loads	Ancillary AC Generator 1	Ancillary AC Generator 2
		Load (kW)	Load (kW)
1.	Post-Accident Monitoring (PAM) Emergency and Panel Lighting (Division B) in Main Control Room and ancillary fans		6.5
2.	Post-Accident Monitoring (PAM) Emergency and Panel Lighting (Division C) in Main Control Room and ancillary fans	6.5	
3[(a)]	PCS Recirculation Pumps	23.6	23.6
4.	Ancillary Generator Room Lights	0.5	0.5
5.	Ancillary Generator Fuel Tank Heater	1.5 kW	1.5 kW
	Total	32.1 kW	32.1 kW

Note:

a. There are two PCS pumps; however, only one pump will be operating at any point in time on each generator. In case of fire fighting, two pumps (one on each generator) may be used.

Table 8.3.1-5
Indication and Alarm Points
Standby Diesel Generators

Parameter	Indication		Alarm	
	Control Room	Local	Control Room	Local
Lube Oil Pressure Low (PT014A/B, PT015A/B)	No	Yes	Yes	Yes
Lube Oil Temperature High (TE029A/B)	No	Yes	Yes	Yes
Lube Oil Sump Level Low (LS02A/B)	No	Yes	Yes	Yes
Cooling Water Temperature High (TE005A/B, TE003A/B, TE002A/B)	No	Yes	Yes	Yes
Cooling Water Pressure Low (PT04A/B, PT05A/B, PT06A/B)	No	Yes	Yes	Yes
DG Starting Air Pressure Low (PT103A/B)	Yes	Yes	Yes	Yes

Table 8.3.2-1
250V DC Class 1E Division A Battery
Nominal Load Requirements

Load Description	Power Required (kW)	
	Momentary	Continuous
Bus IDSA DS 1 (24 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0.6	2.6
Emergency Lighting	0	0.1
Containment High Range Monitor	0	0.3
Subtotal	0.6	3.0
250 Vdc Panel		
Reactor Trip Swgr & Solenoid Valves	5	0.9
250 Vdc MCC		
Motor-operated Valves	356	
Total	362	3.9

Table 8.3.2-2
250V DC Class 1E Division B Battery
Nominal Load Requirements

Load Description	Power Required (kW)	
	Momentary	Continuous
Bus IDSB DS 1 (24 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0	1.2
Emergency Lighting and Panel Lighting	0	0.2
Subtotal	0	1.4
250 Vdc Panel		
Reactor Trip Swgr, RCP Trip & Solenoid Valves	11	3.4
250 Vdc MCC		
Motor-operated Valves	520	
Total	531	4.8
BUS IDSB DS 2 (72 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0.6	1.9
Emergency Lighting and Panel Lighting	0	0.3
Containment High Range Monitor	0	0.3
MCR Supply Duct Radiation Monitor	0.9	0.3
Total	1.5	2.8

Table 8.3.2-3
250V DC Class 1E Division C Battery
Nominal Load Requirements

Load Description	Power Required (kW)	
	Momentary	Continuous
Bus IDSC DS 1 (24 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0	0.7
Emergency Lighting and Panel Lighting	0	0.2
Subtotal	0	0.9
250 Vdc Panel		
Reactor Trip Swgr, RCP Trip & Solenoid Valves	11	1.4
250 Vdc MCC		
Motor-operated Valves	293	
Total	304	2.3
BUS IDSC DS 2 (72 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0.6	1.9
Emergency Lighting and Panel Lighting	0	0.3
Containment High Range Monitor	0	0.3
MCR Supply Duct Radiation Monitor	0.9	0.3
Total	1.5	2.8

Table 8.3.2-4
250V DC Class 1E Division D Battery
Nominal Load Requirements

Load Description	Power Required (kW)	
	Momentary	Continuous
Bus IDSD DS 1 (24 hr Battery Bank)		
Inverter		
Protection and Safety Monitoring System	0.6	2.9
Emergency Lighting	0	0.4
Containment High Range Monitor	0	0.3
Subtotal	0.6	3.6
250 Vdc Panel		
Reactor Trip Swgr & Solenoid Valves	5	2.3
250 Vdc MCC		
Motor-operated Valves	481	
Total	487	5.9

Table 8.3.2-5
Component Data - Class 1E DC System
(Nominal Values)

a.	**Battery Bank** 250 Vdc (2 - 125 Vdc) 60 lead calcium cells, 2400 Ah. (8 hrs to 1.75 V per cell @ 77°F).
b.	**Charger** AC input - 480 V, 3-phase, 60 Hz; dc output - 250 Vdc, 200 A continuous; float voltage 2.20 to 2.25 V/cell; equalizing charge voltage 2.33 V/cell.
c.	**Switchboard and Fused Transfer Switch Box** Main bus 600 A (72-hr) and 1600 A (24-hr) continuous, 40,000 A short circuit bracing; fuse disconnect switch 40,000 A interrupting rating, continuous ratings 600 A and 1600 A.
d.	**Spare Fused Transfer Switch Box** Main bus 1600 A continuous, 40,000 A short circuit bracing; fuse disconnect switch, 40,000 A interrupting rating, continuous rating 1600 A.
e.	**Motor Control Center** Main bus 800 A continuous, vertical bus 800 A continuous, 40,000 A short circuit bracing.
f.	**Spare Battery Bank** 2-125V dc 60 lead calcium cells, 2400 Ah. (8 hrs to 1.75 V per cell @ 77°F).
g.	**Spare Charger** AC input - 480 V, 3-phase, 60 Hz; dc output - 250 Vdc, 200 A continuous; float voltage 2.20 to 2.25 V/cell; equalizing charge voltage - 2.33 V/cell.
h.	**Uninterruptible Power Supply (UPS)** i. Inverter 15 kVA with 250 Vdc input and 208Y/120 Vac, 3-phase, 4-wire, 60 Hz output; ac output voltage regulation of ±2% steady state; output frequency variation within 0.5% of nominal 60 Hz. ii. Voltage Regulating Transformer 45 kVA, 480 V - 208Y/120V, 3-phase, 4-wire.

Note:
Refer to Figures 8.3.2-1 and 8.3.2-2 for the system component configuration.

Table 8.3.2-6 (Sheet 1 of 3)
Component Data - Non-Class 1E DC System EDS1 – EDS4
(Nominal Values)

a.	**Battery Bank** 125 Vdc 60 lead calcium cells, minimum 3500 Ah. (8 hrs to 1.75 V per cell @ 77°F).
b.	**Charger** AC input - 480 V, 3-phase, 60 Hz; dc output - 125 Vdc, 1000 A continuous; float voltage - 2.20 to 2.25 V/cell; equalizing charge voltage - 2.33 V/cell.
c.	**Switchgear** Main bus 3000 A continuous, 40,000 A short circuit bracing; breaker 3000A frame size.
d.	**Uninterruptible Power Supply (UPS)**
	i. Inverter 75 kVA with 125 Vdc input and 208 Y/120 Vac, 3-phase, 4-wire, 60 Hz output; ac output voltage regulation of ±2% steady state; output frequency variation within 0.5% of nominal 60 Hz.
	ii. Voltage Regulating Transformer 100 kVA, 480 V - 208 Y/120 V, 3-phase, 4-wire.

Note:
Refer to Figure 8.3.2-3 for the system component configuration.

Table 8.3.2-6 (Sheet 2 of 3)
Component Data - Non-Class 1E DC System EDS5
(Nominal Values)

a.	**Battery Bank** 250 Vdc (2 - 125 Vdc) 60 lead calcium cells, minimum 3500 Ah. (8 hrs to 1.75 V per cell @ 77°F).
b.	**Charger** AC input - 480 V, 3-phase, 60 Hz; dc output - 250 Vdc, 200 A continuous; float voltage - 2.20 to 2.25 V/cell; equalizing charge voltage - 2.33 V/cell.
c.	**Switchgear** Main bus 3000 A continuous, 40,000 A short circuit bracing; breaker 3000 A frame size.

Note:
Refer to Figure 8.3.2-3 for the system component configuration.

Table 8.3.2-6 (Sheet 3 of 3)
Component Data - Non-Class 1E DC System EDSS
(Nominal Values)

a.	**Spare Battery Bank** 250 Vdc (2 - 125 Vdc) 60 lead calcium cells, minimum 3500 Ah. (8 hrs to 1.75 V per cell @ 77°F).
b.	**Spare Charger - 1** AC input - 480 V, 3-phase, 60 Hz; dc output - 125 Vdc, 1000 A continuous; float voltage - 2.20 to 2.25 V/cell; equalizing charge voltage - 2.33 V/cell.
c.	**Spare Charger - 2** AC input - 480 V, 3-phase, 60 Hz; dc output - 125 Vdc, 1000 A continuous; float voltage - 2.20 to 2.25 V/cell; equalizing charge voltage - 2.33 V/cell.

Note:
Refer to Figure 8.3.2-3 for the system component configuration.

Table 8.3.2-7 (Sheet 1 of 5)
Class 1E 250V DC and Class 1E Uninterruptible Power Supplies
Failure Modes and Effects Analysis

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
1.	Battery Charger Division A, IDSA DC 1 Division B, IDSB DC 1, 2 Division C, IDSC DC 1, 2 Division D, IDSD DC 1	Provide IEEE 384 isolation between the non-1E AC power supply and the IDS.	A,B,C	Electrical fault propagation	Failure alarms for downstream divisional equipment annunciated in MCR	None; Other divisions available	Failure of only one div. chgr. falls into single failure criteria and the other three div. are still available.
		Provide ac input undervoltage signals to the protection and safety monitoring system. (24-hr charger only)	A,B,C	No indication	Undervoltage detection by only one of the two sensors connected to the battery charger	None; Other division(s) available to complete 2/4 div. voting logic	1/div. required for containment recirc., ADS actuation. 2/div. required for MCR isolation, boron dilution block.
			A,B	Spurious undervoltage signal	ADS and IRWST Injection unblocked alarm annunciated in MCR	None; 2/4 div. voting logic prevents spurious ESF. Spare battery charger available for connection.	ADS and IRWST injection block is described in Subsection 7.3.1.2.4.1.
2.	Battery Division A, IDSA DB 1A,1B Division B, IDSB DB 1A,1B,2A,2B Division C, IDSC DB 1A,1B,2A,2B Division D, IDSD DB 1A,1B	Provide dc power for 24 and 72 hours without battery charger (Item 1).	A,B	No output or low voltage	Battery monitor provides annunciation in main control room; switchboard failure alarm in main control room for ground detection and bus undervoltage.	None; Other divisions available. Spare battery available for connection.	Power still available with a single ground. Loss of entire battery function is single failure and the other divisions are available.
			C	No output or low voltage	Same as above.	None; Other divisions available; spare battery available.	

Table 8.3.2-7 (Sheet 2 of 5)
Class 1E 250V DC and Class 1E Uninterruptible Power Supplies
Failure Modes and Effects Analysis

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
3.	Fused transfer switch box Division A, IDSA DF 1 Division B, IDSB DF 1,2 Division C, IDSC DF 1,2 Division D, IDSD DF 1	Provide circuit continuity between Item 2 battery and Item 4 switchboard.	A,B,C	Inadvertent opening (blown fuse)	Switchboard failure alarm in main control room for ground detection and bus undervoltage.	None; Other divisions available.	
4.	250V DC Switchboard Division A, IDSA DS 1 Division B, IDSB DS 1,2 Division C, IDSC DS 1,2 Division D, IDSD DS 1	Distribute power via fusible disconnects to loads from chargers and battery.	A,B,C	Bus ground fault	Switchboard failure alarm in main control room for ground detection and bus undervoltage.	None; Other divisions available.	
5.	Fusible disconnect Division A, for Charger 1 Division B, for Charger 1,2 Division C, for Charger 1,2 Division D, for Charger 1	Provide circuit continuity between Item 1 and 4.	A,B	Inadvertent opening (blown fuse)	Alarm in main control room for charger failure (dc no charge).	None; Battery can provide power for 24 and 72 hours without chargers. Other divisions available.	
			C	Inadvertent opening (blown fuse)	Same as above.	None; Battery can provide power for 24 and 72 hours without chargers.	
6.	Fusible disconnect Division A, for Inverter 1 Division B, for Inverter 1,2 Division C, for Inverter 1,2 Division D, for Inverter 1	Provide circuit continuity between Item 4 switchboard and Item 9 inverters.	A,B,C	Inadvertent opening (blown fuse)	Inverter trouble alarm in main control room for loss of dc input, loss of ac output, input, output and backup power supply breaker open.	None; System safety function can be met with loss of one division.	

Table 8.3.2-7 (Sheet 3 of 5)
Class 1E 250V DC and Class 1E Uninterruptible Power Supplies
Failure Modes and Effects Analysis

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
7.	Fusible disconnect for DC MCC Division A Division B Division C Division D	Provide circuit continuity between Item 4 switchboard and Item 13 DC MCC.	A,B,C	Inadvertent opening (blown fuse)	DC MCC trouble alarm in main control room for bus undervoltage.	None; Other divisions available.	
8.	Fusible disconnect for DC dist panel Division A Division B Division C Division D	Provide circuit continuity between Item 4 switchboard and Item 14 dc panel.	A,B,C	Inadvertent opening (blown fuse)	DC dist. panel trouble alarm in main control room for bus undervoltage.	None; Other divisions available.	
9.	Inverter Division A, IDSA DU 1 Division B, IDSB DU 1,2 Division C, IDSC DU 1,2 Division D, IDSD DU 1	Convert 250V DC to 208Y/120V AC and provide 120V AC power.	A,B	No output	Alarm in main control room for common UPS trouble, for loss of dc input, loss of ac output; input and backup power supply breakers open.	None; Static switching function transfers to ac input on loss of inverter output function.	The UPS function is located in the inverter cabinet and switches power input between the inverter and the VRT.
			C	No output	Alarm in main control room for common UPS trouble, for loss of dc input, loss of ac output; input and backup power supply breakers open.	None; System safety function can be met with loss of one division.	Backup VRT is unavailable during station blackout.
10.	Voltage regulating transformer Division A, IDSA DT 1 Division B, IDSB DT 1 Division C, IDSC DT 1 Division D, IDSD DT 1	Provide IEEE 384 isolation between the non-1E AC power supply and AC distribution panel (Item 11).	A,B	Electrical fault propagation	Failure alarms for downstream divisional equipment annunciated in MCR.	None; Other divisions available.	Failure of only one div. VRT falls into single failure criteria; the other divisions are available.

Table 8.3.2-7 (Sheet 4 of 5)
Class 1E 250V DC and Class 1E Uninterruptible Power Supplies
Failure Modes and Effects Analysis

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
11.	208Y/120V AC distr. panel Division A, IDSA EA 1 Division B, IDSB EA 1,3 Division C, IDSC EA 1,3 Division D, IDSD EA 1	Distribute power via breakers to loads	A,B,C	Ground and bus fault	Alarm in main control room for undervoltage.	None; System safety function can be met with loss of one division.	
12.	Class 1E Fuse Panel: Division A, IDSA EA 4 Division B, IDSB EA 4,5 Division C, IDSC EA 4,5 Division D, IDSD EA 4	Provide IEEE 384 isolation between the AC distribution panel (Item 11) and the associated load.	A,B,C	Electrical fault propagation	Failure alarms for downstream divisional equipment annunciated in MCR.	None; Other divisions available.	
13.	Class 1E Fuse Panel: Division B, IDSB EA 6 Division C, IDSC EA 6	Provide IEEE 384 isolation between the AC distribution panel EA-2 and the associated load.	A,B,C	Electrical fault propagation	Failure alarms for downstream divisional equipment annunciated in MCR.	None; Other divisions available.	
14.	DC MCC DIV. A, IDSA DK 1 DIV. B, IDSB DK 1 DIV. C, IDSC DK 1 DIV. D, IDSD DK 1	Distribute power via fusible disconnect to loads.	A,B,C	Ground and bus fault	MCC trouble alarm per MCC in main control room for bus undervoltage and ground detection.	None; Other divisions available.	Power still available with a single ground.
15.	DC Distr. Panel Div. A, IDSA DD1 Div. B, IDSB DD1 Div. C, IDSC DD1 Div. D, IDSD DD1	Distribute power via fusible disconnect to loads.	A,B,C	Ground and bus fault	Panel trouble alarm per panel in main control room for bus undervoltage and ground detection.	None; Other divisions available.	Power still available with a single ground.
16.	Battery monitor fuse panel: Division A, IDSA EA 5 Division B, IDSB EA 7,8 Division C, IDSC EA 7,8 Division D, IDSD EA 5 Spare, IDSS EA 1	Provide IEEE 384 isolation between the battery (Item 2) and the battery monitor.	A,B	Electrical fault propagation	Failure alarms for associated divisional equipment annunciated in MCR.	None; Other divisions available.	

Table 8.3.2-7 (Sheet 5 of 5)
Class 1E 250V DC and Class 1E Uninterruptible Power Supplies
Failure Modes and Effects Analysis

Item No.	Description of Components	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks

- Plant operating modes are represented as follows:

  A – Normal or preferred power available.
  B – Loss of normal power and loss of preferred power and onsite standby diesel generator available.
  C – Blackout (loss of all ac systems, except 208Y/120-V AC UPS system).

  System success criteria are as follows:

  250-V DC System – Three out of four (Division A, B, C or D) divisions required.
  208Y/120-V AC UPS System – Three out of four divisions required.

- The failure of any one fusible disconnect or opening of one circuit breaker under a fault condition results in only the loss of the associated division. The other redundant divisions still remain available.

- This table does not address interfaces between the IDS and non-Class 1E instrumentation and control systems. These interfaces include those signals that provide bus parameters or switch status to the non-Class 1E plant control system. Interfaces between the IDS and non-Class 1E instrumentation and control systems are protected by IEEE 384 qualified isolation devices. In addition, the 24 hour battery banks of IDS Division A, Division B, and Division C are isolated from the non-Class 1E plant control system by current-to-current transmitters. These isolation devices provide IEEE 384 isolation between the non-Class 1E plant control system and the IDS. If one of the isolation devices fail to prevent an electrical fault propagation from the plant control system to the IDS, a faulted channel will be provided to the plant control system and will be indicated in the MCR. Should this electrical fault cause a failure of the downstream divisional equipment, then failure alarms are annunciated in the MCR. This has no effect on the IDS safety function capability because the other IDS divisions are available.

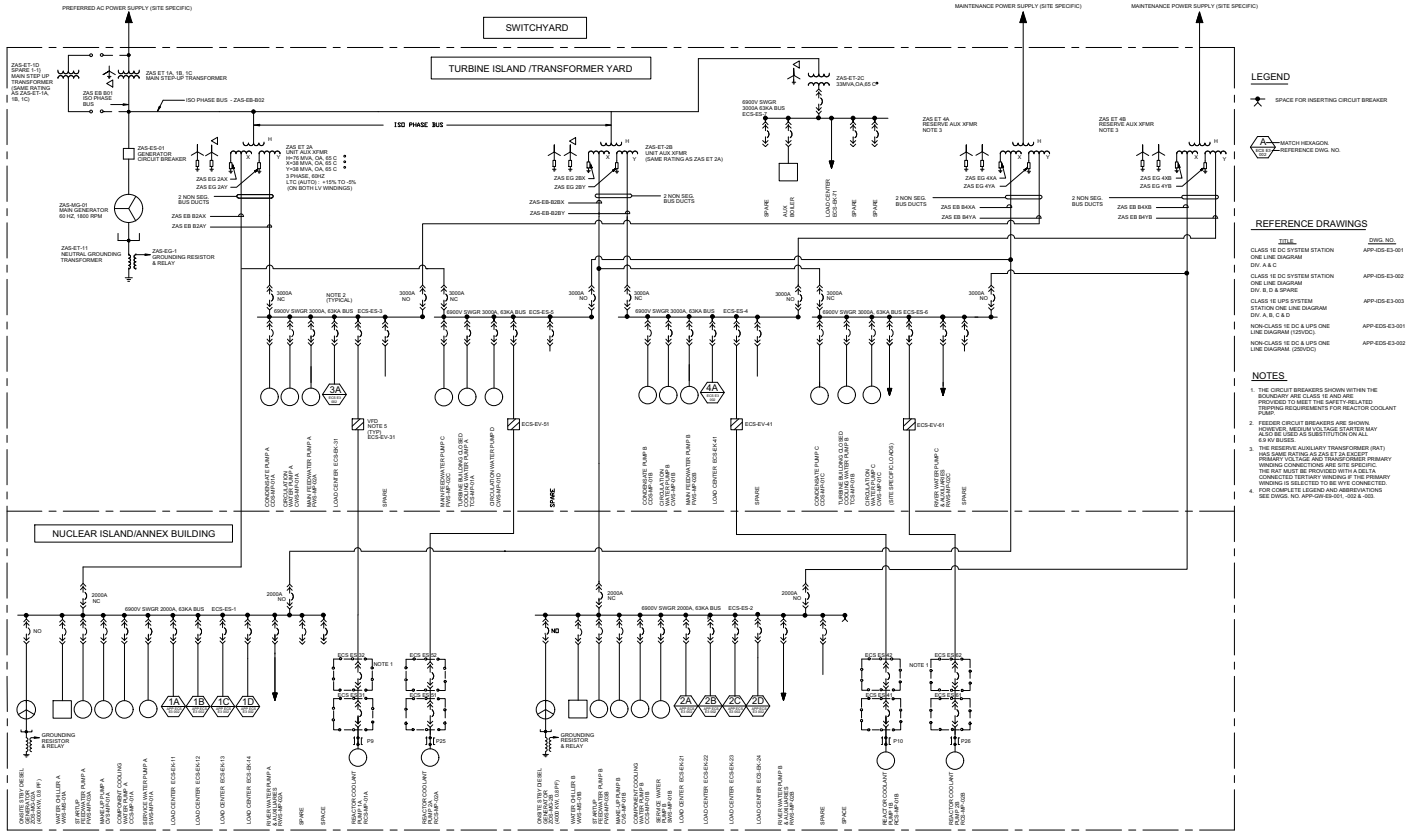


Figure 8.3.1-1
AC Power Station One Line Diagram

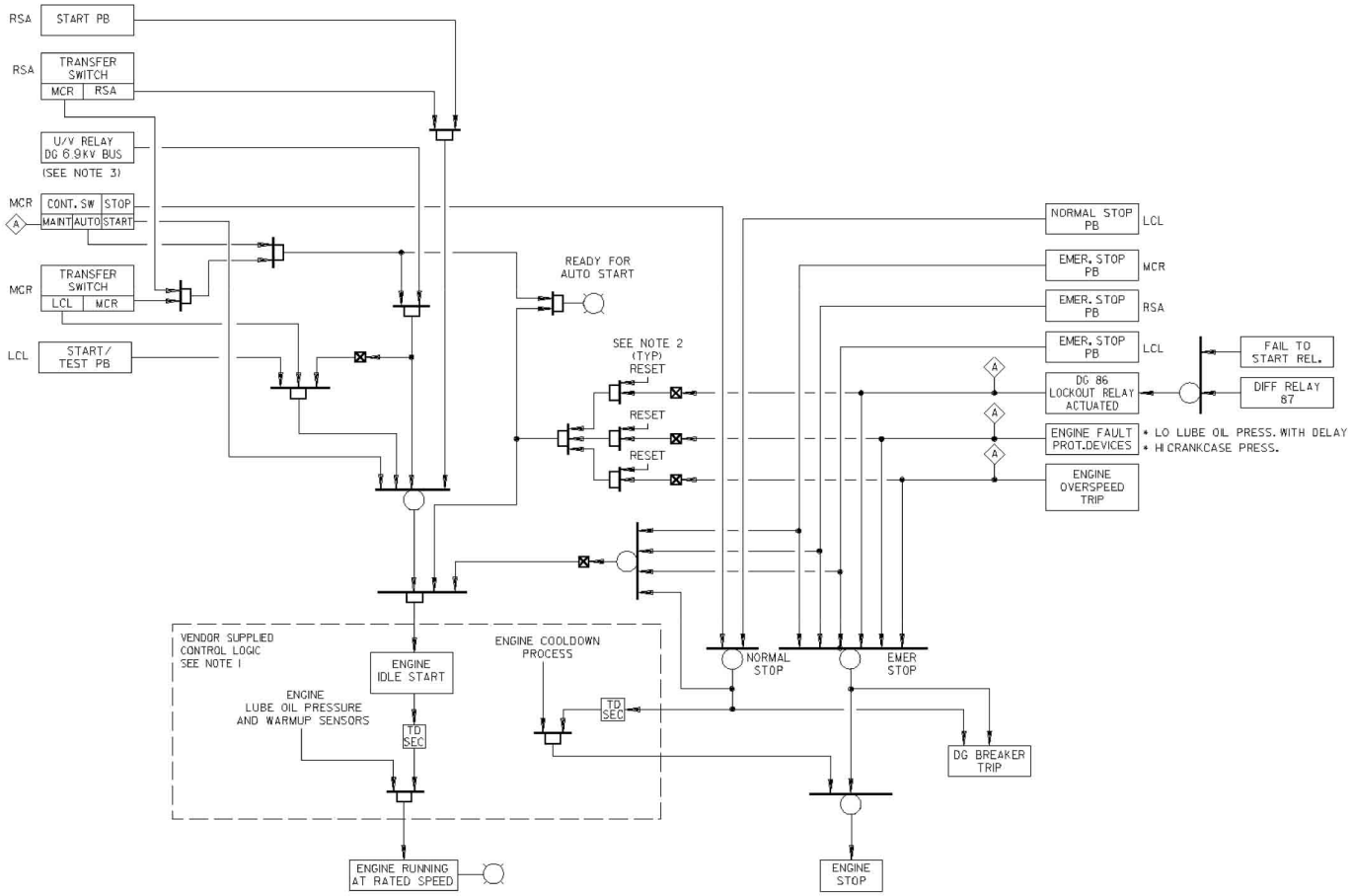


Figure 8.3.1-2
Onsite Standby Diesel Generator Initiating Circuit Logic Diagram

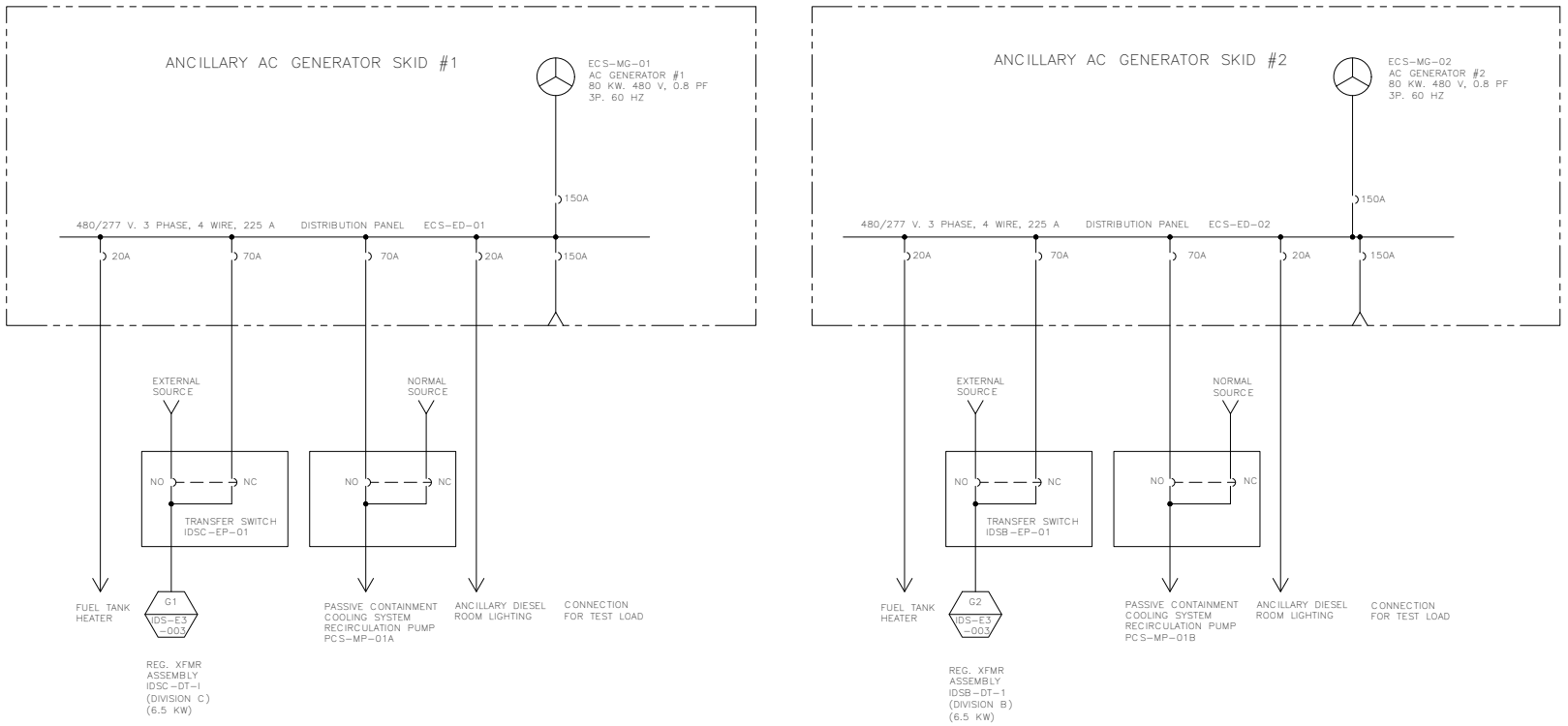
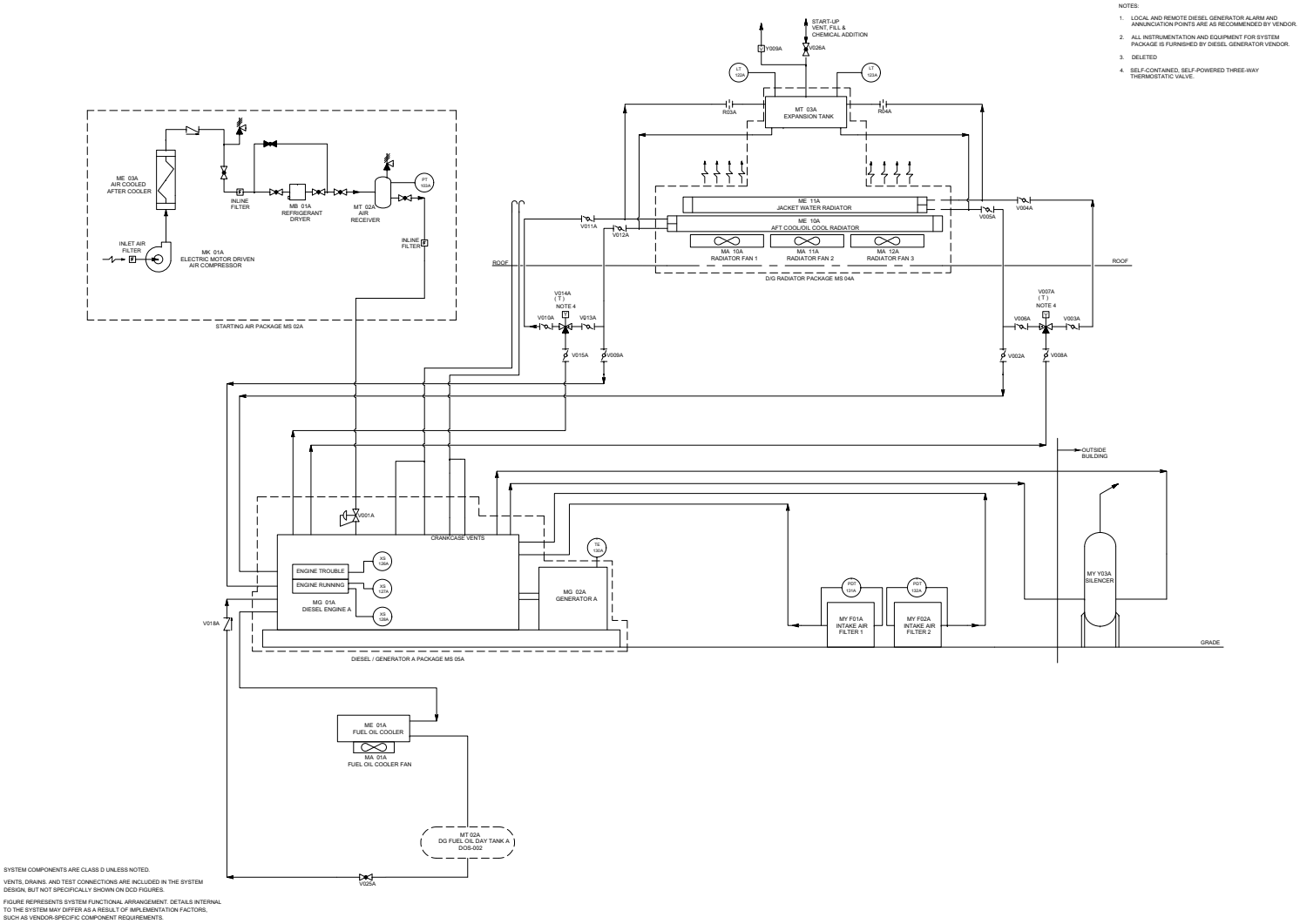
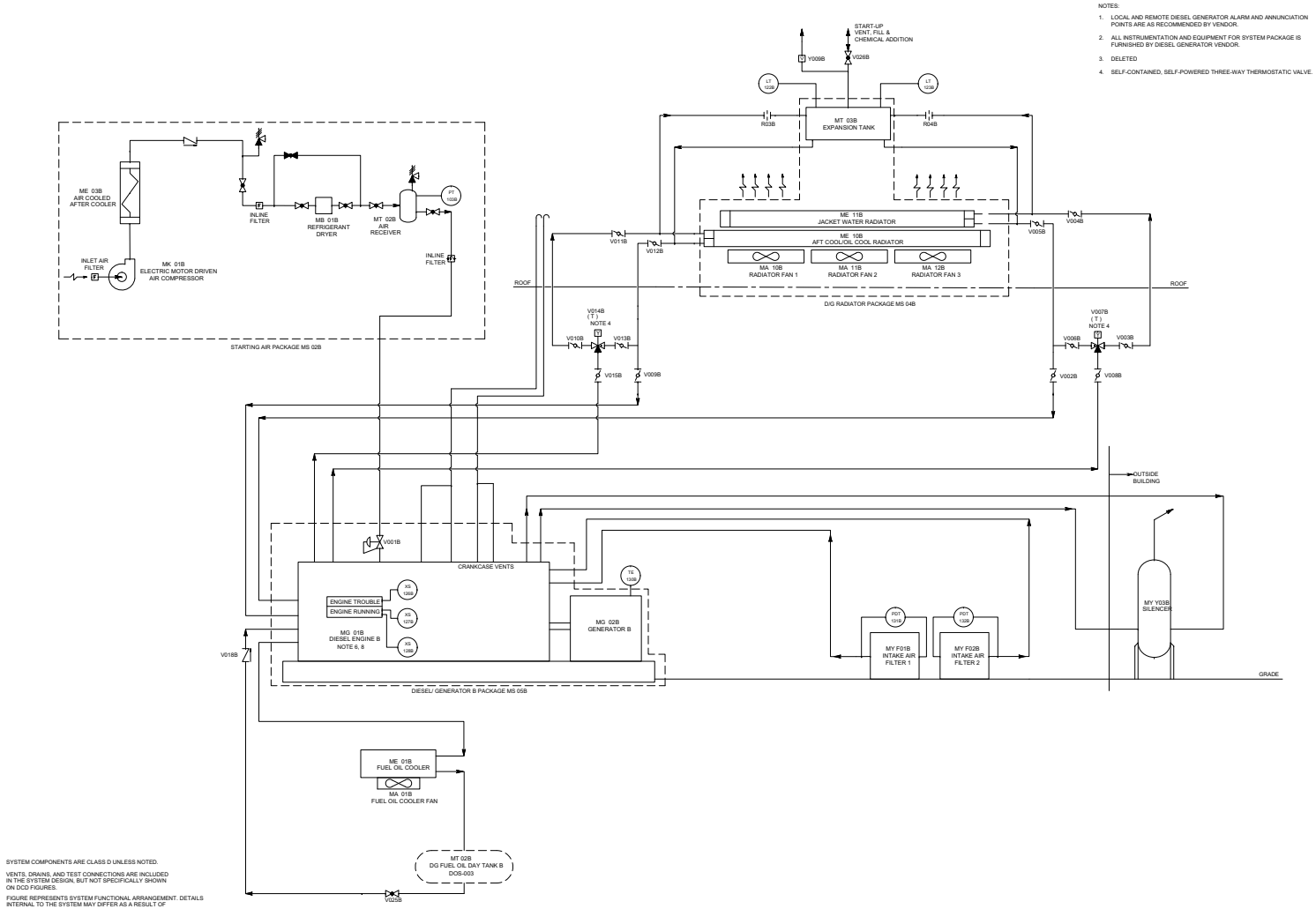


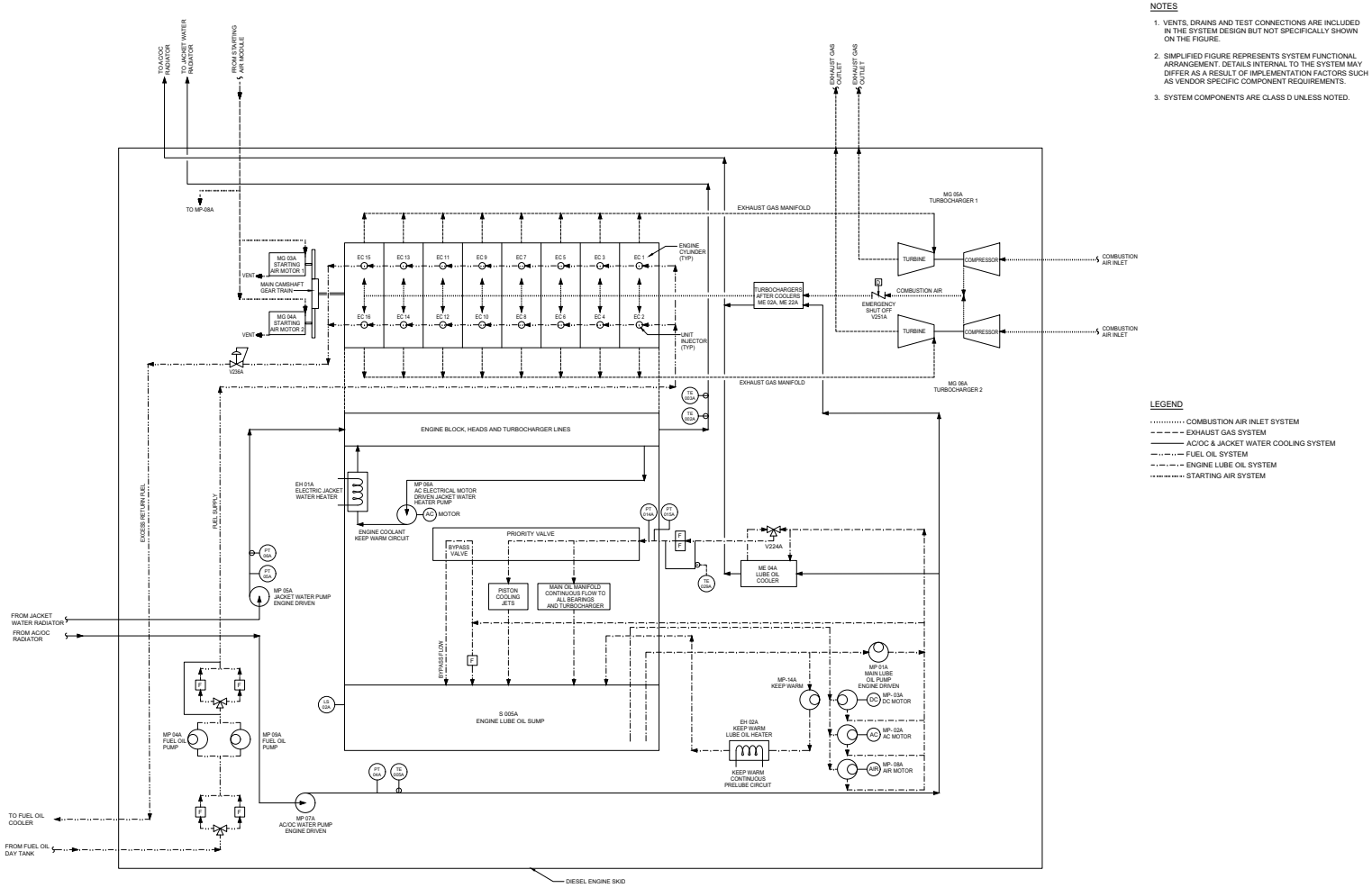
Figure 8.3.1-3
Ancillary Diesel Generator
One Line Diagram



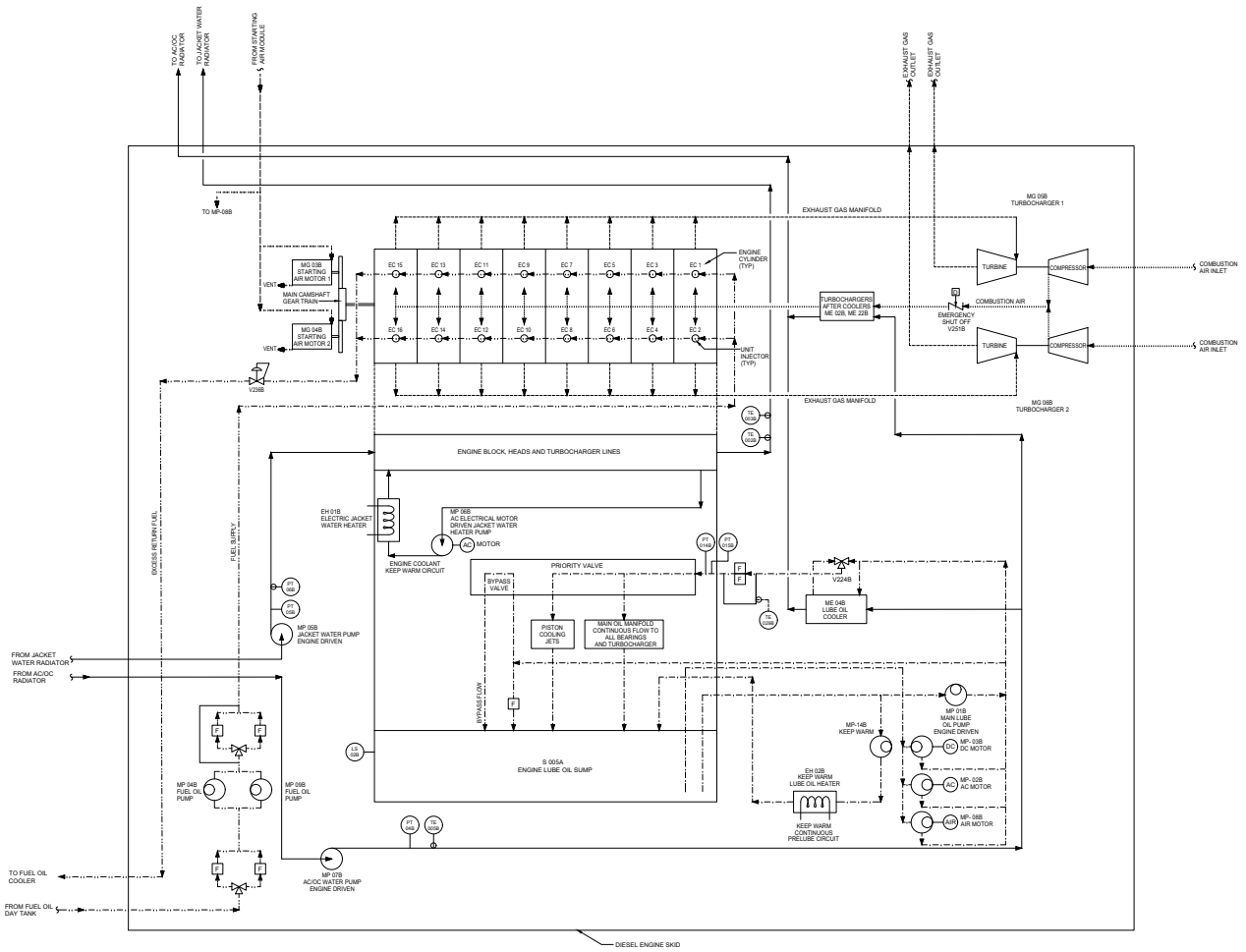
Inside Diesel Generator Building
Figure 8.3.1-4 (Sheet 1 of 2)
Simplified Diesel Generator System Piping and Instrumentation Diagram
(REF) ZOS 001



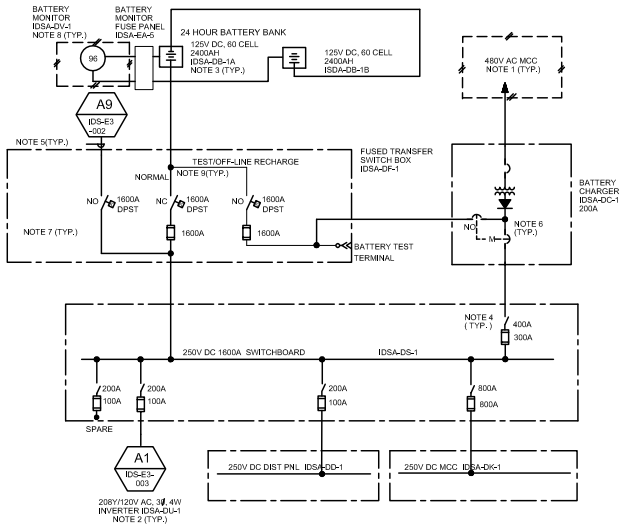
Inside Diesel Generator Building
Figure 8.3.1-4 (Sheet 2 of 2)
Simplified Diesel Generator System Piping and Instrumentation Diagram
(REF) ZOS 002



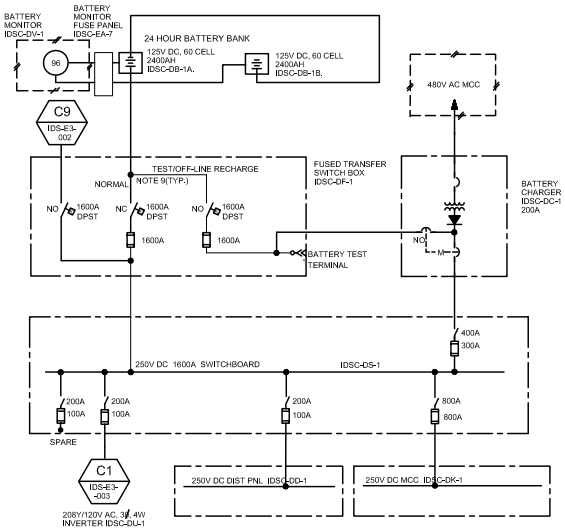
Inside Diesel Generator Building
Figure 8.3.1-5 (Sheet 1 of 2)
Diesel Engine Skid Mounted System
(REF) ZOS K001



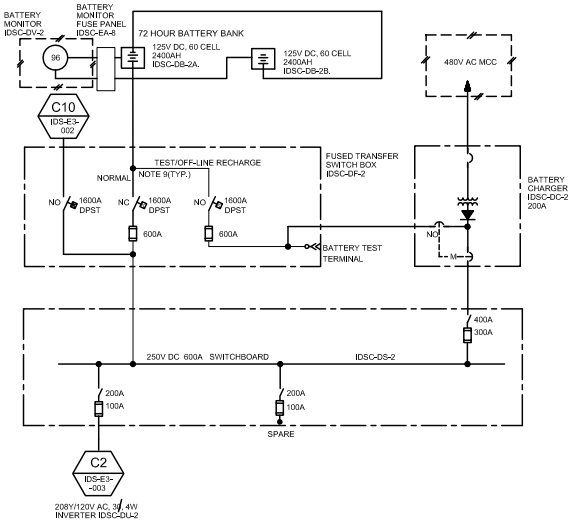
Inside Diesel Generator Building
Figure 8.3.1-5 (Sheet 2 of 2)
Diesel Engine Skid Mounted System
(REF) ZOS K002



24 HOUR BATTERY BANK (DIVISION A)



24 HOUR BATTERY BANK (DIVISION C)



72 HOUR BATTERY BANK (DIVISION C)

NOTES

1. 480V AC INPUT POWER TO BATTERY CHARGERS IS PROVIDED FROM ONSITE STANDBY DIESEL GENERATOR BACKED MCC.
2. SEE DWG. NO. IDS-E3-003 FOR UPS CONFIGURATION.
3. BATTERY AMPERE-HOUR RATING IS BASED ON 8 HOURS DISCHARGE RATE.
4. ALL FUSIBLE DISCONNECT SWITCHES ARE RATED FOR 40 KA SHORT CIRCUIT RATING.
5. SPARE CLASS 1E BATTERY BANK WITH SPARE CLASS 1E BATTERY CHARGER IS UTILIZED FOR CLASS 1E DC SYSTEM AS A TEMPORARY REPLACEMENT FOR ANY 24 HR OR 72 HR BATTERY BANK ONE AT A TIME.
6. MECHANICAL INTERLOCKED IS PROVIDED TO PREMIT CLOSING ONLY ONE CIRCUIT BREAKER AT A TIME.
7. KIRK-KEY INTERLOCK SWITCH IS PROVIDED TO PREVENT TRANSFER OPERATION OF MORE THAN ONE SWITCHBOARD AT A TIME.
8. FOR LEGEND AND ABBREVIATION, SEE DWGS GW-E9-001, -002 AND -003.
9. KIRK-KEY INTERLOCKS ARE PROVIDED TO PREVENT CLOSURE OF SWITCHES AT SAME TIME.

REFERENCE DRAWINGS

TITLE	DWG. NO.
AC POWER SYSTEM - STATION ONE LINE DIAGRAMS	FIG 8.3.1-1
CLASS 1E DC SYSTEM - STATION ONE LINE DIAGRAM DIV. B, D & SPARE	FIG 8.3.2-1 (SHT 2)
CLASS 1E UPS SYSTEM- STATION ONE LINE DIAGRAM DIV A,B,C & D	FIG 8.3.2-2
CLASS 1E DC SYSTEM ONE LINE METER & RELAY DIAGRAMS	IDS-E3-004 THRU 010

Figure 8.3.2-1 (Sheet 1 of 2)
Class 1E DC System One Line Diagram

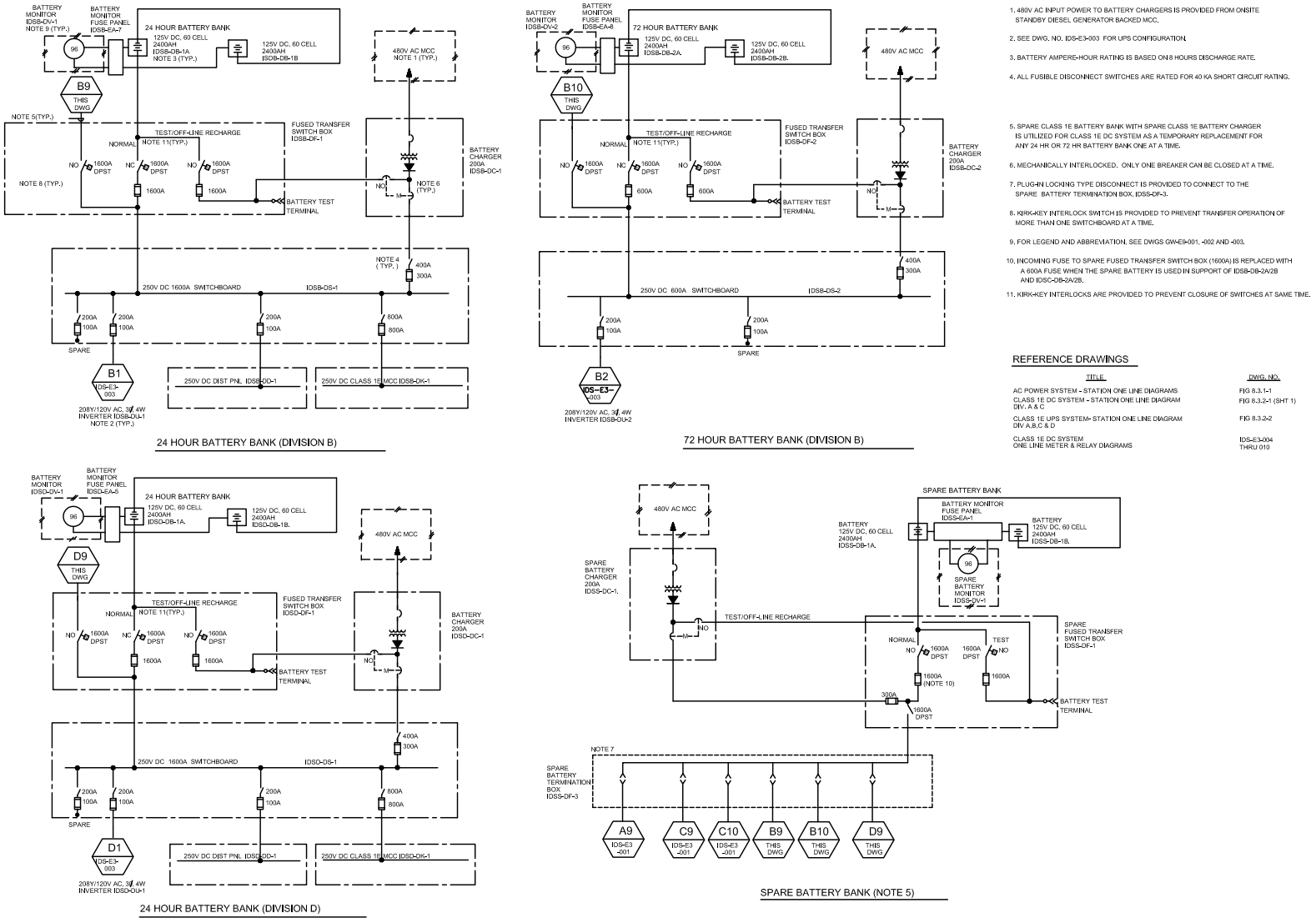


Figure 8.3.2-1 (Sheet 2 of 2)
Class 1E DC System One Line Diagram

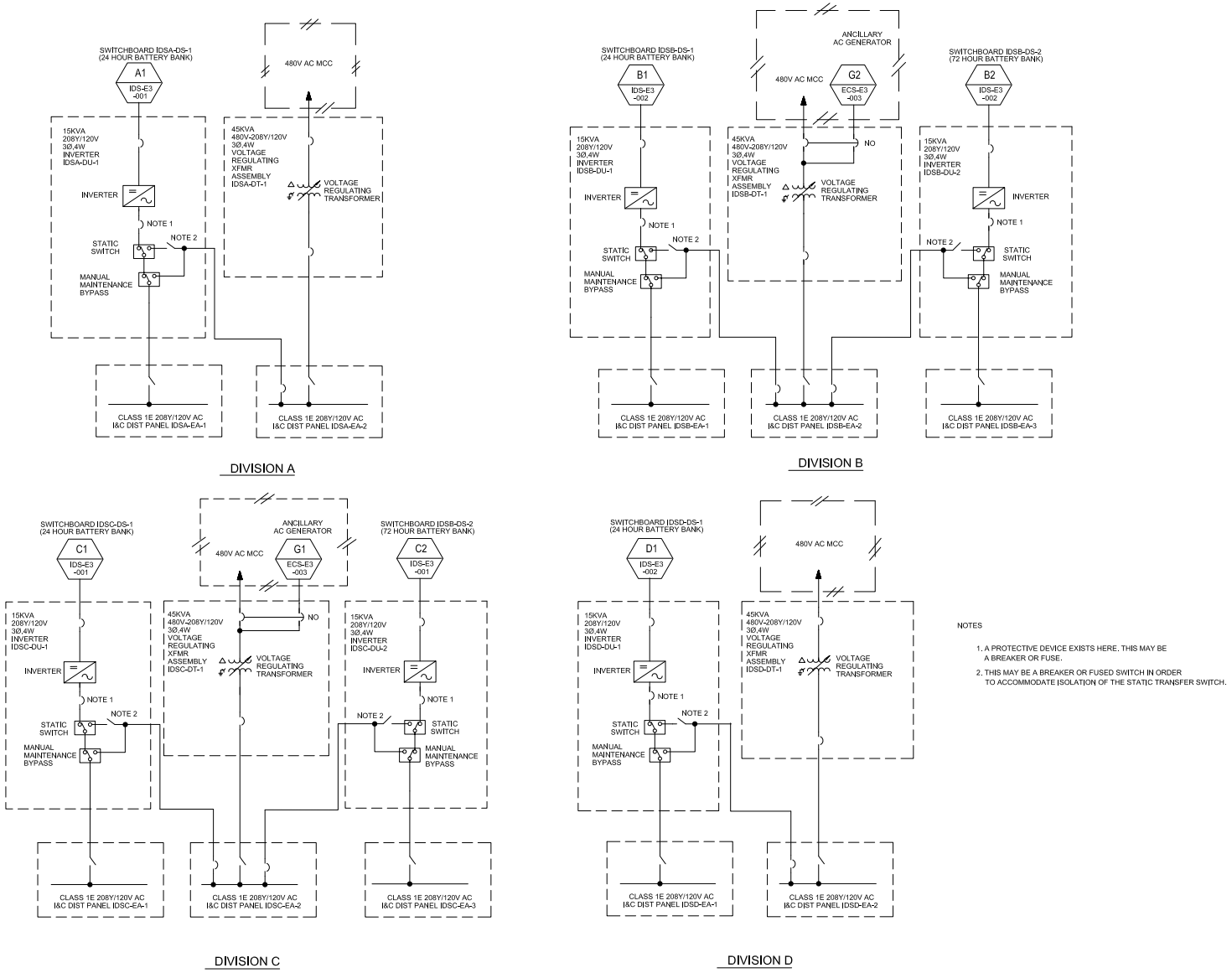
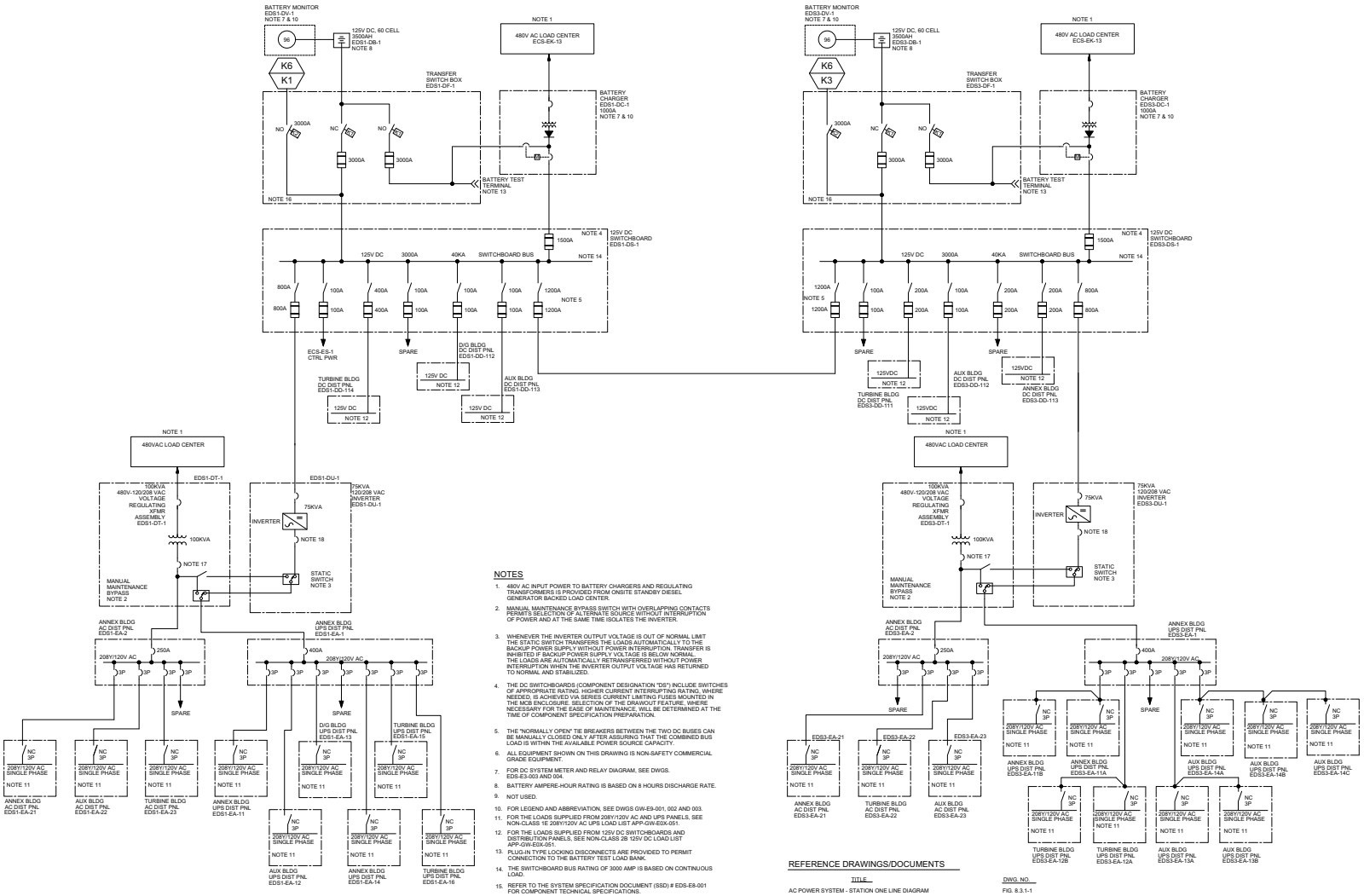


Figure 8.3.2-2
Class 1E 208y/120V UPS One Line Diagram



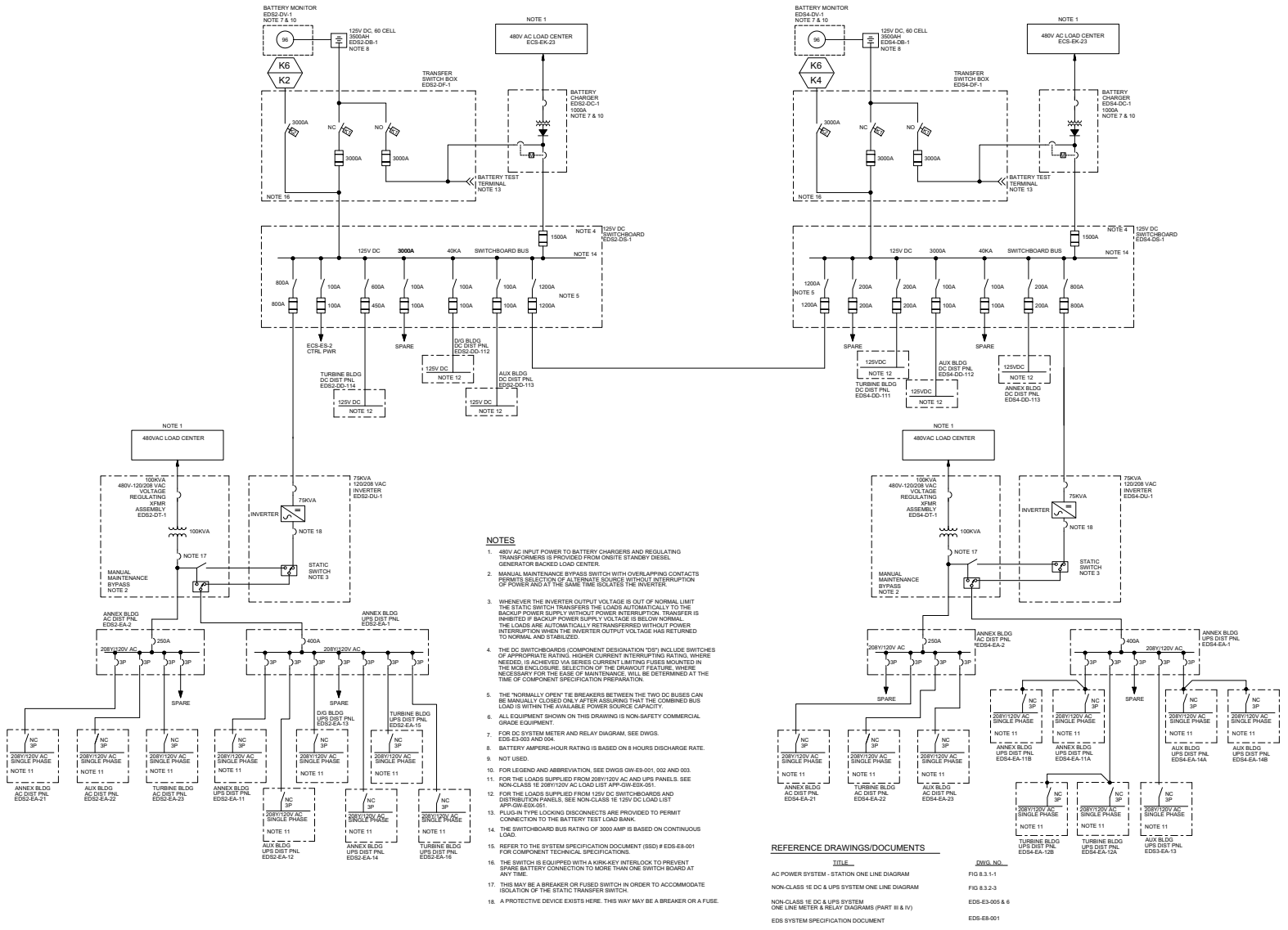
NOTES

1. 480V AC INPUT POWER TO BATTERY CHARGERS AND REGULATING TRANSFORMERS IS PROVIDED FROM ONSITE STANDBY DIESEL GENERATOR BACKED LOAD CENTER.
2. MANUAL MAINTENANCE BYPASS SWITCH WITH OVERLAPPING CONTACTS PERMITS SELECTION OF ALTERNATE SOURCE WITHOUT INTERRUPTION OF POWER AND AT THE SAME TIME ISOLATES THE INVERTER.
3. WHENEVER THE INVERTER OUTPUT VOLTAGE IS OUT OF NORMAL LIMIT THE STATIC SWITCH TRANSFERS THE LOADS AUTOMATICALLY TO THE BACKUP POWER SUPPLY WITHOUT POWER INTERRUPTION. TRANSFER IS INHIBITED IF BACKUP POWER SUPPLY VOLTAGE IS BELOW NORMAL. THE LOADS ARE AUTOMATICALLY RETRANSFERRED WITHOUT POWER INTERRUPTION WHEN THE INVERTER OUTPUT VOLTAGE HAS RETURNED TO NORMAL AND STABILIZED.
4. THE DC SWITCHBOARDS (COMPONENT DESIGNATION "DS") INCLUDE SWITCHES OF APPROPRIATE RATING. HIGHER CURRENT INTERRUPTING RATING, WHERE NEEDED, IS ACHIEVED VIA SERIES CURRENT LIMITING FUSES MOUNTED IN THE MCB ENCLOSURE. SELECTION OF THE DRAWOUT FEATURE, WHERE NECESSARY FOR THE EASE OF MAINTENANCE, WILL BE DETERMINED AT THE TIME OF COMPONENT SPECIFICATION PREPARATION.
5. THE "NORMALLY OPEN" TIE BREAKERS BETWEEN THE TWO DC BUSES CAN BE MANUALLY CLOSED ONLY AFTER ASSURING THAT THE COMBINED BUS LOAD IS WITHIN THE AVAILABLE POWER SOURCE CAPACITY.
6. ALL EQUIPMENT SHOWN ON THIS DRAWING IS NON-SAFETY COMMERCIAL GRADE EQUIPMENT.
7. FOR DC SYSTEM METER AND RELAY DIAGRAM, SEE DWGS. EDS-E3-003 AND 004.
8. BATTERY AMPERE-HOUR RATING IS BASED ON 8 HOURS DISCHARGE RATE.
9. NOT USED.
10. FOR LEGEND AND ABBREVIATION, SEE DWGS GW-E9-001, 002 AND 003.
11. FOR THE LOADS SUPPLIED FROM 208Y/120V AC AND UPS PANELS, SEE NON-CLASS 1E 208Y/120V AC UPS LOAD LIST APP-GW-E0X-051.
12. FOR THE LOADS SUPPLIED FROM 125V DC SWITCHBOARDS AND DISTRIBUTION PANELS, SEE NON-CLASS 2B 125V DC LOAD LIST APP-GW-E0X-051.
13. PLUG-IN TYPE LOCKING DISCONNECTS ARE PROVIDED TO PERMIT CONNECTION TO THE BATTERY TEST LOAD BANK.
14. THE SWITCHBOARD BUS RATING OF 3000 AMP IS BASED ON CONTINUOUS LOAD.
15. REFER TO THE SYSTEM SPECIFICATION DOCUMENT (SSD) # EDS-E8-001 FOR COMPONENT TECHNICAL SPECIFICATIONS.
16. THE SWITCH IS EQUIPPED WITH A KIRK-KEY INTERLOCK TO PREVENT SPARE BATTERY CONNECTION TO MORE THAN ONE SWITCH BOARD AT ANY TIME.
17. THIS MAY BE A BREAKER OR FUSED SWITCH IN ORDER TO ACCOMMODATE ISOLATION OF THE STATIC TRANSFER SWITCH.
18. A PROTECTIVE DEVICE EXISTS HERE. THIS WAY MAY BE A BREAKER OR A FUSE.

REFERENCE DRAWINGS/DOCUMENTS

TITLE	DWG. NO.
AC POWER SYSTEM - STATION ONE LINE DIAGRAM	FIG. 8.3.1-1
NON-CLASS 1E DC & UPS SYSTEM ONE LINE DIAGRAM	FIG 8.3.2-3
NON-CLASS 1E DC & UPS SYSTEM ONE LINE METER & RELAY DIAGRAMS (PART I & II)	EDS-E3-003 & 4
EDS SYSTEM SPECIFICATION DOCUMENT	EDS-E8-001

Figure 8.3.2-3 (Sheet 1 of 3)
Non-Class 1E DC & UPS System One Line Diagram



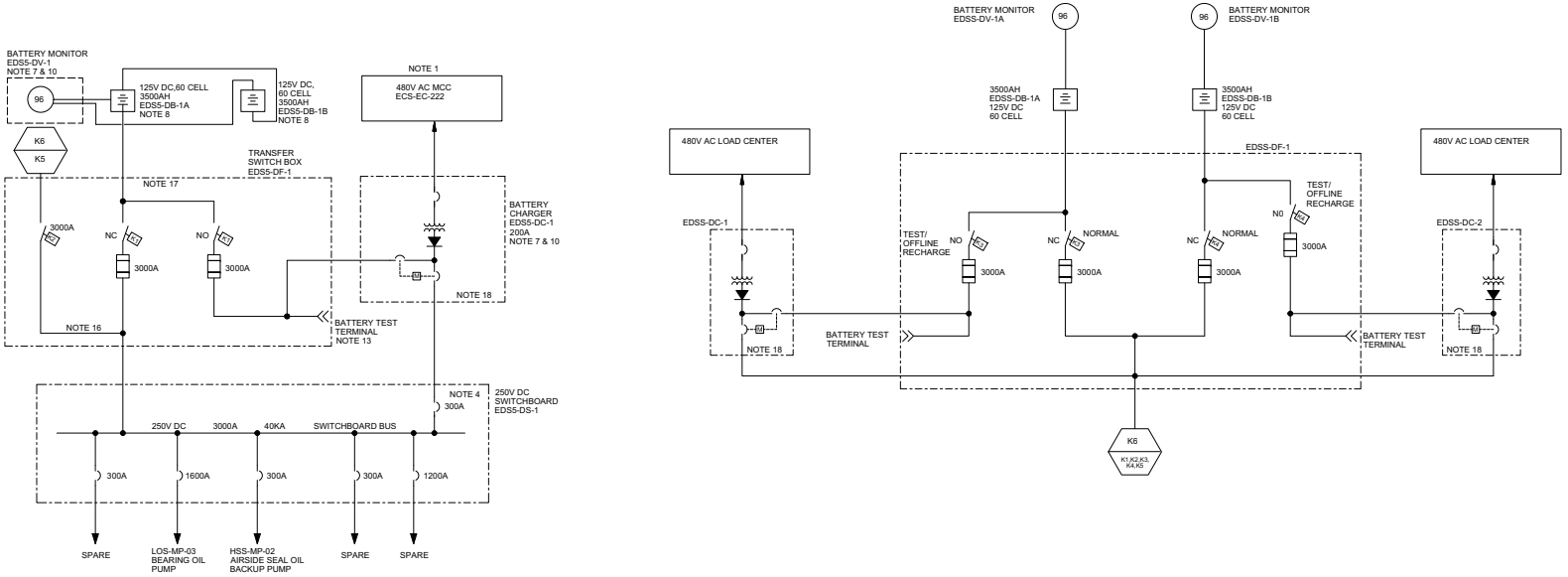
NOTES

1. 480V AC INPUT POWER TO BATTERY CHARGERS AND REGULATING TRANSFORMERS IS PROVIDED FROM ONSITE STANDBY DIESEL GENERATOR BACKED LOAD CENTER.
2. MANUAL MAINTENANCE BYPASS SWITCH WITH OVERLAPPING CONTACTS PERMITS SELECTION OF ALTERNATE SOURCE WITHOUT INTERRUPTION OF POWER AND AT THE SAME TIME ISOLATES THE INVERTER.
3. WHENEVER THE INVERTER OUTPUT VOLTAGE IS OUT OF NORMAL LIMIT THE STATIC SWITCH TRANSFERS THE LOADS AUTOMATICALLY TO THE BACKUP POWER SUPPLY WITHOUT POWER INTERRUPTION. TRANSFER IS INHIBITED IF BACKUP POWER SUPPLY VOLTAGE IS BELOW NORMAL. THE LOADS ARE AUTOMATICALLY RETRANSFERRED WITHOUT POWER INTERRUPTION WHEN THE INVERTER OUTPUT VOLTAGE HAS RETURNED TO NORMAL AND STABILIZED.
4. THE DC SWITCHBOARDS (COMPONENT DESIGNATION "DS") INCLUDE SWITCHES OF APPROPRIATE RATING. HIGHER CURRENT INTERRUPTING RATING, WHERE NEEDED, IS ACHIEVED VIA SERIES CURRENT LIMITING FUSES MOUNTED IN THE MCB ENCLOSURE. SELECTION OF THE DRAWOUT FEATURE, WHERE NECESSARY FOR THE EASE OF MAINTENANCE, WILL BE DETERMINED AT THE TIME OF COMPONENT SPECIFICATION PREPARATION.
5. THE "NORMALLY OPEN" TIE BREAKERS BETWEEN THE TWO DC BUSES CAN BE MANUALLY CLOSED ONLY AFTER ASSURING THAT THE COMBINED BUS LOAD IS WITHIN THE AVAILABLE POWER SOURCE CAPACITY.
6. ALL EQUIPMENT SHOWN ON THIS DRAWING IS NON-SAFETY COMMERCIAL GRADE EQUIPMENT.
7. FOR DC SYSTEM METER AND RELAY DIAGRAM, SEE DWGS. EDS-E3-003 AND 004.
8. BATTERY AMPERE-HOUR RATING IS BASED ON 8 HOURS DISCHARGE RATE.
9. NOT USED.
10. FOR LEGEND AND ABBREVIATION, SEE DWGS GW-E9-001, 002 AND 003.
11. FOR THE LOADS SUPPLIED FROM 208Y/120V AC AND UPS PANELS. SEE NON-CLASS 1E 208Y/120V AC LOAD LIST APP-GW-E0X-051.
12. FOR THE LOADS SUPPLIED FROM 125V DC SWITCHBOARDS AND DISTRIBUTION PANELS, SEE NON-CLASS 1E 125V DC LOAD LIST APP-GW-E0X-051.
13. PLUG-IN TYPE LOCKING DISCONNECTS ARE PROVIDED TO PERMIT CONNECTION TO THE BATTERY TEST LOAD BANK.
14. THE SWITCHBOARD BUS RATING OF 3000 AMP IS BASED ON CONTINUOUS LOAD.
15. REFER TO THE SYSTEM SPECIFICATION DOCUMENT (SSD) # EDS-E8-001 FOR COMPONENT TECHNICAL SPECIFICATIONS.
16. THE SWITCH IS EQUIPPED WITH A KIRK-KEY INTERLOCK TO PREVENT SPARE BATTERY CONNECTION TO MORE THAN ONE SWITCH BOARD AT ANY TIME.
17. THIS MAY BE A BREAKER OR FUSED SWITCH IN ORDER TO ACCOMMODATE ISOLATION OF THE STATIC TRANSFER SWITCH.
18. A PROTECTIVE DEVICE EXISTS HERE. THIS WAY MAY BE A BREAKER OR A FUSE.

REFERENCE DRAWINGS/DOCUMENTS

TITLE	DWG. NO.
AC POWER SYSTEM - STATION ONE LINE DIAGRAM	FIG 8.3.1-1
NON-CLASS 1E DC & UPS SYSTEM ONE LINE DIAGRAM	FIG 8.3.2-3
NON-CLASS 1E DC & UPS SYSTEM ONE LINE METER & RELAY DIAGRAMS (PART III & IV)	EDS-E3-005 & 6
EDS SYSTEM SPECIFICATION DOCUMENT	EDS-E8-001

Figure 8.3.2-3 (Sheet 2 of 3)
Non-Class 1E DC & UPS System One Line Diagram



NOTES

1. 480V AC INPUT POWER TO BATTERY CHARGERS IS PROVIDED FROM ONSITE STANDBY DIESEL GENERATOR BACKED MOTOR CONTROL CENTERS.
2. NOT USED
3. NOT USED
4. THE DC SWITCHBOARDS (COMPONENT DESIGNATION "DS") INCLUDE MOLDED CASE CIRCUIT BREAKERS OF APPROPRIATE RATING. HIGHER CURRENT INTERRUPTING RATING, WHERE NEEDED, IS ACHIEVED VIA SERIES CURRENT LIMITING FUSES MOUNTED IN THE MCB ENCLOSURE. SELECTION OF THE DRAWOUT FEATURE, WHERE NECESSARY FOR THE EASE OF MAINTENANCE, WILL BE DETERMINED AT THE TIME OF COMPONENT SPECIFICATION PREPARATION.
5. NOT USED
6. ALL EQUIPMENT SHOWN ON THIS DRAWING IS NNS COMMERCIAL GRADE EQUIPMENT.
7. FOR NON-CLASS 1E DC SYSTEM METER AND RELAY DIAGRAM. SEE DWGS. EDS-E3-003 AND 004.
8. BATTERY AMPERE-HOUR RATING IS BASED ON 8 HOURS DISCHARGE RATE.
9. NOT USED
10. FOR LEGEND AND ABBREVIATION, SEE DWGS GW-E9-001, 002 AND 003.
11. NOT USED
12. NOT USED
13. PLUG-IN TYPE LOCKING DISCONNECTS ARE PROVIDED TO PERMIT CONNECTION TO THE BATTERY TEST LOAD BANK.
14. THE SWITCHBOARD BUS RATING OF 3000 AMP IS BASED ON CONTINUOUS LOAD.
15. REFER TO THE SYSTEM SPECIFICATION DOCUMENT (SSD) # APP-EDS-E8-001 FOR COMPONENT TECHNICAL SPECIFICATIONS.
16. THE SWITCH IS EQUIPPED WITH A KIRK-KEY INTERLOCK TO PREVENT SPARE BATTERY CONNECTION TO MORE THAN ONE SWITCH BOARD AT ANY TIME.
17. KIRK-KEY INTERLOCKS ARE PROVIDED TO PREVENT CLOSURE OF SWITCHES AT SAME TIME.
18. MECHANICALLY INTERLOCKED, ONLY ONE BREAKER CAN BE CLOSED AT A TIME.

REFERENCE DRAWINGS/DOCUMENTS

TITLE	DWG. NO.
AC POWER SYSTEM - STATION ONE LINE DIAGRAM	FIG. 8.3.1-1
NON-CLASS 1E DC & UPS SYSTEM ONE LINE DIAGRAM	FIG. 8.3.2-3
NON-CLASS 1E DC & UPS SYSTEM ONE LINE METER & RELAY DIAGRAMS (PART I & II)	EDS-E3-003 & 4
EDS SYSTEM SPECIFICATION DOCUMENT	EDS-E8-001

Figure 8.3.2-3 (Sheet 3 of 3)
Non-Class 1E DC & UPS System One Line Diagram

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 9	AUXILIARY SYSTEMS	9.1-1
9.1	Fuel Storage and Handling	9.1-1
9.1.1	New Fuel Storage	9.1-1
9.1.1.1	Design Bases	9.1-1
9.1.1.2	Facilities Description	9.1-1
9.1.1.3	Safety Evaluation	9.1-3
9.1.2	Spent Fuel Storage	9.1-4
9.1.2.1	Design Bases	9.1-4
9.1.2.2	Facilities Description	9.1-5
9.1.2.3	Safety Evaluation	9.1-10
9.1.3	Spent Fuel Pool Cooling System	9.1-10
9.1.3.1	Design Basis	9.1-11
9.1.3.2	System Description	9.1-13
9.1.3.3	Component Description	9.1-14
9.1.3.4	System Operation and Performance	9.1-17
9.1.3.5	Safety Evaluation	9.1-21
9.1.3.6	Inspection and Testing Requirements	9.1-22
9.1.3.7	Instrumentation Requirements	9.1-23
9.1.4	Light Load Handling System (Related to Refueling)	9.1-24
9.1.4.1	Design Basis	9.1-24
9.1.4.2	System Description	9.1-25
9.1.4.3	Safety Evaluation	9.1-30
9.1.4.4	Inspection and Testing Requirements	9.1-35
9.1.5	Overhead Heavy Load Handling Systems	9.1-36
9.1.5.1	Design Basis	9.1-37
9.1.5.2	System Description	9.1-39
9.1.5.3	Safety Evaluation	9.1-45
9.1.5.4	Inservice Inspection/Inservice Testing	9.1-47
9.1.5.5	Load Handling Procedures	9.1-47
9.1.6	Combined License Information for Fuel Storage and Handling	9.1-48
9.1.6.1	Structural Dynamic and Stress Analysis for New Fuel Rack	9.1-48
9.1.6.2	Criticality Analysis for New Fuel Rack	9.1-48
9.1.6.3	Structural Dynamic and Stress Analysis for Spent Fuel Racks	9.1-48
9.1.6.4	Criticality Analysis for Spent Fuel Racks	9.1-48
9.1.6.5	Inservice Inspection Load Handling Systems	9.1-48
9.1.6.6	Operating Radiation Monitor	9.1-49
9.1.6.7	Coupon Monitoring Program	9.1-49
9.1.7	References	9.1-50
9.2	Water Systems	9.2-1
9.2.1	Service Water System	9.2-1
9.2.1.1	Design Basis	9.2-1
9.2.1.2	System Description	9.2-1
9.2.1.3	Safety Evaluation	9.2-6
9.2.1.4	Tests and Inspections	9.2-6
9.2.1.5	Instrument Applications	9.2-6

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
9.2.2	Component Cooling Water System	9.2-6
9.2.2.1	Design Bases	9.2-7
9.2.2.2	System Description	9.2-8
9.2.2.3	Component Description	9.2-9
9.2.2.4	System Operation and Performance	9.2-11
9.2.2.5	Evaluation	9.2-14
9.2.2.6	Inspection and Testing Requirements	9.2-14
9.2.2.7	Instrumentation Requirements	9.2-15
9.2.3	Demineralized Water Treatment System	9.2-15
9.2.3.1	Design Basis	9.2-15
9.2.3.2	System Description	9.2-16
9.2.3.3	Safety Evaluation	9.2-19
9.2.3.4	Tests and Inspections	9.2-19
9.2.3.5	Instrumentation Applications	9.2-19
9.2.4	Demineralized Water Transfer and Storage System	9.2-19
9.2.4.1	Design Basis	9.2-20
9.2.4.2	System Description	9.2-20
9.2.4.3	System Operation	9.2-21
9.2.4.4	Safety Evaluation	9.2-22
9.2.4.5	Tests and Inspections	9.2-23
9.2.4.6	Instrumentation Applications	9.2-23
9.2.5	Potable Water System	9.2-23
9.2.5.1	Design Basis	9.2-23
9.2.5.2	System Description	9.2-24
9.2.5.3	System Operation	9.2-25
9.2.5.4	Safety Evaluation	9.2-25
9.2.5.5	Tests and Inspections	9.2-25
9.2.5.6	Instrumentation Applications	9.2-25
9.2.6	Sanitary Drainage System	9.2-26
9.2.6.1	Design Basis	9.2-26
9.2.6.2	System Description	9.2-26
9.2.6.3	Safety Evaluation	9.2-27
9.2.6.4	Test and Inspection	9.2-27
9.2.6.5	Instrument Application	9.2-28
9.2.7	Central Chilled Water System	9.2-28
9.2.7.1	Design Basis	9.2-28
9.2.7.2	System Description	9.2-28
9.2.7.3	Safety Evaluation	9.2-32
9.2.7.4	Inservice Inspection/Inservice Testing	9.2-32
9.2.8	Turbine Building Closed Cooling Water System	9.2-33
9.2.8.1	Design Basis	9.2-33
9.2.8.2	System Description	9.2-33
9.2.8.3	Safety Evaluation	9.2-36
9.2.8.4	Tests and Inspections	9.2-36
9.2.8.5	Instrument Applications	9.2-36
9.2.9	Waste Water System	9.2-36
9.2.9.1	Design Basis	9.2-36
9.2.9.2	System Description	9.2-37

TABLE OF CONTENTS (CONTINUED)

Section		Title	Page
		9.2.9.3 Safety Evaluation	9.2-39
		9.2.9.4 Tests and Inspections	9.2-39
		9.2.9.5 Instrumentation Applications	9.2-39
	9.2.10	Hot Water Heating System	9.2-40
		9.2.10.1 Design Basis	9.2-40
		9.2.10.2 System Description	9.2-40
		9.2.10.3 Safety Evaluation	9.2-42
		9.2.10.4 Tests and Inspections	9.2-42
		9.2.10.5 Instrument Applications	9.2-42
	9.2.11	Raw Water System	9.2-43
		9.2.11.1 Design Basis	9.2-43
		9.2.11.2 System Description	9.2-44
		9.2.11.3 System Operation	9.2-47
		9.2.11.4 Safety Evaluation	9.2-49
		9.2.11.5 Tests and Inspections	9.2-49
		9.2.11.6 Instrumentation Applications	9.2-49
	9.2.12	Combined License Information	9.2-50
		9.2.12.1 Potable Water	9.2-50
		9.2.12.2 Waste Water Retention Basins	9.2-50
	9.2.13	References	9.2-50
9.3		Process Auxiliaries	9.3-1
	9.3.1	Compressed and Instrument Air System	9.3-1
		9.3.1.1 Design Basis	9.3-1
		9.3.1.2 System Description	9.3-1
		9.3.1.3 Safety Evaluation	9.3-5
		9.3.1.4 Tests and Inspections	9.3-5
		9.3.1.5 Instrumentation Applications	9.3-5
	9.3.2	Plant Gas System	9.3-6
		9.3.2.1 Design Basis	9.3-6
		9.3.2.2 System Description	9.3-6
		9.3.2.3 Safety Evaluation	9.3-8
		9.3.2.4 Tests and Inspections	9.3-8
		9.3.2.5 Instrumentation Requirements	9.3-8
	9.3.3	Primary Sampling System	9.3-8
		9.3.3.1 Design Bases	9.3-9
		9.3.3.2 System Description	9.3-10
		9.3.3.3 Containment Isolation Valves	9.3-11
		9.3.3.4 System Operation and Performance	9.3-11
		9.3.3.5 Design Evaluation	9.3-11
		9.3.3.6 Inspection and Testing Requirements	9.3-12
		9.3.3.7 Instrumentation Requirements	9.3-12
	9.3.4	Secondary Sampling System	9.3-12
		9.3.4.1 Design Basis	9.3-12
		9.3.4.2 System Description	9.3-13
		9.3.4.3 Safety Evaluation	9.3-13
		9.3.4.4 Tests and Inspections	9.3-13
		9.3.4.5 Instrumentation Applications	9.3-13
	9.3.5	Equipment and Floor Drainage Systems	9.3-13

TABLE OF CONTENTS (CONTINUED)

Section			Title	Page
		9.3.5.1	Design Basis	9.3-14
		9.3.5.2	System Description	9.3-15
		9.3.5.3	Safety Evaluation	9.3-17
		9.3.5.4	Tests and Inspections	9.3-17
	9.3.6		Chemical and Volume Control System	9.3-17
		9.3.6.1	Design Bases	9.3-18
		9.3.6.2	System Description	9.3-20
		9.3.6.3	Component Descriptions	9.3-24
		9.3.6.4	System Operation and Performance	9.3-30
		9.3.6.5	Design Evaluation	9.3-34
		9.3.6.6	Inspection and Testing Requirements	9.3-34
		9.3.6.7	Instrumentation Requirements	9.3-35
		9.3.6.8	System Gas Accumulation Assessment and Mitigation	9.3-37
	9.3.7		Combined License Information	9.3-37
	9.3.8		References	9.3-37
9.4			Air-Conditioning, Heating, Cooling, and Ventilation System	9.4-1
	9.4.1		Nuclear Island Nonradioactive Ventilation System	9.4-1
		9.4.1.1	Design Basis	9.4-1
		9.4.1.2	System Description	9.4-4
		9.4.1.3	Safety Evaluation	9.4-14
		9.4.1.4	Tests and Inspection	9.4-14
		9.4.1.5	Instrumentation Applications	9.4-15
	9.4.2		Annex/Auxiliary Buildings Nonradioactive HVAC System	9.4-16
		9.4.2.1	Design Basis	9.4-16
		9.4.2.2	System Description	9.4-17
		9.4.2.3	Safety Evaluation	9.4-26
		9.4.2.4	Tests and Inspections	9.4-26
		9.4.2.5	Instrumentation Applications	9.4-27
	9.4.3		Radiologically Controlled Area Ventilation System	9.4-27
		9.4.3.1	Design Basis	9.4-27
		9.4.3.2	System Description	9.4-30
		9.4.3.3	Safety Evaluation	9.4-36
		9.4.3.4	Tests and Inspections	9.4-36
		9.4.3.5	Instrumentation Applications	9.4-36
	9.4.4		Balance-of-Plant-Interface	9.4-37
	9.4.5		Engineered Safety Features Ventilation System	9.4-37
	9.4.6		Containment Recirculation Cooling System	9.4-37
		9.4.6.1	Design Basis	9.4-37
		9.4.6.2	System Description	9.4-38
		9.4.6.3	Safety Evaluation	9.4-40
		9.4.6.4	Tests and Inspections	9.4-40
		9.4.6.5	Instrumentation Application	9.4-40
	9.4.7		Containment Air Filtration System	9.4-41
		9.4.7.1	Design Basis	9.4-41
		9.4.7.2	System Description	9.4-42
		9.4.7.3	Safety Evaluation	9.4-47
		9.4.7.4	Tests and Inspections	9.4-48

TABLE OF CONTENTS (CONTINUED)

Section		Title	Page
		9.4.7.5 Instrumentation Application	9.4-48
	9.4.8	Radwaste Building HVAC System	9.4-49
		9.4.8.1 Design Basis	9.4-49
		9.4.8.2 System Description	9.4-50
		9.4.8.3 Safety Evaluation	9.4-53
		9.4.8.4 Tests and Inspections	9.4-53
		9.4.8.5 Instrumentation Applications	9.4-53
	9.4.9	Turbine Building Ventilation System	9.4-54
		9.4.9.1 Design Basis	9.4-54
		9.4.9.2 System Description	9.4-54
		9.4.9.3 System Operation	9.4-57
		9.4.9.4 Safety Evaluation	9.4-57
		9.4.9.5 Tests and Inspections	9.4-57
		9.4.9.6 Instrumentation Applications	9.4-58
	9.4.10	Diesel Generator Building Heating and Ventilation System	9.4-58
		9.4.10.1 Design Basis	9.4-58
		9.4.10.2 System Description	9.4-59
		9.4.10.3 Safety Evaluation	9.4-63
		9.4.10.4 Tests and Inspection	9.4-64
		9.4.10.5 Instrumentation Applications	9.4-64
	9.4.11	Health Physics and Hot Machine Shop HVAC System	9.4-64
		9.4.11.1 Design Basis	9.4-64
		9.4.11.2 System Description	9.4-65
		9.4.11.3 Safety Evaluation	9.4-68
		9.4.11.4 Tests and Inspections	9.4-68
		9.4.11.5 Instrumentation Application	9.4-68
	9.4.12	Combined License Information	9.4-68
	9.4.13	References	9.4-69
9.5		Other Auxiliary Systems	9.5-1
	9.5.1	Fire Protection System	9.5-1
		9.5.1.1 Design Basis	9.5-1
		9.5.1.2 System Description	9.5-2
		9.5.1.3 Safety Evaluation (Fire Protection Analysis)	9.5-12
		9.5.1.4 Testing and Inspection	9.5-13
		9.5.1.5 Instrumentation Applications	9.5-13
		9.5.1.6 Personnel Qualification and Training	9.5-14
		9.5.1.7 Quality Assurance	9.5-14
		9.5.1.8 Fire Protection Program	9.5-14
		9.5.1.9 Combined License Information	9.5-23
	9.5.2	Communication System	9.5-23
		9.5.2.1 Design Basis	9.5-24
		9.5.2.2 System Description	9.5-24
		9.5.2.3 System Operation Communication Stations	9.5-27
		9.5.2.4 Inspection and Testing Requirements	9.5-27
		9.5.2.5 Combined License Information	9.5-27
	9.5.3	Plant Lighting System	9.5-27
		9.5.3.1 Design Basis	9.5-27
		9.5.3.2 System Description	9.5-28

TABLE OF CONTENTS (CONTINUED)

Section			Title	Page
		9.5.3.3	Safety Evaluation	9.5-30
		9.5.3.4	Test and Inspections	9.5-30
		9.5.3.5	Combined License Information for Plant Lighting	9.5-31
	9.5.4		Standby Diesel Fuel Oil System	9.5-31
		9.5.4.1	Design Basis	9.5-31
		9.5.4.2	System Description Storage and Transfer	9.5-31
		9.5.4.3	Safety Evaluation	9.5-34
		9.5.4.4	System Evaluation	9.5-34
		9.5.4.5	Tests and Inspections	9.5-34
		9.5.4.6	Instrumentation Applications	9.5-35
		9.5.4.7	Combined License Information	9.5-36
	9.5.5		References	9.5-36
APPENDIX 9A			FIRE PROTECTION ANALYSIS	9A-1
9A.1			Introduction	9A-1
9A.2			Fire Protection Analysis Methodology	9A-1
	9A.2.1		Fire Area Description	9A-1
	9A.2.2		Combustible Material Survey	9A-2
	9A.2.3		Fire Severity Categorization	9A-2
	9A.2.4		Combustible Loading and Equivalent Fire Duration Calculations	9A-2
	9A.2.5		Fire Protection Adequacy	9A-3
	9A.2.6		Fire Protection System Integrity	9A-4
	9A.2.7		Safe Shutdown Evaluation	9A-4
		9A.2.7.1	Criteria and Assumptions	9A-4
		9A.2.7.2	Safe Shutdown Methodology	9A-9
9A.3			Fire Protection Analysis Results	9A-9
	9A.3.1		Nuclear Island	9A-10
		9A.3.1.1	Containment/Shield Building	9A-11
		9A.3.1.2	Auxiliary Building - Nonradiologically Controlled Areas	9A-31
		9A.3.1.3	Auxiliary Building - Radiologically Controlled Areas	9A-65
	9A.3.2		Turbine Building	9A-74
		9A.3.2.1	Fire Area 2000 AF 01	9A-74
		9A.3.2.2	Fire Area 2000 AF 02	9A-77
		9A.3.2.3	Fire Area 2009 AF 01	9A-77
		9A.3.2.4	Fire Area 2009 AF 02	9A-77
		9A.3.2.5	Not used.	9A-78
		9A.3.2.6	Not used.	9A-78
		9A.3.2.7	Fire Area 2000 AF 03	9A-78
		9A.3.2.8	Not used.	9A-78
		9A.3.2.9	Fire Area 2040 AF 01	9A-78
		9A.3.2.10	Fire Area 2043 AF 01	9A-79
		9A.3.2.11	Fire Area 2050 AF 01	9A-80
		9A.3.2.12	Fire Area 2052 AF 01	9A-81
		9A.3.2.13	Fire Area 2053 AF 01	9A-81
		9A.3.2.14	Fire Area 2053 AF 02	9A-82
		9A.3.2.15	Fire Area 2151 AF 01	9A-83

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	9A.3.2.16 Fire Area 2151 AF 02	9A-84
	9A.3.2.17 Fire Area 2000 AF 15	9A-84
9A.3.3	Yard Area and Outlying Buildings	9A-85
9A.3.4	Annex Building	9A-85
	9A.3.4.1 Fire Area 4001 AF 01	9A-86
	9A.3.4.2 Fire Area 4001 AF 02	9A-86
	9A.3.4.3A Fire Area 4002 AF 01	9A-87
	9A.3.4.3B Fire Area 4002 AF 03	9A-87
	9A.3.4.4 Fire Area 4002 AF 02	9A-88
	9A.3.4.5 Fire Area 4003 AF 01	9A-88
	9A.3.4.6 Fire Area 4003 AF 02	9A-89
	9A.3.4.7 Fire Area 4031 AF 01	9A-90
	9A.3.4.8 Fire Area 4031 AF 02	9A-90
	9A.3.4.9 Fire Area 4031 AF 05	9A-92
	9A.3.4.10 Fire Area 4031 AF 06	9A-93
	9A.3.4.11 Fire Area 4032 AF 01	9A-93
	9A.3.4.12 Fire Area 4032 AF 02	9A-94
	9A.3.4.13 Fire Area 4033 AF 01	9A-95
	9A.3.4.14 Fire Area 4034 AF 01	9A-96
	9A.3.4.15 Fire Area 4035 AF 01	9A-98
	9A.3.4.16 Fire Area 4041 AF 01	9A-98
	9A.3.4.17 Fire Area 4041 AF 02	9A-99
	9A.3.4.18 Fire Area 4042 AF 01	9A-100
	9A.3.4.19 Fire Area 4042 AF 02	9A-101
	9A.3.4.20 Fire Area 4051 AF 01	9A-102
	9A.3.4.21 Fire Area 4052 AF 01	9A-103
9A.3.5	Radwaste Building	9A-104
	9A.3.5.1 Fire Area 5031 AF 01	9A-104
9A.3.6	Diesel Generator Building	9A-105
	9A.3.6.1 Fire Area 6030 AF 01	9A-106
	9A.3.6.2 Fire Area 6030 AF 02	9A-107
	9A.3.6.3 Fire Area 6030 AF 03	9A-108
	9A.3.6.4 Fire Area 6030 AF 04	9A-109
	9A.3.6.5 Fire Area 6001 AF 01	9A-109
9A.3.7	Special Topics	9A-110
	9A.3.7.1 Evaluation of Spurious Actuation	9A-110
	9A.3.7.2 Protection of Accident Mitigation Equipment	9A-112
9A.4	References	9A-112

LIST OF TABLES

Table Number	Title	Page
9.1-1	Loads and Load Combinations for Fuel Racks	9.1-52
9.1-2	Spent Fuel Pool Cooling and Purification System Design Parameters	9.1-53
9.1-3	Component Data – Spent Fuel Pool Cooling and Purification System	9.1-54
9.1-4	Station Blackout/Seismic Event Times	9.1-56
9.1-5	Nuclear Island Heavy Load Handling Systems	9.1-57
9.1.5-1	Cask Handling Crane Component Data	9.1-58
9.1.5-2	Special Lifting Devices Used for the Handling of Critical Loads	9.1-59
9.1.5-3	Polar Crane Component Data	9.1-60
9.1.5-4	Equipment/Maintenance Hatch Hoist Component Data	9.1-61
9.2.1-1	Nominal Service Water Flows and Heat Loads at Different Operating Modes	9.2-51
9.2.2-1	Nominal Component Data - Component Cooling Water System	9.2-52
9.2.2-2	Plant Components Cooled by Component Cooling Water System	9.2-53
9.2.3-1	Guidelines for Demineralized Water (Measured at the Outlet of the Demineralized Water Treatment System)	9.2-54
9.2.7-1	Component Data - Central Chilled Water System (Nominal Values)	9.2-55
9.2.8-1	Turbine Building Closed Cooling Water System Equipment Load List	9.2-56
9.2.10-1	Hot Water Heating System Design Data (Nominal Values)	9.2-57
9.3.1-1	Safety-Related Air-Operated Valves	9.3-39
9.3.1-2	Nominal Component Design Data - Instrument Air Subsystem	9.3-41
9.3.1-3	Nominal Component Design Data - Service Air Subsystem	9.3-42
9.3.1-4	Nominal Component Design Data - High-pressure Air Subsystem	9.3-43
9.3.3-1	Primary Sampling System Sample Points - Normal Plant Operations (Liquid And Gaseous)	9.3-44
9.3.3-2	Local Sample Points Not in the Primary Sampling System (Normal Plant Operations)	9.3-45
9.3.4-1	Secondary Sampling System (Continuous and Semi-Continuous Measurements)	9.3-49
9.3.4-2	Secondary Sampling System (Selective Measurements)	9.3-51
9.3.5-1	Component Data - Radioactive Waste Drains System (Nominal Values)	9.3-52
9.3.6-1	Chemical and Volume Control System Parameters	9.3-53
9.3.6-2	Chemical and Volume Control System Nominal Equipment Design Parameters	9.3-54
9.4-1	Design Filtration Efficiencies and Nominal Airflow Rates for HVAC Systems	9.4-71
9.4.1-1	Component Data – Nuclear Island Nonradioactive Ventilation System MCR/CSA HVAC Subsystem (Nominal Values)	9.4-72
9.4.1-2	Component Data – Nuclear Island Nonradioactive Ventilation System Class 1E Electrical Room HVAC Subsystem (Nominal Values)	9.4-74
9.4.1-3	Component Data – Nuclear Island Nonradioactive Ventilation System Passive Containment Cooling System Valve Room Heating and Ventilation Subsystem (Nominal Values)	9.4-77
9.4.2-1	Component Data – Annex/Auxiliary Buildings Nonradioactive HVAC System Switchgear Room HVAC Subsystem (Nominal Values)	9.4-78
9.4.2-2	Component Data – Annex/Auxiliary Buildings Nonradioactive HVAC System Equipment Room HVAC System (Nominal Values)	9.4-79
9.4.3-1	Component Data – Radiologically Controlled Area Ventilation System Auxiliary/Annex Building Ventilation Subsystem (Nominal Values)	9.4-80

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
9.4.6-1	Component Data – Containment Recirculation Cooling System (Nominal Design Values)	9.4-81
9.4.7-1	Component Data – Containment Air Filtration System (Nominal Values)	9.4-82
9.4.10-1	Component Data – Diesel Generator Building Heating And Ventilation System Normal Heating and Ventilation Subsystem (Nominal Values)	9.4-84
9.4.10-2	Component Data – Diesel Generator Building Heating and Ventilation System Standby Exhaust Ventilation Subsystem (Nominal Values)	9.4-86
9.4.10-3	Component Data – Diesel Generator Building Heating and Ventilation System Fuel Oil Day Tank Vault Exhaust Subsystem (Nominal Values)	9.4-87
9.4.10-4	Component Data – Diesel Generator Building Heating and Ventilation System Diesel Oil Transfer Module Enclosures Ventilation and Heating Subsystem (Nominal Values)	9.4-88
9.5.1-1	AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1	9.5-39
9.5.1-2	Component Data - Fire Protection System (Nominal Values)	9.5-71
9.5.1-3	Exceptions to NFPA Standard Requirements	9.5-72
9.5.1-4	Capabilities Used to Achieve Cold Shutdown Following a Fire	9.5-75
9.5.2-1	Communication Equipment and Locations	9.5-76
9.5.4-1	Nominal Component Data Standby Diesel Fuel Oil System	9.5-77
9.5.4-2	Indicating and Alarm Devices - Standby Diesel Fuel System	9.5-79
9.5-201	Not Used	9.5-80
9.5-202	Not Used	9.5-80
9A-1	Heat of Combustion Values	9A-114
9A-2	Safe Shutdown Components	9A-115
9A-3	Fire Protection Summary	9A-129
9A-4	Ventilation Systems Serving Fire Areas Containing Class 1E Components	9A-153

LIST OF FIGURES

Figure Number	Title	Page
9.1-1	(Sheet 1 of 2) New Fuel Storage Rack Layout (72 Storage Location)	9.1-62
9.1-1	(Sheet 2 of 2) New Fuel Storage Rack Cross Section	9.1-63
9.1-2	(Sheet 1 of 2) Region 1 Spent Fuel Storage Rack Layout	9.1-64
9.1-2	(Sheet 2 of 2) Region 1 Spent Fuel Storage Rack Cross Section	9.1-65
9.1-3	(Sheet 1 of 2) Region 2 Spent Fuel Storage Rack Layout	9.1-66
9.1-3	(Sheet 2 of 2) Region 2 Spent Fuel Storage Rack Cross Section	9.1-67
9.1-4	Spent Fuel Storage Pool Layout	9.1-68
9.1-5	Spent Fuel Pool Cooling System (Normal Operation)	9.1-69
9.1-6	(Sheet 1 of 2) Simplified Spent Fuel Pool Cooling System Piping and Instrumentation Diagram	9.1-70
9.1-6	(Sheet 2 of 2) Simplified Spent Fuel Pool Cooling System Piping and Instrumentation Diagram	9.1-71
9.2.1-1	Simplified Service Water System Piping and Instrumentation Diagram	9.2-58
9.2.2-1	Component Cooling Water System Simplified Flow Diagram	9.2-59
9.2.2-2	(Sheet 1 of 5) Simplified Component Cooling Water System Piping and Instrumentation Diagram	9.2-60
9.2.2-2	(Sheet 2 of 5) Simplified Component Cooling Water System Piping and Instrumentation Diagram	9.2-61
9.2.2-2	(Sheet 3 of 5) Simplified Component Cooling Water System Piping and Instrumentation Diagram	9.2-62
9.2.2-2	(Sheet 4 of 5) Simplified Component Cooling Water System Piping and Instrumentation Diagram	9.2-63
9.2.2-2	(Sheet 5 of 5) Simplified Component Cooling Water System Piping and Instrumentation Diagram	9.2-64
9.2.4-1	Demineralized Water Transfer and Storage System Containment Isolation Provision	9.2-65
9.2.5-1	Main Control Room Potable Water System Isolation	9.2-66
9.2.7-1	(Sheet 1 of 4) Simplified Central Chilled Water System Piping and Instrumentation Diagram	9.2-67
9.2.7-1	(Sheet 2 of 4) Simplified Central Chilled Water System Piping and Instrumentation Diagram	9.2-68
9.2.7-1	(Sheet 3 of 4) Simplified Central Chilled Water System Piping and Instrumentation Diagram	9.2-69
9.2.7-1	(Sheet 4 of 4) High Capacity Subsystem Simplified Sketch	9.2-70
9.2-201	(Sheet 1 of 2) Simplified Raw Water System River Water Subsystem Piping and Instrumentation Diagram	9.2-71
9.2-201	(Sheet 2 of 2) Simplified Raw Water System Well Water Subsystem Piping and Instrumentation Diagram	9.2-72
9.3.1-1	(Sheet 1 of 3) Compressed & Instrument Air System Piping and Instrumentation Diagram	9.3-57
9.3.1-1	(Sheet 2 of 3) Compressed & Instrument Air System Piping and Instrumentation Diagram	9.3-58
9.3.1-1	(Sheet 3 of 3) Compressed & Instrument Air System Piping and Instrumentation Diagram	9.3-59
9.3.3-1	Simplified Sketch of the Primary Sampling System	9.3-60
9.3.5-1	General Arrangement of Drainage Systems	9.3-61
9.3.6-1	(Sheet 1 of 2) Simplified Chemical and Volume Control System Piping and Instrumentation	9.3-62

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
9.3.6-1	(Sheet 2 of 2) Simplified Chemical and Volume Control System Piping and Instrumentation	9.3-63
9.4.1-1	(Sheet 1 of 7) Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-89
9.4.1-1	(Sheet 2 of 7) Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-90
9.4.1-1	(Sheet 3 of 7) Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-91
9.4.1-1	(Sheet 4 of 7) Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-92
9.4.1-1	(Sheet 5 of 7) Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-93
9.4.1-1	(Sheet 6 of 7) Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation System	9.4-94
9.4.1-1	(Sheet 7 of 7) Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-95
9.4.2-1	(Sheet 1 of 7) Simplified Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-96
9.4.2-1	(Sheet 2 of 7) Simplified Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-97
9.4.2-1	(Sheet 3 of 7) Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-98
9.4.2-1	(Sheet 4 of 7) Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-99
9.4.2-1	(Sheet 5 of 7) Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-100
9.4.2-1	(Sheet 6 of 7) Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-101
9.4.2-1	(Sheet 7 of 7) Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram	9.4-102
9.4.3-1	(Sheet 1 of 4) Simplified Radiologically Controlled Ventilation System Piping and Instrumentation Diagram	9.4-103
9.4.3-1	(Sheet 2 of 4) Radiologically Controlled Area Ventilation System Piping and Instrumentation Diagram	9.4-104
9.4.3-1	(Sheet 3 of 4) Radiologically Controlled Area Ventilation System Piping and Instrumentation Diagram	9.4-105
9.4.3-1	(Sheet 4 of 4) Inside Auxiliary Building Simplified Radiologically Controlled Ventilation System Piping and Instrumentation Diagram	9.4-106
9.4.6-1	Simplified Containment Recirculation Cooling System Piping and Instrumentation Diagram	9.4-107
9.4.7-1	(Sheet 1 of 2) Simplified Containment Air Filtration System Piping and Instrumentation Diagram	9.4-108
9.4.7-1	(Sheet 2 of 2) Simplified Containment Air Filtration System Piping and Instrumentation Diagram	9.4-109
9.4.8-1	Radwaste Building HVAC System	9.4-110
9.4.9-1	Turbine Building HVAC System	9.4-111
9.4.10-1	(Sheet 1 of 2) Simplified Diesel Generator Building Heating and Ventilation System Piping and Instrumentation Diagram	9.4-112

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
9.4.10-1	(Sheet 2 of 2) Simplified Diesel Generator Building Heating and Ventilation System Piping and Instrumentation Diagram	9.4-113
9.4.11-1	Health Physics and Hot Machine Shop HVAC System	9.4-114
9.5.1-1	(Sheet 1 of 3) Simplified Fire Protection System Piping and Instrumentation Diagram	9.5-81
9.5.1-1	(Sheet 2 of 3) Simplified Fire Protection System Piping and Instrumentation Diagram	9.5-82
9.5.1-1	(Sheet 3 of 3) Simplified Fire Protection System Piping and Instrumentation Diagram	9.5-83
9.5.4-1	(Sheet 1 of 3) Simplified Standby Diesel Fuel Oil System Piping and Instrumentation Diagram	9.5-84
9.5.4-1	(Sheet 2 of 3) Simplified Standby Diesel Fuel Oil System Piping and Instrumentation Diagram	9.5-85
9.5.4-1	(Sheet 3 of 3) Simplified Standby Diesel Fuel Oil System Piping and Instrumentation Diagram	9.5-86
9A-1	(Sheet 1 of 16) Fire Areas Legend	9A-154
9A-1	(Sheet 2 of 16) Nuclear Island Fire Area Plan at Elevation 66'-6"	9A-155
9A-1	(Sheet 3 of 16) Nuclear Island Fire Area Plan at Elevation 82'-6"	9A-156
9A-1	(Sheet 4 of 16) Nuclear Island Fire Area Plan at Elevation 96'-6″	9A-157
9A-1	(Sheet 5 of 16) Nuclear Island Fire Areas Plan at Elevation 100'-0″ & 107'-2″	9A-158
9A-1	(Sheet 6 of 16) Nuclear Island Fire Area Plan at Elevation 117'-6″	9A-159
9A-1	(Sheet 7 of 16) Nuclear Island Fire Area Plan at Elevation 135'-3″	9A-160
9A-1	(Sheet 8 of 16) Nuclear Island Fire Areas Plan at Elevation 153'-0" & 160'-6″	9A-161
9A-1	(Sheet 9 of 16) Nuclear Island Fire Areas Plan at Elevation 160'-6″, 180'-0″, & 329'-0"	9A-162
9A-1	(Sheet 10 of 16) Nuclear Island Fire Area Section A-A	9A-163
9A-1	(Sheet 11 of 16) Nuclear Island Fire Area Section B-B	9A-164
9A-1	(Sheet 12 of 16) Nuclear Island Fire Areas Section C-C & H-H	9A-165
9A-1	(Sheet 13 of 16) Nuclear Island Fire Area Section G-G	9A-166
9A-1	(Sheet 14 of 16) Nuclear Island Fire Area Section J-J	9A-167
9A-1	(Sheet 15 of 16) Nuclear Island Fire Area Section K-K	9A-168
9A-1	(Sheet 16 of 16) Nuclear Island Fire Areas Section I-I & R-R	9A-169
9A-2	(Sheet 1 of 5) Turbine Building Fire Area Plan at Elevation 100′-0″	9A-170
9A-2	(Sheet 2 of 5) Turbine Building Fire Area Plan at Elevation 120'-6"	9A-171
9A-2	(Sheet 3 of 5) Turbine Building Fire Area Plan at Elevation 141′-3″	9A-172
9A-2	(Sheet 4 of 5) Turbine Building Fire Area Plan at Elevation 170′-0″	9A-173
9A-2	(Sheet 5 of 5) Turbine Building Fire Areas Plan at Elevation 255′-3″	9A-174
9A-201	Annex I & II Building Fire Areas Plan at Elevation 100'-0" & 107'-2"	9A-175
9A-3	(Sheet 2 of 3) Annex I & II Building Fire Area Plan at Elevation 117′-6″	9A-176
9A-3	(Sheet 3 of 3) Annex I & II Building Fire Area Plan at Elevation 135′-3″ through 183′-6″	9A-177
9A-4	Radwaste Building Fire Area Plan at Elevation 100′-0″	9A-178
9A-5	Diesel Generator Building Fire Area Plan at Elevation 100'-0″	9A-179

Chapter 9 Auxiliary Systems

9.1 Fuel Storage and Handling

9.1.1 New Fuel Storage

9.1.1.1 Design Bases

New fuel is stored in a high density rack which includes integral neutron absorbing material to maintain the required degree of subcriticality. The rack is designed to store fuel of the maximum design basis enrichment. The rack in the new fuel pit consists of an array of cells interconnected to each other at several elevations and to a thick base plate at the bottom elevation. This rack module is not anchored to the pit floor.

The new fuel rack includes storage locations for 72 fuel assemblies. The rack layout and array center-to-center spacing is shown in Figure 9.1-1. This spacing provides a minimum separation between adjacent fuel assemblies which is sufficient to maintain a subcritical array even in the event the building is flooded with unborated water or fire extinguishant aerosols or during any design basis event. The design of the rack is such that a fuel assembly cannot be inserted into a location other than a location designed to receive an assembly. Surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel.

The requirements of ANS 57.1 are addressed in Subsection 9.1.4. The rack is designed to withstand nominal operating loads and safe shutdown earthquake seismic loads defined in Table 9.1-1. The new fuel storage rack is designed to meet seismic Category I requirements of Regulatory Guide 1.29. Refer to Subsection 1.9.1 for compliance with Regulatory Guides. The rack is also designed to withstand the maximum uplift force of the fuel handling machine.

AP1000 equipment, seismic and ASME Code classifications are discussed in Section 3.2. The requirements of ASME Code Section III, Division I, Article NF3000 are used as the criteria for evaluation of stress analysis. The materials are procured in accordance with the applicable material specifications defined in ASME Section II, Part A as described in APP-GW-GLR-026 (Reference 16). Criticality analyses are performed in accordance with the requirements of ANSI N16.1-75, Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors (Reference 1); and analysis codes are validated against the requirements of ANSI N16.9-75, Validation of Calculational Methods for Nuclear Criticality Safety (Reference 2).

The stress analysis of the new fuel rack satisfies all of the applicable provisions in NRC Regulatory Guide 1.124, Revision 1 for components design by the linear elastic method (Reference 22).

9.1.1.2 Facilities Description

The new fuel storage facility is located within the seismic Category I auxiliary building fuel handling area. The facility is protected from the effects of natural phenomena such as earthquakes, wind, tornados, floods, and external missiles by the external walls of the auxiliary building. See Section 3.5 for additional discussion on protection from missiles. The facility is designed to maintain its structural integrity following a safe shutdown earthquake and to perform its intended function following a postulated event such as fire, internal missiles, or pipe break. The walls surrounding the fuel handling area and new fuel storage pit protect the fuel from missiles generated inside the auxiliary building. The fuel handling area does not contain a credible source of missiles. Refer to Subsection 1.2.4.3 for a discussion of the auxiliary building. Refer to Section 3.8 for a discussion of the structural design of the new fuel storage area. Refer to Subsection 3.5.1 for a discussion of missile sources and protection.

The dry, unlined, approximately 17-feet deep reinforced concrete pit is designed to provide support for the new fuel storage rack. The rack is supported by the pit floor. The walls of the new fuel pit are seismic Category I. The new fuel pit is normally covered to prevent foreign objects from entering the new fuel storage rack. Since the only hoist that can access the new fuel pit is single failure proof and no heavy loads are carried over the new fuel storage pit, a load drop is not likely, and the new fuel pit cover is not designed to protect the fuel assemblies from the effects of a dropped load. Figures 1.2-7 through 1.2-10 show the relationship between the new fuel storage facility and other features of the fuel handling area.

The new fuel storage pit is drained by gravity drains that are part of the radioactive waste drain system (Subsection 9.3.5), draining to the auxiliary building sump and pumped to the waste holdup tanks which are part of the liquid radwaste system (Section 11.2). These drains preclude flooding of the pit by an accidental release of water.

Nonseismic equipment in the vicinity of the new fuel storage rack is evaluated to confirm that its failure could not result in an increase of K_{eff} beyond the maximum allowable K_{eff}. Refer to Subsection 3.7.3.13 for a discussion of the nonseismic equipment evaluation.

The fuel handling machine is used to handle new fuel assemblies in the rail car bay, new fuel rack, and new fuel elevator. The capacity of the fuel handling machine, while over the new fuel storage rack, is limited to lifting a fuel assembly, control rod assembly, and handling tool. The new fuel storage rack is not accessed by the cask handling crane. This precludes the movement of loads greater than fuel components over stored new fuel assemblies.

During fuel handling operations, a ventilation system removes gaseous radioactivity from the atmosphere above the new fuel pit. Refer to Subsection 9.4.3 for a discussion of the fuel handling area HVAC system and Section 11.5 for process radiation monitoring. Security for the new fuel assemblies is described in separate security documents referred to in Section 13.6.

9.1.1.2.1 New Fuel Rack Design

A. Design and Analysis of the New Fuel Rack

The new fuel storage rack array center-to-center spacing of nominally 10.9 inches provides a minimum separation between adjacent fuel assemblies sufficient with neutron absorbing material to maintain a subcritical array. The seismic and stress analyses of the new fuel rack consider the conditions of full and partially filled fuel assembly loadings. The rack is evaluated for the safe shutdown earthquake condition against the seismic Category I requirements. A stress analysis is performed to verify the acceptability of the critical load components and paths under normal and faulted conditions. The rack rests on the pit floor.

The dynamic response of the fuel rack assembly during a seismic event is the condition which produces the governing loads and stresses on the structure. The new fuel storage rack is designed to meet the seismic Category I requirements of Regulatory Guide 1.29.

Loads and Load Combinations

The applied loads to the new fuel rack are:

- Dead loads
- Live loads - effect of lifting the empty rack during installation
- Seismic forces of the safe shutdown earthquake
- Fuel handling machine uplift while over the new fuel rack - postulated stuck new fuel assembly

Table 9.1-1 shows loads and load combinations considered in the analyses of the new fuel rack.

The margins of safety for the new fuel rack in the multi-direction seismic event are produced using loads obtained from the seismic analysis based on the simultaneous application of three statistically independent, orthogonal accelerations.

B. Fuel Handling Machine Uplift Analysis

An analysis is performed to demonstrate that the rack can withstand a maximum uplift load of 4000 pounds. This load is applied to a postulated stuck fuel assembly. Resultant new fuel rack stresses are evaluated against the stress limits and are demonstrated to be acceptable. It is demonstrated that there is no change in new fuel rack geometry of a magnitude which causes the criticality criteria to be violated.

C. New Fuel Assembly Drop Accident Analysis

During normal fuel handling operations, a single failure-proof hoist, designed to meet the requirements of NUREG-0554, is the only hoist capable of moving new fuel above the operating floor. Per the design criteria contained in NUREG-0554, drops from a single failure-proof hoist are deemed unlikely and do not require further analysis. The consequences of such a drop are minimal since no safety-related equipment would be impacted and there are no radiological releases with new unirradiated fuel. Because the likelihood of a new fuel assembly being dropped into the new fuel pit and onto the new fuel racks is minimal, it is unnecessary to evaluate drop scenarios for the new fuel storage rack.

D. Failure of the Fuel Handling Machine

The fuel handling machine is a seismic Category II component. The fuel handling machine is evaluated to show that the machine does not fall into the new fuel pit during a seismic event. The fuel handling machine is also designed to maintain its load carrying and structural integrity functions during a safe shutdown earthquake.

E. Internally Generated Missiles

The fuel handling area does not contain any credible sources of internally generated missiles.

Stress analyses are performed by the vendor using loads developed by the dynamic analysis. Stresses are calculated at critical sections of the rack and compared to acceptance criteria referenced in ASME Section III, Division I, Article NF3000.

9.1.1.3 Safety Evaluation

The new fuel rack, being a seismic Category I structure, is designed to withstand normal and postulated dead loads, live loads, loads resulting from thermal effects, and loads caused by the safe shutdown earthquake event.

The design of the new fuel rack is such that K_{eff} (with all biases and uncertainties) remains less than or equal to 0.95 with full density unborated water and less than or equal to 0.98 with optimum moderation and full reflection conditions.

The criticality evaluation considers the inherent neutron absorbing effect of the materials of construction, including fixed neutron absorbing "poison" material.

The new fuel rack is located in the new fuel storage pit, which has a large cover to protect the new fuel from debris. This large cover contains smaller openings/ports that access each new fuel assembly cell and have their own individual cover. Each small cover is opened/removed sequentially during new fuel transfer operations to gain access to the affected assembly and is then replaced. Both covers typically remain closed to prevent debris and foreign materials from entering the new fuel pit, new fuel rack, and new fuel assemblies. No loads are required to be carried over the new fuel storage pit while the large cover is in place. The large cover is designed such that it will not fall and damage the new fuel or new fuel rack during a seismic event. Administrative controls are utilized when either of the covers is removed for new fuel transfer operations to limit the potential for dropped object damage.

Based on the conservative design and operation of the single failure-proof FHM hoist and associated lifting tools to handle unirradiated new fuel assemblies, dropping a new fuel assembly is deemed unlikely, poses no safety or radiological consequences, and therefore, does not require analysis. Handling equipment (cask handling crane) capable of carrying loads heavier than fuel components is prevented from traveling over the fuel storage area. The new fuel storage rack can withstand an uplift force of 4000 pounds.

Materials used in new fuel rack construction are compatible with the storage pit environment, and surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel. Structural materials are corrosion resistant and will not contaminate the fuel assemblies or storage pit environment. Neutron absorbing "poison" material used in the new fuel rack design has been qualified for the storage environment. Venting of the neutron absorbing material is considered in the detailed design of the new fuel storage rack.

The new fuel assemblies are stored dry. The rack structure is designed to maintain a safe geometric array for normal and postulated accident conditions. The fixed neutron absorbing "poison" material maintains the required degree of subcriticality for normal and postulated accident conditions such as flooding with pure water and low density optimum moderator "misting."

A discussion of the methodology used in the new fuel rack criticality analysis is provided in APP-GW-GLR-030 (Reference 17).

9.1.2 Spent Fuel Storage

9.1.2.1 Design Bases

Spent fuel is stored in high density racks which include integral neutron absorbing material to maintain the required degree of subcriticality. The racks are designed to store fuel of the maximum design basis enrichment. Each rack in the spent fuel pool consists of an array of cells interconnected to each other at several elevations and to a thick base plate at the bottom elevation. These rack modules are free-standing, neither anchored to the pool floor nor braced to the pool wall. The spent fuel storage racks include storage locations for 884 fuel assemblies and five defective fuel assemblies. The Region 1 spent fuel rack layout is shown in Figure 9.1-2. The Region 2 spent fuel rack layout is shown in Figure 9.1-3. The overall spent fuel pool rack layout is presented in Figure 9.1-4. All spent fuel racks will be in place whenever fuel is stored in the spent fuel racks. See Subsection 3.7.5.2, for discussion of site-specific procedures for activities following an earthquake. An activity will be to address measurement of the post-seismic event gaps between spent fuel racks and to take appropriate corrective actions.

The design of the spent fuel racks is such that a fuel assembly cannot be inserted into a location (i.e., between racks) other than a location designed to receive an assembly. Insertion of a fuel assembly into a fuel pool (vs. rack) location not designed to receive it (i.e., tool storage area, adjacent to the defective fuel cells and wall) is prevented administratively and addressed in Subsection 9.1.2.3.

AP1000 equipment, seismic and ASME Code classifications are discussed in Section 3.2. The requirements of ASME Section III, Division I, Article NF3000 are used as the criteria for evaluation of stress analyses. The materials are procured in accordance with the applicable material specifications defined in ASME Section II, Part A as described in APP-GW-GLR-033 (Reference 18). Criticality analyses are performed in accordance with the requirements of ANSI N16.1-75, Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors (Reference 1); analysis codes are validated against the requirements of ANSI N16.9-75, Validation of Calculational Methods for Nuclear Criticality Safety (Reference 2); and overall requirements for fuel storage are in accordance with ANSI N210-76, Design Objectives for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations (Reference 3).

The stress analysis of the spent fuel racks satisfies all of the applicable provisions in NRC Regulatory Guide 1.124, Revision 1 for components designed by the linear elastic analysis method (Reference 22).

The spent fuel pool is designed to preclude inadvertent draining of the water from the pool.

9.1.2.2 Facilities Description

The spent fuel storage facility is designed to the guidelines of ANS 57.2 (Reference 4). The spent fuel storage facility is located within the seismic Category I auxiliary building fuel handling area. The walls of the spent fuel pool are an integral part of the seismic Category I auxiliary building structure. The facility is protected from the effects of natural phenomena such as earthquakes (Subsection 3.7.2), wind and tornados (Section 3.3), floods (Section 3.4), and external missiles (Section 3.5).

The facility is designed to maintain its structural integrity following a safe shutdown earthquake and to perform its intended function following a postulated event such as a fire. Refer to Subsection 1.2.4.3 for further discussions of the auxiliary building fuel handling area.

Nonseismic equipment in the vicinity of the spent fuel storage racks is evaluated to confirm that its failure could not result in an increase of K_{eff} beyond the maximum allowable K_{eff}. Refer to Subsection 3.7.3.13 for a discussion of the nonseismic equipment evaluation.

The spent fuel pool provides storage space for spent fuel. The pool is approximately 42.5 feet deep and constructed of reinforced concrete and concrete filled structural modules as described in Subsection 3.8.4. The portion of the structural modules in contact with the water in the pool is stainless steel and the reinforced concrete portions are lined with a stainless steel plate. The minimum water volume of the pool is about 190,500 gallons of borated water (including racks without fuel at a water level 15 inches below the operating deck) with a nominal boron concentration of 2700 ppm. Figures 1.2-7 through 1.2-10 show the spent fuel pool and other features of the fuel handling area.

The connections for the drain and makeup lines are located to preclude the draining of the spent fuel pool due to a break in a line or failure of a pump to stop. The connection for the spent fuel cooling pumps' suction is located below normal water level and above the level needed to provide sufficient water for shielding and for cooling of the fuel if the spent fuel pool cooling system is unavailable. Skimmers that normally follow the water level surface do not travel below the level of the spent fuel cooling suction. Connections for suction to the chemical and volume control system are located between the normal water level and the spent fuel cooling system pumps' suction connection level. Pipes which discharge into the spent fuel pool include a siphon break between the normal water level and the level of the spent fuel cooling system pumps' suction connection.

The piping which returns the water to the spent fuel pool from the spent fuel pool cooling system enters the pool at the opposite end from the spent fuel pool cooling system pumps' suction connection. The piping arrangement and location ensure thorough mixing of the cooled water into the pool to prevent stagnant or hot regions.

A gated opening connects the spent fuel pool and fuel transfer canal. The fuel transfer canal is connected to the in-containment refueling cavity by a fuel transfer tube. The spent fuel transfer operation is completed underwater, and the waterways are of sufficient depth to maintain a minimum of 8.75 feet of shielding water above the active fuel height of spent fuel assemblies. A metal gate with gasket assembly separates the spent fuel pool and fuel transfer canal. This allows the fuel transfer canal to be drained without reducing the water level in the spent fuel pool. During normal operation, this gate remains open and is only closed to drain the canal. The bottom of the fuel transfer canal has a drain connected to safety-related piping and isolation valves which prevents inadvertent draining after a seismic event. Subsection 9.1.3 further addresses the minimum water level in the spent fuel pool.

Next to the spent fuel pool and accessible by another gated, gasketed opening is a cask loading pit. The cask pit is a lined reinforced concrete structure of the auxiliary building fuel handling area. It is provided for underwater loading of fuel into a shipping cask and cask draining/decontamination prior to cask transshipment from the AP1000 site. The bottom of the cask loading pit has a drain connected to safety-related piping and isolation valve which prevents inadvertent draining after a seismic event. The gate between the spent fuel pool and the cask loading pit is normally closed and opened during refueling and cask loading options. The cask loading pit can be used as a source of water for low pressure injection to the reactor coolant system via the normal residual heat removal pumps during an event in which the reactor coolant system pressure and inventory decrease and the cask loading pit gate is closed.

The fuel handling machine traverses the spent fuel pool, the fuel transfer canal, the cask loading pit, the new fuel storage pit, and the rail car bay. It is used in the movement of both new and spent fuel assemblies. The fuel handling machine is used to transfer new fuel assemblies from the new fuel storage rack into the spent fuel pool. A new fuel elevator in the spent fuel pool lowers the new fuel to an elevation accessible by the fuel handling machine and its associated fuel handling tool.

The cask handling crane is used for operations involving the spent fuel shipping cask. The cask handling crane traverses the auxiliary building and a portion of the fuel handling area. The cask handling crane's path is designed such that the cask cannot pass over the spent fuel pool, new fuel pit, or fuel transfer canal. This precludes the movement of loads greater than fuel components over stored fuel in accordance with Regulatory Guide 1.13.

During fuel handling operations, a ventilation system removes gaseous radioactivity from the atmosphere above the spent fuel pool. Refer to Subsection 9.4.3 for a discussion of the radiologically controlled area ventilation system, Section 11.5 for process radiation monitoring, Subsection 9.1.3 for the spent fuel pool cooling system, and Subsection 12.2.2 for airborne activity levels in the fuel handling area.

9.1.2.2.1 Spent Fuel Rack Design

A. Design and Analysis of Spent Fuel Racks

The spent fuel pool rack layout contains both Region 1 rack modules with a center-to-center spacing of nominally 10.93 inches and Region 2 rack modules with a center-to-center spacing of nominally 9.04 inches. Additionally, there are five defective fuel assembly storage cells with a center-to-center spacing of nominally 11.65 inches. These rack module configurations provide

adequate separation between adjacent fuel assemblies with neutron absorbing material to maintain a subcritical array.

The material used in the AP1000 fuel storage racks is Metamic®, a metal matrix composite material consisting of a Type 6061 aluminum alloy matrix reinforced with boron carbide (B_4C). The Metamic is in the form of sheets having a nominal thickness of 0.106 inches and a minimum ^{10}B areal density of 0.0304 gm/cm^2 (minimum 30.5 wt% B_4C). The panels are not anodized, but will be cleaned via glass bead blasting and washing with demineralized water to ensure removal of surface contamination prior to installation.

No credit is taken for Metamic in the rack structural analysis, and the Metamic panels are completely encased in (and supported by) stainless steel panels (which are vented) so the mechanical properties of the Metamic do not affect the performance of the panels. Nevertheless, mechanical properties (obtained from Reference 24) are summarized below:

Property	Value
Density	2.646 gm/cm^3
Yield Strength	33,000 psi
Ultimate Strength	40,000 psi
Elongation	1.8%

With the exception of density, which is given at 30 wt% B_4C, the properties in this table are all specified for 31 wt% B_4C. Metamic has been evaluated by the NRC for use in spent fuel pool applications (Reference 25).

The Metamic panels are suitable for long-term use in the spent fuel pool environment. The Metamic panels are potentially affected by the pool's temperature, aqueous environment, and radiation field. The effects of each of these parameters are discussed separately in the following paragraphs.

The pool's temperature will exceed the ambient temperature as a result of the stored fuel heat, but will be maintained at or below 120°F. Elevated temperature testing of 31 wt% B_4C Metamic was performed at 750°F in air for nearly a year (Reference 24), with no reduction in thickness, no change in weight, no reduction on ^{10}B content, and no change in density. The complete lack of dimensional or chemical changes in these elevated rate tests is sufficient to show that temperatures up to 120°F, even for 60 years or more, will not detrimentally affect the condition of the Metamic panels.

The aqueous environment of the pool with a nominal dissolved Boron concentration of 2,700 ppm will be slightly acidic. Elevated temperature (200°F) corrosion rate testing of 32 wt% B_4C Metamic (Reference 24) for 90 days indicated that "no corrosion was observed" and there was "no significant change in ^{10}B areal density." The complete lack of any chemical changes in the tests, combined with the knowledge of the effects of temperature and pH on corrosion rate, is sufficient to show that the aqueous spent fuel pool environment, even for 60 years, will not detrimentally affect the condition of the Metamic panels.

Samples of 31 wt% B_4C Metamic were subjected to a radiation field with both gamma (1.5×10^{11} rads) and fast neutron (1.7×10^{18} nvt to 5.8×10^{19} nvt) components. Conclusions of post-irradiation testing were: Metamic exhibits excellent dimensional stability after irradiation and there was no change in Boron-10 areal density (Reference 24). The complete lack of dimensional or chemical changes as a result of these high radiation exposures is sufficient to show that the expected radiation field in the pool, even for 60 years, will not detrimentally affect the condition of the Metamic panels. A coupon tree with 14 coupons is provided with the spent fuel racks.

Coupons are nominally 6 inches wide by 8 inches long by 0.106 inches thick. Coupons of a different width and length are acceptable when boron testing is based on a weight percentage. Each coupon is representative of the panel from which it is cut, including the presence of any scratches or other surface irregularities. The initial B_4C content of Metamic is determined from the amounts of B_4C and aluminum powder mixed together in the manufacturing process. If for example, 1000 pounds of aluminum and 250 pounds of B_4C are used to manufacture one lot of material, it would be 20 percent B_4C. This approach has been validated by Metamic LLC, the supplier of the Metamic poison material, and Holtec International, the rack designer.

The recommended Metamic monitoring schedule is as follows:

- End of Cycle 1 – Remove First Coupon
- End of Cycle 2 – Remove Second Coupon
- End of Cycle 3 – Remove Third Coupon
- End of Cycle 5 – Remove Fourth Coupon
- End of Cycle 10 – Remove Fifth Coupon
- End of Cycle 20 – Remove Sixth Coupon
- End of Cycle 30 – Remove Seventh Coupon
- End of Cycle 40 – Remove Eighth Coupon

If the plant is operated on an 18-month cycle, eight coupons provide 60 years of Metamic surveillance. There are six additional coupons provided.

This coupon tree will be used to monitor the condition of the Metamic over the 60-year life of the spent fuel racks.

The seismic and stress analyses of the spent fuel racks consider the various conditions of full, partially filled, and empty fuel assembly loadings. The racks are evaluated for the safe shutdown earthquake condition and seismic Category I requirements. A detailed stress analysis is performed to verify the acceptability of the critical load components and paths under normal and faulted conditions. The racks rest on the pool floor and are evaluated to determine that under loading conditions the rack-to-rack and rack-to-wall impacts are acceptable on both the racks and the pool walls.

The dynamic response of the fuel rack assembly during a seismic event is the condition which produces the governing loads and stresses on the structure.

Loads and Load Combinations

The applied loads to the spent fuel racks are:

- Dead loads
- Live loads - effect of lifting the empty rack during installation
- Seismic forces of the safe shutdown earthquake
- Fuel assembly drop analysis
- Fuel handling machine uplift - postulated stuck fuel assembly
- Thermal loads

Table 9.1-1 shows loads and load combinations that are considered in the analyses of the spent fuel racks including those given in Reference 5.

The margins of safety for the racks in the multi-direction seismic event are produced using loads obtained from the seismic analysis based on the simultaneous application of three statistically independent, orthogonal accelerations.

B. Fuel Handling Machine Uplift Analysis

An analysis is performed to demonstrate that the racks can withstand a maximum uplift load of 5000 pounds. This load is applied to a postulated stuck fuel assembly. Resultant rack stresses are evaluated against the stress limits and are demonstrated to be acceptable. It is also demonstrated that there is no change in rack geometry of a magnitude which causes the criticality criteria to be violated.

C. Fuel Assembly Drop Accident Analysis

In the unlikely event of dropping a fuel assembly, accidental deformation of the rack is determined and evaluated in the criticality analysis to demonstrate that it does not cause the criticality criterion to be violated. The analysis considers only the case of a dropped spent, irradiated fuel assembly in a flooded pool and takes credit for dissolved boron in the water.

For the analysis of a dropped fuel assembly, two accident conditions are postulated. The first accident condition conservatively assumes that the weight of a fuel assembly, control rod assembly, and handling tool (3100 pounds total) impacts the top of the fuel rack from a drop height of 3 feet above the top of the rack. Both a straight drop and an inclined drop are included in the assessment. Calculations are performed to demonstrate that the impact energy is absorbed by the dropped fuel assembly, the rack cells, and the rack base plate assembly. Under these faulted conditions, credit is taken for dissolved boron in the pool water.

The second accident condition assumes that the dropped fuel assembly, control rod assembly, and handling tool (3100 pounds) fall straight through an empty cell and impact the rack base plate from a drop height of 3 feet above the top of the rack. The analysis is performed and demonstrates that the impact energy is absorbed by the fuel assembly and the rack base plate. At an interior rack location, base plate deformation is limited so that the pool liner is not impacted. At a support pad location, the stresses developed in the pool liner are evaluated to be within allowable limits such that the liner integrity is maintained. Under these faulted conditions, credit is taken for dissolved boron in the pool water.

D. Fuel Rack Sliding and Overturning Analysis

Consistent with the criteria of Reference 5, the racks are evaluated for overturning and sliding displacement due to earthquake conditions under the various conditions of full, partially filled, and empty fuel assembly loadings.

E. Failure of the Fuel Handling Machine

The fuel handling machine is a seismic Category II component. The fuel handling machine is evaluated to show that it does not collapse into the spent fuel pool as a result of a seismic event. The fuel handling machine is also designed to maintain its load carrying and structural integrity functions during a safe shutdown earthquake.

F. Internally Generated Missiles

The spent fuel handling area does not contain any credible sources of internally generated missiles.

Stress analyses are performed by the vendor using loads developed by the dynamic analysis. Stresses are calculated at critical sections of the rack and compared to acceptance criteria referenced in ASME Section III, Division I, Article NF3000.

9.1.2.3 Safety Evaluation

The design and safety evaluation of the spent fuel racks is in accordance with Reference 5. The racks, being Equipment Class D and seismic Category I structures, are designed to withstand normal and postulated dead loads, live loads, loads resulting from thermal effects, and loads caused by the safe shutdown earthquake event.

The design of the racks is such that K_{eff} remains less than or equal to 0.95 under design basis conditions, including fuel handling accidents. Inadvertent insertion of a fuel assembly between the rack periphery and the pool wall or placement of a fuel assembly across the top of a fuel rack is considered a postulated accident, and as such, realistic initial conditions such as boron in the pool water are assumed. These accident conditions have an acceptable K_{eff} of less than 0.95. The criticality evaluation, which meets the requirements of 10 CFR 50.68, Paragraph b (Reference 21), considers the inherent neutron absorbing effect of the materials of construction, including fixed neutron absorbing "poison" material. Soluble boron in the spent fuel pool and assembly burnup is used as reactivity credits.

The racks are also designed with adequate energy absorption capabilities to withstand the impact of a dropped fuel assembly from the maximum lift height of the fuel handling machine. Handling equipment (cask handling crane) capable of carrying loads heavier than fuel components is prevented by design from carrying loads over the fuel storage area. The fuel storage racks can withstand an uplift force greater than or equal to the uplift capability of the fuel handling machine (5000 pounds).

Materials used in rack construction are compatible with the storage pool environment, and surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel. Structural materials are corrosion resistant and will not contaminate the fuel assemblies or pool environment. Neutron absorbing "poison" material used in the rack design has been qualified for the storage environment. Venting of the neutron absorbing material is considered in the detailed design of the storage racks.

Design of the spent fuel storage facility is in accordance with Regulatory Guide 1.13. A discussion of the methodology used in the spent fuel pool criticality analysis is provided in APP-GW-GLR-029 (Reference 27).

9.1.3 Spent Fuel Pool Cooling System

The spent fuel pool cooling system (SFS) is designed to remove decay heat which is generated by stored fuel assemblies from the water in the spent fuel pool. This is done by pumping the high temperature water from within the fuel pool through a heat exchanger, and then returning the water to the pool. A secondary function of the spent fuel pool cooling system is clarification and purification of the water in the spent fuel pool, the transfer canal, and the refueling water. A listing of the major functions of the spent fuel pool cooling system and the corresponding modes of operation is provided below:

- **Spent fuel pool cooling** - Remove heat from the water in the spent fuel pool during operation to maintain the pool water temperature within acceptable limits.

- **Spent fuel pool purification** - Provide purification and clarification of the spent fuel pool water during operation.

- **Refueling cavity purification** - Provide purification of the refueling cavity during refueling operations.
- **Water transfers** - Transfer water between the in-containment refueling water storage tank (IRWST) and the refueling cavity during refueling operations.
- **In-containment refueling water storage tank purification** - Provide purification and cooling of the in-containment refueling water storage tank during normal operation.

9.1.3.1 Design Basis

9.1.3.1.1 Safety Design Basis

The spent fuel pool cooling system has the safety-related function of containment isolation. See Subsection 6.2.3 for the containment isolation system. Safety-related makeup to the spent fuel pool is discussed in Subsection 9.1.3.4.3.

9.1.3.1.2 Power Generation Basis

The principal functions of the spent fuel pool cooling system are outlined above. The spent fuel pool cooling system is designed to perform its function in a reliable and failure tolerant manner. This reliability is achieved with the use of rugged and redundant equipment. The spent fuel pool cooling system is not a safety-related system and is not required to operate following events such as earthquake, fire, passive failures or multiple active failures.

9.1.3.1.3 Spent Fuel Pool Cooling

9.1.3.1.3.1 Partial Core

The spent fuel pool cooling system is designed to remove heat from the spent fuel pool such that the spent fuel pool water temperature will be ≤ 120°F following a partial core fuel shuffle refueling. The system is designed to perform this function based on the following:

- The assumed heat load is based on the decay heat generated by the accumulated maximum number of fuel assemblies stored in the fuel pool, which includes 44% of a core (69 assemblies) being placed into the pool at 120 hours after shutdown.
- Both trains of the spent fuel pool cooling system are assumed to be operating.
- While the reactor is shut down, the component cooling water system (CCS) supply temperature used to determine the performance of the spent fuel pool cooling system (SFS) heat exchangers is based on a service water system heat sink with a maximum normal ambient design wet bulb temperature as defined in Chapter 2, Table 2.0-201.
- While the reactor is at power, the CCS supply temperature to the SFS heat exchangers is based on a service water system heat sink with a maximum safety ambient design wet bulb temperature as defined in Chapter 2, Table 2.0-201.

9.1.3.1.3.2 Full Core Off-Load

The AP1000 normal refueling basis heat load is from a full core off-load. The spent fuel pool cooling system is designed to remove heat from the spent fuel pool such that the spent fuel pool water temperature will be ≤ 120°F following a full core off-load based upon a service water heat sink at a

maximum normal ambient wet bulb temperature as defined by Chapter 2, Table 2.0-201. The system is designed to perform this function based on the following:

- The assumed heat load is based on the decay heat generated by the accumulated maximum number of fuel assemblies stored in the fuel pool, plus one full core placed in the pool at 120 hours after shutdown. The time during the plant operating cycle at which the full core off-load occurs is chosen to maximize the required spent fuel pool cooling system heat load.

- The spent fuel pool cooling system is assumed to function with its full set of equipment available. One train of the normal residual heat removal system (RNS) is also connected to the spent fuel pool and provides cooling as described in Subsection 5.4.7.4.5.

- While the reactor is shut down, the CCS supply temperature used to determine the performance of the SFS heat exchangers is based on a service water system heat sink with a maximum normal ambient design wet bulb temperature as defined in Chapter 2, Table 2.0-201.

- While the reactor is at power, the CCS supply temperature to the SFS heat exchangers is based on a service water system heat sink with a maximum safety ambient design wet bulb temperature as defined in Chapter 2, Table 2.0-201.

- Assuming the heat load scenario identified above, the spent fuel pool water temperature will be < 140°F with one SFS cooling train and one RNS train in operation.

9.1.3.1.4 Spent Fuel Pool Purification

The spent fuel pool cooling system removes radioactive corrosion products, fission product ions and dust to maintain low spent fuel pool (SFP) activity levels and to maintain water clarity during all modes of plant operation. The spent fuel pool cooling system purification capability is such that the occupational radiation exposure (ORE) is minimized to support as-low-as-reasonably-achievable (ALARA) goals. The spent fuel pool cooling system clarification capability is sufficient to permit necessary operations that must be conducted in the spent fuel pool area. The spent fuel pool cooling system is designed to perform its purification function in accordance with the following additional criteria:

- The spent fuel pool cooling system is designed to limit exposure rates to personnel on the spent fuel pool fuel handling machine to less than 2.5 millirem per hour.

- The spent fuel pool cooling system flow rate for one train shall be more than that necessary to provide two water volume changes in 24 hours for the spent fuel pool water.

9.1.3.1.5 Refueling Cavity Purification

The spent fuel pool cooling system removes radioactive corrosion products, fission product ions and dust to maintain low refueling cavity activity levels and to maintain water clarity during refueling operations. The spent fuel pool cooling system purification capability is such that the occupational radiation exposure is minimized to support ALARA goals. Furthermore, the spent fuel pool cooling system clarification capability is sufficient to permit necessary refueling operations that must be conducted in the refueling cavity. The spent fuel pool cooling system is designed to perform its purification function in accordance with the following additional criterion:

- The spent fuel pool cooling system is designed to limit exposure rates to personnel on the refueling machine to less than 2.5 millirem per hour. This corresponds to an activity level in the water of approximately 0.005 microcurie per gram for the dominant gamma-emitting isotopes at the time of refueling.

9.1.3.1.6 Water Transfers

The spent fuel pool cooling system is designed to transfer water from the in-containment refueling water storage tank to the refueling cavity prior to a refueling and then back to the in-containment refueling water storage tank upon completion of the refueling operations. The spent fuel pool cooling system is designed to perform this function in accordance with the AP1000 refueling schedule.

9.1.3.1.7 In-Containment Refueling Water Storage Tank Purification

The spent fuel pool cooling system removes radioactive corrosion products and fission ions to maintain low in-containment refueling water storage tank activity levels during normal plant operation prior to a scheduled refueling. The spent fuel pool cooling system is designed to maintain the water in the in-containment refueling water storage tank consistent with activity requirements of the water in the refueling cavity during a refueling.

9.1.3.1.8 Spent Fuel Pool Water Tritium Concentration Control

The concentration of tritium in the spent fuel pool water is maintained at less than 0.5 µCi/g to provide confidence that the airborne concentration of tritium in the fuel handling area is within 10 CFR 20, Appendix B limits (see Subsection 12.2.2). The tritium concentration in the spent fuel pool is reduced, if necessary, by transferring a portion of the spent fuel pool water to the liquid radwaste system for discharge and replacing it with non-tritiated water.

9.1.3.2 System Description

The spent fuel pool cooling system is a non-safety-related system. The safety-related function of cooling and shielding the fuel in the spent fuel pool is performed by the water in the pool. A simplified sketch of the spent fuel pool cooling system is included as Figure 9.1-5. The piping and instrumentation diagram for the spent fuel pool cooling system is Figure 9.1-6.

The spent fuel pool cooling system consists of two mechanical trains of equipment. Each train includes one spent fuel pool pump, one spent fuel pool heat exchanger, one spent fuel pool demineralizer and one spent fuel pool filter. The two trains of equipment share common suction and discharge headers. In addition, the spent fuel pool cooling system includes the piping, valves, and instrumentation necessary for system operation.

The spent fuel pool cooling system is designed such that either train of equipment can be operated to perform any of the functions required of the spent fuel pool cooling system independently of the other train. One train is continuously cooling and purifying the spent fuel pool while the other train is available for water transfers, in-containment refueling water storage tank purification, or aligned as a backup to the operating train of equipment.

Each train is designed to process spent fuel pool water. Each pump takes suction from the common suction header and discharges directly to its respective heat exchanger. The outlet piping branches into parallel lines. The purification branch is designed to process approximately 20% of the cooling flow while the bypass branch passes the remaining.

Each purification branch is routed directly to a spent fuel pool demineralizer. The outlet of the demineralizer is to a spent fuel pool filter. The outlet of the filter is then connected to the bypass branch which forms a common line that connects to the discharge header.

The spent fuel pool cooling system suction header is connected to the spent fuel pool at two locations. The main suction line connects to the spent fuel pool at an elevation 6 feet below the operating deck. Two skimmer connections take suction from the water surface of the spent fuel pool. This suction arrangement prevents the spent fuel pool from inadvertently being drained below a level that would prevent the water in the spent fuel pool from performing its safety-related function. This arrangement also eliminates the need for a separate skimmer circuit arrangement.

The spent fuel pool pump suction header is connected to the in-containment refueling water storage tank and the refueling cavity. This enables purification of the in-containment refueling water storage tank or the refueling cavity and allows for the transfer of water between the in-containment refueling water storage tank and the refueling cavity.

The spent fuel pool pump suction header is also connected to the fuel transfer canal and the cask loading pit. These connections are provided primarily for the transfer of water from the fuel transfer canal to the cask loading pit. Water that is normally stored in the fuel transfer canal can be sent to the cask loading pit and vice versa.

The spent fuel pool is initially filled for use with water having a nominal boron concentration of 2700 ppm. Demineralized water can be added for makeup purposes, including replacement of evaporative losses, from the demineralized water transfer and storage system. Boron may be added to the spent fuel pool from the chemical and volume control system.

The spent fuel pool water may be separated from the water in the transfer canal by a gate. The gate enables the transfer canal to be drained to permit maintenance of the fuel transfer equipment.

9.1.3.3 Component Description

The general descriptions and summaries of the design requirements for the spent fuel pool cooling system components are provided below. See Table 9.1-2. The key equipment parameters for the spent fuel pool cooling system components are contained in Table 9.1-3. Additional information regarding the applicable codes and classifications is also available in Section 3.2.

9.1.3.3.1 Spent Fuel Pool Pumps

Two spent fuel pool pumps are provided. These pumps are single stage, horizontal, centrifugal pumps having a coupled pump motor shaft driven by an ac powered induction motor. A mechanical seal is used to prevent leakage to the atmosphere. The pumps have flanged suction and discharge nozzles.

Each pump is sized to provide the flow required by its respective heat exchanger for removal of its design basis heat load. The pumps are redundant for normal refueling heat loads.

9.1.3.3.2 Spent Fuel Pool Heat Exchangers

Two spent fuel pool heat exchangers are installed to provide redundant spent fuel heat removal capability for normal refueling heat loads. These heat exchangers are plate type heat exchangers constructed of austenitic stainless steel. Spent fuel pool water circulates through one side of the heat exchanger while component cooling water (CCW) circulates through the other side.

9.1.3.3.3 Spent Fuel Pool Demineralizers

Two mixed bed type demineralizers are provided to maintain spent fuel pool purity. The demineralizers are initially charged with a hydrogen type cation resin and hydroxyl type anion resin to remove fission and corrosion products. The demineralizers will be borated during initial operation with boric acid. Each demineralizer is sized to accept the maximum purification flow from its respective cooling train. The vessels are constructed of austenitic stainless steel.

9.1.3.3.4 Spent Fuel Pool Filters

Two spent fuel pool filters are provided, one downstream of each demineralizer in the purification branch line of each mechanical train. The filters are sized to collect small particulates and resin fines passed by the demineralizer. They are also sized to pass the maximum design purification flow. The filter assembly is constructed of austenitic stainless steel with disposable filter cartridges.

9.1.3.3.5 Spent Fuel Pool Cooling System Valves

Spent fuel pool cooling system valves operate in low temperature and pressure service. Commercially available valves are used in accordance with the codes and standard of Section 3.2. The basic material of construction is stainless steel.

9.1.3.3.5.1 Locked-In-Position Valves

Refueling Cavity Drain Isolation Valve

There is one locked-open valve in the line from the refueling cavity to the steam generator 2 compartment. This valve is provided so that water in the refueling cavity cannot be trapped and be unavailable for passive recirculation cooling by the passive core cooling system (PXS) following an accident. This valve is locked-closed during refueling operations when the refueling cavity is flooded.

Refueling Cavity Connection for Containment Flooding Isolation Valve

There is one locked-open valve in the line that goes through the wall of the refueling canal to provide a water flow path between the refueling canal and the containment floodup water volume following an accident. This valve is locked open so that as the containment floods, the refueling canal will flood before the compartments that contain passive core cooling system components, which are used for safe shutdown. This valve is locked-closed during refueling operations when the refueling cavity is flooded.

Fuel Transfer Canal Drain Valve

There is one locked-closed valve in the bottom connection to the fuel transfer canal. This valve is provided to prevent inadvertent lowering of the spent fuel pool water level in the event that the gate between the fuel transfer canal and spent fuel pool is open during a seismic event that causes a break in the downstream piping.

Spent Fuel Pool Cooling Pump to Passive Core Cooling Discharge Valves

There are two locked-open valves in the spent fuel pool cooling system pump discharge to the passive core cooling system. These locked-open valves allow the containment isolation check valve to open and prevent a potential pressure buildup inside the containment penetration piping. These valves are locked open during normal and shutdown operations except for in-service testing of the containment isolation valves.

9.1.3.3.5.2 Remotely-Operated Valves

Containment Isolation Valves

The spent fuel pool cooling system contains two lines which penetrate containment. They are the lines from the refueling cavity/in-containment refueling water storage tank to the spent fuel pool cooling system suction header and the return line to the refueling cavity/in-containment refueling water storage tank. Two remotely operated valves, one located inside and one outside containment, are provided in the line to the suction header. One remotely operated valve located outside containment and one check valve located inside containment are provided in the return line. These valves are normally closed and are opened only for purification or water transfers between the in-containment refueling water storage tank and the refueling cavity. They are controlled from the main control room. See Subsection 6.2.3.

9.1.3.3.6 Piping Requirements

The portions of the spent fuel pool cooling system rigid piping shown in Figure 9.1-6 are made of austenitic stainless steel. The piping joints and connections in this portion of the system are welded, except where flanged connections or threaded caps are required as indicated on the spent fuel pool cooling system piping and instrumentation diagram (Figure 9.1-6).

9.1.3.3.7 Permanent Cavity Seal Ring

The AP1000 permanent cavity seal ring is part of the fuel handling system and is a permanent welded seal ring used to provide the seal between the vessel flange and the refueling cavity floor. The permanent cavity seal ring does not use pneumatic seals and is not subject to a gross failure due to loss of a seal.

Leakage is not expected with this design. Leakage past or through the seal would not significantly affect the water level in the refueling canal and would be detected as an increase in water level in the containment sump. Water level in the sump is a key parameter in reactor coolant leak detection.

9.1.3.3.8 Reactor Cavity Connections

The spent fuel pool cooling system contains connections to the refueling cavity to prevent excessive holdup of water in the reactor cavity following an accident. The piping connection facilitates draining of the reactor cavity to the steam generator compartment following a postulated accident. The line connects at the bottom of the reactor cavity and discharges to a steam generator compartment, and contains a manual locked-open isolation valve and two check valves in series. The isolation valve is closed during refueling operations to facilitate flooding of the reactor cavity for refueling operations.

The spent fuel pool cooling system also contains a connection between the refueling cavity and Room 11300 to provide a water flow path following an accident. This connection is a single pipe through the wall of the refueling cavity and contains a manual locked-open isolation valve. This connection is provided so that as the containment floods, the refueling canal will flood before the compartments that contain passive core cooling system components, which are used for safe shutdown. Subsection 3.4.1.2.2.1 provides a discussion of post-accident containment flooding. The isolation valve is locked-closed during refueling operations to enable flooding of the reactor cavity for refueling operations.

Other connections are provided to the refueling cavity to facilitate proper draining, filling, and purification of the reactor cavity to support refueling operations.

9.1.3.4 System Operation and Performance

The operation of the spent fuel pool cooling system for the pertinent phases of plant operation are described in the following paragraphs.

9.1.3.4.1 Normal Operation

During normal plant operation, one spent fuel pool cooling system mechanical train of equipment is operating. The operating train is aligned to provide spent fuel pool cooling and purification. The other train is available to perform the other functions of the spent fuel pool cooling system such as water transfers or in-containment refueling water storage tank purification.

9.1.3.4.1.1 Ion Exchange Media Replacement

The initial and subsequent fill of ion exchange media is made through a resin fill nozzle on the top of the ion exchange vessel. When the media is ready to be transferred to the solid radwaste system, the vessel is isolated from the process flow. The flush water line is opened to the sluice piping and demineralized water is pumped into the vessel through the normal process outlet connection upward through the media retention screen. The media fluidizes in the upward, reverse flow. When the bed has been fluidized, the sluice connection is opened and the bed is sluiced to the spent resin tanks in the solid radwaste system (WSS). Demineralized water flow continues until the bed has been removed and the sluice lines are flushed clean of spent resin.

9.1.3.4.1.2 Filter Cartridge Replacement

Replacement of spent filter cartridges is performed as described in Subsection 11.4.2.3.2.

9.1.3.4.2 Refueling

Both spent fuel pool mechanical trains are in operation during refueling. One train is aligned for spent fuel pool cooling and purification throughout the refueling. The other train performs various support functions during the refueling.

Initially the standby mechanical train is used to purify the water in the in-containment refueling water storage tank to prepare for the refueling. When the refueling cavity is ready to be flooded, the pump aligned for in-containment refueling water storage tank purification is stopped and valves are aligned to gravity drain the in-containment refueling water storage tank to the refueling cavity. Eventually the drain rate slows down and the in-containment refueling water storage tank and the refueling cavity have the same water level. At this time, the standby spent fuel pool pump is aligned to transfer the additional in-containment refueling water storage tank water into the refueling cavity.

This water transfer method improves water clarity in the refueling cavity during refueling operations as compared to conventional pressurized water reactors that have performed this function with their residual heat removal system by flooding up through the reactor vessel into the refueling cavity.

Once the refueling cavity is flooded, the standby mechanical train is re-aligned to cool and purify the refueling cavity. This mode of operation continues as needed. If the heat load is such that both pumps and heat exchangers are needed to cool the spent fuel pool, then the spent fuel pool cooling system can be aligned for that operation.

At the completion of the refueling, the standby spent fuel pool pump is used to transfer the water in the refueling cavity back to the in-containment refueling water storage tank. Once this is complete, the standby train can be aligned to cool the spent fuel pool or may be placed in standby.

9.1.3.4.3 Abnormal Conditions

The AP1000 spent fuel pool cooling system is not required to operate to mitigate design basis events. In the event the spent fuel pool cooling system is unavailable, spent fuel cooling is provided by the heat capacity of the water in the spent fuel pool and its connected safety-related spent fuel pool makeup water sources for the first 72 hours following a loss of normal spent fuel pool cooling. The spent fuel pool connected safety-related makeup water sources include the fuel transfer canal, the cask loading pit, and the cask washdown pit and can include PCS when it is not required to be dedicated for containment cooling. Connections to the spent fuel pool are made at an elevation to preclude the possibility of inadvertently draining the water in the pool to an unacceptable level.

In the unlikely event of an extended loss of normal spent fuel pool cooling, the water level will drop. Low spent fuel pool level alarms in the control room will indicate to the operator the need to initiate makeup water to the pool. These alarms are provided from safety-related level instrumentation in the spent fuel pool. With the use of makeup water, the pool level is maintained above the spent fuel assemblies for at least 7 days. Initial spent fuel pool water level is controlled by technical specifications. During the first 72 hours any required makeup water is supplied from safety related sources. If makeup water beyond the safety related sources is required between 72 hours and 7 days, water from the passive containment cooling ancillary water storage tank is provided to the spent fuel pool. The amount of makeup required to provide the 7 day capability depends on the decay heat level of the fuel in the spent fuel pool and is provided as follows:

- When the calculated decay heat level in the spent fuel pool is less than or equal to 4.0 MWt, only the safety-related makeup from the fuel transfer canal is needed to achieve spent fuel pool cooling for at least 72 hours.

- When the calculated decay heat level in the spent fuel pool is greater than 4.0 MWt and less than or equal to 5.0 MWt, safety related makeup from the fuel transfer canal and cask washdown pit is sufficient to achieve spent fuel pool cooling for at least 72 hours. A minimum level of 13.75 feet in the cask washdown pit is provided for this purpose. Availability of the makeup source is controlled by technical requirements manual.

- When the calculated decay heat level in the spent fuel pool is greater than 5.0 MWt and less than or equal to 7.0 MWt, safety-related makeup from the fuel transfer canal, cask washdown pit and cask loading pit is sufficient to achieve spent fuel pool cooling for at least 72 hours. A minimum level of 13.75 feet in the cask washdown pit and 43.9 feet in the cask loading pit is provided for this purpose. Availability of the makeup sources is controlled by technical requirements manual.

- When calculated decay heat level in the spent fuel pool is greater than 7.0 MWt makeup from the passive containment cooling water storage tank or passive containment cooling ancillary water storage tank, or combination of the two tanks, is sufficient to achieve spent fuel pool cooling for at least 7 days.

- When the decay heat level in the reactor is less than or equal to 7.0 MWt, the passive containment cooling water storage tank is not needed for containment cooling and this water can be used for makeup to the spent fuel pool. This tank provides safety related makeup for at least 72 hours. Between 72 hours and 7 days the tank continues to provide makeup water as required until it is empty. If the passive containment cooling water storage tank empties in less than 7 days, non-safety makeup water can be provided from the passive containment cooling ancillary water storage tank.

- When the decay heat level in the reactor is greater than 7.0 MWt, the water in the passive containment cooling water storage tank is reserved for containment cooling. Safety related spent fuel pool cooling is provided for at least 72 hours from the pool itself and makeup water from the cask washdown pit and cask loading pit. After 72 hours, non-safety related makeup can be provided from the passive containment cooling ancillary water storage tank.

- Minimum volume in the passive containment cooling water storage tank for spent fuel pool makeup is 756,700 gallons. Availability of this makeup source for the first 72 hours is controlled by technical requirements manual. Minimum volume in the passive containment cooling ancillary water storage tank for spent fuel pool makeup is 201,600 gallons.

Table 9.1-4 provides the calculated timing and spent fuel pool water levels for several limiting event scenarios which would require makeup to the spent fuel pool.

Alignment of the fuel transfer canal is accomplished by opening the gate, shown in Figure 9.1-6, located between the fuel transfer canal and spent fuel pool. Alignment of the cask washdown pit is accomplished by positioning manual valves located in the waste monitor tank room B (12365) in the auxiliary building. Alignment of the passive containment cooling water storage tank is accomplished by positioning manual valves located in the maintenance floor staging area (12351) and in the passive containment cooling valve room in the upper shield building. Because these alignments are made by positioning manual valves, they are not susceptible to active failures.

Alignment of the cask loading pit is accomplished by opening the gate, shown in Figure 9.1-6, located between the cask loading pit and the spent fuel pool. The cask loading pit gate should be opened prior to exceeding 5.0 MWt in the spent fuel pool.

Gravity driven flow from the cask washdown pit to the spent fuel pool is provided as the cask washdown pit water level will follow the spent fuel pool level. The cask washdown pit is connected to both the spent fuel pool for spent fuel pool cooling needs and to the liquid radwaste system (WLS) for temporary storage of WLS effluents (Section 11.2). However, the cask washdown pit can only perform either spent fuel pool cooling or temporary storage of WLS effluents at a time. Figure 9.1-6 shows the connection of the cask washdown pit to the spent fuel pool and WLS.

Gravity driven flow from the passive containment cooling water storage tank is controlled by a manual throttle valve with local flow indication which is set to achieve the desired flow when the makeup is initiated. Figure 6.2.2-1 shows the flow path from the passive containment cooling water storage tank leading to the spent fuel pool and the tie-in to the spent fuel pool is also shown in Figure 9.1-6.

The flow from the passive containment cooling water storage tank (PCCWST) to the spent fuel pool, required to provide sufficient makeup to the spent fuel pool to keep the fuel covered as the pool water boils off, is 118 gpm. This is the maximum flow required at the initiation of makeup flow from the PCCWST during the worst case conditions in the pool, which is a full core offload. The makeup flow rate required decreases with time as the decay heat decreases.

After 72 hours, makeup water from the passive containment cooling ancillary water storage tank can either be pumped (with the passive containment cooling recirculation pumps) to the passive containment cooling water storage tank and then gravity fed to the spent fuel pool as discussed above, or the water can be pumped directly to the spent fuel pool. When the makeup water is pumped directly to the pool, the flow rate is controlled by the same manual throttle valve which is used to set the flow rate when providing gravity driven flow from the passive containment cooling water storage tank.

The flow rates provided from the passive containment cooling ancillary water storage tank (PCCAWST) to the spent fuel pool by the recirculation pumps depend on the plant condition and spent fuel decay heat. Postulated events require SFP makeup water from the PCCAWST 72 hours following a seismic event combined with a station blackout. The required flow rates provide sufficient makeup to the spent fuel pool to keep the fuel covered as the water boils off. A 35 gpm flow rate is required when the plant has been operating at full power, shortly after startup from a refueling outage and the spent fuel pool decay heat is ≤ 5.0 MWt. A 50 gpm flow rate is required when the plant is being refueled and the spent fuel pool decay heat is > 5.0 MWt and ≤ 7.0 MWt. An 80 gpm flow rate is required when the plant is being refueled and the spent fuel pool decay heat level is > 7.0 MWt. The refueling scenarios consider the time between completion of plant cooldown and just prior to plant startup once the refueling is complete. With a refueling scenario, additional decay heat is located in the spent fuel pool because of the recent offload and enough decay heat remains in the reactor vessel such that the PCCWST is still required for containment cooling and cannot be used for spent fuel pool makeup. These conditions result in the maximum flow required from the PCCAWST because cooling water must be supplied to both the PCCWST and the spent fuel pool to provide both containment and spent fuel cooling for a period of four days following the initial three days of passive systems operation.

Spent fuel pool level instrumentation is discussed in Subsection 9.1.3.7.

9.1.3.4.3.1 Failure of a Spent Fuel Pool Cooling System Pump

If a spent fuel pool cooling system pump fails when only one pump is operating, an alarm is actuated. Due to the heat capacity of the water in the spent fuel pool, sufficient time exists for the operators to manually align the standby spent fuel pool cooling system train of equipment (pump/heat exchanger) to cool the spent fuel pool.

9.1.3.4.3.2 Leakage from the Spent Fuel Pool Cooling System

The connections from the spent fuel pool cooling system to the pool are such that leakage in the spent fuel pool cooling system will not result in the pool water level falling to unacceptable levels. The heat capacity of the water in the pool is sufficient to allow the operators enough time to locate the leak and repair it. In the most probable scenario, cooling will be maintained by operation of the standby train of equipment. However, if spent fuel pool cooling must be terminated, sufficient time exists to allow for repairs of a leak in the system.

9.1.3.4.3.3 Loss of Normal AC Power Operation and Offsite Power

The spent fuel pool cooling system pumps can be manually loaded on the respective onsite standby diesel generator in the event of a loss of normal ac power and offsite power. The spent fuel pool cooling system is capable of providing spent fuel pool cooling following this event.

9.1.3.4.3.4 Station Blackout

Following a loss of all ac power, the heat capacity of the water in the pool is such that cooling of the fuel is maintained. Table 9.1-4 provides the times before boiling would occur in the pool following station blackout for various scenarios as well as the minimum levels of water that would be reached. Water vapor that evaporates from the surface of the spent fuel pool is vented to the outside environment through an engineered relief panel. This vent path maintains the fuel handling area at near atmospheric pressure conditions. The doses resulting from spent fuel pool boiling have been calculated and are included in Chapter 15. The release concentrations at the site boundary are small fractions of the limits specified in 10 CFR 20, Appendix B with no credit for removal of activity by building ventilation systems (which are not available during loss of ac power situations). The equipment in the fuel handling area, rail car bay\filter storage area, and spent resin equipment and

piping areas exposed to elevated temperature and humidity conditions as a result of pool boiling does not provide safety-related mitigation of the effects of spent fuel pool boiling or station blackout. The fuel handling area, rail car bay, and spent resin area do not have connecting ductwork with other areas of the radioactively controlled area of the auxiliary building and connecting floor drains have a water seal which prevents steam migration. The environment in these other areas during spent fuel pool steaming is mild with respect to safety-related equipment qualification and affords access for post-accident actions.

Spent fuel pool makeup for long term station blackout can be provided through seismically qualified safety-related makeup connections from the passive containment cooling system. These connections are located in an area of the auxiliary building that can be accessed without exposing operating personnel to excessive levels of radiation or adverse environmental conditions during boiling of the pool. Operating personnel are not required to enter the fuel handling area when normal cooling is not available, and are not required to enter the area to recover normal cooling.

9.1.3.4.3.5 Reactor Coolant System Makeup

During an event in which the reactor coolant system pressure and inventory decrease the normal residual heat removal system pumps are started to provide makeup water to the reactor coolant system when the primary system pressure is sufficiently reduced for injection to start. The AP1000 procedure for post-accident operation of the normal residual heat removal pumps is that the operators align the pumps to the cask loading pit. This is accomplished by the operator opening a motor operated isolation valve (see Subsection 5.4.7.3.3.5) between the cask loading pit and the normal residual heat removal pump suction line. When the water in this pit nears empty, the pump suction is re-aligned to the IRWST/containment recirculation connection so that the pumps can continue to provide injection to the reactor coolant system. The refueling water from the cask loading pit provides additional water into containment (and thus additional driving head) for the post accident containment recirculation. The AP1000 emergency operating procedures will include a restriction on use of this injection method if the gate between the spent fuel pool and the cask loading pit is open at the initiation of the event. In this case the operators will be instructed to close the gate, if possible, before initiating the makeup flow with the normal residual heat removal pumps. Injection from the cask loading pit will only be initiated if the gate can be closed. The gate is normally in the closed position unless cask loading or refueling operations are in progress.

9.1.3.5 Safety Evaluation

The only spent fuel pool cooling system safety-related functions are containment isolation and emergency makeup connections to the spent fuel pool. Containment isolation evaluation is described in Subsection 6.2.3. The following provides the evaluation of the design of the spent fuel pool as well as the spent fuel pool cooling system:

- The spent fuel pool is designed such that a water level is maintained above the spent fuel assemblies for at least 7 days following a loss of the spent fuel pool cooling system, using only onsite makeup water (see Table 9.1-4). The minimum water level to achieve sufficient cooling is the subcooled, collapsed level (without vapor voids) required to cover the top of the fuel assemblies.

- The maximum heat load is assumed to be the heat load for a full core off load immediately following a refueling in which 44 percent of the fuel assemblies were replaced.

- Safety-related makeup water can be supplied to the fuel pool from the fuel transfer canal, cask washdown pit, cask loading pit, and passive containment cooling water storage tank.

- The spent fuel pool cooling system includes safety-related connections from the passive containment cooling water storage tank in the passive containment cooling system to establish safety-related makeup to the spent fuel pool following a design basis event including a seismic event.

- In addition to the safety-related water sources, makeup water is also obtained from the passive containment cooling ancillary water storage tank. Water from this tank can be pumped by the passive containment cooling system recirculation pumps either to the passive containment cooling water storage tank (and then gravity fed to the spent fuel pool), or directly to the spent fuel pool.

Radiation shielding normally provided by the water above the fuel is not required when normal spent fuel pool cooling is not available. Personnel are not permitted in the area when the level in the pool is below the minimum level.

The acceptability of the design of the spent fuel pool cooling system is based on specific General Design Criteria (GDCs) and Regulatory Guides as described in Sections 3.1 and 1.9.

9.1.3.6 Inspection and Testing Requirements

9.1.3.6.1 Preoperational Testing, Analysis, and Inspection

9.1.3.6.1.1 Pump Flow Capability Testing

Each spent fuel pool cooling system pump will be tested. The flow paths will be aligned for normal spent fuel pool cooling by one train of spent fuel pool cooling system components. The flow delivered to each spent fuel pool cooling system heat exchanger will be measured by a flow instrument at the spent fuel pool cooling system pump discharge. The testing confirms that the pumped flow is equal to or greater than the minimum value shown in Table 9.1-3. This is the minimum value for the spent fuel pool cooling system to meet its functional requirement of normal spent fuel pool cooling.

9.1.3.6.1.2 Heat Transfer Capability Analysis

An analysis will be performed on the spent fuel pool cooling system heat exchangers during heat exchanger design. The analysis is to confirm that the product of the overall heat transfer coefficient and effective heat transfer area, UA, of each heat exchanger is equal to or greater than the minimum value shown in Table 9.1-3. This is the minimum value for the spent fuel pool cooling system to meet its functional requirement of normal spent fuel pool cooling.

9.1.3.6.1.3 Dimensional Inspections

The contained volumes of water in the spent fuel pool, fuel transfer canal, the cask washdown pit, and the cask loading pit are used for cooling the spent fuel by boiling after a prolonged loss of normal spent fuel pool cooling. The inspections are to confirm that the contained volumes are equal to or greater than the minimum values shown in Table 9.1-2. These are the minimum values for the spent fuel pool cooling system to meet its safety-related requirement of spent fuel pool cooling for 3 days after loss of normal cooling.

9.1.3.6.2 Routine Testing

Active components of the spent fuel pool cooling system are either in continuous or intermittent use during normal system operation. Periodic visual inspection and preventive maintenance are conducted.

No specific equipment tests are required since system components are normally in operation when spent fuel is stored in the fuel pool. Sampling of the fuel pool water for gross activity, tritium and particulate matter is conducted periodically.

9.1.3.6.3 System Gas Accumulation Assessment and Mitigation

Subsection 6.3.6.3.1 describes the assessment method to address the potential for gas intrusion for the passive core cooling system in response to Interim Staff Guidance (ISG-019) and Generic Letter 2008-01. The same assessment methodology was used to assess the spent fuel pool cooling system.

The spent fuel pool cooling system locations equipped with manual vent valves will be inspected according to the system surveillance and venting procedures described in Subsection 6.3.6.3 to eliminate identified gas accumulations.

9.1.3.7 Instrumentation Requirements

The instrumentation provided for the spent fuel pool cooling system is discussed in the following paragraphs. Alarms and indications are provided as noted.

A. Temperature

Instrumentation is provided to measure the temperature of the water in the spent fuel pool and to give indication as well as annunciation in the main control room when normal temperatures are exceeded.

Instrumentation is also provided to give indication of the temperature of the spent fuel pool water as it leaves either heat exchanger.

B. Pressure

Instrumentation is provided to measure and give indication of the pressures in the spent fuel pool pump suction and discharge lines. Instrumentation is also provided at locations upstream and downstream from the spent fuel pool filter and demineralizer so that pressure differential across this equipment can be determined. High differential pressure across the spent fuel pool filter and demineralizer is annunciated in the main control room.

C. Flow

Instrumentation is provided to measure and give remote indication of the spent fuel pool cooling loop flow downstream of the spent fuel pool pumps. Purification flow is also continuously measured.

D. Level

Safety-related instrumentation is provided to give an alarm in the main control room when the water level in the spent fuel pool reaches the Low-2 level setpoint. This instrumentation is used for post-accident monitoring on the spent fuel pool level. (See Table 7.5-1) All three safety-related spent fuel pool level instruments and associated instrument tubing lines are located below the fuel handling area operating deck and the cask washdown pit. This location provides protection from missiles that may result from damage to the structure over the spent fuel pool. The SFP level instruments associated with PMS divisions A and C are physically separated from the SFP level instrument associated with PMS division B. The safety-related spent fuel pool level instruments measure the water level from the top of the spent fuel pool to the top of the fuel

racks. These instruments are conservatively calibrated at a reference temperature suitable for normal spent fuel pool operation on a regular basis and accuracy is not affected by power interruptions.

Non-safety-related instrumentation is provided to give an alarm in the main control room when the water level in the spent fuel pool and the cask loading pit reaches either the High level or Low level setpoint. Instrumentation in the spent fuel pool is used to alert the operator that the pool is nearing limits for fuel movement. Instrumentation in the cask loading pit is used to alert the operator to a Low-2 level when injecting water from the pit into the reactor coolant system with the normal residual heat removal pumps.

9.1.4 Light Load Handling System (Related to Refueling)

The fuel handling and refueling system consists of equipment and structures used for conducting the refueling operation. This system conforms to General Design Criteria as defined in Section 3.1. The light load handling system meets the guidelines of American Nuclear Society (ANS) 57.1 (Reference 6). Figures 1.2-9 and 1.2-14 indicate the relationship between the light load handling system and the fuel handling areas.

9.1.4.1 Design Basis

9.1.4.1.1 Safety Design Basis

The following safety design basis apply to the light load handling system:

A. Fuel handling devices have provisions to avoid dropping or jamming of fuel assemblies during transfer operation.

B. Handling equipment has provisions to avoid dropping of fuel handling devices during the fuel transfer operation.

C. Handling equipment used to raise and lower spent fuel has a limited maximum lift height so that the minimum required depth of water shielding is maintained.

D. The fuel transfer system, where it penetrates the containment, has provisions to preserve the integrity of the containment pressure boundary.

E. Criticality during fuel handling operations is prevented by the geometrically safe configuration of the fuel handling equipment.

F. In the event of a safe shutdown earthquake (SSE), handling equipment cannot fail in such a manner as to prevent required function of seismic Category 1 equipment. The refueling machine is designed to maintain its load carrying and structural integrity functions during a safe shutdown earthquake.

G. The inertial loads imparted to the fuel assemblies or core components during handling operations are less than potential damage causing loads.

H. Physical safety features are provided for personnel who operate handling equipment.

9.1.4.1.2 Power Generation Design Basis

Design criteria for the light load handling system are as follows:

A. The primary design requirement of the equipment is reliability. A conservative design approach is used for load bearing parts.

B. The refueling machine and fuel handling machine are designed and constructed in accordance with applicable portions of the Crane Manufacturers Association of America, Inc. (CMAA), Specification 70 for Class A-1 service (Reference 7).

C. The static design loads for the crane structures and lifting components are normal dead and live loads plus the fuel assembly weight.

D. The allowable stresses for the refueling machine and fuel handling machine structures supporting the weight of a fuel assembly are as specified in the American Institute of Steel Construction (AISC) Manual.

E. The design load on the wire rope hoisting cables does not exceed 0.20 times the average breaking strength. Two independent cables are used, and each is assumed to carry one half the load.

F. Components critical to the operation of the equipment are assembled with the fasteners restrained from loosening under vibration.

9.1.4.2 System Description

The light load handling system consists of the equipment and structures needed for the refueling operation. This equipment is comprised of fuel assemblies, core component and reactor component hoisting equipment, handling equipment, and a fuel transfer system. The structures associated with the fuel handling equipment are the refueling cavity, the transfer canal, the fuel transfer tube, the spent fuel pool, the cask loading area, the new fuel storage area, and the new fuel receiving and inspection area.

9.1.4.2.1 Fuel Handling Description

The fuel handling equipment is designed to handle the spent fuel assemblies underwater from the time they leave the reactor vessel until they are placed in a container for shipment from the site. Underwater transfer of spent fuel assemblies provides an effective and transparent radiation shield, as well as a reliable cooling medium for removal of decay heat. The boric acid concentration in the water is sufficient to preclude criticality.

The associated fuel handling structures may be generally divided into two areas: the refueling cavity which is flooded only during plant shutdown for refueling, and the spent fuel pool and transfer canal, which is kept full of water. See Subsection 9.1.1.3 for new fuel assembly storage. The new and spent fuel storage areas are accessible to operating personnel. The refueling cavity and the fuel storage area are connected by the fuel transfer tube which is fitted with a quick opening hatch/blind flange on the canal end and a valve on the fuel storage area end. The hatch/blind flange is in place except during refueling to provide containment integrity. Fuel is carried through the tube on an underwater transfer car.

Fuel is moved between the reactor vessel and the fuel transfer system by the refueling machine. The fuel transfer system is used to move a fuel assembly and its associated core component between the containment building and the auxiliary building fuel handling area. After a fuel assembly is placed in the fuel container, the lifting arm pivots the fuel assembly to the horizontal position for passage through the fuel transfer tube. After the transfer car transports the fuel assembly through the transfer tube, the lifting arm at that end of the tube pivots the assembly to a vertical position so that the assembly can be lifted out of the fuel container.

In the fuel handling area, fuel assemblies are moved about by the fuel handling machine. Initially, a short tool is used to handle new fuel assemblies, but the new fuel elevator must be used to lower the assembly to a depth at which the fuel handling machine can place the new fuel assemblies into or out of the spent fuel storage racks.

Decay heat, generated by the spent fuel assemblies in the fuel pool is removed by the spent fuel pool cooling and cleanup system. After a sufficient decay period, the spent fuel assemblies are removed from the fuel racks and loaded into a spent fuel shipping cask for removal from the site.

9.1.4.2.2 Refueling Procedure

New fuel assemblies received for refueling are removed one at a time from the shipping container and moved into the new fuel assembly inspection area. After inspection, the accepted new fuel assemblies are stored in the new fuel storage rack. For the initial core load, some new fuel assemblies may be stored in the spent fuel pool.

Prior to initiating the refueling operation, the reactor coolant system (RCS) is borated and cooled down to refueling shutdown conditions as specified in the Technical Specifications. Criticality protection for refueling operations is specified in the Technical Specifications. The following significant points are addressed by the refueling procedure:

- The refueling water and the reactor coolant contain a nominal boron concentration of 2700 ppm boron. This concentration is sufficient to keep the core five percent Δk/k subcritical during the refueling operations.

- The water level in the refueling cavity is high enough to keep the radiation levels within acceptable limits when the fuel assemblies are removed from the core. Radiation monitoring is described in Section 11.5.

- Continuous communications are established and maintained between the main control room and the personnel engaged in fuel handling operations. One or more of the systems described in Subsection 9.5.2 are used for this communication.

The refueling operation is divided into four major phases: preparation, reactor disassembly, fuel handling, and reactor assembly. A general description of a typical refueling operation through these phases is provided below.

9.1.4.2.2.1 Phase I - Preparation

The reactor is shut down, borated, and cooled to refueling conditions (≤ 140°F) with a final k_{eff} less than 0.95 (all rods in). Following a radiation survey, the containment building is entered. At this time, the coolant level in the reactor vessel is lowered to a point slightly below the vessel flange. The refueling machine console is removed from storage and placed on the refueling machine and cables are connected. Then, the fuel transfer equipment and refueling machine are checked for operation (Subsection 9.1.4.4).

9.1.4.2.2.2 Phase II - Reactor Disassembly

Head cables are disconnected at the integrated head package (IHP) connector plate to allow removal of the vessel head. See Subsection 3.9.7 for a discussion of the integrated head package. The refueling cavity is prepared for flooding by checking the underwater lights, tools, and fuel transfer system; closing the refueling cavity drain lines; and removing the hatch/blind flange from the fuel transfer tube. With the refueling cavity prepared for flooding, the vessel head is unseated and raised above the vessel flange using the containment polar crane. The vessel head is then transported to its

storage pedestal. See Subsection 9.1.5 for requirements for the polar crane. Water from the in-containment refueling water storage tank (IRWST) is transferred into the refueling cavity by gravity and the spent fuel pool cooling system (See Subsection 9.1.3). When the refueling cavity water level is at a depth to support the control rod drive shaft uncoupling, the control rod drive shafts are disconnected. The refueling cavity is then flooded to a height to support the installation of the internals lift rig, then the internals lift rig is installed and the upper internals are removed from the vessel. See Subsection 9.1.5 for discussion of lifting rig requirements and design. The fuel assemblies are now free from obstructions, and the core is ready for refueling after the refueling cavity is filled to the safe shielding depth Subsection 9.1.4.3.7.

9.1.4.2.2.3 Phase III - Fuel Handling

The refueling sequence is started with the refueling machine.

The general fuel handling sequence is as follows:

1. The refueling machine is positioned over a fuel assembly in the core.

2. The refueling machine mast is lowered over a fuel assembly and engages it.

3. The refueling machine withdraws a spent fuel assembly from the core and raises it to a pre-determined height sufficient to clear the vessel flange and still leave sufficient water covering the fuel assembly.

4. The fuel transfer system car is moved into the refueling cavity from the fuel storage area, and the fuel basket is pivoted to the vertical position by the lifting arm.

5. The refueling machine is moved to line up the fuel assembly with the empty fuel basket.

6. The refueling machine loads the spent fuel assembly into the empty fuel basket of the transfer car.

7. The refueling machine then moves back over the core area, and it is aligned over the next fuel assembly to be removed in the core offload sequence.

8. In parallel with item 7 above, the fuel basket is pivoted to the horizontal position and the fuel transfer system container is moved through the fuel transfer tube to the fuel handling area by the transfer car and pivoted to the vertical position.

9. The spent fuel assembly is then unloaded from the fuel basket by the fuel handling machine.

10. The spent fuel assembly is placed in the spent fuel storage rack.

11. The fuel basket is pivoted to the horizontal position, moved back into the containment building and pivoted to the vertical position.

12. This procedure is repeated until the core is offloaded.

13. Core reload is essentially the reverse of the offload sequence described above.

9.1.4.2.2.4 Phase IV - Reactor Reassembly

Reactor reassembly, following refueling, is achieved by reversing the operations given in Phase II - Reactor Disassembly.

9.1.4.2.3 Spent Fuel Cask Loading

The spent fuel assemblies are normally stored in the spent fuel pool, until fission product activity is low enough to permit shipment. The spent fuel assemblies are then transferred to a shipping cask which is designed to shield radiation. Provisions for handling the spent fuel cask are discussed in Subsection 9.1.5.

The following procedure briefly outlines the typical steps of this operation, assuming that the cask loading pit has been previously filled with water and the gate between the cask loading pit and the spent fuel pool has been removed or opened:

1. The transfer cask containing a clean, empty spent fuel canister is brought into the cask washdown pit. The spent fuel canister is removed as necessary and prepared for cask loading.

2. The transfer cask/spent fuel canister are placed into the cask loading pit.

3. The fuel handling machine is positioned over the specific fuel assembly to be shipped out of the spent fuel storage rack. The fuel assembly is picked up and transported into the cask loading pit. During the transfer process the fuel assembly is always maintained with the top of the active fuel at least 8.75 feet below the water surface. This provides confidence that the direct radiation from the fuel at the surface of the water is minimal.

4. Once the fuel transfer process is complete, the lid is placed on top of the cask to provide the required shielding.

5. The cask is then moved to the washdown pit and cleaned with demineralized water. Decontamination procedures can be started at this time.

6. When the spent fuel canister closure and drying processes are complete, the transfer cask is prepared for transfer into a storage or shipping container as applicable.

During the operations, sufficient water is maintained between plant personnel and fuel assemblies that are being moved to limit dose levels to those acceptable for continuous occupational exposure.

9.1.4.2.4 Component Description

A. Fuel Transfer Tube

The fuel transfer tube penetrates the containment and spent fuel area and provides a passageway for the conveyor car during refueling. During reactor operation, the fuel transfer tube is sealed at the containment end and acts as part of the containment pressure boundary. See Subsection 3.8.2.1.5 for discussion of the fuel transfer penetration.

B. Fuel Handling Machine

The fuel handling machine performs fuel handling operations in the new and spent fuel handling area. It also provides a means of tool support and operator access for long tools used in various services and handling functions. The fuel handling machine is equipped with two 2-ton hoists, one of which is single failure proof and is designed according to NUREG-0554.

The nonsingle-failure-proof hoist is primarily used for submerged handling activities. However, there are areas in the fuel handling area of the auxiliary building that the single-failure-proof hoist is not capable of accessing due to travel limitations. Therefore, it is necessary for the nonsingle-

failure-proof hoist to be used in areas other than the spent fuel pool. The nonsingle-failure-proof hoist will be restricted from handling a load above the operating floor within 15 feet of the spent fuel pool. The nonsingle-failure-proof hoist is also restricted from handling new fuel above the operating floor.

The single-failure-proof hoist will be capable of handling loads in the new fuel handling area and the spent fuel handling area with operator warnings associated with the handling of spent fuel.

C. New Fuel Assembly Handling Tool

The new fuel assembly handling tool is used to lift and transfer new fuel assemblies from the new fuel shipping containers to the new fuel storage rack. The tool is also used to transfer new fuel assemblies from the new fuel storage rack to the new fuel elevator.

D. Spent Fuel Assembly Handling Tool

The spent fuel assembly handling tool is used to lift and transfer spent fuel assemblies from the fuel transfer system to the spent fuel racks and new fuel from the elevator to the spent fuel racks.

E. New Fuel Elevator Hoist

The new fuel elevator lowers new fuel assemblies from the fuel handling area operating floor into the spent fuel pool where they can be picked up by the fuel handling machine.

F. New Rod Cluster Control Handling Tool

The new rod cluster control handling tool is used to lift and transfer new control rods from their shipping containers to the new fuel assemblies, and between new assemblies in the new fuel storage racks.

G. Refueling Machine

The refueling machine performs fuel handling operations in the containment building. It also provides a means of tool support and operator access for long tools used for service, control rod latching and unlatching, and for various handling functions.

H. Wet Annular Burnable Absorber (WABA) Handling Tool

The WABA handling tool is used to lift and transfer burnable absorbers between fuel assemblies and/or storage fixtures.

I. Spent Fuel Rack Storage Insert (SFRSI)

The SFRSI is used to store WABA assemblies or control rods in the spent fuel storage racks.

J. Fuel Transfer System

The fuel transfer system conveys fuel assemblies between the containment building and the auxiliary building fuel handling area.

K. Not used.

L. Control Rod Drive Shaft Unlatching Tool

The control rod drive shaft unlatching tool is used to latch and unlatch the control rod drive shafts from the rod cluster control assemblies. It is operated from the refueling machine walkway.

M. Control Rod Drive Shaft Handling Tool

The control rod drive shaft handling tool is used to latch and unlatch the control rod drive shafts (CRDS) from the rod cluster control assemblies.

N. Irradiation Sample Handling Tool

The irradiation sample handling tool is used to remove irradiated reactor vessel surveillance capsules in the holders located in the reactor internals. It is also used for removing and installing the irradiation sample access plugs in the reactor internals.

O. Irradiation Tube End Plug Seating Jack

The irradiation tube end plug seating jack is used to push the irradiation samples into the specimen guides for the last few inches.

P. Control Rod Drive Shaft Storage Racks

The control rod drive shaft storage racks are located on the refueling cavity wall and are used to store spare control rod drive shafts and any ones that might be removed from the upper internals during refueling.

9.1.4.3 Safety Evaluation

9.1.4.3.1 Refueling Machine

The refueling machine design includes the following provisions to provide for safe handling of fuel assemblies. These safety features include the safety requirements listed in (ANS) 57.1:

A. Safety Interlocks

Operations which could endanger the operator or damage the fuel, designated below by an asterisk (*), are prevented by mechanical or failure tolerant electrical interlocks or by redundant electrical interlocks. Other interlocks are intended to provide equipment protection and may be implemented either mechanically or by electrical interlock and are not required to be fail safe.

Fail safe electrical design of a control system interlock is applied according to the following rules:

1. Fail safe operation of an electrically operated brake is such that the brake engages on loss of power.

2. Fail safe operation of a relay is such that the de-energized state of the relay inhibits unsafe operation.

3. Fail safe operation of a switch, termination, or wire is such that breakage or high resistance of the circuit inhibits unsafe operation. The dominant failure mode of the mechanical operation of a cam-operated limit switch is sticking of the plunger in its depressed position. Therefore, use of the plunger-extended position (on the lower part of the operating cam) to energize a relay is consistent with fail safe operation.

Those parts of a control system interlock which are not or cannot be operated in a fail safe mode as defined in the preceding rules are supplemented by a redundant component or components to provide the requisite protection. Required fail safe operations are:

*1. The refueling machine can only place a fuel assembly in the core, in the in-containment fuel storage rack, or in the fuel transfer system.

*2. When the refueling machine gripper is engaged, the machine cannot traverse unless the fuel assembly bottom nozzle is clear of the lower core plate alignment pins.

*3. When the refueling machine gripper is disengaged, the machine cannot traverse unless the gripper is withdrawn into the mast.

*4. Simultaneous traversing and hoisting operations are prevented.

*5. The refueling machine hoist up travel stops at a predetermined height to prevent a spent fuel assembly from being raised above the minimum water depth for shielding.

*6. When a fuel assembly is raised or lowered, interlocks provide confidence that the refueling machine can only apply loads which are within safe operating limits.

*7. The fuel gripper is monitored by devices to confirm operation to the fully engaged or fully disengaged position. Alarms are actuated if both engage and disengage switches are actuated at the same time or if neither is actuated.

8. Lowering of the gripper is not permitted if slack cable exists in the hoist.

9. The inner mast is prevented from lowering completely out of the mast.

10. Before the fuel gripper can release a fuel assembly, the fuel gripper must be in its down position in the core, in the in-containment fuel storage rack, or in the fuel transfer system.

*11. The weight of the fuel assembly must be off the gripper before the fuel gripper can release a fuel assembly.

12. The refueling machine hoist is prevented from moving in the transfer machine zone unless the upender is vertical. An interlock is provided from the fuel transfer system to the refueling machine to accomplish this.

B. Bridge and Trolley Hold-Down Devices

Both refueling machine bridge and trolley are horizontally restrained on the rails by guide rollers on either side of the rail. Hold down devices are used to prevent the bridge or trolley from leaving the rails in the event of a seismic event.

C. Main Hoist Braking System

The main hoist is equipped with two independent braking systems. The winch has a mechanically-operated load brake to prevent overhauling, and a solenoid activated motor brake. Both brakes are rated at 125 percent of the hoist design load.

D. Fuel Assembly Support System.

The main hoist system is supplied with redundant paths of load support such that failure of any one component will not result in free fall of the fuel assembly. Two wire ropes are anchored to the winch drum and carried to a load equalizing mechanism on the top of the inner mast.

The fuel assembly gripper has four fingers gripping the fuel, any two of which will support the fuel assembly weight.

During each refueling outage and prior to removing fuel, the gripper and hoist system are routinely load tested to 125 percent of the maximum setting on the hoist load limit switch.

9.1.4.3.2 Fuel Transfer System

The following personnel safety features are provided for in the fuel transfer system. These safety features include the safety requirements listed in (ANS) 57.1:

A. Transfer Car Permissive Switch

The transfer car controls are located in the fuel handling area, and conditions in the containment are therefore not visible to the operator. The transfer car permissive switch allows the fuel transfer system containment operator to exercise some control over car movement if conditions visible to him warrant such control.

B. Lifting Arm - Transfer Car Position

An interlock on the fuel transfer system prevents the upender from being moved from the horizontal to the vertical position if the transfer car has not reached the end of its travel.

C. Transfer Car - Valve Open

An interlock on the transfer tube valve permits transfer car operation only when the transfer tube valve position switch indicates the valve is fully open.

D. Fuel Container - Refueling Machine

The fuel transfer system is interlocked with the refueling machine. Whenever the transfer car is located in the refueling cavity, the fuel transfer system cannot be operated unless the refueling machine mast is in the fully retracted position or the refueling machine is over the core.

E. Lifting Arm - Fuel Handling Machine

On the spent fuel pool side, the fuel transfer system is interlocked with the fuel handling machine. The fuel transfer system cannot be operated until the loaded fuel handling machine hoist is at the up limit, the empty tool is clear of the upender, or the fuel handling machine is moved away from the fuel transfer system area. An interlock is provided from the fuel handling machine to the fuel transfer system to accomplish this.

9.1.4.3.3 Fuel Handling Machine

The fuel handling machine design includes the following provisions to provide for safe handling of fuel assemblies and other components within the auxiliary building fuel handling area. These safety features include, but are not limited to the safety requirements listed in (ANS) 57.1 with the exception of grapple release, as this feature is the manual operation of a fuel handling tool:

A. Safety Interlocks

Operations that could endanger the operator or damage the fuel, designated below by an asterisk (*), are prevented by mechanical or failure tolerant electrical interlocks, or by redundant electrical interlocks. Other interlocks are intended to provide equipment protection and may be implemented either mechanically or by electrical interlock and are not required to be fail safe.

Fail safe electrical design of a control system interlock is applied according to the following rules:

1. Fail safe operation of an electrically operated brake is such that the brake engages on loss of power.

2. Fail safe operation of a relay is such that the de-energized state of the relay inhibits unsafe operation.

3. Fail safe operation of a switch, termination, or wire is such that breakage or high resistance of the circuit inhibits unsafe operation.

Those parts of a control system interlock that are not or cannot be operated in a fail safe mode, as defined in the preceding rules, are supplemented by a redundant component or components to provide the requisite protection. Required fail safe operations are as follows:

*1. The fuel handling machine, and its associated fuel handling tool, can only place a fuel assembly in the new fuel rack, spent fuel racks, fuel transfer system, new fuel elevator, spent fuel cask, fuel inspection/repair station, or rail car bay traveler.

*2. When the hoist load weighing system detects a load greater than the spent fuel assembly handling tool, the machine cannot traverse unless the hoist is at the up limit. For new fuel handling, the load is required to be clear of a structure prior to traversing.

*3. Simultaneous traversing and hoisting operations are prevented.

*4. The fuel handling machine hoist up travel stops at a predetermined height to prevent a spent fuel assembly from being raised above the minimum water depth for shielding. This hoist “up” travel stop predetermined height is met by the mechanical “up” limit of the non-single failure-proof hoist combined with the geometry of the spent fuel assembly handling tool (SFAHT). Together these design features assure the bottom nozzle of the spent fuel assembly remains less than 3 feet above the top of the spent fuel storage rack.

*5. When a fuel assembly is raised or lowered, interlocks provide confidence that the fuel handling machine can apply only loads that are within safe operating limits.

*6. Lowering of the hoist is not permitted if slack cable exists.

*7. The fuel handling machine hoist is prevented from moving in the transfer machine zone unless the fuel transfer machine upender is vertical. An interlock is provided from the fuel transfer system to the fuel handling machine to accomplish this.

*8. The fuel handling machine is prevented from transporting new fuel above the operating floor over the spent fuel racks.

B. Bridge Hold-Down Devices

The fuel handling machine bridge is horizontally restrained on the rails by guide rollers on either side of the rail. Hold-down devices are used to prevent the bridge from leaving the rails in a seismic event.

C. Hoist Braking System

The hoists are equipped with a solenoid-activated motor brake. The brake is rated at 125 percent of the hoist design load.

D. Fuel Assembly Support System

The hoists are supplied with redundant paths of load support so that failure of any one component will not result in a free fall of the fuel assembly. When redundant paths are not practical, conservative safety factors shall be applied.

9.1.4.3.4 Fuel Handling Tools and Equipment

Fuel handling tools and equipment handled over an open reactor vessel or spent fuel handling area are designed to prevent inadvertent decoupling from machine hooks; i.e., lifting rigs are pinned to the machine hook, and safety latches are provided on hook supporting tools.

Tools required for handling internal reactor components are designed with fail safe features that prevent disengagement of the component in the event of operating mechanism malfunction.

These safety features apply to the following tools:

A. Control Rod Drive Shaft Unlatching Tool

The air cylinders actuating the gripper mechanism are equipped with backup springs which close the gripper in the event of loss of air to the cylinder. Air-operated valves are equipped with safety locking rings to prevent inadvertent actuation.

B. New Fuel Assembly Handling Tool

When the fingers are latched, the actuating handle is positively locked, preventing inadvertent actuations. The tool is preoperationally tested at 125 percent of the weight of one fuel assembly and the heaviest core component.

C. Spent Fuel Assembly Handling Tool

When the fingers are latched, the actuating handle is positively locked to prevent inadvertent actuations. The tool is preoperationally tested at 125 percent of the weight of one fuel assembly and the heaviest core component.

9.1.4.3.5 Seismic Considerations

The equipment classifications for fuel handling and storage equipment are listed in Section 3.2, which provides criteria for the seismic design of the various components.

For safety and non-safety equipment, design for the safe shutdown earthquake (SSE) is considered if failure might adversely affect safety-related equipment.

9.1.4.3.6 Containment Pressure Boundary Integrity

The fuel transfer tube which connects the refueling cavity (inside the containment) and the fuel storage area (outside the containment) is closed on the refueling cavity side by a hatch/blind flange except during refueling operations. Two seals are located around the periphery of the hatch/blind flange with leak-check provisions between them.

9.1.4.3.7 Radiation Shielding

During spent fuel transfer, the exposure rate to the operator is 2.5 millirem per hour or less. This is accomplished by maintaining a minimum of 8.75 feet of water above the top of the active fuel height during handling operations.

The fuel handling devices used to lift spent fuel assemblies are the refueling machine and the fuel handling machine. The fuel handling machine nonsingle-failure-proof hoist requires the use of the spent fuel handling tool to lift spent fuel. Both the refueling machine and the fuel handling machine nonsingle-failure-proof hoist are equipped with positive stops, which prevent the spent fuel assembly from being raised above the minimum water depth for radiation shielding.

9.1.4.3.8 Radiation Monitoring

Plant procedures require that an operating radiation monitor is mounted on any machine when it is handling fuel. Refer to Subsection 11.5.6.4 for a discussion of augmented radiation monitoring during fuel handling operations.

9.1.4.4 Inspection and Testing Requirements

The test and inspection requirements for the equipment in the light load handling system are as follows:

A. Fuel Handling Machine, Refueling Machine, and New Fuel Elevator

The minimum acceptable tests include the following:

- Hoist and cable are load tested at 125 percent of the rated load.
- The equipment is assembled and checked for function and operation.

The following maintenance and checkout tests are recommended to be performed prior to refueling:

- Visual inspection for loose or foreign parts; maintenance to keep free of dirt and grease.
- Lubrication of exposed gears with proper lubricant.
- Visual inspection of hoist cables for worn or broken strands.
- Visual inspection of limit switches and limit switch actuators for any sign of damaged or broken parts.
- Inspection of the equipment for function and operation.

B. Fuel Assembly Handling Tools

The minimum acceptable tests are as follows:

- The tool shall be load tested to 125 percent of the rated load.
- The tool is assembled and checked for operation.

The following maintenance and checkout tests are recommended to be performed prior to use of the tools:

- Visual inspection of the tool for dirt and loose hardware and for any signs of damage such as nicks and burrs.
- Check of the tool for operation.

C. Fuel Transfer System

The minimum acceptable test is that the system is assembled and checked for function and operation.

The following maintenance and checkout tests are recommended to be performed prior to refueling:

- Visual inspection for loose or foreign parts; maintenance to keep free of dirt and grease.
- Lubrication of exposed gears.
- Visual inspection of limit switches and limit switch actuators for any sign of damaged or broken parts.
- Check of system for function and operation.

The above requirements are part of the plant inspection program for the light load handling system, which is implemented through procedures. In addition to the above inspections, the procedures reflect the manufacturers' recommendations for inspection.

The light load handling program, including system inspections, is implemented prior to receipt of fuel onsite.

9.1.5 Overhead Heavy Load Handling Systems

Heavy load handling systems consist of equipment which lift loads whose weight is greater than the combined weight of a single spent fuel assembly and its handling device. This equipment is part of the mechanical handling system (MHS) and is located throughout the plant. The principal equipment is the containment polar crane and the cask handling crane. Other such equipment includes the reactor coolant pump handling machine, bridge cranes, miscellaneous monorail hoists and fixed hoists. Table 9.1-5 lists the heavy load handling systems located in the safety-related areas of the plant, specifically the nuclear island.

For AP1000, a heavy load is a load whose weight is greater than the combined weight of a fuel assembly with rod cluster control, and the associated handling device. This combined weight is about 3100 pounds. Thus, a heavy load is defined as a load weighing more than 3100 pounds.

The COL Combined License applicants referencing the AP1000 certified design will also provide a heavy load handling program description. Implementation of this program will include safe load paths for movement of heavy loads, to be referenced in procedures and shown on equipment layout drawings. This will minimize the potential to impact irradiated fuel in the reactor vessel and in the spent fuel pool, and safe shutdown equipment from movement of heavy loads.

The heavy loads handling program is based on NUREG 0612 and vendor recommendations. The key elements of the program are:

- Listing of heavy loads to be lifted during operation of the plant. This list will be provided once magnitudes have been accurately formalized but no later than three (3) months prior to fuel receipt.

- Listing of heavy load handling equipment as outlined in Table 9.1-5 and whose characteristics are described in this section.

- Heavy load handling safe load paths and routing plans including descriptions of interlocks, (automatic and manual) safety devices and procedures to assure safe load path compliance. Anticipated heavy load movements are analyzed and safe load paths defined. Safe load path

considerations are based on comparison with analyzed cases, previously defined safe movement areas, and previously defined restricted areas. The analyses are in accordance with Appendix A of NUREG 0612.

- Heavy load handling equipment maintenance manuals and procedures as described in Subsection 9.1.5.5.
- Heavy load handling equipment inspection and test plans, as outlined in Subsections 9.1.5.4 and 9.1.5.5.
- Heavy load handling personnel qualifications, training, and control procedures as described in Subsection 9.1.5.5.
- QA programs to monitor, implement, and ensure compliance with the heavy load-handling procedures as described in Subsection 9.1.5.5.

A quality assurance program, consistent with Paragraph 10 of NUREG-0554, is established and implemented for the procurement, design, fabrication, installation, inspection, testing, and operation of the crane. The program, as a minimum, includes the following elements:

- design and procurement document control
- instructions, procedures, and drawings
- control of purchased material, equipment, and services
- inspection
- testing and test control
- non-conforming items
- corrective action
- records

9.1.5.1 Design Basis

9.1.5.1.1 Safety Design Basis

Section 3.2 identifies safety and seismic classifications for mechanical handling system equipment. Heavy load handling systems are generally classified as nonsafety-related, nonseismic systems. The design function and important-to-safety function of the mechanical handling system is to prevent uncontrolled lowering of a critical load. The design requirements for components accomplishing this important-to-safety function are provided in NUREG-0554 (Reference 11). Those cranes and hoists compliant with NUREG-0554 are considered single failure proof. The components of a single failure proof system (polar crane and cask handling crane) necessary to prevent uncontrolled lowering of a critical load are classified as AP1000 Equipment Class D and seismic Category I. The seismic Category I classification requires fabrication and testing in of these components in compliance with the requirements listed in 10 CFR 50 Appendix B and 10 CFR 21.

The polar crane, cask handling crane, containment equipment hatch hoist, and containment maintenance hatch hoist are single-failure-proof systems and are classified as seismic Category I. They are designed to support a critical load during and after a safe shutdown earthquake. The

equipment and maintenance hatch hoist systems are required to be operational after a safe shutdown earthquake.

A critical load is a heavy load that, if dropped, could cause unacceptable damage to reactor fuel elements, or loss of safe shutdown or decay heat removal capability. The consequences of a postulated load drop are considered to be acceptable when the four evaluation criteria of NUREG-0612 (Reference 8), Paragraph 5.1, are satisfied.

Heavy loads handled in safety-related areas of the plant are classified as critical loads unless the consequences of a load drop have been evaluated and found to be within acceptable limits. (See Subsection 9.1.5.3.)

Plant arrangement and the design of heavy load handling systems are based on the following criteria:

- To the extent practicable, heavy loads are not carried over or near safety-related components, including irradiated fuel and safe shutdown components. Safe load paths are designated for heavy load handling in safety-related areas.
- The likelihood of a load drop is extremely small (that is, the handling system is single failure proof), or the consequences of a postulated load drop are within acceptable limits.
- Single-failure-proof systems can stop and hold a critical load following the credible failure of a single component.
- Single-failure-proof systems can support a critical load during and after a safe shutdown earthquake.

9.1.5.1.2 Codes and Standards

The mechanical handling system conforms to the applicable codes and standards listed in Section 3.2. The polar crane and cask handling cranes are designed according to NUREG-0554 (Reference 11) supplemented by ASME NOG-1 (Reference 12) for a Type I single failure proof crane. Other overhead cranes and hoists handling heavy loads are designed according to ASME NOG-1, CMAA 70 (Reference 7), and to the applicable ANSI standard.

NUREG-0612 references ANSI B30.2 (Reference 9) and CMAA-70 (Reference 7) for the design of cranes in safety-related areas, and references NUREG-0554 (Reference 11) for the design of single-failure-proof cranes. ASME NOG-1 also provides design guidance consistent with that provided by NUREG-0554 for the design of single-failure-proof cranes. The design of AP1000 cranes complies with the requirements of NUREG-0612. The polar crane, cask handling crane, equipment hatch hoist, and maintenance hatch hoist meet the NRC accepted single failure proof requirements of topical report EDR-1-P-A (Reference 26). Because the components necessary to prevent uncontrolled lowering of a critical load are fabricated and tested to seismic Category I requirements, the requirements in 10 CFR 50 Appendix B and 10 CFR 21 are applicable.

As noted in the NRC Safety Evaluation Report for EDR-1-P-A (included as part of Reference 26), additional actions necessary to incorporate a complete X-SAM crane or compact X-SAM hoist in a new facility design are the development of a detailed girder design for the trolley or hoist and the performance of the structural and seismic analyses of the girder or monorail design. Also noted in the NRC Safety Evaluation Report is the requirement for the completion of Appendices B and C of EDR-1-P-A to identify the plant-specific information needed to verify conformance with NUREG-0554 guidelines.

9.1.5.2 System Description

Table 9.1-5 lists the heavy load handling systems located in the safety-related areas of the plant, specifically the nuclear island. The polar crane and cask handling crane are designed according to the requirements of NUREG-0554 supplemented by ASME NOG-1 for a Type I, single-failure-proof crane. A description of these cranes is provided in this subsection. The containment equipment hatch hoist and maintenance hatch hoist are designed according to the requirements of NUREG-0554 supplemented by ASME NOG-1 for a Type I, single-failure-proof hoist. Based on the conservative design of these heavy load handling systems and associated special lifting devices, slings, and load lift points (see Subsection 9.1.5.3), a load drop of the critical loads handled by the polar crane, cask handling crane, containment equipment hatch hoist, and maintenance hatch hoist is unlikely. Except for the containment polar crane, cask handling crane, containment equipment hatch hoist, and containment maintenance hatch hoist, the heavy load handling systems are not single-failure-proof.

9.1.5.2.1 Polar Crane General Description

The containment polar crane is a bridge crane mounted on a circular runway rail supported by the containment structure. The bridge consists of two welded steel box girders held together with structural end beams. The two end beams are supported by wheeled trucks that travel on top of the runway rail.

The trolley is mounted on wheeled trucks which move by tractive power over rails secured to the crane girders. The trolley provides structural support for the crane hoisting machinery. Devices are installed to preclude derailment of the bridge or trolley under seismic loading.

Two electric-powered hoists are provided, a main hoist and an auxiliary hoist. Each hoist raises and lowers loads by reeving wire rope through upper and lower sheaves. The lower sheaves are an integral part of the load block. A hook is attached to each load block.

9.1.5.2.1.1 System Operation

The polar crane lifts a variety of loads for refueling and maintenance, such as the reactor vessel integrated head package, reactor internals, and the reactor coolant pump components. The crane is designed to withstand the containment environmental conditions during all modes of plant operation, including pressurization and depressurization of the containment. The crane is designed to operate only during shutdown periods.

Movements of the bridge, trolley, main, and auxiliary hoists can be controlled from the operator's cab or from a remote control. Both the cab and remote controls include a main power control switch. The polar crane has a keylock switch in the operators cab. The keylock switch can lock out control from the hand held remote. Motion control push buttons in the cab and on the remote return to the OFF position when released.

Bridge, trolley, and hoist speeds, and speed controls are in accordance with ASME NOG-1. All speeds are variable. Speed controls permit precise positioning of the load.

The crane can be used for steam generator replacement. The structural design of the bridge is sufficient to support the steam generator, which is a noncritical load. A special hoist on a temporary trolley may be used for the steam generator replacement. Steam generator replacement is not intended to be accomplished with single-failure-proof equipment.

9.1.5.2.1.2 Component Descriptions

The polar crane is designed according to NUREG-0554 supplemented by ASME NOG-1. Table 9.1.5-3 lists the design characteristics of this crane. This subsection describes how the code requirements are implemented in the design of key hoisting and braking components. Associated lifting devices and load lift points are also described.

Main Hoist Systems

The hoisting rope is wound around the drum in a single layer. If the rope becomes dislodged from its proper groove, the crane drives are automatically shut down and the brakes are set. Features are also provided to contain the drum and prevent disengagement of the gearing in the event of drum shaft or bearing failure. A control brake and two redundant holding brakes are provided.

Two separate, redundant reeving systems are used, so that a single rope failure will not result in the dropping of the load. Two wire ropes are reeved side-by-side through the upper and lower sheaves. Each cable passes through an equalizer that adjusts for unequal cable length. The equalizer is also a load transfer safety system, eliminating sudden load displacement and shock to the crane in the unlikely event of a cable break. In the event of hook overtravel to the point where the load block contacts the crane structure, the ropes cannot be cut or crushed.

The load block provides two separate load attachment points; the main hook is a two-pronged, sister hook with safety latches.

Auxiliary Hoist System

The auxiliary hoist system is similar to that of the main hoist.

Special Lifting Devices

Special lifting devices for critical and non-critical loads are designed to meet the applicable requirements of ANSI N14.6 (Reference 14). The stress design safety factors are based on the combined maximum static and dynamic loads that could be imparted to the handling device, based on the characteristics of the crane. Special lifting devices used for the handling of critical loads are listed in Table 9.1.5-2.

Lifting Devices Not Specially Designed

Slings or other lifting devices not specially designed are selected in accordance with ANSI B30.9 (Reference 15), except that the load rating is based on the combined maximum static and dynamic loads that could be imparted to the sling.

For the handling of critical loads, dual or redundant slings are used, or a sling having a load rating twice that required for a non-critical load is used and shall be constructed of metallic material (chain or wire rope) per NRC Regulatory Issue Summary 2005-25, Supplement 1 (Reference 23).

Load Lift Points

The design stress safety factors for heavy load lift points, such as lifting lugs or cask trunnions, are consistent with the safety factors used for special lifting devices. The design of lift points for critical loads is in accordance with NUREG-0612, Paragraph 5.1.6.(3).

9.1.5.2.1.3 Instrumentation Applications

Limit switches are used to initiate protective responses to:

- Hoist overtravel

- Hoist overspeed
- Hoist overload or unbalanced load
- Improper winding of hoist rope on the drum
- Bridge or trolley overtravel

Redundant limit switches are used with the main hoist and the auxiliary hoists to limit the extent of travel in both the hoisting and lowering directions. The primary protection for each hoist in each direction is a limit switch which interrupts power to the hoist motor via the control circuitry. Interruption of power to the hoist motor causes the hoist brakes to set. The hoist may be operated in the safe direction to back out of the overtravel condition.

The secondary protection for each hoist in the raising direction is a block-actuated limit switch which directly interrupts power to the hoist motor and causes the brake(s) to set. The secondary protection for each hoist in the lowering direction is a limit switch which is mechanically and electrically independent of the primary switch but also interrupts power to the hoist motor via the control circuitry. Actuation of the secondary limit switches prevents further hoisting or lowering until specific corrective action is taken.

A centrifugal-type limit switch, located on the drum shaft, provides overspeed protection for each hoist. Hoist speeds in excess of 115 percent of the rated lowering speed for a critical load cause the hoist motor to stop and the holding brakes to set.

A load-sensing system is used to detect overloading of the hoists. Hoisting motion is stopped when the overload setpoint is exceeded. Similarly, an unbalanced load is detected by a system that stops the hoist motion when there is excessive movement of the equalizer mechanism.

A level wind limit switch is provided to detect improper threading of the hoist rope in the drum grooves. This switch stops crane drive motors and sets the brakes. Further hoisting or lowering is prevented until specific corrective action is taken.

End-of-travel limit switches are provided for the trolley. These switches are set to trip just before the trolley comes into contact with the bumper, thus providing confidence that the kinetic energy of the trolley is within the energy-absorbing capacity of the bumpers.

9.1.5.2.2 Cask Handling Crane General Description

The cask handling crane is a bridge crane mounted on two runway rails supported by the auxiliary building fuel handling area east and west wall structures. The bridge consists of two welded steel box girders held together with structural end beams. The two end beams are supported by wheeled trucks that travel on top of the runway rail.

The trolley is mounted on wheeled trucks which move by tractive power over rails secured to the crane girders. The trolley provides structural support for the crane hoisting machinery. Devices are installed to preclude derailment of the bridge or trolley under seismic loading.

The hoist is electrically powered and raises and lowers loads by reeving wire rope through sheaves that are an integral part of the load block. A hook is attached to the load block.

9.1.5.2.2.1 System Operation

The cask handling crane lifts the spent fuel shipping cask from the cask transporter in the loading bay, into the fuel handling area of the auxiliary building, places the cask in the cask washdown and cask loading pits, is used to remove and replace the cask lid, and lowers the loaded cask onto the cask transporter. The crane is designed to operate in the fuel handling area environmental

conditions, and is typically used only when fuel movement activities associated with refueling the reactor are not in progress.

Movements of the bridge, trolley, main, and auxiliary hoists can be controlled from a radio remote control or from a pendant suspended from the crane. Both the pendant and radio remote controls include a main power control switch. The pendant is equipped with a keylock switch that inhibits control from the radio remote control. Motion control push buttons on the radio remote control and on the pendant return to the OFF position when released.

Bridge, trolley, and hoist speeds, and speed control are in accordance with ASME NOG-1. All speeds are variable. Speed controls permit precise positioning of the load.

9.1.5.2.2.2 Component Descriptions

The cask handling crane is designed according to NUREG-0554 supplemented by ASME NOG-1. Table 9.1.5-1 lists the design characteristics of this crane. This subsection describes how the code requirements are implemented in the design of key hoisting and braking components. Associated lifting devices and load lift points are also described.

Hoist System

The hoisting rope is wound around the drum in a single layer. If the rope becomes dislodged from its proper groove, the crane drives are automatically shut down and the brakes are set. Features are also provided to contain the drum and prevent disengagement of the gearing in the event of drum shaft or bearing failure. A control brake and two redundant holding brakes are provided.

Two separate, redundant reeving systems are used, so that a single rope failure will not result in the dropping of the load. Two wire ropes are reeved side-by-side through the sheave. Each cable passes through an equalizer that adjusts for unequal cable length. The equalizer is also a load transfer safety system, eliminating sudden load displacement and shock to the crane in the unlikely event of a cable break. Overtravel protection is provided (see Subsection 9.1.5.2.2.3); however, even in the event of hook overtravel in the raising direction to the point the load block contacts the crane structure, the ropes cannot be cut or crushed.

The load block provides two separate load attachment points; the main hook is a two-pronged sister hook with safety latches.

Auxiliary Hoist System

The auxiliary hoist system is similar to that of the main hoist.

Special Lifting Devices

Special lifting devices for critical and non-critical loads are designed to meet the applicable requirements of ANSI N14.6 (Reference 14). The stress design safety factors are based on the combined maximum static and dynamic loads that could be imparted to the handling device, based on the characteristics of the crane. Special lifting devices used for the handling of critical loads are listed in Table 9.1.5-2.

Lifting Devices Not Specially Designed

Slings or other lifting devices not specially designed are selected in accordance with ANSI B30.9 (Reference 15), except that the load rating is based on the combined maximum static and dynamic loads that could be imparted to the sling.

For the handling of critical loads, dual or redundant slings are used, or a sling having a load rating twice that required for a non-critical load is used and shall be constructed of metallic material (chain or wire rope) per NRC Regulatory Issue Summary 2005-25, Supplement 1 (Reference 23).

Load Lift Points

The design stress safety factors for heavy load lift points, such as lifting lugs or cask trunnions, are consistent with the safety factors used for special lifting devices. The design of lift points for critical loads is in accordance with NUREG-0612, Paragraph 5.1.6.(3).

9.1.5.2.2.3 Instrumentation Applications

Limit switches are used to initiate protective responses to:

- Hoist overtravel.
- Hoist overspeed.
- Hoist overload or unbalance load.
- Improper winding of hoist rope on the drum.
- Bridge or trolley overspeed.
- Bridge or trolley overtravel.

Redundant limit switches are used with the main hoist and the auxiliary hoists to limit the extent of travel in both the hoisting and lowering directions. The primary protection for each hoist in each direction is a limit switch which interrupts power to the hoist motor via the control circuitry. Interruption of power to the hoist motor causes the hoist brakes to set. The hoist may be operated in the safe direction to back out of the overtravel condition.

The secondary protection for each hoist in the raising direction is a block-actuated limit switch, which is mechanically and electrically independent of the primary limit switch and interrupts power to the hoist motor and causes the brake(s) to set. The secondary protection for each hoist in the lowering direction is a limit switch, which is mechanically and electrically independent of the primary switch, but also interrupts power to the hoist motor via the control circuitry. Actuation of the secondary limit switches prevents further hoisting or lowering until specific corrective action is taken.

A centrifugal-type limit switch, located on the drum shaft, provides overspeed protection for each hoist. Hoist speeds in excess of 115 percent of the rated lowering speed for a critical load causes the hoist motor to stop and the holding brakes to set.

A load-sensing system is used to detect overloading of the hoists. Hoisting motion is stopped when the overload setpoint is exceeded. Similarly, an unbalanced load is detected by a system that stops the hoist motion when there is excessive movement of the equalizer mechanism.

A level wind limit switch is provided to detect improper threading of the hoist rope in the drum grooves. This switch stops crane drive motors and sets the brakes. Further hoisting or lowering is prevented until specific corrective action is taken.

End-of-travel limit switches are provided for the trolley. These switches are set to trip just before the trolley comes into contact with the bumper. This provides confidence that the kinetic energy of the trolley is within the energy-absorbing capacity of the bumpers.

9.1.5.2.3 Equipment Hatch Hoist General Description

The equipment hatch hoist is a hoist that is foot-mounted on a platform supported by the containment structure.

The hoist is electrically powered, and it raises and lowers loads by reeving wire rope through sheaves that are an integral part of the load block. The load block is equipped with a hook or lifting device.

9.1.5.2.3.1 System Operation

The equipment hatch hoist lifts the equipment hatch. The hoist is designed to withstand the containment environmental conditions during all modes of plant operation, including pressurization and depressurization of the containment. The hoist is designed to operate only during shutdown periods.

Movements of the hoist can be controlled from a local pushbutton control station. The pushbutton control station includes a main power control switch. Motion control push buttons on the control station return to the OFF position when released.

Hoist speed is in accordance with ASME NOG-1.

9.1.5.2.3.2 Component Descriptions

The equipment hatch hoist is designed according to NUREG-0554 supplemented by ASME NOG-1. Table 9.1.5-4 lists the design characteristics of this hoist. This subsection describes how the code requirements are implemented in the design of key safety-related components.

Hoist System

The hoisting rope is wound around the drum in a single layer. If the rope becomes dislodged from its proper groove, the hoist drive is automatically shut down and the holding brakes are set. Features are also provided to contain the drum and prevent disengagement of the gearing in the event of drum shaft or bearing failure. Two holding brakes and a third brake on the wire rope drum with dynamic lowering capability are provided.

Two separate, redundant reeving systems are used so that a single rope failure will not result in the dropping of the load. Two wire ropes are reeved side-by-side through the sheave blocks. Each rope connects to an equalizer that adjusts for unequal rope length. The equalizer is also a load transfer safety system, eliminating sudden load displacement and shock to the hoist in the unlikely event of a rope break. Overtravel protection is provided (see Subsection 9.1.5.2.3.3); however, even in the event of overtravel in the raising direction to the point the load block contacts the hoist structure, the ropes cannot be cut or crushed.

The load block provides a load attachment point that has double the normal design factor in lieu of redundancy.

Special Lifting Devices

Special lifting devices shall not be used with the equipment hatch hoist.

Lifting Devices Not Specially Designed

Slings or other lifting devices not specially designed are selected in accordance with ANSI B30.9 (Reference 15), except that the load rating is based on the combined maximum static and dynamic loads that could be imparted to the sling.

For the handling of critical loads, dual or redundant slings are used, or a sling having a load rating twice that required for a non-critical load is used and shall be constructed of metallic material (chain or wire rope) per NRC Regulatory Issue Summary 2005-25, Supplement 1 (Reference 23).

Load Lift Points

The design stress safety factors for heavy load lift points, such as lifting lugs, are consistent with the safety factors used for special lifting devices. The design of lift points for critical loads is in accordance with NUREG-0612, Paragraph 5.1.6.(3).

9.1.5.2.3.3 Instrumentation Applications

Limit switches are used to initiate protective responses to:

- Hoist overtravel.
- Hoist overspeed.
- Hoist overload or unbalanced load.
- Improper winding of hoist rope on the drum.

Redundant limit switches are used with the hoist to limit the extent of travel in both the hoisting and lowering directions. The primary protection for the hoist in each direction is a limit switch, which interrupts power to the hoist motor via the control circuitry. Interruption of power to the hoist motor causes the hoist brakes to set. The hoist may be operated in the safe direction to back out of the overtravel condition.

The secondary protection for the hoist in the raising direction is a block-actuated limit switch, which is mechanically and electrically independent of the primary limit switch and interrupts power to the hoist motor and causes the brake(s) to set. The secondary protection for the hoist in the lowering direction is a limit switch, which is mechanically and electrically independent of the primary switch, but also interrupts power to the hoist motor via the control circuitry. Actuation of the secondary limit switches prevents further hoisting or lowering until specific corrective action is taken.

A centrifugal-type limit switch, located on the drum shaft, provides overspeed protection for the hoist. Hoist speeds in excess of 125 percent of the rated lowering speed for a critical load causes the hoist motor to stop and the holding brakes to set.

A load-sensing system is used to detect overloading of the hoists. Hoisting motion is stopped when the overload setpoint is exceeded. Similarly, an unbalanced load is detected by a system that stops the hoist motion when there is excessive movement of the equalizer mechanism.

A level wind limit switch is provided to detect improper threading of the hoist rope in the drum grooves. This switch stops crane drive motors and sets the brakes. Further hoisting or lowering is prevented until specific corrective action is taken.

9.1.5.2.4 Maintenance Hatch Hoist General Description

The maintenance hatch hoist system is the same as that of the equipment hatch hoist system.

9.1.5.3 Safety Evaluation

The design and arrangement of heavy load handling systems promotes the safe handling of heavy loads by one of the following means:

- A single-failure-proof system is provided so that a load drop is unlikely.

- The arrangement of the system in relationship to safety-related plant components is such that the consequences of a load drop are acceptable per NUREG 0612. Postulated load drops are evaluated in the heavy loads analysis.

The polar crane, the cask handling crane, the containment equipment hatch, and the maintenance hatch hoists are single failure proof. These systems stop and hold a critical load following the credible failure of a single component. A double design factor is provided for hooks where used as load bearing components. Redundancy is provided for load bearing components other than hooks, such as the hoisting ropes, sheaves, equalizer assembly, and holding brakes. These systems are designed to support a critical load during and after a safe shutdown earthquake. The seismic Category I equipment and maintenance hatch hoist systems are designed to remain operational following a safe shutdown earthquake. The polar crane is designed to withstand rapid pressurization of the containment during a design basis loss of coolant accident or main steam line break, without collapsing.

The cask loading pit is separated from the spent fuel pool. The cask handling crane cannot move over the spent fuel pool because the crane rails do not extend over the pool. Mechanical stops prevent the cask handling crane from going beyond the ends of the rails.

A heavy loads analysis is performed to evaluate postulated load drops from heavy load handling systems located in safety-related areas of the plant, specifically the nuclear island. No evaluations are required for critical loads handled by the containment polar crane, the cask handling crane, the containment equipment hatch hoist, and the containment maintenance hatch hoist since a load drop is unlikely.

The heavy loads analysis is to confirm that a postulated load drop does not cause unacceptable damage to reactor fuel elements, or loss of safe shutdown or decay heat removal capability.

For the MSIV monorail hoists, equipment and components required for decay heat removal during MODES 5 or 6 are not located in the load path.

There are no planned heavy load lifts outside those already described. However, over the plant life there may be occasions when heavy loads not presently addressed need to be lifted (i.e., in support of special maintenance/repairs). For these occasions, special procedures are generated that address, as a minimum, the following:

- The special procedure complies with NUREG-0612.
- A safe load path is determined. Mechanical and/or electrical stops are incorporated in the hardware design to prohibit travel outside the safe load path. Maximum lift heights are specified to minimize the impact of an unlikely load drop.
- Where a load drop could occur over irradiated fuel or safe shutdown equipment, the consequence of the load drop is evaluated. If the evaluation concludes that the load drop is not acceptable, an alternate path is evaluated, or the lift is prohibited.
- The lifting equipment is in compliance with applicable ANSI standards and has factors of safety that meet or exceed the requirements of the applicable standards.
- Operator training is provided prior to actual lifts.
- Inspection of crane components is performed in accordance with the manufacturer recommendations.

Plant procedures require that an operating radiation monitor is mounted on any crane when it is handling fuel. Refer to Subsection 11.5.6.4 for a discussion of augmented radiation monitoring during fuel handling operations.

9.1.5.4 Inservice Inspection/Inservice Testing

Preoperational inspection and testing of overhead cranes is governed by NUREG-0554. Tests include operational testing with 100 percent load to demonstrate function and speed controls for bridge, trolley, and hoist drives and proper functioning of limit switches, locking, and safety devices. A rated load test is performed with a 125 percent load.

Following plant startup, inservice inspection of overhead cranes is governed by site-specific procedures in accordance with ANSI B30.2. Testing of crane modifications is governed by NUREG-0554 supplemented by ASME NOG-1. Inservice inspection and testing of other cranes and hoists is in accordance with manufacturer's recommendations and applicable industry standards.

In-service inspection and testing of special lifting devices and slings used in safety-related areas of the plant are in accordance with ANSI N14.6 and ANSI B30.9.

The above requirements are part of the plant inspection program for the overhead heavy load handling system, which is implemented through procedures. In addition to the above inspections, the procedures reflect the manufacturers' recommendations for inspection and the NUREG-0612 recommendations.

The overhead heavy load handling equipment inservice inspection procedures, as a minimum, address the following:

- Identification of components to be examined
- Examination techniques
- Inspection intervals
- Examination categories and requirements
- Evaluation of examination results

The overhead heavy load handling program, including system inspections, is implemented prior to receipt of fuel onsite.

9.1.5.5 Load Handling Procedures

Load handling operations for heavy loads that are handled over, could be handled over or are in the proximity of irradiated fuel or safe shutdown equipment are controlled by written procedures. As a minimum, procedures are used for handling loads with the spent fuel cask bridge and polar cranes, and for those loads listed in Table 3.1-1 of NUREG 0612. The procedures include and address the following elements:

- The specific equipment required to handle load (e.g., special lifting devices, slings, shackles, turnbuckles, clevises, load cells, etc.).
- Qualification and training of crane operators and riggers in accordance with chapter 2-3.1 of ASME B30.2, "Overhead and Gantry Cranes."
- The requirements for inspection and acceptance criteria prior to load movement.
- The defined safe load path and provisions to provide visual reference to the crane operator and/or signal person of the safe load path envelope.

- Specific steps and proper sequence to be followed for handling load.
- Precautions, limitations, prerequisites, and/or initial conditions associated with movement of heavy loads.
- The testing, inspection, acceptance criteria and maintenance of overhead heavy load handling systems. These procedures are in accordance with the manufacturer recommendations and are consistent with ANSI B30.2 or with other appropriate and applicable ANSI standards.

Safe load paths are defined for movement of heavy loads to minimize the potential for a load drop on irradiated fuel in the reactor vessel, spent fuel pool or safe shutdown equipment. Paths are defined clearly in procedures and equipment layout drawings. Equipment layout drawings showing the safe load path are used to define safe load paths in load handling procedures. Deviation from defined safe load paths requires a written alternative procedure approved by a plant safety review committee.

9.1.6 Combined License Information for Fuel Storage and Handling

9.1.6.1 Structural Dynamic and Stress Analysis for New Fuel Rack

The confirmatory structural dynamic and stress analysis for the new fuel rack, as described in Subsection 9.1.1.2.1, is addressed in APP-GW-GLR-026 (Reference 16), and the applicable changes are incorporated into the UFSAR.

9.1.6.2 Criticality Analysis for New Fuel Rack

The confirmatory criticality analysis for the new fuel rack, as described in Subsection 9.1.1.3, is addressed in APP-GW-GLR-030 (Reference 17), and the applicable changes are incorporated into the UFSAR.

This report (Reference 17) addresses the degradation of integral neutron absorbing material in the new fuel pool storage racks as identified in GL-96-04, and assesses the integral neutron absorbing material capability to maintain a 5-percent subcriticality margin.

9.1.6.3 Structural Dynamic and Stress Analysis for Spent Fuel Racks

The confirmatory structural dynamic and stress analysis for the spent fuel racks, as described in Subsection 9.1.2.2.1, is addressed in APP-GW-GLR-033 (Reference 18), and the applicable changes are incorporated into the UFSAR.

9.1.6.4 Criticality Analysis for Spent Fuel Racks

The confirmatory criticality analysis for the spent fuel racks, as described in Subsection 9.1.2.3, is addressed in APP-GW-GLR-029P (Reference 20), and the applicable changes are incorporated into the UFSAR.

9.1.6.5 Inservice Inspection Load Handling Systems

The program for inservice inspection of the light load handling system and the overhead heavy load handling system are addressed in Subsections 9.1.4.4 and 9.1.5.4.

9.1.6.6 Operating Radiation Monitor

The radiation monitor mounted on any crane or fuel handling machine when it is handling fuel is addressed in Subsections 9.1.4.3.8 and 9.1.5.3.

9.1.6.7 Coupon Monitoring Program

A spent fuel rack Metamic coupon monitoring program will be implemented when the plant is placed into commercial operation. This program will include tests to monitor bubbling, blistering, cracking, or flaking; and a test to monitor for corrosion, such as weight loss measurements and / or visual examination. The program will also include testing to monitor changes in physical properties of the absorber material, including neutron attenuation and thickness measurements.

The program will include the methodology and acceptance criteria for the tests listed and provide corrective action requirements based on vendor recommendations and industry operating experience. The program will be implemented through plant procedures.

Metamic Monitoring Acceptance Criteria:

- Verification of continued presence of the boron is performed by neutron attenuation measurement. A decrease of no more than 5% in Boron-10 content, as determined by neutron attenuation, is acceptable. This is equivalent to a requirement for no loss in boron within the accuracy of the measurement.

- Coupons are monitored for unacceptable swelling by measuring coupon thickness. An increase in coupon thickness at any point of no more than 10% of the initial thickness at that point is acceptable.

Changes in excess of either of the above two acceptance criteria are investigated under the corrective action program and may require early retrieval and measurement of one or more of the remaining coupons to provide validation that the indicated changes are real. If the deviation is determined to be real, an engineering evaluation is performed to identify further testing or any corrective action that may be necessary.

Additional parameters are examined for early indications of the potential onset of Metamic degradation that would suggest a need for further attention and possibly a change in the coupon withdrawal schedule. These include visual inspection for surface pitting, blistering, cracking, corrosion or edge deterioration, or unaccountable weight loss in excess of the measurement accuracy.

9.1.7 References

1. ANSI N16.1-75, Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors.

2. ANSI N16.9-75, Validation of Calculational Methods for Nuclear Criticality Safety.

3. ANSI N210-76, Design Objectives for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations.

4. ANS 57.2-1983, Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Plants.

5. USNRC NUREG-0800, SRP 3.8.4, Revision 1, Appendix D, “Technical Position on Spent Fuel Pool Racks,” July 1981.

6. ANS 57.1-1992, Design Requirements for Light Water Reactor Fuel Handling Systems.

7. Specifications for Electric Overhead Travelling Cranes CMAA, Specification 70 – 2000.

8. USNRC, “Control of Heavy Loads at Nuclear Power Plants,” NUREG-0612, July 1980.

9. “Overhead and Gantry Cranes,” ANSI/ASME B30.2-1990.

10. Not used.

11. USNRC, “Single-Failure-Proof Cranes for Nuclear Power Plants,” NUREG-0554, May 1979.

12. “Rules for Construction of Overhead and Gantry Cranes (Top Running Bridge, Multiple Girder),” ASME NOG-1-1998.

13. Not used.

14. “Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds or More,” ANSI N14.6-1993.

15. “Slings,” ASME/ANSI B30.9-1996.

16. APP-GW-GLR-026, “New Fuel Storage Rack Structural/Seismic Analysis,” Westinghouse Electric Company LLC.

17. APP-GW-GLR-030, “New Fuel Storage Rack Criticality Analysis,” Westinghouse Electric Company LLC.

18. APP-GW-GLR-033, “Spent Fuel Storage Rack Structural/Seismic Analysis,” Westinghouse Electric Company LLC.

19. Not used.

20. APP-GW-GLR-029P, Revision 3, “AP1000 Spent Fuel Storage Racks Criticality Analysis,” Westinghouse Electric Company LLC (Westinghouse Proprietary).

21. USNRC, 10 CFR 50.68, “Criticality Accident Requirements,” January 2003.

22. USNRC, Regulatory Guide 1.124, Revision 1, “Service Limits and Loading Combinations for Class 1 Linear-Type Component Supports,” January 1978.

23. USNRC, Regulatory Issue Summary 2005-25, Supplement 1, “Clarification of NRC Guidelines for Control of Heavy Loads,” May 2007.

24. “Source Book for Metamic Performance Assessment,” Holtec Report HI-2043215, Revision 2, Holtec International, September 2006.

25. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Holtec International Report HI-2022871 Regarding the Use of Metamic® in Fuel Pool Applications Facility Operating License NOS DPR-51 and NPF-6 Entergy Operations, Inc Arkansas Nuclear One, Unit Nos. 1 and 2 Docket Nos. 50-313.

26. EDR-1-P-A, Revision 7, “eXtra Safety and Monitoring (X-SAM®) Single Failure Proof Cranes,” September 2015 (The NRC Safety Evaluation Report is included as part of the EDR-P-A, Revision 7 document)

27. APP-GW-GLR-029, Revision 5, “AP1000 Spent Fuel Racks Criticality Analysis,” Westinghouse Electric Company LLC (Westinghouse Proprietary).

Table 9.1-1
Loads and Load Combinations for Fuel Racks

Load Combination	Service Level
D + L D + L + T_o	Level A (Note 1, Note 2)
D + L + T_a D + L + T_o + P_f	Level B (Note 1, Note 2)
D + L + T_a + E'	Level D (Note 2)
D + L + F_d	The functional capability of the fuel racks should be demonstrated. (Note 3)

Note:

1. There is no operating basis earthquake (OBE) for the AP1000 plant.
2. The fuel racks are freestanding; thus, there is minimal or no restraint against free thermal expansion at the base of the rack. As a result, thermal loads applied to the rack (T_o and T_a) produce only local (secondary) stresses.
3. This load combination is not required for the new fuel rack since a load drop is deemed an unlikely accident with a single failure-proof hoist.

Abbreviations are those used in NUREG-0800, Section 3.8.4 (including Appendix D) of the Standard Review Plan (SRP):

D = Dead weight induced loads (including fuel assembly weight)
L = Live load (not applicable to fuel racks since there are no moving objects in the rack load path)
F_d Force caused by the accidental drop of the heaviest load from the maximum possible height
P_f = Upward force on the racks caused by postulated stuck fuel assembly
E' = Safe shutdown earthquake (SSE)
T_o = Differential temperature induced loads based on the most critical transient or steady-state condition under normal operation or shutdown conditions
T_a = Differential temperature induced loads based on the postulated abnormal design conditions

Table 9.1-2
Spent Fuel Pool Cooling and Purification System Design Parameters

Spent fuel pool storage capacity	889 total fuel assemblies
Spent fuel pool water volume (including racks without fuel at water level of 15 inches below the operating deck) (gallons)	190,500
Fuel transfer canal water volume (including gate area) at water level of 15 inches below the operating deck (gallons)	63,500
Minimum combined volume of spent fuel pool, fuel transfer canal, and both gate areas (above the fuel assemblies to the bottom of the spent fuel cooling suction piping) (gallons)	130,350
Minimum volume of the cask washdown pit from the cask washdown pit floor to 13.75 feet above the cask washdown pit floor (gallons)	34,100
Minimum volume of the cask loading pit from the bottom of the cask loading pit gate to the bottom of the spent fuel pool cooling suction piping (gallons)	46,050
Nominal boron concentration of water (ppm)	2,700
Maximum normal refueling case (full core offload) Water temperature with one spent fuel cooling system cooling train and one normal residual heat removal system cooling train in operation (°F)	<140
Maximum emergency core unload case Water temperature with both spent fuel cooling system cooling trains and one normal residual heat removal system cooling train in operation (°F)	<140

Table 9.1-3 (Sheet 1 of 2)
Component Data – Spent Fuel Pool Cooling and Purification System

Spent Fuel Pool Pump		
Number		2
Design pressure (psig)		150
Design temperature (°F)		250
Nominal flow (gallons/minute)		1200
Minimum flow to support normal cooling (gpm)		900
Material		Stainless Steel
Spent Fuel Pool Heat Exchangers		
Number		2
Type		Plate
Design heat transfer (Btu/hour)		14.75×10^6
Design capacity (Btu/hour-°F)		24.0×10^5
Minimum capacity to support normal cooling (Btu/hour-°F)		22.0×10^5
	Side 1	**Side 2**
Design pressure (psig)	200	150
Design temperature (°F)	200	250
Nominal flow (pounds/hour)	6.23×10^5	5.94×10^5
Inlet temperature (°F), typ.	89.5	120
Outlet temperature (°F), typ.	113.3	95.1
Fluid circulated	Component cooling water	Spent fuel pool water
Material	Stainless steel	Stainless steel
Spent Fuel Pool Demineralizers		
Number		2
Design pressure (psig)		160
Design temperature (°F)		250
Nominal flow (gallons/minute)		200
Nominal resin volume (cubic feet)		75
Material		Stainless steel

Table 9.1-3 (Sheet 2 of 2)
Component Data – Spent Fuel Pool Cooling and Purification System

Spent Fuel Pool Filter	
Number	2
Design pressure (psig)	160
Design temperature (°F)	250
Nominal flow (gallons/minute)	200
Filtration requirement	98% retention of particles above 5 μm
Material, vessel	Stainless steel

Table 9.1-4
Station Blackout/Seismic Event Times[1][9]

Event	Time to Saturation[1] (hours)	Height of Water Above Fuel at 72 Hours[4] (feet)	Height of Water Above Fuel at 7 Days[4] (feet)
Seismic Event[2] – Power Operation Immediately Following a Refueling[7]	6.0	0.5	0.5[6]
Seismic Event[8] – Refueling, Immediately Following Spent Fuel Region Offload[3][7]	4.5	1.0[5]	1.0[6]
Seismic Event[8] – Refueling, Emergency Full Core Off-Load[3] Immediately Following Refueling[7]	2.0	8.0[5]	8.0[6]

Notes:

1. Times calculated neglect heat losses to the passive heat sinks in the fuel area of the auxiliary building.
2. Seismic event assumes water in the pool is initially drained to the level of the spent fuel pool cooling system connection simultaneous with a station blackout. Fuel cooling water sources are the spent fuel pool, fuel transfer canal, both gate areas, and cask washdown pit for 72 hours. Between 72 hours and 7 days fuel cooling water provided from passive containment cooling ancillary water storage tank.
3. Fuel movement complete, 150 hours after shutdown.
4. See Subsection 9.1.3.5 for minimum water level.
5. Alignment of PCS water storage for supply of makeup water permits maintaining pool level at this elevation. Decay heat in reactor vessel is at or below 7.0 MWt, thus no PCS water is required for containment cooling for 72 hours.
6. Alignment of the passive containment cooling ancillary water storage tank and initiation of PCS recirculation pumps provide a makeup water supply to maintain this pool level or higher above the top of the fuel.
7. The number of fuel assemblies refueled has been conservatively established to include the worst case for an 18-month fuel cycle plus 5 defective fuel assemblies (69 total assemblies or 44% of the core).
8. Seismic event assumes water in the pool is initially drained to the level of the spent fuel pool cooling system connection simultaneous with a station blackout. Fuel cooling water sources are the spent fuel pool, fuel transfer canal, both gate areas, cask washdown pit, cask loading pit, and passive containment cooling system water storage tank for 72 hours.
9. A minimum of 18 hours is available for operator action to align makeup water to the spent fuel pool after a seismic event.

Table 9.1-5
Nuclear Island Heavy Load Handling Systems(1)

Name	Crane/Hoist Type	Location (Building)	Maximum Load Rating (tons)
Containment Polar Crane	Overhead bridge	Containment	300(2)
Equipment Hatch Hoist	Fixed hoist	Containment	13.5
Maintenance Hatch Hoist	Fixed hoist	Containment	13.5
Cask Handling Crane	Overhead bridge	Auxiliary	150
MSIV Monorails Hoist A	Monorail hoists	Auxiliary	12
MSIV Monorails Hoist B	Monorail hoists	Auxiliary	12

Notes:
1. Nuclear island elevators are discussed in the heavy loads analysis.
2. Trolley maximum load rating for a critical load.

Table 9.1.5-1
Cask Handling Crane Component Data

Bridge	
Bridge span	60 ft - 2 in
Travel speed	See Note 1.
Service/parking/emergency braking system (type and number)	Friction (one) for all three functions
Trolley	
Travel speed	See Note 1.
Service/parking/emergency braking system (type and number)	Friction (one) for all three functions
Main Hoist	
Approximate capacity	See Table 9.1-5.
Hook speed	See Note 1.
Approximate hook travel (elevation)	To cask transport in loading bay (at grade elevation)
Main hoist braking system (diverse systems)	
Control brakes (type and number)	Electric (one)
Holding brakes (type and number)	Friction (one)
Emergency drum brake (type and number)	Friction (one)
Auxiliary Hoist	
Approximate capacity	10 tons
Hook speed	See Note 1
Approximate hook travel (elevation)	To cask transport in loading bay (at grade elevation)
Auxiliary hoist braking system (diverse systems)	
Control brakes (type and number)	Electric (one)
Holding brakes (type and number)	Friction (one)
Emergency drum brake (type and number)	Friction (one)

Note:
1. Bridge, trolley, and hoist speeds are within the recommended ranges of ASME NOG-1.

Table 9.1.5-2
Special Lifting Devices Used for the Handling of Critical Loads

Polar Crane Special Lifting Devices	Description
Integrated head package (IHP)	The IHP combines several separate components into an integral unit. It incorporates the lifting device that provides the interface between the polar crane and the reactor vessel head.
Reactor internals lifting rig	The reactor internals lifting rig is a three-legged carbon steel and stainless steel structure that is attached to the main hook for handling of the upper and lower reactor internals packages. The lower reactor internals are not considered a critical load.
Reactor coolant pump (RCP)	The RCP handling machine is used for removal of the RCP motor and hydraulic elements from the pump casing. The pump/motor shell includes lifting lugs which are attached to a lifting device to allow the RCP motor and hydraulic elements to be handled by the polar crane main hook.
Cask Handling Crane Special Lifting Devices	**Description**
Cask lift yoke, cask lift yoke extension, and loaded canister handling equipment	These devices are used for the handling of the casks and loaded canisters, which provide the interface between the cask handling crane and the shipping cask or loaded canister.

Table 9.1.5-3
Polar Crane Component Data

Bridge	
Bridge span	See Figure 1.2-14 and Figure 1.2-16
Travel speed	See Note 1
Service/parking/emergency braking system (type and number)	Friction (one) for all three functions
Trolley	
Travel speed	See Note 1
Service/parking/emergency braking system (type and number)	Friction (one) for all three functions
Main Hoist	
Approximate capacity	See Table 9.1-5
Hook speed	See Note 1
Approximate hook travel (elevation)	To reactor vessel internals
Main hoist braking system (diverse systems)	
Control brakes (type and number)	Electric (one)
Holding brakes (type and number)	Friction (one)
Emergency drum brake (type and number)	Friction (one)
Auxiliary Hoist	
Approximate capacity	25 tons
Hook speed	See Note 1
Approximate hook travel (elevation)	To reactor coolant pump
Auxiliary hoist braking system (diverse systems)	
Control brakes (type and number)	Electric (one)
Holding brakes (type and number)	Friction (one)
Emergency drum brake (type and number)	Friction (one)

Note:
1. Bridge, trolley and hoist speeds are within the recommended ranges of ASME NOG-1.

Table 9.1.5-4
Equipment/Maintenance Hatch Hoist Component Data

Hoist	
Approximate capacity	See Table 9.1-5.
Hoist speed	See Note 1.
Approximate load block travel (elevation)	To hatch (lowered position)
Main hoist braking system	
Control brakes (type and number)	Dynamic lowering using emergency drum brake (Refer to Emergency drum brake in this table)
Holding brakes (type and number)	Friction (two)
Emergency drum brake (type and number)	Friction (one)

Note:
1. Hoist speed is within the recommended range of ASME NOG-1.

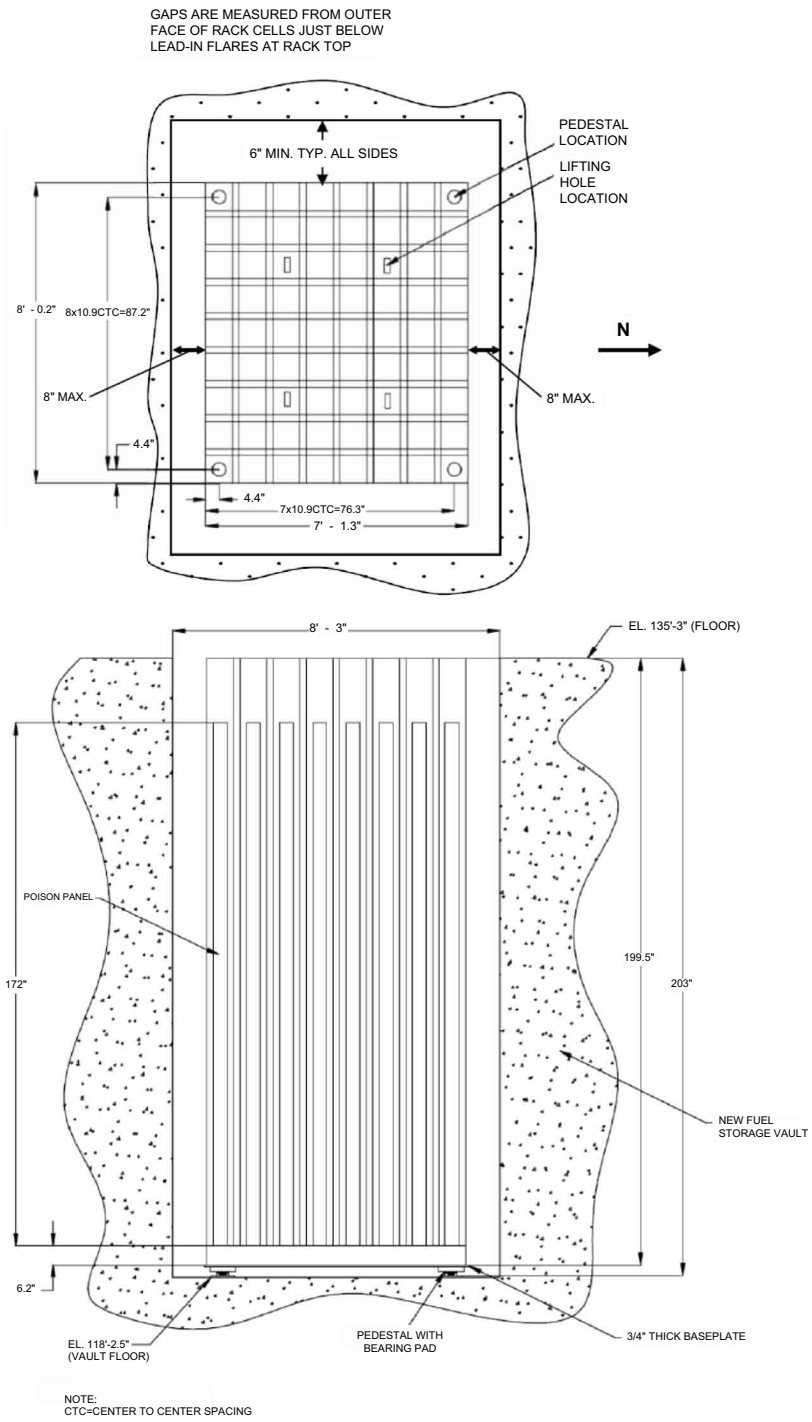


Figure 9.1-1 (Sheet 1 of 2)
New Fuel Storage Rack Layout (72 Storage Location)

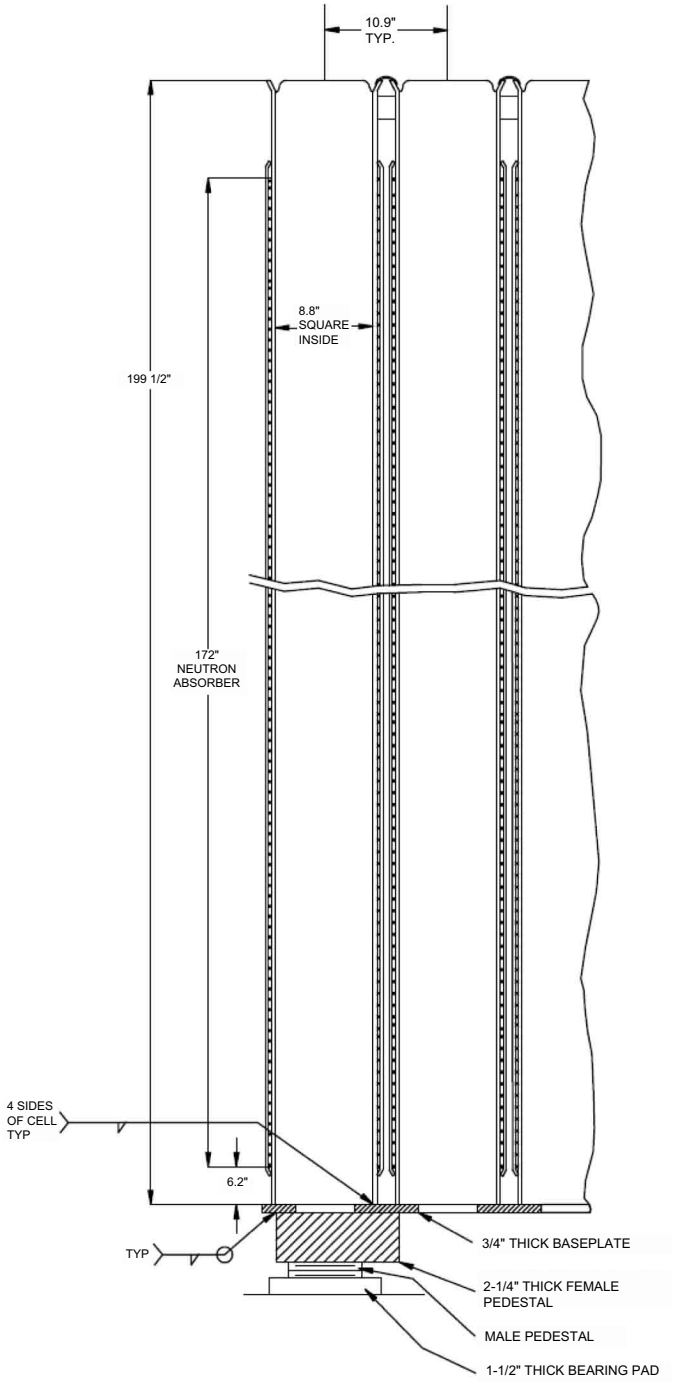


Figure 9.1-1 (Sheet 2 of 2)
New Fuel Storage Rack Cross Section

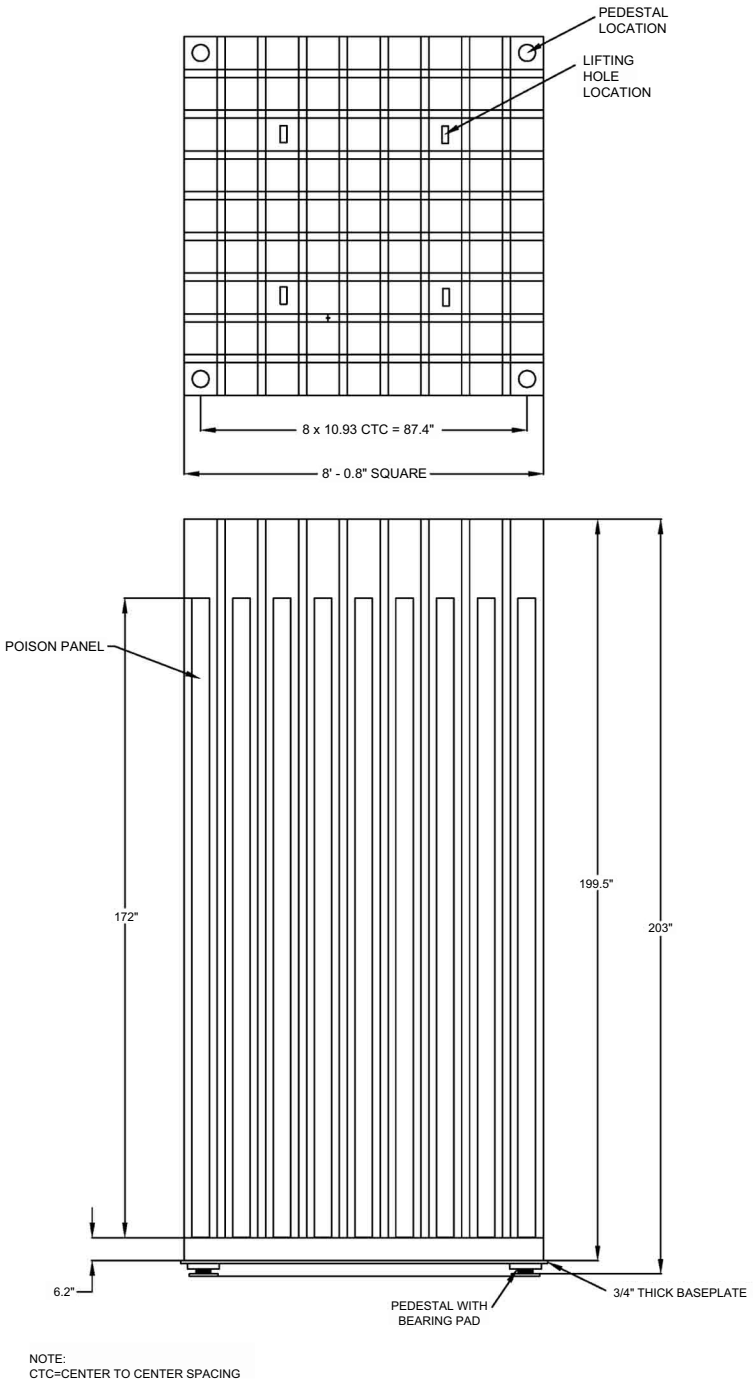


Figure 9.1-2 (Sheet 1 of 2)
Region 1 Spent Fuel Storage Rack Layout

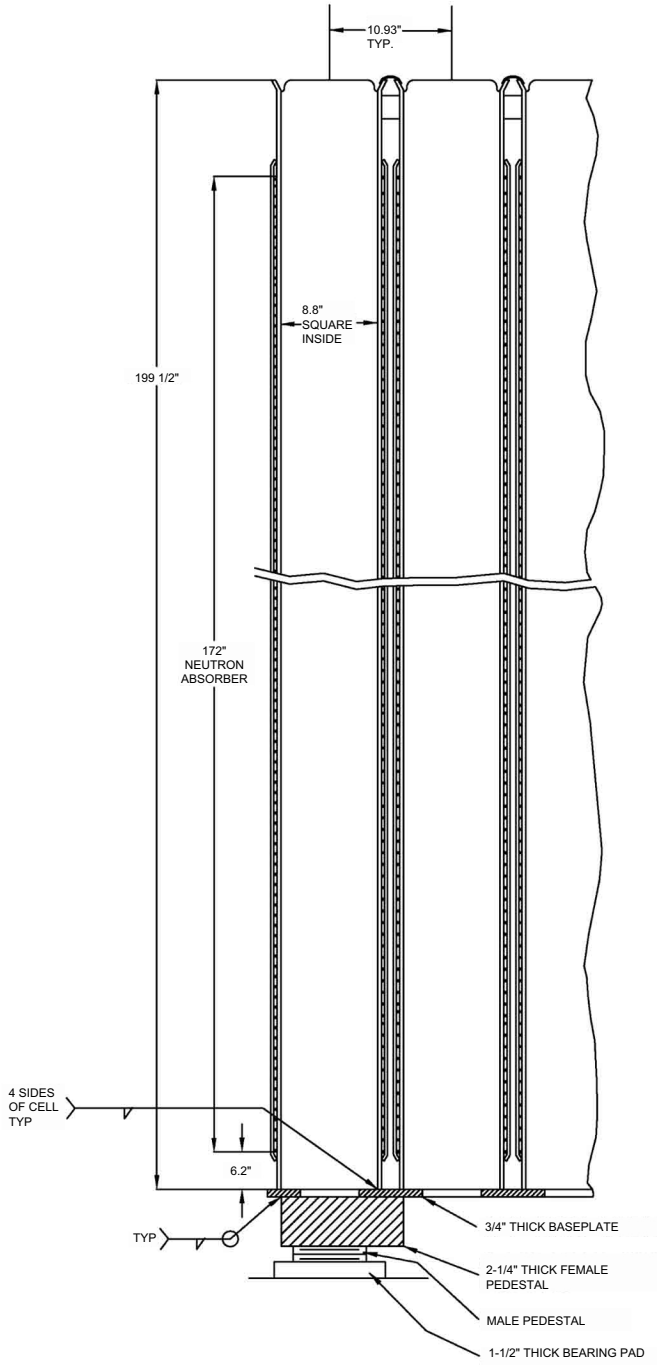


Figure 9.1-2 (Sheet 2 of 2)
Region 1 Spent Fuel Storage Rack Cross Section

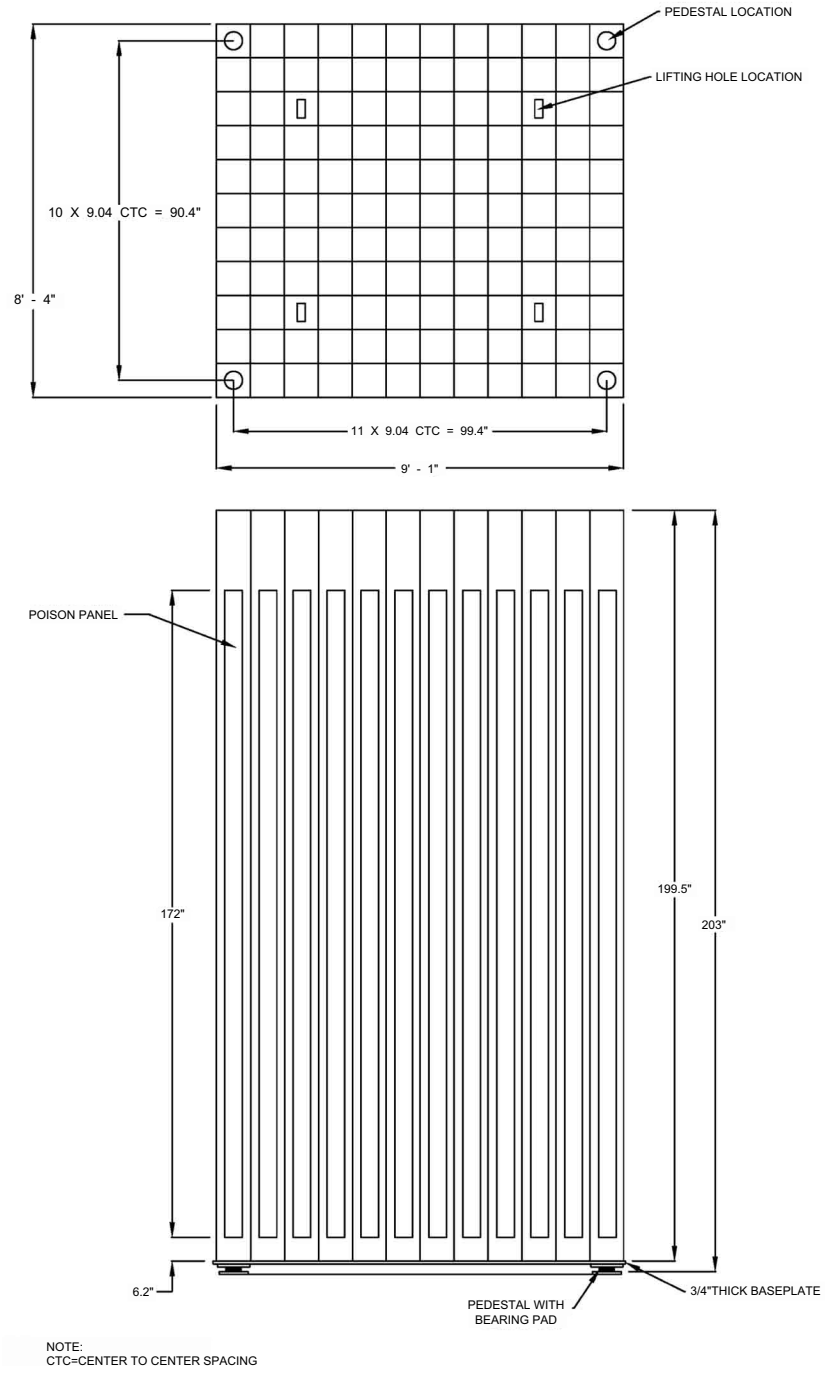


Figure 9.1-3 (Sheet 1 of 2)
Region 2 Spent Fuel Storage Rack Layout

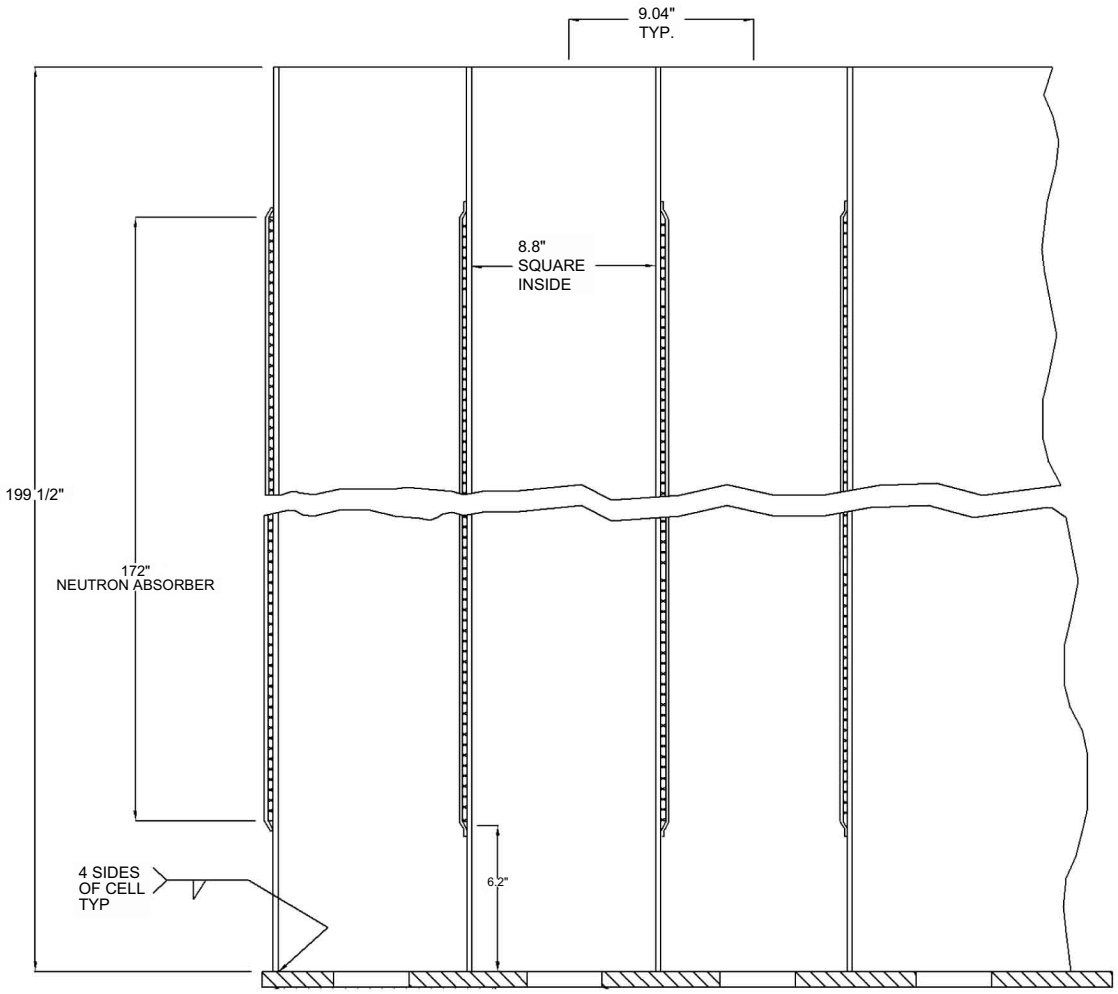


Figure 9.1-3 (Sheet 2 of 2)
Region 2 Spent Fuel Storage Rack Cross Section

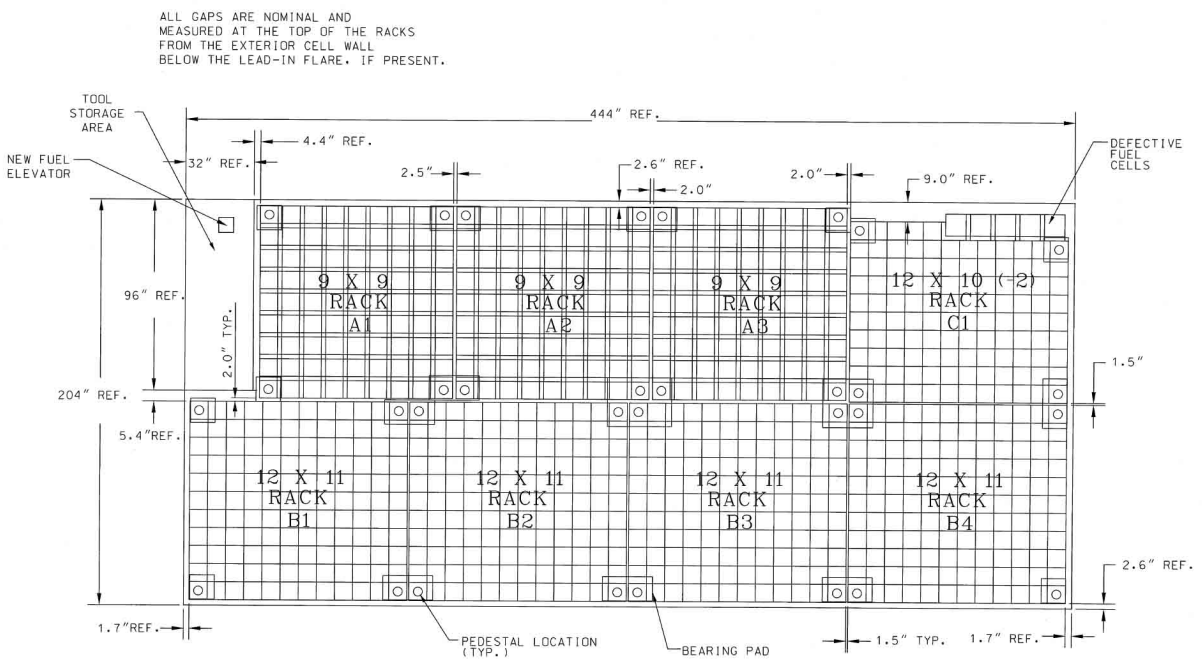


Figure 9.1-4
Spent Fuel Storage Pool Layout
(889 Storage Locations)

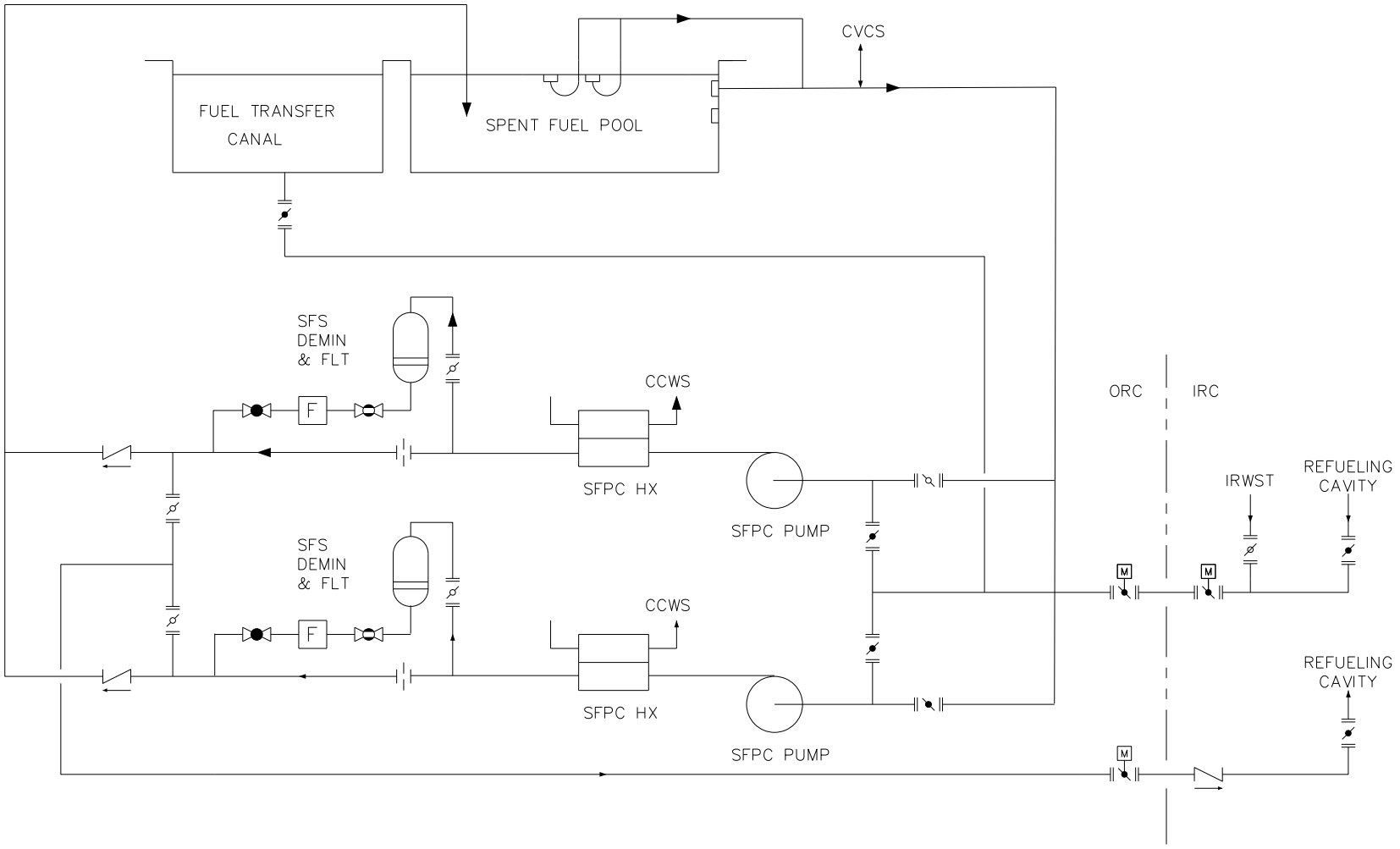


Figure 9.1-5
Spent Fuel Pool Cooling System
(Normal Operation)

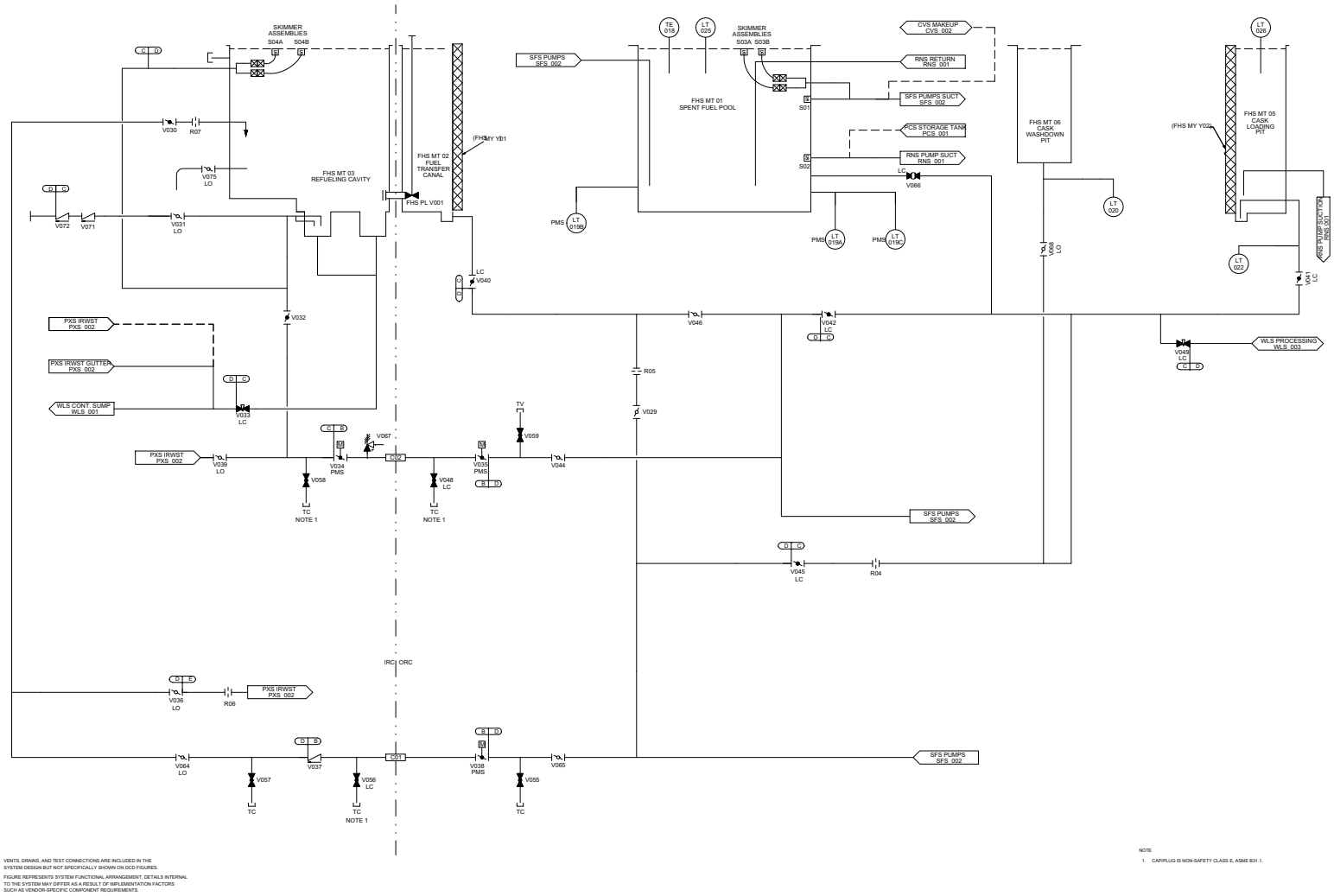


Figure 9.1-6 (Sheet 1 of 2)
Simplified Spent Fuel Pool Cooling System Piping and Instrumentation Diagram
(REF) SFS 001

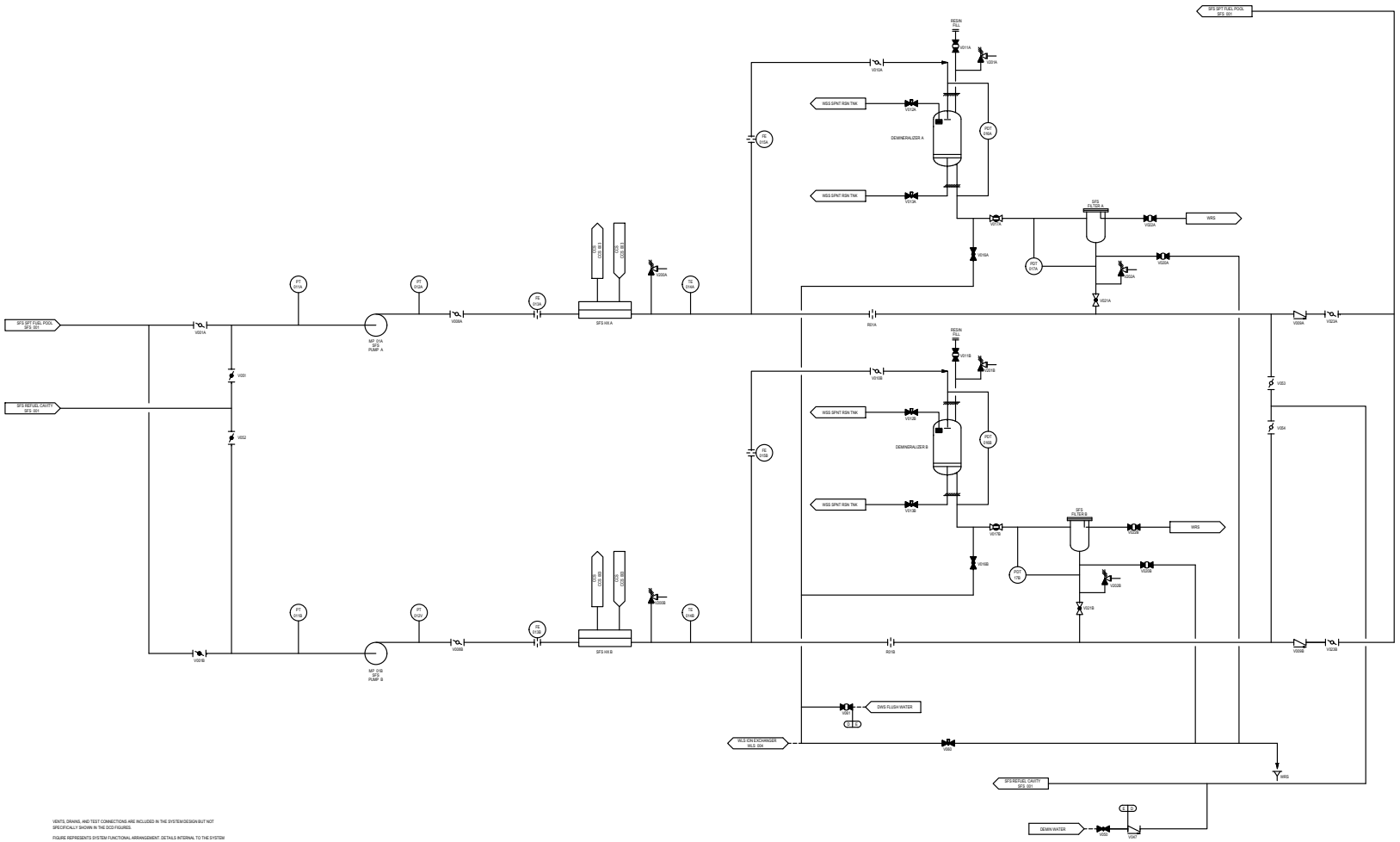


Figure 9.1-6 (Sheet 2 of 2)
Simplified Spent Fuel Pool Cooling System Piping and Instrumentation Diagram (REF) SFS 002

9.2 Water Systems

9.2.1 Service Water System

The service water system (SWS) supplies cooling water to remove heat from the nonsafety-related component cooling water system (CCS) heat exchangers in the turbine building.

9.2.1.1 Design Basis

9.2.1.1.1 Safety Design Basis

The service water system serves no safety-related function and therefore has no nuclear safety design basis.

Failure of the service water system or its components will not affect the ability of safety-related systems to perform their intended function.

9.2.1.1.2 Power Generation Design Basis

The service water system provides cooling water to the component cooling water system heat exchangers located in the turbine building.

During normal power operation, the service water system supplies cooling water at a maximum temperature of 94.1°F to one component cooling water heat exchanger.

During plant cooldown and refueling, the service water system supplies cooling water to both component cooling water heat exchangers to support the cooling requirements for the component cooling water system specified in Subsection 9.2.2.1.2.

9.2.1.2 System Description

9.2.1.2.1 General Description

The service water system is shown in Figure 9.2.1-1. Classification of equipment and components is given in Section 3.2. The system consists of two 100-percent-capacity service water pumps, automatic backwash strainers, a two-cell cooling tower with a divided basin, and associated piping, valves, controls, and instrumentation.

The service water pumps, located in the turbine building, take suction from piping which connects to the basin of the service water cooling tower. Service water is pumped through strainers to the component cooling water heat exchangers for removal of heat. Heated service water from the heat exchangers then returns through piping to a mechanical draft cooling tower where the system heat is rejected to the atmosphere. Cool water, collected in the tower basin, flows through fixed screens to the pump suction piping for recirculation through the system.

A small portion of the service water flow is normally diverted to the circulating water system. This blowdown is used to control levels of solids concentration in the SWS. An alternate blowdown flow path is provided to the waste water system (WWS).

The service water system is arranged into two trains of components and piping. Each train includes one service water pump, one strainer, and one cooling tower cell. Each train provides 100-percent-capacity cooling for normal power operation. Cross-connections between the trains upstream and downstream of the component cooling water system heat exchangers allows either service water

pump to supply either heat exchanger, and allows either heat exchanger to discharge to either cooling tower cell.

Temperatures in the system are moderate and the pressure of the service water system fluid is kept above saturation at all locations. This, along with other design features of the system arrangement and control of valves, minimizes the potential for thermodynamic or transient water hammer.

Service water system materials are compatible with the cooling water chemistry and the chemicals used for the control of long-term corrosion and organic fouling. Water chemistry is controlled by the turbine island chemical feed system (CFS).

Flooding of the turbine building resulting from a service water system failure is less severe than that for the circulating water system. Refer to Subsection 10.4.5.2.3 for a description of flooding due to the circulating water system.

9.2.1.2.2 Component Description

Service Water Chemical Injection

The turbine island chemical feed system equipment injects the required chemicals into the service water system. This injection maintains a noncorrosive, nonscale forming condition and limits biological film formation. Chemicals are injected into service water basin area.

The chemicals can be divided into six categories based upon function: biocide, nonoxidizing biocide, pH adjustor, corrosion inhibitor, scale inhibitor, and silt dispersant. Specific chemicals used within the system, other than the biocide, are determined by the site water conditions. The pH adjustor, corrosion inhibitor, scale inhibitor, and dispersant are metered into the system continuously or as required to maintain proper concentrations. A sodium hypochlorite treatment system is provided for use as the biocide and controls microorganisms that cause fouling. The biocide application frequency may vary with seasons. Nonoxidizing biocide is applied, as necessary, to control algae formation on the cooling tower. The impact of toxic material on main control room habitability is addressed in Section 6.4.

Chemical concentrations are measured through analysis of grab samples. Chlorine residual is measured to monitor the effectiveness of the biocide treatment. Addition of water treatment chemicals is performed by chemical feed system injection metering pumps and is adjusted as required.

Cooling Tower

The cooling tower is a rectilinear mechanical draft structure.

The cooling tower is a counterflow, induced draft tower and is divided into two cells. Each cell utilizes one fan, located in the top portion of the cell, to draw air upward through the fill counter to the downward flow of water. Each fan is driven by a two speed electrical motor through a gear reducer. During normal power operation, one cell is inactive and water flow to that cell is shut off by a motor operated isolation valve. One operating service water pump supplies flow to the operating cell. When the service water system is used to support plant shutdown cooling, both tower cells are normally placed in service along with both service water pumps, for increased cooling capacity.

The cooling tower cold water temperature is normally automatically controlled by operation of the tower fans. The fan in an active cell will be either on high speed, low speed or off, depending on the temperature of the heated service water returning to the cooling tower. When necessary, the water flow to each cooling tower cell can be diverted directly to the basin, bypassing the tower internals.

This is achieved by opening a full flow bypass valve. The bypass can be used during plant startup in cold weather to maintain service water system temperature above 40°F.

After transiting through the cooling tower, cooled service water is collected in a basin located below the tower structure. The basin is partitioned into two halves, with each half collecting the segregated flow from one tower cell. An opening in the partition normally allows the two basin halves to communicate, but a stoplog can be inserted to allow one half of the basin to remain full while the other half is drained for maintenance. Raw water is automatically supplied to the basin to makeup for evaporation, drift and blowdown losses. An alternate makeup water supply is available by gravity flow from both of the fire protection storage tanks, using water that is not dedicated to fire protection purposes. With no makeup to the cooling tower basin, the storage capacity of the basin allows continued system operation for at least 12 hours under limiting conditions with a minimum usable volume of 230,000 gallons, provided that blowdown flow is isolated.

The SWS Cooling Tower was evaluated for potential impacts from interference and air restriction effects due to yard equipment layout and cooling tower operation in an adjacent unit. Based on unit spacing, yard equipment layout and the margins inherent in the performance requirements and design conditions of the towers, no adverse impacts were determined.

Service Water Strainers

An automatic self-cleaning strainer is located in the service water supply piping to each component cooling water heat exchanger. The strainer is sized for a capacity compatible with the flow through the heat exchanger. When in service, each strainer will periodically backwash on a timed cycle, or will backwash if the differential pressure across the strainer exceeds a setpoint. The backwash cleaning features of the strainer can also be manually actuated. Backwash flow from the strainers is discharged to the turbine building sump. Service water strainer internals are not installed on Unit 3.

Service Water Pumps

The service water system includes two service water pumps providing cooling water in the quantities and operating conditions listed in Table 9.2.1-1.

The service water pumps are vertical, centrifugal, constant speed, electric motor-driven pumps. The pumping elements of each pump are enclosed within a suction barrel which connects to supply piping from the cooling tower basin. The suction barrel of each pump is located in the circulating water pipe trench area of the turbine building. The pumps are powered from the normal ac power system and are backed by the standby power source for occurrences of loss of normal ac power and offsite power. Each pump provides 100 percent of the normal power operation flow requirements and is therefore capable of supporting normal power operation with one pump out of service for maintenance.

The starting logic for the service water pumps requires at least one of the cooling tower valves to be open prior to pump start to provide a flow path through the cooling tower or tower bypass. The pump starting logic also interlocks with the motor operated valve at the discharge of each pump. The pump starts with the discharge valve closed and the valve then opens at a controlled rate to slowly admit water to the system while maintaining pump minimum flow. This feature results in reduced fluid velocities during system start to minimize transient effects that may occur as the system sweeps out air that may be present and obtains a water solid condition.

Piping

Service water piping is made of carbon steel and is designed, fabricated, installed, and tested in accordance with ASME B31.1, Power Piping Code. High density polyethylene piping constructed to the requirements of ASME B31.1, Appendix III is also used for the underground portions of the auxiliary makeup line from the primary and secondary fire water tanks, and for the underground

portions of the SWS blowdown line to the CWS cooling tower. Cooling water supply and return piping is accessible for inspection and/or wall thickness determination. Cooling water supply and return piping that runs in the yard is either routed within trenches or may be inspected from the inside.

The service water system is designed to accommodate transient effects that may be generated by the normal starting and stopping of pumps, opening and closing of valves, or other normal operating events. The system pumps water from the basin at the cooling tower, through piping and equipment, to a high point located at the cooling tower riser; the cooling water is then discharged in a spray fashion above the cooling tower basin. The system arrangement is such that high points in the system piping do not lead to the formation of vapor pressure voids upon loss of system pumping. Therefore, the potential for water hammer due to vapor collapse upon pump start is minimized.

Service Water System Valves

Manual isolation valves upstream and downstream of each component cooling water system heat exchanger can be used to isolate the heat exchanger and associated strainer from the service water system. The upstream valves are also normally used during power operation to align the service water system to the component cooling water heat exchanger in use by blocking flow to the inactive heat exchanger. Manual valves in the cross-connection lines between the two service water trains are normally open during power operation to allow the standby pump or standby cooling tower cell to quickly be placed in service if needed. The cross-connection valves are closed as necessary to isolate portions of the system for maintenance, and are normally closed when the system is configured for plant shutdown cooling with both trains in operation.

A motor operated isolation valve downstream of each pump automatically closes when the associated pump stops and automatically opens when the pump starts. Motor operated isolation valves are also used at the cooling tower to isolate flow to a cell that is inactive or out of service for maintenance. The motor operated valves for each train of service water pumps and cooling tower cells are powered by the same onsite standby power source as the associated pump and cooling tower cell fan.

The service water strainers are provided with air-operated backwash valves which open during a backwash cycle. These valves fail closed upon loss of control air or electrical power.

An air operated control valve is provided in the cooling tower blowdown line. This valve allows the plant operator to set the blowdown flowrate. The valve also provides automatic isolation of blowdown flow upon loss of offsite power. The valve fails closed upon loss of control air or electrical power.

Heat Exchangers

The heat exchangers served by the service water system are part of the component cooling water system. For information concerning the component cooling water system heat exchangers refer to Subsection 9.2.2.

9.2.1.2.3 System Operation

The service water system operates during normal modes of plant operation, including startup, power operation (full and partial loads), cooldown, shutdown, and refueling. The service water system is also available during loss of normal ac power conditions.

9.2.1.2.3.1 Service Water System Startup

For initial system startup, service water piping and equipment can be filled with raw water. Thereafter, at least one train normally remains in service. An inactive train is started by starting the associated pump and realigning valves as required.

9.2.1.2.3.2 Plant Startup

During plant startup, the service water system normally provides service to both component cooling water system heat exchangers. This requires that both service water pumps, strainers and cooling tower cells be in service. At the end of this phase of operation, when one of the component cooling water system heat exchangers is removed from service, one of the service water pumps, strainers and cooling tower cells may also be removed from service. Refer to Subsection 9.2.2 for a description of plant startup operation and the conditions under which two component cooling water system heat exchangers may be required.

9.2.1.2.3.3 Power Operation

The service water system, during normal power operation, provides cooling water at a maximum temperature of 94.1°F to the component cooling water heat exchanger in service. One service water pump and one cooling tower cell are in service. The flow rate and heat load are shown in Table 9.2.1-1.

The standby service water pump is automatically started if the operating pump should fail, thereby providing a reliable source of cooling water. The system is designed so either pump can serve as the operating or standby pump.

9.2.1.2.3.4 Plant Cooldown/Shutdown

During the plant cooldown phase in which the normal residual heat removal system has been placed in service and is providing shutdown cooling, the service water cooling tower provides cooling water at a temperature of 88.6°F or less when operating at design heat load and at an ambient wet bulb temperature of no greater than the maximum normal wet bulb temperature as defined in Chapter 2, Table 2.0-201. Two service water pumps and two cooling tower cells are normally used for plant cooldown, and the cross-connection valves between trains are normally closed. The service water system heat load and flow rate are shown in Table 9.2.1-1. During these modes of operation the normal residual heat removal system and the component cooling water system remove sensible and decay heat from the reactor coolant system. The service water system cooling towers are designed with sufficient margin so that normal time-related degradation of tower performance will not prohibit their support of this heat removal function. In the event of failure of a service water system pump or cooling tower fan, the cooldown time is extended.

9.2.1.2.3.5 Refueling

During refueling, the service water system normally provides cooling water flow to both component cooling water system heat exchangers. Two service water pumps normally provide flow through the system for refueling modes.

9.2.1.2.3.6 Loss of Normal AC Power Operation and Offsite Power

In the event of loss of normal ac power and offsite power, the service water pumps and cooling tower fans, along with the associated motor operated valves, are automatically loaded onto their associated diesel bus. This includes isolation of cooling tower blowdown, which minimizes drain down of the system while both pumps are off. What drainage of system fluid that does occur is replaced by air without vapor cavities. The potential for water hammer on pump restart is minimized. Both pumps and both cooling tower cells automatically start after power from the diesel generator is available. Following automatic start, the operator may return the system to the appropriate configuration.

9.2.1.3 Safety Evaluation

The service water system has no safety-related functions and therefore requires no nuclear safety evaluation. If radioactive fluid is detected in the service water system, tower blowdown flow can be isolated by remote manual control. The tower blowdown valve fails closed upon loss of electrical power or instrument air.

9.2.1.4 Tests and Inspections

Preoperational testing is described in Chapter 14. The performance, structural, and leaktight integrity of system components is demonstrated by operation of the system.

9.2.1.5 Instrument Applications

Pressure indication, with low and high alarms, is provided for the discharge of each service water pump. A low pressure signal automatically starts the standby pump. Flow indication, with low and high alarms, is also provided for each service water pump. Due to the system configuration, pump flow indication can also normally be used to monitor flow through the heat exchanger or heat exchangers in service.

Temperature indication is provided for the service water supply to each component cooling water heat exchanger and for the discharge from each heat exchanger to determine the temperature differential across the heat exchanger. Heat exchanger inlet temperature indication also is used for performance monitoring of the service water cooling tower. Low and high heat exchanger inlet temperature alarms are provided. A high alarm is provided for the outlet temperature from each heat exchanger. Temperature instrumentation is provided for the service water return to each cooling tower cell to automatically control the operation of the associated cell fan.

Differential pressure measurement across each service water strainer is provided and will initiate backwash of the strainer on high differential. A high-high differential pressure alarm across the strainer is provided.

Power actuated valves in the SWS are provided with valve position indication instrumentation. In addition, the tower bypass valves are provided with position indication instrumentation.

Level indication is provided for the cooling tower basin along with high and low level alarms. The basin level signal is also used to control the normal makeup water supply valve to maintain the proper level in the cooling tower basin.

A radiation monitor with a high alarm is provided to monitor the service water blowdown flow for detection of potentially radioactive leakage into the SWS from the component cooling water heat exchangers. Provisions are also available for taking local fluid samples.

9.2.2 Component Cooling Water System

The component cooling water system is a non-safety-related, closed loop cooling system that transfers heat from various plant components to the service water system during normal phases of operation. It removes heat from various components needed for plant operation and removes core decay heat and sensible heat for normal reactor shutdown and cooldown.

The AP1000 component cooling water system provides a barrier to the release of radioactivity between the plant components being cooled that handle radioactive fluid and the environment. The component cooling water system also provides a barrier against leakage of service water into primary containment and reactor systems.

9.2.2.1 Design Bases

9.2.2.1.1 Safety Design Basis

Failure of the component cooling water system or its components will not affect the ability of safety-related systems to perform their intended safety functions. The component cooling water system serves no safety-related function except for containment isolation and therefore has no nuclear safety design basis except for containment isolation (see Subsection 6.2.3).

9.2.2.1.2 Power Generation Basis

The component cooling water system is designed to perform its operational functions in a reliable and failure tolerant manner. This reliability is achieved with the use of reliable and redundant equipment and with a simplified system design.

9.2.2.1.2.1 Normal Operation

The component cooling water system transfers heat from various plant components needed to support normal power operation with a single active component failure. The component cooling water system is designed for normal operation in accordance with the following criteria:

- The component cooling water supply temperature to plant components is not more than 100°F assuming a 0 percent exceedance ambient design wet bulb temperature of 86.1°F for service water cooling at normal operations (maximum normal temperature per Table 2.0-201 for normal shutdown).
- The minimum component cooling water supply temperature to plant components is 60°F.
- The component cooling water system provides sufficient surge capacity to accept 50 gallons per minute leakage into or out of the system for 30 minutes before any operator action is required.

9.2.2.1.2.2 Normal Plant Cooldown

The first phase of plant cooldown is accomplished by transferring heat from the reactor coolant system via the steam generators to the main steam systems.

The component cooling water system, in conjunction with the normal residual heat removal system removes both residual and sensible heat from the core and the reactor coolant system and reduces the temperature of the reactor coolant system during the second phase of cooldown.

The component cooling water system reduces the temperature of the reactor coolant system from 350°F at approximately 4 hours after reactor shutdown to 125°F within 96 hours after shutdown by providing cooling to the normal residual heat removal system heat exchangers. This cooldown time is based on operation of both component cooling water system mechanical trains (one pump and one heat exchanger each), and a service water system supply temperature to the component cooling water system heat exchangers resulting from a maximum normal ambient design wet bulb temperature as defined in Table 2.0-201 for service water cooling. In addition to the cooldown time requirements, other system design criteria during cooldown are:

- Operation is consistent with the established reactor coolant system cooldown rates while maintaining the component cooling water supply below 110°F.

- The system design prevents boiling in the component cooling water system during plant cooldown.

- A single failure of an active component during normal cooldown will not cause an increase in reactor coolant system temperature above 350°F. Such a single failure also will not cause the reactor coolant system to boil once the reactor vessel head has been removed and the refueling cavity flooded. The component cooling system continues to provide cooling water to the normal residual heat removal system throughout the shutdown after cooldown is complete.

9.2.2.1.2.3 Refueling

During fuel shuffling (partial core off-load) or a full core off-load, cooling water flow is provided to spent fuel pool heat exchangers to cool the spent fuel pool. For a full core off-load cooling water is also supplied to a normal residual heat removal heat exchanger as part of spent fuel pool cooling. The system design criteria during refueling are:

- System operation is with both component cooling water system mechanical trains available.

- The component cooling water system maintains the spent fuel pool water temperature below 120°F based on a maximum normal ambient design wet bulb temperature as defined in Table 2.0-201 for service water cooling.

9.2.2.1.3 Codes and Standards

The component cooling water system equipment applicable codes and standards are listed in Section 3.2. The containment penetrations, isolation valves, and the pipe between the isolation valves are Safety Class B. A small section of the containment supply and return lines just inside the innermost containment isolation valve is designated Safety Class C. This section of line contains the relief valves provided to protect the containment isolation valves from excess pressure buildup while being closed automatically to isolate a reactor coolant pump external heat exchanger tube leak. The remainder of the component cooling water system piping is designed to ASME B31.1.

9.2.2.2 System Description

The component cooling water system provides a reliable supply of cooling water to the various plant components listed in Table 9.2.2-2.

A simplified sketch of the component cooling water system is included as Figure 9.2.2-1. The details of the system are shown in the piping and instrumentation diagram for the component cooling water system which is included as Figure 9.2.2-2.

The component cooling water system is a closed loop cooling system that transfers heat from various plant components to the service water system cooling tower. It operates during normal phases of plant operation including power operation, normal cooldown, and refueling. The system includes two component cooling water pumps, two component cooling water heat exchangers, one component cooling water surge tank and associated valves, piping, and instrumentation.

The system components are arranged into two mechanical trains. Each train includes one component cooling water pump and one component cooling water heat exchanger. The two trains of equipment take suction from a single return header. The surge tank is connected to the return header. Each pump discharges directly to its respective heat exchanger. A bypass line around each heat exchanger containing a throttle valve prevents overcooling the component cooling water. The discharge of each heat exchanger is to the common supply header.

Component cooling water is distributed to the components by this single supply/return header. Components are grouped in branch lines according to plant arrangement, with one branch line cooling the components inside containment. Loads inside containment are automatically isolated in response to a safeguards actuation signal, which also trips the reactor coolant pumps, and in response to a High-2 bearing water temperature trip signal from one of the reactor coolant pumps. Individual components, except the reactor coolant pumps, can be isolated locally to permit maintenance while supplying the remaining components with cooling water.

The component cooling water surge tank accommodates thermal expansion and contraction. It also accommodates leakage into or out of the component cooling water system until the leak is isolated. Water makeup to the surge tank is provided automatically on a low surge tank level signal by the demineralized water transfer and storage system. A line routed from the pump discharge header to the surge tank includes a mixing tank to add chemicals into the system to inhibit corrosion.

9.2.2.3 Component Description

General descriptions of the component cooling water system components are provided below. The nominal equipment parameters for the component cooling water system components are contained in Table 9.2.2-1.

9.2.2.3.1 Component Cooling Water Pumps

The two component cooling water pumps are horizontal, centrifugal pumps. They have a coupled pump shaft driven by an ac powered induction motor. Each pump provides the flow required by its respective heat exchanger for removal of its heat load. The pumps are redundant for normal operation heat loads. Both pumps are required for the cooldown; however, an extended cooldown can be achieved with only one pump in operation. One pump can be out of service during normal plant operation.

These pumps are risk-significant and are included within the scope of D-RAP. See Table 17.4-1 for further information.

9.2.2.3.2 Component Cooling Water Heat Exchangers

Two component cooling water heat exchangers provide redundant cooling for normal operation heat loads. Both heat exchangers are required to achieve the design cooldown rate; however, an extended cooldown can be achieved with one heat exchanger in operation. Either heat exchanger can be aligned with either component cooling water pump allowing one heat exchanger to be out of service during normal plant operation.

The component cooling water heat exchangers are plate type heat exchangers. Component cooling water circulates through one side of the heat exchanger while service water circulates through the other side. Component cooling water in the heat exchanger is maintained at a higher pressure than the service water to prevent leakage of service water into the system.

9.2.2.3.3 Component Cooling Water Surge Tank

The component cooling water system has a single surge tank. The surge tank accommodates changes in component cooling water volume due to changes in operating temperature. During normal operation, the tank is designed to accommodate a 50 gallons per minute leakage into or out of the system for 30 minutes before any operator action is required. For abnormal operation, the surge tank vent line is sized to accommodate a double-ended tube rupture in the normal residual heat removal system (RNS) heat exchanger (i.e., 520 gpm) without exceeding the surge tank design

pressure or allowing pressure to increase above CCS system design pressure at the highest pressure point in the system.

The tank is a cylindrical, vertical unit constructed of carbon steel.

9.2.2.3.4 Component Cooling Water System Valves

Most of the valves in the component cooling water system are manual valves used to isolate cooling flow from components for which cooling is not required in a given plant operating mode.

Three motor-operated isolation valves and a check valve provide containment isolation for the supply and return component cooling water system lines that penetrate the containment barrier. The motor-operated valves are normally open; however, they are closed upon receipt of a safeguards actuation signal, or a High-2 bearing water temperature reactor trip signal. They are controlled from the main control room and fail as-is.

A relief valve is provided to prevent overpressurization of the return component cooling water line containment penetration. This relief valve prevents overpressurization that might be caused by thermal expansion of the fluid between the containment isolation valves following an event causing containment isolation. This relief valve is located inside the containment.

An air-operated isolation valve is located in the component cooling water discharge line from each reactor coolant pump. These valves, which are normally open, can be closed by an operator from the MCR, following a flow deviation alarm. The alarm is produced when there are flow deviations detected simultaneously in the reactor coolant pump CCS cooling supply and return lines that are indicative of a leak from the pump external heat exchanger to the CCS. Closing these valves prevents radioactive reactor coolant flow through the component cooling water system.

An air-operated isolation valve is located in the component cooling water discharge line from each VWS chiller. These valves are opened by the same signals that initiate the associated pump.

Relief valves are provided in the cooling water outlet line from each reactor coolant pump. These valves are sized to protect the pump motor cooling jacket (design pressure 200 psig) and the component cooling water piping in the event of a tube rupture in the reactor coolant pump external heat exchanger. A relief valve in the cooling water outlet line from the letdown heat exchanger also protects the component cooling water piping in the event of a tube rupture in the heat exchanger. Small relief valves are included in the cooling water outlet line from the other components to relieve the volumetric expansion which occurs if the cooling water lines to the component are isolated and the water temperature rises. One relief valve is also provided in each Safety Class C section of piping, just inside the innermost containment isolation valves on the CCS 10-inch supply and return lines penetrating the containment barrier, to ensure protection of the containment isolation valves from excess pressure while closing on a reactor coolant pump High-2 bearing water temperature trip signal intended to isolate a potential external heat exchanger tube leak. In addition, these valves provide protection of containment isolation valves in the event of a letdown heat exchanger tube rupture.

Relief valves in the cooling water outlet lines from each normal residual heat exchanger also protect the RNS heat exchanger shell and component cooling water piping in the event of a tube leak that occurs while the heat exchanger is isolated from the CCS. These relief valves also provide thermal relief for an isolated RNS heat exchanger.

9.2.2.3.5 Piping Requirements

Component cooling water system piping is made of carbon steel. Piping joints and connections are welded, except where flanged connections are required as indicated on the component cooling water system piping and instrumentation diagram (Figure 9.2.2-2).

9.2.2.4 System Operation and Performance

9.2.2.4.1 Plant Startup

Plant startup is the operation that brings the reactor plant from a cold shutdown condition to no-load operating temperature and pressure, and subsequently to power operation.

Normally both component cooling water system mechanical trains are operating during this post refueling period. Both trains are aligned to provide cooling to the required components as shown in Table 9.2.2-2.

When plant heatup is initiated, the reactor coolant pumps are started, and residual heat removal from the core is discontinued by stopping the residual heat removal pumps. The letdown heat exchanger is placed on automatic temperature control to maintain a constant letdown temperature. Throughout the plant startup, cooling water flows and temperatures are monitored to verify that the values are within the required limits. Once startup activities are complete, one component cooling water pump and one heat exchanger are taken out of service.

9.2.2.4.2 Normal Operation

During normal plant operation, one component cooling water system mechanical train of equipment is operating. The standby train is aligned to automatically start in case of a failure of the operating component cooling water pump. The system is aligned to provide cooling water flows to the appropriate equipment as shown on Table 9.2.2-2.

During normal operation, leakage from the component cooling water system is replaced by automatic actuation of a valve in the makeup line on low surge tank level.

Periodically, a sample of the component cooling water is taken by the plant operator to ascertain that water chemistry specifications are met. If necessary, appropriate chemicals are added via the chemical addition tank and mixing is achieved through a recirculation line from the pump discharge header, through the surge tank to the pump suction line.

9.2.2.4.3 Plant Shutdown

Plant shutdown is the operation that brings the reactor plant from power operation to refueling conditions. During plant shutdown operations, both component cooling water system mechanical trains normally operate. The system is aligned to provide the cooling water flows to the appropriate equipment as shown on Table 9.2.2-2.

The initial phase of plant cooldown is the reactor coolant system cooldown and depressurization utilizing the steam generators and the main steam system. The second phase of plant cooldown is initiated by placing the normal residual heat removal system in service when the reactor coolant temperature and pressure have been reduced to 350°F and 400 to 450 psig, respectively (approximately 4 hours after reactor shutdown).

Prior to starting the residual heat removal pumps, the standby component cooling water pump and heat exchanger are placed in operation and component cooling water flow is initiated to the normal

residual heat removal heat exchangers. Following this, the normal residual heat removal system can be placed into operation by properly aligning valves and starting a residual heat removal pump.

The component cooling water system, in conjunction with the normal residual heat removal system and service water system cools the reactor coolant system to 125°F within 96 hours after shutdown. During the cooldown period, the component cooling water inlet temperature to the various components does not exceed 110°F. Both component cooling water pumps and heat exchangers are required to meet the plant cooldown schedule. In the event of a failure of a component cooling water pump or heat exchanger, the cooldown time is extended.

9.2.2.4.4 Refueling

Both component cooling water system mechanical trains are in operation during refueling. The system is aligned to provide the required flow to the appropriate components as shown on Table 9.2.2-2.

For fuel shuffling (partial core off-load), cooling water flow is provided to both spent fuel pool heat exchangers to maintain the spent fuel pool water temperature below 120°F. With a full core off-load and 10 years accumulation of spent fuel in the pool, both spent fuel pool heat exchangers and one normal residual heat removal heat exchanger maintain the spent fuel pool water temperature below 120°F.

9.2.2.4.5 Abnormal Conditions

9.2.2.4.5.1 Failure of a Component Cooling Water Pump

If a component cooling water pump fails when one pump is in service, an alarm is actuated and the low header flow signal automatically initiates operation of the standby component cooling water pump. If a component cooling water pump fails during plant cooldown, the time to reach the cold shutdown condition is increased.

9.2.2.4.5.2 Leakage into the Component Cooling Water System from a High Pressure Source

Small leakage of reactor coolant into the component cooling water system is detected by a radiation monitor on the common pump suction header, by routine sampling, or by high level in the surge tank.

Flow sensors located in the cooling water inlet and outlet lines from each reactor coolant pump external heat exchanger also detect leakage from a heat exchanger tube into the component cooling water system. Simultaneous flow deviations in both the inlet and outlet lines will generate a flow deviation alarm; this alarm is indicative of leak conditions and would alert the operator to close the valve on the cooling water outlet line on each reactor coolant pump to prevent reactor coolant flow throughout the component cooling water system. Both the flow signals and the isolation valves are nonsafety-related. If the valve on the reactor coolant pump cooling water outlet line is not closed, reactor coolant leakage from the pump can be retained inside containment by closing the safety-related component cooling water containment isolation valves. These containment isolation valves close automatically if the leak rate is sufficiently large to cause a High-2 bearing water temperature reactor and pump trip signal to be generated by the protection and safety monitoring system (PMS). The containment isolation valves can also be closed manually by the operator after being alerted to a reactor coolant pump leak by alarms from component cooling water system instrumentation (surge tank level and/or radiation level in the CCS pump suction header) or from the flow instruments located on the inlet and outlet lines from the leaking reactor coolant pump external heat exchanger. Manual closure of one CCS outlet isolation valve will result in a High-2 bearing water temperature trip of the plant if the affected reactor coolant pump continues to operate.

A safeguards actuation signal results if sufficient reactor coolant system inventory is lost through the leak. This signal will trip the reactor coolant pumps and automatically close the component cooling water containment isolation valves to prevent reactor coolant leakage outside containment. Overpressure protection of the reactor coolant pump motor cooling jacket and the component cooling water piping subjected to the reactor coolant system pressure is provided by means of a relief valve on the cooling water outlet piping downstream of the reactor coolant pump external heat exchanger. Two additional relief valves, one on each CCS cooling water line penetrating the containment inside the innermost containment isolation valve, are provided to protect the containment isolation valves from overpressure while being closed to isolate a high-pressure leak in the CCS inside containment.

The operator is alerted to a large leak from the letdown heat exchanger by a high surge tank level or a high radiation alarm in the absence of a signal from one or both of the reactor coolant pump inlet or outlet flow sensors indicating reactor coolant leakage from a reactor coolant pump external heat exchanger to the component cooling water system. The operator can isolate the reactor coolant flow to the letdown heat exchanger from the main control room by closing the letdown flow isolation valve in the chemical and volume control system. Overpressure protection for the component cooling water system in the case of a letdown heat exchanger tube rupture is provided by a relief valve in the component cooling water system piping near the heat exchanger outlet.

During a normal plant cooldown a normal residual heat removal heat exchanger tube leak or rupture could result in reactor coolant leakage into the component cooling water system. A check of the local flow measurements in the normal residual heat removal heat exchanger cooling water outlet lines will indicate the leaking heat exchanger. High surge tank level and/or high radiation level in the CCS pump suction header would also confirm this condition. Reactor coolant flow to the faulty heat exchanger can be isolated by closing valves in the normal residual heat removal system. If the RNS heat exchanger is isolated from the remainder of the CCS, overpressure protection for the component cooling water system and RNS heat exchanger shell in the case of a normal residual heat exchanger tube rupture is provided by a relief valve in the component cooling water system piping near each heat exchanger outlet.

9.2.2.4.5.3 Leakage from the Component Cooling Water System

Excessive leakage from the component cooling water system causes the water level in the component cooling water surge tank to drop and a low level alarm to be actuated. Makeup water is added automatically to the component cooling water system as required. After the leak is identified by visual inspection or by a change in individual component cooling water flow rate, the affected cooling water circuit containing the leak is isolated from the component cooling water system.

9.2.2.4.5.4 Loss of Normal AC Power Operation and Offsite Power

The component cooling water pumps are automatically loaded on the standby diesel in the event of a loss of normal ac power and offsite power. The component cooling water system therefore continues to provide cooling of required components if normal ac power and offsite power is lost.

9.2.2.4.5.5 Fire Leading to MODE 5, Cold Shut Down

In the event of a loss of normal component cooling system function the Fire Protection System can provide the source of cooling water for a Normal Residual Heat Removal System (RNS) heat exchanger and a RNS pump. Normally closed isolation valves between the Fire Protection System and the Component Cooling Water System are manually opened. An additional valve is manually closed to prevent supply of cooling water to other heat exchangers which are not needed to provide cooling for the Reactor Coolant System. A drain valve on the component cooling water return header is opened and the Fire Protection System water is released after passing through the RNS heat

exchanger. The flow rate of Fire Protection System water is controlled manually to conserve the supply.

9.2.2.5 Evaluation

The component cooling water system penetrates the containment boundary. The containment penetration lines are designed in accordance with the containment isolation criteria system specified in Subsection 6.2.3. The containment isolation valve design evaluation and effects of failures are also presented in Subsection 6.2.3.

The component cooling water system can remove the required heat load during a loss of normal ac power.

The acceptability of the design of the component cooling water system is based on specific General Design Criteria (GDCs) and regulatory guides. The design of the component cooling water system has been compared to the criteria set forth in Subsection 9.2.2, "Reactor Auxiliary Cooling Water System," Revision 3, of the NRC's Standard Review Plan. The specific General Design Criteria identified in the Standard Review Plan section are General Design Criteria 2, 4, 5, 44, 45 and 46. Additionally, Regulatory Guide 1.29 was reviewed to determine the degree of compliance of the AP1000 design with the criteria. Branch Technical Position ASB 3-1 and IEEE 279 were also reviewed as appropriate. The compliance of the component cooling water system design with the applicable General Design Criteria and regulatory guides is discussed in Section 3.1 and Subsection 1.9.1, respectively.

9.2.2.6 Inspection and Testing Requirements

9.2.2.6.1 Preoperational Inspection and Testing

Preoperational testing of the component cooling water system is performed to verify that the system is installed in accordance with plans and specifications. The system is hydrostatically tested and is also tested to verify that proper sequence of valve positions and pump starting occurs on the appropriate signals. The pumps are tested to verify performance and the required flows to the individual components are obtained by proper orifice installation and/or valve setting.

9.2.2.6.1.1 Pump Flow Capability Testing

Each component cooling water system pump will be tested during hot functional testing. The flow paths will be aligned for shutdown cooling by one train of component cooling water system components. The flow delivered to one normal residual heat removal system heat exchanger and one spent fuel pool cooling system heat exchanger, as well as the total component cooling water system flow, will be measured by flow instruments at the normal residual heat removal system heat exchanger, spent fuel pool cooling system heat exchanger, and component cooling water system pump discharge header.

9.2.2.6.1.2 Heat Transfer Capability Analysis

An analysis will be performed on the component cooling water system heat exchangers during heat exchanger design. The analysis is to confirm that the product of the overall heat transfer coefficient and effective heat transfer area, UA, of each heat exchanger is equal to or greater than the minimum value shown in Table 9.2.2-1. This is the minimum value for the component cooling water system to meet its functional requirement of shutdown heat removal and spent fuel pool cooling.

9.2.2.6.2 Routine Testing and Inspection

During normal operation, the standby pump and heat exchanger are periodically tested for operability, or alternatively, placed in normal operation in place of the train which had been operating.

Component cooling water system supply and return containment isolation valves are routinely tested during refueling outages. Descriptions of the testing and inspection programs for these valves are provided in Subsections 3.9.6 and 6.2.3, and Section 6.6.

9.2.2.7 Instrumentation Requirements

Instruments are provided for monitoring system parameters. Essential system parameters are monitored in the main control room. Low flow in the discharge header automatically starts the backup component cooling water pump. A radiation monitor alarms in the main control room if reactor coolant leaks into the component cooling water system.

Level instrumentation on the surge tank provides both high- and low-level alarms in the main control room. Two redundant level channels are provided to reduce the likelihood of reactor trip caused by a single downscale failure of a surge tank level channel that could cause the operating component cooling water pump(s) to trip, thereby initiating loss of cooling flow to the reactor coolant pumps and other cooled components. Also, at a low-tank level, a valve in the makeup water line is automatically actuated by one of the two level channels to provide makeup flow from the demineralized water transfer and storage system into the component cooling water system.

Flow alarms in the main control room, produced by the two flow channels located on the CCS reactor coolant pump cooling water inlet and outlet lines, will alert the operator to a leak from the reactor coolant pump external heat exchanger into the component cooling water system. Signals generated by the PMS, in the event of a High-2 bearing water temperature trip of the reactor, also close the CCS containment isolation valves to eliminate the possibility of reactor coolant from a faulted external heat exchanger tube discharging to portions of the CCS outside the containment.

Component cooling water flow instrumentation is provided in the outlet line from the remaining components as shown in Figure 9.2.2-2.

9.2.3 Demineralized Water Treatment System

The demineralized water treatment system (DTS) receives water from the raw water system (RWS), processes this water to remove ionic impurities, and provides demineralized water to the demineralized water transfer and storage system (DWS). The demineralized water transfer and storage system is described in Subsection 9.2.4.

9.2.3.1 Design Basis

9.2.3.1.1 Safety Design Basis

The demineralized water treatment system serves no safety-related function and therefore has no nuclear safety design basis.

9.2.3.1.2 Power Generation Design Basis

- The demineralized water treatment system provides makeup and fill water to the demineralized water storage tank.

- The capacity of the demineralized water treatment system is sufficient to supply the plant makeup demand during startup, shutdown, and power operation.
- The quality of the water produced by the demineralized water treatment system is in accordance with the guidelines specified in Table 9.2.3-1.

9.2.3.2 System Description

9.2.3.2.1 General Description

Component and equipment classification for the demineralized water treatment system is given in Section 3.2. The system consists of the following major components:

- Reverse osmosis (RO) feed pumps
- Reverse osmosis units for primary demineralization
- Ultraviolet light water treatment units
- EDI units for secondary demineralization
- Mixed bed ion exchange unit
- Cartridge filters
- Reverse osmosis permeate pumps
- Clean in-place (CIP) unit
- Sample panel unit

9.2.3.2.2 Component Description

Cartridge Filter

Two cartridge-type filters arranged in a parallel configuration are provided upstream of the reverse osmosis units. These filters remove particulate such as silt or pipe scale which can foul the reverse osmosis membranes.

Reverse Osmosis Feed Pumps

The design consists of high-pressure centrifugal feed pumps. The pumps maintain the required flow and pressure through the reverse osmosis membranes.

Reverse Osmosis Unit

Each reverse osmosis unit consists of thin film composite membranes enclosed in Fiberglass Reinforced Plastic (FRP) pressure vessels. The system piping arrangement of the individual reverse osmosis units permits operational flexibility for one train to be out of service.

Manual isolation valves are furnished on the product and feed lines of each reverse osmosis unit and reject line. Sample valves are furnished on product and reject streams from each pressure vessel.

PVC piping may be used in low pressure portions of the system. Corrosion-resistant 316 stainless steel is used in higher pressure portions of the system. A pressure sensor, located on the product

manifold, protects the membranes from overpressurization by alarming and shutting down the reverse osmosis unit.

Cleaning connections are provided on each of the reverse osmosis units.

Reverse Osmosis Permeate Transfer Pumps

High-pressure, centrifugal transfer pumps are provided for the ultraviolet light treatment units, electrodeionization units, and mixed bed ion-exchange units. The pump maintains the required flow and pressure through the mixed bed polishing vessels.

Ultraviolet Light Treatment Unit

Ultraviolet light water treatment units are used to reduce total organic carbon (TOC). The ultraviolet light breaks apart organic molecules. The unit uses light bulbs that produce ultraviolet light, which breaks down the organic molecules to simpler compounds or elements.

Electrodeionization Unit

Electrodeionization (EDI) is used for secondary demineralization and the removal of dissolved carbon dioxide gas. The electrodeionization unit consists of multiple component stacks. Each stack component contains cell pairs of membranes. One cell pair consists of an ion-diluting flow (product) channel located between a cation and an anion membrane with an ion concentrating (brine) flow channel located alternately between the cell pairs. A DC potential is maintained across the electrode plates located on opposite ends of the membranes. Ion exchange resin is contained within the product flow channel, acting as an ion selective medium in the electrodeionization process. Isolation valves are provided for each stack component to allow for maintenance of a stack without removing the electrodeionization unit from service.

Mixed Bed Ion-Exhange Units

Mixed bed polishers are provided as the final stage of the effluent treatment. Bypass piping is provided to allow a mixed bed unit to be taken off line for maintenance.

Clean-In-Place Unit

A CIP unit is provided for chemically cleaning the reverse osmosis and EDI units.

Sample Panel Unit

A sample panel unit is provided for monitoring of water parameters.

9.2.3.2.3 System Operation

After receiving water from the raw water system, the water is pumped to the demineralized water treatment system. The demineralized water treatment system is a water purification system consisting of filters, pumps, reverse osmosis units, ultraviolet light treatment units, electrodeionization units, mixed bed demineralizers, and associated piping, valves, and instrumentation.

A pH adjustment chemical is added to adjust the pH of the feedwater. The pH entering the reverse osmosis is maintained within a selected operating range of the reverse osmosis to minimize scaling and corrosion.

A dilute antiscalant, which is chemically compatible with the pH adjustment chemical feed, is metered into the reverse osmosis influent water to increase the solubility of salts (that is, decrease scale formation on the membranes). Antiscalant feed rate is controlled by a signal to the metering pump

based on the demineralized water flow. Note that antiscalant chemicals are considered toxic materials for industrial facilities. The impact of toxic materials on the plant main control room habitability is addressed in Section 6.4.

A chlorine reducing agent is added before the reverse osmosis units to combine with the free chlorine in the water and produce chlorides, which are removed by the reverse osmosis units. Free chlorine must be reduced prior to entering the reverse osmosis membranes.

The pH adjustment chemical, chlorine reducing agent, and antiscalant are injected into the demineralized water treatment process from the turbine island chemical feed system. Refer to Subsection 10.4.11 for a further discussion of the chemical feed system.

The reverse osmosis influent passes through the cartridge filter which removes any particulate carried over from the raw water system and provides mixing for the upstream chemical feed systems.

Primary demineralization is achieved by a reverse osmosis system. The influent to the reverse osmosis unit is pumped from the raw water system through the cartridge filters to the suction of the reverse osmosis feed pump. The feed pump moves the water through the reverse osmosis membranes where ionic impurities are removed. A level signal from the demineralized water storage tank controls the operation of the reverse osmosis feed pumps. The pumps are started when the tank level is low and continue to run until the tank is full and the pumps are stopped.

Each reverse osmosis unit has two stages of pressure vessels; the membranes are contained within the vessels. The product water from the reverse osmosis unit is directed to the ultraviolet unit. The reject flow from the reverse osmosis unit is discharged to the waste water system. The brine flow from the second stage is recycled to the suction of the feed pump of the first unit to improve the fluid recovery rate of the reverse osmosis process. A reverse osmosis unit can be isolated for cleaning and maintenance of the membranes with the reverse osmosis treatment train placed in offline mode.

One reverse osmosis treatment train can be out of service, without affecting the demineralized water treatment effluent water quality. Operation with only one reverse osmosis treatment train results in reduced system capacity.

The product water from the reverse osmosis units flows to the reverse osmosis transfer pump in each train. It is then pumped through ultraviolet light treatment units. The ultraviolet light breaks apart and reduces the total organic carbon molecules within the flow stream. The water then flows to the electrodeionization system for secondary demineralization. Two electrodeionization units operate in parallel, each treating 50 percent of the systems flow. The electrondeionization unit removes ionic impurities and also chemically removes dissolved carbon dioxide gas. The water flows through the electrodeionization stacks where a DC voltage across the electrode plates attracts ions of opposite charge. The membranes allow the ions to penetrate the membrane only in one direction, thereby concentrating the ions in the reject flow channel. The resin serves as an ion selective medium to aid migration of the ions through the membranes. Regeneration of the resin is performed by the DC voltage potential across the stack. The brine flow is blowdown, which is sent to the waste water system. Makeup to the brine flow is provided from the influent to the electrodeionization unit.

The EDI product flow then flows through the mixed bed ion exchangers. The mixed bed units are arranged to accept the full system flow in a series. The mixed beds are piped in such a way that by closing and opening valves, either vessel can be the lead or the lag unit, or either unit can be bypassed for maintenance. The mixed bed is the final stage of demineralization using ion exchange resins.

After these water processes, demineralized water leaves the demineralized water treatment system and is supplied to the demineralized water storage tank. Refer to Subsection 9.2.4 for further discussion of the demineralized water transfer and storage system.

9.2.3.3 Safety Evaluation

The demineralized water treatment system has no safety-related function and therefore requires no nuclear safety evaluation.

There are no potential sources of radioactive contamination within the demineralized water treatment system. Backflow prevention is addressed in the demineralized water transfer and storage system, Subsection 9.2.4.

The effects of flooding due to demineralized water treatment system component failures are described in Section 3.4.

9.2.3.4 Tests and Inspections

The demineralized water treatment system is functionally tested under anticipated operating conditions prior to initial plant startup. This verifies that system components and controls function properly. Proper system performance and integrity during normal plant operation are verified by system operation and visual inspections.

9.2.3.5 Instrumentation Applications

Pressure and flow instrumentation is provided to monitor the operation of the reverse osmosis process. The reverse osmosis feed pump discharge pressure and the effluent flow from the reverse osmosis units provide indication and control for the primary demineralization process. A pH analyzer, located upstream of the reverse osmosis units, maintains the pH level in the water to the reverse osmosis units by adjusting the stroke of the chemical feed pumps. Flow is measured downstream of the RO units and a permissive signal is sent to the chemical feed pumps. Pressure, conductivity, temperature, and flow is measured at each interval of the water treatment process.

Tank level from the demineralized water storage tank controls the operation of the system feed pumps. This level indication is described in Subsection 9.2.4.

Parameters measured such as tank level indication, pressure differentials across filters, system and pump pressures, system flow, and water conductivity outputs are displayed to the data display and processing system.

9.2.4 Demineralized Water Transfer and Storage System

The demineralized water transfer and storage system receives water from the demineralized water treatment system, and provides a reservoir of demineralized water to supply the condensate storage tank and for distribution throughout the plant. Demineralized water is processed in the demineralized water transfer and storage system to remove dissolved oxygen. In addition to supplying water for makeup of systems which require pure water, the demineralized water is used to sluice spent radioactive resins from the ion exchange vessels in the chemical and volume control system (as described in Subsection 9.3.6), the spent fuel pool cooling system (as described in Subsection 9.1.3), and the liquid radwaste system (as described in Section 11.2) to the solid radwaste system.

The demineralized water treatment system is described in Subsection 9.2.3.

9.2.4.1 Design Basis

9.2.4.1.1 Safety Design Basis

The demineralized water transfer and storage system serves no safety-related function other than containment isolation, and therefore has no nuclear safety-related design basis except for containment isolation. See Subsection 6.2.3 for the containment isolation system.

9.2.4.1.2 Power Generation Design Basis

- The demineralized water transfer and storage system provides demineralized water through the demineralized water storage tank to fill the condensate storage tank and to meet required demands and usages of demineralized water in other plant systems.

- The demineralized water transfer pumps provide adequate capacity and head for the distribution of demineralized water.

- The demineralized water storage tank supplies a source of demineralized water to the chemical and volume control makeup pumps during startup and required boron dilution evolutions. The demineralized water transfer and storage system supplies the required amount of water to the chemical and volume control system for reactor water makeup.

- The oxygen content of water supplied to the demineralized water distribution system from the demineralized water storage tank is 100 ppb or less.

- Sufficient storage capacity is provided in the condensate storage tank to satisfy condenser makeup demand based on maximum steam generator blowdown operation during a plant startup duration.

- The condensate storage tank provides the water supply for the startup feedwater pumps during startup, hot standby, and shutdown conditions.

- The condensate storage tank provides a sufficient supply of water to the startup feedwater system to permit 8 hours of hot standby operation, followed by an orderly plant cooldown from normal operating temperature to conditions which permit operation of the normal residual heat removal system over a period of approximately 6 hours.

- The piping from the condensate storage tank to the startup feedwater pumps allows adequate net positive suction head (NPSH) at maximum tank water temperature and minimum water level.

- The condensate storage tank serves as a reservoir to supply or receive condensate as required by the condenser hotwell level control system.

- The oxygen content of water stored in the condensate storage tank is 100 ppb or less.

9.2.4.2 System Description

9.2.4.2.1 General Description

Component and equipment classification for the demineralized water transfer and storage system is given in Section 3.2.

9.2.4.2.2 Component Description

Demineralized Water Storage Tank

The demineralized water storage tank has a capacity of 126,000 gallons. The tank is a vertical cylindrical tank constructed of stainless steel. The tank is provided with level and temperature instrumentation; level controls the operation of the demineralized water treatment system and sends a signal to the reverse osmosis feed pumps to start and stop, thus supplying water to the storage tank. Tank temperature is monitored and controls immersion-type electric heaters to keep the tank contents from freezing.

Demineralized Water Transfer Pump

Two motor-driven, centrifugal, horizontal pumps, located near the demineralized water storage tank, provide the plant demineralized water distribution system pressure and capacity. Each pump provides full flow recirculation through the catalytic oxygen reduction unit as well as providing the required system demand.

Catalytic Oxygen Reduction Units

Oxygen control of the demineralized water is performed by catalytic oxygen reduction units. Two catalytic oxygen reduction units are used in the AP1000 plant. One unit is provided for the demineralized water distribution system as water is pumped from the tank to the distribution system. The second unit is provided at the condensate storage tank to maintain a low oxygen content within the tank and is used in a recirculation path around the tank.

Each catalytic oxygen reduction unit consists of a mixing chamber, a catalytic resin vessel, and a resin trap. The mixing chamber is a stainless steel, in-line, static mixer where dissolution of the reducing agent occurs. Dissolved oxygen is removed chemically by mixing the effluent from the storage tank with hydrogen gas. Hydrogen is supplied from the plant gas system. The resin vessel is a rubber lined, carbon steel vessel containing catalytic resin. The stainless steel resin trap contains a cartridge filter to collect resin fines discharged from the resin vessel.

Condensate Storage Tank

The condensate storage tank has a volume of approximately 656,000 gallons and is a vertical cylindrical tank constructed of stainless steel. Level and temperature instrumentation are provided with the tank level controlled by the makeup valve. Freeze protection is supplied by immersion-type electric heaters.

9.2.4.3 System Operation

9.2.4.3.1 Normal Operation

The water level in the demineralized water storage tank controls the demineralized water treatment system. When the level in the demineralized water storage tank falls to a preset level, the pumps in the demineralized water treatment system start automatically. High water level in the tank stops operation of the demineralized water treatment system. This action, along with the capacitance in the tank, maintains the desired volume to supply the expected demands for demineralized water during normal plant operation.

The demineralized water transfer pumps, taking suction from the demineralized water storage tank, supply water through a catalytic oxygen reduction unit to the demineralized water distribution header. From this header, demineralized water is supplied to the condensate storage tank, is supplied as makeup to the chemical and volume control system pumps, and is distributed throughout the plant. The demineralized water distribution header pressure is maintained by the operation of one transfer

pump. This pump recirculates water that exceeds system demand to the demineralized water storage tank. Controls are provided to automatically start the second pump upon failure of the first to maintain system pressure and demand. A low level alarm on the demineralized water storage tank signals the plant operator to isolate demands on the tank other than chemical and volume control system supply. Demineralized water is distributed to the containment, auxiliary, radwaste, annex, and turbine buildings for system usage.

The condensate storage tank level is maintained by a level control valve in the tank supply line. The valve opens when the water level in the tank drops to a specified level and closes when the level increases to a specified setpoint. When high oxygen levels exist in the condensate storage tank, an oxygen analyzer signal starts the catalytic oxygen reduction unit pump. The pump is shut off when low levels of oxygen are detected. Low oxygen demineralized water is circulated from the tank outlet connection, through the catalytic oxygen reduction unit, and is returned to the tank via the normal inlet supply line of the tank. An orifice controls the recirculation pressure and flow returning to the tank.

Changes in the condensate system inventory are controlled by the condenser hotwell level system. As level falls in the hotwell, makeup from the condensate storage tank is supplied to the hotwell by the makeup control valve. As level rises in the hotwell, condensate is rejected to the condensate storage tank via the condensate pump's discharge control valve. Subsection 10.4.1 describes the function of the condenser hotwell level system.

In the event the main feedwater system is unavailable to supply water to the steam generators during startup, hot standby, or shutdown, the startup feedwater pumps may be activated and require water from the condensate storage tank. Subsection 10.4.9 describes the startup feedwater system function and operation.

Water supplied from the condensate storage tank to the auxiliary steam supply system is described in Subsection 10.4.10.

9.2.4.4 Safety Evaluation

The demineralized water transfer and storage system has no safety-related function other than for containment isolation (see Figure 9.2.4-1), and therefore requires no nuclear safety evaluation, other than containment isolation which is described in Subsection 6.2.3.

Failure of system components has no impact on safety-related systems, structures, or components. Flooding due to demineralized water transfer and storage system component failures which may affect safe shutdown equipment are described in Section 3.4.

The condensate storage tank normally contains no significant radioactive contaminants.

A check valve or atmospheric gap, in conjunction with a block valve or control valve, is used to prevent backflow of fluids from systems that interface with the demineralized water transfer and storage system. For interfacing systems that have a higher operating pressure than the demineralized water transfer and storage system and that normally do not require a supply of demineralized water during plant operations, a check valve with a normally closed block valve is used. For interfacing systems that have a higher operating pressure than the demineralized water transfer and storage system and that normally require demineralized water during plant operations, a check valve is used to prevent backflow into the demineralized water transfer and storage system. For interfacing systems with a lower operating pressure than the demineralized water transfer and storage system, system operating pressure prevents backflow into the demineralized water transfer and storage system; when the demineralized water transfer and storage system is shut down for

maintenance, the check valve, closed block or control valve, or atmospheric gap is relied upon to prevent backflow into the demineralized water transfer and storage system.

9.2.4.5 Tests and Inspections

Proper system performance and integrity during normal plant operation are confirmed by system operation and visual inspections.

Grab samples may be taken from the demineralized water storage tank or the condensate storage tank to verify water chemistry is maintained within acceptable limits. Grab samples are taken to the secondary sampling laboratory for analysis. Water chemistry specifications for demineralized water supplied to the demineralized water transfer and storage system are described in Subsection 9.2.3.

9.2.4.6 Instrumentation Applications

Water level is measured and automatically controlled and alarmed in the demineralized water and condensate storage tanks.

Instrumentation is provided to control the recirculation and distribution of demineralized water from the storage tank through the pumps and to the supply header and condensate storage tank. Controls are provided for automatic starting of the demineralized water transfer and storage system pumps.

An oxygen analyzer signal starts and stops the condensate storage tank catalytic oxygen reduction unit pump on low and high oxygen levels.

Monitoring of instrumentation is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. Local indication, display and manual control are available in portable displays which may be connected to the data display and processing system. See Chapter 7.

9.2.5 Potable Water System

9.2.5.1 Design Basis

The potable water system (PWS) is designed to furnish water for domestic use and human consumption. It complies with the following standards:

- Bacteriological and chemical quality requirements as referenced in EPA "National Primary Drinking Water Standards," 40 CFR Part 141.
- The distribution of water by the system is in compliance with 29 CFR 1910, Occupational Safety and Health Standards, Part 141.

9.2.5.1.1 Safety Design Basis

Certain valves in the potable water system have the safety-related function of main control room isolation. The potable water system penetrates the main control room envelope boundary. A safety related loop seal in the PWS piping that penetrates the main control room envelope boundary prevents in-leakage into the main control room envelope during VES operation. Testing the effectiveness of the boundary isolation function of the loop seal is covered by the main control room pressure boundary testing described in Subsection 6.4.5.2, and by the inservice testing program for valves described in Subsection 3.9.6.

9.2.5.1.2 Power Generation Design Basis

- Potable water is supplied to provide a quantity of 50 gallons/person/day for the largest number of persons expected to be at the station during a 24-hour period during normal plant power generation or outages.
- Water heaters provide a storage capacity equal to the probable hourly demand for potable hot water usage and provide hot water for the main lavatory, shower areas, and other locations where needed.
- A minimum pressure of 20 psig is maintained at the furthermost point in the distribution system.
- No interconnections exist between the potable water system and any potentially radioactive system or any system using water for purposes other than domestic water service.
- During main control room isolation, the 1175-gallon main control room potable water storage tank supplies 35.6 gallons of potable water per person for 11 people per day for 3 days.

9.2.5.2 System Description

9.2.5.2.1 General Description

Classification of components and equipment for the potable water system is given in Section 3.2.

The source of water for the potable water system is the site well water subsystem of the Raw Water System (RWS). The potable water system is a common system that consists of two potable water storage tanks, two potable water pumps, a jockey pump, and a distribution header that serves the Units 3 and 4 power blocks and associated buildings. The potable water storage tanks are located to the south of the CWS cooling towers. The potable water pumps are housed in a pump house near the tanks. The system is not shared with the Units 1 and 2 potable water system. The design of this water supply meets or exceeds the pressure, capacity, and quality requirements in the Subsection 9.2.5.1.

9.2.5.2.2 Component Description

Hot Water Heaters

Electric immersion heating elements located inside the potable water hot water tank are used to produce hot water. This hot water is routed to plumbing fixtures and equipment requiring domestic hot water service.

Potable Water Storage Tanks

The potable water storage tanks are sized to provide sufficient potable water to meet system demands. The tanks are designed and constructed in accordance with the applicable AWWA and Georgia Environmental Protection Division standards.

Potable Water Pumps

Each of the two motor-driven potable water pumps takes suction from the potable water storage tanks and discharges to the domestic water distribution header. The pumps are operated as required to meet the potable water demand in the plant and still maintain a minimum 20 psig pressure at the furthermost point in the distribution system.

Jockey Pump

A continuously operated jockey pump is used to supply potable water to the distribution header and maintain the pressure of the system during periods of low demand. This motor-driven pump takes suction from each of the potable water storage tanks and pumps water through the distribution system. A recirculation line to each of the potable water storage tanks is provided to allow continuous running of the jockey pump when system demand is low.

9.2.5.3 System Operation

The RWS well water subsystem provides well water to the two potable water storage tanks. For each tank, a PWS fill valve is automatically opened and closed based on its potable water storage tank level.

The well water is disinfected at the potable water storage tanks. Sodium hypochlorite is used as the disinfectant. A minimum residual chlorine level of 0.2 ppm is maintained in the system in accordance with Georgia Safe Drinking Water standards.

Two potable water pumps and a system jockey pump are used to supply potable water throughout the system. The potable water system pumps are activated sequentially to maintain the required pressure throughout the distribution system. A pressure transmitter is provided downstream of the potable water system pumps to control their start/stop sequences. The jockey pump operates continuously to maintain system pressure.

Potable water is supplied to areas that have the potential to be contaminated radioactively. Where this potential for contamination exists, the potable water system is protected by a reduced pressure zone type backflow prevention device.

No interconnections exist between the potable water system and any system using water for purposes other than domestic water service including any potentially radioactive system.

9.2.5.4 Safety Evaluation

The potable water system has no safety-related functions other than to prevent in-leakage into the main control room envelope during VES operation. A loop seal in the safety-related PWS piping that penetrates the main control room envelope boundary prevents in-leakage into the main control room envelope.

9.2.5.5 Tests and Inspections

The potable water system is hydrostatically tested for leak-tightness in accordance with the Uniform Plumbing Code. Inspection of the system is in compliance with the Uniform Plumbing Code or governing codes of the local jurisdiction. The system is then disinfected, flushed with potable water, and placed in service. The presence of residual chlorine can be confirmed through laboratory tests of samples at sampling points as required. Tests for microbiological and bacteria presence in potable water are conducted periodically.

9.2.5.6 Instrumentation Applications

Thermostats, high-temperature limit controls, and temperature indication are installed on the potable water system hot water tank. Pressure regulators are employed in those parts of the distribution system where pressure restrictions are imposed.

Instrumentation on the two potable water storage tanks includes level indication for alarm signals and control signals for the PWS fill valve and the potable water system pumps. Each tank is replenished

when its low level setpoint is reached. The potable water system transfer and jockey pumps automatically stop when low-2 tank level setpoint is reached in either of the tanks.

Instrumentation is provided to control the feed of disinfectant to maintain adequate residual chlorine levels in the potable water system.

A pressure transmitter located downstream of the potable water system pumps controls the stop/start sequence of the pumps. The jockey pump runs continuously to maintain system pressure. If the jockey pump is unable to maintain system pressure, a potable water system pump is started. The second potable water system pump starts if the first potable water pump cannot maintain acceptable system pressure.

9.2.6 Sanitary Drainage System

The sanitary drainage system (SDS) is designed to collect the site sanitary waste for treatment, dilution and discharge.

The SDS transports wastes to the Units 1 and 2 sewage treatment plant for treatment, dilution, and discharge.

9.2.6.1 Design Basis

9.2.6.1.1 Safety Design Basis

The sanitary drainage system isolates the SDS vent penetration in the main control room boundary on High-2 particulate or iodine concentrations in the main control room air supply, extended loss of main control room differential pressure, or on extended loss of ac power to support operation of the main control room emergency habitability system as described in Section 6.4. The SDS vent line that penetrates the main control room envelope is safety related and designed as seismic Category I to provide isolation of the main control room envelope from the surrounding areas and outside environment in the event of a design basis accident. An additional penetration from the SDS into the main control room envelope is maintained leak tight using a loop seal in the safety-related seismic Category I piping.

9.2.6.1.2 Power Generation Design Basis

The sanitary drainage system within the scope of the plant covered by Design Certification is designed to accommodate 25 gallons/person/day for up to 500 persons during a 24-hour period.

9.2.6.2 System Description

9.2.6.2.1 General Description

The sanitary drainage system collects sanitary waste from plant restrooms and locker room facilities in the auxiliary building, and annex building, and carries this waste to the treatment plant where it is processed.

The sanitary drainage system does not service facilities in radiologically controlled areas (RCA).

Although this sanitary drainage system transports sanitary waste to the waste treatment plant, the waste treatment plant is site specific and is outside the scope of the standard AP1000 certification. This system description provides a conceptual basis for the site interface design. The site-specific waste treatment plant for VEGP Units 3 and 4 is the Units 1 and 2 sewage treatment plant. The Units

1 and 2 sewage treatment plant has sufficient capacity to process the sanitary waste from all four units.

9.2.6.2.2 Component Description

Isolation Valves

The main control room pressure boundary penetration includes isolation valves, interconnecting piping, and vent and test connections. The isolation valves are classified as Safety Class C (see Subsection 3.2.2.5 and Table 3.2-3) and seismic Category I. Testing the effectiveness of their boundary isolation function is covered by the main control room pressure boundary testing described in Subsection 6.4.5.2, and by the inservice testing program for valves described in Subsection 3.9.6.

The main control room pressure boundary isolation valves have motor operators. The valves are designed to fail as is in the event of loss of electrical power. The valves are qualified to shut tight against control room pressure.

Trunk Line

The trunk line is the primary line that the sanitary drainage system piping connects into for transport of the sanitary drainage to the site treatment plant.

Branch Lines

Branch lines are the sanitary drainage lines that connect the restroom facilities to the trunk line.

Manholes

Manholes are required in the trunk line at the connection of the branch lines into the trunk line, at the change in direction of the trunk line, or at the change in slope or direction of the trunk line. Quantity and location are site specific.

Lift Stations

Lift stations are required in the trunk line when the uniform slope of the trunk line results in excessively deep and costly excavation. Quantity and location are site specific.

9.2.6.3 Safety Evaluation

The sanitary drainage system has no safety-related function other than main control room envelope isolation. Redundant safety-related isolation valves are provided in the vent line penetrating the main control room. Therefore, there are no single active failures that would prevent isolation of the main control room envelope.

There are no interconnections between this system and systems having the potential for containing radioactive material. Potentially radioactive drains are addressed in Subsection 9.3.5 dealing with the radioactive waste drain system.

9.2.6.4 Test and Inspection

The sanitary drainage system is tested by water or air and established to be watertight in accordance with the Uniform Plumbing Code Section 712 (Reference 2). System inspection is performed in compliance with the Uniform Plumbing Code or governing codes of the local jurisdiction.

9.2.6.5 Instrument Application

The instruments associated with this system are part of the waste treatment plant which is site specific. Sufficient instrumentation for operation is provided with the treatment plant. The instrumentation associated with the Units 1 and 2 sewage treatment plant is sufficient for operation of the treatment plant with waste streams from all four units.

9.2.7 Central Chilled Water System

The plant heating, ventilation, and air conditioning (HVAC) systems require chilled water as a cooling medium to satisfy the ambient air temperature requirements for the plant. The central chilled water system (VWS) supplies chilled water to the HVAC systems and is functional during reactor full-power and shutdown operation.

9.2.7.1 Design Basis

9.2.7.1.1 Safety Design Basis

The central chilled water system serves no safety-related function other than containment isolation, and therefore has no nuclear safety design basis except for containment isolation. See Subsection 6.2.3 for the containment isolation system.

9.2.7.1.2 Power Generation Design Basis

The central chilled water system provides chilled water to the cooling coils of the supply air handling units and unit coolers of the plant HVAC systems. It also supplies chilled water to the liquid radwaste system, gaseous radwaste system, and the secondary sampling system.

9.2.7.1.3 Codes and Standards

The central chilled water system is designed to the applicable codes and standards listed in Section 3.2.

9.2.7.2 System Description

9.2.7.2.1 General Description

The system consists of two closed loop subsystems: a high cooling capacity subsystem and a low cooling capacity subsystem. The high capacity subsystem is the primary system used to provide chilled water to the majority of plant HVAC systems and other plant equipment requiring chilled water cooling. The low capacity subsystem is dedicated to the nuclear island nonradioactive ventilation system and the makeup pump and normal residual heat removal pump compartment unit coolers. The low capacity subsystem is illustrated in Figure 9.2.7-1.

The high capacity subsystem consists of two 85-percent capacity chilled water pumps, two 15-percent capacity chilled water pumps, two 85-percent capacity water-cooled chillers, two 15-percent air-cooled chillers, a chemical feed tank, an expansion tank, and associated valves, piping, and instrumentation. The subsystem is arranged in two parallel mechanical trains with common supply and return headers. Each train includes one 15-percent capacity pump, one 85-percent capacity pump, one 15-percent capacity chiller, and one 85-percent capacity chiller. A cross-connection at the discharge of each pump allows for each to feed a given chiller of matching capacity.

The low capacity subsystem consists of two 100-percent capacity chilled water loops. Each loop consists of a chilled water pump, an air-cooled chiller, an expansion tank, a chemical feed tank, and associated valves, piping, and instrumentation. The subsystem is arranged in two independent trains with separate supply and return headers. The subsystem provides a reliable source of chilled water to the main control room (MCR) and control support area (CSA) HVAC subsystem, and the Class 1E electrical equipment room HVAC subsystem. This system configuration provides 100-percent redundancy during normal plant operation and following the loss of normal ac power and offsite power. The air-cooled chillers of the low capacity subsystem are located on the auxiliary building roof.

9.2.7.2.2 Component Description

The general descriptions and summaries of the design requirements for the central chilled water system components are provided below. The piping inside and outside containment has a design pressure of 200 psig and a design temperature of 320°F. The key equipment parameters for the central chilled water system components are contained in Table 9.2.7-1.

Pumps

Six central chilled water system pumps are provided. These pumps are single-stage, horizontal, centrifugal pumps. These pumps have an integral pump motor shaft driven by an ac-powered induction motor. The central chilled water system pumps are constructed of ductile iron or carbon steel and have flanged suction and discharge nozzles. Each pump is sized to provide the maximum water flow required by its respective chiller unit for removal of its associated design heat load.

Two pumps associated with the low capacity subsystem are risk-significant and are included with the scope of D-RAP. See Table 17.4-1 for further information.

Water-Cooled Chillers

Two water cooled liquid chillers are provided. Each chiller unit consists of a compressor, condenser, evaporator, and associated piping and controls. Environmentally safe refrigerants will be used in these chillers.

Air-Cooled Chillers

Four air-cooled liquid chillers are provided. Each chiller unit consists of a compressor, condenser, evaporator, and associated piping and controls. Environmentally safe refrigerants will be used in these chillers.

Two air-cooled chillers associated with the low capacity subsystem are risk-significant and are included with the scope of D-RAP. See Table 17.4-1 for further information.

Expansion Tank

One open and two closed expansion tanks are provided to maintain the pressure above saturation. The high capacity subsystem uses an open expansion tank which is located sufficiently above the high point of the system and connected to the suction side of the pump. The low capacity subsystem uses nitrogen charged expansion tanks on the suction side of the chilled water pumps. The expansion tanks maintain a positive suction pressure for the pumps. The tanks are sized to accommodate the volume of water expansion providing a space into which the noncompressible liquid can expand or contract as the liquid undergoes volumetric changes with changes in temperature.

Chemical Feed Tank

The chemical feed tanks and the associated piping are used to add chemicals to each chilled water subsystem stream to maintain proper water quality.

Valves

Isolation valves are provided upstream and downstream of each pump/chiller train. These valves are butterfly valves and are used to isolate a train of the subsystem for maintenance. An interlock is provided between the downstream isolation valve and the low-capacity pump/chiller controls.

An isolation valve is provided in the line that cross-connects the pump discharge lines in the high capacity subsystem. This manual butterfly valve is normally closed and can be manually aligned to operate the standby chiller with the operating pump of either train.

An air-operated isolation valve and check valve are provided in the chilled water supply and two air-operated isolation valves are provided in the chilled water return line that penetrates containment. The air-operated containment isolation valves automatically close upon receipt of a containment isolation signal. This isolation signal can be bypassed by the MCR operator to be able to restore containment recirculation system cooling with the containment isolated.

Isolation valves are provided at the interconnection with the hot water heating system to provide hot water through the coils of the containment recirculation cooling system for heating during refueling, maintenance, and testing activities under cold weather conditions.

High capacity subsystem temperature control valves are located upstream of each cooling coil or group of coils, except for the containment recirculation cooling system coils. The containment recirculation cooling system coils are provided with temperature controlled modulating valves. These valves control chilled water flow to the containment recirculation cooling system coils, as needed, to maintain the temperature within the design conditions. The flow control valves fail open upon loss of control air or electrical power.

Low capacity subsystem three-way modulating temperature control valves are provided for each group of nuclear island nonradioactive ventilation system cooling coils. These valves bypass chilled water flow around the coils, as needed, to maintain the temperature within the design conditions.

9.2.7.2.3 Instrumentation Requirements

The chiller and pumps are operable from the plant control system. The following describes the instrumentation employed for monitoring the operation of the central chilled water system components.

- Compressor trip and malfunction alarm
- Pump trip alarm
- Flow indication and low-flow alarm
- Temperature indication and high-temperature alarm
- System low/high pressure alarm

A low pressure interlock is provided on the pump suction and a low-low flow interlock is provided on the pump discharge to protect the pumps. Level instrumentation measures expansion tank level and provides signals to low- and high-level alarms to the plant control system and to open and close the makeup supply valve.

9.2.7.2.4 System Operation

The central chilled water system operating modes are described below.

Normal Operation

The high capacity subsystem capacity is based on the maximum and minimum normal ambient design temperatures as defined in Chapter 2, Table 2.0-201. The high capacity subsystem operates during normal modes of plant operation, supplying chilled water to plant components at a normal temperature of 40°F. The capacity of the low capacity subsystem is based on the maximum safety ambient design temperatures as defined in Chapter 2, Table 2.0-201. The low capacity subsystem is designed to operate during all normal modes of operation, supplying chilled water to the nonradioactive ventilation system components at a normal temperature of 40°F. The low capacity system also supplies chilled water to the make-up pump and normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system. The low-capacity air-cooled chillers are provided with freeze protection, such as motor heaters and louvers. Heat tracing has been provided on the chiller supply and return pipe lines located on the auxiliary building roof, which are susceptible to freezing.

During normal operation of the high capacity subsystem, at least one pump and at least one chiller operate to supply chilled water to the following plant HVAC systems:

- Radiologically controlled area ventilation system (Subsection 9.4.3)
- Containment recirculation cooling system (Subsection 9.4.6)
- Containment air filtration system (Subsection 9.4.7)
- Health physics/control access area HVAC system (Subsection 9.4.11)
- Radwaste building ventilation system (Subsection 9.4.8)
- Annex/auxiliary building nonradioactive ventilation system (Subsection 9.4.2)
- In addition, they also supply chilled water to the liquid radwaste system (Section 11.2), the gaseous radwaste system (Section 11.3), the portable and mobile radwaste system (Section 11.4) components, the secondary sampling system (Subsection 9.3.4) components, the electrical switchgear room, the south bay equipment, the control cabinet rooms, and the personnel work area air handling units of the turbine building ventilation system (Subsection 9.4.9).

In the event that either the pump or chiller of the operating train becomes inoperable, the standby train would be aligned to provide chilled water service.

During normal operation of the low capacity subsystem, one pump and one chiller operate to supply chilled water to the associated cooling coils of the nuclear island nonradioactive ventilation system and the makeup pump and normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system. One train provides chilled water to the A and D air handling unit of the Class 1E electrical equipment room HVAC subsystem, the A air handling unit of the main control room/control support area HVAC subsystem, and the A makeup pump and the A and B normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system. The other train provides chilled water to the B and C air handling unit of the Class 1E electrical equipment room HVAC subsystem, the B air handling unit of the main control room/control support area HVAC subsystem, the B makeup pump and the A and B normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system. In the event that one train of the low capacity subsystem is inoperable, the operator can align the standby train to provide cooling to the standby nuclear island nonradioactive ventilation system air handling units and the makeup pump and the normal residual heat removal pump compartment unit coolers of the radiologically controlled area ventilation system.

During plant shutdown in cold weather conditions, the supply and return piping to the containment recirculation cooling system cooling coils may be isolated to permit manual alignment of the hot water heating system to the containment.

The central chilled water system is designed to permit use of the chilled water piping inside containment to the containment recirculation air handling units for containment heating when the plant is shutdown during cold weather. Remote manual realignment to the heating mode, utilizing the hot water system and the same containment recirculation air handling unit coils as the cooling mode, is performed outside containment and the procedure is administratively controlled. During this mode of operation, the high capacity subsystem is functional to meet the demand of those remaining HVAC systems and other equipment requiring chilled water.

Abnormal Operation

The high cooling capacity subsystem piping penetrates the containment to supply chilled water to the containment recirculation system fan coil units. The containment isolation valves, located on the chilled water supply and return lines, close on receipt of containment isolation signals. A bypass mode with main control room indication is provided to restore the containment recirculation cooling system cooling during containment isolation. The remainder of the chilled water system continues to operate normally following containment isolation provided that power is available.

The central chilled water system is designed to remain operable following a loss of normal ac power and offsite power by using standby onsite ac power.

The low capacity subsystem chillers, pumps, and other electrical components are connected to the plant standby diesel generator bus in accordance with the automatic electrical load sequencing. The low capacity subsystem is configured such that the operation is similar to that described above for normal operation. Following the loss of normal ac power and offsite power, one diesel generator and one train of the low capacity subsystem operate to supply chilled water to the associated cooling coils of the nuclear island nonradioactive ventilation system and the makeup pump and normal residual heat removal pump compartment unit coolers as shown in Table 9.2.7-1.

The high capacity subsystem chillers, pumps, and other electrical components are connected to the plant standby diesel generator bus in accordance with the optional electrical load sequencing and can be energized at the option of the operator for investment protection after evaluation of the diesel generator available capacity.

The high capacity subsystem can be used in conjunction with the containment recirculation cooling system to remove heat from the containment atmosphere following certain plant transients, if the systems are available.

9.2.7.3 Safety Evaluation

The central chilled water system has no safety-related function, other than containment isolation and therefore requires no nuclear safety evaluation, other than containment isolation which is described in Subsection 6.2.3.

The central chilled water system components located in safety-related areas of the plant are designed such that a failure in the system will not unacceptably impact the operation of safety-related components.

9.2.7.4 Inservice Inspection/Inservice Testing

The central chilled water piping circuits are hydrostatically tested and balanced to provide design flowrates and temperatures. Periodic inspections are performed to verify proper performance of

system components. Specific test requirements and intervals are contained in the plant operating procedures.

9.2.8 Turbine Building Closed Cooling Water System

The turbine building closed cooling water system (TCS) provides chemically treated, demineralized cooling water for the removal of heat from nonsafety-related heat exchangers in the turbine building and rejects the heat to the circulating water system.

9.2.8.1 Design Basis

9.2.8.1.1 Safety Design Basis

The turbine building closed cooling water system has no safety-related function and therefore has no nuclear safety design basis.

9.2.8.1.2 Power Generation Design Basis

The turbine building closed cooling water system provides corrosion-inhibited, demineralized cooling water to the equipment shown in Table 9.2.8-1 during normal plant operation.

During power operation, the turbine building closed cooling water system provides a continuous supply of cooling water to turbine building equipment at a temperature of 105°F or less assuming a circulating water temperature of 100°F or less.

The cooling water is treated with a corrosion inhibitor and uses demineralized water for makeup. The system is equipped with a chemical addition tank to add chemicals to the system.

The heat sink for the turbine building closed cooling water system is the circulating water system. The heat is transferred to circulating water through plate type heat exchangers which are components of the turbine building closed cooling water system.

A surge tank is sized to accommodate thermal expansion and contraction of the fluid due to temperature changes in the system.

One of the turbine building closed cooling system pumps or heat exchangers may be unavailable for operation or isolated for maintenance without impairing the function of the system.

The turbine building closed cooling water pumps are provided ac power from the 6900V switchgear bus. The pumps are not required during a loss of normal ac power.

9.2.8.2 System Description

9.2.8.2.1 General Description

Classification of equipment and components is given in Section 3.2. The system consists of two 100-percent capacity pumps, three 50-percent capacity heat exchangers (connected in parallel), one surge tank, one chemical addition tank, and associated piping, valves, controls, and instrumentation. Heat is removed from the turbine building closed cooling water system by the circulating water system via the heat exchangers.

The pumps take suction from a single return header. Either of the two pumps can operate in conjunction with any two of the three heat exchangers. Discharge flows from the heat exchangers combine into a single supply header. Branch lines then distribute the cooling water to the various

coolers in the turbine building. The flow rates to the individual coolers are controlled either by flow restricting orifices or by control valves, according to the requirements of the cooled systems. Individual coolers can be locally isolated, where required, to permit maintenance of the cooler while supplying the remaining components with cooling water. A bypass line with a manual valve is provided around the turbine building closed cooling water system heat exchangers to help avoid overcooling of components during startup/low-load conditions or cold weather operation.

The system is kept full of demineralized water by a surge tank which is located at the highest point in the system. The surge tank connects to the system return header upstream of the pumps. The surge tank accommodates thermal expansion and contraction of cooling water resulting from temperature changes in the system. It also accommodates minor leakage into or out of the system. Water makeup to the surge tank, for initial system filling or to accommodate leakage from the system, is provided by the demineralized water transfer and storage system. The surge tank is vented to the atmosphere.

A line from the pump discharge header back to the pump suction header contains valves and a chemical addition tank to facilitate mixing chemicals into the closed loop system to inhibit corrosion in piping and components.

A turbine building closed cooling water sample is periodically taken and analyzed to verify that water quality is maintained.

9.2.8.2.2 Component Description

Surge Tank

A surge tank accommodates changes in the cooling water volume due to changes in operating temperature. The tank also temporarily accommodates leakage into or out of the system. The tank is constructed of carbon steel.

Chemical Addition Tank

The chemical addition tank is constructed of carbon steel. The tank is normally isolated from the system and is provided with a hinged closure for addition of chemicals.

Pumps

Two pumps are provided. Either pump provides the pumping capacity for circulation of cooling water throughout the system. The pumps are single stage, horizontal, centrifugal pumps, are constructed of carbon steel, and have flanged suction and discharge nozzles. Each pump is driven by an ac powered induction motor.

Heat Exchangers

Three heat exchangers are arranged in a parallel configuration. Two of the heat exchangers are in use during normal power operation and turbine building closed cooling water flow divides between them.

The heat exchangers are plate type heat exchangers. Turbine building closed cooling water circulates through one side of the heat exchanger while circulating water flows through the other side. During system operation, the turbine building closed cooling water in the heat exchanger is maintained at a higher pressure than the circulating water so leakage of circulating water into the closed cooling water system does not occur. The heat exchangers are constructed of titanium or stainless steel plates with a carbon steel frame.

Valves

Manual isolation valves are provided upstream and downstream of each pump. The pump isolation valves are normally open but may be closed to isolate the non-operating pump and allow maintenance during system operation. Manual isolation valves are provided upstream and downstream of each turbine building closed cooling water heat exchanger. One heat exchanger is isolated from system flow during normal power operation. A manual bypass valve can be opened to bypass flow around the turbine building closed cooling water heat exchangers when necessary to avoid low cooling water supply temperatures.

Flow control valves are provided to restrict or shut off cooling water flow to those cooled components whose function could be impaired by overcooling. The flow control valves are air operated and fail open upon loss of control air or electrical power. An air operated valve is provided to control demineralized makeup water to the surge tank for system filling and for accommodating leakage from the system. The makeup valve fails closed upon loss of control air or electrical power.

A TCS heat exchanger can be taken out of service by closing the inlet isolation valve. Water chemistry in the isolated heat exchanger train is maintained by a continuous flow of circulating water through a small bypass valve around the inlet isolation valve.

Backwashable strainers are provided upstream of each TCS heat exchanger. They are actuated by a timer and have a backup starting sequence initiated by a high differential pressure across each individual strainer. The backwash can be manually activated.

Piping

System piping is made of carbon steel. Piping joints and connections are welded, except where flanged connections are used for accessibility and maintenance of components. Nonmetallic piping also may be used.

9.2.8.2.3 System Operation

The turbine building closed cooling water system operates during normal power operation. The system does not operate with a loss of normal ac power.

Startup

The turbine building closed cooling water system is placed in operation during the plant startup sequence after the circulating water system is in operation but prior to the operation of systems that require turbine building closed cooling water flow. The system is filled by the demineralized water transfer and storage system through a fill line to the surge tank. The system is placed in operation by starting one of the pumps.

Normal Operation

During normal operation, one turbine building closed cooling water system pump and two heat exchangers provide cooling to the components listed in Table 9.2.8-1. The other pump is on standby and aligned to start automatically upon low discharge header pressure.

During normal operation, leakage from the system will be replaced by makeup from the demineralized water transfer and storage system through the automatic makeup valve. Makeup can be controlled either manually or automatically upon reaching low level in the surge tank.

Shutdown

The system is taken out of service during plant shutdown when no longer needed by the components being cooled. The standby pump is taken out of automatic control, and the operating pump is stopped.

9.2.8.3 Safety Evaluation

The turbine building closed cooling water system has no safety-related function and therefore requires no nuclear safety evaluation.

9.2.8.4 Tests and Inspections

Pre-operational testing is described in Chapter 14. The performance, structural, and leaktight integrity of system components is demonstrated by operation of the system.

9.2.8.5 Instrument Applications

Parameters important to system operation are monitored in the main control room. Flow indication is provided for individual cooled components as well as for the total system flow.

Temperature indication is provided for locations upstream and downstream of the turbine building closed cooling water system heat exchangers. High temperature of the cooling water supply alarms in the main control room. Temperature test points are provided at locations to facilitate thermal performance testing.

Pressure indication is provided for the pump suction and discharge headers. Low pressure at the discharge header automatically starts the standby pump.

Level instrumentation on the surge tank provides level indication and both low- and high-level alarms in the main control room. On low tank level, a valve in the makeup water line automatically actuates to provide makeup flow from the demineralized water transfer and storage system.

9.2.9 Waste Water System

The waste water system collects and processes equipment and floor drains from nonradioactive building areas.

9.2.9.1 Design Basis

9.2.9.1.1 Safety Design Basis

The waste water system isolates the WWS drain line that penetrates the main control room boundary. The WWS drain lines that penetrate the main control room envelope are safety related and designed as seismic Category I to provide isolation of the main control room envelope from the surrounding areas and outside environment in the event of a design basis accident.

9.2.9.1.2 Power Generation Design Basis

The power generation design basis is:

- Remove oil and/or suspended solids from miscellaneous waste streams generated from the plant.
- Collect system flushing wastes during startup prior to treatment and discharge.

- Collect and process fluid drained from equipment or systems during maintenance or inspection activities.

- Direct nonradioactive equipment and floor drains which may contain oily waste to the building sumps and transfer their contents for proper waste disposal. The radioactive equipment and floor drain system is described in Subsection 9.3.5.

9.2.9.2 System Description

9.2.9.2.1 General Description

The waste water system is capable of handling the anticipated flow of waste water during normal plant operation and during plant outages. The classification of components and equipment is given in Section 3.2.

Wastes from the turbine building floor and equipment drains (which include laboratory and sampling sink drains, oil storage room drains, the main steam isolation valve compartment, auxiliary building penetration area and the auxiliary building HVAC room) are collected in the turbine building sumps. Drainage from the auxiliary building sump – north (a nonradioactive sump), the annex building sump, and condensate polishing system (CPS) rinse effluent is also collected in the turbine building sumps. The main turbine building sumps provide a temporary storage capacity and a controlled source of fluid flow to the oil separator. In the event radioactivity is present in the main turbine building sumps, the waste water is diverted from the sumps to the liquid radwaste system (WLS) for processing and disposal. A radiation monitor located on the common discharge piping of the main sump pumps provides an alarm upon detection of radioactivity in the waste water. The radiation monitor also trips the main sump pumps on detection of radioactivity to isolate the contaminated waste water. Provisions are included for sampling the main sumps.

The main turbine building sump pumps route the waste water from the sumps to the oil separator for removal of oily waste. The diesel fuel oil area sump pump and the transformers area waste water collection sump pump also discharge waste water to the oil separator. A bypass line allows for the oil separator to be out of service for maintenance. The oil separator provides temporary storage prior to removal by truck for offsite disposal.

The waste water from the oil separator flows by gravity to an adjacent in-ground sump, then is pumped to the waste water retention basin for settling of suspended solids and treatment, if required, prior to discharge. The wastewater retention basin transfer pumps discharge the basin effluent to the blowdown sump which then mixes with the high volume waste stream (circulating water system cooling tower blowdown) prior to discharge to the Savannah River via the outfall piping.

Design and routing of the condenser waterbox drains is addressed in Subsection 10.4.5.2.2.

9.2.9.2.2 Component Description

Isolation Valve

The main control room pressure boundary penetration includes a normally closed isolation valve and interconnecting piping. The isolation valve is classified as Safety Class C (see Subsection 3.2.2.5 and Table 3.2-3) and seismic Category I. Testing the effectiveness of the boundary isolation function is covered by the main control room pressure boundary testing described in Subsection 6.4.5.2.

Turbine Building Sumps

The sumps collect waste water from the floor and equipment drains, SWS and CWS strainer backwash flows, alternate SWS cooling tower blowdown flow, laboratory drains, sampling waste

drains, plant washdowns from the turbine building, and CPS rinse effluent. Selected drains from both the annex and auxiliary buildings are also collected in these sumps.

Turbine Building Sump Pumps

The sumps have pneumatic, double diaphragm pumps. The main sump pumps route the waste water to the oil separator. Interconnecting piping between the suction of the main sump pumps allows for either pump to transfer waste water from either or both main sumps. The plant service air system provides the supply of air for operation of the pumps. Operation of the pumps is automatic based on sump level with controls provided for manual operation.

Oil Separator

The oil separator removes oily waste from the waste water stream. A sampling connection is provided at the discharge of the oil separator. The waste water flows by gravity to an adjacent sump served by two submersible pumps, which transfer the waste water to the waste water retention basins. A truck connection on the oil separator allows for removal of the waste oil from the oil separator for offsite disposal.

Waste Oil Storage Tank

Waste oil from the oil separator reservoir and other plant areas is stored in a waste oil storage tank. A sampling connection is provided on the tank to verify that the oil does not require handling and disposal as a hazardous material. A truck connection on the tank allows for removal of the waste oil from the tank for offsite disposal.

Waste Water Retention Basin

The waste water retention basin is a lined basin with two compartments and is constructed such that its contents, dissolved or suspended, do not penetrate the liner and leach into the ground. Either of these compartments can receive waste streams for holdup, or if required, for treatment to meet specific environmental discharge requirements.

The configuration and size of the wastewater retention basin allows settling of solids larger than 10 microns. Wastewater can be sampled prior to discharge from the wastewater retention basin. The wastewater retention basins are located northwest of each power block.

Waste Water Sumps

Waste water collection sumps are provided for the auxiliary building, the diesel generator building, the annex building, the transformers area, and the diesel fuel oil area. These collection sumps are drained by air operated pumps. The effluent from the auxiliary building and the annex building sumps is directed to the oil separator via the turbine building sumps for processing and release. The effluent from the diesel generator building, the diesel fuel oil area, and the transformers area is pumped directly to the oil separator.

Sump Pumps

The waste water sump pumps are pneumatic, double diaphragm pumps. The plant service air system provides the supply of air for operation of these pumps. Operation of the pumps is automatic based on sump level with controls provided for manual operation.

Basin Transfer Pumps

Two 100% capacity submersible-type pumps send waste water from the retention basin to the blowdown sump. Each pump is sized to meet the maximum expected influent flow to prevent overflow of the basin. Each pump has a recirculation line off the pump's discharge to provide mixing capability of the waste water retention basin liquid with chemicals and sampling prior to routing the

effluent to the blowdown sump. The recirculation line routes the sump contents back to the waste water retention basin. In the event that water discharged into the retention basin carries high oil content, temporary equipment can be used to absorb the oil prior to discharging the retention basin contents to the blowdown sump. Radiation monitoring of the turbine building sump common discharge piping is provided as described in Subsection 9.2.9.5. If the retention basin contains radioactivity, the retention basin is isolated and the contaminated water is removed or treated. Controls are provided for automatic or manual operation of the pumps based on the level of the retention basin.

Blowdown Sump

A blowdown sump common to both Units 3 and 4 receives input from the wastewater retention basins and the circulating water system (CWS) cooling tower blowdown. The blowdown sump is located to the northeast of Units 3 and 4, outside of the protected area. A connection with the river water subsystem of the raw water system provides an alternate dilution source to the blowdown sump. These inputs are mixed with a dechlorination chemical, as needed, to produce an effluent that meets the NPDES permit requirements. This effluent then flows from the blowdown sump to the outfall structure, and then finally to the river.

Plant Outfall

The plant outfall is the final discharge point for Units 3 and 4. The outfall pipe is sized to drain, via gravity, the maximum expected flow from the blowdown sump. Effluent from the blowdown sump mixes with a small waste stream from the liquid radioactive waste system monitor tanks and is discharged eastward to the Savannah River. Dilution water from the raw water system may be supplied to the blowdown sump for radioactive waste discharges when the circulating water cooling tower blowdown is not available. To prevent radioactive contamination of the blowdown sump, the location of the tie-in between the liquid radwaste and the outfall is downstream and below the bottom elevation of the blowdown sump. The liquid radwaste is monitored for radiation and is addressed in detail in Section 11.2; the applicable radiation monitor is addressed in detail in Subsection 11.5.2.3.3.

9.2.9.3 Safety Evaluation

The waste water system has no safety-related function other than main control room envelope isolation. A normally closed safety-related isolation valve is provided in the drain line penetrating the main control room. The drain line is safety related up to the isolation valve to ensure that the main control room habitability pressure boundary is maintained.

9.2.9.4 Tests and Inspections

System performance and integrity during normal plant operation are verified by system operation and visual inspections.

9.2.9.5 Instrumentation Applications

Level instrumentation and associated pump controls on the turbine building sumps, the auxiliary building sump, the diesel generator building sumps, and the diesel fuel oil sump are provided to prevent overflow of these waste water collection points. High alarms indicate tank level where operator action is required. Level instrumentation is provided at the wastewater retention basin and is used to control operation of the basin transfer pumps. High-level alarms indicate the basin level where operator action is required.

A radiation monitor located on the turbine building sump common discharge piping initiates an alarm and trips the turbine building sump pumps when radioactivity above a preset high level point is detected in the waste stream.

9.2.10 Hot Water Heating System

The hot water heating system (VYS) supplies heated water to selected nonsafety-related air handling units and unit heaters in the plant during cold weather operation and to the containment recirculating fans coil units during cold weather plant outages.

9.2.10.1 Design Basis

9.2.10.1.1 Safety Design Basis

The hot water heating system serves no safety-related function and therefore has no nuclear safety design basis.

9.2.10.1.2 Power Generation Design Basis

- During normal plant operation, the hot water heating system maintains acceptable design ambient air temperatures in various areas throughout the AP1000.
- During plant outages in cold weather, the hot water heating system supplies hot water to the plant chilled water piping serving the containment building recirculation fan coil units to maintain acceptable ambient air temperatures inside containment.

9.2.10.2 System Description

9.2.10.2.1 General Description

Major components of the heating system include heat exchangers, pumps, a surge tank, and provisions for chemical feed. Component and equipment classification for the hot water heating system is given in Section 3.2. The hot water heating system consists of a heat transfer package for the production of hot water and a distribution system to the various HVAC systems and unit heaters. The hot water heating system is a nonsafety-related system.

During cold weather plant operation, the hot water heating system supplies hot water throughout the plant to protect equipment from freezing and for personnel comfort. During cold weather plant outages, the hot water heating system supplies hot water to the containment building recirculation fan coil units to maintain acceptable ambient air temperatures inside containment. During a loss of normal ac power and offsite power, provisions are made to power the hot water heating system from the onsite diesel generators as an investment protection load. In this mode of operation, heating steam is supplied from the auxiliary steam supply system using a temporary boiler.

The hot water heating system, using main steam or the auxiliary boiler, extracts heat energy from the steam through a heat exchanger and transfers this energy to heat water. The heated water is pumped in a closed loop system to hot water coils in the air conditioning systems. Condensate from the heat exchanger is level controlled and drained to the main condenser or auxiliary boiler feedwater system.

One of two system pumps supplies hot water to the heating system by taking suction from the return main and pumping water through one of two heat exchangers and into the main heating hot water system supply header. To prevent flashing of the heated water into steam, the pump in combination with the system surge tank keeps the system pressure above saturation conditions. The surge tank uses elevation to keep the minimum system pressure above saturation conditions at the pump suction. Demineralized water is supplied to the system for surge tank makeup.

During plant outages in cold weather, hot water flows to the containment building recirculation fan coil units to heat the containment atmosphere. The recirculation fan coil units, containment supply and return piping to these units, and the containment isolation valves are part of the central chilled water system as described in Subsection 9.2.7. During normal plant operation the hot water heating system is isolated from the containment recirculation fan coils.

The hot water heating system is a manually actuated system and may operate when the site ambient temperature is 73°F or below.

9.2.10.2.2 Component Description

Major component design data of the hot water heating system are listed in Table 9.2.10-1.

Heat Exchanger

Each heat exchanger is a horizontal, shell-and-tube type, with an integral drain cooler, and uses the heat of vaporization of low-pressure steam for the heating of water. The heat exchanger is located in the closed loop hot water heating system downstream of the system pumps in the turbine building. This heat exchanger provides heated water for selected air handling unit and unit heater hot water coils.

Pumps

One of two system pumps distributes hot water to the various HVAC and unit heater systems. They are motor driven centrifugal pumps.

Surge Tank

The surge tank maintains system pressure by allowing the water to expand when the water temperature increases and provides a volume to accept makeup water to the hot water heating system.

The tank is a carbon steel, welded, pressure vessel with tank recirculation and instrument connections.

Chemical Feed Tank

The chemical feed tank provides a means of chemical mixing in the system. Addition of chemicals provides control of corrosion.

The tank is a vertical cylinder of carbon steel construction with a capacity of less than 150 gallons and a top hinged opening for introducing the chemicals and side connections for transporting water through the chemical mixing tank from the pump discharge or the demineralized water transfer and storage system supply.

9.2.10.2.3 System Operation

As the system is filled with demineralized water, samples are taken and the closed loop water chemistry adjusted with chemicals recirculated through the chemical mixing tank with the use of a single pump. A pump is started and steam is admitted to a hot water system heat exchanger and the system is gradually heated.

A condensate level is maintained in each system heat exchanger by throttling the heat exchanger discharge flow to the condenser. During a plant outage when main steam is shutdown and auxiliary steam is used from the auxiliary boiler, a manual block valve is opened to establish flow of condensate from each heat exchanger to the auxiliary steam supply system deaerator.

Hot water flowing to individual heating coils is controlled by flow balancing fixed orifices, balancing valves, modulating valves, or by temperature controlled solenoid valves, according to the requirements of the heating system. Area temperatures are controlled by cycling the fans in unit heaters, by use of integral face/bypass dampers in air handling units, modulating hot water flow to air handling units, or by thermostats controlling hot water solenoids in heating coils of HVAC ducts. Further detail of hot water heating of the individual unit heaters, air handling units, and duct heating coils is provided in Section 9.4. In the radwaste building, normally isolated hot water supply and return connections are provided for a mobile radwaste system.

9.2.10.3 Safety Evaluation

The hot water heating system has no safety-related function and therefore requires no nuclear safety evaluation.

The hot water heating system interfaces with only nonsafety-related systems. Hot water heating is used in the containment to keep piping and components from freezing during cold weather when the plant is not operating. A hot water heating system interface with the central chilled water system is outside containment and in nonsafety-related piping of the chilled water system. Piping is shared inside the containment between hot water heating and central chilled water. During normal plant operation, the hot water system is isolated from the central chilled water system and containment. Containment isolation by the central chilled water system is described in Subsection 6.2.3.

The effects of flooding on the safe shutdown capability of the plant are described in Section 3.4.

The temperature control range for areas serviced by the hot water heating system is described in Section 9.4 with the ventilation systems.

9.2.10.4 Tests and Inspections

The hot water heating piping circuits are hydrostatically tested and balanced to provide designed flowrates and temperatures. Active component performance is monitored by instrumentation on the system. System performance and integrity during normal plant operation are verified by system operation and visual inspections.

9.2.10.5 Instrument Applications

Instruments are provided for monitoring system parameters. Essential system parameters are monitored in the main control room.

Total system flow is monitored and displayed in the main control room. The system heat exchangers are level controlled with the instrument signals controlling the level control valves as well as sending level indication and low- and high-level alarms to the data system. Temperature measured downstream of the heat exchangers controls steam flow to, the heat exchangers and indicates the temperature of heated water being sent to the hot water heating coils. Also temperature is monitored in the system return main.

Pressure is measured in the pump suction and at the pump discharge. At low-2 pump suction pressure, a signal is sent to stop the hot water heating system pumps.

Level instrumentation on the surge tank provides both high- and low-level alarms. At tank low-level, makeup is provided from the demineralized transfer and storage system. At a high level in the tank, makeup from the demineralized transfer and storage system is discontinued.

9.2.11 Raw Water System

The raw water system consists of two subsystems.

The RWS river water subsystem provides river water for makeup to the CWS natural draft cooling tower basins. The river water subsystem also provides dilution water to the Units 3 and 4 blowdown sump and fill water for the CWS piping.

The RWS well water subsystem provides well water for makeup to the service water system (SWS) mechanical draft cooling tower basins, potable water system (PWS), fire protection systems (FPS's), yard fire water system (YFS), and demineralized water treatment systems (DTS's).

The well water subsystem also provides well water for miscellaneous plant uses.

9.2.11.1 Design Basis

9.2.11.1.1 Safety Design Basis

The RWS serves no safety-related function, and therefore, has no nuclear safety design basis.

Failure of the RWS or its components does not affect the ability of safety-related systems to perform their intended function.

The RWS does not have the potential to be a flow path for radioactive fluids.

9.2.11.1.2 Power Generation Design Basis

9.2.11.1.2.1 Normal Operation

The RWS river water subsystem provides a continuous supply of river water for the following services:

- CWS fill and makeup.
- Dilution water for radwaste discharge when the CWS is not available. Dilution water is provided to the Units 3 and 4 blowdown sump for this purpose.

The RWS well water subsystem provides well water for the following services:

- SWS fill and makeup.
- PWS fill and makeup.
- DTS feed.
- Well water for miscellaneous uses, such as equipment washdown.
- Normal filling and makeup to the FPS primary and secondary fire water storage tanks.
- Normal filling and makeup to the YFS fire water storage tanks.

9.2.11.1.2.2 Outage Mode Operation

During plant outages, CWS cooling tower makeup from the river water subsystem of the RWS is not required. The river water subsystem does provide dilution water for radwaste discharge when the CWS is not available. River water is provided to the common Units 3 and 4 blowdown sump for this purpose.

The RWS well water subsystem provides well water to DTS, PWS, FPS, and YFS as needed. The RWS well water subsystem provides makeup flow to the SWS to support normal plant cooldown. During this operational sequence, the component cooling water system reduces the temperature of the reactor coolant system from 350° F, at approximately 4 hours after reactor shutdown, to 125° F within 96 hours after shutdown by providing cooling to the normal residual heat removal system (RNS) heat exchangers.

9.2.11.2 System Description

9.2.11.2.1 General Description

Classification of components and equipment for the RWS is given in Section 3.2.

9.2.11.2.1.1 RWS River Water Subsystem

The source of water for the river water subsystem of the RWS is the Savannah River. The river water subsystem is shown in Figure 9.2-201 (Sheet 1).

For the river water subsystem, the water is drawn through an intake canal that extends from the river to an intake structure. Refer to Subsection 2.4.8.1 for additional description of the intake canal.

The intake structure is divided into a total of nine independent pump bays. Three bays are dedicated to Unit 3, three bays are dedicated to Unit 4, and the last three bays are empty (to be used for a future unit if pursued). Each Unit 3 and 4 bay is equipped with a river water pump, a trash rack, and a traveling screen. Two bays per unit are equipped with screen wash pumps.

The river water pumps draw untreated river water and forward it to the CWS natural draft cooling tower basins. A side connection provides dilution water to the blowdown sump if required. No additional water treatment is required for the RWS river water subsystem.

9.2.11.2.1.2 RWS Well Water Subsystem

Source water for the well water subsystem is from two deep wells located to the south of the CWS cooling towers. The well water subsystem is shown in Figure 9.2-201 (Sheet 2). The quality of the water provided by the deep wells is sufficient for the FPS and SWS. The piping system is designed to facilitate the connection of additional pretreatment equipment for supply to the DTS, if necessary, to meet water chemistry standards.

The well water makeup pumps supply well water to the common Units 3 and 4 well water storage tank. The well water transfer pumps supply well water from the well water storage tank to the Units 3 and 4 SWS mechanical draft cooling tower basins and the Units 3 and 4 Demineralized Water Treatment Systems (DTS's).

The well water subsystem also provides well water for filling and makeup to the Units 3 and 4 FPS primary and secondary fire water storage tanks and the YFS fire water storage tanks.

The PWS and miscellaneous well water users also receive water from the well water subsystem.

9.2.11.2.2 Component Description

9.2.11.2.2.1 RWS River Water Subsystem

Trash Rack

A rack located near the entrance to the pump bays prevents large debris in the river from entering the bays. A trash rake is provided to clear the rack.

Traveling Screens

Traveling screens at the inlet to each of the intake pump bays provide screening of floating and suspended solids in the river water, and minimize entrainment of aquatic life in the water entering each bay. The screens are sized so that the through screen velocity is less than 0.5 feet per second to reduce impingement mortality of aquatic biota. Buildup on the screens is washed off with spray water and deposited in a debris trough for collection and disposal. Each traveling screen is powered by an electric motor powered from the normal AC power system.

Screen Wash Pumps

Two screen wash pumps for each unit provide spray water to remove debris and aquatic biota from the operational traveling screens. Water scavenged from the recirculated water river water pump output is ordinarily sufficient to provide normal screen wash requirements, with the screen wash pumps in standby. If insufficient water is available from that being recirculated, then a screen wash pump will start. The screen wash pumps are vertical shaft, constant speed electric motor-driven pumps. They are powered from the normal AC power system.

River Water Pumps

Three 50 percent river water pumps are available to draw river water and forward it to the CWS natural draft cooling tower basin. Two pumps normally operate to furnish the required normal CWS makeup flow, with one pump in standby. The river water pumps are vertical turbine, constant speed electric motor-driven pumps. They are powered from the normal AC power system.

Piping

The river water piping is designed to accommodate transient effects that may be generated by the starting and stopping of pumps, opening and closing of valves, or other operating events. The system is designed so that high points do not lead to the formation of vapor voids upon loss of system pumping.

Air release valves are provided in the makeup pump discharge piping to vent air on pump start. The underground RWS river water piping is high-density polyethylene (HDPE) pipe, which is not susceptible to corrosion.

The piping is designed and installed in accordance with the ASME B31.1 piping code.

9.2.11.2.2.2 RWS Well Water Subsystem

Makeup Wells

Two deep makeup wells supply water for Units 3 and 4 via well water makeup pumps to a storage tank. The wells are separated by a minimum distance of 1,000 feet and are screened in the Cretaceous aquifer. The Cretaceous aquifer is considered to be confined because of the low permeability of the Blue Bluff Marl. This confinement prevents contamination of the aquifer due to chemical or radiological contamination of the soil or groundwater above the Blue Bluff Marl.

Well Water Tank

The Units 3 and 4 well water tank is supplied by the well water makeup pumps. For normal plant operations, water is provided from this tank via the well water transfer pumps to meet the water demands for both Units 3 and 4. The tank has a minimum capacity of 300,000 gallons and is designed and constructed in accordance with AWWA D100.

Well Water Makeup Pumps

One well water makeup pump is provided in each of the makeup wells. Each well water makeup pump has a minimum capactiy of 1,500 gpm.

During normal operation, one well water makeup pump is capable of supplying sufficient well water to the well water tank to support normal well water demands for both units. Operation of the well water makeup pumps is controlled by well water tank level.

The well water makeup pumps are vertical shaft, constant speed, electric motor-driven well pumps. The pump shaft extends to a sufficient depth in the well to ensure that pump NPSH requirements are met.

The normal power supply to the well water makeup pumps is the offsite retail power system (ZRS).

A dedicated well water pump house package diesel generator provides power to the well water makeup pumps in the event of a loss of the normal AC power supply.

Well Water Transfer Pumps

Four well water transfer pumps are provided downstream of the well water tank. Each well water transfer pump has a minimum capacity of 750 gpm.

During normal operation, one well water transfer pump taking suction from the well water tank provides sufficient well water to meet normal demands of both Units 3 and 4. The other well water transfer pumps will remain in standby.

During periods of high demand, the standby well water transfer pumps will automatically start, as required to support demand. A recirculation line is provided on the pump discharge header to allow water to be recycled to the well water tank, as necessary, to ensure that the well water transfer pumps operate efficiently.

The well water transfer pumps are housed in the well water and PWS pump house. The well water transfer pumps are horizontal shaft, centrifugal, constant speed, electric motor-driven pumps.

The normal power supply to the well water transfer pumps is the offsite retail power system (ZRS). In the event of a loss of the normal AC power supply, the well water transfer pumps are powered by the dedicated well water pump house package diesel generator.

Piping

The well water piping is designed to accommodate transient effects that may be generated by the starting and stopping of pumps, opening and closing of valves, or other operating events.

The system is designed so that high points do not lead to the formation of vapor voids upon loss of system pumping. Air release valves are provided in the well water makeup pump discharge piping to vent air on pump start.

The underground RWS well water piping is high-density polyethylene (HDPE) pipe, which is not susceptible to corrosion. The piping is designed and installed in accordance with the ASME B31.1 piping code. Heat tracing has been provided on above ground pipe lines that are susceptible to freezing.

Valves

Most of the valves in the RWS well water subsystem are manual valves used to isolate the various well water demands or to isolate well water subsystem equipment or components for maintenance.

Two motor-operated valves are provided, one on each of the recirculation lines from the well water transfer pump discharge header to the well water tank. The normal power supply to these valves is the offsite retail power system (ZRS). In the event of a loss of the normal AC power supply, the valves will be powered by the dedicated well water pump house package diesel generator. The valves are also equipped with handwheels to allow for manual operation if required.

Well Water Pump House Diesel Generator

A dedicated diesel generator is located at the well water pump house. This diesel generator provides backup AC power to the well water makeup pumps, the well water transfer pumps and associated well water system auxiliary equipment and controls required to support continued operation of the well water system if normal power is not available. The diesel generator also supplies backup power to the potable water system to meet state requirements. The capacity of the diesel generator is sufficient to support continuous well water makeup to the Units 3 and 4 SWS cooling tower basins and the Units 3 and 4 potable water system.

9.2.11.3 System Operation

9.2.11.3.1 RWS River Water Subsystem

The RWS river water subsystem operates during normal modes of operation, including startup, power operation, cooldown, shutdown, and refueling.

9.2.11.3.1.1 Plant Startup

The RWS river water subsystem provides water to the CWS cooling tower basin to fill the CWS piping and to replace evaporative losses as the CWS cooling tower is placed into operation.

9.2.11.3.1.2 Power Operation

During normal operation the river water pumps provide water to the CWS basin to replace CWS cooling tower water losses due to evaporation, drift and blowdown.

9.2.11.3.1.3 Plant Cooldown/Shutdown/Refueling

RWS river water makeup to the CWS cooling tower basin is terminated with the shutdown of the CWS after the turbine is taken off-line and a condenser vacuum is no longer required. However, the system is operated as required to support dilution of plant liquid discharges during these modes.

9.2.11.3.1.4 Loss of Normal AC Power Operation

The RWS river water pumps are not available or required during a loss of offsite power (LOOP) when the main turbine is tripped.

9.2.11.3.2 RWS Well Water Subsystem

The RWS well water subsystem operates to meet varying well water demands during normal modes of operation, including startup, power operation, cooldown, shutdown, and refueling.

9.2.11.3.2.1 Plant Startup

The RWS well water subsystem provides well water to the SWS cooling tower basin to initially fill the basin and piping, and to provide makeup to replace evaporative losses as the SWS is placed into operation.

The RWS well water subsystem also supplies makeup water to FPS, DTS, YFS, and PWS on demand.

9.2.11.3.2.2 Power Operation

During normal power operation, the RWS well water subsystem provides makeup to the SWS cooling tower basin to replace water losses due to evaporation, drift, and blowdown.

Well water is also supplied to the FPS, DTS, YFS, and PWS systems on demand.

9.2.11.3.2.3 Plant Cooldown/Shutdown

The RWS well water subsystem alignment during plant cooldown/shutdown uses the same alignment as with normal plant operation. The demand for well water makeup to the SWS cooling tower basin is greater due to added shutdown cooling demand on the SWS system.

Well water is also supplied to the FPS, DTS, YFS, and PWS systems on demand.

9.2.11.3.2.4 Refueling

During refueling, the RWS well water subsystem provides makeup to the SWS cooling tower basin to replace SWS cooling tower water losses due to evaporation, drift, and blowdown.

Well water is also supplied to the FPS, DTS, YFS, and PWS systems on demand.

9.2.11.3.2.5 Loss of Normal AC Power Operation

Backup AC power to the well water makeup pumps, the well water transfer pumps and associated instrumentation and controls is provided from the well water pump house diesel generator. Therefore, the well water system is available for operation during a loss of normal power to provide well water makeup to the SWS cooling tower basins. Only one well water makeup pump and one well water transfer pump are required to support well water makeup to both units SWS during a loss of normal AC power.

The flow control valve on the makeup line to the service water cooling towers is part of the service water system which is described in Subsection 9.2.1. This valve isolates on a loss of normal AC power.

Manual action is required during a loss of normal power to align this valve to provide well water makeup to the SWS cooling tower basin. During a loss of normal power, the well water subsystem will re-circulate water to the well water tank until the makeup flow path is restored by manual alignment.

The well water subsystem is designed to prevent transient water hammer associated with the re-start of system pumps following a loss of normal power. The majority of the system piping is buried below grade, whereas the system demand points and the well water tank are located above grade. Therefore, drainage of large sections of pipe is precluded. In addition, the well water subsystem is equipped with check valves and air release valves as required to prevent the formation of voids within the piping.

9.2.11.4 Safety Evaluation

The RWS has no safety-related function, and therefore, requires no nuclear safety evaluation.

The RWS does not have the potential to be a flow path for radioactive fluids. The RWS has no direct interconnection with any system that contains radioactive fluids.

The RWS river water subsystem supplies an alternate source of dilution for radwaste discharge when the CWS is not in use. To accomplish this, river water is routed to the WWS blowdown sump. The WWS blowdown sump is located on the bluff above the Savannah River. The blowdown sump discharges to the outfall pipe, which in turn drains by gravity into the Savannah River. The radwaste discharge (WLS) line connects to the WWS outfall pipe at a location near the river. The connection between the WWS outfall pipe and the WLS line is located downstream of and more than 100 feet below the blowdown sump, thereby eliminating the ability to contaminate RWS from WLS effluent.

9.2.11.5 Tests and Inspections

Initial test requirements for the RWS are described in Subsection 14.2.9.4.24. System performance and structural and pressure integrity of system components are demonstrated by operation of the system, monitoring of system parameters such as flow, level and pressure, and visual inspections.

9.2.11.6 Instrumentation Applications

9.2.11.6.1 RWS River Water Subsystem

Level indication at the CWS cooling tower basin is used to control the makeup valve to maintain the appropriate water level in the basin.

Level indication is provided in the river intake structure pump bays.

Flow indication is provided for the RWS river water pipe lines to the individual CWS cooling tower basins.

Pressure indication is provided for the RWS river water pump discharge and header piping.

9.2.11.6.2 RWS Well Water Subsystem

Level instrumentation is provided at the well water storage tank and will allow the tank level to be monitored. High and low level signals provide inputs to the well water makeup pump control logic. A low level signal will start one well water makeup pump. A low-low level signal will start the standby well water makeup pump. A low-low-low level signal will initiate an alarm in the control room. A low-low-low-low level signal will trip the well water transfer pumps. A high level signal will stop the well water makeup pumps. A high-high level signal will generate an alarm in the control room.

Flow instrumentation is provided at the discharge of each well water makeup pump and will allow the flow to be monitored. Low flow on an operating pump will provide an alarm to the control room and

low-low flow will stop the pump. Flow instrumentation is also provided for each well water transfer pump and will allow well water transfer pump flow to be monitored.

Pressure instrumentation is provided at the well water transfer pump discharge header and will allow the pressure to be monitored. Normally, one well water transfer pump is run continuously. A demand increase will cause startup of additional well water transfer pumps with sequencing in accordance with the control logic. A demand decrease will cause well water transfer pumps to stop in sequence according to the control logic. Control room alarms are generated for high pressure or low pressure. Local pressure indication is also provided on each well water transfer pump discharge line.

9.2.12 Combined License Information

9.2.12.1 Potable Water

The potable water system outside of the power block is addressed in Subsections 9.2.5.2.1, 9.2.5.2.2, 9.2.5.3, and 9.2.5.6.

9.2.12.2 Waste Water Retention Basins

The plant waste water retention basins and associated discharge piping and retention basins are addressed in Subsections 9.2.9.2.1, 9.2.9.2.2, and 9.2.9.5.

9.2.13 References

1. ASME Code, Section IV, Pt. HWL, 1998.

2. Uniform Plumbing Code, Section 712, 2000.

Table 9.2.1-1
Nominal Service Water Flows and Heat Loads at Different Operating Modes

	CCS Pumps and Heat Exchangers	SWS Pumps and Cooling Tower Cells (Number Normally in Service)	Flow (gpm)	Heat Transferred (Btu/hr)
Normal Operation (Full Load)	1	1	10,500	96.3×10^6
Cooldown	2	2	21,000	339×10^6 (169.5×10^6 per cell)
Refueling (Full Core Offload)	2	2	21,000	61.1×10^6
Plant Startup	2	2	21,000	91.5×10^6
Minimum to Support Shutdown Cooling and Spent Fuel Cooling	1	1	10,000	170×10^6

Table 9.2.2-1
Nominal Component Data - Component Cooling Water System

CCS Pumps (all data is per pump)	
Quantity	2
Type	Horizontal centrifugal
Minimum capacity (gpm, each) to support shutdown cooling and spent fuel pool cooling	8300
Design capacity (gpm, each)	10,030
Design total differential head (ft)	250
Minimum flow rate to support shutdown cooling (gpm)	2685
Minimum flow rate to support spent fuel cooling (gpm)	1200
CCS Heat Exchangers (all data is per exchanger)	
Quantity	2
Type	Plate
Design duty end of cooldown (MBtu/hr)	44.1
Minimum UA (MBtu/hr/°F) to support shutdown cooling and spent fuel pool cooling	14.0
Design UA (MBtu/hr/°F)	15.5
CCS side Design flow rate (gpm)	9691
Service water side Design flow rate (gpm)	10,500
Plate material	Austenitic stainless steel
Seismic design	Non-seismic

Table 9.2.2-2
Plant Components Cooled by Component Cooling Water System

Component	System
RCP 1A	RCS
RCP 1B	RCS
RCP 2A	RCS
RCP 2B	RCS
RCP 1A Variable Frequency Drive	RCS
RCP 1B Variable Frequency Drive	RCS
RCP 2A Variable Frequency Drive	RCS
RCP 2B Variable Frequency Drive	RCS
Letdown HX	CVS
RCDT HX	WLS
RHR HX	RNS
RHR HX	RNS
RHR Pump A	RNS
RHR Pump B	RNS
SFP HX A	SFS
SFP HX B	SFS
Chiller A	VWS
Chiller B	VWS
Sample HX A	PSS
Sample HX B	PSS
Makeup Pump Miniflow HX	CVS
Makeup Pump Miniflow HX	CVS
Air Compressor A	CAS
Air Compressor B	CAS
Air Compressor C	CAS
Air Compressor D	CAS
Cond Pump A Oil Cooler	CDS
Cond Pump B Oil Cooler	CDS
Cond Pump C Oil Cooler	CDS

Table 9.2.3-1
Guidelines for Demineralized Water
(Measured at the Outlet of the Demineralized Water Treatment System)

Parameters	Normal Value	Initiate Action
Specific conductivity, µS/cm at 77°F	≤ 0.1	≤ 0.2
Active silica, ppb	≤ 10	≤ 20
Total silica, ppb	≤ 50	
Suspended solids, ppb	≤ 50	
Aluminum, ppb	≤ 20	
Calcium, ppb	≤ 5	
Magnesium, ppb	≤ 5	
Chloride, ppb	≤ 1	
Sulfate, ppb	≤ 1	
Total organic carbon, ppb	≤ 100	

Table 9.2.7-1
Component Data - Central Chilled Water System
(Nominal Values)

High Capacity Subsystem	
Water Cooled Chillers	
Capacity (nominal tons)	1700
Compressor type	Centrifugal
Maximum power input (kW)	1500
Entering water temperature (°F)	56
Leaving water temperature (°F)	40
Cooling water flowrate (gpm)	3500 (max)
Air-Cooled Chillers	
Capacity (nominal tons)	300
Compressor type	Reciprocating, Screw
Maximum power input (kW)	470
Entering water temperature (°F)	56
Leaving water temperature (°F)	40
Low Capacity Subsystem	
Air-Cooled Chillers	
Capacity (nominal tons)	230
Compressor type	Reciprocating, Screw
Maximum power input (kW)	450
Entering water temperature (°F)	56
Leaving water temperature (°F)	40
Coil	**Flow (gpm)**
VBS MY C01 A/B (MCR/CSA)	101
VBS MY C02 A/C (Class 1E Division A/C Electrical Room)	106
VBS MY C02 B/D (Class 1E Division B/D Electrical Room)	56
VAS MY C07 A/B (CVS Makeup Pump Room)	14
VAS MY C12 A/B (RNS Pump Room)	10
VAS MY C06 A/B (RNS Pump Room)	10

Table 9.2.8-1
Turbine Building Closed Cooling Water System
Equipment Load List

Component
Main turbine lube oil coolers
Main feedwater pump lube oil coolers
Generator hydrogen coolers
Generator stator cooling water cooler
Isolated phase bus coolers
MSR drain pump
EH control coolers
Secondary sampling system coolers

Table 9.2.10-1
Hot Water Heating System Design Data
(Nominal Values)

Available Steam Supply	
Main steam	
Pressure (psia)	200
Enthalpy (Btu/lbm)	1199
Temperature (°F)	382
Auxiliary steam	
Pressure (psia)	210
Enthalpy (Btu/lbm)	1199
Temperature (°F)	386
Heat Exchanger	
Quantity	2
Type	Shell and Tube – subcooled
Capacity per unit (Btu/hr)	21,090,000

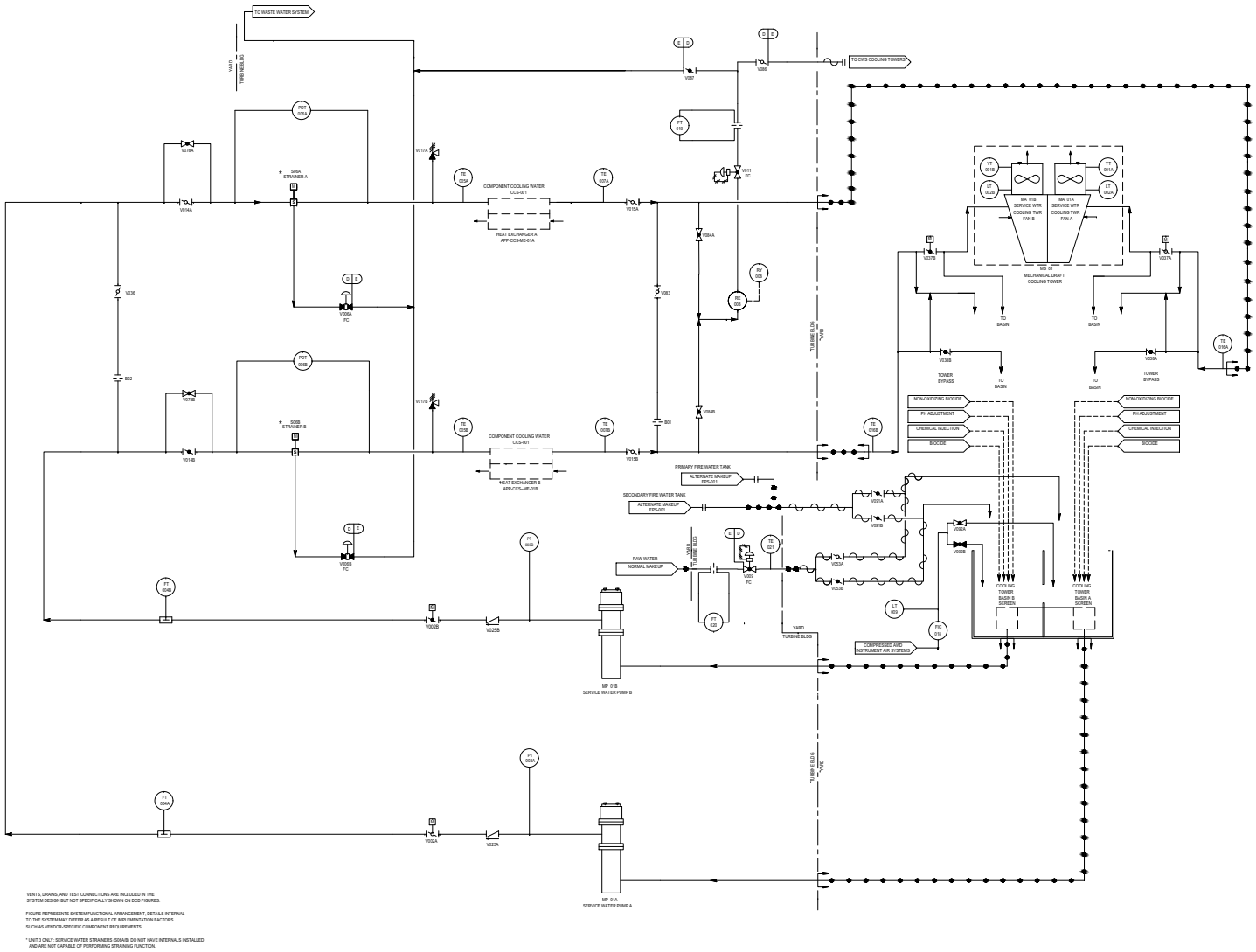


Figure 9.2.1-1
Simplified Service Water System Piping and Instrumentation Diagram (REF) SWS 001

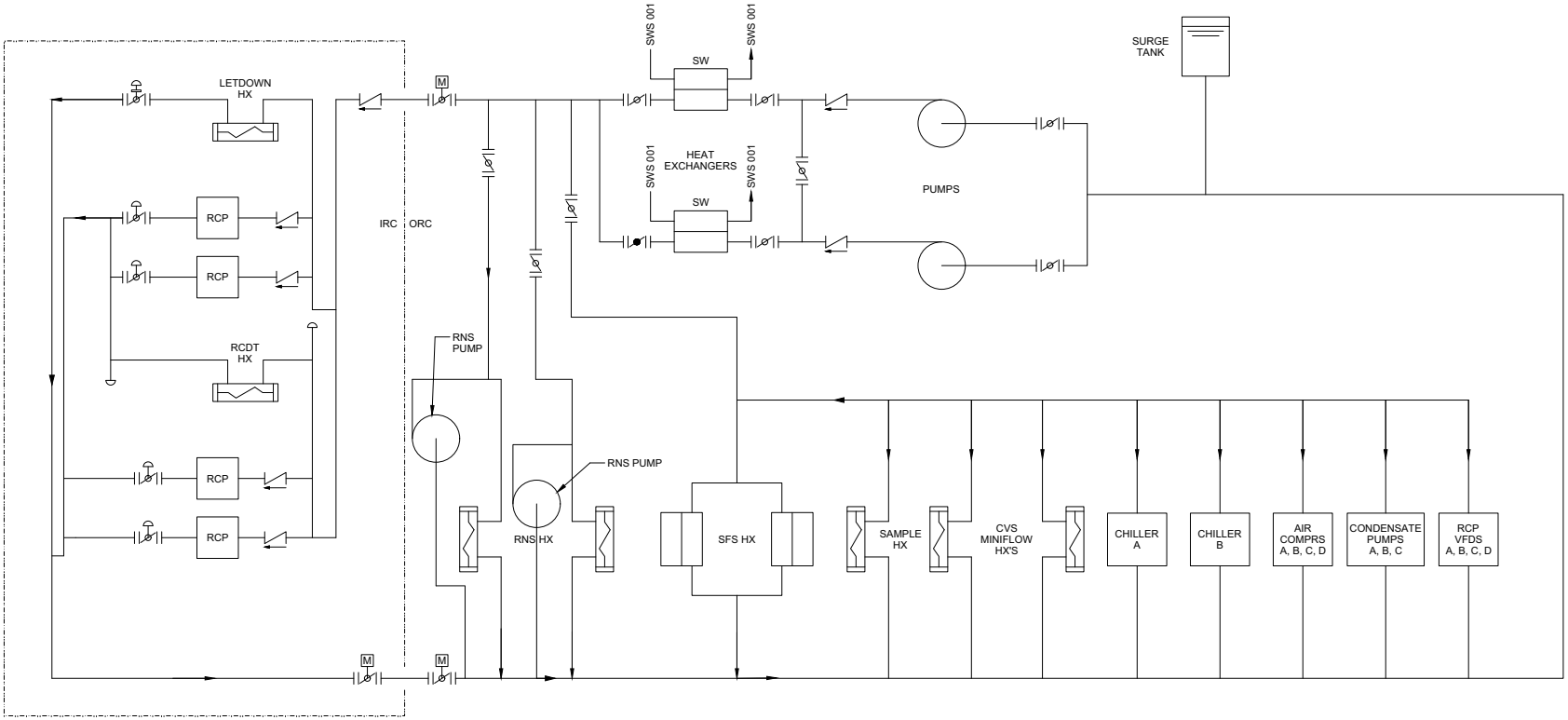
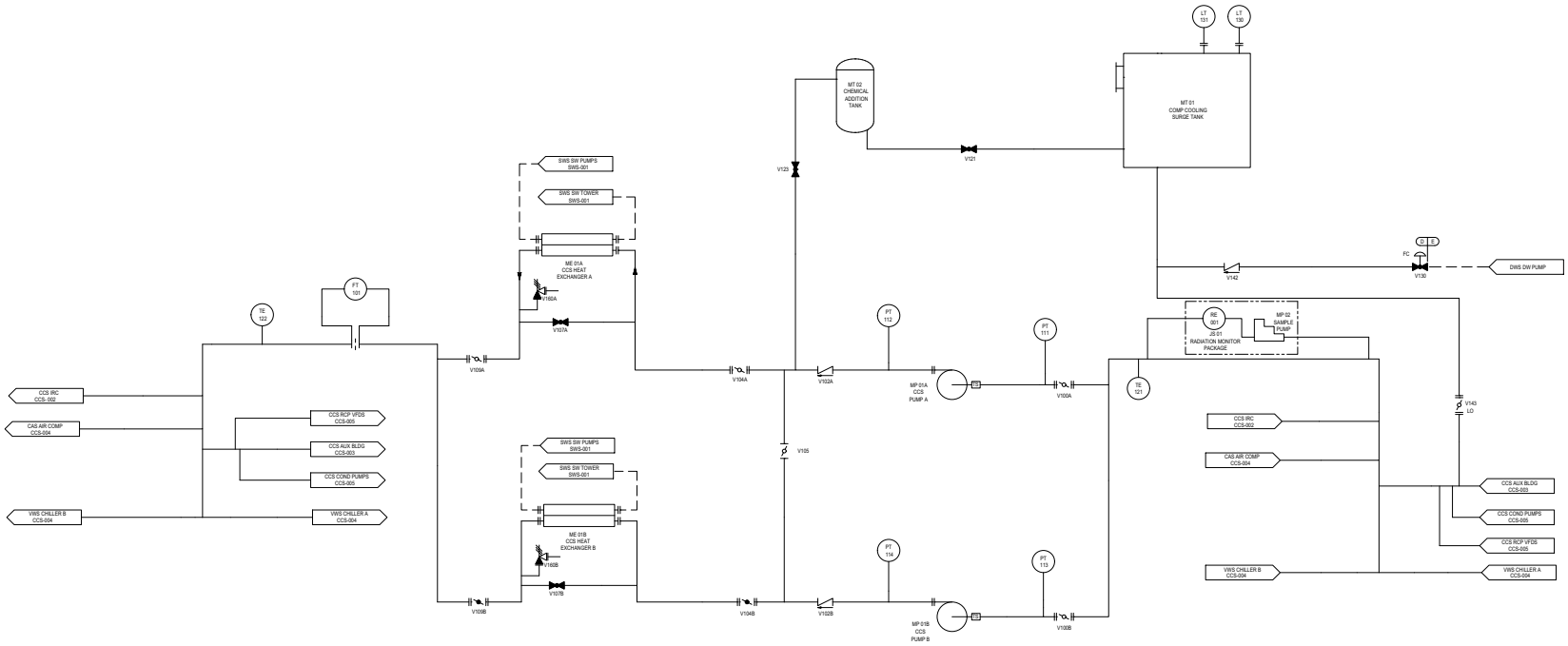


Figure 9.2.2-1
Component Cooling Water System
Simplified Flow Diagram
(REF) CCS



SYSTEM COMPONENTS ARE CLASS D UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN IN THE DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Turbine Building

Figure 9.2.2-2 (Sheet 1 of 5)
Simplified Component Cooling Water System
Piping and Instrumentation Diagram
(REF) CCS 001

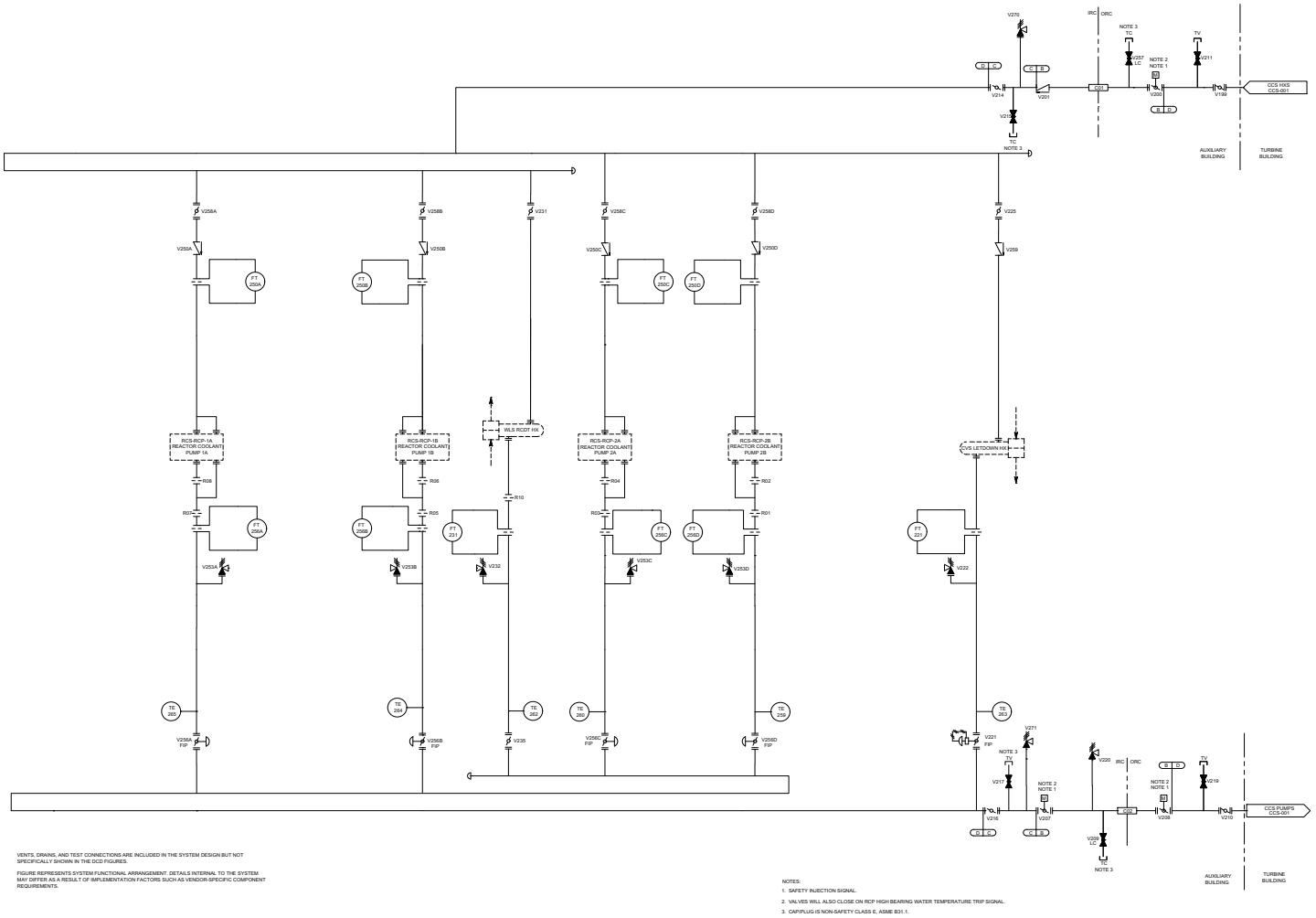
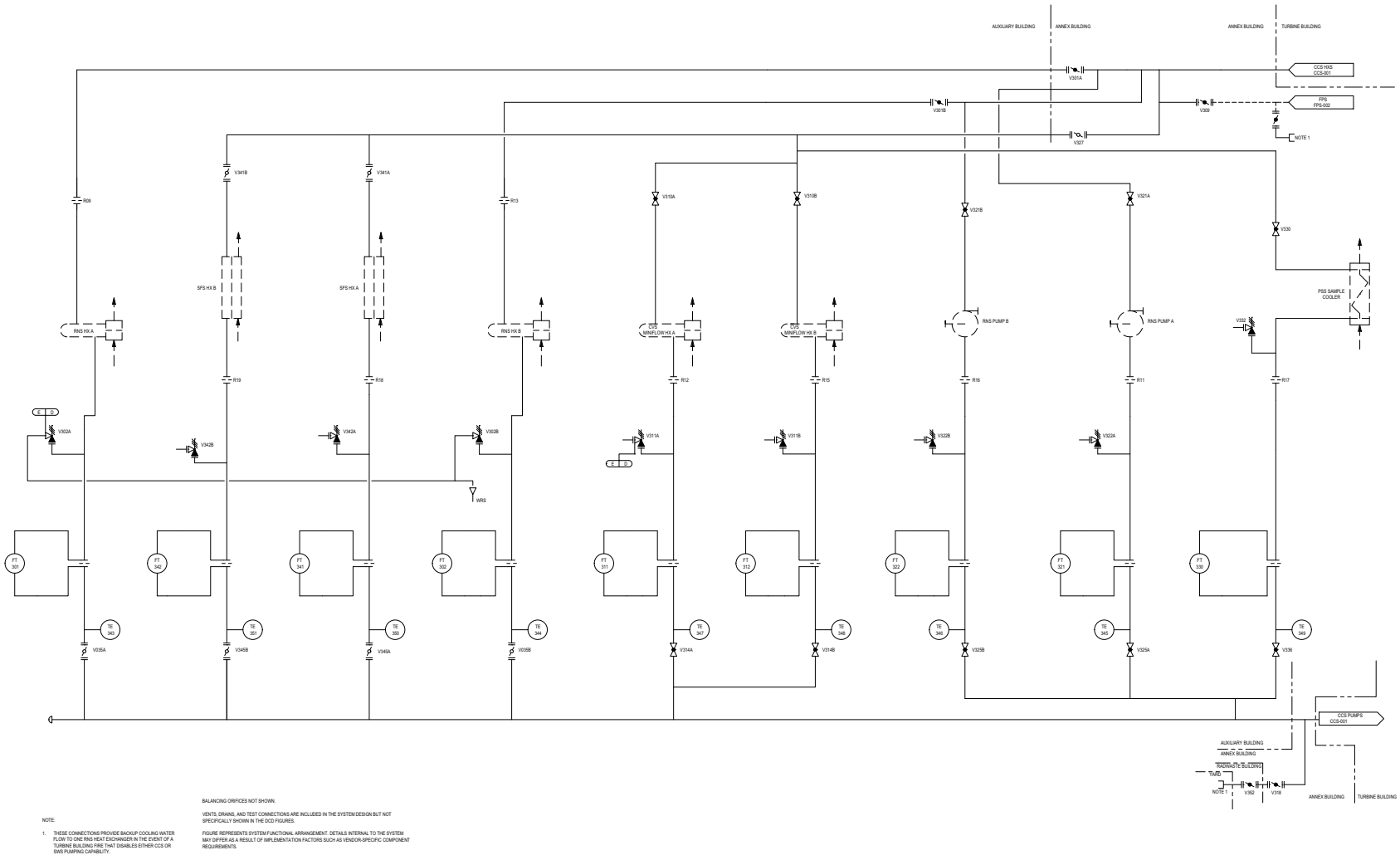


Figure 9.2.2-2 (Sheet 2 of 5)
Simplified Component Cooling Water System
Piping and Instrumentation Diagram
(REF) CCS 002



NOTE:

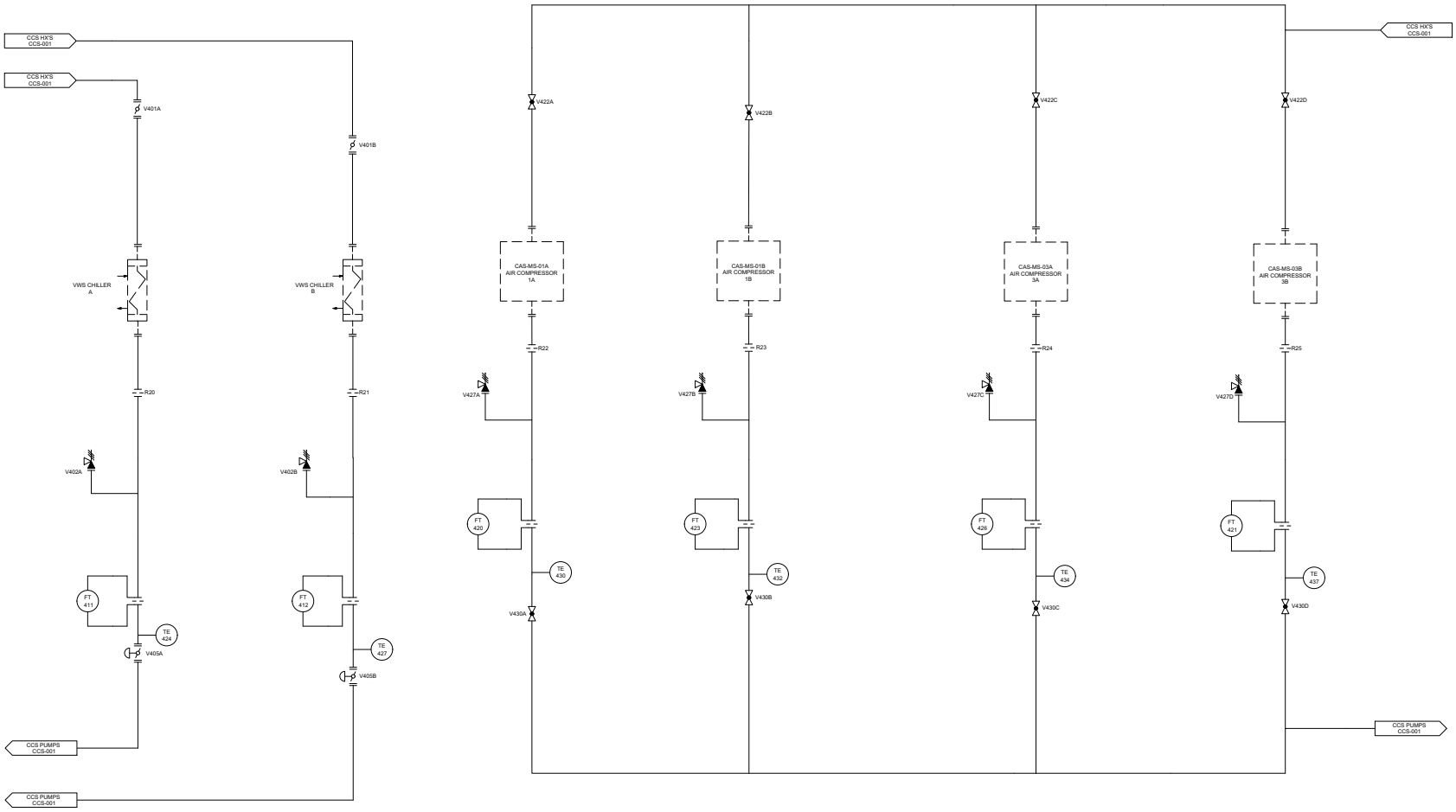
1. THESE CONNECTIONS PROVIDE BACKUP COOLING WATER FLOW TO ONE RNS HEAT EXCHANGER IN THE EVENT OF A TURBINE BUILDING FIRE THAT DISABLES EITHER CCS OR SWS PUMPING CAPABILITY.

BALANCING ORIFICES NOT SHOWN.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN IN THE DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.2.2-2 (Sheet 3 of 5)
Simplified Component Cooling Water System Piping and Instrumentation Diagram
(REF) CCS 003



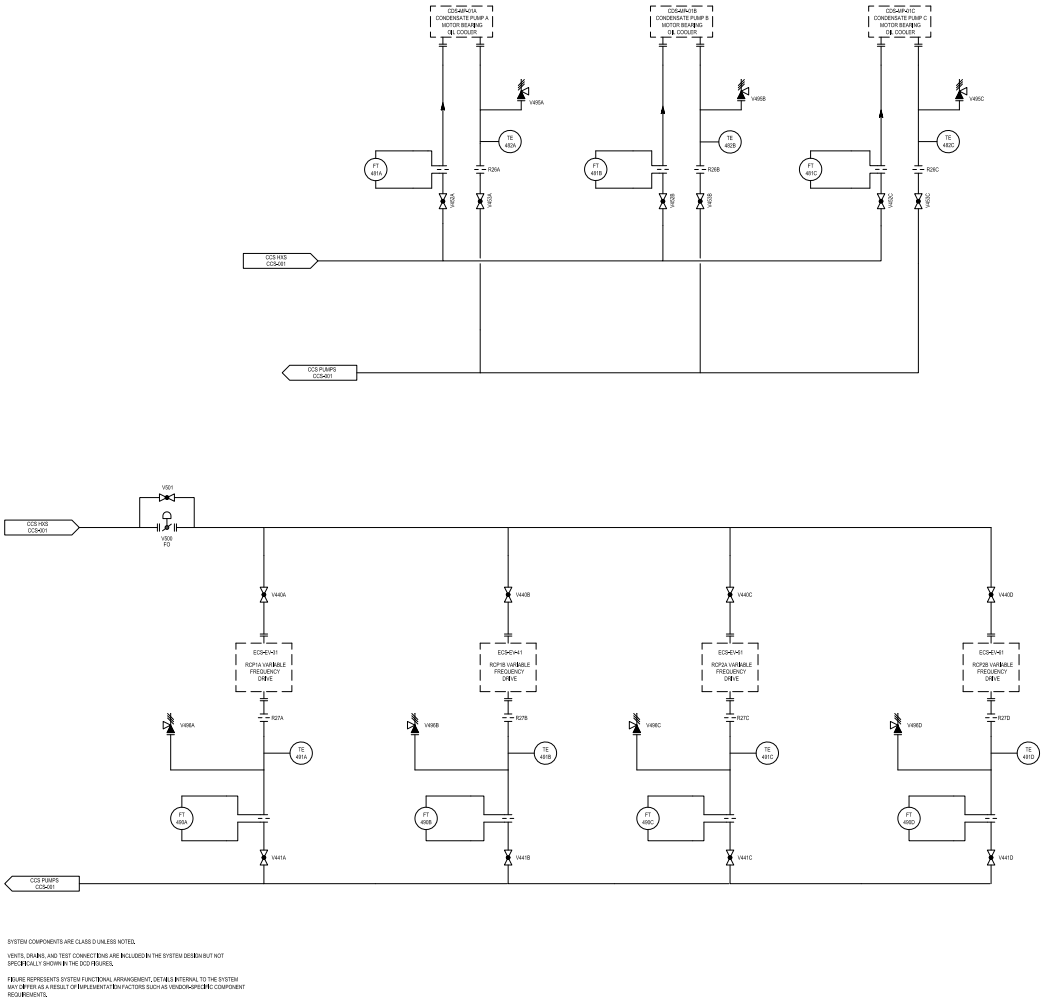
SYSTEM COMPONENTS ARE CLASS D UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN IN THE DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Turbine Building

Figure 9.2.2-2 (Sheet 4 of 5)
Simplified Component Cooling Water System
Piping and Instrumentation Diagram
(REF) CCS 004



SYSTEM COMPONENTS ARE CLASS D UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN IN THE DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Turbine Building

Figure 9.2.2-2 (Sheet 5 of 5)
Simplified Component Cooling Water System Piping and Instrumentation Diagram
(REF) CCS 005

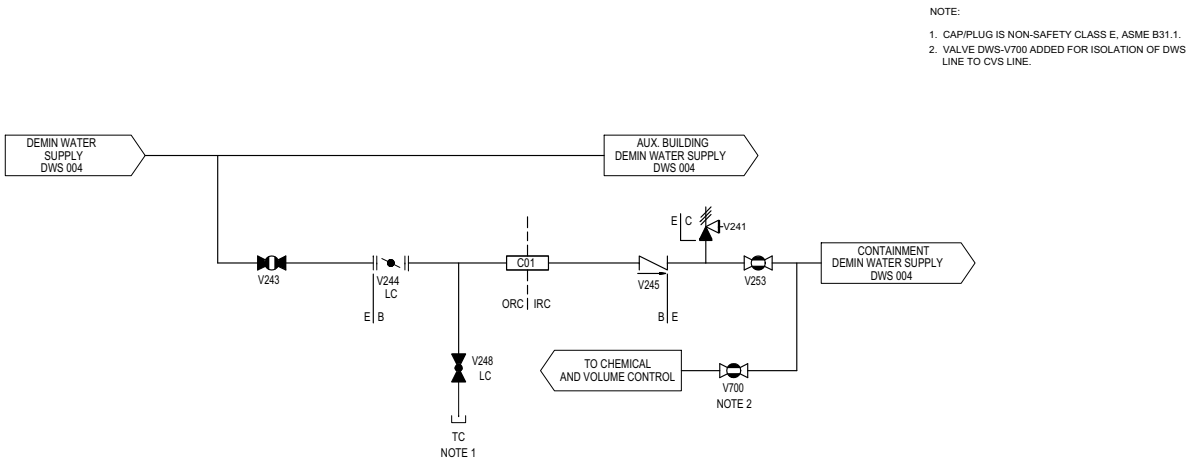


Figure 9.2.4-1
Demineralized Water Transfer and Storage System
Containment Isolation Provision
(REF) DWS 007

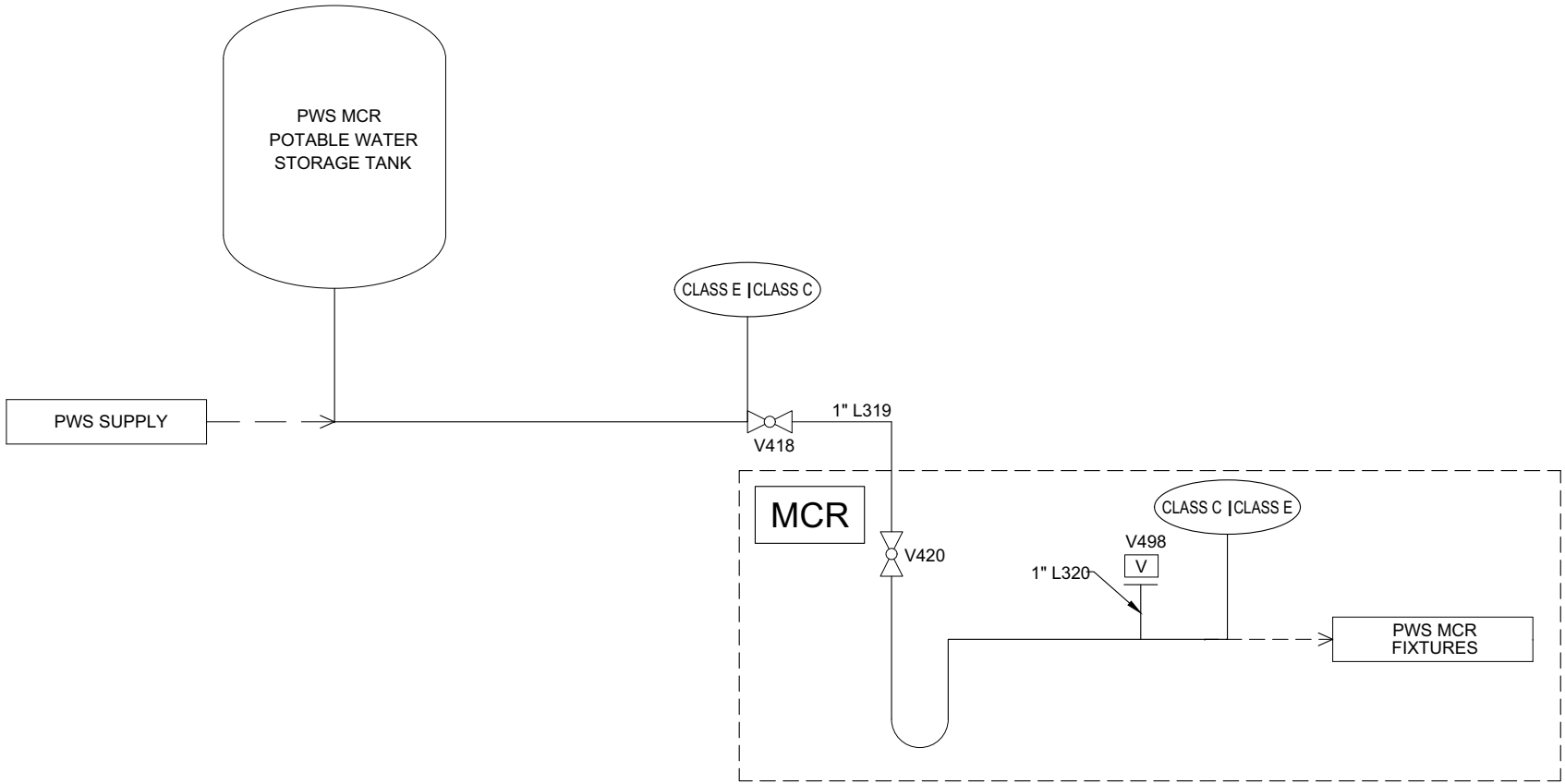
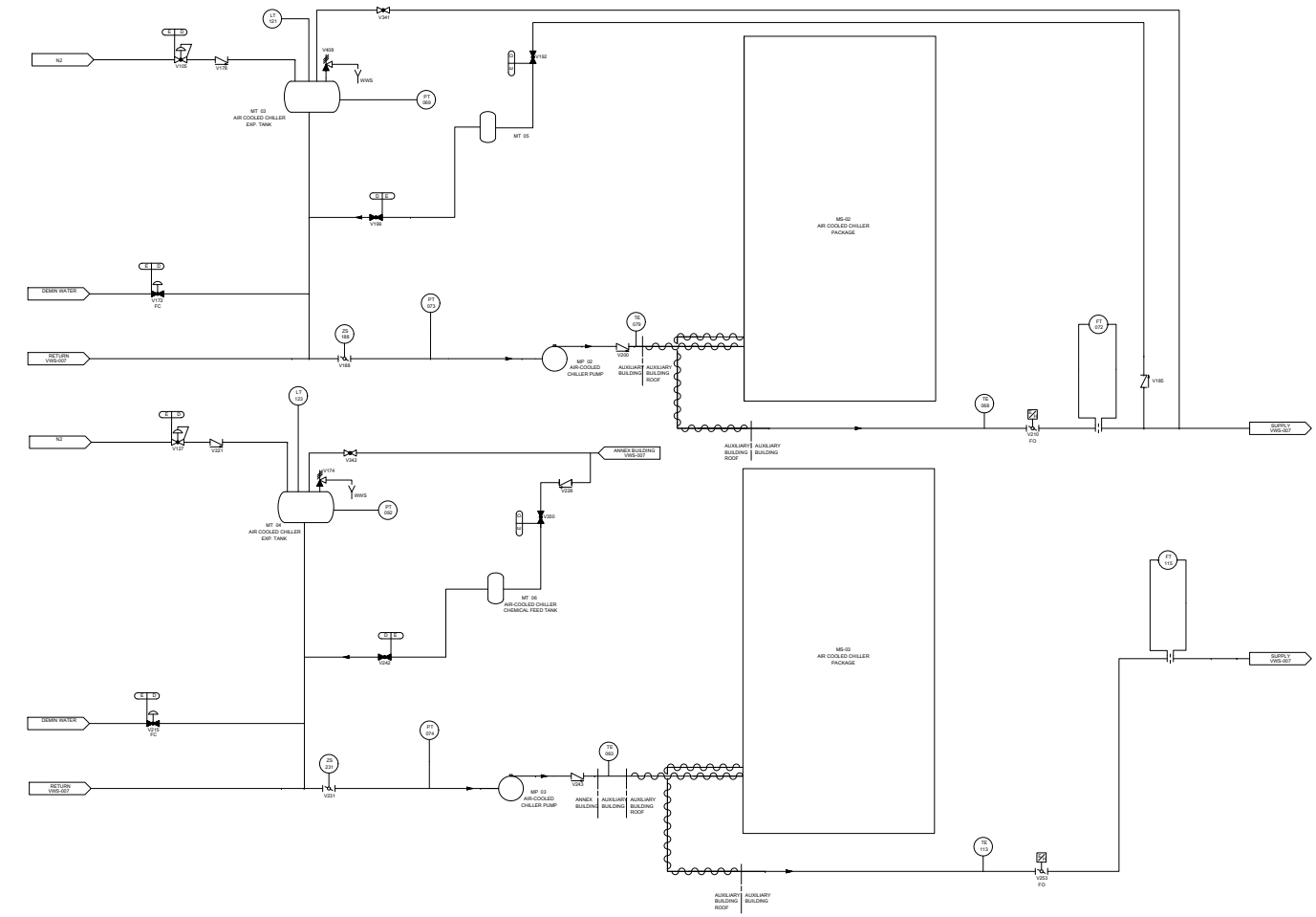


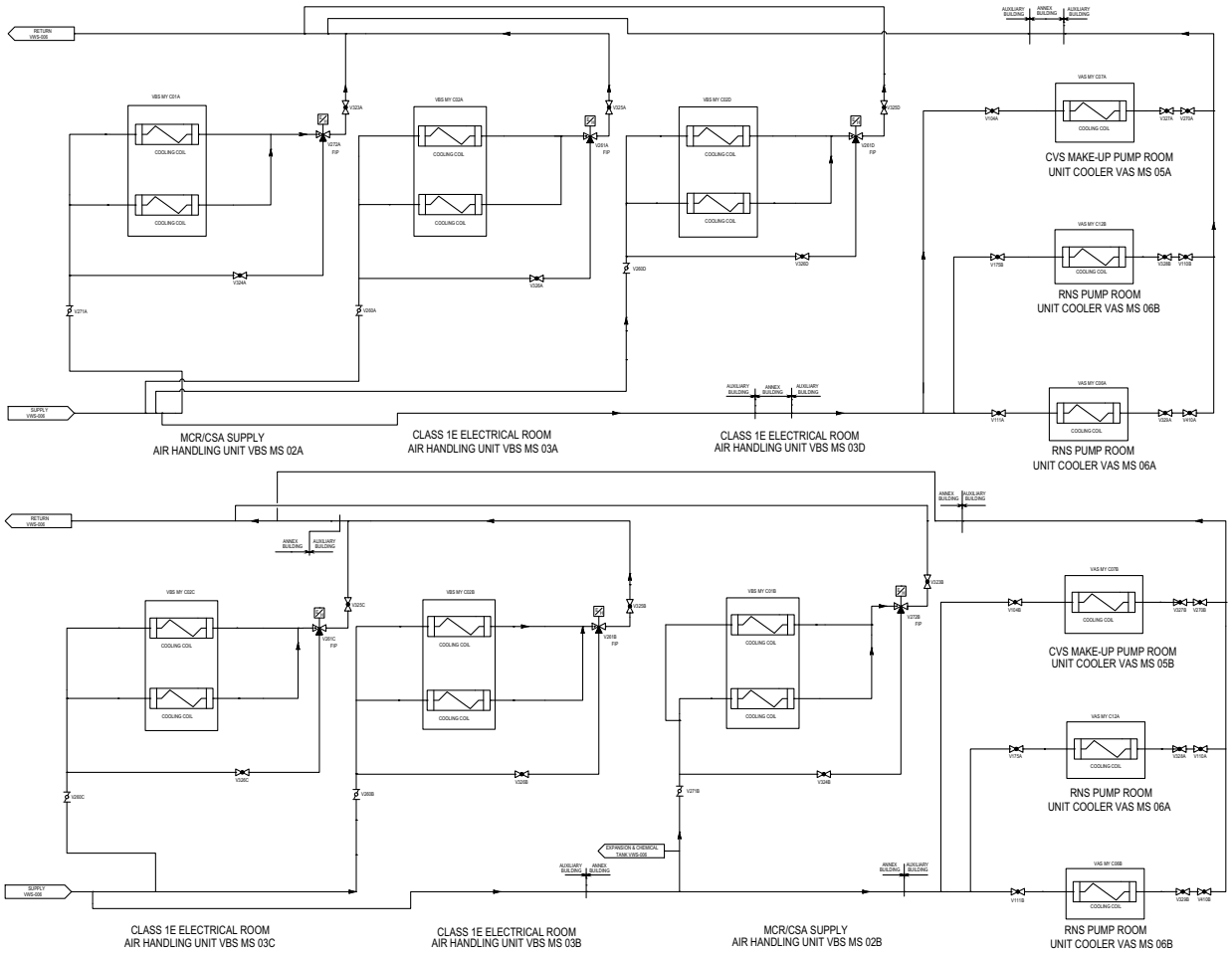
Figure 9.2.5-1
Main Control Room Potable Water System Isolation



VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.2.7-1 (Sheet 1 of 4)
Simplified Central Chilled Water System
Piping and Instrumentation Diagram
(REF) VWS 006



VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.2.7-1 (Sheet 2 of 4)
Simplified Central Chilled Water System
Piping and Instrumentation Diagram
(REF) VWS 007

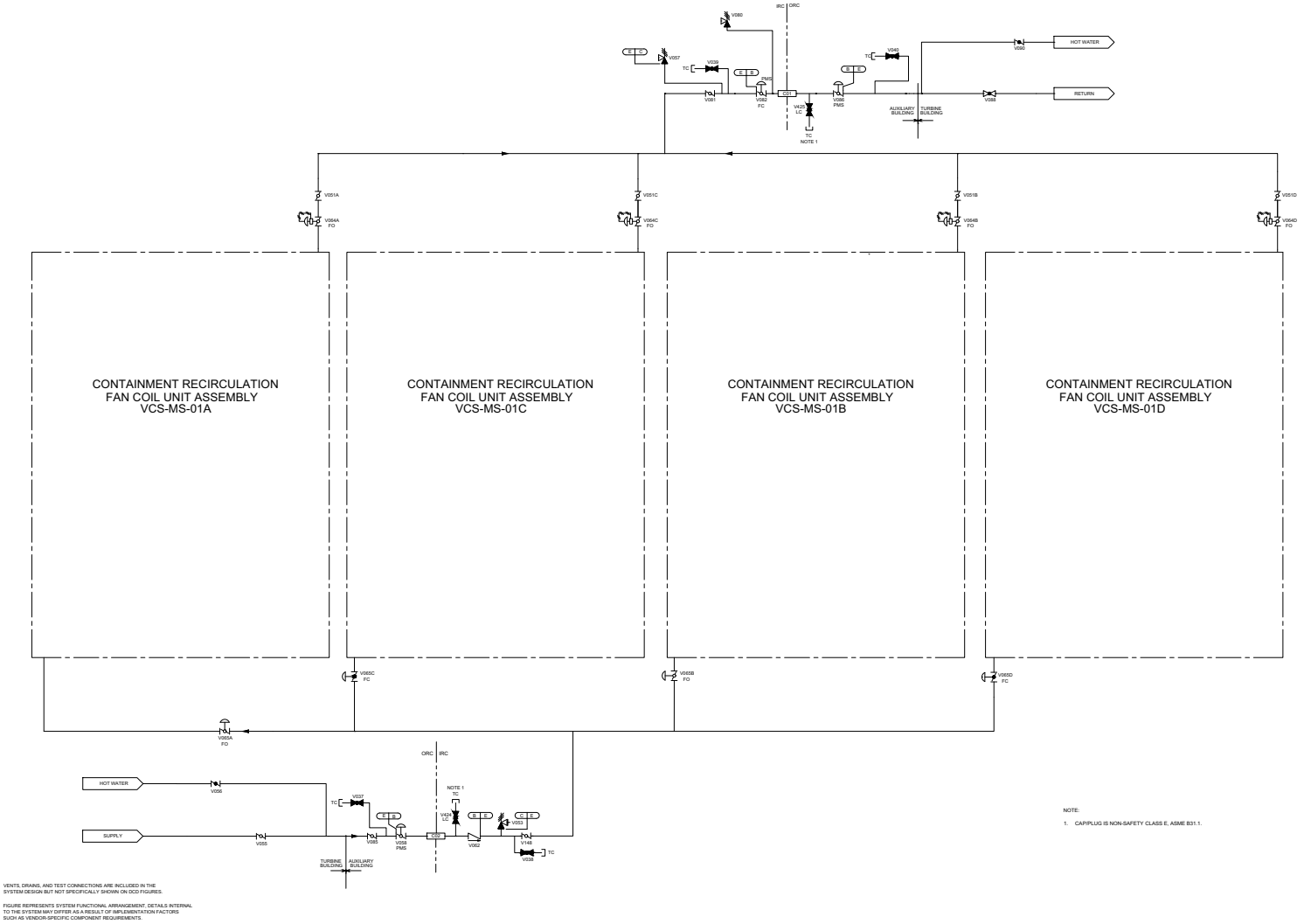


Figure 9.2.7-1 (Sheet 3 of 4)
Simplified Central Chilled Water System
Piping and Instrumentation Diagram
(REF) VWS 003

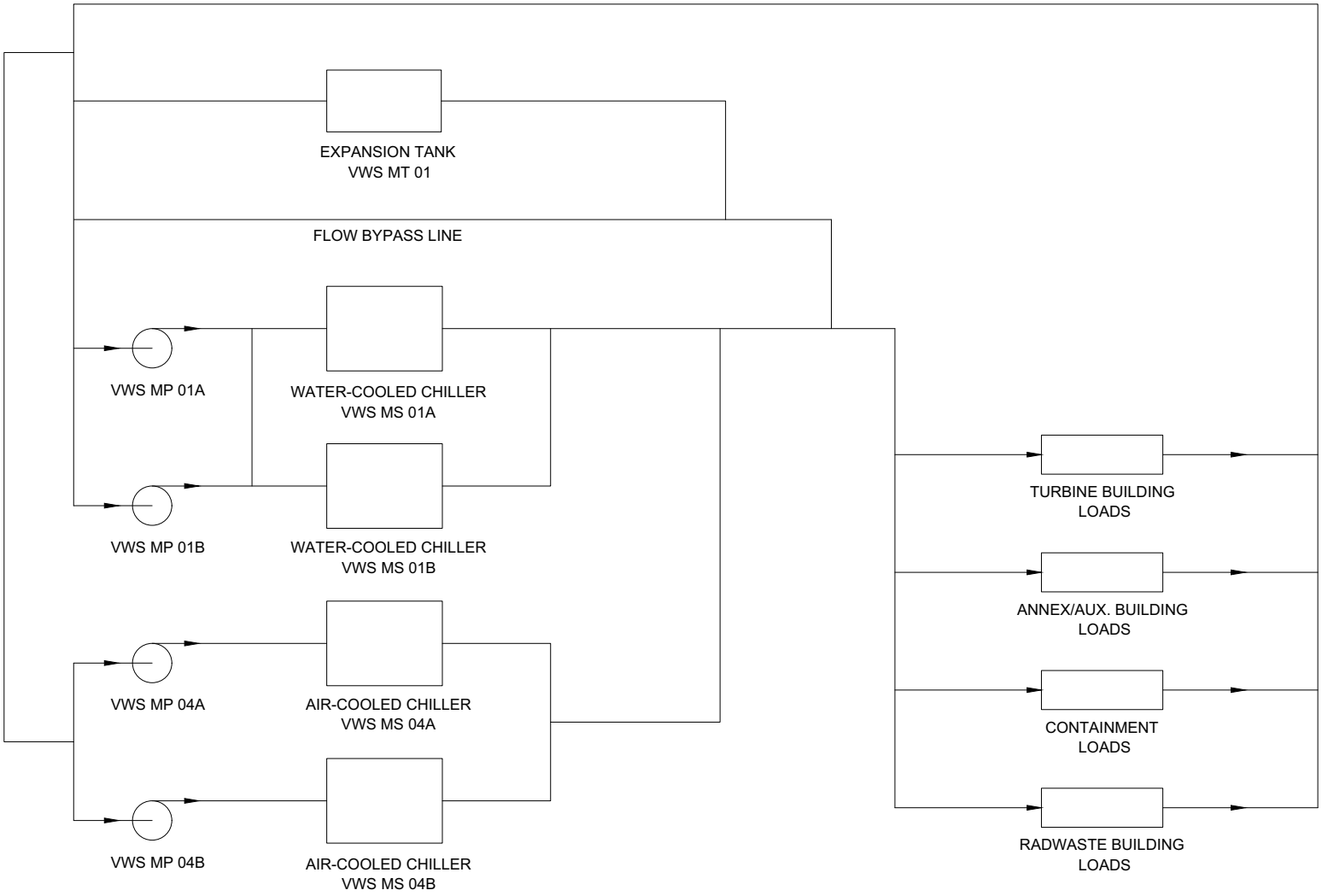


FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.2.7-1 (Sheet 4 of 4)
High Capacity Subsystem Simplified Sketch

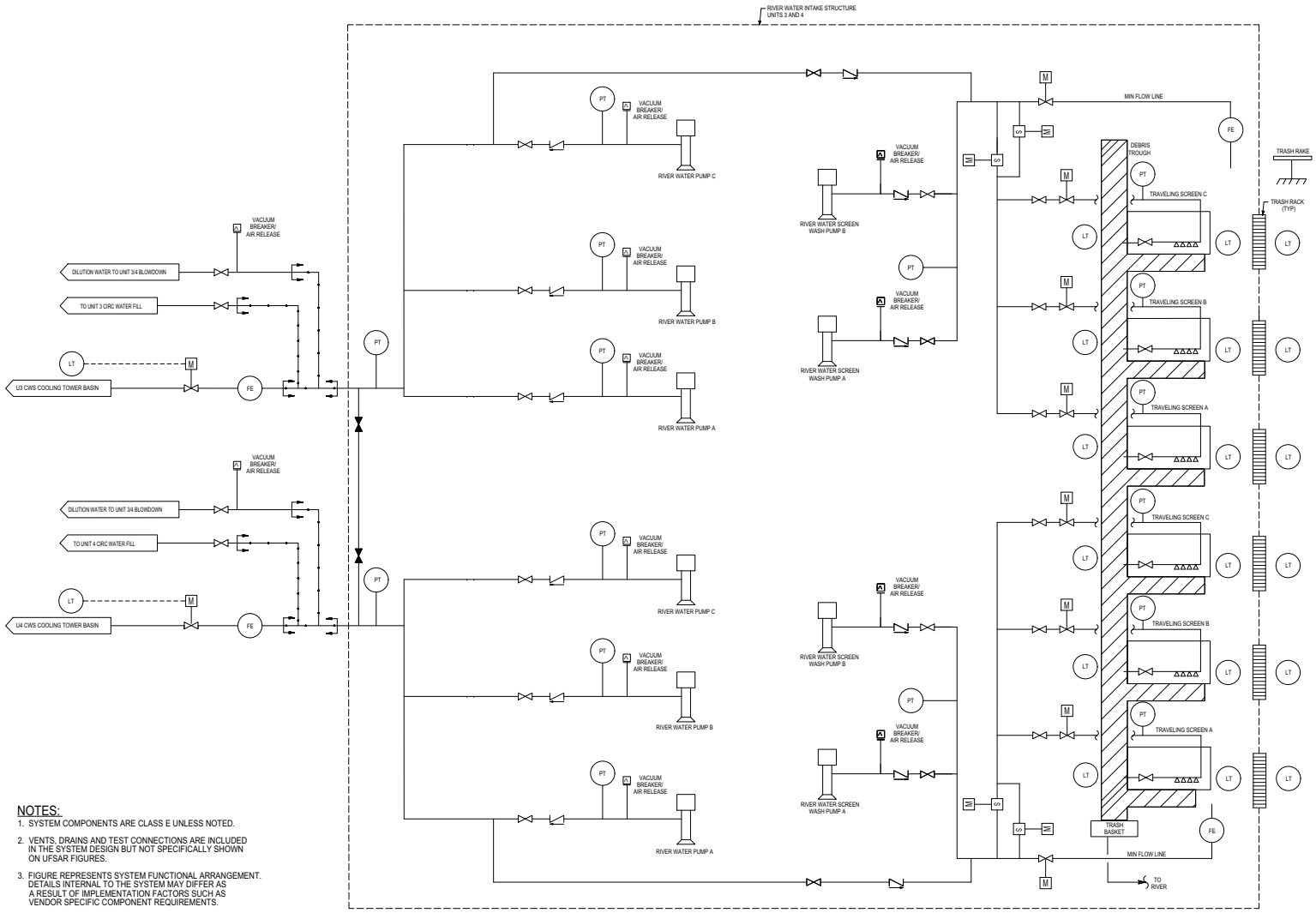
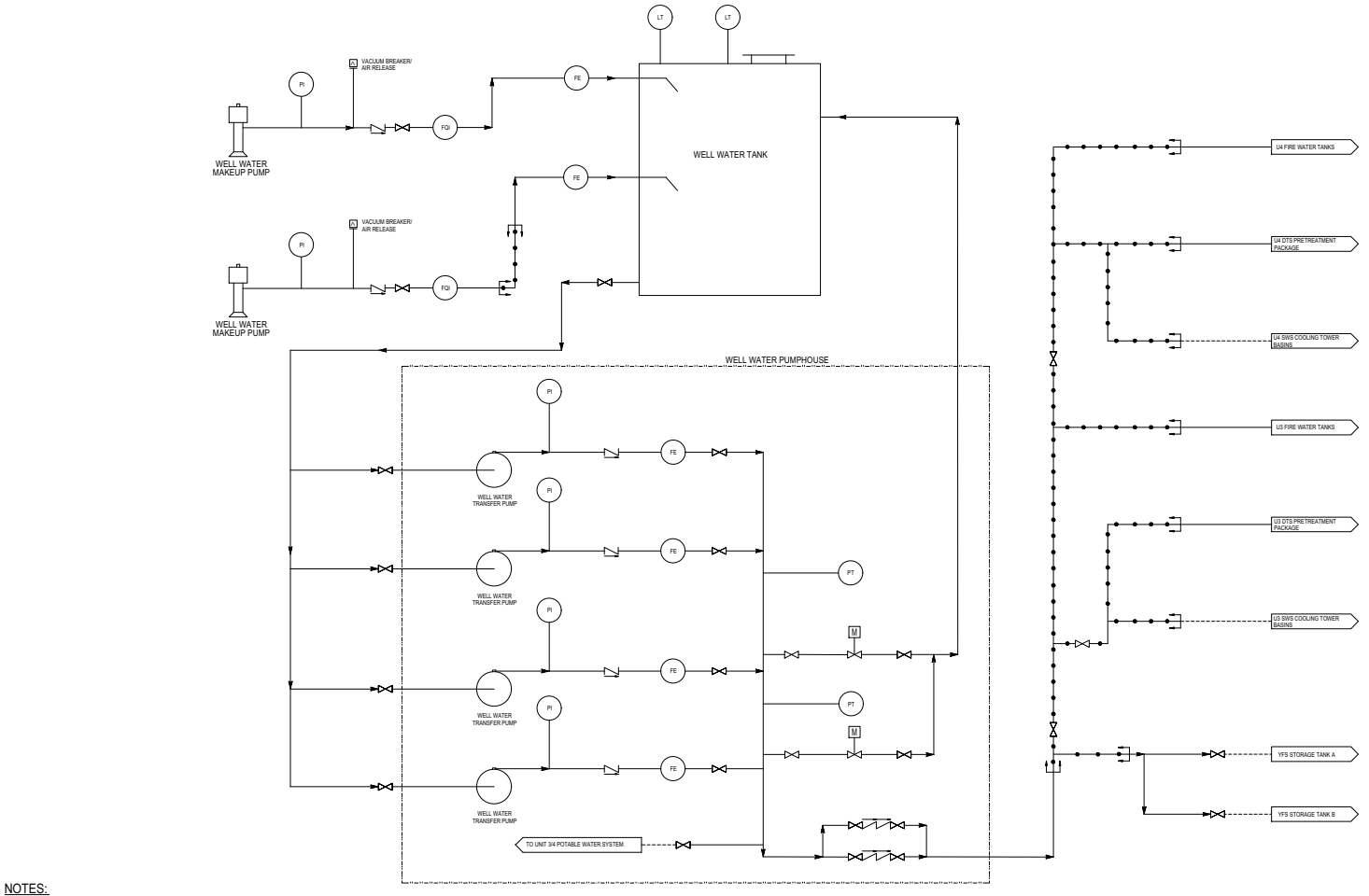


Figure 9.2-201 (Sheet 1 of 2)
Simplified Raw Water System River Water Subsystem Piping and Instrumentation Diagram (REF) SV3/SV4-RWS-001



NOTES:

1. SYSTEM COMPONENTS ARE CLASS E UNLESS NOTED.
2. VENTS, DRAINS AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON UFSAR FIGURES.
3. FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.2-201 (Sheet 2 of 2)
Simplified Raw Water System Well Water Subsystem Piping and Instrumentation Diagram (REF) SV0-RWS-001

9.3 Process Auxiliaries

9.3.1 Compressed and Instrument Air System

The compressed and instrument air system (CAS) consists of three subsystems; instrument air, service air, and high-pressure air. Instrument air supplies compressed air for air-operated valves and dampers. Service air is supplied at outlets throughout the plant to power air-operated tools and is used as a motive force for air-powered pumps. The service air subsystem is also utilized as a supply source for breathing air. Individually packaged air purification equipment is used to produce breathing quality air for protection against airborne contamination. The high-pressure air subsystem supplies air to the main control room emergency habitability system (VES) and fire fighting apparatus recharge station. The high-pressure air subsystem also provides a connection for refilling the VES storage tanks from an offsite source. Major components of the compressed and instrument air system are located in the turbine building.

9.3.1.1 Design Basis

9.3.1.1.1 Safety Design Basis

The compressed and instrument air system serves no safety-related function other than containment isolation and therefore has no nuclear safety design basis except for containment isolation. See Subsection 6.2.3 for the containment isolation system.

9.3.1.1.2 Power Generation Design Basis

The instrument air subsystem provides filtered, dried, and oil-free air for air-operated valves and dampers. The instrument air subsystem consists of two compressors and associated support equipment and controls that are powered from switchgear backed by the nonsafety-related onsite standby diesel generators as an investment protection category load. The subsystem provides high quality instrument air as specified in the ANSI/ISA S7.3 standard (Reference 9.3.8.1).

The service air subsystem provides filtered, dried, and oil-free compressed air for service outlets located throughout the plant. The service air subsystem consists of two compressors and their associated support equipment and controls. Plant breathing air requirements are satisfied by using the service air subsystem as a supply source. Individually packaged air purification equipment is used to improve the service air to Quality Verification Level D breathing air as defined in CGA G-7.1 (Reference 7).

The high-pressure air subsystem consists of one compressor, its associated air purification system and controls, and a high-pressure receiver. It provides clean, oil-free, high-pressure air to recharge the main control room emergency habitability system cylinders and refill the individual fire fighting breathing air bottles. Quality Verification Level E air as defined in CGA G-7.1 (Reference 7), with a pressure dew point of 40°F or lower at 3,400 psig or greater, is produced by this subsystem. See Section 6.4 for a description of the main control room habitability system.

9.3.1.2 System Description

9.3.1.2.1 General Description

Classifications of components and equipment in the compressed and instrument air system are given in Section 3.2. In accordance with NUREG-1275, instrument air quality meets the manufacturer's standards for pneumatic equipment supplied as a part of the plant. Intake filters for instrument air, service air, and high-pressure air compressors remove particulates 10 microns and larger.

Instrument Air Subsystem

The instrument air subsystem consists of two 100 percent capacity parallel air supply trains discharging to a common air distribution system. An air compressor, dryer, controls, and receiver comprise one air supply train. The two compressor trains join to a single instrument air header downstream of the receivers.

Provisions are made to temporarily cross connect the instrument and service air subsystems at the distribution header.

Unit 4 only:

For Unit 4 only, the instrument air line to the containment is normally open; however, air flow to the containment is monitored and a high flow alarm is provided to indicate a possible instrument air line rupture inside containment. Safety-related air-operated valves supplied by the system are identified in Table 9.3.1-1. None of these valves require instrument air to perform their safety-related function. The valves with an active safety-related function fail in the safe position on loss of instrument air pressure.

Unit 3 only:

For Unit 3 only, the instrument air line to the containment is normally open; however, air flow to the containment is monitored and a high flow alarm is provided to indicate a possible instrument air line rupture inside containment. Safety-related air-operated valves supplied by the system are identified in Table 9.3.1-1. None of these valves require instrument air to perform their safety-related function. The valves with an active safety-related function fail in the safe position on loss of instrument air pressure. Nitrogen from the passive core cooling system (PXS) is connected to the containment instrument air line as a backup supply in the case instrument air to containment is lost.

One instrument air compressor train, including its air dryer and associated equipment and controls, can be connected to each of the nonsafety-related onsite standby diesel generators. The compressors are cooled by water supplied from the component cooling water system (CCS). Refer to Subsection 9.2.2 for details. The instrument air subsystem is shown schematically in Figure 9.3.1-1. Major system components are described in Table 9.3.1-2.

Service Air Subsystem

Two 100 percent capacity compressor trains are provided for the service air subsystem. These compressor trains consist of identical equipment and share a common air receiver that feeds the service air distribution system. Cooling water to the service air compressors is supplied from the component cooling water system. Refer to Subsection 9.2.2 for details.

The service air line to containment is normally closed and is opened on an as-needed basis. The service air subsystem is shown schematically in Figure 9.3.1-1 and major system components are described in Table 9.3.1-3.

High-Pressure Air Subsystem

The high-pressure air subsystem consists of a high-pressure air compressor with an integral air purification system, controls, and a receiver.

The high-pressure air subsystem is manually operated and may be loaded on an onsite standby diesel generator. This subsystem supplies air to the main control room emergency habitability system and the fire fighting apparatus recharge station. The isolation valves to these locations are normally closed and are opened on an as-needed basis to refill the specified equipment air storage reservoirs.

The high-pressure air subsystem is shown schematically in Figure 9.3.1-1 and major system components are described in Table 9.3.1-4.

9.3.1.2.2 Component Description

Instrument Air Subsystem

The instrument air subsystem consists of two air compressor trains. Each compressor train consists of a multistage, low-pressure, rotary screw, air compressor package, a desiccant dryer with a prefilter and afterfilter, and an air receiver. Each compressor package includes an intake filter, rotary screw compressor elements, silencer, intercooler, aftercooler, moisture separators, bleed-off cooler, oil cooler, oil reservoir, automatic load controls, relief valves, and a discharge air check valve. Each compressor train produces oil-free air.

Two instrument air receivers function as storage devices for compressed air. The receivers continue to supply the instrument air subsystem following a loss of the instrument air compressors until the receiver pressure drops below system requirements. Each air receiver is equipped with a pressure relief valve.

Two air dryer assemblies are provided for the instrument air subsystem. Each dryer assembly consists of a desiccant-filled, twin tower design. One tower may be used to dry air while the other tower goes through regeneration. When instrumentation senses a high dew point, the towers switch. The former operating tower then undergoes regeneration while the regenerated tower drys the instrument air.

Each dryer assembly includes a coalescing prefilter that removes oil aerosols and moisture droplets, as well as an afterfilter to remove desiccant dust. Each air dryer assembly is provided with an automatic condensate drain valve.

Unit 4 only:

For Unit 4 only, the instrument air subsystem supplies ANSI/ISA S-7.3 high quality instrument air. Table 9.3.1-2 provides design information for the main components associated with the instrument air subsystem.

Unit 3 only:

For Unit 3 Only, the instrument air subsystem supplies ANSI/ISA S-7.3 high quality instrument air. Table 9.3.1-2 provides design information for the main components associated with the instrument air subsystem.The nitrogen backup line for instrument air in containment is equipped with a pressure regulating and pressure relief valve to provide nitrogen at pressures suitable for instrument air use.

Service Air Subsystem

The service air subsystem consists of two air compressor trains. Each compressor train consists of a multistage, low-pressure, rotary screw, air compressor package, and a desiccant dryer with a prefilter and afterfilter. A common air receiver is provided for the two trains. Each compressor package includes an intake filter, rotary screw compressor elements, silencer, intercooler, aftercooler, moisture separators, bleed-off cooler, oil cooler, oil reservoir, automatic load controls, relief valves, and a discharge air check valve. Each compressor train produces oil-free air.

The common service air receiver functions as a storage device for compressed air. This air receiver is equipped with a pressure relief valve.

Two air dryer assemblies are provided for the service air subsystem. Each dryer assembly consists of a desiccant-filled, twin tower design. One tower may be used to dry air while the other tower goes through regeneration. When instrumentation senses a high dew point, the towers switch. The former operating tower then undergoes regeneration while the regenerated tower dries the service air.

Each dryer assembly includes a coalescing prefilter that removes oil aerosols and moisture droplets, as well as an afterfilter to remove desiccant dust. Each air dryer assembly is provided with an automatic condensate drain valve.

Table 9.3.1-3 provides design information for the main components associated with the service air subsystem.

High-Pressure Air Subsystem

The high-pressure air subsystem utilizes an air-cooled, oil-lubricated, four-stage, reciprocating-air compressor with an integral air purification system to produce oil-free air for high-pressure applications. The compressor train includes an intake filter, air-cooled intercoolers, interstage oil/water separators, an air-cooled aftercooler, a final oil/water separator, relief valves, an air purification system, discharge check valves, and a high-pressure receiver.

The high-pressure air subsystem supplies CGA G-7.1 (Reference 7) Quality Verification Level E air. See Table 9.3.1-4 for the design parameters for this system.

9.3.1.2.3 System Operation

Instrument Air Subsystem

The instrument air compressors are operated by a local pressure controller located in the instrument air distribution header, which can be programmed for various sequences of operation. Normally one compressor runs continuously loading and unloading as required to supply compressed air demand. The second compressor serves as a backup and starts automatically if the first unit fails or if demand exceeds the capacity of the operating compressor.

Air from the instrument air subsystem compressor packages discharges to the air dryers and then to the receivers where it is distributed to air-operated valves and dampers throughout the plant. Instrument air pressure is reduced by pressure regulators at the pneumatic component as required.

The onsite standby power system (diesel generators) provides an alternate source of electrical power for the instrument air compressor trains. One compressor train is supplied from each electrical load group.

Unit 3 only:

For Unit 3 only, the backup nitrogen line from containment is to be set at a pressure lower than the operating pressure of nitrogen, but higher than the minimum necessary pressure for operating valves. When normal instrument air to containment is lost, the pressure change between the two lines allows for nitrogen to supplant the lost instrument air.

Service Air Subsystem

The service air subsystem compressors are operated by a local controller that can be programmed for various sequences of operation. Normally one compressor runs continuously and loads and unloads as required to supply service air demand. The second compressor serves as a backup and starts automatically if the first compressor fails or demand exceeds the capacity of the operating compressor. Air from each service air subsystem compressor package discharges to an air dryer and

then to the common receiver. Service air flows from the receiver to the various service air outlets throughout the plant.

Breathing air can be obtained from any service air subsystem outlet by attaching a portable individually packaged air purification system. The breathing air purification package consists of replaceable cartridge-type filters, a pressure regulator, carbon monoxide monitoring equipment, air supply hoses, and air supply devices. Carbon monoxide is controlled by a catalytic conversion to carbon dioxide within the package. Breathing air of a Quality Verification Level D or better is supplied to personnel from the packaged purification system in accordance with the requirements of CGA G-7.1 (Reference 7).

High-Pressure Air Subsystem

The high-pressure air subsystem is operated when a specific high-pressure source requires refilling to replace air lost to leakage or expended during plant operations. System isolation valves to the specified equipment are manually opened and the equipment storage reservoir is replenished from the high-pressure receiver. The compressor is started to replenish the air stored in the high-pressure receiver.

Breathing air of a Quality Verification Level E is supplied from the integral high-pressure air purification system in accordance with the requirements of CGA G-7.1 (Reference 7). This integral air purification system utilizes a series of replaceable cartridge-type filters to produce breathing quality air. Breathing air connections of the high-pressure air subsystem are incompatible with the breathing air connections of the service air subsystem. Carbon monoxide is controlled by a catalytic conversion to carbon dioxide within the package.

The onsite standby power system (diesel generators) provides an alternate source of electrical power for the high-pressure air compressor.

9.3.1.3 Safety Evaluation

The compressed and instrument air system has no safety-related function other than containment isolation and therefore requires no nuclear safety evaluation. Containment isolation functions are described in Subsection 6.2.3.

The compressed and instrument air system is required for normal operation and startup of the plant. Air-operated valves that are essential for safe shutdown and accident mitigation are designed to actuate to the fail-safe position upon loss of air pressure. These air-operated valves utilize safety-related solenoid valves to control the air supply.

The instrument and service air subsystems are classified as moderate-energy systems. There are no adverse effects on safety-related components associated with a postulated failure of the instrument and service air piping.

The high-pressure air subsystem is classified as a high-energy system. The high-pressure compressor and receiver are located in the turbine building, which contains no safety-related, equipment or structures. Air piping routed in safety-related areas is 1 inch or less in diameter and the dynamic consequences of a rupture are not required to be analyzed. The high-pressure air subsystem is not required to operate following a design basis accident nor is it used for safe shutdown of the plant.

9.3.1.4 Tests and Inspections

System components, such as the air compressors and air dryers, are inspected or tested prior to installation. The installed compressed and instrument air system is inspected, tested, and operated

to verify that it meets its performance requirements, including operational sequences and alarm functions.

Air compressors and associated components on standby are checked and operated periodically. Desiccant in the air dryers is changed when required.

Sample points are provided downstream of the air dryers in both the instrument and service air subsystems and downstream of the purifier in the high-pressure air subsystem. Periodic checks are made to ensure high quality instrument air and service air as specified in the ANSI/ISA S-7.3 standard. Periodic checks on the high-pressure air compressor are made on a regular basis to verify that the breathing air meets the Quality Verification Level E as indicated in CGA G-7.1 (Reference 7).

During the initial plant testing prior to reactor startup, safety systems utilizing instrument air are tested as part of the safety system test to verify fail-safe operation of air-operated valves upon complete loss of system pressure, both sudden and gradual, and to partial reduction in system pressure as described in Regulatory Guide 1.68.3. Appendix 1A summarizes conformance with Regulatory Guide 1.68.

9.3.1.5 Instrumentation Applications

An instrumentation package is included with each of the instrument and service air compressors. Each package consists of temperature and pressure transducers, indicators, and automatic protection devices. The temperature and pressure transducers support the automatic control modes of compressor operation. A manual mode of operation is also provided for each control system. Compressed and instrument air system indication and control are available in the main control room.

The high-pressure air subsystem includes pressure and carbon monoxide instrumentation, automatic protection devices, and temperature indication.

9.3.2 Plant Gas System

The plant gas system (PGS) provides hydrogen, carbon dioxide, and nitrogen gases to the plant systems as required.

Other gases, such as oxygen, methane, acetylene, and argon, are supplied in smaller individual containers and are not supplied by the plant gas system.

9.3.2.1 Design Basis

9.3.2.1.1 Safety Design Basis

The plant gas system serves no safety-related function and therefore has no nuclear safety design basis.

9.3.2.1.2 Power Generation Design Basis

The nitrogen portion of the plant gas system supplies nitrogen for pressurizing, blanketing, and purging of various plant components.

The hydrogen gas portion of the plant gas system supplies hydrogen to the main plant electrical generator for cooling as well as to other plant auxiliary systems.

The carbon dioxide portion of the plant gas system supplies carbon dioxide to the generator for purging of hydrogen and air during layup or plant outages.

9.3.2.2 System Description

Classification of equipment and components is given in Section 3.2.

9.3.2.2.1 General Description

Unit 4 only:

For Unit 4 only, the nitrogen portion of the plant gas system is a packaged system consisting of a single very high pressure gaseous nitrogen supply feed through dual pressure reducing manifolds, one high-pressure and one low-pressure. The high-pressure subsystem supplies the accumulators in the passive core cooling system. The high-pressure supply is then reduced to supply makeup to the reactor coolant drain tank for purging and blanketing. Low-pressure nitrogen is provided for component purging, layup/blanketing, and pressurization. The nitrogen system is a single system common to both units and is located in the gas storage area in the yard.

Unit 3 only:

For Unit 3 only, the nitrogen portion of the plant gas system is a packaged system consisting of a single very high pressure gaseous nitrogen supply feed through dual pressure reducing manifolds, one high-pressure and one low-pressure. The high-pressure subsystem supplies the accumulators in the passive core cooling system. The high-pressure supply is then reduced to supply makeup to the reactor coolant drain tank for purging and blanketing. Low-pressure nitrogen is provided for component purging, layup/blanketing, and pressurization. The nitrogen system is a single system common to both units and is located in the gas storage area in the yard. Nitrogen is used as a backup to instrument air inside containment.

The main steam isolation valves (MSIVs) and main feedwater isolation valves (MFIVs) use compressed nitrogen stored within the valve operators as the motive force to close the valves. The main steam isolation valves are described in Subsection 10.3.2.2.4 and the main feedwater isolation valves are described in Subsection 10.4.7.2.2. Nitrogen makeup for these valves (if needed) is provided from portable high-pressure nitrogen bottles using temporary connections on the valves.

The packaged nitrogen system is located in the gas storage area in the yard.

The low-pressure hydrogen gas portion of the plant gas system is a packaged system consisting of a single very high pressure gaseous feed through a pressure reducing manifold to supply hydrogen gas to the main generator for generator cooling and the demineralized water transfer and storage system to support removal of dissolved oxygen. The low-pressure hydrogen system is a single system common to both units and is located in the gas storage area in the yard.

A separate high-pressure hydrogen packaged system supplies hydrogen to the chemical and volume control to support removal of dissolved oxygen in the RCS. The hydrogen for this system is stored as a compressed gas in high-pressure tanks (gas bottles). The high-pressure hydrogen supply package system is located outdoors adjacent to the turbine building.

The gas storage area in the yard is located a sufficient distance away from safety-related structures, systems, and components that they are protected from the effects of explosion, flammable vapor cloud, and fire. The gas storage area is located a sufficient distance away from the air inlet to the control room so that the control room operators are protected from potential toxic effects and asphyxiation. The location of the gas storage area is between the CWS cooling towers near the main drainage ditch. This location is outside the protected area and at least 600 feet from any safety-related SSC.

The carbon dioxide portion of the plant gas system, which is a packaged system consisting of one liquid storage tank and a vaporizer, produces gaseous carbon dioxide to purge the main generator. This packaged system is located in the gas storage area in the yard.

Liquid gas storage tanks are built in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, 1998 Edition, 2000 Addenda (Reference 2).

9.3.2.2.2 Component Description

Gaseous Nitrogen Storage Tanks

Gaseous nitrogen storage tanks are provided. These storage tanks provide storage for high-pressure nitrogen.

Gaseous Hydrogen Storage Tanks

Gaseous hydrogen storage tanks are used to provide for storage of high-pressure hydrogen.

Liquid Carbon Dioxide Storage Tank

Cryogenic liquid carbon dioxide is stored in an insulated single wall tank to minimize heat transfer.

Carbon Dioxide Electric Vaporizer

The liquid carbon dioxide is vaporized using electric resistance heating.

9.3.2.2.3 System Operation

Nitrogen or hydrogen is supplied from a high-pressure gaseous storage tank to a distribution header which leads to the end-use devices. The gas storage tanks are either permanently mounted or a trailer mounted tank(s) supplied by a third party. From the storage tanks, the gas is then directed to a pressure regulator and then a distribution header. Relief valves are used to prevent overpressure of the distribution header. Each unit has an individual gas supply line for each gas type and pressure which travels through an underground pipe to the turbine building. From the turbine building the in-plant piping distribute the gases to the various end-use devices. If required, the gas pressure is further regulated at the end-use devices.

See Subsection 9.3.6 for further discussion of hydrogen use in the chemical and volume control system. The hydrogen used in the chemical and volume control system is supplied from the high-pressure gaseous hydrogen storage tanks.

Liquid carbon dioxide is distributed from a cryogenic storage vessel. An electric vaporizer turns the liquid to a gas. From the vaporizer the gas is then directed to a pressure regulator and then a distribution header. A relief valve is used to prevent overpressure of the distribution header for both units. Each unit has an individual gas supply line which travels through an underground pipe to the turbine building.

9.3.2.3 Safety Evaluation

The plant gas system is required for normal plant operation and startup of the plant. The plant gas system is not required for safe shutdown of the plant. Therefore, it is not designed to meet seismic Category I requirements or single failure criterion. The plant gas system serves no safety-related function and has no safety design basis.

The nitrogen, the carbon dioxide, and the hydrogen system storage is located outside of the main buildings. The storage tanks are analyzed as a potential missile source. Refer to Section 3.5.

Accidents involving accidental detonations of hydrogen from the onsite storage of compressed or liquid hydrogen are evaluated for damage to safety–related structures, systems, and components. Refer to Section 2.2. For explosions, the plant gas system is designed for conformance with Regulatory Guide 1.91.

The effects of the plant gas system on main control room habitability are addressed in Section 6.4. The main control room habitability evaluation considers the flammability and asphyxiation potential for these gases. The AP1000 design assumed liquid storage of the bulk gases. Gaseous storage of the equivalent mass results in an overall lower hazard due to the slower release rates of a gas compared to liquid for the same diameter opening.

9.3.2.4 Tests and Inspections

9.3.2.4.1 Storage Vessel Testing

- Each storage vessel is hydrostatically tested in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, 1998 (Reference 3).
- Each vessel is examined using the magnetic particle method.

9.3.2.5 Instrumentation Requirements

Low-level indication alarms are provided in the main control room.

Pressure indications are provided at various points within the plant gas system.

9.3.3 Primary Sampling System

The AP1000 primary sampling system (PSS) performs the following functions:

- Collects in normal operation mode both liquid and gaseous samples
- Provides for local grab samples during normal operation mode

This system includes equipment to collect representative samples of the various process fluids, including reactor coolant system and containment air, in a manner that adheres to as-low-as-reasonably-achievable (ALARA) principles during normal and post-accident conditions.

The primary sampling system also includes provisions to route sample flow to a laboratory for continuous or intermittent sample analysis, as desired.

The primary sampling system provides a way to monitor the plant and various system conditions using the collected and analyzed samples.

A nonsafety-related containment hydrogen analyzer provided to monitor the containment atmosphere following a postulated loss-of-coolant accident (LOCA) is described in Subsection 6.2.4. A discussion of process radiation monitoring is provided in Section 11.5.

9.3.3.1 Design Bases

9.3.3.1.1 Safety Design Basis

The primary sampling system has no safety-related function, other than containment isolation and therefore requires no nuclear safety evaluation, other than containment isolation, which is described in Subsection 6.2.3.

The equipment and seismic classification are discussed in Section 3.2.

9.3.3.1.2 Power Generation Design Basis

9.3.3.1.2.1 Sampling During Normal Plant Operations

During normal operation, the primary sampling system collects representative samples of fluids in the reactor coolant system (RCS) and auxiliary primary systems process streams and the containment atmosphere for analysis, as listed in Table 9.3.3-1. Local sample points, as listed in Table 9.3.3-2, are provided at various process points of the systems.

The results of the sample analyses are used to perform the following functions:

- Monitor core reactivity
- Monitor fuel rod integrity
- Evaluate ion exchanger (demineralizer) and filter performance
- Specify chemical additions to the various systems;
- Maintain acceptable hydrogen levels in the reactor coolant system
- Detect radioactive material leakage

The measurements are used to evaluate water chemistry and to recommend corrective action by the laboratory staff.

The primary sampling system component classification is provided in Section 3.2.

9.3.3.1.2.2 Post-Accident Sampling

The primary sampling system does not include specific post-accident sampling capability. However, in accordance with Reference 5 there are contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere. These plans include the procedures to analyze, during the later stages of accident response, reactor coolant for boron, containment atmosphere for hydrogen and fission products, and containment sump water for pH.

The primary means of containment atmosphere hydrogen analysis is the hydrogen analyzer described in Subsection 6.2.4, which is not part of the post-accident sampling capabilities.

9.3.3.2 System Description

The primary sampling system is a manually operated system. It collects representative samples of fluids from the reactor coolant system and various primary auxiliary system process streams for analysis by the plant operating staff. This sampling process is performed during normal plant operations.

The primary sampling system consists of two separate portions: the liquid sampling portion and the gas sampling portion.

9.3.3.2.1 Nuclear Sampling System - Liquids

The liquid sampling portion of the primary sampling system collects samples from the reactor coolant system and the auxiliary systems and transports them to a common location in a sample room in the auxiliary building. Control and instrumentation is provided for safe, reliable operation. This portion of the system uses 1/4 inch stainless steel tubing. The small tubing flow area limits flow to less than chemical and volume control system makeup capacity in the event of a leak in the sampling lines. Dissolved gases in the reactor coolant system are collected in this system also.

Sample flow is routed to a grab sampling unit. This unit is in an enclosure, which controls the spread of contamination and provides shielding. The grab sampling unit is further shielded by a concrete wall to minimize radiation exposure.

Valves inside the grab sampling unit have long handles extending outside the enclosure and are manually operated. This arrangement allows the operator to obtain a sample quickly with minimum radiation exposure. A schematic diagram is provided on the front of the grab sampling unit to illustrate the tube routing inside.

Since the motive force during normal operations is the system pressure, the sampling system is designed to reactor coolant system pressure. If system pressure is not available, an eductor supplies the motive force for sample collection.

A direct line from the grab sampling unit to the laboratory provides the capability for continuous liquid sampling and analysis with online monitors.

Prior to the collection of liquid samples either in the laboratory or in the grab sampling unit, the lines are purged with source liquid to provide representative samples. The purging flow returns to the effluent holdup tank of the liquid radwaste system.

Figure 9.3.3-1 is a simplified sketch of the primary sampling system.

9.3.3.2.2 Nuclear Sampling System - Gaseous

This portion of the primary sampling system collects gaseous samples from the containment atmosphere. Gaseous sampling is conducted in the sample room in the auxiliary building, and it shares with the liquid sampling portion the grab sampling unit and the control panel. Similar to the liquid sampling system, the gas sample subsystem is also manually operated with extension stems on the valves and uses stainless steel tubing. Only grab samples are collected for the gas sampling process. The lines are purged prior to sample collection to provide representative samples. The purged gas returns to the containment sump.

Provisions are also made to dilute the gas sample. The dilution process uses nitrogen from a local gas bottle.

The gas sampling system uses an ejector as the motive force for sample collection. The ejector uses nitrogen from a local gas bottle as the motive force.

9.3.3.3 Containment Isolation Valves

Containment isolation valves are classified as Safety Class B. The lines penetrating the reactor containment meet the containment isolation criteria. See Subsection 6.2.3.

Four lines penetrate the containment. Two lines carry the liquid samples from their sources to the grab sampling unit or the laboratory. The third line carries the containment air samples from their

source to the sampling unit. The fourth line returns the liquid or containment air sampling flows to the containment sump. The valves fail closed.

These valves close on a containment isolation signal. In addition, the outside containment isolation valves in the liquid sampling paths close on a high sampling flow temperature, or high radiation or high pressure downstream of the sample coolers. This prevents the operator from working with high temperature fluid and minimizes the possibility of operator injury.

9.3.3.4 System Operation and Performance

The primary sampling system is manually operated. The tubing size and sampling flow rate are selected throughout the system to reduce the amount of purge flow and to provide turbulent sampling flow (to collect representative samples). A delay coil of tubing is installed inside containment to provide at least 60 seconds of transit time for the sampling fluid to exit the containment from the hot leg. This 60-second delay is needed for N-16 decay.

9.3.3.5 Design Evaluation

The primary sampling system has no safety function, other than containment isolation and therefore requires no nuclear safety evaluation, other than containment isolation.

Subsection 6.2.3 provides the safety evaluation for the containment isolation system. Primary sampling system lines penetrating the containment are isolated at the containment boundary by valves that close upon receipt of a containment isolation signal and by manual actuation. (See Subsection 6.2.3 for a discussion of containment isolation.)

The primary sampling system connects to the reactor coolant system and the passive core cooling system (PXS) and therefore provides features consistent with ANSI standards and ASME codes to protect these system pressure boundaries.

The primary sampling system is not required for accident mitigation or post-accident sampling; but there are plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere in accordance with Reference 5.

The acceptability of the design of the primary sampling system is based on specific general design criteria and regulatory guides. The design of the primary sampling system is consistent with the criteria set forth in Subsection 9.3.2, "Process and Post-Accident Sampling Systems," of the NRC's Standard Review Plan (Reference 6) as modified by Reference 5. The specific general design criteria identified in the Standard Review Plan are General Design Criteria 1, 2, 13, 14, 26, 41, 60, 63, and 64. See Section 1.9 for a discussion of regulatory compliance.

9.3.3.6 Inspection and Testing Requirements

9.3.3.6.1 Preoperational Testing

Preoperational testing is performed after installation and prior to plant startup. Proper operation of the primary sampling system is demonstrated during preoperational testing. A sample is drawn from the reactor coolant system, containment atmosphere and other sample points via the sampling system in order to verify proper system operation.

9.3.3.6.2 Operational Testing

The proper operation and availability of the liquid and gaseous sampling subsystems are proven by continued proper sampling operations.

9.3.3.7 Instrumentation Requirements

The primary sampling system uses indicators as required to facilitate manual operation and to verify sample conditions before samples are drawn. Radiation monitoring instruments are used to monitor the incoming fluid (liquid or gas) radioactivity level.

The temperature and pressure indicators inside the grab sampling unit provide a signal to close the respective outside containment isolation valve when the sampling flow temperature or pressure exceeds pre-set limits. Likewise, the radiation monitors also provide a signal to close the outside containment isolation valves when excessive radiation levels are detected, for operator protection.

9.3.4 Secondary Sampling System

The secondary sampling system (SSS) delivers representative samples of fluids from secondary systems to sample analyzer packages. Continuous or semi-continuous online secondary chemistry monitoring detects impurity ingress and provides early diagnosis of system chemistry excursions in the plant. Secondary sampling monitors send control signals to the turbine island chemical feed system that automatically injects corrosion control chemicals into the condensate and feedwater systems.

9.3.4.1 Design Basis

9.3.4.1.1 Safety Design Basis

The secondary sampling system serves no safety-related function and therefore has no nuclear safety design basis.

9.3.4.1.2 Power Generation Design Basis

The secondary sampling system monitors water samples from the condensate, feedwater, main steam, heater drain, steam generator blowdown, auxiliary steam supply, and condensate polishing systems, as listed in Table 9.3.4-1 and Table 9.3.4-2. Water quality analyses are performed on these samples to determine the following:

- pH
- Conductivity levels (specific and cation)
- Dissolved oxygen level
- Residual oxygen scavenger
- Sodium content

The sample analyses are used to control water chemistry and to permit appropriate corrective action.

9.3.4.2 System Description

Classification of equipment and components for the secondary sampling system is given in Section 3.2. The sample points listed in Table 9.3.4-1 are continuously or semi-continuously monitored. The sample points listed in Table 9.3.4-2 are selectively monitored (where a single analyzer package can be used to selectively monitor multiple sample points).

Sample analysis data from the continuous and semi-continuous analyzers is recorded using computer systems that also provide trending capability of the measured process parameters. Measurements are used to automatically control condensate and feedwater system pH and dissolved oxygen levels by chemical addition. Refer to Subsection 10.4.11 for further discussion of the turbine island chemical feed system.

Samples are analyzed and the results are used for automatic or manual control of the plant secondary water chemistry. After being analyzed, pure samples are returned to the condensate system. Sample lines containing reagents and those from sink drains are collected in the waste water system and processed for disposal. Each sample line has a grab sampling capability for laboratory analysis.

Roughing coolers are provided for the samples whose temperatures exceed 125°F. Samples are cooled to approximately 77°F by chilled water supplied to trim coolers.

9.3.4.3 Safety Evaluation

The secondary sampling system has no safety-related function and therefore requires no nuclear safety evaluation.

9.3.4.4 Tests and Inspections

Proper operation of the secondary sampling system is initially demonstrated during preoperational testing.

The system draws continuous, semi-continuous, and selective samples from the condensate, feedwater, main steam, and steam generator blowdown systems for automatic or manual water quality analysis. Calibration of the analyzers is checked periodically through laboratory analysis of a grab sample from the same process flow. The output of the continuous and semi-continuous analyzers is recorded, and abnormal values are evaluated.

9.3.4.5 Instrumentation Applications

The secondary sampling system uses pressure, temperature, and flow indicators to facilitate operation and to verify sample conditions.

9.3.5 Equipment and Floor Drainage Systems

The equipment and floor drainage systems collect liquid wastes from equipment and floor drains during normal operation, startup, shutdown, and refueling. The liquid wastes are then transferred to appropriate processing and disposal systems.

Equipment and floor drainage is segregated according to the type of waste. Liquid wastes are classified and segregated for collection as follows:

- Radioactive liquid waste
- Nonradioactive liquid waste
- Chemical and detergent liquid waste
- Oily liquid waste

9.3.5.1 Design Basis

9.3.5.1.1 Safety Design Basis

The equipment and floor drainage systems are nonsafety-related and serve no safety-related function except for the backflow preventers in drain lines from containment cavities to the containment sump. No nuclear safety design basis is required except for the backflow preventers described in Section 11.2. Single active failures do not prevent the proper function of the safety-related backflow preventers.

The floor drainage systems and equipment are designed to prevent damage to safety-related systems, structures, and equipment. Safety-related components are not damaged as a result of equipment and floor drain components failure from a seismic event. Floor drainage systems and equipment single failures will not prevent the proper function of any safety-related equipment.

9.3.5.1.2 Power Generation Design Basis

Nonradioactive liquid waste sumps and drain tanks that can be potentially radioactive during normal plant operation are provided with sampling capabilities. There are no permanent connections between the radioactive drain system and nonradioactive piping. Provisions for temporary diversion of contaminated water from normally nonradioactive drains to the liquid radwaste system are included.

Equipment drains are adequately sized to meet the flow requirements.

Radioactive sump vents are directed to the ventilation system exhaust ducts, serving the areas where the sump is located. The containment sump vents directly to the containment.

Drainage systems are drained by gravity. The slope of the drain lines is 1/8 inch per foot as a minimum except for the embedded drain piping for areas 1 and 2 of the auxiliary building, elevation 66'-6". At this level, the slope of the drain lines is 1/16 inch per foot minimum. Exceptions are also provided for through-wall penetrations, which can remain horizontal provided that lines are sloped in the direction of drainage to and from the wall penetration. A short section of piping past each end of the wall penetration may be horizontal to accommodate piping fabrication limitations to transition from sloped and horizontal sections. Radioactive drain systems shall have no negative sloping sections except for WRS lines between the annex and auxiliary buildings provided it does not affect system capability to drain as intended, does not affect radiation zoning, and does not increase radiation exposure to plant personnel above the evaluated dose. Nonradioactive drain systems may contain short sections sloping less than 1/8 inch per foot provided it does not affect system capability to drain as intended. The drainage systems are designed not to compromise the integrity of the areas maintained under a slight negative pressure during normal plant operation. This is achieved by avoiding cross connection with adjacent areas that are not maintained under a slight negative pressure.

Radioactive drain systems are designed to avoid crud traps and to minimize drain traps.

Sump and drain tank pumps discharge at a flowrate adequate to prevent sump overflow for drain rates anticipated during normal plant operation, maintenance, decontamination, fire suppression system testing, and fire fighting activities. The containment sump pumping time between high and low level is approximately 1 minute. The auxiliary building radiologically controlled area sump has a pumping time of approximately 8 minutes between high and low level. The waste water system sumps provide a live storage capacity consistent with a quantity of fluid equal to 10 minutes generated from normal anticipated fluid flow.

Plugging of the drain headers is minimized by designing them large enough to accommodate more than the design flow and by making the flow path as straight as possible. Drain headers are at least 4 inches in diameter.

9.3.5.2 System Description

9.3.5.2.1 General Description

The drainage systems include collection piping, equipment drains, floor drains, vents, traps, cleanouts, sampling connections, valves, collection sumps, drain tanks, pumps, and discharge piping. The general arrangement of the drainage systems is shown on Figure 9.3.5-1.

Radioactive Wastes

The radioactive waste drain system is arranged to receive inputs from the radiologically controlled areas of the auxiliary, annex, and radwaste buildings based on segregation of the liquid wastes into chemical and nonchemical drains. The radioactive waste drain system collects radioactive liquid wastes at atmospheric pressure from equipment and floor drainage of the radioactive portions of the auxiliary building, annex building, and radwaste building and directs these wastes to a centrally located sump located in the auxiliary building. The contents of the sump are pumped to the liquid radwaste system tanks. Drainage lines from the negative pressure boundary areas of the auxiliary, radwaste, and annex buildings do not terminate outside the negative pressure boundary without a normally closed valve or plugged drain to maintain the integrity of the negative pressure boundary.

The liquid radwaste system collects radioactive and borated liquid wastes from equipment and floor drains in containment. Waste from the equipment drains inside containment is drained to the reactor coolant drain tank. The liquid waste from floor drains, fan coolers, and the containment wall gutter inside containment is drained to the containment sump. The contents of the drain tank and sump are pumped out of containment for processing by the liquid radwaste system. Refer to Section 11.2 for further details.

The sumps, pumps, and associated valves for the drain systems are located outside of high-radiation areas to the extent practical.

Nonradioactive and Potentially Radioactive Waste Drains

The waste water system collects nonradioactive waste from floor and equipment drains in auxiliary, annex, turbine, and diesel generator building sumps or tanks. Selected normally nonradioactive liquid waste sumps and tanks are monitored for radioactivity to determine whether the liquid wastes have been inadvertently contaminated. If contaminated, the wastes are diverted to the liquid radwaste system for processing and ultimate disposal. Refer to Subsection 9.2.9 for further details. Drainage lines from the positive pressure boundary areas of the auxiliary building do not terminate outside the positive pressure boundary without a closed valve, plugged drain, or water seal to maintain the integrity of the positive pressure boundary.

Chemical Waste Drains

The radioactive waste drain system collects chemical wastes from the auxiliary building chemical laboratory and decontamination solution drains from the annex building and directs these wastes to the chemical waste tank of the liquid radwaste system.

Detergent Waste Drains

The laundry and respirator cleaning functions that generate detergent wastes are performed offsite. Detergent wastes from hot sinks and showers are routed to the chemical waste tank.

Oily Waste Drains

The waste water system collects nonradioactive, oily, liquid waste in drain tanks and sumps. Drain tank and sump liquid wastes are pumped through an oil separator prior to further processing. The oil is collected in a tank for disposal.

Sampling for oil in the waste holdup tank of the liquid radwaste system is provided to detect oil contamination before the ion exchanger resins are damaged. Oily water is pumped from the tank through an oil adsorbing bag filter before further processing. The spent bag filters are transferred to drums and stored in the radwaste building as described in Section 11.4.

9.3.5.2.2 Component Description

General description and summaries of the design requirements for these components are provided below. Key equipment parameters are contained in Tables 9.3.5-1 and 11.2-2. Principal construction codes and standards and the classification applicable to the floor and equipment drainage systems are listed in Section 3.2.

Sumps and Drain Tanks

In general, the inlet drain lines to the sump or drain tank are kept submerged a minimum of 6 inches below pump shutoff level to prevent backgassing. The containment sump inlet is submerged.

Sumps are covered to keep out debris. Covers are removable, or manholes are provided for access. The total capacity of each sump includes a 10 percent freeboard allowance to permit operation of high-high level alarms and associated controls before the overflow point is reached.

Each sump is fitted with a vent connection to exhaust potential sump gases. Nonradioactive drain tanks are vented to the atmosphere. The reactor coolant drain tank is vented to the gaseous radwaste system (Section 11.3). Where necessary for the control of airborne radioactivity, the sump vents are routed to the ventilation system exhaust duct for the room.

Radioactive sumps are stainless steel construction. Nonradioactive collection sumps are constructed of concrete with corrosion resistant coating or liner.

Sump and Drain Tank Pumps

Sumps outside containment are provided with air diaphragm pumps mounted on the sump cover plate. Pumps are equipped with reliable, mechanical diaphragms of demonstrated acceptable design that are easy to maintain. Pumps and associated piping connections and accessories are designed for easy replacement of pump diaphragms. The containment sump pumps are described in Section 11.2. The turbine building sump pumps are described in Subsection 9.2.9.

Valves

Solenoid valves are provided for on/off functions of air supply to the sump pump diaphragms of the radioactive waste drain system and waste water system. Swing check valves, where provided, are installed in horizontal pipe runs. Installation of swing check valves in vertical pipe runs is acceptable provided the flow is up, and the valve is designed such that the center of gravity of the disc causes the disc to close upon loss of flow. Pressure control valves are provided to control air supply pressure to the sump pump diaphragms. Manual ball valves are provided for maintenance purposes.

9.3.5.2.3 System Operation

The equipment and floor drainage systems operate during all modes of normal plant operation. Liquid wastes drain by gravity to collection tanks or sumps. Drainage flowrates vary based on the status of the plant. Sump pumps disposing of collected radioactive wastes discharge to the liquid radwaste system for further processing. Nonradioactive liquid wastes are discharged to the waste water system.

Pump operation is automatic with manual override. The pumps are automatically started and stopped by preset high, high-high, and low level instrumentation.

Where sumps are provided with two pumps, the capability is provided to allow equalizing the operational period of each pump. For the radioactive waste drain system, recirculation of the sump contents is performed through a mixing eductor.

The sump and drain tank pumps are not required to operate during design basis accidents. Sump pumps in the containment are interlocked with the associated containment isolation valves. The pumps trip and the isolation valves close on receipt of containment isolation signals (see Subsection 6.2.3).

The equipment and floor drainage systems can be operated either automatically or manually for cleanup following an accident, including fire, provided that the compressed and instrument air system and ac power are available, and the drainage systems and support systems are not disabled by the event.

9.3.5.2.4 Instrumentation Applications

Level indication is provided in the main control room for the sump in-containment to provide indication of the presence of reactor coolant from unidentified leaks (refer to Subsection 5.2.5). The sump and the drain tank outside containment are monitored for water level. On high sump or tank level, the solenoid-operated three-way valve for the selected pump is energized to admit air to the pump diaphragm. On high-high sump or tank level, the solenoid-operated three-way valve for the remaining pump is also energized to admit air to that pump diaphragm. On low level, both pumps are stopped by deenergizing their respective solenoid valves. Operating status of the pumps is provided to the plant control system.

9.3.5.3 Safety Evaluation

The equipment and floor drainage systems are nonsafety-related except for backflow preventers in drain lines from containment cavities to the containment sump. No nuclear safety evaluation is required other than that described for the backflow preventers in Section 11.2.

9.3.5.4 Tests and Inspections

The operability of equipment and floor drainage systems dependent upon gravity flow can be checked by normal usage. Portions of these systems dependent upon pumps to discharge to interfacing systems may be checked through instrumentation and alarms via the plant control system and trouble alarms in the main control room during operation or test.

9.3.6 Chemical and Volume Control System

The chemical and volume control system is designed to perform the following major functions:

- **Purification** - maintain reactor coolant system fluid purity and activity level within acceptable limits.

- **Reactor coolant system inventory control and makeup** - maintain the required coolant inventory in the reactor coolant system; maintain the programmed pressurizer water level during normal plant operations.

- **Chemical shim and chemical control** - maintain the reactor coolant chemistry conditions by controlling the concentration of boron in the coolant for plant startups, normal dilution to compensate for fuel depletion and shutdown boration, and provide the means for controlling the reactor coolant system pH by maintaining the proper level of lithium hydroxide.

- **Oxygen control** - provide the means for maintaining the proper level of dissolved hydrogen in the reactor coolant during power operation and for achieving the proper oxygen level prior to startup after each shutdown.

- **Filling and pressure testing the reactor coolant system** - provide the means for filling and pressure testing the reactor coolant system. The chemical and volume control system does not perform hydrostatic testing of the reactor coolant system, which is only required prior to initial startup and after major, nonroutine maintenance, but provides connections for a temporary hydrostatic test pump.

- **Borated makeup to auxiliary equipment** - provide makeup water to the primary side systems that require borated reactor grade water.

- **Pressurizer Auxiliary Spray** - provide pressurizer auxiliary spray water for depressurization.

9.3.6.1 Design Bases

9.3.6.1.1 Safety Design Basis

The safety functions provided by the chemical and volume control system are limited to containment isolation of chemical and volume control system lines penetrating containment, termination of inadvertent reactor coolant system boron dilution, isolation of makeup on a steam generator High-3 or pressurizer High-2 level signal, and preservation of the reactor coolant system pressure boundary, including isolation of normal chemical and volume control system letdown from the reactor coolant system.

9.3.6.1.2 Power Generation Design Basis

The principal functions of the chemical and volume control system are outlined above and include controlling reactor coolant system chemistry, purity, and inventory. The system provides some functions necessary for the continued normal operation of the plant. Reliability is achieved by the use of redundant equipment (pumps, filters, and demineralizers). The equipment classification for the chemical and volume control system is contained in Section 3.2.

9.3.6.1.2.1 Purification

The chemical and volume control system removes radioactive corrosion products, ionic fission products, and fission gases from the reactor coolant system to maintain low reactor coolant system activity levels. The chemical and volume control system purification capability considers occupational radiation exposure (ORE) to support ALARA goals.

The chemical and volume control system is designed to maintain the reactor coolant system activity level at less than the technical specification limit for normal operations, with design basis fuel defects. The technical specifications allow these limits to be exceeded for a specified duration.

The purification rate is based on minimizing occupational radiation exposure and providing access to the reactor coolant system equipment. The chemical and volume control system provides a reactor coolant system purification rate of at least one reactor coolant system mass per 16 hours.

The chemical and volume control system has sufficient reactor coolant system purification and degasification capability (in conjunction with the liquid radwaste system) to allow the reactor vessel head to be removed in a timely manner during a refueling shutdown. In addition, purification during shutdowns has positive impact on the occupational radiation exposure to workers during the outage.

The chemical and volume control system supports the plant ALARA goals with the shutdown purification function.

9.3.6.1.2.2 Reactor Coolant System Inventory Control and Makeup

The chemical and volume control system provides a means to add and remove mass from the reactor coolant system, as required, to maintain the programmed inventory during normal plant operations. Operations that are accommodated include startup, shutdown, step load changes, and ramp load changes.

The chemical and volume control system is capable of maintaining a constant volume in the reactor coolant system while the plant is being heated up or cooled down. During a heatup it is necessary to remove reactor coolant system mass due to expansion. The maximum rate of net expansion occurs at the end of the heatup, so the limiting case is based on controlling the pressurizer level during this phase of operation. This expansion is accommodated by the normal letdown path. During cooldown, it is necessary to add mass due to reactor coolant system shrinkage. The chemical and volume control system is capable of maintaining the minimum pressurizer level with makeup during cooldown from hot zero power to cold shutdown while maintaining normal purification flow. Ramp and step load changes, as well as load rejections, are accommodated by the reactor coolant system pressurizer level control system. The chemical and volume control system can function to accommodate normal pressurizer level control system makeup and letdown requirements.

The chemical and volume control system is designed to make up for leaks, including leaks up to 3/8-inch inside diameter and for anticipated steam generator tube leaks, allowing the plant to be taken to cold shutdown conditions without the use of safety-related makeup systems.

9.3.6.1.2.3 Chemical Shim and Chemical Control

The chemical and volume control system provides the means to vary the boron concentration in the reactor coolant system. The system also controls the reactor coolant system chemistry for the purpose of limiting corrosion and enhancing core heat transfer.

Chemical Shim

The concentration of boron in the reactor coolant system is changed, as required, to maintain the desired control rod position with core depletion. The chemical and volume control system has the capacity to accommodate a cold shutdown followed by a return to power at the end of core life and also (as an independent case) to borate the plant to cold shutdown immediately following return to power from refueling. The system has boration and dilution capacity to meet these requirements, as well as the capability to transfer effluents to other systems.

The chemical and volume control system boric acid solutions are stored at concentrations that do not require heat tracing or room temperatures above normal values. The 2.5 weight percent boric acid solution requires freeze protection but does not impose special ambient temperature requirements.

pH Control

Lithium hydroxide (Li7OH) is used to control the pH of the reactor coolant system. The required concentration of Li7OH is varied to minimize the formation of tritium.

9.3.6.1.2.4 Oxygen Control

The chemical and volume control system maintains the proper conditions in the reactor coolant system to minimize corrosion of the fuel and primary surfaces. During power operations, dissolved hydrogen is added to the reactor coolant system to eliminate free oxygen and to prevent ammonia

formation. The chemical and volume control system is capable of maintaining the concentration of dissolved hydrogen in the reactor coolant system at a minimum of 25 cubic centimeters hydrogen, at standard temperature and pressure, per kilogram of coolant, assuming anticipated operating losses.

This concentration can be reduced to 15 cc/kg within 24 hours prior to shutdown. Prior to opening the reactor coolant system during a cold or refueling shutdown, the hydrogen concentration is reduced to approximately 5 cubic centimeters per kilogram. To prevent delays, the chemical and volume control system (in conjunction with the liquid radwaste system) is capable of making this 15 to 5 cubic centimeters per kilogram reduction within the time to achieve normal plant cooldown.

During plant startup from cold shutdown, the chemical and volume control system introduces an oxygen scavenger into the reactor coolant system. The solution is only used for oxygen control at low reactor coolant system temperatures during startup from cold shutdown conditions. At other times during plant operation, hydrogen is used for oxygen control.

During plant startup, the chemical and volume control system will be in demineralizer bypass mode; during which time, valve CVS-PL-V062 will be “open” allowing flow to be diverted through line CVS-PL-L065 instead of through the demineralizer to avoid any negative impacts on demineralizer resin performance by contact with hydrazine.

9.3.6.1.2.5 Filling and Pressure Testing the Reactor Coolant System

The chemical and volume control system provides a means for filling and pressure testing the reactor coolant system. The chemical and volume control system also provides connections for a temporary hydrostatic test pump.

9.3.6.1.2.6 Borated Makeup

The chemical and volume control system provides makeup to the passive core cooling system accumulators, core makeup tanks, in-containment refueling water storage tank, and to the spent fuel pool at various boron concentrations.

9.3.6.2 System Description

The chemical and volume control system consists of regenerative and letdown heat exchangers, demineralizers and filters, makeup pumps, tanks, and associated valves, piping, and instrumentation. The system parameters are given in Table 9.3.6-1. The piping and instrumentation diagram for the chemical and volume control system is included as Figure 9.3.6-1.

9.3.6.2.1 Purification

9.3.6.2.1.1 Ionic Purification

The normal chemical and volume control system purification loop is inside containment and operates at reactor coolant system pressure, utilizing the developed head of the reactor coolant pumps as the motive force for the purification flow. During power operations, fluid is continuously circulated through the chemical and volume control system from the discharge of one of the reactor coolant pumps. It passes through the regenerative heat exchanger where it is cooled by the returning chemical and volume control system flow, and is further cooled by component cooling water in the letdown heat exchanger to a temperature compatible with the demineralizer resins. The purification fluid flows through a mixed bed demineralizer, optionally through a cation bed demineralizer, and through a filter. It returns to the suction of a reactor coolant pump after being heated in the regenerative heat exchanger. The purification loop operates at reactor coolant system pressure.

Since the motive force for the purification loop is the reactor coolant pump head in a closed loop with the reactor coolant system, continuous purification is provided without operating the chemical and volume control system makeup pumps.

The mixed bed demineralizers are provided in the purification loop to remove ionic corrosion products and certain ionic fission products; they also remove zinc during periods of zinc addition. The demineralizers also act as filters. One mixed bed is normally in service, with a second demineralizer acting as backup in case the normal unit should become exhausted during operation. Each demineralizer and filter is sized to provide a minimum of one fuel cycle of service without changeout.

The mixed bed demineralizer in service can be supplemented by intermittent use of the cation bed demineralizer for additional purification in the event of fuel defects. In this case, the cation resin removes mostly lithium and cesium isotopes. The cation bed demineralizer has sufficient capacity to maintain the cesium-136 concentration in the reactor coolant below 1.0 microcurie per cubic centimeter with design basis fuel defects. Each mixed bed and the cation bed demineralizer is sized to accept the maximum purification flow. Filters are provided downstream of the demineralizers to collect particulates and resin fines.

During plant shutdowns when the reactor coolant pumps are stopped, the normal residual heat removal system provides the motive force for the chemical and volume control system purification. Purification flow from the normal residual heat removal system heat exchanger is routed directly through the normal chemical and volume control system purification loop. Boron changes and dissolved gas control are still possible by operating the chemical and volume control system in a semiclosed loop arrangement.

9.3.6.2.1.2 Gaseous Purification

Removal of radiogases from the reactor coolant system are not normally necessary because the gases do not build up to unacceptable levels when fuel defects are within normally anticipated ranges. If radiogas removal is required because of high fuel defects, the chemical and volume control system can be operated by routing flow to the liquid radwaste system degassifier. In this configuration, the letdown fluid is depressurized by flowing through the letdown orifice. The letdown flow is routed outside of containment through the liquid radwaste system degassifier to one of the liquid radwaste system effluent holdup tanks, and then returned to the reactor coolant system with the chemical and volume control system makeup pumps. This provides efficient gas removal.

Removal of radioactive gas and hydrogen during shutdown operations is necessary to avoid extending the maintenance and refueling outages. The reactor coolant system pressure boundary cannot be opened to the containment atmosphere until the gas concentrations are reduced to low levels. The shutdown degassing process is accomplished by operating the chemical and volume control system in the open loop configuration. In addition, a line is provided to allow the letdown orifice to be manually bypassed, so gas removal can continue after the reactor coolant system has been depressurized.

9.3.6.2.2 Reactor Coolant System Inventory Control and Makeup

Changes in reactor coolant volume are accommodated by the pressurizer level program for normal power changes, including transition from hot standby to full-power operation and returning to hot standby. In addition, the pressurizer has sufficient volume, within the deadband of the level control program, to accommodate minor reactor coolant system leakage for some time. The chemical and volume control system provides inventory control to accommodate minor leakage from the reactor coolant system, expansion during heatup from cold shutdown, and contraction during cooldown. This inventory control is provided by letdown and makeup connections to the chemical and volume control system purification loop.

9.3.6.2.3 Chemical Shim and Chemical Control

The chemical and volume control system provides the following functions to support the water chemistry and chemical shim requirements of the reactor coolant system:

- Means of addition and removal of pH control chemicals for startup and normal operation.
- Means of addition and removal of soluble chemical neutron absorber (boron) and makeup water, at concentrations and rates compatible with normal plant operation.

Reactor coolant system chemistry changes are accomplished with a feed and bleed operation. The letdown and makeup paths are operated simultaneously and appropriate chemicals are provided at the suction of the reactor makeup pumps.

9.3.6.2.3.1 Chemical Shim

Reactor coolant system boron changes are required to compensate for fuel depletion, startups, shutdowns, and refueling.

To borate the reactor coolant system, the operator sets the reactor makeup control system to automatically add a preset amount of boric acid by fully diverting the three-way valve in the pump suction line to the boric acid storage tank, with delivered flow measured at the discharge of the makeup pumps. Dilution operates in a similar fashion. In either case, if the pressurizer level exceeds its control point, the letdown path to the liquid radwaste system holdup tanks is automatically opened.

Boric acid is provided to the boric acid storage tank by mixing 2.5 weight percent boric acid solution in the boric acid batching tank. Boric acid crystals are mixed with a mixer, while the mixture is heated to an appropriate temperature to provide efficient mixing by the batching tank immersion heater. After the boric acid crystals are dissolved, the solution is drained by gravity into the boric acid storage tank. No provisions are incorporated for boric acid recycle from the liquid radwaste system.

9.3.6.2.3.2 pH Control

The chemical agent used for pH control is lithium hydroxide (Li7OH). This chemical is chosen for its compatibility with the material and water chemistry of borated water, stainless steel, and zirconium systems. In addition, lithium-7 is produced in the core region because of irradiation of the dissolved boron in the coolant. A chemical mixing tank is provided to introduce the solution to the suction of the makeup pumps as required to maintain the proper concentration of Li7OH in the reactor coolant system.

The solution is poured into the chemical mixing tank and is then flushed to the suction manifold of the makeup pumps with demineralized water. A flow orifice is provided on the demineralized water inlet pipe to allow chemicals to be flushed into the reactor coolant system at acceptable concentrations.

The concentration of lithium-7 in the reactor coolant system varies according to a pH control curve as a function of the boric acid concentration of the reactor coolant system. If the concentration exceeds the proper value, as it may during the early stages of core life when lithium-7 is produced in the core at a relatively high rate, the cation bed demineralizer is used in the letdown path in series with the mixed bed demineralizer to lower the lithium-7 concentration. Since the buildup of lithium is slow, the cation bed demineralizer is used only intermittently. When letdown is being diverted to the liquid radwaste system, the purification flow is routed through the cation bed demineralizer for removal of as much lithium-7 and cesium as possible.

9.3.6.2.3.3 Zinc Addition

A soluble zinc compound may be added to the coolant as a means to reduce radiation fields within the primary system and to reduce the potential for crud-induced power shift (CIPS). The zinc used may be either natural zinc or zinc depleted of ^{64}Zn.

9.3.6.2.4 Oxygen Control

The chemical and volume control system provides control of the reactor coolant system oxygen concentration, both during startup by introducing an oxygen scavenger and during power operations by driving toward zero the equilibrium concentration of oxygen produced by radiolysis in the core by injecting hydrogen.

9.3.6.2.4.1 Startups

During plant startup from cold conditions, an oxygen scavenging agent is used. The oxygen scavenger solution is introduced into the reactor coolant system via the makeup flow and chemical mixing tank, in the same manner as described for lithium-7 addition. The oxygen scavenger is used for oxygen control only at startup from cold shutdown conditions.

During plant startup, the chemical and volume control system will be in demineralizer bypass mode; during which time, valve CVS-PL-V062 will be “open” allowing flow to be diverted through line CVS-PL-L065 instead of through the demineralizer to avoid any negative impacts on demineralizer resin performance by contact with hydrazine.

9.3.6.2.4.2 Power Operation

Dissolved hydrogen is employed during normal power operation to control and scavenge oxygen produced due to radiolysis of water in the core region. Hydrogen makeup is supplied to the reactor coolant system by direct injection of high-pressure gaseous hydrogen. The hydrogen comes from a bottle outside containment, through a containment penetration, and is mixed in the chemical and volume control system purification loop. Hydrogen removal from the reactor coolant system is not necessary because hydrogen is consumed in the core.

9.3.6.2.5 Reactor Coolant System Filling and Pressure Testing

Reactor coolant system filling is accomplished by using the chemical and volume control system makeup pumps to provide fluid at the proper boron concentration (refueling), taking suction from sources that are at or above the minimum shutdown margin boron concentration. If the reactor coolant system (RCS) is drained to a clean WLS effluent holdup tank, this drained volume can be returned by opening the line to the makeup pumps from that holdup tank and running one of the pumps.

The chemical and volume control system makeup pumps produce sufficient head to pressure test the reactor coolant system after maintenance and refueling.

A temporary hydrotest pump is required for initial hydrotesting, which requires higher pressures than can be achieved with the makeup pumps.

9.3.6.2.6 Borated Makeup

The makeup pumps are used to provide makeup at the proper boron concentration to the passive core cooling system accumulators, core makeup tanks, in-containment refueling water storage tank, and to the spent fuel pool. Makeup to these locations is at boric acid concentration as required, which

can be varied from 0 to 4375 (nominal) parts per million (2.5 weight percent). A mixture of 2.5 weight percent boric acid and demineralized water is provided by taking suction from both the boric acid storage tank and the demineralized water tank.

9.3.6.3 Component Descriptions

The general descriptions and summaries of the chemical and volume control system components are provided below. The key equipment parameters for the chemical and volume control system components are contained in Table 9.3.6-2. Information regarding component classifications is available in Section 3.2. See Section 5.2 for additional information on analysis requirements.

9.3.6.3.1 Chemical and Volume Control System Makeup Pumps

Two centrifugal makeup pumps are provided. These pumps are driven by ac motors, and flow is controlled by positioning a control valve in the common discharge line from the pumps. A cavitating venturi in the common discharge line limits the makeup flow and provides protection from excessive pump runout. Each pump has a recirculation loop with a heat exchanger and flow control orifice to provide adequate minimum flow for pump protection. The mini-flow heat exchanger is cooled by component cooling water.

The makeup pumps are arranged in parallel with common suction and discharge headers. Each provides full capability for normal makeup; thus, there is redundancy for normal operations. The normal makeup pump suction fluid comes from the boric acid storage tank and the demineralized water connection. A three-way valve in the suction header is positioned to provide a full range of concentrations.

One makeup pump is capable of maintaining normal reactor coolant system inventory with leaks up to a 3/8-inch inside diameter, without an actuation of the safety injection systems. The second pump can be manually started to provide additional reactor coolant makeup.

These pumps are used to pressure test the reactor coolant system.

Parts of the pump in contact with reactor coolant are constructed of austenitic stainless steel. The pump motor and lube oil are air-cooled.

9.3.6.3.2 Chemical and Volume Control System Heat Exchangers

Letdown Heat Exchanger

One single-shell pass U-tube letdown heat exchanger is provided. The heat exchanger is designed to cool the purification loop flow from the regenerative heat exchanger outlet temperature to the desired letdown temperature allowing the letdown to be processed by the demineralizers while maximizing the thermal efficiency of the chemical and volume control system.

The letdown heat exchanger outlet temperature is controlled by the operator by remotely positioning a component cooling system flow control valve.

The reactor coolant in the purification loop flows through the tubes, which are stainless steel, and component cooling water flows through the shell, which is carbon or stainless steel.

Makeup Pump Miniflow Heat Exchangers

Two miniflow heat exchangers are provided, one in each makeup pump miniflow recirculation line. Each heat exchanger is designed to cool the flow through the chemical and volume control system makeup pump minimum flow recirculation lines to the desired temperature for pump protection. The

makeup water flows through the tubes, which are stainless steel, and component cooling water flows through the shell, which is carbon or stainless steel.

Regenerative Heat Exchanger

One regenerative heat exchanger is provided. This heat exchanger is used to recover heat from the purification loop flow leaving the reactor coolant system by reheating the fluid entering the reactor coolant system. This provides increased thermal efficiency and also reduces thermal stresses on the reactor coolant system.

The design basis for this heat exchanger is the last hour of plant heatup, when expansion of the reactor coolant system requires a net removal of inventory. For this case the regenerative heat exchanger outlet temperature must be low enough to allow the letdown heat exchanger to cool the letdown to the desired temperature with anticipated cooling water temperatures.

The reactor coolant leaving the reactor coolant system flows through the tube side of this heat exchanger, and the returning fluid flows through the shell. This arrangement places the cleaner fluid on the shell side and the lower quality fluid on the tube side, where there are fewer crevices available for crud deposition.

9.3.6.3.3 Chemical and Volume Control System Tanks

Boric Acid Storage Tank

One boric acid storage tank is provided. The tank is sized to allow for one shutdown to cold shutdown followed by a shutdown for refueling at the end of the fuel cycle.

The tank is vented to the atmosphere. Relatively little boric acid is used during power operation, since load follow is accomplished with gray rods and without changes in the reactor coolant system boron concentration. Therefore, the boric acid which is injected has a negligible effect on the free oxygen level in the reactor coolant system.

The tank is a free-standing stainless steel cylindrical design, located outside of the buildings, with only normal freeze protection required to maintain solubility of the 2.5 weight percent boric acid.

Recirculation of the tank contents can also be performed to maintain a homogenous mixture of boric acid in the tank.

Boric Acid Batching Tank

The boric acid batching tank is a cylindrical tank with an immersion heater used in the preparation of 2.5 weight percent boric acid. A mixer is included with the tank. The tank is constructed of austenitic stainless steel and is provided with fill, vent and drain connections.

Chemical Mixing Tank

The chemical mixing tank is a small vertical, cylindrical tank sized to provide sufficient capacity for injecting an oxygen scavenger solution necessary to provide a concentration of ten parts per million in the cold reactor coolant system for oxygen scavenging.

A variety of chemicals to be added to the primary system are mixed in the tank. The solution to be injected is placed into the mixing tank and then flushed to the suction of the makeup pumps with demineralized water.

The tank is constructed of austenitic stainless steel and is provided with fill, vent, and drain connections.

9.3.6.3.4 Chemical and Volume Control System Demineralizers

Cation Bed Demineralizer

One cation resin bed demineralizer is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of lithium-7 (pH control) in the reactor coolant system. The demineralizer is sized to accommodate maximum purification flow when in service, which is adequate to control the lithium-7 and/or cesium concentration in the reactor coolant.

The demineralizer vessel is designed for reactor coolant system pressure and is constructed of austenitic stainless steel, with connections for resin addition, replacement, flushing, and draining. The vessel incorporates a retention screen and mesh screens on the drain connections. The screens are designed to retain the resin with minimum pressure drop. A flow diverter deflects the incoming flow to preserve a smooth resin bed.

Mixed Bed Demineralizers

Two mixed bed demineralizers are provided in the purification loop to maintain reactor coolant purity. Cation or anion resin, or a mixture of these resins, is used in each demineralizer. Both forms of resin remove fission and corrosion products. Each demineralizer is sized to accept the full purification flow during normal plant operation and to have a minimum design life of one core cycle.

The construction of the mixed bed demineralizers is identical to that of the cation bed demineralizer.

9.3.6.3.5 Chemical and Volume Control System Filters

Makeup Filter

One makeup filter is provided to collect particulates in the makeup stream, such as boric acid storage tank sediment. The filter is designed to accept maximum makeup flow. The makeup filter unit is constructed of austenitic stainless steel with a disposable synthetic cartridge and designed for the makeup pump design pressure listed in Table 9.3.6-2.

Reactor Coolant Filters

Two reactor coolant filters are provided. The filters are designed to collect resin fines and particulate matter from the purification stream. Each filter is designed to accept maximum purification flow.

The units are constructed of austenitic stainless steel with disposable synthetic cartridges. The design parameters for the filter are shown in Table 9.3.6-2.

9.3.6.3.6 Chemical and Volume Control System Letdown Orifice

One letdown orifice is provided in the letdown line, where fluid leaves the high-pressure purification loop before it exits containment. The orifice limits the letdown flow to a rate compatible with the chemical and volume control system equipment and also plant heatup and dilution requirements.

The orifice consists of an assembly that provides for permanent pressure loss without recovery and is made of austenitic stainless steel.

A manual bypass line is provided around the orifice to allow shutdown purification and degassing when the reactor coolant system pressure is low.

9.3.6.3.7 Chemical and Volume Control System Valves

The chemical and volume control system valves are stainless steel for compatibility with the borated reactor coolant. Isolation valves are provided at connections to the reactor coolant system. Lines penetrating the reactor containment meet the containment isolation criteria described in Subsection 6.2.3.

Purification Stop Valves

These normally open, motor-operated valves are located inside containment and close automatically on a low pressurizer level signal from the protection and safety monitoring system to preserve reactor coolant pressure boundary and to prevent uncovering of the heater elements in the pressurizer. The valves fail "as is" on loss of power and manual control (open/auto/close) is provided in the main control room and at the remote shutdown workstation.

Letdown Flow Inside Containment Isolation Valve

This normally closed, fail closed, air-operated globe valve is located inside containment and isolates letdown to the liquid radwaste system. This valve automatically opens and closes on a plant control system signal from the pressurizer level control or a containment isolation signal from the protection and safety monitoring system. It automatically opens on high pressurizer level and closes when the pressurizer level returns to normal. It also closes on a high-3 liquid radwaste system degassifier level or a containment isolation signal. This valve operator has a flow restricting orifice in the vent line so it closes more slowly than the letdown flow outside containment isolation valve. Manual control is also provided in the main control room and at the remote shutdown workstation.

Letdown Flow Outside Containment Isolation Valve

This normally closed, fail closed, air-operated globe valve is located outside containment and isolates letdown to the liquid radwaste system. This valve automatically opens and closes on a plant control system signal from the pressurizer level control system or automatically closes upon receipt of a containment isolation signal from the protection and safety monitoring system. This valve operates similar to the letdown flow inside containment isolation valve. The valve throttles during operations when there is letdown without makeup to provide sufficient flow to the shell side of the regenerative heat exchanger. The letdown flow outside containment isolation valve closes more quickly than inside containment letdown flow isolation valve to limit seat wear of inside containment isolation valve. This valve operator has a flow restricting orifice in the air line, so it opens more slowly than inside containment letdown flow isolation valve. In addition, during brief periods of shutdown, when the reactor coolant system is water solid, this valve throttles to maintain the reactor coolant system pressure. Manual control is also provided in the main control room and at the remote shutdown workstation.

Makeup Stop Valve

This normally open, air-operated stop check valve is located inside containment and functions to isolate the flow in the charging line to the reactor coolant system. This valve can be closed from the main control room or the remote shutdown workstation to isolate charging downstream of the regenerative heat exchanger. This valve is closed to support the auxiliary spray function. The valve fails open on loss of power or loss of instrument air so the charging line to the reactor coolant system remains available.

Auxiliary Spray Line Isolation Valve

This normally closed, air-operated globe valve is located inside containment, downstream of the regenerative heat exchanger, and functions to isolate the auxiliary spray line to the reactor coolant system pressurizer. This valve is opened to provide flow to the auxiliary spray line during heatups and cooldowns to add chemicals or to collapse the steam bubble in the pressurizer. This valve fails

closed on a loss of power or loss of instrument air to accomplish the function of preserving the reactor coolant pressure boundary. This valve closes automatically on a low-1 pressurizer level signal from the protection and safety monitoring system to preserve reactor coolant pressure boundary. This valve is operated from the main control room and the remote shutdown workstation.

Makeup Line Containment Isolation Valves

These normally open, motor-operated gate valves provide containment isolation of the chemical and volume control system makeup line and automatically close on a high-2 pressurizer level, High-3 steam generator level, or high-2 containment radiation signal from the protection and safety monitoring system. The valves close on a source range flux doubling signal to terminate possible unplanned boron dilution events. The valves also close on a safeguards actuation signal coincident with high-1 pressurizer level. This allows the chemical and volume control system to continue providing reactor coolant system makeup flow, if the makeup pumps are operating following a safeguards actuation signal. These valves are also controlled by the reactor makeup control system and close when makeup to other systems is provided. Manual control is provided in the main control room and at the remote shutdown workstation.

Hydrogen Addition Containment Isolation Valves

The outside reactor containment valve is a normally open, fail closed, air-operated globe valve, which provides containment isolation of the hydrogen addition line. The inside reactor containment valve is a check valve that supports containment isolation but has no control function. The air-operated valve automatically closes on a containment isolation signal from the protection and safety monitoring system. The air-operated valve also automatically closes on a low-1 pressurizer level signal from the protection and safety monitoring system to preserve the reactor coolant inventory and to prevent uncovering of the heater elements in the pressurizer. Manual control is provided in the main control room and at the remote shutdown workstation.

Zinc Addition Containment Isolation Valves

The normally open, fail closed, air-operated globe valves provide containment isolation of the zinc addition line. The valves automatically close on a containment isolation signal from the protection and safety monitoring system. The valves also automatically close on a low-1 pressurizer level signal from the protection and safety monitoring system to preserve the reactor coolant inventory and to prevent uncovering of the heater elements in the pressurizer. Manual control for both valves is provided in the main control room and at the remote shutdown workstation.

Demineralized Water System Isolation Valves

These normally open, air-operated butterfly valves are located outside containment in the line from the demineralized water storage and transfer system. These valves close on a signal from the protection and safety monitoring system derived by either a reactor trip signal, a source range flux doubling signal, or low input voltage (loss of ac power) to the 1E dc and uninterruptable power supply system battery chargers, isolating the demineralized water source to prevent inadvertent boron dilution events. The protection and safety monitoring system also issues a close signal to these valves when below the P-8 setpoint when the source range flux doubling signal is blocked to prevent inadvertent boron dilution. Manual control for these valves is provided from the main control room and at the remote shutdown workstation.

Makeup Pump Suction Header Valve

This air-operated, three-way valve is automatically controlled by the reactor makeup control system to provide the desired boric acid concentration of makeup to the reactor coolant system (boric acid, demineralized water, or blend based on the desired reactor coolant system boron concentration). The valve fails with the pump suction aligned to the boric acid storage tank on a loss of instrument air. This valve will also align to the boric acid storage tank on a signal from the protection and safety

monitoring system derived from a reactor trip, source range flux doubling, or low input voltage (loss of ac power) to the 1E dc and uninterruptable power supply system battery chargers. This valve also aligns the makeup pump suction to the boric acid storage tank when low pressure is detected in the demineralized water supply line to protect the pump from a loss of suction supply. Manual control for this valve is provided in the main control room and at the remote shutdown workstation.

Makeup Pump Suction Relief Valves

A relief valve is provided in the suction of each makeup pump to prevent overpressurization of the pump suction. These relief valves prevent overpressurization that might be caused by backleakage through the makeup pump discharge check valves when the pump suction valves are closed. The set pressure of these relief valves is equal to the pump suction design pressure. The relief capacity is sufficient to accommodate expected check valve back leakage rates.

Letdown Line Relief Valve

A relief valve is provided to prevent overpressurization of the letdown line connected to the waste processing system. This relief valve prevents overpressurization that might be caused by opening the letdown line with a closed valve in the waste processing system. The set pressure of this relief valve is equal to the design pressure of the line connecting to the waste processing system. The relief capacity is sufficient to accommodate a conservatively high letdown rate assuming minimum flow resistances in the piping, valves, orifices and equipment in the letdown line.

Letdown Line Containment Isolation Thermal Relief Valve

A relief valve is provided to prevent overpressurization of the letdown line containment penetration. This relief valve prevents overpressurization that might be caused by thermal expansion of the fluid between the containment isolation valves following an event causing containment isolation. This relief valve is located inside containment.

Resin Sluice Line Relief Valve

A relief valve is provided to prevent overpressurization of the line that is used to sluice resin from the mixed bed and cation bed demineralizers to the waste processing system. The set pressure of this relief valve is equal to the design pressure of the line it is connected to which is equal to the design pressure of the CVS purification equipment inside containment. The relief capacity is sufficient to accommodate thermal expansion of the water that is trapped between the two containment isolation valves that might occur following an accident that results in heatup of the containment.

Zinc Addition Line Relief Valve

A relief valve is provided to prevent overpressurization of the zinc addition line. The set pressure of this relief valve is equal to the design pressure of the line it is connected to, which is equal to the design pressure of the chemical and volume control system purification equipment inside containment. The relief capacity is sufficient to accommodate thermal expansion of the water that is trapped between the two containment isolation valves, which might occur following an accident that results in heatup of the containment.

Demineralizer Bypass Valve

This normally closed (normal flow through demineralizers) air-operated valve is located inside the containment. The valve is used, in the open position (flow through bypass line CVS-PL-L065), during hydrazine addition at plant startup. The valve's primary function is to avoid any negative impacts on demineralizer resin performance by contact with hydrazine. This valve fails in position on loss of power and loss of air.

9.3.6.3.8 Piping Requirements

The chemical and volume control system piping that handles radioactive liquid is made of austenitic stainless steel. The piping joints and connections are welded, except where flanged connections are required for equipment removal for maintenance and hydrostatic testing.

9.3.6.4 System Operation and Performance

The operation of the chemical and volume control system for the various modes of reactor plant operation is described in the following subsections.

9.3.6.4.1 Plant Startup

Plant startup is the operation that brings the reactor plant from a cold shutdown condition to no-load operating temperature and pressure, and subsequently to power operation.

The makeup pumps initially fill the reactor coolant system via the purification flow return line. During filling, makeup water is drawn from appropriate sources to provide makeup at the desired reactor coolant system boron concentration. The reactor coolant system is vented via the reactor vessel head and the pressurizer. A vacuum fill subsystem may be used to enhance the reactor coolant fill operation.

The auxiliary spray line may be used to fill the pressurizer and establish proper water chemistry in the pressurizer. If water solid operation is desired, reactor coolant system pressure is controlled by operation of the letdown control valve and the makeup control valve. To accomplish this, a letdown flow path is established to the liquid radwaste system with the letdown orifice bypassed. The makeup flow rate is maintained by the makeup control valve at a constant value selected by the operators. At the same time, the letdown control valve controls letdown flow to maintain reactor coolant system pressure at a constant value, also selected by the operators. These water solid operations are not required if vacuum fill is used.

During plant startup from cold shutdown, chemical treatment, using an oxygen scavenger, is performed. The oxygen scavenger is added to the reactor coolant during the initial stages of heatup to scavenge oxygen in the system. Subsequently, hydrogen makeup to the reactor coolant system is started, and the reactor coolant system hydrogen level is brought up to the normal operating point of approximately 30 cubic centimeters per kilogram.

The pressurizer heaters are used to heat up the water in the pressurizer and draw a steam bubble. As the steam bubble grows, effluent continues to be diverted to the liquid radwaste system through the chemical and volume control system letdown line. The makeup pumps are operated to supply demineralized water, so the reactor coolant system boron concentration is reduced to the level required for criticality. Following attainment of pressurizer normal water level, the letdown flow control valve and the makeup pumps are set to operate only as necessary to maintain pressurizer level or on demand from the operator.

Criticality is achieved as follows:

- The reactor coolant system boron concentration is reduced to the calculated level by dilution, routing effluent from the chemical and volume control system purification loop to the liquid radwaste system, and by providing unborated makeup with the makeup pumps taking suction from the demineralized water storage tank.

- Chemical analysis is used to measure water quality, boron concentration, and hydrogen concentration.

- Appropriate control rods are withdrawn.
- Further adjustments in boron concentration are made to establish preferred control group rod positions.

9.3.6.4.2 Normal Operation

Normal operation consists of operation at steady power (base load) level, load follow operation, and hot standby.

9.3.6.4.2.1 Base Load Operation

At a constant power level, the chemical and volume control system purification loop operates continuously as a closed loop around a reactor coolant pump. The purification flow is approximately 100 gallons per minute with one mixed bed demineralizer and one reactor coolant filter in service. The chemical and volume control system makeup pumps and the letdown line to the liquid radwaste system are not normally operating. The makeup pumps are normally available and are set to start automatically on Low-2 pressurizer level. The boric acid blending valve in the pump suction permits the operator to preset the blend of boric acid and demineralized water to achieve the desired makeup concentration. The letdown control valve opens automatically, if the pressurizer level reaches its high (relative to programmed level) setpoint. Reactor coolant samples are taken to check boron and H_2 concentration, water quality, pH, and activity level.

Variations in power demand are accommodated automatically by control rod and gray rod movement. The only adjustments in boron concentration necessary are those to compensate for core burnup. These adjustments are made to maintain the rod control groups within their allowable limits by setting the makeup pumps to provide the required amount of demineralized water as makeup. If necessary, effluent is automatically routed to the liquid radwaste system to maintain the required pressurizer level.

9.3.6.4.2.2 Load Follow Operation

Load follow power changes and the resulting xenon changes are accommodated by the control rods and gray rods, with no changes required to the reactor coolant system boron concentration. The chemical and volume control system does not have load follow functions.

9.3.6.4.3 Plant Shutdown

9.3.6.4.3.1 Hot Shutdown

If required for periods of maintenance or following spurious reactor trips, the reactor is maintained subcritical, with the capability to return to full power within the period of time required to withdraw the control rods. During hot standby operation, the average temperature is maintained at no-load T_{avg} by initially dumping steam to the condenser to provide residual heat removal, or at later stages by running the reactor coolant pumps to maintain system temperature.

Initially the control rods are inserted and the core is maintained at or slightly above the minimum required shutdown margin. Following shutdown, xenon buildup occurs and increases the shutdown margin. The effect of xenon buildup increases the shutdown margin to a minimum of about 3 percent $\Delta k/k$ at about 9 hours following shutdown.

If rapid recovery is required, dilution of the system may be performed to counteract this xenon buildup. A shutdown group of rods is withdrawn during dilution to provide the capability for rapid shutdown if needed, and frequent checks are made on critical rod position.

9.3.6.4.3.2 Cold Shutdown

Cold shutdown is the operation that brings the reactor plant from normal operating temperature and pressure to a cold shutdown temperature and pressure for maintenance or refueling.

The chemical and volume control system purification loop continues to operate normally in advance of a planned shutdown. In addition, in the beginning of a shutdown, the chemical and volume control system is designed so the letdown flow is routed out of containment to the liquid radwaste system, where it is stripped of gases and returned to the makeup pump suction. This gas stripping is required for approximately 48 hours to reduce reactor coolant activity level and hydrogen level sufficiently, permitting personnel access for refueling or maintenance operations.

Before cooldown and depressurization of the reactor coolant system is initiated, the reactor coolant boron concentration is increased to the cold shutdown value. The operator sets the reactor makeup control to "borate" and selects the volume of boric acid solution necessary to perform the boration. Correct concentration is verified by reactor coolant samples. The operator sets the reactor makeup control for makeup at the shutdown reactor coolant boron concentration.

Contraction of the coolant during cooldown of the reactor coolant system results in actuation of the pressurizer level control system to maintain normal pressurizer water level. Makeup continues to be automatic, with the makeup pumps starting and stopping as required.

During shutdowns, after the reactor coolant pumps are stopped, the normal residual heat removal system provides the motive force for chemical and volume control system purification loop. Whenever the reactor coolant system is pressurized, the chemical and volume control system can be operated to provide purification. After the normal residual heat removal system is placed in service and the reactor coolant pumps are stopped, further cooling and depressurization of the pressurizer fluids are accomplished by charging through the auxiliary spray connection.

9.3.6.4.3.2.1 Ion Exchange Media Replacement

The initial and subsequent fill of ion exchange media is made through a resin fill nozzle on the top of the ion exchange vessel. When the media is spent and ready to be transferred to the solid radwaste system (WSS), the vessel is isolated from the process flow. The flush water line is opened to the sluice piping and demineralized water is pumped into the vessel through the normal process outlet connection upward through the media retention screen. The media fluidizes in the upward, reverse flow. When the bed has been fluidized, the sluice connection is opened and the bed is sluiced to the spent resin tanks in the solid radwaste system. Demineralized water flow continues until the bed has been removed and the sluice lines are flushed clean of spent resin.

9.3.6.4.3.2.2 Filter Cartridge Replacement

Replacement of spent filter cartridges is performed as described in Subsection 11.4.2.3.2.

9.3.6.4.4 Abnormal Operation

9.3.6.4.4.1 Reactor Coolant System Leak

The chemical and volume control system is capable of making up for a small reactor coolant system leak with either makeup pump at reactor coolant system pressures above the low-pressure setpoint.

9.3.6.4.5 Accident Operation

The chemical and volume control system can provide borated makeup to the reactor coolant system following accidents such as small loss-of-coolant accidents, steam generator tube rupture events, and small steam line breaks. In addition, pressurizer auxiliary spray can reduce reactor coolant system pressure during certain events such as a steam generator tube rupture.

To protect against steam generator overfill, the makeup function is isolated by closing the makeup line containment isolation valves, if a High-3 steam generator level signal is generated. These valves also close and isolate the system on a High-2 pressurizer level signal.

Some of the valves in the chemical and volume control system are required to operate under accident conditions to effect reactor coolant system pressure boundary and containment isolation, as discussed in Subsection 9.3.6.3.7.

9.3.6.4.5.1 Boron Dilution Events

The chemical and volume control system is designed to address a boron dilution accident by closing redundant safety-related valves, tripping the makeup pumps and/or aligning the suction of the makeup pumps to the boric acid tank.

For dilution events occurring at power (assuming the operator takes no action), a reactor trip is initiated on either an overpower trip or an overtemperature ΔT trip. Following a reactor trip signal, the line from the demineralized water system is isolated by closing two safety-related, air-operated valves. The three-way pump suction control valve aligns so the makeup pumps take suction from the boric acid tank. If the event occurs while the makeup pumps are operating, the realignment of these valves causes the makeup pumps, if they continue to operate, to borate the plant.

For dilution events during shutdown, the source range flux doubling signal is used to isolate the makeup line to the reactor coolant system by closing the two safety-related, motor-operated valves, isolate the line from the demineralized water system by closing the two safety-related, air-operated valves, and trip the makeup pumps. The source range flux doubling function can be manually blocked during shutdown conditions when below the P-8 setpoint after the operator isolates unborated water source flow paths. When blocked during shutdown conditions, an automatic close signal is also sent to the CVS demineralized water system isolation valves to prevent inadvertent boron dilution. For refueling operations, administrative controls are used to prevent boron dilutions by verifying the valves in the line from the demineralized water system are closed and secured.

9.3.6.5 Design Evaluation

The chemical and volume control system has redundant, safety-related isolation valves and piping to protect the reactor coolant system pressure boundary, and is designed in accordance with ANSI/ANS-51.1 (Reference 4).

The chemical and volume control system lines that penetrate containment incorporate valve and piping arrangements, meeting the containment isolation criteria described in subsection 6.2.3.

Since the chemical and volume control system supplies unborated water to the reactor coolant system, the potential for inadvertent boron dilution events exists. A safety-related method of stopping an inadvertent boron dilution, which operates as described in Subsection 9.3.6.4.5.1, is incorporated into the chemical and volume control system.

The chemical and volume control system also incorporates a safety-related method of isolating the makeup to the reactor coolant system upon receipt of a High-3 steam generator level signal or a

High-2 pressurizer level signal, as described in Subsection 9.3.6.4.5. Other chemical and volume control system components are not safety-related.

Chemical and volume control system components and piping are compatible with the radioactive fluids they contain or functions they perform.

The design of the chemical and volume control system is based on specific General Design Criteria and regulatory guides. The design of the chemical and volume control system is compared to the criteria set forth in Subsection 9.3.4, "Chemical and Volume Control System (PWR) (Including Boron Recovery System)," Revision 2, of the Standard Review Plan. The specific General Design Criteria identified in the Standard Review Plan section are General Design Criteria 1, 2, 3, 4, 14, 29, 30, 31, 32, 33, 53, 54, 56, 60, and 61 as discussed in Section 3.1. Additionally, Subsection 1.9.1 discusses compliance with Regulatory Guides 1.26 and 1.29.

9.3.6.6 Inspection and Testing Requirements

The only required surveillance is for containment and reactor coolant pressure boundary isolation valves and boron dilution mitigation valves. These valves are identified as active and are tested in accordance with the in-service test provisions discussed in Subsection 3.9.6.

Other chemical and volume control system components are monitored for acceptable performance as follows:

- Mixed and cation bed demineralizer -- monitor for bed exhaustion by comparing reactor coolant system samples to samples taken at the outlet of the reactor coolant filter.

- Reactor coolant and makeup filters -- remotely monitor differential pressure with the installed gages and change the filter cartridges, or switch to the backup filter when high differential pressure is detected with the installed pressure gage.

Inspection of the various components is required in accordance with their safety class. The safety classification assignments can be found in Section 3.2.

9.3.6.6.1 Preoperational Inspection and Testing

Preoperational tests are conducted to verify proper operation of the chemical and volume control system. The preoperational tests include valve inspection and testing and flow testing.

9.3.6.6.1.1 Valve Inspection and Testing

The inspection requirements of the chemical and volume control system valves that constitute the reactor coolant pressure boundary are consistent with those identified in Subsection 5.2.4. The inspection requirements of the chemical and volume control system valves that isolate the lines penetrating containment are consistent with those identified in Section 6.6.

9.3.6.6.1.2 Flow Testing

Each chemical and volume control system pump is tested to measure the flow rate from each makeup pump to the reactor coolant system. Testing will be performed with the pump suction aligned to the boric acid storage tank and the discharge aligned to the reactor coolant system. Testing will also be performed with the pump suction aligned to the boric acid storage tank and the discharge aligned to the pressurizer auxiliary spray. Flow will be measured using instrumentation in the pump discharge line. Testing will confirm that each pump provides at least 100 gallons per minute of makeup flow at normal reactor coolant system operating pressure. This is the minimum flow rate

necessary to meet the chemical and volume control system functional requirement of providing makeup and pressurizer spray to support the functions described in Subsection 9.3.6.4.4.1. Testing is performed to verify that the maximum makeup flow with both pumps operating is less than 175 gpm, as assumed in the boron dilution analyses presented in Subsection 15.4.6. Testing is performed with both pumps operating and taking suction from the demineralized water system. The chemical and volume control system is aligned to the reactor coolant system at a pressure at or near atmospheric pressure.

9.3.6.6.1.3 Boric Acid Storage Tank Inspection

Inspection of the boric acid storage tank will be performed to verify that the volume in the tank is sufficient to provide 70,000 gallons of borated makeup to the reactor coolant system. This volume of boric acid is required to meet the functional requirement of providing makeup to the reactor coolant system to support the functions described in Subsection 9.3.6.4.4.

9.3.6.7 Instrumentation Requirements

Process control instrumentation is provided to acquire data concerning key parameters about the chemical and volume control system. The location of the instrumentation is shown on the chemical and volume control system piping and instrumentation diagram.

The instrumentation furnishes input signals for monitoring and/or alarming. Indications and/or alarms are provided in the main control room for the following parameters:

- Pressure and differential pressure
- Flow
- Temperature
- Water level

The instrumentation also supplies input signals for control purposes to maintain proper system operation and to prevent equipment damage. Some specific control functions are listed below:

- **Purification isolation** – The purification stop valves preserve the reactor coolant pressure boundary in the event of a break in the chemical and volume control system loop piping. The purification stop valves, the zinc addition line valves, and the hydrogen addition line valve outside containment close automatically on a signal from the protection and safety monitoring system generated by a low-1 pressurizer level signal. This isolation also serves as an equipment protection function to prevent uncovering of the heater elements in the pressurizer. One of these valves also closes on high temperature downstream of the letdown heat exchanger, to protect the resin in the mixed bed and cation demineralizers from being exposed to temperatures that could damage the resins.

- **Containment isolation** – To preserve the containment boundary, containment isolation valves are provided in the letdown line to the liquid radwaste system, the chemical and volume control system makeup line, and the hydrogen and zinc addition lines. These valves are opened or closed manually from the main control room and the remote shutdown workstation. Interlocks are provided to close these valves automatically upon receipt of the applicable isolation signal from the protection and safety monitoring system and require operator action to reopen.

- **Letdown isolation valves** – The letdown isolation valves are used to isolate letdown flow to the liquid radwaste system in addition to the containment isolation function described above. The plant control system provides a signal to automatically open these valves on a high-pressurizer level signal derived from the pressurizer level control system. On a

containment isolation signal from the protection and safety monitoring system, a high-3 liquid radwaste system degassifier level signal (plant control system), or a low-pressurizer level signal (plant control system), these valves automatically close to provide isolation of the letdown line. The letdown isolation valves also receive a signal from the protection and safety monitoring system to automatically close and isolate letdown during midloop operations based on a Low-2 hot leg level. Manual control is provided from the main control room and at the remote shutdown workstation. The letdown flow control valve controls reactor coolant system pressure during startup, as described in Subsection 9.3.6.4.1.

- **Demineralized water system isolation valves** – To prevent inadvertent boron dilution, the demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, or low input voltage (loss of ac power) to the 1E dc and uninterruptible power supply system battery chargers providing a safety-related method of stopping an inadvertent dilution. The valves are closed to prevent inadvertent boron dilution when the source range flux doubling logic is blocked below P-8. The main control room and remote shutdown workstation provide manual control for these valves.

- **Makeup isolation valves** – To isolate the makeup flow to the reactor coolant system, two valves are provided in the chemical and volume control system makeup line. These valves automatically close on a signal from the protection and safety monitoring system derived from source range flux doubling, high-2 pressurizer level, High-3 steam generator level, a safeguards signal coincident with high-1 pressurizer level, or high steam generator water level coincident with P-4 permissive (reactor trip) to protect against pressurizer or steam generator overfill. Manual control for these valves is provided in the main control room and at the remote shutdown workstation. In addition, the valves close on a high-2 containment radiation signal to protect containment integrity.

- **Makeup flow control** – To control makeup flow to the reactor coolant system, a flow controller, which operates in the makeup line, in conjunction with the reactor makeup control system is provided in the chemical and volume control system makeup pump discharge line. This flow controller controls makeup flow by modulating a flow control valve.

- **Makeup pump control** – The makeup pumps can be controlled from the main control room and at the remote shutdown workstation. On a signal from the plant control system generated by a low pressurizer level signal (relative to the programmed level), one of the chemical and volume control system makeup pumps starts automatically to provide makeup. The operating pump automatically stops when the pressurizer level increases to the correct value. During reactor coolant system boron changes (fuel depletion, startups, shutdowns, and refueling), the operator starts one of the makeup pumps after selecting the desired amount of boric acid.

The makeup pumps can be used to provide reactor coolant system makeup following an accident such as a small loss-of-coolant accident, a steam generator tube rupture, or a small steam line break. Following a safeguards actuation signal, if necessary, the operator remotely opens the makeup line isolation valves. One makeup pump automatically starts to control the pressurizer level between 10 and 20 percent. In addition, a makeup pump may be used to provide pressurizer auxiliary spray in reducing the reactor coolant system pressure for certain accident scenarios.

9.3.6.8 System Gas Accumulation Assessment and Mitigation

Subsection 6.3.6.3.1 describes the assessment method to address the potential for gas intrusion for the passive core cooling system in response to Interim Staff Guidance (ISG-019) and Generic Letter 2008-01. The same assessment methodology was used to assess the chemical and volume control system.

The chemical and volume control system locations equipped with manual vent valves will be inspected according to the system surveillance and venting procedures described in Subsection 6.3.6.3 to eliminate identified gas accumulations.

9.3.7 Combined License Information

Generic Issue 43, and the concerns of Generic Letter 88-14 and NUREG-1275 regarding degradation or malfunction of instrument air supply and safety-related valve failure, are addressed by the training and procedures for operations and maintenance of the instrument air subsystem and air-operated valves.

Plant systems, including the compressed and instrument air system, are maintained in accordance with procedures. Maintenance procedures are discussed in Subsection 13.5.2.2.6. The instrument air supply subsystem components are maintained and tested in accordance with manufacturers' recommendations and procedures. The safety-related air-operated valves are maintained in accordance with manufacturers' recommendations and tested in accordance with plant procedures to allow proper function on loss of air. The instrument air is periodically sampled and tested for compliance with the quality requirements of ANSI/ISA-S7.3-1981.

Operators are provided training on loss of instrument air in accordance with abnormal operating procedures. Plant systems, including the compressed and instrument air system, are operated in accordance with system operating procedures, abnormal operating procedures, and alarm response procedures which are written in accordance with Subsection 13.5.2. The training program for operations and maintenance personnel is discussed in Section 13.2.

9.3.8 References

1. Instrument Society of America Standards, "Quality Standard for Instrument Air," S7.3; 1981.

2. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, "Pressure Vessels," 1998 Edition, 2000 Addenda.

3. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, "Pressure Vessels," Subsection A, Part UG-99, Standard Hydrostatic Test, 1998.

4. ANSI/ANS-51.1-1983, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants."

5. Safety Evaluation by the Office of Nuclear Regulation Related to WCAP-14986, “Westinghouse Owners Group Post Accident Sampling System Requirements,” Westinghouse Owners Group Project No. 694, June 14, 2000.

6. NUREG 0800, Standard Review Plan Section 9.3.2 "Process and Post-Accident Sampling Systems."

7. CGA G-7.1-1997, “Commodity Specification for Air.”

Table 9.3.1-1 (Sheet 1 of 2)
Safety-Related Air-Operated Valves

Valve Number	Normal/Failure Position	Function
Compressed and Instrument Air System (CAS)		
CAS-PL-V014	NO/FC	Instrument Air Supply Outside Containment Isolation
Chemical and Volume Control System (CVS)		
CVS-PL-V045	NC/FC	Letdown Containment Isolation IRC
CVS-PL-V047	NC/FC	Letdown Containment Isolation ORC
CVS-PL-V084	NC/FC	Auxiliary Pressurizer Spray Line Isolation
CVS-PL-V092	NO/FC	Zinc Injection Containment Isolation ORC
CVS-PL-V094	NO/FC	Zinc Injection Containment Isolation Valve IRC
CVS-PL-V136A	NO/FC	Demineralized Water System Isolation
CVS-PL-V136B	NO/FC	Demineralized Water System Isolation
CVS-PL-V219	NO/FC	Hydrogen Injection Containment Isolation
Passive Containment Cooling System (PCS)		
PCS-PL-V001A	NC/FO	Passive Containment Cooling Water Storage Tank Isolation
PCS-PL-V001B	NC/FO	Passive Containment Cooling Water Storage Tank Isolation
Primary Sampling System (PSS)		
PSS-PL-V011A	NO/FC	Containment Isolation – Liquid Sample Line
PSS-PL-V011B	NC/FC	Containment Isolation – Liquid Sample Line
PSS-PL-V023	NO/FC	Containment Isolation – Sample Return Line
PSS-PL-V046	NO/FC	Containment Isolation – Air Sample Line
Passive Core Cooling System (PXS)		
PXS-PL-V014A	NC/FO	Core Makeup Tank A Discharge Isolation
PXS-PL-V014B	NC/FO	Core Makeup Tank B Discharge Isolation
PXS-PL-V015A	NC/FO	Core Makeup Tank A Discharge Isolation
PXS-PL-V015B	NC/FO	Core Makeup Tank B Discharge Isolation
PXS-PL-V042	NO/FC	Nitrogen Supply Containment Isolation ORC
PXS-PL-V108A	NC/FO	Passive Residual Heat Removal Heat Exchanger Control
PXS-PL-V108B	NC/FO	Passive Residual Heat Removal Heat Exchanger Control
PXS-PL-V130A	NO/FC	In-Containment Refueling Water Storage Tank Gutter Isolation
PXS-PL-V130B	NO/FC	In-Containment Refueling Water Storage Tank Gutter Isolation
PXS-PL-V230A	NC/FC	Core Makeup Tank A Fill Isolation
PXS-PL-V230B	NC/FC	Core Makeup Tank B Fill Isolation
PXS-PL-V232A	NC/FC	Accumulator A Fill/Drain Isolation
PXS-PL-V232B	NC/FC	Accumulator B Fill/Drain Isolation

Table 9.3.1-1 (Sheet 2 of 2)
Safety-Related Air-Operated Valves

Valve Number	Normal/Failure Position	Function
Normal Residual Heat Removal System (RNS)		
RNS-PL-V006A	NO/FO	RNS HX A Outlet Flow Control
RNS-PL-V006B	NO/FO	RNS HX B Outlet Flow Control
RNS-PL-V008A	NC/FC	RNS HX A Bypass Flow Control
RNS-PL-V008B	NC/FC	RNS HX B Bypass Flow Control
RNS-PL-V029	NC/FC	RNS Discharge to CVS
RNS-PL-V057A	NO/FO	RNS Pump Miniflow Isolation
RNS-PL-V057B	NO/FO	RNS Pump Miniflow Isolation
RNS-PL-V061	NC/FC	Shutdown Purification Flow Isolation
Steam Generator System (SGS)		
SGS-PL-V036A	NO/FC	Steam Line Condensate Drain Isolation
SGS-PL-V036B	NO/FC	Steam Line Condensate Drain Isolation
SGS-PL-V074A	NO/FC	Steam Generator Blowdown Isolation
SGS-PL-V074B	NO/FC	Steam Generator Blowdown Isolation
SGS-PL-V075A	NO/FC	Steam Generator Series Blowdown Isolation
SGS-PL-V075B	NO/FC	Steam Generator Series Blowdown Isolation
SGS-PL-V086A	NC/FC	Steam Line Condensate Drain Control
SGS-PL-V086B	NC/FC	Steam Line Condensate Drain Control
SGS-PL-V233A	NC/FC	Power Operated Relief Valve
SGS-PL-V233B	NC/FC	Power Operated Relief Valve
SGS-PL-V240A	NC/FC	Main Steam Isolation Valve Bypass Isolation
SGS-PL-V240B	NC/FC	Main Steam Isolation Valve Bypass Isolation
SGS-PL-V250A	NO/FC	Main Feedwater Control
SGS-PL-V250B	NO/FC	Main Feedwater Control
SGS-PL-V255A	NC/FC	Startup Feedwater Control
SGS-PL-V255B	NC/FC	Startup Feedwater Control
Main Control Room Emergency Habitability System (VES)		
VES-PL-V022A	NC/FO	Relief Isolation Valve A
VES-PL-V022B	NC/FO	Relief Isolation Valve B
Containment Air Filtration System (VFS)		
VFS-PL-V003	NC/FC	Containment Purge Inlet Containment Isolation Valve
VFS-PL-V004	NC/FC	Containment Purge Inlet Containment Isolation Valve
VFS-PL-V009	NC/FC	Containment Purge Discharge Containment Isolation Valve
VFS-PL-V010	NC/FC	Containment Purge Discharge Containment Isolation Valve
Central Chilled Water System (VWS)		
VWS-PL-V058	NO/FC	Fan Coolers Supply Isolation Valve
VWS-PL-V082	NO/FC	Fan Coolers Return Isolation Valve
VWS-PL-V086	NO/FC	Fan Coolers Return Isolation Valve
Liquid Radwaste System (WLS)		
WLS-PL-V055	NC/FC	Sump Discharge Containment Isolation IRC
WLS-PL-V057	NC/FC	Sump Discharge Containment Isolation ORC
WLS-PL-V067	NC/FC	Reactor Coolant Drain Tank Gas Outlet Containment Isolation IRC
WLS-PL-V068	NC/FC	Reactor Coolant Drain Tank Gas Outlet Containment Isolation ORC

Table 9.3.1-2
Nominal Component Design Data - Instrument Air Subsystem

Air Compressors	
Quantity	2
Type	Rotary
Capacity, each (scfm)	800
Design pressure (psig)	150
Air Receivers	
Quantity	2
Capacity, each (ft^3)	Minimum of 672
Design pressure (psig)	150
Prefilters	
Quantity	2
Type	Coalescing
Air Dryers	
Quantity	2
Type	Desiccant/Purge Air Regenerative
Capacity, each (scfm)	800
Operating pressure dew point, maximum (°F)	-28
Afterfilters	
Quantity	2
Type	Particulate

Table 9.3.1-3
Nominal Component Design Data - Service Air Subsystem

Air Compressor	
Quantity	2
Type	Rotary
Capacity, each (scfm)	800
Design pressure (psig)	150
Air Receiver	
Quantity	1
Capacity (ft^3)	Minimum of 672
Design pressure (psig)	150
Prefilters	
Quantity	2
Type	Coalescing
Air Dryer	
Quantity	2
Type	Desiccant/Purge Air Regenerative
Capacity, each (scfm)	800
Design pressure dew point, maximum (°F)	-28
Afterfilters	
Quantity	2
Type	Particulate

Table 9.3.1-4
Nominal Component Design Data - High-pressure Air Subsystem

Air Compressor	
Quantity	1
Type	Reciprocating
Capacity (scfm)	60
Design pressure (psig)	5000
Breathing Air Purifier	
Quantity	1
Type	Molecular Sieve/Activated Carbon
CO to CO_2 conversion	Catalysis
Air supply quality level	E
Air Receiver	
Quantity	1
Capacity, water volume (ft^3)	46
Design pressure (psig)	4000

Table 9.3.3-1
Primary Sampling System Sample Points - Normal Plant Operations
(Liquid And Gaseous)

Sample Point Name	Type of Sample(a)
Liquid Sample	
1. RCS Hot Leg (before CVS demineralizer)	Grab
2. Pressurizer Liquid Space	Grab
3. CVS Demineralizer Downstream	Grab
4. PXS Accumulators	Grab
5. PXS Core Makeup Tanks (at top)	Grab
6. PXS Core Makeup Tanks (at bottom)	Grab
7. PXS Core Makeup Tanks (at middle) (Unit 3 Only)	Grab
8. Containment Sump (pump discharge)	Grab
Gaseous Sample	
9. Containment Air	Grab

Note:

a. This column shows methods to obtain a sample for chemical analysis. It does not specify the frequency of sampling nor does it specify actual location of sample collection. "Grab" means that a grab sample is required for the intended chemical analysis. Depending on the sampling condition, this grab sample can be obtained in the laboratory or in the grab sampling unit.

Table 9.3.3-2 (Sheet 1 of 4)
Local Sample Points Not in the Primary Sampling System
(Normal Plant Operations)

Sample Point Name	Available Number of Points	Type of Sample[(a)]	Process Measurement
Liquid Sample			
1. CVS boric acid storage tank	1	Grab	pH, chloride, fluoride, boron, silica, suspended solids, radioisotopic liquid, dissolved oxygen, sulfate, aluminum, calcium, magnesium
2. CVS boric acid batching tank	1	Grab	Boron, chloride, fluoride, sulfate
3. Residual heat removal heat exchanger	2	Grab	Radioisotopic liquid, radioisotopic particulate, suspended solids, radioisotopic gas, gross specific activity, strontium, iron, tritium, hydrogen, I-131, conductivity, pH, dissolved oxygen, chloride, fluoride, boron, aluminum, silica, lithium radioisotopic liquid, lithium radioisotopic particulate, magnesium, sulfate, calcium, lithium, nickel
4. PXS IRWST	1	Grab	pH, dissolved oxygen, fluoride, boron, conductivity, gross specific activity, sodium, sulfate, silica, chloride, aluminum, calcium, magnesium
5. Main steam line (Outlet SG 1)	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
6. Main steam line (Outlet SG 2)	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
7. BDS steam generator blowdown	1	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
8. SFS purification (Upstream & downstream of SFS ion exchangers) (spent fuel pool treatment)	2	Grab	Conductivity, pH, chloride, silica, corrosion product metals, gross activity, corrosion product activity, fission product activity, I-131, tritium, turbidity, boron, corrosion product metals, organic impurities, fluoride, sulfate, aluminum, calcium, magnesium
9. PCS water storage tank	1	Grab	Hydrogen peroxide
10. Reactor coolant drain tank	1	Grab	Gross radioactivity and identification and concentration of principal radionuclide and emitters, dissolved gases.

Table 9.3.3-2 (Sheet 2 of 4)
Local Sample Points Not in the Primary Sampling System
(Normal Plant Operations)

Sample Point Name	Available Number of Points	Type of Sample[a]	Process Measurement
11. WLS degasifier (downstream of degasifier discharge pump)	1	Grab	Dissolved gases
12. CCS component cooling surge tank	1	Grab	pH, sodium, chloride, silica, corrosion product metals, corrosion inhibitors, fluoride, sulfate
13. CCS loops (downstream of CCS pumps)	2	Grab	pH, sodium, chloride, silica, corrosion product metals, tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters, fluoride, sulfate, total organic carbon, conductivity
14. CCS hot leg (upstream of CCS pumps)	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
15. WLS discharge (liquid radwaste effluent)	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
16. WLS effluent holdup tanks MT05A, B	2	Grab	Gross radioactivity and identification and concentration of principal radionuclide and alpha emitters, boron
17. WLS waste holdup tanks MT06A, B	2	Grab	Gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
18. WLS monitor tanks MT07A, B, C, D, E, F	6	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters. State and federal environmental discharge requirements such as pH, suspended solids, oil and grease, iron, copper, sodium nitrite
19. WLS ion exchanger pre-filter (downstream)	1	Grab	Suspended solids
20. WLS ion exchanger after-filter (downstream)	1	Grab	Suspended solids

Table 9.3.3-2 (Sheet 3 of 4)
Local Sample Points Not in the Primary Sampling System
(Normal Plant Operations)

Sample Point Name	Available Number of Points	Type of Sample[a]	Process Measurement
21. WLS chemical waste tank	1	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters, boron
22. WSS spent resin tanks (liquid)	1	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
23. SWS blowdown (service water)	1 1	Continuous Grab	Radiation monitor (See Section 11.5, Table 11.5-1) Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
24. WWS turbine building sump	2	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
25. CPS (secondary coolant) spent resin sluice line (liquid)	1	Grab	Tritium, gross radioactivity and identification and concentration of principal radionuclide and alpha emitters
26. Cask Loading pit	1	Grab[d]	Conductivity, pH, chloride, fluoride, sulfate, silica, aluminum, calcium, magnesium, corrosion-product activity, fission product activity, I-131, tritium, turbidity, boron, organic impurities
Gaseous Sample			
27. VES MCR emergency air supply headers	2	Grab	Air quality, oxygen, carbon monoxide, carbon dioxide, contaminants
28. WGS effluent discharge to environment	1	Continuous	Radiation monitor (See Section 11.5, Table 11.5-1)
29. WGS inlet	1	Continuous	Oxygen, hydrogen
30. WGS carbon bed vault	1	Continuous	Hydrogen
31. WGS delay bed outlets MV-02A, B (waste gas holdup)	2	Grab	Noble gases, iodine, particulates, tritium
32. Condenser air removal system[b] (including hogging)	1	Grab	Iodine, noble gases, tritium

Table 9.3.3-2 (Sheet 4 of 4)
Local Sample Points Not in the Primary Sampling System
(Normal Plant Operations)

Sample Point Name	Available Number of Points	Type of Sample[a]	Process Measurement
33. Gland seal system[b]	1	Grab	Iodine, noble gases, tritium
34. Plant vent (including containment purge, auxiliary building ventilation, fuel storage and radwaste area ventilation discharge)	1	Continuous & Grab[c]	Iodine, noble gases, particulates

Notes:

a. This column shows methods to obtain a sample for analysis. "Grab" means that a grab sample is required for the intended analysis. “Continuous” means that the required analysis is performed via a probe that monitors the sampling stream continuously.

b. Continuous monitoring of discharge for radiation provided in turbine island vent (See Section 11.5, Table 11.5-1).

c. Includes analysis for tritium.

d. It is recommended that a sampling method capable of obtaining samples from multiple depths in the CLP is used to ensure that stratification is not an issue.

Table 9.3.4-1 (Sheet 1 of 2)
Secondary Sampling System
(Continuous and Semi-Continuous Measurements)

Continuous Sample Points	Process Measurements
Hotwell (Tube Bundle Condenser Shell A)	Specific Conductivity Cation Conductivity Sodium
Hotwell (Tube Bundle Condenser Shell B)	Specific Conductivity Cation Conductivity Sodium
Hotwell (Tube Bundle Condenser Shell C)	Specific Conductivity Cation Conductivity Sodium
Hotwell (Interconnecting Piping Between Condenser Shell A and Condenser Shell B)	Specific Conductivity Cation Conductivity Sodium
Hotwell (Interconnecting Piping Between Condenser Shell B and Condenser Shell C)	Specific Conductivity Cation Conductivity Sodium
Condensate Pump Discharge	Specific Conductivity Cation Conductivity Sodium pH Dissolved Oxygen
Deaerator Inlet (Condensate)	Specific Conductivity Cation Conductivity Sodium[(a)] pH Oxygen Scavenger Residual Dissolved Oxygen
Feedwater	Specific Conductivity Cation Conductivity Sodium Dissolved Oxygen pH Oxygen Scavenger Residual
Steam Generator Blowdown (SG 1)	Specific Conductivity Cation Conductivity Sodium pH Dissolved Oxygen

Table 9.3.4-1 (Sheet 2 of 2)
Secondary Sampling System
(Continuous and Semi-Continuous Measurements)

Steam Generator Blowdown (SG 2)	Specific Conductivity Cation Conductivity Sodium pH Dissolved Oxygen
Main Steam System (SG 1)	Specific Conductivity Cation Conductivity Sodium[(a)] pH Dissolved Oxygen
Main Steam System (SG 2)	Specific Conductivity Cation Conductivity Sodium[(a)] pH Dissolved Oxygen

Note:

(a) Semi-continuous sampling. “Semi-continuous” means sampling instrumentation cycles through multiple individual sample streams that share a common sample header at pre-defined discrete intervals.

Table 9.3.4-2
Secondary Sampling System
(Selective Measurements)

Condenser Tube Bundle B (North Side)
Condenser Tube Bundle B (South Side)
Heater Drain (LP Heater)
Heater Drain (MSR 1st Stage Tube Drain)
Heater Drain (MSR 2nd Stage Tube Drain)
Heater Drain (MSR Shell Drain)
Auxiliary Steam
Auxiliary Boiler Feedwater
Auxiliary Boiler Drum
Auxiliary Boiler Condensate
Condensate Polisher Outlet
Heater Drain (HP Heater)
Deaerator Outlet (Feedwater)
Startup Feedwater

Table 9.3.5-1
Component Data - Radioactive Waste Drains System
(Nominal Values)

Drain Sump	
Capacity (gal)	1400
Design pressure	Atmospheric
Design temperature (°F)	150
Material	Stainless steel
Drain Sump Pumps	
Quantity per sump	2
Design flow rate (gpm)	125
Pump type	Pneumatic double diaphragm
Material	Stainless steel

Table 9.3.6-1
Chemical and Volume Control System Parameters[a]

Nominal purification flow rate (gpm)	100
Nominal boration flow rate (gpm)	100
Nominal dilution flow rate (gpm)	100
Nominal temperature of reactor coolant entering chemical and volume control system (assumed) (°F)	537
Expected life of demineralizer resin	1 fuel cycle
Maximum temperature of effluent to liquid radwaste system (°F)	130
Nominal effluent flow rate to liquid radwaste system (gpm)	100

Note:

a. Volumetric flow rates are based on 130°F and 2250 psia.

Table 9.3.6-2 (Sheet 1 of 3)
Chemical and Volume Control System
Nominal Equipment Design Parameters

Pumps		
Makeup Pumps		
Number	2	
Type	Multistage horizontal centrifugal	
Design pressure (psig)	3,100	
Design flow (gpm)	135	
Material	Stainless Steel (SS)	
Heat Exchangers		
Regenerative Heat Exchanger		
Number	1	
Type	Counterflow	
	Shell Side	**Tube Side**
Design pressure (psig)	3,100	3,100
Design temperature (°F)	600	650
Design flow (lb/hr)	54,185	54,185
Material	SS	SS
Letdown Heat Exchanger		
Number	1	
Type	U-Tube	
	Shell Side	**Tube Side**
Design pressure (psig)	200	3,100
Design temperature (°F)	200	600
Design flow (lb/hr)	224,044	54,185
Material	CS or SS	SS

Table 9.3.6-2 (Sheet 2 of 3)
Chemical and Volume Control System
Nominal Equipment Design Parameters

Demineralizers	
Mixed Bed Demineralizer	
Number	2
Design pressure (psig)	3,100
Design temperature (°F)	200
Design flow (gpm)	250
Resin volume (ft^3)	50
Material	SS
Resin type	Mixed Bed Li7OH Form
Cation Bed Demineralizer	
Number	1
Design pressure (psig)	3,100
Design temperature (°F)	200
Design flow (gpm)	250
Resin volume (ft^3)	50
Material	SS
Resin type	Cation H+ Form

Table 9.3.6-2 (Sheet 3 of 3)
Chemical and Volume Control System
Nominal Equipment Design Parameters

Filter	
Reactor Coolant Filter	
Number	2
Type	Disposable Cartridge
Design pressure (psig)	3,100
Design temperature (°F)	200
Design flow (gpm)	250
Maximum differential pressure at design flow (psi)	43
Tank	
Boric Acid Tank	
Number	1
Volume (gal)	74,839
Type	Cylindrical
Design pressure (psig)	Atmospheric
Design temperature (°F)	200
Material	SS

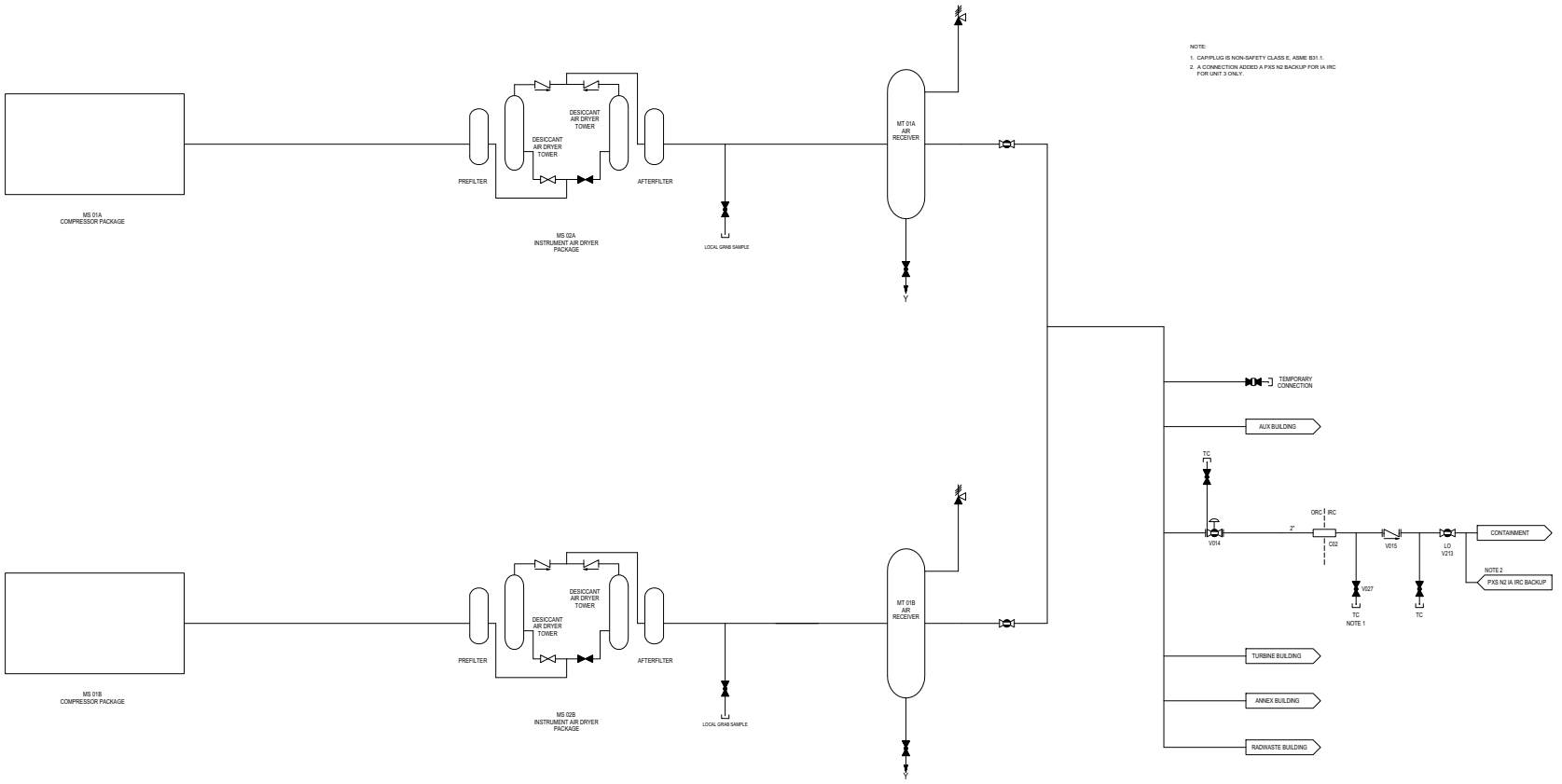


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Figure 9.3.1-1 (Sheet 1 of 3)
Compressed & Instrument Air System
Piping and Instrumentation Diagram
(REF CAS 001 & 005)

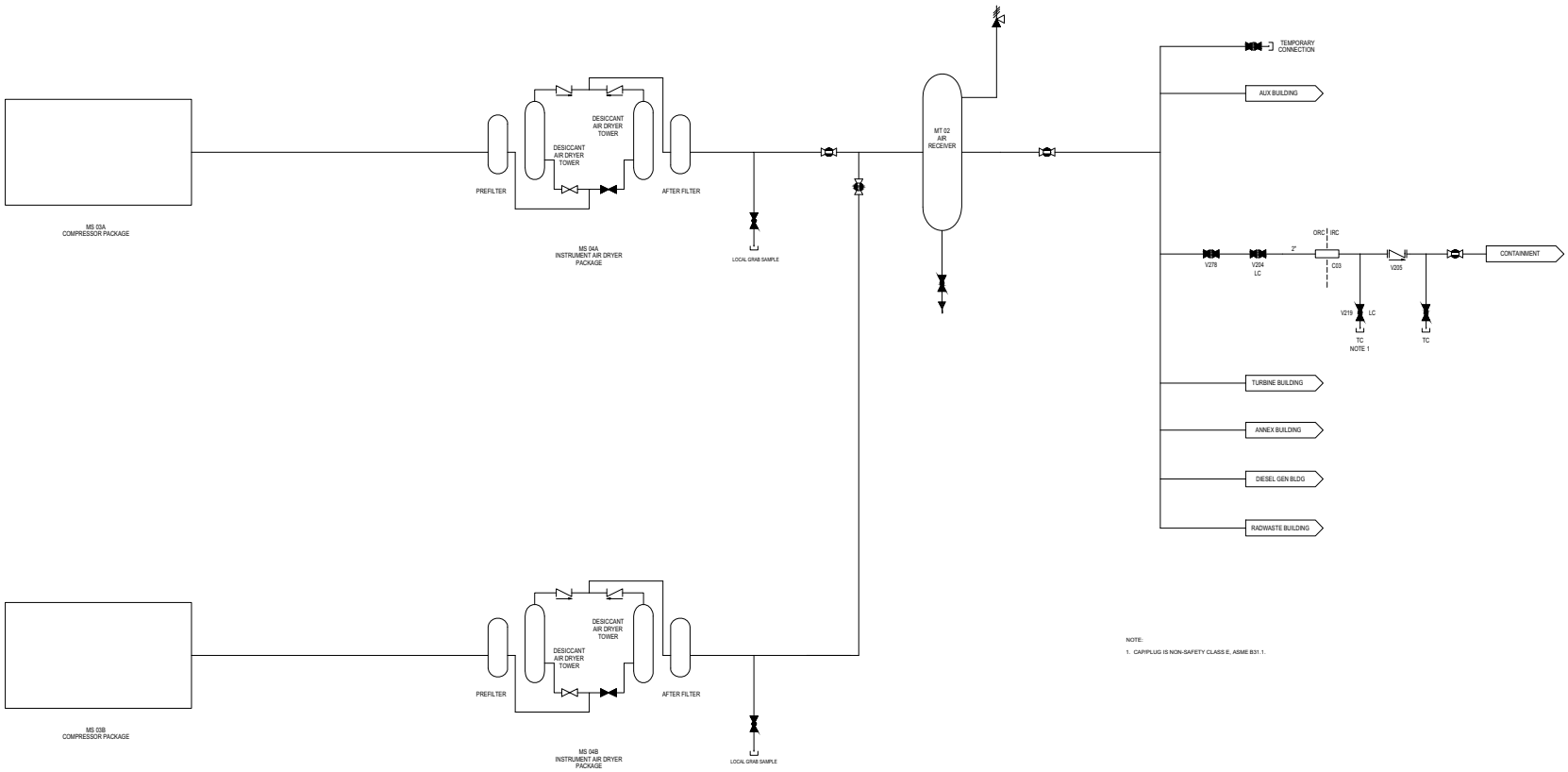


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Figure 9.3.1-1 (Sheet 2 of 3)
Compressed & Instrument Air System
Piping and Instrumentation Diagram
(REF CAS 008 & 012)

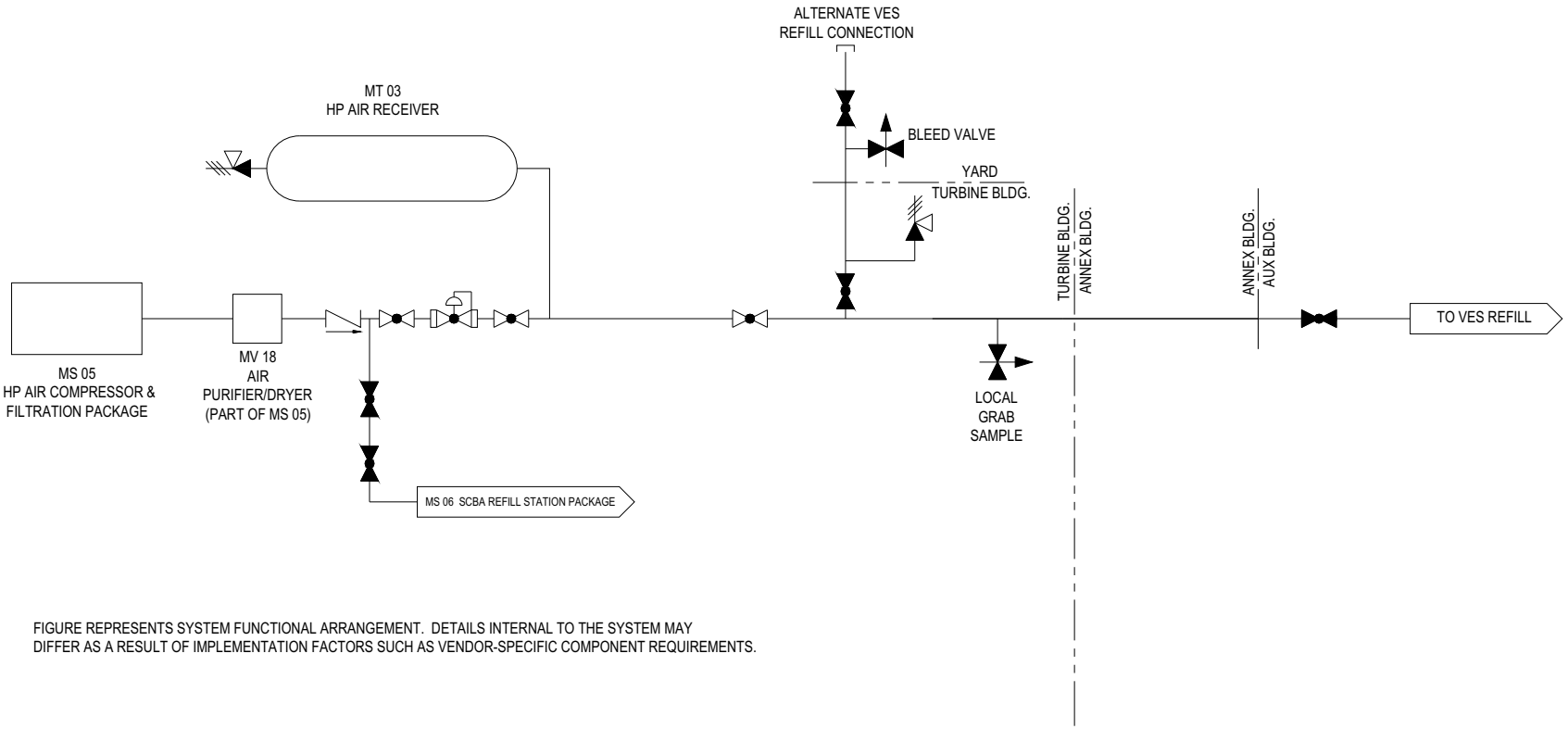


Figure 9.3.1-1 (Sheet 3 of 3)
Compressed & Instrument Air System
Piping and Instrumentation Diagram
(REF CAS 015)

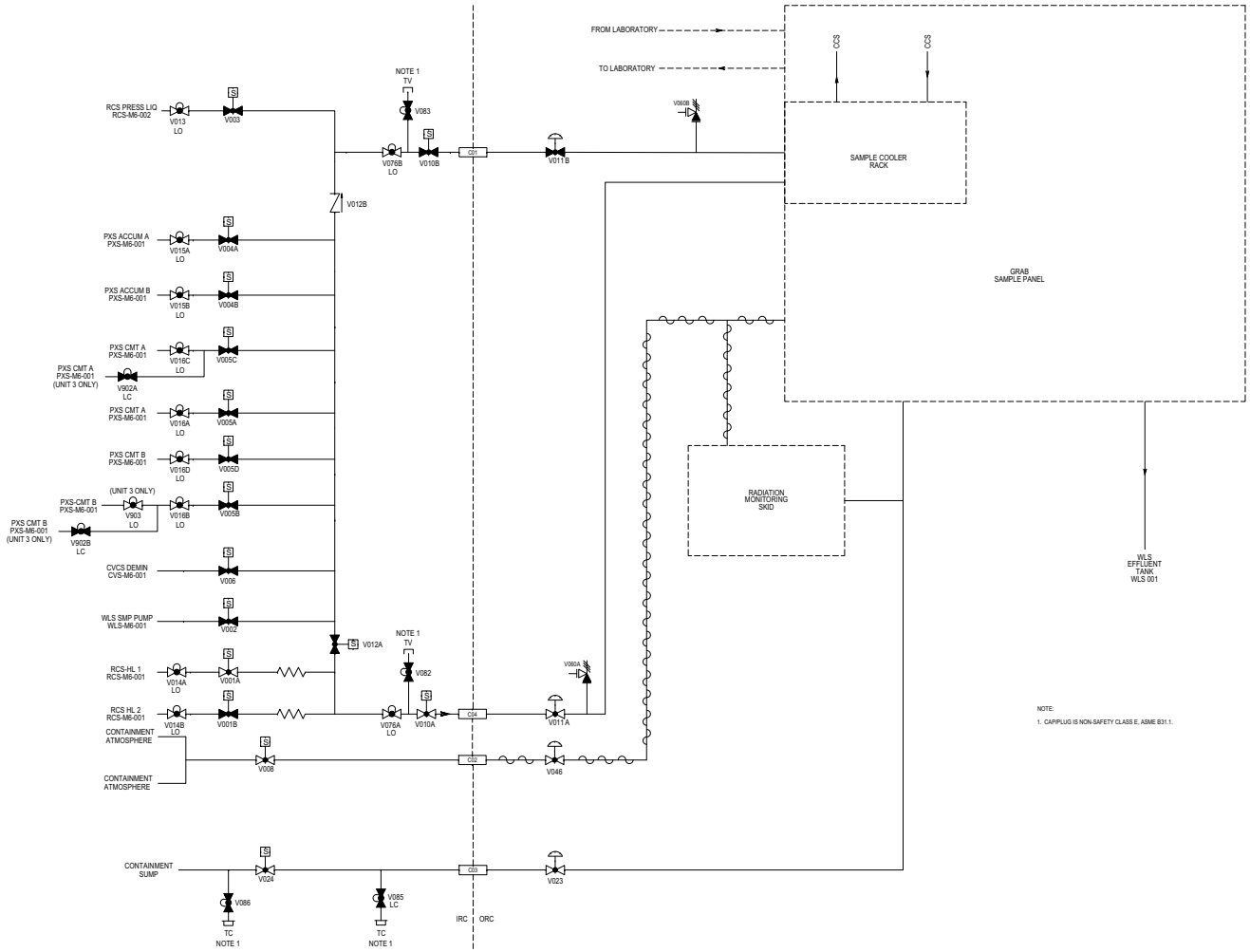


Figure 9.3.3-1
Simplified Sketch of the Primary Sampling System (REF PSS 001)

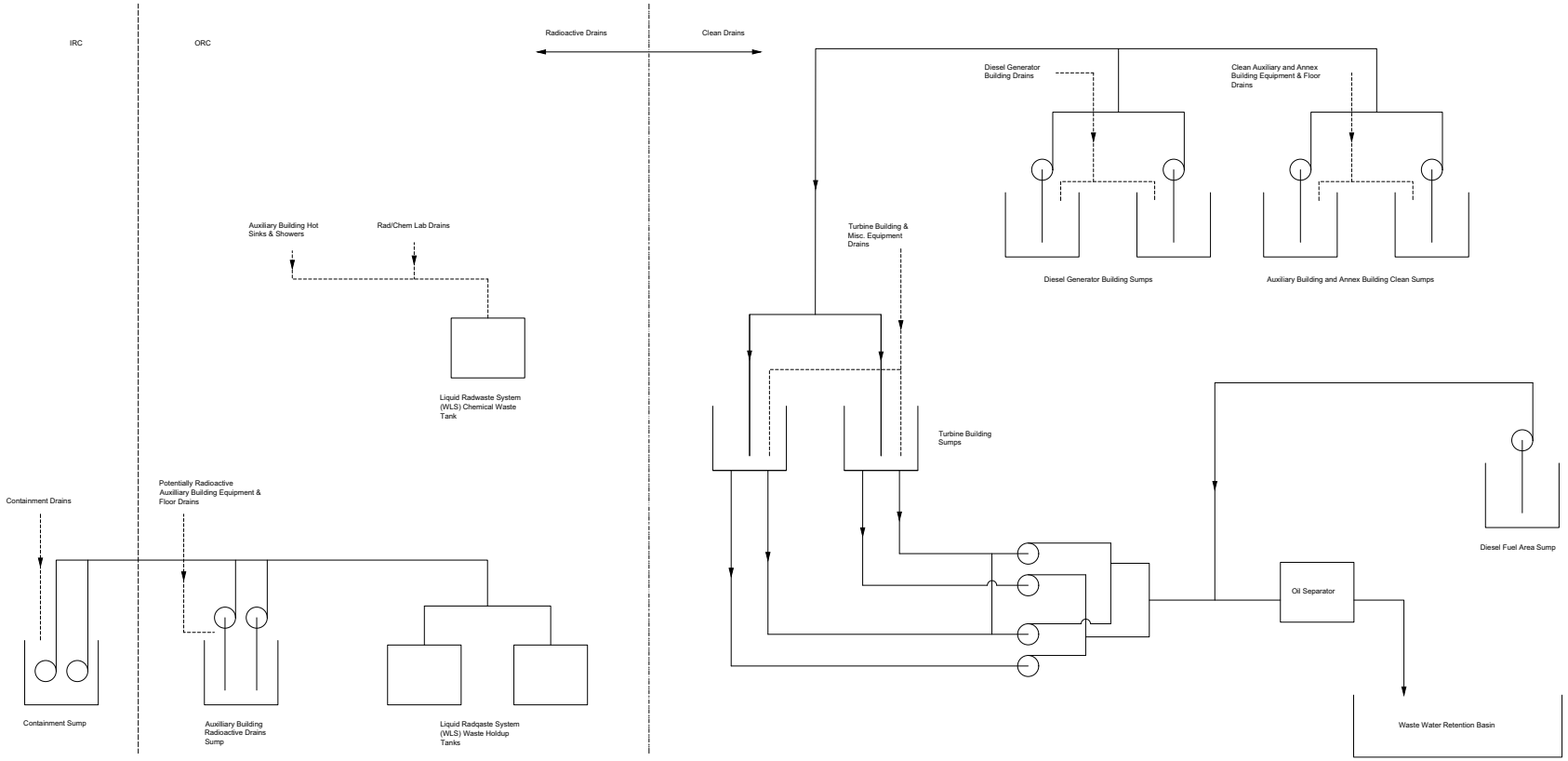


Figure 9.3.5-1
General Arrangement of Drainage Systems

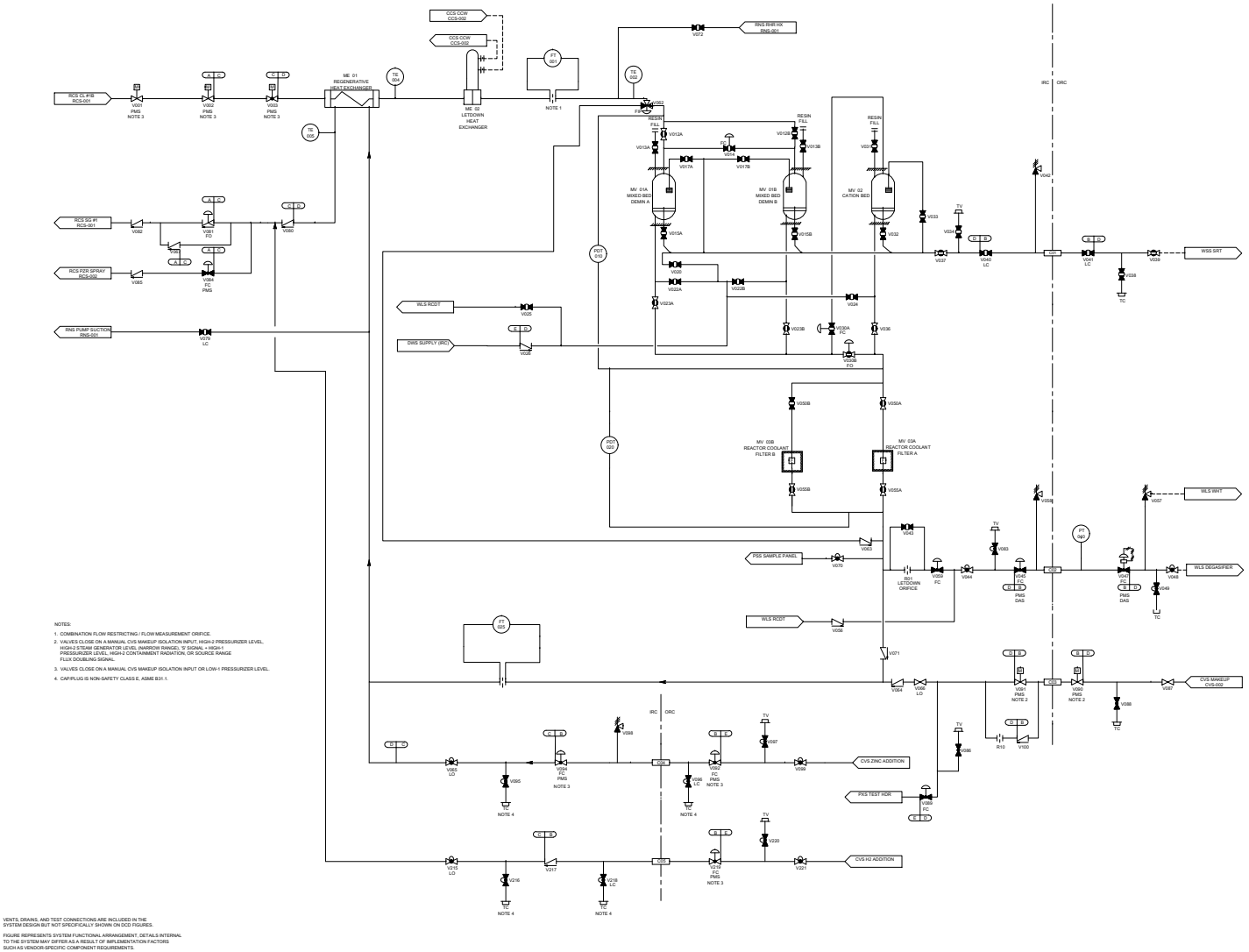


Figure 9.3.6-1 (Sheet 1 of 2)
Simplified Chemical and Volume Control System Piping and Instrumentation (REF) CVS 001, 003, 005

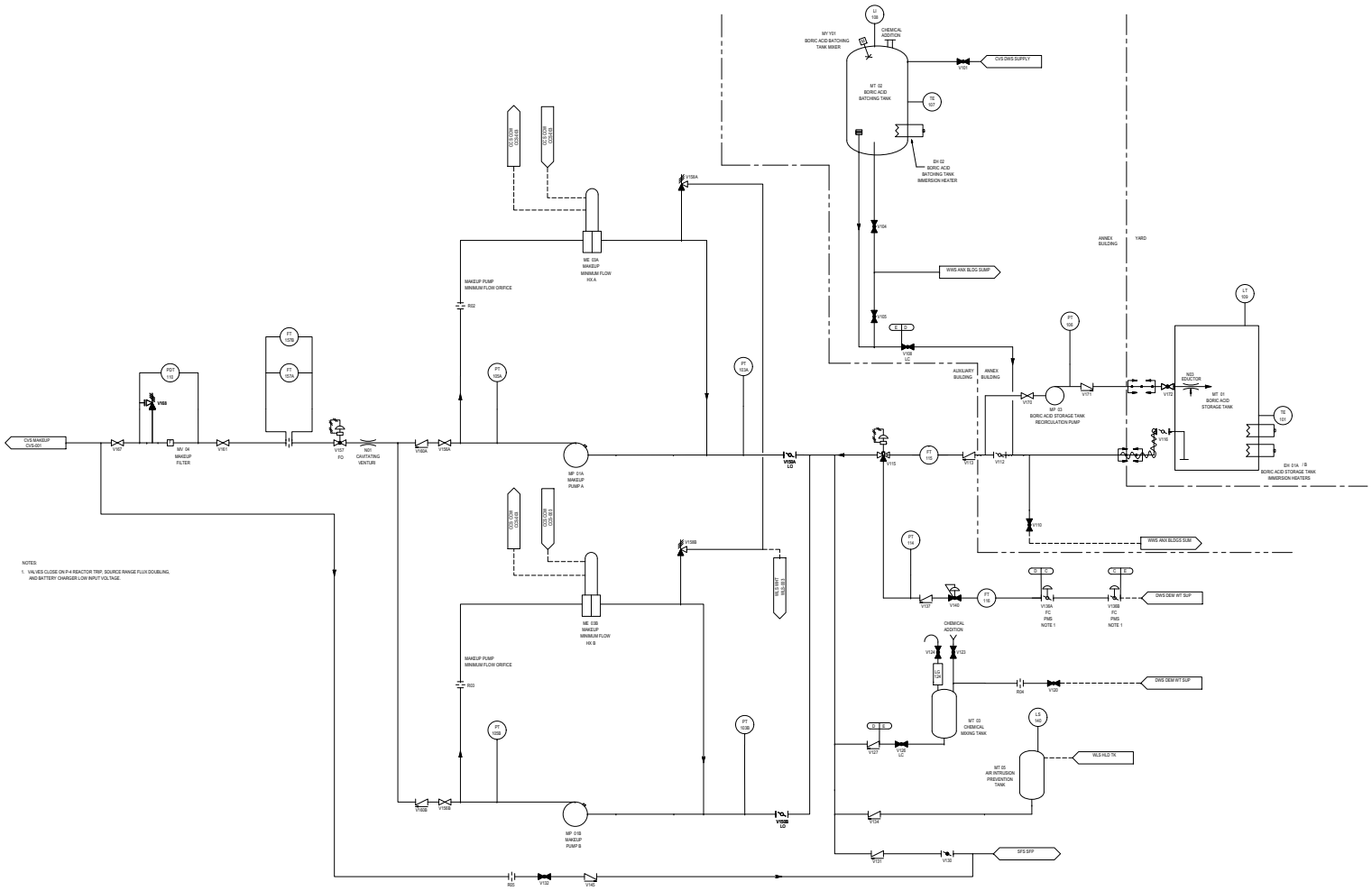


Figure 9.3.6-1 (Sheet 2 of 2)
Simplified Chemical and Volume Control System Piping and Instrumentation (REF) CVS 002, 004

9.4 Air-Conditioning, Heating, Cooling, and Ventilation System

The air-conditioning, heating, cooling, and ventilation system is comprised of the following systems that serve the various buildings and structures of the plant:

- Nuclear island nonradioactive ventilation system (Subsection 9.4.1)
- Annex/auxiliary buildings nonradioactive HVAC system (Subsection 9.4.2)
- Radiologically controlled area ventilation system (Subsection 9.4.3)
- Containment recirculation cooling system (Subsection 9.4.6)
- Containment air filtration system (Subsection 9.4.7)
- Radwaste building HVAC system (Subsection 9.4.8)
- Turbine building ventilation system (Subsection 9.4.9)
- Diesel generator building heating and ventilation system (Subsection 9.4.10)
- Health physics and hot machine shop HVAC system (Subsection 9.4.11)

9.4.1 Nuclear Island Nonradioactive Ventilation System

The nuclear island nonradioactive ventilation system (VBS) serves the main control room (MCR), control support area (CSA), Class 1E dc equipment rooms, Class 1E instrumentation and control (I&C) rooms, Class 1E electrical penetration rooms, Class 1E battery rooms, remote shutdown room, reactor coolant pump trip switchgear rooms, adjacent corridors, and the passive containment cooling system (PCS) valve room during normal plant operation.

The main control room emergency habitability system provides main control room habitability in the event of a design basis accident (DBA) and is described in Section 6.4.

9.4.1.1 Design Basis

9.4.1.1.1 Safety Design Basis

The nuclear island nonradioactive ventilation system provides the following nuclear safety-related design basis functions:

- Monitors the main control room supply air for radioactive particulate and iodine concentrations

- Isolates the HVAC penetrations in the main control room boundary on “High-2” particulate or iodine concentrations in the main control room supply air, extended loss of main control room differential pressure, or on extended loss of ac power to support operation of the main control room emergency habitability system as described in Section 6.4

Those portions of the nuclear island nonradioactive ventilation system which penetrate the main control room envelope are safety-related and designed as seismic Category I to provide isolation of the main control room envelope from the surrounding areas and outside environment in the event of a design basis accident. Other functions of the system are nonsafety-related. HVAC equipment and ductwork whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is nonsafety-related and nonseismic. The equipment is procured to meet the environmental qualifications used in standard building practice.

The nuclear island nonradioactive ventilation system is designed to control the radiological habitability in the main control room within the guidelines presented in Standard Review Plan (SRP) 6.4 and NUREG 0696 (Reference 1), if the system is operable and ac power is available.

Portions of the system that provide the defense-in-depth function of filtration of main control room/ control support area air during conditions of abnormal airborne radioactivity are designed, constructed, and tested to conform with Generic Issue B-36, as described in Section 1.9 and Regulatory Guide 1.140 (Reference 30), as described in Appendix 1A, and the applicable portions of ASME AG-1 (Reference 36), ASME N509 (Reference 2), and ASME N510 (Reference 3).

Power to the ancillary fans to provide post-72-hour ventilation of the control room and I&C rooms is supplied from divisions B and C regulating transformers through two series fuses for isolation. The fuses protect the regulating transformers from failures of the non-Class 1E fan circuits. When normal ventilation is available the ancillary fan circuits are disconnected from the supply with manual normally-open switches.

The nuclear island nonradioactive ventilation system is designed to provide a reliable source of heating, ventilation, and cooling to the areas served when ac power is available. The system equipment and component functional capabilities are to minimize the potential for actuation of the main control room emergency habitability system or the potential reliance on passive equipment cooling. This is achieved through the use of redundant equipment and components that are connected to standby onsite ac power sources.

9.4.1.1.2 Power Generation Design Basis

Main Control Room/Control Support Area (CSA) Areas

The nuclear island nonradioactive ventilation system provides the following specific functions:

- Controls the main control room and control support area relative humidity between 25 to 60 percent
- Maintains the main control room and CSA areas at a slightly positive pressure with respect to the adjacent rooms and outside environment during normal operations to prevent infiltration of unmonitored air into the main control room and CSA areas
- Isolates the main control room and/or CSA area from the normal outdoor air intake and provides filtered outdoor air to pressurize the main control room and CSA areas to a positive pressure of at least 1/8 inch wg when a “High-1” radioactivity concentration (gaseous, particulate, or iodine) is detected in the main control room supply air duct
- Isolates the main control room and/or CSA area from the normal outdoor air intake and provides 100 percent recirculation air to the main control room and CSA areas when a high concentration of smoke is detected in the outside air intake
- Provides smoke removal capability for the main control room and control support area
- Maintains the main control room emergency habitability system passive cooling heat sink below its initial design ambient air temperature limit of 75°F
- Maintains the main control room/control support area carbon dioxide levels below 0.5 percent concentration and the air quality within the guidelines of Table 1 and Appendix C, Table C-1 of Reference 32.

The background noise level in the main control room does not exceed 65 dB(A) when the VBS is operating.

The system maintains the following room temperatures based on the maximum and minimum outside air safety temperature conditions shown in Chapter 2, Table 2.0-201:

Area	Temperature (°F)
Main control room	67 – 75
Control support area	67 – 78

Class 1E Electrical Rooms/Remote Shutdown Room

The nuclear island nonradioactive ventilation system provides the following specific functions:

- Exhausts air from the Class 1E battery rooms to limit the concentration of hydrogen gas to less than 2 percent by volume in accordance with Regulatory Guide 1.128 (Reference 31).
- Maintains the Class 1E electrical room emergency passive cooling heat sink below its initial design ambient air temperature limit of 75°F
- Provides smoke removal capability for the Class 1E electrical equipment rooms and battery rooms

The background noise level in the remote shutdown room does not exceed 65 dB(A) when the VBS is operating.

The system maintains the following room temperatures based on the maximum and minimum outside air safety temperature conditions shown in Chapter 2, Table 2.0-201:

Area	Temperature (°F)
Class 1E battery rooms	67 - 73
Class 1E dc equipment rooms	67 - 73
Class 1E electrical penetration rooms	67 - 73
Class 1E instrumentation and control rooms	67 - 73
Corridors	67 - 73
Remote shutdown room	67 - 73
Reactor coolant pump trip switchgear rooms	67 - 73
HVAC equipment rooms	50 - 85

Passive Containment Cooling System Valve Room

The subsystem maintains the following room temperatures based on the maximum and minimum outside air safety temperature conditions shown in Chapter 2, Table 2.0-201:

Area	Temperature (°F)
Passive containment cooling system valve room	70 - 120

Post-72-Hour Design Basis

Main Control Room

The specific function of the nuclear island nonradioactive ventilation system is to maintain the main control room below a maximum average WBGT Index of 90°F based on operation at the site maximum normal temperature.

Divisions B and C Instrumentation and Control Rooms Design Basis

The specific function of the nuclear island nonradioactive ventilation system is to maintain the I&C rooms below the qualification temperature of the I&C equipment.

9.4.1.2 System Description

The nuclear island nonradioactive ventilation system is shown in Figure 9.4.1-1. The system consists of the following independent subsystems:

- Main control room/control support area HVAC subsystem
- Class 1E electrical room HVAC subsystem
- Passive containment cooling system valve room heating and ventilation subsystem

9.4.1.2.1 General Description

9.4.1.2.1.1 Main Control Room/Control Support Area HVAC Subsystem

The main control room/control support area HVAC subsystem serves the main control room and control support area with two 100 percent capacity supply air handling units, return/exhaust air fans, supplemental air filtration units, associated dampers, instrumentation and controls, and common ductwork. The supply air handling units and return/exhaust air fans are connected to common ductwork which distributes air to the main control room, the CSA, and the toilet serving the CSA. The main control room envelope consists of the main control room, shift manager's office, operation work area, toilets, and operations break room area. The CSA consists of the main control support area operations area, conference rooms, NRC room, computer rooms, and kitchen/rest area. The main control room toilets and the toilet serving the CSA have separate exhaust fans.

Outside supply air is provided to the plant areas served by the main control room/control support area HVAC subsystem through an outside air intake duct that is protected by an intake enclosure located on the roof of the auxiliary building at elevation 153′-0″. The outside air intake duct is located more than 50 feet below and more than 100 feet laterally away from the plant vent discharge. The supply, return, and toilet exhaust are the only HVAC penetrations in the main control room envelope and include redundant safety-related seismic Category I isolation valves that are physically located within the main control room envelope. Redundant safety-related radiation monitor sample line connections are located upstream of the VBS supply air isolation valves. These monitors initiate operation of the nonsafety-related supplemental air filtration units on "High-1" radioactivity concentrations (gaseous, particulate, or iodine) and isolate the main control room from the nuclear island nonradioactive ventilation system on "High-2" particulate or iodine radioactivity concentrations. A Class R seismic Category I static air mixer is located in the VBS ductwork to provide mixed air flow for the radiation monitor sample line connections. See Section 11.5 for a description of the main control room supply air radiation monitors.

Both redundant trains of supplemental air filtration units and one train of the supply air handling unit are located in the main control room mechanical equipment room at elevation 135′-3″ in the auxiliary building. The other supply air handling unit subsystem is located in the main control room mechanical equipment room at elevation 135′-3″ in the annex building. The main control room toilet exhaust fan is located at elevation 135′-3″ in the auxiliary building. A humidifier is provided for each supply air

handling unit. The supply air handling unit cooling coils are provided with chilled water from air-cooled chillers in the central chilled water system. See Subsection 9.2.7 for the chilled water system description.

The main control room/control support area HVAC subsystem has design features to limit migration of smoke, hot gases, and fire suppressant from one fire area to another to the extent that they could adversely affect safe shutdown capabilities, including operator actions. Fire or combination fire and smoke dampers are provided to isolate each fire area from adjacent fire areas during and following a fire in accordance with NFPA 90A (Reference 27) requirements. These combination smoke/fire dampers close in response to smoke detector signals or in response to the heat from a fire. See Appendix 9A for identification of fire areas.

9.4.1.2.1.2 Class 1E Electrical Room HVAC Subsystem

The Class 1E electrical room HVAC subsystem serves the Class 1E electrical rooms, Class 1E instrumentation and control (I&C) rooms, Class 1E electrical penetration rooms, Class 1E battery rooms, spare Class 1E battery room, remote shutdown room, and reactor coolant pump trip switchgear rooms. The A and C electrical divisions, spare battery room, and reactor coolant pump trip switchgear rooms are served by one ventilation subsystem; the B and D electrical divisions and remote shutdown room are served by a second ventilation subsystem.

Each subsystem consists of two 100 percent capacity supply air handling units, return/exhaust air fans, associated dampers, controls and instrumentation, and common ductwork. The supply air handling units and return/exhaust air fans are connected to a common ductwork which distributes air to the Class 1E electrical rooms. The outside supply air intake enclosure for the A and C subsystem is common to the main control room/control support area intake located on the roof of the auxiliary building at elevation 153′-0″. The outside supply air intake for the B and D subsystem is located separate from the main control room/control support area air intake enclosure on the auxiliary building roof at elevation 153′-0″. The exhaust ducts from the battery rooms are connected to the turbine building vent to remove hydrogen gas generated by the batteries.

The HVAC equipment which serves the A and C electrical divisions is located in the nuclear island nonradioactive ventilation system main control room/A and C equipment room at elevation 135′-3″ in the auxiliary building. The HVAC equipment which serves the B and D division of Class 1E electrical equipment is located in the upper and lower nuclear island nonradioactive ventilation system B and D equipment rooms at elevation 117′-0″ and at elevation 135′-3″.

The supply air handling unit cooling coils are provided with chilled water from the air-cooled chillers in the central chilled water system. The two air handling units for each set of electrical divisions are provided with chilled water from redundant air-cooled chillers. Refer to Subsection 9.2.7 for the chilled water system description.

Each subsystem for the Class 1E battery rooms is provided with two 100 percent capacity exhaust fans.

The Class 1E electrical room HVAC subsystem is designed so that smoke, hot gases, and fire suppressant does not migrate from one fire area to another to the extent that they could adversely affect safe shutdown capabilities, including operator actions. Separate ventilation subsystems are provided to serve the electrical division A and C equipment rooms and the electrical division B and D equipment rooms. The use of separate HVAC distribution subsystems for the redundant trains of electrical equipment prevents smoke and hot gases from migrating from one distribution division to the other through the ventilation system ducts. In addition, combination fire-smoke dampers are provided for Class 1E equipment rooms, including the remote shutdown room, to isolate each fire area and block the migration of smoke and hot gases to or from adjacent fire areas in accordance

with NFPA 90A requirements. These combination fire/smoke dampers close in response to smoke detector signals or in response to the heat from a fire. During a fire, the pressure difference across the doors in the stairwells S01 and S02 is maintained in accordance with the guidance of NFPA 92A (Reference 33) by dedicated stairwell pressurization fans. See Appendix 9A for identification of fire areas.

9.4.1.2.1.3 Passive Containment Cooling System Valve Room Heating and Ventilation Subsystem

The passive containment cooling system valve room heating and ventilation subsystem serves the passive containment cooling system valve room.

The subsystem consists of one 100 percent ventilating fan, two 100 percent capacity electric unit heaters, associated dampers, controls and instrumentation. The passive containment cooling system valve room heating and ventilation subsystem equipment is located in the passive containment cooling system valve room in the containment dome area at elevation 286′-6″.

The exhaust fan draws outside air through an intake louver damper and directly exhausts to the environment.

9.4.1.2.2 Component Description

The nuclear island nonradioactive ventilation system is comprised of the following major components. These components are located in buildings on the Seismic Category I Nuclear Island and the Seismic Category II portion of the annex building. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Tables 9.4.1-1, 9.4.1-2 and 9.4.1-3 provide design parameters for major components in each subsystem.

Supply Air Handling Units

Each air handling unit consists of a mixing box section, a low efficiency filter bank, high efficiency filter bank, a hot water heating coil, a chilled water cooling coil bank, and supply and return/exhaust air fans.

Supply and Return/Exhaust Air Fans

The supply and return/exhaust fans are centrifugal type, single width single inlet (SWSI), double width double inlet (DWDI), tubular centrifugal or plenum centrifugal with backward inclined blades that produce non-overloading horsepower characteristics or radial blades that produce overloading horsepower characteristics. Fan configurations are either performance rated in accordance with ANSI/AMCA 210 (Reference 4) or certified in accordance with AMCA 211 (Reference 5). Fan configurations are sound tested in accordance with ANSI/AMCA 300 (Reference 6).

The supply and return/exhaust air fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with high efficiency wheels and backward inclined blades to produce non-overloading horsepower characteristics. The fans are designed and rated in accordance with ANSI/AMCA 210 (Reference 4), ANSI/AMCA 211 (Reference 5) and ANSI/AMCA 300 (Reference 6).

Ancillary Fans

The ancillary fans are centrifugal type with non-overloading horsepower characteristics. Each can provide a minimum of 1,530 cfm. Fan configurations are performance rated in accordance with ANSI/AMCA 210 (Reference 4) and sound tested in accordance with ANSI/AMCA 300 (Reference 6).

Supplemental Air Filtration Units

Each supplemental air filtration unit includes a fan, a high efficiency filter bank, an electric heating coil, a charcoal adsorber with upstream HEPA filter bank, and a downstream postfilter bank. The filtration unit configurations, including housing, internal components, ductwork, dampers, fans and controls, and the location of the fans on the unfiltered side of units are designed, constructed, and tested to meet the applicable performance requirements of ASME AG-1, ASME N509, and ASME N510 (References 36, 2, and 3) to satisfy the guidelines of Regulatory Guide 1.140 (Reference 30).

Low Efficiency Filters, High Efficiency Filters, and Postfilters

The low efficiency filters and high efficiency filters have a rated dust spot efficiency based on ASHRAE 52.1 and 126 (References 7 and 35). Filter minimum average dust spot efficiency is shown in Tables 9.4.1-1 and 9.4.1-2. High efficiency filter performance upstream of HEPA filter banks meet the design requirements of ASME AG-1 (Reference 36), Section FB. Postfilters downstream of the charcoal filters have a minimum DOP efficiency of 95 percent. The filters are UL listed in accordance with UL 900 (Reference 8).

HEPA Filters

HEPA filters are constructed, qualified, and tested in accordance with UL-586 (Reference 9) and ASME AG-1 (Reference 36), Section FC. Each HEPA filter cell is individually shop tested to verify an efficiency of at least 99.97 percent using a monodisperse 0.3-µm aerosol in accordance with ASME AG-1 (Reference 36), Section TA.

Charcoal Adsorbers

Each charcoal adsorber is designed, constructed, qualified, and tested in accordance with ASME AG-1 (Reference 36), Section FE; and Regulatory Guide 1.140 (Reference 30). Each charcoal adsorber is a single assembly with welded construction and 4-inch deep Type III rechargeable adsorber cell, conforming with IE Bulletin 80-03 (Reference 29).

Electric Heating Coils

The electric heating coils are SCR controlled, fin tubular type. The electric heating coils are UL listed in accordance with UL 1996 (Reference 26). The electric heating coils for the supplemental air filtration subsystem are constructed, qualified, and tested in accordance with ASME AG-1 Section CA (Reference 36).

Electric Convection Heaters

The electric convection heaters are single or multi stage fin tubular type. The electric convection heaters are UL listed in accordance with UL 2021 (Reference 40) or UL 1042 (Reference 41) and meet the requirements of the National Electric Code NFPA 70 (Reference 28). The electric convection heaters are controlled by an integral temperature sensor or by a temperature sensor located in the space served by the heater.

Electric Unit Heaters

The electric unit heaters are single or multi stage, fin tubular type. The electric unit heaters are UL listed in accordance with UL 2021 (Reference 40) and meet the requirements of the National Electric Code NFPA 70 (Reference 28).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Hot Water Heating Coils

The hot water heating coils are counterflow, finned tubular type. Heating is controlled by modulating the hot water to the hot water heating coils. The heating coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Humidifiers

The humidifiers are packaged electric steam generator type which converts water to steam and distributes it through the air handling system. The humidifiers are designed and rated in accordance with ARI 640 (Reference 13).

Isolation Dampers and Valves

Nonsafety-related isolation dampers are bubble tight, single- or parallel-blade type. The isolation dampers have spring return actuators which fail closed on loss of electrical power. The isolation dampers are Class R and are designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section DA.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

The main control room pressure boundary penetrations include isolation valves, interconnecting piping, and vent and test connection with manual test valves. The isolation valves are classified as Safety Class C (see Subsection 3.2.2.5 and Table 3.2-3) and seismic Category I. Testing the effectiveness of their boundary isolation function is covered by the main control room pressure boundary testing described in Subsection 6.4.5.2, and by the inservice testing program for valves described in Subsection 3.9.6.

The main control room pressure boundary isolation valves have motor operators. The valves are designed to fail as is in the event of loss of electrical power. The valves are qualified to shut tight against control room pressure.

Tornado Protection Dampers

The tornado protection dampers are split-wing type and designed to close automatically. The tornado protection dampers are designed against the effect of 300 mph wind.

Shutoff and Balancing Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, balancing dampers are opposed-blade type. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow and meet the performance requirements in accordance with ANSI/AMCA 500 (Reference 14). The supplemental air filtration subsystem dampers are Class R and are designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section DA.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Fire Damper

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL-555 (Reference 15). Fire dampers are not provided in locations where combination fire/smoke dampers are provided.

Fire dampers at duct penetrations through fire barriers, which are within ducting that is routed outside the MCR/CSA pressure boundary are Class R and are designed, constructed, and tested in

accordance with ASME AG-1 Section DA (Reference 36). The Class R fire damper is applied to promote an ALARA HVAC design. The use of Class R fire damper mitigates the potential for infiltration of airborne radiation in ducting during operation of the fan coincident with an airborne release from spaces the ducting is routed through.

Combination Fire/Smoke Dampers

Combination fire/smoke dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The combination fire/smoke dampers are designed, constructed, and tested in accordance with UL-555S (Reference 25) and UL-555 (Reference 15).

Smoke Dampers

Smoke dampers are provided to restrict the spread of smoke in HVAC systems. Smoke dampers meet the design, leakage testing, and installation requirements of UL-555S (Reference 25).

Silencers

Silencers are provided to maintain the background noise below acceptable levels in the main control room. The silencers are steel casing packed with glass fiber absorptive fill. The principal construction code is the manufacturer's standard.

Static Air Mixer

A static air mixer is provided to support fully developed air flow to the MCR radiation monitoring packages. The principal construction code is the manufacturer's standard; however, the static air mixer is commercially dedicated to ASME AG-1 (Reference 36).

Ductwork, Duct Supports, and Accessories

Non-Seismic ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards- Metal and Flexible (Reference 17) with the exception of control support area ductwork which is noted below.

Seismic II Category ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34), SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17), and Appendix 3A, with the exception of supplemental air filtration and main control room HVAC subsystem's ductwork which is noted below.

The supplemental air filtration and main control room/control support area HVAC subsystem's ductwork, including the air filtration units and the portion of the ductwork located outside of the main control room envelope, that maintains integrity of the main control room/control support area pressure boundary during conditions of abnormal airborne radioactivity is Class R and is designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section SA, to provide low leakage components necessary to maintain main control room/control support area habitability. Ductwork is constructed of materials consistent with these standards including, but not limited to, galvanized or stainless steel. Duct supports and accessories are constructed of material consistent with these standards including, but not limited to, galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

9.4.1.2.3 System Operation

9.4.1.2.3.1 Main Control Room/Control Support Area HVAC Subsystem

Normal Plant Operation

During normal plant operation, one of the two 100 percent capacity supply air handling units and return/exhaust air fans operates continuously. Outside makeup air supply to the supply air handling units is provided through an outside air intake duct. The outside airflow rate is automatically controlled to maintain the main control room and CSA areas at a slightly positive pressure with respect to the surrounding areas and the outside environment.

The main control room/control support area supply air handling units are sized to provide cooling air for personnel comfort, equipment cooling, and to maintain the main control room emergency habitability passive heat sink below its initial ambient air design temperature. The temperature of the air supplied by each air handling unit is controlled by temperature sensors located in the main control room return air duct and in the computer room B return air duct to maintain the ambient air design temperature within its normal design temperature range by modulating the hot water heat or chilled water cooling. Some spaces have convection heaters for temperature control.

The outside air is continuously monitored by smoke detectors located at the outside air intake plenum and the return air is monitored for smoke upstream of the supply air handling units. The supply air to the main control room is continuously monitored for airborne radioactivity while the supplemental air filtration units remain in a standby operating mode.

The standby supply air handling unit and corresponding return/exhaust fans are started automatically if one of the following conditions shuts down the operating unit:

- Airflow rate of the operating fan is below a predetermined setpoint.
- Return air temperature is above or below predetermined setpoints.
- Differential pressure between the main control room and the surrounding areas and outside environment is above or below predetermined setpoints.
- Loss of electrical and/or control power to the operating unit.

Abnormal Plant Operation

Control actions are taken at two levels of radioactivity as detected in the main control room supply air duct. The first is “High-1” radioactivity based upon radioactivity instrumentation (gaseous, particulate, or iodine). The second is “High-2” radioactivity based upon either particulate or iodine radioactivity instruments.

If “High-1” radioactivity is detected in the main control room supply air duct and the main control room/control support area HVAC subsystem is operable, both supplemental air filtration units automatically start to pressurize the main control room and CSA areas to at least 1/8 inch wg with respect to the surrounding areas and the outside environment using filtered makeup air. The normal outside air makeup duct and the exhaust duct isolation dampers for the main control room toilets and the toilet serving the control support area close. The smoke/purge exhaust isolation dampers close, if open. The main control room/control support area supply air handling unit continues to provide cooling with recirculation air to maintain the main control room passive heat sink below its initial ambient air design temperature and maintains the main control room and CSA areas within their design temperatures. The supplemental air filtration subsystem pressurizes the combined volume of the main control room and control support area concurrently with filtered outside air. A portion of the

recirculation air from the main control room and control support area is also filtered for cleanup of airborne radioactivity. The main control room/control support area HVAC equipment and ductwork that form an extension of the main control room/control support area pressure boundary limit the overall infiltration (negative operating pressure) and exfiltration (positive operating pressure). The system is designed to maintain personnel doses within allowable General Design Criteria (GDC) 19 limits during design basis accidents in both the main control room and the control support area.

If ac power is unavailable for more than 10 minutes, or if main control room differential pressure is below the “Low” setpoint for more than 10 minutes, or if “High-2” particulate or iodine radioactivity is detected in the main control room supply air duct, which may lead to exceeding GDC 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room from the normal main control room/control support area HVAC subsystem by closing the supply, return, and toilet exhaust isolation valves. Main control room habitability is maintained by the main control room emergency habitability system, which is discussed in Section 6.4.

The main control room and CSA areas ventilation supply and return/exhaust ducts can be remotely or manually isolated from the main control room.

If a high concentration of smoke is detected in the outside air intake, an alarm is initiated in the main control room and the main control room/control support area HVAC subsystem is manually realigned to the recirculation mode by closing the outside air and toilet exhaust duct isolation valves. The exhaust fans for the main control room toilets and the toilet serving the control support area are tripped upon closure of the isolation valves. The main control room/CSA areas are not pressurized when operating in the recirculation mode. The main control room/control support area HVAC supply air subsystem continues to provide cooling, ventilation, and temperature control to maintain the emergency habitability passive heat sink below its initial ambient air design temperature and maintains the main control room and CSA areas within their design temperatures.

In the event of a fire in the main control room or control support area, in response to heat from the fire or upon receipt of a smoke signal from an area smoke detector, the main control room/control support area HVAC subsystem is automatically shut down and the combination fire/smoke dampers close automatically to isolate the fire area. The main control room/control support area HVAC subsystem can be manually realigned to the once-through ventilation mode to supply 100 percent outside air to the unaffected area. Realignment to the once-through ventilation mode minimizes the potential for migration of smoke or hot gas from the fire area to the unaffected area. Smoke and hot gases can be removed from the affected area by reopening the closed combination fire/smoke damper(s) from outside of the affected fire area during the once-through ventilation mode. In the once-through ventilation mode, the outside air intake damper to the air handling unit mixing plenum opens and the return air damper to the air handling unit closes to provide 100 percent outside air to the supply air handling unit. In this mode, the subsystem exhaust air isolation damper opens to exhaust the return air directly to the turbine building vent.

In the event of a fire with the potential to disable the main control room/control support area HVAC subsystem, operators may isolate the main control room from the normal ventilation subsystem and actuate the main control room emergency habitability system at their discretion to maintain control room habitability.

Power is supplied to the main control room/control support area HVAC subsystem by the plant ac electrical system. In the event of a loss of the normal ac power and offsite power, the main control room/control support area ventilation subsystem can be transferred to the onsite standby diesel generators. The convection heaters and duct heaters are not transferred to the onsite standby diesel generator.

In the event normal, onsite standby and offsite ac power are lost for more than 72 hours and the outside air is acceptable radiologically and chemically, MCR habitability is maintained by operating one of the two MCR ancillary fans to supply outside air to the MCR. It is expected the radioactivity of the outside air will decrease to an acceptable level within 72 hours following a radiological release. See Subsection 6.4.2.2 for details. The outside air pathway to the ancillary fans is provided through the seismic Category II portion of the annex building, into the auxiliary building mechanical room at floor elevation 135′-3″, and nonradioactive ventilation system supply duct. Warm air from the MCR is vented to the annex building through the clean access corridor at elevation 117′-6″. The ancillary fan capacity and air flow rate maintain the MCR environment below a maximum average WBGT Index of 90°F based on operation at the site maximum normal temperature. The ancillary fans and ducted flow path are located within the auxiliary building which is a Seismic Category I structure.

Power supply to the ancillary fans is from the respective division B or C regulating transformers which receive power from the ancillary diesel generators. For post-72-hour power supply discussion see Subsection 8.3.1.1.1.

9.4.1.2.3.2 Class 1E Electrical Room HVAC Subsystem

The Class 1E electrical room HVAC equipment that serves electrical division A and C equipment is described in this section. The operation of the Class 1E electrical room HVAC equipment that serves electrical division B and D is similar.

Normal Plant Operation

During normal plant operation, one of the redundant supply air handling units, return fans, and battery room exhaust fans operate continuously to provide room temperature control, to maintain the Class 1E electrical room emergency passive heat sink below its initial ambient air temperature, and to purge and prevent build-up of hydrogen gas concentration in the Class 1E Battery Rooms. The temperature of air supplied for heating and cooling is controlled by a temperature sensor located in the supply air duct that provides a signal for a temperature controller. These controls maintain the room air temperature within the normal design range by modulating hot water heating or chilled water cooling. Duct heaters are controlled by temperature sensors located in the space served by the heater.

During normal plant operation, the exhaust airflow from the Class 1E battery rooms is vented directly to the turbine building vent to limit the concentration of hydrogen gas in the rooms to less than 2 percent by volume in accordance with the guidelines of Regulatory Guide 1.128.

The outside makeup air to the supply air handling units is provided through an outside air intake duct. The outside airflow rate is manually balanced during system startup to provide adequate makeup air for the battery room exhaust fans.

The standby supply air handling unit and the corresponding return/exhaust fans are started automatically if one of the following conditions occurs:

- Airflow rate of the operating fan is below a predetermined setpoint.
- Return air temperature is above or below predetermined setpoints.
- Loss of electrical and/or control power to the operating unit.

Abnormal Plant Operation

The Class 1E electrical room HVAC divisions A/C subsystem outside air intake/exhaust dampers close on the start of one or both supplemental filtration unit fans. The Class 1E electrical room HVAC divisions B/D subsystem outside air intake/exhaust dampers close on a “High-2” particulate or iodine signal from the MCR radiation package communicated through the plant control system (PLS).

During a design basis accident (DBA), if the normal ac power and offsite power are unavailable, the Class 1E electrical room passive heat sink provides area temperature control. Refer to Section 6.4 for further details.

If a high concentration of smoke is detected in the outside air intake and an alarm is initiated in the main control room, the Class 1E electrical HVAC subsystem(s) can be manually aligned to the recirculation mode by closing the outside air intake damper to the air handling unit mixing plenum. This allows 100 percent room air to return to the supply air subsystem air handling unit. The subsystem continues to provide cooling, ventilation, and temperature control to maintain the areas served by the subsystem(s) within their design temperatures and pressures.

The Class 1E electrical room HVAC divisions A/C subsystem and the Class 1E electrical room HVAC divisions B/D subsystem are separated such that a fire in a fire area housing the equipment of one subsystem will not disable both subsystems. In the event of a fire in a Class 1E electrical room, in response to heat from the fire or upon receipt of a smoke signal from an area smoke detector, the combination fire/smoke dampers close automatically to isolate the fire area. The affected subsystem continues to provide ventilation/cooling to the remaining areas. Either or both subsystems can be manually realigned to the once-through ventilation mode to supply 100 percent outside air to the unaffected areas. Realignment to the once-through ventilation mode minimizes the potential for migration of smoke and hot gases from a non-Class 1E electrical room or a Class 1E electrical room of one division into the Class 1E electrical room of another division. Smoke and hot gases can be removed from the affected areas by reopening the closed combination fire/smoke dampers from outside of the affected fire area during the once-through ventilation mode. In the once-through ventilation mode, the outside air intake damper to the air handling unit mixing plenum opens and the return air damper to the air handling unit closes to allow 100 percent outside air to the supply air handling unit. The subsystem exhaust air isolation damper also opens to exhaust room air directly to the turbine building vent. During a fire, the pressure difference across the doors in stairwells S01 and S02 is maintained in accordance with the guidance of NFPA 92A (Reference 33) by dedicated stairwell pressurization fans.

The power supplies to the Class 1E electrical room HVAC subsystem are provided by the plant ac electrical system and the onsite standby diesel generators. In the event of a loss of the normal ac power and offsite power, the Class 1E electrical room HVAC subsystem is automatically transferred to the onsite standby diesel generators. The convection heaters and duct heaters are not transferred to the onsite standby diesel generator.

In the event normal, onsite standby and offsite ac power are lost for more than 72 hours, division B and C instrumentation and control room temperature is maintained by operating their respective ancillary fans (VBS-MA-11 and VBS-MA-12) to supply outside air to the I&C rooms. It is expected the radioactivity of the outside air will decrease to an acceptable level within 72 hours following a radiological release. The outside air pathway to the ancillary fans is through the nonradioactive seismic Category II portion of the annex building, into the auxiliary building mechanical room at floor elevation 135′-3″, stairway No. 1 doors at elevation 135′-3″ and 82′-6″, the access corridor at floor elevation 82′-6″, and the divisional battery rooms. The warm air is vented to the annex building through the clean access corridor at elevation 100′-0″. The outside air supply provides cooling and maintains room temperature below the qualification temperature of the I&C equipment. The ancillary fans and ducted flow path are located within the auxiliary building which is a Seismic Category I structure.

In the unlikely event that the nuclear island nonradioactive ventilation subsystems are disabled for more than 8 hours (for other than a loss of ac event), doors of the affected rooms may be opened to mitigate heat-up until HVAC is restored. Ancillary or portable fans also may be utilized in the event of an extended loss of HVAC in order to maintain the ambient temperature below the qualification temperature of the equipment.

Power supply to the ancillary fans is from the respective division B or C regulating transformers which receive power from the ancillary diesel generators. For post-72-hours power supply discussion see Subsection 8.3.1.1.1.

9.4.1.2.3.3 Passive Containment Cooling System Valve Room Heating and Ventilation Subsystem

Normal Plant Operation

The passive containment cooling system valve room ventilation fan exhausts room air to the outside environment to maintain room temperature within its normal design temperature range.

When heating is required, one of the two redundant electric unit heaters provides heating to maintain the passive containment cooling system valve room temperature above its minimum design temperature. The lead electric unit heater starts or stops when the room air temperature is above or below predetermined setpoints. The standby electric unit heater starts automatically if the room air temperature drops below a predetermined setpoint.

Abnormal Plant Operation

The power supplies to the passive containment cooling system valve room unit heaters are provided by the plant ac electrical system and the onsite standby diesel generators. In the event of a loss of the normal ac power and offsite power, the passive containment cooling system valve room unit heaters can be transferred to the onsite standby diesel generators by the operator.

The power supply to the passive containment cooling system valve room ventilation fan is provided by the plant ac electrical system. The room temperature is not expected to exceed 120°F, based on maximum ambient conditions and internal heat sources.

Following a fire in the passive containment cooling system valve room, smoke and hot gases can be removed from the area using portable exhaust fans and flexible ductwork.

9.4.1.3 Safety Evaluation

The nuclear island nonradioactive ventilation system has no safety-related function other than main control room envelope isolation and main control room supply air radioactivity monitoring, and therefore requires no nuclear safety evaluation. Redundant safety-related isolation valves are provided in the supply, return, and exhaust ducts penetrating the main control room. Therefore, there are no single active failures which would prevent isolation of the main control room envelope. The safety-related redundant main control room supply air radiation monitors are provided. The nuclear island nonradioactive ventilation system is designed so that safety-related systems, structures, or components are not damaged as a result of a seismic event.

9.4.1.4 Tests and Inspection

The nuclear island nonradioactive ventilation system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Airflow rates are measured and balanced within specified design flow rate ranges in accordance with the guidelines of SMACNA HVAC Systems - Testing, Adjusting and Balancing (Reference 19). The supplemental air filtration units are tested to confirm airflow capacity in accordance with the guidelines of ASME N510 (Reference 3). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability. Air quality within the MCR/CSA environment is confirmed to be within the guidelines of Table 1 and

Appendix C, Table C-1, of Reference 32 by analyzing air samples taken during preoperational testing.

The supplemental air filtration unit, HEPA filters, and charcoal adsorbers are tested in place in accordance with ASME N510 to verify that these components do not exceed a maximum allowable bypass leakage rate. Samples of charcoal adsorbent, used or new, are periodically tested to verify a minimum charcoal efficiency of 99 percent in accordance with Regulatory Guide 1.140 (Reference 30), except that test procedures and test frequency are conducted in accordance with ASME N510.

The ductwork for the supplemental air filtration subsystem and portions of the main control room/control support area HVAC subsystem that maintain the integrity of the main control room/control support area pressure boundary during conditions of abnormal airborne radioactivity are tested for leak tightness in accordance with ASME N510, Section 6. Testing for main control room/control support area inleakage during Main Control Room/Control Support Area HVAC Subsystem operation will be conducted in accordance with ASTM E741 (Reference 38). The remaining supply and return/exhaust ductwork, constructed in accordance with Equipment Class L requirements, is visually examined to validate ductwork construction and duct sealing methods in accordance with the applicable SMACNA standard (References 16, 17 or 34).

The main control room/control support area HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS) is tested and inspected in accordance with ASME/ANSI AG-1-1997 and Addenda AG-1a-2000 (Reference 201), ASME N509-1989, ASME N510-1989, and Regulatory Guide 1.140.

The VBS is tested as separate components and as an integrated system. Surveillance tests are performed to monitor the condition of the system. Testing methods include:

- Visual inspection
- Housing leak tests
- Airflow capacity and distribution tests
- HEPA filter bank and adsorber bank in-place leak tests
- Air heater performance tests
- Laboratory testing of adsorbers

Testing is performed at the frequency provided in Table 1 of ASME N510-1989.

9.4.1.5 Instrumentation Applications

The nuclear island nonradioactive ventilation system is controlled by the plant control system except for the main control room isolation valves, which are controlled by the protection and safety monitoring system. Refer to Subsection 7.1.1 for a description of the plant control and plant safety and monitoring systems. The instruments discussed below satisfy Table 4.2 of ASME N509 (Reference 2).

Temperature controllers are provided in the supply and return air ducts to control the room air temperatures within the predetermined ranges. Temperature indication and alarms for the main control room return air, Class 1E electrical room return air, air handling unit supply air, supplemental

filtration unit prefilter inlet air and charcoal adsorbers are provided to inform plant operators of abnormal temperature conditions.

Pressure differential indication and alarms are provided across each filter bank (except charcoal filters) to inform plant operators when filter changeout is necessary. Pressure differential indication and alarms are provided to control the main control room and monitor the control support area ambient room pressure differentials with respect to surrounding areas.

Radioactivity indication and alarms are provided to inform the main control room operators of gaseous, particulate, and iodine radioactivity concentrations in the main control room supply air duct. See Section 11.5 for a description of the main control room supply air duct radiation monitors and their actuation functions.

Smoke detectors are provided to detect smoke in the outside air intake duct to the main control room and the main control room and Class 1E electrical room return air ducts.

Airflow indication and alarms are provided to monitor operation of the supply and exhaust fans.

Relative humidity indication and alarms are provided to monitor the average relative humidity in the return air from the main control room/CSA areas and the inlet air to the supplemental air filtration unit charcoal filters.

Status indication is provided to monitor fans, heaters and controlled dampers.

9.4.2 Annex/Auxiliary Buildings Nonradioactive HVAC System

The annex/auxiliary buildings nonradioactive HVAC system serves the nonradioactive personnel and equipment areas, office areas, fire brigade locker room, radiation protection calibration lab, electrical equipment rooms, clean corridors, the ancillary diesel generator room and demineralized water deoxygenating room in the annex building, and the main steam isolation valve compartments, reactor trip switchgear rooms, and piping and electrical penetration areas in the auxiliary building.

9.4.2.1 Design Basis

9.4.2.1.1 Safety Design Basis

The annex/auxiliary buildings nonradioactive HVAC system serves no safety-related function and therefore has no nuclear safety design basis. System equipment and ductwork located in the nuclear island whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is nonseismic.

9.4.2.1.2 Power Generation Design Basis

The annex/auxiliary buildings nonradioactive HVAC system provides the following specific functions:

- Provides conditioned air to maintain acceptable temperatures for equipment and personnel working in the area
- Provides suitable environmental conditions for equipment in the main steam isolation valve (MSIV) compartments
- Prevents the buildup of hydrogen in non-Class 1E battery rooms to less than 2 percent hydrogen by volume

- Removes vitiated air from locker, toilet, shower facilities, and rest rooms

The system maintains the following room temperatures based on maximum and minimum normal outdoor air temperature conditions shown in Chapter 2, Table 2.0-201:

Room or Area	Temperature (°F)
Normal Operation	
Offices, office areas, conference rooms, corridors (annex building)	73-78
Locker rooms, toilet rooms (annex building)	73-78
Security rooms and areas (annex building)	65-78
Non-Class 1E battery rooms (annex building)	67-77
Switchgear and battery charger rooms (annex building)	50-105
HVAC and mechanical equipment rooms (annex building)	50-105
MSIV compartments (auxiliary building)	50-105
Non-safety electrical penetration rooms (auxiliary building)	50-85
Reactor trip SWGR rooms (auxiliary building)	50-105
Valve/piping penetration room (auxiliary building)	50-105
Ancillary diesel generator room (annex building)	50-105
Demineralized water deoxygenating room	50-105
Boric acid batching room	50-105
Fire brigade locker room (annex building)	65-78
Radiation protection calibration lab (annex building)	65-78
Corridor (annex building room 40386)	65-78
Upset Conditions (Loss of Normal ac Power and Offsite Power)	
Switchgear rooms (annex building)	122 (maximum)
Battery charger rooms (annex building)	122 (maximum)
Ancillary diesel generator room (annex building - DG sets operating)	122 (maximum)

9.4.2.2 System Description

The annex/auxiliary buildings nonradioactive HVAC system consists of the following independent subsystems:

- General area HVAC subsystem
- Switchgear room HVAC subsystem
- Equipment room HVAC subsystem
- MSIV compartment HVAC subsystem
- Mechanical equipment areas HVAC subsystem
- Valve/Piping penetration room HVAC subsystem

The defense in depth portion of the system and selected subsystems are shown in Figure 9.4.2-1.

9.4.2.2.1 General Description

9.4.2.2.1.1 General Area HVAC Subsystem

The general area HVAC subsystem serves personnel areas in the annex building outside the security area. The general area HVAC subsystem consists of two 50-percent capacity supply air handling units of about 2,300 scfm each (referred to as the general area air handling units) and two 50-percent capacity supply air handling units of about 5,540 scfm each (referred to as the office area air handling units), a humidifier, a ducted supply and return air system, diffusers and registers, exhaust fan, automatic controls, and accessories. The general area air handling units service the ALARA briefing room and operational support center, offices, computer rooms, and shower areas. The office area air handling units service the fire brigade locker room, radiation protection calibration lab, office areas, kitchen and rest rooms. The air handling units are located on the low roof of the annex building at elevation 117'-6". The units discharge into ducted supply distribution systems which are routed through the building to provide air into the various rooms and areas served via registers. Electric heating coils are provided in select branch supply ducts for tempering the supply air.

Air from the men's and women's locker, toilet, and shower facilities in the annex building is exhausted directly to atmosphere by exhaust fans. Room air from the remaining areas served is recirculated back to the air handling unit via a ceiling return plenum and a return duct system. Outside make-up air is added to the return air stream at the air handling units to replace air exhausted from toilets and showers in the area served.

9.4.2.2.1.2 Switchgear Room HVAC Subsystem

The switchgear room HVAC subsystem serves electrical switchgear Rooms 1 and 2 in the annex building. The switchgear room HVAC system consists of two 100 percent capacity air handling units, a ducted supply and return air system, and automatic controls and accessories.

The air handling units are located in the north air handling equipment room in the annex building at elevation 135′-3″. They are connected to a common intake plenum located along the east wall adjacent to their air handling equipment room. This plenum also supplies air for the equipment room HVAC subsystem. The air handling units discharge into a common duct distribution system that is routed through the building to the rooms served. Air is returned to the air handling units from the rooms served by a return duct system.

The switchgear room HVAC subsystem is designed so that smoke can be removed after a fire by placing the system in a once-through smoke exhaust ventilation mode. See Appendix 9A for identification of fire areas.

9.4.2.2.1.3 Equipment Room HVAC Subsystem

The equipment room HVAC subsystem serves electrical and mechanical equipment rooms in the annex and auxiliary buildings. These rooms include the non-Class 1E battery charger Rooms 1 and 2, the non-Class 1E battery Rooms 1 and 2, the reactor trip switchgear Rooms I and II, the non-Class 1E penetration room on elevation 100′-0″ and the non-Class 1E penetration room on elevation 117′-6″. This subsystem also serves the rooms and areas in the annex building. These include two rest rooms, access areas, and corridors. The equipment room HVAC system consists of two 100 percent capacity air handling units, three battery room exhaust fans, a toilet exhaust fan, a ducted supply and return air system, and automatic controls and accessories.

The air handling units are located in the north air handling equipment room in the annex building at elevation 135′-3″. They are connected to a common intake plenum located along the east wall adjacent to their air handling equipment room. This plenum also supplies air for the switchgear room HVAC subsystem. The air handling units discharge into a common duct distribution system that is routed through the buildings to the various areas served. Air is returned to the air handling units from the rooms served (except the battery rooms and rest rooms) by a return duct system. Electric reheat coils are provided in the ductwork to areas requiring close temperature control such as the security rooms and restrooms. Hot water unit heaters (VXS-MY-W01A, B, and C) are provided in the north air handling equipment room to maintain the area above 50°F.

A humidifier is provided in the branch duct to the security areas to provide a minimum space relative humidity of 35 percent.

Each non-Class 1E battery room and the additional battery room in the annex building are provided with an individual exhaust system to prevent the buildup of hydrogen gas in the room. Each exhaust system consists of an exhaust fan, an exhaust air duct and gravity back draft damper located in the fan discharge. Air supplied to the battery rooms by the air handling units is exhausted to atmosphere. Air from the rest rooms is exhausted to atmosphere by a separate exhaust fan. Battery rooms 1 and 2 in the annex building also have electric duct heaters (VXS-EH-30 and VXS-EH-31).

The portion of the equipment room HVAC subsystem servicing the auxiliary building is designed so that smoke, hot gases, and fire suppressant will not migrate from one fire area to another to the extent that they could adversely affect safe shutdown capabilities, including operator actions. Fire or combination fire and smoke dampers are provided to isolate each fire area from adjacent fire areas during and following a fire in accordance with NFPA 90A (Reference 27) requirements. These combination smoke/fire dampers close in response to smoke detector signals or in response to the heat from a fire. See Appendix 9A for identification of fire areas.

9.4.2.2.1.4 MSIV Compartment HVAC Subsystem

The main steam isolation valve compartment HVAC subsystem serves the two main steam isolation valve compartments in the auxiliary building that contain the main steam and feedwater lines routed between the containment and the turbine building. Each compartment is provided with separate heating and cooling equipment.

The main steam isolation valve compartment HVAC subsystem consists of two 100-percent-capacity supply air handling units per compartment (VXS-MS-04A, B, C, and D) of about 5,300 scfm each with only low efficiency filters, ducted supply air distribution directly to the space served, automatic controls, and accessories for each main steam isolation valve compartment.

The supply air handling units are located directly within the space served. One unit in each compartment normally operates to maintain the temperature of the compartment. The air handling units can be connected to the standby power system, for investment protection, in the event of loss of the normal ac power and offsite power.

9.4.2.2.1.5 Mechanical Equipment Areas HVAC Subsystem

The mechanical equipment areas HVAC subsystem serves the ancillary diesel generator room, demineralized water deoxygenating room, boric acid batching room, upper south air handling equipment room, and lower south air handling equipment room in the annex building.

The mechanical equipment areas HVAC subsystem consists of two 50-percent capacity air handling units (VXS-MS-07A and B) with supply fans of about 1,360 scfm each, a ducted supply and return air system, automatic controls, and accessories.

The air handling units are located in the lower south air handling unit equipment room on elevation 135′-3″ of the annex building. They are supplied from the air intake plenum #2 located at the extreme south end of the annex building between elevation 135′-3″ and 158′. This plenum also supplies air for the health physics and hot machine shop HVAC system and the containment air filtration system. The intake is not protected from tornado missiles.

The ancillary diesel generator room is supplied air from the air handling units to maintain normal design temperatures. Air supplied to the room is exhausted direct to outdoors by means of a separate exhaust fan. Ventilation and cooling for the ancillary diesel generator room when the diesel generators operate is provided by opening the doors to allow airflow into the room. Air from the ancillary diesel generator room is exhausted to the outdoors through the diesel generator radiator(s), ducting, backdraft damper(s), and hurricane louvers. There is a manual damper in the duct downstream of each diesel radiator that discharges air into the room. This manual damper can be used to control room temperature in cold weather.

9.4.2.2.1.6 Valve/Piping Penetration Room HVAC System

The valve/piping penetration room HVAC subsystem serves the valve/piping penetration room on elevation 100′-0″ of the auxiliary building. The valve/piping penetration room HVAC subsystem consists of two 100-percent-capacity air handling units (VXS-MS-08A and B) with supply fans of about 2,070 scfm each, a return air duct system, automatic controls, and accessories.

The air handling units are located directly within the space served.

9.4.2.2.2 Component Description

The annex/auxiliary buildings HVAC system is comprised of the following major components. These components are located in buildings on the Seismic Category I Nuclear Island or in the annex building. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Tables 9.4.2-1 and 9.4.2-2 provide the design parameters for major defense-in-depth components of the system.

Air Handling Units

Air handling units with integral supply and return/exhaust fans are utilized in the equipment room HVAC subsystem and switchgear room HVAC subsystem. Each air handling unit consists of a return/exhaust fan, a return/exhaust air plenum, a low efficiency filter bank, a high efficiency filter bank, a chilled water cooling coil, and a supply air fan.

Supply Air Handling Units

Supply air handling units are utilized in the general area HVAC subsystem, main steam isolation valve compartment HVAC subsystem, the valve/piping penetration room HVAC subsystem, and the mechanical equipment area HVAC subsystem. Each air handling unit consists of a low efficiency filter bank, a hot water heating coil, a chilled water cooling coil, and a supply fan. The general area HVAC subsystem and the mechanical equipment area HVAC subsystem air handling units each include a high efficiency filter bank that has a face and bypass damper on the heating coil.

Supply and Exhaust Air Fans

The supply and exhaust fans are centrifugal type, single width single inlet (SWSI), double width double inlet (DWDI), tubular centrifugal or plenum centrifugal with backward inclined blades that produce non-overloading horsepower characteristics or radial blades and forward curved blades that produce overloading horsepower characteristics. Only air handling unit fans that have littler or no ductwork may utilize forward curved blades. Fan configurations are either performance rated in accordance with ANSI/AMCA 210 (Reference 4) or certified in accordance with AMCA 211

(Reference 5). Fan configurations are sound tested in accordance with ANSI/AMCA 300 (Reference 6).

Low Efficiency Filters and High Efficiency Filters

The low efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52.1 and 126 (References 7 and 35). The filters are UL listed in accordance with UL 900 (Reference 8).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Heating Coils

The hot water heating coils are counterflow, finned tubular type. The heating coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Electric Heating Coils

The electric heating coils are SCR controlled, fin tubular type. The electric heating coils are UL listed in accordance with UL 1996 (Reference 26).

Electric Unit Heaters

The electric unit heaters are single or multi stage, fin tubular type. The electric unit heaters are UL listed in accordance with UL 2021 (Reference 40) and meet the requirements of the National Electric Code NFPA 70 (Reference 28).

Humidifier

The humidifier is a packaged electric steam generator type which converts water to steam and distributes it through the supply duct system. The humidifier is performance rated in accordance with ARI 640 (Reference 13).

Hot Water Unit Heaters

The hot water unit heaters consist of a fan section and hot water heating coil section factory assembled as a complete and integral unit. The unit heaters are either horizontal discharge or vertical downblast type. The hot water unit heaters are tested and rated using the methods and standard conditions provided within ASHRAE Handbook - HVAC Systems and Equipment, “Unit Ventilators, Unit Heaters, and Makeup Air Units” (Reference 42).

Isolation Dampers

Isolation dampers are single- or parallel-blade type. The isolation dampers have spring return actuators which fail closed on loss-of-electrical power or loss-of-air pressure. The isolation dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Shutoff, Volume Control, Balancing, and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, volume control and balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through ventilators, exhaust fans and the valve/piping penetration room air handling units. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow. Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL 555 (Reference 15). Fire dampers are not provided in locations where combination fire/smoke dampers are provided.

Fire dampers at duct penetrations through fire barriers, which are within ducting that is routed through the CSA Pressure Boundary are Class R and are designed, constructed, and tested in accordance with ASME AG-1 Section DA (Reference 36). The fire damper assembly (sleeve) is bubble tight at design pressure. The use of Class R fire dampers is applied to protect and maintain the main control/control support area habitability. The use of Class R fire dampers mitigates the potential for exfiltration/infiltration of air in ducting which routed through the CSA pressure boundary.

Combination Fire/Smoke Dampers

Combination fire/smoke dampers are provided at the duct penetrations through fire barriers between the annex building and the auxiliary building, at the duct penetrations through fire barriers to the ICC/Non-1E penetration room, the Staging and Storage Area/Electrical Switchgear Rooms, the Staging and Storage Area/Annex Building (North) Air Handling Equipment Room, Annex Building (North) Air Handling Equipment Room/Battery Charger Rooms, Non-1E Penetration Room/Reactor Trip Switchgear Rooms to maintain the fire resistance ratings of the barriers. The combination fire/smoke dampers are designed, constructed, and tested in accordance with UL-555S (Reference 25) and UL-555 (Reference 15).

The combination fire/smoke damper assemblies (sleeves) at duct penetration through fire barrier to the Staging and Storage Area I Electrical Switchgear Rooms and the Staging and Storage Area I Annex Building (North) Air Handling Equipment Room are bubble tight at design pressure and Class R. The use of Class R combination fire/smoke damper assemblies mitigates the potential for exfiltration/infiltration of air in ducting, during operation of the HVAC subsystem, coincident with an airborne release from the spaces the subsystem ductwork is routed through.

Ductwork, Duct Supports, and Accessories

Non-Seismic ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17) with the exception of Class R ductwork as noted below:

Ductwork which routed through the Staging and Storage Area (RCA) or the CSA Pressure Boundary is Class R and is designed, constructed, and tested in accordance with ASME AG-1 Section SA (Reference 36).

The Class R ductwork (ASME AG-1 Section SA) is applied to promote an ALARA HVAC design and to maintain main control room/control support area habitability.

Seismic Category II ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17) and Appendix 3A.

Ductwork is constructed of materials consistent with these standards including, but not limited to, galvanized or stainless steel. Duct supports and accessories are constructed of material consistent with these standards including, but not limited to, galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

9.4.2.2.3 System Operation

9.4.2.2.3.1 General Area HVAC Subsystem

Normal Plant Operation

During normal plant operation, all four supply air handling units and the toilet/shower and rest room exhaust fans operate continuously to maintain suitable temperatures in the areas served. Cooling is provided via the supply of VWS chilled water to the air handling units' cooling coils. Heating is provided via a supply of VYS water to the air handling units' heating coils during times when the VYS system has been manually actuated (Refer to Section 9.2.10.2). The temperature of the air supplied by the VXS-MS-01A/B air handling units is controlled by temperature controls with their sensors located in the annex building main return air plenum. For air handlers VXS-MS-03A/B, the temperature of the supply air is controlled by a sensor immediately downstream of the air handler. The temperature sensors send a signal to their temperature controller which automatically modulates the chilled water control valve and the face and bypass dampers across the supply air heating coil to maintain the area within the design range.

Supplemental heating is provided for the men's/women's change room areas by an electric reheat coil located in the supply air duct to the areas served. The reheat coil operates intermittently under the control of its temperature controller with sensor located in the women's change room, which modulates the electric heating elements to maintain the space temperature in the change room areas within the design range.

For the general area air handling units, the supply air is humidified by a common humidifier located in the ductwork downstream of the supply air handling units. A humidistat located in the annex building operates the humidifier to maintain a minimum space relative humidity of 35 percent in the areas served. For the office area air handling units, a humidifier is not provided in the system.

The differential pressure drop across each supply unit filter bank is monitored, and individual alarms are actuated when any pressure drop rises to a predetermined level indicative of the need for filter replacement. To replace the filters on a supply unit, the affected supply fan is stopped and isolated from the duct system by means of isolation dampers. The exhaust fan for the area is also stopped, which may result in a slightly positive pressure with respect to adjacent areas or the outside atmosphere. During filter replacement, the system operates at approximately 50 percent capacity.

Abnormal Plant Operation

The general area HVAC subsystem is not required to operate during any abnormal plant condition. The general area HVAC subsystem outside air intake/exhaust dampers close on a “High-2” particulate or iodine signal from the MCR radiation package communicated through the plant control system (PLS).

9.4.2.2.3.2 Switchgear Room HVAC Subsystem

Normal Plant Operation

During normal plant operation, one air handling unit operates continuously to maintain the indoor temperatures in the two switchgear rooms. Cooling is normally provided via the supply of VWS chilled water to the operating air handling unit’s cooling coil. The temperature of the air supplied by the air handling unit is maintained at setpoint temperature by the temperature controller installed in the supply side of the air handling unit. The temperature controller modulates the chilled water valve. Temperature controllers located in the switchgear rooms provide low limit temperature control. When the temperature of a switchgear room drops to the low temperature setpoint, the controller will limit the travel of the chilled water valve serving the air handling unit cooling coil to prevent the room from

falling below room design minimum temperature. A minimum of outside air is always provided for ventilation requirements.

The differential pressure drop across each air handling unit filter bank is monitored and individual alarms are actuated when the pressure drop rises to a predetermined level indicative of the need for filter replacement. To replace the filters on an air handling unit, the unit is stopped and isolated from the duct system by means of isolation dampers. During filter replacement, the second air handling unit operates at full system capacity.

Abnormal Plant Operation

The switchgear room HVAC subsystem outside air intake/exhaust dampers close on a “High-2” particulate or iodine signal from the MCR radiation package communicated through the plant control system (PLS). In the event of a loss of the normal ac power and offsite power, the air handling unit supply and return/exhaust fans are connected to the standby power system to provide ventilation cooling to the diesel bus switchgear. This cooling permits the switchgear to perform its defense in depth functions in support of standby power system operation. In this mode of operation, the switchgear rooms are cooled using outside air. In this mode of operation, outside air is admitted via the economizer dampers (outside air dampers, return air dampers, and exhaust air dampers), which are modulated by the temperature controller installed in the supply side of the air handling unit. The switchgear rooms will be maintained between 62 and 122°F.

In the event of a fire in a non-1E electrical switchgear room, the combination fire/smoke dampers close automatically to isolate the affected fire area in response to heat from the fire or upon receipt of a smoke signal from an area smoke detector. The VXS subsystem continues to provide ventilation/ cooling to the remaining switchgear room.

9.4.2.2.3.3 Equipment Room HVAC Subsystem

Normal Plant Operation

During normal plant operation, one air handling unit and both battery room exhaust fans operate continuously to maintain the indoor temperatures in the equipment and security access areas served by the system.

The temperature of the air supplied by the air handling unit is maintained at setpoint temperature by the temperature controller installed in the supply side of the air handling unit. The temperature controller modulates the outside air dampers, return air dampers, exhaust air dampers, and chilled water valve. Cooling is normally provided via the supply of VWS chilled water to the air handling unit’s cooling coil. A minimum of outside air is always provided for ventilation requirements.

Electric reheat coils serving security (rooms 40305 and 40306) are controlled by temperature controllers with sensors located in the areas served. The temperature sensor sends a signal to a temperature controller which modulates the electric heating elements to maintain the security access areas at their design temperatures. Hot water unit heaters operate intermittently to provide supplemental heating for the north air handling equipment room to maintain the area temperature above 50°F.

A humidistat located in the security access area intermittently operates the humidifier to maintain the security office area at a minimum space relative humidity of 35 percent.

The differential pressure drop across each air handling unit filter bank is monitored, and individual alarms are actuated when the pressure drop rises to a predetermined level indicative of the need for filter replacement. To replace the filters of an air handling unit, the unit is stopped and isolated from

the duct system by means of isolation dampers. During filter replacement, the second air handling unit operates at full system capacity.

Abnormal Plant Operation

The equipment room HVAC subsystem outside air intake/exhaust dampers close on a “High-2” particulate or iodine signal from the MCR radiation package communicated through the plant control system (PLS). In the event of a loss of the normal ac power and offsite power, the air handling unit supply, the return/exhaust fans, and the economizer dampers are connected to the standby power system to provide ventilation cooling to the dc switchgear and inverters. This cooling permits that equipment to perform its defense in depth functions. In this mode of operation, the rooms are cooled using outside air. In this mode of operation, outside air is admitted via the economizer dampers (outside air dampers, return air dampers, and exhaust air dampers), which are modulated by the temperature controller installed in the supply side of the air handling unit. In this mode of operation, the dc switchgear and inverter areas will be maintained at or below 122°F. Equipment in those areas that operate following a loss of the normal ac power and offsite power are designed for continuous operation at this temperature. To maintain the areas above freezing, the economizer dampers will modulate to maintain a supply air temperature of 52°F for outdoor temperatures below 52°F. For outdoor temperature above 52°F, the outside air, return air, and exhaust air dampers are positioned for a once-through flow.

9.4.2.2.3.4 MSIV Compartment HVAC Subsystem

Normal Plant Operation

During normal plant operation, one of the main steam isolation valve compartment air handling units in each compartment operates continuously in a recirculation mode to maintain the indoor temperature in the equipment area served by the system. Cooling is provided via the supply of VWS chilled water to the air handling units' cooling coils. Heating is provided via a supply of VYS water to the air handling units' heating coils during times when the VYS system has been manually actuated (Refer to Section 9.2.10.2). A temperature controller automatically modulates the chilled water and hot water control valves serving the operating unit to maintain the compartment temperature at or less than 105°F and above a minimum of 50°F.

The differential pressure drop across each air handling unit filter bank is monitored and individual alarms are actuated when the pressure drop rises to a predetermined level indicative of the need for filter replacement. An air handling unit may be shutdown for filter replacement or other maintenance as required, with the other air handling unit in the same compartment operating to maintain the area temperature.

Abnormal Plant Operation

The main steam isolation valve compartment HVAC subsystem is not required to operate during abnormal plant conditions.

9.4.2.2.3.5 Mechanical Equipment Areas HVAC Subsystem

During normal plant operation, the air handling units operate continuously to maintain the indoor temperatures in the areas served. Cooling is provided via the supply of VWS chilled water to the air handling units' cooling coils. Heating is provided via a supply of VYS water to the air handling units' heating coils during times when the VYS system has been manually actuated (Refer to Section 9.2.10.2). The temperature of the air supplied by each air handling unit is controlled by individual temperature controls with their sensors located in the upper south air handling equipment room. The temperature sensor sends a signal to a temperature controller which automatically modulates the face and bypass dampers across the supply air heating coil and the chilled water

control valve to maintain the mechanical equipment areas within the design temperature range. A constant volume of outside air is used to provide ventilation.

Differential pressure drop across each air handling unit filter bank is monitored, and individual alarms are actuated when pressure drop rises to a predetermined level indicative of the need for filter replacement. During filter replacement, the system operates at approximately 50 percent capacity. To replace the filters of an air handling unit, the unit is stopped and isolated from the duct system by means of isolation dampers. To replace the filters of an air handling unit, the unit is stopped and isolated from the duct system by means of isolation dampers.

The exhaust fan for the ancillary diesel generator room operates continuously for room ventilation.

Abnormal Plant Operation

The mechanical equipment areas HVAC subsystem is not required to operate during abnormal plant conditions.

When the ancillary diesel generator sets are operated, a manual damper is opened as required and the outside door is opened to maintain acceptable temperatures.

9.4.2.2.3.6 Valve/Piping Penetration Room HVAC Subsystem

Normal Plant Operation

During normal plant operation, one air handling unit operates continuously in a recirculation mode to maintain the indoor temperature in the room. Cooling is provided via the supply of VWS chilled water to the air handling units' cooling coils. Heating is provided via a supply of VYS water to the air handling units' heating coils during times when the VYS system has been manually actuated (Refer to Section 9.2.10.2). A temperature controller automatically modulates the chilled water control valve and opens and closes the hot water control valve serving the operating unit to maintain the area temperature at or less than 105°F and above a minimum of 50°F.

The differential pressure drop across each air handling unit filter bank is monitored, and individual alarms are actuated when the pressure drop rises to a predetermined level indicative of the need for filter replacement.

Abnormal Plant Operation

The valve/piping penetration room HVAC subsystem is not required to operate during abnormal plant conditions.

9.4.2.3 Safety Evaluation

The annex/auxiliary buildings nonradioactive HVAC system has no safety-related function and therefore requires no nuclear safety evaluation.

9.4.2.4 Tests and Inspections

The annex/auxiliary buildings nonradioactive HVAC system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustments to design conditions are made during the plant preoperational test program. Air flow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC Systems – Testing, Adjusting, and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.2.5 Instrumentation Applications

The annex/auxiliary buildings nonradioactive HVAC system operation is controlled by the plant control system (PLS). Refer to Subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers and thermostats maintain the proper space temperatures. Supply air temperature is controlled by either sensing local room temperature or by sensing the supply air temperature in the air handling unit discharge duct, depending on the subsystem. Unit heaters are controlled by local thermostats. Temperature indication and alarms are accessible locally via the plant control system.

Temperature is indicated for each air handling unit supply air discharge duct, except for local recirculation units such as those in the main steam isolation valve compartment and valve/piping penetration room.

Operational status of fans is indicated in the main control room. The fans and air handling units can be placed into operation or shutdown from the main control room or locally.

Differential pressure indication is provided for each of the filters in the air handling units and an alarm for high pressure drop is provided for each air handling unit.

Airflow is indicated for the air handling unit and exhaust fan discharge ducts. Alarms are provided for low air flow rates in the fan discharge ducts.

An alarm is provided for smoke in discharge ducts from the air handling units.

Position indicating lights are provided for automatic dampers.

9.4.3 Radiologically Controlled Area Ventilation System

The radiologically controlled area ventilation system (VAS) serves the fuel handling area of the auxiliary building, and the radiologically controlled portions of the auxiliary and annex buildings, except for the health physics and hot machine shop areas which are provided with a separate ventilation system (VHS).

9.4.3.1 Design Basis

9.4.3.1.1 Safety Design Basis

The radiologically controlled area ventilation system serves no safety-related function and therefore has no nuclear safety design basis. System equipment and ductwork located in the nuclear island whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is nonseismic.

9.4.3.1.2 Power Generation Design Basis

The radiologically controlled area ventilation system provides the following functions:

- Provides ventilation to maintain the equipment rooms within their design temperature range
- Provides ventilation to maintain airborne radioactivity in the access areas at safe levels for plant personnel
- Maintains the overall airflow direction within the areas it serves from areas of lower potential airborne contamination to areas of higher potential contamination
- Maintains each building area at a slightly negative pressure to prevent the uncontrolled release of airborne radioactivity to the atmosphere or adjacent clean plant areas
- Automatically isolates selected building areas from the outside environment by closing the supply and exhaust duct isolation dampers and starting the containment air filtration system when high airborne radioactivity in the exhaust air duct or high ambient pressure differential is detected. See Subsection 9.4.7 for a description of the containment air filtration system.

The system maintains the following room temperatures based on the maximum and minimum normal outside air temperature conditions shown in Chapter 2, Table 2.0-201:

Access and Equipment Areas	Temperatures (°F)
Auxiliary/Annex Building Subsystem	
Degasifier column	50-130
RNS and CVS pump rooms (pumps not operating)	50-104
RNS and CVS pump rooms (pumps operating)	50-130
Containment purge exhaust filter rooms (fans not operating)	50-104
Containment purge exhaust filter rooms (fans operating)	50-130
Liquid radwaste tank rooms	50-130
Liquid radwaste pump rooms	50-104
HVAC equipment room	50-104
Gaseous radwaste equipment rooms	50-104
Spent fuel pool pump and heat exchanger rooms	50-104
Annex building staging and storage area	50-104
Demineralizer/filter access area and corridor 12261	50-85
VES air storage room	60-80
Other corridors and staging areas	50-104
Fuel Handling Area Ventilation Subsystem	
Rail car bay/filter storage area	50-104
Spent resin equipment rooms	50-130
Corridors and access areas	50-104
Occupied Areas	
Fuel Handling Area Ventilation Subsystem	
Fuel handling area	50-96
Auxiliary/Annex Building Ventilation Subsystem	
Radiation chemistry laboratory	73-78
Primary sample room	50-104
Security rooms	65-78

9.4.3.2 System Description

The radiologically controlled area ventilation system consists of the following subsystems:

- Auxiliary/annex building ventilation subsystem
- Fuel handling area ventilation subsystem

The defense in depth portion of the system is shown in Figure 9.4.3-1.

9.4.3.2.1 General Description

9.4.3.2.1.1 Auxiliary/Annex Building Ventilation Subsystem

The auxiliary/annex building ventilation subsystem serves radiologically controlled equipment, piping and valve rooms and adjacent access and staging areas. See Figure 9.4.3-1, sheet 2 of 4, for a complete listing of rooms and corridors serviced by this subsystem. The auxiliary/annex building ventilation subsystem consists of two 50 percent capacity supply air handling units of about 14,000 scfm each, a ducted supply and exhaust air system, isolation dampers, diffusers and registers, exhaust fans, automatic controls and accessories. The supply air handling units are located in the south air handling equipment room of the annex building at elevation 158′-0″. They are connected to the air intake plenum #3 located in the extreme south end of the annex building. This plenum is not protected from tornado missiles. The units discharge into a ducted supply distribution system which is routed through the radiologically controlled areas of the auxiliary and annex buildings. The supply and exhaust ducts have isolation dampers that close to isolate the auxiliary and annex buildings from the outside environment when high airborne radioactivity is detected in the exhaust air duct. The supply and exhaust ducts are configured so that two building zones may be independently isolated. The annex building staging and storage area, containment air filtration exhaust rooms, containment access corridor, and adjacent auxiliary building staging, equipment areas, middle annulus, middle annulus access room, and security rooms are aligned to one zone. A radiation monitor is located in the exhaust air duct from the annex building areas in this zone, and a second radiation monitor is located in the exhaust air duct from the auxiliary building areas in this zone. The other zone includes the remaining rooms and corridors shown in Figure 9.4.3-1 sheet 2 of 4, including but not limited to the radiation chemistry laboratory, primary sample room, spent fuel pool cooling water pump and heat exchanger rooms, normal residual heat removal pump and heat exchanger rooms, CVS makeup pump room, lower annulus, and various radwaste equipment rooms, pipe chases, and access corridors. Figure 9.4.3-1, sheet 4 of 4, depicts the recirculating air cooling units for the security rooms. A radiation monitor is located in the exhaust air duct from this zone.

The two 50 percent capacity exhaust air fans sized to allow the system to maintain a negative pressure are located in the upper radiologically controlled area ventilation system equipment room at elevation 145′-9″ of the auxiliary building. The exhaust air ductwork is routed to minimize the spread of airborne contamination by directing the supply airflow from the low radiation access areas into the radioactive equipment and piping rooms with a greater potential for airborne radioactivity. Additionally, the exhaust air ductwork is connected to the radioactive waste drain system (WRS) sump to maintain the sump atmosphere at a negative air pressure to prevent the exfiltration of potentially contaminated air into the surrounding area. The sump vent line is constructed of pipe, which is routed upward from the sump to the interface with the HVAC system. The exhaust air ductwork is connected to the radwaste effluent holdup tanks to prevent the potential buildup of airborne radioactivity or hydrogen gas within these tanks. The effluent holdup tanks have an overflow line to the WRS from a nozzle on the side of the tank, and a vent line from a nozzle on the top of the tank. The vent line is constructed of pipe, and is routed upward from the tank to the interface with the HVAC system. The exhaust fans discharge the exhaust air into the plant vent for monitoring of offsite airborne radiological releases.

The ventilation airflow dilutes potential airborne contamination to maintain the concentration at the site boundary within 10 CFR 20 (Reference 21) allowable effluent concentration limits and the internal room airborne concentrations within 10 CFR 20 occupational derived air concentration (DAC) limits during normal plant operation.

Unit coolers are located in the normal residual heat removal system (RNS) and chemical and volume control system (CVS) pump rooms because they have significant cooling loads on an intermittent basis when large equipment is operating. Each unit cooler is sized to accommodate 100 percent of its corresponding pump cooling load. The unit coolers are provided with chilled water from redundant trains of the central chilled water system (VWS) low capacity subsystem. The normal residual heat removal pump room unit coolers have two cooling coils per unit cooler so that chilled water supplied by either train A or train B alone can support concurrent operation of both normal residual heat removal system pumps. The two chemical and volume control makeup pump room unit coolers are connected to redundant trains of the chilled water system; however, operation of either the train A or train B unit cooler alone maintains the common makeup pump room temperature conditions and supports operation of either makeup pump. Condensation from these cooling coils drains to the WRS.

Heating coils are located in the supply air ducts serving plant areas that require supplemental heating during periods of cold outside air temperature conditions. The heating coils are supplied with hot water from the hot water heating system (VYS). The radiation chemistry laboratory is provided with an electric duct heater and humidifier in the supply air duct. Security Room (Room 12451) is provided with an electric duct heater and humidifier in the supply air duct and two local fan coil cooling units. Security Room (Room 40415) is provided with an electric duct heater in the supply air duct. These components are provided to maintain the environmental conditions within the areas suitable for personnel comfort. Electric unit heaters provide supplemental heating in the middle annulus.

The upper annulus is separated from the middle annulus area of the auxiliary building by a concrete floor section and flexible seals that connects the containment steel shell to the shield building. The annulus seal provides a passive barrier during normal plant operation or when the auxiliary building is isolated, preventing the exfiltration of unmonitored releases from the middle annulus to the environment.

9.4.3.2.1.2 Fuel Handling Area Ventilation Subsystem

The fuel handling area ventilation subsystem serves the fuel handling area, rail car bay/filter storage area, resin transfer pump/valve room, spent resin tank room, waste disposal container area, and WSS (spent resin) valve/piping area. The fuel handling area ventilation subsystem consists of two 50 percent capacity supply air handing units of about 4,900 scfm each, a ducted supply and exhaust air system, isolation dampers, diffusers, registers, exhaust fans, automatic controls and accessories. Hot water heating coils supplied with water from the hot water heating system (VYS), cooling coils supplied with water from the central chilled water system (VWS) and electric duct heaters are used to maintain ambient room temperatures within the normal range. The ventilation airflow capacity is designed to maintain environmental conditions that support worker efficiency during fuel handling operations based on a maximum wetbulb globe temperature of 80°F (96°F drybulb) as defined by EPRI NP-4453 (Reference 22). The supply air handling units are located in the south air handling equipment room of the annex building at elevation 158′-0″. They are connected to the air intake plenum #3 located at the south end of the annex building. This common intake plenum is described in Subsection 9.4.3.2.1.1. The units discharge into a ducted supply distribution system which is routed to the fuel handling and rail car bay/filter storage areas of the auxiliary building. The supply and exhaust ducts are provided with isolation dampers that close when high airborne radioactivity in the exhaust air or high pressure differential with respect to the outside atmosphere is detected.

The two 50 percent capacity exhaust air fans sized to allow the system to maintain a negative pressure are located in the upper radiologically controlled area ventilation system equipment room at elevation 145′-9″ of the auxiliary building. The supply and exhaust ductwork is arranged to exhaust the spent fuel pool plume and to provide directional airflow from the rail car bay/filter storage area into the spent resin equipment rooms. The exhaust fans discharge the normally unfiltered exhaust air into the plant vent for monitoring of offsite airborne gaseous and other radiological releases.

The ventilation airflow dilutes potential airborne contamination to maintain the concentration at the site boundary within 10 CFR 20 (Reference 21) allowable effluent concentration limits and the internal room airborne concentrations within 10 CFR 20 occupational derived air concentration (DAC) limits during normal plant operation.

9.4.3.2.2 Component Description

The radiologically controlled area ventilation system is comprised of the following major components. These components are located in buildings on the Seismic Category I Nuclear Island and the Seismic Category II portion of the annex building. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Table 9.4.3-1 provides design parameters for major defense in depth components in the system.

Supply Air Handling Units

Each supply air handling unit consists of a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil bank, a chilled water cooling coil bank, and a supply fan.

Supply and Exhaust Air Fans

The supply and exhaust air fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with backward inclined blades that produce non-overloading horsepower characteristics or radial and forward curved blades that produce overloading horsepower characteristics. Fan configurations are either performance rated in accordance with ANSI/AMCA 210 (Reference 4) or certified in accordance with AMCA 211 (Reference 5). Fan configurations are sound tested in accordance with ANSI/AMCA 300 (Reference 6).

Fan Coil Cooling Units

Each fan coil cooling unit consists of a low efficiency filter, cooling coil and supply fan.

Unit Coolers

Each unit cooler consist of a low efficiency filter bank, a chilled water cooling coil bank and a supply fan. The normal residual heat removal system pump room unit coolers have redundant cooling coil banks. The principal construction code is the manufacturer's standard.

Low and High Efficiency Filters

The low efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52.1 and 126 (References 7 and 35). The filters minimum average dust spot efficiencies for the defense in depth filters are shown in Table 9.4.3-1. The filters are UL listed in accordance with UL 900 (Reference 8).

Electric Unit Heaters

The electric unit heaters are single or multi stage, fin tubular type. The electric unit heaters are UL listed in accordance with UL 2021 (Reference 40) and meet the requirements of the National Electric Code NFPA 70 (Reference 28).

Hot Water Heating Coils

The hot water heating coils are finned tubular type. The outside supply air heating coils are provided with integral face and bypass dampers to prevent freeze damage when modulating the heat output. Coils are performance rated in accordance with ANSI/ARI 410 (Reference 12).

Electric Heating Coils

The electric heating coils are SCR controlled, fin tubular type. The electric heating coils are UL listed in accordance with UL 1996 (Reference 26).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Humidifier

The humidifier is a packaged electric steam generator type which converts water to steam and distributes it through the supply duct system. The humidifier is performance rated in accordance with ARI 640 (Reference 13).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance rating of the barriers. The fire dampers meet the design, testing and installation requirements of UL-555 (Reference 15).

Shutoff and Balancing Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, balancing dampers are opposed-blade type. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow.

Shutoff dampers downstream of exhaust fans, which discharge air into the plant vent stack at a positive pressure, are Class R and are designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section DA. The Class R dampers are applied to promote an ALARA HVAC design. The use of Class R dampers mitigates the potential for exfiltration of airborne radiation in a positive pressure duct during operation of the fan coincident with an airborne release from the spaces the fans serve.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Isolation Dampers

Isolation dampers are single- or parallel-blade type. The isolation dampers have spring return actuators which fail closed on loss of electrical power or loss of air pressure.

Isolation dampers which isolate contaminated air streams are Class R. The Class R isolation dampers have bubble tight (frame/blades) and are designed, constructed, and tested in accordance with ASME AG-1 Section DA (Reference 36).

The isolation dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Ductwork, Duct Supports, and Accessories

Non-Seismic ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17).

Seismic II Category ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34), SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17), and Appendix 3A, with the exception of the Class R ductwork as noted below.

Ductwork downstream of exhaust fans, which discharge air into the plant vent stack at a positive pressure, is Class R and is designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section SA, and Appendix 3A. The Class R ductwork (ASME AG-1 Section SA) is applied to promote an ALARA HVAC design. The use of Class R ductwork mitigates the potential for exfiltration of airborne radiation in a positive pressure duct during operation of the fan coincident with an airborne release from the spaces the fan serves.

Ductwork is constructed of materials consistent with these standards including, but not limited to, galvanized or stainless steel. Duct supports and accessories are constructed of material consistent with these standards including, but not limited to, galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

9.4.3.2.3 System Operation

9.4.3.2.3.1 Auxiliary/Annex Building Ventilation Subsystem

Normal Plant Operation

During normal plant operation, both supply air handling units and both exhaust fans operate continuously to ventilate the areas served on a once-through basis. The inlet vanes of the supply fans are modulated automatically by flow controllers to maintain a constant air flow rate. The exhaust air flow is then balanced to maintain the areas served at a slightly negative pressure differential with respect to the outside environment. The exhaust air is unfiltered and directed to the plant vent for discharge and monitoring of offsite gaseous releases.

The temperature of the supply air is controlled by temperature sensors located in the supply air ducts. When the supply air temperature is low, the face and bypass dampers across the supply air hot water heating coil are modulated to heat the supply air. When the supply air temperature is high, the flow of chilled water is modulated to cool the supply air. A temperature sensor or local thermostat modulates electric duct heaters located in the supply ducts serving personnel comfort areas to temper air and maintain environmental conditions. Building areas that have conductive heat loss to the outside environment during periods of cold outside temperature conditions are provided with electric unit heaters or supply duct hot water heating coils. Electric unit heaters are turned on/off by local thermostats. Temperature sensors control hot water heating (VYS) isolation valves which regulate flow to the supply duct hot water heating coils. The ventilation air is continuously monitored by smoke detectors located in the ductwork downstream of the supply air handling units and upstream of the exhaust fans.

A supply air handling unit is automatically shut down if the supply air temperature is below a predetermined setpoint.

Each chemical and volume control system makeup pump and normal residual heat removal system pump unit cooler automatically starts on a high room temperature signal and stops on a low room temperature signal.

The gaseous radwaste equipment areas have sufficient ventilation to remove hydrogen gas that may leak from the radwaste equipment into the equipment rooms to maintain the concentration of hydrogen below a safe level of about 1 percent. Instrumentation available to monitor hydrogen concentration is listed in Table 11.3-2.

Abnormal Plant Operation

If high airborne radioactivity is detected in the exhaust air from the auxiliary or annex buildings, the supply and exhaust duct isolation dampers automatically close to isolate the affected area from the outside environment. The containment air filtration system mitigates the exfiltration of unfiltered airborne radioactivity by maintaining the isolated zone at a slightly negative pressure with respect to the outside environment and adjacent unaffected plant areas. The auxiliary/annex building ventilation subsystem remains in operation at a reduced capacity if either the auxiliary or annex building is not isolated. A disruption in the normal ventilation airflow rate that causes a high pressure differential with respect to the outside environment causes the same automatic actuations. The containment air filtration system maintains a slightly negative pressure differential with respect to the outside environment until operation of the auxiliary/annex building ventilation subsystem is restored. Refer to Subsection 9.4.7 for a description of the containment air filtration system.

If smoke is detected in the exhaust air ducts, an alarm is initiated in the main control room. The auxiliary/annex building ventilation subsystem remains in operation unless plant operators determine that there is a need to manually shut down the subsystem. If smoke is detected in the supply air ducts, an alarm is initiated in the main control room and the supply and exhaust fans for the corresponding train are automatically shut down. In the event of a fire occurring within the auxiliary or annex buildings, local fire dampers automatically isolate the HVAC ductwork penetrating the fire area when the local air temperature exceeds predetermined setpoints.

In the event of a loss of the normal ac power and offsite power, the unit coolers serving the normal residual heat removal, and chemical and volume control pump rooms can be powered by the onsite standby diesel generators.

9.4.3.2.3.2 Fuel Handling Area Ventilation Subsystem

Normal Plant Operation

During normal plant operation, both supply air handling units and both exhaust fans operate continuously to ventilate the areas served on a once-through basis. The inlet vanes of the supply fans are modulated automatically by flow controllers to maintain a constant air flow rate. The exhaust air flow is then balanced to maintain the areas served at a slightly negative pressure differential with respect to the outside environment. The exhaust air is unfiltered and directed to the plant vent for discharge and monitoring of offsite gaseous releases.

The temperature of the supply air is controlled by temperature sensors located in the supply air ducts. When the supply air temperature is low, the face and bypass dampers across the supply air hot water heating coil are modulated to heat the supply air. A temperature sensor controls supplemental heating in the rail car bay/filter storage area by controlling a hot water (VYS) isolation valve which regulates flow to a supply duct heating coil. A temperature sensor controls supplemental heating in the Fuel Handling Area by modulating electric duct heaters located in the supply ducts. When the supply air temperature is high, the flow of chilled water is modulated to cool the supply air. The ventilation air is continuously monitored by smoke detectors located in the ductwork downstream of the supply air handling units and by a detector upstream of the exhaust fans.

A supply air handling unit is automatically shut down if the supply air temperature is below a predetermined setpoint.

Abnormal Plant Operation

If high airborne radioactivity is detected in the exhaust air from the fuel handling area, the supply and exhaust duct isolation dampers automatically close to isolate the fuel handling area from the outside environment. The containment air filtration system mitigates exfiltration of unfiltered airborne radioactivity by maintaining the isolated zone at a slightly negative pressure differential with respect to the outside environment and adjacent unaffected plant areas. A disruption in the normal ventilation airflow rate that causes a high pressure differential with respect to the outside environment causes the same automatic actuations. The containment air filtration system maintains a slightly negative pressure differential with respect to the outside environment until operation of the fuel handling area ventilation subsystem is restored. Refer to Subsection 9.4.7 for a description of the containment air filtration system.

If smoke is detected in the exhaust air ducts, an alarm is initiated in the main control room. The fuel handling area subsystem remains in operation unless plant operators determine that there is a need to manually shut down the subsystem. If smoke is detected in the supply air ducts, an alarm is initiated in the main control room and the supply and exhaust fans for the corresponding train are automatically shut down. In the event of a fire occurring within the fuel handling area, fire dampers automatically isolate the HVAC ductwork penetrating this fire area when the local air temperature exceeds predetermined setpoints.

9.4.3.3 Safety Evaluation

The radiologically controlled area ventilation system has no safety-related function and therefore requires no nuclear safety evaluation.

The isolation dampers for the fuel handling area, auxiliary and annex buildings are provided to help keep normal plant releases below 10 CFR 20 (Reference 21) limits and 10 CFR 50 Appendix I (Reference 20) guidelines in the event of an abnormal release of airborne radioactivity.

9.4.3.4 Tests and Inspections

The radiologically controlled area ventilation system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Airflow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC Systems – Testing, Adjusting and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.3.5 Instrumentation Applications

The radiologically controlled area ventilation system is controlled by the plant control system (PLS). Refer to Subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers maintain the proper air temperatures and provide indication and alarms. Main control room temperature indication is provided for the normal residual heat removal system pump rooms, and the chemical and volume control makeup pump room to allow room temperatures to be verified during pump operation without requiring personnel access to these rooms.

Operational status of fans and dampers is indicated in the main control room. Fans and air handling units can be placed into operation or shut down from the main control room.

Differential pressure indication and high differential pressure alarms are provided for the filters in the air handling units and room coolers. Pressure differential indication and alarms are provided via instruments (VAS-030, VAS-032, VAS-033, and VAS-034) to monitor the pressure differential in the fuel handling area and the radiologically controlled areas of the auxiliary and annex buildings, and to control system operation in the event of equipment malfunction.

Radioactivity indication and alarms are provided to inform the main control room operators of gaseous radioactivity concentrations in the exhaust ducts from the fuel handling area and radiologically controlled areas of the auxiliary and annex buildings.

Flow indication and alarms are provided to alert plant operators to equipment malfunctions. Smoke alarms are provided.

9.4.4 Balance-of-Plant-Interface

Not applicable to AP1000.

9.4.5 Engineered Safety Features Ventilation System

Not applicable to AP1000.

9.4.6 Containment Recirculation Cooling System

The containment recirculation cooling system controls building air temperature and humidity to provide a suitable environment for equipment operability during normal operation and shutdown.

9.4.6.1 Design Basis

9.4.6.1.1 Safety Design Basis

The containment recirculation cooling system serves no safety-related function and therefore has no nuclear safety design basis. The containment recirculation system is not required to mitigate the consequences of a design basis accident or loss of coolant accident. System equipment and ductwork whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is nonseismic.

9.4.6.1.2 Power Generation Design Basis

The containment recirculation cooling system provides the following functions:

- Controls the containment thermal environment to maintain an average bulk air temperature below 120°F during normal operation
- Controls the containment thermal environment to maintain an average bulk air temperature below 70°F and above 50°F for personnel accessibility and equipment operability during refueling and plant shutdown
- Maintains a homogeneous containment temperature and pressure during containment integrated leak rate testing (ILRT)
- Maintains a homogeneous containment temperature and pressure during a loss of the plant ac electrical system

- Controls the reactor cavity area average concrete temperature to less than 150°F with a maximum local area temperature of 200°F

9.4.6.2 System Description

The containment recirculation cooling system is shown in Figure 9.4.6-1.

9.4.6.2.1 General Description

The containment recirculation cooling system is comprised of four 50 percent capacity fan coil unit assemblies which connect to a common duct ring header and distribution system. Each fan coil unit assembly contains a fan and associated cooling coil banks. The fan coil unit assemblies are located on two platforms at elevation 153'-0", with two fan coil unit assemblies occupying each platform. The platforms are located approximately 180 degrees apart to provide a proper return air and mixing pattern through the ring header. The top of the ring header is approximately at elevation 201'-6". The ring header and the fan assemblies are designed to provide uniform air and temperature distribution inside the containment, considering the possibility that one fan coil unit assembly may be out of service.

The cross-connections between the central chilled water system piping for containment cooling and hot water heating system piping for containment heating are located outside the containment. The water piping inside containment is common to both the central chilled water system and hot water heating system.

9.4.6.2.2 Component Description

The containment recirculation cooling system is comprised of the following components. These components are located in buildings on the Seismic Category I Nuclear Island. Table 9.4.6-1 provides design parameters for the major components of the system.

Containment Recirculation Fan Coil Unit Assemblies

Each 50 percent capacity fan coil unit assembly consists of a return air mixing plenum section with two cooling coils attached to each of the four sides of each plenum section. The cooling coils are counterflow finned tubular type. The cooling coils are rated and meet the performance requirements in accordance with ANSI/ARI 410 (Reference 12) and ASHRAE 33 (Reference 11).

The recirculation fans are vaneaxial upblast type, direct driven with adjustable blades and an inlet bell. The fans are mounted vertically on top of the mixing air plenum section. The fans are designed with a non-overloading two-speed motor. The high speed is used during normal operation and the low speed is used during high ambient air density operating conditions such as the integrated leak rate testing. Fan configurations are performance rated in accordance with ANSI/AMCA 210 (Reference 4) and sound tested in accordance with AHRI 575 (Reference 43).

Ductwork, Duct Supports, and Accessories

The ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction standards (References 16 and 34), SMACNA HVAC Duct Construction Standards – Metal and Flexible (Reference 17) and Appendix 3A. With the exception of nonmetallic flexible connectors, ductwork is constructed of either galvanized or stainless steel. The use of nonmetallic flexible connectors inside containment is limited to ductwork above the operating deck. Duct supports and accessories are constructed of galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

Isolation, Balancing, and Backdraft Dampers

The isolation dampers are manually adjusted, parallel-blade type. Multiblade, balancing dampers are opposite-blade type. Backdraft dampers are provided to prevent reverse flow through the standby fan while the redundant fan is operating. The backdraft dampers also allow start up of the standby fan while the redundant fan remains in operation. The dampers are designed for the same differential pressure as the duct section in which they are located.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Fire Damper

Fire damper is provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire damper meets the design and installation requirements of UL-555 (Reference 15).

9.4.6.2.3 System Operation

Normal Plant Operation

During normal plant operation, one of the two 50 percent capacity fan coil unit assemblies on each platform draws air from the upper levels of the operating floor and delivers cooling air through the ring duct and the secondary ductwork distribution system to the cubicles, compartments, and access areas above and below the operating floor. In addition, cooling air is delivered to the reactor cavity and reactor support areas to maintain appropriate local area and concrete temperatures. The nominal supply air temperature provided by the fan coil unit assemblies during normal operation is 70°F in order to meet the environmental design requirements.

As the supply air absorbs the heat released from various components inside containment, return air rises through vertical passages and openings due to its lower density to the upper containment level where it is again drawn into the fan coil unit assemblies, cooled, dehumidified, and recirculated.

The standby fans will be started automatically if one of the following events occurs:

- Air discharge flow rate from the operating fans decreases to a predetermined setpoint
- Electrical and/or control power is lost

Fans are connected to 480V buses with backup power supply from the onsite standby diesel generators. Following a reactor shutdown when the containment air temperature is below a predetermined temperature, the cooling water supply to the four fan coil unit assemblies will be manually realigned by the operators from the central chilled water system to the hot water heating system. Refer to Subsection 9.2.7 for further details.

Shutdown and Refueling Operation

During reactor shutdown, the system maintains the average bulk air temperature within appropriate limits for personnel access and maintenance. In addition, a portable exhaust air filtration unit is available to protect maintenance personnel by controlling the spread of airborne contamination from the steam generator internals to the other containment areas. This is accomplished by running temporary flexible ductwork from one of the steam generator manways to a portable exhaust air filtration unit, which discharges to the containment atmosphere. This allows the steam generators to be maintained negative with respect to the steam generator compartment during testing and inspections.

Integrated Leak Rate Testing Operation

During integrated leak rate testing, fan coil unit assembly operation is controlled by the main control room operator. When placed into operation, the vaneaxial fans are operated at low speed to prevent the fan motors from exceeding their rated horsepower. The fan coil unit assemblies may be operated during the initial phase of the testing to establish homogeneous conditions within the containment and may be operated during the test to maintain stable conditions. Operation of the vaneaxial fans after the initial containment stabilization could affect the containment integrated leak rate testing results. The recirculation fan coil unit assemblies draw air from the upper levels of the operating floor and deliver airflow through the ring header and its distribution ductwork that is connected to equipment compartments, cubicles, and access areas above and below the operating floor.

Abnormal Plant Operation

The containment recirculation system is not required to mitigate the consequences of a design basis fuel handling accident or a loss of coolant accident. If the system is available following abnormal operational transients, it can be operated at reduced speed for post-event recovery operations to lower the containment temperature and pressure.

The power supplies to the containment recirculation cooling system are provided by the plant ac electrical system and the onsite standby diesel generators. In the event of a loss of the normal ac power and offsite power, the containment recirculation components are auto sequenced on to the onsite standby diesel generators, and fans start automatically and operate at fast speed for investment protection.

9.4.6.3 Safety Evaluation

The containment recirculation cooling system has no safety function and therefore requires no nuclear safety evaluation. The containment recirculation cooling system is designed to preclude damage to safety-related systems, structures, or components as a result of a seismic event.

9.4.6.4 Tests and Inspections

The containment recirculation cooling system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of the system are accessible for periodic inspection. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

The system airflows are balanced in accordance with SMACNA HVAC Systems - Testing, Adjusting and Balancing (Reference 19).

9.4.6.5 Instrumentation Application

The containment recirculation cooling system is controlled by the plant control system. Process indication and alarm signals are locally accessible through the plant control system. Refer to Subsection 7.1.1 for a description of the plant control system.

Temperature controllers are provided in the branch ducts (steam generator compartments service) of the corresponding containment recirculation fan coil unit which provide an input signal to modulate the central chilled water system supply valves to the cooling coils when the unit is in normal power operation. When the unit is shut down for maintenance, refueling, etc., the containment volumetric average temperature is used as the input signal to modulate the central chilled water flow or hot water flow to the cooling coils. The containment volumetric average high and low temperature are

monitored and alarmed when the temperature is out of the normal operating range. The ambient temperature in a specific equipment compartment or areas of the containment are monitored and alarmed.

The discharge flowrate from each containment recirculation fan unit is monitored and a low flow condition is alarmed to alert the operator. The low flow condition will also generate a stop signal to the operating fan, and the standby fan will be started automatically. Flow to the reactor cavity is also monitored and low flow condition is alarmed.

9.4.7 Containment Air Filtration System

The containment air filtration system (VFS) serves the containment, the fuel handling area and the other radiologically controlled areas of the auxiliary and annex buildings, except for the hot machine shop and health physics areas which are served by a separate ventilation system.

9.4.7.1 Design Basis

9.4.7.1.1 Safety Design Basis

The containment air filtration system provides the safety-related functions of containment isolation and containment vacuum relief. System equipment and ductwork whose failure could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portion of the system is non-seismic. The containment isolation function is described in Subsection 6.2.3. The containment vacuum relief function automatically adjusts the internal containment pressure as it approaches the analyzed design parameters described in Subsection 6.2.1.1.4. This adjustment in the pressure across the containment shell preserves the structural integrity of the shell by maintaining the differential pressure within the allowable limits as defined by the structural analysis described in Subsection 3.8.2. The vacuum relief function is actuated on the Low-2 containment pressure signal and manually once the low containment pressure signal is generated.

9.4.7.1.2 Power Generation Design Basis

Containment Area

The containment air filtration system provides the following functions:

- Provides intermittent flow of outdoor air to purge the containment atmosphere of airborne radioactivity during normal plant operation, and continuous flow during hot or cold plant shutdown conditions to provide an acceptable airborne radioactivity level prior to personnel access

- Provides intermittent venting of air into and out of the containment to maintain the containment pressure within its design pressure range during normal plant operation

- Directs the exhaust air from the containment atmosphere to the plant vent for monitoring, and provides filtration to limit the release of airborne radioactivity at the site boundary within acceptable levels

- Monitors gaseous, particulate and iodine concentration levels discharged to the environment through the plant vent

The system conditions and filters outside air supplied to the containment for compatibility with personnel access during maintenance and refueling operations. Based on the maximum and minimum outside air normal temperature conditions shown in Chapter 2, Table 2.0-201, the system

supplies air between 50 and 70°F. The air is distributed and conditioned within the containment by the containment recirculation system (Subsection 9.4.6).

Radiologically Controlled Areas Outside Containment

The containment air filtration system provides filtration of exhaust air from the fuel handling area, auxiliary, or annex buildings to maintain these areas at a slightly negative pressure with respect to the adjacent areas when the radiologically controlled area ventilation system detects high airborne radioactivity or high pressure differential. Refer to Subsection 9.4.3 for a description of the radiologically controlled area ventilation system.

9.4.7.2 System Description

The containment air filtration system is shown in Figure 9.4.7-1.

9.4.7.2.1 General Description

The containment air filtration system consists of two 100 percent capacity supply air handling units, a ducted supply and exhaust air system with containment isolation valves and piping, registers, exhaust fans, filtration units, automatic controls and accessories. The supply air handling units are located in the south air handling equipment room of the annex building at elevation 135′-3″. The supply air handling units are connected to a common air intake plenum, located at the south end of the fan room. The common air intake plenum #2 is located at the extreme south end of the annex building between elevation 135′-3″ and 158′-0″. This plenum supplies air for the health physics and hot machine shop HVAC system, and the containment air filtration system. The intake is not protected from tornado missiles. The containment air filtration system supply air handling units discharge the supply air towards the east containment recirculation cooling system (VCS) recirculation unit to distribute the purge air within the containment. Refer to Subsection 9.4.6 for a description of the containment recirculation cooling system.

The exhaust air filtration units are located within the radiologically controlled area of the annex building at elevation 135′-3″ and 150′-3″. The filtration units are connected to a ducted system with isolation dampers to provide HEPA filtration and charcoal adsorption of exhaust air from the containment, fuel handling area, auxiliary and annex buildings. A gaseous radiation monitor is located downstream of the exhaust air filtration units in the common ductwork to provide an alarm if abnormal gaseous releases are detected. The plant vent exhaust flow is monitored for gaseous, particulate and iodine releases to the environment. During containment purge, the exhaust air filtration units satisfy 10 CFR 50 Appendix I guidelines (Reference 20) for offsite releases and meets 10 CFR 20 (Reference 21) allowable effluent concentration limits when combined with gaseous releases from other sources. During conditions of abnormal airborne radioactivity in the fuel handling area, auxiliary and/or annex buildings, the filtration units provide filtered exhaust to minimize unfiltered offsite releases.

The size of the containment air filtration system supply and exhaust air lines that penetrate the containment pressure boundary is 36 inches in diameter. The air lines on both sides of the supply and exhaust containment penetrations are reduced in size to accommodate inboard and outboard 16-inch diameter containment isolation valves that are opened when the containment air filtration system is connected to the containment. The penetrations are sized at 36 inches to allow for possible future addition of a high volume purge system. In the event of a loss-of-coolant accident (LOCA) while the containment air filtration system is aligned to containment, there will not be a significant release of radioactivity during closure of the 16 inch diameter supply and exhaust valves. The maximum time for valve closure (see Table 6.2.3-1) is consistent with the analysis assumptions for radiological consequences (see Table 15.6.5-2). The closure time is also consistent with the basis (compliance with 10 CFR Part 50.34) for Branch Technical Position CSB 6-4 to Standard Review Plan 6.2.4 (Reference 23) or described in Subsection 6.2.1.5.

The exhaust air containment penetration also includes a containment vessel vacuum relief function to protect the containment from reaching the containment shell design external design pressure. In the event of a LOCA, while these 6-inch motor-operated vacuum relief valves are open, the releases of radioactivity during the maximum time for closure of these valves (see Table 6.2.3-1) have been evaluated. The radiological consequences are bounded by those currently presented in Subsection 15.6.5.3. The maximum time for closure of the vacuum relief valves was also evaluated to determine the impact for the calculation of the LOCA minimum backpressure. The methodology depicted in Subsection 6.2.1.5 bounds the minimum backpressure calculation.

The exhaust air containment penetrations also serve as a connection for the containment integrated leak rate test system to pressurize and depressurize the containment during integrated leak rate testing. Otherwise, the containment air filtration exhaust subsystem is not involved with the containment integrated leak rate test and is isolated from the containment during this time period.

9.4.7.2.2 Component Description

The containment air filtration system is comprised of the following components. These components are located in buildings on the Seismic Category I Nuclear Island and the Seismic Category II portion of the annex building. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Table 9.4.7-1 provides design parameters for the major components of the system.

Supply Air Handling Units

Each supply air handling unit consists of a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil bank, a chilled water cooling coil bank and a supply fan.

Exhaust Air Filtration Units

Each exhaust air filtration unit consists of an electric heater, an upstream high efficiency filter bank, a HEPA filter bank, a charcoal adsorber with a downstream postfilter bank, and an exhaust fan. The filtration unit configurations, including housing, internal components, ductwork, dampers, fans, and controls, are designed, constructed, and tested to meet the applicable performance requirements of ASME AG-1, N509, and N510 (References 36, 2, and 3) to satisfy the guidelines of Regulatory Guide 1.140 (Reference 30) except as noted in Appendix 1A. The filtration unit housings maximum leakage rates do not exceed one percent of the design flow in accordance with ASME AG-1. Refer to Table 9.4-1 for a summary of the containment air filtration system filtration efficiencies and Appendix 1A for a comparison of the containment air filtration system exhaust air filtration units with Regulatory Guide 1.140 (Reference 30).

Isolation Dampers

Isolation dampers are bubble tight, single-blade or parallel-blade type. The isolation dampers have spring return actuators which fail closed on loss of electrical power or instrument air. The isolation dampers are Class R and are designed, constructed, and tested in accordance with ASME AG-1 Section DA (Reference 36).

Pressure Differential Control Dampers

Pressure differential control dampers utilize opposed-blade type construction. Dampers are Class R and are designed, constructed, and tested in accordance with ASME AG-1 Section DA (Reference 36). The dampers maintain a slight negative pressure within the fuel handling building area, with respect to the environment and adjacent non-radiologically controlled plant areas.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Supply and Exhaust Fans

The supply and exhaust air fans are centrifugal type, single width single inlet (SWSI), with radial blades that produce overloading horsepower characteristics. Fan configurations are either performance rated in accordance with ANSI/AMCA 210 (Reference 4) or certified in accordance with AMCA 211 (Reference 5). Fan configurations are sound tested in accordance with ANSI/AMCA 300 (Reference 6).

Containment Penetrations

The containment penetrations include containment isolation valves, interconnecting piping, and vent and test connections with manual test valves. The containment isolation components that maintain the integrity of the containment pressure boundary after a LOCA are classified as Safety Class B and seismic Category I. Seismic Category I debris screens are mounted on Safety Class C, seismic Category I pipe to prevent entrainment of debris through the supply and exhaust openings that may prevent tight valve shutoff. The screens are designed to withstand post-LOCA pressures.

The vent and purge line containment isolation valves inside and outside the containment have air operators. The valves are designed to fail closed in the event of loss of electrical power or air pressure. These valves are controlled by the protection and plant safety monitoring system as discussed in Subsection 7.1.1. The valves shut tight against the containment pressure following a design basis accident.

The motor-operated vacuum relief valves are controlled by the protection and plant safety monitoring system as discussed in Subsection 7.1.1. The valves inside containment are self-actuated check valves. These motor-operated valves and check valves shut tight against the containment pressure following a design basis accident.

Ductwork, Duct Supports, and Accessories

The system air ductwork inside containment meets seismic Category II criteria so that it will not fall and damage any safety-related equipment following a safe shutdown earthquake.

Non-Seismic ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17) with the exception of exhaust air ductwork (per Regulatory Guide 1.140 Compliance Summary) and accessories which are Class R. Exhaust air ductwork (per Regulatory Guide 1.140 Compliance Summary) and accessories are designed, constructed, and leak tested in accordance with ASME AG-1 Section SA (Reference 36).

Seismic II Category ductwork, duct supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34), SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17), and Appendix 3A, with the exception of exhaust air ductwork (per Regulatory Guide 1.140 Compliance Summary) and accessories which are Class R. Exhaust air ductwork (per Regulatory Guide 1.140 Compliance Summary) and accessories are designed, constructed and leak tested in accordance with ASME AG-1 Section SA (Reference 36) and Appendix 3A.

With the exception of nonmetallic flexible connectors, ductwork is constructed of either galvanized or stainless steel. The use of nonmetallic flexible connectors inside containment is limited to ductwork above the operating deck. Duct supports and accessories are constructed of galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

Shutoff and Balancing Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, balancing dampers are opposed-blade type. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow. The containment exhaust air dampers are Class R and are designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section DA.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Fire Dampers

Fire dampers are provided where the ductwork penetrates a fire barrier to maintain the fire resistance rating of the fire barriers. The fire dampers meet the design and installation requirements of UL-555 (Reference 15).

The fire damper within the Class R intake duct which is upstream of the filters is Class R, and is designed, constructed, and tested in accordance with ASME AG-1 Section DA (Reference 36). The Class R fire damper is applied to promote an ALARA HVAC design.

Low Efficiency Filters, High Efficiency Filters, and Postfilters

Low and high efficiency filters are rated in accordance with ASHRAE 52.1 and 126 (References 7 and 35). The minimum average dust spot efficiencies of the filters are shown in Table 9.4.7-1. High efficiency filter performance upstream of HEPA filter banks meet the design requirements of ASME AG-1 (Reference 36), Section FB. Postfilters located downstream of the charcoal adsorbers have a minimum DOP efficiency of 95 percent. The filters are UL listed in accordance with UL 900 (Reference 8).

HEPA Filters

HEPA filters are constructed, qualified, and tested in accordance with ASME AG-1 (Reference 36), Section FC. Each HEPA filter cell is individually shop tested to verify an efficiency of at least 99.97 percent using a monodisperse 0.3-μm aerosol in accordance with ASME AG-1, Section TA.

Charcoal Adsorbers

Each charcoal adsorber is designed constructed, qualified, and tested in accordance with ASME AG-1 (Reference 36), Section FE; and Regulatory Guide 1.140 (Reference 30). Each charcoal adsorber is a single assembly with welded construction and 4-inch deep Type III rechargeable adsorber cell, conforming with 1E Bulletin 80-03 (Reference 29).

Electric Heating Coils

The electric heating coils are SCR controlled, fin tubular type. The electric heating coils are UL listed in accordance with UL 1996 (Reference 26). The electric heating coils are constructed, qualified, and tested in accordance with ASME AG-1 Section CA (Reference 36).

Heating Coils

The heating coils are hot water, finned tubular type. The heating coils are provided with integral face and bypass dampers to prevent freeze damage when modulating the heat output. Coils are performance rated in accordance with ANSI/ARI 410 (Reference 12).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

9.4.7.2.3 System Operation

Normal Plant Operation

During normal plant operation, the containment air filtration system operates on a periodic basis to purge the containment atmosphere as determined by the main control room operator to reduce airborne radioactivity or to maintain the containment pressure within its normal operating range. One supply air handling unit provides outdoor air that is filtered, cooled, or heated to the containment areas above the operating floor. The airflow rate is controlled to a constant value by modulating the supply fan inlet vanes to compensate for filter loading or changes in containment pressure. The cooling coils are supplied with chilled water from the central chilled water system (VWS) to cool and/or dehumidify the outside supply air. The heating coils are supplied with hot water by the hot water heating system (VYS). Refer to Subsections 9.2.7 and 9.2.10 for descriptions of the central chilled water and hot water heating systems.

The temperature of the air supplied by each air handling unit is controlled by temperature sensors located in the supply air duct. When the supply air temperature is low, the face and bypass dampers across the supply air heating coil are modulated to heat the supply air. When the supply air temperature is high, the flow of chilled water is modulated to cool the supply air. The supply air is continuously monitored by smoke detectors located in the ductwork downstream of the supply air handling units.

The airflow rate through the exhaust filters is controlled to a constant value when the exhaust filters are connected to the containment by modulating the exhaust fan inlet vanes to compensate for filter loading or changes in system resistance caused by single or parallel fan operation, or changes in containment pressure. The exhaust lines from the containment include a pair of isolation dampers arranged in parallel to restrict the airflow to maintain the exhaust filter plenums at a negative air pressure when the containment is positively pressurized. Based on predetermined setpoints, the operators select the appropriate damper to open. This prevents exfiltration of unfiltered air from bypassing the filters.

The filtered exhaust air from the containment is discharged to the atmosphere through the plant vent by the exhaust fan. The gaseous effluents in the plant vent are monitored for radioactivity levels before the air is discharged to the environment. Refer to Section 11.5 for a description of the plant vent radiation monitor.

During single subsystem operation, the standby supply and exhaust air units can be started manually by the operator if the operating train fails.

Prior to and during plant shutdown, one or both trains of the containment air filtration system can be operated to remove airborne radioactivity prior to personnel access. During cold ambient conditions, the supply air is heated by the hot water heating system. The exhaust filter unit electric heater controls the relative humidity of the exhaust air entering the charcoal adsorber below 70 percent.

When both trains are operated concurrently, the containment air filtration system provides a maximum airflow rate equivalent to approximately 0.21 air changes per hour.

Abnormal Plant Operation

The containment isolation valves in the supply and exhaust air lines automatically close when containment isolation signals are initiated by the protection and safety monitoring system or diverse actuation system. Refer to Subsections 6.2.3, 7.7.1.11 and 7.3 for discussions of the containment isolation system, diverse actuation system and protection and safety monitoring system.

Main control room operators can connect the containment air filtration system to the containment for cleanup of potential airborne radioactivity while the containment remains isolated if a containment High-1 radiation signal is not present.

The containment vacuum relief valves automatically open when containment vacuum relief signals are initiated by the protection and safety monitoring system. These valves automatically close when containment isolation signals are initiated by the protection and safety monitoring system. Even though these valves are normally closed, they automatically receive a confirmatory close signal if the containment isolation valve inside the reactor containment building is open. As discussed in Subsection 7.6.2.4, this interlock verifies availability of engineered safety features for the containment vacuum relief and containment isolation functions.

If high airborne radioactivity or high pressure differential is detected in the fuel handling area, the auxiliary and/or annex buildings, the radiologically controlled area ventilation system isolates the affected area from the outside environment and starts the containment air filtration exhaust subsystem to maintain a slight negative pressure differential in the isolated zone(s). The airflow rate through the exhaust fan is maintained at a constant value by modulating the fan inlet vanes. An outside air makeup damper modulates to maintain a constant airflow rate through the HEPA and charcoal filters to maintain the isolated area(s) at a slightly negative pressure relative to the clean areas. The containment air filtration system is automatically isolated from the containment, if purging is in progress and the standby exhaust filter train does not start. If both exhaust trains are connected to the containment, one exhaust train is automatically isolated from the containment and realigned to the isolated area(s). The exhaust subsystem can be manually connected to the onsite diesel generators if there is a loss of normal ac power and offsite power.

The containment air filtration system is not required to mitigate the consequences of a design basis fuel handling accident or a loss of coolant accident. If the exhaust air filtration units are operational and ac power is available, they may be used to support post-event recovery operations. The plant vent high range radiation detectors monitor effluents discharged into the plant vent.

If smoke is detected in either supply air duct downstream of each air handling unit, an alarm is initiated and the corresponding train is shut down. The system is automatically shut down upon detection of a fire. Fire dampers are provided for HVAC ductwork that passes through a fire barrier in order to isolate each fire zone in the event of a fire.

9.4.7.3 Safety Evaluation

The containment air filtration system has the safety-related functions of containment isolation and vacuum relief. The containment isolation function is evaluated in Subsection 6.2.3. The vacuum relief system consists of redundant relief devices inside and outside containment. Two independent lines with an automatic isolation valve are provided on the positive pressure side of the system along with two independent lines with a check valve on the negative pressure side of the system penetrate containment. The lines share a common containment penetration. Therefore, there are no single active failures, which would prevent the system from performing its function.

The failure of equipment and ductwork will not reduce the functioning of safety-related systems, structures or components that are required to close to maintain containment isolation integrity after a design basis accident or those components required to function for vacuum relief. Ductwork that is located inside containment whose failure may affect any safety-related equipment is designed to seismic Category II requirements.

9.4.7.4 Tests and Inspections

The containment air filtration system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. The exhaust subsystem is tested to confirm airflow capacity in accordance with the guidelines of ASME N510 (Reference 3). The supply air subsystem airflow rate is measured and balanced in accordance with the guidelines of SMACNA HVAC Systems – Testing, Adjusting and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

The tests and inspections of the containment isolation valves associated with the containment air filtration system are discussed in Subsections 6.2.3 and 6.2.5.

HEPA filters and charcoal adsorbers are tested in place in accordance with ASME N510 to verify that these components do not exceed a maximum allowable bypass leakage. Samples of charcoal adsorbent are periodically tested to verify a minimum charcoal efficiency of 99 percent in accordance with Regulatory Guide 1.140 (Reference 30) except that test procedures and test frequency are conducted in accordance with ASME N510.

The exhaust ductwork and filter plenums are tested in place for leak tightness in accordance with ASME N510, Section 6.

The exhaust subsystem of the containment air filtration system (VFS) is tested and inspected in accordance with ASME/ANSI AG-1-1997 and Addenda AG-1a-2000 (Reference 201), ASME N509-1989, ASME N510-1989, and Regulatory Guide 1.140.

The VFS is tested as separate components and as an integrated system. Surveillance tests are performed to monitor the condition of the system. Testing methods include:

- Visual inspection
- Airflow capacity and distribution tests
- HEPA filter bank and adsorber bank in-place leak tests
- Air heater performance tests
- Laboratory testing of adsorbers

Testing is performed at the frequency provided in Table 1 of ASME N510-1989.

9.4.7.5 Instrumentation Application

The containment air filtration system operation is controlled by the plant control system (PLS) except for the containment isolation valves which are controlled by the protection and safety monitoring system (PMS) and diverse actuation system (DAS). Refer to Subsection 7.1.1 for a discussion of the plant control system, protection and safety monitoring system, and diverse actuation system. Automatic protection and safety monitoring system actuations of these valves are discussed in Section 7.3; the diverse actuation system signals are discussed in Subsection 7.7.1.11. Display and monitoring of system instrumentation is consistent with the requirements of Table 4-2 of ASME N509 (Reference 2).

Temperature controllers maintain the proper supply air temperature. Temperature indication and alarms are provided to inform operators of abnormal temperature conditions for supply air and charcoal adsorbers.

Pressure differential indication and alarms are provided to inform plant operators when air filter changeout is necessary.

Status indication and alarms are provided to monitor operation of fans, controlled dampers and controlled valves. Fans can be placed into operation or shut down from the main control room.

Relative humidity indication and an alarm are provided to monitor the relative humidity of the air upstream of the containment air filtration exhaust air charcoal adsorbers.

Radioactivity indication and alarms are provided to inform the main control room operators of the concentration of gaseous radioactivity in the containment air filtration system exhaust duct and gaseous, particulate and iodine concentrations in the plant vent. See Section 11.5 for a description of these radiation monitors.

Flow indication and alarms are provided to alert plant operators to equipment malfunctions.

9.4.8 Radwaste Building HVAC System

The radwaste building HVAC system serves the radwaste building which includes the clean electrical/mechanical equipment room and the potentially contaminated HVAC equipment room, the waste accumulation room, and the mobile systems facility.

9.4.8.1 Design Basis

9.4.8.1.1 Safety Design Basis

The radwaste building HVAC system serves no safety-related function and therefore has no nuclear safety design basis. The system is nonseismic.

9.4.8.1.2 Power Generation Design Basis

The radwaste building HVAC system provides the following functions:

- Provide conditioned air to work areas to maintain acceptable temperatures for equipment and personnel working in the areas
- Provide confidence that air movement is from clean to potentially contaminated areas to minimize the spread of airborne contaminants
- Collect the vented discharges from potentially contaminated equipment
- Provide for radiation monitoring of exhaust air prior to release to the environment
- Maintain the radwaste building at a negative pressure with respect to ambient to prevent unmonitored releases from the radwaste building

The system maintains the following temperature based on maximum and minimum normal outdoor air temperature conditions shown below in Chapter 2, Table 2.0-201:

Room or Area	Temperatures (°F)
Processing areas and storage areas	50-105
Mechanical and electrical equipment rooms	50-105
Truck staging area	50-105

9.4.8.2 System Description

The radwaste building HVAC system is shown in Figure 9.4.8-1.

9.4.8.2.1 General Description

The radwaste building HVAC system is a once-through ventilation system that consists of two integrated subsystems: the radwaste building supply air system and the radwaste building exhaust air system. The systems operate in conjunction with each other to maintain temperatures in the areas served while controlling air flow paths and building negative pressure.

The supply air system consists of two 50 percent capacity air handling units of about 5,000 scfm each with a ducted air distribution system, automatic controls, and accessories. The air handling units are located in an electrical/mechanical equipment room on elevation 100′-0″ on the southwest side of the building. Each unit draws 100 percent outdoor air through individual louvered outdoor air intakes. The two units discharge into a common duct distribution system which is routed through the building. Branch connections from the main duct supply air through registers into the various areas served.

The exhaust air system consists of two 50 percent capacity exhaust centrifugal fans sized to allow the system to maintain a negative pressure, an exhaust air duct collection system, and automatic controls and accessories. The airflow rates are balanced to maintain a constant exhaust design air flow through the fans. The exhaust fans are located in an equipment room on Elevation 100′-0″ in the northwest corner of the radwaste building.

The exhaust fans discharge to a common duct which is routed to the plant vent. A radiation monitor records activity in the discharge duct and activates an alarm in the main control room when excess activity in the effluent discharge is detected. The radiation monitoring system is described in Section 11.5.

The exhaust air collection duct inside the radwaste building exhausts air from areas and rooms where low levels of airborne contamination may be present. Exhaust connection points are provided to allow the direct exhaust of equipment located on the mobile systems. Where potential for significant airborne release exists, mobile systems include HEPA filtration. Back draft dampers are provided at each mobile system connection to prevent blowback through the equipment in the event of exhaust system trip. Criteria for mobile processing systems are included in Sections 11.2 and 11.4.

9.4.8.2.2 Component Description

The radwaste building HVAC system is comprised of the following major components. These components are located in the non-seismic radwaste building and the Seismic Category II portion of the annex building.

Supply Air Handling Units

Each air handling unit consists of a plenum section, a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil, a chilled water cooling coil bank, and a supply fan with automatic inlet vanes.

Supply and Exhaust Air Fans

The supply and exhaust fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with backward inclined blades to produce non-overloading horsepower characteristics. Fan configurations are either performance rated in accordance with ANSI/AMCA 210 (Reference 4) or certified in accordance with AMCA 211 (Reference 5). Fan configurations are sound tested in accordance with ANSI/AMCA 300 (Reference 6).

Low Efficiency Filters and High Efficiency Filters

The low efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52.1 and 126 (References 7 and 35). The filters are UL listed in accordance with UL 900 (Reference 8).

Hot Water Unit Heaters

The hot water unit heaters consist of a fan section and hot water heating coil section factory assembled as a complete and integral unit. The unit heaters are either horizontal discharge or vertical downblast type. The hot water unit heaters are tested and rated using the methods and standard conditions provided within ASHRAE Handbook - HVAC Systems and Equipment, “Unit Ventilators, Unit Heaters, and Makeup Air Units” (Reference 42).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Heating Coils

The hot water heating coils are counterflow, finned tubular type. The heating coils are provided with integral face and bypass dampers to prevent freeze damage when modulating the heat output. The heating coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Shutoff, Balancing, and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through exhaust connections for mobile systems. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow.

Shutoff dampers downstream of exhaust fans, which discharge air into the plant vent stack at a positive pressure, are Class R and are designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section DA. The Class R dampers are applied to promote an ALARA HVAC design. The use of Class R dampers mitigates the potential for exfiltration of airborne radiation in a positive pressure duct during operation of the fan coincident with an airborne release from the spaces the fans serves.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL 555 (Reference 15).

Fire dampers are Class R and are designed, constructed, and tested in accordance with ASME AG-1 Section DA (Reference 36). The Class R fire dampers are applied to promote an ALARA HVAC design. The use of Class R fire dampers mitigates the potential for exfiltration of airborne radiation in a positive pressure duct during operation of the fan coincident with an airborne release from the spaces the fan serves.

Ductwork, Duct Supports, and Accessories

Ductwork, duct supports and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17) with the exception of the following:

Ductwork downstream of exhaust fans, which discharge air into the plant vent stack at a positive pressure, is Class R and is designed, constructed, and tested in accordance with ASME AG-1 Section SA (Reference 36) and Appendix 3A. The Class R ductwork and accessories are applied to promote an ALARA HVAC design. The use of Class R dampers mitigates the potential for exfiltration of airborne radiation in a positive pressure duct during operation of the fan coincident with an airborne release from the spaces the fan serves.

Ductwork is constructed of materials consistent with these standards including, but not limited to, galvanized or stainless steel. Duct supports and accessories are constructed of material consistent with these standards including, but not limited to, galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

9.4.8.2.3 System Operation

Normal Plant Operation

During normal operation, both supply air handling units and both exhaust fans operate continuously to maintain suitable temperatures in the radwaste building. The inlet vanes of the supply fans are modulated automatically by flow controllers to maintain a constant supply air flow rate. The exhaust air flow is then balanced to maintain the building at a slightly negative pressure with respect to the outside environment. The differential pressure transmitter receives input from a pressure differential sensing instrument mounted indoors in the general building area with sensing lines located inside and outside the building. The sensing line mounted outside the building is shielded from the effects of wind.

The temperature of the air supplied by the air handling unit is controlled by separate heating and cooling controllers, with sensors in the general building area. The cooling controllers modulate the control valves in the chilled water supply lines to the air handling units. The heating controllers modulate the face and bypass dampers of the hot water heating coils in the air handling units.

Differential pressure drop across the supply units filter banks is monitored, and individual alarms are actuated when any pressure drop rises to a predetermined level indicative of the need for filter replacement. To replace the filters on a supply unit, the affected supply fan and exhaust fan are stopped and isolated from the duct system by means of isolation dampers. During filter replacement, the supply and exhaust systems operate at 50 percent capacity. In this mode of operation, radwaste processing operations are adjusted to obtain acceptable temperature in the radwaste building.

The hot water unit heaters in the mobile systems facility and truck staging area are not normally required to operate to maintain the general building temperature. These heaters operate, in response to local thermostat control, to temper air entering the building when a truck access door is opened.

The hot water unit heater in the electrical/mechanical room operates in response to local thermostat control to maintain the required minimum temperature.

Abnormal Plant Operation

The radwaste building HVAC system is not required to operate during any abnormal plant condition.

9.4.8.3 Safety Evaluation

The radwaste building HVAC system has no safety-related function and therefore requires no nuclear safety evaluation.

9.4.8.4 Tests and Inspections

The radwaste building HVAC system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Air flow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC systems - Testing, Adjusting and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.8.5 Instrumentation Applications

The radwaste building HVAC system operation is controlled by the plant control system (PLS). Refer to Subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers and thermostats maintain the proper space temperatures. Supply air temperature is controlled by sensing the temperature in the mobile systems facility and the electrical/mechanical equipment room. Unit heaters are controlled by local thermostats. Temperature indication and alarms are accessible locally via the plant control system.

Temperature is indicated for each air handling unit supply air discharge duct.

Operational status of fans is indicated in the main control room. The fans and air handling units can be placed into operation or shutdown from the main control room.

Differential pressure indication is provided for each of the filters in the air handling units and an alarm for high pressure drop is provided for each air handling unit.

Pressure differential indication and alarms are provided to monitor the radwaste building pressure with respect to the environment.

Airflow is indicated for the air handling unit and exhaust fan discharge ducts. Alarms are provided for abnormal air flow rates in the fan discharge ducts.

An alarm is provided for high radiation in the main exhaust duct to the vent stack.

An alarm is provided for smoke in the discharge ducts from the supply air handling units.

Position indicating lights are provided for automatic dampers.

9.4.9 Turbine Building Ventilation System

The turbine building ventilation system (VTS) operates during startup, shutdown, and normal plant operations. The system maintains acceptable air temperatures in the turbine building for equipment operation and for personnel working in the building.

9.4.9.1 Design Basis

9.4.9.1.1 Safety Design Basis

The turbine building ventilation system serves no safety-related function and therefore has no nuclear safety design basis. The system is nonseismic.

9.4.9.1.2 Power Generation Design Basis

The turbine building ventilation system provides the following functions:

- Maintains acceptable temperatures for equipment operation
- Provides for removal of chemical fumes from the secondary sampling laboratory room, flammable vapors from the lube oil reservoir room and the clean and dirty lube oil storage room
- Provides conditioning air to maintain acceptable temperatures for electrical equipment rooms and personnel work areas
- Maintains the following temperatures based on the ambient outside air(1):
  - General area (operating deck, intermediate levels, and base slab).....50-105°F
  - Electrical equipment rooms (switchgear room 1, switchgear room 2, and electrical equipment room).....50-105°F
  - Personnel work areas (Secondary sampling laboratory).....72-78°F
  - Exciter rectifier room.....50-85°F
  - Control cabinet rooms.....50-105°F
  - South bay equipment areas (various pumps and RCP variable speed drive power converter units.....50-100°F

9.4.9.2 System Description

The turbine building ventilation system consists of the following subsystems:

- General area heating, south bay equipment, and ventilation
- Electrical equipment, control cabinet rooms, and personnel work area HVAC
- Local area heating and ventilation
  - Lube oil reservoir room ventilation
  - Clean and dirty lube oil storage room ventilation

The turbine building HVAC system general area subsystem is shown in Figure 9.4.9-1.

1. Temperature conditions of 95°F DB/77°F WB (coincident), 79°F WB (non-coincident) in summer and -5°F in winter.

9.4.9.2.1 General Description

9.4.9.2.1.1 General Area Heating and Ventilation

Most of the turbine building is supplied by the general area ventilation and heating subsystem. Air is exhausted from the turbine building to the atmosphere by roof exhaust ventilators. The roof exhaust ventilators pull in outside air through wall louvers located at elevations 100’-0", 120’-6", and 141’-3". Wall louvers are located at the operating deck to provide additional air during plant outage operations. The general area heating subsystem uses electric unit heaters to provide local heating throughout the turbine building. During heating operation, the general area ventilation system is not operated.

9.4.9.2.1.2 Electrical Equipment and Personnel Work Area HVAC

The electrical equipment, south bay equipment, control cabinet rooms, and personnel work area air conditioning subsystem serves electrical equipment areas (switchgear rooms and the electrical equipment room), the south bay equipment (CCS pumps, BDS pumps, and reactor coolant pumps variable frequency drive power converter areas), and personnel work areas (secondary sampling laboratory and exciter rectifier room). This subsystem is subdivided into four independent HVAC systems, one serving the electrical equipment areas, one serving the south bay equipment, one serving the personnel work areas, and one serving the control cabinet rooms.

The electrical equipment HVAC system consists of four air handling units with a supply fan, a ducted supply and return air system, automatic controls, and accessories. The air handling units are located on elevation 158’-7" of the turbine building. The temperature of the rooms is maintained by thermostats which control the chilled water control valves for cooling and the integral face/bypass dampers for heating.

The south bay equipment area HVAC system consists of two 50-percent capacity air handling units of about 18,800 cfm capacity each. The air handling units are located on elevation 117′-6″ of the turbine building between column lines 11 and 11.2. The temperature of the area is maintained by thermostats that control the chilled water control valves for cooling and the integral face bypass dampers for heating. Outside air is mixed with the recirculation air to maintain a positive pressure.

The personnel work area HVAC system consists of two 50 percent capacity air handling units, a ducted supply and return air system, automatic controls, and accessories. The air handling units are located on elevation 100′-0″ of the turbine building. The temperature of the rooms is maintained by thermostats which control the chilled water control valves for cooling and the integral face/bypass dampers for heating. Outside air is mixed with recirculated air to maintain a positive pressure.

9.4.9.2.1.3 Local Area Heating and Ventilation

The lube oil reservoir room, clean and dirty lube oil storage room, and secondary sampling laboratory fume hood have centrifugal exhaust fans to remove flammable vapors, odors, or chemical fumes as required.

9.4.9.2.2 Component Description

The turbine building ventilation system is comprised of the following major components. These components are located in the non-seismic turbine building.

HVAC Air Handling Units

Each air handling unit is a horizontal draw-through cabinet type consisting of a mixing box section, low efficiency (25 percent) filter, high efficiency (80 percent) filter, integral face/ bypass damper, hot

water heating coil (except for the control cabinet rooms' air handling units), and chilled water cooling coil. The personnel area and south bay equipment area air handling units include a supply air fan.

Low Efficiency Filters and High Efficiency Filters

The efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52.1 and 126 (References 7 and 35). The filters are UL listed in accordance with UL 900 (Reference 8).

Exhaust Ventilators

The turbine building roof exhaust ventilators are hooded, belt driven, propeller type with gravity-type backdraft damper. Ventilators in the lube oil rooms are centrifugal type. The exhaust ventilators are built to the manufacturer's standards.

Shutoff, Balancing, and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through shut down fans. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Electric Unit Heaters

The electric unit heaters are single or multi stage, fin tubular type. The electric unit heaters are UL listed in accordance with UL 2021 (Reference 40) and meet the requirements of the National Electric Code NFPA 70 (Reference 28).

Electric Duct Heaters

The electric duct heaters are SCR controlled, fin tubular type. The electric duct heaters are UL listed in accordance with UL 1996 (Reference 26). The duct heaters are UL listed for zero clearance and meet requirements of NFPA 70 (Reference 28).

Humidifiers

A humidifier is a packaged electric steam generator type which converts water to steam and distributes it through the air handling system. The humidifier is designed and rated in accordance with ARI 640 (Reference 13).

Fire Dampers

Fire dampers are provided at HVAC duct penetrations through fire barriers to maintain fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL-555 (Reference 15) as applicable.

Ductwork, Duct Supports, and Accessories

Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17). Ductwork is constructed of materials consistent with these standards including, but not limited to, galvanized or stainless steel. Duct supports and accessories are constructed of material consistent with these standards including, but not limited to, galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

9.4.9.3 System Operation

9.4.9.3.1 General Area Heating and Ventilation

The general area ventilation system is manually controlled. Roof exhaust ventilators are manually started and stopped as required to satisfy space temperature conditions. Wall louvers located at the ground floor and the two intermediate levels of the turbine building are normally open during ventilation operation. The wall louvers located at the operating floor are manually opened to increase ventilation air to the area during outage operations. The operating floor louvers normally remain closed during power operation.

Electric unit heaters are controlled automatically or manually. In the automatic mode, the heater fan motors are thermostatically controlled by their respective space thermostats.

9.4.9.3.2 Electrical Equipment, Control System Cabinet Rooms, South Bay Equipment, and Personnel Work Area HVAC

During normal operation, the air handling units of the electrical equipment and south bay equipment area HVAC systems, the two air handling units of the control system cabinet rooms, and the two air handling units of the personnel work area HVAC system operate continuously. The chilled water coils are supplied from the plant central chilled water system (VWS) and the hot water coils are supplied from the plant central hot water heating system.

9.4.9.3.3 Local Area Heating and Ventilation

The ventilation operation for the lube oil reservoir room and the clean and dirty lube oil storage room is similar. Each centrifugal exhaust fan runs continuously to prevent the accumulation of chemical fumes or flammable vapors in its respective room. During normal operation, intake air comes from the turbine building general areas. When general area temperatures exceed 95°F, the intake dampers from the general areas are manually closed and the outside air intake dampers are manually opened.

9.4.9.4 Safety Evaluation

The turbine building ventilation system has no safety-related function and therefore requires no nuclear safety evaluation.

There is no safety-related equipment in the turbine building.

9.4.9.5 Tests and Inspections

The turbine building ventilation system is designed to permit periodic inspection of system components during normal plant operation. System air balance testing and adjustments for the electrical equipment and personnel work areas are conducted in accordance with SMACNA (Reference 19).

Fan configurations are performance rated in accordance with ANSI/AMCA 210 (Reference 4). Water coils are factory tested and rated in accordance with ANSI/ARI 410 (Reference 12).

Ductwork is visually examined to validate ductwork construction and duct sealing methods in accordance with the applicable SMACNA standard (References 16, 17 or 34).

9.4.9.6 Instrumentation Applications

The turbine building ventilation system is controlled by the plant control system.

Temperature indication and controllers control the room air temperatures within a predetermined range.

Temperature indication is provided to allow surveillance of room and space temperatures in the turbine building.

Differential pressure indication is provided for the air filters in each air handling unit. Alarms are provided for high pressure drops across the air filters.

9.4.10 Diesel Generator Building Heating and Ventilation System

The diesel generator building heating and ventilation system serves the standby diesel generator rooms, electrical equipment service modules, stairwell, security room, diesel fuel oil day tank vaults in the diesel generator building and the two diesel oil transfer modules located in the yard near the fuel oil storage tanks.

9.4.10.1 Design Basis

9.4.10.1.1 Safety Design Basis

The diesel generator building heating and ventilation system serves no safety-related function and therefore has no nuclear safety design basis. The system is nonseismic.

9.4.10.1.2 Power Generation Design Basis

The diesel generator building heating and ventilation system provides the following functions:

- Provides sufficient quantities of ventilation air to maintain acceptable temperatures within the generator rooms for equipment operation and reliability during periods of diesel generator operation in order for the onsite standby power system to perform its defense in depth functions
- Provides adequate heating and ventilation for suitable environmental conditions for maintenance personnel working in the diesel generator room when the generators are not in operation
- Provides suitable environmental conditions for equipment operation in each diesel generator electrical equipment service module under the various modes of diesel generator operation
- Prevents the accumulation of combustible vapors and dissipate their concentration in the fuel oil day tank vault
- Provides adequate heating and ventilation to maintain acceptable temperature within the diesel oil transfer module enclosures
- Provides conditioned air to maintain acceptable temperatures for equipment and personnel working in the security room
- Provides adequate heating to maintain a minimum acceptable temperature within the stairwell

The system maintains the following room temperatures based on ambient outside air temperature conditions of 95°F (summer) and -5°F (winter):

Area	Design Minimum (°F)	Temperature Maximum (°F)
Diesel Generator Area		
Diesel Generator On	None	130
Diesel Generator Off	50	105
Service Module		
Diesel Generator On	50	105
Diesel Generator Off	50	105
Diesel Oil Transfer Module Enclosure	40	115
Stairwell	50	NA
Security Room	73	78

9.4.10.2 System Description

The diesel generator building heating and ventilation system is shown in Figure 9.4.10-1.

The system consists of the following subsystems:

- Normal heating and ventilation subsystem
- Standby exhaust ventilation subsystem
- Fuel oil day tank vault exhaust subsystem
- Diesel oil transfer module enclosures ventilation and heating subsystem
- Security Room HVAC Subsystem

9.4.10.2.1 General Description

9.4.10.2.1.1 Normal Heating and Ventilation System

The normal heating and ventilation subsystem serves the diesel generator building. Each diesel generator train is provided with independent ventilation and heating equipment for the building areas serving that diesel generator train.

Each normal heating and ventilation subsystem for a diesel generator train consists of one 100 percent capacity engine room air handling unit which ventilates the diesel generator room, one 100 percent capacity service module air handling unit which ventilates the electrical equipment service module, an exhaust system for the fuel oil storage vault and electric unit heaters in the diesel generator area. Air intake louvers for these units are located as high in the diesel generator building wall as possible.

The engine room air handling units are located above the electrical equipment service module with supply and return ducts in the diesel generator room.

The service module air handling units are located above the service module with supply and return ducts into the module.

Electric unit heaters are provided in the diesel generator room to maintain the space at a minimum temperature of 50°F when the diesel generators are off.

An electric unit heater is provided in the diesel generator stairwell to maintain the space at a minimum temperature.

9.4.10.2.1.2 Standby Exhaust Ventilation Subsystem

The standby exhaust ventilation subsystem for each diesel generator room consists of two 50 percent capacity roof mounted exhaust fans and motor operated air intake dampers mounted in the exterior walls of the room.

9.4.10.2.1.3 Fuel Oil Day Tank Vault Exhaust Subsystem

Each fuel oil day tank vault is continuously ventilated by a centrifugal exhaust fan. The exhaust fans are mounted on the roof of the vault and ducted to draw air from one foot above the vault floor and from above the oil containment dike to remove any oil fumes generated in the space. Air is drawn into the vault from the diesel generator room through an opening protected with a fire damper.

9.4.10.2.1.4 Diesel Oil Transfer Module Enclosures Ventilation and Heating Subsystem

Each diesel oil transfer module enclosure is ventilated by an exhaust fan. Outside air is drawn into the enclosure through louvered air intakes. An electric unit heater is provided in each enclosure to maintain the space at a minimum temperature of 40°F.

9.4.10.2.1.5 Security Room HVAC Subsystem

The security room HVAC subsystem serves the security room within the diesel generator building. The security room HVAC subsystem consists of a single 100 percent capacity split system direct expansion package (air handling unit and condensing unit) with automatic controls and accessories. The air handler is located in the security room of the diesel generator building while the condenser is located on the roof of the diesel generator building. The split system direct expansion package provides conditioning and ventilation of air within the security room to maintain acceptable temperatures and conditions for personnel and equipment.

9.4.10.2.2 Component Description

The diesel generator building heating and ventilation system is comprised of the following major components. These components are located in the non-seismic diesel-generator building or the diesel oil transfer enclosure in the yard. The seismic design classification, safety classification and principal construction code for Class A, B, C, or D components are listed in Section 3.2. Tables 9.4.10-1 through 9.4.10-4 provide design parameters for major components in the system.

Supply Air Handling Units

Each air handling unit consists of a mixing box section, a low efficiency filter bank, a high efficiency filter bank, and a supply fan. Electric heating coils are provided for the service module air handling units for module heating.

Supply and Exhaust Air Fans

The supply and exhaust fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with backward inclined blades that produce non-overloading horsepower characteristics or radial blades that produce overloading horsepower characteristics. The diesel oil transfer module enclosure exhaust fans are continuously operating, direct-drive ventilator fans with integral backdraft dampers. Fan configurations are either performance rated in accordance with ANSI/AMCA 210 (Reference 4) or certified in accordance with AMCA 211 (Reference 5). Fan configurations are sound tested in accordance with ANSI/AMCA 300 (Reference 6).

Low Efficiency Filters and High Efficiency Filters

The low efficiency filters and high efficiency filters have a rated dust spot efficiency based on ASHRAE 52.1 and 126 (References 7 and 35). Filter minimum average dust spot efficiency is shown in Table 9.4.10-1. The filters are UL listed in accordance with UL 900 (Reference 8).

Electric Heating Coils

The electric heating coils are SCR controlled, fin tubular type. The electric heating coils are UL listed in accordance with UL 1996 (Reference 26).

Roof Exhaust Fans

The diesel generator building standby exhaust fans are roof mounted, belt driven upblast ventilators. The fans are equipped with gravity dampers that open when the fan operates and close when the fan is shut down.

Electric Unit Heaters

The electric unit heaters are single or multi stage, fin tubular type. The electric unit heaters are UL listed in accordance with UL 2021 (Reference 40) and meet the requirements of the National Electric Code NFPA 70 (Reference 28).

Shutoff, Volume Control, Balancing, and Backdraft Dampers

Multiblade, two-position shutoff remotely operated dampers are parallel-blade type. Multiblade, volume control and balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through shut down exhaust fans and to relieve pressure from the service module and diesel generator building.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL 555 (Reference 15).

Ductwork, Duct Supports, and Accessories

Ductwork, supports and accessories meet the design and construction requirements of SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards - Metal and Flexible (Reference 17). Ductwork is constructed of materials consistent with these standards including, but not limited to, galvanized or stainless steel. Duct supports and accessories are constructed of material consistent with these standards including, but not limited to, galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

Split System Direct Expansion Package

The split system direct expansion package consists of an air handler unit and a condensing unit which are separated from one another. The air handling unit consists of a fan, filter, evaporator, and electric heating coil. The condensing unit utilizes refrigerant as the cooling medium and is air-cooled. The condensing unit contains a compressor, fan, condensing coil, filter, and drier.

9.4.10.2.3 System Operation

9.4.10.2.3.1 Normal Heating and Ventilation Subsystem

Normal Plant Operation

During normal plant operation, each engine room air handling unit operates continuously. Each air handling unit has 100 percent cooling capacity for the engine room served by the unit. The unit draws outdoor air through a louvered air intake and mixes it with return air from the engine room in required proportion to satisfy a thermostat located in the space served. Excess outside air supplied to the engine room is discharged to outdoors via gravity dampers.

Each service module air handling unit operates continuously, providing 100 percent cooling and heating capacity for the service module served by the unit. The unit draws outside air through a louvered air intake and mixes it with return air from the service module in required proportion to satisfy a space thermostat located in the service module. Excess outside air supplied to the service module flows into the diesel engine area via a wall mounted gravity damper. The electric heating coil in the service module air handling unit is controlled by a separate space thermostat. The service module air handling unit operates continuously regardless of diesel generator status.

The engine room electric unit heaters operate as required to maintain the minimum room temperature when the diesel generators are not operating. No specific minimum room temperature is maintained when the diesel generators operate. Local space thermostats turn the unit heaters on and off as required for temperature control.

The stairwell electric unit heater operates as required to maintain the minimum room temperature. A local space thermostat turns the unit heater on and off as required for temperature control.

Abnormal Plant Operation

The engine room air handling units and service module air handling units operate continuously during normal operation or when the diesel generators operate during a loss of normal ac power and offsite power.

Unit heaters are not required to operate during any abnormal plant condition or when the diesel generators operate.

9.4.10.2.3.2 Standby Exhaust Ventilation Subsystem

Normal Plant Operation

During normal plant operation, the standby exhaust fans operate in conjunction with the diesel generators. Each exhaust fan has 50 percent cooling capacity for the engine room served by the fan. The fans for an engine room start when the diesel generator in that room is started. The fans start one at a time as the temperature in the engine room increases. The fans stop one at a time as the engine room temperature decreases. The fans shut down when the diesel generator is stopped and the engine room temperature satisfies the standby exhaust fan temperature controllers. One or both standby exhaust fans are required to operate to maintain the engine room temperature depending on the outdoor ambient temperature.

The motor operated air intake dampers automatically open when their associated standby exhaust fan starts and close when both their associated standby exhaust fan stops.

The standby exhaust ventilation system is not required to operate when the diesel generators are not operating.

Abnormal Plant Operation

The standby exhaust ventilation system is required to operate to support diesel generator operation during loss of normal ac power and offsite power. System operation is identical to that for normal plant operation.

9.4.10.2.3.3 Fuel Oil Day Tank Vault Exhaust Subsystem

Normal Plant Operation

During normal plant operation, each fuel oil day tank vault exhaust fan operates continuously. The fans are manually started and shut down. Each exhaust fan has 100 percent capacity for ventilation of the day tank vault served by the fan.

Abnormal Plant Operation

The fuel oil day tank vault exhaust subsystem is required to operate to support diesel generator operation during loss of normal ac power and offsite power. System operation is identical to that for normal plant operation.

9.4.10.2.3.4 Diesel Oil Transfer Module Enclosures Ventilation and Heating Subsystem

Normal Plant Operation

During normal plant operation, each diesel oil transfer module enclosure exhaust fan operates continuously to provide ventilation and maintain the enclosure at or below the maximum design temperature. The unit heaters operate as required during the winter to maintain the minimum design enclosure temperature. Outside air is admitted through fixed intake louvers.

Abnormal Plant Operation

The diesel oil transfer module enclosure ventilation and heating subsystem is required to operate to support diesel generator operation during loss of the normal ac power and offsite power. System operation is identical to that for normal plant operation.

9.4.10.2.3.5 Security Room HVAC Subsystem

Normal Plant Operation

During normal plant operation, the split system direct expansion package operates continuously to condition and ventilate the room. The condensing unit provides refrigerant cooling to the evaporator within the air handling unit during cooling mode while the electric heating coil within the air handling unit provides the source of heating. A local thermostat automatically controls the operation of the package.

Abnormal Plant Operation

The security room HVAC subsystem is not required to operate during any abnormal plant condition. However, in the event of a loss of the normal ac power and offsite power, the security room HVAC subsystem can be connected to the plant standby diesel generator bus in accordance with the manual load sequencing after evaluation of the diesel generator available capacity.

9.4.10.3 Safety Evaluation

The diesel generator building heating and ventilation system has no safety-related function and therefore requires no nuclear safety evaluation.

9.4.10.4 Tests and Inspection

The diesel generator building heating and ventilation system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted in the course of the plant preoperational test program. Air flow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC Systems - Testing, Adjusting, and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.10.5 Instrumentation Applications

The diesel generator building heating and ventilation system operation is controlled by the plant control system. Refer to Subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers and thermostats maintain the proper space temperatures. Temperature indication and alarms are accessible locally via the plant control system.

Operational status of fans is indicated in the main control room. All fans and air handling units can be placed into operation or shutdown from the main control room or locally.

Differential pressure indication is provided for each of the filters in the air handling units and an alarm for high pressure drop is provided for each air handling unit.

9.4.11 Health Physics and Hot Machine Shop HVAC System

The health physics and hot machine shop HVAC system serves the personnel decontamination area, frisking and monitoring facilities, containment access corridor, and health physics facilities on the 100′-0″ elevation of the annex building and the hot machine shop on the 107′-2″ elevation of the annex building.

9.4.11.1 Design Basis

9.4.11.1.1 Safety Design Basis

The health physics and hot machine shop HVAC system serves no safety-related function and therefore has no nuclear safety design basis. The system is nonseismic.

9.4.11.1.2 Power Generation Design Basis

The health physics and hot machine shop HVAC system provides the following functions:

- Provides conditioned air to work areas to maintain acceptable temperatures for equipment and personnel working in the areas
- Provides air movement from clean to potentially contaminated areas to minimize the spread of airborne contaminants
- Collects the vented discharges from potentially contaminated equipment in the area
- Provides for exhaust from welding booths, grinders and other miscellaneous equipment located in the hot machine shop

- Provides for radiation monitoring of exhaust air prior to release to the environment
- Maintains the access control area and hot machine shop at a slight negative pressure with respect to outdoors and the clean areas of the annex building to prevent unmonitored releases of radioactive contaminants
- Provides humidification to maintain a minimum of 35 percent relative humidity

The system maintains the following temperatures based on maximum and minimum normal outside air temperature conditions shown in Chapter 2, Table 2.0-201:

Room or Area	Temperatures (°F)
Health physics area	73-78
Hot machine shop	65-85
Security room	73-78
Elevator shaft	120 (max.)

9.4.11.2 System Description

The health physics and hot machine shop HVAC system is shown in Figure 9.4.11-1.

9.4.11.2.1 General Description

The health physics and hot machine shop HVAC system is a once-through ventilation system consisting of two integrated subsystems: a supply air system and an exhaust air system. The systems operate in conjunction with each other to satisfy the functional requirements of maintaining temperatures in the areas served while controlling air flow paths and area negative pressure.

The supply air system consists of two 100 percent capacity air handling units of about 8,640 scfm each with a ducted air distribution system and automatic controls. The air handling units are located in the lower south air handling equipment room on elevation 135′-3″ of the annex building. Heating coils are supplied with water from the hot water heating system and cooling coils are supplied from the central chilled water system. The units draw 100 percent outdoor air through the common, louvered outdoor air intake plenum #2 as described in Subsection 9.4.2. They discharge into a duct distribution system which is routed to the health physics and machine shop areas. Humidification is controlled to maintain a minimum 35 percent relative humidity via a steam humidifier located in the main system supply duct and supplied with water from the demineralized water system.

The exhaust air system consists of two 100 percent capacity exhaust centrifugal fans sized to allow the system to maintain a negative pressure with ductwork and automatic controls, and a separate machine shop exhaust fan and high efficiency filter for exhausting from machine tools and other localized areas in the hot machine shop. The exhaust fans are located in the staging and storage area on elevation 135′-3″ of the annex building. The machine shop exhaust fan and filter are located locally in the machine shop. The air flow rates are balanced to maintain a constant exhaust design air flow through the fans.

The exhaust fans discharge to a common duct which is routed to the plant vent stack. A radiation monitor measures activity in the common discharge duct downstream of the exhaust fans and activates an alarm in the main control room when excess activity in the effluent discharge is detected. The radiation monitoring system is described in Section 11.5.

Individual flexible exhaust duct branches are provided to machine tools. The flexible ducts are connected to a hard duct manifold which is connected to a filter and exhaust fan. The exhaust fan discharges into the main system exhaust ductwork.

Electric unit heaters are provided in the security room and stairwell to maintain the space at a minimum temperature.

9.4.11.2.2 Component Description

The health physics and hot machine shop HVAC system is comprised of the following major components. These components are located in the Seismic Category II portion of the annex building.

Supply Air Handling Units

Each air handling unit consists of a low efficiency filter bank, a high efficiency filter bank, a hot water heating coil, a chilled water cooling coil bank, and a supply fan with automatic inlet vanes.

Supply and Exhaust Air Fans

The supply and exhaust fans are centrifugal type, single width single inlet (SWSI) or double width double inlet (DWDI), with backward inclined blades to produce non-overloading horsepower characteristics or radial blades to produce overloading horsepower characteristics. Fan configurations are either performance rated in accordance with ANSI/AMCA 210 (Reference 4) or certified in accordance with AMCA 211 (Reference 5). Fan configurations are sound tested in accordance with ANSI/AMCA 300 (Reference 6).

Low Efficiency Filters and High Efficiency Filters

The low efficiency (25 percent) filters and high efficiency (80 percent) filters have a rated dust spot efficiency based on ASHRAE 52.1 and 126 (References 7 and 35). The filters are UL listed in accordance with UL 900 (Reference 8).

Cooling Coils

The chilled water cooling coils are counterflow, finned tubular type. The cooling coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Heating Coils

The hot water heating coils are counterflow, finned tubular type. The heating coils are provided with integral face and bypass dampers to prevent freeze damage when modulating heat output. The heating coils are designed and rated in accordance with ASHRAE 33 (Reference 11) and ANSI/ARI 410 (Reference 12).

Humidifier

The humidifier is a packaged electric steam generator type which converts water to steam and distributes it through the air handling system. The humidifier is designed and rated in accordance with ARI 640 (Reference 13).

Shutoff, Balancing, and Backdraft Dampers

Multiblade, two-position remotely operated shutoff dampers are parallel-blade type. Multiblade, balancing dampers are opposed-blade type. Backdraft dampers are provided to prevent backflow through ductwork when operating the machine tools exhaust fan. Air handling unit and fan shutoff dampers are designed for maximum fan static pressure at shutoff flow.

Shutoff dampers downstream of exhaust fans, which discharge air into the plant vent stack at a positive pressure, are Class R and are designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section DA. The Class R dampers are applied to promote an ALARA HVAC design. The use of Class R dampers mitigates the potential for exfiltration of airborne radiation in a positive pressure duct during operation of the fan coincident with an airborne release from the spaces the fan serves.

Dampers are rated in accordance with ANSI/AMCA 500-D (Reference 14).

Fire Dampers

Fire dampers are provided at duct penetrations through fire barriers to maintain the fire resistance ratings of the barriers. The fire dampers meet the design and installation requirements of UL 555 (Reference 15).

Ductwork, Duct Supports, and Accessories

Ductwork, supports, and accessories are designed and constructed in accordance with SMACNA Rectangular and Round Industrial Duct Construction Standards (References 16 and 34) and SMACNA HVAC Duct Construction Standards – Metal and Flexible (Reference 17) with the following exception: Ductwork downstream of exhaust fans, which discharge air into the plant vent stack at a positive pressure, is Class R and is designed, constructed, and tested in accordance with ASME AG-1 (Reference 36), Section SA, and Appendix 3A. The Class R ductwork is applied to promote an ALARA HVAC design. The use of Class R ductwork mitigates the potential for exfiltration of airborne radiation in a positive pressure duct during operation of the fan coincident with an airborne release from the spaces the fan serves. Ductwork is constructed of materials consistent with these standards including, but not limited to, galvanized or stainless steel. Duct supports and accessories are constructed of material consistent with these standards including, but not limited to, galvanized, stainless or coated steel. Ductwork subject to fan shutoff pressures is structurally designed to accommodate fan shutoff pressures.

9.4.11.2.3 System Operation

Normal Plant Operation

During normal operation, one supply air handling unit and one exhaust fan operate continuously to maintain suitable temperatures in the health physics and hot machine shop areas of the annex building. The inlet vanes of the supply fans are modulated automatically by flow controllers to maintain a constant air flow rate. The exhaust air flow is then balanced to maintain a slightly negative pressure differential in the areas served with respect to the outside environment and to surrounding areas which do not have their exhausts monitored for radioactivity. Differential pressure transmitters sense pressure in the general health physics area and atmospheric pressure from an outdoor location shielded from the effects of wind to monitor for negative pressure differential in the health physics area. In addition, a separate differential pressure controller with a sensor in the hot machine shop modulates a damper in the supply air duct to the hot machine shop to maintain a slightly negative pressure differential in the shop with respect to outdoors and to surrounding areas which do not have their exhausts monitored for radioactivity.

The temperature in the health physics and the hot machine shop area is maintained within the design range by a temperature sensor located in the health physics area, with which a controller modulates the control valve on the chilled water supply lines to the cooling coil and the face and bypass damper of the heating coil.

Abnormal Plant Operation

The health physics and hot machine shop HVAC system is not required to operate during any abnormal plant condition.

9.4.11.3 Safety Evaluation

The health physics and hot machine shop HVAC system has no safety-related functions and therefore requires no nuclear safety evaluation.

9.4.11.4 Tests and Inspections

The health physics and hot machine shop HVAC system is designed to permit periodic inspection of system components. Each component is inspected prior to installation. Components of each system are accessible for periodic inspection during normal plant operation. A system air balance test and adjustment to design conditions is conducted during the plant preoperational test program. Air flow rates are measured and balanced in accordance with the guidelines of SMACNA HVAC Systems - Testing, Adjusting and Balancing (Reference 19). Instruments are calibrated during testing. Automatic controls are tested for actuation at the proper setpoints. Alarm functions are checked for operability.

9.4.11.5 Instrumentation Application

The health physics and hot machine shop HVAC system operation is controlled by the plant control system. Refer to Subsection 7.1.1 for a discussion of the plant control system.

Temperature controllers maintain the proper space temperature. Supply air temperature is controlled by sensing the temperature in the general health physics area.

Temperature is indicated for each air handling unit supply air discharge duct.

Operational status of fans is indicated in the main control room. The fans and air handling units can be placed into operation or shutdown from the main control room.

Differential pressure indication is provided for each of the filters in the air handling units and an alarm for high pressure drop is provided for each air handling unit.

Pressure differential indication and alarms are provided to monitor the pressure differential in the health physics area with respect to the environment. A pressure differential controller maintains a slightly negative pressure differential in the hot machine shop.

Airflow is indicated for the air handling unit and exhaust fan discharge ducts. Alarms are provided for abnormal air flow rates in the fan discharge ducts.

An alarm is provided for high radiation in the main exhaust duct to the vent stack.

An alarm is provided for smoke in the discharge ducts from the supply air handling units.

Position indicating lights are provided for automatic dampers.

9.4.12 Combined License Information

The program to maintain compliance with ASME AG-1 (Reference 36), ASME N509 (Reference 2), ASME N510 (Reference 3) and Regulatory Guide 1.140 (Reference 30) for portions of the nuclear island nonradioactive ventilation system and the containment air filtration system identified in

Subsections 9.4.1 and 9.4.7 are addressed in Subsections 9.4.1.4 and 9.4.7.4, respectively. The MCR/CSA HVAC subsystem's recirculation mode during toxic emergencies, and conformance with Regulatory Guide 1.78 (Reference 37) is addressed in Section 6.4.

Section 6.4 does not identify any toxic emergencies that require the main control room/control support area HVAC to enter recirculation mode.

9.4.13 References

1. "Functional Criteria For Emergency Response Facilities," USNRC NUREG 0696.
2. "Nuclear Power Plant Air-Cleaning Units and Components," ASME N509-1989 (R1996).
3. "Testing of Nuclear Air-Cleaning Systems," ASME N510-1989.
4. "Laboratory Methods of Testing Fans for Certified Aerodynamic Performance Rating," ANSI/AMCA 210-2007.
5. "Certified Ratings Program - Product Rating Manual for Fan Air Performance," AMCA 211-13 (Rev. 2015).
6. "Reverberant Room Methods for Sound Testing of Fans," ANSI/AMCA 300-2014.
7. ASHRAE 52.1, “Gravimetric and Dust Spot Procedures for Testing Air-Cleaning Devices Used in General Ventilation for Removing Particulate Matter,” 1992.
8. "Air-Filter Units," UL 900, 8th Edition.
9. "High-Efficiency, Particular, Air-Filter Units," UL-586, 9th Edition.
10. Not Used.
11. "Methods of Testing for Rating Forced Circulation Air Cooling and Air Heating Coils," ASHRAE 33-78.
12. "Forced-Circulation Air Cooling and Air Heating Coils," ANSI/ARI 410-91.
13. "Commercial and Industrial Humidifiers," ARI 640-96.
14. "Laboratory Methods of Testing Dampers for Ratings," ANSI/AMCA 500-D, 2012.
15. "Fire Dampers," UL-555, 7th Edition.
16. "Rectangular Industrial Duct Construction Standards," SMACNA, 1980.
17. "HVAC Duct Construction Standards – Metal and Flexible," SMACNA, 1995.
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21. Code of Federal Regulations, Title 10, Part 20.

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23. Branch Technical Position CSB 6-4 to "Containment Isolation System," Standard Review Plan 6.2.4 of NUREG-0800 Rev. 2, July 1981.

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31. "Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants," Regulatory Guide 1.128, Revision 1, October 1978.

32. "Ventilation for Acceptable Indoor Air Quality," ASHRAE Standard 62-1999.

33. NFPA 92A-2000, "Recommended Practice for Smoke Control Systems."

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35. "Method of Testing HVAC Air Ducts," ASHRAE 126, 2000.

36. "Code on Nuclear Air and Gas Treatment," ASME/ANSI AG-1-1997.

37. "Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release," USNRC Regulatory Guide 1.78, Revision 1, December 2001.

38. "Standard Test Methods for Determining Air Change in a Single Zone by Means of a Tracer Gas Dilution," ASTM E741, 2000.

39. Not used.

40. "Standard for Fixed and Location-Dedicated Electric Room Heaters," UL-2021, 3rd Edition.

41. "Electrical Baseboard Heating Equipment," UL 1042.

42. ASHRAE Handbook - HVAC Systems and Equipment, 2012.

43. "Method of Measuring Machinery Sound Within an Equipment Space," AHRI 575-2008.

201. ASME/ANSI AG-1a-2000, Addenda to ASME AG-1-1997 Code on Nuclear Air and Gas Treatment, Section HA, “Housings.”

Table 9.4-1
Design Filtration Efficiencies and Nominal Airflow Rates for HVAC Systems(1)

Areas Served(1)	Design/Test Standard	Ventilation Airflow (cfm)	Recirculation Flow (cfm)	Humidity Control	HEPA Efficiency	Charcoal Efficiency(3)	Maximum Inleakage (cfm)
MCR/CSA (Supplemental Air)	RG 1.140	800	3,200	Yes	99%	99%	60(4)
Containment	RG 1.140	4,000(2)	N/A	Yes	99%	99%	N/A

Notes:
1. Ventilation cfm is shown for each train unless otherwise noted.
2. Both trains of the containment purge may be operated at the same time prior to and during cold shutdown.
3. Charcoal filters are 4-inch deep Type III adsorber cell.
4. This VBS inleakage represents the total inleakage into the combined MCR/CSA HVAC volume, which includes ingress/egress.

Table 9.4.1-1 (Sheet 1 of 2)
Component Data – Nuclear Island
Nonradioactive Ventilation System
MCR/CSA HVAC Subsystem
(Nominal Values)

Supply Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	17,360
Fan static pressure (in. wg)	7.5
Return Air/Smoke Purge Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	15,860
Fan static pressure (in. wg)	4.4
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	807,140
Water flow (gpm)	See Table 9.2.7-1
Heating Coil Requirements	
Type	Hot Water
Capacity (Btu/hr)	140,810
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, minimum ASHRAE efficiency (%)	80

Table 9.4.1-1 (Sheet 2 of 2)
Component Data – Nuclear Island
Nonradioactive Ventilation System
MCR/CSA HVAC Subsystem
(Nominal Values)

Supplemental Air Filtration Subsystem	
Quantity	2
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	
- Single unit mode	4,000
- Dual unit mode	3,500
Fan static pressure (in. wg)	
- Single unit mode	11.3
- Dual unit mode	14.3
Heating Coil Requirements	
Type	Electric
Capacity (kw)	20
Filter Requirements	
High efficiency filter, minimum ASHRAE efficiency (%)	80
HEPA filter, DOP efficiency (%)	99.97
Post filter, DOP efficiency (%)	95
Charcoal Adsorber Requirements	
Bed depth (in.)	4.0
Decontamination efficiency (%)	99
Air residence time (sec.)	0.5

MCR Envelope and CSA Leakage Rates

Leakage	Inleakage Rate at 1/8 in. wg (scfm)	Outleakage Rate at 1/8 in. wg (scfm) (Note 3)
MCR access doors	--	Note 1
CSA access doors	--	Note 2
MCR structure	--	Note 1
CSA structure	--	Note 2
MCR/CSA HVAC equipment & ductwork (operating)	50	200

Note:

1. The total outleakage rate from the MCR access doors and the MCR structure is 35 scfm.
2. The total outleakage rate from the CSA doors and CSA structure is 120 scfm.
3. In cases where the outside air flow rate is greater than the outside air required to pressurize the MCR envelope and CSA, excess air is exhausted to the outside atmosphere.

Table 9.4.1-2 (Sheet 1 of 3)
Component Data – Nuclear Island
Nonradioactive Ventilation System
Class 1E Electrical Room HVAC Subsystem
(Nominal Values)

Division "A & C" Supply Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	17,900
Fan static pressure (in. wg)	7.0
Return Air/Smoke Purge Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	16,280
Fan static pressure (in. wg)	4.1
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	851,680
Water flow (gpm)	See Table 9.2.7-1
Heating Coil Requirements	
Type	Hot Water
Capacity (Btu/hr)	131,460
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, ASHRAE efficiency (%)	80

Table 9.4.1-2 (Sheet 2 of 3)
Component Data – Nuclear Island
Nonradioactive Ventilation System
Class 1E Electrical Room HVAC Subsystem
(Nominal Values)

Division "A & C" Class 1E Battery Room Exhaust Fans	
Quantity per electrical division	2
System capacity per fan (%)	100
Type	Centrifugal
Design airflow (scfm)	1,320
Fan static pressure (in. wg)	1.5
Division "B & D" Supply Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	10,480
Fan static pressure (in. wg)	6.5
Return Air/Smoke Purge Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	9,790
Fan static pressure (in. wg)	3.0
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	450,320
Water flow (gpm)	See Table 9.2.7-1
Heating Coil Requirements	
Type	Hot Water
Capacity (Btu/hr)	49,820
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, ASHRAE efficiency (%)	80

Table 9.4.1-2 (Sheet 3 of 3)
Component Data – Nuclear Island
Nonradioactive Ventilation System
Class 1E Electrical Room HVAC Subsystem
(Nominal Values)

Division "B & D" Class 1E Battery Room Exhaust Fans	
Quantity per electrical division	2
System capacity per fan (%)	100
Type	Centrifugal
Design airflow (scfm)	990
Fan static pressure (in. wg)	2.1

Table 9.4.1-3
Component Data – Nuclear Island
Nonradioactive Ventilation System
Passive Containment Cooling System
Valve Room Heating and Ventilation Subsystem
(Nominal Values)

Exhaust Fan Data	
Quantity	1
System capacity per fan (%)	100
Type	Propeller
Design airflow (scfm)	1,300
Fan static pressure (in. wg)	0.75
Electric Unit Heater	
Quantity	2
System capacity per unit heater (%)	100
Type	Horizontal
Capacity (kw)	10

Table 9.4.2-1
Component Data –
Annex/Auxiliary Buildings Nonradioactive HVAC System
Switchgear Room HVAC Subsystem
(Nominal Values)

Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	20,400
Static pressure (in. wg)	5.0
Return/Exhaust Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	20,000
Static pressure (in. wg)	1.6

Table 9.4.2-2
Component Data –
Annex/Auxiliary Buildings Nonradioactive HVAC System
Equipment Room HVAC System
(Nominal Values)

Supply Air Handling Units	
Quantity	2
System capacity per unit (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	20,900
Static pressure (in. wg)	5.6
Return/Exhaust Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	18,600
Static pressure (in. wg)	2.6
Battery Rooms 40307 and 40309 Exhaust Fans	
Quantity	2
System capacity per unit (%)	100
Type	Centrifugal
Design airflow (scfm)	750
Static pressure (in. wg)	1.5
Battery Room 40412 Exhaust Fan	
Quantity	1
System capacity per unit (%)	100
Type	Centrifugal
Design airflow (scfm)	780
Static pressure (in. wg)	4.9

Table 9.4.3-1
Component Data – Radiologically Controlled Area Ventilation System
Auxiliary/Annex Building Ventilation Subsystem
(Nominal Values)

Normal Residual Heat Removal Pump Room Unit Coolers	
Quantity	2
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	1,750
Fan static pressure (in. wg)	1.8
Cooling Coil Requirements	
Type	Chilled Water
Capacity per coil (Btu/hr)	75,250
Water flow (gpm)	See Table 9.2.7-1
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
Chemical and Volume Control Makeup Pump Room Unit Coolers	
Quantity	2
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	2,625
Fan static pressure (in. wg)	1.4
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	113,320
Water flow (gpm)	See Table 9.2.7-1
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25

Table 9.4.6-1
Component Data – Containment Recirculation Cooling System (Nominal Design Values)

Fan Coil Unit Assemblies	
Quantity	4
System capacity per assembly (%)	50
Fan Data (per assembly)	
Quantity (fans)	1
Type	Vaneaxial
Normal design air flow (scfm @ 0 psig)	77,000
Low speed design air flow (scfm @ 59 psig)	122,700
Fan total pressure (in. wg)	11
Coil Data (per assembly)	
Quantity (coil banks)	4 (2 coils/bank)
Total cooling capacity (Btu/hr)	4,816,000
Total chilled water flow rate (gpm)	600
Total heating capacity (Btu/hr)	2,437,000
Total hot water flow rate (gpm)	63

Table 9.4.7-1 (Sheet 1 of 2)
Component Data – Containment Air Filtration System
(Nominal Values)

Supply Air Handling Units	
Quantity	2
System capacity per assembly (%)	100
Supply Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	4,000
Fan static pressure (in. wg)	14
Cooling Coil Requirements	
Type	Chilled Water
Capacity (Btu/hr)	380,000
Water flow (gpm)	41
Heating Coil Requirements	
Type	Hot Water
Capacity (Btu/hr)	290,000
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, minimum ASHRAE efficiency (%)	80

Table 9.4.7-1 (Sheet 2 of 2)
Component Data – Containment Air Filtration System
(Nominal Values)

Exhaust Air Filtration Units	
Quantity	2
System capacity per assembly (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	4,000
Fan static pressure (in. wg)	24.0
Heating Coil Requirements	
Type	Electric
Capacity (kw)	20
Filter Requirements	
High efficiency filter, minimum ASHRAE efficiency (%)	80
HEPA filter, DOP efficiency (%)	99.97
Post filter, DOP efficiency (%)	95
Charcoal Adsorber Requirements	
Bed depth (in.)	4.0
Decontamination efficiency (%)	99
Air residence time (sec.)	0.5

Table 9.4.10-1 (Sheet 1 of 2)
Component Data – Diesel Generator
Building Heating And Ventilation System
Normal Heating and Ventilation Subsystem
(Nominal Values)

Engine Room Air Handling Unit	
Quantity	2 (one per diesel generator room)
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	13,000
Static pressure (in. wg)	3.8
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, minimum ASHRAE efficiency (%)	80
Service Module Air Handling Unit	
Quantity	2 (one per diesel generator room)
System capacity per unit (%)	100
Fan Requirements	
Type	Centrifugal
Design airflow (scfm)	4,000
Static pressure (in. wg)	4.0
Motor nameplate horsepower	5.0
Heating Coil Requirements	
Type	Electric
Capacity (kw)	3 (SCR Controlled)
Filter Requirements	
Low efficiency filter, minimum ASHRAE efficiency (%)	25
High efficiency filter, minimum ASHRAE efficiency (%)	80

Table 9.4.10-1 (Sheet 2 of 2)
Component Data – Diesel Generator
Building Heating And Ventilation System
Normal Heating and Ventilation Subsystem
(Nominal Values)

Electric Unit Heaters	
Quantity	4 (two per diesel generator room)
System capacity per unit (%)	50
Type	Horizontal
Capacity (kw)	45

Table 9.4.10-2
Component Data – Diesel Generator
Building Heating and Ventilation System
Standby Exhaust Ventilation Subsystem
(Nominal Values)

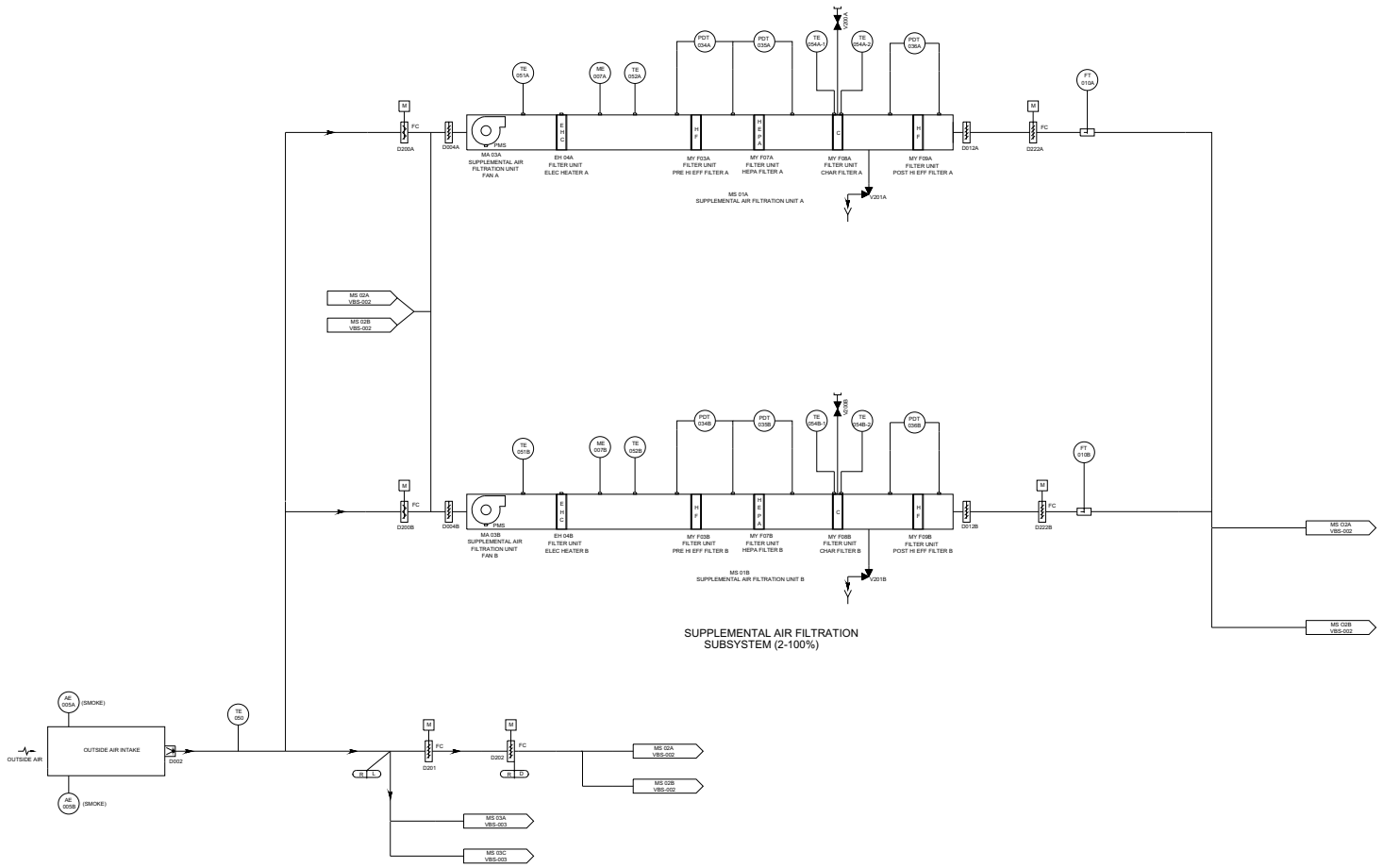
Standby Exhaust Fan	
Quantity	4 (two per diesel generator room)
System capacity per unit (%)	50
Type	Upblast Roof Ventilator
Design airflow (scfm)	24,200
Static pressure (in. wg)	0.25

Table 9.4.10-3
Component Data – Diesel Generator
Building Heating and Ventilation System
Fuel Oil Day Tank Vault Exhaust Subsystem
(Nominal Values)

Fuel Oil Day Tank Vault Exhaust Fan	
Quantity	2 (one per tank vault)
System capacity per unit (%)	100
Type	Centrifugal
Design airflow (scfm)	400
Static pressure (in. wg)	0.8

Table 9.4.10-4
Component Data – Diesel Generator
Building Heating and Ventilation System
Diesel Oil Transfer Module Enclosures
Ventilation and Heating Subsystem
(Nominal Values)

Diesel Oil Transfer Module Enclosure Exhaust Fan	
Quantity	2 (one per enclosure)
System capacity per unit (%)	100
Type	Direct Drive Ventilator
Design airflow (scfm)	160
Static pressure (in. wg)	0.1
Electric Unit Heater	
Quantity	2 (one per enclosure)
System capacity per unit (%)	100
Type	Horizontal
Capacity (kw)	4



BALANCING DAMPERS NOT SHOWN.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

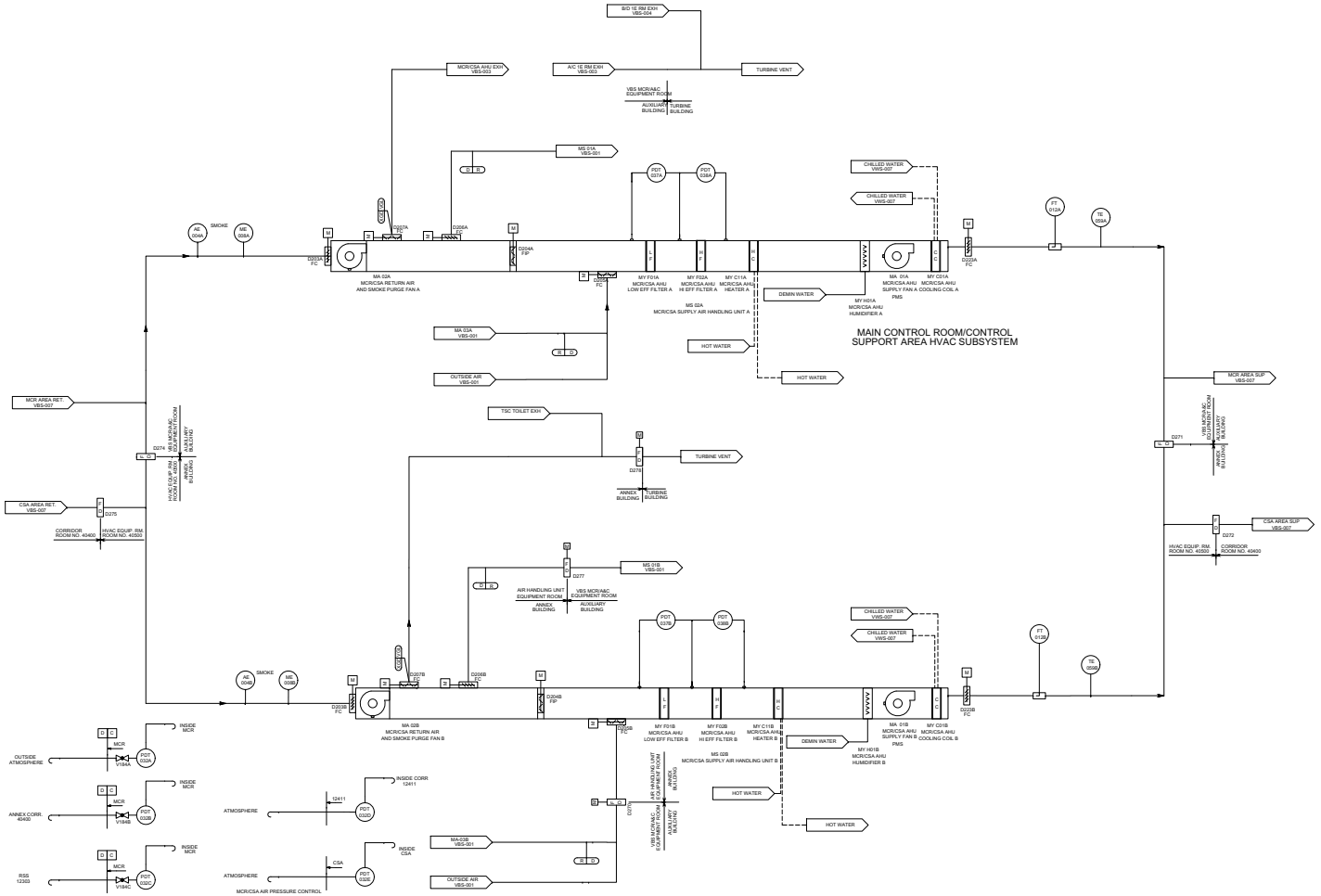
FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 1 of 7)

Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram

(REF) VBS 001



Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 2 of 7)

Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram

(REF) VBS 002

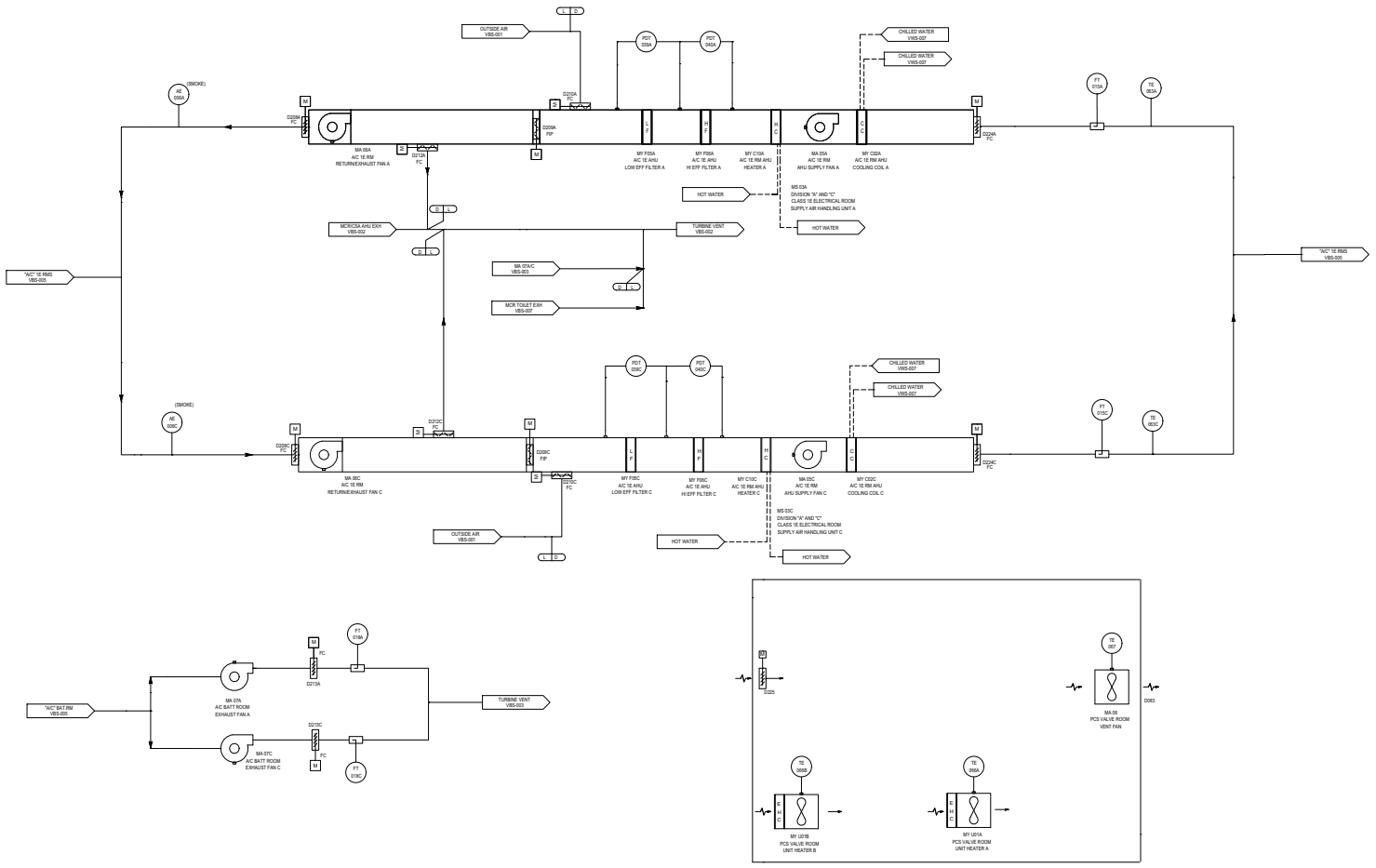


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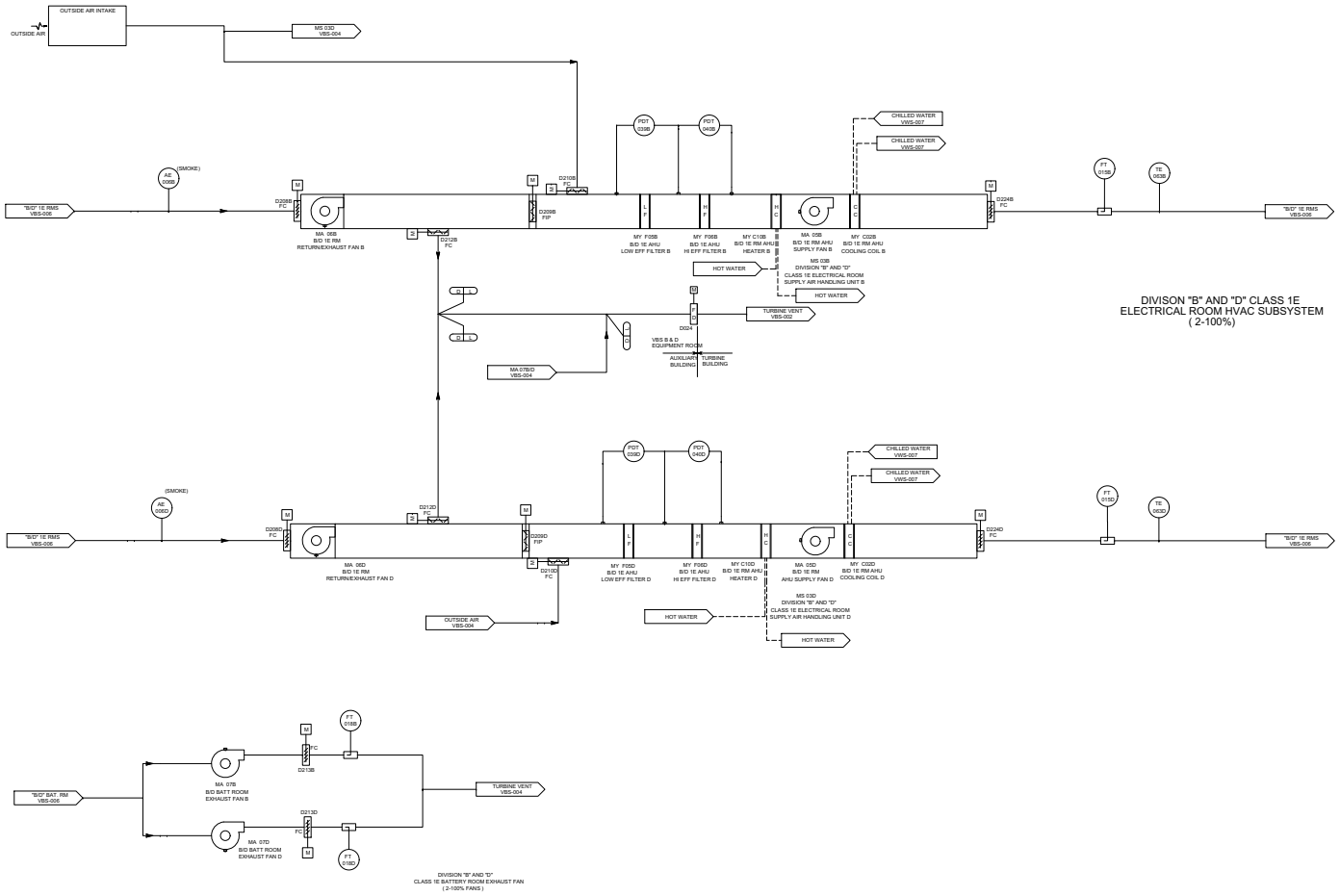
FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 3 of 7)

Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram

(REF) VBS 003



BALANCING DAMPERS ARE NOT SHOWN.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

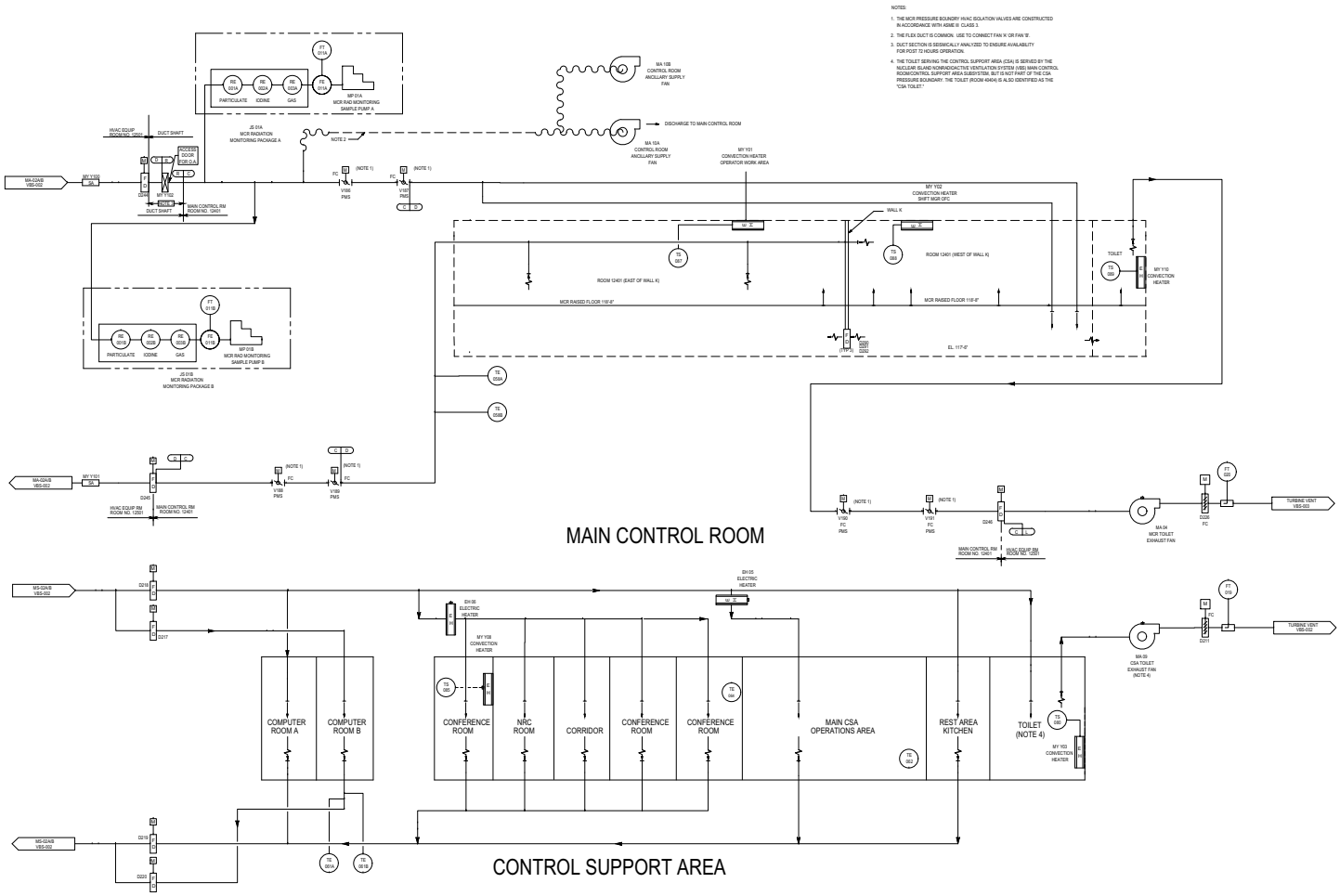
FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 4 of 7)

Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram

(REF) VBS 004



Inside Auxiliary Building

Figure 9.4.1-1 (Sheet 5 of 7)

Simplified Nuclear Island Non-Radioactive Ventilation System Piping and Instrumentation Diagram (REF) VBS 007

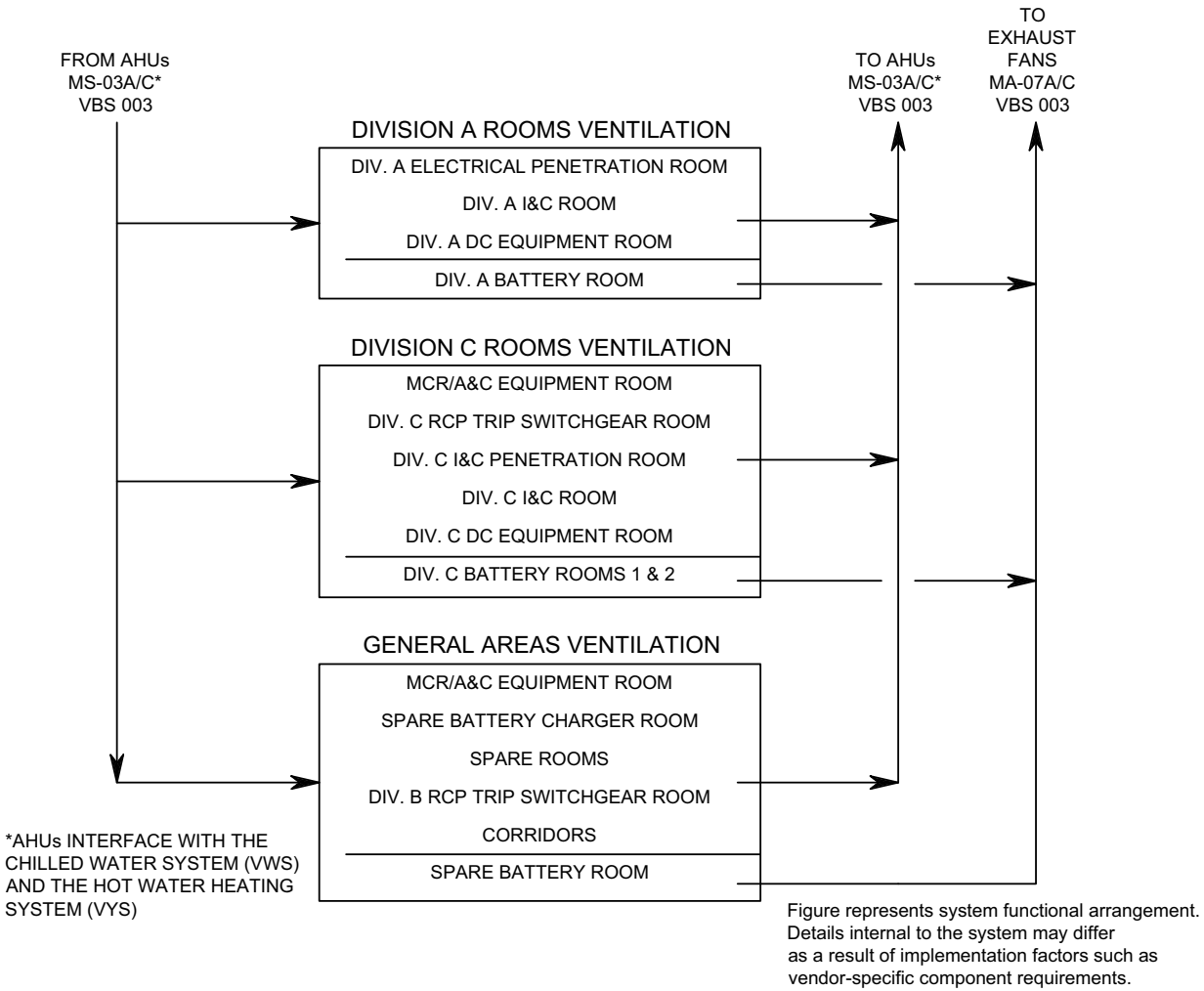


Figure 9.4.1-1 (Sheet 6 of 7)
Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation System
(REF) VBS 005

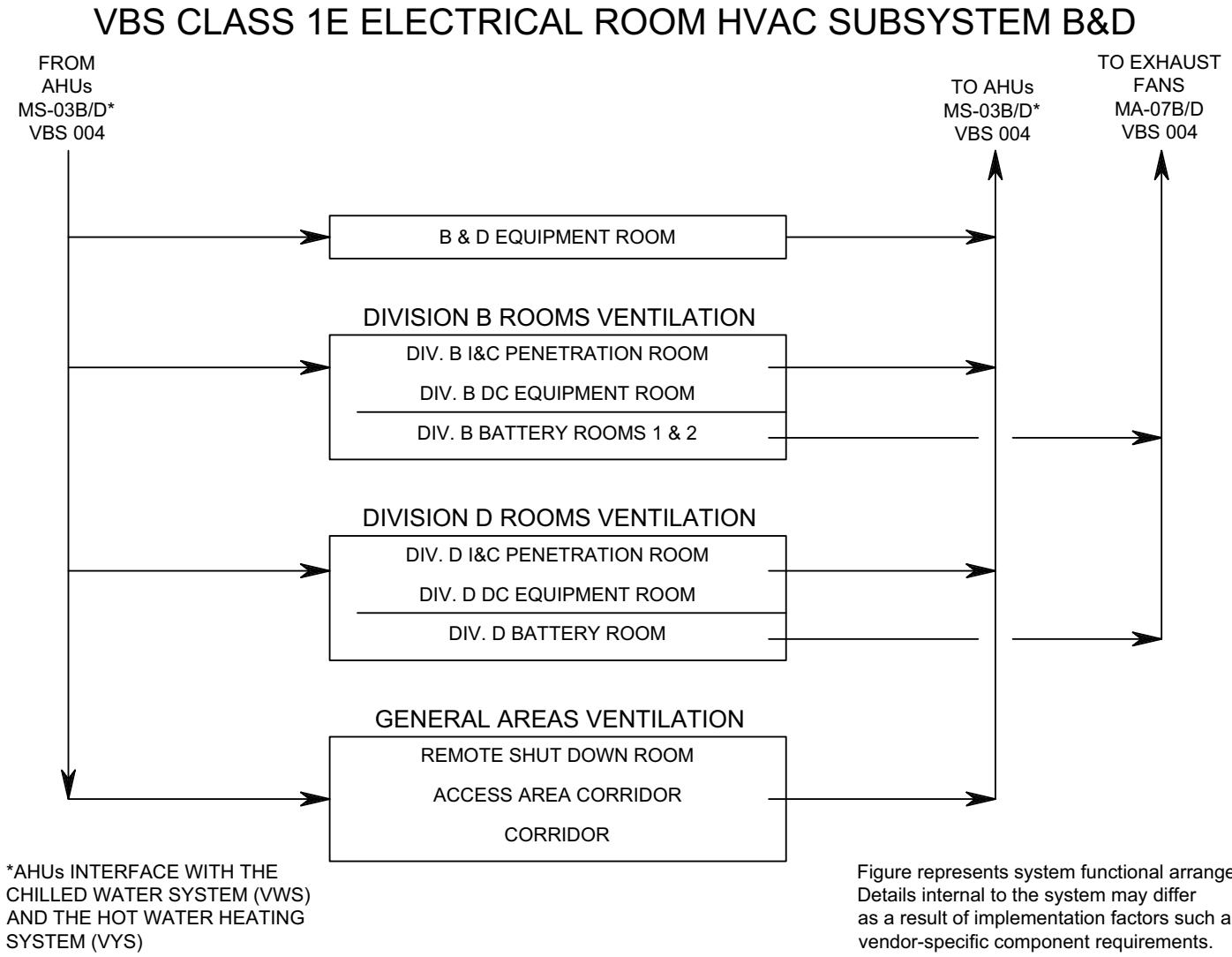
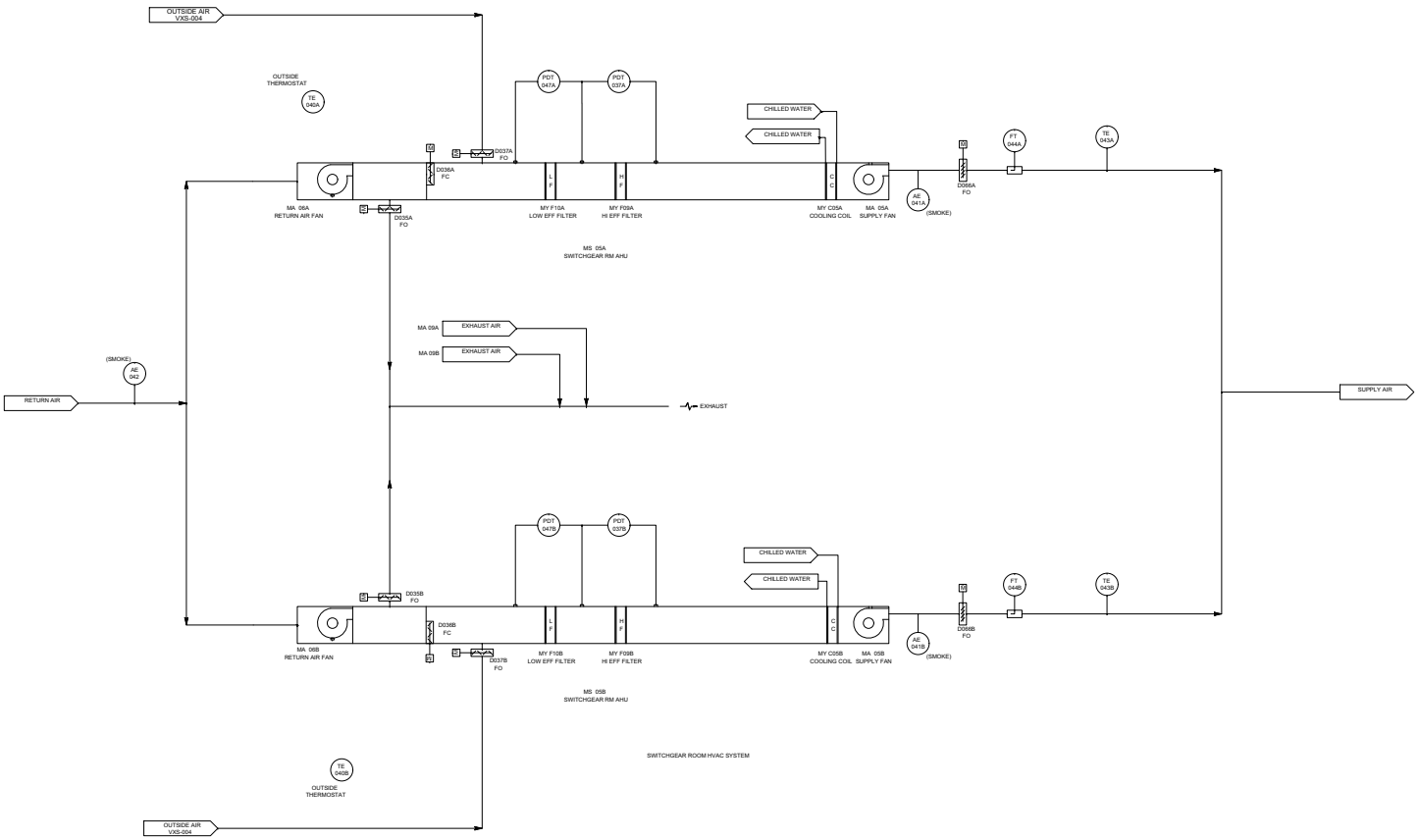


Figure 9.4.1-1 (Sheet 7 of 7)
Nuclear Island Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VBS 006



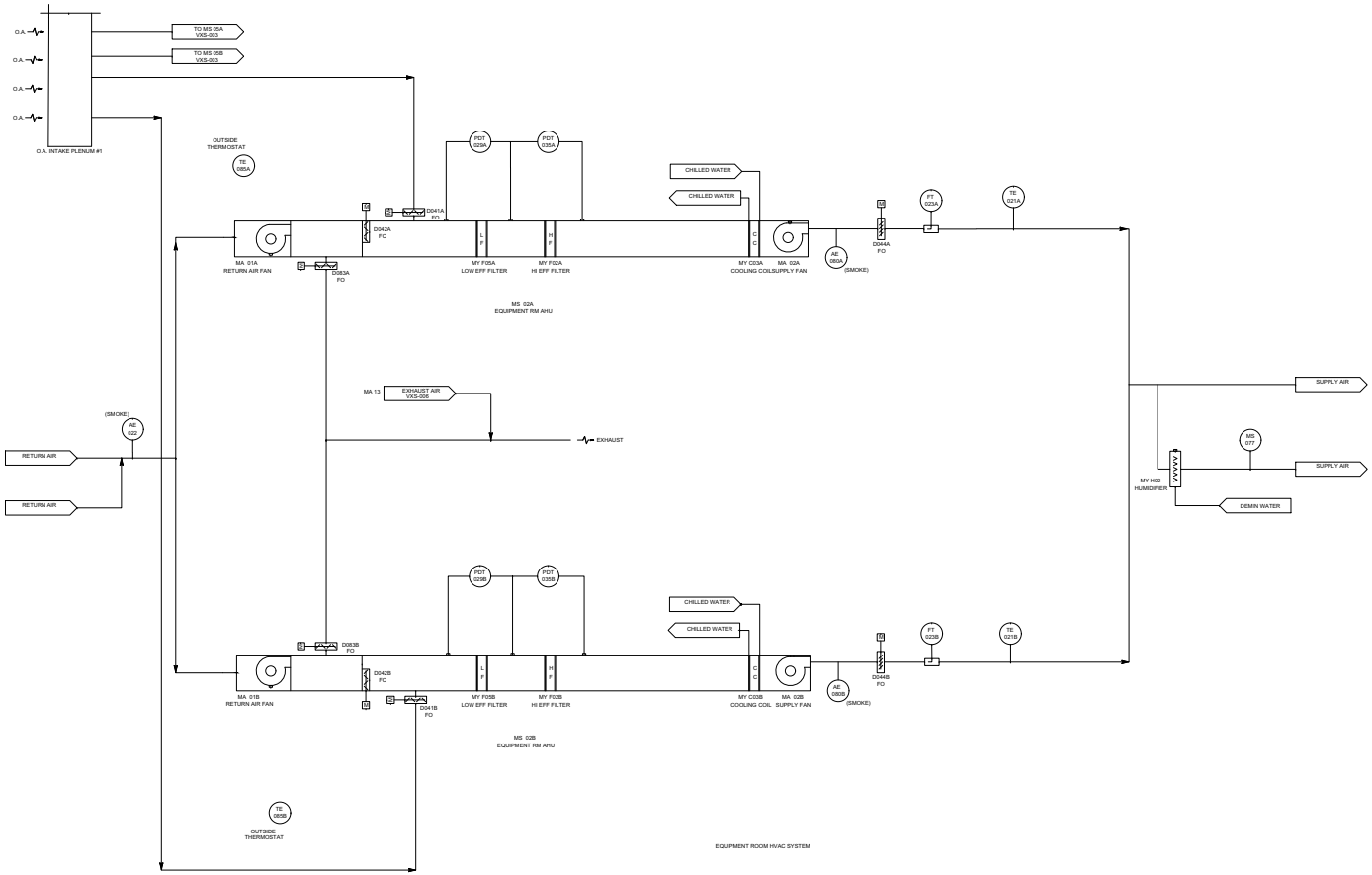
BALANCING DAMPERS ARE NOT SHOWN.

SYSTEM COMPONENTS ARE CLASS D, CLASS E OR CLASS L UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Annex Building
Figure 9.4.2-1 (Sheet 1 of 7)
Simplified Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram (REF) VXS 003



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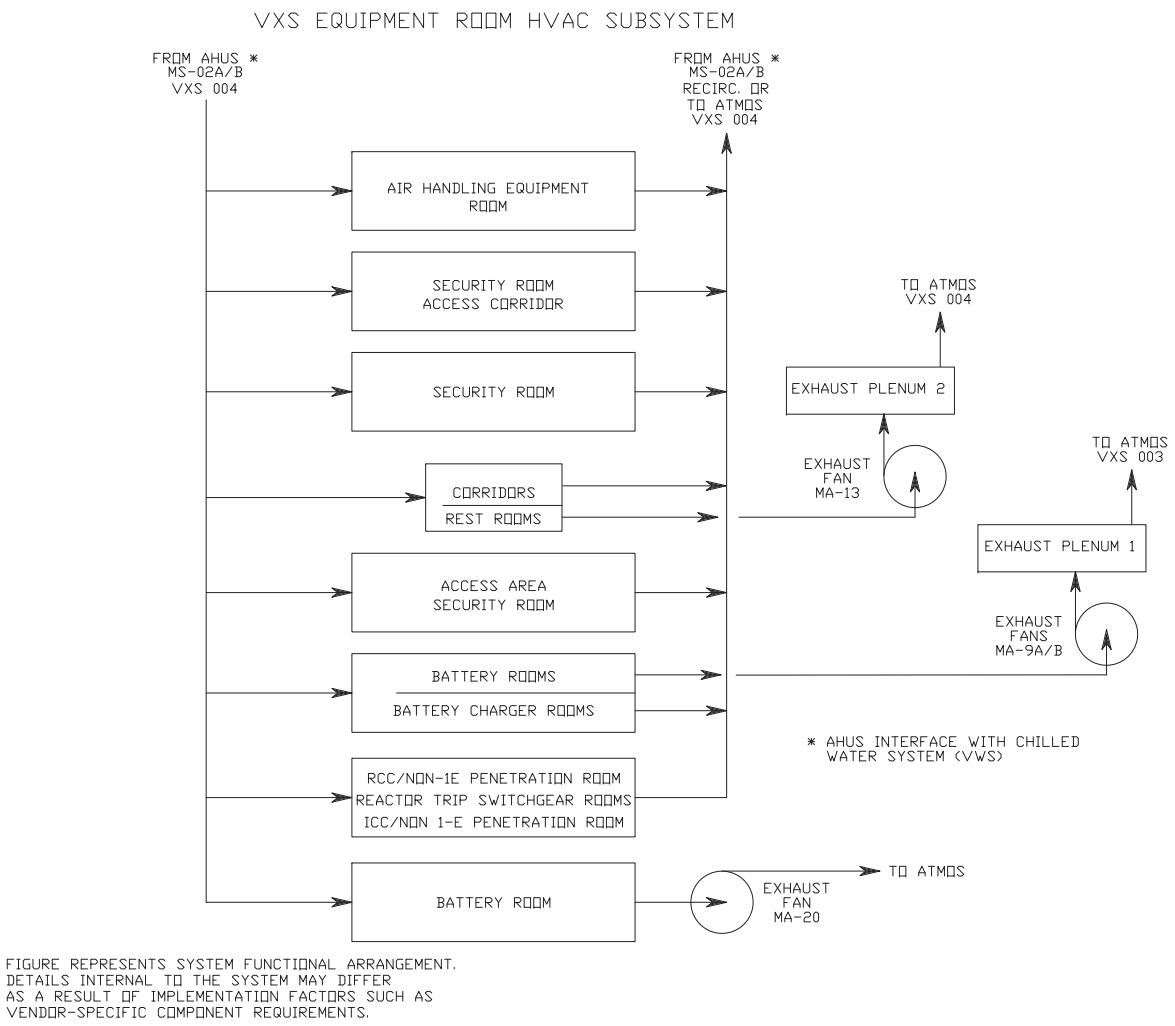
VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Annex Building

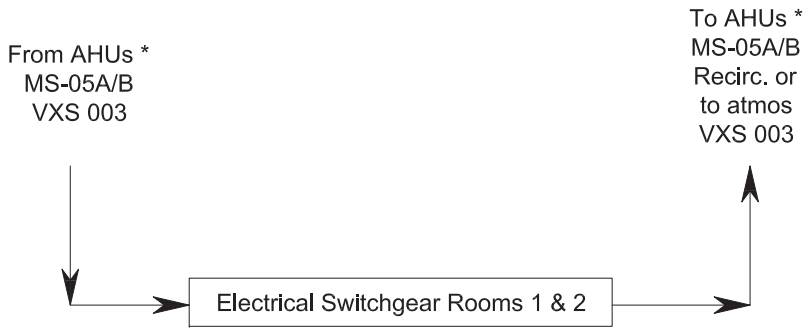
Figure 9.4.2-1 (Sheet 2 of 7)
Simplified Annex/Aux Non-Radioactive Ventilation System Piping and Instrumentation Diagram
(REF) VXS 004



Inside Annex Building

Figure 9.4.2-1 (Sheet 3 of 7)
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 005 & 006

VXS SWITCHGEAR ROOM HVAC SUBSYSTEM



*AHUs interface with chilled water system (VWS)

Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Inside Annex Building
Figure 9.4.2-1 (Sheet 4 of 7)
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 005

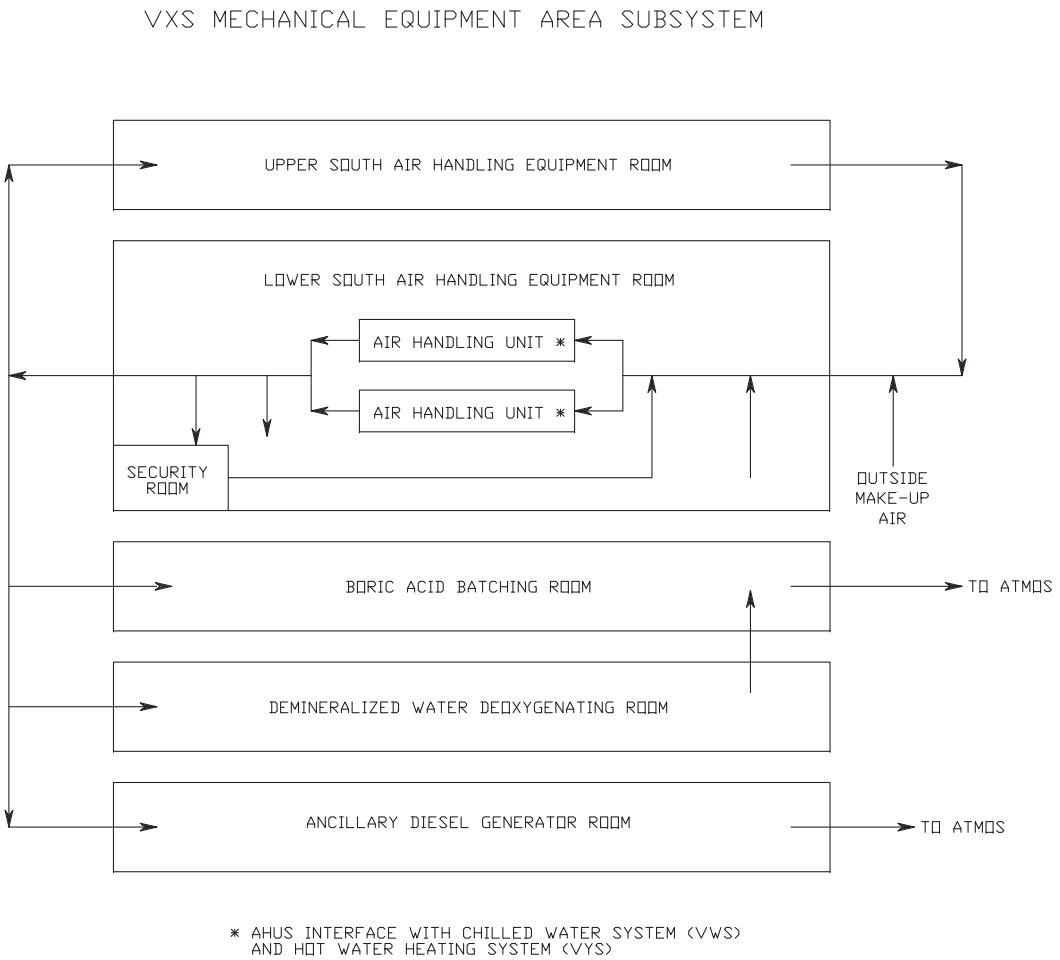


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Inside Annex Building
Figure 9.4.2-1 (Sheet 5 of 7)
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 010

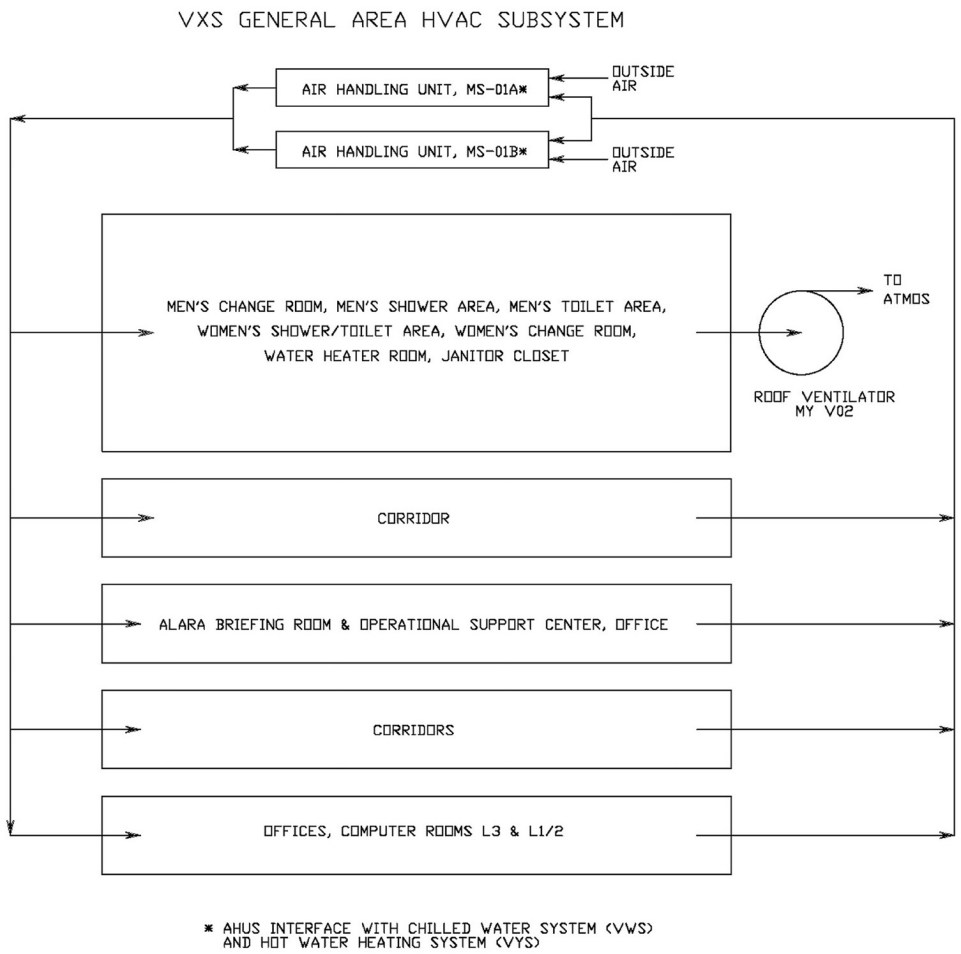
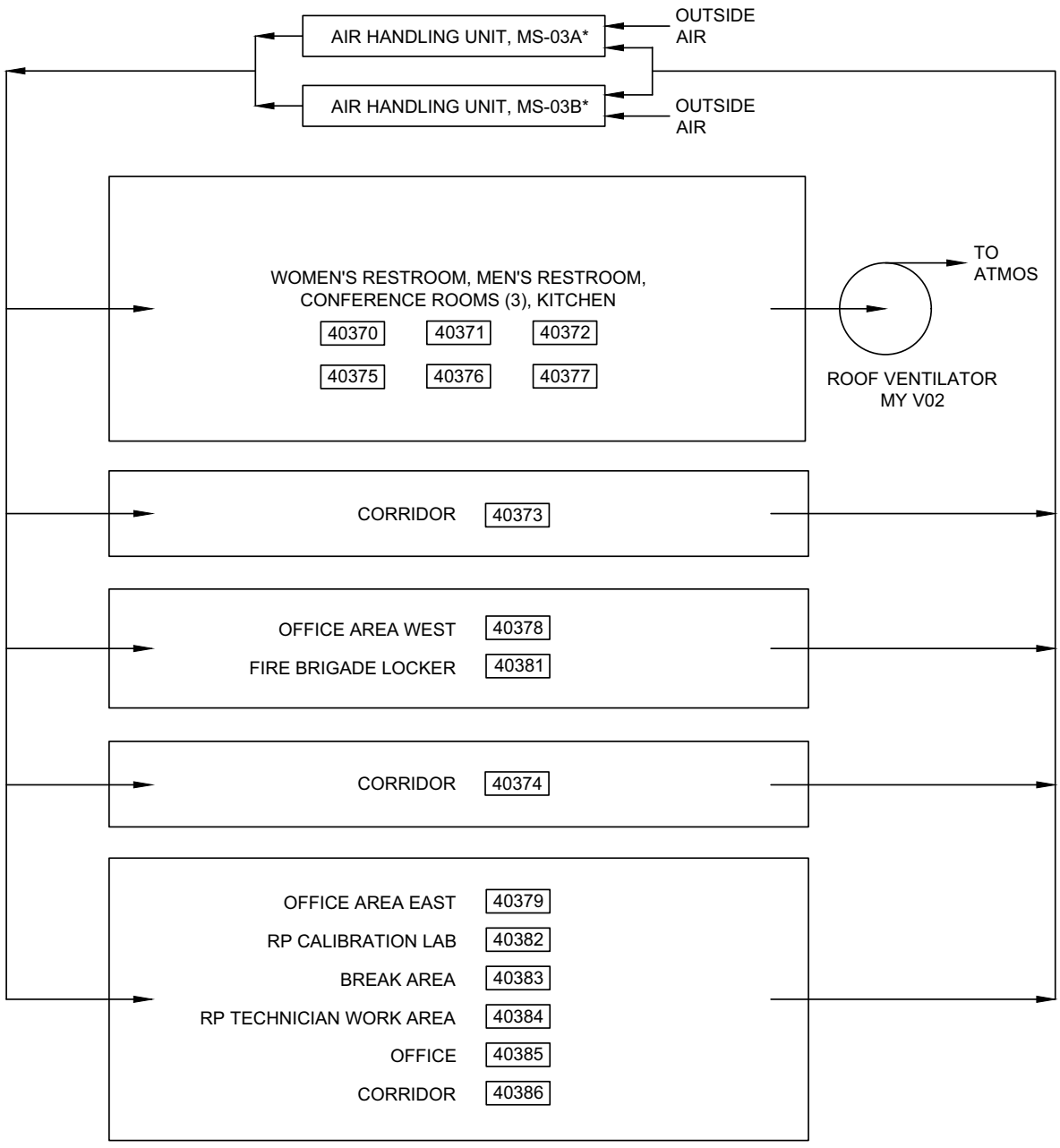


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Inside Annex Building

Figure 9.4.2-1 (Sheet 6 of 7)
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 002

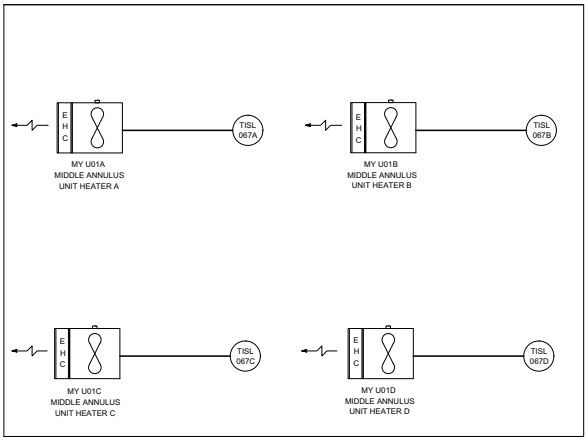


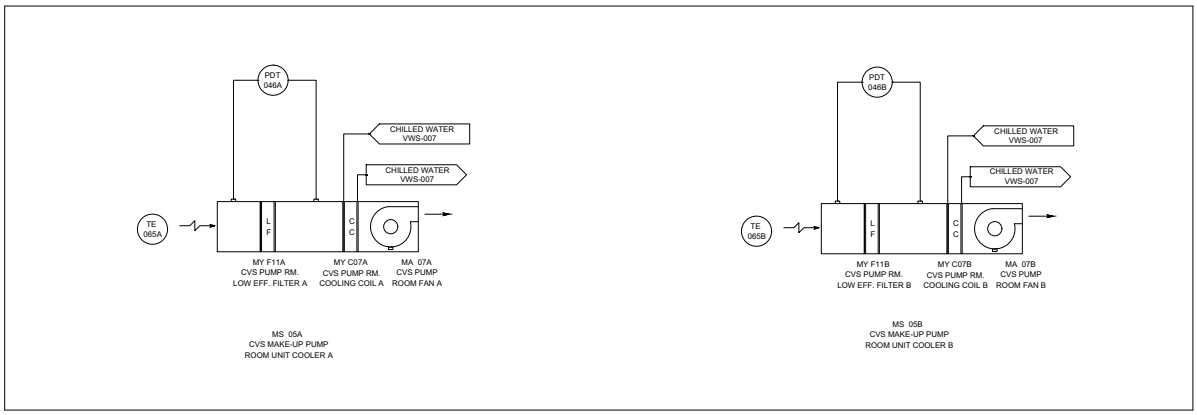
* AHUS INTERFACE WITH CHILLED WATER SYSTEM (VWS)
AND HOT WATER HEATING SYSTEM (VYS)

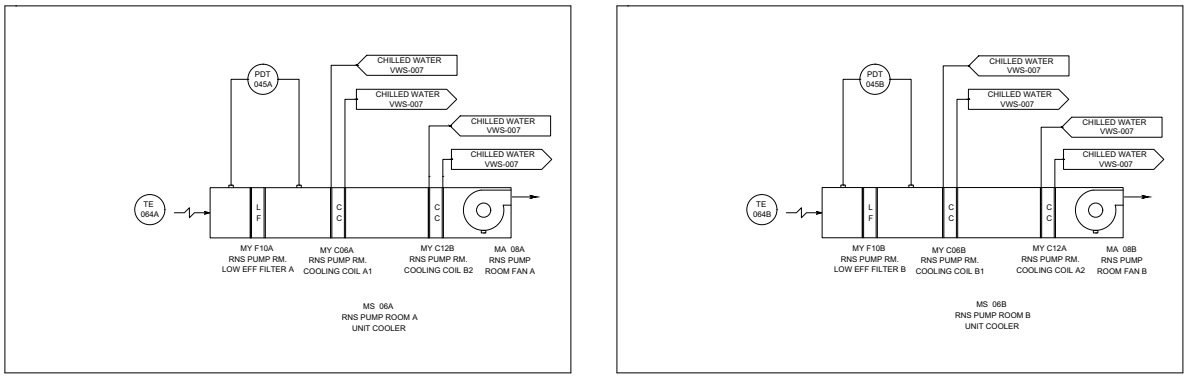
Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Inside Annex Building

Figure 9.4.2-1 (Sheet 7 of 7)
Annex/Aux Non-Radioactive Ventilation System
Piping and Instrumentation Diagram
(REF) VXS 002







SYSTEM COMPONENTS ARE CLASS D OR CLASS E UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT, DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Auxiliary Building
Figure 9.4.3-1 (Sheet 1 of 4)
Simplified Radiologically Controlled Ventilation System Piping and Instrumentation Diagram
(REF) VAS 001

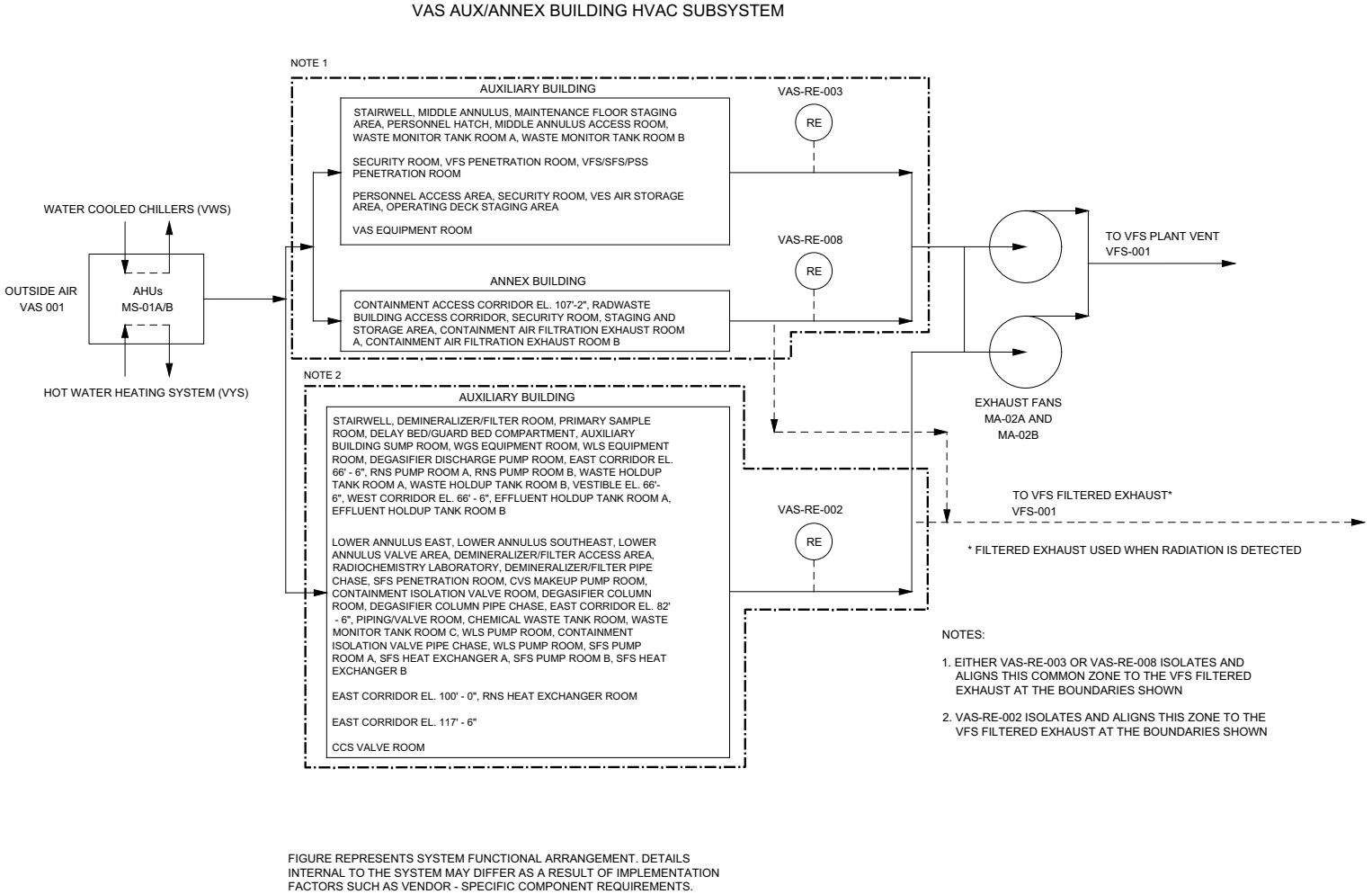


FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR - SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.4.3-1 (Sheet 2 of 4)
Radiologically Controlled Area Ventilation System
Piping and Instrumentation Diagram
(REF) VAS 003 & 010

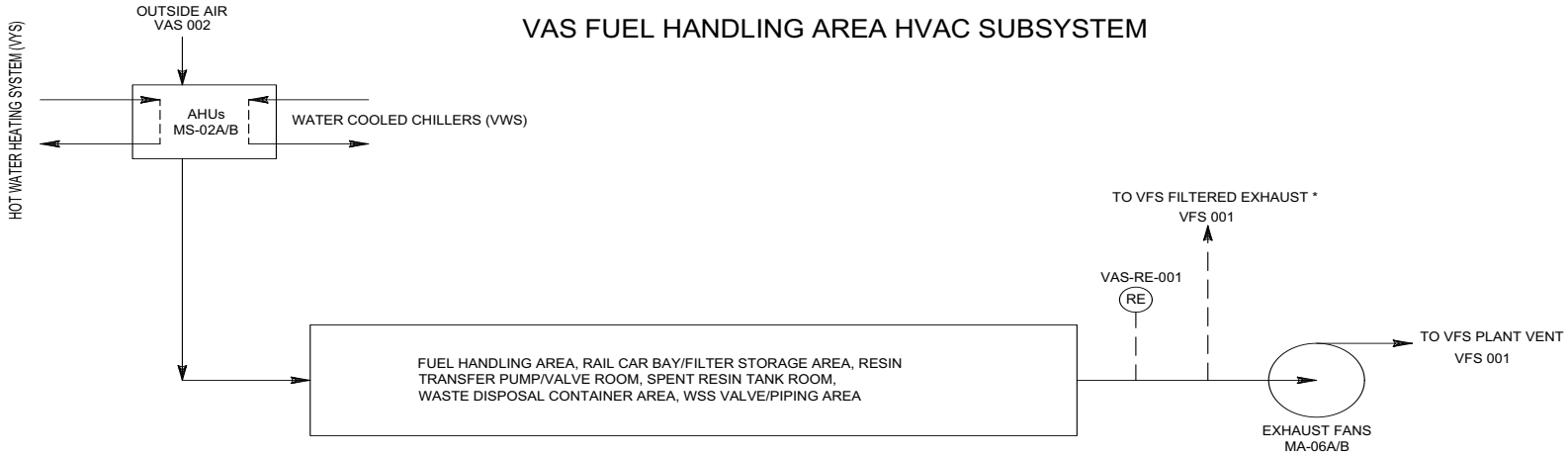


FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR -SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.4.3-1 (Sheet 3 of 4)
Radiologically Controlled Area Ventilation System
Piping and Instrumentation Diagram
(REF) VAS 005

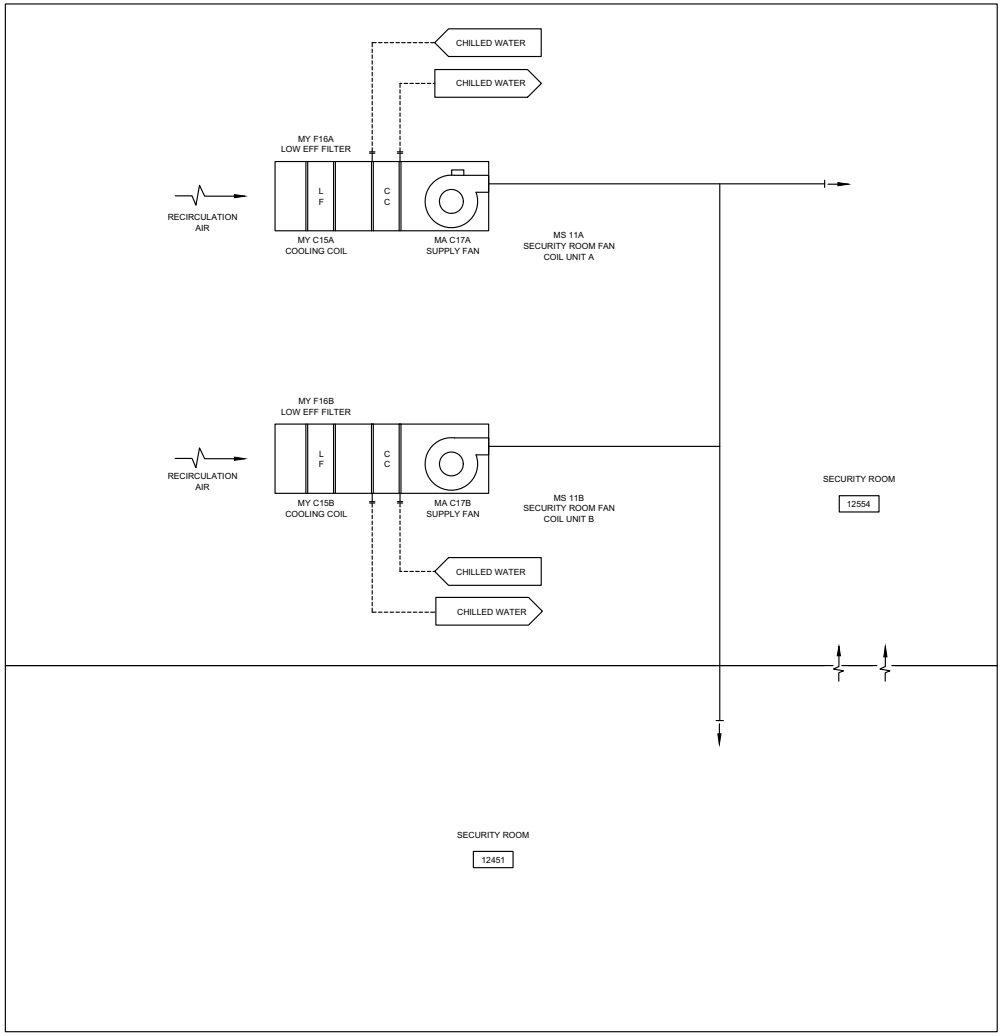
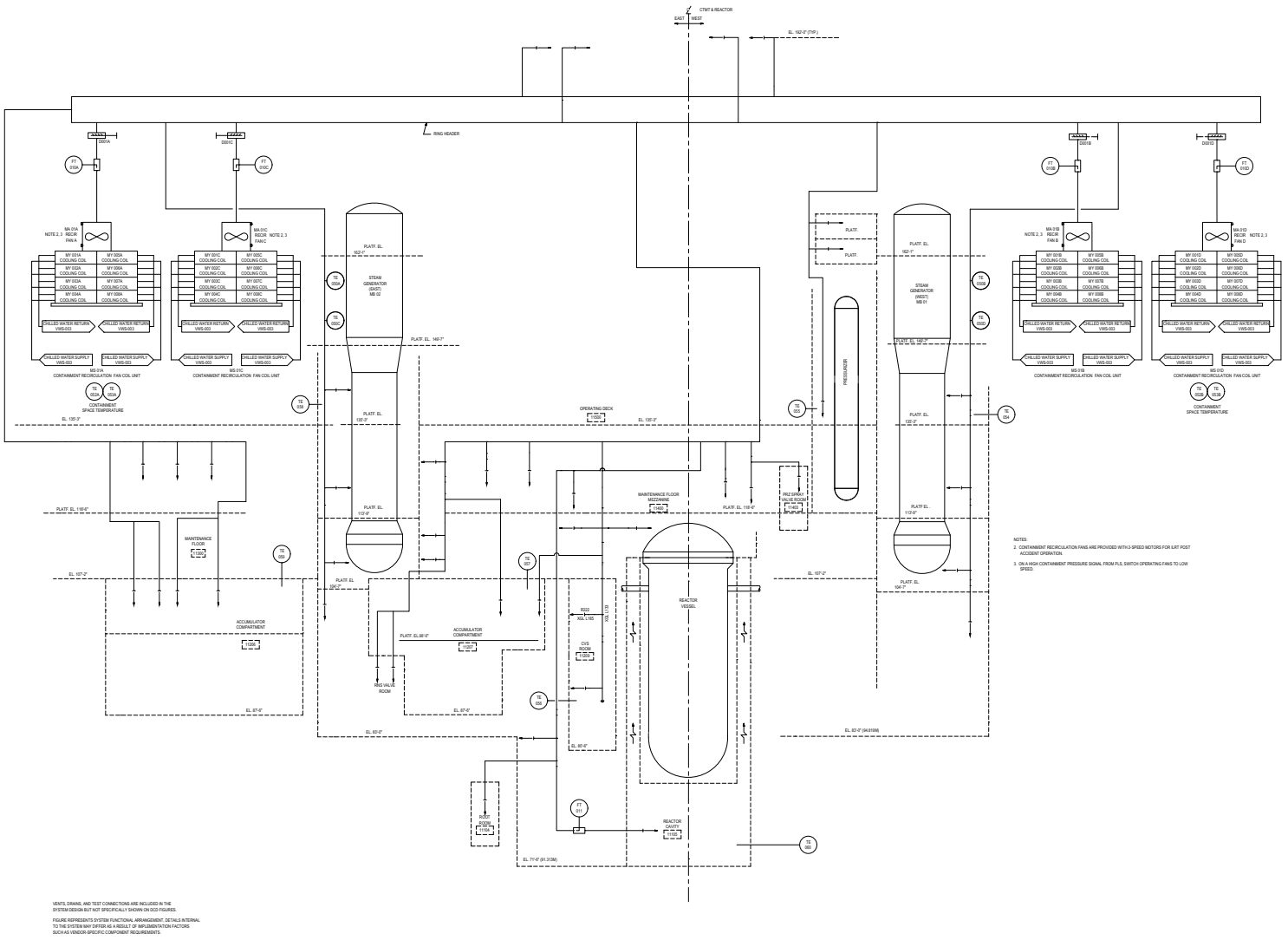


FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.4.3-1 (Sheet 4 of 4)
Inside Auxiliary Building
Simplified Radiologically Controlled Ventilation System
Piping and Instrumentation Diagram
(REF) VAS 009


CTMT & REACTOR
EAST
WEST
EL. 162'-9" (TYP.)
RING HEADER
D001A
D001C
D001B
D001D
FT 0156
FT 0160
FT 0164
FT 0168
MA 01A NOTE 2, 3 RECIR FAN A
MA 01C NOTE 2, 3 RECIR FAN C
MA 01B NOTE 2, 3 RECIR FAN B
MA 01D NOTE 2, 3 RECIR FAN D
MY 001A COOLING COIL
MY 002A COOLING COIL
MY 003A COOLING COIL
MY 004A COOLING COIL
MY 005A COOLING COIL
MY 006A COOLING COIL
MY 007A COOLING COIL
MY 008A COOLING COIL
MY 001C COOLING COIL
MY 002C COOLING COIL
MY 003C COOLING COIL
MY 004C COOLING COIL
MY 005C COOLING COIL
MY 006C COOLING COIL
MY 007C COOLING COIL
MY 008C COOLING COIL
MY 001B COOLING COIL
MY 002B COOLING COIL
MY 003B COOLING COIL
MY 004B COOLING COIL
MY 005B COOLING COIL
MY 006B COOLING COIL
MY 007B COOLING COIL
MY 008B COOLING COIL
MY 001D COOLING COIL
MY 002D COOLING COIL
MY 003D COOLING COIL
MY 004D COOLING COIL
MY 005D COOLING COIL
MY 006D COOLING COIL
MY 007D COOLING COIL
MY 008D COOLING COIL
CHILLED WATER RETURN VWS-003
CHILLED WATER SUPPLY VWS-003
MS 01A CONTAINMENT RECIRCULATION FAN COIL UNIT
MS 01C CONTAINMENT RECIRCULATION FAN COIL UNIT
MS 01B CONTAINMENT RECIRCULATION FAN COIL UNIT
MS 01D CONTAINMENT RECIRCULATION FAN COIL UNIT
TE 0034A
TE 0034C
TE 0034B
TE 0034D
TE 0034
CONTAINMENT SPACE TEMPERATURE
TE 0035
TE 0036
TE 0037
TE 0038
TE 0039
TE 0040
TE 0041
TE 0042
TE 0043
TE 0044
TE 0045
TE 0046
TE 0047
TE 0048
TE 0049
TE 0050
TE 0051
TE 0052
TE 0053
TE 0054
TE

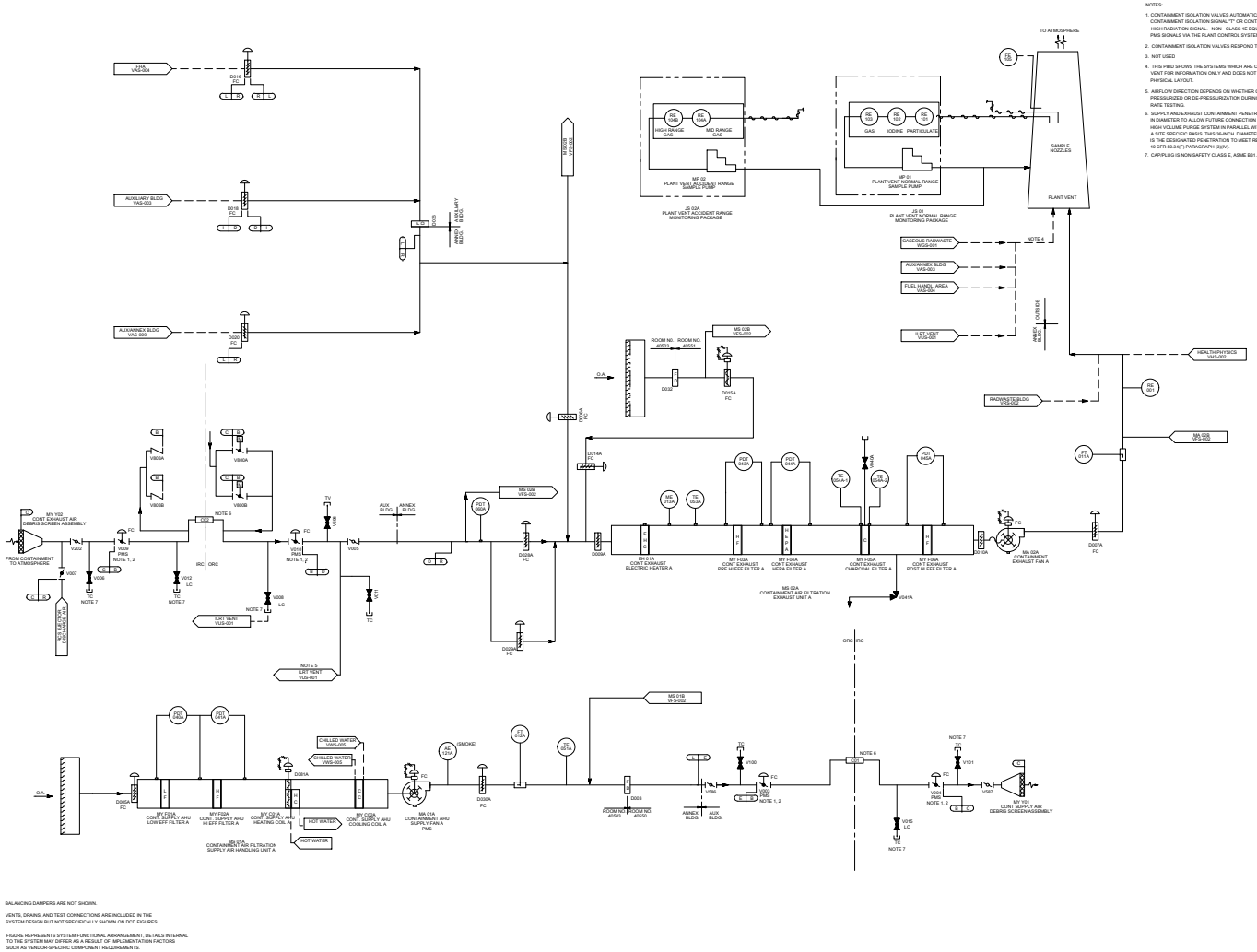
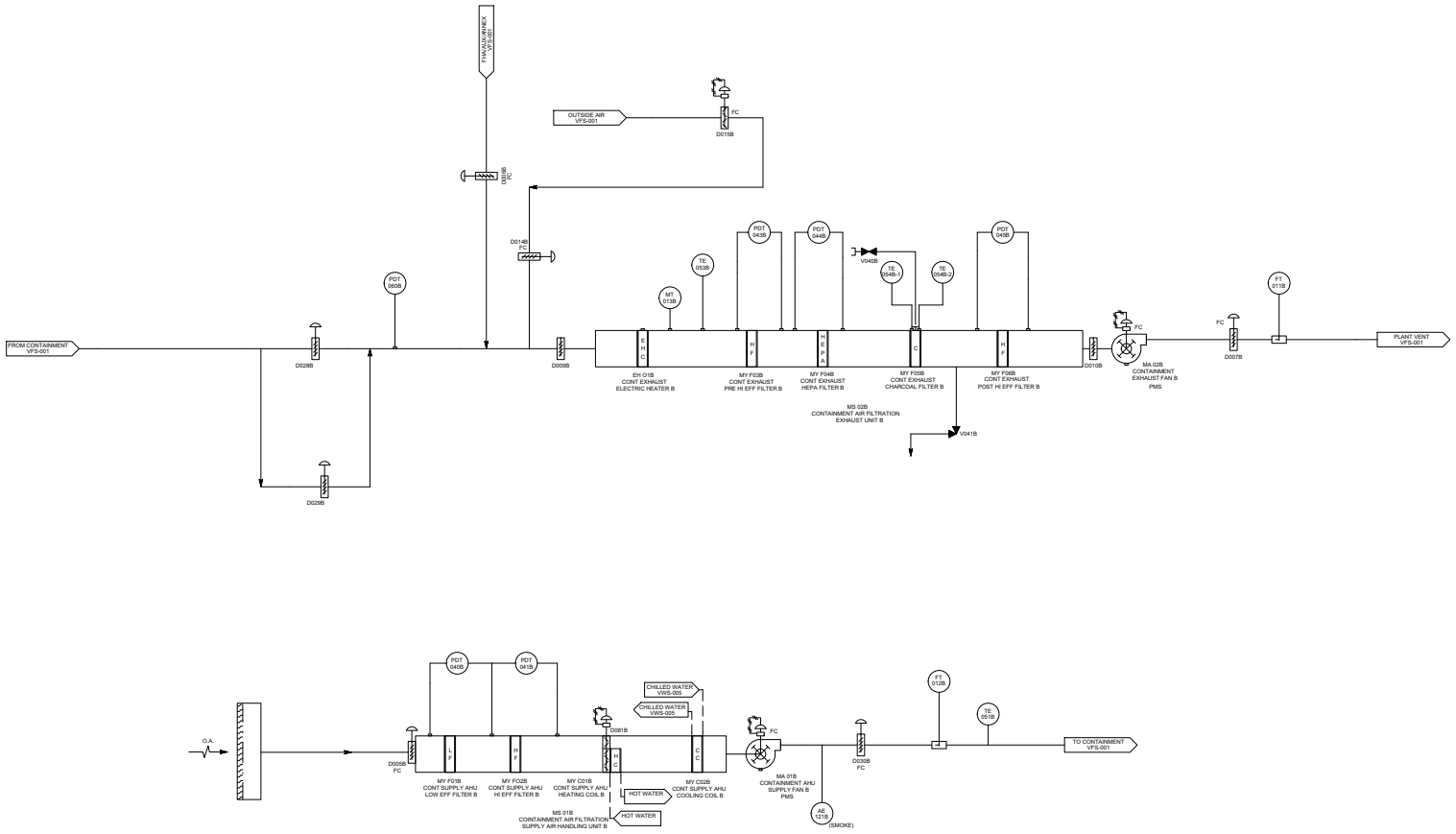


Figure 9.4.7-1 (Sheet 1 of 2)
Simplified Containment Air Filtration System Piping and Instrumentation Diagram (REF) VFS 001



BALANCING DAMPERS ARE NOT SHOWN.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.4.7-1 (Sheet 2 of 2)
Simplified Containment Air Filtration System Piping and Instrumentation Diagram (REF) VFS 002

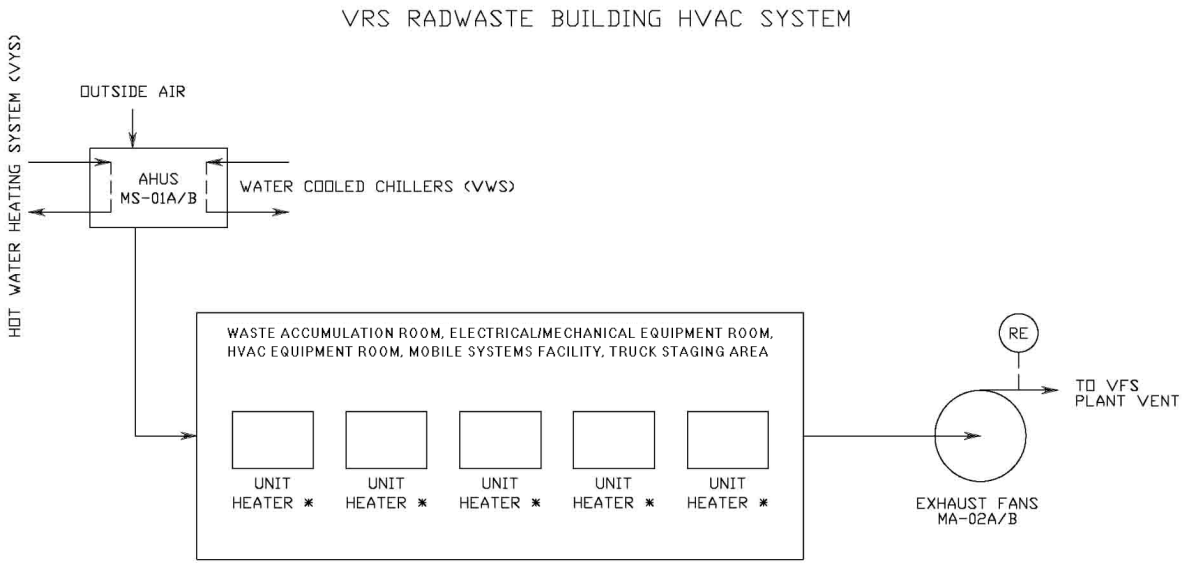


Figure 9.4.8-1
Radwaste Building HVAC System
(REF) VRS 001, 002, 003

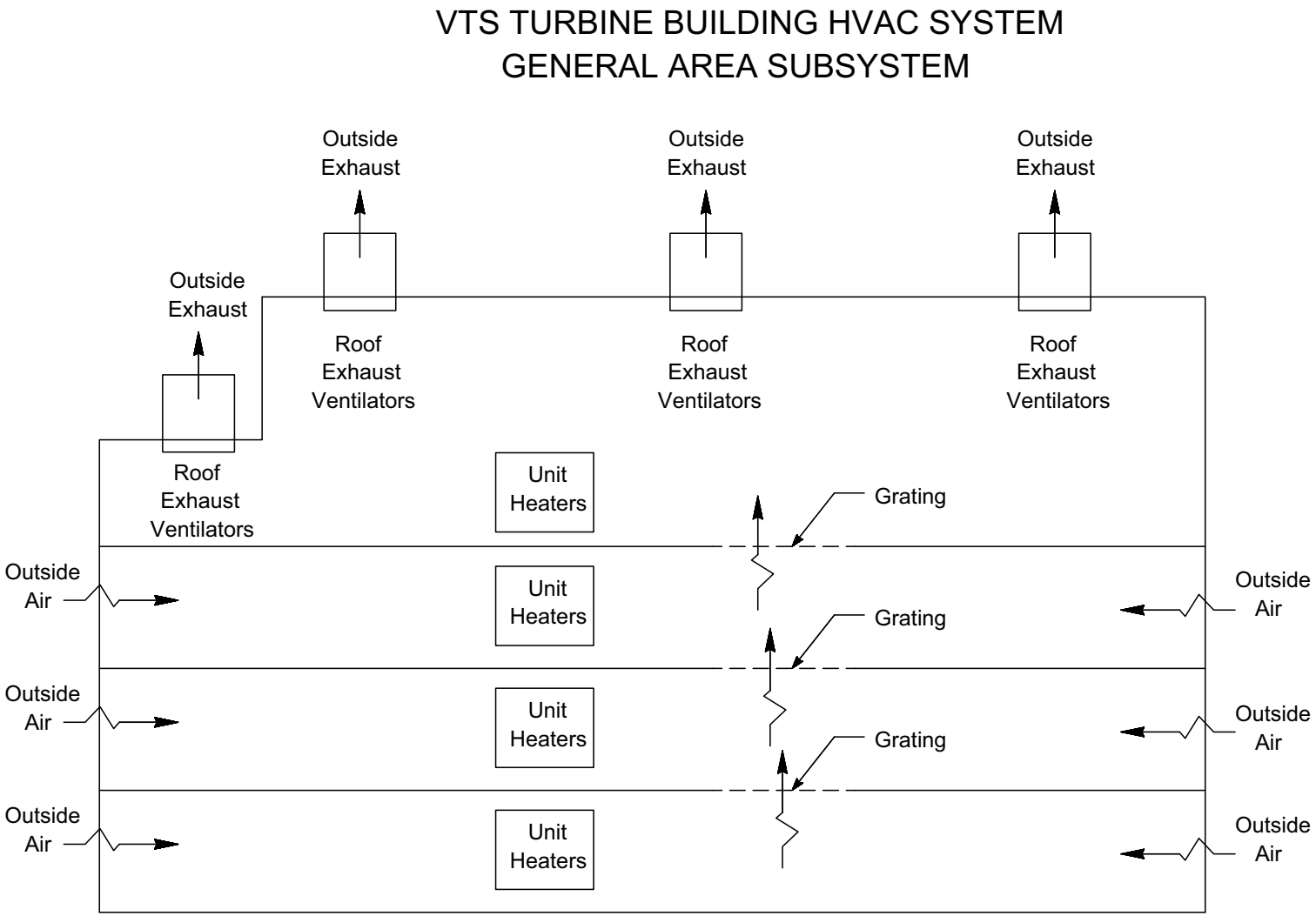
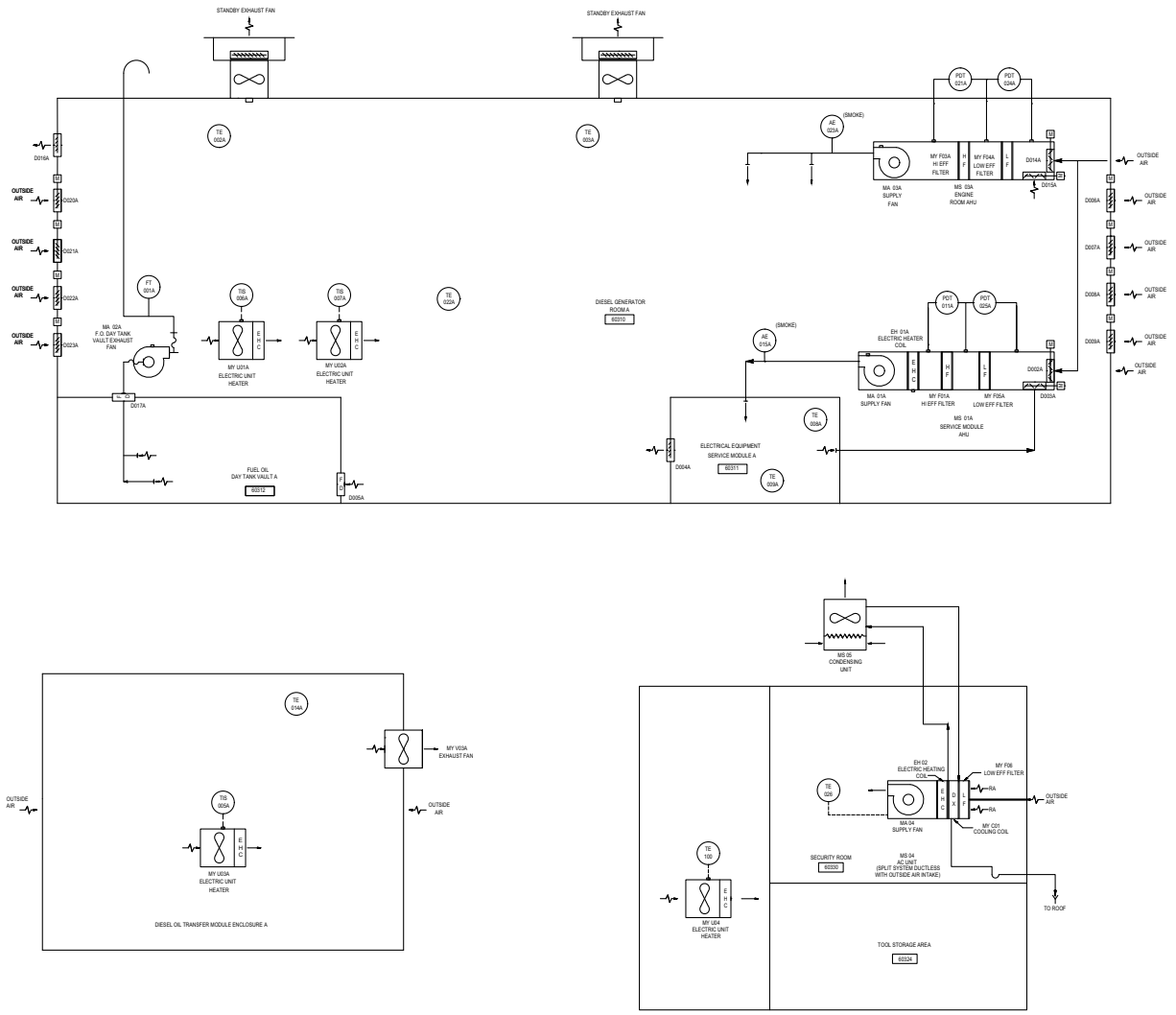


Figure 9.4.9-1
Turbine Building HVAC System
(REF) VTS 001



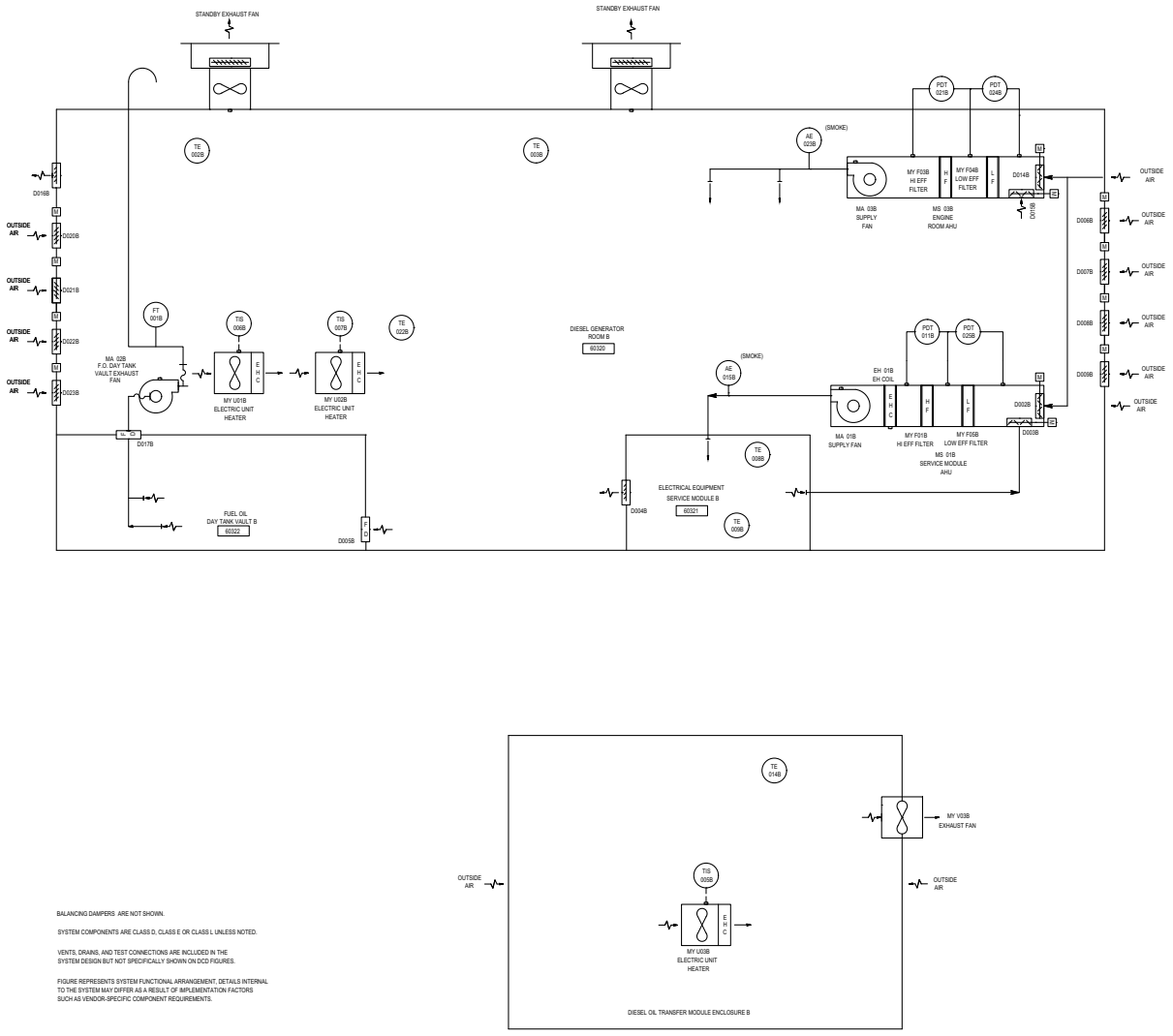
BALANCING DAMPERS ARE NOT SHOWN.

SYSTEM COMPONENTS ARE CLASS D, CLASS E OR CLASS L UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.4.10-1 (Sheet 1 of 2)
Simplified Diesel Generator Building Heating and Ventilation System Piping and Instrumentation Diagram (REF) VZS 001



BALANCING DAMPERS ARE NOT SHOWN.

SYSTEM COMPONENTS ARE CLASS D, CLASS E OR CLASS L UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT, DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 9.4.10-1 (Sheet 2 of 2)
Simplified Diesel Generator Building Heating and Ventilation System Piping and Instrumentation Diagram (REF) VZS 002

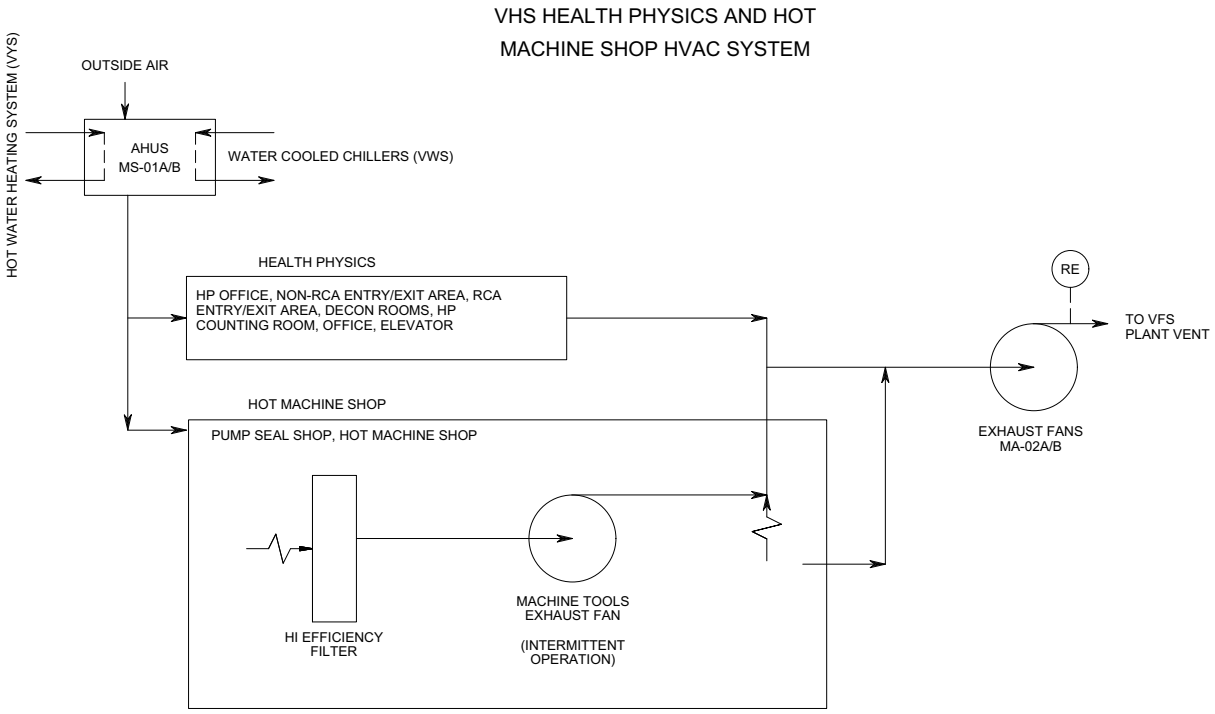


Figure 9.4.11-1
Health Physics and Hot Machine Shop HVAC System
(REF) VHS 001, 002, 003

9.5 Other Auxiliary Systems

9.5.1 Fire Protection System

The primary objectives of the AP1000 fire protection program are to prevent fires and to minimize the consequences should a fire occur. The program provides protection so that the plant can be shut down safely following a fire. The fire protection system (FPS) detects and suppresses fires, and is an integral part of the AP1000 fire protection program. The AP1000 compliance with BTP CMEB 9.5-1 is addressed in Table 9.5.1-1.

9.5.1.1 Design Basis

9.5.1.1.1 Safety Design Basis

To achieve the required high degree of fire safety, and to satisfy fire protection objectives, the AP1000 is designed to:

- Prevent fire initiation by controlling, separating, and limiting the quantities of combustibles and sources of ignition
- Isolate combustible materials and limit the spread of fire by subdividing plant buildings into fire areas separated by fire barriers
- Separate redundant safe shutdown components and associated electrical divisions to preserve the capability to safely shut down the plant following a fire
- Provide the capability to safely shut down the plant using controls external to the main control room, should a fire require evacuation of the control room or damage the control room circuitry for safe shutdown systems
- Separate redundant trains of safety-related equipment used to mitigate the consequences of a design basis accident (but not required for safe shutdown following a fire) so that a fire within one train will not damage the redundant train
- Prevent smoke, hot gases, or fire suppressants from migrating from one fire area to another to the extent that they could adversely affect safe shutdown capabilities, including operator actions
- Provide confidence that failure or inadvertent operation of the fire protection system cannot prevent plant safety functions from being performed
- Preclude the loss of structural support, due to warping or distortion of building structural members caused by the heat from a fire, to the extent that such a failure could adversely affect safe shutdown capabilities
- Provide floor drains sized to remove expected firefighting water flow without flooding safety-related equipment
- Provide firefighting personnel access and life safety escape routes for each fire area
- Provide emergency lighting and communications to facilitate safe shutdown following a fire
- Minimize exposure to personnel and releases to the environment of radioactivity or hazardous chemicals as a result of a fire

The fire protection system is classified as a nonsafety-related, nonseismic system. Special seismic design requirements are applied to portions of the standpipe system located in areas containing equipment required for safe shutdown following a safe shutdown earthquake, as described in Subsection 9.5.1.2.1.5. In addition, the containment isolation valves and associated piping for the fire protection system are safety-related (Safety Class 2) and seismic Category I. The fire protection system is not required to remain functional following a plant accident or the most severe natural phenomena, except as indicated below for a safe shutdown earthquake.

The fire protection system is designed to perform the following functions:

- Detect and locate fires and provide operator indication of the location
- Provide the capability to extinguish fires in any plant area, to protect site personnel, limit fire damage, and enhance safe shutdown capabilities
- Supply fire suppression water at a flow rate and pressure sufficient to satisfy the demand of any automatic sprinkler system plus 500 gpm for fire hoses, for a minimum of 2 hours
- Maintain 100 percent of fire pump design capacity, assuming failure of the largest fire pump or the loss of offsite power
- Following a safe shutdown earthquake, provide water to hose stations for manual firefighting in areas containing safe shutdown equipment
- Satisfy the requirements of the passive containment cooling system as an alternate source of water to wet the containment dome or to refill the passive containment cooling water storage tank after a loss-of-coolant accident, if the fire protection system is available
- Provide an alternate supply of cooling water to the normal residual heat removal system heat exchanger after a loss of normal component cooling water system function.
- Provide nonsafety-related containment spray capability for severe accident management.

9.5.1.1.2 Power Generation Design Basis

AP1000 fire prevention, control, detection, and suppression features provide plant and personnel safety. The fire protection analysis (see Appendix 9A) evaluates the adequacy of fire protection for systems and plant areas important to the generation of electricity.

9.5.1.1.3 NonSafety-Related Containment Spray Function

The fire protection system provides a nonsafety-related containment spray function. This function is discussed in Subsection 6.5.2.

9.5.1.2 System Description

9.5.1.2.1 General Description

The fire protection program and the design of the fire protection system conform to the applicable codes and standards listed in Section 3.2, and the following:

- 10 CFR 50.48, Fire Protection (Reference 15)
- General Design Criterion 3, Fire Protection (Reference 16)
- SECY-93-087, Section I.E., Fire Protection (Reference 17)

Table 9.5.1-1 is a point-by-point description of the conformance of the fire protection program with the guidelines of Branch Technical Position (BTP) CMEB 9.5-1 (Reference 1). AP1000 meets the enhanced fire protection provisions of SECY-93-087 as demonstrated in the fire protection analysis (Appendix 9A). Subsection 9.5.1.8.1.1 discusses use of, exceptions to, and evaluation of the applicable fire protection codes and standards.

The plant includes features to minimize the likelihood that a fire will occur and to limit the spread of fire.

The fire protection system detects fires and provides the capability to extinguish them using fixed automatic and manual suppression systems, manual hose streams, and/or portable firefighting equipment. The fire protection system consists of a number of fire detection and suppression subsystems, referred to as systems, including:

- Detection systems for early detection and notification of a fire
- A water supply system including the fire pumps, yard main, and interior distribution piping
- Fixed automatic fire suppression systems
- Manual fire suppression systems and equipment, including hydrants, standpipes, hose stations and portable fire extinguishers

The fire detection and suppression systems are described later in this subsection.

9.5.1.2.1.1 Plant Fire Prevention and Control Features

Architectural and Structural Features

Plant buildings use noncombustible structural materials, primarily reinforced concrete, gypsum, masonry block, structural steel, steel siding, and concrete/steel composite material. Fireproofing of structural steel is not normally required, but the effects of heat generated by a fire are considered in the design. Localized structural steel fireproofing is provided as required, based on a realistic analysis of the time-temperature fire effects on the structural members. Heat transfer analyses based on the postulated fire are used to determine whether the fire will heat the structural members to a specified critical temperature. Where structural failures could adversely affect safe shutdown capabilities, this analysis of the fire resistance of structural steel members establishes the need for fireproofing.

Firefighting personnel access routes and life safety escape routes are provided for each fire area. Fire exit routes are clearly marked.

Buildings outside primary containment generally have two enclosed stairways for emergency access. Stairwells serving as escape routes, access routes for firefighting, or access routes to areas containing equipment necessary for safe shutdown of the plant are equipped with emergency lighting. Such stairwells, and elevator shafts, which penetrate fire barrier floors, are enclosed in towers. The majority of the stairwell towers in the auxiliary building contain both concrete structural walls and nonstructural walls, consisting of a concrete/steel composite material having a fire resistance rating of at least 2 hours. The fire-resistance rating is based on material testing conducted in accordance with ASTM E-119 and NFPA 251 as addressed in Table 9.5.1-1. These auxiliary building stairwells are protected from potential missiles by other structures or by the selection of the location of the stairwell remote from potential missile sources. Openings are protected with approved automatic or self-closing doors having a rating of 1.5 hours.

Some of the walls of the turbine building and annex building stairwell enclosures, which are exposed to the interior of the buildings, are also constructed with a material having a minimum fire rating of 2 hours. However, the turbine building and annex building stairwell enclosure walls that face the yard area are constructed with an exterior siding common to the overall siding used for the turbine and annex buildings.

The main control room is designed to permit rapid detection and location of fires in the underfloor and ceiling spaces and allow ready access for manual firefighting. Due to the need to provide passive cooling capability into the main control room ceiling, it will not be protected against fires from within the main control room. The ceiling will be a fire barrier from fires in the room above the main control room.

Plant Arrangement

The plant is subdivided into fire areas to isolate potential fires and minimize the risk of the spread of fire and the resultant consequential damage from corrosive gases, fire suppression agents, smoke, and radioactive contamination.

Some fire areas are subdivided into fire zones to permit more precise identification of the type and locations of combustible materials, fire detection, and suppression systems. The subdivision into fire zones is based on the configuration of interior walls and floor slabs, and the location of major equipment within each fire area.

Fire barriers are provided in accordance with BTP CMEB 9.5-1 as addressed in Table 9.5.1-1. Three-hour fire barriers are non-combustible and surround fire areas containing safety-related components. The resistance of fire barriers in nonsafety-related areas of the plant may be less than 3 hours, where justified by the fire protection analysis (Appendix 9A).

Three-hour fire barriers provide complete separation of redundant safe shutdown components, including equipment, electrical cables, instrumentation and controls, except where the need for physical separation conflicts with other important requirements, specifically:

- Fire barrier separation is not provided within the main control room fire area because functional requirements make such separation impractical. The risk of fires in the control room is minimized by the reduction in the quantity of electrical cables. Continuous occupancy provides confidence that fires would be quickly detected and suppressed. Should a fire require evacuation of the main control room, the plant can be safely shut down using independent controls at the remote shutdown workstation, located in a separate fire area.

- Fire barrier separation is not provided between the main control room and the room above it from fires in the main control room. There is fire barrier separation between the main control room and the room above it for fires in the room above.

- Fire barrier separation is not provided within the remote shutdown room fire area because the remote shutdown workstation is not required for safe shutdown unless a fire requires evacuation of the main control room.

- Complete fire barrier separation necessary to define a fire area is not provided throughout the primary containment fire area (including the middle and upper annulus zones of the shield building) because of the need to satisfy other design requirements, such as allowing for pressure equalization within the containment following a high-energy line break. Fire protection features and equipment arrangement which define fire zones within the containment fire area provide confidence that at least one train of safe shutdown equipment will remain undamaged following a fire in any fire zone. The quantity of combustible materials is minimized. The use of sealless reactor coolant pump motors has eliminated the need for

an oil lubrication system. Redundant trains of safe shutdown components are separated whenever possible by existing structural walls, or by distance. Selected cables of a safety-related division which pass through a fire zone of an unrelated division are protected by fire barriers. The fire protection system provides appropriate fire detection and suppression capabilities.

Outside of the primary containment and the main control room, the arrangement of plant equipment and routing of cable are such that safe shutdown can be achieved with all components (except those protected by 3-hour fire barriers) in any one fire area rendered inoperable by fire.

Openings and penetrations through fire barriers are protected in accordance with the guidelines of BTP CMEB 9.5-1 as addressed in Table 9.5.1-1.

Penetrations through the following barriers are rated to withstand a differential pressure of 5 psi to support the conclusions in Appendix 19F:

- Wall I between elevation 117’-6" to 153’-0"
- Wall 5 between elevation 100’-0" to 153’-0"
- Penetrations in the main control room floor (12401) at elevation 117’-6" above corridor 12300
- Penetrations through Wall I into corridor 12300
- Penetrations between Wall I and Wall I.1 into corridor 12300
- Penetrations into the shield building wall from room 12351
- Penetrations into the shield building wall from room 12421
- Penetrations into the shield building wall from room 12553
- Penetrations into the shield building wall from room 12556

The fire protection analysis contains a description of plant fire areas, fire zones, fire barriers, and the protection of fire barrier openings, as well as a description of the separation between redundant safe shutdown components.

Electrical Cable Design, Routing, and Separation

Electrical cable (including fiber optic cable) and methods of raceway construction are selected in accordance with BTP CMEB 9.5-1 as addressed in Table 9.5.1-1. Metal cable trays are used. Rigid metal conduit or metal raceways are used for cable runs not embedded in concrete or buried underground. Flexible metallic tubing is used in short lengths for equipment connections.

The insulating and jacketing material for electrical cables are selected to meet the fire and flame test requirements of IEEE Standard 1202 (Reference 18), IEEE Standard 383 (Reference 3) or the standards for the corresponding test types as listed in Tables K-1 and K-2 in NEI 04-02, Rev 3 excluding the option to use flame source, oil, or burlap.

The design, routing, and separation of cable and raceways are further described in Section 8.3.

Control of Combustible Materials

The plant is constructed of noncombustible materials to the extent practicable. The selection of construction materials and the control of combustible materials are generally in accordance with the design portions of BTP CMEB 9.5-1 as addressed in Table 9.5.1-1 and the design portions of Section 6.3 or Section 3.3 (respectively) of NFPA 804 (Reference 2) with exceptions to NFPA 804 identified in Table 9.5.1-3.

The storage and use of hydrogen are according to NFPA 50A and NFPA 50B (Reference 2). Hydrogen lines in safety-related areas are designed to seismic Category I requirements.

Ventilation systems are designed to maintain the hydrogen concentration in the battery rooms well below 2 percent by volume, as described in Subsections 9.4.1 and 9.4.2.

The containment recirculation cooling system (VCS) (Subsection 9.4.6) provides sufficient air flow through the reactor vessel cavity to mix any off-gassing from the neutron shield blocks with the containment volume. The mixing flow rate maintains the hydrogen concentration in containment well below 2 percent by volume. The containment air filtration system (VFS) (Subsection 9.4.7) also provides periodic flow of outdoor air to purge and filter the containment atmosphere.

The turbine lubrication oil system, located in the turbine building, is separated from areas containing safety-related equipment by 3-hour rated fire barriers.

Outdoor oil-filled transformers are separated from plant buildings according to the design portions of NFPA 804 (Reference 2) with exceptions to NFPA 804 identified in Table 9.5.1-3.

The diesel fuel oil storage tanks and the diesel fuel oil transfer pump enclosure are located in the yard area more than 50 feet from any safety-related structure. Potential oil spills from the storage tanks are confined by a diked enclosure. A diesel generator fuel day tank is located within each diesel generator room and is enclosed in a 3-hour fire rated barrier.

The diesel fuel supply for the ancillary diesel generators is in the same room as the diesel generators. The ancillary diesel generator room is separated from the rest of the annex building by a 3-hour rated fire barrier.

The diesel fuel supply for the diesel-driven fire pump is in the diesel-driven fire pump enclosure. The diesel pump enclosure is located in the yard more than 50 feet from safety-related structures. The enclosure includes a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by operation of an automatic sprinkler system or manually, using hose streams or portable extinguishers.

Quantities and locations of other combustible materials are identified in the fire protection analysis (see Appendix 9A).

Control of Radioactive Materials

As described in the fire protection analysis, materials that collect or contain radioactivity, such as spent ion exchange resins and filters, are protected and stored in accordance with BTP CMEB 9.5-1 as addressed in Table 9.5.1-1.

9.5.1.2.1.2 Fire Detection and Alarm Systems

Fire detection and alarm systems are provided where required by the fire protection analysis, in accordance with the design portions of BTP CMEB 9.5-1 as addressed in Table 9.5.1-1 and the

design portions of NFPA 72 (Reference 2). Fire detection and alarm systems are generally in accordance with the design portions of NFPA 804 (Reference 2) with exceptions identified in Table 9.5.1-3.

Fire detectors respond to smoke, flame, heat, or the products of combustion. The installation of fire detectors is in accordance with NFPA 72 (Reference 2) as addressed in Table 9.5.1-3 and the manufacturer's recommendations. The selection and installation of fire detectors is also based on consideration of the type of hazard, combustible loading, the type of combustion products, and detector response characteristics. The types of detectors used in each fire area are identified in the fire protection analysis.

The fire detection system provides audible and visual alarms and system trouble annunciation in the main control room and at the remote fire alarm annunciator panel. Annunciation circuits connecting zone, main, and remote annunciation panels are electrically supervised.

Each fire detection, indicating, and alarm unit is provided with reliable ac electrical power from the non-Class 1E uninterruptible power supply system. This system is described in Subsection 8.3.2.1.2.

9.5.1.2.1.3 Fire Water Supply System

The fire water supply system is generally designed in accordance with the design portions of BTP CMEB 9.5-1 as addressed in Table 9.5.1-1 and the NFPA standards referenced in NFPA 804 (Reference 2) with exceptions identified in Table 9.5.1-3.

Fire water can be supplied from either the primary or secondary fresh water storage tanks. Both fire water storage tanks contain a standpipe with inlets above the water volume dedicated for fire protection use that is used as a gravity-fed alternate makeup source for the service water system cooling water basin. The secondary fire water tank contains water for use by the fire protection system and the containment spray system.

There are two 100-percent capacity fire pumps. The lead pump is electric motor-driven and the secondary pump is diesel engine-driven. A motor-driven jockey pump is used to keep the fire water system full of water and pressurized, as required. For additional information regarding the fire water tanks and pumps, see Subsection 9.5.1.2.3.

The fire water tanks are permanently connected to the fire pumps suction piping and are arranged so that the pumps can take suction from either or both tanks. One tank is normally isolated from the system. Redundant cross-connect lines are provided to increase reliability of the pump suction lines to the tanks. Piping between the fire water sources and the fire pumps is in accordance with NFPA 20 (Reference 2). A failure in one tank or its piping will not cause both tanks to drain.

Fire protection water is distributed by an underground yard main loop, designed in accordance with NFPA 24 (Reference 2). The yard main includes a building interior header that distributes water to suppression systems within the main plant buildings. Indicator valves provide sectionalized control and permit isolation of portions of the yard main for maintenance or repair. An indicator valve also separates the individual fire pump connections to the main.

Sprinkler and standpipe systems are supplied by connections from the yard main. Where plant areas, other than the containment and outlying buildings, are protected by both sprinkler systems and standpipe systems, the connections from the yard main are arranged so that a single active failure or a crack in a moderate energy line cannot impair both systems.

Manual valves for sectionalized control of the yard main or for shutoff of the water supply to suppression systems are electrically supervised if located above ground and administratively controlled if located underground.

Hydrants are provided on the yard main in accordance with NFPA 24 (Reference 2), at intervals of up to about 250 feet. They provide hose stream protection for every part of each building and two hose streams for every part of the interior of each building not covered by standpipe protection, excluding certain remote areas of the shield building. The lateral to each hydrant is controlled by an isolation valve.

Hose houses are in accordance with NFPA 24 (Reference 2). They are located at intervals of not more than 1000 feet along the yard main.

Outdoor fire water piping and water suppression systems located in unheated areas of the plant are protected from freezing.

A permanent connection between the fire protection system and the component cooling water system in the annex building is normally isolated by two valves in series.

A permanent connection between the fire protection system and the containment spray system in the containment is normally isolated by two valves in series.

Threads compatible with those used by the off-site fire department are provided on all hydrants, hose couplings and standpipe risers, or a sufficient number of thread adapters compatible with the off-site fire department are provided.

9.5.1.2.1.4 Automatic Fire Suppression Systems

Automatic fire suppression systems are generally in accordance with the design portions of BTP CMEB 9.5-1 as addressed in Table 9.5.1-1 and the design portions of the NFPA standards referenced in NFPA 804 (Reference 2) with exceptions identified in Table 9.5.1-3, with consideration of the unique aspects of each application, including building characteristics, materials of construction, environmental conditions, fire area contents, and adjacent structures.

Fixed automatic fire suppression systems are provided based on the results of the fire protection analysis.

The selection of automatic suppression systems for each plant area is based on the design related portions of guidance of NFPA 804 (Reference 2) with exceptions identified in Table 9.5.1-3. Water systems are preferred, but the use of automatic water suppression systems for firefighting in radiation areas is minimized because of the possible spread of contamination. Halon and carbon dioxide fixed flooding systems are not used.

The fire protection analysis describes the fire suppression systems provided for each fire area.

Automatic Water Suppression Systems

Automatic sprinkler and water spray systems are provided generally in accordance with the applicable design requirements of NFPA 13 and NFPA 15 (Reference 2) with exceptions identified in Table 9.5.1-3. Each system consists of overhead piping and components from a water supply valve to the point where water discharges from the system. Some systems have a control valve that is actuated automatically by the fire detection system. Each system has a status monitoring device for actuating an alarm when the system is in operation.

Preaction sprinkler systems are used where the leakage or inadvertent actuation of water-filled sprinkler systems could produce undesirable consequences, such as water discharge on equipment important to continued plant operation.

Each type of automatic sprinkler and automatic water spray system used on AP1000 is briefly described below:

- **Wet Pipe** - A sprinkler system employing closed (fusible link operated) sprinklers attached to a water-filled piping network. Water discharges immediately from those sprinklers where the heat from a fire is sufficient to melt the fusible link. System operation is terminated manually by shutting the water-supply valve.

- **Dry Pipe** - A sprinkler system employing closed sprinklers attached to a piping network containing pressurized air. Heat from a fire opens one or more sprinklers, releasing the air and permitting water supply pressure to open the dry pipe valve. Water flows into the piping network and discharges from the open sprinklers. System operation is terminated manually by shutting the water-supply valve.

- **Preaction** - A sprinkler system employing closed sprinklers attached to a dry piping network, with fire detector(s) installed in the same areas as the sprinklers. Operation of the fire detection system opens a preaction valve, which permits water to flow into the sprinkler piping network and to be discharged from any sprinklers that may have been opened by the fire. System operation is terminated manually by shutting the water-supply valve.

- **Deluge Sprinkler or Water Spray System** - A system employing open sprinklers or spray nozzles attached to a dry piping network, with fire detector(s) installed in the same areas as the sprinklers. Operation of the fire detection system opens a deluge valve, which permits water to flow into the sprinkler piping network and to be discharged from all the sprinklers or spray nozzles. System operation is terminated manually by shutting the water-supply valve.

9.5.1.2.1.5 Manual Fire Suppression Systems

Manual fire suppression capability is provided in areas that do not require an automatic suppression system. Plant areas that have an automatic suppression system also have manual backup fire suppression capability.

Manual fire suppression capabilities include the yard main fire hydrants and hose stations described in Subsection 9.5.1.2.1.3.

Standpipe and Hose Systems

Standpipe systems are provided for each building generally in accordance with NFPA 14 (Reference 2) design requirements for Class III service as addressed in Table 9.5.1-1 and with exceptions identified in Table 9.5.1-3. Wet standpipe systems are used except inside containment with exceptions identified in Table 9.5.1-3. Individual standpipes are at least 4 inches in diameter for multiple hose connections and 2.5 inches in diameter for single hose connections.

Hose stations are located to facilitate access for firefighting, as described in the fire protection analysis. Areas that contain, or could present a fire exposure event to, safety-related equipment are within reach of at least one effective hose stream. Alternative hose stations are provided for an area where the fire could block access to a single hose station serving that area. To the maximum extent practical, hose stations are located outside of high-radiation areas.

Each hose station has not more than 100 feet of 1.5-inch woven-jacket lined fire hose. Nozzles are provided at each station.

Seismic Standpipe System

The standpipe system serving areas containing equipment required for safe shutdown following a safe shutdown earthquake is designed and supported so that it can withstand the effects of a safe shutdown earthquake and remain functional. The seismically analyzed standpipe system is illustrated on Figure 9.5.1-1. This system also supplies water to automatic suppression systems in the nonradiologically controlled portion of the auxiliary building (see Appendix 9A).

The seismic standpipe system is operated in the same manner during normal plant operation or following a safe shutdown earthquake. It is supplied with water from the safety related passive containment cooling system storage tank and normally operates independently of the rest of the fire protection system. The supply line draws water from a portion of the storage tank, using water allocated for fire protection. This volume of water is sufficient to supply two hose streams, each with a flow of 75 gallons per minute, for 2 hours.

The portion of the system outside containment is a wet standpipe system that is pressurized by the static head of water in the passive containment cooling system tank. The portion of the system inside containment is a dry standpipe system. The supply valve is normally closed for containment isolation. During shutdown periods when the containment is occupied, when operation of nonsafety-related containment spray is required, or when containment access is required to fight a fire, the valve is opened to pressurize the system.

In the unlikely event that the water supply from the passive containment cooling system is unavailable or additional water is needed, the seismic standpipe system can be supplied from the fire main by opening the normally closed cross-connect valve with the plant fire main.

A passive containment cooling ancillary water storage tank is provided to supply the seismic standpipe system following a safe shutdown earthquake and after actuation of the passive containment cooling system. The tank is designed and supported so that it can withstand the effects of a safe shutdown earthquake and remain functional. A dedicated portion of the storage capacity of the tank is sufficient to supply two hose streams, each with a flow of 75 gallons per minute, for 2 hours. Normally much more water is available. (Refer to Subsection 6.2.2 for additional information.)

A failure of the seismic standpipe system does not prevent successful operation of the passive containment cooling system. A leak in the standpipe system could result in the loss of only a limited amount of water from the passive containment cooling system storage tank, even if no action were taken to isolate the leak. The volume of water allocated for fire protection is not required for passive containment cooling.

Portable Fire Extinguishers

Portable fire extinguishers are provided throughout the plant. Portable extinguishers are readily accessible for use in high radiation areas but are not located within those areas unless the fire protection analysis indicates that a specific requirement exists.

9.5.1.2.2 System Operation

The fire protection system normally operates in an active standby mode. The fire water supply piping is kept full and pressurized by operation of the jockey pump. Shutoff valves controlling fire suppression systems are normally aligned in the open position. Fire detection and alarm circuits are normally energized and monitored for trouble or loss of power as described in Subsection 9.5.1.2.1.2.

When a fire is detected, the fire detection system produces an audible alarm locally, except in containment where the fire detection system produces a visual alarm locally, and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel.

Where the fire area is protected by an automatic suppression system, operation of the suppression system begins as described in Subsection 9.5.1.2.1.4. Where the fire area is protected by manual suppression methods, the fire brigade reacts to control and extinguish the fire.

Ventilation system fire dampers close automatically against full airflow on high temperature to control the spread of fire and combustion products. Fire dampers serving certain safety-related, smoke-sensitive areas are also closed in response to an initiation signal from the fire detection system. Smoke is removed from the fire area as described in the fire protection analysis.

When water pressure in the yard main begins to fall, due to a demand for water from automatic or manual suppression systems, the motor-driven pump starts automatically on a low-pressure signal. If the motor-driven pump fails to start, the diesel-driven pump starts upon a lower pressure signal. The pump continues to run until it is stopped manually.

Firefighting activities continue until the fire is extinguished. Suppression systems are stopped manually. Operator actions are taken to repair and restore affected detection, alarm, and suppression systems to standby status.

9.5.1.2.3 Component Description

Selected fire protection system components are described below. Table 9.5.1-2 contains additional component data for fire protection equipment.

Fire Water Storage Tanks

Two separate fresh water storage tanks are provided for fire protection in accordance with NFPA 22 (Reference 2) as addressed in Table 9.5.1-3. The storage capacity of each tank is sufficient to maintain the design fire pump flow rate for at least 2 hours. Either tank can be refilled from the raw water system within 8 hours. Freeze protection is provided as needed using electric immersion heaters.

Passive Containment Cooling Ancillary Water Storage Tank

See Subsection 6.2.2.2.3 for a description of this component.

Fire Pumps

Two 100-percent capacity fire pumps are provided in accordance with NFPA 20 (Reference 2). Each pump is rated for 2000 gpm. The lead pump is electric motor-driven and the second pump is diesel engine-driven. The pumps and their controllers are UL-listed. Fire pump status alarms are provided in the main control room.

The motor-driven fire pump is supplied with power from the turbine building 480 Vac non-Class 1E switchgear. The fuel tank for the diesel-driven pump holds enough fuel to operate the pump for at least 8 hours.

Valves

Valves used in the fire protection system are of an approved type for fire protection service. See the Fire Protection Handbook (Reference 4) for typical descriptions of these valves.

Fire Detectors

The types of fire detectors used in specific applications are identified in the fire protection analysis. See Reference 4 for descriptions of these fire detectors and their principles of operation.

9.5.1.3 Safety Evaluation (Fire Protection Analysis)

The fire protection analysis evaluates the potential for occurrence of fires within the plant and describes how fires are detected and suppressed. It also confirms that the plant can be safely shut down following a postulated fire. The fire protection analysis is in Appendix 9A.

The fire protection analysis includes a set of fire area drawings and a discussion of the analysis methodology. It also provides the following information for each fire area in the plant:

- A description of the fire area and its fire barriers, its associated fire zones, as well as fire detection and suppression capabilities
- Identification of the type, quantity, and location of in-situ and anticipated transient combustible materials, and combustible loading
- A listing of safety-related mechanical and electrical equipment
- Fire severity category and equivalent duration
- An evaluation of fire protection system adequacy and the consequences of a fire, including a discussion of the control and removal of smoke and hot gases, and drainage system adequacy.

For fire areas containing safety-related structures, systems, and components the following information is also provided:

- An evaluation of fire protection system integrity. This includes a determination of whether the credible failure of a fire protection system component could cause inadvertent operation of an automatic fire suppression system in the fire area, and the resulting consequences. Also included is verification that no potential single impairment of the fire protection system could incapacitate both the automatic suppression system and the backup manual suppression system (generally a hose station), for fire areas where both types of suppression systems are provided.
- A safe shutdown evaluation confirming the capability to safely shut down the reactor and maintain it in a safe shutdown condition following a fire.

The safe shutdown evaluation is based upon all components in a single fire area outside containment or any fire zone inside containment being disabled by the fire. Success is based upon the plant being able to achieve safe shutdown as discussed in Section 7.4. Safe shutdown is a safe, stable condition that can be maintained indefinitely with the reactor subcritical and reactor coolant pressure at a small fraction of its design pressure. As described in Section 7.4.1.1, safety-related systems achieve this condition automatically using reliable, passive processes. The passive residual heat removal heat exchanger transfers heat to the in-containment refueling water storage tank. Steam from this tank enters the containment which is cooled by the passive containment cooling system. These systems reduce the reactor temperature and pressure to less than 420°F and 600 psia in 36 hours. See Appendix 19E for additional details about the shutdown evaluation. This is a safe and acceptable end state which is used to show compliance with BTP 9.5-1. The safe shutdown fire evaluation in Appendix 9A shows that there is sufficient safety-related equipment available after a fire which

destroys a single fire area outside containment or any fire zone inside containment, to bring the plant to this safe shutdown condition.

It should be noted that following most fires, that nonsafety-related systems are expected to be available to bring the plant to a cold shutdown for repairs. These systems are defense in depth systems with redundant active components. These systems are expected to be available because of the use of redundant equipment and fire protection features, including separation or automatic fire suppression.

Table 9.5.1-4 lists the system capabilities that are expected to be available following a fire to bring the plant to a cold shutdown. This list does not contain the nonsafety-related support systems that are not necessary to operate following a fire. For example, chilled water cooling and non-1E instrumentation are not required following a fire. Heating and ventilation are not required except for the annex/auxiliary non-radioactive ventilation system AHUs used to ventilate the non-1E switchgear rooms. The following safety-related capabilities are used together with these nonsafety-related capabilities to achieve cold shutdown:

- Insertion of control rods to provide reactor shutdown,
- Instrumentation to monitor reactor coolant system conditions,
- Operation of one core makeup tank in a natural circulation mode to provide reactor coolant makeup and boration in case the chemical and volume control system makeup is unavailable due to a fire,
- Manual partial opening (and closing) of one first stage automatic depressurization valve to provide a controlled, limited depressurization of the reactor coolant system to allow initiation of the normal residual heat removal system in case the chemical and volume control system auxiliary spray is unavailable due to a fire.

The use of these safety-related capabilities does not result in significant plant transients. The reactor coolant system pressure boundary is maintained and containment pressure and temperature conditions are not affected by the use of these safety-related capabilities.

If a less likely, more severe fire occurs, these systems are expected to be recovered after reasonable actions are taken to utilize temporary connections or to perform repairs (see Subsections 9.2.2.4.5.5 and 9.5.1.1.1). Recovery of these systems allows the plant to be brought to a cold shutdown for plant repairs. No credit is taken in the Appendix 9A fire evaluation for nonsafety-related systems. As a result, fire separation is not required for these systems.

9.5.1.4 Testing and Inspection

The fire pumps are initially tested by the manufacturer in accordance with NFPA 20 (Reference 2) to verify pressure integrity and performance.

Preoperational testing is in accordance with the Initial Test Program (Chapter 14).

9.5.1.5 Instrumentation Applications

Pressure sensors start the fire pumps on decreasing fire main water pressure. Pressure indicators confirm adequate pressures for automatic and manual suppression systems. Valve position sensors are used to monitor the positions of water supply valves.

Temperature instrumentation is used to monitor fire water storage tank temperature. Level instrumentation is used to monitor levels in the fire water storage tanks and the diesel-driven fire pump fuel storage tank.

9.5.1.6 Personnel Qualification and Training

Preparation and review of the fire protection analysis, and design and selection of fire protection equipment, is performed by fire protection and nuclear safety systems engineers.

The qualification requirements for individuals responsible for development of the fire protection program, training of firefighting personnel, as well as associated administrative procedures are discussed in Subsection 9.5.1.8.1.

Subsections 9.5.1.8.2 and 9.5.1.8.7 summarize the qualification and training programs that are established and implemented for the Fire Protection Program.

9.5.1.7 Quality Assurance

Quality assurance controls are applied to the activities involved in the design, procurement, installation, testing, and maintenance of fire protection systems for safety-related areas, in accordance with the programs outlined in Chapter 17.

9.5.1.8 Fire Protection Program

The fire protection program is established such that a fire does not prevent safe shutdown of the plant and does not endanger the health and safety of the public. Fire protection at the plant uses a defense-in-depth concept that includes fire prevention, detection, control and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. These defense-in-depth principles are achieved by meeting the following objectives:

- Prevent fires from starting.
- Detect rapidly, control, and extinguish promptly those fires that do occur.
- Provide protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities does not prevent the safe shutdown of the plant.
- Minimize the potential for radiological releases.

9.5.1.8.1 Fire Protection Program Implementation

As indicated in Table 13.4-201, the required elements of the fire protection program are fully operational prior to receipt of new fuel for buildings storing new fuel and adjacent fire areas that could affect the fuel storage area in that reactor unit. Other required elements of the fire protection program described in this section are fully operational prior to initial fuel loading in that reactor unit.

Elements of the fire protection program are reviewed on a frequency established by procedures and updated as necessary.

9.5.1.8.1.1 Fire Protection Program Criteria

The fire protection program is based on the criteria of several industry and regulatory documents referenced in Subsection 9.5.5, and also based on the guidance provided in Regulatory Guide 1.189.

Table 9.5.1-1 provides a cross-reference to information addressing compliance with BTP CMEB 9.5-1. Exceptions to the design portions of the National Fire Protection Association (NFPA) Standards Table 9.5.1-3 listed in Subsection 9.5.5 are identified in Table 9.5.1-3.

The NFPA code year identified in Subsection 9.5.5 is the code of record for the AP1000 plant. In accordance with the guidance provided in Regulatory Position C.1.8.6 of Regulatory Guide 1.189, the equivalency concept in meeting the provisions of the NFPA codes and standards may be used. Newer editions of the listed code of record and alternative codes or standards by the same or alternate agencies (e.g., NFPA, ASTM, UL) are evaluated for equivalency by a fire protection engineer prior to use. Per the guidance provided in Sections 1.8.1.3 and 1.8.6 of Regulatory Guide 1.189, equivalencies and clarifications to the NFPA Standards listed in Subsection 9.5.5 are documented and available for inspection.

9.5.1.8.1.2 Organization and Responsibilities

The organizational structure of the fire protection personnel is discussed in Subsection 13.1.1.2.10.

The site executive in charge of the fire protection program, through the engineer in charge of fire protection, is responsible for the following:

a. Programs and periodic inspections are implemented to:

    1. Minimize the amount of combustibles in safety-related areas.

    2. Determine the effectiveness of housekeeping practices.

    3. Provide for availability and acceptability of the following:

        (i) Fire protection system and components.

        (ii) Manual firefighting equipment.

        (iii) Emergency breathing apparatus.

        (iv) Emergency lighting.

        (v) Portable communication equipment.

        (vi) Fire barriers including fire rated walls, floors and ceilings, fire rated doors, dampers, etc., fire stops and wraps, and fire retardant coating. Procedures address the administrative controls in place, including fire watches, when a fire area is breached for maintenance.

    4. Confirm prompt and effective corrective actions are taken to correct conditions adverse to fire protection and preclude their recurrence.

b. Conducting periodic maintenance and testing of fire protection systems, components, and manual firefighting equipment, evaluating test results, and determining the acceptability of systems under test in accordance with established plant procedures.

c. Designing and selecting equipment related to fire protection.

d. Reviewing and evaluating proposed work activities to identify potential transient fire loads.

e. Managing the plant fire brigade, including:

1. Developing, implementing, and administering the fire brigade training program.
2. Scheduling and conducting fire brigade drills.
3. Critiquing fire drills to determine if training objectives are met.
4. Performing a periodic review of the fire brigade roster and initiating changes as needed.
5. Maintaining the fire training program records for members of the fire brigade and other personnel.
6. Maintaining a sufficient number of qualified fire brigade personnel to respond to fire emergencies for each shift.

f. Developing and conducting the fire extinguisher training program.

g. Implementing a program for indoctrination of personnel gaining unescorted access to the protected area in appropriate procedures which implement the fire protection program, such as fire prevention and fire reporting procedures, plant emergency alarms, including evacuation.

h. Implementing a program for instruction of personnel on the proper handling of accidental events such as leaks or spills of flammable materials.

i. Preparing procedures to meet possible fire situations in the plant and for ensuring assistance is available for fighting fires in radiological areas.

j. Implementing a program that uses a permit system that controls and documents inoperability of fire protection systems and equipment. This program initiates proper notifications and compensatory actions, such as fire watches, when inoperability of any fire protection system or component is identified.

k. Developing and implementing preventive maintenance, corrective maintenance, and surveillance test fire protection procedures.

l. Confirming that plant modifications, new procedures and revisions to procedures associated with fire protection equipment and systems that have significant impact on the fire protection program, are reviewed by an individual who possesses the qualifications of a fire protection engineer.

m. Continuing evaluation of fire hazards during construction or modification of other units on the site. Special considerations, such as fire barriers, fire protection capability, and administrative controls are provided as necessary to protect the operating unit(s) from construction or modification activities.

n. Establishing a fire prevention surveillance plan and training plant personnel on that plan.

o. Developing prefire plans and making them available to the fire brigade and control room.

The responsibilities of the engineer in charge of fire protection and his staff are discussed in Subsection 13.1.1.2.10.

9.5.1.8.2 Fire Brigade

9.5.1.8.2.1 General

The organization of the fire brigade is discussed in Subsection 13.1.2.1.6.

To qualify as a member of the fire brigade, an individual must meet the following criteria:

a. Has attended the required training sessions for the position occupied on the fire brigade.

b. Has passed an annual physical exam including demonstrating the ability for performing strenuous activity and the use of respiratory protection.

9.5.1.8.2.2 Fire Brigade Training

A training program is established so that the capability to fight fires is developed and documented. The program consists of classroom instruction supplemented with periodic classroom retraining, practice in firefighting, and fire drills. Classroom instruction and training is conducted by qualified individuals knowledgeable in fighting the types of fires that could occur within the plant and its environs and using onsite firefighting equipment. Individual records of training provided to each fire brigade member, including drill critiques, are maintained as part of the permanent plant files for at least three years to document that each member receives the required training.

The fire brigade leader and at least two brigade members per shift have sufficient training and knowledge of plant safety-related systems to understand the effects of fire and fire suppressants on safe shutdown capability. The brigade leader is competent to assess the potential safety consequences of a fire and advise control room personnel. Such competence by the brigade leader may be evidenced by possession of an operator's license or equivalent knowledge of plant systems.

Personnel assigned as fire brigade members receive formal training prior to assuming brigade duties. The course subject matter is selected to satisfy the requirements of Regulatory Guide 1.189. Course material selection also includes guidance from NFPA 600 (Reference 204) and 1500 (Reference 210) as appropriate. Additional training may also include material selected from NFPA 1404 (Reference 208) and 1410 (Reference 209).

The minimum equipment provided for the fire brigade consists of personal protective equipment such as turnout coats, boots, gloves, hard hats, emergency communications equipment, portable lights, portable ventilation equipment, and portable extinguishers. Self-contained breathing apparatus (SCBA) approved by NIOSH, using full face positive pressure masks, and providing an operating life of at least 30 minutes, are provided for selected fire brigade, emergency repair, and control room personnel. At least ten masks, five per brigade locker plus spares, are provided for fire brigade personnel. Extra air bottles, with at least 60 minutes total operating life, are located onsite for each SCBA. An additional onsite 6-hour supply of reserve air is provided to permit quick and complete replenishment of exhausted supply air bottles. Subsection 6.4.2.3 discusses the portable breathing apparatus for control room personnel. At least six SCBAs are provided in the fire brigade locker for the exclusive use of the fire brigade. The fire brigade leader has ready access to keys for any locked fire doors. SCBAs are provided in the control room for use by Operations. Radiation Protection also maintains additional SCBA near the radiologically controlled area entrance for emergency usage.

The on-duty shift manager has responsibility for taking certain actions based on an assessment of the magnitude of the fire emergency. These actions include safely shutting down the plant, making recommendations for implementing the Emergency Plan, notification of emergency personnel, and requesting assistance from off-duty personnel, if necessary. Emergency Plan consideration of fire emergencies includes the guidance of Regulatory Guide 1.101.

9.5.1.8.2.2.1 Classroom Instruction

Fire brigade members receive classroom instruction in fire protection and firefighting techniques prior to qualifying as members of the fire brigade. This instruction includes:

a. Identification of the types of fire hazards along with their location within the plant and its environs.

b. Identification of the types of fires that could occur within the plant and its environs.

c. Identification of the location of onsite fire fighting equipment and familiarization with the layout of the plant including ingress and egress routes to each area.

d. The proper use of onsite fire fighting equipment and the correct method of fighting various types of fires including at least the following:

   – fires involving radioactive materials

   – fires in energized electrical equipment

   – fires in cables and cable trays

   – fires involving hydrogen

   – fires involving flammable and combustible liquids or hazardous process chemicals

   – fires resulting from construction or modifications (welding)

   – fires involving record files.

e. Review of each individual’s responsibilities under the Fire Protection Program.

f. Proper use of communication, lighting, ventilation, and emergency breathing equipment.

g. Fire brigade leader direction and coordination of firefighting activities.

h. Toxic and radiological characteristics of expected combustion products.

i. Proper methods of fighting fires inside buildings and confined spaces.

j. Detailed review of firefighting strategies, procedures and procedure changes.

k. Indoctrination of the plant firefighting plans, identification of each individual's responsibilities, and review of changes in the firefighting plans resulting from fire protection-related plant modifications.

l. Coordination between the fire brigade and offsite fire departments that have agreed to assist during a major fire onsite is provided to establish responsibilities and duties. Educating the offsite organization in operational precautions when fighting fires on nuclear power plant sites, and awareness of special hazards and the need of radiological protection of personnel.

9.5.1.8.2.2.2 Retraining

Classroom refresher training is scheduled on a biennial basis to supplement retention of the initial training. These sessions may be concurrent with the regular planned meetings.

9.5.1.8.2.2.3 Practice

Practice sessions are held for each fire brigade and for each fire brigade member on the proper method of fighting various types of fires which might occur in the plant. These sessions are scheduled on an annual basis and provide brigade members with team experience in actual fire fighting and the use of emergency breathing apparatus under strenuous conditions encountered in fire fighting.

9.5.1.8.2.2.4 Drills

Fire brigade drills are conducted at least once per calendar quarter for each shift. Each fire brigade member participates in at least two drills annually. Drills are either announced or unannounced. At least one unannounced drill is held annually for each shift fire brigade. At least one drill is performed annually on a “back shift” for each shift’s fire brigade. The drills provide for offsite fire department participation at least annually. Triennially, a randomly selected, unannounced drill shall be conducted and critiqued by qualified individuals independent of the plant staff. Training objectives are established prior to each drill and reviewed by plant management. Drills are critiqued on the following points:

a. Assessment of fire alarm effectiveness.

b. Assessment of time required to notify and assemble the fire brigade.

c. Assessment of the selection, placement, and use of equipment.

d. Assessment of the fire brigade leader’s effectiveness in directing the firefighting effort.

e. Assessment of each fire brigade member’s knowledge of firefighting strategy, procedures, and simulated use of equipment.

f. Assessment of the fire brigade’s performance as a team.

Performance deficiencies identified, based on these assessments, are used as the basis for additional training and repeat drills. Unsatisfactory drill performance is followed by a repeat drill within 30 days.

9.5.1.8.2.2.5 Meetings

Regular planned meetings are held at least quarterly for the fire brigade members to review changes in the Fire Protection Program and other subjects as necessary.

9.5.1.8.3 Administrative Controls

Administrative controls for the Fire Protection Program are implemented through plant administrative procedures. Applicable industry publications are used as guidance in developing those procedures.

Administrative controls include procedures to:

a. Control actions to be taken by an individual discovering a fire, such as notification of the control room, attempting to extinguish the fire, and actuation of local fire suppression systems.

b. Control actions to be taken by the control room operator, such as sounding fire alarms, and notifying the shift manager of the type, size, and location of the fire.

c. Control actions to be taken by the fire brigade after notification of a fire, including location to assemble, directions given by the fire brigade leader, the responsibilities of brigade members, such as selection of firefighting and protective equipment, and use of preplanned strategies for fighting fires in specific areas.

d. Control actions to be taken by the security force upon notification of a fire.

e. Define the strategies established for fighting fires in safety-related areas and areas presenting a hazard to safety-related equipment, including the designation of the:

    1. Fire hazards in each plant area/zone covered by a firefighting procedure (prefire plan). Prefire plans use the guidance of NFPA 1620 (Reference 205).

    2. Fire extinguishers best suited for controlling fires with the combustible loadings of each zone and the nearest location of these extinguishers.

    3. Most favorable direction from which to attack a fire in each area in view of the ventilation direction, access hallways, stairs, and doors that are most likely to be free of fire, and the best station or elevation for fighting the fire. Access and egress routes that involve locked doors are specifically identified in the procedure with the appropriate precautions and methods for access specified.

    4. Plant systems that should be managed to reduce the damage potential during a local fire and the location of local and remote controls for such management (e.g., any hydraulic or electrical system in the zone covered by the specific firefighting procedure that could increase the hazards in the area because of overpressurization or electrical hazards).

    5. Vital heat-sensitive system components that need to be kept cool while fighting a local fire. Particularly hazardous combustibles that need cooling are designated.

    6. Potential radiological and toxic hazards in fire zones.

    7. Ventilation system operation that provides desired plant air distribution when the ventilation flow is modified for fire containment or smoke clearing operations.

    8. Operations requiring control room and shift manager coordination or authorization.

    9. Instructions for plant operators and other plant personnel during a fire.

f. Organize the fire brigade and assign special duties according to job title so that the firefighting functions are covered for each shift by personnel trained and qualified to perform these functions.These duties include command control of the brigade, transporting fire suppression, and support equipment to the fire scenes, applying the extinguishing agent to the fire, communication with the control room, and coordination with offsite fire departments.

9.5.1.8.4 Control of Combustible Materials, Hazardous Materials, and Ignition Sources

The control of combustible materials, hazardous materials, and ignition sources are defined by administrative procedures. These procedures impose the following controls:

a. Prohibit the storage of hazardous chemicals (including unused ion exchange resins) in areas that contain or expose safety-related equipment.

b. Govern the handling of and limit transient fire loads such as flammable liquids, wood, and plastic materials in buildings containing safety-related systems or equipment.

c. Assign responsibility to the appropriate supervisor for reviewing work activities to identify transient fire loads.

d. Govern the use of ignition sources by use of a flame permit system to control welding, flame cutting, grinding, brazing and soldering operations, and temporary electrical power cables. A separate permit is issued for each area where such work is done. If work continues over more than one shift, the permit is valid for not more than 24 hours when the plant is operating or for the duration of a particular job during plant shutdown. NFPA 51B (Reference 202) and 241 (Reference 203) are used as guidance.

e. Minimize waste, debris, scrap, and oil spills or other combustibles resulting from a work activity in the safety-related area while work is in progress, and remove the same upon completion of the activity or at the end of each work shift.

f. Govern periodic inspections for accumulation of combustibles for continued compliance with these administrative controls.

g. Prohibit the storage of acetylene-oxygen and other compressed gasses in areas that contain or expose safety-related equipment or the fire protection system that serves those areas. A permit system is required to control the use of this equipment in safety-related areas of the plant.

h. Govern the use and storage of hazardous chemicals in areas that contain or expose safety-related equipment.

i. Control the use of specific combustibles in safety-related areas. Wood used in safety-related areas during maintenance, modification, or refueling operation (such as lay-down blocks or scaffolding) is treated with a flame retardant in accordance with NFPA 703 (Reference 207). Equipment or supplies shipped in untreated combustible packing containers are unpacked in safety-related areas if required for valid operating reasons. However, combustible materials are removed from the area immediately following unpacking. Transient combustible material (including packing material) is attended, stored in approved containers, or a fire watch is established. Textiles or films used are certified to conform to the fire test methods described in NFPA 701 (Reference 206).

j. Govern the control of electrical heaters in areas that contain or expose safety-related equipment.

9.5.1.8.5 Control of Radioactive Materials

The plant is designed with provisions for sampling of liquids resulting from fire emergencies that may contain radioactivity and may be released to the environment. Plant operating procedures require

such liquids to be collected, sampled, and analyzed prior to discharge. Liquid discharges are required to be below activity limits prior to discharge.

9.5.1.8.6 Testing and Inspection

Testing and inspection requirements, including frequency, are imposed through administrative procedures. Maintenance or modifications to the fire protection system are subject to inspection for conformation to design requirements. Procedures governing the inspection, testing, and maintenance of fire protection alarm and detection systems, and water-based suppression and supply systems, use the guidance of NFPA 72 (Reference 9.5.5.2) and NFPA 25 (Reference 212). Frequency of fire protection equipment maintenance is based on industry guidance and adjusted based on equipment performance. Fire protection equipment is periodically reviewed by site personnel to ensure continued acceptable performance. Installation of portions of the system where performance cannot be verified through preoperational tests, such as penetration seals, fire-retardant coatings, cable routing, and fire barriers are inspected. Inspections are performed by individuals knowledgeable of fire protection design and installation requirements. Open flame or combustion-generated smoke is not used for leak testing or similar procedures such as air flow determination. Inspection and testing procedures address the identification of items to be tested or inspected, responsible organizations for the activity, acceptance criteria, documentation requirements and sign-off requirements.

Fire protection materials subject to degradation (such as fire stops, seals, and fire retardant coatings are visually inspected periodically for degradation or damage. Fire hoses are hydrostatically tested in accordance with NFPA 1962 (Reference 201). Hoses stored in outside hose stations are tested annually and interior standpipe hoses are tested every three years.

The fire protection system is periodically tested in accordance with plant procedures. Testing includes periodic operational tests and visual verification of damper and valve positions. Fire doors and their closing and latching mechanisms are also included in these procedures.

Documentation exists confirming that the as-installed configuration of fire barriers matches the tested configurations. Site procedures describe the process for identifying and dispositioning deviations.

9.5.1.8.7 Personnel Qualification and Training

The engineer in charge of fire protection is responsible for the formulation and implementation of the fire protection program and meets the qualification requirements listed in Subsection 13.1.1.2.10.

Qualification and training of other plant personnel involved in the fire protection program is governed by plant qualification procedures and is conducted by personnel qualified by training and experience in these areas. These classifications include training personnel, maintenance personnel assigned to work on the fire protection system, and operations personnel assigned to system operation and testing.

Qualification for fire watches for hot work also include hands on training with fire extinguishers. A fire watch used as a compensatory measure for an impairment is briefed on the necessary job functions prior to being assigned.

9.5.1.8.8 Fire Doors

Fire doors separating safety-related areas are self-closing or provided with closing mechanisms and are inspected semiannually to verify that the automatic hold open, release and closing mechanisms and latches are operable. Watertight and missile resistant doors are not provided with automatic

closing mechanisms. Fire doors with automatic hold open and release mechanisms are inspected daily to verify that the doorways are free of obstructions.

Fire doors separating safety-related areas are normally closed and latched. Fire doors that are locked closed are inspected weekly to verify position. Fire doors that are closed and latched are inspected daily to ensure that they are in the closed position. Fire doors that are closed and electrically supervised at a continuously manned location are not inspected.

9.5.1.8.9 Emergency Planning

Emergency planning is described in Section 13.3.

9.5.1.9 Combined License Information

9.5.1.9.1 The qualification requirements for individuals responsible for development of the fire protection program, training of firefighting personnel, administrative procedures and controls governing the fire protection program during plant operation, and fire protection system maintenance are addressed as follows:

Qualification requirements for individuals responsible for development of the Fire Protection Program are discussed in Subsections 9.5.1.6 and 9.5.1.8.7.

Training of firefighting personnel is discussed in Subsections 9.5.1.8, 9.5.1.8.2, and 9.5.1.8.7.

Administrative procedures and controls governing the Fire Protection Program during plant operation are discussed in Subsections 9.5.1.8.1.2, 9.5.1.8.3, 9.5.1.8.4, 9.5.1.8.5, and 9.5.1.8.6.

Fire protection system maintenance is discussed in Subsection 9.5.1.8.6.

9.5.1.9.2 The site-specific fire protection analysis information for the yard area, the administration building, and for other outlying buildings consistent with Appendix 9A is addressed in Subsection 9A.3.3.

9.5.1.9.3 The BTP CMEB 9.5-1 issues identified in Table 9.5.1-1 by the acronym "WA" are addressed in Subsections 9.5.1.8.1.1, 9.5.1.8.8, and 9.5.1.8.9 and in Table 9.5.1-1.

9.5.1.9.4 The plant-specific NFPA exceptions are addressed in Subsection 9.5.1.8.1.1.

9.5.1.9.5 The operator actions which minimize the probability of the potential for spurious ADS actuation as a result of a fire are addressed in APP-GW-GLR-027 (Reference 22), and the applicable changes are incorporated into the UFSAR.

9.5.1.9.6 The process for identifying deviations between the as-built installation of fire barriers and their tested configurations is addressed in Subsection 9.5.1.8.6.

9.5.1.9.7 The procedures to minimize risk when fire areas are breached during maintenance are addressed in Subsection 9.5.1.8.1.2.

9.5.1.9.8 The fire resistance test data for the composite material selected for stairwell fire barriers is addressed in APP-GW-GLR-019 (Reference 23), and the applicable changes are incorporated into the UFSAR.

9.5.2 Communication System

The communication system (EFS) provides effective intraplant communications and effective plant-to-offsite communications during normal, maintenance, transient, fire, and accident conditions, including loss of offsite power. The communication system consists of the following subsystems:

- Wireless telephone system
- Telephone/page system
- Private branch exchange (PBX) system
- Sound-powered system
- Emergency offsite communications
- Security communication system.
- Plant Radio System (also known as "Land Mobile Radio Service" or "LMRS")

EFS allows each guard, watchman, or armed response individual on duty to maintain continuous communication with an individual in each manned alarm station and with other agencies both onsite and offsite, as required by 10 CFR 73.55(j). This is accomplished by both the PBX system and the wireless communication system. Each system can provide these communication functions.

Communication equipment used with respiratory protection devices will be designed and selected in accordance with EPRI NP-6559 (Reference 8).

9.5.2.1 Design Basis

EFS serves no safety-related function and therefore has no nuclear safety design basis.

EFS subsystems are independent of one another; therefore, a failure in one subsystem does not degrade performance of the other subsystems.

EFS is in accordance with applicable codes and standards minimizing electromagnetic interference and its potential effects to equipment. "Low-powered" type equipment is used, where possible, which has been demonstrated to have a limited potential for causing interference with electronic equipment (Reference 8) (EPRI NP-6559, Section 5). Communication equipment is shielded, as necessary, from the detrimental effects of electromagnetic interference.

9.5.2.2 System Description

9.5.2.2.1 Wireless Telephone System

The wireless telephone system consists of wireless portable handsets, hands-free type portable headsets, a comprehensive antenna system, and necessary electronics equipment. The wireless telephone system is the primary means of communication for plant operations and maintenance personnel. The telephone-page, PBX telephone, and sound-powered communication systems are for general plant communications and serve as a backup to the wireless system.

The wireless telephone system has the ability to dial fixed PBX telephone stations and vice versa. The wireless system has the capability to access the telephone-page system and the capability to access offsite emergency communication links.

Normal 120-V ac power supplies the wireless telephone switch. Upon loss of the normal power, the switch is powered from the non-Class 1E dc and uninterruptible power supply system and supplies power for system operation for 120 minutes.

9.5.2.2.2 Telephone/Page System

The telephone/page system consists of handsets, amplifiers, loudspeakers, and associated electronic equipment. The system supports paging and party lines without crosstalk or interference. The page party system includes the capability to establish multiple zones. Zone merging control capability is provided at the main control room, the security central alarm station, and the security secondary alarm station.

The telephone/page system has the capability to provide audible tone alarms (siren generator) and pre-recorded messages using the telephone/page system amplifiers and speakers. Alarm initiation capability is provided in the main control room. Paging zones are automatically merged during an alarm condition.

The telephone/page party system is divided into in-plant and outside area physical zones. Each zone can be disconnected from the rest of the system without interrupting the functions of the other unaffected zones or communication between the unaffected zones.

Power to the telephone/page system is provided from the non-Class 1E dc and uninterruptible power supply system sized to supply power for 120 minutes after a loss of ac power.

9.5.2.2.3 Private Branch Exchange System

The private branch exchange (PBX) system provides communication between the system stations, with capability for transferring calls and providing conference calls.

PBX telephones are programmable. Buttons on the phone can be dedicated and color coded to specific telephone numbers.

The PBX system also interfaces with the following communication systems:

- The wireless telephone system
- Redundant connectivity to commercial telephone services to provide communication capability with the load dispatcher to support and coordinate the system grid is as described in Subsection 9.5.2.5
- Access to the telephone page system
- Direct extensions from the PBX locations exterior to the plant as dictated in Subsection 9.5.2.5

The separate, redundant connections between the PBX and commercial telephone service provides communications between the main control room and the headquarters or other facilities in case of a single fault as required in Subsection 9.5.2.5.

Commercial telephone lines are provided by the local area telephone company. The local telephone company lines terminated at the switch are programmed to reserve part of the lines for outgoing calls only. Others are programmed for incoming only so that some lines are available for calling onto and off of the site. The number of lines is defined in Subsection 9.5.2.5.

Power to the PBX is provided from the non-Class 1E dc and uninterruptible power supply system sized to supply power for 120 minutes after a loss of ac power.

9.5.2.2.4 Sound-Powered System

Two unitized systems are provided as follows:

- A loop sound-powered system for refueling
- A multiloop system throughout the plant for startup and maintenance testing

The sound-powered system does not require external power supply for operation.

9.5.2.2.5 Offsite Interfaces

The Emergency Notification System (ENS) is part of the Federal Telecommunication System (FTS). The FTS does not rely on station switches at VEGP, and therefore the requirements of Bulletin 80-15 are satisfied.

Back-up power for the ENS is provided by the FTS 2001 supplier. On-site systems supporting the FTS system are provided with multiple power sources including diesel and battery backup. ENS phones are located in the Control Room, TSC, and EOF. Dedicated telephone communication links provided by the FTS, and their locations, include:

- NRC Emergency Notification System (ENS)
  - Control Room
  - TSC
  - EOF
- NRC Health Physics Network (HPN)
  - TSC
  - EOF
- Reactor Safety Counterpart Link (RSCL)
  - TSC
  - EOF
- Protective Measures Counterpart Link (PMCL)
  - TSC
  - EOF
- Management Counterpart Link (MCL)
  - TSC
  - EOF
- Operations Center LAN (OCL)

- TSC
- EOF

Design specifications include provisions for multiple power sources for the communication system. The design provides for back-up power to be provided by a combination of diesel generator and/or battery supplied power. Communication system power supplies will be identified in Emergency Implementing Procedures.

The Emergency Notification Network (ENN) is the primary means for communication between the Site and the local authorities, including the State of South Carolina and Aiken, Barnwell, and Allendale Counties, and the State of Georgia and Burke County. The ENN system is available on a twenty-four seven basis. Commercial telephones provide backup for the dedicated telephone circuits.

In the event of failure of either the dedicated telephone circuits or the ENN equipment (transmitting station and/or single/multiple receiving stations), commercial telephone lines are used. To transfer to the back-up system, the communicator manually initiates communications using commercial telephone lines for the affected station(s) as directed by Emergency Implementing Procedures.

9.5.2.3 System Operation Communication Stations

Table 9.5.2-1 lists the communication stations provided for operator use during transients.

The main control room and remote shutdown room are designed and instrumented to bring the plant to a safe shutdown condition without relying on communications equipment. Various communication stations are provided throughout the plant.

9.5.2.4 Inspection and Testing Requirements

Communication systems of the types described above are conventional and have a history of reliable operation. Most of these systems are in routine use, and this routine use will demonstrate their availability. Those systems not frequently used, but required during emergency situations, are tested at periodic intervals to demonstrate operability when required.

9.5.2.5 Combined License Information

9.5.2.5.1 Offsite Interfaces

Interfaces to required offsite locations, including the recommendations of BL-80-15 (Reference 21) regarding loss of the emergency notification system due to a loss of offsite power, are addressed in Emergency Plan Section F and Subsection 9.5.2.2.5 of this chapter.

9.5.2.5.2 Emergency Offsite Communications

The emergency offsite communication system, including the crisis management radio system, is addressed in the Emergency Plan and Subsection 9.5.2.2.5 of this chapter.

9.5.2.5.3 Security Communications

The security communication system is addressed in the Physical Security Plan.

9.5.2.5.4 Plant Radio

The plant radio system is used primarily by Security and site fire brigade. The security functions are addressed in the Physical Security Plan. Other site departments also use the radio system periodically. Separate radio talk groups are assigned to each department.

9.5.3 Plant Lighting System

The plant lighting system includes normal, emergency, panel, and security lighting. The normal lighting provides normal illumination during plant operating, maintenance, and test conditions. The emergency lighting provides illumination in areas where emergency operations are performed upon loss of normal lighting. The panel lighting in the control room is designed to provide the minimum illumination required at the safety panels. The security lighting system is described in separate security documents referred to in Section 13.6.

9.5.3.1 Design Basis

The plant lighting system serves no safety-related function and therefore has no nuclear safety design basis. Failure of the plant lighting system or its components will not affect the ability of safety-related systems to perform their intended function.

- The normal and emergency lighting in the main control room and in the remote shutdown room is non-Class 1E.
- The emergency lighting provides illumination in the main control room and the remote shutdown room for 72 hours upon loss of normal lighting. In other plant areas, the emergency lighting provides illumination for 8 hours.
- Lighting for the safety panels in the control room is provided by the panel lighting system.
- During the 72 hour period following a loss of all ac power sources, lighting in the main control room can be provided as described in Subsection 9.5.3.2.2.
- The plant lighting system provides illumination levels for normal and emergency lighting as recommended in Illuminating Engineering Society Lighting Handbook (Reference 5).

9.5.3.2 System Description

9.5.3.2.1 Normal Lighting

Power to the normal lighting system is supplied from the non-Class 1E ac power distribution system at the following voltage levels:

- 480/277 V, three-phase, four-wire, grounded neutral system lighting panels are fed from the 480 V motor control centers; this source is for the lighting fixtures rated at 480/277 V and for the welding receptacles.
- 208/120 V, three-phase, four-wire, grounded neutral system distribution panels are fed from the 480 V motor control centers through dry-type 480-208/120 V transformers; this source is for lighting and utility receptacles.

- 208/120 V, three-phase, four-wire, grounded neutral regulated power fed from the 480 V motor control centers through the Class 1E 480 - 208/120 V voltage regulating transformers (divisions B and C); this source is for the normal and emergency lighting in the main control room and remote shutdown room and is isolated through two series fuses for isolation. The normal lighting in these plant areas is non-Class 1E.

The normal lighting system has the following features:

- The normal lighting system is powered from the diesel-backed buses and the lighting load is distributed between the two onsite standby diesel generator buses.

- The motor control centers powering the normal lighting system are energized from the 480 V load centers connected in a tie-breaker configuration.

- Lighting distribution panel branch circuit breakers are controlled by a lighting control system. Approximately 75 percent of the normal lighting is tripped off automatically upon loss of normal ac power and offsite power (except in the main control room and in the remote shutdown room) to limit the load on the onsite standby diesel generators. The lighting control system allows the operator to energize or de-energize lighting in selected areas based on the actual need and available power from the onsite standby diesel generators.

- The lighting circuits are staggered as much as practical. The staggered circuits receive power from separate buses to prevent complete loss of light in the event of a bus or a circuit failure.

- The lighting fixtures located in the vicinity of safety-related equipment are supported so that they do not adversely impact this equipment when subjected to the seismic loading of a safe shutdown earthquake.

- Mercury vapor lamps and mercury switches are not used in fuel handling areas.

- Unencapsulated, unshielded high-intensity discharge (HID) and fluorescent lamps are not used in the containment and fuel handling areas due to mercury content and the risk of being released to the area environment. Incandescent lighting or other lighting not containing restricted materials may be used in these general areas. High Pressure Sodium (HPS) underwater lighting, with appropriate barriers and protection to prevent contact with the water, or long life lighting not containing restricted materials, are used for underwater lighting in the fuel handling areas outside containment as they provide longer lamp life, longer service intervals and less personnel exposure.

- The control room and remote shutdown room lighting uses semi-indirect, low-glare lighting fixtures and adjustable dimming features. The normal control room lighting provides at least 50 foot candles of illumination at the safety panel and at the workstations when the dimming features are adjusted for maximum illumination. The normal remote shutdown room lighting provides at least 50 foot candles of illumination at the remote shutdown workstation when the dimming features are adjusted for maximum illumination.

9.5.3.2.2 Emergency Lighting

Emergency lighting is designed to provide the required illumination levels in the areas as described below:

- The main control room and remote shutdown room each has emergency lighting consisting of 120 V ac lighting fixtures which are continuously energized. The fixtures are powered from the Class 1E 250 V dc switchboards through the Class 1E 208Y/120 V ac inverters and are

isolated through two series fuses that are coordinated for isolation. Three hour fire barrier separation is provided between redundant emergency lighting power supplies and cables outside the main control room and the remote shutdown area. The control room lighting complies with the human factor requirements by utilizing semi-indirect, low-glare lighting fixtures and adjustable dimming features. The control room emergency lighting is integrated with normal lighting that consists of identical lighting fixtures and dimming features. The emergency lighting system is designed so that, to the extent practical, alternate emergency lighting fixtures are fed from separate divisions of the Class 1E dc and uninterruptible power supply system. Both normal and emergency lighting fixtures, controllers, dimmers, and associated cables used in the main control room and remote shutdown room are nonClass 1E. The ceiling grid network, raceways and fixtures utilize seismic supports. A single fault cannot interrupt all of the lighting in the main control room and at the remote shutdown workstation simultaneously. The emergency lighting provides at least 10 foot candles of illumination at the safety panel, at the workstations in the control room, and at the remote shutdown workstation when the dimming features are adjusted for maximum illumination.

- Following the 72 hour period after a loss of all ac power sources, the lighting in the main control room is powered from two ancillary ac generators as described in Subsection 8.3.1.1.1.

- Emergency lighting in areas outside the main control room and remote shutdown room is accomplished by 8-hour, self-contained, battery pack lighting units. These units are nonClass 1E and provide illumination for safe ingress and egress of personnel following a loss of normal lighting and for those areas which could be involved in power recovery (for example, onsite standby diesel-generators and their controls). In addition, these units are provided in areas where manual actions are required for operation of equipment needed during a fire. These units are normally powered from the non-Class 1E 480/277 V ac motor control centers and they automatically switch to their internal dc source once normal ac power is lost.

9.5.3.2.3 Panel Lighting

Panel lighting is designed to provide lighting in the control room at the safety panels as described below:

- Panel lighting consists of lighting fixtures located on or near safety panels in the control room. The panel lights are continuously energized. The fixtures are powered from the Divisions B and C Class 1E inverters through Class 1E distribution panels.

- The circuits are treated as Class 1E. The panel lighting circuits up to the lighting fixture are classified as associated and are routed in a Seismic Category I raceway system.

- The bulbs are not seismically qualified.

9.5.3.3 Safety Evaluation

The plant lighting system has no safety-related functions and therefore requires no nuclear safety evaluation. Failure of the plant lighting system or its components will not affect the ability of safety-related systems to perform their intended function.

The areas that require lighting for safe shutdown are the main control room and the remote shutdown room when the main control room is not accessible.

- Lighting fixtures in the main control room and remote shutdown room are seismic Category II.
- Emergency and panel lighting circuits up to the lighting fixture are routed in a Seismic Category I raceway system.
- Panel Lighting circuits up to the lighting fixture are treated as Class 1E and Classified as associated. This is acceptable to the Class 1E power supply because of the over current protective device coordination.
- Bulbs are not seismically qualified. However, the bulbs can only fail open and therefore do not represent a hazard to the Class 1E power sources.
- Power to normal and emergency lighting in the main control room and in the remote shutdown room is supplied from the redundant divisions of Class 1E dc and UPS system through two series fuses for isolation. The fuses protect the batteries from failures of the non1E lighting circuits. The Class 1E batteries provided in the Class 1E dc and UPS system are capable of powering the emergency lighting in these rooms for 72 hours when the normal ac sources are not available. Operation beyond 72 hours is described in Subsection 8.3.1.1.1.

9.5.3.4 Test and Inspections

The ac lighting circuits are normally energized and require no periodic testing. The 8-hour battery pack lighting is inspected and tested periodically.

9.5.3.5 Combined License Information for Plant Lighting

This section contained no requirement for additional information.

9.5.4 Standby Diesel Fuel Oil System

This subsection describes the features of the standby diesel fuel oil system. The standby diesel generators are supplied by a combined storage system of fuel oil storage tanks. Two above-ground fuel oil storage tanks for the combined system service are provided. These tanks store diesel grade fuel. The standby diesel generators are described in Subsection 8.3.1.1.2.

9.5.4.1 Design Basis

9.5.4.1.1 Safety Design Basis

The standby diesel fuel oil system serves no safety-related function and therefore has no nuclear safety design basis.

9.5.4.1.2 Power Generation Design Basis

The standby diesel fuel oil system serves no power generation function. Its function is to store and transfer fuel oil for the onsite standby diesel generators. The system is designed to meet the following requirements:

- Provide a supply of fuel sufficient to operate each diesel generator to power automatically sequenced loads with 10% margin for load growth for 7 days
- Provide a 4-day fuel supply for the two ancillary diesel generators

9.5.4.1.3 Codes and Standards

The codes and standards that are applicable to the components of the Standby Diesel Fuel Oil System that support the standby diesel generators are listed in Section 3.2. The portions of the Standby Diesel Fuel Oil System that support the standby diesel generators follow the guidance for distillate fuel oil supply contained in Chapter 13 of the DEMA Standard Practices (Reference 19).

9.5.4.2 System Description Storage and Transfer

9.5.4.2.1 General Description

The standby diesel fuel oil system is shown in Figure 9.5.4-1. The system consists of two fuel oil storage tanks, a diesel generator fuel oil transfer system, and an ancillary diesel generator fuel oil supply system.

Two fuel oil storage tanks are provided, one for each of the standby diesel generators.

The plant finished grade elevation will be higher than the probable maximum flood level (refer to Subsection 3.4.1.1, Protection From External Flooding). Therefore the system will be safe from flooding.

The diesel generator fuel oil transfer system consists of two independent fuel storage, transfer and recirculation flow paths; that is, one path per diesel generator. Each path consists of a fuel oil storage tank, one fuel transfer pump, diesel fuel oil supply and fuel return piping, a day tank, and the associated specialties valves, fittings, and instrumentation. The supply lines from the transfer pumps to the daytanks include fuel oil heaters, filters and moisture separators. The system is protected from the effects of low temperatures by the inline electric oil heater in the transfer line.

The ancillary diesel generator fuel oil supply portion of the system consists of a single 100 percent capacity tank serving both ancillary diesel generators. The tank is located inside the annex building and is served by the annex building heating and ventilation system. The tank is insulated and provided with heaters to maintain the fuel oil above the oil cloud point. Fuel oil lines from the tank to the diesels are insulated. Fuel is transferred from the ancillary diesel generator fuel tank by an internal transfer pump within the ancillary diesel generator skid.

Two separate prefabricated insulated, heated and ventilated weather enclosures are provided for the transfer systems. Each enclosure houses one diesel fuel oil transfer pump assembly. The enclosures are sufficiently separated to prevent a fire in either enclosure from causing an interruption in the other flow path.

Characteristics of the system components are provided in Table 9.5.4-1.

9.5.4.2.2 Component Description

9.5.4.2.2.1 Fuel Storage Tanks

The two fuel oil storage tanks are located on grade. The tanks are designed and fabricated to API-650 Standards. Fittings are provided for each tank for level instrumentation, ventilation, sampling, water removal and sounding. Flanged openings are provided as manholes for access to the tank interior and each tank is equipped with an internal sump and a drain connection. Each tank is erected on a continuous concrete slab totally contained within a concrete dike to contain spills and prevent damage to the environment and seepage into the ground water.

The design of the standby diesel fuel oil system allows replenishment of fuel without interrupting operation of the diesel generator. The tank fill connection includes an internal pipe and diffuser to limit inlet filling velocities to prevent turbulence of sediment on the bottom of the tank. In addition, the diesel fuel oil transfer connections at the fuel oil storage tanks are 12 inches above the tank bottom to reduce the potential of sediment entry into the pipe line. A moisture separator and duplex filters are provided in the diesel fuel oil piping and a duplex fuel oil filter is provided on each engine to prevent detrimental effects on diesel performance from sediment. A 55,000 gallon supply of fuel oil is sufficient to power automatically sequenced loads for 7 days with 10% margin for load growth.

9.5.4.2.2.2 Diesel Generator Fuel Oil Transfer

The diesel generator fuel oil transfer system consists of two modularized skid mounted assemblies, each consisting of suction strainers, a transfer pump, a fuel oil heater, a moisture separator, and a fuel filter with the interconnecting piping, valves and instrumentation.

The fuel oil transfer pumps are of the motor driven gear positive displacement type. Each pump capacity is approximately four times the maximum consumption rate of the associated diesel generator. The pump and pump motor are mounted on a common baseplate. A prefabricated weather enclosure protects the strainer, transfer pumps, heater, moisture separator, and duplex filters and associated piping. There is no fixed fire protection water system inside the enclosure; therefore, spurious actuation of a fire protection system cannot occur.

9.5.4.2.2.3 Standby Diesel Generator Fuel Oil Day Tanks

The diesel generator fuel oil day tanks each provide a 1,300 gallon supply of fuel, which is sufficient to power automatically sequenced loads for 4 hours with 10% margin for load growth without resupply from a fuel oil storage tank. The day tanks are located within the diesel generator building and are separated from the remainder of the diesel generator building by 3-hour rated fire barriers. The day tanks are separate from sources of ignition or high-temperature surfaces. The day tank elevation is selected to provide the necessary suction head for the diesel engine fuel oil pump. The fuel oil piping is run in a piping trench from the tank to the engine. The fuel oil piping on the engine is located away from hot surfaces. Tank fittings provide for external tank fill, water removal, recirculation, and instrumentation. The fuel oil day tank is vented to atmosphere with a line which has a ball float check valve, and flame arrestor at the end. Since venting is to the outside atmosphere, there is not a buildup of combustible fumes within the diesel generator building.

9.5.4.2.2.4 Ancillary Diesel Generator Fuel Oil Storage Tank

The ancillary diesel generator fuel oil storage tank provides four days of operation of the ancillary diesel generators. The tank is analyzed to show that it will withstand an SSE and is located in the same room as the ancillary diesel generators in the annex building. This room is separated from the rest of the annex building by a 3-hour rated fire barrier. The ancillary diesel generator fuel oil storage tank is vented to the atmosphere with a line which has a flame arrestor at the end. Since venting is to the outside atmosphere, there is not a buildup of combustible fumes within the annex. An overfill prevention valve is installed in the tank fill nozzle to prevent an overfilled tank and overflow in the vent line.

9.5.4.2.2.5 Piping and Tank Surfaces

The exterior and interior surfaces of the fuel oil storage tanks are painted with a primer and finish coat system for corrosion protection of the tank surface. Exterior surfaces of the diesel fuel oil transfer piping are painted for corrosion protection. Buried sections are enclosed in guard pipes to prevent leakage to the environment.

The guard pipe containment system is corrosion resistant plastic, designed and fabricated for the site overburden wheel loads which result from equipment removal and replacement.

9.5.4.2.3 System Operation

The fuel oil storage tanks for the diesel generators are replenished from trucks (or other mobile suppliers) as required to maintain a seven day supply for each standby diesel generator. Each storage tank is equipped with a vent line to atmosphere at the top of the tank that ends with a flame arrester. A tank fill line runs to each tank and is extended to the truck unloading station. The fill line incorporates a normally closed valve and a filler cap at the end to preclude the entrance of water. The fill line is above grade. The fill line has a strainer located downstream of the isolation valve to prevent entrance of deleterious solid material into the tank. A water removal port is located at the tank sump.

Each diesel oil transfer pump takes suction from a fuel oil storage tank and discharges fuel oil to the diesel generator fuel oil day tank. Each pump is capable of supplying its diesel generator and, simultaneously, increasing the inventory in the fuel oil day tank. The fuel oil transfer pump is automatically started and stopped on day tank level control. The filter in the discharge line to the day tank is monitored by measuring differential pressures across the filter and by providing a high differential pressure alarm.

In the event the diesel fuel oil degrades during storage, biocides and other fuel additives are introduced to the tanked fuel oil to prevent deterioration of the oil, accumulation of sludge in the storage tanks, and the growth of algae and fungi.

Site-specific conditions determine the requirements for oil supply and emergency fuel delivery.

Provisions are included in the fuel oil storage tanks and day tanks to check and remove accumulated water.

The fuel oil storage tank for the ancillary diesel generators is replenished from trucks (or other mobile supplier) as required to maintain a 4-day supply for both ancillary diesel generators.

9.5.4.3 Safety Evaluation

The standby diesel fuel oil system serves a defense in depth function and requires no nuclear safety evaluation.

9.5.4.4 System Evaluation

The standby diesel generator fuel oil transfer system supplies fuel oil to the diesel generators which provide defense in depth electric power for investment protection.

The fuel oil storage tanks are sized to provide sufficient capacity for seven days of operation for each standby diesel generator. Within this period, the operator can arrange for additional fuel to be delivered to the plant site. An independent fuel supply path consisting of a fuel storage tank, a day tank, strainer, transfer pump, piping, oil heater, oil filter, moisture separator and valves is provided for each diesel generator. Each pump is powered from the electrical bus on which the diesel generator it serves is connected. Failure of a pump or a diesel generator would not affect the operability of components in the other train.

Maintenance of the fuel oil temperature above the cloud point is achieved automatically on low temperatures by an electric fuel oil heater at the discharge of the transfer fuel oil pump and by burial of the transfer piping below the frostline. The fuel oil system can be maintained above the cloud point temperature with the system electric heater in service and operation in the recirculation mode (by

passing the day tank) back to the fuel oil storage tank. Above grade piping and inline equipment outdoors are insulated.

Electrical power supply for the diesel fuel oil transfer pumps and electric heater is from the associated diesel generator backed 480 V bus.

The fuel oil storage tank for the ancillary diesel generators is sized to provide sufficient capacity for four days of operation for both ancillary diesel generators. The ancillary diesel generators are not needed for the first 72 hours following a loss of all ac. Therefore, the operator has seven days to arrange for additional fuel to be delivered to the plant site. Maintenance of the fuel oil temperature above the cloud point when a normal ac source is available is achieved by the normal annex building heating and ventilation system maintaining room temperature within its normal range. Maintenance of the fuel oil temperature above the cloud point during operation of the ancillary diesel generators is achieved by electric tank heaters and tank insulation.

9.5.4.5 Tests and Inspections

9.5.4.5.1 Diesel Generator Fuel Oil Supply

The standby diesel generator fuel oil storage and transfer system operability may be demonstrated during tests of the diesel generator, or testing may be performed by operation of the system in recirculation mode (bypassing the day tank) and pumping fuel through the recirculation line back to the fuel oil storage tank. Fuel reserve for testing is supplied by sizing the storage tanks to contain fuel in excess of the volume required for seven days of continuous operation of all automatically sequenced loads with 10% margin for load growth. Provisions are made to sample and analyze diesel fuel periodically to verify the fuel quality requirements.

9.5.4.5.2 Fuel Oil Quality

The diesel fuel oil testing program requires testing both new fuel oil and stored fuel oil. High fuel oil quality is provided by specifying the use of ASTM Grade 2D fuel oil with a sulfur content as specified by the engine manufacturer. The program includes sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

    1. An API gravity or an absolute specific gravity within limits, when tested in accordance with ASTM D1298;

    2. A flash point and kinematic viscosity is tested to be within the limits specified in Table 1 of ASTM D975 for ASTM 2D fuel oil, and

    3. A clear and bright appearance with proper color is verified per ASTM D4176 or a water and sediment content within limits of ASTM D975.

b. The remaining critical parameters per Table 1 of ASTM D975, other than those addressed above in a., are verified compliant within 30 days following sampling and addition of the new fuel oil to storage tanks.

c. Total particulate concentration of the fuel oil is ≤ 10 mg/L when tested every 92 days.

d. The fuel oil storage tanks are inspected on a quarterly basis for the presence of water. Any accumulated water is to be removed.

9.5.4.6 Instrumentation Applications

9.5.4.6.1 Standby Diesel Generator Fuel Oil Supply

The transfer pumps can be operated from the control room. Alarms and indications of tank levels and transfer pump status are displayed in the control room. A secondary means of tank level determination is provided by dipsticks or sounding ports. Day tank fuel oil transfer pumps start and stop on low and high level, respectively, and the tank level transmitter activates a day tank high or low level alarm. The diesel oil transfer pumps start automatically when the level in the day tank decreases to set capacity. The day tank low level alarm annunciates when the level decreases to a point where 2 hours of fuel remain. The diesel oil transfer pumps are automatically stopped when the day tank level has increased to a higher set level.

Low fuel oil level in the standby diesel fuel oil storage tanks is also alarmed.

9.5.4.6.2 Ancillary Diesel Generator Fuel Oil Supply

There is no control room monitoring or control associated with the ancillary diesel generator fuel oil supply system. All controls and instruments are local/manual only. Provision is made to locally monitor fuel level in the tank.

9.5.4.7 Combined License Information

9.5.4.7.1 The site-specific need for cathodic protection in accordance with NACE Standard RP-01-69 for external metal surfaces of metal tanks in contact with the ground is addressed in APP-GW-GLR-120 (Reference 24), and the applicable changes are incorporated into the UFSAR.

9.5.4.7.2 The site-specific factors in the fuel oil storage tank installation specification to reduce the effects of sun heat input into the stored fuel, the diesel fuel specifications grade and the fuel properties consistent with manufacturers' recommendations, and measures to protect against fuel degradation by a program of fuel sampling and testing are partially addressed in APP-GW-GLR-120 (Reference 24), and the applicable changes are incorporated into the UFSAR, and by the information as delineated in the following paragraph:

The epoxyurethane paint color selected for the exterior of the standby diesel fuel oil storage tanks shall be white to minimize radiant sunlight heat transmission to the tank oil stored fuel volume.

The diesel fuel specifications grade and the fuel properties consistent with manufacturers' recommendations and the measures to protect against fuel degradation by a program of fuel sampling and testing are addressed in Subsection 9.5.4.5.2.

9.5.5 References

1. NUREG-0800, U. S. Nuclear Regulatory Commission Standard Review Plan, Section 9.5.1, "Fire Protection Program," Revision 3, July 1981, including Branch Technical Position (BTP) CMEB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," Revision 2, July 1981.

2. National Fire Protection Association Codes and Standards:

NFPA 10, 1998: Standard for Portable Fire Extinguishers; NFPA 13, 1999: Standard for the Installation of Sprinkler Systems; NFPA 14, 2000: Standard for the Installation of Standpipe, Private Hydrants, and Hose Systems; NFPA 15, 2001: Standard for Water Spray Fixed Systems for Fire Protection; NFPA 20, 1999: Standard for the Installation of Stationary Pumps for Fire Protection; NFPA 22, 1998: Standard for Water Tanks for Private Fire Protection; NFPA 24, 1995: Standard for Installation of Private Fire Service Mains and Their Appurtenances; NFPA 30, 2000: Flammable and Combustible Liquids Code; NFPA 50A, 1999: Standard for Gaseous Hydrogen Systems at Consumer Sites; NFPA 50B, 1999: Standard for Liquefied Hydrogen Systems at Consumer Sites; NFPA 72, 1999: National Fire Alarm Code; NFPA 780, 2000: Standard for the Installation of Lightning Protection Systems; NFPA 804, 2001: Standard for Fire Protection for Advanced Light Water Reactor Electric Generating Plants.

3. "IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations," IEEE Std 3831974.

4. Fire Protection Handbook, Edited by A. E. Cote, National Fire Protection Association, 16th edition.

5. IES - 1987 Lighting Handbook.

6. IEEE Standard 281, "IEEE Standard Service Conditions for Power System Communication Equipment," 1984.

7. Beranek, Lee L., Noise Reduction, McGraw Hill Book Co., 1960.

8. EPRI Report NP 6559, "Voice Communication Systems Compatible with Respiratory Protection."

9. NRC IE Circulator No. 80-89, "Problems with Plant Internal Communications Systems," April 18, 1990.

10. 10 CFR 50, Appendix E, IV.E.9, "ERF Communications."

11. NRC IEN 87-58, "Continuous Communication Following Emergency Notifications."

12. NRC IEN 86-097, "Emergency Communication Systems."

13. Not Used.

14. NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plan."

15. 10 CFR 50, Section 50.48 "Fire Protection."

16. 10 CFR 50, Appendix A, Criterion 3 "Fire Protection."

17. NRC Policy Issue SECY-97-087, "Policy, Technical and Licensing Issues Pertaining to Evolutionary and Advanced Light Water Reactor (ALWR) Designs," Section I.E, "Fire Protection."

18. IEEE Standard for Flame Testing of Cables for Use in Cable Tray in Industrial and Commercial Occupancies, IEEE Std. 1202 - 1991.

19. Standard Practices for Medium Speed Stationary Diesel and Gas Engines, Sixth Edition, Diesel Engine Manufacturers Association, 1972. (Note: Although this standard is obsolete, the guidance for distillate fuel systems in Chapter 13 is applicable for AP1000.)

20. Not Used.

21. NRC Bulletin 80-15, "Possible Loss of Emergency Notification System (ENS) with Loss of Offsite Power," June 18, 1980.

22. APP-GW-GLR-027, "Operator Actions Minimizing Spurious ADS Actuations," Westinghouse Electric Company LLC.

23. APP-GW-GLR-019, "Fire Resistance Test Data," Westinghouse Electric Company LLC.

24. APP-GW-GLR-120, “Cathodic Protection for Metal Tanks in Contact with the Ground,” Westinghouse Electric Company LLC.

201. National Fire Protection Association, “Standard for Inspection, Care, and Use of Fire Hose, Couplings, and Nozzles and the Service Testing of Fire Hose,” NFPA 1962, 2003.

202. National Fire Protection Association, “Standard for Fire Prevention During Welding, Cutting, and Other Hot Work,” NFPA 51B, 2003.

203. National Fire Protection Association, “Standard for Safeguarding Construction, Alteration, and Demolition Operations,” NFPA 241, 2004.

204. National Fire Protection Association, “Standard on Industrial Fire Brigades,” NFPA 600, 2005.

205. National Fire Protection Association, “Recommended Practice for Pre-incident Planning,” NFPA 1620, 2003.

206. National Fire Protection Association, “Standard Methods of Fire Tests for Flame Propagation of Textiles and Films,” NFPA 701, 2004.

207. National Fire Protection Association, “Standard for Fire-Retardant Treated Wood and Fire-Retardant Coatings for Building Materials,” NFPA 703, 2006.

208. National Fire Protection Association, “Standard for Fire Service Respiratory Protection Training,” NFPA 1404, 2006.

209. National Fire Protection Association, “Standard on Training for Initial Emergency Scene Operations,” NFPA 1410, 2005.

210. National Fire Protection Association, “Standard on Fire Department Occupational Safety and Health Program,” NFPA 1500, 2007.

211. Not used.

212. National Fire Protection Association, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” NFPA 25, 2008.

Table 9.5.1-1 (Sheet 1 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
Fire Protection Program			
A. Definition: **Fire Resistance Rating** – *The time that materials or assemblies have withstood a fire exposure as established in accordance with the test procedures of "Standard Methods of Fire Tests of Building Construction and Materials" (NFPA 251).*	B.4	AC	Fire Resistance Ratings may utilize other standard methods of fire tests of building construction and materials that are recognized by a national association (i.e., ASTM, UL, NFPA) and/or the U.S. Nuclear Regulatory Commission. See also Table 9.5.1-3.
1. Direction of fire protection program; availability of personnel.	C.1.a(1)	WA C	See Note 2 Comply. Subsections 9.5.1.8.1.2 and 13.1.1.2.10 address this requirement.
2. Defense-in-depth concept; objective of fire protection program.	C.1.a(2)	WA C	See Note 2 Comply. Subsections 9.5.1.8 and 9.5.1.8.1 address this requirement.
3. Management responsibility for overall fire protection program; delegation of responsibility to staff.	C.1.a(3)	WA C	See Note 2 Comply. Subsections 9.5.1.8.1.2 and 13.1.1.2.10
4. The staff should be responsible for: a. Fire protection program requirements. b. Post-fire shutdown capability. c. Design, maintenance, surveillance, and quality assurance of fire protection features. d. Fire prevention activities. e. Fire brigade organization and training. f. Prefire planning.	C.1.a(3)	WA C	See Note 2 Comply. Subsection 13.1.1.2.10 addresses this requirement.
5. The organizational responsibilities and lines of communication pertaining to fire protection should be defined through the use of organizational charts and functional descriptions.	C.1.a(4)	WA C	See Note 2 Functional descriptions are addressed in Subsections 13.1.1.2.10 and 13.1.2.1.6.
6. Personnel qualification requirements for fire protection engineer, reporting to the position responsible for formulation and implementation of the fire protection program.	C.1.a(5)(a)	WA C	See Note 2 Comply. Subsection 13.1.1.2.10 addresses this requirement.
7. The fire brigade members' qualifications should include a physical examination for performing strenuous activity, and the training described in Position C.3.d.	C.1.a(5)(b)	WA C	See Note 2 Comply. Subsections 9.5.1.8.2.1 and 9.5.1.8.2.2 addresses this requirement.
8. The personnel responsible for the maintenance and testing of the fire protection systems should be qualified by training and experience for such work.	C.1.a(5)(c)	WA C	See Note 2 Comply. Subsection 9.5.1.8.7 addresses this requirement.

Table 9.5.1-1 (Sheet 2 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
9. The personnel responsible for the training of the fire brigade should be qualified by training and experience for such work.	C.1.a(5)(d)	WA C	See Note 2 Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
10. The following NFPA publications should be used for guidance to develop the fire protection program: No. 4, No. 4A, No. 6, No. 7, No. 8, and No. 27.	C.1.a(6)	WA C	See Note 2 Alternate Compliance. The NFPA codes cited in BTP CMEB 9.5-1 are historical. Current NFPA codes are referenced for guidance for the fire protection program. Subsection 9.5.1.8.1.1 addresses this requirement.
11. On sites where there is an operating reactor, and construction or modification of other units is underway, the superintendent of the operating plant should have a lead responsibility for site fire protection.	C.1.a(7)	WA C	See Note 2 Comply. Subsection 13.1.1.2.10 addresses this requirement.
Fire Protection Analysis			
12. The fire protection analysis should demonstrate that the plant will maintain the capability to perform safe shutdown functions and minimize radioactive releases to the environment in the event of a fire.	C.1.b	C	
13. The fire protection analysis should be performed by fire protection and reactor systems engineers to (1) consider potential in situ and transient fire hazards; (2) determine the consequences of a fire in any location in the plant; and (3) specify measures for fire prevention, detection, suppression, and containment.	C.1.b	C	
14. Fires involving facilities shared between units should be considered.	C.1.b	WA C	Comply. The FHA demonstrates the plant's ability to perform safe shutdown functions and minimize radioactive releases to the environment. Postulated fires in shared facilities that do not contain SSCs important to safety and do not contain radioactive materials do not affect these functions.

Table 9.5.1-1 (Sheet 3 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
15. Fires due to man-made site-related events that have a reasonable probability of occurring and affecting more than one reactor unit should be considered.	C.1.b	WA C	To be evaluated on a site-specific basis. Plant siting decisions are expected to preclude the need to consider such events. Comply. Sections 2.2 and 3.5 establish that these events are not credible.
16. Establishing three levels of fire damage limits according to safety function (hot shutdown, cold shutdown and design basis accidents).	C.1.b	C	AP1000 uses two levels of damage limits: safe shutdown and design basis accidents. Safe shutdown capability is protected from damage caused by a single fire.
17. The fire protection analysis should separately identify hazards and provide appropriate protection in locations where safety-related losses can occur.	C.1.b	C	
Fire Suppression System Design Basis			
18. Total reliance should not be placed on a single fire suppression system. Backup fire suppression capability should be provided.	C.1.c(1)	C	Automatic fire suppression systems are backed up by manual suppression systems (standpipe) and portable extinguishers.
19. A single active failure or a crack in a fire suppression system moderate energy line should not impair both the primary and backup fire suppression capabilities.	C.1.c(2)	AC	Criteria followed except for containment and outlying buildings. The piping serving the standpipe and fire hose connections located inside the containment are analyzed to remain functional following a safe shutdown earthquake. The containment isolation piping is qualified to seismic Category I criteria. These attributes reduce the potential for a failure of the system. The buildings outside the auxiliary building do not contain safety-related equipment, or present an exposure hazard to structures containing safety-related equipment. Manual fire suppression capability using hose lines connected to the outside hydrants of the yard main can be provided in the event of a failure of the interior fire suppression systems.

Table 9.5.1-1 (Sheet 4 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
20. The fire suppression system should be capable of delivering water to manual hose stations located within hose reach of areas containing equipment required for safe shutdown following a safe shutdown earthquake (SSE).	C.1.c(3)	AC	Criteria followed except for the PCS valve room, Room 12701 (Fire Zone 1270 AF 12701). The quantity of combustible material in this fire zone is extremely low, consisting primarily of cable insulation related to the six PCS valves and related PCS instrumentation. Portable fire extinguishers are provided on both the lower level (El. 264′-6″) and the upper level (El. 286′-6″) of the PCS valve room for manual fire fighting.
Fire Suppression System Design Basis			
21. Fire protection systems should retain their design capability for natural phenomena of less severity and greater frequency than the most severe natural phenomena.	C.1.c(4)	C	Structures housing the fire protection system meet the applicable requirements of Chapter 3 to provide protection from natural phenomena.
22. Fire protection systems should retain their original design capability for potential man-made, site-related events that have a reasonable probability of occurring at a specific plant site.	C.1.c(4)	WA C	To be evaluated on a site-specific basis. Plant siting decisions are expected to preclude the need to consider such events. Comply. Sections 2.2 and 3.5 establish that these events are not credible.
23. The effects of lightning strikes should be included in the overall plant fire protection program.	C.1.c(4)	C	Lightning protection will be provided per NFPA 780.
24. The consequences of inadvertent operation or of a crack in a moderate energy line in the fire suppression system should meet the guidelines specified for moderate energy systems outside containment in SRP Section 3.6.1.	C.1.c(5)	C	

Table 9.5.1-1 (Sheet 5 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
Alternate or Dedicated Shutdown			
25. Alternative or dedicated shutdown capability should be provided where the protection of systems whose functions are required for safe shutdown is not provided by established fire suppression methods or by Position C.5.b.	C.1.d	AC	In Generic Letter (GL) 86-10, the staff stated its position that, for the purpose of analysis to Section III.G.2 of Appendix R to 10 CFR Part 50 criteria, the safe shutdown capability is defined as one of the two normal safe shutdown trains. The safety-related PXS and PCS are used to achieve and maintain safe shutdown following a fire and are acceptable as an alternative/ dedicated shutdown method for fire areas where the normal shutdown systems have not been protected in accordance with the guidance prescribed in the BTP.
Fire Protection Program Implementation			
26. The fire protection program for buildings storing new reactor fuel and for adjacent fire areas that could affect the fuel storage area should be fully operational before fuel is received at the site.	C.1.e(1)	WA C	See Note 2 Comply. Subsection 9.5.1.8.1 addresses this requirement.
27. The fire protection program for an entire reactor unit should be fully operational prior to initial fuel loading in that unit.	C.1.e(2)	WA C	See Note 2 Comply. Subsection 9.5.1.8.1 addresses this requirement.
28. Special considerations for the fire protection program on reactor sites where there is an operating reactor and construction or modification of other units is under way.	C.1.e(3)	WA C	See Note 2 Comply. Subsection 9.5.1.8.1.2.m addresses this requirement.
29. Establishing administrative controls to maintain the performance of the fire protection system and personnel.	C.2	WA C	See Note 2 Comply as identified in Subsection 9.5.1.8.
Fire Brigade			
30. The guidance in Regulatory Guide 1.101 should be followed as applicable.	C.3.a	WA C	See Note 2 Comply. Subsection 9.5.1.8.2.2 addresses this requirement.

Table 9.5.1-1 (Sheet 6 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
31. Establishing site brigade: minimum number of fire brigade members on each shift; qualification of fire brigade members; competence of brigade leader.	C.3.b	WA C	See Note 2 Comply. Subsections 9.5.1.8.2.2 and 13.1.2.1.6 address this requirement.
32. The minimum equipment provided for the brigade should consist of turnout coats, boots, gloves, hard hats, emergency communications equipment, portable ventilation equipment, and portable extinguishers.	C.3.c	WA C	See Note 2 Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
33. Recommendations for breathing apparatus for fire brigade, damage control, and control room personnel.	C.3.c	C WA	Comply. Subsection 9.5.1.8.2.2 and Subsections 6.4.2.3 and 6.4.4 address these requirements. See Note 2. A breathing air compressor is provided in the compressed and instrument air system (CAS) to replenish the exhausted air supply bottles used by the fire brigade. Additionally, an equivalent 6-hour supply of reserve air (e.g., the 12 additional SCBA bottles) will be maintained in an area located outside of the turbine building. See Subsection 9.3.1 for further information.
34. Recommendations for the fire brigade training program.	C.3.d	WA C	See Note 2 Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
Quality Assurance Program			
35. Establishing quality assurance (QA) programs by applicants and contractors for the fire protection systems for safety-related areas; identification of specific criteria for quality assurance programs.	C.4	C WA	Comply. Subsection 9.5.1.7 and Chapter 17 address this requirement. Fire protection quality assurance programs are incorporated in procurement documents. Deviations are evaluated and controlled. See Items 1. through 11. of this table for on-site implementation. See Note 2.
Building Design			
36. Fire barriers with a minimum fire resistance rating of 3 hours should be provided to separate safety-related systems from any potential fires in nonsafety-related areas.	C.5.a(1)(a)	C	Structures housing safety-related systems are separated from nonsafety-related structures by 3-hour rated fire walls.

Table 9.5.1-1 (Sheet 7 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
37. Fire barriers with a minimum fire resistance rating of 3 hours should be provided to separate redundant divisions of safety-related systems from each other.	C.5.a(1)(b)	C	See Subsection 9.5.1.2.1.1 for discussion of exceptions for the containment, main control room, and remote shutdown room.
38. Fire barriers with a minimum fire resistance rating of 3 hours should be provided to separate individual units on a multiple-unit site.	C.5.a(1)(c)	NA	See discussion of GDC 5 in subsection 3.1.1. The AP1000 is a single-unit plant.
39. Fire barriers should be provided within a single safety division to separate components or cabling that present a fire hazard to other safety-related components.	C.5.a (2)	C	
40. Openings through fire barriers for pipe, conduit, and cable trays that separate fire areas should be sealed or closed to provide a fire resistance rating equal to that required of the barrier.	C.5.a (3)	C	
41. Recommendations for internal sealing of conduits penetrating fire barriers.	C.5.a (3)	C	
42. Fire barrier penetrations that must maintain environmental isolation or pressure differentials should be qualified by test.	C.5.a (3)	C	Fire penetration seals that also perform other barrier functions are qualified by test for intended functions. The fire barrier penetration seal does not perform other barrier functions simultaneously.
43. Penetration designs should use only noncombustible materials.	C.5.a (3)	AC	Fire seal materials meet the guidance of NUREG-1552. The seal design and tests demonstrate that the seals are capable of preventing the spread of fire and perform their intended safety function.

Table 9.5.1-1 (Sheet 8 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
44. The penetration qualification tests should use the time-temperature exposure curve specified by ASTM E-119.	C.5.a (3)	C	
45. Criteria for penetration qualification tests.	C.5.a (3)	AC	Qualification tests for penetration seals meet the acceptance criteria of this paragraph or the criteria of the industry standards accepted in NUREG-1552. In lieu of BTP CMEB 9.5-1 C.5.a(3)(b), RG 1.189 Rev. 1, Section 4.2.1.5b.ii is used: "The temperature levels recorded for the unexposed side of the fire barrier are analyzed and demonstrate that the maximum temperature does not exceed 163 °C (325 °F) or 121 °C (250 °F) above the ambient temperature. Higher temperatures at through-penetrations may be permitted when justified in terms of cable insulation ignitability."
46. Penetration openings for ventilation systems should be protected by fire dampers having a rating equivalent to that required of the barrier.	C.5.a (4)	C	Penetration openings are protected in accordance with NFPA 90A. Fire dampers generally not provided for roof or exterior wall penetrations. Two discharge openings from the Main Control Room Vestibule are not provided with fire dampers. See Subsection 9A.3.1.2.1.2 and 9A.3.1.2.5.1.
47. Flexible air duct couplings in ventilation and filter systems should be noncombustible.	C.5.a (4)	C	
48. Door openings in fire barriers should be protected with equivalently rated doors, frames, and hardware that have been tested and approved by a nationally recognized lab.	C.5.a (5)	C	
49. Fire doors should be self-closing or provided with closing mechanisms.	C.5.a (5)	C	
50. Fire doors should be inspected semiannually to verify that automatic hold-open, release, and closing mechanisms and latches are operable.	C.5.a (5)	WA C	See Note 2 Comply. Subsection 9.5.1.8.8 addresses this requirement.
51. Alternative means for verifying that fire doors protect the door opening as required in case of fire.	C.5.a (5)	WA C	See Note 2 Comply. Subsection 9.5.1.8.8 addresses this requirement.

Table 9.5.1-1 (Sheet 9 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
52. The fire brigade leader should have ready access to keys for any locked fire doors.	C.5.a (5)	WA C	See Note 2 Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
53. Areas protected by automatic total flooding gas suppression systems should have electrically supervised self-closing fire doors or should satisfy guideline (49) above.	C.5.a (5)	NA	No automatic gas suppression systems are used on AP1000.
54. Personnel access routes and escape routes should be provided for each fire area.	C.5.a (6)	C	

Table 9.5.1-1 (Sheet 10 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
55. Stairwells serving as escape routes, access routes for firefighting, or access routes to areas containing equipment necessary for safe shutdown should be enclosed in masonry or concrete towers with a minimum fire resistance rating of 2 hours and self-closing Class B fire doors.	C.5.a(6)	AC WA	AP1000 deviates from this guideline with a design that meets applicable building codes and fire protection requirements. Auxiliary building stairwells, with exception of the exterior wall sections enclosing Stairwell S03 above the auxiliary building roof, are enclosed in towers constructed using both concrete structural walls and nonstructural walls, consisting of a concrete/steel composite material, having a fire resistance rating of at least 2 hours, and self-closing doors, having a rating of 1.5 hours. Auxiliary building Stairwell S03 exterior wall sections enclosing the stairwell and elevator shaft above the auxiliary building roof do not have a fire resistance rating of 2 hours. Openings from the stairwell into the Auxiliary Building and Stair S06 at Elevation 256'-9" are protected with listed automatic or self-closing fire doors having a fire rating of at least 1.5 hours. For buildings outside of the Nuclear Island, exterior wall sections enclosing stairwells do not have a fire resistance rating of 2 hours, only interior stairwell wall sections are rated for the minimum 2 hour fire resistance rating. Openings in the interior stairwell wall sections are protected with listed automatic or self-closing fire doors having a fire protection rating of at least 1.5 hours.

Table 9.5.1-1 (Sheet 11 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
		C	The two-hour fire-resistance test data for the concrete/steel composite material is in accordance with ASTM E-119 and NFPA 251 acceptance criteria to ensure that the stairwell fire-related enclosure will be maintained in accordance with Regulatory Position C.5.a.6 of BTP CMEB 9.5-1. There are no missile hazards in the vicinity of such stairwells. This alternative protection provides an equivalent level of safety as that prescribed in the BTP. Comply. Subsection 9A.3.3 addresses this requirement for miscellaneous buildings located in the yard.
56. Fire exit routes should be clearly marked.	C.5.a (7)	WA C	See Note 2 Comply. Subsection 9.5.1.2.1.1 addresses this requirement.
57. Each cable spreading room should contain only one redundant safety division.	C.5.a (8)	NA	There are no cable spreading rooms in AP1000.
58. Cable spreading rooms should be separated from each other and from other areas of the plant by barriers having a minimum fire resistance of 3 hours.	C.5.a (8)	NA	There are no cable spreading rooms in AP1000.
59. Interior wall and structural components, thermal insulation materials, radiation shielding materials, and soundproofing materials should be noncombustible.	C.5.a (9)	C	
60. Interior finishes should be noncombustible.	C.5.a (9)	C	
61. Metal deck roof construction should be noncombustible and listed as "acceptable for fire" in the UL Building Materials Directory, or listed as Class I in the Factory Mutual Approval Guide.	C.5.a (10)	C	
62. Suspended ceilings and their supports should be of noncombustible construction.	C.5.a (11)	C	

Table 9.5.1-1 (Sheet 12 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
63. Concealed spaces should be devoid of combustibles except as noted in Position C.6.b.	C.5.a(11)	AC	Underfloor or ceiling spaces, contain combustible cable insulation in the main control room, control support area and remote shutdown room. Fire detectors are provided in these areas. The insulating and jacketing materials for the cables used in the plant are qualified in accordance with the criteria specified in IEEE Standard 1202, IEEE Standard 383, or the standards for the corresponding test types as listed in Table K-1 and K-2 in NEI 04-02, Rev 3. This alternative protection provides an equivalent level of safety as that specified in the BTP.
64. Transformers installed inside fire areas containing safety-related systems should be of the dry type or insulated and cooled with noncombustible liquid.	C.5.a(12)	C	
65. Outdoor oil-filled transformers should have oil containment features or drainage away from the buildings.	C.5.a(13)	C	
66. Outdoor oil-filled transformers should be located at least 50 feet distant from the building, or building walls within 50 feet of oil-filled transformers should be without openings and have a 3-hour fire resistance rating.	C.5.a (13)	C	
67. Floor drains sized to remove expected firefighting water flow without flooding safety-related equipment should be provided in areas where fixed water fire suppression systems are installed.	C.5.a (14)	C	
68. Floor drains should be provided in areas where hand hose lines may be used if such firefighting water could cause unacceptable damage to safety-related equipment.	C.5.a (14)	C	
69. Where gas suppression systems are installed, the drains should be provided with adequate seals, or the gas suppression system should be sized to compensate for the loss of the suppression agent through the drains.	C.5.a (14)	NA	No fixed gas suppression systems are used on AP1000.

Table 9.5.1-1 (Sheet 13 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
70. Drains in areas containing combustible liquids should have provisions for preventing the back flow of combustible liquids to safety-related areas through the interconnected drain systems.	C.5.a (14)	C	
71. Water drainage from areas that may contain radioactivity should be collected, sampled, and analyzed before discharge to the environment.	C.5.a(14)	WA C	See Note 2. Capability is provided. Comply. Capability is provided. Subsection 9.5.1.8.5 addresses this requirement.
Safe Shutdown Capability			
72. Fire damage should be limited so that one train of systems necessary to achieve and maintain hot shutdown conditions from either the main control room or emergency control station is free of fire damage.	C.5.b(1)	C	
73. Fire damage should be limited so that systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station can be repaired within 72 hours.	C.5.b (1)	AC	Safe shutdown following a fire is defined for the AP1000 plant as the ability to achieve and maintain the reactor coolant system (RCS) core average temperature below 215.6°C (420°F) without uncontrolled venting of the primary coolant from the RCS. This is a departure from the criteria applied to the evolutionary plant designs, and the existing plants where safe shutdown for fires applies to both hot and cold shutdown capability. With expected RCS leakage, the AP1000 plant can maintain safe shutdown conditions for greater than 14 days. Therefore, repairs to systems necessary to reach cold shutdown need not be completed within 72 hours.

Table 9.5.1-1 (Sheet 14 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
74. Separation requirements for verifying that one train of systems necessary to achieve and maintain hot shutdown is free of fire damage.	C.5.b (2)	C	
75. Provision of alternative or dedicated shutdown capability in certain fire areas.	C.5.b (3)	AC	In Generic Letter (GL) 86-10, the staff stated its position that, for the purpose of analysis to Section III.G.2 of Appendix R to 10 CFR Part 50 criteria, the safe shutdown capability is defined as one of the two normal safe shutdown trains. The safety-related PXS and PCS are used to achieve and maintain safe shutdown following a fire and are acceptable as an alternative/ dedicated shutdown method for fire areas where the normal shutdown systems have not been protected in accordance with the guidance prescribed in the BTP.

Table 9.5.1-1 (Sheet 15 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
76. Alternative or dedicated shutdown capability.	C.5.c	AC	In Generic Letter (GL) 86-10, the staff stated its position that, for the purpose of analysis to Section III.G.2 of Appendix R to 10 CFR Part 50 criteria, the safe shutdown capability is defined as one of the two normal safe shutdown trains. The safety-related PXS and PCS are used to achieve and maintain safe shutdown following a fire and are acceptable as an alternative/ dedicated shutdown method for fire areas where the normal shutdown systems have not been protected in accordance with the guidance prescribed in the BTP. The criteria concerning cold shutdown capability deviates from the criteria applied to the evolutionary reactor designs, but is consistent with the criteria applicable to existing plants. To enhance the survivability of the normal safe shutdown and cold shutdown capability in the event of a fire, and to reduce the reliance on the infrequently utilized safety-related passive systems, automatic suppression or physical separation is provided in those fire areas outside containment where a fire could damage the normal shutdown capability. This criterion does not ensure that the normal shutdown capability will be free of fire damage, or that the equipment necessary to achieve and maintain cold shutdown can be repaired within 72 hours.

Table 9.5.1-1 (Sheet 16 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
Control of Combustibles			
77. Safety-related systems should be separated from combustible materials where possible; where not possible, special protection should be provided to help prevent a fire from defeating the safety system function.	C.5.d (1)	C	Concentrations of combustible materials are located outside structures containing safety-related components. Where this is not possible, appropriate fire protection is provided (see Appendix 9A).
78. Bulk gas storage (compressed or cryogenic) should not be permitted inside structures housing safety-related equipment. Flammable gases should be stored outdoors or in separate detached buildings.	C.5.d (2)	AC	Breathing air storage tanks for the main control room habitability system are safety-related and are provided with overpressure protection. There is no other bulk gas storage in structures housing safety-related equipment.
79. High pressure gas storage containers should be located with the long axis parallel to building walls.	C.5.d (2)	C	
80. Use of compressed gases inside buildings should be controlled.	C.5.d (2)	WA C	See Note 2 Comply. Subsection 9.5.1.8.4.g addresses this requirement.
81. The use of plastic materials should be minimized. Halogenated plastics such as polyvinyl chloride (PVC) and neoprene should be used only when substitute noncombustible materials are not available.	C.5.d (3)	C	
82. Storage of flammable liquids should comply with NFPA 30.	C.5.d (4)	C	See Note 3
83. Hydrogen lines in safety-related areas should be either designed to seismic Category I requirements, or sleeved, or equipped with excess flow valves.	C.5.d (5)	C	Hydrogen lines in safety-related areas are designed to seismic Category I requirements.
Electrical Cable Construction, Cable Trays, and Cable Penetrations			
84. Only metal should be used for cable trays.	C.5.e (1)	C	Cable trays are of all-metal construction.
85. Only metallic tubing should be used for conduit. Thin-wall metallic tubing should not be used.	C.5.e (1)	C	Conduit that is not buried or embedded in concrete is metallic.
86. Flexible metallic tubing should only be used in short lengths to connect components to equipment.	C.5.e (1)	C	
87. Other raceways should be made of noncombustible materials.	C.5.e (1)	C	

Table 9.5.1-1 (Sheet 17 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
88. Redundant safety-related cable systems outside the cable spreading room should be separated from each other and from potential fire exposure hazards in nonsafety-related areas by 3-hour rated fire barriers.	C.5.e (2)	C	
89. These cable trays should be provided with continuous line-type heat detectors.	C.5.e (2)	C	
90. Cables should be designed to allow wetting down with fire suppression water without electrical faulting.	C.5.e (2)	C	
91. Redundant cable trays that route safety-related cables outside the cable spreading room should be accessible for manual firefighting. Manual hose stations and portable hand extinguishers should be provided.	C.5.e (2)	C	
92. Cable trays that route safety-related cables of a single division, which are separated from redundant divisions by a 3-hour rated fire barrier and are accessible for manual firefighting, should be protected from the effects of a potential exposure fire by providing automatic water suppression, unless specific conditions are met.	C.5.e (2)	C	Automatic water suppression is not provided because there is no significant exposure fire hazards and the specified conditions are met.
93. Cable trays that route safety-related cables that are not accessible for manual firefighting should be protected by an automatic water system.	C.5.e (2)	AC	Cable trays that route safety-related cables outside containment are accessible for manual firefighting. Protection of safe shutdown components inside containment is discussed in Appendix 9A.
94. Cable trays that route safety-related cables that are not separated from redundant divisions by 3-hour rated fire barriers should be protected by automatic water suppression systems.	C.5.e (2)	AC	Protection of safe shutdown components inside containment and the main control room is discussed in Appendix 9A.
95. In areas where 3-hour fire barrier separation of redundant cable systems is precluded by overriding design considerations, the capability to achieve safe shutdown considering the effects of a fire involving fixed and transient combustibles should be evaluated with and without actuation of the automatic suppression system.	C.5.e (2)	C	
96. Electric cable construction should pass the flame test in IEEE Std 383.	C.5.e (3)	C	Use IEEE Standard 1202, IEEE Standard 383, or the standards for the corresponding test types as listed in Tables K-1 and K-2 in NEI 04-02, Rev 3 excluding the option to use the alternate flame source, oil, or burlap.
97. Cable raceways should be used only for cables.	C.5.e (4)	C	

Table 9.5.1-1 (Sheet 18 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
98. Miscellaneous storage and piping for combustible liquids or gases should not create a potential exposure hazard to safety-related systems.	C.5.e (5)	C	
Ventilation			
99. Smoke and corrosive gases should be discharged directly outside to an area that will not affect safety-related plant areas.	C.5.f (1)	C	
100. To facilitate manual firefighting, separate smoke and heat vents should be provided in certain areas.	C.5.f (1)	C	Smoke and heat venting capability is provided as described in Appendix 9A.
101. Release of smoke and gases containing radioactive materials to the environment should be monitored.	C.5.f (2)	C	
102. Any ventilation system designed to exhaust potentially radioactive smoke or gases should be evaluated to verify that inadvertent operation or single failures will not violate the radiologically controlled areas of the plant.	C.5.f (2)	C	
103. The power supply and control for mechanical ventilation systems should be run outside the fire area served by the system.	C.5.f (3)	C	
104. Engineered safety feature filters should be protected in accordance with the guidelines of Regulatory Guide 1.52.	C.5.f (4)	C	
105. Air intakes for ventilation systems serving areas containing safety-related equipment should be located remote from the exhaust air outlets and smoke vents of other fire areas.	C.5.f (5)	C	
106. Stairwells should be designed to minimize smoke infiltration during a fire.	C.5.f (6)	C	Stair towers are provided with self-closing doors. Additional measures to minimize smoke infiltration to stair-wells are described in Appendix 9A.
107. Where total flooding gas extinguishing systems are used, ventilation dampers should be controlled in accordance with NFPA 12 and NFPA 12A.	C.5.f (7)	NA	Fixed flooding gas suppression systems are not used on AP1000.

Table 9.5.1-1 (Sheet 19 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
Lighting and Communication			
108. Fixed self-contained lighting units with individual 8-hour battery power supplies should be provided in areas that must be manned for safe shutdown and for access and egress routes to and from all fire areas.	C.5.g (1)	AC	Alternate emergency lighting is provided for the main control room and the remote shutdown workstation as described in Subsection 9.5.3. Emergency lighting in other plant areas is provided by 8-hour battery-powered, fixed, self-contained units to provide safe ingress and egress of personnel and the operation of equipment following a fire, in the event of a loss of the normal lighting. Portable battery-powered lighting is provided for emergency use by plant personnel.
109. Sealed beam battery-powered portable hand lights should be provided for emergency use.	C.5.g (2)	C	
110. Fixed emergency communications, independent of the normal plant communication system, should be installed at preselected stations.	C.5.g (3)	C	
111. A portable radio communications system should be provided for use by the fire brigade and other operations personnel required to achieve safe plant shutdown.	C.5.g (4)	WA C	Comply. Subsections 9.5.1.8.1.2.a.3.v, 9.5.1.8.2.2, and Subsection 9.5.2 address this requirement.
Fire Detection			
112. Fire detection systems should be provided for areas that contain or present a fire exposure to safety-related equipment.	C.6.a (1)	C	
113. Fire detection systems should comply with the requirements of Class A systems as defined in NFPA 72D and Class I circuits as defined in NFPA 70.	C.6.a (2)	C	See Note 3
114. Fire detectors should be selected and installed in accordance with NFPA 72E.	C.6.a (3)	C	See Note 3
115. Testing of pulsed line-type heat detectors should demonstrate that the frequencies used will not affect the actuation of protective relays in other plant systems.	C.6.a (3)	C	
116. Fire detection systems should give audible and visual alarm and annunciation in the main control room.	C.6.a (4)	C	
117. Where zoned detection systems are used in a given fire area, local means should be provided to identify which zone has actuated.	C.6.a (4)	C	

Table 9.5.1-1 (Sheet 20 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
118. Local audible alarms should sound in the fire area.	C.6.a(4)	C	
119. Fire alarms should be distinctive and unique so they will not be confused with any other plant system alarms.	C.6.a (5)	C	
120. Primary and secondary power supplies, which satisfy the provisions of Section 2220 of NFPA 72D, should be provided for the fire detection system and for electrically operated control valves for automatic suppression systems.	C.6.a (6)	C	See Note 3
Fire Protection Water Supply Systems			
121. An underground yard fire main loop should be installed to furnish anticipated water requirements.	C.6.b (1)	C	An underground yard fire main loop is provided in accordance with NFPA 24.
122. Type of pipe and water treatment should be design considerations with tuberculation as one of the parameters.	C.6.b (1)	C	
123. Means of inspecting and flushing the systems should be provided.	C.6.b (1)	C	Flushing of the loop can be accomplished through the use of sectional control valves to direct the flow and yard hydrants to serve as discharge points.
124. Approved visually indicating sectional control valves should be provided to isolate portions of the yard fire main loop for maintenance or repair.	C.6.b (2)	C	Indicator valves are provided for sectionalized control and isolation of portions of the yard fire main loop.
125. Valves should be installed to permit isolation of outside hydrants from the fire main for maintenance or repair without interrupting the water supply to automatic or manual fire suppression systems.	C.6.b (3)	C	A visually indicating or key-operated valve is provided in each lateral from the yard fire main loop to a fire hydrant.
126. The fire main system piping should be separate from service or sanitary water system piping.	C.6.b (4)	C	
127. A common yard fire main loop may serve multi-unit nuclear power plant sites if cross-connected between units. Sectional control valves should permit maintaining independence of the loop around each unit.	C.6.b (5)	NA	See discussion of GDC 5 in subsection 3.1.1. The AP1000 is a single-unit plant.
128. A sufficient number of pumps should be provided so that 100 percent capacity will be available assuming failure of the largest pump or loss of offsite power.	C.6.b (6)	C	Two 100 percent capacity fire pumps (one diesel-driven and one electric motor-driven) are provided.
129. Individual fire pump connections to the yard fire main loop should be separated with sectionalizing valves between connections.	C.6.b (6)	C	
130. Each pump and its driver and controls should be separated from the remaining fire pumps by a 3-hour rated fire wall.	C.6.b (6)	C	

Table 9.5.1-1 (Sheet 21 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
131. The fuel for the diesel fire pump should be separated so that it does not provide a fire source exposing safety-related equipment.	C.6.b (6)	C	
132. Alarms indicating pump running, driver availability, failure to start, and low fire main pressure should be provided in the main control room.	C.6.b (6)	C	
133. The fire pump installation should conform to NFPA 20.	C.6.b (6)	C	See Note 3
134. Outside manual hose installation should be sufficient to provide an effective hose stream to any onsite location where fixed or transient combustibles could jeopardize safety-related equipment. Hydrants should be installed approximately every 250 feet on the yard main system.	C.6.b (7)	C	
135. Recommendations for hose houses and hose carts.	C.6.b (7)	C	
136. Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings, and standpipe risers.	C.6.b (8)	C	
137. Two separate, reliable freshwater supplies should be provided.	C.6.b (9)	C	Two water storage tanks are provided.
138. Recommendations for tanks used to supply fire protection water.	C.6.b (9)	C	See Note 3
139. Recommendations for common tank used to supply fire protection water and other system.	C.6.b (10)	C	The configuration of the water supply for the seismic standpipe system is described in Subsection 9.5.1.2.1. Both fire water supply tanks have a water volume that is dedicated for fire protection purposes. The fire pumps can be aligned through normally closed valves or through temporary connections to supply water for post-accident services. These include refilling of the passive containment cooling water supply tank or supplying the containment spray following a severe accident. This provides adequate defense in depth and will not adversely affect the performance of the fire protection water supply.
140. The fire water supply should be based on the largest expected flow rate for a period of 2 hours, but not less than 300,000 gallons.	C.6.b (11)	C	

Table 9.5.1-1 (Sheet 22 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
141. The fire water supply should be capable of delivering the design demand over the longest route of the water supply systems.	C.6.b (11)	AC	Note that in a single loop main configuration, the longest path and the hydraulically least demanding path being out of service are the same. The NFPA 804 requirement allows for a multiple loop configuration for the fire protection system main. Since the AP1000 has a multiple loop fire water main configuration, the longest path described in BTP CMEB 9.5-1 would require multiple impairments to the fire water main loop. The AP1000 fire protection supply is designed to supply the largest demand with the hydraulically least demanding path out-of-service.
142. Recommendations for freshwater lakes or ponds used to supply fire protection water.	C.6.b (12)	NA	Lakes or ponds are not utilized for fire protection water supply.
143. Recommendations concerning use of a common water supply for fire protection and the ultimate heat sink.	C.6.b (13)	C	
144. Recommendations concerning use of other water systems as the source of fire protection water.	C.6.b (14)	NA	The fire protection system does not rely on the operation of another water system as a second water source.
Water Sprinkler and Hose Standpipe Systems			
145. Recommendations concerning connection of sprinkler systems and manual hose station standpipes to the yard fire main loop.	C.6.c (1)	AC	See remarks for Guideline 19.
146. Each sprinkler and standpipe system should be equipped with OS&Y gate valve or other approved shutoff valve and waterflow alarm.	C.6.c (1)	C	Waterflow alarms are provided for sprinkler and seismic standpipe systems only.
147. Safety-related equipment should be protected from sprinkler discharge if such discharge could result in unacceptable damage to the equipment.	C.6.c (1)	C	
148. Control and sectionalizing valves in the fire water systems should be electrically supervised (with indication in the main control room) or administratively controlled.	C.6.c (2)	C	
149. All valves in the fire protection system should be periodically checked to verify position.	C.6.c (2)	WA C	See Note 2 Comply. Subsection 9.5.1.8.6 addresses this requirement.

Table 9.5.1-1 (Sheet 23 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
150. Fixed water extinguishing systems should conform to requirements of NFPA 13 and NFPA 15.	C.6.c (3)	AC	Automatic sprinkler systems are designed and installed in accordance with the criteria specified in NFPA 13, with the exception of providing individual fire department connections to each sprinkler system. Because the sprinkler systems are supplied by the plant's fire protection water supply, individual connections are not necessary. See Note 3 and also Table 9.5.1-3.
151. Recommendations for interior manual hose installations.	C.6.c (4)	C	
152. Individual standpipes should be at least 4 inches in diameter for multiple hose connections and 2-1/2 inches in diameter for single hose connections.	C.6.c (4)	C	
153. Standpipe and hose station installations should follow the requirements of NFPA 14.	C.6.c (4)	AC	Standpipes for each building are designed and installed in accordance with the criteria specified in NFPA 14 for Class III service except: (1) the water supply to the standpipe inside containment is manually operated, which is an exception to this standard, and (2) the containment isolation valves controlling the water supply to standpipes inside containment are not listed by independent testing laboratories for fire protection service, which is an equivalency to this standard. These deviations will not adversely affect the performance of the hose station and standpipe system. See Note 3 and also Table 9.5.1-3.
154. Hose stations should be located as dictated by the fire hazard analysis to facilitate access and use for firefighting operations.	C.6.c (4)	C	
155. Recommendations concerning seismic design of standpipes and hose connections.	C.6.c (4)	C	
156. Recommendations concerning hose nozzle selection.	C.6.c (5)	C	

Table 9.5.1-1 (Sheet 24 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
157. The fire hose should be hydrostatically tested in accordance with NFPA 1962. Hoses stored in outside hose houses should be tested annually. The interior standpipe hose should be tested every 3 years.	C.6.c (6)	WA C	See Note 2 Comply. Subsection 9.5.1.8.6 addresses this requirement.
158. Consideration of foam suppression systems for flammable liquid fires.	C.6.c (7)	NA	Foam suppression systems are not used on AP1000.
Halon Suppression Systems			
159. Design and testing considerations for Halon fire suppression systems.	C.6.d	NA	Fixed Halon fire suppression systems are not used on AP1000.
Carbon Dioxide Suppression Systems			
160. Carbon dioxide suppression systems should comply with the requirements of NFPA 12.	C.6.e	NA	Fixed carbon dioxide suppression systems are not used on AP1000.
161. Automatic carbon dioxide systems should be equipped with a predischarge alarm system and a discharge delay to permit personnel egress.	C.6.e	NA	Fixed carbon dioxide suppression systems are not used on AP1000.
162. Provisions for locally disarming automatic carbon dioxide systems should be key locked and under administrative control. Disarming of systems should be controlled as described in Position C.2.	C.6.e	NA	Fixed carbon dioxide suppression systems are not used on AP1000.
163. Considerations for design of carbon dioxide suppression systems.	C.6.e	NA	Fixed carbon dioxide suppression systems are not used on AP1000.
Portable Extinguishers			
164. Fire extinguishers should be provided in areas that contain, or could present a fire exposure hazard to, safety-related equipment in accordance with NFPA 10.	C.6.f	C	See Note 3
165. Dry chemical extinguishers should be installed with due consideration given to possible adverse effects on safety-related equipment.	C.6.f	C	
Primary and Secondary Containment			
166. Fire protection for the primary and secondary containment areas should be provided for hazards identified by the fire protection analysis.	C.7.a (1)	C	Fires are identified and fire suppression systems are provided accordingly.
167. Because of the general inaccessibility of primary containment during normal plant operation, protection should be provided by automatic fixed systems.	C.7.a (1)	AC	No automatic suppression systems are needed due to the sealless motor reactor coolant pumps (RCPs) having no external lube oil system. Automatic suppression is provided in one fire zone as described in Appendix 9A.

Table 9.5.1-1 (Sheet 25 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
168. Operation of the fire protection systems should not compromise the integrity of the containment or other safety-related systems.	C.7.a(1)(a)	C	
169. Recommendations for protection of safety-related cables and equipment inside non-inerted containments.	C.7.a(1)(b)	AC	See Appendix 9A for a description of protection inside containment.
170. Recommendations concerning fire detection inside the primary containment.	C.7.a(1)©	C	
171. Standpipe and hose stations inside containment may be connected to a high quality water supply of sufficient quantity and pressure other than the fire main loop if plant-specific features prevent extending the fire main supply inside containment.	C.7.a(1)(d)	C	
172. Recommendations for reactor coolant pump oil collection systems in non-inerted containments.	C.7.a(1)(e)	NA	The reactor coolant pumps are sealless motor pumps and do not require an oil collection system.
173. For secondary containment areas, cable fire hazards that could affect safety should be protected as described in Position C.5.e.(2).	C.7.a (1)(f)	NA	
174. Self-contained breathing apparatus should be provided near the containment entrances for firefighting and damage control personnel. These units should be independent of any breathing apparatus provided for general plant activities.	C.7.a (2)	WA C	See Note 2 Comply. Subsection 9.5.1.8.2.2 addresses this requirement.
Main Control Room Complex			
175. The main control room complex should be separated from other areas of the plant by 3-hour rated fire barriers.	C.7.b	C	
176. Recommendations concerning peripheral rooms in the main control room complex.	C.7.b	NC	The MCR/operator work area wall is not fire-rated based on other design criteria. Manual fire suppression is provided for peripheral rooms. If the MCR must be evacuated, the remote shutdown workstation is provided as an alternate to the MCR.See Appendix 9A.
177. Recommendations concerning the use of Halon and carbon dioxide flooding systems.	C.7.b	NA	No Halon or carbon dioxide flooding systems are used on AP1000.
178. Recommendations concerning manual firefighting capability in the main control room.	C.7.b	C	

Table 9.5.1-1 (Sheet 26 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp(1)	Remarks
179. Recommendations concerning fire detection in the main control room.	C.7.b	NC	Smoke detectors are not provided in cabinets and consoles. The control room is continuously occupied so that a fire is promptly detected and extinguished.
180. Breathing apparatus for main control room operators should be readily available.	C.7.b	WA C	See Note 2 Comply. Subsection 6.4.2.3 addresses this requirement.
181. Recommendations concerning main control room ventilation.	C.7.b	C	
182. Cables that enter the main control room should terminate in the main control room.	C.7.b	C	
183. Cables in underfloor and ceiling spaces should meet the separation criteria necessary for fire protection.	C.7.b	C	
184. Air-handling functions should be ducted separately from cable runs in such spaces.	C.7.b	NC	The underfloor space is used as a distribution plenum for ventilation of the main control room. Smoke detectors in the underfloor space cause prompt closure of combination fire/smoke dampers to shut off air flow.
185. Fully enclosed electrical raceways located in underfloor and ceiling spaces, if over 1 ft^2 in cross-sectional area, should have automatic fire suppression inside.	C.7.b	NA	AP1000 does not have enclosed raceways in the control complex with a cross-sectional area greater than 1 ft^2.
186. Recommendations concerning automatic fire suppression in underfloor and ceiling spaces.	C.7.b	NC	Manual fire suppression is to be used for underfloor and ceiling spaces. The control room is continuously occupied so that a fire is promptly detected and extinguished.
187. There should be no carpeting in the control room.	C.7.b	AC	Carpeting will be installed in the MCR for sound abatement as allowed per the guidance of Revision 1 of RG 1.189. Per the guidelines, the carpeting will be tested to standards such as ASTM D2859, “Standard Test Method for Flammability of Finished Textile Floor Covering Materials,” to establish the flammability characteristics of the material. These characteristics are addressed in the fire hazards analysis.

Table 9.5.1-1 (Sheet 27 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
Cable Spreading Room			
188. Design guidelines for the cable spreading room.	C.7.c	NA	There is no cable spreading room in AP1000.
189. Recommendations concerning fire protection for computers performing safety-related functions.	C.7.d	C	The data display and processing system does not perform safety-related functions.
190. Nonsafety-related computers outside the control room should be separated from safety-related areas by 3-hour rated fire barriers and should be protected as needed to prevent damage to safety-related equipment.	C.7.d	C	

Table 9.5.1-1 (Sheet 28 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
Switchgear Rooms			
191. Switchgear rooms containing safety-related equipment should be separated from the remainder of the plant by 3-hour rated fire barriers. Redundant switchgear safety divisions should be separated from each other by 3-hour rated fire barriers.	C.7.e	C	The electrical equipment and penetration rooms associated with each safety-related division are separated from the rooms associated with other divisions and from the remaining areas of the plant by 3-hour rated fire barriers.
192. Automatic fire detectors should alarm locally and alarm and annunciate in the main control room.	C.7.e	C	
193. Fire hose stations and portable fire extinguishers should be readily available outside the switchgear rooms.	C.7.e	C	
194. Drains should be provided to prevent water accumulation from damaging safety-related equipment.	C.7.e	C	
195. Remote manually actuated ventilation should be provided for venting smoke when manual fire suppression effort is needed.	C.7.e	C	See Subsection 9.4.1 for a description of smoke removal capability for Class 1E equipment rooms.
Remote Safety-Related Panels			
196. Recommendations concerning separation and electrical isolation of remote safety-related panels.	C.7.f	C	
197. The general area housing remote safety-related panels should be provided with automatic fire detectors that alarm locally and alarm and annunciate in the main control room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be readily available in the general area.	C.7.f	C	
Safety-Related Battery Rooms			
198. Safety-related battery rooms should be separated from each other and other areas of the plant by 3-hour rated fire barriers.	C.7.g	C	Safety-related battery rooms are separated from associated electrical rooms of the same division by 1-hour rated fire barriers.
199. Dc switchgear and inverters should not be located in safety-related battery rooms.	C.7.g	C	
200. Automatic fire detection should be provided to alarm locally and annunciate in the main control room.	C.7.g	C	
201. Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration below 2 percent.	C.7.g	C	

Table 9.5.1-1 (Sheet 29 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
202. Main loss of ventilation should be alarmed in the main control room.	C.7.g	C	
203. Portable extinguishers and manual hose stations should be readily available outside the battery rooms.	C.7.g	C	
Turbine Building			
204. The turbine building should be separated from adjacent structures containing safety-related equipment by 3-hour rated fire barriers.	C.7.h	C	
205. The fire barriers should be designed to maintain structural integrity in the event of collapse of the turbine structure.	C.7.h	C	
206. Openings and penetrations in the fire barrier should be minimized and should not be located where the turbine oil system or generator hydrogen cooling system creates a fire exposure hazard to the barrier.	C.7.h	C	
Diesel Generator Areas			
207. Diesel generators should be separated from each other and from other areas of the plant by 3-hour rated fire barriers.	C.7.i	AC	The standby diesel generators are separated from each other by a 3-hour rated fire barrier and are housed in a separate structure, remote from safety-related areas. The ancillary diesel generators are separated from other areas of the plant by 3-hour rated fire barriers. The ancillary diesel generators are not separated from each other, but can be easily replaced with transportable diesel generators.
208. Automatic fire suppression should be installed to combat diesel generator or lubricating oil fires. Such systems should be designed for operation when the diesel is running without affecting the diesel.	C.7.i	C	
209. Automatic fire detection should be provided to alarm locally and annunciate in the main control room.	C.7.i	C	
210. Portable extinguishers and manual hose stations should be readily available outside the area.	C.7.i	C	
211. Drainage for firefighting water and means for local manual venting of smoke should be provided.	C.7.i	C	

Table 9.5.1-1 (Sheet 30 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
Diesel Fuel Oil Storage Areas			
212. Day tanks with total capacity up to 1100 gallons are permitted in the diesel generator area under specified conditions.	C.7.i	NC	Each DG day tank has a total capacity of up to 2000 gallons. Separate 3-hour enclosures and automatic suppression are provided. Tanks are located more than 50 feet from buildings containing safety-related equipment.
213. The day tank should be located in a separate enclosure with a 3-hour fire rating.	C.7.i	AC	The fuel supply for the ancillary diesel generators is not separated from the diesels by a barrier. The ancillary diesels and the tank are separated from the rest of the plant by an enclosure with a 3-hour fire rating.
214. The day tank enclosure should be capable of containing the entire contents of the tank.	C.7.i	C	
215. The day tank enclosure should be protected by an automatic fire suppression system.	C.7.i	C	
216. Recommendations concerning diesel fuel oil tanks.	C.7.j	C	
217. Above-ground tanks should be protected by an automatic fire suppression system.	C.7.j	AC	The diesel fuel oil storage tanks are well-separated from each other and from safety-related structures. Automatic fire suppression systems are not provided.
Safety Related Pumps			
218. Design guidelines for safety-related pump rooms.	C.7.k	NA	There are no active ASME Section III safety-related pumps on AP1000.
New Fuel Area			
219. Recommendations for fire protection of the new fuel area.	C.7.l	C	
Cooling Towers			
Spent Fuel Pool Areas			
220. Protection should be provided by hose stations and portable extinguishers.	C.7.m	C	
221. Automatic fire detection should be provided to alarm locally and annunciate in the main control room.	C.7.m	C	

Table 9.5.1-1 (Sheet 31 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[(1)]	Remarks
Radwaste and Decontamination Areas			
222. Fire barriers, automatic fire suppression and detection, and ventilation controls should be provided.	C.7.n	C	Automatic fire suppression is provided for specific areas in accordance with the fire protection analysis.
Safety-Related Water Tanks			
223. Fire protection provisions for safety-related water tanks.	C.7.o	C	
Records Storage Areas			
224. Records storage areas should be so located and protected that a fire in these areas does not expose safety-related systems or equipment.	C.7.p	C	
225. Cooling towers should be of noncombustible construction or so located and protected that a fire will not adversely affect any safety-related systems or equipment.	C.7.q	WA C	The cooling tower configuration is site-specific. See Note 2 Comply. Subsection 9A.3.3 addresses this requirement.
226. Cooling towers should be of noncombustible construction when the basins are used for the ultimate heat sink or for the fire protection water supply.	C.7.q	NA	The cooling tower basin is not used for an ultimate heat sink or as a source of fire water.
Miscellaneous Areas			
227. Location and protection of miscellaneous areas.	C.7.r	C	
Storage of Acetylene-Oxygen Fuel Gases			
228. Gas cylinder storage locations should not be in areas that contain or expose safety-related equipment or the fire protection systems that serve those safety-related areas.	C.8.a	WA C	See Note 2 Comply. Subsection 9.5.1.8.4.g addresses this requirement.
229. A permit system should be required to use this equipment in safety-related areas of the plant.	C.8.a	WA C	See Note 2 Comply. Subsection 9.5.1.8.4.g addresses this requirement.
Storage Areas for Ion Exchange Resins			
230. Unused ion exchange resins should not be stored in areas that contain or expose safety-related equipment.	C.8.b	WA C	See Note 2 Comply. Subsection 9.5.1.8.4.a addresses this requirement.
Hazardous Chemicals			
231. Hazardous chemicals should not be stored in areas that contain or expose safety-related equipment.	C.8.c	WA C	See Note 2 Comply. Subsection 9.5.1.8.4.h addresses this requirement.

Table 9.5.1-1 (Sheet 32 of 32)
AP1000 Fire Protection Program Compliance With BTP CMEB 9.5-1

BTP CMEB 9.5-1 Guideline	Paragraph	Comp[1]	Remarks
Materials Containing Radioactivity			
232. Materials that collect and contain radioactivity should be stored in closed metal tanks or containers that are located in areas free from ignition sources or combustibles.	C.8.d	C	
233. These materials should be protected from exposure to fires in adjacent areas.	C.8.d	C	
234. Consideration should be given to requirements for removal of decay heat from entrained radioactive materials.	C.8.d	C	
235. Reference Code Years	References	AC	More recent editions of the codes are acceptable upon approved technical documentation that demonstrates equivalency of the alternative standard, system, method, or device.

Notes:

1. Compliance with NUREG-0800 Subsection 9.5.1, Branch Technical Position CMEB 9.5-1 is indicated by the following codes:
   - WA - Will Address: Per Subsection 9.5.1.9.3.
   - C - Compliance: AP1000 is committed to compliance with the guideline.
   - AC - Alternate Compliance: compliance with the guideline by alternate means or intent. Alternative means or design are provided in the remarks column.
   - N/A - Not Applicable: The guideline is not applicable to AP1000.
   - NC - Not in Compliance: AP1000 is not in compliance (explanations in the remarks column.)
2. Procedures and administrative controls governing the fire protection program during plant operation, as well as responsibilities and organizational details for personnel involved in fire protection activities, are discussed in subsection 9.5.1.8.
3. It is intended to fully comply with NFPA standards referenced in Subsection 9.5.5, as they apply to AP1000. However, due to conflicting design considerations, there may be a need to take exception to specific guidance. Known exceptions to the design portions of the NFPA standards are identified in Table 9.5.1-3.

Table 9.5.1-2
Component Data - Fire Protection System
(Nominal Values)

Fire Water Storage Tanks	
Primary Fire Water Tank	
Nominal capacity (gal)	504,000
Volume dedicated to fire protection (gal)	396,000
Design Pressure	Atmospheric
Material	Carbon steel
Secondary Fire Water Tank	
Nominal capacity (gal)	504,000
Volume dedicated to fire protection (gal)	396,000
Design Pressure	Atmospheric
Material	Carbon steel
Fire Pumps	
Motor-Driven	
Pump type	Horizontal centrifugal
Rated flow (gpm)	2000
Required head, approximate (ft)	350
Structural material	Cast iron
Diesel-Driven	
Pump type	Horizontal centrifugal
Rated flow (gpm)	2000
Required head, approximate (ft)	350
Structural material	Cast iron
Fuel tank capacity (min. gal)	385
Motor-Driven Jockey Pump	
Pump type	Centrifugal
Rated flow (gpm)	30
Required head, approximate (ft)	210
Structural material	Cast iron
Containment Spray Nozzles	
Type	Lechler (SPRACO) 1713A
Number	68
Rated flow (gpm)	15.2
Rated pressure design (psi)	40
Structural material	Stainless steel

Table 9.5.1-3 (Sheet 1 of 3)
Exceptions to NFPA Standard Requirements

Requirement	AP1000 Exception and Justification
NFPA 13 Sections 5-14.1.1.2 and 5-15.2 require fire department connections to individual sprinkler system headers, with no intervening shutoff valves.	Individual connections are not provided. Sprinkler systems are supplied from the proprietary fire water supply system, which can be accessed by the fire department at any hydrant along the yard main. Valves between these connection points and the sprinkler systems are electrically supervised or locked open.
NFPA 14 Section 3-4.3 does not allow manual standpipes for Class III systems.	The water supply to the standpipe inside containment is manually operated. This exception was approved with the NRC certification of the AP1000 design.
NFPA 14 Section 3-5 prohibits use of dry standpipes for Class II or Class III systems, and in areas not subject to freezing.	The standpipe system inside containment is classified as a dry standpipe system because it is normally isolated by the outboard containment isolation valve as described in Subsection 9.5.1.2.1.5.
NFPA 14 Section 4-2.2 requires an isolation valve for each standpipe.	One valve is used to isolate two or more short standpipes that supply a small number of hose stations.
NFPA 14 Sections 4-3 and 5-12 require fire department connections for each standpipe system, with no intervening shutoff valves.	Individual connections are not provided. Standpipe systems are supplied from the proprietary fire water supply system, which can be accessed by the fire department at any hydrant along the yard main. Valves between these connection points and the standpipe systems are electrically supervised or locked open, except as described in Subsection 9.5.1.2.1.5.
NFPA 14 Section 5-3.2 requires Class I hose connections at each intermediate landing of exit stairways, on each side of horizontal exit openings, in each exit passageway, and on the roof or at the highest landing of stairways.	Class I hose connections are provided in exit stairways at one intermediate landing between most floors, and at other protected exit locations accessible to firefighters entering the buildings from outside. Flow testing of Class I hose connections is accomplished without providing additional connections on the roofs of buildings or at the highest stairway landings.
NFPA 14 Section 5-5 requires standpipes to be interconnected at the bottom, and when supplied by elevated tanks, also at the top.	Standpipes interconnections are constrained by layout considerations and do not always meet these requirements. Each standpipe receives an adequate water supply at an adequate pressure.
NFPA 14 Section 5-11.2 requires a separate drain connection for each standpipe.	For standpipes located outside radiologically controlled areas and supplied at an elevation above the lowest hose connection, the hose connection is used to provide a means of draining the standpipe.
NFPA 22 Section 11-4.6 requires that pipes for the automatic filling of suction tanks shall discharge into the opposite half of the tanks from the pump suction pipe. Where an over-the-top fill line is used, the outlet shall be directed downward.	The over-the-top fill lines are installed on the opposite side of the tanks from the fire pump suction lines, but are not directed downward. The upward directed fill line has negligible impact to spills, splashing and overfill during tank fill operation and negligible impact to function and safety of the system.
NFPA 804 (Reference 2) Section 2.4 (6) requires the AP1000 fire hazards analysis to analyze the potential effects of a fire on life safety, release of contamination, impairment of operations, and property loss, assuming the operation of installed fire extinguishing equipment.	The AP1000 fire protection analysis does not analyze the potential effects of fire on life safety, impairment of operations, and property loss. This exception was approved with the NRC certification of the AP1000 design.

Table 9.5.1-3 (Sheet 2 of 3)
Exceptions to NFPA Standard Requirements

Requirement	AP1000 Exception and Justification
NFPA 804 (Reference 2) Section 2.4 (8) requires the AP1000 fire hazards analysis to analyze the potential effects of an uncontained fire in causing other problems not related to safe shut-down, such as a release of contamination and impairment of operations.	The AP1000 fire protection analysis does not analyze the potential effects of an uncontained fire in causing other problems not related to safe shut-down. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 2.4 (9) requires the AP1000 fire hazards analysis to analyze the postfire recovery potential.	The AP1000 fire protection analysis does not provide an analysis of the postfire recovery potential. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 3.3.4.4 (2) requires the ignition of leaked or spilled liquid be minimized by using suitable electrical equipment.	The AP1000 fire protection design criteria document does not explicitly require the minimization of the ignition of leaked or spilled liquid by the use of suitable electrical equipment. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 3.3.4.4 (3) requires the ignition of leaked or spilled liquid be minimized by sealing the insulation of hot plant components to prevent liquid saturation.	The AP1000 fire protection design criteria document does not explicitly require the minimization of the ignition of leaked or spilled liquid by sealing the insulation of hot plant components to prevent liquid saturation. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 5.2.2.2 requires the AP1000 safe shutdown analysis to have a shutdown logic diagram.	The AP1000 fire protection analysis does not include a shutdown logic diagram. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 5.3.2.1 requires the preparation of a risk assessment that demonstrates the potential risk from a seismically induced fire in relationship to the plant's core damage frequency.	The AP1000 design has not prepared a seismically induced fire PRA. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 6.1.2.2 requires stairwells and elevator shafts be enclosed with barriers having a fire resistance rating of at least 2 hours.	Auxiliary building stairwells and elevator shafts, with exception of the exterior wall sections enclosing Stairwell S03 and the wall separating Stairwell S03 from the elevator shaft above the Auxiliary Building Roof, are enclosed in towers constructed using both concrete structural walls and nonstructural walls as described in Section 9A of the DCD. For buildings outside of the Nuclear Island, exterior wall sections enclosing stairwells and elevator shafts do not have a fire resistance rating of 2 hours, only interior stairwell and elevator shaft wall sections are rated for the minimum 2 hour fire resistance rating.
NFPA 804 (Reference 2) Section 6.2.1 requires NFPA 101, *Life Safety Code*, be utilized throughout for the life safety from fire in the AP1000 design and operation.	Deviations from the Life Safety Code's exit and egress requirements are identified and the degree of the life safety justified in the Means of Egress Studies.

Table 9.5.1-3 (Sheet 3 of 3)
Exceptions to NFPA Standard Requirements

Requirement	AP1000 Exception and Justification
NFPA 804 (Reference 2) Section 6.5.3 (5) requires the drainage and any associated drainage facilities for a given area be sized to accommodate the volume of liquid based on a manual fire-fighting flow of 500 gal/min (1892.5 L/min) for a duration of 30 minutes, unless the fire hazards analysis demonstrates a different flow rate and duration.	The AP1000 drains are not designed for 500 gpm, nor does the present fire hazards analysis demonstrate a different flow rate and duration. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 8.3.5 requires smoke detectors be provided in the control room complex, the electrical cabinets, and consoles.	Smoke detectors are not provided in the cabinets and consoles. The control room is continuously occupied so that a fire is promptly detected and extinguished.
NFPA 804 (Reference 2) Section 8.3.10 requires the main control room under-floor and above-ceiling spaces to have air-handling functions ducted separately from cable runs, enclosed raceways over 1 ft^2 in cross-sectional area to have automatic fire suppression provided within them, and area automatic fire suppression for exposed cable runs.	The under-floor space of the control room complex is used as a distribution plenum for ventilation of the main control room, smoke detectors in the under-floor space cause prompt closure of combination fire/smoke dampers to shut off air flow, and automatic fire suppression is not provided in cable runs in the underfloor and ceiling spaces of the control room complex. These exceptions were approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 8.4.2.2.1 requires cable tunnels to be provided with automatic fixed suppression systems.	The AP1000 does not provide cable tunnels with automatic fixed suppression systems. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 8.4.3 requires cable tray fire breaks be installed every 20 feet in vertical cable trays that rise over 30 feet, and the provision of automatic sprinkler protection and smoke detection at the ceiling of vertical cable shafts.	Cable shafts and risers are not installed with periodic fire breaks, and automatic sprinkler and smoke detection is not provided at the ceiling of these shafts. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 8.5 requires computer and communication rooms to meet the applicable requirements of NFPA 75, *Standard for the Protection of Electronic Computer/Data Processing Equipment*.	The AP1000 is not explicitly designed to meet this requirement. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 8.8.6 requires turbine generator exciter housings to be protected either internally or externally with an automatic fire suppression system depending on the design of the housing ventilation system.	The AP1000 is not explicitly designed to provide automatic fire suppression for the turbine generator exciter housing or for the entire area it is within. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 8.10.2 requires aboveground diesel fuel storage tanks to be provided with automatic fire suppression systems.	Aboveground diesel fuel storage tanks are not provided with automatic fire suppression systems. This exception was approved with the NRC certification of the AP1000 design.
NFPA 804 (Reference 2) Section 8.28 requires the intake structure to be provided with automatic sprinkler protection.	The intake structure is non-combustible construction, does not provide any safety function, and does not contain any equipment important to safety. Automatic sprinkler protection is not warranted and is not provided.

Table 9.5.1-4
Capabilities Used to Achieve Cold Shutdown Following a Fire

Function	System Capability	Fire Protection
RCS Reactivity Control – Short Term – Long Term	 – Control Rods – (1)	 – separation (6) – (1)
RCS Makeup	– (1)	– (1)
RCS Pressure Control – Increase – Decrease	 – Pressurizer heaters – (2)	 – fire suppression – (2)
Decay Heat Removal (high temperature)	– SFW pumps feeding CST water to SG – SG PORV discharge to atm.	– fire suppression – separation
Decay Heat Removal (cold temperature)	– RNS pumps circulating RCS – CCS cooling RNS – SWS cooling CCS	– separation – fire suppression – fire suppression
Decay Heat Removal (cold temperature alternate)	– RNS pump circulating RCS – FPS cooling RNS (7)	– separation – fire suppression
Process Monitoring	– RCS monitoring instruments (PMS) – Non-1E Instrumentation and Control (3)	– separation – fire suppression or separation
Support Systems	– Instrument Air – Standby Diesel Generators – Non-1E AC Power and Control (3)	– fire suppression – fire suppression and separation – fire suppression or separation

Notes:

(1) CVS makeup from the BAT provides RCS makeup and boration. Automatic suppression is provided in the CVS makeup pump room and in the Non-Class 1E equipment/penetration room. If the CVS is damaged by a fire, one CMT can provide this capability.

(2) CVS auxiliary spray provides pressurizer pressure reduction. Automatic suppression is provided in the CVS makeup pump room and in the Non-Class 1E equipment/penetration room. If the CVS is damaged by a fire, one ADS stage 1 valve used in a low capacity throttled vent mode of operation can slowly depressurize the RCS without loss of RCS pressure boundary.

(3) The portions of the non-1E AC power and the non-1E instrumentation and control system required are those needed to operate cold shutdown components; local control is sufficient (switchgear/control cabinet).

(4) Portions of the non-1E heating and ventilating systems are required to ventilate the main control room, non-1E switchgear rooms, and the required portions of the non-1E instrumentation and control system (see note 3).

(5) The term "separation" means that fire barriers provide separation of redundant components, including equipment, electrical cables, instrumentation and controls, except in the main control room, remote shutdown room, and containment. See Subsection 9A.3.1.1 for discussion on containment and Subsection 9A.3.1.2.5 for discussions on the main control room and remote shutdown room.

(6) Separation is provided for the reactor trip function. The reactor trip breakers are separated.

(7) Connection is provided to allow the fire protection system to furnish water to cool a normal residual heat removal (RNS) pump and heat exchanger following a fire that disables the normal CCS cooling function.

Table 9.5.2-1
Communication Equipment(1) and Locations

Provided for Operator Transient Response(2)
in Addition to Main Control Room and Remote Shutdown Room

Area Locator	Elevation	Primary Area/Location Served
1212	66′-6″	Divisions A, B, C, D Battery Rooms
1222	82′-6″	Divisions A, B, C, D dc Equipment Rooms
1121	96′-0″	Passive Core Cooling System Valve/Accumulator Rooms and Steam Generator
1123		Compartments
1124		
1231	100′-0″	Divisions A and C, I&C Rooms; Divisions B and D, I&C/Penetration Rooms; Valve/Piping Penetration Room
1234	107′-2″	Maintenance Floor Staging Area
1134	107′-2″	Maintenance Floor
1132		
1243	117′-6″	Non-1E Equipment/Penetration Room
1254	135′-3″	Access Corridor Serving Personnel Access Area
1151	135′-3″	Operating Deck
1152		
1251	135′-3″	MSIV Compartments
1162	159′-7″	Steam Generator Feedwater Nozzle Area

Notes:
(1) Stations have Telephone/Page, PBX, and maintenance sound-power capability.
(2) See Standard Review Plan 9.5.2.

Table 9.5.4-1 (Sheet 1 of 2)
Nominal Component Data
Standby Diesel Fuel Oil System

Above Ground Storage Tanks	
Service	Diesel engine supply
Quantity	2
Type	Vertical, cylindrical
Normal fill level / available fuel capacity (gal) per tank	74,000
Available fuel reserved for diesel generator (gal) per tank	69,000
Excess fuel available for testing (gal) per tank	5,000
Operating pressure	Atmospheric
Operating temperature	Ambient
Diesel Oil Transfer System	
Fuel Oil Transfer Pumps	
Quantity	2
Type	Gear, positive displacement
Operating Flow (gpm)	8
Required design capacity (gpm)	35
Fuel Oil Strainer	
Quantity	2
Type	Duplex
Design Capacity (gpm)	35
Fuel Oil Heater	
Quantity	2
Type	Electric
Rating @35 gpm	90 kw
Fuel Oil Water Separator	
Quantity	2
Type	Pressurized/coalesced
Design Capacity (gpm)	35
Duplex Filters	
Quantity	2
Type	Duplex/stacked disc
Design Capacity (gpm)	35
Diesel Fuel Oil Day Tanks	
Quantity	2
Type	Horizontal, cylindrical
Normal available fuel capacity (gal)	1,560
Operating pressure	Atmospheric
Code	ASME VIII

Table 9.5.4-1 (Sheet 2 of 2)
Nominal Component Data
Standby Diesel Fuel Oil System

Ancillary Diesel Fuel Oil Tank	
Quantity	1
Type	**Vertical, rectangular**
Design Capacity (gal)	**700**
Available capacity (gal)	**550**
Operating pressure	Atmospheric
Code	Non-Stamped ASME VIII

Table 9.5.4-2
Indicating and Alarm Devices - Standby Diesel Fuel System

Parameter	Indication		Alarm	
	Control Room	Local	Control Room	Local
Fuel Oil Storage Tank Level - Diesel Oil (DO) Transfer	Yes	Yes	Yes	Yes
DO Day Tank Level	Yes	Yes	Yes	No
DO Transfer Pump Motor-Running Indication	Yes	Yes	No	No
DO Low Fuel Oil Pressure	Yes	Yes	Yes	No
DO Water Separator Differential Pressure	Yes	Yes	Yes	No
DO Filter Differential Pressure	Yes	Yes	Yes	No
DO Pump Suction Strainer Differential Pressure	Yes	Yes	Yes	No
DO Fuel Oil Heater in Service	Yes	Yes	Yes	Yes
DO Fuel Oil Heater Temp Out	Yes	Yes	Yes	No
Fuel Oil Tank Fill Strainer Differential Pressure	No	Yes	No	No

Table 9.5-201
Not Used

Table 9.5-202
Not Used

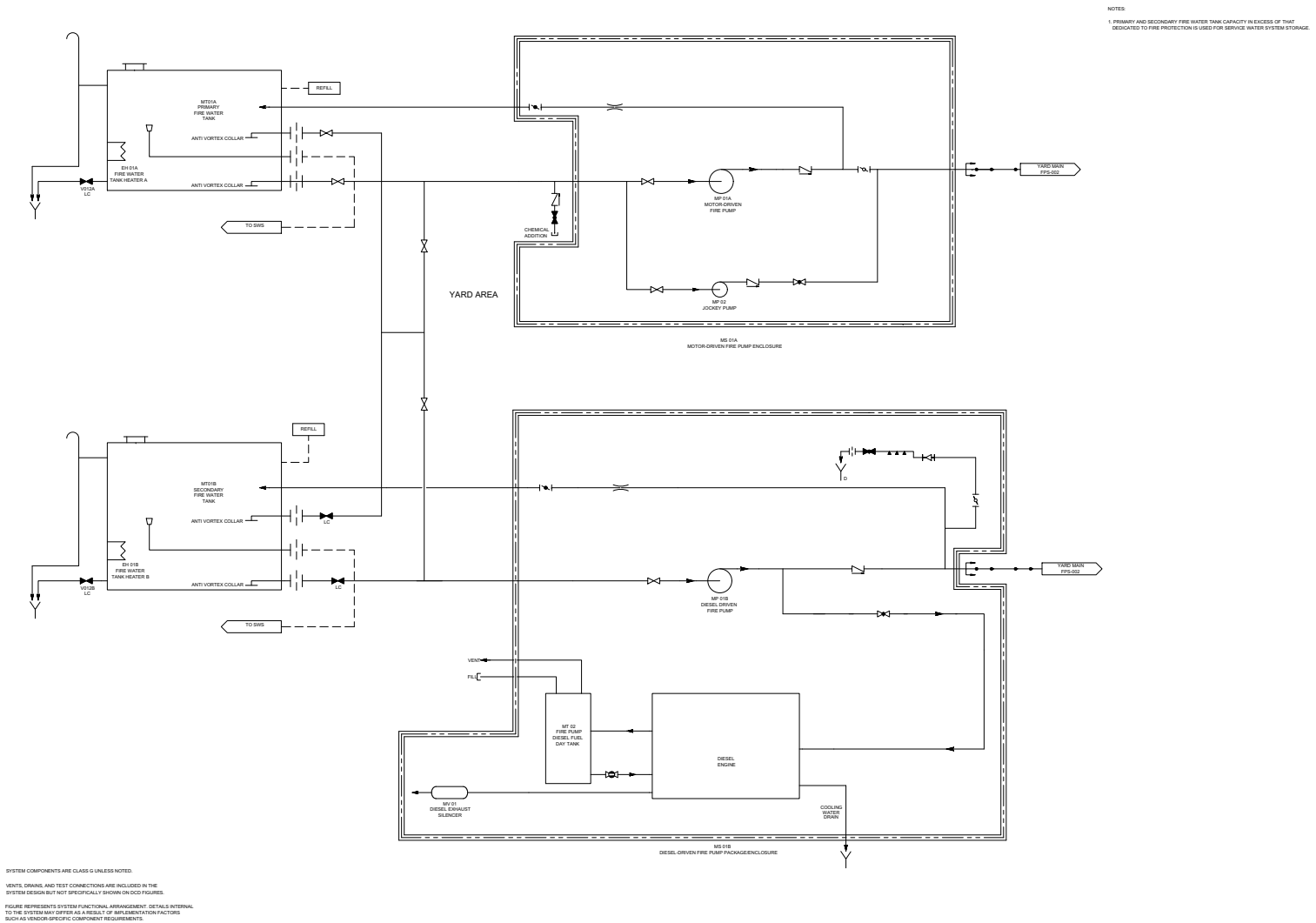


Figure 9.5.1-1 (Sheet 1 of 3)
Simplified Fire Protection System Piping and Instrumentation Diagram (REF FPS 001)

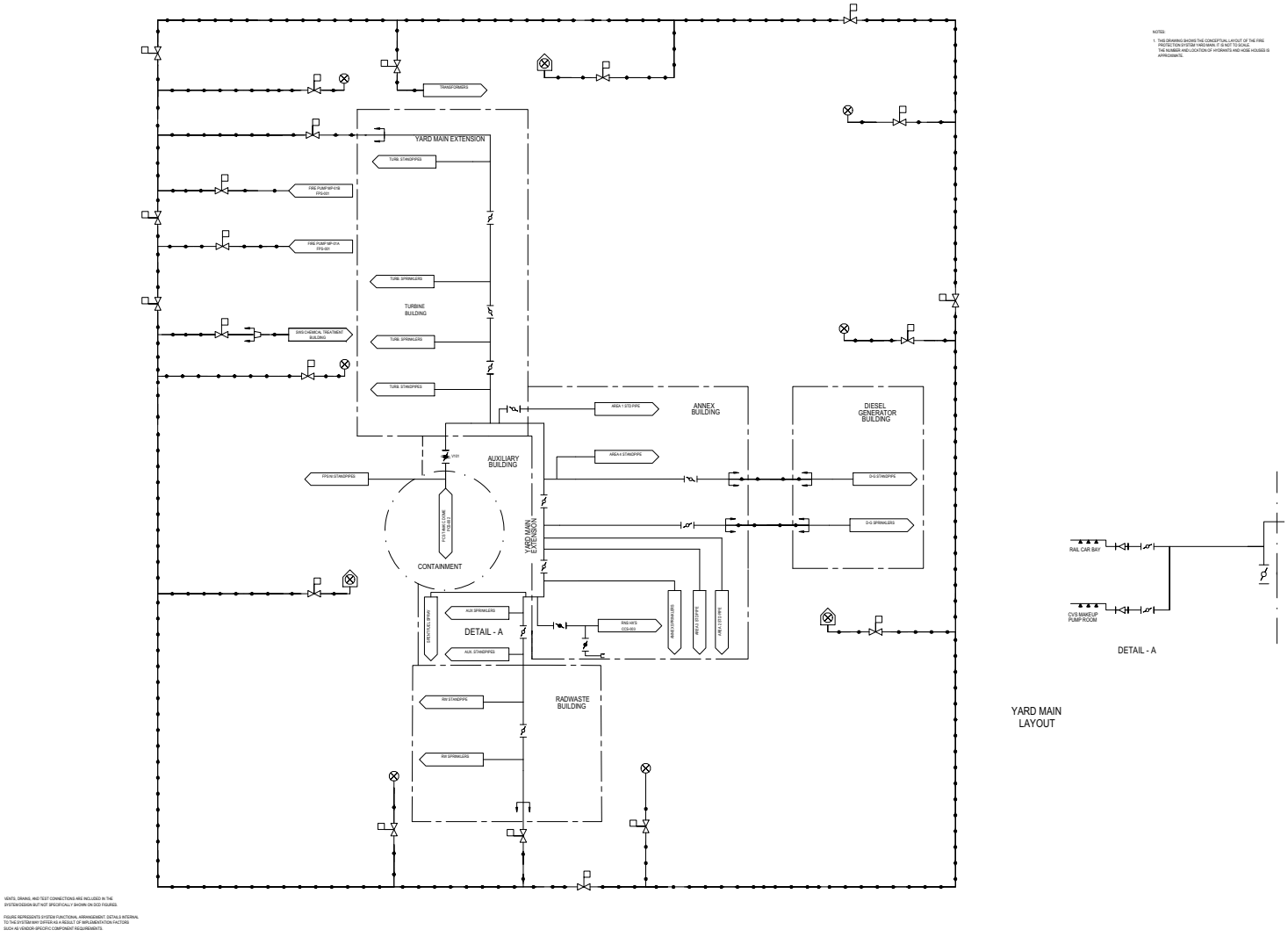


Figure 9.5.1-1 (Sheet 2 of 3)
Simplified Fire Protection System Piping and Instrumentation Diagram
(REF) FPS 002

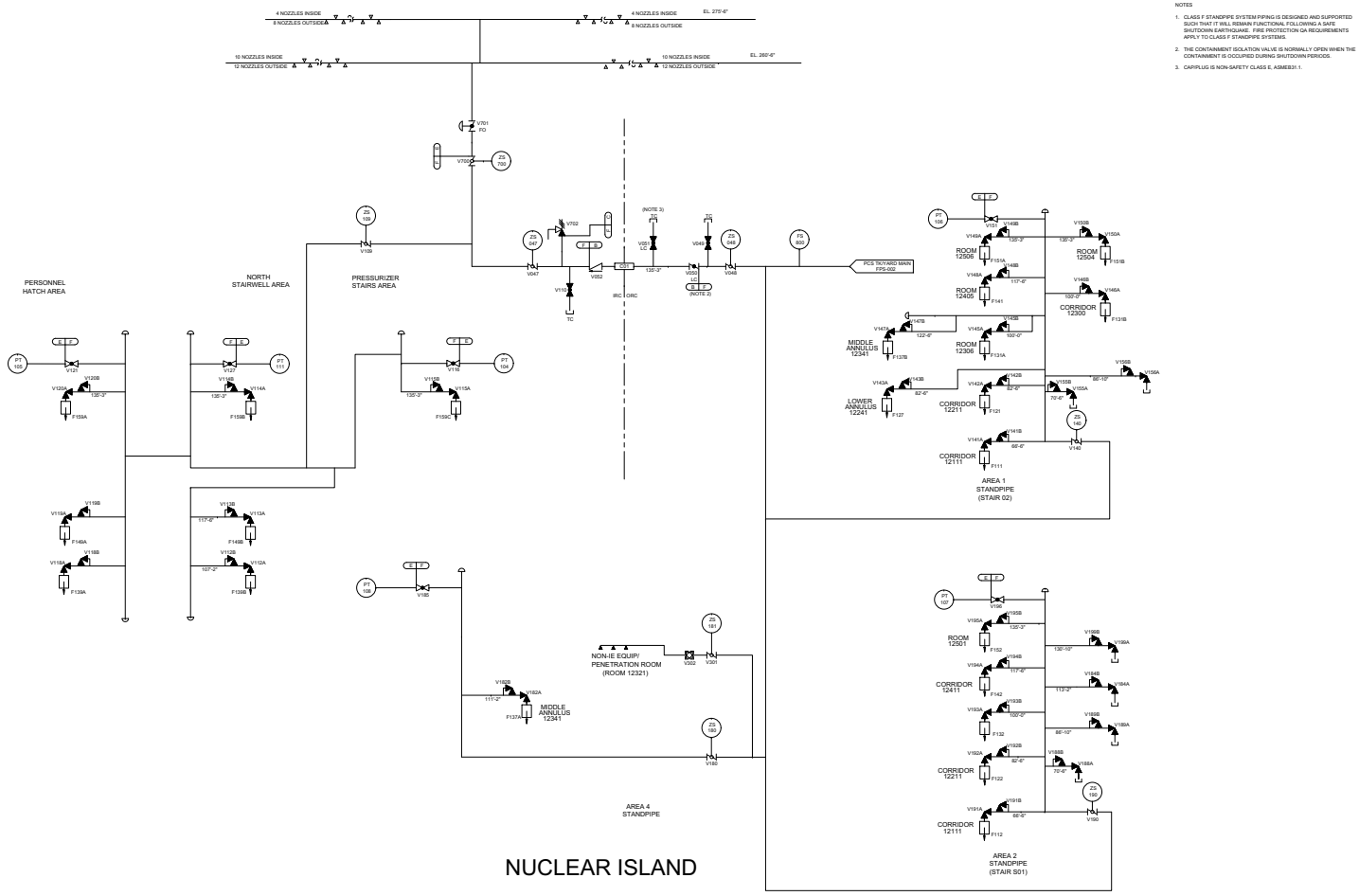


Figure 9.5.1-1 (Sheet 3 of 3)
Simplified Fire Protection System Piping and Instrumentation Diagram (REF FPS 004)

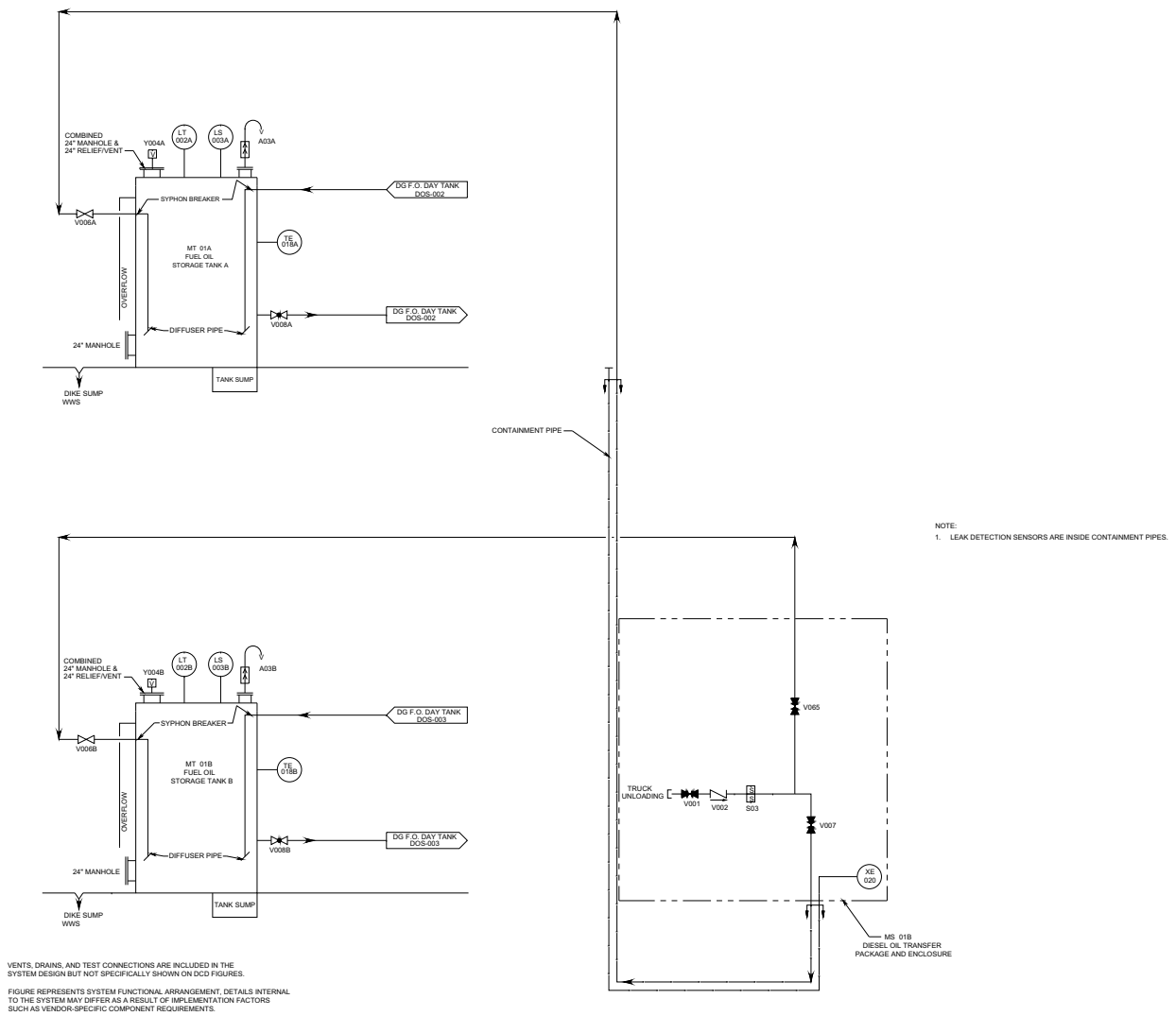
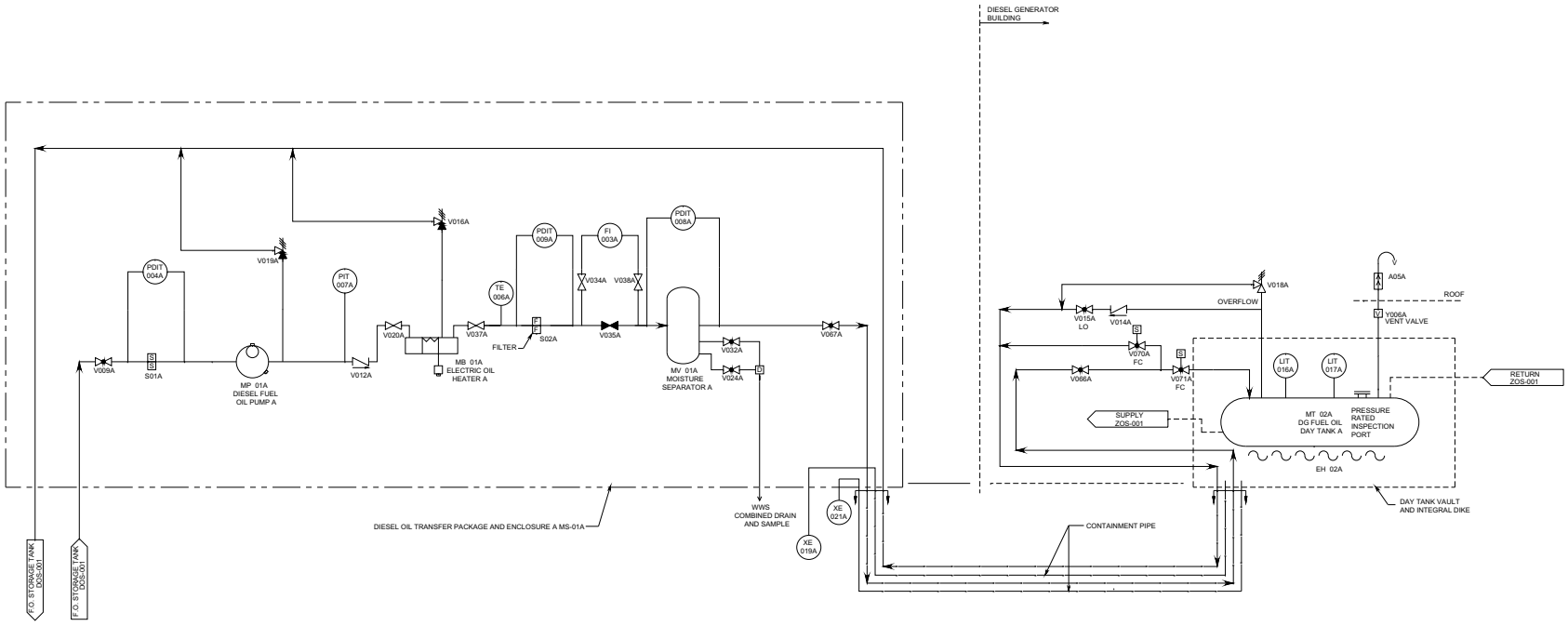


Figure 9.5.4-1 (Sheet 1 of 3)
Simplified Standby Diesel Fuel Oil System
Piping and Instrumentation Diagram
(REF) DOS 001



VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT, DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

NOTE:
1. LEAK DETECTION SENSORS ARE INSIDE CONTAINMENT PIPES.

Figure 9.5.4-1 (Sheet 2 of 3)
Simplified Standby Diesel Fuel Oil System Piping and Instrumentation Diagram (REF) DOS-002

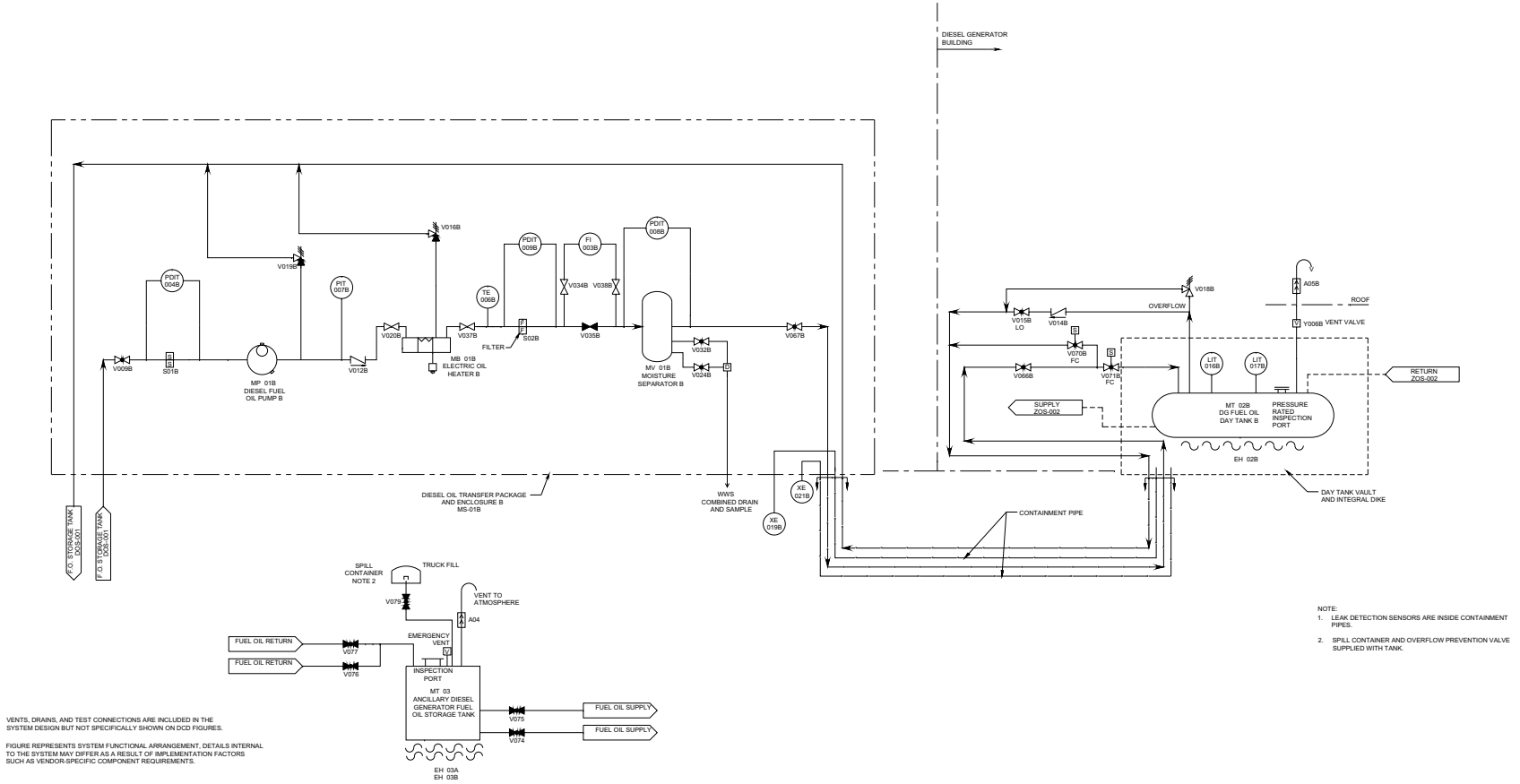


Figure 9.5.4-1 (Sheet 3 of 3)
Simplified Standby Diesel Fuel Oil System Piping and Instrumentation Diagram (REF) DOS-003 and DOS-004

Appendix 9A Fire Protection Analysis

9A.1 Introduction

The AP1000 fire protection analysis is largely based upon the AP600 fire protection analysis that supported the AP600 Design Certification. It evaluates the potential for occurrence of fires within the plant and documents the capabilities of the fire protection system and the capability to safely shut down the plant. The fire protection analysis is an integral part of the process of selecting fire prevention, detection, and suppression methods, and provides a design basis for the fire protection system. The design of the fire protection system is described in Subsection 9.5.1.

The purpose of the fire protection analysis is as follows:

- Identify the potential for fires based on the type, quantity, and location of combustible materials
- Determine the consequences of postulated fires
- Provide a basis for decisions on how to prevent, detect, contain, and suppress fires
- Assess fire protection system adequacy
- Confirm the capability to safely shut down the plant following a fire

The fire protection analysis is performed for each fire area using the methodology described in Section 9A.2. This methodology follows the guidance of Branch Technical Position (BTP) CMEB 9.5-1 (Reference 1). The results of the analysis are provided in Section 9A.3.

The fire protection analysis is performed for areas of the plant containing safety-related components and for areas containing systems important to the generation of electricity. It is performed on an area by area basis outside containment and a zone by zone basis inside containment. This approach provides confidence that plant safety is preserved.

9A.2 Fire Protection Analysis Methodology

9A.2.1 Fire Area Description

The plant is divided into fire areas and fire zones as described in Section 9.5.1.2.1.1. These fire areas/zones and their boundaries are illustrated on Figures 9A-1 through 9A-5. Figure 9A-201 replaces Figure 9A-3 (Sheet 1), to reflect the relocation of the Operations Support Center.

The analysis for each fire area briefly describes the fire area and associated fire zones, and identifies the principal systems and safety-related components in the fire area. Fire detection and suppression features are listed and the means of smoke control is discussed. The term "smoke" is used throughout this document to imply "smoke and products of combustion".

This document also uses terminology defined in NFPA 13, such as "light hazard", "ordinary hazard", and "extra hazard". Normally, these terms apply to sprinkler installations and their water supplies only. However, as used herein, the terms apply to the quantity and combustibility of the contents of a given fire area or fire zone irrespective of whether or not sprinklers are present.

9A.2.2 Combustible Material Survey

Each fire area and fire zone is surveyed to determine the type, quantity and distribution of in-situ combustible materials. Where the presence of transient combustibles is anticipated (for example, materials required to support refueling activities or scheduled maintenance) these materials are also identified.

When estimating quantities of electrical cable insulation, cable trays are normally assumed to have a cable fill of 40 percent of the usable tray depth. The final estimated percentage of cable tray fill depends on cable thickness and positioning of the cables within the cable tray. Cable enclosed in conduit or in closed metal cabinets is not included in the combustible material survey.

9A.2.3 Fire Severity Categorization

For purposes of evaluating fire barrier adequacy, the expected fire severity for each area/zone is categorized from A (slight) to E (severe) in accordance with Table 7-9E of the NFPA Fire Protection Handbook, 16th edition (Reference 2), based on the type of materials present.

Fire severity category A is used for battery cases, category C is used for electrical cable insulation, and category E is used for combustible liquids. For fire areas containing mixed combustibles, an average category is used. If there are significant concentrations of combustible materials in the area/zone, the category assigned is generally more severe than that used for a uniform distribution.

9A.2.4 Combustible Loading and Equivalent Fire Duration Calculations

Fire barriers, detection and suppression methods are based on several factors, including regulatory guidance, the type of combustibles present, and investment protection considerations. Regulatory guidance takes precedent over the other considerations.

Combustible loading and equivalent fire duration calculations are performed for each fire area and each fire zone. The calculations provide information used in the selection of fire detection and suppression methods.

Combustible Loading Calculations

The calculation of combustible loading provides an indication of the maximum heat that is released if all the combustibles in a given fire area/zone are consumed.

The potential heat release (expressed in British thermal units, or Btus) for each type of combustible material in the fire area/zone is the product of the quantity of each combustible multiplied by its heat of combustion. The heat of combustion values used for these calculations are listed in Table 9A-1. The maximum heat release for all combustibles in the fire area/zone is found by adding the potential heat release of each combustible material.

The combustible loading for the fire area/zone is the maximum heat release per square foot (Btus per square foot). It is determined by dividing the maximum heat release for all combustibles in the fire area/zone by the floor area of the fire area or zone.

For fire areas that are not protected based on regulatory guidance and that do not have concentrations of volatile or radioactive combustibles, fire detection and suppression needs are established based on combustible loading, using the following guidelines:

Combustible Loading (Btu/ft^2)	Detection Capability	Suppression Capability
0 to 8,000	None	Manual
8,000 to 80,000	Yes	Manual
Above 80,000	Yes	Automatic and Manual

In addition, concentrations of combustibles were evaluated, including their proximity to fire barriers.

Equivalent Fire Duration

The duration of a fire in a given fire area or zone is influenced by many factors, including:

- The properties of the material (ease of ignition and rate of heat release)
- The surface area of the combustible material
- The presence of fire retardant coatings
- Ventilation parameters and availability of oxygen
- The degree of separation or the presence of barriers between groups of combustible materials

Fire duration is estimated based on the fire severity category and the equivalent combustible loading. Equivalent combustible loading is defined as the weight per square foot of ordinary combustibles (wood or paper) having a heat of combustion of 8,000 Btu/lb, that releases the same total heat as the combustibles in the fire area/zone. The equivalent combustible loading is calculated by dividing the maximum heat release per square foot by 8,000 Btu/lb. The fire endurance lines of Figure 7-9B of the NFPA Fire Protection Handbook, 16th edition (Reference 2), are used to estimate the fire duration in minutes.

Fire barriers are tested by exposure to a fire whose severity follows a time varying temperature curve known as the standard time-temperature curve (NFPA Fire Protection Handbook, 18th edition [Reference 5], Figure 7-5A.) The estimated fire duration for each fire area is normalized based on the standard time-temperature curve to obtain an equivalent fire duration. This value is compared with the fire resistance of the fire area boundaries. This comparison is used in conjunction with other factors, including those listed above, in making a determination of the adequacy of the fire area boundaries.

9A.2.5 Fire Protection Adequacy

The adequacy of the fire protection features for a postulated fire in each fire area or fire zone is evaluated. This evaluation includes the following points:

- A review of the AP600 Design Certification and other regulatory guidance
- A review of how the fire is detected and suppressed
- Verification of the adequacy of the fire resistance of the fire area boundaries

- Verification that the ventilation system for the fire area does not contribute to the spread of fire or smoke
- Verification that a fire in a nonsafety-related area does not threaten safety-related areas of the plant
- Verification that, for a fire in an area containing radioactive materials, the capability to minimize and control a potential release of radioactivity is not adversely affected
- A determination of the need for structural steel fireproofing
- A determination of the capability of the drainage systems to handle fire protection water flow.

9A.2.6 Fire Protection System Integrity

For fire areas containing safety-related components, the potential for a credible inadvertent actuation of automatic suppression systems is determined and the consequences are evaluated.

The design of automatic and manual suppression systems is reviewed to verify that there is no potential single impairment which incapacitates both the automatic suppression system and the manual suppression system.

9A.2.7 Safe Shutdown Evaluation

This subsection describes the methodology for evaluation of the effects of postulated fires in each fire area on the ability of the operator to achieve a safe shutdown of the plant. The criteria and assumptions upon which the evaluation is based are described in Subsection 9A.2.7.1. The safety-related features of the plant designed to provide the safe shutdown capability are described in subsection Subsection 9A.2.7.2.

As indicated in Subsection 9.5.1, this evaluation is based upon satisfying the requirements of BTP CMEB 9.5-1. This basis includes using safe shutdown as defined in the Technical Specifications in lieu of cold shutdown wherever stated in BTP CMEB 9.5-1. The automatic depressurization system is not used as the method for achieving safe shutdown after a fire and spurious actuation of the automatic depressurization system is avoided. The passive residual heat removal heat exchanger is used to remove decay heat for safe shutdown as described in Subsection 7.4.1.3.

In addition, the plant has enhanced capability to achieve cold shutdown following a fire as discussed in Subsection 9.5.1. This capability is not relied upon in the fire evaluation contained in Appendix 9A.

The criteria concerning cold shutdown capability deviates from the criteria applied to the evolutionary reactor designs, but is consistent with the criteria applicable to existing plants. To enhance the survivability of the normal safe shutdown and cold shutdown capability in the event of a fire, and to reduce the reliance on the infrequently utilized safety-related passive systems, automatic suppression or physical separation is provided in those fire areas outside containment where a fire could damage the normal shutdown capability. This criterion is unique to the AP1000 and does not ensure that the normal shutdown capability will be free of fire damage, or that the equipment necessary to achieve and maintain cold shutdown can be repaired within 72 hours.

9A.2.7.1 Criteria and Assumptions

The criteria and assumptions described below are used in performing the safe shutdown evaluation.

Postulated Fire

Only one fire is assumed to occur within the plant at any given time. A postulated fire is assumed to occur in any area (or zone in containment), whether or not the area contains in-situ combustible materials.

Any damage which would prevent proper operation of equipment and which the fire is capable of causing is assumed to occur immediately. Except where explicitly noted, no credit is taken for proper operation of equipment or moving of valves to proper position when not protected from the effects of a postulated fire.

Fire Barriers

As described in Subsection 9.5.1.2.1.1, non-combustible fire barriers are provided in accordance with BTP CMEB 9.5-1. The minimum equivalent fire barrier ratings are shown in Figures 9A-1 through 9A-5 and are those of the barrier itself. Fire-proofing of structural steel is determined as described in Subsections 9.5.1.2.1.1 and 9A.2.5.

Fire Areas

Fire areas are three dimensional spaces designed to contain a fire that may exist within them. They are separated by fire barriers, fire barrier penetration protection, and other devices, such as those within the heating and air conditioning ducts, that isolate a fire to within the fire area.

A postulated fire does not extend beyond the boundary of the fire area. For fire areas outside the main control room, remote shutdown room, and containment fire areas, the zone of influence is defined as the entire fire area and all equipment in any one fire area is assumed to be rendered inoperable by the fire and re-entry into the fire area for repairs and operator actions is assumed to be impossible. For investment protection, an operator may enter an adjacent room to a fire in the same fire area, that is separated by a 1-hour fire barrier, to prevent spurious actuation of the ADS Stage 4 valves. However, no credit is taken for complete fire damage in cases in which complete damage is beneficial and partial damage is not. Chases for electrical raceway, piping or ducts that pass through the fire area but are separated from it by 3-hour fire barriers are treated as an extension of the fire area boundary that they originate from or travel to. Such chases contain internal 3-hour fire-rated barriers (e.g., fire barrier seals) to separate the connected fire areas.

Zone of Influence

Outside containment, zone of influence is not defined. A fire outside containment is assumed to affect its entire fire area. Inside the containment fire area, the zone of influence is defined as the entire fire zone containing the fire. All equipment in any one fire zone is assumed to be rendered inoperable by the fire unless the fire protection analysis demonstrates otherwise. Class 1E electrical cables that are located in or pass through the fire zone but are separated from it by a 3-hour fire barrier are outside that fire zone.

Fire Zones

Fire zones are three dimensional spaces within fire areas. Fire zones are identified uniquely to indicate that they have fire protection features or attributes different than other fire zones in a given area. In containment, fire zones are identified to establish "zones of influence."

Independence of Affected Fire Areas

Only systems, components, and circuits free of fire damage are credited for achieving safe shutdown for a given fire. Systems, components, and circuits outside the zone of influence are considered free of fire damage if the effects of the fire do not prevent them from performing their required safe shutdown functions.

Event Assumptions

Plant accidents and severe natural phenomena are not assumed to occur concurrently with a postulated fire. Furthermore, a concurrent single active component failure (independent of the fire) is not assumed.

Offsite Power

A loss of offsite power is assumed concurrent with the postulated fire only when the safe shutdown evaluation indicates the fire could initiate the loss of offsite power.

Availability of Nonsafety-Related Systems

Only safety-related components and systems are assumed to be available to perform safe shutdown functions. (This is more stringent than required by BTP CMEB 9.5-1.) For each fire area or zone, the safe shutdown evaluation is valid for the worst case fire in the area or zone and initial use of nonsafety-related equipment. Fire protection and smoke control systems are assumed to function as designed to detect and mitigate the effects of the fire.

If offsite power is available, nonsafety-related systems are assumed to continue to operate if a more conservative evaluation would result. Each safe shutdown evaluation is also valid considering the possibility that the operator may initiate safe shutdown using available nonsafety-related systems and that, should the fire later cause those systems to fail, safety-related systems may be automatically or manually actuated to continue the safe shutdown process.

Automatic Suppression Features Assessment

An assessment is performed to demonstrate the ability of the AP1000 to withstand a fire in fire areas outside containment, and achieve safe shutdown without the need for actuating the passive safety-related decay heat removal system. This evaluates the capability of the AP1000 non-safety-related systems to achieve safe shutdown.

Fire suppression is provided outside containment in locations that would degrade the normal nonsafety-related systems used to achieve safe shutdown following a fire, such that the operation of the passive residual heat removal heat exchanger would be required to provide shutdown decay heat removal. Fire suppression minimizes the challenges to the safety-related decay heat removal systems by enhancing the survivability of nonsafety-related systems used for shutdown decay heat removal.

The safe shutdown process, using safety and nonsafety-related systems, is described in Subsection 7.4.1.2. This assessment credits the use of selected safety-related systems other than the passive residual heat removal system to facilitate the transition to cold shutdown conditions. The following safety-related features may be used:

- Insertion of the control rods to provide reactor shutdown,
- Operation of the core makeup tanks to provide boration and reactor coolant system makeup,
- Manual throttling and closing of a first stage automatic depressurization valve to reduce the reactor coolant system pressure to the operating pressure of the normal residual heat removal system,
- Instrumentation used to monitor reactor coolant system conditions.

The use of these safety-related systems do not result in significant plant transients. If the automatic depressurization system is actuated, the operators align the normal residual heat removal system to

provide injection to the reactor coolant system. This action causes the core makeup tank level to remain above the fourth stage valve actuation setpoint and prevents significant steaming to and flooding of the containment.

Process Monitoring

Direct process signals are provided to monitor the shutdown process and to assist in determining proper actions for operation of the shutdown methods.

Manual Operation

One of the required manual actions to achieve plant shutdown for a postulated fire event is to scram the reactor.

Manual actions by operations personnel include manipulation of equipment located anywhere outside the affected fire area, if accessibility and staffing levels permit such actions. Entry into the fire area for repairs or operator actions is assumed to be impossible.

Although the typical shutdown sequence does not require manual actions by the operator, fire damage may not be sufficient in many cases to trip the plant. The operator may take appropriate actions to expedite an orderly shutdown. These actions are performed in the main control room. If the fire occurs in the main control room, these actions are performed at the remote shutdown workstation.

High-Low Pressure Interfaces

NRC Generic Letter 81-12 (Reference 3) requests the identification and evaluation of the interfaces between the high pressure reactor coolant system and low pressure systems such as the normal residual heat removal system. Typically, these high-low pressure interfaces contain two redundant and independent remotely-operated valves in series. These two valves and their control and power cables may be subject to a single fire. This fire may potentially cause the two valves to open, resulting in a fire-initiated loss-of-coolant accident (LOCA) through the high-low pressure system interface. Electrically controlled valves which provide such an interface are identified. These interface valves are considered to be required for safe shutdown.

Associated Circuits

The AP1000 was designed with separation of safety-related circuits and equipment as a primary objective. As a result of the concern for separation from the beginning of the design, the use of associated circuits has been minimized.

The safe shutdown equipment and systems for each fire area are isolated from associated circuits in the fire area so that hot shorts, open circuits, or shorts to ground in the associated circuits will not prevent operation of the safe shutdown equipment. No postulated fire involving associated circuits will prevent safe shutdown.

Associated circuits comply with Regulatory Guide 1.75 position 4 related to associated circuits and IEEE 384-1981 (Section 5.5.2).

Spurious Actuation of Equipment

Fire-caused damage is assumed to be capable of resulting in the following types of circuit faults: hot shorts, open circuits, and shorts to ground. Spurious actuation of components caused by these circuit faults are evaluated. Components are assumed to be energized or de-energized by one or more of the above circuit faults. For example, air operated and solenoid operated valves are assumed to fail open or closed; pumps are assumed to fail running or not running; electrical distribution breakers could fail open or closed. For three-phase ac circuits, the probability of getting a hot short on all three

phases in the proper sequence to cause spurious operation of a motor is considered sufficiently low as to not require evaluation, except for cases involving high-low pressure interfaces. For ungrounded dc circuits, if spurious operation could only occur as a result of two ungrounded hot shorts of the proper polarity, then no further evaluation is necessary, except for any cases involving a high-low pressure interface. Therefore, spurious operation of ac or dc motor operated valves as a result of power cable hot shorts is not assumed, except for cases involving a high-low pressure interface.

It is assumed that a fire results in the loss of all automatic function (signals and logic) from the circuits located in the fire area. In addition, an assessment of multiple/simultaneous spurious actuations or signals resulting from the fire was performed (Reference 6) with the conclusion that either spurious actuations do not occur, or the consequences are such that safe shutdown can still be achieved. The spurious actuations and signals that are evaluated are those that could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

Spurious actuation of the redundant valves in any one high-low pressure interface line are postulated if the circuits for those valves are located in the fire area.

Most control room controls use soft-controls which communicate over multiplexed data channels. Fire-induced spurious actuation from these multiplexed soft controls is not assumed.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation. In the event of a fire in the main control room, control may be transferred to the remote shutdown workstation, depending on the extent of the fire. For a small fire which can be quickly extinguished, control is maintained in the main control room, and the potential for damage or spurious signals is limited. For larger postulated fires, the main control room is evacuated and control is transferred to the remote shutdown workstation. Once control is transferred, the dedicated switches in the main control room are disabled by a transfer switch.

Spurious actuation of squib valves is prevented by the use of a squib valve controller circuit which requires multiple hot shorts for actuation, physical separation of potential hot short locations, and provisions for operator action to remove power from the fire zone. No postulated fire can spread to the hot short locations before the operator can remove power from the fire zone.

Automatic depressurization system stages 1, 2, and 3 consist of parallel paths, each path having two motor-operated valves in series. Spurious stage 1, 2, or 3 actuation is prevented by the use of physical separation of control circuits for the two series valves and provisions for operator action to remove power from the fire zone. No postulated fire can spread to the hot short locations before the operator can remove power from the fire zone.

Multiple High-Impedance Faults

It is postulated that fire-induced circuit faults may occur with high enough impedance to prevent tripping of the affected circuit breaker. If multiple high-impedance faults occur simultaneously, affecting branch circuits fed from a common power source, there is a potential for the sum of the currents from these multiple high-impedance faults to be high enough to trip the main circuit breaker feeding the bus. Once the main breaker trips, components powered from the bus lose their power source. Multiple high-impedance faults are considered in the evaluation of safe shutdown capability.

Plant Personnel

The plant operating staff available for manual actions to achieve safe shutdown, during and after the fire, is limited to the minimum number of posted operator positions minus those assigned to the fire brigade.

Smoke Removal

Where portable equipment is used to remove smoke after a fire, the exhausted smoke is released directly outside to an area that will not affect safety-related plant areas, unless the release is from an area potentially containing radioactive materials. Where portable equipment is used to remove smoke from areas potentially containing radioactive materials, the exhausted smoke is also monitored for radiological releases in accordance with guidance provided in BTP CMEB 9.5-1, paragraph C.5.f.(2).

Equipment Environment

The environment of the equipment required to function for shutdown should not become so severe as to prevent the equipment from functioning. If the environment does exceed the conditions for which the equipment is capable of functioning, it is assumed that the equipment no longer is capable of performing its intended function.

Emergency Lighting

In situations where the safe shutdown evaluation identifies the need for manual operator action in response to a fire, the estimate of the time required for this action considers the availability of emergency lighting in locations where these actions are performed and along the access and egress routes thereto.

Emergency Communications

The safe shutdown evaluations consider the need for and availability of emergency communications within the plant following a fire.

9A.2.7.2 Safe Shutdown Methodology

The safe shutdown process, the systems used, and the functional requirements for safe shutdown are described in Section 7.4. As noted above, only safety-related equipment is utilized for safe shutdown. A description of this equipment is provided in the applicable sections.

Table 9A-2 lists the safety-related components used for safe shutdown and their associated electrical divisions. Each fire area is reviewed to identify the potential scope of fire damage and to verify that the capability to achieve and maintain safe shutdown is preserved.

The shutdown process uses controls located in the main control room. In the event of a fire in the main control room, controls located at the remote shutdown workstation are used.

9A.3 Fire Protection Analysis Results

The fire protection analysis is conducted for the following primary plant structures, which are shown on the site plot plan, Figure 1.2-2:

- Nuclear island
- Turbine building
- Annex building
- Radwaste building
- Diesel generator building

Table 9A-3 identifies the type of combustible materials in each fire area of the primary plant structures and indicates the equivalent fire duration. Fire detection and suppression features are also summarized in Table 9A-3.

Openings through fire barriers for pipe, conduit, and cable trays are sealed or closed to provide a fire resistance rating at least equal to that of the fire barrier itself. Penetration designs conform to the guidelines of BTP CMEB 9.5-1. Fire barrier penetration openings for ventilation are protected by fire dampers having a rating equivalent to that of the fire barrier. For 1-hour rated fire barriers, fire dampers are not required since the duct itself is an adequate barrier. The protection of door openings conforms to the guidelines of BTP CMEB 9.5-1.

Structural steel fireproofing is provided as described in Subsection 9.5.1.2.1.1.

The fire detection and suppression capabilities for each fire area are selected based on the criteria described in Subsection 9A.2.1 and are consistent with the importance of the equipment in the fire area to plant availability. Portable fire extinguishers are accessible throughout the plant.

The presence of radioactive systems is noted in the description of each fire area. Potential releases of radioactivity as a consequence of a fire in these areas is mitigated by measures such as:

- Control and confinement of sources of radioactivity per ALARA principles
- Use of fire dampers to isolate ventilation ducts serving the fire area
- Use of fire suppression systems to quickly suppress the fire
- Provision of curbed floor areas and sizing of sumps to collect and retain fire protection water within the affected fire area or building

The safe shutdown evaluation of spurious equipment actuation as a result of a fire is addressed in Subsection 9A.3.7. The protection of accident mitigation equipment (as opposed to safe shutdown equipment) is also addressed in Subsection 9A.3.7.

9A.3.1 Nuclear Island

Figure 9A-1 identifies fire areas and fire zones within the nuclear island and illustrates the fire resistance of the fire area boundaries. The nuclear island is comprised of the following primary areas:

- Containment/shield building
- Auxiliary building – nonradiologically controlled areas (non-RCA)
- Auxiliary building – radiologically controlled areas (RCA)

The containment/shield building comprises a single fire area for the purposes of this analysis.

The auxiliary building is divided into the radiologically controlled areas and nonradiologically controlled areas which are physically separated by structural walls and floor slabs. These structural barriers are designed to prevent fire propagation across the boundary between these areas.

The auxiliary building is further subdivided into fire areas separated by fire-rated structural barriers. These barriers provide physical separation between the four Class 1E electrical divisions and between these divisions and nonsafety-related areas.

Floor drains accommodate water flow from fire protection systems without a significant accumulation of water in a fire area. Flooding of components required for safe shutdown is also precluded by the

fact that only a limited volume of fire water can be discharged from the fire protection system in fire areas containing those components. This subject is further discussed in Section 3.4.

Drain systems in the radiological controlled area of the nuclear island Annex Building and Radwaste Building drain to fire zones in the nuclear island where there are no safe shutdown components. Fires in these zones due to potential combustible liquid transport by the drains do not affect safe shutdown.

There is no drain path which could drain combustible liquids to the fire areas in the electrical portion of the nuclear island.

For mechanical equipment fire areas in the nonradioactive auxiliary building, fires caused by potential transport of combustible liquid through the drain system are included in the fire hazards analysis.

9A.3.1.1 Containment/Shield Building

This building comprises one fire area - 1000 AF 01. This fire area is separated into fire zones and includes the spaces inside containment as well as the valve room for the passive containment cooling system (PCS), the middle annulus, the upper annulus, and the operating deck staging area outside containment. This fire area excludes the middle annulus penetration room division B, C, and D (rooms 12344, 12343, and 12345) because these are treated as extensions of the adjacent auxiliary building rooms' fire areas. This fire area includes the remainder of the middle annulus including the division A containment penetration area.

The fire protection and the safe shutdown analysis for the containment identifies the location and the separation of the safe shutdown components located inside the containment. The safe shutdown components located inside the containment are primarily components of the passive core cooling system (PXS), the reactor coolant system (RCS), the steam generator system (SGS), and containment isolation.

For this evaluation, the containment shield building is divided into the following fire zones. These zones are based on the establishment of boundaries (structures or distance) that inhibit fire propagation from zone to zone. Complete fire barrier separation cannot be provided inside containment because of the need to maintain the free exchange of gases for purposes such as passive containment cooling. The location of safety-related equipment and the routing of Class 1E electrical cable in each fire zone enhances the separation of redundant safe shutdown components.

Fire Zone

- 1100 AF 11105 Reactor cavity
- 1100 AF 11204 Vertical access and reactor coolant drain tank room
- 1100 AF 11206 Accumulator room A
- 1100 AF 11207 Accumulator room B
- 1100 AF 11208 Normal residual heat removal valve room
- 1100 AF 11209 Chemical and volume control system room
- 1100 AF 11300A Maintenance floor (southeast quadrant access)
- 1100 AF 11300B Maintenance floor (north half)
- 1100 AF 11301 Steam generator compartment 1
- 1100 AF 11302 Steam generator compartment 2
- 1100 AF 11303 Pressurizer compartment
- 1100 AF 11303A Automatic depressurization system lower valve area

- 1100 AF 11303B Automatic depressurization system upper valve area
- 1100 AF 11500 Operating deck
- 1200 AF 12341 Middle annulus
- 1200 AF 12541 Upper annulus
- 1250 AF 12555 Main control room emergency habitability system air storage/operating deck staging area
- 1270 AF 12701 Passive containment cooling system valve room

The equipment and components in this fire area contain radioactive material with the exception of passive containment cooling system and main control room emergency habitability system components.

Fire Detection and Suppression Features

- Fire detectors
  - All fire zones except fire zone 1200 AF 12341
  - Only spot heat detection (Heat) is provided in fire zone 1200 AF 12341 for PCS pressure transmitters as localized equipment protection
- Hose station(s)
- Portable fire extinguishers (during reactor shutdown for maintenance)

Smoke Control Features

Containment air filtration system (VFS) containment isolation valves, if open to the containment atmosphere, are closed by operator action to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by operation of a fire detector, which produces an audible alarm locally, except in containment where the fire detection system produces a visual alarm locally, and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of electrical cable insulation. Concentrations of combustibles are described in the evaluation of each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

The consequences of a break in a fire protection line during normal plant operation are limited because the containment isolation valve for the fire water supply line to the containment hose stations is normally closed and are bounded by other flooding events inside containment. See Section 3.4 for further discussion of flooding events inside containment.

9A.3.1.1.1 Fire Zone 1100 AF 11105

This fire zone is comprised of the following room(s):

Room No.	
11105	Reactor vessel cavity
11205	Reactor vessel nozzle area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of negligible amounts of cable insulation. These cables and instruments are located in the lower part of the fire zone. This fire zone is separated from adjacent fire zones by the thick concrete walls and floor of the reactor vessel cavity, except at the top of the fire zone, where there are penetrations associated with reactor coolant system piping and where the annular space around the reactor vessel flange is closed by the permanent cavity seal ring. There is a doorway to the reactor coolant drain tank room (fire zone 1100 AF 11204) that is closed and a ventilation duct that provides cool air from the containment recirculation cooling system.

Smoke and hot gases from a fire accumulate within this fire zone and gradually migrate via reactor coolant system piping penetrations to adjacent fire zones 1100 AF 11204, 1100 AF 11206, 1100 AF 11301, and 1100 AF 11302. The smoke and hot gases are expected to rise due to their buoyancy and be replaced by air coming from the containment recirculation cooling system. They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 identifies the safe shutdown components located in this fire zone. They are the four excore flux instrumentation channels, one for each division. Although it is unlikely that all of the components would be damaged, a fire in this fire zone is conservatively assumed to disable all of the above instrumentation. The source, intermediate and power range excore detectors are not required for automatic safe shutdown initiation or maintenance during or following a fire in this fire zone. These detectors are used to monitor and verify that the reactor is shut down. The redundant instrumentation used for monitoring core reactivity indirectly are the core exit thermocouples located in fire zone 1100 AF 11500. These thermocouples are mounted within the reactor and integrated head package and have exposed cable high in the integrated head package in fire zone 1100 AF 11500. The thermocouple cables will be unaffected by smoke from a fire in the reactor cavity. In addition, reactor subcriticality after shutdown is maintained by an adequate boron concentration in the reactor coolant. This concentration is establish by the automatic actions taken upon reactor trip such as, isolation of non-borated makeup sources and opening of the flow paths to sources of borated water. Boron concentrations can be checked periodically to determine if adequate levels exist.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.2 Fire Zone 1100 AF 11204

This fire zone is comprised of the following room(s):

Room No.	
11104	Reactor coolant drain tank room
11204	Vertical access area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation associated with the instrumentation in this zone. The cable raceways are located against one structural concrete wall of the fire zone and in the reactor coolant drain tank room at the bottom of the fire zone. The floor of this fire zone is solid concrete at the bottom of containment. Thick concrete walls separate this fire zone from adjacent fire zones, except for access passageways to and from the steam generator compartments (fire zones 1100 AF 11301/11302). Steel grating and the vertical access stairway form the boundary between this fire zone and the maintenance floor above (fire zone 1100 AF 11300B). There is a doorway between the reactor coolant drain tank room and the bottom of the reactor cavity (fire zone 1100 AF 11105) that is closed.

Smoke and hot gases from a fire in this fire zone rise through the grating at the top of the vertical access area and spread through the large maintenance floor air space (fire zones 1100 AF 11300A and B). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components contained in this fire zone. Although it is unlikely that all of the components would be damaged, a fire in this zone is conservatively assumed to disable the reactor coolant system hot leg instrumentation. The redundant reactor coolant system hot leg instrumentation located in 1100 AF 11301 and 1100 AF 11302 are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.3 Fire Zone 1100 AF 11206

This fire zone is comprised of the following room(s):

Room No.	
11206	Passive core cooling system valve/accumulator room A

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe

shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of lubricant in the valve actuators. There are no significant concentrations of combustible materials. This fire zone is physically separated from other fire zones by walls, floor and ceiling with minimum concrete thicknesses of one foot, except for a closed access hatch, an access opening and a small CMT pipe penetration in the ceiling. The penetration is beneath core makeup tank A, located on the maintenance floor (fire zone 1100 AF 11300A).

Smoke and hot gases from a fire in this fire zone rise through the CMT pipe penetration and access opening and spread through the large maintenance floor air space (fire zones 1100 AF 11300A and B). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components contained in this fire zone. A fire in this fire zone is conservatively assumed to disable control of all of the valves and instrumentation in this fire zone. The passive core cooling system safe shutdown components located in fire zones 1100 AF 11207 and 1100 AF 11300B are redundant to those in this fire zone, and are sufficient to perform applicable functions to achieve and maintain safe shutdown. The spent fuel pool cooling system containment isolation valve located outside the containment fire area is redundant to the containment isolation valve inside containment in this fire zone and is sufficient to maintain containment integrity.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.4 Fire Zone 1100 AF 11207

This fire zone is comprised of the following room(s):

Room No.	
11207	Passive core cooling system valve/accumulator room B

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of lubricant in the valve actuators. There are no significant concentrations of combustible materials. This fire zone is physically separated from other fire zones by walls, floor and ceiling with concrete thicknesses of more than one foot, except for a closed access hatch and a CMT pipe penetration in the ceiling, and a passageway to the adjacent RNS valve room (fire zone 1100 AF 11208). The large accumulator vessel stands in front of this passageway and provides a barrier to fire propagation between the two fire zones. The ceiling blockout is beneath core makeup tank B, located on the maintenance floor (fire zone 1100 AF 11300B). The physical arrangement of the small penetration and the large tank and its support results in a tortuous path for fire propagation between these two fire zones. A fire is not expected to propagate to fire zone 1100 AF 11208. If it did, however, fire zone 1100 AF 11206 provides redundant safe shutdown equipment.

Smoke and hot gases from a fire in this fire zone rise through the ceiling CMT pipe penetration and spread through the large maintenance floor air space (fire zones 1100 AF 11300A and B). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components contained in this fire zone. Although it is unlikely that more than one valve would be damaged, a fire in this fire zone is conservatively assumed to disable control of all of the valves in this fire zone. The passive core cooling system safe shutdown components located in fire zone 1100 AF 11206 and 1100 AF 11300A are redundant to those in this fire zone, and are sufficient to perform applicable functions to achieve and maintain safe shutdown.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.5 Fire Zone 1100 AF 11208

This fire zone is comprised of the following room(s):

Room No.	
11208	Normal residual heat removal valve room

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of lubricant in the valve actuators. There are no significant concentrations of combustible materials. This small fire zone is physically separated from other fire zones by walls, floor and ceiling with concrete thicknesses of more than one foot, except for a closed access hatch and a passageway to the adjacent PXS valve/accumulator room (fire zone 1100 AF 11207). The large accumulator vessel stands in front of this passageway and provides a barrier to fire propagation between the two fire zones. If fire were to propagate to fire zone 1100 AF 11207, however, fire zone 1100 AF 11206 provides redundant safe shutdown equipment.

Smoke and hot gases from a fire in this fire zone migrate into the adjacent PXS valve/accumulator room (fire zone 1100 AF 11207). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this zone. Although it is unlikely that more than one valve would be damaged, a fire in this fire zone is conservatively assumed to disable control of all of the valves in this fire zone. During normal power operation, power to the hot leg suction isolation valves is locked out to protect the high-low pressure interface between the reactor coolant system and the normal residual heat removal such that they will be unaffected by the fire in maintaining the reactor coolant pressure boundary. The normal residual heat removal containment isolation valve, located outside the containment fire area, is redundant to the four containment

isolation valves in this zone and is sufficient to maintain containment and reactor coolant pressure boundary integrity.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.6 Fire Zone 1100 AF 11209

This fire zone is comprised of the following room(s):

Room No.	
11209	Chemical and volume control system room

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire in this fire zone does not propagate to the extent that it damages safe shutdown components outside this fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of negligible amounts of cable insulation. There are no significant concentrations of combustible materials. This fire zone is physically separated from other fire zones by walls, floor and ceiling with concrete thicknesses of more than one foot, except for an access stairway, hatches and an opening from the maintenance floor above (fire zone 1100 AF 11300B).

Smoke and hot gases from a fire in this fire zone rise through the opening and spread through the large maintenance floor air space (fire zones 1100 AF 11300A and B). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

There are no safe shutdown components in this fire zone. No further evaluation is required.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.7 Fire Zone 1100 AF 11300A

This fire zone is comprised of the following room(s):

Room No.	
11300	Maintenance floor (southern part)
11400	Maintenance floor mezzanine (southern part)

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation. There are small concentrations of cables at the top of the zone and at several separate locations along the walls. This fire zone is physically separated from fire zones below by the maintenance floor, with a concrete thickness of more than one foot, except for openings described in the evaluation of fire zone 1100 AF 11206. This fire zone is separated from the operating deck above (fire zone 1100 AF 11500) by a ceiling with a concrete thickness of more than one foot, except for the hatches near the containment maintenance hatch, which are covered with steel grating. The walls of this fire zone are the steel containment vessel, the steel wall of the in-containment refueling water storage tank, or walls with a concrete thickness of more than one foot, except for two designated boundaries with the adjacent portion of the maintenance floor (fire zone 1100 AF 11300B). These boundaries are approximately at the centerline of containment, one located in the narrow annular space behind the in-containment refueling water storage tank and the other near the personnel hatch. The steam generator compartments, the refueling cavity, and the in-containment refueling water storage tank provide barriers between the two large maintenance floor fire zones. Safe shutdown components fire zone 1100 AF 11300A are separated from redundant safe shutdown components in fire zone 1100 AF 11300B by these barriers or by a horizontal distance of more than 20 feet with no intervening combustible or fire hazards. In addition, safety-related cables in both of these fire zones are routed in closed cable trays or conduit, minimizing the likelihood that a fire originating in a raceway of one division can propagate to a raceway of another division. Furthermore, passive fire stops are provided for nonsafety-related electrical cables routed in open cable trays in fire zone 1100 AF 11300B (there are no such cable trays in fire zone 1100 AF 11300A), providing additional assurance that a fire will not propagate between these fire zones.

Most of the smoke and hot gases from a fire in this fire zone rises through the large steel grating covered hatches between the containment maintenance hatch and the steam generator 2 compartment into the large air space in the upper portion of containment (fire zone 1100 AF 11500). Small quantities of smoke, especially that which has already cooled, may migrate horizontally into the adjacent portion of the maintenance floor (fire zone 1100 AF 11300B). The smoke and gases are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Temperature effects on the electrical cables routed high above the operating deck and passing over the large steel-grating covered hatches are not expected to be significant, but are not a concern as these are the same cables that continue into this fire zone and are assumed to be lost. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. The passive core cooling system has two IRWST gutter isolation valves located in this zone. These valves close to divert condensate from the passive containment cooling system (on the inside of the containment shell) into the IRWST. This condensate maintains the passive residual heat removal heat exchanger heat sink for the long term. These valves are fail closed air operated valves. They are located at least 12 feet apart horizontally and at least 10 feet apart vertically. One valve is located on the south end of the refueling cavity, the other is located on the east side of the refueling cavity. In addition, a fire detector is located close to each valve. Given the low combustible materials in this fire zone, a fire will only affect one of the valves initially. The fire detector located near the valve that is initially affected will alert the operators so that they can actuate the unaffected valve before the fire can prevent operation of the second valve. These valves are qualified to operate with elevated temperatures of 340°F.

Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to eventually disable all of the safe shutdown components in this fire zone.

The redundant passive core cooling system and steam generator system safe shutdown components (listed in Table 9A-2), located in fire zones 1100 AF 11207 and 1100 AF 11300B, are sufficient to perform applicable functions to achieve and maintain safe shutdown.

The primary sampling system and containment air filtration system containment isolation valves, located outside the containment fire area, are redundant to the containment isolation valves in this fire zone and are sufficient to maintain containment integrity.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.8 Fire Zone 1100 AF 11300B

This fire zone is comprised of the following room(s):

Room No.	
11300	Maintenance floor (northern part)
11400	Maintenance floor mezzanine (northern part)
11403	Pressurizer Spray Valve Room

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is moderate, consisting primarily of cable insulation in the termination boxes and cable trays. There is a concentration of cables on the south side of the zone near the refueling cavity and small concentrations of cables at the top of the zone and at several locations along the walls. This fire zone is physically separated from fire zones below by the maintenance floor, which has a concrete thickness of more than one foot, except for access stairways and hatches. This fire zone is separated from the operating deck above (fire zone 1100 AF 11500) by a ceiling that has a concrete thickness of more than one foot, except for several openings for an access stairway, elevator, hatches and blockouts. The walls of this fire zone are the steel containment vessel, the steel wall of the in-containment refueling water storage tank, the noncombustible enclosure for the division B and D penetrations and raceways (fire zone 1100 AF 11500), or walls with a concrete thickness of more than one foot, except for the designated boundaries with the adjacent portion of the maintenance floor, described in the evaluation of fire zone 1100 AF 11300A. There is a doorway between the lower pressurizer compartment (fire zone 1100 AF 11303) and the steam generator #1 lower manway platform (fire zone 1100 AF 11301).

Safety-related cables are routed in closed cable trays or conduit. For open cable trays, which represent the only significant in-situ combustibles in fire zone 1100 AF 11300B, passive fire stops are provided to prevent postulated fires in these open cable trays from propagating to an adjacent fire zone.

Smoke and hot gases from a fire in this fire zone rise through openings in the ceiling, or migrate via the large steel grating covered hatches between the containment maintenance hatch and the steam generator 2 compartment in the adjacent portions of the maintenance floor (fire zone 1100 AF 11300A), into the large air space in the upper portion of containment. They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. The division A and C electrical penetrations listed in Table 9A-2 are conservatively assumed to be disabled as a result of a fire in this fire zone. The B and D electrical penetrations and their cable trays routed from the electrical penetrations up to the operating deck are functionally part of fire zone 1100 AF 11500. These two divisions are sufficient to perform applicable functions to achieve and maintain safe shutdown as described in Subsection 9A.2.7.

These division B and D electrical penetrations and their associated raceways are protected from a fire in this fire zone by a combination of barriers, distance and passive fire stops. Noncombustible barriers of steel or steel-composite construction form vertical shaft(s) from the floor up to the operating deck, surrounding the division B and D penetrations and the associated cable trays. The significant combustible materials in this fire zone are the nonsafety-related cables routed in open cable trays. These cable trays are located at least 20 feet from the division B and D penetrations and their associated raceways, and they are provided with passive fire stops to prevent postulated fires in these open cable trays from propagating to an adjacent fire zone.

The passive core cooling system has two passive residual heat removal heat exchanger control valves which are located in this fire area. These valves are fail-open air-operated valves. They are located within several feet of each other. The valves are separated from each other by a noncombustible barrier of steel or steel composite materials. One of the valves is located close to the IRWST wall. This valve is assigned to division A. The other valve is assigned to division B. The cables for this valve are enclosed in conduit or enclosed raceways and routed up through the operating deck. Separate fire detectors are provided near each valve. The only combustibles in the area are the valves themselves and their cables. A fire that would affect these valves would be expected to start at one of the valves. The barrier protects the other valve from the initial effects of the fire. The fire detectors would alert the operators and allow them to actuate the other valve before the fire could spread and damage it. These valves are qualified to operate with elevated temperatures of 340°F.

Reactor coolant system, and steam generator system instrumentation located in this fire zone are conservatively assumed to be disabled as a result of a fire in this fire zone. The redundant passive core cooling system instrumentation, reactor coolant system pressurizer, and steam generator system instrumentation located in fire zones 1100 AF 11206, 1100 AF 11300A, 1100 AF 11301, and 1100 AF 11500 are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Reactor coolant system temperature instrumentation located in fire zones 1000 AF 11301 and 1000 AF 11302 are sufficient to provide the monitoring function accomplished by the passive residual heat removal heat exchanger flow instrumentation located in this fire zone.

The reactor coolant system to chemical and volume control system stop valves located in this fire zone are conservatively assumed to be disabled as a result of a fire in this fire zone. The chemical and volume control system containment isolation valves located outside of this fire zone provide backup isolation capability to maintain the reactor coolant pressure boundary.

The chemical and volume control system and the liquid radwaste system containment isolation valves located outside the containment fire area are redundant to the containment isolation valves inside containment in this fire zone and are sufficient to perform the applicable functions to maintain containment integrity.

The redundant steam line pressure instruments located in fire area 1201 AF 05 for steam generator 1 and in fire area 1201 AF 06 for steam generator 2 are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The redundant core exit thermocouples located in fire zone 1100 AF 11500 are sufficient to provide the applicable safe shutdown monitoring function.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.9 Fire Zone 1100 AF 11301

This fire zone is comprised of the following room(s):

Room No.	
11201	Steam generator compartment 1
11301	Steam generator 1 lower manway area
11401	Steam generator 1 tubesheet area
11501	Steam generator 1 operating deck
11601	Steam generator 1 feedwater nozzle area
11701	Steam generator 1 upper manway area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation related to the reactor coolant pump motors and other components in this fire zone. These cables are generally located at separate locations near the perimeter of the fire zone and there are no significant cable concentrations. This fire zone is separated from other fire zones (except fire zone 1100 AF 11500) by structural barriers or partial barriers. The bottom of this fire zone is the solid concrete floor of the steam generator compartment. Up to an elevation more than 17 feet above the operating deck the fire zone is enclosed by walls with a concrete thickness of more than one foot, except for access passageways to and from the pressurizer compartment (fire zone 1100 AF 11303) and the adjoining portion of the vertical access area (fire zone 1100 AF 11204), and the floor grating interface between the vertical access area and the steam generator 1 access room (fire zone 1100 AF 11303). Above the top of these concrete walls, the fire zone is open to the large air space above the operating deck (fire zone 1100 AF 11500). A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Depending on fire location, smoke and hot gases from a fire in this fire zone rise through the annular space surrounding the steam generator or through the pressurizer compartment (fire zone 1100 AF 11303) and into the air space in the upper portion of the containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to disable all of the safe shutdown components in this fire zone.

The redundant reactor coolant system hot leg/cold leg instrumentation located in fire zone 1100 AF 11204 and redundant steam generator system steam generator level instrumentation located in 1100 AF 11300B are sufficient to perform applicable functions to achieve and maintain safe shutdown.

The four divisions of reactor coolant system/reactor coolant pump bearing water temperature instrumentation are assumed to be disabled and would not be available to detect and provide a trip signal on a loss of component cooling water to the pump. If the fire in this fire zone does not disable the pump, the component cooling water flow to the pump will be unaffected by the fire and will continue to provide cooling water to the pump bearings until the pump is tripped by other means.

The reactor coolant system reactor coolant pump shaft speed instruments are conservatively assumed to be disabled. The redundant reactor coolant system hot leg flow instrumentation located in fire zones 1100 AF 11300A and 1100 AF 11300B is sufficient to perform applicable functions to achieve and maintain safe shutdown.

The four reactor coolant system reactor head vent valves are assumed to be disabled. If power is lost while in the closed position, the head vent valves will maintain reactor coolant pressure boundary integrity. Refer to Subsection 9A.3.7.1.1 for a discussion on spurious actuation of reactor coolant system reactor head vent valves.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.10 Fire Zone 1100 AF 11302

This fire zone is comprised of the following room(s):

Room No.	
11202	Steam generator compartment 2
11302	Steam generator 2 lower manway area
11402	Steam generator 2 tubesheet area
11502	Steam generator 2 operating deck
11602	Steam generator 2 feedwater nozzle area
11702	Steam generator 2 upper manway area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation related to the reactor coolant pump motors and other components in this fire zone. These cables are generally located at separate locations near the perimeter of the fire zone and there are no significant cable concentrations. This fire zone is separated from other fire zones (except fire zone 1100 AF 11500) by structural barriers or partial barriers. The bottom of this fire zone is the solid concrete floor of the steam generator compartment. Up to an elevation of more than 17 feet above the operating deck the fire zone is enclosed by walls with a concrete thickness of more than one foot, except for access passageways from the vertical access area (fire zone 1100 AF 11204) and the maintenance

floor (fire zone 1100 AF 11300B). Above the top of these concrete walls, the fire zone is open to the large air space above the operating deck (fire zone 1100 AF 11500). A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone rise through the annular space surrounding the steam generator into the air space in the upper portion of the containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to disable all of the safe shutdown components in this fire zone.

The redundant reactor coolant system hot leg/cold leg instrumentation located in fire zone 1100 AF 11204 are sufficient to perform applicable functions to achieve and maintain safe shutdown.

The four divisions of reactor coolant system/reactor coolant pump bearing water temperature instrumentation are assumed to be disabled and would not be available to detect and provide a trip signal on a loss of component cooling water to the pump. If the fire in this fire zone does not disable the pump, the component cooling water flow to the pump will be unaffected by the fire and will continue to provide cooling water to the pump bearings until the pump is tripped by other means.

The reactor coolant system reactor coolant pump shaft speed instruments are conservatively assumed to be disabled. The redundant reactor coolant system flow instrumentation located in fire zones 1100 AF 11300A and 1100 AF 11300B are sufficient to perform applicable functions to achieve and maintain safe shutdown.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.11 Fire Zone 1100 AF 11303

This fire zone is comprised of the following room(s):

Room No.	
11303	Lower pressurizer compartment
11304	Steam generator 1 access room
11503	Upper pressurizer compartment

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of the cable insulation for the pressurizer heaters. There are no significant cable concentrations. This fire zone is separated from other fire zones (except fire zone 1100 AF 11500) by structural barriers or partial

barriers. The bottom of this fire zone is solid concrete except for floor grating in the steam generator 1 access room (above fire zone 1100 AF 11301). Up to an elevation more than 33 feet above the operating deck this fire zone is enclosed by walls with a minimum concrete thickness of more than one foot, except for access passageways to and from the steam generator 1 compartment (fire zone 1100 AF 11301) and a closed doorway from the maintenance floor (fire zone 1100 AF 11300B). Several feet above the top of these walls, a steel platform separates the top this fire zone from fire zone 1100 AF 11303A directly above. Between the top of the walls and this platform the sides of this fire zone are open to the large air space above the operating deck (fire zone 1100 AF 11500). A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone rise through the annular space surrounding the pressurizer into the air space in the upper portion of the containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components contained in this fire zone. The quantity of combustible materials is low consisting primarily of the cable insulation for the pressurizer heaters located at the bottom of the fire zone. The RCS pressurizer level reference leg temperature instruments are separated from these combustible materials by a distance of approximately 35 feet. There are no intervening combustibles or fire hazards located near to or between the RCS pressurizer level reference leg temperature instruments. Smoke and hot gases from a fire in the cable trays located approximately 35 feet below would not be expected to accumulate in the large open spaces of the fire zone because the fire zone is open to the main containment atmosphere and thus venting of the fire zone will occur. As a result, the safe shutdown components located in this fire zone would not be adversely impacted by a fire. The 35-foot distance will not cause the reference leg temperature, the RTD temperature or the RTD cable temperature to exceed the 700 degree Fahrenheit temperature range of the RTD, and therefore all four compensated level measurements will have good quality.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.12 Fire Zone 1100 AF 11303A

This fire zone is comprised of the following room(s):

Room No.	
11603	Lower automatic depressurization system valve area

Safe Shutdown Evaluation

There are no safe shutdown components located in this fire zone that are required to operate as a result of a fire.

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of lube oil and lubricant in the motor-operated valve actuators. There are no significant cable concentrations. This fire zone is separated from other fire zones (except fire zone 1100 AF 11500) by structural barriers. Steel plate provides separation from the pressurizer compartment (fire zone 1100 AF 11303). Steel plate provides separation from the upper automatic depressurization system valve area (fire zone 1100 AF 11303B). The sides of this fire zone are open to the large containment air space above the operating deck (fire zone 1100 AF 11500). A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone are deflected horizontally by the ceiling into the surrounding air space in the upper portion of the containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.13 Fire Zone 1100 AF 11303B

This fire zone is comprised of the following room(s):

Room No.	
11703	Upper automatic depressurization system valve area

Safe Shutdown Evaluation

There are no safe shutdown components located in this fire zone that are required to operate as a result of a fire.

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of lube oil and lubricant in the motor-operated valve actuators. There are no significant cable concentrations. Steel plate provides separation from the lower automatic depressurization system valve area (fire zone 1100 AF 11303A). The top and sides of this fire zone are open to the large containment air space above the operating deck (fire zone 1100 AF 11500), which has no nearby combustibles. A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone rise into the large air space in the upper portion of containment (fire zone 1100 AF 11500). They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.14 Fire Zone 1100 AF 11500

This fire zone is comprised of the following room(s):

Room No.	
11500	Operating deck
11504	Refueling cavity
11306	Division B/D Penetration Room

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separates this zone from other fire zones are such that a fire which damages safe shutdown components in this zone does not propagate to the extent that it damages redundant safe shutdown components in another fire zone.

The quantity of combustible materials in this fire zone is moderate, consisting primarily of cable insulation. There are small concentrations of cables in horizontal raceways around the circumference of this fire zone high above the operating deck, in vertical raceways at separate locations near the boundaries of this fire zone, and at the center of the fire zone in the vicinity of the reactor vessel integrated head package. This fire zone encompasses much of the containment. It is physically separated from fire zones below by the operating deck or the bottom of the refueling cavity, which have a concrete thicknesses of more than one foot, except for penetrations described in the evaluations of fire zones below this fire zone. There also is a few inch clearance annulus around the entire operating deck. The walls of this fire zone are the steel containment vessel or walls with a concrete thickness of more than one foot, with exceptions as described earlier for fire zones 1100 AF 11301, 1100 AF 11302, 1100 AF 11303, and 1100 AF 11303A & B. The boundary of this fire zone also includes the 3-hour fire barriers that protect the division B and D containment penetrations on elevation 107'-2" and the associated raceways from these penetrations up to the operating deck. A fire does not propagate beyond this fire zone to the extent that it damages redundant safe shutdown components in another fire zone.

Smoke and hot gases from a fire in this fire zone rise into the large air space above the operating deck. They are cooled by mixing with the air and by contact with structural surfaces and thus do not cause propagation of the fire beyond this fire zone. Safe shutdown components listed in Table 9A-2 for the adjacent fire zones are not susceptible to damage by the diluted and cooled smoke and gases from this fire zone.

Table 9A-2 lists the safe shutdown components located in this fire zone. Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to disable all of the safe shutdown components in this fire zone.

Control of all division B and D components in the containment is conservatively assumed to be disabled. The primary division A and C electrical cables that provide power supply to safe shutdown components in containment are located in 1100 AF 11300B and are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The in-core instrumentation system core exit temperature instrument cable assemblies located in this fire zone are conservatively assumed to be disabled as a result of a fire in this fire zone. The reactor coolant system hot leg temperature (wide range) instrumentation located in fire zones 1100 AF 11301 and 1100 AF 11302 provide a diverse means of observing temperature conditions in the reactor vessel to support the safe shutdown process.

The reactor coolant system narrow range level instrumentation is conservatively assumed to be disabled. The redundant reactor coolant system narrow range level instrumentation located in fire zone 1100 AF 11300B is sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The central chilled water system containment isolation valve located outside the containment fire area is redundant to the containment isolation valve inside containment in this fire zone and is sufficient to perform the applicable functions to maintain containment integrity.

The redundant reactor coolant system pressurizer instrumentation and redundant reactor coolant system hot leg instrumentation located in 1100 AF 11300B are sufficient to perform applicable functions to achieve and maintain safe shutdown.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.15 Fire Zone 1200 AF 12341

This fire zone is comprised of the following room(s):

Room No.	
12341	Middle annulus

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire does not propagate to or from this fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of rubber. The Class 1E electrical penetration assemblies also pass through this fire zone, but are separated by 3-hour rated fire barriers constructed between the containment steel shell and the shield building concrete structure. The Class 1E electrical penetration assemblies are considered extensions of the associated Class 1E divisional fire areas on the other side of the shield building wall except for the division A penetration assemblies, which are part of this fire zone. This fire zone is physically separated from other fire zones by the steel wall of containment and by the steel and concrete vessel stiffener and flexible ventilation seal above, and it is separated from adjacent fire areas by the walls and floor of the shield building, which have concrete thicknesses of more than one foot, and the 3-hour fire barriers enclosing the Class 1E electrical penetrations. The access doorway to the middle annulus fire zone is closed by a door.

The radiologically controlled area ventilation system serves this fire area on a once-through basis. Smoke and hot gases are confined in this fire zone following automatic closure of the fire dampers on high temperature, while the balance of the radiologically controlled area ventilation system continues to operate at the discretion of the operator. There is no propagation of the fire beyond this fire zone. Smoke and gases are removed from the fire zone by reopening the fire dampers after a fire. The radiologically controlled area ventilation system exhausts the smoke and gases to the atmosphere.

Table 9A-2 lists the safe shutdown components located in this fire zone. The redundant passive containment cooling system safe shutdown components located in fire area 1200 AF 01 are sufficient to perform applicable functions to achieve and maintain safe shutdown. The Class 1E electrical penetrations for division B, C, and D are separated from this fire zone by 3-hour fire barriers between the containment steel shell and the shield building concrete structure and are part of the associated

divisional fire areas outside the shield building. The division A Class 1E electrical penetration assemblies that are part of this fire zone are not associated with the cables necessary to support the function of the redundant PCS components in fire area 1200 AF 01.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.16 Fire Zone 1200 AF 12541

This fire zone is comprised of the following room(s):

Room No.	
12541	Upper annulus

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire does not propagate to or from this fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of plastic. There are no cable concentrations. This fire zone is physically separated from other fire zones by the steel wall of containment and the steel and concrete vessel stiffener and flexible ventilation seal below, and it is separated from adjacent fire areas by the walls of the shield building, which have a concrete thickness of more than one foot. Access doorways are closed by doors. The physical separation between this fire zone and fire zone 1270 AF 12701 are described in the evaluation for that zone. This fire zone communicates with the environment via the passive containment cooling system air inlets at the top perimeter of the shield building and the passive containment cooling system air outlet at the center of the shield building roof. These openings have screens that prevent the entry of external debris.

Smoke and hot gases from a fire in this fire zone rise to the top of the fire zone and into the atmosphere and thus do not cause propagation of a fire beyond this fire zone.

The safe shutdown components in this fire zone are the Divisions A, B, and C electrical cables that serve the redundant passive containment cooling system valves and instruments located in the passive containment cooling system valve room. Although the consequences of a fire are expected to be very limited, a fire in this fire zone is conservatively assumed to disable these safe shutdown valves and instruments.

The valves for each passive containment cooling system water delivery path are arranged with a normally open motor-operated valve and normally closed/fail open air-operated valve in series. If the fire causes a loss of power to the valves, the air-operated valves will open and passive containment cooling system flow, which has no adverse impact on achieving and maintaining safe shutdown, will be initiated. Refer to Subsection 9A.3.7.1.2 for a discussion of potential spurious actuation of a passive containment cooling system water delivery valve as a result of a fire.

The passive containment cooling system water delivery flow and storage tank level instrumentation are conservatively assumed to be disabled as a result of a fire in this fire zone. The applicable function of verification of passive containment cooling system water delivery can be performed by visual observation via access to the passive containment cooling system air diffuser from the passive containment cooling system valve room.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.17 Fire Zone 1270 AF 12701

This fire zone is comprised of the following room(s):

Room No.	
12701	Passive containment cooling system valve room
S06	Stairwell

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire does not propagate to or from this fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of lubricant related to the valves and instruments in this fire zone. There are no cable concentrations. This fire zone is physically separated from fire zone 1200 AF 12541 by structural partitions and closed doorways.

In the unlikely event of a fire, the fire brigade would approach the PCS valve room (Room 12701, Fire Zone 1270 AF, Fire Area 1000 AF 01) by using stairwell S03 or the adjacent elevator attached to the outside wall on the shield building. The fire brigade would egress from stairwell S03 (Fire Area 1204 AF 02) into the lower level of the PCS valve room (Room 12701) at the El. 264′-6″ platform (Fire Zone 1270 AF, Fire Area 1000 AF 01). Two types of portable fire extinguishers (a dry chemical and a water fire extinguisher) are provided at this lower level for manual fire fighting. The fire brigade would proceed up the inclined stairs S06 to the upper level of the PCS valve room (Room 12701) located on El. 286′-6″. Two types of portable fire extinguishers (a dry chemical and a water fire extinguisher) are also provided at this upper level for manual fire fighting.

Smoke and hot gases from a fire in Room 12701 are exhausted by normal operation of the room exhaust fan to fire zone 1200 AF 12541, where they rise through openings in the top of that fire zone into the atmosphere. There are no combustible materials in the vicinity of the exhaust location and thus the smoke and hot gases do not cause propagation of a fire beyond this fire zone. If the exhaust fan is disabled by the fire, smoke and gases are later removed using portable fans and ductwork. The stairwell S06 is not served by a ventilation system. The quantity of combustible materials in the stairwell is negligible and no fire is postulated.

Table 9A-2 lists the safe shutdown components located in this fire zone. Although it is unlikely that all components would be damaged, a fire in this fire zone is conservatively assumed to disable all of the safe shutdown valves and instruments in this fire zone.

The valves for each passive containment cooling system water delivery path are arranged in three flow paths. Two paths have a normally open motor-operated valve and normally closed/fail open air-operated valve in series. The third path has a normally open motor-operated and a normally closed motor operated valve in series. If the fire causes a loss of power to the air-operated valves, they will open and passive containment cooling system flow, which has no adverse impact on achieving and maintaining safe shutdown, will be initiated. Refer to Subsection 9A.3.7.1.2 for a discussion of potential spurious actuation of a passive containment cooling system water delivery valve as a result of a fire.

The passive containment cooling system water delivery flow and storage tank level instrumentation are conservatively assumed to be disabled as a result of a fire in this fire zone. The applicable function of verification of passive containment cooling system water delivery can be performed by visual observation via access to the passive containment cooling system air diffuser from the passive containment cooling system valve room or from the upper annulus.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.1.18 Fire Zone 1250 AF 12555

This fire zone is comprised of the following room(s):

Room No.	
12555	Main control room emergency habitability system air storage
12556	Operating deck staging area

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire zone, and the characteristics of the barriers that separate this zone from other fire zones are such that a fire does not propagate to or from this fire zone.

The quantity of combustible materials in this fire zone is low, consisting primarily of cable insulation and ordinary combustible material such as paper and plastic, but concentrations of transient combustibles may be present in the floor area outside the main equipment hatch. This fire zone is separated from adjacent fire areas by 3-hour fire barriers and it is separated from adjacent containment fire zones 1100 AF 11500 and 1200 AF 12541 by the main equipment hatch and its enclosure and the shield building wall, which has a concrete thickness of more than one foot.

Smoke and hot gases from a fire are confined in this fire zone following automatic closure of the fire dampers on high temperature and thus do not cause propagation of the fire beyond this fire zone. Smoke and gases are removed from the fire area by reopening the fire dampers after a fire. The radiologically controlled area ventilation system exhausts the smoke and gases to the atmosphere.

This fire zone contains no components required for safe shutdown after a fire. The pressurized main control room emergency habitability system air storage bottles are not required for safe shutdown after a fire, but are protected from fire-induced overpressure by pressure relief valves. There is no permanent storage of combustibles in room 12555.

No fire in this zone can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2 Auxiliary Building - Nonradiologically Controlled Areas

General Arrangement

The safe shutdown systems and components located in the nonradiologically controlled area are portions of the protection and safety monitoring system and the Class 1E dc system, and containment isolation.

The safe shutdown components in the protection and safety monitoring system are the instrumentation and control cabinets located in the nonradiologically controlled area on level 3 (elevation 100′-0″). The safe shutdown components in the Class 1E dc system are the Class 1E batteries on level 1 (elevation 66′-6″) and level 2 (elevation 82′-6″) and the dc electrical equipment, also on level 2.

The nonradiologically controlled areas of the auxiliary building are designed to provide separation between the mechanical and electrical equipment areas.

The piping compartments in the nonradiologically controlled area are the main steam isolation valve compartments on levels 4 and 5 (elevations 117′-6″ and 135′-3″, respectively) and the valve/piping penetration compartment on level 3 (elevation 100′-0″). The mechanical equipment rooms in the nonradiologically controlled area are the HVAC compartments on levels 4 and 5.

The nonradiologically controlled areas of the auxiliary building are also designed to provide separation between the Class 1E and the non-Class 1E electrical equipment.

Smoke Control

Table 9A-4 identifies the ventilation systems serving fire areas containing Class 1E electrical components. This section describes the approach to smoke control for fire areas in the nonradiologically controlled portion of the auxiliary building that contain the main Class 1E electrical equipment rooms served by the nuclear island nonradioactive ventilation system (VBS). Smoke control for fire areas containing other Class 1E components, such as valves, instrumentation and electrical cable, is discussed in the text for the individual fire areas.

The Class 1E electrical equipment room fire areas have been designed to prevent the migration of smoke, hot gases, and fire suppressant to the extent that they could adversely affect safe shutdown capabilities, including operator actions. These fire areas are separated from each other and from other plant areas by 3-hour fire barriers. Smoke from a fire in the turbine building or other nearby fire areas is prevented from affecting the Class 1E areas by isolation of the nuclear island nonradioactive ventilation system outdoor air intakes, as described in Subsection 9.4.1.

The nuclear island nonradioactive ventilation system is designed to control the migration of smoke and hot gases produced by a fire. As described in Subsection 9.4.1, two independent ventilation subsystems, located in separate fire areas, serve the Class 1E electrical equipment rooms. The division A and C Class 1E electrical room HVAC subsystem has three distribution headers. One header supplies the two division A electrical equipment room fire areas, a second header supplies the division C electrical equipment room fire area, and a third header supplies other related fire areas. The division B and D class 1E electrical room HVAC subsystem also has three distribution headers. One header supplies the division B electrical equipment room fire area, a second header supplies the division D electrical equipment room fire area, and a third header supplies other related fire areas.

A fire affecting a division A or C electrical equipment room fire area does not affect operation of the ventilation subsystem serving the division B & D electrical equipment room fire areas and vice versa. In addition, a fire affecting an electrical equipment room fire area affects the operation of only one of the three distribution headers in the subsystem. As described in Subsection 9.4.1.2.3.2, the affected subsystem continues to provide ventilation to the remaining fire areas served by the other two distribution headers.

Similarly, the ventilation subsystem serving the main control room and the ventilation subsystem serving the remote shutdown room operate independently of each other and are located in separate fire areas. A fire affecting the main control room does not affect operation of the ventilation subsystem serving the remote shutdown room and vice versa.

The migration of smoke and hot gases produced by a fire occurring in a Class 1E electrical equipment room fire area is controlled by operation of the nuclear island nonradioactive ventilation system as described in Subsection 9.4.1.2.3. Further information on smoke control is provided in the discussions for the individual fire areas.

9A.3.1.2.1 Division A Electrical Rooms

9A.3.1.2.1.1 Fire Area 1202 AF 04

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1212 AF 12101	12101	Division A battery room
• 1222 AF 12201	12201	Division A dc equipment room
• 1232 AF 12301	12301	Division A instrumentation and control room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the Division C fire area (1202 AF 03). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire and smoke dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Smoke dampers are provided in the ventilation system supply and return ducts to the dc equipment room and to the instrumentation and control room, to delay smoke migration between these fire zones and facilitate operator action to preclude postulated spurious actuations.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the electrical equipment in this fire area. There are concentrations of battery cells on opposite walls of the battery room fire zone. There are small concentrations of cable in the electrical cabinets located on opposite walls of the dc

equipment room fire zone. There are small concentrations of cable overhead and in the electrical cabinets located in the middle of the instrument and control room fire zone. The combustible loading for this fire area exceeds 80,000 Btu/ft^2, warranting the need for detection and automatic and manual suppression capabilities per the guidelines in Subsection 9A.2.4. Automatic suppression is not installed in this fire area as an effort is made to limit water sources in this area for internal flooding concerns. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The three fire zones in this fire area are separated from each other by 1-hour fire barriers, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. These division A electrical rooms are physically separated from the other safety-related divisions and by 3-hour fire barriers. In the event of a fire in one of these rooms, it is assumed that control of all division A components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions. For this event, the division B, C, and D components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Class 1E divisions B, C, and D interdivisional cables for data communication between divisions are in this fire area. In the event of a fire, it is assumed that data transmitted between division A and the other Class 1E divisions is lost. This loss of data does not disable the safe shutdown functions of the three Class 1E divisions.

Control room dedicated switches which are used to initiate engineered safety features at the system level are connected to the engineered safety features actuation cabinets using two-pole, energize-to-actuate, ungrounded dc circuits.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation.

Following detection of a fire in the instrumentation and control room, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the instrumentation and control room.

Following detection of a fire in the dc equipment control room, the operators can close the automatic depressurization system stage 4 block valve, then remove cabinet power from this division using the input power switches on the instrumentation and control cabinets. This operator action will prevent spurious smoke-induced actuation of motor operated valves and squib valves resulting smoke-related integrated circuit failures in the instrumentation and control room.

Power to the passive residual heat removal heat exchanger inlet isolation valve is normally locked out at power to prevent spurious closing.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.1.2 Fire Area 1242 AF 02

This fire area is comprised of the following room(s):

Room No.	
12412	Electrical penetration room division A

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the division C electrical penetration room (in fire area 1202 AF 03). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the containment electrical penetrations. There are small concentrations of cable at the electrical penetrations and in the overhead cable trays. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

Two discharge openings penetrate the 24" thick concrete wall between room 12412 and the main control room vestibule in fire area 1242 AF 01 to provide a purge flow path for the main control room habitability system, as discussed in Subsection 6.4.2.3. The 4-inch (nominal) diameter openings are provided with downturned pipe elbows on each side terminating approximately 6 inches above the floor. A full-scale fire test conducted at a qualified testing facility in accordance with ASTM E814-13a

(Reference 204) demonstrated that this design meets the 3-hour fire barrier requirements for fire rating and temperature rating.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The division A penetration room is physically separated from the other safety-related divisions and nonsafety-related equipment by 3-hour fire barriers. In the event of a fire in this room, it is assumed that control of all division A and C active components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions. For this event, the division B and D components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

In addition, division C electrical cables that serve the redundant passive containment cooling system valves and instruments located in the passive containment cooling system (PCS) valve room (Room 12701) are routed through this fire area. In the event of a fire, it is also assumed that this division is disabled. The remaining division B electrical cables and components routed through and located in other fire areas are sufficient to perform the applicable functions to achieve and maintain safe shutdown. Refer to Subsection 9A.3.1.1.17, Fire Zone 1270 AF 12701, for the Safe Shutdown Evaluation of that zone.

Following detection of a fire in this fire area, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the penetration room.

Power to the passive residual heat removal heat exchanger inlet isolation valve is normally locked out at power to prevent spurious closing.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.2 Division B Electrical Rooms

9A.3.1.2.2.1 Fire Area 1201 AF 02

This fire area contains division B electrical rooms. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1211 AF 12104	12104	Division B battery room 1
• 1221 AF 12204	12204	Division B battery room 2
• 1222 AF 12207	12207	Division B dc equipment room

- 1231 AF 12304 12304 Division B instrumentation and control/penetration room
- 1231 AF 12344 12344 Division B middle annulus penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the division D fire area (1201 AF 03). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire and smoke dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. The middle annulus penetration room division B is treated as an extension of this fire area. No ventilation system serves this fire zone, and smoke and hot gases are confined with no propagation of the fire beyond the fire zone. After the fire, smoke is removed by opening the personnel doors and using portable exhaust fans and flexible ductwork. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Smoke dampers are provided in the ventilation system supply and return ducts to the dc equipment room and to the instrumentation and control/penetration room, to delay smoke migration between these fire zones and facilitate operator action to preclude postulated spurious actuations.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector, which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are concentrations of battery cells on opposite walls of each of the two battery room fire zones. There are small concentrations of cable overhead and in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead, at the electrical penetrations, and in the electrical cabinets located in the middle of the instrumentation and control/penetration room fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. The boundary of this fire area extends to include the electrical penetration assemblies within the containment annulus, which are enclosed by 3-hour fire barriers. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The battery rooms are also separated from the adjacent division B electrical rooms by 1-hour fire barriers, and the dc equipment room is separated from adjacent division B electrical rooms by 1-hour fire barriers, which limit the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. In the auxiliary building, the division B electrical rooms are physically separated from the other safety-related divisions and nonsafety-related equipment by 3-hour fire barriers. In the middle annulus, the Division B electrical penetrations are separated from the other safety-related divisions and nonsafety-related equipment by 3-hour rated fire barriers constructed between the containment steel shell and the shield building concrete structure. In the event of a fire in a division B electrical room, it is assumed that control of all division B active components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions. For this event, the division A, C, and D components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

There is a division D conduit that traverses fire area 1201 AF 02, the cables in this conduit are associated with the main control room (MCR)/remote shutdown room transfer switch function. The habitability of the MCR is not affected by a postulated fire in this zone and the affected cables cannot cause or prevent division D components from functioning.

Class 1E divisions A, C, and D interdivisional cables for data communication between divisions are in this fire area. In the event of a fire, it is assumed that data transmitted between division B and the other Class 1E divisions is lost. This loss of data does not disable the safe shutdown functions of the three Class 1E divisions.

Control room dedicated switches which are used to initiate engineered safety features at the system level are connected to the engineered safety features actuation cabinets using two-pole, energize-to-actuate, ungrounded dc circuits.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation.

Following detection of a fire in the instrumentation and control/penetration room, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the instrumentation and control/penetration room.

Following detection of a fire in the dc equipment control room, the operators can close the automatic depressurization system stage 4 block valve, then remove cabinet power from this division using the input power switches on the instrumentation and control cabinets. This operator action will prevent spurious smoke-induced actuation of motor operated valves and squib valves resulting smoke-related integrated circuit failures in the instrumentation and control room.

Power to the normal residual heat removal hot leg suction isolation valves is normally locked out at power to prevent spurious opening.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.2.2 Fire Area 1220 AF 01

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1222 AF 12212	12212	Division B reactor coolant pump trip switchgear room
• 1222 AF 12213	12213	Spare room
• 1220 AF 12211	12211	Corridor

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, including the fire area for the division C trip switchgear room (1202 AF 03). Fire areas 1200 AF 03 and 1210 AF 01 are served by the same air distribution header as this fire area, but they continue to receive ventilation because they have separate supply ducts. The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation. There are small concentrations of cable in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead and in the electrical cabinets in the reactor coolant pump trip switchgear room and spare room fire zones. There are small concentrations of cable overhead and at the east end of the corridor fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. See Section 3.4 for a discussion of the consequences of a break in a fire protection line in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. A fire in this fire area is assumed to disable the safe shutdown components in the fire area.

The reactor coolant pumps can be tripped by the redundant division C reactor coolant pump trip switchgear, located in fire area 1202 AF 03. The division B and D cable tray in the fire area includes signals to the reactor trip switchgear and inputs to other division protection logic. Inputs from divisions A and C are sufficient to trip the reactor when needed, or the reactor can be tripped manually. Loss of division A and C data input to the division B and D protection logic does not disable the safe shutdown functions of the four Class 1E divisions.

Cable trays in the fire areas include signals to B and D isolation valves outside containment. Containment isolation is provided by redundant containment isolation valves, located in another fire area inside containment. Redundant division C valves control water flow from the passive containment cooling system storage tank. The components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

The steam generator system steam generator 1 startup feedwater flow instrumentation is assumed to be disabled. The steam generator system steam generator 1 wide range level instrumentation located in fire zones 1100 AF 11300B and 1100 AF 11301 provides a diverse means of performing the applicable function of generating a passive residual heat removal actuation signal to achieve and maintain safe shutdown.

The steam generator system steam generator 2 startup feedwater flow instrumentation is assumed to be disabled. The steam generator system steam generator 2 wide range level instrumentation located in fire zones 1100 AF 11300A and 1100 AF 11300B provides a diverse means of performing the applicable function of generating a passive residual heat removal actuation signal to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.3 Division C Electrical Rooms

9A.3.1.2.3.1 Fire Area 1202 AF 03

This fire area contains division C electrical rooms. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1212 AF 12102	12102	Division C battery room 1

- 1222 AF 12202 12202 Division C battery room 2
- 1222 AF 12203 12203 Division C dc equipment room
- 1232 AF 12302 12302 Division C instrumentation and control room
- 1232 AF 12312 12312 Division C reactor coolant pump trip switchgear room
- 1232 AF 12313 12313 Instrumentation and control/division C penetration room
- 1232 AF 12343 12343 Division C middle annulus penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the division A fire area (1202 AF 04). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire and smoke dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. The middle annulus penetration room division C is treated as an extension of this fire area. No ventilation system serves this fire zone, and smoke and hot gases are confined with no propagation of the fire beyond the fire zone. After the fire, smoke is removed by opening the personnel doors and using portable exhaust fans and flexible ductwork. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Smoke dampers are provided in the ventilation system supply and return ducts to the dc equipment room, the instrumentation and control room, and the penetration room to delay smoke migration between these fire zones and facilitate operator action to preclude postulated spurious actuations.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are concentrations of battery cells on opposite walls of each of the two battery room fire zones. There are small concentrations of cable overhead and in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead and in the electrical cabinets located in the middle of the instrument and control room fire zone. There are small concentrations of cable overhead and at the electrical penetrations in the instrumentation and control/penetration room fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. The boundary of this fire area extends to include the electrical penetration assemblies within the containment annulus, which are enclosed by

3-hour fire barriers. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The battery rooms are also separated from the adjacent division C electrical rooms by 1-hour fire barriers, and the dc equipment room is separated from adjacent division C electrical rooms by 1-hour fire barriers, which limit the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. In the auxiliary building, the division C electrical rooms are physically separated from the other safety-related divisions and nonsafety-related equipment by 3-hour fire barriers. In the middle annulus, the Division C electrical penetrations are separated from the other safety-related divisions and nonsafety-related equipment by 3-hour rated fire barriers constructed between the containment steel shell and the shield building concrete structure. In the event of a fire in a division C electrical room, it is assumed that control of all division C components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions. The reactor coolant pumps can be tripped by the redundant division B reactor coolant pump trip switchgear, located in fire area 1220 AF 01. For this event, the division A, B, and D components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Class 1E divisions A, B, and D interdivisional cables for data communication between divisions are in this fire area. In the event of a fire, it is assumed that data transmitted between division C and the other Class 1E divisions is lost. This loss of data does not disable the safe shutdown functions of the three Class 1E divisions.

Control room dedicated switches which are used to initiate engineered safety features at the system level are connected to the engineered safety features actuation cabinets using two-pole, energize-to-actuate, ungrounded dc circuits.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation.

Following detection of a fire in either the instrumentation and control room or the instrumentation and control/division C penetration room, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the instrumentation and control room or the instrumentation and control/division C penetration room.

Following detection of a fire in the dc equipment control room, the operators can close the automatic depressurization system stage 4 block valve, then remove cabinet power from this division using the

input power switches on the instrumentation and control cabinets. This operator action will prevent spurious smoke-induced actuation of motor operated valves and squib valves resulting smoke-related integrated circuit failures in the instrumentation and control room.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.4 Division D Electrical Rooms

9A.3.1.2.4.1 Fire Area 1201 AF 03

The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1211 AF 12105	12105	Division D battery room
• 1221 AF 12205	12205	Division D dc equipment room
• 1231 AF 12305	12305	Division D instrumentation and control/penetration room
• 1231 AF 12345	12345	Division D middle annulus penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, which includes the division B fire area (1201 AF 02). The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire and smoke dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. The middle annulus penetration room division D is treated as an extension of this fire area. No ventilation system serves this fire zone, and smoke and hot gases are confined with no propagation of the fire beyond the fire zone. After the fire, smoke is removed by opening the personnel doors and using portable exhaust fans and flexible ductwork. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Smoke dampers are provided in the ventilation system supply and return ducts to the dc equipment room and to the instrumentation and control/penetration room, to delay smoke migration between these fire zones and facilitate operator action to preclude certain postulated spurious actuations.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are concentrations of battery cells on opposite walls of the battery room fire zone. There are small concentrations of cable overhead and in the electrical cabinets located on opposite walls of the dc equipment room fire zone. There are small concentrations of cable overhead, at the electrical penetrations, and in the electrical cabinets located in the middle of the instrumentation and control/penetration room fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. The boundary of this fire area extends to include the electrical penetration assemblies within the containment annulus, which are enclosed by 3-hour fire barriers. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The three fire zones in this fire area are separated from each other by 1-hour fire barriers, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. In the auxiliary building, the division D electrical rooms are physically separated from safety-related divisions A and C by 3-hour fire barriers. In the middle annulus, the Division D electrical penetrations are separated from the other safety-related divisions and nonsafety-related equipment by 3-hour rated fire barriers constructed between the containment steel shell and the shield building concrete structure. In the event of a fire in one of these rooms, it is assumed that control of all division D components is lost. Because of the physical separation, the fire does not adversely affect the other safety-related electrical divisions with the exception of the division B components located in fire zone 1270 AF 12701. For this event, the divisions A and C components identified in Table 9A-2 are sufficient to achieve and maintain safe shutdown.

Class 1E divisions A, B, and C interdivisional cables for data communication between divisions are in this fire area. In the event of a fire, it is assumed that data transmitted between division D and the other Class 1E divisions is lost. This loss of data does not disable the safe shutdown functions of the three Class 1E divisions.

Control room dedicated switches which are used to initiate engineered safety features at the system level are connected to the engineered safety features actuation cabinets using two-pole, energize-to-actuate, ungrounded dc circuits.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation.

A fire in this fire area is conservatively assumed to disable the division B PCS components located in fire zone 1270 AF 12701. See Subsection 9A.3.1.1.17 for the Safe Shutdown Evaluation for fire zone 1270 AF 12701.

Following detection of a fire in the instrumentation and control/penetration room, the operators can close the automatic depressurization system stage 4 block valve, then remove actuation power from this division using the battery transfer switch located in the dc equipment room to disconnect the battery and remote control from the control room to remove input power from the battery charger and regulating transformer. This operator action will prevent spurious actuation of motor operated valves and squib valves resulting from multiple hot shorts in the instrumentation and control/penetration room.

Following detection of a fire in the dc equipment control room, the operators can close the automatic depressurization system stage 4 block valve, then remove cabinet power from this division using the input power switches on the instrumentation and control cabinets. This operator action will prevent spurious smoke-induced actuation of motor operated valves and squib valves resulting smoke-related integrated circuit failures in the instrumentation and control room.

Power to the normal residual heat removal hot leg suction isolation valves is normally locked out at power to prevent spurious opening.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.5 Principal Class 1E Areas

9A.3.1.2.5.1 Fire Area 1242 AF 01

This fire area consists of the main control room. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1242 AF 12401A	12401	Main control area/operator work area/vestibule
• 1242 AF 12401B	12401	Shift manager's office/kitchen area/operator break room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors (including detectors in the subfloor spaces)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by the main control room/control support area HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). This VBS subsystem will shut down and combination fire-smoke dampers close automatically in response to a smoke detector signal(s) or high temperature to control the spread of fire and smoke. The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation

systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

Since the main control room is continuously manned, a fire is likely to be initially detected by an operator. Otherwise, a fire in this fire area is detected by a fire detector, which produces visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using portable extinguishers or, if necessary, using hose streams.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and paper. There are concentrations of cable under the floor in the north and east portions of this fire area and within the control consoles and display panels in the main control area. There are concentrations of paper in the main control area, the operator work area, and offices. Most of this paper is contained within metal filing cabinets, desks, or bookcases. This is a light hazard fire area and the rate of fire growth is expected to be slow. The fire area is continuously manned and prompt manual fire suppression is expected.

Generally, three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. Due to the need to provide passive cooling capability into the main control room ceilings, it will not be protected against fires from within the main control room. The ceiling will be a fire barrier from fires in the room above the main control room.

The two fire zones are also separated from each other by a 1-hour fire barrier, which limits the spread of fire within the fire area. Within fire zone 1242 AF 12401A the wall that separates the main control area from the operator work area is not fire-rated because it does not extend to the ceiling. This design improves the ceiling heat-absorbing characteristics provided for post-accident main control room habitability.

Two discharge openings penetrate the 24" thick concrete wall between the main control room vestibule and room 12412 in fire area 1242 AF 02 to provide a purge flow path for the main control room habitability system, as discussed in Subsection 6.4.2.3. The 4-inch (nominal) diameter openings are provided with downturned pipe elbows on each side terminating approximately 6 inches above the floor. A full-scale fire test conducted at a qualified testing facility in accordance with ASTM E814-13a (Reference 204) demonstrated that this design meets the 3-hour fire barrier requirements for fire rating and temperature rating.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The main control room contains circuits from the four Class 1E electrical divisions. Electrical separation to and inside the control panels is maintained per industry standards. The remote shutdown workstation is provided as an alternate to the main control room. The transfer of operations to the remote shutdown workstation is controlled by a transfer switch located outside the main control room. In the event of a fire in the main control room, control may be transferred to the remote shutdown workstation, depending on the extent of the fire. For a small fire, control is maintained in the main control room, and the potential for

damage or spurious signals is limited. For larger postulated fires, the main control room is evacuated and control is transferred to the remote shutdown workstation. Once control is transferred, spurious control signals potentially caused by the fire are isolated from the actuated devices by the transfer switch. In this event, the main control room is assumed to be lost for the duration of the event. Safe shutdown is controlled from the remote shutdown workstation. The extent of spurious signals is limited by the time to transfer control to the remote shutdown workstation.

Spurious actuation from control room dedicated switches which could lead to a breach of reactor coolant system pressure boundary, loss of decay heat removal function, or loss of shutdown reactivity control is prevented by the use of dual two-pole, energize-to-actuate, ungrounded dc circuits, which require at least four simultaneous hot shorts of proper polarity for spurious actuation. Following control room evacuation, the dedicated switches are disabled by the transfer switch.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.5.2 Fire Area 1232 AF 01

This fire area is comprised of the following room(s):

Room No.	
12303	Remote shutdown room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas. The system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and paper. There are concentrations of cable under the floor and within the control console. There are concentrations of paper, most of which is contained within metal filing cabinets or

bookcases. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The remote shutdown room contains circuits from the four Class 1E electrical divisions. Electrical separation to and inside the remote shutdown room is maintained per industry standards. The remote shutdown room is an alternate to the main control room. The transfer of operations to the remote shutdown workstation is controlled by a transfer switch set located in the remote shutdown workstation area. In the unlikely event that the fire damages the transfer switch set, causing transfer of control from the main control room to the remote shutdown workstation, the operator restores control to the main control room by de-energizing fire area 1202 AF 05 (stair S05). Safe shutdown is achieved using the safe shutdown components listed in Table 9A-2.

Most remote shutdown workstation controls use soft-controls which communicate over multiplexed data channels. Fire-induced spurious actuation from these multiplexed soft controls is not assumed. Fire-induced actuations from the dedicated switches in this area are prevented during normal operation by the transfer switch logic, which only enables operation from the remote shutdown workstation dedicated switches when control is transferred to the remote shutdown workstation.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.5.3 Fire Area 1243 AF 01

This fire area is comprised of the following room(s):

Room No.	
12423	Reactor trip switchgear 1

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through

smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the reactor trip switchgear, located in the center of this small fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. This fire area contains cable from each of the four Class 1E electrical divisions. This cable provides trip input from each of the four divisions and is separated per industry standards. The safety-related trip inputs are normally energized, so a fire in this area may result in a reactor trip. In the event the fire generates multiple hot shorts, interfering with the reactor trip signal, a reactor trip can be produced in the redundant trip cabinets located outside of this fire area in fire area 1243 AF 02. Furthermore, the reactor can be tripped with the diverse actuation system described in Section 7.7.

This fire does not affect other equipment in the Class 1E divisions. Therefore, the safe shutdown components listed in Table 9A-2 are available to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.5.4 Fire Area 1243 AF 02

This fire area is comprised of the following room(s):

Room No.	
12422	Reactor trip switchgear 2

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the reactor trip switchgear, located in the center of this small fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. This fire area contains cable from each of the four Class 1E electrical divisions. This cable provides trip input from each of the four divisions and is separated per industry standards. The safety-related trip inputs are normally energized, so a fire in this area may result in a reactor trip. In the event the fire generates multiple hot shorts, interfering with the reactor trip signal, a reactor trip can be produced in the redundant trip cabinets located outside of this fire area in fire area 1243 AF 01. Furthermore, the reactor can be tripped with the diverse actuation system described in Section 7.7.

This fire does not affect other equipment in the Class 1E divisions. Therefore, the safe shutdown components listed in Table 9A-2 are available to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.5.5 Fire Area 1210 AF 01

The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1210 AF 12111	12111	Corridor
• 1212 AF 12103	12103	Spare battery room
• 1212 AF 12112	12112	Spare room
• 1212 AF 12113	12113	Spare battery charger room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas, except for fire area 1220 AF 01 which is ventilated by ducts that are isolated by a fire in this fire area. The ventilation system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

If the spare batteries are being used as a backup power source for any division, a fire in this fire area is assumed to disable that division. Smoke from a fire in this fire area does not adversely affect components associated with divisions redundant to that supplied by the spare battery. Fire area 1200 AF 03 is served by the same air distribution header as this fire area, but it continues to receive ventilation because it has a separate supply duct. Fire area 1220 AF 01 is isolated by combination fire-smoke dampers in response to a smoke detector signal. The division B reactor trip switchgear and the division B and D electrical cable in this fire area is not sensitive to the small quantity of smoke that may leak into this fire area.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of plastic battery cell containers and cable insulation for cables associated with the spare batteries and the spare battery charger. There are concentrations of battery cells on opposite walls of the spare battery room fire zone. There are small concentrations of cable along the north wall of the spare battery charger room fire zone. There are assumed to be small concentrations of ordinary combustibles in the spare room. There are small concentrations of cable overhead in the eastern portion of corridor fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. The battery room is also separated from the other fire zones within this fire area by a 1-hour fire barrier, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The spare batteries may be connected as a backup power source for any one of the four Class 1E electrical divisions. The terminations of the cables to these divisions from the spare batteries are not normally energized or connected, so a fire in this area has no impact on the unconnected divisions. If the spare batteries are being used as a backup to a Class 1E division, then the consequence of a fire in this area is the same as a fire in the battery room of the division to which they are connected.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.6 Non-Class 1E Electrical Rooms

9A.3.1.2.6.1 Fire Area 1230 AF 02

The fire area is comprised of the following room:

Room No.	
12321	Non-Class 1E equipment/penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Preaction sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by the preaction sprinkler system or manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are small concentrations of cable overhead, at the electrical penetrations, and at the electrical cabinets located along the east and west walls of room 12321. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. An automatic suppression system is provided to increase the availability of non-safety related systems required to achieve cold shutdown.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system in this fire area is considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The electrical equipment in this area is non-Class 1E; however, some division B and D cables are routed through this area. In the event of a fire, the division B and D cabling in this area can be damaged. This damage can result in loss of control of equipment serviced by these cables. Other components in divisions B and D are not affected.

This fire can also disable the division B and D inputs to the reactor trip switchgear. The signals from the remaining two divisions are sufficient to trip the reactor. Furthermore, the reactor can be tripped with the diverse actuation system described in Section 7.7.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.6.2 Fire Area 1240 AF 01

The fire area is comprised of the following room:

Room No.

12421 Non-Class 1E equipment/penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the electrical equipment and containment penetrations in this fire area. There are small concentrations of cable overhead, at the electrical penetrations, and at the RCC rod control cabinets in the southern portion of room 12421. The combustible loading for this fire area exceeds 80,000 Btu/ft^2, warranting the need for detection and automatic and manual suppression capabilities per the guidelines in Subsection 9A.2.4. Automatic suppression is not installed in this fire area as an effort is made to limit water sources in this area for internal flooding concerns. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The electrical equipment in this area is non-Class 1E; however, some division A and C cables are routed through this area. In the event of a fire, the division A and C cabling in this area can be damaged. This damage can result in loss of control of equipment serviced by these cables. Other components in divisions A and C are not affected.

This postulated fire can disable control of the division A containment isolation valves outside containment. For this event, containment isolation is provided by the redundant containment isolation valves located inside containment outside of this fire area.

Such a fire can also disable control of the divisions A and C passive containment cooling system isolation valves. The redundant division B passive containment cooling system isolation valves are not affected. Therefore, the safe shutdown capability of the passive containment cooling system is maintained.

This fire can also disable the division A and C inputs to the reactor trip switchgear. The signals from the remaining two divisions are sufficient to trip the reactor. Furthermore, the reactor can be tripped with the diverse actuation system described in Section 7.7.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.7 Mechanical/Piping Areas

9A.3.1.2.7.1 Fire Area 1201 AF 04

This fire area consists of two nuclear island nonradioactive ventilation system equipment rooms servicing divisions B and D equipment rooms. Division B and D safe shutdown equipment is located within the fire area. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
● 1241 AF 12405	12405	Lower nuclear island nonradioactive ventilation system divisions B and D equipment room (117'-6")
● 1251 AF 12505	12505	Upper nuclear island nonradioactive ventilation system divisions B and D equipment room (135'-3")

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area houses and is served by the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Closure of these fire dampers interrupts the operation of the division B & D Class 1E electrical room HVAC subsystem. Operation of the independent division A & C Class 1E electrical room HVAC subsystem continues unaffected. Smoke is subsequently removed from the fire area by using portable exhaust fans and flexible ductwork. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems and subsystems. The division A and C electrical cables in fire area 1230 AF 01 are unaffected by the

small quantity of smoke that may leak into that fire area. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of electrical cable insulation for cables supplying fans and valves within this fire area. There are cable concentrations overhead and in the west half of each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area.

A fire in this fire area is conservatively assumed to disable control of all division D active components, as well as the compressed and instrument air system, component cooling water system, passive core cooling system and central chilled water system containment isolation valves within the fire area. The redundant containment isolation valves in the lines for the compressed and instrument air system, component cooling water system, passive core cooling system and central chilled water system are located inside the containment (fire area 1000 AF 01) are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The redundant steam generator 1 steam line pressure instrumentation located in fire zone 1100 AF 11300B is sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The redundant steam generator 2 steam line pressure instrumentation located in fire zone 1100 AF 11300B is sufficient to perform the applicable functions to achieve and maintain safe shutdown.

The remaining division A, B and C components located in other fire areas are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.7.2 Fire Area 1201 AF 05

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
● 1241 AF 12506	12406	Lower main steam isolation valve compartment A
	12506	Upper main steam isolation valve compartment A
● 1231 AF 12306	12306	Valve/piping penetration room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Each of the two fire zones in this fire area is served by independent air handling units of the annex/auxiliary buildings nonradioactive HVAC system (VXS), located within the fire zones served. No ventilating system ducts penetrate the MSIV compartment fire zone. One supply duct enters the valve piping penetration room from the turbine building. A fire damper in this duct closes automatically on high temperature to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems or subsystems. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the motor-operated valves, fans and other components in this fire area. Small quantities of lubricating oil are contained within the housings of some of these components. There are small concentrations of cable overhead in each room. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The recirculation type ventilation system does not contribute to the spread of the fire or smoke to other fire areas.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area.

A fire in this fire area is assumed to disable the safe shutdown components in the fire area. The redundant chemical and volume control system containment isolation valves located inside containment outside of this fire area are sufficient to perform the applicable functions to maintain containment integrity. The steam generator, main steam line, feedwater line, and blowdown line piping located inside containment outside of this fire area is sufficient to perform the applicable functions to maintain containment integrity.

A fire in this fire area is conservatively assumed to disable the division B PCS components located in fire zone 1270 AF 12701. See Subsection 9A.3.1.1.17 for the Safe Shutdown Evaluation for fire zone 1270 AF 12701.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.7.3 Fire Area 1201 AF 06

This fire area is comprised of the following room(s):

Room No.	
12404	Lower main steam isolation valve compartment B
12504	Upper main steam isolation valve compartment B

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by independent air handling units of the annex/auxiliary buildings nonradioactive HVAC system (VXS), located within the fire zones served. No ventilating system ducts penetrate the fire area. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems or subsystems. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation for cables associated with the motor-operated valves, fans and other components in this fire area. Small quantities of lubricating oil are contained within the housings of some of these components. There are small concentrations of cable overhead in each room. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The recirculation type ventilation system does not contribute to the spread of the fire or smoke to other fire areas.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area.

A fire in this fire area is assumed to disable the safe shutdown components in the fire area. The steam generator, main steam line, feedwater line, and blowdown line piping located inside containment outside of this fire area is sufficient to perform the applicable functions to maintain containment integrity.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.7.4 Fire Area 1250 AF 01

This fire area is comprised of the following room(s):

Room No.	
12501	Nuclear island nonradioactive ventilation system main control room/division A and C equipment room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area houses the nuclear island nonradioactive ventilation system (VBS) main control room/control support area supplemental air filtration units, one of two VBS main control room/control support area supply air handling units, and the VBS division A & C Class 1E electrical room HVAC subsystem air handling units. The division A & C Class 1E electrical room HVAC subsystem serves this fire area. Combination fire-smoke dampers in the division A & C Class 1E electrical room HVAC subsystem close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Closure of these combination fire-smoke dampers interrupts the operation of the VBS division A & C Class 1E electrical room HVAC subsystem. Operation of the independent division B & D Class 1E electrical room HVAC subsystem continues unaffected. In the event of a fire emergency in this fire area, operators may isolate the main control room and actuate the main control room emergency habitability system at their discretion to maintain control room

habitability. Smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems or subsystems. The division B reactor coolant pump trip switchgear and the divisions B and D electrical cables located in fire area 1220 AF 01 and the divisions A and C electrical cables located in fire area 1200 AF 03 are unaffected by the small quantity of smoke that may leak into these fire areas. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector, which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. A fire in the fire area is extinguished manually using hose streams or portable extinguishers.

This fire area contains two charcoal adsorbers, located in the nuclear island nonradioactive ventilation system supplemental air filtration units. The normal temperature of the air flowing through the charcoal adsorbers is well below 200°F, while the minimum charcoal ignition temperature is greater than 600°F. Two independent temperature sensors interface with the fire detection system, providing charcoal temperature indication and high and high-high temperature alarms. The filtration unit fan trips at the high temperature alarm setpoint. The setpoints of both alarms are well below the charcoal ignition temperature, allowing the operator time to investigate and take corrective action. In the unlikely event of a fire in the adsorber, the filtration unit can be manually isolated. The adsorber bed deluge piping will be connected to a nearby hose station to cool the charcoal and extinguish the fire.

Combustible materials in this fire area are listed in Table 9A-3. Aside from the charcoal contained within the air filtration units, these materials primarily consist of electrical cable insulation for cables supplying fans and pumps within this fire area. There are cable concentrations near the ceiling and adjacent to the west wall. This is a light hazard fire area and the rate of fire growth is expected to be slow. Generally, three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. Fire barrier separation is not provided between the main control room and this fire area from fires in the main control room. There are no safe shutdown components in this room. There is fire barrier separation between the main control room and this fire area for fires originating in this area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

The quantity and arrangement of the combustible materials in this fire area, and the characteristics of the barriers that separate this area from other fire areas, are such that a fire in this area does not propagate to any adjacent area.

Aside from the charcoal contained within the air filtration units, these materials primarily consist of electrical cable insulation for cables supplying fans and pumps within this fire area. There are cable concentrations near the ceiling and adjacent to the west wall. This is a light hazard fire area and the

rate of fire growth is expected to be slow. Generally, 3-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area. Fire barrier separation is not provided between the main control room and this fire area from fires in the main control room. There is fire barrier separation between the main control room and this fire area for fires originating in this area.

The safe shutdown components routed through this fire area are division A and division C electrical cables that serve the redundant passive containment cooling system valves and instruments located in the passive containment cooling system (PCS) valve room (Room 12701). Although the consequences of a fire are expected to be very limited, a fire in this fire area is conservatively assumed to disable both the division A and division C electrical cables that serve the PCS valves and instruments used for safe shutdown. The remaining division B electrical cables and components routed through and located in other fire areas are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.8 Miscellaneous Areas

9A.3.1.2.8.1 Fire Area 1230 AF 01

This fire area is comprised of the following room(s):

Room No.	
12300	Corridor

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division B & D Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Closure of these dampers interrupts ventilation of adjacent fire areas 1201 AF 02 (division B electrical rooms) and 1232 AF 01 (remote shutdown room) because their ducts are routed through this corridor. The ventilation system continues to provide ventilation to other unaffected fire areas, and may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of small quantities of cable insulation for cables routed overhead through the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The Class 1E divisions A and C cables for data communication between divisions are in this fire area.

In the event of a fire in the division A and C corridor, it is assumed that data output from divisions B and D to the division A and C protection logic is lost. This loss of data does not disable the safe shutdown functions of the four Class 1E divisions.

The division A and C instrument cables serving safe shutdown components are assumed to be disabled. The division B and D instrument cables routed outside of this fire area that serve redundant safe shutdown components are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.8.2 Fire Area 1201 AF 01

This fire area is comprised of the following room(s):

Room No.	
S02	Stairwell

The stairwell serving the northwest portion of the auxiliary building is enclosed by fire barrier walls having a minimum rating of 2 hours. The structural walls are concrete, and the nonstructural walls are made of a concrete/steel composite material. There are no safe shutdown components and no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

Smoke intrusion to the stairwell is limited by fire barrier walls having a minimum rating of 2 hours, and self-closing doors having a minimum rating of 1.5 hours. Additionally, during a fire, a pressure difference across the doors in the stairwell is maintained in accordance with the guidance of NFPA 92A (Reference 4), using a dedicated stairwell pressurization fan.

9A.3.1.2.8.3 Fire Area 1202 AF 01

This fire area is comprised of the following room(s):

Room No.	
S01	Stairwell

The stairwell serving the northeast portion of the auxiliary building is enclosed by fire barrier walls having a minimum rating of 2 hours. The structural walls are concrete, and the nonstructural walls are made of a concrete/steel composite material. There are no safety-related components and no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

Smoke intrusion to the stairwell is limited by fire barrier walls having a minimum rating of 2 hours, and self-closing doors having a minimum rating of 1.5 hours. Additionally, during a fire, a pressure difference across the doors in the stairwell is maintained in accordance with the guidance of NFPA 92A (Reference 4), using a dedicated stairwell pressurization fan.

9A.3.1.2.8.4 Fire Area 1202 AF 05

This fire area is comprised of the following room(s):

Room No.	
S05	Stairwell

The stairwell provides an emergency egress path from the main control room to the emergency shutdown workstation. It is enclosed by 3-hour fire barriers. These barriers are made of concrete. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area.

Smoke intrusion to the stairwell is limited by fire barrier walls having a minimum rating of 2 hours, and self-closing doors having a minimum rating of 1.5 hours. No ventilation system serves this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The stairwell contains circuits for the transfer switch set which is used to transfer control from the control room to the remote shutdown workstation in the event of a control room evacuation. Electrical separation to and inside the stairwell is maintained per industry standards. In the unlikely event that the fire damages the transfer switch set, causing transfer of control from the main control room to the remote shutdown workstation, the operator restores control to the main control room by using controls located in the instrumentation and control rooms. Safe shutdown is achieved using the safe shutdown components listed in Table 9A-2. Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

9A.3.1.2.8.5 Fire Area 1202 AF 02

This fire area contains an elevator and elevator shaft serving five levels on the north side of the auxiliary building. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detector
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

No ventilation system serves this fire area. The nuclear island nonradioactive ventilation system provides ventilation to neighboring fire areas, and may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke and hot gases. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and lubricant associated with the elevator hoisting machinery. This is a light hazard fire area and the rate of fire growth is expected to be slow. Two-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

Safe Shutdown Evaluation

This fire area contains no components required for safe shutdown after a fire. No safe shutdown evaluation is required.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.2.8.6 Fire Area 1200 AF 03

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1230 AF 12311	12311	Elevation 100′-0″ corridor
• 1242 AF 12411	12411	Elevation 117′-6″ corridor

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is served by one of the three air distribution headers of the division A & C Class 1E electrical room HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS). Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. The ventilation system continues to provide ventilation to the unaffected fire areas. Fire areas 1220 AF 01 and 1210 AF 01 are served by the same air distribution header as this fire area, but they continue to receive ventilation because they have separate supply ducts. The ventilation system may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke and hot gases. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode. Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers. Safe shutdown components in these fire areas, identified in Table 9A-4, are sufficient to achieve and maintain safe shutdown.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of small quantities of cable insulation for cables routed overhead in each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. Class 1E divisions A and C cables are routed through these corridors.

The divisions A and C control cables to the reactor trip switchgear are assumed to be disabled. Inputs from divisions B and D, which are routed in a separate fire area, are sufficient to trip the reactor when needed. The reactor can also be tripped with the diverse actuation system described in Section 7.7.

The divisions A and C instrument and control cables serving other safe shutdown components are assumed to be disabled. The instrument and control cables routed outside of this fire area that serve redundant safe shutdown components are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3 Auxiliary Building - Radiologically Controlled Areas

The safe shutdown components located in the radiologically controlled areas are primarily containment isolation valves, which are located near the containment vessel in the lower annulus. Containment isolation valves are also located in the pipe chases southeast of containment. These containment isolation valves are required to either close or remain closed during a safe shutdown operation.

9A.3.1.3.1 Principal Areas

9A.3.1.3.1.1 Fire Area 1200 AF 01

This fire area includes most of the radiologically controlled areas of the auxiliary building outside the fuel handling area. This fire area contains one of the two normal residual heat removal pumps and the heat exchangers, the liquid radwaste system, spent fuel pool cooling system, radiologically controlled area ventilation system, chemical and volume control system makeup pump, containment isolation valve area, and lower annulus areas. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 1200 AF 12241	12241	Lower annulus east
• 1200 AF 12241	12242	Lower annulus southeast
• 1200 AF 12461	12461	Corridor
• 1205 AF 12362	12362	Normal residual heat removal heat exchanger room
• 1205 AF 12365	12365	Waste monitor tank room B
• 1210 AF 12151	12151	Demineralizer/filter room
• 1210 AF 12151	12153	Delay bed/guard bed compartment
• 1210 AF 12151	12155	Gaseous radwaste system equipment room
• 1210 AF 12151	12156	Liquid radwaste system equipment room
• 1210 AF 12151	12158	Degasifier discharge pump room
• 1210 AF 12151	12258	Degasifier column
• 1210 AF 12171	12171	Effluent holdup tank room A
• 1214 AF 12152	12152	Primary sample room
• 1214 AF 12154	12154	Auxiliary building sump room
• 1214 AF 12154	12254	Spent fuel pool cooling system penetration room
• 1214 AF 12354	12354	Mid-annulus access room
• 1215 AF 12161	12161	Corridor
• 1215 AF 12162	12162	Normal residual heat removal pump room A
• 1216 AF 12166	12166	Waste holdup tank room A
• 1216 AF 12167	12167	Waste holdup tank room B
• 1216 AF 12169	12168	Vestibule

- 1216 AF 12169 12169 Corridor
- 1216 AF 12169 12268 Liquid radwaste system pump room
- 1216 AF 12264 12264 Chemical waste tank room
- 1216 AF 12264 12265 Waste monitor tank room C
- 1216 AF 12172 12172 Effluent holdup tank room B
- 1220 AF 12251 12251 Demineralizer/filter access area
- 1220 AF 12251 12255 Chemical and volume control system makeup pump room
- 1220 AF 12259 12259 Pipe chase
- 1220 AF 12256 12256 Containment isolation valve area
- 1220 AF 12269 12269 Pipe chase
- 1220 AF 12256 12253 Pipe chase
- 1220 AF 12272 12272 Spent fuel pool cooling system pump room A
- 1220 AF 12272 12273 Spent fuel pool cooling system heat exchanger room A
- 1220 AF 12272 12274 Spent fuel pool cooling system pump room B
- 1220 AF 12272 12275 Spent fuel pool cooling system heat exchanger room B
- 1224 AF 12252 12252 Radiation chemistry laboratory
- 1225 AF 12261 12261 Corridor
- 1225 AF 12261 12271 Liquid radwaste system pump room
- 1225 AF 12262 12262 Piping/valve room
- 1234 AF 12351 12351 Maintenance floor staging area
- 1234 AF 12352 12352 Personnel hatch
- 1235 AF 12363 12363 Waste monitor tank room A
- 1244 AF 12451 12451 Security room
- 1244 AF 12452 12452 Containment air filtration system penetration room
- 1244 AF 12454 12454 Containment air filtration system/spent fuel pool cooling
- 1235 AF 12361 12361 Corridor
- 1250 AF 12561 12561 Component cooling water system valve room
- 1254 AF 12553 12553 Personnel access area
- 1254 AF 12554 12554 Security room
- 1264 AF 12651 12651 Radiologically controlled area ventilation system equipment room

The equipment and piping in this fire area normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
  - Line type fire detection (Heat) is provided for equipment protection in the upper-most cable tray in rooms 12151, 12155, 12156, 12251, and 12255
  - Spot type detection (Heat) is provided for a dedicated pump in each of the following rooms for equipment protection only: 12162, 12271, 12272, and 12274
  - Area fire detectors are provided in the following rooms: 12152, 12161, 12252, 12256, 12261, 12262, 12269, 12351, 12352, 12361, 12451, 12452, 12461, 12553, 12554, 12561 and 12651

- Wet pipe sprinklers (Fire Zone 1220 AF 12251, room 12255)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radiologically controlled area ventilation system (VAS) serves this fire area on a once-through basis. Some of the ventilation system equipment is also located within this fire area. For a fire that does not disable the ventilation system, the system continues to ventilate the fire area unless the operator decides to shut down the system, until heat from the fire is sufficient to close the fire dampers, or if smoke is detected in the supply air ducts. Fire dampers close automatically on high temperature to control the spread of fire and smoke. If the radiologically controlled area ventilation system is not affected by the fire, smoke is removed from the fire area by reopening the fire dampers after a fire and exhausting to the atmosphere. If the radiologically controlled area ventilation system is unavailable, smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by fire detectors which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by the wet pipe sprinkler system or manually using hose streams or portable extinguishers.

This fire area contains three charcoal adsorbers located in fire zone 1210 AF 12151, Delay Bed/Guard Bed Compartment (Room 12153). Independent temperature monitors located at the inlet and outlet of each charcoal bed and within the delay bed compartment provide high temperature alarms to detect a charcoal bed fire. Upon indication of a fire, the operator closes the Discharge Control Valve to stop effluent, stops WLS Degasifier Vacuum Pumps, stops the WLS Degasifier Vacuum Purge Pump, closes WLS RCDT vent valves, and opens the Nitrogen Purge to System Inlet Isolation Valve to purge the system with nitrogen and extinguish the fire.

Combustible materials in this large fire area are listed in Table 9A-3. Aside from the charcoal contained in the WGS adsorber beds, these materials consist primarily of cable insulation for cables associated with the mechanical equipment and instrumentation in this fire area. There are small concentrations of lubricants in fire zones containing pumps and the radiologically controlled area ventilation system equipment. There are small concentrations of paper and plastic in some fire zones. Concentrations of paper or plastic anti-contamination clothing may also be present in some fire zones. There are small concentrations of cable in the overhead cable trays in many fire zones. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas containing fire safe shutdown components and the fire is contained within the fire area. An automatic suppression system is provided to increase the availability of non-safety related systems required to achieve cold shutdown.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

The consequences of inadvertent operation of an automatic suppression system in this fire area or of fire suppression systems that drains to this fire area from the radwaste building, or of a break in a fire protection line in this fire area, are considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The electrical equipment in this area is non-Class 1E; however, some division A and C cables are routed through this area. In the

event of a fire, the division A and C cabling in this area can be damaged. This damage can result in loss of control of equipment serviced by these cables. Other components in divisions A and C are not affected.

The normal residual heat removal, primary sampling system, spent fuel pool cooling system and containment air filtration system containment isolation valves are conservatively assumed to be disabled as a result of a fire in this fire area. The redundant normal residual heat removal, primary sampling system, spent fuel pool cooling system and containment air filtration system containment isolation valves located inside containment are outside of this fire area and are sufficient to perform the applicable functions to maintain containment integrity and achieve and maintain safe shutdown. Cable trays supplying these valves and other components are not required for safe shutdown.

Spurious DAS actuation of squib valves is prevented by the use of a squib valve controller circuit, which requires multiple hot shorts for actuation, physical separation of potential hot short locations, and provisions for operator action to remove power from the fire area. No postulated fire can spread to the hot short locations before the operator can remove power from the fire area.

The redundant passive containment cooling system safe shutdown components located in fire zone 1200 AF 12341 are sufficient to perform applicable functions to achieve and maintain safe shutdown.

Following detection of a fire in the non-Class 1E equipment/penetration room, the operators can close the automatic depressurization system stage 4 block valves, then remove DAS actuation power. This operator action will prevent spurious actuation of squib valves resulting from multiple hot shorts in the non-Class 1E equipment/penetration room.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3.1.2 Fire Area 1200 AF 02

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
● 1200 AF 12562	12462	Cask washdown pit
● 1200 AF 12562	12463	Cask loading pit
● 1200 AF 12562	12472	New fuel storage pit
● 1200 AF 12562	12562	Fuel handling area
● 1200 AF 12562	12563	Spent fuel storage pool
● 1200 AF 12562	12564	Fuel transfer canal
● 1230 AF 12371	12371	Rail car bay/filter storage area
● 1230 AF 12371	12374	Waste disposal container area
● 1236 AF 12372	12372	Resin transfer pump/valve room
● 1236 AF 12373	12373	Spent resin tank room
● 1246 AF 12471	12471	Solid waste system valve/piping area

The spent fuel storage pool, spent fuel handling systems and components, and the solid radwaste rooms normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
  - Area fire detectors are provided in the following room: 12562
- Wet pipe sprinklers (Fire Zone 1230 AF 12371, room 12371 rail car bay only)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radiologically controlled area ventilation system serves this fire area on a once-through basis. In the event of a fire the system continues to ventilate the fire area unless the operator decides to shut down the system, until heat from the fire is sufficient to close the fire dampers, or if smoke is detected in the supply air ducts. Fire dampers close automatically on high temperature to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers. The radiologically controlled area ventilation system exhausts the smoke and hot gases to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by the wet pipe sprinkler system or manually using hose streams or portable extinguishers.

Combustible materials in this large fire area are listed in Table 9A-3, and consist primarily of cable insulation for the cables associated with the mechanical equipment and instrumentation in this fire area. There are small concentrations of lubricants associated with equipment such as the overhead cranes and the fuel handling machine. Diesel fuel may be present when there is a truck in the rail car bay. Concentrations of paper or plastic anti-contamination clothing may also be present. There are small concentrations of cable in the overhead cable trays. This is generally a light hazard fire area and the rate of fire growth is expected to be slow. Concentrations of transient combustibles in the rail car bay may produce a rapidly growing fire, so an automatic suppression system is provided in that area. Three-hour fire barriers provide adequate separation from adjacent fire areas. The roof and building exterior walls are unrated because there are no significant exposure fire hazards in nearby outdoor areas. Automatic or manual fire suppression activities prevent the fire from propagating beyond the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system or of a break in a fire protection line in this fire area are considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

There are no safe shutdown components in this area, so a fire in this area has no impact on safe shutdown. The electrical equipment in this area is non-Class 1E; however, some division A and C cables are routed through this area. In the event of a fire, the division A and C cabling in this area can be damaged. This damage can result in loss of control of equipment serviced by these cables. Other components in divisions A and C are not affected. Safe shutdown is possible from equipment in other fire areas.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3.1.3 Fire Area 1204 AF 01

This fire area is comprised of the following room:

Room No.	
12163	Normal residual heat removal pump room B

Some of the piping in this fire area normally contains radioactive material.

Fire Detection and Suppression Features

- Fire detectors
  - Spot type detection (Heat) is provided for the motor and pump for equipment protection only
- Hose station(s)

Smoke Control Features

The radiologically controlled area ventilation system serves this fire area on a once-through basis. The system continues to ventilate the fire area unless the operator decides to shut down the system, until heat from the fire is sufficient to close the fire dampers, or if smoke is detected in the supply air ducts. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area by reopening the fire damper(s) after a fire and exhausting to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams.

Combustible materials in this fire area are listed in Table 9A-3, and consist primarily of cable insulation for the cables associated with the mechanical equipment and instrumentation in this fire area. There are small concentrations of cable in overhead cable trays. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. The consequences of a break in a fire protection line in this fire area were considered in the evaluation of internal flooding in Section 3.4.

Safe Shutdown Evaluation

This fire area contains no components required for safe shutdown after a fire. No safe shutdown evaluation is required.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3.1.4 Fire Area 1220 AF 02

This fire area is comprised of the following room(s):

Room No.	
12244	Lower annulus valve area

Some of the piping in this fire area normally contains radioactive material.

Fire Detection and Suppression Features

- Fire detector
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radiologically controlled area ventilation system serves this fire area on a once-through basis. In the event of a fire the system continues to ventilate the fire area unless the operator decides to shut down the system, until heat from the fire is sufficient to close the fire dampers, or if smoke is detected in the supply air ducts. Fire damper(s) close automatically on high temperature to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by reopening the fire dampers. The radiologically controlled area ventilation system exhausts the smoke and hot gases to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and consist primarily of cable insulation for cables associated with the few containment isolation valves in this fire area. There are no significant concentrations of combustible materials. This is a light hazard fire area and the rate of fire growth is expected to be slow. Three-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

Fire Protection System Integrity

An evaluation of the consequences of inadvertent operation of an automatic suppression system is not required because there are no such systems in this fire area. An evaluation of the consequences of a break in a fire protection line is not required because no such lines pass through or terminate in this fire area.

Safe Shutdown Evaluation

Table 9A-2 lists the safe shutdown components located in this fire area. The chemical and volume control system and liquid radwaste system containment isolation valves are conservatively assumed to be disabled as a result of a fire in this fire area. The redundant chemical and volume control

system and liquid radwaste system containment isolation valves located inside containment are outside of this fire area and are sufficient to perform the applicable functions to achieve and maintain safe shutdown.

Neither a fire nor fire suppression activities in this fire area affect the safe shutdown capability of components located in adjacent fire areas.

No fire in this fire area can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety-related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.1.3.2 Miscellaneous Areas

9A.3.1.3.2.1 Fire Area 1204 AF 02

This fire area is comprised of the following room(s):

Room No.	
S03	Stairwell

This fire area is the stairwell serving the shield building. The portion of the stairwell below the elevation of the auxiliary building roof is enclosed by fire barrier walls partially constructed of concrete and partially constructed of a concrete/steel composite material, having a minimum rating of 3 hours. Above the auxiliary building roof, the stairwell enclosure is not fire-rated. There are no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area.

No ventilation system directly serves this fire area.

9A.3.1.3.2.2 Fire Area 1204 AF 03

This fire area contains the elevator and elevator shaft serving the south side of the shield building. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

No ventilation system directly serves this fire area. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and lubricant associated with the elevator hoisting machinery. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas below the elevation of the auxiliary building roof.

Manual fire suppression activities prevent the fire from propagating beyond the nonrated building exterior walls above the roof.

Safe Shutdown Evaluation

There are no safe shutdown components in this fire area. No safe shutdown evaluation is required.

9A.3.1.3.2.3 Fire Area 1205 AF 01

This fire area is comprised of the following room(s):

Room No.	
S04	Stairwell

This stairwell, serving the southeast portion of the auxiliary building, is enclosed by fire barrier walls having a minimum rating of 2 hours. The structural walls are concrete, and the nonstructural walls are made of a concrete/steel composite material. The only safety-related component located in this area is a safety-related and seismically qualified louver located in the barrier from the stairwell to Room 12161 that is opened based on differential pressure to provide flood mitigation. When closed, the louver is a 2-hour fire-rated/smoke-rated component in the fire-rated barrier. There are no radioactive systems in this fire area. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

Smoke intrusion to the stairwell is limited by fire barrier walls having a minimum rating of 2 hours, and self-closing doors having a minimum rating of 1.5 hours. No ventilation system serves this fire area.

9A.3.1.3.2.4 Fire Area 1205 AF 02

This fire area contains the elevator and elevator shaft serving the radiologically controlled area of the auxiliary building. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

No ventilation system serves this fire area. For a fire in the elevator or elevator shaft, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and primarily consist of cable insulation and lubricant associated with the elevator hoisting machinery. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas and the fire is contained within the fire area.

Safe Shutdown Evaluation

There are no safe shutdown components in this fire area. No safe shutdown evaluation is required.

9A.3.2 Turbine Building

Figure 9A-2 identifies fire areas and fire zones within the turbine building and illustrates the fire resistance of the fire area boundaries.

A fire in the turbine building fire areas does not affect safe shutdown capability. Fire areas located in the turbine building are separated from the safety-related areas of the nuclear island by a 3-hour fire barrier wall. The closing of fire dampers in the ventilation systems serving turbine building fire areas does not affect safe shutdown systems because safe shutdown systems are served by independent ventilation systems.

Neither a fire nor fire suppression activities in turbine building fire areas affect the safe shutdown capability of components located in other fire areas.

Floor drains are sized to handle water flow from fixed automatic fire suppression systems without significant accumulation of water in the fire area. Flooding of components required for safe shutdown is not a concern because there are no safe shutdown components in the turbine building.

No fire in the turbine building can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.2.1 Fire Area 2000 AF 01

This fire area contains the main condenser, lubrication equipment auxiliary boiler, turbine-generator and auxiliaries, switchgear rooms, electrical equipment room, feedwater pumps, chemical feed equipment, chiller area, plant air compressors, digital-electrohydraulic skid, main steam piping, office area, and a sampling laboratory. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 2030 AF 20300	20300	Elevation 100'-0" (base slab) general floor area
• 2030 AF 20300	20305	Condensate polishing area
• 2030 AF 20300	20308	Control System Cabinet Room 1
• 2030 AF 20300	20309	Circulating water pipe trench
• 2131 AF 21380	21380	CCS/BDS equipment room
• 2038 AF 20300	----	Main feedwater pump area
• 2039 AF 20301	20301	Chemical storage area
• 2040 AF 20400	20400	Elevation 120'-6" general floor area
• 2040 AF 20400	20408	Control System Cabinet Room 2
• 2040 AF 20400	20409	VWS Chiller Area
• 2141 AF 21480	21480	VTS HVAC equipment room
• 2043 AF 20402	20402	Excitation Equipment Room
• 2050 AF 20500	20500	Elevation 141'-3" general floor area
• 2050 AF 20500	20503	Control System Cabinet Room 4

- 2050 AF 20500 20518 Control System Cabinet Room 3
- 2050 AF 20502 ---- Digital-electrohydraulic skid
- 2151 AF 21580 21580 South bay elevation 135'-3" general area
- 2151 AF 21583 21583 VFD equipment room
- 2052 AF 20504 20510 HVAC equipment area
- 2057 AF 20503 20511 Generator seal oil unit
- 2060 AF 20600 20600 Elevation 170'-0" general floor area
- 2063 AF 20601 20601 Tool room/storage area
- 2063 AF 20602 20602 Office area/engineering workstation at elevation 183'-1 1/2"
- 2070 AF 20700 20700 Heater bay
- 2070 AF 20701 20701 Elevation 196'-3" North West Security Room
- 2070 AF 20702 20702 Elevation 196'-3" North East Security Room
- 2070 AF 20703 20703 Elevation 196'-3" South West Security Room
- 2070 AF 20750 20750 Upper heater bay

This fire area designation consists of the entire turbine building floor areas except those special areas contained within fire rated enclosures and discussed below as separate fire areas. In zones within this area where there is a potential for spills of oil or other combustibles, such as the digital-electrohydraulic skid, condensate polishing area, chemical storage area and the generator seal oil unit, spill control curbs are provided to limit the spread of fire should one occur. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors (See Table 9A-3 for type of detector.)

- Automatic suppression for the oil spill areas around the turbine-generator, the generator seal oil unit, the main feedwater pump area, the digital-electrohydraulic skid, the chemical storage area, the heater bay, and the upper heater bay.

  Automatic suppression for the following equipment: the service water pumps, the start-up feedwater pumps and MCCs and control equipment at elevation 141'-3" (in the area defined by column 13.1 to 14 and P.1 to O).

  Automatic suppression is provided over elevation 100′-0″ down the corridor between the condenser and the main feedwater pumps defined by column 13.1 to column 18, continuing down another corridor defined by column L.2 to column K.5 and for the equipment access area in fire zone 2030-AF-20300, room 20300.

  See Table 9A-3 for identification of the specific types of automatic suppression systems for this fire area.

- Hose station(s)

- Portable fire extinguishers

Smoke Control Features

The general area heating and ventilation subsystem of the turbine building ventilation system (VTS), as described in Subsection 9.4.9, uses roof mounted exhaust ventilators to pull in air through wall

louvers. The roof mounted exhaust ventilators and/or portable ventilation equipment is used to vent smoke to outside areas and prevent migration of smoke to adjacent fire areas and to mitigate excessive buildup of smoke and heat at the ceiling above the turbine building operating deck. If the roof mounted exhaust ventilators are not available, smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by the wet pipe type automatic sprinkler system or a fire detector. Upon sprinkler system or fire detector actuation, visual and audible alarms are produced in the main control room and at the remote fire alarm annunciator panel, and notification alarms are produced locally by the fire alarm detection system. The fire is extinguished by operation of the automatic suppression system, if applicable, or manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. This area contains fire zones with a low quantity of combustible materials and other zones which have moderate to high quantities of combustible materials. Zones containing a low quantity of low heat release combustibles are generally protected by manual suppression. Zones containing moderate to high quantities of high heat release combustibles, such as oil spill areas, are protected by automatic suppression.

The limited amount of combustible material or automatic fire suppression activities prevent fire from propagating to other fire zones in the area and prevent fire from propagating through the exterior walls or roof of the turbine building to other fire areas. The south end of the turbine building is formed by the 3-hour fire barrier exterior walls of the annex and auxiliary building. There are no concentrations of combustibles in the turbine building adjacent to these walls. Therefore, a turbine building fire will not propagate through these exterior walls of the annex or auxiliary building.

The turbine building ventilation system (VTS) serves the turbine building only and therefore does not contribute to the spread of the fire or smoke to fire areas outside the turbine building. The turbine building ventilation system does not contribute to the spread of fire or smoke to other fire areas within the turbine building because fire dampers isolate the other fire areas.

The turbine building ventilation subsystem is shut down upon detection of a fire in fire zone 2052 AF 20504 (Room 20510).

9A.3.2.2 Fire Area 2000 AF 02

This fire area is comprised of the following room(s):

Room No.	
S02	Stairwell
S08	Stairwell

These stairwells serve the southwest portion of the turbine building. The walls of these enclosures that are exposed to the turbine building interior are constructed with material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the turbine building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the turbine building and are not required to be constructed or maintained to a minimum fire rating. There are no safety-related components and no radioactive systems in this fire area. The quantity of combustible materials in the stairwells is negligible and no fire is postulated in this fire area. A fire protection hose riser is located in stairwell S02 with NFPA Class I hose connections at intermediate stair landings.

These stairwells are not served by a ventilation system.

9A.3.2.3 Fire Area 2009 AF 01

This fire area is comprised of the following room(s):

Room No.	
S01	Stairwell

This stairwell serves the northeast portion of the turbine building. The walls of this enclosure that are exposed to the turbine building interior are constructed with a material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the turbine building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the turbine building and are not required to be constructed or maintained to a minimum fire rating. There are no safety-related components or systems in this fire area which contain radioactive material. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. A fire protection hose riser is located in the stairwell with NFPA Class I hose connections at intermediate stair landings.

This stairwell is not served by a ventilation system.

9A.3.2.4 Fire Area 2009 AF 02

This fire area is comprised of the elevator serving the turbine building from elevation 100'-0" to elevation 170'-0". The elevator is enclosed by fire barrier walls having a minimum rating of 2 hours. These nonstructural walls are metal lined gypsum board. There are no radioactive systems in this fire area.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

This fire area is not served by a ventilation system. After the fire, smoke is removed from the fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

The quantity of combustible materials in the elevator shaft is negligible. This is a light hazard fire area and the rate of fire growth is expected to be slow. Two-hour fire barriers provide adequate separation from adjacent fire areas since the fire will be contained within this fire area.

No ventilation systems penetrate the elevator enclosure.

9A.3.2.5 Not used.

9A.3.2.6 Not used.

9A.3.2.7 Fire Area 2000 AF 03

This fire area is comprised of the following room(s):

Room No.	
S03	Stairwell

This stairwell serves the northwest portion of the turbine building from 158'-7" to 196'-3". The walls of this enclosure that are exposed to the turbine building interior are constructed with a material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the turbine building interior; therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the turbine building. There are no safety-related components or systems in this fire area that contain radioactive material. There are no systems in this fire area that contain radioactive material. The quantity of combustible materials in the stairwell is negligible, and no fire is postulated in this fire area. A fire protection hose riser is located in the stairwell with NFPA Class I hose connections at intermediate stair landings.

This stairwell is not served by a ventilation system.

9A.3.2.8 Not used.

9A.3.2.9 Fire Area 2040 AF 01

This fire area is comprised of the following room(s):

Room No.	
20407	Lube oil storage room

This fire area contains the clean and dirty lube oil storage tanks. There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Wet pipe sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Local heating and ventilation for the lube oil storage room is supplied by the turbine building ventilation system (VTS) as described in Subsection 9.4.9. During normal operation, an exhaust ventilator mounted on an exterior wall pulls air in from the outside environment through an exterior wall louver, or through a damper in a wall separating the lube oil storage room from the rest of the turbine building. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Following a fire, the exhaust ventilator, if available, can be used to vent smoke to outside the turbine building.

Fire Protection Adequacy Evaluation

A fire in this area is detected by the wet pipe type automatic sprinkler system. Upon sprinkler system actuation, visual and audible alarms are produced in the main control room and at the remote fire alarm annunciator panel, and notification alarms are produced locally by the fire alarm detection system. The fire is extinguished by operation of an automatic sprinkler system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. Due to the concentration of lubricating oil, this fire area is an extra hazard fire area. This area has a high combustible loading and fires with high heat release rates could develop rapidly. Therefore, an automatic fire suppression system is provided. The 3-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond this fire area.

The lube oil storage area ventilation system portion of the turbine building ventilation system does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.10 Fire Area 2043 AF 01

This fire area is comprised of the following room(s):

Room No.	
20401	Secondary sampling laboratory

There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Wet pipe sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The turbine building ventilation system (VTS) personnel area HVAC subsystem, as described in Subsection 9.4.9, provides heating and cooling to the secondary sampling laboratory. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by the wet pipe type automatic sprinkler system. Upon sprinkler system actuation, visual and audible alarms are produced in the main control room and at the remote fire alarm annunciator panel, and notification alarms are produced locally by the fire alarm detection system. The fire is extinguished by the automatic suppression system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. As volatile chemicals are likely to be present, this fire area is an extra hazard fire area. Due to high heat release rates, fires could develop rapidly. Therefore, an automatic fire suppression system is provided. There are no concentrations of combustibles that could challenge the fire area barrier. The 3-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The VTS personnel area HVAC subsystem serving the secondary sampling laboratory does not contribute to the spread of the fire or smoke to other fire areas. Fire area boundaries are equipped with fire dampers to prevent the propagation of fire between fire areas.

9A.3.2.11 Fire Area 2050 AF 01

This fire area is comprised of the following room(s):

Room No.	
20504	Turbine lube oil reservoir room

There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Automatic water spray system
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

Local heating and ventilation for the turbine lube oil reservoir room is supplied by the turbine building ventilation system (VTS) as described in Subsection 9.4.9. During normal operation, an exhaust ventilator mounted on an exterior wall pulls air in from the outside environment through an exterior wall louver, or through a damper in a wall separating the lube oil reservoir room from the rest of the turbine building. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Following a fire, the exhaust ventilator, if available, can be used to vent smoke to outside the turbine building.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by operation of automatic sprinkler system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. Due to the concentration of lubricating oil, this fire area is an extra hazard fire area. This area has a high combustible loading and fires with high heat release rates could develop rapidly. Therefore, an automatic fire suppression system is provided. The 3-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The turbine lube oil reservoir ventilation system portion of the turbine building ventilation system does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.12 Fire Area 2052 AF 01

This fire area is comprised of the following room(s):

Room No.	
20502	Switchgear room 1

This fire area is the turbine building switchgear room 1 and contains high voltage electrical equipment. There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The turbine building ventilation system (VTS) electrical equipment rooms HVAC subsystem, as described in Subsection 9.4.9, provides heating and cooling to switchgear room 1. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. The fire area has a low concentration of combustibles, primarily cable insulation, with moderate heat release rates. The 2-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The VTS electrical equipment rooms HVAC subsystem of the turbine building ventilation system serving switchgear room 1 does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.13 Fire Area 2053 AF 01

This fire area is comprised of the following room(s):

Room No.	
20513	Electrical equipment room

This fire area is the electrical equipment room and contains low voltage electrical equipment. There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The turbine building ventilation system (VTS) electrical equipment rooms HVAC subsystem, as described in Subsection 9.4.9, provides heating and cooling to the electrical equipment room. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. The fire area has a low concentration of combustibles, primarily cable insulation, with moderate heat release rates. There are no concentrations of combustibles that could challenge the fire area barrier. The 2-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The VTS electrical equipment rooms HVAC subsystem of the turbine building ventilation system serving the electrical equipment room does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.14 Fire Area 2053 AF 02

This fire area is comprised of the following room(s):

Room No.	
20501	Switchgear room 2

This fire area contains high voltage electrical equipment. There are no systems in this fire area which contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The turbine building ventilation system (VTS) electrical equipment rooms HVAC subsystem, as described in Subsection 9.4.9, provides heating and cooling to switchgear room 2. Fire dampers close automatically on high temperature to control the spread of fire and smoke. Smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally with both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. The fire area has a low concentration of combustibles, primarily cable insulation, with moderate heat release rates. There are no concentrations of combustibles that could challenge the fire area barrier. The 2-hour fire barriers that separate this fire area from the rest of the turbine building provide sufficient separation to prevent the fire from propagating beyond the fire area.

The VTS electrical equipment rooms HVAC subsystem of the turbine building ventilation system serving switchgear room 2 does not contribute to the spread of the fire or smoke to other fire areas because fire dampers isolate the fire area.

9A.3.2.15 Fire Area 2151 AF 01

This turbine building fire area contains non-Class 1E batteries. This fire area contains one fire zone:

Fire Zone	Room No.	
2151 AF 21581	21581	Battery room

There are no systems in this fire area that normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The south bay equipment HVAC subsystem of the turbine building ventilation system (VTS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VTS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally, and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and they primarily consist of electrical cable insulation. The combustible materials are relatively uniformly distributed throughout the fire area. The combustible loading for this fire area exceeds 80,000 Btu/ft^2, warranting the need for detection and automatic and manual suppression capabilities per the guidelines in Subsection 9A.2.4. Automatic suppression is not installed in this fire area as an effort is made to limit water sources in the vicinity of electrical equipment. This is a light hazard fire area, and the rate of fire growth is expected to be slow. Minimum 2-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.2.16 Fire Area 2151 AF 02

This turbine building fire area contains non-Class 1E battery charging equipment. This fire area contains one fire zone:

Fire Zone	Room No.	
2151 AF 21582	21582	Battery charger room

There are no systems in this fire area that normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The south bay equipment HVAC subsystem of the turbine building ventilation system (VTS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally, and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and they primarily consist of electrical cable insulation and ordinary combustible material such as paper and plastic. The combustible materials are relatively uniformly distributed throughout the fire area. This is a light hazard fire area, and the rate of fire growth is expected to be slow. Minimum 2-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.2.17 Fire Area 2000 AF 15

Room No.	
S15	Stairwell

This stairwell serves the northwest portion of the turbine building from 158'-7" to 100'-0". The walls of this enclosure that are exposed to the turbine building interior are constructed with a concrete/steel composite material having a minimum fire rating of 2 hours. The walls of the enclosure that face the yard area would not be exposed to the turbine building interior; therefore, these outside walls are constructed with an exterior siding used for the turbine building and are not required to be constructed or maintained to a minimum fire rating. There are no safety-related components or systems in this fire area that contain radioactive material. There are no systems in this fire area that contain radioactive material. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area.

This stairwell is not served by a ventilation system.

9A.3.3 Yard Area and Outlying Buildings

The fire protection system yard main and the location of hydrants and hose houses are described in Subsection 9.5.1. Miscellaneous yard areas do not contain safety-related components or systems and are located such that a fire or effects of a fire, including smoke, do not adversely affect any safety-related systems or equipment. Miscellaneous areas include such structures, for example, as maintenance shops, warehouses, the administrative building, training/office centers, and flammable and combustible material storage tanks. The intake structure is nonsafety-related, does not contain any safety-related equipment, and is remotely located from safety-related structures, systems and components. The miscellaneous areas are located outside of the nuclear island, which is separated from the other yard areas by 3-hour fire rated barriers or a minimum of fifty feet of spatial separation in accordance with NFPA 804 (Reference 203) for exposure protection. Fire detection and suppression are provided as determined by the fire hazards analysis and applicable building codes and insurance company loss prevention standards. Water-based fire suppression systems are supplied by a separate yard main that is independent of AP1000 fire loops. The separate yard main is

designed and constructed in accordance with applicable NFPA and local codes and applicable insurance company loss prevention standards. The separate yard main is maintained in accordance with local codes and insurance company loss prevention standards.

The Radioactive Material and Equipment Storage Building is used for storage of low level radioactive materials. Manual fire suppression, consisting of fire hydrants for manual hoses and portable extinguishers, is provided in accordance with Regulatory Guide 1.189 section 6.2.3. Automatic fire detection is provided in permanent buildings that house radiative material which alarm locally and in a continuously manned location in accordance with Regulatory Guide 1.189 section 6.2.3. Ventilation systems can be manually isolated in the event of a fire. There are no drains to the liquid radwaste collection systems in miscellaneous yard areas or outlying buildings. Pre-Fire Plans contain instruction to collect water run-off from firefighting activities in areas containing radioactive material for sampling prior to release.

High level radioactive materials or materials that collect and contain radioactivity, such as spent ion exchange resins, charcoal filters, and HEPA filters are not stored in the yard area and outlying buildings.

The cooling tower is not used as the ultimate heat sink or for fire protection purposes. Therefore, the guidance specified in BTP CMEB 9.5-1 is not applicable. The cooling tower serves no safety function and has no safety design basis. The cooling tower does not contain any equipment capable of releasing radioactivity to the atmosphere. The cooling tower fill is a PVC material with a flame spread rating of 25 or less. The cooling tower is remotely located from HVAC air intakes such that smoke and products of combustion do not affect any safety-related plant areas.

Stairwells in miscellaneous buildings located in the yard serving as escape routes or access routes for firefighting, are enclosed in masonry or concrete towers with a minimum fire resistance rating of 2 hours and self-closing Class B fire doors. The two hour fire-resistance rating for the masonry or concrete material is based on testing conducted in accordance with ASTM E119 (Reference 201) and NFPA 251 (Reference 202) as addressed in Table 9.5.1-1.

9A.3.4 Annex Building

Figure 9A-201 identifies fire areas and fire zones within the annex building and illustrates the fire resistance of the fire area boundaries.

A fire in the annex building fire areas does not affect safe shutdown capability. A fire is confined to the fire area, and fire areas within the annex building are separated from the safety-related areas of the nuclear island by a 3-hour fire barrier wall, except for those fire areas which include portions of the auxiliary building. Closing of fire dampers in the ventilation system serving the annex building fire areas does not affect safe shutdown systems. Safe shutdown systems are generally served by independent ventilation systems. Fire areas which include portions of the auxiliary building are discussed later in this subsection.

Neither a fire nor fire suppression activities in annex building fire areas affect the safe shutdown capability of components located in other fire areas.

Floor drains are sized to handle water flow from fire protection systems without a significant accumulation of water in the fire area. Flooding of components required for safe shutdown is not a concern because there are no safe shutdown components in the annex building.

No fire in the annex building can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.4.1 Fire Area 4001 AF 01

This fire area is comprised of the following room(s):

Room No.	
S01	Stairwell

This stairwell is enclosed by fire barrier walls having a minimum rating of 2 hours. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

Smoke intrusion to the stairwell is limited by fire barrier walls having a minimum rating of 2 hours, and self-closing doors having a minimum rating of 1.5 hours. No ventilation system serves this fire area.

9A.3.4.2 Fire Area 4001 AF 02

This fire area is comprised of the elevator shaft and elevator.

This elevator is enclosed by fire barrier walls having a minimum rating of 2 hours.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

A damper in the annex/auxiliary buildings nonradioactive HVAC system (VXS) vents the elevator shaft in the event of a fire. After the fire, smoke is removed from the fire area by using the exhaust vent, portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3, and consist primarily of cable insulation and lubricant associated with the elevator hoisting machinery. This is a light hazard fire area and the rate of fire growth is expected to be slow. Two-hour fire barriers provide adequate separation from adjacent fire areas since the fire will be contained within this fire area.

9A.3.4.3A Fire Area 4002 AF 01

This fire area is comprised of the following room(s):

Room No.	
S02	Stairwell

The west wall of this stairwell is exposed to the annex building interior, and it is constructed with a material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the annex building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the annex building. The quantity of

combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

Smoke intrusion to the stairwell is limited by fire barrier walls having a minimum rating of 2 hours, and self-closing doors having a minimum rating of 1.5 hours. No ventilation system serves this fire area.

9A.3.4.3B Fire Area 4002 AF 03

This fire area is comprised of the elevator shaft and the following zones:

Fire Zone	Room No.	
4002 AF 40603	40603	Storage Room
4002 AF 40604	40604	Security Room

This elevator is enclosed by fire barrier walls having a minimum rating of 2 hours.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The health physics and hot machine shop (VHS) HVAC system serves this fire area on a once-through basis. In the event of a fire in the elevator shaft, a combination fire-smoke damper on the elevator shaft closes automatically in response to a smoke detector signal controlling the spread of fire, smoke, and hot gases. The VHS continues to ventilate the remaining fire areas unless the operator decides to shut down the system. If the exhaust fire-smoke damper for the elevator shaft is operable, the damper may be reopened to further reduce the migration of smoke. Smoke is removed from the elevator shaft by reopening the fire damper after a fire and operating the ventilation system to exhaust to the atmosphere or by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3. Combustibles in the elevator shaft consist primarily of cable insulation and lubricant associated with the elevator hoisting machinery. Combustibles in the security and storage rooms consist primarily of cable insulation and ordinary combustible materials such as paper, wood, and plastic. This fire area is generally a light hazard area and the rate of fire growth is expected to be slow. The storage room could contain small concentrations of transient combustibles, which could produce a rapidly growing fire. Two-hour fire barriers provide adequate separation between fire zones within this fire area and from adjacent fire areas since the fire will be contained within this fire area.

9A.3.4.4 Fire Area 4002 AF 02

This fire area is comprised of the following room(s):

Room No.	
S04	Stairwell

This stairwell serves the southeast corner of the annex building. The walls of this enclosure that are exposed to the annex building interior are constructed with a material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the annex building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the annex building. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

Smoke intrusion to the stairwell is limited by fire barrier walls having a minimum rating of 2 hours, and self-closing doors having a minimum rating of 1.5 hours. No ventilation system serves this fire area.

9A.3.4.5 Fire Area 4003 AF 01

This fire area encompasses four levels of the annex building and contains demineralized water deoxygenating equipment and air handling equipment. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4003 AF 40340	40340	Demineralized water deoxygenating room
• 4003 AF 40442	40442	Boric acid batching room
• 4003 AF 40503	40503	Lower south air handling equipment room
• 4003 AF 40503	40504	Air intake plenum 2
• 4003 AF 40503	40505	Security room
• 4003 AF 40601	40601	Upper south air handling equipment room
• 4003 AF 40601	40602	Air intake plenum 3

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors (except Rooms 40504 and 40602)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The mechanical equipment areas HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. This action controls the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as wood and paper. Combustibles are relatively uniformly distributed throughout each fire zone. This is a light hazard fire area and the rate of fire

growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas. The building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.6 Fire Area 4003 AF 02

This fire area is comprised of the following room(s):

Room No.	
S03	Stairwell

This stairwell serves the east side of the annex building. The walls of this enclosure that are exposed to the annex building interior are constructed with a material having a minimum fire rating of 2 hours. The walls of the enclosures that face the yard area would not be exposed to the annex building interior. Therefore, these outside walls are constructed with an exterior siding common to the overall siding used for the annex building. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area. NFPA Class I hose connections are provided in the stairwell for use in fighting fires in other fire areas.

Smoke intrusion to the stairwell is limited by fire barrier walls having a minimum rating of 2 hours, and self-closing doors having a minimum rating of 1.5 hours. No ventilation system serves this fire area.

9A.3.4.7 Fire Area 4031 AF 01

This annex building fire area contains one train of the non-Class 1E batteries and battery charging equipment. This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
● 4031 AF 40307	40307	Battery room 1
● 4031 AF 40308	40308	Battery charger room 1

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally, and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation. The combustible materials are relatively uniformly distributed throughout the fire area. The combustible loading for this fire area exceeds 80,000 Btu/ft^2, warranting the need for detection and automatic and manual suppression capabilities per the guidelines in Subsection 9A.2.4. Automatic suppression is not installed in this fire area as an effort is made to limit water sources in the vicinity of electrical equipment. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided. The battery room is also separated from the adjacent charging room by a 1-hour fire barrier, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.8 Fire Area 4031 AF 02

This annex building fire area contains one train of the non-Class 1E batteries, one additional battery bank, and battery charging equipment. This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4031 AF 40309	40309	Battery room 2
• 4031 AF 40310	40310	Battery charger room 2
• 4031 AF 40411	40411	Computer room B
• 4031 AF 40412	40412	Battery room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing fire zones 4031 AF 40309, 4031 AF 40310, and 4031 AF 40412 stops upon detection of smoke in the supply duct. Combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to isolate fire zones 4031 AF 40309 and 4031 AF 40310. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. This subsystem may be restarted and manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke dampers for these fire zones are operable, the dampers may be reopened to further reduce the migration of smoke. The exhaust fan for fire zone 4031 AF 40412 continues to operate at the discretion of the operator. In the event of a fire emergency in fire zone 4031 AF 40412, operators may isolate the main control room and actuate the main control room emergency habitability system at their discretion to maintain control room habitability. After the fire, smoke is removed from these fire zones by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

The main control room/control support area HVAC subsystem of the NI non-radioactive ventilation system (VBS) serves fire zone 4031 AF 40411. The main control room/control support area HVAC subsystem will shut down and combination fire-smoke dampers close automatically in response to a smoke detector signal or high temperature to control the spread of fire and smoke. Operators may actuate the main control room emergency habitability system at their discretion to maintain control room habitability in the event closure of these fire-smoke dampers interrupts the operation of the main control room/control support area HVAC subsystem. The other VBS subsystems continue to provide ventilation to the unaffected fire areas. The subsystem may be manually realigned to the once-through ventilation mode to minimize the potential for migration of smoke and hot gases. If the exhaust fire-smoke damper for fire zone 4031 AF 40411 is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from the fire zone by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode.

Smoke from a fire in this fire area does not affect safe shutdown components in fire areas that are served by other ventilation systems, subsystems, or air distribution headers.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of batteries and electrical cable insulation. The combustible materials are relatively uniformly distributed throughout the fire area. The combustible loading for this fire area exceeds 80,000 Btu/ft^2, warranting the need for detection and automatic and manual suppression capabilities per the guidelines in Subsection 9A.2.4. Automatic suppression is not installed in this fire area as an effort is made to limit water sources in the vicinity of electrical equipment. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided. The battery room is also separated from the adjacent charging room by a 1-hour fire barrier, which limits the spread of fire within the fire area.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.9 Fire Area 4031 AF 05

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4031 AF 40300	40301	Access corridor
• 4031 AF 40300	40305	Security room
• 4031 AF 40300	40315	Security room
• 4031 AF 40303	40303	Corridor
• 4031 AF 40303	40304	Restroom

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- 2 Hose stations in corridor 40303

- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as paper, wood, and plastic. Combustibles are relatively uniformly distributed throughout each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided. Fire zones within this fire area are separated by walls as shown in Figure 9A-201. The walls for the exit corridors are rated for a minimum of 1 hour in accordance with the Uniform Building Code. The building exterior walls are not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.10 Fire Area 4031 AF 06

This fire area is comprised of the following room(s):

Room No.	
40306	Security room
40302	Security room
40300	Security room

This fire area contains computer and communication equipment. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- 2 Hose stations in Corridor 40303
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as paper, wood, and plastic. Combustibles are relatively uniformly distributed throughout each fire zone. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.11 Fire Area 4032 AF 01

This fire area is comprised of the following room(s):

Room No.	
40326	Non-radiologically controlled area entry/exit area
40327	Health physics office
40350	Radiologically controlled area entry/exit area
40351	Protective clothes pickup and suitup
40352	Access corridor
40354	Health physics counting
40355	Decontamination room
40356	Corridor
40360	Decontamination room
40361	Corridor

The area is used for decontamination and monitoring of personnel leaving the radiological control area of the plant. Low levels of radioactive materials may be present within the fire area.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The health physics and hot machine shop HVAC system (VHS) servicing this fire area stops upon detection of smoke in the area or in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and starting the exhaust fans serving this area.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible material such as wood and paper. Combustibles are relatively uniformly distributed throughout the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.12 Fire Area 4032 AF 02

This fire area is comprised of the following room(s):

Room No.	
40357	Containment access corridor elevation 107′-2″
40362	Radwaste access corridor
40415	Security Room

This fire area contains the corridors used to transport equipment and personnel through the annex building and auxiliary building to and from containment and provides access from the annex building to the radwaste building. As such, low levels of radioactive material may be present within the fire area.

Fire Detection and Suppression Features

- Fire detectors
- Wet pipe sprinklers (Elevation 107′-2″)
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The auxiliary/annex building subsystem of the radiologically controlled area ventilation system (VAS) servicing this fire area alarms in the main control room upon detection of smoke in the area or in the exhaust duct. If smoke is detected in the supply air ducts, an alarm is initiated in the main control room and the supply and exhaust fans for the corresponding train are automatically shut down. Fire dampers close automatically on high temperature to isolate this fire area. The balance of the VAS auxiliary/annex building ventilation subsystem remains in operation unless plant operators determine that there is a need to manually shut down the subsystem. The balance of VAS remains in operation. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers. The ventilation exhaust system serving the area exhausts smoke to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by the wet pipe sprinkler system or manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible material such as wood and paper. Diesel fuel may be present when there is a truck in the containment access corridor. Combustibles are relatively uniformly distributed throughout the fire area except when transient combustibles are present. This is an

ordinary hazard fire area when transient combustibles are present and the rate of fire growth may be rapid. Minimum two-hour fire barriers are provided and the building exterior wall is not rated. An automatic suppression system is provided to address transient combustibles.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.13 Fire Area 4033 AF 01

This fire area is comprised of the following room(s):

Room No.	
40358	Hot machine shop
40359	Pump seal shop

The shop is used for decontamination and repair of equipment from the radiological control area of the plant. As such, low levels of radioactive materials may be present within the fire area.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The health physics and hot machine shop HVAC system (VHS) servicing this fire area stops upon detection of smoke in the area or in the duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and starting the exhaust fans serving this area.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as wood and paper. Combustibles are relatively uniformly distributed throughout the fire area. This is an ordinary hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided. The building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.14 Fire Area 4034 AF 01

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
● 4034 AF 40311	40311	Corridor

- 4034 AF 40311 40312 Corridor
- 4034 AF 40311 40373 Corridor
- 4034 AF 40313 40313 Office
- 4034 AF 40313 40314 Office
- 4034 AF 40316 40316 Computer Room L1/2
- 4034 AF 40317 40317 Computer Room L3
- 4034 AF 40318 40318 ALARA briefing room and HP monitoring room
- 4034 AF 40320 40320 Women's change room
- 4034 AF 40322 40321 Janitor closet
- 4034 AF 40322 40322 Men's change room
- 4034 AF 40322 40323 Water heater room
- 4034 AF 40322 40324 Drying area
- 4034 AF 40322 40325 Shower room
- 4034 AF 40370 40370 Rest room
- 4034 AF 40370 40371 Conference room
- 4034 AF 40370 40372 Conference room
- 4034 AF 40370 40374 Corridor
- 4034 AF 40370 40375 Conference room
- 4034 AF 40370 40376 Kitchen
- 4034 AF 40370 40377 Rest room
- 4034 AF 40378 40378 Office area west
- 4034 AF 40378 40381 Fire Brigade Locker
- 4034 AF 40379 40379 Office area east
- 4034 AF 40379 40382 Radiation Protection (RP) Calibration Lab
- 4034 AF 40379 40383 Break Area
- 4034 AF 40379 40384 RP Technician Work Area
- 4034 AF 40379 40385 Office
- 4034 AF 40379 40386 Corridor

The radiation protection calibration lab includes a sealed radiation source (see Subsection 12.2.1.1.10) located inside shielded calibration equipment. There are no other systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The general area HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate portions of this fire area. These actions control the

spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, an exhaust fan serving the change rooms, and rest rooms mounted on the roof over the fire area, is used to exhaust smoke to the atmosphere from the change rooms and rest rooms. Smoke from other areas may be exhausted using portable exhaust fans and flexible ductwork.

Fire zone 4034 AF 40311 is an exit corridor for the area and is protected with fire dampers on duct penetrations of the corridor envelope in accordance with the Uniform Building Code.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible material such as wood and paper. Combustibles are relatively uniformly distributed throughout the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the building exterior wall is not rated. Fire zones within this fire area are separated by walls as shown in Figure 9A-201. The walls of fire zone 4034 AF 40311 are rated for 1-hour in accordance with Uniform Building Code requirements for exit corridors.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.15 Fire Area 4035 AF 01

This fire area is comprised of the following room(s):

Room No.	
40341	Ancillary diesel generator room

This annex building fire area contains two diesel generator sets and one fuel storage tank. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Automatic dry pipe sprinkler system
- Hose station(s)
- Portable fire extinguishers
- Fire detectors

Smoke Control Features

The mechanical equipment areas HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this area is detected through the operation of the automatic dry pipe sprinkler system and/or a heat detector which produces an audible alarm locally and both visual and audible alarms in the

main control room and at the remote fire alarm annunciator panel. The fire is extinguished by the automatic dry pipe sprinkler system. The sprinklers provide protection for the room and the walled pit under the floor of the room that is used to capture the sprinkler system water and the contents of the fuel storage tank. If necessary the fire can also be extinguished manually.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of diesel fuel oil in the fuel oil storage tank. The tank is partially located in the walled spill containment pit under a grated section of the floor and extends above the floor into the room. The walled spill containment pit has no drains and no doors. The remaining combustibles are relatively uniformly distributed throughout the fire area. This is an ordinary hazard fire area and the rate of heat release is expected to be moderate to high. Minimum three-hour fire barriers are provided and the building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.16 Fire Area 4041 AF 01

This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4041 AF 40403	40403	Control support area
• 4041 AF 40403	40404	Restroom
• 4041 AF 40403	40405	Rest area, kitchen
• 4041 AF 40403	40406	Conference room
• 4041 AF 40403	40407	Conference room
• 4041 AF 40403	40408	NRC room
• 4041 AF 40403	40409	Conference room
• 4041 AF 40410	40410	Computer room A
• 4041 AF 40410	40402	Corridor

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The main control room/control support area HVAC subsystem of the VBS will shut down and combination fire-smoke dampers in this subsystem close automatically upon detection of smoke and/or on high temperature to isolate this fire area. The main control room/control support area HVAC subsystem will shut down upon detection of a fire in this fire area. This subsystem may be manually realigned to the once-through smoke exhaust ventilation mode to minimize the potential migration of smoke. If the exhaust fire-smoke damper for this fire area is operable, the damper may be reopened to further reduce the migration of smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the once-through ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible material such as wood and paper. Combustibles are relatively uniformly distributed throughout the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the building exterior wall is not rated. Fire zones within this fire area are separated by walls as shown in Figure 9A-201. The corridor walls of fire zone 4041 AF 40410 are rated for one-hour in accordance with Uniform Building Code requirements for exit corridors.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.17 Fire Area 4041 AF 02

This fire area is comprised of the following room(s):

Room No.	
40400	Corridor
40401	Restroom

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The equipment room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply duct. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode. In the event of a fire emergency in this fire area, operators may isolate the main control room and actuate the main control room emergency habitability system at their discretion to maintain control room habitability.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation. There are cable concentrations near the ceiling in the southern half of the corridor. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.18 Fire Area 4042 AF 01

This fire area is comprised of the following room(s):

Room No.	
40413	Electrical switchgear room 1 including vertical electrical chase from room 40413 to room 40350 (floor slab Elevation 100′-0″)

This annex building fire area contains the non-Class 1E switchgear for one train, and two motor generator sets with their two associated control cabinets. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The switchgear room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply or return duct. Fire dampers in the system close automatically on high temperature to isolate this fire area. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation within electrical equipment, cabinets, and raceways. There are cable concentrations near the ceiling and the exterior wall. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas. The building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.19 Fire Area 4042 AF 02

This fire area is comprised of the following room(s):

Room No.	
40414	Electrical switchgear room 2

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The switchgear room HVAC subsystem of the annex/auxiliary building non-radioactive ventilation system (VXS) servicing this fire area stops upon detection of smoke in the supply or return duct. Fire dampers in the system close automatically on high temperature to isolate this fire area. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by reopening the fire dampers and operating the ventilation system in the smoke exhaust ventilation mode.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally, and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation within electrical equipment, cabinets, and raceways. There are cable concentrations near the ceiling and the exterior wall. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers provide adequate separation from adjacent fire areas. The building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.4.20 Fire Area 4051 AF 01

This fire area is comprised of the following room(s):

Room No.	
40500	North air handling equipment room
40501	Air intake plenum 1

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors (except Room 40501)
- Hose station(s)
- Portable fire extinguishers
- Automatic wet pipe sprinklers (Room 40500 only)

Smoke Control Features

This fire area houses the annex/auxiliary building non-radioactive ventilation system (VXS) switchgear room HVAC subsystem supply air handling units and the VXS equipment room HVAC subsystem supply air handling units, as well as one of two VBS main control room/control support area HVAC subsystem air handling units. The VXS equipment room HVAC subsystem servicing this fire area stops upon detection of smoke in the supply or return duct. Fire dampers in the system close automatically on high temperature to isolate this fire area. Other VXS subsystems continue to provide ventilation to the unaffected fire areas. After the fire, smoke is removed from this fire area by using

portable exhaust fans and flexible ductwork or by reopening the fire dampers and operating the ventilation system in the smoke exhaust mode if it is still functional.

Combination fire-smoke dampers in this area that close automatically in response to heat from a fire isolate the outdoor air intake to the main control room/control support area HVAC subsystem air handling unit in this area. In the event of a fire emergency in this fire area, operators may isolate the main control room and actuate the main control room emergency habitability system at their discretion to maintain control room habitability.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by operation of an automatic sprinkler or by manually using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation. There are cable concentrations along the west and south walls. This is a light hazard zone and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the exterior wall is not rated.

The ventilation systems contained in this fire area are equipped with fire dampers on their duct penetrations out of and into this fire area. The systems contained in this area are recirculating HVAC systems serving personnel and equipment areas in the annex building, and one train of HVAC equipment serving the main control room.

The ventilation system does not contribute to the spread of fire or smoke as described in the Smoke Control Features section above.

9A.3.4.21 Fire Area 4052 AF 01

This fire area contains the staging, storing, and assembly area for the containment. It also houses the exhaust fans for the health physics area and the containment air filtration exhaust units. The containment air filtration units remove radioactive halogens and particulates from the containment air prior to discharge to the atmosphere. Low levels of radioactive material may be present within the fire area during normal plant operation. This fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 4052 AF 40550	40550	Staging and storage area
• 4052 AF 40551	40551	Containment air filtration exhaust room A
• 4052 AF 40552	40552	Containment air filtration exhaust room B

Fire Detection and Suppression Features

- Fire detectors
- Hose station(s)
- Portable fire extinguishers
- Automatic wet pipe sprinklers (Room 40550 only)

Smoke Control Features

The auxiliary/annex building subsystem of the radiologically controlled area ventilation system (VAS) servicing this fire area alarms in the main control room upon detection of smoke in the area or in the exhaust duct. If smoke is detected in the supply air ducts or if a fire is detected in room 40550, an

alarm is initiated in the main control room and the supply and exhaust fans for the corresponding train (or both trains for a fire detected in room 40550) are automatically shut down. The balance of the this and other VAS subsystems remain in operation unless plant operators determine that there is a need to manually shut down the subsystem. Fire dampers close automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from this fire area by reopening the fire dampers. The ventilation exhaust system serving the area exhausts smoke to the atmosphere.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by operation of an automatic sprinkler or manually using hose streams or portable extinguishers.

This fire area contains two charcoal adsorbers, located in the containment air filtration system exhaust units. The normal temperature of the air flowing through the charcoal adsorbers is well below 200°F, while the minimum charcoal ignition temperature is greater than 600°F. Two independent temperature sensors interface with the fire detection system, providing charcoal temperature indication, and high and high-high temperature alarms. The filtration unit fan trips at the high temperature alarm setpoint. The setpoints of both alarms are well below the charcoal ignition temperature, allowing the operator time to investigate and take corrective action. In the unlikely event of a fire in the adsorber, the filtration unit can be manually isolated. The adsorber deluge piping will be connected to a nearby hose station to cool the charcoal and extinguish the fire.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and charcoal. The charcoal is contained within the sheet metal housings of the containment air filtration system exhaust units. There are cable concentrations along the south and west walls of the fire area. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum two-hour fire barriers are provided and the building exterior wall is not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.5 Radwaste Building

Figure 9A-4 identifies fire zones within the radwaste building fire area and illustrates the fire resistance of the fire area boundaries.

A fire in the radwaste building does not affect safe shutdown capability. A fire is confined to the fire area. The radwaste building fire area is separated from the safety-related areas of the nuclear island by a 3-hour fire barrier wall. The radwaste building is served by the dedicated radwaste building HVAC system. Closing of fire dampers in the ventilation system serving the radwaste building does not affect safe shutdown systems because the safe shutdown systems are served by other ventilation systems.

Neither a fire nor fire suppression activities in the radwaste building affect the safe shutdown capability of components located in other fire areas.

Floor drains are sized to handle water flow from fixed automatic fire protection systems without a significant accumulation of water in the fire area. Curbed areas within the radwaste building have sufficient capacity to retain fire protection water to prevent an unmonitored release to the environment.

No fire in the radwaste building can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.5.1 Fire Area 5031 AF 01

The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
• 5031 AF 50300	50300	Electrical/mechanical equipment room
• 5031 AF 50350	50350	Mobile systems facility
• 5031 AF 50351	50351	Waste accumulation room
• 5031 AF 50353	50353	HVAC equipment room
• 5031 AF 50354	50354	Truck staging area
• 5031 AF 50355	50355	Monitor tanks room

Various radwaste processing and packaging operations are performed utilizing the mobile system facilities. Moderate quantities of radioactive materials are present in the fire area during all modes of plant operation.

Fire Detection and Suppression Features

- Fire detectors
- Preaction sprinklers
- Hose station(s)
- Portable fire extinguishers

Smoke Control Features

The radwaste building HVAC system (VRS) stops and an alarm is sent to the main control room and to the remote fire alarm annunciator panel upon actuation of the fire suppression system in this fire area or if smoke is detected in either supply duct downstream from the air handling units. The VRS HVAC will be shut down automatically by the FPS. The fire damper to the plant vent closes automatically on high temperature to isolate this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area and exhausted to atmosphere by reopening the fire damper and operating the ventilation system exhaust fans.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by the preaction sprinkler system or manually, using hose streams or portable extinguishers.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation and ordinary combustible materials such as cloth and trash. There are concentrations of combustibles in the waste accumulation room and potentially in the mobile systems facility. There are small concentrations of lubricants associated with equipment such as cask transporter vehicles. Diesel fuel may periodically be present when there is a truck present in the truck staging area. Depending upon the processes being performed in the mobile systems facility, the locations of combustible concentrations may change. This is a light hazard fire area and the rate of fire growth is expected to be slow. Minimum three-hour barriers are provided and the building exterior wall is not rated. An automatic suppression system is provided due to the localized areas of high combustible

loading. This system provides confidence that the fire will be promptly extinguished, thus minimizing the potential for release of radioactivity and the radiation exposure of firefighters.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6 Diesel Generator Building

Figure 9A-5 identifies fire areas and fire zones within the diesel generator building and illustrates the fire resistance of the fire area boundaries.

A fire in the diesel generator building does not affect safe shutdown capability. The diesel generator building is not adjacent to any building or area containing safety-related equipment. The diesel generator building heating and ventilation system is dedicated to the diesel generator building and independent of other ventilation systems.

Neither a fire nor fire suppression activities in the diesel generator building fire areas affect the safe shutdown capability of components located in other fire areas.

Floor drains are sized to handle low water flow rates. Water from fixed automatic fire protection systems flows out of the building through opened doors. Flooding of components required for safe shutdown is not a concern because there are no safe shutdown components in the diesel generator building.

No fire in the diesel building can cause spurious actions which could cause a breach in the reactor coolant boundary or defeat safety related decay heat removal capability or cause an increase in shutdown reactivity of the reactor.

9A.3.6.1 Fire Area 6030 AF 01

This fire area contains the diesel generator and supporting equipment for one train of the onsite standby ac power system. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
● 6030 AF 60310	60310	Diesel generator room A
● 6030 AF 60311	60311	Service module A
● 6030 AF 60313	60313	Combustion air cleaner area A

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors in the service module, diesel generator room, and combustion air cleaner
- Dry pipe sprinklers in the diesel generator room
- Hose station(s)
- Portable fire extinguishers (including carbon dioxide)

Smoke Control Features

The diesel generator building ventilation system (VZS) serves this fire area by means of the engine room air handling unit, the service module air handling unit, and the standby exhaust fans. The systems only serve a single room and can not spread smoke or hot gases outside of the affected fire area. If these systems are operating, they will continue to do so until manually shut down; manual action is preferred to prevent normal generator operation (engine radiant heat and smoke from

exhaust) from tripping the ventilation systems unnecessarily. The standby exhaust fans, if already running, will continue to run to help remove smoke; the exhaust fans do not start automatically on a fire signal. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area by manually turning on, if available, the standby exhaust fans mounted on the roof over the fire area, or by opening the roll-up door and personnel doors and utilizing portable exhaust fans.

Fire Protection Adequacy Evaluation

A fire in the diesel generator room is detected through the operation of the dry pipe sprinkler system and/or a heat detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. A fire in the service module is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. A fire in the diesel generator room is extinguished by the automatic fire suppression system or manually, using hose streams or portable extinguishers. A fire in the service module is extinguished manually using hose streams or portable extinguishers.

The area under the diesel generator is shielded from direct impingement of the spray from the dry pipe sprinkler system, but water accumulating on the floor will find its way into this space. The area under the diesel generator is also accessible for manual firefighting. The roll-up door permits access to this space for manual hose streams from outside the building.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation, lube oil and fuel oil. Combustibles concentrations occur at the diesel generator equipment and in the service module. This is an ordinary hazard fire area and the rate of heat release is expected to be moderate to high. Minimum three-hour fire barriers are provided and the building exterior walls are not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6.2 Fire Area 6030 AF 02

This fire area contains the diesel generator and supporting equipment for one train of the onsite standby ac power system, tool storage area and security room. The fire area is subdivided into the following fire zones:

Fire Zone	Room No.	
● 6030 AF 60320	60320	Diesel generator room B
● 6030 AF 60321	60321	Service module B
● 6030 AF 60323	60323	Combustion air cleaner area B
● 6030 AF 60324	60324	Tool storage room
● 6030 AF 60330	60330	Security room

There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Fire detectors in the combustion air cleaner, diesel generator room, service module, and security room
- Dry pipe sprinklers in the diesel generator room and tool storage room
- Hose station(s)
- Portable fire extinguishers (including carbon dioxide)

Smoke Control Features

The diesel generator building ventilation system (VZS) serves this fire area by means of the engine room air handling unit, the service module air handling unit, and the standby exhaust fans. The systems only serve a single room and can not spread smoke or hot gases outside of the affected fire area. If these systems are operating, they will continue to do so until manually shut down; manual action is preferred to prevent normal generator operation (engine radiant heat and smoke from exhaust) from tripping the ventilation systems unnecessarily. The standby exhaust fans, if already running, will continue to run to help remove smoke; the exhaust fans do not start automatically on a fire signal. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area by manually turning on, if available, the standby exhaust fans mounted on the roof over the fire area, or by opening the roll-up door and personnel doors and utilizing portable exhaust fans.

Fire Protection Adequacy Evaluation

A fire in the diesel generator room is detected through the operation of the dry pipe sprinkler system and/or a heat detector which produces an audible alarm locally, and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. A fire in the service module is detected by a fire detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. A fire in the diesel generator room is extinguished by the automatic fire suppression system or manually, using hose streams or portable extinguishers. A fire in the service module is extinguished manually using hose streams or portable extinguishers.

The area under the diesel generator is shielded from direct impingement of the spray from the dry pipe sprinkler system, but water accumulating on the floor will find its way into this space. The area under the diesel generator is also accessible for manual firefighting. The roll-up door permits access to this space for manual hose streams from outside the building.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of electrical cable insulation, lube oil and fuel oil. Combustibles concentrations occur at the diesel generator equipment and in the service module. This is an ordinary hazard fire area and the rate of heat release is expected to be moderate to high. Minimum three-hour fire barriers are provided and the building exterior walls are not rated.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6.3 Fire Area 6030 AF 03

This fire area is comprised of the following room(s):

Room No.	
60312	Diesel fuel day tank vault A

This fire area contains the fuel oil day tank for one train of the onsite standby ac power diesel generator. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Dry pipe sprinklers
- Hose station(s)
- Portable fire extinguishers
- Fire detectors

Smoke Control Features

Fire dampers in the diesel generator building ventilation system (VZS) close automatically on high temperature to isolate this fire area. The tank vault exhaust fan stops upon actuation of the fire suppression system in this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected through the operation of the dry pipe sprinkler system and/or a heat detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by the automatic dry pipe sprinkler system. Water from the sprinklers rapidly fills and cools the small diked area under the tank. If necessary, the fire can also be extinguished manually.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of diesel fuel oil in the oil storage tank. Due to the small vault size and the size of the storage tank, the combustible loading is uniform throughout the fire area. This is an ordinary hazard fire area and the rate of heat release is expected to be high. Minimum three-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6.4 Fire Area 6030 AF 04

This fire area is comprised of the following room(s):

Room No.	
60322	Diesel fuel day tank vault B

This fire area contains the fuel oil day tank for one train of the onsite standby ac power diesel generator. There are no systems in this fire area which normally contain radioactive material.

Fire Detection and Suppression Features

- Dry pipe sprinklers
- Hose station(s)
- Portable fire extinguishers
- Fire detectors

Smoke Control Features

Fire dampers in the diesel generator building ventilation system (VZS) close automatically on high temperature to isolate this fire area. The tank vault exhaust fan stops upon actuation of the fire suppression system in this fire area. These actions control the spread of fire and smoke. After the fire, smoke is removed from the fire area using portable exhaust fans and flexible ductwork.

Fire Protection Adequacy Evaluation

A fire in this fire area is detected through the operation of the dry pipe sprinkler system and/or a heat detector which produces an audible alarm locally and both visual and audible alarms in the main control room and at the remote fire alarm annunciator panel. The fire is extinguished by the automatic dry pipe sprinkler system. Water from the sprinklers rapidly fills and cools the small diked area under the tank. If necessary, the fire can also be extinguished manually.

Combustible materials in this fire area are listed in Table 9A-3 and primarily consist of diesel fuel oil in the oil storage tank. Due to the small vault size and the size of the storage tank, the combustible loading is uniform throughout the fire area. This is an ordinary hazard fire area and the rate of heat release is expected to be high. Minimum three-hour fire barriers are provided.

The ventilation system does not contribute to the spread of the fire or smoke as described in the Smoke Control Features section above.

9A.3.6.5 Fire Area 6001 AF 01

This fire area is comprised of the following rooms:

Room No.	
S01	Stairwell

The stairwell serves the east side of the diesel generator building. The walls of this enclosure that are exposed to the building interior are constructed with a material having a minimum fire rating of 2 hours. The exterior walls of the enclosures would not be exposed to the diesel generator building interior. Therefore, these outside walls do not require the 2-hour fire rating. The quantity of combustible materials in the stairwell is negligible and no fire is postulated in this fire area.

Fire Detection and Suppression Features

- Dry pipe sprinklers
- Fire detectors

9A.3.7 Special Topics

9A.3.7.1 Evaluation of Spurious Actuation

The potential for spurious actuation of equipment as a result of fire damage to electrical circuits is considered for each fire area containing safety-related equipment. As discussed in Subsection 9A.2.7.1, an assessment of multiple/simultaneous spurious actuations or signals resulting from the fire was performed (Reference 6) with the conclusion that either spurious actuations do not occur, or the consequences are such that safe shutdown can still be achieved. Principal spurious actuation are discussed below. In no case does the spurious actuation of equipment prevent safe shutdown.

9A.3.7.1.1 High-Low Pressure Interfaces

NRC Generic Letter 81-12 requests the identification and evaluation of high-low pressure interfaces between the reactor coolant system and interfacing systems such as the normal residual heat removal system. Per the Generic Letter, these interfaces typically contain two redundant and independent motor-operated valves in series. On a typical pressurized water reactor plant, these two valves and their control and power cables may be subject to a single fire. Potential high-low pressure system interfaces of particular interest are discussed below.

Reactor Coolant System Valve Actuation

NRC Generic Letter 81-12 specifically addresses the reactor coolant/residual heat removal system interface on pressurized water reactors. For AP1000, the reactor coolant system to normal residual heat removal system interface is similar to the typical pressurized water reactor configuration. However, the normal residual heat removal system is not a safety-related system and is not required for safe shutdown. To preclude the spurious opening of the interface valves as a result of a fire, the power to the valves is locked out during power operations. Thus, spurious actuation of the reactor

coolant system to normal residual heat removal system interface valves does not occur and the safe shutdown capability is not affected.

Automatic Depressurization System Valve Actuation

The automatic depressurization system valves are not considered to be high-low pressure interface valves when postulating spurious actuation following a fire. The safety issue related to high-low pressure interfaces is expressed in NRC Generic Letter 81-12. The concern is that the spurious opening of two or more isolation valves which form the boundary between the reactor coolant system and a low pressure system could lead to damage to the low pressure system and a loss of coolant outside the containment. Since automatic depressurization system valve actuation cannot damage a low pressure system, and since the system is entirely within containment, the automatic depressurization valves do not represent a high-low pressure interface as described in NRC Generic Letter 81-12.

Spurious actuation of automatic depressurization system stage 4 squib valves is prevented by the use of a squib valve controller circuit which requires multiple hot shorts for actuation, physical separation of potential hot short locations, and provisions for operator action to remove power from the fire zone. No postulated fire can spread to the hot short locations before the operator can remove power from the fire zone.

Automatic depressurization system stages 1, 2, and 3 consist of parallel paths, each path having two motor-operated valves in series. Spurious stage 1, 2, or 3 actuation is prevented by the use of physical separation of control circuits for the two series valves and provisions for operator action to remove power from the fire zone. No postulated fire can spread to the hot short locations before the operator can remove power from the fire zone.

Reactor Coolant System Reactor Vessel Head Vent Valve Actuation

The reactor vessel head vent valves are connected to the reactor vessel head and discharge to the IRWST. The head vent valves are not required to operate following a fire. There are four head vent valves arranged in two flow paths with two series valves in each path. The head vent valves are fail-closed dc powered solenoid valves, and each valve is powered by a separate, safety-related power supply as shown on Table 9A-2. In the event that a spurious signal was to open a head vent valve, the flow path is blocked by the closed series head vent valve. The cables for the control of one head vent valve in each flow path is enclosed in steel conduit up to the valve to prevent a fire inside containment from spuriously actuating two head vent valves in one flow path. Therefore, a single fire is not postulated to result in an uncontrolled LOCA.

The head vent valves are controlled from switches mounted on the primary and secondary dedicated safety panels in the control room. Each safety panel contains a switch for controlling each head vent valve (4 switches per panel). Each switch is a three-position, hold-in-position switch (open-neutral-close). If both switches are in the neutral position, soft control of the valve from the primary dedicated safety panel is allowed. If both switches are in the open position the valve will open. Either switch in the close position will close the valve. If one switch is in neutral position and one in the open position, the valve will hold its previous position but soft control is defeated. During a fire, switches on one panel may be shorted but none of the head vent valves will be opened because the switches on the other panel will be deactivated before the fire shorts them.

9A.3.7.1.2 Other Spurious Actuation

Principal spurious actuation not involving high-low pressure interfaces is discussed below.

Passive Core Cooling System Passive Residual Heat Removal Heat Exchanger Inlet Valve Actuation

One normally open valve is provided to isolate the inlet line to the passive residual heat removal heat exchanger. To preclude the spurious closing of the inlet valve as a result of a fire, the power to the valve is locked out during power operations. Thus, spurious closing of the passive core cooling passive residual heat removal heat exchanger inlet valve does not occur and the safe shutdown capability is not affected.

Passive Containment Cooling System Valve Actuation

Two valves in series isolate each of the three discharge flow paths from the passive containment cooling system storage tank. For purposes of system reliability, one valve in each flow path is normally open and the other is normally closed. Electrical division assignments are shown in Table 9A-2.

Spurious actuation of one of these valves is assumed to occur where a fire affects its electrical circuitry. Such a fire can occur in the main control room, an electrical equipment fire area, in the passive containment cooling system valve room, or in fire areas or fire zones through which the applicable electrical cables are routed.

Spurious actuation of one of these valves causes a passive containment cooling system flow path to be disabled or inadvertently opened, depending on which valve is affected. If a normally closed valve spuriously opens, passive containment cooling system water delivery from that flow path will be initiated which does not adversely affect the capability to achieve and maintain safe shutdown. If one of the normally open valves were spuriously closed to prevent passive containment cooling system water delivery through that flow path when called upon during the safe shutdown process, the redundant passive containment cooling system water delivery flow paths would be sufficient to achieve and maintain safe shutdown.

Containment Isolation Valve Actuation

Spurious actuation of a containment isolation valve is assumed to occur where a fire affects its electrical circuitry. Each containment penetration has redundant means of containment isolation.

Reactor Trip Switchgear

The reactor trip switchgear receives signals from each of the four Class 1E electrical divisions. One signal from each division de-energizes the undervoltage trip attachments and the other signal energizes the shunt trip attachments on two reactor trip breakers in each division. Either attachment will trip related reactor trip breaker. Also, two out of four signals are required to trip. There are two redundant sets of trip switchgear in separate fire areas. There is no single spurious signal which could prevent the reactor from being tripped.

Reactor Coolant Pump Trip Switchgear

There are two redundant sets of reactor coolant pump trip switchgear in separate fire areas. One is controlled from division B; the other from division C. Thus, a spurious signal in either train will not prevent trip of the reactor coolant pumps.

9A.3.7.2 Protection of Accident Mitigation Equipment

Based on the guidance in BTP CMEB 9.5-1, redundant trains of safety-related equipment used to mitigate the consequences of a design basis accident (but not required for safe shutdown following a fire) are separated so that a fire within one train will not damage the redundant train. Both trains are permitted to be damaged by a single exposure fire.

Either diverse methods of performing the accident mitigation function or adequate separation is provided.

9A.4 References

1. NUREG-0800, U. S. Nuclear Regulatory Commission Standard Review Plan, Subsection 9.5.1, “Fire Protection Program,” Revision 3, July 1981, including Branch Technical Position (BTP) CMEB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," Revision 2, July 1981.

2. Fire Protection Handbook, Edited by A. E. Cote, National Fire Protection Association, 16th edition.

3. NRC Generic Letter 81-12, February 20, 1981.

4. NFPA 92A-2000, “Recommended Practice for Smoke Control Systems.”

5. Fire Protection Handbook, National Fire Protection Association, 18th edition.

6. APP-FPS-G1R-002, Revision 2, “AP1000 Fire Induced Multiple Spurious Actuation Report.”

201. American Society of Mechanical Engineers, “Standard Test Methods for Fire Tests of Building Construction and Materials,” ASTM E119-08a.

202. National Fire Protection Association, “Standard Methods of Tests of Fire Endurance of Building Construction and Materials,” NFPA 251, 2006.

203. National Fire Protection Association, “Standard for Fire Protection for Advanced Light Water Reactor Electric Generating Plants,” NFPA 804, 2001.

204. American Society of Testing and Materials, “Standard Test Method for Fire Tests of Penetration Firestop Systems,” ASTM E814-13a.

Table 9A-1
Heat of Combustion Values(Note 1)

Material	Units	Heat of Combustion Btu/Unit
Acetylene	Pounds	21,500
Alcohol (Ethyl)	Gallons	83,700
Alcohol (Methyl)	Gallons	65,300
Battery - GN-29	Cells	461,300
Battery - GC-39	Cells	595,000
Cable Insulation	Pounds	10,200
Carpet	Pounds	13,200
Charcoal	Pounds	14,900
Cloth (cotton)	Pounds	8,800
Fuel Oil	Gallons	144,000
Gasoline	Gallons	127,700
Hydrogen	Pounds	61,100
Lube Oil	Gallons	152,300
Lubricant	Pounds	20,000
Methane	Pounds	23,900
Paper	Pounds	7,700
Plastic	Pounds	13,200
Propane	Pounds	21,700
Rubber	Pounds	12,200
Trash	Pounds	7,700
Volatiles (Note 2)	Gallons	133,600
Wood	Pounds	8,500

Notes:

1. The heat of combustion values shown in the table are the nominal values used in the combustible loading calculations.
2. Miscellaneous volatile liquids such as kerosene and toluene.

Table 9A-2 (Sheet 1 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11105	RCS	Reactor Vessel (MV-01)	Note 4	Note 4	Note 4	Note 4
	RXS	Source Range Excore Detectors	NE-001A	NE-001C	NE-001B	NE-001D
		Intermediate Range Excore Detectors	NE-002A	NE-002C	NE-002B	NE-002D
		Power Range Excore Detectors (Lower)	NE-003A	NE-003C	NE-003B	NE-003D
		Power Range Excore Detectors (Upper)	NE-004A	NE-004C	NE-004B	NE-004D
1000 AF 01/ 1100 AF 11204	RCS	Hot Leg 1 Flow	FT101A	FT101C		
		Hot Leg 2 Flow	FT102A	FT102C		
1000 AF 01/ 1100 AF 11206	PXS	Core Makeup Tank A Discharge Isolation Valve			V015A	V014A
	SFS	Suction Line Containment Isolation Valve			V034	
1000 AF 01/ 1100 AF 11207	PXS	Core Makeup Tank B Discharge Isolation Valve	V015B	V014B		
1000 AF01/ 1100 AF 11208	RNS	Suction from IRWST Cont. Isolation Valve			V023	
		Return from CVS Cont. Isolation Valve			V061	

Table 9A-2 (Sheet 2 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11300A	PSS	Containment Air Sample Cont. Isolation Valve			V008	
		Liquid Sample Line Cont. Isolation Valve			V010A	V010B
		Sample Return Line Cont. Isolation Valve			V024	
	VFS	Containment Purge Discharge Cont. Isolation Valve				V009
	VFS	Containment Purge Inlet Cont. Isolation Valve				V004
	PXS	IRWST Wide Range Level			LT-046	LT-048
		IRWST Gutter Isolation Valve			V130A	V130B
		Core Makeup Tank (MT-02A)	Note 4	Note 4	Note 4	Note 4
	SGS	Steam Generator 2 Wide Range Water Level			LT-014	LT-018
1000 AF 01/ 1100 AF 11300B	CCS	Outlet Line Cont. Isolation Valve	V207			
	CVS	Letdown Containment Isolation Valve	V045			
		Makeup Line Cont. Isolation Valve	V091			
		RCS Purification Stop Valve (RCPB)	V001	V002		
		Zinc Injection Cont. Isolation Valve	V094			

Table 9A-2 (Sheet 3 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11300B	IDS	Class 1E Electrical Penetrations	EY-P11Z	EY-P27Z		
		Class 1E Electrical Penetrations	EY-P12Y	EY-P29Y		
		Class 1E Electrical Penetrations	EY-P13Y	EY-P28Y		
		Cable trays that route Class 1E cables	Note 1	Note 1		
	PXS	PRHR Heat Exchanger Control Valve (Note 3)	V108A		V108B	
		IRWST Wide Range Level		LT-047		
		PRHR Flow Transmitter		FT-049A	FT-049B	
		Core Makeup Tank (MT-02B)	Note 4	Note 4	Note 4	Note 4
	RCS	Pressurizer Pressure	PT-191A	PT-191C		
		Pressurizer Level	LT-195A	LT-195C		
		Hot Leg 1 Wide Range Pressure	PT-140A	PT-140C		
	SGS	Steam Generator 1 Narrow Range Water Level	LT-001	LT-003		
		Steam Generator 2 Narrow Range Water Level	LT-005	LT-007		
		Steam Generator 2 Wide Range Water Level	LT-013	LT-017		

Table 9A-2 (Sheet 4 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11300B	SGS	Steam Generator 1 Wide Range Water Level	LT-011	LT-015		
		SG1 Steam Line Pressure	PT-030	PT-032		
		SG2 Steam Line Pressure	PT-034	PT-036		
	WLS	Sump Discharge Cont. Isolation Valve	V055			
		RCDT Gas Outlet Cont. Isolation Valve	V067			
1000 AF 01/ 1100 AF 11301	RCS	Reactor Head Vent Valve	V150A	V150C	V150B	V150D
		RCP 1A Bearing Water Temperature	TE-211A	TE-211C	TE-211B	TE-211D
		RCP 1B Bearing Water Temperature	TE-212A	TE-212C	TE-212B	TE-212D
		Cold Leg 1A Temperature (Narrow Range)	TE-121A			TE-121D
		Cold Leg 1B Temperature (Narrow Range)		TE-121C	TE-121B	
		Cold Leg 1A Temperature (Wide Range)	TE-125A			
		Cold Leg 1B Temperature (Wide Range)		TE-125C		
		Hot Leg 1 Temperature (Narrow Range)	TE-131A	TE-131C		
		Hot Leg 1 Temperature (Narrow Range)	TE-132A	TE-132C		
		Hot Leg 1 Temperature (Narrow Range)	TE-133A	TE-133C		

Table 9A-2 (Sheet 5 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11301	RCS	Hot Leg 1 Temperature (Wide Range)		TE-135A		
		RCP Shaft Speed	ST-281		ST-282	
		Hot Leg 1 Flow			FT-101B	FT-101D
	SGS	Steam Generator 1 Wide Range Water Level			LT-012	LT-016
1000 AF 01/ 1100 AF 11302	RCS	RCP 2A Bearing Water Temperature	TE-213A	TE-213C	TE-213B	TE-213D
		RCP 2B Bearing Water Temperature	TE-214A	TE-214C	TE-214B	TE-214D
		Cold Leg 2B Temperature (Narrow Range)	TE-122A			TE-122D
		Cold Leg 2A Temperature (Narrow Range)		TE-122C	TE-122B	
		Cold Leg 2A Temperature (Wide Range)			TE-125B	
		Cold Leg 2B Temperature (Wide Range)				TE-125D
		Hot Leg 2 Temperature (Narrow Range)			TE-131B	TE-131D
		Hot Leg 2 Temperature (Narrow Range)			TE-132B	TE-132D
		Hot Leg 2 Temperature (Narrow Range)			TE-133B	TE-133D
		Hot Leg 2 Temperature (Wide Range)			TE-135B	
		RCP Shaft Speed		ST-283		ST-284
		Hot Leg 2 Flow			FT-102B	FT-102D
1000 AF 01/ 1100 AF 11303	RCS	Reference Leg Temperature	TE-193A	TE-193C	TE-193B	TE-193D

Table 9A-2 (Sheet 6 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11500	IDS	Cable trays that route Class 1E cables			Note 1	Note 1
		Class 1E Electrical Penetrations			EY-P30Z	EY-P14Z
		Class 1E Electrical Penetrations			EY-P31Y	EY-P15Y
		Class 1E Electrical Penetrations			EY-P32Y	EY-P16Y
	IIS	Core Exit Temperature		TE-002	TE-001	
		Core Exit Temperature		TE-003	TE-004	
		Core Exit Temperature		TE-005	TE-006	
		Core Exit Temperature		TE-007	TE-011	
		Core Exit Temperature		TE-008	TE-015	
		Core Exit Temperature		TE-010	TE-017	
		Core Exit Temperature		TE-012	TE-019	
		Core Exit Temperature		TE-014	TE-021	
		Core Exit Temperature		TE-016	TE-023	
		Core Exit Temperature		TE-018	TE-025	
		Core Exit Temperature		TE-020	TE-027	
		Core Exit Temperature		TE-022	TE-029	
		Core Exit Temperature		TE-024	TE-031	
		Core Exit Temperature		TE-026	TE-033	
		Core Exit Temperature		TE-028	TE-035	
		Core Exit Temperature		TE-032	TE-036	
		Core Exit Temperature		TE-037	TE-038	
		Core Exit Temperature		TE-039	TE-040	
		Core Exit Temperature		TE-042	TE-041	

Table 9A-2 (Sheet 7 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1000 AF 01/ 1100 AF 11500	PXS	PRHR HX Inlet Isolation Valve (Note 3)	V101			
	SGS	Steam Generator 1 Narrow Range Water Level			LT-002	LT-004
		Steam Generator 2 Narrow Range Water Level			LT-006	LT-008
	VWS	Fan Coolers Return Cont. Isolation Valve			V082	
	RCS	Hot Leg 2 Wide Range Pressure			PT-140B	PT-140D
		Pressurizer Pressure			PT-191B	PT-191D
		Pressurizer Level			LT-195B	LT-195D
1000 AF 01/ 1200 AF 12341	PCS	Containment Pressure			PT-006	PT-008
	IDSA	Class 1E Electrical Penetration	EY-P11Z			
		Class 1E Electrical Penetration	EY-P12Y			
		Class 1E Electrical Penetration	EY-P13Y			
1000 AF 01/ 1200 AF 12541	IDS	Class 1E Cables	Note 1	Note 1	Note 1	
1000 AF 01/ 1270 AF 12701	IDS	Class 1E Cables	Note 1	Note 1	Note 1	
	PCS	PCCWST Isolation Valve	V001A	V001C	V001B	
		PCCWST Series Isolation Valve	V002A	V002C	V002B	
		PCS Water Delivery Flow		FT-001	FT-002	
		PCS Water Delivery Flow			FT-003	
		PCS Storage Tank Level		LT-010	LT-011	
1200 AF 01	IDS	Cable trays that route Class 1E cables	Note 1	Note 1		
	SFS	Suction Line Cont. Isolation Valve	V035			
	VFS	Containment Purge Inlet Cont. Isolation Valve	V003			

Table 9A-2 (Sheet 8 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1200 AF 01	PSS	Liquid Sample Line A Cont. Isolation Valve		V011A		
		Liquid Sample Line B Cont. Isolation Valve	V011B			
		Sample Return Line Cont. Isolation Valve	V023			
		Air Sample Line Cont. Isolation Valve	V046			
	SFS	Discharge Line Cont. Isol. Valve	V038			
	VFS	Containment Purge Discharge Cont. Isolation Valve	V010			
	VFS	Vacuum Relief Containment Isolation Valve	V800A	V800B		
	RNS	Discharge Cont. Isolation Valve	V011			
		Suction Header Cont. Isolation Valve	V022			
	PCS	Containment Pressure	PT-005	PT-007		
1200 AF 03	IDS	Cable trays that route Class 1E cables	Note 1	Note 1		
1201 AF 02	IDSB	24 Hr Battery 1A			DB-1A	
		24 Hr Battery 1B			DB-1B	
		72 Hr Battery 2A			DB-2A	
		72 Hr Battery 2B			DB-2B	
		250 Vdc Distribution Panel			DD-1	
		208/120 Vac Distribution Panel			EA-1	
		208/120 Vac Distribution Panel			EA-2	
		208/120 Vac Distribution Panel			EA-3	
		250 Vdc Switchboard			DS-1	

Table 9A-2 (Sheet 9 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1201 AF 02		250 Vdc Switchboard			DS-2	
		208/120 Vac Inverter			DU-1	
		208/120 Vac Inverter			DU-2	
		Regulating Transformer			DT-1	
		Battery Charger			DC-1	
		Battery Charger			DC-2	
		Voltage to Class 1E Battery Charger			--- 002	
		Voltage to Class 1E Battery Charger			--- 006	
	PMS	Protection and Safety Monitoring System Cabinets			Note 5	
		Class 1E Cables	Note 2	Note 2	Note 2	Note 2
	IDSB	Electrical Penetration			EY-P32Y	
		250 Vdc MCC			DK-1	
		Electrical Penetration			EY-P30Z	
		Electrical Penetration			EY-P31Y	
1201 AF 03	IDSD	Battery 1A				DB-1A
		Battery 1B				DB-1B
		250 Vdc Distribution Panel				DD-1
		208/120 Vac Distribution Panel				EA-1
		208/120 Vac Distribution Panel				EA-2
		250 Vdc Switchboard				DS-1
		208/120 Vac Inverter				DU-1
		Regulating Transformer				DT-1
		Battery Charger				DC-1
		Voltage to Class 1E Battery Charger				--- 004
		Voltage to Class 1E Battery Charger				--- 008
	PMS	Protection and Safety Monitoring System Cabinets				Note 5
		Class 1E Cables	Note 2	Note 2	Note 2	Note 2

Table 9A-2 (Sheet 10 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1201 AF 03	IDS	250 Vdc MCC				DK-1
		Electrical Penetration				EY-P14Z
		Electrical Penetration				EY-P15Y
		Electrical Penetration				EY-P16Y
		Class 1E Cables			Note 1	Note 1
1201 AF 04	IDS	Cable trays that route Class 1E cables			Note 1	Note 1
	CAS	Instrument Air Supply Cont. Isolation Valve				V014
	CCS	Inlet Line Cont. Isolation Valve				V200
	CCS	Outlet Line Cont. Isolation Valve				V208
	PXS	Nitrogen Supply Cont. Isolation Valve				V042
	VWS	Fan Coolers Supply Cont. Isolation Valve				V058
		Fan Coolers Return Cont. Isolation Valve				V086
	SGS	SG 1 Steam Line Pressure			PT-031	PT-033
		SG 2 Steam Line Pressure			PT-035	PT-037
1201 AF 05	CVS	Hydrogen Addition Cont. Isolation Valve				V219
		Zinc Injection Cont. Isolation Valve				V092
	SGS	Steam Gen. Blowdown Cont. Isolation Valve			V075A	V074A
		Steam Gen. Blowdown Cont. Isolation Valve			V074B	V075B

Table 9A-2 (Sheet 11 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1201 AF 05	SGS	PORV and Block Valve- SG 1 Cont. Isolation Valves			V027A	V233A
		Steam Line Cond. Drain Cont. Isolation Valve				V036A
		Main Steam Line Cont. Isolation Valve			V040A	V040A
		Main Feedwater Cont. Isolation Valve			V057A	V057A
		Startup Feedwater Cont. Isolation Valve			V067A	
		Main Steam Line Cond. Drain Control Valve			V086A	
		MSIV Bypass Cont. Isolation Valve			V240A	V240A
	IDS	Class 1E Cables			Note 1	Note 1
1201 AF 06	SGS	PORV and Block Valve SG 2 Cont. Isolation Valve			V233B	V027B
		Steam Line Cond. Drain Cont. Isolation Valve				V036B
		Main Steam Line Cont. Isolation Valve			V040B	V040B
		Main Feedwater Cont. Isolation Valve			V057B	V057B
		Startup Feedwater Cont. Isolation Valve				V067B
		Steam Line Cond. Drain Control Valve			V086B	
		MSIV Bypass Cont. Isolation Valve			V240B	V240B
1202 AF 03	IDSC	24 Hr Battery 1A		DB-1A		
		24 Hr Battery 1B		DB-1B		
		72 Hr Battery 2A		DB-2A		
		72 Hr Battery 2B		DB-2B		
		250 Vdc Distribution Panel		DD-1		

Table 9A-2 (Sheet 12 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1202 AF 03	IDSC	208/120 Vac Distribution Panel		EA-1		
		208/120 Vac Distribution Panel		EA-2		
		208/120 Vac Distribution Panel		EA-3		
		250 Vdc Switchboard		DS-1		
		250 Vdc Switchboard		DS-2		
		208/120 Vac Inverter		DU-1		
		208/120 Vac Inverter		DU-2		
		Regulating Transformer		DT-1		
		Battery Charger		DC-1		
		Battery Charger		DC-2		
		Voltage to Class 1E Battery Charger		---003		
		Voltage to Class 1E Battery Charger		---007		
	PMS	Protection and Safety Monitoring System Cabinets		Note 5		
		Class 1E Cables	Note 2	Note 2	Note 2	Note 2
	ECS	6900V RCP 1A Switchgear		ES-31		
		6900V RCP 2A Switchgear		ES-51		
		6900V RCP 1B Switchgear		ES-41		
		6900V RCP 2B Switchgear		ES-61		
	IDSC	Electrical Penetration		EY-P27Z		
		Electrical Penetration		EY-P29Y		
		Electrical Penetration		EY-P28Y		
		250 Vdc MCC		DK-1		

Table 9A-2 (Sheet 13 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1202 AF 04	IDSA	Battery 1A	DB-1A			
		Battery 1B	DB-1B			
		250 Vdc Distribution Panel	DD-1			
		208/120 Vac Distribution Panel	EA-1			
		208/120 Vac Distribution Panel	EA-2			
		250 Vdc Switchboard	DS-1			
		208/120 Vac Inverter	DU-1			
		Regulating Transformer	DT-1			
		Battery Charger	DC-1			
		Voltage to Class 1E Battery Charger	--- 001			
		Voltage to Class 1E Battery Charger	--- 005			
	PMS	Protection and Safety Monitoring System Cabinets	Note 5			
		Class 1E Cables	Note 2	Note 2	Note 2	Note 2
1202 AF 05	PMS	Transfer Switch Set	JW-004A	JW-004C	JW-004B	JW-004D
1210 AF 01	IDS	Spare Battery (DB-1A)	Note 1	Note 1	Note 1	Note 1
		Spare Battery (DB-1B)	Note 1	Note 1	Note 1	Note 1
		Spare Battery Charger (DC-1)	Note 1	Note 1	Note 1	Note 1
		Spare Fuse Transfer Box (DF-1)	Note 1	Note 1	Note 1	Note 1
1220 AF 01	IDS	Cable trays that route Class 1E cables			Note 1	Note 1
	ECS	6900V RCP 1A Switchgear			ES-32	
		6900V RCP 2A Switchgear			ES-52	
		6900V RCP 1B Switchgear			ES-42	

Table 9A-2 (Sheet 14 of 14)
Safe Shutdown Components

Fire Area/ Fire Zone	System	Description	Class 1E Division			
			A	C	B	D
1220 AF 01	ECS	6900V RCP 2B Switchgear			ES-62	
	SGS	SG 1 Startup Feedwater Flow			FT-055A	FT-055B
		SG 2 Startup Feedwater Flow			FT-056A	FT-056B
1220 AF 02	CVS	Letdown Containment Isolation Valve				V047
		Makeup Line Cont. Isolation Valve				V090
	WLS	Sump Discharge Cont. Isolation Valve				V057
		RCDT Gas Outlet Cont. Isolation Valve				V068
1230 AF 01	IDS	Cable trays that route Class 1E cables	Note 1	Note 1		
1230 AF 02	IDS	Cable trays that route Class 1E cables			Note 1	Note 1
1232 AF 01		Remote Shutdown Room	Note 4	Note 4	Note 4	Note 4
	IDS	Cable trays that route Class 1E cables	Note 1	Note 1	Note 1	Note 1
1240 AF 01	IDS	Cable trays that route Class 1E cables	Note 1	Note 1		
1242 AF 01		MCR Workstation	Note 4	Note 4	Note 4	Note 4
	IDS	Cable trays that route Class 1E cables	Note 1	Note 1	Note 1	Note 1
1242 AF 02	IDS	Class 1E Electrical Penetration	EY-P11Z			
		Class 1E Electrical Penetration	EY-P12Y			
		Class 1E Electrical Penetration	EY-P13Y			
		250 Vdc MCC	DK-1			
		Class 1E Cables	Note 1	Note 1		
1243 AF 01	PMS	Reactor Trip Switchgear I	JD-RTSA01	JD-RTSC01	JD-RTSB01	JD-RTSD01
	IDS	Class 1E Cables	Note 1	Note 1	Note 1	Note 1
1243 AF 02	PMS	Reactor Trip Switchgear II	JD-RTSA02	JD-RTSC02	JD-RTSB02	JD-RTSD02
	IDS	Class 1E Cables	Note 1	Note 1	Note 1	Note 1
1250 AF 01	IDS	Class 1E Cables	Note 1	Note 1		

Notes:

1. This represents equipment such as cables that have no associated tag number.
2. Class 1E interdivisional cables for data communication are addressed in the applicable Appendix 9A Fire Area Description.
3. The valve's position indication is needed as a diverse variable to confirm PRHR flow to support safe shutdown.
4. Identified as a safe shutdown component that is not associated with a specific Class 1E Division.
5. Various PMS Cabinets are located within the identified Fire Area/Fire Zone and associated with the identified division, but each PMS Cabinet is not individually identified as a component within the table.

Table 9A-3 (Sheet 1 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1000 AF 01	YES					3	SEE ZONE	SEE ZONE
1100 AF 11105 REACTOR CAVITY		335	CABLE INS NET CAT.	C C	0		SMOKE[9]	HOSE STATION
1100 AF 11204 VERTICAL ACCESS/RCDT ROOM		750	CABLE INS LUBE OIL NET CAT.	C E E	<10		SMOKE[9]	HOSE STATION
1100 AF 11206 PXS VALVE/ACCUMULATOR ROOM A		890	CABLE INS LUBRICANT NET CAT.	C E E	<2		SMOKE[9]	HOSE STATION
1100 AF 11207 PXS VALVE/ ACCUMULATOR ROOM B		880	CABLE INS LUBRICANT NET CAT.	C E E	<1		SMOKE[9]	HOSE STATION
1100 AF 11208 RNS VALVE ROOM		350	CABLE INS LUBRICANT NET CAT.	C E E	<4		SMOKE[9]	HOSE STATION
1100 AF 11209 CVS ROOM		965	CABLE INS NET CAT.	C C	0		SMOKE[9]	HOSE STATION
1100 AF 11300A MAINTENANCE FLOOR SOUTHEAST		2045	CABLE INS RUBBER TRASH VOLATILES NET CAT.	C D B E E	<9		SMOKE[9]	HOSE STATION
1100 AF 11300B MAINTENANCE FLOOR NORTH		4215	CABLE INS RUBBER TRASH LUBE OIL LUBRICANT VOLATILES NET CAT.	C D B E E E E	<57		SMOKE[9]	HOSE STATION
1100 AF 11301 SG COMPARTMENT I		615	CABLE INS LUBE OIL NET CAT.	C E E	<12		SMOKE[9]	HOSE STATION
1100 AF 11302 SG COMPARTMENT 2		690	CABLE INS LUBE OIL NET CAT.	C E E	<8		SMOKE[9]	HOSE STATION
1100 AF 11303 PRESSURIZER COMPARTMENT		530	CABLE INS NET CAT.	C C	<17		SMOKE[9]	HOSE STATION
1100 AF 11303A LOWER ADS VALVE AREA		275	CABLE INS LUBE OIL LUBRICANT NET CAT.	C E E E	<8		SMOKE[9]	HOSE STATION

Table 9A-3 (Sheet 2 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1100 AF 11303B			CABLE INS	C				
			LUBE OIL	E				
			LUBRICANT	E				
UPPER ADS VALVE AREA		275	NET CAT.	E	<8		SMOKE[9]	HOSE STATION
1100 AF 11500			CABLE INS	C				
			PAPER	C				
			PLASTIC	D				
			RUBBER	D				
			LUBE OIL	E				
			VOLATILES	E				
OPERATING DECK AND REFUELING CAVITY		11420	NET CAT.	E	<31		SMOKE[9]	HOSE STATION
1200 AF 12341			CABLE INS	C				
			RUBBER	D				
MIDDLE ANNULUS		1835	NET CAT.	D	<6		NOTE 10	NONE
1200 AF 12541			CABLE INS	C				
			PLASTIC	D				
			LUBRICANT	E				
			RUBBER	D				
UPPER ANNULUS		1700	NET CAT.	C	<10		HEAT	NONE
1250 AF 12555			CABLE INS	C				
			PAPER	C				
			WOOD	C				
			PLASTIC	D				
			TRASH	B				
			VOLATILES	E				
			RUBBER	D				
			CLOTH	B				
VES AIR STORAGE/ OPERATING DECK STAGING AREA		1395	NET CAT.	E	<24		SMOKE	HOSE STATION
1270 AF 12701			CABLE INS	C				
			LUBRICANT	E				
PCS VALVE ROOM		1025	NET CAT.	E	<1		SMOKE	NONE
FIRE AREA TOTAL		30190	NET CAT.	E	<24			
1200 AF 01	YES					3	SEE ZONE	SEE ZONE
1200 AF 12241			CABLE INS	C				
			RUBBER	D				
LOWER ANNULUS		1865	NET CAT.	D	<3		NONE	HOSE STATION
1200 AF 12461			CABLE INS	C				
			TRASH	B				
			LUBE OIL	E				
CORRIDOR		525	NET CAT.	C	<23		SMOKE	HOSE STATION
1205 AF 12362			CABLE INS	C				
			VOLATILES	E				
RNS HX ROOM		310	NET CAT.	E	<2		NONE	HOSE STATION
1205 AF 12365			CABLE INS	C				
			PAPER	C				
			LUBRICANT	E				
			VOLATILES	E				
WASTE MONITOR TANK ROOM B		380	NET CAT.	E	<3		NONE	HOSE STATION

Table 9A-3 (Sheet 3 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1210 AF 12151 DEMIN./FILTER, WLS & WGS EQUIPMENT ROOMS		1880	CABLE INS PAPER LUBE OIL VOLATILES RUBBER CHARCOAL NET CAT.	C C E E D C E	<53		NOTE 10	HOSE STATION
1210 AF 12171 EFFLUENT HOLDUP TANK ROOM A		860	CABLE INS PAPER VOLATILES NET CAT.	C C E E	<9		NONE	HOSE STATION
1214 AF 12152 PRIMARY SAMPLE ROOM		505	CABLE INS PAPER PLASTIC NET CAT.	C C D D	<9		SMOKE	HOSE STATION
1214 AF 12154 AUX. BLDG SUMP AND SFS PENETRATION ROOM		245	CABLE INS LUBRICANT NET CAT.	C E E	<8		NONE	HOSE STATION
1214 AF 12354 MID ANNULUS ACCESS ROOM		235	CABLE INS NET CAT.	C C	<5		NONE	HOSE STATION
1215 AF 12161 CORRIDOR		615	CABLE INS TRASH RUBBER NET CAT.	C B D D	<17		SMOKE	HOSE STATION
1215 AF 12162 RNS PUMP ROOM A		280	CABLE INS. LUBE OIL NET CAT.	C E E	<2		NOTE 10	HOSE STATION
1216 AF 12166 WASTE HOLDUP TANK ROOM A		460	CABLE INS VOLATILES NET CAT.	C E E	<1		NONE	HOSE STATION
1216 AF 12167 WASTE HOLDUP TANK ROOM B		405	CABLE INS VOLATILES NET CAT.	C E E	<1		NONE	HOSE STATION
1216 AF 12169 WLS PUMP ROOM/ CORRIDOR/VESTIBULE		335	CABLE INS TRASH LUBE OIL VOLATILES NET CAT.	C B E E E	<12		NONE	HOSE STATION
1216 AF 12172 EFFLUENT HOLDUP TANK ROOM B		910	CABLE INS PAPER VOLATILES NET CAT.	C C E D	<7		NONE	HOSE STATION
1216 AF12264 WASTE MONITOR TANK ROOM C & CHEM. WASTE TANK ROOM		875	CABLE INS VOLATILES NET CAT.	C E E	<1		NONE	HOSE STATION

Table 9A-3 (Sheet 4 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1220 AF 12251			CABLE INS PAPER PLASTIC LUBE OIL VOLATILES RUBBER	C C D E E D				
DEMIN./FILTER ACCESS AREA AND CVS MAKEUP PUMP ROOMS		1865	NET CAT.	E	<27		NOTE 10	WET PIPE SPRINKLERS[6] HOSE STATION
1220 AF12256			CABLE INS. LUBRICANT	C E				
EL 92'-6" PIPE CHASE/ VALVE ROOM		660	NET CAT.	E	<2		HEAT	HOSE STATION
1220 AF 12259			CABLE INS	C				
EL 96'-6" PIPE CHASE		840	NET CAT.	C	0		NONE	HOSE STATION
1220 AF 12269			CABLE INS	C				
EL 92'-6" PIPE CHASE		695	NET CAT.	C	0		HEAT	HOSE STATION
1220 AF 12272			CABLE INS LUBE OIL VOLATILES RUBBER	C E E D				
SFS EQUIPMENT ROOMS		1380	NET CAT.	E	<7		NOTE 10	HOSE STATION
1224 AF 12252			CABLE INS PAPER PLASTIC VOLATILES	C C D E				
RADIOACTIVE CHEMISTRY LABORATORY		545	NET CAT.	E	<15		SMOKE	HOSE STATION
1225 AF 12261			CABLE INS TRASH LUBE OIL VOLATILES RUBBER	C B E E D				
WLS PUMP ROOM AND CORRIDOR		985	NET CAT.	E	<28		NOTE 10	HOSE STATION
1225 AF 12262			CABLE INS VOLATILES	C E				
PIPING/VALVE ROOM		600	NET CAT.	E	<2		HEAT	HOSE STATION
1234 AF 12351			CABLE INS PAPER WOOD PLASTIC TRASH VOLATILES RUBBER CLOTH	C C C D B E D B				
MAINTENANCE FLOOR STAGING AREA		1145	NET CAT.	E	<35		SMOKE	HOSE STATION
1234 AF 12352			CABLE INS TRASH	C B				
ELEVATION 107'-2" PERSONNEL HATCH		275	NET CAT.	C	<3		SMOKE	HOSE STATION
1235 AF 12361			CABLE INS TRASH	C B				
CORRIDOR		525	NET CAT.	C	<8		SMOKE	HOSE STATION

Table 9A-3 (Sheet 5 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1235 AF 12363			CABLE INS	C				
			PAPER	C				
			VOLATILES	E				
WASTE MONITOR TANK ROOM A		365	NET CAT.	E	<7		NONE	HOSE STATION
1244 AF 12451			CABLE INS	C				
			PAPER	C				
SECURITY ROOM		315	NET CAT.	C	<9		SMOKE	HOSE STATION
1244 AF 12452			CABLE INS	C				
VFS PENETRATION ROOM		275	NET CAT.	C	<17		SMOKE	HOSE STATION
1244 AF 12454			CABLE INS	C				
			LUBRICANT	E				
VFS/SFS/PSS PENETRATION ROOM		210	NET CAT.	E	<9		NONE	HOSE STATION
1250 AF 12561			CABLE INS	C				
			VOLATILES	E				
			RUBBER	D				
CCS VALVE ROOM AND ACCESS CORRIDOR		485	NET CAT.	E	<5		SMOKE	HOSE STATION
1254 AF 12553			CABLE INS	C				
			PAPER	C				
			TRASH	B				
ELEVATION 135'-3" PERSONNEL ACCESS AREA		1260	NET CAT.	D	<11		SMOKE	HOSE STATION
1254 AF 12554			CABLE INS	C				
			PAPER	C				
SECURITY ROOM		270	NET CAT.	C	<26		SMOKE	HOSE STATION
1264 AF 12651			CABLE INS	C				
			LUBE OIL	E				
			LUBRICANT	E				
			VOLATILES	E				
			RUBBER	D				
VAS EQUIPMENT ROOM		1540	NET CAT.	E	<10		SMOKE	HOSE STATION
FIRE AREA TOTAL:		24920	NET CAT.	E	<14			
1200 AF 02	YES					3/0	SEE ZONE	SEE ZONE
1200 AF 12562			CABLE INS	C				
			PAPER	C				
			WOOD	C				
			PLASTIC	D				
			TRASH	B				
			LUBE OIL	E				
			VOLATILES	E				
			RUBBER	D				
			CLOTH	B				
FUEL HANDLING AREA		4730	NET CAT.	E	<15		SMOKE	HOSE STATION

Table 9A-3 (Sheet 6 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1230 AF 12371			CABLE INS PAPER WOOD TRASH LUBE OIL FUEL OIL PLASTIC RUBBER	C C C B E E D D				
RAIL CAR BAY/ FILTER STORAGE AREA		1425	NET CAT.	E	<32		NONE	WET PIPE SPRINKLERS[6] HOSE STATION
1236 AF 12372			CABLE INS LUBE OIL	C E				
RESIN TRANSFER PUMP/VALVE ROOM		185	NET CAT.	E	<3		NONE	HOSE STATION
1236 AF 12373			CABLE INS	C				
SPENT RESIN TANK ROOM		125	NET CAT.	C	0		NONE	HOSE STATION
1246 AF 12471			CABLE INS	C				
WSS VALVE/PIPING AREA		150	NET CAT.	C	0		NONE	HOSE STATION
FIRE AREA TOTAL:		6615	NET CAT.	E	<18			
1200 AF 03	YES					3	SMOKE	HOSE STATION
1230 AF 12311			CABLE INS TRASH RUBBER	C B D				
CORRIDOR		320	NET CAT.	D	<31			
1242 AF 12411			CABLE INS TRASH RUBBER	C B D				
CORRIDOR		250	NET CAT.	D	<56			
FIRE AREA TOTAL:		570	NET CAT.	D	<42			
1201 AF 01	NO					2	NONE	NONE
STAIRWELL S02			NEGLIGIBLE					
1201 AF 02	YES					3	SMOKE	HOSE STATION
1211 AF 12104 DIVISION B BATTERY ROOM 1		560	CABLE INS BATTERY – GN-29 NET CAT.	C A C	<79			
1221 AF 12204 DIVISION B BATTERY ROOM 2		595	CABLE INS BATTERY – GN-29 NET CAT.	C A C	<86			
1222 AF 12207 DIVISION B DC EQUIPMENT ROOM		435	CABLE INS NET CAT.	C C	<22			
1231 AF 12304 DIVISION B I&C/PENETRATION ROOM		590	CABLE INS NET CAT.	C C	<46			
1231 AF 12344 DIVISION B MIDDLE ANNULUS PENETRATION ROOM		80	NEGLIGIBLE		0			
FIRE AREA TOTAL:		2260	NET CAT.	C	<59			

Table 9A-3 (Sheet 7 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1201 AF 03	YES					3	SMOKE	HOSE STATION
1211 AF 12105 DIVISION D BATTERY ROOM		560	CABLE INS BATTERY – GN-29 NET CAT.	C A C	<82			
1221 AF 12205 DIVISION D DC EQUIPMENT ROOM		565	CABLE INS NET CAT.	C C	<28			
1231 AF 12305 DIVISION D I&C/PENETRATION ROOM		560	CABLE INS NET CAT.	C C	<43			
1231 AF 12345 DIVISION D MIDDLE ANNULUS PENETRATION ROOM		60	NEGLIGIBLE		0			
FIRE AREA TOTAL:		1745	NET CAT.	C	<49			
1201 AF 04	YES					3	SMOKE	HOSE STATION
1241 AF 12405 LOWER VBS B&D EQUIPMENT ROOM		695	CABLE INS PAPER LUBRICANT VOLATILES RUBBER NET CAT.	C C E E D E	<24			
1251 AF 12505 UPPER VBS B&D EQUIPMENT ROOM		695	CABLE INS PAPER LUBRICANT VOLATILES NET CAT.	C C E E E	<21			
FIRE AREA TOTAL:		1390	NET CAT.	E	<23			
1201 AF 05	YES					3	SMOKE	HOSE STATION
1231 AF 12306 VALVE/PIPING PENETRATION ROOM		575	CABLE INS RUBBER NET CAT.	C D D	<11			
1241 AF 12506 MSIV COMPARTMENT A		725	CABLE INS LUBE OIL LUBRICANT RUBBER NET CAT.	C E E D E	<18			
FIRE AREA TOTAL:		1300	NET CAT.	E	<14			
1201 AF 06	YES					3	SMOKE	HOSE STATION
MSIV COMPARTMENT B		730	CABLE INS LUBE OIL LUBRICANT RUBBER NET CAT.	C E E D E	<26			

Table 9A-3 (Sheet 8 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1202 AF 01	NO					2	NONE	NONE
STAIRWELL S01			NEGLIGIBLE					
1202 AF 02	NO					2	HEAT	HOSE STATION
NORTHEAST ELEVATOR SHAFT		205	CABLE INS LUBRICANT NET CAT.	C E E	<2			
1202 AF 03	YES					3	SMOKE	HOSE STATION
1212 AF 12102 DIVISION C BATTERY ROOM 1		560	CABLE INS BATTERY – GN-29 NET CAT.	C A C	<79			
1222 AF 12202 DIVISION C BATTERY ROOM 2		595	CABLE INS BATTERY – GN-29 NET CAT.	C A C	<79			
1222 AF 12203 DIVISION C DC EQUIPMENT ROOM		435	CABLE INS NET CAT.	C C	<32			
1232 AF 12302 DIVISION C I&C ROOM		585	CABLE INS NET CAT.	C C	<40			
1232 AF 12312 DIVISION C RCP TRIP SWITCHGEAR ROOM		360	CABLE INS NET CAT.	C C	<23			
1232 AF 12313 I&C/DIVISION C PENETRATION ROOM		580	CABLE INS NET CAT.	C C	<37			
1232 AF 12343 DIVISION C MIDDLE ANNULUS PENETRATION ROOM		80	NEGLIGIBLE		0			
FIRE AREA TOTAL:		3195	NET CAT.	C	<49			
1202 AF 04	YES					3	SMOKE	HOSE STATION
1212 AF 12101 DIVISION A BATTERY ROOM		525	CABLE INS BATTERY – GN-29 NET CAT.	C A C	<88			
1222 AF 12201 DIVISION A DC EQUIPMENT ROOM		535	CABLE INS NET CAT.	C C	<32			
1232 AF 12301 DIVISION A I&C ROOM		505	CABLE INS NET CAT.	C C	<65			
FIRE AREA TOTAL:		1565	NET CAT.	C	<61			

Table 9A-3 (Sheet 9 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1202 AF 05	NO					3	SMOKE	NONE
STAIRWELL S05			NEGLIGIBLE					
1204 AF 01	YES					3	NOTE 10	HOSE STATION
RNS PUMP ROOM B		230	CABLE INS LUBE OIL NET CAT.	C E E	<5			
1204 AF 02	NO					3/0	NONE	NONE
STAIRWELL S03			NEGLIGIBLE					
1204 AF 03	NO					3/0	HEAT	HOSE STATION
SHIELD BLDG ELEVATOR		195	CABLE INS LUBE OIL NET CAT.	C E E	<4			
1205 AF 01	NO					2	NONE	NONE
STAIRWELL S04			NEGLIGIBLE					
1205 AF 02	NO					2	HEAT	HOSE STATION
SOUTHEAST ELEVATOR SHAFT		195	CABLE INS LUBRICANT NET CAT.	C E E	<2			
1210 AF 01	YES					3	SMOKE	HOSE STATION
1210 AF 12111 CORRIDOR		1555	CABLE INS TRASH RUBBER NET CAT.	C B D D	<5			
1212 AF 12103 SPARE BATTERY ROOM		840	CABLE INS BATTERY – GN-29 NET CAT.	C A C	<59			
1212 AF 12112 SPARE ROOM		395	CABLE INS PAPER PLASTIC TRASH VOLATILES CLOTH NET CAT.	C C D B E B E	<36			
1212 AF 12113 SPARE BATTERY CHARGER ROOM		230	CABLE INS NET CAT.	C C	<33			
FIRE AREA TOTAL:		3020	NET CAT.	E	<26			
1220 AF 01	YES					3	SMOKE	HOSE STATION
1220 AF 12211 CORRIDOR		1520	CABLE INS TRASH RUBBER NET CAT.	C B D D	<40			

Table 9A-3 (Sheet 10 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1222 AF 12212 DIVISION B RCP TRIP SWITCHGEAR ROOM		360	CABLE INS NET CAT.	C C	<18			
1222 AF 12213 SPARE ROOM AND MOTOR CONTROL CTRS		235	CABLE INS PAPER TRASH NET CAT.	C C B C	<41			
FIRE AREA TOTAL:		2115	NET CAT.	D	<36			
1220 AF 02	YES					3	HEAT	HOSE STATION
LOWER ANNULUS VALVE AREA		225	CABLE INS LUBRICANT NET CAT.	C E E	<2			
1230 AF 01	YES					3	SMOKE	HOSE STATION
CORRIDOR		760	CABLE INS TRASH RUBBER NET CAT.	C B D D	<36			
1230 AF 02	YES					3	SMOKE	HOSE STATION PREACTION SPRINKLER
NON-1E EQUIPMENT/ PENETRATION ROOM		885	CABLE INS NET CAT.	C C	<151			
1232 AF 01	YES					3	SMOKE	HOSE STATION
REMOTE SHUTDOWN ROOM		430	CABLE INS PAPER PLASTIC NET CAT.	C C D D	<26			
1240 AF 01	YES					3	SMOKE	HOSE STATION
NON-1E EQUIPMENT/ PENETRATION ROOM		795	CABLE INS NET CAT.	C C	<90			
1242 AF 01	YES					3	SMOKE	HOSE STATION
1242 AF 12401A MCR MAIN CONTROL AREA/OPERATOR WORK AREA/VESTIBULE		1505	CABLE INS PAPER PLASTIC LUBRICANT RUBBER CARPET NET CAT.	C C D E D D E	<39			

Table 9A-3 (Sheet 11 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
1242 AF 12401B			CABLE INS PAPER PLASTIC RUBBER CHARCOAL CARPET	C C D D C D				
MCR SHIFT MANAGER'S OFFICE/KITCHEN AREA/ OPERATOR BREAK AREA		895	NET CAT.	D	<42			
FIRE AREA TOTAL:		2400	NET CAT.	D	<40			
1242 AF 02	YES					3	SMOKE	HOSE STATION
DIVISION A ELECTRICAL PENETRATION ROOM		395	CABLE INS NET CAT.	C C	<44			
1243 AF 01	YES					3	SMOKE	HOSE STATION
REACTOR TRIP SWITCHGEAR 1		100	CABLE INS NET CAT.	C C	<6			
1243 AF 02	YES					3	SMOKE	HOSE STATION
REACTOR TRIP SWITCHGEAR 2		100	CABLE INS NET CAT.	C C	<2			
1250 AF 01	YES					3	SMOKE	HOSE STATION
VBS MCR/A&C EQUIPMENT ROOM		3540	CABLE INS LUBE OIL LUBRICANT VOLATILES RUBBER CHARCOAL NET CAT.	C E E E D C E	<30			
2000 AF 01	NO					0	SEE ZONE	SEE ZONE
2030 AF 20300			CABLE INS LUBE OIL PLASTIC FUEL OIL TRASH LUBRICANT	C E D E B E				
ELEVATION 100'-0" (BASE SLAB) GENERAL FLOOR AREA		72376	NET CAT.	E	<9			WET PIPE SPRINKLERS[6] HOSE STATION
2038 AF 20300			LUBE OIL LUBRICANT TRASH PLASTIC RUBBER	E E B D D				
MAIN FEEDWATER PUMP AREA		3440	NET CAT.	E	<37		HEAT	PREACTION SPRINKLERS

Table 9A-3 (Sheet 12 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
2039 AF 20301 CHEMICAL STORAGE AREA		439	PLASTIC TRASH NET CAT.	D B E	<3			WET PIPE SPRINKLERS[8] HOSE STATION
2040 AF 20400 ELEVATION 120'-6" GENERAL FLOOR AREA		50808	CABLE INS LUBRICANT LUBE OIL TRASH PLASTIC NET CAT.	C E E B D E	<9			WET PIPE SPRINKLERS HOSE STATION
2043 AF 20402 ELEVATION 120'-6" EXCITATION EQUIPMENT ROOM		1067	LUBE OIL PLASTIC TRASH NET CAT.	E D B E	<20		SMOKE	HOSE STATION
2050 AF 20500 ELEVATION 141'-3" GENERAL FLOOR AREA		38308	CABLE INS LUBE OIL PLASTIC TRASH HYDROGEN NET CAT.	C E D B E E	<55			WET PIPE SPRINKLERS HOSE STATION
2050 AF 20502 DEH SKID		400	LUBE OIL LUBRICANT PLASTIC RUBBER TRASH NET CAT.	E E D D B E	>180		HEAT	WATER SPRAY HOSE STATION
2052 AF 20504 HVAC EQUIPMENT AREA		3755	LUBRICANT CABLE INS PAPER RUBBER TRASH NET CAT.	E C C D B D	<1		SMOKE	HOSE STATION
2057 AF 20503 GENERATOR SEAL OIL UNIT		411	LUBE OIL PLASTIC TRASH NET CAT.	E D B E	>180		HEAT	WATER SPRAY HOSE STATION
2060 AF 20600 ELEVATION 170'-0" GENERAL FLOOR AREA		40958	CABLE INS LUBE OIL RUBBER PLASTIC TRASH NET CAT.	C E D D B E	<3			WET PIPE SPRINKLERS[7] HOSE STATION

Table 9A-3 (Sheet 13 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
2063 AF 20601			PAPER PLASTIC RUBBER TRASH	C D D B				
TOOL ROOM/ STORAGE AREA		365	NET CAT.	D	<28		SMOKE	WET PIPE SPRINKLERS HOSE STATION
2063 AF 20602			PAPER PLASTIC RUBBER TRASH	C D D B				
OFFICE AREA/ENGINEERING WORKSTATION		455	NET CAT.	D	<30		SMOKE	HOSE STATION
2131 AF 21380			RUBBER CABLE INS PLASTIC TRASH	D C D B				
CCS & BDS PUMP AREA		4173	NET CAT.	D	<1			WET PIPE SPRINKLERS HOSE STATION
2141 AF 21480			LUBRICANT PAPER CABLE INS PLASTIC RUBBER TRASH	E C C D D B				
SOUTH BAY 117'-6" VTS HVAC EQUIPMENT ROOM		4140	NET CAT.	D	<1		SMOKE	HOSE STATION
2151 AF 21580			CABLE INS PLASTIC TRASH	C D B				
SOUTH BAY 135'-3" GENERAL AREA		2285	NET CAT.	D	<26		SMOKE	HOSE STATION
2151 AF 21583			CABLE INS PLASTIC TRASH	C D B				
SOUTH BAY 148'-10" VFD EQUIPMENT ROOM		4075	NET CAT.	D	<15		SMOKE	HOSE STATION
2070 AF 20700			CABLE INS LUBE OIL PLASTIC TRASH	C E D B				
ELEVATION 196'-3" HEATER BAY		8196	NET CAT.	E	<5			WET PIPE SPRINKLERS HOSE STATION
2070 AF 20701			PAPER PLASTIC TRASH	C D B				
ELEVATION 196'-3" NORTH WEST SECURITY ROOM		360	NET CAT.	E	<14		SMOKE	HOSE STATION
2070 AF 20702			PAPER PLASTIC TRASH	C D B				
ELEVATION 196'-3" NORTH EAST SECURITY ROOM		54	NET CAT.	E	<45		SMOKE	HOSE STATION
2070 AF 20703			PAPER PLASTIC TRASH	C D B				
ELEVATION 196'-3" SOUTH WEST SECURITY ROOM		62	NET CAT.	E	<46		SMOKE	HOSE STATION

Table 9A-3 (Sheet 14 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
2070 AF 20750			LUBE OIL PLASTIC TRASH CABLE INS	E D B C				
ELEVATION 228'-9" UPPER HEATER BAY		8312	NET CAT.	E	<17			WET PIPE SPRINKLERS HOSE STATION
FIRE AREA TOTAL:		244439	NET CAT.	E	<17			
2000 AF 02	NO					2/0	NONE	NONE
STAIRWELLS S02 and S08			NEGLIGIBLE					
2000 AF 03	NO					2	NONE	NONE
STAIRWELL S03			NEGLIGIBLE					
2000 AF 15	NO					2/0	NONE	NONE
STAIRWELL S15			NEGLIGIBLE					
2009 AF 01	NO					2	NONE	NONE
STAIRWELL S01			NEGLIGIBLE					
2009 AF 02	NO					2	HEAT	HOSE STATION
ELEVATOR			NEGLIGIBLE					
2040 AF 01	NO					3	NONE	WET PIPE SPRINKLERS HOSE STATION
CLEAN & DIRTY LUBE OIL STORAGE ROOM		842	LUBE OIL LUBRICANT TRASH NET CAT.	E E B E	>180			
2043 AF 01	NO					3/0	NONE	WET PIPE SPRINKLERS HOSE STATION
SECONDARY SAMPLING LABORATORY		1232	CABLE INS PLASTIC TRASH NET CAT.	C D B E	<21			
2050 AF 01	NO					3	HEAT	WATER SPRAY HOSE STATION
LUBE OIL RESERVOIR ROOM		1127	CABLE INS LUBE OIL PLASTIC TRASH NET CAT.	C E D B E	>180			

Table 9A-3 (Sheet 15 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
2052 AF 01	NO					2/0	SMOKE	HOSE STATION
TURBINE BUILDING SWITCHGEAR ROOM #1		1626	CABLE INS PLASTIC TRASH NET CAT.	C D B C	<25			
2053 AF 01	NO					2/0	SMOKE	HOSE STATION
ELECTRICAL EQUIPMENT ROOM		747	CABLE INS PLASTIC TRASH NET CAT.	C D B D	<58			
2053 AF 02	NO					2/0	SMOKE	HOSE STATION
TURBINE BUILDING SWITCHGEAR ROOM #2		1616	CABLE INS PLASTIC TRASH NET CAT.	C D B C	<24			
2151 AF 01	NO					2	SMOKE	HOSE STATION
2151 AF 21581 BATTERY ROOM		1226	CABLE INS BATTERY – GC-39 NET CAT.	C A C	<118			
2151 AF 02	NO					2	SMOKE	HOSE STATION
2151 AF 21582 BATTERY CHARGER ROOM		395	CABLE INS PAPER PLASTIC NET CAT.	C C D C	<17			
4001 AF 01	NO					2	NONE	NONE
STAIRWELL S01			NEGLIGIBLE					
4001 AF 02	NO					2	HEAT	HOSE STATION
ELEVATOR		60	CABLE INS LUBRICANT RUBBER NET CAT.	C E D E	<41			
4002 AF 01	NO					2/0	NONE	NONE
STAIRWELL S02			NEGLIGIBLE					
4002 AF 02	NO					2/0	NONE	NONE
STAIRWELL S04			NEGLIGIBLE					
4002 AF 03	NO					2	SEE ZONE	SEE ZONE
ELEVATOR		106	CABLE INS LUBRICANT RUBBER NET CAT.	C E D E	<18		SMOKE HEAT	HOSE STATION

Table 9A-3 (Sheet 16 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
4002 AF 40603			LUBRICANT PAPER PLASTIC VOLATILES WOOD RUBBER CLOTH	E C D E C D B				
STORAGE ROOM		106	NET CAT.	E	<30		SMOKE	HOSE STATION
4002 AF 40604			CABLE INS PLASTIC WOOD PAPER TRASH	C D C C B				
SECURITY ROOM		106	NET CAT.	D	<25		SMOKE	HOSE STATION
FIRE AREA TOTAL:		318	NET CAT.	E	<18			
4003 AF 01	NO					2/0	SMOKE EXCEPT 40504, 40602	HOSE STATION
4003 AF 40340			CABLE INS LUBE OIL TRASH PAPER VOLATILES PLASTIC WOOD	C E B C E D C				
DEMINERALIZED WATER DEOXYGENATING ROOM		670	NET CAT.	E	<21			
4003 AF 40442			PAPER WOOD RUBBER CABLE INS PLASTIC LUBRICANT TRASH VOLATILES	C C D C D E B E				
BORIC ACID BATCHING ROOM		670	NET CAT.	E	<12			
4003 AF 40503			CABLE INS LUBRICANT VOLATILES TRASH CLOTH RUBBER PLASTIC WOOD PAPER	C E E B B D D C C				
LOWER SOUTH AIR HANDLING EQUIPMENT ROOM, SECURITY ROOM		3003	NET CAT.	E	<20			
4003 AF 40601			CABLE INS LUBE OIL VOLATILES TRASH CLOTH PAPER PLASTIC RUBBER	C E E B B C D D				
UPPER SOUTH AIR HANDLING EQUIPMENT ROOM		3003	NET CAT.	E	<8			
FIRE AREA TOTAL:		7346	NET CAT.	E	<15			

Table 9A-3 (Sheet 17 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
4003 AF 02	NO					2/0	NONE	NONE
STAIRWELL S03			NEGLIGIBLE					
4031 AF 01	NO					2	SMOKE	HOSE STATION
4031 AF 40307			CABLE INS	C				
			TRASH	B				
			VOLATILES	E				
			BATTERY – GC-39	A				
			PLASTIC	D				
			CLOTH	B				
BATTERY ROOM #1		734	NET CAT.	D	<90			
4031 AF 40308			CABLE INS	C				
			TRASH	B				
			PLASTIC	D				
			PAPER	C				
BATTERY CHARGER ROOM #1		734	NET CAT.	D	<72			
FIRE AREA TOTAL:		1468	NET CAT.	D	<101			
4031 AF 02	NO					2	SMOKE	HOSE STATION
4031 AF 40309			CABLE INS	C				
			TRASH	B				
			VOLATILES	E				
			BATTERY – GC-39	A				
			PLASTIC	D				
			CLOTH	B				
BATTERY ROOM #2		734	NET CAT.	D	<88			
4031 AF 40310			CABLE INS	C				
			TRASH	B				
			PLASTIC	D				
			PAPER	C				
BATTERY CHARGER ROOM #2		734	NET CAT.	D	<62			
4031 AF 40411			CABLE INS	C				
			TRASH	B				
			PLASTIC	D				
			WOOD	C				
			PAPER	C				
			CLOTH	B				
COMPUTER ROOM B		564	NET CAT.	D	<63			
4031 AF 40412			BATTERY – GC-39	A				
			CABLE INS	C				
			PLASTIC	D				
			CLOTH	B				
			TRASH	B				
			VOLATILES	E				
BATTERY ROOM		259	NET CAT.	C	<250			
FIRE AREA TOTAL:		2291	NET CAT.	D	<92			
4031 AF 05	NO					2/0	SMOKE	HOSE STATION
4031 AF 40300			CABLE INS	C				
			PLASTIC	D				
			VOLATILES	E				
			WOOD	C				
			PAPER	C				
			CLOTH	B				
SECURITY ACCESS, CONTROL AREA		1567	NET CAT.	E	<34			

Table 9A-3 (Sheet 18 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
4031 AF 40303			CABLE INS WOOD PAPER	C C C				
CORRIDOR AND RESTROOM		1285	NET CAT.	C	<41			
FIRE AREA TOTAL:		2852	NET CAT.	D	<37			
4031 AF 06	NO					2	SMOKE	HOSE STATION
			CABLE INS PLASTIC WOOD TRASH PAPER	C D C B C				
SECURITY AREA		1099	NET CAT.	D	<34			
4032 AF 01	NO					2/0	SMOKE	HOSE STATION
			CABLE INS WOOD PAPER PLASTIC VOLATILES TRASH CLOTH LUBE OIL	C C C D E B B E				
HEALTH PHYSICS AREA AND SECURITY ACCESS CONTROL AREA		6066	NET CAT.	E	<31			
4032 AF 02	NO					2/0	SMOKE	WET PIPE SPRINKLERS[6] HOSE STATION
			CABLE INS TRASH VOLATILES PAPER PLASTIC FUEL OIL LUBRICANT LUBE OIL	C B E C D E E E				
CONTAINMENT ACCESS CORRIDOR AND RADWASTE ACCESS CORRIDOR		2276	NET CAT.	E	<21			
4033 AF 01	NO					2/0	SMOKE	HOSE STATION
			CABLE INS LUBE OIL LUBRICANT ACETYLENE CLOTH PAPER TRASH VOLATILES WOOD	C E E E B C B E C				
HOT MACHINE SHOP		1847	NET CAT.	E	<35			

Table 9A-3 (Sheet 19 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
4034 AF 01	NO					2/0	SMOKE	HOSE STATION
4034 AF 40311			CABLE INS	C				
			TRASH	B				
			PAPER	C				
			PLASTIC	D				
			WOOD	C				
CORRIDORS 40311, 40312, AND 40373		2417	NET CAT.	C	<22			
4034 AF 40313			CABLE INS	C				
			CLOTH	B				
			PAPER	C				
			PLASTIC	D				
			TRASH	B				
			WOOD	C				
OFFICES		344	NET CAT.	D	<94			
4034 AF 40316			CABLE INS	C				
			CLOTH	B				
			PLASTIC	D				
			TRASH	B				
			WOOD	C				
COMPUTER ROOM L1/2		514	NET CAT.	D	<34			
4034 AF 40317			CABLE INS	C				
			CLOTH	B				
			PLASTIC	D				
			TRASH	B				
			WOOD	C				
COMPUTER ROOM L3		560	NET CAT.	D	<29			
4034 AF 40318			CABLE INS	C				
			CLOTH	B				
			PLASTIC	D				
			WOOD	C				
			TRASH	B				
ALARA BRIEFING AND			PAPER	C				
HP MONITORING ROOM		801	NET CAT.	D	<26			
4034 AF 40320			CLOTH	B				
			PLASTIC	D				
			WOOD	C				
			TRASH	B				
			PAPER	C				
WOMEN'S CHANGE ROOM		1027	NET CAT.	C	<26			
4034 AF 40322			CLOTH	B				
			PAPER	C				
			PLASTIC	D				
			RUBBER	D				
			VOLATILES	E				
			WOOD	C				
			TRASH	B				
			LUBRICANT	E				
MEN'S CHANGE ROOM		2647	NET CAT.	E	<18			

Table 9A-3 (Sheet 20 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
4034 AF 40370			CLOTH PAPER PLASTIC TRASH WOOD	B C D B C				
KITCHEN, CONF. ROOMS, REST ROOMS, CORRIDOR		1347	NET CAT.	C	<17			
4034 AF 40378			CABLE INS CLOTH PAPER PLASTIC WOOD	C B C D C				
OFFICE AREA WEST		3136	NET CAT.	C	<48			
4034 AF 40379			CABLE INS CLOTH PAPER PLASTIC WOOD	C B C D C				
OFFICE AREA EAST		6260	NET CAT.	C	<49			
FIRE AREA TOTAL:		19053	NET CAT.	E	<37			
4035 AF 01	NO					3/0	HEAT	DRY PIPE SPRINKLERS HOSE STATION
ANCILLARY DIESEL GENERATOR ROOM		235	CABLE INS CLOTH FUEL OIL LUBE OIL PLASTIC TRASH VOLATILES NET CAT.	C B E E D B E E	>180			
4041 AF 01	NO					2/0	SMOKE	HOSE STATION
4041 AF 40403			CABLE INS PAPER PLASTIC WOOD CLOTH TRASH	C C D C B B				
CONTROL SUPPORT AREA		3549	NET CAT.	D	<27			
4041 AF 40410			CABLE INS PLASTIC WOOD CLOTH	C D C B				
COMPUTER ROOM A, CORRIDOR		1047	NET CAT.	D	<37			
FIRE AREA TOTAL:		4596	NET CAT.	D	<29			
4041 AF 02	NO					2	SMOKE	HOSE STATION
CORRIDOR AND RESTROOM		1246	CABLE INS PLASTIC PAPER NET CAT.	C D C C	<44			

Table 9A-3 (Sheet 21 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
4042 AF 01	NO					2/0	SMOKE	HOSE STATION
ELECTRICAL SWITCHGEAR ROOM #1		3111	CABLE INS PLASTIC TRASH NET CAT.	C D B E	<55			
4042 AF 02	NO					2/0	SMOKE	HOSE STATION
ELECTRICAL SWITCHGEAR ROOM #2		3346	CABLE INS PLASTIC RUBBER TRASH NET CAT.	C D D B E	<48			
4051 AF 01	NO					2/0	SMOKE EXCEPT 40501	WET PIPE SPRINKLERS (ROOM 40500 ONLY) HOSE STATION
NORTH AIR HANDLING EQUIPMENT ROOM		7304	CABLE INS PAPER LUBE OIL PLASTIC RUBBER TRASH VOLATILES NET CAT.	C C E D D B E E	<13			
4052 AF 01	NO					2/0	SMOKE	SEE ZONE
STAGING AND STORAGE AREAS		8156	4052 AF 40550 CABLE INS ACETYLENE CLOTH LUBE OIL LUBRICANT PAPER PLASTIC RUBBER TRASH VOLATILES WOOD NET CAT.	C E B E E C D D B E C E	<4			HOSE STATION WET PIPE SPRINKLERS
CONTAINMENT AIR FILTRATION EXHAUST ROOM A		610	4052 AF 40551 CABLE INS TRASH CHARCOAL NET CAT.	C B C E	<49			HOSE STATION
CONTAINMENT AIR FILTRATION EXHAUST ROOM B		614	4052 AF 40552 CABLE INS TRASH CHARCOAL NET CAT.	C B C E	<49			HOSE STATION
FIRE AREA TOTAL:		9380	NET CAT.	E	<10			

Table 9A-3 (Sheet 22 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
5031 AF 01	NO					0	SMOKE HEAT	PREACTION SPRINKLERS HOSE STATION
5031 AF 50300			CABLE INS LUBRICANT PLASTIC VOLATILES CLOTH	C E D E B				
ELECTRICAL/MECHANICAL EQUIPMENT ROOM		1015	NET CAT.	E	<14			
5031 AF 50350			LUBRICANT CABLE INS PLASTIC FUEL OIL VOLATILES WOOD LUBE OIL ACETYLENE RUBBER TRASH CLOTH	E C D E E C E E D B B				
MOBILE SYSTEMS FACILITY		5468	NET CAT.	E	<15			
5031 AF 50351			CABLE INS PLASTIC RUBBER WOOD PAPER VOLATILES CLOTH TRASH	C D D C C E B B				
WASTE ACCUMULATION ROOM		2428	NET CAT.	E	<16			
5031 AF 50353			LUBRICANT BATTERY – GC-39 LUBE OIL RUBBER	E A E D				
HVAC EQUIPMENT ROOM		829	NET CAT.	E	<75			
5031 AF 50354 TRUCK STAGING AREA		861	CABLE INS NET CAT.	C E	<11			
5031 AF 50355			CABLE INS LUBE OIL	C E				
MONITOR TANK ROOM		1192	NET CAT.	E	<13			
FIRE AREA TOTAL:		11793	NET CAT.	E	<19			

Table 9A-3 (Sheet 23 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
6001 AF 01	NO					2/0	SMOKE	DRY PIPE SPRINKLERS
STAIRWELL			NEGLIGIBLE					
6030 AF 01	NO					3/0	SEE ZONE	SEE ZONE
6030 AF 60310			CABLE INS LUBRICANT RUBBER LUBE OIL	C E D E				
DIESEL GENERATOR ROOM A		1676	NET CAT.	E	<42		HEAT	DRY PIPE SPRINKLERS HOSE STATION
6030 AF 60311			CABLE INS BATTERY – GC-39	C A				
SERVICE MODULE A		300	NET CAT	D	<99		SMOKE	HOSE STATION
6030 AF 60313			PAPER	C				
COMBUSTION AIR CLEANER AREA A		380	NET CAT.	C	<1		HEAT	HOSE STATION
FIRE AREA TOTAL:		2356	NET CAT.	E	<43			
6030 AF 02	NO					3/0	SEE ZONE	SEE ZONE
6030 AF 60320			CABLE INS LUBRICANT RUBBER LUBE OIL	C E D E				
DIESEL GENERATOR ROOM B		1676	NET CAT.	E	<42		HEAT	DRY PIPE SPRINKLERS HOSE STATION
6030 AF 60321			CABLE INS BATTERY – GC-39	C A				
SERVICE MODULE B		300	NET CAT.	D	<99		SMOKE	HOSE STATION
6030 AF 60323			PAPER	C				
COMBUSTION AIR CLEANER AREA B		380	NET CAT.	C	<1		HEAT	HOSE STATION
6030 AF 60324			LUBRICANT PAPER PLASTIC VOLATILES WOOD RUBBER CLOTH	E C D E C D B				
TOOL STORAGE AREA		132	NET CAT.	C	<24		NONE	DRY PIPE SPRINKLERS HOSE STATION
6030 AF 60330			PAPER TRASH CABLE INS	C B C				
SECURITY ROOM		132	NET CAT.	C	<59		SMOKE	HOSE STATION
FIRE AREA TOTAL		2620	NET CAT.	E	<43			

Table 9A-3 (Sheet 24 of 24)
Fire Protection Summary

Fire Area/Zone [1]	Safety Area?[2]	Floor Area Sq Ft	Combust. Material[3]	Fire Sev. Cat.	Equiv. Dur. (Min)	Boundary Fire Res.[4] (Hours)	Detect. Cap.	Fixed Suppression Capability[5]
6030 AF 03	NO					3	HEAT	DRY PIPE SPRINKLERS HOSE STATION
DIESEL FUEL DAY TANK VAULT A		183	FUEL OIL NET CAT.	E E	>180			
6030 AF 04	NO					3	HEAT	DRY PIPE SPRINKLERS HOSE STATION
DIESEL FUEL DAY TANK VAULT B		180	FUEL OIL NET CAT.	E E	>180			

Notes:

1. The first four digits of the fire area and fire zone numbers indicate the building, level and building area in which the fire area/zone is located. When the third or fourth digit is a zero, the fire area/zone spans more than one level or building area. The last two digits in a fire area number are a sequence number only. The last five digits in a fire zone number coincide with the room number of a prominent room in the fire zone.
2. A YES indication in the Safety Area column means that one or more safety-related components are located in the fire area.
3. Where the presence of transient combustibles is anticipated, their presence is indicated by the listing of volatiles or trash. The units and heat of combustion values for the combustible materials are shown in Table 9A-1.
4. The boundary fire resistance for each fire area represents the minimum resistance, in hours, for the surrounding walls, floor, and ceiling, except that:
   - A non-rated barrier capable of qualifying as a three-hour barrier is considered to have a resistance of three hours, provided that penetrations are adequately sealed.
   - Stairwells, elevator shafts and the like, which are enclosed by two-hour (minimum) fire barrier walls, may comprise a portion of the boundary of a fire area having a three hour resistance.
   - Building exterior walls below grade (soil on the outside) are considered to have a fire resistance of at least three hours even though they are not fire-rated.

   A boundary fire resistance designation such as "3/0" indicates that part of the fire area boundary consists of nonrated building exterior walls/roof above grade, but that the minimum resistance of the fire barriers separating the fire area from adjacent fire areas is three hours. For detailed information about the fire resistance of fire area boundaries see Figures 9A-1 through 9A-5.
5. The fixed suppression capability is indicated for each fire area. Sprinkler and spray systems are automatic. In most cases, charcoal bed deluge systems require operator action to connect to a water source supplied by a manual hose station. Where a hose station is indicated, one or more hose streams are available. In addition to fixed suppression capability, portable extinguishers are provided throughout the plant.
6. Partial suppression coverage in this zone. See Section 9A.3, “Fire Protection Analysis Results,” for details.
7. Wet pipe sprinklers for fire zone 2060 AF 20600 are provided for the turbine generator where oil piping is routed (for example, under lagging, at the turbine generator bearing seals, and in the exciter).
8. Wet pipe sprinklers for fire zone 2039 AF 20301 are provided by the adjacent general area wet pipe sprinkler system for fire zone 2030 AF 20300. See Section 9A.3, “Fire Protection Analysis Results,” for details.
9. Containment vessel is provided with smoke detection for a general alarm.
10. See appropriate fire area discussion for identified spot detection for equipment.

Table 9A-4
Ventilation Systems Serving Fire Areas Containing Class 1E Components

Ventilation Systems Serving Fire Areas Containing Class 1E Division A and C Components				
Fire Area	**RCA**	**Class 1E Components**	**Ventilation System - Subsystem**	**Distribution Header**
1202 AF 04	No	Division A batteries and equipment; Division A, B, C, & D interdivisional cable	VBS - A&C	AC-1
1242 AF 02	No	Division A equipment and penetrations; Division A & C cable	VBS - A&C	AC-1
1202 AF 03	No	Division C batteries, equipment & penetrations; Division A, B, C, & D interdivisional cable	VBS - A&C	AC-2
1200 AF 03	No	Division A & C cable only	VBS - A&C	AC-3
1230 AF 01	No	Division A & C cable only	VBS - B&D	BD-3
1240 AF 01	No	Division A & C cable only	VXS - Equip. room	Aux. building
1200 AF 01	Yes	Division A & C valves, equipment & cable	VAS - Aux/annex	Aux/annex
1250 AF 01	No	Division A & C cable only	VBS - A&C	AC-2
Ventilation Systems Serving Fire Areas Containing Class 1E Division B and D Components				
Fire Area	**RCA**	**Class 1E Components**	**Ventilation System - Subsystem**	**Distribution Header**
1201 AF 02	No	Division B batteries, equipment & penetrations; Division A, B, C, and D interdivisional cable	VBS - B&D	BD-1
1201 AF 03	No	Division D batteries, equipment & penetrations; Division B and D cable; Division A, B, C, and D interdivisional cable	VBS - B&D	BD-2
1201 AF 04	No	Division D valves; Division B & D equipment; Division B & D cable	VBS - B&D	BD-Common
1220 AF 01	No	Division B & D equipment & cable	VBS - A&C	AC-3
1201 AF 05	No	Division B & D valves; Division B & D cable	VXS	Self-contained
1201 AF 06	No	Division B & D valves	VXS	Self-contained
1230 AF 02	No	Division B & D cable only	VXS - Equip. Room	Aux. building
1220 AF 02	Yes	Division D valves	VAS - Aux/annex	Aux. building
Ventilation Systems Serving Principal Class 1E Fire Areas				
Fire Area	**RCA**	**Description**	**Ventilation System - Subsystem**	**Distribution Header**
1242 AF 01	No	Main control room	VBS - MCR/CSA	MCR
1232 AF 01	No	Remote shutdown room	VBS - B&D	BD-3
1210 AF 01	No	Spare battery fire area	VBS - A&C	AC-3
1243 AF 01	No	Reactor trip switchgear I	VXS - Equip. room	Aux. building
1243 AF 02	No	Reactor trip switchgear II	VXS - Equip. room	Aux. building
1202 AF 05	No	Stair S05	VBS - MCR/CSA	N/A
1000 AF 01	Yes	Containment/shield building	VFS	A and B

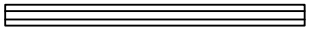
LEGEND



MINIMUM 3 HOUR FIRE BARRIER RATED
FOR FIRE ABOVE FLOOR SLAB ONLY



MINIMUM 3 HOUR FIRE BARRIER
(WITH 3 HOUR FIRE DOORS)



MINIMUM 3 HOUR FIRE BARRIER
(NON-RATED, BUT CAPABLE
OF QUALIFYING AS A RATED
3 HOUR FIRE BARRIER)



MINIMUM 2 HOUR FIRE BARRIER
(WITH 1½ HOUR FIRE DOORS)



MINIMUM 1 HOUR FIRE BARRIER
(WITH ¾ HOUR FIRE DOORS)



MINIMUM 3 HOUR | MINIMUM 2 HOUR | MINIMUM 1 HOUR | MINIMUM 3 HOUR RATED FOR FIRE ABOVE FLOOR SLAB ONLY

FIRE BARRIER RATINGS
OF FLOORS
(IN PLAN VIEWS)

FIRE ZONE BOUNDARY

CONTAINMENT FIRE ZONE
BOUNDARY WITHOUT
STRUCTURE OR BARRIER

BBLA AF XX
FIRE AREA NUMBER

BBLA AF BBLXX
FIRE ZONE NUMBER

XXXX
ROOM NUMBER

Figure 9A-1 (Sheet 1 of 16)
Fire Areas Legend

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 2 of 16)
Nuclear Island Fire Area
Plan at Elevation 66'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 3 of 16)
Nuclear Island Fire Area
Plan at Elevation 82'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 4 of 16)
Nuclear Island Fire Area
Plan at Elevation 96'-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 5 of 16)
Nuclear Island Fire Areas
Plan at Elevation 100'-0″ & 107'-2″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 6 of 16)
Nuclear Island Fire Area
Plan at Elevation 117'-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 7 of 16)
Nuclear Island Fire Area
Plan at Elevation 135'-3″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 8 of 16)
Nuclear Island Fire Areas
Plan at Elevation 153'-0" & 160'-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 9 of 16)
Nuclear Island Fire Areas
Plan at Elevation 160'-6″, 180'-0″, & 329'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 10 of 16)
Nuclear Island Fire Area
Section A-A

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 11 of 16)
Nuclear Island Fire Area
Section B-B

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 12 of 16)
Nuclear Island Fire Areas
Section C-C & H-H

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 13 of 16)
Nuclear Island Fire Area
Section G-G

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 14 of 16)
Nuclear Island Fire Area
Section J-J

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 15 of 16)
Nuclear Island Fire Area
Section K-K

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-1 (Sheet 16 of 16)
Nuclear Island Fire Areas
Section I-I & R-R

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-2 (Sheet 1 of 5)
Turbine Building Fire Area
Plan at Elevation 100′-0″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-2 (Sheet 2 of 5)
Turbine Building Fire Area
Plan at Elevation 120'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-2 (Sheet 3 of 5)
Turbine Building Fire Area
Plan at Elevation 141′-3″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-2 (Sheet 4 of 5)
Turbine Building Fire Area
Plan at Elevation 170′-0″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-2 (Sheet 5 of 5)
Turbine Building Fire Areas
Plan at Elevation 255′-3″

Security-Related Information, Withheld Under 10 CFR 2.390d

(Note: This figure replaces Figure 9A-3 Sheet 1 of 3.)

Figure 9A-201
Annex I & II Building Fire Areas
Plan at Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-3 (Sheet 2 of 3)
Annex I & II Building Fire Area Plan at Elevation 117′-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-3 (Sheet 3 of 3)
Annex I & II Building Fire Area
Plan at Elevation 135′-3″ through 183′-6″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-4
Radwaste Building Fire Area
Plan at Elevation 100′-0″

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 9A-5
Diesel Generator Building Fire Area
Plan at Elevation 100'-0″

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 10	STEAM AND POWER CONVERSION	10.1-1
10.1	Summary Description	10.1-1
10.1.1	General Description	10.1-1
10.1.2	Protective Features	10.1-2
10.1.3	Combined License Information on Erosion-Corrosion Monitoring	10.1-3
10.1.3.1	Erosion-Corrosion Monitoring	10.1-3
10.1.3.2	Procedures	10.1-4
10.1.3.3	Plant Chemistry	10.1-5
10.1.4	References	10.1-5
10.2	Turbine-Generator	10.2-1
10.2.1	Design Basis	10.2-1
10.2.1.1	Safety Design Basis	10.2-1
10.2.1.2	Power Generation Design Basis	10.2-1
10.2.2	System Description	10.2-1
10.2.2.1	Turbine-Generator Description	10.2-2
10.2.2.2	Turbine-Generator Cycle Description	10.2-2
10.2.2.3	Excitation System	10.2-3
10.2.2.4	Digital Electrohydraulic System Description	10.2-3
10.2.2.5	Turbine Protective Trips	10.2-7
10.2.2.6	Other Protective Systems	10.2-9
10.2.2.7	Plant Loading and Load Following	10.2-9
10.2.2.8	Inspection and Testing Requirements	10.2-9
10.2.3	Turbine Rotor Integrity	10.2-9
10.2.3.1	Materials Selection	10.2-9
10.2.3.2	Fracture Toughness	10.2-10
10.2.3.3	High Temperature Properties	10.2-11
10.2.3.4	Turbine Rotor Design	10.2-12
10.2.3.5	Preservice Tests and Inspections	10.2-12
10.2.3.6	Maintenance and Inspection Program Plan	10.2-13
10.2.4	Evaluation	10.2-14
10.2.5	Instrumentation Applications	10.2-14
10.2.6	Combined License Information on Turbine Maintenance and Inspection	10.2-15
10.2.7	References	10.2-16
10.3	Main Steam Supply System	10.3-1
10.3.1	Design Basis	10.3-1
10.3.1.1	Safety Design Basis	10.3-1
10.3.1.2	Power Generation Design Basis	10.3-3
10.3.2	System Description	10.3-3
10.3.2.1	General Description	10.3-3
10.3.2.2	Component Description	10.3-4
10.3.2.3	System Operation	10.3-8
10.3.3	Safety Evaluation	10.3-9
10.3.4	Inspection and Testing Requirements	10.3-10
10.3.4.1	Preoperational Testing	10.3-10
10.3.4.2	In-service Testing	10.3-11
10.3.5	Water Chemistry	10.3-11

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
10.3.5.1	Chemistry Control Basis	10.3-11
10.3.5.2	Contaminant Ingress	10.3-12
10.3.5.3	Condensate Polishing	10.3-12
10.3.5.4	Chemical Addition	10.3-12
10.3.5.5	Action Levels for Abnormal Conditions	10.3-13
10.3.5.6	Layup and Heatup	10.3-13
10.3.5.7	Chemical Analysis Basis	10.3-13
10.3.5.8	Sampling	10.3-14
10.3.5.9	Condenser Inspection	10.3-14
10.3.5.10	Conformance to Branch Technical Position 5-1	10.3-14
10.3.6	Steam and Feedwater System Materials	10.3-14
10.3.6.1	Fracture Toughness	10.3-14
10.3.6.2	Material Selection and Fabrication	10.3-14
10.3.7	Combined License Information	10.3-15
10.3.8	References	10.3-15
10.4	Other Features of Steam and Power Conversion System	10.4-1
10.4.1	Main Condensers	10.4-1
10.4.1.1	Design Basis	10.4-1
10.4.1.2	System Description	10.4-1
10.4.1.3	Safety Evaluation	10.4-2
10.4.1.4	Tests and Inspections	10.4-3
10.4.1.5	Instrumentation Applications	10.4-3
10.4.2	Main Condenser Evacuation System	10.4-3
10.4.2.1	Design Basis	10.4-3
10.4.2.2	System Description	10.4-4
10.4.2.3	Safety Evaluation	10.4-5
10.4.2.4	Tests and Inspections	10.4-5
10.4.2.5	Instrumentation Applications	10.4-5
10.4.3	Gland Seal System	10.4-5
10.4.3.1	Design Basis	10.4-5
10.4.3.2	System Description	10.4-6
10.4.3.3	Safety Evaluation	10.4-7
10.4.3.4	Tests and Inspections	10.4-7
10.4.3.5	Instrumentation Applications	10.4-7
10.4.4	Turbine Bypass System	10.4-7
10.4.4.1	Design Basis	10.4-7
10.4.4.2	System Description	10.4-8
10.4.4.3	System Operation	10.4-9
10.4.4.4	Safety Evaluation	10.4-9
10.4.4.5	Inspection and Testing Requirements	10.4-10
10.4.4.6	Instrumentation Applications	10.4-10
10.4.5	Circulating Water System	10.4-10
10.4.5.1	Design Basis	10.4-10
10.4.5.2	System Description	10.4-10
10.4.5.3	Safety Evaluation	10.4-13
10.4.5.4	Tests and Inspections	10.4-13
10.4.5.5	Instrumentation Applications	10.4-13
10.4.6	Condensate Polishing System	10.4-14

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	10.4.6.1 Design Basis	10.4-14
	10.4.6.2 System Description	10.4-15
	10.4.6.3 System Operation	10.4-15
	10.4.6.4 Safety Evaluations	10.4-16
	10.4.6.5 Tests and Inspections	10.4-16
	10.4.6.6 Instrument Applications	10.4-16
10.4.7	Condensate and Feedwater System	10.4-16
	10.4.7.1 Design Basis	10.4-17
	10.4.7.2 System Description	10.4-19
	10.4.7.3 Safety Evaluation	10.4-27
	10.4.7.4 Tests and Inspections	10.4-28
	10.4.7.5 Instrumentation Applications	10.4-29
10.4.8	Steam Generator Blowdown System	10.4-29
	10.4.8.1 Design Basis	10.4-30
	10.4.8.2 System Description	10.4-31
	10.4.8.3 Safety Evaluation	10.4-35
	10.4.8.4 Inspection and Testing Requirements	10.4-36
10.4.9	Startup Feedwater System	10.4-37
	10.4.9.1 Design Basis	10.4-37
	10.4.9.2 System Description	10.4-39
	10.4.9.3 Safety Evaluation	10.4-43
	10.4.9.4 Tests and Inspections	10.4-43
	10.4.9.5 Instrumentation Applications	10.4-44
10.4.10	Auxiliary Steam System	10.4-44
	10.4.10.1 Design Basis	10.4-44
	10.4.10.2 System Description	10.4-44
	10.4.10.3 Safety Evaluation	10.4-46
	10.4.10.4 Tests and Inspections	10.4-46
	10.4.10.5 Instrumentation Applications	10.4-46
10.4.11	Turbine Island Chemical Feed	10.4-46
	10.4.11.1 Design Basis	10.4-46
	10.4.11.2 System Description	10.4-47
	10.4.11.3 Safety Evaluation	10.4-48
	10.4.11.4 Tests and Inspections	10.4-48
	10.4.11.5 Instrumentation Applications	10.4-48
10.4.12	Combined License Information	10.4-49
	10.4.12.1 Circulating Water System	10.4-49
	10.4.12.2 Condensate, Feedwater and Auxiliary Steam System Chemistry Control	10.4-49
	10.4.12.3 Potable Water	10.4-49
10.4.13	References	10.4-49

LIST OF TABLES

Table Number	Title	Page
10.1-1	Significant Design Features and Performance Characteristics for Major Steam and Power Conversion System Components	10.1-6
10.2-1	Turbine-Generator and Auxiliaries Design Parameters	10.2-17
10.2-2	Turbine Overspeed Protection	10.2-18
10.2-3	Generator Protective Devices Furnished with the Voltage Regulator Package	10.2-19
10.2-4	Turbine-Generator Valve Closure Times	10.2-21
10.3.2-1	Main Steam Supply System Design Data	10.3-16
10.3.2-2	Design Data for Main Steam Safety Valves	10.3-17
10.3.2-3	Description of Main Steam and Main Feedwater Piping	10.3-18
10.3.2-4	Main Steam Branch Piping (2.5-Inch and Larger) Downstream of MSIV	10.3-19
10.3.3-1	Main Steam Supply System Failure Modes and Effects Analysis	10.3-20
10.3.5-1	Conformance to Branch Technical Position 5-1, Monitoring of Secondary Side Water Chemistry in PWR Steam Generators	10.3-30
10.3.5-2	Not Used	10.3-33
10.3.5-3	Not Used	10.3-34
10.4.1-1	Main Condenser Design Data	10.4-50
10.4.5-1	Design Parameters for Major Circulating Water System Components	10.4-51
10.4.7-1	Condensate and Feedwater System Component Failure Analysis	10.4-52
10.4.9-1	Startup Feedwater System Component Failure Analysis	10.4-54
10.4.9-2	Nominal Component Design Data – Startup Feedwater System	10.4-56
10.4-201	Not Used	10.4-57
10.4-202	Not Used	10.4-57

LIST OF FIGURES

Figure Number	Title	Page
10.1-1	Rated Heat Balance	10.1-7
10.2-1	(Sheet 1 of 2) Turbine Generator Outline Drawing	10.2-22
10.2-1	(Sheet 2 of 2) Turbine Generator Outline Drawing	10.2-23
10.2-2	Turbine Overspeed Trip System Functional Diagram	10.2-24
10.3.2-1	(Sheet 1 of 2) Simplified Main Steam Piping and Instrumentation Diagram (Safety-Related System)	10.3-35
10.3.2-1	(Sheet 2 of 2) Simplified Main Steam Piping and Instrumentation Diagram (Safety Related System)	10.3-36
10.3.2-2	Main Steam System Diagram	10.3-37
10.4.3-1	Gland Seal System Piping and Instrumental Diagram	10.4-58
10.4.6-1	Condensate Polishing System Piping and Instrumentation Diagram (Typical)	10.4-59
10.4.7-1	(Sheet 1 of 4) Condensate and Feedwater System Piping and Instrumentation Diagram	10.4-60
10.4.7-1	(Sheet 2 of 4) Condensate and Feedwater System Piping and Instrumentation Diagram	10.4-61
10.4.7-1	(Sheet 3 of 4) Condensate and Feedwater System Piping and Instrumentation Diagram	10.4-62
10.4.7-1	(Sheet 4 of 4) Simplified Condensate and Feedwater System Piping and Instrumentation Diagram	10.4-63
10.4.8-1	Steam Generator Blowdown System Piping and Instrumentation Diagram	10.4-64
10.4-201	Simplified Circulating Water System Piping and Instrumentation Diagram	10.4-65

Chapter 10 Steam and Power Conversion

10.1 Summary Description

The steam and power conversion system is designed to remove heat energy from the reactor coolant system via the two steam generators and to convert it to electrical power in the turbine-generator. The main condenser deaerates the condensate and transfers heat that is unusable in the cycle to the circulating water system. The regenerative turbine cycle heats the feedwater, and the main feedwater system returns it to the steam generators.

Table 10.1-1 gives the significant design and performance data for the major system components. Figure 10.1-1 shows the rated heat balance for the turbine cycle process.

10.1.1 General Description

The steam generated in the two steam generators is supplied to the high-pressure turbine by the main steam system. After expansion through the high-pressure turbine, the steam passes through the two moisture separator/reheaters (MSRs) and is then admitted to the three low-pressure turbines. A portion of the steam is extracted from the high- and low-pressure turbines for seven stages of feedwater heating.

Exhaust steam from the low-pressure turbines is condensed and deaerated in the main condenser. The heat rejected in the main condenser is removed by the circulating water system (CWS). The condensate pumps take suction from the condenser hotwell and deliver the condensate through four stages of low-pressure closed feedwater heaters to the fifth stage, open deaerating heater. Condensate then flows to the suction of the steam generator feedwater booster pump and is discharged to the suction of the main feedwater pump. The steam generator feedwater pumps discharge the feedwater through two stages of high-pressure feedwater heating to the two steam generators.

The turbine-generator has an output of approximately 1,199,500 kW for the Westinghouse nuclear steam supply system (NSSS) thermal output of 3,415 MWt. The principal turbine-generator conditions for the turbine rating are listed in Table 10.1-1. The rated system conditions for the NSSS are listed in Table 10.1-1. The systems of the turbine cycle have been designed to meet the maximum expected turbine generator conditions.

Instrumentation systems are designed for the normal operating conditions of the steam and condensate systems. The systems are designed for safe and reliable control and incorporate requirements for performance calculations and periodic heat balances. Instrumentation for the secondary cycle is also provided to meet recommendations by the turbine supplier and ANSI/ASME TDP-2-1985, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation." Design features for prevention of water hammer in the steam generator are described in Subsection 5.4.2.2. Continuous or semi-continuous sampling instrumentation and grab sample points are provided so that water chemistry in the secondary cycle can be maintained within acceptable limits, as required by the nuclear steam system and turbine suppliers (see Subsections 9.3.4 and 10.3.5). Condenser tube/tube sheet leakage can be identified and isolated by using condenser conductivity sampling provisions.

Criteria and bases for safety-related instrumentation for main steam isolation are discussed in Section 7.3.

10.1.2 Protective Features

Loss of External Electrical Load and/or Turbine Trip Protection

In the event of turbine trip, steam is bypassed to the condenser via the turbine bypass valves and, if required, to the atmosphere via the atmospheric relief valves. Steam relief permits energy removal from the reactor coolant system. Load rejection capability is discussed in Subsections 10.3.2.3.1 and 15.2.2.

Overpressure Protection

Spring-loaded safety valves are provided on both main steam lines, in accordance with the ASME Code, Section III. The pressure relief capacity of the safety valves is such that the energy generated at the high-flux reactor trip setting can be dissipated through this system. The design capacity of the main steam safety valves equals or exceeds 105 percent of the NSSS design steam flow at an accumulation pressure not exceeding 110 percent of the main steam system design pressure. Overpressure protection for the main steam lines is a safety-related function. The main steam safety valves are described in Subsection 10.3.2.

In addition, the shell sides of the feedwater heaters and the moisture separator/reheaters are provided with overpressure protection in accordance with ASME Code, Section VIII, Division 1, or equivalent standards.

Loss of Main Feedwater Flow Protection

The startup feedwater pumps provide feedwater to the steam generators for the removal of sensible and decay heat whenever main feedwater flow is interrupted, including loss of normal ac power and offsite power. This system is described in Subsection 10.4.9.

Turbine Overspeed Protection

During normal operations, turbine overspeed protection is provided by the action of the redundant controller of the electro-hydraulic control system. Additional protection is provided by an overspeed protection system, which continuously monitors critical turbine parameters on a three-channel basis. Each of the channels is independently testable under load with overspeed protection during testing provided by the channels not being tested. If turbine speed exceeds 110 percent of rated speed, the electronic trip system causes steam supply valves to close, tripping the unit. This system is described in Subsection 10.2.2.5.

Turbine Missile Protection

Turbine rotor integrity minimizes the probability of generating turbine missiles and is discussed in Subsection 10.2.3. Turbine missiles are addressed in Subsection 3.5.1.3. The favorable orientation of the turbine-generator directs potential missiles away from safety-related equipment and structures.

Radioactivity Protection

Under normal operating conditions, there are no significant radioactive contaminants present in the steam and power conversion system. However, it is possible for the system to become contaminated through steam generator tube leakage. In this event, radiological monitoring of the main condenser air removal system, the steam generator blowdown system, and the main steam lines will detect contamination and alarm high radioactivity concentrations. A discussion of the radiological aspects of primary-to-secondary system leakage and limiting conditions for operation is contained in Chapter 11. The steam generator blowdown system described in Subsection 10.4.8 and the condensate polishing system described in Subsection 10.4.6 serve to limit the radioactivity level in the secondary cycle.

Erosion-Corrosion Protection

Erosion-corrosion resistant materials are used in steam and power conversion systems for components exposed to single-phase or two-phase flow where significant erosion can occur. Factors considered in the evaluation of erosion-corrosion include system piping and component configuration and geometry, water chemistry, piping and component material, fluid temperature, and fluid velocity. Carbon steel with only carbon and manganese alloying agents is not used for applications subject to significant erosion-corrosion.

In addition to material selection, pipe size and layout may also be used to minimize the potential for erosion-corrosion in systems containing water or two-phase flow. The secondary side water chemistry (see Subsection 10.3.5) uses a volatile pH adjustment chemical to maintain a noncorrosive environment. Steam and power conversion systems are designed to facilitate inspection and erosion-corrosion monitoring programs.

An industry-sponsored computer program developed for nuclear and fossil power plant applications is used to evaluate the rate of wall thinning for components and piping potentially susceptible to erosion-corrosion. The engineering models are the result of research and development in the fields of material science, water chemistry, fluid mechanics, and corrosion engineering. The program quantifies the benefits of piping material, system layout, and sizing considerations used to reduce corrosion rates.

10.1.3 Combined License Information on Erosion-Corrosion Monitoring

10.1.3.1 Erosion-Corrosion Monitoring

The flow accelerated corrosion (FAC) monitoring program analyzes, inspects, monitors and trends those nuclear power plant components that are potentially susceptible to erosion-corrosion damage such as carbon steel components that carry wet steam. In addition, the FAC monitoring program considers the information of Generic Letter 89-08, EPRI NSAC-202L-R4, and industry operating experience. The program requires a grid layout for obtaining consistent pipe thickness measurements when using Ultrasonic Test Techniques. The FAC program obtains actual thickness measurements for highly susceptible FAC locations for new lines as defined in EPRI NSAC-202L-R4 (Reference 201). At a minimum, a CHECWORKS type Pass 1 analysis is used for low and highly susceptible FAC locations and a CHECWORKS type Pass 2 analysis is used for highly susceptible FAC locations when Pass 1 analysis results warrant. To determine wear of piping and components where operating conditions are inconsistent or unknown, the guidance provided in EPRI NSAC-202L is used to determine wear rates.

10.1.3.1.1 Analysis

An industry-sponsored program is used to identify the most susceptible components and to evaluate the rate of wall thinning for components and piping potentially susceptible to FAC. Each susceptible component is tracked in a database and is inspected, based on susceptibility. Analytical methods utilize the results of plant-specific inspection data to develop plant-specific correction factors. This correction accounts for uncertainties in plant data, and for systematic discrepancies caused by plant operation. For each piping component, the analytical method predicts the wear rate, and the estimated time until it must be re-inspected, repaired, or replaced. Carbon steel piping (ASME III and ASME B31.1) that is used for single or multi-phase high temperature flow are the most susceptible to erosion-corrosion damage and receive the most critical analysis.

10.1.3.1.2 Industry Experience

Review and incorporation of industry experience provides a valuable supplement to plant analysis. Industry experience is used to update the program by identifying susceptible components or piping features.

10.1.3.1.3 Inspections

Wall thickness measurements establish the extent of wear in a given component, provide data to help evaluate trends, and provide data to refine the predictive model. Components are inspected for wear using ultrasonic techniques (UT), radiography techniques (RT), or by visual observation. The initial inspections are used as a baseline for later inspections. Each subsequent inspection determines the wear rate for the piping and components and the need for inspection frequency adjustment for those components.

10.1.3.1.4 Training and Engineering Judgement

The FAC program is administered by both trained and experienced personnel. Task specific training is provided for plant personnel that implement the monitoring program. Specific non-destructive examination (NDE) is carried out by personnel qualified in the given NDE method. Inspection data is analyzed by engineers or other experienced personnel to determine the overall effect on the system or component.

10.1.3.1.5 Long-Term Strategy

This strategy focuses on reducing wear rates and performing inspections on the most susceptible locations.

10.1.3.2 Procedures

10.1.3.2.1 Generic Plant Procedure

The FAC monitoring program is governed by procedure. This procedure contains the following elements:

- A requirement to monitor and control FAC.
- Identification of the tasks to be performed and associated responsibilities.
- Identification of the position that has overall responsibility for the FAC monitoring program at each plant.
- Communication requirements between the coordinator and other departments that have responsibility for performing support tasks.
- Quality Assurance requirements.
- Identification of long-term goals and strategies for reducing high FAC wear rates.
- A method for evaluating plant performance against long-term goals.

10.1.3.2.2 Implementing Procedures

The FAC implementing procedures provide guidelines for controlling the major tasks. The plant procedures for major tasks are as follows:

- Identifying susceptible systems.
- Performing FAC analysis.
- Selecting and scheduling components for initial inspection.
- Performing inspections.
- Evaluating degraded components.
- Repairing and replacing components when necessary.
- Selecting and scheduling locations for the follow-on inspections.
- Collection and storage of inspections records.

10.1.3.3 Plant Chemistry

The responsibility for system chemistry is under the purview of the plant chemistry section. The plant chemistry section specifies chemical addition in accordance with plant procedures.

10.1.4 References

201. EPRI NSAC-202L-R4, Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R4), Electric Power Research Institute (EPRI) Technical Report 3002000563, Palo Alto, CA, 2013.

Table 10.1-1
Significant Design Features and
Performance Characteristics for Major
Steam and Power Conversion System Components

Nuclear Steam Supply System, Full Power Operation	
Rated NSSS power (MWt)	3415
Steam generator outlet pressure (psig)	821
Steam generator inlet feedwater temperature (°F)	440
Maximum steam generator secondary separator outlet steam moisture (%)	0.25
Steam generator outlet steam temperature (°F)	523
Quantity of steam generators	2
Flow rate per steam generator (lb/hr)	7.50×10^6
Turbine	
Nominal output (kW)	1,199,500
Turbine type	Tandem-compound 6-flow, 52 in. last-stage blade
Turbine elements	1 high pressure 3 low pressure
Operating speed (rpm)	1800

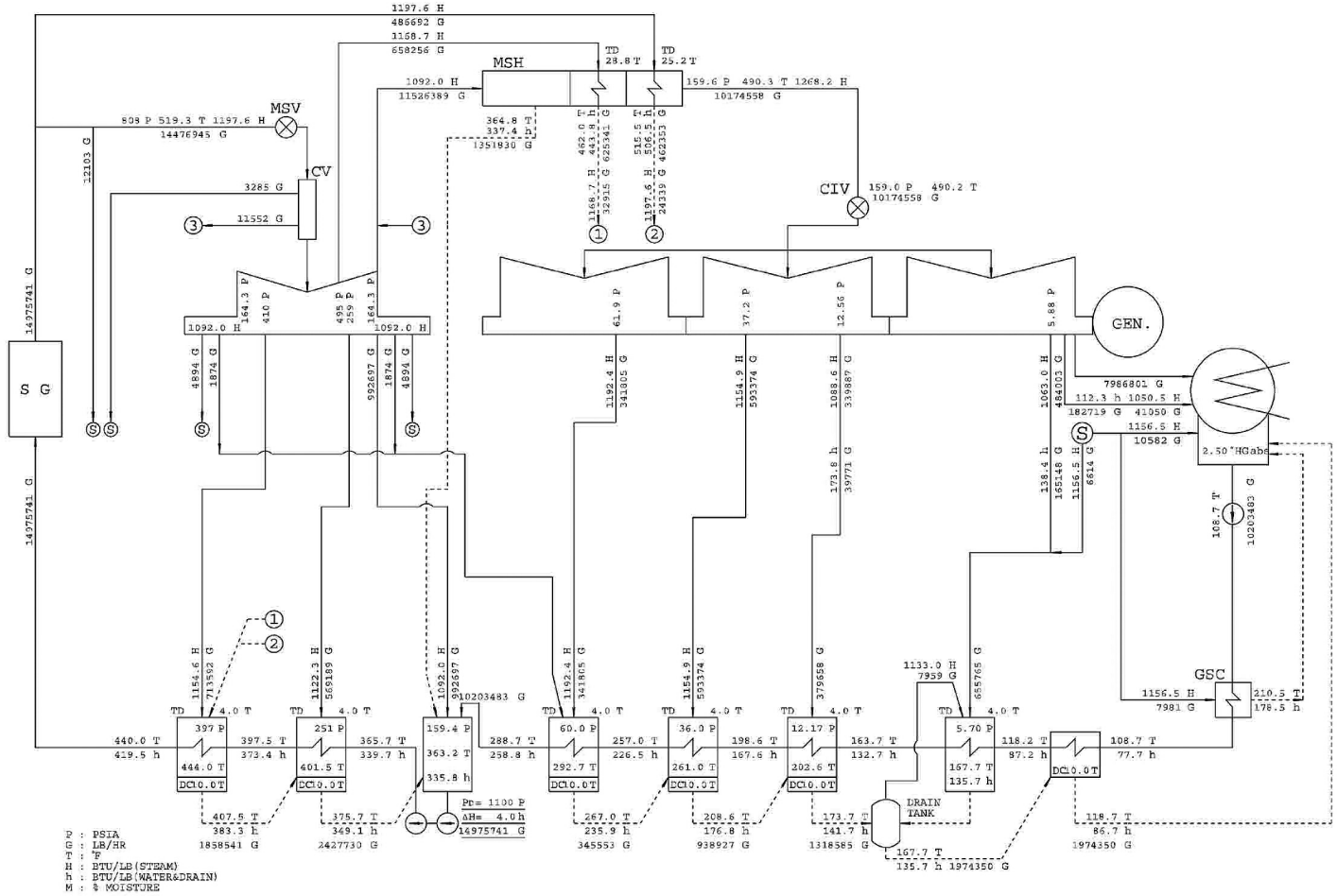


Figure 10.1-1
Rated Heat Balance

10.2 Turbine-Generator

The function of the turbine-generator is to convert thermal energy into electric power.

10.2.1 Design Basis

10.2.1.1 Safety Design Basis

The turbine-generator serves no safety-related function and therefore has no nuclear safety design basis.

10.2.1.2 Power Generation Design Basis

The following is a list of the principal design features:

- The turbine-generator is designed for baseload operation and for load follow operation.
- The main turbine system (MTS) is designed for electric power production consistent with the capability of the reactor and the reactor coolant system.
- The turbine-generator is designed to trip automatically under abnormal conditions.
- The system is designed to provide proper drainage of related piping and components to prevent water induction into the main turbine.
- The main turbine system satisfies the recommendations of Nuclear Regulatory Commission Branch Technical Position ASB 3-1 as related to breaks in high-energy and moderate-energy piping systems outside containment. The main turbine system is considered a high-energy system.
- The system provides extraction steam for seven stages of regenerative feedwater heating.

10.2.2 System Description

The turbine-generator is designated as a TC6F 52-inch last-stage blade unit consisting of turbines, a generator, external moisture separator/reheaters, controls, and auxiliary subsystems. (See Figure 10.2-1.) The major design parameters of the turbine-generator and auxiliaries are presented in Table 10.2-1. The piping and instrumentation diagram containing the stop, control, intercept, and reheat valves is shown in Figure 10.3.2-2.

The turbine-generator and associated piping, valves, and controls are located completely within the turbine building. There are no safety-related systems or components located within the turbine building. The probability of destructive overspeed condition and missile generation, assuming the recommended inspection and test frequencies, is less than 1×10^{-5} per year. In addition, orientation of the turbine-generator is such that a high-energy missile would be directed at a 90 degree angle away from safety-related structures, systems, or components. Failure of turbine-generator equipment does not preclude safe shutdown of the reactor. The turbine-generator components and instrumentation associated with turbine-generator overspeed protection are accessible under operating conditions. Subsection 3.5.1.3 addresses the probability of generation of a turbine missile for AP1000 plants in a side-by-side configuration.

Preoperational and startup tests provide guidance to operations personnel to ensure the proper operability of the turbine generator system.

10.2.2.1 Turbine-Generator Description

The turbine is a 1800-rpm, tandem-compound, six-flow, reheat unit with 52-inch last-stage blades (TC6F 52-inch LSB). The high-pressure turbine element includes one double-flow, high-pressure turbine. The low-pressure turbine elements include three double-flow, low-pressure turbines and two external moisture separator/reheaters (MSRs) with two stages of reheating. The single direct-driven generator is hydrogen gas and de-ionized water cooled and rated at 1375 MVA minimum at 0.90 PF lagging, 0.95 PF leading. Other related system components include a complete turbine-generator bearing lubrication oil system, a digital electrohydraulic (D-EHC) control system with supervisory instrumentation, a turbine steam sealing system (refer to Subsection 10.4.3), overspeed protective devices, turning gear, a stator cooling water system, a generator hydrogen and seal oil system, a generator CO_2 system, a rectifier section, an excitation transformer, and a voltage regulator.

The turbine-generator foundation is a spring-mounted support system. A spring-mounted turbine-generator provides a low-tuned, turbine-pedestal foundation. The springs dynamically isolate the turbine-generator deck from the remainder of the structure in the range of operating frequencies, thus allowing for an integrated structure below the turbine deck. The condenser is supported on springs and attached rigidly to the low-pressure turbine exhausts.

The foundation design consists of a reinforced concrete deck mounted on springs and supported on a structural steel frame that forms an integral part of the turbine building structural system. The lateral bracing under the turbine-generator deck also serves to brace the building frame. This "integrated" design reduces the bracing and number of columns required in the building. Additionally, the spring-mounted design allows for dynamic uncoupling of the turbine-generator foundation from the substructure. The spring mounted support system is much less site dependent than other turbine pedestal designs, since the soil structure is decoupled from turbine dynamic effects. The turbine-generator foundation consists of a concrete table top while the substructure consists of supporting beams and columns. The structure below the springs is designed independent of vibration considerations. The turbine-generator foundation and equipment anchorage are designed to the same seismic design requirement as the turbine building. See Subsection 3.7.2.8 for additional information on seismic design requirements. See Subsection 10.4.1.2 for a description of the support of the condenser.

10.2.2.2 Turbine-Generator Cycle Description

Steam from each of two steam generators enters the high-pressure turbine through four stop valves and four governing control valves. Crossties are provided upstream of the turbine stop valves to provide pressure equalization with one or more stop valves closed. Downstream of the pressure equalization header, steam from each of the main steam line flow paths A and B splits and enters the high pressure turbine through two parallel stop valves in series with two associated control valves. The bodies of the turbine stop valves in the branches of each main steam line flow path are cross-connected, and provide steam flow to both of the associated downstream control valves. After expanding through the high-pressure turbine, exhaust steam flows through two external moisture separator/reheater vessels. The external moisture separators reduce the moisture content of the high-pressure exhaust steam from approximately 10 to 13 percent at the rated load to 0.5 percent moisture or less.

The AP1000 employs a 2 stage reheater, of which the first stage reheater uses the extraction steam from the high pressure turbine and the second reheater uses a portion of the main steam supply to reheat the steam to superheated conditions. The reheated steam flows through separate reheat stop and intercept valves in each of six reheat steam lines leading to the inlets of the three low-pressure turbines. Turbine steam extraction connections are provided for seven stages of feedwater heating. Steam from the extraction points of the high-pressure turbine is supplied to high-pressure feedwater heater No. 6 and No. 7. The high-pressure turbine exhaust also supplies steam to the deaerating

feedwater heater. The low-pressure turbine third, fourth, fifth, and sixth extraction points supply steam to the low-pressure feedwater heaters No. 4, 3, 2, and 1, respectively.

Moisture is removed at a number of locations in the blade path. The no-return drain catchers provided at the nozzle diaphragms (stationary blade rings) accumulate the water fraction of the wet steam, and the accumulated water discharges into each extract, reheat, and exhaust lines directly or through drainage holes drilled through the nozzle diaphragms. A few grooves are provided on the rotating blades near the last stage of the low-pressure turbines to capture the large water droplets of the wet steam and to enhance the moisture removal effectiveness.

The external moisture separator/reheaters use multiple vane chevron banks (shell side) for moisture removal. The moisture removed by the external moisture separator/reheaters drain to a moisture separator drain tank and is pumped to the deaerator.

Condensed steam in the reheater (tube side) is drained to the reheater drain tank, flows into the shell side of the No. 7 feedwater heater, and cascades to the No. 6 feedwater heater.

10.2.2.3 Excitation System

The excitation system is a static excitation system using the thyristor full bridge rectifier.

Excitation power used in this system is fed from the generator main lead through the excitation transformer. The excitation transformer is of outdoor use type, and it will be located adjacent to the turbine building. After stepping down the voltage at the excitation transformer, ac current from the generator main lead will be rectified by the thyristor rectifier.

The voltage control system uses the digital controller for major control function. The system has two master controller configurations (i.e., one is for normal operation and the other is stand-by). The voltage setting range of the automatic voltage regulator is +/-10% of the generator rated voltage; however, the operating range of the generator is +/-5% of the generator rated voltage. The excitation system is equipped with a power system stabilizer.

10.2.2.4 Digital Electrohydraulic System Description

The turbine-generator is equipped with a digital electrohydraulic (D-EHC) system that combines the capabilities of redundant processors and high-pressure hydraulics to regulate steam flow through the turbine. The control system provides the functions of speed control, load control, overspeed protection, and automatic turbine control (ATC), which may be used, either for control or for supervisory purposes, at the option of the plant operator.

The D-EHC system employs three electric speed inputs whose signals are processed in redundant processors. Valve opening actuation is provided by a hydraulic system that is independent of the bearing lubrication system. Valve closing actuation is provided by springs and steam forces upon reduction or relief of fluid pressure. The system is designed so that loss of fluid pressure, for any reason, leads to valve closing and consequent turbine trip.

Steam valves are provided in an in-line configuration. The stop valves are tripped by the overspeed trip system; the control valves are modulated by the control system and are also actuated by the trip system.

10.2.2.4.1 Speed Control (Normal Turbine Operation)

Three active speed sensors provide signals for the turbine rotation rate. These are the 3 probes A,B,C shown on Figure 10.2-2. The 3 signals are input to 3 separate speed detection modules each

located on three separate I/O branches. Each of these modules has an onboard microprocessor which converts the sensor input to a turbine rpm value.

Independence of the three speed sensor signal branches is assured in that failure of the transmission of one branch of the signal does not affect the transmission of the signal in the other two branches. Each I/O branch is separately fused and fed by redundant power sources. Also, failure of a speed detection module (receiving one branch of the signal) does not affect the function of the remaining two speed detection modules from receiving their signals.

The speed control function of the turbine control and protection system's redundant controller provides speed control and acceleration functions for normal turbine operation. The speed error signal is derived by comparing the desired setpoint speed with the actual speed of the turbine. This error drives an algorithm that positions the control valves at the desired setpoint. Acceleration rates can also be entered by the operator or calculated by the control system in the auto start-up mode. A failure of one speed input generates an alarm. Failure of two or more speed inputs also generates an alarm and trips the turbine. In addition, if both of the Ovation controllers fail or power to them is lost, the turbine will trip. The design is fail safe; the system is designed to de-energize to trip.

The speed control function exists in triplicate channels, which include the load (frequency) control function if the main generator breaker is closed. If one channel fails, the average of the two remaining signals is fed into the valve positioning control function.

The control system's operator automatic (OA) controller provides the speed control function. At 101% of rated speed, the control valves and intercept valves begin to close, but do not trip the turbine.

The speed control function is designed to prevent the operator from holding the turbine speed at a bearing critical or blade resonance point.

10.2.2.4.2 Load Control

The load control function of the turbine control and protection system's OA controller develops signals that are used to regulate unit load. Signal outputs are based on a proper combination of the speed error and megawatt setpoints to generate a flow demand to the control valves.

When the first-stage pressure and megawatt control loops are out of service, steam flow is not controlled by feedback, but rather by a characterization of maximum nozzle flow (at rated pressure and temperature) per valve versus control valve position. Under this condition, the turbine operator requests a certain megawatt load target. The control system calculates the required flow demand to adjust the steam flow from the steam generators supplied to the turbine.

10.2.2.4.3 Valve Control

The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four control valves. The function of the stop valves is to shut off the steam flow to the turbine when required. The stop valves are closed by actuation of the overspeed trip system. This system is independent of the control system. Stop valves No. 1 and No. 3 are controlled by a hydraulic actuator so that the stop valve is either fully open or fully closed. The No. 2 and No. 4 stop valves each has a bypass valve, which is controlled by an electro-hydraulic servo actuator for control valve warming.

The turbine control valves are positioned by electrohydraulic servo actuators in response to signals from their respective servo modules. The servo module signal positions the control valves for wide-range speed control through the normal turbine operating range, and for load control after the turbine-generator unit is synchronized.

The reheat stop and intercept valves, located in the hot reheat lines at the inlet to the low-pressure turbines, control steam flow to the low-pressure turbines. During normal operation of the turbine, the reheat stop valves open under hydraulics control. The intercept valve independent servo module positions valves Nos. 1, 3, and 5 during startup and normal operation. Intercept valves Nos. 2, 4, and 6 open under hydraulics control. The intercept valves close rapidly on loss of turbine load. The reheat stop and intercept valves close completely on a turbine trip.

The control, stop, reheat stop, and intercept valves have fast-acting valves connected to the hydraulic portion of their respective valve actuators. Opening a fast-acting valve causes the connected control or stop valve to rapidly close. The fast-acting valve actuators are connected to trip headers and open in response to loss of pressure in the connected trip header. The control and intercept fast-acting valves are connected to the relay trip header, and stop and reheat stop fast-acting valves are connected to the auto stop emergency trip header. Valve closure times are provided in Table 10.2-4.

10.2.2.4.4 Power/Load Unbalance (Main Breaker Closed)

A power/load unbalance circuit initiates fast closing control valve and intercept valve action under load rejection conditions that might lead to rapid rotor acceleration and consequent overspeed.

Load unbalance operates when load is equal to or greater than 40% of full load and reheat pressure exceeds the corresponding expected megawatts. Cold reheat pressure is used as a measure of power. Generator current is used as a measure of load to provide discrimination between loss of load incidents and occurrences of electric system faults. This causes the control and intercept valves to close quickly under fast-acting solenoid valve action.

When the circuitry detects a power/load unbalance condition, the turbine control and protection system initiates closure of the control and intercept valves by energizing fast-acting solenoid valves on the valve actuators. One-half of the intercept valves are “controlling” and are equipped with a servo valve. The “controlling” intercept valves allow recovery from a partial load rejection by blowing down the reheated steam. Simultaneously, the load reference signal is reduced to a specific value (approximately 60% of full turbine load). When the condition disappears, the power/load unbalance circuitry resets automatically and the load reference signal is recalculated based on the new calculation of flow demand.

10.2.2.4.5 Overspeed Protection

The turbine control and protection system has four functions to protect the turbine against overspeed. The first is the overspeed protection system (OSP), which at 101% of rated speed, begins to close the control and intercept valves as discussed in Subsection 10.2.2.4.1. The second and third are the 110% emergency electrical and 111% backup electrical overspeed trip functions also discussed in Subsection 10.2.2.5. The fourth function is the partial load unbalance discussed in Subsection 10.2.2.4.4.

Redundancy is built into the overspeed protection system. The failure of a single valve will not disable the trip functions. The overspeed protection components are designed to fail in a safe position. Loss of the hydraulic pressure in the emergency trip system causes a turbine trip. Therefore, damage to the overspeed protection components, results in the closure of the valves and the interruption of steam flow to the turbine.

Quick closure of the steam valves prevents turbine overspeed. Valve closing times are given in Table 10.2-4.

10.2.2.4.6 Automatic Turbine Control

Automatic turbine control provides safe and proper startup and loading of the turbine generator. The applicable limits and precautions are monitored by the automatic turbine control programs even if the automatic turbine control mode has not been selected by the operator. When the operator selects automatic turbine control, the programs both monitor and control the turbine. The D-EHC controller takes advantage of the capability of the control system to scan, calculate, make decisions, and take positive action.

The automatic turbine control is capable of automatically:

- Changing speed reference
- Changing acceleration rates
- Generating speed holds
- Changing load rates
- Generating load holds

The thermal stresses in the rotor are calculated by the automatic turbine controls programs based on actual turbine steam and metal temperatures as measured by thermocouples or other temperature measuring devices. Once the thermal stress (or strain) is calculated, it is compared with the allowable value, and the difference is used as the index of the permissible first stage temperature variation. This permissible temperature variation is translated in the computer program as an allowable speed or load or rate of change of speed or load.

Values of some parameters are stored for use in the prediction of their future values or rates of change, which are used to initiate corrective measures before alarm or trip points are reached.

The rotor stress (or strain) calculations used in the program, and its decision-making counterpart are the main controlling sections. They allow the unit to roll with relatively high acceleration until the anticipated value of stress predicts that limiting values are about to be reached. Then a lower acceleration value is selected and, if the condition persists, a speed hold is generated. The same philosophy is used on load control in order to maintain positive control of the loading rates.

The automatic turbine controls programs are stored and executed in redundant distributed processing units, which contain the rotor stress programs and the automatic turbine controls logic programs. Once the turbine is reset, the automatic turbine controls programs are capable of rolling the turbine from turning gear to synchronous speed.

Once the turbine-generator reaches synchronous speed, the startup or speed control phase of automatic turbine control is completed and no further action is taken by the programs. Upon closing the main generator breaker, the D-EHC automatically picks up approximately 5 percent of rated load to prevent motoring of the generator. At this time, the D-EHC is in load control logic and automatically reverts control to the operator mode.

The operator can also select the automatic turbine control mode. The automatic turbine control selects the loading rate (based on turbine temperature) and allows load changes until an alarm condition occurs. If the operating parameters being monitored (including rotor stress) exceed their associated alarm limit, a load hold is generated in conjunction with the appropriate alarm message. The D-EHC generates the load hold by ignoring any further load increase or decrease until the alarm condition is cleared or until the operator overrides the alarm condition.

The operator may remove the turbine-generator from automatic turbine control. This action places the turbine control in operator auto mode and the automatic turbine control in a supervisory capacity.

10.2.2.5 Turbine Protective Trips

Turbine protective trips, when initiated, cause tripping of the main stop, control, intercept, and reheat stop valves. The protective trips are:

- Low bearing oil pressure
- Low electrohydraulic fluid pressure
- High condenser back pressure
- Turbine overspeed
- Thrust bearing wear
- Remote trip that accepts external trips

A description of the trip system for turbine overspeed is provided below.

10.2.2.5.1 Overspeed Trip System

The purpose of the electrical overspeed trip system is to detect undesirable operating conditions of the turbine-generator, take appropriate trip actions, and provide information to the operator about the detected conditions and the corrective actions. In addition, means are provided for testing emergency trip equipment and circuits.

The system hydraulic manifold configuration permits on line testing with continuous protection afforded during the test sequence.

The trip system includes an online testable hydraulic manifold, speed sensors, trip relays, independent power supplies, and a test graphic. These items and the function of the overspeed trips are described in the following three subsystems.

10.2.2.5.2 Emergency Trip Block/Master Trip Device

The emergency trip supply pressure is established when the master trip solenoid valves are closed. The valves are arranged in two channels for testing purposes. Both valves in a channel will open to trip that channel. Both channels must trip before the emergency trip supply pressure collapses to close the turbine steam inlet valves. Each tripping function of the electrical emergency trip system can be individually tested from the operator/test graphic without tripping the turbine by separately testing each channel of the appropriate trip function. The solenoid valves may be individually tested.

The emergency trip system opens a drain path for the hydraulic fluid in the emergency trip supply. The loss of fluid pressure in the trip header will cause the main stop and reheat stop valves to close. Also, a relay trip valve in the connection to the emergency trip supply opens to drop the pressure in the relay emergency trip supply and cause the control and intercept valves to close. The control and intercept valves are redundant to the main stop and reheat stop valves respectively.

10.2.2.5.3 Overspeed Trip Functions and Mechanisms

The overspeed trips for the AP1000 turbine consist of a diverse 110% trip in the emergency electrical overspeed trip system and a 111% trip in the backup electrical overspeed trip system using three Ovation speed detection modules independent of the OA controller described in Subsection 10.2.4.4.1 (see also Figure 10.2-2). The overspeed trip setpoints are identified in Table 10.2-2. The overspeed protection system will function for all abnormal conditions, including a single failure of any component or subsystem.

The 110% emergency electrical overspeed trip is implemented electronically rather than mechanically as indicated in the review procedure in SRP 10.2, Part III-2-C. An independent and

redundant backup electrical overspeed trip circuit senses the turbine speed by magnetic pickup and closes all valves associated with speed control at approximately 111% of rated speed.

The diverse 110% emergency electrical overspeed trip system has triplicated passive speed sensors separate from the triplicated active speed sensors used in the 111% backup electrical overspeed trip system. Both trip functions use solenoid valves to drain the emergency trip hydraulic supply. The hydraulic fluid in the trip and overspeed protection control headers is independent of the bearing lubrication system to minimize the potential for contamination of the fluid.

The diverse 110% emergency electrical overspeed trip system, combined with the 111% backup electrical overspeed trip system of the turbine control and protection system, provide a level of redundancy and diversity at least equivalent to the recommendations for turbine overspeed protection found in III.2 of Standard Review Plan (NUREG-0800) Section 10.2. The control signals from the two turbine-generator overspeed trip systems are isolated from, and independent of, each other. Each trip is initiated electrically in separate systems. The 110% and 111% trip systems have diverse hardware and software/firmware to eliminate common cause failures (CCFs) from rendering the trip functions inoperable. Additionally, the issues and problems with overspeed protection systems identified in NUREG-1275 (Reference 3) have been addressed.

The turbine rpm signals discussed in Subsection 10.2.2.4.1 are also used by redundant Ovation controllers for normal speed and load control functions (SRP 10.2 Part III.2.B). The rpm signals are also monitored by a setpoint on each of the speed detection modules to support the backup overspeed trip at 111% overspeed (Part III.2.D). When the rpm speed reaches the backup turbine overspeed trip setpoint, the microprocessor on each speed detection module issues a trip command to the onboard relay. When at least two out of three channels indicate a trip, a trip signal is sent to the turbine.

Independence of the electrohydraulic control system of SRP 10.2 Part III.2.B and the backup electrical overspeed trip circuit of Part III.2.D is assured in that failure of the Ovation controllers does not affect the ability of the speed detection module to trip the turbine at the backup turbine overspeed trip setpoint. Although the electrohydraulic control system and the backup electrical overspeed trip circuit are located in the same cabinet, common failure modes have been addressed to ensure the 111% backup electrical overspeed trip function in SRP 10.2 Part III.2.D cannot be rendered inoperable or affected by the failure of the Ovation controllers. The control system also has diagnostic capabilities to provide information to the operator in the main control room in case of other failures or problems in the system or its components.

10.2.2.5.4 Trip Instrumentation

Low bearing oil pressure, low electrohydraulic fluid pressure, and high condenser back pressure are each sensed by separate instrumentation. Each assembly consists of triplicate pressure transmitters with instrument valves. Each assembly is arranged into three channels.

If two of the three signals (pressure or vacuum) reach a trip setpoint, then the pressure sensors cause the master trip device to operate.

The trip function can be checked by the plant control system that simulates pressure to activate the trip outputs from the modules.

10.2.2.5.5 Thrust Bearing Trip Device

Three position pickups, which are part of the turbine supervisory instrument package, monitor movement of a disc mounted on the rotor near the thrust bearing collar. Axial movement of this collar is reflected in movement of the disc. Excessive movement of the disc is an indication of thrust

bearing wear. Should excessive movement occur, signals from the supervisory instrument modules initiate a turbine trip by the condition that two out of the three bearing wear position pickups exceed the setpoint.

The thrust bearing trip function can be checked by the plant control system that simulates movement of the rotor to activate the trip outputs from the modules.

10.2.2.5.6 Remote Trip

The emergency trip system also has provisions to trip the turbine in response to a signal from the plant control system or plant safety and monitoring system.

10.2.2.6 Other Protective Systems

Additional protective features of the turbine and steam system are:

- Moisture separator reheater safety relief valves
- Rupture diaphragms located on each of the low-pressure turbine cylinder covers
- Turbine water induction protection systems on the extraction steam lines

10.2.2.7 Plant Loading and Load Following

The AP1000 turbine-generator control system and control strategy has the same loading and load following characteristics as the control system described in Section 7.7. In addition, the turbine-generator has the following capabilities:

- Daily load change between 100 and 50 percent of rated power
- Transition between baseload and load follow operation
- Extended weekend reduced power operation
- Rapid return to up to 90 percent of rated power

For the AP1000, this load following capability is maintained for most of cycle life.

10.2.2.8 Inspection and Testing Requirements

Major system components are readily accessible for inspection and are available for testing during normal plant operation. Turbine trip circuitry is tested prior to unit startup.

10.2.3 Turbine Rotor Integrity

Turbine rotor integrity is provided by the integrated combination of material selection, rotor design, fracture toughness requirements, tests, and inspections. This combination results in a very low probability of a condition that could result in a rotor failure.

Operations and maintenance procedures mitigate the following potential degradation mechanisms in the turbine rotor and buckets/blades: pitting, stress corrosion cracking, corrosion fatigue, low-cycle fatigue, erosion, and erosion-corrosion.

10.2.3.1 Materials Selection

Fully integral turbine rotors are made from ladle refined, vacuum deoxidized, Ni-Cr-Mo-V alloy steel by processes which maximize steel cleanliness and provide high toughness. Residual elements are controlled to the lowest practical concentrations consistent with melting practices. The chemical property limits of ASTM A470, Classes 5, 6, and 7 are the basis for the material requirements for the

turbine rotors. This material has the lowest fracture appearance transitions temperatures (FATT) and the highest Charpy V-notch energies obtainable on a consistent basis from water-quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Charpy tests and tensile tests in accordance with American Society of Testing and Materials (ASTM) specification A370 are required from the forging supplier.

The production of steel for the turbine rotors starts with the use of high-quality, low residual element scrap. An oxidizing electric furnace is used to melt and dephosphorize the steel. Ladle furnace refining is then used to remove oxygen, sulphur, and hydrogen from the rotor steel. The steel is then further degassed using a process whereby steel is poured into a mold under vacuum to produce an ingot with the desired material properties. This process minimizes the degree of chemical segregation since silicon is not used to deoxidize the steel.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in Subsection 10.2.3.1 to produce a balance of material strength and toughness to provide safety while simultaneously providing high reliability, availability, and efficiency during operation. The limits on phosphorous, sulphur, and aluminum in the rotor steel provides for the appropriate balance of material strength and toughness.

Bore stress calculations include components due to centrifugal loads and thermal gradients where applicable. Fracture toughness will be at least $220\,\mathrm{MPa}\bullet\sqrt{\mathrm{m}} = 200\,\mathrm{ksi}\bullet\sqrt{\mathrm{in}}$ and the ratio of fracture toughness to the maximum applied stress intensity factor for rotors at speeds from normal to design overspeed will be at least 2. Material fracture toughness needed to maintain this ratio is verified by mechanical property tests on material taken from the rotor.

The rotor is evaluated for fracture toughness by criteria that include the design duty cycle stresses, number of cycles, ultrasonic examination capability and growth rate of potential flaws. Conservative factors of safety are included for the size uncertainty of potential or reported ultrasonic indications, rate of flaw growth (da/dN versus dK) and the duty cycle stresses and number.

Reported rotor forging indications are adjusted for size uncertainty and interaction. A rotor forging with a reported indication that would grow to critical size in the applicable duty cycles is not accepted. The combined rotation and maximum transient thermal stresses used in the applicable duty cycles are based on the brittle fracture and rotor fatigue analyses described below.

Maximum transient thermal stresses are determined from historical maximum loading rates for nuclear service rotors.

10.2.3.2.1 Brittle Fracture Analysis

A brittle fracture analysis is performed on the turbine rotor to provide confidence that small flaws in the rotor, especially near the centerline, do not grow to a critical size with unstable growth resulting in a rotor burst. The brittle fracture analysis process includes determining the stresses in the rotor resulting from rotation, steady-state thermal loads, and transient thermal loads from startup and load change. These stresses are combined to generate the maximum stresses and locations of maximum stress for the startup and load change transients. A fracture mechanics analysis is performed at the location(s) of maximum stress to verify that an initial flaw, equal to the minimum reportable size, will not grow to critical crack size over the life of the rotor under the cumulative effects of startup and load change transients.

A fracture mechanics analysis is done at the location(s) of maximum stress to determine the critical crack size and the initial flaw area that would just grow to the critical size when subjected to the

number of startup and load change cycles determined to represent the lifetime of the rotor. This initial flaw area is divided by a factor of safety to generate an allowable initial flaw area. The minimum reportable flaw size is multiplied by a conservative factor to correct for the imperfect nature of a flaw as an ultrasonic reflector, as compared to the calibration reflector. The resulting area is the corrected flaw area. For an acceptable design, the allowable initial flaw area must be greater than or equal to the corrected flaw area.

A flaw is assumed to be an internal elliptical crack on the centerline for rotors without bores. For rotor contour or for flaws near the rotor bore (for bored rotors), a surface connected elliptical crack is assumed. Flaw analysis is done assuming various flaw aspect ratios and the most conservative results are used. The flaw is assumed to be orientated normal to the maximum principle stress direction.

The beginning-of-life fracture appearance transition temperature for the high pressure and low pressure rotor is specified in the material specification for the specific material alloy selected. Both the high pressure and low pressure turbines operate at a temperature at which temperature embrittlement is insignificant. The beginning-of-life fracture appearance transition temperature is not expected to shift during the life of the rotor due to temperature embrittlement.

Minimum material toughness is provided in the turbine rotors by specification of maximum fracture appearance transition temperature and minimum upper shelf impact energy for the specific material alloy selected. There is not a separate material toughness (K_{IC}) requirement for AP1000 rotors.

10.2.3.2.2 Rotor Fatigue Analysis

A fatigue analysis is performed for the turbine rotors to show that the cumulative usage is acceptable for expected transient conditions including normal plant startups, load following cycling, and other load changes. The fatigue design curves are based on mean values of fatigue test data. Margin is provided by assuming a conservatively high number of turbine start and stop cycles. The Toshiba-designed turbine rotors in operating nuclear power plants were designed using this methodology and have had no history of fatigue crack initiation due to duty cycles.

In addition to the low cycle fatigue analysis for transient events, an evaluation for high cycle fatigue is performed. This analysis considers loads due to gravity bending, bearing elevation misalignment, control stage partial arc admission bearing reactions, and steady-state unbalance stress. The local alternating stress is calculated at critical rotor locations considering the bending moments due to the loads described above. The maximum alternating stress is less than the smooth bar endurance strength modified by a size factor.

The AP1000 turbine generator is supported by a spring-mounted system to isolate the dynamic behavior of the turbine-generator equipment from the foundation structure. The support system includes a reinforced concrete deck on which the turbine generator is mounted. The deck is sized to maintain the gravity load and misalignment load bending stresses within allowable limits. The evaluation of the loads includes a dynamic analysis of the combined turbine-generator and foundation structure.

10.2.3.3 High Temperature Properties

The operating temperatures of the high-pressure rotors are below the creep rupture range. Creep rupture is, therefore, not considered to be a significant factor in providing rotor integrity over the lifetime of the turbine. Basic data are obtained from laboratory creep rupture tests.

10.2.3.4 Turbine Rotor Design

The turbine assembly is designed to withstand normal conditions and anticipated transients, including those resulting in turbine trip, without loss of structural integrity. The design of the turbine assembly meets the more restrictive of the following criteria:

- The combined stresses of a low-pressure turbine disk at design overspeed due to centrifugal forces, interference fit, and thermal gradients do not exceed 0.75 of the minimum specified yield strength of the material; or,
- The tangential stresses will not cause a flaw, which is twice the corrected ultrasonic examination reportable size, to grow to critical size in the design life of the rotor. This will result in the ratio of fracture toughness to the maximum applied stress intensity factor for the rotor at speeds from normal to design overspeed being at least 2.

The high-pressure turbine has fully integral rotors forged from a single ingot of low alloy steel. This design is inherently less likely to have a failure resulting in a turbine missile than previous designs with shrunk-on discs. A major advantage of the fully integral rotor is the elimination of disc bores and keyways. In the fully integral rotor design, the location of peak stresses is in the lower stress blade fastening areas. This difference results in a substantial reduction of the rotor peak stresses, which in turn reduces the potential for crack initiation. The reduction in peak stress also permits selection of a material with improved ductility, toughness, and resistance to stress corrosion cracking.

The non-bored design of the high-pressure turbine element provides the necessary design margin by virtue of its inherently lower centerline stress. Metallurgical processes permit fabrication of the rotors without a center borehole. The use of solid rotor forgings was qualified by evaluation of the material removed from center-bored rotors for fossil power plants. This evaluation demonstrated that the material at the center of the rotors satisfied the rotor material specification requirements. Forgings for no-bore rotors are provided by suppliers who have been qualified based on bore material performance.

The low-pressure turbine element is a fully integral rotor fabricated from a single forging. There are no keyways, which can be potential locations for stress risers and corrosive contaminate concentration, exposed to a steam environment. The integral disc profiles are carefully designed to limit the surface stress in areas vulnerable to stress corrosion. Surface stress in less than ideal steam environments is limited to less than 50 percent of the yield strength to reduce the chances of stress corrosion as far as practicable.

10.2.3.5 Preservice Tests and Inspections

Preservice inspections for turbine rotors include the following:

- Rotor forgings are rough machined with a minimum stock allowance prior to heat treatment.

- Each rotor forging is subjected to a 100-percent volumetric (ultrasonic) examination. Each finish-machined rotor is subjected to a surface magnetic particle and visual examination. Results of the above examination are evaluated by use of criteria that are more restrictive than those specified for Class 1 components in ASME Code, Section III and V. These criteria include the requirement that subsurface sonic indications are either removed or evaluated to verify that they do not grow to a size which compromises the integrity of the unit during the service life of the unit.

- Finish-machined surfaces are subjected to a magnetic particle examination. No magnetic particle flaw indications are permissible in bores (if present) or other highly stressed regions.

- Each fully bladed turbine rotor assembly is spin tested at 20 percent overspeed, the maximum speed following a load rejection from full load.

Rotor areas which require threaded holes are not subjected to a magnetic particle examination of the threaded hole. The number of threaded holes is minimized, and threaded holes are not located in high stress areas.

10.2.3.6 Maintenance and Inspection Program Plan

The maintenance and inspection program plan for the turbine assembly and valves is based on turbine missile probability calculations, operating experience of similar equipment, and inspection results. The methodology for analysis of the probability of generation of missiles for fully integral rotors was submitted in WCAP-16650-P (Reference 1). The methodology used in the analysis of the missile generation probability was used to determine turbine valve test frequency as described in Section 5.2 through Section 8 of WCAP-16651-P (Reference 2). The maintenance and inspection program includes the activities outlined below:

- Disassembly of the turbine is conducted during plant shutdown. Inspection of parts that are normally inaccessible when the turbine is assembled for operation (couplings, coupling bolts, turbine rotors, and low-pressure turbine blades) is conducted.

  This inspection consists of visual, surface, and volumetric examinations as indicated below:

  – Each rotor and stationary and rotating blade path component is inspected visually and by magnetic particle testing on accessible surfaces. Ultrasonic inspection of the outer dovetail and the bucket pin is conducted. These inspections are conducted at intervals of about 10 years for low-pressure turbines and about 8 years for high-pressure turbines.

  – A 100 percent surface examination of couplings and coupling bolts is performed.

  – Fluorescent penetrant examination is conducted on nonmagnetic components.

- At least one main steam stop valve, one main steam control valve, one reheat stop valve, and one intercept valve are dismantled approximately every 3 years during scheduled refueling or maintenance shutdowns. A visual and surface examination of valve internals is conducted. If unacceptable flaws or excessive corrosion are found in a valve, the other valves of its type are inspected. Valve bushings are inspected and cleaned, and bore diameters are checked for proper clearance.

- Main stop valves, control valves, reheat stop and intercept valves may be tested with the turbine online. The turbine control and protection system is used to stroke or partially stroke the valves.

- Extraction nonreturn valves are tested prior to each startup.

- Turbine valve testing is performed at six-month intervals. The semi-annual testing frequency is based on nuclear industry experience that turbine-related tests are the most common cause of plant trips at power. Plant trips at power may lead to challenges of the safety-related systems. Evaluations show that the probability of turbine missile generation with a semi-annual valve test is less than the evaluation criteria.

- Extraction nonreturn valves are tested locally by stroking the valve full open with air, then equalizing air pressure, allowing the spring closure mechanism to close the valve. Closure of each valve is verified by direct observation of the valve arm movement.

The valve inspection frequency of three years noted above is consistent with an 18-month fuel cycle for AP1000 and is based on evaluations performed to support this valve inspection interval at operating plants with 18-month fuel cycles. A monitoring program is in place at operating nuclear power plants to verify the success of longer valve inspection intervals. A recommendation for a valve inspection frequency longer than three years may be justified when a longer interval is supported by operating and inspection program experience and supported by the missile generation probability calculations.

The non-destructive examinations for the turbine assembly provide assurance that rotor flaws that lead to brittle fracture of a rotor are detected.

10.2.4 Evaluation

Components of the turbine-generator are conventional and typical of those which have been extensively used in other nuclear power plants. Instruments, controls, and protective devices are provided to confirm reliable and safe operation. Redundant, fast actuating controls are installed to prevent damage resulting from overspeed and/or full-load rejection. The control system initiates a turbine trip upon reactor trip. Automatic low-pressure exhaust hood water sprays are provided to prevent excessive hood temperatures. Exhaust casing rupture diaphragms are provided to prevent low-pressure cylinder overpressure in the event of loss of condenser vacuum. The diaphragms are flange mounted and designed to maintain atmospheric pressure within the condenser and turbine exhaust housing while passing full flow.

Since the steam generated in the steam generators is not normally radioactive, no radiation shielding is provided for the turbine-generator and associated components. Radiological considerations do not affect access to system components during normal conditions. In the event of a primary-to-secondary system leak due to a steam generator tube leak, it is possible for the steam to become contaminated. Discussions of the radiological aspects of primary-to-secondary leakage are presented in Chapters 11 and 12.

10.2.5 Instrumentation Applications

The turbine-generator is provided with turbine supervisory instrumentation including monitors for the following:

- Speed
- Stop valve position
- Control valve position
- Reheat intercept and stop valve positions
- Temperatures as required for controlled starting, including:
  - External valve chest inner surface
  - External valve chest outer surface
  - First-stage shell lower inner surface
  - Crossover pipe upstream of reheat stop valve No. 1
  - Crossover pipe upstream of reheat stop valve No. 2
  - Crossover pipe upstream of reheat stop valve No. 3
  - Crossover pipe upstream of reheat stop valve No. 4
  - Crossover pipe upstream of reheat stop valve No. 5
  - Crossover pipe upstream of reheat stop valve No. 6
- Casing and shaft differential expansion
- Vibration of each bearing
- Shaft eccentricity
- Bearing metal temperatures

Alarms are provided for the following abnormal conditions:

- High vibration
- Turbine supervisory instruments common alarm

In addition to the turbine protective trips listed in Subsection 10.2.2.5, the following trips are provided:

- High exhaust hood temperature
- Low emergency trip system pressure
- Low shaft-driven lube oil pump discharge pressure
- High shell level in a moisture separator/reheater

Indications of the following miscellaneous parameters are provided:

- Main steam throttle pressure
- Steam seal supply header pressure
- Steam seal condenser vacuum
- Bearing oil header pressure
- Bearing oil coolers coolant temperature
- D-EHC control fluid header pressure
- D-EHC control fluid temperature
- Crossover pressure
- Moisture separator drain tank level
- First-stage pressure
- High-pressure turbine exhaust pressure
- Extraction steam pressure, each extraction point (either on the piping or on the corresponding feedwater heater shell)
- Low-pressure turbine exhaust hood spray pressure
- Exhaust hood temperature for each exhaust

Generator supervisory instruments are provided, with sensors and/or transmitters mounted on the associated equipment. These indicate or record the following:

- Multiple generator stator winding temperatures; the detectors are built into the generator, protected from the cooling medium, and distributed around the circumference in positions having the highest expected temperature

- Stator coil cooling water temperature (one detector per coil)

- Hydrogen cooler inlet gas temperature (two detectors at each point)

- Hydrogen gas pressure

- Hydrogen gas purity

- Generator ampere, voltage, and power

Alarms and trips associated with over-voltage and over-frequency protection are part of the generator protection relay system. Additional generator protective devices are listed in Table 10.2-3.

10.2.6 Combined License Information on Turbine Maintenance and Inspection

A turbine maintenance and inspection program will be submitted to the NRC staff for review prior to fuel load. The program will be consistent with the maintenance and inspection program plan activities

and inspection intervals identified in Subsection 10.2.3.6. Plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis will be available for review after fabrication of the turbine and prior to fuel load.

10.2.7 References

1. WCAP-16650-P, Proprietary and WCAP-16650-NP, Nonproprietary, "Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines," Revision 0, February 2007.

2. WCAP-16651-P, Proprietary and WCAP-16651-NP, Nonproprietary, "Probabilistic Evaluation of Turbine Valve Test Frequency," Revision 1, May 2009.[1]

3. NUREG-1275, Vol. 11, Operating Experience Feedback Report - Turbine-Generator Overspeed Protection Systems, Commercial Power Reactors, H. L. Ornstein, Nuclear Regulatory Commission, April 1995.

1. The UFSAR text incorporates by reference portions or all of this document.

Table 10.2-1
Turbine-Generator and Auxiliaries Design Parameters

Manufacturer	Toshiba
Turbine	
Type	TC6F 52-in. LSB
No. of elements	1 high pressure; 3 low pressure
Last-stage blade length (in.)	52
Operating speed (rpm)	1800
Condensing pressure (in. HgA)	2.9
Generator	
Generator rated output (kW) (minimum)	1,237,500
Power factor	0.95 (leading) 0.90 (lagging)
Generator rating (kVA) (minimum)	1,375,000
Hydrogen pressure (psig)	75
Moisture separator/reheater	
Moisture separator	Chevron vanes
Reheater	U-tube
Number	2 shell
Stages of reheating	2

Table 10.2-2
Turbine Overspeed Protection

Percent of Rated Speed (Approximate)	Event
100	Turbine is initially at valves wide open. Full load is lost. Speed begins to rise. When the breaker opens, the load drop anticipator immediately closes the control and intercept valves if the load at time of separation is greater than 30 percent.
101	Control and intercept valves begin to close.
108	Peak transient speed with normally operating speed control system. If the power/load unbalance and speed control systems had failed prior to loss of load, then:
110	A trip signal is sent by the emergency electrical overspeed trip system to actuate closure of the main stop, control, intercept, and reheat stop valves by releasing the hydraulic fluid pressure in the valve actuators using a two-out-of-three logic system.
111	The backup electrical overspeed trip system closes the main stop, control, intercept, and reheat stop valves by releasing the hydraulic fluid pressure in the valve actuators using a two-out-of-three trip logic system.

Note:
Following the above sequence of events, the turbine may approach but not exceed 120 percent of rated speed.

Table 10.2-3 (Sheet 1 of 2)
Generator Protective Devices Furnished with the Voltage Regulator Package

Device	Action		
• Generator Minimum Excitation Limiter	Limiter	–	maintains generator reactive power output above certain level (normally steady-state stability limit level)
	Alarm	–	when limiter is limiting
• Generator Maximum Excitation Limiter	Limiter	–	maintains generator field current at or below a predetermined setpoint to prevent thermal overload
	Alarm	–	when limiter is timing
	Alarm	–	when limiter is limiting
• Generator Overexcitation Protection	Alarm	–	changes the standby controller when overexcitation protection pickup level is exceeded
		–	the system has two master controller configurations; i.e., one is for normal operations and the other is standby
Inverse Timer	Alarm	–	when timing commences
	Regulator trip	–	when timed out
Fixed Timer	Alarm	–	when timing
	Unit trip	–	when timed out
• Generator Volts/Hertz Limiter	Limiter	–	maintains machine terminal volts/Hertz ratio below certain level
	Alarm	–	when limiter is limiting
• Generator Automatic Field Ground Detection	Alarm	–	ground
• Regulator Firing Circuit - Loss of Thyristor Firing Pulse Protection	Alarm	–	loss of one firing circuit
	Unit Trip	–	loss of both firing circuits
• Thyristor Blown Fuse Detection	Alarm	–	When one or more thyristor fuses in power drawers open

Table 10.2-3 (Sheet 2 of 2)
Generator Protective Devices Furnished with the Voltage Regulator Package

Device	Action		
• Regulator Forcing Indication	Alarm	–	online forcing
	Alarm	–	offline forcing (blocks "Raise" controls of dc regulator and ac regulator adjusters)
• Regulator Loss of Power Supply (s) Protection	Alarm	–	loss of one power supply
	Unit trip	–	loss of both power supplies
• Regulator Loss of Sensing Protection	Alarm and ac regulator trip	–	when regulator voltage transformer changes the standby controller. The system has two master controller configurations; i.e., one is for normal operation and the other is for standby
• Excitation Supply Breaker	Alarm Excitation trip		
• Power System Stabilizer (PSS) Excessive Output Protection	Alarm Power System Stabilizer trip	–	When PSS output exceeds specified level for specified time
• Power System Stabilizer Inservice Instrumentation Indication	Indicator	–	lamps and contacts

Table 10.2-4
Turbine-Generator Valve Closure Times

Valve	Closing Time (seconds)
Main Stop Valves	0.3
Control Valves	0.3
Intercept Valves	0.3
Reheat Stop Valves	0.3
Extraction Nonreturn Valves	<1.0

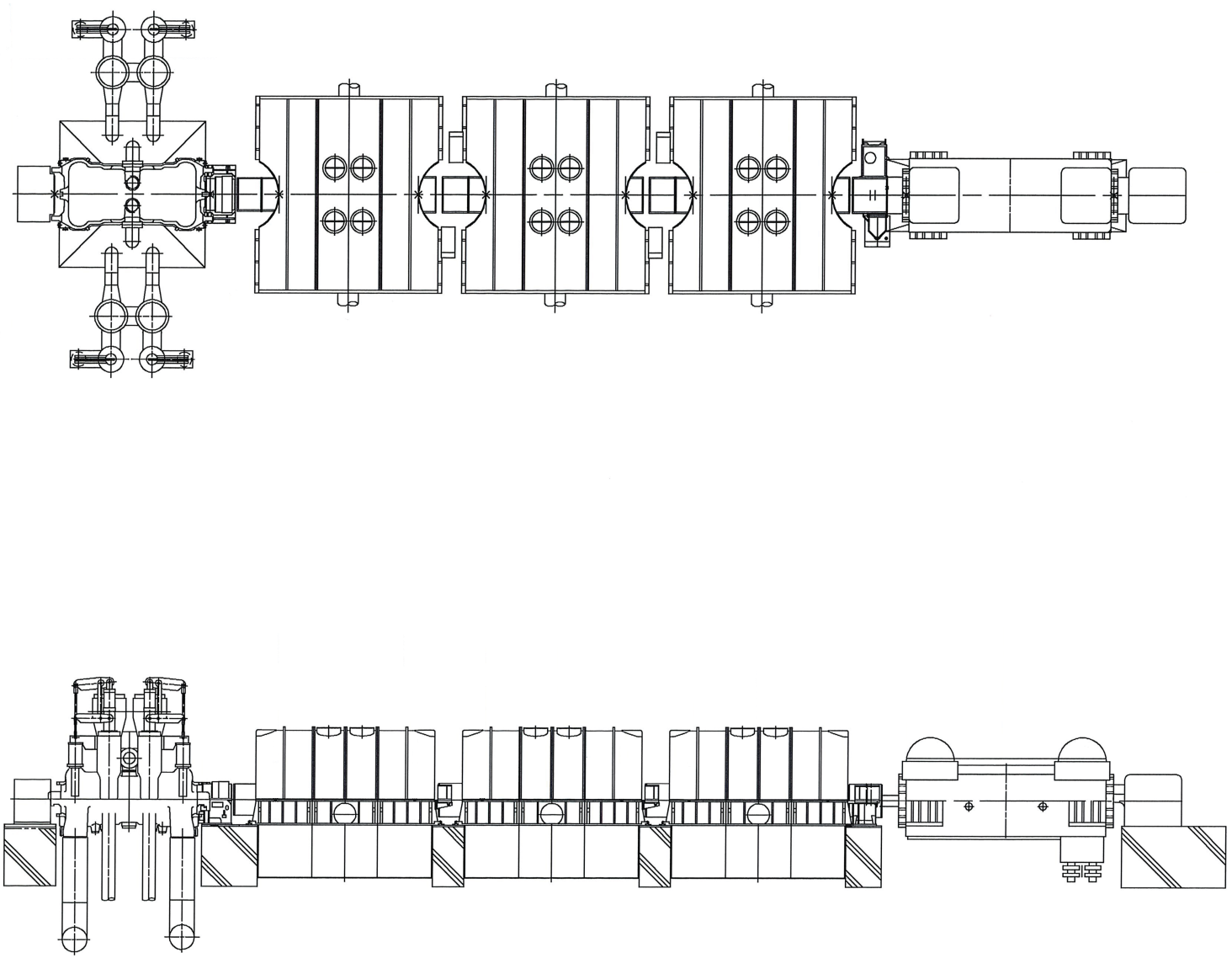


Figure 10.2-1 (Sheet 1 of 2)
Turbine Generator Outline Drawing

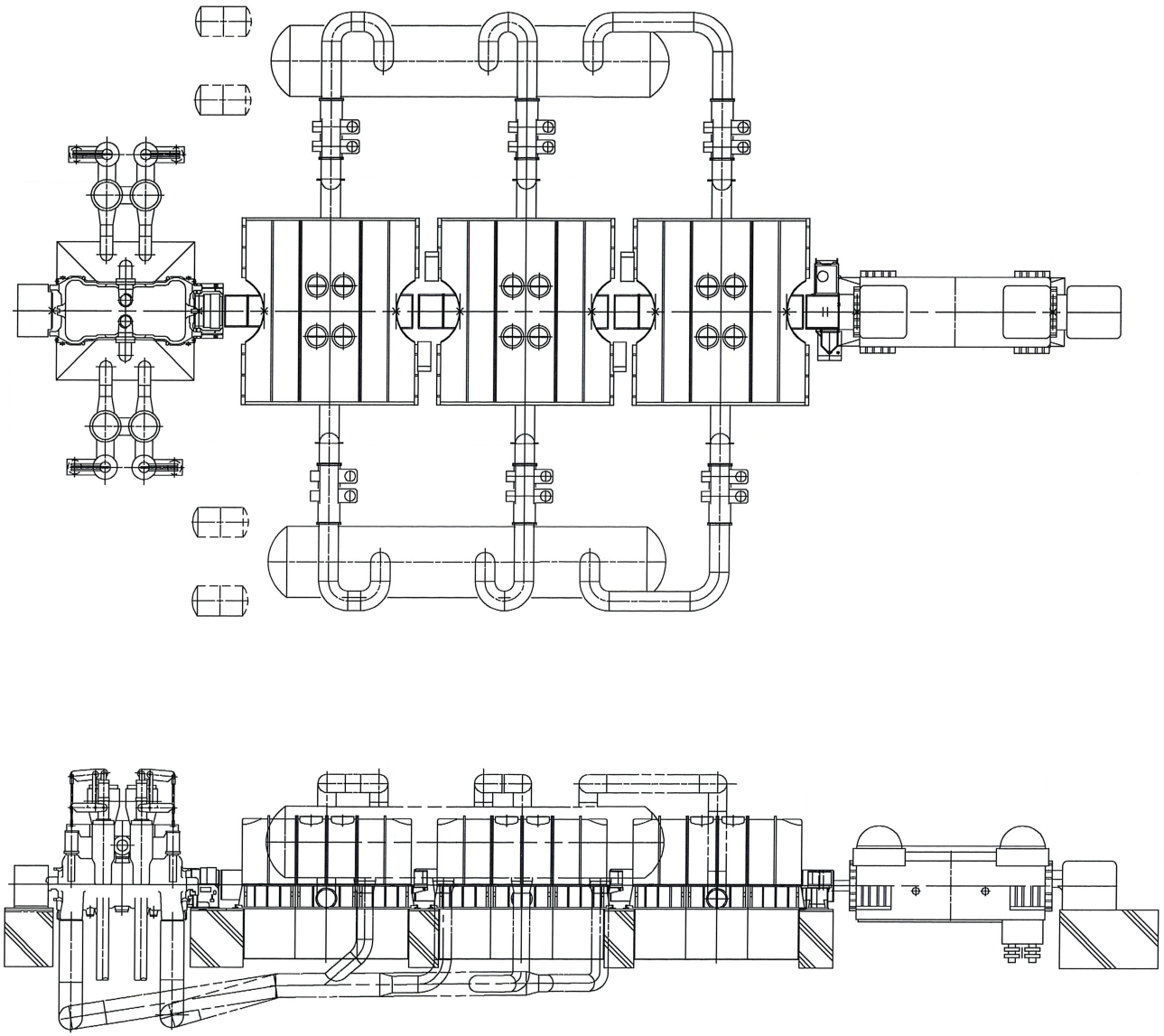


Figure 10.2-1 (Sheet 2 of 2)
Turbine Generator Outline Drawing

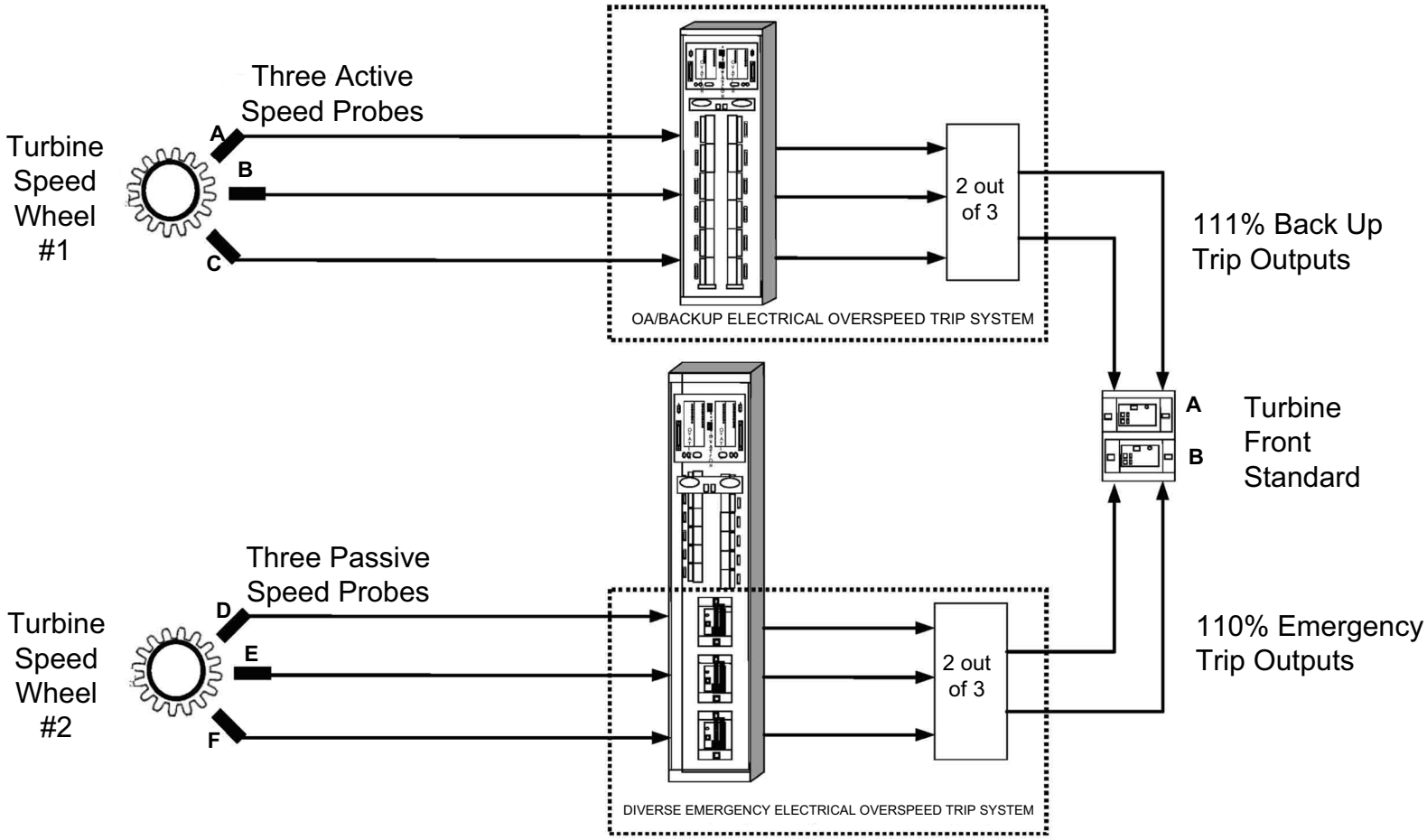


Figure 10.2-2
Turbine Overspeed Trip System Functional Diagram

10.3 Main Steam Supply System

The main steam supply system as described in this section includes components of the AP1000 steam generator system (SGS), main steam system (MSS), and main turbine system (MTS).

The function of the main steam supply system is to supply steam from the steam generators to the high-pressure turbine over a range of flows and pressures covering the entire operating range from system warmup to maximum calculated turbine conditions.

The system provides steam to the moisture separator/reheaters and the gland seal system for the main turbine. The system dissipates heat generated by the nuclear steam supply system (NSSS) by means of steam dump valves to the condenser or to the atmosphere through power-operated atmospheric relief valves or spring-loaded main steam safety valves when either the turbine-generator or condenser is unavailable.

10.3.1 Design Basis

10.3.1.1 Safety Design Basis

The main steam supply system safety design bases are as follows:

- The system is provided with a main steam isolation valve (MSIV) and associated MSIV bypass valve on each main steam line from its respective steam generator. These valves isolate the secondary side of each of the steam generators to prevent the uncontrolled blowdown of more than one steam generator and isolate nonsafety-related portions of the system.

- Codes and standards utilized in the design of the main steam supply system are identified in Section 3.2, according to the AP1000 equipment class of the component. The main steam supply system contains class B and class C safety-related components.

  Table 3.2-3 identifies the safety-related mechanical equipment in the main steam supply system, and lists the associated ASME code class. (Since all the safety-related components of the main steam supply system are in the AP1000 steam generator system [SGS], they appear in that table with an SGS prefix. For example, the main steam isolation valves [MSIVs] are listed there as SGS-PL-V040A and B).

  The following main steam supply system components are classified as equipment class B and are safety-related:

  – The main steam line piping from the steam generator up to, and including, the main steam isolation valves

  – The main steam isolation valve bypass piping up to, and including, the main steam isolation bypass valve

  – The inlet piping from the main steam line up to, and including, the main steam safety valves

  – The inlet piping from the main steam line up to, and including, the power operated relief valve block valve

  – The instrumentation piping up to, and including, the main steam line pressure instrument root valves

- The vent line on the main steam line up to, and including, the first isolation valve, and the nitrogen connection on the main steam line up to, and including, the first isolation valve

- The main steam drain condensate pot located upstream of the main steam isolation valves, and the drain piping up to, and including, the first isolation valve

The following main steam supply system components are classified as equipment class C and are safety-related:

- The main steam line piping from the main steam isolation valves outlet to the pipe restraint located on the wall between the auxiliary building and the turbine building

- The main steam safety valve discharge piping and vent stacks

- The piping from the outlet of the power operated relief block valve up to, and including, the power operated relief valve

- The condensate drain piping from the outlet of the class B isolation valve to the restraint on the wall between the auxiliary building and the turbine building

(The remainder of the main steam supply system is nonsafety-related. Except for the power operated relief valve discharge piping from the power operated relief valve outlet to the power operated relief valve silencer, which is class D, the remainder of the main steam supply system is class E).

- The system provides suitable overpressure protection of the steam generator secondary side and class 2 main steam piping in accordance with ASME Code, Section III.

- The safety-related portion of the system is designed to withstand the effects of a safe shutdown earthquake and to perform its intended function following postulated events.

- The safety-related portions of the system are protected from wind and tornado effects, as described in Section 3.3; flood protection is described in Section 3.4; missile protection is described in Section 3.5; protection against dynamic effects associated with the postulated rupture of piping is described in Section 3.6; seismic protection is described in Section 3.7; environmental design is described in Section 3.11; and fire protection is described in Section 9.5.

- The safety-related portion of the system is designed so that a single, active failure in the main steam supply system will not result in:

  - A loss-of-coolant accident

  - Loss of integrity of other steam lines

  - Loss of the capability of the engineered safety features system to effect a safe reactor shutdown

  - Transmission of excessive loading to the containment pressure boundary

  Component or functional redundancy is provided so that safety functions can be performed assuming a single, active failure coincident with loss of offsite power. Consistent with NUREG 0138 and Standard Review Plan Section 10.3, the nonsafety-related valves downstream of the main steam isolation valves are assumed functional to effect this capability.

- The portion of the main steam supply system that is constructed in accordance with ASME Code, Section III, requirements is provided with access to welds and removable insulation, as required for in-service inspection in accordance with ASME Code, Section XI. (See Subsection 10.3.4.2.)

- The main steam supply system is designed to function in the normal and accident environments identified in Section 3.11.

- The main steam supply system is qualified to leak-before-break criteria as described in Section 3.6.

- The main steam supply system design complies with containment isolation criteria as discussed in Subsection 6.2.3.

- The nonsafety-related turbine stop, turbine control, turbine bypass, and moisture separator reheater 2nd stage steam isolation valves are credited in a single failure analysis to mitigate the event for those cases in which the rupture of the main steam or feedwater piping inside containment is the postulated initiating event.

10.3.1.2 Power Generation Design Basis

The following is a list of the principal power generation design bases:

- The main steam supply system delivers steam from the steam generators to the turbine-generator for the range of flowrates, temperatures, and pressures existing from warmup to rated power conditions.

- Each main steam line is sized and routed to provide balanced steam pressures to the turbine stop valves.

- The main steam supply system provides the capacity to dump up to 40 percent of rated main steam flow to the condenser during plant step-load reductions.

- The system provides the means of dissipating residual and sensible heat generated from the nuclear steam supply system during hot shutdown and cooldown even when the main condenser is not available. Power-operated atmospheric relief valves are provided to allow controlled cooldown of the steam generator and the reactor coolant system when the condenser is not available.

- Piping system components located downstream of the auxiliary building wall anchor assemblies are designed in accordance with the Power Piping Code, ASME B31.1.

10.3.2 System Description

10.3.2.1 General Description

The main steam supply system shown in Figures 10.3.2-1 and 10.3.2-2 include the following major components:

- Main steam piping from the steam generator outlet steam nozzles to the main turbine stop valves

- One main steam isolation valve and one main steam isolation valve bypass valve per main steam line

- Main steam safety valves
- Power-operated atmospheric relief valves and upstream isolation valves

Table 10.3.2-1 lists the design data for the major components of the main steam supply system. Table 10.3.2-2 lists the design data for the main steam safety valve.

10.3.2.2 Component Description

10.3.2.2.1 Main Steam Piping

A description of the main steam piping from the steam generators to the turbine stop valves is presented in Table 10.3.2-3.

The main steam lines deliver a steamflow from the secondary side of the two steam generators. A portion of the main steamflow is directed to the reheater and steam seals, with the turbine receiving the remaining steamflow. Table 10.3.2-1 lists the performance data for the main steam supply system. Each of the main steam lines from the steam generators is anchored at the auxiliary building wall and has sufficient flexibility to accommodate thermal expansion.

Design of seismic Category I piping and supports takes into consideration the loads discussed in Subsection 3.9.3.

The main steam lines between the steam generator outlet nozzle and the containment penetration flued head inboard weld are designed to meet the leak-before-break criteria. The portion of the main steam lines between the containment penetration flued head inboard weld and the anchor downstream of the main steam isolation valves is part of the break exclusion zone. Section 3.6 addresses the applicability of leak-before-break and break exclusion zone to the main steam line.

The layout of the steam piping provides for the collection and drainage of condensate to avoid water entrainment, by the proper sloping of lines and the use of condensate drain pots.

The sizing and layout of the main steam piping hydraulically balances the steam line pressure drops from the respective steam generator to the inlet of each turbine stop valve. Two main steam lines are cross-connected into a common header just before branching into each turbine stop valve. This arrangement equalizes flow and pressure to the inlet of the turbine stop valves. This also permits online testing of each turbine stop valve without exceeding the allowable limit on steam generator pressure differential. Each steam generator outlet nozzle contains an internal flow restrictor arrangement to limit flow in the event of a main steam line break. A further description of the flow restrictor is provided in Subsection 5.4.4.

Sampling connections are installed in the nonsafety-related portion of each main steam line, downstream of the main steam isolation valves. These nozzles are used for the sampling of steam. The sampling is monitored and analyzed through the secondary sampling system (SSS). Refer to Subsection 9.3.4 for further discussion of the secondary sampling system.

Containment penetrations are described in Subsection 6.2.3.

Turbine bypass valves are provided between the main steam isolation valves and turbine-generator stop valves, as discussed under the turbine bypass system (refer to Subsection 10.4.4).

Main steam piping is designed to consider the effects of erosion/corrosion. Piping is constructed of erosion/corrosion resistant low alloy steel. Velocities in the main steam piping to the high pressure turbine are limited to reduce the potential for pipe erosion. Low point drains are provided for

collecting and draining moisture and to help reduce the potential for water carryover to the high and low pressure turbines. Pipe wall thickness inspections are performed as required to monitor wall erosion rates.

Branch connections are provided from the main steam system to perform various functions. Upstream of the main steam isolation valves, there are connections for the power-operated atmospheric relief valves, main steam safety valves, low point drains, high point vents, and nitrogen blanketing. Branch piping downstream of the main steam line isolation valves includes connections for the two stage reheaters, turbine bypass system, auxiliary steam/gland seal system, and low point drains. Table 10.3.2-4 further describes branch piping, 2.5 inches and larger, that is downstream of the main steam isolation valves.

Operations and maintenance procedures include precautions, when appropriate, to minimize the potential for steam and water hammer, including:

- Prevention of rapid valve motion
- Process for avoiding introduction of voids into water-filled lines and components
- Proper filling and venting of water-filled lines and components
- Process for avoiding introduction of steam or heated water that can flash into water-filled lines and components
- Cautions for introduction of water into steam-filled lines or components
- Proper warmup of steam-filled lines
- Proper drainage of steam-filled lines
- The effects of valve alignments on line conditions

10.3.2.2.2 Main Steam Safety Valves

Main steam safety valves with sufficient rated capacity are provided to prevent the steam pressure from exceeding 110 percent of the main steam system design pressure:

- Following a turbine trip without a reactor trip and with main feedwater flow maintained
- Following a turbine trip with a delayed reactor trip and with the loss of main feedwater flow

A total main steam safety valve rated capacity as indicated in Table 10.3.2-2 meets this requirement. At the same time, the individual safety valves are limited to the maximum allowable steam relief valve capacity as indicated in Table 10.3.2-2 for a system pressure equal to main steam design pressure plus 10 percent overpressure. This value sufficiently limits potential uncontrolled blowdown flow and the ensuing reactor transient should a single safety valve inadvertently fail or stick in the open position.

Six safety valves are provided per main steam line for the plant. Table 10.3.2-2 lists the performance data and set pressures for the main steam safety valves.

The main steam supply system safety valves are located in the safety-related portion of the main steam piping upstream of the main steam isolation valves and outside the containment in the auxiliary building. Adequate provision is made in the steam piping for the installation and support of

the valves. Consideration is given to the static and dynamic loads when operating or when subjected to seismic events.

The piping and valve arrangement minimizes the loads on the attachment, and analysis confirms the design by use of guidelines in ASME Section III, Nonmandatory Appendix O, "Rules for Design of Safety Valve Installations."

Each safety valve is connected to vent stacks by an open umbrella-type transition piece schematically depicted in detail A of Figure 10.3.2-1.

The vent stacks are designed to:

- Direct the relieved steam away from adjoining structures
- Prevent backflow of relieved steam through the umbrella-type transition section
- Draw a small quantity of ambient air through the umbrella-type transition section and mix with the total steam flow which leaves the vent stack outlet
- Minimize the backpressure on the valve outlet so that it does not restrict the valve's rated capacity

The vent stacks are structurally designed to withstand safe-shutdown earthquake loads. Tornado missiles are not a design basis load on the vent stacks. Missile impact on vent stacks is described in Subsection 3.5.2.

10.3.2.2.3 Power-Operated Atmospheric Relief Valves

A power-operated atmospheric relief valve is installed on the outlet piping from each steam generator to provide for controlled removal of reactor decay heat during normal reactor cooldown when the main steam isolation valves are closed or the turbine bypass system is not available. The valves are sized to provide a flow as indicated in Table 10.3.2-1. The maximum capacity of the relief valve at design pressure is limited to reduce the magnitude of a reactor transient if one valve would inadvertently open and remain open.

Each power-operated relief valve is located outside the containment in the auxiliary building upstream of the main steam isolation valves, in the safety-related portion of the main steam line associated with each steam generator. This location permits valve operation following transient conditions, including those which could result in closure of the main steam isolation valves.

The operation of the power-operated relief valves is automatically controlled by steam line pressure during plant operations. The power-operated relief valves automatically modulate open and exhaust to atmosphere whenever the steam line pressure exceeds a predetermined setpoint. As steam line pressure decreases, the relief valves modulate closed, reseating at a pressure at least 10 psi below the opening pressure. The setpoint is selected between no-load steam pressure and the set pressure of the lowest set safety valves.

The steam generator power-operated atmospheric relief valves provide a nonsafety-related means for plant cooldown by discharging steam to the atmosphere when the turbine bypass system is not available. Under such circumstances, the relief valves (in conjunction with the startup feedwater system) allow the plant to be cooled down at a controlled cooldown rate from the pressure setpoint of the lowest set of safety valves down to the point where the normal residual heat removal (RNS) system can remove the reactor heat.

For their use during plant cooldown, the power-operated atmospheric relief valves are automatically controlled by steam line pressure, with remote manual adjustment of the pressure setpoint from the control room or the remote shutdown workstation. To effect a plant cooldown, the operator manually adjusts the pressure setpoint downward in a step-wise fashion. The maximum cooldown rate achievable is limited by the flow-passing capability of the relief valves, the number of steam generators (and hence the number of relief valves) in service, the available startup feedwater pumping capacity and by the desire to either maintain or recover steam generator water levels during the cooldown.

The power-operated atmospheric relief valves also help to avoid actuation of the safety valves during certain transients and, following safety valve actuation, act to assist the safety valves to positively reseat by automatically reducing and regulating steam pressure to a value below the safety valve reseating pressure. The operation of each power-operated atmospheric relief valve is controlled in response to measurements of steam line pressure provided by four separate pressure taps on the associated steam line.

The valve operator is an air-operated modulating type, providing throttling capability over a range of steam pressures.

The atmospheric relief valves are controlled by nonsafety-related control systems for the modulating steam relief function. The capability for remote manual valve operation is provided in the main control room and at the remote shutdown workstation. A safety-related solenoid is provided to vent the air from the valve operator to terminate a steam line depressurization transient.

An isolation valve with remote controls is provided upstream of each power operated relief valve providing isolation of a leaking or stuck-open valve. The upstream location allows for maintenance on the power-operated relief valve operator at power. The motor-operated isolation valve employs a safety-related operator and closes automatically on Low-2 steam line pressure to terminate steam line depressurization transients. The isolation valve is a containment isolation boundary and therefore is specified as safety-related, active, ASME Code, Section III, Safety Class 2.

10.3.2.2.4 Main Steam Isolation Valves

The function of the main steam isolation is to limit blowdown to one steam generator in the event of a steam line break to:

- Limit the effect upon the reactor core to within specified fuel design limits
- Limit containment pressure to a value less than design pressure

Main steam isolation consists of one quick-acting gate valve in each main steam line and one associated globe main steam isolation bypass valve with associated actuators and instrumentation. These valves are located outside the containment, downstream of the steam generator safety valves and the atmospheric relief valve, in the auxiliary building. The isolation valves provide positive shutoff with minimum leakage during postulated line severance conditions either upstream or downstream of the valves.

The main steam isolation valves close fully upon receipt of a manual or automatic signal and remain fully closed. Upon receipt of the closing signal, the main steam isolation valves complete the closing cycle despite loss of normally required utility services for actuator and/or instrumentation. On loss of actuating hydraulic power, the valves fail to the closed position. On loss of electrical power the valves remain in their current position. Position indication and remote manual operation of the isolation valves are provided in the control room and remote shutdown workstation. Additionally, provisions are made for in-service inspection of the isolation valves.

Closure of the main steam isolation valves and main steam isolation bypass valves is initiated by the following:

- Low-2 steam line pressure in one of two loops
- High-2 containment pressure
- High negative steam pressure rate in one of two loops
- Low-2 T_{cold} in either reactor coolant loop
- Manual actuation: There are two controls for main steam line actuation. These controls provide system level actuation: that is, isolate both steam lines.
- Manual reset: In addition to the controls for manual isolation actuation, there are two controls for manual reset of the steam line isolation signal, one for each of the logic divisions associated with steam line controls, which can be used to manually reset that division's steam line isolation signal.

Each main steam isolation valve is a bidirectional wedge type gate valve composed of a valve body that is welded into the system pipeline. The main steam isolation gate valve is provided with a hydraulic/pneumatic actuator. The valve actuator is supported by the yoke, which is attached to the top of the body. The valve actuator consists of a hydraulic cylinder with a stored energy system to provide emergency closure of the isolation valve. The energy to operate the valve is stored in the form of compressed nitrogen contained in one end of the actuator cylinder. The main steam isolation valve is maintained in a normally open position by high-pressure hydraulic fluid. For emergency closure, redundant solenoids are energized resulting in the high-pressure hydraulic fluid being dumped to a fluid reservoir.

The main steam isolation bypass valves are used to permit warming of the main steam lines prior to startup when the main steam isolation valves are closed. The bypass valves are modulating, air-operated globe valves. For emergency closure, redundant 1E solenoids are provided. Each solenoid is energized from a separate safety-related division.

10.3.2.3 System Operation

10.3.2.3.1 Normal Operation

During normal power operation, the main steam supply system supplies steam to meet the demand of the main turbine system. The main steam supply system also supplies steam as required to the auxiliary steam system, and reheating steam to the moisture separator reheater. The main steam supply system also provides steam to the turbine gland seal system.

The main steam supply system is capable of accepting a ±10-percent step change in load or a ±5-percent/min ramp change without discharging steam to the atmosphere through the main steam safety valves or to the main condenser through the turbine bypass system. For large step change load reductions, steam is bypassed (up to 40 percent of rated main steam flow) directly to the condenser via the turbine bypass system. As discussed in Subsection 10.4.4, the main steam supply system, in conjunction with the turbine bypass system, is capable of accepting a 100-percent net load rejection without reactor trip (in conjunction with a reactor rapid power reduction) and without lifting safety valves. If the turbine bypass system is not available, steam is vented to the atmosphere via the power-operated atmospheric relief valves and the main steam safety valves, as required.

10.3.2.3.2 Emergency Operation

In the event that the plant must be shut down, the main steam isolation valves with associated main steam isolation bypass valves and other valves associated with the main steam lines can be closed. The power-operated atmospheric relief valves are then used to remove reactor decay and primary system sensible heat to cooldown to conditions at which the normal residual heat removal system can perform the remaining cooldown function. If the power-operated atmospheric relief valve for an individual main steam line is unavailable because of the loss of its control or power supply, the respective safety valves will provide overpressure protection. The remaining power-operated atmospheric relief valve is sufficient to cooldown the plant.

In the event that a design basis accident occurs, which results in a large steam line break, the main steam isolation valves with associated main steam isolation bypass valves automatically close. The closure of the main steam isolation valves and associated main steam isolation bypass valves result in no more than one steam generator supplying a postulated break.

The passive residual heat removal system (Section 6.3) provides safety-related decay heat removal capability should steam relief and feedwater be unavailable.

10.3.3 Safety Evaluation

- Each main steam line is provided with safety valves that limit the pressure in the line to limit over-pressurization and remove stored energy. Each line is provided with a power-operated atmospheric relief valve to permit reduction of the main steam line pressure and remove stored energy to achieve an orderly shutdown. The startup feedwater system, described in Subsection 10.4.9, provides makeup to the steam generators consistent with the steaming rate.

- Redundant power supplies and power divisions operate the main steam isolation valves and main steam isolation bypass valves to isolate safety and nonsafety-related portions of the system. Branch lines upstream of the main steam isolation valves contain normally closed, power-operated atmospheric relief valves which modulate open and closed on steam line pressure. In the event the atmospheric relief valves fail closed, the safety valves provide overpressure protection.

  Releases of radioactivity from the main steam system are minimized because there are no significant amounts of radioactivity in the system under normal operating conditions. Additionally, the main steam isolation system provides controls for reducing releases, as described in Chapter 15, following a steam generator tube rupture.

  Detection of radioactive leakage into the system, which is characteristic of a steam generator tube leak or rupture, is facilitated by adjacent-to-line radiation monitors on each steam line, the radiation monitor in the turbine vent and drain system which monitors condenser air removal, and the steam generator blowdown line radiation monitor.

- Section 3.2 provides the quality group classification, the required design and fabrication codes, and seismic category applicable to the safety-related portion of this system and supporting systems. The power supplies and controls necessary for safety-related functions of the main steam supply system are safety-related, as described in Chapters 7 and 8.

- The safety-related portion of the main steam supply system is located in the containment and auxiliary building. These buildings are designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, external missiles, and other appropriate natural phenomena. Sections 3.3, 3.4, 3.5, 3.7, and 3.8 describe the bases of the structural design of these buildings.

  The safety-related portion of the main steam supply system is designed to remain functional after a safe shutdown earthquake. Sections 3.7 and 3.9 provide the design loading conditions that were considered. Sections 3.5, 3.6, and 9.5 describe the analyses to provide confidence that a safe shutdown, as outlined in Section 7.4, is achieved and maintained.

- As indicated by the failure mode and effects analysis in Table 10.3.3-1, no single failure coincident with loss of offsite power compromises the system safety functions.

- The main steam supply system is initially tested with the program given in Chapter 14. Periodic in-service functional testing is done in accordance with Subsection 10.3.4.

  Section 6.6 provides the ASME Code, Section XI requirements that are appropriate for the safety-related portions of the main steam supply system.

- The safety-related components of the main steam supply system are qualified to function in normal, test, and accident environmental conditions. The environmental qualification program is described in Section 3.11.

- A discussion of high energy pipe break locations and evaluation of effects are provided in Subsections 3.6.1 and 3.6.2.

- A discussion of the leak-before-break application and criteria is presented in Subsection 3.6.3.

10.3.4 Inspection and Testing Requirements

10.3.4.1 Preoperational Testing

10.3.4.1.1 Valve Testing and Inspection

The operability and relief setpoints of the main steam safety valves will be verified at operating temperature using steam as the pressurization fluid. The advantage of this approach is that the testing at temperature will reduce the probability of having to adjust the valve setpoints during hot functional testing heatup. The valves may be either bench tested or in-situ tested. The valves will be adjusted to lift at their set pressure defined in Table 10.3.2-2.

The sum of the rated capacities of the valves shall exceed the capacity specified in Table 10.3.2-2. The relieving capacity of the valve is certified in accordance with the ASME Code, Section III NC-7000.

The lift-point of each power-operated atmospheric relief valve is checked against pressure gauges mounted in the main steam piping.

The power operated relief valves will be verified to have a relief capacity of at least 300,000 lbs/hour at 1106 psia in order to satisfy their non-safety related function of decay heat removal.

The main steam isolation valves are tested to verify the closing time prior to initial startup.

10.3.4.1.2 System Testing

The main steam supply system is designed to allow testing of system operation for both normal and emergency operating modes. This includes operation of applicable portions of the protection system.

The safety-related components of the system are designed and located to permit pre-service and in-service inspections.

10.3.4.1.3 Pipe Testing

The main steam lines within the containment and the auxiliary building are visually and volumetrically inspected at installation as required by ASME Code, Section XI pre-service inspection requirements.

10.3.4.2 In-service Testing

The performance and structural leaktight integrity of system components are demonstrated by operation.

Additional description of in-service inspection and in-service testing of ASME Code, Section III, Class 2 and 3 components is contained in Section 6.6 and Subsection 3.9.6. The nonsafety-related turbine stop, turbine control, and moisture separator reheater 2nd stage steam isolation valves are included in the inservice test program discussed in Subsection 3.9.6.

10.3.5 Water Chemistry

The objectives of the secondary side water chemistry program are as follows:

- Minimizing general corrosion in the steam generators, turbine, and feedwater system by maintaining proper pH control and by minimizing oxygen ingress (coupled with oxygen scavenging)
- Minimizing localized corrosion in the steam generators, turbine, and feedwater system by minimizing chemical contaminant ingress and by controlling contaminant levels through condensate polishing and steam generator blowdown.

10.3.5.1 Chemistry Control Basis

Steam Generator Owner's Group recommendations are considered in the secondary side water chemistry program.

Secondary side water chemistry control basis for AP1000 is shown below:

System Design

- Selection of secondary side materials to minimize corrosive species such as copper oxides
- Capability of deaeration in the demineralized water supply path, condenser, and deaerator
- Capability of continuous blowdown of the steam generator bulk water
- Capability of post-construction cleaning of the feedwater system followed by wet layup of the feedwater system and steam generators

Operation Phase

- Early identification of contaminant ingress (salts, corrosion products, and oxygen)
- Capability to filter and demineralize condensate by passage of part of the condensate flow through a condensate polisher system prior to and during plant startup and shutdown and during power operation with abnormal secondary cycle chemistry.
- Chemical addition to establish and maintain an environment that minimizes system corrosion
- Identification of action levels based on chemistry conditions, as determined by high sensitivity continuous or semi-continuous monitoring or by grab sampling

10.3.5.2 Contaminant Ingress

Contaminants may be introduced into the secondary side water system through three major mechanisms: makeup water; condenser tube leaks; atmospheric leaks at the condenser or pump seals. The following methods are used to detect the ingress of contaminants in the secondary water system:

- Demineralized water is continuously monitored as it is being produced in the water treatment plant.
- Ionic contaminants are detected by monitoring (either continuous process monitors or sample analysis) the condensate pump discharge, feedwater downstream of addition of heater and moisture separator drains, and steam generator bulk flow as blowdown.
- Atmospheric ingress is detected by monitoring the condensate pump discharge for excessive dissolved oxygen and by monitoring condenser air removal rate.

10.3.5.3 Condensate Polishing

A condensate polishing system with a capacity of one third design condensate flow is provided to remove corrosion products and ionic contaminants. This polishing system will not normally be employed during all phases of plant operation.

The secondary side water system has provisions for recirculating feedwater to the condenser prior to and during startup. The polisher may be used during this phase to remove corrosion products from the feedwater and thus prevent their ingress into the steam generators. Full flow or near full flow condensate polishing is possible at the lower condensate flows that exist during startup and low-power operation. See Subsection 10.4.6 for additional information.

10.3.5.4 Chemical Addition

AP1000 employs an all-volatile treatment (AVT) method to minimize general corrosion in the feedwater system, steam generators, and main steam piping. A pH adjustment chemical and an oxygen scavenger are the two chemicals to be injected into the condensate pump discharge header, downstream of the condensate polishers.

To reduce the general corrosion rate of ferrous alloys, a volatile pH adjustment chemical is injected to maintain a noncorrosive environment. Although the pH adjustment chemical is volatile and will not concentrate in the steam generator, it will reach an equilibrium level which will help establish noncorrosive conditions.

An oxygen scavenger is added to maintain the dissolved oxygen content in the feedwater within specified limits for each mode of operation. The oxygen scavenger also promotes the formation of a protective magnetite layer on ferrous surfaces and keeps this layer in a reduced state, further inhibiting general corrosion.

Alkaline chemistry supports maintaining iodine compounds in their nonvolatile form. When iodine is in its elemental form, it is volatile and free to react with organic compounds to create organic iodine compounds, which are not assumed to remain in solution. It is noted that no significant level of organic compounds is expected in the secondary system. The secondary water chemistry, thus, does not directly impact the radioactive iodine partition coefficients.

10.3.5.5 Action Levels for Abnormal Conditions

Appropriate responses to abnormal chemistry conditions provide for the long-term integrity of secondary cycle components. Action taken when chemistry parameters are outside normal operating ranges will, in general, be consistent with action levels described in Reference 1 in accordance with the secondary side water chemistry program.

10.3.5.6 Layup and Heatup

AP1000 anticipates no long-term steam generator layup under dry conditions. When maintenance or inspection is required on the secondary side of the steam generators, the steam generators are drained hot under nitrogen atmosphere. After cooling, the nitrogen purge is lifted and the maintenance/inspection begun.

Wet layup conditions are established for corrosion protection during outages. Guidelines are given in the secondary side water chemistry program, which is based on Reference 1.

Before heatup to full power, the bulk water in the steam generators is normally brought into power operation specifications by draining and refilling or by feeding and bleeding. Guidelines for heatup are provided in the secondary side water chemistry program, which is based on Reference 1.

10.3.5.7 Chemical Analysis Basis

Guidelines for chemical control and diagnostic parameters are provided in the secondary side water chemistry program, which is based on Reference 1. Each parameter will be addressed as indicated below.

Oxygen in the presence of moisture rapidly corrodes carbon steel. These corrosion products may be carried through the feedwater system and form sludge in the steam generator. This sludge forms an environment for localized corrosion mechanisms on steam generator tubes. Thus, concentrations of oxygen are kept as low as practical in the feedwater system, and dissolved oxygen is controlled at the condenser and deaerator to prevent oxygen transport to the feedwater system.

Residual concentration of the oxygen scavenger is also measured in the feedwater sample and is used as input for injection of the oxygen scavenger.

In the absence of significant impurities, the pH is controlled by the concentration of the volatile pH adjustment chemical and the oxygen scavenger. Maintaining the pH within the recommended band results in minimal corrosion rates of ferrous materials.

Conductivity is also a measure of the presence of ionic contamination and provision is made for monitoring conductivity in samples of condensate, feedwater, and steam generator blowdown.

Provision is also made for specific ions, such as sodium and chloride, which could be indicative of aggressive chemistry conditions.

10.3.5.8 Sampling

The sampling points are identified in Table 9.3.4-1 (continuous and semi-continuous sample points) and Table 9.3.4-2 (selective measurements). Additionally, sample points are addressed in the secondary side water chemistry program, which is based on Reference 1.

10.3.5.9 Condenser Inspection

The secondary side water chemistry program includes an inspection program of the condenser to verify condenser integrity. This program includes a visual inspection of the condenser during outages and component inspection for air leaks during plant operation.

10.3.5.10 Conformance to Branch Technical Position 5-1

Conformance to Branch Technical Position 5-1 is discussed in Table 10.3.5-1.

10.3.6 Steam and Feedwater System Materials

10.3.6.1 Fracture Toughness

The material specifications for pressure-retaining materials in safety-related portions of the main steam and feedwater systems meet the fracture toughness requirements of ASME Code, Section III, Articles NC-2300 and ND-2300 for Quality Group B and Quality Group C components.

10.3.6.2 Material Selection and Fabrication

Pipe, flanges, fittings, valves, and other piping material conform to the referenced ASME, ASTM, ANSI, or Manufacturer Standardization Society-Standard Practice code.

No copper or copper-bearing materials are used in the steam and feedwater systems.

The following requirements apply to the nonsafety-related portion of the main steam system.

Component	**Alloy/Carbon Steel**
Pipe	ANSI/ASME B36.10M
Fittings	ANSI/ASME B16.9, B16.11
Flanges	ANSI/ASME B16.5

Material selection and fabrication requirements for ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems are consistent with the requirements for ASME Class 2 and 3 systems and components outlined in Subsections 6.1.1.1 and 6.1.1.2. Material specifications for the main steam and feedwater systems are listed in Table 10.3.2-3.

Conformance with the applicable regulatory guides is described in Subsection 1.9.1.

Nondestructive inspection of ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems is addressed in Subsection 6.6.5.

Appropriate operations and maintenance procedures provide the necessary controls during operation to minimize the susceptibility of components made of stainless steel and nickel-based materials to intergranular stress-corrosion cracking by controlling chemicals that are used on system components.

10.3.7 Combined License Information

This section contained no requirement for information.

10.3.8 References

1. "PWR Secondary Water Chemistry Guidelines," EPRI.

Table 10.3.2-1
Main Steam Supply System Design Data

Steam Flow	Maximum Calculated
Per steam generator (lb/hr)	7.50×10^6
Total (lb/hr)	14.99×10^6
Design Conditions	
Design pressure (psia)	1200
Design temperature (°F)	600°F
Operating Conditions	
Full plant load pressure (psia)	836
Full plant load temperature (°F)	523.3
No load (hot standby) pressure (psia)	1106
No load (hot standby) temperature (°F)	557
Main Steam Piping: See Table 10.3.2-3.	
Steam Generator Flow Restrictor	
Number per steam generator outlet nozzle	7
Throat size (ft^2)	0.2
Total area (ft^2)	1.4
Power-Operated Relief Valve	
Number per main steam line	1
Normal set pressure	1138 psig
Design capacity	
Minimum:	70,000 lb/hr at 100 psia steam generator pressure
Maximum:	1,020,000 lb/hr at 1200 psia steam generator pressure
Code	ASME Code, Section III, Class 3, seismic Category I
Actuator	Air-operated modulating

Table 10.3.2-2
Design Data for Main Steam Safety Valves

Number per main steam line		6
Total number of valves required per steam line for full power operation		6
Relieving capacity per valve at 110% of design pressure		1,370,000 lb/hr
Relieving capacity per steam line at 110% of design pressure		8,240,000 lb/hr
Total relieving capacity, 2 lines at 110% of design pressure		16,480,000 lb/hr
Valve size		8 x 10 (Dual Discharge)
Design code		ASME Code, Section III, Class 2, seismic Category I
Valve Number	**Set Pressure (psig)**	**Relieving Capacity[(a)] (lb/hr)**
SGS PL V030A(B)	1185	≥ 1,320,000
SGS PL V031A(B)	1197	≥ 1,340,000
SGS PL V032A(B)	1209	≥ 1,350,000
SGS PL V033A(B)	1221	≥ 1,360,000
SGS PL V034A(B)	1232	≥ 1,370,000
SGS PL V035A(B)	1232	≥ 1,370,000
Total capacity, at 103% valve setpoint pressures, 2 lines		≥ 16,220,000

Note:

a. Based on system accumulation pressure of 3%, per Subsection NC-7512 of ASME Code, Section III, Division 1, 1998 Edition with 2000 Addenda, Subsection NC, Class 2 components.

Table 10.3.2-3
Description of Main Steam and Main Feedwater Piping

Segment	Material Specification
Main Steam Line	
Steam generator outlet to containment penetration	SA-335 Gr. P11 seamless pipe
Containment penetration to MSIV	SA-335 Gr. P11 seamless pipe
MSIV to auxiliary/turbine building wall	SA-335 Gr. P11 seamless pipe
Auxiliary/turbine building wall to equalization header[(a)]	ASTM A-335 Gr. P11 seamless pipe
Branch lines to turbine stop valves[(a)]	ASTM A-335 Gr. P11 seamless pipe
Main Feedwater Line	
Feedwater pump outlet to individual steam generator feedwater lines[(a)]	ASTM A-335 Gr. P-11 and ASTM A-106 Gr. B
Feedwater heater bypass line[(a)]	ASTM A-335 Gr. P-11 and ASTM A-106 Gr. B
Start of individual steam generator feedwater lines to auxiliary/ turbine building wall[(a)]	ASTM A-335 Gr. P-11
Auxiliary/turbine building wall to MFIV	SA-335 Gr. P-11
MFIV to containment penetration	SA-335 Gr. P-11
Containment penetration to steam generator nozzle	SA-335 Gr. P-11

Note:
a. Piping is beyond the ASME Section III piping boundary.

Table 10.3.2-4
Main Steam Branch Piping
(2.5-Inch and Larger)
Downstream of MSIV

Description	Maximum Steam Flow	Shutoff Valve	Valve Closure Time	Actuator	Comments
Turbine bypass lines to condenser; 6 lines total	999,333 lb/hr each line[c, d]	16-in. globe (turbine bypass valve)	5 sec or less[a] when tripped closed	Air operator; fail close	Bypass valve is tripped closed on main steam isolation signal
Reheating steam to moisture separator reheater (MSR), 2 lines total	242,000 lb/hr, each MSR[c]	10-in. globe (MSR reheat 2nd stage steam isolation valve, 2 each)	5 sec or less[a]	Air operators, fail close	Main steam flow to reheater ceases (thermodynamically) following turbine trip flow ceases following valve closure on a main steam isolation signal
Main steam supply to auxiliary steam system	<450,000 lb/hr[b]	16-in. globe (isolation valve)	10 sec or less	Air operator; fail close	Main steam flow to auxiliary steam system terminates following isolation valve closure on a main steam isolation signal
High pressure turbine steam supply lines; 4 lines total	3,744,000 lb/hr each line[c]	28-in. stop valve in each line	5 sec or less[a]	Hydraulically operated from electro-hydraulic turbine control system	Main steam flow to high pressure turbine ceases following stop valve closure on a turbine trip
Main steam supply to turbine glands	<50,000 lb/hr[b]	6-in. gate (isolation valve)	60 sec or less	Motor operator; manually operated	Main steam flow to turbine seals continues following a turbine trip; however, this steam flow is relatively small and has been considered in the steam line break analysis (Section 3.6)

Notes:

a. Specified closure times are for safety analysis purposes; other system performance requirements may dictate more rapid closure.
b. Analysis maximum — design maximum is less than value shown.
c. Design maximum.
d. Turbine Bypass System maximum flow rate is 40 percent of rated main steam flow as discussed in Subsection 10.4.4. Rated main steam flow is listed in Table 10.3.2-1.

Table 10.3.3-1 (Sheet 1 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
1	MSIVs V040A(B) normally open, fail closed with self contained hydraulic operator	Isolates SG A(B) in the event of a MSLB to prevent blowdown of more than one SG; Isolates containment in conjunction with SG and main steam line inside containment	a. All but DBA	b. Fails closed or fails to open on command	a. Position indication on main control room & remote shutdown work-station	a. None; Plant goes to or remains in a safe shutdown condition	One MSIV is provided for each steam line. Each MSIV redundantly activated from separate safety-related power divisions. Redundant backup provided by downstream isolation valves. Redundant containment isolation provided by SG and main steam line inside containment.
			b. DBA Except SGTR	b. Fails to close upon ESF isolation signal	b. Position indica-tion on main control room & remote shutdown workstation	b. None; closure of either MSIV or downstream valves prevent blowdown of more than one SG; containment integrity is maintained by MSIV and either SG and steam line integrity inside containment or downstream valves.	
			c. DBA-SGTR	c. Fails to close on ESF isolation signal	c. Same as 1b	c. None; limiting failure is PORV failed open discharging to atmo-sphere. Termination of break flow occurs on automatic block valve closure plus PRHR actuation. Continued break flow past MSIV precluded by redundant downstream isolation valves.	Redundant isolation provided by downstream isolation valves

Table 10.3.3-1 (Sheet 2 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
2	Main steam power operated relief valve V233A(B) normally closed fail closed, air-operated control valve	Isolates SG A(B) in the event of a MSLB to prevent blowdown from more than one SG in conjunction with block valve	a. All but DBA	a1. Fails to open upon open signal	a1. Position indication on main control room & remote shutdown workstation; steam line high pressure	a1. None; heat removal available via steam dump or PRHR; safety valves provide over-pressure protection	
				a2. Fails open or fails to close on command including spurious operation	a2. Position indication on main control room & remote shutdown workstation; low SG level or SG pressure	a2. None; maximum flow less than DBA limit; shutdown effected with 1 PORV, PRHR, or steam dump	Redundant isolation provided by PORV and block valve via separate safety-related power divisions
			b. DBA except SGTR	b. Fails to close	b. Position indication on main control room & remote shutdown workstation; steam line low pressure alarm	b. None, redundant isolation provided by PORV block valve	Dose analysis based on failed open PORV with subsequent block valve closure
			c. DBA - SGTR	c. Fail to close	c. Position indication on main control room & remote shutdown workstation; streamline low pressure alarm	c. None; automatic redundant isolation provided by PORV block valve. Releases based on signal generation and closure time delay	

Table 10.3.3-1 (Sheet 3 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
3	Main steam line PORV block valve V027A(B), normally open fail as is motor-operated globe valve	Isolates SG A(B) in the event of a MSLB to prevent blowdown from more than 1 SG in conjunction with PORV and provides containment integrity in conjunction with SG and main steam line inside containment	a. All but DBA	a1. Same as 2.a1 a2. Same as 2.a2	a1. Same as 2.a1 a2. Same as 2.a2	a1. Same as 2.a1 a2. Same as 2.a2	Redundant steam line isolation provided by PORV and block valve via separate safety-related power divisions. Redundant containment isolation provided by SG and main steam line inside containment.
			b. DBA except SGTR	b. Same as 2b	b. Position indication on main control room & remote shutdown workstation	b. Same as 2b; containment integrity is maintained by SG and main steam line inside containment	
			c. DBA SGTR	c. Same as 2b	c. Position indication on main control room & remote shutdown workstation	c. None, automatic redundant isolation of the PORV on Low-2 steam line pressure	Dose analysis based on failed open PORV isolated by block valve. Releases equivalent.

Table 10.3.3-1 (Sheet 4 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
4	Main steam isolation bypass valve V240A(B) normally closed, fail closed air-operated valve	Isolates SG A(B) in the event of a MSLB to prevent blowdown of more than one SG; isolates containment in conjunction with SG and main steam line inside containment	a. All but DBA	a. Fails closed or fails to open on command	a. Position indication on main control room and remote shutdown workstation	a. Plant continues operation or goes to or remains at a safe shutdown condition	One MSIV bypass is provided for each steam line. Each bypass valve redundantly activated from separate 1E power divisions. Redundant backup provided by downstream isolation valves. Redundant containment isolation provided by SG and main steam line inside containment.

Table 10.3.3-1 (Sheet 5 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			b. DBA except SGTR	b. Fails to close upon ESF isolation signal	b. Position indication on main control room & remote shutdown workstation	b. None, closure of either bypass valve or down-stream isolation valves prevents blowdown of more than 1 SG; containment integrity maintained by either MSIV bypass valve or SG/steam line integrity inside containment	
			c. DBA-SGTR	c. Fails to close on ESF isolation signal	c. Position indication on main control room & remote shutdown workstation	c. None, limiting failure is PORV failed open discharging to atmosphere. Termination of break flow occurs on automatic block valve closure plus passive RHR actuation. Continued break flow past MSIV bypass precluded by redundant downstream isolation valves	Redundant isolation provided by downstream isolation valves

Table 10.3.3-1 (Sheet 6 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
5	Main steam line drain isolation valve V036A(B), normally open fail closed, air-operated valve	Isolates containment in conjunction with SG and main steam line inside containment. Isolates SG No. 1(2) in the event of a MSLB to prevent blowdown from more than one SG.	a. All but DBA	a. Fails closed or fails to open on command	a. Position indication on main control room & high level alarm in condensate drain pot	a. None; local drains provided to limit moisture carry to turbine	
			b. DBA including SGTR	b. Fails to close upon ESF isolation signal	b. Position indication on main control room	b. None; closure of either series isolation valves provides steam line isolation; containment integrity is maintained by either condensate isolation or SG and main steam line inside containment	

Table 10.3.3-1 (Sheet 7 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
6	Main steam line drain control valve V086A(B) normally closed, fail closed, air-operated valve	Isolates SG A(B) in the event of a main steam line break to prevent blowdown to more than one SG	a. All but DBA	a. Fails closed or fails to open on command	a. Position indication on main control room and high level alarm in condensate drain pot	a. None; local drains provided to limit moisture carryover to turbine	
			b. DBA including SGTR	b. Fails to close upon ESF isolation signal	b. Position indication provided on main control room	b. None, closure of either series isolation valves provides steam line isolation	

Table 10.3.3-1 (Sheet 8 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
7	Main steam safety valves V030A, V031A, V032A, V033A, V034A, V035A (V030B, V031B, V032B, V033B, V034B, V035B), normally closed	Protect SG A(B) and associated steam line up to MSIV from overpressurization	All	a. Fails to open when required	a. Higher pressure and/or water level in SG A(B)	a. None, 5 out of 6 safety valves for SG A(B) still available with PORV available to supplement relief capacity; also, plant trip occurs on High-3 steam generator level	
				b. Spurious opening or failure to reset after opening	b. Low steam line pressure	b. None, maximum flow from one safety valve less than DBA analysis assumptions, Shutdown effected by other SG or PRHR	

Table 10.3.3-1 (Sheet 9 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
8	Steam Generator blowdown isolation V074A(B), normally open, fail closed air-operated valve	Isolates blowdown from SG A(B) upon PRHR actuation; isolates containment in conjunction with SG and blowdown lines inside containment	All	a. Fails closed or fails to open upon command	a. Position indication on the main control room and zero flow measured in blowdown system	a. None, blowdown is terminated but has no safety impact	
				b. Fails open or fails to close on command	b. Position indication on main control room	b. None, redundant isolation of blowdown via series isolation valve V075A(B), Containment integrity is maintained by blowdown isolation or SG and blowdown lines inside containment	Redundant isolation is provided for SG volume for PRHR operation via series valves; containment isolation via blowdown isolation or SG and blowdown lines inside containment

Table 10.3.3-1 (Sheet 10 of 10)
Main Steam Supply System Failure Modes and Effects Analysis

Item	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
9	Steam Generator blowdown isolation V075A(B), normally open, fail closed air-operated valve	Isolates blowdown from SG A(B) upon PRHR actuation	All	a. Fails closed or fails to open upon command	a. Position indication on main control room and zero flow in blowdown system	a. None, blowdown is terminated but has no safety impact	
				b. Fails open or fails to close on command	b. Position indication on main control room	b. None, redundant isolation of blowdown via series isolation valve V074A(B)	Redundant isolation is provided for SG volume for PRHR operation via series valves

Table 10.3.5-1
Conformance to Branch Technical Position 5-1, Monitoring of Secondary Side Water Chemistry in PWR Steam Generators

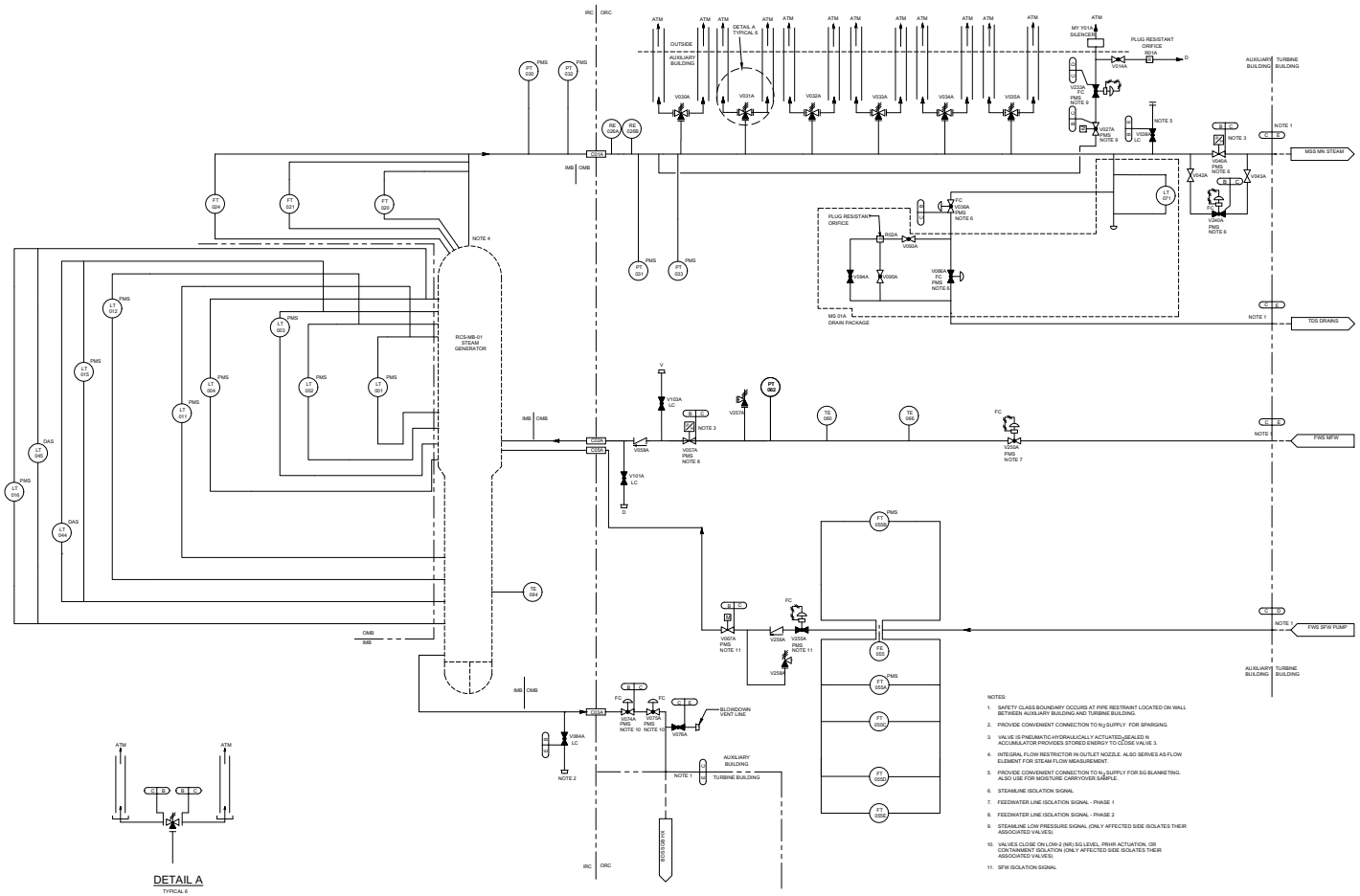
Branch Technical Position	Conformance
B.1 The applicant's final safety analysis report (FSAR) should describe the implementation of a secondary water chemistry monitoring and control program in accordance with the supplier's recommended procedure to inhibit steam generator corrosion and tube degradation. The applicant should address how its program meets industry guidelines (e.g., EPRI's secondary water chemistry guidelines and Nuclear Energy Institute (NEI) 97-06). In addition, this program should cover all operational modes.	Conforms. As described in UFSAR Section 10.3.5, the secondary side water chemistry program is in accordance with Reference 1, as required by NEI 97-06, Section 3.7.
Each of the modes should be defined with regard to percent rated thermal power and approximate temperature range.	Conforms. The modes (rated thermal power and approximate temperature range) are specified in the secondary side water chemistry program.
B.2 The secondary water chemistry monitoring and control program should identify a sampling schedule for critical parameters during each mode of operation, as well as the acceptance control criteria for these parameters. At a minimum, the program should control pH, cation conductivity, sodium, and dissolved oxygen. However, other parameters merit consideration, such as specific conductivity, chloride, fluoride, suspended solids, silica, total iron, copper, sulfate, lead, ammonia, and residual hydrazine. Additives to each steam generator should be controlled separately.	Conforms. The secondary side water chemistry program includes the identified content, as applicable.
B.3 The reviewer will evaluate the secondary water chemistry control and monitoring program of each individual plant. Significant deviations from the industry guidelines should be noted and justified technically.	Conforms. The program has no significant deviations from the current industry guidelines.
Records should be made of the monitored item values and should be made available for audit and inspection when deemed necessary.	Conforms. Records are made of the monitored item values through use of the chemistry program procedures.
B.4 Routine changes to the secondary water chemistry control and monitoring program should be reported as part of the biannual FSAR update, as required by 10 CFR 50.71. Changes shall be evaluated in accordance with the requirements of 10 CFR 50	Conforms. Routine FSAR changes to the secondary side water chemistry program are reported as required by 10 CFR 50.71.
Changes shall be evaluated in accordance with the requirements of 10 CFR 50	Conforms. Changes to the program are screened, and evaluated as needed, in accordance with 10 CFR 50.59.

Table 10.3.5-1 (Sheet 2 of 3)
Not Used

Table 10.3.5-1 (Sheet 3 of 3)
Not Used

Table 10.3.5-2
Not Used

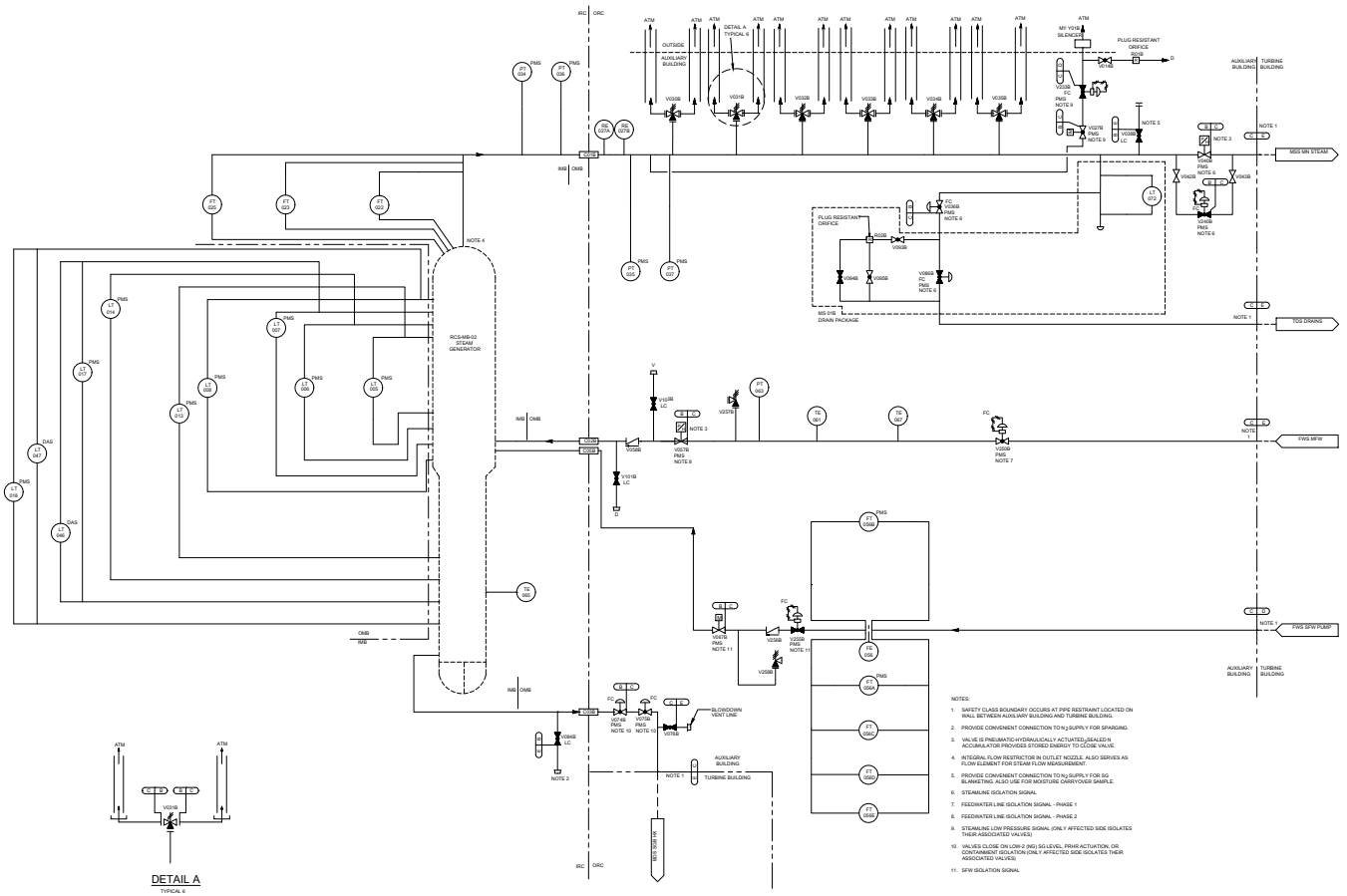
Table 10.3.5-3
Not Used



VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN, BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS, SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

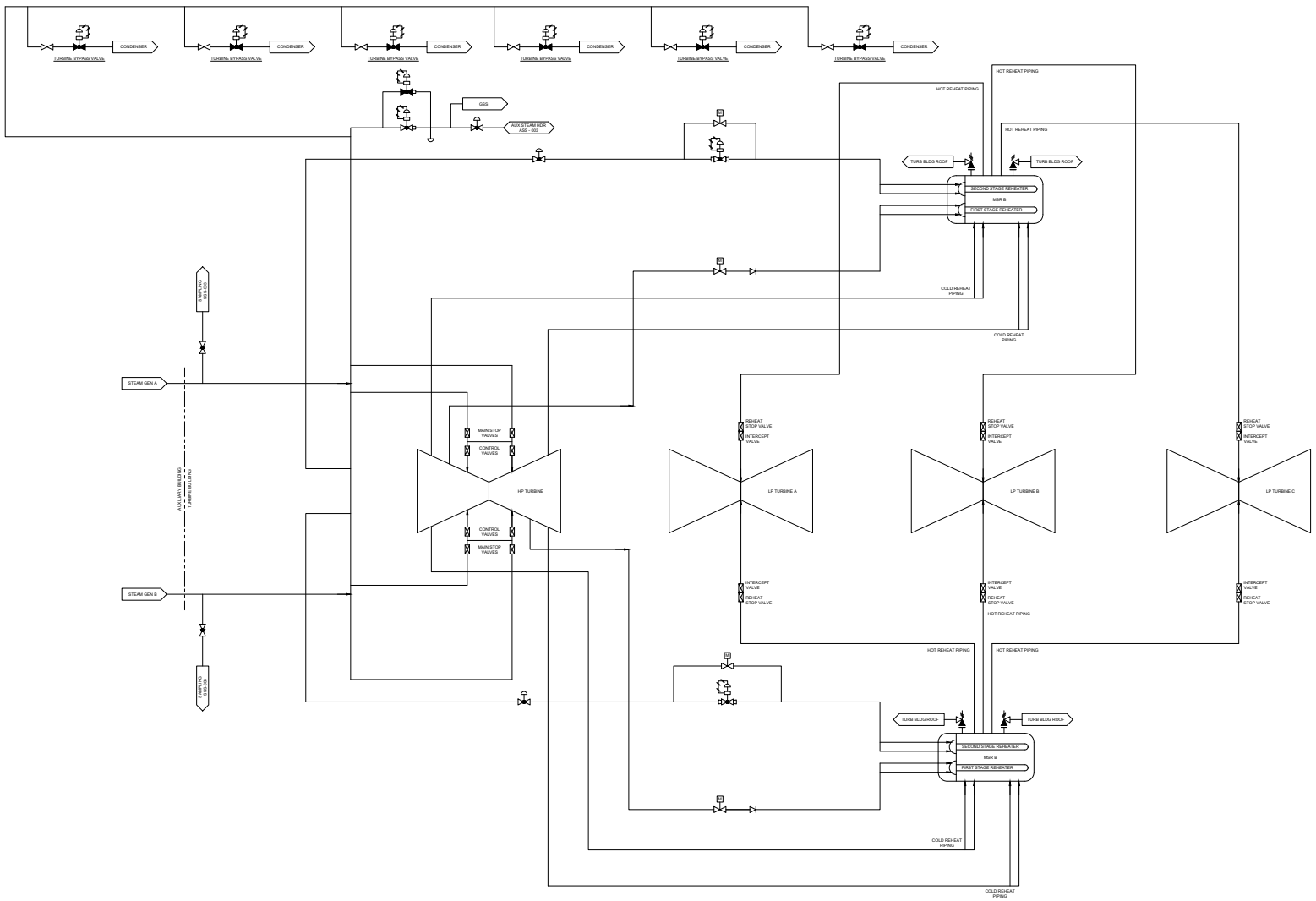
Figure 10.3.2-1 (Sheet 1 of 2)
Simplified Main Steam Piping and Instrumentation Diagram (Safety-Related System)
(REF) SGS 001



VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN, BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS, SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 10.3.2-1 (Sheet 2 of 2)
Simplified Main Steam Piping and Instrumentation Diagram (Safety Related System)
(REF) SGS 002



Inside Turbine Building
Figure 10.3.2-2
Main Steam System Diagram
(REF) MSS 001

10.4 Other Features of Steam and Power Conversion System

This section provides descriptions of each of the principal design features of the steam and power conversion system not in Sections 10.2 and 10.3.

10.4.1 Main Condensers

The main condenser functions as the steam cycle heat sink, receiving and condensing exhaust steam from the main turbine and the turbine bypass system.

10.4.1.1 Design Basis

10.4.1.1.1 Safety Design Basis

The main condenser serves no safety-related function and therefore has no nuclear safety design basis.

10.4.1.1.2 Power Generation Design Basis

The main condenser is designed to receive and condense the full-load main steamflow exhausted from the main turbine and serves as a collection point for vents and drains from various components of the steam cycle system.

The main condenser is designed to receive and condense steam bypass flows up to 40 percent of rated main steam flow while condensing the remaining low-pressure turbine steam flow. This condensing action is accomplished without exceeding the maximum allowable condenser backpressure for main turbine operation.

The condenser hotwell is designed to store at the normal operating water level an amount of condensate equivalent to at least three minutes of full load condensate system operating flow.

The main condenser is designed to deaerate the condensate so that the dissolved oxygen content of the condensate remains under 10 ppb during normal full power operation.

10.4.1.2 System Description

The main condenser is part of the AP1000 condensate system (CDS). The condensate system is described in Subsection 10.4.7 and shown in Figure 10.4.7-1. Classification of equipment and components is given in Section 3.2. Table 10.4.1-1 provides main condenser design data.

The main condenser is a three-shell, single-pass, multipressure, spring-supported unit. Each shell is located beneath its respective low-pressure turbine. The condenser is equipped with titanium or stainless steel tubes. The titanium material provides good corrosion and erosion resisting properties. Freshwater cooled plants do not require the high level corrosion and erosion resistance provided by titanium; therefore, 304L, 316L, 904L, or AL-6X may be substituted if desired.

In a multipressure condenser, the condenser shells operate at slightly different pressures and temperatures. Condensate that is condensed in the low pressure condenser shell drains through internal piping to the high pressure (hottest) shell where it is slightly heated and mixed with condensate of the high pressure shell. Condensate then flows through a single outlet to the suction of the condensate pumps.

The condenser shells are located below the turbine building operating floor and are supported on a spring-mounted foundation from the turbine building basemat. A rigid connection is provided between

each low-pressure turbine exhaust opening and the steam inlet connections of the condenser. Two low-pressure feedwater heaters are located in the neck area of each condenser shell. Piping is installed for hotwell level control and condensate sampling.

10.4.1.2.1 System Operation

During normal power operation, exhaust steam from the low-pressure turbines is directed into the main condenser shells. The condenser also receives auxiliary system flows, such as feedwater heater vents and drains and gland sealing steam spillover and drains.

The hotwell level controller provides automatic makeup or rejection of condensate to maintain a normal level in the condenser hotwells. On low level, the makeup control valves open and admit condensate by vacuum draw to the hotwell from the condensate storage tank. On high-water level the condensate reject control valves open to divert water from the condensate pump discharge to the condensate storage tank. This rejection automatically stops when the hotwell level falls to within normal operating range. Rejection to the storage tank can be manually overridden upon an indication of high-hotwell conductivity to prevent transfer of contaminants into the condensate storage tank in the event of a condenser tube failure.

Air inleakage and noncondensable gases contained in the turbine exhaust steam are collected in the condenser and removed by the main condenser air removal system. The condenser air removal system is discussed further in Subsection 10.4.2.

To protect the condenser shells and turbine exhaust hoods from overpressurization, steam relief blowout diaphragms are provided in the low-pressure turbine exhaust hoods.

The main condenser is capable of accepting up to 40 percent of rated main steam flow from the turbine bypass system. Operation of the turbine bypass system is discussed in Subsection 10.4.4. In the event of high condenser pressure or trip of the circulating water pumps, the turbine bypass valves are prohibited from opening.

Distribution headers are incorporated to protect the condenser tubes, feedwater heaters located in the condenser neck, and other condenser components from turbine bypass or high-temperature drains entering the condenser shell.

The main condenser interfaces with secondary sampling system (SSS) to permit sampling of the condensate in the condenser hotwell. Also, grab sampling capability is provided for each condenser tubesheet. Should circulating water in-leakage occur, these provisions permit determination of which tube bundle has sustained the leakage. Steps may be taken to repair or plug the leaking tubes. This is performed by isolating the circulating water system from the affected water box. Plant power is reduced as necessary. This will temporarily reduce condenser capacity by approximately 50 percent. The water box is then drained and the affected tubes are either repaired or plugged. Refer to Subsection 10.3.5.5 for a discussion regarding action levels for abnormal secondary cycle chemistry conditions.

A condenser tube cleaning system performs mechanical cleaning of the circulating water side of the tubes. This cleaning, along with chemical treatment of the circulating water, reduces fouling and helps to maintain the thermal performance of the condenser.

10.4.1.3 Safety Evaluation

The main condenser has no safety-related function and therefore requires no nuclear safety evaluation.

During normal operation and shutdown, the main condenser has no significant inventory of radioactive contaminants. Radioactive contaminants may enter through a steam generator tube leak. A discussion of the radiological aspects of primary-to-secondary leakage, including anticipated operating concentrations of radioactive contaminants, is included in Chapter 11. No hydrogen buildup in the main condenser is anticipated. The failure of the main condenser and any resultant flooding will not preclude operation of any essential system since no safety-related equipment is located in the turbine building and the water cannot reach safety-related equipment located in Category I plant structures.

10.4.1.4 Tests and Inspections

The condenser water boxes are hydrostatically tested at the fabrication facility, prior to field assembly. After erection, the condenser shells are tested in accordance with Reference 1. Tube joints are leak tested during construction.

10.4.1.5 Instrumentation Applications

The main condenser hotwell is equipped with level control devices for control of automatic makeup and rejection of condensate. Condensate level in the condenser hotwell is indicated in the main control room and alarms on high or low level.

Condenser pressure for each condenser shell is indicated in the main control room and alarms on high level. Also, pressure instrumentation is provided to alarm prior to reaching the maximum turbine operating backpressure limit. Pressure devices are provided to trip the main turbine on high turbine exhaust pressure.

Temperature indication for monitoring condenser performance is provided.

10.4.2 Main Condenser Evacuation System

Main condenser evacuation is performed by the condenser air removal system (CMS). The system removes noncondensable gases and air from the main condenser during plant startup, cooldown, and normal operation. This action is provided by liquid ring vacuum pumps.

10.4.2.1 Design Basis

10.4.2.1.1 Safety Design Basis

The condenser air removal system serves no safety-related function and therefore has no nuclear safety design basis.

10.4.2.1.2 Power Generation Design Basis

- The condenser air removal system removes air and noncondensable gases from the condenser during plant startup, cooldown, and normal operation from the steam side of the three main condenser shells and exhausts them into the atmosphere.

- The system establishes and maintains a vacuum in the condenser during startup and normal operation by the use of liquid ring vacuum pumps.

10.4.2.2 System Description

10.4.2.2.1 General Description

Classification of equipment and components is given in Section 3.2.

The air removal system consists of four liquid ring vacuum pumps that remove air and noncondensable gases from the three condenser shells during normal operation and provide condenser hogging during startup. One vacuum pump is provided for each condenser shell, and one pump is provided as a standby. The noncondensable gases, together with a quantity of vapor, are drawn through the air cooler sections of condenser shells to the suction of the vacuum pumps. These noncondensables consist mainly of air, nitrogen, and ammonia. No hydrogen buildup is anticipated in the system (see Subsection 10.4.1.3). Dissolved oxygen is present in the condensate and condenser hotwell inventory. Only trace amounts of this oxygen are released in the condenser, and the amounts are negligible compared to the amount of gas and vapor being evacuated by the system. Therefore, the potential for explosive mixtures within the condenser air removal system does not exist.

The circulating water system (CWS) provides the cooling water for the vacuum pump seal water heat exchangers. The seal water is kept cooler than the saturation temperature in the condenser to maintain satisfactory vacuum pump performance.

The noncondensable gases and vapor mixture discharged to the atmosphere are not normally radioactive. However, it is possible for the mixture to become contaminated in the event of primary-to-secondary system leakage. Air inleakage and noncondensable gases removed from the condenser and discharged by the vacuum pumps are routed to the turbine island vents, drains, and relief system (TDS) and monitored for radioactivity. Upon detection of unacceptable levels of radiation, operating procedures are implemented. A discussion of the radiological aspects of primary-to-secondary leakage, including anticipated release from the system, is included in Chapter 11.

The discharge from the condenser air removal system has a connection for taking local grab samples. Connections also allow the installation of portable, continuous sampling equipment.

Should the condenser air removal system become inoperable, a gradual increase in condenser back pressure would result from the buildup of noncondensable gases. This increase in backpressure would cause a decrease in the turbine cycle efficiency. If the condenser air removal system remains inoperable, condenser backpressure increases to the turbine trip setpoint, and a turbine trip is initiated. Loss of the main condenser vacuum causes a turbine trip but does not close the main steam isolation valves. A loss of condenser vacuum incident is described in Subsection 15.2.5.

10.4.2.2.2 Component Description

The liquid ring vacuum pumps are supplied as packaged units. Major components in each package include a vacuum pump, seal water heat exchanger, seal water pump, and air/water separator. Seal water is supplied to seal the clearances in the pump and also to condense vapor at the inlet to the pump. Seal water flows through one side of the seal water heat exchanger and circulating water flows through the other side. Seal water make up is provided by the demineralized water transfer and storage system (DWS).

Piping and valves are carbon steel. The piping is designed to ASME B31.1.

10.4.2.2.3 System Operation

During startup operation, air is removed from the condenser by operating three liquid ring vacuum pumps. The fourth pump is on standby.

During normal plant operation, noncondensable gases are removed from the condenser by three vacuum pumps. If one pump trips, the condition is alarmed in the main control room, and the standby pump is started.

10.4.2.3 Safety Evaluation

The condenser air removal system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.2.4 Tests and Inspections

Testing and inspection of the system is performed prior to plant operation. A performance test is conducted on each pump in accordance with Reference 2. In addition, the pumps are hydrostatically tested.

10.4.2.5 Instrumentation Applications

The effectiveness of the air removal system is indicated by monitoring condenser pressure, using instrumentation described in Subsection 10.4.1.5. Vacuum pump skid status (enabled/disabled) is indicated in the main control room, and pump trips are alarmed.

Volumetric flow indication is provided to monitor the quantity of exhausted noncondensable gases.

A radiation detector monitors the discharge of the condenser vacuum pumps through the turbine island vents, drains, and relief system (TDS). The radiation detector is indicated and alarmed. For process and effluent radiological monitoring and sampling systems, refer to Section 11.5.

10.4.3 Gland Seal System

10.4.3.1 Design Basis

10.4.3.1.1 Safety Design Basis

The gland seal system (GSS) serves no safety-related function and therefore has no nuclear safety design basis.

10.4.3.1.2 Power Generation Design Basis

- The gland seal system prevents air leakage into and steam leakage out of the casings of the turbine-generator.
- The system returns condensed steam to the condenser and exhausts noncondensable gases into the atmosphere via the turbine island vents, drains, and relief system.
- The presence of radioactive contamination in the noncondensable gas exhausted from the gland seal condenser, is detected by a radiation monitor in the turbine island vents, drains, and relief system.

10.4.3.2 System Description

10.4.3.2.1 General Description

The gland seal system consists of the following items and assemblies:

- Steam supply header
- Steam drains/noncondensable gas exhaust header
- Two motor driven gland seal condenser exhaust blowers
- Associated piping, valves, and controls
- Gland seal condenser
- Vent and drain lines

The quality group standards for the gland seal system are provided in Section 3.2. The gland seal system is shown in Figure 10.4.3-1.

10.4.3.2.2 System Operation

The annular space through which the turbine shaft penetrates the turbine casing is sealed by steam supplied to the rotor glands. Where the packing seals against positive pressure, the sealing steam connection acts as a leakoff. Where the packing seals against vacuum, the sealing steam either is drawn into the casing or leaks outward to a vent annulus maintained at a slight vacuum. The vent annulus receives air leakage from the outside. The air-steam mixture is drawn to the gland seal condenser.

Sealing steam is distributed to the turbine shaft seals through the steam-seal header. This sealing steam is supplied from either the auxiliary steam system (ASS), or from main steam (MSS), extracted ahead of the high-pressure turbine control valves. Steam flow to the header is controlled by the steam-seal feed valve which responds to maintain the steam-seal supply header pressure. The low and high pressure turbine gland steam pressures are maintained by pressure regulating valves provided in both main steam and auxiliary steam system piping. Excess steam is returned to Condenser A via the spillover control valve which automatically opens to bypass excess steam from the GSS.

During the initial startup phase of turbine-generator operation, steam is supplied to the gland seal system from the auxiliary steam header which is supplied from the auxiliary boiler. At times other than initial startup, turbine-generator sealing steam is supplied from the MSV and CV gland steam leak-off, the auxiliary steam system, or from main steam.

At the outer ends of the glands, collection piping routes the mixture of air and excess seal steam to the gland seal condenser. The gland seal condenser is a shell and tube type heat exchanger where the steam-air mixture from the turbine seals is discharged into the shell side and condensate flows through the tube side as a cooling medium. The gland seal condenser internal pressure is maintained at a slight vacuum by a motor-operated blower. There are two 100-percent blowers mounted in parallel. Condensate from the steam-air mixture drains to the main condenser while noncondensables are exhausted to the turbine island vents, drains, and relief system through a common discharge line shared by the vapor extractor blowers.

The mixture of noncondensable gases discharged from the gland seal condenser blower is not normally radioactive; however, in the event of significant primary-to-secondary system leakage due to a steam generator tube leak, it is possible to discharge radioactively contaminated gases. The headered discharge line vents to the turbine vents, drains, and relief system which contains a radiation monitor for detection of radioactivity. Upon detection of unacceptable levels of radiation,

operating procedures are implemented. A description of the radiological aspects of primary-to-secondary system leakage is included in Chapter 11.

Failure of the gland seal system normally results in no release of radioactivity to the atmosphere.

10.4.3.3 Safety Evaluation

The gland seal system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.3.4 Tests and Inspections

The system is tested in accordance with written procedures during the initial testing and operation program. Since the gland seal system is in use and essential parameters are monitored during normal plant operation, the satisfactory operation of the system components demonstrates system operability.

10.4.3.5 Instrumentation Applications

A pressure controller is provided to maintain the steam-seal supply header pressure by providing signals to the steam-seal feed valve. Excess steam flow is handled by the gland spillover control valve which discharges to Condenser A.

The gland seal condenser is monitored for shell side pressure and internal liquid level.

Pressure indication with appropriate alarm is provided for monitoring the operation of the system. A radiation detector with an alarm is provided in the turbine island vents, drains, and relief system to detect radiation associated with primary-to-secondary side leakage in the steam generators.

10.4.4 Turbine Bypass System

The turbine bypass system provides the capability to bypass main steam from the steam generators to the main condenser in a controlled manner to dissipate heat and to minimize transient effects on the reactor coolant system during startup, hot shutdown, cooldown, and step-load reductions in generator load. The turbine bypass system is also called the steam dump system, and is part of the main steam system (MSS).

10.4.4.1 Design Basis

10.4.4.1.1 Safety Design Basis

The turbine bypass system serves no safety-related function and therefore has no nuclear safety design basis. The nonsafety-related turbine bypass valves are credited in a single failure analysis to mitigate the event for those cases in which the rupture of the main steam or feedwater piping inside containment is the postulated initiating event.

10.4.4.1.2 Power Generation Design Basis

The turbine bypass system has the capacity to bypass up to 40 percent of rated main steam flow to the main condenser.

The turbine bypass system bypasses steam to the main condenser during plant startup and permits a manually controlled cooldown of the reactor coolant system to the point where the normal residual heat removal system can be placed in service.

The turbine bypass system total flow capacity, in combination with bypass valve response time, reactor coolant system design, and reactor control system response, is sufficient to reduce challenges to the main steam power-operated relief valves, main steam safety valves, and pressurizer safety valves during: reactor trip from 100-percent power; and 100-percent load rejection or turbine trip from 100-percent power without reactor trip.

10.4.4.2 System Description

10.4.4.2.1 General Description

The turbine bypass system is part of the main steam system and is shown on Figure 10.3.2-2. The system consists of a manifold connected to the main steam lines upstream of the turbine stop valves and of lines from the manifold with regulating valves to each condenser shell.

The capacity of the system, along with the NSSS control systems, provides the capability to meet the design requirement bases specified in Subsection 10.4.4.1.2. For power changes less than or equal to a 10 percent change in electrical load, the turbine bypass system is not actuated; the total power change is handled by the reactor power control, pressurizer level control, pressurizer pressure control, and the steam generator level control systems described in Section 7.7. For load rejections greater than 10 percent but less than 50 percent, or a turbine trip from 50 percent power or less, the turbine bypass system operates in conjunction with the same control systems used for the 10 percent or less load change to meet the design basis requirements specified in Subsection 10.4.4.1.2. For load rejections greater than 50 percent power, the rapid power reduction system (described in Section 7.7) operates in conjunction with the previously mentioned control systems to meet the design basis requirements. The rapid power reduction system is designed to rapidly reduce the nuclear power to a value that can be handled by the turbine bypass system. Certain transient conditions or system degradations beyond those of Subsection 10.4.4.1.2 may result in a reactor trip and may result in the operation of the main steam power operated relief and safety valves.

10.4.4.2.2 Component Description

The turbine bypass valves are globe valves and are electropneumatically operated. The valves fail to a closed position upon loss of air or electric signal. A modulating positioner responds to the electric signal from the control system and provides an appropriate air pressure to the valve actuator for modulating the valve open.

Solenoid valves located in the air line to each bypass valve actuator serve as protective interlocks for bypass valve actuation and for tripping the valve open or closed. One of the solenoid valves is energized, when required, to bypass the modulating positioner and provide full air pressure to the actuator to quickly trip open the bypass valve. Other solenoid valves, when deenergized, block the air supply to the actuator and vent the actuator; this action blocks the bypass valve from opening, or closes the valve if opened.

Two of the blocking solenoid valves for each turbine bypass valve are redundant and block bypass valve actuation upon low reactor coolant system T_{avg}. This minimizes the possibility of excessive reactor coolant system cooldown. However, the low T_{avg} block can be manually bypassed for the bypass valves that are designated as cooldown valves to allow operation during plant cooldown.

Another blocking solenoid valve prevents actuation of the bypass valve when the condenser is not available. This solenoid valve also prevents unblocking the steam dump valve when the condenser is available unless one of the following signals exist:

- High negative rate of change of turbine pressure
- Reactor trip

- Control system in the steam header pressure control mode (see Subsection 10.4.4.3)

10.4.4.3 System Operation

The turbine bypass system has two modes of operation:

- T_{avg} control mode
- Pressure control mode

The T_{avg} control mode is the normal at-power control mode. The turbine bypass system is regulated by the difference between the measured reactor coolant system average coolant temperature (T_{avg}) and a T_{avg} setpoint derived from turbine first-stage pressure. This prevents a large increase in reactor coolant temperature following a large, sudden load decrease. Turbine bypass valve control in conjunction with reactor power control results in a match between reactor power and turbine load.

The pressure control mode is used to remove decay heat during plant startup and cooldown and to control steam pressure following a reactor trip. The difference between steam header pressure and a pressure setpoint is used to control the turbine bypass flow. The pressure setpoint is manually adjustable and is based on the desired reactor coolant system temperature. The turbine bypass system is operated in the pressure control mode when the plant is at no-load and there is no turbine load reference. There are three pressure control operational modes as follows:

- Header pressure – control derived from the difference between header pressure and pressure setpoint

- Cooldown – control derived from the manually selected desired reactor coolant system cooldown rate and the target reactor coolant system temperature

- Manual – control derived from direct use of valve loading signals.

The bypass valves are divided into two banks. The banks are opened sequentially; the second bank starts to open only after a demand signal that is greater than the full-open demand of the first bank is generated.

The turbine bypass valves have two stroke control modes, modulate and trip open/close. If the demand signal is greater than the full open demand for the particular bank of valves, a trip open demand signal is generated. When the demand signal decreases below the full-open demand, the trip open demand clears and the valves return to the modulating mode. Additional description of steam dump logic is given in Section 7.7.

Chapter 15 addresses credible single failures of the turbine bypass system. If the bypass valves fail-open, additional heat load is placed on the condenser. If this load is great enough, the turbine is tripped on high condenser pressure. Ultimate overpressure protection for the condenser is provided by turbine rupture discs. If the bypass valves fail-closed, the power operated relief valves (reference Subsection 10.3.2.2.3) permit controlled cooldown of the reactor.

10.4.4.4 Safety Evaluation

There is no safety-related equipment in the vicinity of the turbine bypass system. The high-energy lines of the turbine bypass system are located in the turbine building.

The failure of a turbine bypass high-energy line will not disable the turbine speed control system. The turbine speed control system is designed in such a manner that its failure will cause a turbine trip. Additional information concerning speed control can be found in Subsection 10.2.2.3.

10.4.4.5 Inspection and Testing Requirements

Before the system is placed in service, turbine bypass valves are tested to verify they function properly. Leaktightness of the steam lines is confirmed by an initial service test. System piping and valves are accessible for inspection. No inservice inspection and testing is required except for the turbine bypass valves which are included in the inservice program as discussed in Subsection 3.9.6.

10.4.4.6 Instrumentation Applications

Turbine bypass controls are described in Section 7.7. Controls in the main control room are provided for selection of the system operating mode. Pressure indication and valve position indication are also provided in the main control room.

10.4.5 Circulating Water System

10.4.5.1 Design Basis

10.4.5.1.1 Safety Design Basis

The circulating water system (CWS) serves no safety-related function and therefore has no nuclear safety design basis.

10.4.5.1.2 Power Generation Design Basis

The CWS supplies cooling water to remove heat from the main condensers. The CWS also supplies cooling water to the turbine building closed cooling water system (TCS) heat exchangers and the condenser vacuum pump seal water heat exchangers under varying conditions of power plant loading and design weather conditions.

10.4.5.2 System Description

10.4.5.2.1 General Description

Classification of components and equipment in the circulating water system is given in Section 3.2.

The CWS and the cooling tower provide a heat sink for the waste heat exhausted from the steam turbine. Additional cooling is supplied from the CWS through a tap in the main supply header for the TCS heat exchangers and the condenser vacuum pump seal water heat exchangers. CWS design parameters are provided in Table 10.4.1-1and Table 10.4.5-1.

The CWS consists of four 25-percent-capacity circulating water pumps, one hyperbolic natural draft cooling tower (NDCT), and associated piping, valves, and instrumentation.

Makeup water to the CWS is provided by the raw water system (RWS). In addition, water chemistry is controlled by a local chemical feed system.

10.4.5.2.2 Component Description

Circulating Water Pumps

The four circulating water pumps are vertical, wet pit, single-stage, mixed-flow pumps driven by electric motors. The pumps are mounted in a pump pit, which is attached to the cooling tower basin. The four pump discharge lines connect to a common header which connects to the two inlet water boxes of the condenser and may also supply cooling water to the TCS and condenser vacuum pump seal water heat exchangers. Each pump discharge line has a motor-operated butterfly valve located

between the pump discharge and the main header. This permits isolation of one pump for maintenance and allows for three-pump operation.

Cooling Tower

The hyperbolic NDCT is designed to reject the full-load waste heat to the atmosphere by evaporation as the circulating water passes through the heat exchanger section. The cooling tower is designed to cool the circulating water to 90.9°F based on a design wet bulb temperature of 77°F.

The cooling tower is located approximately 1000 ft. south of the plant and has a basin water level of approximately 222 ft. MSL. Should a cooling tower basin wall break, little, if any, water would reach the plant because of the remote location of the tower and the grading of the site. The height of the cooling tower is approximately 600 ft., thus, there is no potential for the cooling tower to fall and damage safety related structures or components. Because of the remote location, the cooling tower height, and the buoyant rise of the plumes, the plumes will dissipate before they interfere with the SWS cooling towers intake, any plant ventilation intake, or the plant switchyard. Because of the height of cooling tower it is unlikely there will be fogging near the plant as a result of the cooling tower plume.

Cooling Tower Makeup and Blowdown

The circulating water system makeup is provided by the raw water system. In addition, a small portion of Service Water System (SWS) flow is normally diverted to the circulating water system cooling tower basins as blowdown to control the level of solids concentration in the SWS. Makeup to and blowdown from the CWS is controlled by the makeup and blowdown control valves. The makeup control valves maintain the cooling tower basin level. These valves, along with a local chemical feed system, provide chemistry control in the circulating water in order to maintain a noncorrosive, nonscale-forming condition and limit biological growth in CWS components.

Piping and Valves

The underground portions of the CWS piping are constructed of prestressed concrete cylinder pipe (PCCP). The remainder of the piping is carbon steel and is coated internally with a corrosion-resistant compound. The primary drainage path for the condenser water boxes and tube bundles is via gravity to the cooling tower basins using the service water blowdown line (Subsection 9.2.1.2.2). As an alternate, condenser water box drain lines are provided that direct drainage to the turbine building sumps. Motor-operated butterfly valves are provided in each of the circulating water lines at their inlet to and exit from the condenser shell to allow isolation of portions of the condenser. Control valves provide regulation of cooling tower makeup and blowdown.

The circulating water system is designed to withstand the maximum operating discharge pressure of the circulating water pumps. Piping includes the expansion joints, butterfly valves, condenser water boxes, and tube bundles. Due to differences in distance and elevation from the circulating water pumps, CWS components and piping have different design working pressures. The design working pressure rating of each component exceeds the maximum operating discharge pressure developed by the circulating water pumps at the location of each component. The design working pressures for each component are listed below.

Component	Design Working
Steel Pipe	150 psi
PCCP Pipe	100 psi
Expansion Joints	90 psi
Condenser Tube Bundle	90 psi
Water Box	90 psi

Circulating Water Chemical Injection

Circulating water chemistry is maintained by a local chemical feed skid at the CWS cooling tower. Circulating water system chemical feed equipment injects the required chemicals into the circulating water at the CWS cooling tower basin area. This maintains a noncorrosive, nonscale-forming condition and limits the biological film formation that reduces the heat transfer rate in the condenser and the heat exchangers supplied by the circulating water system.

The specific chemicals used within the system are determined by the site water conditions and are monitored by plant chemistry personnel.The chemicals can be divided into six categories based upon function: biocide, nonoxidizing biocide, pH adjuster, corrosion inhibitor, scale inhibitor, and a silt dispersant. The pH adjuster, corrosion inhibitor, scale inhibitor, and dispersant are metered into the system continuously or as required to maintain proper concentrations. The biocide application frequency may vary with seasons. The biocide, and/or nonoxidizing biocide is applied, as necessary, to control algae formation on the cooling tower.

Table 6.4-201 lists the typical classes and examples of chemicals used on site. The specific chemicals are varied based on water conditions and as water chemistry technology changes. Any chemicals used, including vendor proprietary chemicals, are approved per procedure by plant personnel to ensure compliance with site health, safety and environmental requirements (including control room habitability), the CWS water quality requirements, and to maintain compliance with site environmental permits for water discharge.

Bulk chlorine gas is not used for chemical control. Chlorine containing chemicals (e.g., sodium hypochlorite) that could react to produce free chlorine gas are stored in separate bermed areas from chemicals that would cause such a reaction (e.g., strong acids).

Addition of biocide and water treatment chemicals is performed by local chemical feed injection metering pumps and is adjusted as required. Chemical concentrations are measured through analysis of grab samples from the CWS. Residual chlorine is measured to monitor the effectiveness of the biocide treatment.

10.4.5.2.3 System Operation

The four circulating water pumps take suction from the circulating water pump pit and circulate the water through the tube side of the main condenser, with smaller flows to the TCS, the condenser vacuum pump seal water heat exchangers, and back through the piping discharge network to the NDCT. See Figure 10.4-201. The NDCT cools the circulating water by discharging the water through nozzles in the tower distribution headers. The water is then diffused through fill material to the basin beneath the tower and, in the process, rejects heat to the atmosphere. Provisions are made during freezing weather to minimize the possibility of ice accumulation.

Isolation of portions of the cooling tower and bypass of flow directly into the basin are both accomplished via manipulation of the flume slide gates. Closing the flume slide gates takes a portion of the tower out of service and can be used to prevent freezing conditions within the tower.

The raw water system supplies makeup water to the cooling tower basin to replace water losses due to evaporation, wind drift, and blowdown. A separate connection is also provided between the RWS and CWS to fill the CWS piping.

A condenser tube cleaning system is installed to clean the circulating water side of the main condenser tubes. Blowdown from the CWS is taken from the discharge of the CWS pumps and is discharged to the plant outfall.

The circulating water system is used to supply cooling water to the main condenser to condense the steam exhausted from the main turbine. If the circulating water pumps, the cooling tower, or the circulating water piping malfunction such that condenser backpressure rises above the maximum allowable value, the main condenser will no longer be able to adequately support unit operation. Cooldown of the reactor may be accomplished by using the power-operated atmospheric steam relief valves or safety valves rather than the turbine bypass system when the condenser is not available.

Passage of condensate from the main condenser into the circulating water system through a condenser tube leak is not possible during power generation operation, since the circulating water system operates at a greater pressure than the condenser.

Turbine building closed cooling water in the TCS heat exchangers is maintained at a higher pressure than the circulating water to prevent leakage of the circulating water into the closed cooling water system.

Cooling water to the condenser vacuum pump seal water heat exchangers is supplied from the circulating water system. Cooling water flow from the circulating water system is normally maintained through all four heat exchangers to facilitate placing the spare condenser vacuum pump in service. Isolation valves are provided for the condenser vacuum pump seal water heat exchanger cooling water supply lines to facilitate maintenance.

Small circulating water system leaks in the turbine building will drain into the waste water system. Large circulating water system leaks due to pipe failures will be indicated in the control room by a loss of vacuum in the condenser shell. The effects of flooding due to a circulating water system failure, such as the rupture of an expansion joint, will not result in detrimental effects on safety-related equipment since there is no safety-related equipment in the turbine building and the base slab of the turbine building is located at grade elevation. Water from a system rupture will run out of the building through a relief panel in the turbine building west wall before the level could rise high enough to cause damage. Site grading will carry the water away from safety-related buildings.

The cooling tower is located so that collapse of the tower has no potential to damage equipment, components, or structures required for safe shutdown of the plant.

10.4.5.3 Safety Evaluation

The circulating water system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.5.4 Tests and Inspections

Components of the circulating water system are accessible as required for inspection during plant power generation. The circulating water pumps are tested in accordance with standards of the Hydraulic Institute. Performance, hydrostatic, and leakage tests associated with preinstallation and preoperational testing are performed on the circulating water system. The system performance and structural and leaktight integrity of system components are demonstrated by continuous operation.

Thermal performance of the cooling towers is tested and verified using established industry test standards.

10.4.5.5 Instrumentation Applications

Instrumentation provided indicates the open and closed positions of motor-operated butterfly valves in the circulating water piping. Controls and interlocks are in place to ensure the safe operation of the pumps. Alarms will alert plant operators to any abnormal conditions and to take action accordingly.

Local grab samples are used to periodically test the circulating water quality to limit harmful effects to the system piping and valves due to improper water chemistry.

Pressure indication is provided on the circulating water pump discharge lines.A differential pressure transmitter is provided between one inlet and outlet branch to the condenser. This differential pressure transmitter is used to determine the frequency of operating the condenser tube cleaning system (CES).

Temperature indication is supplied on the common CWS inlet header to the TCS heat exchanger trains.This temperature is also representative of the inlet cooling water temperature to the main condenser.

A flow element is provided on the common discharge line from the TCS heat exchangers to allow monitoring of the total flow through the TCS heat exchangers.Flow measurement for the raw water makeup to the cooling tower and for the cooling tower blowdown is also provided.

Level instrumentation provided in the cooling tower basin activates makeup flow from the RWS to the cooling tower basin. Level instrumentation also annunciates a Low-2 water level, Low level, and a High water level in the pump structure, and Low and High water levels in the cooling tower basin.

The circulating water chemistry is controlled by regulating cooling tower blowdown and by chemical addition, to maintain the circulating water with an acceptable Langelier Index and is maintained in range established by plant chemistry personnel. The system accomplishes this by regulating the blowdown valve. This regulation causes the tower basin water level to fluctuate. The fluctuation is sensed by a level controller that operates the makeup valve to the cooling tower basin.

The control approach is to allow the makeup water to concentrate naturally to its upper limit. Provisions are made to add chemicals for pH control.

The cycles of concentration at which the cooling tower is operated is dependent on the quality of the cooling tower makeup water.Cooling tower blowdown is discharged to the Savannah River via the waste water system.

Monitoring of the circulating water system is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. See Chapter 7.

10.4.6 Condensate Polishing System

The condensate polishing system (CPS) can be used to remove corrosion products and ionic impurities from the condensate system during plant startup, hot standby, power operation with abnormal secondary cycle chemistry, safe shutdown, and cold shutdown operations.

10.4.6.1 Design Basis

10.4.6.1.1 Safety Design Basis

The condensate polishing system serves no safety-related function and therefore has no nuclear safety-related design basis.

10.4.6.1.2 Power Generation Design Basis

The power generation design bases are to:

- Remove corrosion products, dissolved solids and other impurities from the condensate system and maintain a noncorrosive environment within the condensate, feedwater and steam generator systems
- Provide polishing capacity for processing one-third of the maximum condensate flow in a sidestream arrangement
- Provide polishing capability during normal startup and shutdown operations of the plant
- Provide for plant operation with a “continuous” condenser tube leak of .001 gpm or a “faulted” leak of 0.1 gpm until repairs can be completed or until an orderly shutdown is achieved

10.4.6.2 System Description

The condensate polishing system is used during operating modes of startup, hot standby, power operation with abnormal secondary cycle chemistry, safe shutdown, and cold shutdown. Classification of components in the CPS is identified in Section 3.2. The major components for the condensate polishing system are described below. The condensate polishing system is shown in Figure 10.4.6-1.

Deep Bed Mixed Resin Polishers

The polisher vessels are constructed of carbon steel with a protective rubber lining on the inside of the vessel. Level indication (site glass) is provided.

Resin Trap

The resin traps are located in the effluent piping of the vessels. Differential pressure across the trap is monitored.

Spent Resin Tank

The spent resin tank is constructed of carbon steel with an interior protective rubber lining. It is used for storage of exhausted or spent resin prior to shipping offsite for regeneration or disposal.

Resin Addition Hopper and Eductor

The resin addition hopper stores regenerated or new resin and the eductor is used to inject resin into the polisher vessels. The hopper is constructed of carbon steel. The eductor uses demineralized water to transfer the resin to the vessels.

10.4.6.3 System Operation

The condensate polishing system cleans up the condensate during startup to meet condensate and feedwater system water chemistry specifications as described in Subsection 10.3.5. The condensate system is recirculated to the hotwell during startup until the desired water quality is attained. Condensate system startup operation is described in Subsection 10.4.7. Utilization of the condensate polishing system during startup assists in minimizing the startup duration of the plant.

During power operation, the condensate polishers are used only when abnormal secondary cycle conditions exist. This allows for continued operation of the plant with a “continuous” condenser tube leak of 0.001 gpm or a “faulted” leak of 0.1 gpm until repairs can be made or until an orderly shutdown is achieved. The condensate polisher flow is controlled by the condensate polisher bypass valve.

Exhausted or spent resin is removed from the vessels and replaced with new or regenerated resin. Resin replacement requires the polisher vessel to be out of service. Spent resin is transferred directly from the polisher vessel to a truck or to the spent resin tank until it can be removed offsite. Spent condensate polishing resin will normally be nonradioactive and not require any special packaging prior to disposal. In the event of radioactive contamination of the resin in a vessel, temporary shielding is installed (if required). Radioactive resin is transferred directly from the condensate polishing vessel or from the spent resin tank to a temporary processing unit. Radiation monitors associated with the steam generator blowdown system, the steam generator system (main steam), and the turbine island vents, drains and relief system provide the means to determine if the secondary side is radioactively contaminated. Subsection 11.4.2 describes waste management of radioactively contaminated resin. A spill containment barrier is provided to contain spent resin tank or condensate polisher vessel contents in the event of a tank failure. The spill containment barrier is a curb surrounding the area containing the spent resin tank and condensate polisher vessels with sufficient height to contain the contents of a full tank or vessel.

The procedures for radiation protection and the handling and processing of radwaste are addressed in Chapters 11 and 12. Shielding design is described in Section 12.3.

Upon removal of the exhausted resin from the polisher vessel, the vessel is rinsed and the new resin is placed in the vessel using the resin addition hopper and eductor. After the new cation and anion resins are placed in the vessel, demineralized water is added until the water level is just above the resin bed. Compressed air from the plant service air system is injected up through the resin bed to fluidize and thoroughly mix the resins. Prior to plant startup, a new resin bed is rinsed and resin performance is verified, with flow through the vessel discharged to the waste water system. The polisher vessel is then placed in operation or on standby.

10.4.6.4 Safety Evaluations

The condensate polishing system has no safety-related function and therefore requires no nuclear safety evaluation.

10.4.6.5 Tests and Inspections

The condensate polishing system is operationally checked prior to plant startup to verify proper functioning of the polisher vessels and associated instrumentation and controls.

10.4.6.6 Instrument Applications

When the condensate polishing system is in service, polishing system differential pressure instrumentation provides a control signal to the condensate bypass valve which maintains sufficient flow through the polisher vessels for optimum performance. One or both polisher(s) is/are removed from service when: 1) a high differential pressure exists across the polisher vessel, 2) the ion exchange resin capacity becomes exhausted as evidenced by a high effluent conductivity, or 3) at the completion of a pre-determined volume through-put. The resin traps are monitored for high differential pressure and an alarm indicates the need to backwash the trap.

10.4.7 Condensate and Feedwater System

The condensate and feedwater system provides feedwater at the required temperature, pressure, and flow rate to the steam generators. Condensate is pumped from the main condenser hotwell by the condensate pumps, passes through the low-pressure feedwater heaters to the feedwater pumps, and is then pumped through the high-pressure feedwater heaters to the steam generators.

The condensate and feedwater system is composed of components from the condensate system (CDS), main and startup feedwater system (FWS), and steam generator system (SGS). The startup feedwater system is described in Subsection 10.4.9.

10.4.7.1 Design Basis

10.4.7.1.1 Safety Design Basis

The safety-related portion of the system is required to function following a design basis accident (DBA) to provide containment and feedwater isolation, as discussed below, for the main lines routed into containment.

The portion of the feedwater system from the steam generator inlets outward through the containment up to and including the main feedwater isolation valves (MFIVs) is constructed in accordance with the requirements of ASME Code, Section III for Class 2 components and is designed to seismic Category I requirements. The portion of the feedwater system from the main feedwater isolation valve (MFIV) inlets to the piping restraints at the interface between the auxiliary building and the turbine building is constructed in accordance with the requirements of ASME Code, Section III for Class 3 components and is designed to seismic Category I requirements.

The system provides redundant isolation valves, as described below, for the main feedwater lines routed into containment. The isolation valves close after receipt of an isolation signal in sufficient time to limit the mass and energy release to containment consistent with the containment analysis presented in Chapter 6.

- The safety-related portions of the feedwater system are designed to remain functional after a safe shutdown earthquake (SSE) and to perform their intended function of isolating feedwater flow following postulated events.

- The safety-related portions of the feedwater system are protected from wind and tornado effects, as described in Section 3.3; flood protection is described in Section 3.4; missile protection is described in Section 3.5; protection against dynamic effects associated with the postulated rupture of piping is described in Section 3.6; seismic protection is described in Section 3.7; environmental design is described in Section 3.11; and fire protection is described in Section 9.5.

- The portion of the feedwater system to be constructed in accordance with ASME Code, Section III, Class 2 requirements is provided with access to welds and removable insulation for inservice inspection, in accordance with ASME Code, Section XI. The portion of the feedwater system to be constructed in accordance with ASME Code, Section III, Class 3 requirements is also designed and configured to accommodate inservice inspection in accordance with ASME Code, Section XI.

- The condensate and feedwater system classification is described in Section 3.2. The control functions and power supplies are described in Chapters 7 and 8.

- For a main feedwater or main steam line break (MSLB) inside the containment, the condensate and feedwater system is designed to limit high energy fluid to the broken loop. High energy line break for piping not qualified for leak before break (LBB) criteria is discussed in Subsection 3.6.3.

- Double valve main feedwater isolation is provided via the main feedwater control valve (MFCV) and main feedwater isolation valve (MFIV). Valves fail closed on loss of actuating fluid. Both valves are designed to close automatically on main feedwater isolation signals, an appropriate engineered safety features (ESF) isolation signal, within the time established within the Technical Specifications.

- The MFCVs provide backup isolation to their respective containment isolation valves in order to terminate feedwater flow. The MFCVs are located in the auxiliary building in piping designed to ASME Code, Section III, Class 3 seismic Category I requirements. These valves are components of the steam generator system (SGS).

- For a steam generator tube rupture event, positive and redundant isolation is provided for the main feedwater system (MFIV and MFCV) with ESF isolation signals generated by the protection and safety monitoring system.

10.4.7.1.2 Power Generation Design Basis

- The condensate and feedwater system provides a continuous feedwater supply to the two steam generators at the required pressures and temperatures for steady-state and anticipated transient conditions.

- Plant operation is possible at 100-percent power with one condensate pump out of service, and approximately 70-percent power with one booster/main feedwater pump assembly out of service.

- Plant operation is possible at greater than 70-percent power with one feedwater heater string out of service.

- The feedwater and condensate pumps and pump control system are designed so that loss of one booster/main feedwater pump assembly or one condensate pump does not result in trip of the turbine-generator or reactor.

- The pumps and other system components are designed so that the condensate, feedwater booster and feedwater pumps are protected from running with very low net positive suction heads without tripping on short transient low levels in a hotwell or deaerator tank.

- The condenser hotwell is designed to store, at the normal operating water level, an amount of condensate equivalent to at least three minutes of full-load condensate system operating flow.

- The system is able to accommodate ten-percent step or five-percent per minute ramp load changes without significant deviation from the programmed water levels in the steam generators or major effect on the feedwater system.

- The system has the capability of accommodating the necessary changes in feedwater flow to the steam generators with the steam pressure increase resulting from a 100-percent load rejection.

- The booster/main feedwater pumps are tripped simultaneously with the feedwater isolation signal to close the main feedwater isolation valves. In addition, the same isolation signal closes the isolation valve in the cross connect line between the main feedwater pump discharge header and the startup feedwater pump discharge header.

- A check valve, which acts on reverse pressure differential, is provided in the main feedwater line to each steam generator between the MFIV and the containment penetration. The check valve is designed to withstand the forces encountered when closing after a main feedwater line rupture. The valves perform no safety-related function but will serve to prevent blowdown from more than one steam generator during feedline break while the appropriate engineered safety features signal is generated to isolate using the MFIV and MFCV. During normal or upset conditions, the function of these check valves is to prevent reverse flow from the steam generators whenever the feedwater system is not in operation.

10.4.7.2 System Description

10.4.7.2.1 General Description

The condensate and feedwater system is shown schematically in Figure 10.4.7-1, and in Figure 10.3.2-1. Classification of equipment and components is given in Section 3.2.

The condensate and feedwater system supplies the steam generators with heated feedwater in a closed steam cycle using regenerative feedwater heating. The condensate and feedwater system is composed of the condensate system, the main feedwater system, and portions of the steam generator system. The condensate system collects condensed steam from the condenser and pumps condensate forward to the deaerator. The feedwater system takes suction from the deaerator and pumps feedwater forward to the steam generator system utilizing high-pressure main feedwater pumps. The steam generator system contains the safety-related piping and valves that deliver feedwater to the steam generators. The condensate and feedwater systems are located within the turbine building, and the steam generator system is located within the auxiliary building and containment.

The main portion of the feedwater flow originates from condensate pumped from the main condenser hotwell by the condensate pumps. The main condenser hotwell receives makeup from the condensate storage tank. (Refer to Subsection 9.2.4 for a description of the condensate storage system.) The condensate passes in sequence through: the condensate polishing system or condensate polishing bypass (described in Subsection 10.4.6); the gland steam condenser; three strings of low-pressure heaters, each string consisting of a No. 1 and No. 2 low-pressure heater; two strings of low-pressure heaters No. 3 and No. 4; the No. 5 open low pressure heater (deaerator); the three parallel booster/main feedwater pumps; and two strings of high-pressure heaters, No. 6 and No. 7. Feedwater is pumped to the plant's two steam generators through each generator's respective flow element, control valve, feedwater isolation valve, and check valve. The balance of the plant's feedwater flow is provided by drains from the main steam system moisture separator reheater, drains from the No. 6 and No. 7 feedwater heaters, and steam condensed in the deaerator. These flows are collected in the deaerator and pumped forward in the feedwater cycle. A portion of the condensate flow downstream of the condensate polishers is diverted to provide cooling to the steam generator blowdown system heat exchangers before returning to the main condensate flow at the deaerator.

During plant startup, three recirculation paths facilitate system cleanup and adjustment of water quality prior to initiating feed to the steam generators. These cleanup loops are designed for approximately 33 percent of design condensate flow and include a hotwell recirculation loop, a deaerator recirculation loop, and a third recirculation loop from downstream of the No. 7 feedwater heaters. Steam is provided to the deaerating feedwater heater from the auxiliary steam supply system to preheat the feedwater as feedwater begins to flow towards the steam generators. This preheating action, along with chemical addition, minimizes formation of iron oxides in the condensate system.

The condensate polishing system is described in Subsection 10.4.6 and may be in service or bypassed. Each of the two main feedwater lines to the two steam generators contains a feedwater

flow element, a main feedwater control valve, a main feedwater isolation valve, and a check valve. A thermal relief valve is included in each main feedwater line between the control valve and isolation valve to prevent overpressure due to thermal expansion when both valves are closed.

The turbine island chemical feed system (CFS) described in Subsection 10.4.11 is provided to inject an oxygen scavenging agent and a pH control agent into the condensate pump discharge downstream of the condensate polishers and an oxygen scavenging agent and pH control agent upstream of the feedwater booster pump suction. Injection points are shown in Figure 10.4.7-1. During normal power operation, the addition of an oxygen scavenging agent and pH control agent to the condensate system downstream of the condensate demineralizers is in automatic control, with manual control available. The added chemicals control pH according to the condensate and feedwater system chemistry requirements and establish an oxygen scavenging agent residual in the feedwater system. The oxygen scavenger agent is hydrazine and the pH control agent is methoxypropylamine (MPA). During shutdown conditions, carbohydrazide may be used in place of hydrazine.

Oxygen scavenging and ammoniating agents are selected and utilized for plant secondary water chemistry optimization following the guidance of NEI-97-06, "Steam Generator Program Guidelines" (Reference 201). The EPRI Pressurized Water Reactor Secondary Water Chemistry Guidelines are followed as described in NEI 97-06.

A cross connection from the main feedwater pump discharge header to the startup feedwater header allows any booster/main feedwater pump to supply feedwater to the startup feedwater control valves. The startup feedwater system is described in Subsection 10.4.9. Thus, feedwater from the deaerator storage tank can be supplied by the booster/main feedwater pumps through the startup feedwater connections to the steam generators during hot standby, plant startup and low power operation. A check valve in the cross connection piping prevents the startup feedwater pumps from supplying the main feedwater header, and a nonsafety-related isolation valve in the cross connection piping automatically closes upon the feedwater isolation signal that trips the main feedwater pumps.

A condensate and feedwater failure analysis for safety-related components is presented in Table 10.4.7-1. Occurrences which produce an increase in feedwater flow or decrease in feedwater temperature result in increased heat removal from the reactor coolant system which is compensated for by control system action, as described in Subsection 10.4.7.5. Events which produce the opposite effect (i.e., decreased feedwater flow or increased feedwater temperature) result in reduced heat transfer in the steam generators. Normally, automatic control system action is available to adjust feedwater flow to prevent excess energy accumulation in the reactor coolant system, and the increasing reactor coolant temperature provides a negative reactivity feedback, reducing reactor power. In the absence of normal control action, either the high-outlet temperature or the high-pressure trips of the reactor protection system are available to provide reactor safety. Loss of all feedwater is examined in Section 15.3.

Refer to Subsection 5.4.2.2 for a description of steam generator design features to prevent fluid flow water hammer. The main feedwater connection on each of the steam generators is the highest point of each feedwater line downstream of the MFIV. The feedwater lines contain no high-point pockets that could trap steam and lead to water hammer. The horizontal pipe length from the main nozzle to the downward turning elbow of each steam generator is minimized.

Operations and maintenance procedures include precautions, when appropriate, to minimize the potential for steam and water hammer, including:

- Prevention of rapid valve motion
- Process for avoiding introduction of voids into water-filled lines and components

- Proper filling and venting of water-filled lines and components
- Process for avoiding introduction of steam or heated water that can flash into water-filled lines and components
- Cautions for introduction of water into steam-filled lines or components
- Proper warmup of steam-filled lines
- Proper drainage of steam-filled lines
- The effects of valve alignments on line conditions

10.4.7.2.2 Component Description

The feedwater system is constructed in accordance with the requirements of ASME Code, Section III for Class 2 components and seismic Category I requirements from the steam generator out through the MFIVs. From upstream of the MFIV to the restraint at the interface between the auxiliary building and turbine building, the system is constructed in accordance with ASME Code, Section III for Class 3 components and seismic Category I requirements. The remaining piping of the condensate and feedwater system meets ASME B31.1 requirements. Safety-related feedwater piping materials are described in Subsection 10.3.6.

Feedwater Piping

Feedwater is supplied to each of the two steam generators by a main feedwater line during normal operation. Each of the lines is anchored at the auxiliary building/turbine building interface, and has sufficient flexibility to provide for relative movement of the steam generators resulting from thermal expansion.

The feedwater system and steam generator design minimize the potential for waterhammer and subsequent effects. Details are provided in Subsection 5.4.2.2. Feedwater piping analysis considers the following factors and events in the evaluation:

- Steam generators with top feed ring design (BTP ASB 10-2)
- Main feedwater check valves due to line breaks (BTP MEB 3-1)
- Spurious isolation or feedwater control valve trips
- Pump trips
- Deaerator regulating flow control valve trip
- Local feedwater piping, anchors, supports, and snubbers, as applicable

Feedwater Isolation Valves

One MFIV is installed in each of the two main feedwater lines outside the containment and downstream of the feedwater control valve. The MFIVs are installed to prevent uncontrolled blowdown from the steam generators in the event of a feedwater pipe rupture. The main feedwater check valve provides backup isolation. In the event of a secondary side pipe rupture inside the containment, the MFIVs limit the quantity of high energy fluid that enters the containment through the broken loop and limit cooldown. The MFCV provides backup isolation to limit cooldown and high energy fluid addition.

Each MFIV is a bidirectional wedge type gate valve composed of a valve body that is welded into the system pipeline. The MFIV gate valve is provided with a hydraulic/pneumatic actuator. The valve actuator is supported by the yoke, which is attached to the top of the body. The valve actuator consists of a hydraulic cylinder with a stored energy system to provide emergency closure of the

isolation valve. The energy to operate the valve is stored in the form of compressed nitrogen contained in one end of the actuator cylinder. The MFIV is maintained in a normally open position by high-pressure hydraulic fluid. For emergency closure, redundant solenoids are energized resulting in the high-pressure hydraulic fluid being dumped to a fluid reservoir.

The feedwater isolation functional diagram is shown in Figure 7.2-1. To provide safety function actuation, the redundant actuation solenoid valves are powered from separate Class 1E power divisions. Redundant control and indication channels are provided for each of the isolation valves. Provisions are made for inservice inspection of the isolation valves.

Feedwater Control Valves

The MFCVs are air-operated control valves with the dual purpose of controlling feedwater flow rate as well as providing backup isolation of the feedwater system. The valve body is a globe design. Seats and trim are of an erosion resistant material. The design allows for removal and replacement of seats and other wearing parts.

The feedwater control valves (MFCVs) automatically maintain the water level in the steam generators during operational modes. Positioning of the main feedwater control valve during normal operation is the function of an automatic feedwater level control system using a refinement of a standard three element control scheme. The three-element control system maintains feedwater flow equal to the steam flow, and steam generator water level is used as an input to trim feedwater flow and maintain programmed water level. Refinements on the standard control are made by varying the flow demand of the valve based on the actual stem position.

In the event of a secondary side pipe rupture inside the containment, the main feedwater control valves provide a redundant isolation to the MFIVs to limit the quantity of high energy fluid that enters the containment through the broken loop. For emergency closure of the MFCV, a solenoid is deenergized to close the valve in sufficient time to limit the mass and energy release to containment consistent with the containment analysis presented in Chapter 6.

Feedwater Check Valves

Each main feedwater line includes a check valve installed outside containment. During normal and upset conditions, the check valve prevents reverse flow from the steam generator whenever the feedwater pumps are tripped. In addition, the closure of the valves prevents more than one steam generator from blowing down in the event of feedwater pipe rupture. The check valve is designed to limit blowdown from the steam generator and to prevent slam resulting in potentially severe pressure surges due to water hammer. The valves are designed to withstand the closure forces encountered during the normal, upset and faulted conditions. Rapid closure associated with a feedline rupture does not impose unacceptable loads on the steam generator or the steam generator system. The closure of the valves provides for isolation of the steam generators in the event of a feedwater line break to prevent blowdown from both steam generators. The valves are seismic Category I, ASME Code, Section III, Class 2 valves.

Feedwater Thermal Relief Valves

A relief valve is provided to prevent overpressurization of the main feedwater lines between the MFIVs and MFCVs. The relief valve prevents overpressurization that could be caused by thermal expansion of the fluid trapped between the isolation and control valves following an event causing main feedwater isolation.

Plant Main Condenser

For a description of main condenser, refer to Subsection 10.4.1.

Condensate Pumps

The three 50-percent, vertical, multistage, centrifugal condensate pumps are motor-driven and operate in parallel. Valving allows individual pumps to be removed from service. Pump capacity meets normal, full-power requirements with two of the three pumps in operation.

Condensate Regulating Valves

The main condensate flow to the deaerator is regulated by two parallel, split-ranged, pneumatically operated control valves. Condensate is regulated to maintain the level in the deaerator storage tank. During startup and low loads, the smaller valve modulates to control flow while the larger valve remains closed. As load increases, the larger valve modulates to control flow.

Low-Pressure Feedwater Heaters

These heaters are shell and tube heat exchangers with the heated condensate flowing through the tube side and the extraction steam condensing on the shell side. Parallel strings of low-pressure feedwater heaters No. 1 and 2 are located in each of three condenser necks. Feedwater heaters No. 3 and 4 are also parallel strings of heaters. The closed low-pressure feedwater heaters use drain coolers. The cascaded drains from the heaters are dumped to their respective condenser shell.

A drain line from the heater allows direct discharge of the heater drains to the condenser in the event the normal drain path is not available or flooding occurs in the heater.

The low-pressure feedwater heater shells are carbon steel, and the tubes are stainless steel.

Deaerator

The deaerator is a tray type, horizontal shell, direct contact heater with a horizontal storage tank. Condensate enters the deaerator from the top. The heating steam flows upward and is condensed, and raises the temperature of the condensate to near saturation, liberating dissolved gases from the condensate. Condensate drains from the deaerator into the storage tank. Noncondensables are vented from the top of the deaerator and flow through an orifice and valve assembly to the main condenser.

Auxiliary steam from the auxiliary steam supply system (see Subsection 10.4.10) is supplied to the deaerator (as pegging steam) following the recirculation and cleanup steps and maintains the pressure in the tank at saturation conditions. As main steam becomes available to supplement the auxiliary boiler steam, this pegging steam keeps the deaerator above atmospheric pressure. This pressure is maintained as condensate and feedwater flow (and also reactor power and main steam flow) increases to and beyond the point of turbine synchronization, until the normal heating steam flow from the HP turbine exhaust is sufficient to maintain deaerator pressure. Auxiliary steam is also automatically supplied to the deaerator following turbine trip to assist in maintaining deaerator pressure above atmospheric.

The shell of the deaerator storage tank is carbon steel. Most of the internals of the deaerator, including the tray assemblies, vent condenser, and spray valves, are stainless steel.

A high level dump line and control valve provide overflow protection to the deaerator storage tank. During high level conditions, water from the deaerator storage tank is drained to the main condenser.

High-Pressure Feedwater Heaters

The main feedwater pumps discharge into a parallel string of No. 6 and No. 7 high-pressure feedwater heaters. These heaters are shell and tube heat exchangers. Heated feedwater flows through the tubes and extraction steam condenses in the shell. The No. 6 and No. 7 heaters drain into low-pressure heater No. 5 (deaerator).

A drain line from each heater allows direct discharge of the heater drains to the condenser in the event the normal drain path is not available or flooding occurs in the heater.

The high-pressure feedwater heater shells are carbon steel, and the tubes are stainless steel.

Feedwater Booster Pumps

The feedwater booster pumps are horizontal, centrifugal pumps located upstream of the main feedwater pumps. Each feedwater booster pump takes suction from the deaerator storage tank and pumps forward to its associated main feedwater pump. An electric motor drives both the booster pump and the main feedwater pump. The booster pump is driven by one end of the motor shaft and the main pump is driven by the other end through a mechanical speed increaser. The booster pump, operating at a lower speed than the main feedwater pump, boosts the pressure of feedwater from the deaerator to meet the net positive suction head requirements of the main feedwater pump.

Main Feedwater Pumps

The three main feedwater pumps operate in parallel and take suction from the associated feedwater booster pumps. The combined discharge from the main feedwater pumps is supplied to the No. 6 high-pressure feedwater heater, the No. 7 high-pressure feedwater heater, and then to the steam generator system. Each main feedwater pump is a horizontal, centrifugal pump driven, through a mechanical speed increaser, by the motor that drives the associated feedwater booster pump.

Isolation valves allow each of the booster/main feedwater pumps to be individually removed from service while continuing power operations at reduced capacity.

Pump Recirculation Systems

Minimum flow control systems automatically protect the pumps in the condensate and feedwater system from pumping below the minimum flow rate to prevent pump damage. The condensate pumps recirculate to the main condenser. The booster/main feedwater pumps recirculate to the deaerator storage tank.

10.4.7.2.3 System Operation

10.4.7.2.3.1 Plant Startup

During plant startup, the condensate and feedwater system operates in several different configurations. These are described in Subsections 10.4.7.2.3.1.1 through 10.4.7.2.3.1.4.

10.4.7.2.3.1.1 Hotwell Recirculation

The hotwell recirculation flow path is used to recirculate flow from downstream of the gland steam condenser to the main condenser to facilitate cleanup of the condensate inventory in the main condenser hotwell. This flow path also provides a minimum flow for operation of the gland steam condenser and the condensate pumps. With a condensate pump operating, the setpoint of the recirculation valve is manually adjusted to achieve the desired flow rate for cleanup of condensate. Condensate polishing equipment is aligned and placed in service to attain the required water quality.

The hotwell recirculation valve is placed in automatic operation when minimum flow is required only for operation of the gland steam condenser and one or two condensate pumps. The recirculation valve automatically maintains the minimum flow and closes when system flow to the deaerator exceeds the required minimum. The recirculation valve remains on standby and opens, as necessary, if system flow drops below minimum.

Once the hotwell recirculation loop is placed in service and cooling is available to the gland steam condenser, sealing steam may be applied to the turbine glands. Condenser vacuum can then be drawn using condenser air removal equipment.

10.4.7.2.3.1.2 Deaerator Recirculation

The deaerator recirculation flow path is used to recirculate condensate from downstream of the deaerator storage tank to the main condenser to facilitate cleanup of condensate. Deaerator recirculation is initiated by adjusting the recirculation flow control valve from the main control room to achieve the desired flow rate. Condensate is recirculated for cleanup of water quality using the condensate polishing equipment. Auxiliary steam can be admitted to the deaerator to facilitate removal of noncondensable gases.

10.4.7.2.3.1.3 Third Stage Recirculation

The third stage of condensate/feedwater recirculation during the plant heatup cycle can begin when condensate and feedwater has been sufficiently cleaned and deaerated at the feedpump suction. Flow is initiated by adjusting the recirculation flow control valve from the main control room to achieve the desired flow rate. Feedwater is recirculated from downstream of the No. 7 feedwater heaters to the main condenser for cleanup and deaeration of the condensate and feedwater inventory.

10.4.7.2.3.1.4 Plant Heatup

The condenser hotwell makeup and overflow valves are enabled and function automatically during the plant heatup cycle to maintain condensate inventory. Condensate is returned to the condensate storage tank as volume expansion occurs, and makeup occurs as needed for system losses.

During heatup, the main condenser is available to accept turbine bypass steam from the main steam system, as well as various drains, vents, and condensate/feedwater recirculation flow. Noncondensable gases are removed in the air removal sections of the main condenser and through the deaerator vents. Control and monitoring of water quality and chemistry are accomplished by operation of the condensate polishing equipment, chemical feed system, and secondary sampling equipment as required.

The steam generators are filled, as required, either by the startup feedwater pumps using water from the condensate storage tank, or alternatively by a booster/main feedwater pump using water from the deaerator storage tank and supplied through cross connect piping to the startup feedwater control valves. The steam generators are drained, as required, through the steam generator blowdown system.

During the initial stages of plant heatup, one condensate pump operates as necessary to maintain level in the deaerator storage tank. Either one or both startup feedwater pumps, or one booster/main feedwater pump, is in operation when feeding water to the steam generators. The feedwater pumps in use operate on minimum flow recirculation as necessary while maintaining the water level of the steam generators. The pump heat from this recirculated minimum flow, in conjunction with auxiliary steam, is used to heat the deaerator.

Feedwater is controlled by the startup feedwater control valves (SFCVs) which are operated either manually from the control room or automatically in accordance with steam generator level demand. Condensate flow to the steam generator blowdown heat exchangers is controlled during plant heatup to obtain the necessary cooling to the blowdown stream. Any excess level in the deaerator storage tank is drained to the main condenser through the deaerator high level dump flow path.

10.4.7.2.3.2 Power Operation

One operating condensate pump supplies sufficient condensate flow to the deaerator during initial power operation and at low-power levels. As power escalates, a second condensate pump is started prior to exceeding approximately 50-percent, full-load condensate flow. The third condensate pump is in standby.

The condensate regulating valves to the deaerator automatically maintain the level of the deaerator storage tank. If condensate flow to the deaerator drops below the minimum required flow for operation of the gland steam condenser or the condensate pumps, the hotwell recirculation valve to the condenser opens to provide the minimum flow.

Noncondensables are removed by the deaerating section of the main condenser and by the deaerator. Condensate polishing, chemical feed and condensate sampling are performed, as needed, to maintain water quality.

For normal operating conditions between 0- and 100-percent load, system operation is primarily automatic. Automatic level control systems control the water levels in the feedwater heaters and the condenser hotwell. Feedwater heater water levels are controlled by modulating flow control valves. Level control valves in the makeup line to the condenser from the condensate storage tank and in the return line to the condensate storage tank control the level in the condenser hotwell.

During reactor startup and at very low power levels, feedwater is supplied to the steam generators through the startup feedwater control valves using either the startup feedwater pumps drawing from the condensate storage tank, or a booster/main feedwater pump drawing from the deaerator storage tank. Refer to Subsection 10.4.9 for a description of the startup feedwater system. If the startup feedwater pumps are initially in use, transfer is made to a booster/main feedwater pump prior to exceeding the capacity limit of the startup pumps. As power increases, startup feedwater continues to be supplied through the startup feedwater control valves until control of feedwater is automatically transferred from the startup feedwater control valves to the main feedwater control valves. The startup feedwater control valves close, and the main feedwater control valves open to supply main feedwater to the steam generators and maintain steam generator level. Position indication is available in the main control room for the main and startup feedwater control valves. As power escalates, booster/main feedwater pump minimum flow recirculation automatically decreases as the forward flow to the steam generators increases. The second and third booster/main feedwater pumps are brought into operation as required.

Condensate flow to the steam generator blowdown heat exchangers is normally automatically controlled. In the automatic mode, condensate flow is regulated to control the steam generator blowdown outlet temperature from the blowdown heat exchangers.

Ten-percent step load and 5-percent/minute ramp changes are accommodated without major effect to the condensate and feedwater system. The system is capable of providing the necessary feedwater flow to the steam generators with the steam pressure increase resulting from a 100-percent load rejection.

10.4.7.2.3.3 Plant Shutdown

Operation during power descent is largely the reverse of power ascent. As power is decreased, one of the two operating condensate pumps may be stopped; one or two booster/main feedwater pumps may be stopped as well. At low feedwater flow, control of feedwater is automatically transferred from the main feedwater control valves to the startup feedwater control valves.

Following reactor trip or other reactor shutdown, feedwater is supplied through the startup feedwater control valves to maintain steam generator inventories. Decay heat and sensible heat are removed by steam release via the steam dump system to the condenser to cool the plant and bring it to safe shutdown. During this time, startup feedwater is supplied either by an operating booster/main feedwater pump drawing from the deaerator storage tank, or by the startup feedwater pumps drawing from the condensate storage tank.

10.4.7.2.3.4 Emergency Operation

In the event of a design basis event (with or without normal ac power supplies available), feedwater isolation signals are generated as required. The MFIVs and MFCVs automatically close on receipt of the isolation signals. The condensate and feedwater system is not required to supply feedwater under accident conditions to effect plant shutdown or to mitigate the consequences of an accident. However, the startup feedwater system is expected to be available as a nonsafety-related system to provide a source of feedwater for the steam generators. Also, the condenser may be available to accept turbine bypass steam for secondary side heat removal. Coordinated operation of the startup feedwater system (Refer to Subsection 10.4.9), if available, and the main steam supply system (Refer to Section 10.3) removes the primary loop sensible heat and reactor decay heat.

10.4.7.3 Safety Evaluation

- The safety-related portions of the main feedwater system are located in the containment and auxiliary buildings. These buildings are designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, external missiles, and other natural phenomena. Sections 3.3, 3.4, 3.5, 3.7, and 3.8 provide the bases for the adequacy of the structural design of these buildings.

- The safety-related portions of the main feedwater system are designed to remain functional after a design basis earthquake. Subsection 3.7.2 and Section 3.9 provide the design loading conditions that are considered. Sections 3.5, 3.6, and Subsection 9.5.1 describe the analyses to provide confidence that a safe shutdown, as outlined in Section 7.4, is achieved and maintained.

- The main feedwater system safety-related functions are accomplished by redundant means. A single, active component failure of the safety-related portion of the system does not compromise the safety function of the system. Table 10.4.7-1 provides a failure analysis of the safety-related active components of the feedwater system. Power is supplied from onsite power systems, as described in Chapter 8.

- Preoperational testing of the safety-related portion of the condensate and feedwater system is performed as described in Chapter 14. Periodic inservice functional testing is done in accordance with Subsection 10.4.7.4. Section 6.6 provides the ASME Code, Section XI requirements that are appropriate for the feedwater system.

- Section 3.2 delineates the quality group classification and seismic category applicable to the safety-related portion of this system and supporting systems. The controls and power supplies necessary for the safety-related functions of the condensate and feedwater system are Class 1E, and are described in Chapters 7 and 8.

- For a main feedwater line break inside the containment or a main steam line break, the MFIVs and the main feedwater control valves automatically close upon receipt of a feedwater isolation signal. The signals that produce a main feedwater isolation signal are identified and discussed in Subsection 7.3.1.2.6.

- The MFIVs are provided with solenoids supplied by redundant power divisions. Failure of either of the power divisions or solenoids does not prevent closure of the MFIV. Releases of radioactivity from the condensate and feedwater system, resulting from the main feedwater line break, are minimal because of the negligible amount of radioactivity in the system under normal operating conditions. Following a steam generator tube rupture, the main steam isolation system and the passive residual heat removal heat exchanger reduce accidental releases, as discussed in Section 10.3 and Chapter 15. Detection of radioactive leakage into and out of the system is facilitated by area radiation monitoring (described in Subsection 12.3.4), process radiation monitoring (described in Section 11.5), and steam generator blowdown sampling (described in Subsection 10.4.8).

- For a steam generator tube rupture event, positive and redundant isolation is provided for the main feedwater (MFIV and MFCV) with isolation signals generated by the protection and safety monitoring system (PMS). Refer to Subsection 7.3.1.2.6.

- Prevention and mitigation of feedline-related water hammer is accomplished through operation of the feedwater delivery system as described in Subsection 5.4.2.2. The feedwater piping at the steam generators is sloped so that it does not drain into the steam generators. These features help avoid the formation of a steam pocket in the feedwater piping which, when collapsed, could create a hydraulic instability.

10.4.7.4 Tests and Inspections

10.4.7.4.1 Preoperational Valve Testing

The MFIVs and feedwater control valves are checked for closing time prior to initial startup.

10.4.7.4.2 Preoperational Pipe Testing

The main feedwater lines from the steam generator to the anchor at the interface between the turbine building and the auxiliary building are classified as ASME Code, Section III, Class 2 and 3 and seismic Category I piping. The Class 2 portions of the main feedwater system piping are tested and inspected to the requirements of ASME Code, Section III, Class 2 piping. The portion of the piping between the containment penetration and the anchor, which is considered as the break exclusion zone described in Subsection 3.6.2, is subjected to 100-percent volumetric inspection at installation.

10.4.7.4.3 Preoperational System Testing

Preoperational testing of the condensate and feedwater system is performed as described in Chapter 14. Tests described in Subsection 14.2.9.1.7, under item c) of General Test Method and Acceptance Criteria satisfy BTP (AS) 10-2. Additional testing of the feedwater system is conducted during startup testing as described in Subsection 14.2.10.4.18.

10.4.7.4.4 Inservice Inspections

The performance, and structural and leaktight integrity of the condensate and feedwater system components are demonstrated by continuous operation.

Additional description of inservice testing and inspection for the MFIV and MFCV is presented in Subsection 3.9.6 and Section 6.6.

10.4.7.5 Instrumentation Applications

The condensate and feedwater instrumentation, is designed to facilitate automatic operation, remote control, and indication of system parameters.

Positioning of the main feedwater control valve during normal operation is the function of an automatic feedwater level control system using a refinement of a standard three element control scheme. For each steam generator, the three-element control system maintains feedwater flow equal to the steam flow, and steam generator water level is used as an input to trim feedwater flow and maintain programmed water level. Refinements on the standard control are made by varying the valve flow demand based on actual stem position (accounting for varying C_v versus lift) dynamic line losses and feedwater temperature. A flow venturi is located in each feedwater line to provide signals for the three element feedwater control system. Feedwater control is further described in Subsection 7.7.1.8.

The main feedwater pumps are tripped by manual actuation or feedwater isolation described in Section 7.3. A flow element in the discharge piping from each main feedwater pump provides a flow signal for control of the associated minimum flow recirculation valve.

Level transmitters, located at the deaerator storage tank, control deaerator level. Condensate flow to the deaerator is regulated by two split ranged control valves upstream of the deaerator. During normal power generation, the valves are regulated by a three element control system; total feedwater flow is used as a feed forward demand signal, and the control is trimmed by measured feedback of total condensate flow and deaerator storage tank level.

In the event a feedwater heater experiences a sizable tube leak or a feedwater heater water level control valve fails closed, the main turbine is protected from failure resulting from flooding on the shell side of a feedwater heater and subsequent water induction into the moving turbine blades. This is accomplished by automatic closure of the isolation valve in the steam extraction line to that heater and opening the high-level dump control valve that dumps the heater excess drains to the condenser. For heaters that do not have extraction line isolation valves, condensate isolation valves are automatically closed to isolate condensate flow to the heater tubes.

The total water volume in the condensate and feedwater system is maintained through automatic makeup and rejection of condensate to the condensate storage tank. The system makeup and rejection are controlled by the condenser hotwell level controller. Level transmitters are provided at the condenser hotwell for use by the hotwell level controller. The system water quality requirements are automatically maintained through the injection of an oxygen scavenging agent and a pH control agent into the condensate system. The pH control agent and oxygen scavenging agent injection is controlled by pH and the level of oxygen scavenging agent residual in the system which are continuously monitored by the secondary sampling system.

Instrumentation, including pressure indication, flow indication, and temperature indication, required for monitoring the system, is provided in the control room.

10.4.8 Steam Generator Blowdown System

The steam generator blowdown system (BDS) assists in maintaining acceptable secondary coolant water chemistry during normal operation and during anticipated operational occurrences of main condenser inleakage or primary to secondary steam generator tube leakage. It does this by removing impurities which are concentrated in the steam generator. The steam generator blowdown system accepts water from each steam generator and processes the water as required.

10.4.8.1 Design Basis

Appendix 1A discusses the conformance of BDS design with the criteria of Regulatory Guide 1.143. Exceptions for treatment of the BDS in comparison with the radwaste systems is consistent with the regulatory philosophy of treating structures, systems, and components commensurate with their importance to safety since the BDS does not normally contain radioactivity and only contains radioactivity in the infrequent event of primary to secondary tube leakage.

10.4.8.1.1 Safety-Related Design Basis

The safety-related portion of each blowdown line is part of the steam generator system (SGS). Effects of a blowdown system line break are discussed in Section 3.6. The safety-related design bases are as follows:

- The system is provided with two isolation valves on each steam generator. These valves isolate the secondary side of the steam generators to preserve the steam generator inventory. This action provides a heat sink for a safe shutdown or design basis accident mitigation. It also provides isolation of nonsafety-related portions of the system.

- The steam generator blowdown system safety-related functions can be performed assuming a single, active component failure coincident with the loss-of-offsite or onsite power.

- Piping and valves from the steam generator up to and including the containment isolation valve, the first valve on the outboard side of the containment, are designed to ASME Code, Section III, Class 2, and seismic Category I requirements. The blowdown system piping and valves from the outlet of the containment isolation valve up to and including pipe anchors located at the auxiliary building wall are designed in accordance with ASME Code, Section III, Class 3, and seismic Category I requirements.

- The safety-related portion of the system is designed to withstand the effects of a safe shutdown earthquake. The safety-related portion of the system is protected from the effects of natural phenomena and is capable of performing its intended function following postulated events such as fire, internal missile, and pipe break.

- The safety-related portion of the system is designed so that a single, active failure in the blowdown system will not result in:

  – Loss-of-coolant accident
  – Loss of integrity of steam lines
  – Loss of the capability to effect a safe reactor shutdown
  – Transmission of excessive loading to the containment pressure boundary.

- The portion of the steam generator system that is constructed in accordance with ASME Code, Section III, Class 2 and 3, requirements is provided with access to welds and removable insulation, as required for inservice inspection in accordance with ASME Code, Section XI. (See Subsection 10.4.8.4.)

- The safety-related portion of the blowdown system is designed to function in the normal and accident environments identified in Subsection 3.11.1.

- The safety-related portion of the blowdown system is designed as described in Section 3.6 with regard to high-energy pipe break location and evaluation.

10.4.8.1.2 Power Generation Design Basis

The steam generator blowdown system draws secondary water from each steam generator via the blowdown line and processes this water as required to:

- Assist in controlling steam generator secondary side water chemistry during normal plant operation
- Establish and maintain steam generator wet layup conditions during plant shutdown periods
- Drain the secondary side of the steam generators for maintenance

10.4.8.2 System Description

10.4.8.2.1 General Description

Figures 10.4.8-1 and 10.3.2-1 illustrate the steam generator blowdown system piping and instrumentation design. Classification of equipment and components for the steam generator blowdown system is given in Section 3.2. The system consists of two blowdown trains, one for each steam generator. A crosstie is provided to process blowdown from both steam generators through both heat exchangers during high capacity blowdown from one steam generator.

The blowdown water is extracted from each steam generator through holes in the top surface (secondary side) of the tube sheet. The blowdown from each steam generator is cooled by a regenerative heat exchanger, and flow is controlled and pressure reduced by blowdown flow control valves. To recover the thermal energy, the condensate system provides cooling for the heat exchangers. To recover the blowdown fluid, each blowdown train has an electrodeionization (EDI) demineralizing unit which removes impurities from the blowdown flow. Downstream of the electrodeionization units, both trains combine into a common header that contains a relief valve for providing overpressure protection for the low-pressure portion of the system. A back-pressure control valve maintains pressure in the system between the flow control valve and the back-pressure control valve.

A pump is provided to drain the secondary side of the steam generator. The pump is also used for recirculation during low-pressure steam generator wet layup operations.

System isolation from the steam generator under normal operating and transient conditions is accomplished either by the two isolation valves located in the auxiliary building or by isolation valves located downstream of the heat exchangers and sampling connections. The upstream valves in the auxiliary building close on actuation of the passive residual heat removal system or containment isolation. The isolation valves downstream of the heat exchangers close in the case of high blowdown system temperature flow, radiation, or pressure.

10.4.8.2.2 System Operation

The various modes of operation are described in the following subsections.

10.4.8.2.2.1 Plant Startup

While low-pressure conditions exist in the steam generator, the blowdown flow control valves are operated with their bypass valves fully open to discharge the blowdown flow to the condensate system (CDS) for processing and recovery.

When the steam generator pressure is sufficiently high, the bypass valves can be closed and the blowdown flow control valves modulate to control the blowdown rate. The condensate control valves, which control the supply of cooling water to the heat exchangers, are adjusted during startup. The cooling water flow to the heat exchangers controls blowdown water to a temperature that is acceptable to the blowdown system electrodeionization units.

10.4.8.2.2.2 Normal Operation

The effectiveness of the blowdown system in controlling water chemistry depends upon the blowdown rate. The normal blowdown flowrate varies from a minimum of about 0.06 percent to a maximum of about 0.6 percent of maximum steaming rate. During normal operation, when the impurities are low, the expected blowdown rate is approximately 0.1 percent of maximum steaming rate (about 30 gpm total, or 15 gpm per steam generator), which maximizes the detection sensitivity for condenser tube leakage. The blowdown flow is cooled by the heat exchanger, and the pressure is reduced by the flow control valves. The blowdown fluid is processed through the electrodeionization units and discharged to the condensate system (condenser hotwell) for reuse.

In the event of main condenser tube leakage, when the concentration of impurities is high, the blowdown rate is increased to a maximum of approximately 0.6 percent of the maximum steaming rate (about 186 gpm total, or 93 gpm per steam generator at standard conditions). Normal operation is to recover the blowdown flow through the condensate system. However, blowdown with high levels of impurities can be discharged to the waste water system.

The back-pressure control valve is preset to a pressure which prevents flashing of the blowdown fluid in the electrodeionization units.

The blowdown discharge flow and the electrodeionization reject (waste stream) flow are both continuously monitored for radioactivity from steam generator primary to secondary tube leakage. If such radioactivity is detected, the liquid radwaste system (WLS) is aligned to process the blowdown and electrodeionization waste effluent. If radioactivity reaches a preset high level, the blowdown flow control valves and the isolation valves downstream of the heat exchangers and sampling connections automatically close.

The system operates normally under automatic control, except for flow control adjustments or flow path changes.

10.4.8.2.2.3 Subsection Not Used

10.4.8.2.2.4 Steam Generator Wet Layup

The system can be operated to establish and maintain wet layup conditions in the steam generators during plant shutdown periods. During wet layup operation, water is circulated through the steam generators and the heat exchangers are not required. To maintain the correct pH and oxygen concentration in the secondary water, chemicals are added to the recirculation flow via the turbine island chemical feed system (CFS). (See Subsection 10.4.11 for chemical feed system details.)

10.4.8.2.2.5 Steam Generator Drain

The steam generator blowdown system can be operated to drain the steam generator using the recirculation/drain pump and bypassing the flow control valves and the electrodeionization units. Total drain flowrate is approximately 200 gpm at standard conditions. During this mode of operation, the blowdown discharge maybe sent to the waste water system, the liquid radwaste system or the condensate system.

10.4.8.2.2.6 Steam Generator Tube Sheet Flush

The system can be operated for a short time at a total flowrate of approximately 1.85 percent of the maximum steaming rate (about 280 gpm) from one steam generator. To accommodate the high flow, the blowdown from one steam generator is isolated and the flow from the other steam generator is routed through both heat exchanger trains at a rate of approximately 140 gpm per train. The blowdown flow control valves and the blowdown electrodeionization units are bypassed during this operation. The blowdown flow is controlled by throttling the flow control valve bypass isolation valves which are in series with a flow restricting orifice. The blowdown is discharged to the waste water system (WWS).

10.4.8.2.2.7 Emergency Operation

Blowdown system isolation is actuated on Low-2 steam generator narrow range water levels. The isolation of steam generator blowdown provides for a continued availability of the steam generator as a heat sink for decay heat removal in conjunction with operation of the passive residual heat removal system and the startup feedwater system.

10.4.8.2.3 Component Description

A description of the major steam generator blowdown system components is provided in this subsection.

10.4.8.2.3.1 Blowdown Regenerative Heat Exchangers

Two regenerative heat exchangers are provided, one for each steam generator blowdown train. The heat exchangers are located in the turbine building at the base slab elevation.

10.4.8.2.3.2 Blowdown Flow Control Valves

Two blowdown flow control valves are provided, one for each steam generator blowdown train. The control valves are capable of controlling the flow and pressure over the range of normal operating conditions.

10.4.8.2.3.3 Recirculation/Drain Pump

One centrifugal pump is provided for use during operating modes when steam generator pressure is low.

10.4.8.2.3.4 Pressure Control Valve

A backpressure control valve is provided to maintain appropriate system backpressure, within the operating range of blowdown flows, and prevent flashing within the low pressure section of the system when the blowdown is discharged to the condenser hotwell.

10.4.8.2.3.5 Blowdown Isolation Valves

Two valves in series, located outside containment in the auxiliary building, are provided to automatically isolate the blowdown system in the event of abnormal conditions within the blowdown system, the reactor coolant system, or the main steam system. The valves are air-operated globe valves that fail close on loss of air or actuating power. See Section 7.3 for a description of the automatic control functions on the valves.

The first isolation valve provides a containment isolation function in addition to redundant isolation of the blowdown system. The valves close on an engineered safeguards actuation signal and provide containment integrity in conjunction with the steam generator and blowdown line inside containment. The valves are active, ASME Code, Section III, Safety Class 2, seismic Category I.

The isolation valves provide for redundant isolation of the blowdown system upon actuation of the passive residual heat removal system, Low-2 steam generator narrow range water level, or abnormal conditions in the blowdown system. Each isolation valve receives an actuation signal from the protection and safety monitoring system (PMS) upon passive residual heat removal actuation to preserve steam generator inventory. The valves also close upon receiving a Low-2 steam generator narrow range water level signal to preserve steam generator inventory. The second isolation valves are active, ASME Code, Section III, Safety Class 3, seismic Category I.

The valves are located outside containment within the auxiliary building and are attached to seismic Category I piping.

Additionally, Class E, non-seismic, isolation valves downstream of the heat exchangers and sampling connections in the turbine building receive high radiation signal, high temperature signal, high flow signal, and high pressure signal, indicating abnormal conditions in the blowdown system and actuating automatic isolation of the system.

10.4.8.2.3.6 Electrodeionization Unit

Two trains of electrodeionization demineralizing units are provided for the steam generator blowdown system electrodeionization. The electrodeionization unit in each train is configured in a stack arrangement. The stack normally contains numerous pairs of stacked membranes. One cell pair consists of an ion-diluting flow (product) channel located between a cation and an anion membrane with an ion concentrating (reject) flow channel located alternately between the cell pairs. A DC potential is maintained across the electrode plates which are located on opposite ends of the stacked membranes. Ion exchange resin is contained within the product flow channel, acting as an ion selective media in the electrodeionization process, aiding in the transfer of ions from the product stream to the reject stream. Isolation valves are provided for each stack to allow for maintenance of a stack.

Filters upstream of the electrodeionization stack in each train remove suspended solids and particulate matter from electrodeionization influent.

The ion concentrate reject stream is directed to the waste water system (WWS) or the liquid radwaste system (WLS).

The electrodeionization stacks are located in the turbine building and in an area where provisional shielding can be put in place. Anionic and cationic resins are contained within the electrodeionization stacks. These resins are not consumed or exhausted in the electrodeionization process. Radiation monitors associated with the steam generator blowdown system, steam generator system (main steam), and the condenser air removal system provides the means to determine if the secondary side is radioactively contaminated.

After prolonged use, the electrodeionization units will be replaced. If they are not radioactively contaminated, they require no special packaging and may be disposed as clean solid waste. If they are radioactively contaminated, they will be dewatered, the nozzles blocked and packaged for transport according to DOT regulations. Packaged electrodeionization units may be stored in the Radwaste Building.

10.4.8.2.3.7 Electrodeionization Reject Pressure Regulating Valve

A backpressure regulating valve is provided to maintain appropriate system backpressure to the reject path of the EDI modules. By keeping a constant backpressure, this valve will also keep a steady flow through radiation monitor BDS-RE011. This valve will also modulate within the operating range of blowdown flows during normal operation.

10.4.8.2.4 Instrumentation Applications

Flow, pressure, temperature, and radioactivity indicators with alarms monitor system operation. If pressure, temperature, or radioactivity reach a high level setpoint, an alarm is annunciated and the blowdown flow control valves and upstream isolation valves are automatically closed.

Flow elements and transmitters measure and control blowdown flow from the steam generators. The flow elements are located downstream of the blowdown flow control valves.

Temperature instrumentation monitors the temperature of blowdown fluid upstream and downstream of each heat exchanger. The heat exchanger outlet temperature controls heat exchanger cooling water flow as well as the blowdown flow to limit high temperature blowdown fluid to the electrodeionization unit.

Radioactivity detection instrumentation detects and monitors the presence of radioactivity in the combined blowdown stream from both trains. A radiation element is located in the common header upstream of the recovered blowdown three-way valve. This three-way valve normally directs the recovered blowdown flow to the condenser. When recovery of the blowdown fluid is not possible, the flow is diverted to the waste water system. Upon detection of significant levels of radioactivity via a radiation transmitter alarm, the steam generator blowdown flow is diverted to the liquid radwaste system for processing. A second radioactive detection instrument is located on the waste stream of the electrodeionization blowdown. Similarly, a three-way valve normally directs this electrodeionization reject to the waste water system. With detection of significant levels of radioactivity, the reject is diverted to the liquid radwaste system.

10.4.8.3 Safety Evaluation

- Each blowdown line is provided with redundant safety-related valves that isolate the secondary side of the steam generator to preserve the steam generator inventory. The inventory is maintained as a heat sink for sensible and decay heat removal from the reactor coolant system.

- The steam generator blowdown system safety-related functions are accomplished by redundant means. A single, active component failure within the safety-related portion of the system does not compromise the safety-related function of the system. Power is supplied by the Class 1E dc power system as described in Chapter 8.

- Section 3.2 delineates the quality group classification. The controls and power supplies necessary for safety-related functions of the steam generator blowdown system are Class 1E, and are described in Chapters 7 and 8.

- The safety-related portion of the steam generator blowdown system are located in the containment and auxiliary buildings. These buildings and areas are designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, external missiles, and other natural phenomena. Sections 3.3, 3.4, 3.5, 3.7, and 3.8 provide the bases for the adequacy of the

structural design of these buildings and areas. The safety-related portions of the steam generator blowdown system are designed to remain functional after a safe shutdown earthquake. Sections 3.7 and 3.9 provide the design loading conditions that are considered.

- No single failure coincident with loss of offsite power compromises the safety-related functions of the system or will result in:

  – Loss-of-coolant accident
  – Loss of integrity of steam lines
  – Loss of the capability to effect a safe reactor shutdown
  – Transmission of excessive loading to the containment pressure boundary.

  Component or functional redundancy is provided so that safety-related functions can be performed, assuming a single, active failure coincident with loss of ac power.

- The steam generator blowdown system is initially tested in accordance with the program described in Chapter 14. Periodic inservice functional testing is done in accordance with Subsection 10.4.8.4. Section 6.6 provides the ASME Code, Section XI requirements that are appropriate for the safety-related portions of the steam generator blowdown system.

- The safety-related components of the steam generator blowdown system are qualified to function in normal, test, and accident environmental conditions. The environmental qualification program is provided in Section 3.11.

- Discussions of high energy pipe break locations and evaluation of effects are provided in Subsections 3.6.1 and 3.6.2.

- Subsection 6.2.3 delineates the criteria and compliance with applicable requirements and the criteria for the containment isolation provisions.

- The failure modes and effects analysis for the steam generator blowdown system is provided in Table 10.3.3-1.

10.4.8.4 Inspection and Testing Requirements

10.4.8.4.1 Preservice Testing/Inspection

The blowdown system components are tested and inspected during plant startup as a part of the preservice test program as discussed in Chapter 14. The steam generator blowdown system's safety-related functions are designed to include the capability for testing. This includes operation of applicable portions of the protection system. The safety-related components of the system (valves and piping,) are designed and located to permit preservice and inservice inspections to the extent practical.

The steam generator blowdown lines within the containment and the auxiliary building are visually and volumetrically inspected at installation as required by ASME Code, Section XI preservice inspection requirements.

10.4.8.4.2 Inservice Testing/Inspection

The performance and structural leaktight integrity of system components are demonstrated by normal operation.

Additional discussion of inservice inspection of the blowdown containment isolation valves is contained in Section 6.6 and Subsection 3.9.6.

Instruments and controls are calibrated during startup and recalibrated, as necessary, to maintain system operation within its design specifications.

10.4.9 Startup Feedwater System

The startup feedwater system supplies feedwater to the steam generators during plant startup, hot standby and shutdown conditions, and during transients in the event of main feedwater system unavailability. The startup feedwater system is composed of components from the AP1000 main and startup feedwater system (FWS) and steam generator system (SGS).

10.4.9.1 Design Basis

10.4.9.1.1 Safety Design Basis

The safety functions of the startup feedwater system are to provide for containment isolation, steam generator isolation and feedwater isolation following design basis events requiring these actions. Containment isolation is provided to limit radioactive releases to the environment following design basis events that result in the releases of radioactivity to the containment. Steam generator isolation is provided to limit rapid blowdown to a single steam generator following a feedwater or steam line break. Feedwater isolation limits excessive feedwater flow to the steam generators to limit mass and energy releases to containment to limit excessive RCS cooldown and to limit steam generator overfill.

The portion of the startup feedwater system from the steam generator inlets outward through the containment up to and including the startup feedwater isolation valves (SFIVs) is constructed in accordance with the requirements of ASME Code, Section III for Class 2 components and is designed to seismic Category I requirements. The portion of the startup feedwater system from the startup feedwater isolation valve inlets to the piping restraints at the interface between the auxiliary building and the turbine building is constructed in accordance with the requirements of ASME Code, Section III for Class 3 components and is designed to seismic Category I requirements.

The startup feedwater system provides redundant isolation valves, as described below, for the startup feedwater lines routed into containment. The isolation valves close after receipt of an isolation signal in sufficient time to limit the mass and energy release to containment consistent with the containment analysis presented in Section 6.2.

- The safety-related portions of the startup feedwater system are designed to remain functional after a safe shutdown earthquake (SSE) and to perform their intended function of isolating startup feedwater flow following postulated events.

- The safety-related portions of the startup feedwater system are protected from wind and tornado effects, as described in Section 3.3; flood protection is described in Section 3.4; missile protection is described in Section 3.5; protection against dynamic effects associated with the postulated rupture of piping is described in Section 3.6; seismic protection is described in Section 3.7; environmental design is described in Section 3.11; and fire protection is described in Section 9.5.

- The portion of the startup feedwater system to be constructed in accordance with ASME Code, Section III, Class 2 requirements is provided with access to welds and removable insulation for inservice inspection, in accordance with ASME Code, Section XI. The portion of the startup feedwater system to be constructed in accordance with ASME

Code, Section III, Class 3 requirements is also designed and configured to accommodate inservice inspection in accordance with ASME Code, Section XI. The startup feedwater system is designed so that the active components are capable of limited testing during plant operation.

- The startup feedwater system quality group classification codes are identified in Section 3.2. The control functions and power supply are described in Chapters 7 and 8.

- Double valve startup feedwater isolation is provided by the startup feedwater control valve and the startup feedwater isolation valve. Both valves are designed to close on a startup feedwater isolation signal, an appropriate engineered safeguards features (ESF) signal as indicated on Figure 7.2-1. The startup feedwater isolation valve also serves as a containment isolation valve. The startup feedwater control valve fails closed on loss of air. See Section 7.3. Backflow in the startup feedwater line results in closure of the startup feedwater check valve.

- For a steam generator tube rupture event, positive and redundant isolation is provided for the startup feedwater system (startup feedwater isolation valve and startup feedwater control valve), with isolation signals generated by the protection and safety monitoring system.

10.4.9.1.2 Power Generation Design Basis

- During normal plant startup, shutdown or hot standby, feedwater can be supplied through the startup feedwater control valves to the steam generators using either a booster/main feedwater pump drawing water from the deaerator storage tank (refer to Subsection 10.4.7), or using the startup feedwater pumps drawing water from the condensate storage tank.

- In the event of loss of the main feedwater system, the startup feedwater pumps automatically supply feedwater to the steam generators for heat removal from the reactor coolant system. The heat removal function of the startup feedwater system is nonsafety-related. The startup feedwater system avoids the need for actuation of the safety-related passive core cooling system. Following the transient, the system refills the steam generators and supports reactor coolant system cooldown.

- One operating startup feedwater pump delivers sufficient flow to the steam generators to avoid actuation of the passive core cooling system following a reactor trip. The maximum flow available from two operating startup feedwater pumps does not result in overcooling the reactor coolant system, overfilling the steam generators, or inputting excessive mass/energy to containment following a main steam line break.

- The startup feedwater pumps use the condensate storage tank as a water supply source. A sufficient volume of feedwater is available from the condensate storage tank (refer to Subsection 9.2.4) to achieve cold shutdown, based on 8 hours of operation at hot standby conditions and subsequent cooldown of the reactor coolant system within 6 hours to conditions which permit operation of the normal residual heat removal system.

- The startup feedwater pumps are headered at the pump discharge, and a separate line runs from the header to each steam generator.

- For a main feedwater or main steam line break (MSLB) inside the containment, the startup feedwater lines provide a nonsafety-related path for the addition of feedwater to the remaining intact loop if ac power is available.

- For a main feedwater line break upstream of the main feedwater isolation valve (outside of the containment), the startup feedwater lines provide a nonsafety-related path for the addition of feedwater to maintain steam generator level if ac power is available.

- Two startup feedwater pumps are provided with a single pump capable of satisfying the startup feedwater system flow demand for decay heat removal. These pumps automatically start and maintain steam generator water level when the main feedwater system is unavailable.

- In the event of loss of normal ac power and offsite power, the startup feedwater pumps and associated motor operated isolation valves are powered by the onsite standby ac power supply (diesels). Each of the two startup feedwater pumps is powered by its respective standby diesel.

- During normal plant startup, feedwater is supplied through the startup feedwater control valves to the steam generators until transition is made to the main feedwater control valves of the main feedwater system. During normal plant shutdown, feedwater is supplied through the startup feedwater control valves after transition is made from the main feedwater control valves, and until the normal residual heat removal system is placed in service.

10.4.9.2 System Description

10.4.9.2.1 General Description

The startup feedwater system is shown schematically in Figure 10.4.7-1 as part of the condensate and feedwater system piping and instrument diagram and in Figure 10.3.2-1 as part of the main steam system piping and instrument diagram. Classification of equipment and components is given in Section 3.2.

Startup feedwater is defined to be feedwater that passes through the startup feedwater control valves, and can be supplied from either of two sources. Startup feedwater can be supplied by a booster/main feedwater pump drawing from the deaerator storage tank and delivering through cross connect piping to the startup feedwater header; or, startup feedwater can be supplied by one or both startup feedwater pumps drawing from the condensate storage tank and delivering to the startup feedwater header. The startup feedwater header is defined to be the common segment of startup feedwater piping downstream of the startup feedwater pumps. The booster/main feedwater pumps are part of the condensate and feedwater system and are described in Subsection 10.4.7. As described in Subsection 10.4.7.2.1, the cross connection piping between the main feedwater pump discharge header and the startup feedwater header contains a check valve and a nonsafety-related, air-operated isolation valve. The check valve prevents the startup feedwater pumps from supplying the main feedwater header, and the isolation valve automatically closes upon a main feedwater isolation signal to isolate the main feedwater system from the startup feedwater system.

Two parallel startup feedwater pumps are provided and take suction from the condensate storage tank. Each startup feedwater pump discharges to the startup feedwater header through a venturi flow element, an automatic recirculation valve, and a remotely-operated isolation valve. The venturi flow element provides a flow measurement signal at normal flow rates, and cavitates at a flow rate near pump runout to choke the flow and avoid further flow increase. The automatic recirculation valve functions as a check valve to prevent reverse flow through the pump, and also functions as a minimum flow control valve for pump protection; during conditions of low forward flow to the system, sufficient flow from the pump is automatically recirculated back to the condensate storage tank to meet pump minimum flow requirements. The discharge isolation valve is closed when the associated pump is not operating; when in standby operation, the valve automatically opens when the associated pump starts.

The startup feedwater header branches into individual lines to the two steam generators. Each individual line contains a startup feedwater control valve, a check valve, and a startup feedwater isolation valve. Startup feedwater flow in each line is controlled by the associated startup feedwater control valve to maintain level in the associated steam generator.

A thermal relief valve is included in each startup feedwater line between the check valve and isolation valve to prevent overpressure between the control valve and isolation valve due to thermal expansion when both valves are closed.

A startup feedwater system failure analysis for safety-related components is presented in Table 10.4.9-1.

10.4.9.2.2 Component Description

From the connections at the steam generators out through the startup feedwater isolation valves, the startup feedwater system is designed in accordance with the requirements of ASME Code, Section III for Class 2 components and seismic Category I requirements. From upstream of the startup feedwater isolation valve to the restraints at the interface between the auxiliary building and turbine building, the system is designed in accordance with ASME Code, Section III for Class 3 components and seismic Category I requirements. The remaining portion of the startup feedwater system is nonsafety-related.

Startup Feedwater Pump

Each startup feedwater pump is a multistage, centrifugal pump driven by an ac motor. Each pump can supply 100 percent of the required flow to the two steam generators to meet the decay heat removal requirements specified in Subsection 10.4.9.1.2. The pumps automatically start as described in Subsection 10.4.9.2.3.4. Isolation valves at the pump suction and discharge allow each startup feedwater pump to be individually serviced. The discharge isolation valve for each pump is powered by the same train of the onsite standby ac power supply as the associated pump.

Startup Feedwater Control Valve

The startup feedwater control valves are air-operated, modulating control valves with the dual purpose of controlling startup feedwater flow rate, as well as providing isolation of the startup feedwater system. The valve body is a globe design that provides the required range of startup feed control, as well as positive isolation. The startup feedwater control valves operator is equipped with an auxiliary air accumulator to provide independent operation of the startup feedwater control valves upon loss of normal instrument air supply.

The startup feedwater control valves automatically maintain water level in the steam generators during operation of the startup feedwater system, in response to signals generated by the plant control system.

In the event of a secondary side pipe rupture inside the containment, the startup feedwater control valve provides a secondary backup to the startup feedwater isolation valve limiting the quantity of high-energy fluid that enters the containment through the broken pipe. For emergency closure of the valve, a solenoid is deenergized, resulting in valve closure in sufficient time to limit the mass and energy release to containment consistent with the containment analysis presented in Section 6.2. The electrical solenoid is energized from a Class 1E source.

Startup Feedwater Isolation Valve

One startup feedwater isolation valve is installed in each startup feedwater line outside containment and downstream of a startup feedwater control valve and a startup feedwater check valve. The following primary functions are performed by the valve:

- The startup feedwater isolation valve is provided to prevent the uncontrolled blowdown from more than one steam generator in the event of startup feedwater line rupture. The startup feedwater control valve provides backup isolation.

- The startup feedwater isolation valve and the startup feedwater control valve provide isolation of the nonsafety-related portions of the system from the safety-related portions.

- In the event of a secondary pipe rupture inside containment, the startup feedwater isolation valve and startup feedwater control valve provide isolation to limit the quantity of high energy fluid that enters the containment.

- In the event of a steam generator tube rupture, the startup feedwater isolation valve and startup feedwater control valve limit overfill of the steam generator by terminating startup feed flow.

The startup feedwater isolation valve is a remotely-operated gate valve designed in accordance with ASME Code, Section III Class 2 requirements. The valve operator is designed to stroke against steam generator pressure or startup feedwater pump shutoff head.

The startup feedwater isolation valve and startup feedwater control valve functional diagrams are shown in Figure 7.2-1. To provide the safety function actuation (closure) as well as reliable alignment, and redundant and independent actuation, the startup feedwater isolation valve and startup feedwater control valve are powered from separate Class 1E power sources.

Startup Feedwater Thermal Relief Valves

A relief valve is provided between the startup feedwater check valve and isolation valve to prevent overpressurization of the startup feedwater lines between the startup feedwater isolation valve and startup feedwater control valve. The relief valve prevents overpressurization that could be caused by thermal expansion of the fluid trapped between the isolation and control valves following an event causing startup feedwater isolation.

10.4.9.2.3 System Operation

The startup feedwater system supplies the steam generators with feedwater during conditions of plant startup, hot standby and shutdown, and during transients in the event of main feedwater system unavailability. The startup feedwater system also supplies feedwater during low power operation under conditions when the startup feedwater control valves regulate the feedwater flow to the steam generators.

10.4.9.2.3.1 Startup

During reactor startup and at low power levels, feedwater is supplied to the steam generators through the startup feedwater control valves using either the startup feedwater pumps drawing from the condensate storage tank, or a booster/main feedwater pump drawing from the deaerator storage tank. Refer to Subsection 10.4.7 for a description of the operation of the condensate and feedwater system and the booster/main feedwater pumps. The feedwater pumps in use operate on minimum flow recirculation as necessary while maintaining the water level of the steam generators. Feedwater is controlled by the startup feedwater control valves, which are operated either manually from the control room or automatically in accordance with steam generator level demand. If the startup feedwater pumps are initially in use, transfer is made to a booster/main feedwater pump prior to exceeding the capacity limit of the startup pumps. As power increases, feedwater continues to be supplied through the startup feedwater control valves until control of feedwater is automatically transferred from the startup feedwater control valves to the main feedwater control valves. As the main feedwater control valves open and assume responsibility for maintaining steam generator water

level, the startup feedwater control valves close. Position indication is available in the main control room for the main and startup feedwater control valves.

10.4.9.2.3.2 Hot Standby

During hot standby conditions, feedwater is supplied to the steam generators through the startup feedwater control valves using either one or both startup feedwater pumps drawing from the condensate storage tank, or a booster/main feedwater pump drawing from the deaerator storage tank. The startup feedwater control valves operate to maintain the steam generator levels, and minimum flow recirculation is automatically utilized as required to protect the feedwater pumps that are in use.

10.4.9.2.3.3 Shutdown

Operation during power descent and shutdown is generally the reverse of operation during startup and power ascent. At low feedwater flows, control of feedwater is automatically transferred from the main feedwater control valves to the startup feedwater control valves. Feedwater is supplied by an operating booster/main feedwater pump drawing from the deaerator storage tank. Feedwater can continue to be supplied by a booster/main feedwater pump during the shutdown process; alternatively, feedwater supply can be transferred to the startup feedwater pumps when flow demand has decreased to within their capacity. Feedwater continues to be supplied until the normal residual heat removal system is placed in service.

10.4.9.2.3.4 Automatic Starts

The startup feedwater pumps automatically start upon conditions resulting from insufficient main feedwater flow to the steam generators. An automatic pump start signal is generated by the plant control system (PLS). The signal is generated on low main feedwater flow coincident with low steam generator level. As a backup to this logic, it is also initiated on steam generator level alone, at a setpoint below the low steam generator level setpoint.

The amount of startup feedwater flow delivered to each steam generator is determined by the associated startup feedwater control circuit, which sends a signal to modulate the startup feedwater control valve (Figure 10.3.2-1) in response to steam generator water level control signals. The control valve is modulated as required to maintain the programmed steam generator water level setpoint.

Following a reactor trip that is not the result of a main feedwater system malfunction and in which the main feedwater system remains available, the startup feedwater pumps do not automatically start. In this case, the startup feedwater control valves take control and open to supply the steam generators using feedwater delivered from a booster/main feedwater pump through cross-connect piping. The startup feedwater pumps remain on standby for backup protection, and can be manually started if desired by the plant operator.

10.4.9.2.3.5 Emergency Operation

The startup feedwater system is not required to supply feedwater under accident conditions. However, the startup feedwater system is expected to be available as a nonsafety-related, first line of defense to provide a source of feedwater for the steam generators. Coordinated operation of the startup feedwater system (which starts automatically, as discussed in Subsection 10.4.9.2.3.4), if available, and the main steam supply system (refer to Section 10.3) are employed to remove the primary loop sensible heat and reactor decay heat. A minimum condensate storage tank volume of 325,000 gallons is required for defense-in-depth purposes. The condensate storage tank size is shown in Subsection 9.2.4.2.2.

10.4.9.3 Safety Evaluation

- The safety-related portions of the startup feedwater system are located in the containment and auxiliary buildings. These buildings are designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, external missiles, and other natural phenomena. Sections 3.3, 3.4, 3.5, 3.7, and 3.8 provide the bases for the adequacy of the structural design of these buildings.

- The safety-related portions of the startup feedwater system are designed to remain functional after a design basis earthquake. Subsection 3.7.2 and Section 3.9 provide the design loading conditions that are considered. Sections 3.5, 3.6, and Subsection 9.5.1 provide the analyses to provide confidence that a safe shutdown, as outlined in Section 7.4, is achieved and maintained.

- The startup feedwater system safety-related functions are accomplished by redundant means. A single, active component failure of the safety-related portion of the system does not compromise the safety function of the system. Table 10.4.9-1 provides a failure analysis of the safety-related active components of the startup feedwater system. Power is supplied from onsite power systems, as described in Chapter 8.

- Preoperational testing of the safety-related portion of the condensate and feedwater system is performed as described in Chapter 14. Periodic inservice functional testing is done in accordance with Subsection 10.4.9.4. Section 6.6 provides the ASME Code, Section XI requirements that are appropriate for the startup feedwater system.

- Section 3.2 delineates the quality group classification and seismic category applicable to the safety-related portion of this system and supporting systems. The controls and power supplies necessary for the safety-related functions of the startup feedwater system are Class 1E, as described in Chapters 7 and 8.

- The startup feedwater isolation valves and the startup feedwater control valves automatically close upon receipt of a feedwater isolation signal, which occurs on a steam generator High-3 water level and other appropriate engineered safeguards signals as shown on the diagrams titled “Feedwater Isolation” and “Steam Line Isolation” in Figure 7.2-1.

- For a steam generator tube rupture event, positive and redundant isolation is provided for the startup feedwater system (startup feedwater isolation valve and startup feedwater control valve) to prevent steam generator overfill, with engineered safeguards isolation signals generated by the protection and safety monitoring system (PMS).

10.4.9.4 Tests and Inspections

10.4.9.4.1 Preoperational Valve Testing

The startup feedwater isolation valves and startup feedwater control valves are checked for closing time prior to initial startup.

10.4.9.4.2 Preoperational Pipe Testing

The Class 2 portion of the startup feedwater system piping is tested and inspected to the requirements of ASME Code, Section III, Class 2 piping. In addition, the portion of the piping between the containment penetration and the anchor, which is traditionally considered as the break exclusion zone described in Subsection 3.6.2, is subjected to 100-percent volumetric inspection at installation (that is, 100-percent volumetric examination of shop and field longitudinal and circumferential welds).

10.4.9.4.3 Preoperational System Testing

Preoperational testing of the startup feedwater system is performed as described in Chapter 14. Tests described in Subsection 14.2.9.1.7, under item c) of General Test Method and Acceptance Criteria satisfy BTP (AS) 10-2. Additional testing of the startup feedwater system is conducted during startup testing as described in Subsection 14.2.10.4.18.

10.4.9.4.4 Inservice Inspections

The performance and structural and leaktight integrity of the startup feedwater system components are demonstrated by normal operation.

The inservice inspection program for ASME Section III Class 2 and 3 components is described in Section 6.6. The inservice testing program, including testing for the startup feedwater isolation valve and startup feedwater control valve, is described in Subsection 3.9.6.

10.4.9.5 Instrumentation Applications

The startup feedwater system instrumentation is designed to facilitate automatic operation, remote control, and continuous indication of system parameters.

The startup feedwater flow is controlled by a steam generator level demand signal modulating the startup feedwater control valve. The control valve may either be in manual or automatic control. Refer to Section 7.7. The startup feedwater flow transmitters also provide redundant indication of startup feedwater and automatic safeguards actuation input on Low-2 flow coincident with Low-2 steam generator narrow range water level. See Section 7.3.

10.4.10 Auxiliary Steam System

The auxiliary steam system (ASS) provides the steam required for plant use during startup, shutdown, and normal operation. Steam is supplied from either the auxiliary boiler or the main steam system. During a loss of normal ac power, a temporary boiler can be used for investment protection.

10.4.10.1 Design Basis

10.4.10.1.1 Safety Design Basis

The auxiliary steam system serves no safety-related function and therefore has no nuclear safety design basis.

10.4.10.1.2 Power Generation Design Basis

The auxiliary steam system supplies steam required by the unit for a cold start of the main steam system and turbine-generator. Additionally, the auxiliary steam system provides steam for hot water heating. Main steam supplements the auxiliary steam header during startup and supplies the auxiliary steam header during normal operation. The auxiliary boiler provides steam to the header during plant shutdown.

10.4.10.2 System Description

10.4.10.2.1 General Description

The auxiliary boiler is located in the turbine building. The system consists of steam generation equipment and distribution headers.

Condensate from the condensate storage tank is chemically treated and pumped to the auxiliary boiler deaerator where oxygen and non-condensables are removed using auxiliary steam. The auxiliary boiler feedwater pumps deliver condensate from the auxiliary boiler deaerator to the auxiliary boiler. A feedwater control valve, located in the feedwater piping, regulates water level in the auxiliary boiler. Feedwater flow is proportional to auxiliary boiler steaming rate. Steam generated by the auxiliary boiler is supplied to the plant auxiliary steam distribution piping.

Boiler water quality is maintained by controlling boiler blowdown flow to an atmospheric blowdown tank and by feeding oxygen scavenging and pH control chemicals to the boiler makeup water system.

Water level in the auxiliary boiler deaerator is maintained by an automatic control valve in the condensate supply and deaerator overflow piping. Makeup water is supplied from the demineralized water transfer and storage system.

During a loss of normal ac power, the auxiliary steam supply system provides steam to the hot water heating system for investment protection. To accomplish this, provisions are made to power the auxiliary boiler makeup and feed pumps from the onsite diesel generators. Steam is supplied by a temporary boiler with diesel-backed control power

10.4.10.2.2 Component Description

Auxiliary steam system component classification is as described in Section 3.2.

Auxiliary Steam System and Boiler

The auxiliary steam boiler is an electric package boiler with a nominal net output capacity of approximately 62,000 pounds per hour of saturated steam at 195 psig. The system is protected from overpressure by safety valves located on the boiler, boiler deaerator, and auxiliary steam header.

Pumps

Two 100-percent capacity auxiliary boiler feedwater pumps are provided to feed the auxiliary steam boiler. These pumps are also used to supply the temporary boiler for investment protection.

Two 100-percent capacity auxiliary boiler makeup pumps maintain level in the boiler deaerator.

Auxiliary Boiler Deaerator

The auxiliary boiler deaerator is a 100-percent-capacity deaerator which uses steam supplied by the auxiliary steam header. The auxiliary boiler deaerator steam blanket is controlled for preheating and deaerating boiler makeup water. The auxiliary boiler deaerator removes oxygen and non-condensables from auxiliary boiler feedwater.

Chemical Treatment Components

The auxiliary boiler makeup water is treated with pH control and oxygen scavenging chemicals. Chemical injections maintain proper water chemistry during operational conditions. Batch chemicals for cleaning and layup are injected into the auxiliary boiler and auxiliary boiler deaerator when they are not in operation. Chemical feed equipment for the auxiliary steam system is part of the turbine island chemical feed system (CFS) and is described in Subsection 10.4.11.

10.4.10.2.3 System Operation

When in operation, the auxiliary steam system provides the following services:

- Steam to the plant hot water heating system (VYS) heat exchangers where water is heated and pumped to the heating system ventilation coils.

- Steam for the condensate system deaerator prior to plant startup. This heating occurs in two stages: initially the only source of auxiliary steam is the auxiliary boiler, which provides limited heating steam to the deaerator due to the steam demand of the VYS and the gland steam system (GSS). Once main steam is available to augment the auxiliary boiler steam, the auxiliary steam system has adequate steam to maintain the deaerator at a positive pressure, at feedwater flows required for turbine synchronization.

- Sealing steam to the glands of the main turbine prior to the availability of main steam.

- Steam for maintaining pressure in the condensate system deaerator after a turbine trip when extraction steam is lost.

Operational safety features are provided within the system for the protection of plant personnel and equipment. The auxiliary steam system does not interface directly with nuclear process systems.

10.4.10.3 Safety Evaluation

The auxiliary steam system has no safety-related function and therefore requires no nuclear safety evaluation. High energy pipe rupture analysis is not required for the auxiliary steam system since none of the lines pass through areas where safety related equipment is located.

10.4.10.4 Tests and Inspections

Testing of the auxiliary steam system is performed prior to initial plant operation.

Components of the system are monitored during operation to verify satisfactory performance.

10.4.10.5 Instrumentation Applications

A boiler control system is provided with the auxiliary boiler package for automatic control of the auxiliary boiler. Features of the control system include automatic shutdown of the auxiliary boiler on an abnormal condition.

The auxiliary steam system is provided with the necessary controls and indicators for local or remote monitoring of the operation of the system.

10.4.11 Turbine Island Chemical Feed

The turbine island chemical feed system (CFS) injects required chemicals into the condensate (CDS), feedwater (FWS), auxiliary steam (ASS), service water (SWS), and demineralized water treatment (DTS). CFS components are located in the turbine building, SWS chemical treatment building, and SWS cooling tower basin area.

10.4.11.1 Design Basis

10.4.11.1.1 Safety Design Basis

The turbine island chemical feed system serves no safety-related function and therefore has no nuclear safety design basis.

10.4.11.1.2 Power Generation Design Basis

A noncorrosive condition is maintained within the systems serviced by the turbine island chemical feed system.

The secondary sampling system (SSS), as described in Subsection 9.3.4, contains sampling requirements in accordance with water chemistry specifications that are provided in the secondary side water chemistry program, as described in Subsection 10.3.5.

10.4.11.2 System Description

Classification of equipment and components is given in Section 3.2.

10.4.11.2.1 Component Description

Condensate, Feedwater and Auxiliary Steam

An all-volatile chemical feed system (AVT) is used for condensate, feedwater and auxiliary steam water chemistry control. An oxygen scavenger is injected into the condensate system downstream of the condensate polishers to control the dissolved oxygen level. Feedwater chemistry is controlled by maintaining a residual level of oxygen scavenger. The injection point for the feedwater oxygen scavenger is located upstream of the feedwater booster pump suction. A pH adjuster is also injected into the condensate system downstream of the condensate polishers for pH control. Injection for pH control of the feedwater is located upstream of the feedwater booster pump suction. Chemical feed pumps and tanks are used to store and inject the chemicals into the piping system. Subsection 10.4.10.2.2 describes chemical feed for the auxiliary steam system.

Service Water

A biocide, pH adjuster, and dispersant/corrosion/scale inhibitor are injected into the service water system as required. A nonoxidizing biocide can be fed to the service water cooling tower basin. Subsection 9.2.1.2.2 describes chemical feed for the service water system.

Demineralized Water Treatment

A pH adjuster, chlorine reducing agent, and scale inhibitor are injected into the demineralized water treatment system. Subsection 9.2.3.2.3 describes chemical feed for the demineralized water treatment system.

10.4.11.2.2 System Operation

Condensate, Feedwater and Auxiliary Steam System Chemistry Control

An oxygen scavenger is injected upstream of the feedwater booster pump suction to maintain a residual level of oxygen scavenger and a dissolved oxygen level of not more than 5 ppb at the inlet to the steam generator.

A pH adjuster is also injected upstream of the feedwater booster pump suction to maintain the pH at the steam generator inlet within the control program for pH.

An oxygen scavenger is injected into the condensate system downstream of the condensate polishers to maintain a dissolved oxygen level of not more than 10 ppb at the inlet of the deaerator.

A pH adjuster is injected into the condensate system downstream of the condensate polishers to maintain the pH above 9.0 at the deaerator inlet within the control program for pH.

The chemical feed system may be used to place the steam generators in wet layup. This layup process is accomplished using the chemical feed system in conjunction with the steam generator blowdown system. Refer to Subsection 10.4.8.2 for details of this process.

An oxygen scavenger and pH adjuster are injected into the auxiliary steam system downstream of the boiler makeup pumps to maintain the dissolved oxygen level and pH within the auxiliary boiler program levels. The chemical feed rates are manually adjusted.

Service Water System Chemistry Control

A biocide, pH adjuster and dispersant/corrosion/scale inhibitor are injected in the SWS cooling tower basin as required. Chemical feed rates for the biocide and dispersant/corrosion/scale inhibitor are either manually or automatically adjusted to maintain proper concentrations. The pH adjuster chemical feed rate is controlled electronically from instrumentation that measures pH.

A nonoxidizing biocide is provided to control algae formation on the service water cooling tower. The feed rate is either manually or automatically adjusted.

Demineralized Water Treatment System Chemistry Control

A pH adjuster, chlorine reducing agent, and scale inhibitor are injected into the raw water supply to the demineralized water treatment system.

10.4.11.3 Safety Evaluation

The turbine island chemical feed system has no safety-related function and therefore requires no nuclear safety evaluation.

Toxic gases, such as chlorine, are not used in the turbine island chemical feed system. The impact of toxic material on main control room habitability is addressed in Section 6.4.

10.4.11.4 Tests and Inspections

The turbine island chemical feed system is operationally checked before initial plant startup to verify proper functioning of the feed systems and chemical sensors.

10.4.11.5 Instrumentation Applications

The secondary sampling system (SSS), as described in Subsection 9.3.4, provides instrumentation which measures dissolved oxygen, oxygen scavenger residual, and pH for the condensate, feedwater, and steam generator systems. These analyzers provide an indication of water quality and inputs for either manual or automatic control of the condensate and feedwater systems oxygen scavenging and pH control chemical feed pumps. Grab samples are analyzed to provide input for manual adjustment of feed rates for the auxiliary steam system oxygen scavenging and pH control chemical feed pumps. Wet layup operations are manually performed based on the results of the grab sample analysis.

Grab samples are analyzed to provide input for either manual or automatic adjustment of feed rates for biocide, pH adjustment, and/or dispersant/corrosion/scale inhibitor chemicals for service water and demineralized water treatment.

10.4.12 Combined License Information

10.4.12.1 Circulating Water System

The configuration of the plant circulating water system is addressed in Subsections 10.4.5.2.1, 10.4.5.2.2, and 10.4.5.5.

10.4.12.2 Condensate, Feedwater and Auxiliary Steam System Chemistry Control

The oxygen scavenging agent and pH adjuster selection for the turbine island chemical feed system is addressed in Subsection 10.4.7.2.1.

10.4.12.3 Potable Water

Potable water is produced on site by the Potable Water System (PWS). Source water for the PWS is from the well water subsystem to the Raw Water System. Sodium hypochlorite is used as the biocide. The PWS is discussed in Subsection 9.2.5.

10.4.13 References

1. ASME Performance Test Code 19.11, 2008.

2. Heat Exchange Institute Performance Standard for Liquid Ring Vacuum Pumps.

3. Not Used.

201. Nuclear Energy Institute, "Steam Generator Program Guidelines," NEI 97-06.

Table 10.4.1-1
Main Condenser Design Data

Condenser Data	
Condenser type	Multipressure, Single pass
Hotwell storage capacity	3 min
Heat transfer	7,540 x 10^6 Btu/hr
Design operating pressure (average of all shells)	2.9 in.-Hg
Shell pressure (design)	0 in.-Hg absolute to 15 psig
Circulating water flow	600,000 gpm
Water box pressure (design)	90 psig
Tube-side inlet temperature	91°F
Approximate Tube-side temperature rise	25.2°F
Condenser outlet temperature	116.2°F
Waterbox material	Carbon Steel
Condenser Tube Data	
Tube material (main section)	Titanium(1)
Tube size	1″ O.D. – 23 BWG
Tube material (periphery)	Titanium(1)
Tube size	1″ O.D. – 23 BWG
Tube sheet material	Titanium or Titanium Clad Carbon Steel(2)
Support plates	Modular Design/Carbon Steel

Note:
1. For fresh water plants, an equivalent tube material such as 304L, 316L, 904L, or AL-6X may be substituted.
2. If one of the alternate tube materials is used, the tube sheet shall be carbon steel, clad with the same material as the tubes.

Table 10.4.5-1
Design Parameters for Major Circulating Water System Components

Circulating Water Pump	
Quantity	Four per unit
Flow rate (gal/min)	156,200 (note 2)
Natural Draft Cooling Tower	
Quantity	One per unit
Approach temperature (°F)	13.6
Inlet temperature (°F)	116.7 (note 3)
Outlet temperature (°F)	90.9
Approximate Temperature range (°F)	25.8
Flow rate (gal/min)	622,000
Heat transfer (Btu/hr)	$7{,}628 \times 10^6$ (note 3)
Wind velocity design (mph) Seismic design criteria per Uniform Building Code	110

Notes:

1. Not used.
2. Nominal CWS pump flow rate includes blowdown (2,801 gpm) which is discharged from the pump discharge common header. This flow rate (156,200 gpm) is the minimum flow rate needed to meet system design requirements.
3. The inlet temperature (°F) is approximately 115.2°F, as the condenser outlet flow is expected to be cooled by the return flow stream from the TCS.

Table 10.4.7-1 (Sheet 1 of 2)
Condensate and Feedwater System Component Failure Analysis

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
1. SGS PL V057A (MFIV)	1a. Valve fails closed or fails to open on command. Train “A” is not available for FW flow to SG “A.”	FW Train “B” available. SFW Train “A” available.	None. Decay heat removal is maintained via PRHR actuation on ESF signal. SFW available to provide flow to SG “A.”
	1b. Valve fails open or fails to close on command. Trains “A” and “B” are available for FW flow. Isolation function of V057A is not available. Redundant power division closure of MFIV provided for reliability; backup isolation provided by V058A and V250A.	Valve V250A (MFCV) provides backup isolation to terminate feedwater flow. Check valve V058A provides redundant feedwater blowdown isolation from SG “A;” redundant containment isolation provided by SG and feedwater line inside containment.	None. RCS integrity is maintained by valve V058A/V250A available to prevent SG “A” blowdown. Decay heat removal available via PRHR and SFW actuated by ESF signal. SG overfill protection provided by backup isolation of V250A.
2. SGS PL V057B (MFIV)	2a. Same as except for SG “B.”	FW Train “A” available. SFW Train “B” available.	Same as 1a except for SG “B.”
	2b. Same as 1B except isolation function of V057B is not available.	Same as 1b except for “B” train valves and SG “B.”	Same as 1b except for “B” train valves and SG “B.”
3. SGS PL V250A (MFCV)	3a. Valve fails closed or fails to open on command. Train “A” is not available for FW flow to SG “A.”	FW Train “B” available. SFW Train “A” available.	None. Decay heat removal is maintained via PRHR actuation on ESF signal. SFW available to provide flow to SG “A.”
	3b. Valve fails open or fails to close on command. Trains “A” and “B” are available for FW flow without flow control to SG “A.” Backup isolation provided by V058A and V057A.	Valve V057A (MFIV) provides backup isolation to terminate feedwater flow. Check valve V058A and V057A provide redundant feedwater blowdown isolation from SG “A.” SFW train “A” and “B” available for decay heat removal.	None. RCS integrity is maintained by valve V057A and V058A closure to limit SG blowdown. Decay heat removal available via PRHR and SFW actuated by ESF signal. SG overfill protection provided by redundant isolation of V057A.

Table 10.4.7-1 (Sheet 2 of 2)
Condensate and Feedwater System Component Failure Analysis

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
4. SGS PL V250B (MFCV)	4a. Same as 3a, except for train “B” and SG “B.”	Same as 3a except train “B.”	Same as 3a except for SG “B.”
	4b. Same as 3b, except for SG “B” and valves V057B and V058B.	Same as 3b except valves V057B and V058B and SG “B.”	Same as 3b except for V057B and V058B.

Table 10.4.9-1 (Sheet 1 of 2)
Startup Feedwater System Component Failure Analysis

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
1. SGS PL V255A (SFCV)	1a. Valve fails closed or fails to open on command. SFW Flow is not available to SG A.	System is not available for SFW supply to SG “A.”	None. Decay heat removal is maintained via PRHR actuation on ESF signal.
	1b. Valve fails open or fails to close on command. SFW flow is uncontrolled.	Downstream isolation valve V067A trips closed on high SG level; system pumps are tripped on high SG level.	None. RCS integrity is maintained by V067A closure and main feedwater isolation. SG overfill terminated by ESF closure of V067A.
2. SGS PL V225B (SFCV)	2a. Same as 1a except flow is not available to SG B.	System is not available for SFW supply to SG “B.”	None. Same as 1a.
	2b. Same as 1b.	Same as 1b except valve V067B trips closed on high SG level.	Same as 1b except RCS integrity is maintained by V067B and main feedwater isolation, and overfill terminated by closure of V067B.
3. SGS PL V067A (SFIV)	3a. Valve fails closed. SFW flow is not available to SG A.	System is not available for SFW supply to SG “A.”	None. Same as 1a.
	3b. Valve fails open. Isolation function of V067A is not available; backup isolation provided by V0255A and V256A.	None. Valve V255A is automatically closed and SFW pumps tripped on an ESF signal. SG overfill protection provided by automatic isolation of V255A.	None. RCS integrity is maintained by V255A closure to limit cooldown; PRHR available for decay heat removal and SG overfill protection provided by redundant isolation of V255A.

Table 10.4.9-1 (Sheet 2 of 2)
Startup Feedwater System Component Failure Analysis

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
4. SGS PL V067B (SFIV)	4a. Same as 3a except flow not available to SG “B.”	Same as 3a except SFW supply not available to SG “B.”	Same as 1a.
	4b. Same as 3b.	Same as 3b except reference valve is V255B.	Same as 3b except reference valve is V255B.

Table 10.4.9-2
Nominal Component Design Data – Startup Feedwater System

Startup Feedwater Pump	
Type	Multi-stage, centrifugal
Driver	Electric Motor
Quantity	2
Capacity	520 gpm @ 80°F
Head	3250 ft
Motor hp	800

Table 10.4-201
Not Used

Table 10.4-202
Not Used

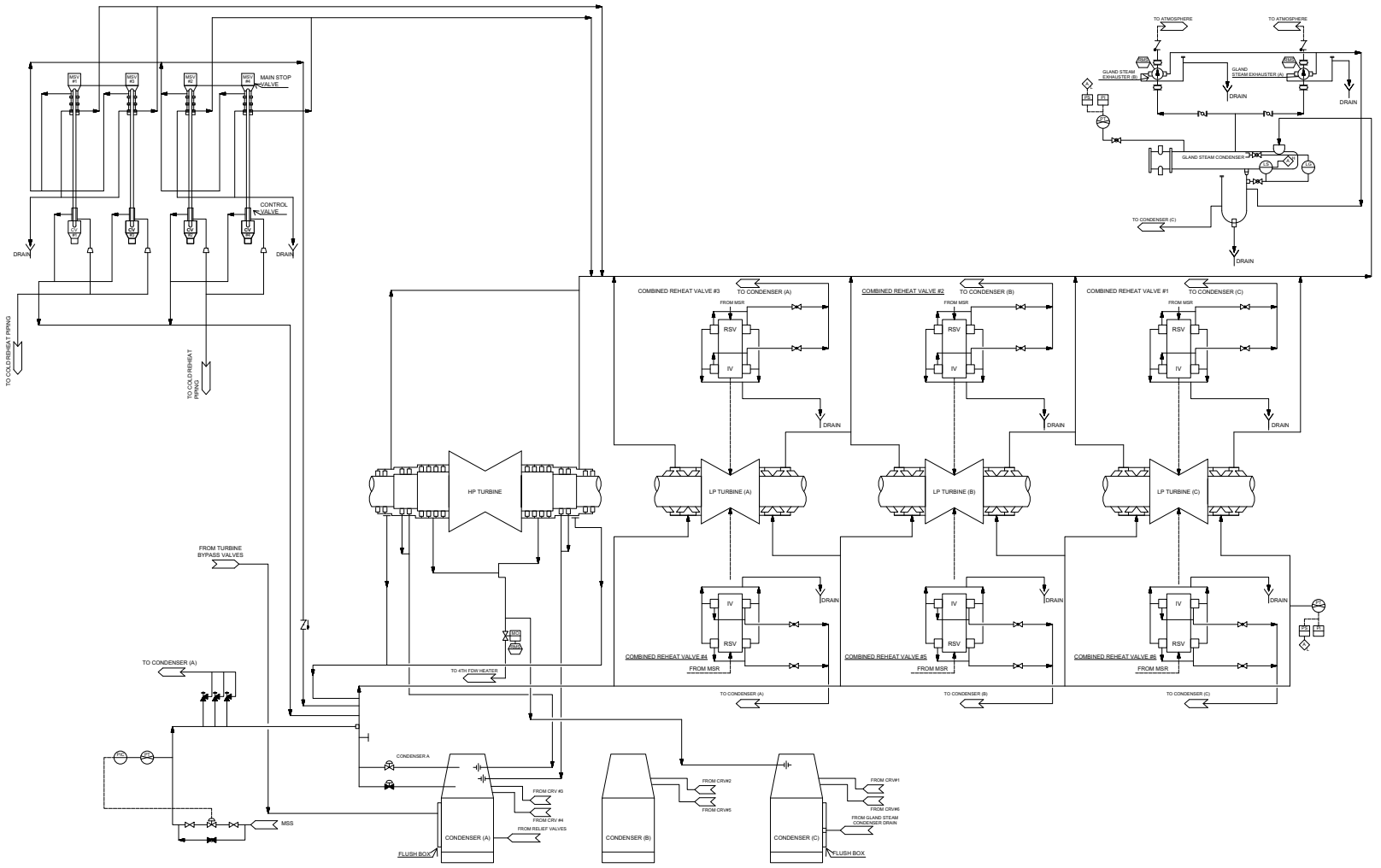


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Figure 10.4.3-1
Gland Seal System
Piping and Instrumental Diagram
(REF) GSS 001, 002

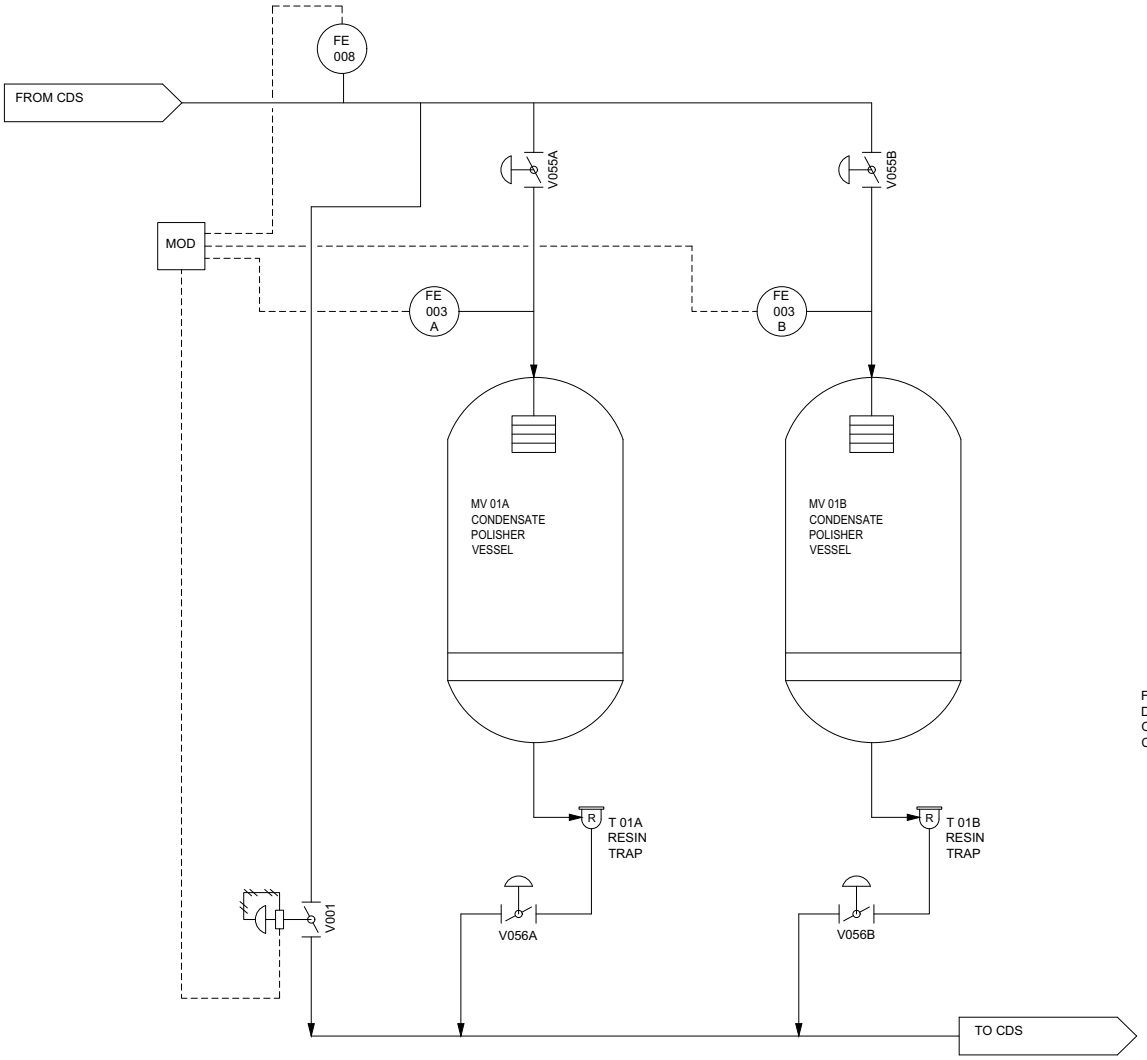


FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Inside Turbine Building

Figure 10.4.6-1
Condensate Polishing System
Piping and Instrumentation Diagram (Typical)

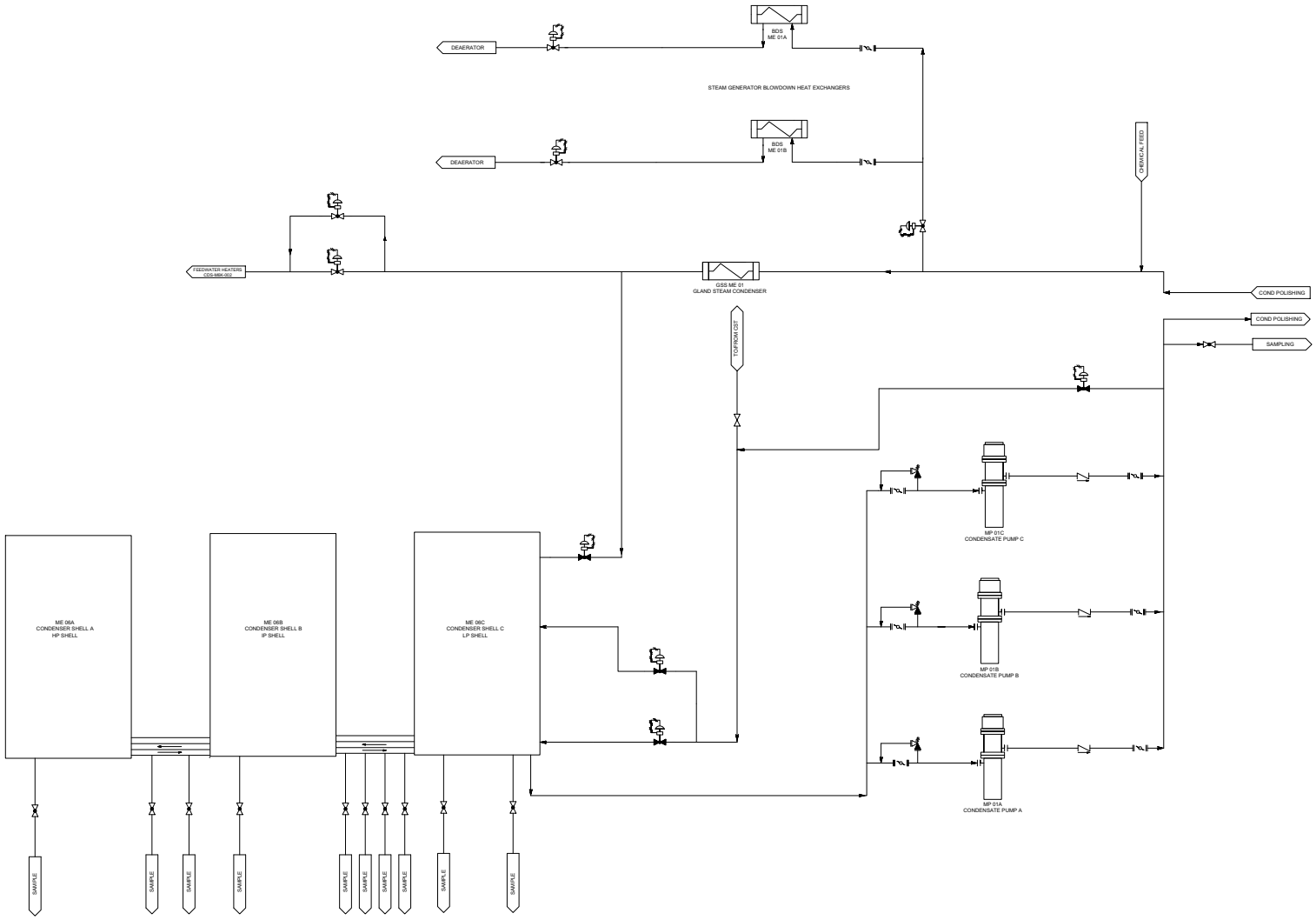


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Figure 10.4.7-1 (Sheet 1 of 4)
Condensate and Feedwater System
Piping and Instrumentation Diagram

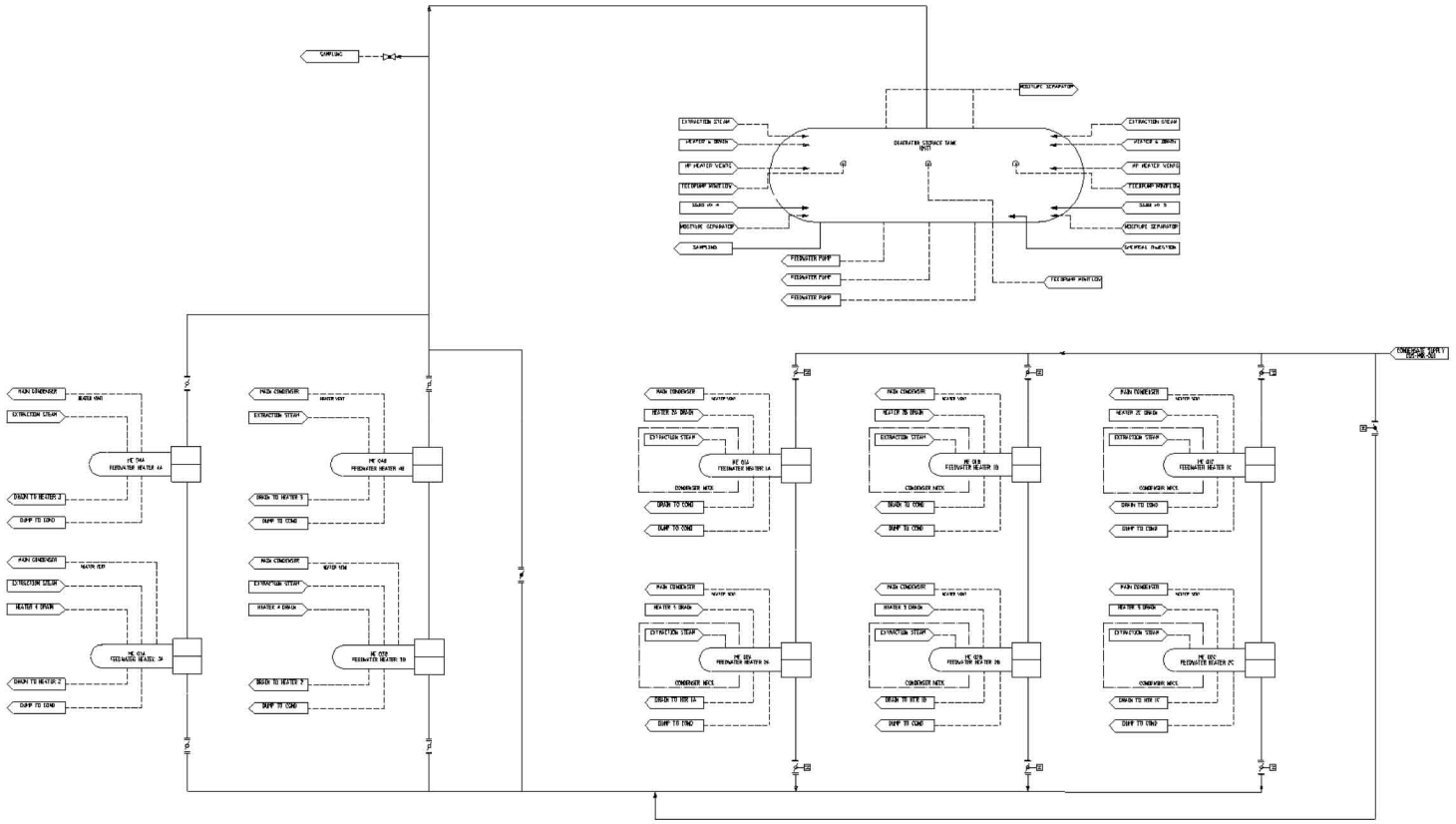


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Figure 10.4.7-1 (Sheet 2 of 4)
Condensate and Feedwater System
Piping and Instrumentation Diagram

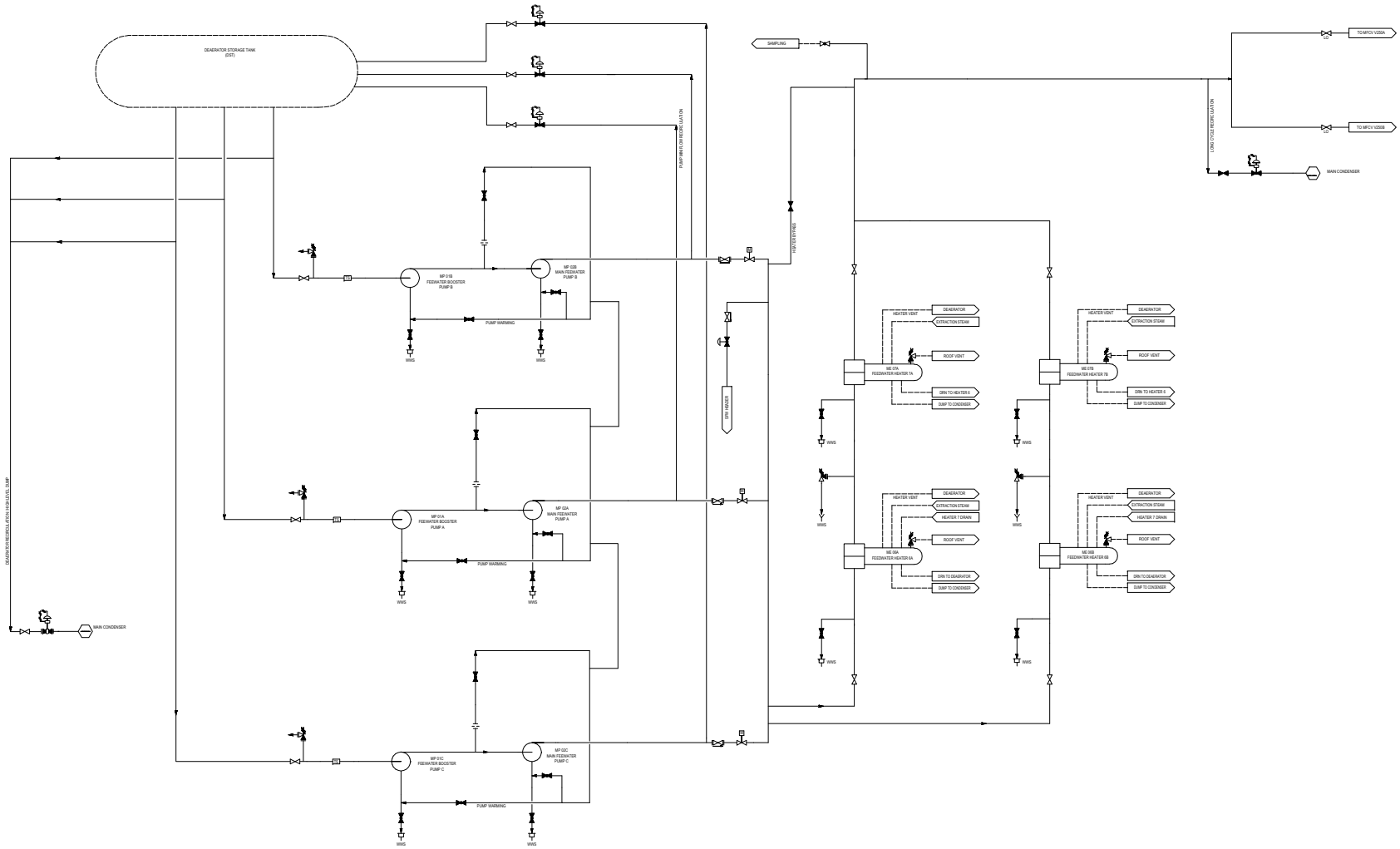
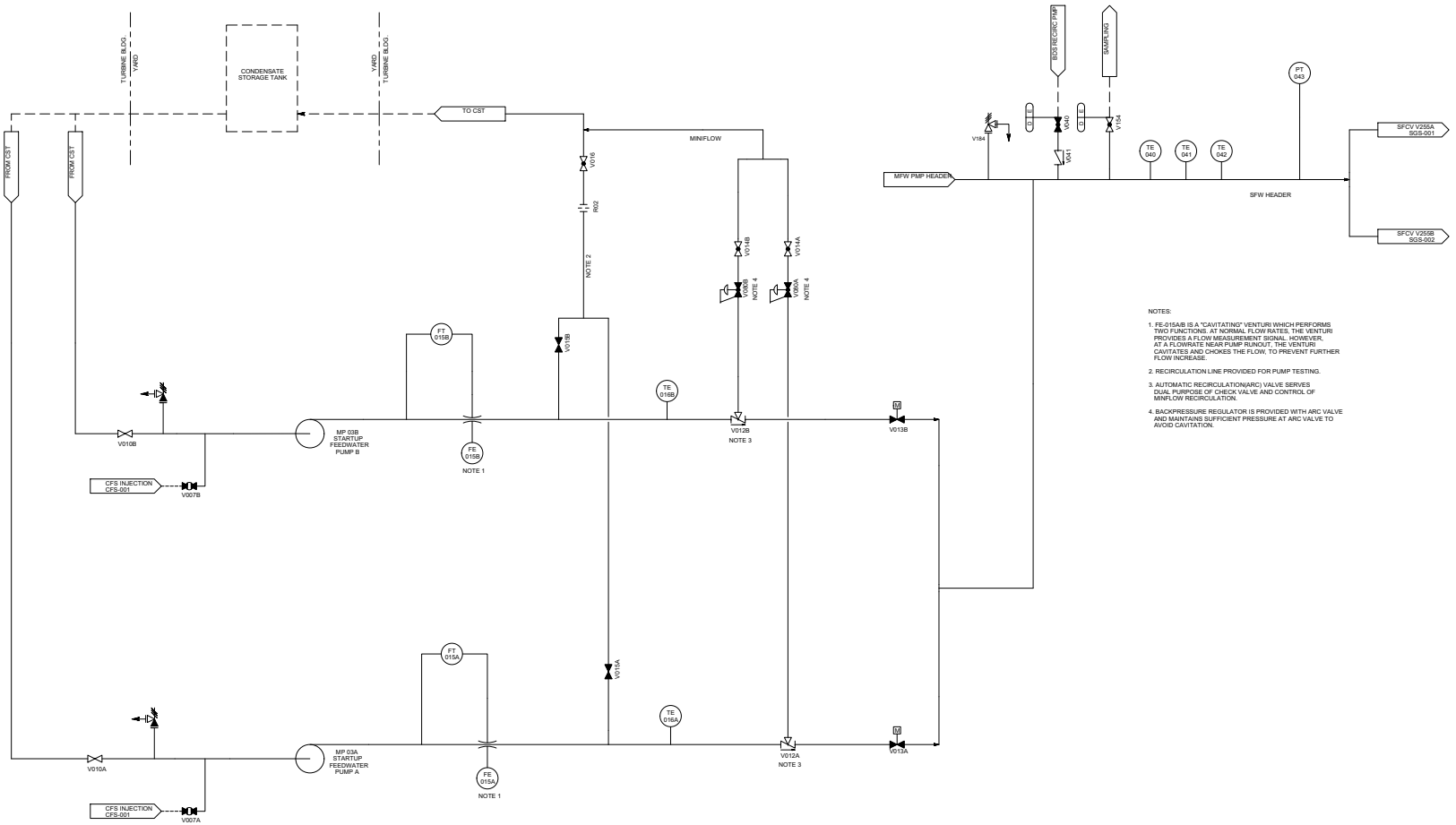


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Figure 10.4.7-1 (Sheet 3 of 4)
Condensate and Feedwater System
Piping and Instrumentation Diagram

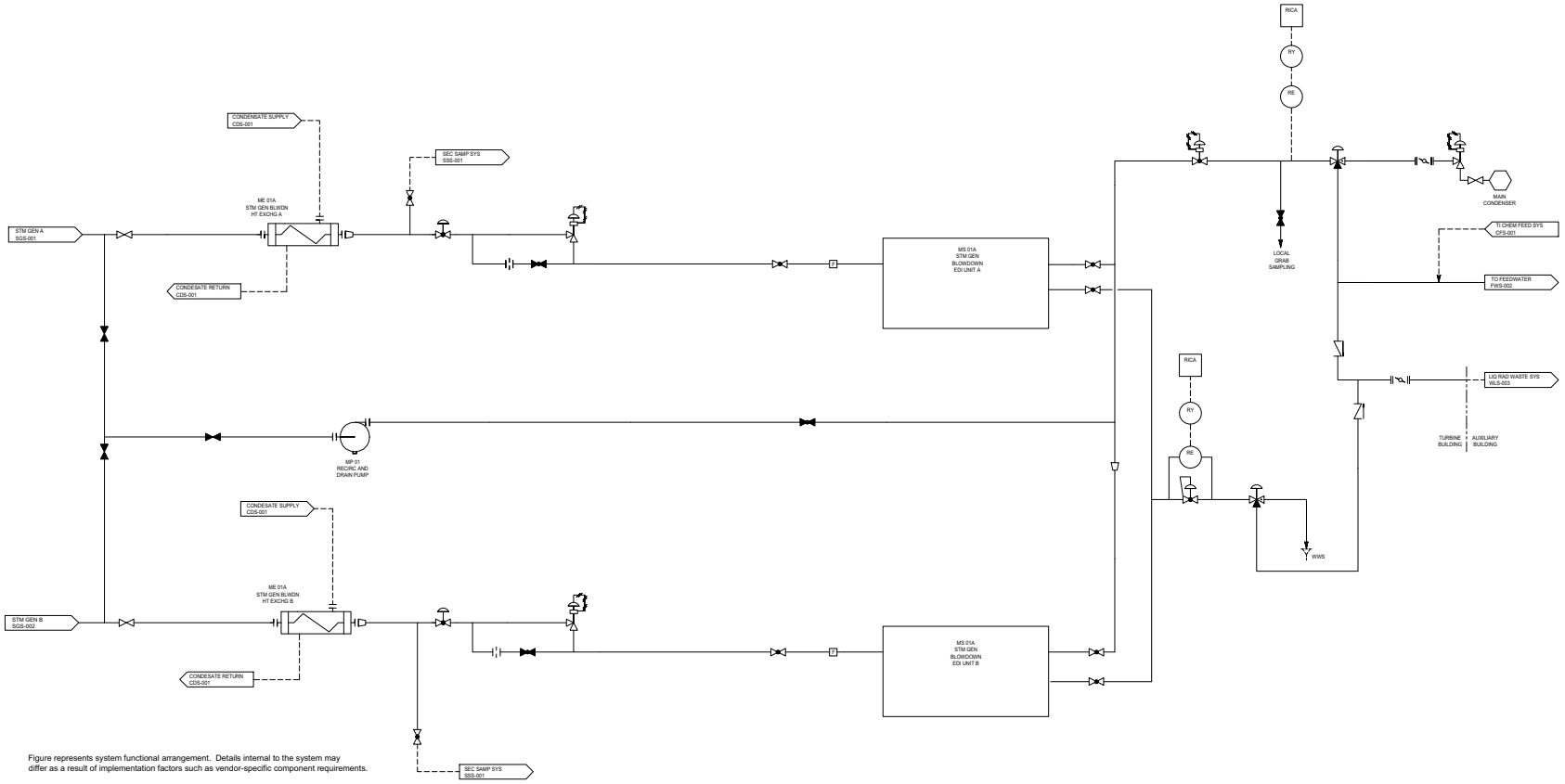


SYSTEM COMPONENTS ARE CLASS D UNLESS NOTED.

VENTS, DRAINS, AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN, BUT NOT SPECIFICALLY SHOWN ON DCD FIGURES.

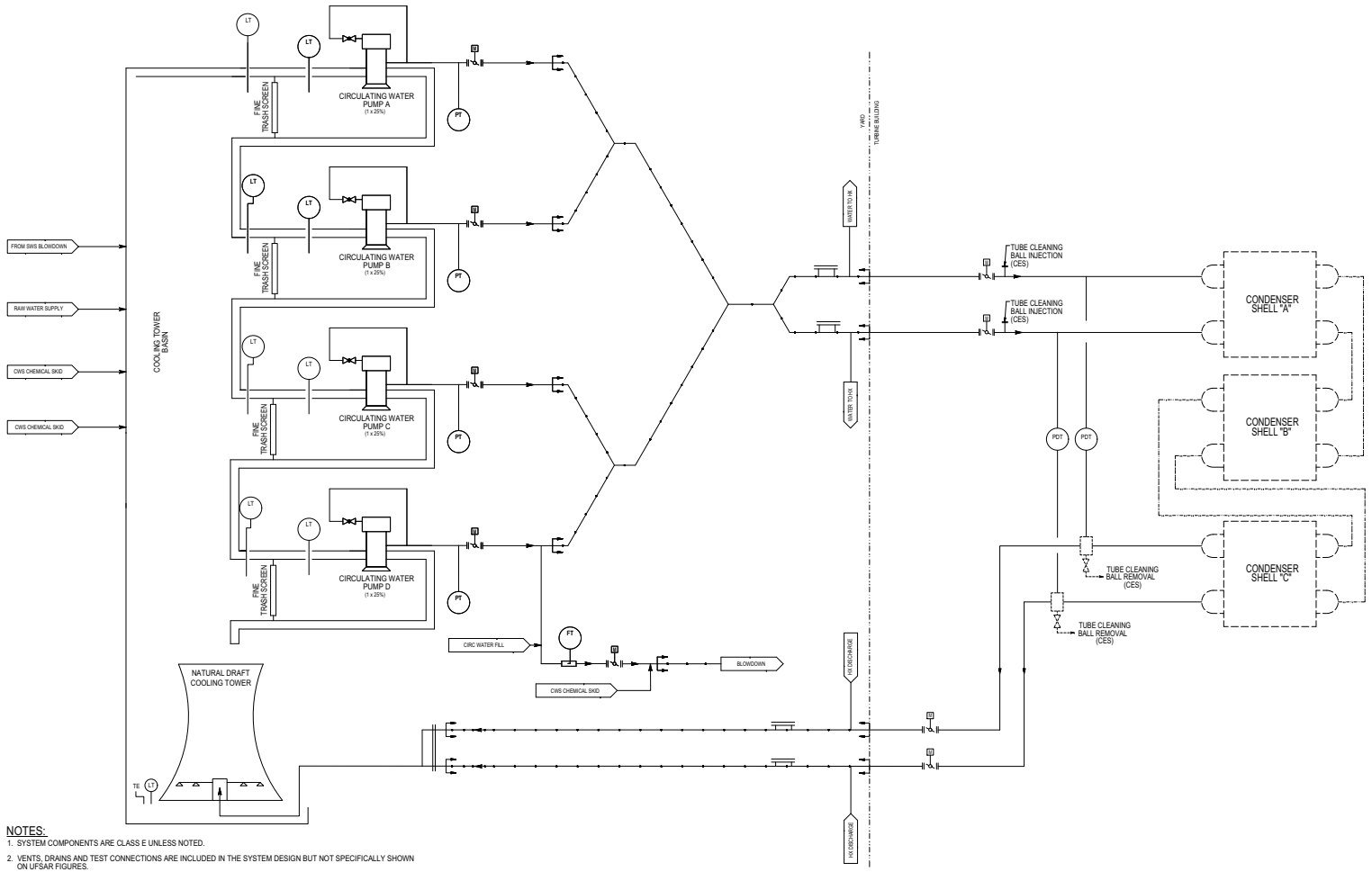
FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS, SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 10.4.7-1 (Sheet 4 of 4)
Simplified Condensate and Feedwater System Piping and Instrumentation Diagram
(REF) FWS 002



Inside Turbine Building

Figure 10.4.8-1
Steam Generator Blowdown System
Piping and Instrumentation Diagram



NOTES:

1. SYSTEM COMPONENTS ARE CLASS E UNLESS NOTED.
2. VENTS, DRAINS AND TEST CONNECTIONS ARE INCLUDED IN THE SYSTEM DESIGN BUT NOT SPECIFICALLY SHOWN ON UFSAR FIGURES.
3. FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR SPECIFIC COMPONENT REQUIREMENTS.

Figure 10.4-201
Simplified Circulating Water System Piping and Instrumentation Diagram (REF) CWS-001, -002, -800001, -800002, -800003, -800004, -800005, -800006 & -800007

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 11	RADIOACTIVE WASTE MANAGEMENT	11.1-1
11.1	Source Terms	11.1-1
11.1.1	Design Basis Reactor Coolant Activity	11.1-1
11.1.1.1	Fission Products	11.1-1
11.1.1.2	Corrosion Products	11.1-3
11.1.1.3	Tritium	11.1-3
11.1.1.4	Nitrogen-16	11.1-3
11.1.1.5	In-Containment Refueling Water Storage Tank	11.1-3
11.1.2	Design Basis Secondary Coolant Activity	11.1-4
11.1.3	Realistic Reactor Coolant and Secondary Coolant Activity	11.1-4
11.1.4	Core Source Term	11.1-4
11.1.5	Process Leakage Sources	11.1-4
11.1.6	Combined License Information	11.1-4
11.1.7	References	11.1-4
11.2	Liquid Waste Management Systems	11.2-1
11.2.1	Design Basis	11.2-1
11.2.1.1	Safety Design Basis	11.2-1
11.2.1.2	Power Generation Design Basis	11.2-1
11.2.1.3	Compliance with 10 CFR 20.1406	11.2-7
11.2.2	System Description	11.2-7
11.2.2.1	Waste Input Streams	11.2-7
11.2.2.2	Other Operations	11.2-10
11.2.2.3	Component Description	11.2-10
11.2.2.4	Instrumentation Design	11.2-13
11.2.2.5	System Operation and Performance	11.2-14
11.2.3	Radioactive Releases	11.2-17
11.2.3.1	Discharge Requirements	11.2-17
11.2.3.2	Estimated Annual Releases	11.2-17
11.2.3.3	Dilution Factor	11.2-18
11.2.3.4	Release Concentrations	11.2-18
11.2.3.5	Estimated Doses	11.2-18
11.2.3.6	Quality Assurance	11.2-21
11.2.4	Preoperational Testing	11.2-21
11.2.4.1	Sump Level Instrument Testing	11.2-21
11.2.4.2	Discharge Control/Isolation Valve Testing	11.2-21
11.2.4.3	Preoperational Inspection	11.2-21
11.2.5	Combined License Information	11.2-21
11.2.5.1	Liquid Radwaste Processing by Mobile Equipment	11.2-21
11.2.5.2	Cost Benefit Analysis of Population Doses	11.2-22
11.2.5.3	Identification of Ion Exchange and Adsorbent Media	11.2-22
11.2.5.4	Dilution and Control of Boric Acid Discharge	11.2-22
11.2.6	References	11.2-22
11.3	Gaseous Waste Management System	11.3-1
11.3.1	Design Basis	11.3-1
11.3.1.1	Safety Design Basis	11.3-1
11.3.1.2	Power Generation Design Basis	11.3-1
11.3.1.3	Compliance with 10 CFR 20.1406	11.3-4

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
11.3.2	System Description	11.3-4
11.3.2.1	General Description	11.3-4
11.3.2.2	System Operation	11.3-5
11.3.2.3	Component Description	11.3-6
11.3.3	Radioactive Releases	11.3-8
11.3.3.1	Discharge Requirements	11.3-8
11.3.3.2	Estimated Annual Releases	11.3-8
11.3.3.3	Release Points	11.3-8
11.3.3.4	Estimated Doses	11.3-9
11.3.3.5	Maximum Release Concentrations	11.3-11
11.3.3.6	Quality Assurance	11.3-11
11.3.4	Inspection and Testing Requirements	11.3-11
11.3.4.1	Preoperational Testing	11.3-11
11.3.4.2	Preoperational Inspection	11.3-12
11.3.5	Combined License Information	11.3-12
11.3.5.1	Cost Benefit Analysis of Population Doses	11.3-12
11.3.5.2	Identification of Adsorbent Media	11.3-12
11.3.6	References	11.3-12
11.4	Solid Waste Management	11.4-1
11.4.1	Design Basis	11.4-1
11.4.1.1	Safety Design Basis	11.4-1
11.4.1.2	Power Generation Design Basis	11.4-1
11.4.1.3	Functional Design Basis	11.4-1
11.4.1.4	Compliance with 10 CFR 20.1406	11.4-3
11.4.2	System Description	11.4-3
11.4.2.1	General Description	11.4-3
11.4.2.2	Component Description	11.4-6
11.4.2.3	System Operation	11.4-7
11.4.2.4	Waste Processing and Disposal Alternatives	11.4-10
11.4.2.5	Facilities	11.4-11
11.4.3	System Safety Evaluation	11.4-12
11.4.4	Tests and Inspections	11.4-12
11.4.5	Quality Assurance	11.4-13
11.4.6	Combined License Information for Solid Waste Management System Process Control Program	11.4-13
11.4.6.1	Procedures	11.4-13
11.4.6.2	Third Party Vendors	11.4-14
11.4.6.3	Long Term On-Site Storage Facility	11.4-14
11.4.7	References	11.4-16
11.5	Radiation Monitoring	11.5-1
11.5.1	Design Basis	11.5-1
11.5.1.1	Safety Design Basis	11.5-1
11.5.1.2	Power Generation Design Basis	11.5-2
11.5.2	System Description	11.5-2
11.5.2.1	Radiation Monitoring System	11.5-2
11.5.2.2	Monitor Functional Description	11.5-3
11.5.2.3	Monitor Descriptions	11.5-3

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	11.5.2.4 Inservice Inspection, Calibration, and Maintenance	11.5-11
11.5.3	Effluent Monitoring and Sampling	11.5-11
11.5.4	Process and Airborne Monitoring and Sampling	11.5-12
	11.5.4.1 Effluent Sampling	11.5-12
	11.5.4.2 Representative Sampling	11.5-12
11.5.5	Post-Accident Radiation Monitoring	11.5-14
11.5.6	Area Radiation Monitors	11.5-14
	11.5.6.1 Design Objectives	11.5-14
	11.5.6.2 Post-Accident Area Monitors	11.5-15
	11.5.6.3 Normal Range Area Monitors	11.5-16
	11.5.6.4 Fuel Handling Area Radiation Monitors	11.5-16
	11.5.6.5 Quality Assurance	11.5-17
11.5.7	Preoperational Testing	11.5-17
11.5.8	Combined License Information	11.5-17
11.5.9	References	11.5-18

LIST OF TABLES

Table Number	Title	Page
11.1-1	Parameters Used in the Calculation of Design Basis Fission Product Activities	11.1-5
11.1-2	Design Basis Reactor Coolant Activity	11.1-7
11.1-3	Tritium Sources	11.1-8
11.1-4	Parameters Used to Calculate Secondary Coolant Activity	11.1-9
11.1-5	Design Basis Steam Generator Secondary Side Liquid Activity	11.1-10
11.1-6	Design Basis Steam Generator Secondary Side Steam Activity	11.1-11
11.1-7	Parameters Used to Describe Realistic Sources	11.1-12
11.1-8	Realistic Source Terms	11.1-13
11.2-1	Liquid Inputs and Disposition	11.2-24
11.2-2	Component Data – Liquid Radwaste System	11.2-26
11.2-3	Summary of Tank Level Indication, Level Annunciators, and Overflows	11.2-33
11.2-4	Tank Surge Capacity	11.2-34
11.2-5	Decontamination Factors	11.2-35
11.2-6	Input Parameters for the GALE Computer Code	11.2-36
11.2-7	Releases to Discharge Canal Calculated by GALE Code	11.2-39
11.2-8	Comparison of Annual Average Liquid Release Concentrations with 10 CFR 20 for Expected Releases Effluent Concentration Limits	11.2-41
11.2-9	Comparison of Annual Average Liquid Release Concentrations with 10 CFR 20 Effluent Concentration Limits for Releases with Maximum Defined Fuel Defects	11.2-43
11.2-201	Liquid Pathway Parameters	11.2-45
11.2-202	Liquid Pathway Consumption Factors for Maximally Exposed Individual	11.2-45
11.2-203	Release of Activities in Liquid Effluent	11.2-46
11.2-204	Liquid Pathway Doses for Maximally Exposed Individuals	11.2-49
11.2-205	Comparison of Maximally Exposed Individual Doses with 10 CFR 50, Appendix I Criteria	11.2-49
11.2-206	Comparison of Maximally Exposed Individual Doses with 40 CFR 190 Criteria	11.2-50
11.2-207	Collective Total Body Doses Within 50 Miles	11.2-50
11.3-1	Gaseous Radwaste System Parameters	11.3-14
11.3-2	Component Data (Nominal) — Gaseous Radwaste System	11.3-15
11.3-3	Expected Annual Release of Airborne Radionuclides as Determined by the Revised GALE Code	11.3-17
11.3-4	Comparison of Calculated Offsite Airborne Concentrations with 10 CFR 20 Limits	11.3-20
11.3-201	Gaseous Pathway Parameters	11.3-22
11.3-202	Gaseous Pathway Consumption Factors for Maximally Exposed Individual	11.3-22
11.3-203	Release of Activities in Gaseous Effluent	11.3-23
11.3-204	Gaseous Pathway Receptor Locations	11.3-25
11.3-205	Gaseous Pathway Doses for Maximally Exposed Individuals	11.3-26
11.3-206	Comparison of Maximally Exposed Individual Doses with 10 CFR 50, Appendix I Criteria	11.3-27
11.3-207	Comparison of Maximally Exposed Individual Doses with 40 CFR 190 Criteria	11.3-27
11.3-208	Collective Total Body Doses Within 50 Miles	11.3-28
11.4-1	Estimated Solid Radwaste Volumes	11.4-18

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
11.4-2	Expected Annual Curie Content of Primary Influents	11.4-19
11.4-3	Maximum Annual Curie Content of Primary Influents	11.4-21
11.4-4	Expected Annual Curie Content of Shipped Primary Wastes	11.4-23
11.4-5	Maximum Annual Curie Content of Shipped Primary Wastes	11.4-25
11.4-6	Expected Annual Curie Content of Secondary Waste as Generated	11.4-27
11.4-7	Maximum Annual Curie Content of Secondary Waste as Generated	11.4-29
11.4-8	Expected Annual Curie Content of Shipped Secondary Wastes	11.4-31
11.4-9	Maximum Annual Curie Content of Shipped Secondary Wastes	11.4-33
11.4-10	Component Data — Solid Waste Management System (Nominal)	11.4-35
11.5-1	Radiation Monitor Detector Parameters	11.5-19
11.5-2	Area Radiation Monitor Detector Parameters	11.5-21
11.5-201	Minimum Sampling Frequency	11.5-22
11.5-202	Minimum Sensitivities	11.5-24

LIST OF FIGURES

Figure Number	Title	Page
11.2-1	Liquid Radwaste System Simplified Piping and Instrumentation Diagram	11.2-51
11.2-2	(Sheet 1a of 8) Unit 3 Liquid Radwaste System Piping and Instrumentation Diagram	11.2-52
11.2-2	(Sheet 1b of 8) Unit 4 Liquid Radwaste System Piping and Instrumentation Diagram	11.2-53
11.2-2	(Sheet 2 of 8) Liquid Radwaste System Piping and Instrumentation Diagram	11.2-54
11.2-2	(Sheet 3 of 8) Liquid Radwaste System Piping and Instrumentation Diagram	11.2-55
11.2-2	(Sheet 4 of 8) Liquid Radwaste System Piping and Instrumentation Diagram	11.2-56
11.2-2	(Sheet 5 of 8) Liquid Radwaste System Piping and Instrumentation Diagram	11.2-57
11.2-2	(Sheet 6 of 8) Liquid Radwaste System Piping and Instrumentation Diagram	11.2-58
11.2-2	(Sheet 7 of 8) Liquid Radwaste System Piping and Instrumentation Diagram	11.2-59
11.2-2	(Sheet 8 of 8) Liquid Radwaste System Piping and Instrumentation Diagram	11.2-60
11.3-1	Gaseous Radwaste System Simplified Sketch	11.3-29
11.3-2	Simplified Gaseous Radwaste System Piping and Instrumentation Diagram	11.3-30
11.4-1	Waste Processing System Flow Diagram	11.4-37
11.5-1	Process In-Line Radiation Monitor	11.5-25
11.5-2	Safety-Related Containment High Range Radiation Monitor	11.5-26
11.5-3	Containment Atmosphere Radiation Monitor	11.5-27
11.5-4	Plant Vent Radiation Monitor	11.5-28
11.5-5	In-Line HVAC Duct Radiation Monitor	11.5-29
11.5-6	Safety-Related Main Control Room Supply Duct Radiation Monitor	11.5-30
11.5-7	Liquid Offline Radiation Monitor	11.5-31
11.5-8	Adjacent to Line Radiation Monitor	11.5-32
11.5-9	HVAC Duct Particulate Radiation Monitor	11.5-33

Chapter 11 Radioactive Waste Management

11.1 Source Terms

This section addresses the sources of radioactivity that are treated by the liquid and gaseous radwaste systems. Radioactive materials are generated within the core (fission products) and have the potential of leaking to the reactor coolant system by way of defects in the fuel cladding. The core radiation field also results in activation of the coolant to form N-16 from oxygen and the activation of corrosion products in the reactor coolant system.

Two source terms are presented for the primary and the secondary coolant. The first is a conservative, or design basis, source term that assumes the design basis fuel defect level. This source term serves as a basis for system design and shielding requirements.

The second source term is a realistic model. This source term represents the expected average concentrations of radionuclides in the primary and the secondary coolant. These values are determined using the model in the PWR-GALE code (Reference 1) and which provides the bases for estimating typical concentrations of the principal radionuclides that are expected to occur. This source term model reflects the industry experience at a large number of operating PWR plants.

11.1.1 Design Basis Reactor Coolant Activity

11.1.1.1 Fission Products

For the design basis source term it is assumed that there is a significant fuel defect level, well above that anticipated during normal operation. It is assumed that small cladding defects are present in fuel rods producing 0.25 percent of the core power output (also stated as 0.25 percent fuel defects). The defects are assumed to be uniformly distributed throughout the core.

The parameters used in the calculation of the reactor coolant fission product concentrations, including pertinent information concerning the fission product escape rate coefficients, coolant cleanup rate, and demineralizer effectiveness, are listed in Table 11.1-1. Since the fuel defects are assumed to be uniformly distributed in the core, the fission product escape rate coefficients are based on average fuel temperature.

The determination of reactor coolant activity is based on time-dependent fission product core inventories that are calculated by the ORIGEN code (Reference 2).

The fission product activity in the reactor coolant is calculated using the following differential equations.

For parent nuclides in the coolant:

$$\frac{dN_{cp}}{dt} = \frac{FR_p\, N_{Fp}}{M_c}$$

$$-\left[\lambda_p + D_p + \frac{Q_L}{M_c}\left(\frac{DF_p - 1}{DF_p}\right)\right] N_{cp}$$

For daughter nuclides in the coolant:

$$\frac{dN_{cd}}{dt} = \frac{FR_d N_{Fd}}{M_c} + f_p \lambda_p N_{c_p} -$$

$$\left[\lambda_d + D_d + \frac{Q_L}{M_c}\left(\frac{DF_d - 1}{DF_d}\right)\right] N_{cd}$$

where:

N_c = Concentration of nuclide in the reactor coolant (atoms/gram)

N_F = Population of nuclide in the fuel (atoms)

t = Operating time (seconds)

R = Nuclide release coefficient (1/sec)

F = Fraction of fuel rods with defective cladding

M_c = Mass of reactor coolant (grams)

λ = Nuclide decay constant (1/sec)

D = Dilution coefficient by feed and bleed (1/sec) $= \frac{\beta}{B_O - \beta t} \times \frac{1}{DF}$

B_o = Initial boron concentration (ppm)

β = Boron concentration reduction rate (ppm/sec)

DF = Nuclide demineralizer decontamination factor

Q_L = Purification or letdown mass flow rate (grams/sec)

f = Fraction of parent nuclide decay events that result in the formation of the daughter nuclide

Subscript p refers to the parent nuclide.

Subscript d refers to the daughter nuclide.

Table 11.1-2 lists the resulting reactor coolant radionuclide concentrations. The values presented are the maximum values calculated to occur during the fuel cycle from startup through the equilibrium cycle. Thus, the source term does not represent any particular time in the fuel cycle but is a conservative composite.

The design basis source term based on 0.25 percent fuel defects is used to ensure a consistent set of design values for interfaces among the radioactive waste processing systems. The Technical Specifications, which are related to fuel failure are also based upon 0.25 percent fuel defects. In

addition, the liquid and gaseous radioactive waste processing systems have the capability to process wastes based upon 1.0 percent fuel defects.

11.1.1.2 Corrosion Products

The reactor coolant corrosion product activities are based on operating plant data and are independent of fuel defect level. The concentrations of corrosion products are included in Table 11.1-2.

11.1.1.3 Tritium

A number of tritium production processes add tritium to the reactor coolant:

- Fission product formation in the fuel (ternary fission) forms tritium which can diffuse through the fuel clad or leak through fuel clad defects
- Neutron reactions with soluble boron in the reactor coolant
- Burnable neutron absorber
- Neutron reactions with soluble lithium in the reactor coolant
- Neutron reactions with deuterium in the reactor coolant
- Neutron reactions with secondary sources

The production in the coolant through neutron reactions with soluble boron and the transfer from secondary sources through neutron reactions with lithium are the principle contributors of tritium in the reactor coolant. Table 11.1-3 contains the total conservative estimated tritium activity released into the reactor coolant each cycle.

The first two processes are the principal contributors to tritium in the reactor coolant. Table 11.1-3 lists the tritium introduced to the reactor coolant from each of the processes.

Tritium exists in the reactor coolant primarily combined with hydrogen (that is, a tritium atom replaces a hydrogen atom in a water molecule) and thus cannot be readily separated from the coolant by normal processing methods. The maximum concentration of tritium in the reactor coolant is less than 3.5 microcuries per gram as a result of losses due to leakage and the controlled release of tritiated water to the environment.

11.1.1.4 Nitrogen-16

Activation of oxygen in the coolant results in the formation of N-16 which is a strong gamma emitter. Because of its short half-life of 7.11 seconds, N-16 is not of concern outside the containment. Table 12.2-3 provides N-16 concentrations at various points in the reactor coolant system. After shutdown, N-16 is not a source of radiation inside of containment.

11.1.1.5 In-Containment Refueling Water Storage Tank

The in-containment refueling water storage tank (IRWST) liquid source term is calculated as a mass balance using the IRWST liquid as a control volume. Nuclides are produced via reactor coolant system inleakage (via passive residual heat removal heat exchanger and refueling cavity drain-down) and decay of parent radionuclides. The reactor coolant leakage into the IRWST is assumed to have radionuclide concentrations as defined in Table 11.1-2. Nuclides are removed via

spent fuel pool cooling system cleanup, radioactive decay, draining (overflow) to the sump, evolution of gaseous radionuclides, and settling within the IRWST. Nuclides that are removed from the tank liquid via evolution into the air space or settling to the tank floor are tracked independently using similar equations.

11.1.2 Design Basis Secondary Coolant Activity

Steam generator tube defects cause the introduction of reactor coolant into the secondary cooling system. The resulting radionuclide concentrations in the secondary coolant depend upon the primary-to-secondary leak rate, the nuclide decay constant, and the steam generator blowdown rate.

The reactor coolant leakage into the secondary system is assumed to have radionuclide concentrations as defined in Table 11.1-2. The parameters used in the calculation of the secondary side activities are provided in Table 11.1-4 and the resulting radionuclide concentrations in the steam generator secondary side water and steam are presented in Tables 11.1-5 and 11.1-6.

11.1.3 Realistic Reactor Coolant and Secondary Coolant Activity

The realistic source terms for both the reactor coolant and the secondary coolant are determined using the modeling in ANSI-18.1 (Reference 3). This modeling is also incorporated into a version of the PWR-GALE code modified to accept inputs from an updated version of ANSI-18.1. The reference plant values provided in ANSI-18.1 were adjusted to be consistent with the AP1000 parameters listed in Table 11.1-7. The adjustment factors are applied to the fission products. The realistic source term is listed in Table 11.1-8.

11.1.4 Core Source Term

The core fission product inventories used to establish source terms for accident radiological consequence analyses are provided in Appendix 15A.

11.1.5 Process Leakage Sources

The systems containing radioactive liquids are potential sources for the release of radioactive material to plant buildings and then to the environment. The leakage sources and the resulting airborne concentrations are discussed in Section 12.2.

Release pathways for radioactive materials are discussed in Sections 11.2 and 11.3.

11.1.6 Combined License Information

This section contained no requirement for information.

11.1.7 References

1. “Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code),” NUREG-0017, Revision 1, March 1985.

2. RSIC Computer Code Collection CCC-371, ORIGEN 2.1 Isotope Generation and Depletion Code - Matrix Exponential Method, August 1, 1991.

3. ANSI/ANS-18.1-1999, “Radioactive Source Term for Normal Operation of Light Water Reactors.”

Table 11.1-1 (Sheet 1 of 2)
Parameters Used in the Calculation of Design Basis Fission Product Activities

Core thermal power (MWt)	3,400
Reactor coolant liquid volume (ft^3)[(a)]	9,575
Reactor coolant full-power average temperature (°F)	578.1
Purification flow rate (gal/min)[(b)]	
Maximum	100
Normal	91.3
Effective cation demineralizer flow, annual average (gal/min)[(b)]	9.1
Nuclide release coefficients (the product of the failed fuel fraction and the fission product escape rate coefficient)	
Equivalent fraction of core power produced by fuel rods containing small cladding defects (failed fuel fraction)	0.0025
Fission product escape rate coefficients during full-power operation (s^{-1}):	
Kr and Xe isotopes Br, Rb, I, and Cs isotopes Mo, Tc, and Ag isotopes Te isotopes Sr and Ba isotopes Y, Zr, Nb, Ru, Rh, La, Ce, and Pr isotopes	6.5×10^{-8} 1.3×10^{-8} 2.0×10^{-9} 1.0×10^{-9} 1.0×10^{-11} 1.6×10^{-12}
Chemical and volume control system mixed bed demineralizers	
Resin volume (ft^3)	50
Demineralizer isotopic decontamination factors:	
Kr and Xe isotopes Br and I isotopes Sr and Ba isotopes Other isotopes	1 10 10 1

Table 11.1-1 (Sheet 2 of 2)
Parameters Used in the Calculation of Design Basis Fission Product Activities

Chemical and volume control system cation bed demineralizer	
Resin volume (ft^3)	50
Demineralizer isotopic decontamination factors:	
Kr and Xe isotopes Sr and Ba isotopes Rb-86, Cs-134, and Cs-137 Rb-88, Rb-89, Cs-136, and Cs-138 Other isotopes	1 1 10 1 1
Other isotopic removal mechanisms	See Note c.
Initial boron concentration (ppm)	1,400
Operation time (effective full-power hours)	12,492

Notes:

a. Reactor coolant mass used in defining fission product activities is based on above stated conditions before thermal expansion (conservative).

b. Flow calculated at 2250 psia and 250°F.

c. For all isotopes, except the isotopes of Kr, Xe, Br, I, Rb, Cs, Sr, and Ba, a removal decontamination factor of 10 is assumed to account for removal mechanisms other than ion exchange, such as plateout or filtration. This decontamination factor is applied to the normal purification letdown flow.

Table 11.1-2
Design Basis Reactor Coolant Activity

Nuclide	Activity (μCi/g)	Nuclide	Activity (μCi/g)
Kr-83m	1.8×10^{-1}	Rb-88	1.5
Kr-85m	8.4×10^{-1}	Rb-89	6.9×10^{-2}
Kr-85	3.0	Sr-89	1.1×10^{-3}
Kr-87	4.7×10^{-1}	Sr-90	4.9×10^{-5}
Kr-88	1.5	Sr-91	1.7×10^{-3}
Kr-89	3.5×10^{-2}	Sr-92	4.1×10^{-4}
Xe-131m	1.3	Y-90	1.3×10^{-5}
Xe-133m	1.7	Y-91m	9.2×10^{-4}
Xe-133	1.2×10^{2}	Y-91	1.4×10^{-4}
Xe-135m	1.7×10^{-1}	Y-92	3.4×10^{-4}
Xe-135	3.5	Y-93	1.1×10^{-4}
Xe-137	6.7×10^{-2}	Zr-95	1.6×10^{-4}
Xe-138	2.5×10^{-1}	Nb-95	1.6×10^{-4}
Br-83	3.2×10^{-2}	Mo-99	2.1×10^{-1}
Br-84	1.7×10^{-2}	Tc-99m	2.0×10^{-1}
Br-85	2.0×10^{-3}	Ru-103	1.4×10^{-4}
I-129	1.5×10^{-8}	Rh-103m	1.4×10^{-4}
I-130	1.1×10^{-2}	Rh-106	4.5×10^{-5}
I-131	7.1×10^{-1}	Ag-110m	4.0×10^{-4}
I-132	9.4×10^{-1}	Te-127m	7.6×10^{-4}
I-133	1.3	Te-129m	2.6×10^{-3}
I-134	2.2×10^{-1}	Te-129	3.8×10^{-3}
I-135	7.8×10^{-1}	Te-131m	6.7×10^{-3}
Cs-134	6.9×10^{-1}	Te-131	4.3×10^{-3}
Cs-136	1.0	Te-132	7.9×10^{-2}
Cs-137	5.0×10^{-1}	Te-134	1.1×10^{-2}
Cs-138	3.7×10^{-1}	Ba-137m	4.7×10^{-1}
Cr-51	1.3×10^{-3}	Ba-140	1.0×10^{-3}
Mn-54	6.7×10^{-4}	La-140	3.1×10^{-4}
Mn-56	1.7×10^{-1}	Ce-141	1.6×10^{-4}
Fe-55	5.0×10^{-4}	Ce-143	1.4×10^{-4}
Fe-59	1.3×10^{-4}	Pr-143	1.5×10^{-4}
Co-58	1.9×10^{-3}	Ce-144	1.2×10^{-4}
Co-60	2.2×10^{-4}	Pr-144	1.2×10^{-4}

Note:
These activities are used for shielding and radwaste system interface design. For 1 percent fuel defect calculations (maximum release and liquid and gaseous radwaste system capability) multiply the activities above by 4 except for iodines, noble gases, and corrosion products (Cr-51, Mn-54, Mn-56, Fe-55, Fe-59, Co-58 and Co-60).

Table 11.1-3
Tritium Sources

Conservative Estimated Tritium Release into Coolant (curies/cycle(1))	2672

Note:
1. Cycle length of 18 months

Table 11.1-4
Parameters Used to Calculate Secondary Coolant Activity

Total secondary side water mass (lb/steam generator)	1.68×10^5
Steam generator steam fraction	0.058
Total steam flow rate (lb/hr)	1.5×10^7
Moisture carryover (percent)	0.1
Total makeup water feed rate (lb/hr)	700
Total blowdown rate (gpm)	186
Total primary-to-secondary leak rate (gpd)	300
Iodine partition factor (mass basis)	100

Table 11.1-5
Design Basis Steam Generator Secondary Side Liquid Activity

Nuclide	Activity (µCi/g)	Nuclide	Activity (µCi/g)
Br-83	1.4E-05	Y-91m	1.0E-06
Br-84	2.4E-06	Y-91	1.3E-07
Br-85	3.1E-08	Y-92	2.8E-07
I-129	1.3E-11	Y-93	8.2E-08
I-130	7.9E-06	Zr-95	1.5E-07
I-131	6.3E-04	Nb-95	1.5E-07
I-132	4.2E-04	Mo-99	1.9E-04
I-133	1.0E-03	Tc-99m	1.7E-04
I-134	4.9E-05	Ru-103	1.2E-07
I-135	5.0E-04	Ru-106	4.1E-08
Rb-86	1.4E-05	Rh-103m	1.2E-07
Rb-88	1.4E-04	Rh-106	4.1E-08
Rb-89	5.6E-06	Ag-110m	4.0E-07
Cs-134	1.1E-03	Te-125m	1.5E-07
Cs-136	1.7E-03	Te-127m	7.0E-07
Cs-137	8.2E-04	Te-127	2.2E-06
Cs-138	5.9E-05	Te-129m	2.4E-06
H-3	3.8E-01	Te-129	2.1E-06
Cr-51	1.3E-06	Te-131m	5.6E-06
Mn-54	6.6E-07	Te-131	1.6E-06
Mn-56	7.8E-05	Te-132	7.0E-05
Fe-55	5.0E-07	Te-134	2.0E-06
Fe-59	1.3E-07	Ba-137m	7.7E-04
Co-58	1.9E-06	Ba-140	9.4E-07
Co-60	2.2E-07	La-140	3.3E-07
Sr-89	1.8E-06	Ce-141	1.4E-07
Sr-90	8.0E-08	Ce-143	1.2E-07
Sr-91	1.9E-06	Ce-144	1.1E-07
Sr-92	2.4E-07	Pr-143	1.4E-07
Y-90	1.4E-08	Pr-144	1.1E-07

Table 11.1-6
Design Basis Steam Generator Secondary Side Steam Activity

Nuclide	Activity (μCi/g)
Kr-83m	1.10E-06
Kr-85m	4.30E-06
Kr-85	1.50E-05
Kr-87	2.40E-06
Kr-88	7.70E-06
Kr-89	1.80E-07
Xe-131m	6.90E-06
Xe-133m	8.70E-06
Xe-133	6.40E-04
Xe-135m	5.50E-06
Xe-135	1.90E-05
Xe-137	3.40E-07
Xe-138	1.30E-06
I-129	1.50E-13
I-130	8.70E-08
I-131	6.90E-06
I-132	4.70E-06
I-133	1.10E-05
I-134	5.40E-07
I-135	5.50E-06
H-3	3.80E-01

Table 11.1-7
Parameters Used to Describe Realistic Sources

Parameter	Symbol	Units	AP1000 Value	Nominal Value
Thermal power	P	MWt	3400	3400
Steam flow rate	FS	lb/hr	1.5×10^7	1.5×10^7
Weight of water in reactor coolant system	WP	lb	4.3×10^5	5.5×10^5
Weight of water in all steam generators	WS	lb	3.5×10^5	4.5×10^5
Reactor coolant purification flow	FD	lb/hr	4.3×10^4	3.7×10^4
Reactor coolant letdown flow (yearly average for boron control)	FB	lb/hr	1.5×10^2	5.0×10^2
Steam generator blowdown flow (total)	FBD	lb/hr	7.5×10^4	7.5×10^4
Fraction of radioactivity in blowdown stream which is not returned to the secondary coolant system	NBD	-	0.0	1.0
Flow through the purification system cation demineralizer	FA	lb/hr	4.3×10^3	3.7×10^3
Ratio of condensate demineralizer flow rate to the total steam flow rate	NC	-	0.33	0.0
Fraction of the noble gas activity in the letdown stream which is not returned to the reactor coolant system	Y	-	0.0	0.0
Primary-to-secondary leakage	FL	lb/day	75	75

Table 11.1-8 (Sheet 1 of 4)
Realistic Source Terms

Noble Gases		
Nuclide	**Reactor Coolant Activity (µCi/g)**	**Steam Generator Steam Activity (µCi/g)**
Kr-85m	0.021	4.40E-09
Kr-85	1.4	2.90E-07
Kr-87	0.022	4.4E-09
Kr-88	0.023	4.9E-09
Xe-131m	1.1	2.3E-07
Xe-133m	0.093	2.0E-08
Xe-133	0.041	8.4E-09
Xe-135m	0.17	3.5E-08
Xe-135	0.087	1.8E-08
Xe-137	0.044	9.2E-09
Xe-138	0.078	1.7E-08

Halogens			
Nuclide	**Reactor Coolant Activity (µCi/g)**	**Steam Generator Liquid Activity (µCi/g)**	**Steam Generator Steam Activity (µCi/g)**
Br-84	2.0E-02	1.2E-07	1.2E-09
I-131	1.8E-03	1.2E-07	1.2E-09
I-132	7.1E-02	1.5E-06	1.5E-08
I-133	2.5E-02	1.4E-06	1.4E-08
I-134	1.2E-01	1.2E-06	1.2E-08
I-135	6.0E-02	2.3E-06	2.3E-08

Table 11.1-8 (Sheet 2 of 4)
Realistic Source Terms

Rubidium, Cesium			
Nuclide	**Reactor Coolant Activity (µCi/g)**	**Steam Generator Liquid Activity (µCi/g)**	**Steam Generator Steam Activity (µCi/g)**
Rb-88	0.24	8.9E-07	4.4E-09
Cs-134	3.1E-05	7.6E-09	4.0E-11
Cs-136	7.4E-04	1.7E-07	8.7E-10
Cs-137	4.4E-05	1.1E-08	5.4E-11
Tritium			
Nuclide	**Reactor Coolant Activity (µCi/g)**	**Steam Generator Liquid Activity (µCi/g)**	**Steam Generator Steam Activity (µCi/g)**
H-3	1	1.0E-3	1.0E-3

Table 11.1-8 (Sheet 3 of 4)
Realistic Source Terms

Miscellaneous Nuclides			
Nuclide	**Reactor Coolant Activity (µCi/g)**	**Steam Generator Liquid Activity (µCi/g)**	**Steam Generator Steam Activity (µCi/g)**
Na-24	4.6E-02	3.6E-06	1.8E-08
Cr-51	2.6E-03	3.6E-07	1.8E-09
Mn-54	1.3E-03	1.8E-07	9.2E-10
Fe-55	1.0E-03	1.4E-07	7.0E-10
Fe-59	2.5E-04	3.3E-08	1.7E-10
Co-58	4.6E-02	1.9E-06	9.4E-09
Co-60	4.4E-04	6.1E-08	3.1E-10
Zn-65	4.3E-04	5.9E-08	2.8E-10
Sr-89	1.2E-04	1.6E-08	8.1E-11
Sr-90	1.0E-05	1.4E-09	6.7E-12
Sr-91	9.9E-04	6.4E-08	3.2E-10
Y-91m	5.7E-04	5.6E-09	2.8E-11
Y-91	4.4E-06	5.9E-10	3.1E-12
Y-93	4.3E-03	2.8E-07	1.4E-09
Zr-95	3.3E-04	4.5E-08	2.2E-10
Nb-95	2.4E-04	3.1E-08	1.6E-10
Mo-99	5.6E-03	6.7E-07	3.2E-09
Tc-99m	5.1E-03	2.4E-07	1.2E-09
Ru-103	6.3E-03	8.6E-07	4.5E-09
Ru-106	7.5E-02	1.0E-05	5.0E-08
Ag-110m	1.1E-03	1.5E-07	7.5E-10
Te-129m	1.6E-04	2.2E-08	1.1E-10

Table 11.1-8 (Sheet 4 of 4)
Realistic Source Terms

Miscellaneous Nuclides			
Nuclide	**Reactor Coolant Activity (µCi/g)**	**Steam Generator Liquid Activity (µCi/g)**	**Steam Generator Steam Activity (µCi/g)**
Te-129	2.9E-02	3.9E-07	2.0E-09
Te-131m	1.4E-03	1.4E-07	7.0E-10
Te-131	9.7E-03	4.9E-08	2.5E-10
Te-132	1.5E-03	1.8E-07	8.9E-10
Ba-137m	4.4E-05	1.1E-08	5.4E-11
Ba-140	1.1E-02	1.4E-06	7.2E-09
La-140	2.3E-02	2.4E-06	1.2E-08
Ce-141	1.3E-04	1.7E-08	8.6E-11
Ce-143	2.6E-03	3.6E-07	1.3E-09
Ce-144	3.4E-03	4.5E-07	2.3E-09
W-187	2.3E-03	2.2E-07	1.1E-09
Np-239	2.0E-03	2.2E-07	1.1E-09

11.2 Liquid Waste Management Systems

The liquid waste management systems include the systems that may be used to process and dispose of liquids containing radioactive material. These include the following:

- Steam generator blowdown processing system (Subsection 10.4.8);
- Radioactive waste drain system (Subsection 9.3.5);
- Liquid radwaste system (WLS) (Section 11.2).

This section primarily addresses the liquid radwaste system. The other systems are also addressed in Subsection 11.2.3, which discusses the expected releases from the liquid waste management systems.

The liquid radwaste system is designed to control, collect, process, handle, store, and dispose of liquid radioactive waste generated as the result of normal operation, including anticipated operational occurrences.

11.2.1 Design Basis

Subsection 1.9.1 discusses the conformance of the liquid radwaste system design with the criteria of Regulatory Guide 1.143.

11.2.1.1 Safety Design Basis

The liquid radwaste system serves no safety-related functions except for:

- Containment isolation; see Subsection 6.2.3.

- Back flow prevention check valves in the drain lines from the chemical and volume control system compartment and the passive core cooling system compartments to the containment sump, which prevent cross flooding of these compartments. Each drain line has two check valves in series so that a single failure does not compromise the back flow prevention safety function. See Subsection 6.3.3.3.2 for a discussion of containment flooding.

11.2.1.2 Power Generation Design Basis

11.2.1.2.1 Capacity

The liquid radwaste system provides holdup capacity as shown in Table 11.2-2, and permanently installed processing capacity of 75 gpm through the ion exchange/filtration train. This is adequate capacity to meet the anticipated processing requirements of the plant. The projected flows of various liquid waste streams to the liquid radwaste system under normal conditions are identified in Table 11.2-1.

The liquid radwaste system design can accept equipment malfunctions without affecting the capability of the system to handle both anticipated liquid waste flows and possible surge load due to excessive leakage. Table 11.2-4 contains information on the surge capacity of individual tanks.

Portions of the liquid radwaste system may become unavailable as a result of the malfunctions listed in Subsection 11.2.1.2.2.

Ample surge capacity of the system, provisions for using mobile processing equipment and the low load factor of the processing equipment permits the system to accommodate waste until failures can

be repaired and normal plant operation resumed. In addition, the liquid radwaste system is designed to accommodate the anticipated operational occurrences described in Subsection 11.2.1.2.3.

11.2.1.2.2 Failure Tolerance

11.2.1.2.2.1 Pump Failure

Where operation is not essential and surge capacity is available, a single pump is provided. This applies to most applications in the liquid radwaste system. Two reactor coolant drain tank pumps and two containment sump pumps are provided because the relative inaccessibility of the containment during power operation would hinder maintenance. The containment sump pumps are submersible pumps. To protect them from damage due to loss of suction, each pump is interlocked to stop on a low level condition in the sump. The reactor coolant drain tank pumps are vertical sump type pumps with motors above the reactor coolant drain tank shaft coupled to pumps submersed in the liquid within the reactor coolant drain tank. This arrangement minimizes contamination of the motors and permits removal and maintenance of the motors outside of the radiation area.

Process pumps located outside containment are air-operated, double diaphragm type. These pumps are capable of significant suction lifts, and can thus be located on or near the top of the associated waste tank, with internal suction piping. They can pump slurries with high solids fractions, run deadheaded, and run dry without damage. In addition, they can operate over a wide range of hydraulic conditions by varying the driving air input. This makes it possible to fulfill many different applications with a single pump model, thereby facilitating maintenance and reducing the inventory of spare parts.

11.2.1.2.2.2 Filter or Ion Exchanger Plugging

Instrumentation is provided to give indication of the pressure drop across filters and ion exchangers. Periodic checks of the pressure drops provide indication of equipment fouling, thus permitting corrective action to be taken before an excessive pressure drop is reached. Change of filter cartridges and ion exchange beds is expected to occur based upon radiation survey.

11.2.1.2.3 Anticipated Operational Occurrences

11.2.1.2.3.1 High Primary Coolant System Leakage Rate

The system is designed to handle an abnormal primary coolant system leak in addition to the expected leakage during normal operation. Operation of the system is the same as for normal operation, except that the load on the system is increased.

11.2.1.2.3.2 High Use of Decontamination Water

If large quantities of water are used to decontaminate areas or equipment, the load on the liquid radwaste system is increased. However, the liquid radwaste system is designed to handle a large, continuous input to the waste holdup tanks. If the water can be discharged without processing based on sampling which shows acceptably low activity, the overall liquid radwaste system capacity is increased.

To accommodate the possible use of special decontamination fluids or very large volumes of decontamination fluids, mobile equipment is used as discussed in Subsection 11.2.1.2.5.2.

11.2.1.2.3.3 Steam Generator Tube Leakage

During normal operations, steam generator blowdown is returned to the condensate system, as described in Subsection 10.4.8. However, if excessive radioactivity is detected, the blowdown is diverted to the liquid radwaste system for processing and disposal.

The blowdown fluid is brought into the waste holdup tanks, which provide some surge capacity to hold the fluid during processing. It is then processed in the same fashion as, and combined with, other inputs.

In the event of a steam generator tube rupture, the condensate storage tank may also become contaminated. In this event, the tank is cleaned by the use of temporary equipment brought to the site for the purpose, as described in Subsection 11.2.1.2.5.2.

11.2.1.2.3.4 Refueling

The load on the liquid radwaste system is expected to increase during refueling because of the increased level of maintenance activities in the plant, but operation is the same as for normal plant operation. There is no significant effect on the performance capability of the liquid radwaste system.

11.2.1.2.4 Controlled Release of Radioactivity

The liquid radwaste system provides the capability to reduce the amounts of radioactive nuclides released in the liquid wastes through the use of demineralization and time delay for decay of short-lived nuclides.

The assumed equipment decontamination factors appear in Table 11.2-5. Estimates of the radioactive source terms and annual average flow rate that will be processed in the liquid radwaste system or discharged to the environment during normal operation appear in Table 11.2-1.

Before radioactive liquid waste is discharged, it is pumped to a monitor tank. A sample of the monitor tank contents is analyzed, and the results are recorded. In this way, a record is kept of planned releases of radioactive liquid waste.

The liquid waste is discharged from the monitor tank in a batch operation, and the discharge flow rate is restricted as necessary to maintain an acceptable concentration when diluted by the circulating water discharge flow. These provisions preclude uncontrolled releases of radioactivity.

In addition, the discharge line contains a radiation monitor with diverse methods of stopping the discharge. The first method closes an isolation valve in the discharge line, which prevents any further discharge from the liquid radwaste system. The valve automatically closes and an alarm is actuated if the activity in the discharge stream reaches the monitor setpoint. The second method stops the monitor tank pumps.

To minimize leakage from the liquid radwaste system, the portion of the system normally expected to contain radioactive material is of welded construction except where flanged connections are required to facilitate component maintenance or to allow connection of temporary or mobile equipment. Air-operated diaphragm pumps, sealless pumps, or pumps having mechanical seals are used. These pumps minimize system leakage thereby minimizing the release of radioactive gas that might be entrained in the leaking fluid to the building atmosphere.

Provisions are made to control spills of radioactive liquids due to tank overflows. Table 11.2-3 lists the provisions for tank level indication, alarms, and overflow disposition for liquid radwaste system tanks outside containment. In addition, the radioactive waste collection tanks (i.e., the effluent holdup

tanks, waste holdup tanks, and chemical tank) are located within the auxiliary building, which is well sealed and equipped with an extensive floor drain system. The radwaste monitor tanks are located in the auxiliary building and in the radwaste building, which has a well sealed, contiguous basemat with integral curbing and a floor drain system. Routing of both of the auxiliary building and radwaste building floor drain systems are to the liquid radwaste system. This eliminates the potential for undetected tank leakage to the environment and supports compliance with 10 CFR 20.1406 (Reference 5).

The liquid radwaste system is designed so that the annual average concentration limits established by 10 CFR 20 (Appendix B, table 2, column 2) (Reference 1) for liquid releases are not exceeded during plant operation. Subsection 11.2.3 describes the calculated releases of radioactive materials from the liquid radwaste system and other portions of the liquid waste management systems resulting from normal operation.

The monitored radwaste discharge pipeline is engineered to preclude leakage to the environment. This pipe is routed from the auxiliary building to the radwaste building (the short section of pipe between the two buildings is fully available for visual inspection as noted above) and then out of the radwaste building to the licensed release point for dilution and discharge. The discharge radiation monitor and isolation valve are located inside the radiologically controlled area. The exterior piping is designed to preclude inadvertent or unidentified releases to the environment; it is either enclosed within a guard pipe and monitored for leakage, or accessible for visual inspection. No valves or vacuum breakers are incorporated outside of monitored structures. This greatly reduces the potential for undetected leakage from this discharge to the environment at a non-licensed release point, and supports compliance with 10 CFR 20.1406 (Reference 5).

The liquid radwaste system (WLS) exterior discharge piping from the Units 3 and 4 Radwaste Building is buried, stainless steel, enclosed within a guard pipe and monitored for leakage to comply with 10 CFR 20.1406. The WLS discharge lines connect to the Waste Water System (WWS) plant outfall pipe within the Exclusion Area Boundary for dilution below the release limits of 10 CFR Part 20, Appendix B, Table II, Column 2. Dilution at this point, downstream of the WWS blowdown sump, is primarily supplied by the circulating water blowdown flow. The blowdown sump and plant outfall are described in Subsection 9.2.9.2.2.

The WWS blowdown line to the plant outfall at the Savannah River is a high density polyethylene single-walled buried pipe. There are no valves, vacuum breakers, or pumps along the WWS blowdown line between the point where the WLS connects and the plant outfall. Monitoring for leakage downstream of the WLS radwaste discharge line connection is per NEI 08-08A (Reference 201) as described in Appendix 12AA. This monitoring will be implemented as part of the Units 3 and 4 groundwater monitoring program.

11.2.1.2.4.1 Abnormal Operation

Subsections 11.2.1.2.2 and 11.2.1.2.3 describe the capability of the liquid radwaste system to accommodate abnormal conditions for various equipment and other anticipated operational occurrences. During these anticipated occurrences, the effectiveness of the liquid radwaste system in controlling releases of radioactivity remains unaffected, so releases are limited as during normal operation.

Subsection 11.2.3 discusses the calculated releases of radioactive materials from the liquid radwaste system for abnormal situations.

The liquid radwaste system also provides indication of floodup within the radiologically controlled area of the auxiliary building through the use of level sensors. See Subsection 3.4.1.2.2.2 for a discussion of floodup for the radiologically controlled area of the auxiliary building.

11.2.1.2.5 Equipment Design

11.2.1.2.5.1 Permanently Installed Equipment

The liquid radwaste system equipment design parameters are provided in Table 11.2-2.

The seismic design classification and safety classification for the liquid radwaste system components and structures are listed in Section 3.2. The components listed are located in the Seismic Category I Nuclear Island and in the radwaste building.

The monitor tanks in the non-seismic radwaste building are used to store processed water. The radioactivity content of processed water in each tank will be less than the A_1 and A_2 levels of 10 CFR 71 Appendix A, Table A-1.

11.2.1.2.5.2 Use of Mobile and Temporary Equipment

The liquid radwaste system is designed to handle most liquid effluents and other anticipated events using installed equipment. However, for events occurring at a very low frequency or producing effluents not compatible with the installed equipment, temporary equipment may be brought into the radwaste building mobile treatment facility truck bays.

Connections are provided to and from various locations in the liquid radwaste system to these mobile equipment connections. This allows the mobile equipment to be used in series with installed equipment, as an alternate to it with the treated liquids returned to the liquid radwaste system, or as an ultimate disposal point for liquids that are to be removed from the plant site for disposal elsewhere.

The use of temporary equipment is common practice in operating plants. The radwaste building truck bays and laydown space for mobile equipment, in addition to the flexibility of numerous piping connections to the liquid radwaste system, allow the plant operator to incorporate mobile equipment in an integrated fashion.

Temporary equipment is also used to clean up the condensate storage tank if it becomes contaminated following steam generator tube leakage. This use of temporary equipment is similar to that just described, except that the equipment is used in the yard rather than in the radwaste building truck bays.

When mobile or temporary equipment is selected to process liquid effluents, the equipment design and testing meets the applicable requirements of Regulatory Guide 1.143. When confirmed through sampling that the radioactive waste contents do not exceed the A_2 quantities for radionuclides specified in Appendix A to 10 CFR Part 71, the liquid effluent may be processed with mobile or temporary equipment in the Radwaste Building. When the A_2 quantities are exceeded, liquid effluent is processed in the Seismic Category I auxiliary building.

Operating procedures also discussed in Section 13.5 include administrative controls to limit the total cumulative radioactive inventory of unpackaged wastes located in the radwaste building so that the Regulatory Guide 1.143 unmitigated radiological release criteria of 5 rem to site personnel, and the 10 CFR Part 20.1301 dose limits of 100 millirem at the protected area boundary for members of the public, are not exceeded. These unpackaged wastes include liquid waste, wet waste, solid waste, gaseous waste, activated or contaminated metals and components, and contaminated waste. These administrative controls limit the radionuclide inventory to less than the A2 limit specified in Appendix A to 10 CFR Part 71 in each of the three (3) radwaste monitor tanks, in each of up to three (3) mobile radwaste processing systems, and in any additional equipment located in the radwaste building. Transfer or packaging of spent media from a mobile radwaste processing system located in

the radwaste building is procedurally controlled such that either spent media packaging for off-site shipment in process in the radwaste building is considered in the inventory with the operation of the mobile radwaste processing system, or the spent media is transferred to the seismic Category I auxiliary building for packaging. Once the packaging in the radwaste building is complete, the activity of the packaged spent media is no longer added to the applicable mobile radwaste processing system activity for comparison with the applicable A2 quantity limit. This results in preventing exposures from any unmitigated radiological release in the radwaste building, occurring over a two hour exposure period, from exceeding the Regulatory Guide 1.143 unmitigated radiological release criteria and 10 CFR Part 20.1301 dose limits to site personnel and members of the public at the protected area boundary, respectively. The unmitigated, unshielded worker dose is calculated at 11 feet from the source. Unlimited worker occupancy workstations and low dose rate waiting areas are located no closer than 11 feet from a mobile radwaste processing system or a radwaste monitor tank.

Mobile and temporary equipment are designed in accordance with the applicable mobile and temporary radwaste treatment systems guidance provided in Regulatory Guide 1.143, including the codes and standards listed in Table 1 of the Regulatory Guide.

Mobile and temporary equipment has the following features:

- Level indication and alarms (high-level) on tanks.
- Screwed connections are permitted only for instrument connections beyond the first isolation valve.
- Remote operated valves are used where operations personnel would be required to frequently manipulate a valve.
- Local control panels are located away from the equipment, in low dose areas.
- Instrumentation readings are accessible from the local control panels (i.e., temperature, flow, pressure, liquid level, etc.).
- Wetted parts are 300 series stainless steel, except flexible hose and gaskets.
- Flexible hose is used only for mobile equipment within the designated “black box” locations between mobile components and at the interface with the permanent plant piping.
- The contents of tanks are capable of being mixed, either through recirculation or with a mixer.
- Grab sample points are located in tanks and upstream and downstream of the process equipment.

Inspection and testing of mobile or temporary equipment is in accordance with the codes and standards listed in Table 1 of Regulatory Guide 1.143 with the following additions:

- After placement in the station, the mobile or temporary equipment is hydrostatically, or pneumatically, tested prior to tie-in to permanent plant piping.
- A functional test, using demineralized water, is performed. Remote operated valves are stroked (open-closed-open or closed-open-closed) under full flow conditions. The proper function of the instrumentation, including alarms, is verified. The operating procedures are verified correct during the functional test.

- Tank overflows are routed to floor drains.
- Floor drains are confirmed to be functional prior to placing mobile or temporary equipment into operation.

11.2.1.3 Compliance with 10 CFR 20.1406

In accordance with the requirements of 10 CFR 20.1406 (Reference 5), the liquid radwaste system is designed to minimize, to the extent practicable, contamination of the facility and the environment, facilitate decommissioning, and minimize, to the extent practicable, the generation of radioactive waste. This is done through appropriate selection of design technology for the system, and incorporation of the ability to update the system to use the best available technology throughout the life of the plant.

11.2.2 System Description

The liquid radwaste system, shown in Figure 11.2-1, includes tanks, pumps, ion exchangers, and filters. The liquid radwaste system is designed to process, or store for processing by mobile equipment, radioactively contaminated wastes in four major categories:

- Borated, reactor-grade, waste water – this input is collected from the reactor coolant system (RCS) effluents received through the chemical and volume control system (CVS), primary sampling system sink drains and equipment leakoffs and drains.
- Floor drains and other wastes with a potentially high suspended solids content – this input is collected from various building floor drains and sumps.
- Detergent wastes – this input comes from the plant hot sinks and showers, and some cleanup and decontamination processes. It generally has low concentrations of radioactivity.
- Chemical waste – this input comes from the laboratory and other relatively small volume sources. It may be mixed hazardous and radioactive wastes or other radioactive wastes with a high dissolved-solids content.

Nonradioactive secondary-system waste is not processed by the liquid radwaste system. Secondary-system effluent is normally handled by the steam generator blowdown processing system and the waste water system as described in Subsection 10.4.8.

Radioactivity can enter the secondary systems from steam generator tube leakage. If significant radioactivity is detected in secondary-side systems, blowdown is diverted to the liquid radwaste system for processing and disposal.

11.2.2.1 Waste Input Streams

11.2.2.1.1 Reactor Coolant System Effluents

The effluent subsystem receives borated and hydrogen-bearing liquid from two sources: the reactor coolant drain tank and the chemical and volume control system. The reactor coolant drain tank collects leakage and drainage from various primary systems and components inside containment. Effluent from the chemical and volume control system is produced mainly as a result of reactor coolant system heatup, boron concentration changes and RCS level reduction for refueling.

Input collected by the effluent subsystem normally contains hydrogen and dissolved radiogases. Therefore, it is routed through the liquid radwaste system vacuum degasifier before being stored in the effluent holdup tanks.

The liquid radwaste system degasifier can also be used to degas the reactor coolant system before shutdown by operating the chemical and volume control system in an open loop configuration. This is done by taking one of the effluent holdup tanks out of normal waste service and draining it. Then normal chemical and volume control system letdown is directed through the degasifier to the dedicated effluent holdup tank. From there, it is pumped back to the suction of the chemical and volume control system makeup pumps with the effluent holdup tank pump. The makeup pumps return the fluid to the reactor coolant system in the normal fashion. This process is continued as necessary for degassing the reactor coolant system as described in Subsection 9.3.6.

The input to the reactor coolant drain tank is potentially at high temperature. Therefore, provisions are made for recirculation through a heat exchanger for cooling. The tank is inerted with nitrogen and is vented to the gaseous radwaste system. Transfer of water from the reactor coolant drain tank is controlled to maintain an essentially fixed tank level to minimize tank pressure variation.

Reactor coolant system effluents from the chemical and volume control system letdown line or the reactor coolant drain subsystem pass through the vacuum degasifier, where dissolved hydrogen and fission gases are removed. These gaseous components are sent via a water separator to the gaseous radwaste system. A degasifier discharge pump then transfers the liquid to the currently selected effluent holdup tank. If flows from the letdown line and the reactor coolant drain tank are routed to the degasifier concurrently, the letdown flow has priority and the drain tank input is automatically suspended.

In the event of abnormally high degasifier water level, inputs are automatically stopped by closing the letdown control and containment isolation valves.

The effluent holdup tanks vent to the radiologically controlled area ventilation system and, in abnormal conditions, may be purged with air to maintain a low hydrogen gas concentration in the tanks' atmosphere. Hydrogen monitors are included in the tanks vent lines to alert the operator of elevated hydrogen levels.

The contents of the effluent holdup tanks may be recirculated and sampled, recycled through the degasifier for further gas stripping, returned to the reactor coolant system via the chemical and volume control system makeup pumps, discharged to the mobile treatment facility, processed through the ion exchangers, or directed to the monitor tanks for discharge without treatment.

Processing through the ion exchangers is the normal mode.

The AP1000 liquid radwaste system processes waste with an upstream filter followed by four ion exchange resin vessels in series. Any of these vessels can be manually bypassed and the order of the last two can be interchanged, so as to provide complete usage of the ion exchange resin.

The top of the first vessel is normally charged with activated carbon, to act as a deep-bed filter and remove oil from floor drain wastes. Moderate amounts of other wastes can also be routed through this vessel. It can be bypassed for processing of relatively clean waste streams. This vessel is somewhat larger than the other three, with an extra sluice connection to allow the top bed of activated carbon to be removed. This feature is associated with the deep bed filter function of the vessel; the top layer of activated carbon collects particulates, and the ability to remove it without disturbing the underlying zeolite bed minimizes solid-waste production.

The second, third and fourth beds are in identical ion exchange vessels, which are selectively loaded with resin, depending on prevailing plant conditions.

After deionization, the water passes through an after-filter where radioactive particulates and resin fines are removed. The processed water then enters one of the monitor tanks. When one of the monitor tanks is full, the system is automatically realigned to route processed water to another tank.

The contents of the monitor tank are recirculated and sampled. In the unlikely event of radioactivity in excess of operational targets, the tank contents are returned to a waste holdup tank for additional processing.

Normally, however, the radioactivity will be well below the discharge limits, and the dilute boric acid is discharged for dilution to the circulating water blowdown. The discharge flow rate is set to limit the boric acid concentration in the circulating water blowdown stream to an acceptable concentration for local requirements. Detection of high radiation in the discharge stream stops the discharge flow and operator action is required to re-establish discharge. The raw water system which provides makeup for the circulating water system is used as a backup source for dilution water when cooling tower blowdown is not available for the discharge path.

11.2.2.1.2 Floor Drains and Other Wastes with Potentially High Suspended Solid Contents

Potentially contaminated floor drain sumps and other sources that tend to be high in particulate loading are collected in the waste holdup tank. Additives may be introduced to the tank to improve filtration and ion exchange processes. Tank contents may be recirculated for mixing and sampling. The tanks have sufficient holdup capability to allow time for realignment and maintenance of the process equipment.

The waste water is processed through the waste pre-filter to remove the bulk of the particulate loading. Next it passes through the ion exchangers and the waste after-filter before entering a monitor tank. The monitor tank contents are sampled and, if necessary, returned to a waste holdup tank and processed through the filters and ion exchangers.

Waste water meeting the discharge limits is discharged to the circulating water blowdown through a radiation detector that stops the discharge if high radiation is detected.

11.2.2.1.3 Detergent Wastes

The detergent wastes from the plant hot sinks and showers contain soaps and detergents. These wastes are generally not compatible with the ion exchange resins described in Subsections 11.2.2.1.1 and 11.2.2.1.2. The detergent wastes are not processed and are collected in the chemical waste tank. If the detergent wastes activity is low enough, the wastes can be discharged without processing.

When sufficient detergent wastes are produced and processing is necessary, installed equipment or mobile processing equipment (brought into one of the radwaste building mobile systems facility truck bays provided for this purpose) may be used to process the waste prior to discharge or waste water may be shipped offsite for processing.

11.2.2.1.4 Chemical Wastes

Inputs to the chemical waste tank normally are generated at a low rate. Chemicals can be added to the tank for pH or other adjustment. Since the volume of these wastes is low, they can be treated by installed equipment or the use of mobile equipment or by shipment offsite.

11.2.2.1.5 Steam Generator Blowdown

Steam generator blowdown is normally accommodated within the steam generator blowdown system, which is described in Subsection 10.4.8.

If steam generator tube leakage results in significant levels of radioactivity in the steam generator blowdown stream, this stream is redirected to the liquid radwaste system for treatment before release. In this event, one of the waste holdup tanks is drained to prepare it for blowdown processing. The blowdown stream is brought into that holdup tank, and continuously or in batches pumped through the waste ion exchangers. The number of ion exchangers in service is determined by the operator to provide adequate purification without excessive resin usage. The blowdown is then collected in a monitor tank, sampled, and discharged in a monitored fashion.

11.2.2.1.6 Prevention of Commingling of Chelating Agents With Radioactive Liquids

Chelating agents, as defined in 10 CFR 61.2, are not routinely used in liquid radioactive waste processing at VEGP Units 1 and 2, and similarly, they will not be routinely used in liquid radioactive processing at VEGP Units 3 and 4. In the event chelating agents are required for a specific purpose (such as cleaning of steam generators or other plant systems), an evaluation will be conducted prior to use, and specific controls will be implemented to ensure that wastes are segregated and managed appropriately to prevent commingling with plant's normal liquid radwaste system.

11.2.2.2 Other Operations

11.2.2.2.1 Sampling

Grab sampling taps are provided where required to monitor influent boron and radioactivity concentrations; to monitor performance of various components; to determine tank water characteristics before transfer, processing or discharge; to verify performance of the on-line analyzers; and to collect samples of discharges to the environs for analysis and documentation. Samples are taken in low radiation areas.

11.2.2.2.2 Tank Cleaning

Extraordinary measures for tank cleaning are not normally required because the pumps take suction from the low point of the tank, and the tank bottoms are sloped so that the tank can be fully drained. Recirculation connections are provided to allow the tanks to be effectively mixed. Also, the air-operated double-diaphragm pumps used can pump air, water or slurries without damage, and can run dry to clear the bottoms of the tanks.

Provisions are made for tank cleaning using a portable tank cleaning rig. Suction is taken from the tank bottom via a temporary hose. The pump discharge passes through a filter and the hose to a tank cleaning lance, which is manually inserted through a manway on the tank. The operator can direct the high-velocity water throughout the inside of the tank.

11.2.2.3 Component Description

The general descriptions and summaries of the design basis requirements for the liquid radwaste system components follow. Table 11.2-2 contains the operating parameters for the liquid radwaste system components.

Additional information regarding the applicable codes and classifications is also available in Section 3.2.

11.2.2.3.1 Liquid Radwaste System Pumps

Reactor Coolant Drain Tank Pumps

Two full-capacity, stainless steel, reactor coolant drain tank pumps recirculate the reactor coolant drain tank contents for cooling and to discharge the reactor coolant drain tank contents to the degasifier or to an effluent holdup tank. These vertical sump pumps have permanently lubricated bearings and mechanical seals. The pumps start and stop on high and low level.

Containment Sump Pumps

Two full-capacity containment sump pumps are provided. These submersible pumps discharge the containment sump contents to the waste holdup tank. The pumps start and stop on high and low level.

Degasifier Vacuum Pumps

Two stainless steel, full-capacity, liquid ring type, degasifier vacuum pumps maintain the degasifier at a low pressure for efficient gas stripping.

These liquid ring pumps use water as the compressant. The water is recycled to minimize consumption. Excess water from vapor condensation is discharged to an effluent holdup tank.

Degasifier Vacuum Purge Pump

One vacuum pump provides continuous removal of air in-leakage and continuous removal of nitrogen purge.

Degasifier Separator Pump

Two full capacity centrifugal pumps are provided to discharge recovered compressor water from the degasifier separator back to the degasifier vacuum pumps. The pump also serves to discharge any excess compressor water accumulation in the separator to an effluent holdup tank. The pumps start and stop to share the duty. The pump is constructed of stainless steel and has a mechanical seal.

Other Pumps

The following air-operated double-diaphragm pumps are mounted near the associated tanks with internal suction piping. Construction is of stainless steel, with elastomeric diaphragms.

- Degasifier discharge pumps (2)
- Effluent holdup tank pumps (2)
- Waste holdup tank pumps (2)
- Monitor tank pumps (6)
- Chemical waste tank pump (1)

11.2.2.3.2 Liquid Radwaste System Heat Exchangers

Reactor Coolant Drain Tank Heat Exchanger

One horizontal U-tube heat exchanger is provided. The heat exchanger shell is removable to allow for inspection and cleaning of the tube bundles.

The heat exchanger is designed to prevent the reactor coolant drain tank contents from boiling with hot leakage influent as shown in Table 11.2-4.

The reactor coolant drain tank contents flow through stainless steel tubes, and component cooling water flows inside a carbon or stainless steel shell.

Vapor Condenser

One horizontal U-tube heat exchanger assists in drying the gases drawn out of the liquid waste by the vacuum pump, before they are sent to the gaseous radwaste system. As the gas bearing water cascades down through the packing in the degasifier vessel, it boils in the low pressure. To minimize the size of the vacuum pumps, a vapor condenser is provided between the degasifier vessel and the vacuum pumps. In the vapor condenser, most of the water vapor is condensed out of the gas stream before it enters the vacuum pump. The vapor condenser is cooled by chilled water. Chilled water flows through the tubes, which are stainless steel. Water vapor condenses on the tubes and drains through a subcooling section in the stainless steel shell. The non-condensible gases and condensate are recombined in a common pipe leading to the suction of the liquid ring type vacuum pumps.

11.2.2.3.3 Liquid Radwaste System Tanks

Reactor Coolant Drain Tank

One reactor coolant drain tank is provided. The tank is sized to accommodate two vertical sump type pumps and to have a volume above the normal operating water level sufficient to accept the influent rate shown in Table 11.2-4.

The reactor coolant drain tank is a stainless steel, horizontal, cylindrical tank with dished heads. It is provided with a vacuum breaker to prevent excess external pressure during containment leak testing. It is protected from excess internal pressure by a relief valve which vents to the containment sump.

Effluent Holdup Tanks

These stainless steel tanks contain effluent waste prior to processing. They are horizontal cylinders with internal pump suction piping at the low point of the tank, and with side manways for maintenance.

Waste Holdup Tanks

These stainless steel tanks contain floor and equipment drain waste before processing. They are vertical cylinders with internal pump suction piping at the low points of the tanks and with side manways for maintenance.

Monitor Tanks

These stainless steel tanks contain processed waste before discharge. They are vertical cylinders with internal pump suction piping at the low points of the tanks and with side manways for maintenance.

Chemical Waste Tank

This stainless steel tank contains chemical waste along with detergent wastes from hot sinks, hot showers, and equipment decontamination before processing. The configuration is a vertical cylinder with internal pump suction piping at the low point of the tank and with a side manway for maintenance.

11.2.2.3.4 Liquid Radwaste System Sump

Containment Sump

The containment sump is a stainless steel, rectangular sump tank designed for embedment in concrete. The containment sump is sized as shown in Table 11.2-4.

11.2.2.3.5 Liquid Radwaste System Vessels

Degasifier Column

A one-stage, stainless steel degasifier column is provided. The degasifier column is designed to meet the performance parameters shown in Table 11.2-5.

Agitation and surface exposure are accomplished by spraying the influent onto the top of a column of packing which breaks up the flow and spreads it into thin films as it cascades downward. The low pressure causes the inlet water to boil. The flashed vapor accompanies the gas bearing water downward through the packing. Exposure to low pressure draws out the non-condensible gases consistent with Henry's Law and they pass out the vacuum connection. The vacuum connection is located near the last point of contact with the degassed water where the vacuum is greatest and conditions are least conducive to reabsorption. A stainless steel mesh demister is provided at the vessel vacuum connection to remove water droplets which are entrained in the gas/vapor mixture as it is exiting to the vapor condenser.

Degasifier Separator

One stainless steel separator is provided. It is designed to remove compressor water from the vacuum pump discharge flow for reuse. It also serves as a silencer.

11.2.2.3.6 Liquid Radwaste System Ion Exchangers

Four ion exchange vessels are provided, with resin volumes as shown in Table 11.2-2. The media will be selected by the plant operator to optimize system performance. The ion exchange vessels are stainless steel, vertical, cylindrical pressure vessels with inlet and outlet process nozzles plus connections for resin addition, sluicing, and draining. The process outlet and flush water outlet connections are equipped with resin retention screens designed to minimize pressure drop.

11.2.2.3.7 Liquid Radwaste System Filters

Waste Pre-Filter

This filter is provided to collect particulate matter in the process stream before ion exchange. The unit is constructed of stainless steel and has disposable filter bags.

Waste After-Filter

This filter is provided downstream of the ion exchangers to collect particulate matter, such as resin fines. The unit is constructed of stainless steel and has disposable filter cartridges.

11.2.2.4 Instrumentation Design

Instrumentation readout is available in the main control room and on display and control panels.

Alarms are provided to the data display system including a radwaste system annunciator in the main control room.

Pressure indicators provide pressure drops across demineralizers, filters, and strainers.

Releases to the environment are monitored for radioactivity. Section 11.5 describes this instrumentation.

Each tank is provided with level instrumentation that actuates an alarm on high liquid level in the tank, thus warning of potential tank overflow. High level in redundant tank pairs also diverts the flow to the standby tank. Table 11.2-3 provides a summary of the tank level alarms.

11.2.2.5 System Operation and Performance

11.2.2.5.1 Reactor Coolant System Effluent Processing

11.2.2.5.1.1 Reactor Coolant Systems Effluent: Letdown Line

Chemical and volume control system letdown is directed to the degasifier. This letdown flow automatically takes priority by causing isolation of influent to the degasifier from the reactor coolant drain tank pumps to prevent the design capacity of the degasifier from being exceeded.

When the degasifier and waste gas system are placed in operation one of the degasifier vacuum pumps operates to maintain a vacuum in the degasifier column. The degasifier separator pump operates to return compressor water to the vacuum pump. The degasifier separator vents to the gaseous radwaste system. Its level is automatically controlled by discharging excess water (due to condensation of vapor carryover from the degasifier column) to an effluent holdup tank. In the event of abnormally high level, chemical and volume control system letdown flow is automatically stopped.

Two effluent holdup tanks are provided. One is aligned to receive inputs. When it fills to the appropriate level, an alarm alerts the operator that the tank is full and ready for processing. The inlet diversion valve automatically realigns the system to route input to the other tank upon high-high alarm.

11.2.2.5.1.2 Reactor Coolant System Effluent: Reactor Coolant Drain Tank

The reactor coolant drain tank receives input from the reactor coolant system and other drains inside containment that have the potential to contain radioactive gas or hydrogen.

Initially and after servicing, the reactor coolant drain tank is filled with demineralized water and then purged with nitrogen to dilute and displace oxygen. The tank vent to the gaseous radwaste system normally remains closed. One of the reactor coolant drain tank pumps and the discharge valve are automatically controlled to maintain reactor coolant drain tank water level within a narrow band to minimize tank pressure variation. An alarm alerts the operator if the reactor coolant drain tank reaches a temperature consistent with the design leak of saturated RCS coolant. The system automatically realigns valves and recirculates the tank contents through the reactor coolant drain tank heat exchanger.

The cumulative quantity discharged from the reactor coolant drain tank is totalized and indicated for use in reactor coolant leakage evaluations.

The discharge may have a relatively high dissolved hydrogen concentration and is therefore aligned to the degasifier. However, during reactor coolant system loop drain operations the hydrogen and radioactive gas concentrations should be low and discharge may be directly aligned to an effluent holdup tank.

11.2.2.5.1.3 Processing of the Reactor Coolant System Effluents

Each effluent holdup tank vent includes a hydrogen detector to monitor the hydrogen concentration in the tank atmosphere. In the event of high alarm, the operator initiates air purge through the tank to dilute the hydrogen gas and maintain it below the flammable limits. The tanks vent to the radiologically controlled area ventilation system.

An effluent holdup tank high level alarm alerts the operator that the tank is full and ready for processing. The inlet diversion valve automatically directs the influent to the other tank upon high-high alarm.

To process the contents of the filled tank, the effluent holdup tank pump is started to recirculate and sample the tank contents. If additional gas stripping is required, the tank contents may be recirculated through the degasifier. The degasifier functions automatically as described in Subsection 11.2.2.5.1.1.

The discharge of either effluent holdup tank pump can be aligned to the suction of the chemical and volume control system makeup pumps. This mode of operation is used during reactor coolant system degassing operations. Reactor coolant from the chemical and volume control system letdown is degassed in the degasifier, collected in one of the effluent holdup tanks, and continuously pumped back to the chemical and volume control system makeup pumps. The pump returns the degassed water to the reactor coolant system.

Reactor coolant collected in an effluent holdup tank during reactor coolant system loop drain operations may also be pumped to the chemical and volume control system makeup pumps for refill of the reactor coolant system. Before beginning this process, the operator fully drains the effluent holdup tank receiving the reactor coolant so that the boron concentration of the reactor coolant system is not significantly affected.

The effluent may be transferred to the mobile treatment facility for concentration or solidification. This disposal method is used only during unusual conditions that restrict the normal processed waste discharge mode described in the following paragraphs.

The normal mode of operation is to process the effluent by ion exchange and filtration to remove the radioactive materials. The ion exchangers operate in series as described in Subsection 11.2.2.1.1.

The last bed provides a polishing function and also prevents radioactivity breakthrough to the monitor tank when the upstream unit becomes exhausted. This allows the full capacity of the upstream resin beds to be used, reducing the amount of spent resin that is generated.

When the analysis of samples taken periodically downstream of the ion exchange processing indicates an increase in radioactivity above prescribed limits, the operator isolates the expended unit(s) for resin replacement. Flow continues through the other units until a fresh resin bed is ready. When one of the last two ion exchangers has been replenished, the fresh unit is then brought online as the downstream unit.

The after-filter removes resin fines and other particulate matter that may pass through the ion exchangers. A high differential pressure alarm alerts the operator to the need for filter element replacement. Normally, filter element replacement is initiated on high radioactivity determined by periodic survey.

Process discharge is normally aligned to one of the monitor tanks. When one of the tanks is full, an alarm alerts the operator that the tank is full and ready to be discharged. The inlet diversion valve automatically realigns the system to route processed waste to another tank upon high-high level.

The operator then starts the monitor tank pump to recirculate the tank contents and samples the processed waste. Since the ion exchangers operate in the borated saturated mode, the water contains boric acid. The radioactivity and chemistry of the processed waste is determined by sample analysis. In the unlikely event that radioactivity exceeds discharge limitations, the tank contents are returned to a waste holdup tank for reprocessing.

Once it is confirmed that the waste water is within radioactivity discharge limitations, the operator prepares the system for discharge. The operator initiates discharge by starting the monitor tank pump and opening the remotely operated discharge valve. During controlled discharge, grab samples are taken for laboratory analysis and documentation of discharge.

If the radiation monitor in the discharge line detects high radiation, the valve automatically closes. The operator is alerted to this condition by a high radiation alarm, and is required to take corrective action. A manual drain valve is opened to flush the radiation monitor and confirm low radiation before re-establishing discharge to the circulating water blowdown. Low monitor tank level automatically stops the monitor tank pump.

11.2.2.5.2 Floor Drain and Equipment Drain Waste Processing

Miscellaneous liquid wastes normally include influent from the radioactive floor drains, equipment drains and auxiliary building sump and excess water from the solid radwaste system. These wastes collect in one of two waste holdup tanks.

A high level alarm in the tank alerts the operator that the tank is full and ready to be processed. The inlet diversion valve automatically directs influents to the second waste holdup tank upon high-high level. The waste holdup tank pump is started to recirculate and sample the tank contents. Additives may be introduced to the waste holdup tank to optimize filtration and ion exchange processes.

Floor drain wastes are also brought into the waste holdup tanks from the containment sump. High sump level automatically opens the containment isolation valves and starts a pump to transfer the sump contents. Low level automatically stops the pump and closes the isolation valves. An alarm is provided to alert the operator to abnormally high containment sump level and the standby pump is automatically started. Cumulative flow is totalized and indicated to support reactor coolant leakage analysis.

The normal mode of operation is to process the waste water through the pre-filter, ion exchangers, and after-filter to the monitoring tank as described for the reactor coolant system effluent processing. Under abnormal conditions, the waste may also be transferred directly to a mobile treatment facility.

11.2.2.5.3 Detergent Waste Processing

The detergent wastes from the plant hot sinks and showers are routed to the chemical waste tank. Normally, these wastes are sampled and confirmed suitable for discharge without processing. If processing prior to discharge is necessary, three courses of action are available. The waste water may be transferred to a waste holdup tank and processed in the same manner as other radioactively contaminated waste water. If the onsite processing capabilities are not suitable for the composition of the detergent waste, processing can be performed using mobile equipment brought into one of the truck bays of the radwaste building or the waste water can be shipped offsite for processing. After processing by mobile equipment the water may be transferred to a waste holdup tank for further processing by the onsite equipment or transferred to a monitor tank for sampling and discharge.

11.2.2.5.4 Chemical Waste Processing

Radioactively contaminated chemical wastes are collected in the chemical waste tank. Chemicals may be added to the tank for pH or other adjustment. The volume of these wastes is expected to be low. The design includes alternatives for processing or discharge of chemical wastes. They may be processed onsite using mobile equipment, but are expected to be suitable for discharge without treatment or for processing by installed equipment before discharge. When not suitable for onsite processing, they can be shipped offsite for processing. After processing by mobile equipment the

water may be transferred to a waste holdup tank for further processing by the onsite equipment or transferred to a monitor tank for sampling and discharge.

11.2.2.5.5 Steam Generator Blowdown Processing

Normal steam generator blowdown processing is accommodated by the steam generator blowdown system, which is described in Subsection 10.4.8.

If steam generator tube leakage results in levels of radioactivity in the blowdown stream above what can be accommodated by the secondary-side systems, this stream is directed to the liquid radwaste system. For this function, the operator aligns the steam generator blowdown system to the inlet of the waste holdup tank. The blowdown waste is then processed in the same way as other wastes.

11.2.2.5.6 Ion Exchange Media Replacement

The initial and subsequent fill of ion exchange media is made through a resin fill nozzle on the top of the ion exchange vessel. When the media are spent and ready to be transferred to the solid radwaste system, the vessel is isolated from the process flow. The flush water line is opened to the sluice piping and demineralized water is pumped into the vessel through the normal process outlet connection upward through the media retention screen. The media fluidize in the upward, reverse flow. When the bed has been fluidized, the sluice connection is opened and the bed is sluiced to the spent resin tanks in the solid radwaste system (WSS). Demineralized water flow continues until the bed has been removed and the sluice lines are flushed clean of spent resin.

11.2.3 Radioactive Releases

Liquid waste is produced both on the primary side (primarily from adjustment of reactor coolant boron concentration and from reactor coolant leakage) and the secondary side (primarily from steam generator blowdown processing and from secondary side leakage). Primary and secondary coolant activity levels are provided in Section 11.1 for both the design case and the anticipated case, which is based on operating plant experience.

Except for reactor coolant system degasification in anticipation of shutdown, the AP1000 does not recycle primary side effluents for reuse. Primary effluents are discharged to the environment after processing. Fluid recycling is provided for the steam generator blowdown fluid which is normally returned to the condensate system.

The only liquid effluent site interface parameter outside of the Westinghouse scope is the release point to the Savannah River.

11.2.3.1 Discharge Requirements

The release of radioactive liquid effluents from the plant may not exceed the concentration limits specified in Reference 1 nor may the releases result in the annual offsite dose limits specified in 10 CFR 50, Appendix I (Reference 2) being exceeded.

11.2.3.2 Estimated Annual Releases

The annual average release of radionuclides from the plant is determined using the PWR-GALE code (Reference 3). The PWR-GALE code models releases which use source terms derived from data obtained from the experience of operating PWRs. The code input parameters used in the analysis to model the AP1000 plant are listed in Table 11.2-6. The annual releases for a single-unit site are presented in Table 11.2-7.

In agreement with Reference 3, the total releases include an adjustment factor of 0.16 curies per year to account for anticipated operational occurrences. The adjustment uses the same distribution of nuclides as the calculated releases.

11.2.3.3 Dilution Factor

The dilution factor provided for the activity released is site dependent; the value of 6000 gpm used herein is based on cooling tower blowdown requirements and is expected to be conservatively low. The plant operator will select dilution flow rates to ensure that the effluent concentration limits of 10 CFR Part 20, the annual offsite dose limits in 10 CFR 50 Appendix I, and any local requirements are continuously met. If the available dilution is low, the discharge rate can be reduced to maintain acceptable concentrations.

The required dilution flow is dependent on the liquid waste discharge rate and, while the monitor tank pumps have a design flow rate of 100 gpm, the discharge flow is controlled to be compatible with the available dilution flow. With a typical liquid waste release of 1925 gallons per day, the nominal circulating water blowdown flow of 6000 gpm provides sufficient dilution flow to maintain the annual average discharge concentrations well below the effluent concentration limits. Actual plant operation is dependent on the waste liquid activity level and the available dilution flow.

The site-specific dilution factor is addressed in Subsection 11.2.3.5.

11.2.3.4 Release Concentrations

The annual release data provided in Table 11.2-7 represent expected releases from the plant. To demonstrate compliance with the Reference 1 effluent concentration limits, the discharge concentrations have been evaluated for the release of a typical daily liquid waste volume of 1925 gallons per day and using the nominal circulating water blowdown flow of 6000 gpm. Table 11.2-8 lists the annual average nuclide release concentrations and the fraction of the effluent concentration limits using base GALE code assumptions. As shown in Table 11.2-8, the overall fraction of the effluent concentration limit is well below the allowable value of 1.0.

The annual releases from the plant have also been evaluated based on operation with the maximum defined fuel defect level. The maximum defined fuel defect level is conservatively established at 1.0 percent fuel defects, corresponding to four times the Technical Specification limit on coolant activity which is based on 0.25 percent fuel defects, as described in Table 11.1-2. Table 11.2-9 lists the annual average nuclide release concentrations and the fractions of the effluent concentration limits for the maximum defined fuel defects. As shown in Table 11.2-9, the overall fraction of the effluent concentration limit for the maximum defined fuel defect level is well below the allowable value of 1.0.

11.2.3.5 Estimated Doses

11.2.3.5.1 Exposure Pathways

Small quantities of radioactive liquids would be discharged to the Savannah River during normal operation of the new units. VEGP Units 3 and 4 discharge structure and associated piping provide a pathway for liquid effluents, including radioactive liquids, discharged to the Savannah River. The impact of these releases on individuals and the population in the vicinity of the new units is evaluated by considering the most important pathways from the release to the receptors of interest. The major pathways are those that could yield the highest radiological doses for a given receptor. The relative importance of a pathway is based on the type and amount of radioactivity released, the environmental transport mechanism, and the consumption or usage factors at the receptor.

The exposure pathways considered and the analytical methods used to estimate doses to the maximally exposed individual (MEI) and to the population surrounding the new units are based on NRC Regulatory Guide 1.109, *Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR 50, Appendix I*, Revision 1, October 1977. An MEI is a member of the public located to receive the maximum possible calculated dose. The MEI allows dose comparisons with established criteria for the public.

Liquid effluent releases would be to Savannah River. The discharge is assumed to be fully mixed with the river flow. The NRC-endorsed LADTAP II computer program (Reference 203) is used to calculate liquid effluent doses, with parameters specific to the river and downstream locations. This program implements the radiological exposure models described in Regulatory Guide 1.109 for radioactivity releases in liquid effluent. The following exposure pathways are considered in LADTAP II in calculating MEI and population doses:

- Ingestion of aquatic foods
- Ingestion of drinking water
- External exposure to shoreline sediments
- External exposure to water through boating and swimming

The input parameters for the liquid pathway are presented in Tables 11.2-201, 11.2-202, and 11.2-203.

11.2.3.5.2 Liquid Pathway Doses

Based on the parameters shown in Tables 11.2-201, 11.2-202, and 11.2-203, the LADTAP II computer program is used to calculate doses to the MEI and the population via the following activities:

- Eating fish caught in Savannah River
- Drinking water from Savannah River
- Boating, swimming, and using the shoreline for recreational purposes

The liquid activity releases (source terms) for the two proposed AP1000 units are obtained from Table 11.2-7 (Reference 207) and are shown in Table 11.2-203. These are conservative, projected values that were calculated using the PWR-GALE computer code (Reference 202). Table 11.2-203 also shows the maximum measured activity releases for Units 1 and 2, based on information presented in the annual effluent reports (References 204, 205, 206). Projected activity concentrations in Savannah River are based on the calculated activity releases for Units 3 and 4 as well as the measured activity releases from Units 1 and 2. The concentrations are within the limits of 10 CFR 20, Appendix B, Table 2, Column 2. The calculated annual doses to the MEI are presented in Table 11.2-204. The maximum annual organ dose of 0.021 mrem per unit would be received by the liver of the maximally exposed child.

Table 11.2-205 shows that the doses to the MEI from the liquid effluents of a new unit meet the design objectives of 10 CFR 50, Appendix I. The total site doses due to liquid and gaseous effluents from the two existing units and the two new units would be well within the regulatory limits of 40 CFR 190, as shown in Table 11.2-206. Since 40 CFR 190 is more restrictive than 10 CFR 20.1301, compliance with the limits of 40 CFR 190 also demonstrates compliance with the 0.1 rem limit of 10 CFR 20.1301. Table 11.2-207 shows the doses from the new and existing units to the population

within 50 miles of the ESP site. The doses from the proposed units are much higher than from the existing units because doses from the existing units are more realistic, based on measurements, whereas the doses from the proposed units are based on conservative calculations.

Table 11.2-207 reports a total body population dose from liquid effluents within 50 miles of VEGP Units 3 and 4 of 0.037 person-rem/year or 0.019 person-rem/year per reactor. In addition, the corresponding thyroid dose has been calculated to be 0.0022 person-rem/year per reactor.

11.2.3.5.3 Liquid Radwaste Cost Benefit Analysis Methodology

The application of the methodology of Regulatory Guide 1.110 was used to satisfy the cost benefit analysis requirements of 10 CFR Part 50. Appendix I, Section II.D. The parameters used in calculating the Total Annual Cost (TAC) are fixed and are given for each radwaste treatment system augment listed in Regulatory Guide 1.110, including the Annual Operating Cost (AOC) (Table A-2), Annual Maintenance Cost (AMC) (Table A-3), Direct Cost of Equipment and Materials (DCEM) (Table A-1), and Direct Labor Cost (DLC) (Table A-1). The following variable parameters were used:

- Capital Recovery Factor (CRF) -This factor is taken from Table A-6 of Regulatory Guide 1.110 and reflects the cost of money for capital expenditures. A cost-of-money value of 7% per year is assumed in this analysis, consistent with the "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission" (NUREG/BR-0058). A CRF of 0.0806 was obtained from Table A-6.

- Indirect Cost Factor (ICF) -This factor takes into account whether the radwaste system is unitized or shared (in the case of a multi-unit site) and is taken from Table A-5 of Regulatory Guide 1.110. It is assumed that the radwaste system for this analysis is a unitized system at a 2-unit site, which equals an ICF of 1.625.

- Labor Cost Correction Factor (LCCF) -This factor takes into account the differences in relative labor costs between geographical regions and is taken from Table A-4 of Regulatory Guide 1.110. A LCCF of 1.0 (the lowest value) is assumed in this analysis.

Appendix I to 10 CFR Part 50 prescribes a $1,000 per person-rem criterion for determining the cost benefit of actions to reduce radiation exposure.

The analysis used a conservative assumption that the respective radwaste treatment system augment is a "perfect" system that reduces the effluent and dose by 100 percent. The liquid radwaste treatment system augments annual costs were determined and the lowest annual cost considered a threshold value. The lowest-cost option for liquid radwaste treatment system augments is a 20 gpm Cartridge Filter at $11,140 per year, which yields a threshold value of 11.14 person-rem total body or thyroid dose from liquid effluents.

For AP1000 sites with population dose estimates less than 11.14 person-rem total body or thyroid dose from liquid effluents. no further cost-benefit analysis is needed to demonstrate compliance with 10 CFR 50, Appendix I Section II.D.

11.2.3.5.4 Liquid Radwaste Cost Benefit Analysis

As discussed in Subsection 11.2.3.5.3, the lowest cost liquid radwaste system augment is $11,140. Assuming 100% efficiency of this augment, the minimum possible cost per person-rem is determined by dividing the cost of the augment by the population dose. This is $586,316 per person-rem total body ($11,140/0.019 person-rem) and $5,063,636 per person-rem thyroid ($11,140/0.0022 person-rem). These costs per person-rem reduction exceed the $1,000 per person-rem criterion prescribed in Appendix I to 10 CFR Part 50 and are therefore not beneficial.

11.2.3.6 Quality Assurance

The quality assurance program for design, fabrication, procurement, and installation of the liquid radwaste system is in accordance with the overall quality assurance program described in Chapter 17.

Since the impact of radwaste systems on safety is limited, the extent of control required by Appendix B to 10 CFR Part 50 is similarly limited. Thus, a supplemental quality assurance program applicable to design, construction, installation and testing provisions of the liquid radwaste system is established by procedures that complies with the guidance presented in Regulatory Guide 1.143.

11.2.4 Preoperational Testing

11.2.4.1 Sump Level Instrument Testing

One of the diverse methods of detecting small reactor coolant pressure boundary leaks is monitoring the containment sump level. (See Subsection 5.2.5 for a full discussion.) A sump capacity calibration test is performed so the containment sump level instruments can provide a display that is correlated to the contained volume of water in the sump.

In addition to a normal level accuracy calibration of the containment sump level instruments, WLS-LIT-034, WLS-LIT-035, and WLS-LIT-036, their displays will be correlated to the volume of water during preoperational testing. A known volume of water will be added to the containment sump. The change in sump level will be measured by using a local measurement method. The change in the display of the sump level instruments will be compared to the level change measured by a local measurement methodology. A sump level change corresponding to a volume of water which is smaller than that released in an hour by 0.5 gpm reactor coolant system leak can be detected.

11.2.4.2 Discharge Control/Isolation Valve Testing

The AP1000 effluent discharge line includes a radiation monitor, WLS-RE-229, as described in Subsection 11.5.2.3.3. A concentration of radioactivity in the effluent, which exceeds the radiation monitor setpoint, causes a high radiation signal to automatically close the discharge control/isolation valve.

A test will be performed on the liquid radwaste system discharge control/isolation valve, WLS-PL-V223, during preoperational testing. A simulated WLS-RE-229 high radiation signal will be sent to the plant control system and the discharge control/isolation valve will be observed to close.

11.2.4.3 Preoperational Inspection

The performance of the liquid radwaste system has been evaluated based upon using a predetermined quantity and type of ion-exchange media. An inspection will confirm that the proper volume of media, as listed in Table 11.2-2, “Component Data – Liquid Radwaste System,” has been installed into the appropriate liquid radwaste system components, MV03 and MV04A/B/C.

11.2.5 Combined License Information

11.2.5.1 Liquid Radwaste Processing by Mobile Equipment

The mobile or temporary equipment used for storing or processing liquid radwaste is addressed in Subsection 11.2.1.2.5.2.

11.2.5.2 Cost Benefit Analysis of Population Doses

The site specific cost-benefit analysis to address the requirements of 10 CFR 50, Appendix I, regarding population doses due to liquid effluents is addressed in Subsections 11.2.3.3, 11.2.3.5, 11.2.3.5.3 and 11.2.3.5.4.

11.2.5.3 Identification of Ion Exchange and Adsorbent Media

The types of liquid waste ion exchange and absorbent media to be used in the liquid radwaste system (WLS) are addressed in APP-GW-GLR-008 (Reference 6), and the applicable changes are incorporated into the UFSAR.

11.2.5.4 Dilution and Control of Boric Acid Discharge

The planned discharge flow rate for borated wastes and controls for limiting the boric acid concentration in the circulating water system blowdown is addressed in APP-GW-GLR-014 (Reference 7), and the applicable changes are incorporated into the UFSAR.

11.2.6 References

1. "Annual Limits on Intake (ALIs) and Derived Air Concentrations (DACs) of Radionuclides for Occupational Exposure; Effluent Concentrations; Concentrations for Release to Sewerage," 10 CFR Part 20, Appendix B, Issued by 58 FR 67657, April 28, 1995.

2. "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As Low As Is Reasonably Achievable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," 10 CFR Part 50, Appendix I.

3. "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code)," NUREG-0017, Revision 1, March 1985.

4. ANSI/ANS-55.6-1993, "Liquid Radioactive Waste Processing Systems for Light Water Reactor Plants."

5. "Minimization of Contamination," 10 CFR 20.1406.

6. APP-GW-GLR-008, "Identification of Ion Exchange and Absorbent Media, Completing COL Items 11.2-3 and 11.3-2," Westinghouse Electric Company LLC.

7. APP-GW-GLR-014, "Closure of COL Items in DCD Chapter 11, Dilution and Control of Boric Acid Discharge," Westinghouse Electric Company LLC.

8. "Appendix A to Part 71 – Determination of A_1 and A_2," 10 CFR 71 Appendix A, Table A-1.

201. NEI 08-08A, Generic FSAR Template Guidance for Life Cycle Minimization of Contamination, Revision 0, October 2009 (ML093220445).

202. **(NRC 1985)** NUREG-0017, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code)*, Revision 1, U. S. Nuclear Regulatory Commission, 1985.

203. **(NRC 1986)** NUREG/CR-4013, *LADTAP II Technical Reference and User Guide*, U. S. Nuclear Regulatory Commission, 1986.

204. **(SNC 2002)** *Annual Radioactive Effluent Release Report for January 1, 2001 to December 31, 2001*, Southern Nuclear Company, 2002.

205. **(SNC 2003)** *Annual Radioactive Effluent Release Report for January 1, 2002 to December 31, 2002*, Southern Nuclear Company, 2003.

206. **(SNC 2004)** *Annual Radioactive Effluent Release Report for January 1, 2003 to December 31, 2003,* Southern Nuclear Company, 2004.

207. **(Westinghouse 2005)** AP1000 Document APP-GW-GL-700, *AP1000 Design Control Document, Tier 2 Material*, Revision 15, Westinghouse Electric Company, 2005.

208. **(WSRC 2006)** WSRC-TR-2006-00007, *Savannah River Site Environmental Report for 2005,* Washington Savannah River Company, 2006. Accessed from http://www.srs.gov/general/pubs/ERsum/er06/liqdos_05.htm, April 18, 2007.

Table 11.2-1 (Sheet 1 of 2)
Liquid Inputs and Disposition

Collection Tank and Sources	Expected Input Rate	Activity	Basis	Disposition
1. Effluent holdup tanks				Filtered, demineralized, and discharged
Chemical and volume control system letdown	159,000 gpy	100% of reactor coolant	AP1000-specific calculations[(a)]	
Leakage inside containment (to reactor coolant drain tank)	10 gpd	167% of reactor coolant	ANSI/ANS-55.6	
Leakage outside containment (to effluent holdup tanks)	80 gpd	100% of reactor coolant	ANSI/ANS-55.6	
Sampling drains	200 gpd	5% of reactor coolant	ANSI/ ANS-55.6	
2. Waste holdup tank				Filtered, demineralized and discharged
Reactor containment cooling	500 gpd	0.1% of reactor coolant	ANSI/ANS-55.6	
Spent fuel pool liner leakage	25 gpd	0.1% of reactor coolant	ANSI/ANS-55.6	
Misc. drains	675 gpd	0.1% of reactor coolant	ANSI/ANS-55.6	

Table 11.2-1 (Sheet 2 of 2)
Liquid Inputs and Disposition

Collection Tank and Sources	Expected Input Rate	Activity	Basis	Disposition
3. Detergent waste				Filtered, demineralized, monitored, and discharged. If necessary, processed with mobile equipment or shipped offsite.
Hot shower	0 gpd	10^{-7} µCi/g	ANSI/ANS-55.6	
Hand wash	200 gpd	10^{-7} µCi/g	ANSI/ANS-55.6	
Equipment and area decontamination	40 gpd	0.1% of reactor coolant	ANSI/ANS-55.6	
Laundry			Offsite laundry	
4. Chemical wastes	2 gpd	≤ reactor coolant	Estimate	Filtered, demineralized, and discharged. If necessary, processed with mobile equipment or shipped offsite.

Notes:
a. Average letdown for all normal reactor fuel cycle operations; initial heatup, dilutions and borations.

Table 11.2-2 (Sheet 1 of 7)
Component Data – Liquid Radwaste System

Pumps	
Containment sump pumps	
Number	2
Type	Submersible centrifugal
Design pressure (psig)	32.5 external
Design temperature (°F)	250
Design flow (gpm)	100
Material	Stainless steel
Reactor coolant drain tank pumps	
Number	2
Type	Vertical sump type, centrifugal
Design pressure (psig)	10 external
Design temperature (°F)	250
Design flow (gpm)	100
Material	Stainless steel
Degasifier separator pump (part of vacuum degasifier)	
Number	2
Type	Centrifugal
Design pressure (psig)	125
Design temperature (°F)	200
Design flow (gpm)	7
Material	Stainless steel

Table 11.2-2 (Sheet 2 of 7)
Component Data – Liquid Radwaste System

Pumps	
Standard waste processing pump Standard waste processing pump used for:(1) Number — Application 2 — Degasifier discharge pumps 2 — Effluent holdup tank pumps 2 — Waste holdup tank pumps 6 — Monitor tank pumps 1 — Chemical waste tank pump	
Type	Air-operated, double-diaphragm
Design pressure (psig)	125
Design temperature (°F)	150
Design flow (gpm)	100 (can be varied by varying air supply flow)
Material	Stainless steel body, Elastomeric diaphragm
Degasifier vacuum pumps (part of vacuum degasifier package)	
Number	2
Type	Liquid ring
Design pressure (psig)	75
Design temperature (°F)	150
Design flow (scfm) (total hydrogen and water vapor flow)	641
Material	Stainless steel

Table 11.2-2 (Sheet 3 of 7)
Component Data – Liquid Radwaste System

Filters	
Waste pre-filter	
Number	1
Type	Disposable bag
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (gpm)	75
Particle size (micron, 98% retention)	For U3: Up to 40 microns, For U4: 25 microns
Materials	
Housing	Stainless steel
Filter	Polypropylene/pleated paper
Waste after-filter	
Number	1
Type	Disposable bag or cartridge
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (gpm)	75
Particle size (micron, 98% retention)	For U3: Up to 20 microns, For U4: 0.5 microns
Materials	
Housing	Stainless steel
Filter medium	Polypropylene/pleated paper

Table 11.2-2 (Sheet 4 of 7)
Component Data – Liquid Radwaste System

Heat Exchangers	
Reactor Coolant drain tank heat exchanger	
Number	1
Type	Horizontal U-tube
Design pressure (psig)	200 tubeside, 200 shellside
Design temperature (°F)	250 tubeside, 200 shellside
Design flow (lb/hr)	48,700 tubeside, 62,200 shellside
Heat Transfer Design Case	
Temperature inlet (°F)	175 tubeside, 95 shellside
Temperature outlet (°F)	143 tubeside, 120 shellside
Material	SS tubeside, CS or SS shellside
Vapor condenser	
Number	1
Type	Horizontal U-tube
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (lb/hr)	125,000 tubeside, 1800 shellside
Heat Transfer Design Case	
Temperature inlet (°F)	40 tubeside, 87.1 shellside
Temperature outlet (°F)	55.7 tubeside, 60 shellside
Material	SS

Table 11.2-2 (Sheet 5 of 7)
Component Data – Liquid Radwaste System

Ion Exchangers	
Deep bed filter	
Number	1
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (gpm)	75
Nominal resin volume (ft^3)	50
Material	Stainless steel
Resin type	Layered: Activated charcoal on zeolite resin (Adjustable for plant conditions)
Process decontamination factors	See Table 11.2-5
Waste ion exchangers	
Number	3
Design pressure (psig)	150
Design temperature (°F)	150
Design flow (gpm)	75
Nominal resin volume (ft^3)	30
Materials	Stainless steel
Resin type	One cation, Two mixed (Adjustable for plant conditions)
Process decontamination factors	See Table 11.2-5

Table 11.2-2 (Sheet 6 of 7)
Component Data – Liquid Radwaste System

Tanks	
Reactor coolant drain tank	
Number	1
Nominal volume (gal)	900
Type	Horizontal
Design pressure (psig)	internal — 20 for the tank and 10 for the valves and attached instruments external pressure range — -0.2 to 1.0
Material	Stainless steel
Containment sump	
Number	1
Nominal volume (gal)	220
Type	Rectangular
Design pressure (psig)	Atmospheric
Design temperature (°F)	200
Material	Stainless steel
Effluent holdup tanks	
Number	2
Nominal volume (gal)	28,000
Type	Horizontal
Design pressure (psig)	Atmospheric
Design temperature (°F)	150
Material	Stainless steel
Waste holdup tanks	
Number	2
Nominal volume (gal)	15,000
Type	Vertical
Design pressure (psig)	Atmospheric
Design temperature (°F)	150
Material	Stainless steel

Table 11.2-2 (Sheet 7 of 7)
Component Data – Liquid Radwaste System

Monitor tanks	
Number	6
Nominal volume (gal)	15,000
Type	Vertical
Design pressure (psig)	Atmospheric
Design temperature (°F)	150
Material	Stainless steel
Chemical waste tank	
Number	1
Nominal volume (gal)	7,700
Type	Vertical
Design pressure (psig)	Atmospheric
Design temperature (°F)	150
Material	Stainless steel
Degasifier separator (part of vacuum degasifier package)	
Number	1
Nominal volume (gal)	45
Type	Vertical
Design pressure (psig)	150
Design temperature (°F)	200
Material	Stainless steel
Degasifier column (part of vacuum degasifier package)	
Number	1
Nominal volume (gal)	900
Type	Vertical
Design pressure (psig)	150 internal 15 external
Design temperature (°F)	150
Material	Stainless steel

Note:
1. This same pump is also used for other applications, such as sumps outside containment.

Table 11.2-3
Summary of Tank Level Indication, Level Annunciators, and Overflows

Tank	Level Indication Location (Note 3)	Alarm Location	Alarm	Overflow To
Effluent holdup	MCR	MCR	High	Room drains to auxiliary building sump which is pumped to waste holdup tank (Note 2)
Waste holdup	MCR	MCR	High	Room (Note 4)
Chemical waste	MCR	MCR	High	Room (Note 2)
Monitor	MCR	MCR	High	Room (Note 5)

Notes:

1. MCR = main control room
2. Room is piped to a floor drain within the auxiliary building, which is seismic Category I and water-tight with curbs or walls of sufficient height to contain the entire contents of the contained tank.
3. Monitoring of the liquid radwaste system is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. Local indication and control are available on displays which may be connected to the data display and processing system. See Chapter 7.
4. Room is within the auxiliary building, which is seismic Category I and water-tight with curbs or walls of sufficient height to contain the entire contents of the contained tank.
5. Room is piped to a floor drain within the auxiliary building, which is seismic Category I and water-tight with curbs or walls of sufficient height to contain the entire contents of the contained tank, or to a floor drain within the radwaste building, which is water tight with curbs or walls of sufficient height to contain the entire contents of the contained tank.

Table 11.2-4
Tank Surge Capacity

Reactor Coolant Drain Tank • Sized to accept 10 gpm of saturated reactor coolant for 30 minutes without discharge or overflow. • Reactor coolant drain tank heat exchanger designed to limit the temperature to less than 175°F with this input assumed to be at 580°F.
Containment Sump • Sized to allow collection of 60 gallons of water between pumping cycles.
Effluent Holdup Tanks • Sized to allow (together) a back-to-back plant shutdown and restart without delay at any time during the first 85 percent of core life. This operation requires nominal processing of the effluent monitor tanks and normal discharge with temporary storage of waste fluid in the cask washdown pit. • Sized to allow (together) a single plant shutdown and restart without delay at any time during the first 80 percent of core life. This operation requires nominal processing to the monitor tanks, but no discharge from the plant.
Other Tanks • Sized based on accommodating maximum input without operator intervention for reasonable lengths of time.

Table 11.2-5
Decontamination Factors

Decontamination factors assumed per NUREG-0017, Revision 1 (PWR-GALE code input) to be as follows:

Resin Type/Component	Iodine	Cs/Rb	Other
Zeolite/deep bed filter (Note 1)	1	100	1
Cation/waste ion exchanger 1	1	10	10
Mixed/waste ion exchanger 2	100	2 (Note 2)	100
Mixed/waste ion exchanger 3	10	10 (Note 2)	10 (Note 2)

Other components not directly involved in discharge from the plant:

Degasifier Column

Reduce hydrogen by a factor of 40

Assuming inlet flow of 100 gpm at 130°F.

Notes:

1. This component is not included in NUREG-0017. DFs based upon "Reduction of Cesium and Cobalt Activity in Liquid Radwaste Processing Using Clinoptilolite Zeolite at Duke Power Company," by O.E. Ekechokwu, et al., Proc. Waste Management '92, Tucson, Arizona, March 1992, University of Arizona, Tucson.
2. Credit for this decontamination factor not taken in determination of anticipated annual releases.

Table 11.2-6 (Sheet 1 of 3)
Input Parameters for the GALE Computer Code

Thermal power level (MWt)	3400
Mass of primary coolant (lb)	4.35×10^5
Primary system letdown rate (gpm)	100
Letdown cation demineralizer flow rate, annual average (gpm)	10
Number of steam generators	2
Total steam flow (lb/hr)	14.97×10^6
Mass of liquid in each steam generator (lb)	1.75×10^5
Total blowdown rate (lb/hr)	4.2×10^4
Blowdown treatment method	0(1)
Condensate demineralizer regeneration time	N/A
Condensate demineralizer flow fraction	0.33
Primary coolant bleed for boron control	
Bleed flow rate (gpd)	435
Decontamination factor for I(3)	10^3
Decontamination factor for Cs and Rb(3)	10^3
Decontamination factor for others(3)	10^3
Collection time (day)	30
Process and discharge time (day)	0
Fraction discharged	1.0
Equipment Drains and Clean Waste	
Equipment drains flow rate (gpd)	290
Fraction of reactor coolant activity	0.368
Decontamination factor for I	10^3
Decontamination factor for Cs and Rb	10^3
Decontamination factor for others	10^3
Collection time (day)	30
Process and discharge time (day)	0
Fraction discharged	1.0

Table 11.2-6 (Sheet 2 of 3)
Input Parameters for the GALE Computer Code

Dirty Waste	
Dirty waste input flow rate (gpd)	1200
Fraction of reactor coolant activity	0.001
Decontamination factor for I	10^3
Decontamination factor for Cs and Rb	10^3
Decontamination factor for others	10^3
Collection time (day)	10
Process and discharge time (day)	0
Fraction discharged	1.0
Blowdown Waste	
Blowdown fraction processed	1
Decontamination factor for I	100
Decontamination factor for Cs and Rb	10
Decontamination factor for others	100
Collection time	N/A
Process and discharge time	N/A
Fraction discharged	0
Regenerant Waste	N/A

Table 11.2-6 (Sheet 3 of 3)
Input Parameters for the GALE Computer Code

Gaseous Waste System	
Continuous gas stripping of full letdown purification flow	None
Holdup time for xenon, (days)	38
Holdup time for krypton, (days)	2
Fill time of decay tanks for gas stripper	N/A
Gas waste system: HEPA filter	None
Auxiliary building: Charcoal filter	None
Auxiliary building: HEPA filter	None
Containment volume (ft^3)	2.1×10^6
Containment atmosphere internal cleanup rate (ft^3/min)	N/A
Containment high volume purge:	
Number of purges per year (in addition to two shutdown purges)	0
Charcoal filter efficiency (%)	90
HEPA filter efficiency (%)	99
Containment normal continuous purge rate (ft^3/min) (based on 20 hrs/week at 4000 ft^3/min)	500
Charcoal filter efficiency (%)	90
HEPA filter efficiency (%)	99
Fraction of iodine released from blowdown tank vent	N/A
Fraction of iodine removed from main condenser air ejector release	0.0
Detergent Waste Decontamination Factor	0.0(2)

Notes:
1. A "0" is input to indicate that the blowdown is recycled to the condensate system after treatment in the blowdown system.
2. A "0.0" is input to indicate that the plant does not have an onsite laundry.
3. Input decontamination factors result in overall decontamination factors of 1000 for iodine, 1000 for cesium and rubidium, and 1000 for other elements.

Table 11.2-7 (Sheet 1 of 2)
Releases to Discharge Canal Calculated by GALE Code

Nuclide	Shim Bleed +Equip. Drains	Miscellaneous Wastes	Turbine Building	Total Release
	Activity Release[1], Ci/year	Activity Release[1], Ci/year	Activity Release[1], Ci/year	Activity Release[1], Ci/year
Corrosion and Activation Products				
C-14	1.9E-06	negl.	negl.	1.9E-06
Na-24	9.4E-04	6.3E-06	7.6E-05	1.0E-03
Cl-36	negl.	negl.	negl.	negl.
Cr-51	1.2E-03	3.4E-06	7.5E-06	1.2E-03
Mn-54	8.6E-04	1.9E-06	3.8E-06	8.6E-04
Fe-55	1.3E-02	2.9E-05	5.7E-05	1.3E-02
Fe-59	1.3E-04	negl.	negl.	1.3E-04
Co-58	1.1E-02	2.7E-05	5.5E-05	1.1E-02
Co-60	6.1E-03	1.4E-05	2.5E-05	6.1E-03
Ni-63	1.4E-02	3.2E-05	5.8E-05	1.5E-02
Zn-65	2.7E-04	negl.	1.2E-06	2.7E-04
Nb-94	negl.	negl.	negl.	negl.
W-187	7.6E-05	negl.	4.7E-06	8.1E-05
U-234	negl.	negl.	negl.	negl.
U-235	negl.	negl.	negl.	negl.
U-238	negl.	negl.	negl.	negl.
Np-237	negl.	negl.	negl.	negl.
Pu-238	negl.	negl.	negl.	negl.
Pu-239	negl.	negl.	negl.	negl.
Pu-240	negl.	negl.	negl.	negl.
Pu-241	2.2E-06	negl.	negl.	2.2E-06
Pu-242	negl.	negl.	negl.	negl.
Am-241	negl.	negl.	negl.	negl.
Am-243	negl.	negl.	negl.	negl.
Cm-242	negl.	negl.	negl.	negl.
Cm-244	negl.	negl.	negl.	negl.
Fission Products				
As-76	negl.	negl.	negl.	negl.
Br-82	negl.	negl.	negl.	negl.
Rb-86	negl.	negl.	negl.	negl.
Rb-88	1.1E-05	negl.	negl.	1.1E-05
Sr-89	6.4E-05	negl.	negl.	6.5E-05
Sr-90	6.6E-06	negl.	negl.	6.7E-06
Y-91	2.4E-06	negl.	negl.	2.5E-06
Zr-95	1.9E-04	negl.	negl.	1.9E-04
Nb-95	1.7E-04	negl.	negl.	1.7E-04

Table 11.2-7 (Sheet 2 of 2)
Releases to Discharge Canal Calculated by GALE Code

Nuclide	Shim Bleed +Equip. Drains	Miscellaneous Wastes	Turbine Building	Total Release
	Activity Release(1), Ci/year	Activity Release(1), Ci/year	Activity Release(1), Ci/year	Activity Release(1), Ci/year
Mo-99	5.0E-04	3.1E-06	1.4E-05	5.2E-04
Tc-99m	4.8E-04	3.0E-06	1.0E-05	4.9E-04
Tc-99	negl.	negl.	negl.	negl.
Ru-103	3.2E-03	8.5E-06	1.8E-05	3.3E-03
Ru-106	negl.	negl.	negl.	negl.
Ag-110m	6.9E-04	1.6E-06	3.1E-06	7.0E-04
Sn-117m	negl.	negl.	negl.	negl.
Sb-122	negl.	negl.	negl.	negl.
Sb-124	negl.	negl.	negl.	negl.
Sb-125	negl.	negl.	negl.	negl.
I-129	negl.	negl.	negl.	negl.
I-131	4.1E-04	1.7E-06	6.7E-06	4.2E-04
I-132	5.1E-04	2.5E-06	2.3E-05	5.4E-04
I-133	7.1E-04	4.7E-06	7.2E-05	7.8E-04
I-134	1.6E-04	1.1E-06	negl.	1.6E-04
Cs-134	2.0E-04	negl.	negl.	2.1E-04
I-135	5.5E-04	3.6E-06	8.7E-05	6.4E-04
Cs-136	2.5E-04	negl.	2.3E-06	2.5E-04
Cs-137	6.1E-04	1.4E-06	2.9E-06	6.2E-04
Ba-140	3.6E-04	1.3E-06	3.0E-06	3.7E-04
La-140	4.8E-04	1.8E-06	5.5E-06	4.9E-04
Ce-144	2.1E-03	4.8E-06	9.2E-06	2.2E-03
Pr-144	2.1E-03	4.8E-06	9.2E-06	2.2E-03
All Others	negl.	negl.	negl.	negl.
Total	**6.6E-02**	**1.7E-04**	**5.8E-04**	**6.6E-02**

Tritium Release in Liquid Effluents(2) = 902 Ci/Yr

Notes:
(1) Values less than 1 microcurie are considered to be negligible
(2) Tritium release based on Westinghouse TRICAL computer code

Table 11.2-8 (Sheet 1 of 2)
Comparison of Annual Average Liquid Release Concentrations with 10 CFR 20 for Expected Releases Effluent Concentration Limits

Nuclide	Discharge Concentration[1] (μCi/ml)	Effluent Concentration Limit[2] (μCi/ml)	Fraction of Concentration Limit
Na-24	3.8E-10	5.0E-05	7.5E-06
Cr-51	4.5E-10	5.0E-04	9.1E-07
Mn-54	3.2E-10	3.0E-05	1.1E-05
Fe-55	4.9E-09	1.0E-04	4.9E-05
Fe-59	4.9E-11	1.0E-05	4.9E-06
Co-58	4.1E-09	2.0E-05	2.0E-04
Co-60	2.2E-09	3.0E-06	7.5E-04
Zn-65	1.0E-10	5.0E-06	2.0E-05
W-187	3.0E-11	3.0E-05	1.0E-06
Np-239	1.5E-16	2.0E-05	7.4E-12
Br-84	0.0E+00	4.0E-04	0.0E+00
Rb-88	3.9E-12	4.0E-04	9.8E-09
Sr-89	2.4E-11	8.0E-06	3.0E-06
Sr-91	0.0E+00	2.0E-05	0.0E+00
Y-91m	0.0E+00	2.0E-03	0.0E+00
Y-93	0.0E+00	2.0E-05	0.0E+00
Zr-95	6.9E-11	2.0E-05	3.4E-06
Nb-95	6.1E-11	3.0E-05	2.0E-06
Mo-99	1.9E-10	2.0E-05	9.6E-06
Tc-99m	1.8E-10	1.0E-03	1.8E-07
Ru-103	1.2E-09	3.0E-05	4.0E-05
Rh-103m	1.2E-09	6.0E-03	2.0E-07
Ru-106	1.0E-13	3.0E-06	3.3E-08
Rh-106	1.0E-13	6.0E-03	1.7E-11
Ag-110m	2.6E-10	6.0E-06	4.3E-05
Ag-110	3.3E-11	0.0E+00	---
Te-129m	0.0E+00	7.0E-06	0.0E+00
Te-129	0.0E+00	4.0E-04	0.0E+00
Te-131m	0.0E+00	8.0E-06	0.0E+00
Te-131	0.0E+00	8.0E-05	0.0E+00
I-131	1.5E-10	1.0E-06	1.5E-04
Te-132	5.9E-11	9.0E-06	6.5E-06
I-132	2.0E-10	1.0E-04	2.0E-06

Table 11.2-8 (Sheet 2 of 2)
Comparison of Annual Average Liquid Release Concentrations with 10 CFR 20 for Expected Releases Effluent Concentration Limits

Nuclide	Discharge Concentration[1] (μCi/ml)	Effluent Concentration Limit[2] (μCi/ml)	Fraction of Concentration Limit
I-133	2.9E-10	7.0E-06	4.1E-05
I-134	5.9E-11	4.0E-04	1.5E-07
Cs-134	7.6E-11	9.0E-07	8.4E-05
I-135	2.4E-10	3.0E-05	7.9E-06
Cs-136	9.3E-11	6.0E-06	1.5E-05
Cs-137	2.3E-10	1.0E-06	2.3E-04
Ba-137m	4.3E-09	0.0E+00	---
Ba-140	1.3E-10	8.0E-06	1.7E-05
La-140	1.8E-10	9.0E-06	2.0E-05
Ce-141	2.3E-11	3.0E-05	7.6E-07
Ce-143	0.0E+00	2.0E-05	0.0E+00
Pr-143	0.0E+00	2.0E-05	0.0E+00
Ce-144	7.9E-10	3.0E-06	2.6E-04
Pr-144	7.9E-10	6.0E-04	1.3E-06
Tritium (H-3)	9.4E-05	1.0E-03	9.4E-02
		Total =	0.096

Notes:
1. Annual average discharge concentration based on release of average daily discharge for 292 days per year with 6000 gpm dilution flow.
2. Effluent concentration limits are from Reference 1.

Table 11.2-9 (Sheet 1 of 2)
Comparison of Annual Average Liquid Release Concentrations with 10 CFR 20 Effluent Concentration Limits for Releases with Maximum Defined Fuel Defects

Nuclide	Discharge Concentration[1] (μCi/ml)	Effluent Concentration Limit[2] (μCi/ml)	Fraction of Concentration Limit
Na-24	3.8E-10	5.0E-05	7.5E-06
Cr-51	7.1E-10	5.0E-04	1.4E-06
Mn-54	5.0E-10	3.0E-05	1.7E-05
Fe-55	4.9E-09	1.0E-04	4.9E-05
Fe-59	7.8E-11	1.0E-05	7.8E-06
Co-58	4.1E-09	2.0E-05	2.0E-04
Co-60	2.2E-09	3.0E-06	7.5E-04
Zn-65	1.0E-10	5.0E-06	2.0E-05
W-187	3.0E-11	3.0E-05	1.0E-06
Np-239	1.5E-16	2.0E-05	7.4E-12
Br-84	0.0E+00	4.0E-04	0.0E+00
Rb-88	3.1E-11	4.0E-04	7.6E-08
Sr-89	2.6E-10	8.0E-06	3.3E-05
Sr-90	1.5E-11	5.0E-07	3.1E-05
Sr-91	0.0E+00	2.0E-05	0.0E+00
Y-91m	0.0E+00	2.0E-03	0.0E+00
Y-93	0.0E+00	2.0E-05	0.0E+00
Zr-95	8.7E-11	2.0E-05	4.3E-06
Nb-95	9.0E-11	3.0E-05	3.0E-06
Mo-99	8.3E-09	2.0E-05	4.2E-04
Tc-99m	8.2E-09	1.0E-03	8.2E-06
Ru-103	1.2E-09	3.0E-05	4.0E-05
Rh-103m	2.2E-09	6.0E-03	3.7E-07
Ru-106	1.9E-13	3.0E-06	6.2E-08
Rh-106	N/A	6.0E-03	0.0E+00
Ag-110m	1.1E-09	6.0E-06	1.8E-04
Ag-110	N/A	0.0E+00	0.0E+00
Te-129m	0.0E+00	7.0E-06	0.0E+00
Te-129	0.0E+00	4.0E-04	0.0E+00
Te-131m	0.0E+00	8.0E-06	0.0E+00
Te-131	0.0E+00	8.0E-05	0.0E+00
I-131	1.7E-08	1.0E-06	1.7E-02
Te-132	4.0E-09	9.0E-06	4.5E-04
I-132	8.8E-10	1.0E-04	8.8E-06
I-133	4.4E-09	7.0E-06	6.3E-04

Table 11.2-9 (Sheet 2 of 2)
Comparison of Annual Average Liquid Release Concentrations with 10 CFR 20 Effluent Concentration Limits for Releases with Maximum Defined Fuel Defects

Nuclide	Discharge Concentration(1) (μCi/ml)	Effluent Concentration Limit(2) (μCi/ml)	Fraction of Concentration Limit
I-134	7.3E-11	4.0E-04	1.8E-07
Cs-134	1.9E-07	9.0E-07	2.1E-01
I-135	1.0E-09	3.0E-05	3.5E-05
Cs-136	1.4E-07	6.0E-06	2.4E-02
Cs-137	1.5E-07	1.0E-06	1.5E-01
Ba-137m	N/A	0.0E+00	0.0E+00
Ba-140	2.2E-09	8.0E-06	2.8E-04
La-140	1.8E-10	9.0E-06	2.0E-05
Ce-141	5.4E-11	3.0E-05	1.8E-06
Ce-143	0.0E+00	2.0E-05	0.0E+00
Pr-143	0.0E+00	2.0E-05	0.0E+00
Ce-144	1.5E-09	3.0E-06	4.9E-04
Pr-144	7.9E-10	6.0E-04	1.3E-06
(Tritium) H-3	9.4E-05	1.0E-03	9.4E-02
		Total =	0.496

Notes:
1. Annual average discharge concentration based on release of average daily discharge for 292 days per year with 6000 gpm dilution flow.
2. Effluent concentrations limits are from Reference 1.

Table 11.2-201
Liquid Pathway Parameters

Parameter	Value
Release source terms	Table 11.2-203
Effluent discharge rate	9,229 ft^3/sec[a]
Dilution factor for discharge	1[a]
Transit time to receptor	0.1 hr for MEI, 16 hr average for population[b]
Impoundment reconcentration model	None[c]
Population within 50 miles	6.74E+05[d]
Population sport fishing harvest	3.5E+04 kg/yr[e]
Population shoreline usage	9.6E+05 hr/yr[e]
Population swimming	1.6E+05 hr/yr[e]
Population boating	1.1E+06 hr/yr[e]

[a] Liquid discharge assumed fully mixed with annual average flow rate of Savannah River at Vogtle.
[b] 16 hr is the average transit time to a point halfway along 50-mile stretch of Savannah River.
[c] Completely mixed model used for Savannah River.
[d] See Subsection 2.1.3.2.
[e] Savannah River Site Environmental Report for 2005 (Reference 208).

Table 11.2-202
Liquid Pathway Consumption Factors for Maximally Exposed Individual

	Annual Rate			
Consumption Factor	Adult	Teen	Child	Infant
Fish consumption (kg/yr)	21	16	6.9	0
Drinking water consumption (l/yr)	730	510	510	330
Shoreline usage (hr/yr)	12	67	14	0

Note: These are obtained from Regulatory Guide 1.109.

Table 11.2-203 (Sheet 1 of 3)
Release of Activities in Liquid Effluent

Isotope	Release (Ci/yr)			Concentration (µCi/ml)		Fraction of ECL
	Units 3 & 4	Units 1 & 2	Total	Site	ECL	
H-3	2.0E+03	1.9E+03	4.0E+03	4.8E-07	1.0E-03	4.8E-04
Be-7	-	8.3E-06	8.3E-06	1.0E-15	6.0E-04	1.7E-12
Na-24	3.3E-03	2.7E-05	3.3E-03	4.0E-13	5.0E-05	8.0E-09
Cr-51	3.7E-03	2.2E-03	5.9E-03	7.1E-13	5.0E-04	1.4E-09
Mn-54	2.6E-03	3.7E-03	6.3E-03	7.6E-13	3.0E-05	2.5E-08
Fe-55	2.0E-03	7.7E-02	7.9E-02	9.6E-12	1.0E-04	9.6E-08
Fe-59	4.0E-04	1.9E-04	5.9E-04	7.1E-14	1.0E-05	7.1E-09
Co-57	-	1.1E-04	1.1E-04	1.3E-14	6.0E-05	2.2E-10
Co-58	6.7E-03	2.5E-02	3.2E-02	3.9E-12	2.0E-05	1.9E-07
Co-60	8.8E-04	5.7E-02	5.7E-02	7.0E-12	3.0E-06	2.3E-06
Zn-65	8.2E-04	5.5E-06	8.3E-04	1.0E-13	5.0E-06	2.0E-08
Br-84	4.0E-05	-	4.0E-05	4.9E-15	4.0E-04	1.2E-11
Rb-86	-	9.3E-06	9.3E-06	1.1E-15	7.0E-06	1.6E-10
Rb-88	5.4E-04	-	5.4E-04	6.6E-14	4.0E-04	1.6E-10
Sr-89	2.0E-04	2.7E-04	4.7E-04	5.7E-14	8.0E-06	7.2E-09
Sr-90	2.0E-05	1.5E-04	1.7E-04	2.0E-14	5.0E-07	4.0E-08
Sr-91	4.0E-05	-	4.0E-05	4.9E-15	2.0E-05	2.4E-10
Sr-92	-	2.4E-05	2.4E-05	2.9E-15	4.0E-05	7.2E-11
Y-91m	2.0E-05	-	2.0E-05	2.4E-15	2.0E-03	1.2E-12
Y-91	-	2.3E-04	2.3E-04	2.8E-14	8.0E-06	3.5E-09
Y-92	-	9.3E-06	9.3E-06	1.1E-15	4.0E-05	2.8E-11
Y-93	1.8E-04	4.0E-05	2.2E-04	2.7E-14	2.0E-05	1.3E-09
Zr-95	4.6E-04	6.3E-04	1.1E-03	1.3E-13	2.0E-05	6.6E-09
Nb-95	4.2E-04	1.3E-03	1.7E-03	2.0E-13	3.0E-05	6.8E-09
Nb-97	-	1.6E-04	1.6E-04	1.9E-14	3.0E-04	6.4E-11
Mo-99	1.1E-03	-	1.1E-03	1.4E-13	2.0E-05	6.9E-09
Tc-99m	1.1E-03	-	1.1E-03	1.3E-13	1.0E-03	1.3E-10
Ru-103	9.9E-03	-	9.9E-03	1.2E-12	3.0E-05	4.0E-08

Table 11.2-203 (Sheet 2 of 3)
Release of Activities in Liquid Effluent

Isotope	Release (Ci/yr)			Concentration (µCi/ml)		Fraction of ECL
	Units 3 & 4	Units 1 & 2	Total	Site	ECL	
Ru-106	1.5E-01	-	1.5E-01	1.8E-11	3.0E-06	5.9E-06
Rh-103m	9.9E-03	-	9.9E-03	1.2E-12	6.0E-03	2.0E-10
Rh-106	1.5E-01	-	1.5E-01	1.8E-11	-	-
Ag-110m	2.1E-03	5.6E-05	2.2E-03	2.6E-13	6.0E-06	4.4E-08
Ag-110	2.8E-04	-	2.8E-04	3.4E-14	-	-
Sn-113	-	3.6E-06	3.6E-06	4.4E-16	3.0E-05	1.5E-11
Sb-122	-	4.7E-06	4.7E-06	5.6E-16	1.0E-05	5.6E-11
Sb-124	-	1.7E-04	1.7E-04	2.0E-14	7.0E-06	2.9E-09
Sb-125	-	1.9E-02	1.9E-02	2.4E-12	3.0E-05	7.9E-08
Te-125m	-	4.9E-02	4.9E-02	5.9E-12	2.0E-05	3.0E-07
Te-129m	2.4E-04	-	2.4E-04	2.9E-14	7.0E-06	4.2E-09
Te-129	3.0E-04	-	3.0E-04	3.6E-14	4.0E-04	9.1E-11
Te-131m	1.8E-04	-	1.8E-04	2.2E-14	8.0E-06	2.7E-09
Te-131	6.0E-05	-	6.0E-05	7.3E-15	8.0E-05	9.1E-11
Te-132	4.8E-04	5.1E-05	5.3E-04	6.4E-14	9.0E-06	7.2E-09
I-131	2.8E-02	5.5E-05	2.8E-02	3.4E-12	1.0E-06	3.4E-06
I-132	3.3E-03	4.7E-05	3.3E-03	4.0E-13	1.0E-04	4.0E-09
I-133	1.3E-02	3.6E-05	1.3E-02	1.6E-12	7.0E-06	2.3E-07
I-134	1.6E-03	-	1.6E-03	2.0E-13	4.0E-04	4.9E-10
I-135	9.9E-03	-	9.9E-03	1.2E-12	3.0E-05	4.0E-08
Cs-134	2.0E-02	1.5E-03	2.1E-02	2.6E-12	9.0E-07	2.9E-06
Cs-136	1.3E-03	-	1.3E-03	1.5E-13	6.0E-06	2.5E-08
Cs-137	2.7E-02	2.6E-03	2.9E-02	3.6E-12	1.0E-06	3.6E-06
Ba-137m	2.5E-02	-	2.5E-02	3.0E-12	-	-
Ba-140	1.1E-02	-	1.1E-02	1.3E-12	8.0E-06	1.7E-07
La-140	1.5E-02	3.5E-06	1.5E-02	1.8E-12	9.0E-06	2.0E-07
Ce-141	1.8E-04	1.7E-06	1.8E-04	2.2E-14	3.0E-05	7.4E-10
Ce-143	3.8E-04	-	3.8E-04	4.6E-14	2.0E-05	2.3E-09
Ce-144	6.3E-03	-	6.3E-03	7.7E-13	3.0E-06	2.6E-07

Table 11.2-203 (Sheet 3 of 3)
Release of Activities in Liquid Effluent

Isotope	Release (Ci/yr)			Concentration (µCi/ml)		Fraction of ECL
	Units 3 & 4	Units 1 & 2	Total	Site	ECL	
Pr-143	2.6E-04	-	2.6E-04	3.2E-14	2.0E-05	1.6E-09
Pr-144	6.3E-03	-	6.3E-03	7.7E-13	6.0E-04	1.3E-09
Hf-181	-	3.9E-07	3.9E-07	4.7E-17	2.0E-05	2.4E-12
W-187	2.6E-04	-	2.6E-04	3.2E-14	3.0E-05	1.1E-09
Np-239	4.8E-04	-	4.8E-04	5.8E-14	2.0E-05	2.9E-09
Total	2.0E+03	1.9E+03	4.0E+03	4.8E-07	-	5.0E-04

Note: The releases for Units 3 and 4 are based on the AP1000 DCD (Reference 207) and are for two units. The releases for Units 1 and 2 are based on annual effluent release reports (References 204, 205, 206) and are for two units. The effluent concentration limits (ECLs) are from 10 CFR 20, Appendix B, Table 2, Column 2.

Table 11.2-204
Liquid Pathway Doses for Maximally Exposed Individuals

	Dose per Unit (mrem/yr)							
	Skin	**Bone**	**Liver**	**Total Body**	**Thyroid**	**Kidney**	**Lung**	**GI-LLI**
Adult	1.3E-05	8.8E-03	2.1E-02	1.7E-02	9.0E-03	1.1E-02	7.2E-03	7.9E-03
Teen	7.2E-05	9.3E-03	2.0E-02	1.0E-02	7.0E-03	9.2E-03	5.9E-03	5.7E-03
Child	1.5E-05	1.2E-02	2.1E-02	9.9E-03	1.3E-02	1.2E-02	8.9E-03	8.6E-03
Infant	0.0E+00	5.8E-04	7.8E-03	7.2E-03	1.5E-02	7.4E-03	7.2E-03	7.7E-03
Maximum	7.2E-05	1.2E-02	2.1E-02	1.7E-02	1.5E-02	1.2E-02	8.9E-03	8.6E-03
	Teen	Child	Child	Adult	Infant	Child	Child	Child

Note: GI-LLI is gastrointestinal-lining of lower intestine.

Table 11.2-205
Comparison of Maximally Exposed Individual Doses with 10 CFR 50, Appendix I Criteria

	Location	**Dose per Unit (mrem/yr)**	
		Estimated	**Limit**
Total Body	Savannah River	0.017	3
Maximum Organ - Liver	Savannah River	0.021	10

Table 11.2-206
Comparison of Maximally Exposed Individual Doses with 40 CFR 190 Criteria

	Dose (mrem/yr)					
	Units 3 and 4			Units 1 and 2	Site Total	Regulatory Limit
	Liquid	Gaseous	Total			
Total Body	0.020	2.2	2.3	0.092	2.4	25
Thyroid	0.027	12	12	0.069	12	75
Other Organ - Bone	0.023	8.8	8.8	0.054	8.9	25

Note: Doses for Units 3 and 4 are for a child, the age group receiving the maximum total dose. Doses for Units 1 and 2 are the maximum reported in the annual effluent release reports for 2001, 2002, and 2003 (References 204, 205, 206).

Table 11.2-207
Collective Total Body Doses Within 50 Miles

	Dose (person-rem/yr)
Units 3 & 4	0.037
Units 1 & 2	0.0079
Total	0.045

Note: Doses for Units 1 and 2 are based on the maximum activity releases in the annual effluent release reports for 2001, 2002, and 2003 (References 204, 205, 206).

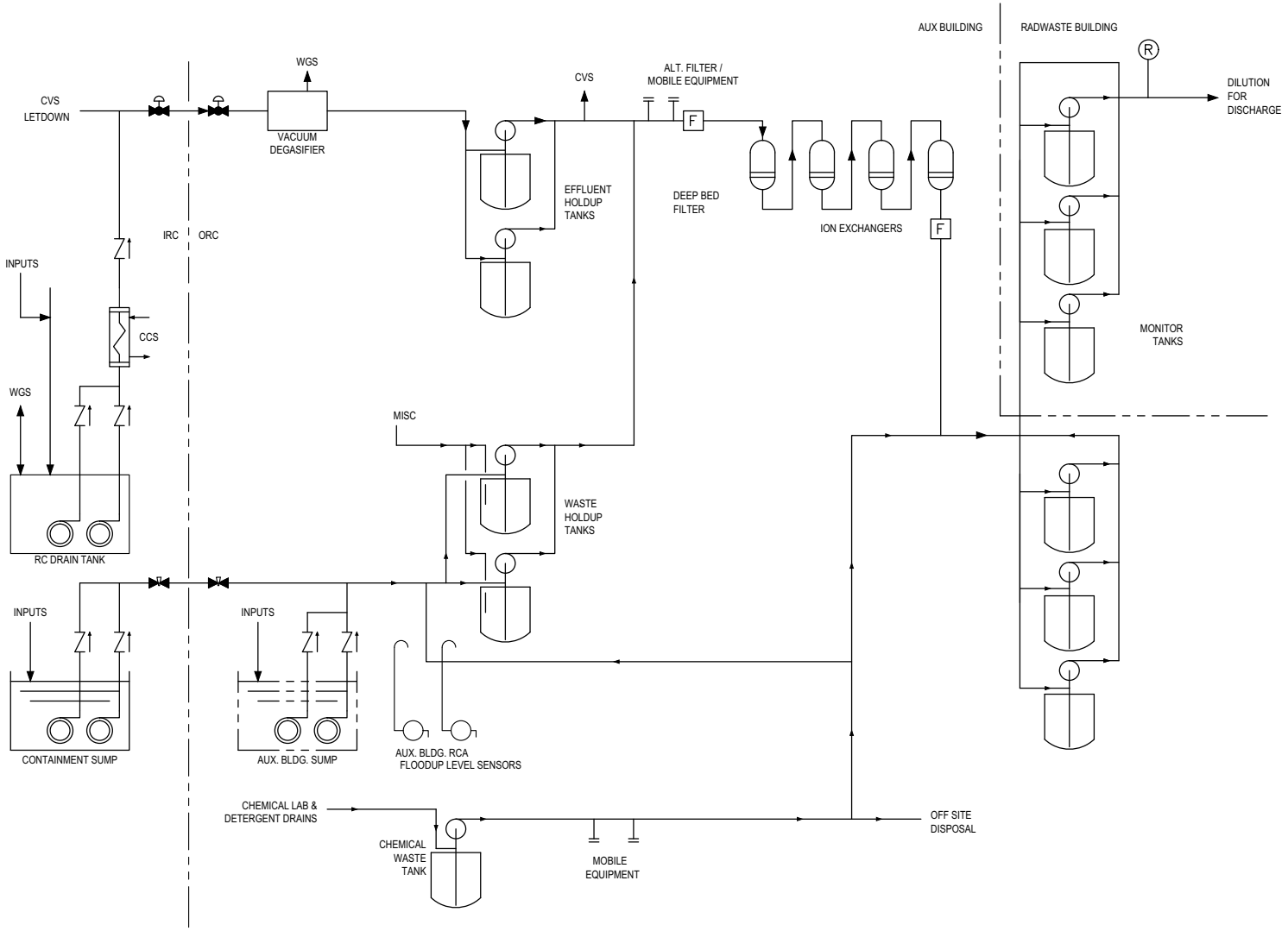


Figure 11.2-1
Liquid Radwaste System
Simplified Piping and Instrumentation Diagram
(REF) WLS

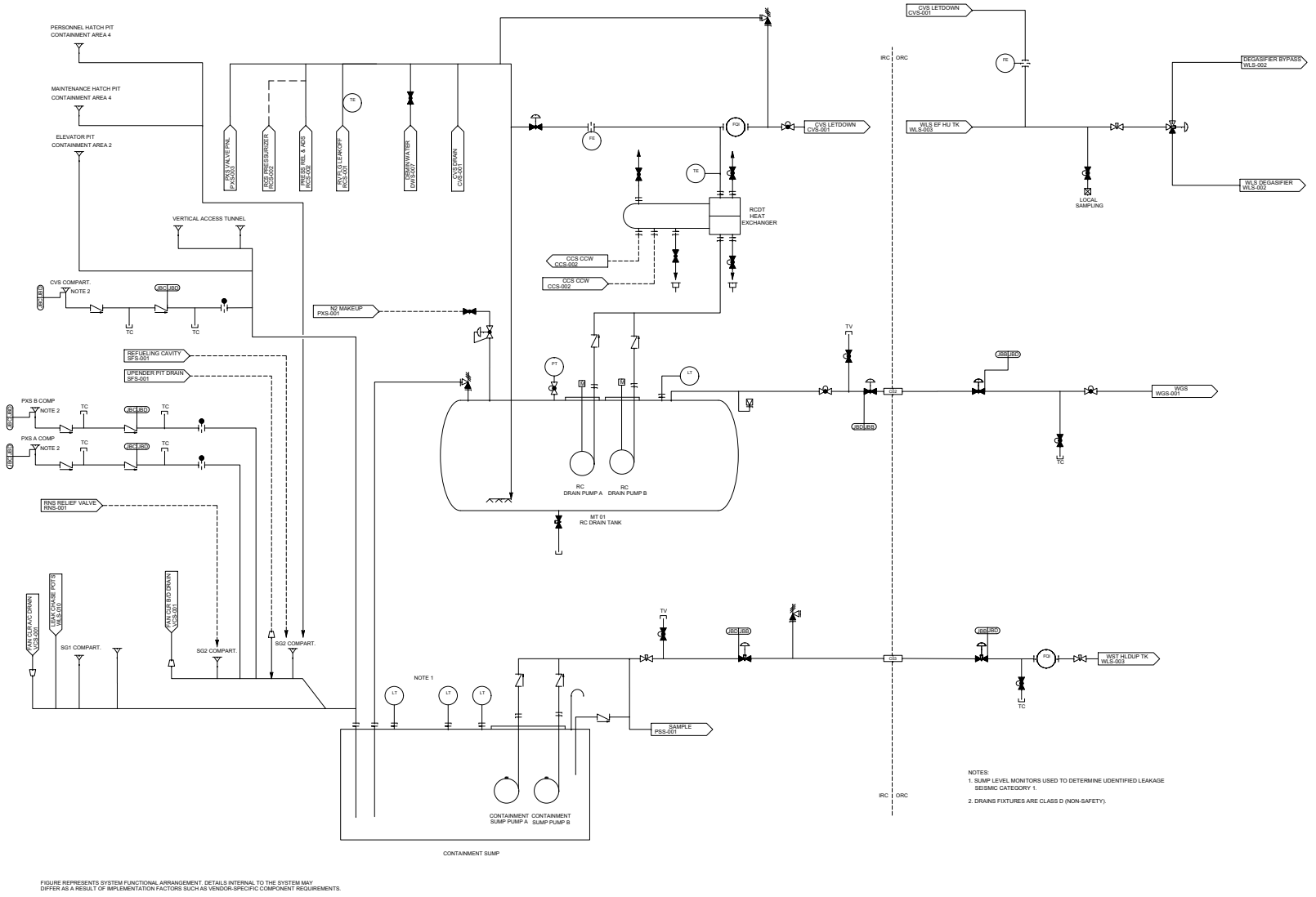


FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 11.2-2 (Sheet 1a of 8)
Unit 3 Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 001

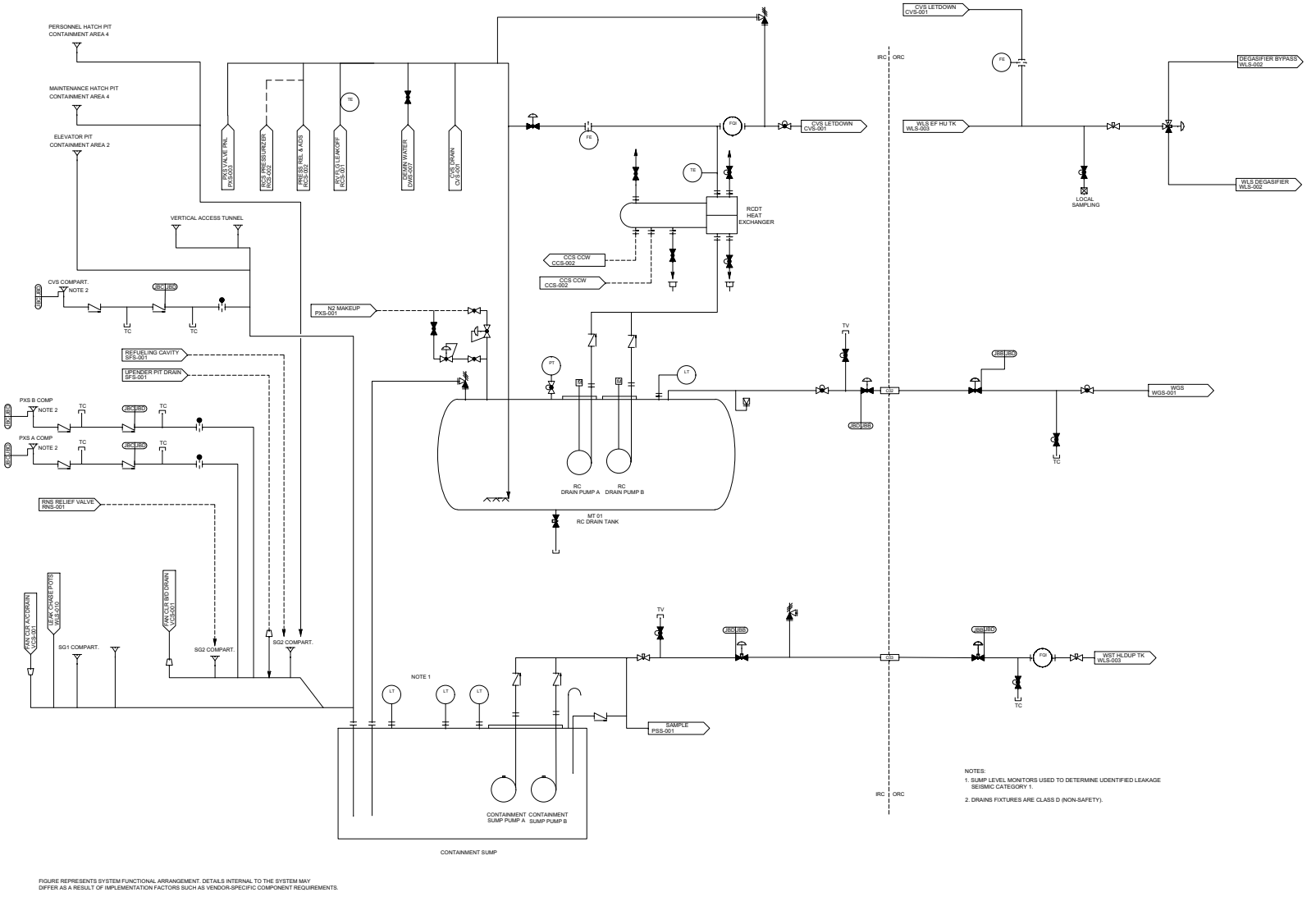


FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 11.2-2 (Sheet 1b of 8)
Unit 4 Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 001

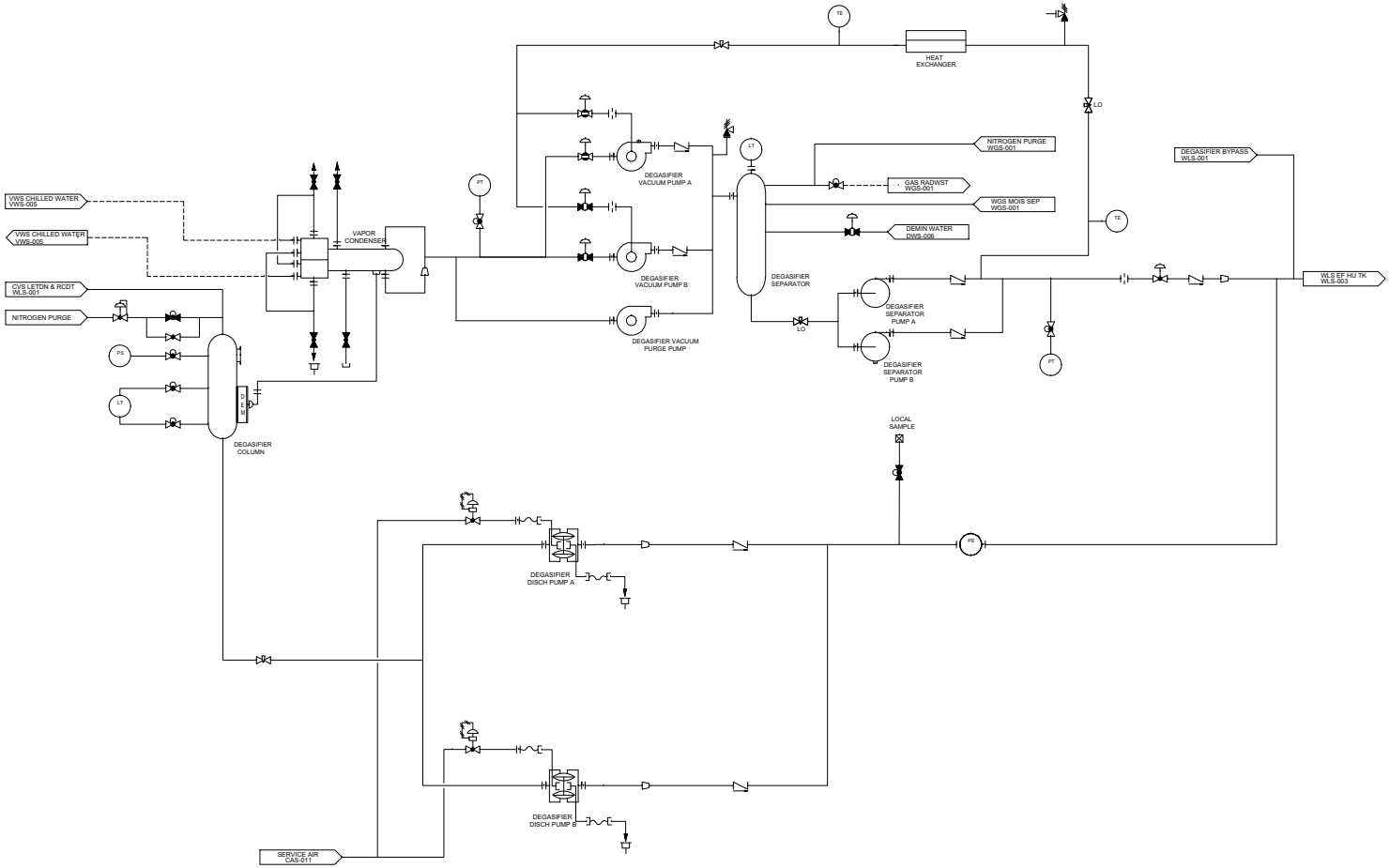


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Inside Auxiliary Building
Figure 11.2-2 (Sheet 2 of 8)
Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 002

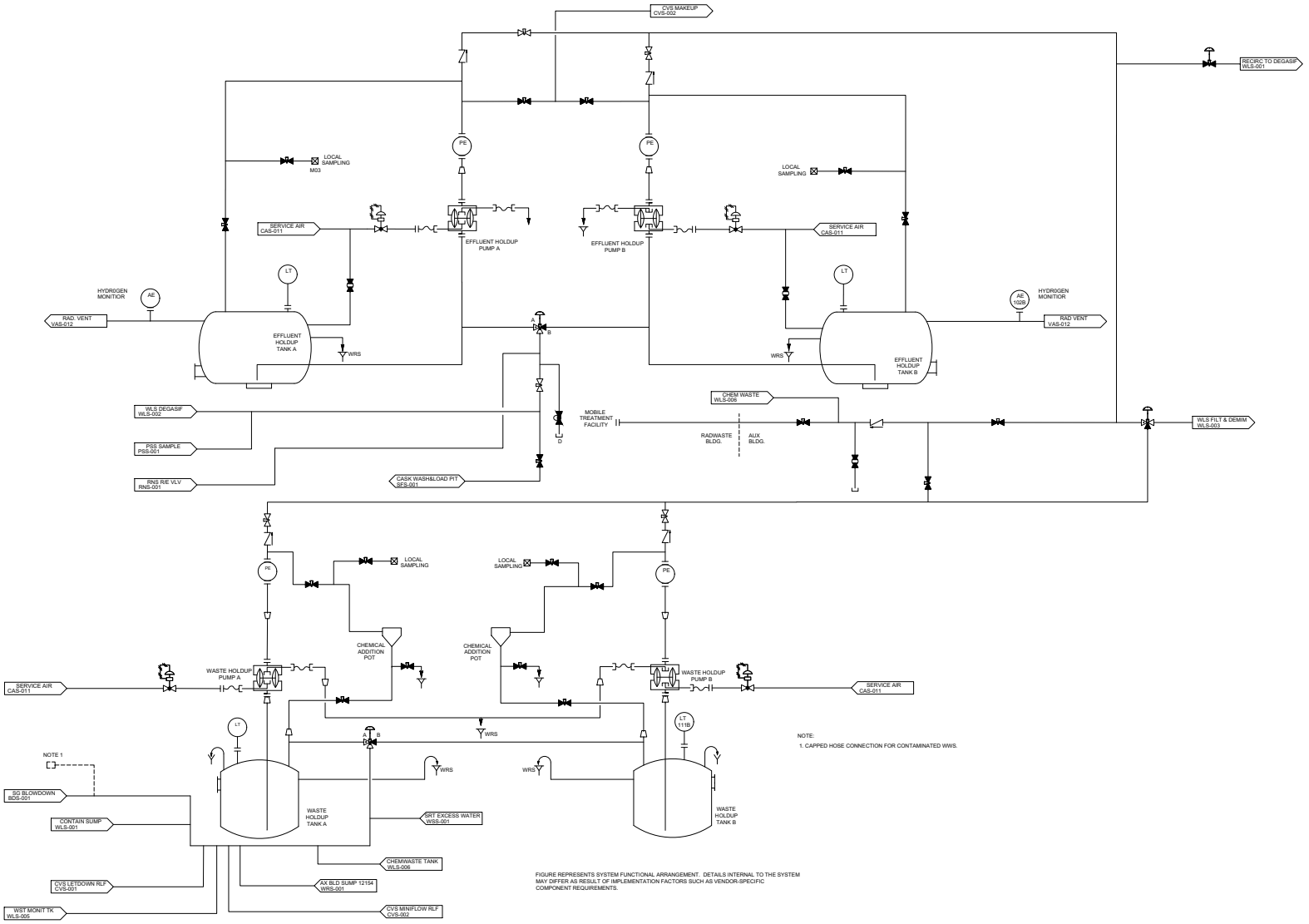


Figure 11.2-2 (Sheet 3 of 8)
Liquid Radwaste System
Piping and Instrumentation Diagram
(REF WLS 003)

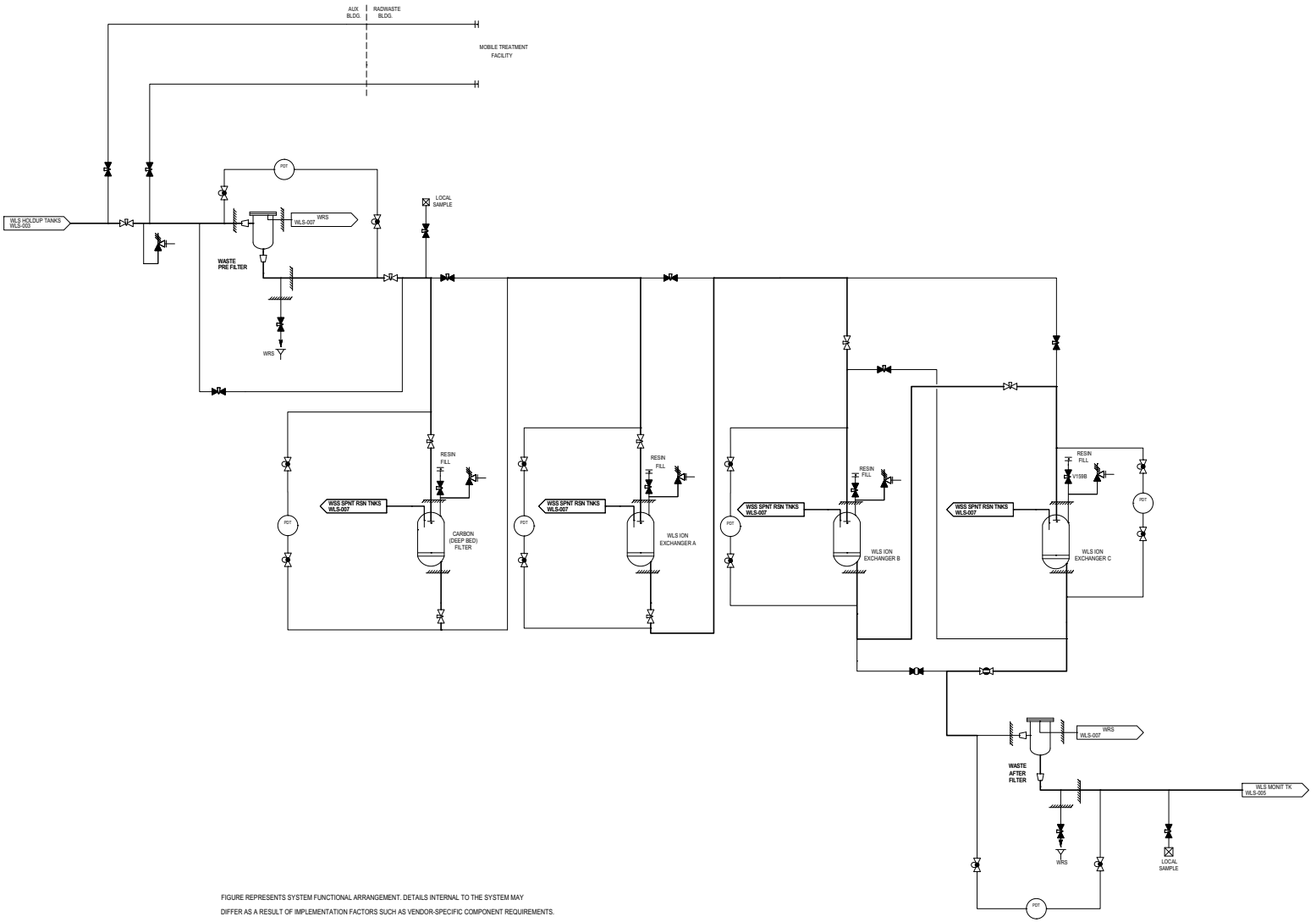


Figure 11.2-2 (Sheet 4 of 8)
Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 004

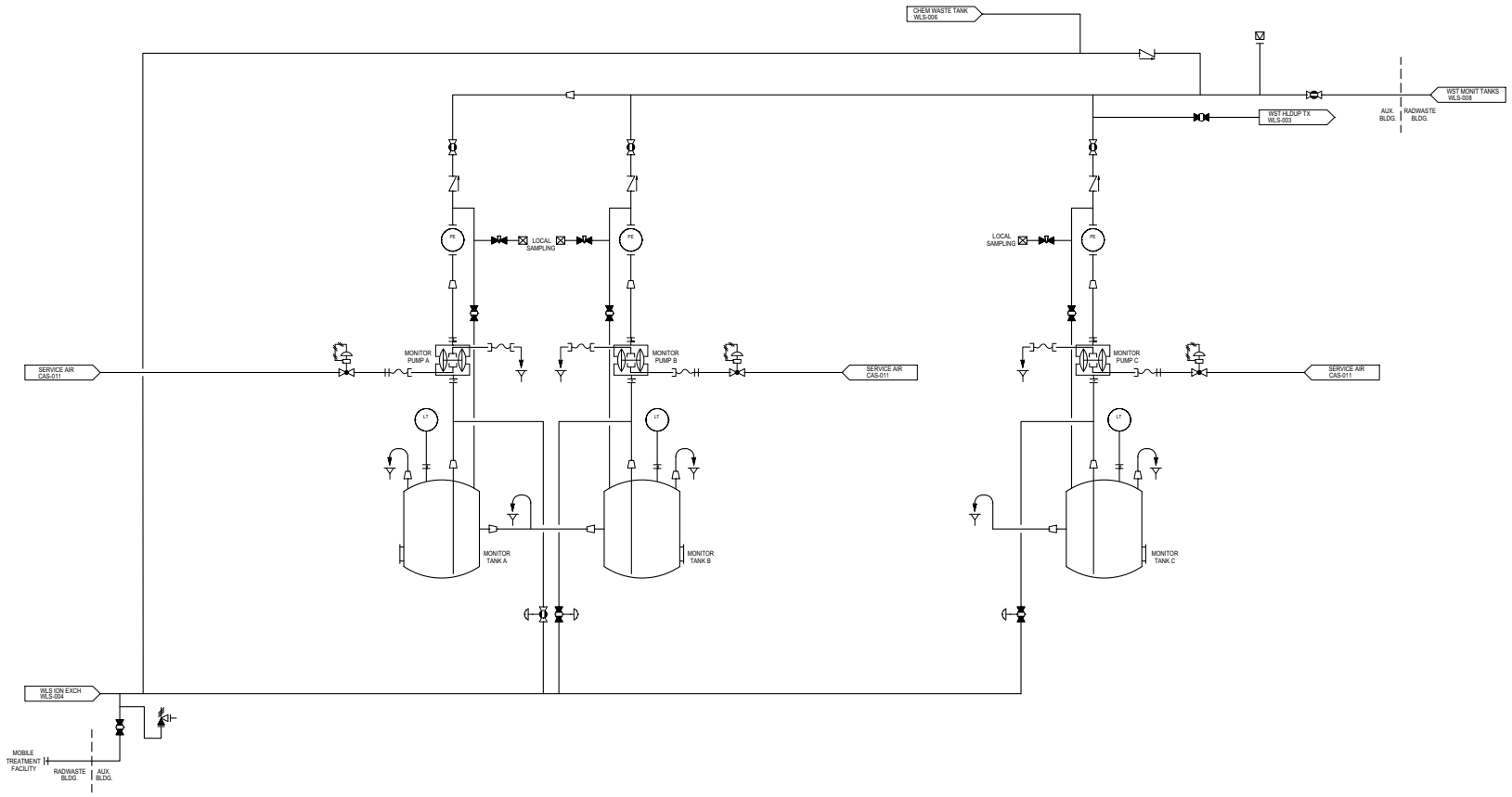


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Figure 11.2-2 (Sheet 5 of 8)
Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 005

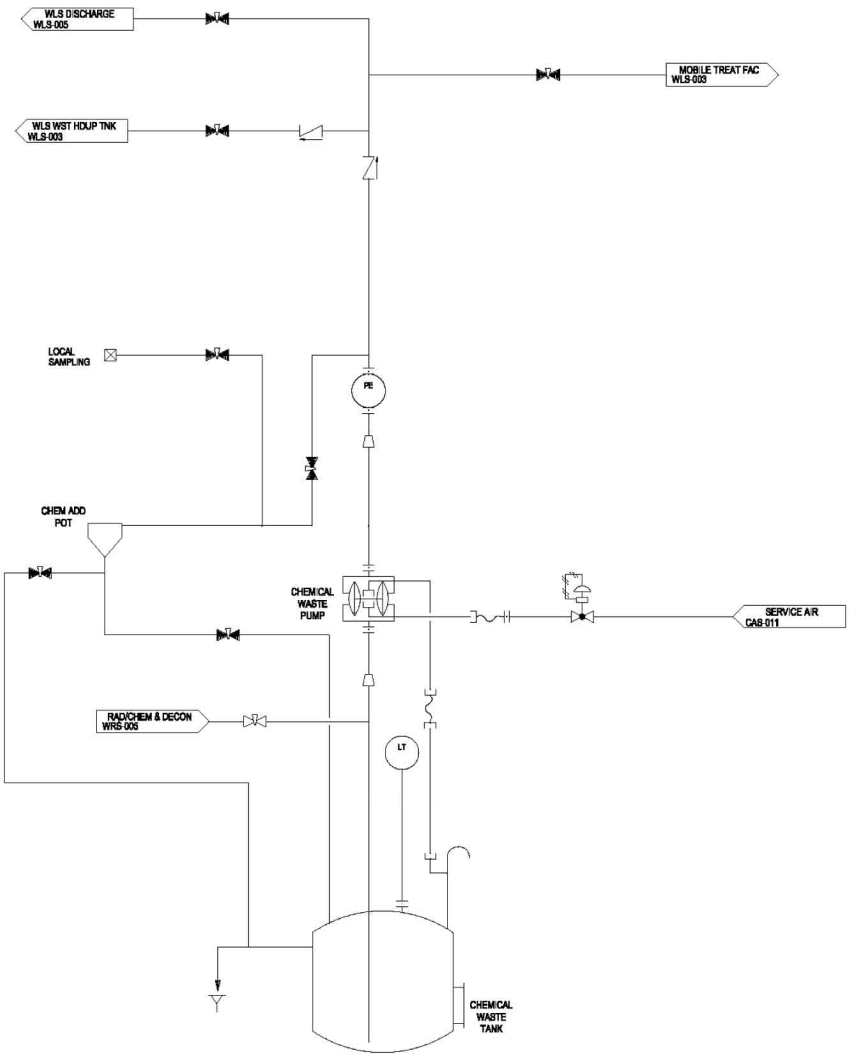


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Inside Auxiliary Building
Figure 11.2-2 (Sheet 6 of 8)
Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 006

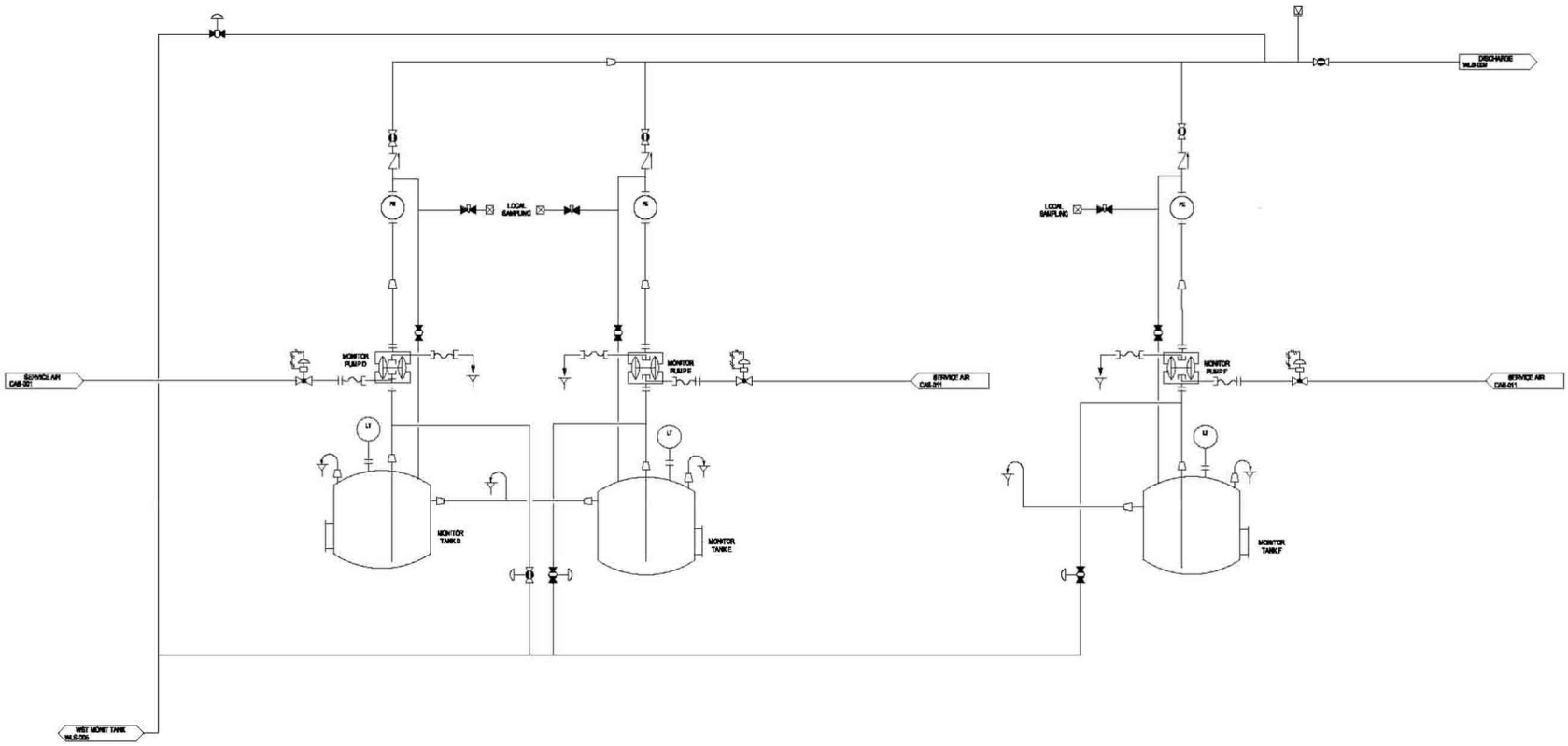


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Inside Radwaste Building
Figure 11.2-2 (Sheet 7 of 8)
Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 008

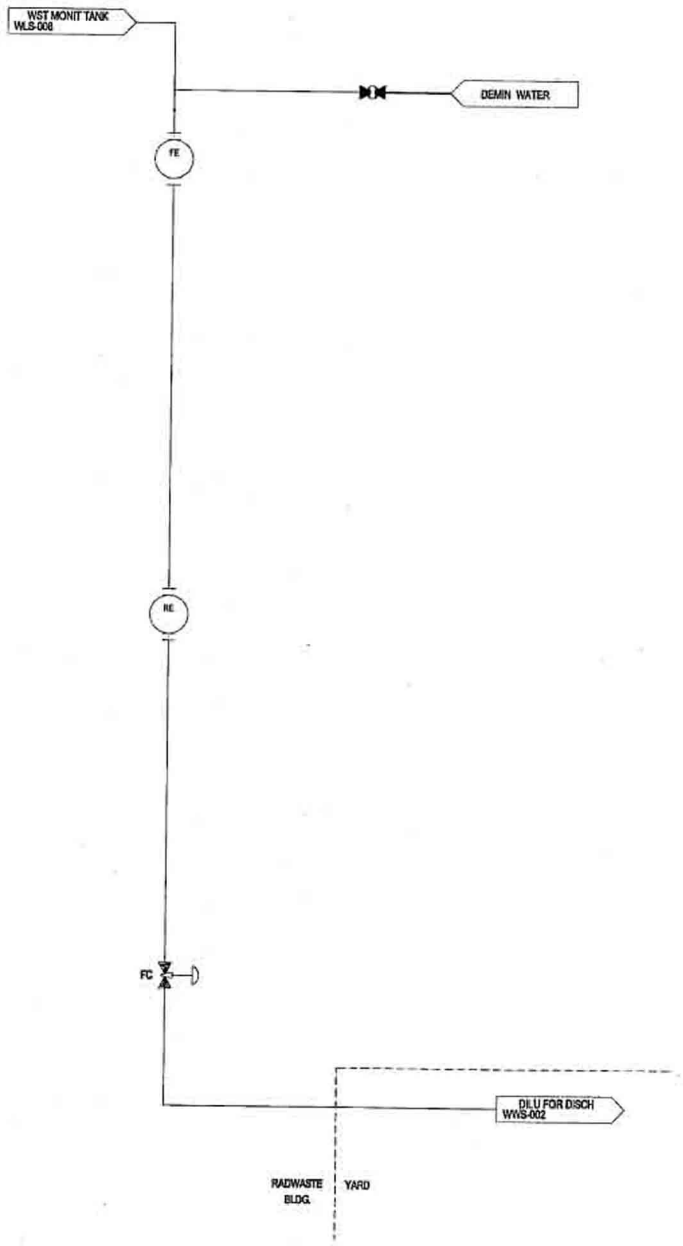


Figure represents system functional arrangement. Details internal to the system may differ as a result of implementation factors such as vendor-specific component requirements.

Inside Radwaste Building
Figure 11.2-2 (Sheet 8 of 8)
Liquid Radwaste System
Piping and Instrumentation Diagram
(REF) WLS 009

11.3 Gaseous Waste Management System

During reactor operation, radioactive isotopes of xenon, krypton, and iodine are created as fission products. A portion of these radionuclides is released to the reactor coolant because of a small number of fuel cladding defects. Leakage of reactor coolant thus results in a release to the containment atmosphere of the noble gases. Airborne releases can be limited both by restricting reactor coolant leakage and by limiting the concentrations of radioactive noble gases and iodine in the reactor coolant system.

Iodine is removed by ion exchange in the chemical and volume control system (CVS). Removal of the noble gases from the reactor coolant system (RCS) is not normally necessary because the gases will not build up to unacceptable levels when fuel defects are within normally anticipated ranges. If noble gas removal is required because of high reactor coolant system concentration, the chemical and volume control system can be operated in conjunction with the liquid radwaste system degasifier, to remove the gases. See Subsection 9.3.6 for a description of these operations.

The AP1000 gaseous radwaste system (WGS) is designed to perform the following major functions:

- Collect gaseous wastes that are radioactive or hydrogen bearing
- Process and discharge the waste gas, keeping off-site releases of radioactivity within acceptable limits.

In addition to the gaseous radwaste system release pathway, release of radioactive material to the environment occurs through the various building ventilation systems. These systems are described in Section 9.4 with a summary of system air flow rates and filter efficiencies provided in Table 9.4-1. The estimated annual release reported in Subsection 11.3.3 includes contributions from the major building ventilation pathways.

11.3.1 Design Basis

Subsection 1.9.1 discusses the conformance of the gaseous radwaste system design with the criteria of Regulatory Guide 1.143.

11.3.1.1 Safety Design Basis

The gaseous radwaste system serves no safety-related functions and therefore has no nuclear safety design basis.

11.3.1.2 Power Generation Design Basis

11.3.1.2.1 Capacity

11.3.1.2.1.1 Gaseous Waste Collection

The gaseous radwaste system is designed to receive hydrogen bearing and radioactive gases generated during process operation. The radioactive gas flowing into the gaseous radwaste system enters as trace contamination in a stream of hydrogen and nitrogen.

The design basis period of operation is the last 45 days of a fuel cycle. During this time, reactor coolant system dilution and subsequent letdown from the chemical and volume control system into the liquid radwaste system is at a maximum. Gaseous radwaste system inputs are as follows:

- Letdown diversion for dilution, reactor coolant system with maximum hydrogen concentration. This input is 0.5 standard cubic feet per minute (scfm) on an intermittent basis carrying a very small volume of radiogas, yielding 550 scf total hydrogen.

- Letdown diversion for degasification of the entire reactor coolant system in anticipation of shutdown, assumed to remove gases from the reactor coolant system to a level of 5 cc/kg beginning with the reactor coolant system at the maximum hydrogen concentration of 45 cc/kg. At its maximum this input is 0.58 scfm hydrogen carrying a very small volume of radiogas yielding approximately 281 scf total hydrogen.

- Reactor coolant drain tank liquid transfer to maintain proper reactor coolant drain tank level, assuming 0.25 gallons per minute liquid input from the reactor coolant system, intermittently yielding 0.5 scfm hydrogen and nitrogen carrying a very small volume of radiogas, yielding about 80 scf hydrogen and nitrogen total.

- Reactor coolant drain tank gas venting, conservatively estimated at 1 scf per day, yielding 45 scf total nitrogen and hydrogen.

11.3.1.2.1.2 Waste Gas Processing

The gaseous radwaste system is designed to reduce the controlled activity releases in support of the overall AP1000 release goals.

Given the various inputs to the gaseous radwaste system, with licensing basis assumptions for analysis and with normally operating gaseous radwaste system equipment available, the combined plant releases must be within the limits outlined in 10 CFR 20 and 10 CFR 50 Appendix I (References 1 and 2, respectively).

11.3.1.2.2 Failure Tolerance

11.3.1.2.2.1 System Leakage

The gaseous radwaste system operates at low pressures, slightly above atmospheric pressure, thus limiting the potential for leakage. Manual valves are the type which eliminate the potential for stem leakage. The system is of welded construction to further limit leakage.

11.3.1.2.2.2 Water Incursion

A number of features prevent wetting the activated carbon delay beds. These features include controls and alarms in the liquid radwaste system to prevent high degasifier separator water level, the gas cooler, moisture separator, drain traps, and automatic isolation of the guard bed inlet on high moisture separator level in the gaseous radwaste system. Additional protection is provided by the activated carbon guard bed, which removes residual moisture from the gas stream.

If moisture enters the first activated carbon delay bed, the operator bypasses that bed and either dries it with a nitrogen purge or replaces the activated carbon.

11.3.1.2.3 Anticipated Operational Occurrences

11.3.1.2.3.1 Prevention of Hydrogen Ignition

Since the carrier gas for the radiogas inputs to the gaseous radwaste system includes hydrogen, the gaseous radwaste system is designed to prevent hydrogen ignition both within its own boundaries

and in connected systems (the liquid radwaste system and the nuclear island radioactive ventilation system).

The gaseous radwaste system is operated at a slightly positive pressure to prevent air ingress. The room containing gaseous radwaste system components incorporates a hydrogen monitor to detect leakage out of the system before combustible levels are reached. In addition, continuous oxygen analysis, using independent, redundant monitors, is provided within the gaseous radwaste system. Upon high oxygen level in the system, an alarm alerts the operator. At an oxygen concentration of 3 percent or less, the liquid radwaste system vacuum pumps automatically stop to isolate potentially oxygenated inputs to the gaseous radwaste system, and a valve automatically opens to initiate a nitrogen purge. The discharge isolation valve of the gaseous radwaste system is continuously pressurized with nitrogen to prevent ingress of air into the system from the discharge path.

The gaseous radwaste system also eliminates sources of hydrogen ignition. The system incorporates electrical grounding, and a nitrogen purge. In addition, the system design and control logic minimizes automatic actuation of valves when an oxygen concentration of greater than 3 percent exists in the system. Discharge to the heating, ventilating and air-conditioning duct is downstream of the exhaust fans to provide additional protection against hydrogen ignition.

11.3.1.2.4 Controlled Release of Radioactivity

11.3.1.2.4.1 Expected Releases

The AP1000 design prevents the annual average concentration limits established by 10 CFR 20 (Appendix B, table 2, column 1) (Reference 1) for gaseous releases from being exceeded due to the releases resulting during plant operation. Subsection 11.3.3 describes the calculated releases of radioactive materials from the gaseous radwaste system and other pathways during normal operation.

Subsection 11.3.3 also contains an evaluation which demonstrates that the doses to individuals, at or beyond the site boundary, resulting from the expected releases from the gaseous waste management systems are within numerical design objectives of Appendix I of 10 CFR 50 (Reference 2).

11.3.1.2.4.2 Monitoring Releases

Releases from the gaseous radwaste system are continuously monitored by a radiation detector in the discharge line. In addition, the system includes provisions for taking grab samples of the discharge flow stream for analysis. In this manner, the requirements of General Design Criterion 64 are met as described in Section 3.1. Section 11.5 discusses radiation monitoring.

11.3.1.2.4.3 Operator Error or Equipment Malfunction

To prevent the release of radioactive gases resulting from equipment failure or operator error, a radiation monitor is located in the discharge line. This instrument provides an alarm signal at a high level setpoint to alert operators of rising radiation levels. The monitor is also interlocked with an isolation valve in the discharge line; the valve closes on the same high radiation signal.

Few operator actions are required during gaseous radwaste system operation since, once aligned for operation, the system operates automatically in response to the control signals from the instrumentation.

11.3.1.3 Compliance with 10 CFR 20.1406

In accordance with the requirements of 10 CFR 20.1406 (Reference 4), the gaseous radwaste system is designed to minimize, to the extent practicable, contamination of the facility and the environment, facilitate decommissioning, and minimize, to the extent practicable, the generation of radioactive waste. This is done through appropriate selection of design technology for the system.

11.3.2 System Description

11.3.2.1 General Description

The AP1000 gaseous radwaste system, as shown on Figure 11.3-1 is a once-through, ambient-temperature, activated carbon delay system. The system includes a gas cooler, a moisture separator, an activated carbon-filled guard bed, and two activated carbon-filled delay beds. Also included in the system are an oxygen analyzer subsystem and a gas sampling subsystem.

The radioactive fission gases entering the system are carried by hydrogen and nitrogen gas. The primary influent source is the liquid radwaste system degasifier. The degasifier extracts both hydrogen and fission gases from the chemical and volume control system letdown flow which is diverted to the liquid radwaste system or from the reactor coolant drain tank discharge.

Reactor coolant degassing is not required during power operation with fuel defects at or below the design basis level of 0.25 percent. However, the gaseous radwaste system periodically receives influent when chemical and volume control system letdown is processed through the liquid radwaste system degasifier during reactor coolant system dilution and volume control operations. Since the degasifier is a vacuum type and requires no purge gas, the maximum gas influent rate to the gaseous radwaste system from the degasifier equals the rate that hydrogen enters the degasifier (dissolved in liquid).

The other major source of input to the gaseous radwaste system is the reactor coolant drain tank. Hydrogen dissolved in the influent to the reactor coolant drain tank enters the gaseous radwaste system either via the tank vent or the liquid radwaste system degasifier discharge.

The tank vent is normally closed, but is periodically opened on high pressure to vent the gas that has come out of solution. The reactor coolant drain tank liquid is normally discharged to the liquid radwaste system via the degasifier, where the remaining hydrogen is removed.

The reactor coolant drain tank is purged with nitrogen gas to discharge nitrogen and fission gases to the gaseous radwaste system before operations requiring tank access. The reactor coolant drain tank is also purged with nitrogen gas to dilute and discharge oxygen after tank servicing or inspection operations which allow air to enter the tank.

Influents to the gaseous radwaste system first pass through the gas cooler where they are cooled to about 40°F by the chilled water system. Moisture formed due to gas cooling is removed in the moisture separator.

After leaving the moisture separator, the gas flows through a guard bed that protects the delay beds from abnormal moisture carryover or chemical contaminants. The gas then flows through two delay beds in series where the fission gases undergo dynamic adsorption by the activated carbon and are thereby delayed relative to the hydrogen or nitrogen carrier gas flow. Radioactive decay of the fission gases during the delay period significantly reduces the radioactivity of the gas flow leaving the system.

The effluent from the delay bed passes through a radiation monitor and discharges to the ventilation exhaust duct. The radiation monitor is interlocked to close the gaseous radwaste system discharge isolation valve on high radiation. The discharge isolation valve also closes on low ventilation system exhaust flow rate to prevent the accumulation of hydrogen in the aerated vent.

11.3.2.2 System Operation

11.3.2.2.1 Normal Operation

The gaseous radwaste system is used intermittently. Most of the time during normal operation of the AP1000, the gaseous radwaste system is inactive. When there is no waste gas inflow to the system, the discharge isolation valve closes, which maintains the gaseous radwaste system at a positive pressure, preventing the ingress of air during the periods of low waste gas flow.

When the gaseous radwaste system is in use, its operation is passive, using the pressure provided by the influent sources to drive the waste gas through the system.

The largest input to the gaseous radwaste system is from the liquid radwaste system degasifier, which processes the chemical and volume control system letdown flow when diverted to the liquid radwaste system and the liquid effluent from the liquid radwaste system reactor coolant drain tank.

The chemical and volume control system letdown flow is diverted to the liquid radwaste system during dilutions, borations, and reactor coolant system degassing in anticipation of shutdown. The design basis influent rate from the liquid radwaste system degasifier is the full diversion of the chemical and volume control system letdown flow, when the reactor coolant system is operating with maximum allowable hydrogen concentration. Since the liquid radwaste system degasifier is a vacuum type that operates without a purge gas, this input rate is very small, about 0.6 scfm.

The liquid radwaste system degasifier is also used to degas liquid pumped out of the reactor coolant drain tank. The amount of fluid pumped out, and therefore the gas sent to the gaseous radwaste system, is dependent upon the input into the reactor coolant drain tank. This is smaller than the input from the chemical and volume control system letdown line.

The final input to the gaseous radwaste system is from the reactor coolant drain tank vent. A nitrogen cover gas is maintained in the reactor coolant drain tank. This input consists of nitrogen, hydrogen, and radioactive gases. The tank operates at nearly constant level, with its vent line normally closed, so this input is minimal. Venting is required only after enough gas has evolved from the input fluid to increase the reactor coolant drain tank pressure.

The influent first passes through a gas cooler. Chilled water flows through the gas cooler at a fixed rate to cool the waste gas to about 40°F regardless of waste gas flow rate. Moisture formed due to gas cooling is removed in the moisture separator, and collected water is periodically discharged automatically. To reduce the potential for waste gas bypass of the gas cooler in the event of valve leakage, a float-operated drain trap is provided which automatically closes on low water level.

The gas leaving the gas cooler is monitored for temperature, and a high alarm alerts the operator to an abnormal condition requiring attention. Oxygen concentration is also monitored. On a high oxygen alarm, a nitrogen purge is automatically injected into the influent line.

The waste gas then flows through the guard bed, where chemical (oxidizing) contaminants are removed. The guard bed also removes any remaining excessive moisture from the waste gas.

The waste gas then flows through the two delay beds where xenon and krypton are delayed by a dynamic adsorption process. The discharge line is equipped with a valve that automatically closes on

either high radioactivity in the gaseous radwaste system discharge line or low ventilation exhaust duct flow.

The adsorption of radioactive gases in the delay bed occurs without reliance on active components or operator action. Operator error or active component failure does not result in an uncontrolled release of radioactivity to the environment. Failure to remove moisture prior to the delay beds (due to loss of chilled water or other causes) results in a gradual reduction in gaseous radwaste system performance. Reduced performance is indicated by high temperature and discharge radiation alarms. High-high radiation automatically terminates discharge.

11.3.2.2.2 Purge Operations

The gaseous radwaste system is purged with nitrogen gas to expel residual oxygen gas after servicing operations. The system is purged until the effluent from the outlet indicates a low oxygen concentration. The gaseous radwaste system oxygen analyzer is temporarily aligned to monitor the flow in the discharge line. Nitrogen connections are also provided to the sample system and to the system discharge line for purge before and after maintenance operations.

11.3.2.3 Component Description

The general descriptions and summaries of the design basis requirements for the gaseous radwaste system components follow. Table 11.3-2 lists the key design parameters for the gaseous radwaste system components.

The seismic design classification and safety classification for the gaseous radwaste system components are listed in Section 3.2. The components listed are located in the Seismic Category I Nuclear Island.

11.3.2.3.1 Sample Pumps

Two sample pumps are provided. One sample pump normally operates continuously to provide flow through the oxygen analyzers. The other sample pump is periodically used to provide flow from various sample points through a sample cylinder. It is used as a backup to provide flow through the oxygen analyzers.

11.3.2.3.2 Gas Cooler

The gas cooler heat exchanger is designed to cool the gas flow to near the temperature of the chilled water supply (40°F) for efficient moisture removal. The pressure of the gas flow through the gas cooler is less than the chilled water pressure to minimize the potential for contaminating the chilled water system.

11.3.2.3.3 Gaseous Radwaste System Tanks

Moisture Separator

The moisture separator is sized for the design basis purge gas flow rate and is oversized for the lower normal flow rate. The unit includes connections for water level instrumentation for detecting high and low water levels.

Guard Bed

The activated carbon guard bed protects the delay beds from abnormal moisture or chemical contaminants. Under normal operating conditions, the guard bed provides increased delay time for xenon and krypton.

The flow through the activated carbon bed is downward. A retention screen on the outlet of the guard bed prevents the loss of activated carbon from the unit. Activated carbon can be added to or vacuumed from the unit via a blind flange port.

Delay Beds

Two activated carbon delay beds in series are provided. Together, the beds provide 100 percent of the stated system capacity under design basis conditions. During normal operation a single bed provides adequate performance. This provides operational flexibility to permit continued operation of the gaseous radwaste system in the event of operational upsets in the system that requires isolation of one bed.

The waste gas flows vertically through columns of activated carbon. The activated carbon mass is given in Table 11.3-1.

No retention screens are required on the delay beds since the flow enters and leaves each delay bed at its top.

The guard bed and the delay beds, including supports, in the gaseous radwaste system are designed for seismic loads in conformance with Regulatory Guide 1.143. These are the only AP1000 components used to store or delay the release of gaseous radioactive waste. The beds are located in the seismic Category I auxiliary building at elevation 66′6″.

11.3.2.3.4 Remotely Operated Valves

Moisture Separator Level Control Valve

This normally closed, fail-open globe valve is located in the liquid drain line from the moisture separator outlet line. It maintains the level in the moisture separator by regulating the flow from the moisture separator to the liquid radwaste system. The valve receives a signal to automatically open on a high level in the moisture separator and to close on low level. The valve can also be manually controlled from the gaseous waste panel.

A float-operated drain trap serves as a backup to this valve. This drain trap automatically closes on a low water level in the moisture separator to stop drain flow to the liquid radwaste system in the event of a valve or instrument failure. This prevents waste gas bypass around the gas cooler due to level control valve failure.

Gaseous Radwaste System Discharge Isolation Valve

This normally closed, fail-closed globe valve is at the outlet of the system as shown in Figures 11.3-1 and 11.3-2. The valve opens during operation of the system. The valve is interlocked to close on a high radiation signal in the gaseous radwaste system discharge line to prevent the release of radioactivity in the event of a gaseous radwaste system failure. The valve also receives a signal to automatically close in the event of a low ventilation system exhaust flow rate which prevents accumulation of a flammable or explosive concentration of hydrogen in the aerated vent line.

Manual control is provided on the gaseous radwaste panel.

Nitrogen Purge Pressure Control Valve

This is a self-contained pressure regulating valve in the nitrogen purge line. It is set to maintain a small positive pressure in the gaseous radwaste system to prevent ingress of air during periods of low flow.

11.3.3 Radioactive Releases

Releases of radioactive effluent by way of the atmospheric pathway occur due to:

- Venting of the containment which contains activity as a result of leakage of reactor coolant and as a result of activation of naturally occurring Ar-40 in the atmosphere to form radioactive Ar-41
- Ventilation discharges from the auxiliary building which contains activity as a result of leakage from process streams
- Condenser air removal system and gland seal system, which connect together as one vent line discharging from the turbine island vent (gaseous activity entering the secondary coolant as a result of primary to secondary leakage is released via this pathway)
- Gaseous radwaste system discharges.

These releases are on-going throughout normal plant operations. There is no gaseous waste holdup capability in the gaseous waste management system and thus no criteria are required for determining the timing of releases or the release rates to be used.

There are no gaseous effluent site interface parameters outside of the Westinghouse scope.

11.3.3.1 Discharge Requirements

The release of radioactive gaseous and particulate effluents to the atmosphere may not exceed the concentration limits specified in Reference 1 nor may the releases result in the annual offsite dose limits specified in 10 CFR 50, Appendix I (Reference 2) being exceeded.

11.3.3.2 Estimated Annual Releases

The annual average airborne releases of radionuclides from the plant are determined using the PWR-GALE code (Reference 3). The GALE code models releases using realistic source terms derived from data obtained from the experience of many operating pressurized water reactors. The code input parameters used in the analysis to model the AP1000 plant are provided in Table 11.2-6. The expected annual releases for a single unit site are presented in Table 11.3-3.

To demonstrate compliance with the effluent concentration limits in Reference 1, the expected releases from Table 11.3-3 are used to determine the annual average concentration at the site boundary, and the results are compared with the Reference 1 concentration limits for unrestricted areas in Table 11.3-4. As shown in Table 11.3-4, the overall fraction of the effluent concentration limit for the expected releases is 0.030, which is significantly below the allowable value of 1.0.

11.3.3.3 Release Points

Airborne effluents are normally released through the plant vent or the turbine island vent. The plant vent provides the release path for containment venting releases, auxiliary building ventilation releases, annex building releases, radwaste building releases, and gaseous radwaste system discharge. The turbine island vents, drains, and relief system (TDS) provides the release path for the condenser air removal system and gland seal condenser exhaust.

11.3.3.4 Estimated Doses

With the annual airborne releases listed in Table 11.3-3, the air doses at ground level at the site boundary are 2.1 mrad for gamma radiation and 10.1 mrad for beta radiation. These doses are based on the annual average atmospheric dispersion factor from Section 2.3 (2.0×10^{-5} seconds per cubic meter). These doses are below the 10 CFR 50, Appendix I, design objectives of 10 mrad per year for gamma radiation or 20 mrad per year for beta radiation.

The radiological consequences due to a single failure of an active component in the gaseous radwaste system are evaluated assuming a 1- hour bypass of the delay beds and 30 minutes of decay before release to the environs. This analysis assumes a pre-existing condition of operation with reactor coolant activity corresponding to 1 percent fuel defects as described in the Note for Table 11.1-2. Using the site boundary (0 to 2 hr) atmospheric dispersion factor from Table 2-1, the site boundary whole body dose is 0.1 rem.

The VEGP Units 3 and 4 site-specific values are bounded by the DCD identified acceptable releases. With the annual airborne releases listed in Table 11.3-206, the site specific air doses at ground level at the site boundary are 0.67 mrad for gamma radiation and 2.8 mrad for beta radiation. These doses are based on the annual average atmospheric dispersion factor from Section 2.3. These doses are below the 10 CFR Part 50, Appendix I design objectives of 10 mrad per year for gamma radiation or 20 mrad per year for beta radiation.

11.3.3.4.1 Exposure Pathways

Small quantities of radioactive gases would be discharged to the environment during normal operation of the new units. VEGP Units 3 and 4 airborne effluents are normally released through the plant vent or the turbine island vent. The plant vent is the release pathway for ventilation flows and discharges from the containment, the auxiliary building, the annex building, the radwaste building, and the gaseous radwaste system. The turbine island vents, drains, and relief system (TDS) provides the release path for the condenser air removal system and gland seal condenser exhaust. The impact of these releases on individuals and the population in the vicinity of the new units is evaluated by considering the most important pathways from the release to the receptors of interest. The major pathways are those that could yield the highest radiological doses for a given receptor. The relative importance of a pathway is based on the type and amount of radioactivity released, the environmental transport mechanism, and the consumption or usage factors at the receptor.

The exposure pathways considered and the analytical methods used to estimate doses to the maximally exposed individual (MEI) and to the population surrounding the new units are based on NRC Regulatory Guide 1.109, *Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR 50, Appendix I*, Revision 1, October 1977 and NRC Regulatory Guide 1.111, *Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors*, Revision 1, July 1977. An MEI is a member of the public located to receive the maximum possible calculated dose. The MEI allows dose comparisons with established criteria for the public.

The NRC-endorsed GASPAR II computer program (Reference 203) is used to calculate the doses to offsite receptors from the new units. This program implements the radiological exposure models described in Regulatory Guide 1.109 to estimate the doses resulting from radioactive releases in gaseous effluent. The atmospheric dispersion component of the analysis is calculated with the NRC-sponsored program XOQDOQ (Reference 201). Dispersion and deposition factors are calculated from onsite meteorological parameters (wind speed, wind direction, stability class) for 1998-2002. Subsection 2.3.5 shows dispersion data for the locations shown in Table 11.3-204 as well as deposition and undecayed/undepleted dispersion factors within 50 miles of the plant. Decayed/

undepleted and decayed/depleted dispersion factors within 50 miles are calculated using the same methodology as presented in Subsection 2.3.5.

The following exposure pathways are considered in GASPAR II:

- External exposure to airborne plume
- External exposure to contaminated ground
- Inhalation of airborne activity
- Ingestion of contaminated vegetables
- Ingestion of contaminated meat

The input parameters for the gaseous pathway are presented in Tables 11.3-201, 11.3-202, and 11.3-203 and the receptor locations are shown in Table 11.3-204.

11.3.3.4.2 Gaseous Pathway Doses

Based on the parameters in Tables 11.3-201 to 11.3-203, the GASPAR II computer program is used to calculate doses to the maximally exposed adult, teenager, child, and infant at the following locations:

- Nearest site boundary
- Nearest residence
- Nearest vegetable garden
- Nearest meat animal

The gaseous activity releases (source terms) for the two proposed AP1000 units are obtained from Table 11.3-3 and are shown in Table 11.3-203. These are conservative, projected values that were calculated using the PWR-GALE computer code (Reference 202). Table 11.3-203 also shows the maximum measured activity releases for Units 1 and 2, based on information presented in the annual effluent reports (References 204, 205, 206). Projected activity concentrations at the site boundary are based on the calculated activity releases for Units 3 and 4 as well as the measured activity releases from Units 1 and 2. The concentrations are within the limits of 10 CFR 20, Appendix B, Table 2, Column 1. The calculated annual doses to the MEI are presented in Table 11.3-205.

Table 11.3-206 shows that the doses to the MEI from the gaseous effluents of a new unit meet the design objectives of 10 CFR 50, Appendix I. The total site doses due to liquid and gaseous effluents from the two existing units and the two new units would be well within the regulatory limits of 40 CFR 190, as shown in Table 11.3-207. Since 40 CFR 190 is more restrictive than 10 CFR 20.1301, compliance with the limits of 40 CFR 190 also demonstrates compliance with the 0.1 rem limit of 10 CFR 20.1301. Table 11.3-208 shows the doses from the new and existing units to the population within 50 miles of the ESP site. The doses from the proposed units are much higher than from the existing units because doses from the existing units are more realistic, based on measurements, whereas the doses from the proposed units are based on conservative calculations.

Table 11.3-208 reports a total body population dose from gaseous effluents within 50 miles of VEGP Units 3 and 4 of 1.8 person-rem/year or 0.9 person-rem/per reactor. In addition, the corresponding thyroid dose has been calculated to be 3.0 person-rem/year per reactor.

11.3.3.4.3 Gaseous Radwaste Cost-Benefit Analysis Methodology

The guidance for performing cost-benefit analysis for the gaseous radwaste system is similar to that used and described for the liquid radwaste system in Section 11.2. The gaseous radwaste treatment system augments annual costs were determined and the lowest annual cost considered a threshold value. The lowest-cost option for gaseous radwaste treatment system augments is the Steam Generator Flash Tank Vent to Main Condenser at $6,320 per year, which yields a threshold value of 6.32 person-rem total body or thyroid from gaseous effluents.

For AP1000 sites with population dose estimates less than 6.32 person-rem total body or thyroid dose from gaseous effluents, no further cost-benefit analysis is needed to demonstrate compliance with 10 CFR 50, Appendix I, Section II.D.

11.3.3.4.4 Gaseous Radwaste Cost-Benefit Analysis

As discussed in Subsection 11.3.3.4.3, the lowest cost gaseous radwaste system augment is $6,320. Assuming 100 percent efficiency of this augment, the minimum possible cost per person-rem is determined by dividing the cost of the augment by the population dose. This is $7,022 per person-rem total body ($6,320/0.9 person-rem) and $2,107 per person-rem thyroid ($6,320/3.0 person-rem thyroid). These costs per person-rem reduction exceed the $1,000 per person-rem criterion prescribed in Appendix I to 10 CFR Part 50 and are therefore not cost beneficial.

11.3.3.5 Maximum Release Concentrations

The annual releases of radioactive gases and iodine provided in Table 11.3-3 represent expected releases from the plant and reflect an expected level of fuel cladding defects. If the plant operates with the maximum defined fuel defect level, the releases would be substantially greater. The maximum defined fuel defect level is conservatively established at 1.0 percent fuel defects, corresponding to four times the Technical Specification limit on coolant activity which is based on 0.25 percent fuel defects, as described in Table 11.1-2. To demonstrate compliance with the effluent concentration limits of Reference 1, the releases from Table 11.3-3 have been adjusted to reflect operation with the maximum defined fuel defect level, and the resulting airborne radionuclide concentrations at the site boundary are compared in Table 11.3-4 with the Reference 1 limits for concentrations in unrestricted areas. As shown in Table 11.3-4, the overall fraction of the effluent concentration limit for operation with the maximum defined fuel defect level is 0.33, which is well below the allowable value of 1.0.

11.3.3.6 Quality Assurance

The quality assurance program for design, fabrication, procurement, and installation of the gaseous radwaste system is in accordance with the overall quality assurance program described in Chapter 17.

Since the impact of radwaste systems on safety is limited, the extent of control required by Appendix B to 10 CFR Part 50 is similarly limited. Thus, a supplemental quality assurance program applicable to design, construction, installation, and testing provisions of the gaseous radwaste system is established by procedures that complies with the guidance presented in Regulatory Guide 1.143.

11.3.4 Inspection and Testing Requirements

11.3.4.1 Preoperational Testing

Preoperational tests are performed to verify the proper operation of the WGS. The operational tests include automatic closure of the discharge control/isolation valve, WGS-PL-V051, upon receipt of a

simulated high radiation signal. The discharge line of the gaseous radwaste system includes a radiation monitor, WGS-RE017, which detects a high radiation condition and generates an alarm that automatically closes the discharge control/isolation valve. By imposing a simulated high radiation alarm signal, proper operation of the discharge control/isolation valve is confirmed by its closure.

11.3.4.2 Preoperational Inspection

The proper performance of the gaseous radwaste system depends upon delay of gaseous radionuclides by chemical adsorption on activated carbon. As the radionuclides are delayed, they decay and are no longer available for release to the environment. The rate of release and site boundary dose rates have been evaluated based upon the quantity of activated carbon in a delay bed being at least 80 cubic feet. An inspection of the gaseous radwaste system activated carbon delay beds, WGS-MV-02A and WGS-MV-02B, will confirm that the contained volume of each delay bed is at least 80 cubic feet.

11.3.5 Combined License Information

11.3.5.1 Cost Benefit Analysis of Population Doses

The site specific cost-benefit analysis to demonstrate compliance with 10 CFR 50, Appendix I, regarding population doses due to gaseous effluents is addressed in Subsections 11.3.3.4, 11.3.3.4.3 and 11.3.3.4.4.

11.3.5.2 Identification of Adsorbent Media

The types of adsorbent media to be used in the gaseous radwaste system is addressed in APP-GW-GLR-008 (Reference 5), and the applicable changes are incorporated into the UFSAR.

11.3.6 References

1. "Annual Limits on Intake (ALIs) and Derived Air Concentrations (DACs) of Radionuclides for Occupational Exposure; Effluent Concentrations; Concentrations for Release to Sewerage," 10 CFR Part 20, Appendix B, Issued by 58 FR 67657, April 28, 1995.

2. "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion >As-Low-As-Is-Reasonably-Achievable= for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," 10 CFR Part 50, Appendix I.

3. "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code)," NUREG-0017, Revision 1, March 1985.

4. "Minimization of Contamination," 10 CFR 20.1406.

5. APP-GW-GLR-008, "Request for Closure of COL Items in DCD Chapter 11, Identification for Adsorbent Media," Westinghouse Electric Company LLC.

201. **(NRC 1982)** NUREG/CR-2919, *XOQDOQ: Computer Program for the Meteorological Evaluation of Routine Effluent Releases at Nuclear Power Stations Final Report*, U. S. Nuclear Regulatory Commission, 1982.

202. **(NRC 1985)** NUREG-0017, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code)*, Revision 1, U. S. Nuclear Regulatory Commission, 1985.

203. **(NRC 1987)** NUREG/CR-4653, *GASPAR II Technical Reference and User Guide*, U. S. Nuclear Regulatory Commission, 1987.

204. **(SNC 2002)** *Annual Radioactive Effluent Release Report for January 1, 2001 to December 31, 2001*, Southern Nuclear Company, 2002.

205. **(SNC 2003)** *Annual Radioactive Effluent Release Report for January 1, 2002 to December 31, 2002*, Southern Nuclear Company, 2003.

206. **(SNC 2004)** *Annual Radioactive Effluent Release Report for January 1, 2003 to December 31, 2003,* Southern Nuclear Company, 2004.

207. **(Westinghouse 2005)** AP1000 Document APP-GW-GL-700, *AP1000 Design Control Document, Tier 2 Material*, Revision 15, Westinghouse Electric Company, 2005.

Table 11.3-1
Gaseous Radwaste System Parameters

Design operating influent pressure (psig)	2
Design influent flow rate (scfm)	1.18
Activated carbon bed design operating dew point (°F)	45
Minimum Activated carbon in delay beds (pounds combined total)	4495
Maximum Activated carbon in delay beds (pounds combined total)	6593

Table 11.3-2 (Sheet 1 of 2)
Component Data (Nominal) — Gaseous Radwaste System

Mechanical Components		
Pumps		
Sample Pumps		
Number	2	
Type	Diaphragm	
Heat Exchangers		
Gas Cooler		
Number	1	
Type	Dual tube coil	
	Process Side	**Cooling Side**
Design pressure (psig)	150	150
Design temperature (°F)	200	200
Design flow	1.18 scfm	0.15 gpm
Temperature inlet (°F)	125	40
Temperature outlet (°F)	40.1	42
Material	Stainless steel	Stainless steel
Tanks		
Guard Bed		
Number	1	
Nominal volume (ft^3)	8	
Type	Vertical pipe	
Design pressure (psig)	150	
Design temperature (°F)	200	
Material	Stainless steel	
Delay Bed		
Number	2	
Nominal volume (ft^3)	80	
Type	Vertical serpentine	
Design pressure (psig)	150	
Design temperature (°F)	200	
Material	Carbon steel	
Moisture Separator		
Number	1	
Nominal volume (gal)	3	
Type	Vertical	
Design pressure (psig)	150	
Design temperature (°F)	200	
Material	Stainless steel	

Table 11.3-2 (Sheet 2 of 2)
Component Data (Nominal) — Gaseous Radwaste System
Summary of Instrument Indication and Alarms

Instrumentation	Indicate (Note 4)	Alarm
Gas Cooler		
Gas inlet temperature	X	
Cooling water outlet temperature	X	
Gas inlet pressure	X	X – Hi
Gas outlet temperature	X	X – Hi
Carbon Delay Beds		
Gas inlet temperature	X	X – Hi
Gas outlet temperature 2 channels	X	X – Hi
Gas outlet flow	X	
Gas outlet radiation (Note 3)	X	X – Hi
Gas outlet pressure	X	X – Hi, Lo-2
Carbon Bed Vault		
Vault hydrogen (Note 2)	X	X – Hi
Vault temperature (Note 1)	X	X – Hi
Moisture Separator		
Water level	X	X – Hi-2
Sampling Subsystem		
Hydrogen concentration	X	X
Oxygen concentration 2 channels	X	X – Hi
Gas flow	X	X – Lo

Notes:

1. Vault temperature monitor common for guard bed and delay bed.
2. Vault hydrogen monitor common for guard bed and delay bed.
3. High outlet radiation alarm closes gas outlet isolation valve.
4. Monitoring of the gaseous radwaste system is performed through the data display and processing system. Control functions are performed by the plant control system. Appropriate alarms and displays are available in the control room. Local indication and control are available on portable displays which may be connected to the data display and processing system. See Chapter 7.

Table 11.3-3 (Sheet 1 of 3)
Expected Annual Release of Airborne Radionuclides as Determined by the Revised GALE Code

Release Rates in Ci/year						
Nuclide	Waste Gas System	Building/Area Ventilation			Condenser Air Removal System	Total Release
		Containment Building	Auxiliary Building	Turbine Building		
Kr-85m	1.2E-02	3.8E-03	4.3E-01	2.3E-05	2.1E-01	6.5E-01
Kr-85	8.1E+01	3.0E-01	1.4E+00	7.9E-05	6.9E-01	8.4E+01
Kr-87	negl.	1.2E-03	4.6E-01	6.9E-06	6.0E-02	5.2E-01
Kr-88	1.8E-04	2.7E-03	4.8E-01	2.6E-05	2.3E-01	7.2E-01
Xe-131m	3.0E+01	8.3E-01	4.8E+00	2.5E-04	2.2E+00	3.7E+01
Xe-133m	9.6E-04	1.8E-01	2.0E+00	1.1E-04	9.4E-01	3.1E+00
Xe-133	6.6E+00	2.4E+00	1.7E+01	9.0E-04	7.9E+00	3.4E+01
Xe-135m	negl.	1.8E-03	3.5E+00	1.9E-04	1.6E+00	5.1E+00
Xe-135	negl.	8.3E-02	4.5E+00	7.9E-04	6.9E+00	1.2E+01
Xe-137	negl.	negl.	9.1E-01	4.9E-05	4.3E-01	1.3E+00
Xe-138	negl.	7.8E-04	1.6E+00	8.9E-05	7.8E-01	2.4E+00
					Total Noble Gas	1.8E+02

Table 11.3-3 (Sheet 2 of 3)
Expected Annual Release of Airborne Radionuclides as Determined by the Revised GALE Code

Release Rates in Ci/year (GBq/year)						
Nuclide	Fuel Handling Area	Building/Area Ventilation			Condenser Air Removal System	Total Release
		Containment Building	Auxiliary Building	Turbine Building		
I-131	2.0E-04	15.1E-04	4.8E-03	6.5E-05	2.6E-05	5.6E-03
I-133	2.9E-04	2.0E-03	7.1E-03	2.0E-05	8.0E-05	9.5E-03
					Total Airborne Radioiodine	1.5E-02

Table 11.3-3 (Sheet 3 of 3)
Expected Annual Release of Airborne Radionuclides as Determined by the Revised GALE Code

Release Rates in Ci/year (GBq/year)					
		Building/Area Ventilation			
Nuclide	Waste Gas System	Containment Building	Auxiliary Building	Fuel Handling Area	Total Release
Cr-51	negl.	negl.	3.2E-06	1.8E-06	6.1E-06
Mn-54	negl.	negl.	negl.	3.0E-06	4.3E-06
Co-57	negl.	negl.	negl.	negl.	negl.
Co-58	negl.	2.5E-06	1.9E-05	2.1E-04	2.3E-04
Co-60	negl.	negl.	5.1E-06	8.2E-05	8.7E-05
Fe-59	negl.	negl.	negl.	negl.	negl.
Sr-89	negl.	1.3E-06	7.5E-06	2.1E-05	3.0E-05
Sr-90	negl.	negl.	2.9E-06	8.0E-06	1.2E-05
Zr-95	negl.	negl.	1.0E-05	negl.	1.0E-05
Nb-95	negl.	negl.	negl.	2.4E-05	2.5E-05
Ru-103	negl.	negl.	negl.	negl.	negl.
Ru-106	negl.	negl.	negl.	negl.	negl.
Sb-125	negl.	negl.	negl.	negl.	negl.
Cs-134	negl.	negl.	5.4E-06	1.7E-05	2.3E-05
Cs-136	negl.	negl.	negl.	negl.	negl.
Cs-137	negl.	negl.	7.2E-06	2.7E-05	3.6E-05
Ba-140	negl.	negl.	4.0E-06	negl.	4.2E-06
Ce-141	negl.	negl.	negl.	negl.	negl.
				Total Particulates	4.7E-04

Tritium Release via Gaseous Pathway(2) (Ci/Yr) = 48
C-14 Released via Gaseous Pathway (Ci/Yr) = 7.3
Ar-41 Released via Gaseous Pathway (Ci/Yr) = 34

Notes:

(1) Values less than 1 microcurie are considered to be negligible.
(2) Tritium release based on Westinghouse TRICAL computer code.
(3) The fuel handling area is within the auxiliary building but is considered separately.

Table 11.3-4 (Sheet 1 of 2)
Comparison of Calculated Offsite Airborne Concentrations with 10 CFR 20 Limits

Radionuclide	Effluent Concentration Limit[a] µCi/ml	Expected Site Boundary[b] Concentration µCi/ml	Fraction of Concentration Limit[b] (expected)	Maximum Site Boundary Concentration[c] µCi/ml	Fraction of Concentration Limit[c] (maximum)
Kr-85m	1.00E-07	5.15E-13	5.15E-06	2.05E-11	2.05E-04
Kr-85	7.00E-07	6.66E-11	9.51E-05	1.42E-10	2.03E-04
Kr-87	2.00E-08	4.12E-13	2.06E-05	8.88E-12	4.44E-04
Kr-88	9.00E-09	5.71E-13	6.34E-05	3.70E-11	4.11E-03
Xe-131m	2.00E-06	2.93E-11	1.47E-05	3.56E-11	1.78E-05
Xe-133m	6.00E-07	2.46E-12	4.10E-06	4.44E-11	7.40E-05
Xe-133	5.00E-07	2.70E-11	5.39E-05	8.15E-08	1.63E-01
Xe-135m	4.00E-08	4.04E-12	1.01E-04	4.14E-12	1.03E-04
Xe-135	7.00E-08	9.51E-12	1.36E-04	3.83E-10	5.47E-03
Xe-138	2.00E-08	1.90E-12	9.51E-05	5.98E-12	2.99E-04
I-131	2.00E-10	4.44E-15	2.22E-05	1.74E-12	8.71E-03
I-133	1.00E-09	7.53E-15	7.53E-06	3.86E-13	3.86E-04
H-3	1.00E-07	3.81E-11	3.81E-04	3.81E-11	3.81E-04
C-14	3.00E-09	1.30E-11	4.33E-03	1.30E-11	4.33E-03
Ar-41	1.00E-08	2.70E-11	2.70E-03	2.70E-11	2.70E-03
Cr-51	3.00E-08	4.84E-18	1.61E-10	4.84E-18	1.61E-10
Mn-54	1.00E-09	3.41E-18	3.41E-09	3.41E-18	3.41E-09
Co-57	9.00E-10	6.50E-20	7.22E-11	6.50E-20	7.22E-11
Co-58	1.00E-09	1.82E-16	1.82E-07	1.82E-16	1.82E-07
Co-60	5.00E-11	6.90E-17	1.38E-06	6.90E-17	1.38E-06
Fe-59	5.00E-10	6.26E-19	1.25E-09	6.26E-19	1.25E-09
Sr-89	2.00E-10	2.38E-17	1.19E-07	8.72E-16	4.36E-06
Sr-90	6.00E-12	9.51E-18	1.59E-06	1.86E-16	3.11E-05
Zr-95	4.00E-10	7.93E-18	1.98E-08	1.54E-17	3.84E-08
Nb-95	2.0E-09	2.0E-17	9.9E-09	5.28E-17	2.64E-08
Ru-103	9.00E-10	6.34E-19	7.05E-10	6.34E-19	7.05E-10

Table 11.3-4 (Sheet 2 of 2)
Comparison of Calculated Offsite Airborne Concentrations with 10 CFR 20 Limits

Radionuclide	Effluent Concentration Limit[a] µCi/ml	Expected Site Boundary[b] Concentration µCi/ml	Fraction of Concentration Limit[b] (expected)	Maximum Site Boundary Concentration[c] µCi/ml	Fraction of Concentration Limit[c] (maximum)
Ru-106	2.0E-11	6.2E-19	3.1E-08	6.18E-19	3.09E-08
Sb-125	7.0E-10	4.8E-19	6.9E-10	4.84E-18	6.91E-09
Cs-134	2.0E-10	1.8E-17	9.1E-08	1.62E-12	8.12E-03
Cs-136	9.0E-10	6.7E-19	7.5E-10	3.64E-15	4.05E-06
Cs-137	2.0E-10	2.9E-17	1.4E-07	1.30E-12	6.49E-03
Ba-140	2.0E-09	3.3E-18	1.7E-09	3.33E-18	1.66E-09
Ce-141	8.0E-10	3.3E-19	4.2E-10	6.53E-19	8.16E-10
Totals			9.06E-03		2.05E-01

Notes:
(a) Effluent concentration limit is from Reference 1.
(b) Expected site boundary concentration based on annual releases predicted by the PWR-GALE code (Table 11.3-3) and an annual average X/Q of 2.0×10^{-5} seconds per cubic meter.
(c) Maximum site boundary concentration based on adjusting the releases predicted by the PWR-GALE code (Table 11.3-3) to reflect operation with maximum defined fuel defect level and an annual average X/Q of 2.0×10^{-5} seconds per cubic meter.

Table 11.3-201
Gaseous Pathway Parameters

Parameter	Value
Release source terms	Table 11.3-203
Population distribution	Figures 2.1-203 & 2.1-210
Milk production rate within 50 miles	6.37E+07 l/yr[a]
Meat production rate within 50 miles	1.03E+07 kg/yr[a]
Vegetable production rate within 50 miles	6.57E+07 kg/yr[a]
Atmospheric dispersion factors	Table 2.3-219
Ground deposition factors	Table 2.3-219

[a] Animal and vegetable production from 2002 National Census of Agriculture. Production converted to food products using average conversion factors: 17,050 lb milk/cow; 377 lb beef/cow, calf; 81.2 lb meat/hog, pig; 95.8 lb meat/sheep, and 8,090 kg vegetables/acre.

Table 11.3-202
Gaseous Pathway Consumption Factors for Maximally Exposed Individual

	Annual Rate			
Consumption Factor	Adult	Teen	Child	Infant
Leafy vegetable consumption (kg/yr)	64	42	26	0
Meat consumption (kg/yr)	110	65	41	0
Vegetable/fruit consumption (kg/yr)	520	630	520	0

Note: These are obtained from Regulatory Guide 1.109. Leafy vegetables are assumed to be grown in the MEI's garden 58% of the year.

Table 11.3-203 (Sheet 1 of 2)
Release of Activities in Gaseous Effluent

Isotope	Release (Ci/yr)			Concentration (µCi/ml)		Fraction of ECL
	Units 3 & 4	Units 1 & 2	Total	Site	ECL	
H-3	7.0E+02	2.0E+02	9.0E+02	1.6E-10	1.0E-07	1.6E-03
Be-7	-	7.0E-06	7.0E-06	1.2E-18	3.0E-08	4.1E-11
C-14	1.5E+01	-	1.5E+01	2.5E-12	3.0E-09	8.5E-04
Ar-41	6.8E+01	1.6E+00	7.0E+01	1.2E-11	1.0E-08	1.2E-03
Cr-51	1.2E-03	3.2E-06	1.2E-03	2.1E-16	3.0E-08	7.1E-09
Mn-54	8.6E-04	-	8.6E-04	1.5E-16	1.0E-09	1.5E-07
Fe-59	1.6E-04	-	1.6E-04	2.8E-17	5.0E-10	5.5E-08
Co-57	1.6E-05	-	1.6E-05	2.9E-18	9.0E-10	3.2E-09
Co-58	4.6E-02	5.9E-06	4.6E-02	8.0E-15	1.0E-09	8.0E-06
Co-60	1.7E-02	9.6E-06	1.7E-02	3.0E-15	5.0E-11	6.1E-05
Kr-85m	7.2E+01	3.8E-05	7.2E+01	1.3E-11	1.0E-07	1.3E-04
Kr-85	8.2E+03	3.4E+00	8.2E+03	1.4E-09	7.0E-07	2.0E-03
Kr-87	3.0E+01	-	3.0E+01	5.2E-12	2.0E-08	2.6E-04
Kr-88	9.2E+01	-	9.2E+01	1.6E-11	9.0E-09	1.8E-03
Sr-89	6.0E-03	1.1E-06	6.0E-03	1.0E-15	2.0E-10	5.2E-06
Sr-90	2.4E-03	4.5E-08	2.4E-03	4.2E-16	6.0E-12	7.0E-05
Zr-95	2.0E-03	-	2.0E-03	3.5E-16	4.0E-10	8.7E-07
Nb-95	5.0E-03	6.2E+00	6.2E+00	1.1E-12	2.0E-09	5.4E-04
I-131	2.4E-01	2.1E-02	2.6E-01	4.5E-14	2.0E-10	2.3E-04
I-132	-	3.6E-06	3.6E-06	6.2E-19	2.0E-08	3.1E-11
I-133	8.0E-01	4.9E-04	8.0E-01	1.4E-13	1.0E-09	1.4E-04
Xe-131m	3.6E+03	1.1E-01	3.6E+03	6.3E-10	2.0E-06	3.1E-04
Xe-133m	1.7E+02	3.3E-02	1.7E+02	3.0E-11	6.0E-07	5.1E-05
Xe-133	9.2E+03	2.2E+01	9.2E+03	1.6E-09	5.0E-07	3.2E-03
Xe-135m	1.4E+01	-	1.4E+01	2.4E-12	4.0E-08	6.1E-05
Xe-135	6.6E+02	4.0E-01	6.6E+02	1.2E-10	7.0E-08	1.6E-03
Xe-138	1.2E+01	-	1.2E+01	2.1E-12	2.0E-08	1.0E-04
Ru-103	1.6E-04	-	1.6E-04	2.8E-17	9.0E-10	3.1E-08

Table 11.3-203 (Sheet 2 of 2)
Release of Activities in Gaseous Effluent

Isotope	Release (Ci/yr)			Concentration (µCi/ml)		Fraction of ECL
	Units 3 & 4	Units 1 & 2	Total	Site	ECL	
Ru-106	1.6E-04	-	1.6E-04	2.7E-17	2.0E-11	1.4E-06
Sb-125	1.2E-04	-	1.2E-04	2.1E-17	7.0E-10	3.0E-08
Cs-134	4.6E-03	-	4.6E-03	8.0E-16	2.0E-10	4.0E-06
Cs-136	1.7E-04	-	1.7E-04	3.0E-17	9.0E-10	3.3E-08
Cs-137	7.2E-03	2.2E-07	7.2E-03	1.3E-15	2.0E-10	6.3E-06
Ba-140	8.4E-04	-	8.4E-04	1.5E-16	2.0E-09	7.3E-08
Ce-141	8.4E-05	-	8.4E-05	1.5E-17	8.0E-10	1.8E-08
Total	2.3E+04	2.3E+02	2.3E+04	4.0E-09	-	1.4E-02

Note: The releases for Units 3 and 4 are based on the AP1000 DCD (Reference 207) and are for two units. The releases for Units 1 and 2 are based on annual effluent release reports (References 204, 205, 206) and are for two units. The effluent concentration limits (ECLs) are from 10 CFR 20, Appendix B, Table 2, Column 1.

Table 11.3-204
Gaseous Pathway Receptor Locations

Receptor	Direction	Distance (miles)
Nearest site boundary	NE	0.50
Nearest residence	NE	0.67
Nearest vegetable garden	NE	0.67
Nearest meat animal	NE	0.67

Note: This data is taken from Table 2.3-219. There are no milk cows or goats within 5 miles of the plant.

Table 11.3-205
Gaseous Pathway Doses for Maximally Exposed Individuals

Location	Pathway		Dose per Unit (mrem/yr)			
			Total Body	Thyroid	Bone	Skin
Nearest Site Boundary (0.50 mi NE)	Plume		4.1E-01	4.1E-01	4.1E-01	2.1E+00
	Ground		1.5E-01	1.5E-01	1.5E-01	1.8E-01
	Inhalation	Adult	4.5E-02	4.3E-01	7.1E-03	4.4E-02
		Teen	4.6E-02	5.3E-01	8.6E-03	4.4E-02
		Child	4.1E-02	6.2E-01	1.1E-02	3.9E-02
		Infant	2.3E-02	5.6E-01	5.3E-03	2.3E-02
Nearest Residence (0.67 mi NE)	Plume		2.6E-01	2.6E-01	2.6E-01	1.3E+00
	Ground		8.7E-02	8.7E-02	8.7E-02	1.0E-01
	Inhalation	Adult	2.8E-02	2.6E-01	4.3E-03	2.7E-02
		Teen	2.8E-02	3.2E-01	5.2E-03	2.7E-02
		Child	2.5E-02	3.8E-01	6.3E-03	2.4E-02
		Infant	1.4E-02	3.4E-01	3.2E-03	1.4E-02
Nearest Garden (0.67 mi NE)	Vegetable	Adult	2.0E-01	2.0E+00	9.9E-01	1.8E-01
		Teen	3.0E-01	2.7E+00	1.6E+00	2.8E-01
		Child	6.7E-01	5.2E+00	3.6E+00	6.3E-01
Nearest Meat Animal (0.67 mi NE)	Meat	Adult	6.2E-02	1.5E-01	2.7E-01	6.0E-02
		Teen	5.0E-02	1.2E-01	2.3E-01	4.9E-02
		Child	9.1E-02	1.9E-01	4.3E-01	8.9E-02
Maximally Exposed Individual (0.67 mi NE)	Internal Only	Adult	2.9E-01	2.4E+00	1.3E+00	2.7E-01
		Teen	3.8E-01	3.1E+00	1.8E+00	3.5E-01
		Child	7.8E-01	5.8E+00	4.1E+00	7.4E-01
		Infant	1.4E-02	3.4E-01	3.2E-03	1.4E-02
	Total	Adult	6.4E-01	2.8E+00	1.6E+00	1.7E+00
		Teen	7.2E-01	3.5E+00	2.1E+00	1.7E+00
		Child	1.1E+00	6.1E+00	4.4E+00	2.1E+00
		Infant	3.6E-01	6.8E-01	3.5E-01	1.4E+00

Note: The internal doses for the maximally exposed individual are obtained by adding the doses from the inhalation, vegetable, and meat pathways. The total doses add the plume and ground doses to the internal doses.

Table 11.3-206
Comparison of Maximally Exposed Individual Doses with 10 CFR 50, Appendix I Criteria

Dose Type	Location	Dose per Unit	
		Estimated	Limit
Gamma Air (mrad)	Site Boundary	0.67	10
Beta Air (mrad)	Site Boundary	2.8	20
Total Body (mrem)	Site Boundary	0.56	5
Skin (mrem)	Site Boundary	2.2	15
Iodines and Particulates Maximum Organ - Thyroid (mrem)	Maximally Exposed Individual	5.9	15

Note: Total body and skin doses are the sums of plume and ground doses from Table 11.3-205. The dose due to iodines and particulates is for a child, the age group receiving the maximum total dose.

Table 11.3-207
Comparison of Maximally Exposed Individual Doses with 40 CFR 190 Criteria

	Dose (mrem/yr)					
	Units 3 and 4			Units 1 and 2	Site Total	Regulatory Limit
	Liquid	Gaseous	Total			
Total Body	0.020	2.2	2.3	0.092	2.4	25
Thyroid	0.027	12	12	0.069	12	75
Other Organ - Bone	0.023	8.8	8.8	0.054	8.9	25

Note: Doses for Units 3 and 4 are for a child, the age group receiving the maximum total dose. Doses for Units 1 and 2 are the maximum reported in the annual effluent release reports for 2001, 2002, and 2003 (References 204, 205, 206).

Table 11.3-208
Collective Total Body Doses Within 50 Miles

	Dose (person-rem/yr)		
	Units 3 and 4	**Units 1 and 2**	**Total**
Noble Gases	0.57	0.0011	0.57
Iodines & Particulates	0.14	0.16	0.30
H-3 & C-14	1.1	0.09	1.2
Total	1.8	0.26	2.1

Note: Doses for Units 1 and 2 are based on the maximum activity releases in the annual effluent release reports for 2001, 2002, and 2003 (References 204, 205, 206).

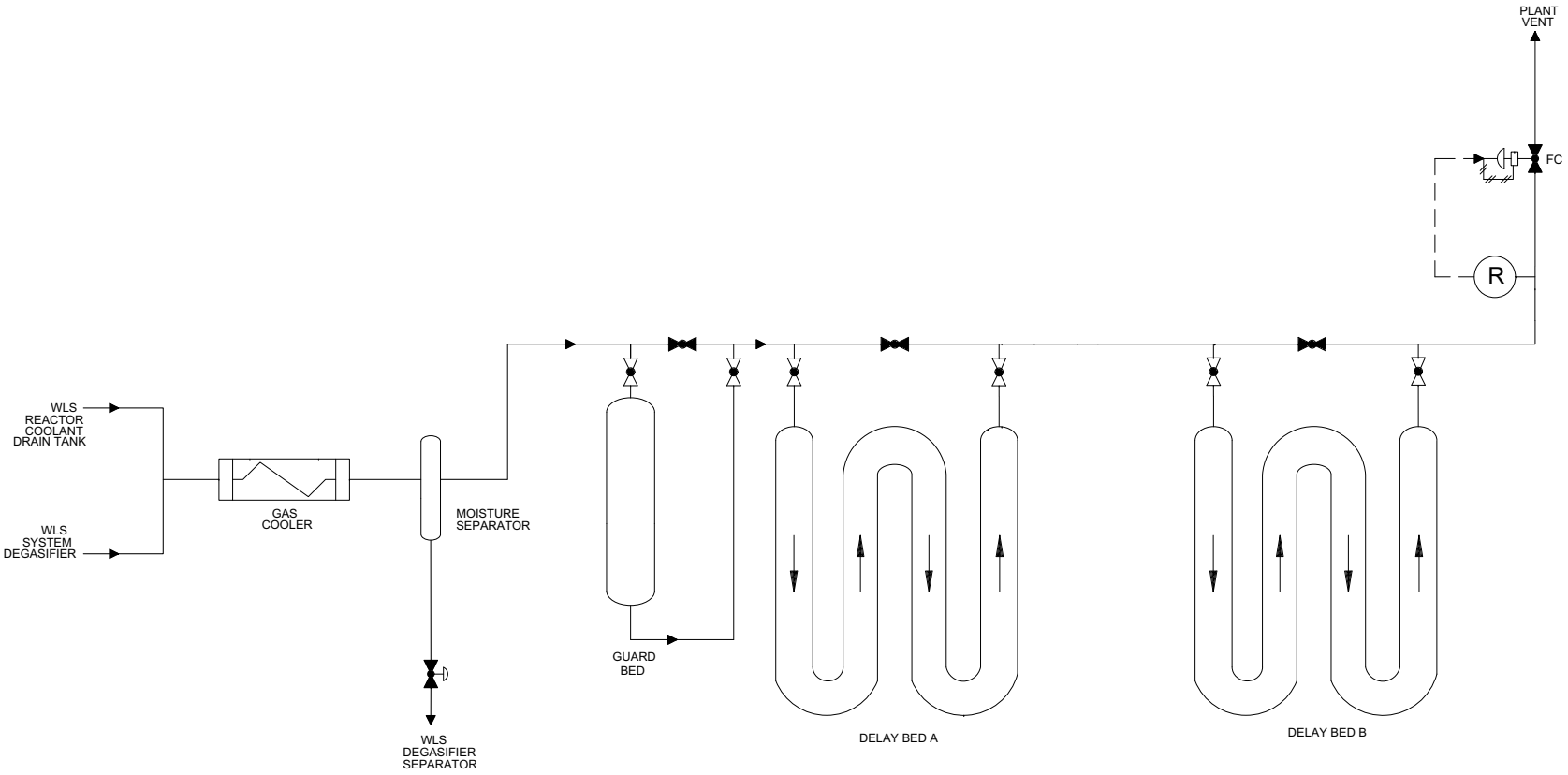


FIGURE REPRESENTS SYSTEM FUNCTIONAL ARRANGEMENT. DETAILS INTERNAL TO THE SYSTEM MAY DIFFER AS A RESULT OF IMPLEMENTATION FACTORS SUCH AS VENDOR-SPECIFIC COMPONENT REQUIREMENTS.

Figure 11.3-1
Gaseous Radwaste System
Simplified Sketch

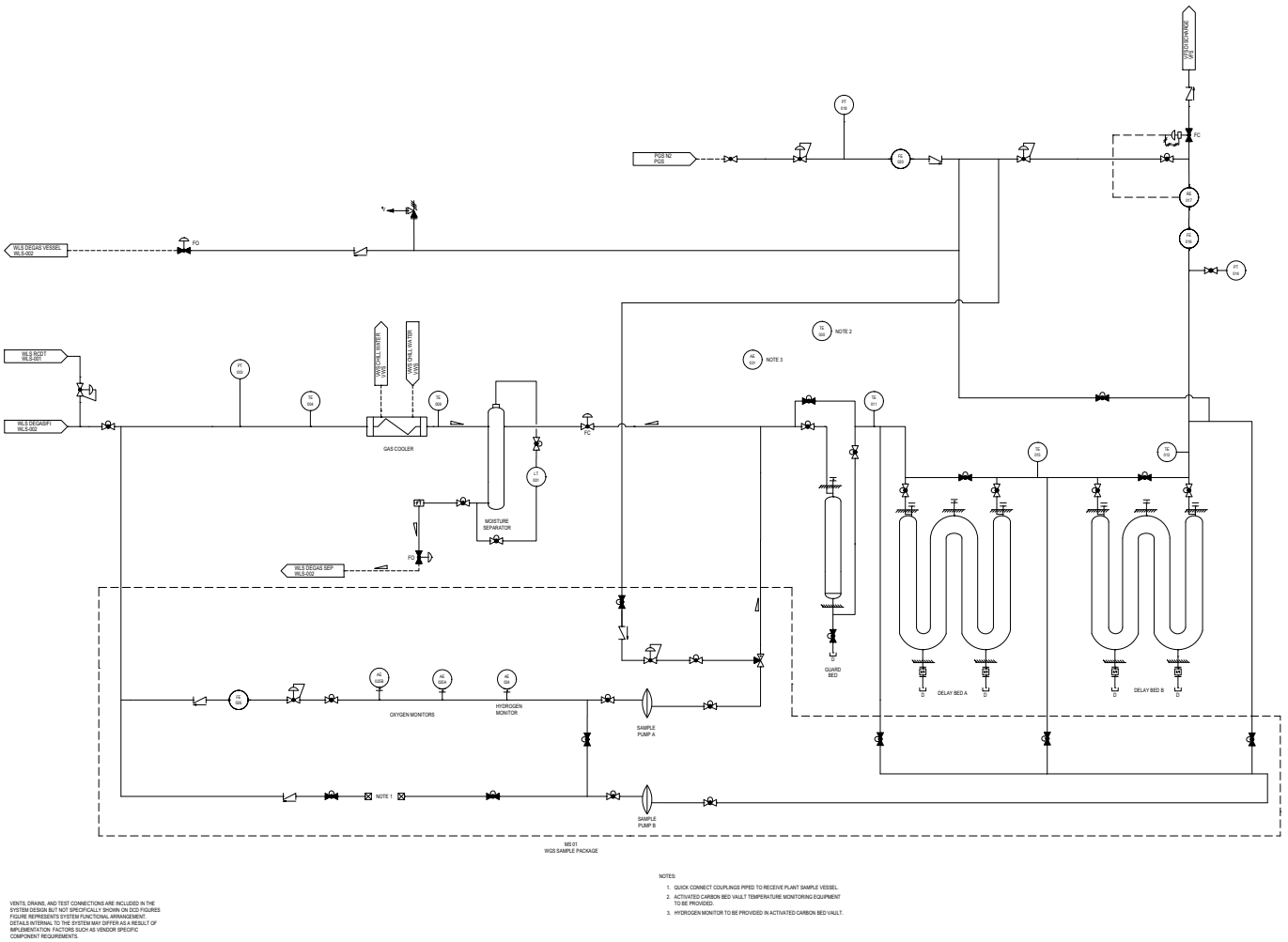


Figure 11.3-2
Simplified Gaseous Radwaste System Piping and Instrumentation Diagram (REF) WGS 001

11.4 Solid Waste Management

The solid waste management system (WSS) is designed to collect and accumulate spent ion exchange resins and deep bed filtration media, spent filter cartridges, dry active wastes, and mixed wastes generated as a result of normal plant operation, including anticipated operational occurrences. The system is located in the auxiliary and radwaste buildings. Processing and packaging of wastes are by mobile systems in the auxiliary building rail car bay and in the mobile systems facility part of the radwaste building. The packaged waste is stored in the auxiliary and radwaste buildings until it is shipped offsite to a licensed disposal facility.

The use of mobile systems for the processing functions permits the use of the latest technology and avoids the equipment obsolescence problems experienced with installed radwaste processing equipment. The most appropriate and efficient systems may be used as they become available.

This system does not handle large, radioactive waste materials such as core components or radioactive process wastes from the plant's secondary cycle. However, the volumes and activities of the secondary cycle wastes are provided in this section.

11.4.1 Design Basis

11.4.1.1 Safety Design Basis

The solid waste management system performs no function related to the safe shutdown of the plant. The system's failure does not adversely affect any safety-related system or component; therefore, the system has no nuclear safety design basis.

There are no safety related systems located near heavy lifts associated with the solid waste management system. Therefore, a heavy loads analysis is not required.

11.4.1.2 Power Generation Design Basis

The solid waste management system provides temporary onsite storage for wastes prior to processing and for the packaged wastes. The system has a 60-year design objective and is designed for maximum reliability, minimum maintenance, and minimum radiation exposure to operating and maintenance personnel. The system has sufficient temporary waste accumulation capacity based on maximum waste generation rates so that maintenance, repair, or replacement of the solid waste management system equipment does not impact power generation.

11.4.1.3 Functional Design Basis

The solid waste management system is designed to meet the following objectives:

- Provide for the transfer and retention of spent radioactive ion exchange resins and deep bed filtration media from the various ion exchangers and filters in the liquid waste processing, chemical and volume control, and spent fuel cooling systems

- Provide the means to mix, sample, and transfer spent resins and filtration media to high integrity containers or liners for dewatering or solidification as required

- Provide the means to change out, transport, sample, and accumulate filter cartridges from liquid systems in a manner that minimizes radiation exposure of personnel and spread of contamination

- Provide the means to accumulate spent filters from the plant heating, ventilation, and air-conditioning systems
- Provide the means to segregate solid wastes (trash) by radioactivity level and to temporarily store the wastes
- Provide the means to accumulate radioactive hazardous (mixed) wastes
- Provide the means to segregate clean wastes originating in the radiologically controlled area (RCA)
- Provide the means to store packaged wastes for at least 6 months in the event of delay or disruption of offsite shipping
- Provide the space and support services required for mobile processing systems that will reduce the volume of and package radioactive solid wastes for offsite shipment and disposal according to applicable regulations, including Department of Transportation regulation 49 CFR 173 (Reference 1) and NRC regulation 10 CFR 71 (Reference 2)
- Provide the means to return liquid radwaste to the liquid radwaste system (WLS) for subsequent processing and monitored discharge

The solid waste management system is designed according to NRC Regulatory Guide 1.143 to meet the requirements of General Design Criterion (GDC) 60 as discussed in Sections 1.9 and 3.1. The seismic design classifications of the radwaste building and system components are provided in Section 3.2.

Provisions are made in the auxiliary and radwaste buildings to use mobile radwaste processing systems for processing and packaging each waste stream including concentration and solidification of chemical wastes from the liquid waste management system, spent resin dewatering, spent filter cartridge encapsulation and dry active waste sorting and compaction.

The radioactivities of influents to the solid waste management system are based on estimated radionuclide concentrations and volumes. These estimates are based on operating plant experience, adjusted for the size and design differences of AP1000. The influent source terms are consistent with Section 11.1.

The solid waste management system airborne effluents are released through the monitored plant vent as described as part of the 10 CFR 50 (Reference 3), Appendix I, analysis presented in Subsection 11.3.3.

The solid waste management system collects and stores radioactive wastes within shielding to maintain radiation exposure to plant operation and maintenance personnel as low as is reasonably achievable (ALARA) according to General Design Criteria 60 as discussed in Section 3.1 and Regulatory Guide 8.8. Personnel exposures will be maintained well below the limits of 10 CFR 20 (Reference 4). Design features incorporated to maintain exposures ALARA include remote and semi-remote operations, automatic resin transport line flushing, and shielding of components, piping and containers holding radioactive materials. Access to the solid waste storage areas is controlled, to minimize inadvertent personnel exposure, by suitable barriers such as heavy storage cask covers and locked or key-card-operated doors or gates (see Section 12.1).

The solid waste management system conforms to the design criteria of NRC Branch Technical Position ETSB 11-3. Suitable fire protection systems are provided as described in Subsection 9.5.1.

Waste disposal containers are to be selected from available designs that meet the requirements of the DOT and NRC. The solid waste management system does not require source-specific waste containers. Waste containers must meet the regulatory requirements for radioactive waste transportation in 49 CFR 173 and for radioactive waste disposal in 10 CFR 61 (Reference 5) as well as specific disposal facility requirements.

11.4.1.4 Compliance with 10 CFR 20.1406

In accordance with the requirements of 10 CFR 20.1406 (Reference 11), the solid radwaste system is designed to minimize, to the extent practicable, contamination of the facility and the environment, facilitate decommissioning, and minimize, to the extent practicable, the generation of radioactive waste. This is done through appropriate selection of design technology for the system, plus incorporating the ability to update the system to use the best available technology throughout the life of the plant.

11.4.2 System Description

11.4.2.1 General Description

The solid waste management system includes the spent resin system. The flows of wastes through the solid waste management system are shown on Figure 11.4-1. The radioactivity of influents to the system are dependent on reactor coolant activities and the decontamination factors of the processes in the chemical and volume control system, spent fuel cooling system, and the liquid waste processing system.

The parameters used to calculate the estimated activity of the influents to the solid waste management system are listed in Table 11.4-1. The estimated expected isotopic curie content of the primary spent resin and filter cartridge wastes to be processed on an annual basis is listed on Table 11.4-2. Table 11.4-3 provides the same information for the estimated maximum annual activities. The AP1000 has sufficient radwaste storage capacity to accommodate the maximum generation rate.

The radioactivity of the dry active waste is expected to normally range from 0.1 curies per year to 8 curies per year with a maximum of about 16 curies per year. This waste includes spent HVAC filters, compressible trash, non-compressible components, mixed wastes and solidified chemical wastes. These activities are produced by relatively long lived radionuclides (such as Cr-51, Fe-55, Co-58, Co-60, Nb-95, Cs-134 and Cs-137), and therefore, radioactivity decay during processing and storage is minimal. These activities thus apply to the waste as generated and to the waste as shipped.

The estimated expected and maximum annual quantities of waste influents by source and form are listed in Table 11.4-1 with disposal volumes. The annual radwaste influent rates are derived by multiplying the average influent rate (e.g. volume per month, volume per refueling cycle) by one year of time. The annual disposal rate is determined by applying the radwaste packaging efficiency to the annual influent rate. The influent volumes are conservatively based on an 18-month refueling cycle. Annual quantities based on a 24-month refueling cycle are less than those for an 18-month cycle. The estimated expected isotopic curie content of the primary spent resin and filter cartridge wastes to be shipped offsite are presented in Table 11.4-4 based on 90 days of decay before shipment. The same information is presented in Table 11.4-5 for the estimated maximum activities based on 30 days of decay before shipment.

Section 11.1 provides the bases for determination of liquid source terms used to calculate several of the solid waste management system influent source terms. The influent data presented in Tables 11.4-2 and 11.4-3 are conservatively based on Section 11.1 design basis (Technical Specification) values.

All radwaste which is packaged and stored by AP1000 will be shipped for disposal. The AP1000 has no provisions for permanent storage of radwaste. Radwaste is stored ready for shipment. Shipped volumes of radwaste for disposal are estimated in Table 11.4-1 from the estimated expected or maximum influent volumes by making adjustments for volume reduction processing by mobile systems and the expected container filling efficiencies. For drum compaction, the overall volume reduction factor, including packaging efficiency, is 3.6. For box compaction, the overall volume reduction factor is 5.4. These adjustments result in a packaged internal waste volume for each waste source, and the number of containers required to hold this volume is based on the container's internal volume. The disposal volume is based on the number of containers and the external (disposal) volume of the containers.

The expected disposal volumes of wet and dry wastes are approximately 547 and 1417 cubic feet per year, respectively as shown in Table 11.4-1. The wet wastes shipping volumes include 510 cubic feet per year of spent ion exchange resins and deep bed filter activated carbon, 20 cubic feet of volume reduced liquid chemical wastes and 17 cubic feet of mixed liquid wastes. The spent resins and activated carbon are initially stored in the spent resin storage tanks located in the rail car bay of the auxiliary building. When a sufficient quantity has accumulated, the resin is sluiced into two 158 cubic feet high-integrity containers in anticipation of transport for offsite disposal. Liquid chemical wastes are reduced in volume and packaged into three 55-gallon drums per year (about 20 cubic feet) and are stored in the waste accumulation room of the radwaste building. The mixed liquid wastes fill less than three drums per year (about 17 cubic feet per year) and are stored on containment pallets in the waste accumulation room of the radwaste building until shipped offsite for processing.

The two spent resin storage tanks (250 cubic feet usable, each) and one high integrity container in the spent resin waste container fill station at the west end of the rail car bay of the auxiliary building provide more than a year of spent resin storage at the expected rate, and several months of storage at the maximum generation rate. The expected radwaste generation rate is based upon the following:

- All ion exchange resin beds are disposed and replaced every refueling cycle.
- The WGS activated carbon guard bed is replaced every refueling cycle.
- The WGS delay beds are replaced every ten years.
- All wet filters are replaced every refueling cycle.
- Rates of compactible and non-compactible radwaste, chemical waste, and mixed wastes are estimated using historical operating plant data.

The maximum radwaste generation rate is based upon the following:

- The ion exchange resin beds are disposed based upon operation with 0.25% fuel defects.
- The WGS activated carbon guard bed is replaced twice every refueling cycle.
- The WGS delay beds are replaced every five years.
- All wet filters are replaced based upon operation with 0.25% fuel defects.
- The expected rates of compactible and non-compactible radwaste, chemical waste, and mixed wastes are increased by about 50%.

- Primary to secondary system leakage contaminates the condensate polishing system and blowdown system resins and membranes which are replaced.

The dry solid radwaste includes 1383 cubic feet per year of compactible and non-compactible waste packed into about 14 boxes (90 cubic feet each) and ten drums per year. Drums are used for higher activity compactible and non-compactible wastes. Compactible waste includes HVAC exhaust filter, ground sheets, boot covers, hair nets, etc. Non-compactible waste includes about 60 cubic feet per year of dry activated carbon and other solids such as broken tools and wood. Solid mixed wastes will occupy 7.5 cubic feet per year (one drum). The low activity spent filter cartridges may be compacted to fill about 0.40 drums per year (3 ft^3/year) and are stored in the waste accumulation room. Compaction is performed by mobile equipment or is performed offsite. High activity filter cartridges fill three drums per year (22.5 cubic feet per year) and are stored in the filter storage area in the auxiliary building.

The total volume of packaged radwaste to be stored in the radwaste building waste accumulation room is 1417 cubic feet per year at the expected rate and 2544 cubic feet per year at the maximum rate. The compactible and non-compactible dry wastes, packaged in drums or steel boxes, are stored with the mixed liquid and mixed solid, volume reduced liquid chemical wastes, and the lower activity filter cartridges. The quantities of packaged liquid radwaste stored in the waste accumulation room of the radwaste building consist of 20 cubic feet of chemical waste and 17 cubic feet of mixed liquid waste. The available minimum useful storage volume for packaged waste in the waste accumulation room is 3900 cubic feet (10 feet deep, 30 feet long, and 13 feet high), which accommodates more than one full offsite waste shipment using a tractor-trailer truck. The waste accumulation room provides storage for more than two years at the expected rate of generation and more than a year at the maximum rate of generation. One four-drum containment pallet provides more than 8 months of storage capacity for the liquid mixed wastes and the volume reduced liquid chemical wastes at the expected rate of generation and more than 4 months at the maximum rate.

A conservative estimate of solid wet waste includes blowdown material based on continuous operation of the steam generator blowdown purification system, with leakage from the primary to secondary system. The volume of radioactively contaminated material from this source is estimated to be 540 cubic feet per year. Provisions for processing and disposal of radioactive steam generator blowdown resins and membranes are described in Subsection 10.4.8. Note that, although included here for conservatism, this volume of contaminated resin will be removed from the plant within the contaminated electrodeionization unit and not stored as wet waste.

The condensate polishing system includes mixed bed ion exchanger vessels for purification of the condensate as described in Subsection 10.4.6. Should the resins become radioactive, the resins are transferred from the condensate polishing vessel directly to a temporary processing unit or to the temporary processing unit via the spent resin tank. The processing unit, located outside of the turbine building, dewaters and processes the resins as required for offsite disposal. Radioactive condensate polishing resin will have very low activity. It will be disposed in containers as permitted by DOT regulations. After packaging, the resins may be stored in the radwaste building. Based on a typical condensate polishing system operation of 30 days per refueling cycle with leakage from the primary system to the secondary system, the volume of radioactively contaminated resin is estimated to be 331 cubic feet per year (two 248 cubic foot beds per refueling cycle). Normal disposal of nonradioactive condensate polishing system resins is described in Subsection 10.4.6.

The parameters used to calculate the activities of the steam generator blowdown solid waste and condensate polishing resins are given in Table 11.4-1. Based on the above volumes, the disposal volume is estimated to be 1095 cubic feet per year. The expected and maximum activities of the resins as generated are given in Tables 11.4-6 and 11.4-7, respectively. The expected and maximum activities of resins as shipped, based on 90 days decay prior to shipment, are given in Tables 11.4-8 and 11.4-9, respectively.

11.4.2.2 Component Description

The seismic design classification and safety classification for the solid waste management system components are listed in Section 3.2. The components listed are located in the seismic Category I Nuclear Island. Table 11.4-10 lists the solid waste management system equipment design parameters. The following subsections provide a functional description of the major system components.

11.4.2.2.1 Spent Resin Tanks

The spent resin tanks provide holdup capacity for spent resin and filter bed media decay before processing. High- and low-activity resins may be mixed to limit the radioactivity concentration in the waste containers to 10 Ci/ft^3 in accordance with the USNRC Technical Position on Waste Form (Reference 6).

Resin mixing capability is provided by mixing eductors in each tank, and resin dewatering, air sparging and complete draining capabilities are also provided. The ultrasonic level sensors and dewatering screens are arranged for remote removal. The vent and overflow connections have screens to prevent the inadvertent discharge of spent resin, and they are routed to the radioactive waste drain system (WRS).

11.4.2.2.2 Resin Mixing Pump

The resin mixing pump provides the motive force to fluidize and mix the resins in the spent resin tanks, to transfer water between spent resin tanks, to discharge excess water from the spent resin tanks to the liquid waste processing system, and to flush the resin transfer lines.

11.4.2.2.3 Resin Fines Filter

The resin fines filter minimizes the spread of high-activity resin fines and dislodged crud particles by filtering the water used for line flushing or discharged from the spent resin tanks to the liquid waste processing system.

11.4.2.2.4 Resin Transfer Pump

The resin transfer pump provides the motive force for recirculation of spent resins via either one of the spent resin tanks for mixing and sampling, for transferring spent resin between tanks, and for blending high- and low-activity resins to meet the specific activity limit for disposal. The resin transfer pump is also used to transfer spent resins to a waste container in the fill station or in its shipping cask located in the auxiliary building rail car bay.

11.4.2.2.5 Resin Sampling Device

The resin sampling device collects a representative sample of the spent resin either during spent resin recirculation or during spent resin waste container filling operations. A portable shielded cask is provided for sample jar transfer.

11.4.2.2.6 Filter Transfer Cask

The filter transfer cask permits remote changing of filter cartridges, dripless transport to the storage area in the auxiliary building, transfer of the filter cartridges into and out of the filter storage, and loading of the filter cartridges into disposal containers.

11.4.2.3 System Operation

11.4.2.3.1 Spent Resin Handling Operations

Demineralized water is used to transfer spent resins from the various ion exchangers to the spent resin tanks. A demineralized water transfer pump provides the pressurized water flow to transfer the spent resins as described in Subsection 9.2.4. Before the transfer operation, it is verified that the selected spent resin tank is aligned as a receiver and has the capacity to accept the bed. It is also verified that the resin mixing pump is aligned to discharge excess transfer water through the resin fines filter to the liquid waste processing system.

During the transfer operation the tank level is monitored and the resin mixing pump is operated, if required, to limit tank water level. The operator stops the transfer when the CCTV camera viewing the sight flow glass indicates on a control panel monitor that the sluice water is clear and the transfer line is, therefore, flushed of resins.

After the bed transfer, the tank solids level can be checked by operating the resin mixing pump to lower the water level below the solids level. The solids level can be determined by the ultrasonic surface detector.

Between bed transfer operations the water level in the spent resin tanks is maintained above the solids level. Demineralized water is supplied for water level adjustment as well as a backup water source for flushing resin handling lines after resin recirculation and waste disposal container filling operations.

The solids bed can be agitated and mixed at any time by using compressed air or by operating the resin mixing pump in the resin mixing mode. In the resin mixing mode, water is drawn from the spent resin tank via resin retention screens. The water is returned via tank mixing eductors that generate a resin slurry recirculation within the tank equivalent to about four times the flow rate generated by the resin mixing pump. The solids bed is locally fluidized during this operation.

The resin mixing mode is established to fluidize and mix the solids bed in the spent resin tank before waste disposal container filling. The resin transfer pump is then started in the recirculation mode. A resin slurry is drawn from the spent resin tank and returned to the same tank. A representative resin sample may be obtained during recirculation or container filling modes by operating the sampling device.

The portable system's container fill valve is opened to initiate the filling operation. The resin dewatering pump of the portable dewatering system is started to dewater the resin as it accumulates in the container. The resin dewatering pump discharges the water to the recirculation line. The water flows back to the spent resin tank, thereby preserving the water inventory in the system and retaining any resin fines or dislodged crud within the system.

The resin mixing pump can be stopped at any time during the filling operation. When the solids level nears the top of the container, as detected by level sensors and observed by a television camera, the fill valve is closed and cycled to top off the container. Excessive water or solids level automatically closes the fill valve.

When the filling operation is complete, the line flushing sequence controller is manually initiated to automatically operate the pumps and valves to flush the resin transfer lines back to the spent resin tank. The container fill valve is opened for a short time period to flush the remaining resin to the waste container. The resin mixing pump supplies filtered flush water from the spent resin tank. The portable dewatering system's dewatering pump is operated periodically until no further dewatering flow is detected by the pump discharge pressure indicator and/or audible indications from the pump.

11.4.2.3.2 Spent Filter Processing Operations

A filter transfer cask is used to change the higher-activity filters of the chemical and volume control system and spent fuel cooling system. The filter vessel is drained, and the filter cover is opened remotely. The shield plug of the port over the filter is removed and the transfer cask, without its bottom shield cover, is lifted and positioned on the port directly over the cartridge in the filter vessel.

A grapple inside the transfer cask is remotely lowered and connected to the filter cartridge. The cartridge is lifted into the transfer cask, and the cask is transferred over plastic sheeting to the bottom shield cover. The dose rate of the cartridge is measured with a long probe, and the cask is lowered onto and connected to the bottom shield cover. The transfer cask is then moved to the auxiliary building rail car bay.

If recent applicable sample analysis results are available, the filter cartridge can be loaded directly into a disposal container as described in the following paragraph. If analysis is required, a sample of the filter media may be obtained through a port in the transfer cask or by other sampling methods. The filter cartridge is placed in the waste disposal container area until sample analysis results are available. The transfer cask bottom cover is disconnected, the transfer cask is lifted by the crane and transferred to a position over a waste container in the waste disposal container area, and the spent filter cartridge is lowered into the container. After moving the transfer cask away, the crane is used to replace the lid over the waste disposal container area. Any water draining from the filter during storage drains to a floor drain for subsequent transfer to the liquid radwaste system.

When sample analysis is complete and packaging requirements are established, the transfer cask is used to retrieve the spent cartridges from storage and deposit them into a waste container via a port in the top of a portable processing and storage cask. Plastic coverings are removed and the container is capped, smear-surveyed, and decontaminated as required, using reach rod tools through a cask port. The dose rate survey is also made through a cask port. Transfer of the filled waste container to the shipping cask, including cask cover handling, is then performed using the rail car bay crane under remote control.

Filters with dose rates less than 15 R/hr on contact may be changed from outside of filter vessel shielding by using reach rod tools. The filter vessel is drained, and the cover is removed. Then the spent filter cartridge is grappled and lifted out and into a filter transfer cask.

At the radwaste building, low and moderate activity filter cartridges are deposited into disposal or storage drums. The drums are stored within portable shield casks in the shielded accumulation room, which is serviced by the mobile systems facility crane. Depending on dose rates and analysis results, stabilization may or may not be required. Cartridges not requiring stabilization are loaded into standard, 55 gallon shipping drums with absorbent and may be compacted using a mobile system. When stabilization is required, the cartridges may be loaded into either high integrity containers or standard drums. If standard drums are used, mobile equipment is used to encapsulate the contents of the drums.

The drum covers are manually installed, and the drums are smear surveyed, decontaminated by wiping, if required, weighed, stacked on pallets, and placed in the waste accumulation room.

When a truck-load quantity of waste containers accumulates, shipment to a low-level waste disposal facility is initiated by loading pallets of drums and other low-level waste containers into a closed van using the scissor lift or onto a flat-bed trailer using the crane. If the activity level is too high for unshielded shipment, the drums are loaded onto a cask pallet and into a shielded shipping cask using the mobile systems facility crane.

Radioactive filters from ventilation exhaust filtration units are bagged and transported to the radwaste building, where they are temporarily stored. The filters are compacted along with other dry active wastes by a mobile system as described in the following subsection.

11.4.2.3.3 Dry Waste Processing Operations

Dry wastes are segregated by measuring the contact dose rate of the wastes to determine the appropriate processing method. The contact dose rates for initial waste segregation are as follows:

Low activity	<5 mR/hr
Moderate activity	5 mR/hr to 100 mR/hr
High activity	>100 mR/hr

These activity levels may be adjusted by the operator to minimize exposures while maximizing processing efficiency.

Wastes from surface contamination areas in the radiologically controlled area are placed in bags or containers and tagged at the point of origin with information on radiation levels, waste type, and destination. The bags or containers are transported to the radwaste building, where they are placed into low-, moderate-, or high-activity storage, segregated by portable shielding as appropriate.

The high-activity wastes (greater than 100 mR/hr) are normally expected to be compacted in drums using a mobile compactor system in the same manner as lower-activity filter cartridges.

Moderate-activity wastes (5 mR/hr to 100 mR/hr) are expected to be sorted in a mobile system to remove reusable items such as protective clothing articles and tools, hazardous wastes, and larger noncompressible items. The remaining wastes are normally compacted by mobile equipment. The packaged wastes may be loaded directly onto a truck for shipment or may be stored in the waste accumulation room until a truck load quantity accumulates.

Low-activity, dry active waste (less than 5 mR/hr) generally contains a large amount of nonradioactive material. It is expected that these wastes normally will be processed through a mobile radiation monitoring and sorting system to remove non-radioactive items for reuse or local disposal. A radiation survey allows identification and removal of potentially clean items for the clean waste verification. The remaining radioactive wastes are normally compacted or packaged for disposal as appropriate.

Materials that enter the radiologically controlled area are verified as nonradioactive before being released for reuse or disposal. Tools and equipment belonging to personnel and contractors are surveyed at the radiologically controlled area exit in the annex building. If these items cannot be released or decontaminated, they become plant inventory or dry active waste and are handled as described previously.

Other wastes generated in the radiologically controlled area but outside of surface contamination areas are collected in bags or containers and are delivered to the temporary storage location in the radwaste building. These wastes normally are processed through a mobile radiation monitoring system to verify that they are nonradioactive and suitable for disposal in a local waste landfill.

11.4.2.3.4 Mixed Waste Processing Operations

Mixed wastes from the radiologically controlled area are collected in suitable containers and brought to the radwaste building, where separate containment pallets and accumulation drums are provided

for solid and liquid mixed wastes. Mixed wastes are normally sent to an offsite facility having mixed-waste processing and disposal capabilities.

11.4.2.4 Waste Processing and Disposal Alternatives

11.4.2.4.1 Portable and Mobile Radwaste Systems Capabilities

Portable or mobile processing and packaging systems can be located in the auxiliary building rail car bay or the radwaste building mobile systems facility. Chemical wastes may be processed in the radwaste building by a mobile concentration and/or solidification system when a batch accumulates in the chemical waste tank. Mobile systems may also be used to encapsulate high-activity filters, to sort, decontaminate and compact dry active wastes, and to verify nonradioactive wastes.

The spent resin system includes connections in the fill station and rail car bay to allow spent resins to be delivered to a disposal container in either location for dewatering using portable equipment.

Branch Technical Position ETSB 11-3 provides guidance for portable solid waste systems in Section IV. Compliance with the four guidance items is achieved as follows:

IV.I The spent resin tanks are the only tanks that contain a significant volume of wet wastes, and these tanks are permanently installed. Concentrates that may be produced by mobile evaporation systems will be produced and stored by the mobile systems only in small batches prior to being solidified by the mobile systems. As described in Subsection 1.2.7, the radwaste building is designed to retain spillage from mobile or portable systems.

IV.2 Permanently installed piping for transport of radioactive wastes to mobile or portable systems is routed close to the mobile or portable systems thereby minimizing the use of flexible interfacing hose. The hydrostatic test requirements of Regulatory Guide 1.143 will be applied to the flexible interfacing hose.

IV.3 Portable or mobile systems will be located in either the rail car bay of the auxiliary building or in the mobile systems facility in the radwaste building. The spent resin waste container fill station or the shipping cask in the auxiliary building collects spillage of spent resin during waste container filling operations. The radwaste and auxiliary buildings contain and drain spillage to the liquid radwaste system via the radioactive waste drain system as described in Subsection 1.2.7 and Section 11.2. Portable or mobile systems will, when required, have their own HEPA filtered exhaust ventilation system. HEPA filtered exhaust is required when airborne radioactivity would exceed 10 CFR 20 derived air concentration limits for radiation workers. The mobile systems facility has connections on the exhaust ventilation ducts for connecting exhaust duct from mobile or portable processing systems to the building's exhaust ventilation system.

IV.4 Although the seismic criteria of Regulatory Guide 1.143 are not applicable to structures housing mobile or portable solid radwaste systems, the portable equipment used for spent resin container filling and dewatering and high-activity filter cartridge packaging will be housed within the Seismic Category I auxiliary building. The radwaste building, which provides shelter for mobile or portable radwaste systems, is non-seismic in accordance with Branch Technical Position ETSB 11-3.

11.4.2.4.2 Central Radwaste Processing Facility

As an alternative to the mobile or portable processes for lower-activity wastes, the wastes may be sent to a licensed central radwaste processing facility for processing and disposal. This option requires minimal onsite processing to remove radioactive materials from the waste streams. The

wastes are loaded into a cargo container. The mobile systems facility includes a designated laydown area, and the mobile systems facility crane may be used to handle a cargo container.

11.4.2.4.3 Alternatives for B and C Wastes

It is expected that Class B and C wastes will constitute approximately 5 percent by volume of the low level radioactive waste (LLRW) that will be generated by the plant with the balance being Class A waste. The volume of wet Class B and C waste is approximately 100 percent of the total Class B and C waste. As of July 1, 2008, the LLRW disposal facility in Barnwell, South Carolina is no longer accepting Class B and C waste from sources in states that are outside of the Atlantic Compact. However, the disposal facility in Clive, Utah is still accepting Class A waste from out of state. Should there be no disposal facilities that will accept the Class B and C wastes after the plant begins operation, there are several options available for storage of such waste:

- As provided in referenced Subsection 11.4.2, the Auxiliary Building is designed to have more than a year of spent resin storage capacity at the expected rate and the spent resin tanks may be mixed to limit the radioactivity concentrations thereby limiting the volume of Class B and C wet waste requiring storage.

- Vendor services are available to process Class A, B, and C waste and transfer for storage of that material until a disposal site is available. Currently, Waste Control Specialists (WCS) of Texas is available to store Class A, B, and C material pending the availability of a licensed disposal site.

- If additional storage capacity were eventually needed, the plant could construct or expand storage facilities onsite or gain access to a storage facility at another licensed nuclear plant.

11.4.2.5 Facilities

11.4.2.5.1 Auxiliary Building

Resin and filtration media transfer lines from the various ion exchangers are routed to the spent resin tanks on elevation 100′ - 0″ in the southwest corner of the auxiliary building. The spent resin system pumps, valves, and piping are located in shielded rooms near the spent resin tanks.

Liquid radwaste system transfer lines to and from the radwaste building are routed to the south wall of the auxiliary building where they penetrate and enter into a shielded pipe pit in the base mat of the radwaste building.

Accessways in the auxiliary building are used to move the filter transfer casks. This includes filter transfer cask handling from the containment, where the chemical and volume control filters are located, to the auxiliary building rail car bay, where the filter cartridges are stored and subsequently packaged using mobile equipment. These accessways are also used to move dry active waste from various collection locations to the radwaste building. Enclosed access is provided between the auxiliary building and the radwaste building on elevation 100′-0″ (grade level).

11.4.2.5.2 Radwaste Building

The radwaste building, described in Section 1.2, houses the mobile systems facility and the waste accumulation room. These rooms are serviced by the mobile systems facility crane.

In the mobile systems facility, three truck bays provide for mobile or portable processing systems and for waste disposal container shipping and receiving. A shielded pipe trench to each of the truck bays is used to route liquid radwaste supply and return lines from the connections in the shielded pipe pit at the auxiliary building wall. Separate areas are reserved for empty (new) waste disposal container

storage, container laydown, and forklift charging. An area is available near the door to the annex building for protective clothing dropoff and frisking.

The waste accumulation room is divided as needed, using partitions and portable shielding to adjust the storage areas for different waste categories as needed to complement the radioactivity levels and volumes of generated wastes. The accumulation room also contains three 1000 cubic feet (10 feet x 10 feet x 10 feet) bunkers with removable steel shield bunker roof plates and removable steel shield bunker door plates. The design functions of this removable shielding are described in Subsection 12.3.2.2.5. The accumulation room has lockable doors to minimize unauthorized entry and inadvertent exposure.

The bunkers have been evaluated for hydrogen gas generation resulting from the temporary storage of resin, specifically condensate polishing system (CPS) resin and steam generator blowdown system electrodeionization (EDI) unit resin. Hydrogen was selected as the most credible source of explosive gas generation. Based on table 3.1 of NUREG/CR 6673 other flammable gases formed by radiolysis in resin are insignificant in comparison to hydrogen. Methane was also considered, but was found not to be a credible source because the AP1000 CPS and EDI systems utilize resin beads which do not have the cellulose component that could support the growth of bacteria and methane production. Generation of flammable gases by processes such as biodegradation, decomposition and waste material interaction due to chemistry, was also determined to not be credible based on the waste forms intended for storage in the AP1000 radwaste bunkers; i.e., secondary side spent resin, and miscellaneous contaminated / activated components or tools.

The evaluation assumes two storage scenarios of the bounding amounts of CPS and EDI resins expected to be generated over one cycle of operation and then stored in a single, unventilated bunker for one year. The scenarios result in a maximum hydrogen concentration of less than 4 volume percent hydrogen in air, and conclude that there is no risk of radiolytic hydrogen gas generation that could result in the creation of a hazard within the stated assumptions. Although the evaluation is focused on storing a bounding amount of resin into only one bunker, all three bunkers are available for use.

The existing administrative controls in Subsections 11.2.1.2.5.2 and 13.5.2.2.5 limit the total cumulative radioactive inventory of unpackaged wastes allowed in the radwaste building and bunkers, and the existing radiation zoning and access requirements in Subsection 12.3.1.2 further restrict the amount and activities of resins that are allowed to be stored in the bunker. Therefore, a new evaluation for hydrogen gas generation resulting from the temporary storage of resin would only be needed in the unlikely event that storage of resins with total volume or activity higher than that of the evaluated resins, or for a longer storage period, is desired. The new evaluation would be needed to confirm the risk associated with potential hydrogen gas generation by demonstrating that the hydrogen concentration in the bunker air space will not exceed 4 volume percent hydrogen in air.

The heating and ventilating system for the radwaste building is described in Subsection 9.4.8.

11.4.3 System Safety Evaluation

The solid waste management system has no safety-related function and therefore requires no nuclear safety evaluation.

11.4.4 Tests and Inspections

Preoperational tests are conducted as described in Subsection 14.2.9. Tests are performed to demonstrate the capability to transfer ion exchange resins and deep bed filtration media from the ion exchangers and filters to the spent resin tanks or directly to a waste disposal container.

Preoperational tests of the solid waste management system components are performed to prepare the system for operation.

After plant operations begin, the operability and functional performance of the solid waste management system is periodically evaluated according to Regulatory Guide 1.143 by monitoring for abnormal or deteriorating performance during routine operations. Instruments and setpoints are also calibrated on a scheduled basis. The preventive maintenance program includes periodic inspection and maintenance of active components.

11.4.5 Quality Assurance

The quality assurance program for design, installation, procurement, and fabrication issues of the solid waste management system is in accordance with the overall quality assurance program described in Chapter 17.

Since the impact of radwaste systems on safety is limited, the extent of control required by Appendix B to 10 CFR Part 50 is similarly limited. Thus, a supplemental quality assurance program applicable to design, construction, installation and testing provisions of the solid radwaste system is established by procedures that complies with the guidance presented in Regulatory Guide 1.143.

11.4.6 Combined License Information for Solid Waste Management System Process Control Program

A Process Control Program (PCP) is developed and implemented in accordance with the recommendations and guidance of NEI 07-10A (Reference 201). The PCP describes the administrative and operational controls used for the solidification of liquid or wet solid waste and the dewatering of wet solid waste. Its purpose is to provide the necessary controls such that the final disposal waste product meets applicable federal regulations (10 CFR Parts 20, 50, 61, 71, and 49 CFR Part 173), state regulations, and disposal site waste form requirements for burial at a low level waste (LLW) disposal site that is licensed in accordance with 10 CFR Part 61.

Waste processing (solidification or dewatering) equipment and services may be provided by the plant or by third-party vendors. Each process used meets the applicable requirements of the PCP.

No additional onsite radwaste storage is required beyond that described in the DCD.

Table 13.4-201 provides milestones for PCP implementation.

11.4.6.1 Procedures

Operating procedures specify the processes to be followed to ship waste that complies with the waste acceptance criteria (WAC) of the disposal site, 10 CFR 61.55 and 61.56, and the requirements of third party waste processors.

Each waste stream process is controlled by procedures that specify the process for packaging, shipment, material properties, destination (for disposal or further processing), testing to verify compliance, the process to address non-conforming materials, and required documentation.

Where materials are to be disposed of as non-radioactive waste (as described in Subsection 11.4.2.3.3), final measurements of each package are performed to verify there has not been an accumulation of licensed material resulting from a buildup of multiple, non-detectable quantities. These measurements are obtained using sensitive scintillation detectors, or instruments of equal sensitivity, in a low-background area.

Procedures document maintenance activities, spill abatement, upset condition recovery, and training.

Procedures document the periodic review and revision, as necessary, of the PCP based on changes to the disposal site, WAC regulations, and third party PCPs.

11.4.6.2 Third Party Vendors

Third party equipment suppliers and/or waste processors are required to supply approved PCPs. Third party vendor PCPs describe compliance with Regulatory Guide 1.143 (Reference 7), Generic Letter 80-09 (Reference 8), and Generic Letter 81-39 (Reference 9). Third party vendor PCPs are referenced appropriately in the plant PCP before commencement of waste processing.

11.4.6.3 Long Term On-Site Storage Facility

Storage space for six-month's volume of packaged waste is provided in the radwaste building. Radioactive waste generated by VEGP Units 3 and 4 will normally be shipped to a licensed disposal or off-site storage facility. However, should disposal facilities or off-site storage facilities not be available, storage capacity will be expanded as described below to provide additional on-site storage for VEGP Units 3 and 4.

Additional on-site low-level radioactive waste (LLRW) storage capabilities are available if Class B and C waste cannot be disposed at a licensed disposal facility. An outside storage pad will be utilized to provide this capability. The VEGP Units 3 and 4 LLRW storage facility would be located outside the Protected Area (PA) in the Owner Controlled Area (OCA). The storage facility would be enclosed by an eight-foot high fence with locked gates and would be provided with area lighting. The storage of LLRW would be in high integrity containers (HICs) or other suitable containers that will not decay over time, which would be stored within shielded containers. The design of the storage facility will comply with the guidance of documents as identified in this section which is consistent with NUREG-0800, Appendix 11.4A. The design storage capacity is based on the expected generation in Table 11.4-1, industry experience that indicates approximately 100% of the Class B and C waste is expected to be in the form of wet waste, and volume minimization/reduction programs. The site waste management plan will include radioactive wet waste reduction initiatives for waste Class B and C.

The storage facility will be sited such that it could be sized to accommodate storage of Class B and C waste over the operating life of the plant and designed to accommodate future expansion as needed. Capacity would be added in phases based on the expected availability of off-site treatment and storage, and disposal facilities.

11.4.6.3.1 Outside Storage Pad Design Considerations

The following design considerations would be applied to the on-site LLRW storage facility: (References 202, 203, and 10):

- The location of the storage pad would meet the dose rate criteria of 40 CFR 190 and 10 CFR 20.1302 for both the site boundary and unrestricted area. The onsite storage will be located such that any additional dose contributes less than 1 mrem per year to the 40 CFR Part 190 limits. Onsite dose limits will be controlled per 10 CFR 20, including the ALARA principle of 10 CFR 20.1101.

- The outside storage pad would be an engineered feature designed to minimize settling and would be constructed of reinforced concrete or engineered gravel.

- The storage pad location would avoid natural or engineered surface drainage and be located at an elevation with regard to the site's design bases flood level.
- The storage pad would have a fence or other suitable security measures consistent with its location on the site.
- If the storage pad is used to store an aggregated category 1 or category 2 quantity of radioactive material (radioactive waste), then the 10 CFR Part 37 Physical Protection Program would be applied.
- The waste containers (typically high integrity containers) would be stored inside of a shielded container, typically consisting of reinforced concrete containers that provide radiation shielding and weather protection.
- The configuration of the storage shields would be arranged to be accessible from the perimeter road or from a center aisle using a mobile crane (if used).
- Personnel passages would be provided between rows of storage shields for access to the container for inspection.
- Adequate electrical power and lighting would be provided at the storage facility to allow power for tools, analytical equipment, sample pumps, radiation instruments, boroscope lights, etc.
- Fire protection, fire hydrants or fire extinguishers, for vehicle fires should be provided.

11.4.6.3.2 Outside Storage Pad Operating Considerations

The following operating considerations for on-site storage pad operations are based on NRC and Industry guidance (References 202, 203, and 10) and would be included in operating procedures:

- Identification of the arrangement of storage shields, waste handling, storage methods, safety analysis limitations, accident conditions, and off site dose calculations.
- The use of hold-down devices to secure the waste container during severe environmental events, such as strong wind would be provided for, unless the waste container and storage shields can be demonstrated to remain in place without restraints during such events.
- The waste container selected for use is compatible with the waste form stored to ensure waste container integrity.
- Shielding requirements would be determined before the waste container is loaded into a storage shield to eliminate the radiation exposure associated with adding additional shielding.
- If additional shield walls around the perimeter of the storage pad are required, the shield walls would be easily installed and capable of being moved.
- Periodic inspection and testing requirements for outside storage pad operation would include the following:
  - Dose rate and contamination surveys in accordance with health physics procedures.
  - Sampling of storage shields for water and storage shields containing dewatered resin for explosive gas build-up.

  - Visual inspection of selected waste containers in storage to detect unexpected changes / container integrity. (Remote inspection methods and the use of high integrity containers will allow reduced scope for ALARA practices.)

  - Defoliation and general condition of the onsite storage pad.

- Total radioactive material inventory limits would be established to demonstrate compliance with the design limits for the storage area, dose limits for members of the public and safety features or measures provided by the storage module.

- The contents of records for inventory controls, monitoring and inspection and other relevant data are maintained and retrievable.

- Operational safety features for handling waste containers and storage shields would include the training required for personnel operating cranes, forklifts, tie downs and heavy equipment during any waste container/storage shield transfer activity.

- Criteria for the end of storage period that would include waste container inspection and additional reprocessing required prior to shipment offsite.

11.4.7 References

1. "Shippers-General Requirements for Shipments and Packagings," 49 CFR 173.

2. "Packaging and Transportation of Radioactive Material," 10 CFR 71.

3. "Domestic Licensing of Production and Utilization Facilities," 10 CFR 50.

4. "Standards for Protection Against Radiation," 10 CFR 20.

5. "Licensing Requirements for Land Disposal of Radioactive Waste," 10 CFR 61.

6. "USNRC Technical Position on Waste Form," Rev. 1, January 1991.

7. Regulatory Guide 1.143, "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants."

8. USNRC Generic Letter GL-80-009, "Low Level Radioactive Waste Disposal," dated January 29, 1980.

9. USNRC Generic Letter GL-81-039, "NRC Volume Reduction Policy (Generic Letter No. 81-39)," dated November 30, 1981.

10. USNRC Generic Letter GL-81-038, "Storage of Low-Level Radioactive Wastes at Power Reactor Sites," dated November 10, 1981.

11. USNRC, "Minimization of Contamination," 10 CFR 20.1406.

201. NEI 07-10A, “Generic FSAR Template Guidance for Process Control Program (PCP),” Revision 0, March 2009 (ML091460627).

202. Technical Report 1018644 “Guidelines for Operating an Interim On Site Low Level Radioactive Waste Storage Facility,” Revision 1, EPRI, Palo Alto, CA, February 2009.

203. Regulatory Issue Summary 2008-32 “Interim Low Level Radioactive Waste Storage at Reactor Sites,” December 2008.

Table 11.4-1
Estimated Solid Radwaste Volumes

Source	Expected Generation (ft^3/yr)	Expected Shipped Solid (ft^3/yr)	Maximum Generation (ft^3/yr)	Maximum Shipped Solid (ft^3/yr)
Wet Wastes				
Primary Resins (includes spent resins and wet activated carbon)	400(2)	510	1700(4)	2160
Chemical	350	20	700	40
Mixed Liquid	15	17	30	34
Condensate Polishing Resin(1)	0	0	331(5)	415
Steam Generator Blowdown(1)(6) Material (Resin and Membrane)	0	0	540(5)	680
Wet Waste Subtotals	**765**	**547**	**3301**	**3329**
Dry Wastes				
Compactible Dry Waste	4750	1010	7260	1550
Non-Compactible Solid Waste	234	373	567	910
Mixed Solid	5	7.5	10	15
Primary Filters (includes high activity and low activity cartridges)	5.2(3)	26	9.4(3)	69
Dry Waste Subtotals	**4994**	**1417**	**7846**	**2544**
TOTAL WET & DRY WASTES	**5759**	**1964**	**11147**	**5873**

Notes:

1. Radioactive secondary resins and membranes result from primary to secondary systems leakage (e.g., SG tube leak).
2. Estimated activity basis is ANSI 18.1 source terms in reactor coolant.
3. Estimated activity basis is breakdown and transfer of 10% of resin from upstream ion exchangers.
4. Reactor coolant source terms corresponding to 0.25% fuel defects.
5. Estimated activity basis from Tables 11.1-5, 11.1-7 and 11.1-8 and a typical 30 day process run time, once per refueling cycle.
6. Estimated volume and activity used for conservatism. Resin and membrane will be removed with the electrodeionization units and not stored as wet waste. See Subsection 10.4.8.

Table 11.4-2 (Sheet 1 of 2)
Expected Annual Curie Content of Primary Influents

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Br-83	—	—
Br-84	1.98E-01	1.98E-02
Br-85	—	—
I-129	—	—
I-130	—	—
I-131	1.42E+02	1.42E+01
I-132	1.04E+01	1.04E+00
I-133	5.29E+01	5.29E+00
I-134	6.89E+00	6.89E-01
I-135	3.49E+01	3.49E+00
Rb-86	—	—
Rb-88	9.72E-01	9.72E-02
Rb-89	—	—
Cs-134	3.06E+02	3.06E+01
Cs-136	3.16E+00	3.16E-01
Cs-137	4.64E+02	4.64E+01
Cs-138	—	—
Ba-137m	4.44E+02	4.44E+01
Cr-51	3.21E+01	3.21E+00
Mn-54	1.04E+02	1.04E+01
Mn-56	—	—
Fe-55	1.04E+02	1.04E+01
Fe-59	5.00E+00	5.00E-01
Co-58	2.05E+02	2.05E+01
Co-60	9.59E+01	9.59E+00
Zn-65	3.02E+01	3.02E+00
Sr-89	2.67E+00	2.67E-01
Sr-90	1.13E+00	1.13E-01
Sr-91	1.72E-01	1.72E-02
Sr-92	—	—
Ba-140	6.29E+01	6.29E+00
Y-90	—	—
Y-91m	—	—
Y-91	3.74E-06	3.74E-07

Table 11.4-2 (Sheet 2 of 2)
Expected Annual Curie Content of Primary Influents

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Y-92	—	—
Y-93	—	—
La-140	—	—
Zr-95	2.80E-04	2.80E-05
Nb-95	—	—
Mo-99	—	—
Tc-99m	—	—
Ru-103	5.35E-03	5.35E-04
Ru-106	6.37E-02	6.37E-03
Rh-103m	—	—
Rh-106	—	—
Te-132	—	—
Te-125m	—	—
Te-127m	—	—
Te-127	—	—
Te-129m	1.36E-04	1.36E-05
Te-129	—	—
Te-131m	—	—
Total:	2.11E+03	2.11E+02

Note:
Values shown as "—" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-3 (Sheet 1 of 2)
Maximum Annual Curie Content of Primary Influents

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Br-83	7.03E+00	7.03E-01
Br-84	3.42E-01	3.42E-02
Br-85	3.74E-03	3.74E-04
I-129	3.44E-03	3.44E-04
I-130	9.00E+00	9.00E-01
I-131	5.45E+03	5.45E+02
I-132	1.97E+02	1.97E+01
I-133	1.66E+03	1.66E+02
I-134	7.31E+00	7.31E-01
I-135	3.81E+02	3.81E+01
Rb-86	2.97E+01	2.97E+00
Rb-88	2.52E+01	2.52E+00
Rb-89	9.83E-01	9.83E-02
Cs-134	9.57E+03	9.57E+02
Cs-136	1.72E+03	1.72E+02
Cs-137	9.14E+03	9.14E+02
Cs-138	1.06E+01	1.06E+00
Ba-137m	8.66E+03	8.66E+02
Cr-51	3.95E+01	3.95E+00
Mn-54	1.18E+02	1.18E+01
Mn-56	4.75E+01	4.75E+00
Fe-55	1.14E+02	1.14E+01
Fe-59	5.84E+00	5.84E-01
Co-58	3.03E+02	3.03E+01
Co-60	2.45E+02	2.45E+01
Zn-65	—	—
Sr-89	4.56E+01	4.56E+00
Sr-90	1.09E+01	1.09E+00
Sr-91	1.16E+00	1.16E-01
Sr-92	9.96E-02	9.96E-03
Ba-140	1.19E+01	1.19E+00
Y-90	1.07E+01	1.07E+00
Y-91m	3.48E-01	3.48E-02
Y-91	5.48E-01	5.48E-02

Table 11.4-3 (Sheet 2 of 2)
Maximum Annual Curie Content of Primary Influents

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Y-92	4.19E-02	4.19E-03
Y-93	9.07E-05	9.07E-06
La-140	1.07E+01	1.07E+00
Zr-95	—	—
Nb-95	—	—
Mo-99	—	—
Tc-99m	—	—
Ru-103	—	—
Ru-106	—	—
Rh-103m	—	—
Rh-106	—	—
Te-132	—	—
Te-125m	—	—
Te-127m	—	—
Te-127	—	—
Te-129m	—	—
Te-129	—	—
Te-131m	—	—
Total:	3.78E+04	3.78E+03

Note:
Values shown as "—" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-4 (Sheet 1 of 2)
Expected Annual Curie Content of Shipped Primary Wastes

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Br-83	—	—
Br-84	—	—
Br-85	—	—
I-129	—	—
I-130	—	—
I-131	6.04E-02	6.04E-03
I-132	—	—
I-133	—	—
I-134	—	—
I-135	—	—
Rb-86	—	—
Rb-88	—	—
Rb-89	—	—
Cs-134	2.81E+02	2.81E+01
Cs-136	2.61E-02	2.61E-03
Cs-137	4.61E+02	4.61E+01
Cs-138	—	—
Ba-137m	4.61E+02	4.61E+01
Cr-51	3.37E+00	3.37E-01
Mn-54	8.50E+01	8.50E+00
Mn-56	—	—
Fe-55	9.75E+01	9.75E+00
Fe-59	1.23E+00	1.23E-01
Co-58	8.51E+01	8.51E+00
Co-60	9.29E+01	9.29E+00
Zn-65	2.34E+01	2.34E+00
Sr-89	8.05E-01	8.05E-02
Sr-90	1.13E+00	1.13E-01
Sr-91	—	—
Sr-92	—	—
Ba-140	4.80E-01	4.80E-02
Y-90	1.13E+00	1.13E-01
Y-91m	—	—
Y-91	4.03E-04	4.03E-05

Table 11.4-4 (Sheet 2 of 2)
Expected Annual Curie Content of Shipped Primary Wastes

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Y-92	—	—
Y-93	—	—
La-140	5.52E-01	5.52E-02
Zr-95	1.09E-04	1.09E-05
Nb-95	1.31E-04	1.31E-05
Mo-99	—	—
Tc-99m	—	—
Ru-103	1.10E-03	1.10E-04
Ru-106	5.38E-02	5.38E-03
Rh-103m	1.11E-03	1.11E-04
Rh-106	5.38E-02	5.38E-03
Te-132	—	—
Te-125m	—	—
Te-127m	—	—
Te-127	—	—
Te-129m	2.10E-05	2.10E-06
Te-129	1.37E-05	1.37E-06
Te-131m	—	—
Total:	1.60E+03	1.60E+02

Note:
Values shown as "—" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-5 (Sheet 1 of 2)
Maximum Annual Curie Content of Shipped Primary Wastes

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Br-83	—	—
Br-84	—	—
Br-85	—	—
I-129	3.44E-03	3.44E-04
I-130	—	—
I-131	4.10E+02	4.10E+01
I-132	—	—
I-133	6.27E-08	6.27E-09
I-134	—	—
I-135	—	—
Rb-86	9.76E+00	9.76E-01
Rb-88	—	—
Rb-89	—	—
Cs-134	9.31E+03	9.31E+02
Cs-136	3.47E+02	3.47E+01
Cs-137	9.13E+03	9.13E+02
Cs-138	—	—
Ba-137m	9.13E+03	9.13E+02
Cr-51	1.86E+01	1.86E+00
Mn-54	1.10E+02	1.10E+01
Mn-56	—	—
Fe-55	1.12E+02	1.12E+01
Fe-59	3.66E+00	3.66E-01
Co-58	2.26E+02	2.26E+01
Co-60	2.42E+02	2.42E+01
Zn-65	—	—
Sr-89	3.06E+01	3.06E+00
Sr-90	1.09E+01	1.09E+00
Sr-91	—	—
Sr-92	—	—
Ba-140	2.35E+00	2.35E-01
Y-90	1.09E+01	1.09E+00
Y-91m	—	—
Y-91	3.90E-01	3.90E-02

Table 11.4-5 (Sheet 2 of 2)
Maximum Annual Curie Content of Shipped Primary Wastes

Isotope	Primary Resin Total Ci/yr	Primary Filter Total Ci/yr
Y-92	—	—
Y-93	—	—
La-140	2.70E+00	2.70E-01
Zr-95	—	—
Nb-95	—	—
Mo-99	—	—
Tc-99m	—	—
Ru-103	—	—
Ru-106	—	—
Rh-103m	—	—
Rh-106	—	—
Te-132	—	—
Te-125m	—	—
Te-127m	—	—
Te-127	—	—
Te-129m	—	—
Te-129	—	—
Te-131m	—	—
Total:	2.91E+04	2.91E+03

Note:
Values shown as "—" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-6 (Sheet 1 of 2)
Expected Annual Curie Content of Secondary Waste as Generated

Isotope	Secondary Resin Total Ci/yr
Na-24	1.83E-02
Cr-51	4.29E-02
Mn-54	2.95E-02
Fe-55	2.35E-02
Fe-59	4.49E-03
Co-58	7.78E-02
Co-60	1.03E-02
Zn-65	9.56E-03
Br-84	2.22E-05
Rb-88	8.99E-05
Sr-89	2.24E-03
Sr-90	2.37E-04
Sr-91	2.11E-04
Y-90	2.06E-04
Y-91	2.53E-04
Y-91m	1.82E-04
Y-93	9.80E-04
Zr-95	6.53E-03
Nb-95	5.19E-03
Nb-95m	4.74E-03
Mo-99	1.52E-02
Tc-99m	1.41E-02
Ru-103	1.13E-01
Ru-106	1.65E+00
Rh-103m	1.39E-01
Rh-106	2.11E+00
Ag-110	2.12E-02
Ag-110m	2.45E-02
Te-129	2.29E-03
Te-129m	2.79E-03
Te-131	1.14E-03
Te-131m	1.42E-03
Te-132	4.74E-04

Table 11.4-6 (Sheet 2 of 2)
Expected Annual Curie Content of Secondary Waste as Generated

Isotope	Secondary Resin Total Ci/yr
I-131	1.70E-01
I-132	7.93E-03
I-133	5.23E-02
I-134	1.18E-03
I-135	2.56E-02
Xe-131m	—
Xe-133	—
Xe-135	—
Cs-134	2.50E-01
Cs-135	4.70E-10
Cs-136	1.48E-02
Cs-137	3.39E-01
Ba-136m	1.39E-02
Ba-137m	3.42E-01
Ba-140	1.17E-01
La-140	1.47E-01
Ce-141	2.13E-03
Ce-143	2.91E-03
Ce-144	7.35E-02
Pr-143	2.04E-03
Pr-144	6.37E-02
Total:	5.96E+00

Note:
Values shown as "—" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-7 (Sheet 1 of 2)
Maximum Annual Curie Content of Secondary Waste as Generated

Isotope	Secondary Resin Total Ci/yr
Na-24	4.62E-04
Cr-51	5.17E-01
Mn-54	3.55E-01
Mn-56	2.24E-01
Fe-55	2.78E-01
Fe-59	5.88E-02
Co-58	9.25E-01
Co-60	1.23E-01
Br-83	3.73E-02
Br-84	1.41E-03
Br-85	1.64E-06
Kr-83m	—
Kr-85	—
Kr-85m	—
Rb-88	4.56E-02
Rb-89	1.53E-03
Sr-89	9.10E-01
Sr-90	5.00E-02
Sr-91	2.13E-02
Sr-92	7.25E-04
Y-90	4.60E-02
Y-91	4.34E-02
Y-91m	2.11E-02
Y-92	2.66E-03
Y-93	1.04E-03
Zr-95	7.74E-02
Nb-95	8.25E-02
Nb-95m	5.52E-02
Mo-99	1.52E+01
Tc-99m	1.68E+01
Ru-103	6.28E-02
Ru-103m	3.87E-02
Rh-103m	6.29E-02
Rh-106	5.95E-02

Table 11.4-7 (Sheet 2 of 2)
Maximum Annual Curie Content of Secondary Waste as Generated

Isotope	Secondary Resin Total Ci/yr
Ag-110	1.34E-02
Ag-110m	2.24E-01
Te-129	1.19E+00
Te-129m	1.10E+00
Te-131	2.35E+00
Te-131m	2.01E-01
Te-132	6.75E+00
Te-134	1.49E-03
I-130	1.19E-01
I-131	1.37E+02
I-132	6.77E+00
I-133	2.51E+01
I-134	4.99E-02
I-135	3.99E+00
Xe-131m	—
Xe-133	—
Xe-135	—
Cs-134	6.90E+02
Cs-135	6.16E-08
Cs-136	5.15E+02
Cs-137	5.00E+02
Cs-138	3.41E-02
Ba-136m	6.35E+02
Ba-137m	5.14E+02
Ba-140	2.83E-01
La-140	3.31E-01
Ce-141	6.42E-02
Ce-143	4.94E-03
Ce-144	6.33E-02
Pr-143	4.63E-02
Pr-144	6.33E-02
Total:	3.08E+03

Note:
Values shown as "—" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-8 (Sheet 1 of 2)
Expected Annual Curie Content of Shipped Secondary Wastes

Isotope	Secondary Resin Total Ci/yr
Na-24	—
Cr-51	4.55E-03
Mn-54	2.40E-02
Fe-55	2.19E-02
Fe-59	1.14E-03
Co-58	3.25E-02
Co-60	9.95E-03
Zn-65	7.42E-03
Br-84	—
Rb-88	—
Sr-89	6.86E-04
Sr-90	2.36E-04
Sr-91	—
Y-90	2.31E-04
Y-91	6.71E-09
Y-91m	—
Y-93	—
Zr-95	2.52E-03
Nb-95	4.06E-03
Nb-95m	2.32E-03
Mo-99	—
Tc-99m	—
Ru-103	2.34E-02
Ru-106	1.38E+00
Rh-103m	2.87E-02
Rh-106	1.77E+00
Ag-110	1.66E-02
Ag-110m	1.92E-02
Te-129	3.44E-04
Te-129m	4.48E-04
Te-131	—
Te-131m	—

Table 11.4-8 (Sheet 2 of 2)
Expected Annual Curie Content of Shipped Secondary Wastes

Isotope	Secondary Resin Total Ci/yr
Te-132	—
I-131	7.32E-05
I-132	—
I-133	—
I-134	—
I-135	—
Xe-131m	—
Xe-133	—
Xe-135	—
Cs-134	2.31E-01
Cs-135	4.86E-10
Cs-136	1.56E-04
Cs-137	3.36E-01
Ba-136m	1.47E-04
Ba-137m	3.40E-01
Ba-140	8.97E-04
La-140	1.05E-03
Ce-141	3.13E-04
Ce-143	—
Ce-144	5.91E-02
Pr-143	2.38E-05
Pr-144	5.12E-02
Total:	4.38E+00

Note:
Values shown as "—" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-9 (Sheet 1 of 2)
Maximum Annual Curie Content of Shipped Secondary Wastes

Isotope	Secondary Resin Total Ci/yr
Na-24	—
Cr-51	5.47E-02
Mn-54	2.89E-01
Mn-56	—
Fe-55	2.60E-01
Fe-59	1.50E-02
Co-58	3.87E-01
Co-60	1.19E-01
Br-83	—
Br-84	—
Br-85	—
Kr-83m	—
Kr-85	—
Kr-85m	—
Rb-88	—
Rb-89	—
Sr-89	2.79E-01
Sr-90	4.96E-02
Sr-91	—
Sr-92	—
Y-90	5.12E-02
Y-91	1.12E-06
Y-91m	—
Y-92	—
Y-93	—
Zr-95	2.98E-02
Nb-95	5.19E-02
Nb-95m	2.70E-02
Mo-99	2.72E-09
Tc-99m	3.04E-09
Ru-103	1.30E-02
Ru103m	3.27E-02

Table 11.4-9 (Sheet 2 of 2)
Maximum Annual Curie Content of Shipped Secondary Wastes

Isotope	Secondary Resin Total Ci/yr
Rh-103m	1.30E-02
Rh-106	5.03E-02
Ag-110	1.05E-02
Ag-110m	1.76E-01
Te-129	1.92E-01
Te-129m	1.77E-01
Te-131	—
Te-131m	—
Te-132	2.90E-08
Te-134	—
I-130	—
I-131	5.94E-02
I-132	2.36E-08
I-133	—
I-134	—
I-135	—
Xe-131m	—
Xe-133	—
Xe-135	—
Cs-134	6.35E+02
Cs-135	6.36E-08
Cs-136	5.42E+00
Cs-137	4.98E+02
Cs-138	—
Ba-136m	6.69E+00
Ba-137m	5.11E+02
Ba-140	2.18E-03
La-140	2.87E-03
Ce-141	9.41E-03
Ce-143	—
Ce-144	5.08E-02
Pr-143	4.75E-04
Pr-144	5.08E-02
Total:	1.66E+03

Note:
Values shown as "—" Ci/yr are those calculated to be lower than 1.0E-10 Ci/yr, and thus considered to have insignificant contributions to total.

Table 11.4-10 (Sheet 1 of 2)
Component Data — Solid Waste Management System (Nominal)

Tanks	
Spent resin tank	
Number	2
Total volume (ft^3)	300
Type	Vertical, conical bottom, dished top
Design pressure (psig)	15
Design temperature (°F)	150
Material	Stainless steel
Pumps	
Resin mixing pump	
Number	1
Type	Pneumatic diaphragm
Design pressure (psig)	125
Design temperature (°F)	150
Design flow rate (gpm)	100
Air supply pressure (psig)	100
Air consumption (scfm)	130
Material	Stainless steel housing, Buna N diaphragms
Resin transfer pump	
Number	1
Type	Material handling positive displacement
Design pressure (psig)	125
Design temperature (°F)	150
Design flow rate (gpm)	100
Material	Stainless steel housing, Buna N flexible parts

Table 11.4-10 (Sheet 2 of 2)
Component Data — Solid Waste Management System (Nominal)

Filters	
Resin fines filter	
Number	1
Type	Filter cartridge for inside to outside flow
Design pressure (psig)	150
Design temperature (°F)	150
Design flowrate (gpm)	120
Filtration rating	Up to 20 microns
Material	Stainless steel housing and pleated polypropylene cartridge with stainless steel screen outer jacket
Sampler	
Resin sampling device	
Number	1
Type	Inline sampler, positive displacement sample collection and portable pig for sample jar
Material	Stainless steel and EPDM wetted parts

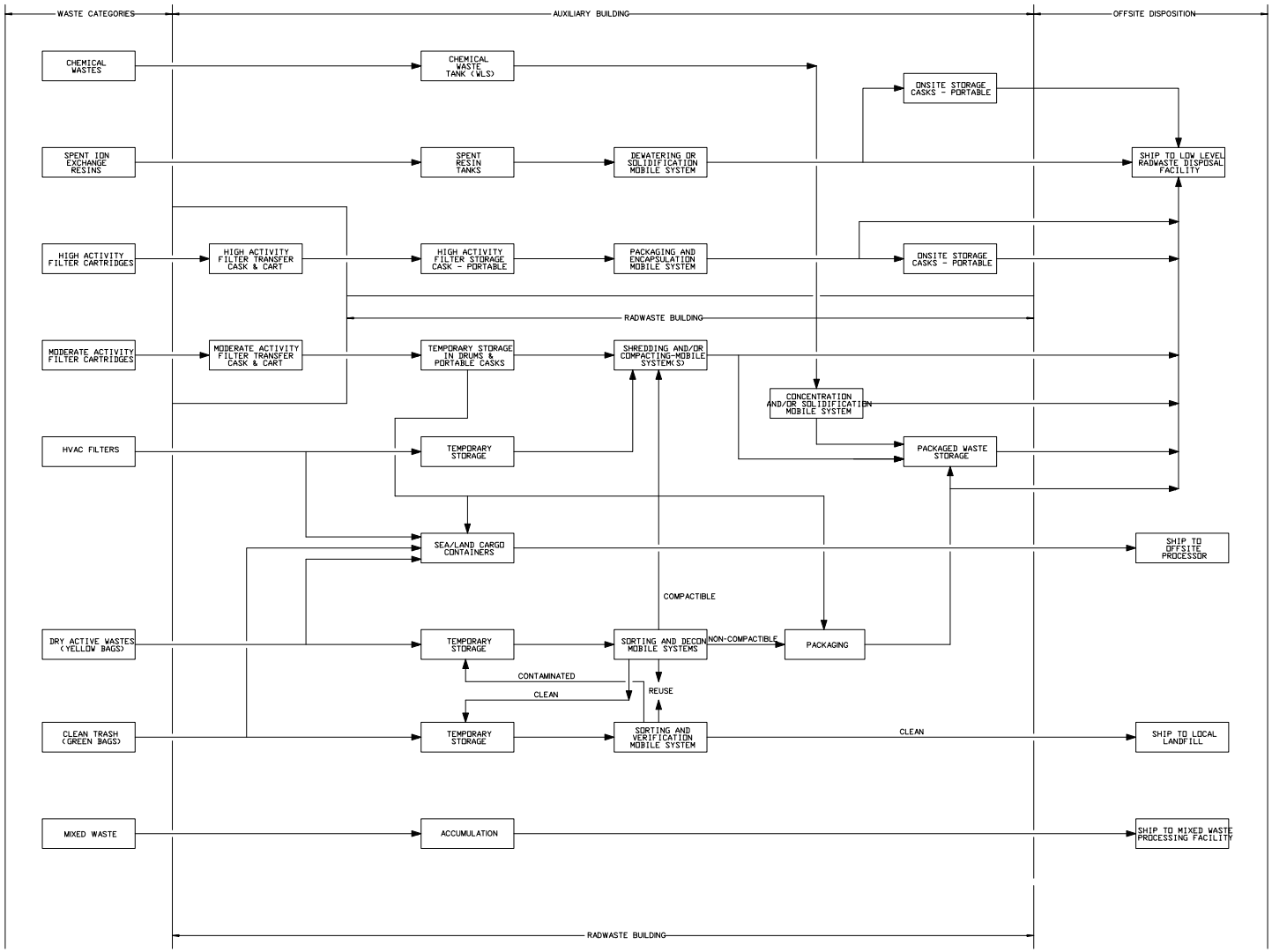


Figure 11.4-1
Waste Processing System
Flow Diagram

11.5 Radiation Monitoring

The radiation monitoring system (RMS) provides plant effluent monitoring, process fluid monitoring, airborne monitoring, and continuous indication of the radiation environment in plant areas where such information is needed. Radiation monitors that have a safety-related function are qualified environmentally, seismically, or both. Class 1E radiation monitors conform to the separation criteria described in Subsection 8.3.2 and to the fire protection criteria described in Subsection 9.5.1. Equipment qualification requirements, including seismic qualification requirements, and general location information for radiation monitors are listed in Section 3.11. Seismic Categories for the buildings housing radiation monitors are listed in Section 3.2.

The radiation monitoring system is installed permanently and operates in conjunction with regular and special radiation survey programs to assist in meeting applicable regulatory requirements. The radiation monitoring system for the VFS plant is designed in accordance with guidelines in ANSI N13.1-1969. The use of alternate sampling systems such as single point shrouded nozzles is also an acceptable method for obtaining representative samples. The liquid effluent monitors are designed in accordance with ANSI-N42.18-1980.

The radiation monitoring system is divided functionally into two subsystems:

- Process, airborne, and effluent radiological monitoring and sampling
- Area radiation monitoring

11.5.1 Design Basis

11.5.1.1 Safety Design Basis

While the radiation monitoring system is primarily a surveillance system, certain detector channels perform safety-related functions. The components used in these channels meet the equipment qualification requirements for safety-related equipment as described in Subsection 7.1.4.

Channel and equipment redundancy is provided for safety-related monitors to maintain the safety-related function in case of a single failure.

The design objectives of the radiation monitoring system during postulated accidents are:

- Initiate containment air filtration isolation in the event of abnormally high radiation inside the containment (High-1)
- Initiate normal residual heat removal system suction line containment isolation in the event of abnormally high radiation inside the containment (High-2)
- Initiate main control room supplemental filtration in the event of abnormally high particulate, iodine, or gaseous radioactivity in the main control room supply air (High-1)
- Initiate main control room ventilation isolation and actuate the main control room emergency habitability system in the event of abnormally high particulate or iodine radioactivity in the main control room supply air (High-2)
- Provide long-term post-accident monitoring (using both safety-related and nonsafety-related monitors)

The scope of the radiation monitoring system for post-accident monitoring is set forth in General Design Criterion 64 and in the provisions of Regulatory Guide 1.97.

11.5.1.2 Power Generation Design Basis

The radiation monitoring system is designed to support the requirements of 10 CFR 20 and to provide:

- Equipment to meet the applicable regulatory requirements for both normal operation and transient events
- Data to aid plant health physics personnel in limiting release of radioactivity to the environment and limiting exposure of operation and maintenance personnel to meet ALARA (as-low-as-reasonably-achievable) guidance
- Early indication of a system or equipment malfunction that could result in excessive radiation dose to plant personnel or lead to plant damage
- Data collection and data storage to support compliance reporting for the applicable NRC requirements and guidelines, such as General Design Criterion 64 and Regulatory Guide 1.21 and Regulatory Guide 4.15, Revision 1.
- Exhausts to the environment from the personnel areas in the annex building, electrical and mechanical equipment rooms in the annex and auxiliary buildings, and the diesel generator rooms will not be radioactive because they contain no radioactive materials. These ventilation exhausts are not monitored.

11.5.2 System Description

11.5.2.1 Radiation Monitoring System

The radiation monitoring system uses distributed radiation monitors, where each radiation monitor consists of one or more radiation detectors and a dedicated radiation processor.

Each radiation processor receives, averages and stores radiation data and transmits data to the data display and processing system (which, in turn, transmits data to the plant control system) or to the protection and safety monitoring system (for safety-related monitors) for control (as required), display and recording. These alarms include: low (fail), alert, and high. Storage of radiation readings is provided.

Each radiation detector, except the in-duct radiation detectors and the containment high range ion chambers, has a check source that is actuated from the associated local radiation processor. The check source is used to verify detector and monitor operation. The check source is shielded to meet ALARA requirements, and returns to its fully retracted/shielded position upon loss of actuator power. The in-duct radiation detector operation may be checked using an internal LED to simulate light pulses emitted in response to radiation. The containment high range monitors have an internal source that provides a minimum reading; loss of signal from the detector indicates detector inoperability.

Radiation monitoring data, including alarm status, are provided to AP1000 operators via the plant control system (and the protection and safety monitoring system for Class 1E monitors). The information is available in either counts per minute (count rate), microCuries/cc (activity concentration), or R/hr (radiation dose rate).

Safety-related channels are environmentally qualified and are powered from the Class 1E dc and uninterruptible power supply system. Nonsafety-related Regulatory Guide 1.97 channels are powered by non-Class 1E dc and uninterruptible power supply system. Other nonsafety-related channels are powered by non-Class 1E ac power.

11.5.2.2 Monitor Functional Description

The process and effluent radiological monitoring and sampling subsystem provides radiation monitoring for the four functional classifications listed below. Individual monitors may provide functionality in more than one of these classifications.

- Fluid process monitors determine concentrations of radioactive material in plant fluid systems
- Airborne monitors provide operators with information on concentrations of radioactivity at various points in the ventilation system, providing information on airborne concentrations in the plant
- Liquid and gaseous effluent monitors measure radioactive materials discharged to the environs
- Post-accident monitors monitor potential pathways for release of radioactive materials during accident conditions

The area radiation monitoring subsystem provides plant personnel information on radiation at fixed locations in AP1000. Post-accident monitoring functions are also performed by certain area monitors.

11.5.2.3 Monitor Descriptions

For offline gaseous monitors, the radiation monitor includes a low pressure drop flow sensor suitable for measuring the sample flow. The radiation processor receives an analog signal input from this flow sensor. This signal is used by the radiation processor to control sample flow. The analog signal is transmitted to the plant control system (protection and safety monitoring system for safety-related monitors). For offline liquid monitors, a flow indicator is provided for manual adjustment of the flow.

Those airborne radiation monitors which monitor plant areas which may be occupied by plant personnel will be capable of detecting 10 DAC-hours. The specific radiation monitors which are included in this category are identified in Table 11.5-1.

11.5.2.3.1 Fluid Process Monitors

Steam Generator Blowdown Radiation Monitors

The steam generator blowdown radiation monitors (BDS-JE-RE010, RE011) measure the concentration of radioactive material in the blowdown from the steam generators. One measures radiation in the purification process before it is returned to the condensate system. The other measures radioactivity in the blowdown system electrodeionization reject (waste stream) before it is discharged to the waste water system. The presence of radioactive material in the steam generator blowdown indicates a leak between the primary side and the secondary side of the steam generator. Refer to Subsection 5.2.5 for details of leakage monitoring and to Subsections 10.4.8 and 11.2 for process system details. The steam generator blowdown radiation monitors meet the guidelines of Regulatory Guide 1.97 as discussed in Appendix 1A and Section 7.5.

AP1000 has two steam generators, each of which has a blowdown line. Each blowdown line has a heat exchanger upstream of the blowdown flow control valve. The steam generator blowdown

radiation detectors are located in the lines downstream of these heat exchangers. Therefore, the radiation monitors do not require a sample cooler.

When its predetermined setpoint is exceeded, each steam generator blowdown radiation monitor initiates an alarm in the main control room, initiates closure of the blowdown system train isolation valves and the steam generator blowdown flow control valves, and diverts flow to the liquid radwaste system.

The steam generator blowdown radiation monitors use inline gamma-sensitive, thallium-activated, sodium iodide scintillation detectors. The steam generator blowdown radiation monitor detector range and principal isotopes are listed in Table 11.5-1.

The arrangement for the steam generator blowdown radiation monitor is shown in Figure 11.5-1.

Component Cooling Water System Radiation Monitor

The component cooling water system radiation monitor (CCS-JE-RE001) measures the concentration of radioactive material in the component cooling water system. Radioactive material in the component cooling water system provides indication of leakage. Refer to Subsection 5.2.5 for details of leakage monitoring and to Subsection 9.2.2 for process system details.

If the concentration of radioactive materials exceeds a predetermined setpoint, the component cooling water system radiation monitor initiates an alarm in the main control room.

The component cooling water system radiation monitor is an offline monitor that uses a gamma-sensitive, thallium-activated, sodium iodide scintillation detector. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the component cooling water system radiation monitor is shown in Figure 11.5-7.

Main Steam Line Radiation Monitors

The main steam line radiation monitors (SGS-JE-RE026A/B and SGS-JE-RE027A/B) measure the concentration of radioactive materials in the two main steam lines. Additionally, the main steam line radioisotope concentration data are used to calculate releases to the environment if the steam generator safety relief or power operated relief valves release steam to the atmosphere. The main steam line radiation monitors (SGS-JE-RE026A and SGS-JE-RE027A) meet the guidelines of Regulatory Guide 1.97 as discussed in Appendix 1A and Section 7.5. If the concentration of radioactive materials exceeds a predetermined setpoint, the main steam line radiation monitors initiate alarms in the main control room.

The main steam line radiation monitors are positioned adjacent to the steam lines. Each monitor detector shield is arranged so that the detector sensitive volume is exposed to the radiation originating inside the steam line on which it is located, and is shielded from radiation originating in the other steam line. Radioactive material in the main steam line provides early indication of leakage in the form of a steam generator tube leak. Refer to Subsection 5.2.5 for details of leakage monitoring and to Section 10.3 for process system details.

The main steam line radiation monitor detectors use gamma-sensitive detectors.

Each main steam line radiation monitor range and principal isotopes are listed in Table 11.5-1.

The arrangement for a main steam line radiation monitor is shown in Figure 11.5-8.

Service Water Blowdown Radiation Monitor

The service water blowdown radiation monitor (SWS-JE-RE008) measures the concentration of radioactive materials in the blowdown flow from the service water system. Upstream of the radiation monitor, local grab sampling is available.

The service water blowdown radiation monitor initiates an alarm in the main control room if the concentration of radioactive materials exceeds a predetermined setpoint. Following the alarm, the operator can manually isolate the blowdown flow. Refer to Subsection 9.2.1 for system details.

The service water blowdown monitor is an inline monitor using a gamma-sensitive, thallium-activated, sodium iodide scintillation detector. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the service water blowdown radiation monitor is shown in Figure 11.5-1.

Primary Sampling System Liquid Sample Radiation Monitor

The primary sampling system (PSS) liquid sample radiation monitor (PSS-JE-RE050) measures and indicates the concentration of radioactive materials in the samples from the reactor coolant system. The liquid sample radiation monitor's primary function is to indicate elevated sample radiation levels following a design basis or severe accident. High radiation levels show the need for sample dilution to limit operator exposure during sampling and sample transport for analysis. The monitor may also be used to provide early indication of a significant increase in the radioactivity of the reactor coolant indicating a possible fuel cladding breach. When a predetermined setpoint is exceeded, the primary sampling system liquid sample radiation monitor isolates the sample flow by closing the outside containment isolation valve and initiates an alarm in the main control room and locally to alert the operator. Refer to Subsection 9.3.3 for system details.

The primary sampling system liquid sample radiation monitor utilizes a gamma-sensitive radiation detector that is adjacent to the sampling line immediately downstream of the sample cooler. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the primary sampling system liquid sample radiation monitor is shown in Figure 11.5-8.

Primary Sampling System Gaseous Sample Radiation Monitor

The primary sampling system gaseous sample radiation monitor (PSS-JE-RE052) measures the radiation from gaseous samples taken from containment atmosphere. The gaseous sample radiation monitor is used to provide indication of significant radioactivity in the gaseous sample being taken and the need for dilution of the sample to limit operator exposure during sampling and transport for analysis. When a predetermined setpoint is exceeded, the primary sampling system gaseous sample radiation monitor initiates an alarm locally and in the main control room to alert the operator. Refer to Subsection 9.3.3 for system details.

The primary sampling system gaseous sample radiation monitor utilizes a gamma-sensitive radiation detector that is adjacent to the sampling line immediately upstream of the sample bottle. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the primary sampling system gaseous sample radiation monitor is shown in Figure 11.5-8.

Main Control Room Supply Air Duct Radiation Monitors

The main control room supply air duct radiation monitors (particulate detectors VBS-JE-RE001A and VBS-JE-RE001B, iodine detectors VBS-JE-RE002A and VBS-JE-RE002B, and noble gas detectors VBS-JE-RE003A and VBS-JE-RE003B) are offline monitors that continuously measure the concentration of radioactive materials in the air that is supplied to the main control room by the nuclear island nonradioactive ventilation system air handling units. The control support area ventilation is also part of this air supply system. The air supply is partially outside air. Refer to Subsection 9.4.1 for system details. The main control room supply air duct radiation monitors receive safety-related power. When predetermined setpoints are exceeded, the monitors provide signals to initiate the supplemental air filtration system on a High-1 gaseous, particulate, or iodine concentration, and to isolate the main control room air intake and exhaust ducts and activate the main control room emergency habitability system on High-2 particulate or iodine concentrations. Alarms are also provided in the main control room for these high concentrations.

The main control room supply air duct radiation monitor components are qualified environmentally and seismically in accordance with the guidelines of Regulatory Guides 1.89 and 1.100, respectively. Each monitor meets the guidelines of Regulatory Guide 1.97 as discussed in Appendix 1A and Section 7.5.

The particulate detectors are beta-sensitive scintillation detectors that view a fixed filter. The iodine detectors are gamma-sensitive, thallium-activated, sodium iodide scintillation detectors that view a fixed charcoal filter. The gas detectors are beta-sensitive scintillation detectors. The range and principal radioisotopes are listed in Table 11.5-1.

The arrangement for a main control room supply air duct radiation monitor is shown in Figure 11.5-6.

Containment Air Filtration Exhaust Radiation Monitor

The containment air filtration exhaust radiation monitor (VFS-JE-RE001) measures the concentration of radioactive materials in the containment purge exhaust air.

The monitor provides an alarm in the main control room when the concentration of radioactive gases in the exhaust exceeds a predetermined setpoint. Refer to Subsection 9.4.7 for system details.

The containment air filtration exhaust radiation monitor is an inline monitor that uses a beta-sensitive scintillation detector. It is located downstream of the containment air filtration units with its sensitive volume inside the duct. The detector range and principal radioisotopes are listed in Table 11.5-1.

The arrangement of the containment air filtration exhaust radiation monitor is shown in Figure 11.5-5.

Gaseous Radwaste Discharge Radiation Monitor

The gaseous radwaste discharge radiation monitor (WGS-JE-RE017) measures the concentration of radioactive materials in the releases from the gaseous radwaste system to the plant vent. The measurement is made before the discharge reaches the plant vent or is diluted by any other flows.

The gaseous radwaste discharge radiation monitor provides an alarm in the main control room and terminates the release of radioactive gas to the plant vent by closing the discharge isolation valve when a predetermined setpoint is exceeded. Refer to Section 11.3 for system details.

The monitor is an inline monitor using a gamma sensitive, thallium-activated, sodium iodine scintillation detector with its sensitive volume inside the piping. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the gaseous radwaste discharge radiation monitor is shown in Figure 11.5-1.

Containment Atmosphere Radiation Monitor

The containment atmosphere radiation monitor measures the radioactive gaseous (PSS-JE-RE026) and F18 particulate (PSS-JE-RE027) concentrations in the containment atmosphere. The containment atmosphere radiation monitor is a part of the reactor coolant pressure boundary leak detection system described in Subsection 5.2.5. The presence of gaseous or F18 radioactivity in the containment atmosphere is an indication of reactor coolant pressure boundary leakage. Refer to Subsection 5.2.5 for further details. Conformance with Regulatory Guide 1.45 is discussed in Appendix 1A.

The containment atmosphere radiation monitor has the capability to compensate for the influence of pressure differentials between the sampling system and the containment atmosphere.

The radiogas detector is a beta-sensitive scintillation detector. The F18 particulate detector is also a beta-sensitive scintillation detector. The ranges and principal isotopes are listed in Table 11.5-1.

The arrangement for the containment atmosphere radiation monitor is shown in Figure 11.5-3.

11.5.2.3.2 Airborne Monitors

Fuel Handling Area Exhaust Radiation Monitor

The fuel handling area exhaust radiation monitor (VAS-JE-RE001) measures the concentration of radioactive materials in the exhaust air from the fuel handling area. This radiation monitor is located upstream of the exhaust air isolation damper.

When a predetermined setpoint is exceeded, the fuel handling area exhaust radiation monitor provides signals to alarm in the main control room, to initiate closure of the fuel handling area supply and exhaust air isolation dampers, to open the fuel handling area exhaust air isolation damper to the containment air filtration exhaust units, and to start a containment air filtration exhaust unit. These actions provide a filtered air path from the fuel handling area to the plant vent. Refer to Subsection 9.4.3 for system details.

The fuel handling area exhaust radiation monitor is an inline monitor that uses a beta-sensitive scintillation detector. It is located with the sensitive volume inside the exhaust duct. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the fuel handling area exhaust radiation monitor is shown in Figure 11.5-5.

Auxiliary Building Exhaust Radiation Monitor

The auxiliary building exhaust radiation monitors (VAS-JE-RE002 and VAS-JE-RE003) measure the concentration of radioactive materials in the radiologically controlled area ventilation system exhaust air from the auxiliary building. The auxiliary building radiation monitor detectors are upstream of the exhaust air isolation damper.

When a predetermined setpoint is exceeded, indicating abnormal airborne radiation, the auxiliary building exhaust radiation monitors provide signals to alarm in the main control room, to initiate automatic closure of the affected radiologically controlled area ventilation system zone supply and exhaust air isolation dampers, to automatically open the radiologically controlled area ventilation system zone exhaust air isolation damper to the containment air filtration exhaust units, and to automatically start a containment air filtration exhaust unit. These actions provide a filtered air path from the affected radiologically controlled area ventilation system zone to the plant vent. Once automatically closed, the zone supply and exhaust air isolation dampers do not automatically reopen and can only be opened manually when airborne radioactivity levels decrease to below the predetermined setpoint of the affected radiation monitor. The operators only restore normal zone

supply and exhaust operation after determining and correcting the source of abnormal airborne radioactivity in the affected zone. Refer to Subsection 9.4.3 for system details.

The auxiliary building exhaust radiation monitors are inline monitors that use a beta-sensitive scintillation detector. The detectors are located with the sensitive volume inside the exhaust duct. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the auxiliary building exhaust radiation monitors are shown in Figure 11.5-5.

Annex Building Exhaust Radiation Monitor

The annex building exhaust radiation monitor (VAS-JE-RE008) measures the concentration of radioactive materials in the radiologically controlled area ventilation system exhaust air from the annex building. The annex building exhaust radiation monitor is located upstream of the annex building exhaust air isolation damper.

When a predetermined setpoint is exceeded, indicating abnormal airborne radiation, the annex building exhaust radiation monitor provides signals to alarm in the main control room, to initiate automatic closure of the affected radiologically controlled area ventilation system zone supply and exhaust air isolation dampers, to automatically open the radiologically controlled area ventilation system zone exhaust air isolation damper to the containment air filtration units, and to automatically start a containment air filtration exhaust unit. These actions provide a filtered air path from the affected radiologically controlled area ventilation system zone to the plant vent. Once automatically closed, the zone supply and exhaust air isolation dampers do not automatically reopen and can only be opened manually when airborne radioactivity levels decrease to below the predetermined setpoint of the affected radiation monitor. The operators only restore normal zone supply and exhaust operation after determining and correcting the source of abnormal airborne radioactivity in the affected zone. Refer to Subsection 9.4.3 for system details.

The annex building monitor is an inline monitor that uses a beta-sensitive scintillation detector. It is located with the sensitive volume inside the exhaust duct. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the annex building exhaust radiation monitor is shown in Figure 11.5-5.

Health Physics and Hot Machine Shop Exhaust Radiation Monitor

The health physics and hot machine shop exhaust radiation monitor (detector VHS-JE-RE001) measures the concentration of radioactive materials in the exhaust air from the health physics area and the hot machine shop. The monitor provides an alarm in the main control room when the concentration of radioactive gases in the exhaust exceeds a predetermined setpoint. Refer to Subsection 9.4.11 for system details.

The monitor is an offline monitor, located downstream of the exhaust fans, that uses a beta-sensitive scintillation detector viewing a fixed particulate filter. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the health physics and hot machine shop exhaust radiation monitor is shown in Figure 11.5-9.

Radwaste Building Exhaust Radiation Monitor

The radwaste building exhaust radiation monitor (VRS-JE-RE023) measures the concentration of radioactive materials in the exhaust air from the radwaste building. The monitor provides an alarm in the main control room when radioactive material concentrations in the exhaust duct exceed a predetermined setpoint. Refer to Subsection 9.4.8 for system details.

The monitor is an offline monitor, located downstream of the exhaust fans, that uses a beta-sensitive scintillation detector viewing a fixed particulate filter. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the radwaste building exhaust radiation monitor is shown in Figure 11.5-9.

11.5.2.3.3 Liquid and Gaseous Effluent Monitors

Plant Vent Radiation Monitor

The plant vent radiation monitor measures the concentration of radioactive airborne contamination being released through the plant vent, which is the only design pathway for the release of radioactive materials to the atmosphere. The plant vent radiation monitor includes sample nozzle assemblies and a plant vent effluent flow sensor. Heat tracing is provided for the sample line. The monitor also provides particulate, iodine, and gaseous grab sampling capability.

The plant vent is sampled continuously for the full range of concentrations between normal conditions and those postulated in Regulatory Guide 1.97. The plant vent radiation monitor is a post-accident monitor and meets the guidelines of Regulatory Guide 1.97 and NUREG-0737 as discussed in Appendix 1A and Section 7.5. Alarms are provided in the main control room if radioactivity concentrations exceed predetermined setpoints. The plant vent radiation monitor also provides data for plant effluent release reports identified in Regulatory Guide 1.21. For further process details, refer to Subsection 11.3.3.

The normal range particulate detector, VFS-JE-RE101, uses a beta-sensitive scintillation detector that views a fixed filter. The accident range particulate filter is fixed and identical to the normal range filter. The accident range particulate filter is analyzed in an onsite laboratory.

The normal range iodine detector, VFS-JE-RE102, is a gamma-sensitive, thallium-activated, sodium iodide, scintillation detector that views a fixed charcoal filter. The accident range iodine filter is a fixed silver zeolite filter. The accident range iodine filter is analyzed in an onsite laboratory.

The three radiogas channels measure the entire specified range, with overlap in the detector ranges. The normal range radiogas detector, VFS-JE-RE103, is a beta-sensitive scintillation detector. The accident range radiogas detectors, VFS-JE-RE104A (mid-range) and VFS-JE-RE104B (high-range), are beta/gamma-sensitive detectors with small sensitive volumes compared to the normal range radiogas detector.

The plant vent radiation monitor detector ranges and principal radioisotopes are listed in Table 11.5-1. The arrangement for the plant vent radiation monitor is shown in Figure 11.5-4.

The plant vent radiation monitor accepts analog signal inputs from the plant vent effluent and sample flow sensor. These signals are used to calculate concentrations, releases and flow rates at standard conditions. These analog signals are also used to calculate total process flow, total sample flow, and total discharge for an operator-selected period.

The normal range particulate, iodine, and radiogas detectors are deactivated automatically when the gas channel concentration exceeds the normal range. The sample flow bypasses the normal range detectors and a small portion is extracted for the accident range particulate and iodine sample filters and radiogas detectors. This prevents normal range detector damage and allows these detectors to be used to measure the concentrations after they decrease again to within the normal range detector ranges.

The following design criteria for particulate and iodine collection are applied to the design of the plant vent and vent sampling system:

- The sample extraction point is located at a sufficient distance downstream of perturbations or flow entry points to provide fully developed flow in the turbulent regime.
- The sample extraction point is located between the discharge plane of a fan and the stack exit plane, and is not located close the to the stack exit plane where wind effects significantly influence the velocity profile at the sampling location.
- The sample nozzles provide high efficiency transmission ratios (80 to 130%) and an aspiration ratio of 0.80 to 1.50 over the expected normal and off-normal flow range for 10 micron aerodynamic diameter (AD) particles.
- The sample line layout includes features to provide particle transport efficiency, including the following:
  - Non-reactive materials are used in the construction of sample lines.
  - Sample line deposition analyses are performed.
  - The distance between the sampling nozzles and the sample collection stations is minimized, within the requirements of the overall layout requirements.
  - Long horizontal runs are avoided.
  - Long radius bends are used.
  - Heat tracing is included if needed to avoid condensation of water or iodine.

Turbine Island Vent Discharge Radiation Monitor

The turbine island vent discharge radiation monitor (TDS-JE-RE001A/B) measures the concentration of radioactive gases in the steam and non-condensable gases that are discharged by the condenser vacuum pumps and the gland seal steam condenser. This measurement provides early indication of leakage between the primary and secondary sides of the steam generators. The monitor provides an alarm in the main control room if concentrations exceed a predetermined setpoint. Refer to Subsection 5.2.5 for leakage monitoring details and to Subsections 10.4.2 and 10.4.3 for process system details. The turbine island vent discharge radiation monitor meets the guidelines of Regulatory Guide 1.97 as discussed in Appendix 1A and Section 7.5.

The turbine island vent discharge radiation monitor provides data for reports of gaseous releases of radioactive materials in accordance with Regulatory Guide 1.21. The monitor is an inline monitor that uses two beta/gamma-sensitive Geiger-Mueller tubes with overlap in the detector ranges. The range and principal isotopes are listed in Table 11.5-1.

The arrangement for the turbine island vent discharge radiation monitor is shown in Figure 11.5-1.

Liquid Radwaste Discharge Radiation Monitor

The liquid radwaste discharge radiation monitor (WLS-JE-RE229) measures the concentration of radioactive materials in liquids released to the environment. The liquid releases are made in batches that are mixed thoroughly and sampled. The samples are analyzed on site before discharge to determine that the discharge is within allowable concentration limits and within allowable totals.

The liquid radwaste discharge radiation monitor provides data for reports of liquid releases of radioactive materials in accordance with Regulatory Guide 1.21.

The liquid radwaste discharge radiation monitor is an inline monitor that provides signals to isolate the discharge of liquid radwaste, stop the liquid radwaste system discharge pumps and alarms in the main control room if the concentrations exceed a predetermined setpoint. For process system details refer to Section 11.2.

The range and principal isotopes are listed in Table 11.5-1. The detector is a gamma-sensitive, thallium-activated, sodium iodide scintillation detector.

The arrangement for the liquid radwaste discharge radiation monitoring channel is shown in Figure 11.5-1.

Waste Water Discharge Radiation Monitor

The waste water discharge radiation monitor (WWS-JE-RE021) measures the concentration of radioactive materials in the discharge from the waste water system. The waste water discharge radiation monitor provides data for reports of liquid releases of radioactive materials in accordance with Regulatory Guide 1.21.

The waste water discharge radiation monitor is an inline monitor. It stops the turbine building sump pumps and initiates an alarm in the main control room if the concentration of radioactive materials exceeds a predetermined setpoint. Following an alarm, the operator can manually realign the discharge to the liquid radwaste system for processing. For process system details refer to Subsection 9.2.9.

The range and principal isotopes are listed in Table 11.5-1. The detector is a gamma-sensitive, thallium-activated, sodium iodide scintillation detector.

The arrangement for the waste water discharge radiation monitor is shown in Figure 11.5-1.

11.5.2.4 Inservice Inspection, Calibration, and Maintenance

The operability of each radiation monitoring system channel is checked periodically.

Test and inspection requirements for safety-related channels and certain nonsafety-related channels are provided in the Technical Specifications.

Daily checks of effluent monitoring system operability are made by observing channel behavior. Detector response is routinely observed with a remotely-positioned check source in accordance with plant procedures. Instrument background count rate is also observed to determine proper functioning of the monitors. Any detector whose response cannot be verified by observation during normal operation or by using the remotely-positioned check source can have its response checked with a portable check source. A record is maintained showing the background radiation level and the detector response.

Calibration of the continuous radiation monitors is done with commercial radionuclide standards that have been standardized using a measurement system traceable to the National Institute of Standards and Technology.

11.5.3 Effluent Monitoring and Sampling

The primary means of quantitatively evaluating the isotopic activities in effluent paths is a program of sampling and onsite laboratory measurements. Gross activity measurements provided by the

radiation monitors described in Subsection 11.5.2.3 are used to determine the activities released in effluent paths by calibrating the monitors against normalized laboratory results.

Sample points are located on the gaseous effluent radiation monitor skids.

The requirements of General Design Criterion 64 are satisfied by the sampling program and the effluent radiation monitors described in Subsection 11.5.2.3.

SNC is extending the existing SNC program for quality assurance of radiological effluent and environmental monitoring that is based on Regulatory Guide 4.15, Revision 1, to apply to Vogtle Units 3 and 4. Regulatory Guide 4.15, Revision 1, is a proven methodology for quality assurance of radiological effluent and environmental monitoring programs that is acceptable to the NRC staff as a method for demonstrating compliance with applicable requirements of 10 CFR Parts 20, 50, 52, 61, and 72. Use of Revision 2 of Regulatory Guide 4.15 would necessitate conducting two separate programs involving the use of common staff facilities, and equipment, which will create an undue burden and may lead to an increased possibility for human error. Therefore, SNC commits to use Regulatory Guide 4.15, Revision 1, methodology for Vogtle Units 3 and 4 for optimal consistency, efficiency, and practicality.

11.5.4 Process and Airborne Monitoring and Sampling

Radiation monitors are used to initiate automatic closure of isolation valves and dampers in liquid and gaseous process systems as described in Subsection 11.5.2.3. These radiation monitors address the requirement of General Design Criterion 60 to suitably control the release of radioactive materials in gaseous and liquid effluents. The sampling program for liquid and gaseous effluents will conform to Regulatory Guide 4.15, Revision 1 (See Appendix 1A).

Radiation monitors are used in the radioactive waste processing systems as described in Subsection 11.5.2.3. These radiation monitors address the requirement of General Design Criterion 63 to monitor radiation levels in radioactive waste systems.

Radiation monitors are used in the ventilation systems as described in Subsection 11.5.2.3 to ensure that airborne concentrations within the plant are within the limits of 10 CFR 20.

11.5.4.1 Effluent Sampling

Effluent sampling of potential radioactive liquid and gaseous effluent paths is conducted on a periodic basis to verify effluent processing meets the discharge limits to offsite areas. The effluent sampling program provides the information for the effluent measuring and reporting required by 10 CFR 50.36a and 10 CFR Part 20 and implemented through the Offsite Dose Calculation Manual (ODCM) and plant procedures. The frequency of the periodic sampling and analyses described herein are nominal and may be increased as permitted by procedure. Tables 11.5-201 and 11.5-202 summarize the sample and analysis schedules and sensitivities, respectively. The information contained in Tables 11.5-201 and 11.5-202 are derived from Regulatory Guide 1.21.

Laboratory isotopic analyses are performed on continuous and batch effluent releases in accordance with the ODCM. Results of these analyses are compiled and appropriate portions are utilized to produce the Radioactive Effluent Release Report.

11.5.4.2 Representative Sampling

Representative samples are obtained from well-mixed streams or volumes of effluent liquid through the use of proper sampling equipment, proper location of sampling points, and the development and use of sampling procedures. The recommendations of ANSI N 42.18 (Reference 203) are considered

for the selection of instrumentation specific to the continuous monitoring of radioactivity in liquid effluents.

Sampling of effluent liquids is consistent with guidance in Regulatory Guide 1.21. When practical, effluent releases are batch-controlled, and prior to sampling, large volumes of liquid waste are mixed, in as short a time span as practicable, so that solid particulates are uniformly distributed in the liquid volume. Sampling and analysis is performed, and release conditions set, before release. Sample points are located to minimize flow disturbance due to fittings and other characteristics of equipment and components. Sample lines are flushed consistent with plant procedures to remove sediment deposits.

Representative sampling of process effluents is attained through sample and monitor locations and methods and criteria detailed in plant procedures.

Composite sampling is employed to analyze for hard to measure radionuclides and to monitor effluent streams that normally are not expected to contain significant amounts of radioactive contamination. Composite liquid samples are collected in proportion to the volume of each batch of effluent release. The composite is thoroughly mixed prior to analysis. Collection periods for composites are as short as practicable and periodic checks are performed to identify changes in composite samples. When grab samples are collected instead of composite samples, the time of the sample, location, and frequency are considered to provide a representative sample of the radioactive materials.

The pressure head of the fluid, if available, is used for taking samples. If sufficient pressure head is not available to take samples, then sample pumps are used to draw the sample from the process fluid to the detector panels and back to the process.

Testing and obtaining representative samples using the radiation monitors described in Section 11.5 will be performed in accordance with ANSI N13.1 (Reference 201).

For obtaining representative samples in unfiltered ducts, sample probe configuration is tested and used in accordance with ANSI N13.1 (Reference 201).

Analytical Procedures

Typically, samples of process and effluent gases and liquids are analyzed in the station laboratory or by an outside laboratory via the following techniques:

- Gross alpha/beta counting
- Gamma spectrometry
- Liquid scintillation counting

"Available" instrumentation and counting techniques change as other instruments and techniques become available. For this reason, the frequency of sampling and the analysis of samples are generalized in this subsection.

Gross alpha/beta analysis may be performed directly on unprocessed samples (e.g., air filters) or on processed samples (e.g., evaporated liquid samples). Sample volume, counting geometry, and counting time are chosen to match measurement capability with sample activity. Correction factors for sample-detector geometry, self-absorption and counter resolving time are applied to provide the required accuracy.

Liquid effluent samples are prepared for alpha/beta counting by evaporation onto steel planchets. Gamma analysis may be done on any type of sample (gas, solid or liquid) in a gamma spectrometer.

Tritiated water vapor samples are collected by condensation or adsorption, and the resultant liquid is analyzed by liquid scintillation counting techniques.

Radiochemical separations are used for the routine analysis of Sr-89 and Sr-90.

Liquid samples are collected in polyethylene bottles to minimize absorption of nuclides onto container walls.

11.5.5 Post-Accident Radiation Monitoring

The radiation monitors listed below meet the guidelines of Regulatory Guide 1.97 and are described in Subsections 11.5.2.3 and 11.5.6.2. For further Regulatory Guide 1.97 information refer to Appendix 1A and Section 7.5.

- Main steam line radiation monitors
- Steam generator blowdown radiation monitor
- Main control room supply air duct radiation monitors
- Plant vent radiation monitor
- Turbine island vent discharge radiation monitor
- Containment high range radiation monitors
- Primary sampling room area monitor
- CSA area monitor

The post-accident sampling system is described in Subsection 9.3.3 and is used to obtain samples for onsite laboratory analysis, including radioisotopic analysis, after a postulated accident.

11.5.6 Area Radiation Monitors

The area radiation monitors are provided to supplement the personnel and area radiation survey provisions of the AP1000 health physics program described in Section 12.5 and to comply with the personnel radiation protection guidelines of 10 CFR 20 and 10 CFR 50 and Regulatory Guides 1.97, 8.2, and 8.8.

During refueling operations in containment and the fuel handling area, radiation monitoring functions, as stated in 10 CFR 50.68(b)(6), are performed by the area radiation monitors in combination with portable bridge monitors.

11.5.6.1 Design Objectives

The design objectives of the area radiation monitors during normal operating plant conditions and anticipated operational occurrences are to:

- Measure the radiation intensities in specific areas of AP1000

- Warn of uncontrolled or inadvertent movement of radioactive material in AP1000
- Provide local and remote indication of ambient gamma radiation and local and remote alarms at key points where substantial changes in radiation flux might be of immediate importance to personnel
- Annunciate and warn of possible equipment malfunctions and leaks in specific areas of AP1000
- Furnish information for radiation surveys
- Minimize the time, effort, and radiation received by operating personnel during routine maintenance and calibration
- Incorporate modular design concepts throughout, to provide easy maintenance

By meeting the above objectives, the radiation monitoring system aids health physics personnel in keeping radiation exposures as-low-as-reasonably-achievable (ALARA).

Locations of area monitor detectors are based on the following criteria:

- Area monitors are located in areas that are normally accessible and where changes in normal plant operating conditions can cause significant increases in exposure rates above those expected for the areas.
- Area monitors are located in areas that are normally or occasionally accessible where significant increases in exposure rates might occur because of operational transients or maintenance activities.
- Area monitors are located to best measure the increase in exposure rates within a specific area and to avoid shielding of the detector by equipment or structural materials.
- In the selection of area monitors, consideration is given to the environmental conditions under which the monitor operates.
- Area monitors are located to provide access so that minimal maintenance equipment is required and to provide an uncluttered area near the detector and local processing electronics to allow for field alignment and calibration.

The area radiation monitors are listed in Table 11.5-2.

11.5.6.2 Post-Accident Area Monitors

The following area monitors are provided to meet Regulatory Guide 1.97 guidelines as discussed in Appendix 1A and Section 7.5.

Containment High Range Radiation Monitor

The containment high range radiation monitors (PXS-JE-RE160, PXS-JE-RE161, PXS-JE-RE162, and PXS-JE-RE163) measure the radiation from the radioactive gases in the containment atmosphere. The monitors receive safety-related power. The detectors are ion chambers, designed to measure the radiation from the radioactive gases inside the containment in accordance with Regulatory Guide 1.97 and NUREG-0737. The monitors are qualified environmentally and seismically in accordance with the guidelines of Regulatory Guides 1.89 and 1.100, respectively.

The containment high range radiation data are displayed in the main control room. When predetermined setpoints are exceeded, the containment high range radiation monitors provide main control room alarms and signals to the protection and safety monitoring system for containment air filtration isolation and normal residual heat removal system valve closure (refer to Section 7.3 for further details). The containment high range radiation monitors provide data for maintaining a record of the gamma radiation intensities after a postulated accident as a function of time, so that the inventory of radioactive materials in the containment volume can be estimated.

The monitor range and type are listed in Table 11.5-2.

The high range radiation detectors are mounted inside the containment on the containment wall in widely separated locations. The locations allow the detectors to be exposed to a significant volume of containment atmosphere without obstruction so that the readouts are representative of the containment atmosphere. The arrangement for a containment high range monitor is shown in Figure 11.5-2.

Primary Sampling Room Area Monitor

The primary sampling station is the location where samples are collected and/or analyzed after a postulated accident. The primary sampling room area radiation monitor (RMS-JE-RE008) is located so that its readout is representative of the radiation to which the operating personnel are exposed. A local readout, an audible alarm, and visual alarms are provided in the primary sampling room to alert operating personnel to increasing exposure rates. Indication and alarms are also provided in the main control room.

The monitor is an extended range monitor that uses a gamma-sensitive ion chamber and Geiger-Mueller tube. The monitor range and type are listed in Table 11.5-2.

Control Support Area (CSA) Area Monitor

The control support area is the location from which engineering support will be provided to the operators following a postulated accident. The CSA area radiation monitor (RMS-JE-RE016) is located so that its readout is representative of the radiation to which the support personnel are exposed. A local readout, an audible alarm, and visual alarms are provided locally to alert personnel to increasing exposure rates.

The monitor is a normal range monitor that uses a gamma-sensitive Geiger-Mueller tube. The monitor range and type are listed in Table 11.5-2.

11.5.6.3 Normal Range Area Monitors

Normal range area radiation monitors are located in accordance with the location criteria given in Subsection 11.5.6.1. A local readout, an audible alarm, and visual alarms are provided in each monitored area to alert operating personnel to increasing exposure rates. Indication and alarms are also provided in the main control room.

The monitor detectors are gamma-sensitive Geiger-Mueller tubes. The monitors and their ranges are listed in Table 11.5-2.

11.5.6.4 Fuel Handling Area Radiation Monitors

Radiation monitoring of the fuel handling and storage areas is performed in accordance with 10 CFR 50.68(b)(6) by radiation monitors RMS-JE-RE012 and RMS-JE-RE020. The area radiation monitoring is augmented during fuel handling operations by a portable radiation monitor on the machine handling fuel. The fuel handling area radiation monitor parameters are provided in

Table 11.5-2. For additional information regarding radiation monitoring during initial fuel receipt and storage, see Section 12AA.5.

11.5.6.5 Quality Assurance

The quality assurance program for design, fabrication, procurement, and installation of the radiation monitoring system and radiation monitors from other systems is in accordance with the overall quality assurance program described in Chapter 17.

The sampling program and the associated monitors conform to Regulatory Guide 4.15, Revision 1 (See Appendix 1A).

11.5.7 Preoperational Testing

Except as noted below, confirmation testing on the plant vent will be performed during plant startup to qualify the sample extraction location.

Velocity profile mapping at the sample extraction point will confirm that the velocity profile, including cyclonic flow, does not substantially affect flow mixing or sample nozzle performance, and is acceptable for obtaining a representative sample.

Performance testing with tracer gas and particulates will be performed over normal and selected off-normal flow conditions. Tracer gas and particulates testing will confirm an acceptably representative sample is obtained. The tracer gas and particulates testing can be performed on a scale model of the plant vent prior to preoperational testing.

The quantitative test acceptance criteria are dependent on the final design of the sampling system. The acceptance criteria will be established prior to testing and will be defined in the test procedures.

This set of confirmation tests will be performed for the first plant. For subsequent units, either these tests may be performed, or documentation may be used to justify that the plant vent geometry and the effluent flow conditions are the same or similar, and that these test results remain applicable.

11.5.8 Combined License Information

An Offsite Dose Calculation Manual (ODCM) is developed and implemented in accordance with the recommendations and guidance of NEI 07-09A (Reference 202). The ODCM contains the methodology and parameters used for calculating doses resulting from liquid and gaseous effluents. The ODCM addresses operational setpoints, including planned discharge rates, for radiation monitors and monitoring programs (process and effluent monitoring and environmental monitoring) for the control and assessment of the release of radioactive material to the environment. The ODCM provides the limitations on operation of the radwaste systems, including functional capability of monitoring instruments, concentrations of effluents, sampling, analysis, 10 CFR Part 50, Appendix I dose and dose commitments, and reporting. The ODCM will be finalized prior to fuel load with site-specific information.

Table 13.4-201 provides milestones for ODCM implementation.

The process and effluent monitoring and sampling per ANSI N13.1 and Regulatory Guides 1.21 and 4.15 is addressed in Subsections 11.5.1.2, 11.5.2.4, 11.5.3, 11.5.4, 11.5.4.1, 11.5.4.2, and 11.5.6.5.

The 10 CFR Part 50, Appendix I guidelines for maximally exposed offsite individual doses and population doses via liquid and gaseous effluents are addressed in Subsections 11.2.3.5 and 11.3.3.4 for liquid and gaseous effluents, respectively.

11.5.9 References

201. ANSI N13.1-1969, “Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities.”

202. NEI 07-09A, “Generic FSAR Template Guidance for Offsite Dose Calculation Manual (ODCM) Program Description,” Revision 0, March 2009 (ML091050234).

203. ANSI N42.18-2004, “Specification and Performance of On-Site Instrumentation for Continuously Monitoring Radioactivity in Effluents.”

Table 11.5-1 (Sheet 1 of 2)
Radiation Monitor Detector Parameters

Detector	Type	Service	Isotopes	Nominal Range
BDS-JE-RE010	γ	Steam Generator Blowdown Discharge Radiation (Note 6)	Cs-137	1.0E-7 to 1.0E-2 µCi/cc
BDS-JE-RE011	γ	Steam Generator Blowdown Electrodeionization Reject (Note 6)	Cs-137	1.0E-7 to 1.0E-2 µCi/cc
CCS-JE-RE001	γ	Component Cooling Water System	Cs-137	1.0E-7 to 1.0E-2 µCi/cc
VFS-JE-RE101	β	Plant Vent Particulate	Sr-90 Cs-137	1.0E-12 to 1.0E-7 µCi/cc
VFS-JE-RE102	γ	Plant Vent Iodine	I-131	1.0E-11 to 1.0E-6 µCi/cc
VFS-JE-RE103	β	Plant Vent Gas (Normal Range)	Kr-85 Xe-133	1.0E-7 to 1.0E-2 µCi/cc
VFS-JE-RE104A	β/γ	P.V. Extended Range Gas (Accident Mid Range) (Note 6)	Kr-85 Xe-133	1.0E-4 to 1.0E+2 µCi/cc
VFS-JE-RE104B	β/γ	P.V. Extended Range Gas (Accident High Range) (Note 6)	Kr-85 Xe-133	1.0E-1 to 1.0E+5 µCi/cc
PSS-JE-RE026	β	Containment Atmosphere Gas (Note 2)	Kr-85 Xe-133 Ar-41 N-13	1.0E-6 to 1.0E-1 µCi/cc
PSS-JE-RE027	β	Containment Atmosphere beta-sensitive scintillation detector (Note 2)	F18	1.0E-10 to 1.0E-5 µCi/cc
PSS-JE-RE050	γ	Primary Sampling Liquid	I-131 Cs-137	1.0E-1 to 1.0E+4 µCi/cc
PSS-JE-RE052	γ	Primary Sampling Gaseous	Kr-85 Xe-133	1.0E-1 to 1.0E+4 mR/hr
SGS-JE-RE026A	γ	Main Steam Line (Note 6)	Kr, Xe, I	1.0E-1 to 1.0E+3 µCi/cc
SGS-JE-RE026B	γ	Main Steam Line	N-16	30 to 200 gallons per day
SGS-JE-RE027A	γ	Main Steam Line (Note 6)	Kr, Xe, I	1.0E-1 to 1.0E+3 µCi/cc
SGS-JE-RE027B	γ	Main Steam Line	N-16	30 to 200 gallons per day
SWS-JE-RE008	γ	Service Water Blowdown	Cs-137	1.0E-7 to 1.0E-2 µCi/cc
TDS-JE-RE001A/B	ß/γ	Turbine Island Vent Discharge (Note 3) (Note 6)	Kr-85 Xe-133	1.0E-6 to 1.0E+5 µCi/cc (Note 4)
VAS-JE-RE001	β	Fuel Handling Area Exhaust (Note 5)	Kr-85 Xe-133	1.0E-6 to 3.0E-2 µCi/cc
VAS-JE-RE002	β	Auxiliary Building Exhaust (Note 5)	Kr-85 Xe-133	1.0E-6 to 3.0E-2 µCi/cc
VAS-JE-RE003	β	Auxiliary Building Exhaust (Note 5)	Kr-85 Xe-133	1.0E-6 to 3.0E-2 µCi/cc

Table 11.5-1 (Sheet 2 of 2)
Radiation Monitor Detector Parameters

Detector	Type	Service	Isotopes	Nominal Range
VAS-JE-RE008	β	Annex Building Exhaust (Note 5)	Kr-85 Xe-133	1.0E-6 to 3.0E-2 µCi/cc
VBS-JE-RE001A	β	Main Control Room Supply Air Duct (Particulate) (Note 1) (Note 5) (Note 6)	Sr-90 Cs-137	1.0E-12 to 1.0E-7 µCi/cc
VBS-JE-RE001B	β	Main Control Room Supply Air Duct (Particulate) (Note 1) (Note 5) (Note 6)	Sr-90 Cs-137	1.0E-12 to 1.0E-7 µCi/cc
VBS-JE-RE002A	γ	MCR Supply Air Duct (Iodine) (Note 1) (Note 5) (Note 6)	I-131	1.0E-11 to 1.0E-5 µCi/cc
VBS-JE-RE002B	γ	MCR Supply Air Duct (Iodine) (Note 1) (Note 5) (Note 6)	I-131	1.0E-11 to 1.0E-5 µCi/cc
VBS-JE-RE003A	β	MCR Supply Air Duct (Gas) (Note 1) (Note 5) (Note 6)	Kr-85 Xe-133	1.0E-7 to 1.0E-1 µCi/cc
VBS-JE-RE003B	β	MCR Supply Air Duct (Gas) (Note 1) (Note 5) (Note 6)	Kr-85 Xe-133	1.0E-7 to 1.0E-1 µCi/cc
VFS-JE-RE001	β	Containment Air Filtration Exhaust (Note 5)	Kr-85 Xe-133	5.0E-7 to 3.0E-2 µCi/cc
VHS-JE-RE001	β	H.P. & Hot Machine Shop Exhaust (Note 5)	Sr-90 Cs-137	1.0E-12 to 1.0E-7 µCi/cc
VRS-JE-RE023	β	Radwaste Building Exhaust (Note 5)	Sr-90 Cs-137	1.0E-12 to 1.0E-7 µCi/cc
WGS-JE-RE017	γ	Gaseous Radwaste Discharge	Kr-85 Xe-133	1.0E-4 to 1.0E+2 µCi/cc
WLS-JE-RE229	γ	Liquid Radwaste Discharge	Cs-137	1.0E-7 to 1.0E-1 µCi/cc
WWS-JE-RE021	γ	Waste Water Discharge	Cs-137	1.0E-7 to 1.0E-2 µCi/cc

Notes:
1. Safety-related
2. Seismic Category I
3. The condenser air removal system (CMS) and the gland seal system (GSS) discharge into the turbine island vents, drains and relief system (TDS). The exhaust from the TDS into the turbine island vent is continuously monitored for radiation.
4. Turbine island vent radiation monitor includes two G-M tubes with nominal ranges of 1.0E-6 to 1.0E+0 µci/cc and 1.0E-1 to 1.0E+5 µci/cc.
5. Monitor is sensitive enough to detect 10 Derived Air Concentration (DAC)-hours.
6. These detectors are for post-accident monitoring; refer to Table 7.5-1.

Table 11.5-2
Area Radiation Monitor Detector Parameters

Detector	Type	Service	Nominal Range
PXS-JE-RE160	γ	Containment High Range (Note 3)	1.0E-0 to 1.0E+7 R/hr
PXS-JE-RE161	γ	Containment High Range (Note 3)	1.0E-0 to 1.0E+7 R/hr
PXS-JE-RE162	γ	Containment High Range (Note 3)	1.0E-0 to 1.0E+7 R/hr
PXS-JE-RE163	γ	Containment High Range (Note 3)	1.0E-0 to 1.0E+7 R/hr
RMS-JE-RE008	γ	Primary Sampling Room	1.0E-1 to 1.0E+7 mR/hr
RMS-JE-RE009	γ	Containment Area Upper Personnel Hatch – Operating Deck	1.0E-1 to 1.0E+4 mR/hr (Note 1)
RMS-JE-RE010	γ	Main Control Room	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE011	γ	Chemistry Laboratory Area	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE012	γ	Fuel Handling Area	1.0E-1 to 1.0E+4 mR/hr (Note 2)
RMS-JE-RE013	γ	Rail Car Bay/Filter Storage Area (Note 4)	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE014	γ	Liquid and Gaseous Radwaste Area	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE016	γ	CSA Area	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE017	γ	Radwaste Bldg. Mobile Systems Facility (Note 4)	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE018	γ	Hot Machine Shop	1.0E-1 to 1.0E+4 mR/hr
RMS-JE-RE019	γ	Annex Staging & Storage Area	1.0E-1 to 1.0E+4 mR.hr
RMS-JE-RE020	γ	Fuel Handling Area	1.0E-1 to 1.0E+4 mR/hr (Note 2)
RMS-JE-RE021	γ	Containment Area Lower Personnel Hatch – Maintenance Level	1.0E-1 to 1.0E+04 mR/hr (Note 1)

Notes:

1. Radiation levels are monitored by the permanent containment area radiation monitor and by a portable bridge monitor during refueling operations. The containment area radiation monitor is located to best measure the increase in exposure rates for this area and to provide an alarm locally and in the main control room.
2. Radiation levels are monitored by the permanent fuel handling area radiation monitors and by a portable bridge monitor during fuel handling operations. The fuel handling area radiation monitors are located to best measure the increase in exposure rates for this area and to provide an alarm locally and in the main control room.
3. Safety-related
4. Monitors areas used for storage of wet wastes (including processed and packaged spent resins) and dry wastes.

Table 11.5-201 (Sheet 1 of 2)
Minimum Sampling Frequency

Stream	Sampled Medium	Frequency
Gaseous	Continuous Release	A sample is taken within one month of initial criticality, and at least weekly thereafter to determine the identity and quantity for principal nuclides being released. A similar analysis of samples is performed following each refueling, process change, or other occurrence that could alter the mixture of radionuclides. When continuous monitoring shows an unexplained variance from an established norm. Monthly for tritium.
	Batch Release	Prior to release to determine the identity and quantity of the principal radionuclides (including tritium).
	Filters (particulates)	Weekly. Quarterly for Sr-89 and Sr-90. Monthly for gross alpha.

Table 11.5-201 (Sheet 2 of 2)
Minimum Sampling Frequency

Stream	Sampled Medium	Frequency
Liquid	Continuous Releases	Weekly for principal gamma-emitting radionuclides.
		Monthly, a composite sample for tritium and gross alpha.
		Monthly, a representative sample for dissolved and entrained fission and activation gases.
		Quarterly, a composite sample for Sr-89, Sr-90, and Fe-55.
	Batch Releases	Prior to release for principal gamma-emitting radionuclides.
		Monthly, a composite sample for tritium and gross alpha.
		Monthly, a representative sample from at least one representative batch for dissolved and entrained fission and activation gases.
		Quarterly, a composite sample for Sr-89, Sr-90 and Fe-55.

Table 11.5-202
Minimum Sensitivities

Stream	Nuclide	Sensitivity
Gaseous	Fission & Activation Gases	1.0E-04 μCi/cc
	Tritium	1.0E-06 μCi/cc
	Iodines & Particulates	Sufficient to permit measurement of a small fraction of the activity that would result in annual exposures of 15 mrem to thyroid for iodines, and 15 mrem to any organ for particulates, to an individual in an unrestricted area.
	Gross Radioactivity	Sufficient to permit measurement of a small fraction of the activity that would result in annual air dose of 1) 10 mrad due to gamma, and 2) 20 mrad of beta at any location near ground level at or beyond the site boundary.
Liquid	Gross Radioactivity	1.0E-07 μCi/ml
	Gamma-emitters	5.0E-07 μCi/ml
	Dissolved & Entrained Gases	1.0E-05 μCi/ml
	Gross Alpha	1.0E-07 μCi/ml
	Tritium	1.0E-05 μCi/ml
	Sr-89 & Sr-90	5.0E-08 μCi/ml
	Fe-55	1.0E-06 μCi/ml

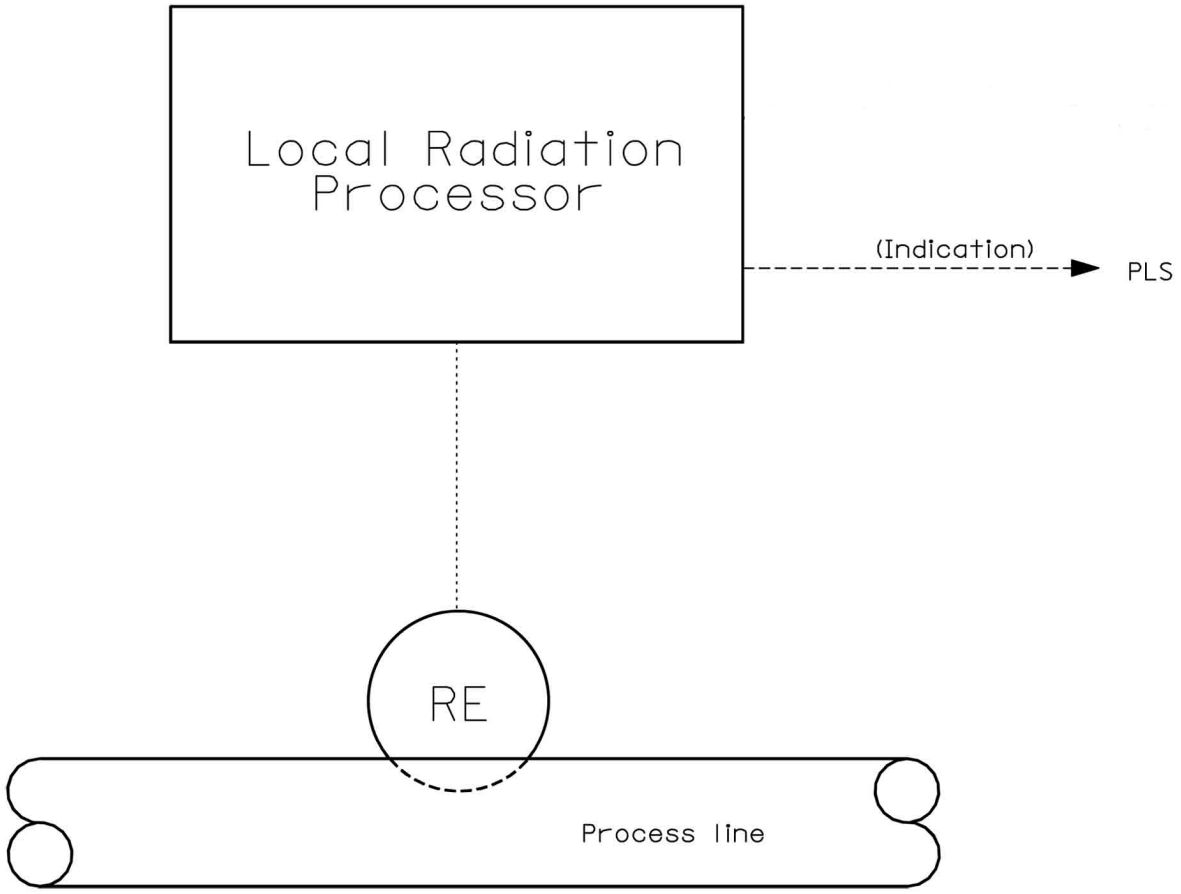


Figure 11.5-1
Process In-Line Radiation Monitor

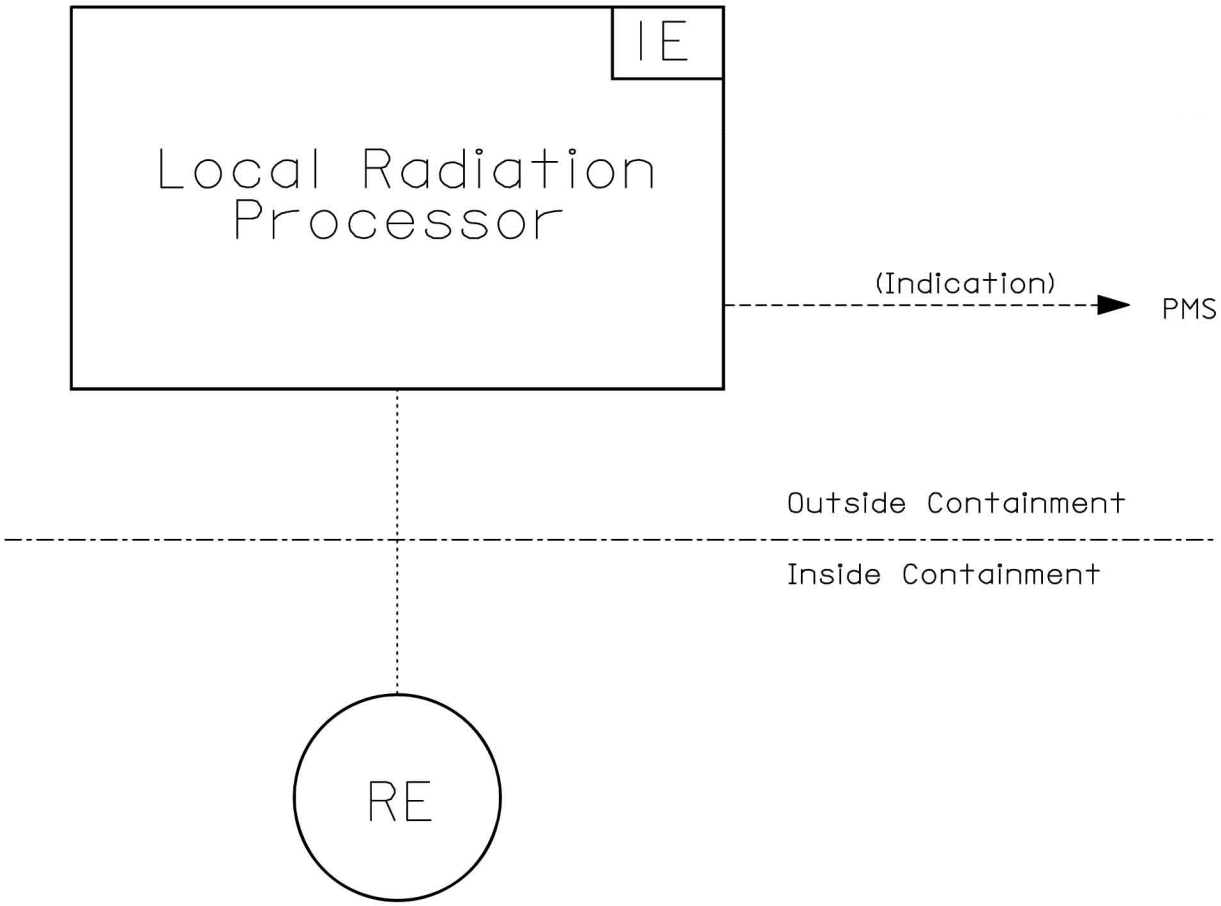


Figure 11.5-2
Safety-Related Containment High Range Radiation Monitor

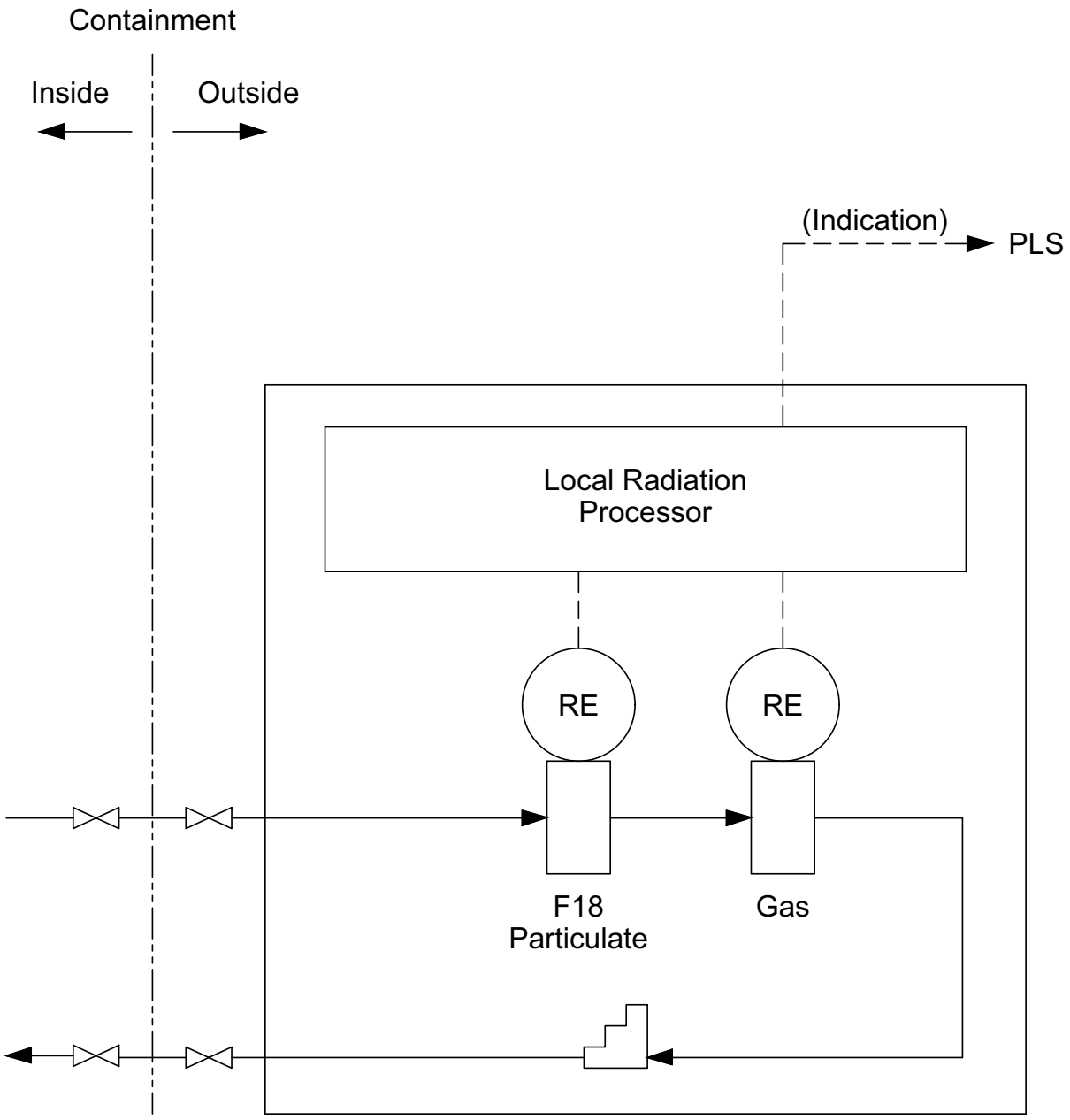


Figure 11.5-3
Containment Atmosphere Radiation Monitor

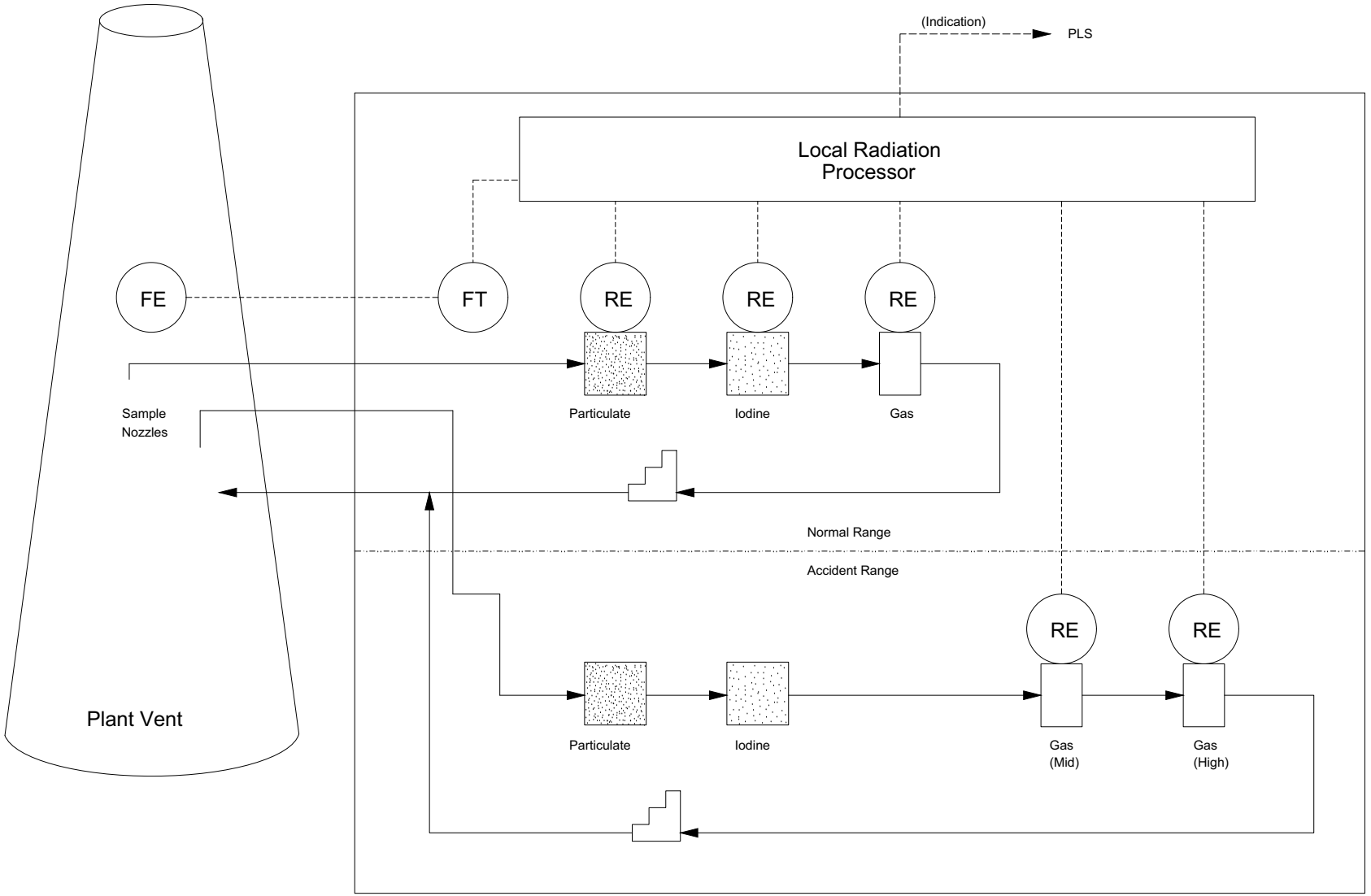


Figure 11.5-4
Plant Vent Radiation Monitor

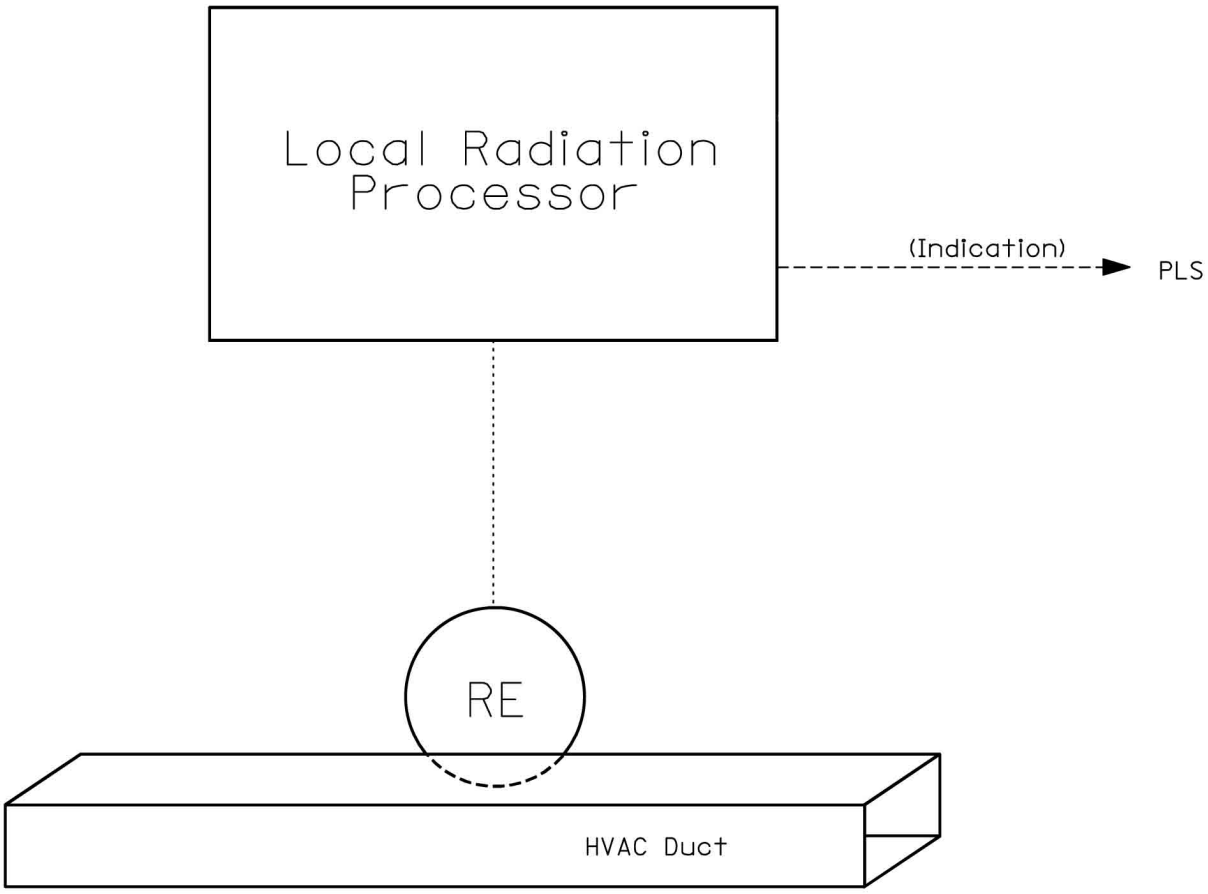


Figure 11.5-5
In-Line HVAC Duct Radiation Monitor

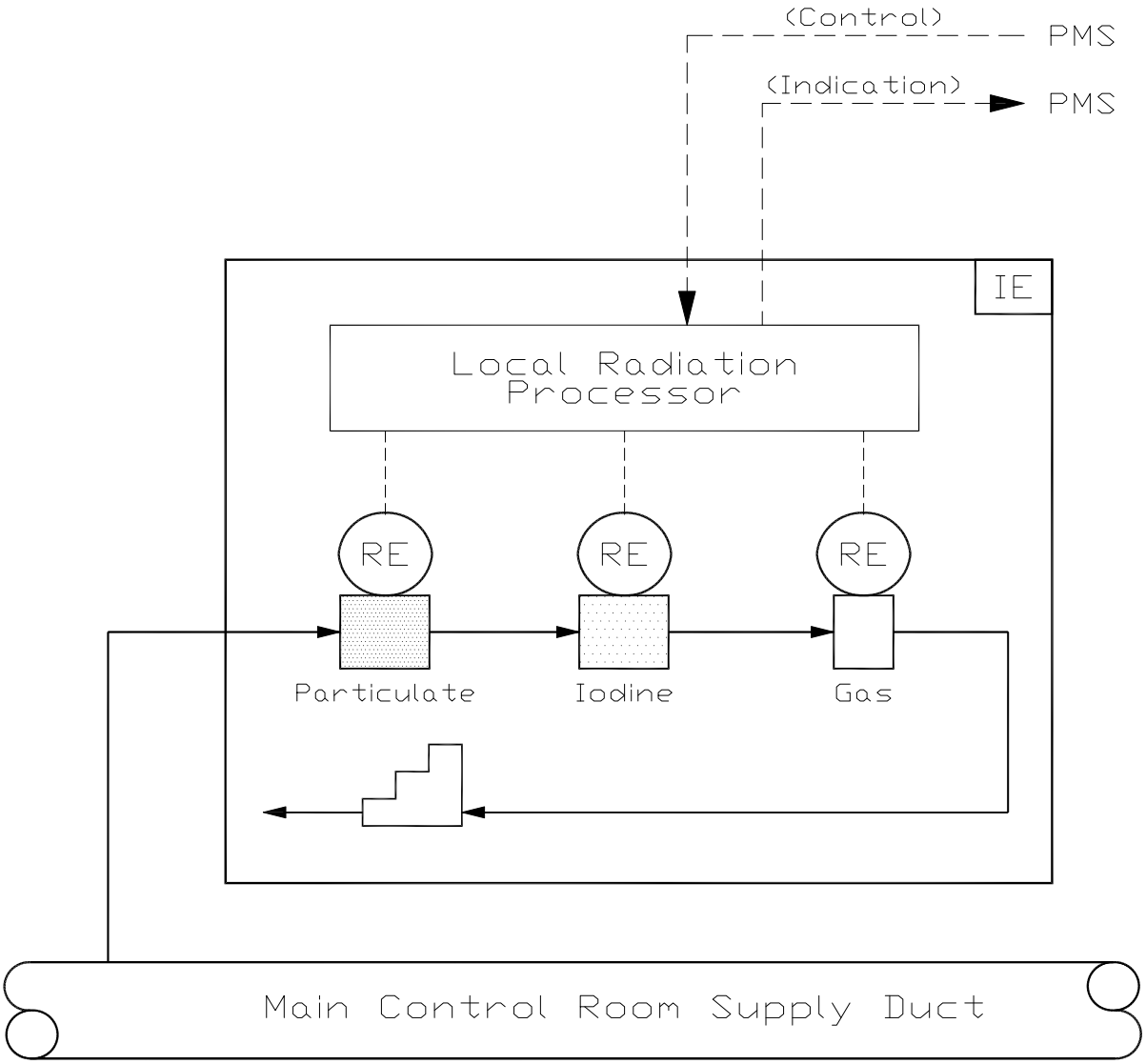


Figure 11.5-6
Safety-Related Main Control Room Supply Duct Radiation Monitor

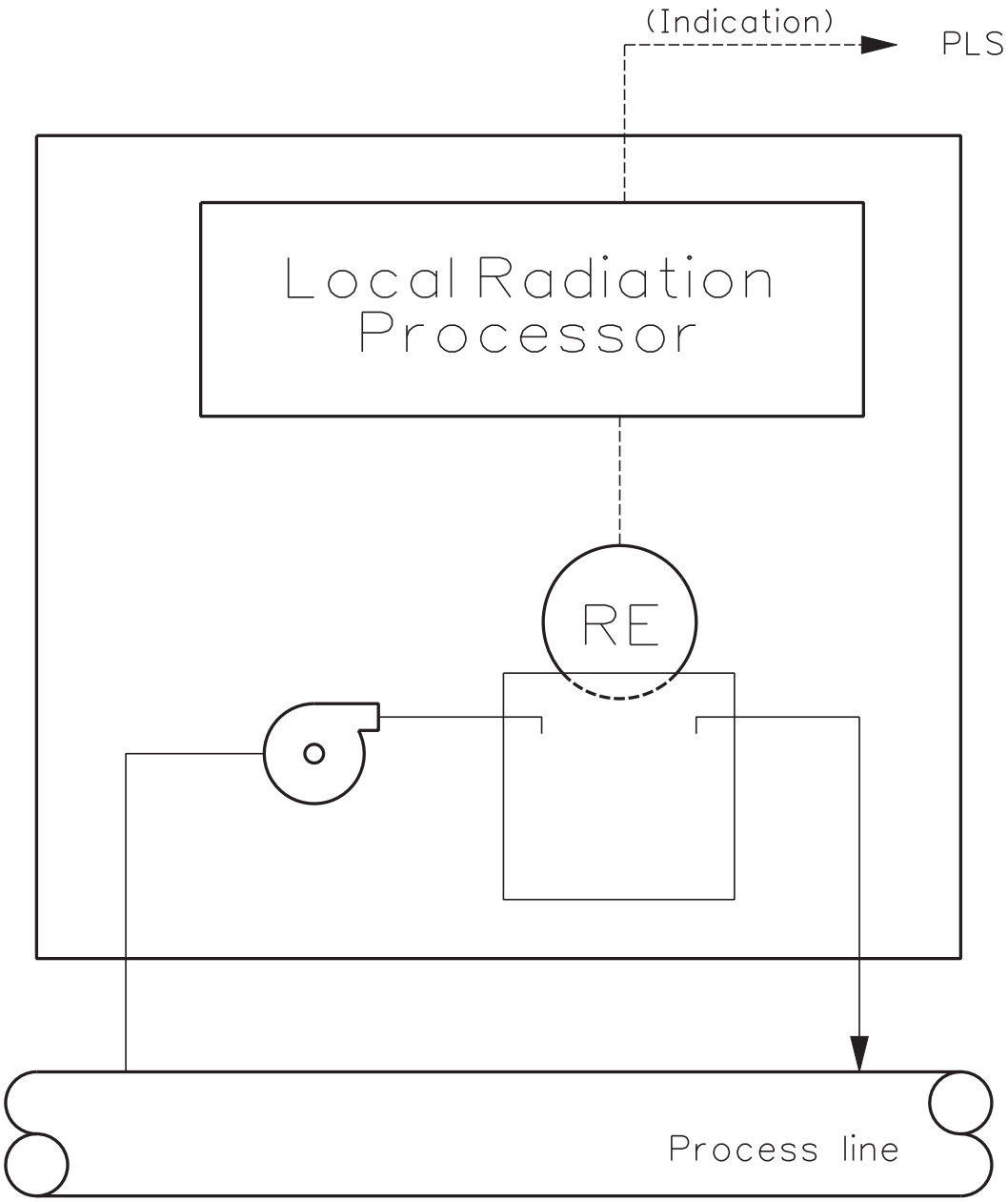


Figure 11.5-7
Liquid Offline Radiation Monitor

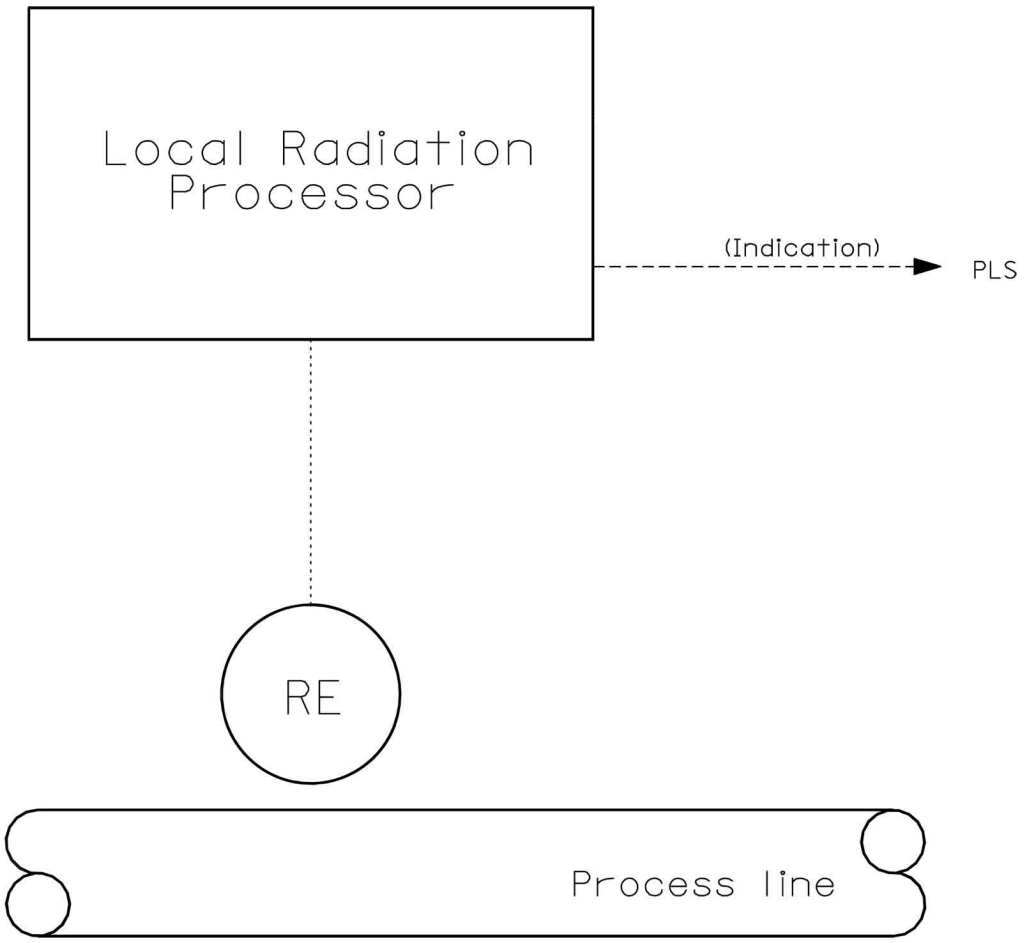


Figure 11.5-8
Adjacent to Line Radiation Monitor

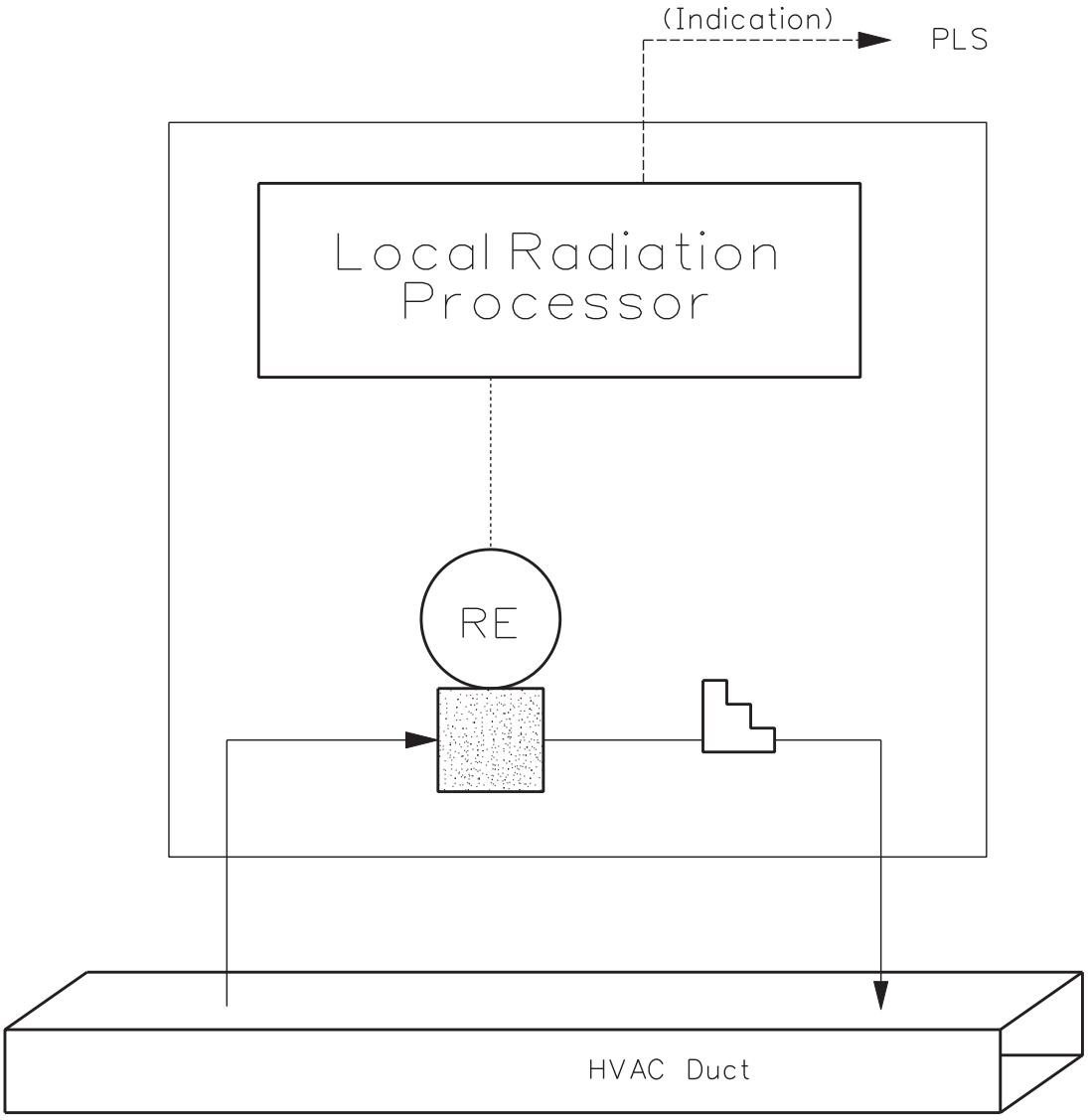


Figure 11.5-9
HVAC Duct Particulate Radiation Monitor

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 12	RADIATION PROTECTION	12.1-1
12.1	Assuring that Occupational Radiation Exposures Are As-Low-As-Reasonably Achievable (ALARA)	12.1-1
12.1.1	Policy Considerations	12.1-1
12.1.2	Design Considerations	12.1-2
12.1.3	Operational Considerations	12.1-7
12.1.4	Combined License Information	12.1-10
12.1.5	References	12.1-10
12.2	Radiation Sources	12.2-1
12.2.1	Contained Sources	12.2-1
12.2.2	Airborne Radioactive Material Sources	12.2-7
12.2.3	Combined License Information	12.2-8
12.2.4	References	12.2-8
12.3	Radiation Protection Design Features	12.3-1
12.3.1	Facility Design Features	12.3-1
12.3.2	Shielding	12.3-8
12.3.3	Ventilation	12.3-13
12.3.4	Area Radiation and Airborne Radioactivity Monitoring Instrumentation	12.3-16
12.3.5	Combined License Information	12.3-19
12.3.6	References	12.3-20
12.4	Dose Assessment	12.4-1
12.4.1	Occupational Radiation Exposure	12.4-1
12.4.2	Radiation Exposure at the Site Boundary	12.4-8
12.4.3	Combined License Information	12.4-8
12.4.4	References	12.4-8
12.5	Health Physics Facilities Design	12.5-1
12.5.1	Objectives	12.5-1
12.5.2	Equipment, Instrumentation, and Facilities	12.5-1
12.5.3	Other Design Features	12.5-2
12.5.4	Controlling Access and Stay Time	12.5-3
12.5.5	Combined License Information	12.5-4
Appendix 12AA	Radiation Protection Program Description	12AA-1
12AA.5	Radiation Protection Program	12AA-1
12AA.5.1	Management Policy	12AA-2
12AA.5.2	Organization	12AA-3
12AA.5.3	Facilities, Instrumentation and Equipment	12AA-3
12AA.5.4	Procedures	12AA-5
12AA.5.5	References	12AA-16

LIST OF TABLES

Table Number	Title	Page
12.2-1	Radiation Flux at the Primary Shield Concrete	12.2-9
12.2-2	Core Average Gamma Ray Source Strengths at Various Times After Shutdown	12.2-10
12.2-3	Reactor Coolant Nitrogen-16 Activity	12.2-12
12.2-4	Pressurizer Nitrogen-16 Source Strengths	12.2-13
12.2-5	Pressurizer Liquid and Steam Phase Source Strengths and Specific Activity	12.2-14
12.2-6	Isotopic Composition and Specific Activity of Typical Out-of-Core Crud Deposits	12.2-18
12.2-7	Chemical and Volume Control System Components Source Strengths and Specific Activity	12.2-19
12.2-8	Spent Fuel Pool Cooling System Component Source Strengths and Specific Activity	12.2-27
12.2-9	Liquid Radwaste System Component Source Terms	12.2-28
12.2-10	Gaseous Radwaste System Component Source Terms	12.2-35
12.2-11	Spent Demineralizer Resin Source Strengths and Specific Activities	12.2-39
12.2-12	Normal Residual Heat Removal System Source Strengths and Specific Activities	12.2-41
12.2-13	Core Average and Spent Fuel Neutron Source Strengths at Various Times After Shutdown	12.2-43
12.2-14	Spent Fuel Gamma Ray Source Strengths	12.2-44
12.2-15	Irradiated Control Rod and Gray Rod Source Strengths	12.2-46
12.2-16	Irradiated SB-BE Secondary Source Rod Gamma Ray Source Strengths	12.2-48
12.2-17	Irradiated SB-BE Secondary Source Rod Neutron Source Strengths	12.2-49
12.2-18	Irradiated Stainless Steel Source Strengths (0.05 Weight Percent Cobalt)	12.2-50
12.2-19	Irradiated Flux Thimble Source Strengths	12.2-51
12.2-20	Core Melt Accident Source Strengths in Containment Atmosphere as a Function of Time	12.2-52
12.2-21	Core Melt Accident Integrated Source Strengths in Containment Atmosphere	12.2-53
12.2-22	Parameters and Assumptions Used for Calculating Containment Airborne Radioactivity Concentrations	12.2-54
12.2-23	Containment Airborne Radioactivity Concentrations	12.2-55
12.2-24	Parameters and Assumptions Used for Calculating Fuel Handling Area Airborne Radioactivity Concentrations	12.2-58
12.2-25	Fuel Handling Area Airborne Radioactivity Concentrations	12.2-59
12.2-26	Parameters and Assumptions Used for Calculating Auxiliary Building Airborne Radioactivity Concentrations	12.2-61
12.2-27	Auxiliary Building Airborne Radioactivity Concentrations	12.2-62
12.2-28	Core Melt Accident Source Strengths from MCR HVAC Filters as a Function of Time	12.2-64
12.2-29	Core Melt Accident Integrated Source Strengths from MCR HVAC Filters	12.2-66
12.2-30	IRWST Design Basis Source Strengths and Specific Activity	12.2-67
12.2-31	IRWST Expected Source Strengths and Specific Activity	12.2-73
12.3-1	Equipment Specification Limits for Cobalt Impurity Levels	12.3-22
12.4-1	Dose Estimate for Reactor Operations and Surveillance	12.4-9

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
12.4-2	Dose Estimate for Routine Inspection and Maintenance	12.4-10
12.4-3	Not Used	12.4-11
12.4-4	Dose Estimate for Sludge Lancing of Steam Generators	12.4-12
12.4-5	Dose Estimate for Visual Examination of Steam Generator Secondary Side	12.4-13
12.4-6	Dose Estimate for Inservice Inspection	12.4-14
12.4-7	Dose Estimate for Steam Generator Eddy Current Tube Inspection and Tube Plugging	12.4-15
12.4-8	Dose Estimate for Steam Generator Inservice Inspection (10-Year Interval)	12.4-17
12.4-9	Dose Estimate for Special Maintenance Operations	12.4-18
12.4-10	Dose Estimate for Waste Processing	12.4-19
12.4-11	Design Improvements That Reduce Refueling Doses	12.4-20
12.4-12	Dose Estimate for Refueling Activities	12.4-21
12.4-201	Annual Construction Worker Doses	12.4-22
12.4-202	Comparison with 10 CFR 20.1301 Criteria for Doses to Members of the Public	12.4-23
12.4-203	Comparison with 40 CFR 190 Criteria for Doses to Members of the Public	12.4-24
12.4-204	Comparison with 10 CFR 50, Appendix I Criteria for Effluent Doses	12.4-25
12AA-201	Very High Radiation Areas (VHRA)	12AA-18

LIST OF FIGURES

Figure Number	Title	Page
12.3-1	(Sheet 1 of 16) Radiation Zones, Normal Operation/Shutdown Legend	12.3-23
12.3-1	(Sheet 2 of 16) Site Radiation Zones, Normal Operations/Shutdown	12.3-24
12.3-1	(Sheet 3 of 16) Radiation Zones, Normal Operations/Shutdown Nuclear Island, Elevation 66'-6"	12.3-25
12.3-1	(Sheet 4 of 16) Radiation Zones, Normal Operations/Shutdown Nuclear Island, Elevation 82'-6"	12.3-26
12.3-1	(Sheet 5 of 16) Radiation Zones, Normal Operations/Shutdown Nuclear Island, Elevation 96'-6"	12.3-27
12.3-1	(Sheet 6 of 16) Radiation Zones, Normal Operations/Shutdown Nuclear Island, Elevation 100'-0" & 107'-2"	12.3-28
12.3-1	(Sheet 7 of 16) Radiation Zones, Normal Operations/Shutdown Nuclear Island, Elevation 117'-6"	12.3-29
12.3-1	(Sheet 8 of 16) Radiation Zones, Normal Operations/Shutdown Nuclear Island, Elevation 135'-3"	12.3-30
12.3-1	(Sheet 9 of 16) Radiation Zones, Normal Operations/Shutdown Nuclear Island, Elevation 153'-0" & 160'-6"	12.3-31
12.3-1	(Sheet 10 of 16) Radiation Zones, Normal Operations/Shutdown Nuclear Island, Elevation 160'-6", 180'-0", & 329'-0"	12.3-32
12.3-201	Radiation Zones, Normal Operations/Shutdown Annex Building, Elevation 100'-0" & 107'-2"	12.3-33
12.3-1	(Sheet 12 of 16) Radiation Zones, Normal Operations/Shutdown Annex Building, Elevation 117'-6" & 126'-3"	12.3-34
12.3-1	(Sheet 13 of 16) Radiation Zones, Normal Operations/Shutdown Annex Building, Elevation 135'-3" through 183'-6"	12.3-35
12.3-1	(Sheet 14 of 16) Radiation Zones, Normal Operations/Shutdown Radwaste Building, Elevation 100'-0"	12.3-36
12.3-1	(Sheet 15 of 16) Radiation Zones, Normal Operations/Shutdown Turbine Building, Elevation 100'-0"	12.3-37
12.3-1	(Sheet 16 of 16) Radiation Zones, Normal Operations/Shutdown Turbine Building, Elevation 120'-6"	12.3-38
12.3-2	(Sheet 1 of 15) Radiation Zones, Post-Accident Legend	12.3-39
12.3-2	(Sheet 2 of 15) Site Radiation Zones, Post-Accident	12.3-40
12.3-2	(Sheet 3 of 15) Radiation Zones, Post-Accident Nuclear Island, Elevation 66'-6"	12.3-41
12.3-2	(Sheet 4 of 15) Radiation Zones, Post-Accident Nuclear Island, Elevation 82'-6"	12.3-42
12.3-2	(Sheet 5 of 15) Radiation Zones, Post-Accident Nuclear Island, Elevation 96'-6"	12.3-43
12.3-2	(Sheet 6 of 15) Radiation Zones, Post-Accident Nuclear Island, Elevation 100'-0" & 107'-2"	12.3-44
12.3-2	(Sheet 7 of 15) Radiation Zones, Post-Accident Nuclear Island, Elevation 117'-6"	12.3-45
12.3-2	(Sheet 8 of 15) Radiation Zones, Post-Accident Nuclear Island, Elevation 135'-3"	12.3-46
12.3-2	(Sheet 9 of 15) Radiation Zones, Post-Accident Nuclear Island, Elevation 153'-0" & 160'-6"	12.3-47
12.3-2	(Sheet 10 of 15) Radiation Zones, Post-Accident Nuclear Island, Elevation 160'-6", 180'-0", & 329'-0"	12.3-48

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
12.3-202	Radiation Zones, Post-Accident Annex Building, Elevation 100'-0" & 107'-2"	12.3-49
12.3-2	(Sheet 12 of 15) Radiation Zones, Post-Accident Annex Building, Elevation 117'-6" & 126'-3"	12.3-50
12.3-2	(Sheet 13 of 15) Radiation Zones, Post-Accident Annex Building, Elevation 135'-3" through 183'-6"	12.3-51
12.3-2	(Sheet 14 of 15) Radiation Zones, Post-Accident Radwaste Building, Elevation 100'-0"	12.3-52
12.3-2	(Sheet 15 of 15) Radiation Zones, Post-Accident Turbine Building, Elevation 100'-0"	12.3-53
12.3-3	(Sheet 1 of 16) Radiological Access Controls Legend	12.3-54
12.3-3	(Sheet 2 of 16) Site Radiation Access Controls, Normal Operations/ Shutdown	12.3-55
12.3-3	(Sheet 3 of 16) Radiological Access Controls, Normal Operations/ Shutdown Nuclear Island, Elevation 66'-6"	12.3-56
12.3-3	(Sheet 4 of 16) Radiological Access Controls, Normal Operations/ Shutdown Nuclear Island, Elevation 82'-6"	12.3-57
12.3-3	(Sheet 5 of 16) Radiological Access Controls, Normal Operations/ Shutdown Nuclear Island, Elevation 96'-6"	12.3-58
12.3-3	(Sheet 6 of 16) Radiological Access Controls, Normal Operations/ Shutdown Nuclear Island, Elevation 100'-0" & 107'-2"	12.3-59
12.3-3	(Sheet 7 of 16) Radiological Access Controls, Normal Operations/ Shutdown Nuclear Island, Elevation 117'-6"	12.3-60
12.3-3	(Sheet 8 of 16) Radiological Access Controls, Normal Operations/ Shutdown Nuclear Island, Elevation 135'-3"	12.3-61
12.3-3	(Sheet 9 of 16) Radiological Access Controls, Normal Operations/ Shutdown Nuclear Island, Elevation 153'-0" & 160'-6"	12.3-62
12.3-3	(Sheet 10 of 16) Radiological Access Controls, Normal Operations/ Shutdown Nuclear Island, Elevation 160'-6", 180'-0", & 329'-0"	12.3-63
12.3-203	Radiological Access Controls, Normal Operations/Shutdown Annex Building, Elevation 100'-0" & 107'-2"	12.3-64
12.3-3	(Sheet 12 of 16) Radiological Access Controls, Normal Operations/ Shutdown Annex Building, Elevation 117'-6" & 126'-3"	12.3-65
12.3-3	(Sheet 13 of 16) Radiological Access Controls, Normal Operations/ Shutdown Annex Building Elevation 135'-3" through 183'-6"	12.3-66
12.3-3	(Sheet 14 of 16) Radiological Access Controls, Normal Operations/ Shutdown Radwaste Building, Elevation 100'-0"	12.3-67
12.3-3	(Sheet 15 of 16) Radiological Access Controls, Normal Operations/ Shutdown Turbine Building, Elevation 100'-0"	12.3-68
12.3-3	(Sheet 16 of 16) Radiological Access Controls, Normal Operations/ Shutdown Turbine Building, Elevation 120'-6"	12.3-69

Chapter 12 Radiation Protection

12.1 Assuring that Occupational Radiation Exposures Are As-Low-As-Reasonably Achievable (ALARA)

This section incorporates NEI 07-08A, Generic FSAR Template Guidance for Ensuring That Occupational Radiation Exposures Are As Low As Is Reasonably Achievable (ALARA). VEGP 3&4 takes exception to the annual ALARA retraining frequency defined in NEI 07-08A Subsection 12.1.1. ALARA retraining frequency is defined in Subsection 12.1.1.2. ALARA practices are developed in a phased milestone approach as part of the procedures necessary to support the Radiation Protection Program. Table 13.4-201 describes the major milestones for ALARA procedures development and implementation.

12.1.1 Policy Considerations

The AP1000 plant is designed with administrative programs and procedures to maximize the incorporation of good engineering practices and lessons learned to accomplish ALARA objectives.

12.1.1.1 Design and Construction Policies

The ALARA policy is applied during the design of AP1000. The design is reviewed for ALARA considerations and updated and modified as experience from operating plants is applied. ALARA reviews include the plant design and integrated layout, considering shielding, ventilation, and monitoring instrument designs as they relate to traffic control, security, access control and health physics.

Similarly, routing of pipe containing radioactive fluids is reviewed as part of the design effort. This confirms that lines expected to contain significant radiation sources are adequately shielded and properly routed to minimize exposure of personnel.

Many of the engineers and supervisors assigned to the AP1000 design have performed similar design work or service work on other nuclear power plants. Through this experience, they have acquired knowledge of the radiation protection aspects which are applied to AP1000. Nuclear plant operating experience is incorporated through Nuclear Regulatory Commission (NRC) inspection and enforcement bulletins, information notices, and other documents. Independent reviews are conducted by the Electric Power Research Institute (EPRI) and Utility Steering Committee and its subcommittees. Knowledge of radiation protection and ALARA is applied to AP1000 design. This allows integration of experience and ALARA considerations from plant operators and plant designers and promotes incorporation of recent operating and service experience and lessons learned.

12.1.1.2 Operation Policies

Company and station policies are to keep all radiation exposure of personnel within limits defined by 10 CFR 20, Standards for Protection Against Radiation (Reference 12.1-1). Administrative procedures and practices related to maintaining radiation exposure of personnel as low as is reasonable achievable (ALARA) are described in this section.

The ALARA policy is consistent with the guidelines of Regulatory Guide 8.8, *Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As is Reasonably Achievable* (Reference 12.1-7), and Regulatory Guide 8.10, *Operating Philosophy for Maintaining Occupational Radiation Exposures As Low As is Reasonably Achievable* (Reference 12.1-9) in establishing, organizing, and operating an effective ALARA program.

To varying extents, all station personnel are responsible for ALARA. Each supervisor is responsible for enforcing the ALARA requirements as described in 10CFR 20.1101. Individual workers are responsible for complying with ALARA requirements, which are presented during initial plant training and reinforced through retraining in accordance with the requirements contained in 10 CFR 19.12. Retraining frequency is established by a Systematic Approach to Training analysis at a frequency of every 48 months nominal not to exceed 51 months. The extent of ALARA training provided for each person is at least commensurate with the worker's job responsibilities and plant areas frequented. The radiation protection training program is maintained and implemented by the training department.

To ensure that personnel comply with established radiological policies, procedures and practices, radiation protection management personnel are charged with the responsibility to promptly advise higher management of any radiologically unsafe practices which exceed their authority to correct. They have the authority to halt any operation which, in their judgment, is radiologically unsafe. Radiation protection technicians are responsible for notifying the operations shift supervision or radiation protection management immediately in order to stop work on any operation deemed to be radiologically unsafe.

12.1.1.3 Compliance with 10 CFR 20 and Regulatory Guides 1.8, 8.8, and 8.10

Compliance of the design with 10 CFR 20 is confirmed by compliance of the design and operation of the facility within the guidelines of Regulatory Guides 1.8, 8.8, and 8.10. Compliance with Regulatory Guides 1.8, 8.8, and 8.10 is addressed as discussed in Appendix 1A and below.

The design of AP1000 meets the guidelines of Regulatory Guide 8.8, Sections C.2 and C.4, which address facility, equipment and instrumentation design features. Features of the plant that are examples of compliance with Regulatory Guide 8.8 are delineated in Section 12.3.

As further discussed in Section 12.5, the station's ALARA policies and practices are consistent with the applicable regulations in 10 CFR 20 (Reference 201). Compliance with the guidance found in Regulatory Guides 1.8, 1.206, 8.2, 8.7, 8.8, 8.9, 8.10, 8.13, 8.15, 8.27, 8.28, 8.29, 8.34, 8.35, 8.36, and 8.38 is discussed in Appendix 1A and Section 12AA.5. Compliance with the applicable portions of NUREG-1736 (References 202 and 204 through 219) is discussed in Section 12AA.5, Radiation Protection Program. Compliance with Regulatory Guide 1.8 is further discussed in Section 13.2, Training. ALARA procedures are established, implemented, maintained and reviewed consistent with 10 CFR 20.1101 and the quality assurance criteria described in Part III of the Quality Assurance Program Description, which is discussed in Section 17.5.

12.1.2 Design Considerations

Provisions and designs for maintaining personnel exposures ALARA are presented in the following paragraphs. The basic management philosophy guiding the AP1000 design effort so that radiation exposures are ALARA can be expressed as:

- Design structures, systems and components for reliability and maintainability, thereby effectively reducing the maintenance requirements on radioactive components.

- Design structures, systems and components to reduce the radiation fields, thereby allowing operation, maintenance and inspection activities to be performed in the minimum design radiation field.

- Design structures, systems and components to reduce access, repair and removal times, thereby effectively reducing the time spent in radiation fields during operation, maintenance, and inspection.

- Design structures, systems and components to accommodate remote and semi-remote operation, maintenance and inspection, thereby effectively reducing the time spent in radiation fields.

12.1.2.1 General Design Considerations for ALARA Exposures

General design considerations and methods to maintain in-plant radiation exposures ALARA consistent with the recommendations of Regulatory Guide 8.8 have two objectives:

- Minimizing the necessity for access to and personnel time spent in radiation areas

- Minimizing radiation levels in routinely occupied plant areas in the vicinity of plant equipment expected to require personnel attention

Equipment and facility layouts and designs are considered for maintaining exposures ALARA during plant operations, including:

- Normal operation
- Maintenance and repairs
- Refueling operations and fuel storage
- Inservice inspection and calibrations
- Radioactive waste handling and disposal
- Other anticipated operational occurrences
- Decommissioning

The actual design features are described in Section 12.3. Examples of features that assist in maintaining exposures ALARA include:

- Provision of features to allow maintenance of state-of-the-art reactor coolant chemistry conditions, such that corrosion and consequential source terms are minimized: these include pH control capability sufficient to meet current and evolving industry standards and the ability to add zinc to the primary coolant

- Provision of features to allow draining, flushing, and decontaminating equipment and piping

- Design of equipment to minimize the creation and buildup of radioactive material and to ease flushing of crud traps

- Provision of shielding for personnel protection during maintenance or repairs and during decommissioning

- Provision of means and adequate space for the use of movable shielding

- Separation of more highly radioactive equipment from less radioactive equipment and provision of separate shielded compartments for adjacent items of radioactive equipment

- Provision of shielded access hatches for installation and removal of plant components

- Provision of design features, such as the chemical and volume control system, to minimize crud buildup

- Provision for means and adequate space for the use of remote and robotic maintenance and inspection equipment

- Simplifying the plant design compared to previous pressurized water reactors with design approaches such as:

  – Elimination of boron recycle
  – Elimination of evaporators
  – Use of an extended fuel cycle
  – Reduction in components containing radioactive fluids
  – Clearly and deliberately separating clean areas from potentially radioactive ones

12.1.2.2 Equipment General Design Considerations for ALARA

Equipment design considerations to minimize the necessity for, and amount of, time spent in a radiation area generally include:

- Reliability, durability, constructibility, and design features of equipment, components, and materials to reduce or eliminate the need for repair or preventive maintenance.

- Servicing convenience for anticipated maintenance or potential repair, including ease of disassembly and modularization of components for replacement or removal to a lower radiation area for repair (For example, the passive residual heat removal heat exchanger is designed with extra tubes to allow for plugging of some tubes. Heat exchangers have drains to allow draining of the shell side water.)

- Provisions, where practicable, to remotely or mechanically operate, repair, service, monitor, or inspect equipment.

- Redundancy of equipment or components to reduce the need for immediate repair when radiation levels may be high and when there is no feasible method available to reduce radiation levels.

- Provisions for equipment to be operated from, and have its instrumentation and control in, accessible areas both during normal and abnormal operating conditions.

- Provisions for remote operation, draining and flushing of systems such as the chemical and volume control system.

- Past experience and lessons learned from servicing currently operating nuclear power plants.

Equipment design considerations directed toward minimizing radiation levels near equipment or components requiring personnel attention include:

- Selection of materials that minimize the creation of radioactive contamination.

- Provision of equipment and piping designs that minimize the accumulation of radioactive materials (for example, the use of seamless piping and minimizing the number of fittings reduces radiation accumulation at the seams and welds).

- Provisions for draining, flushing, or if necessary, remote cleaning or decontamination of equipment containing radioactive materials.

- Provision in the design for limiting leaks or controlling the fluid that does leak. This includes the use of high quality valves and valve packings, and the direction of leakage via drip pans and piping to sumps and floor drains.

- Provisions for isolating equipment from radioactive process fluids.

- Provisions for the chemical and volume control system; the spent fuel pool cleanup system; and the liquid radwaste cleanup system to limit radioactive isotope levels in the process water.

12.1.2.3 Facility Layout General Design Considerations for ALARA

Facility design considerations to minimize the amount of personnel time spent in a radiation area include the following:

- Locating equipment, instruments, and sampling stations that require routine maintenance, calibration, operation, or inspection, in a manner that promotes ease of access and minimum of required occupancy time in radiation areas

- Laying out plant areas to allow remote or mechanical operation, service, monitoring, or inspection of highly radioactive equipment

- Providing, where practicable, for transportation of equipment or components requiring service to a lower radiation area

Facility design considerations directed toward minimizing radiation levels in plant access areas and in the vicinity of equipment requiring personnel attention generally include the following:

- Separating radiation sources and occupied areas, where practicable (for example, pipes or ducts containing potentially highly radioactive fluids do not pass through occupied areas). Redundant components requiring periodic maintenance that are a source of radiation are located in separate compartments to allow maintenance of one component while the other component is in operation.

- Providing shielding to separate equipment such as demineralizers and filters from nonradioactive equipment to provide unrestricted maintenance on the nonradioactive equipment.

- Providing shielding between radiation sources and access and service areas.

- Providing labyrinth entrances to radioactive pump, equipment, and valve rooms. Adequate space is provided in labyrinth entrances for easy access. Highly radioactive passive components with minimal maintenance requirements are located in completely enclosed compartments and are provided with access via a shielded hatch or removable blocks.

- Separating equipment or components in service areas with permanent shielding, where appropriate.

- Providing means and adequate space for using movable shielding for sources within the service area, when required.

- Incorporating, within the plant layout, restrictions and control of access to the various radiation zones. Access to a given radiation zone generally does not require passing through a higher radiation zone. In the case of an abnormal occurrence or accident, the zone restrictions may change due to increased dose rates. Special access controls would be implemented at that time as discussed in Appendix 12AA.

- Locating equipment, instruments, and sampling sites in the lowest practicable radiation zone.

- Providing control panels to permit remote operation of essential instrumentation and controls from the lowest radiation zone practicable.
- Providing means to control contamination or facilitate decontamination of potentially contaminated areas.
- Providing means for decontamination of service areas.
- Maintaining ventilation air flow patterns from areas of lower radioactivity to areas of higher radioactivity.
- Provide adequate lighting and support services (electrical power, compressed air, demineralized water, ventilation, and communications) at workstations.

12.1.2.4 Equipment and Facility Layout General Design Considerations for 10 CFR 20.1406

General equipment and facility layout design considerations to prevent the spread of contamination and to facilitate eventual decommissioning in accordance with 10 CFR 20.1406 include the features discussed in the following subsections.

12.1.2.4.1 Piping

The use of embedded pipes is minimized to the extent possible, consistent with maintaining radiation doses ALARA.

To the extent possible, radioactive piping is located inside the auxiliary building and the containment vessel. This minimizes the potential for leakage to the groundwater from piping or fittings. The few exceptions are as follows:

- Process piping to and from the radwaste building (which can be fully visually inspected from the radwaste building pipe trench to the auxiliary building wall).
- Drain lines from the radwaste building and annex building back to the auxiliary building. These lines are not normally water filled, and can also be fully visually inspected from the annex or radwaste building pipe trench to the auxiliary building wall.
- Piping associated with the waste monitor tanks in the radwaste building. These tanks contain processed water, and they are located within the curbed radwaste building, which drains to the liquid radwaste system.
- Monitored radwaste discharge pipeline as discussed below.

The monitored radwaste discharge pipeline is engineered to preclude leakage to the environment. This pipe is routed from the auxiliary building to the radwaste building (the short section of pipe between the two buildings is fully available for visual inspection as noted above) and then out of the radwaste building to the appropriate point for dilution and discharge. The exterior piping either incorporates a guard pipe, or is available for visual inspection. No valves or vacuum breakers are incorporated outside of monitored structures.

As discussed in Subsections 11.1.2 and 11.1.3, operation with primary to secondary leakage would lead to limited radiological contamination of some secondary side systems. Liquid leakage from piping or components located in the turbine building will be collected by the waste water system and routed to a turbine building sump.

Outdoor piping between the condenser hotwell and the condensate storage tank is located above ground where liquid leakage can be detected.

12.1.2.4.2 Fuel Pool Design

The spent fuel pool and connected pools are designed to eliminate undetected leakage to the groundwater as follows:

- The walls of these pools are constructed using modular construction techniques. This allows higher quality than traditional construction. The advanced welding techniques used minimize the potential for weld failures during operation, and allow for inspection to verify weld quality.
- The walls are made of 1/2-inch stainless steel plates, joined to one another with full penetration welds.
- The thickness of the wall plate and the use of full penetration welds prevents wall or weld damage from fuel handling operations, including tool manipulation and storage.
- The pools are equipped with leak chases or alternate means of leak detection at each weld located below normal operating water level range upper value. For a limited number of pool structural welds where the use of leak chase channels behind the weld are not practical, alternate means that establish a leak tight inspectable barrier between the pool water and these structural welds are provided. The leak chase collection system uses piping that is adequately sized to allow testing and to minimize the potential for blockage by encrustation of precipitates (boric acid), and facilitates removal of any such blockage.
- The pool leak detection system will be zoned to allow identification of the area of the pool liner which is leaking, even for very small leaks.
- To the extent possible, these pools are located entirely inside the auxiliary and containment building, so that any theoretical leakage from the tanks is into the building rather than having the potential for release to the environment. Specifically, for pools other than a portion of the fuel transfer canal, the concrete support structure of the pools may be inspected from rooms adjacent to or below (i.e., outside) the pool.

12.1.2.4.3 Equipment Layout

A video record of the equipment layout in areas where radiation fields are expected to be high following operations may be used to assist in ALARA planning and to facilitate decommissioning.

12.1.3 Operational Considerations

The ALARA program is based on mature programs in use at other operating commercial nuclear facilities. As such, it inherently incorporates lessons-learned from decades of operating experience. Industry operating experience is regularly reviewed, and applicable lessons-learned are incorporated into plans, procedures, and policies as warranted.

Functional Structure

The functional structure for the ALARA program is described in Section 12.5.

Organizational Structure

Organizational structure is discussed in Section 13.1 and/or Section 17.5, the Quality Assurance Program Description.

Radiation Protection Program

The station has a radiation protection program and an ALARA program which contain the operational ALARA philosophy. These programs, made available to plant personnel, define management's commitment to ALARA and designate those individuals who have the responsibility and authority to implement the ALARA program. Section 12.5 provides a complete description of the radiation protection program.

Training

ALARA training is described in Sections 12.5 and 13.2.

Procedures

Procedures are developed and maintained in accordance with Sections 13.5 and 17.5. During initial preparation, radiation protection personnel review the procedures with potential radiological impact for operations, maintenance, refueling, inservice inspections, and operation of the radwaste system for compliance with ALARA guidelines outlined in the radiation protection program.

ALARA Program Review and Improvement

The ALARA Committee and plant management perform periodic reviews of the radiation program content and implementation. In addition to evaluating the implementation of the radiation protection program, these reviews are used to monitor workgroup trends as a means of controlling and reducing personnel exposure. All employees are encouraged to submit suggestions on methods of reducing personnel exposure and improving the ALARA program. Operating procedures are revised, as necessary, to incorporate ALARA lessons-learned from these reviews and suggestions.

Plant Modifications

Modifications to plant equipment and facilities are made where they will substantially reduce exposures at a reasonable cost. Specifications for replacement equipment reflect modifications based on experience gained from using the original equipment. Written procedures direct that all proposed plant modifications are screened for potential adverse radiological impacts. The initial screening review of these proposed modifications is typically performed by engineering personnel. Radiological protection and management personnel perform further review as warranted by level of potential radiological impact.

Work Practices

Radiation protection training, the radiation protection plan, the RWP system, and procedure reviews all help to ensure that radiation exposure of personnel is maintained ALARA. The following examples illustrate the incorporation of ALARA work practices:

- Personnel required to be monitored for radiation exposure in accordance with 10 CFR 20.1502 are assigned appropriate dosimetry to establish exposure history.
- Workers are provided with direct-reading dosimeters on jobs, so that the worker can determine accumulated exposure at any time during a job.
- Dose rate meters are used as needed to identify elevated dose rates.
- Pre-job briefs are used to review radiological surveys and to plan work before personnel enter a radiation area. Written procedures provide guidelines regarding the amount of detail to be included in the pre-job briefings.

- Post-job debriefs are used to ascertain lessons learned. Incorporation of these lessons may result in lower personnel exposure on future jobs. The requirement for post-job debriefings is specified by procedures.

- For work involving high radiation areas, high collective doses, high levels of removable contamination relative to site posting criteria for contamination areas, or known or suspected airborne radioactivity areas:

  1. Work is preplanned to minimize personnel exposure as defined in ALARA program procedures.

  2. Radiation protection personnel provide coverage as required by radiation protection procedures.

- On complex jobs in high radiation areas, dry-run training may be utilized. In some cases, mockups are used to familiarize workers with the operations that they are to perform. These techniques are beneficial to improving worker efficiency and minimizing the amount of time spent in the radiation field.

- On jobs where general area radiation levels are greater than 1.5 rem/hour or when individual exposure greater than 500 mrem per entry is expected, stay times are considered as further protection against unnecessary exposure.

- As practical, work area entry and exit points are established in areas with low radiation levels. This is done to minimize dose accumulated while changing protective clothing and respiratory equipment. Control points are also established to minimize the spread of removable contamination from the job site.

- As much as practicable, jobs and activities such as reading instruction manuals or maintenance procedures, adjusting tools or jigs, repairing valve internals, and prefabricating components are performed outside radiation areas.

- Individuals working in radiologically controlled areas are trained to be aware of the varying intensities of radiation fields within the general vicinity of their job locations, and are instructed to remain in the areas of lower radiation levels as much as possible, consistent with performing their assigned tasks.

- For high radiation area jobs, maps, postings, and/or detailed instructions are provided to clearly delineate the source of radiation or to alert personnel concerning the location of elevated dose rates. Provided with this information, workers will be cognizant of their immediate radiological environment, and will minimize their stay times in areas of elevated dose rates, thus maintaining exposures ALARA.

- Protective clothing and respiratory equipment prescribed by radiation protection personnel are commensurate with the radiological hazards involved. These requirements cannot be modified without the permission of radiation protection personnel. Consideration is given to the discomfort of workers to minimize the effect of protective efforts on efficiency and the time spent in a radiation area.

- Contamination containments (e.g., glove bags, plastic bottles, tents) and special ventilation systems (e.g., HEPA units) are used where practicable when personnel are working on highly contaminated equipment.

- Special tools or jigs are used on jobs when their use permits the job to be performed more efficiently or prevents errors, thus reducing the time spent in a radiation area.
- Where applicable, special tools are used to increase the distance from the source to the worker, thereby reducing the exposure received.
- Consideration is given to the use of remote monitoring of personnel with various combinations of audio, visual and dose information to reduce exposure of personnel. Direct communications (e.g., radios) may be used to further enhance radiation protection.
- Some systems and components which are subject to buildup of activated corrosion products are equipped with flush connections to reduce hot-spot buildup. Prior to performing maintenance work on these systems or components, consideration is given to flushing and/or chemically decontaminating the system or piece of equipment in order to reduce the crud levels, thereby reducing dose rates which may result in lower personnel exposure.
- Permanent shielding is used, where practicable, to reduce radiation exposure at the work site and in designated "waiting areas" for personnel during periods when they are not actively involved in the work.
- On some jobs, temporary shielding such as lead sheets draped or strapped over a pipe or concrete blocks stacked around a piece of equipment is used. Temporary shielding is used only if the estimated total exposure, which includes exposure received during installation and removal, is reduced. Experience with such operations is used in developing guidelines in this area.

12.1.4 Combined License Information

Operational considerations of ALARA, as well as operational policies and continued compliance with 10 CFR 20 and associated Regulatory Guides, are addressed in NEI 07-08A and Appendix 12AA.

12.1.5 References

201. 10 CFR 20, Standards for Protection Against Radiation.

202. USNRC, “Qualification and Training of Personnel for Nuclear Power Plants,” Regulatory Guide 1.8, Revision 3, May 2000.

203. USNRC, “Quality Assurance Program Requirements (Operation)”, Regulatory Guide 1.33, Revision 2, February 1978.

204. USNRC, “Combined License Applications for Nuclear Power Plants (LWR Edition)”, Regulatory Guide 1.206, June 2007.

205. USNRC, “Guide for Administrative Practices in Radiation Monitoring”, Regulatory Guide 8.2, February 1973.

206. USNRC, “Instructions for Recording and Reporting Occupational Radiation Dose Data”, Regulatory Guide 8.7, Revision 2, November 2005.

207. USNRC, “Information Relevant to Ensuring that Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable”, Regulatory Guide 8.8, Revision 3, June 1978.

208. USNRC, “Acceptable Concepts, Models, Equations, and Assumptions for a Bioassy Program”, Regulatory Guide 8.9, Revision 1, July 1993.

209. USNRC, “Operating Philosophy for Maintaining Occupational Radiation Exposures As Low As Is Reasonably Achievable”, Regulatory Guide 8.10, Revision 1-R, September 1975.

210. USNRC, “Instructions Concerning Prenatal Radiation Exposure”, Regulatory Guide 8.13, Revision 3, June 1999.

211. USNRC, “Acceptable Programs for Respiratory Protection”, Regulatory Guide 8.15, Revision 1, October 1999.

212. USNRC, “Radiation Protection Training for Personnel at Light-Water-Cooled Nuclear Power Plants”, Regulatory Guide 8.27, March 1981.

213. USNRC, “Audible-Alarm Dosimeters”, Regulatory Guide 8.28, August 1981.

214. USNRC, “Instructions Concerning Risks from Occupational Radiation Exposure”, Regulatory Guide 8.29, Revision 1, February 1996.

215. USNRC, “Monitoring Criteria and Methods to Calculate Occupational Radiation Doses”, Regulatory Guide 8.34, July 1992.

216. USNRC, “Planned Special Exposures”, Regulatory Guide 8.35, June 1992.

217. USNRC, “Radiation Dose to the Embryo/Fetus”, Regulatory Guide 8.36, July 1992.

218. USNRC, “Control of Access to High and Very High Radiation Areas in Nuclear Power Plants”, Regulatory Guide 8.38, Revision 1, May 2006.

219. USNRC, “Consolidated Guidance: 10 CFR Part 20 - Standards for Protection Against Radiation”, NUREG-1736, October 2001.

12.2 Radiation Sources

This section describes the sources of radiation that form the basis for shielding design calculations and the sources of airborne radioactivity used for the design of personnel protection measures and dose assessment.

12.2.1 Contained Sources

The shielding design source terms are based on the three plant conditions of normal full-power operation, shutdown, and design basis accident events.

12.2.1.1 Sources for Full-Power Operation

The primary sources of radioactivity during normal full-power operation are direct core radiation, coolant activation processes, leakage of fission products from pinhole defects in fuel rod cladding, and activation of reactor coolant corrosion products. The design basis for fission product activities is operation with cladding defects in fuel rods producing 0.25 percent of the core thermal power. The design basis for activation and corrosion product activities is derived from measurements at operating plants and is independent of the fuel defect level.

12.2.1.1.1 Reactor Core

The neutron and gamma flux from the reactor core is reduced by the reactor internals and by the reactor vessel. Table 12.2-1 lists the neutron and gamma energy flux spectra in the reactor cavity outside the reactor vessel for several energy groups. The values are maximum values on the inside surface of the primary shield concrete at the core midplane.

12.2.1.1.2 Reactor Coolant System

Sources of radiation in the reactor coolant system are fission products released from fuel and activation of the coolant and of corrosion products that are circulated in the reactor coolant. These sources and their bases are described in Section 11.1.

The activation product, nitrogen-16 (N-16), is the predominant contributor to the activity in the reactor coolant pumps, steam generators, and reactor coolant piping during operation. The N-16 activity in each of the components depends on the total transit time to the component and the average residence time in the component. Table 12.2-3 presents the reactor coolant N-16 activity as a function of transport time in a reactor coolant loop. The N-16 activity for the pressurizer is tabulated in Table 12.2-4.

Fission and corrosion product activities circulating in the reactor coolant system and out-of-core crud deposits comprise the remaining significant radiation sources during full-power operation. The fission and corrosion product activities circulating in the reactor coolant are given in Section 11.1. The fission and corrosion product source strengths and specific activities in the pressurizer liquid and vapor phases are given in Table 12.2-5.

The isotopic composition and specific activity of typical out-of-core crud deposits are given in Table 12.2-6. Typically, one milligram of deposited crud material is found on one square centimeter of a relatively smooth surface. This may be as much as 50 times higher in crud trap areas. Crud trap areas are generally locations of high turbulence, areas of high momentum change, gravitational sedimentation areas, high affinity material areas, and possibly thin boundary layer regions.

The N-16 activity is not a factor in the radiation sources for systems and components located outside containment. This is due to its short half-life (7.11 seconds) and the greater than one minute transport

time before flow exits the containment. The normal letdown flow path is entirely inside containment. Primary coolant is directed outside containment only when it is diverted to the liquid radwaste system (e.g., due to boron dilution operations or for degassing prior to shutdown).

12.2.1.1.3 Chemical and Volume Control System

Radiation sources in the chemical and volume control system consist of radionuclides carried in the reactor coolant. The chemical and volume control system components in the purification path are located inside containment. The chemical and volume control system carries radioactive fluid out of the containment only when reactor coolant is directed to the liquid radwaste system.

The shielding design of the chemical and volume control system components is based on processing reactor coolant having the design basis source term presented in Section 11.1. The regenerative and letdown heat exchanger sources include contributions from N-16. Owing to its short half-life, the concentration of N-16 is highly sensitive to the location of these heat exchangers with respect to the reactor coolant loop piping. The concentration of N-16 at the heat exchangers is assumed to be the value in the reactor coolant when it exits the steam generator (see Table 12.2-3). The radiation sources for the other components in the purification loop do not include a contribution from N-16. The N-16 contribution to the shielding source term for the filter and demineralizers is determined based on the additional decay afforded by the time delay resulting from the system layout. The chemical and volume control system component sources are provided in Table 12.2-7.

12.2.1.1.4 Service Water System and Component Cooling Water System

These systems are normally nonradioactive or, if there is inleakage of radioactive material into the systems, of very low level activity. For shielding and dose assessment purposes, these systems are assumed to be nonradioactive.

12.2.1.1.5 Spent Fuel Pool Cooling System

One of the functions of the spent fuel pool cooling system is to provide cleanup of the water in the spent fuel pool, the refueling cavity, and the in-containment refueling water storage tank. The equipment considered in designing shielding are the spent fuel pool cooling system demineralizers and filters which accumulate activity, primarily Co-58 and Co-60 from radioactive crud that is resuspended in the water during the course of fuel handling. The source terms for this equipment are provided in Table 12.2-8. Based on operating experience, the remainder of the spent fuel pool cooling system may contain a significant amount of crud and thus requires shielding. The composition of crud is provided in Table 12.2-6.

12.2.1.1.6 Main Steam Supply System

Potential radioactivity in the main steam supply system is a result of steam generator tube leaks and is sufficiently low so that radiation shielding is needed around secondary components, which are capable of concentrating the system's activity, including the steam generator blowdown system (BDS) filter, the electrodeionization (EDI) unit, and the condensate polisher(s).

12.2.1.1.7 Liquid Radwaste System

Radioactive inputs include fission and activation product radionuclides produced in the core and reactor coolant. Shielding for each component of the liquid radwaste system is based on the sources listed on Table 12.2-9. Radiation sources for the various pumps in the liquid radwaste system are assumed to be identical to the liquid sources in the tank from which the pump takes suction.

12.2.1.1.8 Gaseous Radwaste System

Radioactive gases and hydrogen removed from the reactor coolant when coolant is discharged to the liquid radwaste system comprise the bulk of the gas processed by the gaseous radwaste system. There is no gas stripping performed in the reactor coolant purification loop of the chemical and volume control system. The result is that the volume of gases processed by the gaseous radwaste system is small. Table 12.2-10 lists the shielding sources for the components in the gaseous radwaste system.

12.2.1.1.9 Solid Radwaste System

The solid radwaste system handles various radioactive waste products ranging from relatively low activity materials to high activity spent resins and filter cartridges. Solid wastes are packaged for shipment to a burial or long-term storage facility.

Prior to packaging, the spent resin is stored in a spent resin storage tank. Two spent resin storage tanks are provided, one for high activity resins and the other for low activity resins. The initial gamma source strength in the high activity spent resin storage tank is assumed to be the same as that in the chemical and volume control system mixed bed demineralizer. After a 30-day decay period, only the cesium and cobalt isotopes are significant contributors to the radiation field. Table 12.2-11 lists the source strengths and specific activities both initially and after 30 days of decay.

Spent filter cartridge sources are as listed in Tables 12.2-7, 12.2-8, and 12.2-9.

12.2.1.1.10 Miscellaneous Sources

There are additional contained sources used for instrument calibration or for radiography. These sources will be identified as discussed in Subsection 12.2.3.

Licensed sources containing byproduct, source, and special nuclear material that warrant shielding design consideration meet the applicable requirements of 10 CFR Parts 20, 30, 31, 32, 33, 34, 40, 50, and 70.

There are byproduct and source materials with known isotopes and activity manufactured for the purpose of measuring, checking, calibrating, or controlling processes quantitatively or qualitatively.

These sources include but are not limited to:

- Sources in field monitoring equipment.
- Sources in radiation monitors to maintain a threshold sensitivity.
- Sources used for radiographic operations.
- Depleted uranium slabs used to determine beta response and correction factors for portable monitoring instrumentation.
- Sources used to calibrate and response check field monitoring equipment (portable and fixed).
- Liquid standards and liquids or gases used to calibrate and verify calibration of laboratory counting and analyzing equipment.
- Radioactive waste generated by the use of radioactive sources.

Specific details of these sources are maintained in a database on-site following procurement. This database, at a minimum, contains the following information:

- Isotopic composition
- Location in the plant
- Source strength
- Source geometry

Written procedures are established and implemented that address procurement, receipt, inventory, labeling, leak testing, surveillance, control, transfer, disposal, storage, issuance and use of these radioactive sources. These procedures are developed in accordance with the radiation protection program to comply with 10 CFR Parts 19 and 20.

Sources maintained on-site for instrument calibration purposes are shielded while in storage to keep personnel exposure ALARA. Sources used to service or calibrate plant instrumentation are also routinely brought on-site by contractors. Radiography is performed by the licensed utility group or licensed contractors. These sources are maintained and used in accordance with the provisions of the utility group's or contractor's license. Additional requirements and restrictions may apply depending on the type of source, use, and intended location of use. If the utility group or contractor source must be stored on-site, designated plant personnel must approve the storage location, and identify appropriate measures for maintaining security and personnel protection.

The radiation protection (RP) calibration lab equipment containing a sealed source (up to 725 curies Cs-137) is to be located so that the adjacent rooms are maintained at Zone I levels.

During the period prior to the implementation of the Emergency Plan (in preparation for the initial fuel loading following the 52.103(g) finding), no specific materials related emergency plan will be necessary because:

a) No byproduct material will be received, possessed, or used in a physical form that is "in unsealed form, on foils or plated sources, or sealed in glass," that exceeds the quantities in Schedule C in 10 CFR 30.72, and

b) No 10 CFR Part 40 specifically licensed source material, including natural uranium, depleted uranium and uranium hexafluoride will be received, possessed, or used during this period.

The following radioactive sources will be used for the Radiation Monitoring System and laboratory/ portable monitoring instrumentation:[1]

Radioactive Licensee Material (Element and Mass Number)[1]	Chemical and/or Physical Form[1]	Maximum Quantity That Licensee May Possess at Any One Time[1]
• Any byproduct material with atomic numbers 1 through 93 inclusive	Sealed Sources[2]	No single source to exceed 100 millicuries 5 Curies total
• Americium-241	Sealed Sources[2]	No single source to exceed 300 millicuries 500 millicuries total
• Cesium-137 stationary source located in RP calibration lab calibration equipment	Sealed Source	725 curies

Notes:

1. This information remains in effect between the issuance of the COL and the Commission's 52.103(g) finding for each unit, and will be designated historical information after that time.
2. Includes calibration and reference sources.

12.2.1.1.11 Passive Core Cooling System

The passive core cooling system is comprised, in part, of the in-containment refueling water storage tank (IRWST) and the passive residual heat removal heat exchanger (PRHR HX). Radioactivity is assumed to enter the IRWST via reactor coolant system inleakage from the PRHR HX and refueling cavity drain-down. Nuclides are removed from the liquid via the spent fuel pool cooling system (SFS) cleanup, radioactive decay, draining (overflow) to the sump, evolution of gaseous radionuclides, and plateout within the IRWST.

IRWST design basis fission and corrosion product source strengths and specific activities are listed in Table 12.2-30. IRWST expected fission and corrosion product source strengths and specific activities are listed in Table 12.2-31.

12.2.1.2 Sources for Shutdown

In the reactor shutdown condition, the only additional significant sources requiring permanent shielding consideration are the spent reactor fuel and the residual heat removal system. Individual components may require shielding during shutdown due to deposited crud material. Estimates of accumulated crud in the reactor coolant system are given in Subsection 12.2.1.1. The radiation sources in the reactor coolant system and other systems addressed in Subsection 12.2.1.1 are bounded by the sources given for full power operation with the exception of a short time period (less than 24 hours) following shutdown, during which crud bursts can result in increased radiation sources. Crud bursts are the resuspension of a portion of the accumulated deposited corrosion products into the reactor coolant system during shutdown operation. Activity increases also occur during planned coolant oxygenation procedures prior to refueling activities.

12.2.1.2.1 Normal Residual Heat Removal System

The maximum gamma ray source strengths in the normal residual heat removal system for four and eight hours after reactor shutdown are given in Table 12.2-12 along with the listing of contributing nuclides. The system may be placed in operation at the maximum flow rate at approximately four hours following a shutdown. The system removes decay heat from the reactor for the duration of the shutdown. The sources given are maximum values taking into account activity increases due to coolant oxygenation measures.

12.2.1.2.2 Reactor Core

The core average gamma ray and neutron source strengths are used in the evaluation of radiation levels within and around the shutdown reactor.

The basis for the core average source strengths is an equilibrium cycle core at end-of-life. Feed enrichment of 4.9 (68 assemblies) weight-percent U-235 was assumed. The regions operate at a specific power of 40.7 megawatts (thermal) per metric ton of uranium for 520, 1040, and 1561 effective full-power days, respectively (this is for an 18 month fuel cycle with a 95 percent capacity factor).

Core average gamma ray source strengths are presented in Table 12.2-2 for various times after shutdown. These source strengths may be put on a per-unit volume of homogenized core basis by multiplying them by the core power density (109.7 watts/cc).

Neutrons are produced in the shutdown reactor by spontaneous fission of the transplutonium isotopes and by (α, n) reactions of alpha particles with 0-17 and 0-18 in the uranium dioxide fuel.

Core average neutron source strengths are given in Table 12.2-13 for various times after shutdown. The neutron source strengths may be put on a per-unit volume of homogenized core basis by multiplying them by the power density.

12.2.1.2.3 Spent Fuel

Spent fuel gamma ray and neutron source strengths are used in the evaluation of radiation levels for fuels handling, spent fuel storage, and shipping.

The basis for the spent fuel data presented here is the discharge region of an equilibrium cycle core at end of life. A feed enrichment of 4.9 weight-percent U-235 is assumed. The discharge region was operated at a specific power of 40.7 megawatts (thermal) per metric ton of uranium for 1561 effective full-power days.

Spent fuel gamma ray source strengths are presented in Table 12.2-14 for various times after shutdown. These source strengths may be put on a per-unit volume of homogenized core basis by multiplying by the power density (109.7 watts/cc).

Spent fuel neutron source strengths are given in Table 12.2-13 for various times after shutdown. The neutron source strengths may be put on a per-unit volume of homogenized core basis by multiplying them by the power density.

12.2.1.2.4 Irradiated Control Rods, Gray Rods, and Secondary Source Rods

The gamma ray source strengths of the irradiated control rods, gray rods, and secondary source rods are used in establishing radiation shielding requirements during refueling operations and during shipping of irradiated rods.

The absorber material used in the control rods is silver-indium-cadmium (Ag-In-Cd). The gray rods contain tungsten in a nickel alloy 718 sleeve. The gamma ray source strengths associated with the irradiated Ag-In-Cd control rod absorber and gray rod materials are listed in Table 12.2-15 for various times after shutdown.

The photoneutron source material used in the secondary source rods is an equal volume mixture of antimony and beryllium (Sb-Be). The gamma ray source strengths associated with the secondary source rods are listed in Table 12.2-16 for various times after shutdown and Table 12.2-17 lists the neutron source strengths. The source values are per cubic centimeter of source material for an irradiation period of 400 days.

The material used for the control rod cladding, gray rod cladding and/or pellets and secondary source rod cladding is Type 304 stainless steel with a maximum cobalt content of 0.05 weight percent. The gamma ray source strengths associated with the irradiated stainless steel are listed in Table 12.2-18 for various times after shutdown.

12.2.1.2.5 Incore Flux Thimbles

Irradiated incore flux thimble gamma ray source strengths are given in Table 12.2-19.

12.2.1.3 Sources for the Core Melt Accident

The AP1000 is designed to provide adequate core cooling in the event of a postulated loss of coolant accident (LOCA) so that there is no significant core damage. Following a LOCA, the normal residual heat removal system could be used, if available, to provide post-accident cooling. Use of the normal

residual heat removal system is acceptable only if the source term is close to the design basis source term (see Table 12.2-12).

For the evaluation of the radiological consequences of the LOCA, it is assumed that major degradation of the core takes place, including melting of the core. The source term used for the LOCA dose analysis assumes no core release for 10 minutes, then there is a gap release from a small number of fuel rods before the onset of core degradation. The first half hour of core release is restricted to releases from the fuel cladding gap; this gap release phase is followed by the in-vessel core melt phase that has a duration of 1.3 hours. After the in-vessel core melt phase, there is assumed to be no further release of activity from the core. This core activity release model is based on the source term model from NUREG-1465 (Reference 1). The source term is described in detail in Subsection 15.6.5.3.

12.2.1.3.1 Containment

If there is core degradation, core cooling would be provided by the passive core cooling system which is totally inside the containment such that no high activity sump solution would be recirculated outside the containment. The shielding provided for the containment addresses this post-LOCA source term. The source strengths as a function of time are provided in Table 12.2-20 and the integrated source strengths are provided in Table 12.2-21.

12.2.1.3.2 Main Control Room HVAC Filter

During operation of the nuclear island nonradioactive ventilation system (VBS) supplemental filtration or the main control room emergency habitability system (VES), filters in the control room HVAC work to remove particulate and iodine from the air. As radioactivity accumulates within the filters, this becomes a potential source of dose. These source strengths as a function of time are provided in Table 12.2-28 and the integrated source strengths are provided in Table 12.2-29.

12.2.2 Airborne Radioactive Material Sources

This subsection deals with the models, parameters, and sources required to evaluate airborne concentration of radionuclides during plant operations in various plant radiation areas where personnel occupancy is expected.

12.2.2.1 Containment Atmosphere

The main sources of airborne activity in the containment is leakage of primary coolant and activation of naturally occurring argon in the atmosphere. During normal power operation, excessive activity buildup in the containment atmosphere is prevented by periodic purging of the containment (approximately 20 hours per week). When the plant is shut down for refueling or maintenance, additional purging of the containment atmosphere is performed to further reduce the activity levels consistent with the increased level of worker presence in the containment. The assumptions and parameters used to determine the airborne activity levels in the containment are listed in Table 12.2-22. The airborne concentrations are provided in Table 12.2-23. Three situations are considered: normal power operation without purge, normal power operation with 20 hours of purge operation per week, and shutdown operation.

12.2.2.2 Fuel-Handling Area Atmosphere

The source of airborne activity in the fuel-handling area is leakage from stored spent fuel assemblies and the evaporation losses from the spent fuel pool. The maximum airborne concentration in the fuel-handling area is calculated using the assumptions and parameters in Table 12.2-24. The resulting airborne isotopic concentrations are provided in Table 12.2-25.

12.2.2.3 Auxiliary Building Atmosphere

The source of airborne activity in the auxiliary building atmosphere is primarily equipment leakage. The ventilation system constantly removes activity and discharges it to the plant vent. The maximum airborne concentration in the auxiliary building is calculated using the assumptions and parameters in Table 12.2-26. The resulting airborne isotopic concentrations are provided in Table 12.2-27.

12.2.2.4 Airborne Activity Model

The airborne concentration of each nuclide in the atmosphere is calculated by:

$$C_i(t) = \frac{(LR)_i \, A_i \, (PF)_i \, (1 - e^{-\lambda_{Ti} t})}{(V)\,(\lambda_{Ti})}$$

where:

$(LR)_i$ = leak or evaporation rate of the Ith radioisotope in the applicable region (g/s)

A_i = activity concentration of the Ith leaking or evaporating radioisotope (μCi/g)

$(PF)_i$ = partition factor or the fraction of the leaking activity that is airborne for the Ith radioisotope

λ_{Ti} = total removal rate constant for the Ith radioisotope from the applicable region (s^{-1})

= $\lambda_{di} + \lambda_e$, the removal rate constants in s^{-1} due to radioactive decay for the Ith radioisotope and the exhaust from the applicable region, respectively

t = time elapsed from the start of the leak and the time at which the concentration is evaluated (s)

V = free volume of the region in which the leak occurs (cm^3)

$C_i(t)$ = airborne concentration of the Ith radioisotope at time t in the applicable region (μCi/cm^3).

From the above equation, the peak or equilibrium concentration, C_{Egi}, of the Ith radioisotope in the applicable volume is given by the following expression:

$$C_{Egi} = (LR)_I \, A_I \, (PF)_I \, / V\lambda_{Ti}$$

With high exhaust rates, this peak concentration is reached within a few hours.

12.2.3 Combined License Information

The additional contained radiation sources not identified in Subsection 12.2.1, including radiation sources used for instrument calibration or radiography, are addressed in Subsection 12.2.1.1.10.

12.2.4 References

1. L. Soffer, et al., "Accident Source Terms for Light-Water Nuclear Power Plants," NUREG-1465, February 1995.

Table 12.2-1
Radiation Flux at the Primary Shield Concrete

Neutron Flux	
Energy	**Flux (n/cm^2-sec)**
≥ 1 Mev	2.4E+09
0.1 Mev to 1 Mev	1.8E+10
0.414 ev to 0.1 Mev	2.7E+10
< 0.414 ev	6.4E+9
Gamma Energy Flux	
Energy	**Flux (Mev/cm^2-sec)**
≥ 6.0 Mev	1.2E+10
3.0 Mev to 6.0 Mev	8.3×10^9
1.0 Mev to 3.0 Mev	5.9×10^9
< 1.0 Mev	3.9×10^9

Table 12.2-2 (Sheet 1 of 2)
Core Average Gamma Ray Source Strengths
at Various Times After Shutdown

Energy Group (Mev/gamma)	Source Strength at Time After Shutdown (Mev/watt-sec)				
	12 Hours	24 Hours	100 Hours	1 Week	1 Month
0.000-0.020	1.8E+08	1.5E+08	6.5E+07	3.1E+07	1.4E+06
0.020-0.030	4.2E+07	3.7E+07	2.2E+07	1.6E+07	3.9E+06
0.030-0.045	1.1E+08	1.0E+08	6.1E+07	4.5E+07	1.5E+07
0.045-0.070	6.5E+07	5.9E+07	3.2E+07	2.0E+07	1.9E+06
0.070-0.100	3.6E+08	3.2E+08	1.6E+08	9.4E+07	8.6E+06
0.100-0.150	1.5E+09	1.3E+09	6.3E+08	3.6E+08	8.7E+07
0.150-0.300	2.2E+09	1.8E+09	7.1E+08	3.5E+08	1.4E+07
0.300-0.450	9.3E+08	8.2E+08	5.2E+08	3.9E+08	7.6E+07
0.450-0.700	5.3E+09	4.3E+09	2.4E+09	1.9E+09	9.5E+08
0.700-1.000	6.8E+09	5.9E+09	4.3E+09	3.8E+09	2.6E+09
1.000-1.500	2.0E+09	1.2E+09	4.9E+08	3.3E+08	9.2E+07
1.500-2.000	3.4E+09	3.1E+09	2.6E+09	2.3E+09	6.6E+08
2.000-2.500	3.0E+08	2.0E+08	1.4E+08	1.2E+08	4.9E+07
2.500-3.000	1.9E+08	1.8E+08	1.5E+08	1.3E+08	3.9E+07
3.000-4.000	5.2E+06	1.9E+06	1.6E+06	1.4E+06	4.4E+05
4.000-6.000	3.5E+05	1.9E+04	4.6E+00	4.6E+00	4.4E+00
6.000-8.000	7.4E-01	7.4E-01	7.4E-01	7.4E-01	7.1E-01
8.000-11.000	1.2E-01	1.2E-01	1.2E-01	1.1E-01	1.1E-01

Table 12.2-2 (Sheet 2 of 2)
Core Average Gamma Ray Source Strengths
at Various Times After Shutdown

Energy Group (Mev/gamma)	Source Strength at Time After Shutdown (Mev/watt-sec)			
	3 Months	6 Months	1 Year	5 Years
0.000-0.020	3.0E+05	1.7E+05	1.0E+05	2.9E+04
0.020-0.030	9.6E+05	3.8E+05	2.2E+05	7.4E+04
0.030-0.045	6.7E+06	4.3E+06	2.8E+06	4.5E+05
0.045-0.070	2.5E+05	1.6E+05	1.1E+05	5.6E+04
0.070-0.100	2.5E+06	1.9E+06	1.3E+06	1.4E+05
0.100-0.150	3.4E+07	1.6E+07	8.7E+06	7.0E+05
0.150-0.300	1.5E+06	6.4E+05	3.8E+05	2.0E+05
0.300-0.450	5.6E+06	2.5E+06	1.9E+06	6.4E+05
0.450-0.700	4.8E+08	3.1E+08	2.3E+08	9.4E+07
0.700-1.000	1.5E+09	7.2E+08	2.0E+08	3.3E+07
1.000-1.500	4.3E+07	3.5E+07	2.7E+07	8.4E+06
1.500-2.000	2.9E+07	2.8E+06	1.8E+06	2.9E+05
2.000-2.500	2.1E+07	1.6E+07	1.0E+07	3.1E+05
2.500-3.000	1.7E+06	1.6E+05	1.0E+05	6.6E+03
3.000-4.000	4.8E+04	2.8E+04	1.9E+04	1.2E+03
4.000-6.000	4.1E+00	3.8E+00	3.4E+00	2.7E+00
6.000-8.000	6.7E-01	6.2E-01	5.5E-01	4.4E-01
8.000-11.000	1.0E-01	9.6E-02	8.6E-02	6.8E-02

Table 12.2-3
Reactor Coolant Nitrogen-16 Activity

Position in Loop	Loop Transit Time (sec)	Nitrogen-16 Activity (µCi/g)
Leaving core	0.0	280
Leaving reactor vessel	0.9	256
Entering steam generator	1.2	249
Leaving steam generator	6.8	144
Entering reactor vessel	8.0	128
Entering core	9.5	122
Leaving core	10.3	280

Table 12.2-4
Pressurizer Nitrogen-16 Source Strengths

Discrete Energy (Mev/gamma)	Energy Group (Mev/gamma)	Source Strength	
		Liquid Phase[(a)] (Mev/gram-sec)	Steam Phase[(b)] (Mev/cm^3-sec)
1.75	1.35 - 1.80	5.4E-02	1.4E-01
2.74	2.6 - 3.0	5.0E-01	1.3E+00
6.13	6.0 - 7.0	1.0E+02	2.6E+02
7.12	7.0 - 7.5	8.5E+00	2.2E+01

Notes:

a. Based on an insurge to the pressurizer following a ten percent step load power increase.

b. Based on a boron equalization spray rate of 80 gpm.

Table 12.2-5 (Sheet 1 of 4)
Pressurizer Liquid and Steam Phase
Source Strengths and Specific Activity

1000 Cubic Foot Liquid Phase Source Strengths	
Energy Group (Mev/gamma)	**Source Strength (Mev/gram-sec)**
0-0.02	1.4E+03
0.02-0.03	1.6E+03
0.03-0.045	6.9E+04
0.045-0.07	3.2E+02
0.07-0.1	1.4E+05
0.1-0.15	1.1E+03
0.15-0.3	4.3E+04
0.3-0.45	2.3E+04
0.45-0.7	1.0E+05
0.7-1.0	1.3E+05
1.0-1.5	1.2E+05
1.5-2.0	5.9E+04
2.0-2.5	9.3E+04
2.5-3.0	1.5E+04
3.0-4.0	2.6E+03
4.0-6.0	5.0E+02
6.0-8.0	-
8.0-11.00	-
Total	7.9E+05

Table 12.2-5 (Sheet 2 of 4)
Pressurizer Liquid and Steam Phase
Source Strengths and Specific Activity

1000 Cubic Foot Liquid Phase Specific Activity	
Nuclide	**Activity (µCi/gram)**
Kr-87	4.7E-01
Kr-88	1.5E+00
Kr-89	3.5E-02
Xe-131m	1.3E+00
Xe-133m	1.7E+00
Xe-133	1.2E+02
Xe-135	3.5E+00
Br-84	1.7E-02
I-131	7.1E-01
I-132	9.3E-01
I-133	1.3E+00
I-134	2.2E-01
I-135	7.8E-01
Rb-88	1.5E+00
Cs-134	6.9E-01
Cs-136	1.0E+00
Cs-138	3.7E-01
Tc-99m	2.0E-01

Table 12.2-5 (Sheet 3 of 4)
Pressurizer Liquid and Steam Phase
Source Strengths and Specific Activity

1100 Cubic Foot Steam Phase Source Strengths (Mev/cm^3-sec)	
Energy Group (Mev/gamma)	**Normal 2-gpm Spray**
0-0.02	2.3E+03
0.02-0.03	2.1E+03
0.03-0.045	1.3E+05
0.045-0.07	2.0E-04
0.07-0.1	2.7E+05
0.1-0.15	1.9E+00
0.15-0.3	6.7E+03
0.3-0.45	5.0E+02
0.45-0.7	1.7E+03
0.7-1.0	8.4E+02
1.0-1.5	6.3E+02
1.5-2.0	6.3E+02
2.0-2.5	2.9E+03
2.5-3.0	1.3E+02
3.0-4.0	4.3E+00
4.0-6.0	2.2E-05
6.0-8.0	-
8.0-11.00	-
Total	4.1E+05

Table 12.2-5 (Sheet 4 of 4)
Pressurizer Liquid and Steam Phase
Source Strengths and Specific Activity

1100 Cubic Foot Steam Phase Specific Activity ($\mu Ci/cm^3$)	
Nuclide	**Normal 2-gpm Spray**
Kr-85m	5.2E-02
Kr-85	9.0E+00
Kr-87	6.7E-03
Kr-88	5.5E-02
Kr-89	1.7E-08
Xe-131m	2.9E+00
Xe-133m	1.4E+00
Xe-133	2.4E+02
Xe-135	4.6E-01
Xe-138	1.7E-04
I-131	7.1E-03
I-132	9.3E-03
I-133	1.3E-02
I-134	2.2E-03
I-135	7.8E-03

Table 12.2-6
Isotopic Composition and Specific Activity of Typical Out-of-Core Crud Deposits[a]

Composition (Nuclide)	Activity (μCi/mg) of Deposited Crud for Effective Full Power Years of Plant Operation			
	1 Year	2 Years	5 Years	10 Years
Mn-54	1.0	1.1	1.3	1.4
Fe-59	0.5	0.5	0.5	0.5
Co-58	12.0	12.0	12.0	12.0
Co-60	1.5	2.3	4.0	6.0

Note:

a. In addition to corrosion products, about 1.0 μg of mixed actinides and fission products may be present for each 1 g of deposited crud.

Table 12.2-7 (Sheet 1 of 8)
Chemical and Volume Control System Components
Source Strengths and Specific Activity

A. Regenerative heat exchanger		
Energy Group (Mev/gamma)	**Source Strength (Mev/gram-sec)**	
	Tube Side	**Shell Side**
0-0.02	1.4E+03	1.4E+03
0.02-0.03	1.6E+03	1.6E+03
0.03-0.045	6.9E+04	6.9E+04
0.045-0.07	3.2E+02	3.2E+02
0.07-0.1	1.4E+05	1.4E+05
0.1-0.15	1.1E+03	1.1E+03
0.15-0.3	4.3E+04	4.2E+04
0.3-0.45	2.3E+04	1.5E+04
0.45-0.7	1.0E+05	4.7E+04
0.7-1.0	1.3E+05	7.5E+04
1.0-1.5	1.2E+05	7.7E+04
1.5-2.0	7.1E+04	4.2E+04
2.0-2.5	9.3E+04	8.9E+04
2.5-3.0	1.3E+05	1.5E+04
3.0-4.0	2.6E+03	2.2E+03
4.0-6.0	5.0E+02	5.0E+02
6.0-8.0	2.5E+07	-
8.0-11.00	-	-
Total	2.5E+07	6.2E+05

Table 12.2-7 (Sheet 2 of 8)
Chemical and Volume Control System Components
Source Strengths and Specific Activity

A. Regenerative heat exchanger		
Nuclide	**Activity (µCi/gram)**	
	Tube Side	**Shell Side**
Kr-87	4.7E-01	4.7E-01
Kr-88	1.5E+00	1.5E+00
Kr-89	3.5E-02	3.5E-02
Xe-131m	1.3E+00	1.3E+00
Xe-133m	1.7E+00	1.7E+00
Xe-133	1.2E+02	1.2E+02
Xe-135	3.5E+00	3.5E+00
Br-84	1.7E-02	--
I-131	7.1E-01	--
I-132	9.3E-01	--
I-133	1.3E+00	--
I-134	2.2E-01	--
I-135	7.8E-01	--
Rb-88	1.5E+00	1.5E+00
Cs-134	6.9E-01	6.9E-01
Cs-136	1.0E+00	1.0E+00
Cs-138	3.7E-01	3.7E-01
Tc-99m	2.0E-01	2.0E-01
Ba-137m	--	4.7E-01
N-16	1.4E+02	--

Table 12.2-7 (Sheet 3 of 8)
Chemical and Volume Control System Components
Source Strengths and Specific Activity

B. Letdown heat exchanger	
Energy Group (Mev/gamma)	**Source Strength (Mev/gram-sec)**
0-0.02	1.4E+03
0.02-0.03	1.6E+03
0.03-0.045	6.9E+04
0.045-0.07	3.2E+02
0.07-0.1	1.4E+05
0.1-0.15	1.1E+03
0.15-0.3	4.3E+04
0.3-0.45	2.3E+04
0.45-0.7	1.0E+05
0.7-1.0	1.3E+05
1.0-1.5	1.2E+05
1.5-2.0	7.1E+04
2.0-2.5	9.3E+04
2.5-3.0	1.3E+05
3.0-4.0	2.6E+03
4.0-6.0	5.0E+02
6.0-8.0	2.5E+07
8.0-11.00	-
Total	2.5E+07

Table 12.2-7 (Sheet 4 of 8)
Chemical and Volume Control System Components
Source Strengths and Specific Activity

B. Letdown heat exchanger	
Nuclide	**Activity (µCi/gram)**
Kr-87	4.7E-01
Kr-88	1.5E+00
Kr-89	3.5E-02
Xe-131m	1.3E+00
Xe-133m	1.7E+00
Xe-133	1.2E+02
Xe-135	3.5E+00
Br-84	1.7E-02
I-131	7.1E-01
I-132	9.3E-01
I-133	1.3E+00
I-134	2.2E-01
I-135	7.8E-01
Rb-88	1.5E+00
Cs-134	6.9E-01
Cs-136	1.0E+00
Cs-138	3.7E-01
Tc-99m	2.0E-01
N-16	1.4E+02

Table 12.2-7 (Sheet 5 of 8)
Chemical and Volume Control System Components
Source Strengths and Specific Activity

C. Mixed bed demineralizer (50 cubic feet of resin)	
Energy Group (Mev/gamma)	**Source Strength (Mev/gram-sec)**
0-0.02	1.7E+04
0.02-0.03	1.1E+05
0.03-0.045	3.5E+05
0.045-0.07	4.8E+04
0.07-0.1	2.2E+05
0.1-0.15	4.8E+03
0.15-0.3	2.2E+06
0.3-0.45	2.8E+07
0.45-0.7	1.8E+08
0.7-1.0	9.9E+07
1.0-1.5	2.8E+07
1.5-2.0	4.2E+06
2.0-2.5	8.7E+05
2.5-3.0	7.4E+05
3.0-4.0	9.9E+04
4.0-6.0	2.7E+03
6.0-8.0	-
8.0-11.00	-
Total	3.4E+08

Table 12.2-7 (Sheet 6 of 8)
Chemical and Volume Control System Components
Source Strengths and Specific Activity

C. Mixed bed demineralizer (50 cubic feet of resin)	
Nuclide	**Activity (µCi/gram)**
Mn-54	6.2E+01
Mn-56	1.3E+01
Co-58	7.2E+01
Co-60	7.8E+01
I-131	2.4E+03
I-132	4.3E+01
I-134	3.9E+00
I-135	9.9E+01
Rb-88	8.9E+00
Cs-134	3.0E+03
Cs-136	1.6E+02
Cs-137	3.0E+03
Ba-137m	2.8E+03

Table 12.2-7 (Sheet 7 of 8)
Chemical and Volume Control System Components
Source Strengths and Specific Activity

D. Cation bed demineralizer (50 cubic feet of resin)	
Energy Group (Mev/gamma)	**Source Strength (Mev/gram-sec)**
0-0.02	6.3E+03
0.02-0.03	-
0.03-0.045	3.3E+05
0.045-0.07	4.8E+04
0.07-0.1	3.1E+04
0.1-0.15	2.9E+03
0.15-0.3	5.1E+05
0.3-0.45	9.9E+05
0.45-0.7	1.6E+08
0.7-1.0	9.0E+07
1.0-1.5	1.6E+07
1.5-2.0	1.9E+06
2.0-2.5	4.4E+05
2.5-3.0	6.9E+05
3.0-4.0	9.3E+04
4.0-6.0	2.7E+03
6.0-8.0	-
8.0-11.00	-
Total	2.7E+08

Table 12.2-7 (Sheet 8 of 8)
Chemical and Volume Control System Components
Source Strengths and Specific Activity

D. Cation bed demineralizer (50 cubic feet of resin)	
Nuclide	**Activity (μCi/gram)**
Rb-88	8.9E+00
Cs-134	3.0E+03
Cs-136	1.6E+02
Cs-137	3.0E+03
Cs-138	3.7E+00
Ba-137m	2.8E+03
E. Reactor coolant filter	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.4 - 0.9	5.7E+07
0.9 - 1.35	1.5E+07

Table 12.2-8
Spent Fuel Pool Cooling System Component
Source Strengths and Specific Activity

A. Demineralizer (75 cubic feet of resin)	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.4 - 0.9	3.0E+06
0.9 - 1.35	4.7E+06
Nuclide	**Activity ($\mu Ci/cm^3$)**
Co-58	5.8E+01
Co-60	3.4E+01
B. Filters	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.4 - 0.9	1.1E+07
0.9 - 1.35	3.0E+06
Source Dimensions (inches)	**Source Composition (volume percent)**
Radius = 3.375	Air – 67
Length = 19	Water – 33

Table 12.2-9 (Sheet 1 of 7)
Liquid Radwaste System
Component Source Terms

A. Reactor coolant drain tank		
	Source Strength (Mev/cm^3-sec)	
Energy Group (Mev/gamma)	**Liquid Phase (450 gallons)**	**Gas Space (60 cubic feet)**
0.000-0.020	1.4E+03	1.4E+02
0.020-0.030	1.6E+03	2.0E+02
0.030-0.045	6.9E+04	7.6E+03
0.045-0.070	3.2E+02	6.1E-05
0.070-0.100	1.4E+05	1.5E+04
0.100-0.150	1.1E+03	8.4E-02
0.150-0.300	4.3E+04	4.2E+02
0.300-0.450	2.3E+04	2.6E+01
0.450-0.700	1.0E+05	4.1E+03
0.700-1.000	1.3E+05	2.3E+01
1.000-1.500	1.2E+05	1.4E+01
1.500-2.000	5.9E+04	3.3E+01
2.000-2.500	9.3E+04	2.0E+02
2.500-3.000	1.5E+04	1.0E+01
3.000-4.000	2.6E+03	3.7E-01
4.000-6.000	5.0E+02	2.2E-03
6.000-8.000	-	-
8.000-11.000	-	-
Total	7.9E+05	2.8E+04

Table 12.2-9 (Sheet 2 of 7)
Liquid Radwaste System
Component Source Terms

A. Reactor coolant drain tank		
Nuclide	**Activity ($\mu Ci/cm^3$)**	
	Liquid Phase	**Gas Space**
Mn-56	1.7E-01	-
I-132	9.3E-01	-
I-134	2.2E-01	-
Kr-87	4.7E-01	-
Kr-88	1.5E+00	-
I-131	7.1E-01	-
I-133	1.3E+00	-
Xe-133	1.2E+02	-
I-135	7.8E-01	-
Xe-135	3.5E+00	-
Xe-138	2.4E-01	-
Rb-88	1.5E+00	-
Cs-134	6.9E-01	-
Cs-136	1.0E+00	-
Ba-137m	4.7E-01	-
Cs-138	3.7E-01	-
Kr-85	-	5.0E+01
Kr-87	-	5.4E-04
Kr-88	-	3.8E-03
Xe-131m	-	3.4E-01
Xe-133m	-	8.0E-02
Xe-133	-	1.4E+01
Xe-135	-	2.8E-02

Notes:
The liquid activities listed are 99% of the total source strength.
The vapor activities listed are essentially 100% of the source strength.

Table 12.2-9 (Sheet 3 of 7)
Liquid Radwaste System
Component Source Terms

B. Effluent tank (28,000 gal) and waste holdup tank (15,000 gal)			
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**		
	Effluent Tank		**Holdup Tank Liquid**
	Liquid Phase	**Vapor Phase**	
0.000-0.020	1.9E+01	3.4E+03	1.9E+01
0.020-0.030	1.6E+01	4.0E+03	1.2E+01
0.030-0.045	2.7E+02	1.8E+05	2.7E+02
0.045-0.070	3.2E+02	4.5E-05	3.2E+02
0.070-0.100	2.2E+02	3.7E+05	2.1E+02
0.100-0.150	1.0E+03	3.6E+01	9.8E+02
0.150-0.300	3.4E+03	7.6E+04	3.3E+03
0.300-0.450	7.5E+03	5.4E+03	7.0E+03
0.450-0.700	4.1E+04	6.1E+03	3.8E+04
0.700-1.000	6.5E+04	1.0E+04	5.6E+04
1.000-1.500	7.1E+04	6.5E+03	4.7E+04
1.500-2.000	2.5E+04	1.5E+04	2.1E+03
2.000-2.500	6.5E+03	9.1E+04	5.7E+02
2.500-3.000	7.3E+03	4.0E+03	1.4E+02
3.000-4.000	1.5E+03	1.3E+02	1.7E+01
4.000-6.000	4.5E+02	9.8E-18	-
6.000-8.000	-	-	-
8.000-11.000	-	-	-
Total	2.3E+05	7.7E+05	1.6E+05

Table 12.2-9 (Sheet 4 of 7)
Liquid Radwaste System
Component Source Terms

B. Effluent tank (28,000 gal) and waste holdup tank (15,000 gal)			
	Activity ($\mu Ci/cm^3$)		
	Effluent Tank		
Nuclides	**Liquid Phase**	**Vapor Phase**	**Holdup Tank Liquid**
Mn-56	1.7E-02	–	1.7E-02
I-131	-	–	7.1E-02
I-132	9.3E-02	–	9.3E-02
I-133	1.3E-01	–	1.3E-01
I-134	2.2E-02	–	–
I-135	7.8E-02	–	7.8E-02
Rb-88	1.5E+00	–	–
Rb-89	6.9E-02	–	–
Cs-134	6.9E-01	–	6.9E-01
Cs-136	1.0E+00	–	1.0E+00
Cs-137	5.0E-01	–	5.0E-01
Ba-137m	5.0E-01	–	5.0E-01
Sr-89	–	–	1.1E-04
Cs-138	3.7E-01	–	–
Mo-99	2.1E-01	–	2.1E-01
Kr-85m	–	1.3E+00	–
Kr-85	–	8.0E+00	–
Kr-87	–	2.1E-01	–
Kr-88	–	1.8E+00	–
Xe-131m	–	3.6E+00	–
Xe-133m	–	4.3E+00	–
Xe-133	–	3.3E+02	–
Xe-135	–	7.3E+00	–

Notes:
The liquid activities listed are 99% of the total source strength.
The vapor activities listed are essentially 100% of the source strength.

Table 12.2-9 (Sheet 5 of 7)
Liquid Radwaste System
Component Source Terms

C. Chemical waste tank (7,700 gal)	
Energy Group (Mev/gamma)	**Source Strength (Mev/gram-sec)**
0-0.02	6.3E-01
0.02-0.03	1.2E-01
0.03-0.045	2.5E+01
0.045-0.07	3.1E-04
0.07-0.1	5.3E-03
0.1-0.15	3.2E-02
0.15-0.3	3.8E+00
0.3-0.45	5.6E+00
0.45-0.7	1.6E+04
0.7-1.0	9.7E+03
1.0-1.5	1.0E+03
1.5-2.0	1.5E+02
2.0-2.5	3.2E+01
2.5-3.0	5.3E+01
3.0-4.0	6.9E+00
4.0-6.0	–
6.0-8.0	–
8.0-11.00	–
Total	2.7E+04
Nuclide	**Activity (µCi/gram)**
Co-58	1.9E-03
Cs-134	3.4E-01
Cs-137	2.5E-01
Te-127m	3.8E-04
Ba-137m	2.3E-01
Ce-144	5.8E-05

Table 12.2-9 (Sheet 6 of 7)
Liquid Radwaste System
Component Source Terms

D. Waste ion exchanger and charcoal deep bed filter vessel[(a)]	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0-0.02	1.2E+03
0.02-0.03	5.5E+03
0.03-0.045	5.1E+04
0.045-0.07	5.8E+04
0.07-0.1	4.8E+04
0.1-0.15	3.4E+03
0.15-0.3	6.7E+05
0.3-0.45	2.5E+06
0.45-0.7	9.1E+06
0.7-1.0	1.1E+07
1.0-1.5	9.3E+06
1.5-2.0	6.0E+05
2.0-2.5	1.4E+05
2.5-3.0	2.9E+04
3.0-4.0	3.5E+03
4.0-6.0	–
6.0-8.0	–
8.0-11.00	–
Total	3.3E+07

Note:
a. Source term for the charcoal deep bed filter vessel is based on operation charged with resin instead of charcoal since this is the most conservative mode of operation for source terms.

Table 12.2-9 (Sheet 7 of 7)
Liquid Radwaste System
Component Source Terms

D. Waste ion exchanger and charcoal deep bed filter vessel[a]	
Nuclide	**Activity (μCi/cm^3)**
Mn-56	3.4E+00
I-131	1.2E+02
I-132	1.7E+01
I-133	1.1E+02
I-135	2.8E+01
Cs-134	1.4E+02
Cs-136	1.9E+02
Cs-137	9.9E+01
Ba-137m	9.4E+01
E. Waste prefilter and waste after filter	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.4 - 0.9	1.1E+07
0.9 - 1.35	3.0E+06
Total	1.4E+07
Source Dimensions (inches)	**Source Composition (volume percent)**
Radius = 3.375	Air - 67
Length = 19	Water - 33

Note:
a. Source term for the charcoal deep bed filter vessel is based on operation charged with resin instead of charcoal since this is the most conservative mode of operation for source terms.

Table 12.2-10 (Sheet 1 of 4)
Gaseous Radwaste System
Component Source Terms

A. Gas cooler and moisture separator	
Energy Group (MeV/gamma)	**Source Strength (MeV/cm^3-sec)**
0.000 - 0.020	3.2E+04
0.020 - 0.030	3.8E+04
0.030 - 0.045	1.7E+06
0.045 - 0.070	7.1E+00
0.070 - 0.100	3.4E+06
0.100 - 0.150	6.6E+02
0.150 - 0.300	9.4E+05
0.300 - 0.450	1.7E+05
0.450 - 0.700	1.6E+05
0.700 - 1.000	2.4E+05
1.000 - 1.500	1.6E+05
1.500 - 2.000	4.1E+05
2.000 - 2.500	2.0E+06
2.500 - 3.000	1.8E+05
3.000 - 4.000	1.8E+04
4.000 - 6.000	1.1E+03
6.000 - 8.000	0.0E+00
8.000 - 11.000	0.0E+00
Total	9.4E+06

Table 12.2-10 (Sheet 2 of 4)
Gaseous Radwaste System
Component Source Terms

A. Gas cooler and moisture separator	
Nuclide	**Activity ($\mu Ci/cm^3$)**
Kr-83m	4.4E+00
Kr-85m	2.0E+01
Kr-85	7.2E+01
Kr-87	1.2E+01
Kr-88	3.6E+01
Kr-89	8.4E-01
Xe-131m	3.2E+01
Xe-133m	4.1E+01
Xe-133	3.0E+03
Xe-135m	4.2E+00
Xe-135	8.5E+01
Xe-137	1.6E+00
Xe-138	5.9E+00

Table 12.2-10 (Sheet 3 of 4)
Gaseous Radwaste System
Component Source Terms

B. Charcoal guard and delay beds	
Energy Group (MeV/gamma)	**Source Strength (MeV/cm^3-sec)**
0.000 - 0.020	3.2E+04
0.020 - 0.030	3.8E+04
0.030 - 0.045	1.7E+06
0.045 - 0.070	7.1E+00
0.070 - 0.100	3.4E+06
0.100 - 0.150	6.6E+02
0.150 - 0.300	9.4E+05
0.300 - 0.450	1.7E+05
0.450 - 0.700	1.6E+05
0.700 - 1.000	2.4E+05
1.000 - 1.500	1.6E+05
1.500 - 2.000	4.1E+05
2.000 - 2.500	2.0E+06
2.500 - 3.000	1.8E+05
3.000 - 4.000	1.8E+04
4.000 - 6.000	1.1E+03
6.000 - 8.000	0.0E+00
8.000 - 11.000	0.0E+00
Total	9.4E+06

Note:
Due to the long hold-up time in the guard and delay beds, the source strength in the beds vary throughout the length of the beds as the source decays. The source strength listed represents the source strength entering the guard bed and delay beds.

Table 12.2-10 (Sheet 4 of 4)
Gaseous Radwaste System
Component Source Terms

B. Charcoal guard and delay beds	
Nuclide	**Activity ($\mu Ci/cm^3$)**
Kr-85m	2.0E+01
Kr-85	7.2E+01
Kr-87	1.2E+01
Kr-88	3.6E+01
Xe-131m	3.2E+01
Xe-133m	4.1E+01
Xe-133	3.0E+03
Xe-135m	4.2E+00
Xe-135	8.5E+01
Xe-138	5.9E+00

Table 12.2-11 (Sheet 1 of 2)
Spent Demineralizer Resin
Source Strengths and Specific Activities

Energy Group (Mev/gamma)	Spent Resin Source Strength (Mev/cm^3-sec)	
	Initial	After 30 Days
0-0.02	1.7E+04	1.3E+04
0.02-0.03	1.1E+05	8.1E+03
0.03-0.045	3.5E+05	3.0E+05
0.045-0.07	4.8E+04	9.7E+03
0.07-0.1	2.2E+05	2.1E+04
0.1-0.15	4.8E+03	5.7E+02
0.15-0.3	2.2E+06	2.6E+05
0.3-0.45	2.8E+07	2.3E+06
0.45-0.7	1.8E+08	1.6E+08
0.7-1.0	9.9E+07	8.8E+07
1.0-1.5	2.8E+07	1.7E+07
1.5-2.0	4.2E+06	1.9E+06
2.0-2.5	8.7E+05	3.8E+05
2.5-3.0	7.4E+05	6.4E+05
3.0-4.0	9.9E+04	8.3E+04
4.0-6.0	2.7E+03	–
6.0-8.0	–	–
8.0-11.00	–	–
Total	3.4E+08	2.7E+08

Table 12.2-11 (Sheet 2 of 2)
Spent Demineralizer Resin
Source Strengths and Specific Activities

Nuclide	Spent Resin Activity (μCi/cm^3)	
	Initial	After 30 Days
Mn-54	6.2E+01	5.8E+01
Mn-56	1.3E+01	-
Co-58	7.2E+01	5.4E+01
Co-60	7.8E+01	7.7E+01
I-131	2.4E+03	1.8E+02
I-132	4.3E+01	–
I-134	3.9E+00	–
I-135	9.9E+01	–
Rb-88	8.9E+00	–
Cs-134	3.0E+03	3.0E+03
Cs-136	1.6E+02	3.1E+01
Cs-137	3.0E+03	3.0E+03
Ba-137m	2.8E+03	2.8E+03

Table 12.2-12 (Sheet 1 of 2)
Normal Residual Heat Removal System
Source Strengths and Specific Activities

Energy Group (Mev/gamma)	Source Strength (Mev/gram-sec)	
	4 Hours After Shutdown	8 Hours After Shutdown
0.000 -0.020	1.3E+03	1.2E+03
0.020 -0.030	1.5E+03	1.4E+03
0.030 -0.045	6.7E+04	6.6E+04
0.045 -0.070	2.1E+02	1.4E+02
0.070 -0.100	1.4E+05	1.3E+05
0.100 -0.150	9.6E+02	9.2E+02
0.150 -0.300	3.0E+04	2.2E+04
0.300 -0.450	1.1E+04	7.2E+03
0.450 -0.700	4.6E+04	2.7E+04
0.700 -1.000	3.5E+05	3.3E+05
1.000 -1.500	5.6E+04	3.5E+04
1.500 -2.000	2.0E+04	7.8E+03
2.000 -2.500	3.0E+04	1.1E+04
2.500 -3.000	2.6E+03	7.9E+02
3.000 -4.000	4.7E+02	1.7E+02
4.000 -6.000	1.7E+02	6.2E+01
6.000 -8.000	–	–
8.000-11.000	–	–
Total	7.6E+05	6.4E+05

Table 12.2-12 (Sheet 2 of 2)
Normal Residual Heat Removal System
Source Strengths and Specific Activities

Nuclide	Activity (μCi/gram)	
	4 Hours After Shutdown	8 Hours After Shutdown
Kr-87	5.3E-02	6.0E-03
Kr-88	5.5E-01	2.1E-01
Xe-131m	1.3E+00	1.3E+00
Xe-133m	1.6E+00	1.5E+00
Xe-133	1.2E+02	1.2E+02
Xe-135	2.7E+00	2.0E+00
I-131	4.7E-01	3.1E-01
I-132	1.9E-01	4.0E-02
I-133	7.5E-01	4.4E-01
I-135	3.4E-01	1.5E-01
Rb-88	5.9E-01	2.2E-01
Cs-134	4.6E-01	3.1E-01
Cs-136	6.8E-01	4.5E-01
Tc-99m	1.9E-01	1.8E-01
Ba-137m	3.1E-01	2.1E-01
Co-58	1.0E+01	1.0E+01
Co-60	1.0E-01	1.0E-01

Table 12.2-13
Core Average and Spent Fuel Neutron Source Strengths at Various Times After Shutdown

Time After Shutdown	Core Average (n/watt-sec)	Spent Fuel (n/watt-sec)
12 hours	22	77
24 hours	22	77
100 hours	22	76
1 week	22	76
1 month	21	75
3 months	20	71
6 months	18	68
1 year	16	63
5 years	13	51

Table 12.2-14 (Sheet 1 of 2)
Spent Fuel Gamma Ray Source Strengths

Energy Group (Mev/gamma)	Source Strength at Time After Shutdown (Mev/watt-sec)				
	12 Hours	24 Hours	100 Hours	1 Week	1 Month
0-0.02	2.3E+08	2.0E+08	8.4E+07	4.1E+07	1.7E+06
0.02-0.03	4.3E+07	3.7E+07	2.2E+07	1.6E+07	4.1E+06
0.03-0.045	1.1E+08	1.0E+08	6.0E+07	4.4E+07	1.5E+07
0.045-0.07	8.5E+07	7.6E+07	4.3E+07	2.9E+07	2.9E+06
0.07-0.1	4.4E+08	3.9E+08	1.9E+08	1.1E+08	9.6E+06
0.1-0.15	1.8E+09	1.6E+09	7.4E+08	4.0E+08	8.2E+07
0.15-0.3	2.5E+09	2.1E+09	8.6E+08	4.2E+08	1.6E+07
0.3-0.45	1.0E+09	8.9E+08	5.4E+08	3.9E+08	7.5E+07
0.45-0.7	5.4E+09	4.5E+09	2.7E+09	2.2E+09	1.2E+09
0.7-1.0	6.7E+09	5.9E+09	4.2E+09	3.6E+09	2.5E+09
1.0-1.5	2.3E+09	1.5E+09	7.6E+08	5.6E+08	1.8E+08
1.5-2.0	3.3E+09	3.0E+09	2.4E+09	2.1E+09	6.1E+08
2.0-2.5	3.9E+08	3.1E+08	2.4E+08	2.0E+08	7.9E+07
2.5-3.0	1.8E+08	1.7E+08	1.4E+08	1.2E+08	3.5E+07
3.0-4.0	4.6E+06	1.8E+06	1.5E+06	1.3E+06	4.2E+05
4.0-6.0	2.5E+05	1.3E+04	1.6E+01	1.6E+01	1.6E+01
6.0-8.0	2.6E+00	2.6E+00	2.6E+00	2.6E+00	2.6E+00
8.0-11.00	4.1E-01	4.1E-01	4.1E-01	4.1E-01	4.0E-01

Table 12.2-14 (Sheet 2 of 2)
Spent Fuel Gamma Ray Source Strengths

Energy Group (Mev/gamma)	Source Strength at Time After Shutdown (Mev/watt-sec)			
	3 Months	6 Months	1 Year	5 Years
0-0.02	3.8E+05	2.4E+05	1.6E+05	6.4E+04
0.02-0.03	1.2E+06	5.2E+05	3.2E+05	1.1E+05
0.03-0.045	6.8E+06	4.6E+06	3.1E+06	6.9E+05
0.045-0.07	3.4E+05	2.2E+05	1.7E+05	9.6E+04
0.07-0.1	2.7E+06	2.1E+06	1.4E+06	2.5E+05
0.1-0.15	3.3E+07	1.6E+07	9.1E+06	1.2E+06
0.15-0.3	1.9E+06	9.6E+05	6.6E+05	3.7E+05
0.3-0.45	6.8E+06	3.7E+06	2.9E+06	9.7E+05
0.45-0.7	7.3E+08	5.3E+08	4.1E+08	1.6E+08
0.7-1.0	1.5E+09	7.9E+08	3.2E+08	6.8E+07
1.0-1.5	7.7E+07	6.2E+07	5.0E+07	1.7E+07
1.5-2.0	3.1E+07	5.2E+06	3.3E+06	5.6E+05
2.0-2.5	2.3E+07	1.6E+07	1.0E+07	3.2E+05
2.5-3.0	1.6E+06	2.4E+05	1.6E+05	1.0E+04
3.0-4.0	6.6E+04	4.4E+04	3.1E+04	2.0E+03
4.0-6.0	1.5E+01	1.4E+01	1.3E+01	1.1E+01
6.0-8.0	2.5E+00	2.3E+00	2.2E+00	1.8E+00
8.0-11.00	3.8E-01	3.6E-01	3.4E-01	2.8E-01

Table 12.2-15
Irradiated Control Rod and Gray Rod Source Strengths

Energy Group (Mev/gamma)	Silver-Indium-Cadmium Control Rod Source Strength at Time After Shutdown (Mev/cm^3-sec)		
	1 Day	**1 Week**	**1 Month**
0.20 - 0.40	2.3E+08	2.3E+08	2.2E+08
0.40 - 0.90	1.1E+12	1.1E+12	1.0E+12
0.90 - 1.35	2.0E+11	1.9E+11	1.8E+11
1.35 - 1.80	3.7E+11	3.7E+11	3.4E+11
(Mev/gamma)	**6 Months**	**1 Year**	**5 Years**
0.20 - 0.40	1.4E+08	8.5E+07	1.5E+06
0.40 - 0.90	6.6E+11	4.0E+11	7.1E+09
0.90 - 1.35	1.2E+11	7.2E+10	1.3E+09
1.35 - 1.80	2.3E+11	1.4E+11	2.5E+09

Note: The absorber cross-sectional area is 0.589 and 0.521 square centimeters for the upper and lower portions of the rods, respectively, and the absorber material density is 10.2 grams per cubic centimeter.

Energy Group (Mev/gamma)	Tungsten Gray Rod Source Strength at Time After Shutdown (Mev/cm^3-sec)		
	1 Day	**1 Week**	**1 Month**
0.00 - 0.25	6.5E+11	2.7E+11	8.3E+10
0.25 - 0.40	1.2E+11	5.2E+10	4.1E+10
0.40 - 0.90	5.1E+11	1.3E+11	1.1E+11
0.90 - 1.35	3.7E+10	7.9E+09	7.4E+09
1.35 - 1.80	9.2E+09	4.5E+07	8.7E+06
1.80 - 2.20	2.0E+09	7.2E+06	4.7E+05
(Mev/gamma)	**6 Months**	**1 Year**	**5 Years**
0.00 - 0.25	8.1E+09	1.7E+09	1.9E+06
0.25 - 0.40	2.1E+10	9.8E+09	2.6E+07
0.40 - 0.90	5.5E+10	2.5E+10	6.8E+07
0.90 - 1.35	5.5E+09	4.3E+09	2.1E+09
1.35 - 1.80	3.2E+06	1.0E+06	2.6E+03
1.80 - 2.20	1.3E+05	5.0E+04	2.1E+04

Note: The absorber cross-sectional area is 0.197 square centimeters and the absorber material density is 19.2 grams per cubic centimeter.

Table 12.2-15 (continued)
Irradiated Control Rod and Gray Rod Source Strengths

Energy Group (Mev/gamma)	Gray Rod Sleeve (Nickel Alloy 718) Source Strength at Time After Shutdown (Mev/cm^3-sec)		
	1 Day	1 Week	1 Month
0.00 - 0.25	8.2E+09	2.9E+09	1.3E+09
0.25 - 0.40	1.3E+10	1.1E+10	5.9E+09
0.40 - 0.90	4.1E+11	3.6E+11	2.4E+11
0.90 - 1.35	2.1E+12	2.1E+12	2.1E+12
1.35 - 1.80	8.0E+08	5.6E+08	4.4E+08
1.80 - 2.20	1.9E+08	2.0E+07	2.0E+07
2.20 - 2.60	7.9E+06	4.2E+04	4.1E+04
2.60 - 3.00	1.0E+08	1.0E+05	-

(Mev/gamma)	6 Months	1 Year	5 Years
0.00 - 0.25	9.4E+08	8.4E+08	4.9E+08
0.25 - 0.40	1.8E+08	3.1E+07	1.6E+07
0.40 - 0.90	2.5E+10	5.1E+09	4.5E+08
0.90 - 1.35	2.0E+12	1.8E+12	1.1E+12
1.35 - 1.80	1.0E+08	1.6E+07	4.4E+02
1.80 - 2.20	1.9E+07	1.8E+07	1.0E+07
2.20 - 2.60	3.9E+04	3.7E+04	2.2E+04
2.60 - 3.00	-	-	-

Note: The absorber cross-sectional area is 0.29 square centimeters and the absorber material density is 8.2 grams per cubic centimeter.

Table 12.2-16
Irradiated SB-BE Secondary Source Rod
Gamma Ray Source Strengths

Energy Group (MeV/gamma)	Source Strength at Time After Shutdown (MeV/cm^3-sec)					
	1 Day	1 Week	1 Month	6 Months	1 Year	5 Years
0.020 - 0.035	5.9E+10	2.4E+10	1.1E+10	2.5E+09	5.7E+08	5.5E+07
0.035 - 0.05	4.2E+10	1.7E+10	7.9E+09	1.4E+09	1.8E+08	6.0E+06
0.05 - 0.075	5.7E+10	2.3E+10	1.1E+10	1.9E+09	2.2E+08	6.0E+05
0.075 - 0.125	1.0E+11	4.0E+10	1.9E+10	3.3E+09	4.0E+08	1.7E+06
0.125 - 0.175	7.3E+10	3.8E+10	2.4E+10	7.8E+09	2.3E+09	1.7E+07
0.175 - 0.250	6.6E+10	2.6E+10	1.2E+10	2.2E+09	3.1E+08	2.0E+07
0.250 - 0.40	1.4E+11	5.8E+10	2.9E+10	5.2E+09	6.6E+08	2.0E+07
0.40 - 0.90	1.3E+13	7.1E+12	4.4E+12	7.8E+11	9.5E+10	1.0E+09
0.90 - 1.35	8.6E+11	5.9E+11	4.0E+11	7.2E+10	8.5E+09	4.3E+02
1.35 - 1.80	7.3E+12	6.8E+12	5.2E+12	9.2E+11	1.1E+11	5.5E+03
1.80 - 2.20	9.8E+11	9.2E+11	7.0E+11	1.3E+11	1.5E+10	7.4E+02
2.20 - 2.60	8.1E+09	7.6E+09	5.8E+09	1.0E+09	1.2E+08	6.1E+00
2.60 - 3.00	9.8E+08	9.2E+08	7.0E+08	1.3E+08	1.5E+07	7.4E-01

Notes:
The Sb-Be material density is 3.56 g/cm^3.
The secondary source rod cross-sectional area is 0.432 cm^2 per rod.
The average neutron energy is 30 kev.

Table 12.2-17
Irradiated SB-BE Secondary Source Rod
Neutron Source Strengths

Time After Shutdown	Sb-124 Concentration (curies/cm^3)	Neutron Source (N/cm^3-sec)
1 day	2.2E+02	4.4E+08
1 week	2.0E+02	4.1E+08
1 month	1.6E+02	3.1E+08
6 months	2.8E+01	5.6E+07
1 year	3.3E+00	6.6E+06
5 years	1.6E-07	3.3E-01

Notes:

The Sb-Be material density is 3.56 g/cm^3.

The secondary source rod cross-sectional area is 0.432 cm^2 per rod.

The average neutron energy is 30 kev.

Table 12.2-18
Irradiated Stainless Steel Source Strengths
(0.05 Weight Percent Cobalt)

Energy Group (Mev/gamma)	Source Strength at Time After Shutdown (Mev/cm^3-sec)		
	1 Day	1 Week	1 Month
0.00 - 0.25	4.7E+08	4.2E+08	3.2E+08
0.25 - 0.40	1.1E+10	9.6E+09	5.4E+09
0.40 - 0.90	3.7E+10	3.5E+10	3.2E+10
0.90 - 1.35	2.3E+11	2.2E+11	2.1E+11
1.35 - 1.80	3.6E+08	1.3E+08	1.0E+08
1.80 - 2.20			
2.20 - 2.60			
(Mev/gamma)	6 Months	1 Year	5 Years
0.00 - 0.25	1.1E+08	7.8E+07	4.4E+07
0.25 - 0.40	1.3E+08	4.2E+06	1.5E+06
0.40 - 0.90	1.8E+10	1.1E+10	4.3E+08
0.90 - 1.35	1.8E+11	1.6E+11	9.7E+10
1.35 - 1.80	2.1E+07	3.2E+06	4.0E+01
1.80 - 2.20	1.7E+06	1.6E+06	9.3E+05
2.20 - 2.60	3.5E+10	3.3E+03	1.9E+03

Notes:

The various cross-section areas per rod are as follows:

– Ag-In-Cd control rod cladding - 0.136 cm^2
– Sb-Be secondary source rod cladding - 0.136 cm^2 (outer) and 0.118 cm^2 (inner)
– Gray rod cladding - 0.184 cm^2

Table 12.2-19
Irradiated Flux Thimble
Source Strengths

Energy Group (MeV/gamma)	Source Strength at Time After Shutdown (MeV/cm^3-sec)			
	12 Hours	1 Day	70 Hours	1 Week
<0.15	4.0E+09	3.2E+09	2.2E+09	1.2E+09
0.15 - 0.45	7.9E+09	7.2E+09	6.4E+09	5.4E+09
0.45 - 1.0	4.2E+10	2.4E+10	2.2E+10	2.0E+10
1.0 - 1.5	1.2E+11	1.2E+11	1.2E+11	1.2E+11
1.5 - 2.0	1.0E+10	4.8E+08	7.5E+07	7.2E+07
2.0 - 2.5	6.3E+09	2.5E+08	9.9E+05	9.8E+05
2.5 - 3.0	1.1E+09	4.3E+07	1.2E+03	1.0E+03
3.0 - 4.0	1.2E+08	4.7E+06	2.0E+01	–
(MeV/gamma)	1 Month	6 Months	1 Year	5 Years
<0.15	5.5E+08	3.6E+08	3.1E+08	1.2E+08
0.15 - 0.45	2.9E+09	7.5E+07	5.1E+06	2.1E+06
0.45 - 1.0	1.7E+10	9.3E+09	5.5E+09	2.1E+08
1.0 - 1.5	1.1E+11	9.7E+10	9.0E+10	5.3E+10
1.5 - 2.0	5.7E+07	1.3E+07	2.2E+06	1.7E+00
2.0 - 2.5	9.8E+05	9.2E+05	8.6E+05	5.1E+05
2.5 - 3.0	1.0E+03	9.6E+02	9.0E+02	5.3E+02
3.0 - 4.0	–	–	–	–

Note:
The flux thimble cross-sectional area is 0.682 cm^2.

Table 12.2-20
Core Melt Accident Source Strengths in Containment Atmosphere as a Function of Time

Energy Group (Mev/gamma)	Source Strength at Time After Release (Mev/watt-sec)				
	10 Min.	40 Min	1.97 Hours	3.97 Hours	5.97 Hours
<0.175	2.0E+07	2.0E+07	2.4E+08	1.9E+08	1.6E+08
0.175 - 0.4	4.0E+07	3.9E+07	3.9E+08	2.5E+08	1.7E+08
0.4 - 0.9	3.5E+08	3.1E+08	1.6E+09	6.2E+08	2.7E+08
0.9 - 1.35	1.8E+08	1.5E+08	7.5E+08	3.1E+08	1.4E+08
1.35 - 1.8	1.6E+08	1.4E+08	6.0E+08	2.3E+08	1.1E+08
1.8 - 2.2	6.3E+07	5.3E+07	5.0E+08	2.9E+08	1.7E+08
2.2 - 2.6	7.8E+07	7.7E+07	7.1E+08	3.9E+08	2.3E+08
2.6 - 3.5	2.8E+07	1.8E+07	7.4E+07	3.3E+07	1.9E+07
3.5 - 5.0	7.1E+06	1.9E+06	8.5E+06	4.5E+06	2.7E+06
5.0 - 10.0	2.1E+05	2.1E+03	3.0E+04	1.9E+04	1.2E+04
Beta	4.3E+08	3.6E+08	2.9E+09	1.7E+09	1.1E+09
(Mev/gamma)	11.97 Hours	1 Day	1 Week	1 Month	1 Year
<0.175	1.3E+08	1.1E+08	4.9E+07	2.5E+06	7.7E+04
0.175 - 0.4	8.2E+07	3.9E+07	7.0E+06	9.5E+05	2.4E+04
0.4 - 0.9	5.4E+07	2.8E+07	4.0E+06	1.9E+06	1.3E+06
0.9 - 1.35	2.6E+07	7.3E+06	3.2E+05	8.4E+04	2.0E+04
1.35 - 1.8	2.2E+07	3.8E+06	7.1E+05	2.3E+05	2.6E+04
1.8 - 2.2	3.8E+07	2.5E+06	1.6E+04	6.1E+02	1.1E+02
2.2 - 2.6	5.1E+07	2.9E+06	4.7E+04	1.4E+04	2.7E+01
2.6 - 3.5	4.2E+06	2.2E+05	1.2E+03	3.8E+02	5.7E+00
3.5 - 5.0	6.2E+05	3.3E+04	1.0E-03	9.7E-04	5.2E-04
5.0 - 10.0	2.7E+03	1.5E+02	6.3E-06	6.1E-06	4.6E-06
Beta	5.6E+08	3.7E+08	1.5E+08	1.2E+07	3.6E+06

Note:
No release from core until 10 minutes after incident (see Subsection 15.6.5.3).

Table 12.2-21
Core Melt Accident Integrated Source Strengths in Containment Atmosphere

Energy Group (Mev/gamma)	Source Strength at Time After Release (Mev/watt)			
	10 Min.	40 Min	1.97 Hours	3.97 Hours
<0.175	2.0E+07	3.5E+10	6.6E+11	2.2E+12
0.175 - 0.4	4.0E+07	7.0E+10	1.2E+12	3.4E+12
0.4 - 0.9	3.5E+08	5.9E+11	6.3E+12	1.4E+13
0.9 - 1.35	1.8E+08	2.9E+11	2.8E+12	6.3E+12
1.35 - 1.8	1.6E+08	2.8E+11	2.4E+12	5.1E+12
1.8 - 2.2	6.3E+07	1.0E+11	1.5E+12	4.2E+12
2.2 - 2.6	7.8E+07	1.4E+11	2.2E+12	6.0E+12
2.6 - 3.5	2.8E+07	3.9E+10	2.9E+11	6.4E+11
3.5 - 5.0	7.1E+06	5.7E+09	3.3E+10	7.7E+10
5.0 - 10.0	2.1E+05	5.2E+07	1.2E+08	3.0E+08
Beta	4.3E+08	6.9E+11	9.0E+12	2.5E+13

(Mev/gamma)	11.97 Hours	1 Day	1 Week	1 Month	1 Year
<0.175	6.4E+12	1.1E+13	5.0E+13	8.1E+13	8.6E+13
0.175 - 0.4	7.5E+12	1.0E+13	1.7E+13	2.3E+13	2.4E+13
0.4 - 0.9	1.9E+13	2.1E+13	2.6E+13	3.1E+13	7.4E+13
0.9 - 1.35	9.2E+12	9.9E+12	1.1E+13	1.1E+13	1.2E+13
1.35 - 1.8	7.4E+12	7.9E+12	8.4E+12	9.3E+12	1.1E+13
1.8 - 2.2	7.7E+12	8.2E+12	8.4E+12	8.4E+12	8.4E+12
2.2 - 2.6	1.1E+13	1.1E+13	1.2E+13	1.2E+13	1.2E+13
2.6 - 3.5	1.0E+12	1.1E+12	1.1E+12	1.1E+12	1.1E+12
3.5 - 5.0	1.3E+11	1.4E+11	1.4E+11	1.4E+11	1.4E+11
5.0 - 10.0	5.4E+08	5.8E+08	5.8E+08	5.8E+08	5.8E+08
Beta	5.2E+13	7.2E+13	1.9E+14	3.0E+14	4.2E+14

Note:
No release from core until 10 minutes after incident (see Subsection 15.6.5.3)

Table 12.2-22
Parameters and Assumptions Used for Calculating
Containment Airborne Radioactivity Concentrations

Parameter/Assumption	Value
Reactor coolant leakage rate	30 lb/day
Time used to estimate equilibrium concentration	100 days
Containment free air volume	2.06E6 cu. ft
Flashing fraction	0.40
Fuel defects	0.250%
Reactor coolant tritium concentration	3.5 µCi/g
Normal operation purge flow rate	4,000 cfm
Normal operation purge duration	20 hrs/week
Shutdown purge flow rate	8,000 cfm

Table 12.2-23 (Sheet 1 of 3)
Containment Airborne Radioactivity Concentrations
($\mu Ci/cm^3$)

Isotope	Equilibrium Activity (no purge)	Maximum Activity (with normal purge)	Shutdown Activity (shutdown purge for 24 hrs)
Cr-51	1.0E-11	9.1E-12	2.1E-13
Mn-54	5.1E-12	4.6E-12	1.1E-13
Mn-56	0.0E+00	0.0E+00	0.0E+00
Fe-55	3.9E-12	3.5E-12	8.2E-14
Fe-59	9.7E-13	8.8E-13	2.0E-14
Co-58	1.5E-11	1.4E-11	3.2E-13
Co-60	1.7E-12	1.6E-12	3.6E-14
Br-83	0.0E+00	0.0E+00	0.0E+00
Br-84	3.4E-11	3.2E-11	2.5E-26
Br-85	0.0E+00	0.0E+00	0.0E+00
Kr-83m	0.0E+00	0.0E+00	0.0E+00
Kr-85m	1.3E-08	7.9E-09	2.2E-10
Kr-85	3.3E-05	4.1E-07	6.5E-08
Kr-87	3.4E-09	2.9E-09	1.5E-14
Kr-88	1.4E-08	1.0E-08	4.4E-11
Kr-89	0.0E+00	0.0E+00	0.0E+00
Rb-88	2.8E-10	2.7E-10	4.1E-36
Rb-89	0.0E+00	0.0E+00	0.0E+00
Sr-89	4.7E-13	4.2E-13	9.7E-15
Sr-90	3.9E-14	3.5E-14	8.2E-16
Sr-91	3.6E-12	3.2E-12	1.4E-14
Sr-92	0.0E+00	0.0E+00	0.0E+00
Y-90	4.6E-15	4.2E-15	7.6E-17
Y-91m	1.2E-12	1.1E-12	6.8E-23
Y-91	1.7E-14	1.6E-14	3.6E-16
Y-92	0.0E+00	0.0E+00	0.0E+00
Y-93	1.6E-11	1.4E-11	6.9E-14

Table 12.2-23 (Sheet 2 of 3)
Containment Airborne Radioactivity Concentrations
($\mu Ci/cm^3$)

Isotope	Equilibrium Activity (no purge)	Maximum Activity (with normal purge)	Shutdown Activity (shutdown purge for 24 hrs)
Zr-95	1.3E-12	1.2E-12	2.7E-14
Nb-95	9.3E-13	8.4E-13	1.9E-14
Mo-99	2.2E-11	2.0E-11	3.6E-13
Tc-99m	1.8E-11	1.6E-11	2.5E-14
Ru-103	2.5E-11	2.2E-11	5.1E-13
Ag-110m	4.3E-12	3.9E-12	9.0E-14
Te-127m	0.0E+00	0.0E+00	0.0E+00
Te-129m	6.2E-13	5.6E-13	1.3E-14
Te-129	7.1E-11	6.6E-11	1.1E-18
Te-131m	5.3E-12	4.8E-12	6.5E-14
Te-131	1.4E-11	1.4E-11	2.1E-30
Te-132	5.8E-12	5.2E-12	9.9E-14
TE-134	0.0E+00	0.0E+00	0.0E+00
I-129	0.0E+00	0.0E+00	0.0E+00
I-130	0.0E+00	0.0E+00	0.0E+00
I-131	2.9E-09	1.4E-10	8.8E-12
I-132	6.5E-09	6.9E-10	3.7E-14
I-133	8.9E-09	4.8E-10	1.5E-11
I-134	4.1E-09	8.6E-10	4.2E-19
I-135	1.4E-08	9.0E-10	5.2E-12
Xe-131m	4.4E-06	2.7E-07	4.8E-08
Xe-133m	6.9E-08	1.3E-08	3.1E-09
Xe-133	6.4E-06	7.1E-07	1.5E-07
Xe-135m	6.2E-10	6.0E-10	5.8E-37
Xe-135	1.4E-07	6.1E-08	8.0E-09
Xe-137	3.9E-11	3.9E-11	0.0E+00
Xe-138	5.0E-10	4.8E-10	0.0E+00

Table 12.2-23 (Sheet 3 of 3)
Containment Airborne Radioactivity Concentrations
($\mu Ci/cm^3$)

Isotope	Equilibrium Activity (no purge)	Maximum Activity (with normal purge)	Shutdown Activity (shutdown purge for 24 hrs)
Cs-134	2.3E-11	2.1E-11	4.8E-13
Cs-136	2.9E-12	2.6E-12	5.8E-14
Cs-137	3.1E-11	2.8E-11	6.5E-13
Cs-138	0.0E+00	0.0E+00	0.0E+00
Ba-137m	1.7E-12	1.7E-12	0.0E+00
Ba-140	4.3E-11	3.9E-11	8.5E-13
La-140	8.8E-11	8.0E-11	1.2E-12
Ce-141	5.1E-13	4.6E-13	1.0E-14
Ce-143	9.9E-12	9.0E-12	1.3E-13
Pr-143	1.2E-11	1.1E-11	2.3E-13
Ce-144	1.3E-11	1.2E-11	2.8E-13
Pr-144	3.9E-12	3.8E-12	0.0E+00
H-3	9.4E-06	1.2E-07	1.7E-09
Ar-41	3.8E-07	2.9E-07	2.2E-13
Na-24	1.7E-10	1.6E-10	1.2E-12
Zn-65	1.7E-12	1.5E-12	3.5E-14
Ru-106	2.9E-10	2.6E-10	6.1E-12
Rh-103m	1.4E-11	1.3E-11	7.3E-21
W-187	8.7E-12	7.9E-12	9.3E-14
Np-239	7.7E-12	7.0E-12	1.2E-13
Total	5.4E-05	1.9E-06	2.7E-07
Iodines	3.6E-08	3.1E-09	2.9E-11
Particulates	1.3E-09	1.2E-09	1.4E-11
Noble Gases	4.4E-05	1.8E-06	2.7E-07

Table 12.2-24
Parameters and Assumptions Used for Calculating Fuel Handling Area Airborne Radioactivity Concentrations

Parameter/Assumption	Value
Assumed fuel load	Full core offload
Ventilation flow through fuel handling area(1)	9,500 cfm(2)
Fuel handling area free air volume	284,000 ft^3
Fuel defects	0.25%
Time from shutdown to reactor vessel head removal	48 hours
Refueling time	10 days
Spent fuel pool purification flow rate	150 gpm
Decontamination factors of mixed-bed demineralizer for spent fuel pool purification system:	
Iodines	100
Cs and Rb	2
Others	50
Spent fuel pool temperature	120°F
Partition coefficients:	
Noble gases	Freely released
Tritium	1
Halogens	100
Others	1,000
Evaporation rate of spent fuel pool water	430 lbs/hr
Reactor coolant tritium concentration	3.5 µCi/g

Notes:

1. This flow rate is defined as the sum of the fuel handling area exhaust flow from room 12562 (fuel handling area) and exhaust flow from room 12562 to room 12471 (solid radwaste system valve/piping area).
2. This is the nominal expected ventilation flow rate. For conservatism, the calculated airborne radioactivity concentrations are based on a 10% lower flow rate.

Table 12.2-25 (Sheet 1 of 2)
Fuel Handling Area Airborne Radioactivity Concentrations[1]
($\mu Ci/cm^3$)

Isotope	Activity[2]
Cr-51	2.2E-12
Mn-54	1.2E-12
Fe-55	8.7E-13
Fe-59	2.2E-13
Co-58	3.3E-12
Co-60	3.8E-13
Br-83	1.9E-16
Kr-85m	4.0E-12
Kr-85	4.6E-10
Kr-87	1.6E-20
Kr-88	1.2E-13
Rb-88	1.2E-13
Sr-89	1.9E-12
Sr-90	8.6E-12
Sr-91	6.9E-14
Sr-92	8.1E-19
Y-90	8.7E-14
Y-91	2.4E-13
Y-92	2.5E-17
Y-93	5.8E-15
Zr-95	2.7E-13
Nb-95	2.7E-13
Mo-99	2.1E-10
Tc-99m	1.9E-10
Ru-103	2.4E-13
Ag-110m	7.0E-13
Te-127m	1.3E-12
Te-129m	4.3E-12
Te-131m	3.9E-12
Te-131	8.7E-13
Te-132	8.7E-11
I-129	2.6E-16
I-130	1.1E-11
I-131	1.0E-08
I-132	2.7E-15
I-133	4.1E-09
I-135	5.9E-11
Xe-131m	4.1E-10
Xe-133m	1.2E-09
Xe-133	6.0E-08
Xe-135	4.1E-10

Table 12.2-25 (Sheet 2 of 2)
Fuel Handling Area Airborne Radioactivity Concentrations[1]
($\mu Ci/cm^3$)

Isotope	Activity[2]
Cs-134	1.2E-09
Cs-136	1.6E-09
Cs-137	8.9E-10
Ba-137m	8.4E-10
Ba-140	1.6E-12
La-140	2.2E-13
Ce-141	2.7E-13
Ce-143	8.3E-14
Pr-143	2.4E-13
Ce-144	2.1E-13
Pr-144	2.1E-13
H-3	6.4E-06
Rb-86	4.6E-18
Rh-103m	2.3E-13
Ru-106	1.3E-19
Rh-106	1.3E-19
Np-239	2.7E-18
Sb-127	1.1E-17
Sb-129	1.5E-20
Rh-105	8.6E-20
Zr-97	5.0E-20
Nd-147	1.5E-19
Pu-241	2.9E-20
Total (excluding tritium)	8.2E-08
Iodines	1.4E-08
Particulates	5.1E-09
Noble Gases	6.3E-08

Notes:

1. The maximum activity concentration is calculated to occur 2 hours after removal of the head, or 50 hours after shutdown in this case.
2. The following nuclides are expected to exist in the FHA at the time of maximum airborne concentrations with individual nuclide activity concentrations less than 1.0E-20 $\mu Ci/cm^3$:
   ^{91m}Y, ^{129}Te, ^{134}Te, ^{134}I, ^{139}Ba, ^{105}Ru, ^{141}La, ^{142}La, ^{241}Am, ^{238}Pu, ^{239}Pu, ^{240}Pu, ^{242}Cm, and ^{244}Cm.

Table 12.2-26
Parameters and Assumptions Used for Calculating Auxiliary Building Airborne Radioactivity Concentrations

Parameter/Assumption	Value
Ventilation exhaust flow(1)	25,320 cfm(2)
Free air volume	411,200 ft^3
Primary coolant leakage to auxiliary building(3)	296 lb/day
Flashing fraction	
Noble gases and Tritium	1
Other Radionuclides	0.1
Primary coolant source term	See Table 11.1-2.
Fuel defects	0.25%

Notes:

1. This flow rate is defined as the sum of the auxiliary/annex building exhaust fan flow minus the annex building exhaust flows from room 40357 (containment access corridor), room 40551 (containment air filtration exhaust room A), and 40552 (containment air filtration exhaust room B).
2. This is the nominal expected ventilation flow rate. For conservatism, the calculated airborne radioactivity concentrations are based on a 10% lower flow rate.
3. This value represents the total leakage of primary coolant to the auxiliary building from equipment leakage (128 lb/day) and from primary sampling activities (168 lb/day). As indicated in ANSI/ANS 55.6-1993, only 5% of the 168 lb/day leakage from primary sampling activities can be assumed to contain design basis RCS source term activity. This decreases the total primary coolant leakage to the auxiliary building with design basis RCS source term activity used for calculating auxiliary building radioactivity concentrations to 136 lb/day.

Table 12.2-27 (Sheet 1 of 2)
Auxiliary Building Airborne Radioactivity Concentrations
(μCi/cm^3)

Isotope	Activity
Cr-51	8.6E-12
Mn-54	4.5E-12
Mn-56	1.1E-09
Fe-55	3.3E-12
Fe-59	8.6E-13
Co-58	1.3E-11
Co-60	1.5E-12
Br-83	2.0E-10
Br-84	8.1E-11
Br-85	2.5E-12
Kr-83m	1.1E-08
Kr-85m	5.3E-08
Kr-85	2.0E-07
Kr-87	2.7E-08
Kr-88	9.3E-08
Kr-89	4.7E-10
Rb-88	5.8E-09
Rb-89	2.5E-10
Sr-89	7.3E-12
Sr-90	3.3E-13
Sr-91	1.1E-11
Sr-92	2.5E-12
Y-90	8.6E-14
Y-91m	4.9E-12
Y-91	9.3E-13
Y-92	2.1E-12
Y-93	7.2E-13
Zr-95	1.1E-12
Nb-95	1.1E-12
Mo-99	1.4E-09
Tc-99m	1.3E-09
Ru-103	9.3E-13
Rh-103m	7.6E-13
Ag-110m	2.7E-12
Te-127m	5.1E-12
Te-129m	1.7E-11
Te-129	2.1E-11
Te-131m	4.4E-11

Table 12.2-27 (Sheet 2 of 2)
Auxiliary Building Airborne Radioactivity Concentrations
($\mu Ci/cm^3$)

Isotope	Activity
Te-131	1.9E-11
Te-132	5.2E-10
Te-134	5.6E-11
I-129	1.0E-16
I-130	7.2E-11
I-131	4.7E-09
I-132	5.7E-09
I-133	8.6E-09
I-134	1.2E-09
I-135	5.0E-09
Xe-131m	8.6E-08
Xe-133m	1.1E-07
Xe-133	8.0E-06
Xe-135m	6.2E-09
Xe-135	2.3E-07
Xe-137	1.0E-09
Xe-138	8.8E-09
Cs-134	4.6E-09
Cs-136	6.6E-09
Cs-137	3.3E-09
Cs-138	1.8E-09
Ba-137m	5.3E-10
Ba-140	6.6E-12
La-140	2.1E-12
Ce-141	1.1E-12
Ce-143	9.3E-13
Pr-143	1.0E-12
Ce-144	8.0E-13
Pr-144	4.6E-13
H-3	2.3E-07
Total	9.1E-06
Iodines	2.5E-08
Particulates	2.8E-08
Noble Gases	8.8E-06

Table 12.2-28 (Sheet 1 of 2)
Core Melt Accident Source Strengths from MCR HVAC Filters as a Function of Time

VES Filter[1] Source Strengths after a Loss of Coolant Accident				
Energy Group (Mev/gamma)	Source Strength (Mev/sec)			
	2 hours	8 hours	24 hours	30 days
0.01 - 0.02	1.19E+06	3.11E+06	1.81E+06	1.97E+05
0.02 - 0.03	1.47E+06	5.26E+06	3.89E+06	2.65E+05
0.03 - 0.06	2.87E+06	8.30E+06	5.46E+06	6.47E+05
0.06 - 0.1	3.03E+06	8.13E+06	5.22E+06	5.41E+05
0.1 - 0.2	5.76E+06	1.41E+07	8.76E+06	9.02E+05
0.2 - 0.4	6.14E+07	2.61E+08	2.46E+08	1.87E+07
0.4 - 0.6	1.86E+08	6.02E+08	3.60E+08	1.83E+07
0.6 - 0.7	1.47E+08	2.33E+08	1.47E+08	1.03E+08
0.7 - 0.8	1.09E+08	1.80E+08	1.05E+08	7.30E+07
0.8 - 1.0	1.85E+08	1.67E+08	6.99E+07	7.13E+06
1.0 - 1.5	3.36E+08	6.99E+08	1.85E+08	1.22E+07
1.5 - 2.0	1.21E+08	2.55E+08	4.97E+07	2.69E+04
2.0 - 3.0	3.13E+07	3.87E+07	7.28E+06	9.07E+03
3.0 - 4.0	3.68E+05	5.98E+03	5.56E+02	1.41E+02
4.0 - 5.0	1.42E+04	3.16E+01	8.55E-04	7.80E-04
5.0 - 6.0	3.31E-05	3.12E-04	3.35E-04	3.21E-04
6.0 - 7.0	1.32E-05	1.24E-04	1.33E-04	1.28E-04
7.0 - 8.0	5.11E-06	4.82E-05	5.17E-05	4.96E-05
8.0 - 10.0	2.68E-06	2.53E-05	2.71E-05	2.60E-05
10.0 - 14.0	1.69E-07	1.60E-06	1.71E-06	1.64E-06
Total	1.19E+09	2.47E+09	1.19E+09	2.35E+08

Table 12.2-28 (Sheet 2 of 2)
Core Melt Accident Source Strengths from MCR HVAC Filters as a Function of Time

VBS Filter[2] Source Strengths after a Loss of Coolant Accident				
Energy Group (Mev/gamma)	Source Strength (Mev/sec)			
	2 hours	8 hours	24 hours	30 days
0.01 - 0.02	6.86E+08	1.00E+09	5.75E+08	6.21E+07
0.02 - 0.03	9.55E+08	1.76E+09	1.27E+09	8.46E+07
0.03 - 0.06	1.71E+09	2.71E+09	1.75E+09	2.10E+08
0.06 - 0.1	1.72E+09	2.60E+09	1.63E+09	1.70E+08
0.1 - 0.2	3.49E+09	4.61E+09	2.81E+09	2.91E+08
0.2 - 0.4	3.54E+10	8.45E+10	7.59E+10	5.76E+09
0.4 - 0.6	1.03E+11	1.91E+11	1.10E+11	5.61E+09
0.6 - 0.7	7.99E+10	7.20E+10	4.39E+10	3.04E+10
0.7 - 0.8	5.97E+10	5.62E+10	3.17E+10	2.16E+10
0.8 - 1.0	1.03E+11	5.23E+10	2.13E+10	2.11E+09
1.0 - 1.5	1.86E+11	2.20E+11	5.64E+10	3.62E+09
1.5 - 2.0	6.71E+10	8.03E+10	1.53E+10	8.78E+06
2.0 - 3.0	1.66E+10	1.22E+10	2.24E+09	3.09E+06
3.0 - 4.0	1.82E+08	1.93E+06	1.89E+05	4.81E+04
4.0 - 5.0	6.86E+06	7.65E+03	2.91E-01	2.65E-01
5.0 - 6.0	3.74E-02	1.12E-01	1.14E-01	1.09E-01
6.0 - 7.0	1.49E-02	4.47E-02	4.54E-02	4.35E-02
7.0 - 8.0	5.78E-03	1.74E-02	1.76E-02	1.69E-02
8.0 - 10.0	3.03E-03	9.11E-03	9.24E-03	8.86E-03
10.0 - 14.0	1.92E-04	5.75E-04	5.84E-04	5.60E-04
Total	6.59E+11	7.82E+11	3.65E+11	7.00E+10

Notes:
1. Based upon a particulate filter density of 0.212 g/cc and charcoal filter density of 0.440 g/cc.
2. Based upon a particulate filter density of 0.230 g/cc and charcoal filter density of 0.632 g/cc.

Table 12.2-29
Core Melt Accident Integrated Source Strengths from MCR HVAC Filters

Energy Group (Mev/gamma)	30-Day Integrated Source Strength (Mev)	
	VES[1]	VBS[2]
0.01 - 0.02	1.75E+08	5.65E+10
0.02 - 0.03	3.81E+08	1.26E+11
0.03 - 0.06	5.89E+08	1.90E+11
0.06 - 0.1	5.77E+08	1.84E+11
0.1 - 0.2	9.03E+08	2.95E+11
0.2 - 0.4	3.34E+10	1.05E+13
0.4 - 0.6	2.36E+10	7.44E+12
0.6 - 0.7	3.81E+10	1.15E+13
0.7 - 0.8	2.63E+10	7.92E+12
0.8 - 1.0	7.57E+09	2.39E+12
1.0 - 1.5	1.77E+10	5.67E+12
1.5 - 2.0	4.03E+09	1.34E+12
2.0 - 3.0	6.47E+08	2.18E+11
3.0 - 4.0	1.20E+06	4.46E+08
4.0 - 5.0	4.17E+04	1.52E+07
5.0 - 6.0	1.03E-01	3.51E+01
6.0 - 7.0	4.08E-02	1.40E+01
7.0 - 8.0	1.59E-02	5.42E+00
8.0 - 10.0	8.32E-03	2.84E+00
10.0 - 14.0	5.25E-04	1.80E-01
Total	1.54E+11	4.79E+13

Notes:
1. Based upon a particulate filter density of 0.212 g/cc and charcoal filter density of 0.440 g/cc.
2. Based upon a particulate filter density of 0.230 g/cc and charcoal filter density of 0.632 g/cc.

Table 12.2-30 (Sheet 1 of 6)
IRWST Design Basis Source Strengths and Specific Activity

Vapor Specific Activity	
Nuclide	**Concentration (μCi/cm^3)**
Kr-83m	3.0E-04
Kr-85m	3.5E-03
Kr-85	2.4E+01
Kr-87	5.5E-04
Kr-88	3.9E-03
Kr-89	1.7E-06
Xe-131m	3.4E-01
Xe-133m	8.1E-02
Xe-133	1.4E+01
Xe-135m	4.1E-05
Xe-135	2.9E-02
Xe-137	3.9E-06
Xe-138	5.4E-05

Table 12.2-30 (Sheet 2 of 6)
IRWST Design Basis Source Strengths and Specific Activity

Plateout Specific Activity	
Nuclide	**Concentration ($\mu Ci/cm^2$)**
Zr-95	2.4E-01
Ru-103	2.4E-01
Ce-141	1.5E-02
Ce-144	1.3E-02
Cr-51	8.6E-03
Mn-54	7.6E-01
Mn-56	3.2E-05
Fe-55	2.3E-01
Fe-59	2.4E-01
Co-58	5.4E+00
Co-60	3.1E+00

Table 12.2-30 (Sheet 3 of 6)
IRWST Design Basis Source Strengths and Specific Activity

Liquid Specific Activity			
Nuclide	**Concentration (μCi/cm^3)**	**Nuclide**	**Concentration (μCi/cm^3)**
Br-83	4.1E-06	Te-134	4.2E-07
Br-84	5.0E-07	I-129	5.8E-11
Br-85	5.3E-09	I-130	6.4E-06
Rb-88	2.5E-05	I-131	2.1E-03
Rb-89	9.6E-07	I-132	1.2E-04
Sr-89	4.0E-06	I-133	1.2E-03
Sr-90	1.9E-07	I-134	1.1E-05
Sr-91	7.9E-07	I-135	2.6E-04
Sr-92	5.9E-08	Cs-134	4.8E-03
Y-90	1.9E-07	Cs-136	5.0E-03
Y-91m	4.2E-08	Cs-137	3.5E-03
Y-91	5.2E-07	Cs-138	1.1E-05
Y-92	6.4E-08	Ba-137m	3.5E-03
Y-93	5.5E-08	Ba-140	3.2E-06
Zr-95	1.8E-07	La-140	4.4E-07
Nb-95	5.7E-07	Ce-141	1.8E-07
Mo-99	4.0E-04	Ce-143	1.8E-07
Tc-99m	6.1E-05	Ce-144	1.4E-07
Ru-103	1.6E-07	Pr-143	4.8E-07
Rh-103m	7.2E-09	Pr-144	1.9E-09
Rh-106	2.1E-11	N-16	2.8E-05
Ag-110m	1.6E-06	Cr-51	8.5E-06
Sb-124	3.3E-06	Mn-54	4.4E-06
Te-127m	2.9E-06	Mn-56	2.2E-05
Te-129m	9.2E-06	Fe-55	3.4E-06
Te-129	2.4E-07	Fe-59	8.2E-07
Te-131m	7.8E-06	Co-58	1.6E-04
Te-131	9.8E-08	Co-60	1.5E-06
Te-132	1.7E-04	-	-

Table 12.2-30 (Sheet 4 of 6)
IRWST Design Basis Source Strengths and Specific Activity

Vapor Source Strength	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.01 - 0.02	8.4E+02
0.02 - 0.03	2.0E+03
0.03 - 0.06	8.6E+03
0.06 - 0.1	1.8E+04
0.1 - 0.2	2.0E+03
0.2 - 0.4	1.4E+03
0.4 - 0.6	2.1E+03
0.6 - 0.7	2.4E+01
0.7 - 0.8	1.8E+00
0.8 - 1.0	2.2E+01
1.0 - 1.5	1.5E+01
1.5 - 2.0	4.3E+01
2.0 - 3.0	2.1E+02
3.0 - 4.0	3.7E-01
4.0 - 5.0	2.8E-03
5.0 - 6.0	4.0E-08
6.0 - 7.0	0.0E+00
7.0 - 8.0	0.0E+00
8.0 - 10.0	0.0E+00
10.0 - 14.0	0.0E+00
Total	3.6E+04

Table 12.2-30 (Sheet 5 of 6)
IRWST Design Basis Source Strengths and Specific Activity

Liquid Source Strength	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.01 - 0.02	3.8E-01
0.02 - 0.03	4.8E-01
0.03 - 0.06	1.7E+00
0.06 - 0.1	2.3E+00
0.1 - 0.2	6.8E+00
0.2 - 0.4	5.9E+01
0.4 - 0.6	5.0E+01
0.6 - 0.7	1.9E+02
0.7 - 0.8	1.4E+02
0.8 - 1.0	1.5E+02
1.0 - 1.5	2.1E+02
1.5 - 2.0	5.7E+00
2.0 - 3.0	1.5E+00
3.0 - 4.0	6.8E-02
4.0 - 5.0	2.1E-02
5.0 - 6.0	9.1E-03
6.0 - 7.0	4.2E+00
7.0 - 8.0	3.6E-01
8.0 - 10.0	7.4E-03
10.0 - 14.0	4.8E-06
Total	8.3E+02

Table 12.2-30 (Sheet 6 of 6)
IRWST Design Basis Source Strengths and Specific Activity

Plateout Source Strength	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^2-sec)**
0.01 - 0.02	1.0E+02
0.02 - 0.03	8.7E+01
0.03 - 0.06	2.0E+02
0.06 - 0.1	2.0E+02
0.1 - 0.2	3.9E+02
0.2 - 0.4	2.9E+02
0.4 - 0.6	3.5E+04
0.6 - 0.7	3.4E+02
0.7 - 0.8	6.5E+03
0.8 - 1.0	1.9E+05
1.0 - 1.5	3.0E+05
1.5 - 2.0	1.8E+03
2.0 - 3.0	3.2E+00
3.0 - 4.0	6.7E-03
4.0 - 5.0	0.0E+00
5.0 - 6.0	0.0E+00
6.0 - 7.0	0.0E+00
7.0 - 8.0	0.0E+00
8.0 - 10.0	0.0E+00
10.0 - 14.0	0.0E+00
Total	5.4E+05

Table 12.2-31 (Sheet 1 of 6)
IRWST Expected Source Strengths and Specific Activity

Vapor Specific Activity	
Nuclide	**Concentration ($\mu Ci/cm^3$)**
Kr-85m	7.7E-06
Kr-85	9.9E-02
Kr-87	2.0E-06
Kr-88	8.4E-06
Xe-131m	2.6E-03
Xe-133m	4.0E-05
Xe-133	3.8E-03
Xe-135m	3.7E-07
Xe-135	8.2E-05
Xe-137	2.3E-08
Xe-138	2.9E-07

Table 12.2-31 (Sheet 2 of 6)
IRWST Expected Source Strengths and Specific Activity

Plateout Specific Activity	
Nuclide	**Concentration ($\mu Ci/cm^2$)**
Zr-95	6.0E-03
Ru-103	6.1E-03
Ce-141	3.6E-04
Ce-144	1.2E-03
Cr-51	3.4E-05
Mn-54	1.7E-02
Fe-55	9.1E-04
Fe-59	6.0E-03
Co-58	1.3E-01
Co-60	7.4E-02
Zn-65	1.2E-01

Table 12.2-31 (Sheet 3 of 6)
IRWST Expected Source Strengths and Specific Activity

Liquid Specific Activity			
Nuclide	**Concentration (μCi/cm^3)**	**Nuclide**	**Concentration (μCi/cm^3)**
Br-84	5.3E-09	I-133	1.4E-06
Rb-88	3.6E-08	I-134	1.9E-07
Sr-89	2.5E-08	I-135	9.1E-07
Sr-90	3.2E-09	Cs-134	1.9E-06
Sr-91	4.6E-09	Cs-136	7.8E-08
Y-90	3.2E-09	Cs-137	2.6E-06
Y-91m	2.4E-10	Ba-137m	2.6E-06
Y-91	9.6E-10	Ba-140	1.2E-06
Y-93	2.2E-08	La-140	4.4E-07
Zr-95	4.4E-09	Ce-141	1.7E-09
Nb-95	4.4E-08	Ce-143	4.1E-08
Mo-99	1.7E-07	Ce-144	4.6E-08
Tc-99m	1.6E-08	Pr-143	3.3E-07
Ru-103	8.3E-08	Pr-144	4.9E-10
Ru-106	3.1E-10	W-187	5.1E-07
Rh-103m	3.0E-09	Np-239	5.4E-07
Rh-106	3.1E-10	N-16	4.0E-08
Ag-110m	3.2E-07	Na-24	8.5E-06
Sb-124	6.6E-08	Cr-51	3.4E-08
Te-129m	2.9E-08	Mn-54	1.8E-08
Te-129	1.7E-08	Fe-55	1.4E-08
Te-131m	2.0E-08	Fe-59	3.3E-09
Te-131	2.0E-09	Co-58	6.1E-07
Te-132	5.2E-08	Co-60	6.0E-09
I-131	3.0E-06	Zn-65	5.8E-09
I-132	2.9E-07	-	-

Table 12.2-31 (Sheet 4 of 6)
IRWST Expected Source Strengths and Specific Activity

Vapor Source Strength	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.01 - 0.02	3.0E+00
0.02 - 0.03	3.7E+00
0.03 - 0.06	8.3E+00
0.06 - 0.1	9.9E+00
0.1 - 0.2	7.6E+00
0.2 - 0.4	4.9E+00
0.4 - 0.6	8.6E+00
0.6 - 0.7	7.0E-02
0.7 - 0.8	4.3E-03
0.8 - 1.0	5.1E-02
1.0 - 1.5	3.4E-02
1.5 - 2.0	9.7E-02
2.0 - 3.0	4.6E-01
3.0 - 4.0	1.3E-03
4.0 - 5.0	1.2E-08
5.0 - 6.0	0.0E+00
6.0 - 7.0	0.0E+00
7.0 - 8.0	0.0E+00
8.0 - 10.0	0.0E+00
10.0 - 14.0	0.0E+00
Total	4.7E+01

Table 12.2-31 (Sheet 5 of 6)
IRWST Expected Source Strengths and Specific Activity

Liquid Source Strength	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^3-sec)**
0.01 - 0.02	1.3E-03
0.02 - 0.03	1.2E-03
0.03 - 0.06	2.7E-03
0.06 - 0.1	2.9E-03
0.1 - 0.2	6.2E-03
0.2 - 0.4	4.3E-02
0.4 - 0.6	5.9E-02
0.6 - 0.7	1.3E-01
0.7 - 0.8	6.7E-02
0.8 - 1.0	6.1E-02
1.0 - 1.5	4.9E-01
1.5 - 2.0	4.5E-02
2.0 - 3.0	8.7E-01
3.0 - 4.0	8.1E-04
4.0 - 5.0	3.1E-05
5.0 - 6.0	1.4E-05
6.0 - 7.0	6.0E-03
7.0 - 8.0	5.1E-04
8.0 - 10.0	1.1E-05
10.0 - 14.0	6.9E-09
Total	1.8E+00

Table 12.2-31 (Sheet 6 of 6)
IRWST Expected Source Strengths and Specific Activity

Plateout Source Strength	
Energy Group (Mev/gamma)	**Source Strength (Mev/cm^2-sec)**
0.01 - 0.02	2.5E+00
0.02 - 0.03	2.2E+00
0.03 - 0.06	5.0E+00
0.06 - 0.1	4.8E+00
0.1 - 0.2	1.0E+01
0.2 - 0.4	6.8E+00
0.4 - 0.6	8.6E+02
0.6 - 0.7	8.7E+00
0.7 - 0.8	1.7E+02
0.8 - 1.0	4.2E+03
1.0 - 1.5	9.5E+03
1.5 - 2.0	3.9E+01
2.0 - 3.0	6.5E-02
3.0 - 4.0	0.0E+00
4.0 - 5.0	0.0E+00
5.0 - 6.0	0.0E+00
6.0 - 7.0	0.0E+00
7.0 - 8.0	0.0E+00
8.0 - 10.0	0.0E+00
10.0 - 14.0	0.0E+00
Total	1.5E+04

12.3 Radiation Protection Design Features

12.3.1 Facility Design Features

Specific design features for maintaining personnel exposure as low as reasonably achievable (ALARA) are presented in this subsection. The design feature recommendations given in Regulatory Guide 8.8 are utilized to minimize exposures to personnel.

12.3.1.1 Plant Design Features for ALARA

The equipment and plant design features employed to maintain radiation exposures ALARA are based upon the design considerations of Subsection 12.1.2 and are outlined in this subsection.

12.3.1.1.1 Common Equipment and Component Designs for ALARA

This subsection describes the design features utilized for several general classes of equipment or components. These classes of equipment are common to many of the plant systems; thus, the features employed for each system to maintain minimum exposures are similar and are presented by equipment class in the following paragraphs.

Reactor Vessel

The reactor vessel design includes an integrated head package which combines the head lifting rig, control and gray rod drive mechanism (CRDM/GRDM), lift columns, control rod drive mechanism cooling system and power and instrumentation cabling into an effective, one-package reactor vessel head design. Mounted directly on the reactor vessel head assembly, the system helps to minimize the time, manpower, and radiation exposure associated with head removal and replacement during refueling. Integral in the design is permanent shielding for reducing work area dose rates from the control rod drive mechanism drive shafts.

The combination thermocouple/incore detector system is not kept with head assembly during refueling, but instead remains with the upper internals. This allows the thermocouple/incore detector system to be shielded underwater in the refueling cavity during a majority of refueling operations, reducing dose rates around the head assembly.

The reactor vessel nozzle welds are designed to accommodate remote inspection with ultrasonic sensors. The nozzle area is tapered along the reinforced areas to provide a smooth transition, and pipe branch locations are selected to avoid interference from one branch to the next. Weld-to-pipe interfaces require a smooth, high quality finish.

Reactor Vessel Upper and Lower Blocks

The reactor vessel is equipped with upper and lower shielding blocks (shown in Figure 5.3-7) to minimize neutron and gamma radiation streaming within the containment in order to reduce worker radiation doses during operations and outage maintenance.

Reactor Coolant Pumps

The sealless high-inertia reactor coolant pumps are designed to require infrequent maintenance and inspection. When maintenance or replacement is required, the pump can be removed and moved to a low radiation background work area using a specially provided pump removal cart.

Reactor Vessel Insulation

Insulation in the area of the reactor vessel nozzle welds is fabricated in sections with a thin reflective metallic sheet covering and quick disconnect clasps to facilitate removal of the insulation. Permanent identification markings of the sections of insulation are provided to accommodate rapid reinstallation.

Steam Generators

The steam generator incorporates many design features to facilitate maintenance and inspection in reduced radiation fields. The tube ends are designed to be flush with the tube sheet in the steam generator channel head to eliminate a potential crud trap. The steam generator manways (entrance to channel head) are sized for easy entrance and exit of workers with protective clothing, and to facilitate the installation and removal of tooling.

The specification of low cobalt tubing material for the AP1000 steam generator design is an important feature of the design; not only in terms of reduced exposure relative to the steam generator, but to the total plant radiation source term. The cobalt content has been substantially reduced to 0.015 weight percent for the AP1000 steam generator tubing.

The steam generator design includes a sludge control system/mud drum which is designed to reduce the need for sludge lancing, and reduces tube and tube support degradation. Steam generator tube support plates design and full depth tubesheet expansion of tubes reduce corrosion and occupational exposure.

Reactor Coolant Pipe Connections

To minimize crud buildup in branch lines, piping connections to the reactor coolant loops are located on or above the horizontal centerline of the pipe wherever practicable.

Filters

Cartridges and filter bags that accumulate radioactivity are removed with semi-remote tools. Adequate space is provided to allow removing, and transporting the cartridge to storage and packaging areas as described in Section 11.4.

Liquid systems containing radioactive filters are provided with remote or semi-remote filter handling systems for the removal of spent radioactive filter elements from their housings and for their transfer to temporary storage or for packaging and shipment from the site for burial. The process is accomplished in such a manner that exposure to personnel and the possibility of inadvertent radioactive release to the environment is minimized. The filter handling is designed to be simple, with a minimum of components susceptible to malfunction.

Demineralizers

Demineralizers for radioactive systems are designed so that spent resins can be remotely and hydraulically transferred to spent resin tanks prior to processing and so that fresh resin can be loaded into the demineralizer remotely. The demineralizers and piping include provisions for being flushed with demineralized water. The system design prevents inadvertent flushing of the resin into the purification loop through the demineralizer inlet.

Pumps

Air operated diaphragm, sealless pumps or pumps with mechanical seals are used in radioactive systems to reduce leakage and seal servicing time. Pumps and associated piping are arranged to provide adequate space for access to the pumps for servicing. Small pumps are installed in a manner which allows easy removal if necessary. Large pumps are selected with back pullout features that permit removal of the pump impeller or mechanical seals without disassembly of attached piping.

Pumps in radioactive waste systems are provided with flanged or threaded connections for ease of removal.

Tanks and Sumps

Tanks are provided with sloped bottoms and bottom outlet connections. Overflow lines are directed to the waste collection system to control contamination within plant structures. Tanks containing radioactivity are fabricated from stainless steel, and sumps which can contain radioactive liquid are lined with stainless steel to facilitate decontamination.

Heat Exchangers

Vertical heat exchangers are designed so that the shell-to-tube sheet joint need not be broken for inspection. The shell and tube assembly can be lifted intact above the channel head to expose the tube ends for inspection and testing for leaks.

Heat exchangers are provided with corrosion-resistant tubes of stainless steel to reduce leakage. Impingement plates are provided and as necessary and tube side and shell side velocities are limited to minimize erosive effects. Wherever practicable, the radioactive fluid passes through the tube side of the heat exchanger.

Instruments

Instrument devices are located in low radiation zones away from radiation sources whenever practicable. Primary instrument devices, which for functional reasons are located in high radiation zones, are designed for easy removal to a lower radiation zone for calibration. Transmitters and readout devices are located in low radiation zones, such as corridors for servicing. Non-contact type instruments or self cleaning instruments are used whenever possible.

Some instruments in high radiation zones, such as thermocouples, are provided in duplicate to reduce access and service time required. In-containment instruments are located outside the secondary shield (area of lower radiation at power and shutdown) whenever practicable.

Integral radiation check sources for response verification for airborne radiation monitors and area radiation monitors are provided.

Chemical seals are provided on the instrument sensing lines on process piping, which may contain highly radioactive solids, to reduce the servicing time required to keep the lines free of solids. Instrument and sensing line connections are located slightly above the pipe midplane wherever practicable to minimize radioactive crud buildup.

Valves

To minimize personnel exposures from valve operations, motor-operated, air-operated, or other remotely actuated valves are used where justified by the activity levels and frequency of use. Valves are located in valve galleries so that they are shielded separately from the major components. Long runs of exposed piping are minimized in valve galleries. In areas where manual valves are used on frequently operated process lines, either valve stem extenders or shielding is provided such that personnel need not enter a high radiation area for valve operation.

Wherever testing is required, valves of the bolted body-to-bonnet forging type are used to permit the use of ultrasonic testing in place of radiography. This facilitates inspection and maintenance time. Valves under 2 inches in diameter located in the piping carrying radioactive fluids in containment or carrying highly radioactive fluids outside containment are hermetically sealed valves to preclude radioactive releases to the environment, except for some passive core cooling system test header valves, where the valve stems are not normally pressurized, and hermetically sealed valves are

impractical due to design constraints and availability limitations. The design of large-bore valves may include live-loaded packing configuration and other improved design features such as graphite packing to reduce the potential for stem leakage.

When equipment in high radiation areas is operated infrequently, those valves associated with normal processing are provided with remote-manual operators or reach rods. Other valve operations are performed with equipment in the shutdown mode.

For valves located in radiation areas, provisions are made to drain adjacent radioactive components when maintenance is required. To the extent practicable, valves are not located at piping low points.

Manually operated valves in the filter and demineralizer modules required for normal operation and shutdown are equipped with reach rods extending through the shield plates. Personnel do not enter the module during spent resin or cartridge transfer operations. The modules are designed to reduce personnel exposure during maintenance of components within or adjacent to the modules and to protect personnel who operate the valves.

Piping

The piping in pipe chases is designed for 60 year design objective with consideration for corrosion and operating environment. Pipe bends are used instead of elbows where practicable to reduce potential crud traps. Welds are made smooth to prevent crud traps from forming. Butt welds are used to the extent practicable. When radioactive piping is routed through areas where routine maintenance is required, pipe chases or distance separation are provided to reduce the radiation contribution from these pipes to levels appropriate for the inspection or maintenance requirements. Piping containing radioactive material is routed to minimize radiation exposure to plant personnel.

Floor and Equipment Drains

Floor drains and sloped floors are provided, where practicable, for rooms or cubicles containing serviceable components which contain radioactive liquids on plant elevations above the basemat. Floor drains are also provided on the Nuclear Island basemat in potentially contaminated areas, but sloping of floors around the drains is not required. If floor sloping is not incorporated on top of the Nuclear Island basemat, housekeeping activities shall be used to convey radioactive leakage to the available floor drains. When practicable, shielded pipe chases are used for radioactive pipes. Floor coatings are specified which simplify cleanup of spills. If a radioactive drain line must pass through a plant area requiring personnel access, shielding or distance separation is provided as necessary to maintain radiation levels consistent with the required access.

Lighting

Wherever practicable, multiple electric lights are provided for rooms containing highly radioactive components so that the burnout of a single lamp does not require entry and immediate replacement of the defective lamp since sufficient illumination is still available. Incandescent lights are provided inside containment. They require less time for servicing and, hence, the personnel exposure is reduced. The fluorescent lights which are used outside containment do not require frequent service due to the increased life of the tubes. High Pressure Sodium (HPS) underwater lighting, with appropriate barriers and protection to prevent contact with the water, or long life lighting not containing restricted materials, are used for underwater lighting in the fuel handling areas outside containment as they provide longer lamp life, longer service intervals and less personnel exposure.

Heating, Ventilation, and Air-Conditioning

The heating, ventilation, and air-conditioning (HVAC) system design facilitates replacement of the filter elements. Ventilation airflow is routed from areas of lower potential airborne contamination to areas of potentially higher contamination. In the radiologically-controlled area ventilation system

(VAS) high airborne activity causes the exhaust air to be rerouted through HEPA and charcoal filters in the containment air filtration system (VFS).

Sample Stations

Proper shielding and ventilation are provided at the primary sample room to minimize personnel exposure during sampling. The counting room and laboratory facilities are described in Section 12.5. The fly ash used in the concrete for these areas is screened before use to confirm the radioactivity is less than the design limit.

Clean Services

Whenever practicable, clean services and equipment such as compressed air piping, clean water piping, ventilation ducts, and cable trays are not routed through radioactive pipeways.

Materials

Equipment specifications for components exposed to high temperature reactor coolant as part of normal plant operations contain limitations on the cobalt content of the base metal as given in Table 12.3-1. The use of hard facing material with cobalt content such as stellite is limited to applications where its use is necessary for reliability considerations. Nickel-based alloys in the reactor coolant system (Co-58 is produced from activation of Ni-58) are similarly used only where component reliability may be compromised by the use of other materials. The major use of nickel-based alloys in the reactor coolant system is the inconel steam generator tubes.

General prohibitions on antimony and other low melting point metals are contained in Subsection 6.1.1. In addition, the reactor coolant pump mechanical design criteria prohibits antimony completely from the reactor coolant pump and its bearings.

Improved Head Closure System

The head closure system is designed to minimize the reactor head stud tensioning time.

12.3.1.1.2 Common Facility and Layout Designs for ALARA

This subsection describes the design features utilized for standard plant process and layout situations. These features are employed in conjunction with the general equipment described in Subsection 12.3.1.1.1 and include the features described in the following paragraphs.

Valve Modules

Selected valve modules are provided with shielded entrances for personnel protection. Floor drains are provided to control radioactive leakage. To facilitate decontamination, concrete surfaces are covered with a smooth surface coating which allows decontamination.

Piping

Pipes carrying radioactive materials are routed through controlled access areas properly zoned for that level of activity. Radioactive piping runs are analyzed to determine the potential radioactivity level and the dose rate 1 foot from the surface, in accordance with 10 CFR 20. Where it is necessary that radioactive piping be routed through corridors or other low radiation zone areas, shielded pipeways or distance separation are provided. Whenever practicable, valves and instruments are not placed in radioactive pipeways. Equipment compartments are used as pipeways for those pipes associated with equipment in the compartment.

When practicable, radioactive and nonradioactive piping are separated to minimize personnel exposure. Should maintenance be required, provision is made to isolate and drain radioactive piping and associated equipment.

Piping is designed to minimize low points and dead legs. Drains are provided on piping where low points and dead legs cannot be eliminated. In radioactive systems, the use of nonremovable backing rings in the piping joints is prohibited. Whenever practicable, branch lines having little or no flow during normal operation are connected above the horizontal midplane of the main pipe.

Piping which carries resin slurries is run vertically and horizontal runs carrying spent resin are sloped toward the spent resin tanks, as much as practicable. Large radius bends are utilized instead of elbows. Where sloped lines or large radius bends are impractical, adequate flush and drain capability is provided to prevent flow blockage and minimize crud traps.

The use of embedded pipes is minimized to the extent possible, consistent with maintaining radiation doses ALARA. To the extent possible, pipes are routed in accessible areas, such as dedicated pipe routing tunnels or pipe trenches, which provide good conditions for decommissioning.

Wall Penetrations

To minimize radiation streaming through wall penetrations, as many wall penetrations as practicable are located with offsets between the radioactive source and the normally accessible areas. If offsets are not practicable, penetrations are located as far as practicable above the floor elevation to reduce radiation exposure to personnel. If these two methods are not used, alternate means are employed, such as baffle shield walls or grouting the penetration annulus.

Contamination Control

Access control and traffic patterns are considered in the plant layout to reduce the spread of contamination. Routinely used equipment vents and drains from highly radioactive systems are piped directly to the collection system to minimize airborne and floor contamination. Vents and drains from highly radioactive systems that are used less than once per refueling cycle are either piped directly to the collection system or are isolated with a valve and pipe end cap if direct piping is impractical. Discharge from infrequently used vents and drains that use a valve and pipe end cap is routed to the appropriate collection system with temporary flexible hose during the infrequent use. Welded piping systems are employed on radioactive systems to the maximum extent practicable to reduce system leakage and crud buildup at joints.

The number of passageways (doors) between the radiologically controlled area and the environment has been minimized. When such doors are incorporated, systems of drains and floor and exterior concrete sloping are used to prevent (potentially radioactive) fluid from the interior of the buildings from exiting the buildings, and also to prevent surface water from entering the buildings.

Decontamination of potentially contaminated areas and equipment within the plant is facilitated by the application of epoxy paints and suitable smooth-surface coatings to the concrete floors and walls. Sloping floors with floor drains are provided, where practicable, in potentially contaminated areas of the plant on plant elevations above the basemat. Floor drains are also provided on the Nuclear Island basemat in potentially contaminated areas, but sloping of floors around the drains is not required. If floor sloping is not incorporated on top of the Nuclear Island basemat, housekeeping activities shall be used to convey radioactive leakage to the available floor drains. In addition, radioactive and potentially radioactive drains are separated from nonradioactive drains.

In radiologically controlled areas where contamination is expected, radiation monitoring equipment is provided (Section 11.5). Those systems that become highly radioactive, such as the spent resin lines in the radwaste system, are provided with flush and drain connections.

Because of the potential for adsorption of contaminated fluids, the use of concrete block walls in the radiologically controlled areas of the plant is minimized. Where such walls are used, they are fully sealed at the ceiling or top of the block in order to prevent liquid incursion.

The role of the ventilation systems in minimizing the spread of airborne contamination is described in Subsection 12.3.3.

Equipment Layout

In those systems where process equipment is a major radiation source; pumps, valves, and instruments are separated from the process component. This allows servicing and maintenance of these items in reduced radiation zones. Control panels are located in low radiation zones.

Major components such as tanks, demineralizers, and filters in radioactive systems are located in shielded compartments insofar as practical. Labyrinth shields or shielding doors are provided for compartments where radiation could stream or scatter to access areas and exceed the radiation zone dose limits for those areas. For potentially high radiation components (such as ion exchangers, filters and spent resin tanks), shielded compartments with hatch openings or removable shield walls are used. Equipment in nonradioactive systems that requires lubrication is located in low radiation zones. Wherever practicable, lubrication of equipment in high radiation areas is achieved with the use of tube-type extensions to reduce exposure during maintenance.

Exposure from routine in-plant inspection is controlled by locating, whenever practicable, inspection points in low-background radiation areas. Radioactive and nonradioactive systems are separated as far as practicable to limit radiation exposure from routine inspection of nonradioactive systems. For radioactive systems, emphasis is placed on adequate space and ease of motion in a properly shielded inspection area. Where longer times for routine inspection are required and permanent shielding is not feasible, space for portable shielding is provided.

Field Run Piping

Field run radioactive piping is minimized in the plant design. Radioactive process piping is routed dimensionally on orthographic drawings. Fabrication isometrics of radioactive process piping are reviewed to provide adequate shielding.

12.3.1.2 Radiation Zoning and Access Control

Access to areas inside the plant structures and plant yard area is regulated and controlled by posting of radiation signs, control of personnel, and use of alarms and locks (Section 12.5). During plant operation, access to the radiologically controlled area (RCA) is through the access control area in the annex building.

Plant areas are categorized into radiation zones according to design basis radiation levels and anticipated personnel occupancy with consideration given toward maintaining personnel exposures ALARA and within the standards of 10 CFR 20. Rooms, corridors, and pipeways are evaluated for potential radiation sources during normal, shutdown, spent resin transfer, and emergency operations; for maintenance occupancy requirements; for general access requirements; and for material exposure limits to determine appropriate zoning. Each radiation zone defines the radiation level range expected in the zone. The radiation zone categories employed and zoning for each plant area under normal conditions is shown in Figure 12.3-1. The zoning for each plant area under accident conditions is shown in Figure 12.3-2. Radiation zones shown in the figures are based upon conservative design data. Actual in-plant zones and control of personnel access are based upon surveys conducted by the Combined License holder. Access control provisions for each plant area under normal expected conditions are shown in Figure 12.3-3. These provisions implement the

requirements of 10 CFR 20 and utilize the alternative access control methods outlined in Regulatory Guide 8.38.

Figure 12.3-201, Figure 12.3-202, and Figure 12.3-203 replace Figure 12.3-1 (sheet 11), Figure 12.3-2 (sheet 11), and Figure 12.3-3 (sheet 11), respectively, to reflect the relocation of the Operations Support Center.

Based on actual operating plant data, ingress or egress of plant operating personnel to radiologically restricted areas is controlled and monitored as discussed in Subsection 12.3.5 such that radiation levels and exposures are within the limits prescribed in 10 CFR 20.

Posting of radiation signs, control of personnel access, and use of alarms and locks are discussed in Subsection 12.3.5.

12.3.2 Shielding

The bases for the nuclear radiation shielding and the shielding configurations are discussed in this subsection.

12.3.2.1 Design Objectives

The objective of the plant radiation shielding is to minimize personnel and population exposures, while maintaining a program of controlled personnel access to and occupancy of radiation areas. Radiation levels are within the requirements of 10 CFR 50 during design basis accidents and ALARA within the requirements of 10 CFR 20 during normal operation. Shielding and equipment layout and design are considered in providing confidence that exposures are kept ALARA during anticipated personnel activities in areas of the plant containing radioactive materials. Design recommendations given in Regulatory Guide 8.8 are utilized where practicable.

The nuclear radiation shielding is designed to provide personnel protection and is based on the following operating states:

- Normal, full-power operation
- Shutdown operation
- Spent resin transfer
- Emergency operations (for required access to safety-related equipment)

The shielding design objectives for the plant during these operating states are:

- Radiation exposure to plant operating personnel, contractors, administrators, visitors, and site boundary occupants is ALARA and within the limits of 10 CFR 20.

- Sufficient personnel access and occupancy time is provided to allow normal anticipated maintenance, inspection, and safety-related operations required for each plant equipment and instrumentation area.

- Reduce potential equipment neutron activation and mitigate the effects of radiation on materials.

- Provide sufficient shielding for the control room so that for design basis accidents (DBAs) the direct dose plus the inhalation dose (calculated in Chapter 15) does not exceed the limits of 10 CFR 50, Appendix A, General Design Criterion 19.

12.3.2.2 General Shielding Design

Systems containing radioactivity and other sources of radiation are identified for four plant conditions defined in Subsection 12.3.2.1. Shielding is provided to attenuate direct radiation through walls and penetrations and scattered radiation to less than the upper limit of the radiation zone for each area shown in Figure 12.3-1. Design criteria for shield penetrations are consistent with the recommendations of Regulatory Guide 8.8 and are described in Subsection 12.3.1.1.2.

Materials used in shielding typically include lead, steel, water, and concrete. The material used for most of the plant shielding is ordinary concrete with a bulk density of approximately 140 lb/ft^3. Whenever poured-in-place concrete has been replaced by concrete blocks, an equivalent shielding basis as determined by the density of the concrete block is selected. Steel is used as shielding in the chemical and volume control system and other modules, as well as around the reactor vessel flange at the floor of the refueling cavity. Water is used as the primary shield material for areas above the spent fuel storage area and refueling cavity during refueling operations.

12.3.2.2.1 Containment Shielding Design

During reactor operation, the shield building protects personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and primary loop components. The concrete shield building wall and the reactor vessel and steam generator compartment shield walls reduce radiation levels outside the shield building to less than 0.25 mrem/hr from sources inside containment. The shield building completely surrounds the reactor coolant system components.

For design basis accidents, the shield building and the main control room shielding reduce the plant radiation intensities from fission products inside the containment to acceptable levels, as defined by 10 CFR 50, Appendix A, General Design Criterion 19, for the main control room. (See Subsection 12.3.2.2.7.)

Where personnel locks and equipment hatches or penetrations pass through the shield building wall, additional shielding is provided to attenuate radiation to the level defined by the outside radiation zone during normal operation and shutdown, and to acceptable levels during design basis accidents as defined by General Design Criterion 19.

12.3.2.2.2 Containment Interior Shielding Design

During reactor operation, many areas inside the containment are Zone V or greater and are normally inaccessible. Shielding is provided to reduce dose rates to approximately 100 mrem/hr or less in areas of the containment that potentially require access at power. These are the Zone IV or lower areas shown in Figure 12.3-1.

The main sources of radiation are the reactor vessel and the primary loop components, consisting of the steam generators, pressurizer, reactor coolant pumps, and associated piping. The reactor vessel is shielded by the concrete primary shield and by the concrete secondary shield which also surrounds other primary loop components. Air cooling is provided to prevent overheating, dehydration, and degradation of the shielding and structural properties of the primary shield.

The primary shield is a large mass of reinforced concrete surrounding the reactor vessel. The primary shield meets the following objectives:

- In conjunction with the secondary shield, reduce the radiation level from sources within the reactor vessel and reactor coolant system to allow limited access to the containment during normal, full-power operation.

- After shutdown, limit the radiation level from sources within the reactor vessel, permit limited access to the reactor vessel and the reactor coolant system equipment.

- Limit neutron activation of component and structural materials.

The secondary shield is a structural module filled with concrete surrounding the reactor coolant system equipment, including piping, pumps, and steam generators. This shield protects personnel from the direct gamma radiation resulting from reactor coolant activation products and fission products carried away from the core by the reactor coolant. In addition, the secondary shield supplements the primary shield by attenuating neutron and gamma radiation escaping from the primary shield. The secondary shield is sized to allow limited access to the containment during full-power operation.

The reactor cavity has been designed so that the dose rates on the operating deck due to neutron streaming are less than 100 mrem/hr.

Components of the purification portion of the chemical and volume control system (CVS) in the containment are located in a shielded compartment. Shielding is provided for equipment in the purification system consistent with its postulated maximum activity (Subsection 12.2.1) and with the access and zoning requirements of adjacent areas. This equipment includes the regenerative heat exchanger, the letdown heat exchanger, chemical and volume control system filters and demineralizers, and the letdown lines.

After shutdown, the containment is accessible for limited periods of time and access is controlled. Areas are surveyed to establish allowable working periods. Dose rates are expected to range from 0.5 to 1000 mrem/hr, depending on the location inside the containment (excluding reactor cavity). These dose rates result from residual fission products and neutron activation products (components and corrosion products) in the reactor coolant system.

Spent fuel is the primary source of radiation during refueling. Because of the high activity of the fission products contained in the spent fuel elements, extensive shielding is provided for areas surrounding the refueling cavity and the fuel transfer canal to limit the radiation levels to below zone levels specified for adjacent areas. Water provides the shielding over the spent fuel assemblies during fuel handling.

12.3.2.2.3 Auxiliary Building Shielding

During normal operations, the major components in the auxiliary building with potentially high radioactivity are those in liquid radwaste, gaseous radwaste, and spent resin handling systems. Shielding is provided consistent with the postulated maximum activity (See Sections 11.1, 11.2, 11.3, and 12.2) and with the access and zoning requirements of adjacent areas. (See Figure 12.3-1.)

Depending on the equipment in the compartments, the radiation zones vary. Corridors are generally shielded to allow Zone II access, and operator areas for valve modules are generally Zone II or III for access.

Concrete plugs are utilized to provide necessary access for equipment maintenance and spent filter cartridge replacement. Where necessary, labyrinth entrances with provisions for adequate ingress and egress for equipment maintenance and inspection are provided and are designed to be consistent with the access and zoning requirements of adjacent areas.

Following reactor shutdown, the normal residual heat removal (RNS) system pumps and heat exchangers are in operation to remove heat from the reactor coolant system. The radiation levels in the vicinity of this equipment temporarily reach Zone V or higher levels due to corrosion and fission

products in the reactor coolant water. Shielding is provided to attenuate radiation from normal residual heat removal equipment during shutdown cooling operations to levels consistent with the radiation zoning requirements of adjacent areas.

12.3.2.2.4 Fuel Handling Area Shielding Design

The concrete shield walls surrounding the spent fuel cask loading and decontamination areas, and the shield walls surrounding the fuel transfer and storage areas are sufficiently thick to limit radiation levels outside the shield walls in accessible areas to Zone II. The building external walls are sufficient to shield external plant areas which are not controlled to Zone I.

Spent fuel removal and transfer operations are performed under borated water to provide radiation protection and maintain subcriticality. Minimum allowable water depths above active fuel in a fuel assembly during fuel handling are 8.75 feet in the reactor cavity and 8.75 feet in the fuel transfer canal and spent fuel pool. This limits the dose to personnel on the spent fuel pool handling machine to less than 2.5 mrem/hr for an assembly in a vertical position. Minimum water depth above the stored assemblies is about 26 feet, and for this depth the dose rate at the pool surface is insignificant. The concrete walls of the fuel transfer canal and spent fuel pool walls supplement the water shielding and limit the maximum radiation dose levels in working areas to less than 2.5 mrem/hr.

The spent fuel pool cooling system (SFS) shielding (Section 9.1) is based on the activity discussed in Subsection 12.2.1 and the access and zoning requirements of adjacent areas. Equipment in the spent fuel pool cooling system to be shielded includes the spent fuel cooling system heat exchangers, pumps, piping, filters and demineralizers which may be contaminated with radioactive crud.

12.3.2.2.5 Radwaste Building Shielding Design

Shielding is provided as necessary for the waste storage areas in the radwaste building to meet the radiation zone and access requirements. Depending on the equipment in the compartments, the radiation zoning varies from Zone I through IV as shown on the radiation zone drawing of Figure 12.3-1. Temporary partitions and shield walls will be provided, as required, to supplement the permanent shield walls surrounding the waste accumulation room inside the radwaste building. The three bunkers described in Subsection 11.4.2.5.2 include removable steel shield bunker roof plates that provide vertical shielding during storage of moderate and high activity waste to maintain radiation levels as Zone II to Zone III on the normally unoccupied and access controlled radwaste building roof, and removable steel shield bunker door plates, that may be installed for ALARA considerations. The removable steel shield bunker door plates are not required to be installed to maintain radiation levels in the worker occupied areas in the radwaste building and in the adjacent plant yard areas as Zone I to Zone IV as defined in Figure 12.3-1 (Sheet 14).

12.3.2.2.6 Turbine Building Shielding Design

The steam generator blowdown demineralizers and the resin columns associated with the secondary sampling system (SSS) steam generator blowdown sample panel are shielded when required to meet the radiation zone and access requirements. Radiation shielding is not required for other process equipment located in the turbine building. Space has been provided so that shielding may be added around the steam generator blowdown system (BDS) filter, the electrodeionization (EDI) unit, and the condensate polishing demineralizers if they become radioactive.

12.3.2.2.7 Control Room Shielding Design

The design basis loss-of-coolant accident dictates the shielding requirements for the control room. The rod ejection accident dictates the shielding requirements for the main control room emergency

habitability (VES) filter in the operator break room. Consideration is given to shielding provided by the shield building structure. Shielding combined with other engineered safety features is provided to permit access and occupancy of the control room following a postulated loss-of-coolant accident, so that radiation doses are limited to five rem whole body from contributing modes of exposure for the duration of the accident, in accordance with General Design Criterion 19.

Shielding of the VES filtration unit is accomplished by safety-related metal shielding. This shielding is composed of either tungsten that is 0.25 inches thick or stainless steel shown to provide an equivalent amount of shielding. The length and width of the shielding are designed to match the length and width of the filtration unit being shielded.

12.3.2.2.8 Miscellaneous Plant Areas and Plant Yard Areas

With limited exceptions, sufficient shielding is provided for plant buildings containing radiation sources so that radiation levels at the outside surfaces of the buildings are maintained below Zone I levels. The yard area west of the turbine building first bay could experience Zone II levels under design basis conditions if the steam generator blowdown system demineralizers and resin columns are not shielded as described in Subsection 12.3.2.2.6. The yard area outside the auxiliary building fuel handling area could experience Zone III levels at elevations more than 20 feet above the grade elevation during resin transfer operations under design basis conditions. Plant yard areas that are frequently occupied by plant personnel are fully accessible during normal operation and shutdown. Tanks containing radioactive materials are not located in the yard.

12.3.2.2.9 Spent Fuel Transfer Canal and Tube Shielding

The spent fuel transfer tube is shielded to within adjacent area radiation zone limits. This is primarily achieved through the use of concrete and water. The only removable shielding consists of concrete or steel hatches which reduce radiation in accessible areas to within those levels prescribed in the normal operation radiation zone maps (Figure 12.3-1).

The spent fuel transfer tube is completely enclosed in concrete and there is no unshielded portion of the spent fuel transfer tube during the refueling operation. The only potential radiation streaming path associated with the tube shielding configuration is the 2 inch (5.08 cm) seismic gap between the fuel transfer tube shielding and the steel containment wall. Shielding of this gap is provided by a water-filled bladder. This "expansion gap" radiation shield provides effective reduction of the radiation fields during fuel transfer and accommodates relative movement between the containment and the concrete transfer tube shielding with no loss in shield integrity. A removable hatch in the shield configuration provides access for inspection of the fuel transfer tube welds. The opening of this hatch is administratively controlled and is treated as an entrance to a very high radiation area under 10 CFR 20. This hatch is in place during the spent fuel transfer operation.

12.3.2.3 Shielding Calculational Methods

The shielding thicknesses provided for compliance with plant radiation zoning and to minimize plant personnel exposure are based on maximum equipment activities under the plant operating conditions described in Chapter 11 and Section 12.2. The thickness of each shield wall surrounding radioactive equipment is determined by approximating as closely as practicable the actual geometry and physical condition of the source or sources. The isotopic concentrations are converted to energy group sources using data from standard references (References 1 through 6).

The geometric model assumed for shielding evaluation of most tanks, heat exchangers, filters, ion exchangers, and the containment is a finite cylindrical volume source. For shielding evaluation of piping, the geometric model is a finite shielded cylinder. In cases where radioactive materials are deposited on surfaces such as pipe, the latter is treated as an annular cylindrical surface source.

Computer codes based on point kernel and Monte Carlo methods are used to calculate gamma dose rates. Most dose rates for non-complex geometries are calculated with a point kernel code MicroShield 6.20 (Reference 22), which is a PC shielding code with a menu-guided user-interface. For complex geometries, Monte Carlo or discrete ordinate methods were used for radiation analysis. Some simplifications are made in the modeling, concerning non-active components connected to the sources, and shielding. As a rule, these simplifications result in conservative dose rate estimates, but do not significantly affect the overall evaluation of the radiological conditions in the containment. Non-homogenous sources, such as fuel assemblies, ion exchange resin beds are homogenized, where this does not underestimate the dose rates.

Complex geometries are modeled in MCNP code (Reference 21). Due to the need of larger computer and work resources MCNP is used only in those cases that cannot be calculated by methods based on line-of-sight attenuation such as point kernel method. Such cases may involve labyrinth structures, penetrations, dominance of scattered radiation etc.

For very simple geometries also analytical formulas using gamma energy yields of radioactive isotopes are used.

The source activity (Ci) and gamma ray source strengths (MeV/sec) are calculated using one of the following computer codes: ORIGEN (Reference 17), SOURCE2/ACCUM (Reference 12), or RADGAS3 (Reference 13). ACCUM (Reference 12) is an option within SOURCE2 that computes isotope accumulation for several time periods from a given flow of isotopes in curies per second. This accumulated activity may then be decayed for any number of decay times at which gamma energy spectra and isotope Curie activity are computed. The generation of daughter products is included during the accumulation and decay periods. FIPCO, CORA, and RADGAS3 compute isotopic activity in radioactive liquid and gaseous systems. The total activity in system lines or equipment is computed from the initial isotope flow, equipment accumulating (operating) time, and parameters which describe the physical accounts for instantaneous mixing or uniform flow and plateout of particulate daughter products. Isotope data is based on the Table of Isotopes (Reference 5) and ORIGEN library data (Reference 6).

The shielding thicknesses of walls and slabs are selected to reduce the aggregate computed radiation level from the contributing sources below the upper limit of the radiation zone specified for each plant area. The labyrinths are constructed so that the scattered dose rate, plus the transmitted dose rate through the shield wall from all contributing sources, is below the upper limit of the radiation zone specified for each plant area. Shielding requirements in each plant area are evaluated at the point of maximum radiation dose through any wall. In addition, for shielding design purposes the concrete density of 140 lb/ft^3 was assumed. Therefore, the actual anticipated radiation level in each plant area is less than this maximum dose and consequently less than the radiation zone upper limit.

Neutron radiation is calculated either with MCNP code or hand calculation methods combined to literature data on neutron attenuation (References 7 and 8).

12.3.3 Ventilation

The plant heating, ventilating, and air-conditioning systems are designed to provide a suitable environment for personnel and equipment during normal operation.

12.3.3.1 Design Objectives

The plant heating, ventilating, and air-conditioning systems for normal operation are designed to meet the requirements of 10 CFR 20 and 10 CFR 50.

12.3.3.2 Design Criteria

Design criteria for the plant HVAC systems include the following:

- During normal operation the average and maximum airborne radioactivity levels to which plant personnel are exposed in restricted areas of the plant are ALARA and within the limits specified in 10 CFR 20. The average and maximum airborne radioactivity levels in unrestricted areas of the plant during normal operation, are ALARA and within the limits of 10 CFR 20.

- During normal operations the dose from concentrations of airborne radioactive material in unrestricted areas beyond the site boundary is ALARA and within the limits specified in 10 CFR 20 and 10 CFR 50, Appendix I.

12.3.3.3 Design Features

To accomplish the design objectives and to conform to the design criteria, the following design features are incorporated wherever practicable.

12.3.3.3.1 Design Features to Minimize Airborne Radioactivity

- Access control and traffic patterns are considered in the plant layout to minimize the spread of contamination.

- Routinely used equipment vents and drains from highly radioactive systems are piped directly to a collection device connected to the collection system. This is to minimize airborne contamination and to prevent contaminated fluid from flowing across the floor to a floor drain. Vents and drains from highly radioactive systems that are used less than once per refueling cycle are either piped directly to the collection system or are isolated with a valve and end cap if direct piping is impractical. Discharge from infrequently used vents and drains that use a valve and pipe end cap is routed to the appropriate collection system with temporary flexible hose during the infrequent use.

- Welded piping systems are employed on systems containing radioactive fluids to the maximum extent practicable. If welded piping systems are not employed, drip trays are provided at the points of potential leakage. Drains from drip trays are piped directly to the collection system.

- Suitable coatings are applied to the concrete floors and walls of potentially contaminated areas to facilitate decontamination.

- Design of equipment incorporates features that minimize the spread of radioactivity during maintenance operations. These features include flush and drain connections on pump casings for draining and flushing the pump prior to maintenance and flush connections on piping systems that could become highly radioactive.

12.3.3.3.2 Design Features to Control Airborne Radioactivity

- The airflow is directed from areas with lesser potential for contamination to areas with greater potential for contamination.

- In building compartments with a potential for contamination, the exhaust is designed for greater volumetric flow than is supplied to that area. This minimizes the amount of uncontrolled exfiltration from the area.

- Consideration is given to the potential disruption of normal airflow patterns by maintenance operations, and provisions are made in the design to the extent practicable to prevent adverse airflow direction. Administrative controls, such as those described in Subsection 12AA.5.4.8, are implemented during maintenance operations where necessary to prevent the spread of contamination.

- The ventilation system design for radiologically controlled areas is discussed in Subsections 9.4.3, 9.4.7, 9.4.8, and 9.4.11. The exhaust air from these areas is normally unfiltered except for the containment atmosphere which is filtered by the containment air filtration system exhaust filters. A description of these filter units is given in Subsection 12.3.3.5.

- Air discharged from the containment is passed through high efficiency particulate air filters and charcoal adsorbers to remove particulates and halogens. Air exhausted from the auxiliary building, fuel handling area of the auxiliary building, and the annex building is monitored for high airborne activity. Means are provided to shut off supply air and divert exhaust air through high efficiency particulate air filters and charcoal adsorbers upon detection of high airborne activity. Alarms are provided in the main control room for these discharge flows and for flows from the radwaste building and the health physics/hot machine shop area. These alarms alert the operator of high radioactivity concentrations in the air. This minimizes the discharge of contaminants to the environment and in-plant exposures.

- Atmospheric tanks which contain radioactive materials are vented to the respective building ventilation system for release to the monitored plant vent.

12.3.3.3.3 Design Features to Minimize Personnel Exposure from HVAC Equipment

- The guidelines of Regulatory Guide 8.8 have been utilized, as practicable, in the design of the plant ventilation systems.

- Ventilation fans and filters are provided with adequate access space to permit servicing with minimum personnel radiation exposure. The HVAC system is designed to allow rapid replacement of components.

- Ventilation ducts are designed to minimize the buildup of radioactive contamination within the ducts.

- Ventilating air for radiologically controlled areas of the plant is a once-through design.

- Access to ventilation systems in potentially radioactive areas can result in operator exposure during maintenance, inspection, and testing. Equipment locations are selected to minimize personnel exposures. The outside air supply units and building exhaust system components are located in ventilation equipment rooms. These equipment rooms are accessible to the operators. Work space is provided around each unit for anticipated maintenance, testing, and inspection.

12.3.3.4 Design Description

The ventilation systems serving the following structures are considered to be potentially radioactive and are discussed in detail in Section 9.4.

- Containment building (See Subsection 9.4.7)
- Auxiliary building (See Subsection 9.4.3)
- Fuel handling area of the auxiliary building (See Subsection 9.4.3)

- Annex building (See Subsection 9.4.3)
- Radwaste building (See Subsection 9.4.8)
- Health physics and hot machine shop (See Subsection 9.4.11)

The main control room is considered to be a nonradioactive area. The associated ventilation system design is described in Section 6.4 and Subsection 9.4.1.

Other structures contain insignificant sources of airborne radioactivity and are not addressed in this chapter.

12.3.3.5 Air Filtration Units

The guidance and recommendations of Regulatory Guide 1.140 concerning maintenance and inplace testing provisions for atmospheric cleanup systems, air filtration, and adsorption units are used in the design of the various ventilation systems. The extent to which Regulatory Guide 1.140 has been incorporated is discussed in Subsection 1.9.1.

Provisions specifically included to minimize personnel exposures and to facilitate maintenance or inplace testing operations are as follows.

A. The loading of the filters and adsorbers with radioactive material during normal plant operation is a slow process. Therefore, in addition to monitoring for pressure drop, the filters are checked for radioactivity on a scheduled maintenance basis with portable equipment. The filter elements are replaced before the radioactivity level is of sufficient magnitude to create a personnel hazard. No shielding is provided since it is not required for the level of radioactivity accumulation during normal operation. In case of excessive radioactivity caused by a postulated accident, the filter is replaced before normal personnel access is resumed. It is not necessary for workers to handle filter units immediately after a design basis accident, so exposures can be minimized by allowing the short-lived isotopes to decay before changing the filter.

B. Active components of the atmospheric cleanup systems are designed for ease of removal.

C. Access to active components is direct from working platforms to simplify element handling. Ample space is provided on the platforms for accommodating safe personnel movement during replacement of components, including the use of necessary material handling equipment and inplace testing devices.

D. No filter bank is more than three filter cells high, where each filter cell is 2 feet by 2 feet. The access to the level or platform at which the filter is serviced is by stairs.

E. The clear space for access to filter banks and active components is a minimum of 20 inches by 50 inches.

F. The HEPA filter banks are designed with replaceable cells that are clamped in place against compression seals. The charcoal adsorbers are designed to be replaced with bulk charcoal using a vacuum transfer system. The filter housing is designed and tested to be airtight with bulkhead type doors that are closed against compression seals.

12.3.4 Area Radiation and Airborne Radioactivity Monitoring Instrumentation

For a description of the radiation monitoring system (RMS), refer to Section 11.5.

Procedures detail the criteria and methods for obtaining representative measurement of radiological conditions, including in-plant airborne radioactivity concentrations in accordance with applicable portions of 10 CFR Part 20 and consistent with the guidance in Regulatory Guides 1.21-Appendix A, 8.2, 8.8, and 8.10. Additional discussion of radiological surveillance practices is included in the radiation protection program description provided in Appendix 12AA.

Surveillance requirements are determined by the functional manager in charge of radiation protection based on actual or potential radiological conditions encountered by personnel and the need to identify and control radiation, contamination, and airborne radioactivity. These requirements are consistent with the operational philosophy in Regulatory Guide 8.10. Frequency of scheduled surveillance may be altered by permission of the functional manager in charge of radiation protection or their designee. Radiation Protection periodically provides cognizant personnel with survey data that identifies radiation exposure gradients in area resulting from identified components. This data includes recent reports, with survey data, location and component information.

The following are typical criteria for frequencies and types of surveys:

Job Coverage Surveys

- Radiation, contamination, and/or airborne surveys are performed and documented to support job coverage.
- Radiation surveys are sufficient in detail for Radiation Protection to assess the radiological hazards associated with the work area and the intended/specified work scope.
- Surveys are performed commensurate with radiological hazard, nature and location of work being conducted.
- Job coverage activities may require surveys to be conducted on a daily basis where conditions are likely to change.

Radiation Surveys

- Radiation surveys are performed at least monthly in any radiological controlled area (RCA) where personnel may frequently work or enter. Survey frequencies may be modified by the functional manager in charge of radiation protection as previously noted.
- Radiation surveys are performed prior to or during entry into known or suspected high radiation areas for which up to date survey data does not exist.
- Radiation surveys are performed prior to work involving highly contaminated or activated materials or equipment.
- Radiation surveys are performed at least semiannually in areas outside the RCA. Areas to be considered include shops, offices, and storage areas.
- Radiation surveys are performed to support movement of highly radioactive material.
- Neutron radiation surveys are performed when personnel may be exposed to neutron emitting sources.

Contamination Surveys

- Contamination surveys are performed at least monthly in any RCA where personnel may frequently work or enter. Survey frequencies may be modified by the functional manager in charge of radiation protection as previously noted.

- Contamination surveys are performed during initial entry into known or suspected contamination area(s) for which up to date survey data does not exist.

- Contamination surveys are performed at least daily at access points, change areas, and high traffic walkways in RCAs that contain contaminated areas. Area access points to a High Radiation Area or Very High Radiation Area are surveyed prior to or upon access by plant personnel or if access has occurred.

- Contamination surveys are performed at least semiannually in areas outside the RCA. Areas to be considered include shops, offices, and storage areas.

- A routine surveillance is conducted in areas designated by the functional manager in charge of radiation protection or their designee likely to indicate alpha radioactivity. If alpha contamination is identified, frequency and scope of the routine surveillance is increased.

Airborne Radioactivity Surveys

- Airborne radioactivity surveys are performed during any work or operation in the RCA known or suspected to cause airborne radioactivity (e.g., grinding, welding, burning, cutting, hydrolazing, vacuuming, sweeping, use of compressed air, using volatiles on contaminated material, waste processing, or insulation).

- Airborne radioactivity surveys are performed during a breach of a radioactive system, which contains or is suspected of containing significant levels of contamination.

- Airborne radioactivity surveys are performed during initial entry (and periodically thereafter) into any known or suspected airborne radioactivity area.

- Airborne radioactivity surveys are performed immediately following the discovery of a significant radioactive spill or spread of radioactive contamination, as determined by the functional manager in charge of radiation protection.

- Airborne radioactivity surveys are performed daily in occupied radiological controlled areas where the potential for airborne radioactivity exists, including containment.

- Airborne radioactivity surveys are performed any time respiratory protection devices, alternative tracking methods such as derived air concentration-hour (DAC-hr), and/or engineering controls are used to control internal exposure.

- Airborne radioactivity surveys are performed using continuous air monitors (CAMs) for situations in which airborne radioactivity levels can fluctuate and early detection of airborne radioactivity could prevent or minimize inhalations of radioactivity by workers. Determination of air flow patterns are considered for locating air samplers.

- Airborne radioactivity surveys are performed prior to use and monthly during use on plant service air systems used to supply air for respiratory protection to verify the air is free of radioactivity.

- Tritium sampling is performed near the spent fuel pool when irradiated fuel is in the pit and other areas of the plant where primary system leaks occur and tritium is suspected.

Appropriate counting equipment is used based on the sample type and the suspected identity of the radionuclides for which the sample is being done. Survey results are documented, retrievable, and processed per site document control and records requirements consistent with Regulatory Guide 8.2.

Completion of survey documentation includes the update of room/area posting maps and revising area or room postings and barricades as needed.

Air samples indicating activity levels greater than a procedure specified percentage of DAC are forwarded to the radiochemistry laboratory for isotopic analysis. Samples which cannot be analyzed on-site are forwarded to an offsite laboratory or a contractor for analysis; or, the DAC percentage may be hand calculated using appropriate values from 10 CFR Part 20, Appendix B.

The responsible radiation protection personnel review survey documentation to evaluate if surveys are appropriate and obtained when required, records are complete and accurate, and adverse trends are identified and addressed.

An in-plant radiation monitoring program maintains the capability to accurately determine the airborne iodine concentration in areas within the facility where personnel may be present under accident conditions. This program includes the training of personnel, procedures for monitoring, and provisions for maintenance of sampling and analysis equipment consistent with Regulatory Guides 1.21 (Appendix A) and 8.8. Training and personnel qualifications are discussed in Appendix 12AA.

Emergency operating procedures include provisions for use of a portable monitoring system, consistent with the criteria in NUREG-0737, Item III.D.3.3, to sample and analyze for radioiodine in areas of the plant during and following an accident. Procedures include methods for taking and analyzing samples in the field, as well as for analyzing samples in the count room facility, accounting for techniques to reduce counting system saturation from a high-activity sample. Accident monitoring instrumentation complies with applicable parts of 10 CFR Part 50, Appendix A.

Sampling cartridges can be removed to a low background area for further analysis. These cartridge samples can be purged of any entrapped noble gases, when necessary, prior to being analyzed.

12.3.5 Combined License Information

12.3.5.1 Administrative Controls for Radiological Protection

The administrative controls for use of the design features provided to control access to radiologically restricted areas, including potentially very high radiation areas, are addressed in Subsection 12.5.4 and Appendix 12AA.

12.3.5.2 Criteria and Methods for Radiological Protection

The criteria and methods for obtaining representative measurement of radiological conditions, including airborne radioactivity concentrations in work areas, and the use of portable instruments, and the associated training and procedures, are addressed in Subsection 12.3.4.

12.3.5.3 Groundwater Monitoring Program

In accordance with Reference 23, the groundwater monitoring program is addressed in Appendix 12AA.

12.3.5.4 Record of Operational Events of Interest for Decommissioning

In accordance with Reference 23, the program to provide documentation of operational events deemed to be of interest for decommissioning, including remediation of any leaks that have the potential to contaminate groundwater, is addressed in Appendix 12AA.

12.3.6 References

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2. Martin, J. J., "Radioactive Atoms Supplement 1," ORNL 4923, Oak Ridge National Laboratory, August 1973.

3. Bowman, W. W., and MacMurdo, K. W., "Radioactive Decay λ's Ordered by Energy and Nuclide," Atomic Data and Nuclear Data Tables, Academic Press, February 1970.

4. Meek, M. E., and Gilbert, R. S., "Summary of γ and β Energy and Intensity Data," NEDO-12037, General Electric Company, January 1970.

5. Lederer, C. M., et al., Table of Isotopes, seventh edition, Lawrence Radiation Laboratory, University of California, April 1978.

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11. SHIELD-SG - Point Kernel Gamma Shielding Program, Bechtel Corporation.

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14. RSIC Computer Code Collection CCC-120, SPACETRAN-I/SPACETRAN-II - Dose from Cylindrical Surface.

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20. RSIC Computer Code Collection CCC-543, TORT-DORT - Two- and Three-Dimensional Discrete Ordinates Transport, Version 2.73.

21. RSIC Computer Code Collection CCC-200, Monte Carlo Neutron and Photon Transport Code System.

22. MicroShield, Version 6.20, User's Manual, Grove Engineering Inc., 2005.

23. USNRC, "Minimization of Contamination," 10 CFR 20.1406.

24. Electric Power Research Institute, "Advanced Light Water Reactor Utility Requirements Document," Vol. II. ALWR Passive Plant, Chapter 1, Revision 6, December 1993.

25. EPRI NP-2681, Project 1784-3, "Evaluation of Cobalt Sources in Westinghouse-Designed Three- and Four-Loop Plants," Final Report, October 1982.

Table 12.3-1
Equipment Specification Limits for
Cobalt Impurity Levels(1)

Region, Component, or Application (Specific inclusions and examples are noted parenthetically.)			Maximum Weight Percent of Cobalt
Primary Components	Steam generator tubing	(Inconel tubing)	0.015
	Primary components other than steam generators	(Primary weld cladding surfaces core shroud, lower and upper core plates, lower core barrel and neutron panels or thermal shields)	0.05
Fuel Assembly Components		Inconel and stainless steel components in the fuel assembly	
Auxiliary Heat Exchangers			
Other Components in Regions of High Neutron Flux			
Steam Generator Surfaces Other than Tubing			0.10
Small Components	In regions of high neutron flux		0.20
Bolting Materials or Fasteners	Outside of regions of high neutron flux	(Bolting materials in primary and auxiliary components)	Not limited
Weld Material Other than Cladding(2)			
Bearing and Hardfacing Materials(3)			
Other Auxiliary Components(2)		(Valves, piping, instrumentation, and tanks)	

Notes:

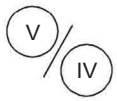
1. Parts or components identified to exceed the cobalt limits are evaluated for acceptability considering actual cobalt content, the wetted surface area of the part, the location of the part within the primary system, the estimated plant cobalt input, and the estimates for personnel dose presented in Section 12.4. The evaluation considers industry ALARA guidance in Reference 24, along with the methods of Reference 25 to evaluate cobalt input to the RCS, and in conjunction with ALARA principles from Regulatory Guide 8.8, the estimated dose impact from each exceedance is estimated. The dose impact for the part or component is then used to determine whether re-fabrication, replacement, or use of the part as-is will be warranted to satisfy ALARA design principles. The evaluation methods maintain part and plant design conformance with ALARA design principles as described in this section of the licensing basis and Regulatory Guide 8.8.
2. Stainless steels manufactured without cobalt limitations generally contain 0.15 to 0.20 weight percent of cobalt.
3. The use of hard facing material with cobalt content such as stellite is limited to applications where its use is necessary for reliability considerations.

LEGEND:

A. PLANT RADIATION ZONES:

DESIGNATION	MAXIMUM DESIGN DOSE RATE	DESCRIPTION
0	≤ 0.05 mRem/hr	NO RADIATION SOURCES; UNLIMITED GENERAL OCCUPANCY; OUTSIDE "CONTROLLED AREA"
I	≤ 0.25 mRem/hr	VERY LOW OR NO RADIATION SOURCES; INSIDE "CONTROLLED AREA" AND OUTSIDE "RESTRICTED AREA"
"RESTRICTED AREA" ZONES		
II	≤ 2.5 mRem/hr	LOW RADIATION SOURCES; UNLIMITED WORKER OCCUPANCY
III	≤ 15.0 mRem/hr	LOW-TO-MODERATE RADIATION SOURCES; LIMITED WORKER OCCUPANCY
IV	≤ 100 mRem/hr	MODERATE RADIATION SOURCES; LIMITED WORKER OCCUPANCY
V	≤ 1 Rem/hr	HIGH RADIATION SOURCES; LIMITED WORKER OCCUPANCY
VI	≤ 10 Rem/hr	SAME AS ZONE V ABOVE
VII	≤ 100 Rem/hr	SAME AS ZONE V ABOVE
VIII	≤ 500 Rad/hr	SAME AS ZONE V ABOVE
IX	> 500 Rad/hr	VERY HIGH RADIATION SOURCES; VERY LIMITED WORKER ACCESS

B. DRAWING SYMBOLS:



- UPPER RADIATION ZONE NUMERAL FOR FULL POWER OPERATION/ LOWER NUMERAL FOR 24 HOURS AFTER PLANT SHUTDOWN (IF DIFFERENT)

- RADIATION ZONE BOUNDARY

C. GENERAL DRAWING NOTES

1. ACCESS CONTROL REQUIREMENTS AND TRAFFIC PATTERNS ARE SHOWN IN SERIES 201 DRAWINGS.
2. DOSE RATES INSIDE CONTAINMENT DURING POWER OPERATION ARE SUBJECT TO SIGNIFICANT VARIABILITY OWING TO LOCALIZED NEUTRON STREAMING/ SCATTERING EFFECTS. ACTUAL RADIATION FIELDS WILL BE DETERMINED FROM RADIATION SURVEYS AND ACCESS TO THE CONTAINMENT DURING POWER OPERATION WILL BE STRICTLY CONTROLLED.

Figure 12.3-1 (Sheet 1 of 16)
Radiation Zones, Normal Operation/Shutdown Legend

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 2 of 16)
Site Radiation Zones, Normal Operations/Shutdown

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 3 of 16)
Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 66'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 4 of 16)
Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 82'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 5 of 16)
Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 96'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 6 of 16)
Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 7 of 16)
Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 117'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 8 of 16)
Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 135'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 9 of 16)
Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 153'-0" & 160'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 10 of 16)
Radiation Zones, Normal Operations/Shutdown
Nuclear Island, Elevation 160'-6", 180'-0", & 329'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

(Note: This figure replaces Figure 12.3-1 Sheet 11 of 16.)

Figure 12.3-201
Radiation Zones, Normal Operations/Shutdown
Annex Building, Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 12 of 16)
Radiation Zones, Normal Operations/Shutdown
Annex Building, Elevation 117'-6" & 126'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 13 of 16)
Radiation Zones, Normal Operations/Shutdown
Annex Building, Elevation 135'-3" through 183'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

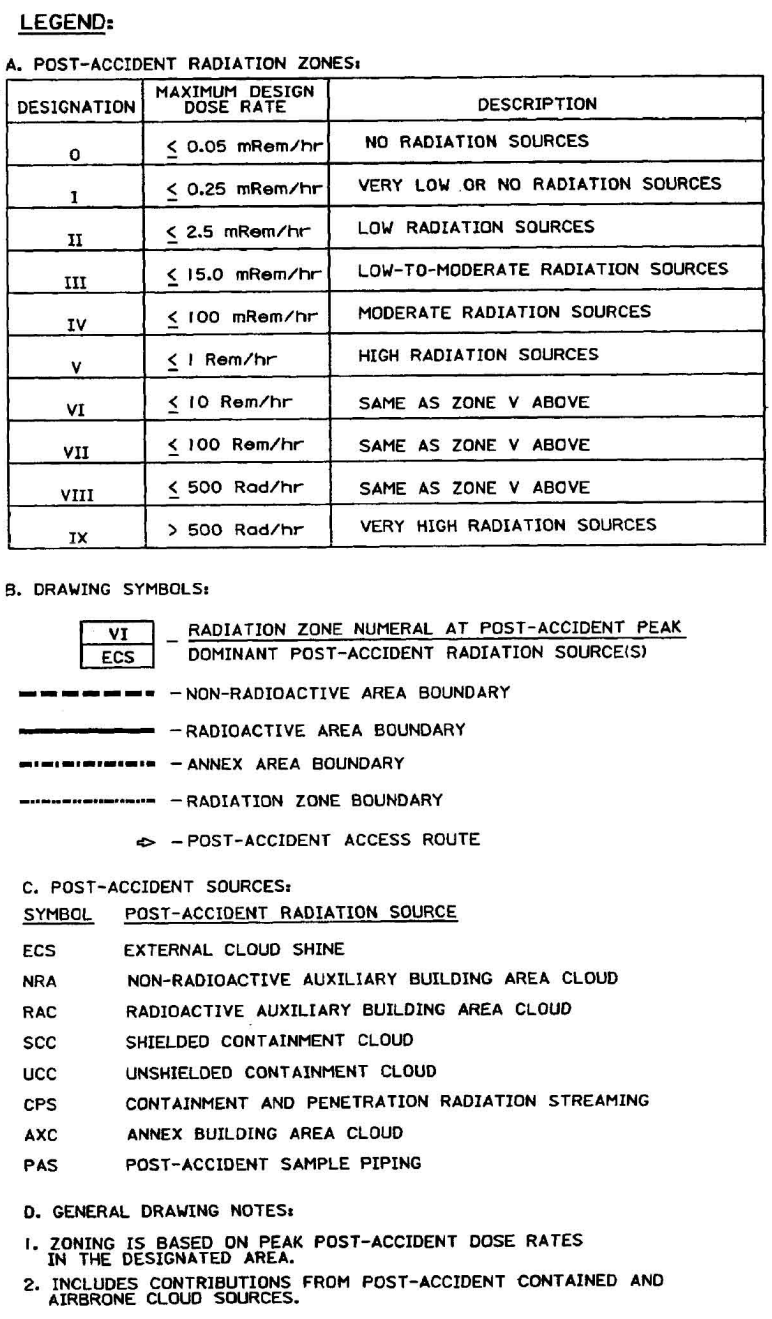
Figure 12.3-1 (Sheet 14 of 16)
Radiation Zones, Normal Operations/Shutdown
Radwaste Building, Elevation 100'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 15 of 16)
Radiation Zones, Normal Operations/Shutdown
Turbine Building, Elevation 100'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-1 (Sheet 16 of 16)
Radiation Zones, Normal Operations/Shutdown
Turbine Building, Elevation 120'-6"



LEGEND:

A. POST-ACCIDENT RADIATION ZONES:

DESIGNATION	MAXIMUM DESIGN DOSE RATE	DESCRIPTION
0	≤ 0.05 mRem/hr	NO RADIATION SOURCES
I	≤ 0.25 mRem/hr	VERY LOW OR NO RADIATION SOURCES
II	≤ 2.5 mRem/hr	LOW RADIATION SOURCES
III	≤ 15.0 mRem/hr	LOW-TO-MODERATE RADIATION SOURCES
IV	≤ 100 mRem/hr	MODERATE RADIATION SOURCES
V	≤ 1 Rem/hr	HIGH RADIATION SOURCES
VI	≤ 10 Rem/hr	SAME AS ZONE V ABOVE
VII	≤ 100 Rem/hr	SAME AS ZONE V ABOVE
VIII	≤ 500 Rad/hr	SAME AS ZONE V ABOVE
IX	> 500 Rad/hr	VERY HIGH RADIATION SOURCES

B. DRAWING SYMBOLS:

VI / ECS – RADIATION ZONE NUMERAL AT POST-ACCIDENT PEAK / DOMINANT POST-ACCIDENT RADIATION SOURCE(S)

– NON-RADIOACTIVE AREA BOUNDARY

– RADIOACTIVE AREA BOUNDARY

– ANNEX AREA BOUNDARY

– RADIATION ZONE BOUNDARY

– POST-ACCIDENT ACCESS ROUTE

C. POST-ACCIDENT SOURCES:

SYMBOL	POST-ACCIDENT RADIATION SOURCE
ECS	EXTERNAL CLOUD SHINE
NRA	NON-RADIOACTIVE AUXILIARY BUILDING AREA CLOUD
RAC	RADIOACTIVE AUXILIARY BUILDING AREA CLOUD
SCC	SHIELDED CONTAINMENT CLOUD
UCC	UNSHIELDED CONTAINMENT CLOUD
CPS	CONTAINMENT AND PENETRATION RADIATION STREAMING
AXC	ANNEX BUILDING AREA CLOUD
PAS	POST-ACCIDENT SAMPLE PIPING

D. GENERAL DRAWING NOTES:

1. ZONING IS BASED ON PEAK POST-ACCIDENT DOSE RATES IN THE DESIGNATED AREA.
2. INCLUDES CONTRIBUTIONS FROM POST-ACCIDENT CONTAINED AND AIRBRONE CLOUD SOURCES.

Figure 12.3-2 (Sheet 1 of 15)
Radiation Zones, Post-Accident Legend

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 2 of 15)
Site Radiation Zones, Post-Accident

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 3 of 15)
Radiation Zones, Post-Accident
Nuclear Island, Elevation 66'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 4 of 15)
Radiation Zones, Post-Accident
Nuclear Island, Elevation 82'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 5 of 15)
Radiation Zones, Post-Accident
Nuclear Island, Elevation 96'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 6 of 15)
Radiation Zones, Post-Accident
Nuclear Island, Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 7 of 15)
Radiation Zones, Post-Accident
Nuclear Island, Elevation 117'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 8 of 15)
Radiation Zones, Post-Accident
Nuclear Island, Elevation 135'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 9 of 15)
Radiation Zones, Post-Accident
Nuclear Island, Elevation 153'-0" & 160'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 10 of 15)
Radiation Zones, Post-Accident
Nuclear Island, Elevation 160'-6", 180'-0", & 329'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

(Note: This figure replaces Figure 12.3-2 Sheet 11 of 15.)

Figure 12.3-202
Radiation Zones, Post-Accident
Annex Building, Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 12 of 15)
Radiation Zones, Post-Accident
Annex Building, Elevation 117'-6" & 126'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 13 of 15)
Radiation Zones, Post-Accident
Annex Building, Elevation 135'-3" through 183'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 14 of 15)
Radiation Zones, Post-Accident
Radwaste Building, Elevation 100'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-2 (Sheet 15 of 15)
Radiation Zones, Post-Accident
Turbine Building, Elevation 100'-0"

LEGEND:

A. PLANT ACCESS CONTROL PROVISIONS:

AREA TYPE	DOSE RATE	SINGLE AREA	MULTIPLE AREAS
RADIATION AREA	> 5 mRem/hr		
HIGH RADIATION AREA	> 100 mRem/hr	BARRICADED OR ALARMED	BARRICADED OR ALARMED
HIGH RADIATION AREA	> 1 Rem/hr	LOCKED OR (IF OPEN AREA) BARRICADED WITH LOCAL ALARM	LOCKED OR BARRICADED WITH LOCKED COMMON ENTRY AND LOCAL CONTROL POINT
VERY HIGH RADIATION AREA	> 500 Rad/hr	LOCKED	LOCKED OR BARRICADED WITH LOCKED COMMON ENTRY, LOCAL CONTROL POINT AND SURVEILLANCE

B. DRAWING SYMBOLS:

⇨ - PERSONNEL TRAFFIC PATTERN

▲ - ENTRANCE BARRICADE (e.g. ROPE, CHAIN, ETC.)

● - LOCKED ENTRANCE

(C) - LOCAL ACCESS CONTROL POINT

(A) - ALARM LOCATION

(S) - SURVEILLANCE POINT

– – – – – – – – ACCESS CONTROL BARRIER (e.g. CHAIN LINK FENCE, ETC.)

———————— - "RESTRICTED" AREA BOUNDARY

– · – · – · –

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 2 of 16)
Site Radiation Access Controls, Normal Operations/Shutdown

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 3 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 66'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 4 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 82'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 5 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 96'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 6 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 7 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 117'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 8 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 135'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 9 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 153'-0" & 160'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 10 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Nuclear Island, Elevation 160'-6", 180'-0", & 329'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

(Note: This figure replaces Figure 12.3-3 Sheet 11 of 16.)

Figure 12.3-203
Radiological Access Controls, Normal Operations/Shutdown
Annex Building, Elevation 100'-0" & 107'-2"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 12 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Annex Building, Elevation 117'-6" & 126'-3"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 13 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Annex Building Elevation 135'-3" through 183'-6"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 14 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Radwaste Building, Elevation 100'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 15 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Turbine Building, Elevation 100'-0"

Security-Related Information, Withheld Under 10 CFR 2.390d

Figure 12.3-3 (Sheet 16 of 16)
Radiological Access Controls, Normal Operations/Shutdown
Turbine Building, Elevation 120'-6"

12.4 Dose Assessment

Radiation exposures in the AP1000 are primarily due to direct radiation from components and equipment containing radioactive material. In addition, in some areas of the plant there can be radiation exposure to personnel due to the presence of airborne radionuclides. This section addresses the anticipated occupational radiation exposure (ORE) due to normal operation and anticipated inspection and maintenance.

12.4.1 Occupational Radiation Exposure

Radiation exposures to operating personnel are restricted to be within the limits of 10 CFR 20. The health physics program in Section 12.5 and the radiation protection features described in Section 12.3 together maintain occupational radiation exposures as low as reasonably achievable (ALARA).

In the analysis of occupational radiation exposure data from operating plants (domestic plants having Westinghouse designed nuclear steam supply systems), the best operating plant performance is 0.1 man-rem per MWe-year of electricity produced. Major factors contributing to this level of occupational radiation exposure include low plant radiation fields, good layout and access provisions, and operational practices and procedures that minimize time spent in radiation fields.

As discussed in Section 12.3, the AP1000 design incorporates features to reduce occupational radiation exposure that go beyond the designs provided for plants currently in operation.

The estimated annual occupational radiation exposures are developed within the following categories:

- Reactor operations and maintenance
- Routine maintenance
- Inservice inspection
- Special maintenance
- Waste processing
- Fuel handling operations

Exposure data obtained from operating plants have been reviewed to obtain a breakdown of the doses incurred within each category. For several routinely performed operations, this information has been used to develop detailed dose predictive models. These models identify the various steps that are included in the operation, the radiation zones, the required number of workers, and the time to perform each step. This information has been used to develop dose estimates for each of the preceding categories.

There is no separate determination of doses due to airborne activity. Past experience demonstrates that the dose from airborne activity is not a significant contributor to the total doses.

12.4.1.1 Reactor Operations and Surveillance

To support plant operations, the performance of various systems and components is monitored. Also, operation of some manual valves requires personnel to enter radiation fields. Examples of activities in this category are:

- On-Line Exposure
- Routine patrols and inspections
- Tagging
- Testing

- Health physics
- Shielding
- Calibration of instrumentation

When the plant is at power, the containment radiation fields are significantly higher than at plant shutdown. The frequency and duration of at-power containment entries is dependent on the plant operator. Based on review of current plant operations and on the AP1000 design changes and reliability improvements, it is assumed that 100 worker-hours per year spent in the containment during power operations.

Table 12.4-1 provides a breakdown of the collective doses for reactor operations and surveillance.

12.4.1.2 Routine Inspection and Maintenance

Routine inspection and maintenance are required for mechanical and electrical components. Table 12.4-2 provides a breakdown of the collective doses for routine inspection and maintenance. These estimates are based on having good access to equipment (a characteristic of the AP1000 layout).

Table 12.4-4 itemizes the doses estimated to be incurred from steam generator sludge lancing operations and Table 12.4-5 lists the doses resulting from the visual examination of the secondary side of the steam generators.

12.4.1.3 Inservice Inspection

ASME Code, Section XI requires periodic inservice inspection (ISI) on plant safety-related components. The Code defines the inservice inspection interval as a 10-year period and sets requirements for each one-third interval (each 40 months). In general, at least 25 percent (with credit for no more than 33-1/3 percent) of the specified inspections must be performed in each 40-month testing interval. The amount of inspection required for an area varies according to the category but is explicitly defined in the Code. Table 12.4-6 provides the doses for inservice inspection activities.

Detailed listings of the doses associated with certain major inservice inspection activities appear in Table 12.4-7 (eddy current inspection of 33 1/3 percent of the steam generator tubes and plugging of three tubes) and Table 12.4-8 (steam generator exterior). The dose estimates in Table 12.4-7 reflect the dose-reducing features of the AP1000 design, such as:

- Permanent work platforms
- Manway cover handling device
- Improved manway insert fasteners (tapered-end type)
- Trailer-mounted data collection station
- Use of robotics to perform eddy current inspection and tube plugging

12.4.1.4 Special Maintenance

Maintenance that goes beyond the routine scheduled maintenance is considered to be special maintenance. This category includes both the modification of equipment to upgrade the plant and repairs to failed components. Dose estimates assume no significant equipment upgrade efforts. The occupational radiation exposure resulting from unscheduled repairs on valves, pumps, and other components will be lower for the AP1000 than for current plant designs because of the reduced radiation fields, increased equipment reliability, and the reduced number of components relative to currently operating plants.

In the past, special maintenance of the steam generators has resulted in significant personnel doses. The AP1000 benefits both from design changes and from improved primary and secondary water chemistry. The plugging of three tubes per steam generator each time eddy current examination is performed is included in the inservice inspection category.

No special maintenance activities are forecast for the sealless motor reactor coolant pumps.

Table 12.4-9 provides the estimated doses due to special maintenance operations.

12.4.1.5 Waste Processing

The AP1000 radwaste system designs incorporate an uncomplicated approach to waste processing. The AP1000 design does not include waste or boron recycle evaporators and it does not include a catalytic hydrogen recombiner in the gaseous radwaste system. Elimination of high maintenance components contributes significantly to lower anticipated doses due to waste processing activities.

Estimated annual doses from waste processing operations appear in Table 12.4-10.

12.4.1.6 Fuel Handling

Radiation monitoring of the new fuel handling and storage areas is performed in accordance with 10 CFR 50.68(b)(6). Details of the fuel handling area monitoring are provided in Subsections 11.5.6 and 11.5.6.4.

The refueling process is labor intensive. Detailed planning and coordination of effort are essential in order to maintain personnel doses as-low-as-reasonably achievable. Incorporation of advanced technology into the refueling process also reduces doses. Table 12.4-11 lists some of the AP1000 features that reduce doses during refueling operations.

Table 12.4-12 provides dose estimates for the various refueling activities.

12.4.1.7 Overall Plant Doses

The estimated annual personnel doses associated with the six activity categories discussed above are summarized below:

Category	Percent of Total	Estimated Annual (man-rem)
Reactor operations and surveillance	12.0	3.7
Routine inspection and maintenance	37.4	11.7
Inservice inspections	22.6	7.1
Special maintenance	6.1	1.9
Waste processing	10.5	3.3
Refueling	11.5	3.6
Total	100	31.2

These dose estimates are based on operation with an 18-month fuel cycle and are bounding for operation with a 24-month fuel cycle.

12.4.1.8 Post-Accident Actions

Requirements of 10 CFR 52.79(b) relative to plant area access and post-accident sampling (10 CFR 50.34 (f) (2)(viii) are included in Subsection 1.9.3. If procedures are followed, the design prevents radiation exposures to any individual from exceeding 5 rem to the whole body or 50 rem to the extremities. Figure 12.3-2 in Section 12.3 contains radiation zone maps for plant areas including those areas requiring post-accident access. This figure shows projected radiation zones in areas requiring access and access routes or ingress, egress and performance of actions at these locations. The radiation zone maps reflect maximum radiation fields over the course of an accident. The analyses that confirm that the individual personnel exposure limits following an accident are not exceeded reflect the time-dependency of the area dose rates and the required post-accident access times. The analyses include the assumption that the appropriate respiratory protection equipment is used to maintain radiation exposure within the exposure limits. The areas that require post-accident accessibility are:

- Main control room
- Class 1E regulating transformer areas
- Ventilation control area for MCR and I & C rooms with PAMS equipment
- Valve area to align spent fuel pool makeup
- Ancillary diesel generator room
- Passive containment water inventory makeup area
- Auxiliary building RCA for long-term containment water inventory makeup

12.4.1.9 Radiation Exposure to Construction Workers

12.4.1.9.1 Site Layout

The physical location of VEGP Units 3 and 4 relative to Units 1 and 2 is depicted on Figure 1.1-202. As shown, Units 3 and 4 will be immediately west of Units 1 and 2. Construction activity will take place outside the Units 1 and 2 protected area, but inside the restricted area boundary.

12.4.1.9.2 Radiation Sources

During the construction of Units 3 and 4, the construction workers could be exposed to radiation sources from the routine operation of Units 1 and 2. Furthermore, Unit 4 construction workers could be exposed to radiation from Unit 3 operation.

12.4.1.9.2.1 Direct Radiation

The principal sources from Units 1 and 2 that contribute to direct radiation exposure at the construction site include the reactor buildings and the planned Independent Spent Fuel Storage Installation (ISFSI), which will be located east of Unit 1 (See Figure 1.1-202). In addition, workers constructing Unit 4 could be exposed to direct radiation from the Unit 3 reactor building.

12.4.1.9.2.2 Gaseous Effluents

Sources of gaseous releases for Units 1 and 2 are currently confined to the following paths: plant vents (Unit 1 and Unit 2), the condenser air ejector, the steam packing exhauster systems (Unit 1 and Unit 2), Radwaste Processing Facility and the DAW (Dry Active Waste Building). Waste gas decay tanks are batch released through the Unit 1 plant vent. The containment purges are released through their respective plant vents. (Reference 203)

The annual releases for the 2002 were reported as 26.3 Ci of fission and activation products, 0.0207 Ci of I-131, 1.67 x 10^{-5} Ci of particulates with half-lives greater than eight days, and 105 Ci of tritium

(Reference 202). The annual releases for 2002 were selected because they resulted in the maximum exposure to the public among the years 2001-2004.

Unit 4 construction workers could also be exposed to radioactivity in gaseous effluents from Unit 3. Table 11.3-3 presents the projected gaseous effluent releases for Unit 3.

12.4.1.9.2.3 Liquid Effluents

Effluents from the liquid waste disposal system result in small amounts of radioactivity in the Savannah River. The annual liquid radioactivity releases for 2001 were reported as 0.220 Ci of fission and activation products, 1,490 Ci tritium, and 0.000423 Ci of dissolved and entrained gases (Reference 201). The annual releases for 2001 were selected because they were reported as the maximum exposure to the public among the years 2001-2004.

Unit 4 construction workers could be exposed to radioactivity in liquid effluents from Unit 3, but that is unlikely given that drinking water is derived from sources other than the Savannah River. Table 11.2-7 presents the projected liquid effluent releases for Unit 3. Applying the Units 1, 2, and 3 liquid effluent doses to Unit 4 construction workers is conservative in that it assumes these construction workers engage in the same activities that lead to the calculated liquid effluent doses (i.e., consuming fish and drinking surface water).

12.4.1.9.3 Measured and Calculated Dose Rates

The measured or calculated dose rates used to estimate worker doses are presented below.

12.4.1.9.3.1 Direct Radiation

Units 1 and 2 External Radiation Exposure

TLD data from 2003 is representative of annual results from Units 1 and 2, based on the completeness of the data set and having operated with a 95 percent plant capacity factor for that year. The average accumulated exposure from the six thermoluminescent dosimeters (TLDs) along the Units 1 and 2 Protected Area Fence closest to the construction site over a 365 day period is 115.9 mrem. The average TLD exposure from sixteen environmental locations surrounding the site over a 365 day period is 49.0 mrem. The measured radiation dose from the Protected Area Fence TLDs minus the Surrounding Environmental Site TLD's, is:

115.9 mrem per year - 49.0 mrem per year = 66.9 mrem per year

Independent Spent Fuel Storage Installation (ISFSI)

The dose to construction workers from the planned ISFSI is negligible for the Units 3 and 4 construction workforce.

Unit 3 Direct Radiation Exposure to Unit 4 Construction Workers

Conservatively assuming that the 66.9 mrem per year value presented above for Units 1 and 2 is attributable only to direct radiation from these units, and assuming this would be representative of the direct radiation dose from Unit 3 to Unit 4 construction workers gives a direct radiation dose to Unit 4 construction workers from Unit 3 operations of:

66.9 mrem per year / 2 units = 33.5 mrem per year (for one unit)

Summary of External Radiation

From all of the above sources discussed above, the highest direct radiation dose to construction workers will be during Unit 4 construction and is estimated to be 100.4 mrem per year (66.9 mrem from Units 1 and 2 + 33.5 mrem from Unit 3). The highest direct radiation exposure during Unit 3 construction is estimated to be 66.9 mrem per year (from Units 1 and 2). Therefore the Unit 4 construction workers doses would be bounding and are discussed in the remainder of this section.

12.4.1.9.3.2 Gaseous Effluents

Units 1 and 2

The XOQDOQ and GASPAR II codes were used to calculate the dose to Unit 4 workers from Units 1 and 2 gaseous effluents. The calculation is analogous to that for Units 3 and 4 as described in Subsection 11.3.3.4. Unit 4 construction workers would receive a total body radiation dose of 0.077 mrem per year and a maximum organ (lung) dose of 0.16 mrem per year from Units 1 and 2 normal radiological releases.

Unit 3 Gaseous Effluent Exposure to Unit 4 Construction Workers

Using the XOQDOQ and GASPAR II codes, as described in Subsection 11.3.3.4, Unit 4 construction workers would receive a total body radiation dose of 0.74 mrem per year and a maximum organ (skin) dose of 2.51 mrem per year from Unit 3 normal radiological releases.

12.4.1.9.3.3 Liquid Effluents

Units 1 and 2

The Annual Radioactive Effluent Release Report for 2001 (Reference 201) reports a total body dose of 0.0907 mrem and a critical organ dose (GI-LLI) of 0.153 mrem to the maximally exposed member of the public due to the release of liquid effluents from Units 1 and 2, calculated in accordance with Units 1 and 2 Offsite Dose Calculation Manual (Reference 204). SNC assumes this dose rate represents the rate for construction workers from Units 1 and 2 releases.

Unit 3 Liquid Effluent Exposure to Unit 4 Construction Workers

Using the LADTAP II code, as described in Subsection 11.2.3.5, the maximally exposed member of the public would receive a total body radiation dose of 0.017 mrem per year and a maximum organ (liver) dose of 0.021 mrem per year from normal Unit 3 liquid radiological releases.

12.4.1.9.4 Construction Worker Doses

Construction worker doses were conservatively estimated using the following information:

- The estimated maximum dose rate for each pathway
- An exposure time of 2000 hours per year
- All gaseous releases assumed at ground level
- A peak loading of 4,400 construction workers per year total for two AP1000 units

The estimated maximum annual dose for each pathway as well as the total dose is shown in Table 12.4-201.

12.4.1.9.4.1 Direct Radiation

Subsection 12.4.1.9.3.1 indicates an average annual direct radiation dose of 100.4 mrem based on TLD measurements. These TLD measurements and calculated doses reflect continuous exposures for long periods of time. The average measured dose rate of 100.4 mrem/yr is based on continuous exposure.

Adjusting for an exposure time of 2000 hours/year yields an annual worker whole body dose or total effective dose equivalent (TEDE) of 22.9 mrem.

12.4.1.9.4.2 Gaseous Effluents

The annual gaseous effluent doses to a Unit 4 construction worker after Unit 3 is operating (Subsection 12.4.1.9.3.2), which accounts for an exposure time of 2,000 hours per year, are 0.077 mrem for the total body, and 0.16 mrem for the critical organ (lung) from Units 1 and 2 gaseous effluent releases and 0.74 mrem for the total body, and 2.51 mrem (skin) for the critical organ from Unit 3 gaseous effluent releases. The total dose is 0.81 mrem total body and 2.60 mrem to the critical organ (skin).

12.4.1.9.4.3 Liquid Effluents

As the annual liquid effluent doses to the maximally exposed member of the public in Subsection 12.4.1.9.3 are based on continuous occupancy, they were adjusted for an exposure time of 2000 hr/yr. Although it is unlikely that the construction workers will be exposed to liquid effluent pathways, it is assumed that the liquid effluent dose rates to which the workers will be exposed are the same as those for the maximally exposed member of the public.

The resulting doses are 0.021 mrem for the total body and 0.035 mrem for the critical organ (GL-LLI) from Units 1 and 2 liquid effluent releases and 0.0038 mrem for the total body, and 0.0047 mrem for the critical organ (liver) from Unit 3 liquid effluent releases. The total annual dose is 0.025 mrem total body and 0.037 mrem to the critical organ (GI-LLI).

12.4.1.9.4.4 Total Doses

The annual doses from all three pathways are summarized in Table 12.4-201 and compared to the public dose criteria in the 10 CFR 20.1301 and 40 CFR 190 in Table 12.4-202 and Table 12.4-203, respectively. The unrestricted area dose rate in Table 12.4-202 was estimated from the annual TLD doses. Since the calculated doses (24.1 mrem per year and 0.012 mrem per hour) meet the public dose criteria of the 10 CFR 20.1301 and 40 CFR 190, the workers will not need to be classified as radiation workers. Table 12.4-204 provides documentation confirming that the doses also meet the design objectives of 10 CFR 50, Appendix I, for gaseous and liquid effluents.

The maximum annual collective dose to the AP1000 construction work force (4,400 workers) is estimated to be 106 person-rem. The calculated doses are based on available dose rate measurements and calculations. It is possible that these dose rates will increase in the future as site conditions change. However, the VEGP site will be continually monitored during the construction period and appropriate actions will be taken as necessary to ensure that the construction workers are protected from radiation.

12.4.1.9.4.5 Operating Unit Radiological Surveys

The operating unit conducts radiological surveys in the unrestricted and controlled area and radiological surveys for radioactive materials in effluents discharged to unrestricted and controlled

areas in implementing 10 CFR 20.1302. These surveys demonstrate compliance with the dose limits of 10 CFR 20.1301 for construction workers.

12.4.2 Radiation Exposure at the Site Boundary

12.4.2.1 Direct Radiation

The direct radiation from the containment and other plant buildings is negligible. The AP1000 design also provides storage of refueling water inside the containment instead of in an outside storage tank that eliminates it as a radiation source.

12.4.2.2 Doses due to Airborne Radioactivity

Subsection 11.3.3 discusses doses at the site boundary due to activity released as a result of normal operations.

12.4.3 Combined License Information

This section contained no requirement for additional information.

12.4.4 References

201. Southern Nuclear Company, Vogtle Electric Generating Plant - Units 1 and 2, NRC Docket Nos. 50-424 and 50-425, Facility Operating License Nos. NPF-68 and NPF-81, Annual Radioactive Effluent Release Report for January 1, 2001 to December 31, 2001.

202. Southern Nuclear Company, Vogtle Electric Generating Plant - Units 1 and 2, NRC Docket Nos. 50-424 and 50-425, Facility Operating License Nos. NPF-68 and NPF-81, Annual Radioactive Effluent Release Report for January 1, 2002 to December 31, 2002.

203. Southern Nuclear Company, Vogtle Electric Generating Plant - Units 1 and 2, NRC Docket Nos. 50-424 and 50-425, Facility Operating License Nos. NPF-68 and NPF-81, Annual Radioactive Effluent Release Report for January 1, 2003 to December 31, 2003.

204. Southern Nuclear Company, Offsite Dose Calculation Manual for Southern Nuclear Operating Company Vogtle Electric Generating Plant, Version 22, June 25, 2004.

Table 12.4-1
Dose Estimate for Reactor Operations and Surveillance

Work Description	Cycle Dose (man-rem)
Operation Supervision	
On-Line Exposure	2.39
Routine Patrols and Inspections	0.387
Tagging	0.072
Testing	0.177
Health Physics	1.168
Shielding	0.356
Calibration of Instrumentation	0.545
Total Collective Dose (annual)	3.397
Total Collective Dose (per fuel cycle)	5.095

Table 12.4-2
Dose Estimate for Routine Inspection and Maintenance

Work Description	Annual Dose (man-Rem)
Valve Adjustment / Repacking	2.117
Pressurizer Spray Valve Maintenance	0.379
SG Sludge Lance	2.543
Scaffolding Work (erection, removal)	0.253
Snubber Inspections	0.308
Insulation-related Tasks	0.287
Miscellaneous Work	1.775
SG Secondary Side Inspection	0.963
Ex-core Detector Work (removal, maintenance, replacement)	1.880
IRWST / Annulus Maintenance	0.103
Total Collective Dose (annual)	10.608
Total Collective Dose (per fuel cycle)	15.912

Table 12.4-3
Not Used

Table 12.4-4
Dose Estimate for Sludge Lancing of Steam Generators

Activity	Average Dose Rate (mRem/h)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-Rem)
Move equipment into containment[c]	2.5	10	4	0.1
Remove insulation and handhole cover[b]	15	2	3	0.09
Initial sludge lance containment equipment setup[c]	6.25[c]	5	12	0.375
Install lance on handholes[b]	15	2	4	0.12
Operate water lance[b]	15	2	12	0.36
Cleanliness Inspection[b]	15	2	2	0.06
Foreign object search and retrieval[b]	15	2	8	0.24
Sludge lance equipment move across containment (SG1 to SG2)[c]	2.5	5	12	0.15
Final tear down and stage sludge lance equipment[c]	15	5	12	0.90
Remove equipment[c]	6.25[d]	10	4	0.25
Install handhole cover and insulation[b]	15	2	5	0.15
Total ORE for both SG = 3.815 man-Rem / 18 month Annual total ORE for two SGs = 2.543 man-Rem/year[a]				

Notes:
a. The dose calculated based on an 18-month fuel cycle bounds plant operation with a 24-month fuel cycle.
b. These activities are performed twice per outage; once for each steam generator.
c. These activities are performed once per outage.
d. Only about 30% of the time for setup and demobilization is spent at the handholes, while the rest of the time is spent outisde of the SG compartment shield.

Table 12.4-5
Dose Estimate for Visual Examination of Steam Generator Secondary Side

Activity[d]	Average Dose Rate (mRem/h)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-Rem)
Remove insulation and two manway covers[a]	0.4	2	7	0.0056
Inspection equipment pack-in and set-up / check-out	4	2	8	0.064
Inspect separator orifices and feedwater ring[a]	4	2	8	0.064
Install two manway covers and insulation[a]	0.4	2	9	0.0072
Remove handhole cover and insulation	15	2	1	0.030
Photograph support plates	15	2	12	0.360
Install handhole cover and insulation	15	2	5	0.150
Teardown / move and set-up inspection equipment (SG A to SG B)	6.875[c]	2	6	0.083
Total ORE for two SGs = 1.444 man-Rem / 18 months Annual total ORE for two SGs = 0.963 man-Rem/year[b]				

Notes:

a. Secondary side water level at the lower deck plate.
b. The dose calculated based on an 18-month fuel cycle bounds plant operation with a 24-month fuel cycle.
c. Data from existing plants show that 34-35% of the time will be spent at the SG, while the rest of the time will be spent moving the equipment through containment.
d. All of the activities are completed twice per outage, except for the “Teardown / move and set-up inspection equipment (SG A to SG B)” activity, which is performed once per outage.

Table 12.4-6
Dose Estimate for Inservice Inspection

Component	Cycle Dose (man-Rem)
Valve Bodies and Boltings	1.05
Reactor Coolant Loop Piping and Supports	0.15
Other Piping	0.30
Heat Exchanger Shells	0.20
Pressurizer Shell	0.18
Pumps	0.06
Tank Shells and Supports	0.03
Filter Housing and Supports	0.02
SG Primary Side In-service Inspection	2.971
SG Eddy Current Testing	3.862
Reactor Head and Reactor Vessel	0.523
PRHR Inspection in IRWST	0.077
Total Dose (per Fuel Cycle)	9.423
Total Dose (Annual)	6.282

Table 12.4-7 (Sheet 1 of 2)
Dose Estimate for Steam Generator Eddy Current Tube Inspection and Tube Plugging

Activity	Average Dose Rate (mRem/h)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-Rem)
Move equipment into containment	0.8	8	4	0.0256
Install ventilation equipment	15	4	2	0.120
Remove insulation on both manway covers	15	2	1	0.030
Remove both manway covers with handling fixture	20	3	4	0.240
Remove both manway inserts	60	2	0.5	0.060
Insert nozzel dams cold & hot legs (manual entries)	2,000/20[(a)]	3	1.5	0.1567
Install robotic manipulator hot leg, set up eddy current (EC)	20	2	4	0.160
Perform EC exam of 3340 tubes (33 1/3%)	0.4	1	8	0.0032
Remove EC end effector and replace with mechanical plugging end effector	20	1	1	0.020
Insert plugs in three tubes	20	1	0.75	0.015
Transfer robotic arm to cold leg	20	2	2	0.080
Cold leg eddy current	0.4	1	2	0.0008
Remove EC end effector and replace with mechanical plugging end effector	20	1	1	0.020

Note:

a. Nozzle dam installation involves a limited amount of manual access to the SG, requiring an individual to spend about two minutes in a 2,000 mrem/hr field.

Table 12.4-7 (Sheet 2 of 2)
Dose Estimate for Steam Generator Eddy Current Tube Inspection and Tube Plugging

Activity	Average Dose Rate (mRem/h)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-Rem)
Insert plugs in 3 tubes	20	1	0.75	0.015
Remove robotic manipulator, equipment teardown	20	2	3	0.120
Remove nozzle dams hot & cold legs	2,000/20[b]	3	2	0.1867
Install manway inserts	60	2	1	0.120
Install both manway covers with handling fixture	20	3	6	0.360
Replace insulation both manway covers	20	2	2	0.080
Remove ventilation equipment	20	2	2	0.080
Move equipment out of containment	0.8	8	6	0.0384
Total SG special maintenance ORE = 1.931 man-Rem / 18 months Total SG special maintenance ORE for two SGs = 3.862 man-Rem / 18 months Annual total ORE for two SGs = 2.575 man-Rem/year[c]				

Note:

b. This task involves a limited amount of manual access to the SG, requiring an individual to spend about two minutes in a 2,000 mrem/hr field.

c. The dose calculated based on an 18-month fuel cycle bounds plant operation a 24-month fuel cycle.

Table 12.4-8
Dose Estimate for Steam Generator
Inservice Inspection (10-Year Interval)

Activity	Average Dose Rate (mRem/h)	Crew Size (no. workers)	Time (hours)	Occupational Radiation Exposure (man-Rem)
Ultrasonic Inspection				
Tubesheet-to-channel head weld	40	2	48	3.84
Inlet nozzle-to-safe end butt weld	40	2	12	0.960
Outlet nozzle-to-RCP pump casing butt weld	2000/0.04[a]	2	120	0.343
PRHR nozzle-to-safe end butt weld	40	2	12	0.960
Elliptical head knuckle-to-upper shell weld	0.4	2	48	0.0384
Tubesheet-to-lower shell weld	40	2	48	3.84
Start-up feedwater nozzle-to-shell weld	4	2	12	0.096
Main feedwater nozzle-to-shell weld	4	2	12	0.096
Main feedwater nozzle inside radius section	4	2	12	0.096
Dye Penetrant Inspection				
Inlet nozzle-to-safe end butt weld	40	2	4	0.320
Outlet nozzle-to-RCP pump casing butt weld	40	2	8	0.640
PRHR nozzle-to-safe end butt weld	40	2	4	0.320
CVS nozzle-to-channel head weld	40	1	1	0.040
Visual Inspection				
Inlet nozzle-to-safe end butt weld	60	1	4	0.240
Outlet nozzle inside radius section	60	1	8	0.480
PRHR nozzle inside radius section	60	1	1	0.060
Studs and nuts less than 2" diameter	20	2	4	0.160
Pedestal steam generator support	15	1	2	0.030
Magnetic Particle Inspection				
Start-up feedwater nozzle-to-shell weld	4	2	4	0.032
Main feedwater nozzle-to-shell weld	4	2	4	0.032
Welded attachments; intermediate and upper lateral support trunnions and support pads	15	2	16	0.480
Total ORE from first 10-year inspection interval = 26.2068 man-Rem. Total ORE for remaining five 10-year inspection intervals = 18.527 man-Rem. Outage average over 60-year (40 18-month outages) life of plant = 2.971 man-Rem/outage. Annual average over 60-year life of plant = 1.980 man-Rem/year				

Note:
a. 10 minutes of this task requires a worker inside of the channel head to set up equipment.

Table 12.4-9
Dose Estimate for Special Maintenance Operations

Work Description	Annual Dose (man-rem)
Emergent Work	2.135
Modifications	0.461
Total Collective Dose (per Fuel Cycle)	2.597
Total Collective Dose (Annual)	1.731

Table 12.4-10
Dose Estimate for Waste Processing

Work Description	Annual Dose (man-rem)
Routine rad waste handling and decontamination	0.740
Dry active waste processing	0.586
Waste liquid processing	0.237
Trash, laundry, and decon activities	1.206
Filter change-outs / Resin sluicing	1.478
Tri-nuclear filters	0.209
Total Collective Dose (per Fuel Cycle)	4.456
Total Collective Dose (Annual)	2.971

Table 12.4-11
Design Improvements That Reduce Refueling Doses

Improved Design/Method	Reference Design/Method
Integrated RV Head Package	Conventional RV head package
RV Head Insulation with Suitcase-Type Fasteners and Permanent ID Markings	Insulation fastened with screws (no markings)
Combination Thermocouples and Flux Detectors	Top-mounted thermocouples and bottom-mounted flux detectors
Fuel Transfer Tube Hatch/Blind Flange	Bolted cover
Quick-Acting Stud Tensioner	Threaded-on stud tensioner
Pass and One-Half Stud Tensioning Procedure	Three-pass stud tensioning procedure
Electrical-Driven Stud Spin-Out Tool	Air-driven, spin-out tool
Permanent Cavity Seal Ring	Bolted or inflatable seal ring
Expandable Stud Hole Plugs	Threaded stud hole plugs
Shielded RV Head Storage Stand	Nonshielded stand
Smooth-Finish Reactor Cavity Liner (#1 Finish)	Rough-finish reactor cavity liner

Table 12.4-12
Dose Estimate for Refueling Activities

Refueling Operations Work Description	Dose (man-rem)
Preparation	0.207
Reactor Disassembly	1.859
Fuel Shuffle	0.571
Reactor Reassembly	2.171
Clean-Up	0.088
Total Refueling Dose:	5.385[(b)]
Average Annual Dose:	3.590

Note:

a. Based on an 18-month fuel cycle. The stated dose bounds operation with a 24-month fuel cycle.

b. The sum of refueling activity dose estimates is increased by 10% to consider small changes in work activity time durations, the number of personnel exposed, and the addition of unplanned outage tasks.

Table 12.4-201
Annual Construction Worker Doses

	Annual Dose (mrem)		
	Total Body	Critical Organ	Total Effective Dose Equivalent (TEDE)
Direct radiation	22.9	NA	22.9
Gaseous effluents	0.81	2.6 (skin)	1.16
Liquid effluents	0.025	0.037 (GI-LLI)	0.034
Total	23.8	2.6 (skin)	24.1

Table 12.4-202
Comparison with 10 CFR 20.1301 Criteria for Doses to Members of the Public

Criterion	Dose Limit	Estimated Dose (TEDE)
Annual dose (mrem)	100	24.1
Unrestricted area dose rate (mrem/hour)	2	0.012

Table 12.4-203
Comparison with 40 CFR 190 Criteria for Doses to Members of the Public

	Annual Dose (mrem)	
Organ	Limit	Estimated
Total body	25	23.8
Thyroid	75	1.4
Other organ	25	2.6 (skin)

Table 12.4-204
Comparison with 10 CFR 50, Appendix I Criteria for Effluent Doses

	Annual Dose (mrem)	
	Limit	Estimated
Total body dose from liquid effluents	3	0.025
Organ dose from liquid effluents	10	0.037 (GI-LLI)
Total body dose from gaseous effluents	5	0.81
Organ dose from radioactive iodine and radioactive particulates in gaseous effluents	15	0.81 (thyroid)

12.5 Health Physics Facilities Design

12.5.1 Objectives

The health physics (HP) facilities are designed with the objectives of:

- Providing capability for administrative control of the activities of plant personnel to limit personnel exposure to radiation and radioactive materials as low as reasonably achievable (ALARA) and within the guidelines of 10 CFR 20.
- Providing capability for administrative control of effluent releases from the plant to maintain the releases ALARA and within the limits of 10 CFR 20 and the plant Technical Specifications.
- Providing capability for administrative control of waste shipments from the plant to meet applicable requirements for the shipment and receipt of the material at the storage or burial site.

12.5.2 Equipment, Instrumentation, and Facilities

The health physics (HP) facilities are located at elevation 100′-0″ in the annex building. See Figure 1.2-201 for a plan view of elevation 100′-0″ of the annex building.

12.5.2.1 Access and Exit of Radiologically Controlled Areas

Access to the radiologically controlled area (RCA) encompassing the containment and potentially contaminated areas of the annex, auxiliary, and radwaste buildings is normally through the entry/exit area of the health physics section of the annex building. Exit from the RCA is at the same location.

12.5.2.2 Facilities

The ALARA briefing room is located off the main corridor immediately beyond the main entry to the annex building. Near this room are several offices that may be used for other health physics functions.

Changes rooms are provided where radiation workers remove street clothes and put on modesty garments. These rooms are provided with lockers, wash sinks, showers and toilet facilities.

Radiation workers don anti-contamination clothing in the protective clothing pickup and suitup room. Workers then proceed to the central health physics booth.

Personnel access to and from the RCA is controlled at the health physics booth at the entry/exit points of the health physics area. Logging into the Radiation Permit System and issuance of dosimetry is also handled at this location. The health physics booth is equipped with computer terminals, desks, filing cabinets, and shelves, and other facilities needed for effective control and monitoring of radiation workers in the RCA. Workers are logged into a radiation exposure tracking system. The health physics and security log-in functions are integrated. Facilities and equipment are provided at the health physics booth for the following functions:

- Issuing respirators, as needed
- Issuing radiation dosimetry, as required

- Updating radiation work permits as needed based on information provided by health physics at local control points and at the work locations

The booth has a counter such that the health physics personnel can easily monitor the flow of workers. It is located adjacent to and visible from the health physics pickup and suitup room.

As radiation workers exit the work areas they go through personnel contamination monitors, shower for decontamination if needed, and receive radiologically controlled first-aid if needed. The health physics area contains the personnel contamination monitoring equipment, decontamination shower facilities, and first-aid equipment.

The hot machine shop is located at elevation 107′-2″ in the south end of the annex building. Contaminated equipment can be decontaminated at the facility and maintenance and repair operations can be performed in a low radiation background area with in the RCA and with appropriate radiation protection and contamination control measures in place.

12.5.2.3 Whole Body Counting Instrumentation

The whole body counter(s) is located in a low background radiation area of the plant. The whole body counting equipment is capable of detecting fractional body burdens of gamma emitting radionuclides.

12.5.2.4 Portable Survey Instrumentation

Portable radiation survey instrumentation is stored at the access control health physics booth and at in-plant control points. This instrumentation allows plant personnel to perform radiation, contamination, and neutron surveys, as needed, as well as collect samples for airborne analysis. Adequate facilities are provided in accordance with Subsection 12AA.5.3 for radioactivity analysis laboratory facilities and for calibration of survey instruments.

12.5.2.5 Other Health Physics Instrumentation

The area radiation monitoring system is installed in areas where it is desirable to have constant dose rate information. Monitors indicate dose rate in the control room and provide appropriate alarms upon reaching a preset dose rate. Fixed continuous airborne radioactivity monitors are also provided at strategic locations, where personnel exposure to airborne radionuclides is likely. More information on these fixed instruments is given in Sections 12.3 and 11.5.

12.5.3 Other Design Features

12.5.3.1 Radiation Protection Design Features

Specific design features for maintaining personnel exposure ALARA and plant shielding provisions are incorporated into the plant design. These features are described in Section 12.3.

12.5.3.2 Job Planning Facilities

Areas are provided where personnel may study, as appropriate: blueprints, drawings, photographs, videotapes, previous inspection reports, previous radiation and contamination surveys, or previous RWPs appropriate to the particular job prior to entry into radiation areas to perform inspections. Work rooms are provided where equipment is checked or calibrated to verify it is operating properly prior to entry into the radiation area. The ALARA briefing and operational support room in the annex building is an example of such a facility where job planning and ALARA briefing and debriefing activities can take place.

12.5.3.3 Radwaste Handling

The handling of radwaste has been minimized by plant design. Some of the activities involving radwaste or radioactively contaminated materials are performed offsite or using mobile equipment brought onsite. Cleaning of protective clothing and respiratory protective equipment are activities that are performed offsite or in mobile equipment.

The radwaste system is shielded and incorporates remotely operated liquid and solid radwaste systems. The systems are designed to minimize operator exposure in waste processing and handling operations. The liquid radwaste system and solid waste handling system are described in Chapter 11.

12.5.3.4 Spent Fuel Cask Loading and Shipping

Spent fuel handling and loading of a shipping cask is designed to be performed underwater, using the fuel handling cranes and/or manual extension tools.

Some of the design features included to maintain exposure ALARA are:

- Maintenance of at least 8.75 feet of water above the active fuel in a fuel assembly to minimize direct radiation.
- Purification of fuel pool water to minimize exposure due to water activity.
- Cooling of the spent fuel pool water.
- Providing continuous air sampling while moving fuel to evaluate airborne activity.

12.5.3.5 Normal Operation

The plant is designed so that significant radiation sources are minimized, locally shielded, and/or located in shield cubicles. Much of the instrumentation required for normal operation reads out remotely in the control room or in other low radiation areas. Instrumentation that cannot be placed remotely or that is read infrequently is situated, where possible, so that it can be read from the entrance to the cubicle or from a low radiation area within the cubicle.

Area radiation monitoring equipment, which is included as part of the radiological monitoring system, is available and provides indication of radiation levels and local alarms. The ventilation system is designed to minimize spread of airborne contamination.

12.5.3.6 Sampling

Provisions are made for sampling of radioactive systems in the sampling room. Protective clothing and gloves are available when sampling radioactive systems to prevent contamination of personnel.

12.5.3.7 Surface Coatings

Special coatings are applied to walls and floors of areas containing radioactive fluids, which aid in decontaminating these areas.

12.5.4 Controlling Access and Stay Time

Areas in the plant are classified as non-radiation areas and restricted radiologically controlled areas for radiation protection purposes. Restricted areas are further categorized as radiation areas, high

radiation areas, airborne radioactivity areas, contamination areas, and radioactive materials areas, to comply with 10 CFR 20 and plant procedures and instructions.

The radiation protection calibration lab in the annex building is a Zone II restricted area and access control is consistent with Subsection 12.3.1.2.

Entrance to the RCA area is normally through the access control area at the health physics area entry/exit location in the annex building, see Subsection 12.5.2.

High and very high radiation areas are segregated and identified in accordance with 10 CFR 20. The entrances to high and very high radiation areas are locked or barricaded and equipped with audible and/or visible alarms, as required.

A closed circuit television system may be installed in high radiation areas to allow remote monitoring of individuals entering high radiation areas by personnel qualified in radiation protection procedures.

12.5.5 Combined License Information

The organization and procedures used for radiological protection, and to provide methods so that personnel radiation exposures are maintained ALARA, are addressed in Appendix 12AA.

Radiation protection program information is included in Appendix 12AA.

Appendix 12AA Radiation Protection Program Description

This appendix incorporates NEI 07-03A, Generic FSAR Template Guidance for Radiation Protection Program Description. The numbering of NEI 07-03A is revised from 12.5# to 12AA.5#.
Table 13.4-201 provides milestones for radiation protection program implementation.

12AA.5 Radiation Protection Program

A radiation protection program is developed, documented, and implemented through plant procedures that address quality requirements commensurate with the scope and extent of licensed activities, sufficient to ensure compliance with the provisions of 10 CFR Parts 19, 20, 50, 52, and 71 and consistent with the guidance in Regulatory Guides 1.8, 1.206, 8.2, 8.4, 8.6, 8.7, 8.8, 8.9, 8.10, 8.13, 8.15, 8.27, 8.28, 8.29, 8.34, 8.35, 8.36, 8.38, and the consolidated guidance in NUREG-1736.

In accordance with 10 CFR 20, Subpart B, the purpose of the radiation protection program is to maintain occupational and public doses below regulatory limits and as low as is reasonably achievable (ALARA). To achieve this, the program will include:

I. A documented management commitment to keep exposures ALARA;

II. A trained and qualified organization with sufficient authority and well-defined responsibilities; and

III. Adequate facilities, equipment, and procedures to effectively implement the program.

The operational radiation protection program is implemented in stages consistent with the following milestones:

1. Prior to initial receipt of by-product, source, or special nuclear materials (excluding Exempt Quantities as described in 10 CFR 30.18), and thereafter, when such radioactive materials are possessed under this license, the following radiation protection program elements will be in place:

    a. Organization – A radiation protection supervisor and at least one (1) radiation protection technician, each selected, trained and qualified consistent with the guidance in Regulatory Guide 1.8.

    b. Facilities – A facility or facilities to support the receipt, storage and control of non-exempt radioactive sources in accordance with 10 CFR 20.1801, 20.1802, and 20.1906.

    c. Instrumentation and Equipment – Adequate types and quantities of instrumentation and equipment will be selected, maintained, and used to provide for the appropriate detection capabilities, ranges, sensitivities, and accuracies to conduct radiation surveys and monitoring (in accordance with 10 CFR 20.1501 and 20.1502) for the types and levels of radiation anticipated for the non-exempt sources possessed under this license.

    d. Procedures – Procedures will be established, implemented and maintained sufficient to maintain adequate control over the receipt, storage, and use of radioactive materials possessed under this license and as necessary to assure compliance with 10 CFR 19.11 and 19.12 and the applicable portions of 10 CFR Part 20, commensurate with the types and quantities of radioactive materials received and possessed under this license.

e. Training – Initial and periodic training will be provided to individuals responsible for the receipt, control or use of non-exempt radioactive sources possessed under this license in accordance with 10 CFR 19.12 and consistent with the guidance in Regulatory Guides 1.8, 8.13, 8.27, and 8.29.

2. Prior to receiving reactor fuel under this license, and thereafter, when reactor fuel is possessed under this license, plant procedures on criticality accident requirements will be established, implemented and maintained and radiation monitoring will be provided in accordance with 10 CFR 50.68, in addition to the radiation protection program elements specified under item 1, above. During initial fuel receipt and storage, portable radiation monitors meeting the functional requirements described in Subsection 11.5.6 may be used in lieu of permanently installed fuel handling and storage area radiation monitors.

3. Prior to initial loading of fuel in the reactor, all of the radiation program functional areas described in Appendix 12AA will be fully implemented, with the exception of the organization, facilities, equipment, instrumentation, and procedures necessary for transferring, transporting or disposing of radioactive materials in accordance with 10 CFR Part 20, Subpart K, and applicable requirements in 10 CFR Part 71. In addition, the position of radiation protection manager (as described in Section 13.1) will be filled and at least one (1) radiation protection technician for each operating shift, selected, trained, and qualified consistent with the guidance in Regulatory Guide 1.8, will be onsite and on duty when fuel is initially loaded in the reactor, and thereafter, whenever fuel is in the reactor.

4. Prior to initial transfer, transport or disposal of radioactive materials, the organization, facilities, equipment, instrumentation, and procedures will be in place as necessary to assure compliance with 10 CFR Part 20, Subpart K, and applicable requirements in 10 CFR Part 71.

The radiation protection program content and effectiveness of implementation are reviewed periodically (at least annually) pursuant to plant procedures.

12AA.5.1 Management Policy

Plant management will establish written policy on radiation protection that is consistent with the guidance in Regulatory Guides 8.8 and 8.10, including management's commitment to:

I. Assure that the plant is designed, constructed, and operated such that occupational and public radiation exposures and releases of licensed radioactive materials are ALARA;

II. Comply with regulatory radiation requirements, dose limits, and limits on release of radioactive materials;

III. Implement and maintain a radiation protection program to keep radiation doses below regulatory limits and ALARA;

IV. Assure that each manager and supervisor in the plant organization understands and is held accountable for implementing his or her responsibility to integrate appropriate radiation protection controls into work activities;

V. Assure that each individual working at the facility understands and accepts the responsibility to follow radiation protection procedures and instructions provided by radiation protection staff and to maintain his or her dose ALARA;

VI. Provide the radiation protection manager the delegable authority to stop work or order an area evacuated (in accordance with approved procedures) when, in his or her judgment, the radiation conditions warrant such an action and such actions are consistent with plant safety;

VII. Establish a direct reporting chain of the Radiation Protection Manager to the Plant Manager that is at the same reporting level as, but independent of, the reporting chains for Operations and Maintenance.

VIII. Establish an ALARA Committee with delegated authority from the Plant Manager that includes, at a minimum, the managers of Operations, Maintenance, Work Control, Engineering and Radiation Protection to help assure effective implementation of line organization responsibilities for maintaining worker doses ALARA.

12AA.5.2 Organization

Qualification and training criteria for site personnel are consistent with the guidance in Regulatory Guide 1.8 and clarified in Appendix 1A and are described in Chapter 13. Specific radiation protection responsibilities for key positions within the plant organization are described in Section 13.1.

Subsections 12.5.2.1 through 12.5.2.5 of NEI 07-03A are not incorporated into Appendix 12AA.

12AA.5.3 Facilities, Instrumentation and Equipment

Adequate facilities, instrumentation and equipment are provided to support implementation of the radiation protection program during routine operations, refueling and other outages, abnormal occurrences, and accident conditions. The types and characteristics of facilities, instrumentation, and equipment provided are consistent with the guidance in Regulatory Guides 1.97 (and guidance provided in Branch Technical Position 7-10, Revision 5 to NUREG 0800), 8.2, 8.4, 8.6, 8.8, 8.9, 8.10, 8.15, and 8.28 and the criteria in NUREG-0737, Items II.B.3 and III.D.3.3.

Subsection 12.5.3.1 of NEI 07-03A is not incorporated into Appendix 12AA. Facilities are described in Subsection 12.5.2.2.

12AA.5.3.1 Monitoring Instrumentation and Equipment

Radiation monitoring instrumentation and equipment are selected, maintained and used to provide the appropriate detection capabilities, ranges, sensitivities and accuracies required for the types and levels of radiation anticipated at the plant and in the environs during routine operations, major outages, abnormal occurrences, and postulated accident conditions. The quantities of instrumentation and equipment are sufficient to meet the anticipated needs of the plant during all anticipated conditions –taking into account the amount of instrumentation and equipment that may be unavailable at any one time due to periodic testing and calibration, maintenance, and repair.

The types and nominal characteristics of the instrumentation are as follows:

Laboratory and Fixed Instrumentation

- Multi-channel gamma analysis system to identify and measure gamma emitting radionuclides in solid, liquid and gaseous samples. Some of the sample types analyzed include primary reactor coolant, liquid and gaseous waste and airborne contaminants.
- Counters to measure gross beta and gamma activity.
- A low background counter to detect and measure gross alpha activity.

- A liquid scintillation counter to measure tritium in liquid and gaseous samples.
- A whole-body counter to detect and quantify personnel intakes of radioactivity.
- Fixed instrumentation, such as small article monitors, hand and foot monitors, and portal monitors, to monitor for contamination on personnel, materials, and equipment.

Portable Monitoring Instrumentation and Equipment (nominal ranges are given in parentheses for illustrative purposes only)

- Beta-gamma count rate survey meters (0-50,000 cpm) to detect radioactive contamination on surfaces and for low level exposure rate measurements.
- Low-range (0-50 mR/hr) and high range (0-1,000 R/hr) beta-gamma survey meters and ion chamber survey meters (0-50 R/hr) are used to measure the full range of dose rates necessary for radiation protection purposes during routine operations (including underwater operations), abnormal occurrences and accidents.
- Beta-gamma survey meters (0-10,000 R/hr) to monitor the plant and environs during and following an accident.
- Count rate meters (0-500,000 cpm) to monitor directly for alpha activity.
- Neutron survey instruments (0-5 rem/hr) to measure neutron dose rates for radiation protection purposes (including underwater operations).
- High and low volume air samplers equipped with appropriate filter media are used to take grab samples that are analyzed to assess airborne radioactivity concentrations, estimate actual or potential exposure, and to determine respiratory protection measures.
- Continuous air monitors (CAMs) provide a means to observe trends in airborne radioactivity concentrations. CAMs equipped with local alarm capability are used in occupied areas where needed to alert personnel to sudden changes in airborne radioactivity concentrations.
- Hand-held friskers to detect radioactive contamination.
- Portable air sampling and analysis system to determine airborne radioiodine concentrations during and following an accident consistent with the criteria in NUREG-0737, Item III.D.3.3.
- Portable sampling and onsite analysis capability to assess airborne radiohalogens and particulates released during and following an accident consistent with the criteria in Regulatory Guide 1.97 (and guidance provided in Branch Technical Position 7-10, Revision 5 to NUREG 0800).

Personnel Monitoring Instrumentation and Equipment

- Individual personnel dosimeters to measure gamma, beta and neutron radiation dose with sensitivities and ranges appropriate to measure the expected levels and types of radiation.
- Direct-reading dosimeters to provide real-time gamma dose information with sensitivities and ranges appropriate to measure the expected levels and types of radiation.
- Special dosimeters to monitor extremity dose with sensitivities and ranges appropriate to measure the expected levels and types of radiation.

- Personnel air samplers to monitor individual exposure to airborne radioactivity.
- Remote and local reading alarm dosimeters (which may be coupled with direct or electronic surveillance equipment, as necessary).

12AA.5.3.2 Personnel Protective Clothing and Equipment

A sufficient inventory of serviceable personnel protective clothing and equipment is maintained for use during plant operations, refueling and other outages, abnormal conditions, and accidents. Only respirators that are tested and certified by the National Institute for Occupational Safety and Health/Mine Safety and Health Administration (NIOSH/MSHA), or otherwise approved by the NRC, are used.

If circumstances arise in which NIOSH tested and certified respiratory equipment is not used, compliance with 10 CFR 20.1703(b) and 20.1705 is maintained.

Personnel protective clothing and equipment includes the following:

- Anti-contamination clothing for both dry and wet work conditions, including heat stress reduction accessories
- Head covers, shoe covers, gloves, and safety-related items
- Full facemask respirators with high-efficiency particulate and charcoal filters
- Pressure demand full facemask air line respirators
- Pressure demand full facemask self-contained breathing apparatus

12AA.5.3.3 Other Protective Equipment

- Portable ventilation systems with HEPA filters
- Temporary containments, tents, and enclosures
- Heat-stress reduction equipment
- Vacuums with HEPA filters
- Portable liquid filtration equipment
- Temporary shielding such as lead and/or tungsten shield bricks, blankets, and curtains.

12AA.5.4 Procedures

Radiation protection procedures are established, implemented and maintained sufficient to provide adequate control over the receipt, possession, use, transfer, and disposal of byproduct, source, and special nuclear material and assure compliance with applicable requirements in 10 CFR Parts 19, 20, 50, 70, and 71. Procedures for radiation protection that include quality assurance requirements are prepared consistent with the guidance in Regulatory Guides 1.8, 8.2, 8.7, 8.8 and 8.10 and the consolidated guidance referenced in NUREG-1736 that is applicable to power reactors. The procedures are implemented by Radiation Protection staff trained and qualified in accordance with the requirements in 10 CFR 50.120 and consistent with the guidance in Regulatory Guide 1.8. Additionally, some procedures are implemented by plant staff trained in accordance with the

requirements of 10 CFR 19.12 and consistent with the guidance in Regulatory Guides 8.13, 8.27, and 8.29.

12AA.5.4.1 Radiological Surveillance

Radiological surveillance procedures comply with 10 CFR 20.1501 and are consistent with the guidance in Regulatory Guides 8.2, 8.8, and 8.10.

Trained and qualified radiation protection staff will routinely survey accessible areas in the plant and environs to assess the presence and levels of radiation, radioactive contamination, and airborne radioactivity. The instrumentation and techniques used for these surveys are selected based upon the purpose of the survey and the anticipated types and levels of radiation and radioactivity involved. Surveys are performed using effective practices to minimize personnel exposure and avoid the spread of contamination.

The frequency and extent of the surveys will depend upon several factors, such as location, actual or potential radiation levels, plant operational status and work in progress, and accessibility/occupancy. The frequency of surveys may be weekly, monthly, quarterly, semiannually, annually, or as directed by the Radiation Protection Manager. Surveys are performed more frequently in accessible areas subject to changes in radiological conditions. Site specific procedures will define the survey frequencies and extent.

Survey results are recorded and maintained in accordance with the requirements in 10 CFR Part 20. Survey results for accessible areas are posted or otherwise made available to provide adequate notice to workers of radiological conditions.

Radiation surveys are routinely performed for detection of beta and gamma radiation. Surveys for neutron radiation are performed in accessible areas where such radiation may be present.

Area contamination surveys are routinely performed for the detection of removable and fixed beta-gamma contamination. Surveys for alpha contamination are performed where alpha contamination is anticipated. Alpha contamination surveys will also be performed periodically as a check to verify that alpha contamination is not present. Personnel will monitor themselves for contamination after exiting from contaminated areas and at exit points from the RCA or other Restricted Areas with a potential for contamination. Materials and equipment are monitored for contamination after removal from contaminated areas and prior to being released from the RCA or other Restricted Areas with a potential for contamination.

Surveys to assess airborne radioactivity levels are performed with continuous air monitors (CAMs) and by taking grab samples (using portable low or high volume air samplers) with appropriate media for collecting particulate, iodine, gas, or tritium samples. In order to warn personnel of changing airborne conditions, CAM alarm set points are set at a fraction of the concentration values given in 10 CFR Part 20, Appendix B, Table 1, Column 3, for radionuclides expected to be encountered. Air monitoring and sampling are sufficient to identify the potential hazard(s), determine the need for and verify the effectiveness of process and engineering controls, permit proper selection of respiratory protection equipment, and estimate doses from intakes.

Emergency operating procedures include provisions for use of a portable monitoring system, consistent with the criteria in NUREG-0737, Item III.D.3.3, to sample and analyze for radioiodine in areas of the plant during and following an accident. Procedures include methods for taking and analyzing samples in the field, as well as for analyzing samples in the count room facility, accounting for techniques to reduce counting system saturation from a high-activity sample.

Instrumentation and equipment used to perform surveys are calibrated prior to initial use, after performance of maintenance or repairs that might affect the calibration, and at least annually. Operational checks to test function or response are made daily for continuously operating instrumentation and equipment (e.g., friskers, portal monitors, and continuous air monitors) and prior to use or daily, whichever is less frequent, for other instrumentation and equipment. Operational checks are performed for emergency and special use instrumentation and equipment on a regular schedule as specified in written procedures.

Survey records and records of calibration and maintenance of instrumentation and equipment used for surveys are documented and maintained in accordance with applicable requirements in 10 CFR 20.2101-20.2110.

12AA.5.4.2 Methods to Maintain Exposures ALARA

Methods to maintain exposures ALARA in accordance with Regulatory Guides 8.8 and 8.10 are included in radiation protection procedures, as well as applicable operating and maintenance procedures. Key ALARA operational policies and considerations are described in FSAR Section 12.1. Some examples of the types of methods that will be used to maintain exposures ALARA are discussed below for the following operational categories.

Refueling

After the reactor coolant system is depressurized, it is degassed as needed and sampled to verify that the gaseous radioactivity is low, prior to removing the reactor head. The Radiation Work Permit (RWP) system is used to maintain positive radiological control over work in progress. Prior to and during refueling, the refueling pool water is continually purified in order to maintain exposures from activity in the water ALARA. During refueling operations, irradiated fuel assemblies are maintained underwater at all times. By following these procedures, exposures from refueling operations are maintained ALARA.

Inservice Inspection

Prior to entry into radiation areas to perform inspections, personnel should study, as appropriate: blueprints, drawings, photographs, videotapes, previous inspection reports, previous radiation and contamination surveys, and/or previous RWPs appropriate to the particular inspection/job to be performed. This will acquaint personnel with the inspection location, room layout and equipment configuration, the work to be done, and radiation and contamination levels previously experienced at the location. Surveys are performed to the extent required to determine current contamination and/or radiation levels. From this data, previous data, and past work experience of personnel for similar jobs/inspections performed, an RWP (paragraph 12.5.4.5) is issued. Equipment is checked and/or calibrated to verify it is operating properly prior to entry into the radiation area. Temporary shielding will be used, where practicable, to reduce personnel radiation exposures.

Routine Maintenance

Routine maintenance is comprised of the categories of preventive maintenance (planned and scheduled maintenance such as lubrication, adjustments, and tests) and corrective maintenance (unscheduled maintenance such as valve packing, pump seal replacement, and stopping leaks). Procedures are usually written for preventive maintenance jobs and for some recurring corrective maintenance jobs. These procedures specify the precautions to be taken to minimize personnel exposure while performing the maintenance. The procedures list the required lubricants, special tools and equipment, and the acceptance standards. This serves to minimize the time spent in the radiation area and thereby minimize personnel dose.

In addition, the preventive maintenance procedure normally states whether an RWP is required. When the RWP is issued, the radiation and/or contamination levels are listed, shielding is specified, if

appropriate, and additional specific instructions are given to personnel. For corrective maintenance jobs in radiation areas, a similar approach is used.

Extension tools are used when practical to minimize personnel dose when working on radioactive components/equipment. Detailed surveys are performed and the RWP is issued (if required) with specific instructions. The individuals performing the work may be required to read procedure manuals or may be shown pictures or sketches of the work area to aid in understanding what is to be accomplished, how it is to be accomplished as safely and quickly as possible, and what the acceptance criteria are for completing the job. At the discretion of health physics personnel, additional requirements may be imposed to reduce personnel exposures.

After the job is completed, debriefings may be conducted to obtain input from personnel actually performing the work, as well as from supervisory and support personnel. This will assist in revising procedures for ALARA considerations.

Calibration

Calibration of most ranges of the portable gamma detection instruments is performed inside a shielded calibrator, thereby eliminating a large portion of the exposure received from calibration of portable instruments. Portable sources used to calibrate fixed instruments (such as the area radiation monitoring system) are transported in shielded containers to minimize personnel exposure.

Where possible, fixed instruments requiring routine calibration are situated so that the necessary test signals needed for calibration can be inserted from a low radiation area with the instruments in place.

12AA.5.4.3 Posting and Labeling

Procedures for posting and labeling will assure compliance with 10 CFR 20.1901, 20.1902, 20.1903, 20.1904, and 20.1905.

Based on current survey results, Radiation Areas, High Radiation Areas, Very High Radiation Areas, Airborne Radioactivity Areas, and Radioactive Materials Areas are posted in accordance with the requirements in 10 CFR 20.1901, 20.1902, and 20.1903. Containers of licensed radioactive materials are labeled in accordance with 10 CFR 20.1904 and 20.1905.

Criteria and procedures are established for posting areas and marking items (e.g., tools and equipment) to indicate the presence of fixed or removable surface contamination. Areas posted to indicate the presence of removable contamination, are referred to hereafter as “Contamination Areas.”

“Posted areas”, as used in Section 12.5, refers to Radiation Areas, High Radiation Areas, Very High Radiation Areas, Airborne Radioactivity Areas, Contamination Areas, and Radioactive Materials Areas.

12AA.5.4.4 Access Control

Procedures for access control will assure compliance with 10 CFR 20.1902, 20.1903, 20.1601, and 20.1602 and are consistent with the guidance in Regulatory Guide 8.38.

Access to posted areas is restricted and controlled, at a minimum, through the use of instructions to workers, radiation work permits, caution signs, and barriers. Access to High and Very High Radiation Areas is controlled consistent with the guidance in Regulatory Guide 8.38, including the use of alternative methods for access control as described in the regulatory guide and specified in plant technical specifications.

Table 12AA-201 identifies plant areas designated as Very High Radiation Areas (VHRAs), lists corresponding plant layout drawings showing the VHRA in Section 12.3, specifies the condition under which the area is designated VHRA, identifies the primary source of the VHRA, and summarizes the frequency of access and reason for access. VHRAs are listed as Radiation Zone IX, which corresponds to a dose rate greater than 500 rad/hr.

In each of the VHRAs, with the exception of the Reactor Vessel Cavity and Delay-Bed / Guard-Bed Compartment, the primary radioactive source is transient (such as fuel passing through the transfer tube), removable (such as resin in the demineralizers), or can be relocated. When the primary source is removed, the dose rate in each of these areas will be less than Zone IX and, in effect, the area will no longer be a VHRA. With planning, the need for human entrance to a VHRA when the primary source is present can be largely or entirely avoided.

In addition to the access control requirements for high radiation areas, the following control measures are implemented to control access to very high radiation areas in which radiation levels could be encountered at 500 rads or more in one hour at one meter from a radiation source or any surface through which the radiation penetrates:

- Sign(s) conspicuously posted stating GRAVE DANGER, VERY HIGH RADIATION AREA.

- Area is locked. Each lock shall have a unique core. The keys shall be administratively controlled by the functional manager in charge of radiation protection as described in Section 13.1.

- Plant Manager's (or designee) approval required for entry.

- Radiation Protection personnel shall accompany person(s) making the entry. Radiation Protection personnel shall assess the radiation exposure conditions at the time of the entry.

A verification walk down will be performed with the purpose of verifying barriers to the Very High Radiation Areas in the final design of the facility are consistent with Regulatory Guide 8.38 guidance as part of the implementation of the Radiation Protection and ALARA programs on the schedule identified in Table 13.4-201.

Unescorted access to Radiation Areas or Radioactive Materials Areas will require, at a minimum, authorization by Radiation Protection, the use of an RWP, and instruction of individuals gaining unescorted access in accordance with 10 CFR 19.12 and consistent with the guidance in Regulatory Guide 8.13. In addition to the foregoing, unescorted access to Contamination, High Radiation, Very High Radiation, or Airborne Radioactivity Areas will require, at a minimum, training of individuals gaining unescorted access consistent with Regulatory Guides 8.27 and 8.29.

Posted areas will generally be contained within the plant Security Area, i.e., an area to which access is controlled in accordance with 10 CFR Part 73. Unescorted access to the plant Security Area will require instruction of individuals gaining unescorted access in accordance with 10 CFR 19.12.

Areas where significant doses could be received (e.g., High Radiation, Very High Radiation, and Airborne Radioactivity Areas), are generally contained within the plant building complex. A Radiological Controlled Area (RCA) is established to encompass the plant building complex to enhance control over access to such areas. Access to the RCA is through a primary access control point or alternate access control points as established by Radiation Protection. Unescorted access to the RCA will require authorization by Radiation Protection, the use of an RWP and instruction and

training of individuals gaining unrestricted access in accordance with 10 CFR 19.12 and consistent with the guidance in Regulatory Guides 8.13, 8.27, and 8.29.

Radiation Protection may authorize access to the Security Area, RCA, or a Radiation or Radioactive Materials Area for individuals without instruction or training where such individuals are continuously under the control of a designated escort. The designated escort shall be instructed and trained in accordance with the requirements of 10 CFR 19.12 and the guidance in Regulatory Guides 8.13, 8.27, and 8.29, and shall be instructed on the duties and responsibilities associated with being an escort.

Access by a worker who is a minor (i.e., under the age of 18 years) or a declared pregnant worker to posted areas with a potential for significant exposure, e.g., High Radiation, Very High Radiation, and Airborne Radioactivity Areas is restricted unless otherwise authorized by Radiation Protection.

12AA.5.4.5 Radiation Work Permits

Procedures covering the use of a radiation work permit (RWP) are consistent with the guidance in Regulatory Guide 8.8.

RWPs are issued by Radiation Protection to help ensure adequate protection of personnel for access to and work within areas with a potential for significant exposure. Access to any posted area will require an RWP. An RWP may control access to multiple areas or to a set of related jobs or tasks.

At a minimum, each RWP will include the following information:

- Description of the area(s) to be accessed and work to be performed;
- Designation of personnel or groups covered by the RWP;
- Radiological conditions existing within the area(s) to be accessed, based on current radiological surveys, and anticipated radiological conditions for the time span over which the work is performed (including location of hot spots, radiation gradients, and low dose “waiting areas”);
- Requirements for use of personnel monitoring devices, protective clothing, and respiratory protection equipment;
- Special instructions and a description of special tools, shielding, other equipment utilized to perform work, and any process and engineering controls being employed to minimize exposures; and
- Extent and type of radiation protection monitoring and surveillance to be provided.

As described in Section 12.1, for access to and work within High Radiation and Very High Radiation Areas, the applicable RWP will specify a limitation on staytime or a means for limiting dose received while in the area (e.g., via an alarm set point for an electronic dosimeter).

12AA.5.4.6 Personnel Monitoring

Personnel monitoring procedures are sufficient to assure compliance with 10 CFR Parts 19 and 20 and are consistent with the guidance in Regulatory Guides 8.2, 8.7, 8.9, 8.13, 8.34, 8.35, and 8.36.

Each individual accessing the RCA or a posted area on an unescorted basis, or for whom occupational dose monitoring of external dose is required in accordance with 10 CFR 20, is monitored using an individual monitoring device that is appropriate for monitoring the types of

external radiation to which the individual is exposed. For individuals who are required to be monitored in accordance with 10 CFR Part 20, if the individual monitoring device does not provide real-time dose information (i.e., the capability for the individual to track his or her own dose as it occurs), then an additional means of monitoring is provided for the individual that fulfills that function.

Individuals accessing the RCA or a posted area on an escorted basis, for whom occupational dose monitoring of external dose is not required in accordance with 10 CFR Part 20, are monitored either with an individual monitoring device worn by the individual or via an individual monitoring device worn by the escort.

Individual monitoring devices that require processing, except for those devices excluded by 10 CFR 20.1501(c), are processed and evaluated by a NVLAP-accredited processor, as appropriate, for the type(s) and ranges of radiation being monitored with the device. Each individual whose internal dose is required to be monitored in accordance with 10 CFR Part 20, or who wears a respirator for radiation protection purposes, or who accesses an Airborne Radioactivity Area, is monitored by means sufficient to identify and quantify intakes in order to be able to estimate his or her committed effective dose equivalent (CEDE) and, as applicable, his or her committed dose equivalent (CDE).

Situations that may result in a person receiving an abnormal or inadvertent intake are evaluated on a case-by-case basis to determine the need for monitoring by means sufficient to identify and quantify intakes in order to be able to estimate the CEDE or CDE, as applicable.

Individuals suspected of having received an intake are evaluated to quantify the intake, if any, in order to estimate the CEDE or CDE, as applicable. In demonstrating compliance with regulatory requirements, effective dose equivalent may be used in lieu of deep dose equivalent consistent with the guidance in Regulatory Issue Summary (RIS) 2003-04 and other related guidance.

Individual monitoring results are reported annually to the individual, and at the request of an individual who is terminating employment or who is requesting this information from a previous employer, in accordance with the requirements in 10 CFR 19.13.

Personnel monitoring records, as well as records associated with testing, calibration, processing, and maintaining instrumentation and equipment used for personnel monitoring, are documented and maintained in accordance with applicable requirements in 10 CFR 20-2101-20.2110.

12AA.5.4.7 Dose Control

Compliance is maintained with the requirements in 10 CFR 20.1201, 20.1202, 20.1203, and 20.1204, as they relate to demonstrating compliance with internal and external occupational dose limits contained in 10 CFR 20, Subpart C. Doses to adult workers are kept below the occupational dose limits in 10 CFR 20.1201. Doses to workers who are minors and declared pregnant workers are kept below the respective occupational dose limits in 10 CFR 20.1207 and 10 CFR 20.1208. Doses to members of the public are kept below public dose limits in 10 CFR 20.1301, which is demonstrated by complying with the requirements of 10 CFR 20.1302.

To the extent practical, procedures and engineered controls based on sound radiation protection principles are used to keep occupational doses and doses to members of the public as low as is reasonably achievable (ALARA). A description of facility design features and engineered controls intended to maintain occupational exposures ALARA is included in Sections 12.3-12.4. A description of systems and facility design features intended to maintain public exposures ALARA is included in Chapter 11.

As described in Sections 12.1, Appendix 12AA and 13.1, management policy is established, and organizational responsibilities and authorities are assigned to implement an effective program for

maintaining occupational radiation exposures ALARA. Procedures are established and implemented that are in accordance with 10 CFR 20.1101 and consistent with the guidance in Regulatory Guides 8.8 and 8.10. Examples of such procedures include the following:

I. During the construction, pre-operational and operational phases, Radiation Protection will assure that new or modified designs and the selection of equipment are reviewed to assure that measures are considered to minimize occupational and public radiation exposures during operation, refueling, and decommissioning of the plant.

II. Radiation Protection will assure that procedures and methods for operation, maintenance, repair, surveillance, refueling, and other activities that may involve significant exposures are reviewed prior to initial use and periodically thereafter that assure measures are considered to minimize occupational and public radiation exposures. For example, “significant exposures” may include activities that are estimated to involve greater than 1 person-rem of collective dose.

III. For activities involving significant exposures, pre-job briefings are conducted for personnel who will receive the exposures. The briefings are intended to assure that personnel understand the radiological conditions expected to be present and the measures being employed to control and minimize dose. Post-job reviews are performed to evaluate the effectiveness of measures employed to control and minimize dose and to identify and implement improvements to minimize occupational and/or public radiation exposures for future similar activities.

Planned special exposures, as described in 10 CFR 20.1206, if used, will be conducted in accordance with the requirements in 10 CFR 20.2104 and consistent with the guidance in Regulatory Guide 8.35.

12AA.5.4.8 Contamination Control

Contamination control procedures are established to help assure compliance with 10 CFR Parts 20.1406 and 20.1701 and to prevent the unauthorized release of radioactive materials to unrestricted areas.

Areas, items, and personnel are routinely surveyed and monitored for contamination to protect personnel, ensure that contamination control methods are effective and to prevent licensed materials from being released from an RCA or Controlled Area in an unauthorized manner. Areas and items with fixed or removable contamination are posted, labeled, or marked in a conspicuous manner to indicate the presence of contamination.

Personnel accessing Contamination or Airborne Radioactivity Areas are required to use protective clothing and equipment appropriate to the circumstances to prevent personal contamination.

Personnel found with external contamination are decontaminated promptly. Contaminated items are decontaminated or disposed of as radioactive waste or are marked and controlled. Areas that become contaminated are decontaminated as soon and as thoroughly as practical, taking into account factors such as the nature of operations in the area and the potential for exposure associated with the decontamination. The number of accessible contaminated areas within the plant are kept to a minimum.

Facility design and operational procedures are reviewed to identify nonradioactive systems that could possibly become radioactive through interfaces with radioactive systems. Routine sampling and monitoring of these systems is described in the plant radiation monitoring program, and overall guidance is consistent with Bulletin 80-10.

Practical measures are implemented to prevent the spread of contamination, including:

- Air pressure gradients and airflows are maintained from areas of low potential contamination to areas of higher potential contamination and then to installed filters and/or ventilation systems;
- Leaks and spills are contained promptly and repaired or cleaned up as soon as practical;
- Potentially contaminated systems, equipment, and components are surveyed for the presence of contamination when opened or prior to removal;
- Containments, caches and enclosures are used during maintenance, repairs, and testing, when practical, to contain spills or releases;
- Engineering controls, such as portable ventilation or filtration units to reduce concentrations of radioactivity in air or fluids, are used where practical;
- Criteria for selecting tools, materials, and equipment for use in contaminated areas will include minimizing the use of porous or other materials that are difficult to decontaminate;
- The use of disposable materials that are likely to become contaminated and necessitate disposal as radioactive waste are minimized;
- Areas, surfaces, and tools that are prone to contamination are designed and coated (e.g., using agents to “fix” contamination, such as strippable coatings), as practical, to facilitate decontamination;
- Contaminated tools and equipment are segregated from clean tools and equipment.

This subsection adopts NEI 08-08A (Reference 201), for a description of the operational and programmatic elements and controls that minimize contamination of the facility, site, and the environment, to meet the requirements of 10 CFR 20.1406.

12AA.5.4.9 Respiratory Protection

Respiratory protection procedures will assure compliance with 10 CFR Part 20, Subpart H, and are consistent with the guidance in Regulatory Guide 8.15.

A written policy statement established by the plant management covers the use of process and engineering controls in lieu of respirator use to limit intakes and to limit the routine, non-routine, and emergency use of respirators.

Written procedures are established and implemented that cover the following:

- Monitoring, including air sampling and bioassays;
- Supervision and training of respirator users;
- Fit-testing;
- Respirator selection;
- Breathing air quality;

- Inventory, control, storage, issuance, maintenance, repair, testing, and quality assurance of respiratory protection equipment;
- Recordkeeping; and
- Limitations on periods of use and relief from respirator use.

An assessment is performed to assure that the total effective dose equivalent (TEDE) is maintained ALARA, when respiratory protection equipment is used to limit intakes of radioactive materials.

Airborne radioactivity is minimized by the design and configuration of the plant's heating, ventilation and air conditioning systems (HVAC), the use of enclosures and containments, and good housekeeping practices. Portable air movers and vacuums equipped with HEPA filters to minimize concentrations of radioactivity in air or on surfaces are vented to monitored, filtered discharge pathways.

When it is not practical to apply process and engineering controls to control the concentrations of radioactive materials in the air and maintain the TEDE ALARA, intakes are limited by controlling access to and limiting stay times in Airborne Radioactivity Areas and by using respiratory protection equipment or other controls.

The Radiation Protection Manager will assign to a single individual, knowledgeable in the area of respiratory protection consistent with the guidance in Regulatory Guide 8.15, the overall responsibility to establish and maintain a respiratory protection program and procedures that include:

- air sampling and monitoring sufficient to identify hazards, select proper equipment, and determine doses from intakes;
- conducting surveys and bioassays as necessary to evaluate actual intakes; and
- testing respirators for operability immediately prior to each use.

Only respiratory protection equipment that is tested and certified by the National Institute for Occupational Safety and Health/Mine Safety and Health Administration (NIOSH/MSHA) is used, unless otherwise authorized by the NRC.

Prior to being fit-tested for a face sealing respirator, and before the first field use of a non-face sealing respirator, individuals are certified as medically fit by a qualified medical practitioner. Recertification of medical fitness is made every twelve months or at a frequency specified by the medical practitioner.

Each respirator user is advised that he or she may leave the area at any time for relief from any conditions (such as equipment malfunction, physical or psychological distress, or communications failure) that might require such relief.

In selecting and using respiratory protection equipment, provisions are made for vision correction, adequate communications, extreme temperature conditions, and concurrent use of other safety or radiological protection equipment.

For circumstances when respiratory protection equipment is used from which an unaided individual would have difficulty extricating himself or herself, and therefore might be exposed to a potentially life-threatening situation, a standby rescue person is required. The standby rescue person shall be

equipped with respiratory protection equipment appropriate for the potential hazards and shall be immediately available to provide assistance.

12AA.5.4.10 Radioactive Material Control

Procedures are established, implemented and maintained that assure compliance with the requirements of 10 CFR 20.1801, 20.1802, 20.1902, 20.1904, 20.1905, 20.1906, 20.2001, 20.2005, 20.2006, 20.2007, 20.2201, and 10 CFR 71.5 to assure positive control over licensed radioactive material so that unnecessary or inadvertent exposures do not occur and such material is not released into uncontrolled areas in a manner that is not authorized by regulation or the license.

12AA.5.4.11 Radiation Protection Training

Procedures are developed, implemented, and maintained that assure that selection, qualification, training, and periodic retraining of radiation protection staff and radiation workers are conducted in accordance with the requirements in 10 CFR Parts 19, 20, and 10 CFR 50.120 and consistent with the guidance in Regulatory Guides 1.8, 8.13, 8.15, 8.27, and 8.29.

12AA.5.4.12 Quality Assurance

The radiation protection program and procedures are established, implemented, maintained and reviewed consistent with the 10 CFR 20.1101 and the quality assurance criteria described in Part III of the Quality Assurance Program Description described in Section 17.5.

Consistent with the requirements in 10 CFR 71.101(f), quality assurance requirements apply to the program, procedures and activities involving the transportation of radioactive material.

12AA.5.4.13 Reports

Procedures are established, implemented, and maintained to assure that reports and notifications are made in accordance with 10 CFR 20, Subpart M.

12AA.5.4.14 Groundwater Monitoring Program

A groundwater monitoring program beyond the normal radioactive effluent monitoring program is developed. If necessary to support this groundwater monitoring program, design features will be installed during the plant construction process. Areas of the site to be specifically considered in this groundwater monitoring program are (all directions based on plant standard):

- West of the auxiliary building in the area of the fuel transfer canal.
- West and south of the radwaste building.
- East of the auxiliary building rail bay and the radwaste building truck doors.

This subsection adopts NEI 08-08A (Reference 201), for the Groundwater Monitoring Program description.

12AA.5.4.15 Record of Operational Events of Interest for Decommissioning

This subsection adopts NEI 08-08A (Reference 201), for discussion of record keeping practices important to decomissioning.

12AA.5.5 References

1. 10 CFR Part 19, “Notices Instructions, and Reports to Workers: Inspections and Investigations.”

2. 10 CFR Part 20, “Standards for Protection Against Radiation.”

3. 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities.”

4. 10 CFR Part 52, “Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Plants.”

5. 10 CFR Part 71, “Packaging and Transportation of Radioactive Material.”

6. 10 CFR Part 73, “Physical Protection of Plants and Materials”

7. Regulatory Guide 1.8, Revision 3, “Qualification and Training of Personnel for Nuclear Power Plants.”

8. Regulatory Guide 1.97, Revision 3, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident.”

9. Regulatory Guide 1.206, “Combined License Applications for Nuclear Power Plants (LWR Edition).”

10. Regulatory Guide 8.2, “Guide for Administrative Practices in Radiation Monitoring.”

11. Regulatory Guide 8.4, “Direct-Reading and Indirect-Reading Pocket Dosimeters.”

12. Regulatory Guide 8.6, “Standard Test Procedures for G-M Counters.”

13. Regulatory Guide 8.7, Revision 2, “Instructions for Recording and Reporting Occupational Radiation Exposure Data.”

14. Regulatory Guide 8.8, Revision 3, “Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will Be as Low as Is Reasonably Achievable.”

15. Regulatory Guide 8.9, Revision 1, “Acceptable Concepts, Models, Equations, and Assumptions for a Bioassay Program.”

16. Regulatory Guide 8.10, Revision 1R, “Operational Philosophy for Maintaining Occupational Radiation Exposures as Low as Is Reasonably Achievable.”

17. Regulatory Guide 8.13, Revision 3, “Instruction Concerning Prenatal Radiation Exposure.”

18. Regulatory Guide 8.15, Revision 1, “Acceptable Programs for Respiratory Protection.”

19. Regulatory Guide 8.27, “Radiation Protection Training for Personnel at Light-Water-Cooled Nuclear Power Plants.”

20. Regulatory Guide 8.28, “Audible Alarm Dosimeters.”

21. Regulatory Guide 8.29, Revision 1, “Instruction Concerning Risks from Occupational Radiation Exposure.”

22. Regulatory Guide 8.34, “Monitoring Criteria and Methods To Calculate Occupational Radiation Doses.”

23. Regulatory Guide 8.35, “Planned Special Exposures.”

24. Regulatory Guide 8.36, “Radiation Doses to Embryo/Fetus.”

25. Regulatory Guide 8.38, Revision 1, “Control of Access to High and Very High Radiation Areas of Nuclear Power Plants.”

26. NUREG-0737, “Clarification of TMI Action Plan Requirements.”

27. NUREG-1736, “Consolidated Guidance: 10 CFR Part 20 Standards For Protection Against Radiation.”

28. Regulatory Issue Summary 2003-04, “Use of the Effective Dose Equivalent In Place of the Deep Dose Equivalent in Dose Assessments.”

29. SRP Branch Technical Position (BTP) 7-10, “Guidance on Application of Regulatory Guide 1.97,” NUREG-0800.

201. NEI 08-08A, Generic FSAR Template Guidance for Life Cycle Minimization of Contamination, Revision 0, October 2009 (ML093220445).

Table 12AA-201 (Sheet 1 of 2)
Very High Radiation Areas (VHRA)

Room Number	VHRA Location	Figure 12.3-1, Sheet No.	Primary Source(s)	VHRA Conditional Notes	Frequency of Access to VHRA Areas While VHRA Conditions Exist
11105	Reactor Vessel Cavity	3, 4, 5	Neutron activation of the material in and around the cavity during reactor operations, such as the concrete shield walls and the reactor insulation	Note 1	None Required
12151	Spent Fuel Pool Cooling System / Liquid Radwaste System Demineralizer/ Filter room (Inside Wall)	3	Resin in vessels	Notes 6, 8	None Required
12153	Delay-Bed/ Guard-Bed Compartment	3	Activated carbon holding radioactive gases	Note 10	None Required
12371	Filter-Storage Area	6, 7	Spent filter cartridges	Notes 4, 6, 7	None required
12372	Resin Transfer Pump/Valve Room	6	Spent resin in lines	Note 6	None required
12373	Spent-Resin Tank Room	6	Spent resin in tanks	Note 6	None Required
12374	Waste Disposal Container Area	6	Spent resin in vault	Note 6	None Required
12463	Cask Loading Pit	6	Spent fuel	Notes 2, 6	None Required
12563	Spent Fuel Pool	5, 6	Spent fuel	Note 6	None Required
Fuel Transfer Areas					
12564	Fuel Transfer Tube	6	Fuel in transit	Notes 2, 5, 9	None Required
11205	Reactor Vessel Nozzle Area	5	Fuel in transit	Notes 2, 3, 9	None Required
11504	Refueling Cavity	6	Fuel in transit	Notes 2, 3, 9	None Required

Table 12AA-201 (Sheet 2 of 2)
Very High Radiation Areas (VHRA)

Notes

1. VHRA during full power operation; less than 10 Rem/hr 24 hours after plant shutdown.
2. During underwater spent fuel transfer operations, this area can be as high as VHRA.
3. During underwater reactor internals transfers/ storage, this area can be as high as VHRA.
4. During spent resin waste disposal container transfer or loading, this area can be as high as VHRA. The contact dose rate of spent resin containers can be greater than 1000 Rem/hr.
5. Discussion about the Spent Fuel Transfer Canal and Tube Shielding is provided in Subsection 12.3.2.2.9.
6. Source is transient, removable, or can be relocated.
7. VHRA when hatch is removed during spent resin container handling operation.
8. In the event that the room does need to be accessed for maintenance or other reasons, temporary shielding is put in place and the resin is removed from the vessels. These measures reduce exposure rates in the room, such that this room is no longer a VHRA. Remote handling is used for any tasks that require the opening of the access hatch in the ceiling of this room when media is present.
9. These areas have no planned reasons for entry and are only classified as VHRAs during periods of fuel movement. In the event that these rooms do need to be accessed to repair the Fuel-Transfer System, Fuel Transfer Tube Gate Valve, or other components, it is done during a non-fuel movement time. This keeps the dose received by the worker as low as reasonably achievable.
10. Inspection of the equipment in this room, when required, is done using remote viewing equipment. Two plugs between Room 12153 and 12155 contain instruments and the plugs are expected to be removed every 12 to 18 months for performance of maintenance. Administrative procedures are implemented to protect workers pursuant to Regulatory Guide 8.38.

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 13	CONDUCT OF OPERATION	13.1-1
13.1	Organizational Structure	13.1-1
13.1.1	Management and Technical Support Organization	13.1-1
13.1.1.1	Design, Construction, and Operating Responsibilities	13.1-1
13.1.1.2	Provisions for Technical Support Functions	13.1-2
13.1.1.3	Organizational Arrangement	13.1-7
13.1.1.4	Qualifications of Technical Support Personnel	13.1-7
13.1.2	Operating Organization	13.1-8
13.1.2.1	Plant Organization	13.1-8
13.1.3	Qualifications of Nuclear Plant Personnel	13.1-10
13.1.3.1	Qualification Requirements	13.1-10
13.1.3.2	Qualifications of Plant Personnel	13.1-10
13.1.4	Combined License Information Item	13.1-10
13.1.5	References	13.1-11
13.2	Training	13.2-1
13.2.1	Licensed Operator Training	13.2-2
13.2.1.1	Licensed Operator Initial Training Program	13.2-2
13.2.1.2	Continuing Training for Licensed Personnel	13.2-2
13.2.2	Training for Positions Listed in 10 CFR 50.120	13.2-3
13.2.2.1	Non-Licensed Operator (NLO) Initial Training	13.2-3
13.2.2.2	Shift Manager Initial Training	13.2-3
13.2.2.3	Shift Technical Advisor Initial Training Program	13.2-3
13.2.2.4	Instrumentation and Control (I&C) Technician Initial Training	13.2-4
13.2.2.5	Electrical Maintenance Initial Training Program	13.2-4
13.2.2.6	Mechanical Maintenance Initial Training Program	13.2-4
13.2.2.7	Radiological Protection Technician Initial Training	13.2-5
13.2.2.8	Chemistry Technician Initial Training	13.2-5
13.2.2.9	Engineering Personnel Initial Training	13.2-5
13.2.2.10	Continuing Training for Personnel Listed in 10 CFR 50.120	13.2-6
13.2.3	General Employee Training (GET) Program	13.2-6
13.2.3.1	Plant Access Training	13.2-6
13.2.3.2	Radiation Worker Training Program	13.2-6
13.2.3.3	General Employee Requalification Training	13.2-7
13.2.4	Selected Other Training Programs	13.2-7
13.2.4.1	Fire Protection Training	13.2-7
13.2.4.2	Emergency Plan Training Program	13.2-7
13.2.4.3	Physical Security Training Program	13.2-7
13.2.4.4	Station Management Training Program	13.2-7
13.2.5	Training Effectiveness Evaluation Program	13.2-8
13.2.5.1	Supervisory Review for Training Effectiveness	13.2-8
13.2.5.2	Trainee Review of Training Effectiveness	13.2-8
13.2.5.3	Review for Effectiveness of Instructional Techniques and Materials	13.2-8
13.2.6	Combined License Information Item	13.2-8
13.2.7	References	13.2-8

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
13.2A	— Cold License Training Plan	13.2A-1
13.2A.1	Licensed Operator Experience Requirements Prior To Commercial Operation	13.2A-1
13.2A.2	Crew Experience Requirements during First Year of Operation	13.2A-2
13.2A.3	Conduct of On-the-Job Training (OJT)	13.2A-3
13.2A.4	Use of Part-Task/Limited Scope Simulators	13.2A-3
13.2A.5	Licensed Operator Continuing Training	13.2A-3
13.2A.6	Cold Licensing Process Applicability and Termination	13.2A-3
13.2A.7	Initial Licensed Operator Examination Schedule	13.2A-4
13.2A.8	References	13.2A-4
13.3	Emergency Planning	13.3-1
13.3.1	Combined License Information Item	13.3-1
13.4	Operational Programs	13.4-1
13.4.1	Combined License Information Item	13.4-1
13.4.2	References	13.4-1
13.5	Plant Procedures	13.5-1
13.5.1	Administrative Procedures	13.5-2
13.5.2	Operating and Maintenance Procedures	13.5-3
13.5.2.1	Operating and Emergency Operating Procedures	13.5-3
13.5.2.2	Maintenance and Other Operating Procedures	13.5-4
13.5.3	Combined License Information Item	13.5-7
13.5.4	References	13.5-7
13.6	Security	13.6-1
13.6.1	Combined License Information Item	13.6-2
13.6.2	ESP COL Action Items	13.6-2
13.6.3	References	13.6-2
13.7	Fitness for Duty	13.7-1
13.7.1	References	13.7-2
APPENDIX 13AA	CONSTRUCTION-RELATED ORGANIZATION	13AA-1

LIST OF TABLES

Table Number	Title	Page
13.1-201	Not Used	13.1-12
13.1-202	Minimum On-Duty Operations Shift Organization for Two-Unit Plan	13.1-13
13.2A-201	Comparison of Hot and Cold License Guidance	13.2A-5
13.2A-202	Illustration of Cold Licensing Plan by Candidate Type	13.2A-9
13.2A-203	Cumulative Nuclear Power Plant Operating Crew Experience Equivalencies	13.2A-10
13.4-201	Operational Programs Required by NRC Regulations	13.4-2
13.5-201	Pre-COL Phase Administrative Programs and Procedures	13.5-8

LIST OF FIGURES

Figure Number	Title	Page
13.1-201	Not Used	13.1-14
13.1-202	Not Used	13.1-15
13.1-203	Not Used	13.1-16
13AA-201	Deleted	13AA-6
13AA-202	Hiring Schedule for Plant Staff	13AA-7

Chapter 13 Conduct of Operation

This chapter provides information relating to the preparations and plans for operation of the AP1000 units at Vogtle 3 and 4 after construction. Its purpose is to provide reasonable assurance that the plant will establish and maintain a staff of sufficient size and technical competence and that operating plans provide reasonable assurance of adequate protection of the public health and safety. The requirements for Initial Test Program personnel and activities are covered under Chapter 14, Initial Test Program.

13.1 Organizational Structure

The organizational structure must be consistent with the human system interface design assumptions. See Section 1.8 and Chapter 18 for interface requirements pertaining to organizational structure.

This section describes organizational positions of a nuclear power station and owner/applicant corporations and associated functions and responsibilities. The position titles used in the text are generic and describe the function of the position.

13.1.1 Management and Technical Support Organization

Southern Nuclear Operating Company, Inc. (SNC) has over 30 years of experience in the design, construction, and operation of nuclear generating plants. SNC, with its architectural engineering predecessor Southern Company Services, Inc., has designed, constructed, and currently operates six nuclear units at three sites: Edwin I. Hatch Nuclear Plant Units 1 and 2, Joseph M. Farley Nuclear Plant Units 1 and 2, and Vogtle Electric Generating Plant Units 1 and 2.

Vogtle 3 and 4 will be owned by Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia[1], and the City of Dalton, and operated by SNC.

13.1.1.1 Design, Construction, and Operating Responsibilities

The Chairman, President & Chief Executive Officer (CEO) Southern Nuclear has overall responsibility for functions involving design, construction, and operation. Line responsibilities for those functions are assigned to the Executive Vice President of Vogtle 3&4 for the design, construction, and initial operation of Vogtle 3&4 and to the Chief Nuclear Officer (CNO) for long term operation of Vogtle 3&4. At the appropriate time designated by the President and CEO Southern Nuclear, the CNO accepts responsibility for the additional unit/units at the VEGP site and then maintains direct control of nuclear plant operation through the Site Vice President, operations support, engineering, and other direct reports.

The first priority and responsibility of each member of the nuclear staff throughout the life of the plant is nuclear safety. Decision-making for plant activities is performed in a conservative manner with expectations of this core value regularly communicated to appropriate personnel by management interface, training, and plant directives. Lines of authority, decision making, and communication are clearly and unambiguously established to enable the understanding of the various project members, including contractors, that utility management is in charge of and directs on the project. Key executive and corporate management positions, functions, and responsibilities are discussed in Subsection 13.1.1.3.1, the Nuclear Development Quality Assurance Manual (NDQAM), or the Quality Assurance Topical Report (QATR). The corporate organization is described in the NDQAM or the

1. On June 24, 2015, Municipal Electric Authority of George (MEAG) transferred its ownership interest to its wholly owned subsidiaries: MEAG Power SPVM, LLC; MEAG Power SPVJ, LLC; and MEAG Power SPVP, LLC.

QATR. The management and technical support organization for design, construction, and preoperational activities is addressed in Appendix 13AA.

13.1.1.2 Provisions for Technical Support Functions

Before beginning preoperational testing, the Executive Vice President of Vogtle 3&4 establishes the organization of managers, functional managers, supervisors, and staff sufficient to perform required functions for support of safe and efficient preoperational and startup testing. Sufficient numbers of personnel are assigned to perform preoperational and startup testing to facilitate safe and efficient implementation of the testing program. To improve operational experience, operations and technical staff are used as support in conducting the test program and in reviewing test results. Prior to fuel load, the organization of managers, functional managers, supervisors, and staff sufficient to perform the required functions for support of safe plant operation shall be present. These functions include the following:

- Nuclear, mechanical, civil, structural, electrical, thermal-hydraulic, metallurgical and material, and instrumentation and controls engineering
- Safety review
- Quality assurance, audit and surveillance
- Plant chemistry and environmental support
- Radiation protection
- Fueling and refueling operations support
- Training
- Maintenance support
- Operations support
- Fire protection
- Emergency planning
- Outside contractual assistance

In the event that plant personnel are not qualified to deal with a specific problem, the services of qualified individuals from other functions within the company or an outside consultant are engaged. For example, major contractors, such as the reactor technology vendor or turbine generator manufacturer, provide technical support when equipment modifications or special maintenance problems are considered. Special studies, such as environmental monitoring, may be contracted to qualified consultants. See the NDQAM or QATR for description of responsibilities and authorities of management positions for organizations providing technical support.

Multiple layers of protection are provided to preserve unit integrity including organization. Organizationally, operators and other shift members are assigned to a specific unit, with the exception of some shared shift support supervisor and system operator positions. Physical separation of units helps to minimize wrong-unit activities. In addition, plant procedures and programs provide operating staff with methods to minimize human error including tagging programs, procedure adherence requirements, and training.

13.1.1.2.1 Engineering

The engineering department consists of system engineering, engineering plant support, and design engineering. These groups are responsible for performing the site engineering activities as well as providing engineering expertise in other areas. Each of the engineering groups has a functional manager who reports to the engineering director.

The engineering department is responsible for:

- Support of plant operations in the engineering areas of mechanical, structural, electrical, thermal-hydraulic, metallurgy and materials, electronic, instrument and control, and fire protection. Priorities for support activities are established based on input from the plant manager with emphasis on issues affecting safe operation of the plant.
- Engineering plant support.
- Support of procurement, chemical, and environmental analysis and maintenance activities in the plant as requested by the plant manager.
- Performance of design engineering of plant modifications.
- Human factors engineering design process
- Quality control (QC) inspection/testing activities to support plant operation, maintenance, and outages.

Reactor engineering provides technical assistance in the areas of core design, core operations, core thermal limits, and core thermal hydraulics.

Engineering work may be contracted to and performed by outside companies in accordance with the quality assurance (QA) program.

Engineering resources are shared between units. A single management organization oversees the engineering work associated with the plant units.

13.1.1.2.2 Safety Review

Review and audit activities are addressed in Chapter 17. Safety review oversight of plant programs, procedures, and activities is governed by the independent review function described in the QA Program Description (QAPD).

Personnel who perform safety review are shared between units.

13.1.1.2.3 Quality Assurance

Safety-related activities associated with the operation of the plant are governed by QA direction established in Chapter 17 and the QAPD. The requirements and commitments contained in the QAPD apply to activities associated with structures, systems, and components that are safety-related and are mandatory and must be implemented, enforced, and adhered to by individuals and organizations. QA requirements are implemented through the use of approved procedures, policies, directives, instructions, or other documents that provide written guidance for the control of quality-related activities and provide for the development of documentation to provide objective evidence of compliance. The QA function includes:

- Maintaining the QAPD.
- Coordinating the development of audit schedules.
- Auditing, performing surveillance, and evaluating nuclear division suppliers.
- Supporting general QA indoctrination and training for the nuclear station personnel.

The QA organization is independent of the plant management line organization.

Personnel resources of the QA organization are shared between units. A single management organization oversees the QA group for the plant units.

13.1.1.2.4 Chemistry

A chemistry program is established to monitor and control the chemistry of various plant systems such that corrosion of components and piping is minimized to maintain reliable equipment performance and radiation from corrosion byproducts is kept to levels that allow operations and maintenance with radiation doses as low as reasonably achievable. Department responsibilities include:

- Primary and secondary water chemistry
- Process and effluent monitoring and sampling
- Closed cooling water chemistry
- Demineralized water treatment chemistry
- Diesel fuel oil testing, analysis, and controls
- Plant chemical control

The Chemistry Manager reports to the Plant Manager. The staff of the chemistry department consists of laboratory technicians, support personnel, and supervisors who report to the Chemistry Manager.

Personnel resources of the chemistry organization are shared between units. A single management organization oversees the chemistry group for the plant units.

13.1.1.2.5 Radiation Protection

A radiation protection (RP) program is established to protect the health and safety of the public and the personnel working at the plant by establishing means to maintain radiation exposure as low as reasonably achievable (ALARA) and to prevent the spread of contamination. The RP program is described in Appendix 12AA. The program includes:

- Respiratory protection
- Personnel dosimetry
- Bioassay
- Survey instrument calibration and maintenance

- Radioactive source control
- Effluents and environmental monitoring and assessment
- Radioactive waste shipping
- Radiation work permits
- Job coverage
- Radiation monitoring and surveys

The RP department is staffed by RP technicians, support personnel, and supervisors who report to the Radiation Protection Manager. To provide sufficient organizational freedom from operating pressures, the Radiation Protection Manager reports directly to the Plant Manager.

Personnel resources of the RP organization are shared between units. A single management organization oversees the RP group for both units.

The terms radiation protection and health physics are used interchangeably in function descriptions.

13.1.1.2.6 Fueling and Refueling Support

The function of fueling and refueling is performed by a combination of personnel from various departments including, but not limited to, work management, operations, maintenance, radiation protection, engineering, and reactor technology vendor or other contractor staff. Personnel resources used to support fueling and refueling are shared between units.

13.1.1.2.7 Training and Development

The training department is responsible for analysis, design, development, implementation and evaluation of plant training programs in accordance with regulatory requirements, accreditation standards, and company policies. The objective of the training programs is to qualify operations, maintenance, RP, chemistry, and engineering personnel to operate and maintain the plant in a safe and efficient manner and in compliance with the license, technical specifications, and applicable regulations. In addition, the training department administers plant access (general employee) training, radworker training, security training, and emergency response training. The senior manager responsible for training reports independently of the line organization to provide for independence from operating pressures. Plant training programs are described in Section 13.2.

Personnel resources of the training department are shared between units. A single management organization provides oversight of plant training activities.

13.1.1.2.8 Maintenance Support

In support of maintenance activities, planners, schedulers, and parts specialists prepare work packages, acquire proper parts, and develop procedures that provide for the successful completion of maintenance tasks. Maintenance tasks are integrated into the plant schedule for evaluation of operating or safe shutdown risk elements and to provide for efficient and safe performance. The Maintenance Director reports to the Plant Manager.

Personnel of the maintenance support organization are shared between units. A single management organization oversees the function of maintenance support for the plant units.

13.1.1.2.9 Operations Support

The operations support function is provided under the direction of the Operations Director. Operations support includes the following programs:

- Operations procedures
- Operations surveillances
- Equipment tagging

13.1.1.2.10 Fire Protection

The plant is committed to maintaining a fire protection program as described in Section 9.5. Once the nuclear plant is operational, the Site Vice President, through the engineer in charge of fire protection, is responsible for the fire protection program. Assigning the responsibilities at that level provides the authority to obtain the resources and assistance necessary to meet fire protection program objectives, resolve conflicts, and delegate appropriate responsibility to fire protection staff. Fire protection for the facility is organized and administered by the engineer in charge of fire protection. The engineer in charge of fire protection is trained and experienced in fire protection and nuclear plant safety or has available personnel who are trained and experienced in fire protection and nuclear plant safety.

The Site Vice President, through the engineer in charge of fire protection, is responsible for developing and implementing the fire protection program including developing fire protection procedures, site personnel and fire brigade training, and inspections of fire protection systems and functions. The engineer in charge of fire protection coordinates operations-related fire protection program activities with the Operations Director or designee. Functional descriptions of position responsibilities are included in appropriate procedures. Plant personnel are responsible for adhering to the fire protection/prevention requirements detailed in Section 9.5. The Executive Vice President of Vogtle 3&4 has the lead responsibility for the overall site fire protection during construction of the new units.

Personnel resources of the fire protection organization are shared between units. A single management organization oversees the fire protection group for the plant units.

13.1.1.2.11 Emergency Organization

The emergency organization is a matrixed organization composed of personnel who have the experience, training, knowledge, and ability necessary to implement actions to protect the public in the case of emergencies. Managers and plant personnel assigned positions in the emergency organization are responsible for supporting the emergency preparedness organization and emergency plan as required. The staff members of the emergency planning organization administrate and orchestrate drills and training to maintain qualification of plant staff members and develop procedures to guide and direct the emergency organization during an emergency. The staff is also responsible for maintaining emergency facilities and equipment. The functional manager in charge of emergency preparedness reports to the senior manager responsible for Regulatory Affairs. Once the protected area is combined with Units 1 and 2, emergency response is combined with Units 1 and 2.

The site emergency plan organization is described in the Emergency Plan. Resources of the emergency planning group are shared between units. A single management organization oversees the emergency planning group for the plant units.

13.1.1.2.12 Outside Contractual Assistance

Contract assistance with vendors and suppliers of services not available from organizations established as part of utility staff is provided by the materials, purchasing, and contracts organization. Personnel in the materials, purchasing, and contracts organization perform the necessary functions to contract vendors of special services to perform tasks for which utility staff does not have the experience or equipment required. The functional manager in charge of materials, purchasing, and contracts reports to the department manager in charge of materials, purchasing, and contracts.

Resources of the materials, purchasing, and contracts organization are shared between units. A single management organization oversees the materials, purchasing, and contracts group for the plant units.

13.1.1.3 Organizational Arrangement

13.1.1.3.1 Executive Management Organization

The nuclear operations organization, under the supervision of the Chairman, President & CEO Southern Nuclear, has direct responsibility for the operation and maintenance of Southern Company's nuclear plants. Executive management establishes expectations such that a high level of quality, safety, and efficiency is achieved in aspects of plant operations and support activities through an effective management control system and an organization selected and trained to meet the above objectives. Site executives and management with direct line of authority for activities associated with operation of the plant are described in the NDQAM or SNC QATR. The structure of the nuclear operations organization is described in the NDQAM or SNC QATR. Portions of the SNC Fleet Operations Support, Engineering, and General Counsel and External Affairs are also described in the following paragraphs, in the NDQAM or SNC QATR.

13.1.1.3.1.1 Associate General Counsel

The Associate General Counsel is a matrixed report to the Chairman, President & CEO. This individual is responsible for the legal, compliance, and external affairs associated with the SNC plants. This individual is also responsible for external affairs activities which include governmental affairs and corporate communications. The corporate concerns and compliance manager also reports to this position.

13.1.1.3.1.2 Vice President Treasurer and Secretary

The Vice President Treasurer and Secretary reports directly to the Chairman, President & CEO and is responsible for the development, coordination, management, and communication of all financial matters, including budgeting and analysis, accounting and billing, and the maintenance of an effective system of internal controls.

13.1.1.4 Qualifications of Technical Support Personnel

The qualifications of managers and supervisors of the technical support organization meet the qualification requirements in education and experience for those described in ANSI/ANS-3.1-1993 (Reference 201) as endorsed and amended by Regulatory Guide 1.8. The qualification and experience requirements of headquarters staff is established in corporate policy and procedure manuals.

13.1.2 Operating Organization

13.1.2.1 Plant Organization

Plant personnel responsibilities, authorities, and organizational relationships are described in the NDQAM or the QATR except for those positions described below.

13.1.2.1.1 Operations Managers

The Operations Services Manager, Shift Operations Manager, and Operations Support Manager report to the Operations Director and share the responsibility to ensure plant operations are conducted per Technical Specifications, standing orders, the Offsite Dose Calculation Manual (ODCM) and approved procedures and may function as the Operations Director when designated.

13.1.2.1.2 Shift Manager (SM)

The Shift Manager (SM) reports to the Shift Operations Manager. The SM is the senior management representative on each shift and is responsible for the safe and efficient operation of the plant. The SM ensures plant operations are conducted in accordance with appropriate standing orders, the ODCM, unit operating procedures, and Technical Specifications. The SM has responsibility for the entire plant in the absence of the Site VP, Plant Manager, and Operations Director. The SM has their authority, including issuing standing orders and other special orders, in their absence. The Shift Manager shall possess an SRO License.

13.1.2.1.2.1 Shift Supervisor (SS)

One Shift Supervisor (SS) is assigned to each operating unit on each shift. The SS is responsible for the safe and efficient operation of the assigned unit. Each SS shall possess an SRO License. The SS(s) report to the Shift Manager (SM) and supervise the Reactor Operators, Non-Licensed Operators, and Shift Support Supervisors. The SS is responsible for ensuring that plant operations are conducted per the Technical Specifications, ODCM, and approved procedures and standing orders.

13.1.2.1.2.1.1 Reactor Operator (RO)

The Reactor Operators report to the SS and are responsible to operate the reactor and power plant per approved procedures, standing orders, and Technical Specifications. The Reactor Operator shall possess a reactor operators license.

13.1.2.1.2.1.2 System Operator (SO)

System Operators report to the respective unit's Shift Supervisor (SS) or Support Shift Supervisor (SSS) and are responsible for operating and monitoring plant auxiliary equipment and/or systems outside the main control room. System Operators are non-licensed operators.

13.1.2.1.2.2 Shift Support Supervisor (SSS)

The SSS reports to the Shift Manager (SM) and is responsible for ensuring shift operations are conducted per Technical Specifications, ODCM, and approved procedures and are responsible for monitoring performance of operator rounds, system and equipment lineups, and surveillances.

13.1.2.1.3 Shift Technical Advisor (STA)

One Shift Technical Advisor (STA) is assigned per shift during plant operation. A shift manager or another SRO on shift, who meets the qualifications for the combined Senior Reactor Operator/Shift Technical Advisor position, as specified for option 1 of Generic Letter 86-04, NRC's "Policy Statement on Engineering Expertise On Shift", may also serve as the STA. If this option is used for a shift, then the separate STA position may be eliminated for that shift. Section 13.2 describes STA training, and Subsection 13.1.3 describes STA qualifications.

13.1.2.1.4 Conduct of Operations

Plant operations are controlled and/or coordinated through the control room. Maintenance activities, surveillances, and removal from/return to service of structures, systems, and components affecting the operation of the plant may not commence without the approval of senior control room personnel. The rules of practice for control room activities, as described by administrative procedures, which are based on Regulatory Guide 1.114, address the following:

- Position/placement of operator at the controls workstation and the expected area of the control room where the majority of the time of the supervisor/manager in charge on shift should be spent.
- Definition and outline of "surveillance area" and requirement for continuous surveillance by the operator at the controls.
- Relief requirements for operator at the controls and the supervisor/manager in charge on shift.

In accordance with 10 CFR 50.54:

- Reactivity controls may be manipulated only by licensed ROs and SROs except as allowed for training under 10 CFR 55.
- Apparatus and mechanisms other than controls that may affect reactivity or power level of the reactor shall be operated only with the consent of the operator at the controls or the manager/supervisor in charge on-shift.
- During operation of the facility in modes other than cold shutdown or refueling, an SRO shall be in the control room and a licensed RO or SRO shall be present at the controls.

Line of Succession:

The line of succession of authority and responsibility for overall operations in the event of unexpected events of a temporary nature is:

a. Plant Manager

b. Operations Director

c. Shift Manager

d. Shift Supervisor

13.1.2.1.5 Operating Shift Crews

Plant administrative procedures implement the required shift staffing. These procedures establish crews with sufficient qualified plant personnel to staff the operational shifts and be readily available in the event of an abnormal or emergency situation. The objective is to operate the plant with the required staff and to develop work schedules that minimize overtime for plant staff members who perform safety-related functions. Work hour limitations and shift staffing requirements defined by TMI Action Plan I.A.1.3 are retained in plant procedures. When overtime is necessary, the provisions in the Technical Specifications, 10 CFR 26, and the plant administrative procedures apply. Shift crew staffing plans may be modified during refueling outages to accommodate safe and efficient completion of outage work in accordance with the proceduralized work hour limitations.

The minimum composition of the operating shift crew is contingent on the unit operating status. Position titles, license requirements, and minimum shift staffing for various modes of operation are contained in Technical Specifications, administrative procedures, and Table 13.1-202.

13.1.2.1.6 Fire Brigade

The station is designed and the fire brigade organized to be self-sufficient with respect to firefighting activities. The fire brigade is organized to deal with fires and related emergencies that could occur. It consists of a fire brigade leader and a sufficient number of team members to be consistent with the equipment that must be put in service during a fire emergency. A sufficient number of trained and physically qualified fire brigade members are available on site during each shift. The fire brigade consists of at least five members on each shift. The fire brigade leader and at least two members will be knowledgeable of the building layout and system design sufficient to understand the effects of fire fighting on safety-related equipment. The assigned fire brigade members for any shift does not include the shift manager nor any other members of the minimum shift operating crew necessary for safe shutdown of the unit. It does not include any other personnel required for other essential functions during a fire emergency. Fire brigade members for a shift are designated in accordance with established procedures at the beginning of the shift. Fire brigade personnel may include personnel from Units 1 and 2 once the protected area is combined.

13.1.3 Qualifications of Nuclear Plant Personnel

13.1.3.1 Qualification Requirements

Qualifications of managers, supervisors, operators, and technicians of the operating organization meet the qualification requirements in education and experience for those described in ANSI/ANS-3.1-1993 (Reference 201), as endorsed and amended by Regulatory Guide 1.8 and clarified in Appendix 1A.

13.1.3.2 Qualifications of Plant Personnel

Résumés and/or other documentation of qualification and experience of initial appointees to appropriate management and supervisory positions are available for review by regulators upon request after position vacancies are filled.

13.1.4 Combined License Information Item

The organizational structure is addressed in Subsections 13.1.1 through 13.1.3.

13.1.5 References

201. American Nuclear Society, “American National Standard for Selection, Qualification, and Training of Personnel for Nuclear Power Plants,” ANSI/ANS-3.1-1993.

202. U.S. Nuclear Regulatory Commission, “Generic Letter 86-04, Policy Statement on Engineering Expertise on Shift.”

203. American Nuclear Society, “American National Standard for Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” N18.7-1976/ANS-3.2.

204. American Nuclear Society, “American National Standard for Selection, Qualification, and Training of Personnel for Nuclear Power Plants,” ANSI/ANS-3.1-2014.

Table 13.1-201
Not Used

Table 13.1-202
Minimum On-Duty Operations Shift Organization for Two-Unit Plan

Units Operating	Two Units Two Control Rooms
All Units Shutdown	1 SM (SRO) 2 RO 3 NLO
One Unit Operating[(a)]	1 SM (SRO) 1 SRO 3 RO 3 NLO
Two Units Operating[(a)]	1 SM (SRO) 2 SRO 4 RO 4 NLO

SM – shift manager
SRO – Licensed Senior Reactor Operator
RO – Licensed Reactor Operator
NLO – non-licensed operator

a) Operating modes other than cold shutdown or refueling.

Notes:

1. In addition, one Shift Technical Advisor (STA) is assigned per shift during plant operation. A shift manager or another SRO on shift, who meets the qualifications for the combined Senior Reactor Operator/Shift Technical Advisor position, as specified for option 1 of Generic Letter 86-04, (Reference 202) the commission's policy statement on engineering expertise on shift, may also serve as the STA. If this option is used for a shift, then the separate STA position may be eliminated for that shift.
2. In addition to the minimum shift organization above, during refueling a licensed senior reactor operator or senior reactor operator limited (fuel handling only) is required to directly supervise any core alteration activity.
3. A shift manager/supervisor (SRO licensed for each unit that is fueled), shall be on site at all times when at least one unit is loaded with fuel.
4. A radiation protection technician shall be on site at all times when there is fuel in a reactor.
5. A chemistry technician shall be on site during plant operation in modes other than cold shutdown or refueling.
6. To operate, or supervise the operation of more than one unit, an operator (SRO or RO) must hold an appropriate, current license for each unit.

Figure 13.1-201
Not Used

Figure 13.1-202
Not Used

Figure 13.1-203
Not Used

13.2 Training

This section incorporates NEI 06-13A, Template for an Industry Training Program Description with the following VEGP 3&4 exceptions:

- The annual General Employee Requalification training frequency defined in Subsection 1.3.3. The General Employee Requalification training frequency is defined in Subsection 13.2.3.3.

- The Engineering Personnel Initial Training defined in Subsection 1.2.9, Fundamentals, which is satisfied by prerequisite entry level education and experience.

Training programs incorporate instructional requirements to qualify personnel to operate and maintain the facility in a safe manner in all modes of operation (Reference 202). The programs are developed and maintained in compliance with the facility license and applicable regulations. The training programs are periodically evaluated and revised to reflect industry experience and to incorporate changes to the facility, procedures, regulations, and quality assurance requirements, and are periodically reviewed by management for effectiveness. These training programs are described in site and/or corporate procedures, as appropriate. Sufficient records are maintained and kept available for NRC inspection to verify adequacy of the programs.

The Training Department provides the required training based on individual employee experience, the intended position, and previous training and education. Training Department personnel may be supplemented by other personnel such as subject matter experts, contract staff, and vendor representatives. Formal instruction may be presented through a combination of classroom lectures, e-learning, assigned reading, simulator training and evaluations, and other delivery techniques.

For reactor operators, senior reactor operators, fuel handlers, fire protection personnel, and positions specified in 10 CFR 50.120 (Reference 13.2-4), programs are developed, established, implemented and maintained using a systems (or systematic) approach to training (SAT) as defined by 10 CFR 55.4 (Reference 13.2-8) and ANSI/ANS-3.1-1993 (Reference 13.2-14), as endorsed by Regulatory Guide 1.8 (Reference 13.2-16) and clarified in Appendix 1A.

Initial and continuing training programs accredited by the National Academy for Nuclear Training (NANT) provide personnel with the skills and knowledge to perform assigned tasks. Accredited training programs include the following:

- Non-licensed operator
- Reactor operator
- Senior reactor operator
- Shift manager
- Shift technical advisor
- Continuing training for licensed personnel
- Instrument and control technician
- Electrical maintenance personnel
- Mechanical maintenance personnel
- Chemistry technician
- Radiological protection technician
- Engineering personnel

The results of reviews of operating experience are incorporated into training and retraining programs in accordance with the provisions of TMI Action Item I.C.5, Appendix 1A. Training programs encompass all phases of plant operation including preoperational testing and low-power operation in accordance with the provisions of TMI Action Item I.G.1 (Reference 13.2-19). Supplemental operator

training requirements during startup testing are described in Subsection 14.2.6.1. Before initial fuel loading, sufficient plant staff will be trained to provide for safe plant operations. Table 13.4-201 provides milestones for training implementation.

Operators involved in the Human Factors Engineering Verification and Validation (V&V) Program receive additional training specific to the task of performing V&V. A systematic approach to training is incorporated in developing this training program along with input from WCAP-14655, Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel (Reference 201).

Chapter 18, Section 18.10 references WCAP 14655. This document describes input from the designer on the training of the operations personnel who participate as subjects in the human factors engineering (HFE) verification and validation. The WCAP also describes how training insights are passed from the designer.

13.2.1 Licensed Operator Training

The Reactor Operator (RO) and Senior Reactor Operator (SRO) training programs, including initial and requalification training, provide the means to train individuals in the knowledge, skills, and abilities needed to perform licensed operator duties. The licensed operator training program includes the requalification program as required by 10 CFR 55.59 (Reference 13.2-13). Collectively, ROs and SROs are referred to as Licensed Operators. Before initial fuel loading, the number of persons trained in preparation for RO and SRO licensing examinations will be sufficient to meet regulatory requirements, with allowances for examination contingencies and without the need for planned overtime.

The site employs a simulator in accordance with 10 CFR 55.46 (Reference 13.2-12) and guidance of Regulatory Guide 1.149 (Reference 13.2-17). This simulator is used for training licensed personnel, and for the administration of the operating test.

13.2.1.1 Licensed Operator Initial Training Program

The Licensed Operator Initial Training Program prepares RO and SRO candidates for the NRC license exam. This program is implemented in accordance with administrative procedures.

13.2.1.1.1 Reactor Operator

Reactor Operator candidates receive training in the topics listed in 10 CFR 55.41 (Reference 13.2-9). RO candidates receive plant simulator training to demonstrate understanding and the ability to perform the actions listed in 10 CFR 55.45 (Reference 13.2-11).

13.2.1.1.2 Senior Reactor Operator

In addition to the Reactor Operator topics listed in 10 CFR 55.41 (Reference 13.2-9), candidates for the Senior Reactor Operator license receive training in the topics listed in 10 CFR 55.43 (Reference 13.2-10). SRO candidates receive plant simulator training to demonstrate understanding and the ability to perform the actions listed in 10 CFR 55.45 (Reference 13.2-11).

13.2.1.2 Continuing Training for Licensed Personnel

Continuing training for licensed personnel consists of regularly scheduled formal instruction, evaluation, and on-the-job training. Training material is developed using the SAT process, and includes Operational Experience (OE). Licensed operators participate in continuing training.

Program content, course schedules and examination schedules comply with 10 CFR 55.59 (Reference 13.2-13). Continuing training for licensed personnel is conducted in accordance with administrative procedures.

13.2.2 Training for Positions Listed in 10 CFR 50.120[1]

This section addresses training programs for the positions listed in 10 CFR 50.120 (Reference 13.2-4). The systematic approach to training (SAT) process is used to establish and maintain training programs. Course duration and content are determined by the SAT process and by administrative procedure. This program will commence no later than eighteen months prior to initial fuel loading.

13.2.2.1 Non-Licensed Operator (NLO) Initial Training

Personnel employed as NLOs receive instruction on operation of plant equipment and components under normal and emergency conditions. This program is a combination of formal instruction and on-the-job training. Training is given in:

- Fundamentals of mechanical and electrical components
- Operation of equipment and systems
- Operating procedures
- Surveillance requirements
- Operation of systems important to plant safety

In-plant training includes system walk downs, which emphasize the use of procedures, the proper operation of equipment, and safe operating practices.

13.2.2.2 Shift Manager Initial Training

Shift managers have been trained as Senior Reactor Operators and receive additional training that addresses higher-level management skills and behaviors, and provides a broader perspective of plant operations. Initial training includes such topics as:

- Application of Operating Experience
- Problem-solving skills
- Planning and managing evolutions
- Maintaining a broad view of plant operations
- Application of observation skills
- Operating philosophy
- Shift team management
- Application of design bases to plant operations
- Emergency Plan
- Transient and Accident Analysis
- Systematic Approach to Training
- Work controls

13.2.2.3 Shift Technical Advisor Initial Training Program

Shift technical advisors provide engineering expertise on-shift. Training provides them with the skill and knowledge to monitor equipment and system operation, and assess plant conditions during abnormal and emergency events. Initial training for individuals who fill the position of shift technical advisor includes instruction in the following areas:

1. 10 CFR 52.78 (Reference 13.2-6) requires that Combined License applicants demonstrate compliance with 10 CFR 50.120.

- Responses to accidents and analyses of plant transients
- Application of engineering principles to protection of the core
- Mitigation of plant accidents
- Basis of plant and systems design
- Reactor theory, thermodynamics, heat transfer, and fluid flow
- General Operating Procedures, Technical Specifications, and Administrative Controls
- Operational transient and accident analysis
- Simulator training, including exercises in the following situations:
  - Plant or reactor startups to include a range such that reactivity feedback from nuclear heat addition is noticeable and heatup rate is established
  - Plant shutdown
  - Manual control of feedwater during startup or shutdown.
  - Significant (10 percent) power changes due to manual changes in control rod position.
- Accident response training

13.2.2.4 Instrumentation and Control (I&C) Technician Initial Training

Initial training for I&C technicians includes instruction in the following areas:

- Fundamentals of instrumentation and control
- Pneumatic systems and equipment
- Electronics
- Fundamental systems training
- I&C and other job related procedures
- Surveillance requirements
- Mitigating core damage training commensurate with their responsibilities during accidents that involve severe core damage
- On-the-job training

On-the-job training allows I&C technicians to practice the skills learned in the classroom under the guidance of experienced and qualified I&C personnel.

13.2.2.5 Electrical Maintenance Initial Training Program

Initial training for electrical maintenance technicians includes instruction in the following areas:

- Print reading
- Use of electrical tools and test equipment
- Fundamental systems training
- Electrical components and equipment
- Electrical maintenance practices
- Maintenance procedures
- On-the-job training

On-the-job training allows Electricians to practice the skills learned in the classroom under the guidance of experienced and qualified electrical maintenance personnel.

13.2.2.6 Mechanical Maintenance Initial Training Program

Initial training for mechanical maintenance technicians includes instruction in the following areas:

- Print reading
- Use of hand tools, power tools, and measurement devices
- Fundamental systems training

- Mechanical components and equipment
- Mechanical maintenance practices
- Maintenance procedures
- On-the-job training

On-the-job training allows Mechanics to practice the skills learned in the classroom under the guidance of experienced and qualified mechanical maintenance personnel.

13.2.2.7 Radiological Protection Technician Initial Training

Initial training for radiological protection technicians includes instruction in the following areas:

- Principles of radiation
- Radiation protection and safety
- Use of survey instruments
- Use of analytical equipment
- Radiation Protection procedures
- Emergency Plan procedures
- ALARA practices and procedures
- Fundamental systems training
- Mitigating core damage training commensurate with their responsibilities during accidents that involve severe core damage

On-the-job training provides the trainee opportunities to practice actual operation of radiation protection equipment and use of procedures under the guidance of experienced technicians. Further information on training for radiological protection technicians can be found in Appendix 12AA.5.

13.2.2.8 Chemistry Technician Initial Training

Initial training for chemistry technicians includes instruction in the following areas:

- Chemistry procedures
- Laboratory practices
- Conduct of analytical tests
- Operation of laboratory equipment
- Fundamental systems training
- On-the-job training to include actual operation of analytical equipment and the use of procedures
- Mitigating core damage training commensurate with their responsibilities during accidents that involve severe core damage
- Power plant chemistry

On-the-job training provides the trainee opportunities to practice actual operation of analytical equipment and use of procedures under the guidance of experienced technicians.

13.2.2.9 Engineering Personnel Initial Training

Engineering personnel complete orientation training on topics such as those listed below. The topics are chosen to familiarize engineering support personnel with various aspects of nuclear technology in an operating plant environment. Training topics include:

- Records management and document control
- Applicable industrial and nuclear regulations, codes, and standards
- Procedures and drawings

- Applicable programs such as corrective action, configuration management, work control, and the QA program
- Technical Specifications
- Plant systems, instrumentation, and components
- Plant operations
- Introductory review of accidents
- Design processes

13.2.2.10 Continuing Training for Personnel Listed in 10 CFR 50.120

Non-licensed plant personnel specified in Subsection 13.2.2 [i.e., personnel listed in 10 CFR 50.120 (Reference 13.2-4)] receive continuing training to maintain qualifications and enhance proficiency. Continuing training reinforces initial training by reiterating selected portions of the material. Continuing training also addresses new and modified procedures and plant design changes.

Operating Experience (OE) is included in continuing training, providing personnel with actual examples of good practices and lessons learned. OE topics are selected from Licensee Event Reports, corrective action databases, industry groups, and other sources.

Continuing training material is developed in accordance with the systematic approach to training and is conducted in accordance with administrative procedures.

STA qualifications are maintained by participation in continuing training for licensed personnel.

13.2.3 General Employee Training (GET) Program

13.2.3.1 Plant Access Training

As part of the GET program, members of the station staff, contractor workers, and unescorted visitors participate in Plant Access Training, which consists of the following topics, prior to being granted unescorted access to the plant:

- Station organization
- Station facilities and layout
- Station administration
- Nuclear plant overview
- Industrial safety
- Fire protection
- Quality assurance and quality control
- Plant security
- Emergency planning
- Radiological orientation
- Appropriate portions of 10 CFR 26 (Reference 13.2-2)
- Appropriate portions of 10 CFR 19 (Reference 13.2-1)

13.2.3.2 Radiation Worker Training Program

Personnel whose job duties require them to have unescorted access to radiologically controlled areas of the plant receive instruction in the applicable aspects of radiation protection. Topics include the following:

- Sources of radiation
- Types and measurement of radiation
- Biological effects

- Limits and guidelines, including Reg. Guide 8.13 (Reference 13.2-18)
- Concept of As Low As Reasonably Achievable (ALARA)
- Radiation dosimetry
- Contamination
- Internal exposure
- Radiation work permits
- Radiological postings
- Radiological alarms
- Radioactive waste
- Rights and responsibilities
- Protective clothing

13.2.3.3 General Employee Requalification Training

Personnel with unescorted access to the plant participate in requalification training at a frequency of every 48 months nominal, not to exceed 51 months. Requalification training includes those topics in 13.2.3.1 and 13.2.3.2, as applicable to access requirements. Emphasis is placed on significant changes to the plant, plant procedures, government regulations regarding the operation of the plant, and quality assurance requirements. As applicable, training is conducted on industry operating experiences, Licensee Event Reports, and personnel errors.

13.2.4 Selected Other Training Programs

This subsection addresses training for positions not specified by 10 CFR 55 (Reference 13.2-7) or 10 CFR 50.120 (Reference 13.2-4).

13.2.4.1 Fire Protection Training

Initial fire protection training is completed prior to receipt of fuel at the site. Personnel assigned as fire brigade members receive formal training prior to assuming brigade duties, and regularly scheduled retraining. Fire brigade training complies with NFPA Standard 600 (Reference 13.2-15).

Training appropriate to the assigned work is also provided for the fire protection staff, fire watch personnel, and the general employee. Subsection 9.5.1 includes additional information regarding fire protection training.

13.2.4.2 Emergency Plan Training Program

Emergency Plan training meets the requirements of 10 CFR 50 Appendix E Section IV.F (Reference 13.2-5) and the standards of 10 CFR 50.47(b)(15) (Reference 13.2-3). Further details of the Emergency Plan training program can be found in the Emergency Plan, which is a separate document.

13.2.4.3 Physical Security Training Program

Training of security personnel is discussed in Section 13.6 and in the Physical Security Plan, which is a separate document.

13.2.4.4 Station Management Training Program

Station supervisors receive Fitness for Duty (FFD) supervisory training in accordance with 10 CFR 26.29. The remaining definitions and recommendations in this subsection are taken from ANSI/ANS-3.1-1993 (Reference 13.2-14) as endorsed by Regulatory Guide 1.8 (Reference 13.2-16).

The qualification requirements for managers and middle managers include training or experience in supervision or management. Training for supervisors develops their skills in the following areas:

- Leadership
- Interpersonal communications
- Management responsibilities and limits
- Motivation of personnel
- Problem analysis and decision making
- Administrative policies and procedures
- Observation skills
- Coaching

13.2.5 Training Effectiveness Evaluation Program

The program to evaluate the effectiveness of training programs is based on three independent inputs or perspectives: the supervisor of the trainee, the trainee, and an educational content evaluation. Each of these reviews is discussed below.

13.2.5.1 Supervisory Review for Training Effectiveness

The purpose of this review is to monitor the content and effectiveness of training programs as related to the duties and job responsibilities of the trainees. Reviews may be performed by supervisors of employees meeting with appropriate Training personnel, by designated oversight personnel, or by observing subsequent job performance. Observations are discussed to determine topics that may require additional training or subjects that may be removed from the training program.

13.2.5.2 Trainee Review of Training Effectiveness

Following selected courses, or training cycles, trainees have the opportunity to provide comments regarding the effectiveness of the instructional methods and content relevancy to their jobs. These comments are used in the evaluation of both instruction and content of the training program.

13.2.5.3 Review for Effectiveness of Instructional Techniques and Materials

Training material and instructional aids are assessed for clarity and applicability. Observations of instructors in the teaching environment are conducted by this qualified individual to monitor classroom performance. Full time instructors receive basic indoctrination in instructional techniques as soon as practicable after assuming instructional duties. The educational specialist conducts periodic seminars in instructional techniques, discussing areas where group performance could be improved and recommends innovative techniques observed at this or other power stations.

13.2.6 Combined License Information Item

The training programs for plant personnel, including the training program for the operations personnel who participate as subjects in the human factors engineering verification and validation and the scope of licensing examinations, as well as new training requirements, are addressed in Section 13.2.

13.2.7 References

13.2-1. 10 CFR 19, "Notices, Instructions, and Reports to Workers; Inspection and Investigations"

13.2-2. 10 CFR 26, "Fitness for Duty"

13.2-3. 10 CFR 50.47, "Emergency Plans"

13.2-4. 10 CFR 50.120, "Training and Qualification of Nuclear Power Plant Personnel"

13.2-5. 10 CFR 50 Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities"

13.2-6. 10 CFR 52.78, "Contents of Applications; Training and Qualification of Nuclear Power Plant Personnel"

13.2-7. 10 CFR 55, "Operator's Licenses"

13.2-8. 10 CFR 55.4, "Definitions"

13.2-9. 10 CFR 55.41, "Written Examinations: Operators"

13.2-10. 10 CFR 55.43, "Written Examinations, Senior Operators"

13.2-11. 10 CFR 55.45, "Operating Tests"

13.2-12. 10 CFR 55.46(c), "Plant-Referenced Simulators"

13.2-13. 10 CFR 55.59, "Requalification"

13.2-14. American National Standards Institute, "Selection, Qualification, and Training of Personnel for Nuclear Power Plants," ANSI/ANS-3.1-1993

13.2-15. National Fire Protection Association, "Standard on Industrial Fire Brigade," NFPA Standard 600, 2005 Edition

13.2-16. U.S. Nuclear Regulatory Commission, "Qualification and Training of Personnel for Nuclear Power Plants," Regulatory Guide 1.8, Revision 3, May 2000

13.2-17. U.S. Nuclear Regulatory Commission, "Nuclear Power Plant Simulation Facilities for Use in Operator Training, License Examinations, and Applicant Experience Requirements," Regulatory Guide 1.149, Revision 4, April 2011

13.2-18. U.S. Nuclear Regulatory Commission, "Instruction Concerning Prenatal Radiation Exposure," Regulatory Guide 8.13, November, 1980.

13.2-19. U.S. Nuclear Regulatory Commission, "Clarification of TMI Action Plan Requirements", NUREG-0737, Revision 3, June 1999

13.2-20. U.S. Nuclear Regulatory Commission, "Policy Statement on Engineering Expertise on Shift", GL 86-04

201. Westinghouse, "Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel," WCAP-14655, Revision 1, August 1996.

202. NEI 06-13A, Template for an Industry Training Program Description, Nuclear Energy Institute, Revision 2, March 2009.

13.2A — Cold License Training Plan

LICENSED OPERATOR TRAINING PROGRAM PRIOR TO COMPLETION OF THE FIRST REFUELING OUTAGE

Prior to operation, plant experience requirements specified in Regulatory Guide 1.8 (Revision 3) and ANSI/ANS 3.1-1993 cannot be met. Additionally, other standard guidance for operator selection, training, and qualification cannot be met.

Cold licensing of operators provides the method for operations personnel to acquire the knowledge and experience required for licensed operator duties during the unique conditions of new plant construction and initial operation.

Persons eligible for the cold license process shall meet the following requirements:

- Candidates for a Reactor Operator license shall have a High School Diploma or equivalent as required by R.G. 1.8 Revision 3.
- Candidates for a Senior Reactor Operator license shall have at least one of the following qualifications:
  - Previously held a Senior Reactor Operator license for an operating nuclear power plant.
  - Previously held a Reactor Operator license for an operating nuclear power plant.
  - Bachelor's Degree in engineering or science as defined by R.G. 1.8 Revision 3.
  - Experience as a licensed operator training instructor with an SRO certification. This experience will be evaluated and approved on a case by case basis by the NRC.
  - Two years military experience in a position equivalent to a reactor operator.

The provisions in this section are applicable to each unit of a multiple unit site separately.

The cold licensing process for the selection, training and licensing of Operations personnel for the new nuclear plants adheres to current industry guidance for operating plants with exemptions and alternatives in the following areas.

13.2A.1 Licensed Operator Experience Requirements Prior To Commercial Operation

Licensed operator candidates need not satisfy the experience requirements prior to entering a licensed operator training program. Experience and plant evolution requirements that have not been met at the time the licensed operator examination is administered shall be met prior to issuing the individual's NRC operator license. In such a case, the Licensee will notify the NRC when the candidate meets the experience and plant evolution requirements.

The methods listed below provide the licensed operator candidate with meaningful experience on the reactor for which the license is sought. Methods for gaining meaningful experience include completing systematically designed training courses, and participating in practical work assignments such as preoperational testing, procedure development and validation, human factors engineering activities, task analysis verification, or conducting licensed operator classroom or simulator training. Additionally, for these activities to be considered meaningful, they must be associated with safety significant, defense-in-depth, or other major plant components or systems. All cold licensed operator candidates will:

- Complete a systematically designed site layout course.
- Complete a site-specific non-licensed operator on-the-job training program on selected non-licensed operator tasks. The selected non-licensed operator tasks are those tasks that are important to plant operation with regard to nuclear safety, defense-in-depth, or that are risk significant.
- Participate in practical work assignments for a minimum of six months that includes preoperational testing, and one or more of the following:
  - Procedure development and validation
  - Human factors engineering activities
  - Task analysis verification
  - Licensed operator classroom presentations or simulator training implementation

Senior reactor operator cold license candidates will complete a site-specific reactor operator and senior reactor operator training course.

Senior reactor operator cold license candidates without "hot" plant experience will complete a plant operational excellence course that is conducted in a plant simulator or they will observe control room activities at an operating nuclear plant for at least six weeks. The course and the observation activity are designed to familiarize the candidate with the operational interfaces encountered by decision makers in a nuclear plant control room.

Hot plant experience is defined as performance of senior reactor operator duties for at least six months including:

- At least 6 weeks of operation above 20 percent power
- A startup from subcritical to 20 percent power
- A shutdown from above 20 percent power to cold (less than 212°F) and subcritical
- Startup preparations following a fueling or refueling outage

The startup, shutdown, and startup preparations may have been performed at an operating plant or a plant simulator.

Table 13.2A-201, Comparison of Hot and Cold License Guidance, shows the current experience requirement and the associated cold license experience method. Table 13.2A-202, Illustration of Cold Licensing Plan by Candidate Type, shows education and experience methods for each licensed operator candidate type.

13.2A.2 Crew Experience Requirements during First Year of Operation

Each operating crew's cumulative nuclear power plant experience shall be > 6 years; and the crew's cumulative power plant experience shall be > 13 years.

The crew's cumulative nuclear power plant experience is gained by working at nuclear power plants and military nuclear propulsion plants, conducting licensed operator training, participating in new nuclear plant construction and testing, and completing academic degree requirements. The

cumulative crew nuclear power plant experience is the sum of each individual's experience after applying weighting factors and maximum credit limits in Table 13.2A-201, Cumulative Nuclear Power Plant Operating Crew Experience Equivalencies.

When determining cumulative nuclear power plant experience, all 6 years shall not be attributed from one crew member.

The crew's cumulative power plant experience is the sum of each individual's power plant experience. Power plant experience, for example, is experience gained by working at nuclear power plants, conventional power plants, and military propulsion plants. Cumulative power plant experience does not involve weighting factors or maximum credit limits.

In addition to the experience requirement mentioned above, each operating crew shall be staffed with a senior reactor operator with hot plant experience (previously defined in 1.1, Licensed Operator Experience Requirements Prior to Commercial Operation). If a senior reactor operator with hot plant experience is not available, then a shift advisor may be substituted. The shift advisor will have at least one year of on-shift licensed senior reactor operator experience at a similar type (PWR/BWR) operating plant, and will have completed a training program on the design for which they are advising. While observing crew performance, the shift advisor will make recommendations to the shift manager only, and will not interfere with the licensed responsibilities of the operating crew. The shift advisor will have direct access to plant senior management to resolve issues. Shift advisor duties include, but are not limited to the following:

- Monitor procedure adherence
- Observe the conduct of prejob briefs shift turnover, plant evolutions, non- licensed operator rounds, plant tours, and post job debriefs
- Monitor overall station risk

Weighting factors and maximum credit limits for determining cumulative nuclear power plant operating crew experience are shown in Table 13.2A-203, Cumulative Nuclear Power Plant Operating Crew Experience Equivalencies.

13.2A.3 Conduct of On-the-Job Training (OJT)

Until plant construction is completed, acceptable methods for the conduct of on-the-job training include discussion, simulation, and use of mockup equipment and virtual reality technology.

13.2A.4 Use of Part-Task/Limited Scope Simulators

Part-task or limited scope simulators may be used during licensed operator training.

13.2A.5 Licensed Operator Continuing Training

Licensed operator continuing training begins within 90 days following the issuance of the first operator license. Continuing training content is systematically determined to maintain operator knowledge of plant operation.

13.2A.6 Cold Licensing Process Applicability and Termination

The cold licensing process described in this document may be applied to each unit of a multi-unit site.

Cold license guidance items 1 through 9 on Table 13.2A-201 will apply to any licensed operator training class started prior to initial fuel load.

Cold license guidance items 3 through 9 on Table 13.2A-201 will apply to any licensed operator training class started after initial fuel load and before completion of the first refueling outage. Items 1 and 2 cold license guidance are no longer allowable after initial fuel load.

The cold licensing process will terminate after completion of the first refueling outage.

As plant systems, components, and structures are completed, and as integrated plant operations begin, the systematic approach to training process will be used to adjust cold license class training methods and settings used to implement the guidance in Table 13.2A-201 items 1 through 9. The purpose is to optimize student learning using actual in-plant training and experience opportunities as they become available.

13.2A.7 Initial Licensed Operator Examination Schedule

Administration of licensed operator examinations begins approximately 18 months prior to fuel load.

13.2A.8 References

13.2-201. Nuclear Energy Institute (NEI), "Technical Report on a Template for an Industry Training Program Description," NEI 06-13A

Table 13.2A-201
Comparison of Hot and Cold License Guidance

Current Hot License Guidance	Applicable Position	References	Cold License Guidance
1. Six months on-site at reactor for which license is sought.	All	ANSI 3.1-1993; 4.4.1 4.4.2 4.5.1. Regulatory Guide 1.8 Rev 3: 2.8 2.10. NUREG 1021 Rev 9 ES-202	Six months practical work assignments and Complete a site layout course
2. One year on-site at the reactor for which the license is sought with six months as a nonlicensed operator.	Reactor operator	ANSI 3.1-1993: 4.5.1. Regulatory Guide 1.8 Rev 3: 2.10. NUREG 1021 Rev 9 ES-202	Six months practical work assignments and Complete a site layout course and Complete a site-specific non-licensed operator training program for selected nonlicensed operator tasks

Table 13.2A-201
Comparison of Hot and Cold License Guidance

Current Hot License Guidance	Applicable Position	References	Cold License Guidance
3. Pre-requisite experience requirements must be met to enter training program.	All	NUREG 1021 Rev 9 ES-202 Section D.	Applicable experience requirements shall be met prior to NRC license issuance.
4. Three years power plant experience at least one of which should have been at the plant for which the license is sought.	Reactor operator	ANSI 3.1-1993: 4.5.1 Regulatory Guide 1.8 Rev 3: 2.10 NUREG 1021 Rev 9 ES-202	Six months practical work assignments and Cumulative operating crew experience requirements apply
5. Reactor operator license actively involved in the performance of licensed duties for at least one year.	Senior reactor operator (Non-degreed)	Regulatory Guide 1.8 Rev 3: 2.8 NUREG 1021 Rev 9 ES-202	Complete a site layout course and Complete a site-specific non-licensed operator training program for selected nonlicensed operator tasks and Complete a reactor operator and senior reactor operator training course

Table 13.2A-201
Comparison of Hot and Cold License Guidance

Current Hot License Guidance	Applicable Position	References	Cold License Guidance
6. At least three years of responsible nuclear power plant experience.	Senior reactor operator (Degreed)	Regulatory Guide 1.8 Rev 3: 1.3 2.8	Complete a site layout course and Complete a site-specific non-licensed operator training program for selected nonlicensed operator tasks and Complete a reactor operator and senior reactor operator training course
7. At least six weeks of operation above 20% power, and startup from subcritical to 20% power, and shutdown from above 20% power to cold (less than 212°F) and subcritical, and startup preparations following a fueling or refueling outage.	Shift Supervisor (Shift Manager)	ANSI 3.1-1993: 4.4.1	Cumulative Operating Crew Experience requirements apply and Complete a Plant Operational Excellence Course or plant observation activity

Table 13.2A-201
Comparison of Hot and Cold License Guidance

Current Hot License Guidance	Applicable Position	References	Cold License Guidance
8. At least six weeks of operation above 20% power.	Senior reactor operator	ANSI 3.1-1993: 4.4.2	Cumulative Operating Crew Experience requirements apply and Complete a Plant Operational Excellence Course or plant observation activity
9. Three years power plant experience and three years nuclear power plant experience	Senior reactor operator	ANSI 3.1-1993 4.4.1 4.4.2 Regulatory Guide 1.8 Rev 3: 2.8 NUREG 1021 Rev 9 ES-202	Six months practical work assignments and Cumulative Operating Crew Experience requirements apply

Table 13.2A-202
Illustration of Cold Licensing Plan by Candidate Type

License Candidate	Education	Site Layout Course	NLO Task Training	RO Training	SRO Training	Plant Operational Excellence Course or Observation Activity	Six Months Practical Work Assignments (1)
Reactor operator	High school diploma	Yes	Yes	Yes	N/A	N/A	Yes
Senior reactor operator – degreed manager or degreed nonlicensed operator or technical staff	Bachelor of Science or equivalent in engineering, engineering technology, or physical science	Yes	Yes	Yes	Yes	Yes	Yes
Senior reactor operator – previous license or military equivalent	High school diploma	Yes	Yes	Yes	Yes	Yes (2)	Yes
Senior reactor operator – certified instructor	High school diploma	Yes	Yes	Yes	Yes	Yes	Yes

(1): practical work assignments includes activities such as participating in preoperational testing, procedure development and validation, human factors engineering activities, and task analysis verification, or conducting licensed operator classroom or simulator training

(2): No, if candidate has hot license experience

Table 13.2A-203
Cumulative Nuclear Power Plant Operating Crew Experience Equivalencies (1)

Type of Experience	Weighting Factor	Max Credit	Justification
1. Commercial Nuclear Plant RO/SRO on same type plant (PWR/BWR)	1.00	No Limit	Task Analysis for same type plant are essentially the same
2. Commercial Nuclear Plant RO/SRO from different type plant (PWR/BWR)	0.75	No Limit	Task Analysis demonstrates that 75% of PWR/BWR tasks are similar
3. Military Nuclear Propulsion Plant Experience (Propulsion Plant Watch Officer, Engineering Watch Supervisor, Reactor Operator, Engineering Officer of the Watch, Propulsion Plant Watch Supervisor)	0.5	36 months	For these military nuclear propulsion plant watch qualifications, approximately 50% of the job tasks are similar
4. Military Nuclear Propulsion Plant Experience (Other than watch qualifications in 3 above such as Machinist Mate, Electricians Mate, Engineering Laboratory Technician, or Electronics Technician)	0.25	36 months	For these (other) watch qualifications, a range of similarities between job tasks (25-75%) exists, so a conservative value of 25% is credited

Table 13.2A-203
Cumulative Nuclear Power Plant Operating Crew Experience Equivalencies (1)

Type of Experience	Weighting Factor	Max Credit	Justification
5. Reference Plant Simulator	5.00	12 months	Industry analysis demonstrated that activities completed in a simulator, compare to an operating Control Room, occur in a ratio of approx. 400/1
6. Limited Scope Simulator	3.00	9 months	Similar to Reference Plant
7. Actual nuclear plant experience during construction	0.25	12 months	Approximately 25% of the tasks during construction testing in preparation for system turnover to operations is similar to an operating facility
8. Actual nuclear plant experience during pre-operational testing	0.75	12 months	75% of tasks during pre- operational testing are similar to an operating facility
9. Actual nuclear plant experience during fuel load and startup testing	1.00	12 months	Tasks during initial startup are similar to operating facility

Table 13.2A-203
Cumulative Nuclear Power Plant Operating Crew Experience Equivalencies (1)

Type of Experience	Weighting Factor	Max Credit	Justification
10. License Classroom training	0.25	9 months	Theory of ops and specific plant design knowledge is critical to an operator's success
11. Participation in operator duties at another commercial nuclear facility. This includes nonlicensed operator duties	0.75	12 months	Task similarities
12. Other Nuclear Plant experience	0.25	12 months	Procedure writing, facility operation (water plant and other support facilities, etc)
13. Licensed operator instructor	0.50	12 months	Instructors will have participated in a train-the- trainer program that includes simulator, classroom (systems, theory).
14. Bachelors Degree in an Engineering, Science or Technical field	n/a	24 months	College work (in these fields) gives student an understanding of the fundamentals of plant operations

Table 13.2A-203
Cumulative Nuclear Power Plant Operating Crew Experience Equivalencies (1)

Type of Experience	Weighting Factor	Max Credit	Justification
15. Associates Degree (technical)	n/a	6 months	Student gains knowledge of fundamentals

(1): Weighting factors and max credit values based on those in “Industry Evaluation of Operating Shift Experience Requirements” By: J.H. Miller Jr. 2/24/1984, and endorsed by Generic Letter number 84-16, Adequacy of On-Shift Operating Experience For Near Term Operating License Applicants, except for shaded rows which are added experience types based on new technology or additional analysis.

13.3 Emergency Planning

See the Emergency Plan for the locations of the Technical Support Center and the Operations Support Center. See Subsection 1.2.5 for the location of the decontamination facilities. See Section 9.4 for a description of the HVAC systems for the main control room/control support area and the annex building. See Section 18.8 for the high level requirements for the technical support center and the operations support center. See Section 7.5 for identification of plant variables that are provided for interface to the emergency planning areas.

Communication interfaces among the main control room, the technical support center and the emergency planning centers are discussed below and in the Emergency Plan.

Staffing of the emergency operations facility occurs consistent with current operating practice and with revision 1 of NUREG-0654/FEMA-REP-1.

The emergency planning information is submitted to the Nuclear Regulatory Commission as a separate licensing document.

Post-72 hour support actions, as discussed in Subsections 1.9.5.4 and 6.3.4, are addressed in Subsections 6.2.2, 8.3, and 9.1.3. Provisions for establishing post-72 hour ventilation for the main control room, instrumentation and control rooms, and dc equipment rooms are established in operating procedures.

The emergency plan describes the plans for coping with emergency situations, including communications interfaces and staffing of the emergency operations facility.

Table 13.4-201 provides milestones for emergency planning implementation.

13.3.1 Combined License Information Item

Emergency planning including post-72 hour actions and its communication interface are addressed in Section 13.3.

Activation of the emergency operations facility consistent with current operating practice and NUREG-0654/FEMA-REP-1 is addressed in Section 13.3 and in the Emergency Plan.

13.4 Operational Programs

Operational programs are specific programs that are required by regulations. Table 13.4-201 lists each operational program, the regulatory source for the program, the section of the FSAR in which the operational program is described, and the associated implementation milestone(s).

13.4.1 Combined License Information Item

Operational programs are addressed in Section 13.4.

13.4.2 References

201. ASME Boiler and Pressure Vessel Code (B&PVC), “Section XI - Rules for Inservice Inspection of Nuclear Power Plant Components.”

202. ASME “OM Code for the Operation and Maintenance of Nuclear Power Plants.”

Table 13.4-201 (Sheet 1 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation Milestone	Implementation Requirement
1.	Inservice Inspection Program	10 CFR 50.55a(g)	5.2.4, 5.4.2.5, 6.6	Prior to Commercial service	10 CFR 50.55a(g), ASME XI IWA-2430(b) (Reference 201)
2.	Inservice Testing Program	10 CFR 50.55a(f); 10 CFR Part 50, Appendix A	3.9.6, 5.2.4	After generator online on nuclear heat[(a)]	10 CFR 50.55a(f), ASME OM Code (Reference 202)
3.	Environmental Qualification Program	10 CFR 50.49(a)	3.11	Prior to initial fuel load	License Condition
4.	Preservice Inspection Program	10 CFR 50.55a(g)	5.2.4, 5.4.2.5, 6.6	Completion prior to initial plant start-up	10 CFR 50.55a(g); ASME XI IWB-2200(a) (Reference 201)
5.	Reactor Vessel Material Surveillance Program	10 CFR 50.60; 10 CFR 50.61; 10 CFR Part 50, Appendix H	5.3.2.6	Prior to initial criticality	License Condition
6.	Preservice Testing Program	10 CFR 50.55a(f)	3.9.6	Prior to initial fuel load	License Condition

Table 13.4-201 (Sheet 2 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation Milestone	Implementation Requirement
7.	Containment Leakage Rate Testing Program	10 CFR 50.54(o); 10 CFR 50, Appendix A (GDC 52); 10 CFR 50, Appendix J	6.2.5.1	Prior to initial fuel load	License Condition
8.	Fire Protection Program	10 CFR 50.48	9.5.1.8	Prior to receipt of fuel onsite Prior to initial fuel load	License Condition
	(portions applicable to radioactive material)	10 CFR 30.32 10 CFR 40.31 10 CFR 70.22		Prior to initial receipt of byproduct, source, or special nuclear materials (excluding Exempt Quantities as described in 10 CFR 30.18)	10 CFR 30.32(a) 10 CFR 40.31(a) 10 CFR 70.22(a)
9.	Process and Effluent Monitoring and Sampling Program:				
	Radiological Effluent Technical Specifications/Standard Radiological Effluent Controls	10 CFR 20.1301 and 20.1302; 10 CFR 50.34a; 10 CFR 50.36a; 10 CFR 50, Appendix I, Section II and IV	11.5	Prior to initial fuel load	License Condition
	Offsite Dose Calculation Manual	Same as above	11.5	Prior to initial fuel load	License Condition

Table 13.4-201 (Sheet 3 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation Milestone	Implementation Requirement
	Radiological Environmental Monitoring Program	Same as above	11.5	Prior to initial fuel load	License Condition
	Process Control Program	Same as above	11.4	Prior to initial fuel load	License Condition
10.	Radiation Protection Program (including ALARA principle)	10 CFR 20.1101 10 CFR 20.1406 10 CFR Part 37	12.1 12.5 11.4		License Condition
	• Radioactive Source Control (assignment of RP Supervisor) • Assignment of RP Supervisor • Minimization of Contamination			1. Prior to initial receipt of by-product, source, or special nuclear materials (excluding Exempt Quantities as described in 10 CFR 30.18)	
	• Personnel Dosimetry • Radiation Monitoring and Surveys • Radiation Work Permits			2. Prior to receipt of fuel onsite	
	• Assignment of RP Manager • Respiratory Protection • Bioassay			3. Prior to initial fuel load	

Table 13.4-201 (Sheet 4 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation Milestone	Implementation Requirement
	• Effluents and Environmental Monitoring and Assessment				
	• Job Coverage				
	• Radioactive Waste Shipping			4. Prior to first shipment of radioactive waste	
11.	Non Licensed Plant Staff Training Program	10 CFR 50.120	13.2	18 months prior to scheduled date of initial fuel load	10 CFR 50.120(b)
	(portions applicable to radioactive material)	10 CFR 30.32 10 CFR 40.31 10 CFR 70.22		Prior to initial receipt of byproduct, source, or special nuclear materials (excluding Exempt Quantities as described in 10 CFR 30.18)	10 CFR 30.32(a) 10 CFR 40.31(a) 10 CFR 70.22(a)
12.	Reactor Operator Training Program	10 CFR 55.13; 10 CFR 55.31; 10 CFR 55.41; 10 CFR 55.43; 10 CFR 55.45	13.2	18 months prior to scheduled date of initial fuel load	License Condition
13.	Reactor Operator Requalification Program	10 CFR 50.34(b); 10 CFR 50.54(i); 10 CFR 55.59	13.2	Within 3 months after the date the Commission makes the finding under 10 CFR 52.103(g)	10 CFR 50.54 (i-1)

Table 13.4-201 (Sheet 5 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation Milestone	Implementation Requirement
14.	Emergency Planning	10 CFR 50.47; 10 CFR 50, Appendix E	13.3	Full participation exercise conducted within 2 years of scheduled date for initial loading of fuel.*	10 CFR Part 50, Appendix E, Section IV.F.2.a(ii)
				Onsite exercise conducted within 1 year before the schedule date for initial loading of fuel	10 CFR Part 50, Appendix E, Section IV.F.2.a(ii)
				Applicant's detailed implementing procedures for its emergency plan submitted at least 180 days prior to scheduled date for initial loading of fuel	10 CFR Part 50, Appendix E, Section V
15.	Security Program:				
	Physical Protection Program (applicable to protection of special nuclear material prior to the protected area being declared operational)	10 CFR 73.1 10 CFR 73.67	13.5.2.2.8 13.6	Prior to initial receipt of special nuclear material	10 CFR 73.1(a) 10 CFR 73.67
	Physical Security Program	10 CFR 73.55(b); 10 CFR 73.55(c)(3); 10 CFR 73.56; 10 CFR 73.57;	13.6	Prior to initial fuel load into the reactor[(b)]	NRC exemption dated November 23, 2021

* License Amendments 95 and 94 for VEGP Units 3 and 4, respectively, approved a change such that the VEGP 3 and 4 exercises will be partial participation exercises. As permitted by 10 CFR Part 50, Appendix E, Section IV.F.2.a(iii), the full participation exercise requirement will be satisfied by the biennial exercise conducted for VEGP Units 1 and 2. VEGP Unit 4 is exempt from the requirement to perform the partial participation exercise, because the exercise is duplicative of the Unit 3 exercise. (See exemption ML20126G297 granted by the NRC on 07-21-2020).

Table 13.4-201 (Sheet 6 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation Milestone	Implementation Requirement
	Safeguards Contingency Program	10 CFR 73.55(c)(5); 10 CFR 73.55(k); 10 CFR Part 73, Appendix C	13.6	Prior to initial fuel load into the reactor[(b)]	NRC exemption dated November 23, 2021
	Training and Qualification Program	10 CFR 73.55(c)(4); 10 CFR 73.55(d)(3); 10 CFR Part 73, Appendix B	13.6	Prior to initial fuel load into the reactor[(b)]	NRC exemption dated November 23, 2021
16.	Quality Assurance Program – Operation	10 CFR 50.54(a); 10 CFR Part 50, Appendix A (GDC 1); 10 CFR Part 50, Appendix B	17.5	COL issuance	10 CFR 50.54(a)(1)
17.	Maintenance Rule	10 CFR 50.65	17.6	Prior to fuel load authorization per 10 CFR 52.103(g)	10 CFR 50.65(a)(1)
18.	Motor-Operated Valve Testing	10 CFR 50.55a(b)(3)(ii)	3.9.6	Prior to initial fuel load	License Condition

Table 13.4-201 (Sheet 7 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation	
				Milestone	Requirement
19.	Initial Test Program	10 CFR 50.34; 10 CFR 52.79(a)(28)	14.2	Prior to the first preoperational test for the Preoperational Test Program Prior to initial fuel load for the Startup Test Program	License Condition
20.	Fitness for Duty (FFD) Program for Construction (workers and first-line supervisors)	10 CFR 26.4(f)	13.7	Prior to initiating 10 CFR Part 26 construction activities	10 CFR Part 26, Subpart K
	FFD Program for Construction (management and oversight personnel)	10 CFR 26.4(e)	13.7	Prior to initiating 10 CFR Part 26 construction activities	10 CFR Part 26, Subparts A – H, N, and O

Table 13.4-201 (Sheet 8 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation Milestone	Implementation Requirement
	FFD Program for Security Personnel	10 CFR 26.4(e)(1)	13.7	Prior to initiating 10 CFR Part 26 construction activities	10 CFR Part 26, Subparts A – H, N, and O
		10 CFR 26.4(a)(5) or 26.4(e)(1)		Prior to the earlier of: A. Licensee's receipt of SNM in the form of fuel assemblies, or B. Establishment of a protected area(c)	10 CFR Part 26, Subparts A – I, N, and O
	FFD Program for FFD Program personnel	10 CFR 26.4(g)	13.7	Prior to initiating 10 CFR Part 26 construction activities	10 CFR Part 26, Subparts A, B, D – H, N, O, and C per licensee's discretion
	FFD Program for persons required to physically report to the Technical Support Center (TSC) or Emergency Operations Facility (EOF)	10 CFR 26.4(c)	13.7	Prior to the conduct of the first full-participation emergency preparedness exercise under 10 CFR Part 50, App. E, Section F.2.a	10 CFR Part 26, Subparts A – I, N, and O, except for §§ 26.205 – 209

Table 13.4-201 (Sheet 9 of 9)
Operational Programs Required by NRC Regulations

Item	Program Title	Program Source (Required by)	FSAR Section	Implementation Milestone	Implementation Requirement
	FFD Program for Operation	10 CFR 26.4(a) and (b)	13.7	Prior to establishment of a protected area[(c)]	10 CFR Part 26, Subparts A – I, N, and O, except for individuals listed in § 26.4(b), who are not subject to §§ 26.205 – 209
21.	Cyber Security Program	10 CFR 73.54(b); 10 CFR 73.55(b)(8); 10 CFR 73.55(c)(6)	13.6	Prior to initial fuel load into the reactor[(b)]	NRC exemption dated November 23, 2021
22.	SNM Material Control and Accounting Program	10 CFR 74, Subpart B (§§ 74.11 – 74.19, excl. § 74.17)	13.5.2.2.9	Prior to receipt of special nuclear material	License Condition
23.	10 CFR Part 37 Physical Protection Program	10 CFR 37 Subparts A, B, C, D, F	13.5.2.2.8, 13.5.2.2.10 13.6, 11.4	Prior to possession of aggregated category 1 or category 2 quantity of radioactive material	10 CFR Part 37

(a) Inservice Testing Program will be fully implemented by generator on line on nuclear heat. Appropriate portions of the program are implemented as necessary to support the system operability requirements of the technical specifications.

(b) VEGP Units 3 and 4 is exempt from the 10 CFR 73.55(a)(4) and 10 CFR 73.56(a)(3) requirements to implement these Programs, including the Access Authorization Program required by §73.56, prior to the receipt of fuel onsite (protected area). (See exemption granted by the NRC on November 23, 2021 [ML21320A043].)

(c) See exemption granted by the NRC on December 21, 2021 [ML21334A417], which removed the 10 CFR 52.103(g) finding as a Milestone.

13.5 Plant Procedures

This section describes the administrative and other procedures that the operating organization (plant staff) uses to conduct the routine operating, abnormal, and emergency activities in a safe manner.

The Quality Assurance Program Description (QAPD), as discussed in Section 17.5, describes procedural document control, record retention, adherence, assignment of responsibilities, and changes.

Procedures are identified in this section by topic, type, or classification in lieu of the specific title and represent general areas of procedural coverage.

Procedures are issued prior to fuel load to allow sufficient time for plant staff familiarization and to develop operator licensing examinations.

The format and content of procedures are controlled by the applicable AP1000 Writer's Guideline. Upon site acceptance of these procedures, the format and content will be controlled per plant specific administrative procedures.

Each procedure is sufficiently detailed for an individual to perform the required function without direct supervision, but does not provide a complete description of the system or plant process. The level of detail contained in the procedure is commensurate with the qualifications of the individual normally performing the function.

Procedures are developed consistent with guidance described in Section 18.9, "Procedure Development" and with input from the human factors engineering process and evaluations.

References to applicable combined license information are included in Section 1.8. This includes, for example, reference to guidelines on inservice inspection in Chapters 3 and 8, and initial testing in Chapter 14. Operational experience and the resolution of generic issues to be considered in the preparation of plant procedures are outlined in Section 1.9. All portions of the safety-related logic circuitry will be adequately covered in the surveillance procedures as described in Generic Letter 96-01 (Reference 8).

The acceptability of the computerized procedure system, and its backup, for application to the AP1000 design will be determined as outlined in Section 18.8.

The development of plant specific refueling plans (Appendix 19E provides input for refueling plans) is as discussed in Subsection 13.5.2.1.

Outage plans are discussed in Subsection 13.5.2.1 and should as a minimum address the following elements:

- An outage philosophy, which includes safety as a primary consideration in outage planning and implementation,
- Separate organizations responsible for scheduling and overseeing the outage; provisions for an independent safety review team that would be assigned to perform final review and grant approval for outage activities,
- Control procedures, which address both the initial outage plan and all safety-significant changes to schedule,
- Provisions to ensure that all activities receive adequate resources,

- Provisions to ensure defense-in-depth during shutdown and ensure that margins are not reduced; an alternate or backup system must be available if a safety system or a defense-in-depth system is removed from service, and

- Provisions to ensure that all personnel involved in outage activities are adequately trained; this should include operator simulator training to the extent practicable; other plant personnel, including temporary personnel, should receive training commensurate with the outage tasks they will be performing.

If freeze seals are to be used, plant-specific guidelines will be developed to reduce the potential for loss of RCS boundary and inventory when they are in use.

13.5.1 Administrative Procedures

This section describes administrative procedures that provide administrative control over activities that are important to safety for the operation of the facility.

Procedures outline the essential elements of the administrative programs and controls as described in ANSI/ANS 3.2-1988 (Reference 201) and in Section 17.5. These procedures are organized such that the program elements are prescribed in documents normally referred to as administrative procedures. Regulatory and industry guidance for the appropriate format, content and typical activities delineated in written procedures is implemented as appropriate.

Administrative procedures contain adequate programmatic controls to provide effective interface between organizational elements. This includes contractor and owner organizations providing support to the station operating organization.

A Writer's Guideline promotes the standardization and application of human factors engineering principles to procedures. The Writer's Guideline establishes the process for developing procedures that are complete, accurate, consistent, and easy to understand and follow. The Writer's Guideline provides objective criteria so that procedures are consistent in organization, style, and content. The Writer's Guideline includes criteria for procedure content and format including the writing of action steps and the specification of acceptable acronym lists and acceptable terms to be used.

Procedure maintenance and control of procedure updates are performed in accordance with the QAPD, as discussed in Section 17.5.

The administrative programs and associated procedures developed in the pre-COL phase are described in Table 13.5-201 (for future designation as historical information).

The plant administrative procedures provide procedural instructions for the following:

- Procedures review and approval.

- Equipment control procedures - These procedures provide for control of equipment, as necessary, to maintain personnel and reactor safety, and to avoid unauthorized operation of equipment.

- Control of maintenance and modifications.

- Crane Operation Procedures - Crane operators who operate cranes over fuel pools are qualified and conduct themselves in accordance with ANSI B30.2 (Chapter 2-3), "Overhead and Gantry Cranes" (Reference 202).

- Temporary changes to procedures.
- Temporary procedure issuance and control.
- Special orders of a temporary or self-canceling nature.
- Standing orders to shift personnel including the authority and responsibility of the shift manager, licensed senior reactor operator in the control room, control room operator and shift technical advisor.
- Manipulation of controls and assignment of shift personnel to duty stations per the requirements of 10 CFR 50.54 (i), (j), (k), (l), and (m) including delineation of the space designated for the “At the Controls” area of the control room.
- Shift relief and turnover procedures.
- Fitness for Duty.
- Control Room access.
- Working hour limitations.
- Feedback of design, construction, and applicable important industry and operating experience.
- Shift Manager administrative duties.
- Verification of correct performance of operational activities.
- A vendor interface program that provides vendor information for safety related components is incorporated into plant documentation.
- Fire protection program implementation.
- A process for implementing the safety/security interface requirements of 10 CFR 73.58.

13.5.2 Operating and Maintenance Procedures

13.5.2.1 Operating and Emergency Operating Procedures

The process to manage the development, review, and approval of AP1000 Normal Operating, Abnormal Operating, Emergency Operating, Refueling and Outage Planning, Alarm Response, Administrative, Maintenance, Inspection, Test, and Surveillance Procedures, as well as the procedures which address the operation of post-72 hour equipment, is delineated in APP-GW-GLR-040 (Reference 10). In addition, APP-GW-GLR-040 provided to the NRC the Writer’s Guidelines for Normal Operating and Two-Column Format Procedures, APP-GW-GJP-100 and APP-GW-GJP-200, respectively.

Upon site review and acceptance of the procedures delineated above, these procedures become site specific. The development, review, and approval of these site specific procedures will be controlled per plant specific processes/procedures.

13.5.2.2 Maintenance and Other Operating Procedures

The QAPD, as described in Section 17.5, provides guidance for procedural adherence. Regulatory and industry guidance for the appropriate format, content, and typical activities delineated in written procedures is implemented as appropriate.

13.5.2.2.1 Plant Radiation Protection Procedures

The plant radiation protection program is contained in procedures. Procedures are developed and implemented for such things as: maintaining personnel exposures, plant contamination levels, and plant effluents ALARA; monitoring both external and internal exposures of workers, considering industry-accepted techniques; routine radiation surveys; environmental monitoring in the vicinity of the plant; radiation monitoring of maintenance and special work activities; evaluation of radiation protection implications of proposed modifications; establishing quality assurance requirements applicable to the radiation protection program; and maintaining radiation exposure records of workers and others.

13.5.2.2.2 Emergency Preparedness Procedures

A discussion of emergency preparedness procedures can be found in the Emergency Plan.

13.5.2.2.3 Instrument Calibration and Test Procedures

The QAPD, as discussed in Section 17.5, provides a description of procedural requirements for instrumentation calibration and testing.

13.5.2.2.4 Chemistry Procedures

Procedures provided for chemical and radiochemical control activities include the nature and frequency of sampling and analyses; instructions for maintaining fluid quality within prescribed limits; the use of control and diagnostic parameters; and limitations on concentrations of agents that could cause corrosive attack, foul heat transfer surfaces or become sources of radiation hazards due to activation.

Procedures are also provided for the control, treatment, and management of radioactive wastes and control of radioactive calibration sources.

13.5.2.2.5 Radioactive Waste Management Procedures

Procedures for the operation of the radwaste processing systems provide for the control, treatment, and management of on-site radioactive wastes. Procedural controls are in place for radiological releases.

Operating procedures to limit the total cumulative radioactive inventory of unpackaged wastes located in the radwaste building will be developed, implemented, and maintained prior to initial fuel load. These operating procedures are based on monitoring and controlling the radioactive inventory of unpackaged wastes so that the Regulatory Guide 1.143 unmitigated radiological release criteria of 5 rem to site personnel, and the 10 CFR Part 20.1301 dose limits of 100 millirem at the protected area boundary for members of the public, are not exceeded. These administrative controls limit the radionuclide inventory to less than the A2 limit specified in Appendix A to 10 CFR Part 71 in the radwaste building. Further details regarding administrative controls of unpackaged radioactive waste located in the radwaste building are described in Section 11.2.

13.5.2.2.6 Maintenance, Inspection, Surveillance, and Modification Procedures

13.5.2.2.6.1 Maintenance Procedures

Maintenance procedures describe maintenance planning and preparation activities. Maintenance procedures are developed considering the potential impact on the safety of the plant, license limits, availability of equipment required to be operable, and possible safety consequences of concurrent or sequential maintenance, testing or operating activities.

Maintenance procedures contain sufficient detail to permit the maintenance work to be performed correctly and safely. Procedures include provisions for conducting and recording results of required tests and inspections, if not performed and documented under separate test and inspection procedures. References are made to vendor manuals, plant procedures, drawings, and other sources as applicable.

Instructions are included, or referenced, for returning the equipment to its normal operating status. Testing is commensurate with the maintenance that has been performed. Testing may be included in the maintenance procedure or be covered in a separate procedure.

The preventive maintenance program, including preventive and predictive procedures, as appropriate for structures, systems and components, prescribes the frequency and type of maintenance to be performed. An initial program based on service conditions, experience with comparable equipment and vendor recommendations is developed prior to fuel loading. The program is revised and updated as experience is gained with the equipment. To facilitate this, equipment history files are created and kept current. The files are organized to provide complete and easily retrievable equipment history.

13.5.2.2.6.2 Inspection Procedures

The QAPD, as discussed in Section 17.5, provides a description of procedural requirements for inspections.

13.5.2.2.6.3 Modification Procedures

Plant modifications and changes to setpoints are developed in accordance with approved procedures. These procedures control necessary activities associated with the modifications such that they are carried out in a planned, controlled, and orderly manner. For each modification, design documents such as drawings, equipment and material specifications, and appropriate design analyses are developed or the as-built design documents are utilized. Separate reviews are conducted by individuals knowledgeable in both technical and QA requirements to verify the adequacy of the design effort.

Proposed modification(s) which involve a license amendment or a change to Technical Specifications are processed as proposed license amendment request(s).

Plant procedures impacted by modifications are changed prior to declaring the system operable to reflect revised plant conditions; and cognizant personnel who are responsible for operating and maintaining the modified equipment are adequately trained.

13.5.2.2.6.4 Surveillance Procedures

Procedures to perform rod control system surveillance tests specified below (from Reference 7, Section 4.8.2), at the beginning of each fuel cycle are provided as discussed in Subsection 13.5.1.

The recommended additional surveillance tests to meet the detectability requirement is as follows:

- Once per cycle, verify that correct current orders are being generated for each group of control and shutdown rods. It is recommended that the surveillance be performed during the rod drop timing test. Essentially, the same equipment and personnel are required for both tests. With proper coordination, performing the two together will not result in any additional plant down time.

- It is recommended that the test be performed by monitoring the lift, movable and stationary currents, in the Power Cabinet, for one rod in each group, for both insertion and withdrawal. Performing the monitoring in the Power Cabinet rather than in the Logic Cabinet is recommended because this will detect any Power Cabinet failures that result in current regulation failures that also can corrupt the current profiles and affect individual rod motions within a group.

- While a bank of rods is being withdrawn for the rod drop test, record a few steps of the lift, movable and stationary withdrawal current profiles of one rod in each group. Before the rods are fully withdrawn, insert them a few steps and record the lift, movable and stationary current profiles. When the recordings have been made, continue to withdraw the rods to complete the rod drop test for that group. Verify that the current profiles are in accordance with the system design. Repeat for each shutdown and control bank.

The test being recommended verifies that correct current orders are being generated, for insertion and withdrawal, and therefore that no failures are present in the system at each startup following refueling. The justification for only performing the test once per cycle is that the failures that are required to be detected are only those that do not affect rod motion and therefore are not detectable by means of the existing rod motion surveillance requirement. In order to affect rod motion, a second failure is required. It has further been determined that all failures that affect rod motion of a single group of rods, are bounded by existing analyses. Performing the additional surveillance once per cycle, with the reactor shut down, is therefore considered appropriate.

13.5.2.2.7 Material Control Procedures

The QAPD, as discussed in Section 17.5, provides a description of procedural requirements for material control.

13.5.2.2.8 Security Procedures

A discussion of security procedures is provided in the Security Plan.

The Special Nuclear Material (SNM) Physical Protection Program describes the 10 CFR Part 70 required protection program in effect for the period of time during which new fuel as SNM is received and stored in a controlled access area (CAA), in accordance with the requirements of 10 CFR 73.67.

Fleet procedures address the applicable 10 CFR 73.67 requirements in the event that unirradiated new fuel assemblies or components are returned to the supplying fuel manufacturer(s) facility.

A 10 CFR Part 37 Physical Protection Program addresses the applicable 10 CFR Part 37 requirements to provide physical protection for an aggregated category 1 or category 2 quantity of radioactive material.

13.5.2.2.9 Special Nuclear Material (SNM) Material Control and Accounting Procedures

A material control and accounting system consisting of special nuclear material accounting procedures is utilized to delineate the requirements, responsibilities, and methods of special nuclear material control from the time special nuclear material is received until it is shipped from the plant. These procedures provide detailed steps for SNM shipping and receiving, inventory, accounting, and preparing records and reports.

13.5.2.2.10 10 CFR Part 37 Physical Protection Program Procedures

A 10 CFR Part 37 Physical Protection Program consisting of procedures is utilized to delineate the requirements, responsibilities, and methods associated with the physical protection of an aggregated category 1 or category 2 quantity of radioactive material. These procedures provide the detailed steps for receipt, use, storage, transport and preparation of records and reports.

13.5.3 Combined License Information Item

The plant procedures are addressed in APP-GW-GLR-040 (Reference 10), and the applicable changes are incorporated into the UFSAR, and in Section 13.5.

13.5.4 References

1. Not used.
2. Not used.
3. Not used.
4. Not used.
5. Not used.
6. Not used.
7. WCAP-13864, “Rod Control System Evaluation Program,” Revision 1-A, November 1994.
8. USNRC Generic Letter 96-01, “Testing of Safety-Related Logic Circuits,” January 10, 1996.
9. Not used.
10. APP-GW-GLR-040, “Plant Operations Maintenance and Surveillance Procedures,” Westinghouse Electric Company LLC.

201. ANSI/ANS 3.2-1988, “Administrative Control and Quality Assurance for the Operational Phase of Nuclear Power Plants.”

202. ANSI B30.2 (Chapter 2-3), “Overhead and Gantry Cranes.”

Table 13.5-201
Pre-COL Phase Administrative Programs and Procedures

(This table is included for future designation as historical information.)

- Design/Construction Quality Assurance Program
- Reporting of Defects and Noncompliance, 10 CFR Part 21 Program
- Design Reliability Assurance Program

13.6 Security

The Security Plan consists of the Physical Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan. The Security Plan was submitted to the Nuclear Regulatory Commission as a separate licensing document in order to fulfill the requirements for 10 CFR 52.79(a)(35) and 10 CFR 52.79(a)(36). The Security Plan meets the requirements of 10 CFR 73.55 and is maintained in accordance with the requirements of 10 CFR 52.98(c). The plan is designated as Safeguards Information and is withheld from public disclosure pursuant to 10 CFR 73.21.

The footprint area for the two new Westinghouse AP1000 units is west of, and adjacent to, the existing two units on the VEGP site. A Protected Area encompasses the new and existing units and provides a physical boundary that serves to control access to the entire VEGP site in accordance with 10 CFR 73.55. Additional elements of the physical protection program that meet the requirements of 10 CFR 73.55 include the screening of plant personnel upon entrance to the Protected Area for contraband or explosives; the detection and assessment of intrusion into the Protected Area; the operation, maintenance, and testing of security equipment; the installation of station features that deter or delay potential intrudes; the placement and protection of security personnel for response to a land-based threat against the site; the placement of a vehicle barrier system around the site to protect against a vehicle bomb threat; and liaison with local law enforcement personnel. These and other elements of the physical protection program are described within the Physical Security Plan.

Additionally, the “AP1000 Interim Compensatory Measures Report” (Reference 2), the “AP1000 Enhancement Report” (Reference 3), and the “AP1000 Safeguards Assessment Report” (Reference 4) were submitted to the Nuclear Regulatory Commission as separate licensing documents to establish the design basis of the AP1000 Standard Plant Security Systems. Each document is designated as Safeguards information and is withheld from public disclosure pursuant to 10 CFR 73.21. Subsequently, applicable information from References 2, 3, and 4 were incorporated into the Security Plan, which therefore constitutes the current licensing basis.

The characteristics of the VEGP Units 3 and 4 footprint are such that implementation of the applicable requirements of 10 CFR 73.55, “Requirements for physical protection of licensed activities in nuclear power reactors against radiological sabotage,” and NRC Regulatory Guide 4.7, “General Site Suitability Criteria for Nuclear Power Stations,” as well as the post-9/11 NRC Orders, are met. The VEGP site is sufficiently large to provide adequate distances between structures and the location of the security boundaries to allow interdiction and neutralization of threats.

The VEGP site is bordered on the east by the Savannah River. For the existing units, SNC has an approved security program in place in compliance with the post-9/11 NRC Orders and in accordance with NEI 03-12, “Template for Security Plan and Training and Qualification Plan.” In the event that new units are added to the VEGP site, those program requirements would continue to be met and would be extended to include the new units.

The final design of the VEGP Units 3 and 4 power block and supporting buildings utilizes design features as appropriate to assure that the existing security spatial distances outlined in the regulations above, as well as the Design Basis Threat requirements, are adequate. In accordance with 10 CFR 100.21(f), SNC maintains site characteristics adequate to implement security plans and measures.

There are no security hazards in the vicinity of the VEGP site. The VEGP site is located in Burke County in the State of Georgia. Written letters of agreement with the Burke County Sheriff and the Georgia State Patrol are maintained to establish for law enforcement response in the event of a VEGP security (or radiological) emergency. Examples are identified in Reference 201;

Reference 202. Burke County has mutual aid agreements with surrounding counties in place, if necessary, to provide support during VEGP emergencies.

A 10 CFR Part 37 Physical Protection Program is established, implemented, and maintained in order to protect an aggregated category 1 or category 2 quantity of radioactive material from theft or diversion per 10 CFR Part 37 requirements.

The explosive cartridge assembly used in the squib valves (see Subsection 6.3.2.2.8.9) has been determined by the Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) to be exempt (Reference 5) from the requirements of 27 CFR 555 as special explosive devices pursuant to 27 CFR 555.32 for possession and use for their intended purpose in the AP1000 nuclear reactor passive safety system. However, the explosive materials used in their manufacture are subject to the provisions of 27 CFR, Part 555. Thus, any alterations to the explosive cartridge assembly will render this exemption void and any explosive materials removed from the explosive cartridge assembly are subject to the regulations of 27 CFR 555.

The Cyber Security Plan was submitted to the Nuclear Regulatory Commission as a separate licensing document to fulfill the requirements contained in 10 CFR 52.79(a)(36) and 10 CFR 73.54. The Cyber Security Plan is maintained in accordance with the requirements of 10 CFR 52.98. The Plan is designated as Security-Related Information and is withheld from public disclosure pursuant to 10 CFR 2.390.

Table 13.4-201 provides milestones for security program, 10 CFR Part 37 physical protection program, and cyber security program implementation.

13.6.1 Combined License Information Item

Information for the Security Plan is addressed in Section 13.6.

Information for the Physical Security ITAAC is addressed in Subsection 14.3.2.3.2.

Information for the cyber security program is addressed in Section 13.6.

13.6.2 ESP COL Action Items

The specific access control measures to address the existing rail spur are addressed in Part 8, Physical Security Plan, Section 11.3.

13.6.3 References

1. Not used.

2. APP-GW-GLR-067, “AP1000 Interim Compensatory Measures Report,” Westinghouse Electric Company LLC.

3. APP-GW-GLR-062, “AP1000 Enhancement Report,” Westinghouse Electric Company LLC.

4. APP-GW-GLR-066, “AP1000 Safeguards Assessment Report,” Westinghouse Electric Company LLC.

5. U.S. Department of Justice, Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) letter to Westinghouse Electric Company, dated October 6, 2015, and associated Special Explosive Device Determination and exemption (ATF Reference No. 15-801205).

201. **(Burke County Sheriff 2004)** Burke County Sheriff's Office letter of agreement for law enforcement support for VEGP security and radiological emergencies, dated April 15, 2004.

202. **(Georgia State Patrol 2004)** Georgia State Patrol letter of agreement for law enforcement support for VEGP security and radiological emergencies, dated April 22, 2004.

13.7 Fitness for Duty

The Fitness for Duty Program (FFD) is implemented and maintained in multiple and progressive phases dependent on the activities, duties, or access afforded to certain individuals at the construction site. In general, two different FFD programs will be implemented: a construction FFD program and an operations FFD program. The construction and operations phase programs are illustrated in Table 13.4-201.

The construction FFD program is consistent with NEI 06-06 (Reference 201), as endorsed by NRC Regulatory Guide 5.84, Revision 0, as amended by the exceptions documented in Appendix 1A, and the pre-access provisions for reinstatement described in 10 CFR 26.65. NEI 06-06 applies to persons constructing or directing the construction of safety- and security-related structures, systems, or components performed onsite where the new reactor will be installed and operated. Management and oversight personnel, as further described in NEI 06-06, and security personnel prior to the receipt of special nuclear material in the form of fuel assemblies (with certain exceptions) will be subject to the operations FFD program that meets the requirements of 10 CFR Part 26, Subparts A through H, N, and O. At the establishment of a protected area, all persons who are granted unescorted access will meet the requirements of an operations FFD program. The NRC endorsed NEI 06-06 (Reference 201) and the FFD program subject to Subpart K was revised to reflect the changes.

The following site-specific information is provided:

- The construction site is defined in the Physical Security Plan, Appendix E and is under the control of SNC. The 10 CFR Part 26 requirements are implemented for the construction site area based on the descriptions provided in Table 13.4-201.
- Construction Workers & First Line Supervisors are covered by the SNC FFD Program (elements Subpart K) except when escorted by a construction escort.
- Control of construction visitors and construction escorts is described in the Appendix 1A entry for Regulatory Guide 5.84.
- SNC employees and personnel contracted for construction management and oversight are covered by the SNC FFD Program (elements Subpart A – H, N and O).
- Security personnel are covered by the SNC FFD Program (elements Subpart A – H, N and O). This coverage is applicable from the start of construction activities to the earlier of (1) the receipt of SNM in the form of fuel assemblies, (2) the establishment of a protected area, or (3) the 10 CFR 52.103(g) finding.
- FFD Program personnel are covered by the SNC FFD Program (elements Subpart A, B, D – H, N, O, and C per licensee's discretion).
- Security personnel protecting fuel assemblies, or the established protected area, or the facility following the 10 CFR 52.103(g) finding are covered by the SNC FFD Program (elements Subpart A – I, N and O).
- Personnel required to physically report to the Technical Support Center (TSC) or Emergency Operations Facility (EOF) when that requirement is in effect are covered by the SNC FFD Program (elements Subpart A – I, N, and O, except for §§ 26.205 – 209).

The operations phase FFD program is consistent with the applicable subparts of 10 CFR Part 26 (elements Subpart A – I, N, and O, except for individuals listed in §26.4(b), who are not subject to §§ 26.205 – 209.

13.7.1 References

201. Nuclear Energy Institute “Fitness for Duty Program Guidance for New Nuclear Power Plant Construction Sites,” NEI 06-06, Revision 6, April 2013 (ML13093A342).

Appendix 13AA Construction-Related Organization

The information in this appendix is included for future designation as historical information. Paragraphs are numbered to be subsequent to Subsection 13.1.1.1

13AA.1.1.1.1 Design and Construction Activities

The Westinghouse Electric Company (WEC) was originally selected to design, fabricate, deliver, and install the AP1000 advanced light water pressurized water reactors (PWR) and to provide technical direction for installation and startup of this equipment. However, during construction, Southern Nuclear Company (SNC) made a transition and is now resonsible for installation and startup of this equipment. Subsection 1.4.1 provides detailed information regarding WEC past experience in design, development, and manufacturing of nuclear power facilities. Operating experience from design, construction, and operation of earlier WEC PWRs is applied in the design, construction, and operation of the AP1000 as described in numerous locations throughout (e.g., Subsections 3.6.4.4, 3.9.4.2.1, 4.2.3.1.3).

Westinghouse provides plant construction support and additional design activities for selected site specific portions of the plant.

Other design and construction activities are generally contracted to qualified suppliers of such services. Implementation or delegation of design and construction responsibilities is described in the subsections below. Quality assurance aspects of these activities are described in Chapter 17.

13AA.1.1.1.1.1 Principal Site-Related Engineering Work

The principal site engineering activities accomplished towards the construction and operation of the plant are:

a. Meteorology

Information concerning local (site) meteorological parameters is developed and applied by station and contract personnel to assess the impact of the station on local meteorological conditions. An onsite meteorological measurements program is employed by station personnel to produce data for the purpose of making atmospheric dispersion estimates for postulated accidental and expected routine airborne releases of effluents. A maintenance program is established for surveillance, calibration, and repair of instruments. More information regarding the study and meteorological program is found in Section 2.3.

b. Geology

Information relating to site and regional geotechnical conditions is developed and evaluated by utility and contract personnel to determine if geologic conditions could present a challenge to the safety of the plant. Items of interest include geologic structure, seismicity, geological history, and ground water conditions. During construction, foundations within the power block area are mapped or visually inspected and photographed. Section 2.5 provides details of these investigations.

c. Seismology

Information relating to seismological conditions is developed and evaluated by utility and contract personnel to determine if the site location and area surrounding the site is appropriate from a safety standpoint for the construction and operation of a nuclear power plant. Information regarding tectonics, seismicity, correlation of seismicity with tectonic structure, characterization of seismic

sources, and ground motion are assessed to estimate the potential for strong earthquake ground motions or surface deformation at the site. Section 2.5 provides details of these investigations.

d. Hydrology

Information relating to hydrological conditions at the plant site and the surrounding area is developed and evaluated by utility and contract personnel. The study includes hydrologic characteristics of streams, lakes, shore regions, the regional and local groundwater environments, and existing or proposed water control structures that could influence flood control and plant safety. Section 2.4 includes more detailed information regarding this subject.

e. Demography

Information relating to local and surrounding area population distribution is developed and evaluated by utility and contract personnel. The data is used to determine if requirements are met for establishment of exclusion area, low population zone, and population center distance. Section 2.1 includes more detailed information regarding population around the plant site.

f. Environmental Effects

Monitoring programs are developed to enable the collection of data necessary to determine possible impact on the environment due to construction, startup, and operational activities and to establish a baseline from which to evaluate future environmental monitoring.

13AA.1.1.1.1.2 Design of Plant and Ancillary Systems

Responsibility for design and construction of systems outside the power block such as circulating water, service water, switchyard, and secondary fire protection systems are delegated to qualified contractors.

13AA.1.1.1.1.3 Review and Approval of Plant Design Features

Design engineering review and approval is performed in accordance with the reactor technology vendor QA program and Section 17.1. The reactor technology vendor is responsible for design control of the power block. Verification is performed by competent individuals or groups other than those who performed the original design. Design issues arising during construction are addressed and implemented with notification and communication of changes to the engineering director for review. Systems are tested and approved for turnover and operation as construction activities are completed. Design authority is turned over to SNC separately at the discretion of the Senior Manager for Engineering, prior to fuel load for each unit. The Engineering Director, along with functional managers and staff, assumes responsibility for review and approval of modifications, additions, or deletions in plant design features, as well as control of design documentation, in accordance with the Operational QA Program. Design control becomes the responsibility of the Engineering Director prior to loading fuel. During construction, startup, and operation, changes to human-system interfaces of control room design are approved using a human factors engineering evaluation addressed within Chapter 18. See Organization Charts, Figure 13.1-202, and the Nuclear Development Quality Assurance Manual for reporting relationships.

13AA.1.1.1.1.4 Site Layout with Respect to Environmental Effects and Security Provisions

Site layout was considered when determining the expected environmental effects from construction.

The Physical Security Plan is designed with provisions that meet the applicable NRC regulations. Site layout was considered when developing the Security Plan.

13AA.1.1.1.1.5 Development of Safety Analysis Reports

Information regarding the development of the Final Safety Analysis Report is found in Chapter 1.

13AA.1.1.1.1.6 Review and Approval of Material and Component Specifications

Safety-related material and component specifications of structures, systems, and components designed by the reactor technology vendor are reviewed and approved in accordance with the reactor technology vendor quality assurance program and Section 17.1. Review and approval of items not designed by the reactor vendor are controlled for review and approval by Section 17.5 and the Quality Assurance Program Description.

13AA.1.1.1.1.7 Procurement of Materials and Equipment

Procurement of materials and equipment (modules, engineered components, ASME III materials, and highly engineered materials) during the construction phase is the responsibility of the reactor technology vendor and constructor. Procurement of all other materials and equipment during the construction phase is the responsibility of SNC. The process is controlled by the construction QA program of Westinghouse. Oversight of the inspection and receipt of materials and equipment process is the responsibility of the manager in charge of quality assurance.

13AA.1.1.1.1.8 Management and Review of Construction Activities

Overall management and responsibility for construction activities is assigned to the Executive Vice President of Vogtle 3&4 who directs the organizations responsible for construction oversight. Monitoring and review of construction activities by utility personnel is a continuous process at the plant site. SNC performance is monitored to provide objective data to utility management in order to identify problems early and develop proper corrective actions and solutions. Monitoring of construction activities verifies that contractors are in compliance with contractual obligations for quality, schedule, and cost. Monitoring and review of construction activities is divided functionally across the various disciplines of the utility construction staff, e.g. electrical, mechanical, instrument and control, etc., and tracked by schedule based on system and major plant components/areas. For construction oversight positions and functional area descriptions reporting to the Executive Vice President of Vogtle 3&4 during the construction phase, see Section 17.5 and the Nuclear Development Quality Assurance Manual.

After each system is turned over to plant staff, the construction organization relinquishes responsibility for that system. At that time they will be responsible for completion of construction activities as directed by plant staff and available to provide support for preoperational and start-up testing as necessary.

Periodic assessment involving both the construction and operations organizations continues to identify SSCs that could reasonably be expected to be impacted by scheduled construction activities. Appropriate administrative and managerial controls are then established as necessary. Specific hazards, impacted SSCs, and managerial and administrative controls are reviewed on a recurring basis and, if necessary, controls are revised/developed and implemented and maintained current as work progresses on site. For example, prior to construction activities that involve the use of large construction equipment such as cranes, managerial and administrative controls are in place to prevent adverse impacts on any operating unit(s)' overhead power lines, switchyard, security boundary, etc., by providing the necessary restrictions on the use of large construction equipment.

13AA.1.1.1.2 Preoperational Activities

The Executive Vice President of Vogtle 3&4 is responsible for the activities required to transition the unit from the construction phase to the operational phase. These activities include turnover of systems from construction, preoperational testing, schedule management, procedure development for tests, fuel load, integrated startup testing, and turnover of systems to plant staff.

During construction and initial testing, SNC is responsible for equipment maintenance. To ensure equipment operability and reliability, plant maintenance programs such as preventive and corrective maintenance are developed prior to system turnover and become effective as each system is turned over to the plant staff with approved administrative procedures under the direction of the managers in charge of maintenance, engineering, and work control. For positions and functional area descriptions, see the Nuclear Development Quality Assurance Manual.

13AA.1.1.1.2.1 Development of Human Factors Engineering Design Objectives and Design Phase Review of Proposed Control Room Layouts

Human factors engineering (HFE) design objectives are initially developed by the reactor technology vendor in accordance with Chapter 18. As a collaborative team, personnel from the reactor technology vendor design staff and personnel, including licensed operators, engineers, and instrumentation and control technicians from owner and other organizations in the nuclear industry, assess the design of the control room and man-machine interfaces to attain safe and efficient operation of the plant. See Section 18.2 for additional details of HFE program management.

Modifications to the certified design of the control room or man-machine interface described in the Design Control Document are reviewed per engineering and site support procedures, as required by Section 18.2, to evaluate the impact to plant safety. The engineering director is responsible for the human factors engineering (HFE) design process and for the design commitment to HFE during construction and throughout the life of the plant as noted in Subsection 13.1.1.2.1. The HFE program is established in accordance with the description and commitments in Chapter 18.

13AA.1.1.1.2.2 Preoperational and Startup Testing

Preoperational and startup testing is conducted by the Initial Test Program (ITP) organization. The ITP organization, functions, and responsibilities are addressed in Section 14.2. Sufficient numbers of personnel are assigned to perform preoperational and startup testing to facilitate safe and efficient implementation of the testing program. Plant-specific training provides instruction on the administrative controls of the test program. To improve operational experience, operations and technical staff are used as support in conducting the test program and in reviewing test results.

13AA.1.1.1.2.3 Development and Implementation of Staff Recruiting and Training Programs

Staffing plans are developed based on operating plant experience with input from the reactor technology vendor for safe operation of the plant as determined by HFE. See Section 18.6. These plans are developed under the direction and guidance of the Executive Vice President of Vogtle 3&4. Staffing plans are completed and necessary manager level positions are filled prior to start of preoperational testing. Personnel selected to be licensed reactor operators and senior reactor operators along with other staff necessary to support the safe operation of the plant are hired with sufficient time available to complete appropriate training programs, and become qualified, and licensed, if required, prior to fuel being loaded in the reactor vessel. See Figure 13AA-202 for an estimated timeline of hiring requirements for operator and technical staff relative to fuel load.

Because of the dynamic nature of the staffing plans and changes that occur over time, it is expected that specific numbers of personnel on site will change. Recruiting of personnel to fill positions is the shared responsibility of the manager in charge of human resources and the various heads of departments. The training program is described in Section 13.2.

Figure 13AA-201
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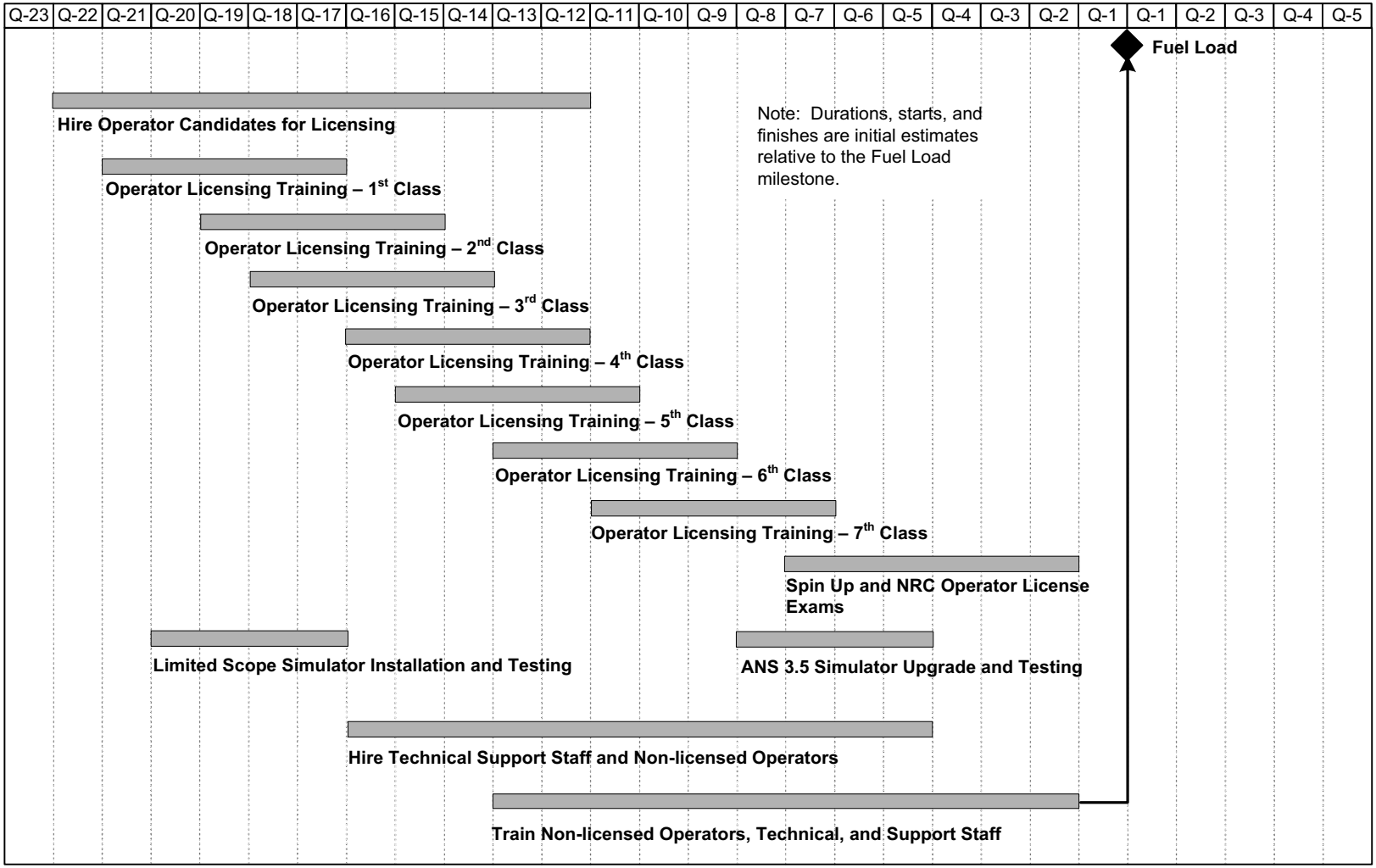

Figure 13AA-202
Hiring Schedule for Plant Staff

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 14	INITIAL TEST PROGRAM	14.1-1
14.1	Specific Information to be Included in Preliminary/Final Safety Analysis Reports	14.1-1
14.2	Specific Information to be Included in Standard Safety Analysis Reports	14.2-1
14.2.1	Summary of Initial Test Program and Objectives	14.2-1
14.2.1.1	Preoperational Test Program Objectives	14.2-2
14.2.1.2	Startup Test Program Objectives	14.2-3
14.2.1.3	Testing of First of a Kind Design Features	14.2-3
14.2.1.4	Credit for Previously Performed Testing of First of a Kind Design Features	14.2-4
14.2.2	Organization, Staffing, and Responsibilities	14.2-4
14.2.2.1	ITP Organization	14.2-4
14.2.2.2	ITP Organization Personnel Qualifications and Training	14.2-6
14.2.2.3	Joint Test Working Group	14.2-6
14.2.2.4	ITP Test Groups	14.2-8
14.2.2.5	ITP Organizational Support Groups	14.2-9
14.2.3	Test Procedures	14.2-9
14.2.3.1	Conduct of Initial Test Program	14.2-10
14.2.3.2	Review of Test Results	14.2-13
14.2.3.3	Test Records	14.2-14
14.2.4	Compliance of Initial Test Program with Regulatory Guides	14.2-14
14.2.5	Utilization of Reactor Operating and Testing Experience in the Development of Initial Test Program	14.2-14
14.2.5.1	Use of OE During Test Procedure Preparation	14.2-18
14.2.5.2	Sources and Types of Information Reviewed for ITP Development	14.2-18
14.2.5.3	Conclusions from Review	14.2-18
14.2.5.4	Summary of Test Program Features Influenced by the Review	14.2-18
14.2.5.5	Use of OE during Conduct of ITP	14.2-18
14.2.6	Use of Plant Operating and Emergency Procedures	14.2-18
14.2.6.1	Operator Training and Participation during Certain Initial Tests (TMI Action Plan Item I.G.1, NUREG-0737)	14.2-19
14.2.7	Initial Fuel Loading and Initial Criticality	14.2-19
14.2.7.1	Initial Fuel Loading	14.2-19
14.2.7.2	Initial Criticality	14.2-21
14.2.7.3	Power Ascension	14.2-21
14.2.8	Initial Test Program Schedule	14.2-22
14.2.9	Preoperational Test Descriptions	14.2-23
14.2.9.1	Preoperational Tests of Systems with Safety-Related Functions	14.2-24
14.2.9.2	Preoperational Testing of Defense-in-Depth Systems	14.2-49
14.2.9.3	Preoperational Testing of Nonsafety-Related Radioactive Systems	14.2-69

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	14.2.9.4 Preoperational Tests of Additional Nonsafety-Related Systems	14.2-74
	14.2.10 Startup Test Procedures	14.2-89
	14.2.10.1 Initial Fuel Loading and Precritical Tests	14.2-90
	14.2.10.2 Initial Criticality Tests	14.2-103
	14.2.10.3 Low Power Tests	14.2-106
	14.2.10.4 Power Ascension Tests	14.2-109
14.3	Certified Design Material	14.3-1
	14.3.1 CDM Section 1.0, Introduction	14.3-2
	14.3.2 CDM Section 2.0, System Based Design Descriptions and ITAAC	14.3-2
	14.3.2.1 Design Descriptions	14.3-3
	14.3.2.2 Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC)	14.3-6
	14.3.2.3 Site-Specific ITAAC (SS-ITAAC)	14.3-9
	14.3.3 CDM Section 3.0, Non-System Based Design Descriptions and ITAAC	14.3-10
	14.3.3.1 Non-System Based Site Specific ITAAC	14.3-10
	14.3.3.2 Pipe Rupture Hazard Analysis ITAAC	14.3-10
	14.3.3.3 Piping Design ITAAC	14.3-11
	14.3.4 Certified Design Material Section 4.0, Interface Requirements	14.3-11
	14.3.5 CDM Section 5.0, Site Parameters	14.3-12
	14.3.6 Initial Test Program	14.3-12
	14.3.7 Elements of AP1000 Design Material Incorporated into the Certified Design Material	14.3-12
	14.3.8 Summary	14.3-13
	14.3.9 References	14.3-13
14.4	Combined License Applicant Responsibilities	14.4-1
	14.4.1 Organization and Staffing	14.4-1
	14.4.2 Test Procedures	14.4-1
	14.4.3 Conduct of Initial Test Program	14.4-1
	14.4.4 Review and Evaluation of Test Results	14.4-1
	14.4.5 Interface Requirements	14.4-1
	14.4.6 First-Plant-Only and Three-Plant-Only Tests	14.4-1
APPENDIX 14A	DESIGN ACCEPTANCE CRITERIA/ITAAC CLOSURE PROCESS	14A-1

LIST OF TABLES

Table Number	Title	Page
14.3-1	ITAAC Screening Summary	14.3-14
14.3-2	Design Basis Accident Analysis	14.3-18
14.3-3	Anticipated Transient Without Scram	14.3-35
14.3-4	Fire Protection	14.3-36
14.3-5	Flood Protection	14.3-38
14.3-6	Probabilistic Risk Assessment	14.3-40
14.3-7	Radiological Analysis	14.3-50
14.3-8	Severe Accident Analysis	14.3-53
14.3-201	Not Used	14.3-53

Chapter 14 Initial Test Program

14.1 Specific Information to be Included in Preliminary/Final Safety Analysis Reports

Not applicable to the AP1000.

14.2 Specific Information to be Included in Standard Safety Analysis Reports

14.2.1 Summary of Initial Test Program and Objectives

The purpose of this section is to describe the initial test program that is performed for the AP1000 plant.

The overall objective of the initial test program is to demonstrate that the plant has been constructed as designed, that the systems perform consistent with the plant design, and that activities culminating in operation at full licensed power including initial fuel load, initial criticality, and power ascension are performed in a controlled and safe manner.

A graded approach, based on the criteria provided in Regulatory Guide 1.68, is used to develop and implement the Initial Test Program (ITP). Preoperational and/or startup testing is performed on those systems that are:

a) Relied upon for safe shutdown and cooldown of the reactor under normal plant conditions and for maintaining the reactor in a safe condition for an extended shutdown period;

b) Relied upon for safe shutdown and cooldown of the reactor under transient and postulated accident conditions and for maintaining the reactor in a safe condition for an extended shutdown period following such conditions;

c) Relied upon for establishing conformance with safety limits or limiting conditions for operation that will be included in the facility technical specifications;

d) Classified as engineered safety features actuation systems (ESFAS) or are relied upon to support or ensure operation of engineered safety features actuation systems within design limits;

e) Assumed to function or for which credit is taken in the accident analysis of the AP1000 as described in this document.

f) Used to process, store, control, or limit the release of radioactive materials.

g) Other systems identified in Regulatory Guide 1.68, Revision 2, Appendix A that are in the AP1000 and are not captured by criteria a) through f).

The inspections, tests, analyses and acceptance criteria of 10 CFR 52.47 (b)(1) relating to the AP1000 design are found in the AP1000 Certified Design Material (see Section 14.3).

The ITP is implemented in two phases, categorized as preoperational and startup testing. The individual programs for these two phases, which make up the overall ITP, are discussed in Subsections 14.2.1.1 and 14.2.1.2. For clarity, it is noted that construction and installation tests, including component tests, are performed to verify that the construction, installation, and assembly processes have been properly performed. Construction and installation tests, including component tests, are not considered part of the ITP.

- Preoperational tests are performed after associated prerequisites for the required test, such as a completion of associated construction activities, component and/or preliminary tests, and inspections, but prior to initial fuel loading to demonstrate the capability of plant systems to meet performance requirements. These prerequisites should be completed before beginning preoperational tests (to the degree that outstanding items could not be expected to affect the validity of test results).

- Startup tests begin with the initial fuel loading and are performed to demonstrate the capability of individual systems, as well as the integrated plant, to meet performance requirements.

Section 14.2 provides the requirements to be included in the ITP Administrative Manual (Procedures), as discussed in Subsection 14.4.3. The information referenced in this section meets the Initial Test Program (ITP) criteria of NUREG-0800 and is formatted to follow Regulatory Guide 1.206, Part I, Section C.I.14.2.

The ITP is applied to structures, systems, and components that perform the functions described in the Regulatory Guide 1.68 evaluation in Section 1.9. The ITP is also applied to other structures, systems and components. The ITP Administrative Manual will reference the AP1000 structures, systems and components to which the ITP is applied.

14.2.1.1 Preoperational Test Program Objectives

Following completion of associated prerequisites, preoperational tests are performed to demonstrate that equipment and systems perform in accordance with design criteria so that initial fuel loading, initial criticality, and subsequent power operation can be safely undertaken. Preoperational tests at elevated pressure and temperature are referred to as hot functional tests.

The general objectives of the preoperational test program are the following:

- Demonstrate that essential plant components and systems, including alarms and indications, meet appropriate criteria based on the design
- Provide documentation of the performance and condition of equipment and systems
- Provide baseline test and operating data on equipment and systems for future use and reference
- Operate equipment for a sufficient period to demonstrate performance
- Demonstrate that plant systems operate on an integrated basis

A graded approach, in accordance with Regulatory Guide 1.68, is used to develop and implement the preoperational test program. Acceptance criteria, consisting of performance objectives and functional requirements, are established for each safety-related or defense-in-depth function the SSCs perform. Either qualitative or quantitative in nature, acceptance criteria are used to determine success or failure of these preoperational tests. Functional criteria are established for functions the SSCs perform which are neither safety-related nor defense-in-depth. Test procedures will differentiate between acceptance criteria and functional criteria for preoperational tests.

- Abstracts for preoperational tests for portions of systems/components that perform safety-related functions and/or defense-in-depth functions are provided in Subsections 14.2.9.1 and 14.2.9.2, respectively.
- Abstracts for preoperational tests for portions of systems/components that contain, transport, or isolate radioactive material and for other applicable systems that are specified in Regulatory Guide 1.68, Appendix A, Revision 2, are provided in Subsections 14.2.9.3 and 14.2.9.4, respectively.

Plant operating, emergency, and surveillance procedures are incorporated into the initial test program procedures to the extent practical. These procedures are verified through use, to the extent practicable, during the preoperational test program and revised if necessary, prior to fuel loading.

Plant equipment used in the performance of preoperational tests is operated, to the extent practical, in accordance with appropriate operating procedures, thereby giving the plant operating staff an opportunity to gain experience in using these procedures and demonstrating their adequacy prior to plant initial criticality.

14.2.1.2 Startup Test Program Objectives

The startup test program begins with initial fuel loading after the preoperational testing has been successfully completed.

Startup tests can be grouped into four broad categories:

- Tests related to initial fuel loading
- Tests performed after initial fuel loading but prior to initial criticality
- Tests related to initial criticality and those performed at low power (less than 5 percent)
- Tests performed at power levels greater than 5 percent

During performance of the startup test program, the plant operating staff has the opportunity to obtain practical experience in the use of normal and abnormal operating procedures while the plant progresses through heatup, criticality, and power operations.

The general objectives of the startup test program are:

- Install the nuclear fuel in the reactor vessel in a controlled and safe manner.
- Verify that the reactor core and components, equipment, and systems required for control and shutdown have been assembled according to design and meet specified performance requirements.
- Achieve initial criticality and operation at power in a controlled and safe manner.
- Verify that the operating characteristics of the reactor core and associated control and protection equipment are consistent with design requirements and accident analysis assumptions.
- Obtain the required data and calibrate equipment used to control and protect the plant.
- Verify that the plant is operating within the limits imposed by the Technical Specifications.

Abstracts of the startup tests are provided in Subsection 14.2.10.

14.2.1.3 Testing of First of a Kind Design Features

First of a kind (FOAK) testing may occur in any of the phases, depending on the nature of the testing and required sequencing of the tests. When testing FOAK design features, applicable operating experience from previous test performance on other AP1000 plants is reviewed, where available, and the ITP modified as needed based on those lessons learned.

14.2.1.4 Credit for Previously Performed Testing of First of a Kind Design Features

In some cases, FOAK testing is required only for the first of a new design or for the first few plants of a standard design. In such cases, credit may be taken for the previously performed tests.

14.2.2 Organization, Staffing, and Responsibilities

SNC has the overall responsibility to manage and conduct preoperational and startup testing.

The ITP Organization is described in Subsection 14.2.2.1. The organization for operating and maintaining the AP1000 plant is described in Section 13.1.

Table 13.4-201 provides milestones for initial test program implementation.

14.2.2.1 ITP Organization

The ITP organization is functionally comprised of testing groups and organizational support groups. The groups are responsible for supporting and conducting preoperational and startup testing and may be divided by functional area. The ITP Organization structure (organizational chart) is included in the ITP Administrative Manual.

14.2.2.1.1 Senior Managers Responsible for ITP

The Senior Managers Responsible for ITP are responsible for:

- Staffing the ITP Organization.
- Developing and reviewing the administrative and technical procedures associated with preoperational and startup testing.
- Managing the ITP Organization.
- Implementing the preoperational and startup testing schedule.
- Managing contracts associated with preoperational and startup testing.

14.2.2.1.2 Functional Managers In Charge of ITP Organization Support

The functional managers in charge of ITP Organization support report to the Senior Managers Responsible for ITP and are responsible for providing the necessary supporting structure and processes required for the effective implementation of the ITP. Specifically, these managers are responsible for:

- Planning and scheduling procedure development to support preoperational and startup testing
- Managing turnover from construction to the ITP organization and the transition from the ITP organization to operations
- Implementing work controls during the ITP including planning of test packages
- Managing the training and qualification of ITP personnel
- Managing the processing of ITP records and documents for storage

- Managing JTWG activities including the review and approval of ITP administrative procedures
- Scheduling and tracking ITP activities to support the project schedule

14.2.2.1.3 Functional ITP Managers in Charge of Testing

The functional managers in charge of testing report to the Senior Managers Responsible for ITP and are responsible for:

- Managing testing per the test schedule.
- Managing initial energization.
- Managing component checkout, calibration and digital controls interface verification for plant components.
- Ensuring that the JTWG reviews and approves preoperational test procedures for SSCs identified in Subsections 14.2.9.1 and 14.2.9.2.
- Reviewing and approving preoperational test procedures for SSCs identified in Subsections 14.2.9.3 and 14.2.9.4.
- Ensuring that the JTWG reviews and approves startup test procedures.
- Coordinating vendor participation in testing activities, as required.
- Supervising and directing test personnel.
- Supporting administrative controls to address system and equipment configuration control.
- Verifying the adequacy of test results.
- Supporting the transition from construction to the preoperational testing phase.
- Preparing and/or reviewing preoperational test procedures.
- Involving operations personnel in testing activities. Utilizing operations personnel, to the extent practical, as test witnesses or test performers to provide the operations personnel with experience and knowledge.
- Preparing a detailed startup testing schedule.
- Maintaining the startup schedule.

14.2.2.1.4 Test Engineers

Test engineers report directly to one of the functional managers in charge of testing. The test engineers are responsible for:

- Complying with administrative controls.
- Developing, reviewing, and performing test procedures.

- Identifying any special or temporary equipment or services needed to support testing.
- Coordinating testing with involved groups.
- Reviewing and evaluating test results.

14.2.2.2 ITP Organization Personnel Qualifications and Training

Procedures are prepared to identify the appropriate training, qualification, and certification for test personnel. Records are kept to document training, qualification and certification, as appropriate. Test personnel are qualified as described below:

- Acceptable qualifications of non-supervisory test engineers follow the guidance provided in Regulatory Guide 1.28 as discussed in Appendix 1A, i.e., ASME NQA-1-1994, Appendix 2A-1, Nonmandatory Guidance on the Qualification of Inspection and Test Personnel.
- Acceptable qualifications of supervisory test engineers follow the guidance in Regulatory Guide 1.28, i.e., ANSI/ANS-3.1-1993, Selection Qualification, and Training of Personnel for Nuclear Power Plants.

The training program/procedures shall include:

- The education, training, experience, and qualification requirements for ITP Organization supervisory and test personnel responsible for managing, developing, or conducting each test phase, or development of testing procedures. Refer to Section 13.2 for training and qualification information for the organization responsible for operating and maintaining the plant.

The ITP Administrative Manual (Procedure) shall include:

- The implementation of measures to verify that personnel formulating and conducting test activities are not the same personnel who designed or are responsible for satisfactory performance of the system(s) or design features(s) being tested. This provision does not preclude members of the design organization from participating in test activities. This description also includes considerations of staffing effects that could result from overlapping initial test programs at multi-unit sites.

14.2.2.3 Joint Test Working Group

The Joint Test Working Group (JTWG) consists of an organizational group of authorized representative personnel from the Plant's operations and support group functions, Responsible Design Organization and other test support groups as identified below.

SNC has the overall responsibility for conduct of the ITP. The Senior Managers Responsible for ITP have been assigned overall responsibility and authority for technical direction of the preoperational and startup testing and may act as the JTWG Chairman.

The JTWG Chairman reports to the Senior Managers Responsible for ITP or designee(s), for matters of preoperational or startup testing authority and acceptance.

The JTWG provides the following administrative oversight activities associated with preoperational and startup testing:

- Review and approve ITP Administrative Manual.

- Review and approve preoperational test procedures, for tests described in Subsections 14.2.9.1 and 14.2.9.2, and startup test procedures.
- Oversee the implementation of preoperational and startup testing, including planning, scheduling, and performance.
- Review and approve preoperational test results, for tests described in Subsections 14.2.9.1 and 14.2.9.2, and startup test results.

The JTWG is composed of qualified representatives provided from the following organizations:

- Operations Group
- Maintenance Group
- ITP Test Groups
- Engineering Group
- Responsible Design Organization

The following are additional generic details of the key responsibilities, authorities and interfaces of the organizations delineated above:

- Operations Group

  The Operations Group has the overall responsibility for Plant Operations, including administrative control and tag-outs subsequent to system turnover. Their primary interfaces are with the Engineering and Technical Support organizations as well as the responsible design organization and ITP Testing Teams.

- Maintenance Group

  The Maintenance Group has the overall responsibility for the Maintenance of Plant systems and components subsequent to System Turnover. They are key participants and maintainers of system maintenance control and tag-outs. Their primary interfaces are with the Operations Group and Technical Support organizations as well as the responsible design organization and ITP Testing Teams.

- ITP Test Groups

  The ITP Test Groups have the primary responsibility for the development, maintenance and performance of preoperational and startup procedures at the site. The primary interfaces for these groups are the Operations Group and Technical support organizations as well as the responsible design organization and the Construction Services Group.

- Engineering Group

  This group has the primary responsibility for engineering and design oversight of the plant components and systems, as well as interfacing with the vendor engineering organization. This organization primarily interfaces with the Operations Group as well as the responsible design organization and ITP Testing Teams.

- Responsible Design Organization

The responsible design organization will vary and may be Westinghouse Electric Company (WEC), and/or Southern Company depending on the particular area or SSC in question. This organization has the primary responsibility for the approval of the document indicating that the acceptance and/or functional criteria are in accordance with the current approved design. Resolution of any questions from the review and use of engineering documents to support test procedures is the responsible design organization's responsibility through interface between the site and the vendor's home offices. The responsible design organization will resolve any deficiencies that occur during testing of structures, systems, and components that cannot be resolved within the ITP Organization.

The responsible design organization will interface with the ITP Organization. As necessary, the responsible design organization may also interface with the Licensee Operations, Maintenance and Engineering groups.

14.2.2.4 ITP Test Groups

The ITP Test Groups perform the following functions and scope of work as necessary to support the Initial Test Program:

- Support acceptance of construction turnover to the ITP organization.
- Support/perform initial energization and operation of plant equipment as well as functional performance tests at the component or sub-system level.
- Perform component checkout, calibration, and digital controls interface verification for plant components.
- Coordinate tagging and maintenance to support testing.
- Manage and oversee the testing of plant systems to support completion of hot functional testing.
- Resolve open items and exceptions identified during implementation of the Preoperational Test Program.
- Present preoperational test results, for tests described in Subsections 14.2.9.1 and 14.2.9.2, to the JTWG for review and approval.
- Coordinate other support tasks required during Preoperational Testing activities with responsible groups.
- Assist in planning, scoping, and scheduling plant systems, structures and components for testing, to support startup testing.
- Support initial fuel loading and precritical testing, initial criticality, low power, and power ascension testing.
- Resolve open items and exceptions identified during implementation of the Startup Test Program.
- Coordinate other support tasks required during Startup Testing activities with responsible groups.

14.2.2.5 ITP Organizational Support Groups

The ITP Organizational Support Groups perform the following functions and scope of work as necessary to support the Initial Test Program:

- Support acceptance of construction to the ITP organization and transition from the ITP organization to operations
- Implement work controls during the ITP
- Process ITP records and documents for storage
- Train and qualify ITP personnel
- Plan, scope and schedule plant systems for testing

14.2.3 Test Procedures

Preoperational and startup tests are performed using test procedures.

For each test, the test procedure specifies the following, as applicable:

- Objectives for performing the test
- Prerequisites that must be completed before the test can be performed
- Initial conditions under which the test is started
- Special precautions required for the safety of personnel or equipment
- Instructions delineating how the test is to be performed
- Identification of the required data to be obtained and the methods for documentation
- Data reduction analysis methods as appropriate
- Test acceptance and/or functional criteria

Test procedures are developed and reviewed by personnel with appropriate technical backgrounds and experience. This includes the participation of responsible design organizations in the establishment of test performance requirements and acceptance and/or functional criteria.

Available information on operating or testing experiences of operating reactors is factored into the test procedures as appropriate.

Copies of the test procedures for the startup tests are available to NRC inspection personnel not less than 60 days prior to the scheduled fuel loading date.

Copies of the test procedures are available to NRC inspection personnel approximately 60 days prior to the scheduled performance of the following preoperational tests:

- Tests of systems/components that perform safety-related functions
- Tests of systems/components that are nonsafety-related but perform defense in-depth functions.

Test procedures for preoperational tests described in Subsections 14.2.9.3 and 14.2.9.4 of the plant systems/components which perform no safety-related or defense-in-depth functions are available to NRC inspection personnel prior to the scheduled performance of these tests.

Preoperational and startup tests are performed with the quality assurance requirements as specified in Section 17.5.

The ITP Administrative Manual shall include the following controls:

- Controls to provide for turnover of plant systems and components from construction to the preoperational testing group. These administrative controls also ensure that general prerequisites are satisfied prior to preoperational and/or startup tests of individual systems or components.
- For preoperational and startup tests, controls to provide test procedures that include appropriate prerequisites, objectives, special precautions, initial test conditions, methods to direct and control test performance, and acceptance and/or functional criteria by which the test is evaluated.
- For preoperational and startup tests, controls for the format of individual test procedures to provide consistency with the guidance contained in Regulatory Guide 1.68, as applicable.
- For preoperational and startup tests, controls to provide for participation of the responsible design organizations in establishing test objectives, test acceptance and/or functional criteria, and related performance requirements during the development of detailed test procedures. Each test procedure should include acceptance criteria that account for the uncertainties used in transient and accident analyses. The responsible design organization will solicit support from design agents (i.e., major contractors, subcontractors, and vendors) as needed.
- Controls to provide for personnel with appropriate technical backgrounds and experience to develop and review preoperational and startup test procedures and/or written work instructions. Persons filling designated management positions should perform final procedure review and approval.
- Controls to make the approved preoperational and startup test procedures for satisfying FSAR testing commitments available to NRC inspectors approximately 60 days prior to their intended use and prior to fuel load, respectively.

14.2.3.1 Conduct of Initial Test Program

Administrative procedures and requirements that govern the activities of the conduct of the initial test program include the following:

- Format and content of test procedures
- Process for both initial issue and subsequent revisions of test procedures
- Review process for test results
- Process for resolution of failures to meet performance criteria and of other operational problems or design deficiencies
- Various phases of the initial test program and the requirements for progressing from one phase to the next, as well as requirements for moving beyond selected hold points or milestones within a given phase

- Controls to monitor the as-tested status of each system and modifications including retest requirements deemed necessary for systems undergoing or already having completed testing

- Qualifications and responsibilities of test personnel within the ITP Organization

The ITP Administrative Manual (procedures) supplements normal plant administrative procedures by addressing those administrative issues that are unique to the ITP.

The ITP Administrative Manual (procedure) governs the initial testing and is issued no later than 60 days prior to the beginning of the preoperational test phase. Testing during all phases of the test program is conducted using approved test procedures.

14.2.3.1.1 Preoperational and Startup Test Procedure Verification

Since procedures may be approved for implementation weeks or months in advance of the scheduled test date, a review of the approved test procedure is required before commencement of testing. The test engineer is responsible for verifying:

- Drawing and document revision numbers listed in the reference section of the test procedure agree with the latest revisions.

- The procedure text reflects any design and licensing (i.e., FSAR and Technical Specifications) changes made since the procedure was originally approved for implementation.

- Any new (since preparation of the procedure) Operating Experience lessons learned are incorporated into individual test procedures.

Procedures require signoff verification for prerequisites and instruction steps. This signoff includes identification of the person doing the signoff and the date of completion.

Test engineers maintain logs of test status to facilitate turnover and aid in maintaining configuration control. These logs become part of the test documentation.

There is a documented test turnover process to make known the test status and equipment configuration when personnel transfer responsibilities, such as during a shift change.

Test briefings are conducted for each test in accordance with administrative procedures. When a shift change occurs before test completion, another briefing occurs before resumption or continuation of the test.

Data collected is marked or identified with test, date, and person collecting data. This data becomes part of the test documentation.

Test issues (collectively including deficiencies, discrepancies, exceptions, non-conformances, delays, etc.) will be documented and addressed in accordance with the requirements stipulated in the ITP Administrative Manual. Those determined by the ITP Administrative Manual criteria and the test results that do not meet test acceptance or functional criteria are entered into the applicable corrective action program.

Plant management approves proceeding from one test phase to the next during the ITP.

Administrative procedures detail the test documentation review and approval process.

14.2.3.1.2 Work Control

The group having jurisdictional control is responsible for initiating work requests when assistance is required from the Construction or Licensee's organization. Work requests are issued in accordance with site specific procedures governing the work management process.

After turnover to the Licensee, activities requiring Construction organization work efforts are performed under plant equipment clearance procedures. Equipment clearance requests are governed by a site-specific procedure for protection of personnel and equipment.

The group having jurisdictional control is responsible for supervising minor repairs and modifications, changing equipment settings, and disconnecting and reconnecting electrical terminations as stipulated in a test or administrative procedure. Test Engineers may perform independent verification of changes made in accordance with approved procedures.

14.2.3.1.3 System Turnover

During the construction phase, systems, subsystems, and equipment are completed and turned over in an orderly and well-coordinated manner. Guidelines are established to define the boundary and interface between related system/subsystem and are used to generate boundary scope documents; for example, marked-up piping and instrument diagrams (P&IDs) and electrical schematic diagrams are provided for scheduling and subsequent development of component and system turnover packages. The system turnover process includes requirements for the following:

- Documenting inspections performed by the construction organization (e.g., highlighted drawings showing areas inspected).
- Documenting results of construction testing.
- Determining the construction-related inspections and tests, including component testing, that need to be completed before preoperational testing begins.
- Evaluating any open items for acceptability before commencing preoperational or startup testing.
- Developing and implementing plans for correcting adverse conditions and open items, and means for tracking such conditions and items.
- Verifying completeness of construction and documentation of incomplete items.

14.2.3.1.4 Conduct of Modifications and Configuration Changes During the Initial Test Program

Temporary configuration changes may be required to conduct certain tests. These configuration changes are documented in the test procedures, and/or written work instructions, or in accordance with the ITP Administrative Manual. The test procedures, and/or written work instructions, contain restoration steps and retesting necessary to confirm satisfactory restoration to the required configuration. Modifications may be performed by the Construction organization or the plant staff processes prior to NRC issuance of the 10 CFR 52.103(g) finding. If the modification invalidates a previously completed ITAAC, then that ITAAC is re-performed. Each modification is reviewed to determine the scope of post-modification testing that is to be performed. Testing is conducted and documented to maintain the validity of preoperational testing and ITAAC. Modifications and configuration changes made following NRC issuance of the 10 CFR 52.103(g) finding are in

accordance with plant processes and meet license conditions. Modifications that require changes to ITAAC require NRC approval of the ITAAC change.

14.2.3.1.5 Conduct of Maintenance During the Initial Test Program

Corrective or preventive maintenance activities are reviewed to determine the scope of postmaintenance testing to be performed. Prior to NRC issuance of the 10 CFR 52.103(g) finding, post-maintenance testing is conducted and documented to maintain validity of associated preoperational testing and ITAAC remain valid. Maintenance performed following NRC issuance of the 10 CFR 52.103(g) finding is in accordance with plant staff processes and meets license conditions.

14.2.3.2 Review of Test Results

Final review of the individual tests is discussed in Section 14.4.

14.2.3.2.1 Review and Approval Responsibilities

Upon completion of a test, the test engineer is responsible for:

- Reviewing the test data.
- Evaluating the test results.
- Verifying that the acceptance and/or functional criteria are met.
- Verifying that the test results that do not meet acceptance and/or functional criteria are entered into the applicable corrective action program.
- Verifying that the results of retesting do not invalidate ITAAC acceptance criteria.

Preoperational test results, for tests described in Subsections 14.2.9.1 and 14.2.9.2, and startup test results are reviewed and approved by the JTWG. Preoperational test results, for tests described in Subsections 14.2.9.3 and 14.2.9.4, are reviewed and approved by Functional ITP Manager in Charge of Testing. Test deficiencies which do not meet acceptance and/or functional criteria are identified to the affected and responsible design organizations, as appropriate, and entered into the applicable corrective action program. Implementation of corrective actions and retests are performed as required.

Prior to initial fuel load, the results of the preoperational test phase are comprehensively reviewed by the ITP Organization and the JTWG to verify the results indicate that the required plant structures, systems, and components are capable of supporting the initial fuel load and subsequent startup testing. The plant manager approves fuel loading.

Completed startup tests are reviewed and evaluated by the ITP Organization and the JTWG. The test results at each power ascension testing power plateau are reviewed and evaluated by the ITP Organization and the JTWG and approved by the plant manager before proceeding to the next plateau. Startup test reports are prepared in accordance with the guidance in position C.9 of Regulatory Guide 1.68, “Initial Test Programs for Water-Cooled Nuclear Power Plants.”

14.2.3.2.2 Technical Evaluation

Each completed test is reviewed by technically qualified personnel to confirm satisfactory demonstration of plant, system or component performance and compliance with design and license criteria.

14.2.3.3 Test Records

Retention periods for test records are based on considerations of their usefulness in documenting initial plant performance characteristics, and are retained in accordance with Regulatory Guide 1.28.

14.2.3.3.1 Startup Test Reports

Startup test reports are generated describing and summarizing the completion of tests performed during the ITP. A startup report is completed at the earliest of:

1) 9 months following initial criticality,

2) 90 days after completion of the ITP, or

3) 90 days after start of commercial operations. If one report does not cover all three events, then supplemental reports are completed every three months until all three events are completed. These reports:

- Address each ITP test described in the FSAR.
- Provide a general description of measured values of operating conditions or characteristics obtained from the ITP as compared to design or specification values.
- Describe any corrective actions that were required to achieve satisfactory operation.
- Include any other information required by license conditions.

14.2.4 Compliance of Initial Test Program with Regulatory Guides

Subsection 1.9.1 and Table 1.9-1 discuss compliance with the applicable NRC regulatory guides.

14.2.5 Utilization of Reactor Operating and Testing Experience in the Development of Initial Test Program

The design, testing, startup, and operating experience from previous pressurized water reactor plants is utilized in the development of the preoperational and startup test program for the AP1000 plant. Other sources of experience reported and described in documents such as NRC reports, including Inspection and Enforcement bulletins and Institute of Nuclear Power Operations (INPO) reports, including Significant Operating Event Reports (SOER), are also utilized in the AP1000 preoperational and startup test program.

Special tests to further establish a unique phenomenological performance parameter of the AP1000 design features beyond testing performed for Design Certification of the AP600 and that will not change from plant to plant, are performed for the first plant only. Because of the standardization of the AP1000 design, these special tests (designated as first plant only tests) are not required on follow plants. These first plant only tests are identified in the individual test descriptions. (See

Subsections 14.2.9 and 14.2.10.) The following is a listing of the first plant only tests, and the corresponding section in which they appear

First Plant Only Test	Section
IRWST Heatup Test	14.2.9.1.3 Item (h)
Pressurizer Surge Line Stratification Evaluation	14.2.9.1.7 Item (d)
Reactor Vessel Internals Vibration Testing	14.2.9.1.9 – Prototype Test
[*Natural Circulation Tests*]*	14.2.10.3.6, [*14.2.10.4.29*]*
Rod Cluster Control Assembly Out of Bank Measurements	14.2.10.4.6
Load Follow Demonstration	14.2.10.4.22

Other special tests which further establish a unique phenomenological performance parameter of the AP1000 design features beyond testing performed for Design Certification for the AP600 and that will not change from plant to plant, are performed for the first three plants. Because of the standardization of the AP1000 design, once these special tests have affirmed consistent passive system function they are not required on follow plants. These tests required on the first three plants are identified in the individual test descriptions (See Subsection 14.2.9). The following is a listing of the tests required on the first three plants, and the corresponding section in which they appear.

[*First Three Plant Tests*	*Section*
Core Makeup Tank Heated Recirculation Tests	*14.2.9.1.3 Items (k) and (w)*
ADS Blowdown Test	*14.2.9.1.3 Item (s)*

For subsequent plants, the COL holder shall either perform the subject test, or justification shall be provided that the results of the first-plant-only tests or first-three-plant tests are applicable to the subsequent plant.]*

The justifications for the first-plant-only tests and the first-three-plant tests are provided below:

IRWST Heatup Test (14.2.9.1.3 item (h))

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

During preoperational testing of the passive core cooling system, a natural circulation test and a forced flow test of the passive residual heat removal (PRHR) heat exchanger is conducted (items f and g). For the first plant only, temperature sensors are placed in the IRWST to observe the thermal profile developed during the heatup of the IRWST water during PRHR heat exchanger operation. This test will be useful in confirming the results of the AP600 Design Certification Program PRHR tests with regards to IRWST mixing, and is useful in quantifying the conservatism in the Chapter 15 transient analyses.

Due to the standardization of the AP1000, the heatup and thermal stratification characteristics of the IRWST will not vary from plant to plant. The PRHR heat exchanger design, and the size and configuration of the IRWST are standardized, such that the heatup characteristics will not significantly change from plant to plant.

Therefore, since the phenomenon to be tested (i.e., heatup and mixing characteristics of the IRWST) will not vary significantly from plant to plant due to standardization, a first plant only test of the IRWST heatup characteristics is justified.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Core Makeup Tank Heated Recirculation Tests (14.2.9.1.3 Items (k) and (w))

These first three plant only tests were completed at the first three AP1000 units. These tests are not required to be conducted at Vogtle Units 3 & 4.

During preoperational testing of the passive core cooling system, a test is performed for each plant to verify the CMT inlet piping resistances. In addition, cold draining tests of the CMTs are conducted that verify the discharge piping resistance and proper drain rate of the CMTs for each plant. For the first three plants, two additional CMT tests are conducted during hot functional testing of the RCS. These tests are a natural circulation heatup of the CMTs followed by a test to verify the ability of the CMTs to transition from a recirculation mode to a draindown mode while at elevated temperature and pressure.

Operation of the CMTs in their natural circulation mode is conducted on the first three plants only for the following reasons:

- Natural circulation of the CMTs will not vary from plant to plant, provided that the other verifications discussed above are performed as specified.
- Natural circulation testing of the CMTs was extensively tested as part of the Design Certification Tests.
- Performance of this test results in significant thermal transients on Class 1 components including the CMTs and the direct vessel injection nozzles.

ADS Blowdown Test (14.2.9.1.3 Item (s))

This first three plant only test was completed at the first three AP1000 units. This test is not required to be conducted at Vogtle Units 3 & 4.

During preoperational testing of the passive core cooling system, the resistance of the automatic depressurization system Stage 1, 2, 3 flow path(s) is verified. For the first three plants only, an automatic depressurization blowdown test is performed to verify proper operation of the ADS valves, and demonstrate the proper operation of the ADS spargers to limit the hydrodynamic loads in containment to less than design limits. This test is performed on only the first three plants for the following reasons:

- The operation of the ADS, and the resultant hydrodynamic loads will not vary significantly from plant to plant.
- Full scale automatic depressurization testing was performed in the AP600 Design Certification Program. Testing was conducted to conservatively bound ADS flow rates and resultant hydrodynamic loads that will be experienced by the plant during ADS operation.
- Performance of this test results in significant thermal transients on Class 1 components including the primary components. It also results in hydrodynamic loads in containment including the IRWST.

Pressurizer Surge Line Stratification Evaluation (14.2.9.1.7 Item (d))

This test is not required to be conducted at Vogtle Units 3 and 4.

Reactor Vessel Internals Vibration Testing (14.2.9.1.9)

This first plant only instrumented vibration test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

The preoperational vibration test program for the reactor internals of the AP1000 conducted on the first AP1000 is consistent with the guidelines of Regulatory Guide 1.20 for a comprehensive vibration assessment program. This program is discussed in Subsection 3.9.2.

Natural Circulation Test (Steam Generator) (14.2.10.3.6)

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

Natural circulation test using the steam generators is performed at low core power during the startup test phase of the initial test program for the first AP1000. This testing of the heat removal system meets the intent of the requirement to perform natural circulation testing and the results of this testing is factored into the operator training as discussed in Subsection 1.9.4, Item I.G.1. This test is only required to be performed once because its purpose is to obtain data to benchmark the operator training simulator.

Natural Circulation Test (Passive Residual Heat Removal Heat Exchanger) (14.2.10.4.29)

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

Natural circulation test using the passive residual heat removal heat exchanger is performed using decay heat during the power ascension test phase of the initial test program for the first AP1000. This testing of the heat removal system meets the intent of the requirement to perform natural circulation testing and the results of this testing are factored into the operator training as discussed in Subsection 1.9.4, Item I.G.1. This test is only required to be performed once because its purpose is to obtain data to benchmark the operator training simulator.

Rod Cluster Control Assembly Out of Bank Measurements (14.2.10.4.6)

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

Rod cluster control assembly out of bank measurements are performed during power ascension tests. The test is performed at the 30-percent to 50-percent power level so the plant does not exceed peaking factor limits. The test is required to be performed only for the first plant because its purpose is to validate calculation tools and instrument responses.

Load Follow Demonstration (14.2.10.4.22)

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

A load follow demonstration test is not required by Regulatory Guide 1.68. However, the AP1000 performs load follow with gray rods, as opposed to current Westinghouse PWRs which manipulate RCS boron concentration to perform load follow operations. Therefore, Westinghouse has included a load follow test for the first AP1000, to demonstrate the ability of the AP1000 plant to load follow.

Utilization of Operating Experience

Administrative procedures provide methodologies for evaluating and initiating action for operating experience information (OE). This subsection describes the general use of operating experience in the development of the test program.

14.2.5.1 Use of OE During Test Procedure Preparation

Administrative procedures require review of recent internal and external operating experience when preparing test procedures.

14.2.5.2 Sources and Types of Information Reviewed for ITP Development

Multiple sources of operating experience were reviewed to develop this description of the ITP administration program. These included INPO Reports, INPO Guidelines, INPO Significant Event Reports, INPO Significant Operating Experience Reports and NRC Regulatory Guide 1.68.

14.2.5.3 Conclusions from Review

The following conclusions are a result of the OE review conducted to develop this ITP administration program description:

- The test procedures should provide guidance as to the expected plant response and instructions concerning what conditions warrant aborting the test. Errors and problems with the procedures should be anticipated. A means for prompt but controlled approval of changes to test procedures is needed. Critical test procedures should provide specific criteria for test termination and specific steps to conduct termination are conducted in a safe and orderly manner. Providing procedural guidance for aborting the test could prevent delays in plant restoration. Conservative guidance for actions to be taken should be included in the procedures.
- Plant simulators may prove useful in preparing for special tests and verifying procedures.
- Appropriate component/system operability should be verified prior to critical tests.
- The need to perform physics tests that can produce severe power tilts should be evaluated, particularly if tests at other similar reactors have provided sufficient data to verify the adequacy of the nuclear physics analysis.
- Compensatory measures should be implemented in accordance with guidance for infrequently performed tests or evolutions, where appropriate.

14.2.5.4 Summary of Test Program Features Influenced by the Review

The conclusions from the preceding section were incorporated in Section 14.2.

14.2.5.5 Use of OE during Conduct of ITP

Administrative procedures require discussion of operating experience when performing pre-job briefs immediately prior to the conduct of a test.

14.2.6 Use of Plant Operating and Emergency Procedures

As appropriate and to the extent practicable, plant normal, abnormal, and emergency operating procedures are used when performing preoperational tests.

The use of these procedures is intended:

- To demonstrate the adequacy of the specific procedure or to identify changes that may be required

- To increase the level of knowledge of plant personnel on the systems being tested

A test procedure using a normal, abnormal, or emergency operating procedure references the procedure directly or extracts a series of steps from the procedure in the way that accomplishes the operator training goals while safely and efficiently performing the specified testing.

These procedures are used extensively in the Human-Machine Interface Testing, which is integrated as a part of the Control Room Design finalization. Additionally, the AP1000 plant operating and emergency procedures are developed to support the following design finalization activities:

- Human Factors Engineering
- Operational Task Analysis
- Training Simulator Development
- Verification and Validation of the Procedures and the Training Material

The AP1000 emergency, abnormal and some normal operating procedures, along with some Alarm Response Procedures and surveillance procedures, are exercised and verified in the processes delineated above and in the Control Room design finalization process.

14.2.6.1 Operator Training and Participation during Certain Initial Tests (TMI Action Plan Item I.G.1, NUREG-0737)

The objective of operator participation is to increase the capability of shift crews to operate facilities in a safe and competent manner by assuring that training for plant changes and offnormal events is conducted.

The ITP may result in the discovery of an acceptable plant or system response that differs from the expected response. Test results are reviewed to identify these differences and the training for operators is changed to reflect them. Training is conducted as soon as is practicable in accordance with training procedures. Just in Time training is conducted for selected startup tests.

14.2.7 Initial Fuel Loading and Initial Criticality

Initial fuel loading and subsequent initial criticality and power ascension to full licensed power are performed during the startup test program. Prior to the initiation of these operations, the systems and conditions necessary to bring the plant into compliance with the Technical Specifications must be operable and satisfied. These operations are performed in a controlled and safe manner by using test procedures that specify:

- Required prerequisite testing
- Operational status of required systems
- Step-by-step instructions
- Precautions which must be observed
- Actions to be taken in the event of unanticipated or abnormal response

14.2.7.1 Initial Fuel Loading

The minimum conditions for initial core loading include:

- The composition, duties, and emergency procedure responsibilities of the fuel handling crew are established.

- Radiation monitors, nuclear instrumentation, manual initiation controls, and other devices to actuate alarms and ventilation controls are tested and verified to be operable.
- The status of systems required for fuel loading is established and verified.
- The status of protection systems, interlocks, alarms, and radiation protection equipment is established and verified for fuel loading.
- Inspections of fuel and control rods have been made.
- Containment integrity has been established to the extent required by the Technical Specifications.
- The reactor vessel status has been established for fuel loading. Components are verified to be in place or out of the vessel as required for fuel loading.
- Required fuel handling tools are available, operational, and calibrated to include indexing of the manipulator crane with a dummy fuel element. The fuel handling tools have been successfully tested.
- Reactor coolant water quality requirements are established and the reactor coolant water quality is verified.
- The reactor vessel is filled with water to a level at or above the center of the vessel outlet nozzles. The reactor coolant water is circulating at a rate which provides uniform mixing.
- The boron concentration in the reactor coolant is verified to be equal to or greater than required by the plant Technical Specifications for refueling and is being maintained under a surveillance program.
- Sources of unborated water to the reactor coolant system have been isolated and are under a surveillance program.
- At least two neutron detectors are calibrated, operable, and located in such a way that changes in core reactivity can be detected and recorded. One detector is connected to an audible count rate indicator and a containment alarm.
- A response check of nuclear instruments to a neutron source is required within 8 hours prior to loading (or resumption of loading if delayed for 8 hours or more).

Fuel assemblies together with inserted components (control rods, burnable poison assemblies, primary and secondary neutron sources) are placed in the reactor vessel, according to an established and approved sequence.

During and following the insertion of each fuel assembly, until the last fuel assembly has been loaded, the response of the neutron detectors is observed and compared with previous fuel loading data or calculations to verify that the observed changes in core reactivity are as expected. Specific instructions are provided if unexpected changes in reactivity are observed.

Because of the unique conditions that exist during initial fuel loading, temporary neutron detectors may be used in the reactor vessel to provide additional reactivity monitoring. Credit for the use of temporary detectors may be taken in meeting Technical Specifications requirements on the number of operable source range channels.

14.2.7.2 Initial Criticality

Following initial fuel loading, the reactor upper internals and the pressure vessel head are installed. Additional mechanical and electrical tests are performed in preparation for critical and power operations. The following conditions exist prior to initial criticality:

- The reactor coolant system is filled and vented.
- Tests are completed on the control rod drive system that demonstrate that the control rods have been latched, that the control and position indication systems are functioning properly, and that the rod drop time under hot full flow conditions is less than or equal to the Technical Specifications limit.
- Tests are completed that demonstrate that plant control and protection systems are operable and that the reactor trip breakers respond as designed to appropriate trip signals.
- The reactor coolant system is at hot no-load temperature and pressure. The reactor coolant boron concentration is such that the shutdown margin requirements of the Technical Specifications are satisfied for the safe shutdown condition.

Initial criticality is achieved in an orderly, controlled fashion by the combination of shutdown and control bank withdrawal and reactor coolant system boron concentration reduction.

During the approach to initial criticality, the response of the source range nuclear instruments is used as an indication of the rate of reactivity addition and the proximity to a critical condition so that criticality is achieved in a controlled, predictable fashion.

Rates for rod withdrawal and boron reduction are specified in such a way that the startup rate is less than one decade per minute.

Following criticality and prior to operation at power levels greater than 5 percent of rated power, physics tests are performed to verify that the operating characteristics of the reactor core are consistent with design predictions. During these tests, values are obtained for the reactivity worth of control and shutdown rod banks, isothermal temperature coefficient, and critical boron concentration for selected rod bank configurations.

Other tests at low power include verification of the response of the nuclear instrumentation system and radiation surveys.

14.2.7.3 Power Ascension

After the operating characteristics of the reactor have been verified by low-power testing, a power ascension program brings the unit to its full rated power level in successive stages. At each successive stage, hold points are provided to evaluate and approve test results prior to proceeding to the next stage. The minimum test requirements for each successive stage of power ascension are specified in the applicable startup test procedures.

During the power ascension program, tests are performed at various power levels as follows:

- Statepoint data, including secondary system heat balance measurements, are obtained at various power levels up to full licensed power. This information is used to project plant performance during power escalation, provide calibration data for the various plant control and protection systems, and provide the bases for plant trip setpoints.

- At prescribed power levels, the dynamic response characteristics of the primary and secondary systems are evaluated. System response characteristics are measured for design step load changes, rapid load reductions, and plant trips.

- Adequacy of the radiation shielding is verified by gamma and neutron radiation surveys. Periodic sampling is performed to verify the chemical and radiochemical analysis of the reactor coolant.

- Using the incore instrumentation as appropriate, the power distribution of the reactor core is measured to verify consistency with design predictions and Technical Specifications limits on peaking factors.

14.2.8 Initial Test Program Schedule

The schedule for the initial fuel load and for each major phase of the initial test program includes the timetable for generation, review, and approval of procedures as well as the actual testing and analysis of results.

Preoperational testing is performed as system and equipment availability allows. The interdependence of systems is also considered.

Sequencing of the startup tests depends on specified power and flow conditions and intersystem prerequisites. The initial test schedule establishes that, prior to core load, the preoperational test requirements identified in Subsection 14.2.9 are met for those plant structures, systems, and components that are relied upon to prevent, limit, or mitigate the consequences of postulated accidents. Testing is sequenced so that the safety of the plant is not dependent on untested systems, components, or features.

A site-specific initial test program schedule will be provided to the NRC after issuance of the COL. This schedule will address each major phase of the test program (including tests that are required to be completed before fuel load), as well as the organizational impact of any overlap of first unit initial testing with initial testing of the second unit.

The sequential schedule for individual startup tests should establish that testing is completed in accordance with plant technical specification requirements for structures, systems and components (SSC) operability before changing plant modes. Additionally, the schedule establishes that the safety of the plant is not dependent on the performance of untested SSCs. Guidance provided in Regulatory Guide 1.68 is used for development of the schedule.

The ITP Administrative Manual shall include the following controls:

- Test Procedure Development Schedule:

  – Controls to establish a schedule for the development of detailed testing procedures. Startup procedures, to the extent practical, are trial-tested and corrected during the initial test program prior to fuel loading in order to establish their adequacy.

  – Controls to confirm that approved preoperational test procedures are in a form suitable for review by NRC inspectors in accordance with Subsection 14.2.3, or at least 60 days prior to fuel loading for fuel loading and startup test procedures.

  – Controls to provide timely notification to the NRC of changes in approved preoperational and startup test procedures previously available for NRC review.

- Initial Test Program Schedule:
  - Controls to establish a schedule to conduct the major phases of the initial test program, relative to the expected fuel loading date. This is covered in License Conditions in Part 10 of the COL Application.
  - Controls to allow at least 9 months for conducting preoperational testing.
  - Controls to allow at least 3 months for conducting startup testing, including fuel loading, low-power tests, and power-ascension tests.
  - Controls to overlap test program schedules (for multi-unit sites) such that they do not result in significant divisions of responsibilities or dilutions of the staff provided to implement the test program.
  - Controls to sequence the schedule for individual startup tests, insofar as is practicable, such that testing is completed prior to exceeding 25 percent power for the plant SSCs that are relied upon to prevent, limit, or mitigate the consequences of postulated accidents. The schedule should establish that, insofar as is practicable, testing is accomplished as early in the test program as is feasible and that the safety of the plant is not dependent on the performance of untested SSCs.

The milestone schedule for developing plant operating procedures is presented in Table 13.4-201. The operating and emergency procedures are available prior to start of licensed operator training and, therefore, are available for use during the ITP. Required or desired procedure changes may be identified during their use. Administrative procedures describe the process for revising plant operating procedures.

14.2.9 Preoperational Test Descriptions

During preoperational testing, it may be necessary to return system control to Construction organization to repair or modify the system or to correct new problems. Administrative procedures include direction for:

- Means of releasing control of systems and or components to construction.
- Methods used for documenting actual work performed and determining impact on testing.
- Identification of required testing to restore the system to operability/functionality/availability status, and to identify tests to be re-performed based on the impact of the work performed.
- Verifying retests stay in compliance with ITAAC.

Test abstracts are provided for testing of systems/components in accordance with Regulatory Guide 1.68, Revision 2, Appendix A. Test abstracts for preoperational tests contain a section which identifies the test method, acceptance criteria, and functional criteria. Certain criteria in this section may be required to be completed prior to testing; these criteria are considered prerequisites in accordance with Regulatory Guide 1.68. Acceptance criteria are those criteria used to evaluate whether SSCs can successfully perform their safety-related or defense-in-depth functions. All other criteria, listed in this section, are considered functional criteria.

Test procedures, which contain a greater level of detail than test abstracts, will distinguish between acceptance criteria and functional criteria as well as clearly identify the prerequisites required for completion prior to performance of each test.

A limited number of these testing abstracts establish performance parameters of AP1000 design features that will not change from plant to plant. Because the AP1000 design is standardized, these tests need only be performed on the first AP1000 plant. These testing abstracts are clearly identified.

14.2.9.1 Preoperational Tests of Systems with Safety-Related Functions

14.2.9.1.1 Reactor Coolant System Testing

Purpose

The purpose of the reactor coolant system testing is to verify that the as-installed reactor coolant system properly performs the following safety-related functions:

- Provide reactor coolant system pressure boundary integrity as described in Section 5.2
- Provide core cooling and boration in conjunction with the passive core cooling system as described in Sections 5.1 and 6.3
- Measure process parameters required for safety-related actuations and safe shutdown as described in Sections 7.2, 7.3 and 7.4
- Measure selected process parameters required for post-accident monitoring as described in Section 7.5
- Vent the reactor vessel head as discussed in Subsection 5.4.12

Testing is also performed to verify that the system properly performs the following defense-in-depth functions described in Section 5.2:

- Provide forced circulation cooling of the reactor core in conjunction with heat removal by the steam generator(s) as described in Section 5.1
- In conjunction with the steam generator(s) and normal residual heat removal system, provide the capability to remove core decay heat and cool the reactor coolant to permit the reactor to be refueled and started up in a controlled manner
- Provide pressurizer pressure control during normal operation
- Provide pressurizer level control in conjunction with the chemical and volume control system
- Provide pressurizer spray

Prerequisites

The component testing of the reactor coolant system has been successfully completed. The pre-operational testing of the component cooling water system, service water system, chemical and volume control system, main ac power electrical power system, and required interfacing systems is completed to the extent sufficient to support the specified testing. The reactor coolant system is filled, vented, and pressurized above the minimum required pressure for reactor coolant pump operation, and component cooling water flow to the reactor coolant pumps is initiated prior to starting the pumps.

In preparation for the hydrostatic test of the reactor coolant system, the reactor vessel lower and upper internals and the closure head are installed. The closure head studs are properly tensioned for the hydrostatic test pressure. The pressurizer safety valves and instrumentation within the test boundary are either removed, recalibrated or verified to be able to withstand the hydrostatic test pressure. Welds within the test boundaries are verified as ready for hydrostatic testing. A hydrostatic test pump is available for the pressure boundary integrity testing.

General Test Method and Acceptance and Functional Criteria

Reactor coolant system performance is observed and recorded during a series of individual component and system tests. The following testing demonstrates that the reactor coolant system can perform the functions described above and in appropriate design specifications:

a) The integrity and leaktightness of the reactor coolant system and the high-pressure portions of associated systems is verified by performing a cold hydrostatic pressure test in conformance with Section III of the American Society of Mechanical Engineers (ASME) Code. The reactor coolant system is pressurized in stages by operation of the temporary hydrostatic test pump, while monitoring system welds, piping, and components for leaks at each stage. The hydrostatic test verifies that there are no leaks at welds or piping within the test boundaries during the final inspection. Any identified pressure boundary leaks (i.e. piping walls, vessel walls, welds, valve bodies, etc.) are repaired and the hydrostatic test repeated.

   Leakage through valve seats, valve packing, flanges, and threaded or mechanical fittings is acceptable during the hydrostatic test as long as the hydrostatic test pump can maintain the proper test pressure. Leakage through these items may, as necessary and practical, be isolated, repaired, and retested at a later date.

b) Proper operation of the safety-related reactor coolant system and reactor coolant pressure boundary valves is verified by the performance of baseline in-service tests as described in Subsection 3.9.6.

c) The operability of the pressurizer safety valves is demonstrated by a bench test at temperature and pressure with steam as the pressurizing fluid or with a suitable in-situ test. This testing verifies that each pressurizer safety valve actuates at the required set pressure, with appropriate tolerance as specified in the Technical Specifications. The safety valve rated capacity, as recorded on the valve vendor code plates, is verified to be greater than or equal to that described in Section 5.4.

d) During hot functional testing, reactor coolant system leakage is verified to be within the limits specified in the Technical Specifications. Proper calibration and operation of instrumentation, controls, actuations, and interlocks related to reactor coolant system leak detection are verified. The pressurizer water level is set to the no-load level, the chemical and volume control system makeup pumps and letdown line do not operate, and no primary system samples are taken. During this test, the identified and unidentified reactor coolant system leakage rates are determined by monitoring the reactor coolant system water inventory, reactor coolant drain tank level, containment sump level, and other leak detection instrumentation as described in Subsection 5.2.5 over a specified period of time.

e) The leakage across individual valves between high pressure and low pressure systems, as specified in the Technical Specifications, is verified to be less than design requirements.

f) The as-installed safety valve discharge chamber rupture disks are inspected to verify the manufacturer’s stamped set pressure is within the limits specified in the appropriate design specifications.

g) Proper calibration and operation of safety-related instrumentation, controls, actuation signals and interlocks are verified. This testing includes the following:

- Hot leg and cold leg resistance temperature detectors
- Flow instrumentation at selected locations in the reactor coolant loop
- Reactor coolant system wide range pressure transmitters
- Hot leg level instruments
- Pressurizer pressure and level instruments
- Reactor coolant pump bearing water temperature detectors
- Reactor coolant pump speed sensor instruments
- Reactor vessel head vent valve controls

This testing includes demonstration of proper actuation of safety-related functions from the main control room.

h) Automatic trip of the reactor coolant pumps following appropriate safety-related actuation signals is demonstrated.

i) Proper operation of the reactor vessel head vent valves is verified with the reactor coolant system pressurized.

The following testing demonstrates that the system properly performs the defense-in-depth functions described above and in appropriate design specifications:

j) The pressurizer spray valves are verified to operate properly over the range of reactor coolant system operating temperatures and with the reactor coolant pumps operating.

k) Proper calibration and operation of defense-in-depth related instrumentation, controls, actuation signals and interlocks are verified. This testing includes actuation of the pressurizer spray valves on receipt of appropriate signals, as well as actuation from the main control room.

l) Reactor coolant pump and motor performance and operating characteristics are initially verified with the reactor coolant system at cold conditions. This testing includes verification of the proper flow through the reactor coolant system when all four reactor coolant pumps are operated in various combinations and speeds as specified in the appropriate design specifications and operating procedures. In addition, the proper operation of the pump motor instrumentation, alarms, and interlocks is verified including:

- Motor current
- Motor power
- Pump vibration
- Motor Stator temperature
- Proper transfer from variable speed startup operation

m) The reactor coolant system is heated from cold conditions to hot standby conditions by operating the reactor coolant pumps and the pressurizer heaters. The reactor coolant system is operated at conditions representative of full flow for at least 240 hours prior to core loading. The reactor coolant temperature is maintained at or above 515°F for at least one-half of this operating time. In addition to facilitating the reactor coolant system tests that are required to be performed hot and pressurized, these hot functional testing conditions allow the plant operators to control the plant using the plant operating procedures for the reactor coolant system, secondary side systems, and auxiliary systems.

Other preoperational tests that require these hot and/or dynamic conditions are conducted during this hot functional testing period.

n) During hot functional testing, the reactor coolant pump and motor operating characteristics are measured and recorded at various temperature plateaus during reactor coolant system heatup to verify proper operation over their operating temperature range. This testing includes verification of the proper pump flow; proper motor current, power, and stator temperature; and pump vibration level.

o) The pressurizer spray continuous flow rate is established, and the proper spray line temperature is verified for each pressurizer spray line.

p) The proper operation of the pressurizer heaters, pressurizer spray, and pressure control functions and alarms is verified during the heatup, operation at hot functional test conditions, and cooldown of the reactor coolant system.

q) The proper operation of the pressurizer level control functions and alarms is verified during the heatup, operation at hot functional test conditions, and cooldown of the reactor coolant system.

r) The pressure drops across the major components of the reactor coolant system are measured and recorded using temporary instrumentation during flow testing, and verified to be in accordance with appropriate design specifications.

Tests associated with the automatic depressurization functions of reactor coolant system components are described in Subsection 14.2.9.1.3.

14.2.9.1.2 Steam Generator System Testing

Purpose

The purpose of the steam generator system testing is to verify that the as-installed components properly perform the following safety-related functions as described in Sections 5.4, 10.3 and 10.4:

- Provide steam generator isolation, including isolation of the main steam lines, feedwater lines, and blowdown lines
- Remove heat from the reactor coolant system and provide secondary side overpressure protection
- Measure process parameters required for safety-related actuations as described in Sections 7.2, 7.3, and 7.4
- Measure process parameters required for post-accident monitoring as described in Section 7.5

This testing also verifies that the as-installed components properly perform the following defense-in-depth functions as described in Section 10.4:

- Provide heat removal from the reactor coolant system
- Provide overpressure protection for the steam generators to minimize required actuations of the spring-loaded safety valves
- Measure process parameters and provide actuation signals for the diverse actuation system

Prerequisites

The component tests of the as-installed system have been completed. The reactor coolant system as well as other systems used in power generation are functional since portions of the steam generator system testing is performed during the plant hot functional tests. Prerequisite testing of required interfacing systems are completed to the extent sufficient to support the specified testing and the appropriate system configuration. Component testing of the portion of the special monitoring system identified as the digital metal impact monitoring system has been completed to the extent necessary to support preoperational testing. Required electrical power supplies are energized and operational.

General Test Method and Acceptance and Functional Criteria

The performance of the steam generator system is observed and recorded during a series of individual component and integrated system testing that characterizes its modes of operation. The following testing demonstrates that the steam generator system operates as specified in Sections 10.3 and 10.4, and appropriate design specifications:

a) Proper operation of the steam generator system safety-related valves is verified by the performance of baseline in-service tests as described in Subsection 3.9.6. In addition, the ability of these valves to perform their safety related functions is verified during hot functional testing with the steam generators at normal operating pressure and temperature. The following valves are tested:

   - Steam line condensate drain control and isolation valves
   - Main steam line isolation valves
   - Main and startup feedwater isolation valves
   - Steam generator blowdown isolation valves
   - Steam generator power-operated relief valves
   - Main steam isolation valve bypass isolation valves
   - Main and startup feedwater control valves

   This testing includes verification of the capability of the steam generator power operated relief valves to provide the required heat removal rate from steam generators/reactor coolant system.

b) Proper operation of safety-related and defense-in-depth instrumentation, controls, actuation signals, and interlocks is verified. This testing includes actuation of equipment from the main control room.

c) The proper operation of the steam generator safety valves is demonstrated in a bench test at temperature and pressure with steam as the pressurizing fluid or with suitable in-situ testing. The safety valve rated capacity recorded on the valve vendor code plates is verified to be greater than or equal to the required relief capacity.

Heat transfer performance of the steam generator system is verified by startup testing of the reactor coolant system described in other sections.

14.2.9.1.3 Passive Core Cooling System Testing

Purpose

The purpose of the passive core cooling system testing is to verify that the as-installed components and their associated piping and valves properly perform the following safety functions, described in Section 6.3:

- Emergency core decay heat removal
- Reactor coolant system emergency makeup and boration

- Safety injection
- Containment pH control

Prerequisites

The component testing of the passive core cooling system, or of a specific portion of the system to be tested, is successfully completed. The preoperational testing of the reactor coolant system, normal residual heat removal system, chemical and volume control system, the refueling cavity, the Class 1E dc and uninterruptible power supply, the ac electrical power and distribution systems, and other interfacing systems required for operation of the above systems is completed as needed to support the specified testing and system configurations. A source of water, of a quality acceptable for filling the passive core cooling system components and the reactor coolant system, is available.

General Test Method and Acceptance and Functional Criteria

The performance of the passive core cooling system is observed and recorded during a series of individual component testing and testing with the reactor coolant system. The following testing demonstrates that the passive core cooling system operates as described in Section 6.3 and appropriate design specifications.

a) Proper operation of safety-related valves is verified by the performance of baseline in-service tests as described in Subsection 3.9.6. Also, the proper operation of non-safety-related valves is verified including manual valve locking devices. This testing does not include actuation of the squib valves, which is discussed in Item t, below.

b) Proper calibration and operation of safety-related instrumentation, controls, actuation signals, and safety related interlocks as specified in Section 7.6, is verified. This testing includes the following:

   - Passive residual heat removal heat exchanger flow
   - Core makeup tank level
   - In-containment refueling water storage tank level
   - Containment floodup level
   - Core makeup tank inlet/outlet valve controls
   - Passive residual heat removal heat exchanger inlet/outlet valve controls
   - In-containment refueling water storage tank outlet valve controls
   - Containment recirculation valve controls
   - Automatic depressurization valve controls
   - In-containment refueling water storage tank gutter isolation valve controls

   This testing includes demonstration of proper actuation of safety-related functions from the main control room.

c) Proper calibration and operation of instrumentation, controls, and interlocks required to demonstrate readiness of a safety-related component is verified. This testing includes the following:

   - Accumulator pressure and level and alarms
   - Passive residual heat removal heat exchanger temperatures
   - Passive residual heat removal heat exchanger high point vent level
   - Core makeup tank inlet line temperatures
   - Core makeup tank inlet line high point levels
   - Direct vessel injection line temperatures
   - In-containment refueling water storage tank level and temperatures

d) Proper calibration and operation of temporary instrumentation and data recording devices used in this testing is verified. This testing includes the following:

- CMT level
- CMT flow and balance line temperatures
- PRHR supply line temperatures
- Accumulator wide range level
- In-containment refueling water storage tank and sump-recirculation flow
- ADS piping differential pressure

The passive core cooling system emergency core decay heat removal function is verified by the following testing of the passive residual heat removal heat exchanger.

e) During hot functional testing of the reactor coolant system, the heat exchanger supply and return line piping water temperatures are recorded to verify that natural circulation flow can initiate. The measured supply line temperature is > 400°F and the measured return line temperature is < 220°F.

f) Not used.

g) The proper operation of the passive residual heat removal heat exchanger and its heat transfer capability with forced flow is verified by initiating and operating the heat exchanger with all four reactor coolant pumps running. This testing is performed during hot functional testing with the reactor coolant system at an elevated initial temperature $\geq$ 350°F. The heat exchanger heat transfer is determined by measuring the heat exchanger flow rate and its inlet and outlet temperatures while the reactor coolant system is cooled to $\leq$ 250°F. The acceptance criteria for the PRHR HX heat transfer under forced circulation conditions are listed in Table 3.9-17. The heat transfer rate and flow resistance measured in the test should be adjusted to account for differences in the hot leg and IRWST temperatures and number of tubes plugged. The line resistance of the PRHR subsystem is measured. The flow rate and the differential pressure across the PRHR subsystem are used to determine the resistance of the PRHR subsystem. The acceptance criterion for the resistance of the line is $\leq$ 3.085E-06 ft/gpm^2.

h) This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

The passive core cooling system emergency makeup and boration function is verified by the following testing of the core makeup tanks.

i) The resistance of the core makeup tank cold leg balance lines is determined by filling the core makeup tanks with flow from the cold legs. This testing is performed by filling the cold, depressurized reactor coolant system using a constant, measured discharge flow from the normal residual heat removal pumps. The reactor coolant system is maintained at a constant level above the top of the cold leg balance line(s). The normal residual heat removal system flow rate and the differential pressure across the cold leg balance lines are used to determine the resistance of the balance lines. The acceptance criterion for the resistance of these lines is $\leq$ 7.21 x 10^{-6} ft/gpm^2.

j) During hot functional testing of the reactor coolant system, the core makeup tank cold leg balance line piping water temperature at various locations is recorded to verify that the water in this line is sufficiently heated to initiate recirculation flow through the CMTs.

k) This first three plant only test was completed at the first three AP1000 units. This test is not required to be conducted at Vogtle Units 3 & 4.

The passive core cooling system safety injection function is verified by the following testing of the core makeup tanks, accumulators, in-containment refueling water storage tank, containment sump, automatic depressurization, and their associated piping and valves.

l) Proper flow resistance of each of the core makeup tank injection lines is verified by gravity draining each tank filled with cold water through the direct vessel injection flow path, while measuring the CMT level (driving head) and discharge flow rate. Air enters the top of the draining tank from the reactor coolant system cold leg via the cold leg balance line. If necessary, the flow limiting orifice in the core makeup tank discharge line is to be resized, and the core makeup tank retested to obtain the required line resistance. The acceptance criteria for the resistance of these lines are $\leq 2.25 \times 10^{-5}$ ft/gpm^2 and $\geq 1.81 \times 10^{-5}$ ft/gpm^2 with all valves open.

m) The proper flow resistance of each of the accumulator injection lines is verified by performing a blowdown from a partially pressurized accumulator through the direct vessel injection flow path, while measuring the change in accumulator level and pressure. If necessary, the flow orifice in the accumulator discharge line is to be resized and the accumulator retested to obtain the required discharge line resistance. The acceptance criteria for the resistance of these lines are $\leq 1.83 \times 10^{-5}$ ft/gpm^2 and $\geq 1.47 \times 10^{-5}$ ft/gpm^2.

n) The proper flow resistance of each of the in-containment refueling water storage tank injection lines is verified by gravity draining water from the tank through the direct vessel injection flow path, while measuring the water level (driving head) and discharge flow rate using temporary instrumentation. A test fixture with prototypical resistance may be used to simulate the squib valves in the flow paths tested. The acceptance criteria for the resistance of these lines are $\leq 9.09 \times 10^{-6}$ ft/gpm^2 and $\geq 5.35 \times 10^{-6}$ ft/gpm^2 for line A and $\leq 1.05 \times 10^{-5}$ ft/gpm^2 and $\geq 6.15 \times 10^{-6}$ ft/gpm^2 for line B with all valves open.

o) The flow resistance of each of the flow paths from the in-containment refueling water storage tank to each containment sump, and from each containment sump to the reactor is verified by a series of tests. These tests gravity drain water from the in-containment refueling water storage tank to the containment sump, and from the sump through the direct vessel injection flow path, while measuring the storage tank water level (driving head) and injection flow rate using temporary instrumentation. This testing is performed using temporary piping to prevent flooding of the containment. A test fixture with prototypical resistance may be used to simulate the squib valves in the flow paths tested. The acceptance criteria for the resistance of the lines between each containment sump and the reactor are $\leq 1.33 \times 10^{-5}$ ft/gpm^2 for line A and $\leq 1.21 \times 10^{-5}$ ft/gpm^2 for line B with all valves open. The acceptance criterion for the resistance of the lines between the IRWST and each containment sump is $\leq 4.44 \times 10^{-6}$ ft/gpm^2.

p) The resistance of each automatic depressurization stage 1, 2, and 3 flow path and flow path combination is verified by pumping cold water from the in-containment refueling water storage tank into the cold, depressurized, water-filled reactor coolant system; and back to the in-containment refueling water storage tank using the normal residual heat removal pump(s). The resistances are determined by measuring the residual heat removal pump flow rate and the pressure drop across the flow paths tested using temporary instrumentation. The acceptance criteria for the resistance of these lines is $\leq 2.91 \times 10^{-6}$ ft/gpm^2 for each ADS stage 1, 2, 3 group with all valves open.

q) The resistance of each automatic depressurization stage 4 flow path is verified by pumping cold water from the in-containment refueling water storage tank into the cold, depressurized, water-filled reactor coolant system using the normal residual heat removal pump(s). The resistances are determined by measuring the residual heat removal pump flow rate and the pressure drop across the flow paths tested using temporary instrumentation. A test fixture with prototypical resistance may be used to simulate the squib valves in the flow paths tested. The acceptance criteria for the resistance of these lines are:

- Loop 1, sub-loop A: ≤ 5.91 x 10^{-7} ft/gpm^2
- Loop 1, sub-loop C: ≤ 6.21 x 10^{-7} ft/gpm^2
- Loop 2, sub-loop B: ≤ 4.65 x 10^{-7} ft/gpm^2
- Loop 2, sub-loop D: ≤ 6.20 x 10^{-7} ft/gpm^2

r) The proper operation of the vacuum breakers in the automatic depressurization discharge lines is verified.

s) This first three plant only test was completed at the first three AP1000 units. This test is not required to be conducted at Vogtle Units 3 & 4.

t) The proper operation of at least one of each squib valve size and type including a containment recirculation, in-containment refueling water storage tank injection, and a stage 4 automatic depressurization squib valve is demonstrated. Squib valve functionality is validated via squib valve lot acceptance testing. Flow through the actuated squib valves is validated via the squib valve qualification program. This test does not have to be performed in the plant.

u) The proper operation of the containment sump instrumentation is demonstrated by simulating the containment flood-up water levels.

v) The proper operation of the CMT level instrumentation is demonstrated during the draindown testing of the CMTs, specified in Item l) above.

w) This first three plant only test was completed at the first three AP1000 units. This test is not required to be conducted at Vogtle Units 3 & 4.

14.2.9.1.4 Passive Containment Cooling System Testing

Purpose

The purpose of the passive containment cooling system testing is to verify that the as-installed components perform properly to accomplish their safety-related functions to transfer heat from inside the containment to the environment, as described in Subsection 6.2.2. The passive containment cooling water storage tank also provides a safety-related source of makeup water for the spent fuel pool, and provides a seismically qualified source of water for the fire protection system. Testing of these functions are discussed in Subsections 14.2.9.2.7 Spent Fuel Pool Cooling System Testing, and 14.2.9.2.8 Fire Protection System Testing.

Prerequisites

The component testing of the passive containment cooling system is successfully completed. The preoperational testing of the Class 1E dc electrical power and uninterruptible power supply systems, the non-Class 1E electrical power supply system, the compressed and instrument air system, and other interfacing systems required for operation of the above systems is available as needed to

support the specified testing and system configurations. Additionally, a sufficient quantity of acceptable quality water for filling the passive containment cooling water storage tank and draining onto the containment is available, and a means of filling the tank is available.

General Test Method and Acceptance and Functional Criteria

Passive containment cooling system performance is observed and recorded during a series of individual component testing that characterizes passive containment cooling system operation. The following testing demonstrates that the passive containment cooling system operates as described in Section 6.2 and appropriate design specifications:

a) Proper operation of safety-related valves is verified by the performance of baseline in-service tests as described in Subsection 3.9.6.

b) Proper calibration and operation of safety-related, defense-in-depth, and system readiness instrumentation, controls, actuation signals and interlocks as discussed in Sections 7.3 and 7.5 are verified. This testing includes the following:

- Normal range containment pressure
- High range containment pressure
- Passive containment cooling water flow rate
- Passive containment cooling water storage tank level
- Passive containment cooling water isolation valve instrumentation and controls
- Diverse actuation system passive containment cooling initiation
- Passive containment cooling water storage tank water temperature
- Air inlet and shield plate freeze protection heater controls

This testing includes demonstration of proper actuation of these functions from the main control room.

c) Flow testing is performed to demonstrate proper system flow rates by draining the passive containment cooling system water storage tank. This testing demonstrates the proper resistance of the four passive containment cooling water storage tank delivery flow paths. This testing also demonstrates that water is supplied at the specified flow rates and times for 72 hours consistent with the design basis analyses presented in Subsection 6.2.1.

d) The proper operation of the passive containment cooling water distribution bucket and weirs is verified and proper wetting of the containment is observed and recorded during draindown testing in Item c, above. Water delivery and coverage is verified at the initial minimum water level and as each of the first two standpipes is uncovered. Water coverage is measured at any elevation between elevation 266 ft. and the spring line and the base of the upper annulus as described in Subsection 6.2.2.4.2.

e) The proper operation of the drains in the upper containment/shield building annulus to drain the containment cooling water from the annulus floor is verified.

f) Not used.

g) Sample coupons from the containment shell with and without an appropriate coating of paint are laboratory tested to determine their conductivity.

h) The proper operation of each of the passive containment cooling water storage tank recirculation/makeup pumps to makeup sufficient water to the passive containment cooling water storage tank from the passive containment cooling ancillary water storage tank is verified.

14.2.9.1.5 Chemical and Volume Control System Isolation Testing

Purpose

The purpose of the chemical and volume control system isolation testing is to verify that the as-installed components properly perform the following safety-related isolation functions, described in Section 9.3:

- Termination of inadvertent dilution of the reactor coolant boron concentration
- Isolation of unborated water sources for reactor makeup
- Reactor coolant system pressure boundary isolation
- Isolation/termination of excessive makeup to the reactor

Prerequisites

The component testing of the chemical and volume control system has been successfully completed. The required preoperational testing of appropriate support and interfacing systems is completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Performance of the chemical and volume control system isolation functions is observed and recorded during a series of individual component and integrated system testing that characterizes the system isolation modes of operation. The following testing demonstrates that the chemical and volume control system properly performs the safety-related isolations as specified in Section 9.3 and appropriate design specifications:

a) Proper operation of the safety-related valves is verified by the performance of baseline in-service tests as described in Subsection 3.9.6, including:

   - Purification loop isolation valves
   - Letdown isolation valves
   - Demineralized water isolation valves
   - Makeup isolation valves
   - Auxiliary spray isolation valve

b) Proper calibration and operation of safety-related instrumentation, controls, actuation signals and interlocks is verified. This testing includes the following:

   - Purification isolation valve controls
   - Letdown isolation valve controls
   - Demineralized water isolation controls
   - Makeup isolation valve controls

   This testing includes demonstration of proper actuation of safety-related functions from the main control room.

14.2.9.1.6 Main Control Room Emergency Habitability System Testing

Purpose

The purpose of the main control room emergency habitability system testing is to verify that the as-installed components properly perform the safety-related functions described in Section 6.4, including the following:

- Provide sufficient breathable quality air to the main control room

- Maintain the main control room at positive pressure
- Provide passive cooling of designated equipment

In addition, the following safety-related functions performed by the nuclear island nonradioactive ventilation system described in Subsection 9.4.1 are tested:

- Provide isolation of the main control room from the surrounding areas and outside environment during a design basis accident if the nuclear island nonradioactive ventilation system becomes inoperable.

- Monitor the radioactivity in the main control room normal air supply and provide signals to isolate the incoming air and actuate the main control room emergency habitability system.

In addition, the following safety-related functions performed by the potable water system, described in Subsection 9.2.5; the sanitary drainage system, described in Subsection 9.2.6; and the waste water system, described in Subsection 9.2.9, are tested:

- Provide isolation of the main control room from the surrounding areas and outside environment during a design basis accident.

Prerequisites

The component testing of the main control room habitability system has been successfully completed. The required preoperational testing of the compressed and instrument air system, Class 1E electrical power and uninterruptible power supply systems, normal control room ventilation system, and other interfacing systems required for operation of the above systems is available as needed to support the specified testing and system configurations. The main control room air supply tanks are filled with air acceptable for breathing. The main control room construction is complete and its leak-tight barriers are in place.

General Test Method and Acceptance and Functional Criteria

Performance of the main control room habitability system is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the habitability system operates as specified in Section 6.4 and as specified in the appropriate design specifications:

a) Proper operation of safety-related valves is verified by the performance of baseline in-service tests as described in Subsection 3.9.6.

b) Proper calibration and operation of safety-related and system readiness instrumentation, controls, actuation signals and interlocks is verified. This testing includes the following:

   - Air storage tank pressure
   - Refill line connection pressure
   - Main control room differential pressure
   - Air supply line flow rate
   - Controls for the main control room pressure relief valves
   - Controls for the air supply isolation valves
   - Controls for the main control room air inlet isolation valves
   - Air intake radiation
   - Passive filtration line flow rate
   - Filter performance
   - Sanitary drainage system vent isolation valves

c) The proper flow rate of emergency air to the main control room is verified, demonstrating proper sizing of each air flow limiting orifice, proper operation of each air supply pressure regulator, and the ability to maintain proper control room air quality. The MCR passive filtration system flow rate and filter performance will also be verified at this time to ensure a filtration flow rate of at least 600 cfm greater than the main control room emergency habitability system makeup design flow rate. This testing demonstrates the control room pollutant concentrations during the first 6 hours of operation. To determine the control room air quality at 72 hours, the CO_2 concentrations can be predicted based on calculations. The other pollutants described in Table 1 and Appendix C, Table 1 of ASHRAE Standard 62-1989 can be predicted by extrapolating their concentrations for the entire 72-hour period.

d) The ability of the emergency air supply to maintain the main control room at the proper positive pressure is demonstrated, verifying proper operation of the main control room pressure relief dampers.

e) The ability of the emergency air supply to limit air inleakage to the main control room is verified by inleakage testing as specified in Subsection 6.4.5.4.

f) The ability to maintain the main control room environment within specified limits for 72 hours (Reference Subsection 6.4.3.2) is verified with a test simulating a loss of the nuclear island nonradioactive ventilation system. This testing demonstrates the control room heatup from 0 to 6 hours with the actual heat loads from the battery powered equipment and personnel specified for this time period (for the MCR [room 12401], there is automatic de-energization of specific nonsafety-related MCR heat loads). The control room temperature versus time versus heat load data are used to verify the analysis basis used to assure that the control room conditions remain within specified limits for the 72 hour time period. Periodic grab samples will be taken of the control room air environment to support analyses to confirm that specified limits would not be exceeded for 72 hours.

g) The ability to maintain temperatures in the protection and safety monitoring system cabinet and emergency switchgear rooms within specified limits for 72 hours (Reference Subsection 6.4.3.2) is verified with a test simulating a loss of the nuclear island nonradioactive ventilation system. This testing demonstrates the room heatup from 0 to 6 hours with the actual heat loads from battery powered equipment. The room temperature versus time versus heat load data are used to verify the analysis basis used to assure that the room temperature will not exceed the specified limit for the 72 hour time period.

14.2.9.1.7 Expansion, Vibration and Dynamic Effects Testing

Purpose

The purpose of the expansion, vibration and dynamic effects testing is to verify that the safety-related, high energy piping and components are properly installed and supported such that expected movement due to thermal expansion during normal heatup and cooldown, and as a result of transients; thermal stratification and thermal cycling; as well as vibrations caused by steady-state or dynamic effects do not result in excessive stress or fatigue to safety-related plant systems and equipment, as described in Section 3.9.

Prerequisites

The component testing and preoperational testing of the reactor coolant system at cold conditions has been successfully completed. Required portions of the chemical and volume control system, passive core cooling system, normal residual heat removal system, main feedwater system, startup feedwater system, steam generator system, and steam generator blowdown system are operational. Piping and components within the reactor coolant system and steam generator system pressure

boundaries and their associated supports and restraints have been inspected and determined to be installed as designed. Permanently installed support devices have been verified to be in their expected cold, static positions and temporary restraining devices such as hanger locking pins have been removed. The instrumentation required for this testing is installed.

General Test Method and Acceptance and Functional Criteria

During hot functional testing, verifications that ASME Code Class 1, 2, and 3 high-energy piping system components, piping, support, and restraint deflections are unobstructed and within design basis functional requirements. The systems to be monitored during preoperational vibration and dynamic effects tests include:

- ASME Code, Class 1, 2, and 3 piping
- High-energy piping systems inside seismic Category I structures
- High-energy portions of systems whose failure could reduce the functioning of seismic Category I plant features to an unacceptable safety level
- Seismic Category I portions of moderate-energy piping systems located outside the containment

The high-temperature portions of the following systems are considered for inclusion in this test:

- Reactor coolant system
- Chemical and volume control system
- Passive core cooling system
- Steam generator system (including the safety-related portions of main steam system, main and startup feedwater systems, and steam generator blowdown system)
- Normal residual heat removal system

a) Thermal expansion testing during the preoperational testing phase consists of displacement measurements on the above systems during heatup and cooldown of the reactor coolant system and associated systems (including heatup and cooldown of the passive core cooling system). The testing is performed in accordance with Subsection 3.9.2.1.2 and consists of a combination of visual inspections and local and remote displacement measurements. This testing includes the inspection and measurement of deflection data associated with support thermal movements to verify support swing clearance at specified heatup and cooldown intervals; that there is no evidence of blocking of the thermal expansion of any piping or components, other than by installed supports, restraints, and hangers; that spring hanger movements remain within the hot and cold setpoints; that moveable supports do not become fully retracted or extended; and that piping and components return to their approximate baseline cold positions.

b) Vibration testing is performed on safety-related and high-energy system piping and components during both cold and hot conditions to demonstrate that steady-state vibrations are within acceptable limits. See Subsection 3.9.2.1.1 for the acceptable standard for alternating stress intensity due to steady-state vibration. This testing includes visual observation and local and remote monitoring in critical steady-state operating modes. Results are acceptable when visual observations show no signs of excessive vibration and when measured vibration amplitudes are within acceptable levels.

c) Testing for significant vibrations caused by dynamic effects is conducted during hot functional testing and may be performed as part of other specified preoperational tests. This testing is conducted to verify that stress analyses of safety-related and high-energy system piping under transient conditions are acceptable. See Subsection 3.9.2.1.1 for the acceptable standard for alternating stress intensity due to dynamic effects vibration. These tests are performed to verify that the dynamic effects caused by transients such as pump starts and stops, valve stroking, and significant process flow changes are within expected values. These tests include anticipated normal operating evolutions with system differential temperatures, such as startup, which could induce dynamic effects. Suitable instrumentation is used to monitor for the occurrence of water hammer noise and vibration. Visual inspections are performed to confirm the integrity of system piping and supports.

   Deflection measurements during various plant transients are recorded and compared to acceptance limits and it is confirmed that no effects due to water hammer are detected.

d) Not used.

The main control room habitability system is classified as a high energy system based on the pressure criteria, not temperature. Tests that measure thermal movements are not required. Vibration testing of the high pressure portion of the main control room habitability system is performed during testing of the air delivery rate provided to the control room. See Subsection 14.2.9.1.6 for information on the testing of the main control room habitability system.

14.2.9.1.8 Control Rod Drive System

Purpose

The purpose of the control rod drive system testing is to verify the proper operation of the control rod drive mechanisms, motor-generator sets and system components as described in Subsection 3.9.4 and Section 4.6, and in appropriate design specifications.

Prerequisites

The component tests of the control rod system have been completed. Required interfacing systems, as needed, are completed to the extent sufficient to support the specified testing and the appropriate system configuration. Required electrical power supplies are energized and operational.

For the control rod drive mechanism cooling test, the plant is at or near normal operating temperature and pressure, and hot functional testing is in progress. The integrated head and control rod drive mechanism cooling system are in their normal operational alignment.

For the control rod drive mechanism motor-generator sets tests, a three-phase load bank is available for motor generator set testing under loaded conditions.

General Test Method and Acceptance and Functional Criteria

Performance is observed and recorded during a series of individual component and integrated system tests. The following tests verify that the control rod drive system operates properly:

a) Tests are conducted to verify the current command sequence, timing, and rod speed signals by initiating control rod drive mechanism withdrawal and insertion. Proper operation of the bank overlap unit to control rod bank sequence is verified.

b) Tests are conducted to verify the adequacy of the integrated head and control rod drive mechanism cooling system for maintaining control rod drive mechanism temperature. This test is conducted by measuring control rod drive mechanism coil resistances and calculating the coil temperatures.

c) Tests are conducted to verify control rod drive mechanism motor-generator set and system component control circuits, including interlock and alarm functions.

d) Tests are conducted to verify generator phasing for parallel generator operation. Operation of the control rod drive mechanism motor generator sets and control system during starting, running, and parallel operations is verified.

14.2.9.1.9 Reactor Vessel Internals Vibration Testing

Purpose

The AP1000 reactor internals testing is part of a comprehensive vibration assessment program performed in accordance with Regulatory Guide 1.20 as discussed in Subsection 3.9.2.4. This verifies the structural integrity of the AP1000 reactor internals with regard to flow-induced vibrations, as part of an internals vibration assessment program. This program includes visual examination of the reactor internals before and after hot functional testing.

The reactor internals are visually inspected before and after the hot functional test to confirm the structural integrity of the reactor internals with regard to flow-induced vibrations. The major features of the reactor internals outlined in Subsection 3.9.2.4 are visually inspected for signs of abnormal wear and structural changes.

Prerequisites

The component testing of the reactor coolant system has been completed. The first plant only portions of this test have been completed at the first AP1000 unit. The internals pre-test visual inspection has been completed. The internals are installed in the reactor vessel. The reactor vessel head is installed in preparation for the cold hydrostatic test of the reactor coolant system.

General Test Method and Acceptance and Functional Criteria

Pre-test and post-test visual inspections of the internals are performed to confirm that the stresses and wear on the AP1000 internals, due to flow induced vibration during plant operation, are acceptably low. The criteria for evaluating testing results are established in the AP1000 reactor internals flow-induced vibration assessment program (see Section 7 of WCAP-17894), and appropriate design specifications.

Visual inspections are performed before and after the hot functional test. When no indications of harmful vibrations or signs of abnormal wear are detected and no structural damage or changes are apparent, the core support structures are considered to be structurally adequate and sound for operation. If such indications are detected, further evaluation is required.

14.2.9.1.10 Containment Isolation and Leak Rate Testing

Purpose

The purpose of the containment isolation and leak rate testing is to demonstrate that the as-installed containment isolation valves, piping and electrical containment penetrations, and hatches, and the containment vessel properly perform the following safety functions as described in Section 6.2:

- Automatic isolation of the piping penetrating containment required to assure containment integrity

- The containment vessel, penetration, and isolation valve leakage is less than the design basis leakage at or near the containment design pressure consistent with 10 CFR 50, Appendix J pressure test requirements.

Prerequisites

The component testing of the containment, containment hatches/airlocks and containment penetrations including the containment pressure test as specified in Subsection 3.8.2.7 has been completed. The component testing of the piping and isolation valves or electrical wiring through the penetrations, has been completed. The instrumentation to be used in performing the Type A, B, and C testing is calibrated and available, including their associated data processing equipment. The required preoperational testing of the protection and safety monitoring system, plant control system, the Class 1E electrical power uninterruptible power supply, and other interfacing systems required for operation of the containment isolation devices and data collection is available.

General Test Method and Acceptance and Functional Criteria

Containment isolation functions, leak rate, and structural integrity performance are observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the containment functions as described in Section 6.2 and the appropriate design specifications are achieved. The testing is in accordance with the Containment System Leakage Testing Program and is discussed in Subsection 6.2.6, which meets the requirements of ANSI/ANS-56.8-1994, as appropriate.

a) Proper operation of safety-related containment isolation valves, listed in Table 6.2.3-1, is verified by the performance of baseline in-service tests as specified in Subsection 3.9.6.

b) Proper calibration and operation of safety-related containment isolation instrumentation, controls, actuation signals and interlocks is verified. This testing includes actuation of the containment isolation valves from the main control room, and upon receipt of a containment isolation signal.

c) The appropriate Type C leakage testing is performed for each piping path penetrating the containment boundary, verifying the leakage for each containment isolation valve (listed in Table 6.2.3-1) or set of isolation valves. This testing for individual isolation valves may be performed in conjunction with the associated system test.

d) The appropriate Type B leakage testing is performed for each containment penetration whose design incorporates seals, gaskets, sealants, or bellows. This testing includes door or hatch operating mechanisms and seals.

e) A general inspection of the accessible interior and exterior surfaces of the containment structure and components is performed as specified in Subsection 6.2.5.2.2.

f) A Type A integrated leak rate test is performed to verify that the actual containment leak rate does not exceed the design basis leak rate specified in the Technical Specifications.

14.2.9.1.11 Containment Hydrogen Control System Testing

Purpose

The purpose of the containment hydrogen control system testing is to verify that the system properly performs the following non-safety defense-in-depth functions described in Section 6.2:

- Prevent the concentration of hydrogen in containment from reaching the flammability limit.
- Prevent the concentration of hydrogen in containment from reaching the detonation limit.
- Monitor the containment hydrogen concentration as required by Regulatory Guide 1.97.

Prerequisites

The component testing of the containment hydrogen control system is completed. The non-Class 1E dc and uninterruptible power supply system, main ac power system, and other interfacing systems required for operation of the above systems and calibrated data collection instrumentation are available as needed to support the specified testing.

General Test Method and Acceptance and Functional Criteria

Performance of the containment hydrogen control system is observed and recorded during a series of individual component testing. The following testing verifies that the system operates as described in Subsection 6.2.4 and as specified in the appropriate design specifications:

a) Proper operation of the non-Class 1E containment hydrogen concentration instrumentation and alarms is verified.

b) The ability of the passive autocatalytic recombiners to properly respond to a known inlet hydrogen/air mixture is verified by removing and testing one plate or cartridge from each manufacturing lot of catalyst material, contained in each recombiner unit. This verification is performed in accordance with the guidance provided in Subsection 6.2.4.5.1 using a manufacturer's standard test device and test procedure. Plate performance is verified to be consistent with the response obtained in manufacturer's tests.

c) Manual actuation and operation of the hydrogen igniters confirm that the igniters are supplied by two power groups from two subsystems of the non-Class 1E dc and UPS system. Operability of the igniters is confirmed by verification that the igniter surface temperature meets or exceeds the temperature specified in Subsection 6.2.4.

14.2.9.1.12 Protection and Safety Monitoring System Testing

Purpose

The purpose of the protection and safety monitoring system preoperational testing is to verify that the as-installed components properly perform the following safety-related functions, described in Section 7.1:

- Receive and analyze sensor inputs required for reactor trip and automatically initiate reactor trip signals when plant conditions reach the appropriate setpoints

- Provide actuation signals to the engineered safety features to limit the consequences of design basis accidents

- Provide instrumentation and display systems to monitor the safety-related functions of the plant during and following the occurrence of design basis accidents in accordance with Regulatory Guide 1.97

Preoperational testing is also performed to verify proper operation of the following defense-in-depth functions, described in Section 7.1:

- Provide data from the safety-related sensors to the plant control system
- Provide information to the data display and processing system
- Provide data to the monitor bus for use by other systems within the plant

Prerequisites

Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and the initial software diagnostics tests have been completed. Required electrical power supplies and control circuits are energized and operational. Plant systems or components which are to be operated during testing are specifically identified in the preoperational test procedures, are properly aligned, and have proper support systems operating prior to actuation of the particular system or component. Equipment or components which can not be actuated without damage or upsetting the plant are isolated using the test switches provided by the Protection and Safety Monitoring System to block device actuation. Continuity of wiring up to the actuation equipment is verified.

General Test Method and Acceptance and Functional Criteria

Performance of the protection and safety monitoring system is observed and recorded during a series of individual component and integrated tests designed to verify operation of the system components. The following testing verifies that the system operates as described in Section 7.1 and appropriate design specifications:

a) Processing of the analog and digital signals is verified by injecting reference signals and verifying the outputs at the associated division safety display and non-Class1E workstation display.

b) Capability to process sensor data and main control room manual inputs resulting in the initiation of appropriate reactor trip signals is demonstrated by simulating inputs for each of the trip functions. Response times are verified by demonstrating that the applicable trip or actuate signal reaches the actuated equipment within the maximum allowable period following a defined step change in the applicable simulated input, above or below the trip or actuate setpoint. Operation of the protection cabinet trip/normal/bypass switches and indicators for each of the reactor trip functions is demonstrated by verifying appropriate outputs. Verification that the reactor trip bypass logic satisfies the single failure criteria is demonstrated by operating the bypass switches while simulating channel failures. Proper operation of the reactor trip reset function which is a nonsafety function of the Plant Control System (PLS) will be verified.

c) Operation of the reactor trip breakers, including breaker interlock, alarm, and tripping functions and verification that reactor trip response times are less than the specified maximum allowable response times is performed by initiating a manual reactor trip from the main control room. The capability of the undervoltage coil and the shunt trip coil functions to independently trip the reactor trip breakers is verified during this test using the test capabilities provided by the reactor trip switchgear interface.

d) The capability to trip the reactor from the remote shutdown workstation is demonstrated by verifying actuation of the reactor trip breaker undervoltage and shunt trip attachments upon initiation of a reactor trip at the remote shutdown workstation location.

e) The capability of the protection and safety monitoring system to process sensor data and manual inputs, resulting in appropriate engineered safety features actuation at design setpoints, is demonstrated by verifying that injection of simulated inputs for each of the engineered safety features actuation functions results in the proper output as indicated by contact operation, component actuation, or electrical test. Response times associated with the engineered safety features actuation functions are evaluated during these tests to provide verification that the applicable trip or actuate signal reaches the actuated equipment within the maximum allowable period following a defined step change in the applicable simulated

input above or below the trip or actuate setpoint. Operation of the manual actuation/bypass switches and indicators for each of the engineered safety features functions is verified by demonstrating appropriate system outputs. Verification that the engineered safety features bypass logic satisfies the single failure criteria is demonstrated by operating the bypass switches while simulating channel failures. Correct input processing and calculational accuracy of the redundant actuation equipment and operator interface features is verified for each defined engineered safety features actuation function using simulated inputs. Proper operation of the engineered safety features reset functions will be verified.

f) Correct processing of inputs by redundant equipment and operation of the processing, permissive, interlock, display and operator interface features is verified by demonstrating that simulated command inputs result in correct output or actuation functions as indicated by contact operation, component actuation, or electrical test.

g) Accurate processing of component-level manual actuation commands from the main control room to the protection logic cabinets is verified by issuing main control room commands. Processing of component status information is demonstrated by monitoring protection logic cabinet outputs at the associated division safety display and on a non-Class 1E workstation display.

h) Processing of component-level actuation commands from the remote shutdown workstation to the protection logic cabinets is verified by actuating remote shutdown workstation commands. Processing of component status information is verified by monitoring protection logic cabinet outputs on the non-Class 1E remote shutdown workstation display.

i) Operation of the automatic testing features provided in the protection and safety monitoring system is verified by observing the automatic test functions while simulating component failures and utilizing man-machine interface capabilities to evaluate system performance.

j) The capability of the protection and safety monitoring system to provide the plant operator with correct equipment status, component position indication, component control modes and abnormal operating conditions is verified by evaluating system response to simulated inputs representing feedback from actuation devices and position indicators. Communication of information via the plant monitor bus/data display and processing system, such as channel input quality, neutron flux detector high voltage, partial trip/actuation, permissive, interlock, block, reset, bypass, automatic test, reactor trip switchgear and system level actuation status, from the protection and safety monitoring system to external systems is verified by evaluating system response to injected reference signals and operating applicable block and bypass controls.

k) Operation of the qualified data processing equipment is verified by monitoring outputs and qualified display indications generated in response to simulated inputs representing data from the integrated protection cabinets and sensor inputs to the qualified data processing I/O cabinets.

l) Operation of the isolated data links and data highways used for communication between the engineered safety features actuation cabinets and protection logic cabinets is verified.

m) Preoperational testing of plant sensors used to provide data related to plant equipment monitored by the protection and safety monitoring system is performed in conjunction with testing of the respective systems in which these sensors are located.

n) The capability of the protection and safety monitoring system to provide data from the safety-related sensors to the plant control system is verified by injecting reference signals into the integrated protection cabinets and monitoring the plant control system display.

14.2.9.1.13 Incore Instrumentation System Testing

Purpose

The purpose of the incore instrumentation system preoperational testing is to verify that the as-installed components properly perform the following safety-related functions, described in Section 7.1:

- Provide reactor coolant system pressure boundary integrity for the incore instrumentation thimble assemblies which penetrate the upper head of the reactor vessel
- Provide the protection and safety monitoring system with the core exit temperature signals required for post-accident monitoring

Testing is also performed to verify the following nonsafety-related defense-in-depth functions, described in Subsection 4.4.6:

- Provide core exit temperature signals to the diverse actuation system dedicated display in the main control room

Prerequisites

Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Required electrical power supplies are energized and operational.

General Test Method and Acceptance and Functional Criteria

Performance of the incore instrumentation system is observed and recorded during a series of individual component and integrated tests designed to confirm operation of the system components outside the reactor vessel. The following testing verifies that the system operates as described in Section 7.1 and the appropriate design specifications:

a) Reactor coolant system pressure boundary integrity at the incore instrumentation reactor vessel head penetrations is verified during hydrostatic testing of the reactor coolant system.

b) Processing of the incore thermocouple signals is verified by thermocouple signals at the incore instrumentation thimble assembly connectors and verifying the thermocouple signal paths.

14.2.9.1.14 Class 1E DC Power and Uninterruptible Power Supply Testing

Purpose

The purpose of the Class 1E dc power and uninterruptible power supply testing is to verify that the as-installed components properly perform the following safety-related functions described in Section 8.3:

- Provide the electrical power required for the operation of the plant safety-related equipment, equipment controls, and instrumentation

- Provide the required safety-related electrical power for at least 72 hours following a design basis event, independent of both offsite and onsite ac electrical power supplies

- Provide separation and independence of Class 1E power divisions from other Class 1E divisions and non-Class 1E systems

Testing is also performed to verify proper operation of the following defense-in-depth functions described in Subsection 8.3.2:

- The capability to recharge the batteries from the onsite or offsite ac electrical sources is verified so that safety-related functions can be supported for an indefinite time

Prerequisites

The component testing of the Class 1E dc power and uninterruptible power supply components has been completed. The necessary permanently installed and test instrumentation is calibrated and operational. The 480V ac electrical power system is in operation and supplying power to the battery chargers and regulating transformers. A test load is available for the performance of battery capacity tests.

General Test Method and Acceptance and Functional Criteria

Performance of the Class 1E dc power and uninterruptible power supply is observed and recorded during a series of individual component and integrated system tests that characterize the operation of the system. The following testing verifies that this system operates as described in Section 8.3 and appropriate design specifications:

a) The capability of each of the seven Class 1E batteries to provide the required momentary and continuous load is verified by a battery service test performed in accordance with IEEE Standard 450. Following this discharge testing, the voltage of each cell is verified to be greater than or equal to the specified minimum cell voltage.

b) The capacity of each of the seven Class 1E batteries is verified to meet or exceed the required ampere-hour rating by a battery performance test performed in accordance with IEEE Standard 450. Following this discharge testing, the voltage of each cell is verified to be greater than or equal to the specified minimum cell voltage.

c) The capability of each of the seven battery chargers to charge its associated battery at the required rate is verified. This testing includes verification that the individual voltage of each cell is within the specified limits for a charged battery.

d) The capability of each of the six inverters to provide the required output current, frequency, and voltage is verified.

e) The capability of each of the four regulating transformers to provide the proper ac current to the Class 1E ac distribution panels is verified.

f) The capability of each of the static transfer switches to automatically transfer the electrical loads supplied by each inverter to its associated regulating transformer is verified.

g) The separation and independence of each redundant division of the Class 1E dc power and uninterruptible power supply is verified by successively powering only one division at a time and verifying power to the proper loads and the absence of voltage at the bus and loads not under test.

h) The proper calibration and operation of instrumentation and alarms, electrical ground detection, and permissive and prohibitive interlocks is verified.

Testing the Class 1E DC and uninterruptible power supply system battery monitors is not required during the initial test program.

14.2.9.1.15 Fuel Handling and Reactor Component Servicing Equipment Test

Purpose

To verify proper operation of the fuel-handling and reactor component servicing equipment as described in Section 9.1. This includes the refueling machine, fuel handling machine, fuel transfer system, and refueling tools used to lift, transport, or otherwise manipulate fuel, control rods and other incore instruments.

Prerequisites

The component tests have been completed. Prerequisites of the required interfacing systems are completed to the extent sufficient to support the specified testing. Required electrical power supplies are energized and operational. Compressed air, as required for tool operation, is available. The reactor vessel head has been removed, the reactor vessel and refueling cavity are drained, and the area in which the refueling machine moves is free of structures or components that could interfere with fuel handling operations.

The spent fuel pool and fuel transfer canal are drained, and the area in which the fuel handling machine moves is free of any structures or components that interfere with design fuel handling operations.

The fuel transfer system is operable and capable of transporting a dummy fuel assembly from the spent fuel pool to containment. A dummy fuel assembly, resembling an actual fuel assembly in weight, envelope, and mating hardware, is available for use. The fuel transfer system and new fuel elevator are operable as required to permit testing of fuel handling machine functions.

General Test Method and Acceptance and Functional Criteria

The following tests are performed to verify the refueling machine operation:

a) The refueling machine is operated to simulate actual refueling operations, using a dummy fuel assembly. This testing includes manual and automatic modes of operation, displays, interlocks, and limits. These tests verify:

- The ability to move a fuel assembly from the fuel transfer system to the reactor vessel and back
- The consistency of measured trolley, bridge, and hoist speeds with each mode of operation
- The operability of interlocks limiting motion, speed, and weight, including interlocks with other plant equipment
- The operability of displays indicating position, mode, alarm status, and load
- The adequacy of indexing (by placing the dummy fuel assembly in selected core locations)

b) A known weight or a calibrated spring scale is used to calibrate and set the load limits for the refueling machine load cells. A static load test or the manufacturer's test results are used to verify the ability of the refueling machine hoists to support 125 percent of their rated loads.

The following tests are performed to verify the operation of the fuel handling machine:

c) The fuel handling machine is operated to simulate actual refueling operations, using a dummy fuel assembly. These tests verify:

- The ability to transfer fuel assemblies between the new fuel elevator, fuel transfer system, fuel storage racks, and other areas of the pool where fuel is serviced or stored
- The consistency of measured trolley, bridge, and hoist speeds with each mode of operation
- The operability of interlocks limiting motion, speed, and weight, including interlocks with other plant equipment
- The operability of displays indicating position, mode, alarm status, and load

d) The fuel handling machine is operated to verify its capability to transfer fuel between the new fuel elevator, fuel transfer system, fuel storage racks, and other areas of the pool where fuel is serviced or stored.

e) A known weight or a calibrated spring scale is used to calibrate and set the load limits for the fuel handling machine load cells. A static load test or the manufacturer's test results are used to verify the ability of the fuel handling machine hoists to support 125 percent of their rated loads.

The following tests are performed to verify the proper operation of the fuel transfer system and refueling tools:

f) Using appropriate plant operating procedures, the operability of the new fuel elevator is verified. Testing is performed to demonstrate the proper operation of controls, displays, and limit switches, including operation of the interlock that prevents raising the elevator when it contains a fuel assembly.

g) Using appropriate plant operating procedures, the fuel transfer system is operated to simulate actual refueling operations, using a dummy fuel assembly. During these operations, the following items are verified:

- The ability to move fuel assemblies between the fuel building and containment, including proper operation of upenders in both locations
- The operability and setpoints of limit switches and of interlocks between stations and with other plant equipment
- The operability of displays indicating mode of operation and status

h) Tests are performed to verify that the refueling tools operate properly. Included are tools for handling new fuel assemblies, fuel assembly inserts, irradiation specimens, control rod drive shafts, as well as tools for such operations as control rod drive shaft latching and reactor vessel stud tensioning. As applicable, power is applied to each tool to verify proper operation

of controls, limit switches, actuators, and indicators. Stud tensioning equipment is checked when assembling the reactor for hot functional testing. The new fuel handling tool is tested with the dummy fuel assembly during the test of the new fuel elevator.

14.2.9.1.16 Long-Term Safety-Related System Support Testing

Purpose

The purpose of this testing is verify the capability to perform the following functions for maintaining the extended operation of the safety-related systems and components as described in Section 1.9:

- Supply makeup water to the passive containment cooling system.
- Supply makeup water to the spent fuel pool.
- Provide electrical power for post-accident instrumentation, control room lighting and ventilation, division B and C I&C room ventilation, passive containment cooling system pumps, ancillary generator room lights, ancillary generator tank heaters.
- Provide ventilation cooling to the main control room.
- Provide ventilation cooling to the Class 1E cabinets for post-accident instrumentation.

Prerequisites

The component tests of the safety-related systems and/or components designed for long-term actions have been successfully completed. The preoperational testing of these systems and/or components, including instrument calibrations, has been completed as required for the specified testing, system configurations, and operations. Equipment required for data collection is available and operable. Water used in this testing should be of a quality suitable for filling the specified components. Equipment used to provide the required long-term actions is available.

General Test Method and Acceptance and Functional Criteria

The ability to perform the required long-term actions is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the long-term actions can be performed as discussed in Section 1.9 and as specified in appropriate design specifications:

a) The ability to provide makeup water to the passive containment cooling water storage tank as described in Subsection 6.2.2 is verified.

b) The ability to provide electrical power to the post-accident monitoring instrumentation, control room lighting and ventilation, division B and C I&C room ventilation, passive containment cooling system pumps, ancillary generator room lights, ancillary generator tank heaters, using the ancillary diesel generators as described in Section 8.3 is verified.

c) The ability to provide main control room ventilation cooling using ancillary fans as described in Subsection 9.4.1 is verified.

d) The ability to provide ventilation cooling to post-accident monitoring instrumentation equipment rooms using ancillary fans as described in Subsection 9.4.1 is verified.

e) The ability to provide makeup water to the spent fuel pool via the safety-related makeup connection from the passive containment cooling system water storage tank, as described in Subsection 9.1.3, is verified.

14.2.9.2 Preoperational Testing of Defense-in-Depth Systems

14.2.9.2.1 Main Steam System Testing

Purpose

The purpose of the main steam system testing is to verify that the as-installed system properly performs the following functions, as described in Sections 10.2, 10.3 and 10.4 and appropriate design specifications:

- Provide backup isolation of the steam lines as credited in the safety analysis by closure of the turbine bypass valves, the main steam moisture separator reheater 2nd stage steam isolation valves, and the turbine steam stop and control valves to prevent blowdown of steam from the steam generators following an event where steam line isolation is required.(1)
- Provide backup isolation of the steam lines not credited in the safety analysis by closure of the auxiliary steam supply isolation valve.(2)
- Provide protection of the turbine from water induction and/or overspeed by closure of the extraction steam isolation and non-return valves.(2)

Notes:

1. This is not a defense-in-depth function but is included in this section of the test descriptions since these backup isolation valves are credited in the safety analysis and included in inservice testing which is not typical of Non-Safety Class E structures, systems and components.
2. These are not defense-in-depth functions but are included in this section since the testing of these valves is performed in the same test procedure as the testing of the backup isolation valves credited in the safety analysis.

Prerequisites

The component tests of the as-installed main steam system have been completed. Prerequisites of the required interfacing systems are completed to the extent sufficient to support the specified testing and the appropriate system configuration.

General Test Method and Acceptance and Functional Criteria

Main steam system performance is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the system operates as described in Sections 10.2, 10.3 and 10.4 and appropriate design specifications:

Proper operation of the following system valves is verified.

- Turbine steam stop and control valves
- Turbine bypass valves
- Auxiliary steam system supply header isolation valve
- Main steam moisture separator reheater 2nd stage steam isolation valves
- Extraction steam isolation and non-return valves

This testing includes actuation of these valves from the main control room.

14.2.9.2.2 Main and Startup Feedwater System

Purpose

The purpose of the main and startup feedwater system testing is to verify that the as-installed system properly performs the following nonsafety-related defense-in-depth function, as described in Subsections 10.4.7 and 10.4.9:

- Provide startup feedwater to the steam generators to remove heat from the reactor coolant system following the loss of normal feedwater

Prerequisites

The component testing of the main and startup feedwater system components and instruments, or specific portion to be tested has been completed. Required interfacing systems are available.

General Test Method and Acceptance and Functional Criteria

The main and startup feedwater system performance is observed and recorded during a series of individual component and integrated system testing. The following defense-in-depth testing demonstrates that the system operates as described in Subsections 10.4.7 and 10.4.9 and appropriate design specifications:

a) Proper operation of defense-in-depth instrumentation, controls, actuation signals and interlocks is verified. This testing includes actuation of startup feedwater pumps and remotely-operated valves from the main control room including isolation of the main feedwater system.

b) The capability of the startup feedwater pumps to operate properly when performing their defense-in-depth function and main feedwater pumps are verified with the steam generator at normal operating pressure. Testing of one Main Feedwater Pump can be performed any time prior to initial criticality during the startup test phase.

c) The capability of the startup feedwater pumps to operate properly with miniflow to the condensate storage tank is verified.

d) The capability to restore normal steam generator water level from the low narrow range water level, without causing unacceptable feedwater or steam generator water hammer, is demonstrated (refer to Subsections 14.2.9.1.7 and 14.2.10.4.18).

14.2.9.2.3 Chemical and Volume Control System Testing

Purpose

The purpose of the chemical and volume control system testing is to verify that the as-installed system properly performs the following defense-in-depth functions described in Subsection 9.3.6 and appropriate design specifications:

- Provide makeup water to the reactor coolant system
- Provide boration of the reactor coolant system
- Provide auxiliary pressurizer spray

Prerequisites

The component testing of the as-installed chemical and volume control system is completed. The following interfacing and support systems are available as necessary to support testing: component cooling water system; service water system; reactor coolant system; electrical power and distribution

systems. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Chemical and volume control system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies the system properly performs the defense-in-depth functions described in Subsection 9.3.6 and appropriate design specifications:

a) Operation of pumps and valves which perform defense-in-depth functions is verified, including:

- Makeup pumps
- Boric acid mixing control valve
- Makeup flow control valve

b) Calibration and operation of defense-in-depth related instrumentation, controls, actuation signals and interlocks is verified, including:

- Automatic makeup pump actuation and shutoff
- Automatic alignment of the boric acid tank
- Pressurizer auxiliary spray initiation and termination
- Letdown/purification isolation

This testing includes actuation of defense-in-depth pumps and remotely-operated valves from the main control room. Pressurizer level control testing is described in Subsection 14.2.9.1.1.

c) The capability of the makeup pumps to operate when performing their normal makeup and pressurizer spray functions is verified with the reactor coolant system at normal operating pressure.

d) The capability of the makeup pumps to operate at miniflow and the operation of the makeup pump miniflow heat exchanger is verified.

e) The proper purification loop flowrate through the demineralizers and filters is verified.

14.2.9.2.4 Normal Residual Heat Removal System Testing

Purpose

The purpose of the normal residual heat removal system testing is to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the following defense-in-depth functions, as discussed in Section 5.4:

- Remove reactor core decay heat and cool the reactor coolant system during shutdown operations at low pressure and temperature
- Remove reactor core decay heat from the reactor coolant system during reduced reactor coolant inventory operations in Modes 5 and 6
- Following actuation of the automatic depressurization system, provide makeup to the reactor coolant system at low pressure

- Circulate and cool water from the containment after draindown of the in-containment water storage tank
- Provide low temperature overpressure protection for the reactor coolant system
- Remove reactor core decay heat and cool the spent fuel pool during refueling operations when the core is off-loaded from the reactor vessel to the spent fuel pool.

Prerequisites

The component testing of the normal residual heat removal system is completed. The required preoperational testing of the in-containment refueling water storage tank, reactor coolant system, passive core cooling system, component cooling water system, service water system, ac electrical power and distribution systems, and other interfacing systems required for operation of the above systems and data collection is available as needed to support the specified testing and system configurations. The reactor coolant system and the in-containment refueling water storage tank have an adequate water inventory to support testing.

General Test Method and Acceptance and Functional Criteria

Normal residual heat removal system performance is observed and recorded during a series of individual component and system testing, that characterizes system operation. The following testing verifies that the normal residual heat removal system performs its defense-in-depth functions as described in Subsection 5.4.7.6.1 and appropriate design specifications:

a) Operation of valves to open, to close, or to control flow as required to perform the above defense-in-depth functions is verified.

b) Operation of system controls, alarms, instrumentation, and interlocks associated with performing the above defense-in-depth functions is verified. In addition, the proper operation of the normal residual heat removal system/reactor coolant system isolation valve interlocks specified in Section 7.6 is verified.

c) The normal residual heat removal system pumps testing includes verification that the pump flow rate corresponds to the expected system alignment, proper pump miniflow operation, and verification that adequate net positive suction head is available for the configurations tested. The following system configurations are tested with each pump operating individually and with two pumps operating:

    - Recirculation from and to the reactor coolant system with the reactor coolant system at mid-loop hot leg water level and atmospheric pressure
    - Makeup to the reactor from the in-containment refueling water storage tank with approximately 4 feet of water in the tank
    - Makeup to the reactor from the cask loading pit with water in the pit at a sufficient level to support pump operation
    - Recirculation from and to the spent fuel pool with the pool at normal minimum level.

d) During the verifications of normal residual heat removal system flow to the reactor coolant system, verify that the pumped flow provides sufficient back pressure to maintain a water level in the CMT.

e) The capability of the normal residual heat removal heat exchangers to provide the required heat removal rate from the reactor coolant system is verified by testing performed with flow from and to the heated reactor coolant system, with each normal residual heat removal pump/heat exchanger operating individually.

f) The capability of the normal residual heat removal heat exchangers to provide the required heat removal rate from the spent fuel pool is verified. Since the spent fuel pool is not heated during pre-operational testing, this verification can be made based on the flowrate from Item c and heat removal capability from Item e, above.

g) Operation of the normal residual heat removal system relief valves which provide low temperature overpressure protection for the reactor coolant system is verified by the performance of baseline in-service testing, as specified in Subsection 3.9.6. The acceptance criteria are based on the valve performance criteria specified in Subsection 5.4.9.

h) Operation of the system to facilitate draining the reactor coolant system water level to near the centerline of the hot leg for reduced inventory operations is verified. This test is performed in conjunction with the chemical and volume control system, and is used to demonstrate the performance of the reactor coolant system hot leg level instruments as discussed in Subsection 14.2.9.1.1.

14.2.9.2.5 Component Cooling Water System Testing

Purpose

The purpose of the component cooling water system testing is to verify that the as-installed system properly performs the following defense-in-depth functions as described in Subsection 9.2.2:

- Provide cooling water to defense-in-depth components and transfer heat to the service water system. In addition, this system provides cooling water to other nonsafety-related components for heat removal.

Prerequisites

The component testing of the component cooling water system is completed. Preoperational testing of the cooled components has been completed as necessary to support testing of the component cooling water system. Required support systems are available, including applicable portions of the service water system and electrical power and distribution systems. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Component cooling water system performance is observed and recorded during a series of individual component and integrated system testing that characterizes the various modes of system operation. The following testing demonstrates that the system operates as described in Subsection 9.2.2 and in appropriate design specifications:

a) Proper operation of the component cooling water pumps is verified.

b) Proper operation of defense-in-depth related instrumentation, controls, actuation signals and interlocks is verified, including:

- Automatic pump actuation if an operating pump stops
- Pump flow rate
- Pump discharge pressure
- Surge tank water level and control

- Water flow rate to defense-in-depth components

This testing includes actuation of the system pumps and remotely-operated valves from the main control room as appropriate.

c) The capability to provide the expected cooling water flow rates to and from the required components with both pumps operating, and with either individual pump and heat exchanger operating as specified in the appropriate design specifications is verified.

d) In conjunction with Item c above, the pump(s) runout flow rate is verified to be properly limited, and adequate net positive suction head is verified to be available during its operating modes.

e) The capability of the heat exchanger(s) to transfer heat properly to the service water system is verified under simulated plant conditions during plant hot functional testing. Testing conditions assume both pumps/heat exchangers in operation and with either one of the pumps/heat exchangers operating.

14.2.9.2.6 Service Water System Testing

Purpose

The purpose of the service water system testing is to verify the capability of the as-installed system to perform the following defense-in-depth function as described in Subsection 9.2.1:

- Transfer heat from the component cooling water heat exchangers to the environment

Prerequisites

The component testing of the service water system is completed. Preoperational testing of the component cooling water heat exchangers so that they can receive service water has been completed, as well as the electrical power and distribution systems, and other interfacing systems required for operation of the service water system. Data collection is available as needed to support the specified testing and system configurations. The component cooling water system and components it cools are functional and hot preoperational testing of the reactor coolant system is in progress in order to confirm the service water system heat removal and heat rejection capability.

General Test Method and Acceptance and Functional Criteria

Service water system performance is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the service water system properly performs its defense-in-depth functions, as described in Subsection 9.2.1 and appropriate design specifications:

a) Proper operation of the service water pumps, valves, strainers, cooling tower fans, and freeze protection provisions are verified.

b) Proper operation of the defense-in-depth related instrumentation, controls, actuation signals and interlocks is verified, including:

- Automatic pump actuation if an operating pump stops
- Pump flow rate
- Pump discharge pressure
- Cooling tower water level and control
- Cooling tower basin water temperature and control
- Water supply and return temperature

- Cooling tower fan control

This testing includes actuation of defense-in-depth pumps and remotely-operated valves from the main control room as appropriate.

c) The capability of the pumps to provide the expected cooling flow rates to and from the component cooling water heat exchangers is verified. Testing conditions include both pumps operating and either individual pump operating.

d) In conjunction with Item c above, the pump(s) runout flow rate is verified to be properly limited, and adequate net positive suction head is verified to be available during appropriate operating modes.

e) The heat removal and heat rejection capability of the service water system during the conditions of the plant hot functional testing is verified. Testing conditions include both pumps/cooling towers cells in operation and with either one of the pumps/cooling tower cells operating.

14.2.9.2.7 Spent Fuel Pool Cooling System Testing

Purpose

The purpose of the spent fuel pool cooling system testing is to verify that the system properly performs the following defense-in-depth function described in Subsection 9.1.3:

- Remove heat from the spent fuel stored in the spent fuel pool.
- Prevention of back flow through refueling canal drain lines when other in-containment compartments have been flooded is also verified.

Prerequisites

The component testing of the spent fuel pool cooling system has been completed. The spent fuel pool is filled with water of acceptable quality and chemistry. The ac electrical power and distribution systems and other interfacing systems required for operation of the pumps and for data collection are available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Spent fuel pool cooling system performance is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the system properly performs its defense-in-depth function as described in subsection 9.1.3 and appropriate design specifications:

a) Proper operation of the spent fuel pool cooling pumps, valves, and strainers is verified.

b) Proper operation of the instrumentation, controls, actuation signals, and interlocks is verified, including:

- Pump flow rate
- Pump discharge pressure
- Spent fuel pool water level and control
- Spent fuel pool water temperature
- Water return temperature

This testing includes operation of the system pumps from the main control room.

c) The capability of the pumps to provide the expected cooling flow rates to and from the pool is verified; with both pumps operating, with either individual pump operating, and with either heat exchanger operating.

d) In conjunction with Item c above, the pump(s) runout flow rate is verified to be properly limited, and adequate net positive suction head is verified to be available during the appropriate operating modes.

e) The proper operation of the spent fuel pool siphon breakers is verified.

f) The proper operation of the spent fuel pool post-72 hour gravity drain flowpaths from the cask washdown pit and the passive containment cooling water storage tank is verified.

g) The gates, drains, bellows, and gaskets in the refueling canal and fuel storage pool are checked for unacceptable leakage.

14.2.9.2.8 Fire Protection System Testing

Purpose

The purpose of the fire protection system testing is to verify the system properly performs the following defense-in-depth function as described in Subsection 9.5.1:

- Provide equipment for manual fire fighting in areas containing safe shutdown equipment
- Provide automatic fire suppression in areas containing selected non-safety-related equipment.
- Provide a nonsafety-related containment spray to reduce offsite dose following a severe accident

Prerequisites

The component tests of the fire protection system have been completed. Required preoperational testing of the ac power and distribution systems and other interfacing systems required for operation of the fire protection system. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Fire protection system performance is observed and recorded during a series of individual component and integrated system testing to verify the system performs its defense-in-depth function. The following testing demonstrates that the system performs its defense-in-depth functions specified in Subsection 9.5.1 and as specified in appropriate design specifications:

a) The capability of the seismic standpipes to supply the required fire water quantity and adequate water pressure for effective hose streams as the required flow rate is verified.

b) The operability of the fire detection equipment is verified to be able to properly detect fires and alert personnel.

c) The proper installation and operation of fire barriers, fire walls, and portions of HVAC systems used for smoke control and exhaust is verified.

d) The proper operation of the fire pumps, fire water storage tank, and fire water supply piping, valves, and instrumentation to provide the as-designed fire water supply is verified.

e) The proper installation and operation of automatic fire suppression equipment is verified.

f) The proper installation and operation of electrical isolation devices for non-safety related equipment in opposite divisional fire areas is verified.

g) Operation of the containment spray remotely operated valve and the continuity of a flow path through the containment spray piping is verified.

14.2.9.2.9 Central Chilled Water System Testing

Purpose

The purpose of the central chilled water system testing is to verify that the as-installed low capacity portion of this system properly performs the following defense-in-depth function, as described in Subsection 9.2.7:

- Provide chilled water to cool air used to cool safety-related or defense-in-depth equipment rooms

The proper function of the high capacity portion of this system is also verified.

Prerequisites

The component testing of the low capacity subsystem of the central chilled water system has been completed. The required preoperational testing of the component cooling and service water systems, ac electrical power and distribution systems, and other interfacing systems required for operation of the central chilled water system has been completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Central chilled water system performance is observed and recorded during a series of individual component and integrated system testing. The following testing demonstrates that the central chilled water system performs its defense-in-depth functions described in Subsection 9.2.7 and appropriate design specifications:

a) Proper operation of the low capacity portion of the central chilled water system equipment is verified, including chillers, pumps, and valves.

b) Proper calibration and operation of defense-in-depth related instrumentation, controls, actuation signals and interlocks are verified, including:

   - Temperature control of the chilled water
   - Chiller and chilled water pump actuation
   - Chilled water pump flow
   - Chilled water flow control to air handling units

   This testing includes actuation of the defense-in-depth pumps and remotely operated valves from the main control room.

c) The proper chilled water flow rate to each of the nuclear island nonradioactive ventilation system air handling units is established, and the capability of each pump to provide this chilled water flow rate is verified.

d) In conjunction with Item c above, the pump(s) runout flow rate is verified to be properly limited, and adequate net positive suction head is verified to be available during the appropriate operating modes.

e) The heat removal capability of the air-cooled chillers is verified when the component areas cooled by the nuclear island nonradioactive ventilation system air handling units are operating.

In addition, the operability of the high capacity portion of the central chilled water system described in Subsection 9.2.7 and appropriate design specifications, is verified.

14.2.9.2.10 Nuclear Island Nonradioactive Ventilation System Testing

Purpose

The purpose of the nuclear island nonradioactive ventilation system testing is to verify that the as-installed system properly performs the following defense-in-depth functions, as described in Subsection 9.4.1:

- Protect the main control room and control support area from smoke infiltration
- Provide the capability to remove smoke from the main control room, control support area, and Class 1E electrical equipment rooms
- Provide heating, ventilation, and cooling for the main control room, control support area, and Class 1E electrical equipment rooms
- Provide air filtration to limit radioactivity in the main control room and control support area
- Maintain passive heat sinks at acceptably low initial temperatures
- Maintain the main control room and control support area at positive pressure

The safety-related functions associated with this system are tested as part of the main control room emergency habitability testing described in Subsection 14.2.9.1.6.

Prerequisites

The component testing of the nuclear island nonradioactive ventilation system has been completed. The required preoperational testing of central chilled water system, the hot water heating system, the ac electrical power and distribution systems, and other interfacing systems required for operation of the above systems has been completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Nuclear island nonradioactive ventilation system performance is observed and recorded during a series of individual component and integrated system testing to verify the system performs its defense-in-depth functions. The following testing demonstrates that the system performs its defense-in-depth functions as described in Subsection 9.4.1 and appropriate design specifications:

a) Proper function of the fans, filters, heaters, coolers, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

- Smoke detectors and alarms
- Air handling unit and fan flows, controls, and alarms
- Differential air pressures and alarms
- Air and air filtration unit charcoal temperatures, controls, and alarms
- Air relative humidity measurements, controls, and alarms
- Isolation/shutoff damper controls
- Fire/smoke damper controls

This testing includes operation from the main control room.

c) The proper air flows from and through each air handling unit, as well as to and from the main control room, control support area, and other equipment rooms is established for each mode of operation.

d) The main control room and control support area are verified to be maintained at the proper positive pressure.

e) The main control room, control support area, class 1E equipment rooms, and passive heat sink areas are verified to be maintained at their proper temperature during hot functional testing.

f) Air inleakage into the main control room and control support area is measured using a tracer gas.

14.2.9.2.11 Radiologically Controlled Area Ventilation System

Purpose

The purpose of the radiologically controlled area ventilation system testing is to verify that the as-installed system properly performs the following defense-in-depth function, as described in Subsection 9.4.3:

- In conjunction with the low capacity portion of the central chilled water system, maintain the normal residual heat removal system and chemical and volume control system pump rooms at proper temperature during pump operation

Prerequisites

The component testing of the radiologically controlled area ventilation system has been completed. The required preoperational testing of the central chilled water system, the ac electrical power and distribution systems, and other interfacing systems required for operation of the radiologically controlled area ventilation system has been completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Radiologically controlled area ventilation system performance is observed and recorded during a series of individual component and integrated system testing to verify the system performs its defense-in-depth function as described in Subsection 9.4.3 and appropriate design specifications:

a) Proper function of the defense-in-depth fans, filters, heaters, and coolers is verified.

b) Proper operation of defense-in-depth instrumentation, controls, actuation signals, alarms, and interlocks is verified. This testing includes operation of the normal residual heat removal and chemical and volume control pump room cooler/fans from the main control room.

c) The proper air flow and cooling capability of the normal residual heat removal and chemical and volume control pump room cooler/fans is verified.

d) The proper actuation of the normal residual heat removal and chemical and volume control pump room cooler fans in response to high and low room temperature is verified.

14.2.9.2.12 Plant Control System Testing

Purpose

The purpose of the plant control system testing is to verify that the as-installed components perform the following nonsafety-related defense-in-depth functions, described in Section 7.1:

- Provide control and coordination of the plant during startup, ascent to power, power operation and shutdown conditions by integrating the automatic and manual control of the reactor, reactor coolant and reactor support processes required for normal and off-normal conditions. This includes rod control, pressurizer pressure and level control, steam generator water level control, steam dump (turbine bypass) control and rapid power reduction.

- Provide control of other defense-in-depth systems and components.

Prerequisites

Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and the initial software diagnostics tests have been completed. Required electrical power supplies and control circuits are energized and operational. Required plant control system field wiring is electrically isolated to prevent operation of components controlled by the plant control system. Equipment or components that cannot be operated without damage or upsetting the plant are isolated, either by using test switches provided by the Plant Control System or by racking out power circuit breakers, to block device operation. Continuity of wiring up to the equipment is verified.

General Test Method and Acceptance and Functional Criteria

Performance of the plant control system hardware and software is observed and recorded during a series of individual component and integrated tests designed to verify operation of defense-in-depth functions. The following testing demonstrates that the system operates as described in Section 7.1 and applicable design specifications:

a) Processing of analog and digital signals is verified by injecting reference signals and monitoring the outputs of the plant control system.

b) Interfaces with other applicable plant equipment and systems such as reactor power control, feedwater control and turbine control are verified by demonstrating that injection of simulated inputs for each of the control functions provided in the main control room results in the proper output as indicated by contact operation, component actuation, or electrical test.

c) Interfaces with applicable plant equipment and systems are verified by demonstrating that injection of simulated inputs for selected control functions provided at the remote shutdown workstation results in the proper output as indicated by contact operation, component actuation, or electrical test.

d) Proper operation of defense-in-depth processing, signal selector processing, monitoring, display and operator interface features provided by the plant control system is demonstrated by monitoring system outputs in response to simulated inputs, including simulated device or data highway failures, and utilization of provided self-test functions.

e) Proper functioning of the rod control system is verified by evaluating response to simulated demands from the plant control system and protection and safety monitoring system. The reactor vessel integrated head package is installed for this test and tests f) and g). Control rod drive mechanism operation is verified with all control rod drive mechanism cables connected, and the integrated head and control rod drive mechanism cooling system in operation. Control rod drive mechanisms are operated and current traces are taken to verify proper current, rod speed, and coil timing.

f) Proper operation of the digital rod position indication system is demonstrated by evaluating system response to simulated control rod position inputs, utilizing applicable displays, annunciators and alarms.

g) Proper operation of logic and controls for the pressurizer level and pressure control functions, including interlocks and equipment protective devices, is demonstrated by injecting simulated input signals representing anticipated pressurizer level and pressure transients.

14.2.9.2.13 Data Display and Processing System Testing

Purpose

The purpose of the data display and processing system testing is to verify that the as-installed components properly perform the following nonsafety-related defense-in-depth functions, described in Section 7.1:

- Display plant parameters for normal and emergency operations
- Provide plant alarm functions for normal and emergency plant operations
- Provide operational support for plant personnel, including computerized, interactive plant procedures
- Provide analysis, logging and historical storage and retrieval of plant data
- Provide a redundant communications network for transmission of plant parameters, plant status, displays, alarms and data files

Prerequisites

Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and the initial software diagnostics tests have been determined acceptable. Required electrical power supplies are energized and operational. Required system interfaces are connected and available or simulated as necessary to support the specified test configurations.

General Test Method and Acceptance and Functional Criteria

Performance of the data display and processing system hardware and software is observed and recorded during a series of individual component and integrated tests designed to verify that the data display and processing system equipment operates as described in Section 7.1 and the applicable design specifications:

a) Initial operation of installed devices is verified by completing the diagnostics tests provided for the components and equipment.

b) Proper operation of the data display and processing system software and hardware is demonstrated by utilizing the data display and processing system to provide the processing, monitoring, display and operator interface features required during preoperational testing of associated plant instrumentation and control systems.

c) Verification that the time periods associated with accessing displays, displaying data after it has been made available on the plant monitor bus and display refresh or update rates are within the maximum allowable times is demonstrated. This verification is performed while utilizing the data display and processing system to provide the processing, monitoring, display and operator interface features required during preoperational testing of associated plant instrumentation and control systems.

14.2.9.2.14 Diverse Actuation System Testing

Purpose

The purpose of the diverse actuation system preoperational testing is to verify that the as-installed components properly perform the following nonsafety-related defense-in-depth functions, described in Section 7.7:

- Provide diverse (from the safety-related protection and safety monitoring system) automatic actuation of the following:
  - Reactor/turbine trip
  - Passive residual heat removal heat exchanger
  - Core makeup tanks/reactor coolant pump trip
  - Passive containment cooling
  - Isolation of selected containment penetrations
- Provide a diverse, alternate means for manual actuation of reactor trip and engineered safety features functions
- Provide a diverse system for monitoring selected plant parameters used to provide guidance for manual operation and confirmation of reactor trip and selected engineered safety features actuation

Prerequisites

Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and initial system diagnostics tests have been determined acceptable. Required electrical power supplies and control circuits are energized and operational. Required field wiring is electrically isolated to prevent operation of components controlled by the diverse actuation system. Exceptions are specifically identified in the preoperational test procedures if plant systems or components are to be operated during testing and these systems or components are to be properly aligned and have proper support systems operating prior to actuation of the particular system or component. Equipment or components that cannot be actuated without damage or upsetting the plant are isolated using the test switches provided by the Diverse Actuation System to block device actuation. Continuity of wiring up to the actuation equipment is verified.

General Test Method and Acceptance and Functional Criteria

Performance of the diverse actuation system is observed and recorded during a series of individual component and integrated tests designed to verify operation of the system components. The following testing demonstrates that the system operates as described in Section 7.7 and applicable design specifications:

a) Processing of the analog and digital signals is verified by injecting reference signals and verifying the outputs at various locations in the system.

b) Correct outputs or actuation functions, for the automatic actuation logic mode, are verified by demonstrating that injection of simulated inputs for each of the specified actuation functions results in the proper output as indicated by contact operation, component actuation, or electrical test.

c) Correct outputs or actuation functions, for the manual actuation logic mode, are verified by demonstrating that each manual actuation function results in the proper output as indicated by contact operation, component actuation, or electrical test.

d) Proper operation of indications and alarms for the specified inputs, including those which provide reactor trip or engineered safety features actuation status, are verified by injecting simulated input signals.

14.2.9.2.15 Main AC Power System Testing

Purpose

The purpose of the main ac power system testing is to verify that the as-installed components properly perform the following nonsafety-related function:

- Provide ac electrical power to plant nonsafety-related loads as described in Subsection 8.3.1; and the following nonsafety-related function:

- Provide onsite power for post-72 hour electrical requirements.

Prerequisites

The component tests for the individual components associated with the main ac power system have been completed. The required test instrumentation is properly calibrated and operational. Additionally, the plant offsite grid connection is complete and available.

General Test Method and Acceptance and Functional Criteria

The capability of the main ac power system to provide power to plant loads under various plant operating conditions is verified. The system components to be tested include the ancillary diesel generator, the medium and low voltage power system, load centers, motor control centers, and instrumentation and controls. The following tests verify that the main ac power system provides its functions as specified in Subsection 8.3.1 and appropriate design specifications:

a) Verify the operability of medium-voltage supply breakers.

b) Energize the diesel-backed buses from their associated onsite standby diesel-generator supplies. Verify the bus voltages are within design limits. This test can be performed in conjunction with the testing of the standby diesel generator.

c) Energize the medium voltage buses from their associated unit auxiliary transformer. Verify the bus voltages are within design limits.

d) Energize each medium voltage bus from its applicable reserve auxiliary transformer. Verify the bus voltages are within design limits.

e) Operate the automatic and maintenance bus transfer schemes. Verify successful transfer and return operation.

f) Verify correct operation of the manual controls, annunciation, and instrumentation for the 480 V load centers and their 6900 V feeder breakers.

g) Simulate fault conditions at the 480 V load centers and verify alarms and operation of trip devices and protective relays.

h) Energize the 480 V load centers. Verify the bus voltages are within design limits.

i) Verify the operability of motor control center supply breakers.

j) Simulate fault conditions at the motor control centers and verify alarms and operation of trip devices and protective relays.

k) Energize the motor control centers. Verify the bus voltages are within design limits.

l) Start ancillary diesel generators, energize voltage regulating transformers. Verify the input voltages to the regulating transformers are within design limits.

14.2.9.2.16 Non-Class 1E dc and Uninterruptible Power Supply System Testing

Purpose

The purpose of the non-Class 1E dc and uninterruptible power supply system testing is to verify the ability to provide continuous, reliable power for the non-Class 1E control and instrumentation defense-in-depth loads.

Prerequisites

The component tests for the individual components associated with the non-Class 1E dc and uninterruptible power supply system have been completed. Permanently installed and test instrumentation are properly calibrated and operational. The 480 V ac system is in operation to supply power to the battery chargers. Additionally, a test load is available for the performance of battery capacity tests.

General Test Method and Acceptance and Functional Criteria

The non-Class 1E dc and uninterruptible power supply system consists of electrical equipment including batteries, battery chargers, inverters, static transfer switches, and associated instrumentation and alarms that is used to supply power for the non-Class 1E control and instrumentation loads. Performance is observed and recorded during a series of individual component and integrated system tests. These tests verify that the non-Class 1E dc and uninterruptible power supply system operates as specified in Subsection 8.3.2 and appropriate design specifications:

a) The capability of each non-Class 1E battery serving defense-in-depth loads is verified to meet or exceed the required ampere-hour rating by a battery performance test in accordance with IEEE 450. Following this discharge, the voltage of each cell is verified to be greater than or equal to the specified minimum cell voltage.

b) The capability of each charger serving defense-in-depth loads to meet the rating specified by Table 8.3.2-6 is verified. This testing includes a verification that the charger output voltage is within design limits.

c) The capability of each inverter to meet the rating specified by Table 8.3.2-6 is verified. This testing includes a verification that the output frequency and voltage to be within the limits specified in Table 8.3.2-6.

d) The proper operation and calibration of instrumentation and alarms, electrical ground detection, and permissive and prohibitive interlocks is verified.

Testing the non-class 1E dc and uninterruptible power supply system battery monitors is not required during the initial test program.

14.2.9.2.17 Standby Diesel Generator Testing

Purpose

The purpose of the standby diesel generator testing is to verify the capability to provide electrical power to plant nonsafety-related loads that enhance an orderly plant shutdown if off-site ac power is not available.

Prerequisites

The component tests have been completed. The necessary permanently installed instrumentation is properly calibrated and operational. Appropriate electrical power sources and diesel generator building heating and ventilation system are available for use. The plant control system is available for operation as applicable to the diesel generators. Sufficient diesel fuel is available, on site or readily accessible, to perform the tests.

General Test Method and Acceptance and Functional Criteria

Performance is observed and recorded during a series of individual component and integrated tests. These tests verify that the diesel generators operate properly as specified in Sections 8.3 and 9.5 through the following testing:

a) Verify the operability of generator protection features described in Subsection 8.3.1.1.2.2.

b) Simulate the loss of ac voltage and verify proper operation of undervoltage relay. Verify sequencer control logic support the description in Tables 8.3.1-1 and 8.3.1-2.

c) Verify the diesel generators fuel transfer pumps start and stop automatically in response to simulated day tank low level and high level signals.

d) Transfer fuel oil from the fuel oil storage tank to the diesel fuel oil day tanks by means of the transfer pumps. Verify flow parameters are within design limits.

e) Verify proper operation of diesel generators building heating and ventilation system fans and dampers, manual and automatic controls, alarms, and indicating instruments, as described in Subsection 9.4.10.

f) Verify the air flow in the diesel generator building heating and ventilation system is acceptable.

g) Verify the diesel generator lockout features (turning gear engaged, emergency stop).

h) Verify that the diesel generator air starting system has sufficient capacity for cranking the engine for prescribed number of automatic or manual starts without recharging.

i) Start the diesel generators. Verify voltage and frequency control.

j) Verify the full load-carrying capability for a period of not less than 24 hours, of which 2 hours at are at a load equivalent to the 2-hour (Standby) rating of the diesel generators and 22 hours at a load equivalent to the continuous rating of the diesel generators. Verify the voltage and frequency requirements are maintained. Verify that the diesel generator cooling system functions within design limits.

k) Following the full-load capability test, simulate loss of ac voltage and verify proper automatic startup, sequencing, and operation of the diesel generators. Verify diesel generators bus de-energization and load shedding. Verify diesel generators attain frequency and voltage within design limits within the time described in Subsection 8.3.1.1.2.3. Verify sequencer control logic meets the description in Tables 8.3.1-1 and 8.3.1-2. Verify that the diesel generators continuous rating is not exceeded. Verify voltage and frequency requirements are maintained.

l) Verify that the rate of fuel consumption and the operation of the fuel transfer pumps and associated components, while providing power to the load equivalent to those specified in Table 8.3.1-1 or 8.3.1-2, are such that the design capacity of the fuel oil storage tanks meets the Subsection 9.5.4 requirement for 7-day storage inventory.

m) With each diesel generator bus supplied only by the diesel generator and supplying loads up to its continuous rating, trip a load equivalent to the largest single load in Table 8.3.1-1 or 8.3.1-2. Verify that the voltage and frequency values are maintained within design limits.

n) With each diesel generator supplying loads up to its continuous rating, trip the generator breaker that supplies power to the diesel generator bus. Verify that the diesel engine continues to run and does not trip on overspeed.

14.2.9.2.18 Radiation Monitoring System Testing

Purpose

The purpose of the radiation monitoring system testing is to verify that the as-installed radiation monitors perform their defense-in-depth function as described in Section 11.5.

Prerequisites

The component testing of the radiation monitoring system has been completed. The radiation monitors have been calibrated and the monitor check sources are installed, as appropriate. The required preoperational testing of the protection and safety monitoring system, plant control system, the electrical power and distribution systems, and other interfacing systems required for operation and data collection is available as needed to support the specified testing.

General Test Method and Acceptance and Functional Criteria

Radiation monitoring system performance is observed and recorded during a series of individual component and integrated system testing to verify the system performs its defense-in-depth

functions. The following testing demonstrates that the system operates as specified in Section 11.5 and as specified in appropriate design specifications:

a) The proper calibration and operation of each radiation detector assembly and associated equipment using a standard radiation source or portable calibration unit are verified.

b) Proper operation of the monitoring equipment and controls required for manually initiated operation of the monitor check sources is verified.

c) Proper operation of the local processors that process and transmit radiation monitoring data to the protection and safety monitoring system or plant control system, as appropriate, is verified.

d) Proper actuation of alarms and signals for actuation of equipment responses following receipt of a high radiation signal is verified.

With the potential exception of the tracer gas and particulates testing, the preoperational testing discussed in Subsection 11.5.7 is performed following successful completion of the testing described above.

14.2.9.2.19 Plant Lighting System Testing

Purpose

The purpose of plant lighting system testing is to verify that the system can perform its defense-in-depth function of providing emergency lighting in the main control room and remote shutdown workstation area to illuminate these areas for emergency operations upon loss of normal lighting, as described in Subsection 9.5.3. In addition, the operability of lighting for emergency ingress and egress is verified.

Prerequisites

The component testing of the plant lighting system is completed. The required preoperational testing of the interfacing and support systems required for testing the emergency lighting function is available as needed to support the specified testing and system configurations including the Class 1E dc and uninterruptible power supply system, and the main ac power system.

General Test Method and Acceptance and Functional Criteria

Plant lighting system performance is observed during a series of individual component and integrated system testing to verify the system capability to perform its defense-in-depth functions. The following testing verifies that the system operates as described in Subsection 9.5.3 and in appropriate design specifications:

a) The proper operation of the plant lighting system emergency lighting is verified when powered from the Class 1E dc and uninterruptible power supply system.

b) Self-contained emergency lighting units are verified to be operable and installed into the proper ingress and egress paths, standby diesel generator rooms, switchgear rooms (annex and turbine buildings), fire pump enclosures, access route between the main control room and remote shutdown workstation, and appropriate connecting corridors and stairwells.

Testing of self contained emergency lighting units can be performed any time prior to use of the secondary system for heat removal during the startup test phase.

14.2.9.2.20 Primary Sampling System Testing

Purpose

The purpose of the primary sampling system testing is to verify that the as installed components properly perform the following nonsafety-related defense-in-depth functions described in Subsection 9.3.3:

- Provide the capability to obtain samples of the reactor coolant, passive core cooling system, containment sump water, and containment atmosphere
- Provide the capability to analyze and measure samples.

Prerequisites

Component testing of the primary sampling system has been completed. Component cooling water is being provided to the sample cooler when samples are taken from the reactor coolant system when it is at elevated temperature. The systems/components to be sampled are filled and at their normal pressure and temperature. The liquid radwaste system is available to receive discharged sample fluid. Electrical power is available for operation of the system components and a source of compressed gas is available for operation of the gas sample eductor.

General Test Method and Acceptance and Functional Criteria

The performance of the primary sampling system is observed and recorded during a series of individual component tests and testing in conjunction with the reactor coolant system and passive core cooling system operation. The following testing demonstrates that the primary sampling system performs its defense-in-depth functions as described in Subsection 9.3.3 and appropriate design specifications.

a) Proper operation of the system's remotely-operated valves and eductor supply pump is verified.

b) Proper calibration and operation of instrumentation, controls, actuation signals, and interlocks are verified.

c) Verify the capability to obtain samples from the reactor coolant system, core makeup tanks, accumulators, containment sump, and containment atmosphere.

d) Verify the ability to return the sample stream fluid to the containment sump or liquid radwaste system, as appropriate.

e) Verify the capability to route sample streams to the laboratory.

f) Verify the operability of the test laboratory equipment used to analyze or measure radiation levels and radioactivity concentrations.

14.2.9.2.21 Annex/Auxiliary Building Nonradioactive HVAC System

Purpose

The purpose of the annex/auxiliary non-radioactive HVAC system testing is to verify that the as installed system properly performs the defense-in-depth function, as described in Subsection 9.4.2, to provide conditioned air to maintain the diesel bus switchgear rooms and battery charger rooms (containing DC switchgear) within their design temperature range during operation of the onsite standby power system.

Prerequisites

The component testing of the annex/auxiliary building HVAC system has been successfully completed. The required preoperational testing of the interfacing systems required for the operation of the above system is completed and these systems are available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

The annex/auxiliary building non-radioactive HVAC system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 9.4.2 and appropriate design specifications:

a) Proper function of the fans, filters, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

- Air handling unit and fan flows, controls, and alarms
- Air temperatures, alarms, and controls
- Damper open, close and modulate control in response to monitored parameters

This testing includes operation from the main control room.

c) The switchgear and equipment room subsystem air handling unit supply and return fans are verified to be automatically connected to the onsite standby power supplies on a loss of power to the buses powered by the standby diesels.

14.2.9.2.22 Pressurizer Surge Line Testing (First Plant Only)

Not used.

14.2.9.3 Preoperational Testing of Nonsafety-Related Radioactive Systems

14.2.9.3.1 Liquid Radwaste System Testing

Purpose

The purpose of the liquid radwaste system testing is to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the following safety-related function described in Subsection 11.2.1.1:

- Prevent back flow through the drain lines from the containment sump to the chemical and volume control system compartment and the passive core cooling system compartments, in order to prevent cross flooding of these compartments

The liquid radwaste system testing is performed to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the nonsafety-related functions described in Subsection 11.2.1.2, including receiving and processing reactor coolant system effluents, radioactive equipment and floor drains, and other radioactive liquid wastes from the plant.

Prerequisites

The component testing of the liquid radwaste system is completed. The required preoperational testing of the interfacing and support systems required for testing has been completed. Data collection is available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Liquid radwaste system performance is observed and recorded during a series of individual component and system testing that characterizes system operation. This testing verifies that the system operates as specified in Section 11.2 and appropriate design specifications.

a) The drain lines from the passive core cooling system compartments and the refueling cavity are verified to provide a flow path to the reactor compartment.

b) Proper operation of the backflow prevention check valves is verified by the performance of baseline in-service tests, as specified in Subsection 3.9.6.

c) Proper operation of the system pumps and valves is verified, including:

- Effluent holdup tank pumps
- Waste holdup tank pumps
- Degasifier separator pumps
- Chemical waste tank pump
- Monitor tank pumps
- Reactor coolant drain tank pumps

d) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified, including:

- Pump controls and alarms
- Tank level control and alarms
- Valve and pump responses to safeguards signals
- Valve and pump responses to high radiation isolation signals

e) In conjunction with the gaseous radwaste system testing in Subsection 14.2.9.3.2, the proper operation of the degasifier is verified.

f) The proper operation of the liquid radwaste filters and ion exchangers is verified.

14.2.9.3.2 Gaseous Radwaste System Testing

Purpose

The purpose of the gaseous radwaste system testing is to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the following nonsafety-related functions described in Section 11.3.

- Collect waste gases that contain radioactivity or hydrogen
- Provide holdup for radioactive waste gases as appropriate

Prerequisites

The component testing of the gaseous radwaste system is completed. The required preoperational testing of the interfacing and support systems required for testing is completed, and data collection is available as needed to support the specified testing and system configurations. In addition, a source of hydrogen and calibration gases is available.

General Test Method and Acceptance and Functional Criteria

The performance of the gaseous radwaste system is observed and recorded during a series of individual component and system tests that characterizes the various modes of system operation.

This testing verifies that the gaseous radwaste system operates as described in Section 11.3 and appropriate design specifications:

a) System and component control circuits, including response to normal control, interlock, and alarm signals are verified. The gaseous radwaste system instrumentation, controls, valves, and interlocks are verified to respond to various inputs and provide proper isolation and alarm signals. Appropriate automatic control functions are verified in response to abnormal conditions inputs.

b) Nitrogen, hydrogen, and calibration gases are routed through the system. Performance characteristics of the instrumentation and control systems are verified, and the delay bed operation is verified.

c) Moist test gas is routed through the system to verify proper moisture removal and detection.

d) The degasifier vacuum pump is verified to operate properly. Manual override of the automatic control functions of the drainpot and moisture separator drain and isolation valves is verified.

e) Sample pumps are operated and the sample flow meter indication is observed.

f) The proper operation of the degasifier moisture separator is demonstrated.

14.2.9.3.3 Solid Radwaste System Testing

Purpose

The purpose of the solid radwaste system testing is to verify that the as-installed components and associated piping, valves, and instrumentation operate properly to prepare waste generated during the normal operation of the plant for processing, packaging, and shipment as described in Subsection 11.4.1.2.

Prerequisites

The component testing of the solid radwaste system is completed. The interfacing and support systems required for testing and data collection are available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

The performance of the solid radwaste system is observed and recorded during a series of individual component and system tests that characterizes the various modes of system operation. This testing verifies that the solid radwaste system operates as described in Section 11.4 and in appropriate design specifications:

a) Tests are performed to verify that manual and automatic system controls, alarms, and instruments are functional; the system instrumentation, controls, valves, and interlocks respond properly to various inputs and provide proper isolation and alarm signals; and appropriate automatic control functions occur in response to abnormal condition inputs.

b) Tests are performed to verify proper system process rates as described in Section 11.4, and that no free liquids are present in packaged waste.

c) The capability to properly transfer and retain spent resins is verified.

d) The capability to properly handle filter cartridges in a manner that minimizes personnel radiation exposure is demonstrated.

Any portion of the Solid Radwaste System testing can be performed any time prior to initial criticality during the startup test phase.

14.2.9.3.4 Radioactive Waste Drain System Testing

Purpose

The purpose of the radioactive waste drain system testing is to verify that the as-installed components and associated piping, valves, and instrumentation properly perform the following functions, described in Section 11.2 and Subsection 9.3.5:

- Drain floor and equipment compartments
- Collect drainage and transfer drainage to the liquid radwaste system

Prerequisites

The component testing of the radioactive waste drain system is completed. The interfacing and support systems required for testing and data collection are available as needed to support the specified testing and system configurations, including the liquid radwaste system and compressed air supply.

General Test Method and Acceptance and Functional Criteria

The performance of the radioactive drain system is observed and recorded during a series of individual component and system tests that characterizes the various modes of system operation. This testing verifies that the system operates as described in Section 11.2 and Subsection 9.3.5, and in appropriate design specifications:

a) Proper operation of system instrumentation, controls, alarms, and interlocks is verified.

b) Proper operation of the system pumps and valves is verified.

c) Proper system and component flow paths and flowrates, including pump capacities and sump tank volumes, is verified.

d) Flow water in each drain path to verify that the drains discharge to their designated destination and that proper drain path segregation is maintained.

14.2.9.3.5 Steam Generator Blowdown System Testing

Purpose

The purpose of the steam generator blowdown system testing is to verify that the as-installed components and associated piping, valves, and instrumentation operate properly to provide an isolatable flow path for the controlled removal of water from the secondary side of the steam generators as described in Section 10.4.

Prerequisites

The component testing of the steam generator blowdown system is completed. The interfacing and support systems required for testing and data collection are available as needed to support the specified testing and system configurations. A portion of this testing is performed during the hot functional testing of the plant, when the steam generators are at or near normal operating pressure and temperature.

General Test Method and Acceptance and Functional Criteria

The performance of the steam generator blowdown system is observed and recorded during a series of individual component and system tests that characterize the various modes of system operation. This testing demonstrates that the system operates as described in Section 10.4 and in appropriate design specifications:

a) Proper operation of system instrumentation, controls, alarms, and interlocks is verified.

b) Proper operation of the system pump and valves is verified.

c) The proper operation of the electrodeionization units is verified.

d) The heat transfer capability of each blowdown heat exchanger is verified.

e) The automatic isolation of steam generator blowdown on Low-2 steam generator narrow range water level is verified.

Any portion of the Steam Generator Blowdown System testing (except automatic isolation described in e) can be performed any time prior to initial criticality during the startup test phase.

Furthermore, UFSAR Section 14.2.9.3.5 testing requirements c) and d) can be performed any time prior to exceeding 30% power during the startup test phase, so long as the flowpath through the blowdown heat exchanger can be placed in service and the blowdown system is available to support sampling and SGS chemistry control.

14.2.9.3.6 Waste Water System Testing

Purpose

The purpose of the waste water system testing is to verify that the as-installed components and associated piping, valves, and instrumentation operate properly to collect and perform appropriate processing of normally non-radioactive drains, as described in Section 11.2 and Subsection 9.2.9.

Prerequisites

The component testing of the waste water system is completed. The interfacing and support systems required for testing and data collection are available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

Waste water system performance is observed and recorded during a series of individual component and system testing that characterizes system operation. This testing verifies that the system operates as described in Section 11.2 and Subsection 9.2.9 and appropriate design specifications.

a) Proper operation of the system pumps and valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks is verified.

c) Proper system and component flow paths and flowrates, including pump capacities and sump tank volumes is verified.

d) Verify the ability of the waste water system radiation alarm to stop the turbine building sump pumps.

14.2.9.4 Preoperational Tests of Additional Nonsafety-Related Systems

14.2.9.4.1 Condensate System Testing

Purpose

The purpose of the condensate system testing is to verify that the as-installed components properly perform the system functions, described in Subsection 10.4.7, of delivering the required flow of heated water from the condenser hotwell to the feedwater system.

Prerequisites

The component testing of the condensate system has been completed. The component testing of the condenser is completed and a source of water of appropriate quality is available for filling the condenser hotwell. The steam generator feedwater system is available to receive flow from the condensate system. Required electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Condensate system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the condensate system can perform its functions as described in Subsection 10.4.7 and appropriate design specifications:

a) Proper operation of the condensate pumps and system valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

c) Proper operation of the heater drains is verified.

d) During the plant hot functional testing, the integrated operation of the condensate system in conjunction with the feedwater system is verified with the condenser and circulating water system in operation.

Any portion of Condensate System testing can be performed any time prior to use of the secondary system for heat removal during the startup test phase.

14.2.9.4.2 Condenser Air Removal System Testing

Purpose

The purpose of the condenser air removal system testing is to verify that the as-installed components properly perform the system functions to establish and maintain the required vacuum in the main condenser, as described in Subsection 10.4.2.

Prerequisites

The component testing of the condenser air removal system has been completed. The component testing of the condenser has been completed and a source of water of appropriate quality is available for filling the condenser hotwell. The turbine gland sealing system and exhaust blower are in operation. A source of steam such as the auxiliary boiler is available. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Condenser air removal system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the condensate system can perform its functions as described in Subsection 10.4.2 and appropriate design specifications:

a) Proper operation of the vacuum pumps and system valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

c) The capability of the vacuum pumps to establish the required vacuum in the main condenser is verified.

14.2.9.4.3 Main Turbine System and Auxiliaries Testing

Purpose

The purpose of the main turbine system testing is to verify that the as-installed main turbine and its auxiliary components properly perform their functions, described in Sections 10.2 and 10.4. This testing includes testing of the turbine gland sealing system, lube oil system, turning gear, turbine controls and protective functions, and moisture separator reheater.

Prerequisites

The component testing of the main turbine and its auxiliaries has been completed. The component testing of the condenser is completed and a source of water of appropriate quality is available for filling the condenser hotwell. The main turbine is on turning gear and the condenser air removal system is operable. A source of steam such as the auxiliary boiler is available. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Because this testing is performed using a temporary steam source, the extent to which the turbine can be tested in preoperational testing is limited. However, the proper function of the turbine auxiliaries is verified to assure the turbine will operate properly when a greater amount of steam is provided.

Main turbine system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the turbine and its auxiliaries function as described in Sections 10.2 and 10.4 and in appropriate design specifications:

a) Proper operation of the turbine lube oil pump and turning gear motor, gland seal exhaust blower, and moisture separator and gland seal valves is verified.

b) Proper operation of system valves including the turbine control and intercept valves is verified.

c) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

d) Proper turbine operation during the turning gear testing is verified. The turning gear engagement and disengagement functions are verified to operate properly.

e) Proper performance of the turbine trip functions is verified.

Any portion of Main Turbine System and Auxiliaries testing can be performed any time prior to placing the main generator on-line during the startup test phase.

14.2.9.4.4 Main Generator System and Auxiliaries Testing

Purpose

The purpose of the main generator system testing is to verify that the as-installed main generator and its auxiliary components properly perform their functions, described in Sections 8.2 and 10.2. This testing includes testing of the generator cooling systems, lube oil system, controls, and protective functions.

Prerequisites

The component testing of the main generator and its auxiliaries has been completed. The component testing of the condenser is completed. The turbine cooling water system is operable, and required support systems, electrical power supplies, and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Performance is observed and recorded during a series of individual component and integrated tests. These tests verify that the generator operated as specified in Sections 8.2 and 10.2 through the following testing:

a) Verify the operability of the generator protection features.

b) Verify proper cooling of the generator stator and rotor.

c) Verify MW, MVAR, and frequency control.

Any portion of Main Generator System and Auxiliaries testing can be performed any time prior to the load swing test described in subsection 14.2.10.4.20 during the startup test phase.

14.2.9.4.5 Turbine Building Closed Cooling Water System Testing

Purpose

The purpose of the turbine building closed cooling water system testing is to verify that the as-installed components properly perform their functions of supplying adequate cooling water to the designated turbine building components, as described in Subsection 9.2.8.

Prerequisites

The component testing of the turbine building closed cooling water system has been completed. The cooled components are operational and operating to the extent possible, especially for verifying the heat exchanger capability. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Turbine building closed cooling water system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 9.2.8 and appropriate design specifications:

a) Proper operation of the system pumps and valves is verified.

b) Proper operation of the system instrumentation, controls, actuation signals, and interlocks is verified.

14.2.9.4.6 Circulating Water System Testing

Purpose

The purpose of the circulating water system testing is to verify that the as-installed components properly perform the functions of cooling and circulating adequate cooling water to the main condenser and turbine building closed cooling water system heat exchangers as described in Subsection 10.4.5.

Prerequisites

The component testing of the circulating water system has been completed. The main condenser and turbine building closed cooling water heat exchangers are operational. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Since there will be little, if any, heat rejected to the circulating water system, verification of the heat removal capability of the cooling tower(s) is performed during the startup testing of the plant when the reactor is producing power.

Circulating water system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 10.4.5 and appropriate design specifications:

a) Proper operation of the system pumps and valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

   The proper operation of the system freeze protection equipment is verified, as applicable.

Any portion of the Circulating Water System testing can be performed any time prior to use of the secondary system for heat removal during the startup test phase.

14.2.9.4.7 Turbine Island Chemical Feed System Testing

Purpose

The purpose of the turbine island chemical feed system testing is to verify that the as-installed components properly perform the functions of adding appropriate chemicals to the condensate, service water, and auxiliary boiler in a controlled manner, as described in Subsection 10.4.11.

Prerequisites

The component testing of the chemical feed system has been completed. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Turbine island chemical feed system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 10.4.11 and appropriate design specifications:

a) Proper operation of the system pumps and valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

Any portion of Turbine Island Chemical Feed System testing can be performed any time prior to use of the secondary system for heat removal during the startup test phase.

14.2.9.4.8 Condensate Polishing System Testing

Purpose

The purpose of the condensate polishing system testing is to verify that the as-installed components properly perform the functions of removing corrosion products, dissolved solids, and other impurities from the condensate system, as described in Subsection 10.4.6.

Prerequisites

The component testing of the condensate polishing system has been completed and a source of water of appropriate quality is available for filling the condenser hotwell. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Condensate polishing system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 10.4.6 and appropriate design specifications:

a) Proper operation of the system valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

14.2.9.4.9 Demineralized Water Transfer and Storage System Testing

Purpose

The purpose of the demineralized water transfer and storage system testing is to verify that the as-installed components properly perform the function of providing reservoirs of demineralized water and deliver deoxygenated, demineralized water to various plant users, as described in Subsection 9.2.4.

Prerequisites

The component testing of the demineralized water transfer and storage system has been completed. The demineralized water treatment system is operational and the equipment which uses demineralized water is able to accept water. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Demineralized water transfer and storage system performance is observed and recorded during a series of individual component and integrated system testing. The following defense-in-depth testing verifies that the system functions as described in Subsection 9.2.4 and appropriate design specifications:

a) Proper operation of the system pumps, valves, blower, and heaters is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

14.2.9.4.10 Compressed and Instrument Air System Testing

Purpose

The purpose of the compressed and instrument air system testing is to verify that the as-installed components properly perform the functions of providing compressed air at the required pressures to various plant users, as described in the Compressed and Instrument Air portion of Section 9.3.

Prerequisites

The component testing of the compressed and instrument air system has been completed. The component cooling water system is operational and providing cooling for the compressor units. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Compressed and instrument air system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system and its plant users, where applicable, function as described in Subsection 9.3.1.4 and appropriate design specifications:

a) Proper operation of the system compressors, receivers, prefilters, air dryers, afterfilters, purifiers, and valves is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

c) Integral testing is performed to verify that the instrument air subsystem can provide sufficient air pressure to accommodate the maximum number of air-operated valves expected to operate simultaneously.

d) Testing is performed to verify the fail-safe positioning of safety-related air-operated valves for complete loss of system pressure, both sudden and gradual, and to partial reduction in system pressure as described in Subsection 9.3.1.4.

e) Proper calibration is verified for system relief valves that protect the system from overpressure conditions.

14.2.9.4.11 Containment Recirculation Cooling System Testing

Purpose

The purpose of the containment recirculation cooling system testing is to verify that the as-installed components properly perform the functions of maintaining the proper containment air temperature during normal plant operation and during refueling and maintenance operations, as described in Subsection 9.4.6.

Prerequisites

The component testing of the containment recirculation cooling system has been completed. The central chilled water system and hot water heating system are operational. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Containment recirculation cooling system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 9.4.6 and appropriate design specifications:

a) Proper operation of the system fans and dampers is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

14.2.9.4.12 Containment Air Filtration System Testing

Purpose

The purpose of the containment air filtration system testing is to verify that the as-installed components properly perform the functions of supplying and exhausting air to maintain the proper containment air pressure, and filter exhaust air to minimize radiation release, as described in Subsection 9.4.7.

Prerequisites

The component testing of the containment air filtration system has been completed. The portions of the radiologically controlled area ventilation system connected to the air filtration system are operational. The hot water heating and chilled water systems are required for verification of the air filtration heating and cooling functions. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Containment air filtration system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 9.4.7 and appropriate design specifications:

a) Proper operation of the system fans and dampers is verified.

b) Proper calibration and operation of the system instrumentation, controls, actuation signals, and interlocks are verified.

c) Proper operation of the containment air filtration filters is verified.

14.2.9.4.13 Plant Communications System Testing

Purpose

The purpose of the plant communications system testing is to verify that the as-installed components properly perform the functions of verifying the proper operation and adequacy of the plant communication systems used during normal and abnormal operations, as described in Section 9.5.

Prerequisites

The component testing of the communication system has been completed. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Plant communications system performance is observed and recorded during a series of individual component and integrated system testing. The inplant communications system includes the following subsystems:

- Wireless telephone system
- Telephone/page system
- Private Branch Exchange (PBX) System
- Sound Powered Phone System
- Emergency Offsite Communication System
- Security Communication System
- Plant Radio System

The following testing verifies that the system functions as described in Section 9.5 and appropriate design specifications:

a) Transmitters and receivers are verified to operate without excessive interference.

b) Proper operation of controls, switches, and interfaces is verified.

c) Proper operation of the public address, including the plant emergency alarms, is verified.

d) The proper operation of equipment expected to function under abnormal conditions such as a loss of electrical power, shutdown from outside the control room, or execution of the plant emergency plan is verified. This functional testing will be performed under conditions that simulate the maximum plant noise levels being generated during the various operating conditions, including fire and accident conditions, to demonstrate system capabilities.

14.2.9.4.14 Mechanical Handling System Crane Testing

Purpose

The purpose of the mechanical handling system crane testing is to verify that the as-installed components properly perform their functions. The test ensures operation and adequacy of the containment polar crane, which is used to lift and relocate components providing access to the reactor fuel, vessel internals, and reactor components during refueling and servicing operations.

In addition, the following load handling systems described in Subsection 9.1.5 are tested; the equipment hatch hoist, the maintenance hatch hoist, and the cask handling crane.

Prerequisites

The component testing of the heavy lift cranes has been completed. Required support systems, electrical power supplies and control circuits are operational. The heavy load analysis, defining the load paths, has been completed.

General Test Method and Acceptance and Functional Criteria

Heavy load crane performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the crane systems function as described in Subsection 9.1.5 and in appropriate design specifications:

a) Proper operation and assembly of the various cables, grapples, and hoists including brakes, limit switches, load cells, and other equipment protective devices are verified.

b) Proper operation of control, instrumentation, interlocks, and alarms is verified.

c) Dynamic and static load testing of cranes and hoists, and associated lifting and rigging equipment are performed including a static load test at 125 percent of rated load and full operational test at 100 percent of rated load.

14.2.9.4.15 Seismic Monitoring System Testing

The seismic monitoring system testing described in this section also applies to site-specific seismic sensors.

Purpose

The purpose of the seismic monitoring system testing is to verify that the as-installed components properly perform the functions of verifying proper operation in response to a seismic event, as described in Section 3.7.

Prerequisites

The component testing of the seismic monitoring system has been completed. Required support systems, electrical power supplies and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

Seismic monitoring system instrumentation performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Section 3.7 and appropriate design specifications:

a) Proper calibration and response of seismic instrumentation are verified, including verification of alarm and initiation setpoints.

b) Proper operation of internal calibration and test features are verified.

c) Proper integrated system response, including actuations, alarms, and annunciations, is verified.

d) Verify the proper operation of the recording and analysis functions on a loss of AC power sourced.

14.2.9.4.16 Special Monitoring System Testing

Purpose

The purpose of the special monitoring system testing is to verify that the as-installed components of the portion of the special monitoring system that is identified as the digital metal impact monitoring system properly perform the following nonsafety-related functions, described in Subsection 4.4.6:

- Detect the presence of metallic debris in the reactor coolant system
- Obtain baseline data for metal impact monitoring prior to power operations

Prerequisites

Related system interfaces are available or simulated as necessary to support the specified test configurations. Component testing and instrument calibrations have been completed. Programming has been completed and initial system diagnostics tests have been determined acceptable. Required electrical power supplies are energized and operational.

General Test Method and Acceptance and Functional Criteria

Performance of the special monitoring system is observed and recorded during a series of individual component and integrated tests designed to verify system operation in response to specified input conditions. The following testing demonstrates that the system operates as described in Subsection 4.4.6 and the applicable design specifications:

a) Proper calibration and response of digital metal impact monitoring instrumentation are verified.

b) Proper operation of the digital metal impact monitoring system is verified by evaluating system response to simulated input signals representing the anticipated signal range.

c) Baseline response data is obtained for the digital metal impact monitoring system to serve as a reference for monitoring degradation of sensor response.

14.2.9.4.17 Secondary Sampling System Testing

Purpose

The purpose of the secondary sampling system testing is to verify that the as-installed components properly perform the following nonsafety-related functions, described in Subsection 9.3.4:

- Provide the capability to continuously or semi-continuously monitor selected secondary water and steam process streams in order to establish and maintain proper water chemistry during plant operation
- Provide the capability to manually analyze additional secondary water and steam process streams

Prerequisites

Component testing of the secondary sampling system has been completed. Cooling water is being provided to the sample coolers when samples are taken from sample points with fluid temperatures exceeding 125°F. The systems/components to be sampled are filled and operating at their preoperational pressure and temperature. Electrical power is available for operation of the on-line chemistry analyzers.

General Test Method and Acceptance and Functional Criteria

The performance of the secondary sampling system is observed and recorded during a series of individual component tests and testing in conjunction with the plant in operation at preoperational pressure and temperature. The following testing verifies that the secondary sampling system operates as described in Subsection 9.3.4 and appropriate design specifications.

a) Proper calibration and operation of on-line continuous and semi-continuous analyzers, data collection and display, controls, and actuation signals to the turbine island chemical feed system are verified.

b) Proper calibration and operation of the portable analyzer are verified.

c) Proper operation of the sample coolers is verified.

d) Capability to obtain grab samples from the sample points is verified.

Any portion of Secondary Sampling System testing can be performed any time prior to placing the main generator on-line during the startup test phase (except for the heater drain system portion of the system, which will be tested as extraction steam increases with the main generator online prior to completion of the startup test phase of the initial test program).

14.2.9.4.18 Turbine Building Ventilation System

Purpose

The purpose of the turbine building ventilation system testing is to verify that the as installed system properly performs the normal air conditioning and ventilation functions, as described in Subsection 9.4.9.

Prerequisites

The component testing of the turbine building ventilation system has been successfully completed. The required preoperational testing of the central chilled water and hot water heating systems, and other interfacing systems required for the operation of the above systems and data collection is completed and these systems are available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

The turbine building ventilation system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 9.4.9 and appropriate design specifications:

a) Proper function of the fans, filters, heaters, coolers, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

- Air handling unit and fan flows, controls, and alarms
- Damper open, close and modulate control

This testing includes operation from the main control room.

Any portion of Turbine Building Ventilation System testing can be performed any time prior to placing the main generator on-line during the startup test phase.

14.2.9.4.19 Health Physics and Hot Machine Shop HVAC System

Purpose

The purpose of the health physics and hot machine shop HVAC system testing is to verify that the as installed system properly performs the normal air conditioning and ventilation functions, as described in Subsection 9.4.11.

Prerequisites

The component testing of the health physics and hot machine shop HVAC system has been successfully completed. The required preoperational testing of the central chilled water and hot water heating systems, and other interfacing systems required for the operation of the above systems is completed and these systems are available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

The health physics and hot machine shop HVAC system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 9.4.11 and appropriate design specifications:

a) Proper function of the fans, filters, heaters, coolers, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

- Radiation detectors and alarms
- Air handling unit and fan flows, controls, and alarms
- Air temperatures, alarms, and controls
- Differential air pressure and alarms
- Damper open, close and modulate control

This testing includes operation from the main control room.

c) The health physics and hot machine shop HVAC system is verified to maintain the access control area and hot machine shop at a slightly negative pressure with respect to outdoors and clean areas of the annex building to prevent unmonitored releases of radioactive contaminants.

14.2.9.4.20 Radwaste Building HVAC System

Purpose

The purpose of the radwaste building HVAC system testing is to verify that the as installed system properly performs the normal air conditioning and ventilation functions, as described in Subsection 9.4.8, as required for personnel and equipment in serviced areas; and provides the proper filtration of air from potentially contaminated areas.

Prerequisites

The component testing of the radwaste building HVAC system has been successfully completed. The required preoperational testing of the central chilled water and hot water heating systems, the ac electrical power and distribution systems, and other interfacing systems required for the operation of the above systems is completed and these systems are available as needed to support the specified testing and system configurations.

General Test Method and Acceptance and Functional Criteria

The radwaste building HVAC system performance is observed and recorded during a series of individual component and integrated system testing. The following testing verifies that the system functions as described in Subsection 9.4.8 and appropriate design specifications:

a) Proper function of the fans, filters, heaters, coolers, and dampers is verified.

b) Proper operation of instrumentation, controls, actuation signals, and alarms and interlocks is verified. This testing includes the following:

- Radiation detectors and alarms
- Air handling unit and fan flows, controls, and alarms
- Air temperatures, alarms, and controls
- Differential air pressures and alarms

- Damper open, close and modulate control in response to monitored parameters

This testing includes operation from the main control room.

c) The radwaste building is verified to be maintained at a slightly negative pressure with respect to outdoors to prevent unmonitored releases of radioactive contaminants.

14.2.9.4.21 Main, Unit Auxiliary and Reserve Auxiliary Transformer Test

Purpose

The purpose of the main, unit auxiliary and reserve auxiliary transformer testing is to demonstrate the energization of the transformers and the proper operation of associated protective relaying, alarms, and control devices.

Prerequisites

The component tests for the individual components associated with the main, unit auxiliary and reserve auxiliary transformers have been completed. The required test instrumentation is properly calibrated and operational. Additionally, the plant offsite grid connection is complete and available.

General Test Method and Acceptance and Functional Criteria

The following tests demonstrate proper energization of the main, unit auxiliary and reserve auxiliary transformers and proper operation of protective relaying, alarms, and control devices associated with the transformers:

a) Energize the unit auxiliary transformers. Verify phase rotation. Verify phase voltages are within design limits.

b) Energize the reserve auxiliary transformers. Verify phase rotation. Verify phase voltages are within design limits.

c) Simulate fault conditions and verify alarms and operation of protective relaying circuits.

14.2.9.4.22 Not Used

14.2.9.4.23 Off-site AC Power Systems

Purpose

Off-site alternating current (ac) power system testing demonstrates the energization and proper operation of the as-installed switchyard components, as described in Section 8.2.

Prerequisites

Component testing of plant off-site ac power systems, supporting systems, and components is completed. The components are operational and the switchyard equipment is ready to be energized. The required test instrumentation is properly calibrated and operational. The off-site grid connection is complete and available.

General Test Method and Acceptance and Functional Criteria

The plant off-site ac power system components undergo a series of individual component and integrated system tests to verify that the off-site ac power system performs in accordance with the associated component design specifications. The individual component and integrated tests include:

a. Availability of ac and direct current (dc) power to the switchyard equipment is verified.

b. Operation of high voltage (HV) circuit breakers is verified.

c. Operation of HV disconnect switches and ground switches is verified.

d. Operation of substation transformers is verified.

e. Operation of current transformers, voltage transformers, and protective relays is verified.

f. Operation of switchyard equipment controls, metering, interlocks, and alarms that affect plant off-site ac power system performance is verified.

g. Design limits of switchyard voltages and stability are verified.

h. Under simulated fault conditions, proper function of alarms and protective relaying circuits is verified.

i. Operation of instrumentation and control alarms used to monitor switchyard equipment status.

j. Proper operation and load carrying capability of breakers, switchgear, transformers, and cables, and verification of these items by a non-testing means such as a QC nameplate check of as built equipment where testing would not be practical or feasible.

k. Verification of proper operation of the automatic transfer capability of the preferred power supply to the maintenance power supply through the reserve auxiliary transformer.

l. Switchyard interface agreement and protocols are verified.

The test results confirm that the off-site ac power systems meet the technical and operational requirements described in Section 8.2.

14.2.9.4.24 Raw Water System

Purpose

Raw water system testing verifies that the as-installed components supply raw water to the circulating water cooling tower basin, service water system cooling tower basin, fire protection water storage tanks, and other systems, as described in Subsection 9.2.11.

Prerequisites

Component testing of the raw water system is completed. The components are operational and the storage tanks and cooling tower basins are able to accept water. Required support systems, electrical power supplies, and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

The raw water system component and integrated system performance is observed to verify that the system functions, as described in Subsection 9.2.11 and in appropriate design specifications. The individual component and integrated system tests include:

a. Operation of the system pumps, traveling screens, automatic strainers, and valves is verified.

b. Operation of the system instrumentation, controls, actuation signals, alarms, and interlocks is verified.

c. Operation of heat tracing on system piping is verified.

14.2.9.4.25 Sanitary Drainage System

Purpose

Sanitary drainage system testing verifies that the as-installed components properly collect and discharge sanitary waste, as described in Subsection 9.2.6.

Prerequisites

Component testing of the sanitary drainage system is completed. Required support systems, electrical power supplies, and control circuits are operational.

General Test Method and Acceptance and Functional Criteria

The sanitary drainage system component and integrated system performance is observed to verify that the system functions, as described in Subsection 9.2.6.2.1 and in appropriate design specifications. The individual component and integrated system tests include:

a. Operation of lift stations and valves is verified.

b. Operation of the system instrumentation, controls, actuation signals, and interlocks is verified.

14.2.9.4.26 Fire Brigade Support Equipment

Purpose

Fire brigade support equipment testing verifies that the equipment operates and is available when needed to perform the fire brigade functions, as described in Section 9.5.

Prerequisites

Equipment is ready and available for testing.

General Test Method and Acceptance and Functional Criteria

The fire brigade support equipment undergoes a series of inspections to verify availability and operability. Equipment is available for selection and use, based on the hazard. Fire brigade support equipment tests include:

a. Location of portable extinguishers is verified; portable extinguishers are verified fully charged.

b. Operation of portable ventilation equipment is verified.

c. Operation of portable communication equipment is verified.

d. Operation of portable lighting is verified.

e. Operation of self-contained breathing apparatus and face masks is verified.

f. Operation of keys to open locked fire area doors is verified.

g. Turnout gear functionality and availability is verified.

h. Compatibility of threads for hydrants, hose couplings, and standpipe risers with the local fire department equipment is verified, or alternatively, an adequate supply of readily available hose thread adaptors is verified.

14.2.9.4.27 Portable Personnel Monitors and Radiation Survey Instruments

Purpose

Portable personnel monitors and radiation survey instruments testing verifies that the devices operate in accordance with their intended function in support of the radiation protection program, as described in Chapter 12.

Prerequisites

Portable personnel monitors, radiation survey instruments, and appropriate certified test sources are on site.

General Test Method and Acceptance and Functional Criteria

The portable personnel monitors and radiation survey instruments are source checked, tested, maintained, and calibrated in accordance with the manufacturers' recommendations. The portable monitors and instruments tests include:

a. Proper function of the monitors and instruments to respond to radiation is verified, as required.

b. Proper operation of instrumentation controls, battery, and alarms, if applicable.

14.2.10 Startup Test Procedures

The startup testing program is based on increasing power in discrete steps. Major testing is performed at discrete power levels as described in Subsection 14.2.7. The first tests during Power Ascension Testing that verify movements and expansion of equipment are in accordance with design, and are conducted at a power level as low as practical (approximately 5 percent).

The governing Power Ascension Test Plan requires the following operations to be performed at appropriate steps in the power-ascension test phase:

- Conduct any tests that are scheduled at the test condition or power plateau.
- Confirm core performance parameters (core power distribution) are within expectations.
- Determine reactor power by heat balance, calibrate nuclear instruments accordingly, and confirm the existence of adequate instrumentation overlap between the startup range and power range detectors.
- Reset high-flux trips just prior to ascending to the next level to a value no greater than 20 percent beyond the power of the next level unless Technical Specification limits are more restrictive.
- Perform general surveys of plant systems and equipment to confirm that they are operating within expected values.
- Check for unexpected radioactivity in process systems and effluents.
- Perform reactor coolant leak checks.

- Review the completed testing program at each plateau; perform preliminary evaluations, including extrapolation core performance parameters for the next power level; and obtain the required management approvals before ascending to the next power level or test condition.

Upon completion of a given test, a preliminary evaluation is performed that confirms acceptability for continued testing. Smaller transient changes are performed initially, gradually increasing to larger transient changes. Test results at lower powers are extrapolated to higher power levels to determine acceptability of performing the test at higher powers. This extrapolation is included in the analysis section of the lower power procedure.

Surveillance test procedures may be used to document portions of tests, and ITP tests or portions of tests may be used to satisfy Technical Specifications surveillance requirements in accordance with administrative procedures. At Startup Test Program completion, a plant capacity warranty test is performed to satisfy the contract warranty and to confirm safe and stable plant operation.

Those tests comprising the startup test phase are discussed in this subsection. For each test a general description is provided for test objective, test prerequisites, test description, and test performance criteria, where applicable. In describing a test, the operating and safety-related characteristics of the plant to be tested and evaluated are identified. The startup test phase also includes any testing from Section 14.2.9 that allows deferral of the applicable testing scope to be completed prior to the specified startup test conditions.

Where applicable, the relevant performance criteria for the test are discussed. Some of the criteria relate to the value of process variables assigned in the design or analysis of the plant, component systems, and associated equipment. Other criteria may be associated with expectations relating to the performance of systems.

The specifics of the startup tests relating to test methodology, plant prerequisites, initial conditions, performance criteria, and analysis techniques are discussed in Section 14.4 in the form of plant, system and component performance and testing procedures.

14.2.10.1 Initial Fuel Loading and Precritical Tests

Tests performed after preoperational testing is complete but prior to initial criticality are described in this section. These tests include those performed prior to core load to verify the plant is ready for core loading, the loading of the core and the tests performed under hot conditions after the core has been loaded but prior to initial criticality.

Tests to be performed prior to and during initial core loading are described in Subsections 14.2.10.1.1 through 14.2.10.1.5. These tests verify the systems necessary to monitor the fuel loading process are operational and that the core loading is conducted properly.

After core load, tests are performed at hot conditions to bring the plant to a final state of readiness prior to initial criticality.

14.2.10.1.1 Fuel Loading Prerequisites and Periodic Checks

Objectives

- Specify the prerequisites for initial fuel loading, including the status of required systems, plant conditions, and special equipment

- Provide a checklist for periodic verification that the conditions required for fuel loading are being maintained

Prerequisites

- Plant systems required for initial fuel loading have been satisfactorily tested and turned over to the plant operating staff, and are in the status specified
- Plant conditions required for initial core loading are as specified
- Special equipment required for initial fuel loading is available and operable

Test Method

- Prior to the beginning of fuel loading, verify and document the required status of test prerequisites
- Throughout fuel loading, verify through periodic checks that conditions required for safe fuel loading are being maintained

Performance Criterion

The required status of prerequisites for initial fuel loading is verified and documented prior to fuel loading and maintained throughout the loading process.

14.2.10.1.2 Reactor Systems Sampling for Fuel Loading

Objective

- Verify that the dissolved boron concentration in the reactor coolant system and directly connected portions of associated auxiliary systems is uniform and equals or exceeds the value required by the plant Technical Specifications for fuel loading.

Prerequisites

- Plant Technical Specifications for fuel loading are complete and verified.
- The boric acid storage tank, chemical and volume control system makeup pumps, and associated piping and equipment are filled and operable.
- The reactor vessel is filled with borated water to a level at or above the centerline of the outlet nozzles.
- The water in the reactor vessel and reactor coolant system piping, including all directly connected auxiliary systems, is borated to a value that equals or exceeds the value specified in the plant Technical Specifications for fuel loading, and that water is circulating through the normal residual heat removal system at a rate that provides reasonable assurance of a uniform concentration.

Test Method

- Operate the normal residual heat removal system until a uniform boron concentration is established, and then obtain boron concentration samples from the reactor vessel and operating residual heat removal loop to verify the concentrations are within a specified range of each other.
- Obtain and analyze samples from at least one representative point in each auxiliary system and at four equidistant depths in the reactor vessel for boron concentration
- Periodically repeat sampling until the performance criteria are met

Performance Criterion

- The minimum boron concentration of all samples equals or exceeds the value specified in the plant Technical Specifications for fuel loading. If the minimum boron concentration criteria is not met, the chemical and volume control system is used to increase the boron concentration to above the specified limit.

14.2.10.1.3 Fuel Loading Instrumentation and Neutron Source Requirements

Objectives

- Verify alignment, calibration, and neutron response of the temporary core loading instrumentation (if temporary instrumentation is implemented to satisfy the test requirements) prior to the start of fuel loading

- Verify the neutron response of the nuclear instrumentation system source range channels prior to the start of fuel loading

- Verify the neutron response of the temporary (if temporary instrumentation is implemented to satisfy the test requirements) and nuclear instrumentation system source range instrumentation prior to resumption of fuel loading following any delay of 8 hours or more

Prerequisites

- The following special equipment is available:

  – The temporary core loading package (if temporary instrumentation is implemented to satisfy the test requirements) consisting of three complete counting channels, including preshipment alignment and calibration data

  – A neutron source, either a portable source or a fuel assembly containing a primary source, with sufficient strength to verify detector response

- Preoperational testing of the nuclear instrumentation system source range channels is completed

Test Method

- Prior to the start of fuel loading, verify the response of temporary (if temporary instrumentation is implemented to satisfy the test requirements) and nuclear instrumentation system source range channels to neutrons by using a neutron source

- Verify proper alignment and calibration of the temporary channels (if temporary instrumentation is implemented to satisfy the test requirements) by comparing the neutron response data to the data obtained during preshipment testing

- Prior to resumption of fuel loading following a delay of 8 hours or more, verify proper operation of the temporary (if temporary instrumentation is implemented to satisfy the test requirements) and nuclear instrumentation system source range channels by performing a neutron response check (using the neutron source) or by statistical analysis of the count rate data

- Verify count rates attributable to core neutrons are available on at least two of the pulse-type nuclear channels (either temporary channels or nuclear instrumentation system source range channels) at all times following the installation of the initial nucleus of nuclear fuel assemblies

(approximately eight fuel assemblies, one of which contains a neutron source) and during subsequent fuel loadings, which permits meaningful Inverse Count Rate Ratio (ICRR) monitoring

Performance Criterion

Equipment used for neutron monitoring during fuel loading is operating correctly and is responsive to changes in neutron flux levels. At least two pulse-type nuclear channels are available and detecting neutrons during fuel loading, following installation of the initial nucleus of fuel assemblies (approximately eight fuel assemblies, one of which contains a neutron source).

14.2.10.1.4 Inverse Count Rate Ratio Monitoring for Fuel Loading

Objective

Verify the neutron monitoring data obtained during initial fuel loading is consistent with calculations showing the predicted response and, for plants subsequent to the first plant, with data obtained during a previous similar fuel loading.

Prerequisites

- Temporary (if temporary instrumentation is implemented to satisfy the test requirements) and plant source range nuclear instrumentation has been operational for a minimum of 60 minutes to allow the equipment to attain stable operating conditions
- The plant is prepared for initial fuel loading
- Neutron monitoring data from a previous similar initial fuel loading or calculations showing the predicted response of monitoring channels are available for evaluating monitoring data

Test Method

- Prior to inserting the first fuel assembly into the reactor vessel, obtain background count rates for each temporary (if temporary instrumentation is implemented to satisfy the test requirements) and plant source range channel
- During the insertion of each fuel assembly, continuously observe the response of at least one channel for unexpected changes in count rate
- Construct a plot of Inverse Count Rate Ratio, versus fuel loading step number, from monitoring data obtained after each fuel assembly is loaded to aid in the assessment of whether fuel loading may continue
- Compare Inverse Count Rate Ratio data to predicted response using data obtained from calculations or obtained during a previous similar fuel loading for plants subsequent to the first plant

Performance Criteria

The following criteria are used to suspend core alterations until evaluated by engineering:

- An unanticipated increase in the neutron count rate by a factor of two occurs in all responding nuclear channels during any single loading step after the initial nucleus of fuel assemblies is loaded (approximately eight fuel assemblies, one of which contains a neutron source)
- An unanticipated increase in the count rate by a factor of five occurs on any individual responding nuclear channel during any single loading step after the initial nucleus of fuel assemblies is loaded (approximately eight fuel assemblies, one of which contains a neutron source)

14.2.10.1.5 Initial Fuel Loading

Objectives

- Establish the conditions under which the initial fuel loading is to be accomplished
- Accomplish initial fuel loading in a safe manner

Prerequisites

- The nuclear design of the initial reactor core specifying the final core configuration of fuel assemblies and inserts is completed.
- Preoperational testing is completed on systems specified as required for initial fuel loading.
- Preoperational testing is completed on required fuel handling tools. Tools are available, operational, and calibrated, including indexing of the manipulator crane with a dummy fuel element.
- Containment integrity is established.
- The reactor vessel is filled with water to a level at or above the center of the vessel outlet nozzles. The water is being circulated at a rate to provide uniform mixing.
- The boron concentration in the reactor coolant equals or exceeds the concentration required by the plant Technical Specifications for refueling. Core moderator chemistry conditions (particularly boron concentration) are prescribed in the core loading procedure document and are verified periodically by chemical analysis of moderator samples taken prior to and periodically during core loading operations.
- Sources of unborated water to the reactor coolant are isolated.
- Temporary (if temporary instrumentation is implemented to satisfy the test requirements) and plant source range channels are operable as required to monitor changes in core reactivity.
- A surveillance program verifies that the conditions for fuel loading are maintained throughout the fuel loading program.
- Auxiliary system status is in accordance with Technical Specification requirements.
- The overall process of initial fuel loading will be supervised by a licensed senior reactor operator with no other concurrent duties.

Test Method

- Place fuel assemblies, together with inserted components (control rods, burnable poison elements, primary and secondary neutron sources), in the reactor vessel one at a time according to an established and approved sequence
- During and following the insertion of each fuel assembly and until the last fuel assembly has been loaded, the response of the neutron detectors is observed and compared to previous fuel loading data, or calculations, to verify that the observed changes in response are as expected
- Check sheets are completed at prescribed intervals verifying that the conditions required for initial fuel loading are being maintained

- Fuel assemblies, together with inserted components (control rod assemblies, burnable poison inserts, source spider, or thimble plugging devices) are placed in the reactor vessel one at a time according to a previously established and approved sequence, which was developed to provide reliable core monitoring with minimum possibility of core mechanical damage. The core loading procedure documents include detailed tabular check sheets that prescribe and verify the successive movements of each fuel assembly and its specified inserts from its initial position in the storage racks to its final position and orientation in the core. Multiple checks are made of component serial numbers and types at successive transfer points to guard against possible inadvertent exchanges or substitutions of components, and fuel assembly status boards are maintained throughout the core loading operation. The results of each loading step will be reviewed and evaluated before the next prescribed step is started.

- Immediately stop loading operations if a decrease in boron concentration greater than 20 ppm is determined from two successive samples of reactor coolant system water until the decrease is explained.

Performance Criteria

All fuel assemblies have been loaded into the vessel in the correct location and orientation consistent with the prespecified configuration for the initial reactor core. All fuel loading steps are documented, including the final core configuration.

14.2.10.1.6 Post-Fuel Loading Precritical Test Sequence

Objective

Specify the sequence of events constituting the precritical test program.

Prerequisites

- Plant system conditions are established as required by the individual test instructions within the precritical test sequence, as described in Subsections 14.2.10.1.7 through 14.2.10.1.20

- The systems, structures, and components required by Technical Specifications shall be operable as required for the specified plant operational mode prior to initiation of precritical testing. Preoperational and precritical tests shall be completed to confirm the operability of required plant safety systems to support precritical testing prior to the initiation of the precritical tests.

Test Method

The instructions establish the sequence for required testing after core loading, until the plant has completed precritical testing.

Performance Criteria

Performance criteria are contained in the various individual tests conducted during this time (Subsections 14.2.10.1.7 through 14.2.10.1.20).

14.2.10.1.7 Incore Instrumentation System Precritical Verification

Objectives

- Verify that the incore instrumentation thimbles have been installed correctly following initial fuel loading

- Verify proper operation of the incore thermocouples prior to plant heatup

Prerequisites

- Initial fuel loading has been completed, all incore instrumentation thimble assemblies have been installed, and all mechanical and electrical connections have been completed, with the exception of the connections to the instruments at the incore instrumentation thimble assembly refueling disconnect.
- The plant is at ambient temperature and pressure prior to heatup for initial criticality.
- Incore instrumentation system signal processing software has been installed and is operational.

Test Method

- With the plant at ambient conditions following initial fuel loading and prior to heatup for initial criticality, make electrical continuity checks at the incore instrumentation system panel to verify proper installation and connection of the incore sensor strings.
- Obtain incore thermocouple data and compare with the measured reactor coolant system temperature to verify proper operation of the incore thermocouples and signal processing.

Performance Criterion

- Prior to plant heatup, proper connections to the incore instrumentation thimbles are verified and outputs from the incore thermocouple system are consistent with existing plant conditions.

14.2.10.1.8 Resistance Temperature Detectors-Incore Thermocouple Cross Calibration

Objectives

- Verify calibration coefficients for the resistance temperature detectors installed in the reactor coolant system.
- Determine calibration coefficients for resistance temperature detectors replaced in the reactor coolant system following hot functional testing as required.
- Verify the incore instrumentation system incore thermocouples are operating within design requirements by comparing the temperature indications to the average of the derived resistance temperature detector temperature indications.

Prerequisites

- Initial fuel loading has been completed and the reactor coolant system is filled and vented prior to heatup for initial criticality.
- Reactor coolant system resistance temperature detectors that were replaced as a result of preoperational testing are operational, and an initial alignment has been completed according to the manufacturer’s calibration data.
- The incore instrumentation system, including signal processing software, has been installed and is operational, and the preoperational testing has been completed.
- Instrumentation and data collection equipment is operational and available for logging plant data.

Test Method

- With the reactor coolant system at ambient temperature, and at isothermal conditions at specified temperature plateaus during heatup to normal operating temperature, collect data from each resistance temperature detector installed in the reactor coolant system and each installed incore thermocouple, along with supplemental plant data.
- Using the calibration coefficients determined during hot functional testing and the manufacturer's resistance versus temperature calibration data for the replaced resistance temperature detectors, determine the best-estimate temperature of each temperature plateau from the average of the median value for each resistance temperature detector's temperature.
- On an iterative basis, recompute the best-estimate plateau temperature after removing from the average calculation the data from resistance temperature detectors whose temperature differs from the average by a predetermined amount.
- Verify or recompute calibration coefficients for each resistance temperature detector, as required, based on the final plateau average temperatures.

Performance Criteria

- For each resistance temperature detector, the adequacy of the final calibration coefficients is verified when the temperature derived from the resistance temperature detector resistance agrees with the plateau average temperatures within predetermined limits.
- The adequacy of each incore thermocouple is verified when the temperature derived from the thermocouple output agrees with the plateau average temperatures within predetermined limits.

14.2.10.1.9 Nuclear Instrumentation System Precritical Verification

Objective

Establish and determine voltage settings, trip settings, operational settings, and alarm settings on source range instrumentation prior to initial criticality.

Prerequisite

The nuclear instrumentation system is aligned according to the design requirements.

Test Method

- Calibrate, test, and verify functions using permanently installed controls and adjustment mechanisms.
- Set operational modes of the source range channels for their proper functions, in accordance with the test instructions.

Performance Criteria

- The source range channels are operable.
- Neutron count rate is greater than or equal to 0.5 cps in Mode 3 for the source range channels in proximity of the primary neutron sources.

- Signal to noise ratio is greater than or equal to 2 for the source range channels in proximity of the primary neutron sources.

14.2.10.1.10 Setpoint Precritical Verification

Objectives

- Prior to fuel load, verify that initial values of instrumentation setpoints assumed in the design, operation, and safety analysis of the nuclear steam supply system have been installed correctly, and identify which of these are expected to be readjusted based on the results of startup testing and initial operations.

- Prior to fuel load, document final values of instrumentation setpoints assumed in the design, operation, and safety analysis of the plant and as modified by preoperational testing or reanalysis to serve as a basis for future plant operations.

Prerequisites

- Initial alignment and calibration of plant instrumentation has been completed, and initial set points are installed per applicable design documentation.

- Preoperational testing of affected plant instrumentation has been completed, and test results are documented.

Test Method

- Review applicable design documentation and generate a list of the instrumentation setpoints assumed in the design, operation, and safety analysis of the plant. Identify setpoints expected to be modified based on the results of initial startup tests and operations.

- Prior to fuel load, the results of preoperational tests, as applicable, are reviewed to verify that initial setpoints have been installed correctly. Document the results of this review for future use.

- Prior to fuel load, summarize and document the setpoint values for future plant operations.

Performance Criterion

Prior to fuel load, installed setpoint values are verified to be consistent with Technical Specifications.

14.2.10.1.11 Rod Control System

Objective

Demonstrate and document that the rod control system performs the required control and indication functions just prior to initial criticality.

Prerequisites

- The reactor coolant system is at no-load operating temperature and pressure
- The nuclear instrumentation system source range channels are aligned and operable

Test Method

- With the reactor at no-load temperature and pressure, just prior to initial criticality, verify the operation of the rod control system in various modes including tests of control rod block and inhibit functions.

- Verify the operation of status lights, alarms, and indicators

Performance Criteria

- The rod control system performs in accordance with its design requirements
- The rod control system withdraws and inserts each rod bank
- The rod position and indication system tracks each rod bank as it is being moved
- The control banks overlap system starts and stops rod movement at the designated bank positions

14.2.10.1.12 Rod Position Indication System

Objective

Verify that the rod position indication system satisfactorily performs required indication and alarm functions for each individual rod and that each rod operates satisfactorily over its entire range of travel.

Prerequisites

- The reactor coolant system is at no-load operating temperature and pressure
- At least one reactor coolant pump is in service, with reactor coolant boron concentration not less than specified in the Technical Specifications for refueling shutdown

Test Method

Individually withdraw rod banks from the core and reinsert them, according to the test procedure. Record rod position sensor output signals, and rod position readouts and group step counters in the main control room.

Performance Criterion

The rod position indication system performs the required indication and alarm functions as discussed in Subsection 7.7.1.3, and each rod operates over its entire range of travel.

14.2.10.1.13 Control Rod Drive Mechanisms

Objectives

- Demonstrate operation of each control rod drive mechanism under hot standby conditions
- Provide verification of coil stack assembly current profile

Prerequisites

- The reactor coolant system is in hot standby
- Rods are fully inserted
- Nuclear instrumentation channels are available
- A fast-speed oscillograph, or equivalent, to monitor test parameters is available

Test Method

- With the reactor core installed and the reactor in hot standby condition, confirm that the rod control system power cabinets supply current profiles to the control rod drive mechanism stepping magnet coils.

- Verify operation of all control rod drive mechanisms under hot standby conditions. Record the control rod drive mechanism magnet coil currents.

Performance Criterion

The control rod drive mechanisms conform to the requirements for proper mechanism operation and timing including control rod withdrawal and insertion speeds as described in the applicable design specifications.

14.2.10.1.14 Rod Drop Time Measurement

Objectives

- Determine the rod drop time of each rod cluster control assembly under hot full-flow conditions, with the reactor at normal operating temperature and pressure.

- Verify the operability of the control rod deceleration device.

Prerequisites

- Initial core loading is completed
- Source range channels are in operation
- Rods are fully inserted
- Reactor coolant pumps are operational

Test Method

- Withdraw each rod cluster control assembly

- Interrupt the electrical power to the associated control rod drive mechanism

- Measure and record the rod drop time, and verify control rod deceleration

- Perform a minimum of three additional drops for each control rod whose drop time falls outside the two-sigma limit, as determined from the drop times obtained for each test condition

Performance Criteria

- Measured rod drop times are consistent with the design basis functional requirements and the applicable plant Technical Specifications

- The control rod is slowed by the control rod deceleration device during rod drop testing

14.2.10.1.15 Rapid Power Reduction System

Objective

Verify proper operation of the rapid power reduction system prior to power operations.

Prerequisites

- The following systems are operable to the extent necessary to support the test: rod control system, rod position indication system, reactor trip breakers, and reactor protection system.
- The reactor is shut down, the reactor coolant system boron concentration is such that Technical Specifications requirements for shutdown margin will be met with required rod withdrawal, and all control banks are near their fully inserted positions.

Test Method

- Input signals simulating operation at the full power condition to the reactor control and protection system. Close the reactor trip breakers.
- Input signals simulating a rapid loss of load exceeding 50 percent power are input to the rapid power reduction system. Verify the response of the system.
- Demonstrate procedures for returning the plant to power following a partial trip.

Performance Criteria

- Performance of the rapid power reduction system is in accordance with Subsection 7.7.1.10.
- In response to the simulated loss of load, gripper power is interrupted to a selected grouping of control rods, so that rods drop freely into the core.
- Gripper power to only those control rods selected for drop is interrupted.
- Procedures for returning the plant to power operations without a reactor trip are verified.

14.2.10.1.16 Process Instrumentation Alignment

Objective

Align ΔT process instrumentation under isothermal conditions prior to initial criticality.

Prerequisites

- Reactor coolant pumps are operating
- The reactor coolant system average temperature is at the hot no-load average temperature

Test Method

- Align ΔT according to test instructions at isothermal conditions prior to criticality

Performance Criterion

The indicated values for reactor coolant system ΔT under isothermal conditions are within the limits of the applicable design requirements.

14.2.10.1.17 Reactor Coolant System Flow Measurement

Objectives

- Prior to initial criticality, verify that the reactor coolant system flow rate is sufficient to permit operation at power.

Prerequisites

- The core is installed and the plant is at normal operating temperature and pressure.
- Special instrumentation is installed and calibrated for obtaining reactor coolant flow data.

Test Method

- Prior to initial criticality, measure the reactor coolant flow measurement parameters with all four coolant pumps in operation. Estimate the reactor coolant flow rate using these data.

Performance Criterion

The estimated reactor coolant flow rate from data taken prior to initial criticality equals or exceeds 90 percent of the minimum value required by the plant Technical Specifications for full power operation.

14.2.10.1.18 Reactor Coolant System Flow Coastdown

Objectives

- Measure the rate at which reactor coolant loop flow and pump speed changes, subsequent to tripping all reactor coolant pumps.

Prerequisites

- Required component testing and instrument calibration are complete
- Required electrical power supplies and control circuits are operational
- The reactor core is installed, and the plant is at normal operating temperature and pressure with all reactor coolant pumps running

Test Method

- Record loop flow, pump speeds following the trip of all reactor coolant pumps

Performance Criterion

The loop flows and pump speed data are obtained for verification of the complete loss of forced reactor coolant flow in Subsection 15.3.2.

14.2.10.1.19 Pressurizer Spray Capability and Continuous Spray Flow Verification

Objectives

- Establish the optimum continuous spray flow rate
- Determine the effectiveness of the normal control spray

Prerequisites

- The reactor coolant system is at no-load operating temperature and pressure.
- All reactor coolant pumps are operating.

Test Method

- While maintaining constant pressurizer level, adjust spray bypass valves until a minimum flow is achieved that maintains the temperature difference between the spray line and the pressurizer within acceptable limits.

- With the pressurizer heaters de-energized, fully open both spray valves, and record the time to lower the pressurizer pressure a specified amount.

Performance Criteria

- The spray bypass valves are throttled so that the minimum flow necessary to keep the spray line warm is achieved.

- The pressurizer pressure response to the opening of the pressurizer spray valves is within design basis functional limits as specified in the applicable pressure control system design specification documentation.

14.2.10.1.20 Feedwater Valve Stroke Test

Objective

Verify proper operation of the main and startup feedwater control valves prior to the start of power operations.

Prerequisites

- Preoperational testing of the feedwater control systems has been completed
- Main and startup feedwater pumps are off
- Initial fuel loading has been completed prior to initial criticality.

Test Method

For each main and startup feedwater flow control valve, the following tests are performed:

- Using simulated signals for several valve demand positions covering the range from fully closed to fully open, verify the actual valve position to be within the prescribed tolerances of the demand signal.

- For selected valve position changes, measure the time required from the initiation of the demand signal until the valve reaches the final position. Typical demands changes are the following: fully closed to fully open, fully open to fully closed, 25 percent open to 75 percent open, and 75 percent open to 25 percent open.

- Use simulated signals to vary the valve position over the full range of travel and verify the valve overshoot/undershoot is less than prescribed tolerances. Typical demand changes are 3% to 10% over the full range of valve travel.

Performance Criterion

The main and startup feedwater valves operate as described in Subsection 7.7.1.8 and appropriate design specifications including:

- The time between the initiation of the demand signal and the final valve position for each of the demand changes is within specified ranges as discussed in applicable design specifications.

14.2.10.2 Initial Criticality Tests

Initial criticality testing is described in this section. Following completion of the core loading and precriticality testing, the plant is brought to initial criticality, according to the test procedures in Subsection 14.2.10.2.1.

14.2.10.2.1 Initial Criticality Test Sequence

Objective

Define the sequence of tests and operations to bring the core to initial criticality.

Prerequisite

Plant system conditions are established as required by the individual test instructions within this sequence.

Test Method

An individual test instruction will establish the plant conditions required for initial criticality.

Performance Criteria

Relevant performance criteria are provided in each of the test procedure abstracts.

14.2.10.2.2 Initial Criticality

Objective

Achieve initial criticality in a controlled manner.

Prerequisites

- The nuclear instrumentation is verified to be operating properly (See Subsection 14.2.10.2.3)
- The reactor coolant system temperature and pressure are stable at the normal hot no-load values
- Control rod banks are inserted, and shutdown rod banks are withdrawn
- The reactor coolant system boron concentration is sufficiently high so the reactor is shut down by at least 1000 pcm with all banks withdrawn

Test Method

- Accomplish initial criticality by the controlled withdrawal of the rods using the same rod withdrawal sequence used for normal plant startup, followed by the dilution of the reactor coolant system boron concentration.
- At preselected points during rod withdrawal and/or boron dilution, gather data to plot the inverse count rate ratio to monitor the approach to critical evolution for reactivity monitoring.
- As criticality is approached, slow or stop dilution rate to allow criticality to occur during mixing or by withdrawal of rods that have been slightly inserted for control.

Performance Criterion

The reactor is critical.

14.2.10.2.3 Nuclear Instrumentation System Verification

Objective

Establish and determine voltage settings, trip settings, operational settings, alarm settings, and overlap of channels on source and intermediate range instrumentation, from prior to initial criticality and during initial criticality.

Prerequisite

The nuclear instrumentation system is aligned according to the design requirements.

Test Method

- Calibrate, test, and verify functions using permanently installed controls and adjustment mechanisms.
- Set operational modes of the source and intermediate range channels for their proper functions, in accordance with the test instructions.

Performance Criteria

- The nuclear instrumentation system operates in accordance with the design basis functional requirements.
- The nuclear instrumentation system demonstrates an overlap of indication between the source and intermediate range instrumentation.
- The nuclear instrumentation minimum neutron count rate and noise to signal ratio are within appropriate design specifications.

14.2.10.2.4 Post-Critical Reactivity Computer Checkout

Objective

Demonstrate proper operation of the reactivity computer through a dynamic test using neutron flux signals.

Prerequisites

- The reactor is critical with the neutron flux level within the range for low-power physics testing
- The reactor coolant system temperature and pressure are stable at the normal no-load values
- The neutron flux level and reactor coolant system boron concentration are stable
- The reactivity computer is installed, checked out, and operational, and input flux signals are representative of the core average neutron flux level
- The controlling rod bank is positioned in such a way that the required reactivity insertion can be made by rod motion alone
- The systems, structures, and components required by Technical Specifications shall be operable as required for the specified plant operational mode prior to initiation of precritical, low power physics, and power ascension testing. Verification of proper operation of

source-range and intermediate-range excore nuclear instrumentation and associated alarms and protective functions in Startup Test Subsection 14.2.10.2.3 shall be completed prior to initiation of this startup test.

Test Method

- By control rod motion, add positive reactivity to the core as directed in the test procedure.
- During the resultant increase in flux level, make two independent measurements of core reactivity; one using the reactivity computer, and one using an analysis of the rate of change of flux level (for example, reactor period or doubling time).

Performance Criterion

Each measurement deviation between the two independent sources of reactivity is within design tolerances. Adjustment and recalibration or repair of the reactivity computer may be required if the deviation between the two independent sources of reactivity is not within design tolerances.

14.2.10.3 Low Power Tests

Following successful completion of the initial criticality tests, low power tests are conducted, typically at power levels less than 5 percent, to measure physics characteristics of the reactor system and to verify the operability of the plant systems at low power levels.

14.2.10.3.1 Low-Power Test Sequence

Objective

Define the sequence of tests and operations that constitutes the low-power testing program.

Prerequisite

Plant system conditions are established as required by the individual test instructions within this sequence.

Test Method

Individual test instruction will establish the plant conditions required for and during the low-power testing program following initial criticality.

Performance Criteria

Relevant performance criteria are provided in each of the test procedure abstracts.

14.2.10.3.2 Determination of Physics Testing Range

Objectives

- Determine the reactor power level at which the effects from fuel heating are detectable
- Establish the range of neutron flux in which zero power reactivity measurements are to be performed

Prerequisites

- The reactor is critical, and the neutron flux level is below the expected level of nuclear heating

- The reactor coolant system temperature and pressure are stable at the normal no-load values
- The neutron flux level and reactor coolant system boron concentration are stable
- The reactivity computer is installed, checked out, and operational, and input flux signals are representative of the core average neutron flux level
- The controlling rod bank is positioned in such a way that the required reactivity insertion can be made by rod motion alone

Test Method

- Withdraw the control rod bank and allow the neutron flux level to increase until nuclear heating effects are indicated by the reactivity computer
- Record the reactivity flux level and the corresponding intermediate range channel currents at which nuclear heating occurs
- Multiply the measured reactivity flux level by 0.3 to determine the maximum value for the zero power testing range

Performance Criterion

The zero power testing range is determined.

14.2.10.3.3 Boron Endpoint Determination

Objective

Determine the critical reactor coolant system boron concentration appropriate to an endpoint rod configuration.

Prerequisites

- The reactor is critical, and the neutron flux level is within the range for low-power physics testing
- The reactor coolant system temperature and pressure are stable at the normal no-load values
- The neutron flux level and reactor coolant system boron concentration are stable
- Instrumentation and equipment used to measure and compute reactivity is installed, checked out, and operational, with input flux signals representative of the core average neutron flux level
- The controlling rod bank is positioned in such a way that limited reactivity insertion will be required to achieve the endpoint condition

Test Method

- Move the rods to the desired endpoint configuration without boron concentration adjustment
- Directly measure the just-critical boron concentration by chemical analysis

- Measure and convert the change in reactivity and the reactor coolant temperature difference from program to an equivalent change in boron concentration
- Add the changes to the just-critical boron concentration to yield the endpoint for the given rod configuration

Performance Criterion

The measured value for the boron endpoint is consistent with the design value within design limits as specified in the Technical Specifications.

14.2.10.3.4 Isothermal Temperature Coefficient Measurement

Objectives

- Determine the isothermal temperature coefficient
- Calculate the moderator temperature coefficient

Prerequisites

- The reactor is critical, and the neutron flux level is within the range for low-power physics testing
- The reactor coolant system temperature and pressure are stable at the normal no-load values
- The neutron flux level and reactor coolant system boron concentration are stable
- Instrumentation and equipment used to measure and compute reactivity is installed, checked out, and operational, with input flux signals representative of the core average neutron flux level
- The controlling rod bank is positioned near fully withdrawn

Test Method

- Vary reactor coolant system temperature (heatup/cooldown) while maintaining rods and boron concentration constant
- Monitor reactivity results and determine the isothermal temperature coefficient
- Calculate the moderator temperature coefficient using the isothermal temperature coefficient and design values

Performance Criterion

- The measured value for the moderator temperature coefficient is more negative than the Technical Specification limit

14.2.10.3.5 Bank Worth Measurement

Objective

Validate design calculations of the reactivity worth of the rod cluster control banks.

Prerequisites

- The reactor is critical and the neutron flux level is within the range for low-power physics testing
- The reactor coolant system temperature and pressure are stable at the normal no-load values
- The neutron flux level and reactor coolant system boron concentration are stable
- Instrumentation and equipment used to measure and compute reactivity is installed and operational, with input flux signals representative of the core average neutron flux level

Test Method

- One of the following methods will be used to measure the worth of all of the individual control rod banks:
  - A bank is stepwise inserted into the core from fully withdrawn and the worth is measured using the reactivity computer
  - Exchange bank with another bank measured as above, with the worth determined from the critical positions and the worth of the reference bank

Performance Criteria

- The measured value for the individual bank worth is consistent with the design value within specified limits.
- The sum of the measured bank worth is consistent with the design value within the assumed uncertainty used in the shutdown margin calculation

14.2.10.3.6 Natural Circulation (First Plant Only)

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

14.2.10.3.7 Deleted

14.2.10.4 Power Ascension Tests

After low power testing is completed, testing is performed at specified elevated power levels to demonstrate the facility operates in accordance with design during normal steady-state operations, and to the extent practical, during and following anticipated transients. During power ascension, tests are performed to obtain operational data and to demonstrate the operational capabilities of the plant.

14.2.10.4.1 Test Sequence

Objective

Define the sequence of operations, beginning at approximately 5 percent rated thermal power, that constitutes the power ascension testing program.

Prerequisite

Plant system conditions are established, as required, by the individual test instruction within this sequence.

Test Method

Present the sequence of operations and tests, along with instructions, specific plant conditions, and test procedures.

Performance Criteria

Relevant performance criteria are provided in each of the test procedures.

14.2.10.4.2 Incore Instrumentation System

Objectives

- Obtain data for incore thermocouple and flux maps at various power levels during ascension to full power determine flux distributions and verify proper core loading and fuel enrichments.

Prerequisites

- Incore instrumentation system signal processing software is installed and operational
- For incore thermocouple and flux mapping, the plant is at various power levels greater than approximately 20 percent of rated thermal power

Test Method

- With the plant at approximate power levels of 25, 50, 75 and 100 percent of rated thermal power, obtain data from the incore instrumentation system and process to produce incore thermocouple and flux maps. (Actual power levels will be specified in the power ascension program test sequence.)
- Use data from the incore maps to verify that core power distribution is consistent with design predictions and the limits imposed by the plant Technical Specifications, including detection of potential fuel loading errors, and to calibrate other plant instrumentation. Refer to Technical Specifications Section 3.2, Power Distribution Limits.

Performance Criteria

- Core power peaking factors derived from the incore data are consistent with design predictions and the limitations of the plant Technical Specifications
- Data required for calibration of other plant instrumentation are obtained

14.2.10.4.3 Nuclear Instrumentation System

Objective

Establish and determine voltage settings, trip settings, operational settings, alarm settings, and overlap of channels on intermediate range and power range instrumentation from zero power to at or near full rated thermal power.

Prerequisite

The nuclear instrumentation system is aligned according to the design requirements.

Test Method

- Calibrate, test, and verify functions using permanently installed controls and adjustment mechanisms

- Set operational modes of the intermediate range and power range channels for their proper functions, in accordance with the test instructions

Performance Criteria

- The nuclear instrumentation system operates in accordance with the design basis functional requirements.

- The nuclear instrumentation system demonstrates an overlap of indication between the intermediate and power range instrumentation.

14.2.10.4.4 Setpoint Verification

Objective

During power ascension, document final values of instrumentation setpoints as modified by initial startup testing, operations, or reanalysis to serve as a basis for future plant operations.

Prerequisites

- Initial alignment and calibration of plant instrumentation have been completed, and initial set points are installed per applicable design documentation

- Preoperational and startup testing of affected plant instrumentation has been completed, and test results are documented

- The results of the precritical verification of the instrument setpoints are completed and documented

Test Method

- Identify setpoints modified based on the results of initial startup tests and operations

- During power ascension testing, readjust specific setpoints noted for readjustment on the data sheets if required. Record final setpoint values.

Performance Criterion

Setpoint changes based on initial startup testing and operations are documented for future reference.

14.2.10.4.5 Startup Adjustments of Reactor Control Systems

Objectives

- Determine the adequacy of the reactor coolant system programmed T_{avg}

- Obtain plant data during power ascension which would provide the basis for any required changes to the turbine pressure versus turbine power program

Prerequisites

- The reactor coolant system is at no-load operating temperature and pressure
- The reactor coolant system temperature is being controlled by the steam dump valves with the turbine offline

Test Method

- Verify the reactor coolant temperature is controlled at an average temperature that is consistent with the T_{avg} program calculated based on the calorimetric power when the turbine is online.

- Obtain system temperature and steam pressure data at steady-state conditions for zero rated thermal power and at hold points during power escalations

- Evaluate the turbine pressure versus turbine power curve against plant data at intermediate and full powers and perform calibration based on calorimetric power. Final calibration is performed at the full power testing plateau.

- Compare the full power steam pressure to the full power design value to determine adequacy of the programmed T_{avg}.

Performance Criterion

The full power T_{avg} program does not exceed the design T_{avg} limit to obtain the design steam pressure.

14.2.10.4.6 Rod Cluster Control Assembly Out of Bank Measurements (First Plant Only)

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

14.2.10.4.7 Axial Flux Difference Instrumentation Calibration

Objectives

- Calibrate the power range nuclear instrumentation signals used as axial flux difference (delta flux) input to the reactor protection system

- Calibrate instrumentation used to display and monitor axial flux difference

Prerequisites

- The reactor is at a power level greater than 50 percent of rated thermal power
- The incore instrumentation system is available for obtaining incore power distribution data
- A preliminary calibration of the axial flux difference indication instrumentation is completed

Test Method

- Using control rod movement, xenon redistribution, or a combination of both, vary the axial power distribution of the core over a specified range of interest. At selected values of indicated axial flux difference, obtain reactor thermal power data along with the outputs from the nuclear instrumentation power range channels and the incore instrumentation system. (For the first plant, a minimum of three data sets will be taken; subsequent cores may require less.)

- Calibrate signals from the nuclear instrumentation power range channels based on incore power distribution and thermal power data.

Performance Criterion

Axial flux difference signals, derived from the nuclear instrumentation power range detectors and input to the reactor protection system, display, and monitoring instrumentation, reflect actual incore power distribution within specified limits.

14.2.10.4.8 Primary and Secondary Chemistry

Objective

Verify proper water quality in the reactor coolant system and secondary coolant system.

Prerequisite

The plant is at the steady-state condition at approximately 0, 25, 50, 75, and 100 percent rated thermal power.

Test Method

Analyze samples to determine the chemical and radiochemical concentrations.

Performance Criterion

The chemical and radiochemical control systems maintain the water chemistry within the applicable guidelines as discussed in Subsections 5.2.3.2 and 10.3.5.

14.2.10.4.9 Process Measurement Accuracy Verification

Objectives

- Measure the temperature variation in the reactor coolant loops resulting from non-uniform flow effects such as streaming
- Measure the sensitivity of the excore detectors to variations in control bank position and reactor coolant loop cold leg temperature

Prerequisites

- For the reactor coolant loop temperature measurements:
  - Special temperature measuring equipment, including recording and indicating instrumentation, is installed, as required, on the reactor coolant loops hot and cold leg piping
  - The reactor is at a stable power level of approximately 0, 50, 75 and 100 percent of rated thermal power
- For the excore detector measurements:
  - The reactor is at a stable power level of approximately 25, 50 and 100 percent of rated thermal power

Test Method

- For the reactor coolant loop temperature measurements, at each power level:
  - Measure reactor power level, using calorimetric data

  - Simultaneously, measure the hot and cold leg temperatures, using normal plant instrumentation and any other required instrumentation

- For the excore detector tests, with the reactor at constant power level:

  - Measure the response of the excore detectors as selected control banks are moved over prescribed ranges of travel

  - Measure excore detector response as the reactor coolant cold leg temperature is varied over a prescribed range

  - Simultaneously, for each of the preceding measurements, obtain calorimetric data to verify reactor power level

Performance Criteria

- Uncertainties in reactor coolant loop temperature measurements resulting from non-uniform flow effects such as streaming are consistent with allowances used in the plant safety analyses.

- Uncertainties in excore detector response resulting from control rod motion and reactor coolant loop cold leg temperature changes are consistent with allowances used in the plant safety analyses.

14.2.10.4.10 Process Instrumentation Alignment at Power Conditions

Objective

Align ΔT and T_{avg} process instrumentation at power conditions.

Prerequisites

- Reactor coolant pumps are operating.
- The reactor system is operating at the required power level.

Test Method

- Align ΔT and T_{avg} according to test instructions at approximately 75 percent rated thermal power. Extrapolate the 75 percent data to determine ΔT and T_{avg} values for the 100 percent plateau.

- At or near 100 percent rated thermal power, check the alignment of the ΔT and T_{avg} channels for agreement with the results of the thermal power measurement.

Performance Criterion

The indicated values for reactor coolant system T_{hot}, T_{cold}, T_{avg}, and ΔT at or near full thermal power are within the limits of the applicable design requirements, as discussed in Section 5.1.

14.2.10.4.11 Reactor Coolant System Flow Measurement at Power Conditions

Objective

At power, verify that the reactor coolant flow equals or exceeds the minimum value required by the plant Technical Specifications.

Prerequisites

- The reactor is at power levels greater than 75 percent and up to and including 100 percent of rated thermal power
- Special instrumentation required for measuring reactor thermal power and reactor coolant inlet and outlet temperatures is installed and calibrated

Test Method

With the reactor at steady-state power greater than 75 percent and up to and including 100 percent of rated thermal power, measure the reactor thermal power and coolant inlet and outlet temperatures. Determine the reactor coolant flow rate using the data in conjunction with hydraulic analysis of differential pressures at different locations in the reactor coolant system.

Performance Criterion

The reactor coolant system flow determined from the measurements at approximately 100 percent rated thermal power equals or exceeds the minimum value required by the plant Technical Specifications.

14.2.10.4.12 Steam Dump Control System

Objective

Verify automatic operation of the T_{avg} steam dump control system, demonstrate controller setpoint adequacy, and obtain final settings from steam pressure control of the condenser dump valves.

Prerequisites

- Steam dump control system is aligned and calibrated to initial settings
- Plant is at no-load temperature and pressure
- Condenser vacuum is established
- Reactor is critical

Test Method

- Increase reactor power to less than 10 percent rated thermal power by rod withdrawal and steam dump to condenser to demonstrate setpoint adequacy
- Adjust the pressure controller setpoint prior to switching to T_{avg} control mode, which modulates the steam condenser dump valves to obtain the new pressure.
- Enable the steam dump arming logic and transfer to the T_{avg} control mode to demonstrate the closed loop response of the load rejection controller.

Performance Criteria

- After placing the steam dump controller system in the T_{avg} control mode, the load rejection controller demonstrates closed loop control wherein the steam dump valves respond properly to changes in T_{avg}.
- The steam header pressure controller responds to maintain a stable pressure.

14.2.10.4.13 Steam Generator Level Control System

Objective

Verify the stability of the automatic steam generator level control system by introducing simulated transients at various power levels during escalation to full power.

Prerequisites

- The reactor is critical and stable at various power levels during the power escalation test program. (Typical power levels are 30, 75 and 90 percent of full rated thermal power)
- The steam generator level control system is checked and calibrated
- Steam generator alarm setpoints are set for each generator

Test Method

- At each power level, with the steam generator control system in manual mode, simulate level transients by changing the level setpoint. Verify the steam generator level control response when the control system is returned to automatic control.
- During the recovery from a simulated steam generator level transient, verify steam generator level control response is within design requirements for overshoot or undershoot to the new level, time required to achieve the new level, and error between the actual level and the control setpoint.
- Verify the main feedwater control valves open and stabilize at various power plateaus in accordance with design requirements.

Performance Criterion

- No manual intervention of steam generator level control system is required to prevent steam generator water level from reaching the high or low steam generator level protection setpoints.

14.2.10.4.14 Radiation and Effluent Monitoring System

Objectives

- For monitors that:
  - Are used for establishing conformance within the safety limits or limiting conditions for operation that are included in the Technical Specifications, or
  - Are classified as engineered safety features, or are relied on to support operation of the engineered safety features within design limits, or
  - Are assumed to function or for which credit is taken in the accident analysis of the facility, and
  - Are used to process, store, control, or limit the release of radioactive materials
- The objectives are:
  - Verify the calibration of the process and effluent radiation monitor against an acceptable standard

- Establish baseline activity and background levels
- Demonstrate that process and effluent radiation monitoring systems respond correctly by performing independent analyses

Prerequisites

- The plant is stable at the desired power level
- The sampling systems for the process and effluent radiation monitoring systems are operable

Test Method

- Perform calibrations with the use of radioactive sources to verify proper operation of the monitors and detectors
- Collect and analyze samples with laboratory instruments, and compare the results from the process and effluent monitor to verify proper monitor operation
- Establish background levels at low power (less than 5 percent rated thermal power)
- Establish background levels and baseline activity levels determined by sampling at 100 percent rated thermal power to monitor the buildup of activity

Performance Criteria

- Radiation monitors are calibrated against radioactive standards
- Baseline activities are established

14.2.10.4.15 Ventilation Capability

Objective

Verify that heating, ventilation, and air conditioning systems for the containment and areas housing engineered safety features continue to maintain design temperatures.

Prerequisite

The plant is operating at or near the desired power (0, 50, and 100 percent of rated power).

Test Method

- Record temperature readings in specified areas while operating with normal ventilation lineups
- Record temperature readings in specified areas while operating the designed minimum number of heating ventilation and air conditioning components consistent with existing plant conditions
- Record surface concrete temperatures adjacent to the high temperature piping penetrations and at selected locations on the concrete shielding (at 100 percent rated thermal power only)

Performance Criterion

The heating, ventilation and air conditioning systems for the containment and areas housing engineered safeguards features perform as designed.

14.2.10.4.16 Biological Shield Survey

Objectives

- Document the radiation levels in accessible locations of the plant outside of the biological shield while at power
- Obtain baseline radiation levels for comparison with future measurements of level buildup with operation

Prerequisites

- Radiation survey instruments are calibrated
- Background radiation levels are measured in designated locations prior to initial criticality
- The plant is stable at the applicable power level

Test Method

Measure gamma and neutron radiation dose rates at designated locations at approximately 25, 50, 75, and 100 percent rated thermal power.

Performance Criterion

Radiation levels are acceptable for full-power operation and consistent with design expectations.

14.2.10.4.17 Thermal Power Measurement and Statepoint Data Collection

Objective

Obtain thermal power measurement and statepoint data at selected power levels during the power ascension testing program, typically at 25, 50, 75, and 100 percent of rated thermal power.

Prerequisites

- The following equipment is installed and is operational: sensors for measuring steam generator feedwater temperature, differential pressure measuring devices for determining feedwater flow to each steam generator, and pressure gauges to measure steam pressure at steam generator outlets.
- The pressurizer pressure and level control system, and the steam generator level control system are in automatic mode.
- Instrumentation and data collection equipment is available for logging supplemental plant data.
- Reactor power is stable at the required level.

Test Method

The required data are obtained using installed plant equipment, special test equipment, and the plant data processing equipment. These data are subsequently used to determine reactor thermal power and assess the performance of the plant.

Performance Criterion

Reactor thermal power is stable at each power level and at the rated level at full power conditions. Operability of the pressurizer pressure and level control systems not previously verified as part of reactor coolant system preoperational testing (Subsection 14.2.9.1.1) is demonstrated.

14.2.10.4.18 Dynamic Response

Objectives

Demonstrate during power range testing that the stress analysis for selected systems and components, under transient conditions is within design functional requirements. Portions of systems that meet the selection criteria for Subsection 14.2.9.1.7 for dynamic effects testing, but were not tested because system conditions during hot functional testing are not conducive to prototypical systems conditions, are tested.

Prerequisites

- Temporary instrumentation is installed, as required, to monitor the deflections of components under test and the occurrence of water hammer noise and vibration.
- Points are monitored and baseline data are established.

Test Method

- Record deflection measurements during various plant transients.
- Monitor for the occurrence of water hammer noise and vibration.

Performance Criteria

- The movements due to flow-induced loads do not exceed the stress analysis of the monitored points. See Subsection 3.9.2.1.1 for the acceptable standard for alternating stress intensity due to vibration.
- Flow-induced movements and loads do not cause malfunctions of plant equipment or instrumentation.
- No effects due to water hammer are detected.

14.2.10.4.19 Reactor Power Control System

Objective

Demonstrate the capability of the reactor power control system to respond to input signals.

Prerequisites

- The reactor is at equilibrium at the power level specified by the startup test program reference document.
- Setpoints and controls for the pressurizer, steam generator steam dump, and feedwater pump are checked and are set to proper values.

Test Method

- Vary T_{avg} from the T_{ref} setpoint to verify the transient recovery capabilities of the automatic reactor power control system.
- Vary the axial flux difference setpoint to verify the capabilities of the automatic axial offset control and the interaction with the automatic reactor temperature control.

Performance Criteria

- T_{avg} returns to the T_{ref} setpoint, within pre-specified limits and without manual intervention.

- Axial flux difference returns to the setpoint within pre-specified limits without manual intervention.

14.2.10.4.20 Load Swing Test

Objective

Verify nuclear plant transient response, including automatic control system performance, when 10 percent step-load changes are introduced to the turbine-generator at 30, 75, and 100 percent rated thermal power levels.

Prerequisite

The plant is operating in a steady-state condition at the desired thermal power level.

Test Method

Change the turbine-generator output as rapidly as possible to achieve a step 10 percent load increase or decrease. Monitor and record plant parameters of reactor power, reactor coolant system temperature, pressurizer pressure and level, and steam generator pressure and level during the load transients. Core power should not exceed 100-percent power as indicated by the excore nuclear instrumentation.

Performance Criterion

The primary and secondary control systems, with no manual intervention, maintain reactor power, reactor coolant system temperatures, pressurizer pressure and level, and steam generator levels and pressures within acceptable ranges during and following the transient. Control system response is reviewed and compared to the control system setpoint and performance analysis, and adjustments to the control systems are made, if necessary, prior to proceeding to the next power plateau.

14.2.10.4.21 100 Percent Load Rejection

Objective

Demonstrate the ability of the AP1000 plant to accept a 100 percent load rejection from full power.

Prerequisites

- The plant is operating at a stable power level of approximately 100 percent rated thermal power. Reactor and turbine control systems are in the automatic mode of operation. Plant temperatures, pressures, levels, and flow rates are within their normal range for full-power operation.

- Startup testing of the reactor and turbine control and protection systems is completed, and final setpoints are installed according to applicable plant technical manuals.

- The incore instrumentation system, including signal processing software, is operational, and all preoperational and startup testing is completed.

- Instrumentation and data collection equipment is operational and available for logging plant data.

- Special test instrumentation is installed and operational as required to augment normal data logging ability.

Test Method

- With the plant at nominal full-power steady-state conditions, to effect a rejection of 100 percent load, manually place the main step-up transformer high side breaker in the trip position.

- Prior to the load rejection, and until the plant stabilizes at the lower power level, record key plant parameters using the data display and processing system and special test instrumentation. The key plant parameters include plant temperatures, pressures, levels and flow rates for the primary and secondary systems.

Performance Criteria

- The plant is capable of accepting a 100 percent load rejection from full rated thermal power without reactor trip or operation of the steam generator relief valves or pressurizer safety valves.

- The turbine speed does not exceed 108% of rated speed.

- The turbine is capable of continued stable operation at the minimum house loads.

14.2.10.4.22 Load Follow Demonstration (First Plant Only)

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

14.2.10.4.23 Hot Full Power Boron Endpoint

Objective

Measure the reactor coolant system critical boron concentration at beginning of cycle life for the all rods out, hot full power, xenon equilibrium condition.

Prerequisites

- The reactor is operating at approximately 100 percent of full licensed power and has been at that power for a sufficient time to reach xenon equilibrium.

- The reactor power level and reactor coolant system boron concentration and temperature are stable, and control and shutdown rod banks are in the near fully withdrawn position.

- Current core burnup data are available.

Test Method

- During the power ascension test program, and, as soon as practicable after achieving xenon equilibrium at full licensed power, obtain and analyze samples of reactor coolant for dissolved boron content.

- Using plant calorimetric and statepoint data obtained at the same time as coolant sampling, correct the measured boron concentration, as required, for control rod insertion, xenon nonequilibrium, and any difference between T_{avg} and T_{ref}.

- The resultant boron value, corresponding to the measured critical boron concentration for all rods out, hot full power, and xenon equilibrium, is compared with design predictions for the current accumulated core burnup (Figure 4.3-3).

- As permitted by the plant Technical Specifications, use the corrected measured boron concentration to renormalize the predicted curve of boron concentration as a function of core burnup.

Performance Criterion

The reactivity equivalent of the difference between measured and predicted boron concentrations is less than the design limit.

14.2.10.4.24 Manual Reactor Trip Test from 100 Percent Power and Main Generator Trip Test from 100 Percent Power

Objectives

- Verify the ability of the plant automatic control systems to sustain a main generator trip from 100 percent rated thermal power and bring the plant to stable conditions following the transient.
- Assess the dynamic response of the plant for the event that subjects the turbine to its maximum credible overspeed condition.
- Verify the ability of the plant automatic control systems to sustain a manual reactor trip from 100 percent thermal power and bring the plant to stable conditions following the transient and determine the overall response time of the hot leg resistance temperature detectors (RTDs).
- Optimize the control systems setpoints, if necessary.

Prerequisite

The plant is operating in a steady-state condition at full rated thermal power.

Test Method

Main Generator Output Breaker Trip Test

- Trip the plant by opening the main generator breaker.
- Monitor and record selected plant parameters.
- If necessary, adjust the control systems setpoints to obtain optimal response.

Manual Reactor Trip Test

- Manually trip the reactor.
- Monitor plant conditions and verify the plant is stabilized and maintained at the no-load conditions.
- Calculate the overall response time of the hot leg temperature measurement.
- If necessary, adjust the control system setpoints to obtain optimal response.

Performance Criteria

Main Generator Output Breaker Trip Test

- Following the opening of the main generator breaker while at 100 percent rated thermal power:
  - The primary and secondary control systems and operator actions can stabilize and maintain reactor coolant system temperature, pressurizer pressure and level, and steam generator levels at the reduced power conditions.
  - The primary and secondary safety valves are not challenged.

  - The turbine speed does not exceed 108 percent of rated speed.

Manual Reactor Trip Test

- Following the manual reactor trip while at 100 percent rated thermal power:

  - The primary and secondary control systems can stabilize and maintain reactor coolant system temperature, pressurizer pressure and level, and steam generator levels at the no-load operating temperature and pressure.
  - The primary and secondary safety valves are not challenged.
  - The overall hot leg response times are verified to be less than or equal to the values determined by the safety analysis method.

14.2.10.4.25 Thermal Expansion

Objective

Demonstrate that essential nuclear steam supply system and balance-of-plant components can expand without obstruction and that the expansion is in accordance with design. Also, during cooldown, the components return to their approximate baseline cold position. Testing is conducted to resolve discrepancies from hot functional testing as in Subsection 14.2.9.1.1, and to test modifications made since hot functional testing was completed. Portions of systems that meet the selection criteria for Subsection 14.2.9.1.7 for thermal dynamic testing, but were not tested because system conditions during hot functional testing are not conducive to prototypical system conditions are tested.

Prerequisite

Temporary instrumentation is installed, as required, to monitor the deflections for the components under test.

Test Method

For the components tested, the following apply:

- During plant heatup and cooldown, record deflection data.
- Verify support movements by recording hot and cold positions.

Performance Criteria

Thermal expansion testing is performed in accordance with Subsection 3.9.2.1.2. For the components tested, the following apply:

- There is no evidence of blocking of the thermal expansion of piping or component, other than by installed supports, restraints, and hangers.

- Spring hanger movements must remain within the hot and cold setpoints and supports must not become fully retracted or extended.

- Piping and components return to their approximate baseline cold position.

14.2.10.4.26 Loss of Offsite Power

Objective

Demonstrate plant response following a plant trip with no offsite power available.

Prerequisites

- The plant is at minimum power level supplying normal house loads through the unit auxiliary transformers.
- The unit is disconnected from the electrical grid.

Test Method

- The turbine is tripped and the generator output breaker opens, removing ac power from the unit auxiliary transformers.

Performance Criteria

- The reactor trips.
- Both standby diesel generators start and pick up the required loads.
- Class 1E dc and non-1E dc loads are uninterrupted and are provided by the battery subsystems.
- The primary plant is placed in a stable condition.

14.2.10.4.27 Feedwater Heater Loss and Out of Service Test

Objective

Demonstrate the plant response to the loss of one of the feedwater heaters during power operation due to single failure or operator error. Demonstrate the plant response to a pair of feedwater heaters taken out of service during power operation. Verify the ability of operators to manually reduce steam flow and place a pair of feedwater heaters out of service while maintaining reactor power operation.

Prerequisites

The plant is operating in a steady-state condition at the rated thermal powers described.

Test Method

LOSS OF FEEDWATER HEATER

- With the plant operating at 50% power, isolate the extraction steam supply to one of the main feedwater heaters.
- With the plant operating at 90% power, isolate the extraction steam supply to one of the main feedwater heaters.

FEEDWATER OUT OF SERVICE TEST

- The operators calculate the appropriate steam flow reduction which will maintain the plant at the desired thermal load after the heaters have been taken out of service.
- Reduce steam flow by the appropriate amount and allow plant conditions to reach a new steady-state (approximately 10 minutes).
- Take a pair of feedwater heaters out of service.

Performance Criteria

The plant control systems properly respond to the loss of a main feedwater heater, without reactor or turbine trip.

The operator successfully removes a pair of feedwater heaters from service without causing a reactor trip.

14.2.10.4.28 Remote Shutdown Workstation

Objective

Demonstrate the ability of the operators to conduct a remote shutdown of the plant during a simulated main control room evacuation.

Prerequisites

Approved operation procedures for performing a remote shutdown is available. Communication exists between the control room and the remote shutdown room. Procedures for transferring control back to the main control room are available if an emergency or unsafe condition develops during the testing that cannot be managed by the shutdown crew.

The plant is operating in a steady-state condition at 10-20 percent of power.

Test Method

- Using the appropriate operating procedures, the operators transfer control of the plant from the main control room to the remote shutdown workstation.
- From the remote shutdown workstation, the operators bring the plant to hot standby, and maintain hot standby conditions for at least 30 minutes.
- From the remote shutdown workstation, the operators lower the reactor coolant system pressure and temperature to the appropriate conditions, and place the normal residual heat removal system into service. The normal residual heat removal system, in conjunction with the component cooling water system and service water system are used to cool the plant at least 50°F without exceeding prescribed cooldown limits.

Performance Criteria

The operators successfully demonstrate the ability transfer control of the plant to the remote shutdown workstation, shut down the reactor, maintain hot standby, and then demonstrate the ability to transition to cold shutdown conditions, while performing these operations from the remote shutdown workstation.

14.2.10.4.29 Passive Residual Heat Removal Heat Exchanger (First Plant Only)

This first plant only test was completed at the first AP1000 unit. This test is not required to be conducted at Vogtle Units 3 & 4.

14.2.10.4.30 Cooling Tower(s)

Objectives

- Verify proper cooling tower(s) function. Provide thermal acceptance testing of the cooling tower's heat removal capabilities.

Prerequisites

- The cooling tower(s) is structurally complete and in good operating condition.
- Circulating water system testing is complete.
- Required support systems, electrical power supplies, and control circuits are operational.

Test Method

Verify cooling tower operation at 100% power when the cooling tower maintains condenser pressure below the alarm setpoint, the turbine building closed cooling water system (TCS) heat exchangers maintain cooling water below the alarm setpoints, and the condenser air removal system (CMS) maintains adequate cooling of the condenser vacuum pumps.

Performance Criteria

The cooling tower(s) perform as described in Subsection 10.4.5.2.3 and in appropriate design specifications.

14.3 Certified Design Material

This section provides the selection criteria and processes used to develop the AP1000 Certified Design Material (CDM). This document provides the principal design bases and design characteristics that are certified by the 10 CFR Part 52 rulemaking process and included in the design certification rule.

The top-level design information in the Certified Design Material is extracted directly from the AP1000 design information. Limiting the certified design contents to top-level information reflects the tiered approach to design certification endorsed by the U.S. Nuclear Regulatory Commission (see References 1 through 5).

The objective of this section is to define the bases and methods that were used to develop the Certified Design Material for the AP1000. This section contains no new technical information regarding the AP1000 design.

The AP1000 Certified Design Material consists of the following:

- An introduction section which defines terms used in the Certified Design Material and lists general provisions that are applicable to all Certified Design Material entries. Also included is a list of acronyms and legends used in the Certified Design Material. (Because this material is self-explanatory, it is not discussed in this section.)

- Design descriptions for selected systems that are within the scope of the AP1000 design certification, and the applicable portions of those selected systems that are only partially within the scope of the AP1000 design certification. The Certified Design Material design descriptions delineate the principal design bases and principal design characteristics that are referenced in the design certification rule. The design descriptions are accompanied by the inspections, tests, analyses, and acceptance criteria (ITAAC) required by 10 CFR 52.47(a)(26) to be part of the design certification application. The ITAAC define verification activities that are to be performed for a facility with the objective of confirming that the plant is built and will operate in accordance with the design certification. Completion of these certified design ITAAC, together with the Combined License applicant's ITAAC for the site-specific portions of the plant, will be the basis for NRC authorization to load fuel per the provisions of 10 CFR Part 52.103.

- Design descriptions and their associated ITAAC for design and construction activities that are applicable to more than one system. Design-related processes have been included in the Certified Design Material for:

  – Aspects of the AP1000 design likely to undergo rapid, beneficial technological developments in the lifetime of the design certification. Certifying the design processes associated with these areas of the design, rather than specific design details, permits future license applicants referencing the AP1000 design certification to take advantage of the best technology available at the time of combined license application and facility construction.

  – Aspects of the design dependant upon characteristics of as-procured, as-installed systems, structures, and components. These characteristics are not available at the time of certification and, therefore, cannot be used to develop and certify design details.

  – Aspects of the seismic, structural and piping design for which detailed design has not been developed. These details are not available at the time of certification and, therefore, cannot be used to certify design details. Certifying the design processes associated with

these design details provides the basis for future license applicants referencing the AP1000 design certification to establish and implement seismic, structural and piping design details as part of the COL application process.

- Interface requirements as defined by 10 CFR Part 52.47(a)(25). Interface requirements are defined as those which must be met by the site-specific portions of the complete nuclear power plant that are not within the scope of the certified design. These requirements define characteristics of the site-specific features that must be provided for the certified design to comply with certification commitments. AP1000 has no interfaces meeting this definition. The Certified Design Material does not include ITAAC or a requirement for COL developed ITAAC for interface requirements.

- Site parameters used as the basis for AP1000 design presented in the Tier 2 Material. These parameters represent a bounding envelope of site conditions for any license application referencing the AP1000 design certification. No ITAAC are necessary for the site parameters entries because compliance with site parameters will be verified as part of issuance of a license for a plant that references the AP1000 design certification.

The following is a description of the criteria and methods used to select specific technical entries for the Certified Design Material. The structure of the description is based on the Certified Design Material report structure.

The criteria and methods discussed in the following sections are guidelines only. For some matters, the contents of the Certified Design Material may not directly correspond to these guidelines because special considerations related to the matters may warrant a different approach. For such matters, a case-by-case determination is made regarding how or whether the matters should be addressed in the Certified Design Material. These determinations are based upon the principles inherent in Part 52.

14.3.1 CDM Section 1.0, Introduction

This section provides definitions, general provisions, a figure legend, and a list of acronyms used in the AP1000 Certified Design Material.

Selection Criteria – Section 1.1 is used to define terms used throughout the Certified Design Material. Selection of entries is based on a judgment that a particular word/phrase merits definition – with particular emphasis on terms associated with implementation of the ITAAC. Section 1.2 contains a mixture of provisions that is selected on the basis that the provision is necessary to either define technical requirements applicable to multiple systems in the Certified Design Material or to provide clarification and guidance for future users of the Certified Design Material.

Selection Methodology – Entries in the Definition section are made on the basis of a self-evident need for a term to be defined. These terms are accumulated during the preparation and review of the Certified Design Material. Entries in the General Provisions section also are developed as part of the Certified Design Material selection and review process. Each entry has a unique background, but the overall intent is to state the broad guidelines and interpretations that are used to prepare Certified Design Material for the AP1000.

14.3.2 CDM Section 2.0, System Based Design Descriptions and ITAAC

This section of the Certified Design Material has the design description and ITAAC material for the selected AP1000 systems. The intent of this list of AP1000 systems is to define at the Certified Design Material level the full scope of the certified design.

14.3.2.1 Design Descriptions

The certified design descriptions for selected AP1000 systems address the top-level design features and performance standards that pertain to the safety of the plant and include descriptive text and supporting figures. The intent of the Certified Design Material design descriptions is to define the AP1000 design characteristics referenced in the design certification rule as a result of the certification provisions of 10 CFR Part 52.

Selection Criteria – The following criteria are considered in determining the information included in the certified design descriptions:

- The information in the certified design descriptions is selected from the technical information presented in the Tier 2 Material. This reflects the approach that the Certified Design Material contains top-level design information and is based on the NRC directive in Reference 2 that there "be less detail in a certification than in an application for certification." In this context, the certification is the Certified Design Material and the application for certification includes the Tier 2 Material.

- The certified design descriptions contain only the information from the Tier 2 Material that is most significant to safety. The Tier 2 Material contains a wide spectrum of information on various aspects of the AP1000 design. Not all of this information is included in the certified design descriptions. This selection criterion reflects the NRC directive in Reference 2 that the certified design should "encompass roughly the same design features that Section 50.59 prohibits changing without prior NRC approval." In determining those structures, systems, or components for which certified design descriptions and ITAAC must be prepared, the following questions are considered for each structure, system, or component:

  – Are there any features or functions classified as Class A, B, or C?

  – Are there any defense–in–depth features or functions provided?

  – For nonsafety–related systems, are there any features or functions credited for mitigation of design basis events?

  – For nonsafety–related systems, are there any features or functions that have been identified in Section 16.3 as candidates for additional regulatory oversight?

  If the answer to the first question is yes, then a certified design description and ITAAC are prepared using the safety function stated in the Tier 2 Material and the parameters from the safety analysis.

  If the answer to either of the next two questions is yes, then a certified design description and ITAAC are prepared using the functions stated in the Tier 2 Material and the parameters from the system design calculations.

  If the answer to the last question is yes and the feature or function is not a programmatic requirement related to operations, maintenance or other programs, then a certified design description and ITAAC are prepared using the functions stated in the Tier 2 Material and the parameters from system design calculations.

  In addition, the following questions were considered for each structure, system, or component not already selected for ITAAC using the above selection criteria:

- Are any features or functions necessary to satisfy the NRC's regulations in Parts 20, 50, 52, 73 and 100?

- Are there any features or functions that represent an important assumption for probabilistic risk assessment?

- Are any features or functions important in preventing or mitigating severe accidents?

- Are there any features or functions that have a significant impact on the safety and operation of the plant?

- Are any features or functions the subject of a provision in the Technical Specifications?

If the answer to any of the above questions is yes, then a design description and ITAAC are prepared using the appropriate functions stated in the Tier 2 material and the parameters from the system design calculations.

A summary of the AP1000 structures, systems, or components considered for selection is given in Table 14.3-1.

- In general, safety-related and defense-in-depth features and functions of structures, systems, and components are discussed in the certified design descriptions. Structures, systems, and components that are not classified as safety-related or defense-in-depth are discussed in the certified design descriptions to the extent that they have features or functions that mitigate a design basis event.

- The certified design descriptions for structures, systems, and components are limited to a discussion of design features and functions. The design bases of structures, systems, and components, and explanations of their importance to safety, are provided in the Tier 2 Material and are not included in the certified design descriptions. The Certified Design Material design descriptions define the certified design. Justification that the design meets regulatory requirements is presented in the Tier 2 Material.

- The certified design descriptions focus on the physical characteristics of the facility. The certified design descriptions do not contain programmatic requirements related to operating conditions or to operations, maintenance, or other programs. These matters are controlled by other means such as the technical specifications.

- The certified design descriptions in Section 2.0 of the Certified Design Material discuss the functional arrangement and performance characteristics that the structures, systems, and components should have after construction is completed. In general, the certified design descriptions do not address the processes that will be used for designing and constructing a plant that references the AP1000 design certification. This is acceptable because the safety-function of a structure, system, or component is dependent upon its final as-built condition and not the processes used to achieve that condition. Exceptions to this criterion are the selected design and qualification processes defined in the instrumentation and control portions and piping portions of Section 2 and the piping, seismic, structural and human factors portion of Section 3.

  The programmatic aspects of the design and construction processes (training, qualification of welders, and the like) are part of the licensee's programs and are subject to commitments made at the time of combined license issuance. Consequently, these issues are not addressed in the AP1000 Certified Design Material.

- The certified design descriptions address fixed design features expected to be in place for the lifetime of the facility. Portable equipment and replaceable items are controlled through operational related programs.

- The certified AP1000 design descriptions do not discuss component types (for example, valve and instrument types), component internals, or component manufacturers. This approach is based on the premise that the safety function of a particular design element can be performed by a variety of component types from different manufacturers.

- The certified design descriptions do not contain proprietary information.

- For the applicant or licensee of a plant that references the AP1000 design certification to take advantage of improvements in technology, the certified design descriptions in general do not prescribe design features that are the subject of rapidly evolving technology.

- The Certified Design Material design description is intended to be self-contained and does not make direct reference to the Tier 2 Material, industrial standards, regulatory requirements, or other documents. (There are some exceptions involving the ASME Code and the Code of Federal Regulations.) If these sources contain technical information of sufficient safety significance to warrant Certified Design Material treatment, the information is extracted from the source and included directly in the appropriate system design description.

  This approach is appropriate because it is unambiguous and it avoids potential questions regarding how much of a referenced document is encompassed in, and becomes part of, the Certified Design Material.

- Selection of the technical terminology to be used in the Certified Design Material is guided by the principle that the terminology should be as consistent as possible with that used in the Tier 2 Material and the body of regulatory requirements and industrial standards applicable to the nuclear industry. This approach is intended to minimize problems in interpreting Certified Design Material commitments.

A review of those sections of the AP1000 Tier 2 Material that document plant safety evaluations was conducted. Specifically, reviews were conducted of the following chapters of the AP1000 Tier 2 Material; the flooding analysis in Chapter 5, the analysis of overpressure protection in Chapter 5, containment analysis in Chapter 6, the core cooling analysis in Chapters 6 and 15, the analysis of fire protection in Chapter 9, the safety analysis of transients in Chapter 15, the analysis of anticipated transients without scram (ATWS) in Chapters 7 and 15, the radiological analysis in Chapter 15, the resolution of unresolved or generic safety issues and Three Mile Island issues in Chapter 1, and the PRA and severe accident information in Chapter 19. These reviews were important in identifying safety-related system design information warranting consideration in the design descriptions and the accompanying design commitments.

Selection Methodology – The Certified Design Material uses a system report structure. The certified design description entry for any system is based on review of the multiple sources having technical information related to that system. Using the selection criteria listed, design description material is developed for each system by reviewing the Tier 2 Material, safety analysis, test programs, and design documents relating to that system.

Application of the criteria listed results in a graded treatment of the systems. This leads to variation in the scope of the design description entries. The following lists the types of AP1000 systems and is a summary of this graded treatment:

System Type	Scope of Design Description
Systems with safety-related functions that contribute to plant performance during design basis accidents	Major safety-related features and performance characteristics
Systems with defense-in-depth functions that contribute to plant performance during design basis accidents	Major defense-in-depth features and performance characteristics
Nonsafety-related systems potentially impacting safety	Brief discussion of design features that prevent or mitigate the potential safety concern
Nonsafety-related systems with no relationship to safety	No discussion

For safety-related systems, application of this criteria results in design description entries that include the following information, as applicable:

- System name and scope
- System purpose
- Summary of the system's safety-significant components (usually shown by a figure)
- Equipment seismic and ASME classifications
- Piping ASME classification and Leak-Before-Break criteria
- Type of electrical power provided for the system
- System's important instruments, controls, and alarms to the extent located in the main control room or remote shutdown workstation
- Equipment to be qualified for harsh environments
- Motor-operated valves within the system that have an active safety-related function
- Other features or functions that are significant to safety

The certified design descriptions for nonsafety-related systems include the information listed to the extent that the information is relevant to the system and is significant to safety. Since much of this information is not relevant to nonsafety-related systems, the certified design descriptions for nonsafety-related systems are less extensive than the descriptions for safety-related systems.

14.3.2.2 Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC)

A table of ITAAC entries is provided for each system that has design description entries. The intent of these ITAAC is to define activities that will be undertaken to verify the as-built system conforms with the design features and characteristics defined in the design description. ITAAC are provided in tables with the following three-column format:

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria

Each design commitment in the left-hand column of the ITAAC tables has an associated inspections, tests, or analyses (ITA) requirement specified in the middle column. The acceptance criteria for the ITA are defined in the right-hand column.

Design Acceptance Criteria (DAC)/ITAAC closure is outlined in Appendix 14A.

Selection Criteria – The following are considered when determining what information is included in the Certified Design Material ITAAC entries:

- The scope and content of the ITAAC correspond to the scope and content of the certified design descriptions. There are no ITAAC for aspects of the design not addressed in the design description. This is appropriate because the objective of the ITAAC design certification entries is to verify that the as-built facility has the design features and performance characteristics defined in the Certified Design Material descriptions.

  Each AP1000 system with a design description has an ITAAC table. This reflects the assessment that a design feature meriting a Certified Design Material description also merits an ITAAC entry to verify that the feature has been included in the as-built facility.

- One inspection, test, or analysis may verify one or more provisions in the certified design description. An ITAAC that specifies a system functional test or an inspection may verify a number of provisions in the design description. There is not necessarily a one-to-one correspondence between the ITAAC and the design descriptions.

- As required by 10 CFR 52.103, the inspections, tests, and analyses must be completed (and the acceptance criteria satisfied) prior to fuel loading. Therefore, the ITAAC do not include any inspections, tests, or analyses that are dependent upon conditions that exist only after fuel load.

- Because the design descriptions are limited to fixed design features expected to be in place for the lifetime of the facility, the ITAAC are limited to a verification of fixtures in the plant. There are no ITAAC for nuclear fuel, fuel channels, and control rods because they are changed by a licensee.

- The ITAAC verify the as-built configuration and performance characteristics of structures, systems, and components as identified in the Certified Design Material design descriptions.

Selection Methodology – Using the selection criteria, ITAAC table entries are developed for each selected system. This is achieved by evaluating the design features and performance characteristics defined in the Certified Design Material design description and preparing an ITAAC table entry for the design description criteria that satisfied the selection criteria. There is a close correlation between the left-hand column of the ITAAC table and the corresponding design description entries.

The ITAAC table is completed by selecting the method to be used for verification (either a test, an inspection, or an analysis [ITA]) and the acceptance criteria for the as-built feature.

The selection of the ITAs is guided by the following:

ITA Approach	Application
Inspection	To be used when verification can be accomplished by visual observations, physical examinations, review of records based on visual observations, or physical examinations that compare the as-built structure, system, or component condition to one or more design description commitments.
Test	To be used when verification can be accomplished by the actuation or operation, or establishment of specified conditions, to evaluate the performance or integrity of the as-built structures, systems, or components. The type of tests identified in the ITAAC tables includes activities such as factory testing, special test facility programs, and laboratory testing.
Analysis	To be used when verification can be accomplished by calculation, mathematical computation, or engineering or technical evaluations of the as-built structures, systems, or components.

The proposed verification activity is identified in the middle column of the ITAAC table. Where appropriate, the Tier 2 Material provides details regarding implementation of the verification activity. This Tier 2 Material is not referenced in the Certified Design Material and is not part of the Certified Design Material; Tier 2 Material is considered as providing one of potentially several acceptable methods for completing the ITA.

Selection of acceptance criteria is dependent upon the design characteristic being verified by the ITAAC table entry: in most cases, the appropriate acceptance criteria is self-evident and is based upon the Certified Design Material design description. For many of the AP1000 ITAAC, the acceptance criteria is a statement that the as-built facility has the design feature or performance characteristic identified in the design description. A guiding principle for acceptance criteria preparation is the recognition that the criteria should be objective and unambiguous. The use of objective and unambiguous terms for the acceptance criteria will minimize opportunities for multiple, subjective (and potentially conflicting) interpretations as to whether an acceptance criteria has, or has not, been met. In some cases, the ITAAC acceptance criteria contain numerical parameters from the Tier 2 Material that are not specifically identified in the Certified Design Material design description or the design commitment column of the ITAAC table. This is acceptable because the design description defines the important design feature/performance that merits Certified Design Material treatment. The acceptance criterion defines a measurement standard for determining if the as-built facility is in compliance with the Certified Design Material design description commitment. Where appropriate, the Tier 2 Material identifies criteria applicable to the same design feature or function that is the subject of more general acceptance criteria in the ITAAC table.

For numerical acceptance criteria, ranges and/or tolerances are included. This is necessary and acceptable because of the following:

- Specification of a single-value acceptance criteria is impractical because trivial deviations will represent unnecessary noncompliances.

- Tolerances recognize that legitimate site variations can occur in complex construction projects.

- Minor variations in plant parameters within the tolerance bounds have no impact on plant safety.

14.3.2.3 Site-Specific ITAAC (SS-ITAAC)

A table of inspections, tests, analyses, and acceptance criteria (ITAAC) entries is provided for each site-specific system described in this FSAR that meets the selection criteria, and that is not included in the certified design. The intent of these ITAAC is to define activities that are undertaken to verify the as-built system conforms with the design features and characteristics defined in the system design description. ITAAC are provided in tables with the following three-column format:

Design Commitment	Inspection, Tests, Analyses	Acceptance Criteria

Each design commitment in the left-hand column of the ITAAC tables has associated inspections, tests, or analyses (ITA) requirements specified in the middle column. The acceptance criteria for the ITA are defined in the right-hand column.

SS-ITAAC do not address ancillary buildings and structures on the site, such as administrative buildings, parking lots, warehouses, training facilities, etc.

Selection Criteria

- In determining those structures, systems, or components for which ITAAC must be prepared, the following questions are considered for each structure, system, or component:

  – Are any features or functions classified as Class A, B, or C?

  – Are any defense-in-depth features or functions provided?

  – For nonsafety-related systems, are any features or functions credited for mitigation of design basis events?

  – For nonsafety-related systems, are there any features or functions that have been identified in Section 16.3 as candidates for additional regulatory oversight?

  If the answer to any of the above questions is yes, then ITAAC are prepared.

- The scope and content of the ITAAC correspond to the scope and content of the site-specific system design description.

- One inspection, test, or analysis may verify one or more provisions in the system design description. An ITAAC that specifies a system functional test or an inspection may verify a number of provisions in the system design description. There is not necessarily a one-to-one correspondence between the ITAAC and the system design descriptions.

- As required by 10 CFR 52.103, the inspections, tests, and analyses are completed (and the acceptance criteria satisfied) prior to initial fuel loading.

- The ITAAC verify the as-built configuration and performance characteristics of structures, systems, and components as identified in the system design descriptions.

Selection Methodology – Using the selection criteria, ITAAC table entries are developed for each selected system. This is achieved by evaluating the design features and performance characteristics defined in the system design descriptions and preparing an ITAAC table entry for each design description criterion that satisfies the selection criteria. A close correlation exists between the left-hand column of the ITAAC and the corresponding design description entries.

The ITAAC table is completed by selecting the method to be used for verification (either a test, an inspection, or an analysis) and the acceptance criteria for the as-built feature.

The approach used to perform the tests, inspections, or analyses is similar to that described in Subsection 14.3.2.2.

14.3.2.3.1 Emergency Planning ITAAC (EP-ITAAC)

EP-ITAAC were developed in the Early Site Permit (ESP) Application to address implementation of elements of the Emergency Plan. Site-specific EP-ITAAC are based on the generic ITAAC provided in Table 13.3-1 of SECY-05-0197. These ITAAC have been tailored to the specific reactor design and emergency planning program requirements.

14.3.2.3.2 Physical Security ITAAC (PS-ITAAC)

Generic PS-ITAAC have been developed in a coordinated effort between the NRC and the Nuclear Energy Institute (NEI). These generic ITAAC have been tailored to the AP1000 design and site-specific security requirements.

14.3.2.3.3 Other Site-Specific Systems

One additional site-specific system has been determined to meet the ITAAC selection criteria, and ITAAC have been included for the Transmission Switchyard and Offsite Power System (ZBS) as indicated in Table 14.3-1. Systems not meeting the selection criteria are subject to the normal functional testing to verify that newly designed and installed systems, structures, or components perform as designed.

A summary of the AP1000 structures, systems, or components considered for selection is given in Table 14.3-1.

14.3.3 CDM Section 3.0, Non-System Based Design Descriptions and ITAAC

Entries in this section of the Certified Design Material have the same structure as the system material discussed in Subsection 14.3.2; that is, design description text and figures and a table of ITAAC entries. The objective of this Certified Design Material is to address selected design and construction activities which are applicable to more than one system. There are six entries in Section 3.0 of the Certified Design Material: nuclear island buildings, initial test program, emergency response facilities, human factors engineering, Design Reliability Assurance Program, and radiation protection.

14.3.3.1 Non-System Based Site Specific ITAAC

Site specific ITAAC (SS-ITAAC) for the Nuclear Island engineered backfill and waterproof membrane are provided in Subsections 2.5.4.5.5 and 3.8.5 respectively.

14.3.3.2 Pipe Rupture Hazard Analysis ITAAC

A pipe rupture hazard analysis is part of the piping design. The analyses will document that structures, systems, and components (SSCs) which are required to be functional during and following a design basis event have adequate high-energy and moderate-energy pipe break mitigation features. The locations of postulated ruptures and essential targets will be established and required pipe whip restraint and jet shield designs will be included. The as-designed pipe rupture hazards analysis will be based on the as-designed piping analysis and will be in accordance with the criteria outlined in Subsections 3.6.1.3.2 and 3.6.2.5. The evaluation will address environmental and flooding effects of cracks in high and moderate energy piping. The report of the pipe rupture hazard

analysis shall conclude that, for each postulated piping failure, the systems, structures, and components that are required to be functional during and following a design basis event are protected.

The as-built reconciliation of the pipe rupture hazards evaluation whip restraint and jet shield design in accordance with the criteria outlined in Subsections 3.6.1.3.2 and 3.6.2.5 are covered in as-built ITAAC identified in DCD Tier 1 to demonstrate that the as-built pipe rupture hazards mitigation features reflect the design, as reconciled. The reconciliation report will be made available for NRC inspection or audit when it has been completed.

The as-designed pipe rupture hazard analysis completed for the first standard AP1000 plant will be available to subsequent standard AP1000 plants under the "one issue, one review, one position" approach for closure.

14.3.3.3 Piping Design ITAAC

The piping design ITAAC consists of the piping analysis for safety-related ASME Code piping. The piping design is completed on a package-by-package basis for applicable systems. In order to support closure of the piping design ITAAC, information consisting of the as-designed piping analysis for piping lines chosen to demonstrate all aspects of the piping design will be made available for NRC review, inspection, and/or audit. This information will consist of a design report referencing the as-designed piping calculation packages, including ASME Section III piping analysis, support evaluations and piping component fatigue analysis for Class I piping. The piping packages to be analyzed are identified in the DCD.

The ASME Code prescribes certain procedures and requirements that are to be followed for completing the piping design. The piping design ITAAC includes a verification of the ASME Code design report to ensure that the appropriate code design requirements for each system's safety class have been implemented.

A reconciliation of the applicable safety-related as-built piping systems is covered in as-built ITAAC identified in DCD Tier 1 to demonstrate that the as-built piping reflects the design, as reconciled. The reconciliation report will be made available for NRC inspection or audit when it has been completed.

The piping design completed for the first standard AP1000 plant will be available to subsequent standard AP1000 plants under the "one issue, one review, one position" approach for closure.

14.3.4 Certified Design Material Section 4.0, Interface Requirements

AP1000 is a plant design incorporating the nuclear island, the annex building and associated equipment, the diesel generator building and associated equipment, the turbine building, the turbine/generator equipment, and the radwaste facilities. As a result, no interfaces need to be identified between or among these portions of the plant. There are no safety-related interfaces between the AP1000 certified design and other portions of a facility with a combined license under 10 CFR Part 52.

Initial testing of interfacing non-safety systems in portions of the plant outside the scope of design certification is as discussed in Section 14.4. Section 1.8, Table 1.8-1, lists the interfacing systems and structures. Those systems that meet the requirements of 10 CFR 52.47(a)(25) are tabulated in Subsection 14.4.5.

14.3.5 CDM Section 5.0, Site Parameters

This section of the Certified Design Material defines the site parameters used as a basis for the design defined in the AP1000 certification application. These entries respond to the 10 CFR 52.47(a)(25) requirement that the design certification documentation include site parameter information. It is intended that applicants referencing the AP1000 design certification demonstrate that these parameters for the selected site are within the certification envelope or provide additional analysis to show acceptability of deviations from the interface envelope.

Site-specific external events that relate to the acceptability of the design (and not to the acceptability of the site) are not considered site parameters and are addressed as interface requirements in the appropriate system entry in Section 4 of the Certified Design Material.

Section 5.0 of the Certified Design Material does not include any ITAAC and is limited to defining the AP1000 site parameters. This is an appropriate approach because compliance of the site with these parameters is demonstrated by a license applicant prior to issuance of the license.

Selection Criteria – Section 2.0, Table 2.0-1, provides the envelope of site design parameters used for the AP1000 design. The corresponding Certified Design Material Section 5.0 is based on using Table 2.0-1. Section 5.0 is limited to a tabular entry; no supporting text material is required.

14.3.6 Initial Test Program

The AP1000 Initial Test Program defines testing activities that will be conducted following completion of construction and construction-related inspections and tests. The Initial Test Program extends through the start of commercial operation of the facility. This program is discussed in Chapter 14.

A summary of the Initial Test Program is included in Certified Design Material Section 3.4. This summary includes an overview of the Initial Test Program structure. This information is included in the Certified Design Material because of the importance of the Initial Test Program defining pre- and post-fuel load testing for the as-built facility. Key pre-fuel load Initial Test Program testing for individual systems is defined in the system ITAAC in Certified Design Material Sections 2 and 3.

No ITAAC entries have been included in the Certified Design Material for the Initial Test Program. This is acceptable because of the following:

- The Initial Test Program activities involve testing with the reactor at various power levels and thus cannot be completed prior to fuel load (Part 52 requires ITAAC to be completed prior to fuel load).

- Testing activities specified as part of the ITAAC in Certified Design Material Sections 2 and 3 must be performed prior to fuel load. Because these ITAAC testing activities address the design features and characteristics of safety significance, additional ITAAC for the Initial Test Program are not necessary to ensure that the as-built plant conforms with the certified design.

14.3.7 Elements of AP1000 Design Material Incorporated into the Certified Design Material

Tables 14.3-2 through 14.3-8 summarize the design material that has been incorporated into the CDM in the areas of 1) Design Basis Accident Analysis, 2) Anticipated Transients Without Scram (ATWS), 3) Fire Protection, 4) Flood Protection, 5) Probabilistic Risk Assessment, 6) Radiological Analysis, and 7) Severe Accident Analysis. PRA assumptions incorporated into these tables encompass elements of the system design and assumptions that were expressly included in Tier 1

due to their importance. Both types of PRA assumptions were included for completeness, but are not distinguished in the tables. CDM falling outside of the seven subject areas are intentionally not incorporated in these tables. However, the referenced AP1000 DCD sections may contain more information than encompassed by these seven subject areas. Each table may also include design information (certified or non-certified) that is not directly related to the particular subject area. Further, these tables are not intended to include all system-specific CDM information that is provided in the AP1000 Tier 2 system descriptions.

14.3.8 Summary

An element of the design certification processes deriving from 10 CFR Part 52 is the selection and documentation of the technical information to be included in the design certification rule as the certified design. The certified design material is a subset of the design information presented in the Tier 2 Material. It includes the following:

- Key, important safety-significant aspects of the design described in the certification application
- Inspections, tests, analyses, and acceptance criteria (ITAAC) that will be used to verify that the as-built facility conforms with the certified design
- Interface requirements and site parameters

The information presented in the AP1000 Certified Design Material is prepared using the selection criteria and methodology described in this section and is intended to satisfy the above Part 52 requirements for design certification. The ITAAC entries in Sections 2.0 and 3.0 confirm that key design performance characteristics and design features are implemented in the as-built facility.

14.3.9 References

1. SECY-90-377, “Requirements for Design Certification under 10 CFR Part 52,” February 15, 1991.

2. 10 CFR, Part 52, “Statements of Consideration,” (54 Federal Register 15372 [1989]).

3. SECY-90-241, “Level of Detail Required for Design Certification under Part 52,” August 31, 1990.

4. SECY-90-377, “Requirements for Design Certification Under 10 CFR Part 52,” November 8, 1990.

5. SECY-91-178, “Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC) for Design Certifications and Combined Licenses,” June 12, 1991.

Table 14.3-1 (Sheet 1 of 4)
ITAAC Screening Summary

Structure/ System Acronym	Structure/ System Description	Selected for ITAAC
ADS	Automatic Depressurization System	X
ASS	Auxiliary Steam Supply System	X
BDS	Steam Generator Blowdown System	X
CAS	Compressed and Instrument Air System	X
CCS	Component Cooling Water System	X
CDS	Condensate System	X
CES	Condenser Tube Cleaning System	X
CFS	Turbine Island Chemical Feed System	X
CMS	Condenser Air Removal System	X
CNS	Containment System	X
CPS	Condensate Polishing System	X
CVS	Chemical and Volume Control System	X
CWS	Circulating Water System	X
DAS	Diverse Actuation System	X
DDS	Data Display Processing System	X
DOS	Standby Diesel Fuel Oil System	X
DRS	Storm Drain System	XX
DTS	Demineralized Water Treatment System	X
DWS	Demineralized Water Transfer and Storage System	X
ECS	Main AC Power System	X
EDS	Non Class 1E DC and UPS System	X
EFS	Communication System	X
EGS	Grounding and Lightning Protection System	X

Table 14.3-1 (Sheet 2 of 4)
ITAAC Screening Summary

Structure/ System Acronym	Structure/ System Description	Selected for ITAAC
EHS	Special Process Heat Tracing System	X
ELS	Plant Lighting System	X
EQS	Cathodic Protection System	X
FHS	Fuel Handling System	X
FPS	Fire Protection System	X
FWS	Main and Startup Feedwater System	X
GSS	Gland Seal System	X
HCS	Generator Hydrogen and CO_2 Systems	X
HDS	Heater Drain System	X
HSS	Hydrogen Seal Oil System	X
IDS	Class 1E DC and UPS System	X
IIS	Incore Instrumentation System	X
LOS	Main Turbine and Generator Lube Oil System	X
MES	Meteorological and Environmental Monitoring System	XX
MHS	Mechanical Handling System	X
MSS	Main Steam System	X
MTS	Main Turbine System	X
OCS	Operations and Control Centers	X
PCS	Passive Containment Cooling System	X
PGS	Plant Gas System	X
PLS	Plant Control System	X
PMS	Protection and Safety Monitoring System	X
PSS	Primary Sampling System	X

Table 14.3-1 (Sheet 3 of 4)
ITAAC Screening Summary

Structure/ System Acronym	Structure/ System Description	Selected for ITAAC
PWS	Potable Water System	X
PXS	Passive Core Cooling System	X
RCS	Reactor Coolant System	X
RDS	Gravity and Roof Drain Collection System	X
RMS	Radiation Monitoring System	X
RNS	Normal Residual Heat Removal System	X
RWS	Raw Water System	XX
RXS	Reactor System	X
SDS	Sanitary Drainage System	X
SES	Plant Security System	X
SFS	Spent Fuel Cooling System	X
SGS	Steam Generator System	X
SJS	Seismic Monitoring System	X
SMS	Special Monitoring System	X
SSS	Secondary Sampling System	X
SWS	Service Water System	X
TCS	Turbine Building Closed Cooling Water System	X
TDS	Turbine Island Vents, Drains and Relief Systems	X
TOS	Main Turbine Control and Diagnostics System	X
TVS	Closed Circuit TV System	XX
VAS	Radiologically Controlled Area Ventilation System	X
VBS	Nuclear Island Nonradioactive Ventilation System	X
VCS	Containment Recirculation Cooling System	X
VES	Main Control Room Emergency Habitability System	X

Table 14.3-1 (Sheet 4 of 4)
ITAAC Screening Summary

Structure/ System Acronym	Structure/ System Description	Selected for ITAAC
VFS	Containment Air Filtration System	X
VHS	Health Physics and Hot Machine Shop HVAC System	X
VLS	Containment Hydrogen Control System	X
VPS	Pump House Building Ventilation System	NA
VRS	Radwaste Building HVAC System	X
VTS	Turbine Island Building Ventilation System	X
VUS	Containment Leak Rate Test System	X
VWS	Central Chilled Water System	X
VXS	Annex/Auxiliary Nonradioactive Ventilation System	X
VYS	Hot Water Heating System	X
VZS	Diesel Generator Building Ventilation System	X
WGS	Gaseous Radwaste System	X
WLS	Liquid Radwaste System	X
WRS	Radioactive Waste Drain System	X
WSS	Solid Radwaste System	X
WWS	Waste Water System	X
YFS	Yard Fire Water System	XX
ZAS	Main Generator System	X
ZBS	Transmission Switchyard and Offsite Power System	XX
ZOS	Onsite Standby Power System	X
ZRS	Offsite Retail Power System	XX
ZVS	Excitation and Voltage Regulation System	X

Legend: X = Selected for ITAAC
X = Selected for ITAAC - title only, no entry for Design Certification

XX = Site-specific system selected for ITAAC – title only, no entry for COLA
XX = Selected for ITAAC
NA = System is not part of VEGP design

Table 14.3-2 (Sheet 1 of 17)
Design Basis Accident Analysis

Reference		Design Feature	Value
Section	3.10	The protection and safety monitoring system equipment is seismically qualified to meet safe shutdown earthquake levels.	
Section	3.11.3	The design of the protection and safety monitoring system equipment has margin to accommodate a loss of the normal HVAC.	
Section	5.1.2	Safety valves are installed above and connected to the pressurizer to provide overpressure protection for the reactor coolant system.	
Section	5.1.2	The RCS has two hot legs and four cold legs.	
Section	5.1.2	The RCS has two steam generators and four reactor coolant pumps.	
Section	5.1.2	The RCS contains a pressurizer and a surge line connected to one hot leg.	
Section	5.1.3.3	Rotating inertia needed for flow coast-down, is provided.	
Table	5.1-3	Minimum measured flow rate with 10% tube plugging (gpm/ loop)	150,835
Table	5.1-3	Initial rated reactor core thermal power (MWt)	3400
Section	5.2.2	Reactor coolant system and steam system overpressure protection during power operation are provided by the pressurizer safety valves and the steam generator safety valves, in conjunction with the action of the PMS.	
Section	5.2.2.1	Safety valve capacity exists to prevent exceeding 110 percent of system design pressure for the following events: – Loss of electrical load and/or turbine trip – Uncontrolled rod withdrawal at power – Loss of reactor coolant flow – Loss of normal feedwater – Loss of offsite power to the station auxiliaries	
Section	5.2.2.1	Overpressure protection for the steam system is provided by steam generator safety valves	
Section	5.3.2.3	Non-destructive examination (NDE) of the reactor vessel and its appurtenances is conducted in accordance with ASME Code Section III requirements.	

Table 14.3-2 (Sheet 2 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 5.3.2.5	The initial Charpy V-notch minimum upper shelf fracture energy levels for the reactor vessel beltline base metal transverse direction and welds are 75 foot-pounds, as required by Appendix G of 10 CFR 50.	
Section 5.4.1.2.1	Resistance temperature detectors (RTDs) monitor motor cooling circuit water temperature. These detectors provide indication of anomalous bearing or motor operation. They also provide a system for automatic shutdown in the event of a prolonged loss of component cooling water.	
Section 5.4.1.3.4	It is important to reactor protection that the reactor coolant continues to flow for a time after reactor trip and loss of electrical power. To provide this flow, each reactor coolant pump has a high-inertia rotor.	
Section 5.4.1.3.4	A reactor coolant pump trip occurs on High-2 bearing water temperature.	
Section 5.4.5.2.3	Power to the pressurizer heaters is blocked when the core makeup tanks are actuated.	
Section 5.4.6	Automatic depressurization system stage 1, 2 and 3 valves are connected to the pressurizer and discharge via the spargers to the in-containment refueling water storage tank.	
Section 5.4.6	Automatic depressurization system stage 4 valves are connected to each hot leg.	
Section 5.4.9.3	In the analysis of overpressure events, the pressurizer safety valves are assumed to actuate at 2500 psia. The safety valve flowrate assumed is based on full flow at 2575 psia, assuming 3 percent accumulation.	
Section 5.4.9.3	The pressurizer safety valves prevent reactor coolant system pressure from exceeding 110% of system design pressure.	
Section 5.4.12	The reactor head vent valves can be operated from the main control room to provide an emergency letdown path.	
Table 5.4-1	Minimum reactor coolant motor/pump moment of inertia sufficient to provide flow coastdown as given in Figure 15.3.2-1.	
Table 5.4-11	Reactor Coolant System Design Pressure Settings: – Safety valves begin to open (psig)	2485

Table 14.3-2 (Sheet 3 of 17)
Design Basis Accident Analysis

Reference		Design Feature	Value
Table	5.4-17	Pressurizer Safety Valves - Design Parameters: – Number – Minimum required relieving capacity per valve (lbm/hr) – Set pressure (psig)	 2 ≥ 750,000 2485 ± 25
Section	6.1.1.4	The aluminum surfaces of the excore (source range, intermediate range, and power range) detectors are encased in a watertight stainless steel or titanium housing.	
Table	6.1-2	The exterior of the containment vessel (above plant elevation 135′ 3″) and the interior of the containment vessel is coated with an inorganic zinc coating.	
Section	6.1.2.1.5	The nonsafety-related coatings used inside containment on walls, floors, ceilings, structural steel which is part of the building structure, and on the polar crane have a minimum dry film density (lb/ft^3).	≥ 100
Figure	6.2.2-1	The passive containment cooling system consists of a water storage tank, cooling water flow discharge path to the containment shell, a water distribution system for the containment shell, and a cooling air flow path.	
Table	6.2.2-1	The minimum duration the PCS cooling water flow is provided from the PCCWST (hours).	≥ 72
Table	6.2.2-1	The water coverage of the containment shell exceeds the amount used in the safety analysis.	
Table	6.2.2-1	The minimum drain flow rate capacity of the upper annulus drain (gpm).	≥ 525
Table	6.2.2-1	The minimum makeup flow rate capability from an external source to the PCS water storage tank (gpm).	≥ 100
Table	6.2.2-1	The minimum makeup flow rate capability from the PCS water storage tank to the spent fuel pool (gpm).	≥ 118
Table	6.2.2-1	The minimum PCS water storage tank volume for makeup to the spent fuel pool (non-coincident with PCS operation) (gallons).	≥ 756,700
Table	6.2.2-1	The minimum long term makeup capability from the PCCAWST to the PCCWST (days).	≥ 4

Table 14.3-2 (Sheet 4 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Table 6.2.2-1	The minimum long term makeup flow capability from the PCCAWST to the PCCWST (gpm).	≥ 100
Table 6.2.2-1	The minimum long term makeup flow capability from the PCCAWST to the spent fuel pool (gpm).	> 35
Table 6.2.2-2	The first (i.e., tallest) standpipe's elevation above the tank floor (feet).	24.1 ± 0.2
Table 6.2.2-2	The second tallest standpipe's elevation above the tank floor (feet).	20.3 ± 0.2
Table 6.2.2-2	The third tallest standpipe's elevation above the tank floor (feet).	16.8 ± 0.2
Table 6.2.2-1	The passive containment cooling water flow rate at 72 hours (gpm).	≥ 100.7
Table 6.2.2-1	The passive containment cooling water flow rate when the PCCWST water level uncovers the third tallest standpipe (gpm).	≥ 144.2
Table 6.2.2-1	The passive containment cooling water flow rate when the PCCWST water level uncovers the second tallest standpipe (gpm).	≥ 176.3
Table 6.2.2-1	The passive containment cooling water flow rate when the PCCWST water level uncovers the first (i.e., tallest) standpipe (gpm).	≥ 226.6
Table 6.2.2-1	The passive containment cooling water flow rate with water inventory at a level of 27.4 ft + 0.2, -0.0 ft above the tank floor (gpm).	≥ 469.1
Section 6.3	The passive core cooling system provides core decay heat removal during design basis events.	
Section 6.3	The passive core cooling system provides RCS makeup, boration, and safety injection during design basis events.	
Section 6.3	The passive core cooling system provides pH adjustment of water flooding the containment following design bases events.	

Table 14.3-2 (Sheet 5 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 6.3.1.1	The passive core cooling system is designed to provide emergency core cooling during events involving increases and decreases in secondary side heat removal and decreases in reactor coolant system inventory.	
Section 6.3.2.1.1	The heat exchanger consists of a bank of C-tubes, connected to a tubesheet and channel heat arrangement at the top (inlet) and bottom (outlet). The passive exchanger connects to the reactor coolant system through an inlet line from one reactor coolant system hot leg and an outlet line to the associated steam generator cold leg plenum (reactor coolant pump suction).	
Section 6.3.2.1.1	For the passive residual heat removal heat exchanger, the normal water temperature in the inlet line will be hotter than the discharge line.	
Section 6.3.2.1.2	The actuation of the core makeup tanks following a steam line break provides injection of borated water via water recirculation to mitigate the reactivity transient and provide the required shutdown margin.	
Section 6.3.2.2.1	The CMT inlet diffuser has a minimum flow area (in^2).	≥ 165
Section 6.3.2.2.3	The in-containment refueling water storage tank contains one passive residual heat removal heat exchanger.	
Section 6.3.2.2.6	The connection of the sparger branch arms to the sparger hub are submerged below the in-containment refueling water storage tank overflow level (ft).	≤ 11.5
Section 6.3.2.2.6	Automatic depressurization system stage 1, 2 and 3 valves are connected to the pressurizer and discharge via the spargers to the in-containment refueling water storage tank.	
Section 6.3.2.2.7.1	The containment recirculation screens have a protective plate that is located no more than 1 foot, 3 inches above the top of the face of the screens, which extends at least 8 feet, 3 inches perpendicular to the front and at least 7 feet to the side of the face of the screens, to prevent coating debris from reaching the screens.	
Section 6.3.2.2.7.1	The type of insulation used on ASME Class 1 lines inside containment and on the reactor vessel, reactor coolant pumps, pressurizer and steam generators is a metal reflective or suitable equivalent insulation.	

Table 14.3-2 (Sheet 6 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 6.3.2.2.7.3	The surface materials used in the vicinity of the containment recirculation screens are stainless steel. In the vicinity of the containment recirculation screens includes surfaces located above the bottom of the recirculation screens up to and including the bottom surface of the plate discussed in subsection 6.3.2.2.7.1, and the surfaces extending at least 8 feet, 3 inches perpendicular to the front and at least 7 feet to the side of the face of the screens.	
Section 6.3.2.2.7.3	The bottom of the containment recirculation screens are located above the loop compartment floor (ft).	≥ 2
Section 6.3.3.2.1	For a loss of main feedwater event, the passive residual heat removal heat exchanger is actuated. If the core makeup tanks are not initially actuated, they actuate later when passive residual heat exchanger cooling sufficiently reduces pressurizer level.	
Section 6.3.3.2.2	For a feedwater system pipe failure event, the passive residual heat removal heat exchanger and the core makeup tanks are actuated.	
Section 6.3.3.3.1	For a steam generator tube rupture event, the nonsafety-related makeup pumps are automatically actuated when reactor coolant system inventory decreases and a reactor trip occurs, followed by actuation of the startup feedwater pumps. Makeup pumps automatically function to maintain the programmed pressurizer level. The core makeup tanks subsequently actuate on Low-2 pressurizer level, if they are not already actuated. Actuation of the core makeup tanks automatically actuates the passive residual heat removal system heat exchanger.	
Section 6.3.6.1	The piping resistances connecting the following PXS components and the RCS are bounded by the resistances assumed in the Chapter 15 safety analysis: – Core makeup tanks – Accumulators – In-containment refueling water storage tank injection – Containment recirculation – Automatic depressurization system valves	
Section 6.3.6.1.3	The bottom of the core makeup tanks are located above the reactor vessel direct vessel injection nozzle centerline (ft).	≥ 7.5

Table 14.3-2 (Sheet 7 of 17)
Design Basis Accident Analysis

Reference		Design Feature	Value
Section	6.3.6.1.3	The bottom of the in-containment refueling water storage tank is located above the direct vessel injection nozzle centerline (ft).	≥ 3.4
Section	6.3.6.1.3	The pH baskets are located below plant elevation 107′ 2″.	
Figure	6.3-1	The passive core cooling system has two direct vessel injection lines.	
Table	6.3-2	The passive core cooling system has two core makeup tanks, each with a minimum required volume (ft^3).	2487
Table	6.3-2	The passive core cooling system has two accumulators, each with a minimum required volume (ft^3)	2,000
Table	6.3-2	The passive core cooling system has an in-containment refueling water storage tank with a minimum required water volume (ft^3)	73,100
Section	6.3.2.2.3	The containment floodup volume for a LOCA in PXS room B has a maximum volume (ft^3) (excluding the IRWST) below a containment elevation of 107.68 feet.	71,960
Table	6.3-2	Each sparger has a minimum discharge flow area (in^2).	≥ 274
Table	6.3-2	The passive core cooling system has four pH adjustment baskets with a total minimum required volume (ft^3).	560
Section	14.2.9.1.3f	The passive residual heat removal heat exchanger minimum natural circulation heat transfer rate (Btu/hr) – With 520°F hot leg and 80°F IRWST – With 420°F hot leg and 80°F IRWST	 ≥ 1.78 E+08 ≥ 1.11 E+08
Section	6.3.6.1.3	The centerline of the HX's upper channel head is located above the HL centerline (ft).	≥ 26.3
Section	6.3.7.4.1	The CMT level sensors (PXS-11A/B/C/D, -12A/B/C/D, -13A/B/C/D, and -14A/B/C/D) upper level tap line has a downward slope of ≥ 2.4 degrees from the centerline of the connection to the CMT to the centerline of the connection to the standpipe.	≥ 2.4 degrees
Figure	6.3-1	The CMT inlet lines (cold leg to high point) have no downward sloping sections.	
Figure	6.3-1	The maximum elevation of the CMT injection lines between the connection to the CMT and the reactor vessel is the connection to the CMTs.	
Figure	6.3-1	The PRHR inlet line (hot leg to high point) has no downward sloping sections.	

Table 14.3-2 (Sheet 8 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Figure 6.3-1	The maximum elevation of the IRWST injection lines (from the connection to the IRWST to the reactor vessel) and the containment recirculation lines (from the containment to the IRWST injection lines) is less than the bottom inside surface of the IRWST.	
Figure 6.3-1	The maximum elevation of the PRHR outlet line (from the PRHR to the SG) is less than the PRHR lower channel head top inside surface.	
Section 7.1.2.10	Isolation devices are used to maintain the electrical independence of divisions and to see that no interaction occurs between nonsafety-related systems and the safety-related system. Isolation devices serve to prevent credible faults in circuit from propagating to another circuit.	
Section 7.1.4.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire, flooding, explosions, missiles, electrical faults and pipe whip.	
Section 7.1.2	The flexibility of the protection and safety monitoring system enables physical separation of redundant divisions.	
Section 7.2.2.2.1	The protection and safety monitoring system initiates a reactor trip whenever a condition monitored by the system reaches a preset level.	
Section 7.2.2.2.8	The reactor is tripped by actuating one of two manual reactor trip controls from the main control room.	
Section 7.3.1.2.2	The in-containment refueling water storage tank is aligned for injection upon actuation of the fourth stage automatic depressurization system via the protection and safety monitoring system.	
Section 7.3.1.2.3	The core makeup tanks are aligned for operation on a safeguards actuation signal or on a low-2 pressurizer level signal via the protection and safety monitoring system.	
Section 7.3.1.2.4	The fourth stage valves of the automatic depressurization system receive a signal to open upon the coincidence of a Low-6 core makeup tank water level in either core makeup tank and low reactor coolant system pressure following a preset time delay after the third stage depressurization valves receive a signal to open via the protection and safety monitoring system.	

Table 14.3-2 (Sheet 9 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 7.3.1.2.4	The first stage valves of the automatic depressurization system open upon receipt of a signal generated from a core makeup tank injection alignment signal coincident with core makeup tank water level less than the Low-3 setpoint in either core makeup tank via the protection and safety monitoring system.	
Section 7.3.1.2.4	The second and third stage valves open on time delays following generation of the first stage actuation signal via the protection and safety monitoring system.	
Section 7.3.1.2.5	The reactor coolant pumps are tripped upon generation of a safeguards actuation signal or upon generation of a low-2 pressurizer water level signal.	
Section 7.3.1.2.7	The passive residual heat removal heat exchanger control valves are opened on Low-2 steam generator wide range water level or on a CMT actuation signal via the protection and safety monitoring system.	
Section 7.3.1.2.9	The containment recirculation isolation valves are opened on a safeguards actuation signal in coincidence with low-3 in-containment refueling water storage tank water level via the protection and safety monitoring system.	
Section 7.3.1.2.14	The demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, or low input voltage to the 1E dc uninterruptible power supply battery chargers.	
Section 7.3.1.2.15	The chemical and volume control system makeup line isolation valves automatically close on a signal from the protection and monitoring system derived from a source range flux doubling, high-2 pressurizer level, High-3 steam generator level signal, a safeguards signal coincident with high-1 pressurizer level, high steam generator water level coincident with P-4 permissive (reactor trip) or high-2 containment radioactivity.	
Section 7.3.2.2.1	The protection and monitoring system automatically generate an actuation signal for an engineered safety feature whenever a monitored condition reaches a preset level.	
Section 7.3.2.2.9	Manual initiation at the system-level exists for the engineered safety features actuation.	

Table 14.3-2 (Sheet 10 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 7.4.3.1	If temporary evacuation of the main control room is required because of some abnormal main control room condition, the operators can establish and maintain safe shutdown conditions for the plant from outside the main control room through the use of controls and monitoring located at the remote shutdown workstation.	
Section 7.4.3.1.1	The remote shutdown workstation equipment is similar to the operator workstations in the main control room and is designed to the same standards. One remote shutdown workstation is provided.	
Section 7.4.3.1.3	The remote shutdown workstation achieves and maintains safe shutdown conditions from full power conditions and maintains safe shutdown conditions thereafter.	
Section 7.5.4	The protection and safety monitoring system provides signal conditioning, communications, and display functions for Category 1 variables and for Category 2 variables that are energized from the Class 1E uninterruptible power supply system.	
Section 7.6.1.1	An interlock is provided for the normally closed motor-operated normal residual heat removal system inner and outer suction isolation valves. Each valve is interlocked so that it cannot be opened unless the reactor coolant system pressure is below a preset pressure.	
Section 8.2.2	Following a turbine trip during power operation, the reverse-power relay will be blocked for a minimum time period (sec).	≥ 15
Section 8.3.2.1.2	The non-Class 1E dc and UPS system (EDS) consists of the electric power supply and distribution equipment that provides dc and uninterruptible ac power to nonsafety-related loads.	

Table 14.3-2 (Sheet 11 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 9.1.1.2.1.C	During normal fuel handling operations, a single failure-proof hoist, designed to meet the requirements of NUREG-0554, is the only hoist capable of moving new fuel above the operating floor. Per the design criteria contained in NUREG-0554, drops from a single failure-proof hoist are deemed unlikely and do not require further analysis. The consequences of such a drop are minimal since no safety-related equipment would be impacted and there are no radiological releases with new unirradiated fuel. Because the likelihood of a new fuel assembly being dropped into the new fuel pit and onto the new fuel racks is minimal, it is unnecessary to evaluate drop scenarios for the new fuel storage rack.	
Section 9.1.3.5	The spent fuel pool is designed such that a water level is maintained above the spent fuel assemblies for at least 7 days following a loss of the spent fuel cooling system using only on-site makeup water sources (See Table 9.1-4).	
Section 9.1.3.5	The spent fuel pool cooling system includes safety-related connections to establish safety-related makeup to the spent fuel pool following a design basis event including a seismic event.	
Section 9.1.4.1.1	In the event of a safe shutdown earthquake (SSE), handling equipment cannot fail in such a manner as to prevent required function of seismic Category 1 equipment.	
Section 9.3.6.3.7	The chemical and volume control system contains two redundant safety-related valves to isolate the demineralized water system from the makeup pump suction.	
Section 9.3.6.3.7	The chemical and volume control system contains two safety-related valves to isolate the makeup flow to the reactor coolant system.	
Section 9.3.6.4.5	The chemical and volume control system contains two safety-related valves to isolate the makeup flow to the reactor coolant system.	
Section 9.3.6.4.5.1	The chemical and volume control system contains two redundant safety-related valves to isolate the demineralized water system from the makeup pump suction.	

Table 14.3-2 (Sheet 12 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 9.3.6.7	The demineralized water system isolation valves close on a signal from the protection and safety monitoring system derived from either a reactor trip signal, a source range flux doubling signal, or low input voltage to the 1E dc and uninterruptible power supply battery chargers.	
Section 9.3.6.7	The chemical and volume control system makeup line isolation valves automatically close on a signal from the protection and safety monitoring system derived from a source range flux doubling, high-2 pressurizer level, High-3 steam generator level signal, high steam generator water level coincident with P-4 permissive (reactor trip), high-2 containment radioactivity, or a safeguards signal coincident with high-1 pressurizer level.	
Section 10.1.2	Safety valves are provided on both main steam lines.	
Section 10.2.2.4.3	The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. The stop valves are closed by actuation of the emergency trip system devices.	
Section 10.3.1.1	The main steam supply system is provided with a main steam isolation valve and associated MSIV bypass valve on each main steam line from its respective steam generator.	
Section 10.3.1.1	A main steam isolation valve (MSIV) on each main steam line prevents the uncontrolled blowdown of more than one steam generator and isolates nonsafety-related portions of the system.	
Section 10.3.1.2	Power-operated atmospheric relief valves are provided to allow controlled cooldown of the steam generator and the reactor coolant system when the condenser is not available.	
Section 10.3.2.1	The main steam supply system includes: – One main steam isolation valve and one main steam isolation valve bypass valve per main steam line. – Main steam safety valves. – Power-operated atmospheric relief valves and upstream isolation valves.	
Section 10.3.2.3.2	In the event that a design basis accident occurs, which results in a large steam line break, the main steam isolation valves with associated main steam isolation bypass valves automatically close.	

Table 14.3-2 (Sheet 13 of 17)
Design Basis Accident Analysis

Reference		Design Feature	Value
Figure	10.3.2-1	The steam generator system consists of two main steam, two main feedwater, and two startup feedwater lines.	
Table	10.3.2-2	Design data for main steam supply safety system valves: – Number per main steam line – Minimum relieving capacity per valve at 110% of design pressure (lb/hr)	 6 1,370,000
Table	10.3.2-2	The flow capacity of the steam generator safety valves (lbm/hr) at 110% of design pressure.	≥ 8,240,000
Table	10.3.2-2	The maximum set pressure of the steam generator safety valves (psig).	≤ 1,242
Section	10.4.8.3	The safety-related portions of the steam generator blowdown system are located in the containment and auxiliary buildings and are designed to remain functional after a safe shutdown earthquake.	
Section	10.4.7.1.1	Double valve main feedwater isolation is provided via the main feedwater control valve and main feedwater isolation valve. Both valves close automatically on main feedwater isolation signals, an appropriate engineered safety features isolation signal, within the time established with the Technical Specifications. The startup feedwater control valve also serves as a containment isolation valve.	
Section	10.4.7.1.1	The condensate and feedwater system provides redundant isolation valves for the main feedwater lines routed into containment.	
Section	10.4.7.1.1	For a main feedwater or main steam line break (MSLB) inside the containment, the condensate and feedwater system is designed to limit high energy fluid to the broken loop.	
Section	10.4.7.1.2	The booster/main feedwater pumps are tripped simultaneously with the feedwater isolation signal to close the main feedwater isolation valves.	
Section	10.4.7.2.1	The main feedwater pumps and booster pumps are tripped with the feedwater isolation signal that closes the main feedwater isolation valves. The same isolation signal closes the isolation valve in the cross connect line between the main feedwater pump discharge header and the startup feedwater pump discharge header.	

Table 14.3-2 (Sheet 14 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 10.4.7.2.2	One MFIV is installed in each of the two main feedwater lines outside the containment and downstream of the feedwater control valve. The MFIVs are installed to prevent uncontrolled blowdown from the steam generators in the event of a feedwater pipe rupture. The main feedwater check valve provides backup isolation. In the event of a secondary side pipe rupture inside the containment, the MFIVs limit the quantity of high energy fluid that enters the containment through the broken loop and limit cooldown. The MFCV provides backup isolation to limit cooldown and high energy fluid addition.	
Section 10.4.7.2.2	In the event of a secondary side pipe rupture inside the containment, the main feedwater control valves provide a redundant isolation to the MFIVs to limit the quantity of high energy fluid that enters the containment through the broken loop.	
Section 10.4.7.3	For a main feedwater line break inside the containment or a main steam line break, the MFIVs and the main feedwater control valves automatically close upon receipt of a feedwater isolation signal.	
Section 10.4.7.3	For a steam generator tube rupture event, positive and redundant isolation is provided for the main feedwater (MFIV and MFCV) with isolation signals generated by the protection and safety monitoring system (PMS).	
Section 10.4.8.2.2.7	Blowdown system isolation is actuated on Low-2 steam generator narrow range water levels. The isolation of steam generator blowdown provides for a continued availability of the steam generator as a heat sink for decay heat removal in conjunction with operation of the passive residual heat removal system and the startup feedwater system.	
Section 10.4.8.3	The safety-related portions of the steam generator blowdown system located in the containment and auxiliary buildings are designed to remain functional after a safe shutdown earthquake.	
Section 10.4.9.1.1	Double valve startup feedwater isolation is provided by the startup feedwater control valve and the startup feedwater isolation valve. Both valves close on a startup feedwater isolation signal, an appropriate engineered safeguards features signal, within the time established within the Technical Specifications.	

Table 14.3-2 (Sheet 15 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 10.4.9.1.1	For a steam generator tube rupture event, positive and redundant isolation is provided for the startup feedwater system (startup feedwater isolation valve and startup feedwater control valve), with isolation signals generated by the protection and safety monitoring system.	
Section 10.4.9.2.2	In the event of a steam generator tube rupture, the startup feedwater isolation valve and startup feedwater control valve limit overfill of the steam generator by terminating startup feed flow.	
Section 10.4.9.2.2	In the event of a secondary pipe rupture inside containment, the startup feedwater isolation valve and startup feedwater control valve provide isolation to limit the quantity of high energy fluid that enters the containment.	
Section 10.4.9.2.2	The startup feedwater isolation valve is provided to prevent the uncontrolled blowdown from more than one steam generator in the event of startup feedwater line rupture. The startup feedwater isolation valve provides backup isolation.	
Table 15.0-1	Initial core thermal power (MWt).	3400
Table 15.0-3	Nominal values of pertinent plant parameters used in accident analysis with 10% steam generator tube plugging – Reactor coolant flow (gpm)	296,000
Section 15.1.2.1	Continuous addition of excessive feedwater is prevented by the steam generator High-3 water level signal trip, which closes the feedwater isolation valves and feedwater control valves and trips the turbine, main feedwater pumps and reactor.	
Section 15.1.4.1	For an inadvertent opening of a steam generator relief or safety valve, core makeup tank actuation occurs from one of four sources: – Two out of four Low-3 pressurizer pressure signals – Two out of four low-2 pressurizer level signals – Two out of four Low-2 T_{cold} signals in any one loop – Two out of four Low-2 steam line pressure signals in any one loop	
Section 15.1.4.1	After an inadvertent opening of a steam generator relief or safety valve, redundant isolation of the main feedwater lines closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.	

Table 14.3-2 (Sheet 16 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 15.1.5.1	Following a steam line rupture, core makeup tank actuation occurs from one of five sources: – Two out of four Low-3 pressurizer pressure signals – Two out of four high-2 containment pressure signals – Two out of four Low-2 steam line pressure signals in any loop – Two out of four Low-2 T_{cold} signals in any one loop – Two out of four low-2 pressurizer level signals	
Section 15.1.5.1	After a steam line rupture, redundant isolation of the main feedwater lines closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.	
Section 15.1.5.2.1	Core makeup tanks and the accumulators are the portions of the passive core cooling system used in mitigating a steam line rupture.	
Section 15.1.6.1	The heat sink for the PRHR heat exchanger is provided by the IRWST, in which the PRHR heat exchanger is submerged.	
Section 15.2.6.2.1	Following a loss of ac power, the PRHR heat exchanger is actuated by Low-2 steam generator wide range water level.	
Section 15.2.8.2.1	Receipt of a Low-2 steam line pressure signal in at least one steam line initiates a steam line isolation signal that closes all main steam line and feed line isolation valves. This signal also gives a safeguards signal that initiates flow of cold borated water from the core makeup tanks to the reactor coolant system.	
Section 15.3.3.2.2	The pressurizer safety valves are fully open at 2575 psia. Their capacity for steam relief is described in Section 5.4.	
Section 15.4.6.2.2	A safety signal from the protection and safety monitoring system automatically isolates the potentially unborated water from the demineralized water transfer and storage system and thereby terminates the dilution.	
Section 15.5.1.1	Following inadvertent operation of the core makeup tanks during power operation, the high-3 pressurizer level signal actuates the PRHR heat exchanger and blocks the pressurizer heaters.	

Table 14.3-2 (Sheet 17 of 17)
Design Basis Accident Analysis

Reference	Design Feature	Value
Section 15.5.2.1	The pressurizer heaters are blocked, and the main feedwater lines, steam lines, and chemical and volume control system are isolated.	
Table 15.6.5-10	ADS Valve Minimum Effective Flow Areas (in^2) – ADS Stage 1 Control Valve – ADS Stage 2 Control Valve – ADS Stage 3 Control Valve – ADS Stage 4A Valve – ADS Stage 4B Valve	 ≥ 4.6 ≥ 16 ≥ 16 ≥ 66 ≥ 66
Table 15.6.5-10	ADS Valve Opening Times (sec) – ADS Stage 1 Control Valve – ADS Stage 1 Isolation Valve – ADS Stage 2 Control Valve – ADS Stage 2 Isolation Valve – ADS Stage 3 Control Valve – ADS Stage 3 Isolation Valve	 ≤ 48 ≤ 30 ≤ 120 ≤ 60 ≤ 120 ≤ 60
Section 18.8.3.2	The main control area includes the reactor operator workstations, the supervisor's workstation, the dedicated safety panel and the wall panel information system.	
Section 18.8.3.2	The human system interface resources available at each workstation are the plant information system displays, the control displays (soft controls), the alarm system displays, computerized procedure system, and the screen and component selector.	

Note:

The ADS Stage 4A Valve and ADS Stage 4B Valve minimum effective flow areas of ≥ 66 in^2 are assumed in the small-break LOCA analyses to account for potential deformation during actuation that may reduce the effective flow area to less than the required as-manufactured flow area of ≥ 67 in^2.

Table 14.3-3
Anticipated Transient Without Scram

Reference	Design Feature	Value
Section 7.7.1.11	The diverse actuation system is a nonsafety-related system that provides a diverse backup to the protection and safety monitoring system.	
Section 7.7.1.11	The diverse actuation system trips the reactor control rods and the turbine on low wide range steam generator water level, or on low pressurizer water level, or on high hot leg temperature.	
Section 7.7.1.11	The diverse actuation system initiates passive residual heat removal on low wide range steam generator water level or high hot leg temperature; actuates core makeup tanks and trips the reactor coolant pumps on low pressurizer water level; and isolates selected containment penetrations and starts passive containment cooling on high containment temperature.	
Section 7.7.1.11	The manual actuation function of the diverse actuation system is implemented by wiring the controls located in the main control room directly to the final loads in a way that bypasses the normal path through the protection and safety monitoring system cabinets and the diverse actuation system logic.	
Section 7.7.1.11	The diverse actuation system uses microprocessor or special purpose logic processor boards different from those used in the protection and safety monitoring system.	
Section 7.7.1.11	The diverse actuation system hardware implementation is different from that of the protection and safety monitoring system.	
Section 7.7.1.11	The operating system and programming language of the diverse actuation system is different from that of the protection and safety monitoring system.	

Table 14.3-4 (Sheet 1 of 2)
Fire Protection

Reference	Design Feature	Value
Section 9A.3.1	Separation is maintained between Class 1E divisions and between Class 1E divisions and non-Class 1E cables in accordance with the fire areas.	
Section 3.4.1.1.2	The AP1000 arrangement provides physical separation of redundant safety-related components and systems from each other and from nonsafety-related components.	
Section 3.8.4.1.1	The conical roof supports the passive containment cooling system tank, which is constructed with a stainless steel liner on reinforced concrete walls.	
Section 7.1.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire and flooding.	
Section 7.4.3.1	If temporary evacuation of the main control room is required because of some abnormal main control room condition, the operators can establish and maintain safe shutdown conditions for the plant from outside the main control room through the use of controls and monitoring located at the remote shutdown workstation.	
Section 7.4.3.1.1	The remote shutdown workstation equipment is similar to the operator workstations in the main control room and is designed to the same standards. One remote shutdown workstation is provided.	
Section 7.4.3.1.3	The remote shutdown workstation achieves and maintains safe shutdown conditions from full power conditions and maintains safe shutdown conditions thereafter.	
Section 8.3.2.2	The four divisions of Class 1E battery chargers and Class 1E voltage regulating transformers are independent, located in separate rooms, cannot be interconnected, and their circuits are routed in dedicated, physically separated raceways.	
Section 8.3.2.3	Each safety-related circuit and the raceway that routes them is given a unique identification number to distinguish between circuits and raceways of different voltage level or separation groups.	

Table 14.3-4 (Sheet 2 of 2)
Fire Protection

Reference	Design Feature	Value
Section 8.3.2.4.2	Cables of one separation group are run in separate raceway and physically separated from cables of other separation groups. Group N raceways are separated from safety-related groups A, B, C, and D. Non-class 1E circuits are electrically isolated by isolation devices, shielding and wiring techniques, physical separation, or an appropriate combination thereof.	
Section 9.5.1.2.1.1	Separation is maintained between redundant safe shutdown components, including equipment, electrical cables, and instrumentation controls, in accordance with the fire areas.	
Section 9.5.1.2.1.5	The standpipe system is supplied with water from the safety-related passive containment cooling system storage tank and normally operates independently of the rest of the fire protection system. The supply line draws water from a portion of the storage tank, using water allocated for fire protection.	
Section 9.5.1.2.1.5	The standpipe system serving areas containing equipment required for safe shutdown following a safe shutdown earthquake is designed and supported so that it can withstand the effects of a safe shutdown earthquake and remain functional.	
Section 9.5.1.2.1.5	The volume of the water in the PCS tank is sufficient to supply two hose streams, each with a flow of 75 gallons per minute, for two hours (gal).	≥ 18,000
Table 9.5.1-2	Each fire pump is rated: – Flow rate (gpm) – Total head (ft)	 ≥ 2000 ≥ 350
Section 18.8.3.2	The human system interface resources available at each workstation are the plant information system displays, the control displays (soft controls), the alarm system displays, computerized procedure system, and the screen and component selector.	
Section 18.8.3.4	The mission of the remote shutdown workstation is to provide the resources to bring the plant to a safe shutdown condition after an evacuation of the main control room.	
Section 18.12.3	The controls, displays, and alarms listed in Table 18.12.2-1 are retrievable from the remote shutdown workstation.	

Table 14.3-5 (Sheet 1 of 2)
Flood Protection

Reference		Design Feature	Value
Section	Appendix 1-A RG 1.143 Section C.1.1.3 Clarification	The lowest level of the auxiliary building, elevation 66′-6″, contains the components of the radwaste system within a common flood zone with watertight floors and walls. This volume of this enclosed flood zone is sufficient to contain the contents of the radwaste system.	
Table	2.0-201	Plant elevation for maximum flood level (ft).	≤ 100
Section	3.4.1.1.1	The seismic Category I structures below grade are protected against flooding by a waterproofing system.	
Section	3.4.1.1.2	The boundaries between mechanical equipment rooms and the electrical and instrumentation and control equipment rooms of the auxiliary building are designed to prevent flooding of rooms that contain safe shutdown equipment up to the maximum flood level for each room.	
Section	3.4.1.2.2	The boundaries between mechanical equipment rooms inside containment and the electrical and instrumentation and control equipment rooms of the auxiliary building are designed to prevent flooding of rooms that contain safe shutdown equipment up to the maximum flood level for each room.	
Section	3.4.1.2.2	Boundaries exist to prevent flooding between the following rooms which contain safety-related equipment: PXS valve/ accumulator room A, PXS valve/accumulator room B, and chemical and volume control room.	
Section	3.4.1.2.2	The AP1000 arrangement provides physical separation of redundant safety-related components and systems from each other and from nonsafety-related components.	
Section	3.4.1.2.2	The safety-related components available for safety shutdown are located in the auxiliary building and inside containment. No credit is taken for operation of sump pumps to mitigate the consequences of flooding.	
Section	3.4.1.2.2.1	The PXS-A compartment, PXS-B compartment and the chemical and volume control system compartment are physically separated and isolated from each other by structural walls such that flooding in any one of these compartments cannot cause flooding in any of the other compartments at elevations up to the top of these compartments.	

Table 14.3-5 (Sheet 2 of 2)
Flood Protection

Reference	Design Feature	Value
Section 3.6	In the event of a high- or moderate-energy pipe failure within the plant, adequate protection is provided so that essential structures, systems, or components are not impacted by the adverse effects of postulated pipe failure.	
Section 7.1.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire and flooding.	

Table 14.3-6 (Sheet 1 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Table 3.2-2	The Nuclear Island structures include the containment and the shield and auxiliary buildings. These structures are seismic Category I.	
Table 3.2-3	The components identified under Reactor Systems in Table 3.2-3, as ASME Code Section III are designed and constructed in accordance with ASME Code Section III Requirements.	
Table 3.2-3	The Nuclear Island structures include the containment and the Shield and Auxiliary Buildings. These structures are seismic Category I.	
Section 3.4.1.1.2	The boundaries between mechanical equipment rooms and the electrical and instrumentation and control equipment rooms of the auxiliary building are designed to prevent flooding of rooms that contain safe shutdown equipment up to the maximum flood level for each room.	
Section 3.4.1.1.2	The AP1000 arrangement provides physical separation of redundant safety-related components and systems from each other and from nonsafety-related components.	
Section 9A.3.1	Separation is maintained between Class 1E divisions and between Class 1E divisions and non-Class 1E cables in accordance with the fire areas.	
Section 3.4.1.2.2	Boundaries exist to prevent flooding between the following rooms which contain safety-related equipment: PXS valve/ accumulator room A, PXS valve/accumulator room B, and chemical and volume control room.	
Section 3.4.1.2.2	The boundaries between mechanical equipment rooms inside containment and the electrical and instrumentation and control equipment rooms of the auxiliary building are designed to prevent flooding of rooms that contain safe shutdown equipment up to the maximum flood level for each room.	
Section 3.4.1.2.2	The safety-related components available for safety shutdown are located in the auxiliary building and inside containment. No credit is taken for operation of sump pumps to mitigate the consequences of flooding.	

Table 14.3-6 (Sheet 2 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Section 3.4.1.2.2.1	The PXS-A compartment, PXS-B compartment and the chemical and volume control system compartment are physically separated and isolated from each other by structural walls such that flooding in any one of these compartments or in the reactor coolant system compartment cannot cause flooding in any of the other compartments.	
Section 3.11.3	The design of the protection and safety monitoring system equipment has margin to accommodate a loss of the normal HVAC.	
Section 3D.6	RXS equipment in Appendix 3D is seismically qualified.	
Section 5.1.3.7	ADS has four stages. Each stage is arranged into two separate groups of valves and lines. – Stages 1, 2, and 3 discharge from the top of the pressurizer to the IRWST. – Each stage 4 discharges from a hot leg to the RCS loop compartment.	
Section 5.3.1.1	The reactor vessel provides a high integrity pressure boundary to contain the reactor coolant, heat generating reactor core, and fuel fission products. The reactor vessel is the primary boundary for the reactor coolant and the secondary barrier against the release of radioactive fission products.	
Section 5.4.6	ADS has four stages. Each stage is arranged into two separate groups of valves and lines. – Stages 1, 2, and 3 discharge from the top of the pressurizer to the IRWST. – Each stage 4 discharges from a hot leg to the RCS loop compartment.	
Section 5.4.6.2	Each ADS stage 1, 2, and 3 line contains two normally closed motor-operated valves (MOVs).	
Section 5.4.6.2	Each ADS stage 4 line contains a normally open MOV valve and a normally closed squib valve.	
Section 5.4.7	The RNS removes heat from the core and reactor coolant system at reduced RCS pressure and temperature conditions after shutdown.	

Table 14.3-6 (Sheet 3 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Section 5.4.7	The normal residual heat removal system (RNS) provides a safety-related means of performing the following functions: – Containment isolation for the RNS lines that penetrate the containment – Long-term, post-accident makeup water to the RCS	
Section 5.4.7.1.1	The RNS containment isolation and pressure boundary valves are safety-related. The motor-operated valves are powered by Class 1E dc power.	
Section 5.4.7.1.2.1	The component cooling water system (CCS) provides cooling to the RNS heat exchanger.	
Section 6.2.4	The containment hydrogen control system provides nonsafety-related hydrogen igniters for control of the containment hydrogen concentration for beyond design basis accidents.	
Section 6.2.4.2.3	At least 66 hydrogen igniters are provided.	
Section 6.3.1.1.3	The automatic depressurization system provides a safety-related means of depressurizing the RCS.	
Section 6.3	The in-containment refueling water storage tank subsystem provides a safety-related means of performing the following functions: – Low-pressure safety injection – Core decay heat sink during design basis events – Flooding of the lower containment, the reactor cavity and the loop compartment by draining the IRWST into the containment. – Borated water	
Section 6.3.1	The core makeup tanks provide safety-related means of safety injection of borated water to the RCS.	
Section 6.3.1	Passive residual heat removal (PRHR) provides a safety-related means of removing core decay heat during design basis events.	
Section 6.3.2	The ADS valves are powered from Class 1E dc power.	

Table 14.3-6 (Sheet 4 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Section 6.3.2	There are two CMTs, each with an injection line to the reactor vessel/DVI nozzle. – Each CMT has a pressure balance line from an RCS cold leg. – Each injection line is isolated with a parallel set of air-operated valves (AOVs). – These AOVs open on loss of air. – The injection line for each CMT also has two check valves in series.	
Section 6.3.2	The IRWST subsystem has the following flow paths: – Two (redundant) injection lines from the IRWST to the reactor vessel/DVI nozzle. Each line is isolated with a parallel set of valves; each set with a check valve in series with a squib valve. – Two (redundant) recirculation lines from the containment to the IRWST injection line. Each recirculation line has two paths: one path contains a squib valve and an MOV, the other path contains a squib valve and a check valve. – The two MOV/squib valve lines also provide the capability to flood the reactor cavity.	
Section 6.3.2	There are screens for each IRWST injection line and recirculation line.	
Section 6.3.2	PRHR is actuated by opening redundant, parallel air-operated valves. These air-operated valves open on loss of air.	
Section 6.3.2.2	The passive core cooling system (PXS) is composed of the following: – Accumulator subsystem – Core makeup tank (CMT) subsystem – In-containment refueling water storage tank (IRWST) subsystem – Passive residual heat removal (PRHR) subsystem. – The automatic depressurization system (ADS), which is a subsystem of the reactor coolant system (RCS), also supports passive core cooling functions.	
Section 6.3.2.2.2	There are two accumulators, each with an injection line to the reactor vessel/direct vessel injection (DVI) nozzle. Each injection line has two check valves in series.	

Table 14.3-6 (Sheet 5 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Section 6.3.2.2.2	The accumulators provide a safety-related means of safety injection of borated water to the RCS.	
Section 6.3.2.2.8.7	The accumulator discharge check valves are of a different type than the CMT discharge check valves.	
Section 6.3.3	IRWST squib valves and MOVs are powered by Class 1E dc power.	
Section 6.3.3	The CMT AOVs are automatically and manually actuated from PMS and DAS.	
Section 6.3.3	The PRHR air-operated valves are automatically actuated and manually actuated from the control room by either PMS or DAS.	
Section 6.3.3	The squib valves and MOVs for injection and recirculation are automatically and manually actuated via PMS, and the squib valves are manually actuated via DAS.	
Section 6.3.3	The squib valves and MOVs for reactor cavity flooding are manually actuated via PMS from the control room. The squib valves are manually actuated via DAS from the control room.	
Section 6.3.7	The positions of the containment recirculation isolation MOVs are indicated in the control room.	
Section 6.3.7	The position of the inlet PRHR valve is indicated in the control room.	
Section 6.3.7.6.1	The ADS first-, second-, and third-stage valve positions are indicated in the control room.	
Section 7.1.1	The diverse actuation system provides a nonsafety-related means of performing the following functions: – Initiates automatic and manual reactor trip – Automatic and manual actuation of selected engineered safety features – Main control room display of selected plant parameters.	
Section 7.1.1	The protection and safety monitoring system provides a safety-related means of performing the following functions: – Automatic and manual reactor trip – Automatic and manual actuation of engineered safety features (ESF).	

Table 14.3-6 (Sheet 6 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Section 7.1.1	PMS provides for the minimum inventory of fixed position controls and displays in the control room.	
Section 7.1.2	Each PMS division is powered from its respective Class 1E dc division.	
Section 7.1.2	PMS has four divisions of reactor trip and ESF actuation.	
Section 7.1.2.5	PMS has two divisions of safety-related post-accident parameter data processing equipment.	
Section 7.1.2.9	PMS automatically blocks an attempt to bypass more than one channel of a function that uses 2-out-of-4 logic.	
Section 7.1.2.14	The PMS hardware and software are developed using a planned design process which provides for specific design documentation and reviews during the design requirement, system definition, development, test and installation phases.	
Section 7.1.4.2	The ability of the protection and safety monitoring system to initiate and accomplish protective functions is maintained despite degraded conditions caused by internal events such as fire and flooding.	
Section 7.1.2	The flexibility of the protection and safety monitoring system enables physical separation of redundant divisions.	
Section 7.2.2.2.1	The protection and safety monitoring system initiates a reactor trip whenever a condition monitored by the system reaches a preset level.	
Section 7.4.3 18.12.2	The PMS allows for the transfer of control capability from the main control room to the remote shutdown workstation. The minimum inventory of displays and controls in the remote shutdown workstation is provided.	
Section 7.3.1 8.3.2.1.1	The ADS valves are powered from Class 1E dc power.	
Section 7.7.1.11 7.3.1.2.4	The ADS valves are automatically and manually actuated via the protection and safety monitoring system (PMS), and manually actuated via the diverse actuation system (DAS).	
Section 7.3.1.2.3 7.7.1.11	The CMT AOVs are automatically and manually actuated from PMS and DAS.	
Section 7.3.1.2.2 7.3.1.2.9 7.7.1.11	The squib valves and MOVs for injection and recirculation are automatically and manually actuated via PMS, and the squib valves are manually actuated via DAS.	

Table 14.3-6 (Sheet 7 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Figure 7.2-1 (Sheets 16 and 21)	The squib valves and MOVs for reactor cavity flooding are manually actuated via PMS from the control room. The squib valves are manually actuated via DAS from the control room.	
Section 7.3.1.2.7 7.7.1.11	The PRHR air-operated valves are automatically actuated and manually actuated from the control room by either PMS or DAS.	
Section 7.3.1.2.20	The RNS containment isolation MOVs are actuated via PMS.	
Section 7.5.4	PMS has four divisions of safety-related post-accident parameter display.	
Section 7.6.1.1	An interlock is provided for the normally closed motor-operated normal residual heat removal system inner and outer suction isolation valves. Each valve is interlocked so that it cannot be opened unless the reactor coolant system pressure is below a preset pressure.	
Section 7.7.1.11	The diverse actuation system is a nonsafety-related system that provides a diverse backup to the protection and safety monitoring system.	
Section 7.7.1.11	The diverse actuation system trips the reactor control rods and the turbine on low wide range steam generator water level, or on low pressurizer water level, or on high hot leg temperature.	
Section 7.7.1.11	DAS manual initiation functions are implemented in a manner that bypasses the signal processing equipment of the DAS.	
Section 7.7.1.11	The DAS automatic actuation signals are generated in a functionally diverse manner from the PMS signals. Diversity between DAS and PMS is achieved by the use of different architectures, different hardware implementations, and different software, if any. Software diversity between the DAS and PMS will be achieved through the use of different algorithms, logic, program architecture, executable operating system, and executable software/logic.	

Table 14.3-6 (Sheet 8 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Section 8.3.1.1.1	On loss of power to a 6900V diesel-backed bus, the associated diesel generator automatically starts and produces ac power. The source circuit breakers and bus load circuit breakers are opened, and the generator is connected to the bus. Each generator has an automatic load sequencer to enable controlled loading on the associated buses.	
Section 8.3.1.1.2.1	Two onsite standby diesel generator units provide power to the selected nonsafety-related ac loads.	
Section 8.3.1.1.4	The main ac power system distributes non-Class 1E power from onsite sources to selected nonsafety-related loads.	
Section 8.3.2.1	The Class 1E dc and uninterruptible power supply (UPS) system (IDS) provides dc and uninterruptible ac power for the safety-related equipment.	
Section 8.3.2.1.1.1	There are four independent, Class 1E 250 Vdc divisions. Divisions A and D are each composed of one battery bank, one switchboard, and one battery charger. Divisions B and C are each composed of two battery banks, two switchboards, and two battery chargers. The first battery bank in the four divisions is designated as the 24-hour battery bank. The second battery bank in Divisions B and C is designated as the 72-hour battery bank.	
Section 8.3.2.1.1.1	Battery chargers are connected to dc switchboard buses. The input ac power for the Class 1E dc battery chargers is supplied from onsite diesel-generator-backed low-voltage ac power supplies.	
Section 8.3.2.1.1.1	The 24-hour battery banks provide power to the loads for a period of 24 hours without recharging. The 72-hour battery banks supply a dc switchboard bus load for a period of 72 hours without recharging.	
Section 8.3.2.1.2	The non-Class 1E dc and UPS system (EDS) consists of the electric power supply and distribution equipment that provides dc and uninterruptible ac power to nonsafety-related loads.	
Section 8.3.2.1.2	EDS load groups 1, 2, 3, and 4 provide 125 Vdc power to the associated inverter units that supply the ac power to the non-Class 1E uninterruptible power supply ac system.	

Table 14.3-6 (Sheet 9 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Section 8.3.2.1.2	Battery chargers are connected to dc switchboard buses. The input ac power for the non-Class 1E dc battery chargers is supplied from onsite diesel-generator-backed low-voltage ac power supplies.	
Section 8.3.2.1.2	The onsite standby diesel-generator-backed low-voltage ac power supply provides the normal ac power to the battery chargers.	
Section 8.3.2.4.2	Separation is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E cables.	
Section 9.2.1	The service water system is a nonsafety-related system that transfers heat from the component cooling water heat exchangers to the atmosphere.	
Section 9.2.1.2.1	The SWS is arranged into two trains. Each train includes one pump and one cooling tower cell.	
Section 9.2.2	The component cooling water system is a nonsafety-related system that removes heat from various components and transfers the heat to the service water system (SWS).	
Section 9.2.2.2	The CCS is arranged into two trains. Each train includes one pump and one heat exchanger.	
Section 9.3.6	The CVS provides a nonsafety-related means to perform the following functions: – Makeup water to the RCS during normal plant operation – Boration following a failure of reactor trip – Coolant to the pressurizer auxiliary spray line.	
Section 9.3.6.1.1	The chemical and volume control system (CVS) provides a safety-related means to terminate inadvertent RCS boron dilution.	
Section 9.4.1	The main control room has its own ventilation system and is pressurized. The ventilation system for the remote shutdown room is independent of the ventilation system for the main control room.	
Section 9.5.1.2.1.1	The PMS allows for the transfer of control capability from the main control room to the remote shutdown workstation. The minimum inventory of displays and controls at the remote shutdown workstation is provided.	

Table 14.3-6 (Sheet 10 of 10)
Probabilistic Risk Assessment

Reference	Design Feature	Value
Section 9.5.1.2.1.1	Class 1E divisional cables are routed in their respective divisional raceways.	
Section 9.5.1.2.1.1	Separation is maintained between Class 1E divisions and between Class 1E divisions and non-Class 1E cables in accordance with the fire areas.	
Section 17.4.1	D-RAP provides reasonable assurance that the design of risk-significant SSCs is consistent with their PRA assumptions.	
Section 18.8.3.2	The main control area includes the reactor operator workstations, the supervisor's workstation, the dedicated safety panel and the wall panel information system.	
Section 18.12.2	The minimum inventory of instrumentation includes those displays, controls, and alarms that are used to monitor the status of the critical safety functions and to manually actuate the safety-related systems that achieve the critical safety functions. The minimum inventory resulting from the implementation of the selection criteria is provided in Table 18.12.2-1.	

Table 14.3-7 (Sheet 1 of 3)
Radiological Analysis

Reference	Design Feature	Value
Table 2.0-201	Plant elevation for maximum flood level (ft)	≤ 100
Section 2.3.4	Atmospheric dispersion factors - X/Q (sec/m^3) – Site Boundary X/Q 0 - 2 hour time interval – Low Population Zone Boundary X/Q 0 - 8 hours 8 - 24 hours 24 - 96 hours 96 - 720 hours	 $\leq 5.1 \times 10^{-4}$ $\leq 2.2 \times 10^{-4}$ $\leq 1.6 \times 10^{-4}$ $\leq 1.0 \times 10^{-4}$ $\leq 8.0 \times 10^{-5}$
Table 6.2.3-1	Containment penetration isolation features are configured as in Table 6.2.3-1	
Table 6.2.3-1	Maximum closure time for remotely operated containment purge valves (seconds)	≤ 10
Table 6.2.3-1	Maximum closure time for all other remotely operated containment isolation valves (seconds)	≤ 60
Section 6.4.2.3	The minimum storage capacity of all storage tanks in the VES (scf)	≥ 327,574
Section 6.4.4	The maximum temperature in the instrumentation and control rooms and dc equipment rooms following a loss of the nuclear island nonradioactive ventilation system remains over a 72-hour period (°F).	≤ 120
Section 6.4.4	The main control emergency habitability system nominally provides 65 scfm of ventilation air to the main control room from the compressed air storage tanks.	65 ± 5
Section 6.4.4	Sixty-five ± five scfm of ventilation flow is sufficient to pressurize the control room to $1/8^{th}$ inch water gauge differential pressure (WIC).	$1/8^{th}$
Section 6.4.5.1	The maximum temperature in the main control room pressure boundary following a loss of the nuclear island nonradioactive ventilation system over a 72-hour period (°F) (dry bulb temperature).	95
Figure 6.4-2	The main control room emergency habitability system consists of four sets of emergency air storage tanks and an air delivery system to the main control room.	
Section 6.5.3	The passive heat removal process and the limited leakage from the containment result in offsite doses less than the regulatory guideline limits.	

Table 14.3-7 (Sheet 2 of 3)
Radiological Analysis

Reference	Design Feature	Value
Section 8.3.1.1.6	Electrical penetrations through the containment can withstand the maximum short-circuit currents available either continuously without exceeding their thermal limit, or at least longer than the field cables of the circuits so that the fault or overload currents are interrupted by the protective devices prior to a potential failure of a penetration.	
Section 9.4.1.1.1	The VBS isolates the HVAC ductwork that penetrates the main control room boundary on High-2 particulate or iodine concentration in the main control room supply air, extended Low main control room differential pressure, or on extended loss of ac power to support operation of the main control room emergency habitability system.	
Section 12.3.2.2.1	During reactor operation, the shield building protects personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and primary loop components. The concrete shield building wall and the reactor vessel and steam generator compartment shield walls reduce radiation levels outside the shield building to less than 0.25 mrem/hr from sources inside containment. The shield building completely surrounds the reactor components.	
Section 12.3.2.2.2	The reactor vessel is shielded by the concrete primary shield and by the concrete secondary shield which also surrounds other primary loop components. The secondary shield is a structural module filled with concrete surrounding the reactor coolant system equipment, including piping, pumps and steam generators. Extensive shielding is provided for areas surrounding the refueling cavity and the fuel transfer canal to limit the radiation levels.	
Section 12.3.2.2.3	Shielding is provided for the liquid radwaste, gaseous radwaste and spent resin handling systems consistent with the maximum postulated activity. Corridors are generally shielded to allow Zone II access, and operator areas for valve modules are generally Zone II or III for access. Shielding is provided to attenuate radiation from normal residual heat removal equipment during shutdown cooling operations to levels consistent with radiation zoning requirements of adjacent areas.	

Table 14.3-7 (Sheet 3 of 3)
Radiological Analysis

Reference	Design Feature	Value
Section 12.3.2.2.4	The concrete shield walls surrounding the spent fuel cask loading and decontamination areas, and the shield walls surrounding the fuel transfer and storage are sufficiently thick to limit radiation levels outside the shield walls in accessible areas to Zone II. The building walls are sufficient to shield external plant areas which are not controlled to Zone I.	
Section 12.3.2.2.5	Shielding is provided as necessary for the waste storage areas in the radwaste building to meet the radiation zone and access requirements.	
Section 12.3.2.2.7	Shielding combined with other engineered safety features is provided to permit access and occupancy of the control room following a postulated loss-of-coolant accident, so that radiation doses are limited to five rem whole body from contributing modes of exposure for the duration of the accident, in accordance with General Design Criteria 19.	
Section 12.3.2.2.9	The spent fuel transfer tube is shielded to within adjacent area radiation limits, is completely enclosed in concrete, and there is no unshielded portion of the spent fuel transfer tube during the refueling operation.	

Table 14.3-8
Severe Accident Analysis

Reference	Design Feature	Value
Section 1.2	The discharge from the IRWST vents located in the roof of the IRWST next to the containment vessel are oriented away from the containment vessel.	
Section 5.3.1.2	There are no penetrations in the reactor vessel below the core.	
Section 5.3.5	The reflective (or suitable equivalent) reactor vessel insulation provides an engineered flow path to allow the ingression of water and venting of steam for externally cooling the vessel. – A flow path exists from the loop compartment to the reactor vessel cavity (ft^2). – A flow path area to vent steam exists between the vessel insulation and the reactor vessel (ft^2).	 ≥ 6 ≥ 12
Section 6.2.4.2.3	The hydrogen ignition subsystem consists of 66 hydrogen igniters strategically distributed throughout the containment.	
Table 6.2.4-3	The minimum surface temperature of the hydrogen igniters (°F).	≥ 1700
Section 6.3	The ADS provides a safety-related means of depressurizing the RCS.	
Section 6.3	The PXS provides a safety-related means of flooding the reactor cavity by draining the IRWST into the containment.	
Section 7.3.1.2.9	Signals to align the IRWST containment recirculation isolation valves are generated by manual initiation.	
Section 7.7.1.11	Initiation of containment recirculation is a diverse manual function.	

Table 14.3-201
Not Used

14.4 Combined License Applicant Responsibilities

14.4.1 Organization and Staffing

The staff, staff responsibilities, authorities, and personnel qualifications for performing the AP1000 initial test program are addressed in Section 14.2. This test organization is responsible for the planning, executing, and documenting of the plant initial testing and related activities that occur between the completion of plant/system/component construction and commencement of plant commercial operation. Transfer and retention of experience and knowledge gained during initial testing for the subsequent commercial operation of the plant is an objective of the test program.

14.4.2 Test Procedures

Preoperational and startup test procedures are available to the NRC in accordance with the requirements of Subsection 14.2.3. The controls for development of test procedures are also described in Subsection 14.2.3.

A cross reference list is provided between ITAACs and test procedures and/or sections of test procedures.

14.4.3 Conduct of Initial Test Program

A site-specific ITP Administrative Manual (procedures), which contains the administrative procedures and requirements that govern the activities associated with the plant initial test program, as described in Section 14.2 is provided.

14.4.4 Review and Evaluation of Test Results

Review and evaluation of individual test results, as well as final review of overall test results and selected milestones or hold points are addressed in Subsection 14.2.3.2. Test exceptions or results that do not meet acceptance and/or functional criteria are identified to the affected and responsible design organizations, and corrective actions and retests, as required, are performed.

14.4.5 Interface Requirements

The test abstracts required of structures and systems which are outside the scope of the design certification are addressed in Subsections 14.2.9.4.15, 14.2.9.4.23 through 14.2.9.4.27, 14.2.10.4.30, and in the Physical Security Plan.

14.4.6 First-Plant-Only and Three-Plant-Only Tests

[*The COL holder for the first plant and the first three plants will perform the tests listed in subsection 14.2.5. For subsequent plants, either tests listed in subsection 14.2.5 shall be performed, or the COL applicant shall provide a justification that the results of the first-plant-only tests or first-three-plant tests are applicable to the subsequent plant.*]*

First-plant-only and first-three-plant-only tests either are performed in accordance with Subsection 14.2.5 or a justification is provided that the results of the first-plant-only and first-three-plant-only tests are applicable to a subsequent plant. If the tests are not performed, the justification is provided prior to preoperational testing.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Appendix 14A Design Acceptance Criteria/ITAAC Closure Process

Design Acceptance Criteria (DAC) are a set of prescribed limits, parameters, procedures, and attributes upon which the NRC relies, in a limited number of technical areas, in making a final safety determination to support a design certification. DAC is to be objective (measurable, testable, or subject to analysis using pre-approved methods), and must be verified as a part of the ITAAC performed to demonstrate that the as-built facility conforms to the certified design (SECY 92-053).

There are three process options for DAC/ITAAC resolution:

- Resolve through amendment to design certification
- Resolve as part of COL review
- Resolve after COL is issued

In the first two options, the applicant will submit the design information and the NRC will document its review in a safety evaluation. In the third option, the COL holder notifies the NRC of availability of design information and the staff will document its review in an inspection report.

Should the third option be implemented for the first standard AP1000 plant, subsequent COL applicants may reference the first standard plant closure documentation and close the DAC/ITAAC under the concept of “one issue, one review, one position,” identified in NRC guidance.

Additionally, Westinghouse may submit licensing topical reports for NRC review of the material supporting the DAC/ITAAC closure and request that the NRC issue a safety evaluation in conjunction with a closure letter or inspection report concluding that the acceptance criteria of the DAC/ITAAC have been met. Subsequent COL applicants may reference these reports and NRC closure documents in an effort to close the DAC/ITAAC.

For technical areas where DAC/ITAAC applies in the design certification rule, COL applicants will provide an ITAAC and associated closure schedule indicating the approach to be applied. For subsequent COL applicants following the first standard AP1000 plant, the indication could be to reference the existing DAC/ITAAC closure documentation for the first standard plant.

NRC guidance for DAC/ITAAC is provided in Regulatory Guide 1.206, Section C.III.5. Further information on the staff’s position of DAC/ITAAC being used as part of the 10 CFR Part 52 review process is provided in SECY-92-053.

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 15	ACCIDENT ANALYSES	15.0-1
15.0.1	Classification of Plant Conditions	15.0-1
15.0.1.1	Condition I: Normal Operation and Operational Transients	15.0-1
15.0.1.2	Condition II: Faults of Moderate Frequency	15.0-2
15.0.1.3	Condition III: Infrequent Faults	15.0-3
15.0.1.4	Condition IV: Limiting Faults	15.0-3
15.0.2	Optimization of Control Systems	15.0-4
15.0.3	Plant Characteristics and Initial Conditions Assumed in the Accident Analyses	15.0-4
15.0.3.1	Design Plant Conditions	15.0-4
15.0.3.2	Initial Conditions	15.0-4
15.0.3.3	Power Distribution	15.0-5
15.0.4	Reactivity Coefficients Assumed in the Accident Analysis	15.0-6
15.0.5	Rod Cluster Control Assembly Insertion Characteristics	15.0-6
15.0.6	Protection and Safety Monitoring System Setpoints and Time Delays to Trip Assumed in Accident Analyses	15.0-7
15.0.7	Instrumentation Drift and Calorimetric Errors	15.0-7
15.0.8	Plant Systems and Components Available for Mitigation of Accident Effects	15.0-8
15.0.9	Fission Product Inventories	15.0-8
15.0.10	Residual Decay Heat	15.0-8
15.0.10.1	Total Residual Heat	15.0-8
15.0.10.2	Distribution of Decay Heat Following a Loss-of-Coolant Accident	15.0-8
15.0.11	Computer Codes Used	15.0-9
15.0.11.1	FACTRAN Computer Code	15.0-9
15.0.11.2	LOFTRAN Computer Code	15.0-9
15.0.11.3	TWINKLE Computer Code	15.0-10
15.0.11.4	VIPRE-01 Computer Code	15.0-10
15.0.11.5	COAST Computer Program	15.0-10
15.0.11.6	ANC Computer Code	15.0-11
15.0.12	Component Failures	15.0-11
15.0.12.1	Active Failures	15.0-11
15.0.12.2	Passive Failures	15.0-11
15.0.12.3	Limiting Single Failures	15.0-12
15.0.13	Operator Actions	15.0-12
15.0.14	Loss of Offsite ac Power	15.0-12
15.0.15	Combined License Information	15.0-13
15.0.16	References	15.0-13
15.1	Increase in Heat Removal From the Primary System	15.1-1
15.1.1	Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature	15.1-1
15.1.1.1	Identification of Causes and Accident Description	15.1-1
15.1.1.2	Analysis of Effects and Consequences	15.1-2
15.1.1.3	Conclusions	15.1-2
15.1.2	Feedwater System Malfunctions that Result in an Increase in Feedwater Flow	15.1-2

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	15.1.2.1 Identification of Causes and Accident Description	15.1-2
	15.1.2.2 Analysis of Effects and Consequences	15.1-3
	15.1.2.3 Conclusions	15.1-5
15.1.3	Excessive Increase in Secondary Steam Flow	15.1-5
	15.1.3.1 Identification of Causes and Accident Description	15.1-5
	15.1.3.2 Analysis of Effects and Consequences	15.1-6
	15.1.3.3 Conclusions	15.1-7
15.1.4	Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-8
	15.1.4.1 Identification of Causes and Accident Description	15.1-8
	15.1.4.2 Analysis of Effects and Consequences	15.1-9
	15.1.4.3 Margin to Critical Heat Flux	15.1-10
	15.1.4.4 Conclusions	15.1-11
15.1.5	Steam System Piping Failure	15.1-11
	15.1.5.1 Identification of Causes and Accident Description	15.1-11
	15.1.5.2 Analysis of Effects and Consequences	15.1-12
	15.1.5.3 Conclusions	15.1-16
	15.1.5.4 Radiological Consequences	15.1-16
	15.1.5.5 Steam System Piping Failure at Full Power	15.1-18
15.1.6	Inadvertent Operation of the PRHR Heat Exchanger	15.1-20
	15.1.6.1 Identification of Causes and Accident Description	15.1-20
	15.1.6.2 Analysis of Effects and Consequences	15.1-21
	15.1.6.3 Conclusions	15.1-21
15.1.7	Combined License Information	15.1-21
15.1.8	References	15.1-21
15.2	Decrease in Heat Removal by the Secondary System	15.2-1
15.2.1	Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	15.2-1
15.2.2	Loss of External Electrical Load	15.2-1
	15.2.2.1 Identification of Causes and Accident Description	15.2-1
	15.2.2.2 Analysis of Effects and Consequences	15.2-2
	15.2.2.3 Conclusions	15.2-3
15.2.3	Turbine Trip	15.2-3
	15.2.3.1 Identification of Causes and Accident Description	15.2-3
	15.2.3.2 Analysis of Effects and Consequences	15.2-4
	15.2.3.3 Conclusions	15.2-7
15.2.4	Inadvertent Closure of Main Steam Isolation Valves	15.2-7
15.2.5	Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip	15.2-7
15.2.6	Loss of ac Power to the Plant Auxiliaries	15.2-8
	15.2.6.1 Identification of Causes and Accident Description	15.2-8
	15.2.6.2 Analysis of Effects and Consequences	15.2-9
	15.2.6.3 Conclusions	15.2-10
15.2.7	Loss of Normal Feedwater Flow	15.2-11
	15.2.7.1 Identification of Causes and Accident Description	15.2-11

TABLE OF CONTENTS (CONTINUED)

Section		Title	Page
		15.2.7.2 Analysis of Effects and Consequences	15.2-12
		15.2.7.3 Conclusions	15.2-14
	15.2.8	Feedwater System Pipe Break	15.2-14
		15.2.8.1 Identification of Causes and Accident Description	15.2-14
		15.2.8.2 Analysis of Effects and Consequences	15.2-15
		15.2.8.3 Conclusions	15.2-18
	15.2.9	Combined License Information	15.2-18
	15.2.10	References	15.2-18
15.3		Decrease in Reactor Coolant System Flow Rate	15.3-1
	15.3.1	Partial Loss of Forced Reactor Coolant Flow	15.3-1
		15.3.1.1 Identification of Causes and Accident Description	15.3-1
		15.3.1.2 Analysis of Effects and Consequences	15.3-2
		15.3.1.3 Conclusions	15.3-3
	15.3.2	Complete Loss of Forced Reactor Coolant Flow	15.3-3
		15.3.2.1 Identification of Causes and Accident Description	15.3-3
		15.3.2.2 Analysis of Effects and Consequences	15.3-3
		15.3.2.3 Conclusions	15.3-4
	15.3.3	Reactor Coolant Pump Shaft Seizure (Locked Rotor)	15.3-4
		15.3.3.1 Identification of Causes and Accident Description	15.3-4
		15.3.3.2 Analysis of Effects and Consequences	15.3-5
		15.3.3.3 Radiological Consequences	15.3-7
	15.3.4	Reactor Coolant Pump Shaft Break	15.3-9
		15.3.4.1 Identification of Causes and Accident Description	15.3-9
		15.3.4.2 Conclusion	15.3-9
	15.3.5	Combined License Information	15.3-9
	15.3.6	References	15.3-10
15.4		Reactivity and Power Distribution Anomalies	15.4-1
	15.4.1	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low-Power Startup Condition	15.4-1
		15.4.1.1 Identification of Causes and Accident Description	15.4-1
		15.4.1.2 Analysis of Effects and Consequences	15.4-3
		15.4.1.3 Conclusions	15.4-4
	15.4.2	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power	15.4-4
		15.4.2.1 Identification of Causes and Accident Description	15.4-4
		15.4.2.2 Analysis of Effects and Consequences	15.4-6
		15.4.2.3 Conclusions	15.4-8
	15.4.3	Rod Cluster Control Assembly Misalignment (System Malfunction or Operator Error)	15.4-9
		15.4.3.1 Identification of Causes and Accident Description	15.4-9
		15.4.3.2 Analysis of Effects and Consequences	15.4-10
		15.4.3.3 Conclusions	15.4-13
	15.4.4	Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	15.4-13
	15.4.5	A Malfunction or Failure of the Flow Controller in a Boiling Water Reactor Loop that Results in an Increased Reactor Coolant Flow Rate	15.4-14

TABLE OF CONTENTS (CONTINUED)

Section		Title	Page
	15.4.6	Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant	15.4-14
		15.4.6.1 Identification of Causes and Accident Description	15.4-14
		15.4.6.2 Analysis of Effects and Consequences	15.4-15
		15.4.6.3 Conclusions	15.4-20
	15.4.7	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position	15.4-21
		15.4.7.1 Identification of Causes and Accident Description	15.4-21
		15.4.7.2 Analysis of Effects and Consequences	15.4-21
		15.4.7.3 Conclusions	15.4-22
	15.4.8	Spectrum of Rod Cluster Control Assembly Ejection Accidents	15.4-22
		15.4.8.1 Identification of Causes and Accident Description	15.4-22
		15.4.8.2 Analysis of Effects and Consequences	15.4-25
		15.4.8.3 Radiological Consequences	15.4-28
	15.4.9	Combined License Information	15.4-30
	15.4.10	References	15.4-30
15.5		Increase in Reactor Coolant Inventory	15.5-1
	15.5.1	Inadvertent Operation of the Core Makeup Tanks During Power Operation	15.5-1
		15.5.1.1 Identification of the Causes and Accident Description	15.5-1
		15.5.1.2 Analysis of Effects and Consequences	15.5-2
		15.5.1.3 Results	15.5-3
		15.5.1.4 Conclusions	15.5-4
	15.5.2	Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory	15.5-5
		15.5.2.1 Identification of Causes and Accident Description	15.5-5
		15.5.2.2 Analysis of Effects and Consequences	15.5-6
		15.5.2.3 Results	15.5-7
		15.5.2.4 Conclusions	15.5-8
	15.5.3	Boiling Water Reactor Transients	15.5-9
	15.5.4	Combined License Information	15.5-9
	15.5.5	References	15.5-9
15.6		Decrease in Reactor Coolant Inventory	15.6-1
	15.6.1	Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the ADS	15.6-1
		15.6.1.1 Identification of Causes and Accident Description	15.6-1
		15.6.1.2 Analysis of Effects and Consequences	15.6-2
		15.6.1.3 Conclusion	15.6-3
	15.6.2	Failure of Small Lines Carrying Primary Coolant Outside Containment	15.6-3
		15.6.2.1 Source Term	15.6-4
		15.6.2.2 Release Pathway	15.6-4

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
15.6.2.3	Dose Calculation Models	15.6-4
15.6.2.4	Analytical Assumptions and Parameters	15.6-4
15.6.2.5	Identification of Conservatisms	15.6-4
15.6.2.6	Doses	15.6-5
15.6.3	Steam Generator Tube Rupture	15.6-5
15.6.3.1	Identification of Cause and Accident Description	15.6-5
15.6.3.2	Analysis of Effects and Consequences	15.6-8
15.6.3.3	Radiological Consequences	15.6-12
15.6.3.4	Conclusions	15.6-13
15.6.4	Spectrum of Boiling Water Reactor Steam System Piping Failures Outside of Containment	15.6-14
15.6.5	Loss-of-Coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary	15.6-14
15.6.5.1	Identification of Causes and Frequency Classification	15.6-14
15.6.5.2	Basis and Methodology for LOCA Analyses	15.6-14
15.6.5.3	Radiological Consequences	15.6-15
15.6.5.4	Core and System Performance	15.6-20
15.6.5.4A	Large-Break LOCA Analysis Methodology and Results	15.6-20
15.6.5.4B	Small-Break LOCA Analyses	15.6-26
15.6.5.4C	Post-LOCA Long-Term Cooling	15.6-41
15.6.6	References	15.6-47
15.7	Radioactive Release from a Subsystem or Component	15.7-1
15.7.1	Gas Waste Management System Leak or Failure	15.7-1
15.7.2	Liquid Waste Management System Leak or Failure (Atmospheric Release)	15.7-1
15.7.3	Release of Radioactivity to the Environment Due to a Liquid Tank Failure	15.7-1
15.7.4	Fuel Handling Accident	15.7-1
15.7.4.1	Source Term	15.7-2
15.7.4.2	Release Pathways	15.7-2
15.7.4.3	Dose Calculation Models	15.7-3
15.7.4.4	Identification of Conservatisms	15.7-3
15.7.4.5	Offsite Doses	15.7-4
15.7.5	Spent Fuel Cask Drop Accident	15.7-4
15.7.6	Combined License Information	15.7-4
15.7.7	References	15.7-5
15.8	Anticipated Transients Without Scram	15.8-1
15.8.1	General Background	15.8-1
15.8.2	Anticipated Transients Without Scram in the AP1000	15.8-1
15.8.3	Conclusion	15.8-1
15.8.4	Combined License Information	15.8-1
15.8.5	References	15.8-1
APPENDIX 15A	EVALUATION MODELS AND PARAMETERS FOR ANALYSIS OF RADIOLOGICAL CONSEQUENCES OF ACCIDENTS	15A-1
15A.1	Offsite Dose Calculation Models	15A-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
15A.1.1	Immersion Dose (Effective Dose Equivalent)	15A-1
15A.1.2	Inhalation Dose (Committed Effective Dose Equivalent)	15A-1
15A.1.3	Total Dose (Total Effective Dose Equivalent)	15A-2
15A.2	Main Control Room Dose Models	15A-2
15A.2.1	Immersion Dose Models	15A-2
15A.2.2	Inhalation Dose	15A-2
15A.2.3	Total Dose (Total Effective Dose Equivalent)	15A-3
15A.3	General Analysis Parameters	15A-3
15A.3.1	Source Terms	15A-3
15A.3.1.1	Primary Coolant Source Term	15A-3
15A.3.1.2	Secondary Coolant Source Term	15A-3
15A.3.1.3	Core Source Term	15A-4
15A.3.2	Nuclide Parameters	15A-4
15A.3.3	Atmospheric Dispersion Factors	15A-4
15A.4	References	15A-5
APPENDIX 15B	REMOVAL OF AIRBORNE ACTIVITY FROM THE CONTAINMENT ATMOSPHERE FOLLOWING A LOCA	15B-1
15B.1	Elemental Iodine Removal	15B-1
15B.2	Aerosol Removal	15B-1
15B.2.1	Mathematical Models	15B-2
15B.2.1.1	Sedimentation	15B-2
15B.2.1.2	Diffusiophoresis	15B-4
15B.2.1.3	Thermophoresis	15B-4
15B.2.2	Other Removal Mechanisms	15B-5
15B.2.3	Validation of Removal Mechanisms	15B-5
15B.2.4	Parameters and Assumptions for Calculating Aerosol Removal Coefficients	15B-6
15B.2.4.1	Containment Geometry	15B-6
15B.2.4.2	Source Size Distribution	15B-6
15B.2.4.3	Aerosol Void Fraction	15B-6
15B.2.4.4	Fission Product Release Fractions	15B-7
15B.2.4.5	Inert Aerosol Species	15B-7
15B.2.4.6	Aerosol Release Timing and Rates	15B-7
15B.2.4.7	Containment Thermal-Hydraulic Data	15B-7
15B.2.5	Aerosol Removal Coefficients	15B-7
15B.3	References	15B-8

LIST OF TABLES

Table Number	Title	Page
15.0-1	Nuclear Steam Supply System Power Ratings	15.0-15
15.0-2	Summary of Initial Conditions and Computer Codes Used	15.0-16
15.0-3	Nominal Values of Pertinent Plant Parameters Used in Accident Analyses	15.0-20
15.0-4a	Protection and Safety Monitoring System Setpoints and Time Delay Assumed in Accident Analyses	15.0-21
15.0-4b	Limiting Delay Times for Equipment Assumed in Accident Analyses	15.0-23
15.0-5	Not Used	15.0-24
15.0-6	Plant Systems and Equipment Available for Transient and Accident Conditions	15.0-25
15.0-7	Single Failures Assumed in Accident Analyses	15.0-30
15.0-8	Nonsafety-Related System and Equipment Used for Mitigation of Accidents	15.0-32
15.1.2-1	Time Sequence of Events for Incidents That Result in an Increase in Heat Removal From the Primary System	15.1-23
15.1.5-1	Parameters Used in Evaluating the Radiological Consequences of a Main Steam Line Break	15.1-25
15.1.5.5-1	Time Sequence of Events for Steam System Piping Failure at Full Power — 0.87ft^2 Break Size	15.1-26
15.2-1	Time Sequence of Events for Incidents Which Result in a Decrease in Heat Removal By the Secondary System	15.2-19
15.3-1	Time Sequence of Events for Incidents That Result in a Decrease In Reactor Coolant System Flow Rate	15.3-11
15.3-2	Summary of Results for Locked Rotor Transients (Four Reactor Coolant Pumps Operating Initially)	15.3-12
15.3-3	Parameters Used in Evaluating the Radiological Consequences of a Locked Rotor Accident	15.3-13
15.4-1	Time Sequence of Events for Incidents Which Result in Reactivity and Power Distribution Anomalies	15.4-33
15.4-2	Key Input Parameters for Boron Dilution	15.4-36
15.4-3	Not Used	15.4-37
15.4-4	Parameters Used in Evaluating the Radiological Consequences of a Rod Ejection Accident	15.4-38
15.5-1	Time Sequence of Events For Incidents Which Result in an Increase in Reactor Coolant Inventory	15.5-10
15.6.1-1	Time Sequence of Events for Incidents That Cause a Decrease in Reactor Coolant Inventory	15.6-50
15.6.2-1	Parameters Used in Evaluating the Radiological Consequences of a Small Line Break Outside Containment	15.6-51
15.6.3-1	Steam Generator Tube Rupture Sequence of Events	15.6-52
15.6.3-2	Steam Generator Tube Rupture Mass Release Results	15.6-53
15.6.3-3	Parameters Used in Evaluating the Radiological Consequences of a Steam Generator Tube Rupture	15.6-54
15.6.5-1	Core Activity Releases to the Containment Atmosphere	15.6-55
15.6.5-2	Assumptions and Parameters Used in Calculating Radiological Consequences of a Loss-of-Coolant Accident	15.6-56
15.6.5-3	Radiological Consequences of a Loss-of-Coolant Accident With Core Melt	15.6-59

LIST OF TABLES (CONTINUED)

Table Number	Title	Page
15.6.5-4	Major Plant Parameter Assumptions Used in the Best-Estimate Large-Break LOCA Analysis	15.6-60
15.6.5-5	AP1000 LOCA Chronology	15.6-61
15.6.5-6	Best-Estimate Large-Break Sequence of Events for the Limiting PCT Case	15.6-62
15.6.5-7	Summary of Peaking Factor Burndown Supported by AP1000 Plant Best Estimate Large Break LOCA CRR Updated Analysis Considering TCD	15.6-63
15.6.5-8	Best-Estimate Large-Break LOCA Results	15.6-64
15.6.5-9	Initial Conditions for AP1000 Small-Break LOCA Analysis	15.6-65
15.6.5-10	ADS Parameters Used in Small-Break LOCA Analyses	15.6-66
15.6.5-11	Inadvertent ADS Depressurization Sequence of Events	15.6-67
15.6.5-12	2-Inch Cold Leg Break Sequence of Events	15.6-68
15.6.5-13	Double-Ended Direct Vessel Injection Line Break Sequence of Events – 20 psia Containment Backpressure	15.6-69
15.6.5-13A	Not Used	15.6-70
15.6.5-14	10-Inch Cold Leg Break Sequence of Events	15.6-71
15.6.5-15	Double-Ended Direct Vessel Injection Line Break Sequence of Events (Entrainment Sensitivity)	15.6-72
15.7-1	Assumptions Used to Determine Fuel Handling Accident Radiological Consequences	15.7-6
15A-1	Reactor Coolant Iodine Concentrations for Maximum Iodine Spike of 60 µCi/g Dose Equivalent I-131	15A-6
15A-2	Iodine Appearance Rates in the Reactor Coolant	15A-6
15A-3	Reactor Core Source Term	15A-7
15A-4	Nuclide Parameters	15A-9
15A-5	Offsite Atmospheric Dispersion Factors (χ/Q) for Accident Dose Analysis	15A-13
15A-6	Control Room Atmospheric Dispersion Factors (χ/Q) for Accident Dose Analysis	15A-14
15A-7	Control Room Source/Receptor Data for Determination Of Atmospheric Dispersion Factors	15A-15
15A-8	Reactor Coolant Concentrations at Design Fuel Defect Level of 0.25%	15A-16
15A-9	Reactor Coolant Concentrations for Radiological Consequence Analyses	15A-17
15B-1	Aerosol Removal Coefficients in the AP1000 Containment Following a Design Basis LOCA With Core Melt	15B-9

LIST OF FIGURES

Figure Number	Title	Page
15.0.3-1	Overpower and Overtemperature ΔT Protection (Unit 3)	15.0-33
15.0.3-1a	Overpower and Overtemperature ΔT Protection (Unit 4)	15.0-34
15.0.3-2	AP1000 Loop Layout	15.0-35
15.0.4-1	Doppler Power Coefficient used in Accident Analysis	15.0-36
15.0.5-1	RCCA Position Versus Time to Dashpot	15.0-37
15.0.5-2	Normalized Rod Worth Versus Position	15.0-38
15.0.5-3	Normalized RCCA Bank Reactivity Worth Versus Drop Time	15.0-39
15.1.2-1	Feedwater Control Valve Malfunction Nuclear Power	15.1-27
15.1.2-2	Feedwater Control Valve Malfunction Loop ΔT	15.1-28
15.1.2-3	Feedwater Control Valve Malfunction DNBR	15.1-29
15.1.3-1	Nuclear Power Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback	15.1-30
15.1.3-2	Pressurizer Pressure Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback	15.1-31
15.1.3-3	Pressurizer Water Volume Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback	15.1-32
15.1.3-4	Core Average Temperature Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback	15.1-33
15.1.3-5	DNBR Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback	15.1-34
15.1.3-6	Nuclear Power Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback	15.1-35
15.1.3-7	Pressurizer Pressure Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback	15.1-36
15.1.3-8	Pressurizer Water Volume Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback	15.1-37
15.1.3-9	Core Average Temperature Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback	15.1-38
15.1.3-10	DNBR Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback	15.1-39
15.1.3-11	Nuclear Power Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback	15.1-40
15.1.3-12	Pressurizer Pressure Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback	15.1-41
15.1.3-13	Pressurizer Water Volume Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback	15.1-42
15.1.3-14	Core Average Temperature Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback	15.1-43
15.1.3-15	DNBR Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback	15.1-44
15.1.3-16	Nuclear Power Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback	15.1-45
15.1.3-17	Pressurizer Pressure Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback	15.1-46
15.1.3-18	Pressurizer Water Volume Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback	15.1-47

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.1.3-19	Core Average Temperature Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback	15.1-48
15.1.3-20	DNBR Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback	15.1-49
15.1.4-1	K_{eff} Versus Core Inlet Temperature Steam Line Break Events	15.1-50
15.1.4-2	Nuclear Power Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-51
15.1.4-3	Core Heat Flux Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-52
15.1.4-4	Loop 1 Reactor Coolant Temperatures Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-53
15.1.4-5	Loop 2 (Faulted Loop) Reactor Coolant Temperatures Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-54
15.1.4-6	Pressurizer Pressure Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-55
15.1.4-7	Pressurizer and Surge Line Water Volume Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-56
15.1.4-8	Core Flow Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-57
15.1.4-9	Feedwater Flow Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-58
15.1.4-10	Core Boron Concentration Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-59
15.1.4-11	Steam Pressure Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-60
15.1.4-12	Steam Flow Transient Inadvertent Opening of a Steam Generator Relief or Safety Valve	15.1-61
15.1.5-1	Nuclear Power Transient Steam System Piping Failure	15.1-62
15.1.5-2	Core Heat Flux Transient Steam System Piping Failure	15.1-63
15.1.5-3	Loop 1 Reactor Coolant Temperatures Steam System Piping Failure	15.1-64
15.1.5-4	Loop 2 Reactor Coolant Temperatures Steam System Piping Failure	15.1-65
15.1.5-5	Pressurizer Pressure Transient Steam System Piping Failure	15.1-66
15.1.5-6	Pressurizer and Surge Line Water Volume Transient Steam System Piping Failure	15.1-67
15.1.5-7	Core Flow Transient Steam System Piping Failure	15.1-68
15.1.5-8	Feedwater Flow Transient Steam System Piping Failure	15.1-69
15.1.5-9	Core Boron Concentration Transient Steam System Piping Failure	15.1-70
15.1.5-10	Steam Pressure Transient Steam System Piping Failure	15.1-71
15.1.5-11	Steam Flow Transient Steam System Piping Failure	15.1-72
15.1.5-12	Core Makeup Tank Injection Flow Steam System Piping Failure	15.1-73
15.1.5-13	Core Makeup Tank Water Volume Steam System Piping Failure	15.1-74
15.1.5.5-1	Nuclear Power Transient Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size	15.1-75

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.1.5.5-2	Core Heat Flux Transient Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size	15.1-76
15.1.5.5-3	Pressurizer Pressure Transient Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size	15.1-77
15.1.5.5-4	Pressurizer Water Volume Transient Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size	15.1-78
15.1.5.5-5	Vessel Inlet Temperature Transient (Intact and Faulted Loops) Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size	15.1-79
15.1.5.5-6	Steam Generator Pressure Transient (Intact and Faulted Loops) Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size	15.1-80
15.1.5.5-7	Steam Flow Transient (Intact and Faulted Loops) Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size	15.1-81
15.1.6-1–15.1.6-8	Not Used	15.1-82
15.2.3-1	Nuclear Power versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback	15.2-27
15.2.3-2	RCP Outlet Pressure versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback	15.2-28
15.2.3-3	Pressurizer & Surge Line Water Volume versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback	15.2-29
15.2.3-4	Vessel Inlet Temperature versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback	15.2-30
15.2.3-5	Vessel Average Temperature versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback	15.2-31
15.2.3-6	DNBR versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback	15.2-32
15.2.3-7	Core Coolant Mass Flow Rate versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback	15.2-33
15.2.3-8	Nuclear Power versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback	15.2-34
15.2.3-9	RCP Outlet Pressure versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback	15.2-35
15.2.3-10	Pressurizer & Surge Line Water Volume versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback	15.2-36
15.2.3-11	Vessel Inlet Temperature versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback	15.2-37
15.2.3-12	Vessel Average Temperature versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback	15.2-38
15.2.3-13	DNBR versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback	15.2-39
15.2.3-14	Core Coolant Mass Flow Rate versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback	15.2-40

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.2.3-15	Nuclear Power versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback	15.2-41
15.2.3-16	RCP Outlet Pressure versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback	15.2-42
15.2.3-17	Pressurizer & Surge Line Water Volume versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback	15.2-43
15.2.3-18	Vessel Inlet Temperature versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback	15.2-44
15.2.3-19	Vessel Average Temperature versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback	15.2-45
15.2.3-20	Core Coolant Mass Flow Rate versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback	15.2-46
15.2.3-21	Nuclear Power versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback	15.2-47
15.2.3-22	RCP Outlet Pressure versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback	15.2-48
15.2.3-23	Pressurizer & Surge Line Water Volume versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback	15.2-49
15.2.3-24	Vessel Inlet Temperature versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback	15.2-50
15.2.3-25	Vessel Average Temperature versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback	15.2-51
15.2.3-26	Core Coolant Mass Flow Rate versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback	15.2-52
15.2.6-1	Nuclear Power Transient for Loss of ac Power to the Plant Auxiliaries	15.2-53
15.2.6-2	Core Heat Flux Transient for Loss of ac Power to the Plant Auxiliaries	15.2-54
15.2.6-3	Pressurizer Pressure Transient for Loss of ac Power to the Plant Auxiliaries	15.2-55
15.2.6-4	Pressurizer Water Volume Transient for Loss of ac Power to the Plant Auxiliaries	15.2-56
15.2.6-5	Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss of ac Power to the Plant Auxiliaries	15.2-57
15.2.6-6	Reactor Coolant System Temperature Transients in Loop Not Containing the PRHR for Loss of ac Power to the Plant Auxiliaries	15.2-58
15.2.6-7	Steam Generator Pressure Transient for Loss of ac Power to the Plant Auxiliaries	15.2-59
15.2.6-8	PRHR Flow Rate Transient for Loss of ac Power to the Plant Auxiliaries	15.2-60

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.2.6-9	PRHR Heat Transfer Transient for Loss of ac Power to the Plant Auxiliaries	15.2-61
15.2.6-10	Reactor Coolant Volumetric Flow Rate Transient for Loss of ac Power to the Plant Auxiliaries	15.2-62
15.2.6-11	Steam Generator Inventory Transient for Loss of ac Power to the Plant Auxiliaries	15.2-63
15.2.6-12	Steam Generator Safety Valve Relief for Loss of ac Power to the Plant Auxiliaries	15.2-64
15.2.7-1	Nuclear Power Transient for Loss of Normal Feedwater	15.2-65
15.2.7-2	Core Heat Flux Transient for Loss of Normal Feedwater	15.2-66
15.2.7-3	Pressurizer Pressure Transient for Loss of Normal Feedwater	15.2-67
15.2.7-4	Pressurizer Water Volume Transient for Loss of Normal Feedwater	15.2-68
15.2.7-5	Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss of Normal Feedwater Flow	15.2-69
15.2.7-6	Reactor Coolant System Temperature Transient in Loop Not Containing the PRHR for Loss of Normal Feedwater Flow	15.2-70
15.2.7-7	Steam Generator Pressure Transient for Loss of Normal Feedwater	15.2-71
15.2.7-8	PRHR Flow Rate Transient for Loss of Normal Feedwater	15.2-72
15.2.7-9	PRHR Heat Transfer Transient for Loss of Normal Feedwater	15.2-73
15.2.7-10	Reactor Coolant Volumetric Flow Transient for Loss of Normal Feedwater	15.2-74
15.2.7-11	Steam Generator Inventory Transient for Loss of Normal Feedwater	15.2-75
15.2.7-12	DNB Ratio Transient for Loss of Normal Feedwater	15.2-76
15.2.7-13	Steam Generator Safety Valve Relief Transient for Loss of Normal Feedwater	15.2-77
15.2.7-14	Nuclear Power Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-78
15.2.7-15	Core Heat Flux Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-79
15.2.7-16	Pressurizer Pressure Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-80
15.2.7-17	Pressurizer Water Volume Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-81
15.2.7-18	Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-82
15.2.7-19	Reactor Coolant System Temperature Transients in Loop Not Containing the PRHR for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-83
15.2.7-20	Steam Generator Pressure Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-84
15.2.7-21	PRHR Flow Rate Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-85

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.2.7-22	PRHR Heat Transfer Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-86
15.2.7-23	Reactor Coolant Volumetric Flow Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-87
15.2.7-24	Steam Generator Inventory Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-88
15.2.7-25	DNB Ratio Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-89
15.2.7-26	Steam Generator Safety Valve Relief Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries	15.2-90
15.2.8-1	Nuclear Power Transient for Main Feedwater Line Rupture	15.2-91
15.2.8-2	Core Heat Flux Transient for Main Feedwater Line Rupture	15.2-92
15.2.8-3	Faulted Loop Reactor Coolant System Temperature Transients for Main Feedwater Line Rupture	15.2-93
15.2.8-4	Intact Loop Reactor Coolant System Temperature Transients for Main Feedwater Line Rupture	15.2-94
15.2.8-5	Pressurizer Pressure Transient for Main Feedwater Line Rupture	15.2-95
15.2.8-6	Pressurizer Water Volume Transient for Main Feedwater Line Rupture	15.2-96
15.2.8-7	Steam Generator Pressure Transient for Main Feedwater Line Rupture	15.2-97
15.2.8-8	PRHR Flow Rate Transient for Main Feedwater Line Rupture	15.2-98
15.2.8-9	PRHR Heat Flux Transient for Main Feedwater Line Rupture	15.2-99
15.2.8-10	CMT Injection Flow Rate Transient for Main Feedwater Line Rupture	15.2-100
15.3.1-1	Core Mass Flow Transient for Four Cold Legs in Operation, Two Pumps Coasting Down	15.3-15
15.3.1-2	Nuclear Power Transient for Four Cold Legs in Operation, Two Pumps Coasting Down	15.3-16
15.3.1-3	Pressurizer Pressure Transient for Four Cold Legs in Operation, Two Pumps Coasting Down	15.3-17
15.3.1-4	Average Channel Heat Flux Transient for Four Cold Legs in Operation, Two Pumps Coasting Down	15.3-18
15.3.1-5	Hot Channel Heat Flux Transient for Four Cold Legs in Operation, Two Pumps Coasting Down	15.3-19
15.3.1-6	Not Used	15.3-20
15.3.2-1	Core Mass Flow Transient for Four Cold Legs in Operation, Four Pumps Coasting Down	15.3-21
15.3.2-2	Nuclear Power Transient for Four Cold Legs in Operation, Four Pumps Coasting Down	15.3-22
15.3.2-3	Pressurizer Pressure Transient for Four Cold Legs in Operation, Four Pumps Coasting Down	15.3-23
15.3.2-4	Average Channel Heat Flux Transient for Four Cold Legs in Operation, Four Pumps Coasting Down	15.3-24
15.3.2-5	Hot Channel Heat Flux Transient for Four Cold Legs in Operation, Four Pumps Coasting Down	15.3-25

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.3.2-6	DNBR Transient for Four Cold Legs in Operation, Four Pumps Coasting Down	15.3-26
15.3.3-1	Core Mass Flow Transient for Four Cold Legs in Operation, One Locked Rotor	15.3-27
15.3.3-2	Faulted Loop Volumetric Flow Transient for Four Cold Legs in Operation, One Locked Rotor	15.3-28
15.3.3-3	Peak Reactor Coolant Pressure for Four Cold Legs in Operation, One Locked Rotor	15.3-29
15.3.3-4	Average Channel Heat Flux Transient for Four Cold Legs in Operation, One Locked Rotor	15.3-30
15.3.3-5	Hot Channel Heat Flux Transient for Four Cold Legs in Operation, One Locked Rotor	15.3-31
15.3.3-6	Nuclear Power Transient for Four Cold Legs in Operation, One Locked Rotor	15.3-32
15.3.3-7	Cladding Inside Temperature Transient for Four Cold Legs in Operation, One Locked Rotor	15.3-33
15.4.1-1	RCCA Withdrawal from Subcritical Nuclear Power	15.4-40
15.4.1-2	RCCA Withdrawal from Subcritical Average Channel Core Heat Flux	15.4-41
15.4.1-3	RCCA Withdrawal from Subcritical Hot Spot Fuel Average Temperature	15.4-42
15.4.1-4	RCCA Withdrawal from Subcritical Hot Spot Cladding Inner Temperature	15.4-43
15.4.2-1	Nuclear Power Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)	15.4-44
15.4.2-2	Core Heat Flux Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)	15.4-45
15.4.2-3	Pressurizer Pressure Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)	15.4-46
15.4.2-4	Pressurizer Water Volume Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)	15.4-47
15.4.2-5	Core Coolant Average Temperature Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)	15.4-48
15.4.2-6	DNBR Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)	15.4-49
15.4.2-7	Nuclear Power Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)	15.4-50
15.4.2-8	Core Heat Flux Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)	15.4-51
15.4.2-9	Pressurizer Pressure Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)	15.4-52

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.4.2-10	Pressurizer Water Volume Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)	15.4-53
15.4.2-11	Core Coolant Average Temperature Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)	15.4-54
15.4.2-12	DNBR Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)	15.4-55
15.4.2-13	Nuclear Power Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)	15.4-56
15.4.2-14	Core Heat Flux Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)	15.4-57
15.4.2-15	Pressurizer Pressure Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)	15.4-58
15.4.2-16	Pressurizer Water Volume Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)	15.4-59
15.4.2-17	Core Coolant Average Temperature Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)	15.4-60
15.4.2-18	DNBR Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)	15.4-61
15.4.2-19	Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 100-percent Power	15.4-62
15.4.2-20	Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 60-percent Power	15.4-63
15.4.2-21	Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 10-percent Power	15.4-64
15.4.2-22–15.4.2-23	Not Used	15.4-65
15.4.3-1	Nuclear Power Transient for Dropped RCCA	15.4-66
15.4.3-2	Core Heat Flux Transient for Dropped RCCA	15.4-67
15.4.3-3	Pressurizer Pressure Transient for Dropped RCCA	15.4-68
15.4.3-4	RCS Average Temperature Transient for Dropped RCCA	15.4-69
15.4.7-1	Representative Percent Change in Local Assembly Average Power for Interchange Between Region 1 and Region 3 Assembly	15.4-70
15.4.7-2	Representative Percent Change in Local Assembly Average Power for Interchange Between Region 1 and Region 2 Assembly with the BP Rods Transferred to Region 1 Assembly	15.4-71
15.4.7-3	Representative Percent Change in Local Assembly Average Power for Enrichment Error (Region 2 Assembly Loaded into Core Central Position)	15.4-72
15.4.7-4	Representative Percent Change in Local Assembly Average Power for Loading Region 2 Assembly into Region 1 Position Near Core Periphery	15.4-73
15.4.8-1	Nuclear Power Transient Versus Time for the PCMI Rod Ejection Accident	15.4-74

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.4.8-2	Nuclear Power Transient Versus Time for the High Clad Temperature Rod Ejection Accident	15.4-75
15.4.8-3	Nuclear Power Transient Versus Time for the Peak Enthalpy and Fuel Centerline Temperature Rod Ejection Accident	15.4-76
15.4.8-4	Not Used	15.4-77
15.5.1-1	Core Nuclear Power Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves	15.5-12
15.5.1-2	RCS Temperature Transient in Loop Containing the PRHR for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves	15.5-13
15.5.1-3	RCS Temperature Transient in Loop Not Containing the PRHR for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves	15.5-14
15.5.1-4	Pressurizer Pressure Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves	15.5-15
15.5.1-5	Pressurizer Water Volume Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves	15.5-16
15.5.1-6	Steam Generator Pressure Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves	15.5-17
15.5.1-7	CMT Flow Rate Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves	15.5-18
15.5.1-8	PRHR Flow Rate Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves	15.5-19
15.5.2-1	Core Nuclear Power Transient for Chemical and Volume Control System Malfunction	15.5-20
15.5.2-2	RCS Temperature Transient in Loop Containing the PRHR for Chemical and Volume Control System Malfunction	15.5-21
15.5.2-3	RCS Temperature Transient in Loop Not Containing the PRHR for Chemical and Volume Control System Malfunction	15.5-22
15.5.2-4	Pressurizer Pressure Transient for Chemical and Volume Control System Malfunction	15.5-23
15.5.2-5	Pressurizer Water Volume Transient for Chemical and Volume Control System Malfunction	15.5-24
15.5.2-6	CVS Flow Rate Transient for Chemical and Volume Control System Malfunction	15.5-25
15.5.2-7	Steam Generator Pressure Transient for Chemical and Volume Control System Malfunction	15.5-26
15.5.2-8	CMT Injection Line and Balance Line Flow Transient for Chemical and Volume Control System Malfunction	15.5-27
15.5.2-9	PRHR Flow Rate Transient for Chemical and Volume Control System Malfunction	15.5-28

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.6.1-1	Nuclear Power Transient Inadvertent Opening of a Pressurizer Safety Valve	15.6-73
15.6.1-2	DNBR Transient Inadvertent Opening of a Pressurizer Safety Valve	15.6-74
15.6.1-3	Pressurizer Pressure Transient Inadvertent Opening of a Pressurizer Safety Valve	15.6-75
15.6.1-4	Core Average Temperature Transient Inadvertent Opening of a Pressurizer Safety Valve	15.6-76
15.6.1-5	Nuclear Power Transient Inadvertent Opening of an ADS Stage 2 or 3 Train	15.6-77
15.6.1-6	DNBR Transient Inadvertent Opening of an ADS Stage 2 or 3 Train	15.6-78
15.6.1-7	Pressurizer Pressure Transient Inadvertent Opening of an ADS Stage 2 or 3 Train	15.6-79
15.6.1-8	Core Average Temperature Transient Inadvertent Opening of an ADS Stage 2 or 3 Train	15.6-80
15.6.3-1	Pressurizer Level for SGTR	15.6-81
15.6.3-2	Reactor Coolant System Pressure for SGTR	15.6-82
15.6.3-3	Secondary Pressure for SGTR	15.6-83
15.6.3-4	Intact Loop Hot and Cold Leg Reactor Coolant System Temperature for SGTR	15.6-84
15.6.3-5	Primary-to-Secondary Break Flow Rate for SGTR	15.6-85
15.6.3-6	Ruptured Steam Generator Water Volume for SGTR	15.6-86
15.6.3-7	Ruptured Steam Generator Mass Release Rate to the Atmosphere for SGTR	15.6-87
15.6.3-8	Intact Steam Generator Mass Release Rate to the Atmosphere for SGTR	15.6-88
15.6.3-9	Plant Total Chemical and Volume Control System and Core Makeup Tank Injection Flow for SGTR	15.6-89
15.6.3-10	Integrated Flashed Break Flow for SGTR	15.6-90
15.6.5.4A-1	WCOBRA/TRAC Peak Cladding Temperature for All Five Rod Groups for 95th Percentile Estimator PCT Case	15.6-91
15.6.5.4A-2	HOTSPOT Cladding Temperature Transient at Limiting Elevation for 95th Percentile Estimator PCT Case	15.6-92
15.6.5.4A-3	Mass Flow at Top of Hot Assembly Channel for 95th Percentile Estimator PCT Case	15.6-93
15.6.5.4A-4	Pressurizer Pressure for 95th Percentile Estimator PCT Case	15.6-94
15.6.5.4A-5	Accumulator Injection Flow for 95th Percentile Estimator PCT Case	15.6-95
15.6.5.4A-6	Core Makeup Tank Injection Flow for 95th Percentile Estimator PCT Case	15.6-96
15.6.5.4A-7	Mass Flow at Top of Peripheral Assemblies Channel for 95th Percentile Estimator PCT Case	15.6-97
15.6.5.4A-8	Mass Flow at Top of Guide Tube Assemblies Channel for 95th Percentile Estimator PCT Case	15.6-98
15.6.5.4A-9	Mass Flow at Top of Support Column/Open Hole Assemblies Channel for 95th Percentile Estimator PCT Case	15.6-99
15.6.5.4A-10	Break Mass Flow for 95th Percentile Estimator PCT Case	15.6-100

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.6.5.4A-11	Core Channel Collapsed Liquid Levels for 95th Percentile Estimator PCT Case	15.6-101
15.6.5.4A-12	Downcomer Channel Collapsed Liquid Levels for 95th Percentile Estimator PCT Case	15.6-102
15.6.5.4A-13	PBOT/PMID Box Supported by AP1000 ASTRUM Analysis	15.6-103
15.6.5.4B-1(a)	Inadvertent ADS – RCS Pressure	15.6-104
15.6.5.4B-1(b)	Inadvertent ADS – RCS Pressure (Zoomed)	15.6-105
15.6.5.4B-1(c)	Inadvertent ADS – Containment Pressure	15.6-106
15.6.5.4B-2	Inadvertent ADS – Pressurizer Mixture Level	15.6-107
15.6.5.4B-3	Inadvertent ADS – ADS 1-3 Liquid Discharge	15.6-108
15.6.5.4B-4(a)	Inadvertent ADS – ADS 1-3 Vapor Discharge	15.6-109
15.6.5.4B-4(b)	Inadvertent ADS – ADS 1-3 Integrated Discharge	15.6-110
15.6.5.4B-5	Inadvertent ADS – CMT-1 Injection Rate	15.6-111
15.6.5.4B-6	Inadvertent ADS – CMT-2 Injection Rate	15.6-112
15.6.5.4B-7	Inadvertent ADS – CMT-1 Mixture Level	15.6-113
15.6.5.4B-8	Inadvertent ADS – CMT-2 Mixture Level	15.6-114
15.6.5.4B-9	Inadvertent ADS – Downcomer Mixture Level	15.6-115
15.6.5.4B-10	Inadvertent ADS – Accumulator-1 Injection Rate	15.6-116
15.6.5.4B-11	Inadvertent ADS – Accumulator-2 Injection Rate	15.6-117
15.6.5.4B-12(a)	Inadvertent ADS – ADS-4 Integrated Discharge	15.6-118
15.6.5.4B-12(b)	Inadvertent ADS – ADS-4 Liquid Discharge	15.6-119
15.6.5.4B-12(c)	Inadvertent ADS – ADS-4 Vapor Discharge	15.6-120
15.6.5.4B-13	Inadvertent ADS – IRWST-1 Injection Rate	15.6-121
15.6.5.4B-14	Inadvertent ADS – IRWST-2 Injection Rate	15.6-122
15.6.5.4B-15(a)	Inadvertent ADS – RCS System Inventory	15.6-123
15.6.5.4B-15(b)	Inadvertent ADS – Reactor Vessel Mixture Inventory	15.6-124
15.6.5.4B-16(a)	Inadvertent ADS – Core/Upper Plenum Mixture Level	15.6-125
15.6.5.4B-16(b)	Inadvertent ADS – Peak Cladding Temperature	15.6-126
15.6.5.4B-17(a)	2-inch Cold Leg Break – RCS Pressure	15.6-127
15.6.5.4B-17(b)	2-Inch Cold Leg Break – RCS Pressure (Zoomed)	15.6-128
15.6.5.4B-17(c)	2-Inch Cold Leg Break – Containment Pressure	15.6-129
15.6.5.4B-18	2-inch Cold Leg Break – Pressurizer Mixture Level	15.6-130
15.6.5.4B-19	2-inch Cold Leg Break – CMT-1 Mixture Level	15.6-131
15.6.5.4B-20	2-inch Cold Leg Break – CMT-2 Mixture Level	15.6-132
15.6.5.4B-21	2-inch Cold Leg Break – Downcomer Mixture Level	15.6-133
15.6.5.4B-22	2-inch Cold Leg Break – CMT-1 Injection Rate	15.6-134
15.6.5.4B-23	2-inch Cold Leg Break – CMT-2 Injection Rate	15.6-135
15.6.5.4B-24	2-inch Cold Leg Break – Accumulator-1 Injection Rate	15.6-136
15.6.5.4B-25	2-inch Cold Leg Break – Accumulator-2 Injection Rate	15.6-137
15.6.5.4B-26	2-inch Cold Leg Break – IRWST-1 Injection Rate	15.6-138
15.6.5.4B-27	2-inch Cold Leg Break – IRWST-2 Injection Rate	15.6-139
15.6.5.4B-28(a)	2-inch Cold Leg Break – ADS-4 Liquid Discharge	15.6-140
15.6.5.4B-28(b)	2-Inch Cold Leg Break – ADS-4 Vapor Discharge	15.6-141
15.6.5.4B-28(c)	2-Inch Cold Leg Break – ADS-4 Integrated Discharge	15.6-142
15.6.5.4B-29(a)	2-inch Cold Leg Break – RCS System Inventory	15.6-143
15.6.5.4B-29(b)	2-Inch Cold Leg Break – Reactor Vessel Mixture Inventory	15.6-144
15.6.5.4B-30(a)	2-inch Cold Leg Break – Core/Upper Plenum Mixture Level	15.6-145
15.6.5.4B-30(b)	2-Inch Cold Leg Break – Peak Cladding Temperature	15.6-146
15.6.5.4B-31(a)	2-inch Cold Leg Break – ADS 1-3 Liquid Discharge	15.6-147

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.6.5.4B-31(b)	2-Inch Cold Leg Break – ADS 1-3 Vapor Discharge	15.6-148
15.6.5.4B-31(c)	2-Inch Cold Leg Break – ADS 1-3 Integrated Discharge	15.6-149
15.6.5.4B-32	2-inch Cold Leg Break – Liquid Break Discharge	15.6-150
15.6.5.4B-33	2-inch Cold Leg Break – Vapor Break Discharge	15.6-151
15.6.5.4B-34	2-inch Cold Leg Break – PRHR Heat Removal Rate	15.6-152
15.6.5.4B-35	2-inch Cold Leg Break – Integrated PRHR Heat Removal	15.6-153
15.6.5.4B-36	20 psia DEDVI Line Break – Vessel Side Liquid Break Discharge	15.6-154
15.6.5.4B-37	20 psia DEDVI Line Break – Vessel Side Vapor Break Discharge	15.6-155
15.6.5.4B-38(a)	20 psia DEDVI Line Break – RCS Pressure	15.6-156
15.6.5.4B-38(b)	20 psia DEDVI Line Break – RCS Pressure (Zoomed)	15.6-157
15.6.5.4B-39	20 psia DEDVI Line Break – Broken CMT Injection Rate	15.6-158
15.6.5.4B-40	20 psia DEDVI Line Break – Intact CMT Injection Rate	15.6-159
15.6.5.4B-41	20 psia DEDVI Line Break – Core/Upper Plenum Mixture Level	15.6-160
15.6.5.4B-42	20 psia DEDVI Line Break – Downcomer Mixture Level	15.6-161
15.6.5.4B-43(a)	20 psia DEDVI Line Break – ADS 1-3 Vapor Discharge	15.6-162
15.6.5.4B-43(b)	20 psia DEDVI Line Break – ADS 1-3 Liquid Discharge	15.6-163
15.6.5.4B-43(c)	20 psia DEDVI Line Break – ADS 1-3 Integrated Discharge	15.6-164
15.6.5.4B-44	20 psia DEDVI Line Break – Core Exit Void Fraction	15.6-165
15.6.5.4B-45	20 psia DEDVI Line Break – Core Exit Liquid Flow Rate	15.6-166
15.6.5.4B-46	20 psia DEDVI Line Break – Core Exit Vapor Flow Rate	15.6-167
15.6.5.4B-47	20 psia DEDVI Line Break – Lower Plenum to Core Flow Rate	15.6-168
15.6.5.4B-48(a)	20 psia DEDVI Line Break – ADS-4 Liquid Discharge	15.6-169
15.6.5.4B-48(b)	20 psia DEDVI Line Break – ADS-4 Vapor Discharge	15.6-170
15.6.5.4B-49	20 psia DEDVI Line Break – ADS-4 Integrated Discharge	15.6-171
15.6.5.4B-50	20 psia DEDVI Line Break – Intact Accumulator Flow Rate	15.6-172
15.6.5.4B-51	20 psia DEDVI Line Break – Intact IRWST Injection Rate	15.6-173
15.6.5.4B-52	20 psia DEDVI Line Break – Intact CMT Mixture Level	15.6-174
15.6.5.4B-53(a)	20 psia DEDVI Line Break – RCS System Inventory	15.6-175
15.6.5.4B-53(b)	20 psia DEDVI Line Break – Reactor Vessel Mixture Inventory	15.6-176
15.6.5.4B-54	20 psia DEDVI Line Break – PRHR Heat Removal Rate	15.6-177
15.6.5.4B-55	20 psia DEDVI Line Break – Integrated PRHR Heat Removal	15.6-178
15.6.5.4B-56(a)	10-inch Cold Leg Break – RCS Pressure	15.6-179
15.6.5.4B-56(b)	10-Inch Cold Leg Break – RCS Pressure (Zoomed)	15.6-180
15.6.5.4B-57	10-inch Cold Leg Break – Pressurizer Mixture Level	15.6-181
15.6.5.4B-58	10-inch Cold Leg Break – CMT-1 Mixture Level	15.6-182
15.6.5.4B-59	10-inch Cold Leg Break – CMT-2 Mixture Level	15.6-183
15.6.5.4B-60	10-inch Cold Leg Break – Downcomer Mixture Level	15.6-184
15.6.5.4B-61	10-inch Cold Leg Break – CMT-1 Injection Rate	15.6-185
15.6.5.4B-62	10-inch Cold Leg Break – CMT-2 Injection Rate	15.6-186
15.6.5.4B-63	10-inch Cold Leg Break – Accumulator-1 Injection Rate	15.6-187
15.6.5.4B-64	10-inch Cold Leg Break – Accumulator-2 Injection Rate	15.6-188
15.6.5.4B-65	10-inch Cold Leg Break – IRWST-1 Injection Rate	15.6-189
15.6.5.4B-66	10-inch Cold Leg Break – IRWST-2 Injection Rate	15.6-190
15.6.5.4B-67(a)	10-inch Cold Leg Break – ADS-4 Liquid Discharge	15.6-191
15.6.5.4B-67(b)	10-Inch Cold Leg Break – ADS-4 Vapor Discharge	15.6-192
15.6.5.4B-68(a)	10-inch Cold Leg Break – RCS System Inventory	15.6-193
15.6.5.4B-68(b)	10-Inch Cold Leg Break – Reactor Vessel Mixture Inventory	15.6-194

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.6.5.4B-69	10-inch Cold Leg Break – Core/Upper Plenum Mixture Level	15.6-195
15.6.5.4B-70(a)	10-inch Cold Leg Break – ADS 1-3 Liquid Discharge	15.6-196
15.6.5.4B-70(b)	10-Inch Cold Leg Break – ADS 1-3 Vapor Discharge	15.6-197
15.6.5.4B-70(c)	10-Inch Cold Leg Break – ADS 1-3 Integrated Discharge	15.6-198
15.6.5.4B-71	10-inch Cold Leg Break – Core Exit Liquid Flow	15.6-199
15.6.5.4B-72	10-inch Cold Leg Break – Core Exit Vapor Flow	15.6-200
15.6.5.4B-73	10-inch Cold Leg Break – Core Exit Void Fraction	15.6-201
15.6.5.4B-74	10-inch Cold Leg Break – ADS-4 Integrated Discharge	15.6-202
15.6.5.4B-75	10-inch Cold Leg Break – Liquid Break Discharge	15.6-203
15.6.5.4B-76	10-inch Cold Leg Break – Vapor Break Discharge	15.6-204
15.6.5.4B-77	10-inch Cold Leg Break – PRHR Heat Removal Rate	15.6-205
15.6.5.4B-78	10-inch Cold Leg Break – Integrated PRHR Heat Removal	15.6-206
15.6.5.4B-79(a)	DEDVI Entrainment – Downcomer Pressure Comparison	15.6-207
15.6.5.4B-79(b)	DEDVI Entrainment – Downcomer Pressure Comparison (Zoomed)	15.6-208
15.6.5.4B-80	DEDVI Entrainment – Intact IRWST Integrated Injection Flow	15.6-209
15.6.5.4B-81	DEDVI Entrainment – Intact DVI Line Injection Flow	15.6-210
15.6.5.4B-82	DEDVI Entrainment – ADS-4 Integrated Liquid Discharge Comparison	15.6-211
15.6.5.4B-83	DEDVI Entrainment – Upper Plenum Mixture Mass Comparison	15.6-212
15.6.5.4B-84	DEDVI Entrainment – ADS-4 Integrated Vapor Discharge Comparison	15.6-213
15.6.5.4B-85	DEDVI Entrainment – Downcomer Region Mass Comparison	15.6-214
15.6.5.4B-86(a)	DEDVI Entrainment – Core Region Mass Comparison	15.6-215
15.6.5.4B-86(b)	DEDVI Entrainment – Core Region Mass Comparison (Smoothed)	15.6-216
15.6.5.4B-87	DEDVI Entrainment – Vessel Mixture Mass Comparison	15.6-217
15.6.5.4B-88(a)	DEDVI Entrainment – Core/Upper Plenum Mixture Level Comparison	15.6-218
15.6.5.4B-88(b)	DEDVI Entrainment – Core/Upper Plenum Mixture Level Comparison (Smoothed)	15.6-219
15.6.5.4B-89(a)	DEDVI Entrainment – Core Collapsed Liquid Level Comparison	15.6-220
15.6.5.4B-89(b)	DEDVI Entrainment – Core Collapsed Liquid Level Comparison (Smoothed)	15.6-221
15.6.5.4B-90	DEDVI Entrainment – Pressurizer Mixture Level Comparison	15.6-222
15.6.5.4C-1	Collapsed Level of Liquid in the Downcomer (DEDVI Case)	15.6-223
15.6.5.4C-2	Collapsed Level of Liquid over the Heated Length of the Fuel (DEDVI Case)	15.6-224
15.6.5.4C-3	Void Fraction in Core Hot Assembly Top Cell (DEDVI Case)	15.6-225
15.6.5.4C-4	Void Fraction in Core Hot Assembly Second from Top Cell (DEDVI Case)	15.6-226
15.6.5.4C-5	Collapsed Liquid Level in the Hot Leg of Pressurizer Loop (DEDVI Case)	15.6-227
15.6.5.4C-6	Vapor Rate out of the Core (DEDVI Case)	15.6-228
15.6.5.4C-7	Liquid Flow Rate out of the Core (DEDVI Case)	15.6-229
15.6.5.4C-8	Collapsed Liquid Level in the Upper Plenum (DEDVI Case)	15.6-230
15.6.5.4C-9	Mixture Flow Rate Through ADS Stage 4A Valves (DEDVI Case)	15.6-231

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
15.6.5.4C-10	Mixture Flow Rate Through ADS Stage 4B Valves (DEDVI Case)	15.6-232
15.6.5.4C-11	Upper Plenum Pressure (DEDVI Case)	15.6-233
15.6.5.4C-12	Peak Cladding Temperature (DEDVI Case)	15.6-234
15.6.5.4C-13	DVI–A Mixture Flow Rate (DEDVI Case)	15.6-235
15.6.5.4C-14	DVI–B Mixture Flow Rate (DEDVI Case)	15.6-236
15.6.5.4C-15	Collapsed Level of Liquid in the Downcomer (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-237
15.6.5.4C-16	Collapsed Level of Liquid Over the Heated Length of the Fuel (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-238
15.6.5.4C-17	Void Fraction in Core Hot Assembly Top Cell (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-239
15.6.5.4C-18	Void Fraction in Core Hot Assembly Second from Top Cell (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-240
15.6.5.4C-19	Collapsed Liquid Level in the Hot Leg of Pressurizer Loop (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-241
15.6.5.4C-20	Vapor Rate out of the Core (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-242
15.6.5.4C-21	Liquid Flow Rate out of the Core (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-243
15.6.5.4C-22	Collapsed Liquid Level in the Upper Plenum (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-244
15.6.5.4C-23	Mixture Flow Rate Through ADS Stage 4A Valves (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-245
15.6.5.4C-24	Mixture Flow Rate Through ADS Stage 4B Valves (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-246
15.6.5.4C-25	Upper Plenum Pressure (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-247
15.6.5.4C-26	Hot Rod Cladding Temperature Near Top of Core (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-248
15.6.5.4C-27	DVI-A Mixture Flow Rate (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-249
15.6.5.4C-28	DVI-B Mixture Flow Rate (Wall-to-Wall Floodup Case) – 14.7 psia	15.6-250
15A-1	Site Plan with Release and Intake Locations	15A-18

Chapter 15 Accident Analyses

15.0.1 Classification of Plant Conditions

The ANSI 18.2 (Reference 1) classification divides plant conditions into four categories according to anticipated frequency of occurrence and potential radiological consequences to the public. The four categories are as follows:

- Condition I: Normal operation and operational transients
- Condition II: Faults of moderate frequency
- Condition III: Infrequent faults
- Condition IV: Limiting faults

The basic principle applied in relating design requirements to each of the conditions is that the most probable occurrences should yield the least radiological risk, and those extreme situations having the potential for the greatest risk should be those least likely to occur. Where applicable, reactor trip and engineered safeguards functioning are assumed to the extent allowed by considerations such as the single failure criterion in fulfilling this principle.

15.0.1.1 Condition I: Normal Operation and Operational Transients

Condition I occurrences are those that are expected to occur frequently or regularly in the course of power operation, refueling, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between a plant parameter and the value of that parameter requiring either automatic or manual protective action.

Because Condition I events occur frequently, they must be considered from the point of view of their effect on the consequences of fault conditions (Conditions II, III, and IV). In this regard, analysis of each fault condition described is generally based on a conservative set of initial conditions corresponding to adverse conditions that can occur during Condition I operation.

A typical list of Condition I events follows.

Steady-State and Shutdown Operations

See Table 1.1-1 of the Technical Specifications.

Operation with Permissible Deviations

Various deviations that occur during continued operation as permitted by the plant Technical Specifications are considered in conjunction with other operational modes. These deviations include the following:

- Operation with components or systems out of service (such as an inoperable rod cluster control assembly [RCCA])
- Leakage from fuel with limited cladding defects
- Excessive radioactivity in the reactor coolant:
  - Fission products
  - Corrosion products
  - Tritium
- Operation with steam generator tube leaks

- Testing

Operational Transients

- Plant heatup and cooldown
- Step load changes (up to ±10 percent)
- Ramp load changes (up to 5 percent/minute)
- Load rejection up to and including design full-load rejection transient

15.0.1.2 Condition II: Faults of Moderate Frequency

These faults, at worst, result in a reactor trip with the plant being capable of returning to operation. By definition, these faults (or events) do not propagate to cause a more serious fault (Condition III or IV events). In addition, Condition II events are not expected to result in fuel rod failures, reactor coolant system failures, or secondary system overpressurization. The following faults are included in this category:

- Feedwater system malfunctions that result in a decrease in feedwater temperature (see Subsection 15.1.1)
- Feedwater system malfunctions that result in an increase in feedwater flow (see Subsection 15.1.2)
- Excessive increase in secondary steam flow (see Subsection 15.1.3)
- Inadvertent opening of a steam generator relief or safety valve (see Subsection 15.1.4)
- Inadvertent operation of the passive residual heat removal heat exchanger (see Subsection 15.1.6)
- Loss of external electrical load (see Subsection 15.2.2)
- Turbine trip (see Subsection 15.2.3)
- Inadvertent closure of main steam isolation valves (see Subsection 15.2.4)
- Loss of condenser vacuum and other events resulting in turbine trip (see Subsection 15.2.5)
- Loss of ac power to the station auxiliaries (see Subsection 15.2.6)
- Loss of normal feedwater flow (see Subsection 15.2.7)
- Partial loss of forced reactor coolant flow (see Subsection 15.3.1)
- Uncontrolled RCCA bank withdrawal from a subcritical or low-power startup condition (see Subsection 15.4.1)
- Uncontrolled RCCA bank withdrawal at power (see Subsection 15.4.2)
- RCCA misalignment (dropped full-length assembly, dropped full-length assembly bank, or statically misaligned assembly) (see Subsection 15.4.3)
- Startup of an inactive reactor coolant pump at an incorrect temperature (see Subsection 15.4.4)

- Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant (see Subsection 15.4.6)
- Inadvertent operation of the core makeup tanks during power operation (see Subsection 15.5.1)
- Chemical and volume control system malfunction that increases reactor coolant inventory (see Subsection 15.5.2)
- Inadvertent opening of a pressurizer safety valve (see Subsection 15.6.1)
- Failure of small lines carrying primary coolant outside containment (see Subsection 15.6.2)

15.0.1.3 Condition III: Infrequent Faults

Condition III events are faults that may occur infrequently during the life of the plant. They may result in the failure of only a small fraction of the fuel rods. The release of radioactivity is not sufficient to interrupt or restrict public use of those areas beyond the exclusion area boundary, in accordance with the guidelines of 10 CFR 50.34. By definition, a Condition III event alone does not generate a Condition IV event or result in a consequential loss of function of the reactor coolant system or containment barriers. The following faults are included in this category:

- Steam system piping failure (minor) (see Subsection 15.1.5)
- Complete loss of forced reactor coolant flow (see Subsection 15.3.2)
- RCCA misalignment (single RCCA withdrawal at full power) (see Subsection 15.4.3)
- Inadvertent loading and operation of a fuel assembly in an improper position (see Subsection 15.4.7)
- Inadvertent operation of automatic depressurization system (see Subsection 15.6.1)
- Loss-of-coolant accidents (LOCAs) resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary (small break) (see Subsection 15.6.5)
- Gas waste management system leak or failure (see Subsection 15.7.1)
- Liquid waste management system leak or failure (atmospheric release) (see Subsection 15.7.2)
- Release of radioactivity to the environment due to a liquid tank failure (see Subsection 15.7.3)
- Spent fuel cask drop accidents (see Subsection 15.7.5)

15.0.1.4 Condition IV: Limiting Faults

Condition IV events are faults that are not expected to take place, but are postulated because their consequences include the potential of the release of significant amounts of radioactive material. They are the faults that must be designed against, and they represent limiting design cases. Condition IV faults are not to cause a fission product release to the environment resulting in doses in excess of the guideline values of 10 CFR 50.34. A single Condition IV event is not to cause a consequential loss of

required functions of systems needed to cope with the fault, including those of the emergency core cooling system and the containment. The following faults are classified in this category:

- Steam system piping failure (major) (see Subsection 15.1.5)
- Feedwater system pipe break (see Subsection 15.2.8)
- Reactor coolant pump shaft seizure (locked rotor) (see Subsection 15.3.3)
- Reactor coolant pump shaft break (see Subsection 15.3.4)
- Spectrum of RCCA ejection accidents (see Subsection 15.4.8)
- Steam generator tube rupture (see Subsection 15.6.3)
- LOCAs resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary (large break) (see Subsection 15.6.5)
- Fuel handling accidents (see Subsection 15.7.4)

15.0.2 Optimization of Control Systems

A control system setpoint study is performed prior to plant operation to simulate performance of the primary plant control systems and overall plant performance. In this study, emphasis is placed on the development of the overall plant control systems that automatically maintain conditions in the plant within the allowed operating window and with optimum control system response and stability over the entire range of anticipated plant operating conditions. The control system setpoints are developed using the nominal protection and safety monitoring system setpoints implemented in the plant. Where appropriate (such as in margin to reactor trip analyses), instrumentation errors are considered and are applied in an adverse direction with respect to maintaining system stability and transient performance. The accident analysis and plant control system setpoint study in combination show that the plant can be operated and meet both safety and operability requirements throughout the core life and for various levels of power operation.

The plant control system setpoint study is comprised of analyses of the following control systems: plant control, axial offset control, rapid power reduction, steam dump (turbine bypass), steam generator level, pressurizer pressure, and pressurizer level.

15.0.3 Plant Characteristics and Initial Conditions Assumed in the Accident Analyses

15.0.3.1 Design Plant Conditions

Table 15.0-1 lists the principal power rating values assumed in the analyses performed. The thermal power output includes the effective thermal power generated by the reactor coolant pumps. Selected AP1000 loop layout elevations are shown in Figure 15.0.3-2 to aid in interpreting plots shown in other Chapter 15 subsections.

The values of other pertinent plant parameters used in the accident analyses are given in Table 15.0-3.

15.0.3.2 Initial Conditions

For most accidents that are departure from nucleate boiling (DNB) limited, nominal values of initial conditions are assumed. The allowances on power, temperature, and pressure are determined on a

statistical basis and are included in the departure from nucleate boiling ratio (DNBR) design limit values (see Section 4.4), as described in WCAP-11397-P-A (Reference 2). This procedure is known as the Revised Thermal Design Procedure (RTDP) and is discussed more fully in Section 4.4.

For most accidents that are not DNB limited, or for which the revised thermal design procedure is not used, the initial conditions are obtained by adding the maximum steady-state errors to rated values. The following conservative steady-state errors are assumed in the analysis:

Core power	± 1 percent allowance for calorimetric error.
Average reactor coolant system temperature	± 8.0°F allowance for controller deadband and measurement errors
Pressurizer pressure	± 50 psi allowance for steady-state fluctuations and measurement errors

Initial values for core power, average reactor coolant system temperature, and pressurizer pressure are selected to minimize the initial DNBR unless otherwise stated in the sections describing the specific accidents. Table 15.0-2 summarizes the initial conditions and computer codes used in the accident analyses.

The plant operating instrumentation selected for feedwater flow measurement is a Caldon [Cameron] LEFM CheckPlus System (Reference 201), which will be calibrated (in a certified laboratory using a piping configuration representative of the plant piping design) prior to installation and will be tested after installation in the plant in accordance with the LEFM CheckPlus commissioning procedure. This selected plant operating instrumentation has documented instrumentation uncertainties to calculate a power calorimetric uncertainty that confirms the 1% uncertainty assumed for the initial reactor power in the safety analysis bounds the calculated calorimetric power uncertainty values. The calculated calorimetric is done in accordance with a previously accepted Westinghouse methodology (Reference 202). Administrative controls implement maintenance and contingency activities related to the power calorimetric instrumentation.

15.0.3.3 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of fuel assemblies and control rods. Power distribution may be characterized by the nuclear enthalpy rise hot channel factor ($F_{\Delta H}$) and the total peaking factor (F_q). Unless specifically noted otherwise, the peaking factors used in the accident analyses are those presented in Chapter 4.

For transients that may be DNB limited, the radial peaking factor is important. The radial peaking factor increases with decreasing power level due to control rod insertion. This increase in $F_{\Delta H}$ is included in the core limits illustrated in Figure 15.0.3-1 and Figure 15.0.3-1a. Transients that may be departure from nucleate boiling limited are assumed to begin with an $F_{\Delta H}$, consistent with the initial power level defined in the Technical Specifications.

The axial power shape used in the DNB calculation is a chopped cosine, as discussed in Section 4.4, for transients analyzed at full power and the most limiting power shape calculated or allowed for accidents initiated at nonfull power or asymmetric RCCA conditions.

The radial and axial power distributions just described are input to the VIPRE-01 code as described in Section 4.4.

For transients that may be overpower-limited, the total peaking factor (F_q) is important. Transients that may be overpower-limited are assumed to begin with plant conditions, including power distributions, which are consistent with reactor operation as defined in the Technical Specifications.

For overpower transients that are slow with respect to the fuel rod thermal time constant (for example, the chemical and volume control system malfunction that results in a slow decrease in the boron concentration in the reactor coolant system as well as an excessive increase in secondary steam flow) and that may reach equilibrium without causing a reactor trip, the fuel rod thermal evaluations are performed as discussed in Section 4.4.

For overpower transients that are fast with respect to the fuel rod thermal time constant (for example, the uncontrolled RCCA bank withdrawal from subcritical or lower power startup and RCCA ejection incident, both of which result in a large power rise over a few seconds), a detailed fuel transient heat transfer calculation is performed.

15.0.4 Reactivity Coefficients Assumed in the Accident Analysis

The transient response of the reactor system is dependent on reactivity feedback effects, in particular, the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients are discussed in Subsection 4.3.2.3.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values; while for other events, the use of small reactivity coefficient values is conservative. The values used are given in Figure 15.0.4-1, which shows the upper and lower bound Doppler power coefficients as a function of power, used in the transient analysis. The justification for use of conservatively large versus small reactivity coefficient values is treated on an event-by-event basis. In some cases, conservative combinations of parameters are used to bound the effects of core life, although these combinations may not represent possible realistic situations.

15.0.5 Rod Cluster Control Assembly Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCAs as a function of time and the variation in rod worth as a function of rod position. For accident analyses, the critical parameter is the time of insertion up to the dashpot entry, or approximately 85 percent of the rod cluster travel. In analyses where all of the reactor coolant pumps are coasting down prior to, or simultaneous, with RCCA insertion, a time of 2.3 seconds is used for insertion time to dashpot entry.

In Figure 15.0.5-1, the curve labeled “complete loss of flow transients” shows the RCCA position versus time normalized to 2.3 seconds assumed in accident analyses where all reactor coolant pumps are coasting down. In analyses where some or all of the reactor coolant pumps are running, the RCCA insertion time to dashpot is conservatively taken as 2.7 seconds. The RCCA position versus time normalized to 2.7 seconds is also shown in Figure 15.0.5-1.

The use of such a long insertion time provides conservative results for accidents and is intended to apply to all types of RCCAs, which may be used throughout plant life. Drop time testing requirements are specified in the Technical Specifications.

Figure 15.0.5-2 shows the fraction of total negative reactivity insertion versus normalized rod position for a core where the axial distribution is skewed to the lower region of the core. An axial distribution skewed to the lower region of the core can arise from an unbalanced xenon distribution. This curve is used to compute the negative reactivity insertion versus time following a reactor trip, which is input to the point kinetics core models used in transient analyses. The bottom-skewed power distribution itself is not an input into the point kinetics core model.

There is inherent conservatism in the use of Figure 15.0.5-2 in that it is based on a skewed flux distribution, which would exist relatively infrequently. For cases other than those associated with unbalanced xenon distributions, significantly more negative reactivity is inserted than that shown in the curve, due to the more favorable axial distribution existing prior to trip.

The normalized RCCA negative reactivity insertion versus time is shown in Figure 15.0.5-3. The curves shown in this figure were obtained from Figures 15.0.5-1 and 15.0.5-2. A total negative reactivity insertion following a trip of 4 percent Δk is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available as shown in Table 4.3-3.

The normalized RCCA negative reactivity insertion versus time curve for an axial power distribution skewed to the bottom (Figure 15.0.5-3) is used in those transient analyses for which a point kinetics core model is used. Where special analyses require use of three-dimensional or axial one-dimensional core models, the negative reactivity insertion resulting from the reactor trip is calculated directly by the reactor kinetics code and is not separable from the other reactivity feedback effects. In this case, the RCCA position versus time of Figure 15.0.5-1 is used as code input.

15.0.6 Protection and Safety Monitoring System Setpoints and Time Delays to Trip Assumed in Accident Analyses

A reactor trip signal acts to open two trip breaker sets connected in series, feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the RCCAs, which then fall by gravity into the core. There are various instrumentation delays associated with each trip function including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall. Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 15.0-4a. Reference is made in that table to overtemperature and overpower ΔT trip shown in Figure 15.0.3-1 and Figure 15.0.3-1a. As described in Section 7.2 and in Reference 16, the overpower ΔT trip protects the core from exceeding the design overpower limit, and the overtemperature ΔT trip protects the core from exceeding the DNB design limit. As shown on Figure 15.0.3-1, the overtemperature ΔT setpoint plus the error allowances tracks the core DNB design limits, except that the setpoint includes an upper limit on allowable inlet temperature for Unit 3. For Unit 4, the overtemperature ΔT setpoint plus the error allowances bounds the core DNB design limits and includes an upper limit on allowable inlet temperature as shown on Figure 15.0.3-1a.

Table 15.0-4a also summarizes the setpoints and the instrumentation delay for engineered safety features (ESF) functions used in accident analyses. Time delays associated with equipment actuated (such as valve stroke times) by ESF functions are summarized in Table 15.0-4b.

The difference between the limiting setpoint assumed for the analysis and the nominal setpoint represents an allowance for instrumentation channel error and setpoint error. Nominal setpoints are maintained by the setpoint program, which is described in the plant Technical Specifications. During plant startup tests, it is demonstrated that actual instrument time delays are equal to or less than the assumed values. Additionally, the protection system is calibrated and surveillances are performed in accordance with the plant Technical Specifications.

15.0.7 Instrumentation Drift and Calorimetric Errors

The calorimetric uncertainty is the uncertainty assumed in the determination of core thermal power as obtained from secondary plant measurements. On a daily basis, these secondary plant measurements are compared with the ΔT power signal (Reference 16) and with the total ion chamber

current (sum of the top and bottom currents) and those signals are adjusted if necessary for acceptable conformance with the calorimetric power measurement.

The secondary power is obtained from measurement of feedwater flow, feedwater inlet temperature to the steam generators, and steam pressure. Installed plant instrumentation is used for these measurements.

15.0.8 Plant Systems and Components Available for Mitigation of Accident Effects

The plant is designed to afford proper protection against the possible effects of natural phenomena, postulated environmental conditions, and dynamic effects of the postulated accidents. In addition, the design incorporates features that minimize the probability and effects of fires and explosions.

Chapter 17 discusses the quality assurance program that is implemented to provide confidence that the plant systems satisfactorily perform their assigned safety functions. The incorporation of these features in the plant, coupled with the reliability of the design, provides confidence that the normally operating systems and components listed in Table 15.0-6 are available for mitigation of the events discussed in Chapter 15.

In determining which systems are necessary to mitigate the effects of these postulated events, the classification system of ANSI N18.2-1973 (Reference 1) is used. The design of safety-related systems (including protection systems) is consistent with IEEE Standard 379-2000 and Regulatory Guide 1.53 in the application of the single-failure criterion. Conformance to Regulatory Guide 1.53 is summarized in Subsection 1.9.1.

Table 15.0-8 summarizes the nonsafety-related systems assumed in the analyses to mitigate the consequences of events. Except for the cases listed in Table 15.0-8, control system action is not used for mitigation of accidents.

15.0.9 Fission Product Inventories

The sources of radioactivity for release are dependent on the specific accident. Activity may be released from the primary coolant, from the secondary coolant, and from the reactor core if the accident involves fuel damage. The radiological consequences analyses use the conservative design basis source terms identified in Appendix 15A.

15.0.10 Residual Decay Heat

15.0.10.1 Total Residual Heat

Residual heat in a subcritical core is calculated for the LOCA according to the requirements of 10 CFR 50.46, as described in WCAP-10054-P-A and WCAP-12945-P-A and WCAP-16009-P-A (References 3, 4, and 15). The large-break LOCA methodology considers uncertainty in the decay power level. The small-break LOCA events and post-LOCA long-term cooling analyses use 10 CFR 50, Appendix K, decay heat, which assumes infinite irradiation time before the core goes subcritical to determine fission product decay energy. For all other accidents, the same models are used, except that fission product decay energy is based on core average exposure at the end of an equilibrium cycle.

15.0.10.2 Distribution of Decay Heat Following a Loss-of-Coolant Accident

During a LOCA, the core is rapidly shut down by void formation, RCCA insertion, or both, and a large fraction of the heat generation considered comes from fission product decay gamma rays. This heat is not distributed in the same manner as steady-state fission power. Local peaking effects, which are

important for the neutron-dependent part of the heat generation, do not apply to the gamma ray contribution. The steady-state factor, which represents the fraction of heat generated within the cladding and pellet, drops to 95 percent or less for the hot rod in a LOCA.

For example, consider the transient resulting from the postulated double-ended break of the largest reactor coolant system pipe; one-half second after the rupture, about 30 percent of the heat generated in the fuel rods is from gamma ray absorption. The gamma power shape is less peaked than the steady-state fission power shape, reducing the energy deposited in the hot rod at the expense of adjacent colder rods. A conservative estimate of this effect on the hot rod is a reduction of 10 percent of the gamma ray contribution or 3 percent of the total heat. Because the water density is considerably reduced at this time, an average of 98 percent of the available heat is deposited in the fuel rods; the remaining 2 percent is absorbed by water, thimbles, sleeves, and grids. Combining the 3 percent total heat reduction from gamma redistribution with this 2 percent absorption produce as the net effect a factor of 0.95, which exceeds the actual heat production in the hot rod. The actual hot rod heat generation is computed during the AP1000 large-break LOCA transient as a function of core fluid conditions.

15.0.11 Computer Codes Used

Summaries of some of the principal computer codes used in transient analyses are given as follows. Other codes – in particular, specialized codes in which the modeling has been developed to simulate one given accident, such as those used in the analysis of the reactor coolant system pipe rupture (see Subsection 15.6.5) – are summarized in their respective accident analyses sections. The codes used in the analyses of each transient are listed in Table 15.0-2. WCAP-15644 (Reference 11) provides the basis for use of analysis codes.

15.0.11.1 FACTRAN Computer Code

FACTRAN (Reference 5) calculates the transient temperature distribution in a cross section of a metal-clad UO_2 fuel rod and the transient heat flux at the surface of the cladding using as input the nuclear power and the time-dependent coolant parameters (pressure, flow, temperature, and density). The code uses a fuel model which simultaneously exhibits the following features:

- A sufficiently large number of radial space increments to handle fast transients
- Material properties which are functions of temperature and a sophisticated fuel-to-clad gap heat transfer calculation
- The necessary calculations to handle post-DNB transients: film boiling heat transfer correlations, zircaloy-water reaction, and partial melting of the materials

FACTRAN is further discussed in WCAP-7908-A (Reference 5).

15.0.11.2 LOFTRAN Computer Code

The LOFTRAN (Reference 6) program is used for studies of transient response of a pressurized water reactor system to specified perturbations in process parameters. LOFTRAN simulates a multiloop system by a model containing reactor vessel, hot and cold leg piping, steam generator (tube and shell sides), and pressurizer. The pressurizer heaters, spray, and safety valves are also considered in the program. Point model neutron kinetics, and reactivity effects of the moderator, fuel, boron, and rods are included. The secondary side of the steam generator uses a homogeneous, saturated mixture for the thermal transients and a water level correlation for indication and control. The protection and safety monitoring system is simulated to include reactor trips on high neutron flux, power range high positive flux rate, overtemperature ΔT, high and low pressure, low flow, and high

pressurizer level. Control systems are also simulated, including rod control, steam dump, feedwater control, and pressurizer level and pressure control. The emergency core cooling system, including the accumulators, is also modeled.

LOFTRAN is a versatile program suited to both accident evaluation and control studies as well as parameter sizing.

LOFTRAN also has the capability of calculating the transient value of DNBR based on the input from the core limits illustrated in Figure 15.0.3-1 and Figure 15.0.3-1a. The core limits represent the minimum value of DNBR as calculated for typical or thimble cell.

The LOFTRAN code is modified to allow the simulation of the passive residual heat removal (PRHR) heat exchanger, core makeup tanks, and associated protection and safety monitoring system actuation logic. A discussion of these models and additional validation is presented in WCAP-14234 (Reference 10).

LOFTTR2 (Reference 8) is a modified version of LOFTRAN with a more realistic break flow model, a two-region steam generator secondary side, and an improved capability to simulate operator actions during a steam generator tube rupture (SGTR) event.

The LOFTTR2 code is modified to allow the simulation of the PRHR heat exchanger, core makeup tanks, and associated protection system actuation logic. The modifications are identical to those made to the LOFTRAN code. A discussion of these models is presented in WCAP-14234 (Reference 10).

15.0.11.3 TWINKLE Computer Code

The TWINKLE (Reference 7) program is a multidimensional spatial neutron kinetics code, which is patterned after steady-state codes currently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multiregion fuel-clad-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 2000 spatial points and performs its own steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions, such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits are provided (for example, channelwise power, axial offset, enthalpy, volumetric surge, point-wise power, and fuel temperatures).

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

15.0.11.4 VIPRE-01 Computer Code

The VIPRE-01 code is described in Subsection 4.4.4.5.2.

15.0.11.5 COAST Computer Program

The COAST computer program is used to calculate the reactor coolant flow coastdown transient for any combination of active and inactive pumps and forward or reverse flow in the hot or cold legs. The program is described in Reference 13 and was referenced in Reference 12. The program was approved in Reference 14.

The equations of conservation of momentum are written for each of the flow paths of the COAST model assuming unsteady one-dimensional flow of an incompressible fluid. The equation of

conservation of mass is written for the appropriate nodal points. Pressure losses due to friction, and geometric losses are assumed proportional to the flow velocity squared. Pump dynamics are modeled using a head-flow curve for a pump at full speed and using four-quadrant curves, which are parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed.

15.0.11.6 ANC Computer Code

The ANC computer code is used to solve the two-group neutron diffusion equation in three spatial dimensions. ANC can also solve the three-dimensional kinetics equations for six delayed neutron groups. The ANC code is described in Subsection 4.3.3.3.

15.0.12 Component Failures

15.0.12.1 Active Failures

SECY-77-439 (Reference 9) provides a description of active failures. An active failure results in the inability of a component to perform its intended function.

An active failure is defined differently for different components. For valves, an active failure is the failure of a component to mechanically complete the movement required to perform its function. This includes the failure of a remotely operated valve to change position on demand. The spurious, unintended movement of the valve is also considered as an active failure. Failure of a manual valve to change position under local operator action is included.

Spring-loaded safety or relief valves that are designed for and operate under single-phase fluid conditions are not considered for active failures to close when pressure is reduced below the valve set point. However, when valves designed for single-phase flow are challenged with two-phase flow, such as a steam generator or pressurizer safety valve, the failure to reseat is considered as an active failure.

For other active equipment – such as pumps, fans, and rotating mechanical components – an active failure is the failure of the component to start or to remain operating.

For electrical equipment, the loss of power, such as the loss of offsite power or the loss of a diesel generator, is considered as a single failure. In addition, the failure to generate an actuation signal, either for a single component actuation or for a system-level actuation, is also considered as an active failure.

Spurious actuation of an active component is considered as an active failure for active components in safety-related passive systems. An exception is made for active components if specific design features or operating restrictions are provided that can preclude such failures (such as power lockout, confirmatory open signals, or continuous position alarms).

A single incorrect or omitted operator action in response to an initiating event is also considered as an active failure; the error is limited to manipulation of safety-related equipment and does not include thought-process errors or similar errors that could potentially lead to common cause or multiple errors.

15.0.12.2 Passive Failures

SECY-77-439 also provides a description of passive failures. A passive failure is the structural failure of a static component that limits the effectiveness of the component in carrying out its design

function. A passive failure is applied to fluid systems and consists of a breach in the fluid system boundary. Examples include cracking of pipes, sprung flanges, or valve packing leaks.

Passive failures are not assumed to occur until 24 hours after the start of the event. Consequential effects of a pipe leak – such as flooding, jet impingement, and failure of a valve with a packing leak – must be considered.

Where piping is significantly overdesigned or installed in a system where the pressure and temperature conditions are relatively low, passive leakage is not considered a credible failure mechanism. Line blockage is also not considered as a passive failure mechanism.

15.0.12.3 Limiting Single Failures

The most limiting single active failure (where one exists), as described in Section 3.1, of safety-related equipment, is identified in each analysis description. The consequences of this failure are described therein. In some instances, because of redundancy in protection equipment, no single failure that could adversely affect the consequences of the transient is identified. The failure assumed in each analysis is listed in Table 15.0-7.

15.0.13 Operator Actions

There are several events analyzed in the following sections which require operator action to terminate or mitigate the event. The loss of normal feedwater (Subsection 15.2.7), the inadvertent actuation of a core makeup tank (Subsection 15.5.1), and the chemical and volume control system malfunction (Subsection 15.5.2) assume operator action, after the high-2 pressurizer water level setpoint is reached, to open the safety grade reactor vessel head vent. This action prevents filling the pressurizer and allowing water to escape through the pressurizer safety valves. The analysis of the boron dilution for Mode 1 operation with automatic rod control (Subsection 15.4.6) relies on the operator to terminate the dilution source, after the rod insertion limit alarm, before the required shutdown margin is lost. The small line break outside containment event (Subsection 15.6.2) assumes the operator will isolate the break. In all cases where operator actions are credited, no operator actions are required within the first 30 minutes of the transient. For these events, before operator action is required numerous alarms and indications would be available to the operator to diagnose the transient and ensure that the proper action is taken.

For events where the PRHR heat exchanger is actuated, the plant automatically cools down to a safe, stable condition. Where a stabilized condition is reached automatically following a reactor trip, it is expected that the operator may, following event recognition, take manual control and proceed with orderly shutdown of the reactor in accordance with the normal, abnormal, or emergency operating procedures. The exact actions taken and the time at which these actions occur depend on what systems are available and the plans for further plant operation.

However, for these events, operator actions are not required to maintain the plant in a safe and stable condition for at least 72 hours. Operator actions typical of normal operation are credited for the inadvertent actuations of equipment in response to a Condition II event.

15.0.14 Loss of Offsite ac Power

As required in GDC 17 of 10 CFR Part 50, Appendix A, anticipated operational occurrences and postulated accidents are analyzed assuming a loss of offsite ac power. The loss of offsite power is not considered as a single failure, and the analysis is performed without changing the event category. In the analyses, the loss of offsite ac power is considered to be a potential consequence of the event.

A loss of offsite ac power will be considered a consequence of an event due to disruption of the grid following a turbine trip during the event. Event analyses that do not result in a possible consequential disruption of offsite ac power do not assume offsite power is lost.

For those events where offsite ac power is lost, an appropriate time delay between turbine trip and the postulated loss of offsite ac power is assumed in the analyses. A time delay of 3 seconds is used. This time delay is based on the inherent stability of the offsite power grid as discussed in Section 8.2. Following the time delay, the effect of the loss of offsite ac power on plant auxiliary equipment – such as reactor coolant pumps, main feedwater pumps, condenser, startup feedwater pumps, and RCCAs – is considered in the analyses. Turbine trip occurs 5 seconds following a reactor trip condition being reached. This delay is part of the AP1000 reactor trip system.

Design basis LOCA analyses are governed by the GDC-17 requirement to consider the loss of offsite power. For the AP1000 design, in which all the safety-related systems are passive, the availability of offsite power is significant only regarding reactor coolant pump operation for LOCA events. A sensitivity study for AP1000 has shown that for large-break LOCAs, assuming the loss of offsite power coincident with the inception of the LOCA event is nonlimiting relative to assuming continued reactor coolant pump operation until the automatic reactor coolant pump trip occurs following an “S” signal less than 10 seconds into the transient. For small-break LOCA events, the AP1000 automatic reactor coolant pump trip feature prevents continued operation of the reactor coolant pumps from mixing the liquid and vapor present within a two-phase reactor coolant system inventory to increase the liquid break flow and deplete the reactor coolant system mass inventory rapidly. The automatic reactor coolant pump trip occurs early enough during AP1000 small-break LOCA transients that emergency core cooling system performance is not affected by the loss of offsite power assumption because the total break flow is approximately equivalent for reactor coolant pump trip occurring either at time zero or as a result of the “S” signal. Whether a loss of offsite power is postulated at the inception of the LOCA event or occurs automatically later on is unimportant in the Subsection 15.6.5.4C long-term cooling analyses because with either assumption, the reactor coolant pumps are tripped long before the long-term cooling timeframe.

The AP1000 protection and safety monitoring system and passive safeguards systems are not dependent on offsite power or on any backup diesel generators. Following a loss of ac power, the protection and safety monitoring system and passive safeguards are able to perform the safety functions and there are no additional time delays for these functions to be completed.

15.0.15 Combined License Information

15.0.15.1 Following selection of the actual plant operating instrumentation, calculation of the primary power calorimetric uncertainty is addressed in Subsection 15.0.3.2.

15.0.16 References

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Table 15.0-1
Nuclear Steam Supply System Power Ratings

Thermal power output (MWt)	3415
Effective thermal power generated by the reactor coolant pumps (MWt)	15
Core thermal power (MWt)	3400

Table 15.0-2 (Sheet 1 of 4)
Summary of Initial Conditions and Computer Codes Used

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.1	Increase in heat removal from the primary system					
	Feedwater system malfunctions causing a reduction in feedwater temperature	Bounded by excessive increase in secondary steam flow	–	–	–	–
	Feedwater system malfunctions that result in an increase in feedwater flow	LOFTRAN	0.470	–	Upper curve of Figure 15.0.4-1	0 and 3415
	Excessive increase in secondary steam flow	LOFTRAN	0.0 and 0.470	–	Upper and lower curves of Figure 15.0.4-1	3415
	Inadvertent opening of a steam generator relief or safety valve	LOFTRAN, VIPRE-01	Function of moderator density (see Figure 15.1.4-1)	–	See Subsection 15.1.4.	0 (subcritical)
	Steam system piping failure	LOFTRAN, VIPRE-01	Function of moderator density (see Figure 15.1.4-1) for zero power case 0.470 for full power case	–	See Subsection 15.1.5 for zero power case Upper curve of Figure 15.0.4-1 for full power case	0 (subcritical) and 3415
	Inadvertent operation of the PRHR heat exchanger	N/A	N/A	–	N/A	3415

Table 15.0-2 (Sheet 2 of 4)
Summary of Initial Conditions and Computer Codes Used

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.2	Decrease in heat removal by the secondary system					
	Loss of external electrical load and/or turbine trip	LOFTRAN, FACTRAN, VIPRE-01	0.470 and function of moderator density	–	Lower and upper curves of Figure 15.0.4-1	3415 and 3449.15 (a)
	Inadvertent closure of main steam isolation valves	Bounded by turbine trip event	–	–	–	–
	Loss of condenser vacuum and other events resulting in turbine trip	Bounded by turbine trip event	–	–	–	–
	Loss of nonemergency ac power to the plant auxiliaries	LOFTRAN	0.0	–	Lower curve of Figure 15.0.4-1	3449.15 (a)
	Loss of normal feedwater flow	LOFTRAN	0.0	–	Lower curve of Figure 15.0.4-1	3449.15 (a)
	Feedwater system pipe break	LOFTRAN	0.0	–	Lower curve of Figure 15.0.4-1	3449.15 (a)
15.3	Decrease in reactor coolant system flow rate					

Table 15.0-2 (Sheet 3 of 4)
Summary of Initial Conditions and Computer Codes Used

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.3	Partial and complete loss of forced reactor coolant flow	LOFTRAN, FACTRAN, COAST, VIPRE-01	0.0 and function of moderator density	–	Lower curve of Figure 15.0.4-1	3415
	Reactor coolant pump shaft seizure (locked rotor) and reactor coolant pump shaft break	LOFTRAN, FACTRAN, COAST, VIPRE-01	0.0 and function of moderator density	–	Lower curve of Figure 15.0.4-1	3415 and 3449.15 (a)
15.4	Reactivity and power distribution anomalies					
	Uncontrolled RCCA bank withdrawal from a subcritical or low power startup condition	TWINKLE, FACTRAN, VIPRE-01	–	0.0	Coefficient is consistent with a Doppler defect of -0.90%Δk	0
	Uncontrolled RCCA bank withdrawal at power	LOFTRAN	0.0 and 0.470	–	Upper and lower curves of Figure 15.0.4-1	10%, 60%, and 100% of 3415
	RCCA misalignment	LOFTRAN, VIPRE-01	NA	–	NA	3415
	Startup of an inactive reactor coolant pump at an incorrect temperature	NA	NA	–	NA	NA
15.4	Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant	NA	NA	–	NA	0 and 3415
	Inadvertent loading and operation of a fuel assembly in an improper position	ANC	NA	–	NA	3415
	Spectrum of RCCA ejection accidents	ANC, VIPRE	Refer to Subsection 15.4.8	Refer to Subsection 15.4.8	Refer to Subsection 15.4.8	Refer to Subsection 15.4.8

Table 15.0-2 (Sheet 4 of 4)
Summary of Initial Conditions and Computer Codes Used

Section	Faults	Computer Codes Used	Reactivity Coefficients Assumed			Initial Thermal Power Output Assumed (MWt)
			Moderator Density ($\Delta k/gm/cm^3$)	Moderator Temperature (pcm/°F)	Doppler	
15.5	Increase in reactor coolant inventory					
	Inadvertent operation of the core makeup tanks during power operation	LOFTRAN	0.0	–	Upper curve of Figure 15.0.4-1	3449.15 (a)
	Chemical and volume control system malfunction that increases reactor coolant inventory	LOFTRAN	0.0	–	Upper curve of Figure 15.0.4-1	3449.15 (a)
15.6	Decrease in reactor coolant inventory					
	Inadvertent opening of a pressurizer safety valve and inadvertent operation of ADS	LOFTRAN	0.0	–	Upper curve of Figure 15.0.4-1	3415
	Steam generator tube failure	LOFTTR2	0.0	–	Lower curve of Figure 15.0.4-1	3449.15 (a)
	A break in an instrument line or other lines from the reactor coolant pressure boundary that penetrate containment	NA	NA	–	NA	NA
	LOCAs resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	NOTRUMP WCOBRA/ TRAC	See Subsection 15.6.5 references	–	See Subsection 15.6.5 references	3434.0 (a) (b)

Notes:
a. The Non LOCA analyses assume an initial power of 101% of the NSSS Power (NSSS Power = rated thermal power (RTP) plus 15 MWt for pump heat) and the LOCA analyses assume an initial power of 101% of RTP.
b. Subsection 15.6.5.4A describes the large-break LOCA analysis methodology, which includes treatment of the initial thermal power output uncertainty.

Table 15.0-3
Nominal Values of Pertinent Plant Parameters Used in Accident Analyses

	RTDP With 10% Steam Generator Tube Plugging	Without RTDP[a]	
		Without Steam Generator Tube Plugging	With 10% Steam Generator Tube Plugging
Thermal output of NSSS (MWt)	3415	3415	3415
Core inlet temperature (°F)	535.8	535.5	535.0
Vessel average temperature (°F)	573.6	573.6	573.6
Reactor coolant system pressure (psia)	2250.0	2250.0	2250.0
Reactor coolant flow per loop (gpm)	15.08 E+04	14.99 E+04	14.8 E+04
Steam pressure at steam generator outlet (psia)	802.2	814.0	796.0
Assumed feedwater temperature at steam generator inlet (°F)	440.0	440.0	440.0
Average core heat flux (Btu/-hr-ft^2)	1.99 E+05	1.99 E+05	1.99 E+05

Note:

a. Steady-state errors discussed in Subsection 15.0.3 are added to these values to obtain initial conditions for most transient analyses.

Table 15.0-4a (Sheet 1 of 2)
Protection and Safety Monitoring System
Setpoints and Time Delay Assumed in Accident Analyses

Function	Limiting Setpoint Assumed in Analyses	Time Delays (seconds)
Reactor trip on power range high positive flux rate	15% with 60-second time constant	0.9
Reactor trip on power range high neutron flux, low setting	35%	0.9
Overtemperature ΔT	Variable (see Figure 15.0.3-1 and Figure 15.0.3-1a)	2.0(1)
Overpower ΔT	Variable (see Figure 15.0.3-1 and Figure 15.0.3-1a)	1.0(1)
Reactor trip on High-2 pressurizer pressure	2460 psia	2.0
Reactor trip on Low-2 pressurizer pressure	1800 psia	2.0
Reactor trip on Low-2 reactor coolant flow in either hot leg	87% loop flow	1.45
Reactor trip on Low-2 reactor coolant pump speed	90%	0.65
Reactor trip on Low-2 steam generator narrow range water level	0% of span	2.0
High steam generator narrow range level coincident with reactor trip (P-4)	85% of narrow range level span	2.0 (startup feedwater isolation) 2.0 (chemical and volume control system makeup isolation)
High-3 steam generator level	100% of narrow range level span	2.0 (reactor trip) 7.0 (turbine trip, includes 5.0-second timer delay) 2.0 (feedwater isolation, plus valve closure time, see Table 15.0-4b) 2.0 (CVS isolation)
Reactor trip on high-3 pressurizer water level	76% of span	2.0
Reactor trip on “S” signal	–	2.0(1)
PRHR actuation on Low-2 steam generator wide range water level	13.3% of span	2.0
“S” signal, startup feedwater isolation, and steam line isolation on Low-2 T_{cold}	500°F lower bound 510°F upper bound	2.0(1)

Table 15.0-4a (Sheet 2 of 2)
Protection and Safety Monitoring System
Setpoints and Time Delay Assumed in Accident Analyses

Function	Limiting Setpoint Assumed in Analyses	Time Delays (seconds)
"S" signal, power operated relief valve isolation, and steam line isolation on Low-2 steam line pressure	405 psia (with an adverse environment assumed) 535 psia (without an adverse environment assumed)	2.0
"S" signal on Low-3 pressurizer pressure	1700 psia	2.0
Reactor trip on PRHR discharge valves not closed	Valve not closed	1.25
"S" signal and steamline isolation on high-2 containment pressure	6.7 psig	2.0
Reactor coolant pump trip following "S"	–	5.0 5.3 (LBLOCA)
PRHR actuation on high-3 pressurizer water level	76% of span	2.0 (plus 15.0-second timer delay)
Chemical and volume control system isolation on high-2 pressurizer water level	63.5% of span	2.0
Chemical and volume control system isolation on high-1 pressurizer water level coincident with "S" signal	33% of span	2.0(1)
Boron dilution block on source range flux doubling	3 over 50 minutes	80.0
ADS Stage 1 actuation on core makeup tank Low-3 level signal	67.5% of tank volume	32.0 seconds for control valve to begin to open)
ADS Stage 4 actuation on core makeup tank Low-6 level signal	20% of tank volume	2.0 seconds for squib valve to begin to open)
CMT actuation on pressurizer low-2 water level	0% of span	2.0
PRHR heat exchanger actuation on Low-2 SG narrow range water level coincident with Low-2 startup feedwater flow	0% of span (Low-2 SG narrow range water level) 100 gpm (Low-2 startup feedwater flow)	2.0
DWS isolation on reactor trip	–	2.0
Main control room isolation, air supply initiation, and electrical load de-energization on High-2 control room radioactivity	Iodine: 2.00E-7 Ci/m^3 Particulate: 2.00E-08 Ci/m^3	200.0

Notes:
1. In addition to the response time given, a 4.0 second lag time is used in the accident analysis for this function to account for the associated RTDs. For automatic safeguards actuation, the 4.0 second lag time is only used for the temperature inputs.

Table 15.0-4b
Limiting Delay Times for
Equipment Assumed in Accident Analyses

Component	Time Delays (seconds)
Feedwater isolation valve closure, feedwater control valve closure, or feedwater pump trip	10 (maximum value for non-LOCA) 5 (maximum value for mass/energy)
Steam line isolation valve closure	5
Core makeup tank discharge valve opening time	15 (maximum) 10 (nominal value for best-estimate LOCA)
Chemical and volume control system isolation valve closure	30
PRHR discharge valve opening time	15 (maximum) 10 (nominal value for best-estimate LOCA) 2 (small-break LOCA signal processing delay time added to the maximum opening time of 15 seconds)
Demineralized water transfer and storage system isolation valve closure time	20
Steam generator power-operated relief valve block valve closure	44
Automatic depressurization system (ADS) valve opening times	See Table 15.6.5-10.

Table 15.0-5
Not Used

Table 15.0-6 (Sheet 1 of 5)
Plant Systems and Equipment
Available for Transient and Accident Conditions

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.1			
Increase in heat removal from the primary system			
Feedwater system malfunctions that result in an increase in feedwater flow	High-2 steam generator level, power range high positive flux rate and high neutron flux, overtemperature ΔT, overpower ΔT, manual	High-2 steam generator level produced feedwater isolation and turbine trip	Feedwater isolation valves
Excessive increase in secondary steam flow	Power range high positive flux rate and high neutron flux, overtemperature ΔT, overpower ΔT, manual	–	–
Inadvertent opening of a steam generator safety valve	Power range high positive flux rate and high neutron flux, overtemperature ΔT, overpower ΔT, Low-2 pressurizer pressure, “S”, manual	Low-3 pressurizer pressure, Low-2 compensated steam line pressure, Low-2 T_{cold}, low-2 pressurizer level	Core makeup tank, feedwater isolation valves, main steam isolation valves (MSIVs), startup feedwater isolation, accumulators
Steam system piping failure	Power range high positive flux rate and high neutron flux, overtemperature ΔT, overpower ΔT, Low-2 pressurizer pressure, “S”, manual	Low-3 pressurizer pressure, Low-2 compensated steam line pressure, high-2 containment pressure, Low-2 T_{cold}, manual	Core makeup tank, feedwater isolation valves, main steam line isolation valves (MSIVs), accumulators, startup feedwater isolation
Inadvertent operation of the PRHR	Power range high positive flux rate and high neutron flux, overtemperature ΔT, overpower ΔT, Low pressurizer pressure, “S”, manual PRHR discharge valve position	Low-3 pressurizer pressure, Low-2 T_{cold}, low-2 pressurizer level	Core makeup tank

Table 15.0-6 (Sheet 2 of 5)
Plant Systems and Equipment
Available for Transient and Accident Conditions

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.2			
Decrease in heat removal by the secondary system			
Loss of external load/turbine trip	High-2 pressurizer pressure, High-3 pressurizer water level, overtemperature ΔT, overpower ΔT, Low-2 steam generator narrow range water level, Low-2 RCP speed, manual	–	Pressurizer safety valves, steam generator safety valves
Loss of nonemergency ac power to the station auxiliaries	Low-2 steam generator narrow range water level, High-2 pressurizer pressure, High-3 pressurizer level, Low-2 RCP speed, manual	Low-2 steam generator narrow range water level coincident with Low-2 startup water flow, Low-2 steam generator wide range water level	PRHR, steam generator safety valves, pressurizer safety valves
Loss of normal feedwater flow	Low-2 steam generator narrow range water level, High-2 pressurizer pressure, High-3 pressurizer level, manual	Low-2 steam generator narrow range water level coincident with Low-2 startup water flow, Low-2 steam generator wide range water level	PRHR, steam generator safety valves, pressurizer safety valves, reactor vessel head vent
Feedwater system pipe break	Low-2 steam generator narrow range water level, High-2 pressurizer pressure, High-3 pressurizer level, overtemperature ΔT, “S”, manual	Low-2 steam generator narrow range water level coincident with Low-2 startup feedwater flow, Low-2 steam generator wide range water level, Low-2 steam line pressure, high-2 containment pressure	PRHR, core makeup tank, MSIVs, feedline isolation, pressurizer safety valves, steam generator safety valves

Table 15.0-6 (Sheet 3 of 5)
Plant Systems and Equipment
Available for Transient and Accident Conditions

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.3			
Decrease in reactor coolant system flow rate			
Partial and complete loss of forced reactor coolant flow	Low-2 flow, Low-2 RCP speed, manual	–	Steam generator safety valves, pressurizer safety valves
Reactor coolant pump shaft seizure (locked rotor)	Low-2 flow, High-2 pressurizer pressure, manual	–	Pressurizer safety valves, steam generator safety valves
Section 15.4			
Reactivity and power distribution anomalies			
Uncontrolled RCCA bank withdrawal from a subcritical or low power startup condition	Source range high neutron flux, intermediate range high neutron flux, power range high neutron flux (low setting), power range high neutron flux (high setting), power range high positive flux rate, manual	–	–
Uncontrolled RCCA bank withdrawal at power	Power range high neutron flux, power range high positive flux rate, overtemperature ΔT, over-power ΔT, High-2 pressurizer pressure, High-3 pressurizer water level, manual	–	Pressurizer safety valves, steam generator safety valves
RCCA misalignment	Overtemperature ΔT, Low-2 pressurizer pressure, manual	–	–
Startup of an inactive reactor coolant pump at an incorrect temperature	Power range high neutron flux, power range high positive flux rate, low flow (P-10 interlock), manual	–	–

Table 15.0-6 (Sheet 4 of 5)
Plant Systems and Equipment
Available for Transient and Accident Conditions

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.4 (Cont.)			
Chemical and volume control system malfunction that results in a decrease in boron concentration in the reactor coolant	Source range high neutron flux, power range high neutron flux, power range high positive flux rate, overtemperature ΔT, overpower ΔT, manual	Source range flux doubling	CVS to RCS isolation valves, makeup pump suction isolation valves, from the demineralized water transfer and storage system
Spectrum of RCCA ejection accidents	Power range high neutron flux, power range high positive flux rate, manual	–	Pressurizer safety valves
Section 15.5			
Increase in reactor coolant inventory			
Inadvertent operation of the CMT during power operation	High-2 pressurizer pressure, manual, “safeguards” trip, High-3 pressurizer level	High-3 pressurizer level, Low-2 T_{cold}	Core makeup tank, pressurizer safety valves, chemical and volume control system isolation, PRHR, steam generator safety valves, reactor vessel head vent
Chemical and volume control system malfunction that increases reactor coolant inventory	High-2 pressurizer pressure, “safeguards” trip, High-3 pressurizer level, manual	High-3 pressurizer level, Low-2 T_{cold}, Low-2 steam line pressure	Core makeup tank, pressurizer safety valves, chemical and volume control system isolation, PRHR, reactor vessel head vent
Section 15.6			
Decrease in reactor coolant inventory			
Inadvertent opening of a pressurizer safety valve or ADS path	Low-2 pressurizer pressure, overtemperature ΔT, manual	Low-3 pressurizer pressure	Core makeup tank, accumulator

Table 15.0-6 (Sheet 5 of 5)
Plant Systems and Equipment
Available for Transient and Accident Conditions

Incident	Reactor Trip Functions	ESF Actuation Functions	ESF and Other Equipment
Section 15.6 (Cont.)			
Failure of small lines carrying primary coolant outside containment	–	Manual isolation of the Sample System or CVS discharge lines	Sample System isolation valves, Chemical and volume control system discharge line isolation valves
Steam generator tube rupture	Low-2 pressurizer pressure, overtemperature ΔT, safeguards (“S”), manual	Low-3 pressurizer pressure, High-3 steam generator water level, high steam generator level coincident with reactor trip (P-4), Low-2 steam line pressure, Low-2 pressurizer level	Core makeup tank, PRHR, steam generator safety and/or relief valves, MSIVs, radiation monitors (air removal, steam line, and steam generator blowdown), startup feedwater isolation, chemical and volume control system pump isolation, pressurizer heater isolation, steam generator power-operated relief valve isolation
LOCAs resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary	Low-2 pressurizer pressure, safeguards (“S”), manual	High-2 containment pressure, Low-3 pressurizer pressure	Core makeup tank, accumulator, ADS, steam generator safety and/or relief valves, PRHR, in-containment water storage tank (IRWST)

Table 15.0-7 (Sheet 1 of 2)
Single Failures Assumed in Accident Analyses

Event Description	Failure
Feedwater temperature reduction[a]	–
Excessive feedwater flow	One protection division
Excessive steam flow[a]	
Inadvertent secondary depressurization	One core makeup tank discharge valve
Steam system piping failure	One core makeup tank discharge valve (zero power case) One protection division (full power case)
Inadvertent operation of the PRHR	One protection division
Steam pressure regulator malfunction[b]	–
Loss of external load	One protection division
Turbine trip	One protection division
Inadvertent closure of main steam isolation valve	One protection division
Loss of condenser vacuum	One protection division
Loss of ac power	One PRHR discharge valve
Loss of normal feedwater	One PRHR discharge valve
Feedwater system pipe break	One PRHR discharge valve
Partial loss of forced reactor coolant flow	One protection division
Complete loss of forced reactor coolant flow	One protection division
Reactor coolant pump locked rotor	One protection division
Reactor coolant pump shaft break	One protection division
RCCA bank withdrawal from subcritical	One protection division
RCCA bank withdrawal at power	One protection division
Dropped RCCA, dropped RCCA bank	One protection division
Statically misaligned RCCA[c]	–
Single RCCA withdrawal	One protection division

Notes:
a. No protection action required
b. Not applicable to AP1000
c. No transient analysis

Table 15.0-7 (Sheet 2 of 2)
Single Failures Assumed in Accident Analyses

Event Description	Failure
Flow controller malfunction[b]	–
Uncontrolled boron dilution	One protection division
Improper fuel loading[c]	–
RCCA ejection	One protection division
Inadvertent CMT operation at power	One PRHR discharge valve
Increase in reactor coolant system inventory	One PRHR discharge valve
Inadvertent reactor coolant system depressurization	One protection division
Failure of small lines carrying primary coolant outside containment[c]	–
Steam generator tube rupture	Ruptured steam generator power-operated relief valve fails open
Spectrum of LOCA Small breaks Large breaks	 One ADS Stage 4 valve One CMT valve
Long-term cooling	One ADS Stage 4 valve

Notes:
a. No protection action required
b. Not applicable to AP1000
c. No transient analysis

Table 15.0-8
Nonsafety-Related System and Equipment Used for Mitigation of Accidents

Event		Nonsafety-related System and Equipment
15.1.2	Feedwater system malfunctions that result in an increase in feedwater flow	Main feedwater pump trip
15.1.4	Inadvertent opening of a steam generator relief or safety valve	MSIV backup valves[1] Main steam branch isolation valves
15.1.5	Steam system piping failure	MSIV backup valves[1] Main steam branch isolation valves
15.2.7	Loss of normal feedwater	Pressurizer heater block
15.5.1	Inadvertent operation of the core makeup tanks during power operation	Pressurizer heater block
15.5.2	Chemical and volume control system malfunction that increases reactor coolant inventory	Pressurizer heater block
15.6.2	Failure of small lines carrying primary coolant outside containment	Sample line isolation valves
15.6.3	Steam generator tube rupture	Pressurizer heater block MSIV backup valves(1) Main steam branch isolation valves
15.6.5	Small-break LOCA	Pressurizer heater block

Note:

1. These include the turbine stop or control valves, the turbine bypass valves, and the moisture separator reheater 2nd stage steam isolation valves.

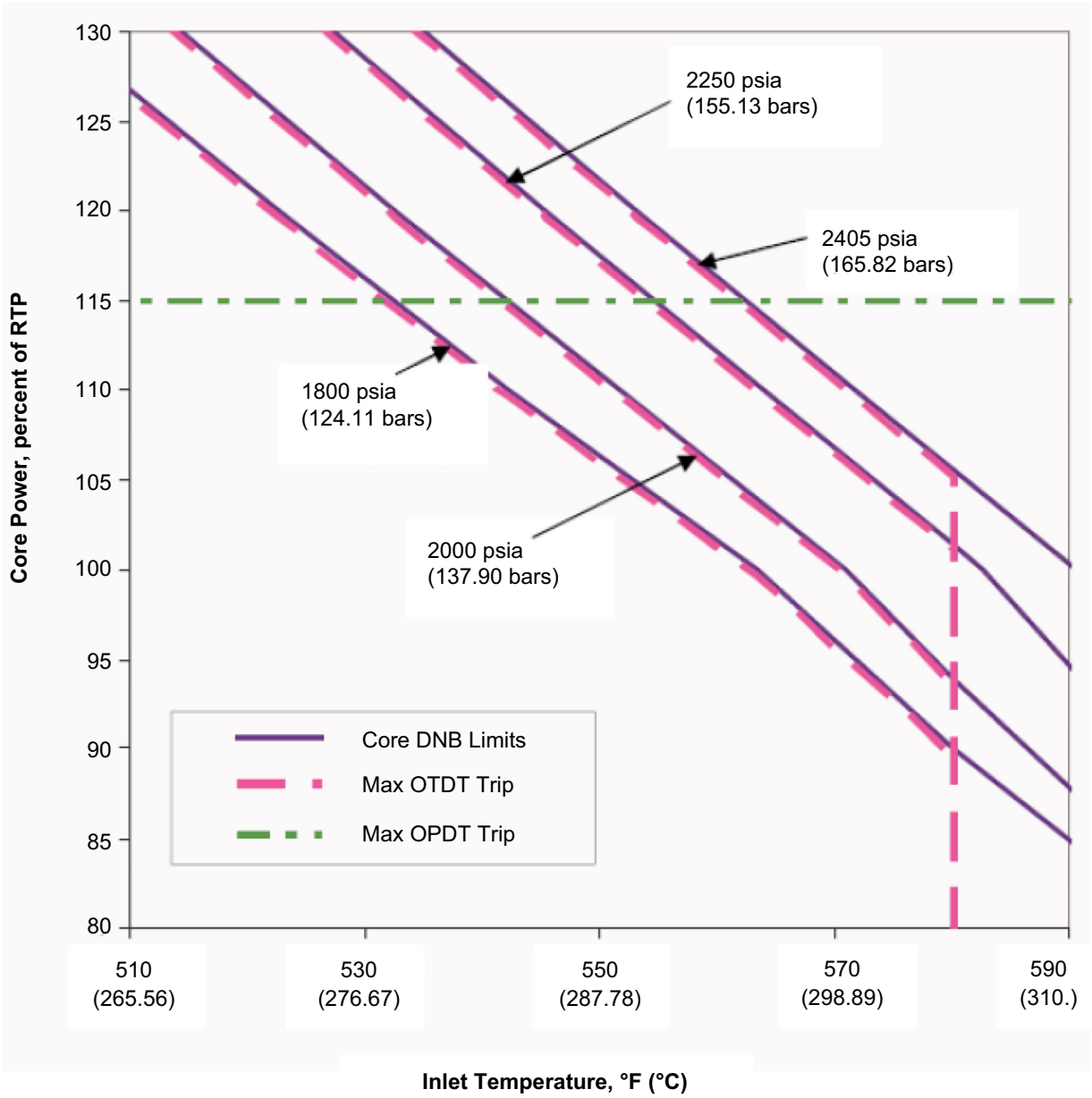

Figure 15.0.3-1
Overpower and Overtemperature ΔT Protection (Unit 3)

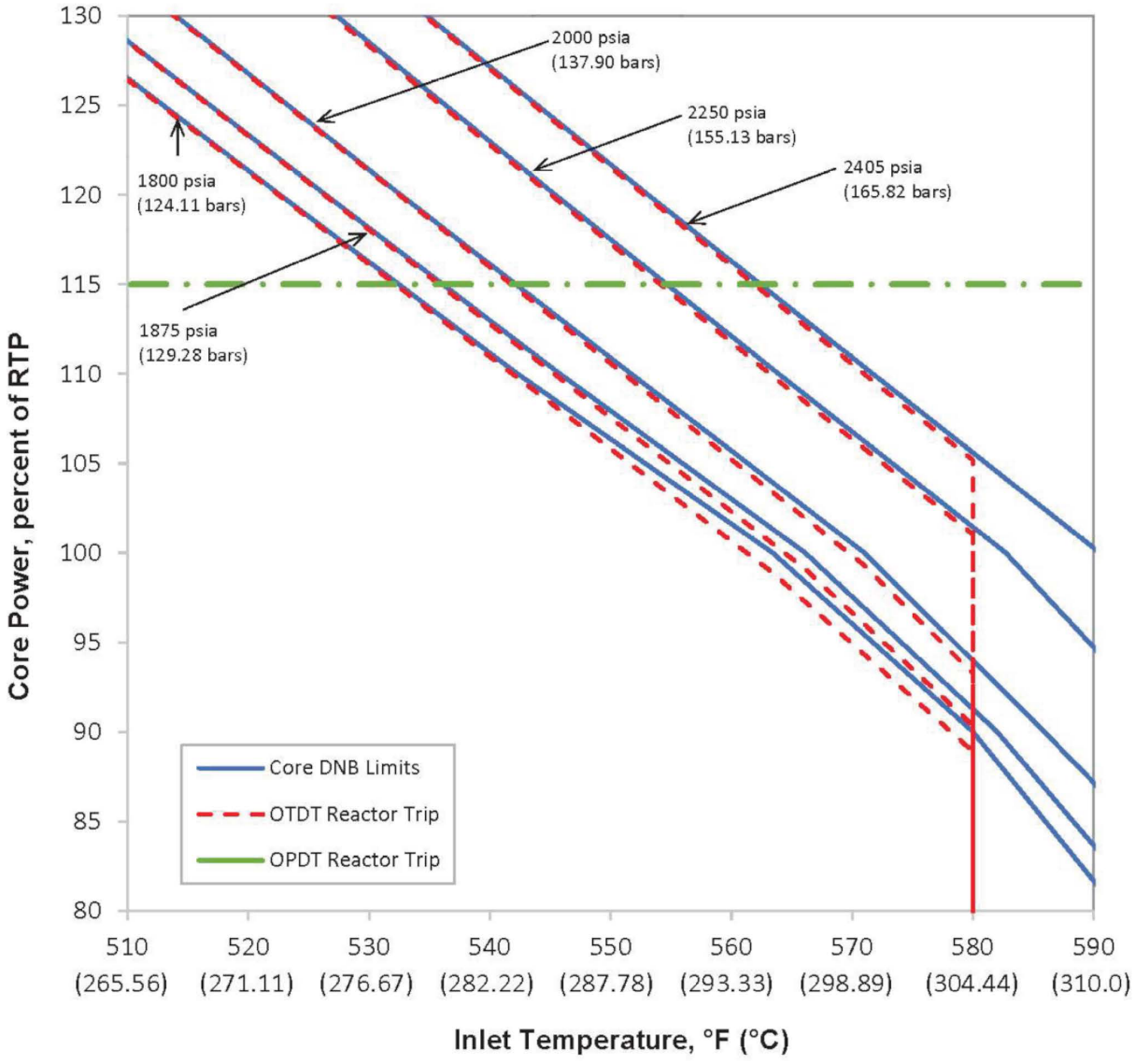

Figure 15.0.3-1a
Overpower and Overtemperature ΔT Protection (Unit 4)

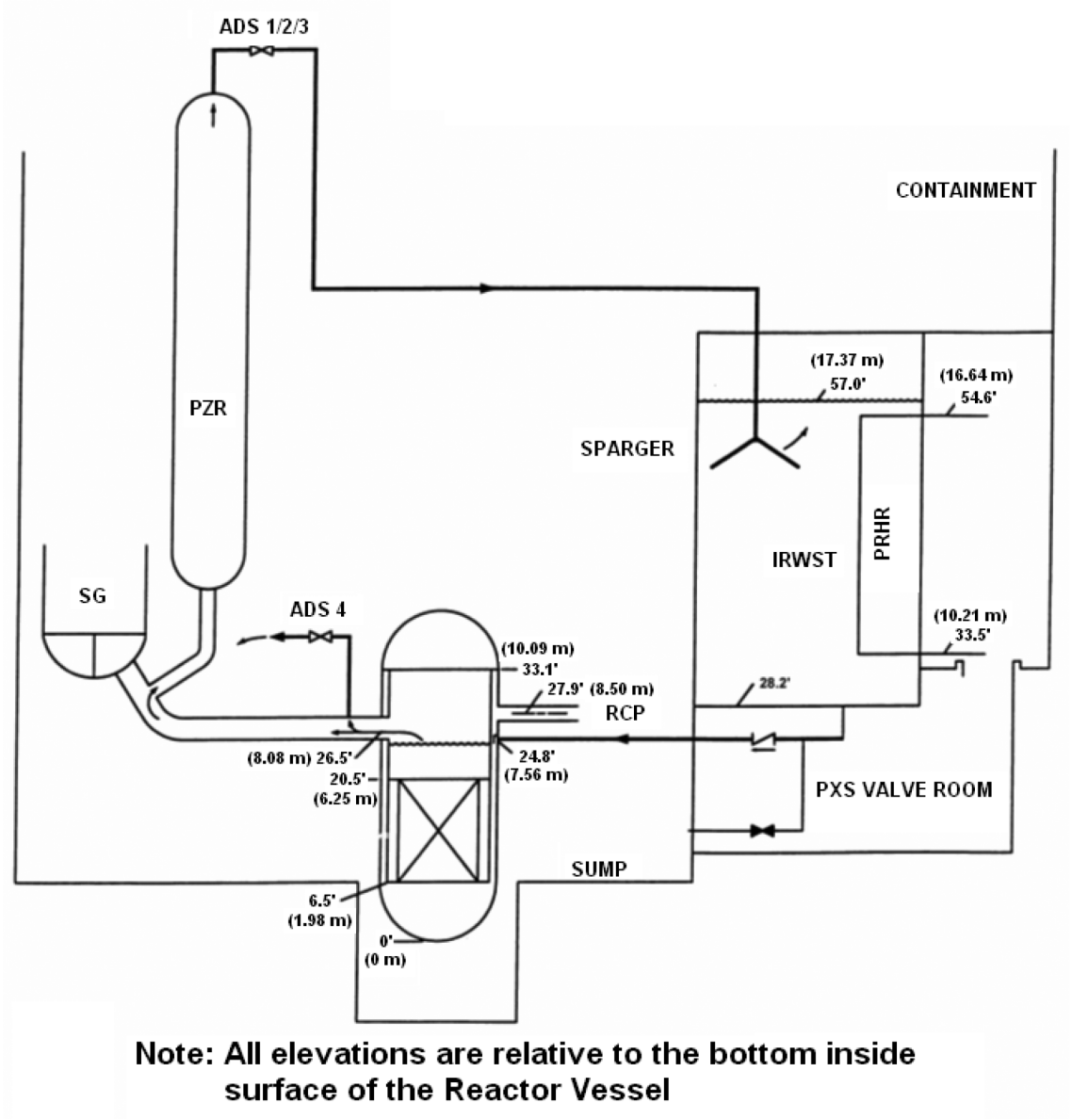

Figure 15.0.3-2
AP1000 Loop Layout

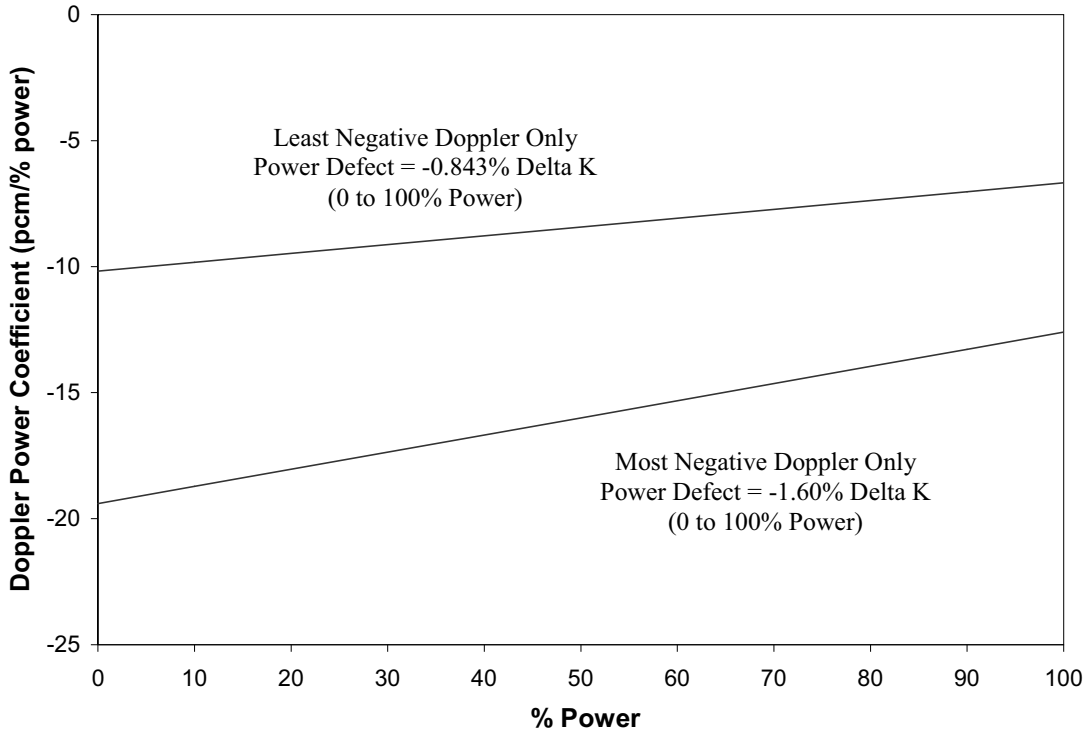

Figure 15.0.4-1
Doppler Power Coefficient used in Accident Analysis

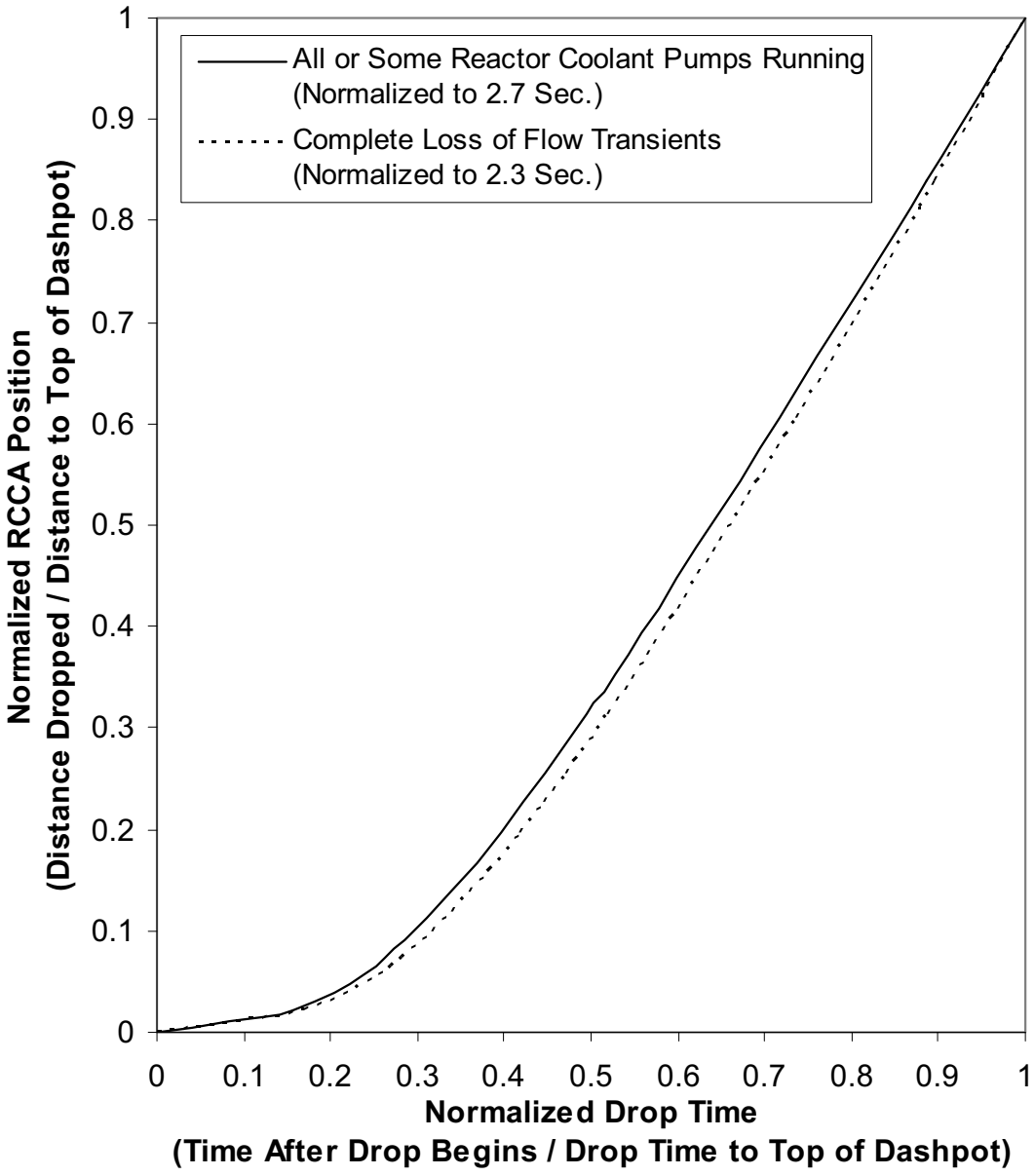

Figure 15.0.5-1
RCCA Position Versus Time to Dashpot

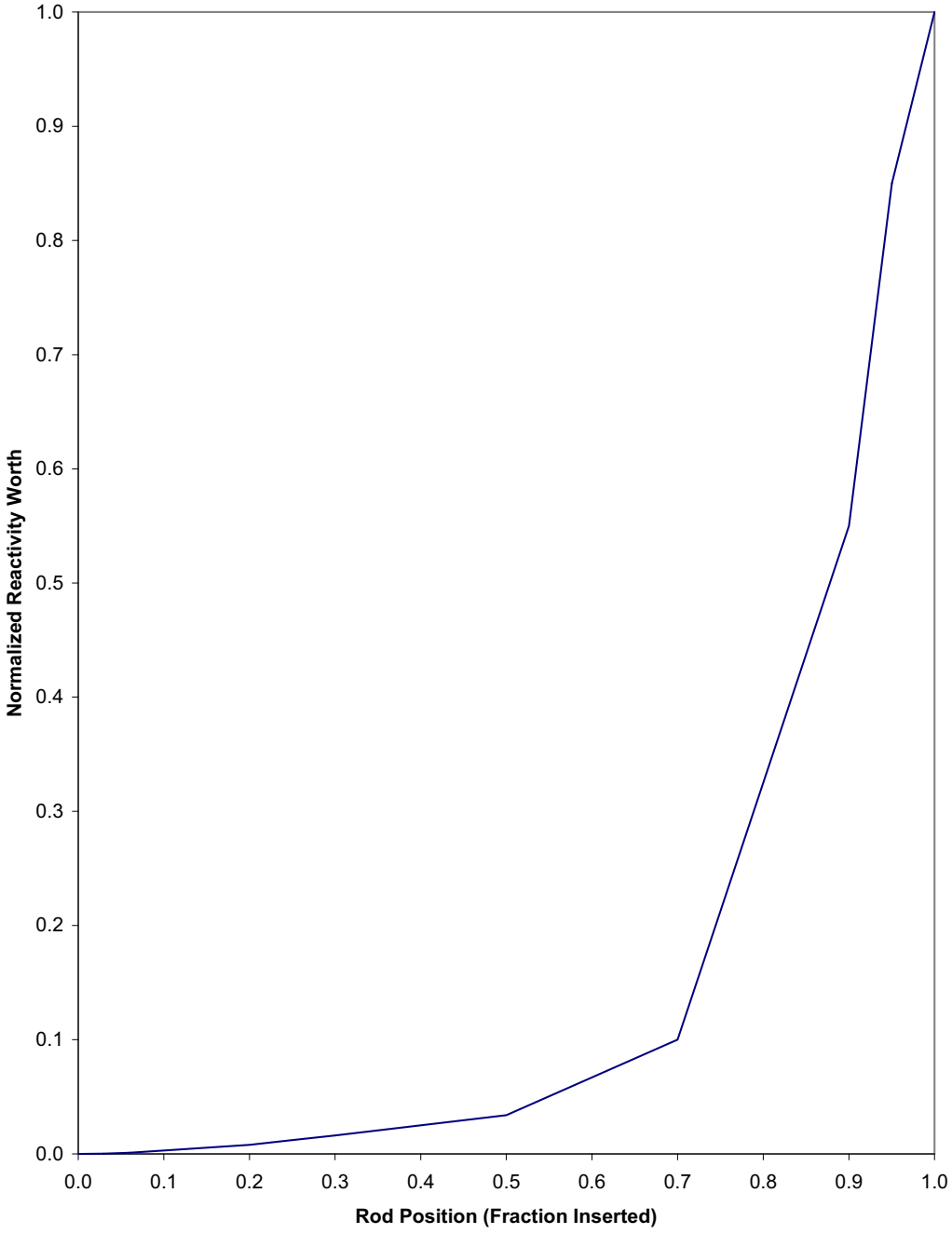

Figure 15.0.5-2
Normalized Rod Worth Versus Position

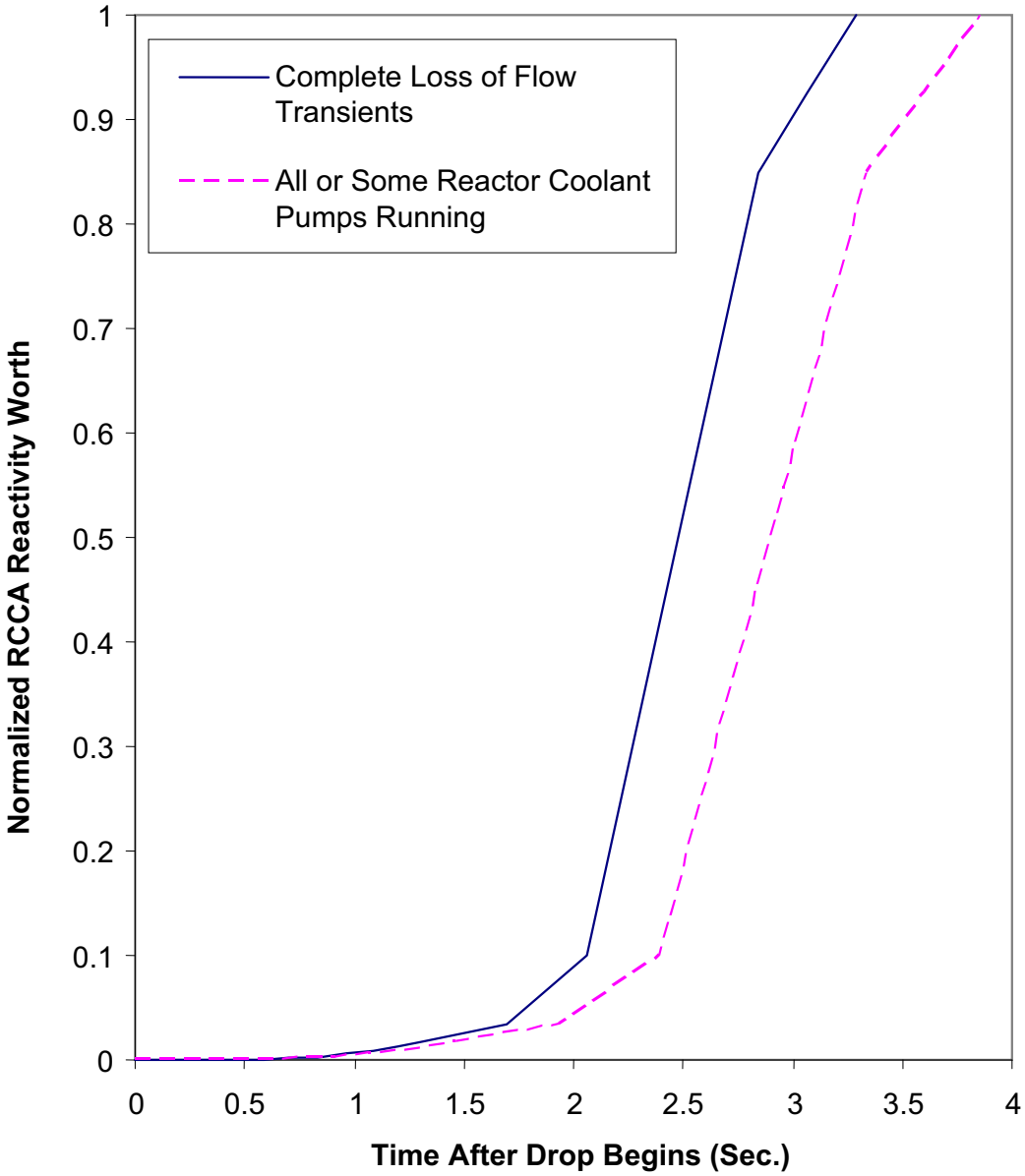

Figure 15.0.5-3
Normalized RCCA Bank
Reactivity Worth Versus Drop Time

15.1 Increase in Heat Removal From the Primary System

A number of events that could result in an increase in heat removal from the reactor coolant system are postulated. Detailed analyses are presented for the events that have been identified as limiting cases.

Discussions of the following reactor coolant system cooldown events are presented in this section:

- Feedwater system malfunctions causing a reduction in feedwater temperature
- Feedwater system malfunctions causing an increase in feedwater flow
- Excessive increase in secondary steam flow
- Inadvertent opening of a steam generator relief or safety valve
- Steam system piping failure
- Inadvertent operation of the passive residual heat removal (PRHR) heat exchanger

The preceding events are Condition II events, with the exception of small steam system piping failures, which are considered to be Condition III, and large steam system piping failure Condition IV events. Subsection 15.0.1 contains a discussion of classifications and applicable criteria.

The accidents in this section are analyzed. The most severe radiological consequences result from the main steam line break accident discussed in Subsection 15.1.5. The radiological consequences are reported only for that limiting case.

15.1.1 Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature

15.1.1.1 Identification of Causes and Accident Description

Reductions in feedwater temperature cause an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and of the reactor coolant system. The overpower/overtemperature protection (power range high neutron flux, power range high positive flux rate, overtemperature ΔT, and overpower ΔT trips) prevents a power increase that could lead to a departure from nucleate boiling ratio (DNBR) less than the safety analysis limit value.

A reduction in feedwater temperature may be caused by a low-pressure heater train or a high-pressure heater train out of service or bypassed. At power, this increased subcooling creates an increased load demand on the reactor coolant system.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in reactor coolant system temperature and a reactivity insertion due to the effects of the negative moderator coefficient of reactivity. However, the rate of energy change is reduced as load and feedwater flows decrease, so the no-load transient is less severe than the full-power case. The net effect on the reactor coolant system due to a reduction in feedwater temperature is similar to the effect of increasing secondary steam flow; that is, the reactor reaches a new equilibrium condition at a power level corresponding to the new steam generator ΔT.

A decrease in normal feedwater temperature is classified as a Condition II event, an incident of moderate frequency.

The protection available to mitigate the consequences of a decrease in feedwater temperature is the same as that for an excessive steam flow increase, as discussed in Subsection 15.0.8 and listed in Table 15.0-6.

15.1.1.2 Analysis of Effects and Consequences

15.1.1.2.1 Method of Analysis

This transient is analyzed by calculating conditions at the feedwater pump inlet following the removal of a low-pressure feedwater heater train from service. These feedwater conditions are then used to recalculate a heat balance through the high-pressure heaters. This heat balance gives the new feedwater conditions at the steam generator inlet.

The following assumptions are made:

- Initial plant power level corresponding to 100-percent nuclear steam supply system thermal output.
- The worst single failure in the pre-heating section of the Main Feedwater System, resulting in the maximum reduction in feedwater temperature, occurs.

Plant characteristics and initial conditions are further discussed in Subsection 15.0.3.

15.1.1.2.2 Results

A fault in the feedwater heaters section of the Feedwater System causes a reduction in feedwater temperature that increases the thermal load on the primary system. The maximum reduction in feedwater enthalpy, due to a single failure in the feedwater system, is 49.98 Btu/lbm. This value is bounded by the enthalpy reduction associated with the Excessive Increase in Secondary Steam Flow event described in Subsection 15.1.3.

15.1.1.3 Conclusions

The decrease in feedwater temperature transient is bounded by the Excessive Increase in Secondary Steam Flow event. Based on the results presented in Subsection 15.1.3, the applicable Standard Review Plan Subsection 15.1.1 evaluation criteria for the decrease in feedwater temperature event are met.

15.1.2 Feedwater System Malfunctions that Result in an Increase in Feedwater Flow

15.1.2.1 Identification of Causes and Accident Description

Addition of excessive feedwater causes an increase in core power by decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and the reactor coolant system. The overpower/overtemperature protection (power range high neutron flux, power range high positive flux rate, overtemperature ΔT, and overpower ΔT trips) prevents a power increase that could lead to a DNBR less than the safety analysis limit value.

An example of excessive feedwater flow is a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. At power, this excess flow causes an increased load demand on the reactor coolant system due to increased subcooling in the steam generator.

With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in reactor coolant system temperature and a reactivity insertion due to the effects of the negative moderator coefficient of reactivity.

Continuous addition of excessive feedwater is prevented by the steam generator High-3 water level signal trip, which closes the feedwater isolation valves and feedwater control valves and trips the turbine, main feedwater pumps, and reactor.

An increase in normal feedwater flow is classified as a Condition II event, fault of moderate frequency.

Plant systems and equipment available to mitigate the effects of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power would be assumed to occur as a consequence of the turbine trip for the excessive feedwater flow case initiated from full-power conditions. However, a consequential loss of ac power would not adversely impact the analysis results, and thus has not been explicitly modeled in the analysis. This conclusion is based on a review of the time sequence of events associated with a consequential loss of ac power in comparison to the reactor shutdown time for the event. The primary effect of the loss of ac power is the coastdown of the reactor coolant pumps (RCPs). The protection and safety monitoring system (PMS) includes a 5-second minimum delay between the reactor trip and the turbine trip. In addition, a 3-second delay between the turbine trip and the loss of offsite ac power is assumed. Considering these delays between the time of the reactor trip and RCP coastdown due to the loss of ac power, it is clear that the plant shutdown sequence will have passed the critical point and the control rods will have been completely inserted before the RCPs begin to coast down. Therefore, the consequential loss of ac power does not adversely impact this analysis, because the plant will be shut down well before the RCPs begin to coast down. As discussed in Subsection 15.0.14, an excessive feedwater flow transient initiated with the plant at no-load conditions need not consider a consequential loss of offsite power. With the plant initially at zero-load, the turbine would not have been connected to the grid, so any subsequent reactor or turbine trip would not disrupt the grid and produce a consequential loss of offsite ac power.

15.1.2.2 Analysis of Effects and Consequences

15.1.2.2.1 Method of Analysis

The excessive heat removal due to a feedwater system malfunction transient is analyzed by using the LOFTRAN computer code (Reference 1). LOFTRAN simulates a multiloop system, neutron kinetics, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures, and power level.

The transient is analyzed to demonstrate plant behavior if excessive feedwater addition occurs because of system malfunction or operator error that allows a feedwater control valve to open fully. The following four cases are analyzed assuming a conservatively large negative moderator temperature coefficient:

- Accidental opening of one feedwater control valve with the reactor just critical at zero load conditions.
- Accidental opening of both feedwater control valves with the reactor just critical at zero load conditions.
- Accidental opening of one feedwater control valve with the reactor in manual and automatic rod control at full power.

- Accidental opening of both feedwater control valves with the reactor in manual and automatic rod control at full power.

The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

- For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction resulting in a step increase to 120 percent of nominal feedwater flow to one steam generator.
- For the full power condition, feedwater temperature is conservatively assumed to be reduced by 34°F from the initial value as a result of the increased flow through the feedwater heaters.
- For the feedwater control valve accident at zero-load condition, a feedwater control valve malfunction occurs, which results in a step increase in flow to one steam generator from 0 to 120 percent of the nominal full-load value for one steam generator.
- For the zero-load condition, feedwater temperature remains constant at a conservatively low value of 179°F.
- No credit is taken for the heat capacity of the reactor coolant system and steam generator thick metal in attenuating the resulting plant cooldown.
- The feedwater flow resulting from a fully open control valve is terminated by a steam generator High-3 level trip signal, which closes feedwater control and isolation valves and trips the main feedwater pumps, the turbine, and the reactor.

Plant characteristics and initial conditions are further discussed in Subsection 15.0.3.

Normal reactor control systems are not required to function. The protection and safety monitoring system may function to trip the reactor because of overpower or high-3 steam generator water level conditions. No single active failure prevents operation of the protection and safety monitoring system. A discussion of anticipated transients without trip considerations is presented in Section 15.8.

15.1.2.2.2 Results

In the case of an accidental full opening of one or both feedwater control valves with the reactor at zero power and the preceding assumptions, the maximum reactivity insertion rate is less than the maximum reactivity insertion rate analyzed in Subsection 15.4.1 for an uncontrolled rod cluster control assembly (RCCA) bank withdrawal from a subcritical or low-power startup condition. Therefore, the results of the analysis are not presented here. If the incident occurs with the unit just critical at no-load, the reactor may be tripped by the power range high neutron flux trip (low setting) set at approximately 25-percent nominal full power, or by the power range high positive flux rate trip.

The full-power case (maximum reactivity feedback coefficients, automatic rod control, multi-loop malfunction) results in the greatest power increase. Assuming the rod control system to be in the manual control mode results in a slightly less severe transient.

When the steam generator water level in the faulted loop reaches the High-3 level setpoint, the feedwater control valves and feedwater isolation valves are automatically closed and the main feedwater pumps are tripped. This prevents continuous addition of the feedwater. In addition, a turbine trip and a reactor trip are initiated.

Transient results show the increase in nuclear power and ΔT associated with the increased thermal load on the reactor (see Figures 15.1.2-1 and 15.1.2-2). A new equilibrium condition is reached and all the plant parameters, except for the SG water level, remain almost constant. The minimum DNBR is predicted to occur before the reactor trip (see Figure 15.1.2-3). The minimum DNBR predicted remains above the safety analysis DNBR limit value; therefore, the DNBR design basis defined in Section 4.4 is met. Following the reactor trip, the plant approaches a stabilized and safe condition; standard plant shutdown procedures may then be followed to further cool down the plant.

Because the power level increases above its nominal value during the excessive feedwater flow incident, the fuel temperature also increases until after reactor trip occurs. The core heat flux lags behind the neutron flux response because of the fuel rod thermal time constant. However, since the peak core heat value does not exceed 118 percent of its nominal value, the peak fuel temperature remains well below the fuel melting temperature.

The transient results show that departure from nucleate boiling (DNB) is not predicted to occur at any time during the excessive feedwater flow incident. Thus, the capability of the primary coolant to remove heat from the fuel rods is not reduced and the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown in Table 15.1.2-1.

15.1.2.3 Conclusions

The results of the analysis show that the minimum DNBR encountered for an excessive feedwater addition at power is above the design limit value. The DNBR design basis is described in Section 4.4.

Additionally, the reactivity insertion rate that occurs at no-load conditions following excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from subcritical condition analysis (see Subsection 15.4.1).

15.1.3 Excessive Increase in Secondary Steam Flow

15.1.3.1 Identification of Causes and Accident Description

An excessive increase in secondary system steam flow (excessive load increase incident) results in a power mismatch between the reactor core power and the steam generator load demand. The plant control system is designed to accommodate a 10-percent step load increase or a 5-percent-per-minute ramp load increase in the range of 25- to 100-percent full power. Any loading rate in excess of these values may cause a reactor trip actuated by the protection and safety monitoring system. Steam flow increases greater than 10 percent are analyzed in Subsections 15.1.4 and 15.1.5.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, turbine bypass to the condenser is controlled by reactor coolant condition signals. A high reactor coolant temperature indicates a need for turbine bypass. A single controller malfunction does not cause turbine bypass. An interlock blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

Protection against an excessive load increase accident is provided by the following protection and safety monitoring system signals:

- Overpower ΔT
- Overtemperature ΔT

- Power range high positive flux rate
- Power range high neutron flux

The possible consequence of this accident (assuming no protective functions) is a departure from nucleate boiling (DNB) with subsequent fuel damage. Note that the accident is typically characterized by an approach of parameter values to the protection setpoints without the setpoints actually being reached. However, the reactor trip setpoints (power range high positive flux rate, power range high neutron flux, overpower ΔT, and overtemperature ΔT) could be reached during the analysis of the excessive load increase event. These protection functions are defeated in the analysis to preclude reactor trip, ensure the most severe DNB condition is reached, and demonstrate that the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

An excessive load increase incident is considered to be a Condition II event, as described in Subsection 15.0.1.

The requirements of GDC 17 of 10 CFR Part 50, Appendix A, which require determination of the effects produced by a possible consequential loss of offsite power during the excessive load increase event are not applicable. As discussed in Subsection 15.0.14, the loss of offsite power need be considered only as a direct consequence of a turbine trip occurring while the plant is operating at power. For the four excessive load increase cases presented, reactor and turbine trips are not predicted to occur. However, even if a reactor trip were to occur, a consequential loss of ac power would not adversely impact the analysis results. This conclusion is based on a review of the time sequence of events associated with a consequential loss of ac power in comparison to the reactor shutdown time for the event. The primary effect of the loss of ac power is the coastdown of the Reactor Coolant Pumps (RCPs). The Protection & Safety Monitoring System (PMS) includes a five second minimum delay between the reactor trip and the turbine trip. In addition, a three second delay between the turbine trip and the loss of offsite ac power is assumed, consistent with Section 15.1.3 of NUREG-1793. Considering these delays between the time of the reactor trip and RCP coastdown due to the loss of ac power, it is clear that the plant shutdown sequence will have passed the critical point and the control rods will have been completely inserted before the RCPs begin to coast down. Therefore, the consequential loss of ac power does not adversely impact this analysis because the plant will be shut down well before the RCPs begin to coast down.

15.1.3.2 Analysis of Effects and Consequences

15.1.3.2.1 Method of Analysis

This accident is primarily analyzed using the LOFTRAN computer code (Reference 1). LOFTRAN simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, steam generator safety valves, and feedwater system. The code computes pertinent plant variables including temperatures, pressures, and power level.

Four cases are analyzed to demonstrate plant behavior following a 10-percent step load increase from rated load. These cases are as follows:

- Reactor control in manual with minimum moderator reactivity feedback
- Reactor control in manual with maximum moderator reactivity feedback
- Reactor control in automatic with minimum moderator reactivity feedback
- Reactor control in automatic with maximum moderator reactivity feedback

For the minimum moderator feedback cases, the core has the least negative moderator temperature coefficient of reactivity; therefore, reductions in coolant temperature have the least impact on core power. For the maximum moderator feedback cases, the moderator temperature coefficient of

reactivity has its highest absolute value. This results in the largest amount of reactivity feedback due to changes in coolant temperature. For all the cases analyzed both with and without automatic rod control, no credit is taken for ΔT trips on overtemperature or overpower in order to demonstrate the inherent transient capability of the plant. Under actual operating conditions, such a trip may occur, after which the plant quickly stabilizes.

A 10-percent step increase in steam demand is assumed, and each case is analyzed without credit being taken for pressurizer heaters. At initial reactor power, reactor coolant system pressure and temperature are assumed to be at their full power values. Uncertainties in initial conditions are included in the limit DNBR as described in WCAP-11397-P-A (Reference 2). Plant characteristics and initial conditions are further discussed in Subsection 15.0.3.

Normal reactor control systems and engineered safety systems are not required to function.

15.1.3.2.2 Results

Figures 15.1.3-1 through 15.1.3-10 show the transient with the reactor in the manual control mode and no reactor trip signals occur. At the beginning of the minimum moderator feedback case, there is a slight power increase and the average core temperature shows a large decrease. This results in a DNBR that increases above its initial value. At the beginning of the maximum moderator feedback manually controlled case, there is a much faster increase in reactor power due to the moderator feedback. A reduction in the DNBR occurs, but the DNBR remains above the design limit (see Section 4.4).

Figures 15.1.3-11 through 15.1.3-20 show the transient assuming the reactor is in the automatic control mode. At the beginning of the maximum moderator feedback case, the core power increases and the coolant average temperature and pressurizer pressure decrease slowly. For this case, no reactor trip signal is generated. For the minimum moderator feedback case, a reactor trip signal setpoint is reached, but conservatively, reactor trip is not credited. At the beginning of the minimum moderator feedback case, the core power increases but the coolant average temperature and pressurizer pressure decrease rapidly. For this case, the transient oscillate and eventually stabilize. For both these cases, the minimum DNBR remains above the design limit (see Section 4.4).

The excessive load increase incident is an overpower transient for which the fuel temperature rises. Reactor trip is not credited in any of the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Because DNB does not occur during the excessive load increase transients, the capability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for the excessive load increase cases with no reactor trip are shown in Table 15.1.2-1.

15.1.3.3 Conclusions

The analysis presented in this subsection demonstrates that for a 10-percent step load increase, the DNBR remains above the design limit. The design basis for DNB is described in Section 4.4. The plant rapidly reaches a stabilized condition following the load increase.

15.1.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

15.1.4.1 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the main steam system are associated with an inadvertent opening of a single steam dump, relief, or safety valve. The analyses performed assuming a rupture of a main steam line are given in Subsection 15.1.5.

The steam release, as a consequence of this accident, results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the reactor coolant system causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity.

The analysis is performed to demonstrate that the following Standard Review Plan Subsection 15.1.4 evaluation criterion is satisfied.

Assuming the most reactive stuck RCCA, with offsite power available, and assuming a single failure in the engineered safety features system, there will be no consequential damage to the fuel or reactor coolant system after reactor trip for a steam release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief, or safety valve. This criterion is met by showing the DNB design basis is not exceeded.

Accidental depressurization of the secondary system is classified as a Condition II event as described in Subsection 15.0.1.2.

The following systems provide the necessary protection against an accidental depressurization of the main steam system (see Subsection 7.2.1.1.2):

- Core makeup tank actuation from one of the following signals:
  - Safeguards (“S”) signal from:
    - Two out of four Low-3 pressurizer pressure signals
    - Two out of four high-2 containment pressure signals
    - Two out of four Low-2 T_{cold} signals in any one loop or
    - Two out of four Low-2 steam line pressure signals in any one loop
  - Two out of four low-2 pressurizer level signals
- The overpower reactor trips (power range high positive flux rate, neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the “S” signal
- Redundant isolation of the main feedwater lines

  Sustained high feedwater flow causes additional cooldown. Therefore, in addition to the normal control action that closes the main feedwater control valves following reactor trip, an “S” signal rapidly closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.
- Redundant isolation of the startup feedwater system

  Sustained high startup feedwater flow causes additional cooldown. Therefore, the Low-2 T_{cold} signal closes the startup feedwater control and isolation valves.
- Trip of the fast-acting main steam line isolation valves (assumed to close in less than 10 seconds) on one of the following signals:

- Two out of four Low-2 steam line pressure signals in any one loop (above permissive P-11)
- Two out of four high negative steam pressure rates in any one loop (below permissive P-11)
- Two out of four Low-2 T_{cold} signals in any one loop, or
- Two out of four high-2 containment pressure signals

Plant systems and equipment available to mitigate the effects of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6.

15.1.4.2 Analysis of Effects and Consequences

15.1.4.2.1 Method of Analysis

The analysis of a secondary system steam release is performed to determine the following:

- The core heat flux and reactor coolant system temperature and pressure resulting from the cooldown, due to the steam release. The LOFTRAN code (References 1 and 6) is used to model the system transient.

- The thermal-hydraulic behavior of the core due to the steam release. A detailed thermal-hydraulic digital computer code, VIPRE-01 (Reference 7), is used to determine if DNB occurs for the core transient conditions computed by the LOFTRAN code.

The following conditions are assumed to exist at the time of a secondary system steam release:

- End-of-life shutdown margin at no-load, equilibrium xenon conditions, and with the most reactive RCCA stuck in its fully withdrawn position. Operation of RCCA mechanical shim and axial offset banks during core burnup is restricted by the insertion limits so that shutdown margin requirements are satisfied.

- A most negative moderator temperature coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature is included. The k_{eff} (considering moderator temperature and density effects) versus temperature corresponding to the negative moderator temperature coefficient used is shown in Figure 15.1.4-1. The core power is calculated as a function of core mass flow, core boron concentration, and core inlet temperature.

- Minimum capability for injection of boric acid solution corresponding to the most restrictive single failure in the passive core cooling system. There are no single failures that prevent core makeup tank injection, however, the analysis models the failure of one core makeup tank discharge valve. Low-concentration boric acid must be swept from the core makeup tank lines downstream of isolation valves before delivery of boric acid (3400 ppm) to the reactor coolant loops. This effect has been accounted for in the analysis.

- The case analyzed models a flow area of 0.2 ft^2, which is based on a steam flow of 520 pounds per second at 1200 psia with offsite power available. This conservatively bounds the maximum capacity of any single steam dump, relief, or safety valve.

- Initial hot shutdown conditions at time zero are assumed because this represents the most conservative initial conditions. Should the reactor be just critical or operating at power at the time of a steam release, the reactor is tripped by the normal overpower protection when power level reaches a trip point. Following a trip at power, the reactor coolant system contains more stored energy than at no-load. This is because the average coolant

temperature is higher than at no-load, and there is appreciable energy stored in the fuel. The additional stored energy is removed via the cooldown caused by the steam release before the no-load conditions of the reactor coolant system temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy is removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis that assumes no-load condition at time zero. However, because the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the reactor coolant system cooldown are less for a steam line release occurring at power:

- In computing the steam flow, the Moody Curve (Reference 3) for f(L/D) = 0 is used.
- Perfect moisture separation occurs in the steam generator.
- Offsite power is available, because this maximizes the cooldown.
- Maximum cold startup feedwater flow is assumed.
- Four reactor coolant pumps are initially operating.
- Manual actuation of the PRHR system at time zero is conservatively assumed to maximize the cooldown.

15.1.4.2.2 Results

The calculated sequence of events for the analyzed case is shown in Table 15.1.2-1. The results presented conservatively indicate the events that would occur assuming a secondary system steam release because it is postulated that the conditions described in Subsection 15.1.4.2.1 exist simultaneously.

Figures 15.1.4-2 through 15.1.4-12 show the transient results for the event. The steam release accounted for in the analysis is bounding compared to the capacity of any single steam dump, relief, or safety valve.

Core makeup tank injection and the associated tripping of the reactor coolant pumps are initiated automatically by the Low-2 T_{cold} "S" signal. Boron solution at 3400 ppm enters the reactor coolant system, providing enough negative reactivity to prevent a significant return to power and core damage. Later in the transient, as the reactor coolant pressure continues to fall, the accumulators actuate and inject boron solution at 2600 ppm.

The transient is conservative with respect to cooldown, because no credit is taken for the energy stored in the system metal other than that of the fuel elements and steam generator tubes, and the PRHR system is assumed to be actuated at time zero. Because the limiting portion of the transient occurs over a period of about 5 minutes, the neglected stored energy would have a significant effect in slowing the cooldown.

The calculated time sequence of events for this accident is listed in Table 15.1.2-1.

15.1.4.3 Margin to Critical Heat Flux

The analysis demonstrates that the DNB design basis, as described in Section 4.4, is met for the inadvertent opening of a steam generator relief or safety valve. As shown in Figure 15.1.4-2, no significant return to power occurs and, therefore, DNB does not occur. The minimum DNBR is conservatively calculated and is above the 95/95 limit.

15.1.4.4 Conclusions

The analysis shows that the criterion stated in this subsection is satisfied. For an inadvertent opening of any single steam dump or a steam generator relief or safety valve, the DNB design basis is met.

15.1.5 Steam System Piping Failure

15.1.5.1 Identification of Causes and Accident Description

The steam release arising from a rupture of a main steam line results in an initial increase in steam flow, which decreases during the accident as the steam pressure falls. The energy removal from the reactor coolant system causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity.

If the most reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam line rupture is a potential problem mainly because of the existing high-power peaking factors, assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by the boric acid solution delivered by the passive core cooling system.

The analysis of a main steam line rupture is performed to demonstrate that the following Standard Review Plan Subsection 15.1.5 evaluation criterion is satisfied.

Assuming the most reactive stuck RCCA with or without offsite power and assuming a single failure in the engineered safety features system, the core cooling capability is maintained. As shown in Subsection 15.1.5.4, radiation doses are within the guidelines.

DNB and possible cladding perforation following a steam pipe rupture are not necessarily unacceptable. The following analysis shows that the DNB design basis is not exceeded for any steamline rupture, assuming the most reactive RCCA is stuck in its fully withdrawn position.

A major steam line rupture is classified as a Condition IV event.

Effects of minor secondary system pipe breaks are bounded by the analysis presented in this section. Minor secondary system pipe breaks are classified as Condition III events, as described in Subsection 15.0.1.3.

The major rupture of a steam line is the most limiting cooldown transient and is analyzed at zero power with no decay heat. Decay heat retards the cooldown and thereby reduces the likelihood that the reactor returns to power. A detailed analysis of this transient with the most limiting break size, a double-ended rupture, is presented here. Certain assumptions used in this analysis are discussed in WCAP-9226-P-A (Reference 4). WCAP-9226-P-A also contains a discussion of the spectrum of break sizes and power levels analyzed.

The steam line rupture at full power conditions is explicitly analyzed and discussed in Subsection 15.1.5.5.

The following functions provide the protection for a steam line rupture (see Subsection 7.2.1.1.2):

- Core makeup tank actuation from one of the following:
  - Safeguards (“S”) signal from:
    - Two out of four Low-3 pressurizer pressure signals
    - Two out of four high-2 containment pressure signals

    - Two out of four Low-2 T_{cold} signals in one loop, or
    - Two out of four Low-2 steam line pressure signals one loop
  - Two out of four low-2 pressurizer level signals

- The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the "S" signal

- Redundant isolation of the main feedwater lines

  Sustained high feedwater flow causes additional cooldown. Therefore, in addition to the normal control action that closes the main feedwater control valves following reactor trip, an "S" signal rapidly closes the feedwater control valves and feedwater isolation valves, and trips the main feedwater pumps.

- Redundant isolation of the startup feedwater system

  Sustained high startup feedwater flow causes additional cooldown. Therefore, the Low-2 T_{cold} signal closes the startup feedwater control and isolation valves.

- Trip of the fast-acting main steam line isolation valves (assumed to close in less than 10 seconds) on one of the following signals:

  – Two out of four high-2 containment pressure

  – Two out of four Low-2 steam line pressure signals in any one loop (above permissive P-11)

  – Two out of four high negative steam pressure rates in any one loop (below permissive P-11)

  – Two out of four Low-2 T_{cold} signals in any one loop, or

  – Two out of four high-2 containment pressure signals.

A fast-acting main steam isolation valve is provided in each steam line. These valves are assumed to fully close within 10 seconds of actuation following a large break in the steam line. For breaks downstream of the main steam line isolation valves, closure of the isolation valves will terminate the blowdown. For any break in any location, no more than one steam generator would experience an uncontrolled blowdown even if one of the main steam line isolation valves fails to close. A description of steam line isolation is included in Chapter 10.

Flow restrictors are installed in the steam generator outlet nozzle, as an integral part of the steam generator. The effective throat area of the nozzles is 1.4 ft^2, which is considerably less than the main steam pipe area; thus, the flow restrictors serve to limit the maximum steam flow for a break at any location.

Design criteria and methods of protection of safety-related equipment from the dynamic effects of postulated piping ruptures are provided in Section 3.6.

15.1.5.2 Analysis of Effects and Consequences

15.1.5.2.1 Method of Analysis

The analysis of the steam pipe rupture is performed to determine the following:

- The core heat flux and reactor coolant system temperature and pressure resulting from the cooldown following the steam line break. The LOFTRAN code (References 1 and 6) is used to model the system transient.

- The thermal-hydraulic behavior of the core following a steam line break. A detailed thermal-hydraulic digital computer code, VIPRE-01 (Reference 7), is used to determine if DNB occurs for the core transient conditions computed by the LOFTRAN code.

The following conditions are assumed to exist at the time of a main steam line break accident:

- End-of-cycle shutdown margin at no-load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position. Operation of RCCA mechanical shim and axial offset banks during core burnup is restricted by the insertion limits so that shutdown margin requirements are satisfied.

- A most negative moderator temperature coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature is included. The k_{eff} (considering moderator temperature and density effects) versus temperature corresponding to the negative moderator temperature coefficient used is shown in Figure 15.1.4-1. The core power is calculated as a function of core mass flow, core boron concentration, and core inlet temperature.

The moderator properties used in the LOFTRAN code for feedback calculations are generated by combining those in the sector nearest the affected steam generator with those associated with the remaining sector. The resultant properties reflect a combination process that accounts for inlet plenum fluid mixing and a conservative weighing of the fluid properties from the coldest core sector.

In verifying the conservatism of this method, the power predictions of the LOFTRAN modeling are confirmed by comparison with detailed core analysis for the limiting conditions of the cases considered. This core analysis conservatively models the hypothetical core configuration (that is, stuck RCCA, non-uniform inlet temperatures, pressure, flow, and boron concentration) and directly evaluates the total reactivity feedback including power, boron, and density redistribution in an integral fashion. The effect of void formation is also included.

Comparison of the results from the detailed core analysis with the LOFTRAN predictions verifies the overall conservatism of the methodology. That is, the specific power, temperature, and flow conditions used to perform the DNB analysis are conservative.

- Minimum capability for injection of boric acid solution corresponding to the most restrictive single failure in the passive core cooling system. The core makeup tanks and the accumulators are the portions of the passive core cooling system used in mitigating a steam line rupture. There are no single failures that prevent core makeup tank injection however, the analysis models the failure of one core makeup tank discharge valve. Low-concentration boric acid must be swept from the core makeup tank lines downstream of isolation valves before delivery of boric acid (3400 ppm) to the reactor coolant loops. This effect has been accounted for in the analysis.

- The maximum overall fuel-to-coolant heat transfer coefficient is used to maximize the rate of cooldown.

- Because the steam generators are provided with integral flow restrictors with a 1.4-ft^2 throat area, any rupture in a steam line with a break area greater than 1.4 ft^2, regardless of location, has the same effect on the primary plant as the 1.4-ft^2 double-ended rupture. The limiting case considered in determining the core power and reactor coolant system transient is the

complete severance of a pipe, with the plant initially at no-load conditions and full reactor coolant flow with offsite power available. The results of this case bound the loss of offsite power case for the following reasons:

– Loss of offsite power results in an immediate reactor coolant pump coastdown at the initiation of the transient. This reduces the severity of the reactor coolant system cooldown by reducing primary-to-secondary heat transfer. The lessening of the cooldown, in turn, reduces the magnitude of the return to power.

– Following its actuation, the core makeup tank provides borated water that injects into the reactor coolant system. Flow from the core makeup tank increases if the reactor coolant pumps have coasted down. Therefore, the analysis performed with offsite power and continued reactor coolant pump operation reduces the rate of boron injection into the core and is conservative.

– The protection system automatically provides a safety-related signal that initiates the coastdown of the reactor coolant pumps in parallel with core makeup tank actuation. Because this reactor coolant pump trip function is actuated early during the steam line break event (right after core makeup tank actuation), there is very little difference in the predicted DNBR between cases with and without offsite power.

– Because of the passive nature of the safety injection system, the loss of offsite power does not delay the actuation of the safety injection system.

- Power peaking factors corresponding to one stuck RCCA are determined at the end of core life. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck RCCA during the return to power phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck RCCA. The power peaking factors depend upon the core power, temperature, pressure, and flow and, therefore, may differ for each case studied.

- The analysis assumes initial hot standby conditions at time zero in order to present a representative case which will yield limiting post-trip DNBR results for this transient. If the reactor is just critical or operating at power at the time of a steam line break, the reactor is tripped by the overpower protection system when power level reaches a trip point.

  Following a trip at power, the reactor coolant system contains more stored energy than at no-load because the average coolant temperature is higher than at no-load, and there is energy stored in the fuel. The additional stored energy reduces the cooldown caused by the steam line break before the no-load conditions of reactor coolant system temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis that assumes a no-load condition at time zero. However, because the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the reactor coolant system cooldown are less for a steam line break occurring at power.

- In computing the steam flow during a steam line break, the Moody Curve (Reference 3) for f(L/D) = 0 is used.

- Perfect moisture separation occurs in the steam generator.

- Maximum cold startup feedwater flow plus nominal 100 percent main feedwater flow is assumed.

- Four reactor coolant pumps are initially operating.
- Manual actuation of the PRHR system at time zero is conservatively assumed in order to maximize the cooldown.

15.1.5.2.2 Results

The calculated sequence of events for the analyzed case is shown in Table 15.1.2-1. The results presented conservatively indicate the events that would occur assuming a steam line rupture because it is postulated that the conditions described in Subsection 15.1.5.2.1 exist simultaneously.

15.1.5.2.3 Core Power and Reactor Coolant System Transient

Figures 15.1.5-1 through 15.1.3-13 show the transient results following a main steam line rupture (complete severance of a pipe) at initial no-load condition.

Offsite power is assumed available so that, initially, full reactor coolant flow exists. During the course of the event, the reactor protection system initiates a trip of the reactor coolant pumps in conjunction with actuation of the core makeup tanks. The transient shown assumes an uncontrolled steam release from only one steam generator. Steam release from more than one steam generator is prevented by automatic trip of the main steam isolation valves in the steam lines by Low-2 steam line pressure signals. Even with the failure of one valve, release is limited to approximately 10 seconds for the other steam generator while the one generator blows down. The main steam isolation valves fully close in less than 10 seconds from receipt of a closure signal.

As shown in Figure 15.1.5-1, the core attains criticality with the RCCAs inserted (with the design shutdown assuming the most reactive RCCA stuck) before boron solution at 3400 ppm (from core makeup tanks) or 2600 ppm (from accumulators) enters the reactor coolant system. A peak core power significantly lower than the nominal full-power value is attained.

The calculation assumes that the boric acid is mixed with and diluted by the water flowing in the reactor coolant system before entering the reactor core. The concentration after mixing depends upon the relative flow rates in the reactor coolant system and from the core makeup tanks or accumulators (or both). The variation of mass flow rate in the reactor coolant system due to water density changes is included in the calculation. The variation of flow rate from the core makeup tanks or accumulators (or both) due to changes in the reactor coolant system pressure and temperature and the pressurizer level is also included. The reactor coolant system and passive injection flow calculations include line losses.

At no time during the analyzed steam line break event does the core makeup tank level approach the setpoint for actuation of the automatic depressurization system. During non-LOCA events, the core makeup tanks remain filled with water. The volume of injection flow leaving the core makeup tank is offset by an equal volume of recirculation flow that enters the core makeup tanks via the reactor coolant system cold leg balance lines.

The PRHR system provides a passive, long-term means of removing the core decay and stored heat by transferring the energy via the PRHR heat exchanger to the in-containment refueling water storage tank (IRWST). The PRHR heat exchanger is normally actuated automatically when the steam generator level falls below the Low-2 steam generator wide range water level. For the main steam line rupture case analyzed, the PRHR exchanger is conservatively actuated at time zero to maximize the cooldown.

15.1.5.2.4 Margin to Critical Heat Flux

The case analyzed conservatively models the expected behavior of the plant during a steam system piping failure. This includes the tripping of the reactor coolant pumps coincident with core makeup tank actuation. A DNB analysis was performed using limiting assumptions that bound those of Subsection 15.1.5.2.1.

Under the low flow (natural circulation) conditions present in the transient, the return to power is severely limited by the large negative feedback due to flow and power. The minimum DNBR is conservatively calculated and remains above the 95/95 limit.

15.1.5.3 Conclusions

DNB and possible cladding perforation are not unacceptable consequences following a steam pipe rupture based on the applicable acceptance criteria. Nevertheless, the preceding analysis shows that no DNB, and therefore no cladding perforation, occurs for the main steam line rupture assuming the most reactive RCCA stuck in its fully withdrawn position.

15.1.5.4 Radiological Consequences

The evaluation of the radiological consequences of a postulated main steam line break outside containment assumes that the reactor has been operating with a limited number of fuel rods containing cladding defects) and that leaking steam generator tubes have resulted in a buildup of activity in the secondary coolant. See Subsection 15.1.5.4.1 and Table 15.1.5-1.

Following the rupture, startup feedwater to the faulted loop is isolated and the steam generator is allowed to steam dry. Any radioiodines carried from the primary coolant into the faulted steam generator via leaking tubes are assumed to be released directly to the environment. It is conservatively assumed that the reactor is cooled by steaming from the intact loop.

15.1.5.4.1 Source Term

The only significant radionuclide releases due to the main steam line break are the iodines and alkali metals that become airborne and are released to the environment as a result of the accident. Noble gases are also released to the environment. Their impact is secondary because any noble gases entering the secondary side during normal operation are rapidly released to the environment.

The analysis considers two different reactor coolant iodine source terms, both of which consider the iodine spiking phenomenon. In one case, the initial iodine concentrations are assumed to be those associated with equilibrium operating limits for primary coolant iodine activity. The iodine spike is assumed to be initiated by the accident with the spike causing an increasing level of iodine in the reactor coolant.

The second case assumes that the iodine spike occurs prior to the accident and that the maximum resulting reactor coolant iodine concentration exists at the time the accident occurs.

The reactor coolant noble gas concentrations are assumed to be those associated with equilibrium operating limits for primary coolant noble gas activity. The reactor coolant alkali metal concentrations are based on those associated with the design basis fuel defect level.

The secondary coolant is assumed to have an iodine source term of 0.01 μCi/g dose equivalent I-131. This is 1 percent of the maximum primary coolant activity at equilibrium operating conditions. The secondary coolant alkali metal concentration is also assumed to be 1 percent of the primary concentration.

15.1.5.4.2 Release Pathways

There are three components to the accident releases:

- The secondary coolant in the steam generator of the faulted loop is assumed to be released out the break as steam. Any iodine and alkali metal activity contained in the coolant is assumed to be released.

- The reactor coolant leaking into the steam generator of the faulted loop is assumed to be released to the environment without any credit for partitioning or plateout onto the interior of the steam generator.

- The reactor coolant leaking into the steam generator of the intact loop would mix with the secondary coolant and thus raise the activity concentrations in the secondary water. While the steam release from the intact loop would have partitioning of non-gaseous activity, this analysis conservatively assumes that any activity entering the secondary side is released.

Credit is taken for decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion by ground deposition during transport offsite.

15.1.5.4.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.1.5.4.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.1.5-1.

15.1.5.4.5 Identification of Conservatisms

The assumptions and parameters used in the analysis contain a number of significant conservatisms:

- The reactor coolant activities are based on conservative assumptions (see Table 15.1.5-1). The activities based on the expected fuel defect level are far less than this (see Section 11.1).

- The assumed leakage of 150 gallons of reactor coolant per day into each steam generator is conservative. The leakage is expected to be a small fraction of this during normal operation.

- The conservatively selected meteorological conditions are present only rarely.

15.1.5.4.6 Doses

Using the assumptions from Table 15.1.5-1, the calculated total effective dose equivalent (TEDE) doses for the case with accident-initiated iodine spike are determined to be less than 0.6 rem at the site boundary for the limiting 2-hour interval (4.8 to 6.8 hours) and 1.1 rem at the low population zone outer boundary. These doses are small fractions of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. A “small fraction” is defined, consistent with the Standard Review Plan, as being 10 percent or less. The TEDE doses for the case with pre-existing iodine spike are determined to be less than 0.5 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and 0.4 rem at the low population zone outer boundary. These doses are within the dose guidelines of 10 CFR Part 50.34.

At the time the main steam line break occurs, the potential exists for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. The 30-day contribution to the dose at the site boundary and low population zone boundary is less than 0.01 rem TEDE. When this is added to the dose calculated for the main steam line break, the resulting total dose remains less than the values reported above.

15.1.5.5 Steam System Piping Failure at Full Power

15.1.5.5.1 Identification of Causes and Accident Description

A rupture in the main steam system piping from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the reactor coolant system via the steam generators. This results in a reduction in reactor coolant system temperature and pressure. In the presence of a strong negative moderator temperature coefficient, typical of end-of-life conditions, the colder core inlet coolant temperature causes the core power to increase from its initial level due to the positive reactivity insertion. The power approaches a level equal to the total steam flow.

Depending upon the break size, the reactor may be tripped on any of the following trip signals to provide the necessary protection against the rupture of a main steam line.

- Overpower ΔT
- Low-2 pressurizer pressure
- Safeguards (“S”) actuation signal
  - Low-2 steam line pressure
  - Low-2 cold leg temperature

The steam system piping failure accident analysis described in Subsection 15.1.5 is performed assuming a hot zero power initial condition with the control rods inserted in the core, except for the most reactive rod in the fully withdrawn position, out of the core. That condition could occur while the reactor is at hot shutdown at the minimum required shutdown margin or after the plant has been tripped manually or by the reactor protection system following a steam line break from an at-power condition. For an at-power break, the analysis of Subsection 15.1.5 represents the limiting condition with respect to core protection for the time period following reactor trip. The purpose of this section is to describe the analysis of a steam system piping failure occurring from an at-power initial condition, to demonstrate that core protection is maintained prior to and immediately following reactor trip. The analysis initiated from hot full power does not extend into the portion of the transient where the PRHR or CMTs are actuated.

Depending on the size of the break, this event is classified as either an ANS Condition III or IV event.

15.1.5.5.2 Analysis of Effects and Consequences

15.1.5.5.2.1 Method of Analysis

The analysis of the steam line rupture is performed in the following stages:

1. The LOFTRAN code (References 1 and 6) is used to calculate the nuclear power, core heat flux, and reactor coolant system temperature and pressure transients resulting from the cooldown following the steam line break.

2. The core radial and axial peaking factors are determined using the thermal hydraulic conditions from LOFTRAN as input to the nuclear core models. A detailed thermal-hydraulic code, VIPRE-01 (Reference 7), is then used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the Revised Thermal Design Procedure (RTDP) as described in WCAP-11397-P-A (Reference 2).

The following assumptions are made in the transient analysis:

1. Initial Conditions — RTDP DNB methodology was used, therefore the uncertainties in the initial conditions are included in the DNBR limits; thus, nominal full power values are used in LOFTRAN. The RCS Minimum Measured Flow is used.

2. Break Size — A spectrum of break sizes was analyzed. Small breaks do not result in a reactor trip. Intermediate breaks result in a reactor trip on overpower ΔT. Larger break sizes result in a reactor trip on Low-2 steam line pressure safeguards actuation.

3. Break flow — In computing the steam flow during a steam line break, the Moody curve (Reference 3) for fL/D = 0 is used.

4. Reactivity Coefficients — The analysis assumes maximum moderator reactivity feedback and minimum Doppler power feedback to maximize the power increase following the break.

5. Protection System — The protection system features that mitigate the effects of a steam line beak are described in Subsection 15.1.5. This analysis only considers the initial phase of the transient initiated from an at-power condition. Protection in this phase of the transient is provided by reactor trip, if necessary (specifically overpower ΔT, and Low-2 steam line pressure safeguards actuation).

6. Control Systems — Control systems are not credited in the accident analysis unless their function would result in more severe consequences. The only control system that is assumed to function during the hot full power steam line break event is the main feedwater system. For this event, the feedwater flow is assumed to match the steam flow.

As required in GDC 17 of 10 CFR Part 50, Appendix A, anticipated operational occurrences and postulated accidents are analyzed assuming a loss of offsite ac power. The loss of offsite power is not considered as a single failure, and the analysis is performed without changing the event category. In the analyses, the loss of offsite ac power is considered to be a potential consequence of an event due to disruption of the grid following a turbine trip during the event.

For those events where offsite ac power is lost, an appropriate time delay between turbine trip and the postulated loss of offsite ac power is assumed in the analyses. A time delay of 3 seconds is used. This time delay is based on the inherent stability of the offsite power grid. Following the time delay, the effect of the loss of offsite ac power on plant auxiliary equipment — such as reactor coolant pumps, main feedwater pumps, condenser, startup feedwater pumps, and RCCAs — is considered in the analyses. Turbine trip occurs 5 seconds following a reactor trip condition being reached. This delay is part of the reactor trip system and was chosen to allow the reactor to be tripped and have the rods inserted to the bottom of the core before a turbine trip signal. As a result, RCP coastdown would be delayed an additional 5 seconds, the control rods would be fully inserted and there would be no adverse DNB impact from the resulting core flow reduction. Thus, there is no need for an explicit analysis of this event with loss of offsite ac power.

15.1.5.5.3 Results

A spectrum of steam line break sizes was analyzed from 0.1 ft^2 to 1.4 ft^2. The results show that for small break sizes up to and including 0.35 ft^2, a reactor trip is not generated. In this case, the event is similar to an excessive load increase event; the core reaches a new equilibrium condition at a higher power equivalent to the increased steam release. For break sizes from 0.36 ft^2 up to and including 0.87 ft^2, the reactor trips on overpower ΔT. For break sizes from 0.88 ft^2 to 1.4 ft^2 the reactor trips on the Low-2 steam line pressure safeguards actuation signal.

The limiting case for demonstrating DNB and kW/ft protection is the 0.87 ft^2 break, the largest break size that results in a trip on overpower ΔT. The time sequence of events for this case is shown on Table 15.1.5.5-1. Figures 15.1.5.5-1 through 15.1.5.5-7 show the transient response.

15.1.5.5.4 Conclusions

The analysis shows that the DNB and fuel centerline melt (kW/ft) design bases are met for the limiting case. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily precluded by the criteria, the above analysis, in fact, shows that the minimum DNBR remains above the limit value for any rupture occurring from an at-power condition prior to and immediately following a reactor trip.

15.1.6 Inadvertent Operation of the PRHR Heat Exchanger

15.1.6.1 Identification of Causes and Accident Description

The inadvertent actuation of the PRHR heat exchanger causes an injection of relatively cold water into the reactor coolant system. This produces a reactivity insertion in the presence of a negative moderator temperature coefficient. To prevent this reactivity increase from causing reactor power increase, a reactor trip is initiated when either PRHR discharge valve is not closed.

The inadvertent actuation of the PRHR heat exchanger could be caused by operator error or a false actuation signal, or by malfunction of a discharge valve. Actuation of the PRHR heat exchanger involves opening one of the isolation valves, which establishes a flow path from one reactor coolant system hot leg, through the PRHR heat exchanger, and back into its associated steam generator cold leg plenum.

The PRHR heat exchanger is located above the core to promote natural circulation flow when the reactor coolant pumps are not operating. With the reactor coolant pumps in operation, flow through the PRHR heat exchanger is enhanced. The heat sink for the PRHR heat exchanger is provided by the IRWST, in which the PRHR heat exchanger is submerged. Because the fluid in the heat exchanger is in thermal equilibrium with water in the tank, the initial flow out of the PRHR heat exchanger is significantly colder than the reactor coolant system fluid. Following this initial insurge, the reduction in cold leg temperature is limited by the cooling capability of the PRHR heat exchanger. Because the PRHR heat exchanger is connected to only one reactor coolant system loop, the cooldown resulting from its actuation is asymmetric with respect to the core.

The response of the plant to an inadvertent PRHR heat exchanger actuation with the plant at no-load conditions is bounded by the analyses performed for the inadvertent opening of a steam generator relief or safety valve event (Subsection 15.1.4) and the steam system piping failure event (Subsection 15.1.5). Both of these events are conservatively analyzed assuming PRHR heat exchanger actuation coincident with the steam line depressurization. Therefore, only the response of the plant to an inadvertent PRHR initiation with the core at power is considered.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, the effects of a possible consequential loss of ac power during an inadvertent PRHR heat exchanger actuation event have been evaluated to not adversely impact the analysis results. This conclusion is based on a review of the time sequence associated with a consequential loss of ac power in comparison to the reactor shutdown time for an inadvertent PRHR heat exchanger actuation event. The primary effect of the loss of ac power is to cause the Reactor Coolant Pumps (RCPs) to coast down. The PMS system includes a 5-second minimum delay between the reactor trip and the turbine trip. In addition, a 3-second delay between the turbine trip and the loss of offsite ac power is assumed, consistent with Section 15.1.3 of NUREG-1793. Considering these delays between the time of the reactor trip and RCP coastdown due to the loss of ac power, it is clear that the plant shutdown sequence will have passed the critical point and the control rods will have been completely inserted before the RCPs begin to coast down. Therefore, the consequential loss of ac power does not adversely impact this inadvertent PRHR heat exchanger actuation analysis because the plant will be shut down well before the RCPs begin to coast down.

The inadvertent actuation of the PRHR heat exchanger event is a Condition II event, a fault of moderate frequency. Plant systems and equipment available to mitigate the effects of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6. The following reactor protection system functions are available to provide protection in the event of an inadvertent PRHR heat exchanger actuation:

- PRHR discharge valve not closed
- Overpower/overtemperature reactor trips (neutron flux and ΔT)
- Two out of four Low-3 pressurizer pressure signals

  Due to the potential consequences as a result of the reactivity excursion, a reactor trip has been designed so that upon an inadvertent PRHR actuation, a reactor trip will occur. This reactor trip is generated when either of the discharge valves is not closed. This ensures that the reactor will be tripped prior to a power increase due to the cold water injection.

15.1.6.2 Analysis of Effects and Consequences

Since a reactor trip is initiated as soon as the PRHR discharge valves are not fully closed, this event is essentially a reactor trip from the initial condition and requires no separate transient analysis. Table 15.1.2-1 shows the sequence of events for the inadvertent PRHR heat exchanger actuation.

15.1.6.3 Conclusions

Inadvertent actuation of the PRHR does not result in violation of the core thermal design limits (DNB and linear power generation) or RCS overpressure.

15.1.7 Combined License Information

This section contained no requirement for additional information.

15.1.8 References

1. Burnett, T. W. T., et al., “LOFTRAN Code Description,” WCAP-7907-P-A (Proprietary), and WCAP-7907-A (Nonproprietary), April 1984.

2. Friedland, A. J., and Ray, S., “Revised Thermal Design Procedure,” WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Nonproprietary), April 1989.

3. Moody, F. S., “Transactions of the ASME, Journal of Heat Transfer,” Figure 3, page 134, February 1965.

4. Wood, D. C. and Hollingsworth, S. D., “Reactor Core Response to Excessive Secondary Steam Releases,” WCAP-9226-P-A, Revision 1 (Proprietary) and WCAP-9227 Revision 1 (Nonproprietary), Approved February 1998.

5. Not used.

6. “AP1000 Code Applicability Report,” WCAP-15644-P Revision 2 (Proprietary) and WCAP-15644-NP, (Nonproprietary), March 2004.

7. Sung, Y. X., Schueren, P., and Meliksetian, A., “VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis,” WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), October 1999.

Table 15.1.2-1 (Sheet 1 of 2)
Time Sequence of Events for Incidents That Result in an Increase in Heat Removal From the Primary System

Accident	Event	Time (seconds)
Excessive increase in secondary steam flow		
– Manual reactor control (minimum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	200.0
– Manual reactor control (maximum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	170.0
– Automatic reactor control (minimum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	400.0*
– Automatic reactor control (maximum moderator feedback)	10-percent step load increase	0.0
	Equilibrium conditions reached (approximate time only)	70.0
Feedwater system malfunctions that result in an increase in feedwater flow (full power)	Both main feedwater control valves fail fully open	0.0
	Minimum DNBR occurs	139.4
	Turbine trip/feedwater isolation and reactor trip on High-3 steam generator level setpoint reached	243.8
	Rod motion begins	245.8
	Turbine trip occurs	250.8
	Feedwater isolation occurs	255.8
Inadvertent operation of the PRHR	PRHR discharge valves go fully open	0.0
	Reactor trip setpoint reached	0.0
	Rod motion begins	1.25
	Rods fully inserted	3.95

* Although oscillation in the transients occurs, the nuclear power and DNBR stabilize after 400 seconds.

Table 15.1.2-1 (Sheet 2 of 2)
Time Sequence of Events for Incidents That
Result in an Increase in Heat Removal From the Primary System

Accident	Event	Time (seconds)
Inadvertent opening of a steam generator relief or safety valve	Inadvertent opening of one main steam safety or relief valve	0.0
	"S" actuation signal on safeguards Low-2 T_{cold}	119.0
	Core makeup tank actuation	136.0
	Boron reaches core	156.2
Steam system piping failure	Steam line ruptures	0.0
	"S" actuation signal on safeguards Low-2 steam line pressure	1.4
	Boron reaches core	30.6
	Pressurizer and surge line empty	50.4
	Criticality attained	55.2

Table 15.1.5-1
Parameters Used in Evaluating the Radiological Consequences of a Main Steam Line Break

Reactor coolant iodine activity	
– Accident-initiated spike	Initial activity equal to the equilibrium operating limit for reactor coolant activity of 1.0 μCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 500 (see Appendix 15A). Duration of spike is 5 hours.
– Pre-accident spike	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 μCi/g of dose equivalent I-131 (see Appendix 15A)
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 μCi/g dose equivalent Xe-133
Reactor coolant alkali metal activity	Based on design basis activity (see Table 15A-9)
Secondary coolant initial iodine and alkali metal activity	1% of reactor coolant concentrations at maximum equilibrium conditions
Duration of accident (hr)	72
Atmospheric dispersion (χ/Q) factors	See Table 15A-5 in Appendix 15A
Steam generator in faulted loop	
– Initial water mass (lb)	3.32 E+05
– Primary to secondary leak rate (lb/hr)	52.25[(a)]
– Iodine partition coefficient	1.0
– Steam released (lb)	
0 - 2 hr	3.321 E+05
2 - 72 hr	3.66 E+03
Steam generator in intact loop	
– Primary to secondary leak rate (lb/hr)	52.25[(a)]
– Iodine partition coefficient	1.0
– Steam released (lb)	
0 - 2 hr	3.321 E+05
2 - 72 hr	3.66 E+03
Nuclide data	See Table 15A-4

Note:
a. Equivalent to 150 gpd cooled liquid at 62.4 lb/ft^3.

Table 15.1.5.5-1
Time Sequence of Events for Steam System Piping Failure at Full Power — 0.87ft^2 Break Size

Event	Time (seconds)
Steam line rupture	0.0
OPΔT reactor trip setpoint reached	12.9
Rods begin to drop	13.9
Minimum DNBR occurs	14.9
Maximum core heat flux occurs	14.9

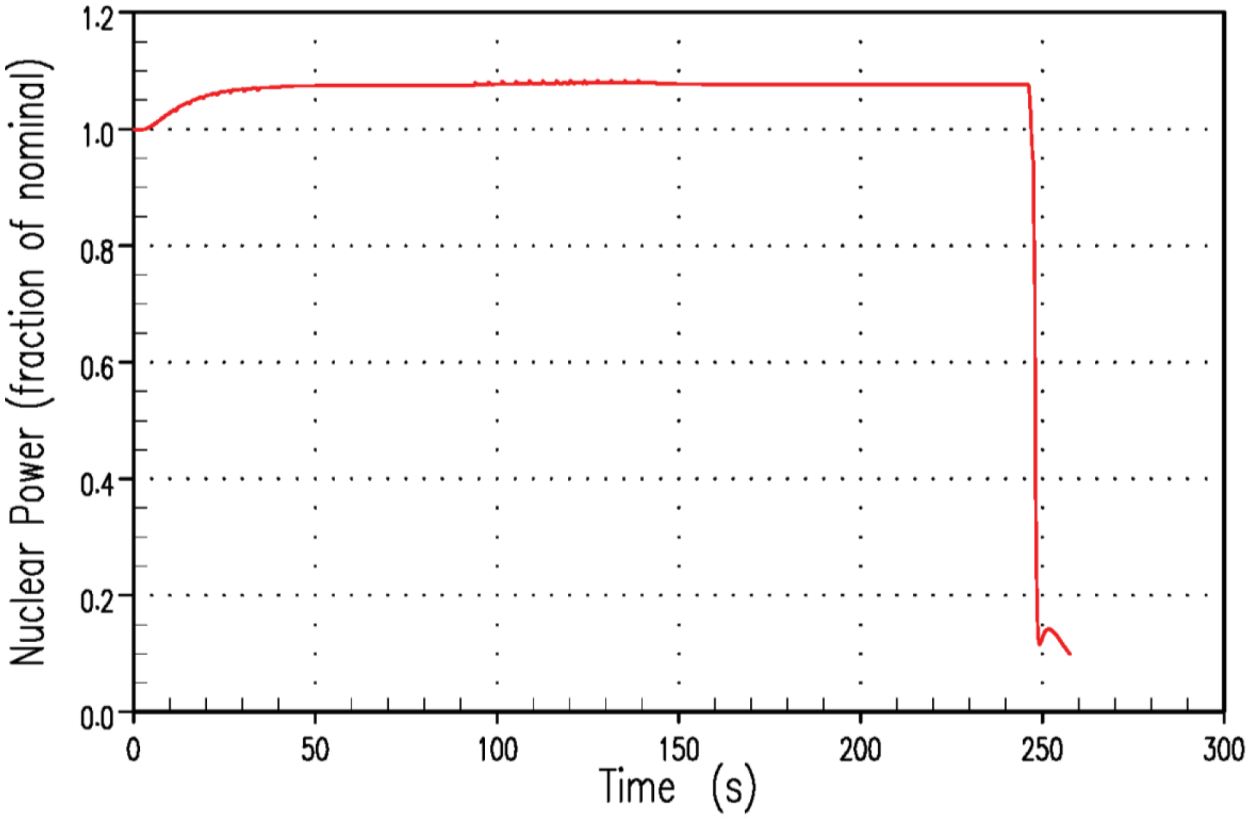

Figure 15.1.2-1
Feedwater Control Valve Malfunction Nuclear Power

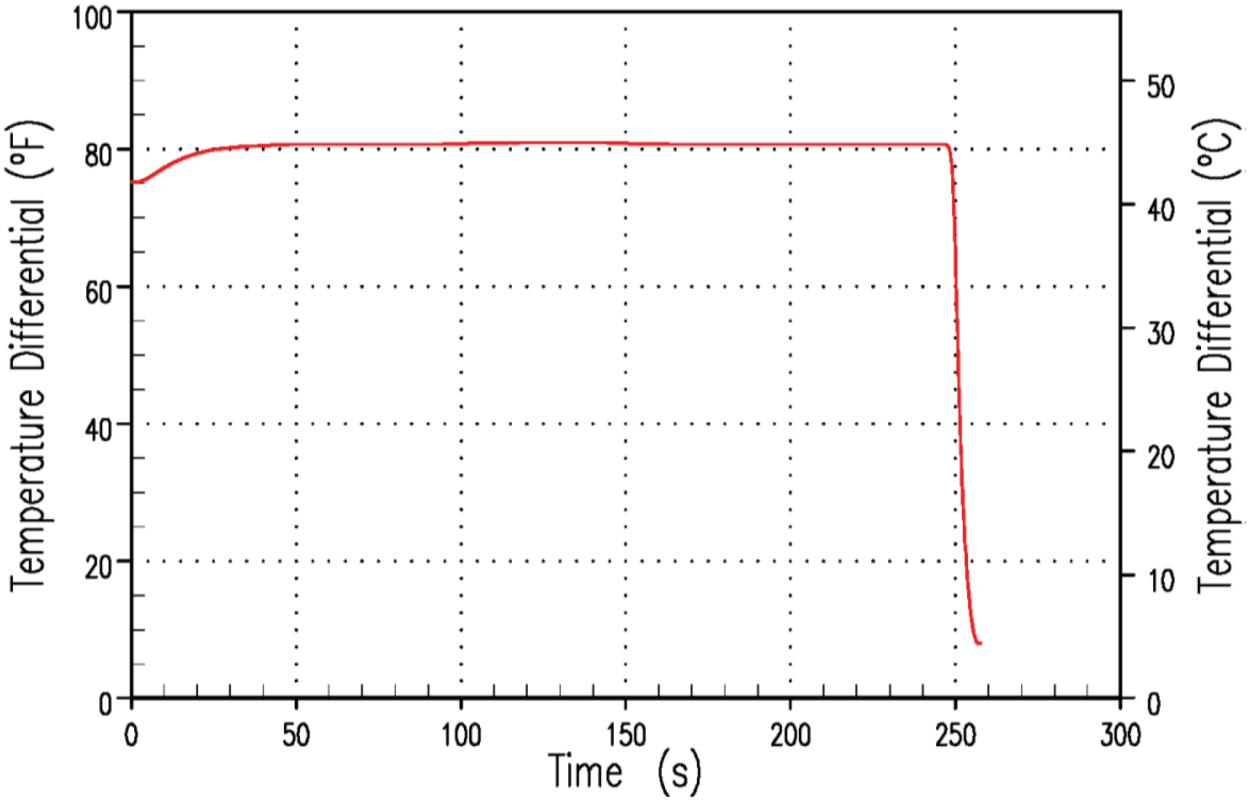

Figure 15.1.2-2
Feedwater Control Valve Malfunction Loop ΔT

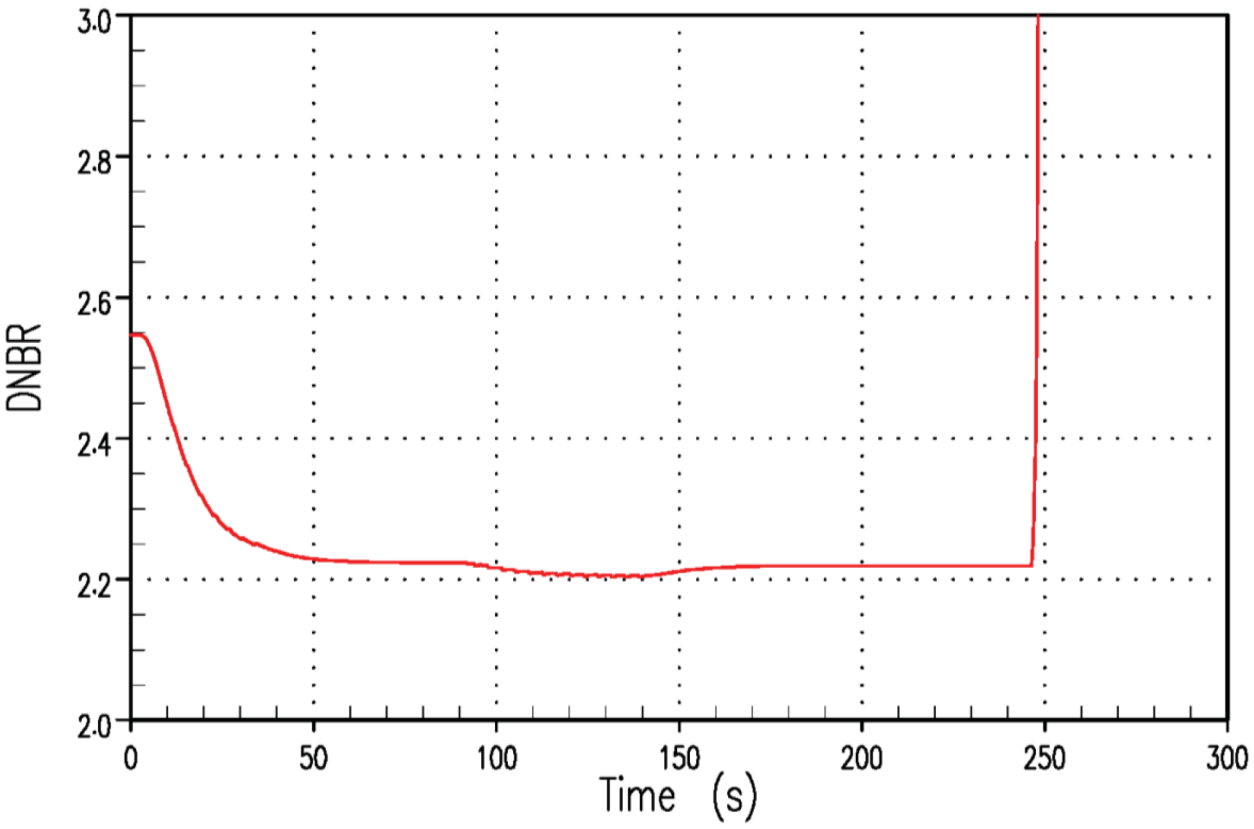

Figure 15.1.2-3
Feedwater Control Valve Malfunction DNBR

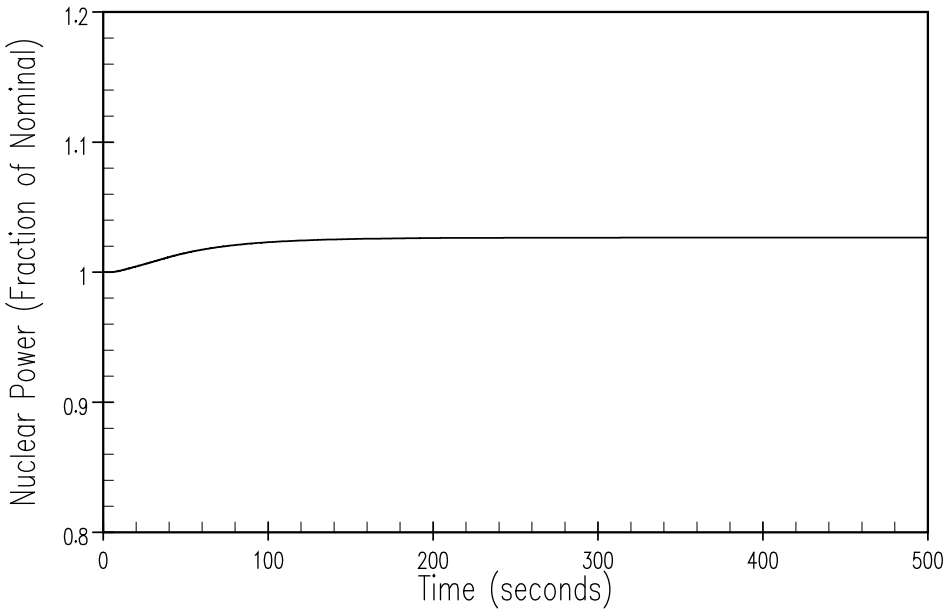

Figure 15.1.3-1
Nuclear Power Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

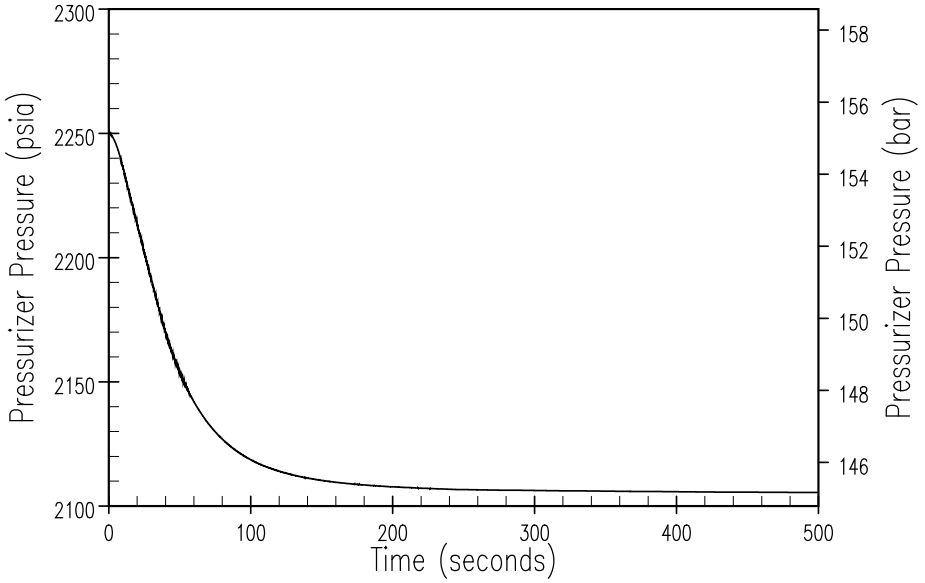

Figure 15.1.3-2
Pressurizer Pressure Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

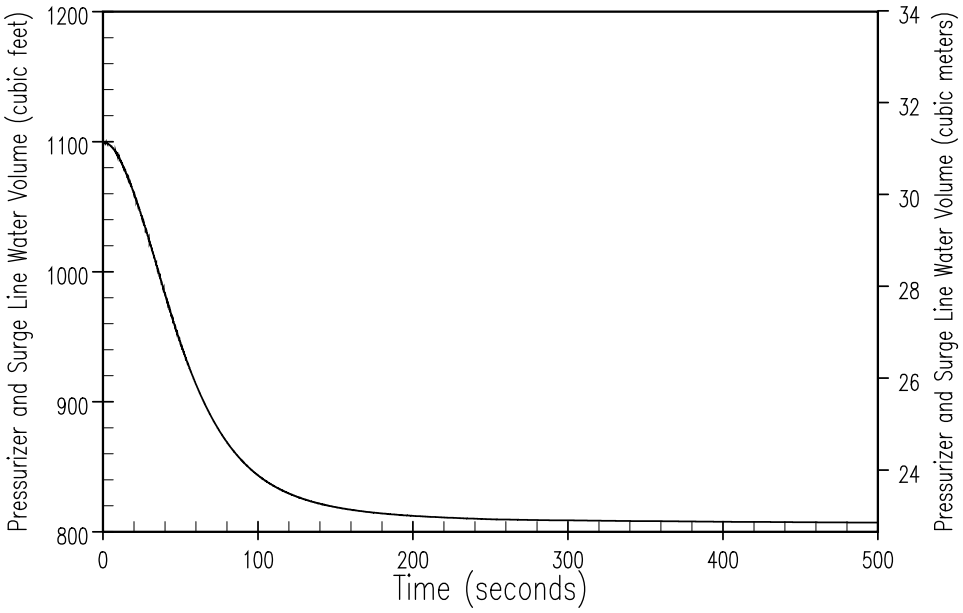

Figure 15.1.3-3
Pressurizer Water Volume Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

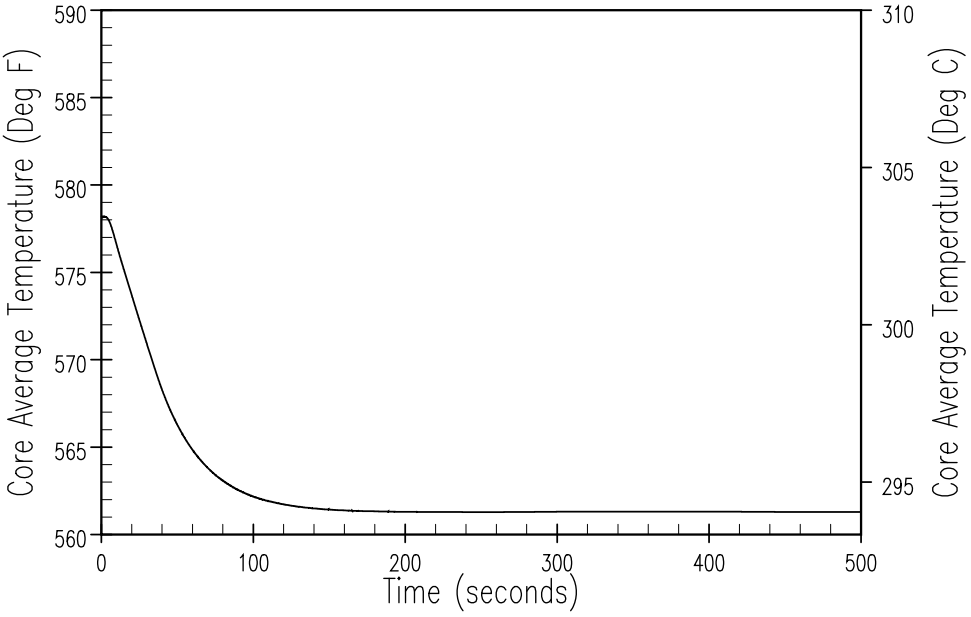

Figure 15.1.3-4
Core Average Temperature Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

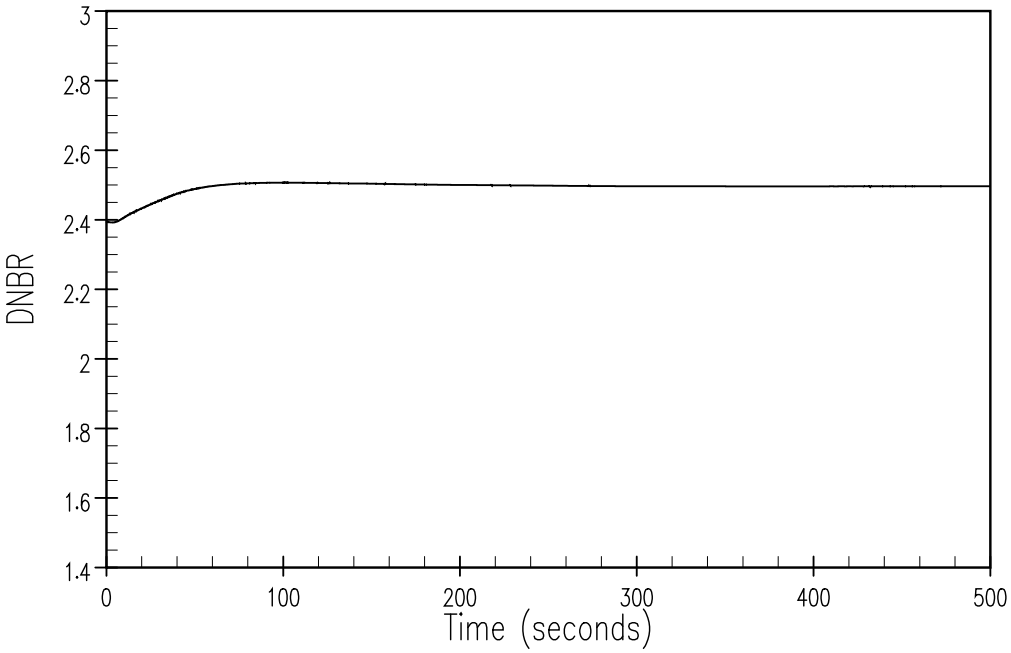

Figure 15.1.3-5
DNBR Versus Time for 10-percent Step Load Increase, Manual Control and Minimum Moderator Feedback

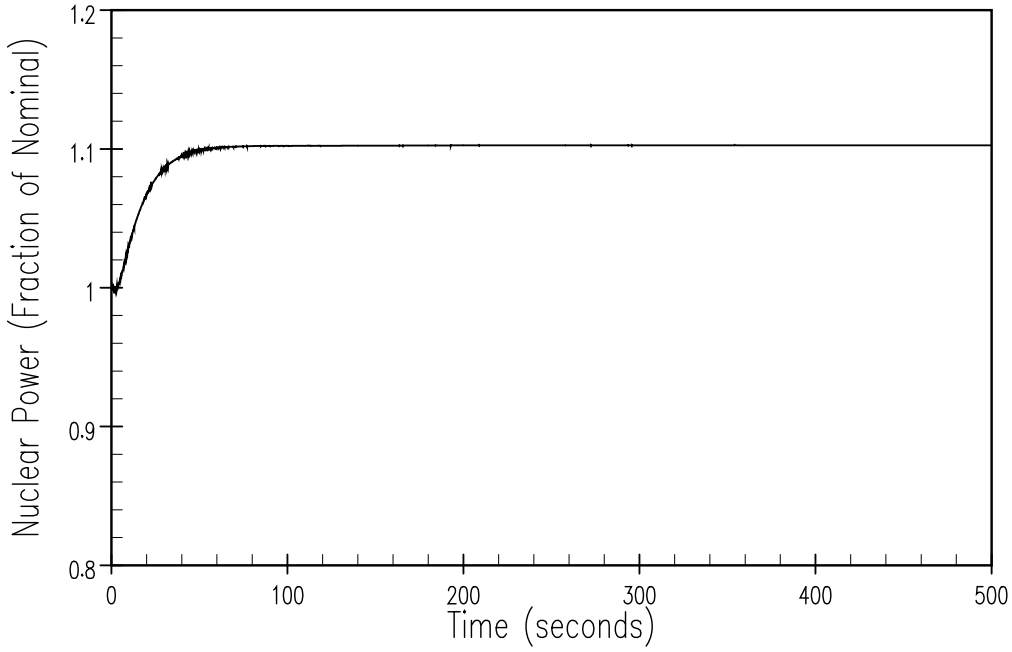

Figure 15.1.3-6
Nuclear Power Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

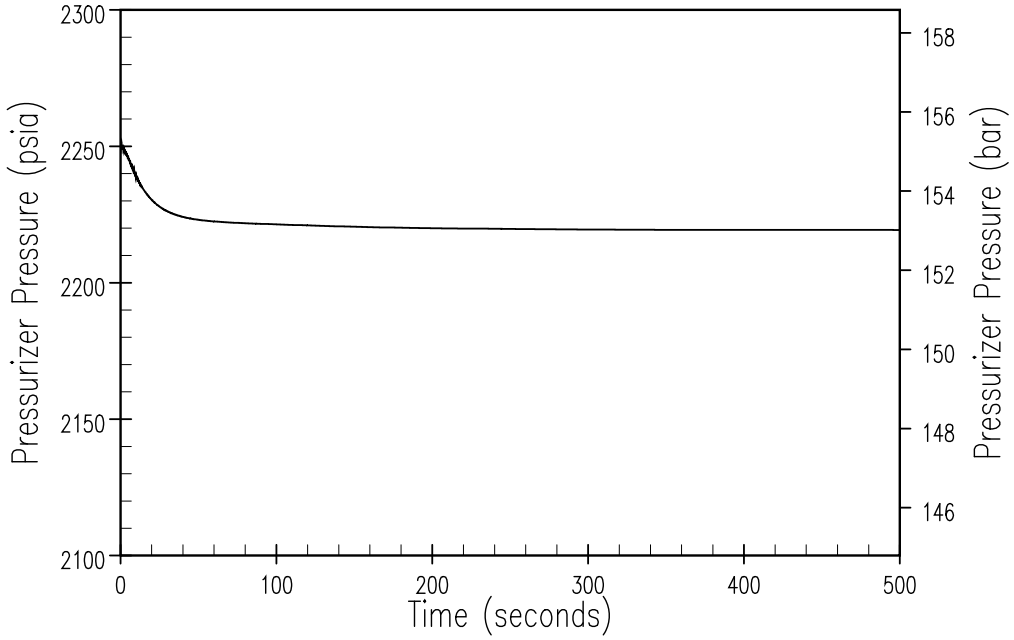

Figure 15.1.3-7
Pressurizer Pressure Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

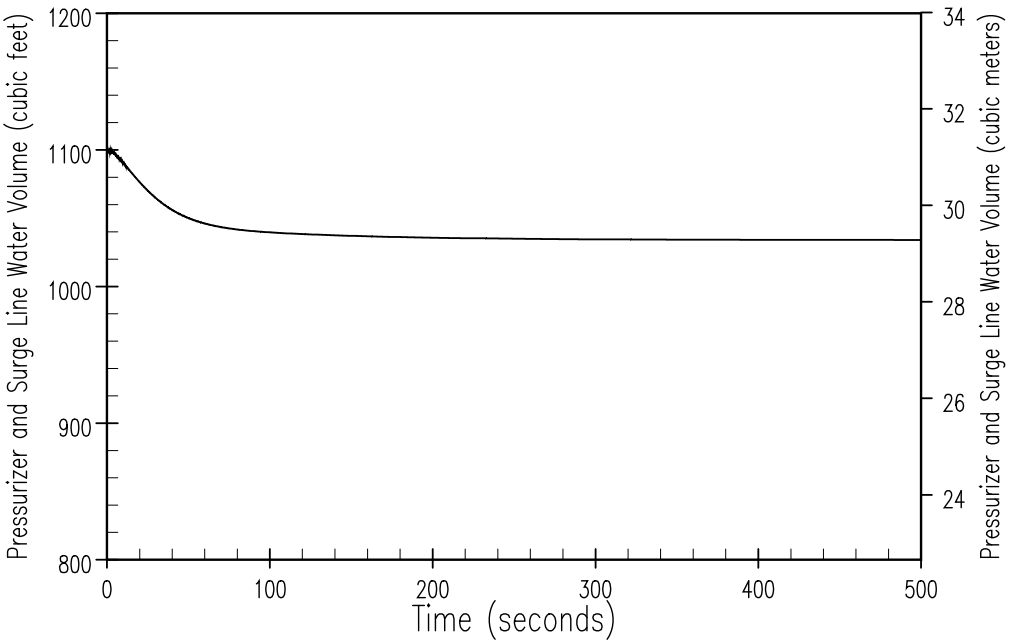

Figure 15.1.3-8
Pressurizer Water Volume Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

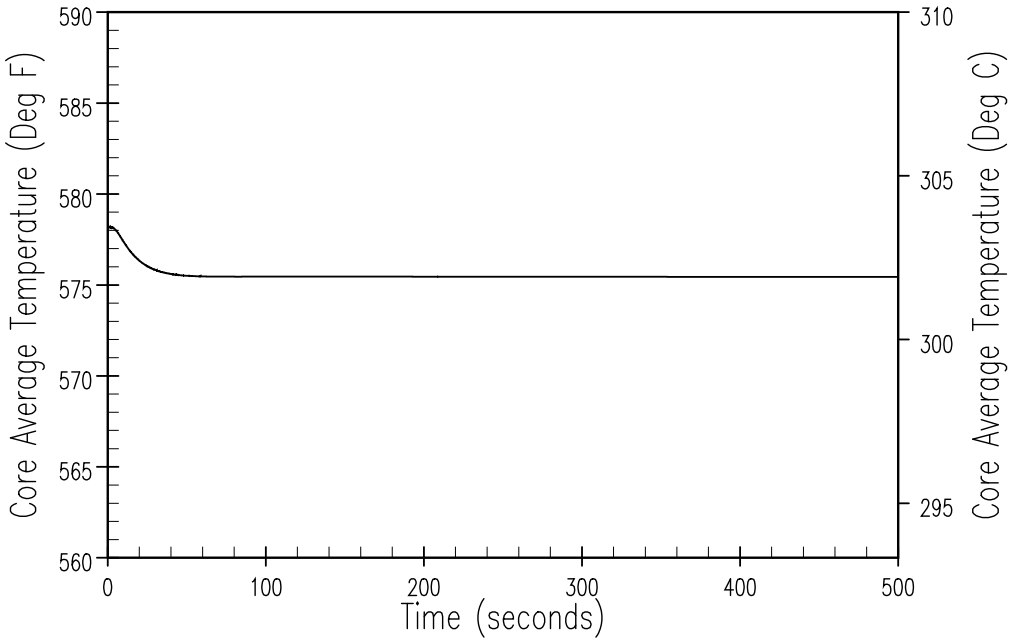

Figure 15.1.3-9
Core Average Temperature Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

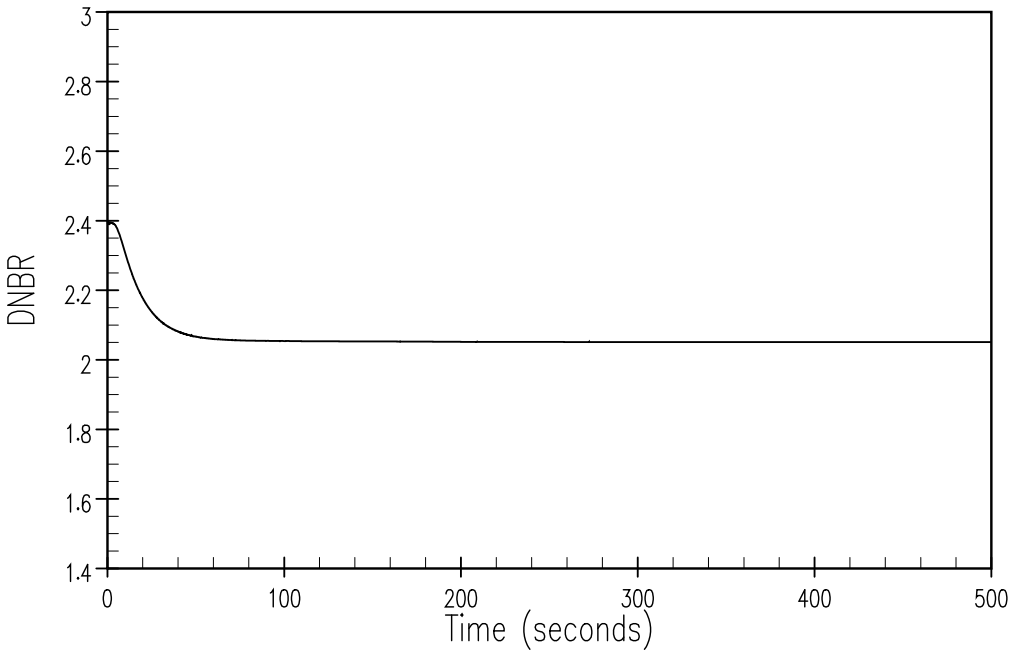

Figure 15.1.3-10
DNBR Versus Time for 10-percent Step Load Increase, Manual Control and Maximum Moderator Feedback

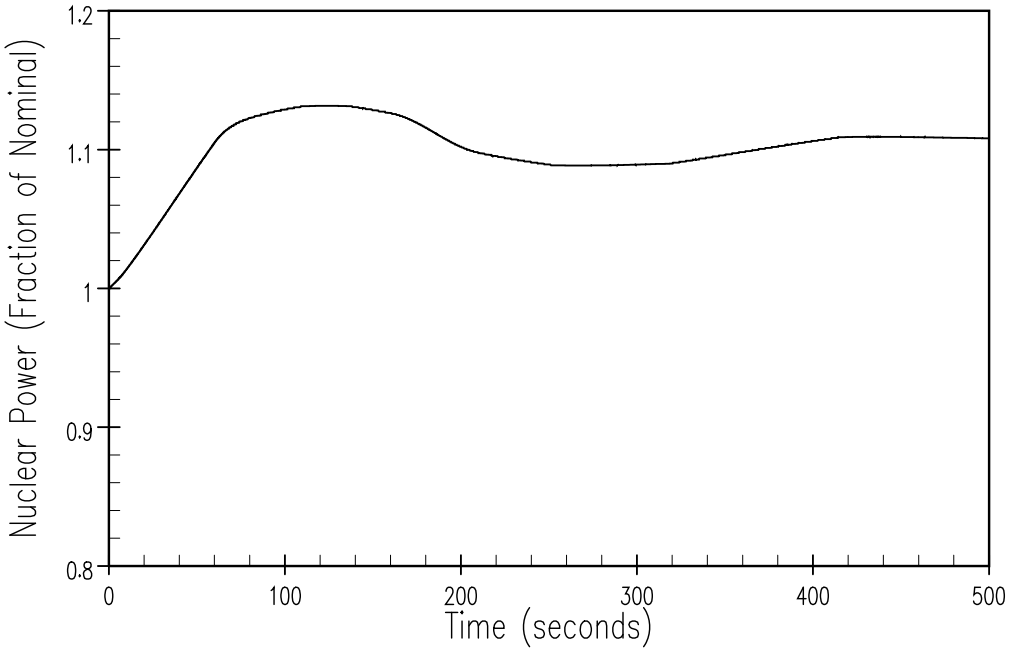

Figure 15.1.3-11
Nuclear Power Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

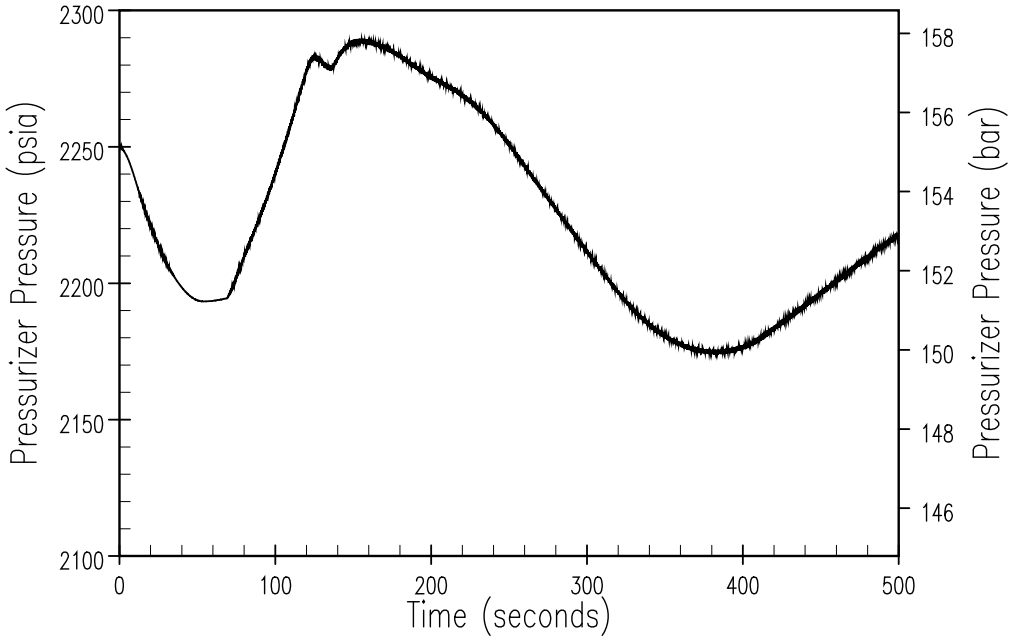

Figure 15.1.3-12
Pressurizer Pressure Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

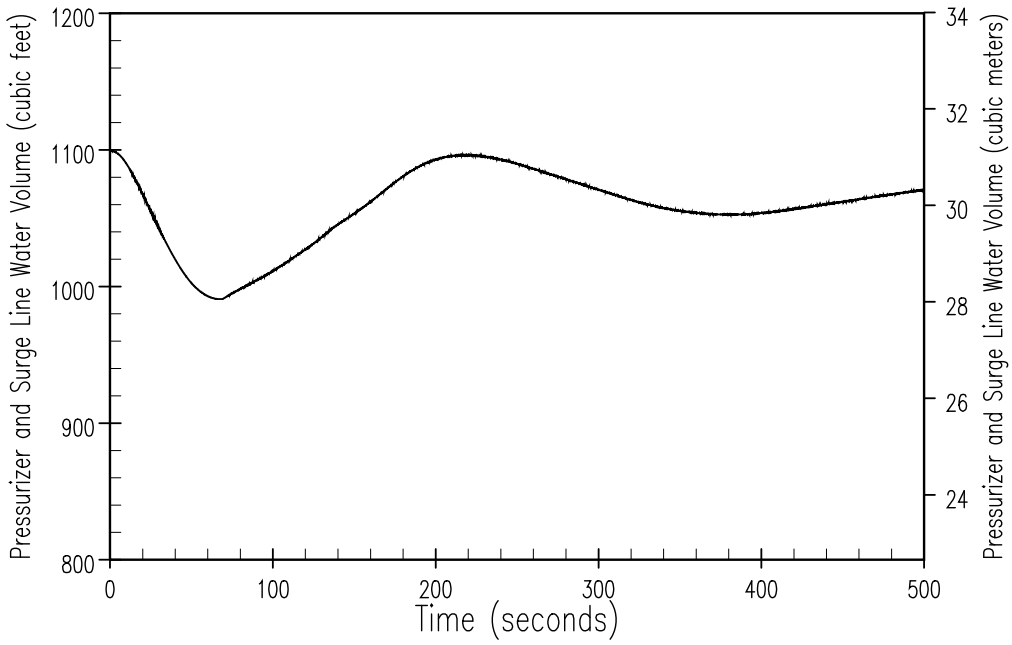

Figure 15.1.3-13
Pressurizer Water Volume Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

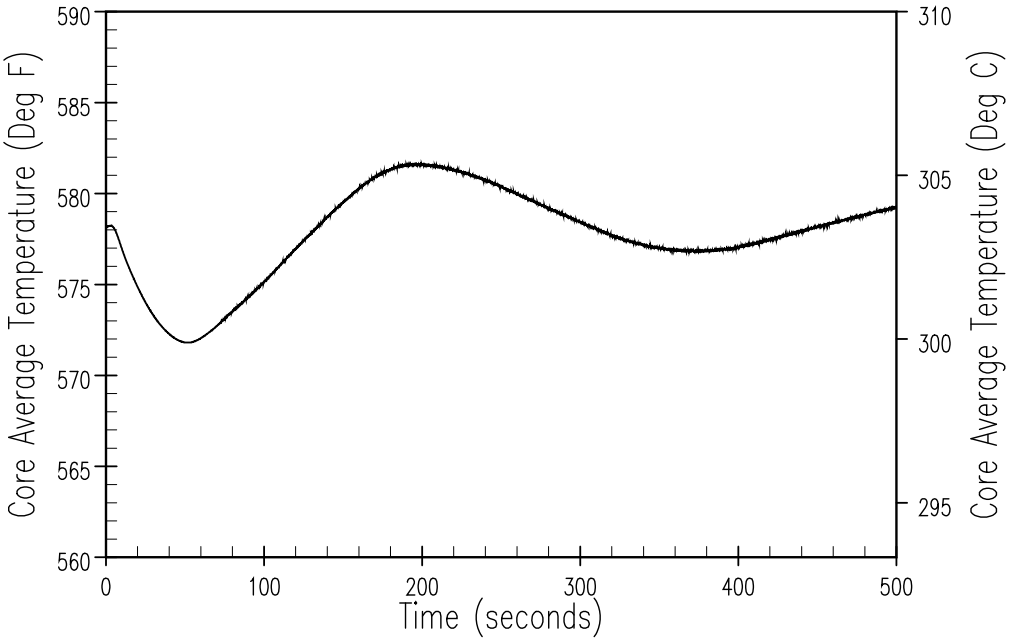

Figure 15.1.3-14
Core Average Temperature Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

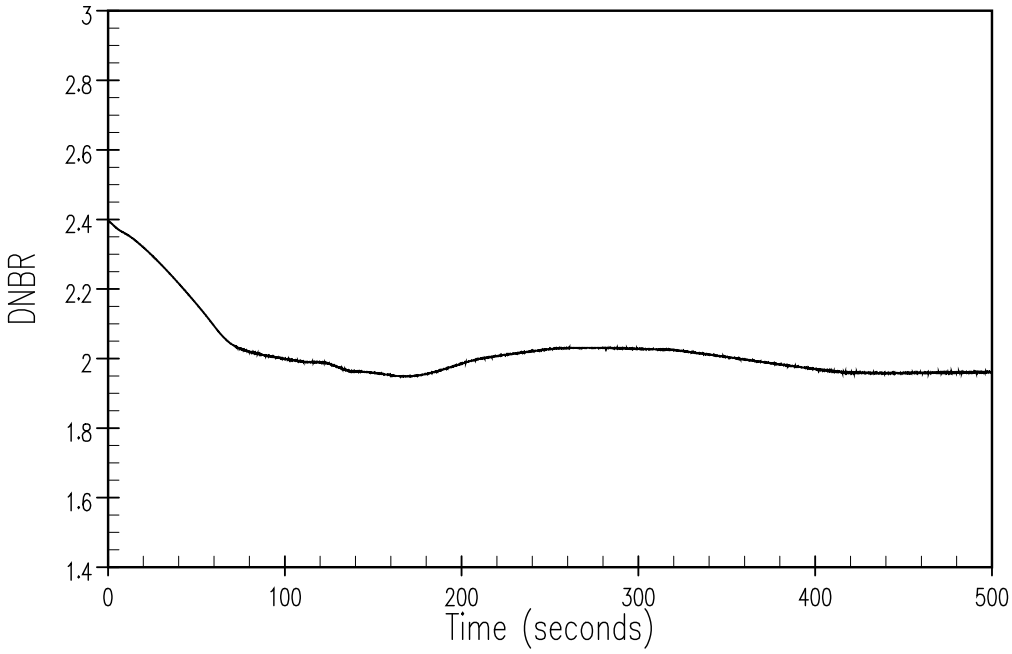

Figure 15.1.3-15
DNBR Versus Time for 10-percent Step Load Increase, Automatic Control and Minimum Moderator Feedback

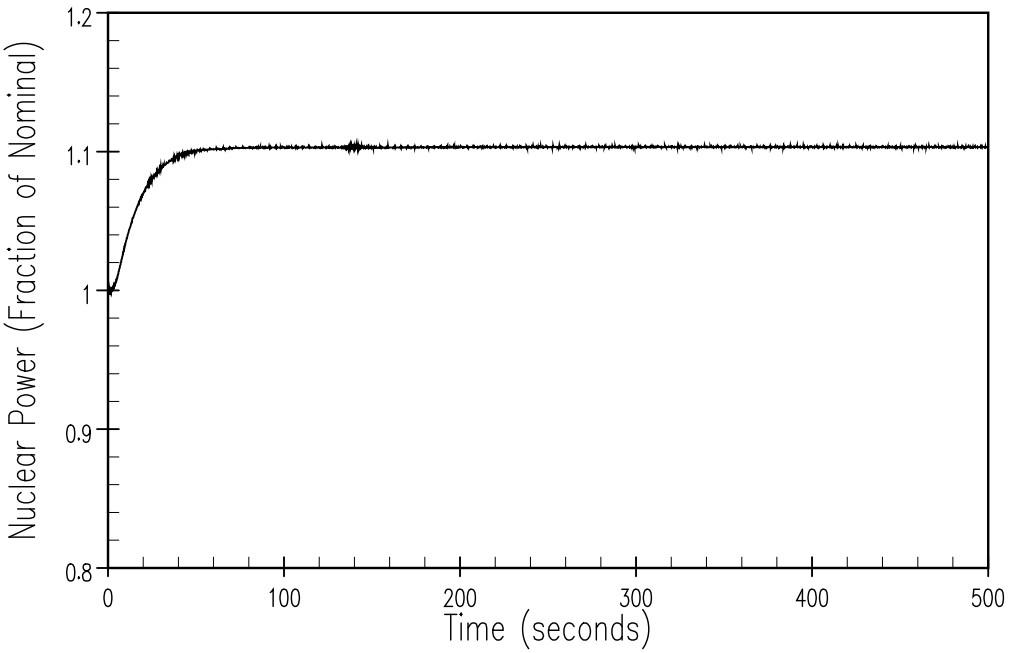

Figure 15.1.3-16
Nuclear Power Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

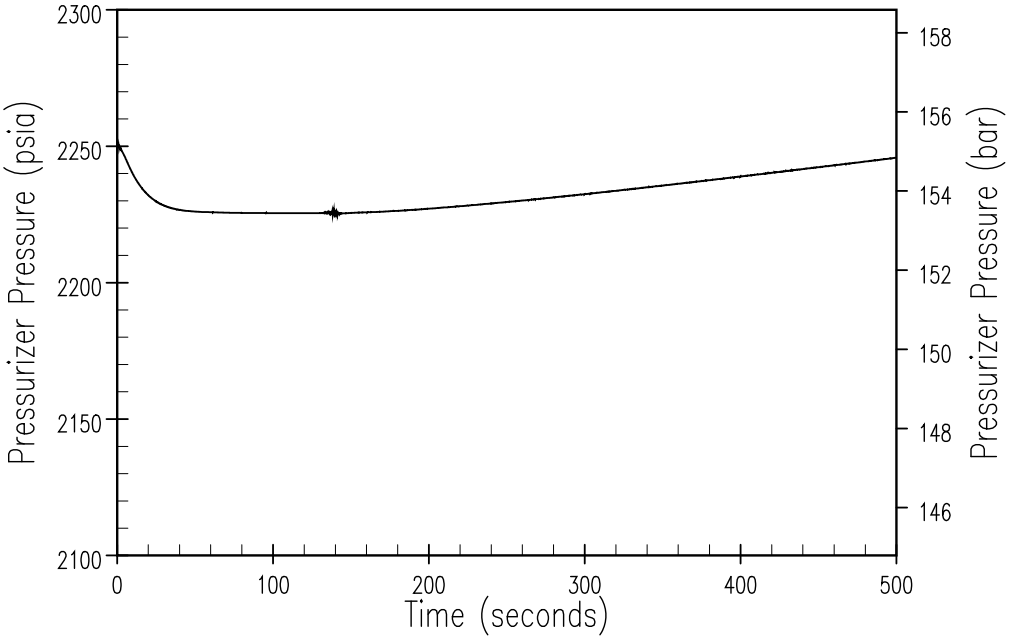

Figure 15.1.3-17
Pressurizer Pressure Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

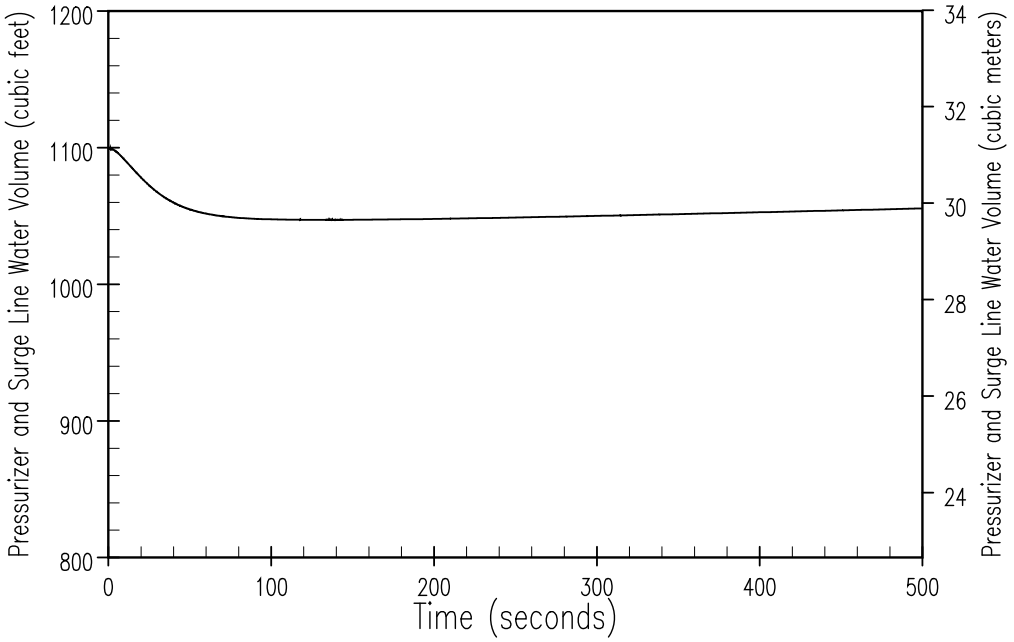

Figure 15.1.3-18
Pressurizer Water Volume Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

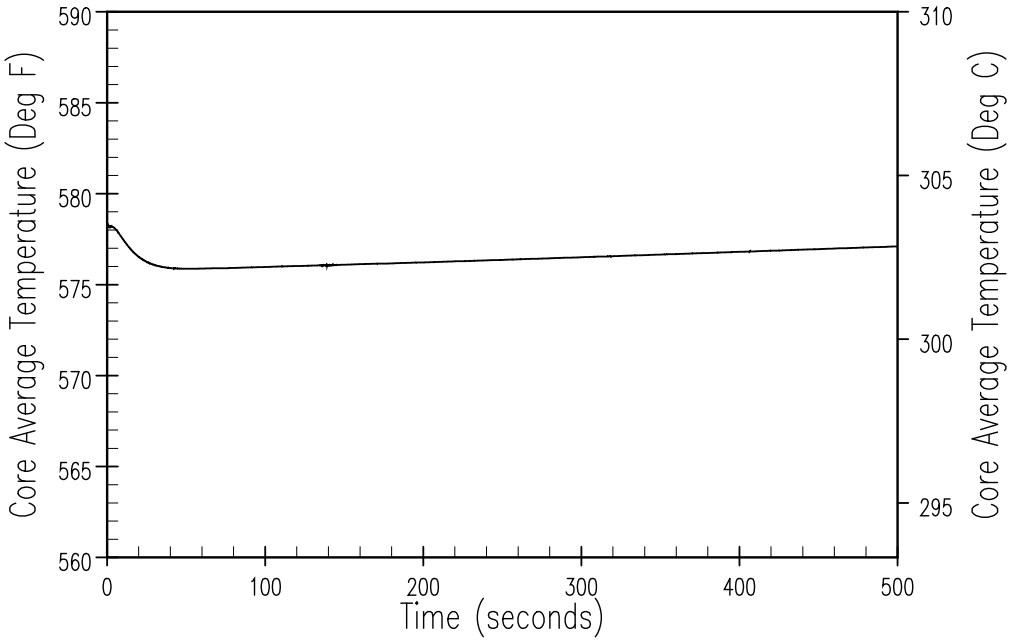

Figure 15.1.3-19
Core Average Temperature Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

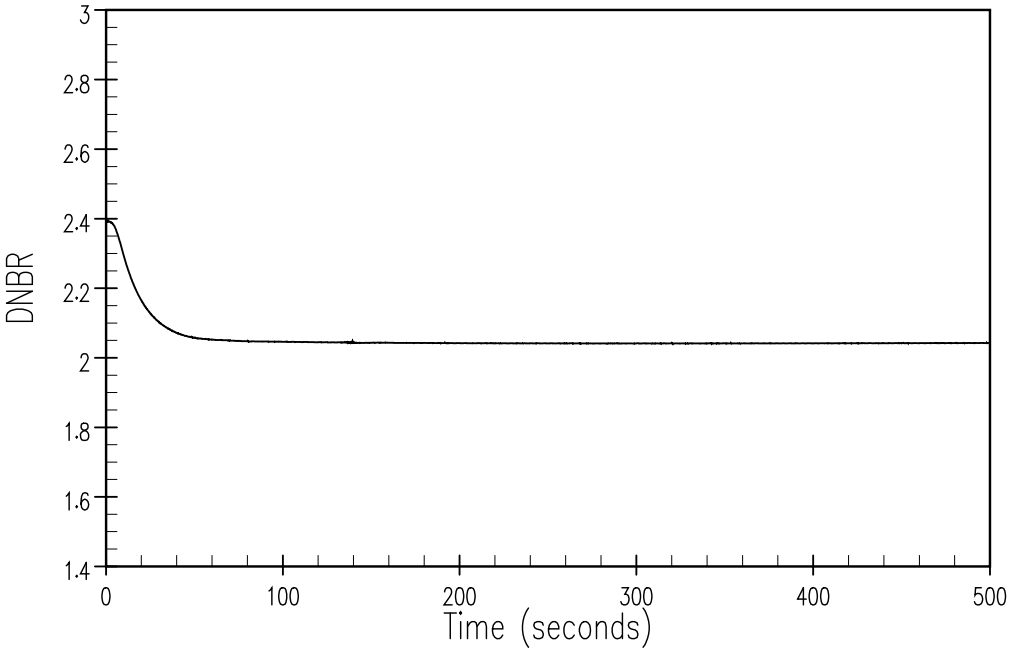

Figure 15.1.3-20
DNBR Versus Time for 10-percent Step Load Increase, Automatic Control and Maximum Moderator Feedback

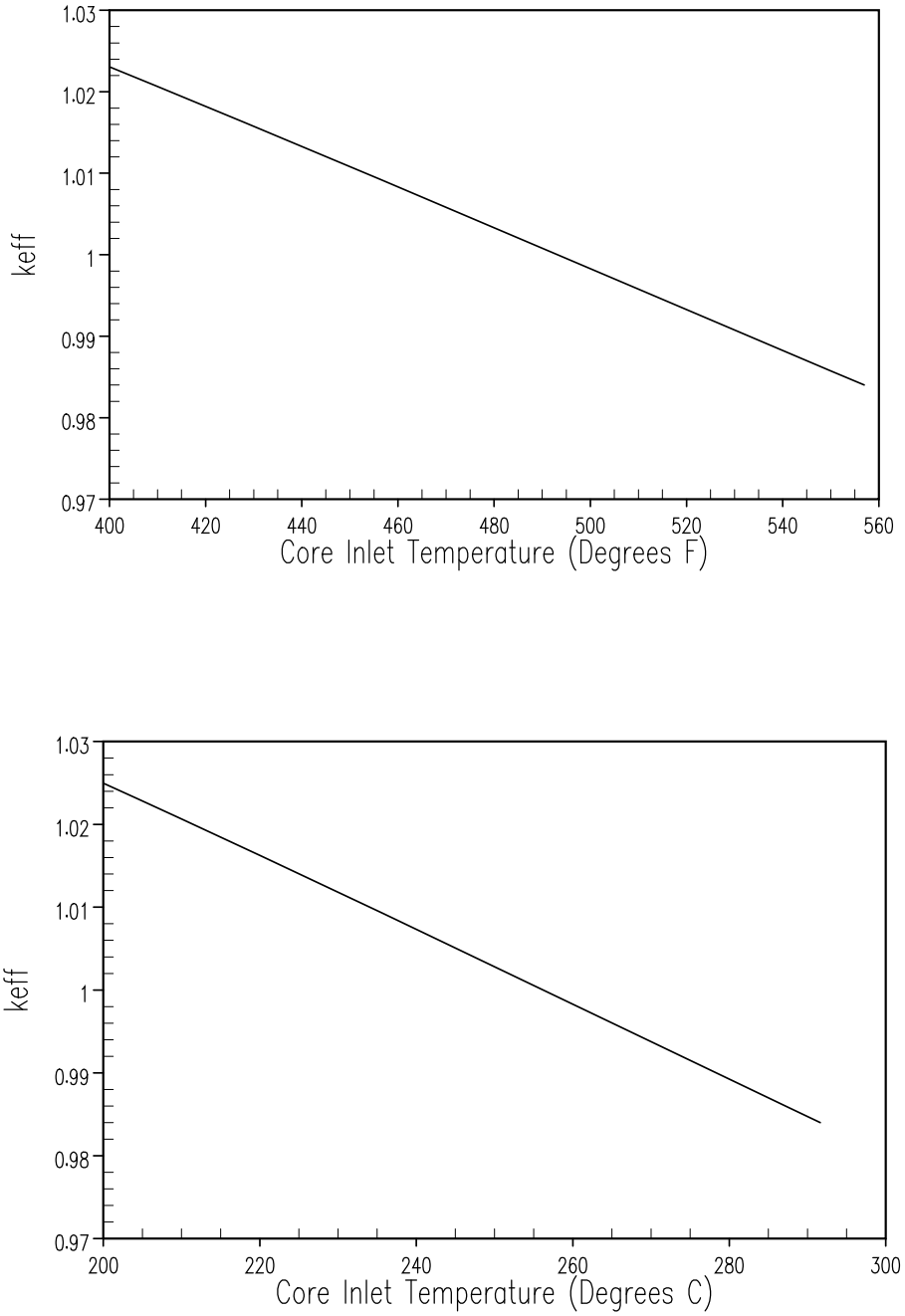

Figure 15.1.4-1
K_{eff} Versus Core Inlet Temperature
Steam Line Break Events

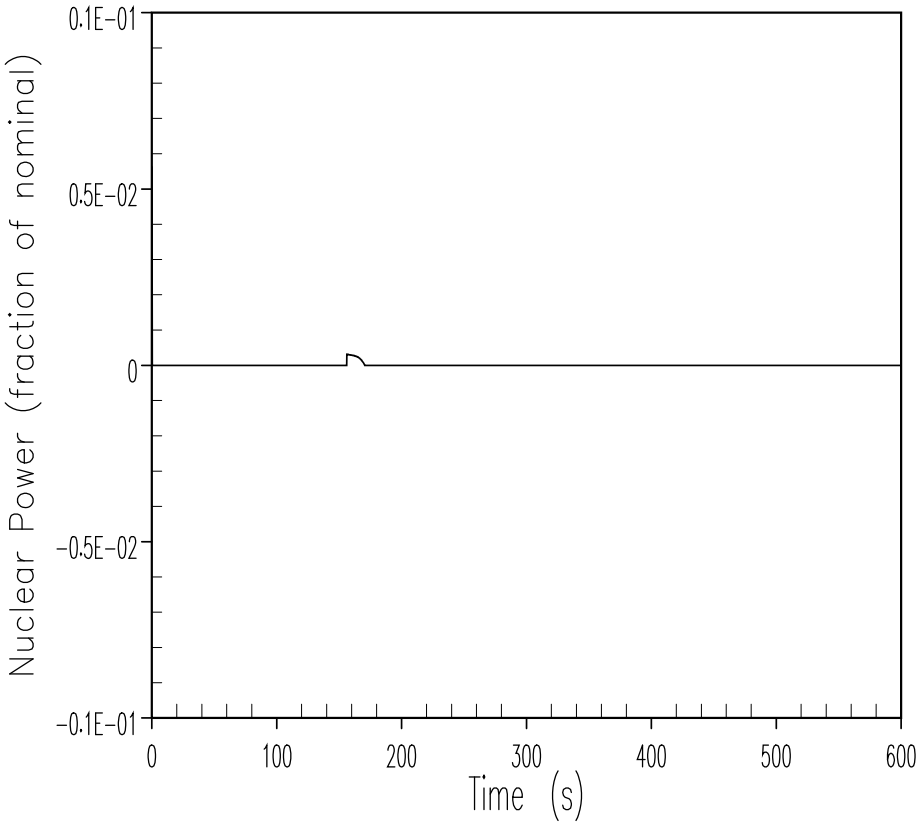

Figure 15.1.4-2
Nuclear Power Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

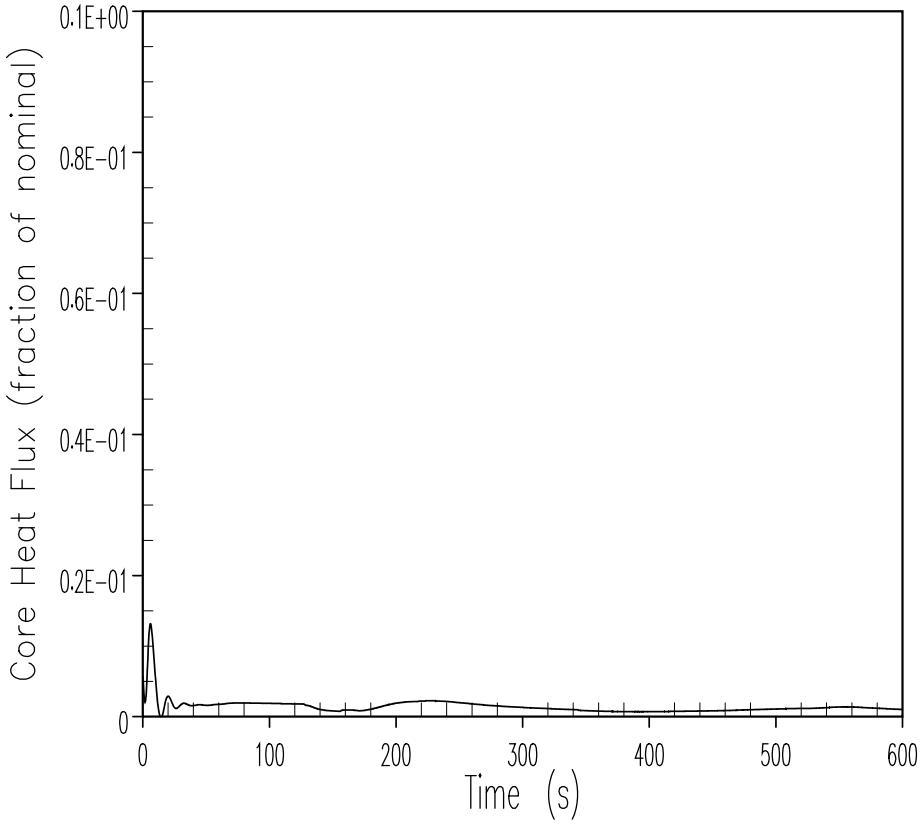

Figure 15.1.4-3
Core Heat Flux Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

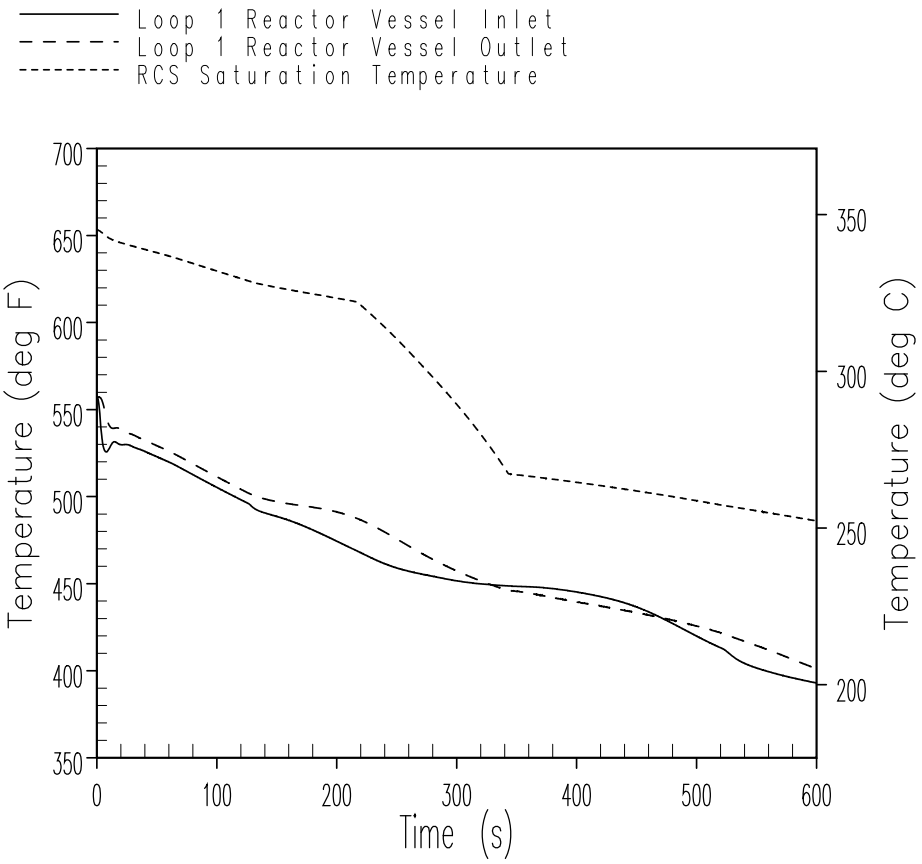

Figure 15.1.4-4
Loop 1 Reactor Coolant Temperatures
Inadvertent Opening of a Steam Generator Relief or Safety Valve

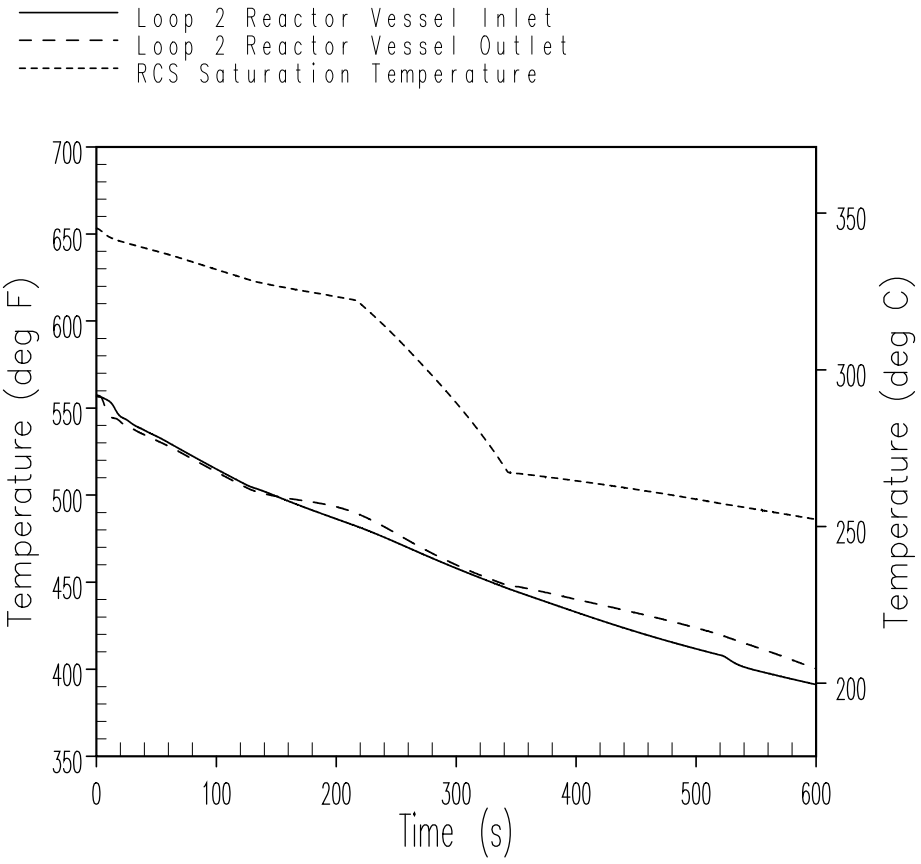

Figure 15.1.4-5
Loop 2 (Faulted Loop) Reactor Coolant Temperatures
Inadvertent Opening of a Steam Generator Relief or Safety Valve

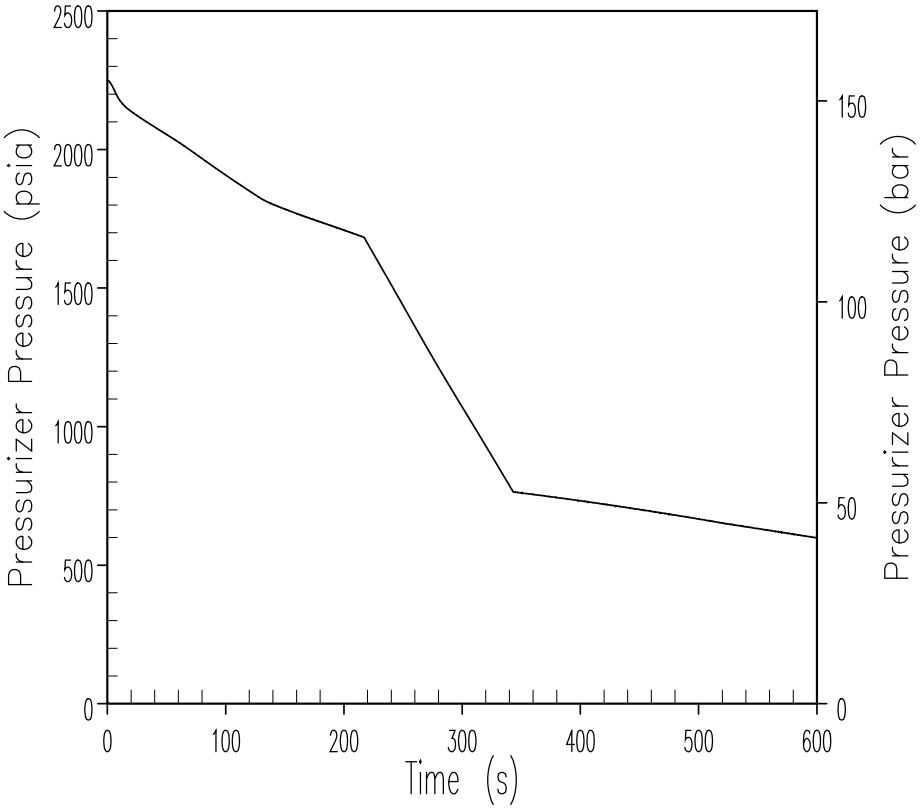

Figure 15.1.4-6
Pressurizer Pressure Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

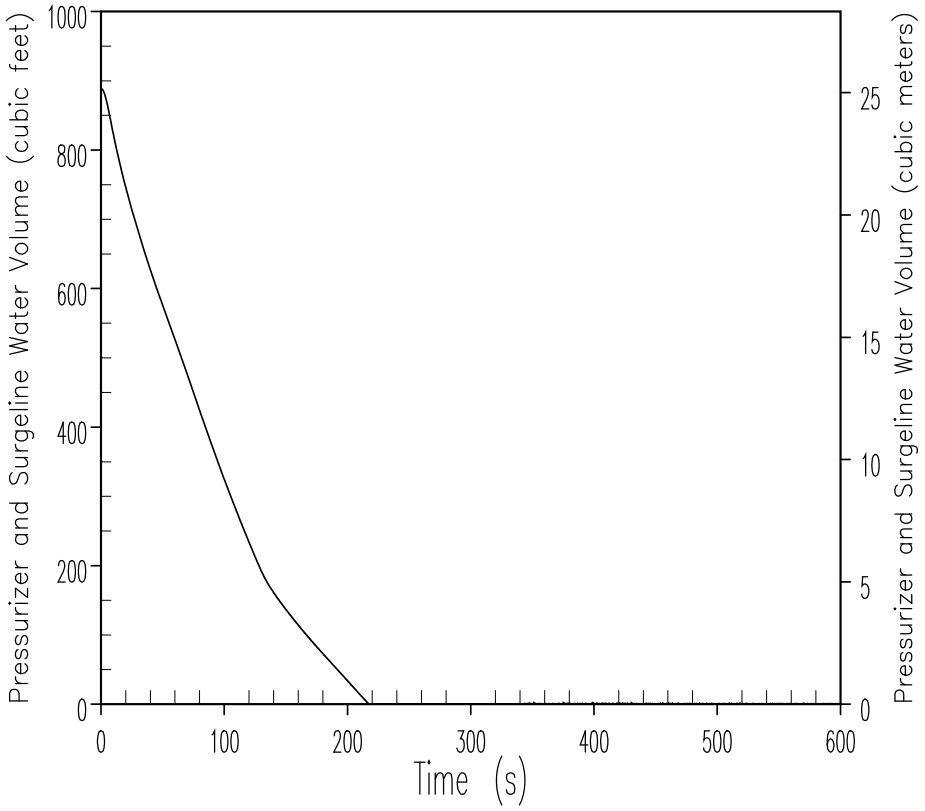

Figure 15.1.4-7
Pressurizer and Surge Line Water Volume Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

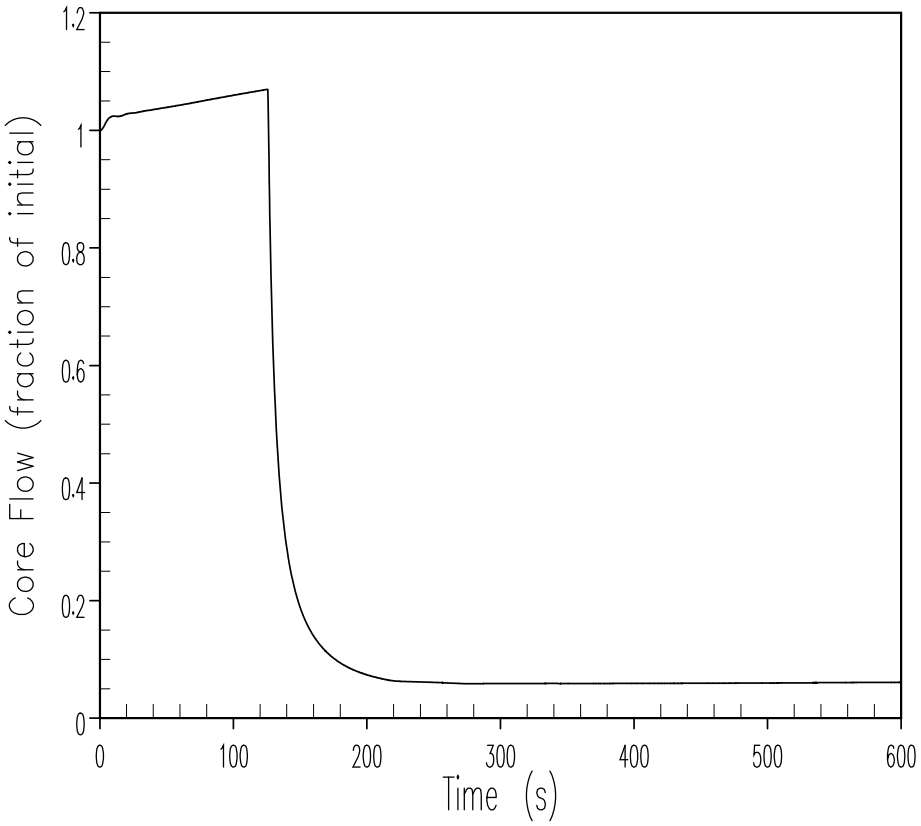

Figure 15.1.4-8
Core Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

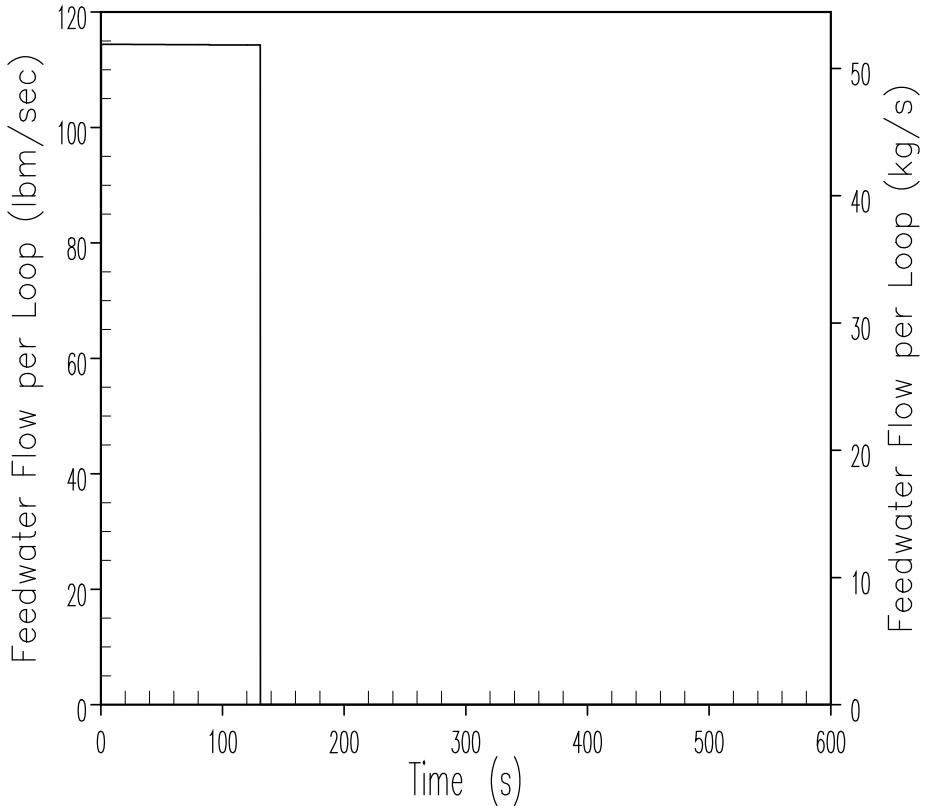

Figure 15.1.4-9
Feedwater Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

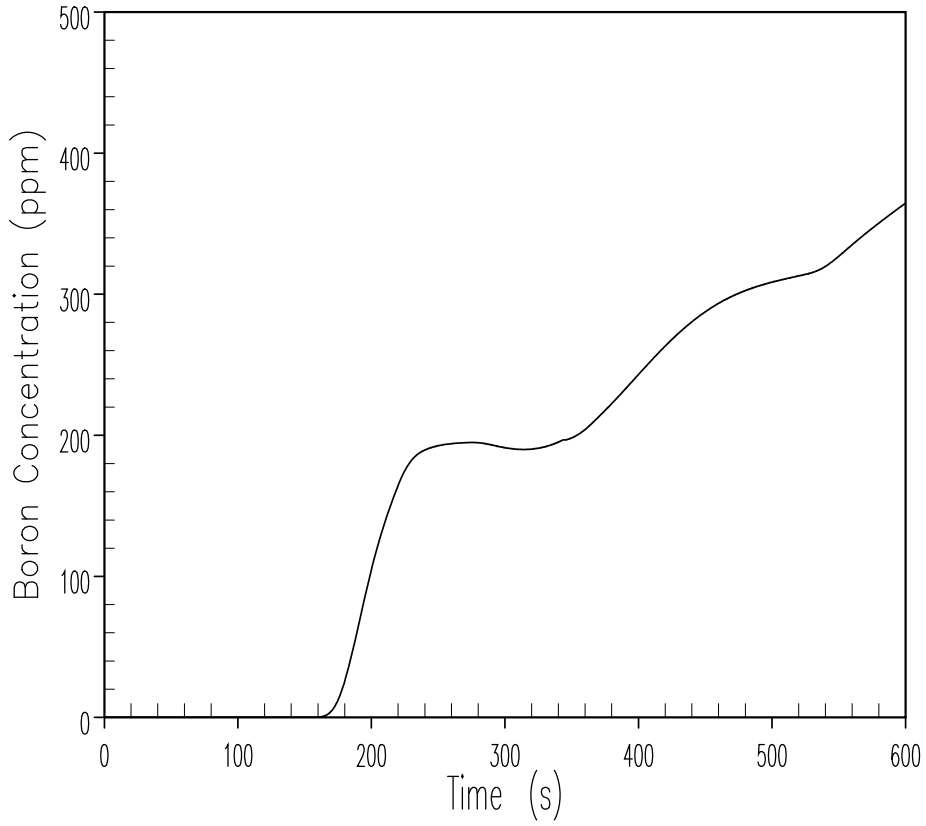

Figure 15.1.4-10
Core Boron Concentration Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

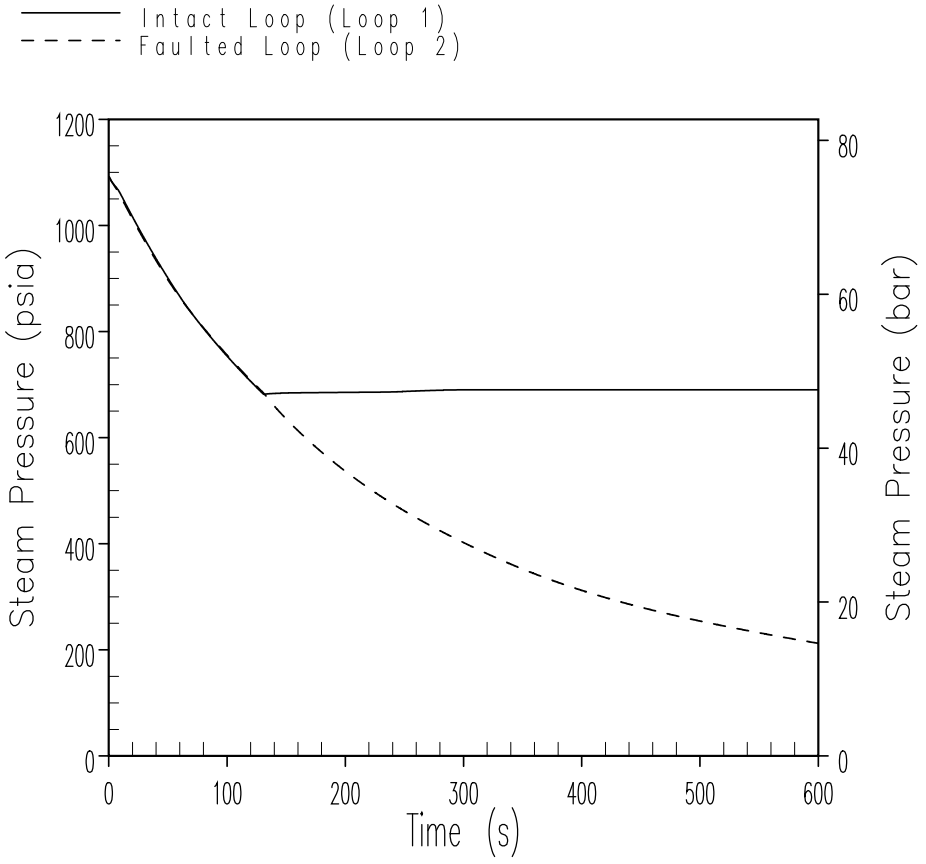

Figure 15.1.4-11
Steam Pressure Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

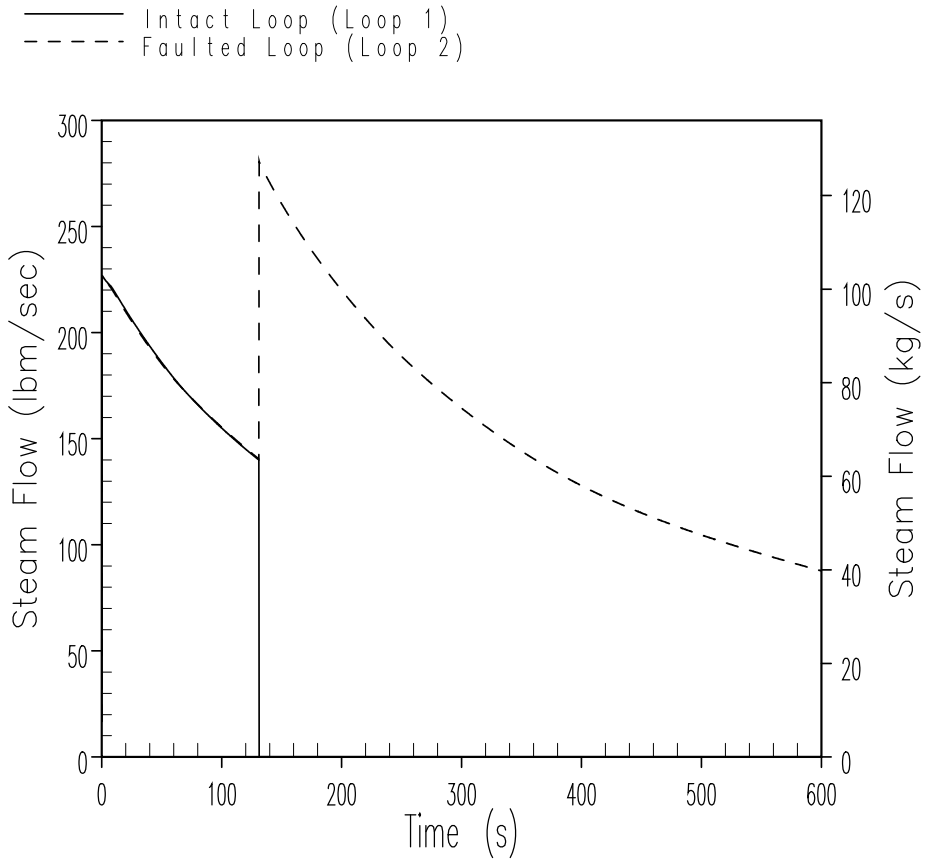

Figure 15.1.4-12
Steam Flow Transient
Inadvertent Opening of a Steam Generator Relief or Safety Valve

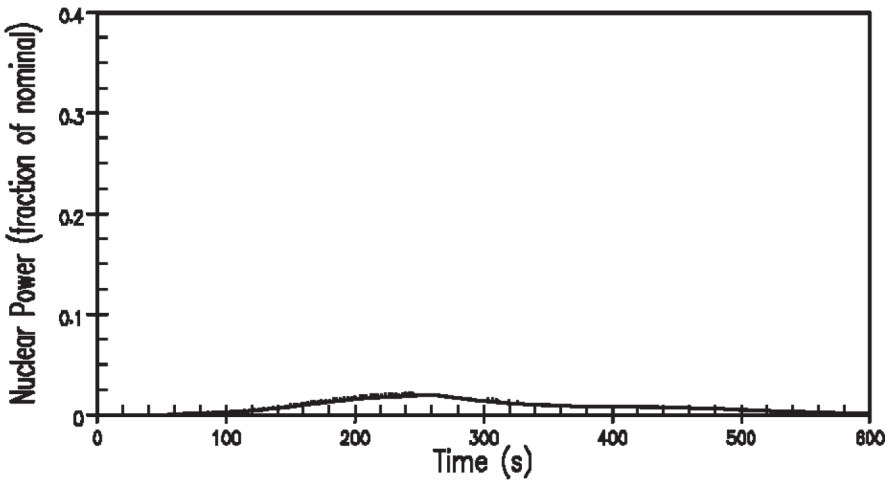

Figure 15.1.5-1
Nuclear Power Transient Steam System Piping Failure

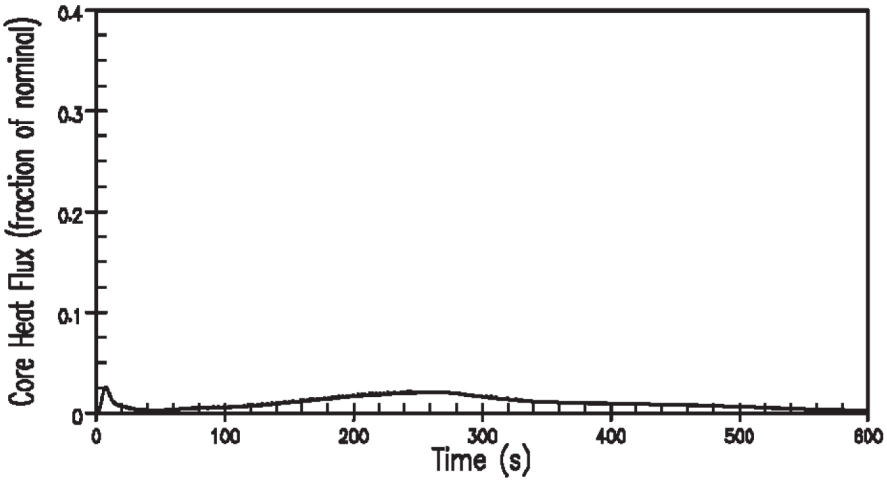

Figure 15.1.5-2
Core Heat Flux Transient Steam System Piping Failure

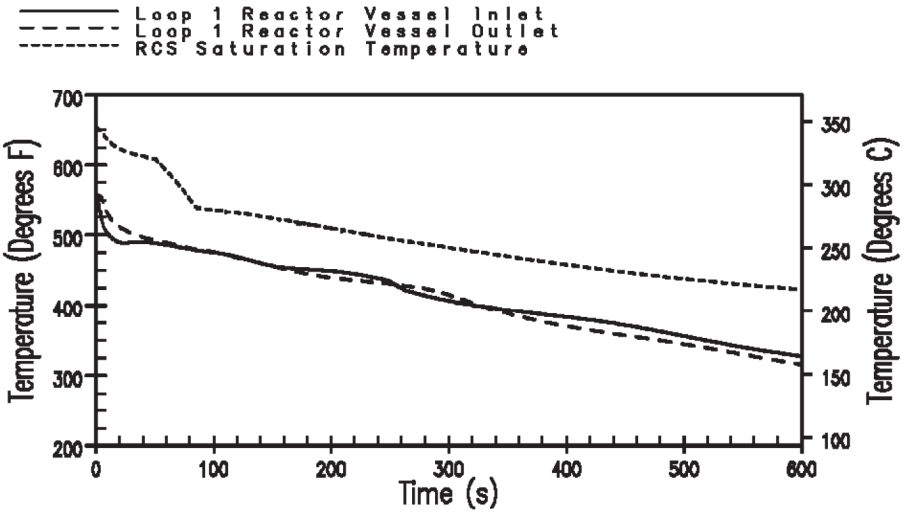

Figure 15.1.5-3
Loop 1 Reactor Coolant Temperatures
Steam System Piping Failure

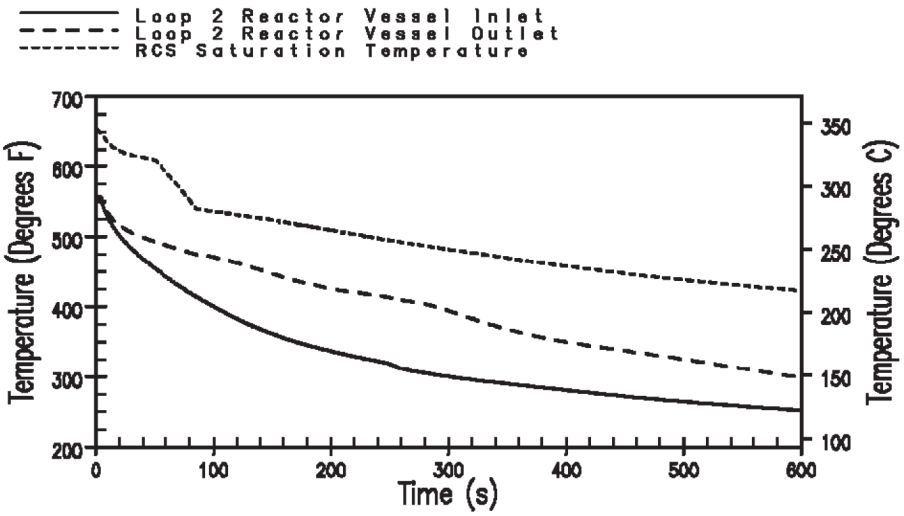

Figure 15.1.5-4
Loop 2 Reactor Coolant Temperatures
Steam System Piping Failure

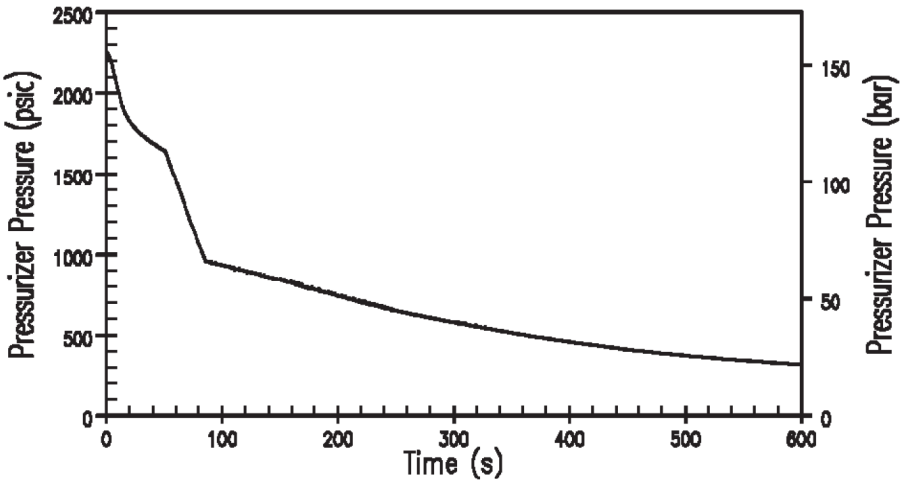

Figure 15.1.5-5
Pressurizer Pressure Transient
Steam System Piping Failure

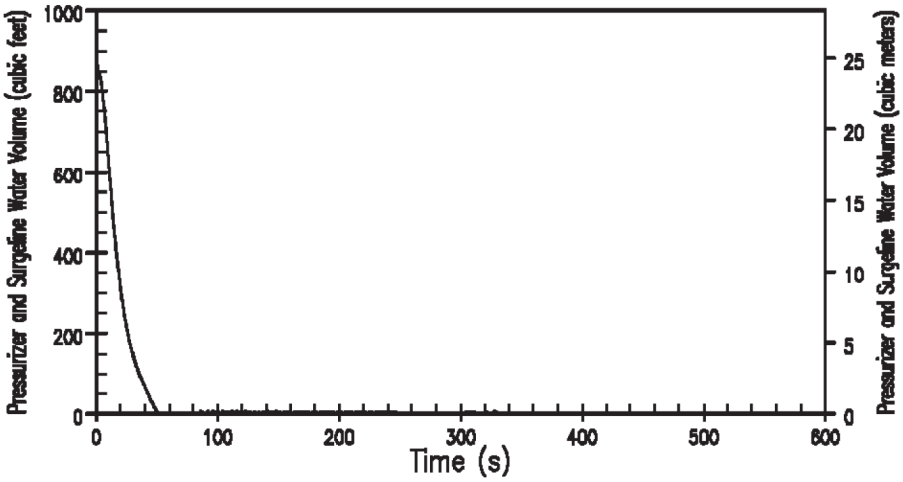

Figure 15.1.5-6
Pressurizer and Surge Line Water Volume Transient
Steam System Piping Failure

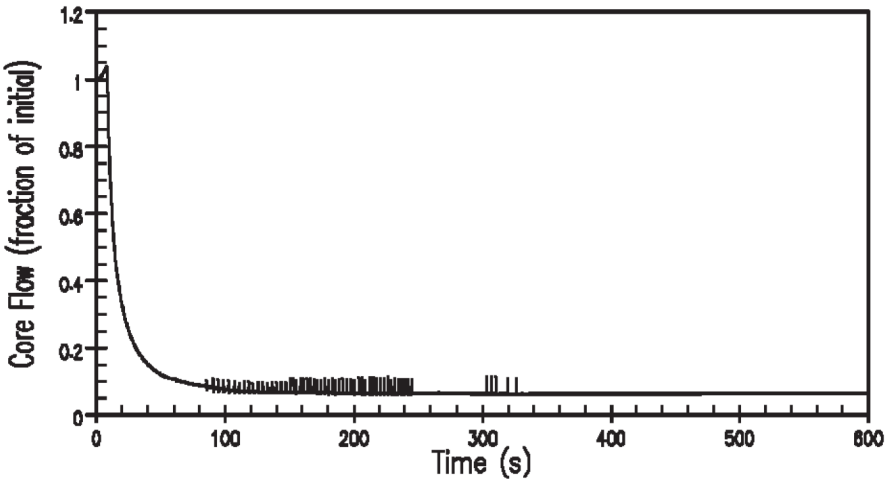

Figure 15.1.5-7
Core Flow Transient Steam System Piping Failure

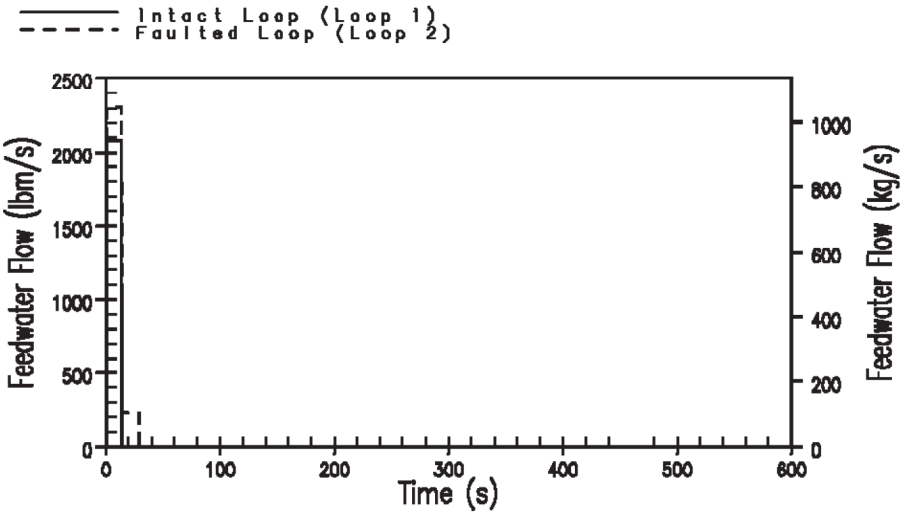

Figure 15.1.5-8
Feedwater Flow Transient Steam System Piping Failure

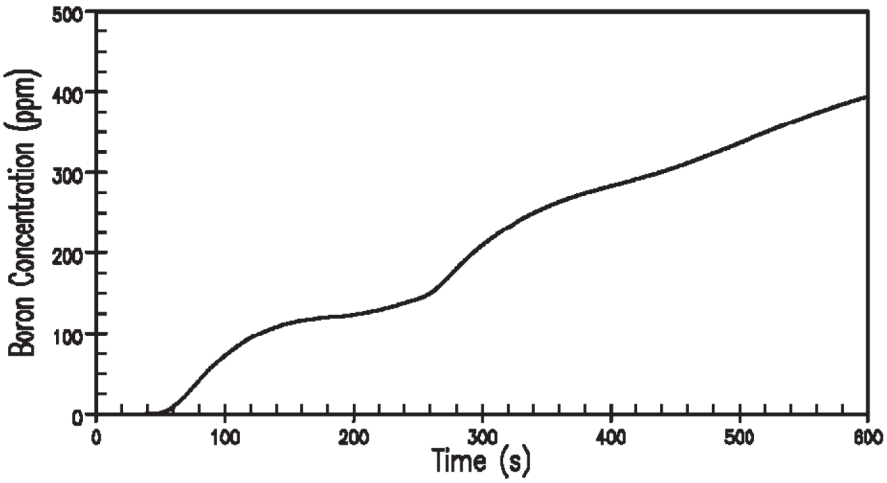

Figure 15.1.5-9
Core Boron Concentration Transient Steam System Piping Failure

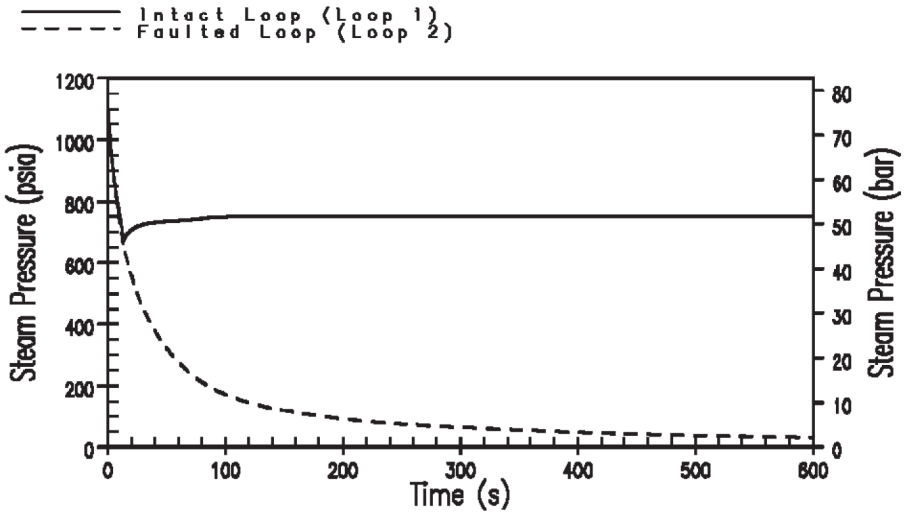

Figure 15.1.5-10
Steam Pressure Transient Steam System Piping Failure

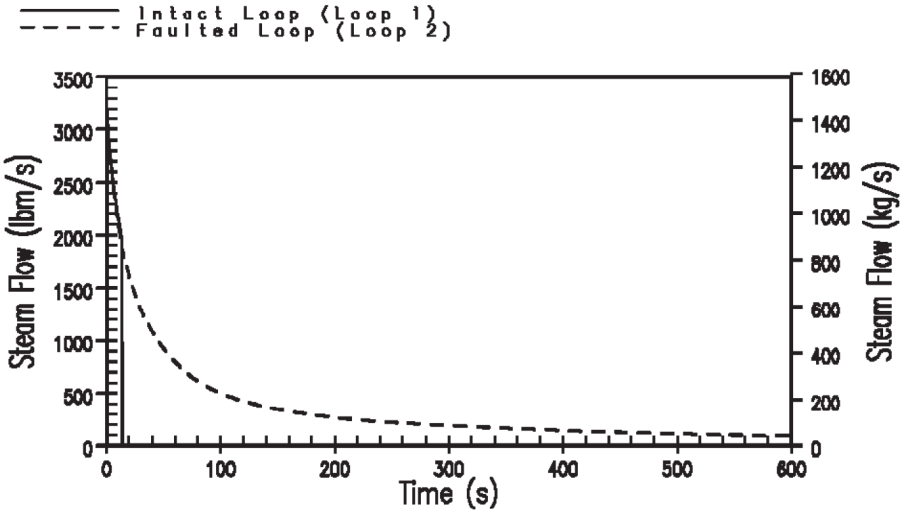

Figure 15.1.5-11
Steam Flow Transient Steam System Piping Failure

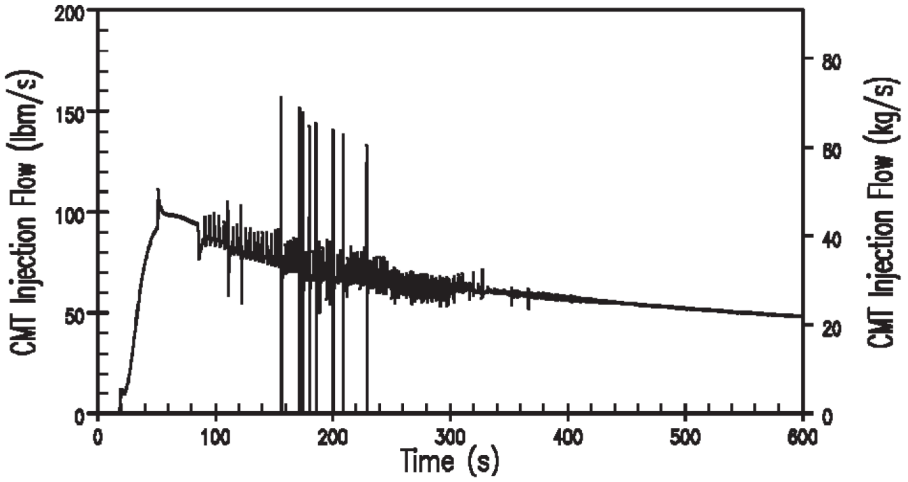

Figure 15.1.5-12
Core Makeup Tank Injection Flow
Steam System Piping Failure

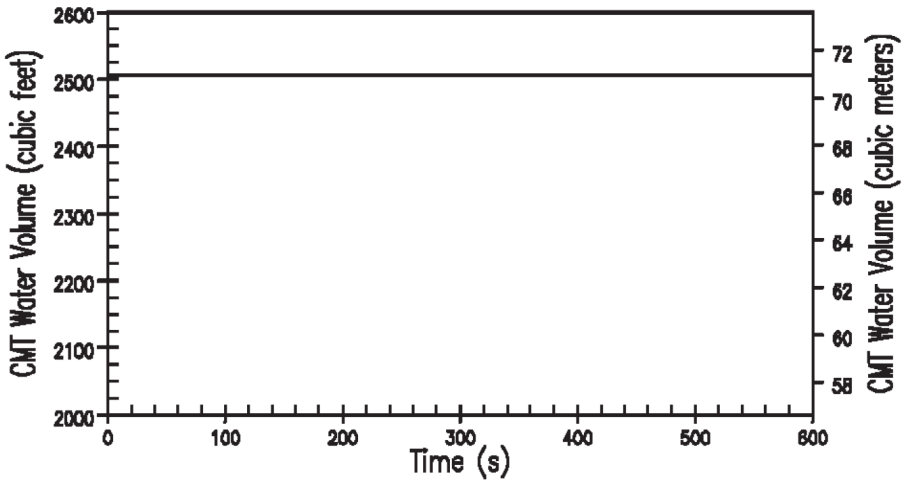

Figure 15.1.5-13
Core Makeup Tank Water Volume Steam System Piping Failure

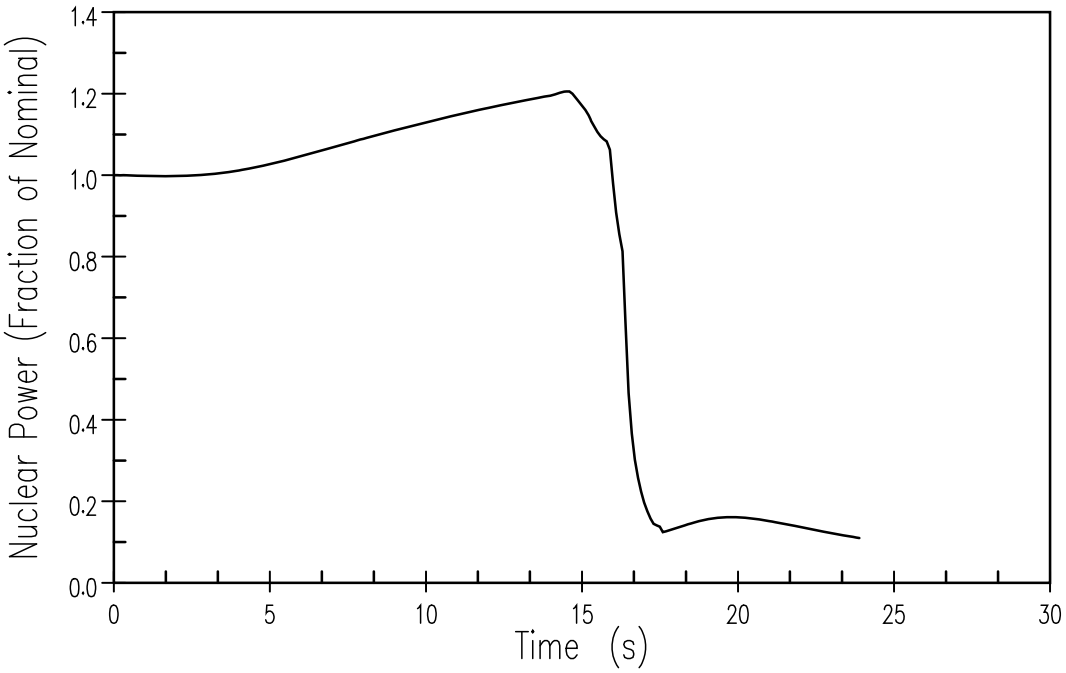

Figure 15.1.5.5-1
Nuclear Power Transient
Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size

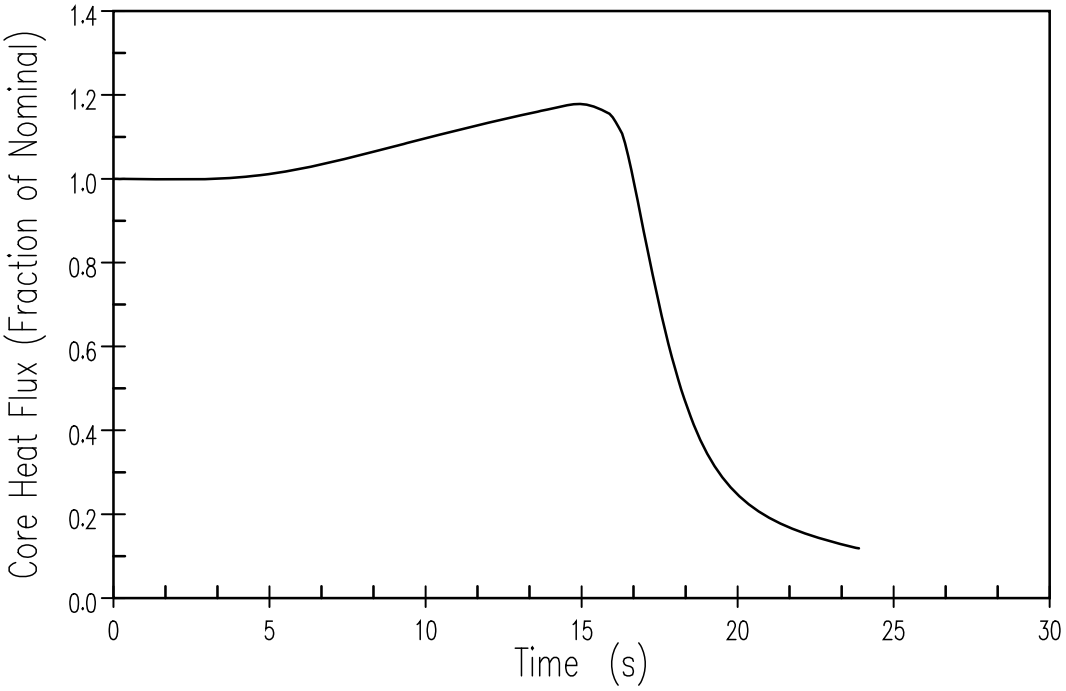

Figure 15.1.5.5-2
Core Heat Flux Transient
Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size

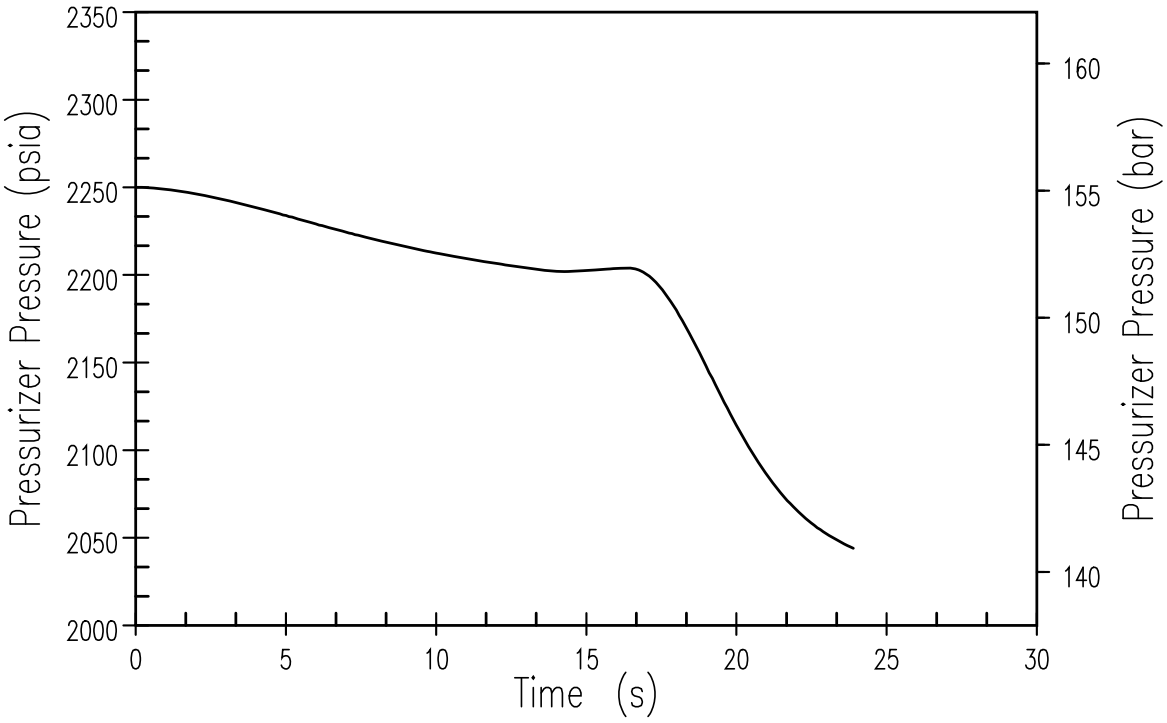

Figure 15.1.5.5-3
Pressurizer Pressure Transient
Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size

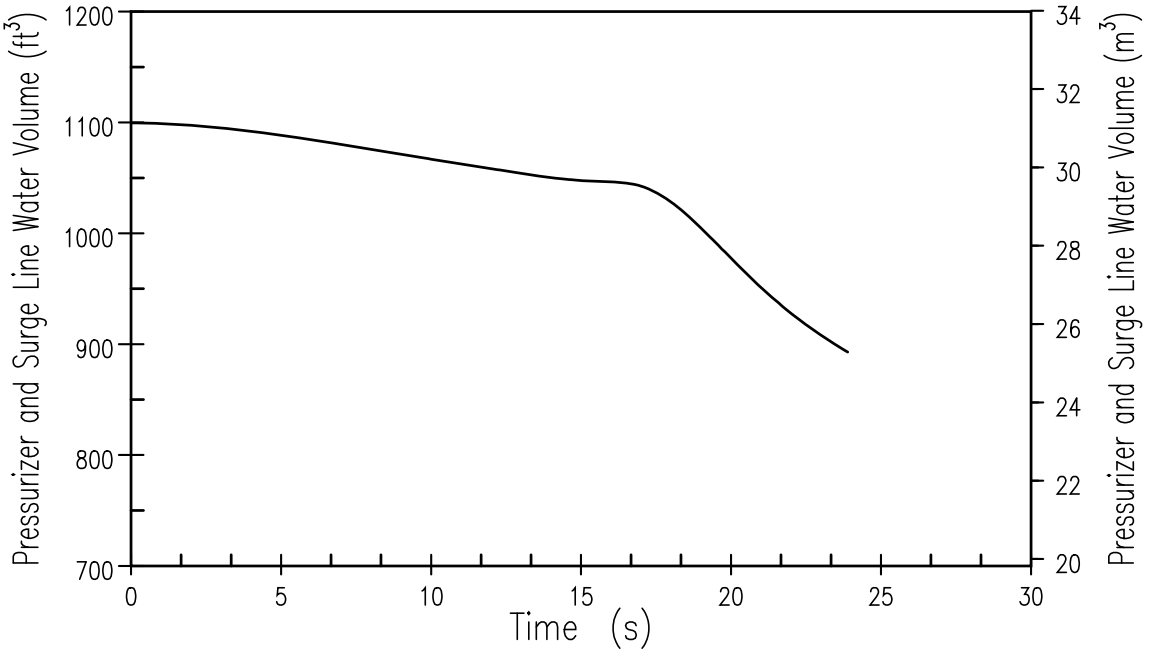

Figure 15.1.5.5-4
Pressurizer Water Volume Transient
Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size

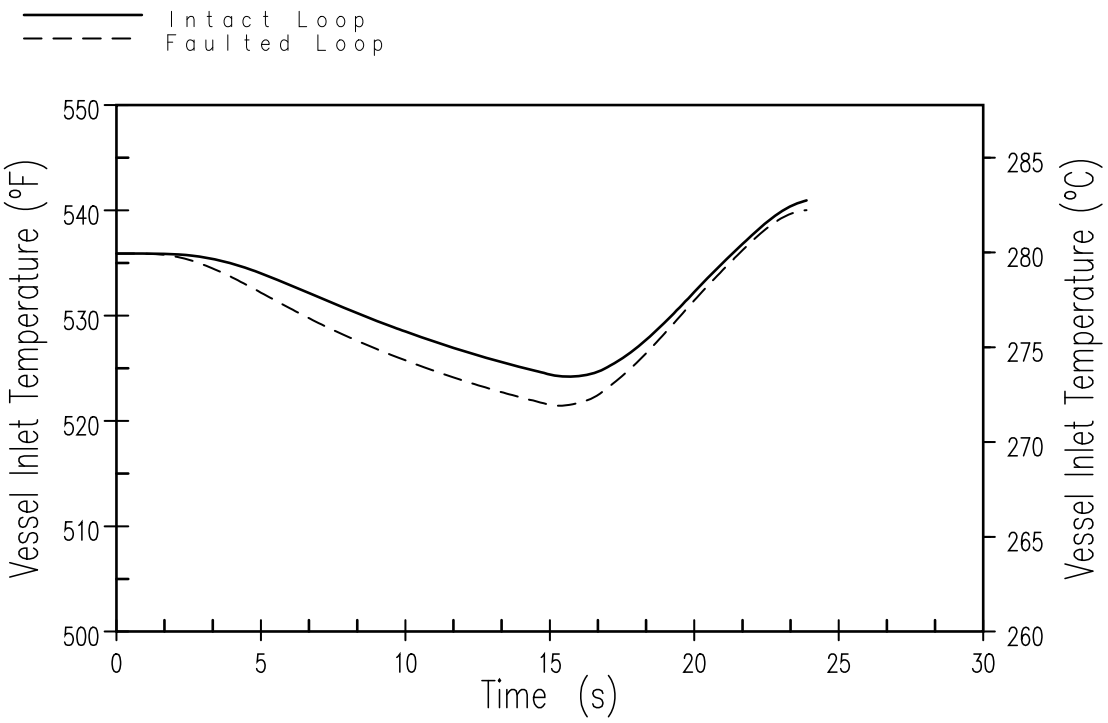

Figure 15.1.5.5-5
Vessel Inlet Temperature Transient
(Intact and Faulted Loops)
Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size

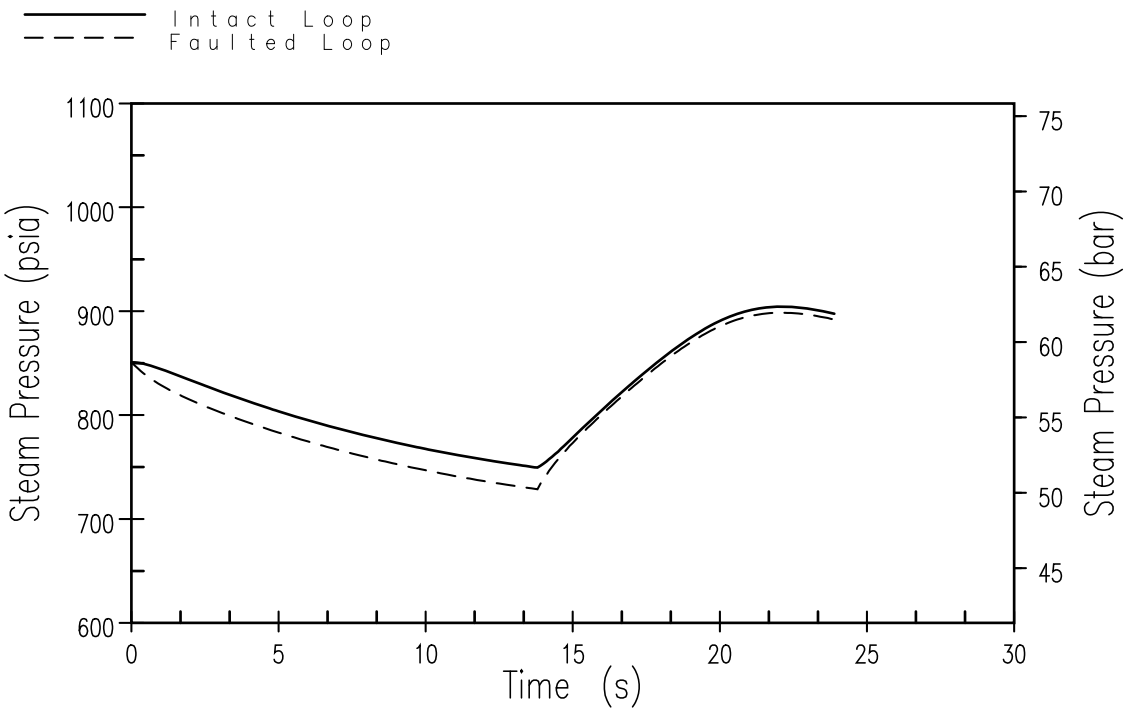

Figure 15.1.5.5-6
Steam Generator Pressure Transient
(Intact and Faulted Loops)
Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size

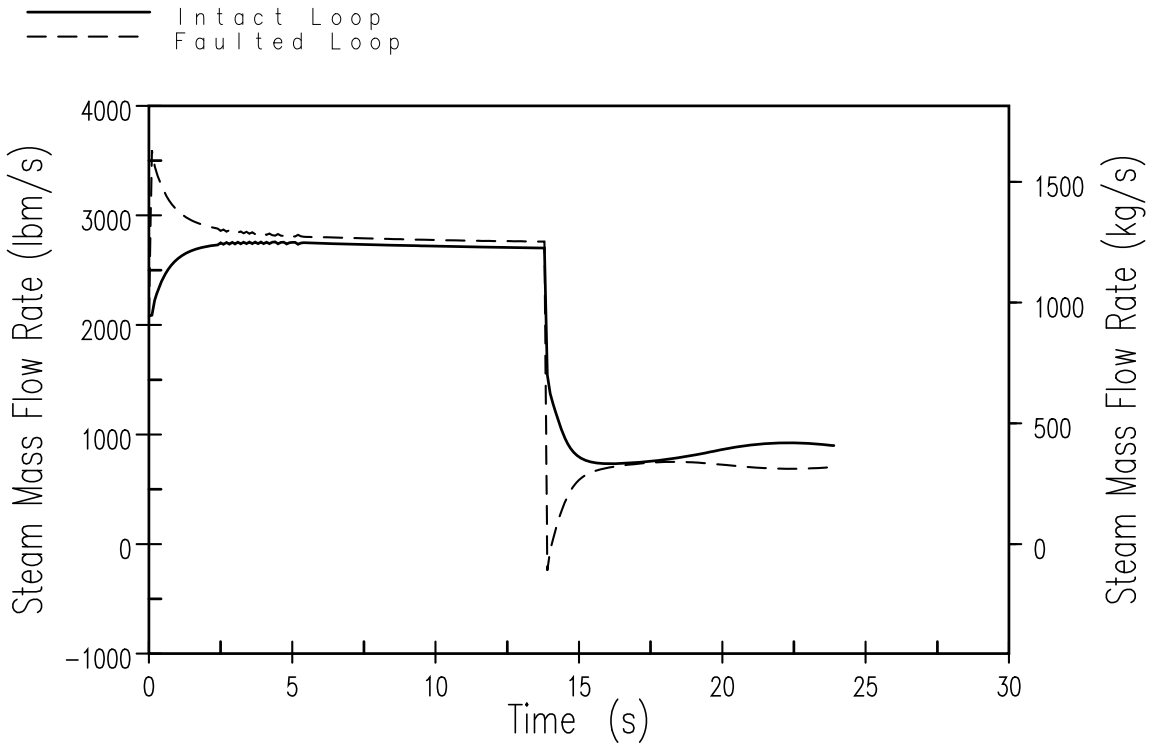

Figure 15.1.5.5-7
Steam Flow Transient (Intact and Faulted Loops)
Steam System Piping Failure at Full Power — 0.87 ft^2 Break Size

Figures 15.1.6-1–15.1.6-8 Not Used

15.2 Decrease in Heat Removal by the Secondary System

A number of transients and accidents that could result in a reduction of the capacity of the secondary system to remove heat generated in the reactor coolant system are postulated. Analyses are presented in this section for the following events that are identified as more limiting than the others:

- Steam pressure regulator malfunction or failure that results in decreasing steam flow
- Loss of external electrical load
- Turbine trip
- Inadvertent closure of main steam isolation valves
- Loss of condenser vacuum and other events resulting in turbine trip
- Loss of ac power to the station auxiliaries
- Loss of normal feedwater flow
- Feedwater system pipe break

The above items are considered to be Condition II events, with the exception of a feedwater system pipe break, which is considered to be a Condition IV event.

For events in this section where PRHR heat exchanger actuation occurs, transients are presented until the PRHR heat exchanger heat removal matches decay heat generation. After that point in time, PRHR heat exchanger performance is driven by the performance of the passive containment cooling systems to control containment pressure and the ability of the condensate collection features to return condensate to the in-containment refueling water storage tank. The performance of these systems, for extended decay heat removal, is described in Subsection 6.3.1.1.1.

The radiological consequences of the accidents in this section are bounded by the radiological consequences of a main steam line break (see Subsection 15.1.5).

15.2.1 Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow

There are no steam pressure regulators in the AP1000 whose failure or malfunction causes a steam flow transient.

15.2.2 Loss of External Electrical Load

15.2.2.1 Identification of Causes and Accident Description

A major load loss on the plant can result from a loss of electrical load due to an electrical system disturbance. The ac power remains available to operate plant components such as the reactor coolant pumps; as a result, the standby onsite diesel generators do not function for this event. Following the loss of generator load, an immediate fast closure of the turbine control valves occurs. The automatic turbine bypass system accommodates the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the turbine bypass system and pressurizer pressure control system function properly. If the condenser is not available, the excess steam generation is relieved to the atmosphere. Additionally, main feedwater flow is lost if the condenser is not available. For this transient, feedwater flow is maintained by the startup feedwater system.

For a loss of electrical load without subsequent turbine trip, no direct reactor trip signal is generated. The plant trips from the protection and safety monitoring system if a safety limit is approached. A continued steam load of approximately 5 percent exists after total loss of external electrical load because of the steam demand of plant auxiliaries.

If a safety limit is approached, protection is provided by High-2 pressurizer pressure, High-3 pressurizer water level, and overtemperature ΔT trips. Voltage and frequency relays associated with the reactor coolant pump provide no additional safety function for this event. Following a complete loss of external electrical load, the maximum turbine overspeed is not expected to affect the voltage and frequency sensors. Any increased frequency to the reactor coolant pump motors results in a slightly increased flow rate and subsequent additional margin to safety limits. For postulated loss of load and subsequent turbine-generator overspeed, an overfrequency condition is not seen by the protection and safety monitoring system equipment or other safety-related loads. Safety-related loads and the protection and safety monitoring system equipment are supplied from the 120-Vac instrument power supply system, which in turn is supplied from the inverters. The inverters are supplied from a dc bus energized from batteries or by a regulated ac voltage.

If the steam dump valves fail to open following a large loss of load, the steam generator safety valves may lift and the reactor may be tripped by the High-2 pressurizer pressure signal, the High-3 pressurizer water level signal, or the overtemperature ΔT signal. This would cause steam generator shell side pressure and reactor coolant temperature to increase rapidly. However, the pressurizer safety valves and steam generator safety valves are sized to protect the reactor coolant system and steam generator against overpressure for load losses, without assuming the operation of the turbine bypass system, pressurizer spray, or automatic rod cluster control assembly control.

The steam generator safety valve capacity is sized to remove the steam flow at the nuclear steam supply system thermal rating from the steam generator, without exceeding 110 percent of the steam system design pressure. The pressurizer safety valve capacity is sized to accommodate a complete loss of heat sink, with the plant initially operating at the maximum turbine load. The pressurizer safety valves can then relieve sufficient steam to maintain the reactor coolant system pressure within 110 percent of the reactor coolant system design pressure.

A discussion of overpressure protection can be found in WCAP-7769, Revision 1 (Reference 1) and WCAP-16779 (Reference 9).

A loss-of-external-load event is classified as a Condition II event, fault of moderate frequency.

A loss-of-external-load event results in a plant transient that is bounded by the turbine trip event analyzed in Subsection 15.2.3. Therefore, a detailed transient analysis is not presented for the loss-of-external-load event.

The primary side transient is caused by a decrease in heat transfer capability, from primary to secondary, due to a rapid termination of steam flow to the turbine, accompanied by an automatic reduction of feedwater flow (should feedwater flow not be reduced, a larger heat sink is available and the transient is less severe). Reduction of steam flow to the turbine following a loss-of-external load event occurs due to automatic fast closure of the turbine control valves. Following a turbine trip event, termination of steam flow occurs via turbine stop valve closure, which occurs in approximately 0.15 seconds. The transient in primary pressure, temperature, and water volume is less severe for the loss-of-external-load event than for the turbine trip due to a slightly slower loss of heat transfer capability.

The protection available to mitigate the consequences of a loss-of-external-load event is the same as that for a turbine trip, as listed in Table 15.0-6.

15.2.2.2 Analysis of Effects and Consequences

Refer to Subsection 15.2.3.2 for the method used to analyze the limiting transient (turbine trip) in this grouping of events. The results of the turbine trip event analysis bound those expected for the loss-of-external-load event, as discussed in Subsection 15.2.2.1.

Plant systems and equipment that may be required to function in order to mitigate the effects of a complete loss of load are discussed in Subsection 15.0.8 and listed in Table 15.0-6.

The protection and safety monitoring system may be required to terminate core heat input and to prevent departure from nucleate boiling (DNB). Depending on the magnitude of the load loss, pressurizer safety valves and/or steam generator safety valves may open to maintain system pressures below allowable limits. No single active failure prevents operation of any system required to function. Normal plant control systems and engineered safety systems are not required to function. The passive residual heat removal (PRHR) system may be automatically actuated following a loss of main feedwater, further mitigating the effects of the transient.

15.2.2.3 Conclusions

Based on results obtained for the turbine trip event and considerations described in Subsection 15.2.2.1, the applicable Standard Review Plan, Subsection 15.2.1, evaluation criteria for a loss-of-external-load event, are met (see Subsection 15.2.3).

15.2.3 Turbine Trip

15.2.3.1 Identification of Causes and Accident Description

The turbine stop valves close rapidly (about 0.15 seconds) on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals. Turbine trip initiation signals include:

- Generator trip
- Low condenser vacuum
- Loss of lubricating oil
- Turbine thrust bearing failure
- Turbine overspeed
- Manual trip
- Reactor trip

Upon initiation of stop valve closure, steam flow to the turbine stops abruptly. The decrease in turbine first-stage impulse pressure when in T_{avg} mode, or an increase in steam header pressure when in pressure control mode, causes the steam dump controller to initiate turbine bypass. The loss of steam flow results in a rapid increase in secondary system temperature and pressure, with a resultant primary system transient, described in Subsection 15.2.2.1, for the loss-of-external-load event. A slightly more severe transient occurs for the turbine trip event due to the rapid loss of steam flow caused by the abrupt valve closure.

The automatic turbine bypass system accommodates up to 40 percent of rated main steam flow. Reactor coolant temperatures and pressure do not increase significantly if the turbine bypass system and pressurizer pressure control system are functioning properly. If the condenser is not available, the excess steam generation is relieved to the atmosphere and main feedwater flow is lost. For this situation, feedwater flow is maintained by the startup feedwater system to provide adequate residual and decay heat removal capability. Should the turbine bypass system fail to operate, the steam generator safety valves may lift to provide pressure control. See Subsection 15.2.2.1 for a further discussion of the transient.

A turbine trip is classified as a Condition II event, fault of moderate frequency.

A turbine trip is a more limiting than a loss-of-external-load event, loss of condenser vacuum, and other events which result in a turbine trip. As such, this event is analyzed and presented in Subsection 15.2.3.2.

15.2.3.2 Analysis of Effects and Consequences

15.2.3.2.1 Method of Analysis

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from 100 percent of full power, without rapid power reduction, primarily to show the adequacy of the pressure-relieving devices, and to demonstrate core protection margins. The turbine is assumed to trip without actuating the rapid power reduction system. This assumption delays reactor trip until conditions in the reactor coolant system result in a trip due to other signals. Thus, the analysis assumes a bounding transient. In addition, no credit is taken for the turbine bypass system. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for startup feedwater or the PRHR heat exchanger (except for long-term recovery) to mitigate the consequences of the transient.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, analyses are performed to evaluate the effects produced by a possible consequential loss of offsite power during a complete loss of steam load. As discussed in Subsection 15.0.14, the loss of offsite power is considered as a direct consequence of a turbine trip occurring while the plant is operating at power. The primary effect of the loss of offsite power is to cause the reactor coolant pumps to coast down.

The turbine trip transients are analyzed by using a modified version of the LOFTRAN code (Reference 2), as described in Reference 6. The program simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables, including temperatures, pressures, and power level.

In the turbine trip analyses, which include a primary coolant flow coastdown caused by a consequential loss of offsite power, a combination of three computer codes is used to perform the departure from nucleate boiling ratio (DNBR) analyses. First, the LOFTRAN code (References 2 and 6) is used to calculate the plant system transient. The FACTRAN code (Reference 7) or the VIPRE-01 fuel rod model (Reference 8), which is equivalent to FACTRAN, is then used to calculate the core heat flux based on nuclear power and reactor coolant flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the DNBR using heat flux from FACTRAN (or VIPRE-01 fuel rod model) and flow from LOFTRAN.

The major assumptions used in the analysis are summarized below.

Initial Operating Conditions

Two sets of initial operating conditions are used. Cases performed to evaluate the minimum DNBR obtained are analyzed using the revised thermal design procedure. Initial core power, reactor coolant temperature, and pressure are assumed to be at their nominal values consistent with steady-state full-power operation. Uncertainties in initial conditions are included in the DNBR limit as described in WCAP-11397-P-A (Reference 5). Instrument bias on the RCS temperature signal is also considered to ensure it is reflected in either the modeled initial conditions or in the safety analysis DNBR limit value.

Cases performed to evaluate the maximum calculated RCS pressure include uncertainties on the initial conditions. Initial core power, reactor coolant temperature, and pressure are assumed to be at the nominal full-power values plus or minus uncertainties. The direction of the uncertainties is chosen to maximize the RCS pressure.

Reactivity Coefficients

Two cases are analyzed:

- Minimum reactivity feedback – A least-negative moderator temperature coefficient and a least-negative Doppler-only power coefficient are assumed (see Figure 15.0.4-1).

- Maximum reactivity feedback – A conservatively large negative moderator temperature coefficient and a most-negative Doppler-only power coefficient are assumed (see Figure 15.0.4-1).

Rod Control

From the standpoint of the maximum RCS pressure and minimum DNBR attained, it is conservative to assume that the reactor is in manual rod control. If the reactor is in automatic rod control, the control rod banks move prior to trip and reduce the severity of the transient.

Steam Release

No credit is taken for the operation of the turbine bypass system or steam generator power-operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through safety valves limits secondary steam pressure at the setpoint value.

Pressurizer Spray

Two cases for both the minimum and maximum reactivity feedback cases are analyzed:

- Full credit is taken for the effect of pressurizer spray in reducing or limiting the coolant pressure. Safety valves are also available. These cases are analyzed primarily to address DNBR concerns.

- No credit is taken for the effect of pressurizer spray in reducing or limiting the coolant pressure. Safety valves are operable. These cases are analyzed to address RCS overpressure concerns.

Feedwater Flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for startup feedwater flow or the PRHR heat exchanger, because a stabilized plant condition is reached before initiation of the startup feedwater or the PRHR heat exchanger is normally assumed to occur. The startup feedwater flow or PRHR heat exchanger removes core decay heat following plant stabilization.

Reactor Trip

Reactor trip is actuated by the first reactor trip setpoint reached, with no credit taken for the rapid power reduction on the turbine trip. Trip signals are expected due to High-2 pressurizer pressure, overtemperature ΔT, Low-2 RCP speed, High-3 pressurizer water level, or Low-2 steam generator narrow range water level.

Plant characteristics and initial conditions are further discussed in Subsection 15.0.3. Plant systems and equipment that may be required to function in order to mitigate the effects of a turbine trip event are discussed in Subsection 15.0.8 and listed in Table 15.0-6.

The protection and safety monitoring system may be required to function following a turbine trip. Pressurizer safety valves and/or steam generator safety valves may be required to open to maintain system pressures below allowable limits. No single active failure prevents operation of systems

required to function. Cases are analyzed, both with and without the operation of pressurizer spray, to determine the worst case for presentation.

Availability of Offsite Power

Each case is analyzed with and without offsite power available. As discussed in Subsection 15.0.14, the loss of offsite power is considered to be a consequence of an event due to disruption of the electrical grid following a turbine trip during the event. The grid is assumed to remain stable for 3 seconds following the turbine trip. In the analysis for the complete loss of steam load, the event is initiated by a turbine trip. Therefore, offsite power is assumed to be lost 3 seconds after the start of the event. For the loss of steam load analysis, the primary impact of the loss of offsite power is a coastdown of the reactor coolant pumps.

Main Steam System Pressure

Additional cases are performed to evaluate the maximum Main Steam System (MSS) pressure, with initial condition uncertainties chosen to maximize MSS pressure. The additional cases include cases with and without offsite power available for minimum and maximum reactivity feedback.

15.2.3.2.2 Results

The transient responses for a turbine trip from 100 percent of full-power operation are shown for eight cases. The eight analysis cases are performed assuming minimum and maximum reactivity feedback, with and without credit for pressurizer spray, and with and without offsite power available. The results of the analyses are shown in Figures 15.2.3-1 through 15.2.3-26. The calculated sequence of events for the accident is shown in Table 15.2-1.

Minimum Reactivity Feedback, With Pressurizer Spray, With and Without Offsite Power Available

Figures 15.2.3-1 through 15.2.3-7 show the transient responses for two cases analyzed for DNBR concerns, with and without offsite power available. In the case with offsite power available, the reactor is tripped by the overtemperature ΔT trip function. The transient DNBR is shown in Figure 15.2.3-6; the minimum DNBR remains above the safety analysis DNBR limit value at all times. Based on this, the DNB design basis defined in Section 4.4 is met.

The case without offsite power is tripped by the Low-2 reactor coolant pump speed trip function. The minimum DNBR remains above the safety analysis DNBR limit value at all times, as shown in Figure 15.2.3-6; therefore, the DNBR design basis defined in Section 4.4 is met. This case is the limiting case with respect to the DNBR margin of the turbine trip cases.

Maximum Reactivity Feedback, With Pressurizer Spray, With and Without Offsite Power Available

Figures 15.2.3-8 through 15.2.3-14 show the transient responses for the other two cases analyzed for DNBR concerns, with and without offsite power available. In the case with offsite power available, the reactor is tripped by the overtemperature ΔT trip function. The transient DNBR is shown in Figure 15.2.3-13; the minimum DNBR remains above the safety analysis DNBR limit value at all times. Based on this, the DNBR design basis defined in Section 4.4 is met for this case.

The case without offsite power is tripped by the Low-2 reactor coolant pump speed trip function. The DNBR transient is similar to, and bounded by, the minimum feedback case with pressurizer spray and without offsite power discussed above. The minimum DNBR remains above the safety analysis DNBR limit value at all times, as shown in Figure 15.2.3-13; therefore, the DNBR design basis defined in Section 4.4 is met.

Minimum Reactivity Feedback, Without Pressurizer Spray, With and Without Offsite Power Available

The results for these cases analyzed to address RCS pressure concerns are shown in Figures 15.2.3-15 through 15.2.3-20. In the case with offsite power available, the reactor is tripped by the High-2 pressurizer pressure trip function. The pressurizer safety valves are actuated in this case and maintain the reactor coolant system pressure below 110 percent of the design value.

If offsite power is lost, the reactor is tripped by the Low-2 reactor coolant pump speed reactor trip function. Offsite power is assumed to be lost 3 seconds after turbine trip. This causes a reduction in the reactor coolant system flow, which is illustrated in Figure 15.2.3-20.

The pressurizer safety valves actuate in both of these cases and maintain the reactor coolant system pressure below 110 percent of the design value. RCS pressure for these cases is shown in Figure 15.2.3-16. Note that the with and without power cases have different assumptions regarding initial pressure. The initial pressure assumptions were based upon sensitivities that were run. With respect to maximum reactor coolant system pressure, the case with offsite power available is the most limiting for turbine trip cases.

Maximum Reactivity Feedback, Without Pressurizer Spray, With and Without Offsite Power Available

Figures 15.2.3-21 through 15.2.3-26 show the transient responses for the two other cases analyzed to address RCS pressure concerns, with and without offsite power available. In the case with offsite power available, the reactor is tripped by the High-2 pressurizer pressure function.

The case without offsite power is tripped by the Low-2 reactor coolant pump speed trip function. RCS pressure for both cases is shown in Figure 15.2.3-22. The pressure within the reactor coolant system is maintained below 110 percent of the design value. Note that the with and without power cases have different assumptions regarding initial pressure. The initial pressure assumptions were based upon sensitivities that were run.

The additional cases performed to address maximum MSS pressure concerns confirm that the steam generator safety valves provide sufficient pressure relief to prevent overpressurization of the MSS.

15.2.3.3 Conclusions

Results of the analyses show that a turbine trip presents no challenge to the integrity of the reactor coolant system or the main steam system. Pressure-relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits.

The analyses show that the predicted DNBR is greater than the safety analysis DNBR limit value at any time during the transient. Thus, the departure from nucleate boiling design basis, as described in Section 4.4, is met.

15.2.4 Inadvertent Closure of Main Steam Isolation Valves

Inadvertent closure of the main steam isolation valves results in a turbine trip with no credit taken for the turbine bypass system. Turbine trips are discussed in Subsection 15.2.3.

15.2.5 Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip

Loss of condenser vacuum is one of the events that can cause a turbine trip. Turbine trip initiating events are described in Subsection 15.2.3. A loss of condenser vacuum prevents the use of steam dump to the condenser. Because steam dump is assumed to be unavailable in the turbine trip

analysis, no additional adverse effects result if the turbine trip is caused by loss of condenser vacuum. Therefore, the analysis results and conclusions contained in Subsection 15.2.3 apply to the loss of the condenser vacuum. In addition, analyses for the other possible causes of a turbine trip, listed in Subsection 15.2.3.1, are covered by Subsection 15.2.3. Possible overfrequency effects, due to a turbine overspeed condition, are discussed in Subsection 15.2.2.1 and are not a concern for this type of event.

15.2.6 Loss of ac Power to the Plant Auxiliaries

15.2.6.1 Identification of Causes and Accident Description

The loss of power to the plant auxiliaries is caused by a complete loss of the offsite grid accompanied by a turbine-generator trip. The onsite standby ac power system remains available but is not credited to mitigate the accident.

From the decay heat removal point of view, in the long term this transient is more severe than the turbine trip event analyzed in Subsection 15.2.3 because, for this case, the decrease in heat removal by the secondary system is accompanied by a reactor coolant flow coastdown, which further reduces the capacity of the primary coolant to remove heat from the core. The reactor will trip:

- Upon reaching one of the trip setpoints in the primary or secondary systems as a result of the flow coastdown and decrease in secondary heat removal.

- Due to the loss of power to the control rod drive mechanisms as a result of the loss of power to the plant.

Following a loss of ac power with turbine and reactor trips, the sequence described below occurs:

- Plant vital instruments are supplied from the Class 1E and uninterruptable power supply.

- As the steam system pressure rises following the trip, the steam generator power-operated relief valves may be automatically opened to the atmosphere. The condenser is assumed not to be available for turbine bypass. If the steam flow rate through the power-operated relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- The onsite standby power system, if available, supplies ac power to the selected plant non-safety loads.

- As the no-load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power-operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot shutdown condition if the startup feedwater is available to supply water to the steam generators.

- If startup feedwater is not available, the PRHR heat exchanger is actuated.

During a plant transient, core decay heat removal is normally accomplished by the startup feedwater system if available, which is started automatically when low levels occur in either steam generator. If that system is not available, emergency core decay heat removal is provided by the PRHR heat exchanger. The PRHR heat exchanger is a C-tube heat exchanger connected, through inlet and outlet headers, to the reactor coolant system. The inlet to the heat exchanger is from the reactor coolant system hot leg, and the return is to the steam generator outlet plenum. The heat exchanger is located above the core to provide natural circulation flow when the reactor coolant pumps are not operating. The IRWST provides the heat sink for the heat exchanger. The PRHR heat exchanger, in

conjunction with the passive containment cooling system, provides core cooling and maintains reactor coolant system conditions to satisfy the evaluation criteria. After the IRWST water reaches saturation, steam starts to vent to the containment atmosphere. The condensation that collects on the containment steel shell (cooled by the passive containment cooling system) returns to the IRWST, maintaining fluid level for the PRHR heat exchanger heat sink. The analysis shows that the natural circulation flow in the reactor coolant system following a loss of ac power event is sufficient to remove residual heat from the core.

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant and PRHR loops.

A loss of ac power to the plant auxiliaries is a Condition II event, a fault of moderate frequency. This event is more limiting with respect to long-term heat removal than the turbine trip initiated decrease in secondary heat removal without loss of ac power, which is discussed in Subsection 15.2.3. A loss of offsite power to the plant auxiliaries will also result in a loss of normal feedwater.

The plant systems and equipment available to mitigate the consequences of a loss of ac power event are discussed in Subsection 15.0.8 and listed in Table 15.0-6.

15.2.6.2 Analysis of Effects and Consequences

15.2.6.2.1 Method of Analysis

The analysis is performed to demonstrate the adequacy of the protection and safety monitoring system, the PRHR heat exchanger, and the reactor coolant system natural circulation capability in removing long-term (approximately 36,000 seconds) decay heat. This analysis also demonstrates the adequacy of these systems in preventing excessive heatup of the reactor coolant system with possible reactor coolant system overpressurization or loss of reactor coolant system water.

A modified version of the LOFTRAN code (Reference 2), described in WCAP-15644 (Reference 6), is used to simulate the system transient following a plant loss of offsite power. The simulation describes the plant neutron kinetics and reactor coolant system, including the natural circulation, pressurizer, and steam generator system responses. The digital program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The assumptions used in this analysis minimize the energy removal capability of the PRHR heat exchanger and maximize the coolant system expansion.

The assumptions used in the analysis are as follows:

- The plant is initially operating at 101 percent of the design power rating with initial reactor coolant temperature 8°F below the nominal value and the pressurizer pressure 50 psi below the nominal value.
- Core residual heat generation is based on ANSI 5.1 (Reference 3). ANSI 5.1 is a conservative representation of the decay energy release rates.
- Reactor trip occurs on RCP Low-2 speed.
- A heat transfer coefficient is assumed in the steam generator associated with reactor coolant system natural circulation flow conditions following the reactor coolant pump coastdown.

- The PRHR heat exchanger is actuated by the Low-2 steam generator narrow range water level (coincident with Low-2 start up feed water flow).

- For the loss of ac power to the station auxiliaries and following reactor trip, the main safety function required is core decay heat removal. That is accomplished by the secondary steam relief through the steam generator safety valves and the PRHR heat exchanger. One of two parallel valves in the PRHR outlet line is assumed to fail to open. This is the worst single failure.

- The pressurizer safety valves are assumed to function.

Plant characteristics and initial conditions are further discussed in Subsection 15.0.3.

Plant systems and equipment necessary to mitigate the effects of a loss of ac power to the station auxiliaries are discussed in Subsection 15.0.8 and listed in Table 15.0-6. Normal reactor control systems are not required to function. The protection and safety monitoring system is required to function following a loss of ac power. The PRHR heat exchanger is required to function with an overall minimum capability to extract heat from the reactor coolant system. No single active failure prevents operation of any system required to function.

Parameters used in the analysis are selected to maximize the pressurizer water volume. Input parameters are not selected to maximize the transient primary side and secondary side pressure. Transient primary side and secondary side pressures during a loss of ac power to station auxiliaries are bounded by those calculated for the turbine trip analyses presented in Subsection 15.2.3.

With respect to DNB concerns, the loss of ac power to station auxiliaries event is bounded by the loss of ac power case analyzed for the turbine trip event presented in Subsection 15.2.3. The consequences of a loss of ac power to station auxiliaries that results in CMT actuation are bounded by the analysis of the Inadvertent Operation of the Core Makeup Tanks During Power Operation event described in Subsection 15.5.1.

15.2.6.2.2 Results

The transient response of the reactor coolant system following a loss of ac power to the plant auxiliaries is shown in Figures 15.2.6-1 through 15.2.6-12. The calculated sequence of events for this event is listed in Table 15.2-1.

The loss of ac power event results in a pressurizer water volume increase until the actuation of the steam generator safety valves. Actuation of the steam generator safety valves attenuates the pressurizer water volume until actuation of the PRHR which turns around the pressurizer water volume increase. PRHR heat extraction and steam generator safety valve relief results in a consequential decrease in the water volume until the safety valve relief stops. After the steam generator safety valve flow stops the pressurizer water volume begins a slight increase until the PRHR heat extraction matches and then exceeds the decay heat addition resulting in a reduction in the pressurizer water volume.

15.2.6.3 Conclusions

Results of the analysis show that for the loss of ac power to plant auxiliaries event, all safety criteria are met. The heat extraction provided by the steam relief capacity of the steam generator safety valves and the operation of the PRHR is sufficient to prevent water relief through the pressurizer safety valves.

The analysis demonstrates that sufficient long-term reactor coolant system heat removal capability exists, via the steam generator safety valves, natural circulation and the PRHR heat exchanger, following reactor coolant pump coastdown to prevent fuel or cladding damage and reactor coolant system overpressure.

15.2.7 Loss of Normal Feedwater Flow

15.2.7.1 Identification of Causes and Accident Description

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of ac power sources) results in a reduction in the capability of the secondary system to remove the heat generated in the reactor core. If startup feedwater is not available, the safety-related PRHR heat exchanger is automatically aligned by the protection and safety monitoring system to remove decay heat.

A small secondary system break can affect normal feedwater flow control, causing low steam generator levels prior to protective actions for the break. This scenario is addressed by the assumptions made for the feedwater system pipe break (see Subsection 15.2.8).

The following occurs upon loss of normal feedwater (assuming main feedwater pump fails or valve malfunctions):

- The steam generator water inventory decreases as a consequence of the continuous steam supply to the turbine. The mismatch between the steam flow to the turbine and the feedwater flow leads to the reactor trip on a Low-2 steam generator narrow range water level signal. The same signal also actuates the startup feedwater system (see Subsection 15.2.6.1).

- As the steam system pressure rises following the trip, the steam generator power-operated relief valves are automatically opened to the atmosphere. The condenser is assumed to be unavailable for turbine bypass. If the steam flow path through the power-operated relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- As the no-load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power-operated relief valves are not available) are used to dissipate the decay heat and to maintain the plant at the hot shutdown condition, if the startup feedwater is used to supply water to the steam generator.

- If startup feedwater is not available, the PRHR heat exchanger is actuated on either a Low-2 steam generator narrow range water level, coincident with a Low-2 startup feedwater flow rate signal or a Low-2 steam generator wide range water level signal.

- The PRHR heat exchanger extracts heat from the reactor coolant system and can lead to an “S” signal on a Low-2 T_{cold} signal. This would actuate the core makeup tanks. Note that in order to confirm the capability of the PRHR heat exchanger to remove decay heat, CMT actuation is not modeled. CMT actuation results in a significant primary side cooldown, and transitions the event from a decrease in heat removal event to an inventory increase event. The consequences of a loss of normal feedwater flow event that results in CMT actuation are bounded by the analysis of the Inadvertent Operation of the Core Makeup Tanks During Power Operation event described in Subsection 15.5.1.

A loss-of-normal-feedwater event is classified as a Condition II event, a fault of moderate frequency.

15.2.7.2 Analysis of Effects and Consequences

The analysis is performed to demonstrate the adequacy of the protection and safety monitoring system and the capability of the PRHR heat exchanger in removing long-term (approximately 36,000 seconds) decay heat following a loss of normal feedwater. This analysis also demonstrates the adequacy of these systems in preventing excessive heatup of the reactor coolant system with possible reactor coolant system overpressurization or loss of reactor coolant system water.

15.2.7.2.1 Method of Analysis

An analysis using a modified version of the LOFTRAN code (Reference 2), described in WCAP-15644 (Reference 6), is performed to obtain the plant transient following a loss of normal feedwater. The simulation describes the neutron kinetics, reactor coolant system (including the natural circulation), pressurizer, and steam generators. The program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

Two cases are analyzed. One case assumes a consequential loss of ac power to the plant auxiliaries resulting from the turbine trip after reactor trip. The loss of ac power results in a coast down of the reactor coolant pumps. A second case does not assume the consequential loss of ac power, which maintains the reactor coolant pumps at normal speed until automatically tripped when an “S” signal is generated.

The assumptions used in the analysis are as follows:

- The plant is initially operating at 101 percent of the design power rating.
- Reactor trip occurs on Low-2 steam generator narrow range water level.
- The principle safety function required after reactor trip is the core decay heat removal. That function is carried out by the PRHR heat exchanger. The worst single failure is assumed to occur in the PRHR heat exchanger. The actuation of the PRHR heat exchanger requires the opening of one of the two fail-open valves arranged in parallel at the PRHR heat exchanger discharge. Because no single failure can be assumed that impairs the opening of both valves, the failure of a single valve is assumed.

  The PRHR heat exchanger is actuated by the Low-2 steam generator narrow range water level signal, coincident with Low-2 start up feedwater flow or by the Low-2 steam generator wide range water level signal.
- Secondary system steam relief is achieved through the steam generator safety valves.
- The initial reactor coolant average temperature is 8°F lower than the nominal value, and initial pressurizer pressure is 50 psi lower than nominal for the case with ac power available. The initial reactor coolant average temperature is 8°F higher than the nominal value, and initial pressurizer pressure is 50 psi higher than nominal for the case without ac power available.

The loss of normal feedwater analyses are performed to demonstrate the adequacy of the protection and safety monitoring system and the PRHR heat exchanger in removing long-term decay heat. Such decay heat removal prevents excessive heatup of the reactor coolant system with possible resultant reactor coolant system overpressurization or loss of reactor coolant system water. The assumptions used in this analysis minimize the energy removal capability of the system, and maximize the coolant system expansion.

With respect to the overpressure evaluation, the loss of normal feedwater transient with and without ac power available events are bounded by the turbine trip event.

Plant characteristics and initial conditions are further discussed in Subsection 15.0.3.

Plant systems and equipment necessary to mitigate the effects of a loss of normal feedwater accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6. Normal reactor control systems are not required to function. The protection and safety monitoring system is required to function following a loss of normal feedwater. The PRHR heat exchanger is required to function with an overall minimum capability to extract heat from the reactor coolant system. No single active failure prevents operation of any system to perform its required function.

15.2.7.2.2 Results

Figures 15.2.7-1 through 15.2.7-13 show the significant plant parameters following a loss of normal feedwater with ac power available.

The loss of main feedwater with ac power available results in an increase in the pressurizer water volume until reactor trip on Low-2 steam generator narrow range water level. The pressurizer water volume then decreases briefly due to the reactor trip. However, due to the loss of secondary heat removal capacity the pressurizer water volume begins to increase. The pressurizer water volume then increases until the PRHR actuates.

The capacity of the PRHR heat exchanger, when the reactor coolant pumps are operating, is much larger than the decay heat, and in the first part of the transient, the reactor coolant system is cooled down. The cool down continues until the reactor coolant temperature reaches the Low-2 T_{cold} setpoint. When the Low-2 T_{cold} setpoint is reached, the reactor coolant pumps are tripped and the core makeup tanks would be actuated. However, in order to confirm the capability of the PRHR heat exchanger to remove long term decay heat, CMT actuation is not modeled.

As a result of the RCP trip, the PRHR heat exchanger heat removal no longer exceeds decay heat, and a second heatup phase occurs, causing pressurizer water volume to begin to increase. This increase continues until the PRHR heat extraction again exceeds the magnitude of the decay heat addition.

The DNBR transient for the loss of normal feedwater event with ac power available is shown in Figure 15.2.7-12.

The calculated sequence of events for this accident is listed in Table 15.2-1.

Figures 15.2.7-14 through 15.2.7-26 show the significant plant parameters following a loss of normal feedwater with a consequential loss of ac power to plant auxiliaries.

The first increase in pressurizer water volume is turned around by the reactor trip on low-2 steam generator narrow range water level, with subsequent increase attenuated by the heat extraction provided by the steam generator safety valves. Due to the steam generator safety valve relief, the pressurizer water volume remains relatively constant until the heat extraction provided by the steam generator safety valves relief stops once steam generator dryout occurs. With no steam generator safety valve relief, the pressurizer water volume begins to increase until the PRHR heat extraction matches and then exceeds the decay heat addition.

15.2.7.3 Conclusions

Results of the analyses show that a loss of normal feedwater or a loss of normal feedwater with a consequential loss of ac power to the plant auxiliaries do not adversely affect the core, the reactor coolant system, or the steam system. The heat removal capacity of the PRHR heat exchanger and the steam generator safety valves is such that reactor coolant water is not relieved from the pressurizer safety valves. DNBR always remains above the design limit values, and reactor coolant system and steam generator pressures remain below 110 percent of their design values. If CMT actuation were to occur, an operator action may be required to mitigate the event, consistent with the operator action presented in Subsection 15.5.1.

15.2.8 Feedwater System Pipe Break

15.2.8.1 Identification of Causes and Accident Description

A major feedwater line rupture is a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the steam generators in order to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedwater line between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. (A break upstream of the feedwater line check valve would affect the plant only as a loss of feedwater. This case is covered by the evaluation in Subsections 15.2.6 and 15.2.7.)

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a reactor coolant system cooldown (by excessive energy discharge through the break) or a reactor coolant system heatup. Potential reactor coolant system cooldown resulting from a secondary pipe rupture is evaluated in Subsection 15.1.5. Therefore, only the reactor coolant system heatup effects are evaluated for a feedwater line rupture in this subsection.

The feedwater line rupture reduces the ability to remove heat generated by the core from the reactor coolant system for the following reasons:

- Feedwater flow to the steam generators is reduced. Because feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip.
- Fluid in the steam generator may be discharged through the break and would not be available for decay heat removal after trip.
- The break may be large enough to prevent the addition of main feedwater after trip.

A major feedwater line rupture is classified as a Condition IV event.

The severity of the feedwater line rupture transient depends on a number of system parameters, including the break size, initial reactor power, and the functioning of various control and safety-related systems. Sensitivity studies presented in WCAP-9230 (Reference 4) illustrate that the most limiting feedwater line rupture is a double-ended rupture of the largest feedwater line. At the beginning of the transient, the main feedwater control system is assumed to malfunction due to an adverse environment. Interactions between the break and the main feedwater control system result in no feedwater flow being injected or lost through the steam generator feedwater nozzles. This assumption causes the water levels in both steam generators to decrease equally until the Low-2 steam generator narrow range water level reactor trip setpoint is reached. After reactor trip, a full double-ended rupture of the feedwater line is assumed such that the faulted steam generator blows down through the break and no main feedwater is delivered to the intact steam generator. These assumptions conservatively bound the most limiting feedwater line rupture that can occur. Analysis is performed at full power assuming the loss of offsite power at the time of the reactor trip. This is more

conservative than the case where power is lost at the initiation of the event. The case with offsite power available is not explicitly examined because, due to the fast generation of an "S" signal (generated by the Low-2 steam line pressure), the reactor coolant pumps would be tripped by the protection and safety monitoring system shortly after the reactor trip. The only difference between the cases with and without offsite power available would be a small difference in when the reactor coolant pumps are tripped.

The following provides the protection for a main feedwater line rupture:

- A reactor trip on any of the following five conditions:
  - High-2 pressurizer pressure
  - Overtemperature ΔT
  - High-3 pressurizer water level
  - Low-2 steam generator narrow range water level in either steam generator
  - "S" signals from either of the following:
    - Two out of four Low-2 steam line pressure in either steam generator
    - Two out of four high containment pressure (high-2)

Refer to Sections 7.1 and 7.2 for a description of the actuation system.

The PRHR heat exchanger functions to:

- Provide a passive method for decay heat removal. The heat exchanger is a C-tube type, located inside the IRWST. The heat exchanger is above the reactor coolant system to provide natural circulation of the reactor coolant. Operation of the PRHR heat exchanger is initiated by the opening of one of the two parallel power-operated valves at the PRHR heat exchanger cold leg.

- Prevent substantial overpressurization of the reactor coolant system (less than 110 percent of design pressures).

- Maintain sufficient liquid in the reactor coolant system so that the core remains in place, and geometrically intact, with no loss of core cooling capability.

Refer to Subsection 6.3.2.2.5 for a description of the PRHR heat exchanger.

15.2.8.2 Analysis of Effects and Consequences

15.2.8.2.1 Method of Analysis

An analysis using a modified version, described in WCAP-15644 (Reference 6), of the LOFTRAN code (Reference 2) is performed to determine the plant transient following a feedwater line rupture. The code describes the reactor thermal kinetics, reactor coolant system (including natural circulation), pressurizer, steam generators, and feedwater system responses and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

The case analyzed assumes a double-ended rupture of the largest feedwater pipe at full power. Major assumptions used in the analysis are as follows:

- The plant is initially operating at 101 percent of the design plant rating. The main feedwater flow measurement supports a 1-percent power uncertainty.

- Initial reactor coolant average temperature is 8.0°F above the nominal value, and the initial pressurizer pressure is 50 psi below its nominal value.

- The pressurizer spray is modeled to function as designed. It is noted that following loss of offsite power and RCP coastdown, the pressurizer spray is not functional (when plant is in natural circulation mode).

- Initial pressurizer level is at a conservative maximum value and a conservative initial steam generator water level is assumed in both steam generators.

- At the start of the transient, interaction between the break in the feedline and the main feedwater control system is assumed to result in a complete loss of feedwater flow to both steam generators. No feedwater flow is delivered to or lost through the steam generator nozzles.

- Reactor trip is assumed to be initiated by the Low-2 steam generator narrow range water level signal on the ruptured steam generator. A two-second delay is assumed following the low level setpoint being reached to allow for the system response times.

- After reactor trip, the faulted steam generator blows down through a double-ended break area of 1.117 ft^2. A saturated liquid discharge is assumed until all the water inventory is discharged from the faulted steam generator. This minimizes the heat removal capability of the faulted steam generator and maximizes the resultant heatup of the reactor coolant. No feedwater flow is assumed to be delivered to the intact steam generator.

- The PRHR heat exchanger is assumed to be actuated by the Low-2 steam generator wide range water level signal. A 17-second delay is assumed following the low level setpoint being reached to allow for the system response times and the valve stroke time.

- Credit is taken for heat energy deposited in reactor coolant system metal during the reactor coolant system heatup.

- No credit is taken for charging or letdown.

- Pressurizer safety valve setpoint is assumed to be at its minimum value.

- Steam generator heat transfer area is assumed to decrease as the shell-side liquid inventory decreases. The heat transfer remains approximately 100 percent in the faulted steam generator until the liquid mass reaches about 11 percent. The heat transfer is then reduced to 0 percent with the liquid inventory.

- Conservative core residual heat generation is assumed based upon long-term operation at the initial power level preceding the trip (Reference 3).

- No credit is taken for the following four protection and safety monitoring system reactor trip signals to mitigate the consequences of the accident:

  – High-2 pressurizer pressure
  – Overtemperature ΔT
  – High-3 pressurizer water level
  – High-2 containment pressure

The PRHR heat exchanger is initiated once the steam generator water level drops to the Low-2 steam generator wide range water level. Similarly, receipt of a Low-2 steam line pressure signal in at

least one steam line initiates a steam line isolation signal that closes all main steam line and feed line isolation valves. This signal also gives an “S” signal that initiates flow of cold borated water from the core makeup tanks to the reactor coolant system.

Plant characteristics and initial conditions are further discussed in Subsection 15.0.3.

No credit is taken for the plant control system to mitigate the consequences of the event. The protection and safety monitoring system is required to function following a feedwater line rupture as analyzed here. No single active failure prevents operation of this system.

The engineered safety features assumed to function are the PRHR heat exchanger, core makeup tank, and steam line isolation valves. The single failure assumed is the failure of one of the two parallel discharge valves in the PRHR outlet line (see Table 15.0-7).

A description and analysis of the core makeup tank is provided in Subsection 6.3.2.2.1. The PRHR heat exchanger is described in Subsection 6.3.2.2.5.

15.2.8.2.2 Results

Calculated plant parameters following a major feedwater line rupture are shown in Figures 15.2.8-1 through 15.2.8-10. The calculated sequence of events for the case analyzed is listed in Table 15.2-1.

The results presented in Figures 15.2.8-5 and 15.2.8-7 show that pressures in the reactor coolant system and main steam system remain below 110 percent of the respective design pressures. Pressurizer pressure decreases after reactor trip on the Low-2 steam generator narrow range water level due to the loss of heat input.

In the first part of the transient, due to the conservative analysis assumptions, the system response following the feedwater line rupture is similar to the loss of ac power to the station auxiliaries (Subsection 15.2.6). Accordingly, like the loss of ac power event documented in Subsection 15.2.6, the feedwater line rupture event is bounded by the turbine trip event presented in Subsection 15.2.3 with respect to DNB concerns.

After the trip, the core makeup tanks are actuated on Low-2 steam line pressure in the ruptured loop while the PRHR heat exchanger is actuated on a Low-2 steam generator wide range water level.

The addition of the PRHR heat exchanger and flow from the core makeup tanks help to cool down the primary system and to provide sufficient fluid to keep the core covered with water.

Pressurizer safety valves open due to the mismatch between decay heat and the heat transfer capability of the PRHR heat exchanger. In the first part of the transient, there is a cooling effect due to the core makeup tanks that inject cold water into the reactor coolant system and receive hot water from the cold leg. This effect decreases due to the heatup of the core makeup tanks from recirculation flow. Also, the injection driving head is lowered as the core makeup tanks heat up.

Reactor coolant system temperatures are low (with the hot leg temperature of the faulted loop at approximately 510°F at about 2,200 seconds) and, in this condition, the PRHR heat exchanger cannot remove the entire decay heat load. Reactor coolant system temperatures then increase until approximately 20,000 seconds reflecting the heat removal limitations of the PRHR heat exchanger. At approximately 23,400 seconds, the heat transfer capability of the PRHR exceeds the decay heat power and the reactor coolant system pressure begins to decrease. Since subcooling is maintained throughout the transient and the reactor coolant system inventory increases (i.e., net core makeup tank injection exceeds net pressurizer safety valve relief), core cooling capability is maintained.

15.2.8.3 Conclusions

Results of the analyses show that for the postulated feedwater line rupture, the capacity of the PRHR heat exchanger is adequate to remove decay heat, to prevent overpressurization of the reactor coolant system, and to maintain the core cooling capability. Radioactivity doses from postulated ruptures of the feedwater lines are less than those presented for the postulated main steam line break. The Standard Review Plan, Subsection 15.2.8, evaluation criteria are therefore met.

15.2.9 Combined License Information

This section contained no requirement for additional information.

15.2.10 References

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7. Hargrove, H. G., “FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod,” WCAP-7908-A, December 1989.

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9. Matthys, C., “Overpressure Protection Report for AP1000 Nuclear Power Plant,” WCAP-16779-NP, April 2007.

Table 15.2-1 (Sheet 1 of 8)
Time Sequence of Events for Incidents Which Result in a Decrease in Heat Removal By the Secondary System

Accident	Event	Time (seconds)
I. Turbine trip		
A.1. With pressurizer spray, minimum reactivity feedback, with offsite power available	Turbine trip; loss of main feedwater	0.0
	Initiation of steam release from steam generator safety valves	10.6
	Minimum DNBR occurs	12.2
	Overtemperature ΔT reactor trip setpoint reached	18.9
	Rods begin to drop	20.9
A.2. With pressurizer spray, minimum reactivity feedback, without offsite power available	Turbine trip; loss of main feedwater	0.0
	Offsite power lost, reactor coolant pumps begin coasting down	3.0
	Low-2 reactor coolant pump speed reactor trip setpoint reached	3.5
	Rods begin to drop	4.1
	Minimum DNBR occurs	6.0
	Initiation of steam release from steam generator safety valves	14.9

Table 15.2-1 (Sheet 2 of 8)
Time Sequence of Events for Incidents Which
Result in a Decrease in Heat Removal By the Secondary System

Accident	Event	Time (seconds)
B.1. With pressurizer spray, maximum reactivity feedback, with offsite power available	Turbine trip; loss of main feedwater flow	0.0
	Minimum DNBR occurs	0.0
	Initiation of steam release from steam generator safety valves	10.7
	Overtemperature ΔT reactor trip setpoint reached	20.9
	Rod motion begins	22.9
B.2. With pressurizer spray, maximum reactivity feedback, without offsite power available	Turbine trip; loss of main feedwater	0.0
	Offsite power lost, reactor coolant pumps begin coasting down	3.0
	Low-2 reactor coolant pump speed reactor trip setpoint reached	3.5
	Rods begin to drop	4.1
	Minimum DNBR occurs	4.9
	Initiation of steam release from steam generator safety valves	16.3

Table 15.2-1 (Sheet 3 of 8)
Time Sequence of Events for Incidents Which
Result in a Decrease in Heat Removal By the Secondary System

Accident	Event	Time (seconds)
C.1. Without pressurizer spray, minimum reactivity feedback, with offsite power available	Turbine trip; loss of main feedwater flow	0.0
	High-2 pressurizer pressure reactor trip point reached	5.1
	Rods begin to drop	7.1
	Initiation of steam release from steam generator safety valves	8.2
	Peak RCS pressure occurs	8.5
C.2. Without pressurizer spray, minimum reactivity feedback, without offsite power available	Turbine trip; loss of main feedwater	0.0
	Offsite power lost, reactor coolant pumps begin coasting down	3.0
	Low-2 reactor coolant pump speed reactor trip setpoint reached	3.5
	Rods begin to drop	4.1
	Peak RCS pressure occurs	6.1
	Initiation of steam release from steam generator safety valves	9.9

Table 15.2-1 (Sheet 4 of 8)
Time Sequence of Events for Incidents Which
Result in a Decrease in Heat Removal By the Secondary System

Accident	Event	Time (seconds)
D.1. Without pressurizer spray, maximum reactivity feedback, with offsite power available	Turbine trip; loss of main feedwater flow	0.0
	High-2 pressurizer pressure reactor trip	5.0
	Rods begin to drop	7.0
	Peak RCS pressure occurs	7.9
	Initiation of steam release from steam generator safety valves	8.2
D.2. Without pressurizer spray, maximum reactivity feedback, without offsite power available	Turbine trip; loss of main feedwater	0.0
	Offsite power lost, reactor coolant pumps begin coasting down	3.0
	Low-2 reactor coolant pump speed reactor trip setpoint reached	3.5
	Rods begin to drop	4.1
	Peak RCS pressure occurs	5.8
	Initiation of steam release from steam generator safety valves	10.0

Table 15.2-1 (Sheet 5 of 8)
Time Sequence of Events for Incidents Which
Result in a Decrease in Heat Removal By the Secondary System

Accident	Event	Time (seconds)
II.A. Loss of ac power to the plant auxiliaries	Offsite ac power is lost, feedwater is lost, RCPs begin to coast down, turbine trip occurs (transient initiation)	10.0
	RCP Low-2 speed reactor trip set point is reached	10.5
	Rods begin to drop	11.2
	Pressurizer safety valves first open	~80.0
	Steam generator safety valves first open	99.2
	Low steam generator narrow range water level reactor trip setpoint reached	454.8
	PRHR heat exchanger actuation on Low-2 steam generator narrow range water level (coincident with Low-2 start up flow rate)	637.0
	Maximum long term pressurizer water volume reached	17,100
	PRHR heat exchanger heat removal matches decay heat	~17,700

Table 15.2-1 (Sheet 6 of 8)
Time Sequence of Events for Incidents Which
Result in a Decrease in Heat Removal By the Secondary System

Accident	Event	Time (seconds)
IIIA. Loss of normal feedwater flow	Feedwater is lost (transient initiation)	10.0
	Low-2 steam generator narrow range water level reactor trip reached	61.1
	Rods begin to drop	63.1
	Minimum DNBR is reached	64.0
	Steam generator safety valves first open	94.5
	PRHR heat exchanger actuation on Low-2 steam generator narrow range water level (coincident with Low-2 start up feeedwater flow rate)	243.1
	Cold leg temperature reaches Low-2 T_{cold} setpoint	1455.6
	Reactor coolant pump trip on Low-2 T_{cold} “S” signal	1455.6
	Steam line isolation on Low-2 T_{cold} “S” signal	1467.6
	Core makeup tank actuation on Low-2 T_{cold} “S” signal	1587.9
	Pressurizer safety valves first open	~2500
	PRHR heat exchanger heat removal matches decay heat addition	~15,500
	Maximum long term pressurizer water volume reached	16,500

Table 15.2-1 (Sheet 7 of 8)
Time Sequence of Events for Incidents Which
Result in a Decrease in Heat Removal By the Secondary System

Accident	Event	Time (seconds)
III.B. Loss of normal feedwater flow with a consequential loss of ac power	Feedwater is lost (transient initiation)	10.0
	Pressurizer safety valves first open	~40
	Low-2 steam generator narrow range water level reactor trip setpoint is reached	60.8
	Rods begin to drop	62.8
	Minimum DNBR is reached	63.5
	RCP trip due to loss of ac power	70.2
	Steam generator safety valves first open	70.8
	Low steam generator wide range water level reactor trip setpoint is reached	194.4
	PRHR heat exchanger actuation on Low-2 steam generator wide range water level	211.4
	PRHR heat exchanger heat removal matches decay heat addition	~1,900
	Maximum long term pressurizer water volume reached	2026

Table 15.2-1 (Sheet 8 of 8)
Time Sequence of Events for Incidents Which Result in a Decrease in Heat Removal By the Secondary System

Accident	Event	Time (seconds)
IV. Feedwater system pipe break	Main feedwater flow to both steam generators stops due to interaction between the break and the main feedwater control system (transient initiation)	10.0
	Low-2 steam generator narrow range water level setpoint reached	60.3
	Rods begin to drop	62.3
	Reverse flow from the faulted steam generator through a full double-ended rupture starts	62.3
	Loss of offsite power	70.3
	Low-2 steam line pressure setpoint is reached	76.6
	Core makeup tank valves fully opened	76.7
	Low-2 steam generator wide range water level setpoint reached	81.6
	All steam isolation valves close	88.6
	PRHR heat exchanger actuation on Low-2 steam generator wide range water level	98.6
	Faulted steam generator empties	122.0
	Intact steam generator safety valves open for the first time	239.6
	Pressurizer safety valves open for the first time	1,998
	PRHR heat exchanger extracted heat matches decay heat	23,400

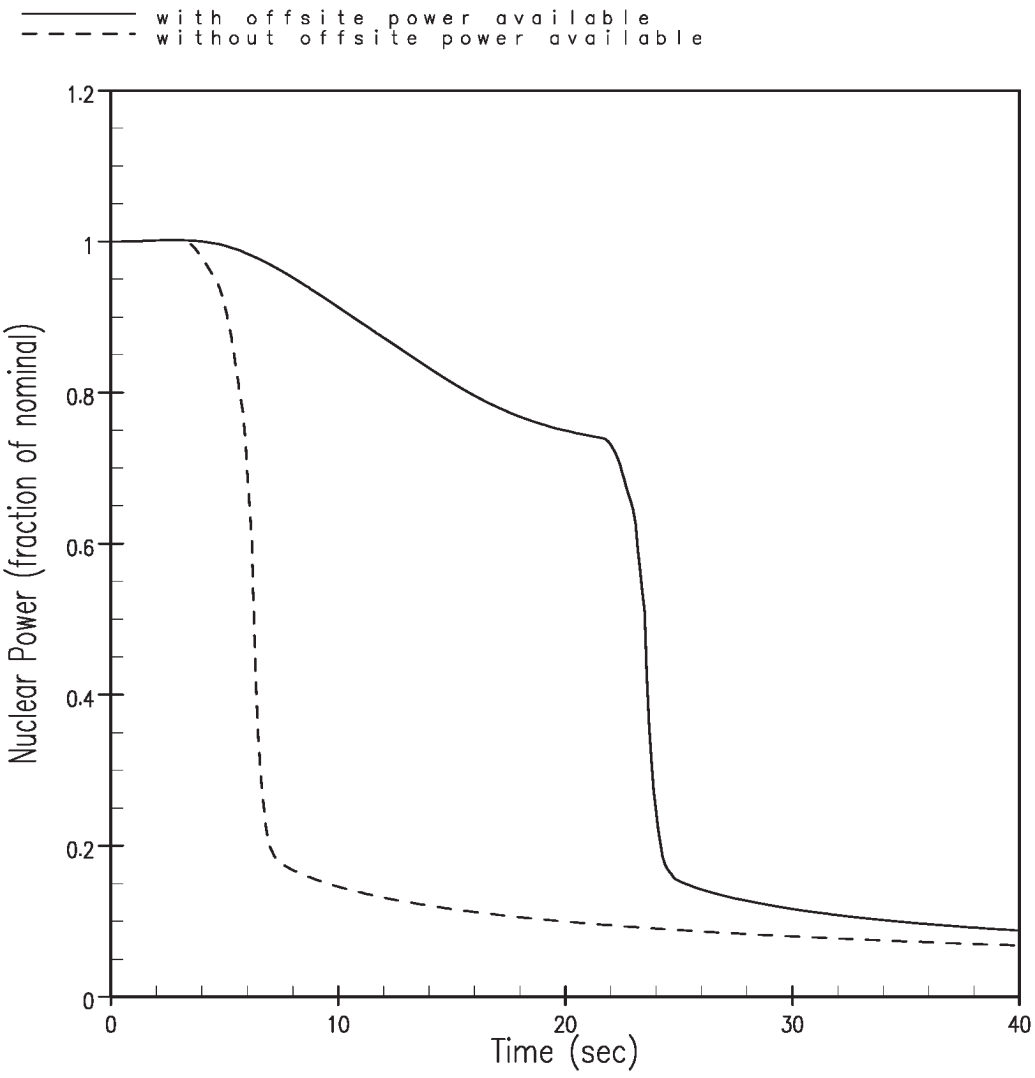

Figure 15.2.3-1
Nuclear Power versus Time for Turbine
Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

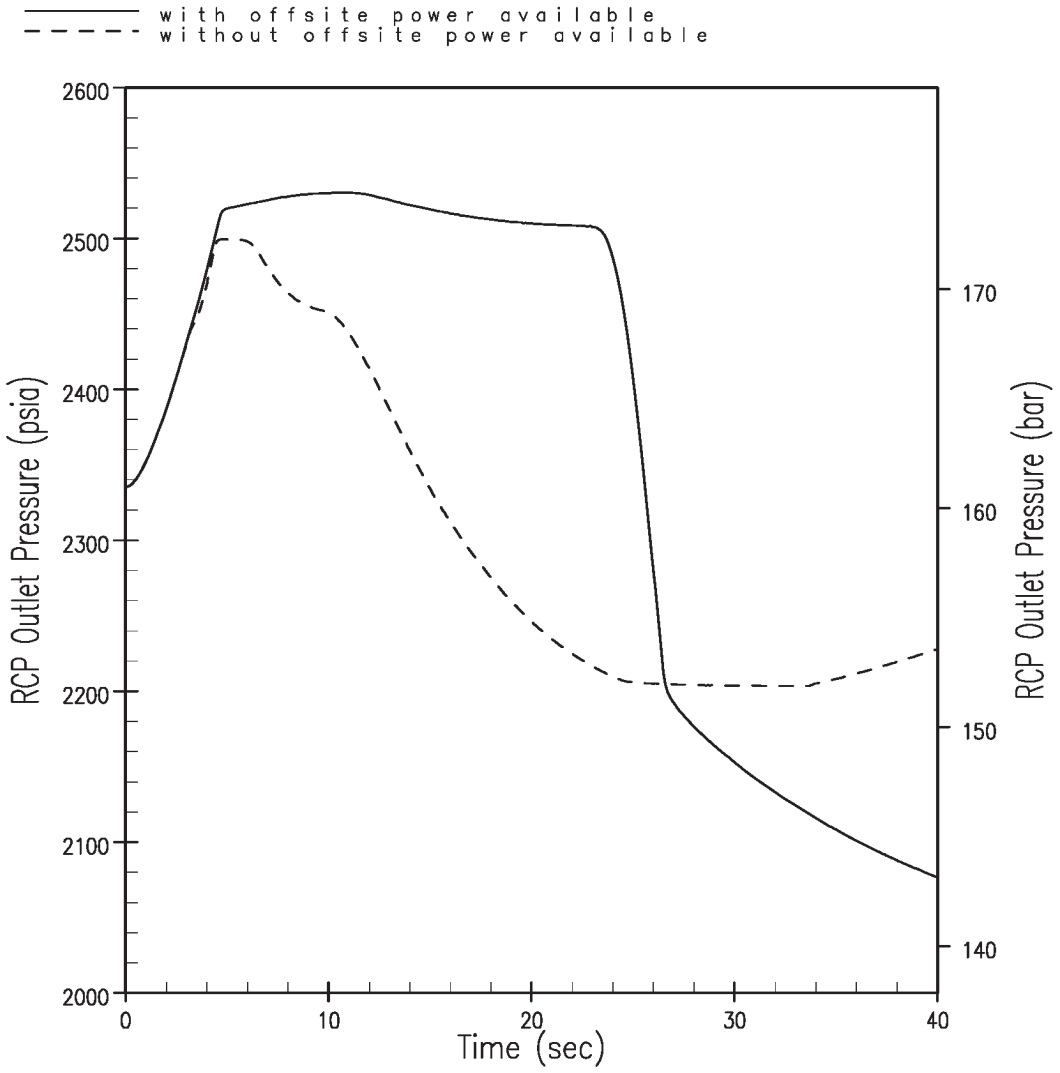

Figure 15.2.3-2
RCP Outlet Pressure versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

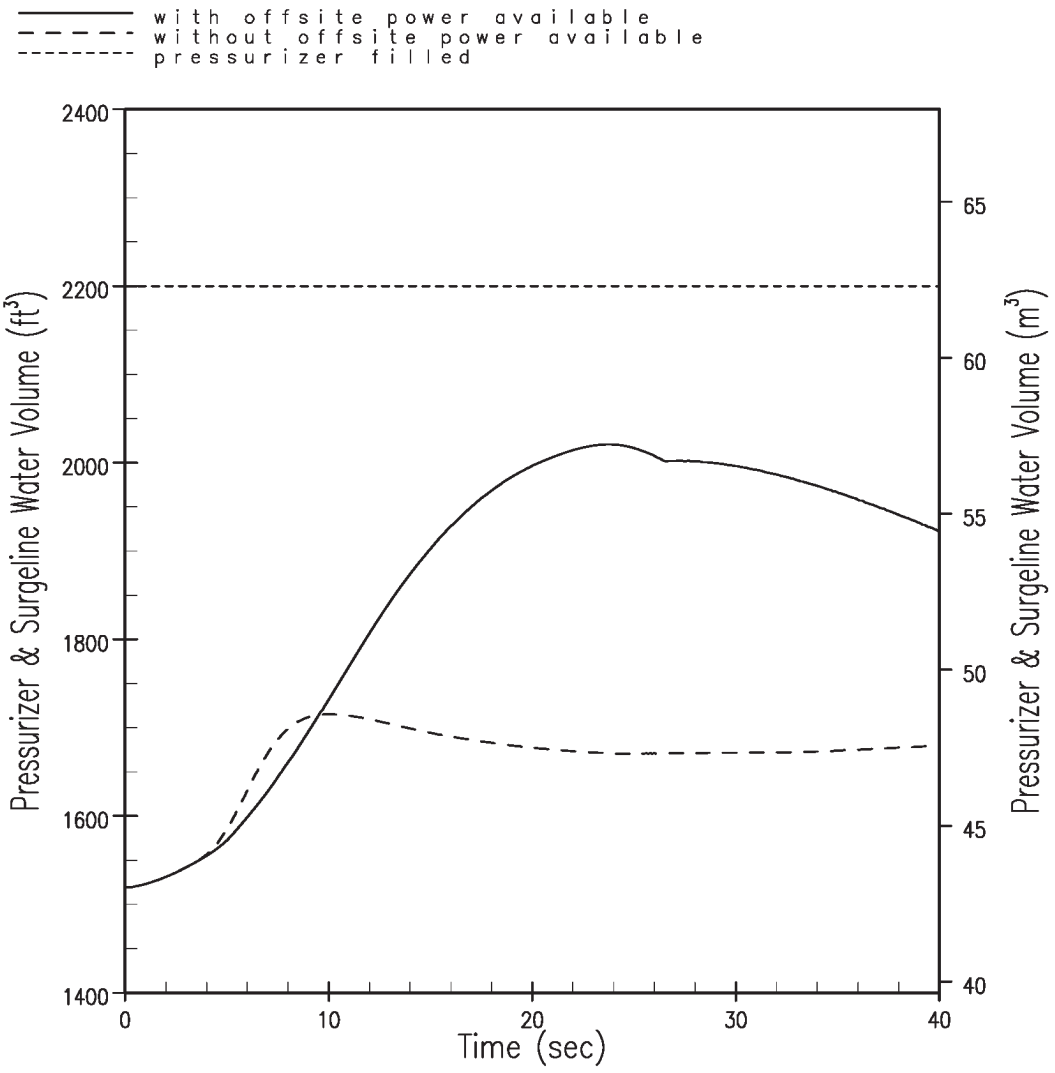

Figure 15.2.3-3
Pressurizer & Surge Line Water Volume versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

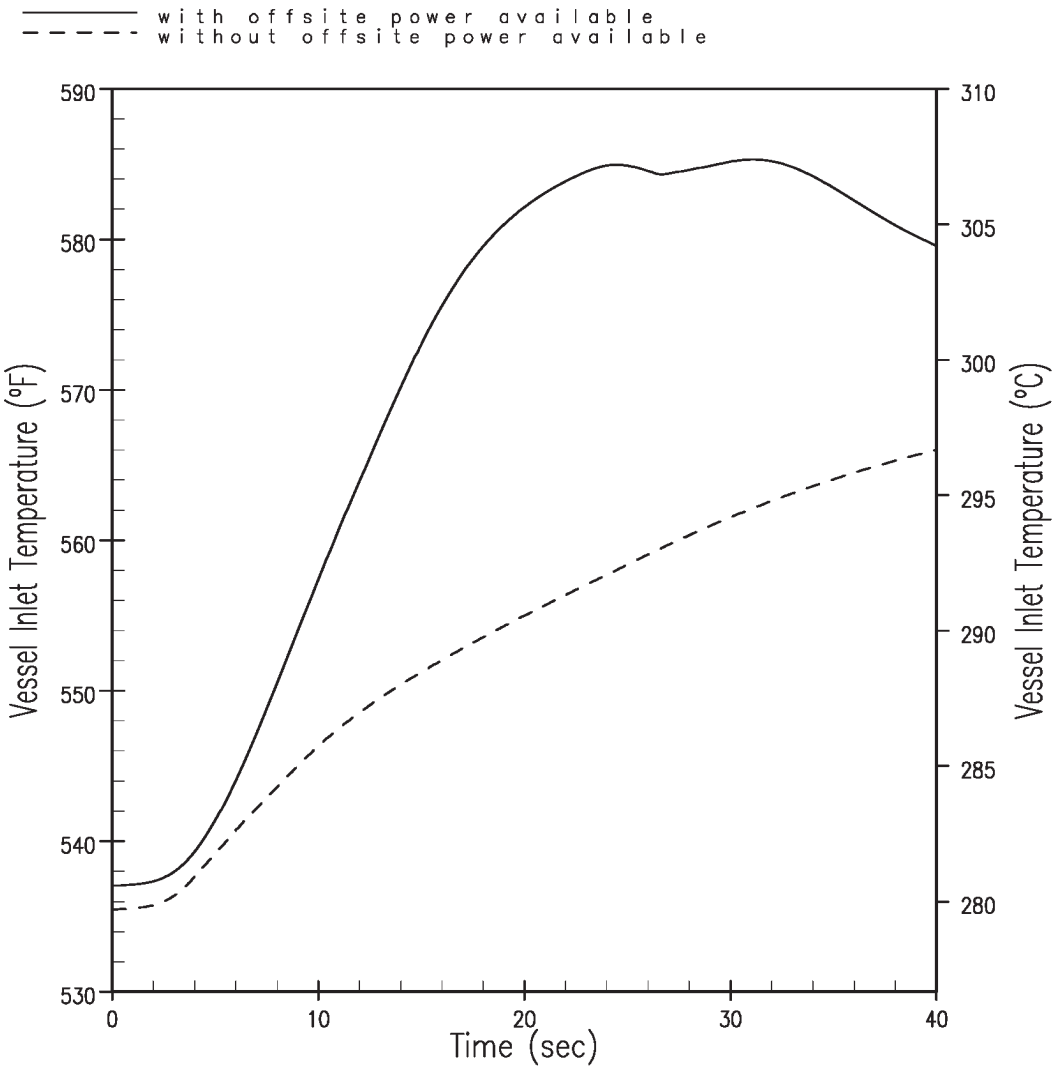

Figure 15.2.3-4
Vessel Inlet Temperature versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

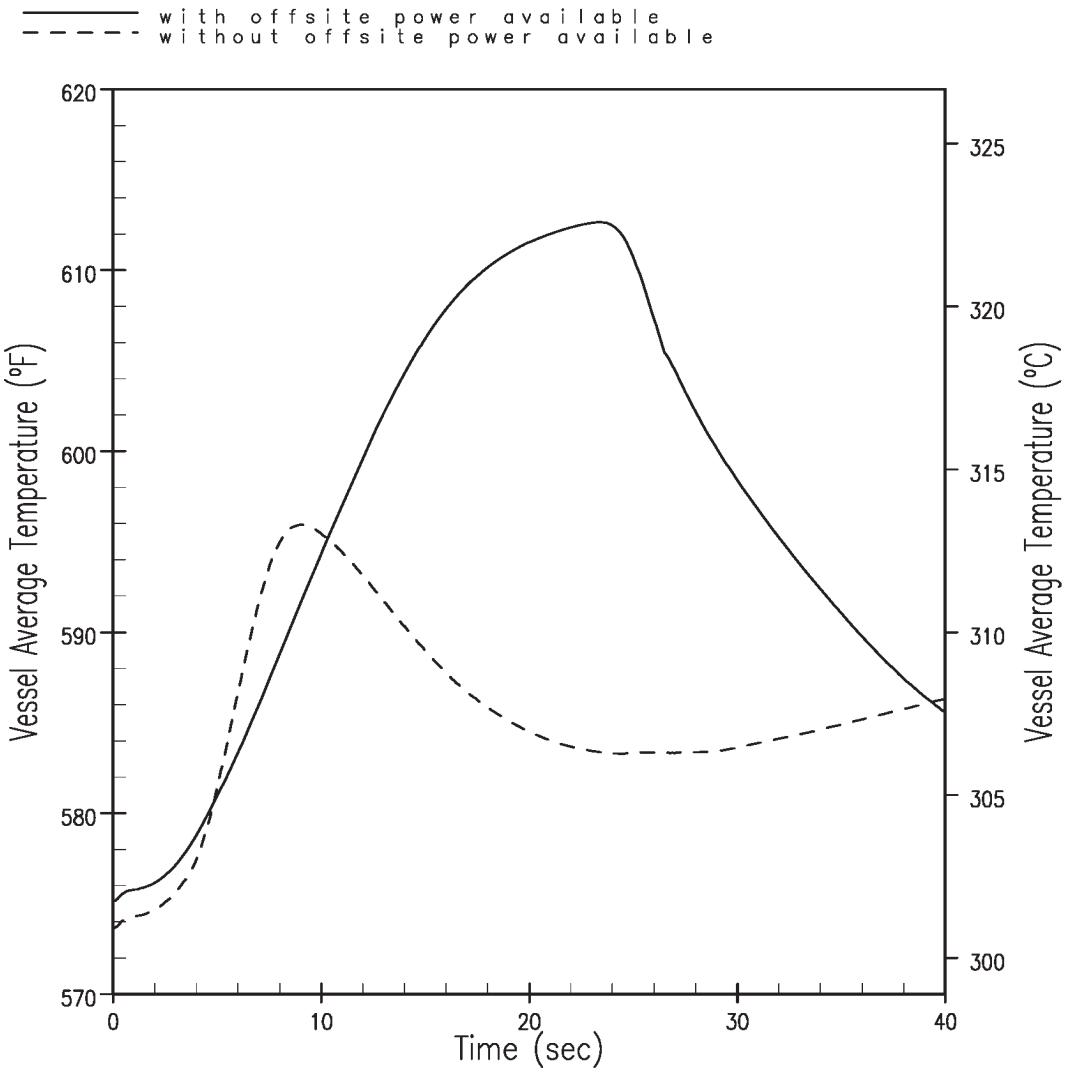

Figure 15.2.3-5
Vessel Average Temperature versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

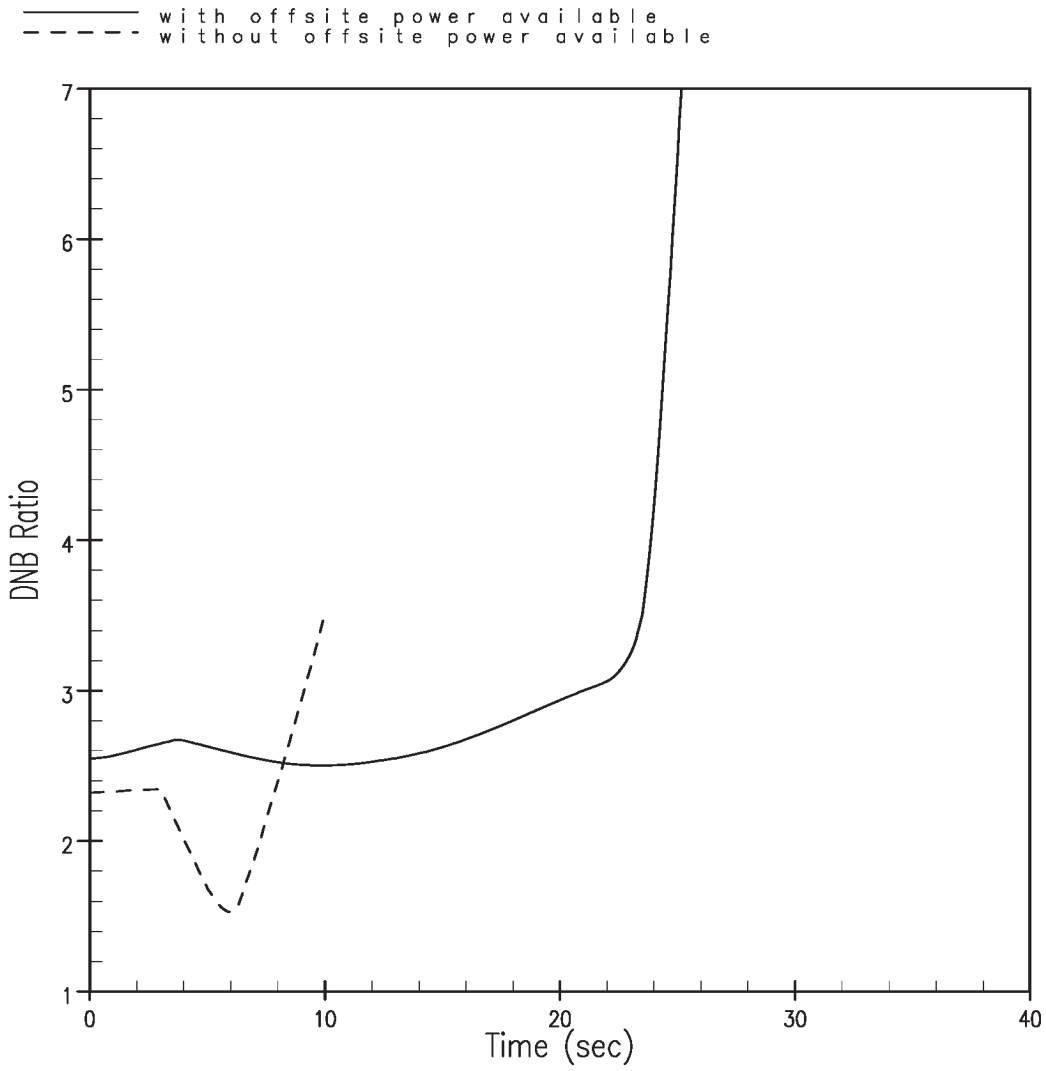

Figure 15.2.3-6
DNBR versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

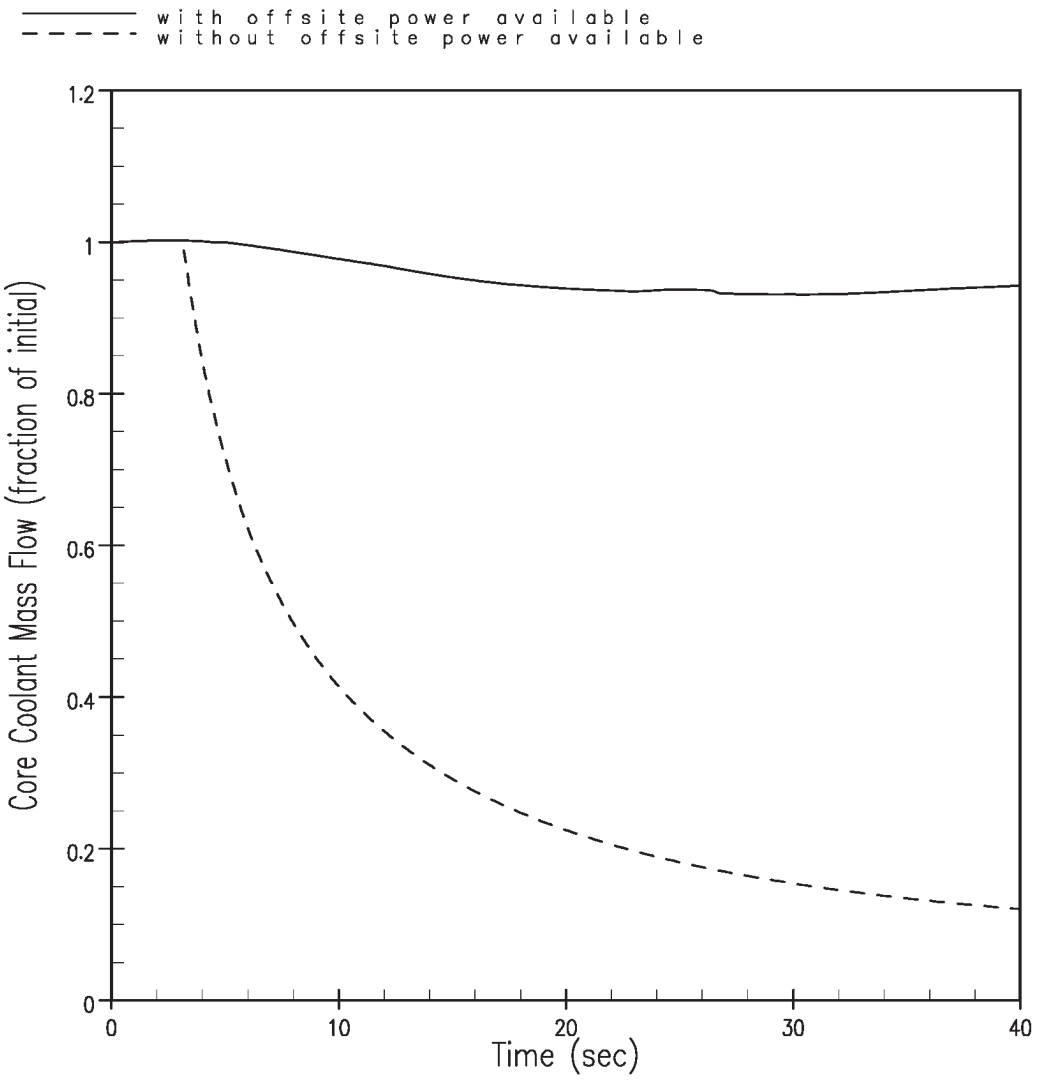

Figure 15.2.3-7
Core Coolant Mass Flow Rate versus Time for Turbine Trip Accident with Pressurizer Spray and Minimum Moderator Feedback

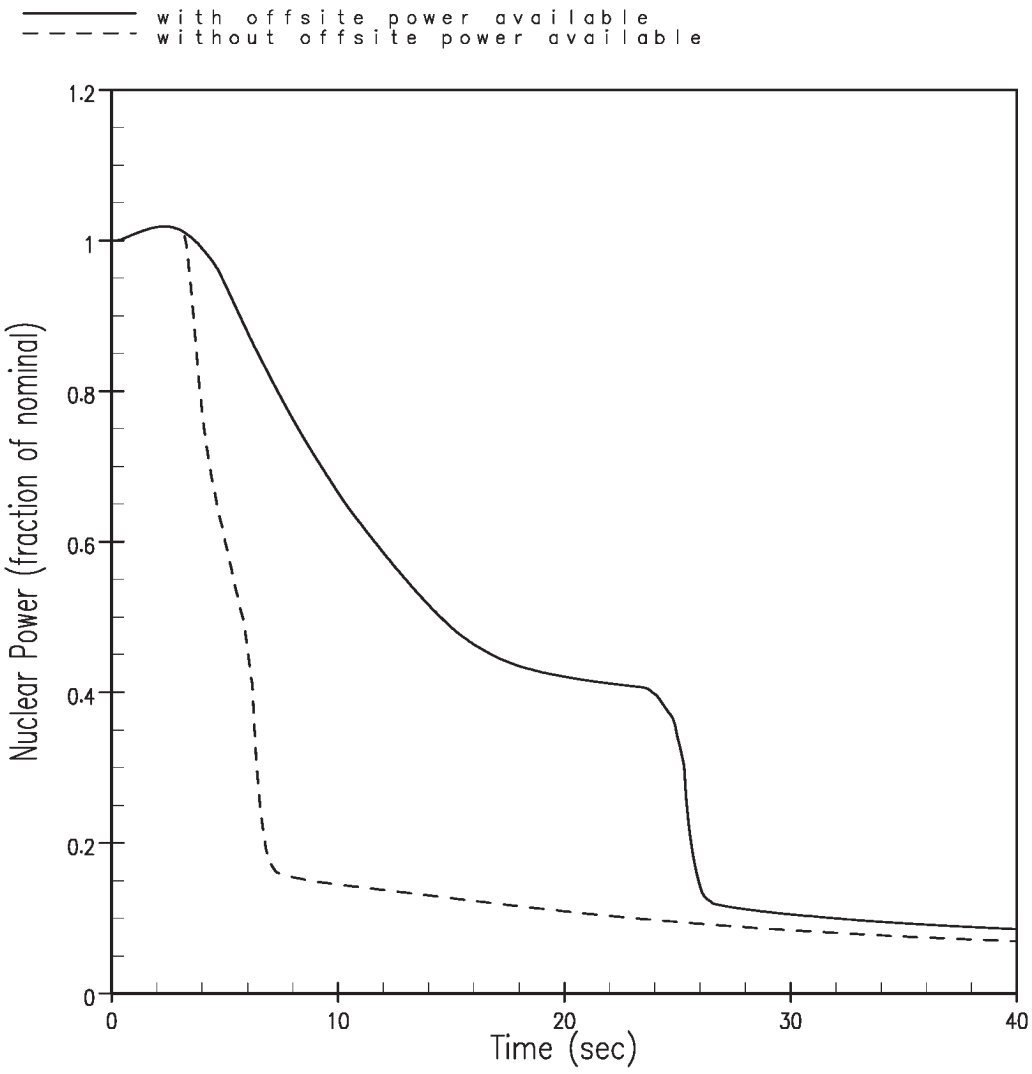

Figure 15.2.3-8
Nuclear Power versus Time for Turbine
Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

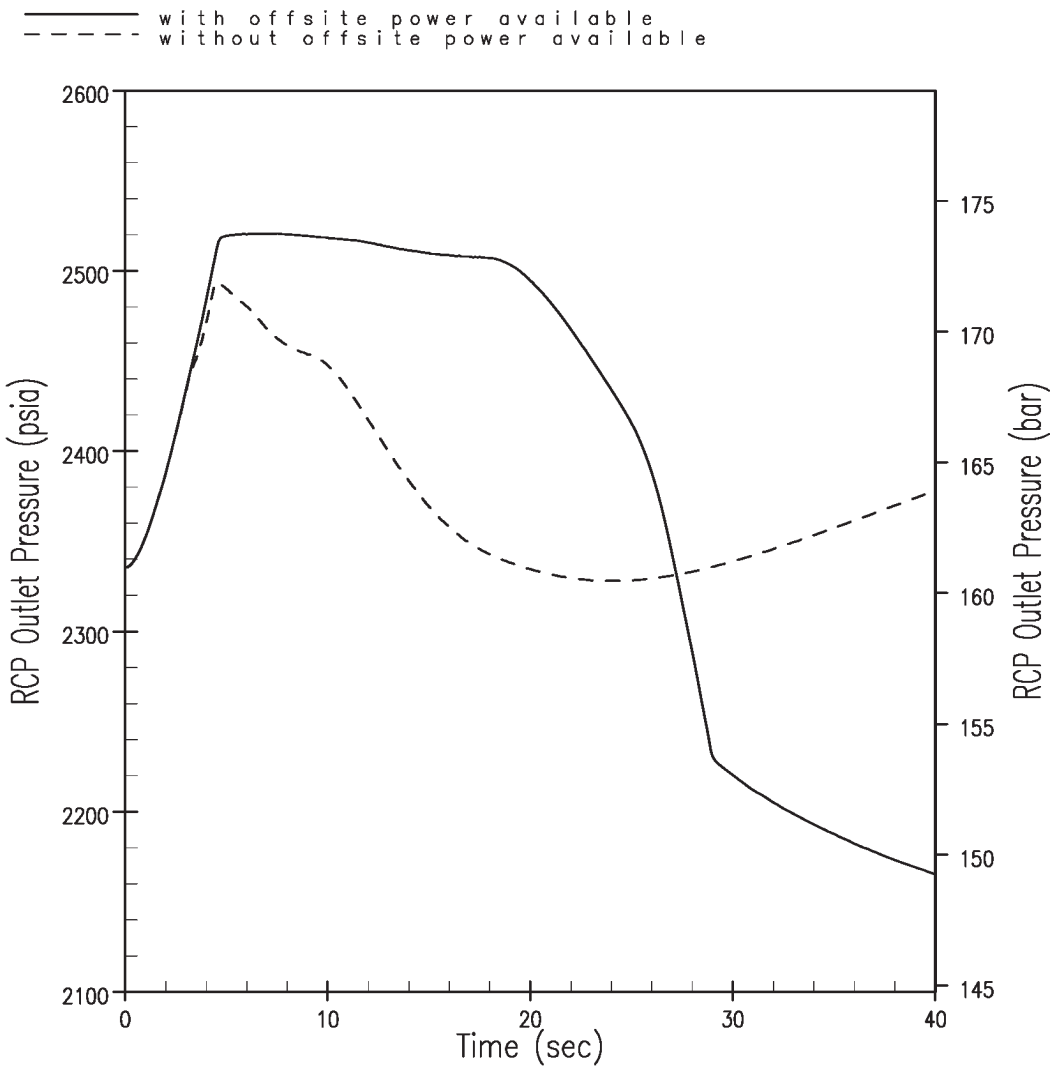

Figure 15.2.3-9
RCP Outlet Pressure versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

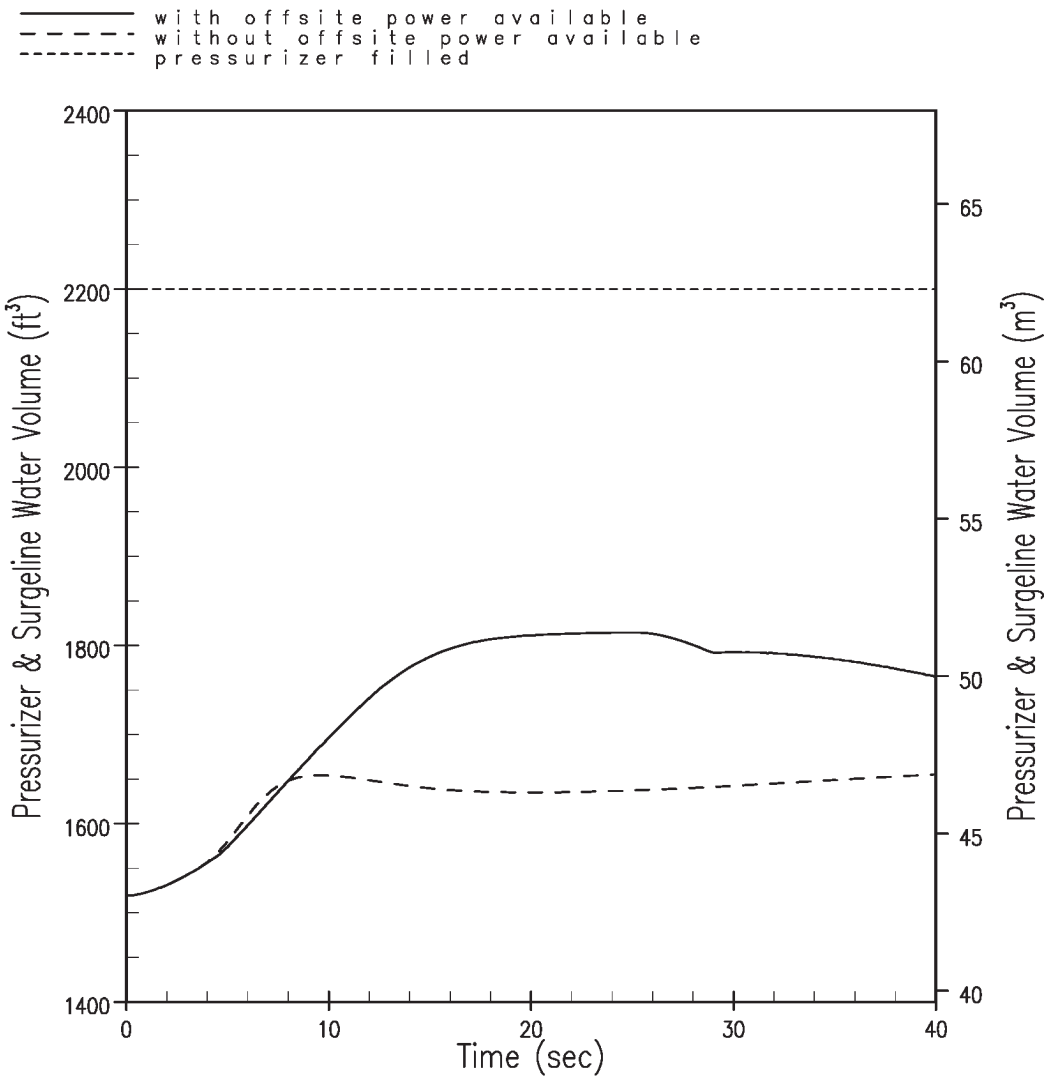

Figure 15.2.3-10
Pressurizer & Surge Line Water Volume versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

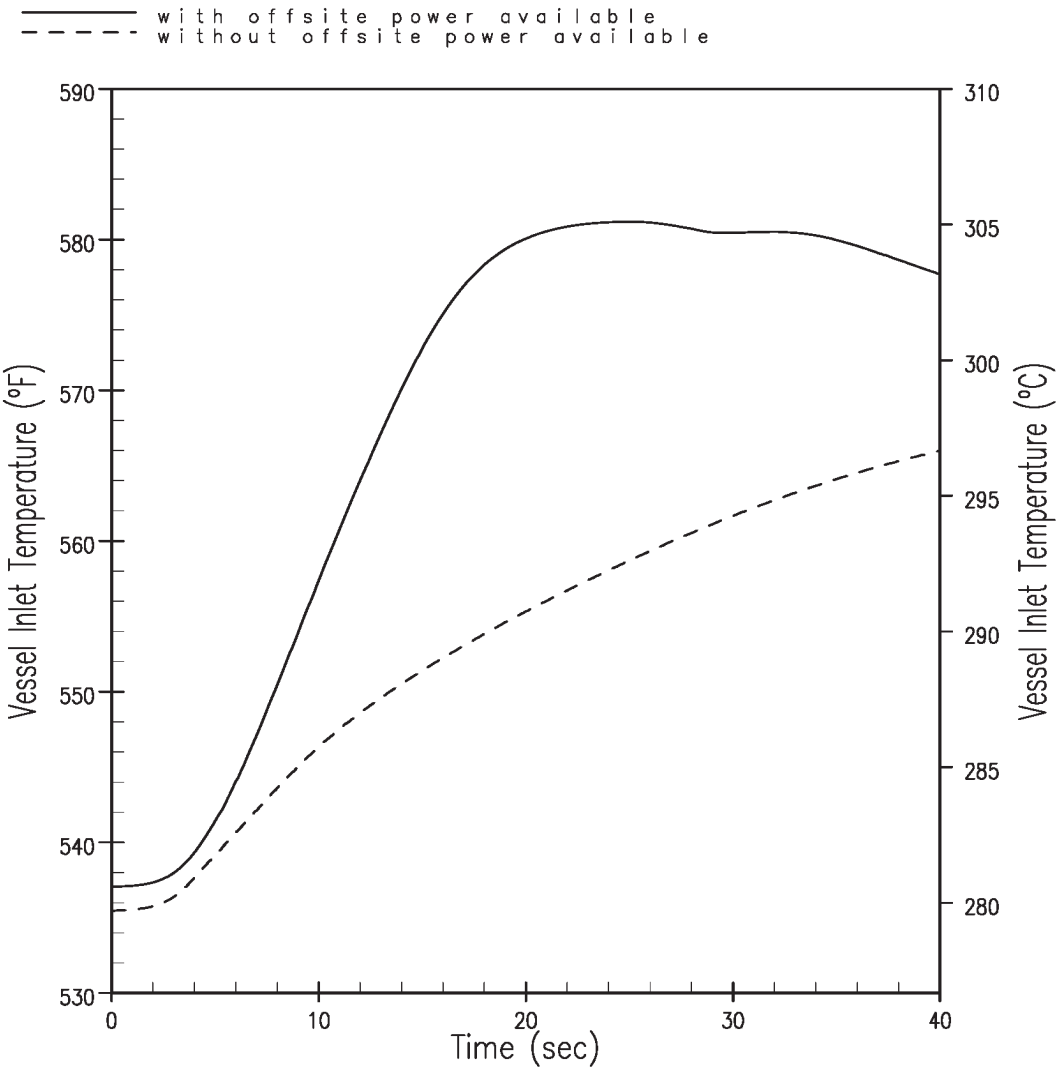

Figure 15.2.3-11
Vessel Inlet Temperature versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

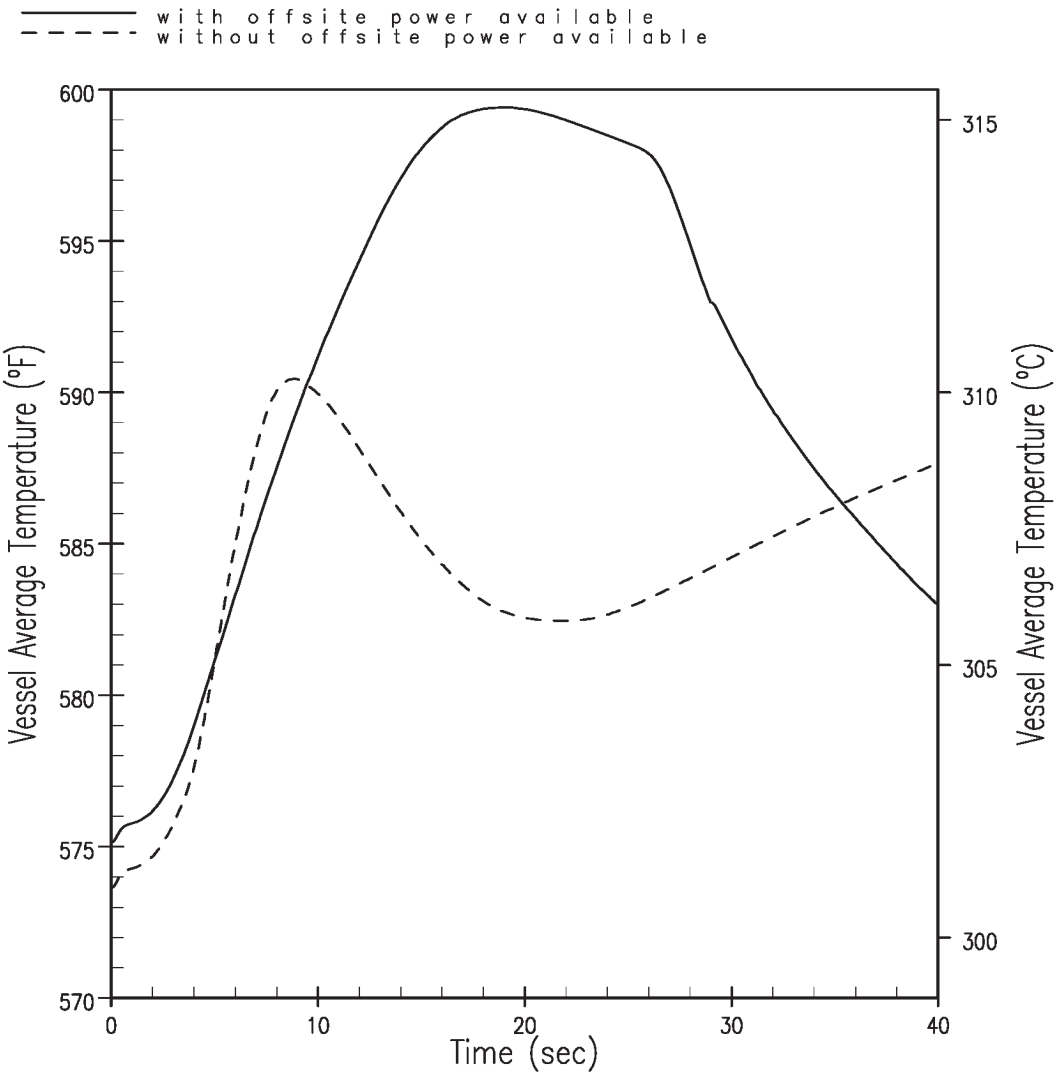

Figure 15.2.3-12
Vessel Average Temperature versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

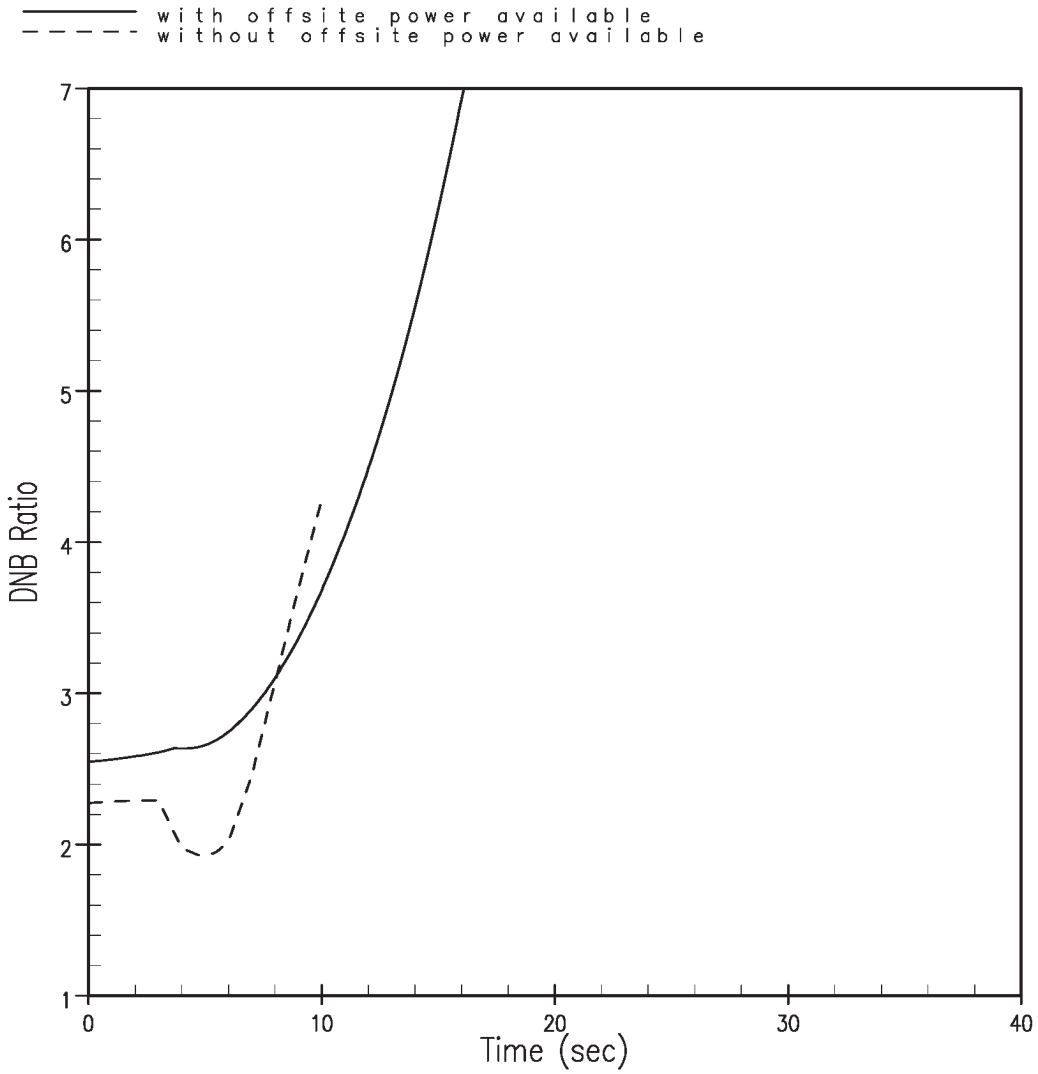

Figure 15.2.3-13
DNBR versus Time for Turbine Trip Accident
with Pressurizer Spray and Maximum Moderator Feedback

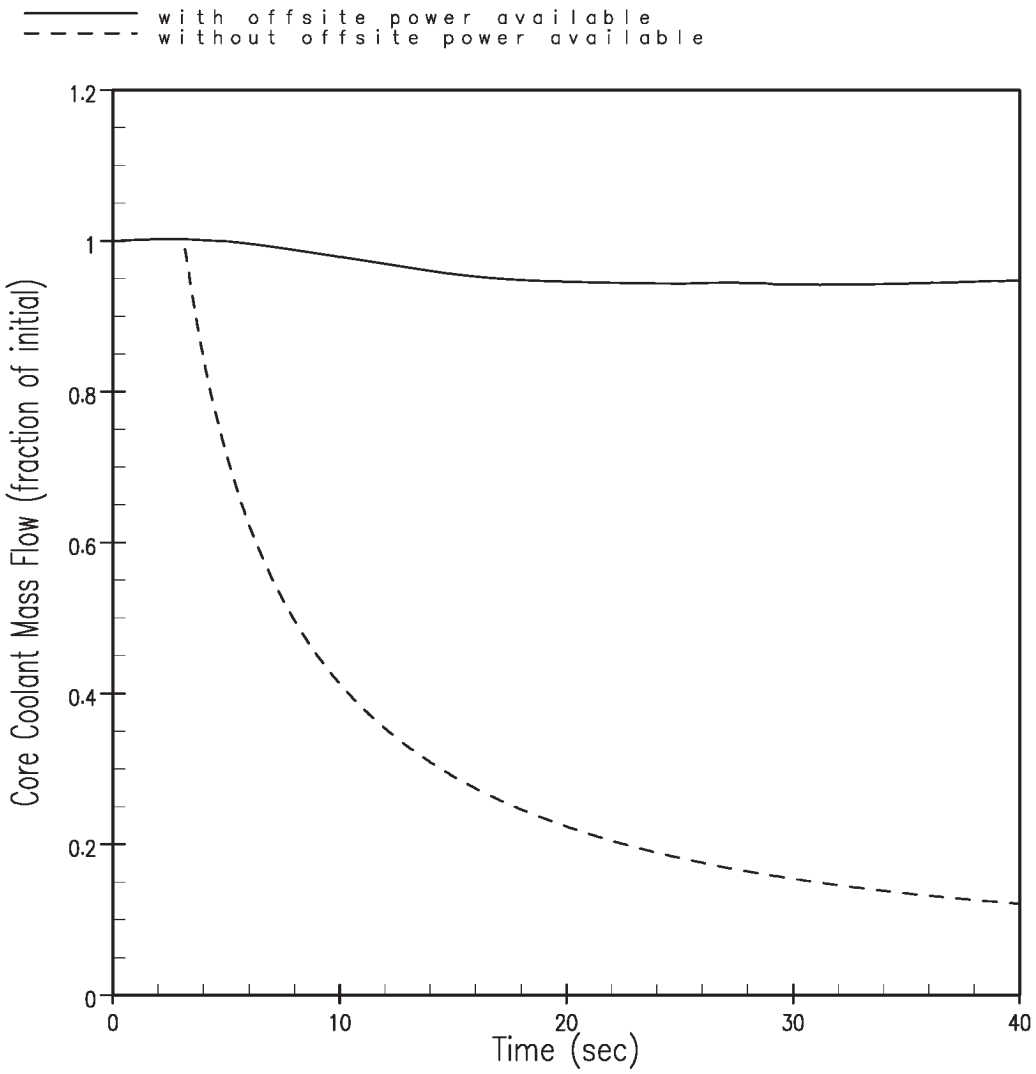

Figure 15.2.3-14
Core Coolant Mass Flow Rate versus Time for Turbine Trip Accident with Pressurizer Spray and Maximum Moderator Feedback

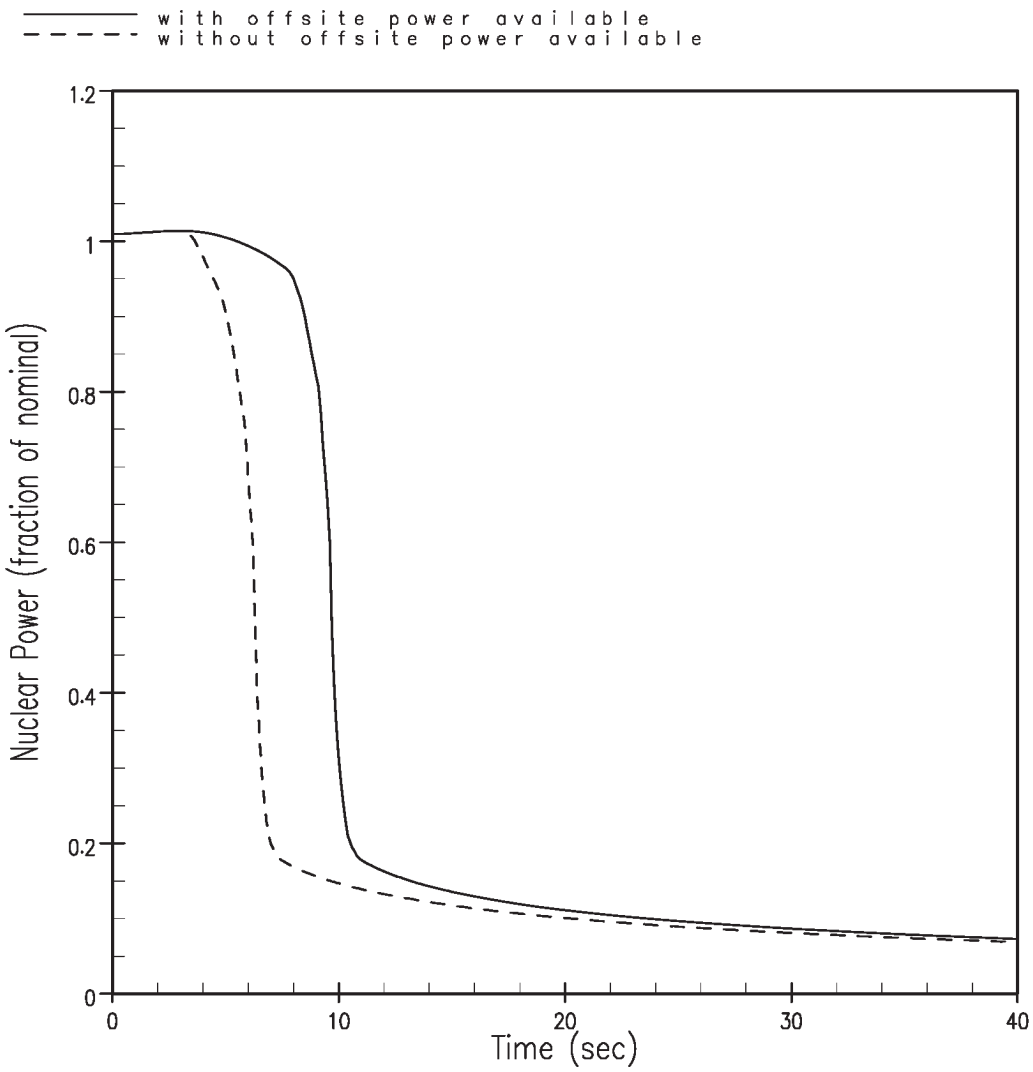

Figure 15.2.3-15
Nuclear Power versus Time for Turbine
Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

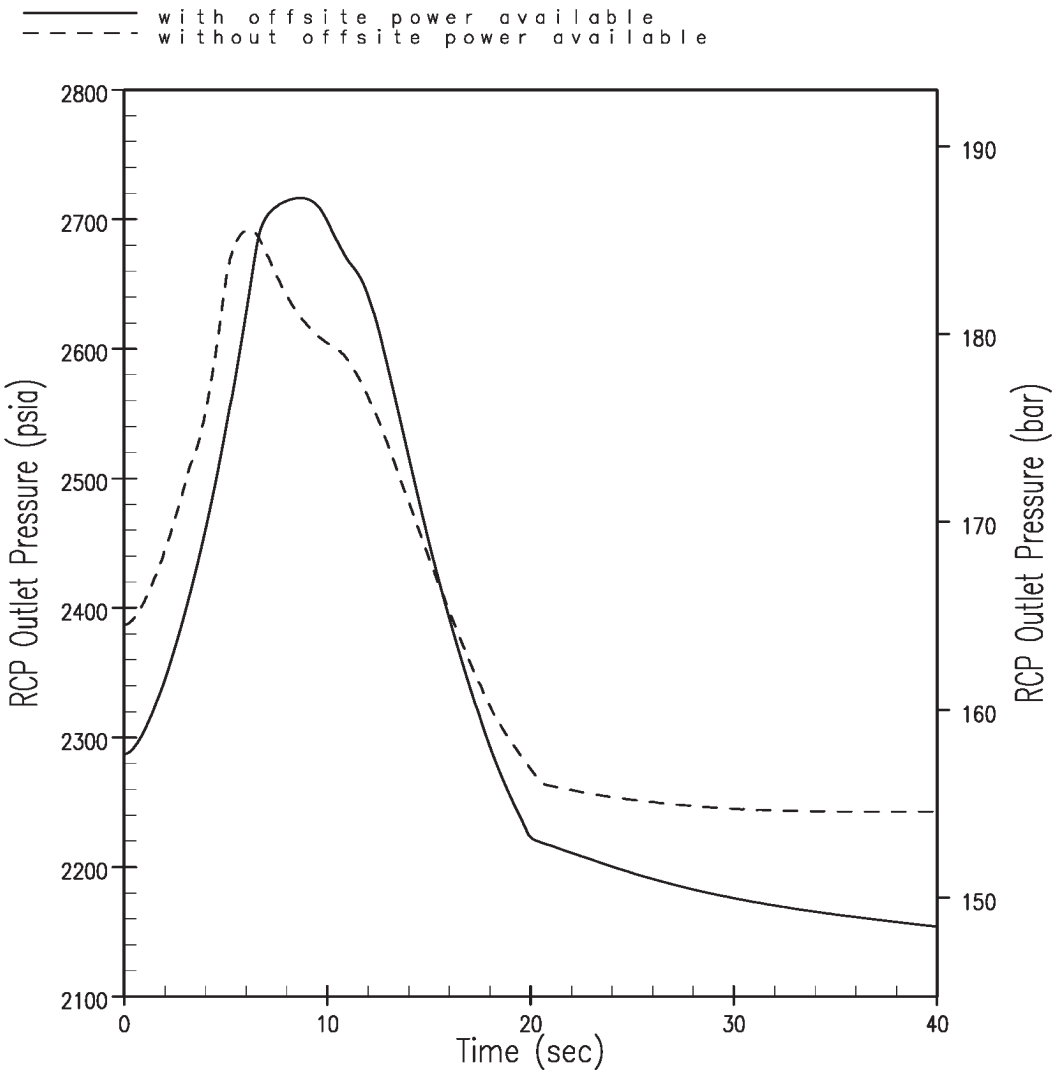

Figure 15.2.3-16
RCP Outlet Pressure versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

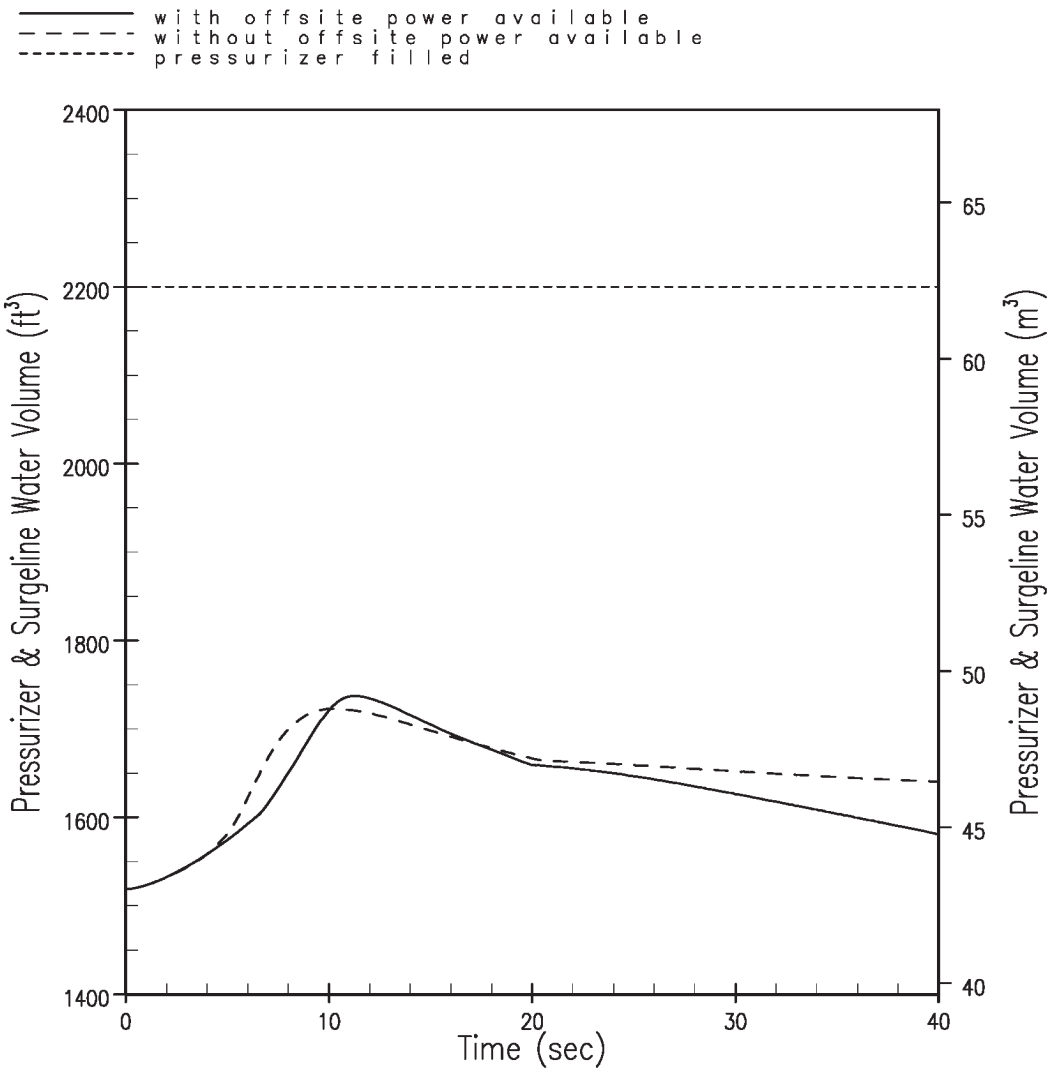

Figure 15.2.3-17
Pressurizer & Surge Line Water Volume versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

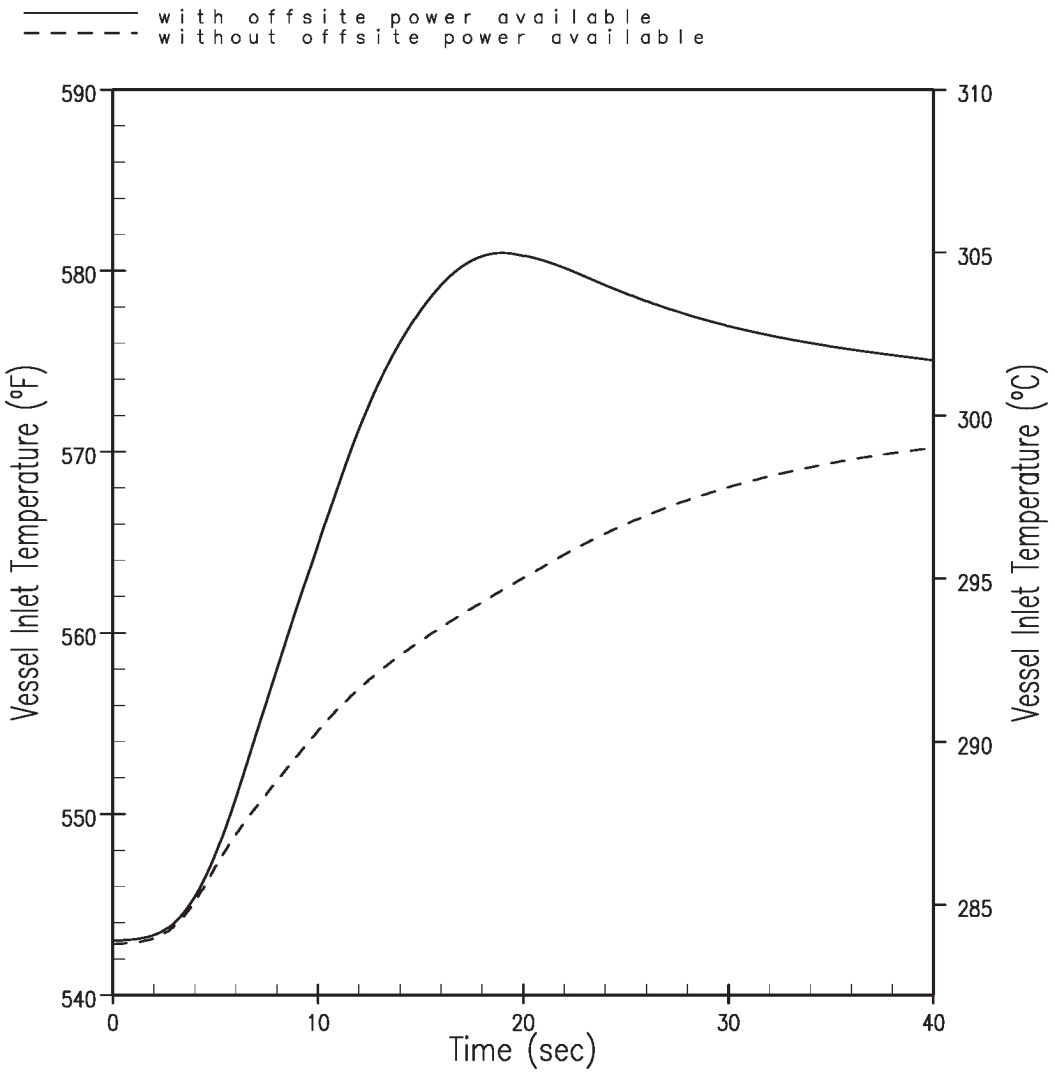

Figure 15.2.3-18
Vessel Inlet Temperature versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

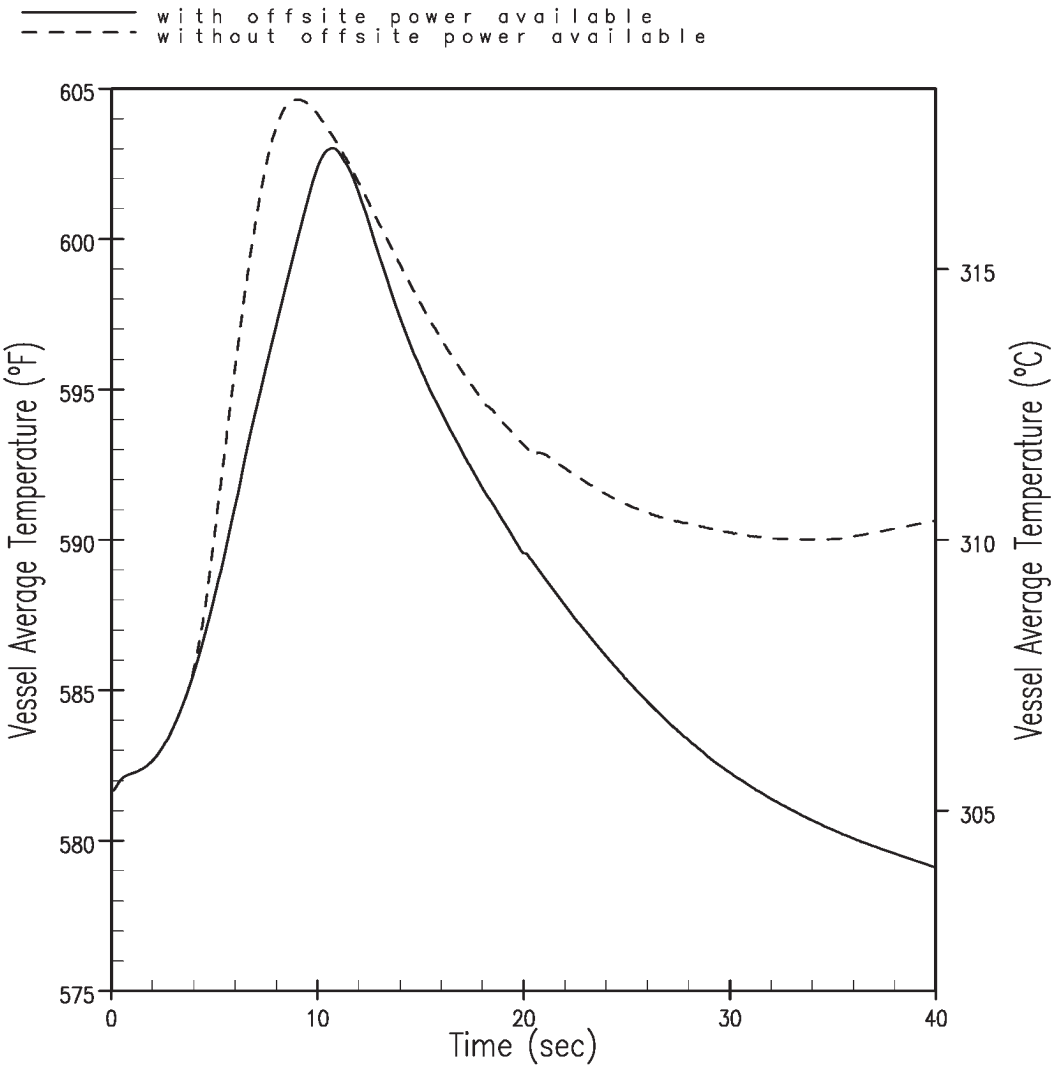

Figure 15.2.3-19
Vessel Average Temperature versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

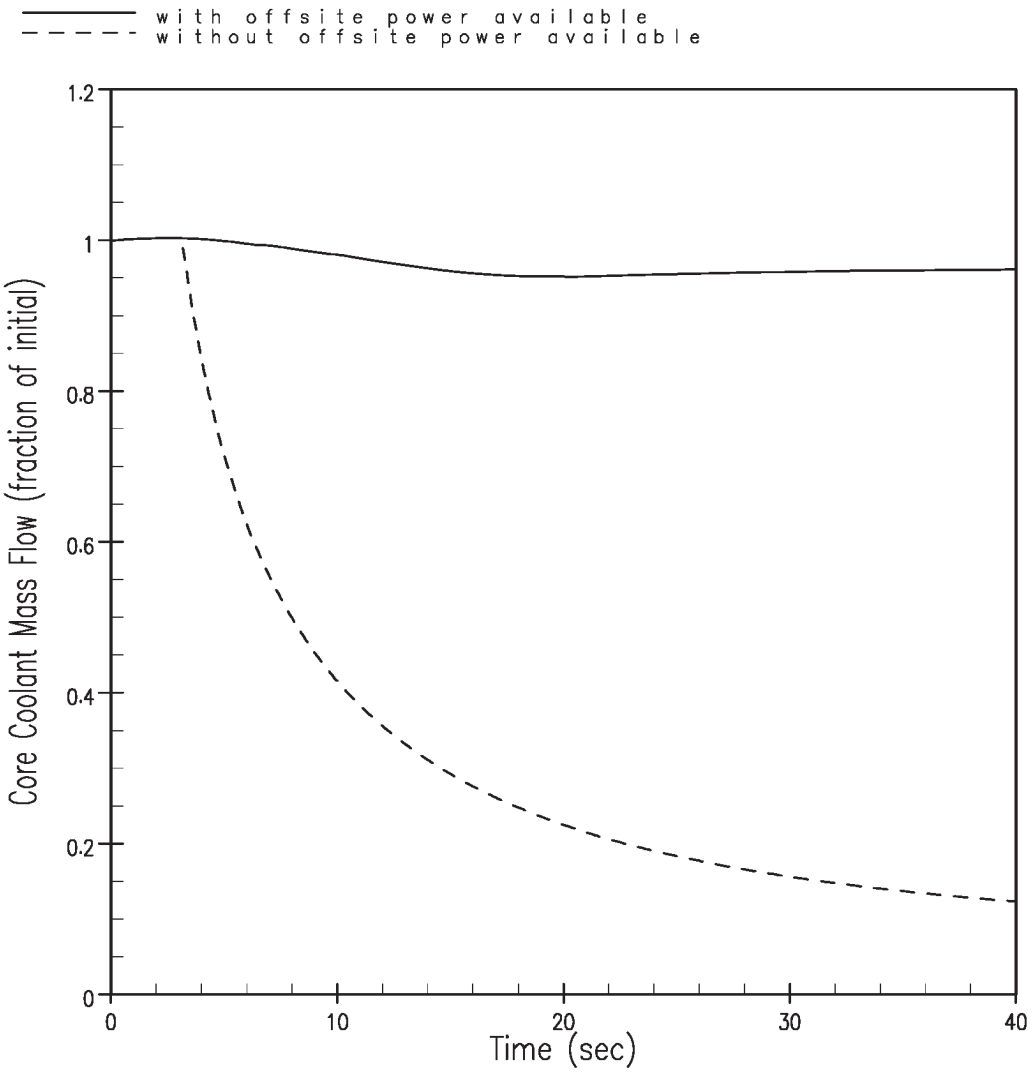

Figure 15.2.3-20
Core Coolant Mass Flow Rate versus Time for Turbine Trip Accident Without Pressurizer Spray and Minimum Moderator Feedback

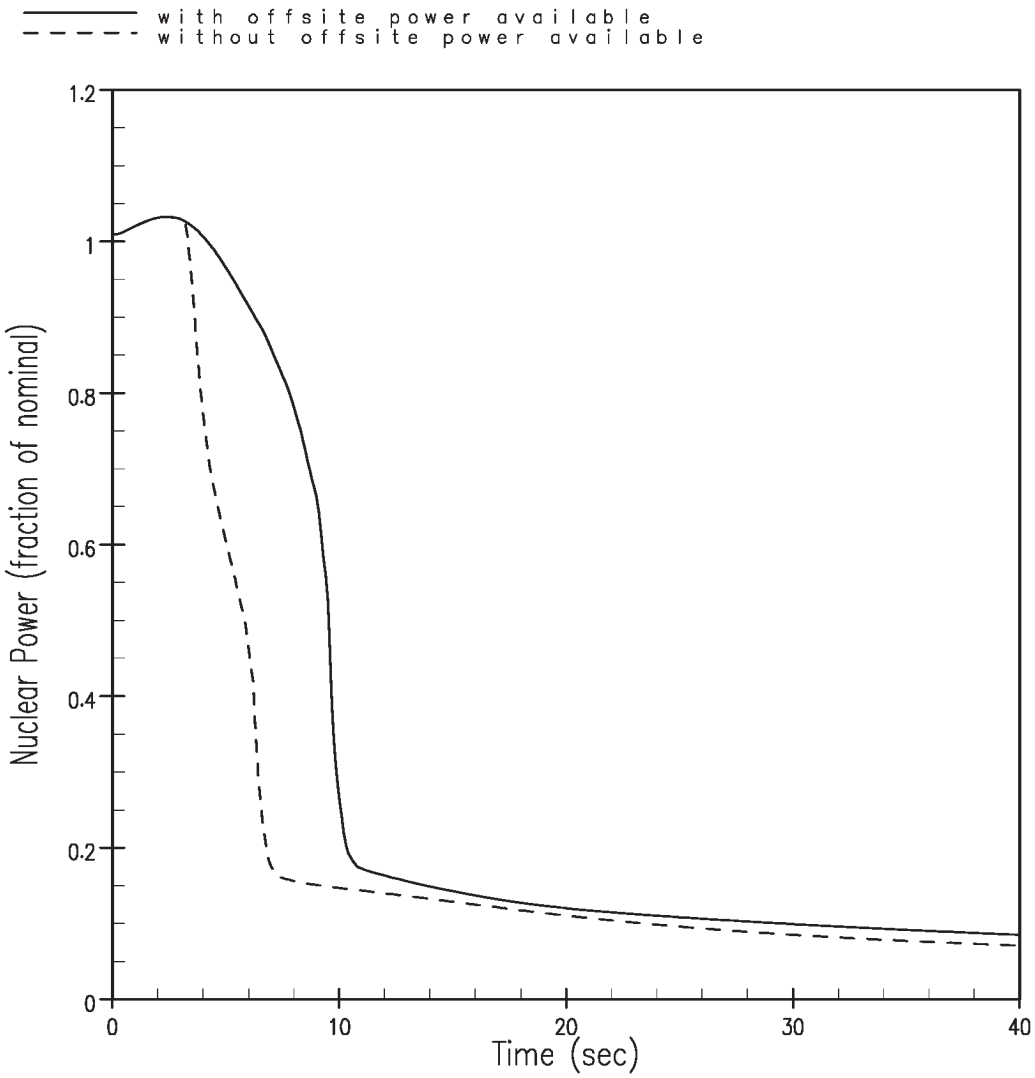

Figure 15.2.3-21
Nuclear Power versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

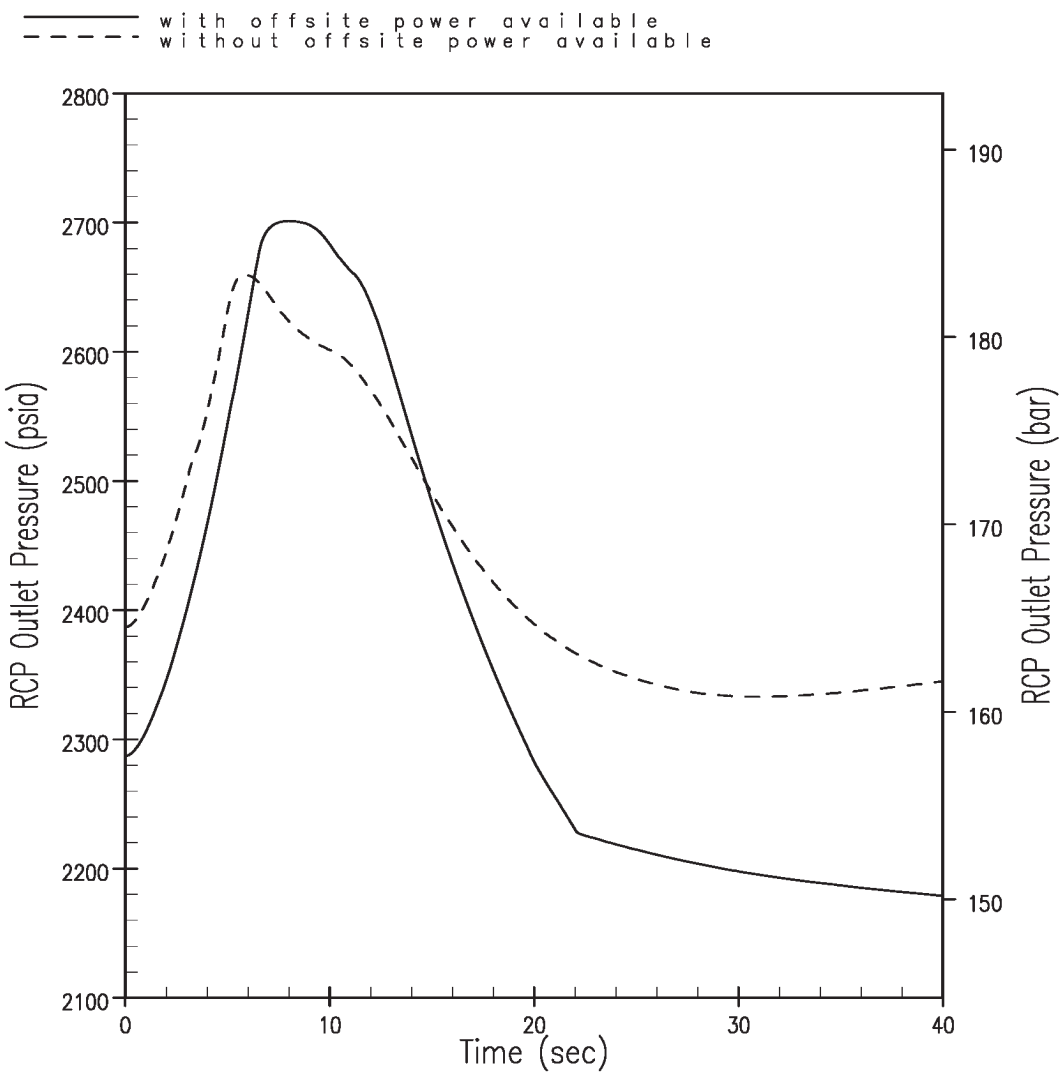

Figure 15.2.3-22
RCP Outlet Pressure versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

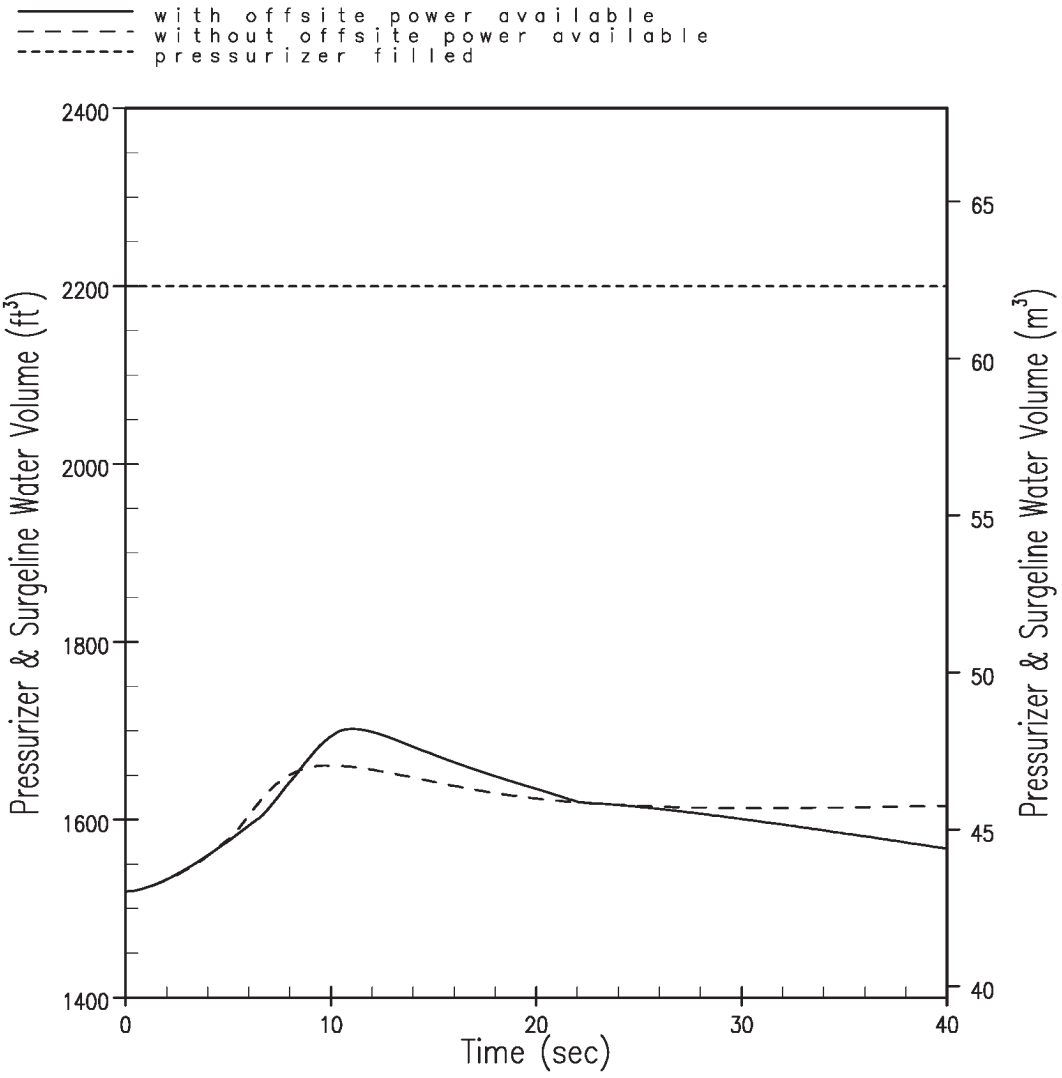

Figure 15.2.3-23
Pressurizer & Surge Line Water Volume versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

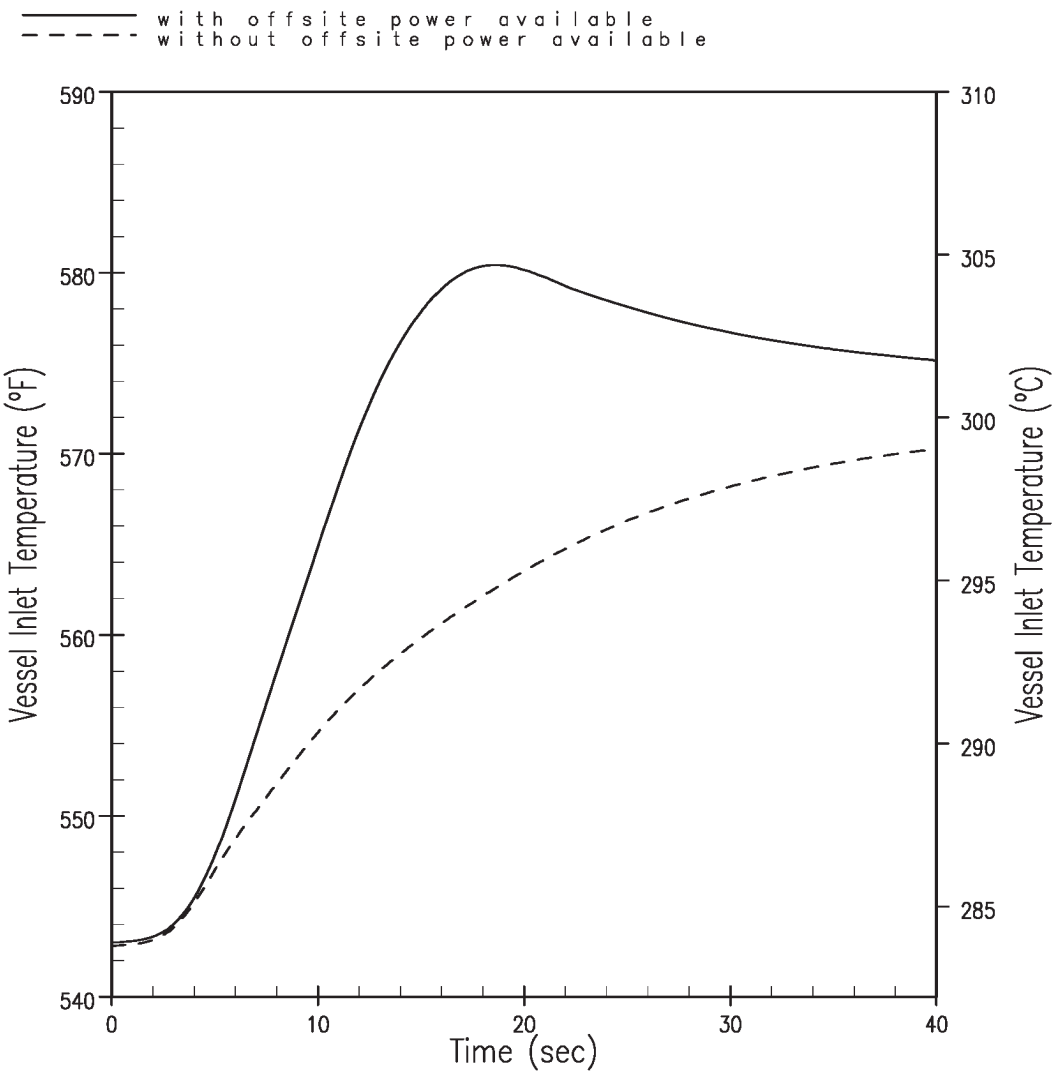

Figure 15.2.3-24
Vessel Inlet Temperature versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

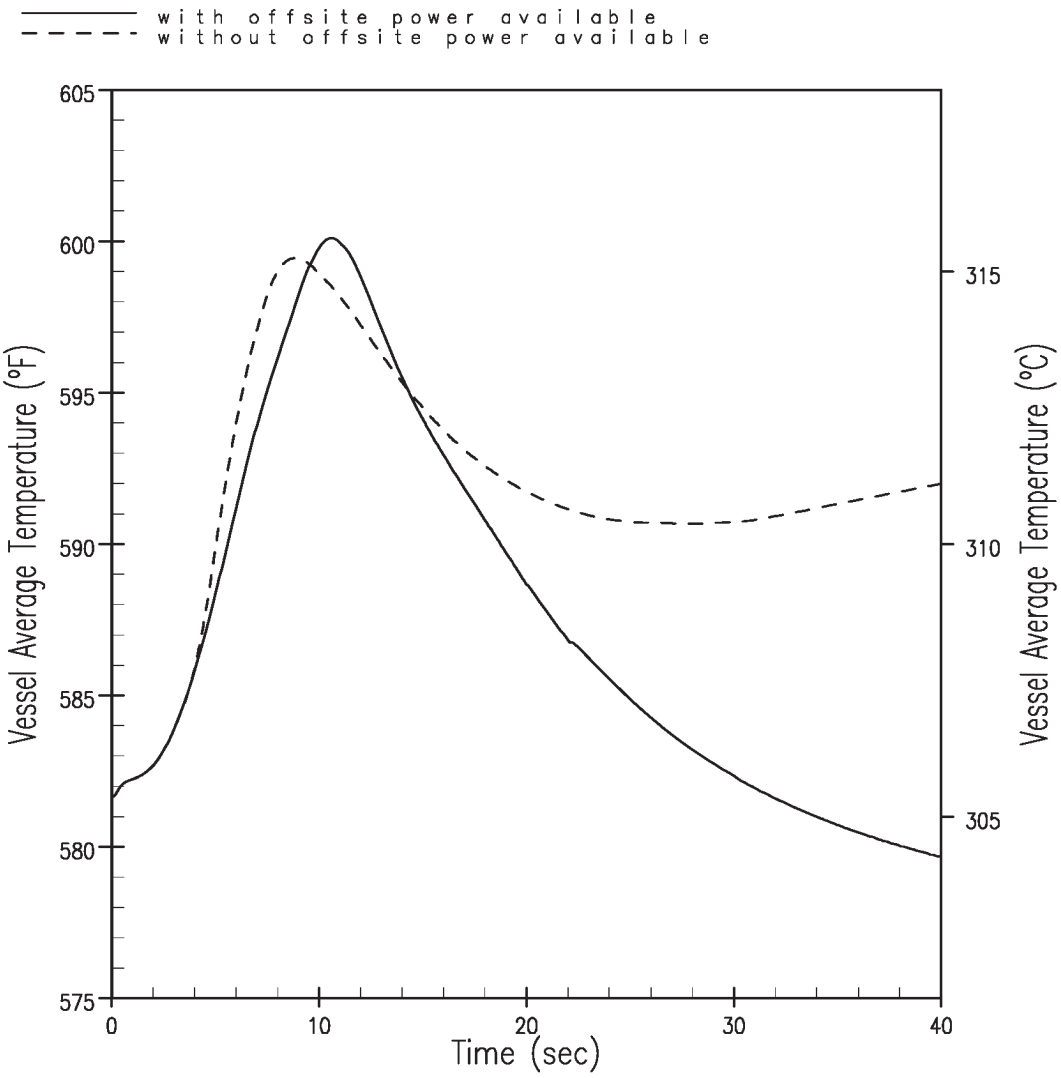

Figure 15.2.3-25
Vessel Average Temperature versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

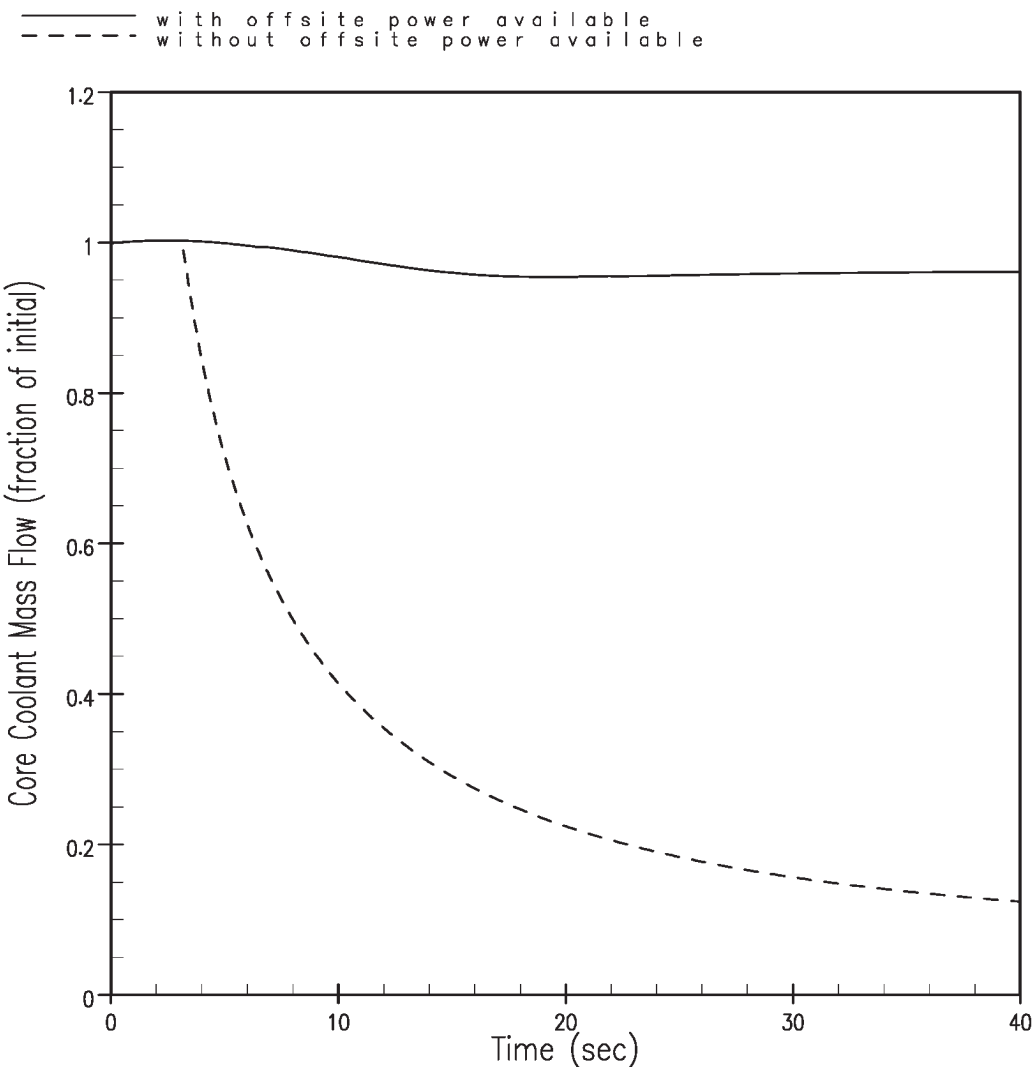

Figure 15.2.3-26
Core Coolant Mass Flow Rate versus Time for Turbine Trip Accident Without Pressurizer Spray and Maximum Moderator Feedback

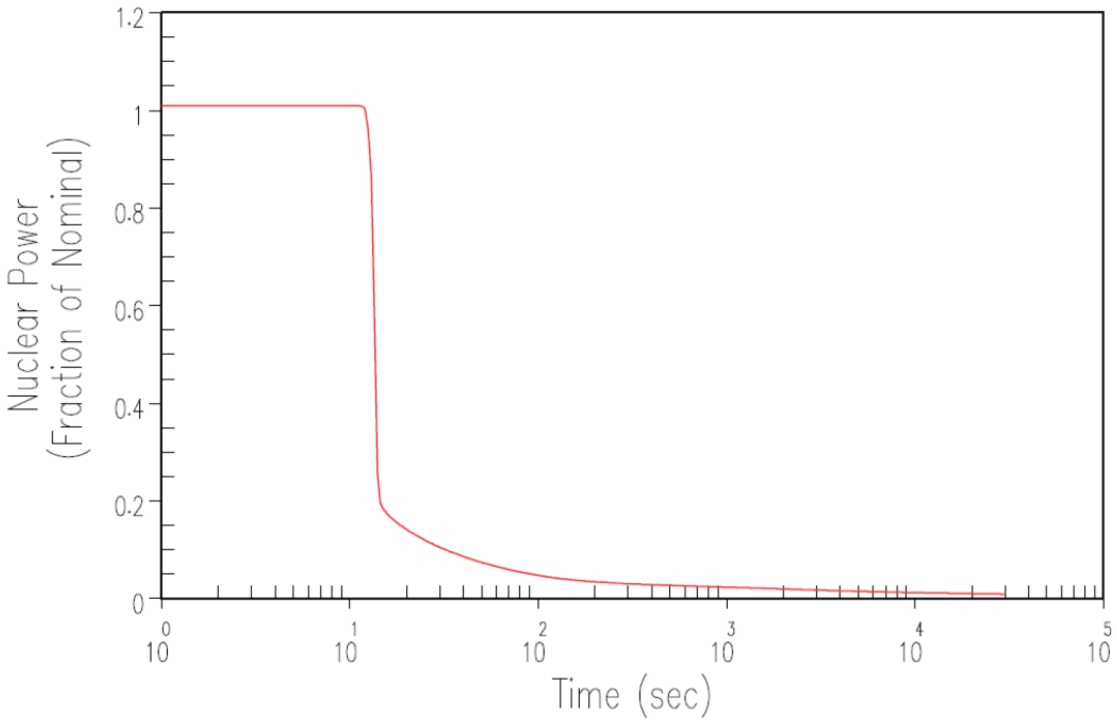

Figure 15.2.6-1
Nuclear Power Transient for Loss of ac Power to the Plant Auxiliaries

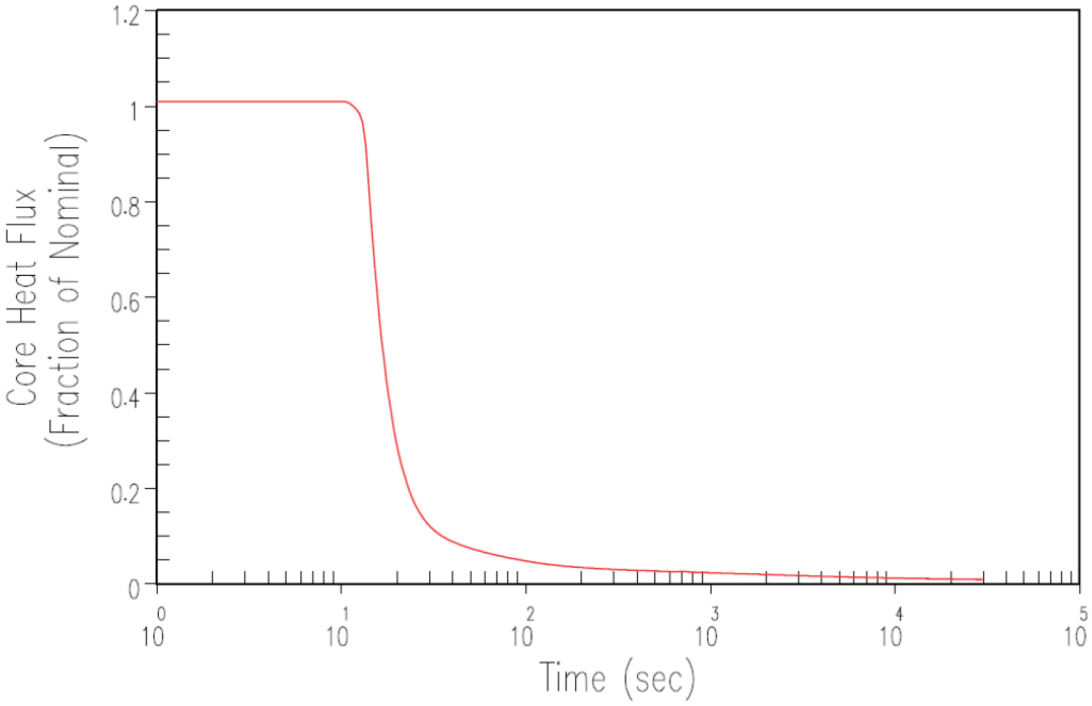

Figure 15.2.6-2
Core Heat Flux Transient for Loss of ac Power to the Plant Auxiliaries

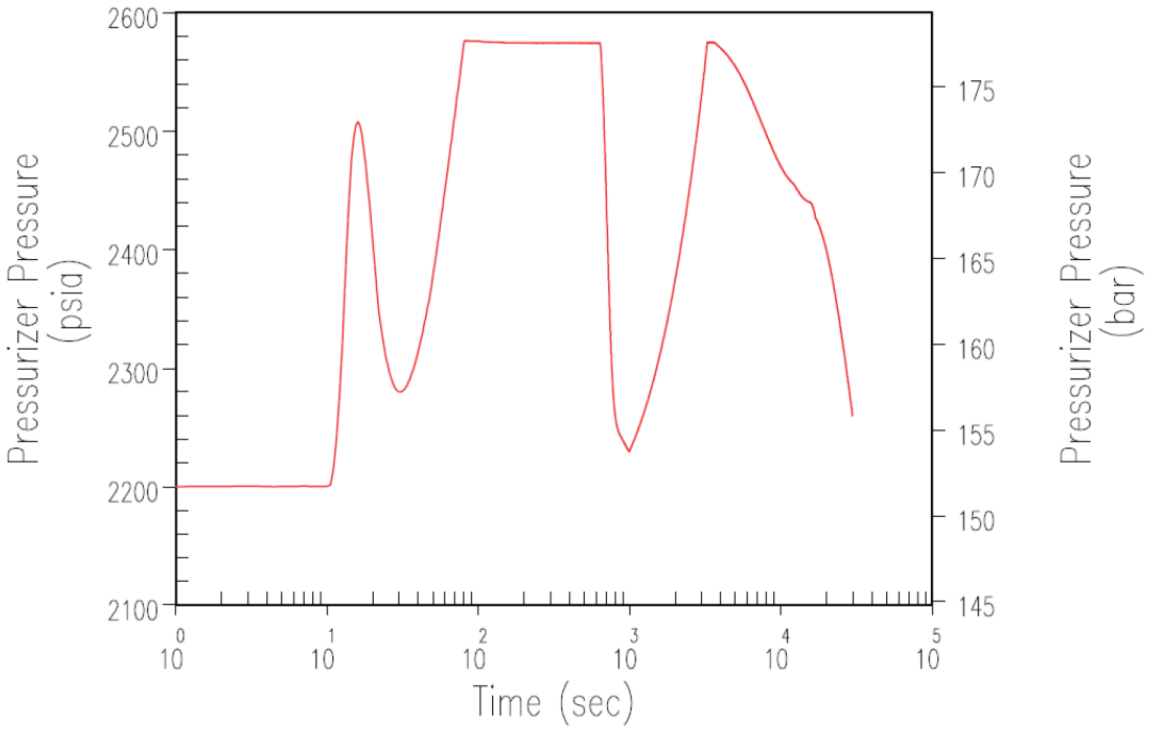

Figure 15.2.6-3
Pressurizer Pressure Transient for Loss of ac Power to the Plant Auxiliaries

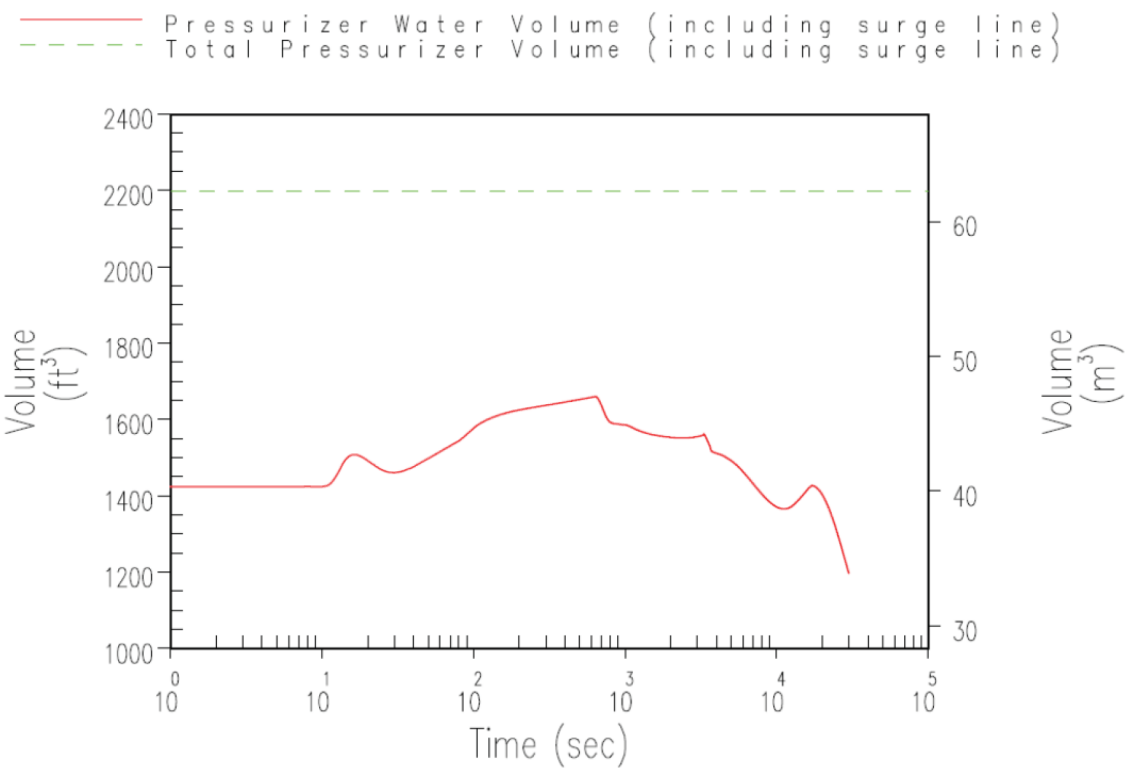

Figure 15.2.6-4
Pressurizer Water Volume Transient for Loss of ac Power to the Plant Auxiliaries

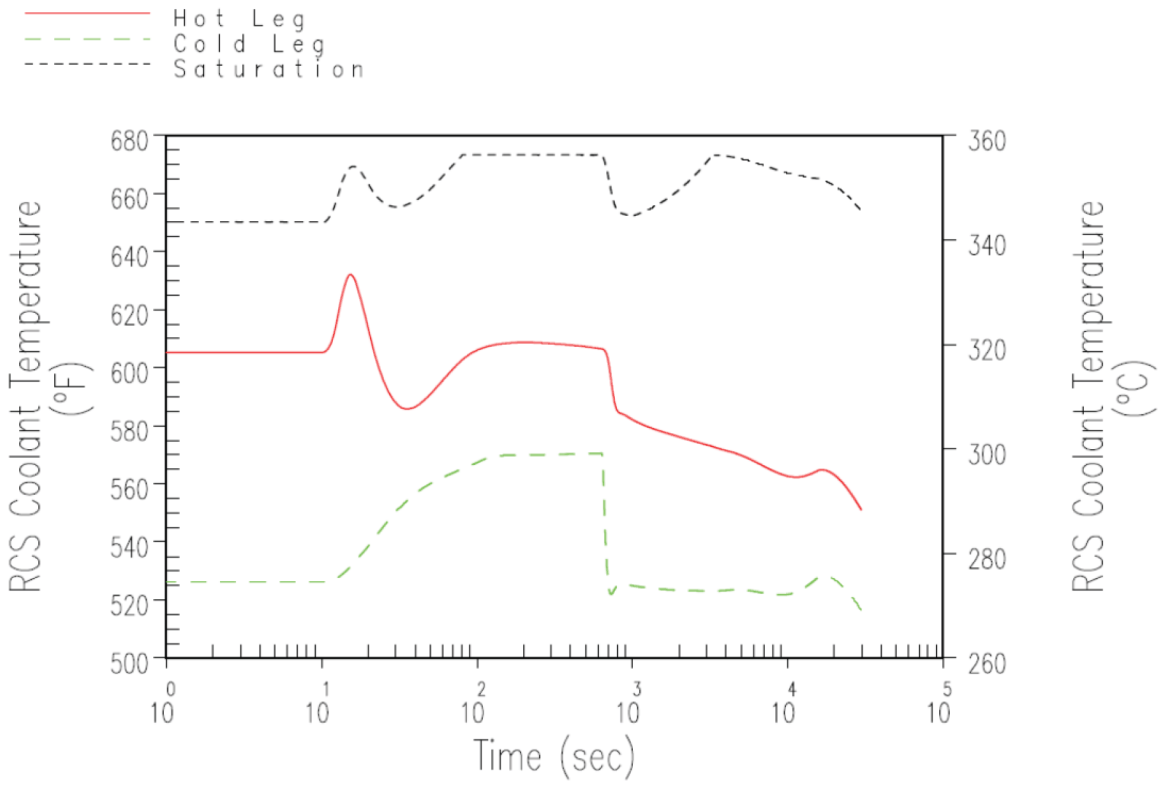

Figure 15.2.6-5
Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss of ac Power to the Plant Auxiliaries

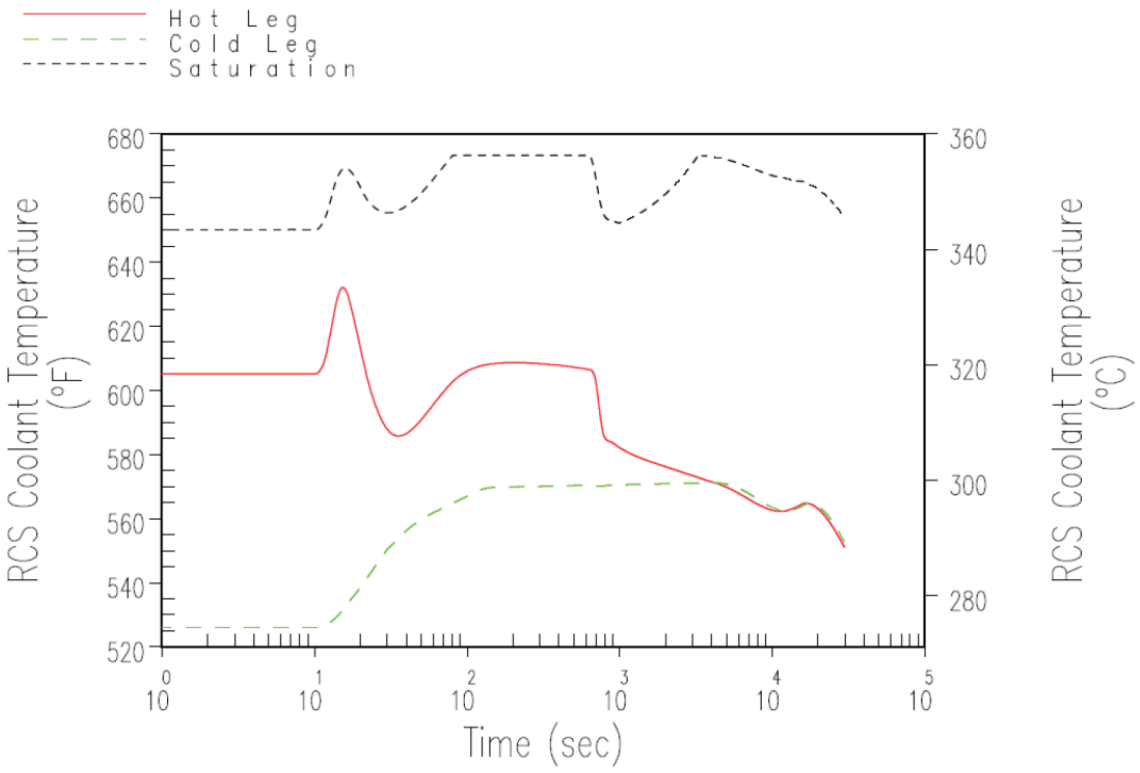

Figure 15.2.6-6
Reactor Coolant System Temperature Transients in Loop Not Containing the PRHR for Loss of ac Power to the Plant Auxiliaries

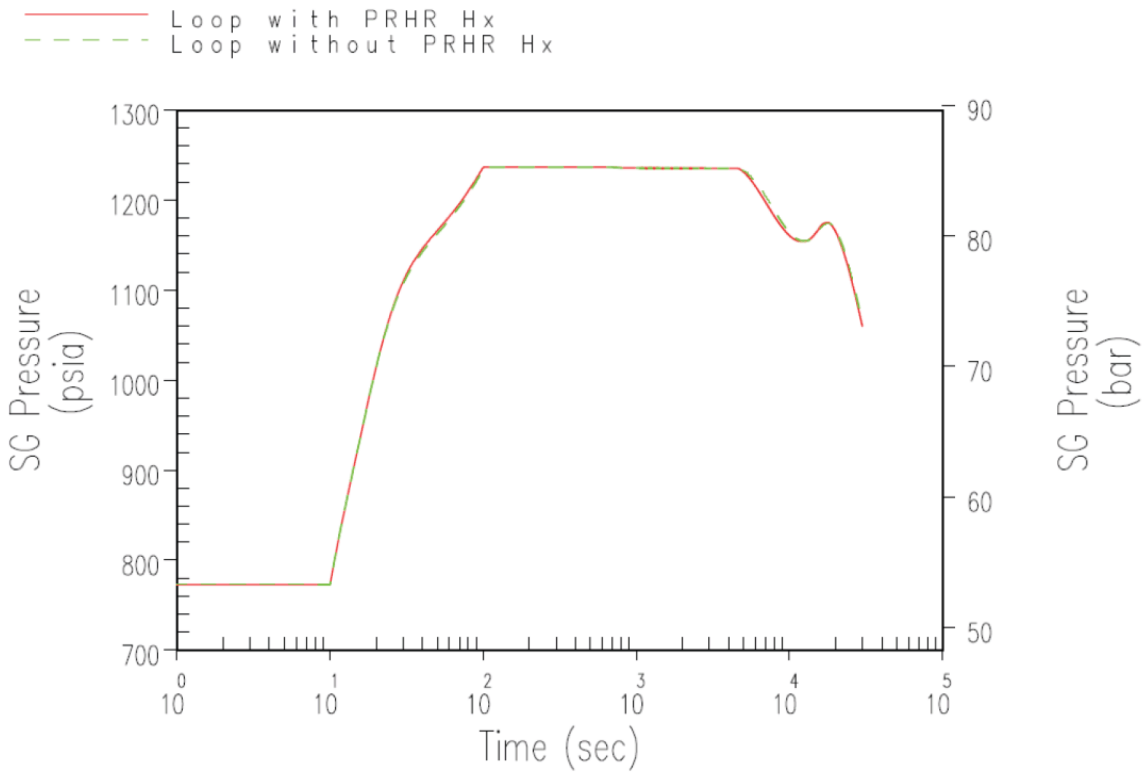

Figure 15.2.6-7
Steam Generator Pressure Transient
for Loss of ac Power to the Plant Auxiliaries

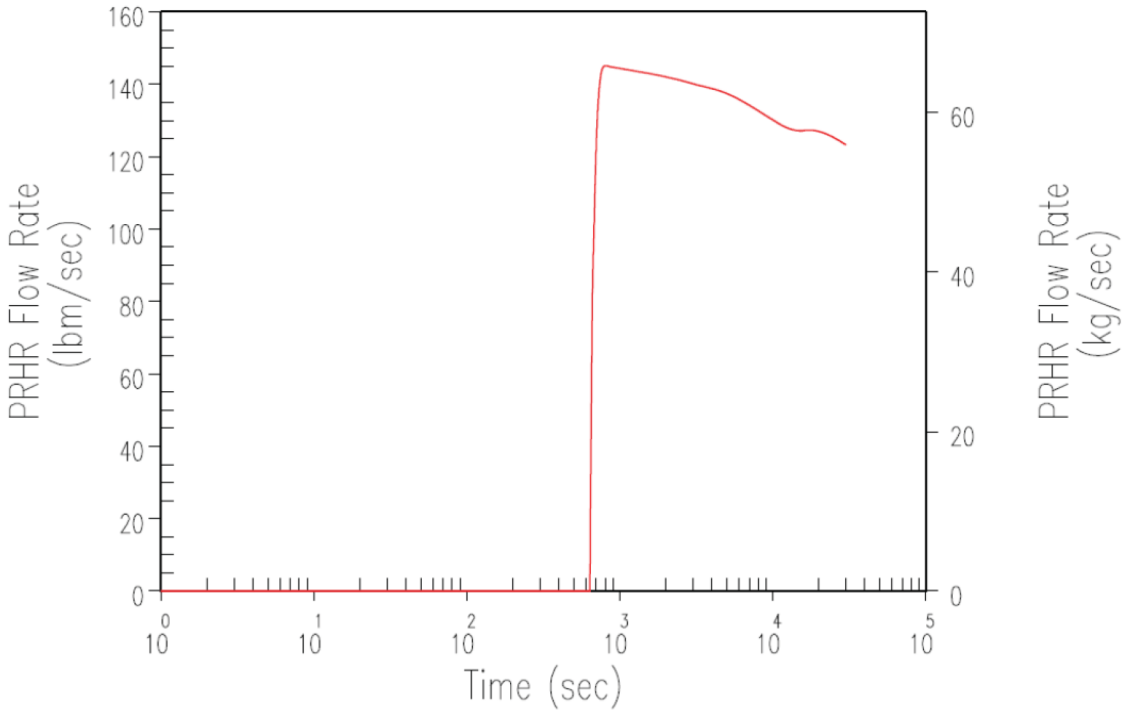

Figure 15.2.6-8
PRHR Flow Rate Transient
for Loss of ac Power to the Plant Auxiliaries

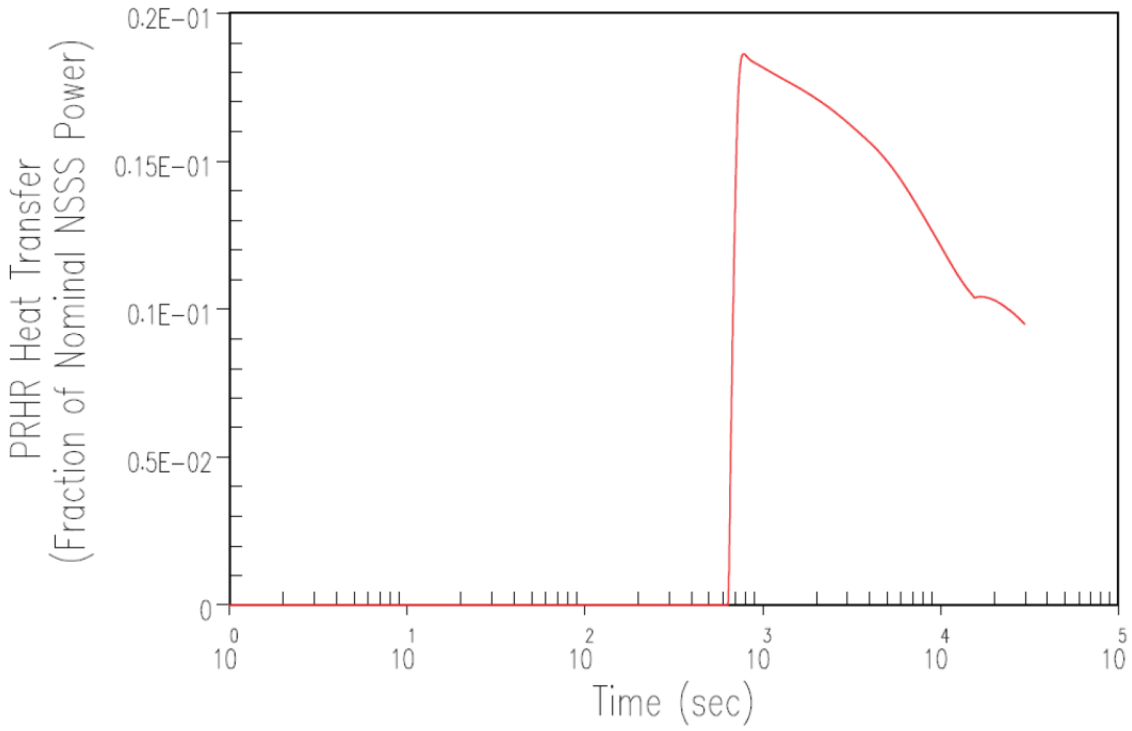

Figure 15.2.6-9
PRHR Heat Transfer Transient
for Loss of ac Power to the Plant Auxiliaries

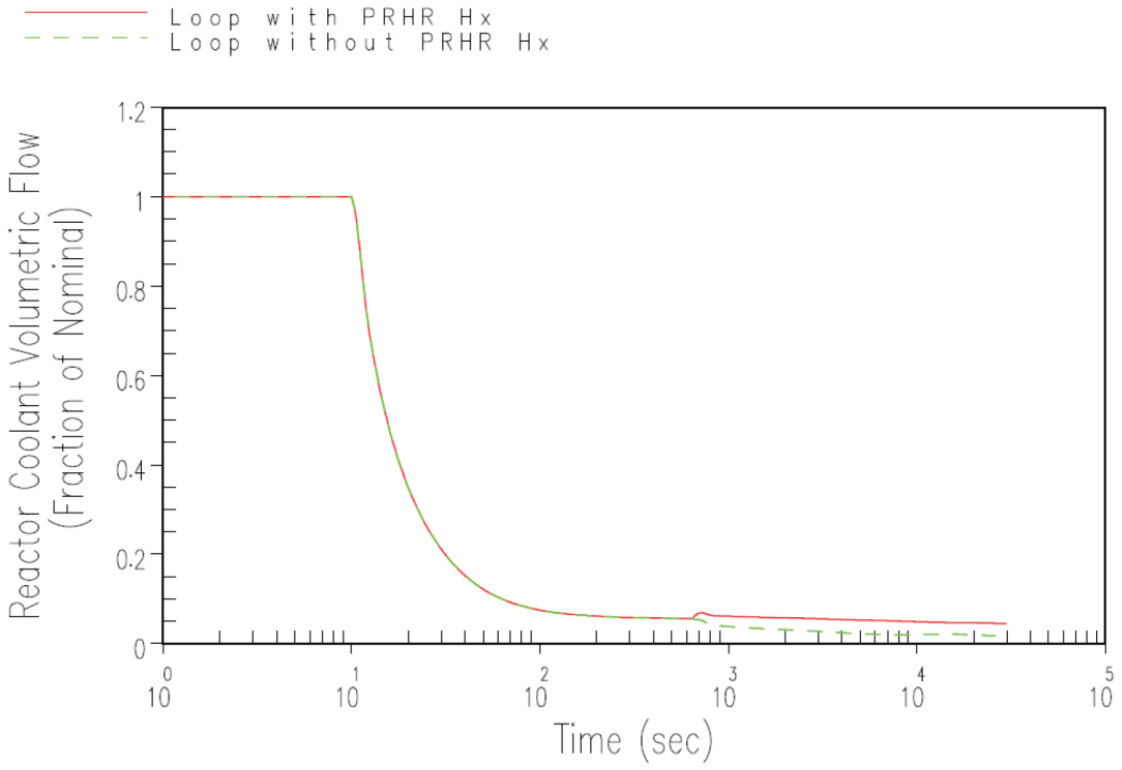

Figure 15.2.6-10
Reactor Coolant Volumetric Flow Rate
Transient for Loss of ac Power to the Plant Auxiliaries

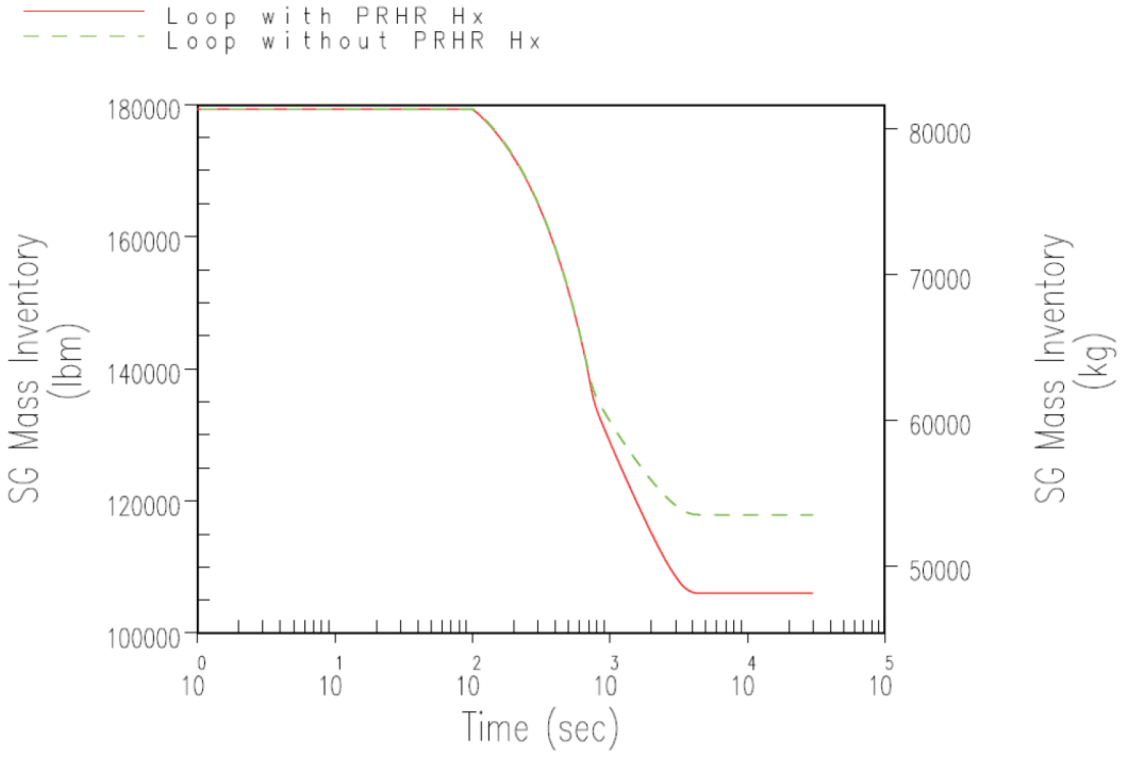

Figure 15.2.6-11
Steam Generator Inventory Transient
for Loss of ac Power to the Plant Auxiliaries

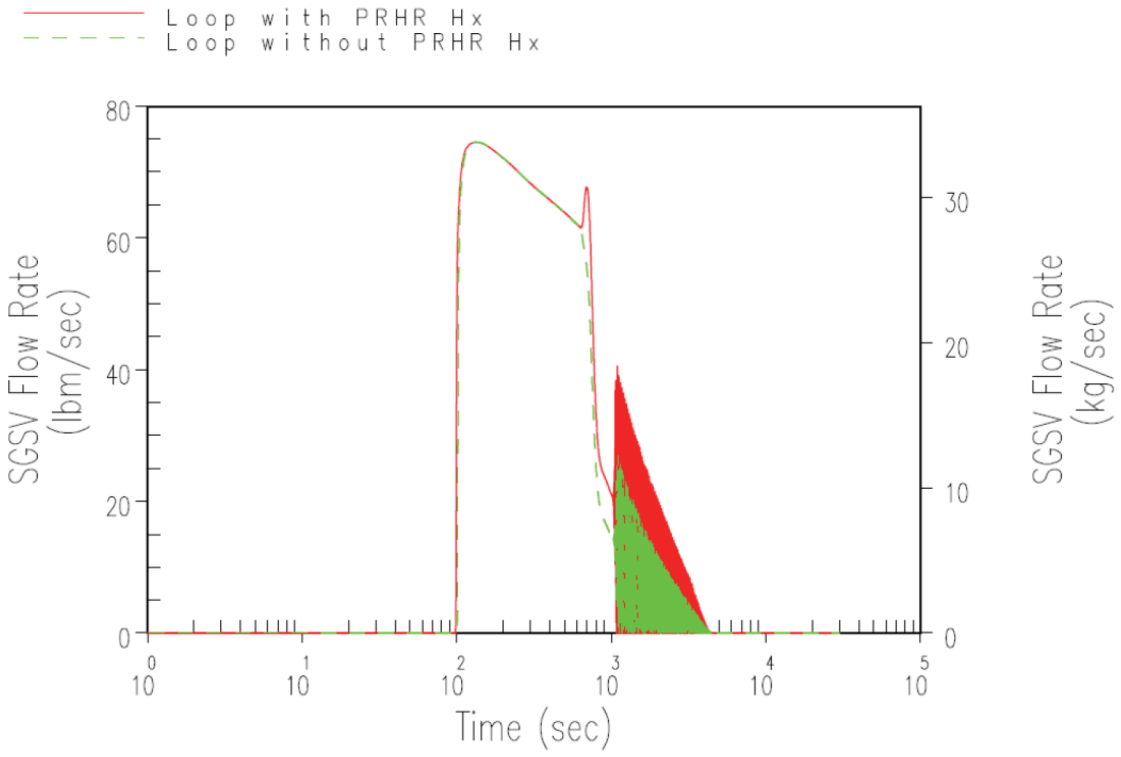

Figure 15.2.6-12
Steam Generator Safety Valve Relief
for Loss of ac Power to the Plant Auxiliaries

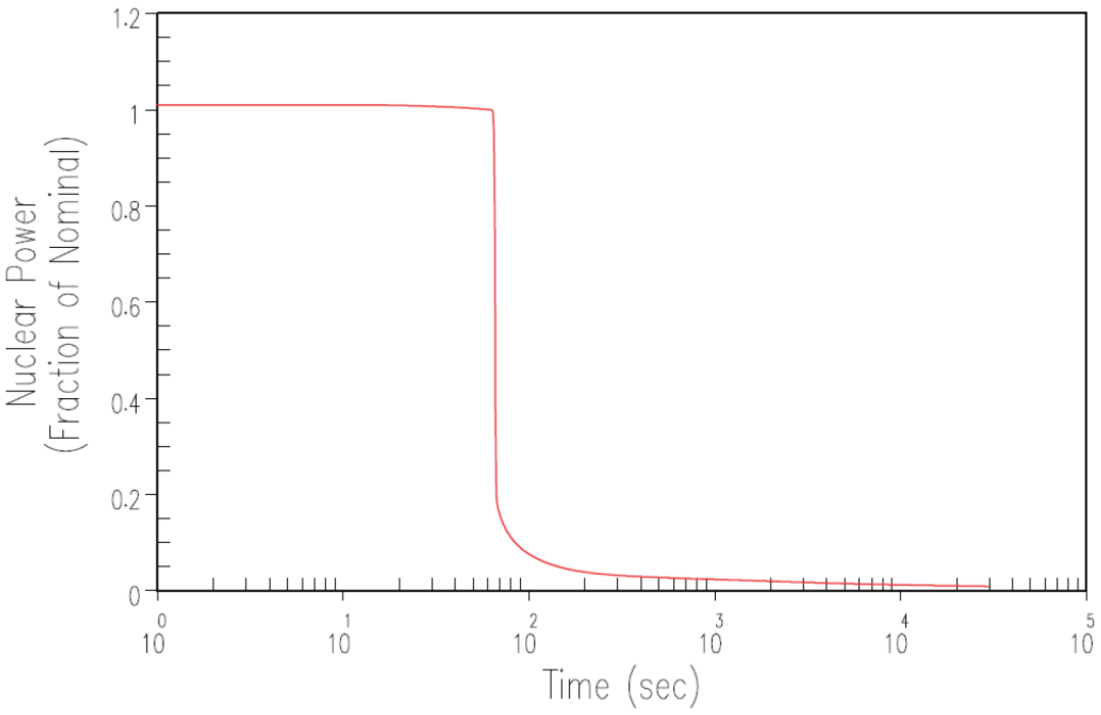

Figure 15.2.7-1
Nuclear Power Transient for Loss of Normal Feedwater

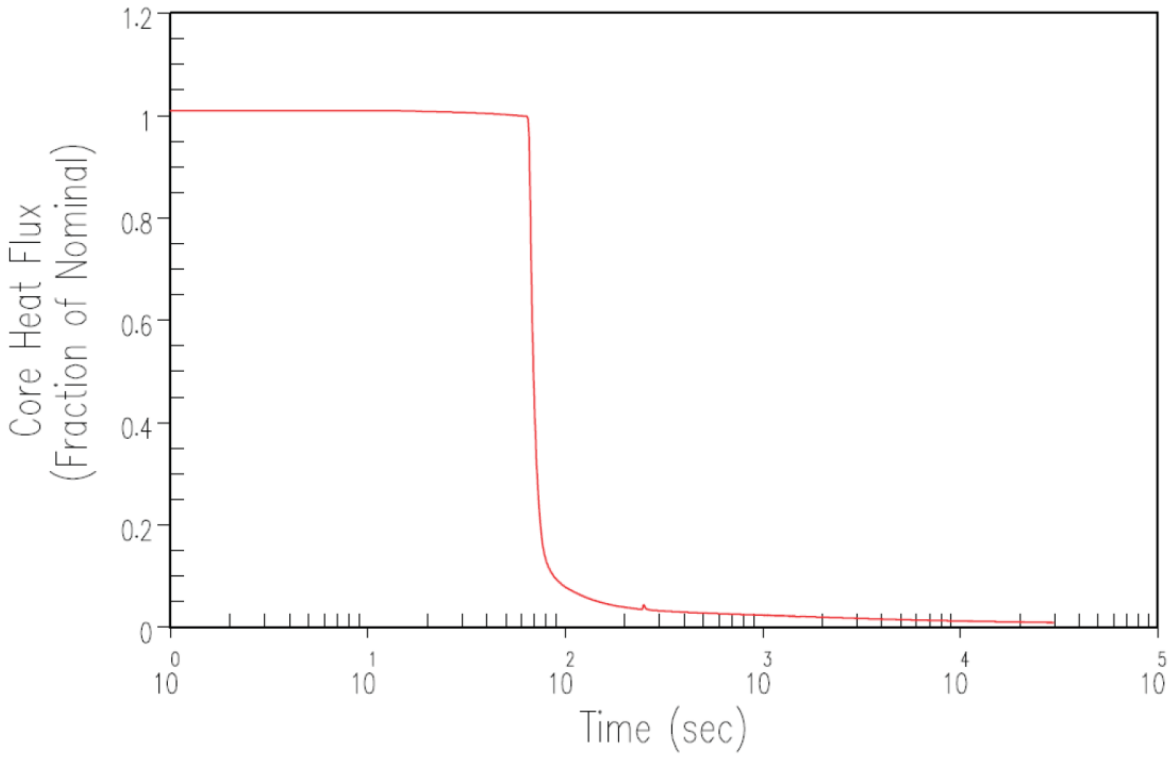

Figure 15.2.7-2
Core Heat Flux Transient for
Loss of Normal Feedwater

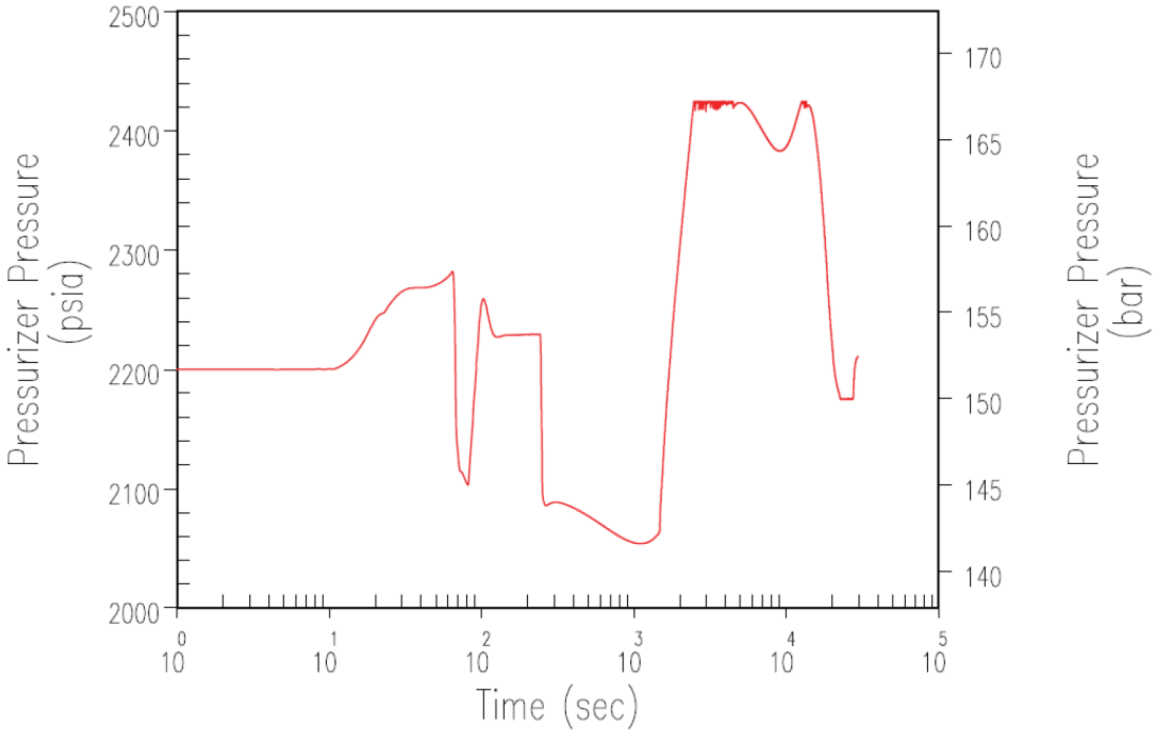

Figure 15.2.7-3
Pressurizer Pressure Transient for Loss of Normal Feedwater

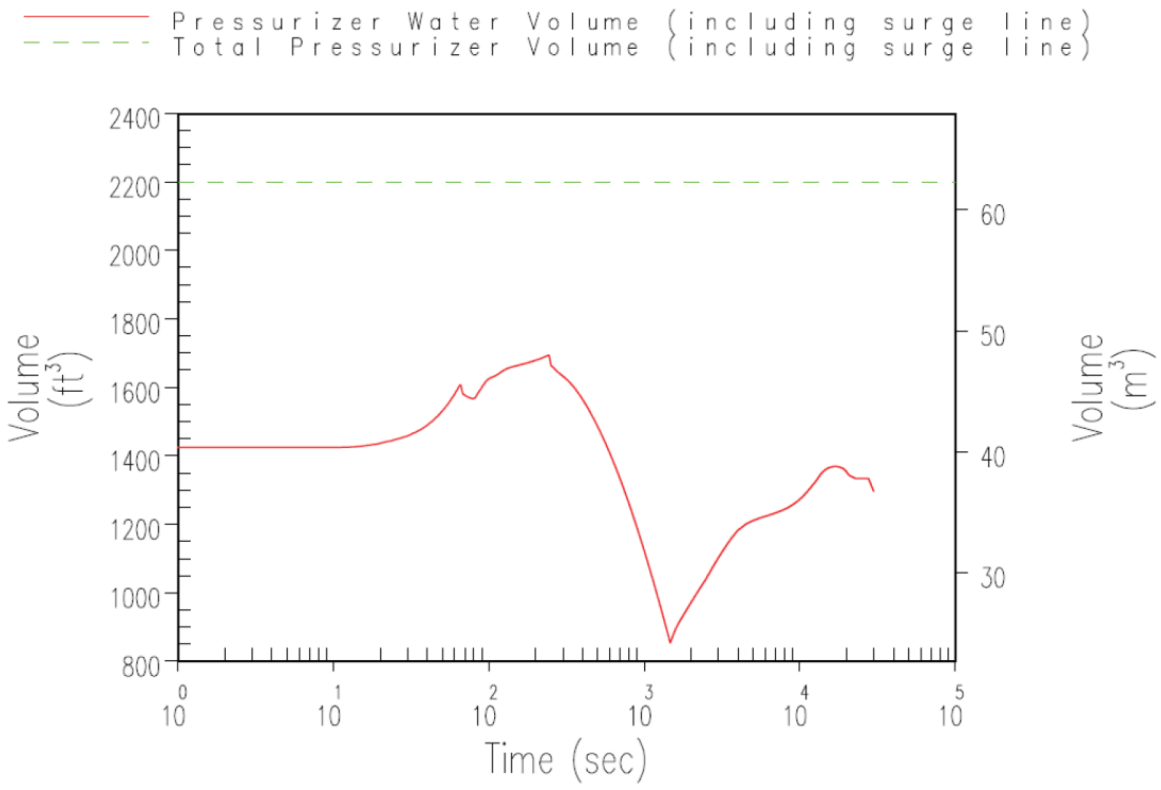

Figure 15.2.7-4
Pressurizer Water Volume Transient
for Loss of Normal Feedwater

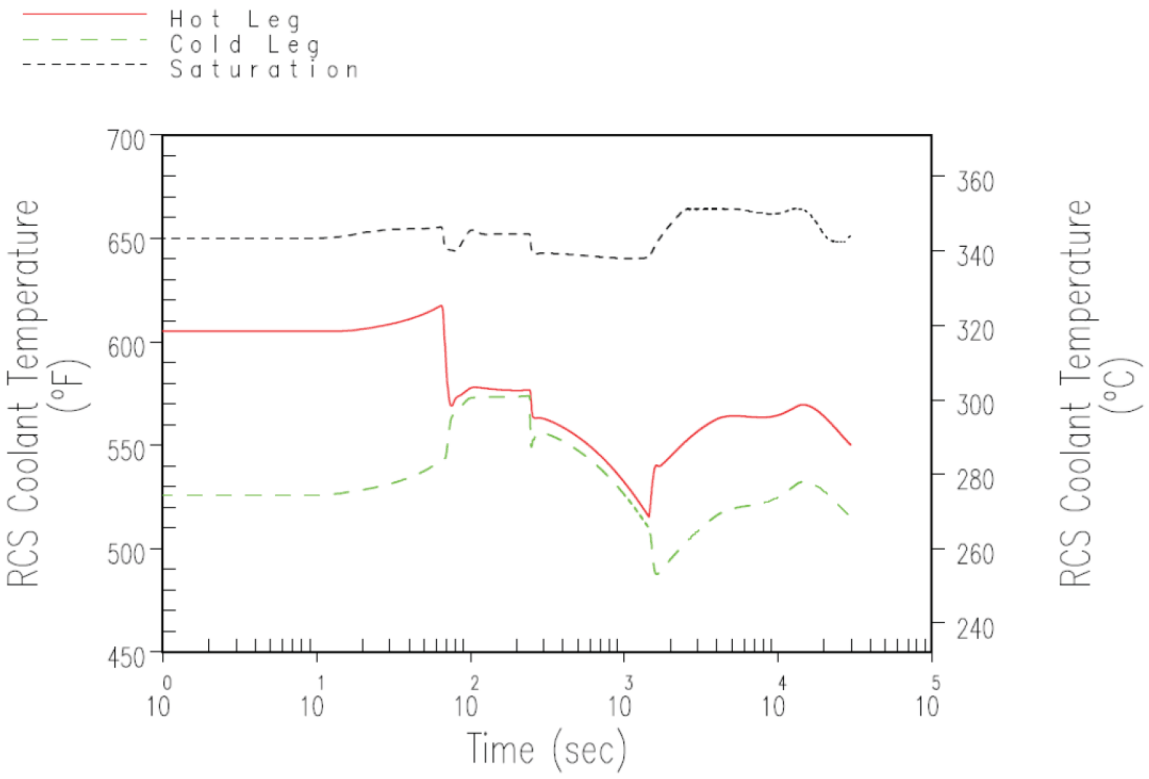

Figure 15.2.7-5
Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss of Normal Feedwater Flow

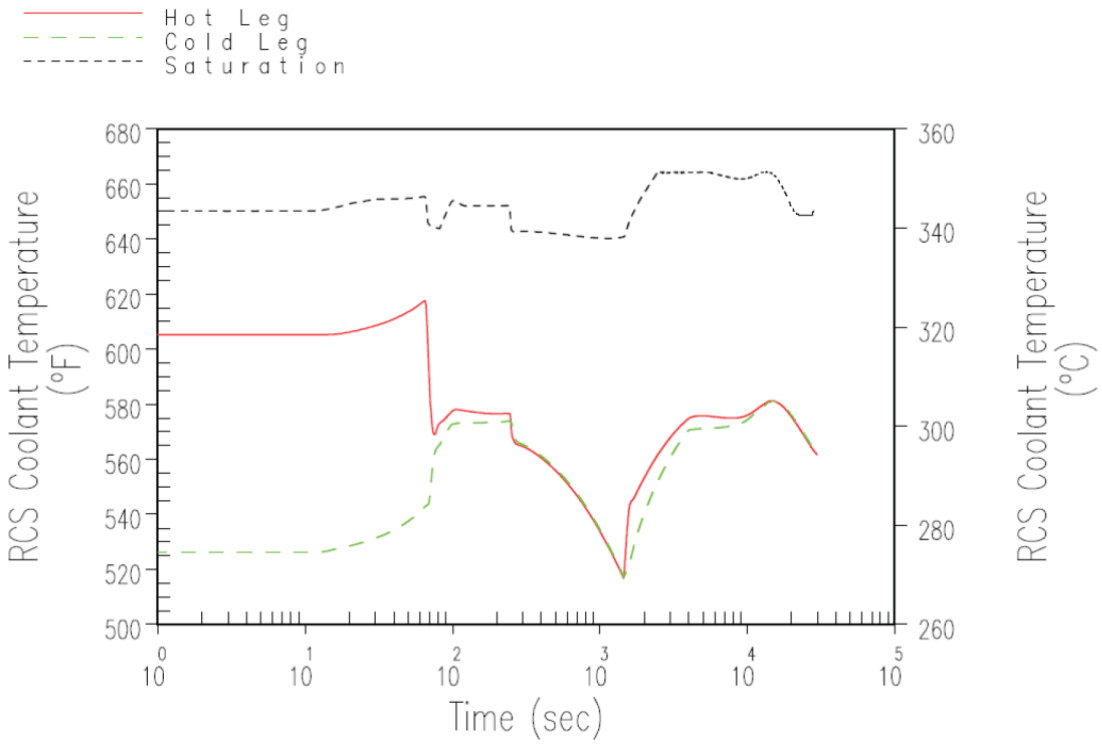

Figure 15.2.7-6
Reactor Coolant System Temperature Transient in Loop Not Containing the PRHR for Loss of Normal Feedwater Flow

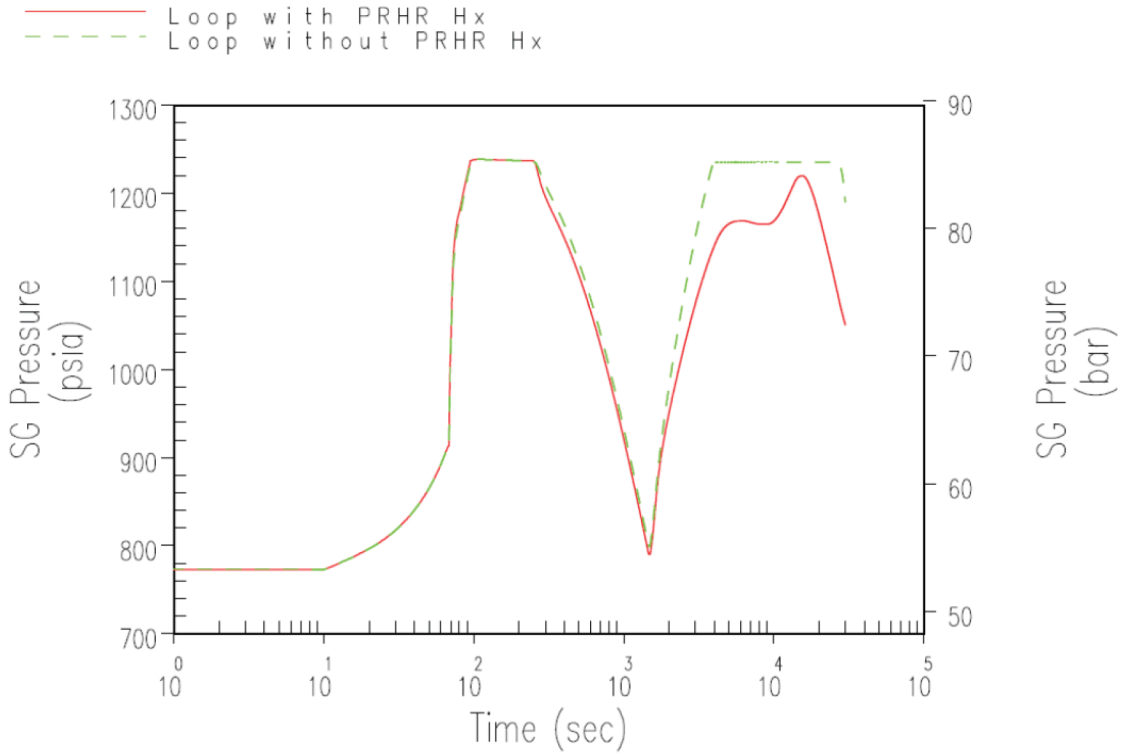

Figure 15.2.7-7
Steam Generator Pressure Transient
for Loss of Normal Feedwater

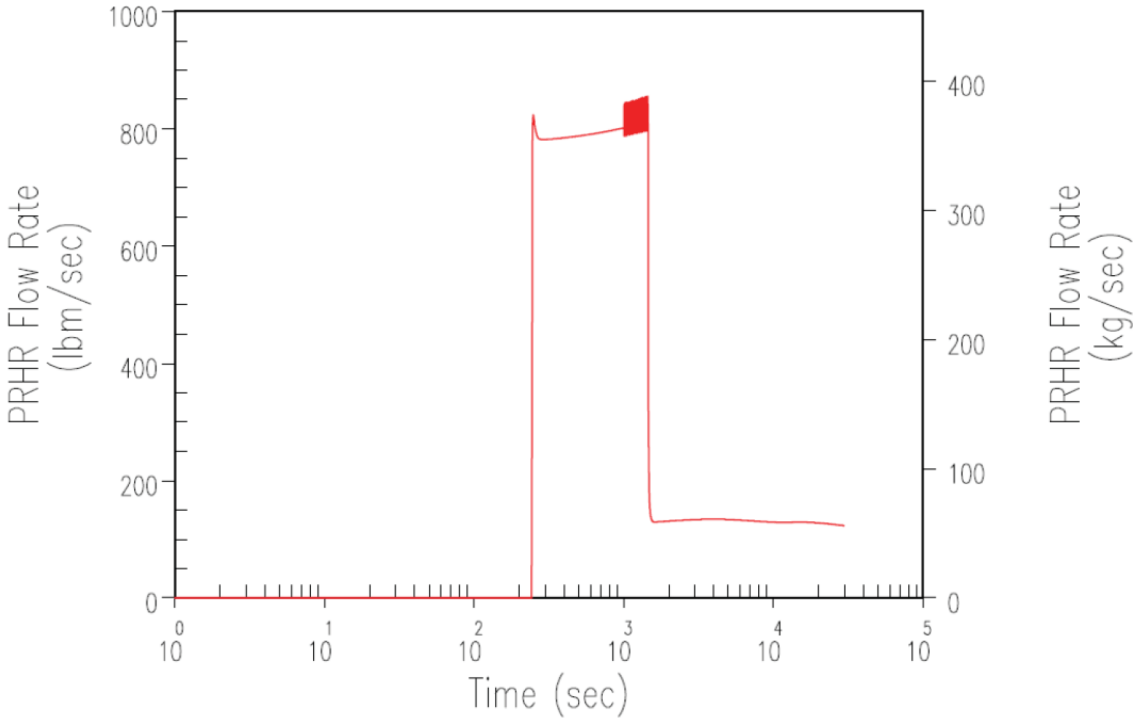

Figure 15.2.7-8
PRHR Flow Rate Transient
for Loss of Normal Feedwater

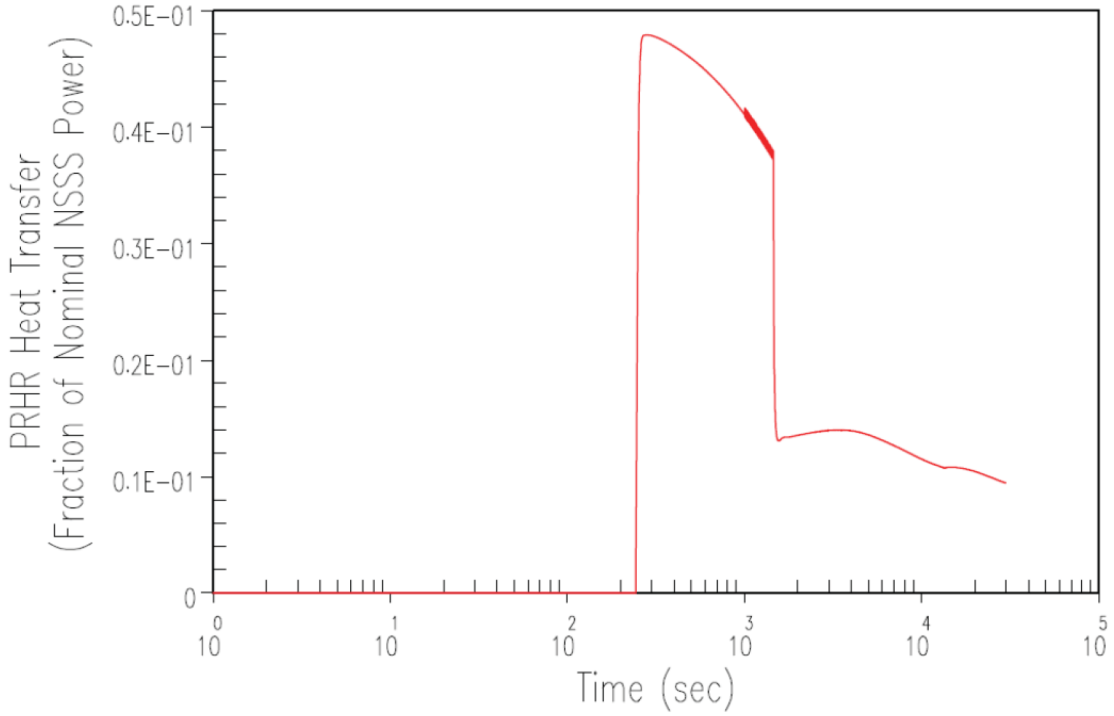

Figure 15.2.7-9
PRHR Heat Transfer Transient
for Loss of Normal Feedwater

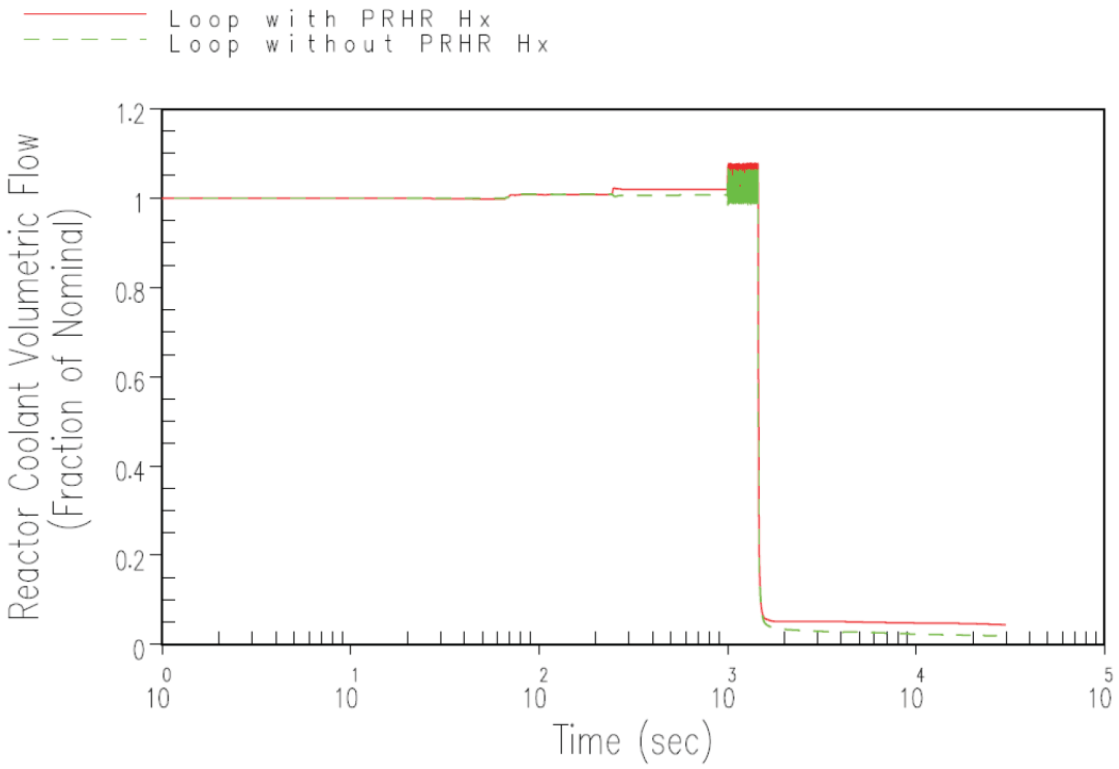

Figure 15.2.7-10
Reactor Coolant Volumetric Flow
Transient for Loss of Normal Feedwater

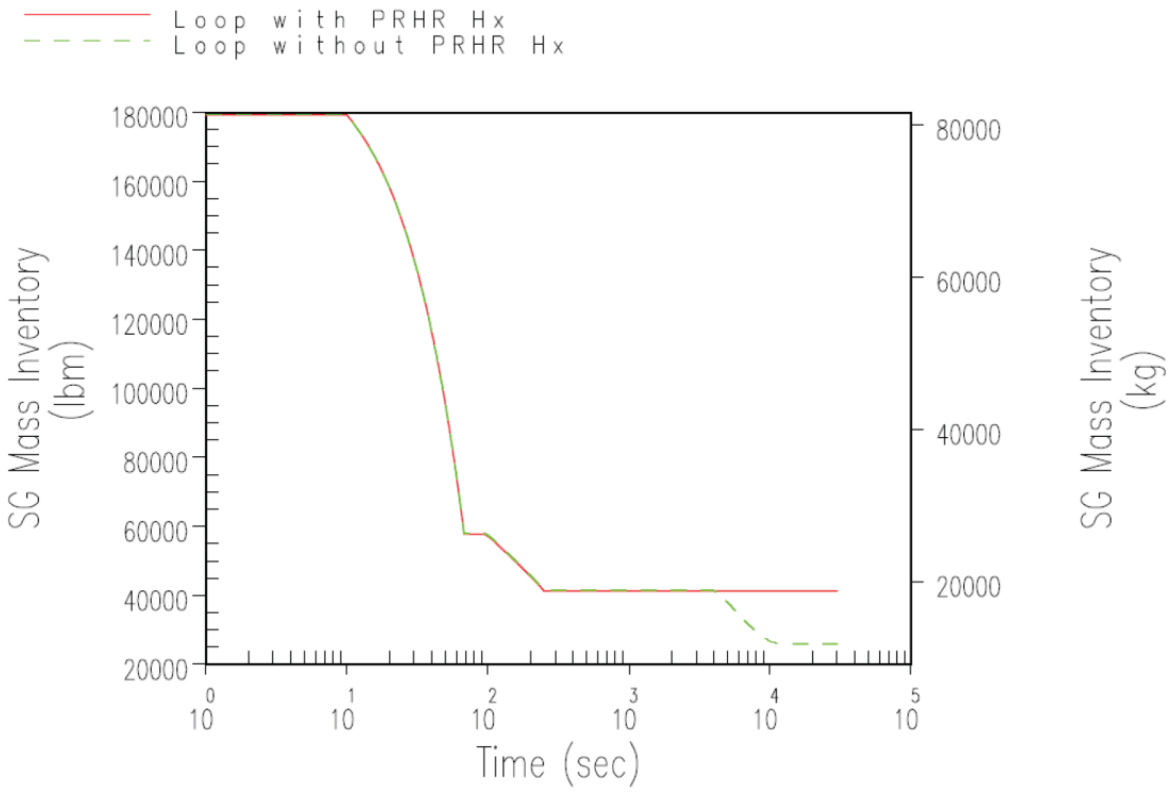

Figure 15.2.7-11
Steam Generator Inventory Transient for Loss of Normal Feedwater

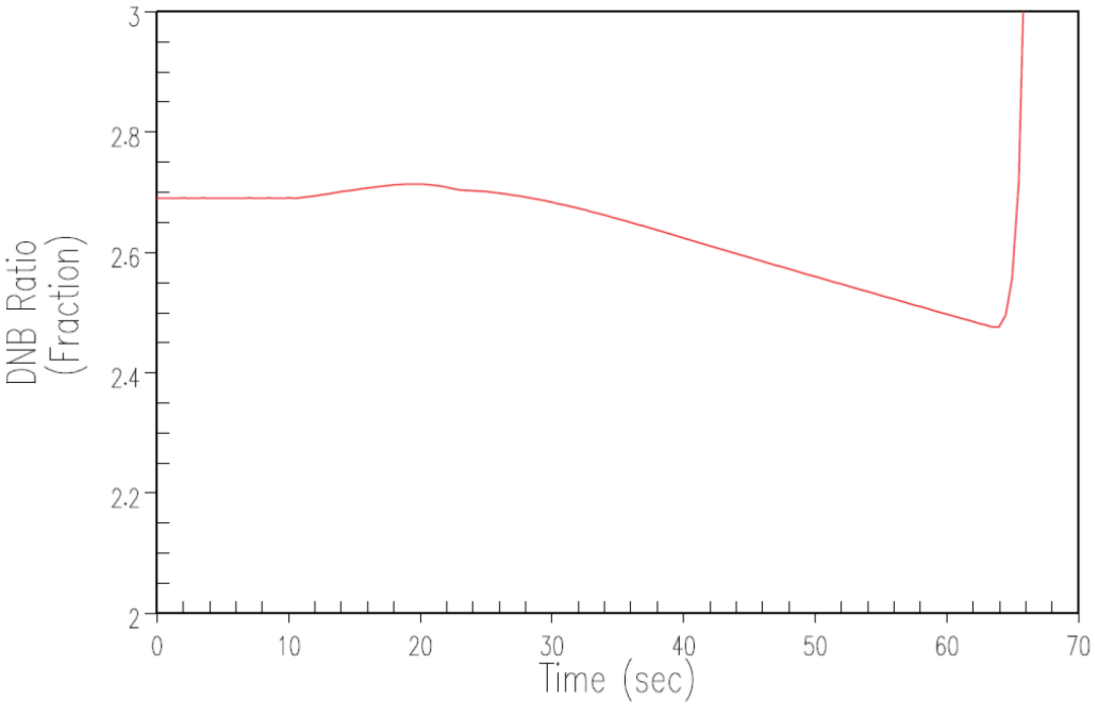

Figure 15.2.7-12
DNB Ratio Transient
for Loss of Normal Feedwater

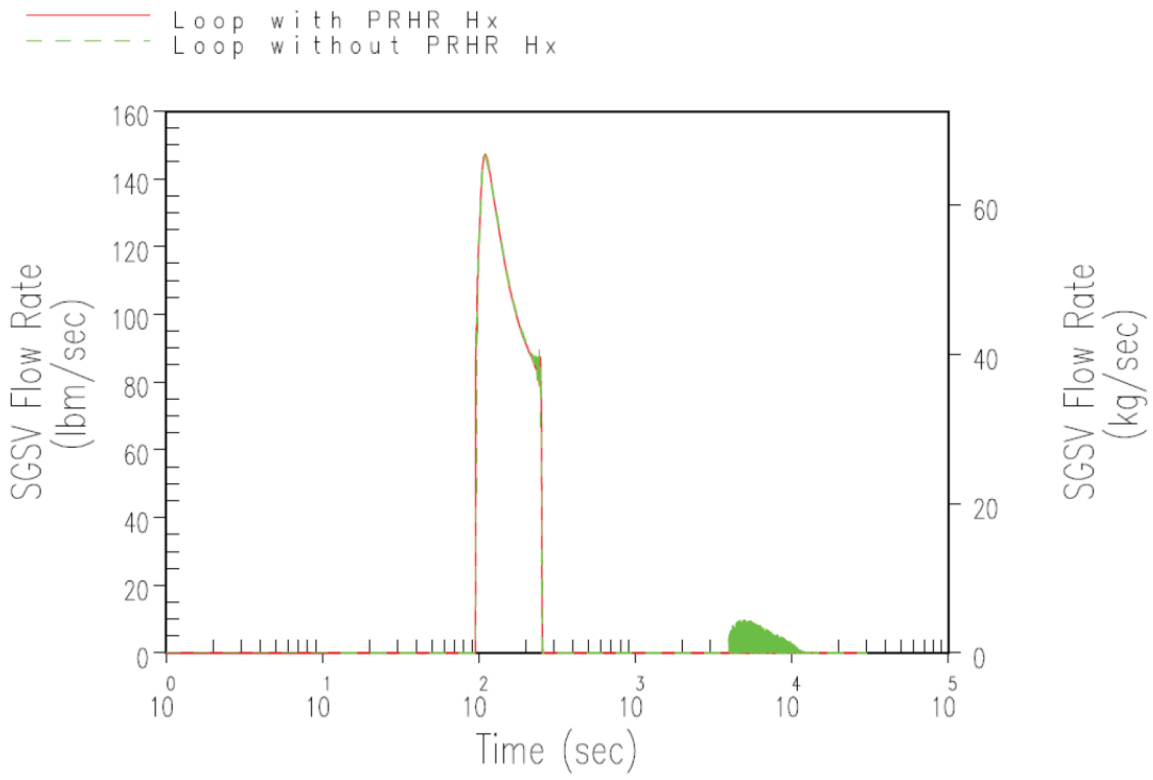

Figure 15.2.7-13
Steam Generator Safety Valve Relief Transient for Loss of Normal Feedwater

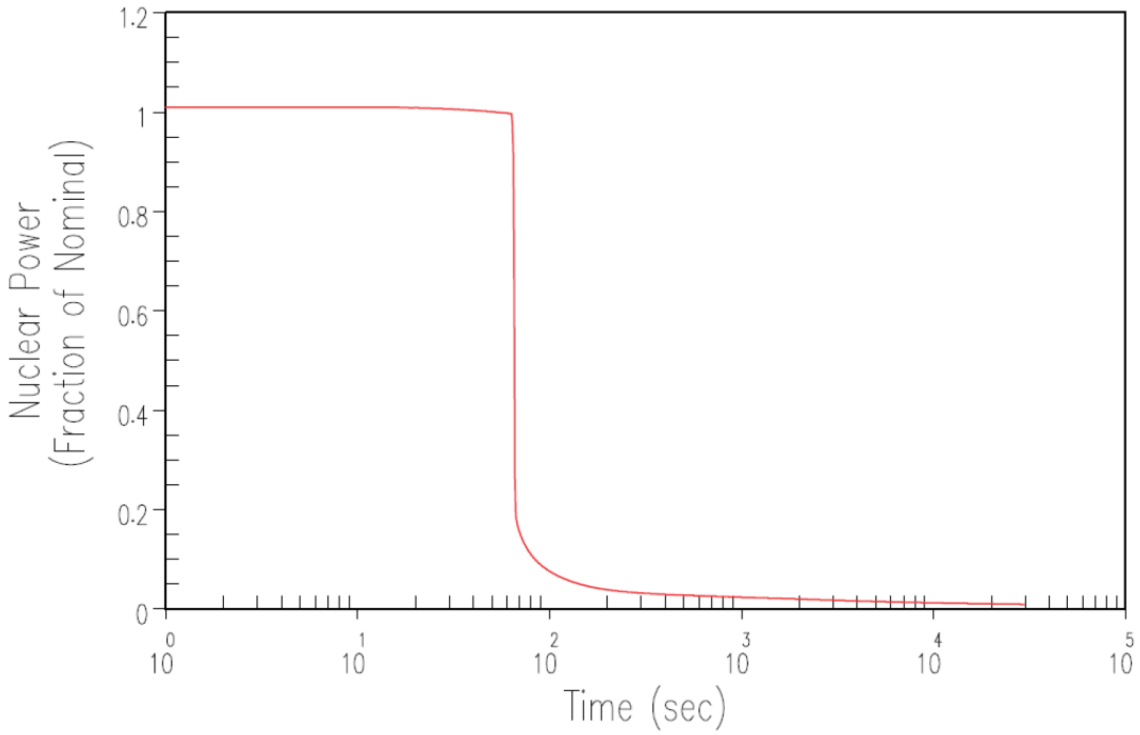

Figure 15.2.7-14
Nuclear Power Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

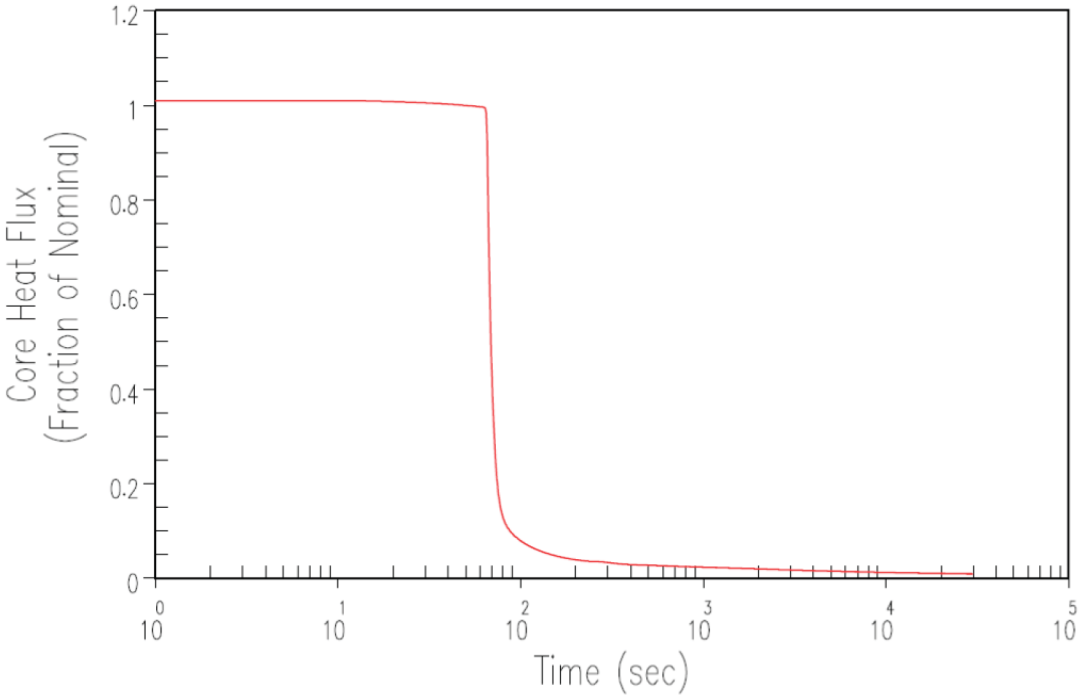

Figure 15.2.7-15
Core Heat Flux Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

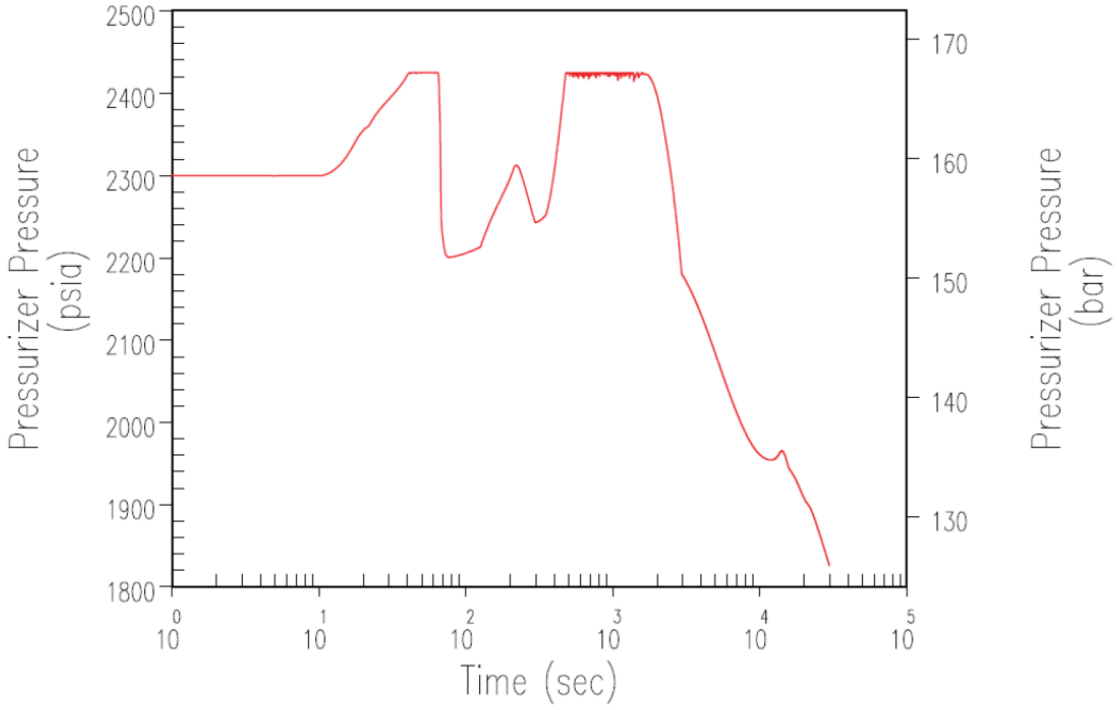

Figure 15.2.7-16
Pressurizer Pressure Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

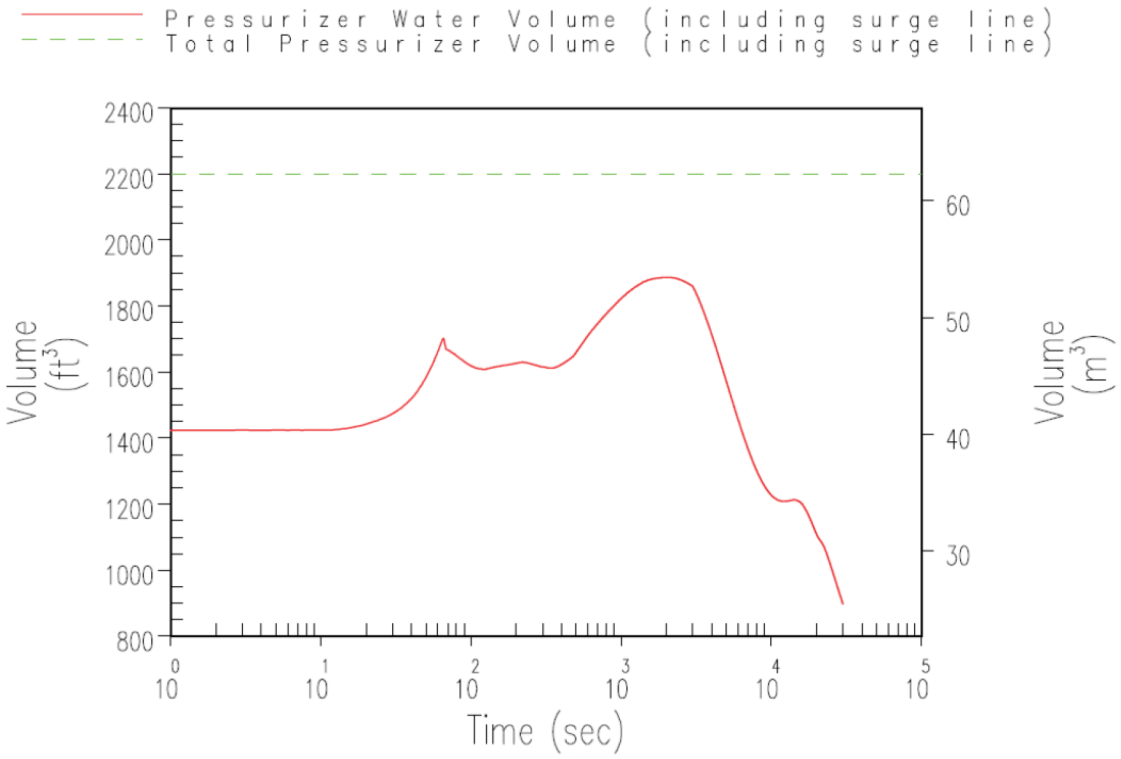

Figure 15.2.7-17
Pressurizer Water Volume Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

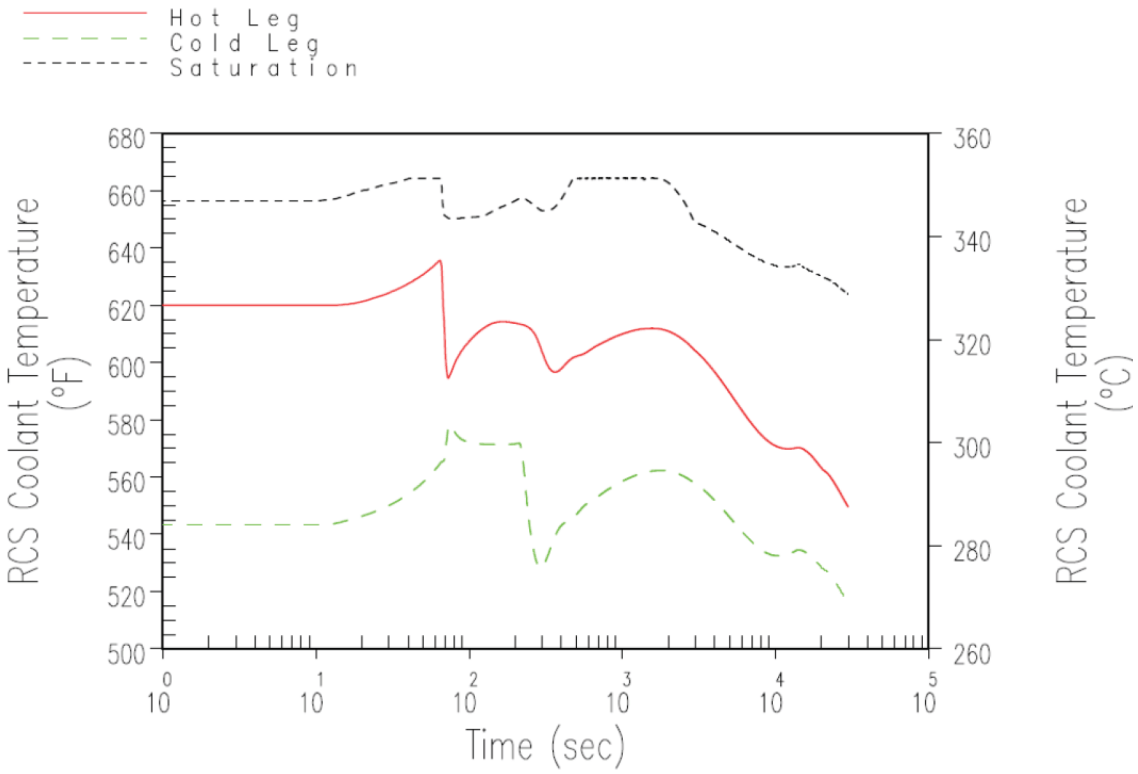

Figure 15.2.7-18
Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

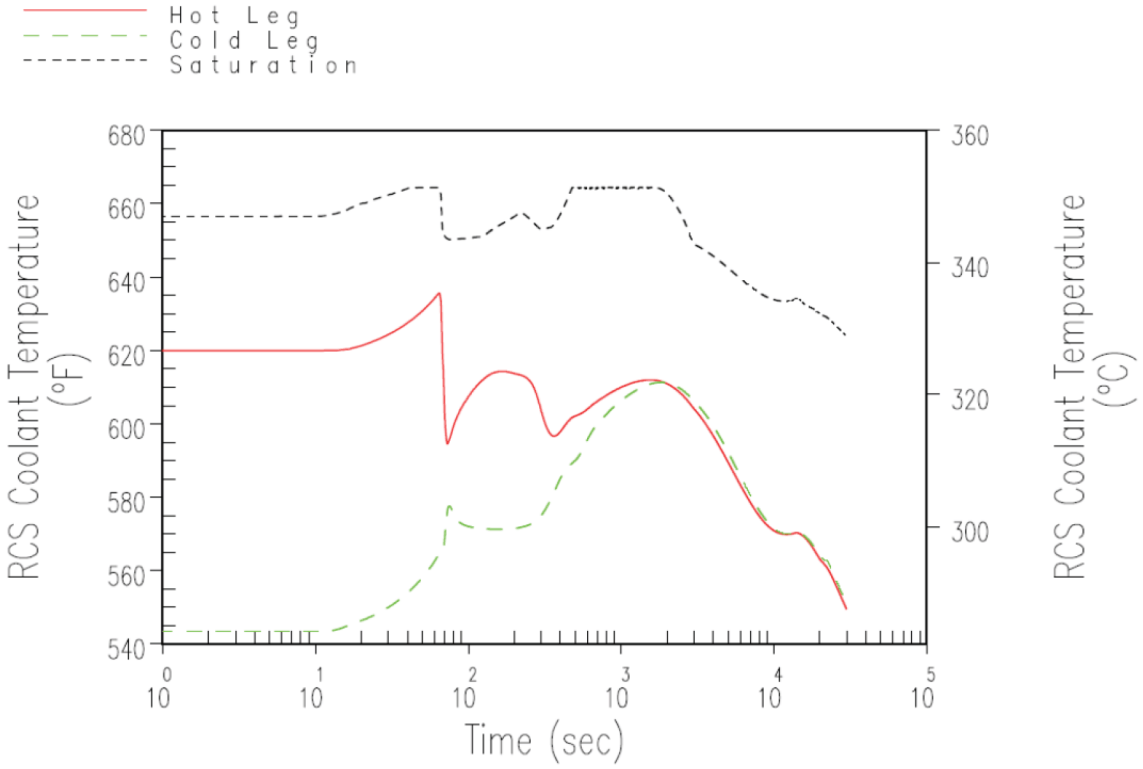

Figure 15.2.7-19
Reactor Coolant System Temperature Transients in Loop Not Containing the PRHR for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

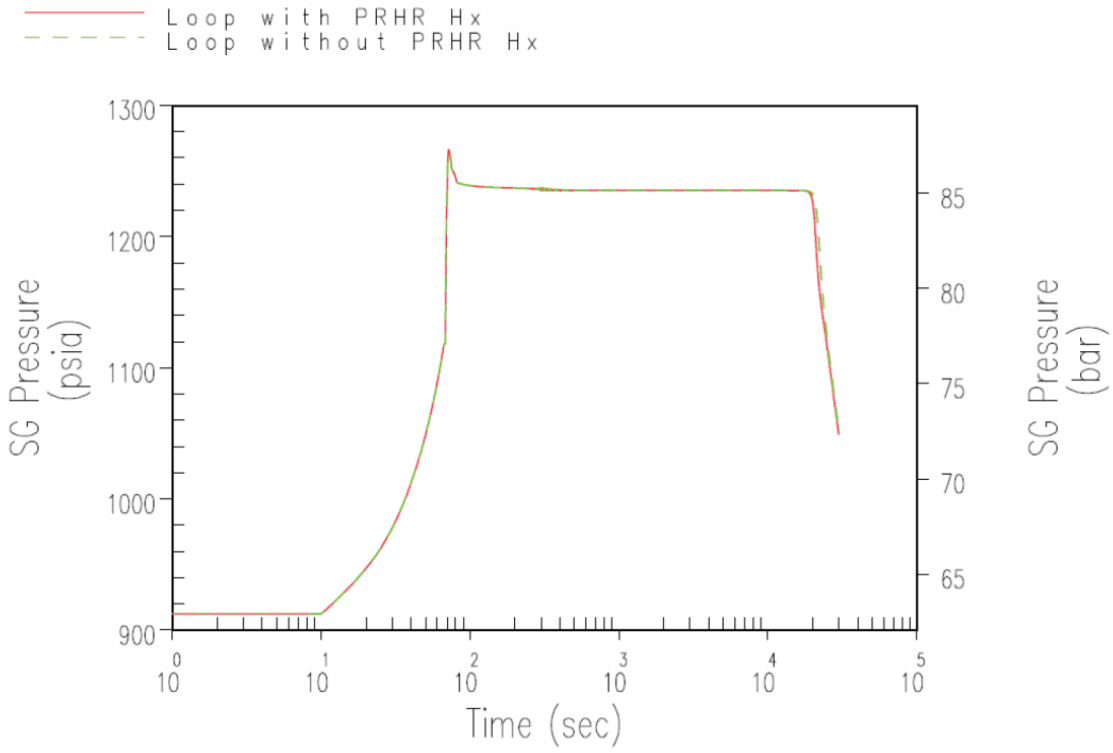

Figure 15.2.7-20
Steam Generator Pressure Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

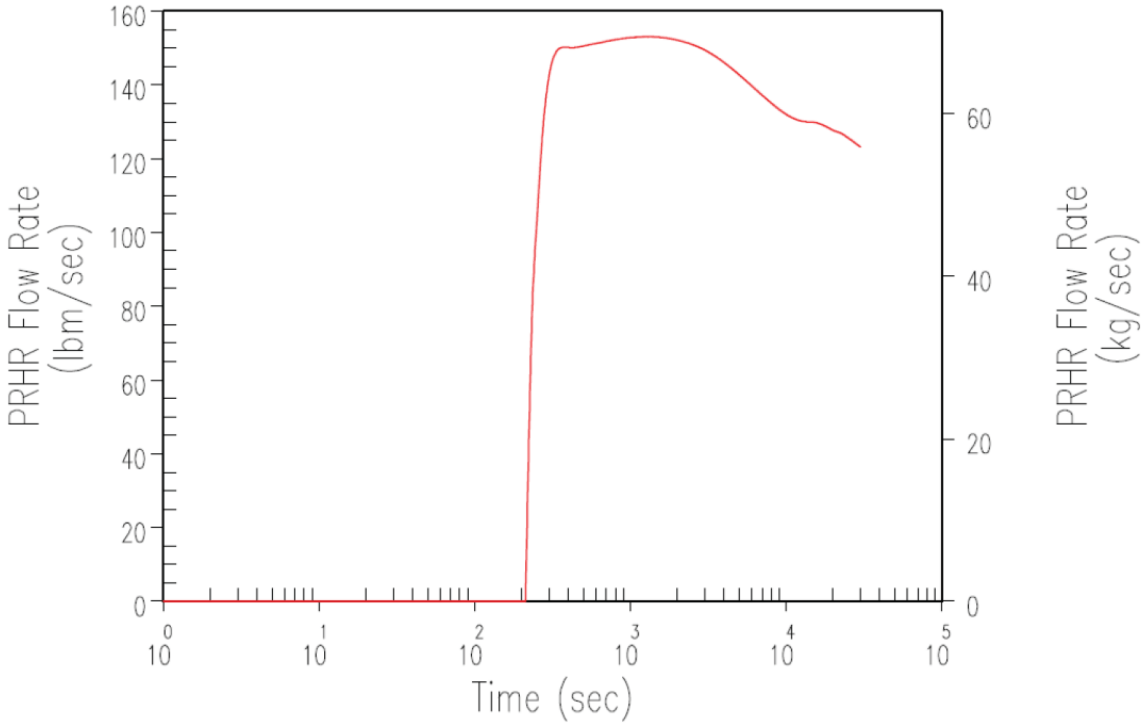

Figure 15.2.7-21
PRHR Flow Rate Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

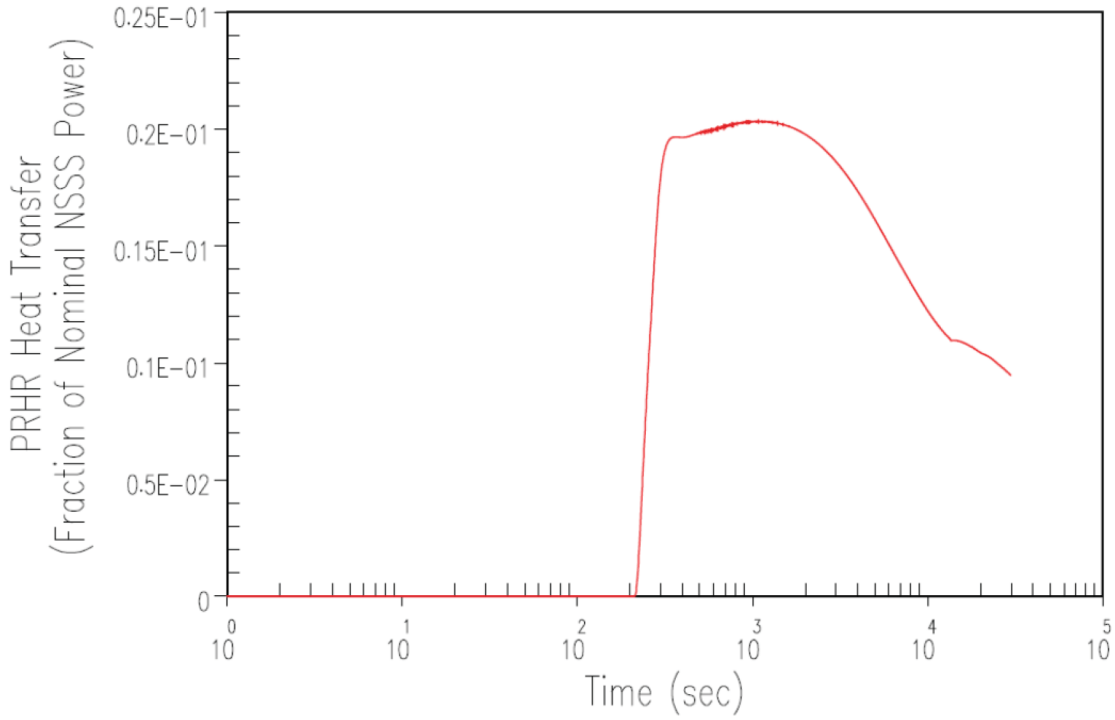

Figure 15.2.7-22
PRHR Heat Transfer Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

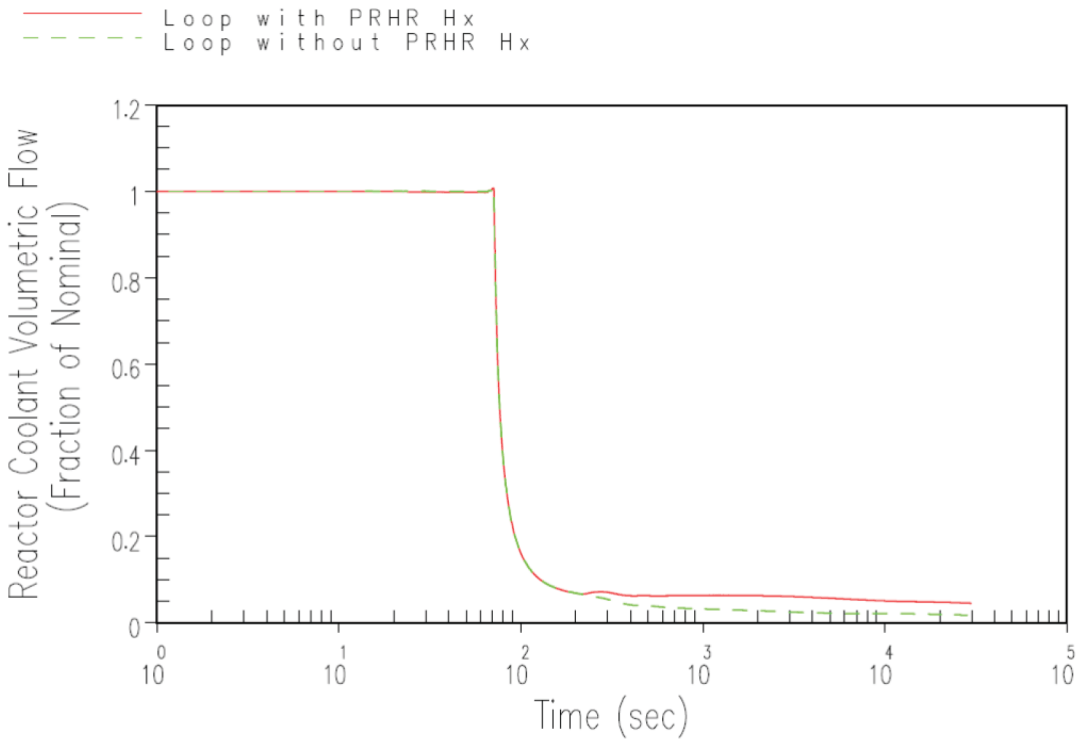

Figure 15.2.7-23
Reactor Coolant Volumetric Flow Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

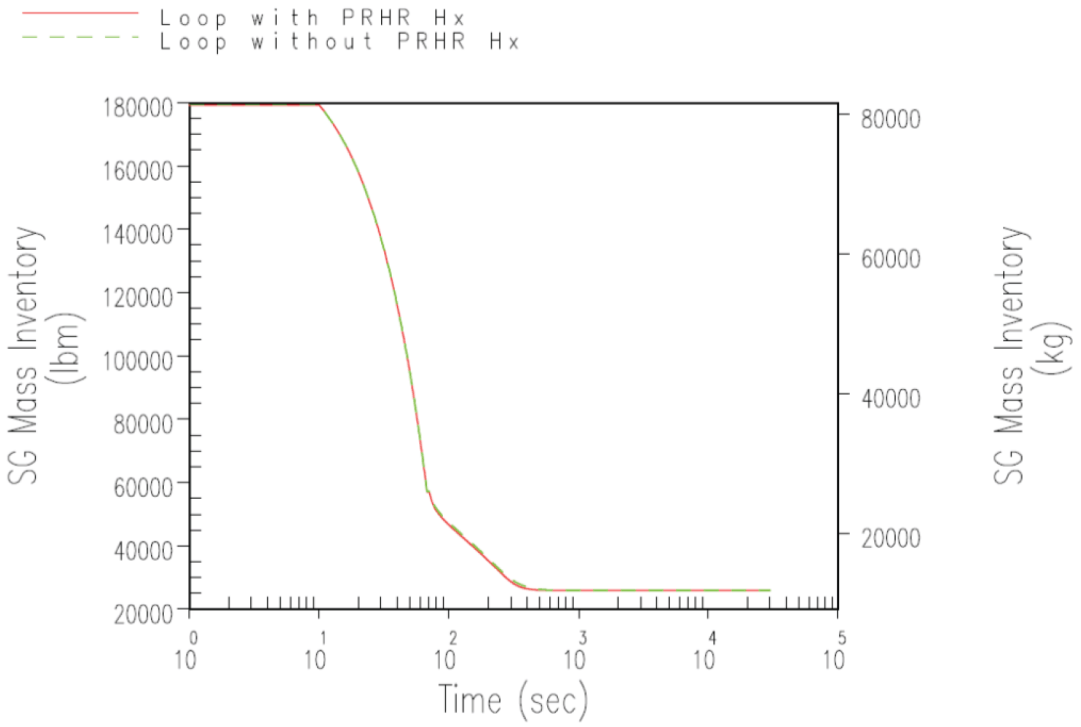

Figure 15.2.7-24
Steam Generator Inventory Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

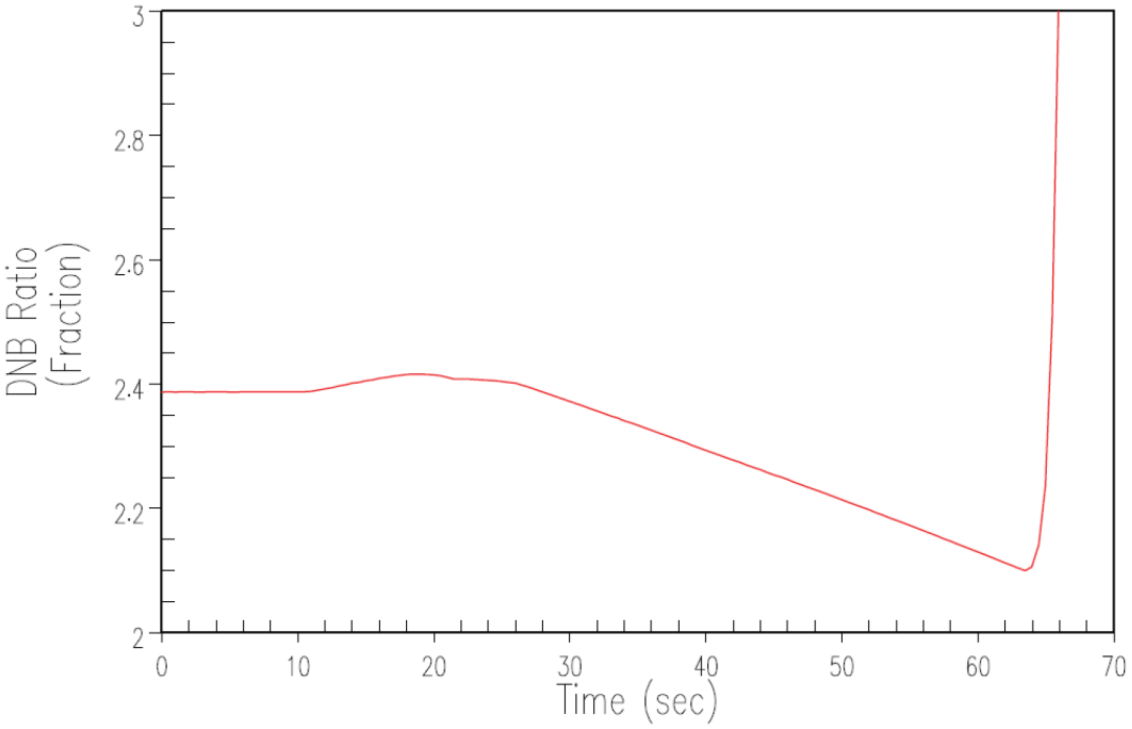

Figure 15.2.7-25
DNB Ratio Transient
for Loss of Normal Feedwater with a
Consequential Loss of ac Power to the Plant Auxiliaries

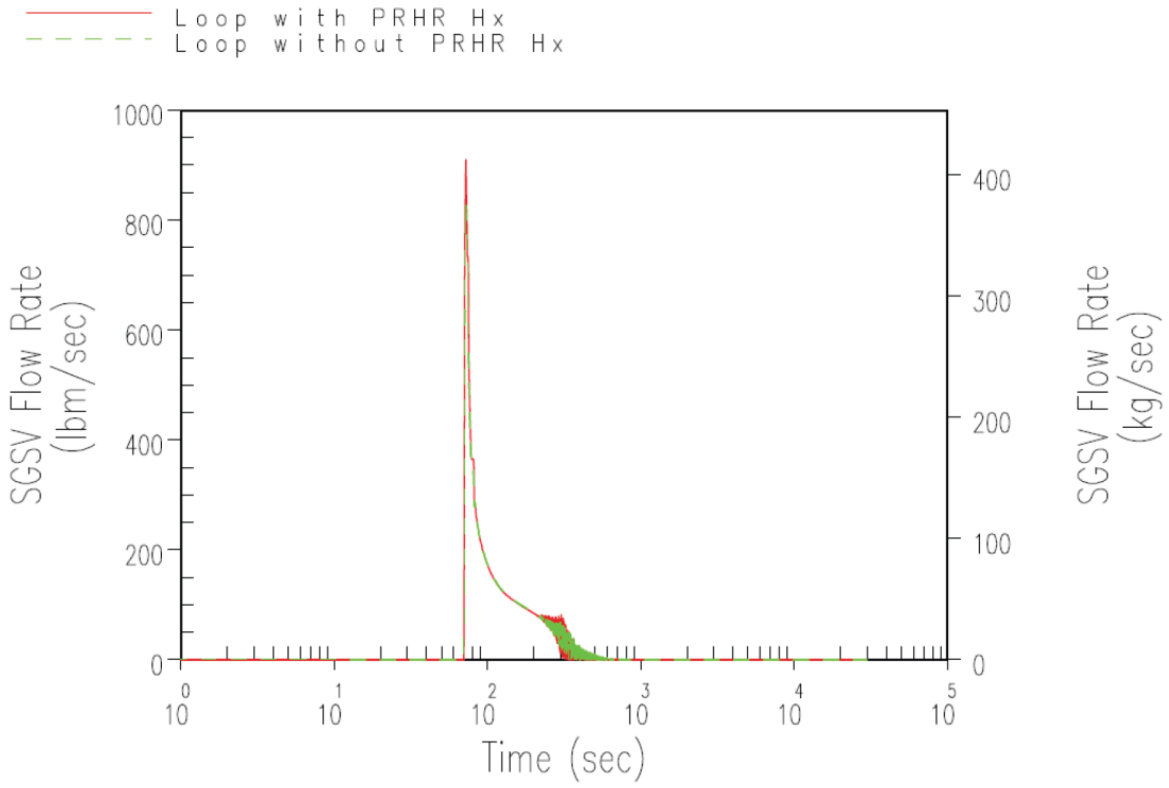

Figure 15.2.7-26
Steam Generator Safety Valve Relief Transient for Loss of Normal Feedwater with a Consequential Loss of ac Power to the Plant Auxiliaries

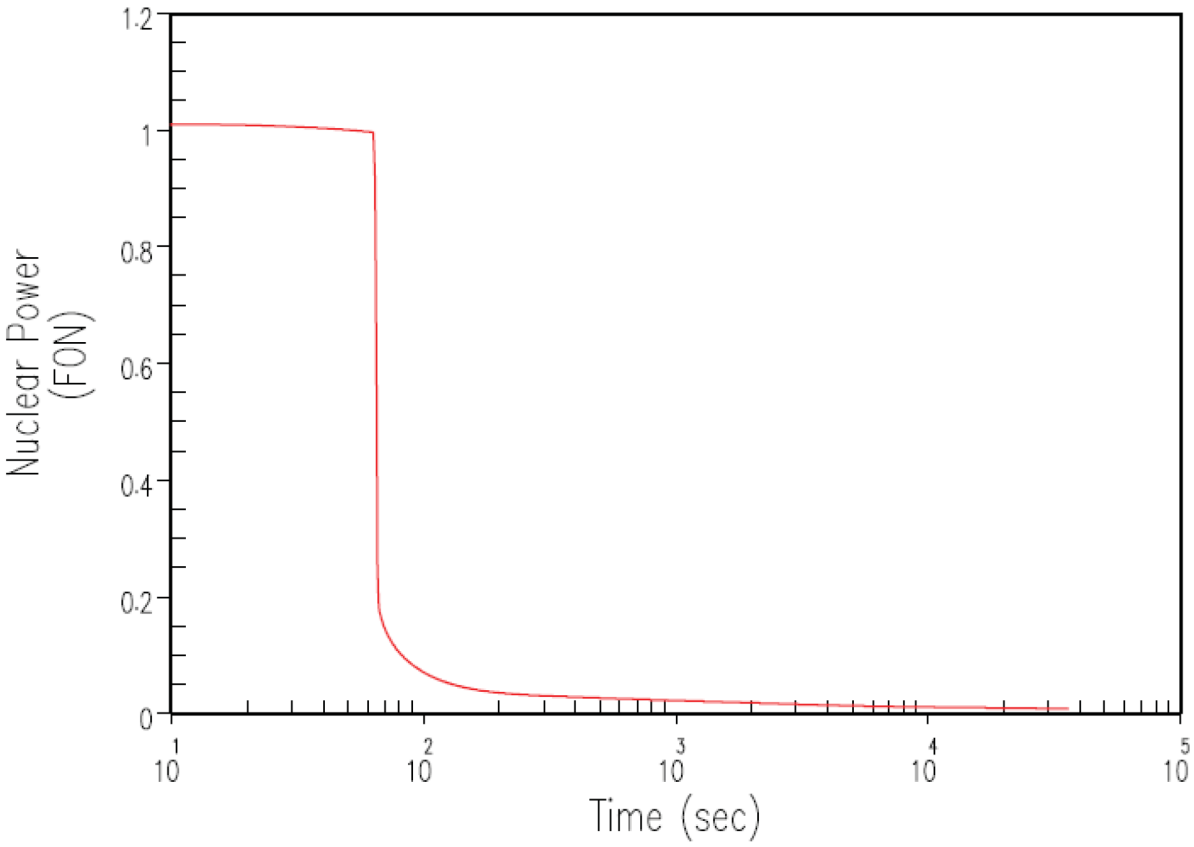

Figure 15.2.8-1
Nuclear Power Transient for
Main Feedwater Line Rupture

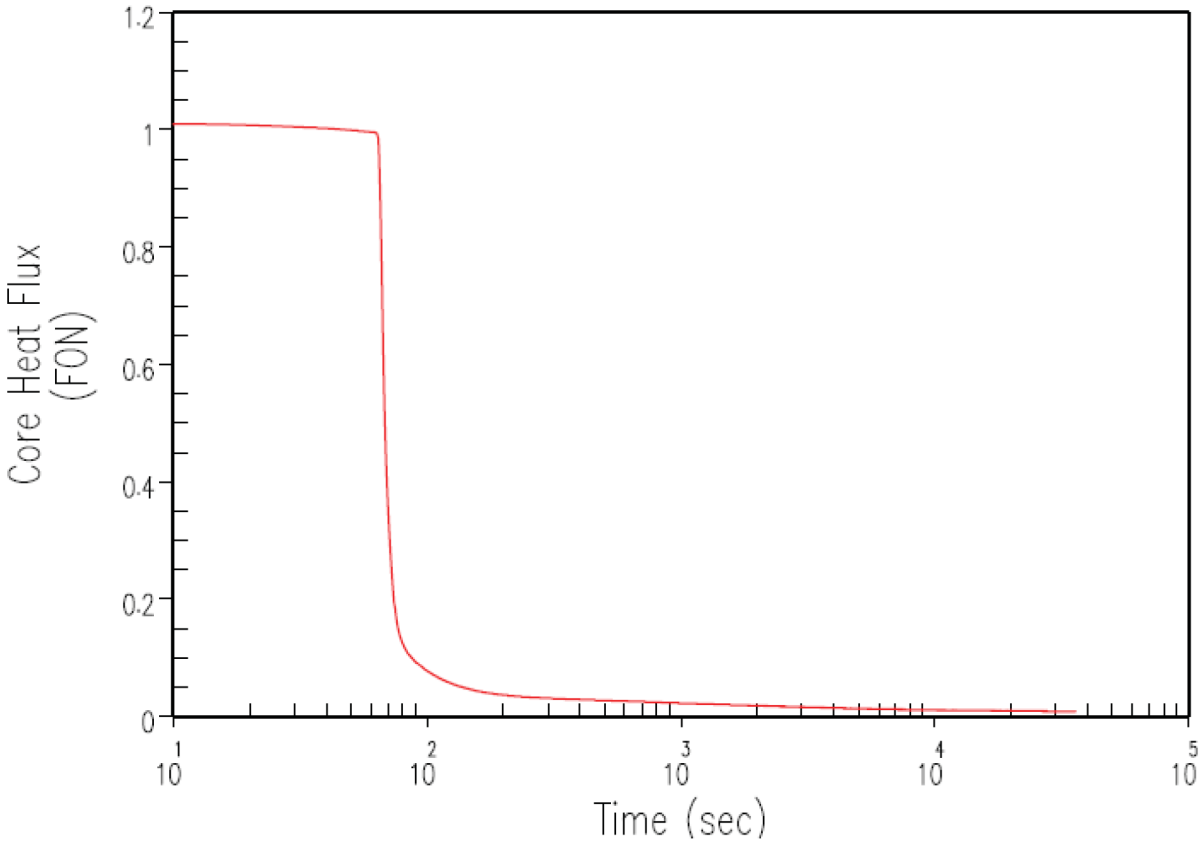

Figure 15.2.8-2
Core Heat Flux Transient for
Main Feedwater Line Rupture

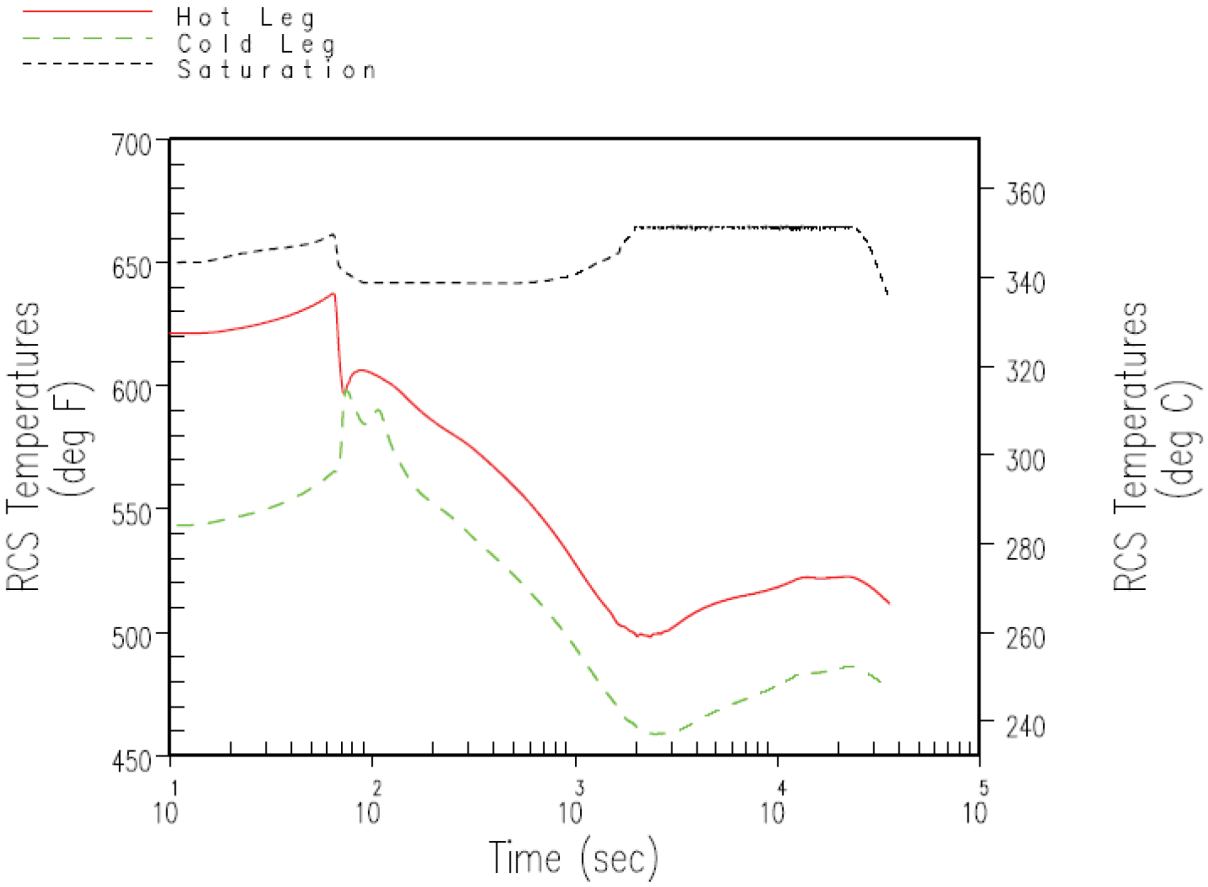

Figure 15.2.8-3
Faulted Loop Reactor Coolant System
Temperature Transients for Main Feedwater Line Rupture

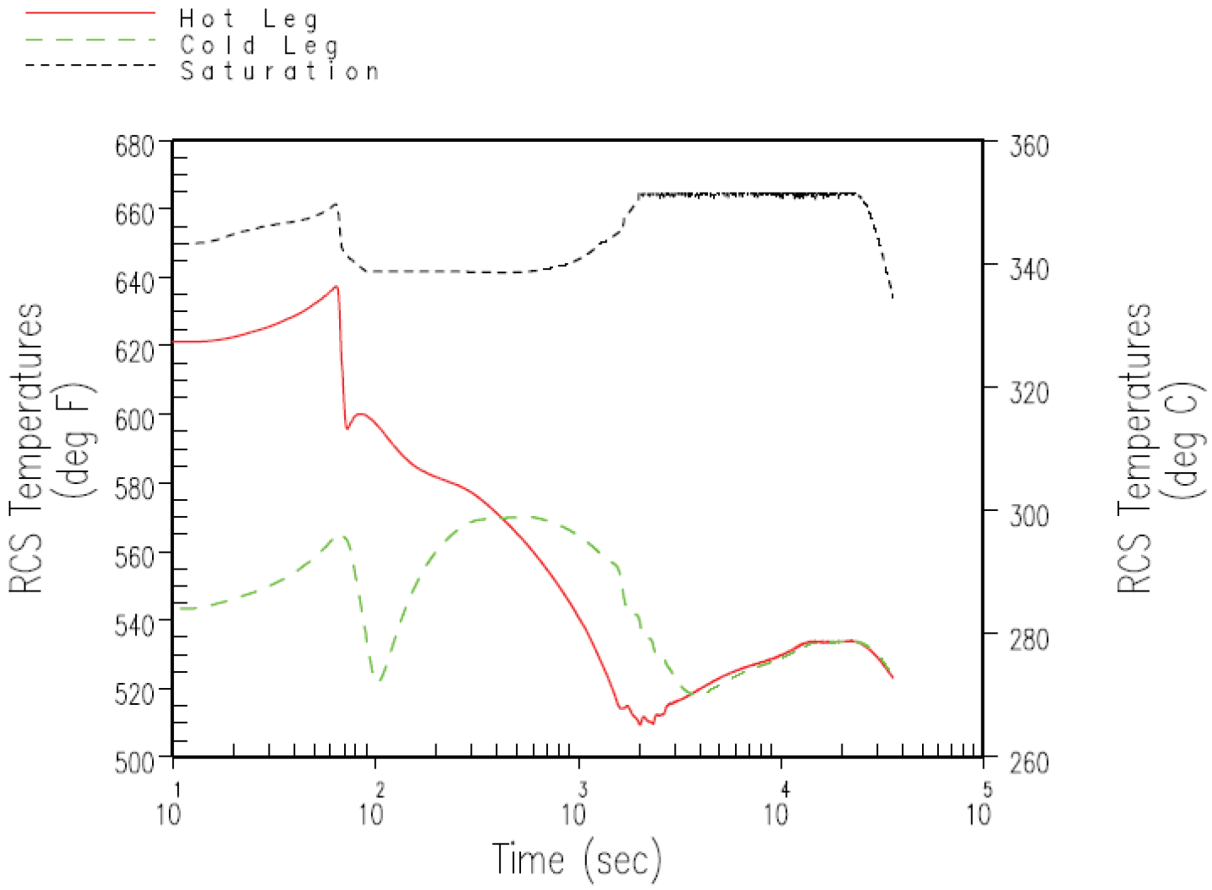

Figure 15.2.8-4
Intact Loop Reactor Coolant System
Temperature Transients for Main Feedwater Line Rupture

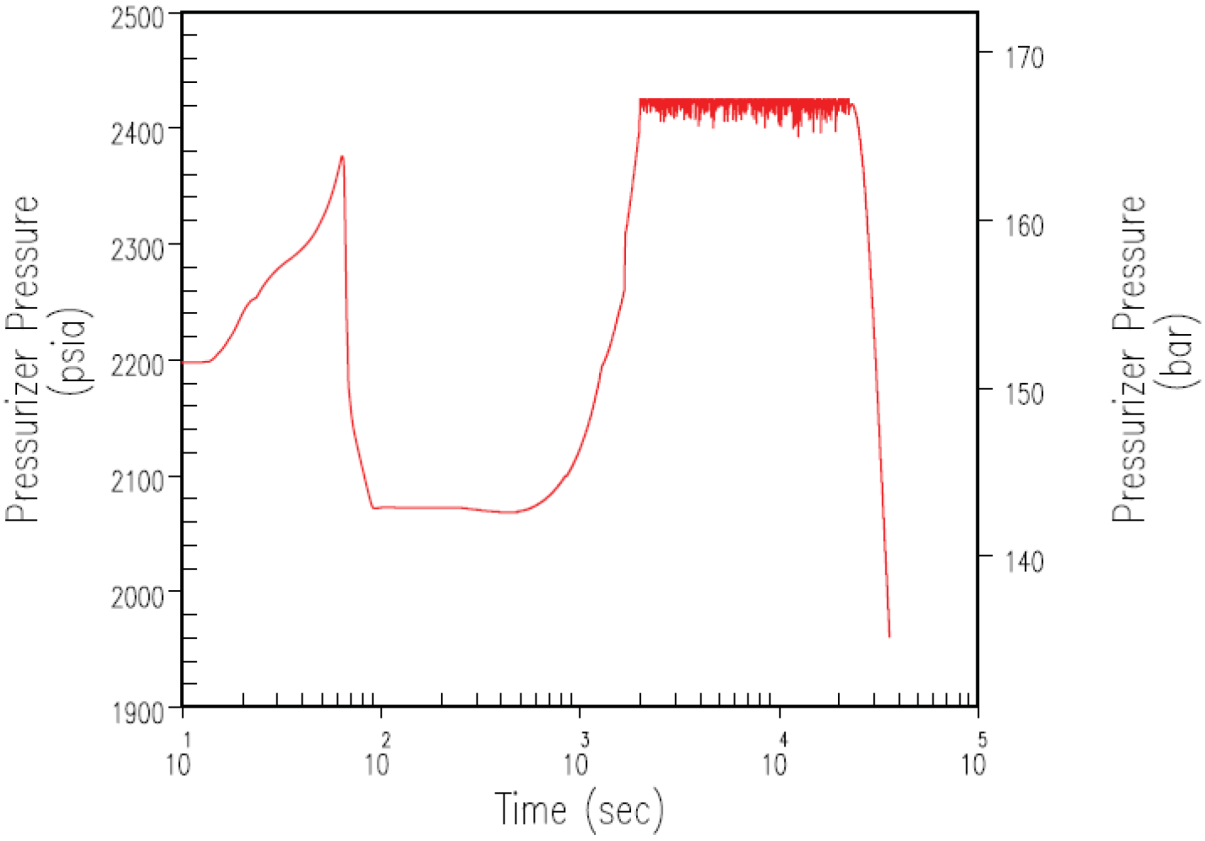

Figure 15.2.8-5
Pressurizer Pressure Transient for Main Feedwater Line Rupture

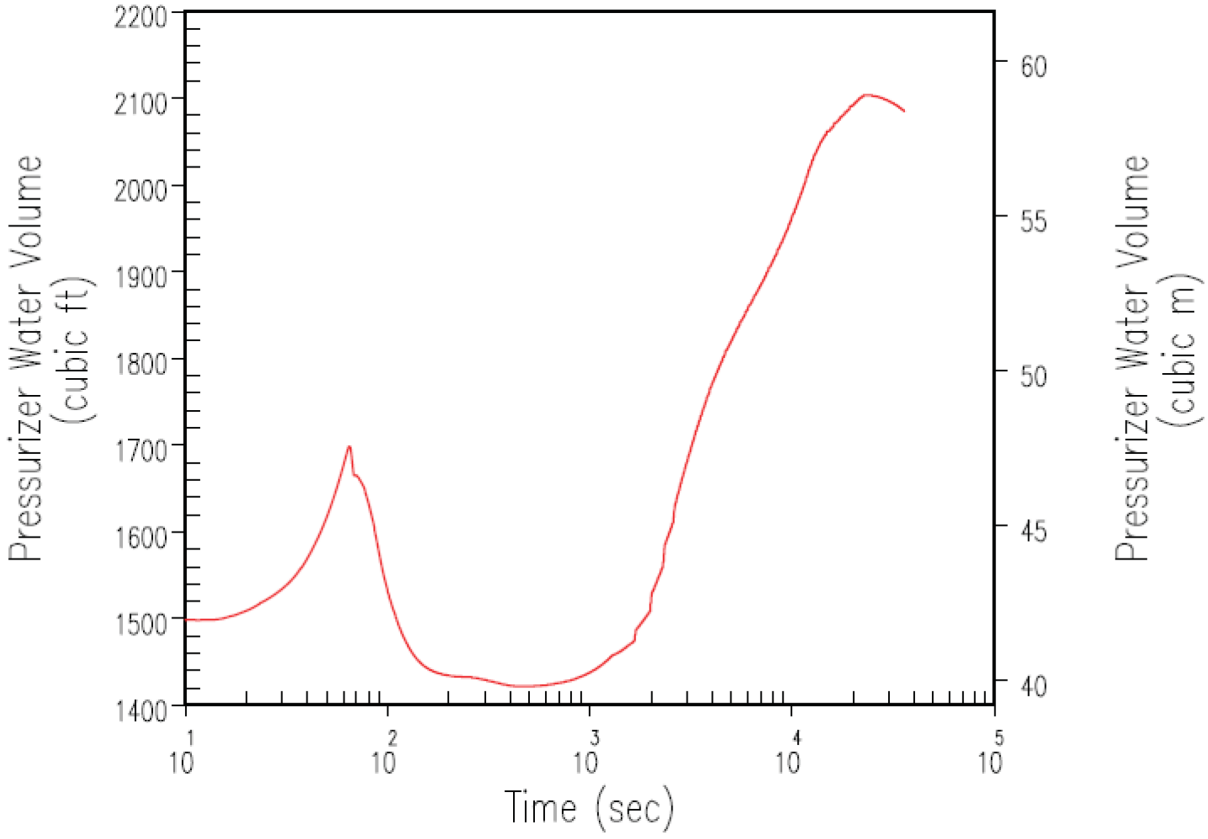

Figure 15.2.8-6
Pressurizer Water Volume Transient for Main Feedwater Line Rupture

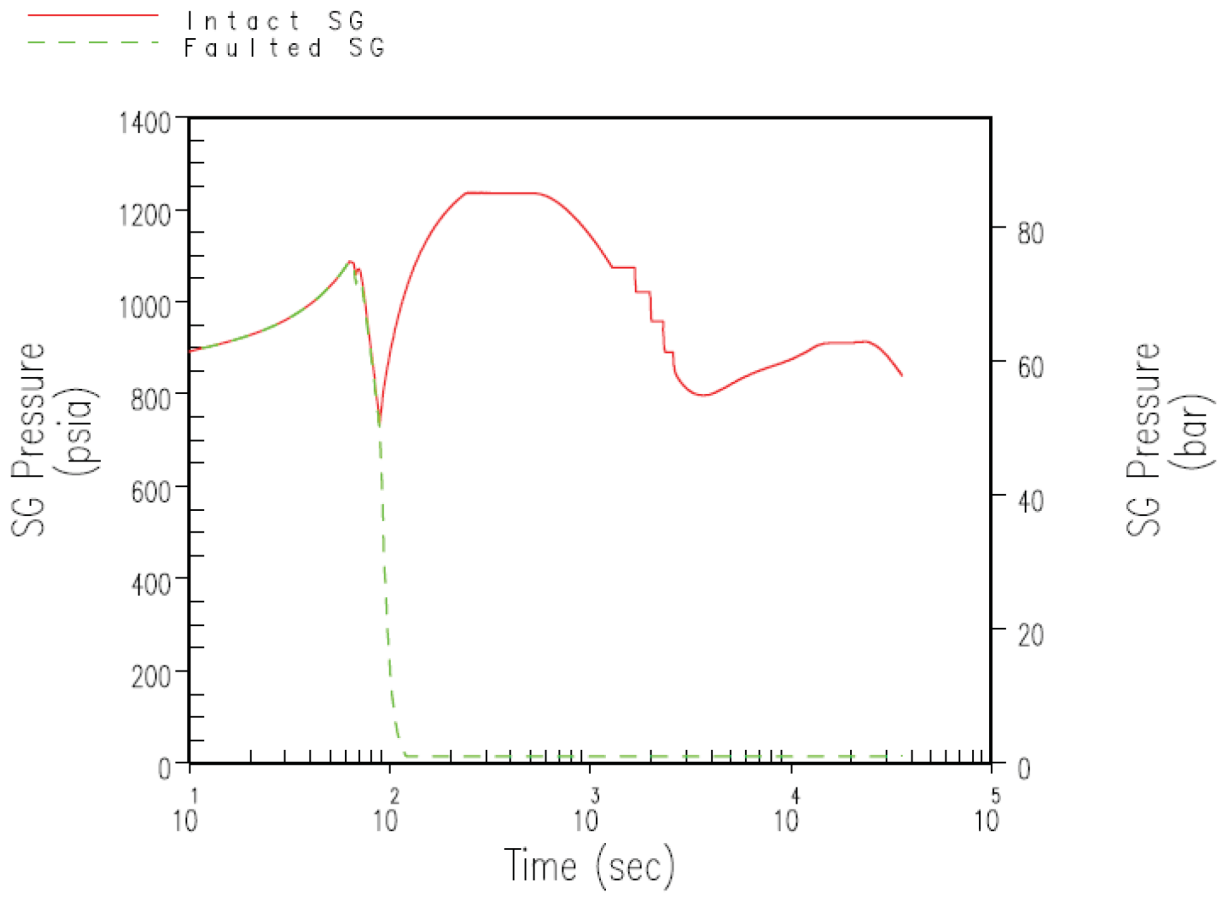

Figure 15.2.8-7
Steam Generator Pressure Transient for Main Feedwater Line Rupture

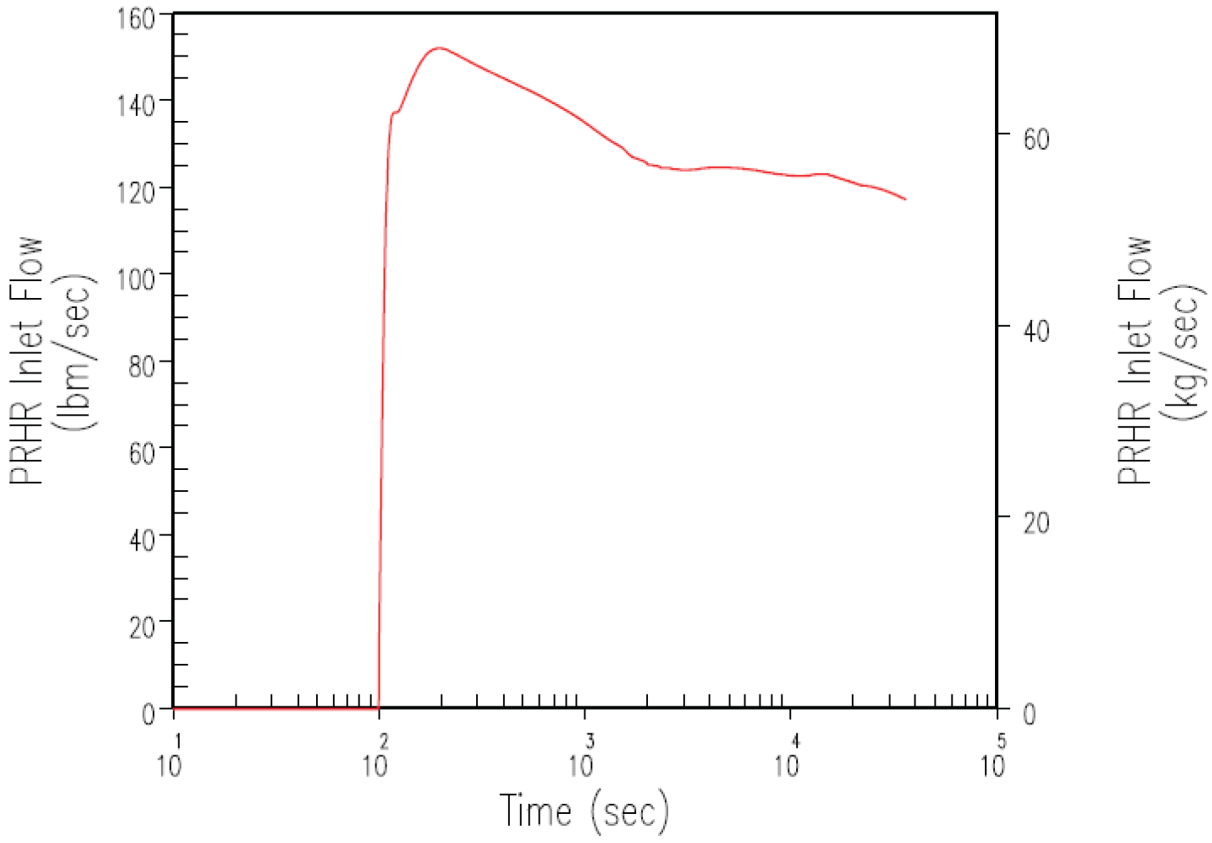

Figure 15.2.8-8
PRHR Flow Rate Transient for Main Feedwater Line Rupture

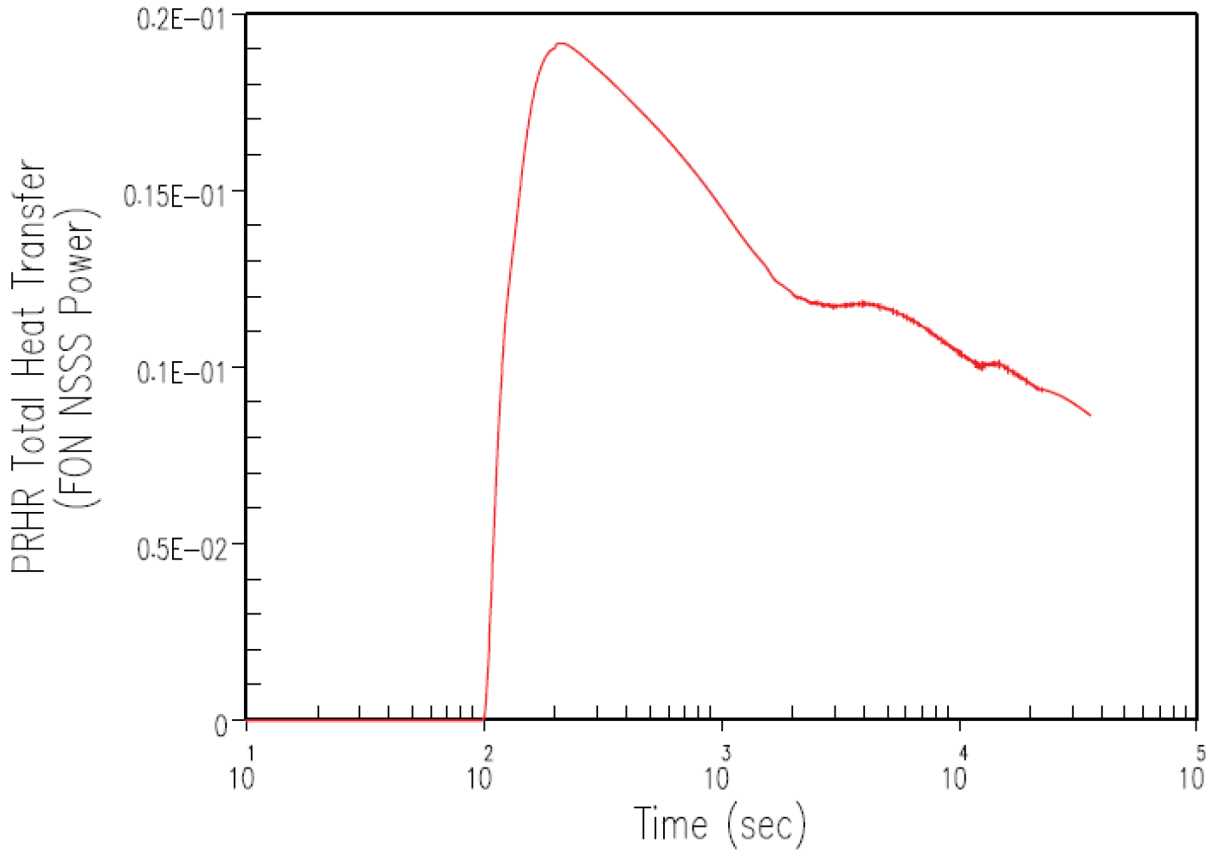

Figure 15.2.8-9
PRHR Heat Flux Transient for Main Feedwater Line Rupture

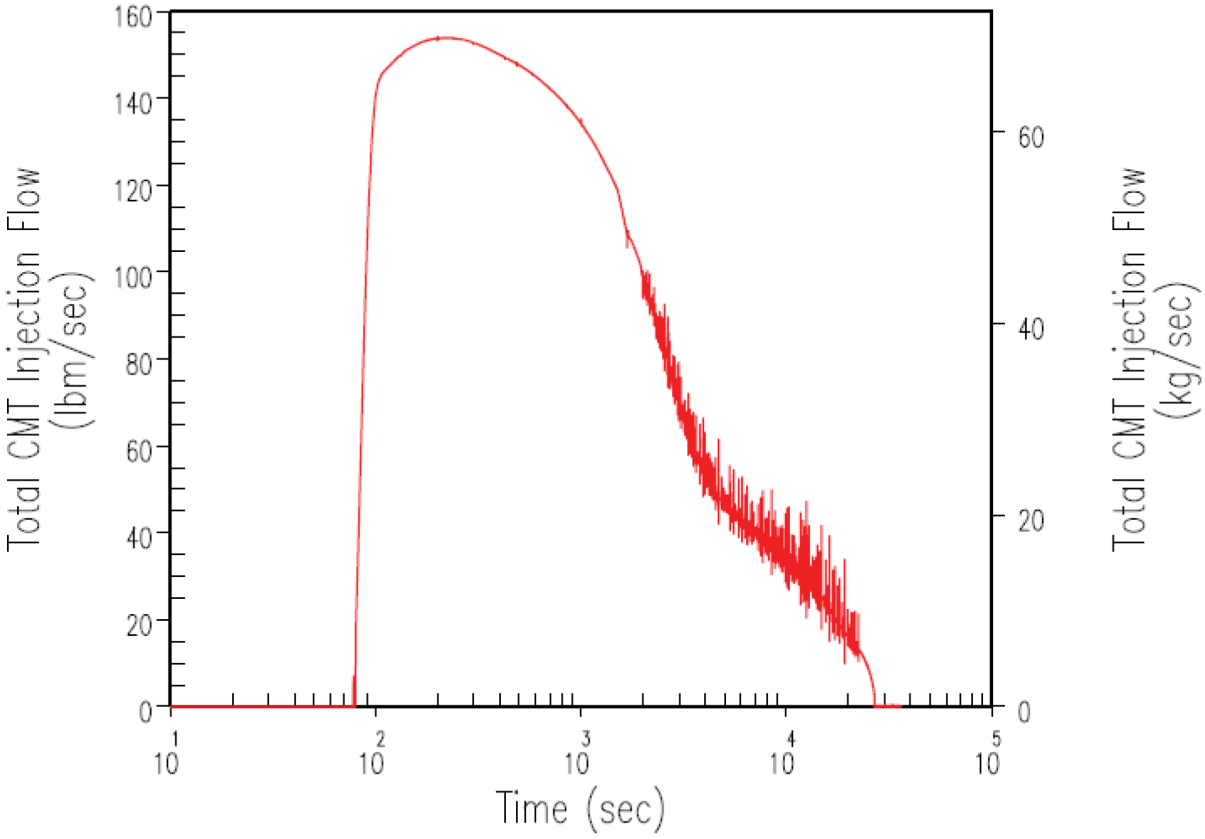

Figure 15.2.8-10
CMT Injection Flow Rate Transient for Main Feedwater Line Rupture

15.3 Decrease in Reactor Coolant System Flow Rate

A number of faults that could result in a decrease in the reactor coolant system flow rate are postulated. These events are discussed in this section. Detailed analyses are presented for the most limiting of the following reactor coolant system flow decrease events:

- Partial loss of forced reactor coolant flow
- Complete loss of forced reactor coolant flow
- Reactor coolant pump shaft seizure (locked rotor)
- Reactor coolant pump shaft break

The first event is a Condition II event, the second is a Condition III event, and the last two are Condition IV events.

The four limiting flow rate decrease events described above are analyzed in this section. The most severe radiological consequences result from the reactor coolant pump shaft seizure accident discussed in Subsection 15.3.3. Doses are reported only for that case.

15.3.1 Partial Loss of Forced Reactor Coolant Flow

15.3.1.1 Identification of Causes and Accident Description

A partial loss of coolant flow accident can result from a mechanical or an electrical failure of a reactor coolant pump or from a fault in the power supply to the pump or pumps. If the reactor is at power at the time of the event, the immediate effect of the loss of coolant flow is a rapid increase in the coolant temperature. For the AP1000 plant design, there are two potential partial loss of flow scenarios. These scenarios include the coast down of one reactor coolant pump and the coast down of two reactor coolant pumps in diametrically opposite loops. Although both scenarios are analyzed, the loss of two reactor coolant pumps bounds the loss of one pump, because it results in a more severe flow coast down. Thus, the two pump partial loss of flow is used as the basis for the discussion within this section.

Normal power for the pumps is supplied through four buses connected to the generator. When a generator trip occurs, the buses are supplied from offsite power and the pumps continue to operate.

A partial loss of coolant flow is classified as a Condition II incident (a fault of moderate frequency), as defined in Subsection 15.0.1.

Protection against this event is provided by the Low-2 primary coolant flow reactor trip signal, which is actuated by two-out-of-four Low-2 flow signals. Above permissive P10, Low-2 flow in either hot leg actuates a reactor trip (see Section 7.2).

As specified in GDC 17 of 10 CFR Part 50, Appendix A, the effects of a loss of offsite power are considered in evaluating partial loss of forced reactor coolant flow transients. As discussed in Subsection 15.0.14, the loss of offsite power is considered to be a potential consequence of the event due to disruption of the electrical grid following a turbine trip during the event. A delay of 3 seconds is assumed between the turbine trip and the loss of offsite power. In addition, turbine trip occurs 5 seconds following a reactor trip condition being reached. This delay on turbine trip is a feature of the AP1000 reactor trip system. The primary effect of the loss of offsite power is to cause the remaining operating reactor coolant pumps to coast down. However, since the loss of offsite power would occur no earlier than 8 seconds into the event, it is well beyond the critical time frame of interest for the partial loss of flow events (i.e., time of rod insertion). Thus, it is not explicitly modeled in the case runs.

15.3.1.2 Analysis of Effects and Consequences

15.3.1.2.1 Method of Analysis

This transient is analyzed using three computer codes. First, the LOFTRAN code (References 1 and 8) is used to calculate the core flow during the transient based on the input loop flows, the nuclear power transient, and the primary system pressure and temperature transients. The FACTRAN code (Reference 2) or the VIPRE-01 fuel rod model (Reference 7), which is equivalent to FACTRAN, is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (see Section 4.4) is used to calculate the departure from nucleate boiling ratio (DNBR) during the transient, based on the heat flux from FACTRAN and the flow from LOFTRAN. The calculated DNBR transient represents the minimum of the typical cell or the thimble cell. Note that an explicit DNBR calculation is only performed for the more limiting complete loss of flow event described in Subsection 15.3.2.

15.3.1.2.2 Initial Conditions

Initial reactor power, pressurizer pressure, and reactor coolant system temperature are assumed to be at their nominal values. Uncertainties in initial conditions are statistically accounted for in the DNBR limit, as described in WCAP-11397-P-A (Reference 5).

Plant characteristics and initial conditions assumed in this analysis are further discussed in Subsection 15.0.3.

15.3.1.2.3 Reactivity Coefficients

The reactivity feedback parameters are chosen so as to maximize the energy transferred to the primary coolant during the flow coastdown. A most-negative Doppler-only power coefficient (see Figure 15.0.4-1) is applied to maximize the positive reactivity addition during the reactor trip and rod motion, which acts to slow the rate of power reduction; the equivalent total integrated Doppler reactivity from 0 to 100 percent power of 0.016 Δk. As there is an initial heatup due to the reduction in RCS flow, a least-negative (minimum feedback) moderator temperature coefficient is most conservative. Therefore, a constant moderator density coefficient of 0.0 Δk/g/cc is modeled. Finally, a curve of trip reactivity versus time based on a 2.7-second rod cluster control assembly insertion time to the dashpot is applied (see Subsection 15.0.5).

15.3.1.2.4 Flow Coastdowns

Conservative flow coastdowns are used to simulate the transient. The flow coastdowns are calculated externally to the LOFTRAN code using the COAST computer code which is described in Subsection 15.0.11.

15.3.1.2.5 Protection Systems

Plant systems and equipment necessary to mitigate the effects of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or equipment adversely affects the consequences of the accident.

15.3.1.2.6 Results

Figures 15.3.1-1 through 15.3.1-5 show the transient response for the loss of two reactor coolant pumps with offsite power available. The partial loss of flow event is evaluated to be bounded by the complete loss of flow event described in Subsection 15.3.2, for which the analysis demonstrates that

the DNBR is always greater than the safety analysis limit value. This demonstrates that the DNB design basis is met. The DNB design basis is described in Section 4.4.

The affected reactor coolant pumps coast down and the core flow reaches a new equilibrium value. The plant is tripped by the Low-2 flow trip rapidly enough so that the capability of the reactor coolant to remove heat from the fuel rods is not greatly reduced. The average fuel and cladding temperatures do not increase significantly above their initial values. With the reactor tripped, a stable plant condition is attained and plant shutdown may then proceed.

The calculated sequence of events for the case analyzed is shown in Table 15.3-1.

In the event that a loss of offsite power occurs as a consequence of a turbine trip during a partial loss of reactor coolant flow, the DNB design basis continues to be met as discussed in Subsection 15.3.1.1.

15.3.1.3 Conclusions

The analysis shows that, for the partial loss of reactor coolant flow, the DNBR does not decrease below the safety analysis limit value at any time during the transient, which demonstrates that the DNB design basis is met. The DNB design basis is described in Section 4.4. The applicable Standard Review Plan, Subsection 15.3.1 (Reference 4), evaluation criteria are met.

15.3.2 Complete Loss of Forced Reactor Coolant Flow

15.3.2.1 Identification of Causes and Accident Description

A complete loss of flow accident may result from a simultaneous loss of electrical supplies to the reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of a loss of coolant flow is a rapid increase in the coolant temperature. Electric power for the reactor coolant pumps is normally supplied through buses, connected to the generator through the unit auxiliary transformers. When a generator trip occurs, the buses receive power from external power lines and the pumps continue to supply coolant flow to the core.

A complete loss of flow accident is a Condition III event (an infrequent fault), as defined in Subsection 15.0.1. The following signals provide protection against this event:

1. Low-2 Reactor coolant pump speed
2. Low primary coolant loop flow

The reactor trip on Low-2 reactor coolant pump speed protects against conditions that can cause a loss of voltage to two-out-of-four reactor coolant pumps. This function is blocked below approximately 10-percent power (permissive P10). The reactor trip on Low-2 reactor coolant pump speed also protects against an underfrequency condition resulting from frequency disturbances on the power grid, so long as the maximum grid frequency decay rate is less than approximately 5 hertz per second. WCAP-8424, Revision 1 (Reference 3), provides analyses of grid frequency disturbances and the resulting protection requirements that are applicable to the AP1000 plant design.

15.3.2.2 Analysis of Effects and Consequences

15.3.2.2.1 Method of Analysis

The complete loss of flow transient is analyzed for a loss of power to four reactor coolant pumps.

For the scenario of a complete loss of voltage, which results in all the reactor coolant pumps coasting down, the method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in Subsection 15.3.1, with three exceptions. Following the loss of power supply to all pumps at power, a reactor trip is actuated by the Low-2 reactor coolant pump speed trip instead of the Low-2 primary coolant flow trip. Also, rather than the bounding value of 0.0 Δk/g/cc, a less limiting, yet still conservative, moderator density coefficient (MDC) curve (MDC as a function of coolant density) is modeled. Finally, a curve of trip reactivity versus time based on a 2.3-second rod cluster control assembly insertion time to the dashpot is applied (see Subsection 15.0.5).

A complete loss of forced primary coolant flow can result from a reduction in the reactor coolant pump motor supply frequency. However, the results of the complete loss of voltage scenario (i.e., free spinning pump coastdown) bound the results of the complete loss of flow initiated by a frequency decay of up to 5 hertz per second. This is due to the reactor coolant pump design, which initially (during the critical time frame of the transient) has a more rapid coastdown as a free spinning pump than for an electrical frequency decay. Therefore, only the results of the complete loss of voltage case scenario are presented in Subsection 15.3.2.2.2.

15.3.2.2.2 Results

Figures 15.3.2-1 through 15.3.2-6 show the transient response for the complete loss of voltage to all four reactor coolant pumps. The reactor is tripped on the Low-2 reactor coolant pump speed signal. Figure 15.3.2-6 demonstrates that the DNBR is always greater than the safety analysis limit value which demonstrates that the DNB design basis is met. The DNB design basis is described in Section 4.4.

The calculated sequence of events for the case analyzed is shown in Table 15.3-1. With respect to DNB concerns, the event is essentially over shortly after reactor trip. However, if the event was extended beyond the time frame analyzed for DNB, the reactor coolant pumps would continue to coast down, and natural circulation flow would be established, as demonstrated in Subsection 15.2.6. With the reactor tripped, a stable plant condition is attained and plant shutdown may then proceed.

15.3.2.3 Conclusions

The analysis demonstrates that, for the complete loss of forced reactor coolant flow, the DNBR does not decrease below the safety analysis limit value at any time during the transient, which demonstrates that the DNB design basis is met. The DNB design basis is described in Section 4.4. The applicable Standard Review Plan, Subsection 15.3.1 (Reference 4), evaluation criteria are met.

15.3.3 Reactor Coolant Pump Shaft Seizure (Locked Rotor)

15.3.3.1 Identification of Causes and Accident Description

The accident postulated is an instantaneous seizure of a reactor coolant pump rotor, as discussed in Section 5.4. Flow through the affected reactor coolant loop is rapidly reduced, leading to a reactor trip on a Low-2 flow signal.

Following the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant, causing the coolant temperature to increase and expand. At the same time, heat transfer to the shell side of the steam generator in the faulted loop is reduced because: 1) the reduced flow results in a decreased tube-side film coefficient, and 2) the reactor coolant in the tubes cools down while the shell-side temperature increases. (Consistent with the AP1000 design, the peak pressure and fuel rod thermal analyses assume a 5 second delay in turbine trip following reactor trip.) The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam

generators, causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, and opens the pressurizer safety valves, in that sequence. For conservatism, the pressure-reducing effect of the spray is not included in the analysis.

This event is classified as a Condition IV incident (a limiting fault), as defined in Subsection 15.0.1.

15.3.3.2 Analysis of Effects and Consequences

15.3.3.2.1 Method of Analysis

Two digital computer codes are used to analyze this transient. The LOFTRAN code (Reference 1) calculates the resulting core flow transient following the pump seizure and the nuclear power following reactor trip. This code is also used to determine the peak pressure. The thermal behavior of the fuel located at the core hot spot is investigated by using the FACTRAN code (Reference 2) or the VIPRE-01 fuel rod model (Reference 7) which is equivalent to FACTRAN. This fuel thermal calculation uses the core flow and the nuclear power calculated by LOFTRAN. The FACTRAN code includes a film-boiling heat transfer coefficient.

At the beginning of the postulated locked rotor accident (at the time the shaft in one of the reactor coolant pumps is assumed to seize), the plant is assumed to be in operation under the most adverse steady-state operating conditions, that is, maximum steady-state thermal power, maximum steady-state pressure, and maximum steady-state coolant average temperature. Plant characteristics and initial conditions are further discussed in Subsection 15.0.3. A curve of trip reactivity versus time based on a 2.3-second rod cluster control assembly insertion time to the dashpot is applied (see Subsection 15.0.5). The accident is evaluated for both cases with and without offsite power available. For the case without offsite power available, power is lost to the unaffected pumps at 3.0 seconds following turbine/generator trip. Turbine trip occurs 5.0 seconds following a reactor trip condition being reached. This delay on turbine trip is a feature of the AP1000 reactor trip system.

For the peak pressure evaluation, the initial pressure is conservatively estimated as 50 psi above nominal pressure (2250 psia), which allows for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. To obtain the maximum pressure in the primary side, conservatively high loop pressure drops are added to the calculated pressurizer pressure.

15.3.3.2.2 Evaluation of the Pressure Transient and Fuel Rod Thermal Design Transient

After pump seizure, the neutron flux is rapidly reduced by control rod insertion. Rod motion is assumed to begin 1.45 seconds after the flow in the affected loop reaches the reactor trip setpoint. No credit is taken for the pressure-reducing effect of the pressurizer spray, steam dump, or controlled feedwater flow after plant trip. Although these operations are expected to result in a lower peak reactor coolant system pressure, an additional conservatism is provided by ignoring their effect.

The pressurizer safety valves are fully open at 2575 psia. Their capacity for steam relief is described in Section 5.4.

For this accident, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Results obtained from analysis of this “hot spot” condition represent the upper limit with respect to cladding temperature and zirconium-water reaction.

In the evaluation, the rod power at the hot spot is conservatively assumed to be 3 times the average rod power (that is, $F_Q = 3.0$) at the initial core power level.

15.3.3.2.3 Evaluation of Departure from Nucleate Boiling in the Core During the Accident

An analysis is performed to determine the percentage of fuel rods that experience DNB. The percentage is determined to be less than the limit value used for the fraction of fuel rods that are predicted to experience a DNB in the radiological consequences calculations reported in Subsection 15.3.3.3.

15.3.3.2.4 Film-Boiling Coefficient

The film-boiling coefficient is calculated in the FACTRAN code (Reference 2) using the Bishop-Sandberg-Tong film-boiling correlation. The fluid properties are evaluated at film temperature (average between wall and bulk temperatures). The program calculates the film coefficient at every time step, based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and mass flow rate as a function of time are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient because they are the most conservative with respect to cladding temperature response. For conservatism, DNB is assumed to start at the beginning of the accident.

15.3.3.2.5 Fuel Cladding Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) have a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and the cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient is assumed to increase from a steady-state value consistent with initial fuel temperature to 10,000 Btu/h-ft^2-°F at the initiation of the transient. Thus, the large amount of energy stored in the fuel because of the small initial value of the gap coefficient is released to the cladding at the initiation of the transient.

15.3.3.2.6 Zirconium-Steam Reaction

The zirconium-steam reaction can become significant above a cladding temperature of 1800°F. The Baker-Just parabolic rate equation is used to define the rate of the zirconium-steam reaction:

$$\frac{d(w^2)}{dt} = 33.3 \times 10^6 \exp\left(-\frac{45{,}500}{1.986\,T}\right)$$

where:

w = amount reacted (mg/cm^2)

t = time (s)

T = temperature (Kelvin)

The reaction heat is 1510 cal/g.

The effect of the zirconium-steam reaction is included in the calculation of the hot spot cladding temperature transient.

Plant systems and equipment available to mitigate the effects of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or equipment adversely affects the consequences of the accident.

15.3.3.2.7 Results

Figures 15.3.3-1 through 15.3.3-7 show the transient results for one locked rotor with four reactor coolant pumps in operation. The without-offsite-power case bounds the results for the case with offsite power. The results of these calculations are also summarized in Table 15.3-2. The peak reactor coolant system pressure reached during the transient is less than that which causes stresses to exceed the faulted condition stress limits of the ASME Code, Section III. Also, the peak cladding surface temperature is considerably less than 2700°F. The cladding temperature is conservatively calculated, assuming that DNB occurs at the initiation of the transient. These results represent the most limiting conditions with respect to the locked rotor event or the pump shaft break.

The calculated sequence of events for the case analyzed is shown in Table 15.3-1. With the reactor tripped, a stable plant condition is eventually attained. Normal plant shutdown may then proceed.

15.3.3.3 Radiological Consequences

The evaluation of the radiological consequences of a postulated locked reactor coolant pump rotor accident assumes that the reactor has been operating with a limited number of fuel rods containing cladding defects and that leaking steam generator tubes have resulted in a buildup of activity in the secondary coolant. Refer to Subsection 15.3.3.3.1 and Table 15.3-3.

As a result of the accident, it is determined that no fuel rods are damaged such that the activity contained in the fuel-cladding gap is released to the reactor coolant. However, a conservative analysis has been performed assuming 10 percent of the rods are damaged. Activity carried over to the secondary side because of primary-to-secondary leakage is available for release to the environment via the steam line safety valves or the power-operated relief valves.

15.3.3.3.1 Source Term

The significant radionuclide releases due to the locked rotor accident are the iodines, alkali metals (cesiums, rubidiums) and noble gases. The reactor coolant iodine source term assumes a pre-existing iodine spike. The reactor coolant noble gas concentrations are assumed to be those associated with equilibrium operating limits for primary coolant noble gas activity. The initial reactor coolant alkali metal concentrations are based on those associated with the design basis fuel defect level. These initial reactor coolant activities are of secondary importance compared to the release of the gap inventory of fission products from the portion of the core assumed to fail because of the accident.

Based on NUREG-1465 (Reference 6), the fission product gap fraction is 3 percent of fuel inventory. For this analysis, the gap fraction is increased to 8 percent of the inventory for I-131, 10 percent for Kr-85, 5 percent for other iodines and noble gases and 12 percent for alkali metals. Also, to address the fact that the failed fuel rods may have been operating at power levels above the core average, the source term is increased by the lead rod radial peaking factor.

The initial secondary coolant activity is assumed to be 1 percent of the maximum equilibrium primary coolant activity for iodines and alkali metals.

15.3.3.3.2 Release Pathways

There are two components to the accident releases:

- The activity initially in the secondary coolant is available for release as long as steam releases continue.

- The reactor coolant leaking into the steam generators is assumed to mix with the secondary coolant. The activity from the primary coolant mixes with the secondary coolant. As steam is released, a portion of the iodine and alkali metal activity in the coolant is released. The fraction of activity released is defined by the assumed flashing fraction and the partition coefficient assumed for the steam generator. The noble gas activity entering the secondary side is released to the environment. These releases are terminated when the steam releases stop.

Credit is taken for the decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion by ground deposition during transport offsite.

15.3.3.3.3 Dose Calculation Models

The models used to calculate offsite doses are provided in Appendix 15A.

15.3.3.3.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.3-3.

Two separate accident scenarios are addressed. In the first scenario, it is assumed that the non-safety grade startup feedwater system is not available to provide feedwater to the steam generators. In this event, the water level in the steam generators drops, resulting in tube uncovery and there is flashing of a portion of the primary coolant assumed to be leaking into the secondary side of the steam generators. Also, the period of steaming is terminated at 1.5 hours when the capacity of the passive residual heat removal system exceeds the decay heat generation rate.

In the second scenario, it is assumed that the startup feedwater system is available to maintain water level in the steam generators such that the tubes remain covered. In this scenario, direct release of flashed primary coolant is not considered. Also, the passive residual heat removal system does not actuate, resulting in a longer period of steaming releases.

15.3.3.3.5 Identification of Conservatisms

The assumptions used in the analysis contain a number of significant conservatisms:

- Although fuel damage is assumed to occur as a result of the accident, no fuel damage is anticipated.

- The reactor coolant activities are based on conservative assumptions (Refer to Table 15.3-3); whereas, the expected activities based on the fuel defect level are far less (see Section 11.1).

- The leakage of reactor coolant into the secondary system, at 300 gallons per day, is conservative. The leakage is normally a small fraction of this.

- It is unlikely that the conservatively selected meteorological conditions are present at the time of the accident.

15.3.3.3.6 Doses

Using the assumptions from Table 15.3-3, the calculated total effective dose equivalent (TEDE) doses are determined to be less than 0.5 rem at the exclusion area boundary for the limiting 2-hour interval (0 to 2 hours) and less than 0.2 rem at the low population zone outer boundary for the scenario in which there is no feedwater available to maintain water level in the steam generators. The doses for the scenario in which it is assumed that water level in the steam generators is maintained are 0.4 rem at the exclusion area boundary for the limiting 2-hour interval of 6 to 8 hours and 0.4 rem at the low population zone outer boundary. These doses are a small fraction of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. A “small fraction” is identified as 10 percent or less consistent with the Standard Review Plan (Reference 4).

At the time the locked reactor coolant pump rotor event occurs, the potential exists for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because the pool boiling would not occur until after the first 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE, and when this is added to the dose calculated for the locked rotor event, the resulting total dose remains less than the value reported above.

15.3.4 Reactor Coolant Pump Shaft Break

15.3.4.1 Identification of Causes and Accident Description

The accident is postulated as an instantaneous failure of a reactor coolant pump shaft. Flow through the affected reactor coolant loop is rapidly reduced, though the initial rate of reduction of coolant flow is greater for the reactor coolant pump rotor seizure event. Reactor trip occurs on a Low-2 flow signal in the affected loop.

Following the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant, causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generator in the faulted loop is reduced because: 1) the reduced flow results in a decreased tube-side film coefficient, and 2) the reactor coolant in the tubes cools down while the shell-side temperature increases. The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, and opens the pressurizer safety valves, in that sequence. For conservatism, the pressure-reducing effect of the spray is not included in the analysis.

This event is classified as a Condition IV incident (limiting fault), as defined in Subsection 15.0.1.

15.3.4.2 Conclusion

With a failed shaft, the impeller could be free to spin in a reverse direction as opposed to being fixed in position as is the case when a locked rotor occurs. This results in a decrease in the end point (steady-state) core flow. For both the shaft break and locked rotor incidents, reactor trip occurs very early in the transient. In addition, the locked rotor analysis conservatively assumes that DNB occurs at the beginning of the transient. The calculated results presented for the locked rotor analysis bound the reactor coolant pump shaft break event.

15.3.5 Combined License Information

This section contained no requirement for additional information.

15.3.6 References

1. Burnett, T. W. T., et al., “LOFTRAN Code Description,” WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.

2. Hargrove, H. G., “FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod,” WCAP-7908-A, December 1989.

3. Baldwin, M. S., et al., “An Evaluation of Loss of Flow Accidents Caused by Power System Frequency Transients in Westinghouse PWRs,” WCAP-8424, Revision 1, May 1975.

4. NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,” U.S. Nuclear Regulatory Commission, July 1981.

5. Friedland, A. J., and Ray, S., “Revised Thermal Design Procedure,” WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Nonproprietary), April 1989.

6. Soffer, L., et al., “Accident Source Terms for Light-Water Nuclear Power Plants,” NUREG-1465, February 1995.

7. Sung, Y. X., et al., “VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis,” WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), October 1999.

8. “AP1000 Code Applicability Report,” WCAP-15644-P (Proprietary) and WCAP-15644-NP-A (Nonproprietary), Revision 2, March 2004.

Table 15.3-1
Time Sequence of Events for Incidents
That Result in a Decrease In Reactor Coolant System Flow Rate

Accident	Event	Time (seconds)
Partial loss of forced reactor coolant flow		
– Loss of two pumps with four pumps running	Two pumps lose power and begin coasting down	0.00
	Low-2 flow reactor trip setpoint reached	1.70
	Rods begin to drop	3.15
	Minimum DNBR occurs	5.20
Complete loss of forced reactor coolant		
– Loss of four pumps with four pumps running	All pumps lose power and begin coasting down	0.00
	Low-2 Reactor coolant pump speed trip setpoint reached	0.49
	Rods begin to drop	1.14
	Minimum DNBR occurs	3.00
Reactor coolant pump shaft seizure (locked rotor)		
– One locked rotor with four pumps running without offsite power available	Rotor on one pump locks	0.00
	Low-2 flow trip point reached	0.10
	Rods begin to drop	1.55
	Maximum reactor coolant system pressure occurs	3.40
	Maximum cladding temperature occurs	4.10

Table 15.3-2
Summary of Results for Locked Rotor Transients
(Four Reactor Coolant Pumps Operating Initially)

	Without Offsite Power Available
Maximum reactor coolant system pressure (psia)	2716.30
Maximum cladding average temperature, core hot spot (°F)	2013
Zr-H_2O reaction, core hot spot (percentage by weight)	0.57

Table 15.3-3 (Sheet 1 of 2)
Parameters Used in Evaluating the Radiological Consequences of a Locked Rotor Accident

Initial reactor coolant iodine activity	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 µCi/gm of dose equivalent I-131 (see Appendix 15A)[a]
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 µCi/gm dose equivalent Xe-133
Reactor coolant alkali metal activity	Based on design basis activity (see Table 15A-9)
Secondary coolant initial iodine and alkali metal activity	1% of design basis reactor coolant concentrations at maximum equilibrium conditions
Fraction of fuel rods assumed to fail	0.10
Core activity	See Table 15A-3
Radial peaking factor (for determination of activity in failed fuel rods)	1.75
Fission product gap fractions I-131 Kr-85 Other iodines and noble gases Alkali metals	 0.08 0.10 0.05 0.12
Reactor coolant mass (lb)	3.7 E+05
Secondary coolant mass (lb)	6.04 E+05
Condenser	Not available
Atmospheric dispersion factors	See Table 15A-5
Primary to secondary leak rate (lb/hr)	104.5[b]
Partition coefficient in steam generators iodine alkali metals	 0.01 0.0035
Accident scenario in which startup feedwater is not available Duration of accident (hr) Steam released (lb) 0-1.5 hours[c] Leak flashing fraction[d] 0-60 minutes > 60 minutes	 1.5 hr 6.48 E+05 0.04 0

Table 15.3-3 (Sheet 2 of 2)
Parameters Used in Evaluating the Radiological Consequences of a Locked Rotor Accident

Accident scenario in which startup feedwater is available	
Duration of accident (hr)	8.0 hr
Steam release rate (lb/sec)	60
Leak flashing fraction	Not applicable

Notes:

a. The assumption of a pre-existing iodine spike is a conservative assumption for the initial reactor coolant activity. However, compared to the activity released to the coolant from the assumed fuel failures, it is not significant.

b. Equivalent to 300 gpd cooled liquid at 62.4 lb/ft^3.

c. Heat removal is achieved by steaming and by passive core cooling system operation in the limiting case where the startup feedwater system is not available. When heat removal by the passive core cooling system exceeds the decay heat load, steam releases are terminated.

d. No credit for iodine partitioning is taken for flashed leakage. Credit is taken for a partition coefficient of 0.10 for alkali metals. Flashing is terminated by the passive core cooling system operation reducing the RCS below the saturation temperature of the secondary.

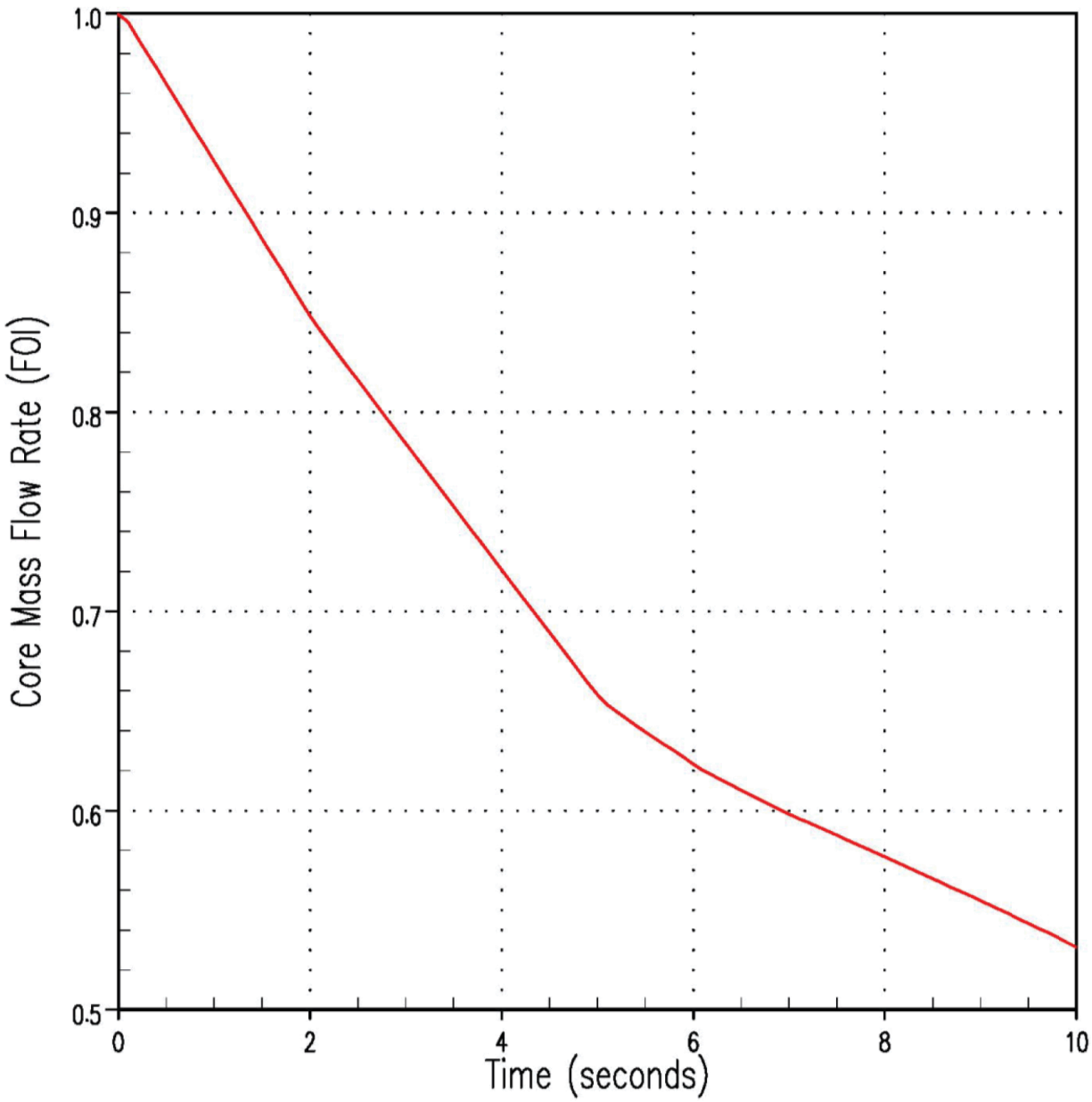

Figure 15.3.1-1
Core Mass Flow Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

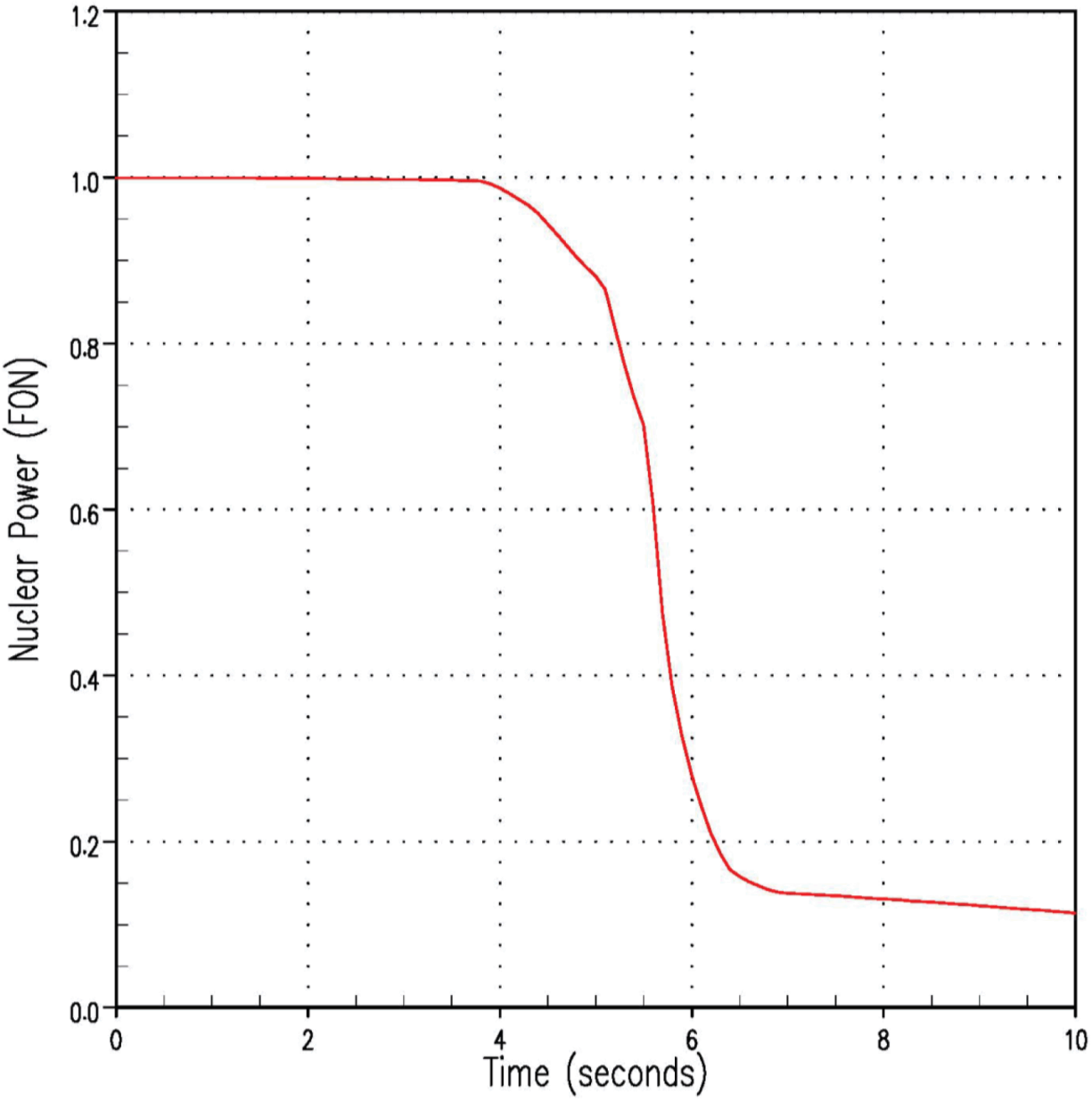

Figure 15.3.1-2
Nuclear Power Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

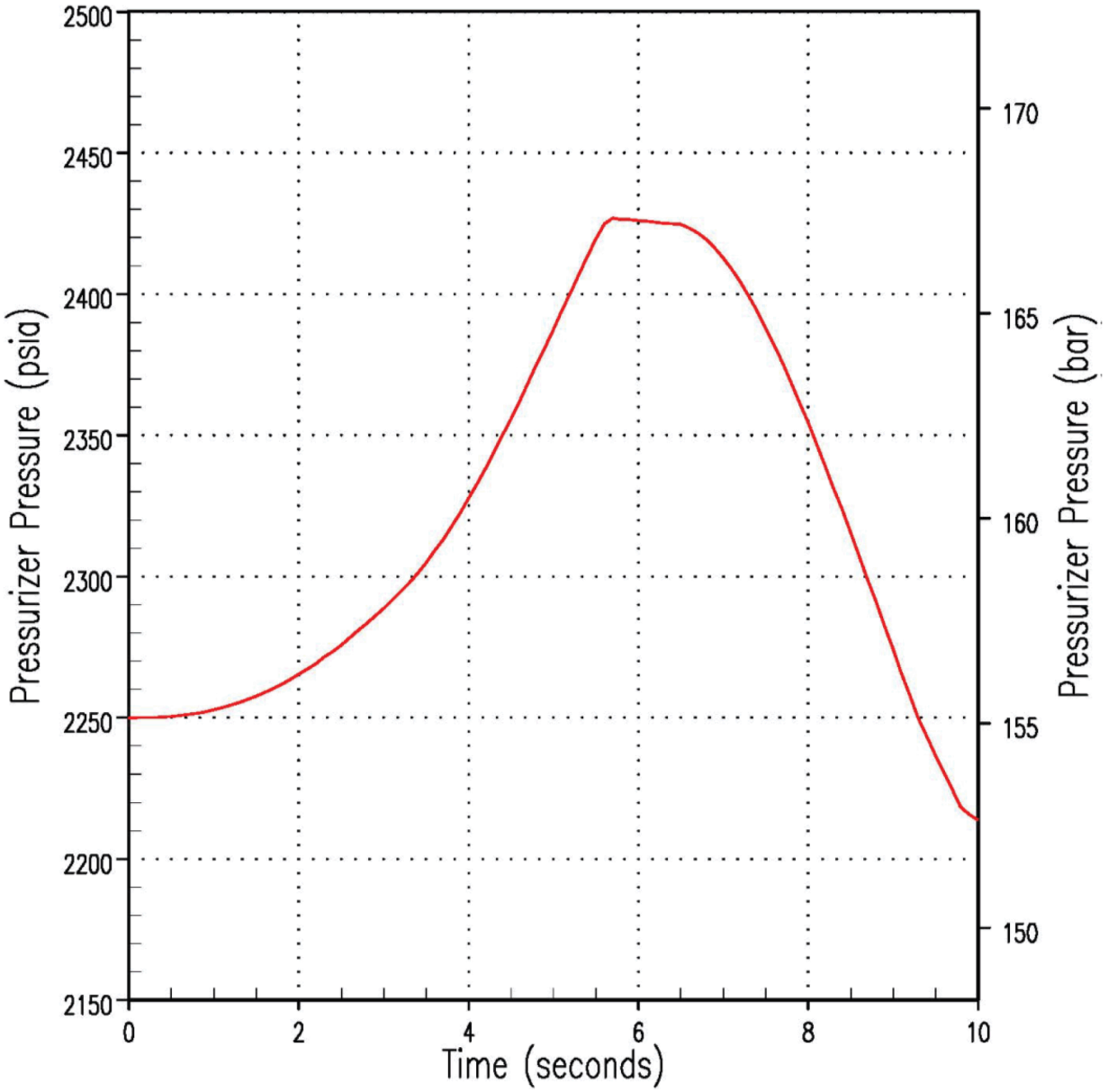

Figure 15.3.1-3
Pressurizer Pressure Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

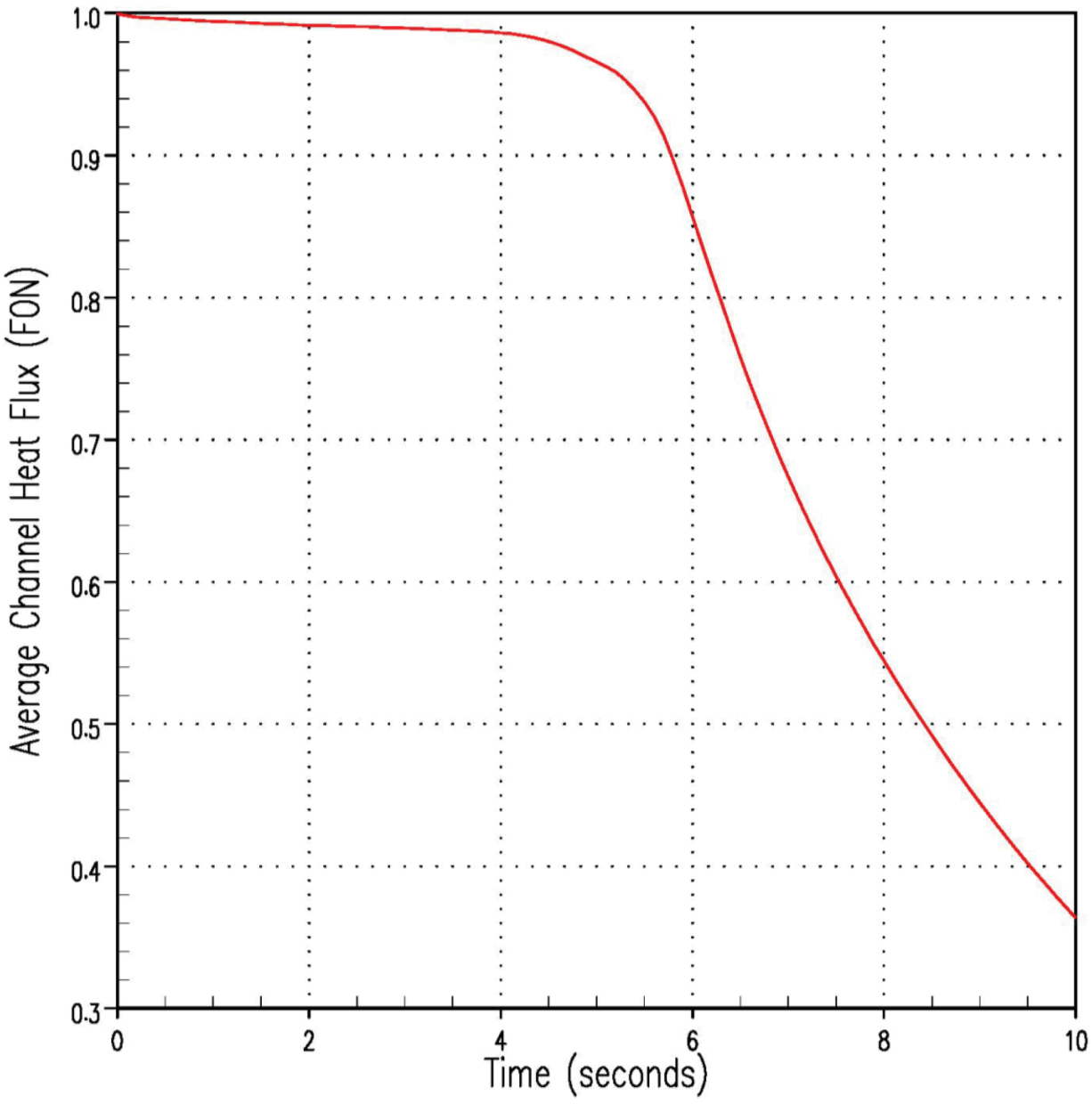

Figure 15.3.1-4
Average Channel Heat Flux Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

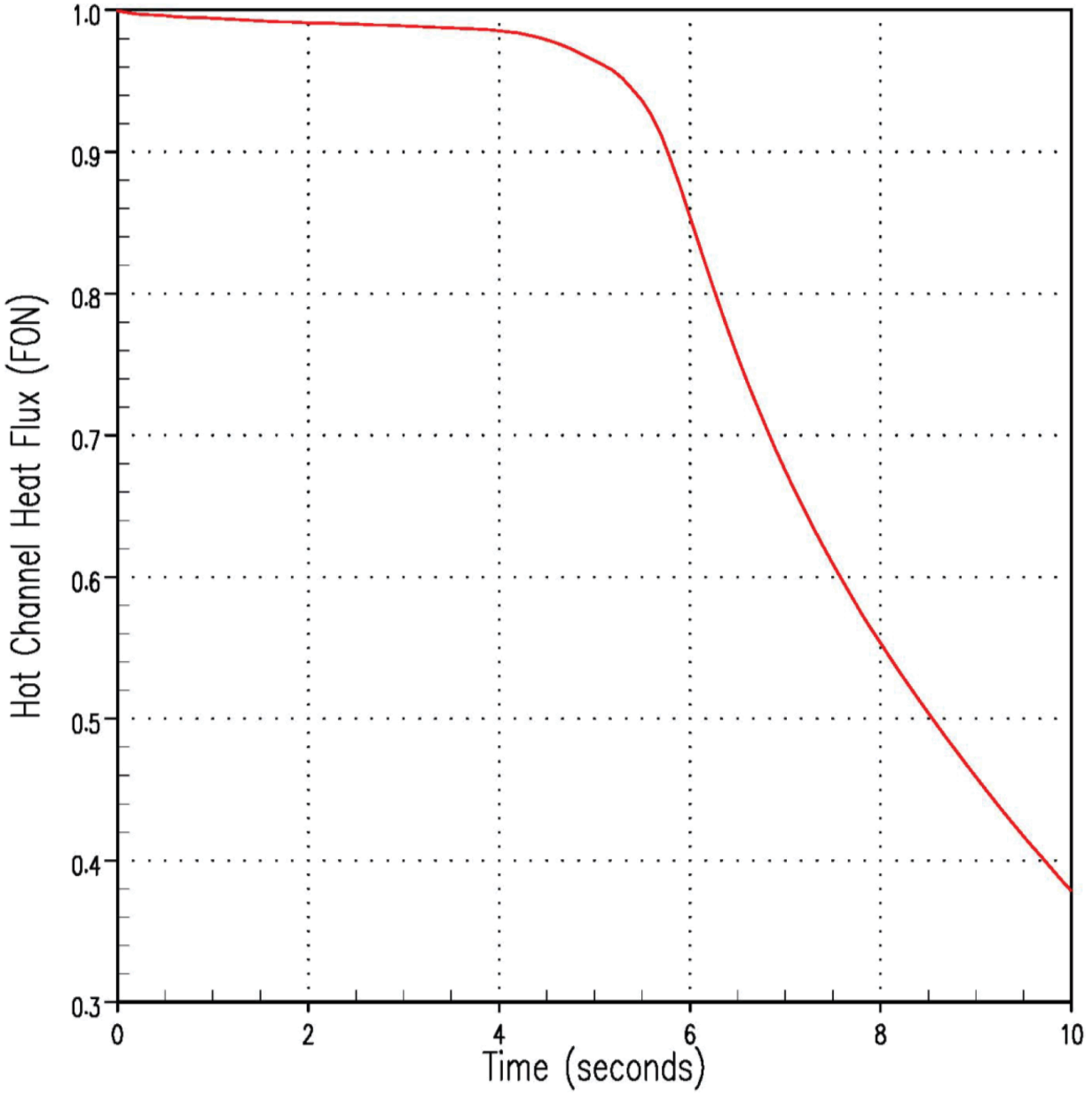

Figure 15.3.1-5
Hot Channel Heat Flux Transient for Four Cold Legs in Operation, Two Pumps Coasting Down

Figure 15.3.1-6 Not Used

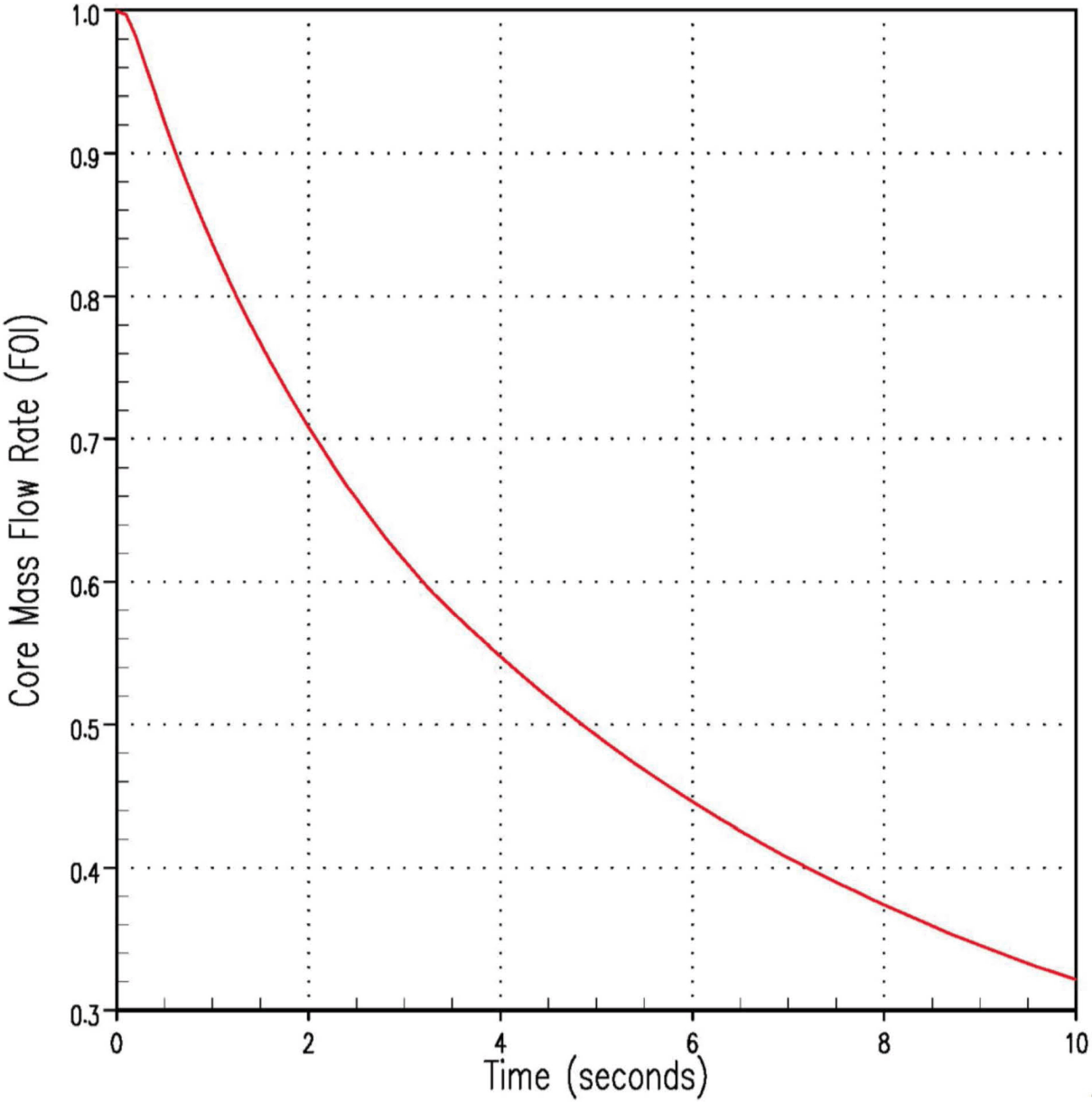

Figure 15.3.2-1
Core Mass Flow Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

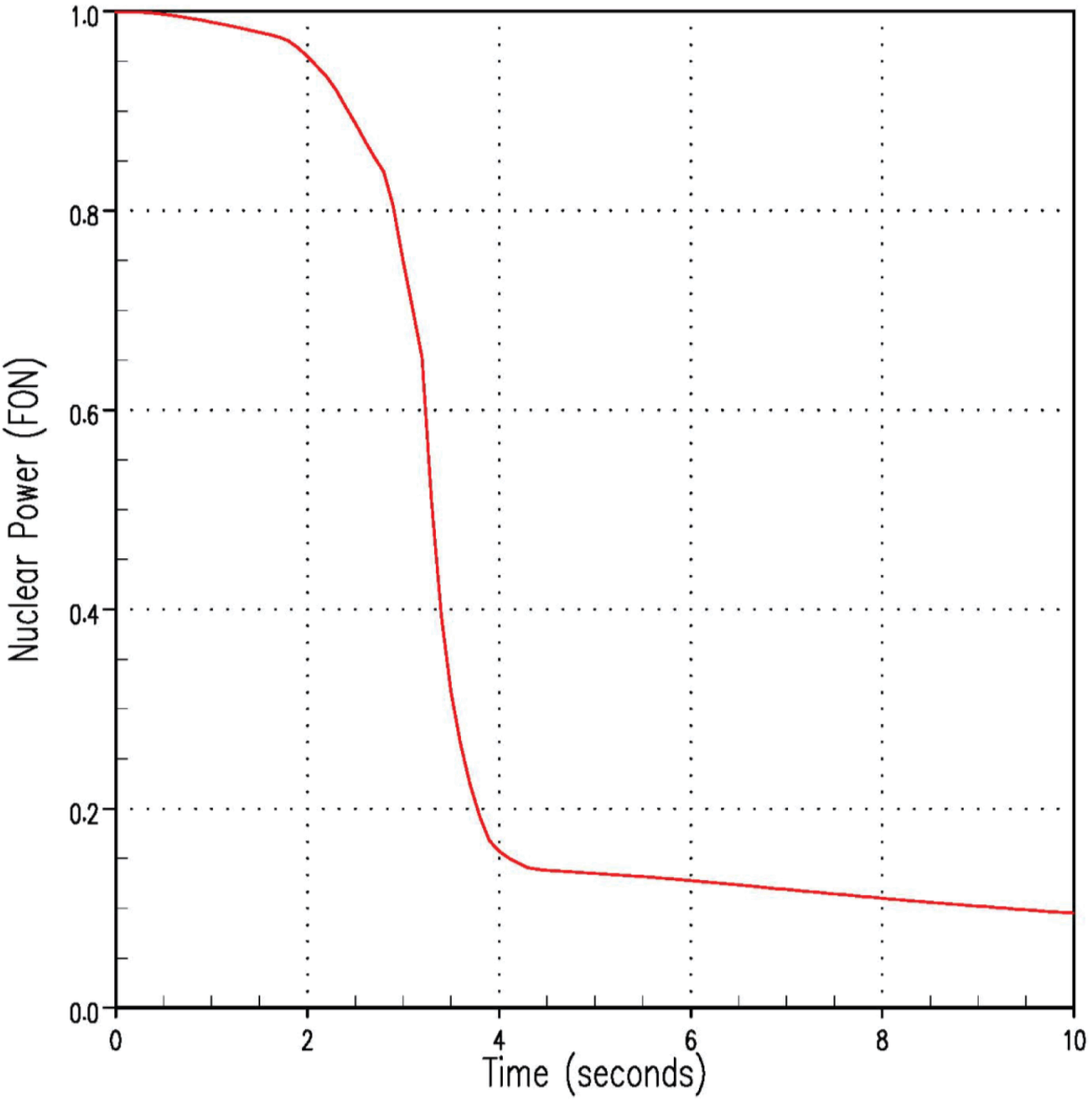

Figure 15.3.2-2
Nuclear Power Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

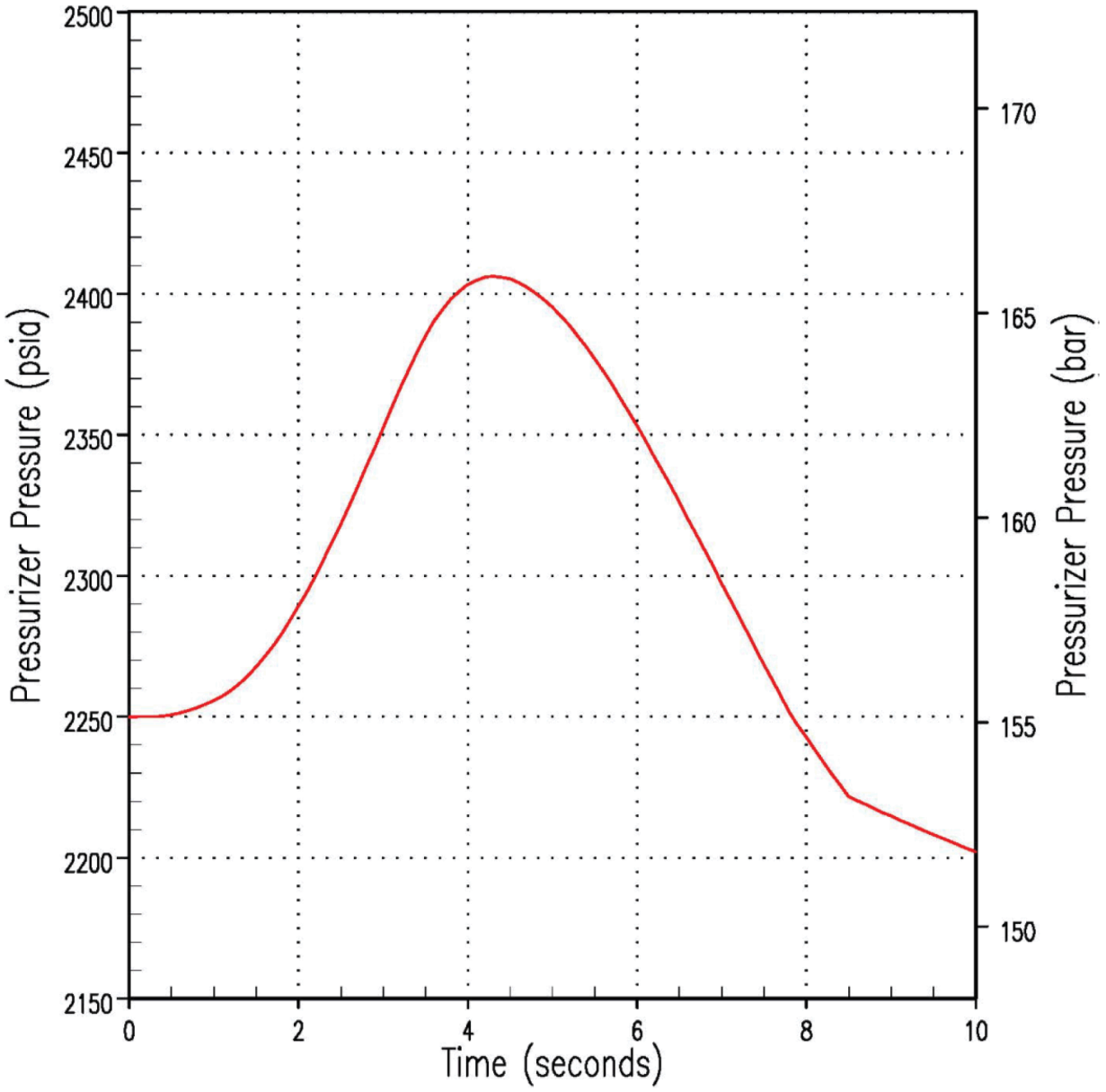

Figure 15.3.2-3
Pressurizer Pressure Transient for Four Cold Legs in Operation, Four Pumps Coasting Down

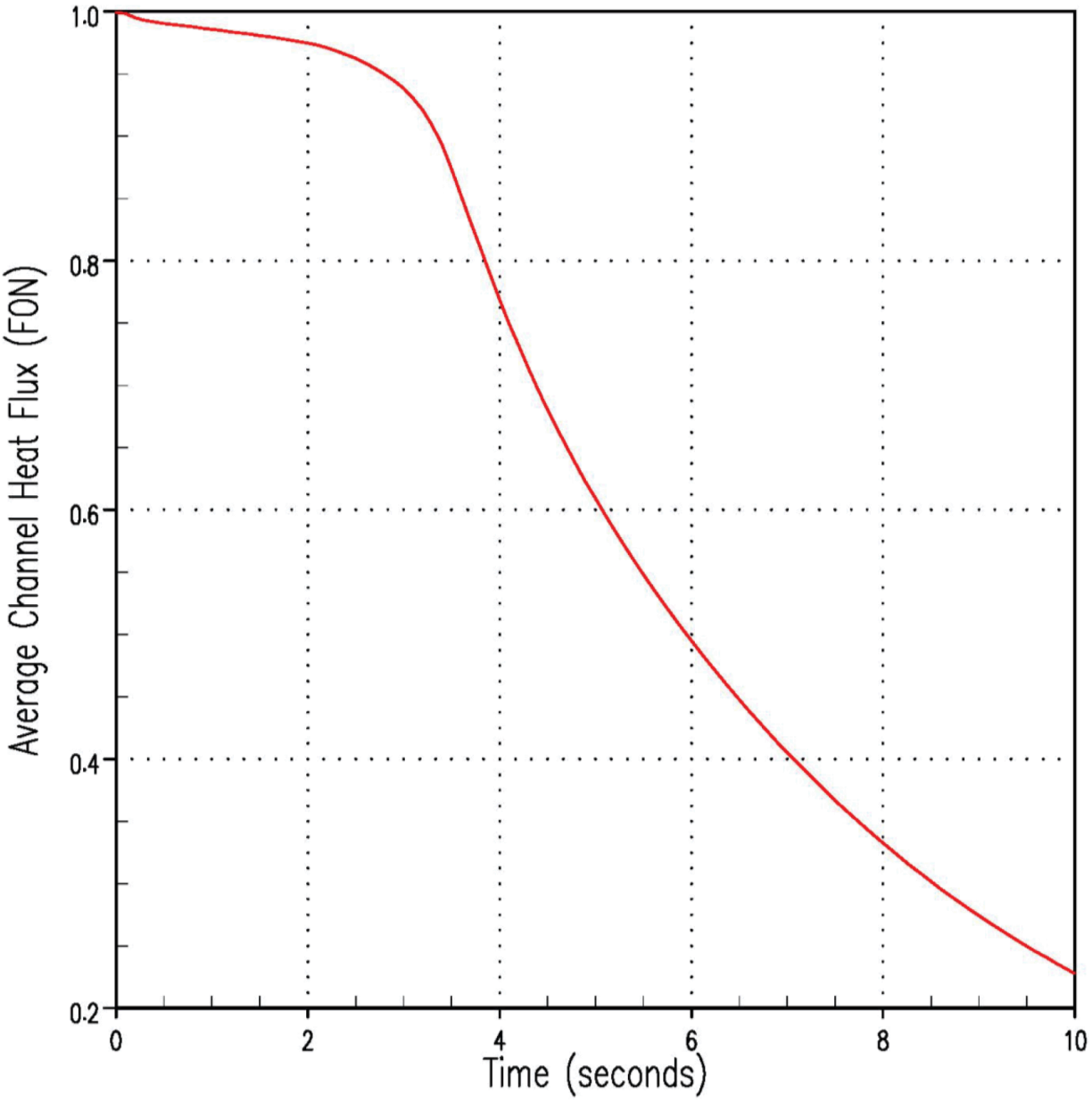

Figure 15.3.2-4
Average Channel Heat Flux Transient for
Four Cold Legs in Operation, Four Pumps Coasting Down

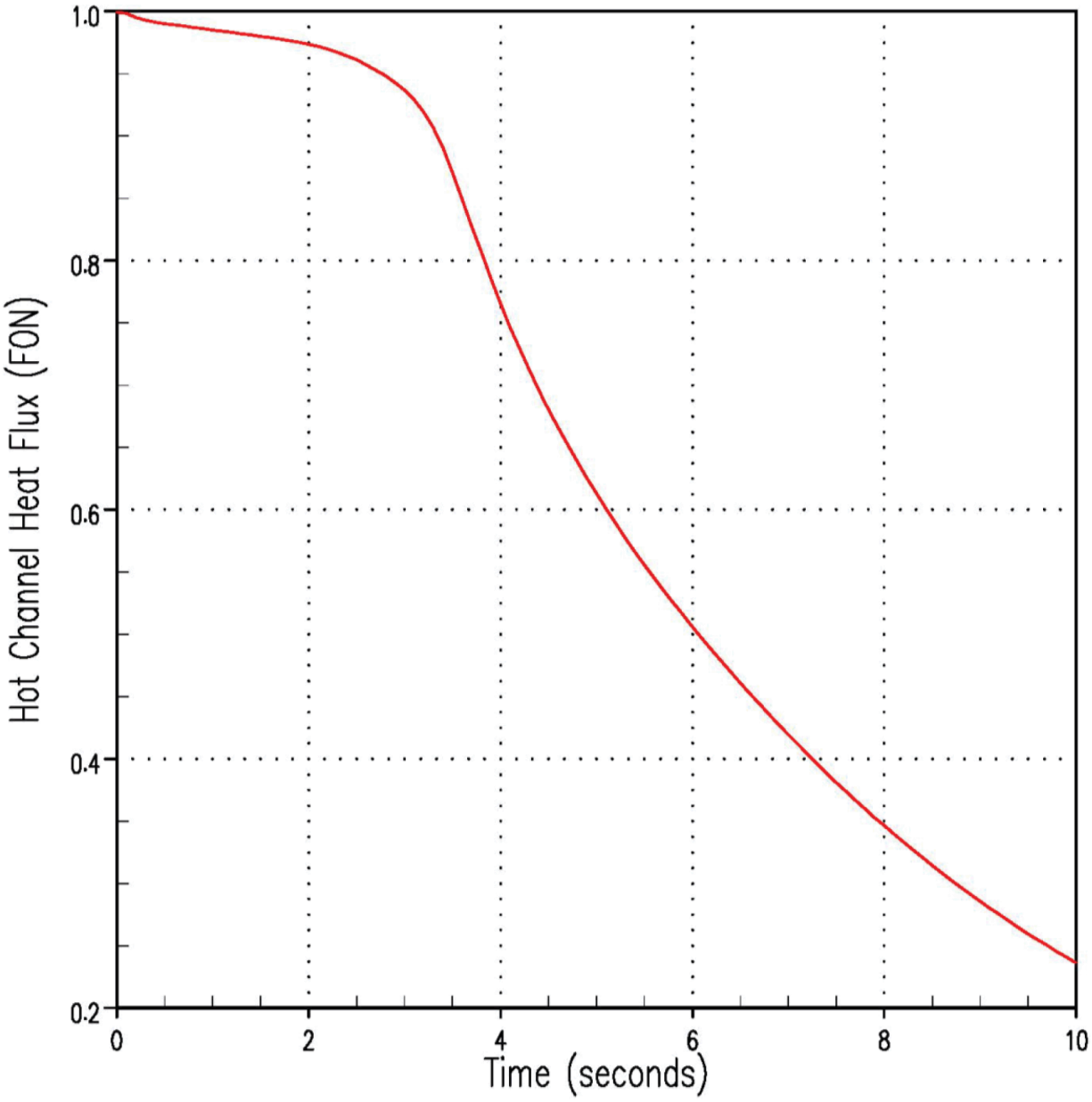

Figure 15.3.2-5
Hot Channel Heat Flux Transient for
Four Cold Legs in Operation, Four Pumps Coasting Down

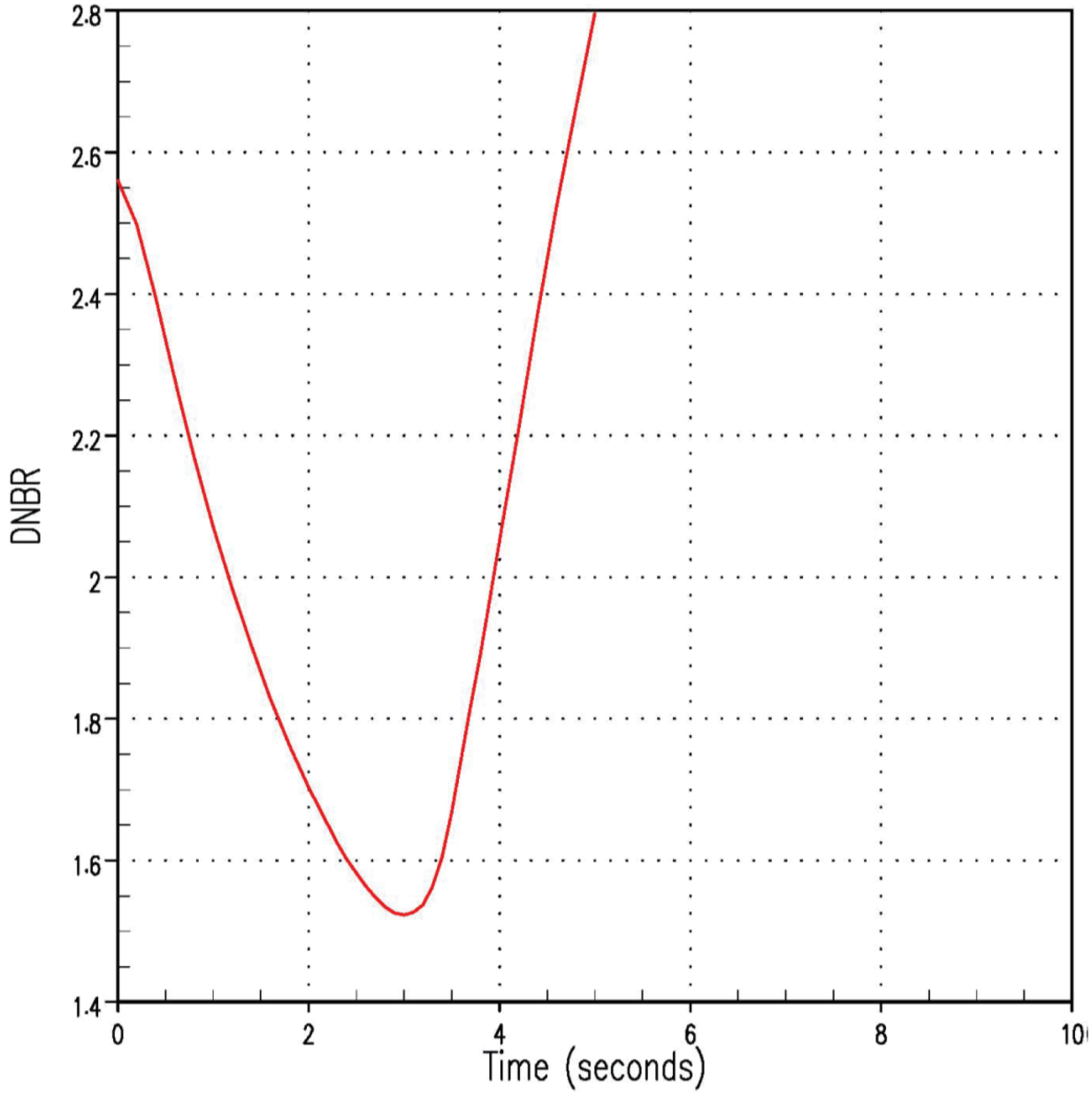

Figure 15.3.2-6
DNBR Transient for Four Cold Legs
in Operation, Four Pumps Coasting Down

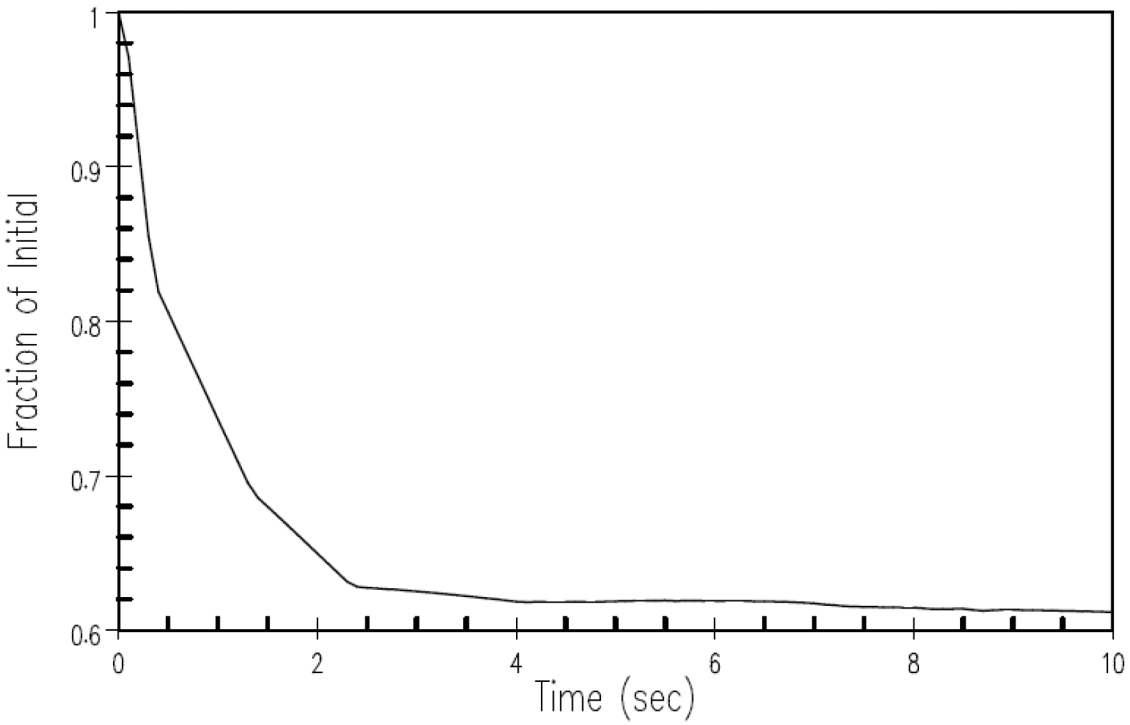

Figure 15.3.3-1
Core Mass Flow Transient for
Four Cold Legs in Operation, One Locked Rotor

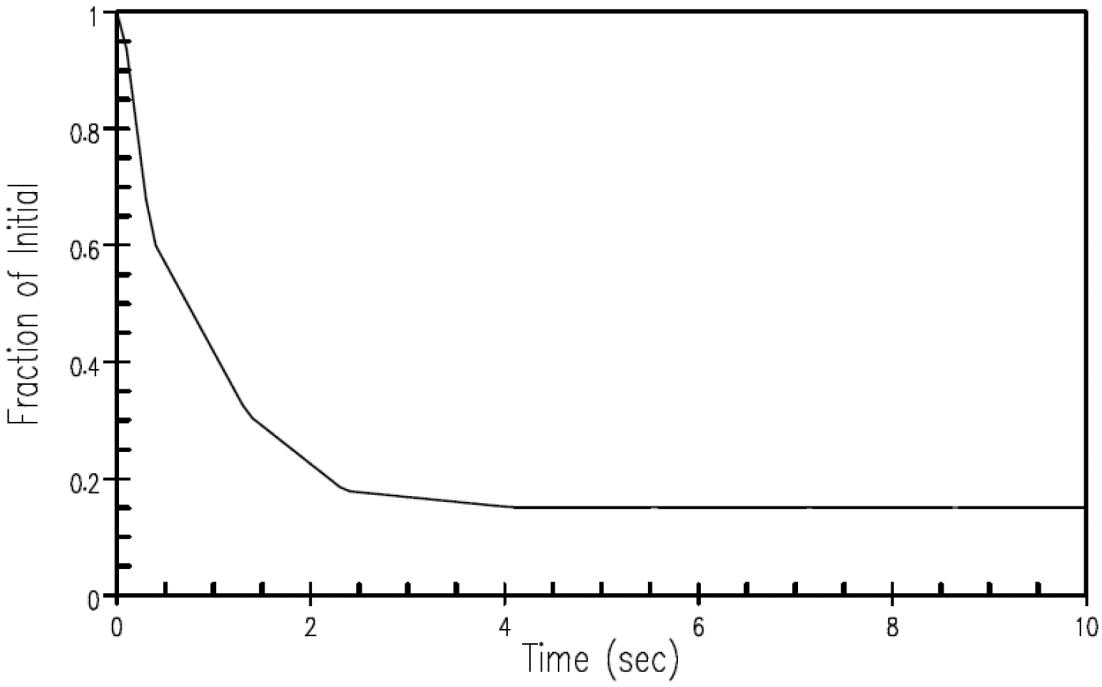

Figure 15.3.3-2
Faulted Loop Volumetric Flow Transient for Four Cold Legs in Operation, One Locked Rotor

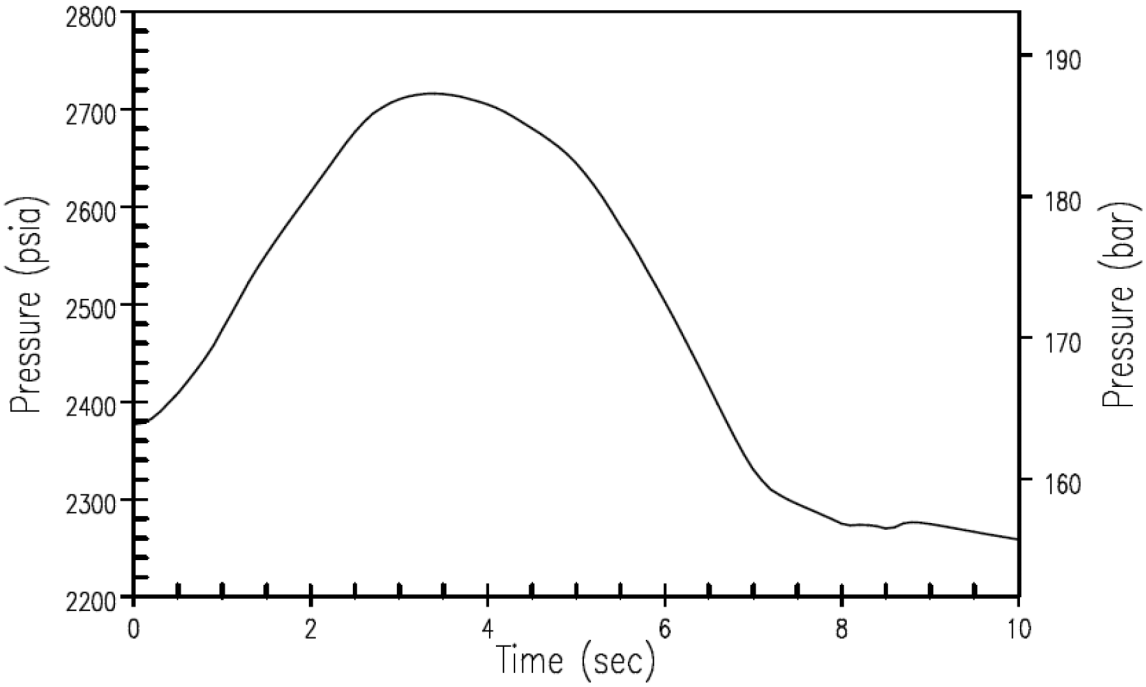

Figure 15.3.3-3
Peak Reactor Coolant Pressure for
Four Cold Legs in Operation, One Locked Rotor

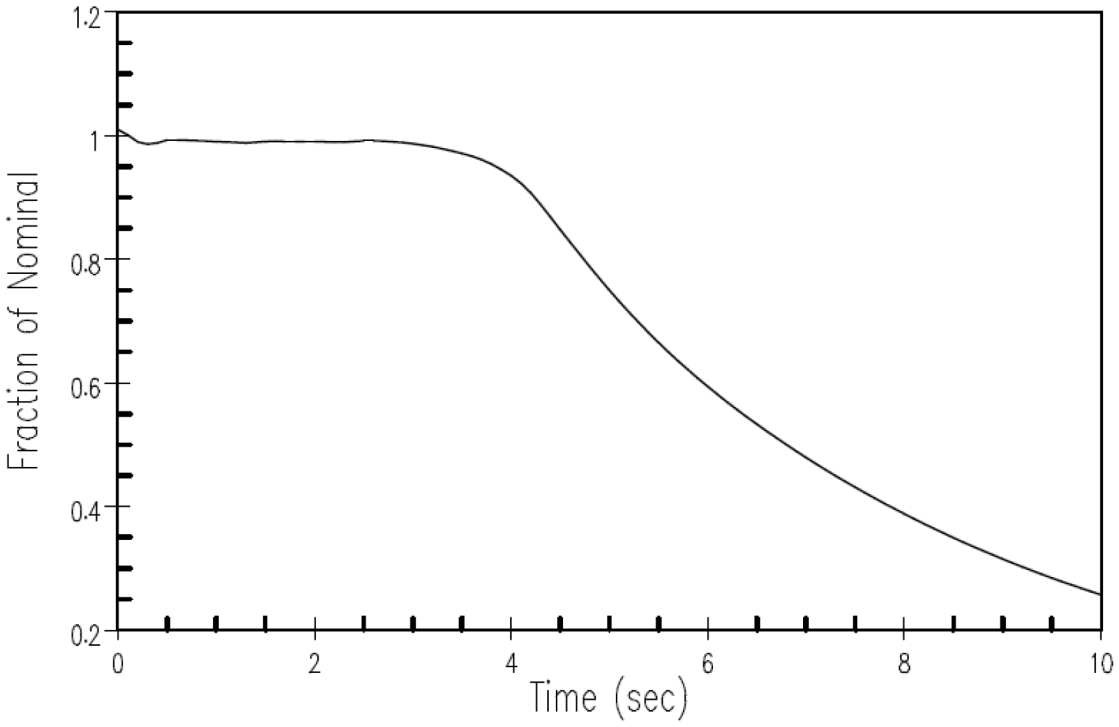

Figure 15.3.3-4
Average Channel Heat Flux Transient for
Four Cold Legs in Operation, One Locked Rotor

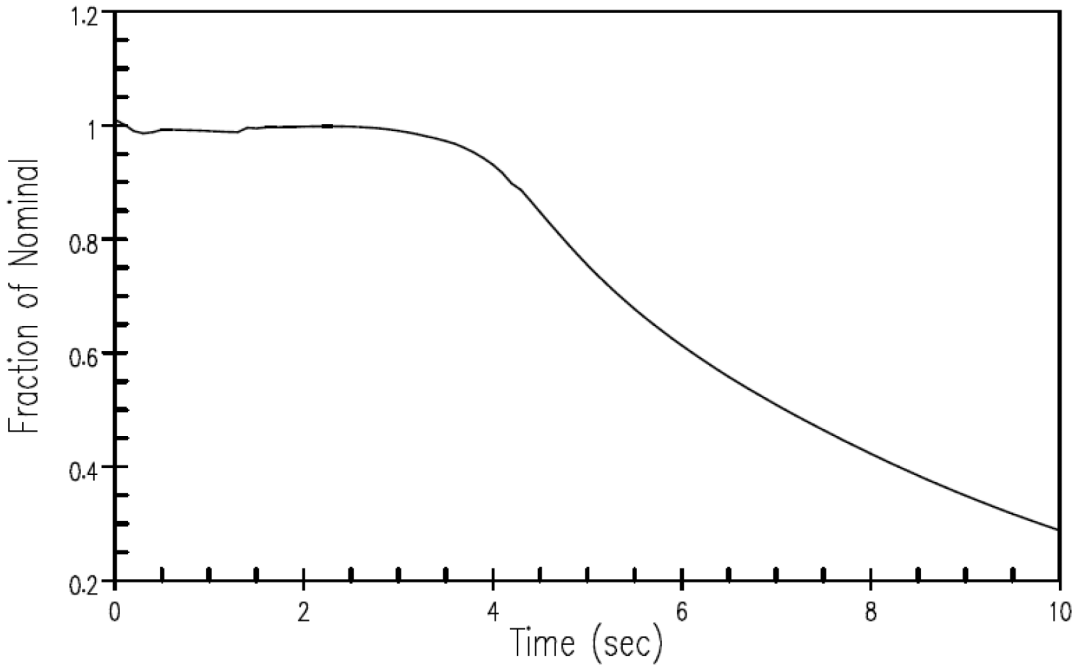

Figure 15.3.3-5
Hot Channel Heat Flux Transient for
Four Cold Legs in Operation, One Locked Rotor

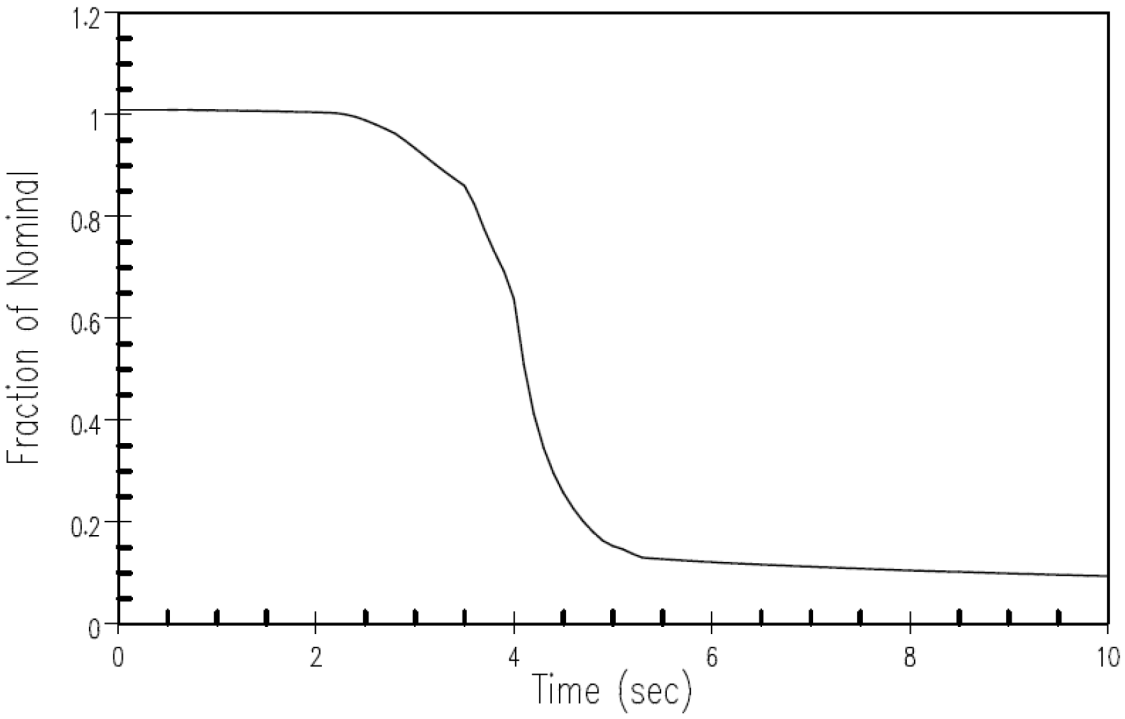

Figure 15.3.3-6
Nuclear Power Transient for
Four Cold Legs in Operation, One Locked Rotor

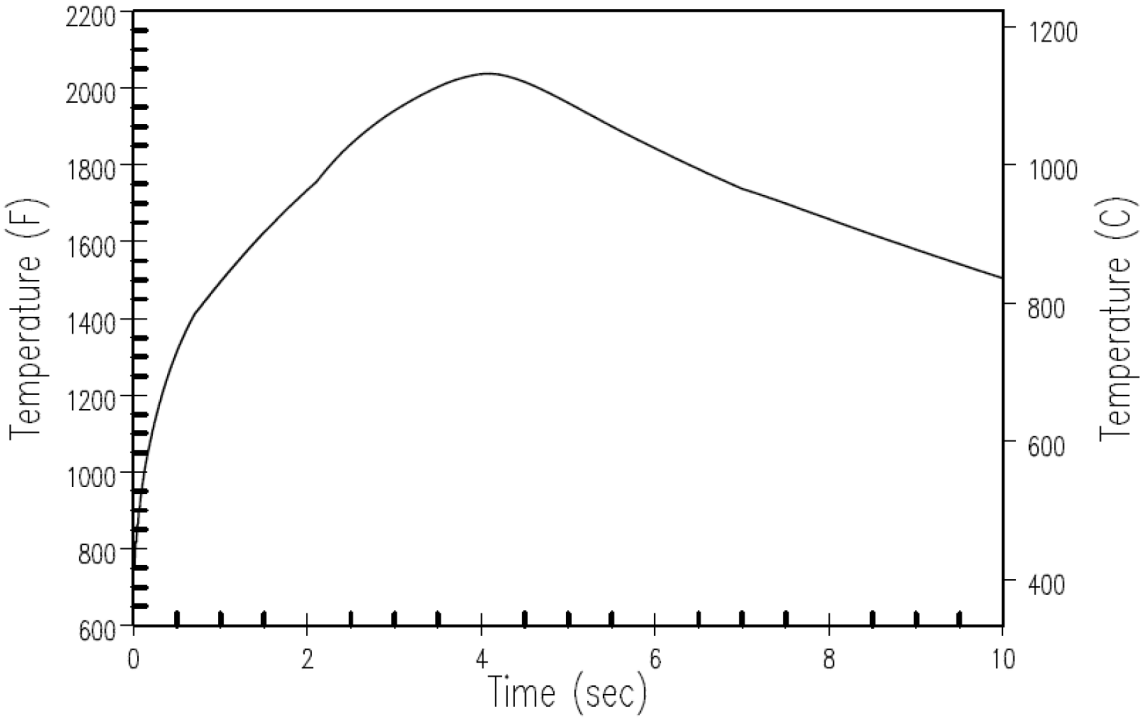

Figure 15.3.3-7
Cladding Inside Temperature Transient for
Four Cold Legs in Operation, One Locked Rotor

15.4 Reactivity and Power Distribution Anomalies

A number of faults are postulated that result in reactivity and power distribution anomalies. Reactivity changes could be caused by control rod motion or ejection, boron concentration changes, or addition of cold water to the reactor coolant system. Power distribution changes could be caused by control rod motion, misalignment, or ejection, or by static means such as fuel assembly mislocation. These events are discussed in this section. Analyses are presented for the most limiting of these events.

The following incidents are discussed in this section:

A. Uncontrolled rod cluster control assembly (RCCA) bank withdrawal from a subcritical or low-power startup condition

B. Uncontrolled RCCA bank withdrawal at power

C. RCCA misalignment

D. Startup of an inactive reactor coolant pump at an incorrect temperature

E. A malfunction or failure of the flow controller in a boiling water reactor recirculation loop that results in an increased reactor coolant flow rate (not applicable to AP1000)

F. Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant

G. Inadvertent loading and operation of a fuel assembly in an improper position

H. Spectrum of RCCA ejection accidents

Items A, B, D, and F above are Condition II events, item G is a Condition III event, and item H is a Condition IV event. Item C includes both Conditions II and III events.

The applicable transients in this section have been analyzed. It has been determined that the most severe radiological consequences result from the complete rupture of a control rod drive mechanism housing as discussed in Subsection 15.4.8.

Radiological consequences are reported only for the limiting case.

15.4.1 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low-Power Startup Condition

15.4.1.1 Identification of Causes and Accident Description

An RCCA withdrawal accident is an uncontrolled addition of reactivity to the reactor core caused by the withdrawal of RCCAs which results in a power excursion. Such a transient can be caused by a malfunction of the reactor control or rod control systems. This can occur with the reactor subcritical, at hot zero power, or at power. The at-power case is discussed in Subsection 15.4.2.

The reactor may be brought to a critical condition by either RCCA withdrawal or boron dilution. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (see Subsection 15.4.6).

The RCCA drive mechanisms are grouped into preselected bank configurations. These groups prevent the RCCAs from being automatically withdrawn in other than their respective banks. Power

supplied to the banks is controlled such that no more than two banks are withdrawn at the same time and in their proper withdrawal sequence. The RCCA drive mechanisms are the magnetic latch type, and coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate analyzed is that occurring with the simultaneous withdrawal of the combination of two sequential RCCA banks having the maximum combined worth at maximum speed.

This event is a Condition II event (a fault of moderate frequency) as defined in Subsection 15.0.1.

The neutron flux response to a continuous reactivity insertion is characterized by a fast rise terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power excursion limits the power during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient is terminated by the following automatic features of the protection and safety monitoring system:

- Source range high neutron flux reactor trip

  This trip function is actuated when two out of four independent source range channels indicate a neutron flux level above a preselected, manually adjustable setpoint. It may be manually bypassed only after an intermediate range flux channel indicates a flux level above a specified level. It is automatically reinstated when the coincident two out of four intermediate range channels indicate a flux level below a specified level.

- Intermediate range high neutron flux reactor trip

  This trip function is actuated when two out of four independent, intermediate range channels indicate a flux level above a preselected, manually adjustable setpoint. It may be manually bypassed only after two out of four power range channels are reading above approximately 10 percent of full power. It is automatically reinstated when the coincident two out of four channels indicate a power level below this value.

- Power range high neutron flux reactor trip (low setting)

  This trip function is actuated when two out of four power range channels indicate a power level above approximately 25 percent of full power. It may be manually bypassed when two out of four power range channels indicate a power level above approximately 10 percent of full power. It is automatically reinstated when the coincident two out of four channels indicate a power level below this value.

- Power range high neutron flux reactor trip (high setting)

  This trip function is actuated when two out of four power range channels indicate a power level above a preset setpoint. It is always active.

- High nuclear flux rate reactor trip

  This trip function is actuated when the positive rate of change of neutron flux on two out of four nuclear power range channels indicate a rate above a preset setpoint.

  In addition, control rod stops on high intermediate range flux level (one out of two) and high power range flux level (one out of four) serve to discontinue rod withdrawal and prevent the need to actuate the intermediate range flux level trip and the power range flux level trip, respectively.

15.4.1.2 Analysis of Effects and Consequences

15.4.1.2.1 Method of Analysis

The analysis of the uncontrolled RCCA bank withdrawal from subcritical accident is performed in three stages: first, an average core nuclear power transient calculation; then, an average core heat transfer calculation; and finally, the departure from nucleate boiling ratio (DNBR) calculation. In the first stage, the average core nuclear calculation is performed using spatial neutron kinetics methods, using the code TWINKLE (Reference 1), to determine the average power generation with time, including the various total core feedback effects (Doppler reactivity and moderator reactivity).

In the second stage, the average heat flux and temperature transients are determined by performing a fuel rod transient heat transfer calculation in FACTRAN (Reference 2). In the final stage, the average heat flux is used in VIPRE-01 (described in Section 4.4) for the transient DNBR calculation.

Plant characteristics and initial conditions are discussed in Subsection 15.0.3. The following assumptions are made to give conservative results for a startup accident:

- Because the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler coefficient, conservatively low values, as a function of power, are used (see Table 15.0-2).

- Contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time between the fuel and the moderator is much longer than the neutron flux response time. After the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. A conservative value is used in the analysis to yield the maximum peak heat flux (see Table 15.0-2).

- The reactor is assumed to be at hot zero power. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient, all of which tend to reduce the Doppler feedback effect and thereby increase the neutron flux peak. The initial effective multiplication factor (k_{eff}) is assumed to be 1.0 because this results in the worst nuclear power transient.

- Reactor trip is assumed to be initiated by the power range high neutron flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and RCCA release, is taken into account. A 10-percent uncertainty increase is assumed for the power range flux trip setpoint, raising it to 35 percent from the nominal value of 25 percent.

  Because the rise in the neutron flux is so rapid, the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible. In addition, the reactor trip insertion characteristic is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. See Subsection 15.0.5 for RCCA insertion characteristics.

- The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the combination of the two sequential RCCA banks having the greatest combined worth at maximum speed (45 inches per minute). Control rod drive mechanism design is discussed in Section 4.6.

- The most limiting axial and radial power shapes, associated with having the two highest combined worth banks in their high-worth position, are assumed in the departure from nucleate boiling (DNB) analysis.

- The initial power level is assumed to be below the power level expected for any shutdown condition (10^{-9} of nominal power). The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

- Four reactor coolant pumps are assumed to be in operation.

- Pressurizer pressure is assumed to be 50 psi below nominal for steady-state fluctuations and measurement uncertainties.

Plant systems and equipment available to mitigate the effects of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or components adversely affects the consequences of the accident. A loss of offsite power as a consequence of a turbine trip disrupting the grid is not considered because the accident is initiated from a subcritical condition where the plant is not providing power to the grid.

15.4.1.2.2 Results

Figures 15.4.1-1 through 15.4.1-4 show the transient behavior for the uncontrolled RCCA bank withdrawal from subcritical incident. The accident is terminated by reactor trip at 35 percent of nominal power. The reactivity insertion rate used is greater than that calculated for the two highest-worth sequential rod cluster control banks, both assumed to be in their highest incremental worth region.

Figure 15.4.1-1 shows the average neutron flux transient. The energy release and the fuel temperature increases are relatively small. The heat flux response (of interest for DNB considerations) is also shown in Figure 15.4.1-2. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux much less than the full-power nominal value. There is margin to DNB during the transient because the rod surface heat flux remains below the critical heat flux value, and there is a high degree of subcooling at all times in the core. Figures 15.4.1-3 and 15.4.1-4 shows the response of the average fuel temperature and the inner clad temperature, respectively. The minimum DNBR at all times remains above the design limit value (see Section 4.4).

The calculated sequence of events for this accident is shown in Table 15.4-1. With the reactor tripped, the plant returns to a stable condition. Subsequently, the plant may be cooled down further by following normal plant shutdown procedures.

15.4.1.3 Conclusions

In the event of an RCCA withdrawal accident from the subcritical condition, the core and the reactor coolant system are not adversely affected because the combination of thermal power and the coolant temperature results in a DNBR greater than the safety analysis limit value. Thus, no fuel or cladding damage is predicted as a result of DNB.

15.4.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

15.4.2.1 Identification of Causes and Accident Description

An uncontrolled RCCA bank withdrawal at power results in an increase in the core heat flux. Because the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise could eventually result in a violatation of the DNB design basis or excessive linear power. Therefore, to avert damage to the fuel cladding, the protection and safety

monitoring system (PMS) is designed to terminate any such transient before the DNBR falls below the design limit (see Section 4.4) or the overpower limit is exceeded.

This event is a Condition II incident (a fault of moderate frequency) as defined in Subsection 15.0.1.

The automatic features of the PMS that prevent core damage following the postulated accident include the following:

- Power range neutron flux instrumentation actuates a reactor trip if two out of four divisions exceed setpoint. In particular, the power range neutron flux instrumentation provides the following reactor trip functions:

  1. Reactor trip on power range high positive flux rate

  2. Reactor trip on power range high neutron flux (high setpoint)

  The first trip protects the core when a sudden abnormal increase in power is detected in the power range neutron flux channel in two out of four PMS divisions. It provides protection against rapid reactivity insertion accidents and is always active. The second trip serves as a backup to the overpower ΔT reactor trip and is always active.

- Reactor trip is actuated if any two out of four ΔT power divisions exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power imbalance, coolant temperature, and pressurizer pressure to protect against violating the DNB design basis. The overtemperature ΔT reactor trip function initiates a reactor trip to prevent the plant from exceeding the core thermal limits. With the overtemperature ΔT reactor trip function, setpoints are selected to match (Unit 3) and to bound (Unit 4) the non-linear characteristics of the core thermal limits. Dynamic compensation is included to account for transport times from the hot and cold legs to the core and to provide protection in a timely fashion such that the core thermal limits are not exceeded.

- Reactor trip is actuated if any two out of four ΔT power divisions exceed an overpower ΔT setpoint. This setpoint is automatically varied with axial power imbalance to prevent the allowable linear heat generation rate (kW/ft) from being exceeded.

- A High-2 pressurizer pressure reactor trip is actuated from any two out of four pressure divisions when a set pressure is exceeded. This set pressure is less than the set pressure for the pressurizer safety valves.

- A High-3 pressurizer water level reactor trip is actuated from any two out of four level divisions that exceed the setpoint when the reactor power is above approximately 10 percent (permissive-P10).

In addition to the preceding reactor trips, there are the following RCCA withdrawal blocks:

- High neutron flux (two out of four power range)
- Overpower ΔT (two out of four)
- Overtemperature ΔT (two out of four)

The area of permissible operation (power, pressure, and temperature) is bounded by the combination of reactor trips:

- Power range high positive flux rate (fixed setpoint)
- High-2 pressurizer pressure (fixed setpoint)

- Low-2 pressurizer pressure (fixed setpoint)
- Overpower and overtemperature ΔT (variable setpoints)

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, the effects of a possible consequential loss of ac power during an uncontrolled RCCA bank withdrawal at power event have been evaluated; and did not adversely impact the analysis results. This conclusion is based on a review of the time sequence associated with a consequential loss of ac power in comparison to the reactor shutdown time for an uncontrolled RCCA bank withdrawal at-power event. The primary effect of the loss of ac power is to cause the reactor coolant pumps (RCPs) to coast down. The PMS includes a five second minimum delay between the reactor trip and the turbine trip. In addition, a three second delay between the turbine trip and the loss of offsite ac power is assumed, consistent with Section 15.1.3 of NUREG-1793. Considering these delays between the time of the reactor trip and RCP coast down due to the loss of ac power, it is clear that the plant shutdown sequence will have passed the critical point and the control rods will have been completely inserted before the RCPs begin to coast down. Therefore, the consequential loss of ac power does not adversely impact this uncontrolled RCCA bank withdrawal at-power analysis because the plant will be shut down well before the RCPs begin to coast down.

15.4.2.2 Analysis of Effects and Consequences

15.4.2.2.1 Method of Analysis

This transient is analyzed using the LOFTRAN (References 3 and 11) code. This code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generators, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The core limits as illustrated in Figure 15.0.3-1 and Figure 15.0.3-1a are used to define the inputs to LOFTRAN that determine the minimum DNBR during the transient.

Plant characteristics and initial conditions are discussed in Subsection 15.0.3. In performing a conservative analysis for an uncontrolled RCCA bank withdrawal at-power accident, the following assumptions are made:

- The nominal initial conditions are assumed in accordance with the revised thermal design procedure. Uncertainties in the initial conditions are included in the DNBR limit as described in WCAP-11397-P-A (Reference 9).

- Two sets of reactivity coefficients are considered:

  Minimum reactivity feedback — A least-negative moderator temperature coefficient of reactivity is assumed, corresponding to the beginning of core life. A variable Doppler power coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed (see Figure 15.0.4-1).

  Maximum reactivity feedback — A conservatively large positive moderator density coefficient corresponding to the end of core life and a large (in absolute magnitude) negative Doppler power coefficient are assumed (see Figure 15.0.4-1).

- The power range high positive flux rate trip is assumed to be actuated when the power range neutron flux changes at a rate higher than 15% per second with a 60 second rate-lag time constant. The overpower ΔT and overtemperature ΔT trips include adverse instrumentation and setpoint uncertainties. The delays for trip actuation assumed are given in Table 15.0-4a.

- The RCCA trip insertion characteristic is based on the assumption that the highest-worth assembly is stuck in its fully withdrawn position.

- A range of reactivity insertion rates is examined. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the combination of the two control banks, having the maximum combined worth at maximum speed.

If RCCA movement causes an adverse effect on the axial core power distribution, then the overtemperature ΔT trip setpoint is decreased as necessary to maintain margin to the DNBR design limit, and the overpower ΔT trip setpoint is decreased as necessary to maintain margin to the overpower limit.

Plant systems and equipment available to mitigate the effects of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6. No single active failure in these systems or equipment adversely affects the consequences of the accident.

15.4.2.2.2 Results

Three reactor trip functions were credited in the analyses to provide protection over the entire range of reactivity insertion rates. These are the power range high positive flux rate, overtemperature ΔT, and overpower ΔT trips.

Figures 15.4.2-1 through 15.4.2-6 show the transient response for a representative rapid (80 pcm/s) RCCA withdrawal incident starting from full power. Reactor trip on power range high positive flux rate occurs shortly after the start of the transient. Because this is rapid with respect to the thermal time constants of the fuel, small changes in temperature and pressure result, and the DNB design basis described in Section 4.4 is met.

The transient response for a representative intermediate (34 pcm/s) RCCA withdrawal from full power is shown in Figures 15.4.2-7 through 15.4.2-12. Reactor trip on overpower ΔT occurs preventing the peak heat flux from exceeding 118%. The DNB design basis described in Section 4.4 is met.

The transient response for a representative slow (5 pcm/s) RCCA withdrawal from full power is shown in Figures 15.4.2-13 through 15.4.2-18. Reactor trip on overtemperature ΔT occurs after a longer period. The rise in temperature and pressure is consequently larger than for rapid RCCA withdrawal. The DNB design basis described in Section 4.4 is met.

Figure 15.4.2-19 shows the minimum DNBR as a function of reactivity insertion rate from initial full-power operation for minimum and maximum reactivity feedback. Minimum DNBR occurs immediately after rod motion. Three reactor trip functions provide protection over the whole range of reactivity insertion rates. These are the power range high positive flux rate, overpower ΔT, and overtemperature ΔT trip functions. The minimum DNBR is greater than the design limit value described in Section 4.4.

Figures 15.4.2-20 and 15.4.2-21 show the minimum DNBR as a function of reactivity insertion rate for RCCA withdrawal incidents for minimum and maximum reactivity feedback, starting at 60-percent and 10-percent power, respectively. Minimum DNBR, occurs immediately after rod motion. The results are similar to the 100-percent power case, except the transient is terminated by either the power range high positive flux rate or overtemperature ΔT reactor trip. The minimum DNBR is greater than the design limit value described in Section 4.4.

The shape of the curves of minimum DNBR versus reactivity insertion rate in the referenced figures is due both to reactor core and coolant system transient response and to PMS action in initiating a reactor trip.

Referring to Figure 15.4.2-19, it is noted that for transients initiated from full power, three reactor trip functions provide the DNB and overpower protection over the range of reactivity insertion rates analyzed. The overtemperature ΔT trip provides DNB protection except for rapid power excursions. The overpower ΔT trip provides protection for the slow to moderate power excursions. The power range high positive flux rate trip prevents both overpower and low DNBR for rapid power excursions.

Steam generator safety valves never open before the reactor trip for transients initiated at full power.

Because the RCCA bank withdrawal at-power incident is an overpower transient, the fuel temperatures rise during the transient until after reactor trip occurs. For rapid power excursions, the overpower transient is fast with respect to the fuel rod thermal time constant and the core heat flux lags behind the neutron flux response. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature still remains below the fuel melting temperature.

For slow to moderate power excursions, the core heat flux remains more nearly in equilibrium with the neutron flux. The overpower transient is terminated by either the overpower ΔT or overtemperature ΔT reactor trip before the DNB design basis is violated. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak centerline temperature remains below the fuel melting temperature.

The reactor is tripped during the RCCA bank withdrawal at-power transient such that the ability of the primary coolant to remove heat from the fuel rods is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown in Table 15.4-1. With the reactor tripped, the plant returns to a stable condition. The plant may be cooled down further by following normal plant shutdown procedures.

15.4.2.2.3 Overpressure Evaluation Results

In addition to the DNB cases discussed above, several cases are analyzed to ensure that the maximum reactor coolant system pressure does not exceed 110% of the design pressure. The cases cover a range of reactivity insertion rates from less than 1 pcm/s to 110 pcm/s and power levels from 10% to 100% power. Initial condition uncertainties on power, pressure and average temperature are conservatively included and the thermal design flow rate is assumed. The most limiting case was for a reactivity insertion rate of 10 pcm/s and an initial power level of 65% power. The peak pressure calculated is well below the limit.

15.4.2.3 Conclusions

The overpower ΔT, overtemperature ΔT, and power range high positive flux rate trip functions provide adequate protection over the entire range of possible reactivity insertion rates. The DNB design basis, as defined in Section 4.4, is met for all cases. The maximum reactor coolant system pressure remains below 110% of design.

15.4.3 Rod Cluster Control Assembly Misalignment (System Malfunction or Operator Error)

15.4.3.1 Identification of Causes and Accident Description

RCCA misoperation accidents include:

- One or more dropped RCCAs within the same group
- Statically misaligned RCCA
- Withdrawal of a single RCCA

Each RCCA has a position indicator channel which displays the position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod-at-bottom signal, which actuates a local alarm and a main control room annunciator. Group demand position is also indicated.

RCCAs are moved in preselected banks, and the banks are moved in a preselected sequence. Each bank of RCCAs is divided into one or two groups of four or five RCCAs each. The rods comprising a group operate in parallel. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation) of the stationary gripper, movable gripper, and lift coils of a mechanism is required to withdraw the RCCA attached to the mechanism. Because the stationary gripper, movable gripper, and lift coils associated with the RCCAs of a rod group are driven in parallel, any single failure which causes rod withdrawal affects the entire group. A single electrical or mechanical failure in the plant control system could, at most, result in dropping one or more RCCAs within the same group. Mechanical failures can cause either RCCA insertion or immobility, but not RCCA withdrawal.

The dropped RCCAs, dropped RCCA bank, and statically misaligned RCCA events are Condition II incidents (incidents of moderate frequency) as defined in Subsection 15.0.1. The single RCCA withdrawal event is a Condition III incident, as discussed below.

No single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the inserted bank at full-power operation. The operator could withdraw a single RCCA in the control bank because this feature is necessary to retrieve an assembly should one be accidentally dropped. The event analyzed results from multiple wiring failures or multiple significant operator errors and subsequent and repeated operator disregard of event indication. The probability of such a combination of conditions is considered low such that the limiting consequences may include slight fuel damage.

The event is classified as a Condition III incident consistent with the philosophy and format of American National Standards Institute, ANSI N18.2. By definition, "Condition III occurrences include incidents, any one of which may occur during the lifetime of a particular plant," and "shall not cause more than a small fraction of fuel elements in the reactor to be damaged . . ." (Reference 10).

This selection of criterion is in accordance with General Design Criterion 25, which states, "The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods." (Emphases have been added.) It has been shown that single failures resulting in RCCA bank withdrawals do not violate specified fuel design limits. Moreover, no single malfunction can result in the withdrawal of a single RCCA. Thus, it is concluded that criterion established for the single rod withdrawal at power is appropriate and in accordance with General Design Criterion 25.

A dropped RCCA or RCCA bank may be detected by one or more of the following:

- Sudden drop in the core power level as seen by the nuclear instrumentation system
- Asymmetric power distribution as seen by the incore or excore neutron detectors or core exit thermocouples, through online core monitoring
- Rod at bottom signal
- Rod deviation alarm
- Rod position indication

Misaligned RCCAs are detected by one or more of the following:

- Asymmetric power distribution as seen by the incore or excore neutron detectors or core exit thermocouples, through online core monitoring
- Rod deviation alarm
- Rod position indicators

The resolution of the rod position indicator channel is ±5 percent span (±7.5 inches). A deviation of any RCCA from its group by twice this distance (10 percent of span or 15 inches) does not cause power distributions worse than the design limits. The deviation alarm alerts the operator to rod deviation with respect to the group position in excess of 5 percent of span.

If one or more of the rod position indicator channels is out of service, operating instructions are followed to verify the alignment of the nonindicated RCCAs. The operator also takes action as required by the Technical Specifications.

In the extremely unlikely event of multiple electrical failures that result in single RCCA withdrawal, rod deviation and rod control urgent failure are both displayed to the operator, and the rod position indicators indicate the relative positions of the assemblies in the bank. The urgent failure alarm also inhibits automatic rod motion in the group in which it occurs. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, results in activation of the same alarm and the same visual indication. Withdrawal of a single RCCA results in both positive reactivity insertion tending to increase core power and an increase in local power density in the core area associated with the RCCA. Automatic protection for this event is provided by the overtemperature ΔT reactor trip. The Condition III Standard Review Plan Section 15.4.3 evaluation criteria are met; however, due to the increase in local power density, the limits in Figure 15.0.3-1 and Figure 15.0.3-1a may be exceeded.

Plant systems and equipment available to mitigate the effects of the various control rod misoperations are discussed in Subsection 15.0.8 and listed in Table 15.0-6. No single active failure in any of these systems or equipment adversely affects the consequences of the accident.

15.4.3.2 Analysis of Effects and Consequences

15.4.3.2.1 Dropped RCCAs, Dropped RCCA Bank, and Statically Misaligned RCCA

15.4.3.2.1.1 Method of Analysis

- One or more dropped RCCAs from the same group

A drop of one or more RCCAs from the same group results in an initial reduction in the core power and a perturbation in the core radial power distribution. Depending on the worth and position of the dropped rods, this may cause the allowable design power peaking factors to be exceeded. Following the drop, the reduced core power and continued steam demand to the turbine causes the reactor coolant temperature to decrease. In the manual control mode, the plant will establish a new equilibrium condition. The new equilibrium condition is reached through reactivity feedback. In the presence of a negative moderator temperature coefficient, the reactor power rises monotonically back to the initial power level at a reduced inlet temperature with no power overshoot. The absence of any power overshoot establishes the automatic operating mode as a limiting case. If the reactor coolant system temperature reduction is very large, the turbine power may not be able to be maintained due to the reduction in the secondary-side steam pressure and the volumetric flow limit of the turbine system. In this case, the equilibrium power level is less than the initial power. In the automatic control mode, the plant control system detects the drop in core power and initiates withdrawal of a control bank. Power overshoot may occur, after which the control system will insert the control bank and return the plant to the initial power level. The magnitude of the power overshoot is a function of the plant control system characteristics, core reactivity coefficients, the dropped rod worth, and the available control bank worth.

For evaluation of the dropped RCCA event, the transient system response is calculated using the LOFTRAN code (References 3 and 11). The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator and steam generator safety valves. The code computes pertinent plant variables, including temperatures, pressures and power level.

Steady-state nuclear models using the computer codes described in Table 4.1-2 are used to obtain a hot channel factor consistent with the primary system transient conditions and reactor power. By combining the transient primary conditions with the hot channel factor from the nuclear analysis, the departure from nucleate boiling design basis is shown to be met using the VIPRE-01 code.

- Statically misaligned RCCA

  Steady-state power distributions are analyzed using the computer codes as described in Table 4.1-2. The peaking factors are then used as input to the VIPRE-01 code to calculate the DNBR.

15.4.3.2.1.2 Results

- One or more dropped RCCAs

  Figures 15.4.3-1 through 15.4.3-4 show the transient response of the reactor to a dropped rod (or rods) in automatic control. The nuclear power and heat flux drop to a minimum value and recover under the influence of both rod withdrawal and thermal feedback. The prompt decrease in power is governed by the dropped rod worth because the plant control system does not respond during the short rod drop time period. The plant control system detects the reduction in core power and initiates control bank withdrawal to restore the primary side power. Power overshoot occurs after which the core power is restored to the initial power level.

  The primary system conditions are combined with the hot channel factors from the nuclear analysis for the DNB evaluation. Uncertainties in the initial conditions are included in the DNB evaluation as discussed in Subsection 15.0.3.2. The calculated minimum DNBR for any single or multiple rod drop from the same group is greater than the design limit value described in Section 4.4. The sequence of events for a representative case is shown in Table 15.4-1.

The analysis described previously includes consideration of drops of the RCCA groups which can be selected for insertion as part of the rapid power reduction system. This system is provided to allow the reactor to ride out a complete loss of load from full power without a reactor trip and is described in Subsection 7.7.1.10. If these RCCAs are inadvertently dropped (in the absence of a loss-of-load signal), the transient behavior is the same as for the RCCA drop described. The evaluation showed that the DNBR remains above the design limit value as a result of the inadvertent actuation of the rapid power reduction system.

The consequential loss of offsite power described in Subsection 15.0.14 is not limiting for the dropped RCCA event. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the minimum DNBR occurs before the reactor coolant pumps begin to coast down.

- Statically misaligned RCCA

  The most severe misalignment situations with respect to DNBR arise from cases in which one RCCA is fully inserted, or where the mechanical shim or axial offset rod banks are inserted up to their insertion limit with one RCCA fully withdrawn while the reactor is at full power. Multiple independent alarms, including a bank insertion limit or rod deviation alarm, alert the operator well before the postulated conditions are approached.

  For RCCA misalignments in which the mechanical shim or axial offset banks are inserted to their respective insertion limits, with any one RCCA fully withdrawn, the DNBR remains above the safety analysis limit value. This case is analyzed assuming the initial reactor power, pressure, and reactor coolant system temperature are at their nominal values, but with the increased radial peaking factor associated with the misaligned RCCA. Uncertainties in the initial conditions are included in the DNB evaluation as described in Subsection 15.0.3.2.

  DNB does not occur for the RCCA misalignment incident, and thus the ability of the primary coolant to remove heat from the fuel rod is not reduced. The peak fuel temperature is that corresponding to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation is well below that which causes fuel melting.

  Following the identification of an RCCA group misalignment condition by the operator, the operator takes action as required by the plant Technical Specifications and operating instructions.

15.4.3.2.2 Single Rod Cluster Control Assembly Withdrawal

15.4.3.2.2.1 Method of Analysis

Power distributions within the core are calculated using the computer codes described in Table 4.1-2. The peaking factors are then used by VIPRE-01 to calculate the DNBR for the event. The case of the worst rod withdrawn from the mechanical shim or axial offset bank inserted at the insertion limit, with the reactor initially at full power, is analyzed. This incident is assumed to occur at beginning of life because this results in the minimum value of moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

15.4.3.2.2.2 Results

For the single rod withdrawal event, two cases are considered as follows:

A. If the reactor is in the manual control mode, continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature and an increase in the local hot channel factor in the area of the withdrawing RCCA. In the overall system response, this case is similar to those presented in Subsection 15.4.2. The increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBRs than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum DNBR from falling below the safety analysis limit value. Evaluation of this case at the power and coolant conditions at which the overtemperature ΔT trip is expected to trip the plant shows that an upper limit for the number of rods with a DNBR less than the safety analysis limit value is 5 percent.

B. If the reactor is in the automatic control mode, the multiple failures that result in the withdrawal of a single RCCA result in the immobility of the other RCCAs in the controlling bank. The transient then proceeds in the same manner as case A.

   For such cases, a reactor trip ultimately occurs although not sufficiently fast in all cases to prevent a minimum DNBR in the core of less than the safety analysis limit value. Following reactor trip, normal shutdown procedures are followed.

   The consequential loss of offsite power described in Subsection 15.0.14 is not limiting for the single RCCA withdrawal event. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the minimum DNBR, for rods where the DNBR did not fall below the design limit value (see Section 4.4) in the cases described, occurs before the reactor coolant pumps begin to coast down.

15.4.3.3 Conclusions

For cases of dropped RCCAs or dropped banks, including inadvertent drops of the RCCAs in those groups selected to be inserted as part of the rapid power reduction system, it is shown that the DNBR remains greater than the safety analysis limit value and, therefore, the DNB design basis is met.

For cases of any one RCCA fully inserted, or the mechanical shim or axial offset banks inserted to their rod insertion limits with any single RCCA in one of those banks fully withdrawn (static misalignment), the DNBR remains greater than the safety analysis limit value (see Section 4.4).

For the case of the accidental withdrawal of a single RCCA, with the reactor in the automatic or manual control mode and initially operating at full power with the mechanical shim or axial offset banks at their insertion limits, an upper bound of the number of fuel rods experiencing DNB is 5 percent of the total fuel rods in the core.

15.4.4 Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature

The Technical Specifications (3.4.4) require all RCPs to be operating while in Modes 1 and 2. The maximum initial core power level for the startup of an inactive loop transient is approximately zero MWt. Furthermore, the reactor will initially be subcritical by the Technical Specification requirement. There will be no increase in core power, and no automatic or manual protective action is required.

15.4.5 A Malfunction or Failure of the Flow Controller in a Boiling Water Reactor Loop that Results in an Increased Reactor Coolant Flow Rate

This subsection is not applicable to the AP1000.

15.4.6 Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant

15.4.6.1 Identification of Causes and Accident Description

Other than control rod withdrawal, the principal means of positive reactivity insertion to the core is the addition of unborated, primary-grade water from the demineralized water transfer and storage system into the reactor coolant system through the reactor makeup portion of the chemical and volume control system. Normal boron dilution with these systems is manually initiated under strict administrative controls requiring close operator surveillance. Procedures limit the rate and duration of the dilution. A boric acid blend system is available to allow the operator to match the makeup water boron concentration to that of the reactor coolant system during normal charging.

An inadvertent boron dilution is caused by the failure of the demineralized water transfer and storage system or chemical and volume control system, either by controller, operator or mechanical failure. The chemical and volume control system and demineralized water transfer and storage system are designed to limit, even under various postulated failure modes, the potential rate of dilution to values that, with indication by alarms and instrumentation, allowing sufficient time for automatic or operator response to terminate the dilution.

An inadvertent dilution from the demineralized water transfer and storage system through the chemical and volume control system may be terminated by isolating the makeup flow to the reactor coolant system, by isolating the makeup pump suction line to the demineralized water transfer and storage system storage tank, or by tripping the makeup pumps. Lost shutdown margin may be regained by adding borated water to the reactor coolant system from the boric acid tank.

Generally, to dilute, the operator would need to perform two actions:

- Switch control of the makeup from the automatic makeup mode to the dilute mode.
- Start the chemical and volume control system makeup pumps.

Failure to carry out either of those actions prevents initiation of dilution. Because the AP1000 chemical and volume control system makeup pumps do not run continuously (they are expected to be operated once per day to make up for reactor coolant system leakage), a makeup pump is started when the volume control system is placed into dilute mode.

The status of the reactor coolant system makeup is available to the operator by the following:

- Indication of the boric acid and blended flow rates
- Chemical and volume control system makeup pumps status
- Deviation alarms, if the boric acid or blended flow rates deviate by more than the specified tolerance from the preset values
- When reactor is subcritical:
  - High flux at shutdown alarm
  - Indicated source range neutron flux count rate

- Audible source range neutron flux count rate
- Source range neutron flux-multiplication alarm

- When the reactor is critical:

  - Axial flux difference alarm (reactor power ≥ 50 percent rated thermal power)
  - Control rod insertion limit low and low-low alarms
  - Overtemperature ΔT alarm (at power)
  - Overtemperature ΔT reactor trip
  - Overpower ΔT alarm
  - Overpower ΔT reactor trip
  - Power range neutron flux-high, both high and low setpoint reactor trips

This event is a Condition II incident (a fault of moderate frequency), as defined in Subsection 15.0.1.

The Technical Specifications contain exceptions which allow all RCPs to be removed from operation in Modes 3, 4, and 5 for a limited duration while performing required tests or while an unborated water source flow path through the chemical mixing tank to the pressurizer is unisolated under administrative controls. This is acceptable provided no operations are permitted that would add coolant to the RCS that has an insufficient boron concentration to meet the required shutdown margin, and the core outlet temperature remains sufficiently subcooled. With respect to chemical additions, the system design includes a flow orifice which limits flow from the chemical mixing tank to 2 gpm and allows combining the chemical addition solution with flow from the boric acid storage tank to the suction of the CVS makeup pumps. Administrative controls include dedicated control room and local operators to secure the unborated water source flow path after completion of the chemical addition or if flow rates indicate the potential for inadequately borated blended flow. Procedural controls also require the chemical addition flow path to be directed to the pressurizer for the short duration allowed for this exception. This limits the flow rate and duration of an unisolated unborated water flow path during this evolution.

15.4.6.2 Analysis of Effects and Consequences

Boron dilutions during refueling, cold shutdown, hot shutdown, hot standby, startup, and power modes of operation are considered in this analysis. Conservative values for critical/key parameters are used (high reactor coolant system critical boron concentrations, high boron worths, minimum shutdown margins, and lower-than-actual reactor coolant system volumes). These assumptions (see Table 15.4-2) result in conservative determinations of the time available for operator or automatic system response after detection of a dilution transient in progress.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power is considered for the boron dilution case initiated from the power mode of operation (Mode 1) with the reactor in manual control. This is the analyzed Mode 1 boron dilution case that produces a reactor and turbine trip (Subsection 15.4.6.2.6). The loss of offsite power is assumed to occur as a direct result of a turbine trip that would disrupt the grid and produce a consequential loss of offsite ac power. As discussed in Subsection 15.0.14, that scenario can occur only with the plant at power and connected to the grid. Therefore, only a boron dilution case initiated from full power will be addressed with respect to the consequential loss of offsite power.

15.4.6.2.1 Dilution During Refueling (Mode 6)

An uncontrolled boron dilution transient cannot occur during this mode of operation. Inadvertent dilution is prevented by administrative controls, which isolate the reactor coolant system from the potential source of unborated water by closing, and locking or otherwise securing specified valves in the chemical and volume control system, and Demineralized Water Transfer and Storage System,

during refueling operations. These valves block the flow paths that allow unborated makeup water to reach the reactor coolant system. Makeup which is required during refueling uses water supplied from the boric acid tank (which contains borated water).

15.4.6.2.2 Dilution During Cold Shutdown (Mode 5)

The following conditions are assumed for inadvertent boron dilution while in this operating mode:

- A dilution flow of 175 gpm of unborated water exists. The dilution flow is assumed to be at 40°F and 14.7 psia. The fluid conditions of the RCS are assumed to be 200°F and 14.7 psia.
- The reactor coolant system volume is 7605.9 ft^3. This is a conservative estimate of the minimum active volume of the reactor coolant system with the reactor coolant system filled and vented and one reactor coolant pump running. The assumed active volume does not include the volume of the reactor vessel upper head region.
- Control rods are fully inserted, which is the normal condition in cold shutdown and a critical boron concentration is 1483 ppm. This is a conservative boron concentration with control rods inserted and accounts for the most reactive rod stuck in the fully withdrawn position.
- The shutdown margin is equal to 1.6-percent Δk/k, the minimum value identified by the core operating limits report (COLR) for the cold shutdown mode. Combined with the critical boron concentration identified above, this gives an initial boron concentration of 1675 ppm.
- The reactor coolant system dilution volume is considered well-mixed. The Technical Specifications require that, when in Mode 5, at least one RCP shall be operating with a flow of at least 3000 gpm. This provides sufficient flow through the system to maintain the system well-mixed. If a reactor coolant pump is not operating, the demineralized water isolation valves are closed (subject to the limited exception discussed in Subsection 15.4.6.1) and an uncontrolled boron dilution transient cannot occur, as discussed in Subsection 15.4.6.2.1.
- A Boron Dilution Protection System (BDPS) safety analysis limit (SAL) flux multiplier setpoint of 3.0 is assumed.

In the event of an inadvertent boron dilution transient during cold shutdown, the source range nuclear instrumentation detects an increase in the neutron flux by comparing the current source range flux to the data recorded over the previous 50 minutes. Upon detecting a sufficiently large flux increase, an alarm is sounded for the operator, and valves are actuated to terminate the dilution automatically.

Upon the actuation of a source range flux multiplier signal, the makeup flow to the reactor coolant system and the makeup pump suction line to the demineralized water transfer and storage system storage tank are isolated. This thereby terminates the dilution. In addition, the makeup pumps are tripped for equipment protection purposes.

No operator action is required to terminate this transient. The analysis demonstrates that the flux multiplier SAL will be reached 30.75 minutes after the dilution transient begins and that there is sufficient time at this point for the automatic protective features to terminate the dilution prior to losing all shutdown margin. After the automatic protection functions take place, the operator may take action to restore the Technical Specification shutdown margin.

15.4.6.2.3 Dilution During Safe Shutdown (Mode 4)

The following conditions are assumed for an inadvertent boron dilution while in this mode:

- A dilution flow of 175 gpm of unborated water exists. The dilution flow is assumed to be at 40°F and 14.7 psia. The fluid conditions of the RCS are assumed to be 420°F and 401 psia.
- The reactor coolant system volume is 7605.9 ft^3. This is a conservative estimate of the minimum active volume of the reactor coolant system with the reactor coolant system filled and vented and one reactor coolant pump running. The assumed active volume does not include the volume of the reactor vessel upper head region.
- All control rods are fully inserted, except the most reactive rod which is assumed stuck in the fully withdrawn position. The critical boron concentration is 1449 ppm.
- The shutdown margin is equal to 1.6-percent Δk/k, the minimum value required by the core operating limits report (COLR) for the hot shutdown mode. Combined with the critical boron concentration given above, this gives an initial boron concentration of 1649 ppm.
- The reactor coolant system dilution volume is considered well-mixed. The Technical Specifications require that at least one reactor coolant pump shall be operating with a flow of at least 3000 gpm when in Mode 4. This provides sufficient flow through the system to maintain the system well-mixed. If a reactor coolant pump is not operating, the demineralized water isolation valves are closed (subject to the limited exception discussed in Subsection 15.4.6.1) and an uncontrolled boron dilution transient cannot occur, as discussed in Subsection 15.4.6.2.1.
- A Boron Dilution Protection System (BDPS) Safety Analysis Limit (SAL) setpoint 3.0 is assumed.

In the event of an inadvertent boron dilution transient during safe shutdown, the source range nuclear instrumentation detects a sufficiently large increase in the neutron flux by comparing the current source range flux to that of about 50 minutes earlier, automatically initiates valve movement to terminate the dilution, and sounds an alarm.

Upon the actuation of a source range flux multiplier signal, the makeup flow to the reactor coolant system and the makeup pump suction line to the demineralized water transfer and storage system storage tank are isolated. This thereby terminates the dilution. Also, the makeup pumps are tripped for equipment protection purposes.

No operator action is required to terminate this transient. The analysis demonstrates that the flux multiplier SAL will be reached 28.83 minutes after the dilution transient begins and that there is sufficient time at this point for the automatic protective features to terminate the dilution prior to losing all shutdown margin. After the automatic protection functions take place, the operator may take action to restore the Technical Specification shutdown margin.

15.4.6.2.4 Dilution During Hot Standby (Mode 3)

The following conditions are assumed for an inadvertent boron dilution while in this mode:

- A dilution flow of 175 gpm of unborated water exists. The dilution flow is assumed to be at 40°F and 14.7 psia. The fluid conditions of the RCS are assumed to be 557°F and 2250 psia.

- The reactor coolant system volume is 7605.9 ft^3. This is a conservative estimate of the minimum active volume of the reactor coolant system with the reactor coolant system filled and vented and one reactor coolant pump running. The assumed active volume does not include the volume of the reactor vessel upper head region.

- Critical boron concentration is 1281 ppm. This is a conservative boron concentration assuming control rods are fully inserted minus the most reactive rod, which is assumed stuck in the fully withdrawn position.

- The shutdown margin is equal to 1.6-percent Δk/k, the minimum value required by the core operating limits report (COLR) for the hot standby mode. Combined with the critical boron concentration given above, this gives an initial boron concentration of 1509 ppm.

- The reactor coolant system dilution volume is considered well-mixed. The Technical Specifications require that at least one reactor coolant pump shall be operating with a flow of at least 3000 gpm when in Mode 3. This provides sufficient flow through the system to maintain the system well mixed. If a reactor coolant pump is not operating, the demineralized water isolation valves are closed (subject to the limited exception discussed in Subsection 15.4.6.1) and an uncontrolled boron dilution transient cannot occur, as discussed in Subsection 15.4.6.2.1.

In the event of an inadvertent boron dilution transient in hot standby, the source range nuclear instrumentation detects a sufficiently large increase in the neutron flux by comparing the current source range flux to that of about 50 minutes earlier, automatically initiates valve movement to terminate the dilution, and sounds an alarm. Upon the actuation of a source range flux multiplier signal, the makeup flow to the reactor coolant system and the makeup pump suction line to the demineralized water transfer and storage system storage tank are isolated. This thereby terminates the dilution. Also, the makeup pumps are tripped for equipment protection purposes.

No operator action is required to terminate this transient. The analysis demonstrates that the flux multiplier SAL will be reached 32.07 minutes after the dilution transient begins and that there is sufficient time at this point for the automatic protective features to terminate the dilution prior to losing all shutdown margin. After the automatic protection functions take place, the operator may take action to restore the Technical Specification shutdown margin.

15.4.6.2.5 Dilution During Startup (Mode 2)

The plant is in the startup mode at the beginning of each cycle. During this mode of operation, rod control is in manual. Normal actions taken to change power level, either up or down, require operator actuation. The Technical Specifications require an available shutdown margin of 1.6-percent Δk/k and four reactor coolant pumps operating. Other conditions assumed are the following:

- A dilution flow of 175 gpm of unborated water exists. The dilution flow is assumed to be at 40°F and 14.7 psia. The fluid conditions of the RCS are assumed to be 565.83°F (5% power) and 2250 psia.

- Minimum reactor coolant system water volume is 8425.5 ft^3. This is a very conservative estimate of the active reactor coolant system volume, minus the pressurizer volume.

- The initial maximum boron concentration, corresponding to the rods inserted to the insertion limits, is 2031 ppm. The minimum change in boron concentration from this initial condition to a hot zero power critical condition with all rods inserted is 1097 ppm, which gives a critical boron concentration of 934 ppm.

This mode of operation is a transitory operational mode in which the operator intentionally dilutes and withdraws control rods to take the plant critical. During this mode, the plant is in manual control. For a normal approach to criticality, the operator manually withdraws control rods and dilutes the reactor coolant with unborated water at controlled rates until criticality is achieved. Once critical, the power escalation is slow enough to allow the operator to manually block the source range reactor trip after receiving the P-6 permissive signal from the intermediate range detectors (nominally at 10^5 cps). Too fast a power escalation (due to an unknown dilution) would result in reaching P-6 unexpectedly, leaving insufficient time to manually block the source range reactor trip. Failure to perform this manual action results in a reactor trip and immediate shutdown of the reactor.

Upon any reactor trip signal, or low input voltage to the Class 1E dc and uninterruptible power supply system battery chargers, a safety-related function automatically isolates the potentially unborated water from the demineralized water transfer and storage system and thereby terminates the dilution. Additionally, the suction lines for the chemical and volume control system pumps are automatically realigned to draw borated water from the chemical and volume control system boric acid tank.

15.4.6.2.6 Dilution During Full Power Operation (Mode 1)

The plant may be operated at power two ways: automatic T_{avg}/rod control and under operator control. The COLR and Technical Specifications require an available shutdown margin of 1.6-percent Δk/k and four reactor coolant pumps operating. With the plant at power and the reactor coolant system at pressure, the dilution rate is limited by the capacity of the chemical and volume control system makeup pumps. The analysis is performed assuming two chemical and volume control system pumps are in operation, even though normal operation is with one pump. Conditions assumed for a dilution in this mode are the following:

- A dilution flow of 175 gpm of unborated water exists.The dilution flow is assumed to be at 40°F and 14.7 psia. The fluid conditions of the RCS are assumed to be 581.6°F (full power) and 2250 psia.

- Minimum reactor coolant system water volume is 8425.5 ft^3. This is a very conservative estimate of the active reactor coolant system volume, minus the pressurizer volume.

- An initial maximum boron concentration, corresponding to the rods inserted to the insertion limits, is 1811 ppm. The minimum change in boron concentration from this initial condition to a hot zero power critical condition with all rods inserted is 877 ppm, which gives a critical boron concentration of 934 ppm. Full rod insertion, minus the most reactive stuck rod, occurs due to reactor trip.

With the reactor in automatic rod control, the pressurizer level controller limits the dilution flow rate to the maximum letdown rate. If a dilution rate in excess of the letdown rate is present, the pressurizer level controller throttles charging flow down to match the letdown rate. For the safety analysis, a conservative dilution flow rate of 175 gpm is assumed. With the reactor in automatic rod control, a boron dilution results in a power and temperature increase in such a way that the rod controller attempts to compensate by slow insertion of the control rods. This action by the controller results in at least three alarms to the operator:

A. Rod insertion limit- low level alarm

B. Rod insertion limit- low-low level alarm if insertion continues

C. Axial flux difference alarm (ΔI outside of the target band)

Given the many alarms, indications, and the inherent slow process of dilution at power, the operator has sufficient time for action. The operator has at least 170.6 minutes from the rod insertion limit low-low alarm until shutdown margin is lost at the beginning of the cycle, which is more than 15 minutes and is not required before 30 minutes. The time is significantly longer at the end of the cycle because of the lower initial and critical boron concentrations.

Because the analysis for the boron dilution event with the reactor in automatic rod control does not predict a reactor and turbine trip, considering the consequential loss of offsite power for this case is not needed.

With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature would rise and cause the reactor to reach the overtemperature or overpower ΔT trip setpoint resulting in a reactor trip. Upon any reactor trip signal, a safety-related function automatically isolates the unborated water from the demineralized water transfer and storage system and thereby terminates the dilution. Additionally, the suction lines for the chemical and volume control system pumps are automatically realigned to draw borated water from the chemical and volume control system boric acid tank.

The boron dilution transient in this case is essentially equivalent to an uncontrolled rod withdrawal at power (see Subsection 15.4.2). The maximum reactivity insertion rate for a boron dilution transient is conservatively estimated to be approximately 0.5 pcm/s and is within the range of insertion rates analyzed for uncontrolled rod withdrawal at power. Before reaching the overtemperature or overpower ΔT reactor trip, the operator receives an alarm overtemperature or overpower ΔT and an overtemperature or overpower ΔT turbine runback.

Should a consequential loss of offsite power occur after reactor and turbine trip, it does not alter the fact that the dilution event has been terminated by automatic protection features. As indicated previously, the reactor trip signal that occurs in parallel with the turbine trip will actuate a safety-related function that automatically isolates the unborated water from the demineralized water system and thereby terminates the dilution. A subsequent loss of offsite power will cause the chemical and volume control system pumps to shut down.

After reactor trip, the automatic termination of the dilution flow from the demineralized water transfer and storage system precludes a post-trip return to criticality.

15.4.6.3 Conclusions

Inadvertent boron dilution events are administratively prevented by the Technical Specifications during refueling (Mode 6) and automatically terminated during cold shutdown (Mode 5), safe shutdown (Mode 4), and hot standby (Mode 3) modes. Inadvertent boron dilution events during startup (Mode 2) or power operation (Mode 1), if not detected and terminated by the operators, result in an automatic reactor trip. Following reactor trip, automatic termination of the dilution occurs and post-trip return to criticality is prevented.

The preceding results demonstrate that in all modes of operation, an inadvertent boron dilution is prevented or responded to by automatic functions, or sufficient time is available for operator action to terminate the transient. Following termination of the dilution flow and initiation of boration, the reactor is in a stable condition.

15.4.7 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position

15.4.7.1 Identification of Causes and Accident Description

Fuel and core loading errors can inadvertently occur, such as those arising from the inadvertent loading of one or more fuel assemblies into improper positions, having a fuel rod with one or more pellets of the wrong enrichment, or having a full fuel assembly with pellets of the wrong enrichment. This leads to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. Also included among possible core-loading errors is the inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods.

An error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes more peaked than those calculated with the correct enrichments. A 5-percent uncertainty margin is included in the design value of power peaking factor assumed in the analysis of Condition I and Condition II transients. The online core monitoring system is used to verify power shapes at the start of life and is capable of revealing fuel assembly enrichment errors or loading errors that cause power shapes to be peaked in excess of the design value. Power-distribution-related measurements are incorporated into the evaluation of calculated power distribution information using the incore instrumentation processing algorithms contained within the online monitoring system. The processing algorithms contained within the online monitoring system are functionally identical to those historically used for the evaluation of power distributions measurements in Westinghouse pressurized water reactors.

Each fuel assembly is marked with an identification number and loaded in accordance with a core-loading diagram to reduce the probability of core loading errors. During core loading, the identification number is checked before each assembly is moved into the core. Serial numbers read during fuel movement are subsequently recorded on the loading diagram as a further check on proper placement after the loading is completed.

The power distortion due to a combination of misplaced fuel assemblies could significantly increase peaking factors and is readily observable with the online core monitoring system. The fixed incore instrumentation within the instrumented fuel assembly locations is augmented with core exit thermocouples. There is a high probability that these thermocouples would also indicate any abnormally high coolant temperature rise. Incore flux measurements are taken during the startup subsequent to every refueling operation.

This event is a Condition III incident (an infrequent fault) as defined in Subsection 15.0.1.

15.4.7.2 Analysis of Effects and Consequences

15.4.7.2.1 Method of Analysis

Steady-state power distributions in the x-y plane of the core are calculated at 30-percent rated thermal power using the three-dimensional nodal code ANC (Reference 7). Representative power distributions in the x-y plane for a correctly loaded core are described in Chapter 4.

For each core loading error case analyzed, the percent deviations from detector readings for a normally loaded core are shown in the incore detector locations. (See Figures 15.4.7-1 through 15.4.7-4.)

15.4.7.2.2 Results

The following core loading error cases are analyzed:

Case A:

Case in which a Region 1 assembly is interchanged with a Region 3 assembly. The particular case considered is the interchange of two assemblies near the periphery of the core (see Figure 15.4.7-1).

Case B:

Case in which a Region 1 assembly is interchanged with a neighboring Region 2 fuel assembly. For the particular case considered, the interchange is assumed to take place close to the core center and with burnable poison rods located in the correct Region 2 position, but in a Region 1 assembly mistakenly loaded in the Region 2 position (see Figure 15.4.7-2).

Case C:

Enrichment error – Case in which a Region 2 fuel assembly is loaded in the core central position (see Figure 15.4.7-3).

Case D:

Case in which a Region 2 fuel assembly instead of a Region 1 assembly is loaded near the core periphery (see Figure 15.4.7-4).

15.4.7.3 Conclusions

Fuel assembly enrichment errors are prevented by administrative procedures implemented in fabrication.

In the event that a single pin or pellet has a higher enrichment than the nominal value, the consequences in terms of reduced DNBR and increased fuel and cladding temperatures are limited to the incorrectly loaded pin or pins and perhaps the immediately adjacent pins.

Fuel assembly loading errors are prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses in this section confirm that resulting power distribution effects are either readily detected by the online core monitoring system or cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

15.4.8 Spectrum of Rod Cluster Control Assembly Ejection Accidents

15.4.8.1 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of an RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

15.4.8.1.1 Design Precautions and Protection

15.4.8.1.1.1 Mechanical Design

The mechanical design is discussed in Section 4.6. Mechanical design and quality control procedures intended to prevent the possibility of an RCCA drive mechanism housing failure are listed below:

- Each control rod drive mechanism housing is completely assembled and shop tested at a minimum of 125% of system design pressure.
- The mechanism housings are hydrotested after they are attached to the reactor vessel head. The housings are included as part of the hydrotest of the completed reactor coolant system.
- The allowable stress levels in the mechanism are not exceeded due to system thermal transients at power or by the thermal movement of the coolant loops. Moments induced by the safe shutdown earthquake can be accepted within the allowable primary working stress range specified by the ASME Code, Section III, for Class 1 components.
- The latch mechanism housing and rod travel housing are each a single length of forged stainless steel. This material exhibits excellent notch toughness at temperatures that are encountered.

A significant margin of strength in the elastic range together with the large energy absorption capability in the plastic range gives additional confidence that gross failure of the housing does not occur. The joint between the latch housing and latch housing nozzle is a full penetration bi-metallic weld, and the joint between the latch housing and rod travel housing is a threaded joint with a canopy seal weld.

15.4.8.1.1.2 Nuclear Design

If a rupture of an RCCA drive mechanism housing is postulated, the operation using chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the power control (or mechanical shim) RCCAs inserted only far enough to permit load follow. The axial offset RCCAs are positioned so that the targeted axial offset can be met throughout core life. Reactivity changes caused by core depletion and xenon transients are normally compensated for by boron changes and the mechanical shim banks, respectively. Further, the location and grouping of the power control and axial offset RCCAs are selected with consideration for an RCCA ejection accident. Therefore, should an RCCA be ejected from its normal position during full-power operation, a less severe reactivity excursion than analyzed is expected.

It may occasionally be desirable to operate with larger than normal insertions. For this reason, a power control and axial offset rod insertion limit is defined as a function of power level. Operation with the RCCAs above this limit provides adequate shutdown capability and an acceptable power distribution. The position of the RCCAs is continuously indicated in the main control room. An alarm occurs if a bank of RCCAs approaches its insertion limit or if one RCCA deviates from its bank. Operating instructions require rapid boration at the low-low level alarm. If the CVS is unavailable or insufficient then the CMTs can be used for boration.

15.4.8.1.1.3 Reactor Protection

The reactor protection in the event of a rod ejection accident is described in WCAP-15806-P-A, (Reference 4). The protection for this accident is provided by the high neutron flux trip (high and low

setting) and the high rate of neutron flux increase trip. These protection functions are described in Section 7.2.

15.4.8.1.1.4 Effects on Adjacent Housings

Failures of an RCCA mechanism housing, due to either longitudinal or circumferential cracking, does not cause damage to adjacent housings. The control rod drive mechanism is described in Subsection 3.9.4.1.1.

15.4.8.1.1.5 Not Used

15.4.8.1.1.6 Not Used

15.4.8.1.1.7 Consequences

The probability of damage to an adjacent housing is considered remote. If damage is postulated, it is not expected to lead to a more severe transient because RCCAs are inserted in the core in symmetric patterns and control rods immediately adjacent to worst ejected rods are not in the core when the reactor is critical. Damage to an adjacent housing could, at worst, cause that RCCA not to fall on receiving a trip signal. This is already taken into account in the analysis by assuming a stuck rod adjacent to the ejected rod.

15.4.8.1.1.8 Summary

Failure of a control rod housing does not cause damage to adjacent housings that increase the severity of the initial accident.

15.4.8.1.2 Limiting Criteria

This event is a Condition IV incident (ANSI N18.2). See Subsection 15.0.1 for a discussion of ANS classification. Because of the extremely low probability of an RCCA ejection accident, some fuel damage is considered an acceptable consequence.

NUREG-0800 Standard Review Plan (SRP) 4.2 Revision 3 (Reference 24) interim criteria applicable to new plant design certification are applied to provide confidence that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are the following:

- The pellet clad mechanical interaction (PCMI) failure criteria is a change in radial average fuel enthalpy greater than the corrosion-dependent limit depicted in Figure B-1 of SRP 4.2 Revision 3 Appendix B.

- The high cladding temperature failure criteria for zero power conditions is a peak radial average fuel enthalpy greater than 170 cal/g for fuel rods with an internal rod pressure at or below system pressure and 150 cal/g for fuel rods with an internal rod pressure exceeding system pressure.

- For intermediate (greater than 5% rated thermal power) and full power conditions, fuel cladding is presumed to fail if local heat flux exceeds thermal design limits (e.g. DNBR).

- For core coolability, it is conservatively assumed that the average fuel pellet enthalpy at the hot spot remains below 200 cal/g (360 btu/lb) for irradiated fuel. This bounds non-irradiated fuel, which has a slightly higher enthalpy limit.

- For core coolability, the peak fuel temperature must remain below incipient fuel melting conditions.
- Mechanical energy generated as a result of (1) non-molten fuel-to-coolant interaction and (2) fuel rod burst must be addressed with respect to reactor pressure boundary, reactor internals, and fuel assembly structural integrity.
- No loss of coolable geometry due to (1) fuel pellet and cladding fragmentation and dispersal and (2) fuel rod ballooning.
- Peak reactor coolant system pressure is less than that which could cause stresses to exceed the “Service Limit C” as defined in the ASME code.

15.4.8.2 Analysis of Effects and Consequences

Method of Analysis

The calculation of the RCCA ejection transients is performed in two stages: first, an average core calculation and then, a hot rod calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time, including the various total core feedback effects (Doppler reactivity and moderator reactivity). Enthalpy, fuel temperature and DNB transients are then determined by performing a conservative fuel rod transient heat transfer calculation.

A discussion of the method of analysis appears in WCAP-15806-P-A (Reference 4).

Average Core Analysis

The three-dimensional nodal code ANC (References 14, 15, 16, 17, 21, 22, and 27) is used for the average core transient analysis. This code solves the two-group neutron diffusion theory kinetic equation in 3 spatial dimensions (rectangular coordinates) for 6 delayed neutron groups. The core moderator and fuel temperature feedbacks are based on the NRC approved Westinghouse version of the VIPRE-01 code and methods (References 18 and 19).

Hot Rod Analysis

The hot fuel rod models are based on the Westinghouse VIPRE models described in WCAP-15806-P-A (Reference 4). The hot rod model represents the hottest fuel rod from any channel in the core. VIPRE performs the hot rod transients for fuel enthalpy, temperature and DNBR using as input the time-dependent nuclear core power and power distribution from the core average analysis. A description of the VIPRE code is provided in Reference 18.

System Overpressure Analysis

If the fuel coolability limits are not exceeded, the fuel dispersal into the coolant or a sudden pressure increase from thermal to kinetic energy conversion is not needed to be considered in the overpressure analysis. Therefore, the overpressure condition may be calculated on the basis of conventional fuel rod to coolant heat transfer and the prompt heat generation in the coolant. The system overpressure analysis is conducted by first performing the core power response analysis to obtain the nuclear power transient (versus time) data. The nuclear power data is then used as input to a plant transient computer code to calculate the peak reactor coolant system pressure. This code calculates the pressure transient, taking into account fluid transport in the reactor coolant system and heat transfer to the steam generators. For conservatism, no credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing.

15.4.8.2.1 Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected as described in Reference 4.

15.4.8.2.1.1 Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using three-dimensional methods. Standard nuclear design codes are used in the analysis. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculation.

Appropriate safety analysis allowances are added to the ejected rod worth and hot channel factors to account for calculational uncertainties, including an allowance for nuclear peaking due to densification as discussed in Reference 4.

15.4.8.2.1.2 Not Used

15.4.8.2.1.3 Moderator and Doppler Coefficients

The critical boron concentration is adjusted in the nuclear code to obtain a moderator temperature coefficient that is conservative compared to actual design conditions for the plant consistent with Reference 4. The fuel temperature feedback in the neutronics code is reduced consistent with Reference 4 requirements.

15.4.8.2.1.4 Delayed Neutron Fraction, β_{eff}

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values no less than 0.50 percent at the end of cycle. The accident is sensitive to β_{eff} if the ejected rod worth is equal to or greater than β_{eff}. To allow for future cycles, a pessimistic estimate of β_{eff} of 0.44 percent is used in the analysis.

15.4.8.2.1.5 Trip Reactivity Insertion

The trip reactivity insertion accounts for the effect of the ejected rod and one adjacent stuck rod. The trip reactivity is simulated by dropping a limited set of rods of the required worth into the core. The start of rod motion occurs 0.9 second after either the power range high positive flux rate or the high or low setting of the high neutron flux setpoint is reached. A curve of trip rod insertion versus time is used, which assumes that insertion to the dashpot does not occur until 2.7 seconds after the start of fall. The choice of such a conservative insertion rate means that there is over 1 second after the trip setpoint is reached before significant shutdown reactivity is inserted into the core. This conservatism is important for the hot full power accidents.

The minimum design shutdown margin available at hot zero power may be reached only at end of life in the equilibrium cycle. This value includes an allowance for the worst stuck rod, adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Calculations show that the effect of two stuck RCCAs (one of which is the worst ejected rod) is to reduce the shutdown by about an additional 1-percent Δk. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor is subcritical when the core returns to hot zero power.

15.4.8.2.1.6 Reactor Protection

As discussed in Subsection 15.4.8.1.1.3, reactor protection for a rod ejection is provided by the high neutron flux trip (high and low setting) and the high rate of neutron flux increase trip. These protection

functions are part of the protection and safety monitoring system. No single failure of the protection and safety monitoring system negates the protection functions required for the rod ejection accident or adversely affects the consequences of the accident.

15.4.8.2.1.7 Results

For all cases, the core is preconditioned by assuming a fuel cycle depletion with control rod insertion that is conservative relative to expected baseload operation. All cases assume that the mechanical shim and axial offset control RCCAs are inserted to their insertion limits before the event and xenon is skewed to yield a conservative initial axial power shape. The limiting RCCA ejection cases for a typical cycle are summarized following the criteria outlined in Subsection 15.4.8.1.2.

- Pellet-Clad Mechanical Interaction (PCMI) and High Clad Temperature (Hot Zero Power)

  The resulting maximum fuel average enthalpy rise and maximum fuel average enthalpy are less than the criteria given in Subsection 15.4.8.1.2.

- High Clad Temperature (≥5% Rated Thermal Power)

  The fraction of the core calculated to have a DNBR less than the safety analysis limit is less than the amount of failed fuel assumed in the dose analysis described in Subsection 15.4.8.3.

- Core Coolability

  The resulting maximum fuel average enthalpy is less than the criterion given in Subsection 15.4.8.1.2. Fuel melting is not predicted to occur at the hot spot.

There are no fuel failures due to the fuel enthalpy deposition, i.e., both fuel and cladding enthalpy limits were met. Additionally, the coolability criteria for peak fuel enthalpy and the fuel melting criteria were met. Therefore, the fuel dispersal into the coolant, a sudden pressure increase from thermal to kinetic energy conversion, gross lattice distortion, or severe shock waves are precluded.

The nuclear power transients for the limiting cases are presented in Figures 15.4.8-1 through 15.4.8-3.

The calculated sequence of events for the limiting cases are presented in Table 15.4-1. Reactor trip occurs early in the transients, after which the nuclear power excursion is terminated.

The ejection of an RCCA constitutes a break in the reactor coolant system, located in the reactor pressure vessel head. The effects and consequences of loss-of-coolant accidents (LOCAs) are discussed in Subsection 15.6.5. Following the RCCA ejection, the plant response is the same as a LOCA.

The consequential loss of offsite power described in Subsection 15.0.14 is not limiting for the enthalpy and temperature transients resulting from an RCCA ejection accident. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the peak fuel and cladding temperatures occur before the reactor coolant pumps begin to coast down.

15.4.8.2.1.8 Fission Product Release

It is assumed that fission products are released from the gaps of all rods entering DNB. In the cases considered, less than 10 percent of the rods are assumed to enter DNB based on a detailed three-dimensional kinetics and hot rod analysis. The maximum fuel average enthalpy rise of rods predicted to enter DNB will be less than 60 cal/g. Fuel melting does not occur at the hot spot.

The consequential loss of offsite power described in Subsection 15.0.14 is not limiting for the calculation of the number of rods assumed to enter DNB for the RCCA ejection accident. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the minimum DNBR, for rods where the DNBR did not fall below the design limit (see Section 4.4) in the cases described, occurs before the reactor coolant pumps begin to coast down.

15.4.8.2.1.9 Peak RCS Pressure

Calculations of the peak reactor coolant system pressure demonstrate that the peak pressure does not exceed that which would cause the stress to exceed the Service Level C Limit as described in the ASME Code, Section III. Therefore, the accident for this plant does not result in an excessive pressure rise or further damage to the reactor coolant system.

The consequential loss of offsite power described in Subsection 15.0.14 is not limiting for the pressure surge transient resulting from an RCCA ejection accident. Due to the delay from reactor trip until turbine trip and the rapid power reduction produced by the reactor trip, the peak system pressure occurs before the reactor coolant pumps begin to coast down.

15.4.8.2.1.10 Lattice Deformations

A large temperature gradient exists in the region of the hot spot. Because the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a differential expansion, tending to bow the midpoint of the rods toward the hotter side of the rod.

Calculations indicate that this bowing results in a negative reactivity effect at the hot spot because the core is undermoderated, and bowing tends to increase the undermoderation at the hot spot. In practice, no significant bowing is anticipated because the structural rigidity of the core is sufficient to withstand the forces produced.

Boiling in the hot spot region would produce a net flow away from that region. However, the heat from the fuel is released to the water relatively slowly, and it is considered inconceivable that crossflow is sufficient to produce lattice deformation. Even if massive and rapid boiling, sufficient to distort the lattices, is hypothetically postulated, the large void fraction in the hot spot region produces a reduction in the total core moderator to fuel ratio and a large reduction in this ratio at the hot spot. The net effect is therefore a negative feedback.

In conclusion, no credible mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analysis.

15.4.8.3 Radiological Consequences

The evaluation of the radiological consequences of a postulated rod ejection accident assumes that the reactor is operating with a limited number of fuel rods containing cladding defects and that leaking steam generator tubes result in a buildup of activity in the secondary coolant. Refer to Subsection 15.4.8.3.1 and Table 15.4-4.

As a result of the accident, 10 percent of the fuel rods are assumed to be damaged (see Subsection 15.4.8.2.1.8) such that the activity contained in the fuel-cladding gap is released to the reactor coolant. No fuel melt is calculated to occur as a result of the rod ejection (see Subsection 15.4.8.2.1.8).

Activity released to the containment via the spill from the reactor vessel head is assumed to be available for release to the environment because of containment leakage. Activity carried over to the secondary side due to primary-to-secondary leakage is available for release to the environment through the steam line safety or power-operated relief valves.

15.4.8.3.1 Source Term

The significant radionuclide releases due to the rod ejection accident are the iodines, alkali metals, and noble gases. The reactor coolant iodine source term assumes a pre-existing iodine spike. The reactor coolant noble gas concentrations are assumed to be those associated with equilibrium operating limits for primary coolant noble gas activity. The initial reactor coolant alkali metal concentrations are based on those associated with the design basis fuel defect level. These initial reactor coolant activities are of secondary importance compared to the release of fission products from the portion of the core assumed to fail.

Based on NUREG-1465 (Reference 12), the fission product gap fraction is 3 percent of fuel inventory. For this analysis, the gap fractions are modified following the guidance of Draft Guide 1199 (Reference 25), which incorporates the effects of enthalpy rise in the fuel following the reactivity insertion, consistent with Appendix B of SRP 4.2, Revision 3 (Reference 24). Draft Guide 1199 included expanded guidance for determining nuclide gap fractions available for release following a rod ejection. Reference 26 was issued as a clarification to the gap fraction guidance in Draft Guide 1199. An enthalpy rise of 60 cal/gm is used to calculate the gap fractions (see Subsection 15.4.8.2.1.8). Also, to address the fact that the failed fuel rods may have been operating at power levels above the core average, the source term is increased by the lead rod radial peaking factor. No fuel melt is calculated to occur as a result of the rod ejection (see Subsection 15.4.8.2.1.8).

The initial secondary coolant activity is assumed to be 1 percent of the maximum equilibrium primary coolant activity for iodines and alkali metals.

15.4.8.3.2 Release Pathways

There are three components to the accident releases:

- The activity initially in the secondary coolant is available for release as long as steam releases continue.

- The reactor coolant leaking into the steam generators is assumed to mix with the secondary coolant. The activity from the primary coolant mixes with the secondary coolant and, as steam is released, a portion of the iodine and alkali metal in the coolant is released. The fraction of activity released is defined by the assumed flashing fraction and the partition coefficient assumed for the steam generator. The noble gas activity entering the secondary side is released to the environment. These releases are terminated when the steam releases stop.

- The activity from the reactor coolant system and the core is released to the containment atmosphere and is available for leakage to the environment through the assumed design basis containment leakage.

Credit is taken for decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion by ground deposition during transport offsite.

15.4.8.3.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.4.8.3.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.4-4.

15.4.8.3.5 Identification of Conservatisms

The assumptions used in the analysis contain a number of conservatisms:

- Although fuel damage is assumed to occur as a result of the accident, no fuel damage is anticipated.
- The reactor coolant activities are based on conservative assumptions (refer to Table 15.4-4); whereas the activities based on the expected fuel defect level are far less (see Section 11.1).
- The leakage of reactor coolant into the secondary system, at 300 gallons per day, is conservative. The leakage is normally a small fraction of this.
- It is unlikely that the conservatively selected meteorological conditions are present at the time of the accident.
- The leakage from containment is assumed to continue for a full 30 days. It is expected that containment pressure is reduced to the point that leakage is negligible before this time.

15.4.8.3.6 Doses

Using the assumptions from Table 15.4-4, the calculated total effective dose equivalent (TEDE) doses are determined to be 4.0 rem at the site boundary for the limiting 2-hour interval (0 to 2 hours) and 5.9 rem at the low population zone outer boundary. These doses are well within the dose guideline of 25 rem total effective dose equivalent identified in 10 CFR Part 50.34. The phrase “well within” is taken as being 25 percent or less.

At the time the rod ejection accident occurs, the potential exists for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because the pool boiling would not occur until after the first 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE, and when this is added to the dose calculated for the rod ejection accident, the resulting total dose remains less than the value reported above.

15.4.9 Combined License Information

This section contained no requirement for additional information.

15.4.10 References

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Table 15.4-1 (Sheet 1 of 3)
Time Sequence of Events for Incidents Which Result in Reactivity and Power Distribution Anomalies

Accident	Event	Time (seconds)
Uncontrolled RCCA bank withdrawal from a subcritical or low-power startup condition	Initiation of uncontrolled rod withdrawal from 10^{-9} of nominal power	0.0
	Power range high neutron flux (low setting) setpoint reached	10.4
	Peak nuclear power occurs	10.6
	Rods begin to fall into core	11.3
	Peak heat flux occurs	12.9
	Minimum DNBR occurs	12.9
	Peak average clad temperature occurs	13.5
	Peak average fuel temperature occurs	13.7
One or more dropped RCCAs	Rods drop	0.0
	Control system initiates control bank withdrawal	0.4
	Peak nuclear power occurs	21.7
	Peak core heat flux occurs	24.2
Uncontrolled RCCA bank withdrawal at power		
1. Case A - Full power with maximum reactivity feedback	Initiation of uncontrolled RCCA withdrawal at a fast reactivity insertion rate (80 pcm/s)	0.0
	Power range high positive flux rate trip point reached	5.2
	Rods begin to fall into core	6.1
	Minimum DNBR occurs	6.4
2. Case B - Full power with maximum reactivity feedback	Initiation of uncontrolled RCCA withdrawal at an intermediate reactivity insertion rate (34 pcm/s)	0.0
	Overpower ΔT setpoint reached	18.0
	Rods begin to fall into core	19.9
	Minimum DNBR occurs	20.1
3. Case C - Full power with maximum reactivity feedback	Initiation of uncontrolled RCCA withdrawal at a slow reactivity insertion rate (5 pcm/s)	0.0
	Overtemperature ΔT setpoint reached	568.3
	Rods begin to fall into core	570.3
	Minimum DNBR occurs	570.4

Table 15.4-1 (Sheet 2 of 3)
Time Sequence of Events for Incidents Which Result in Reactivity and Power Distribution Anomalies

Accident	Event	Time (minutes)
Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant		
Dilution during power operation (Mode 1)		
Automatic reactor control	Operator receives low-low rod insertion limit alarm due to dilution	0.0
	Shutdown margin lost	170.6
Manual reactor control	Dilution initiated	0.0
	Reactor trip on overtemperature ΔT due to dilution	3.3
	Dilution automatically terminated by demineralized water transfer and storage system isolation	3.8
Dilution during startup (Mode 2)	Power range high neutron flux-low setpoint reactor trip due to dilution	0.0
	Shutdown margin lost	205.3
Dilution during hot standby (Mode 3)	Dilution initiated	0.0
	Boron dilution protection system setpoint reached, which initiates isolation of the dilution source	32.1
	Shutdown margin lost	39.6
Dilution during safe shutdown (Mode 4)	Dilution initiated	0.0
	Boron dilution protection system setpoint reached, which initiates isolation of the dilution source	28.8
	Shutdown margin lost	35.6
Dilution during cold shutdown (Mode 5)	Dilution initiated	0.0
	Boron dilution protection system setpoint reached, which initiates isolation of the dilution source	30.8
	Shutdown margin lost	38.1
Dilution during refueling (Mode 6)	Prevented by administrative control	N/A

Table 15.4-1 (Sheet 3 of 3)
Time Sequence of Events for Incidents Which Result in Reactivity and Power Distribution Anomalies

Accident	Event	Time (seconds)
RCCA ejection accident		
1. PCMI Limiting Event	Initiation of rod ejection	0.00
	Peak nuclear power occurs	0.14
	Reactor trip setpoint reached	< 0.30
	Peak cladding temperature occurs	0.36
	Peak enthalpy deposition occurs	0.44
	Rods begin to fall into core	1.20
2. Peak Clad Temperature Limiting Event	Initiation of rod ejection	0.00
	Peak nuclear power occurs	0.08
	Minimum DNBR occurs	0.11
	Peak cladding temperature occurs	0.11
	Reactor trip setpoint reached	< 0.30
	Rods begin to fall into core	1.20
3. Peak enthalpy / Peak Fuel Centerline Temperature Event	Initiation of rod ejection	0.00
	Peak nuclear power occurs	0.06
	Reactor trip setpoint reached	< 0.30
	Rods begin to fall into core	1.20
	Peak fuel center temperature occurs	2.50
	Peak cladding temperature occurs	2.80

Table 15.4-2
Key Input Parameters for Boron Dilution

Dilution Flow Rates		
Mode[1]	**Flow Rate (gal/min)**	**Flow Rate (m^3/hr)**
1 through 5	175	39.75
Active RCS Volume		
Mode[1]	**Volume (ft^3)**	**Volume (m^3)**
1 and 2	8425.5	238.584
3, 4 and 5	7605.98	215.375
Boron Concentration		
Mode[1]	**Initial Concentration (ppm)**	**Critical Concentration (ppm)**
1	1811	934
2	2031	934
3	1509	1281
4	1649	1449
5	1675	1483

Notes:

1. Uncontrolled boron dilution transient in Mode 6 is prevented by administrative control.

Table 15.4-3
Not Used

Table 15.4-4 (Sheet 1 of 2)
Parameters Used in Evaluating the Radiological Consequences of a Rod Ejection Accident

Initial reactor coolant iodine activity	An assumed iodine spike that has resulted in an increase in the reactor coolant activity to 60 μCi/g (2.22E+06 Bq/g) of dose equivalent I-131 (see Appendix 15A)[(a)]
Reactor coolant noble gas activity	Equal to the operating limit for reactor coolant activity of 280 μCi/g (1.036E+07 Bq/g) dose equivalent Xe-133
Reactor coolant alkali metal activity	Based on design basis activity (see Table 15A-9)
Secondary coolant initial iodine and alkali metal activity	1% of reactor coolant concentrations at maximum equilibrium conditions
Radial peaking factor (for determination of activity in failed/melted fuel)	1.75
Fuel cladding failure – Fraction of fuel rods assumed to fail – Fuel Enthalpy Increase (cal/gm) – Fission product gap fractions Iodine 131 Iodine 132 Krypton 85 Other Nobles Gases Other Halogens Alkali Metals	 0.1 60 0.1238 0.1338 0.5120 0.1238 0.0938 0.6860
Iodine chemical form (%) – Elemental – Organic – Particulate	 4.85 0.15 95.0
Core activity	See Table 15A-3 in Appendix 15A
Nuclide data	See Table 15A-4 in Appendix 15A
Reactor coolant mass (lb)	3.7 E+05 (1.68E+05 kg)

Note:
a. The assumption of a pre-existing iodine spike is a conservative assumption for the initial reactor coolant activity. However, compared to the activity assumed to be released from damaged fuel, it is not significant.

Table 15.4-4 (Sheet 2 of 2)
Parameters Used in Evaluating the Radiological Consequences of a Rod Ejection Accident

Condenser	Not available
Duration of accident (days)	30
Atmospheric dispersion (χ/Q) factors	See Table 15A-5 in Appendix 15A
Secondary system release path	
– Primary to secondary leak rate (lb/hr)	104.5[(a)] (47.4 kg/hr)
– Leak flashing fraction	0.04[(b)]
– Secondary coolant mass (lb)	6.06 E+05 (2.75E+05 kg)
– Duration of steam release from secondary system (sec)	1800
– Steam released from secondary system (lb)	1.08 E+05 (4.90E+04 kg)
– Partition coefficient in steam generators	
• Iodine	0.01
• Alkali metals	0.0035
Containment leakage release path	
– Containment leak rate (% per day)	
• 0-24 hr	0.10
• >24 hr	0.05
– Airborne activity removal coefficients (hr^{-1})	
• Elemental iodine	1.9[(c)]
• Organic iodine	0
• Particulate iodine or alkali metals	0.1
– Decontamination factor limit for elemental iodine removal	200
– Time to reach the decontamination factor limit for elemental iodine (hr)	2.78

Notes:
a. Equivalent to 300 gpd (1.14 m^3/day) cooled liquid at 62.4 lb/ft^3 (999.6 kg/m^3).
b. No credit for iodine partitioning is taken for flashed leakage.
c. From Appendix 15B.

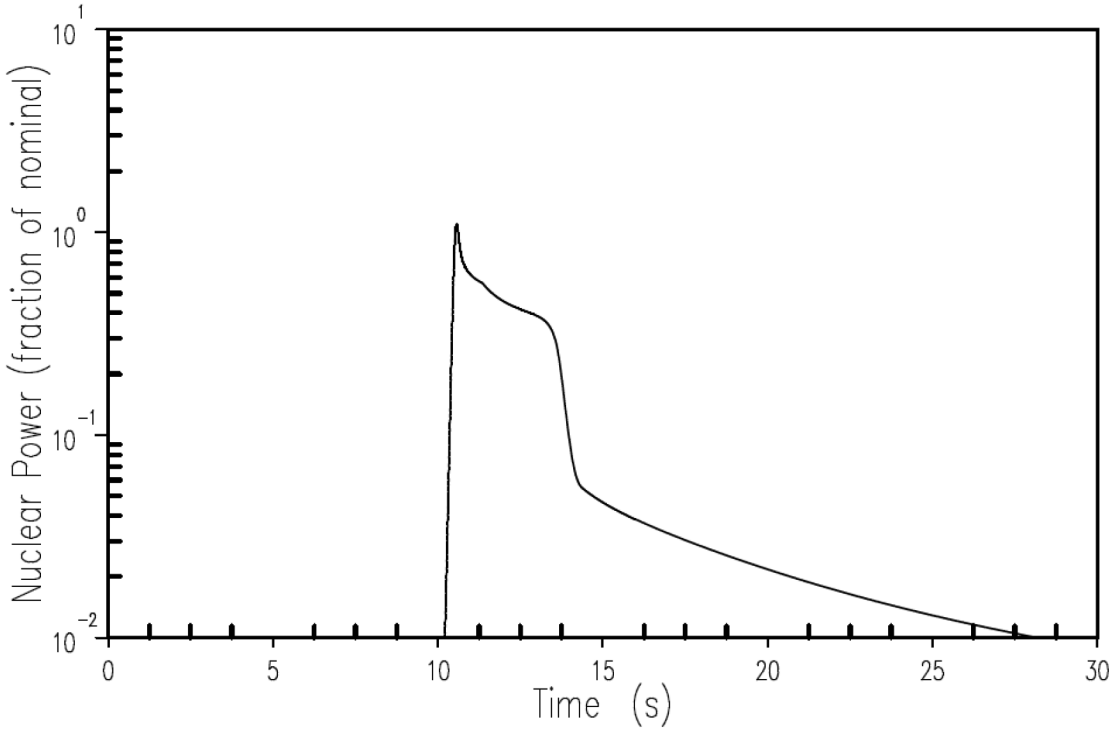

Figure 15.4.1-1
RCCA Withdrawal from Subcritical Nuclear Power

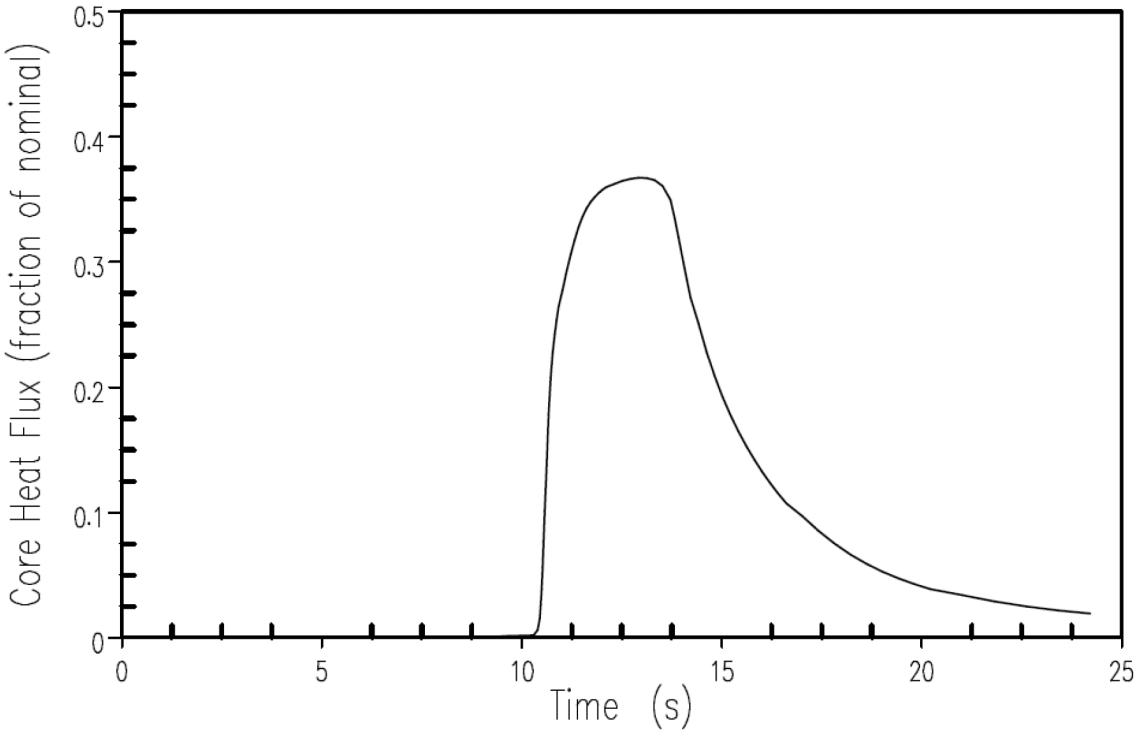

Figure 15.4.1-2
RCCA Withdrawal from Subcritical
Average Channel Core Heat Flux

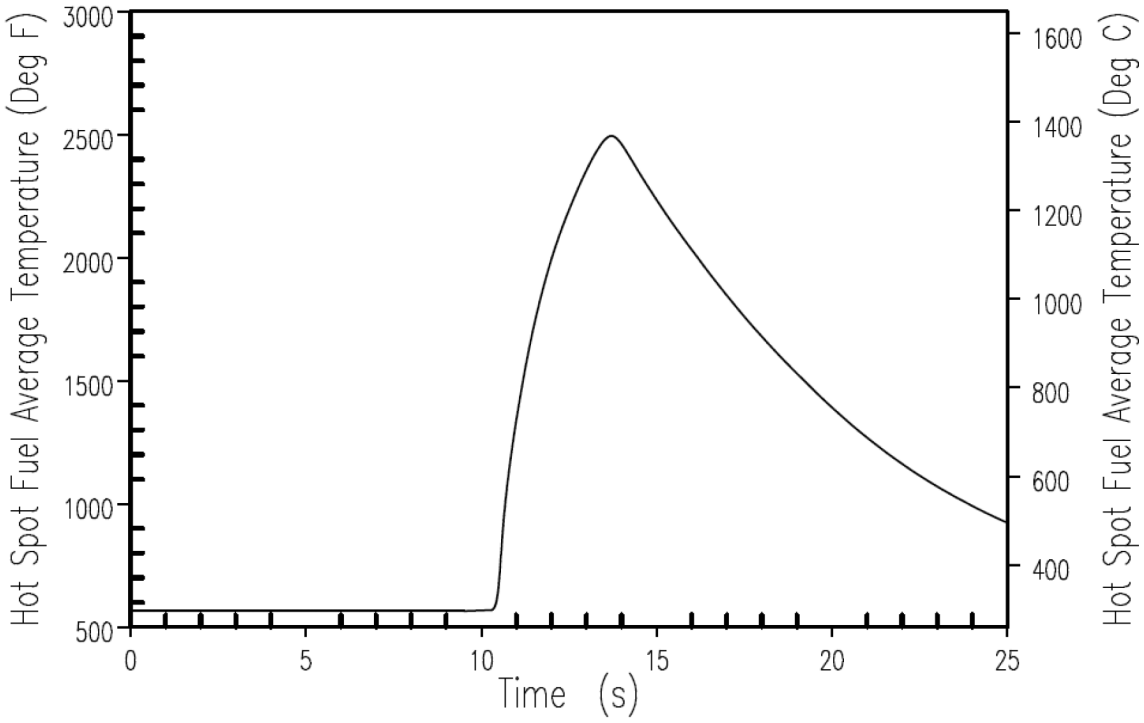

Figure 15.4.1-3
RCCA Withdrawal from Subcritical
Hot Spot Fuel Average Temperature

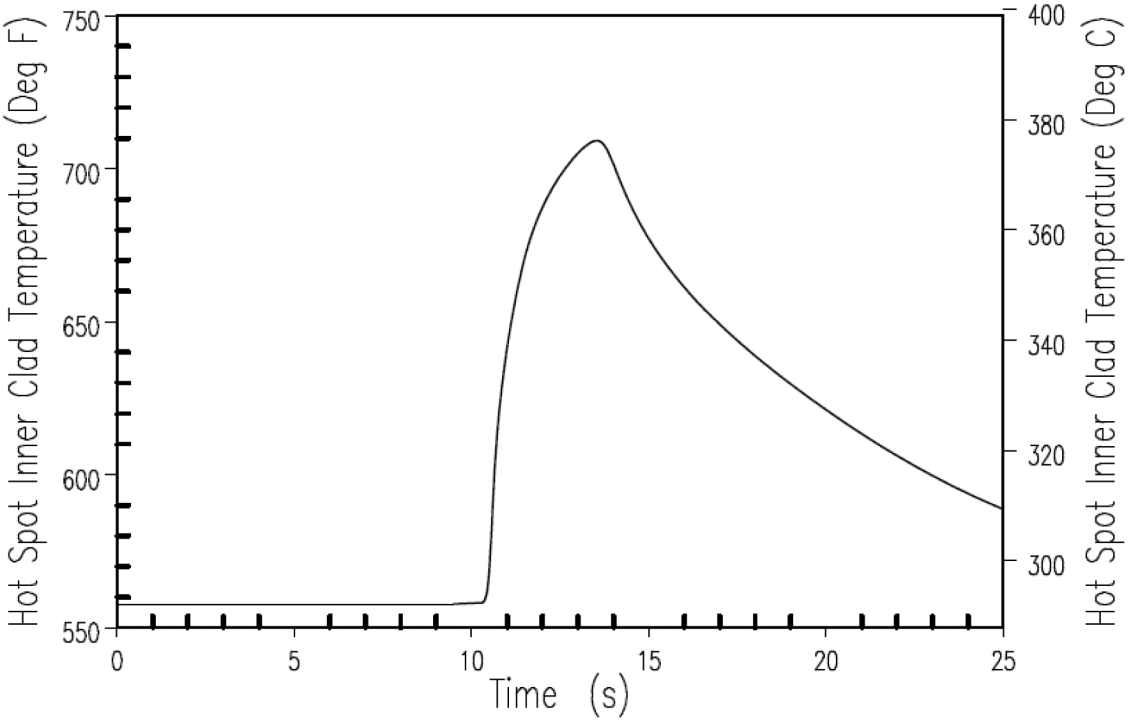

Figure 15.4.1-4
RCCA Withdrawal from Subcritical
Hot Spot Cladding Inner Temperature

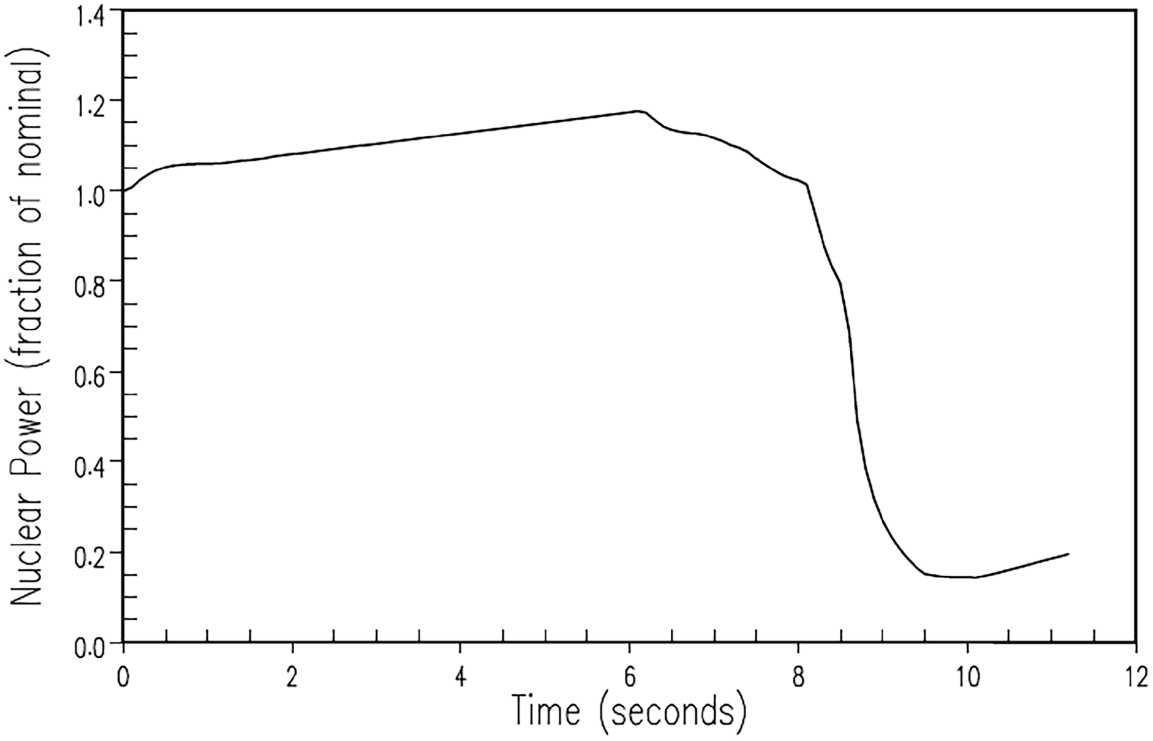

Figure 15.4.2-1
Nuclear Power Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)

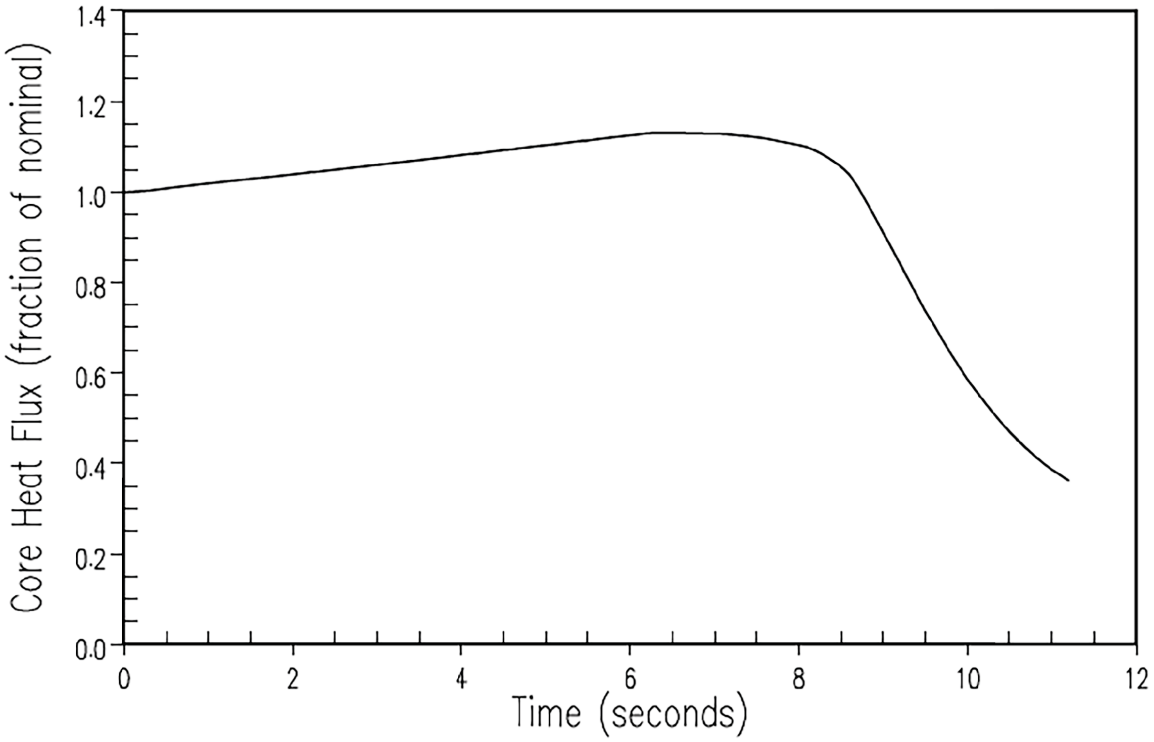

Figure 15.4.2-2
Core Heat Flux Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)

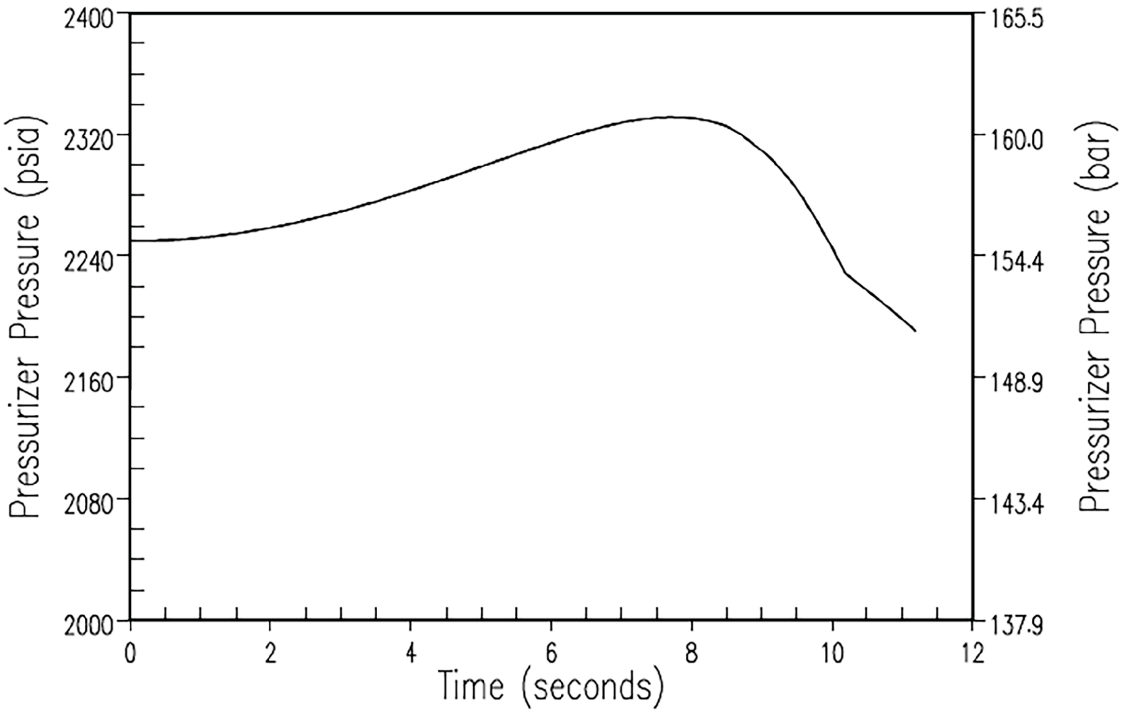

Figure 15.4.2-3
Pressurizer Pressure Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)

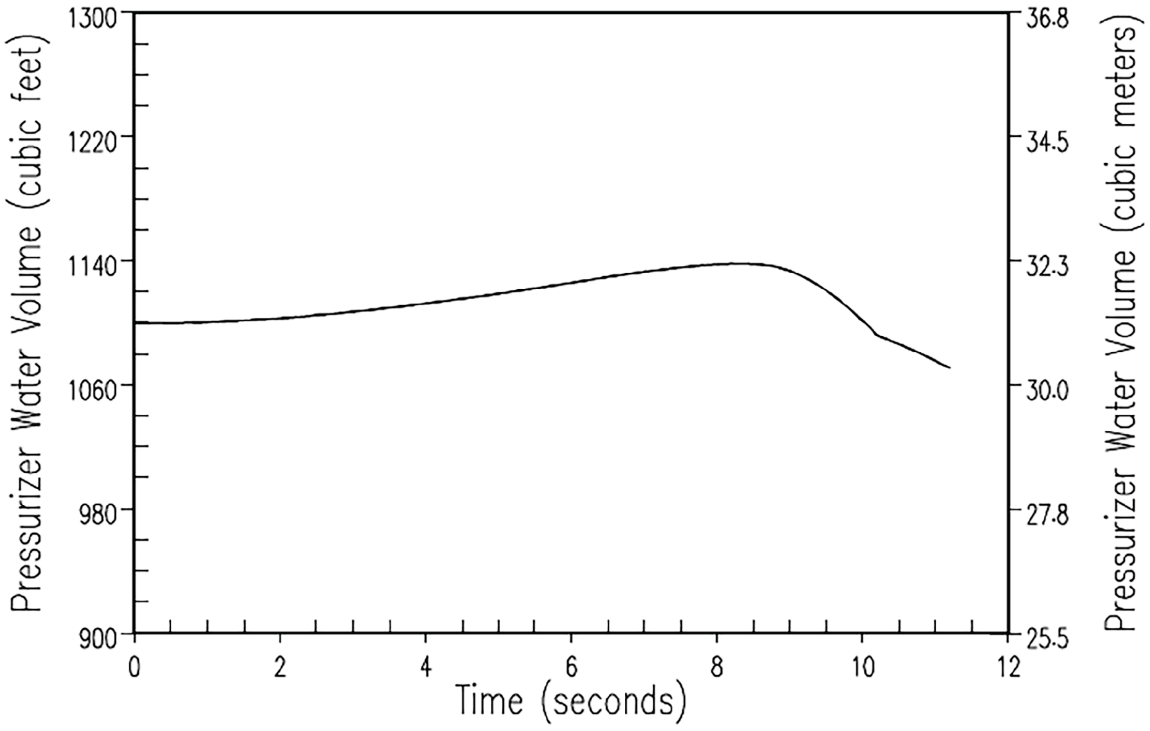

Figure 15.4.2-4
Pressurizer Water Volume Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)

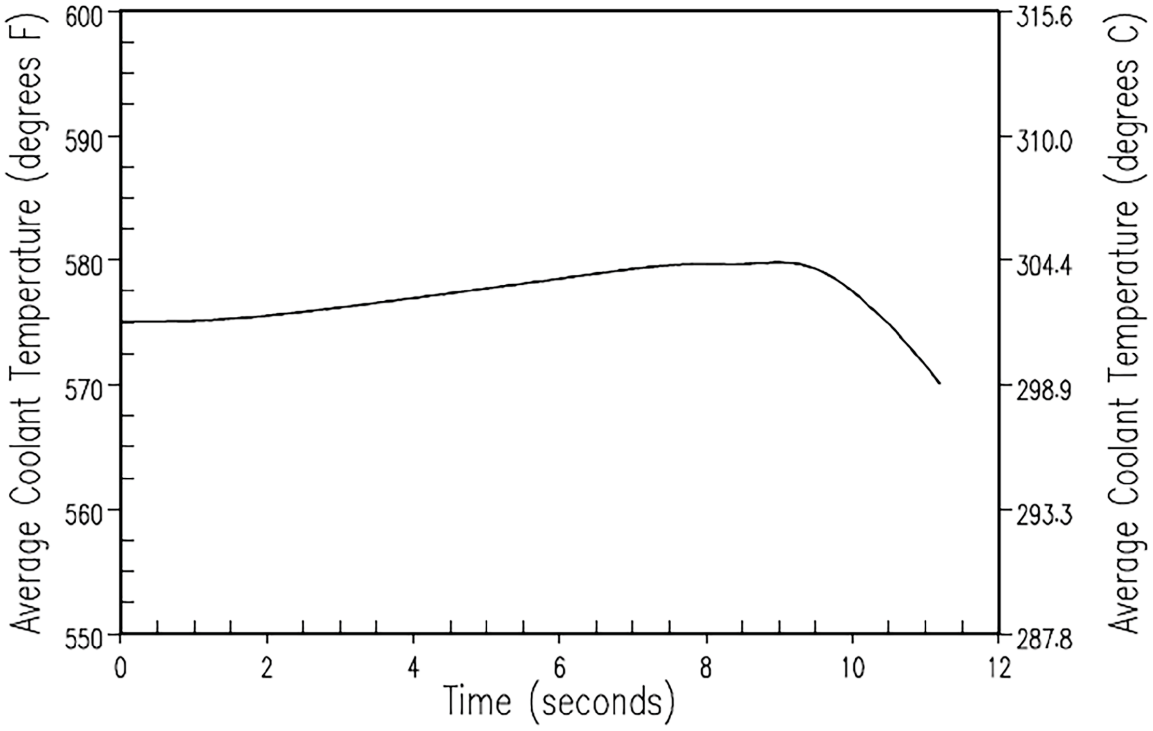

Figure 15.4.2-5
Core Coolant Average Temperature Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (80 pcm/s)

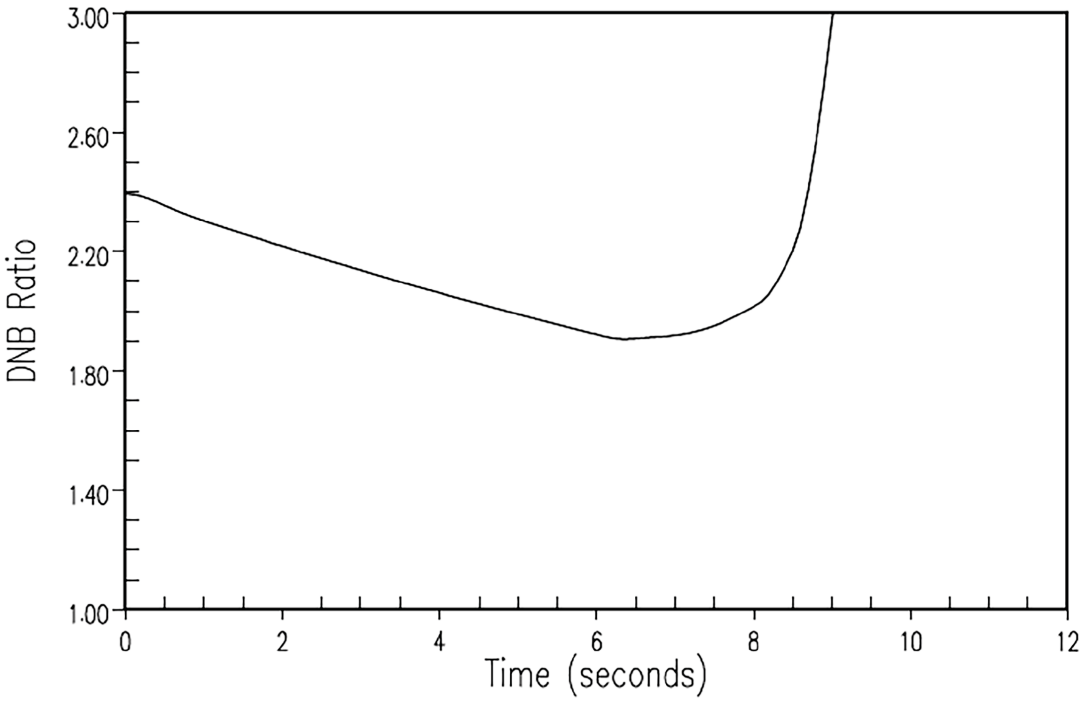

Figure 15.4.2-6
DNBR Transient for an
Uncontrolled RCCA Bank Withdrawal from Full Power
With Maximum Reactivity Feedback (80 pcm/s)

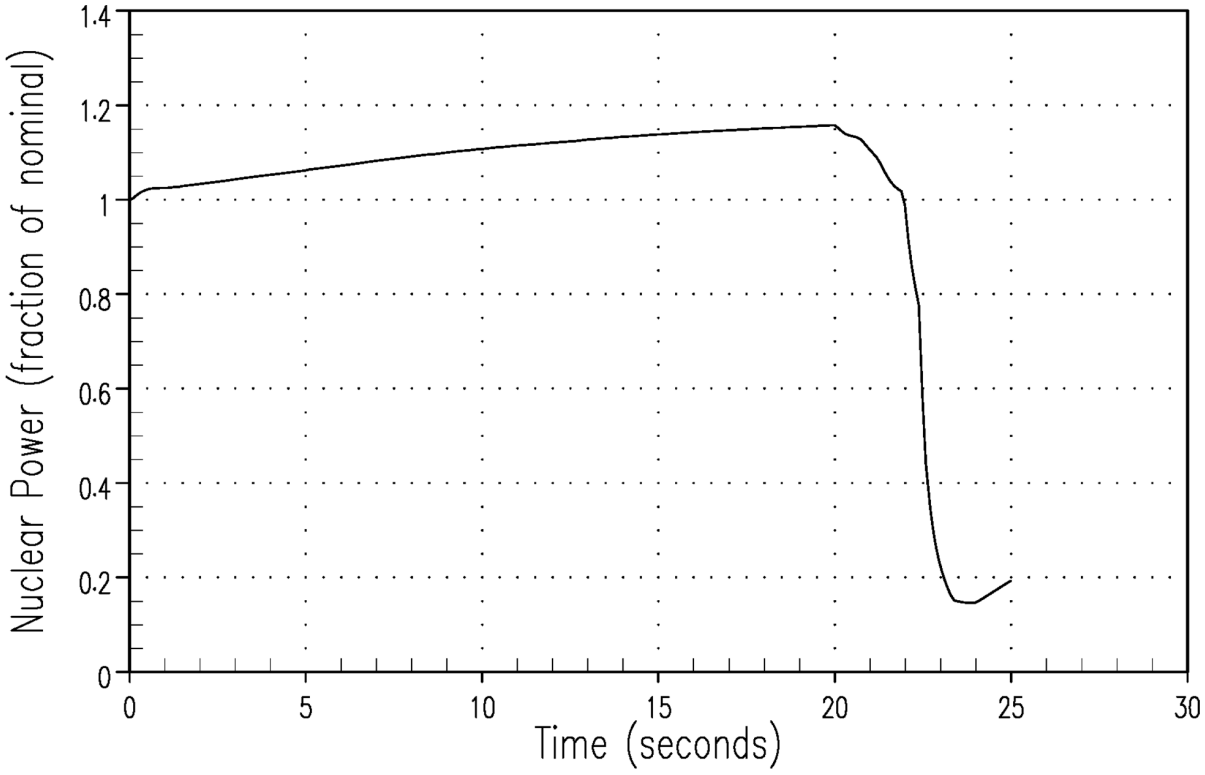

Figure 15.4.2-7
Nuclear Power Transient for an
Uncontrolled RCCA Bank Withdrawal from Full Power
With Maximum Reactivity Feedback (34 pcm/s)

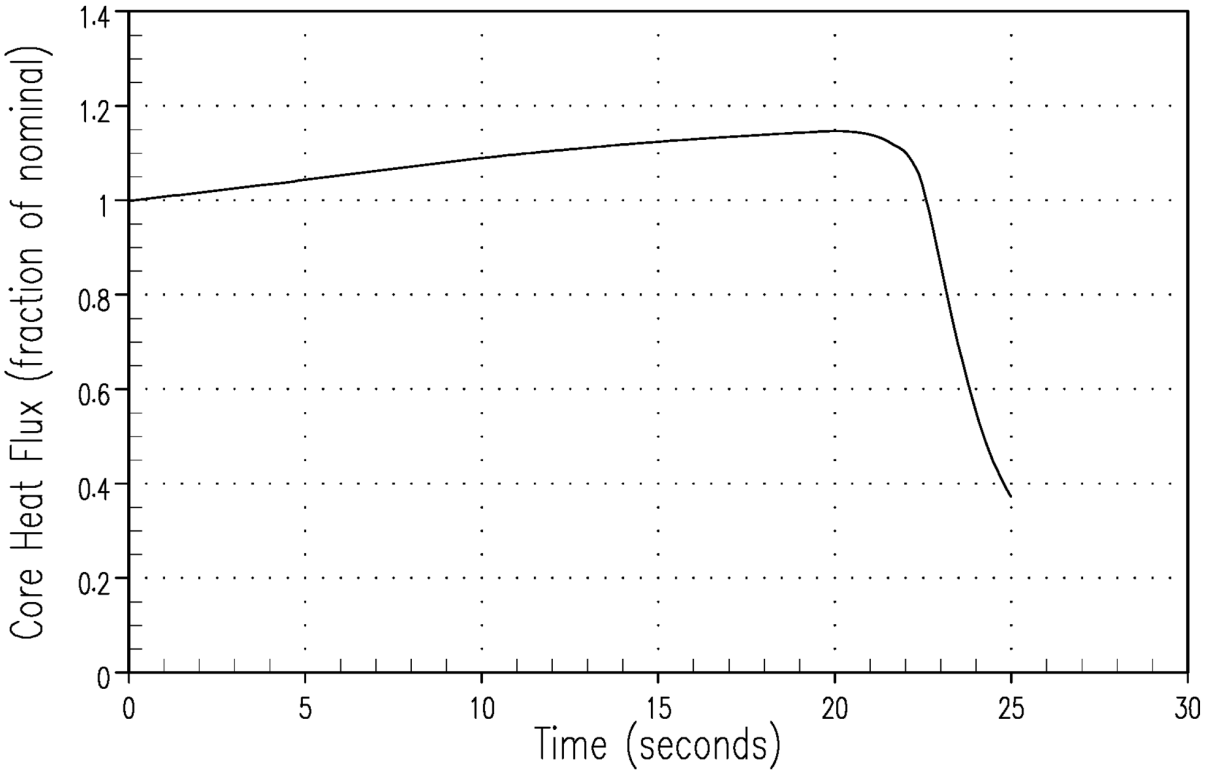

Figure 15.4.2-8
Core Heat Flux Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)

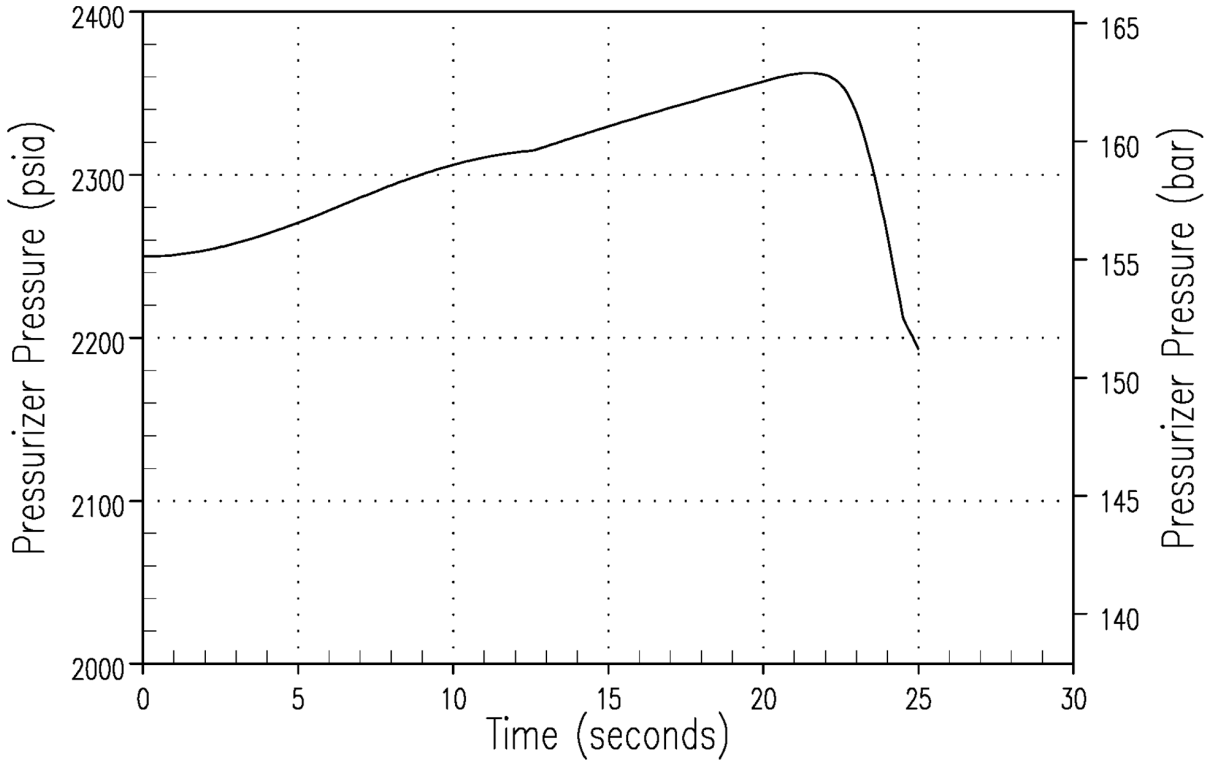

Figure 15.4.2-9
Pressurizer Pressure Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)

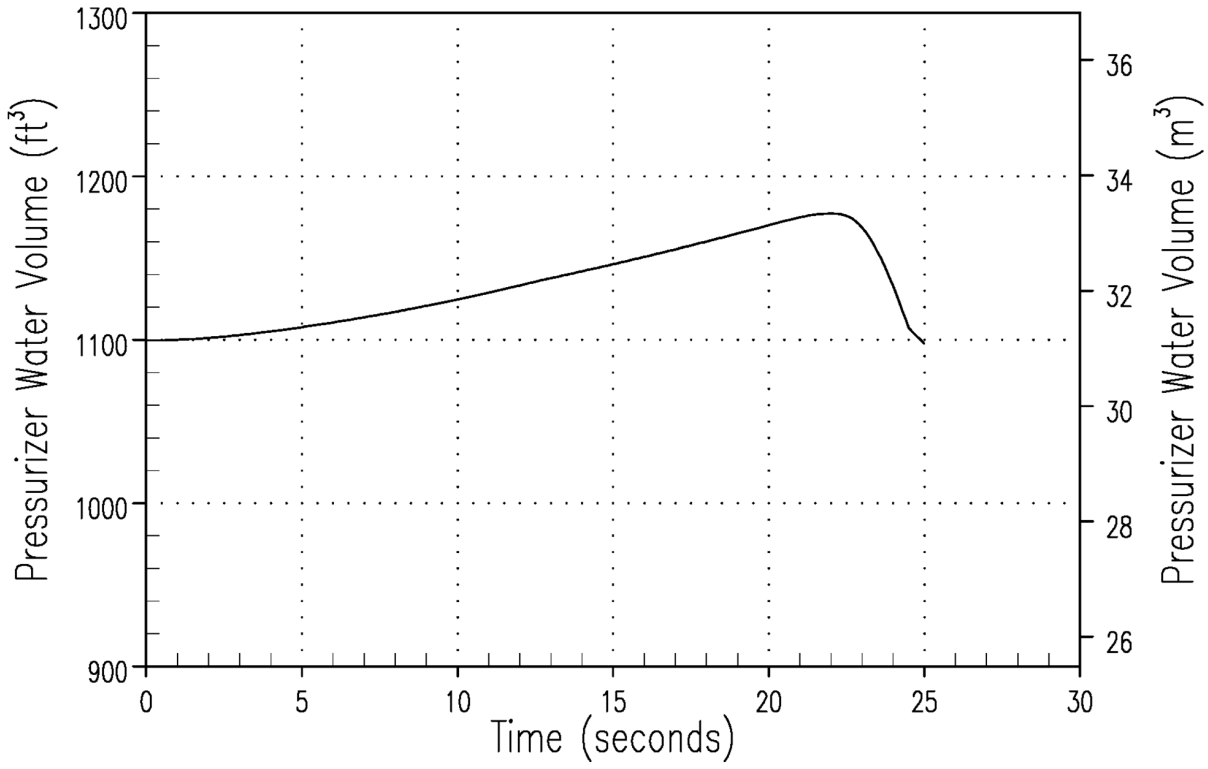

Figure 15.4.2-10
Pressurizer Water Volume Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)

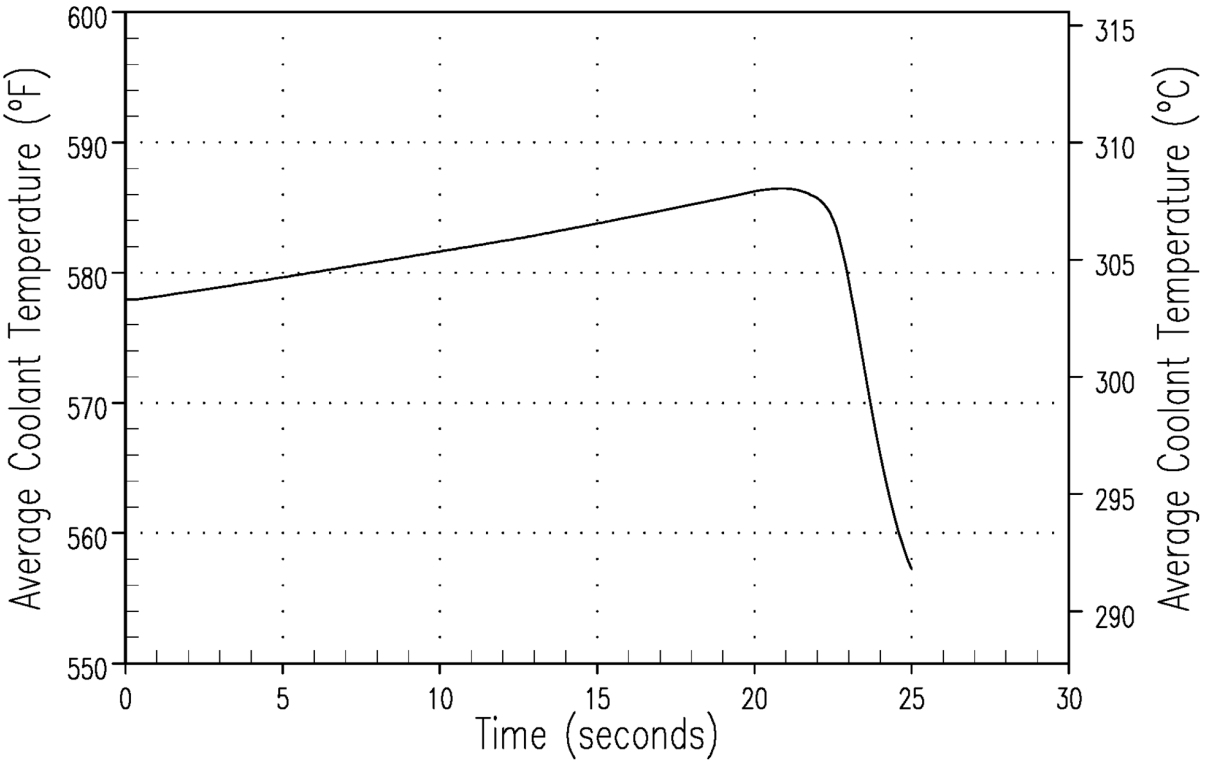

Figure 15.4.2-11
Core Coolant Average Temperature Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (34 pcm/s)

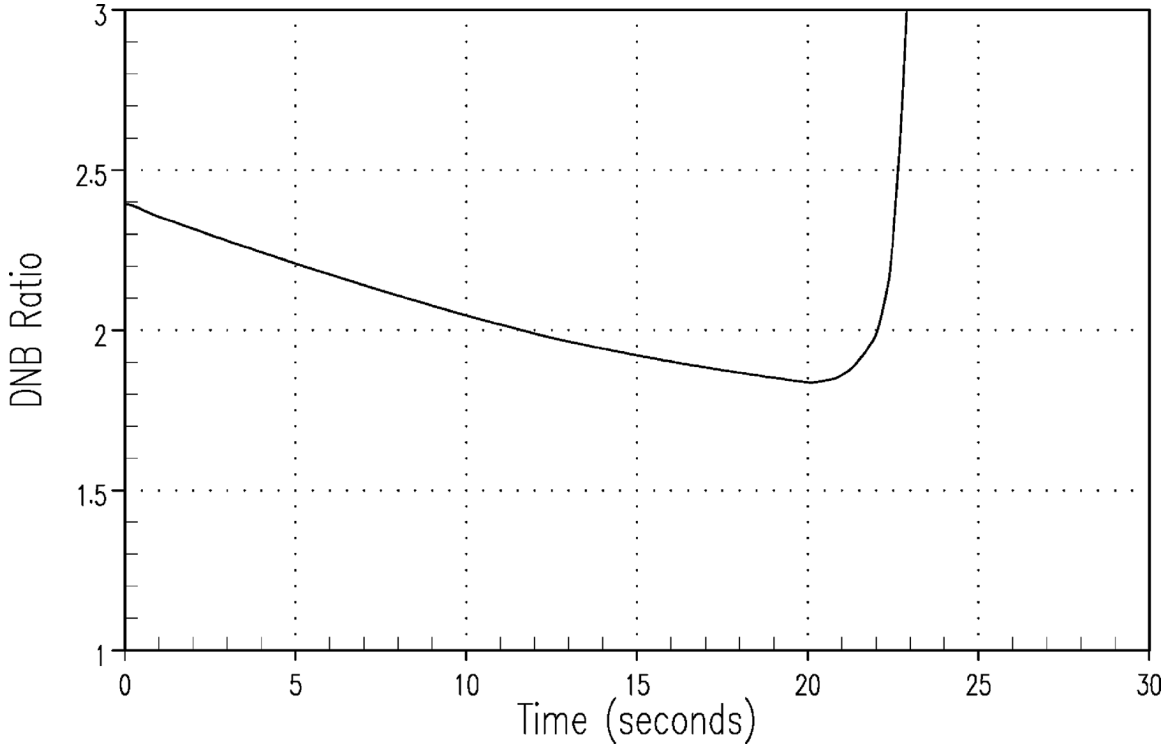

Figure 15.4.2-12
DNBR Transient for an
Uncontrolled RCCA Bank Withdrawal from Full Power
With Maximum Reactivity Feedback (34 pcm/s)

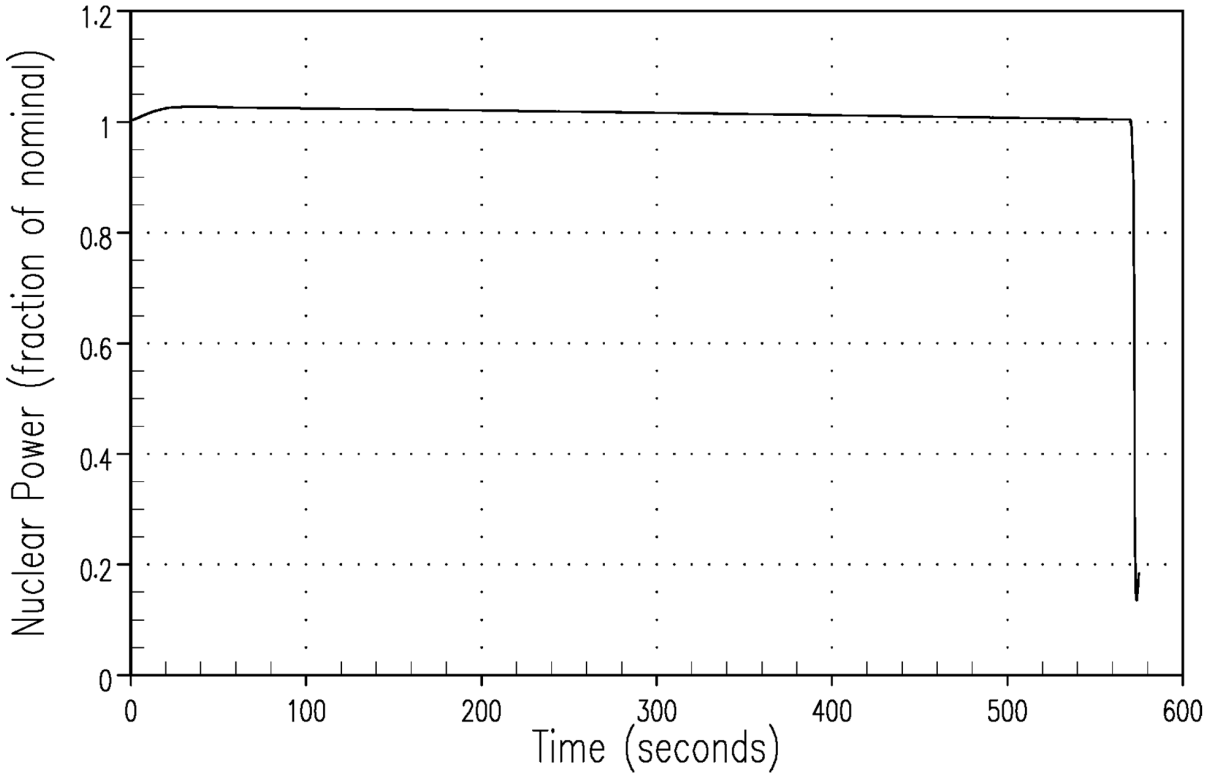

Figure 15.4.2-13
Nuclear Power Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)

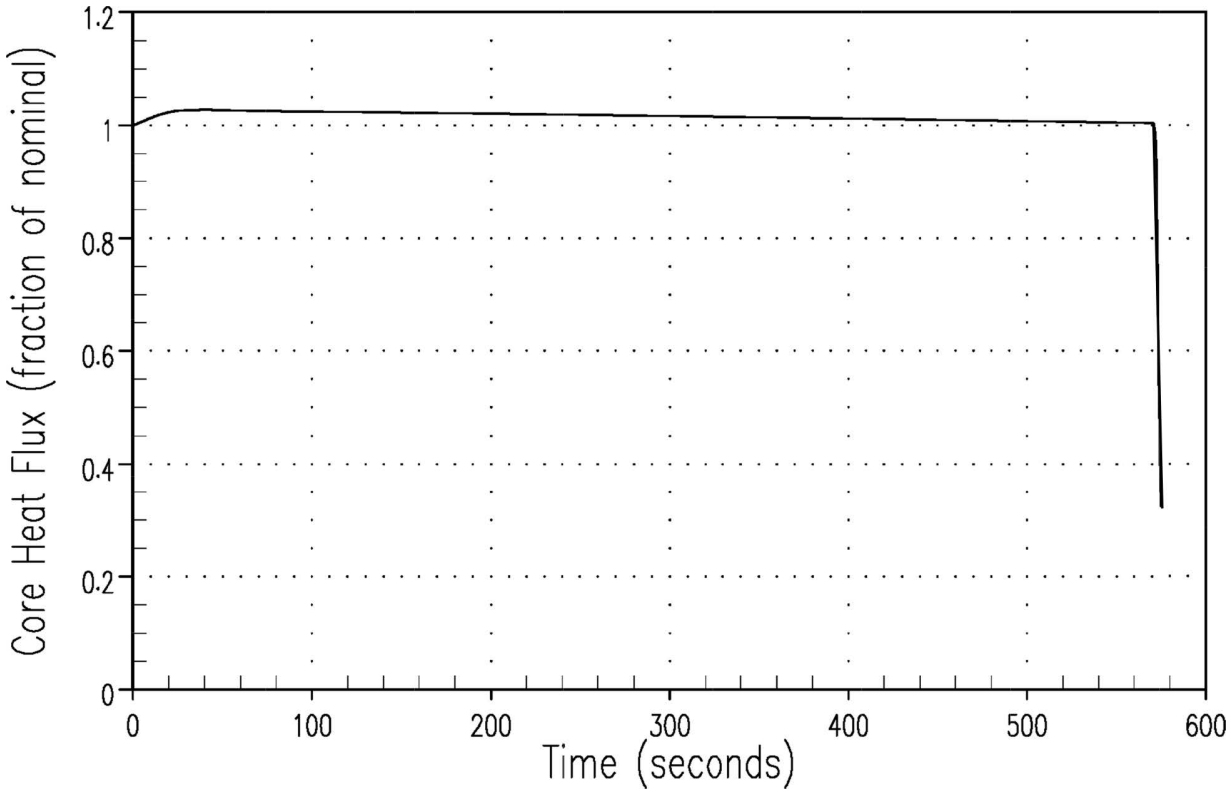

Figure 15.4.2-14
Core Heat Flux Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)

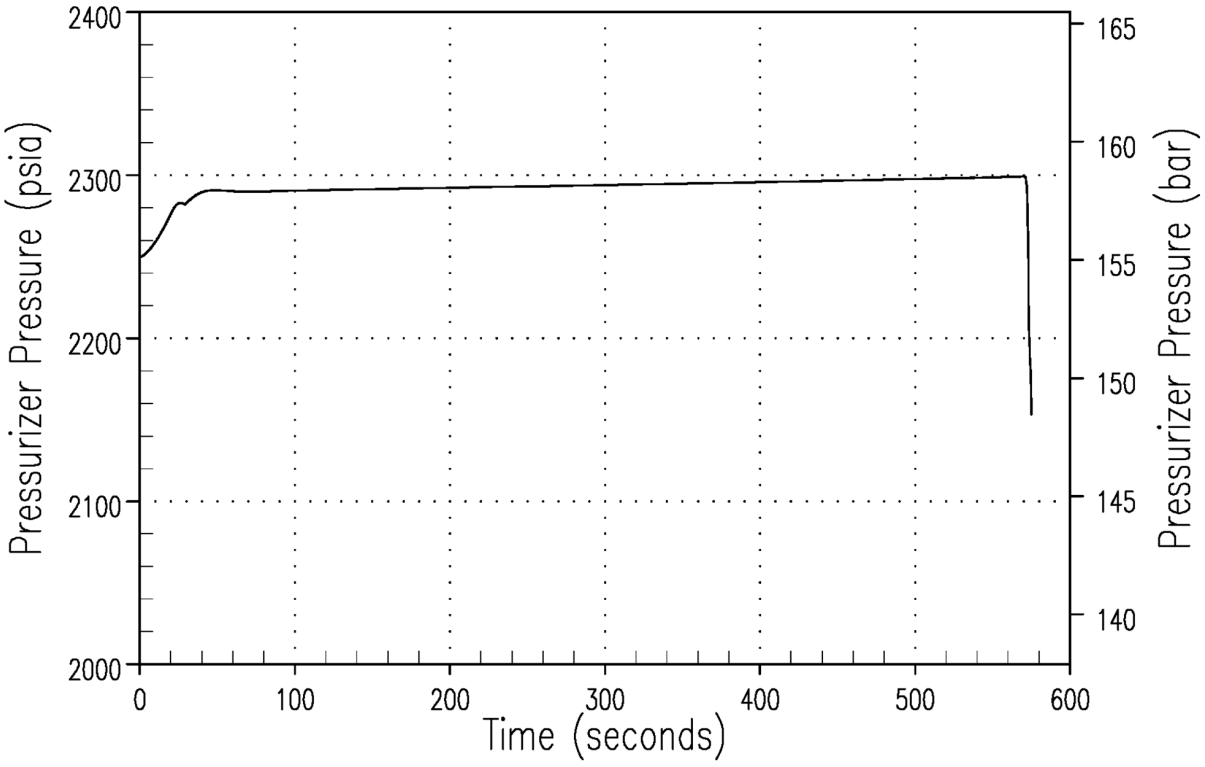

Figure 15.4.2-15
Pressurizer Pressure Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)

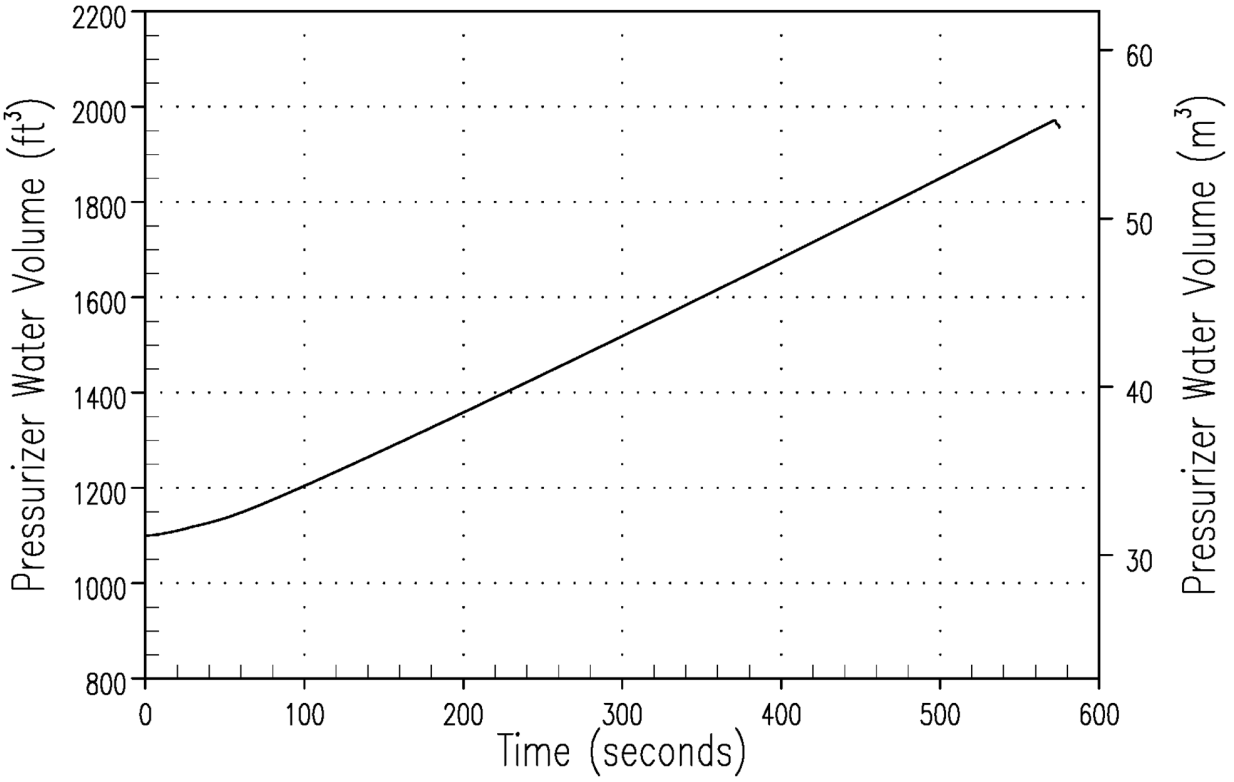

Figure 15.4.2-16
Pressurizer Water Volume Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)

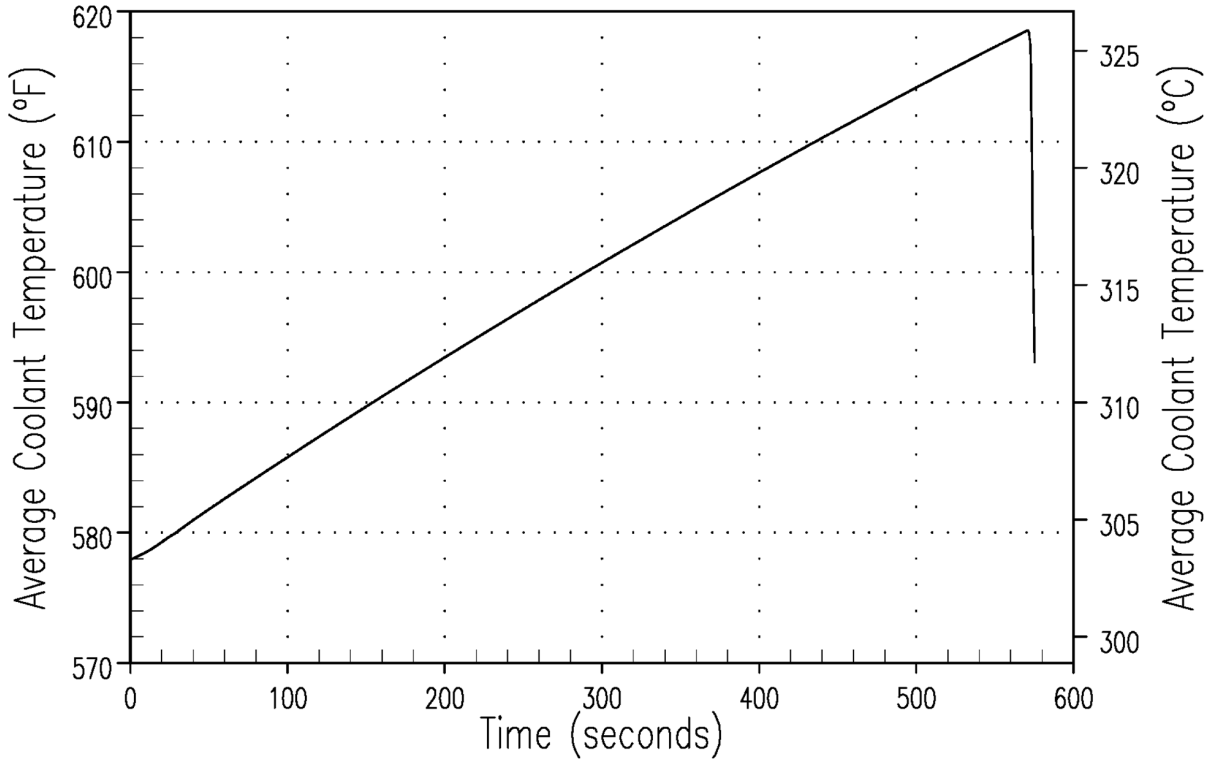

Figure 15.4.2-17
Core Coolant Average Temperature Transient for an Uncontrolled RCCA Bank Withdrawal from Full Power With Maximum Reactivity Feedback (5 pcm/s)

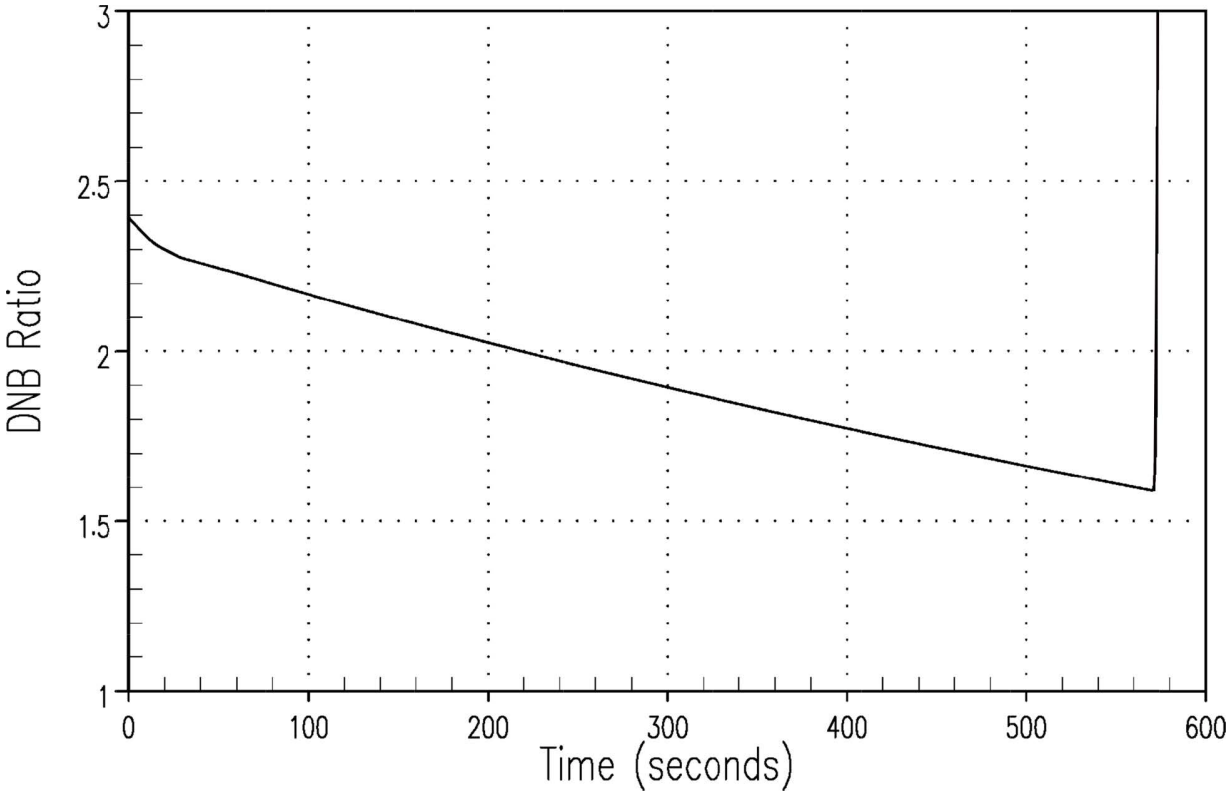

Figure 15.4.2-18
DNBR Transient for an
Uncontrolled RCCA Bank Withdrawal from Full Power
With Maximum Reactivity Feedback (5 pcm/s)

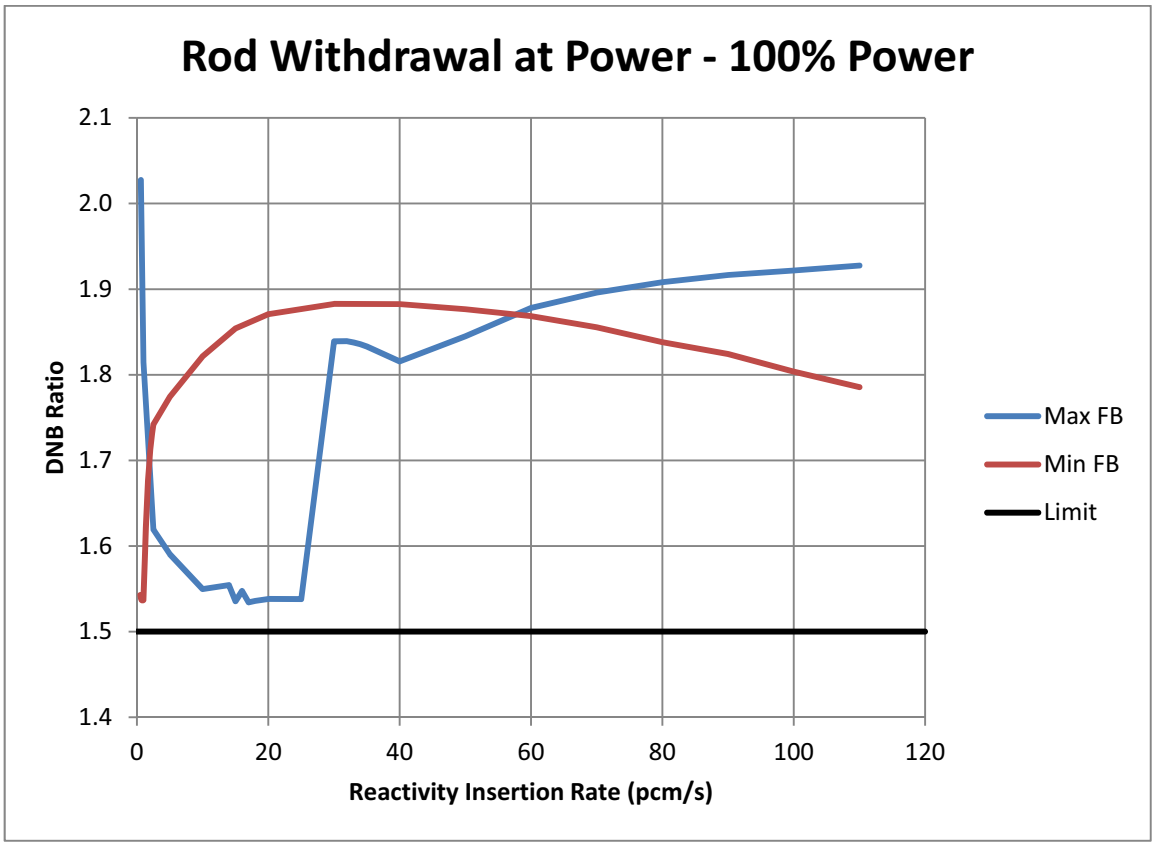

Figure 15.4.2-19
Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 100-percent Power

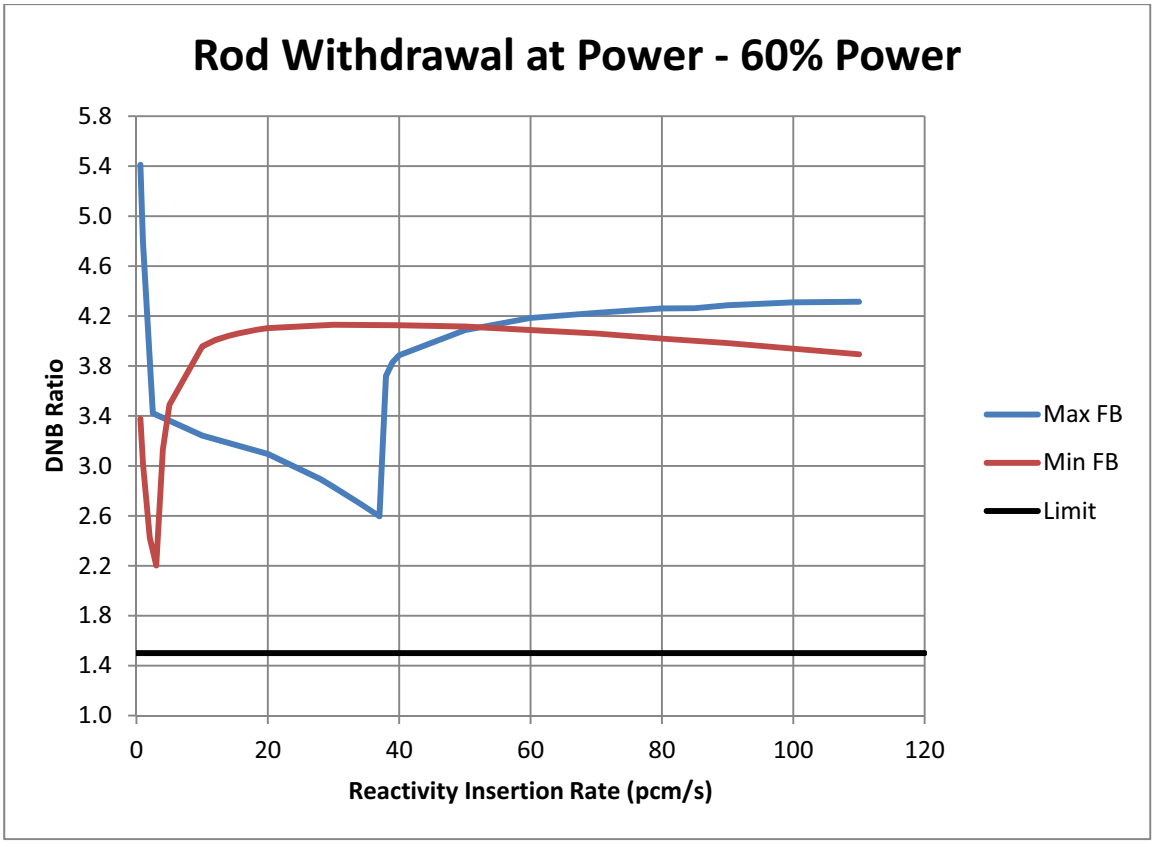

Figure 15.4.2-20
Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 60-percent Power

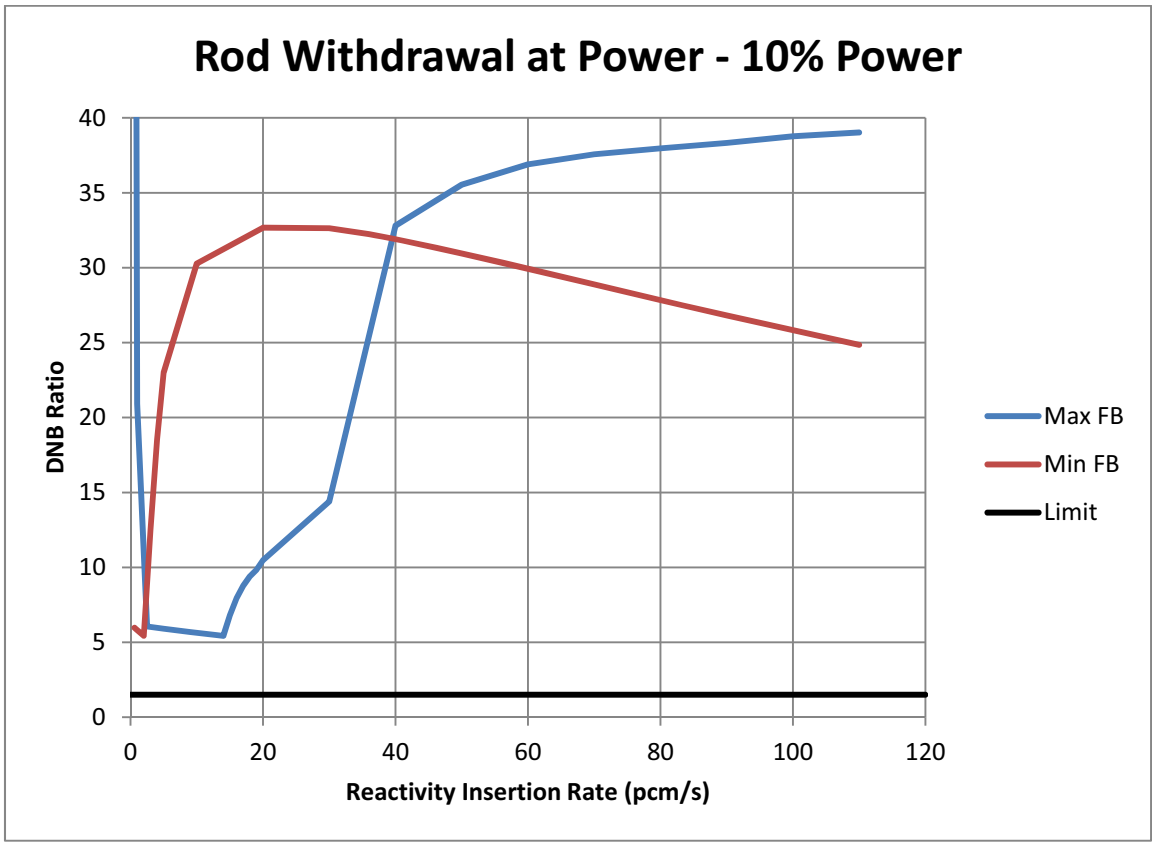

Figure 15.4.2-21
Minimum DNBR Versus Reactivity Insertion Rate for Rod Withdrawal at 10-percent Power

Figures 15.4.2-22–15.4.2-23 Not Used

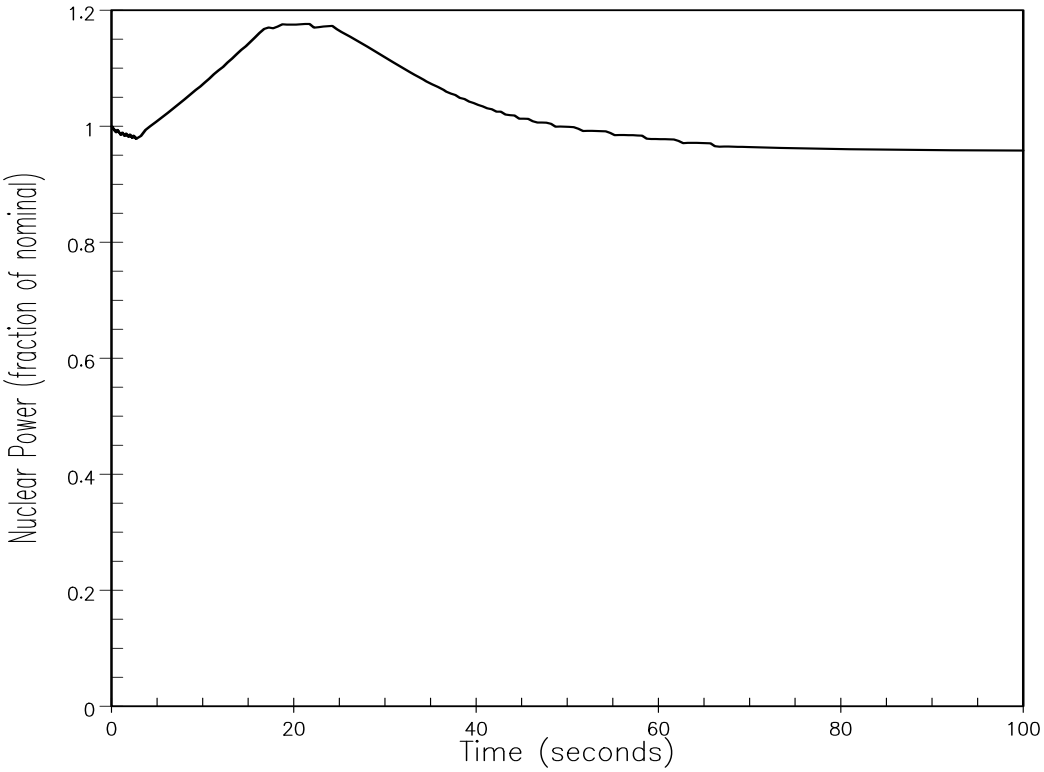

Figure 15.4.3-1
Nuclear Power Transient for Dropped RCCA

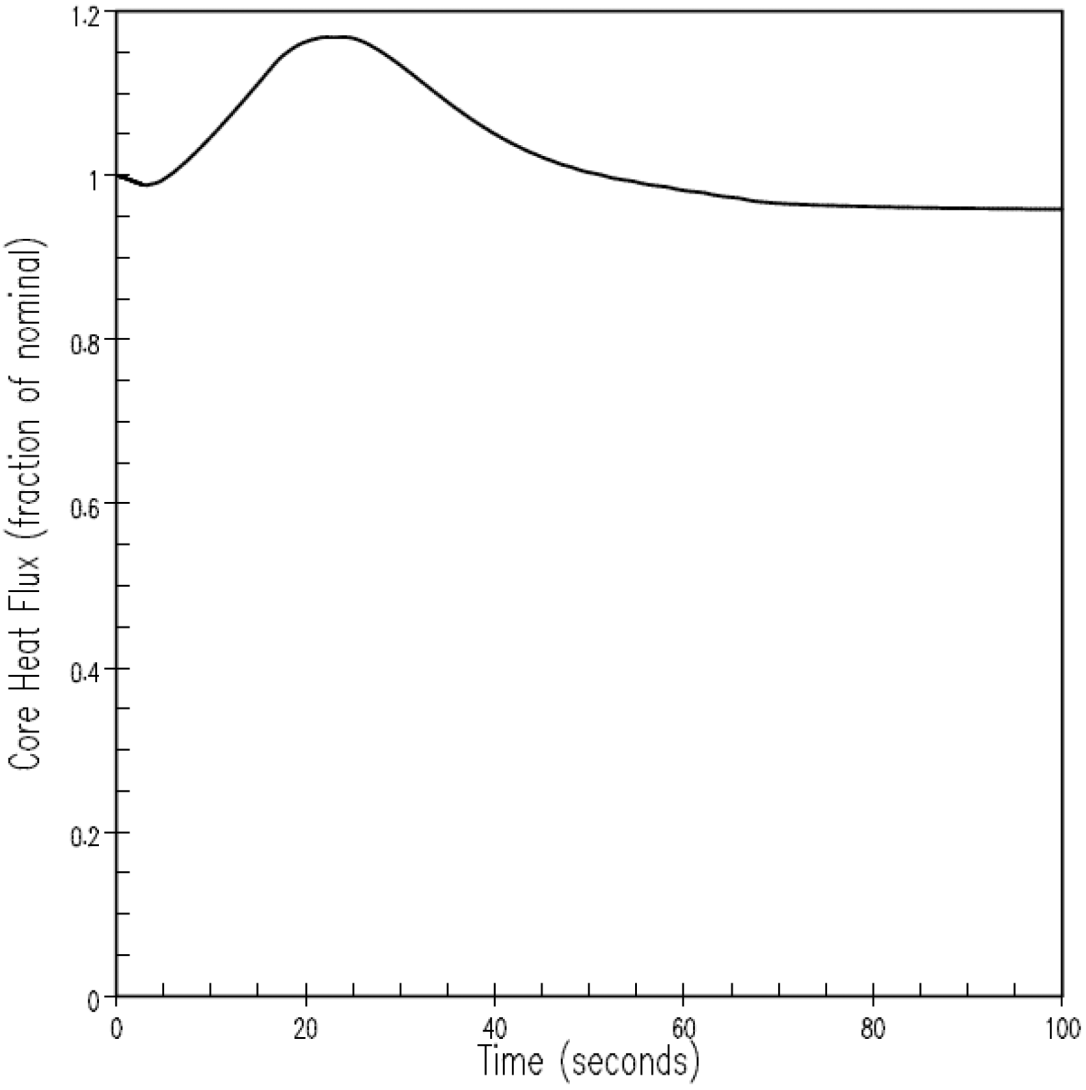

Figure 15.4.3-2
Core Heat Flux Transient for Dropped RCCA

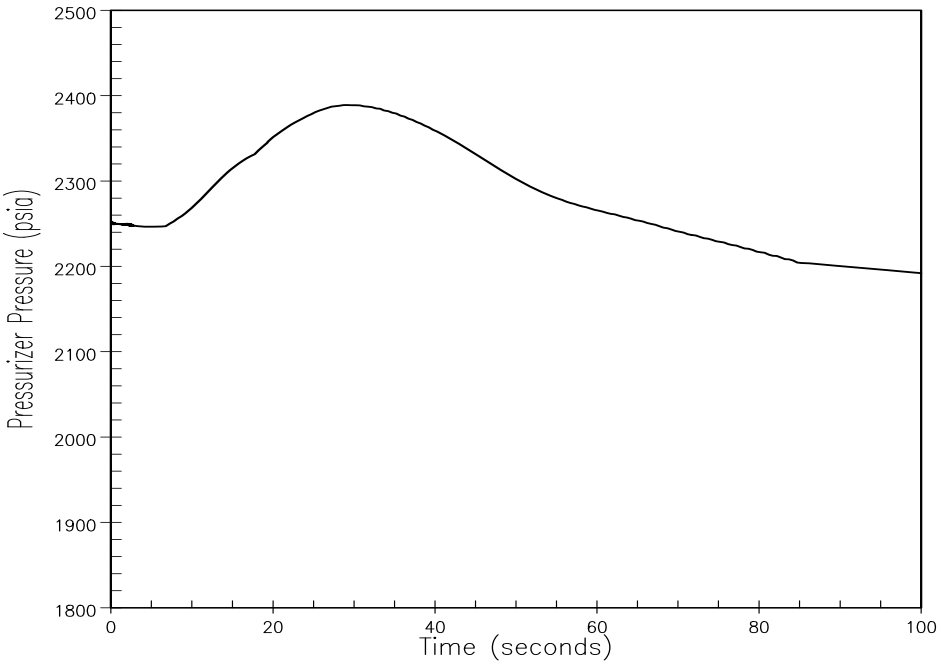

Figure 15.4.3-3
Pressurizer Pressure Transient for Dropped RCCA

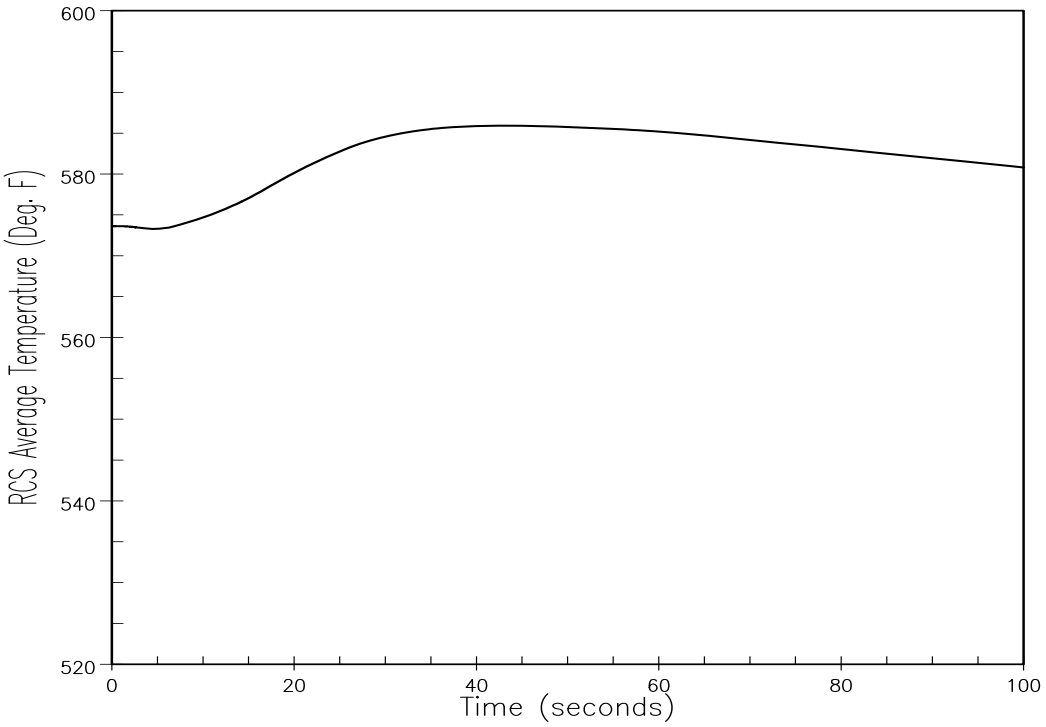

Figure 15.4.3-4
RCS Average Temperature Transient for Dropped RCCA

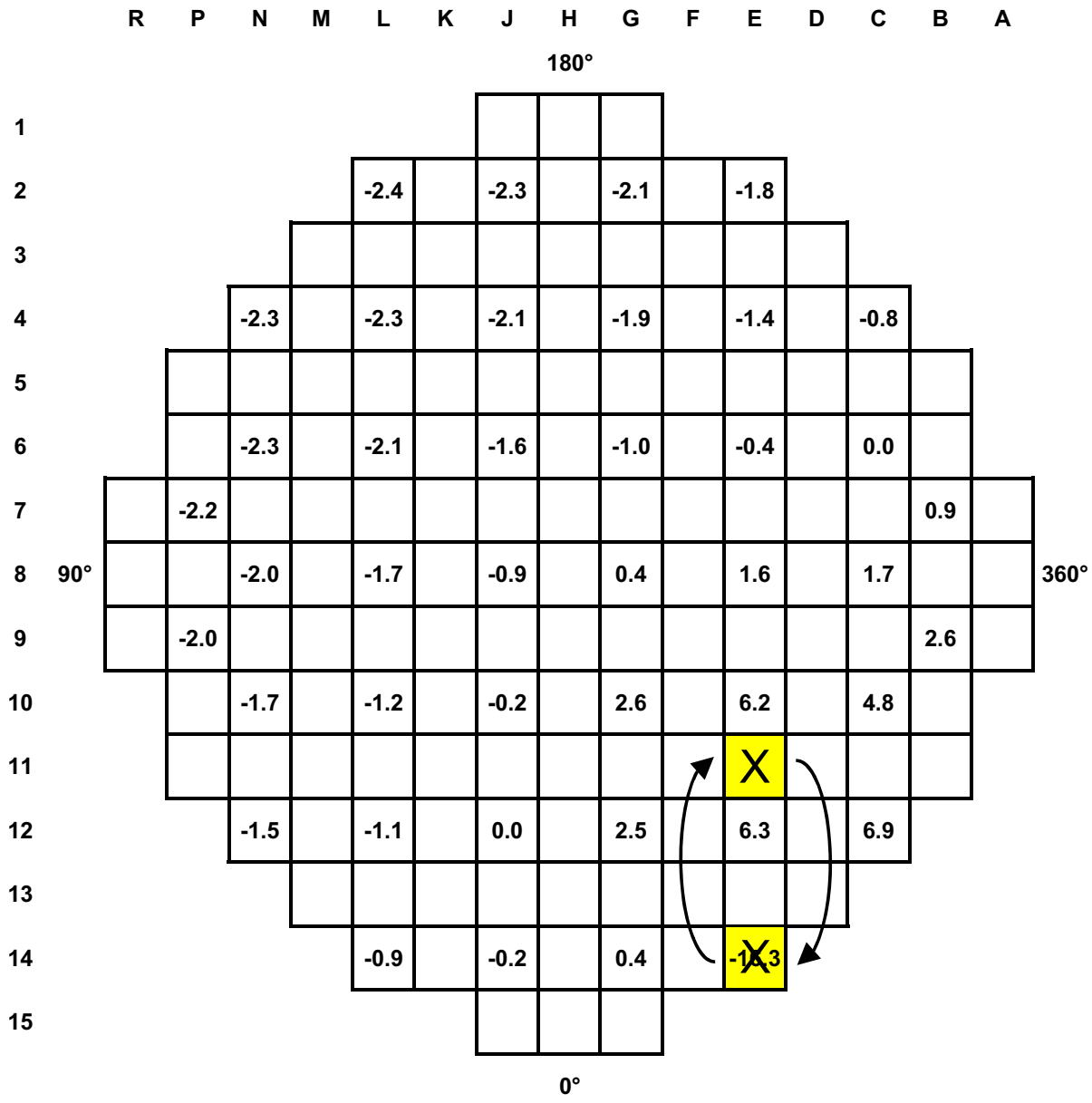

Figure 15.4.7-1
Representative Percent Change in Local Assembly Average Power for Interchange Between Region 1 and Region 3 Assembly

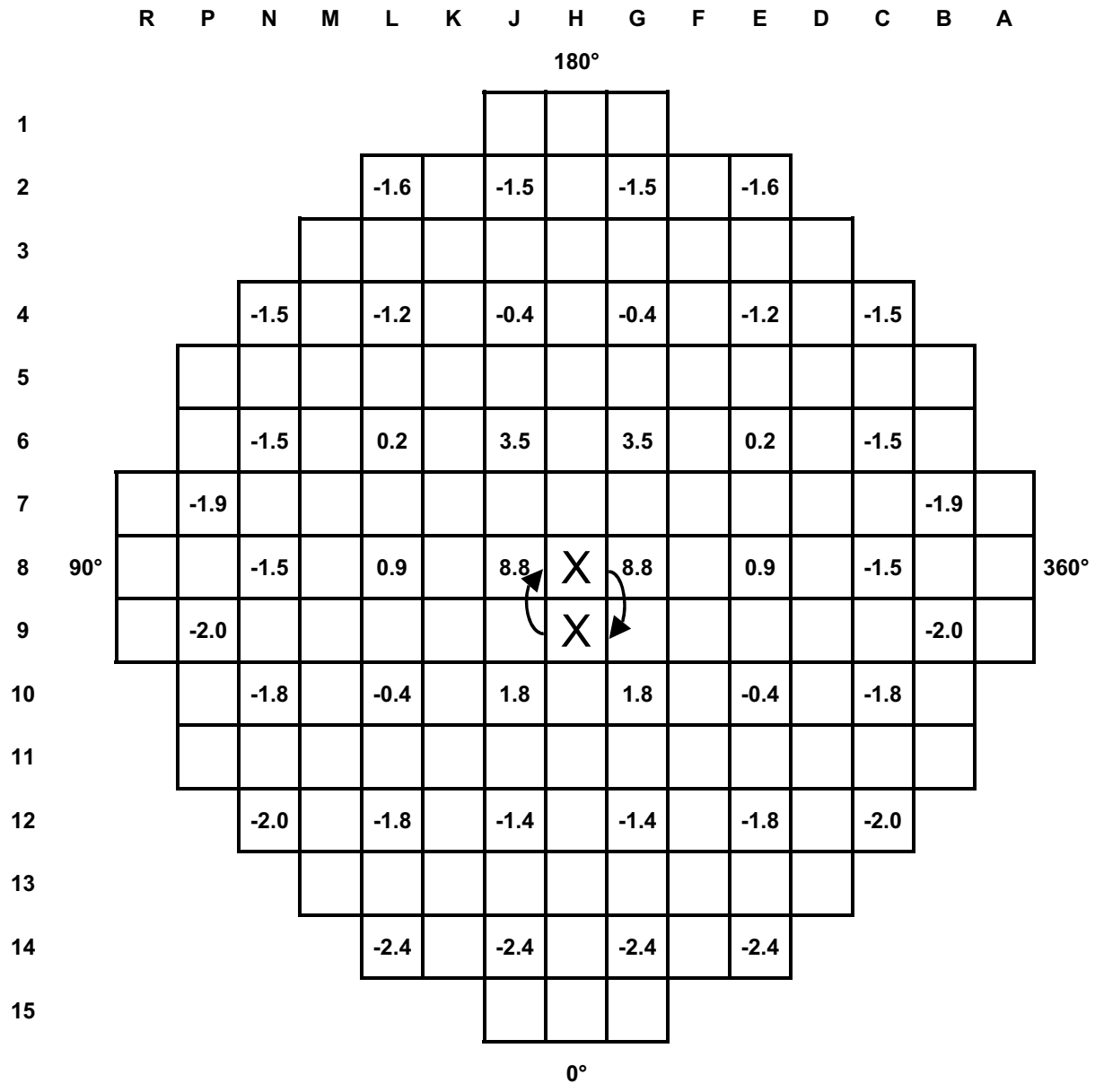

Figure 15.4.7-2
Representative Percent Change in Local Assembly Average Power for Interchange Between Region 1 and Region 2 Assembly with the BP Rods Transferred to Region 1 Assembly

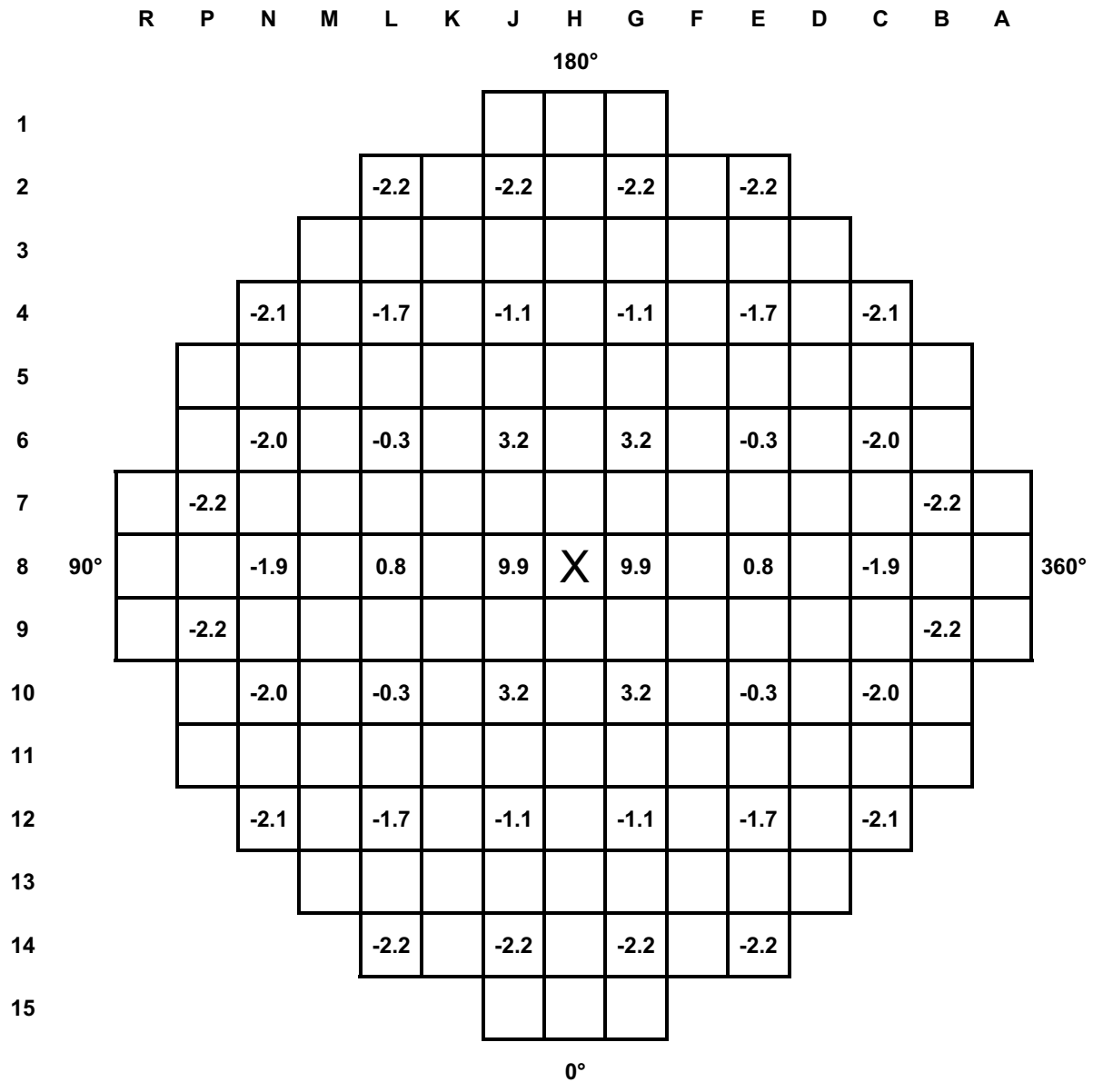

Figure 15.4.7-3
Representative Percent Change in Local Assembly Average Power for Enrichment Error (Region 2 Assembly Loaded into Core Central Position)

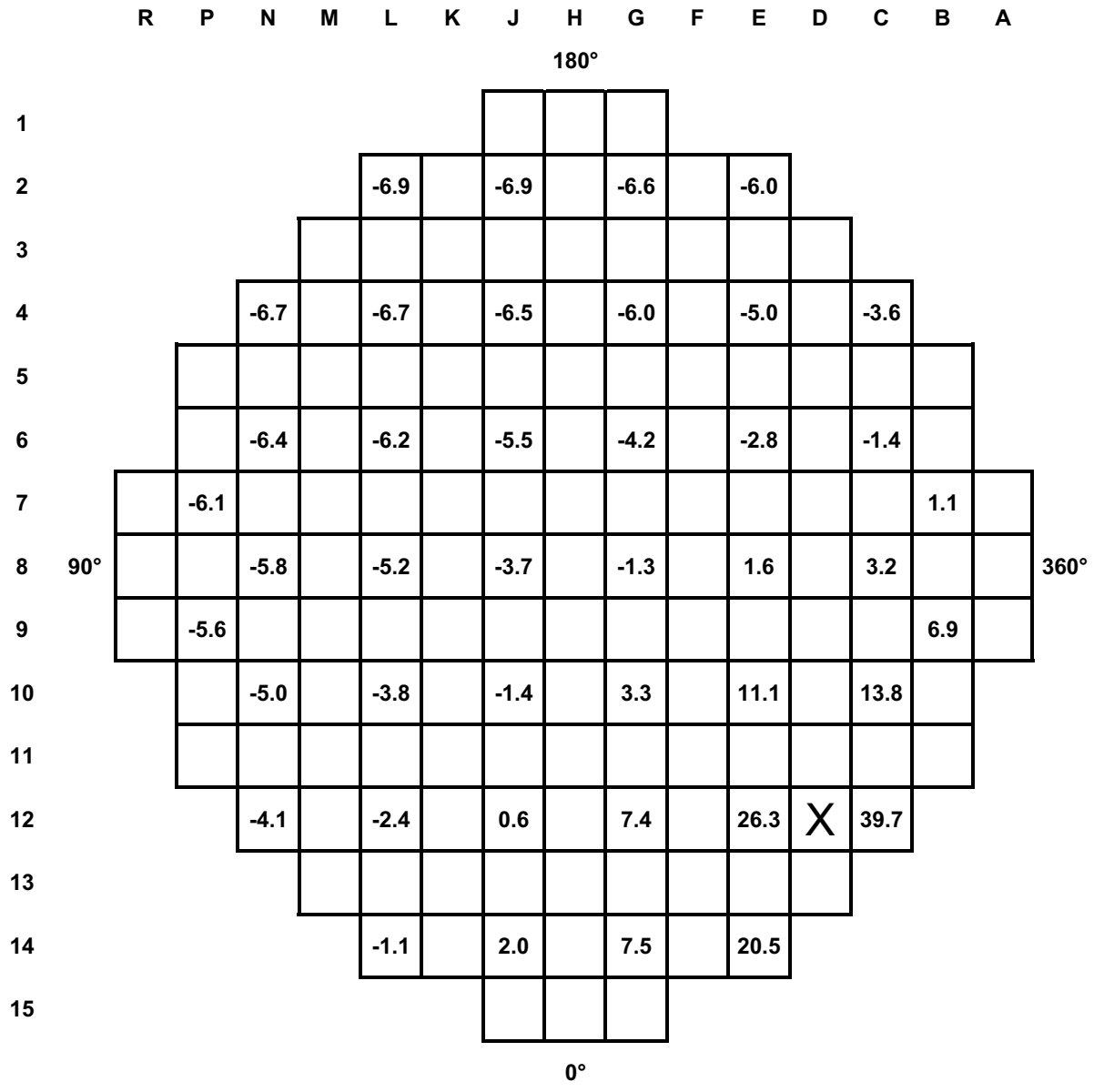

Figure 15.4.7-4
Representative Percent Change in Local Assembly Average Power for Loading Region 2 Assembly into Region 1 Position Near Core Periphery

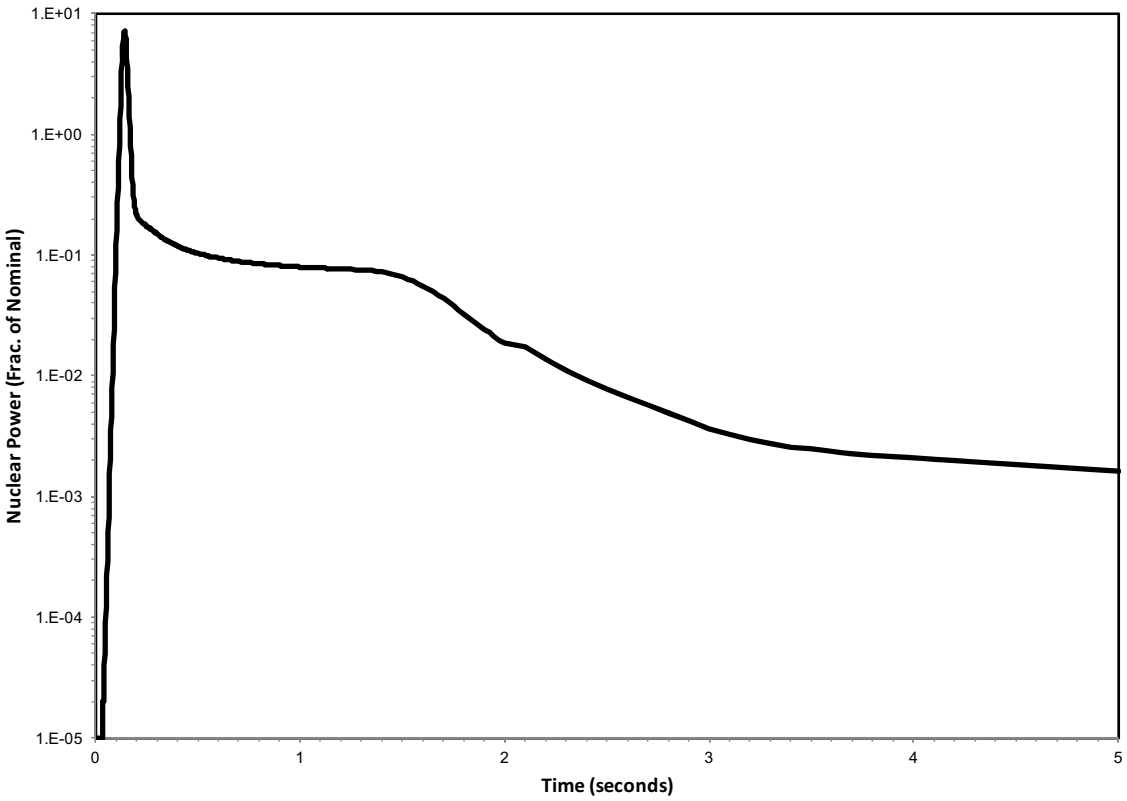

Figure 15.4.8-1
Nuclear Power Transient Versus Time
for the PCMI Rod Ejection Accident

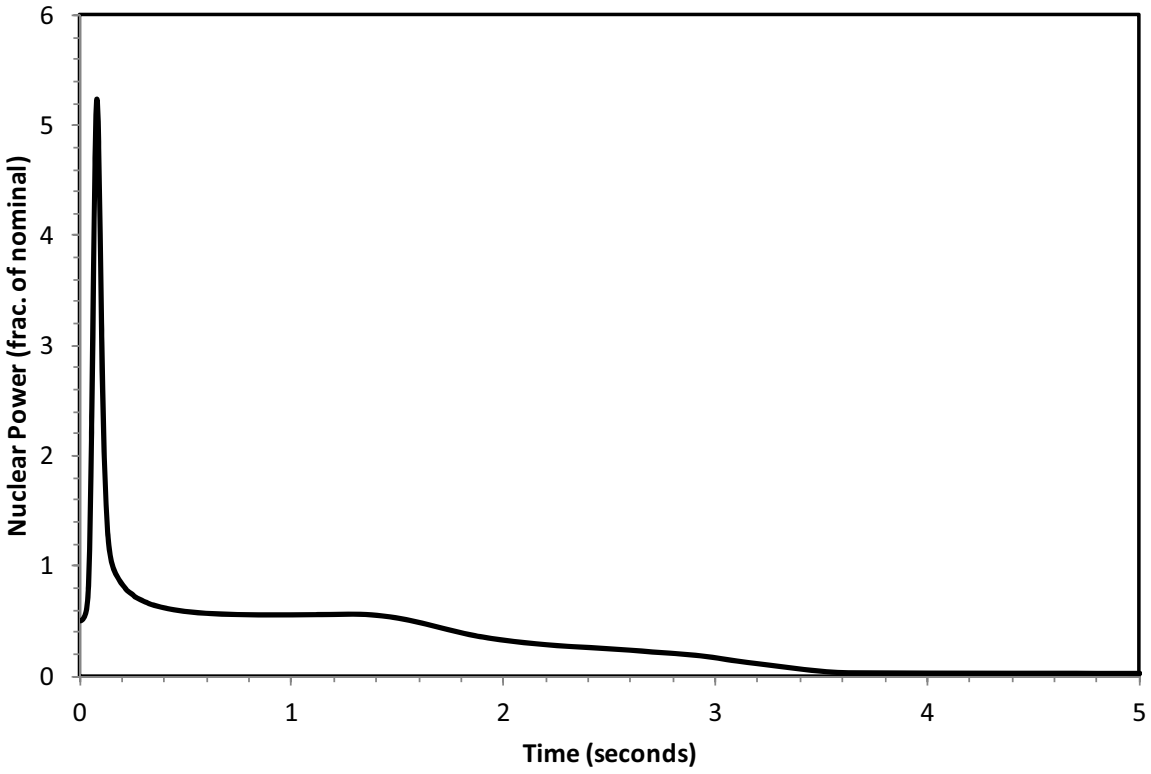

Figure 15.4.8-2
Nuclear Power Transient Versus Time
for the High Clad Temperature Rod Ejection Accident

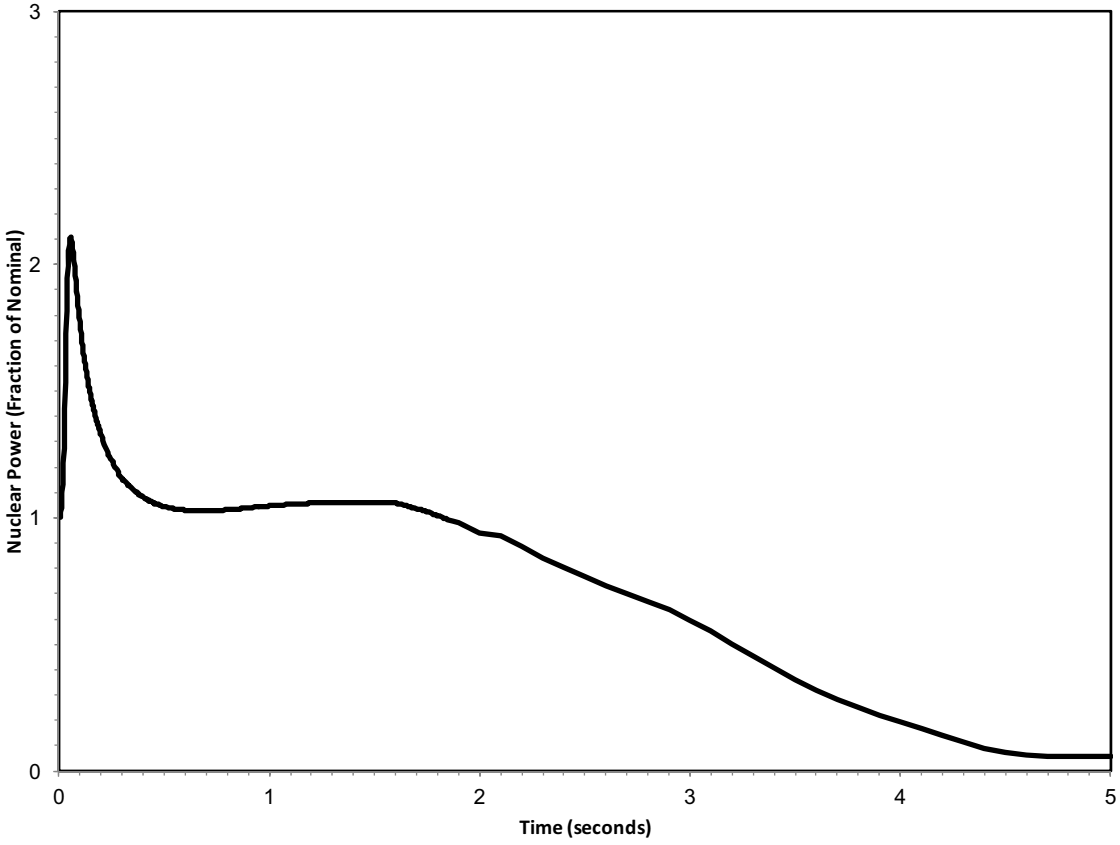

Figure 15.4.8-3
Nuclear Power Transient Versus Time
for the Peak Enthalpy and Fuel Centerline Temperature Rod Ejection Accident

Figure 15.4.8-4 Not Used

15.5 Increase in Reactor Coolant Inventory

This section presents a discussion and analysis of the following events:

- Inadvertent operation of the core makeup tanks during power operation
- Chemical and volume control system malfunction that increases reactor coolant inventory

These Condition II events cause an increase in reactor coolant inventory.

15.5.1 Inadvertent Operation of the Core Makeup Tanks During Power Operation

15.5.1.1 Identification of the Causes and Accident Description

Spurious core makeup tank operation at power could be caused by an operator error, a false electrical actuation signal, or a valve malfunction. A spurious signal may originate from any of the safeguards (“S”) actuation channels as described in Section 7.3. The AP1000 protection logic is such that a single failure cannot actuate both core makeup tanks without also actuating the passive residual heat removal (PRHR) heat exchanger. A scenario such as this is the spurious “S” signal event. However, if one core makeup tank is inadvertently actuated by a single failure, the event may progress with the plant at power until a reactor trip is reached. For the plant under automatic rod control, a reactor trip on high-3 pressurizer water level reactor trip is expected to occur followed by the PRHR actuation and eventually by an “S” signal, which would then actuate the second core makeup tank. When a consequential loss of offsite power is assumed, this event is more limiting than the spurious “S” signal event.

The inadvertent opening of the core makeup tank discharge valves, due to operator error or valve failure, results in significant core makeup tank injection flow leading to a boration similar to that resulting from a chemical and volume control system malfunction event. If the automatic rod control system is operable, it will begin to withdraw rods from the core to counteract the reactivity effects of the boration. As a result, the core makeup tank will continue injection and slowly increase the pressurizer level until the high-2 pressurizer level setpoint is reached and continues until the high-3 pressurizer level reactor trip setpoint is reached. In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power is assumed to occur as a consequence of reactor trip. The primary effect of this assumption is the coastdown of the reactor coolant pumps. The core makeup tank injection will increase as the steam generator outlet temperature increases resulting in a lower density in the CMT balance line. This event will then proceed similar to a spurious “S” signal or chemical and volume control system malfunction event. However, this event is more limiting primarily due to the higher pressurizer level at the time of reactor trip and to the significant heat up of the injected fluid during the pre-trip phase of the accident. Thus, the inadvertent core makeup tank actuation event with a consequential loss of offsite power is analyzed here.

Upon receipt of the high-3 pressurizer level reactor trip signal, the reactor is tripped; then the turbine is tripped after a 5-second delay and a consequential loss of offsite power is assumed 3 seconds after turbine trip. The basis for the 3-second delay is described in Subsection 15.0.14. The high-3 pressurizer level signal also actuates the PRHR heat exchanger and blocks the pressurizer heaters, but a 15-second timer delay prevents unnecessary actuation of the PRHR heat exchanger if offsite power is maintained. Because of the reactor trip the pressurizer level drops and the high-3 signal is cleared before the timer delay is completed, and thus the PRHR heat exchanger is not actuated.

Following reactor trip, the reactor power drops and the average reactor coolant system temperature decreases with subsequent coolant shrinkage. However, due to the assumed loss of offsite power, the reactor coolant cold leg temperature in the loop without PRHR increases and the core makeup tank begins injecting cold water into the reactor coolant system at a much higher rate. The primary coolant system shrinkage is counteracted by the core makeup tank injection, and the pressurizer

water volume increases because of the heatup of the cold injected fluid by the decay heat. The high-3 pressurizer level setpoint is once again reached, and after the 15-second timer delay, the signal is sent to actuate the PRHR heat exchanger and block the pressurizer heaters.

The PRHR heat exchanger extracts heat from the reactor coolant system leading to an "S" signal on a Low-2 T_{cold} signal. The PRHR heat exchanger may inject asymmetrically into the steam generator outlet plenum such that a higher percentage of the PRHR flow goes to one of the two cold legs coming from the steam generator on the PRHR loop. To account for this, the analysis conservatively assumes that the Low-2 T_{cold} setpoint is reached coincident with PRHR heat exchanger actuation. This actuates the second core makeup tank sooner in the transient, which is more limiting with respect to filling the pressurizer.

Both core makeup tanks inject into the reactor coolant system and the pressurizer level continues to increase until the operators act to end the pressurizer level increase transient. The operators are assumed to be alerted to a potential filling event on the high-2 pressurizer level signal, which occurs well before the reactor trip on the first of two high-3 pressurizer level signals. The operator action assumed in the analysis is to open the reactor vessel head vent following receipt of the second high-3 pressurizer level signal; this action occurs at least 30 minutes (45 minutes is conservatively assumed in the analysis) after the operator has been alerted by the high-2 pressurizer level signal. When the head vent is opened, the pressurizer level increase slows and ultimately the level begins to decrease.

This event is a Condition II incident (a fault of moderate frequency) as defined in Subsection 15.0.1.

15.5.1.2 Analysis of Effects and Consequences

The plant response to an inadvertent core makeup tank actuation is analyzed by using a modified version of the computer program LOFTRAN (Reference 1) described in Subsection 15.0.11.2. The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, steam generator safety valves, PRHR heat exchanger, and core makeup tanks. The program computes pertinent plant variables, including temperatures, pressures, and power level.

Reactor power and average temperature drop immediately following the trip, and the operating conditions never approach the core limits. The analysis demonstrates that no reactor coolant system overpressurization occurs.

Core makeup tank and PRHR system performance is conservatively simulated. Core makeup tank enthalpies have been maximized. This is conservative because it minimizes the cooling provided by the core makeup tanks as flow recirculates and thereby increases the peak pressurizer water volume during the transient. The core makeup tank injection and balance lines pressure drops are minimized. This maximizes the core makeup tank flow injected in the primary system. During this event, the core makeup tanks remain filled with water. The volume of injection flow leaving the core makeup tanks is offset by an equal volume of recirculation flow that enters the core makeup tanks via the balance lines. PRHR heat transfer capability has been minimized.

Plant characteristics and initial conditions are further discussed in Subsection 15.0.3.

- Initial operating conditions

  The initial reactor power is assumed to be 101 percent of nominal. The initial pressurizer pressure is assumed to be 50 psi below nominal. The initial reactor coolant system average temperature is assumed to be 8°F below nominal.

- Control systems

  The pressurizer spray, the pressurizer heaters, and the automatic rod control system are conservatively assumed to operate. The pressurizer heaters are automatically blocked on a high-3 pressurizer level signal following a 15-second timer delay, but add heat to the system during the initial part of the transient. Other control systems are conservatively not assumed to function during the transient.

- Moderator and Doppler coefficients of reactivity

  A least-negative moderator temperature coefficient, a low (absolute value) Doppler power coefficient, and a minimum boron worth are assumed. With these minimum feedback parameters and the operability of the pressurizer spray system and automatic rod control system assumed, the reactivity effects of the boron injection from the core makeup tanks is counteracted. As a result, the High-3 pressurizer water level signal is the first reactor trip signal generated during the transient.

- Boron injection

  The transient is initiated by an inadvertent opening of the discharge valves of one of the two core makeup tanks, resulting in the injection of 3400 ppm borated water.

- Protection and safety monitoring system actuations

  The operators are assumed to be alerted to the pressurizer level increase transient by the high-2 pressurizer level signal. Reactor trip is initiated by the first of two high-3 pressurizer level signals. The second high-3 pressurizer level signal triggers the operators to open the reactor vessel head vent; this action is at least 30 minutes after the operator has been alerted by the high-2 pressurizer level signal.

  The core decay heat is removed by the PRHR heat exchanger. The worst single failure is assumed to occur in the outlet line of the PRHR heat exchanger. One of the two parallel isolation valves is assumed to fail to open.

Plant systems and equipment available to mitigate the effect of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6.

15.5.1.3 Results

Figures 15.5.1-1 through 15.5.1-8 show the transient response to the inadvertent operation of one of the two core makeup tanks during power operation. The inadvertent opening of the core makeup tank discharge valves occurs at 10 seconds. As the core makeup tank adds inventory to the primary system, the pressurizer level begins to increase until the high-2 pressurizer level setpoint is reached (783.2 seconds) and continues until the high-3 pressurizer level reactor trip setpoint is reached at about 2,402.0 seconds. After a 2-second delay, the neutron flux starts decreasing due to the reactor trip, which is followed by turbine trip after a 5-second turbine trip delay. Following reactor trip, the reactor power drops and the average reactor coolant system temperature decreases with subsequent coolant shrinkage. Due to the assumed loss of offsite power, the reactor coolant pumps trip at about 2,412.0 seconds. The cold leg temperature increases and the core makeup tank starts injecting cold water into the reactor coolant system at a higher rate due to the increased driving head resulting from the density decrease in the balance line and due to the reduced pressure drop between the cold leg and the injection line connection on the reactor vessel following the trip of the reactor coolant pumps. The post-trip primary coolant system shrinkage is counteracted by the core makeup tank injection, and the pressurizer water volume starts to increase because of the heatup of

the cold injected fluid by the decay heat. The high-3 pressurizer level setpoint is once again reached at 2,554.8 seconds, and after a 15-second timer delay, the signal is sent to actuate the PRHR heat exchanger and block the pressurizer heaters. Following a conservative 17-second delay, the valves are assumed to open to actuate the PRHR heat exchanger at 2,586.8 seconds.

If the PRHR heat exchanger coolant asymmetrically injects into the steam generator outlet plenum, then one cold leg may reach the Low-2 T_{cold} "S" setpoint more quickly than if the flow were split evenly. To conservatively account for this effect, the Low-2 T_{cold} "S" signal is modeled to actuate simultaneously with the actuation of the PRHR heat exchanger (2,586.8 seconds). The Low-2 T_{cold} "S" signal activates the second core makeup tank, which then begins injecting additional mass into the reactor coolant system. An earlier actuation of the second core makeup tank results in a more limiting pressurizer fill transient.

As the second core makeup tank begins injecting, the pressurizer level continues to increase. The operators are assumed to be alerted by the high-2 pressurizer level signal (783.2 seconds) that a pressurizer level increase transient is underway, and it is assumed that the operators are ready to take corrective action no sooner than 30 minutes later. In this analysis, since pressurizer level continues to increase, the high-3 pressurizer level reactor trip setpoint is reached within this time. The operator action assumed in this case is to open the reactor vessel head vent to preclude overfill following receipt of the second high-3 pressurizer level signal (3,483.2 seconds); this action is at least 30 minutes (45 minutes is conservatively assumed in the analysis) after the operator has been alerted by the high-2 pressurizer level signal.

The safety related reactor vessel head vent is opened by the operators and the pressurizer water level increase slows and eventually the level begins to decrease. This demonstrates that the capacity of the reactor vessel head vent is sufficient to preclude pressurizer overfill as a result of an inadvertent actuation of a core makeup tank.

During the event, the departure from nucleate boiling ratio (DNBR) would not drop significantly below the initial value due to the addition of highly borated water from the core makeup tanks to the reactor coolant system. At the time of reactor trip core power and heat flux drop rapidly, which would cause the DNBR to increase well above the design limit value defined in Section 4.4.

The calculated sequence of events is shown in Table 15.5-1.

As noted above, the limiting case presented here models explicit operator action 45 minutes after receipt of the high-2 pressurizer level signal. For pressurizer level increase events, the operator would take action to reduce the increase in coolant inventory. As the pressurizer water level would increase above the High-2 pressurizer water level that normally isolates chemical and volume control system makeup, the normal letdown line could be placed into service to reduce the increase in coolant inventory. If letdown could not be placed into service, the operator could use the safety related reactor vessel head vent valves to reduce the increase in coolant inventory (this is explicitly modeled in the case presented here). For these events, there is sufficient time for the operator to mitigate the consequences by following the procedures outlined in the Emergency Response Guidelines AFR-I.1.

15.5.1.4 Conclusions

The results of this analysis show that inadvertent operation of the core makeup tanks during power operation does not adversely affect the core, the reactor coolant system, or the steam system. Water is not relieved from the pressurizer safety valves. DNBR always remains above the design limit values, and reactor coolant system and steam generator pressures remain below 110 percent of their design values.

15.5.2 Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory

15.5.2.1 Identification of Causes and Accident Description

An increase of reactor coolant inventory from the addition of cold unborated water to the reactor coolant system, is analyzed in Subsection 15.4.6.

In this Subsection 15.5.2, the increase of reactor coolant system inventory due to the addition of borated water is analyzed.

The increase of reactor coolant system coolant inventory may be due to the spurious operation of one or both of the chemical and volume control system pumps or by the closure of the letdown path. If the chemical and volume control system is injecting highly borated water into the reactor coolant system, the reactor experiences a negative reactivity excursion due to the injected boron, causing a decrease in reactor power and subsequent coolant shrinkage. The load decreases due to the effect of reduced steam pressure after the turbine control valve fully opens.

At high chemical and volume control system boron concentration, low reactivity feedback conditions, and reactor in manual rod control, an “S” signal will be generated by either the Low-2 T_{cold} or Low-2 steam line pressure setpoints before the chemical and volume control system can inject a significant amount of water into the reactor coolant system. In this case, the chemical and volume control system malfunction event proceeds similar to, and is only slightly more limiting than, a spurious “S” signal event. If automatic rod control is modeled and the pressurizer spray functions properly to prevent a High-2 pressure reactor trip signal, no “S” signals are generated and this specific event is terminated by automatic isolation of the chemical and volume control system on the safety-related high-2 pressurizer level setpoint.

Under typical operating conditions for the AP1000 plant, the boron concentration of the injected chemical and volume control system water is equal to that of the reactor coolant system. If the chemical and volume control system is functioning in this manner and the pressurizer spray system functions properly to prevent a High-2 pressure reactor trip signal, no “S” signals are generated and this specific event is also terminated by automatic isolation of the chemical and volume control system on the safety-related high-2 pressurizer level setpoint.

While these scenarios are the most probable outcomes of a chemical and volume control system malfunction, several combinations of boron concentration, feedback conditions, and plant system interactions have been identified that could result in more limiting scenarios with respect to pressurizer overfill. The key factors that make this event more limiting than a spurious “S” signal event are that the reactor coolant system is at a lower average temperature, higher pressure, and a higher pressurizer level at the time an “S” signal is generated. These factors produce a greater volume of higher density water and, thus, a larger reactor coolant system mass at the time of the “S” signal. In addition, at lower reactor coolant system average temperature, the PRHR is less effective in removing decay heat, which results in greater expansion of the cold water injected by the core makeup tanks.

The limiting analysis scenario minimizes reactor coolant system average temperature, maximizes reactor coolant system mass, and maximizes pressurizer water volume at the time of an “S” signal. This scenario is as follows:

- Both of the chemical and volume control system pumps spuriously begin delivering flow at a boron concentration slightly higher than that of the reactor coolant system. (Assuming that a chemical and volume control system malfunction results in both chemical and volume control system pumps delivering flow is a conservative assumption. One chemical and volume control system pump is automatically controlled and one is manually controlled.)

- The non-safety-related pressurizer spray is assumed to be available, so that a High-2 pressurizer pressure reactor trip is prevented.

Due to the boron addition in the core, the plant cools down until an "S" signal is generated on Low-2 T_{cold}. On the "S" signal, the reactor is tripped, the core makeup tank discharge valves are opened, the reactor coolant pumps are tripped, the pressurizer heaters are blocked (on core makeup tank actuation), and the main feedwater lines, steam lines, and chemical and volume control system are isolated. After a conservative 17-second delay, the PRHR heat exchanger is actuated.

Normally, the reactor coolant pumps would be tripped 15 seconds after the receipt of the "S" signal. However, to meet the requirements of GDC 17 of 10 CFR Part 50, Appendix A, a loss of offsite power is assumed to occur as a consequence of reactor trip. The primary effect of this assumption is the coastdown of the reactor coolant pumps. Following reactor trip and a 5-second timer delay, the turbine is tripped; 3 seconds after the turbine trip a consequential loss of offsite power is assumed. The basis for the 3-second delay is described in Subsection 15.0.14. As a result, the reactor coolant pumps are conservatively assumed to trip about 10 seconds before they would otherwise trip due to the "S" signal.

This event is a Condition II incident (a fault of moderate frequency) as defined in Subsection 15.0.1.

15.5.2.2 Analysis of Effects and Consequences

The malfunction of the chemical and volume control system is analyzed by using a modified version of the computer program LOFTRAN (Reference 1) described in Subsection 15.0.11.2. The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, pressurizer spray, steam generator, steam generator safety valves, PRHR heat exchanger, and core makeup tanks. The program computes pertinent plant variables including temperatures, pressures, and power level.

Because of the power and temperature reduction during the transient, operating conditions do not approach the core limits. The analysis demonstrates that no reactor coolant system overpressurization or loss of reactor coolant system water occurs.

The assumptions are as follows:

- Initial operating conditions

  The initial reactor power is assumed to be 101 percent of nominal. The initial pressurizer pressure is assumed to be 50 psi above nominal. The initial reactor coolant system average temperature is assumed to be 8°F above nominal.

- Moderator and Doppler coefficients of reactivity

  A least-negative moderator temperature coefficient, a low (absolute value) Doppler power coefficient, and a minimum boron worth are assumed. For a different set of reactivity feedback parameters, a different chemical and volume control system boron concentration can result in an identical transient.

- Reactor control

  Rod control is not modeled.

- Pressurizer heaters

  The pressurizer heaters are automatically blocked on the core makeup tank actuation resulting from the “S” signal on Low-2 T_{cold}, but add heat to the system during the initial part of the transient. Thus, the pressurizer heaters are assumed to be operable during this event.

- Pressurizer spray

  The spray system controls the pressurizer pressure so that a High-2 pressurizer pressure reactor trip is prevented.

- Boron injection

  After 10 seconds at steady state, the chemical and volume control system pumps start injecting borated water, which is slightly above the reactor coolant system boron concentration. Upon receipt of an “S” signal, the core makeup tanks begin injecting 3400 ppm borated water. The chemical and volume control system pumps are isolated on high-2 pressurizer level. In this analysis the boron concentration of the chemical and volume control system is determined by iteration such that the high-2 pressurizer level and the Low-2 T_{cold} “S” setpoint are reached at the same time. This begins core makeup tank injection when the chemical and volume control system pumps are isolated, which is conservative with respect to filling the pressurizer.

- Turbine load

  The turbine load is assumed constant until the turbine D-EHC drives the control valve wide open, after which the turbine load drops as steam pressure drops.

- Protection and safety monitoring system actuations

  If the automatic rod control system is modeled and the pressurizer spray system functions properly, no reactor trip signal is expected to occur. Instead, the event is terminated by automatic isolation of the chemical and volume control system on the safety grade high-2 pressurizer level setpoint. If the automatic rod control system is not active and the pressurizer spray system is assumed to be available, reactor trip may be initiated on either Low-2 T_{cold} “S” or a Low-2 steam line pressure “S” signal.

  The core decay heat is removed by the PRHR heat exchanger. The worst single failure is assumed to occur in the outlet line of the PRHR heat exchanger. One of the two parallel isolation valves is assumed to fail to open.

  Plant systems and equipment available to mitigate the effect of the accident are discussed in Subsection 15.0.8 and listed in Table 15.0-6.

15.5.2.3 Results

Figures 15.5.2-1 through 15.5.2-9 show the transient response to a chemical and volume control system malfunction that results in an increase of reactor coolant system inventory.

As the chemical and volume control system injection flow increases reactor coolant system inventory, pressurizer water volume begins increasing while the primary system is cooling down. At

2,009.6 seconds, the Low-2 T_{cold} setpoint is reached, the reactor trips on the resulting "S" signal, the control rods start moving into the core, the core makeup tank discharge valves are opened, and the pressurizer heaters are blocked. At approximately the same time, the high-2 pressurizer level setpoint is reached and after a conservative delay, the chemical and volume control system injection is isolated.

The turbine is tripped as a result of the reactor trip following a 5-second turbine trip timer delay. After a 3-second delay following a turbine trip, a consequential loss of offsite power is assumed and the reactor coolant pumps trip. The basis for the 3-second delay is described in Subsection 15.0.14. Soon after reactor trip, the main feedwater lines, steam lines, and chemical and volume control system are isolated on the "S" signal. After a conservative 17-second delay, the PRHR heat exchanger is actuated. The core makeup tanks work in recirculation mode, meaning they are always filled with water because cold borated water injected through the injection lines is replaced by hot water coming from the cold leg balance lines.

The operation of the PRHR heat exchanger and the core makeup tanks cools down the plant. Due to the expansion of the core makeup tank water, the pressurizer level continues to increase. The operators are assumed to be alerted by the high-2 pressurizer level signal (2,008.3 seconds) that a pressurizer level increase transient is underway, and it is assumed that the operators are ready to take corrective action at least 30 minutes later. The specific operator action as analyzed in this case is to open the reactor vessel head vent to preclude pressurizer overfill following the high-3 pressurizer level signal at least 30 minutes after the high-2 pressurizer level signal is reached (3,803.3 seconds).

The safety related reactor vessel head vent is opened by the operators and the pressurizer water level increase slows and eventually the level begins to decrease. This demonstrates that the capacity of the reactor vessel head vent is sufficient to preclude pressurizer overfill as a result of a chemical and volume control system malfunction that causes an increase in reactor coolant inventory.

During the event, the DNBR would not drop significantly below the initial value since both the chemical and volume control system and the core makeup tanks add borated water to the reactor coolant system. At the time of reactor trip, core power and heat flux drop rapidly, which would cause the DNBR to increase well above the design limit value defined in Section 4.4.

The calculated sequence of events is shown in Table 15.5-1.

The limiting case presented here models operator action to open the reactor vessel head vent following receipt of the high-3 pressurizer level signal; this action is at least 30 minutes after the operator has been alerted by the high-2 pressurizer level signal. For pressurizer level increase events, the operator could take other actions to reduce the increase in coolant inventory. As the pressurizer water level would increase above the High-2 pressurizer water level that normally isolates chemical and volume control system makeup, the normal letdown line could be placed into service to reduce the increase in coolant inventory. If letdown could not be placed into service, the operator would use the safety-related reactor vessel head vent valves to reduce the increase in coolant inventory. For these events, following operations procedures, there is sufficient time for the operator to mitigate the consequences of this event.

15.5.2.4 Conclusions

The results of this analysis show that a chemical and volume control system malfunction does not adversely affect the core, the reactor coolant system, or the steam system. Water is not relieved from the pressurizer safety valves. DNBR remains above the design limit values, and reactor coolant system and steam generator pressures remain below 110 percent of their design values.

If the automatic rod control system and the pressurizer spray systems are assumed to function, no reactor trip signal is expected to occur. Instead, the event would be terminated by automatic isolation of the chemical and volume control system on the safety grade High-2 pressurizer level setpoint. If manual rod control is assumed and the pressurizer spray system is assumed to be unavailable, reactor trip may be initiated on either a High-2 pressurizer pressure, Low-2 T_{cold} "S", or a Low-2 steamline pressure "S" signal.

15.5.3 Boiling Water Reactor Transients

This subsection is not applicable to the AP1000 design.

15.5.4 Combined License Information

This subsection contained no requirement for additional information.

15.5.5 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.

Table 15.5-1 (Sheet 1 of 2)
Time Sequence of Events For Incidents Which Result in an Increase in Reactor Coolant Inventory

Accident	Event	Time (seconds)
Inadvertent operation of the core makeup tanks during power operation	Core makeup tank discharge valves open	10.0
	High-2 pressurizer level setpoint reached	783.2
	High-3 pressurizer level setpoint reached	2402.0
	Rod motion begins	2404.0
	Loss of offsite power	2412.0
	Reactor coolant pumps trip	2412.0
	High-3 pressurizer level setpoint reached	2554.8
	Pressurizer heaters blocked on high-3 level	2569.8
	PRHR heat exchanger actuated	2586.8
	Low-2 T_{cold} "S" setpoint is reached	2586.8
	Second CMT starts recirculating	2586.8
	Main steam and feed lines are isolated	2598.8
	Operators open the reactor vessel head vent after the high-3 pressurizer level signal is reached (at least 30 minutes after high-2 pressurizer level setpoint is reached; 45 min as analyzed)	3483.2
	Peak pressurizer water volume occurs	5312.5

Table 15.5-1 (Sheet 2 of 2)
Time Sequence of Events For Incidents Which Result in an Increase in Reactor Coolant Inventory

Accident	Event	Time (seconds)
Chemical and volume control system malfunction that increases reactor coolant inventory	Chemical and volume control system charging pumps start	10.0
	High-2 pressurizer level signal is reached	2008.3
	Low-2 T_{cold} "S" signal is reached (approximately coincident with high-2 pressurizer level)	2009.6
	Core makeup tank discharge valves open and pressurizer heaters are blocked	2009.7
	Rod motion begins	2011.6
	Loss of offsite power	2019.6
	Reactor coolant pumps trip	2019.6
	Main steam and feed lines are isolated	2021.6
	PRHR heat exchanger actuated	2026.7
	Chemical and volume control system charging pumps are isolated	2044.3
	Operators open the reactor vessel head vent after the high-3 pressurizer level signal is reached (at least 30 minutes after high-2 pressurizer level setpoint is reached; 30 min as analyzed)	3803.3
	Peak pressurizer water volume occurs	5413.0

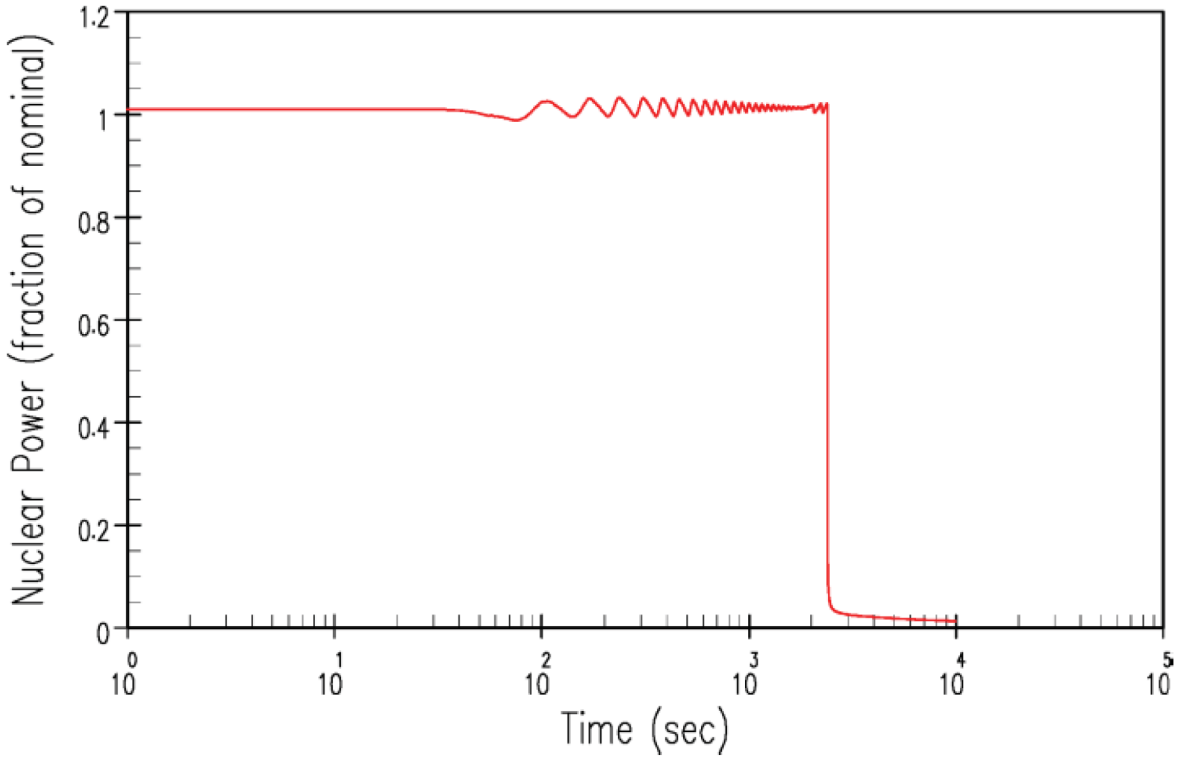

Figure 15.5.1-1
Core Nuclear Power Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

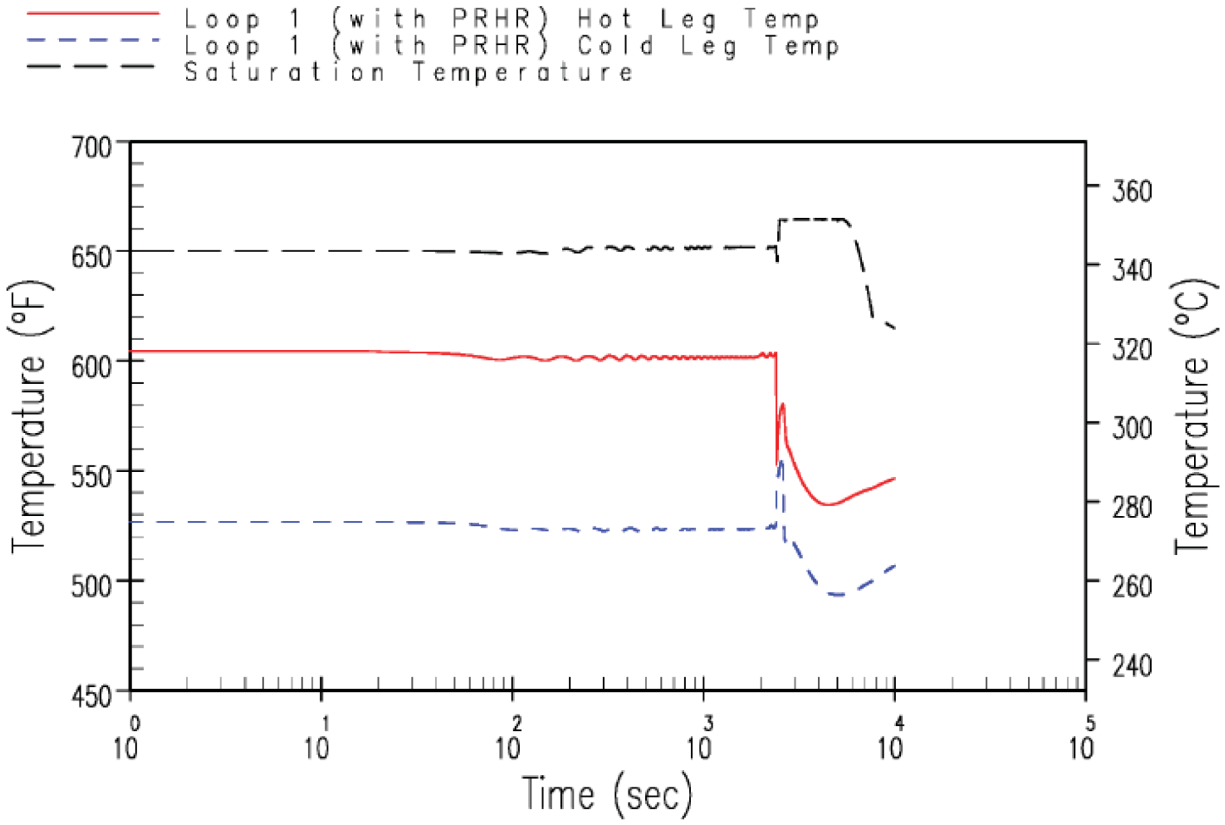

Figure 15.5.1-2
RCS Temperature Transient in Loop Containing the PRHR for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

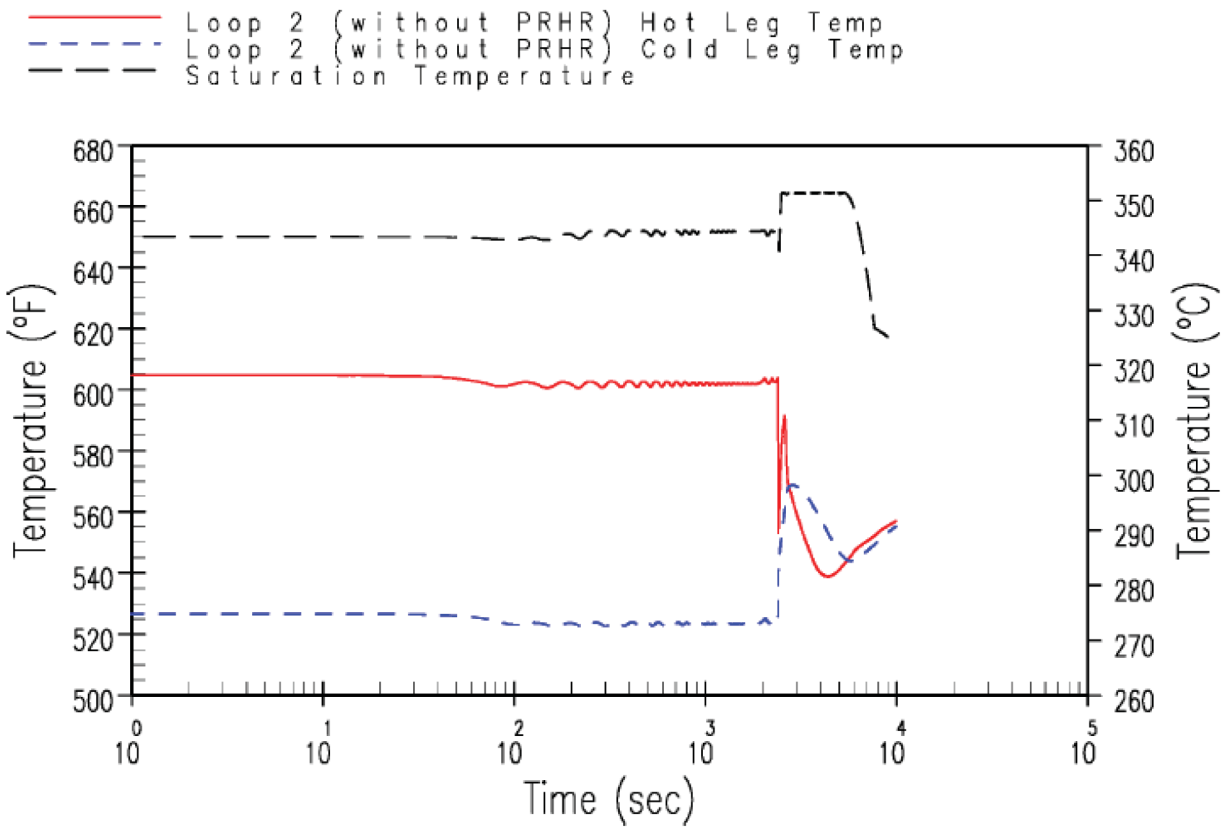

Figure 15.5.1-3
RCS Temperature Transient in Loop Not Containing the PRHR for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

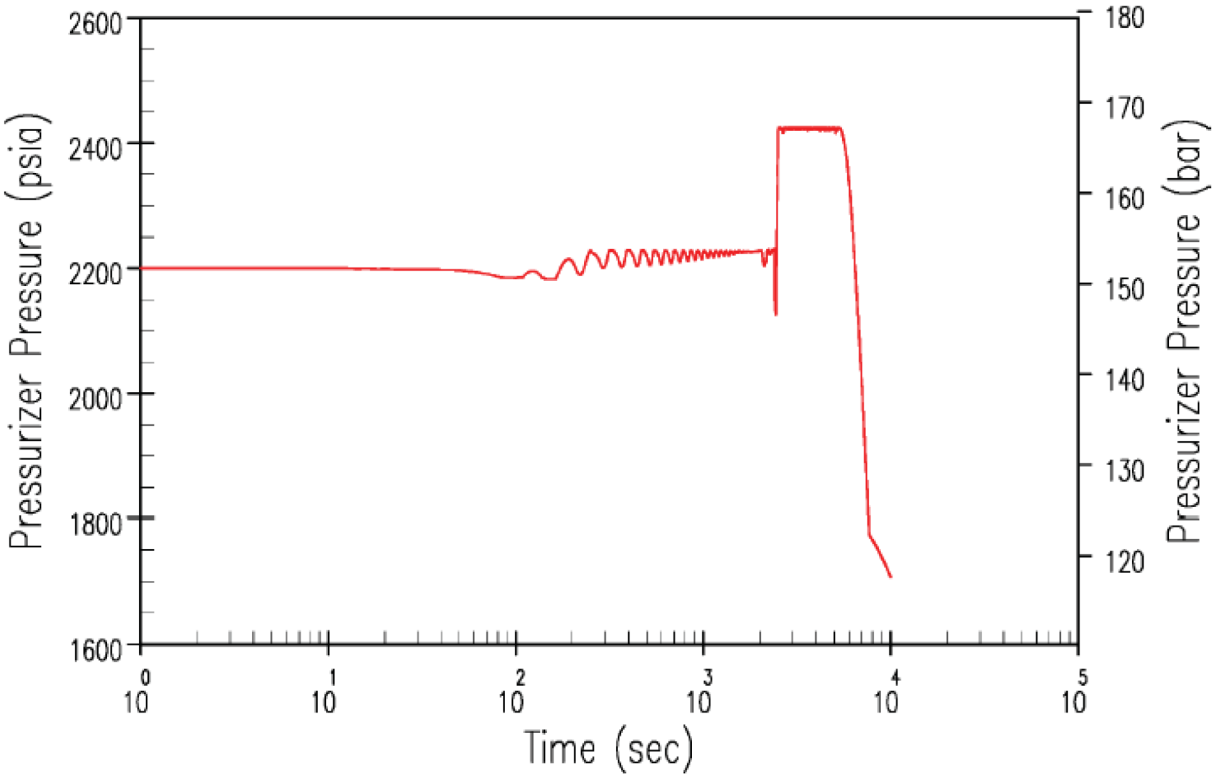

Figure 15.5.1-4
Pressurizer Pressure Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

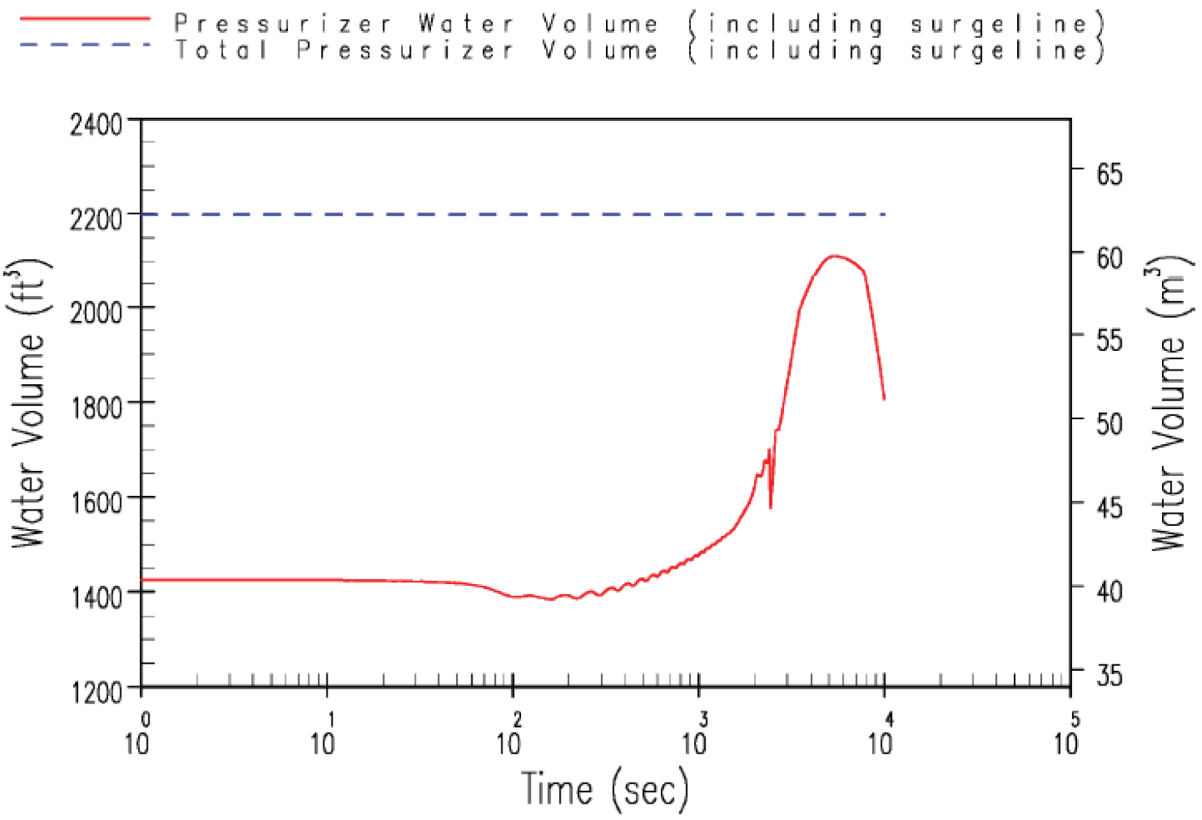

Figure 15.5.1-5
Pressurizer Water Volume Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

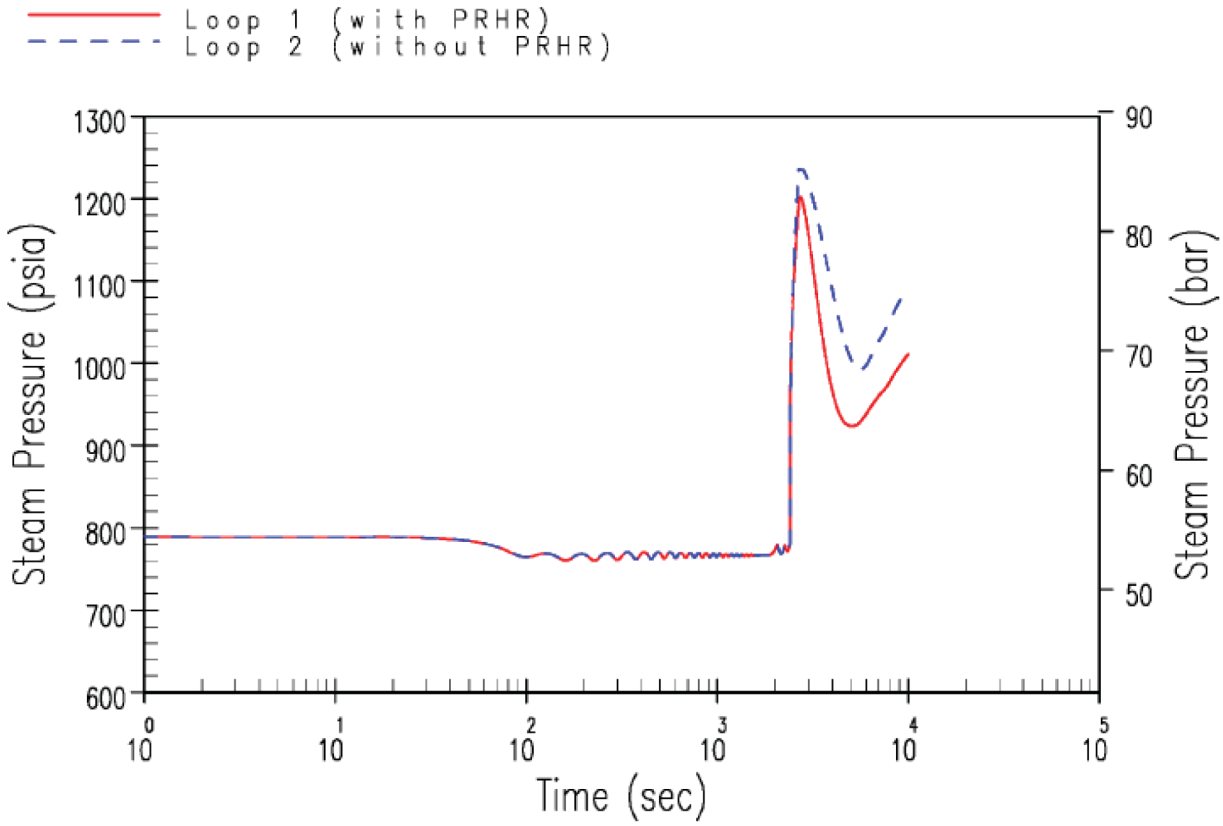

Figure 15.5.1-6
Steam Generator Pressure Transient for Inadvertent Operation of the Emergency Core Cooling System Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

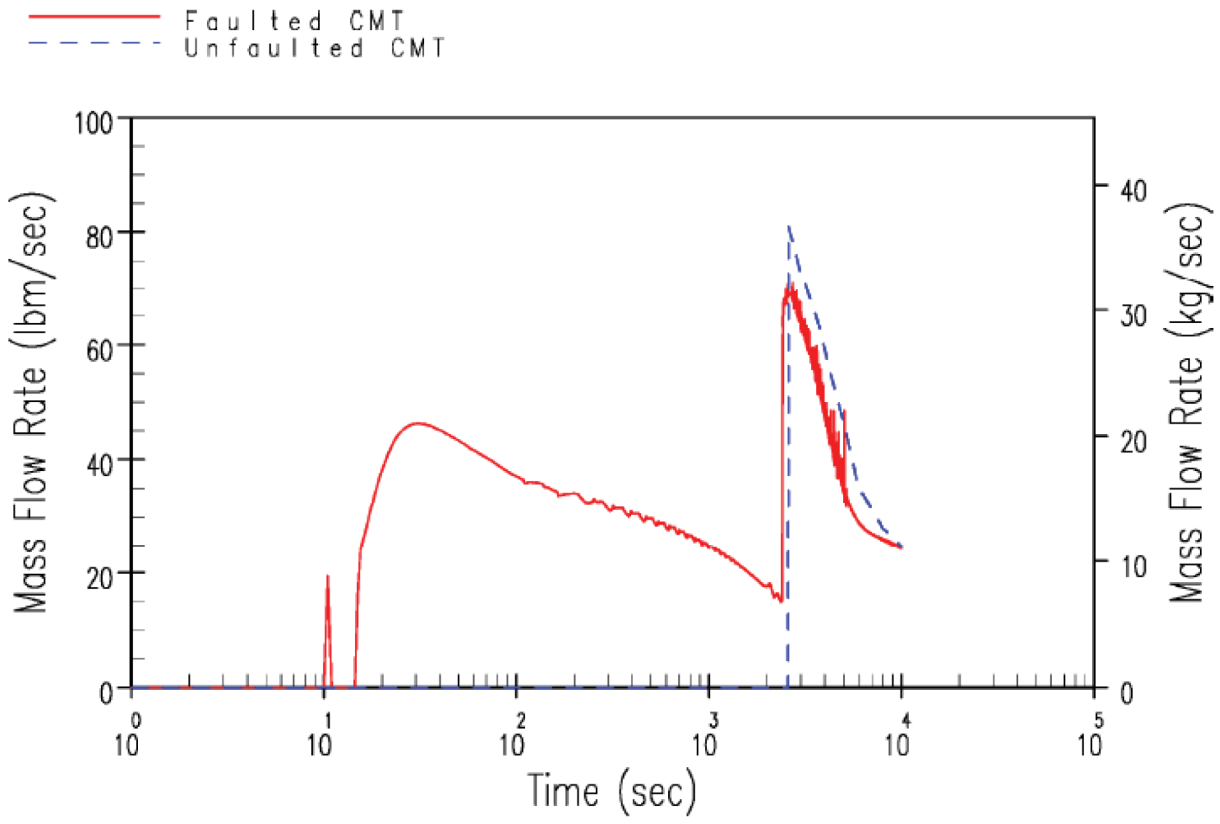

Figure 15.5.1-7
CMT Flow Rate Transient
for Inadvertent Operation of the Emergency Core Cooling System
Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

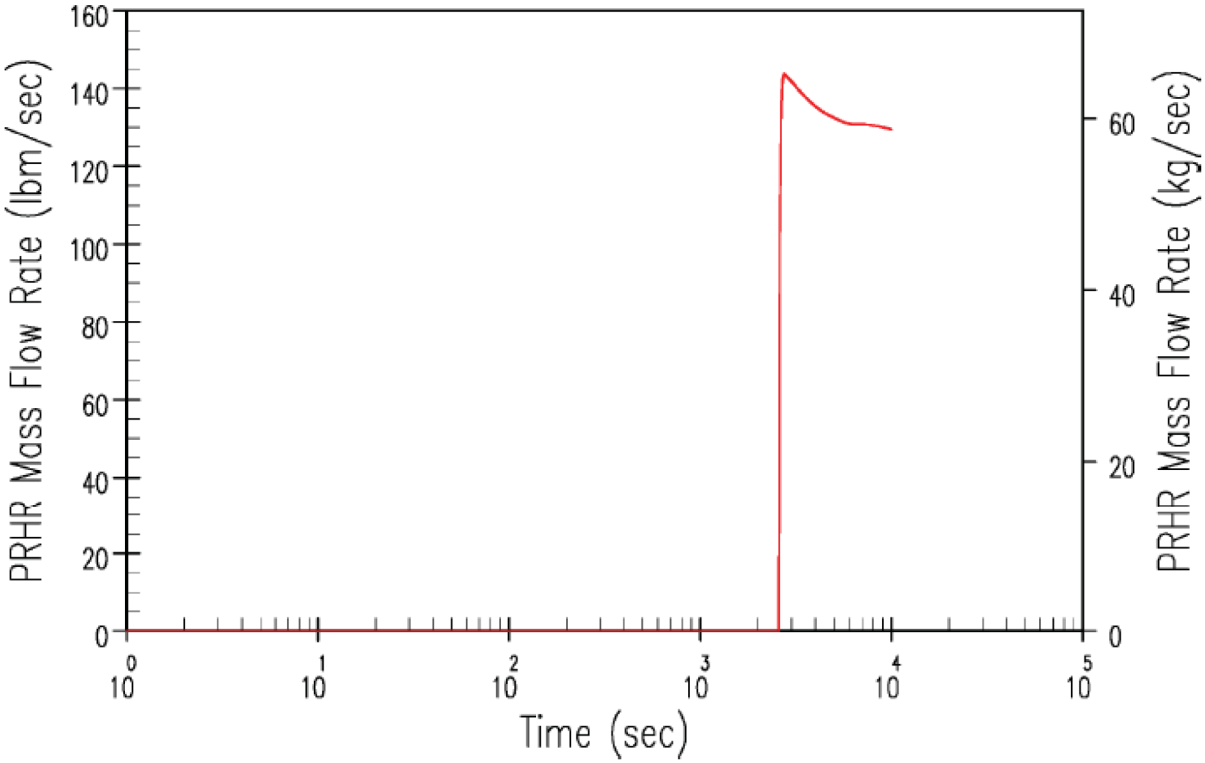

Figure 15.5.1-8
PRHR Flow Rate Transient
for Inadvertent Operation of the Emergency Core Cooling System
Due to a Spurious Opening of the Core Makeup Tank Discharge Valves

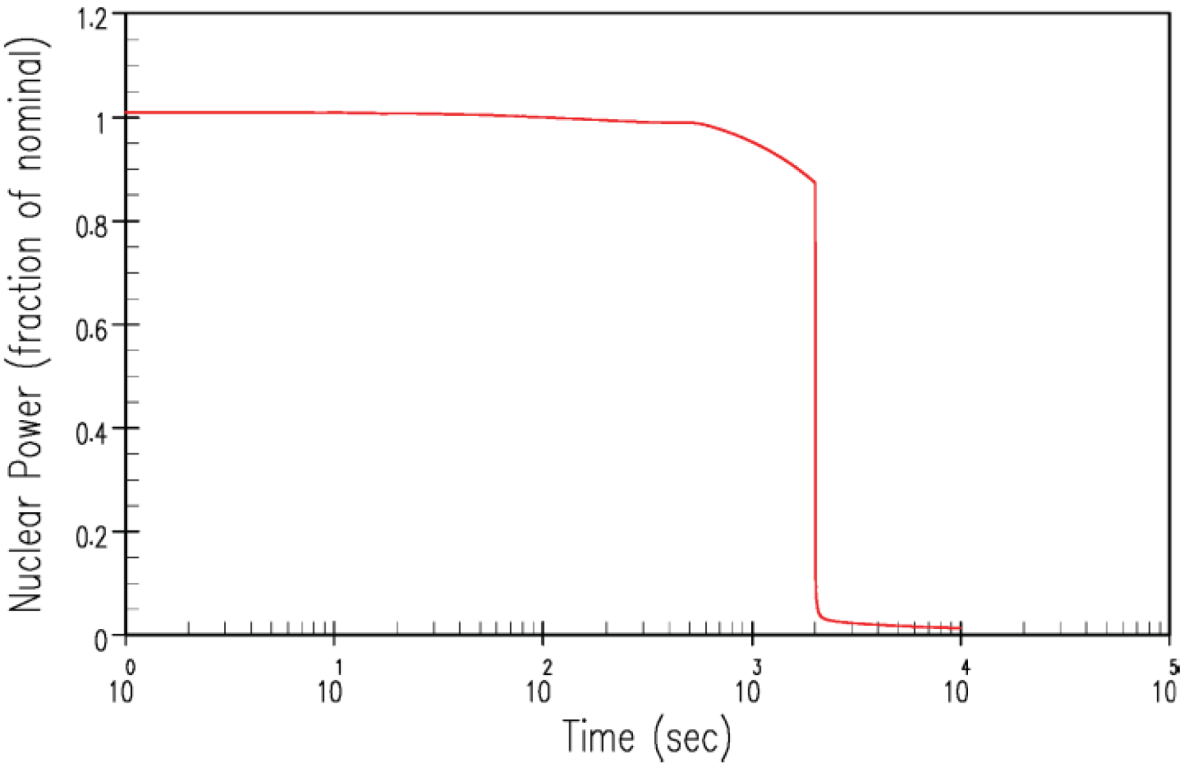

Figure 15.5.2-1
Core Nuclear Power Transient for Chemical and Volume Control System Malfunction

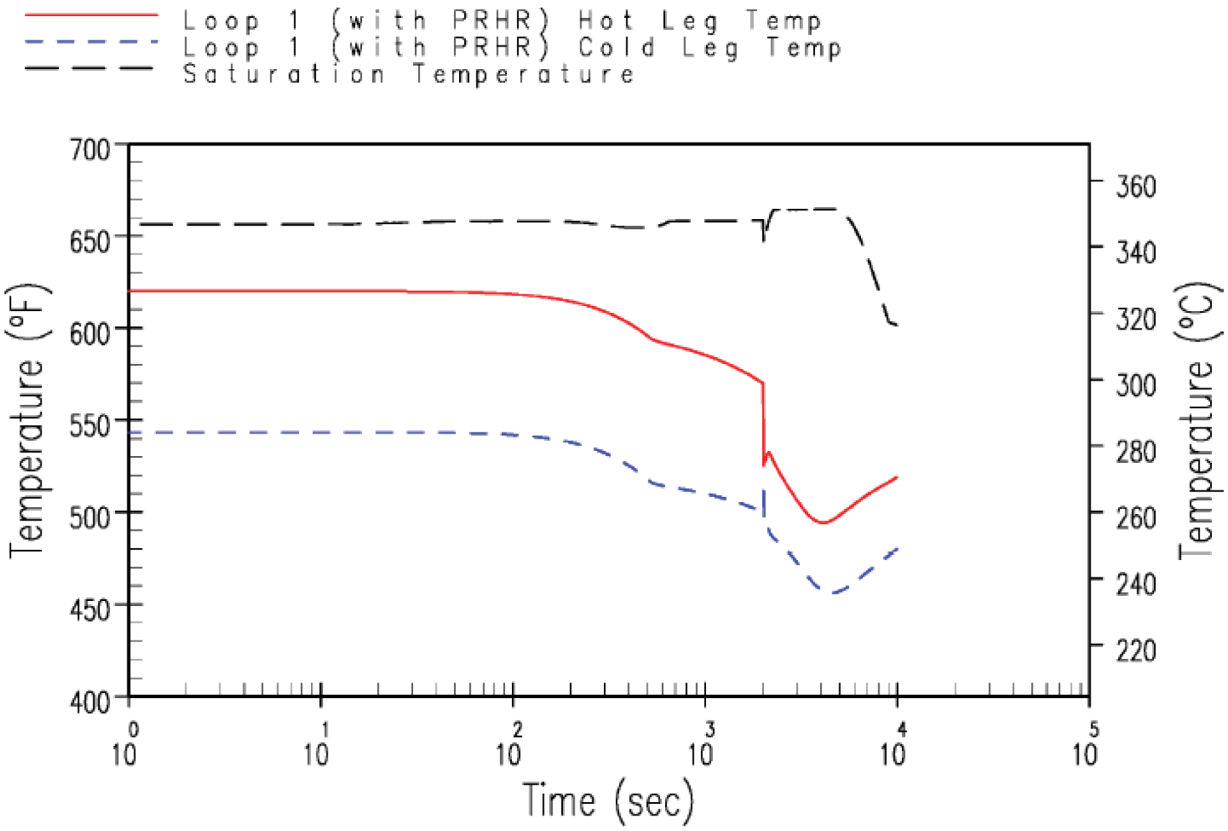

Figure 15.5.2-2
RCS Temperature Transient in Loop Containing the PRHR for Chemical and Volume Control System Malfunction

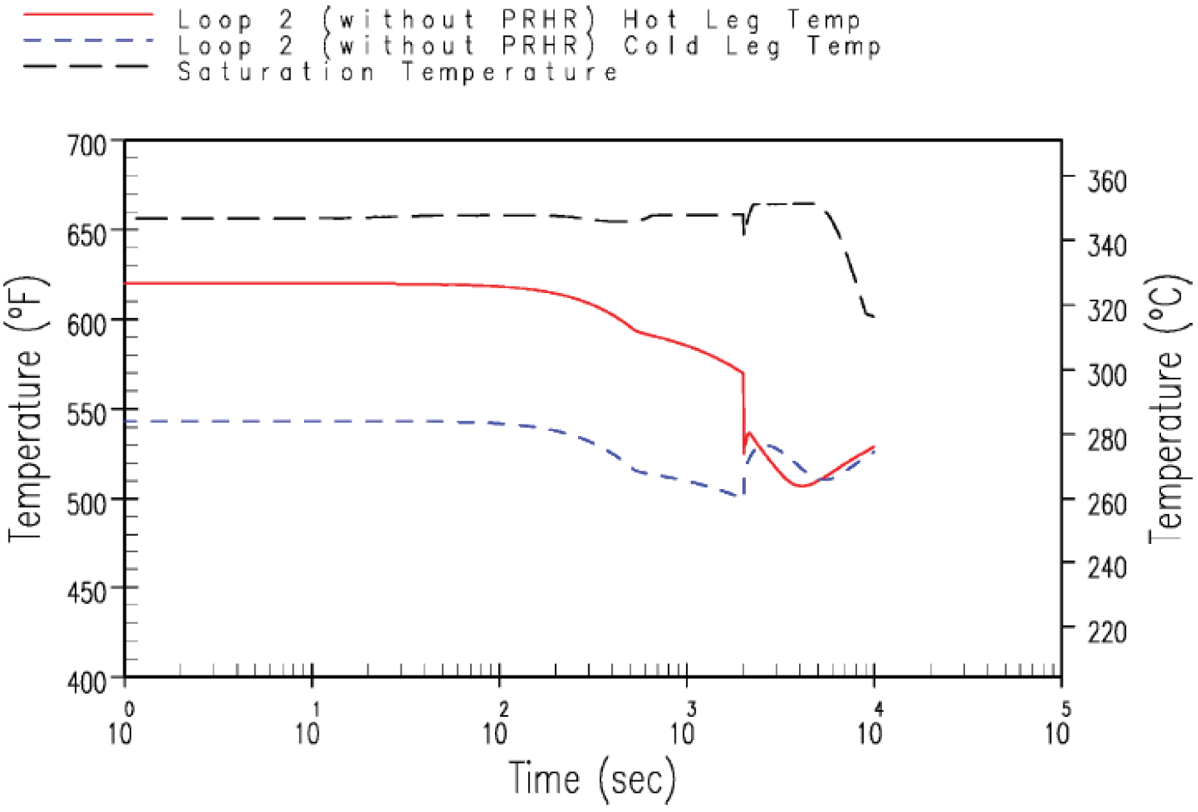

Figure 15.5.2-3
RCS Temperature Transient in Loop Not Containing the PRHR for Chemical and Volume Control System Malfunction

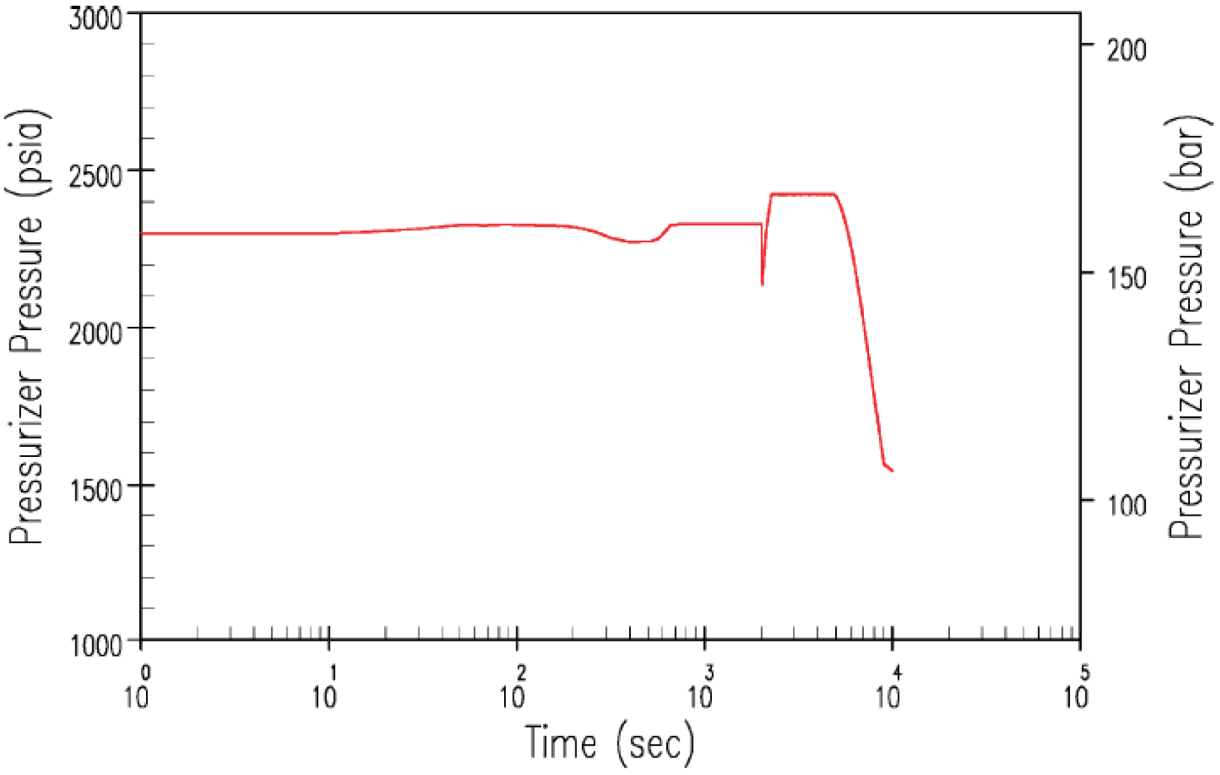

Figure 15.5.2-4
Pressurizer Pressure Transient
for Chemical and Volume Control System Malfunction

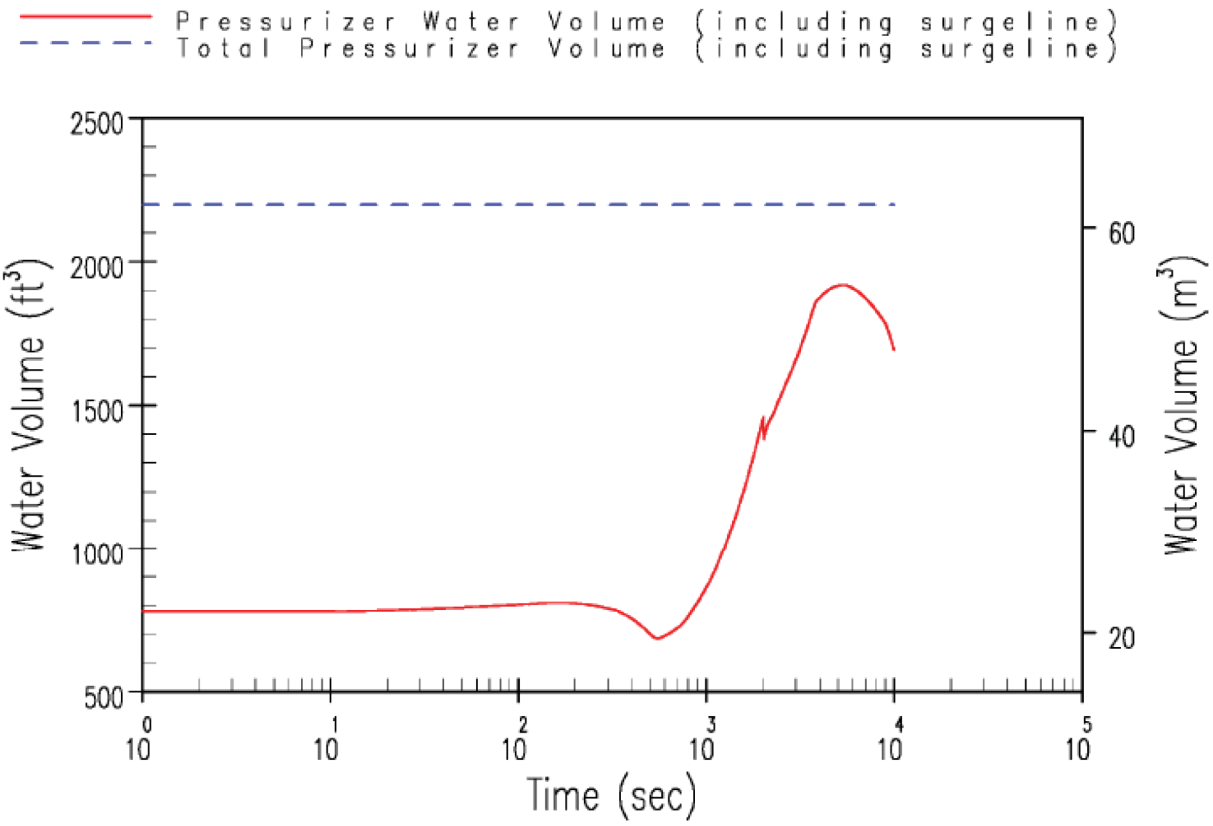

Figure 15.5.2-5
Pressurizer Water Volume Transient
for Chemical and Volume Control System Malfunction

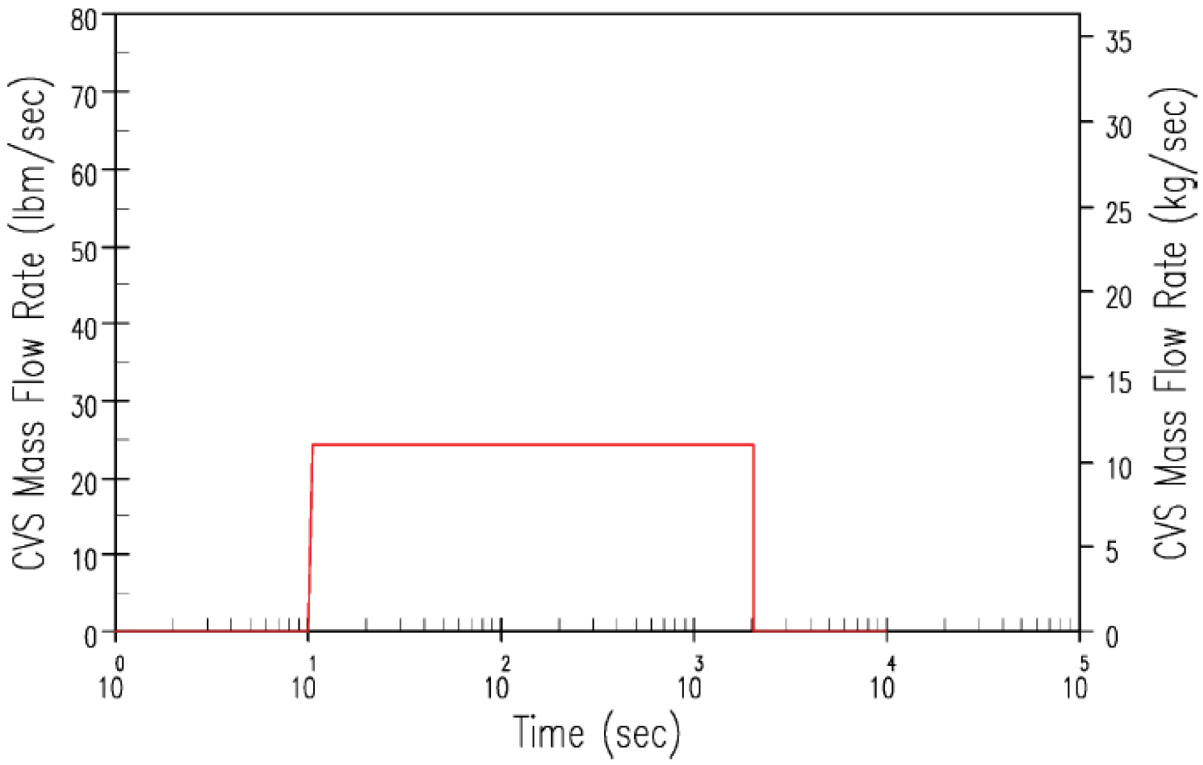

Figure 15.5.2-6
CVS Flow Rate Transient
for Chemical and Volume Control System Malfunction

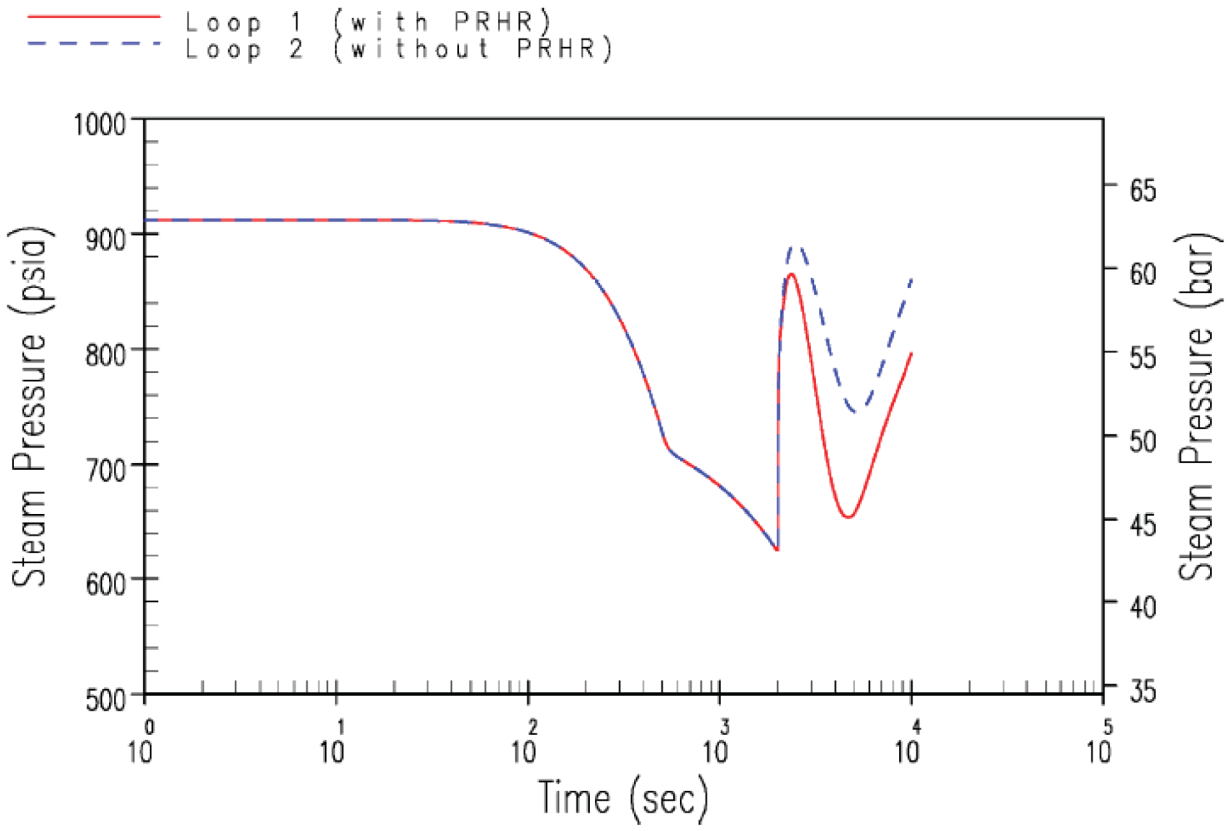

Figure 15.5.2-7
Steam Generator Pressure Transient
for Chemical and Volume Control System Malfunction

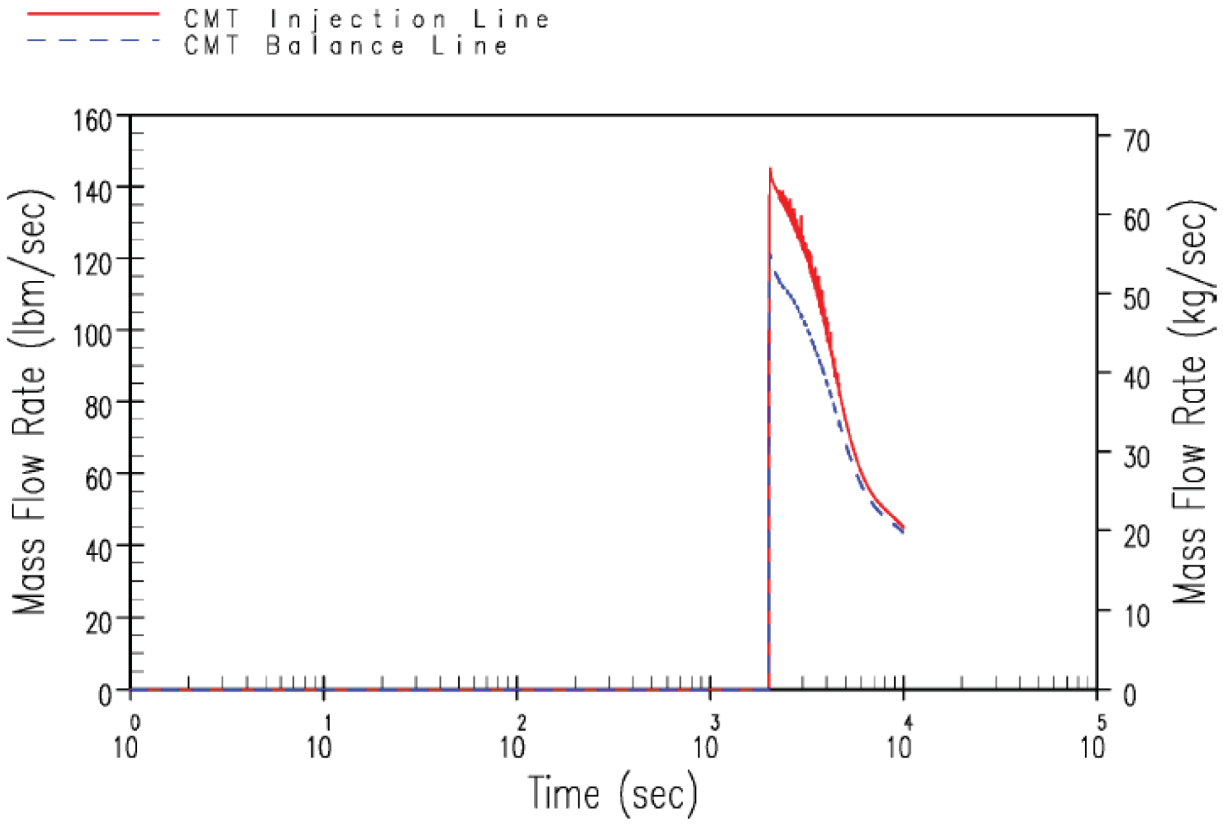

Figure 15.5.2-8
CMT Injection Line and Balance Line Flow Transient for Chemical and Volume Control System Malfunction

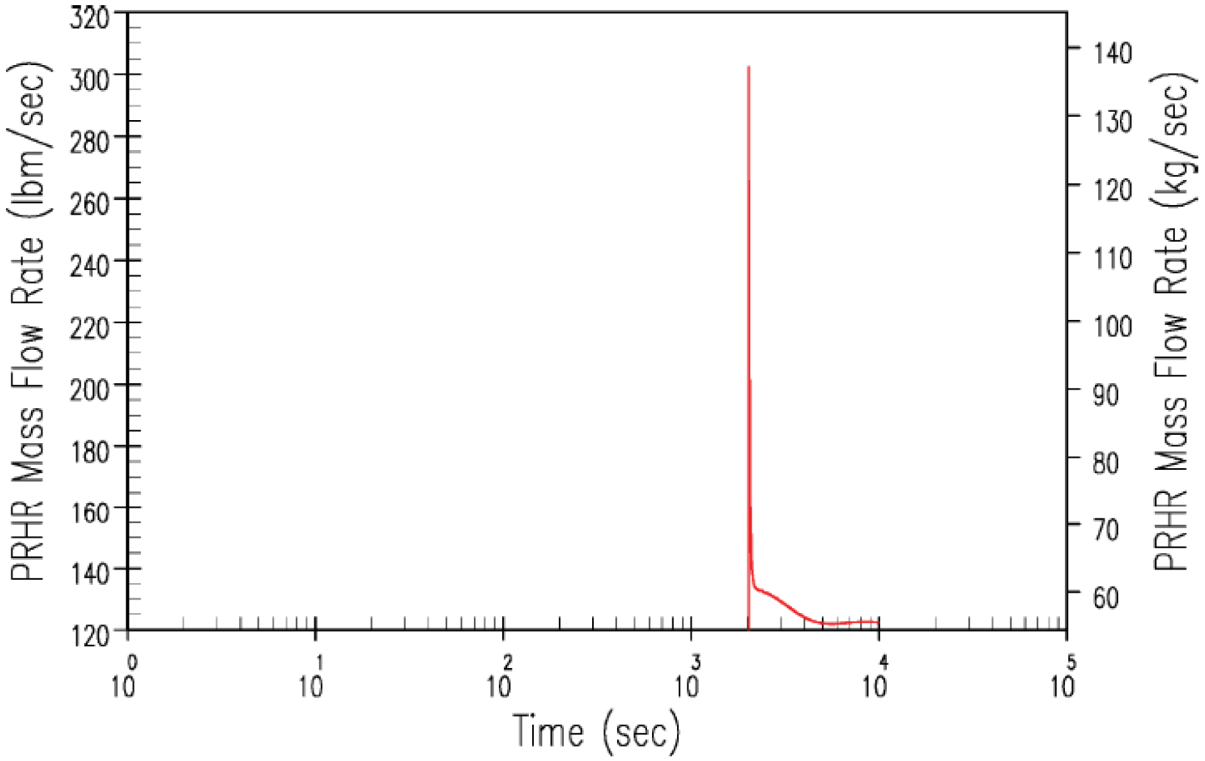

Figure 15.5.2-9
PRHR Flow Rate Transient
for Chemical and Volume Control System Malfunction

15.6 Decrease in Reactor Coolant Inventory

This section discusses the following events that result in a decrease in reactor coolant inventory:

- An inadvertent opening of a pressurizer safety valve or inadvertent operation of the automatic depressurization system (ADS)
- A break in an instrument line or other lines from the reactor coolant pressure boundary that penetrate the containment
- A steam generator tube failure
- A loss-of-coolant accident (LOCA) resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary

The applicable accidents in this category have been analyzed. It has been determined that the most severe radiological consequences result from the major LOCA described in Subsection 15.6.5. The LOCA, chemical and volume control system letdown line break outside the containment and the steam generator tube rupture (SGTR) accidents are analyzed for radiological consequences. Other accidents described in this section are bounded by these accidents.

15.6.1 Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the ADS

15.6.1.1 Identification of Causes and Accident Description

Two types of inadvertent depressurization are discussed in this section. One covers the inadvertent operation of automatic depressurization system (ADS) valves. The other covers inadvertent opening of a pressurizer safety valve.

An inadvertent depressurization of the reactor coolant system can occur as a result of an inadvertent opening of a pressurizer safety valve or ADS valves. Initially, the event results in a rapidly decreasing reactor coolant system pressure. The pressure decrease causes a decrease in power via the moderator density feedback. The average coolant temperature decreases slowly, but the pressurizer level increases until reactor trip.

The reactor may be tripped by the following reactor protection system signals:

- Overtemperature ΔT
- Pressurizer Low-2 pressure

The ADS is designed such that inadvertent operation of the ADS is classified as a Condition III event, an infrequent fault.

An inadvertent opening of a pressurizer safety valve is a Condition II event, a fault of moderate frequency.

The ADS system consists of four stages of depressurization valves. The ADS stages are interlocked. For example, Stage 1 is initiated first and subsequent stages are not actuated until previous stages have completed actuation. Each stage includes two redundant parallel valve paths with two valves in series in each path such that no single failure prevents operation of the ADS stage when it is called upon to actuate and the spurious opening of a single ADS valve does not initiate ADS flow. Since each ADS path includes two valves in series, no mechanical failure could result in an inadvertent operation of an ADS stage. The ADS Stage 4 squib valves cannot be opened while the reactor

coolant system is at nominal operating pressure. To actuate the ADS manually from the main control room, the operators actuate two separate controls positioned at some distance apart on the main control board. Therefore, one unintended operator action does not cause ADS actuation.

ADS Stage 1 has a minimum opening time of 20 seconds and a maximum effective flow area of 7 in^2 (maximum). ADS Stages 2 and 3 have a minimum opening time of 30 seconds and a maximum effective flow area of 19.4 in^2.

For this analysis, multiple failures and or errors are assumed which actuate both Stage 1 ADS paths. Although ADS Stages 2 and 3 have larger depressurization valves, the opening time of the Stage 1 depressurization valves is faster. This results in a more severe reactor coolant system depressurization due to ADS operation with the reactor at power.

Inadvertent opening of a pressurizer safety valve can only be postulated due to a mechanical failure. Although a pressurizer safety valve is smaller than the combined two Stage 1 ADS valves, the pressurizer safety valve is postulated to open in a short time.

Analyses are presented in this section for the inadvertent opening of a pressurizer safety valve and the inadvertent opening of a path of Stage 2 or 3 of the ADS. These analyses are performed to demonstrate that the departure from nucleate boiling ratio (DNBR) does not decrease below the design limit values (see Section 4.4) while the reactor is at power.

In meeting the requirements of GDC 17 of 10 CFR Part 50, Appendix A, the effects of a possible consequential loss of AC power during an RCS Depressurization event have been evaluated to not adversely impact the analysis results. This conclusion is based on a review of the time sequence associated with a consequential loss of AC power in comparison to the reactor shutdown time for an RCS Depressurization event. The primary effect of the loss of AC power is to cause the Reactor Coolant Pumps (RCPs) to coast down. The Protection & Safety Monitoring System (PMS) includes a five second minimum delay between the reactor trip and the turbine trip. In addition, a three second delay between the turbine trip and the loss of offsite AC power is assumed, consistent with the discussion of Subsection 15.0.14. Considering these delays between the time of the reactor trip and RCP coastdown due to the loss of AC power, it is clear that the plant shutdown sequence will have passed the critical point and the control rods will have been completely inserted before the RCPs begin to coast down. Therefore, the consequential loss of AC power does not adversely impact this analysis because the plant will be shut down well before the RCPs begin to coast down.

15.6.1.2 Analysis of Effects and Consequences

15.6.1.2.1 Method of Analysis

The accidental depressurization transient is analyzed by using the computer code LOFTRAN (References 14 and 15). The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer safety valves, main steam isolation valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Plant characteristics and initial conditions are discussed in Subsection 15.0.3. The following assumptions are made to give conservative results in calculating the DNBR during the transient:

- Initial conditions are discussed in Subsection 15.0.3. Uncertainties in initial conditions are included in the DNBR limit as discussed in WCAP-11397-P-A (Reference 16).

- A least negative moderator temperature coefficient is assumed. The spatial effect of voids resulting from local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape.

- A large (absolute value) Doppler coefficient of reactivity is used such that the resulting amount of positive feedback is conservatively high to retard any power decrease.

Plant systems and equipment necessary to mitigate the effects of reactor coolant system depressurization are discussed in Subsection 15.0.8 and are listed in Table 15.0-6.

Normal reactor control systems are not required to function. The rod control system is assumed to be in the automatic mode to maintain the core at full power until the reactor trip protection function is reached. This is a worst case assumption. The reactor protection system functions to trip the reactor on the appropriate signal. No single active failure prevents the reactor protection system from functioning properly.

15.6.1.2.2 Results

The system response to an inadvertent opening of a pressurizer safety valve is shown in Figures 15.6.1-1 through 15.6.1-4. The calculated sequence of events for the inadvertent opening of a pressurizer safety valve scenario is shown in Table 15.6.1-1.

A pressurizer safety valve is assumed to step open at the start of the event. The reactor coolant system then depressurizes until the Low-2 pressurizer pressure reactor trip setpoint is reached. Figure 15.6.1-3 shows the pressurizer pressure transient.

Prior to tripping of the reactor, the core power remains relatively constant (Figure 15.6.1-1). The minimum DNBR during the event occurs shortly after the rods begin to be inserted into the core (Figure 15.6.1-2). The DNBR remains above the design limit values as discussed in Section 4.4 throughout the transient.

The system response for inadvertent operation of the ADS is shown in Figures 15.6.1-5 through 15.6.1-8. The sequence of events is provided in Table 15.6.1-1. The system response for inadvertent operation of the ADS is very similar to that obtained for inadvertent opening of a pressurizer safety valve.

15.6.1.3 Conclusion

The results of the analysis show that the Low-2 pressurizer pressure reactor protection system signal provides adequate protection against the reactor coolant system depressurization events. The calculated DNBR remains above the design limit defined in Section 4.4. The long-term plant responses due to a stuck-open ADS valve or pressurizer safety valve, which cannot be isolated, are bounded by the small-break LOCA analysis.

15.6.2 Failure of Small Lines Carrying Primary Coolant Outside Containment

The small lines carrying primary coolant outside containment are the reactor coolant system sample line and the discharge line from the chemical and volume control system to the liquid radwaste system. These lines are used only periodically. No instrument lines carry primary coolant outside the containment.

When excess primary coolant is generated because of boron dilution operations, the chemical and volume control system purification flow is diverted out of containment to the liquid radwaste system. Before passing outside containment, the flow stream passes through the chemical and volume

control system heat exchangers and mixed bed demineralizer. The flow leaving the containment is at a temperature of less than 140°F and has been cleaned by the demineralizer. The flow out a postulated break in this line is limited to the chemical and volume control system purification flow rate of 100 gpm. Considering the low temperature of the flow and the reduced iodine activity because of demineralization, this event is not analyzed. The postulated sample line break is more limiting.

A continuous sample of the RCS hot legs flows through the normally open isolation valves inside and outside containment. The failure of the sample line is postulated to occur between the isolation valve outside the containment and the sample panel. The loss of sample flow provides indication of the break to plant personnel. In addition, a break in a sample line results in activity release and a resulting actuation of area and air radiation monitors. The loss of coolant tends to reduce the pressurizer level and creates a demand for makeup to the reactor coolant system providing additional indication. Upon indication of a sample line break, the operator would take action to isolate the break.

The sample line includes a flow restrictor at the point of sample to limit the break flow to less than 130 gpm. The liquid sampling lines are 1/4 inch tubing which further restricts the break flow of a sampling line outside containment. Offsite doses are based on a conservative break flow of 130 gpm with isolation after 30 minutes.

15.6.2.1 Source Term

The only significant radionuclide releases are the iodines and the noble gases. The analysis assumes that the reactor coolant iodine is at the maximum Technical Specification level for continuous operation. In addition, it is assumed that an iodine spike occurs at the time of the accident. The reactor coolant noble gas concentrations are assumed to be those associated with equilibrium operating limits for primary coolant noble gas activity.

15.6.2.2 Release Pathway

The reactor coolant that is spilled from the break is assumed to be at high temperature and pressure. A large portion of the flow flashes to steam, and the iodine in the flashed liquid is assumed to become airborne.

The iodine and noble gases are assumed to be released directly to the environment with no credit for depletion, although a large fraction of the airborne iodine is expected to deposit on building surfaces. No credit is assumed for radioactive decay after release.

15.6.2.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.6.2.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.6.2-1.

15.6.2.5 Identification of Conservatisms

The assumptions used contain the following significant conservatisms:

- The reactor coolant activities are based on conservative assumptions (see Table 15.6.2-1); whereas, the expected activities based on the fuel defect level are far less (see Section 11.1).

- It is unlikely that the conservatively selected meteorological conditions would be present at the time of the accident.

15.6.2.6 Doses

Using the assumptions from Table 15.6.2-1, the calculated total effective dose equivalent (TEDE) doses are determined to be 1.3 rem at the exclusion area boundary and 0.6 rem at the low population zone outer boundary. These doses are a small fraction of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. The phrase “a small fraction” is taken as being ten percent or less.

At the time the accident occurs, there is the potential for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because pool boiling would not occur until after 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE and, when this is added to the dose calculated for the small line break outside containment, the resulting total dose remains less than the value reported above.

15.6.3 Steam Generator Tube Rupture

15.6.3.1 Identification of Cause and Accident Description

15.6.3.1.1 Introduction

The accident examined is the complete severance of a single steam generator tube. The accident is assumed to take place at power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited number of defective fuel rods within the allowance of the Technical Specifications. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the reactor coolant system. In the event of a coincident loss of offsite power, or a failure of the condenser steam dump, discharge of radioactivity to the atmosphere takes place via the steam generator power-operated relief valves or the safety valves.

The assumption of a complete tube severance is conservative because the steam generator tube material (Alloy 690) is a corrosion-resistant and ductile material. The more probable mode of tube failure is one or more smaller leaks of undetermined origin. Activity in the secondary side is subject to continual surveillance, and an accumulation of such leaks, which exceeds the limits established in the Technical Specifications, is not permitted during operation.

The AP1000 design provides automatic protective actions to mitigate the consequences of an SGTR. The automatic actions include reactor trip, actuation of the passive residual heat removal (PRHR) heat exchanger, initiation of core makeup tank flow, termination of pressurizer heater operation, and isolation of chemical and volume control system flow and startup feedwater flow on High-3 steam generator level or high steam generator level coincident with reactor trip (P-4). These protective actions result in automatic cooldown and depressurization of the reactor coolant system, termination of the break flow and release of steam to the atmosphere, and long-term maintenance of stable conditions in the reactor coolant system. These protection systems serve to prevent steam generator overfill (see discussion in Subsections 15.6.3.1.2 and 15.6.3.1.3) and to maintain offsite radiation doses within the allowable guideline values for a design basis SGTR. The operator may take actions that would provide a more rapid mitigation of the consequences of an SGTR.

Because of the series of alarms described next, the operator can readily determine when an SGTR occurs, identify and isolate the ruptured steam generator, and complete the required recovery actions

to stabilize the plant and terminate the primary-to-secondary break flow. The recovery procedures are completed on a time scale that terminates break flow to the secondary system before steam generator overfill occurs and limits the offsite doses to acceptable levels without actuation of the ADS. Indications and controls are provided to enable the operator to carry out these functions.

15.6.3.1.2 Sequence of Events for a Steam Generator Tube Rupture

The following sequence of events occur following an SGTR:

- Pressurizer low pressure and low level alarms are actuated and chemical and volume control system makeup flow and pressurizer heater heat addition starts or increases in an attempt to maintain pressurizer level and pressure. On the secondary side, main feedwater flow to the affected steam generator is reduced because the primary-to-secondary break flow increases steam generator level.

- The condenser air removal discharge radiation monitor, steam generator blowdown radiation monitor, and/or main steam line radiation monitor alarm indicate an increase in radioactivity in the secondary system.

- Continued loss of reactor coolant inventory leads to a reactor trip generated by a Low-2 pressurizer pressure or over-temperature ΔT signal. Following reactor trip, the SGTR leads to a decrease in reactor coolant pressure and pressurizer level, counteracted by chemical and volume control system flow and pressurizer heater operation. Either the Low-2 pressurizer level signal or a safeguards (“S”) signal from Low-3 pressurizer pressure, actuates the core makeup tanks. A Low-2 pressurizer level signal also trips the reactor coolant pumps. The “S” signal automatically terminates the normal feedwater supply and trips the reactor coolant pumps. The core makeup tank actuation signal will actuate the PRHR heat exchanger and trip pressurizer heaters. Startup feedwater flow is initiated on a low steam generator narrow range level signal and controls the steam generator levels to the programmed level.

- The reactor trip automatically trips the turbine, and if offsite power is available, the steam dump valves open permitting steam dump to the condenser. In the event of a loss of offsite power or loss of the condenser, the steam dump valves automatically close to protect the condenser. The steam generator pressure rapidly increases resulting in steam discharge to the atmosphere through the steam generator power-operated relief valves and/or the safety valves.

- Following reactor trip and core makeup tank and PRHR actuation, the PRHR heat exchanger operation – combined with startup feedwater flow, borated core makeup tank flow, and chemical and volume control system flow – provides a heat sink that absorbs the decay heat. This reduces the amount of steam generated in the steam generators and steam bypass to the condenser. In the case of loss of offsite power, this reduces steam relief to the atmosphere.

- Injection of the chemical and volume control system and core makeup tank flow stabilizes reactor coolant system pressure and pressurizer water level, and the reactor coolant system pressure trends toward an equilibrium value, where the total injected flow rate equals the break flow rate.

15.6.3.1.3 Steam Generator Tube Rupture Automatic Recovery Actions

The AP1000 incorporates several protection system and passive design features that automatically terminate a steam generator tube leak and stabilize the reactor coolant system, in the highly unlikely event that the operators do not perform recovery actions. Following an SGTR, the injecting chemical

and volume control system flow (and pressurizer heater heat addition if the pressure control system is operating) maintains the primary-to-secondary break flow and the ruptured steam generator secondary level increases as break flow accumulates in the steam generator. Eventually, the ruptured steam generator secondary level reaches the high and High-3 steam generator narrow range level setpoint, which is near the top of the narrow range level span.

The AP1000 protection system automatically provides several safety-related actions to cool down and depressurize the reactor coolant system, terminate the break flow and steam release to the atmosphere, and stabilize the reactor coolant system in a safe condition. The safety-related actions include initiation of the PRHR system heat exchanger, isolation of the chemical and volume control system pumps and pressurizer heaters, and isolation of the startup feedwater pumps. In addition, the protection and safety monitoring system provides a safety-related signal to trip the redundant, nonsafety related pressurizer heater breakers.

Actuating the PRHR heat exchanger transfers core decay heat to the in-containment reactor water storage tank (IRWST) and initiates a cooldown (and a consequential depressurization) of the reactor coolant system.

Isolation of the chemical and volume control system pumps and pressurizer heaters minimizes the repressurization of the primary system. This allows primary pressure to equilibrate with the secondary pressure, which effectively terminates the primary-to-secondary break flow. Because the core makeup tank continues to inject when needed to provide boration following isolation of the chemical and volume control system pumps, isolating the chemical and volume control system pumps does not present a safety concern.

Isolation of the startup feedwater provides protection against a failure of the startup feedwater control system, which could potentially result in the ruptured steam generator being overfilled.

With decay heat removal by the PRHR heat exchanger, steam generator steaming through the power-operated relief valves ceases and steam generator secondary level is maintained.

15.6.3.1.4 Steam Generator Tube Rupture Assuming Operator Recovery Actions

In the event of an SGTR, the operators can diagnose the accident and perform recovery actions to stabilize the plant, terminate the primary-to-secondary leakage, and proceed with orderly shutdown of the reactor before actuation of the automatic protection systems. The operator actions for SGTR recovery are provided in the plant emergency operating procedures. The major operator actions include the following:

- Identify the ruptured steam generator – The ruptured steam generator can be identified by an unexpected increase in steam generator narrow range level or a high radiation indication from any main steam line monitor, steam generator blowdown line monitor, or steam generator sample.

- Isolate the ruptured steam generator – Once the steam generator with the ruptured tube is identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the ruptured steam generator.

- Cooldown of the reactor coolant system using the intact steam generator or the PRHR system – After isolation of the ruptured steam generator, the reactor coolant system is cooled as rapidly as possible to less than the saturation temperature corresponding to the ruptured steam generator pressure. This provides adequate subcooling in the reactor coolant system after depressurization of the reactor coolant system to the ruptured steam generator pressure in subsequent actions.

- Depressurize the reactor coolant system to restore reactor coolant inventory – When the cooldown is completed, the chemical and volume control system and core makeup tank injection flow increases the reactor coolant system pressure until break flow matches the total injection flow. Consequently, these flows must be terminated or controlled to stop primary-to-secondary leakage. However, adequate reactor coolant inventory must first be provided. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after the injection flow is stopped.

Because leakage from the primary side continues after the injection flow is stopped, until reactor coolant system and ruptured steam generator pressures equalize, the reactor coolant system is depressurized to provide sufficient inventory to verify that the pressurizer level remains on span after the pressures equalize.

- Termination of the injection flow to stop primary to secondary leakage – The previous actions establish adequate reactor coolant system subcooling, a secondary side heat sink, and sufficient reactor coolant inventory to verify that injection flow is no longer needed. When these actions are completed, core makeup tank and chemical and volume control system flow is stopped to terminate primary-to-secondary leakage. Primary-to-secondary leakage continues after the injection flow is stopped until the reactor coolant system and ruptured steam generator pressures equalize. Chemical and volume control system makeup flow, letdown, pressurizer heaters, and decay heat removal via the intact steam generator or the PRHR heat exchanger are then controlled to prevent repressurization of the reactor coolant system and reinitiation of leakage into the ruptured steam generator.

Following the injection flow termination, the plant conditions stabilize and the primary-to-secondary break flow terminates. At this time, a series of operator actions is performed to prepare the plant for cooldown to cold shutdown conditions. The actions taken depend on the available plant systems and the plan for further plant repair and operation.

15.6.3.2 Analysis of Effects and Consequences

An SGTR results in the leakage of contaminated reactor coolant into the secondary system and subsequent release of a portion of the activity to the atmosphere. An analysis is performed to demonstrate that the offsite radiological consequences resulting from an SGTR are within the allowable guidelines.

One of the concerns for an SGTR is the possibility of steam generator overfill because this can potentially result in a significant increase in the offsite radiological consequences. Automatic protection and passive design features are incorporated into the AP1000 design to automatically terminate the break flow to prevent overfill during an SGTR. These features include actuation of the PRHR system, isolation of chemical and volume control system flow, and isolation of startup feedwater.

An analysis is performed, without modeling expected operator actions to isolate the ruptured steam generator and cool down and depressurize the reactor coolant system, to demonstrate the role that the AP1000 design features have in preventing steam generator overfill. The limiting single failure for the overfill analysis is assumed to be the failure of the startup feedwater control valve to throttle flow when nominal steam generator level is reached. Other conservative assumptions that maximize steam generator secondary volume (such as high initial steam generator level, minimum initial reactor coolant system pressure, loss of offsite power, maximum chemical and volume control system injection flow, maximum pressurizer heater addition, maximum startup feedwater flow, and minimum startup feedwater delay time) are also assumed.

The results of this analysis demonstrate the effectiveness of the AP1000 protection system and passive system design features and support the conclusion that an SGTR event would not result in steam generator overfill.

For determining the offsite radiological consequences, an SGTR analysis is performed assuming the limiting single failure and limiting initial conditions relative to offsite doses. Because steam generator overfill is prevented for the AP1000, the results of this analysis represent the limiting radiological consequences for an SGTR.

A thermal-hydraulic analysis is performed to determine the plant response for a design basis SGTR, the integrated primary-to-secondary break flow, and the mass releases from the ruptured and intact steam generators to the condenser and to the atmosphere. This information is then used to calculate the radioactivity release to the environment and the resulting radiological consequences.

15.6.3.2.1 Method of Analysis

15.6.3.2.1.1 Computer Program

The plant response following an SGTR until the primary-to-secondary break flow is terminated is analyzed with the LOFTTR2 program (Reference 21). The LOFTTR2 program is modified to model the PRHR system, core makeup tanks, and protection system actions appropriate for the AP1000. These modifications to LOFTTR2 are described in WCAP-14234, Revision 1 (Reference 14).

15.6.3.2.1.2 Analysis Assumptions

The accident modeled is a double-ended break of one steam generator tube located at the top of the tube sheet on the outlet (cold leg) side of the steam generator. The location of the break on the cold leg side of the steam generator results in higher initial primary-to-secondary leakage than a break on the hot side of the steam generator.

The reactor is assumed to be operating at full power at the time of the accident, and the initial secondary mass is assumed to correspond to operation at nominal steam generator mass minus an allowance for uncertainties. Offsite power is assumed to be lost and the rods are assumed to be inserted at the start of the event because continued operation of the reactor coolant pumps has been determined to reduce flashing of primary-to-secondary break flow and, consequently, lower offsite radiological doses. Maximum chemical and volume control system flows and pressurizer heater heat addition are assumed immediately (even though offsite power is not available) to conservatively maximize primary-to-secondary leakage. The steam dump system is assumed to be inoperable, consistent with the loss of offsite power assumption, because this results in steam release from the steam generator power-operated relief valves to the atmosphere following reactor trip. The chemical and volume control system and pressurizer heater modeling is conservatively chosen to delay the Low-3 pressurizer pressure “S” and the low-2 pressurizer level signal and associated protection system actions.

The limiting single failure is assumed to be the failure of the ruptured steam generator power-operated relief valve. Failure of this valve in the open position causes an uncontrolled depressurization of the ruptured steam generator, which increases primary-to-secondary leakage and the mass release to the atmosphere.

It is assumed that the ruptured steam generator power-operated relief valve fails open when the low-2 pressurizer level signal is generated. This results in the maximum integrated flashed primary-to-secondary break flow.

The valve is subsequently isolated when the associated block valve is automatically closed on a Low-2 steam line pressure protection system signal.

No operator actions are modeled in this limiting analysis, and the plant protection system provides the protection for the plant. Not modeling operator actions is conservative because the operators are expected to have sufficient time to recover from the accident and supplement the automatic protection system. In particular, the operator would take action to reduce the primary pressure before the high steam generator level coincident with reactor trip (P-4) chemical and volume control and startup feedwater system shutoff signals are generated. It is also expected that the operator can close the block valve to the ruptured steam generator power-operated relief valve in much shorter time than the automatic protection signal. The operators can quickly diagnose a power-operated relief valve failure based on the rapid depressurization of the steam generator and increase in steam flow. They can then close the block valve from the control panel.

Consistent with the assumed loss of offsite power, the main feedwater pumps coast down and no startup feedwater is assumed to conservatively minimize steam generator secondary inventory and thus maximize secondary activity concentration and steam release.

15.6.3.2.1.3 Results

The sequence of events for this transient is presented in Table 15.6.3-1. The system responses to the SGTR accident are shown in Figures 15.6.3-1 to 15.6.3-10.

Offsite power is lost concurrent with the rupture of the tube. The reactor trips due to the loss of offsite power. The main feedwater pumps are assumed to coast down following reactor trip. The startup feedwater pumps are conservatively assumed not to start. Following the tube rupture, reactor coolant flows from the primary into the secondary side of the ruptured steam generator. In response to this loss of reactor coolant, pressurizer level and reactor coolant system pressure decreases as shown in Figures 15.6.3-1 and 15.6.3-2. As a result of the decreasing pressurizer level and pressure, two chemical and volume control system pumps are automatically initiated to provide makeup flow and the pressurizer heaters turn on.

After reactor trip, core power rapidly decreases to decay heat levels and the core inlet to outlet temperature differential decreases. The turbine stop valves close, and steam flow to the turbine is terminated. The steam dump system is conservatively assumed to be inoperable. The secondary side pressure increases rapidly after reactor trip until the steam generator power-operated relief valves (and safety valves, if their setpoints are reached) lift to dissipate the energy, as shown in Figure 15.6.3-3.

Maximum heat addition to the pressurizer from the pressurizer heaters increases the primary pressure.

As the leak flow continues to deplete primary inventory, Low-2 pressurizer level, core makeup tank actuation, and PRHR actuation signals area reached. Power to the pressurizer heaters is shut off so that they will not provide additional heat to the primary should the pressurizer level return. The ruptured steam generator power-operated relief valve is assumed to fail open at this time.

The failure causes the intact and ruptured steam generators to rapidly depressurize (Figure 15.6.3-3). This results in an initial increase in primary-to-secondary leakage and a decrease in the reactor coolant system temperatures. Both the intact and ruptured steam generators depressurize because the steam generators communicate through the open steam line isolation valves.

The decrease in the reactor coolant system temperature results in a decrease in the pressurizer level and reactor coolant system pressure (Figures 15.6.3-1 and 15.6.3-2). Depressurization of the primary and secondary systems continues until the Low-2 steam line pressure setpoint is reached. As a result, the steam line isolation valves and intact and ruptured steam generator power-operated relief block valves are closed.

Following closure of the block valves, the primary and secondary pressures and the ruptured steam generator secondary water volume and mass increase as break flow accumulates. This increase continues until the steam generator secondary level reaches the high narrow range level when the chemical and volume control and startup feedwater systems are isolated.

With continued reactor coolant system cooldown, depressurization provided by the PRHR heat exchanger, and with the chemical and volume control system isolated, primary system pressure eventually falls to match the secondary pressure. The break flow terminates as shown in Figure 15.6.3-5, and the system is stabilized in a safe condition. As shown in Figure 15.6.3-8, steam release through the intact loop, unfaulted power-operated relief valve does not occur following PRHR initiation because the PRHR is capable of removing the core decay heat.

As shown in Figure 15.6.3-9, the core makeup tank flow trends toward zero because the gravity head diminishes as the core makeup tank temperature approaches the reactor coolant system temperature due to the continued balance line flow. The core makeup tank remains full, and ADS actuation does not occur.

The ruptured steam generator water volume is shown in Figure 15.6.3-6. The water volume in the ruptured steam generator when the break flow is terminated is significantly less than the total steam generator volume of greater than 9000 ft^3.

The design basis SGTR event does not result in fuel failures. In the event of an SGTR, the reactor coolant system depressurizes due to the primary-to-secondary leakage through the ruptured steam generator tube. This depressurization reduces the calculated DNBR. The depressurization prior to reactor trip for the SGTR has been compared to the depressurization for the reactor coolant system depressurization accidents analyzed in Subsection 15.6.1. The rate of depressurization is much slower for the SGTR than for the reactor coolant system depressurization accidents. Following reactor trip, the DNBR increases rapidly. Thus, the conclusion of Subsection 15.6.1, that the calculated DNBR remains above the limit, is extended to the SGTR analysis, justifying the assumption of no failed fuel.

15.6.3.2.1.4 Mass Releases

The mass release of an SGTR event is determined for use in evaluating the exclusion area boundary and low population zone radiation exposure. The steam releases from the ruptured and intact steam generators and the primary-to-secondary leakage into the ruptured steam generator are determined from the LOFTTR2 results for the period from the initiation of the accident until the leakage is terminated.

Following reactor trip, the releases to the atmosphere are through the steam generator power-operated relief valves (and steam generator safety valves for a short period). Steam relief through the power-operated relief valves continues until RNS conditions are met. The mass releases for the SGTR event are presented in Table 15.6.3-2.

15.6.3.3 Radiological Consequences

The evaluation of the radiological consequences of the postulated SGTR assumes that the reactor is operating with a limited number of fuel rods containing cladding defects and that leaking steam generator tubes result in a buildup of activity in the secondary coolant.

Following the rupture, any noble gases carried from the primary coolant into the ruptured steam generator via the break flow are released directly to the environment. The iodine and alkali metal activity entering the secondary side is also available for release, with the amount of release dependent on the flashing fraction of the reactor coolant and on the partition coefficient in the steam generator. In addition to the activity released through the ruptured loop, there is also a small amount of activity released through the intact loop.

15.6.3.3.1 Source Term

The significant radionuclide releases from the SGTR are the noble gases, alkali metals and the iodines that become airborne and are released to the environment as a result of the accident.

The analysis considers two different reactor coolant iodine source terms, both of which consider the iodine spiking phenomenon. In one case, the initial iodine concentrations are assumed to be those associated with the equilibrium operating limits for primary coolant iodine activity. The iodine spike is assumed to be initiated by the accident with the spike causing an increasing level of iodine in the reactor coolant.

The second case assumes that the iodine spike occurs before the accident and that the maximum reactor coolant iodine concentration exists at the time the accident occurs. The reactor coolant noble gas concentrations are assumed to be those associated with equilibrium operating limits for primary coolant noble gas activity. The reactor coolant alkali metal concentrations are based on those associated with the design basis fuel defect level.

The secondary coolant iodine and alkali metal activity is assumed to be 1 percent of the maximum equilibrium primary coolant activity.

15.6.3.3.2 Release Pathways

The noble gas activity contained in the reactor coolant that leaks into the intact steam generator and enters the ruptured steam generator through the break is assumed to be released immediately as long as a pathway to the environment exists. There are three components to the modeling of iodine and alkali metal releases:

- Intact loop steaming, with credit for partitioning of iodines and alkali metals (includes continued primary-to-secondary leakage at the maximum rate allowable by the Technical Specifications)
- Ruptured loop steaming, with credit for partitioning of iodines and alkali metals (includes modeling of increasing activity in the secondary coolant due to the break flow)
- Release of flashed reactor coolant through the ruptured loop, with no credit for scrubbing (this conservatively assumes that break location is at the top of the tube bundle)

Credit is taken for decay of radionuclides until release to the environment. After release to the environment, no consideration is given to radioactive decay or to cloud depletion of iodines by ground deposition during transport offsite.

15.6.3.3.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

15.6.3.3.4 Analytical Assumptions and Parameters

The assumptions and parameters used in the analysis are listed in Table 15.6.3-3.

15.6.3.3.5 Identification of Conservatisms

The assumptions used in the analysis contain a number of significant conservatisms, such as:

- The reactor coolant activities are based on conservative assumptions whereas, the activities based on the expected fuel defect level are far less (see Section 11.1).
- It is unlikely that the conservatively selected meteorological conditions are present at the time of the accident.

15.6.3.3.6 Doses

Using the assumptions from Table 15.6.3-3, the calculated TEDE doses for the case in which the iodine spike is assumed to be initiated by the accident are determined to be 0.7 rem at the exclusion area boundary for the limiting 2-hour interval (0-2 hours) 0.5 rem at the low population zone outer boundary. These doses are a small fraction of the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. A “small fraction” is defined, consistent with the Standard Review Plan, as being ten percent or less.

For the case in which the SGTR is assumed to occur coincident with a pre-existing iodine spike, the TEDE doses are determined to be 1.4 rem at the exclusion area boundary for the limiting 2-hour interval (0 to 2 hours) and 0.7 rem at the low population zone outer boundary. These doses are within the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34.

At the time the accident occurs, there is the potential for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour exclusion area boundary dose because pool boiling would not occur until after 2.0 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE and, when this is added to the doses calculated for the steam generator tube rupture, the resulting total doses remain as reported above.

15.6.3.4 Conclusions

The results of the SGTR analysis show that the overfill protection logic and the passive system design features provide protection to prevent steam generator overfill. Following an SGTR accident, the operators can identify and isolate the ruptured steam generator and complete the required actions to terminate the primary-to-secondary break flow before steam generator overfill or ADS actuation occurs.

Even when no operator actions are assumed, the AP1000 protection system and passive design features initiate automatic actions that can terminate a steam generator tube leak and stabilize the reactor coolant system in a safe condition while preventing steam generator overfill and ADS actuation.

The resulting offsite radiological doses for the limiting case analyzed are within the dose acceptance limits.

15.6.4 Spectrum of Boiling Water Reactor Steam System Piping Failures Outside of Containment

This section is not applicable to the AP1000.

15.6.5 Loss-of-Coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

15.6.5.1 Identification of Causes and Frequency Classification

A LOCA is the result of a pipe rupture of the reactor coolant system pressure boundary. For the analyses reported here, a major pipe break (large break) is defined as a rupture with a total cross-sectional area equal to or greater than 1.0 ft^2. This event is considered a Condition IV event (a limiting fault) because it is not expected to occur during the lifetime of the plant but is postulated as a conservative design basis (see Subsection 15.0.1).

A minor pipe break (small break), as considered in this subsection, is defined as a rupture of the reactor coolant pressure boundary (Section 5.2) with a total cross-sectional area less than 1.0 ft^2 in which the normally operating charging system flow is not sufficient to sustain pressurizer level and pressure. This is considered a Condition III event because it is an infrequent fault that may occur during the life of the plant.

The acceptance criteria for the LOCA are described in 10 CFR 50.46 (Reference 1) and are summarized as follows:

- The calculated maximum fuel element cladding temperature shall not exceed 2200°F.
- Localized cladding oxidation shall not exceed 17 percent of the total cladding thickness before oxidation.
- The amount of hydrogen generated from fuel element cladding reacting chemically with water or steam shall not exceed 1 percent of the total amount if all metal cladding were to react.
- The core remains amenable to cooling for any calculated change in core geometry.
- The core temperature is maintained at a low value, and decay heat is removed for the extended period of time required by the long-lived radioactivity remaining in the core.

These criteria are established to provide significant margin in emergency core cooling system performance following a LOCA.

For the AP1000 plant, the small breaks (less than 1.0 ft^2) yield results with more margin than large breaks.

15.6.5.2 Basis and Methodology for LOCA Analyses

Should a major break occur, depressurization of the reactor coolant system results in a pressure decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer Low-2-pressure trip setpoint is reached. A safeguards actuation (“S”) signal is generated when the appropriate setpoint is reached. These measures limit the consequences of the accident in two ways:

- Reactor trip and borated water injection complement void formation in causing rapid reduction of power to a residual level corresponding to fission product decay heat. Insertion of control rods to shut down the reactor is neglected in the large-break analysis.

- Injection of borated water provides core cooling and prevents excessive cladding temperatures.

The acceptability of the computer codes approved for AP600 LOCA analyses for the AP1000 application is documented in Reference 24. The acceptability of additional computer codes for the AP1000 Best-Estimate Large-Break LOCA analysis is documented in Reference 34.

15.6.5.2.1 Description of Large-Break LOCA Transient

Before the break occurs, the unit is in an equilibrium condition in which the heat generated in the core is being removed via the secondary system. During blowdown, heat from fission product decay stored energy in the fuel, hot internals, and vessel continues to be transferred to the reactor coolant. At the beginning of the blowdown phase, the entire reactor coolant system contains subcooled liquid, which transfers heat from the core by forced convection with some fully developed nucleate boiling. After the break, the core heat transfer is based upon local fluid conditions. Transition boiling and dispersed flow film boiling are the major heat transfer mechanisms.

The heat transfer between the reactor coolant system and the secondary system may be in either direction, depending upon the relative temperatures. In the case of continued heat addition to the secondary system, secondary system pressure increases and the main steam safety valves may lift to limit the pressure. The safeguards actuation signal actuates a feedwater isolation signal, which isolates normal feedwater flow by closing the main feedwater isolation valves.

The reactor coolant pumps trip automatically during the accident following an “S” signal. The effects of pump coastdown are included in the blowdown. The blowdown phase of the transient ends when the reactor coolant system pressure (initially assumed at 2250 psia) falls to a value approaching that of the containment atmosphere.

When the “S” signal occurs, the core makeup tank isolation valves are opened. The core makeup tank begins to inject subcooled borated water into the reactor vessel through the direct vessel injection lines.

Subsection 15.6.5.4C presents calculations that show the effective post-LOCA long-term cooling of the AP1000 by passive means.

15.6.5.2.2 Description of Small-Break LOCA Transient

The detailed description of the small-break LOCA transients for the AP1000 plant design is provided in Subsection 15.6.5.4B.1. Calculations described in Subsection 15.6.5.4B indicate that acceptable core cooling is provided for the small-break LOCA transients. Subsection 15.6.5.4C calculations show that effective post-LOCA core cooling is provided in the long term by passive means.

15.6.5.3 Radiological Consequences

Although the analysis of the core response during a LOCA (see Subsection 15.6.5.4) shows that core integrity is maintained, for the evaluation of the radiological consequences of the accident, it is assumed that major core degradation and melting occur.

The dose calculations take into account the release of activity by way of the containment purge line prior to its isolation near the beginning of the accident and the release of activity resulting from

containment leakage. Purge of the containment for hydrogen control is not an intended mode of operation and is not considered in the dose analysis. While the normal residual heat removal system is capable of post-LOCA cooling, it is not a safety-related system and may not be available following the accident. If it is operable, it would be used only if the source term is not far above the normal shutdown primary coolant source term. It is assumed that core cooling is accomplished by the passive core cooling system, which does not pass coolant outside of containment. Thus, there is no recirculation leakage release path to be modeled.

15.6.5.3.1 Source Term

The release of activity to the containment consists of two parts. The initial release is the activity contained in the reactor coolant system. This is followed by the release of core activity.

15.6.5.3.1.1 Primary Coolant Release

The reactor coolant is assumed to have activity levels consistent with operation at the Technical Specification limits of 280 μCi/gm dose equivalent Xe-133 and 1.0 μCi/gm dose equivalent I-131.

Based on NUREG-1465 (Reference 19), for a plant using leak-before-break methodology, the release of coolant into the containment can be assumed to last for 10 minutes. The AP1000 is a leak-before-break plant, and the water in the reactor coolant system is assumed to blow down into the containment over a period of 10 minutes. The flow rate is assumed to be constant over the 10-minute period. As the reactor coolant enters the containment, the noble gases and half of the iodine activity are assumed to be released into the containment atmosphere.

15.6.5.3.1.2 Core Release

The release of activity from the fuel takes place in two stages as summarized in Table 15.6.5-1. First is the gap release which is assumed to occur at the end of the primary coolant release phase (i.e., at ten minutes into the accident) and continue over a period of half an hour. The second stage is that of the in-vessel core melt in which the bulk of the activity releases associated with the accident occur. The source term model is based on NUREG-1465 and Regulatory Guide 1.183 (Reference 20).

The core fission product inventory at the time of the accident is based on operation near the end of a fuel cycle at 101-percent power and is provided in Table 15A-3 of Appendix 15A. The main feedwater flow measurement supports a 1-percent power uncertainty. Consistent with NUREG-1465, there are three groups of nuclides considered in the gap activity releases: noble gases, iodines, and alkali metals (cesium and rubidium). For the core melt phase, there are five additional nuclide groups for a total of eight. The five additional nuclide groups are the tellurium group, the noble metals group, the cerium group, the lanthanide group, and barium and strontium. The specific nuclides included in the source term are as shown in Table 15A-3.

Gap Activity Release

Consistent with NUREG-1465 guidance for a plant using leak-before-break methodology, the gap release phase begins after the primary coolant release phase ends at ten minutes and has a duration of 0.5 hour.

In-vessel Core Release

After the gap activity release phase, there is an in-vessel release phase which lasts for 1.3 hours and which releases activity to the containment due to core melting. The fractions of the core activity released to the containment atmosphere during this phase are from NUREG-1465:

Noble gases	0.95
Iodines	0.35
Alkali metals	0.25
Tellurium group	0.05
Noble metals	0.0025
Ba and Sr	0.02
Cerium group	0.0005
Lanthanide group	0.0002

Consistent with NUREG-1465, the releases are assumed to occur at a constant rate over the 1.3-hour phase duration.

15.6.5.3.1.3 Iodine Form

The iodine form is consistent with the NUREG-1465 model. The model shows the iodine to be predominantly in the form of nonvolatile cesium iodide with a small fraction existing as elemental iodine. Additionally, the model assumes that a portion of the elemental iodine reacts with organic materials in the containment to form organic iodine compounds. The resulting iodine species split is as follows:

- Particulate 0.95
- Elemental 0.0485
- Organic 0.0015

If the post-LOCA cooling solution has a pH of less than 6.0, part of the cesium iodide may be converted to the elemental iodine form. The passive core cooling system provides sufficient trisodium phosphate to the post-LOCA cooling solution to maintain the solution pH at 7.0 or greater following a LOCA (see Subsection 6.3.2.1.4).

15.6.5.3.2 In-containment Activity Removal Processes

The AP1000 does not include active systems for the removal of activity from the containment atmosphere. The containment atmosphere is depleted of elemental iodine and of particulates as a result of natural processes within the containment.

Elemental iodine is removed by deposition onto surfaces. Particulates are removed by sedimentation, diffusiophoresis (deposition driven by steam condensation), and thermophoresis (deposition driven by heat transfer). No removal of organic iodine is assumed. Appendix 15B provides a discussion of the models and assumptions used in calculating the removal coefficients.

Particulates removed from the containment atmosphere to the containment shell are assumed to be washed off the shell by the flow of water resulting from condensing steam (i.e., condensate flow). The particulates may be either washed into the sump, which is controlled to a pH ≥7 post-accident or into the IRWST, which is not pH controlled post-accident. Due to the conditions in the IRWST, a portion of the particulate iodine washed into the IRWST may chemically convert to an elemental form and re-evolve, subject to partitioning, as airborne. A water-steam partition factor of 10 for elemental iodine is applied. This value bounds the time-dependent partition factors calculated using the NUREG/CR-5950 (Reference 36) models and the calculated IRWST water temperature and pH as a function of time.

The IRWST is a closed tank with weighted louvers, and without boiling, there would be no motive force for the release of re-evolved gaseous iodine from the IRWST gas space to the containment. Thus, the assumption of boiling in the IRWST liquid is imposed to force the release of the re-evolved iodine to the containment atmosphere. A portion (3%) of the re-evolved elemental iodine is assumed to convert to an organic form upon its release to containment.

15.6.5.3.3 Release Pathways

The release pathways are the containment purge line and containment leakage. The activity releases are assumed to be ground level releases.

During the initial part of the accident, before the containment is isolated, it is assumed that containment purge is in operation and that activity is released through this pathway until the purge valves are closed. No credit is taken for the filters in the purge exhaust line.

The majority of the releases due to the LOCA are the result of containment leakage. The containment is assumed to leak at its design leak rate for the first 24 hours and at half that rate for the remainder of the analysis period.

15.6.5.3.4 Offsite Dose Calculation Models

The offsite dose calculation models are provided in Appendix 15A. The models address the determination of the TEDE doses from the combined acute doses and the committed effective dose equivalent doses.

The exclusion area boundary dose is calculated for the 2-hour period over which the highest doses would be accrued by an individual located at the exclusion area boundary. Because of the delays associated with the core damage for this accident, the first 2 hours of the accident are not the worst 2-hour interval for accumulating a dose.

The low population zone boundary dose is calculated for the nominal 30-day duration of the accident.

For both the exclusion area boundary and low population zone dose determinations, the calculated doses are compared to the dose guideline of 25 rem TEDE from 10 CFR Part 50.34.

15.6.5.3.5 Main Control Room Dose Model

There are two approaches used for modeling the activity entering the main control room. If power is available, the normal heating, ventilation, and air-conditioning (HVAC) system will switch over to a supplemental filtration mode (Section 9.4). The normal HVAC system is not a safety-class system but provides defense in depth.

Alternatively, if the normal HVAC is inoperable or, if operable, the supplemental filtration train does not function properly resulting in increasing levels of airborne iodine in the main control room, the

emergency habitability system (Section 6.4) would be actuated when High-2 iodine or particulate activity is detected. The emergency habitability system provides passive pressurization of the main control room from a bottled air supply to prevent inleakage of contaminated air to the main control room. The bottled air also induces flow through the passive air filtration system which filters contaminated air in the main control room. There is a 72-hour supply of air in the emergency habitability system. After this time, the main control room is assumed to be opened and unfiltered air is drawn into the main control room by way of an ancillary fan. After 7 days, offsite support is assumed to be available to reestablish operability of the control room habitability system by replenishing the compressed air supply. As a defense-in-depth measure, the nonsafety-related normal control room HVAC would be brought back into operation with the supplemental filtration train if power is available.

The main control room is accessed by a vestibule entrance, which restricts the volume of contaminated air that can enter the main control room from ingress and egress. The design of the emergency habitability system (VES) provides 65 scfm ±5 scfm to the control room and maintains it in a pressurized state. The path for the purge flow out of the main control room is through the vestibule entrance and this should result in a dilution of the activity in the vestibule and a reduction in the amount of activity that might enter the main control room. However, no additional credit is taken for dilution of the vestibule via the purge. The projected inleakage into the main control room through ingress/egress is 5 cfm. An additional 10 cfm of unfiltered inleakage is conservatively assumed from other sources.

Activity entering the main control room is assumed to be uniformly dispersed. With the VES in operation, airborne activity is removed from the main control room atmosphere via the passive recirculation filtration portion of the VES.

The main control room dose calculation models are provided in Appendix 15A for the determination of doses resulting from activity which enters the main control room envelope.

15.6.5.3.6 Analytical Assumptions and Parameters

The analytical assumptions and parameters used in the radiological consequences analysis are listed in Table 15.6.5-2.

15.6.5.3.7 Identification of Conservatisms

The LOCA radiological consequences analysis assumptions include a number of conservatisms. Some of these conservatisms are discussed in the following subsections.

15.6.5.3.7.1 Primary Coolant Source Term

The source term is based on conservative assumptions whereas, the activities based on the expected fuel defect level are far less.

15.6.5.3.7.2 Core Release Source Term

The assumed core melt is a major conservatism associated with the analysis. In the event of a postulated LOCA, no major core damage is expected. Release of activity from the core is limited to a fraction of the core gap activity.

15.6.5.3.7.3 Atmospheric Dispersion Factors

The atmospheric dispersion factors assumed to be present during the course of the accident are conservatively selected. Actual meteorological conditions are expected to result in significantly higher dispersion of the released activity.

Site-specific χ/Q values provided in Section 2.3 are bounded by the values given in Tables 15A-5 and 15A-6.

15.6.5.3.8 LOCA Doses

15.6.5.3.8.1 Offsite Doses

The doses calculated for the exclusion area boundary and the low population zone boundary are listed in Table 15.6.5-3. The doses are within the 10 CFR 50.34 dose guideline of 25 rem TEDE.

The reported exclusion area boundary doses are for the time period of 1.3 to 3.3 hours. This is the 2-hour interval that has the highest calculated doses. The dose that would be incurred over the first 2 hours of the accident is well below the reported dose.

At the time the LOCA occurs, there is the potential for a coincident loss of spent fuel pool cooling with the result that the pool could reach boiling and a portion of the radioactive iodine in the spent fuel pool could be released to the environment. The loss of spent fuel pool cooling has been evaluated for a duration of 30 days. There is no contribution to the 2-hour site boundary dose because pool boiling would not occur until after the limiting 2 hours. The 30-day contribution to the dose at the low population zone boundary is less than 0.01 rem TEDE and, when this is added to the dose calculated for the LOCA, the resulting total dose remains less than that reported in Table 15.6.5-3.

15.6.5.3.8.2 Doses to Operators in the Main Control Room

The doses calculated for the main control room personnel due to airborne activity entering the main control room are listed in Table 15.6.3-3. Also listed on Table 15.6.3-3 are the doses due to direct shine from the activity in the adjacent buildings, shine from radioactivity accumulated on the VES or VBS filters, and sky-shine from the radiation that streams out the top of the containment shield building and is reflected back down by air-scattering. The total of these dose paths is within the dose criteria of 5 rem TEDE as defined in GDC 19.

As discussed above for the offsite doses, there is the potential for a dose to the operators in the main control room due to iodine releases from postulated spent fuel boiling. The calculated dose from this source is less than 0.01 rem TEDE and is reported in Table 15.6.3-3.

15.6.5.4 Core and System Performance

Subsection 15.6.5.4A describes the large-break LOCA analysis methodology and results. Subsection 15.6.5.4B describes the small-break LOCA analysis methodology and results.

15.6.5.4A Large-Break LOCA Analysis Methodology and Results

Westinghouse applies the WCOBRA/TRAC computer code to perform best-estimate large-break LOCA analyses in compliance with 10 CFR 50 (Reference 5). WCOBRA/TRAC is a thermal-hydraulic computer code that calculates realistic fluid conditions in a PWR during the blowdown and reflood of a postulated large-break LOCA. The methodology used for the AP1000 analysis is documented in WCAP-12945-P-A, WCAP-14171, Revision 2, WCAP-16009-P-A (References 10, 11, 32), and Reference 31.

The NRC staff has reviewed and approved the ASTRUM best-estimate LOCA methodology (ASTRUM methodology), as documented in the SER attached in front of Reference 32 for estimating the 95th percentile PCT for two-loop, three-loop and four-loop Westinghouse pressurized water reactors (PWRs) and the AP600. Application of the ASTRUM methodology for the AP1000 plant was submitted to the NRC staff per Reference 34. The NRC staff has reviewed and approved the ASTRUM methodology for estimating the 95th percentile PCT for the AP1000 plant, as documented in Reference 35. In the ASTRUM methodology, the WCOBRA/TRAC code is used to calculate the effects of initial conditions, power distributions, and global models, and the HOTSPOT code is used to calculate the effects of local models.

In the ASTRUM uncertainty methodology (Reference 32), as used in the AP1000 LB LOCA analysis, global models and initial-condition, power-distribution, and local uncertainties are sampled independently for each of 124 runs over the same ranges of uncertainty and distributions as in References 10, 32, and 33, as described in References 34 and 31. The sampled global models, initial conditions, and power-distribution uncertainties become inputs to each of the WCOBRA/ TRAC calculations. The thermal-hydraulic boundary conditions for the hot rod are input to the local uncertainties calculation performed by the HOTSPOT code.

Results from the calculations are ranked by PCT from highest to lowest. A similar procedure is repeated for maximum local oxidation (MLO) and core wide oxidation (CWO). In order statistics as applied in the ASTRUM methodology, the limiting case for a parameter, such as peak cladding temperature (PCT), is a conservative estimate of the 95th percentile with 95 percent confidence. The limiting PCT, limiting MLO, and CWO may come from the same case or as many as three different cases because each parameter is assumed to be independent of the other two. The assumption of independence of the calculated licensing parameters is a conservative assumption because there is a dependence of MLO and CWO on cladding temperature.

For the AP1000 large-break LOCA analysis, a plant-specific adaptation of the ASTRUM methodology is applied as described in Reference 31. The plant-specific adaptation explicitly models the effects of thermal conductivity degradation and peaking factor burndown. The best-estimate large-break LOCA analysis complies with the stipulated applicability limits in the Reference 3, Reference 32, and Reference 35 approvals. The post-LOCA long-term core cooling and core boron concentration analyses discussed in Subsection 15.6.5.4C are applicable to the large-break LOCA transient.

15.6.5.4A.1 General Description of WCOBRA/TRAC Modeling

WCOBRA/TRAC is the best-estimate thermal-hydraulic computer code used to calculate realistic fluid conditions in the PWR during blowdown and reflood of a postulated large-break LOCA.

The WCOBRA/TRAC Code Qualification Document (Reference 10) contains a complete description of the code models and justifies their applicability to PWR large-break LOCA analysis.

Table 15.6.5-4 lists AP1000-specific parameters identified for use in the large-break LOCA analysis. WCOBRA/TRAC studies were performed for AP1000 to establish sensitivities to parameter variations. These studies included effects of ranging steam generator tube plugging, ranging the relative power in the low-power assemblies, loss of offsite power coincident with the break initiation, and break location. The calculated results were used to identify bounding conditions, which are then used in the AP1000 uncertainty calculations.

The WCOBRA/TRAC vessel nodalization is developed from plant design drawings to divide the vessel into 10 vertical sections. The bottom of section 1 is the inside vessel bottom, and the top of section 10 is the inside top of the vessel upper head. In addition to the major downcomer and core flow paths, the modeled bypass flow paths are the upper head cooling spray, guide thimbles, and core bypass. After defining the elevations for each section, a noding scheme is defined

for the WCOBRA/TRAC model as shown in Reference 34. WCOBRA/TRAC assumes a vertical flow path for vertically stacked channels, unless specified otherwise in the input. Positive flow for the vertically connected channels (and cells) is upward. Several of the 10 sections are divided vertically into 2 or more levels; these levels are referred to as cells within a channel.

The WCOBRA/TRAC loop model represents the major primary, secondary, and passive safety systems components. Both loops are explicitly modeled, including the hot leg, the steam generator, and the two cold legs and associated pumps. The loop designated “1” has the pressurizer and the PRHR system connections, and loop “2” cold legs have the core makeup tank pressure balance line connections. The reactor coolant pump models contain the AP1000 homologous curves together with appropriate two-phase head and torque multipliers and degradation data. AP1000 values for pump coastdown characteristics are also applied. The passive safety features are modeled using design data for elevations, liquid volumes, and line losses. Because the ADS is not actuated until long after the time of PCT in large-break LOCA events, it is not modeled in detail.

15.6.5.4A.2 Steady-State Calculation

A WCOBRA/TRAC LOCA calculation is initiated from a point at which the flows, temperatures, powers, and pressures are at their approximate steady-state values before the postulated break occurs. Steady-state WCOBRA/TRAC calculations are run for a brief time period to verify that the calculated conditions are steady and that the desired reactor conditions are achieved.

The values used to set the steady-state plant conditions reflect the AP1000 parameters for reactor coolant pump flows, core power, and steam generator tube plugging levels. The fuel parameters provide the steady-state fuel temperatures, pressures, and gap conductances as a function of fuel burnup and linear power, accounting for the effects of thermal conductivity degradation as described in Reference 31. The calculated fuel temperatures from WCOBRA/TRAC are adjusted to match the specified fuel data by adjusting the gap heat transfer coefficient between the pellet and the cladding. Once the vessel fluid temperatures, flows, pressures, loop pressure drop, and core parameters are in agreement with the desired values and are steady, a suitable initial condition is achieved.

15.6.5.4A.3 Signal Logic for Large-Break LOCA

The reactor trip signal occurs due to compensated pressurizer pressure within the first seconds of the large-break transient, however control rod insertion is not modeled in WCOBRA/TRAC and no effects of control rod insertion on reactivity ensue. A safeguards “S” signal occurs due to containment High-2 pressure of 6.7 psig at 2.2 seconds of large-break LOCA transients.

As a consequence of this signal, after appropriate delays, the PRHR and core makeup tank isolation valves open, containment isolation occurs, and the reactor coolant pump automatic trip timer begins. The rapid depressurization of the primary system during a large-break LOCA leads to the initiation of accumulator injection early in the large-break transient. The accumulator flow diminishes core makeup tank delivery to such an extent that the core makeup tank level does not approach the ADS Stage 1 valve actuation point until after the accumulator tank is empty. The accumulator empties long after the blowdown portion of the large-break LOCA transient is complete. Actuation of the ADS on CMT water level does not occur until long after the AP1000 PCT is calculated to occur.

15.6.5.4A.4 Transient Calculation

Once the steady-state calculation is found to be acceptable, the transient calculation is initiated. The semi-implicit pipe break model is added to the desired break location. Cold-leg breaks are analyzed because the hot-leg break location is nonlimiting in the large-break LOCA best-estimate methodology. The break size and type are sampled consistent with the WCAP-16009-P-A (Reference 32) methodology. The containment backpressure is specified consistent with

WCAP-16009-P-A (Reference 32) methodology. The steady-state calculation is restarted with the above changes to begin the transient.

Table 15.6.5-5 shows a general sequence of events following a large cold-leg break LOCA and the relationship of these events to the blowdown and reflood portion of the transient.

15.6.5.4A.5 Large-Break LOCA Analysis Results

For the AP1000 large-break LOCA analysis, a plant-specific adaptation of the ASTRUM best-estimate LOCA analysis methodology is applied, as described in Reference 31. The AP1000 large-break LOCA analysis complies with the restrictions in Reference 3, Reference 32, and Reference 35. AP1000 sensitivity calculations evaluated the sensitivity to the modeling of the CMT and PRHR relative to the reference transient configuration. A case in which the CMT was isolated from the rest of the AP1000 was analyzed, and the calculated PCT was lower than the PCT of the reference transient configuration. Also, a case in which the PRHR was isolated from the rest of the AP1000 was analyzed, and the calculated PCT was 2°F higher than the PCT of the reference transient configuration. The ASTRUM methodology samples the parameters ranged in the global model matrix of calculations, and the final 95 percent uncertainty calculations have been performed for AP1000. Further, local and core-wide cladding oxidation values have been determined using the plant-specific adaption of the approved Reference 32 methodology as described in Reference 31.

In the AP1000 ASTRUM analysis, the limiting PCT and limiting MLO results were from two different uncertainty calculations. Both the limiting PCT case and the limiting MLO case were double ended guillotine breaks. Figures 15.6.5.4A-1 through 15.6.5.4A-12 present the parameters of principal interest for the limiting PCT case. Values of the following parameters are presented:

- Highest calculated cladding temperature at any elevation for the five fuel rods modeled
- Hot rod cladding temperature transient at the limiting elevation for PCT
- Core fluid mass flows at the top of the core for the fuel assemblies modeled in WCOBRA/TRAC
- Pressurizer pressure
- Break flow rates
- Core and downcomer collapsed liquid levels
- Accumulator water flow rates
- Core makeup tank flow rates

15.6.5.4A.6 Description of AP1000 Large-Break LOCA Transient

A description of the limiting PCT case from the AP1000 ASTRUM analysis follows. The limiting PCT case is a double-ended guillotine break. The sequence of events is presented in Table 15.6.5-6. The break was modeled to occur in one of the cold legs in the loop containing the core makeup tanks. After the break opens, the vessel rapidly depressurizes and the core flow quickly reverses. The hot assembly fuel rods dry out and begin to heat up (Figures 15.6.5.4A-1 and 15.6.5.4A-2) after the initial flow reversal (Figure 15.6.5.4A-3).

In Figure 15.6.5.4A-1, “Hot Rod” refers to the hot fuel rod at the maximum linear heat rate for the run, “Hot Assembly” refers to the average fuel rod in the hot assembly that contains the hot rod, “Support Column/Open Hole” refers to the fuel rod in average assemblies under support columns or open holes, “Guide Tubes” refers to the fuel rod in average assemblies under guide tubes, and “Low Power” refers to the fuel rod in the low power peripheral fuel assemblies.

The steam generator secondaries are assumed to be isolated immediately at the inception of the break, which maximizes their stored energy. The massive size of the break causes an immediate, rapid pressurization of the containment. At 2.2 seconds, an “S” signal is generated due to High-2

containment pressure. Applying the pertinent signal processing delay means that the valves isolating the core makeup tanks from the direct vessel injection line and the PRHR begin to open at 4.2 seconds into the transient. The reactor coolant pumps automatically trip after a 5.3 second delay from the actuation of the core makeup tank isolation valves, which is 9.5 seconds into the transient. Core shutdown occurs due to voiding; no credit is taken for the control rod insertion effect.

The system depressurizes rapidly (Figure 15.6.5.4A-4) as the initial mass inventory is depleted due to break flow. The pressurizer drains completely approximately 30 seconds into the transient, and accumulator injection commences 13 seconds into the transient (Figure 15.6.5.4A-5). Accumulator actuation shuts off core makeup tank flow (Figure 15.6.5.4A-6), which has been occurring since the isolation valve opened. The CMT liquid level remains well above the ADS Stage 1 actuation setpoint throughout the AP1000 LBLOCA cladding temperature excursion, even though CMT injection begins again around 200 seconds.

The dynamics of the 95th percentile estimator PCT case are shown in terms of the flow rates of liquid, vapor, and entrained liquid at the top of the core (Figures 15.6.5.4A-7 through 15.6.5.4A-9) for the peripheral, open hole/support column average power interior, and guide tube average power interior assemblies (the corresponding figure for the hot assembly is Figure 15.6.5.4A-3).

Figure 15.6.5.4A-7 demonstrates that liquid downflow exists through the top of the peripheral core assemblies from approximately 1 to 3 seconds and again from 9 to 20 seconds in the 95th percentile estimator PCT case. The power of the fuel in this region is significantly lower than that of the fuel in the open hole/support column and guide tube locations (Table 15.6.5-4), so liquid downflow occurs earlier on the periphery than in the average power assemblies. Once the upper head begins to flash, liquid drains directly down the guide tubes and that fraction that is able to penetrate into the core does so, at a maximum flow rate exceeding 1000 lbm/sec of total liquid flow between 5-23 seconds (Figure 15.6.5.4A-8).

Figure 15.6.5.4A-9 presents the open hole/support column assembly top of core flow behavior. In this case, liquid downflow into the support column/open hole assemblies is delayed relative to downflow into the guide tubes; there is continuous liquid flow from approximately 10 seconds until 22 seconds; the entrained liquid flow continues to be significant until 28 seconds as fluid drains through the upper core plate holes into the upper plenum.

The timing of the initial downflow into the hot assembly is similar to that of the downflow into the open hole/support column average assemblies. Around 10 seconds into the transient, liquid that has built up in the global region above the hot assembly begins to flow into the hot assembly (Figure 15.6.5.4A-3). Significant flow of continuous liquid into the hot assembly exists between 10 to 20 seconds. The liquid flow is not enough to quench the hot rod and hot assembly rod or the average rods at all elevations (Figure 15.6.5.4A-1) although some cooling is achieved.

After 13 seconds into the transient, the accumulator begins to inject water into the upper downcomer region, most of which is initially bypassed to the break. The break flow rate diminishes as the transient progresses (Figure 15.6.5.4A-10). At 27.5 seconds, the accumulator injection begins to refill the lower plenum. At approximately 40.0 seconds, the lower plenum fills to the point that water begins to reflood the core from below (Figure 15.6.5.4A-11). The void fraction at the core bottom begins to decrease, and as time passes, core cooling increases substantially. Figure 15.6.5.4A-11 presents the collapsed liquid levels in the core; Figure 15.6.5.4A-12 presents the collapsed liquid levels in the downcomer. The cladding temperature begins to decrease once the core water level has risen high enough in the core.

15.6.5.4A.7 Global Model Sensitivity Studies and Uncertainty Evaluation

Subsection 15.6.5.4A discusses the treatment of the global model parameters and the uncertainty evaluation in the ASTRUM methodology.

15.6.5.4A.8 Large-Break LOCA Conclusions

In accordance with 10 CFR 50.46, the conclusions of the best-estimate large-break LOCA analysis are that there is a high level probability that the following criteria are met.

1. The calculated maximum fuel element cladding temperature (i.e., peak cladding temperature (PCT)) will not exceed 2200°F.

2. The calculated total oxidation of the cladding (i.e., maximum cladding oxidation) will nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam (i.e., maximum hydrogen generation) will not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. The calculated changes in core geometry are such that the core remains amenable to cooling.

   Note that criterion 4 has historically been satisfied by adherence to criteria 1 and 2, and by assuring that fuel deformation due to combined LOCA and seismic loads is specifically addressed. Criteria 1 and 2 are satisfied for best-estimate large-break LOCA applications. The approved methodology specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends beyond the assemblies in the low power channel as defined in the WCOBRA/TRAC model. This situation has not been calculated to occur for the AP1000. Therefore, acceptance criterion 4 is satisfied.

5. After successful initial operation of the emergency core cooling system (ECCS), the core temperature will be maintained at an acceptably low value and decay heat will be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

   Criterion 5 is satisfied if a coolable core geometry is maintained and the core is cooled continuously following the LOCA. The AP1000 passive core cooling system provides effective core cooling following a large-break LOCA event, even assuming the limiting single failure of a core makeup tank delivery line isolation valve. The large-break LOCA transient has been extended beyond fuel rod quench to the time at which the CMT liquid level has decreased to the setpoint that actuates the fourth-stage ADS valves and IRWST injection. A significant increase in safety injection flow rate occurs when the IRWST becomes active. The analysis performed demonstrates that CMT injection is sufficient to maintain the mass inventory in the core and downcomer, from the period of fuel rod quench until IRWST injection. The AP1000 passive core cooling system provides effective post-LOCA long-term core cooling (Subsection 15.6.5.4C).

Table 15.6.5-8 presents the calculated 95th percentile PCT, maximum cladding oxidation, maximum hydrogen generation, and core cooling results.

Based on the analysis, the Westinghouse Best-Estimate Large-Break LOCA methodology has shown that the acceptance criteria of 10 CFR 50.46 are satisfied for AP1000 when the burnup-related effects of thermal conductivity degradation and peaking factor burndown are considered.

15.6.5.4B Small-Break LOCA Analyses

Should a small-break LOCA occur, depressurization of the reactor coolant system results in a pressure decrease in the pressurizer. The reactor trip signal occurs when the pressurizer Low-2 pressure trip setpoint is reached. An “S” signal is generated when the appropriate setpoint is reached. These measures limit the consequences of the accident in two ways:

- Reactor trip leads to a rapid reduction of power to a residual level corresponding to fission product decay heat by the insertion of control rods to shut down the reactor.

- Injection of borated water provides core cooling and prevents excessive cladding temperatures.

15.6.5.4B.1 Description of Small-Break LOCA Transient

The AP1000 plant design includes passive safety features to prevent or minimize core uncovery during small-break LOCAs. The passive safety design approach is to depressurize the reactor coolant system if the break or leak is greater than the capability of the makeup system or if the non-safety makeup system fails to perform. By depressurizing the reactor coolant system, large volumes of borated water in the accumulators and in the IRWST become available for cooling the core. The small-break analyses demonstrate that, with a single failure of one of the ADS Stage 4 valves located off the non-pressurizer loop, the passive systems are capable of depressurizing the reactor coolant system while maintaining acceptable core conditions and establishing stable delivery of cooling water from the IRWST.

During a small-break LOCA, the reactor coolant system depressurizes to the pressurizer Low-2 pressure setpoint, actuating a reactor trip signal. The passive core cooling system is aligned for delivery following the generation of an “S” signal when the pressurizer Low-3 pressure setpoint is reached. The passive core cooling system includes two core makeup tanks, two accumulators, a large IRWST, and the PRHR heat exchanger.

The core makeup tanks operate at reactor coolant system pressure. They provide high-pressure safety injection in the event of a small-break LOCA and are filled with borated water to provide core shutdown margin. The core makeup tanks share a common discharge line with the accumulators and IRWST. Gravity head of the colder water in the core makeup tanks provides the injection of the core makeup tanks. The core makeup tanks are located above the reactor coolant loops, and each is equipped with a pressure balancing line from a cold leg to the top of the tank.

The pressurized accumulators provide additional borated water to the reactor coolant system in the event of a LOCA. Nominally, these 2020 ft^3 tanks are filled with 1700 ft^3 of water and nitrogen cover gas at an initial pressure of 700 psig. Once sufficient reactor coolant system depressurization occurs, either as a result of a LOCA or the actuation of the ADS, accumulator injection begins.

The IRWST provides an additional source of water for core cooling. To attain injection from the IRWST, the reactor coolant system pressure must be lowered to approximately 13 psi above containment pressure. For this pressure to be achieved during a small-break LOCA, the actuation of the ADS valves is required.

The ADS consists of a series of valves, connected to the pressurizer and hot legs, which provide a phased depressurization of the reactor coolant system. As the reactor coolant system loses inventory

through the break, the core makeup tanks provide flow to the reactor vessel. When the inventory in one core makeup tank drops to the 67.5 percent volume, the ADS valves begin opening to accelerate the reactor coolant system depressurization rate. The ADS Stage 1 valves open at the 67.5 percent volume setpoint; the Stage 2 and the Stage 3 valves open in a timed sequence thereafter. The flow from the first three stages of the ADS is discharged into the IRWST through a sparger system. The fourth stages of the ADS are connected to the reactor coolant system hot legs and discharge to containment atmosphere. The ADS Stage 4 valves are activated when one core makeup tank reaches the 20 percent volume and a delay has elapsed after the ADS Stage 3 actuation.

As the reactor system depressurizes and mass is lost out of the break, mass is added to the reactor vessel from the core makeup tanks and the accumulators. When the system is depressurized below the IRWST delivery pressure, flow from the IRWST continues to maintain the core in a coolable state. Calculations described in this section indicate that acceptable core cooling is provided for the small-break LOCA transients.

15.6.5.4B.2 Small-Break LOCA Analysis Methodology

Small-break LOCA response is evaluated for the AP1000 plant with an evaluation model that conforms to 10 CFR 50 Appendix K (Reference 1). The elements of the AP1000 small-break LOCA evaluation model are the following:

- NOTRUMP computer code
- NOTRUMP homogeneous sensitivity model
- Critical heat flux assessment during accumulator injection
- SBLOCTA computer code

15.6.5.4B.2.1 NOTRUMP Computer Code

The NOTRUMP computer code is used in the analysis of LOCAs due to small-breaks in the reactor coolant system. The NOTRUMP computer code is a one-dimensional, general network code, which includes a number of advanced features. Among these features are the calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. The version of NOTRUMP used in AP1000 small-break LOCA calculations has been validated against applicable passive plant test data (References 22 and 24). The code has limited capability in modeling upper plenum (UP) and hot leg entrainment and did not predict the core collapsed level during the accumulator injection phase adequately. The NOTRUMP homogeneous sensitivity model (discussed in Subsection 15.6.5.4B.2.2) and the critical heat flux assessment during the accumulator injection phase (discussed in Subsection 15.6.5.4B.2.3) supplement the base NOTRUMP analysis to demonstrate the adequacy of the design.

In NOTRUMP, the reactor coolant system is nodalized into volumes interconnected by flow paths. The transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum applied throughout the system. A description of NOTRUMP is given in References 12 and 13. The applicability of NOTRUMP to AP600 is documented in Reference 26. The AP600 modeling approach, described in Reference 17, is also used to develop the AP1000 model; the applicability of the NOTRUMP code to the AP1000 plant is documented in Reference 24.

The use of NOTRUMP in the analysis involves the representation of the reactor core as heated control volumes with an associated bubble rise model to permit a transient mixture height calculation. The multi-node capability of the program enables an explicit and detailed spatial representation of various system components. Table 15.6.5-9 lists important input parameters and initial conditions of the analysis.

A steady-state input deck was set up to comply, where appropriate, with the standard small-break LOCA Evaluation Model methodology. Major features of the modeling of the AP1000 plant follow:

- Accumulators are modeled at an initial pressure of 715 psia.

- The flow through the ADS links is modeled using the Henry-Fauske and the homogeneous equilibrium (HEM) critical flow models. The Henry-Fauske subcooled correlation is used for subcooled flow, and the HEM correlation is used for superheated flow. For saturated donor conditions above the transition static quality of 10 percent, the HEM correlation is used. Below the transition quality, the flow is transitioned between the HEM correlation and the Henry-Fauske saturated correlation.

- Isolation and check valves used in the passive safety systems are modeled.

- The IRWST is modeled as two connected fluid nodes. The lower node is connected to the direct vessel injection line and is the source of injection water to the direct vessel injection (DVI) lines driven by gravity head. The upper node acts as a sink for the ADS flow from the pressurizer and as a heat sink for the PRHR heat exchanger. These nodes are modeled as having an initial temperature of 120°F, a pressure reflective of transient-specific containment conditions (described in a subsequent item), and the minimum full-power operation level of 28.03 feet. Therefore, the minimum head for IRWST injection is assumed.

- The PRHR system is modeled in accordance with the guidance provided in References 22 and 24. The PRHR isolation valve is modeled as opening with the maximum delay after the generation of an “S” signal to conservatively deny the cooling capability of the heat exchanger to the reactor coolant system for an extended period.

- The core power is initially set to 101 percent of the nominal core power. The reactor trip signal occurs when the pressurizer pressure falls below 1800 psia. A conservative delay time is modeled between the reactor trip signal and reactor trip. Decay heat is modeled according to the ANS-1971 (Reference 2) standard, with 20 percent uncertainty added consistent with Reference 1.

- The “S” signal is generated when the pressurizer pressure falls below 1700 psia. The isolation valves on the core makeup tank injection lines begin to open after the signal setpoint is reached; the valves are then assumed to open linearly. The main feedwater isolation valves are ramped closed between 2 and 7 seconds after the “S” signal. The reactor coolant pumps are tripped 7 seconds after the “S” signal.

- The ADS actuation signals are generated on low core makeup tank levels and the ADS timer delays. A list of the ADS parameters is given in Table 15.6.5-10. Note that the small-break LOCA transients model the minimum valve flow area given in Table 15.6.5-10. The ADS Stages 1, 2, and 3 are modeled as discharging through spargers submerged in the IRWST at the appropriate depth.

- The inadvertent ADS actuation and 2-inch cold leg break NOTRUMP simulations utilize a time-dependent containment pressure in the boundary node modeling of the containment. The containment conditions were generated by providing mass and energy releases from these breaks to the AP1000 WGOTHIC minimum containment pressure model (described in Section 13.8 of Reference 6). The WGOTHIC code then calculates the containment pressure response. The inadvertent ADS actuation and 2-inch cold leg break NOTRUMP simulations then utilized the time-dependent pressure history curves as generated by WGOTHIC. For the double-ended DVI (DEDVI) line break simulations, a conservatively low 20 psia containment

pressure was used based on containment pressurization calculations performed with the WGOTHIC containment model. The 10-inch cold leg break case models a constant containment pressure of 14.7 psia.

- The steam generator secondary is isolated immediately after the reactor trip signal, due to closure of the turbine stop valves. The main steam safety valves actuate and remove energy from the steam generator secondary when pressure reaches approximately 1210 psia.

Active single failures of the passive safeguards systems are considered. The limiting failure is judged to be one out of four ADS Stage 4 valves failing to open on demand, which is the failure that most severely impacts depressurization capability. The safety design approach of the AP1000 plant is to depressurize the reactor coolant system to the containment pressure in an orderly fashion such that the large reservoir of water stored in the IRWST is available for core cooling. The mass inventory plots provided for the breaks show the minimum inventory condition generally occurs at the start of IRWST injection. Penalizing the depressurization is the most conservative approach in postulating the single failure for such breaks.

The analyzed small-break LOCA break spectrum includes breaks that exhibit a minimum reactor vessel inventory early in the transient, before the ADS Stage 4 depressurization phase: the DEDVI line break at 20 psia containment backpressure and 10-inch cold leg break transients. In these transients, the early mass inventory decrease is terminated by injection flow from the accumulators. For consistency and because the transition to IRWST injection is still a tenuous period of the transients, the conservative failure of one of the ADS Stage 4 valves located off of the non-pressurizer loop is assumed in all cases.

15.6.5.4B.2.1.1 AP1000 Model-Detailed Noding

The AP1000 NOTRUMP model was developed in the same fashion as the AP600 NOTRUMP model (details of the AP600 NOTRUMP model are provided in Reference 17). Modifications of the AP600 model to create the AP1000 model include the following:

- The addition of two core nodes one foot each in length to reflect the added active fuel length of this design.

- The ADS Stage 4 (ADS-4) flow path resistances were increased to accommodate shortcomings in NOTRUMP identified during the integral test facility simulations; namely, the lack of a detailed momentum flux model in the ADS-4 discharge paths. A detailed calculation of the energy and momentum equations is performed for the ADS-4 piping over a range of flow and pressure conditions to provide a benchmark for the NOTRUMP ADS-4 flow path resistance. The methodology used to determine the resistance increase is described in Reference 24. By increasing the ADS-4 resistances, the onset of IRWST injection is more appropriately calculated. This methodology directly addresses the effect of momentum flux in ADS-4. The ADS-4 resistance increase utilized is computed for the NOTRUMP analyses in this section to be a 78 percent ADS-4 flow path resistance increase.

15.6.5.4B.2.1.2 Plant Initial Conditions/Steady-State

Steady-state calculations are performed prior to initiating the transient portion of the calculations.

Table 15.6.5-9 contains the most important initial conditions for the transient calculations. The behaviors of the primary pressure and pressurizer level, steam generator pressures, and the core flow rate are stable at the end of the 100-second steady-state calculation.

15.6.5.4B.2.2 NOTRUMP Homogeneous Sensitivity Model

In order to address the uncertainties associated with entrainment in the upper plenum and hot leg following ADS-4 operation, a sensitivity study is performed with the limiting break with respect to these phenomena, effectively maximizing the amount of entrainment downstream of the core. This methodology is described and the original results are presented for the double-ended direct vessel injection (DEDVI) line break in detail in Reference 24.

[*In order to maximize the entrainment downstream of the core for the limiting break with respect to entrainment, NOTRUMP is run with the regions of the upper plenum, hot leg, and ADS-4 lines in a homogeneous fluid condition, with slip = 1, to demonstrate that even with maximum entrainment, the 10 CFR 50.46 criteria are met.*]*

15.6.5.4B.2.3 Critical Heat Flux Assessment During Accumulator Injection

[*An assessment is performed of the peak core heat flux with respect to the critical heat flux during the later ADS depressurization time period for a double-ended rupture of the direct vessel injection line. This time period corresponds to the accumulator injection phase of the transient. The predicted average mass flux at the core inlet and the reactor pressure from the NOTRUMP computer code base model analysis are used as input parameters to critical heat flux correlation as described in Reference 30. The requirements of 10 CFR 50.46 are met provided the maximum heat flux is less than the critical heat flux calculated by the correlation.*]* NOTRUMP has been shown (Reference 24) to adequately predict mass flux and pressure for integral systems tests.

The predicted mass flux at the core inlet is on the average constant and corresponds to 7.2 lbm ft^{-2} s^{-1} (~35 kg m^{-2} s^{-1}). The key thermal-hydraulic parameters at different times during the ADS depressurization time period are summarized in following table.

Time (sec)	UP Pressure (kPa)	UP Pressure (psia)	Mass Flux (kg/m^2s)	Hot Channel Heat Flux (kW/m^2)
400.5	1300	188.6	35	48.6
450.6	1018	147.6	35	47.2
500.7	643	93.2	35	46.0
569.9	343	49.8	35	44.5

For the critical heat flux assessment, the peak core heat flux is applied to simulate the hot channel condition in a conservative manner. No credit is taken for increased flow in the hot channel that is known to occur in rod bundles.

The correlation applied for this assessment is from vertical tube data (Reference 30) and recognizes two regimes depending on the mass flux. The main difference between the two is the mass flux dependence. The equations for the two regimes are as follows:

$$q^*_{CL} = q^*_{CF} + 0.01351\left(D^*\right)^{-0.473}\left(L/D\right)^{-0.533}\left|G^*\right|^{1.45} \quad \text{for low G*}$$

and,

$$q^*_{CH} = q^*_{CF} + 0.05664\left(D^*\right)^{-0.247}\left(L/D\right)^{-0.501}\left|G^*\right|^{0.77} \quad \text{for high G*}$$

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

The first term of above correlations is,

$$q^*_{CF} = 1.61\left(\frac{A}{Ah}\right)\frac{\left(D^*\right)^{0.5}}{\left[1+\left(\frac{\rho_g}{\rho_1}\right)^{0.25}\right]^2}$$

where A is the flow area and Ah is the heated area.

The dimensionless CHF is calculated as,

$$q^*_{CHF} = \min(q^*_{CL}, q^*_{CH})$$

Dimensionless CHF, G, and D are defined as,

$$q^*_{CHF} = \frac{q''_{CHF}}{h_{fg}\sqrt{\lambda\rho_g g\Delta\rho}}$$

$$G^* = \frac{G}{\sqrt{\lambda\rho_g g\Delta\rho}}$$

$$D^* = \frac{D}{\lambda}$$

where λ is the length scale of the Taylor instability:

$$\lambda = \sqrt{\frac{\sigma}{g\Delta\rho}}$$

Conservative application of this correlation with the AP1000 parameters indicates that the peak AP1000 heat flux during this period is approximately 30 percent or more below the predicted critical heat flux.

This CHF assessment addresses core cooling during a time period where the NOTRUMP computer code may not conservatively predict the core average void fraction. The requirements of 10 CFR 50.46 are met during this period since this CHF assessment indicates peak core heat flux is less than critical heat flux. Cladding temperatures will remain near the coolant saturation temperature, well below the 10 CFR 50.46 peak cladding temperature limit.

15.6.5.4B.2.4 SBLOCTA Computer Code

The LOCTA-IV computer code (Reference 4) was modified as described in Reference 13 to form SBLOCTA, a small-break LOCA specific version of the LOCTA-IV code. The SBLOCTA code calculates the cladding temperature and oxidation transients for the hot rod and hot assembly average rod, which represent the highest power rod and the average of the highest power fuel assembly in the core. Peak cladding temperature (PCT) calculations are performed with the SBLOCTA code using boundary conditions from the NOTRUMP calculation. In addition to PCT, SBLOCTA also calculates the maximum local and axial average zirconium-water oxidation reaction based on the Baker-Just oxidation model. In the event that the NOTRUMP code predicts core uncovery in the core average channel, the NOTRUMP boundary conditions will be transferred to the SBLOCTA code to perform fuel rod heat-up calculations.

15.6.5.4B.3 Small-Break LOCA Analysis Results

Several small-break LOCA transients are analyzed using NOTRUMP, and the results of these calculations are presented. The transients documented herein analyze a single failure of one ADS Stage 4 valve on the non-pressurizer side. The results demonstrate that the minimum reactor vessel mixture mass inventory condition occurs for the relatively small system pipe breaks. Larger breaks exhibit a greater margin-to-core uncovery.

15.6.5.4B.3.1 Introduction

The small-break LOCA safety design approach for the AP1000 plant is to provide for a controlled depressurization of the primary system if the break cannot be terminated, or if the nonsafety-related charging system is postulated to be lost or cannot maintain acceptable plant conditions. Nonsafety-related systems are not modeled in this design basis analysis; the testing conducted in the SPES-2 facility has indicated that the mass inventory condition during small LOCAs is significantly improved when these nonsafety-related systems operate. The core makeup tank level activates primary system depressurization through the actuation of the automatic depressurization system. The core makeup tank provides makeup to help compensate for the postulated break in the reactor coolant system. As the core makeup tank level drops, Stages 1 through 4 of the ADS valves are ramped open in sequence. The ADS valve parameters are presented in Table 15.6.5-10. Note that the small-break LOCA transients model the minimum valve flow area given in Table 15.6.5-10. The reactor coolant system depressurizes due to the break and the ADS valves, while subcooled water from the core makeup tanks and accumulators enters the reactor vessel downcomer to maintain system inventory. Design basis maximum values of passive core cooling system resistances are applied to obtain a conservative prediction of system behavior during the small LOCA events.

During controlled depressurization via the ADS, the accumulators and core makeup tanks maintain system inventory for small-break LOCAs. Once the reactor coolant system depressurizes, injection from the IRWST maintains core cooling. For continued injection from the IRWST, the reactor coolant system must remain depressurized. To conservatively model this condition, design maximum resistance values are specified for the IRWST delivery lines.

A series of small-break LOCA calculations are performed to assess the passive core cooling safety system design performance. In these calculations, the decay heat used is the ANS-1971 standard (Reference 2) plus 20 percent for uncertainty as specified in 10 CFR 50, Appendix K (Reference 1). This maximizes the core steam generation to be vented. The breaks analyzed in this document include the following:

Inadvertent ADS Actuation

A “no-break” small-break LOCA calculation is analyzed that assumes an inadvertent actuation of the ADS. The transient begins with the opening of the Stage 1 valves, which is a situation that minimizes

the venting capability of the reactor coolant system. Only the ADS valve vent area is available; no additional vent area exists due to a break. This case examines whether sufficient vent area is available to completely depressurize the reactor coolant system and achieve injection from the IRWST to prevent/minimize core uncovery. The worst single failure for this situation is a failure of one of two ADS Stage 4 valves connected to the non-pressurizer side hot leg. The ADS Stage 4 valve is the largest ADS valve, and it vents directly to the containment with no additional backpressure from the spargers being submerged in the IRWST. The containment pressure is a conservative, time-dependent containment pressure response. This pressure response is based on iterative execution of the NOTRUMP and WGOTHIC codes. The NOTRUMP code generates the mass and energy releases from the inadvertent ADS actuation simulation which are then input into the WGOTHIC minimum containment pressure model, which calculates the containment pressure response.

2-inch Break in a Cold Leg

A 2-inch equivalent diameter break is analyzed as a representative break, not specific to a particular pipe connection. The small size of the break leads to a long period of recirculatory flow from the cold legs into the core makeup tanks. This delays the formation of a vapor space in the core makeup tank and therefore the actuation of the ADS. The containment pressure is a conservative, time-dependent containment pressure response. This pressure response is based on iterative execution of the NOTRUMP and WGOTHIC codes. The NOTRUMP code generates the mass and energy releases from the 2-inch cold leg break simulation which are then input into the WGOTHIC minimum containment pressure model, which calculates the containment pressure response.

Double-Ended Rupture of the Direct Vessel Injection Line

The DEDVI line break evaluates the ability of the plant to recover from a moderately sized break with only half of the total passive core cooling system capacity available. The vessel side of the break of the DEDVI line break is 4 inches in equivalent diameter. The double-ended nature of this break means that there are effectively two breaks modeled:

- Downcomer to containment. The direct vessel injection nozzle includes a venturi, which limits the available break area.
- Direct vessel injection line into containment from the cold leg balance line and the broken line core makeup tank.

The containment pressure is conservatively assumed to be 20 psia based on iterative execution of the NOTRUMP and WGOTHIC codes. The NOTRUMP code generates the mass and energy releases from the DEDVI line break which are input into the WGOTHIC minimum containment pressure model, which calculates the containment pressure response used to confirm the NOTRUMP containment pressure assumption remains conservative.

The peak core heat flux during the accumulator injection period is assessed relative to the predicted critical heat flux as discussed in Subsection 15.6.5.4B.2.3.

Double-Ended Rupture of the Direct Vessel Injection Line Entrainment Sensitivity

The sensitivity case is performed to assess the effect of higher than expected entrainment in the upper plenum and hot legs on the overall system response and core cooling.

10-inch Cold Leg Break

The 10-inch equivalent diameter break models a break size that approaches the upper limit size for small-break LOCAs.

15.6.5.4B.3.2 Transient Results

The transient results are presented in tables and figures for the key AP1000 parameters of interest in the following sections.

15.6.5.4B.3.3 Inadvertent Actuation of Automatic Depressurization System

An ADS actuation signal is spuriously generated and the ADS Stage 1 valves open. The plant, which is operating at 101-percent power, is depressurized via the ADS alone. Only safety-related systems are assumed to operate in this and other small-break LOCA cases. The ADS Stage 2 and 3 valves open in sequence after the ADS Stage 1 valves open (Table 15.6.5-10). At the 20 percent core makeup tank volume, the operating ADS Stage 4A valve, which is connected to the PRHR inlet pipe, receives a signal to open. After a 60 second delay, both Stage 4B valves (one connected to the non-pressurizer side hot leg and the other connected to the PRHR inlet pipe) open. The path that fails to open as the assumed single active failure is the Stage 4A valve connected to the non-pressurizer side hot leg. The assumed reactor steady-state initial conditions can be found in Table 15.6.5-9. The sequence of events for the transient is given in Table 15.6.5-11.

This case uses a containment backpressure based on the containment pressure history that occurs as a result of the inadvertent ADS actuation. It represents a conservatively low estimate of the expected containment pressure response during the transient. The containment pressurizes for an inadvertent ADS actuation as a result of the ADS Stage 4 discharge paths that vent directly to the containment atmosphere. The time-dependent containment pressure curve (Figure 15.6.5.4B-1(c)) was calculated using the mass and energy releases from the NOTRUMP small-break LOCA code, which were used as inputs in the WGOTHIC containment model.

Transient results are shown in Figures 15.6.5.4B-1(a) through 15.6.5.4B-16(b). The transient is initiated by the opening of the two ADS Stage 1 paths. Reactor trip, reactor coolant pump trip, and safeguards actuation signals are generated via pressurizer low-pressure signals with appropriate delays. After generation of the reactor trip signal, the turbine stop valves close. The main feedwater isolation valves begin to close 2 seconds after the “S” signal pressure setpoint is reached. The reactor coolant pumps begin to coast down due to an automatic trip signal following a 7 second delay from the “S” signal. The opening of the ADS valves and the reduction in core power due to reactor trip causes the primary pressure to fall rapidly (Figure 15.6.5.4B-1(a)). Flow of fluid toward the open ADS paths causes the pressurizer to fill rapidly (Figure 15.6.5.4B-2), and the ADS flow becomes two-phase (Figures 15.6.5.4B-3 and 15.6.5.4B-4(a)). The safeguards actuation signal opens the valves isolating the core makeup tanks and circulation of cold water begins (Figures 15.6.5.4B-5 and 15.6.5.4B-6). The core makeup tanks begin to drain (Figures 15.6.5.4B-7 and 15.6.5.4B-8) during the accumulator injection period (Figures 15.6.5.4B-10 and 15.6.5.4B-11).

Continued mass flow through the ADS Stage 1, 2, and 3 valves drains the upper parts of the reactor coolant system (Figure 15.6.5.4B-4(b)). The cold leg side of the steam generator tubes start to drain, followed by the drop in mixture levels in the hot leg sides. As the ADS Stage 2 and 3 paths begin to open, increased ADS flow causes the primary pressure to fall rapidly (Figures 15.6.5.4B-1(a) and 15.6.5.4B-1(b)). As the cold leg sides of the steam generator tubes empty, the cold legs drain and a mixture level forms in the downcomer (Figure 15.6.5.4B-9).

The primary pressure falls below the pressure in the accumulators thus causing the accumulator check valves to open and accumulator delivery to begin (Figures 15.6.5.4B-10 and 15.6.5.4B-11). The accumulators, and then the core makeup tanks inject until they empty. The ADS flow falls off (Figures 15.6.5.4B-3, 15.6.5.4B-4(a) and 15.6.5.4B-4(b)) as the primary pressure decreases. The flow from the accumulators raise the mixture levels in the upper plenum and downcomer (Figures 15.6.5.4B-16(a) and 15.6.5.4B-9).

As the levels in the core makeup tanks reach the ADS Stage 4 actuation setpoint, the ADS Stage 4 valves open as described earlier. Activating the Stage 4 paths (Figures 15.6.5.4B-12(a), 15.6.5.4B-12(b) and 15.6.5.4B-12(c)) leads to reduced flow through ADS Stages 1, 2, and 3 (Figures 15.6.5.4B-3, 15.6.5.4B-4(a), and 15.6.5.4B-4(b)). The reduced flow allows the pressurizer mixture level to fall (Figure 15.6.5.4B-2), and these stages begin to discharge only steam. After the core makeup tanks are empty (Figures 15.6.5.4B-7 and 15.6.5.4B-8), IRWST injection (Figures 15.6.5.4B-13 and 15.6.5.4B-14) does not begin until the pressure in the DVI line drops below the IRWST injection pressure, creating an injection gap (Table 15.6.5-11 and Figures 15.6.5.4B-5, 15.6.5.4B-6, 15.6.5.4B-13 and 15.6.5.4B-14). The overall decrease in reactor vessel mixture inventory (Figure 15.6.5.4B-15(b)) is large enough to result in a core uncovery (Figure 15.6.5.4B-16(a)). At 4000 seconds, the calculation is considered complete; IRWST delivery exceeds the ADS flows (which are removing the decay heat), and the reactor coolant system inventory and reactor vessel mixture inventory are slowly rising (Figures 15.6.5.4B-15(a) and 15.6.5.4B-15(b)).

The inadvertent opening of the ADS Stage 1 transient confirms the capability of the minimum venting area to depressurize the reactor coolant system to the IRWST pressure. The analysis indicates that the ADS sizing is sufficient to depressurize the reactor coolant system assuming the worst single failure as the failure of a Stage 4 ADS path to open and the 10 CFR 50 Appendix K (Reference 1) required decay heat (based on the ANS-1971 Standard (Reference 2) plus 20 percent), which lead to an over estimation of the core steam generation rate. Even under these limiting conditions, IRWST injection is obtained, and the core mixture level recovers, which terminates the cladding heatup transient (Figure 15.6.5.4B-16(b)).

15.6.5.4B.3.4 2-inch Cold Leg Break

This case models a 2-inch (50.8 mm) break occurring in a cold leg on the pressurizer side of the RCS. The reactor steady-state initial conditions assumed for this transient can be found in Table 15.6.5-9. The event times for this transient are given in Table 15.6.5-12.

This case uses a containment backpressure based on the containment pressure history that occurs as a result of the 2-inch cold leg break. It represents a conservatively low estimate of the expected containment pressure response during the transient. The containment pressurizes for a 2-inch cold leg break as a result of the break and the ADS Stage 4 discharge paths that vent directly to the containment atmosphere. The time-dependent containment pressure curve (Figure 15.6.5.4B-17(c)) was calculated using the mass and energy releases from the NOTRUMP small-break LOCA code, which were used as inputs in the WGOTHIC containment model.

Transient results are shown in Figures 15.6.5.4B-17(a) through 15.6.5.4B-35. The break opens at time zero, and the pressurizer pressure begins to fall as shown in Figure 15.6.5.4B-17(a), as mass is lost out the break. The pressurizer mixture level initially decreases as given in Figure 15.6.5.4B-18. The liquid and vapor flow out of the break is shown in Figures 15.6.5.4B-32 and 15.6.5.4B-33. The pressurizer pressure falls below the reactor trip set point, causing the reactor to trip (after the appropriate time delay) and causing isolation of the steam generator main steam lines. The core makeup tank discharge isolation valves for both core makeup tanks and the PRHR delivery line isolation valves open after an “S” signal occurs (with appropriate delays); the reactor coolant pumps trip after an “S” signal with a 7 second delay. The reactor coolant system is cooled by natural circulation with decay heat being removed by the steam generators through their safety valves, through the break and via the PRHR. The PRHR heat removal and integrated heat removal are shown in Figure 15.6.5.4B-34 and Figure 15.6.5.4B-35. Once the core makeup tank isolation valves open, the core makeup tanks begin to inject borated water into the reactor coolant system as shown in Figures 15.6.5.4B-22 and 15.6.5.4B-23.

As time proceeds, the loops drain to the reactor vessel. The mixture level in the downcomer begins to drop as seen in Figure 15.6.5.4B-21. The core makeup tank reaches the 67.5 percent volume, and after an appropriate delay, the ADS Stage 1 valves open. When the ADS is actuated, the mixture level increases in the pressurizer (Figure 15.6.5.4B-18) because an opening has been created at the top of the pressurizer. After these valves open, a rapid depressurization occurs as seen in Figure 15.6.5.4B-17(a); the accumulator gas cover pressure is reached, and the accumulators begin to inject. The injection flow from the core makeup tanks are shown in Figures 15.6.5.4B-22 and 15.6.5.4B-23, and from the accumulators, in Figures 15.6.5.4B-24 and 15.6.5.4B-25.

As Figures 15.6.5.4B-22 and 15.6.5.4B-23 indicate, when the accumulators begin to inject, the flow from both core makeup tanks is reduced, and the flow is temporarily reversed due to the pressurization of the DVI line and core makeup tanks injection lines by the accumulators.

The ADS Stage 2 valves open, maintaining the depressurization rate as shown in Figure 15.6.5.4B-17(a). ADS Stage 3 valves open, thereby increasing the system venting capability. Figures 15.6.5.4B-31(a), 15.6.5.4B-31(b) and 15.6.5.4B-31(c) indicate the instantaneous liquid, instantaneous vapor and integrated total mass discharged from the ADS Stage 1-3 valves. The ADS Stage 4 valves open when the core makeup tank water volume is reduced to 20 percent. Figures 15.6.5.4B-28(a), 15.6.5.4B-28(b) and 15.6.5.4B-28(c) indicate the instantaneous liquid, instantaneous vapor and integrated total mass discharged from the ADS Stage 4 valves. After the ADS Stage 4 paths open, the pressurizer begins to drain mixture into the hot legs as seen in Figure 15.6.5.4B-18. After the CMTs are empty, IRWST injection does not begin until the pressure in the DVI line drops below the IRWST injection pressure, creating an injection gap (Table 15.6.5-12 and Figures 15.6.5.4B-22, 15.6.5.4B-23, 15.6.5.4B-26, and 15.6.5.4B-27). The mass inventory shown in Figure 15.6.5.4B-29(a) considers the primary inventory to be the reactor coolant system proper, including the pressurizer; the mass present in the passive safety system components is not included. The mass inventory shown in Figure 15.6.5.4B-29(b) considers the reactor vessel mixture inventory, including the downcomer, lower plenum, core fluid channel, upper plenum and upper head, and clearly shows the decrease in the inventory during the injection gap period. Once the pressures in the DVI lines drop below the IRWST injection pressure, flow enters the reactor vessel from the IRWST. The mixture level in the reactor vessel is approximately at the hot leg elevation as shown in Figure 15.6.5.4B-30(a) for the majority of the transient; however, the upper plenum mixture level drops during the injection gap period and the core uncovers as the mixture level drops below the top of the active fuel. The 2-inch break cases exhibits a cladding heatup transient as a result of the core uncovery as shown in Figure 15.6.5.4B-30(b).

15.6.5.4B.3.5 Direct Vessel Injection Line Break

This case models the double-ended rupture of the DVI line at the nozzle into the downcomer. The broken loop injection system (consisting of an accumulator, a core makeup tank, and an IRWST delivery line) is modeled to spill completely out of the DVI line side of the break into containment. The steady-state reactor coolant system conditions for this transient are shown in Table 15.6.5-9. Minimum resistances are applied to the broken loop IRWST injection line to maximize the spill to containment, thus minimizing the reactor coolant system mass inventory. The containment pressurization is calculated using the mass and energy releases from the NOTRUMP small-break LOCA code in the WGOTHIC minimum containment pressure model and demonstrates that the 20 psia containment backpressure assumption is conservative. This case uses a containment backpressure defined to be a constant 20 psia. While not exactly reflecting the containment pressure history that occurs as a result of the DVI line break, it represents a conservatively low estimate of the expected containment pressure response during a DEDVI transient. The containment pressurizes for a DEDVI line break as a result of the break mass and energy releases in addition to the ADS-4 discharge paths that vent directly to the containment atmosphere.

The event times for this transient are shown in Table 15.6.5-13. Transient results are shown in Figures 15.6.5.4B-36 through 15.6.5.4B-55. The break is assumed to open instantaneously at 0 seconds. The accumulator on the broken loop starts to discharge via the DVI line to the containment. Figure 15.6.5.4B-36 shows the subcooled discharge from the downcomer nozzle, which causes a rapid reactor coolant system (RCS) depressurization (Figure 15.6.5.4B-38(a)). A reactor trip signal is generated, followed by generation of the “S” signal. Following a delay, the isolation valves on the core makeup tank and PRHR delivery lines begin to open. The PRHR heat removal and integrated heat removal are shown in Figure 15.6.5.4B-54 and Figure 15.6.5.4B-55. The “S” signal also causes closure of the main feedwater isolation valves after a 2 second delay and trips the reactor coolant pumps after a 7 second delay. The opening of the core makeup tank isolation valves allows the broken loop core makeup tank to discharge directly to the containment (Figure 15.6.5.4B-39), and a small circulatory flow develops through the intact loop core makeup tank (Figure 15.6.5.4B-40).

As the pressure falls, the reactor coolant system fluid saturates, and a mixture level forms in the upper plenum and then falls to the hot leg elevation (Figure 15.6.5.4B-41). The upper parts of the reactor coolant system start to drain, and a mixture level forms in the downcomer (Figure 15.6.5.4B-42) and falls below the elevation of the break. Two-phase discharge, then vapor flow occurs from the downcomer side of the break (Figure 15.6.5.4B-37).

In the core makeup tank connected to the broken loop, a level forms and starts to fall. The ADS Stage 1 setpoint is reached, and the ADS Stage 1 valves open after the signal delay time elapses. The ensuing steam discharge from the top of the pressurizer (through the ADS valves; Figures 15.6.5.4B-43(a), 15.6.5.4B-43(b), and 15.6.5.4B-43(c)) increases the reactor coolant system depressurization rate. The depressurization rate is also increased due to the steam discharge from the downcomer to the containment (Figure 15.6.5.4B-37) as the downcomer mixture level falls below the DVI nozzle (Figure 15.6.5.4B-42).

During the initial portion of the DEDVI line break, only liquid flows out the top of the core (Figure 15.6.5.4B-45). Soon, steam flow follows (Figure 15.6.5.4B-46) correlating with the void fraction increase in the core (Figure 15.6.5.4B-44). The break in the downcomer stalls fluid flow into the bottom of the core (Figure 15.6.5.4B-47) leaving insufficient liquid in the upper plenum. The upper plenum/core mixture level therefore starts to decrease (Figure 15.6.5.4B-41). The mixture level falls early in the transient and then recovers slightly, as flow slowly re-enters the core from the downcomer (Figure 15.6.5.4B-41 compared to 15.6.5.4B-47).

The ADS Stage 2 valves open after the appropriate time delay following the actuation of ADS Stage 1. The intact loop accumulator starts to inject into the downcomer (Figure 15.6.5.4B-50) causing the mixture level in the downcomer to slowly rise (Figure 15.6.5.4B-42). The mixture level also increases slightly within the upper plenum.

The ADS Stage 3 valves open upon completion of the time delay of 120 seconds following the actuation of ADS Stage 2. The broken loop core makeup tank level reaches the ADS Stage 4 setpoint, but the ADS Stage 4 valves do not open until the minimum time delay between the actuation of ADS Stages 3 and 4 occurs. Two-phase discharge ensues through three of the four Stage 4 paths (Figures 15.6.5.4B-48(a), 15.6.5.4B-48(b), and 15.6.5.4B-49). During the same timeframe, the broken loop core makeup tank and accumulator empty rapidly.

The fluid level at the top of the intact loop core makeup tank starts to decrease slowly (Figure 15.6.5.4B-52) because injection from the tank has begun (Figure 15.6.5.4B-40). The intact loop core makeup tank injection is temporarily reduced and then reversed as the intact accumulator injects (Figure 15.6.5.4B-50). Following the accumulator injection, the core makeup tank injects continuously until empty.

During the period of accumulator injection, the downcomer mixture level rises slowly (Figure 15.6.5.4B-42). Figure 15.6.5.4B-53(a) presents the RCS mass inventory, and Figure 15.6.5.4B-53(b) presents the reactor vessel mixture inventory which includes the downcomer, lower plenum, core fluid channel, upper plenum and upper head. Both figures also show the increase in inventory due to the accumulator injection. With injection available only from the intact loop core makeup tank, the downcomer level remains fairly constant. However, reactor vessel mixture inventory depletion continues until sufficient IRWST injection flow can be introduced. The level in the upper plenum is maintained near the hot leg elevation (Figure 15.6.5.4B-41) throughout the remainder of the transient.

Once the pressure in the broken DVI line falls below that in the IRWST discharge piping, the water from the tank begins spilling to containment.

Stable, but decreasing, injection continues from the intact loop core makeup tank as the inventory slowly depletes; the reactor coolant system pressure declines slowly. The reactor coolant system pressure continues to fall until it drops below that of the IRWST and injection begins (Figure 15.6.5.4B-51). With the reduced initial RCS inventory recovery from a single accumulator, core makeup tank, and IRWST injection path available for the DEDVI line break, the minimum inventory occurs after the initiation of continuous IRWST injection flow. After injection flow greater than the sum of the break and ADS flows exists, a slow rise in the reactor vessel mixture inventory (Figure 15.6.5.4B-53(b)) occurs. Since no core uncovery is predicted for this scenario, no cladding heatup occurs.

The critical heat flux assessment described in Subsection 15.6.5.4B.2.3 addresses core cooling during a time period where the NOTRUMP computer code may not conservatively predict the core average void fraction. The requirements of 10 CFR 50.46 (Reference 1) are met during this period since this CHF assessment indicates peak core heat flux is less than critical heat flux. Cladding temperatures will remain near the coolant saturation temperature, well below the 10 CFR 50.46 peak cladding temperature limit.

15.6.5.4B.3.6 10-inch Cold Leg Break

This case models a 10-inch break occurring in the cold leg connected to the balance line of CMT-1. The reactor steady-state initial conditions assumed for this transient are found in Table 15.6.5-9. The event times for this transient are given in Table 15.6.5-14.

Transient results are shown in Figures 15.6.5.4B-56(a) through 15.6.5.4B-78. The break opens at time zero, and the pressurizer pressure begins to fall, as shown in Figure 15.6.5.4B-56(a), as mass is lost out the break. The pressurizer mixture level initially decreases as given in Figure 15.6.5.4B-57. The break fluid flow is shown in Figures 15.6.5.4B-75 and 15.6.5.4B-76 for the liquid and vapor components respectively. The pressurizer pressure falls below the reactor trip set point which causes the reactor to trip (after the appropriate time delay) and isolation of the steam generator main steam lines. The core makeup tank discharge isolation valves for both core makeup tanks and the PRHR delivery line isolation valves open after an “S” signal occurs (with appropriate delays); the reactor coolant pumps trip after an “S” signal with a 7 second delay. The reactor coolant system is cooled by natural circulation with energy being removed by the steam generator safety valves, the core makeup tanks, and the PRHR heat exchanger. The PRHR heat removal rate and integrated heat removal are shown in Figure 15.6.5.4B-77 and Figure 15.6.5.4B-78. Once the core makeup tank isolation valves open, the core makeup tanks begin to inject borated water into the reactor coolant system as shown in Figures 15.6.5.4B-61 and 15.6.5.4B-62.

As time proceeds, the loops drain to the reactor vessel. The mixture level in the downcomer begins to drop as seen in Figure 15.6.5.4B-60, and the core remains completely covered with the exception of a few short oscillatory time intervals in which the mixture level drops below the active fuel

(Figure 15.6.5.4B-69). Due to the size and location of the break involved, the accumulator setpoint is reached prior to the core makeup tanks transitioning from recirculation to injection mode. The flows from the core makeup tanks are shown in Figures 15.6.5.4B-61 and 15.6.5.4B-62, and from the accumulators, in Figures 15.6.5.4B-63 and 15.6.5.4B-64. Once the first core makeup tank reaches the 67.5 percent volume setpoint, and after an appropriate delay, the ADS Stage 1 valves open. When the ADS is actuated, the mixture level increases in the pressurizer (Figure 15.6.5.4B-57) because an opening has been created at the top of the pressurizer. After these valves open, a more rapid depressurization occurs as seen in Figure 15.6.5.4B-56(a).

During the initial portion of the 10-inch break, both liquid and steam flow out the top of the core (Figures 15.6.5.4B-71 and 15.6.5.4B-72) as the void fraction in the core increases (Figure 15.6.5.4B-73). The break in the cold leg draws fluid from the bottom of the core leaving insufficient liquid in the upper plenum. The mixture level, therefore, starts to decrease (Figure 15.6.5.4B-69). The mixture level falls until accumulator flows enter the downcomer (Figures 15.6.5.4B-63 and 15.6.5.4B-64).

As Figures 15.6.5.4B-61 and 15.6.5.4B-62 indicate, when the accumulators begin to inject, the flow from both core makeup tanks is reduced and briefly reversed, due to the pressurization of the core makeup tank injection lines by the accumulators. The opening of ADS Stage 2 valves maintains the depressurization rate as shown in Figure 15.6.5.4B-56(a). ADS Stage 3 valves subsequently open. This increases the system venting capability. Figures 15.6.5.4B-70(a), 15.6.5.4B-70(b) and 15.6.5.4B-70(c) indicate the instantaneous liquid, instantaneous vapor and integrated total mass discharged from the ADS Stage 1-3 valves, respectively. The ADS Stage 4 valves open when the core makeup tank water volume is reduced to 20 percent. Figures 15.6.5.4B-67(a), 15.6.5.4B-67(b) and 15.6.5.4B-74 indicate the instantaneous liquid, instantaneous vapor and integrated total mass discharged from the ADS Stage 4 valves. After the ADS Stage 4 path opens, the pressurizer begins to drain mixture into the hot legs as seen in Figure 15.6.5.4B-57. The Figure 15.6.5.4B-68(a) mass inventory plot considers the primary inventory to be the reactor coolant system proper, including the pressurizer; the mass present in the passive safety system components is not included. The Figure 15.6.5.4B-68(b) mass inventory plot considers the reactor vessel mixture inventory, including the downcomer, lower plenum, core fluid channels, upper plenum and upper head. Once the downcomer pressure drops below the IRWST injection pressure, flow enters the reactor vessel from the IRWST. The mixture level in the reactor vessel is approximately at the hot leg elevation as shown in Figure 15.6.5.4B-69 throughout this transient; core uncovery does not occur for any prolonged period of time and may be deemed negligible. As such, the 10-inch break case exhibits large margins to the 10 CFR 50.46 (Reference 1) peak cladding temperature limit of 2200°F (1204.44°C).

15.6.5.4B.3.7 Direct Vessel Injection Line Break (Entrainment Sensitivity)

In order to assess the potential impact of higher than expected entrainment in the upper plenum and hot legs on the overall system response and core cooling, an AP1000 plant sensitivity run was performed. The simulation utilizes the same initial conditions as the base DEDVI line break case presented in Subsection 15.6.5.4B.3.5.

The transient response is essentially identical until ADS-4 actuation, at which time the bounding entrainment conditions are included in the analysis by assuming homogenous conditions in the regions downstream of the core (upper plenum, hot leg, and PRHR inlet). In addition, since homogenous treatment of these regions will eliminate the pressure drop effect of the accumulated mass stored in the upper plenum, the NOTRUMP model was conservatively adjusted to account for this effect following the transition of the ADS-4 flow paths to non-critical conditions.

The event times for this transient are shown in Table 15.6.5-15. Transient results are shown in Figures 15.6.5.4B-79(a) through 15.6.5.4B-90. Figures 15.6.5.4B-79(a) and 15.6.5.4B-79(b) present comparisons of the pressure in the upper portion of the downcomer between the base and sensitivity

cases. The sensitivity case results in higher pressure in the upper portion of the downcomer and subsequently results in delayed IRWST injection (Figure 15.6.5.4B-80). This can also be observed in the intact DVI line flow, which comprises all intact injection flow components (accumulator, CMT, and IRWST) per Figure 15.6.5.4B-81, and the pressurizer mixture level response (Figure 15.6.5.4B-90), which follows the change in pressure response. As expected, the initial ADS-4 liquid discharge is much higher (Figure 15.6.5.4B-82) until the upper plenum and hot leg region inventory is depleted (Figure 15.6.5.4B-83). The net effect is a decrease in the ADS-4 vapor discharge rate (Figure 15.6.5.4B-84) and subsequently higher RCS pressures.

Due to the elimination of the inventory stored in the upper plenum, the downcomer mass is also reduced (Figure 15.6.5.4B-85). Since the static head that existed in the upper plenum is eliminated when the model is made homogenous, the downcomer mixture is subsequently driven into the core as the static heads equilibrate. This results in the core region mass increasing initially due to the introduction of cold downcomer fluid to the core region (Figures 15.6.5.4B-86(a) and 15.6.5.4B-86(b)). The net effect of the sensitivity case is that the vessel inventory is substantially decreased over the base model simulation (Figure 15.6.5.4B-87); however, this inventory is sufficient to provide adequate core cooling because the ADS-4 continually draws liquid flow through the core (Figure 15.6.5.4B-82). Even though there is no liquid storage in the upper plenum for the homogenous case (Figures 15.6.5.4B-88(a) and 15.6.5.4B-88(b)), the core collapsed liquid level (Figures 15.6.5.4B-89(a) and 15.6.5.4B-89(b)) is not impacted significantly.

The impact on fuel rod heatup due to the periods of oscillatory core uncovery observed in Figures 15.6.5.4B-88(a) and 15.6.5.4B-88(b) was assessed and it was demonstrated that the inadvertent ADS actuation transient presented in Subsection 15.6.5.4B.3.3 remains limiting compared to the entrainment study.

This sensitivity demonstrates that the AP1000 plant response is relatively insensitive to upper plenum and hot leg entrainment for the DEDVI line break, which is the limiting break with respect to entrainment. Overall, the sensitivity shows that even with the assumption of homogenous fluid nodes above the core (i.e., maximum entrainment), adequate core cooling is demonstrated.

15.6.5.4B.4 Conclusions

The small-break LOCA analyses performed show that the passive safeguards systems are sufficient to mitigate small-break LOCAs. Specifically, it is concluded that:

- The primary side can be depressurized by the ADS to allow stable injection into the core.
- Injection from the core makeup tanks, accumulators, and IRWST prevents excessive cladding heatup for small-break LOCAs analyzed, including double-ended ruptures in the passive safeguards system lines. The peak heat flux during the DEDVI line break accumulator injection period is below the predicted critical heat flux.
- The effect of increasing upper plenum/hot leg entrainment does not significantly affect plant safety margins.

The analyses performed demonstrate that the 10 CFR 50.46 Acceptance Criteria are met. Summarizing the small-break LOCA spectrum:

Break Location/Diameter	Minimum Reactor Vessel Mixture Inventory (lbm)	Peak Cladding Temperature (°F)
Inadvertent ADS	54,095	1099
2-inch cold leg break	54,855	874
10-inch cold leg break	78,826	(1)
DEDVI (20.0 psia)	74,575	(1)
DEDVI (Entrainment Study)	54,527	(2)

(1) There is no core heatup as a result of this transient. PCT occurs at transient initiation.
(2) There is minimal core heatup as a result of this transient and the PCT remains significantly less than the limiting inadvertent ADS actuation transient.

The inadvertent ADS actuation transient exhibits the limiting minimum reactor vessel mixture inventory conditions and has the limiting peak cladding temperature. The AP1000 design is such that the minimum reactor vessel mixture inventory occurs around the time of IRWST injection for the limiting breaks. All breaks simulated in the break spectrum produce results that demonstrate significant margin to the 10 CFR 50.46 regulatory limits.

15.6.5.4C Post-LOCA Long-Term Cooling

15.6.5.4C.1 Long-Term Cooling Analysis Methodology

The AP1000 safety-related systems are designed to provide adequate cooling of the reactor indefinitely. Initially, this is achieved by discharging water from the IRWST into the vessel. When the low-3 level setpoint is reached in the IRWST, the containment recirculation subsystem isolation valves open and water from the containment reactor coolant system (RCS) compartment can flow into the vessel through the PXS piping. The water in containment rises in temperature toward the saturation temperature. Long-term heat removal from the reactor and containment is by heat transfer through the containment shell to atmosphere.

The purpose of the long-term cooling analysis is to demonstrate that the passive systems provide adequate emergency core cooling system performance during the IRWST injection/containment recirculation time scale. The long-term cooling analysis is performed using the WCOBRA/TRAC computer code to verify that the passive injection system is providing sufficient flow to the reactor vessel to cool the core and to preclude boron precipitation.

The AP1000 long-term cooling analysis is supported by the series of tests at the Oregon State University AP600 APEX Test Facility. This test facility is designed to represent the AP600 reactor safety-related systems and nonsafety-related systems at quarter-scale during long-term cooling. The data obtained during testing at this facility has been shown to apply to the AP1000 (Reference 25). These tests were modeled using WCOBRA/TRAC (Reference 23) with an equivalent noding scheme to that used for AP600 (Reference 17) in order to validate the code for long-term cooling analysis.

Reference 24 provides details of the AP1000 WCOBRA/TRAC modeling. The coarse reactor vessel modeling used for AP600 has been replaced with a detailed noding like that applied in the large-break LOCA analyses described in Subsection 15.6.5.4A. The reactor vessel noding used in the AP1000 long-term cooling analyses in core and upper plenum regions is equivalent to that used in full-scale test simulations (see Reference 24).

A DEDVI line break is analyzed because it is the most limiting long-term cooling case in the relationship between decay power and available liquid driving head. Because the IRWST spills directly onto the containment floor in a DEDVI break, this event has the highest core decay power when the transfer to sump injection is initiated. In postulated DEDVI break cases, the compartment water level exceeds the elevation at which the DVI line enters the reactor vessel, so water can flow from the containment into the reactor vessel through the broken DVI line; this in-flow of water through the broken DVI line assists in the heat removal from the core. The steam produced by boiling in the core vents to the containment through the ADS valves and condenses on the inner surface of the steel containment vessel. The condensate is collected and drains to the IRWST to become available for injection into the reactor coolant system. The WCOBRA/TRAC analysis presented analyzes the DEDVI small-break LOCA event from a time (3000 seconds) at which IRWST injection is fully established to beyond the time of containment recirculation. During this time, the head of water to drive the flow into the vessel for IRWST injection decreases from the initial level to its lowest value at the containment recirculation switchover time. PXS Room B is the location of the break in the DVI line. At this break location, liquid level in containment at the time of recirculation is a minimum.

A continuous analysis of the post-LOCA long term cooling is provided from the time of stable IRWST injection through the time of sump recirculation for the DEDVI break. Maximum design resistances are applied in WCOBRA/TRAC for both the ADS Stage 4 flow paths and the IRWST injection and containment recirculation flow paths.

The break modeled is a double-ended guillotine rupture of one of the direct vessel injection lines. The long-term cooling phase begins after the simultaneous opening of the isolation valves in the IRWST DVI lines and the opening of ADS Stage 4 squib valves, when flow injection from the IRWST has been fully established. Initial conditions consider the NOTRUMP DEDVI case at 20 psia containment pressure reported in Subsection 15.6.5.4B.

15.6.5.4C.2 DEDVI Line Break with ADS Stage 4 Single Failure, Passive Core Cooling System Only Case; Continuous Case

This subsection presents the results of a DEDVI line break analysis during IRWST injection phase continuing into sump recirculation. Initial conditions at the start of the case are prescribed based on the NOTRUMP DEDVI break results to allow a calculation to begin shortly after IRWST injection begins in the small break long-term cooling transient. The WCOBRA/TRAC calculation is then allowed to proceed until a quasi-steady-state is achieved. At this time, the predicted results are independent of the assumed initial conditions. This calculation uses boundary conditions taken from a WGOTHIC analysis of this event. During the calculation, which is carried out for 10,000 seconds until a quasi-steady-state sump recirculation condition has been established, the IRWST water level is decreased continuously until the sump recirculation setpoint is reached.

In the analysis, one of the two ADS Stage 4 valves in the PRHR loop is assumed to have failed. The initial reactor coolant system liquid inventory and temperatures are determined from the NOTRUMP calculation. The core makeup tanks do not contribute to the DVI injection during this phase of the transient. Steam generator secondary side conditions are taken from the NOTRUMP calculation (at the beginning of long-term cooling). The reactor coolant pumps are tripped and not rotating.

The temperatures of the liquid in the containment sump and the containment pressure are based on WGOTHIC calculations of the conservative minimum pressure during this long-term cooling transient, including operation of the containment fan coolers. Small changes in the RCS compartment level do not have a major effect on the predicted core collapsed liquid level or on the predicted flow rate through the core. The minimum compartment floodup level for this break scenario is 107.6 feet or greater.

In this transient, the IRWST provides a hydraulic head sufficient to drive water into the downcomer through the intact DVI nozzle. Also, water flows into the downcomer from the broken DVI line once the liquid level in the compartment with the broken line is adequate to support flow. The water flows down the downcomer and up through the core, into the upper plenum. Steam produced in the core and liquid flow out of the reactor coolant system via the ADS Stage 4 valves. There is little flow out of ADS Stages 1, 2, and 3 even when the IRWST liquid level falls below the sparger elevation, so they are not modeled in this calculation. The venting provided by the ADS-4 paths enables the liquid flow through the core to maintain core cooling.

Approximately 500 seconds of WCOBRA/TRAC calculation are required to establish the quasi-steady-state condition associated with IRWST injection at the start of long-term cooling and so are ignored in the following discussion. The hot leg levels are such that during the IRWST injection phase the quality of the ADS Stage 4 mass flows varies as water is carried out of the hot legs. This periodically increases the pressure drop across the ADS Stage 4 valves and the upper plenum pressure. The higher pressure in the upper plenum reduces the injection flow. This cycle of pressure variations due to changing void fractions in the flow through ADS Stage 4 is consistent with test observations and is expected to recur often during long-term cooling.

The head of water in the IRWST causes a flow of subcooled water into the downcomer at an approximate rate of 140 lbm/s through the intact DVI nozzle at the start of long-term cooling. The downcomer level at the end of the code initiation (the start of long-term cooling) is about 16.0 feet (Figure 15.6.5.4C-1). Note that the time scale of this and other figures in Subsection 15.6.5.4C.2 is offset by 2500 seconds; that is, a time of 500 seconds on the Figure 15.6.5.4C-1 axis equals 3000 seconds transient time for the DEDVI break. All of the injection water flows down the downcomer and up through the core. The accumulators have been fully discharged before the start of the time window and do not contribute to the DVI flow.

Boiling in the core produces steam and a two-phase mixture, which flows into the upper plenum. The core is 14 feet high, and the core average collapsed liquid level (Figure 15.6.5.4C-2) is shown from the start of long-term cooling. The boiling process causes a variable rate of steam production and resulting pressure changes, which in turn causes oscillations in the liquid flow rate at the bottom of the core and also variations in the core collapsed level and the flow rates of liquid and vapor out of the top of the core. In the WCOBRA/TRAC noding, the core is divided both axially and radially as described in Reference 24. The void fractions in the top two cells of the hot assembly are shown as Figures 15.6.5.4C-3 and 15.6.5.4C-4. The average void fraction of these upper core cells is approximately 0.9 during long-term cooling, during IRWST injection, and into the containment recirculation period. There is a continuous flow of two-phase fluid into the hot legs, and mainly vapor flow toward the ADS Stage 4 valve occurs at the top of the pipe. The collapsed liquid level in the hot leg averages around 1.3 feet (Figure 15.6.5.4C-5). The hot legs on average are approximately 50-percent full. Vapor and liquid flows at the top of the core are shown in Figures 15.6.5.4C-6 and 15.6.5.4C-7, the upper plenum collapsed liquid level in Figure 15.6.5.4C-8. Figures 15.6.5.4C-9 and 15.6.5.4C-10 are ADS stage 4 mass flowrates.

The pressure in the upper plenum is shown in Figure 15.6.5.4C-11. The upper plenum pressure fluctuation that occurs is due to the ADS Stage 4 water discharge. The PCT of the hot rod follows saturation temperature (Figure 15.6.5.4C-12), which demonstrates that no uncovery and no cladding temperature excursion occurs. A small pressure drop is calculated across the reactor vessel, and injection rates through the DVI lines into the vessel are presented in Figures 15.6.5.4C-13 and 15.6.5.4C-14. Figure 15.6.5.4C-14 shows the broken DVI line flow during the start of the long-term cooling period increases to about 75 lbm/s after the compartment water level has increased above the nozzle elevation to permit liquid injection into the reactor vessel. In contrast, the intact DVI line flow falls from 140 lbm/s with a full IRWST to about 60 lbm/s flow from the containment at the end of the calculation. The recirculation core liquid throughput is more than adequate to preclude any boron buildup on the fuel.

15.6.5.4C.3 DEDVI Break and Wall-to-Wall Floodup; Containment Recirculation

This subsection presents a DEDVI line break analysis with wall-to-wall flooding due to leakage between compartments, using the window mode methodology. All containment free volume beneath the level of the liquid is assumed filled in this calculation to generate the minimum water level condition during containment recirculation. The time identified for this calculation is around 14 days into the event, and the core power is calculated accordingly. The initial conditions at the start of the window are consistent with the analysis described in Subsection 15.6.5.4C.2. Containment recirculation is simulated during the time window. The calculation is carried out over a time period long enough to establish a quasi-steady-state solution; after 500 seconds of problem time, the flow dynamics are quasi-steady-state and the predicted results are independent of the assumed initial conditions. The liquid level is simulated constant at 28.2 feet above the bottom inside surface of the reactor vessel (refer to Figure 15.0.3-2 for AP1000 reference plant elevations) during the time window, and the liquid temperatures in the containment sump and the PXS “B” room are both modeled at 212°F. The containment pressure is conservatively assumed to be 14.7 psia. The single failure of an ADS Stage 4 flow path is assumed as in the Subsection 15.6.5.4C.2 case.

Focusing on the post 400-second time interval of this case, the containment liquid provides a hydraulic head sufficient to drive water into the downcomer through the DVI nozzles. The water introduced into the downcomer flows down the downcomer and up through the core, into the upper plenum. Steam produced in the core entrains liquid and flows out of the reactor coolant system via the ADS Stage 4 valves. The DVI flow and the venting provided by the ADS paths provide a liquid flow through the core that enables the core to remain cool.

The downcomer collapsed liquid level (Figure 15.6.5.4C-15) varies between 23 and 24 feet during the analysis. Pressure spikes produced by boiling in the core can cause the mass flow of the DVI flow rates shown in Figures 15.6.5.4C-27 and 15.6.5.4C-28 into the vessel to fluctuate upward and downward.

Boiling in the core produces steam and a two-phase mixture, which flows out of the core into the upper plenum. The core is 14 feet high, and the core collapsed liquid level (Figure 15.6.5.4C-16) maintains a mean level close to the top of the core. The boiling process causes pressure variations, which in turn, cause variations in the core collapsed level and the flow rates of liquid and vapor out of the top of the core. In the WCOBRA/TRAC analysis, the core is nodalized as described in Reference 24. The void fraction in the top cell is shown in Figure 15.6.5.4C-17 for the core hot assembly, and Figure 15.6.5.4C-18 shows the void fraction that exists one cell further down in the hot assembly. The PCT does not rise appreciably above the saturation temperature (Figure 15.6.5.4C.3-26). The flow through the core and out of the reactor coolant system is more than sufficient to provide adequate flushing to preclude concentration of the boric acid solution. Liquid collects above the upper core plate in the upper plenum, where the average collapsed liquid level is about 3.1 feet (Figure 15.6.5.4C-22). There is no significant flow through the cold legs into either the broken or the intact loops, and there is no significant quantity of liquid residing in any of the cold legs.

The pressure in the upper plenum is shown in Figure 15.6.5.4C-25. The upper plenum pressurization, which occurs periodically, is due to the ADS Stage 4 water discharge. The collapsed liquid level in the hot leg of the pressurizer loop increases to >1.5 feet by the end of the simulation (Figure 15.6.5.4C-19). Injection rates through the DVI lines into the vessel are presented in Figures 15.6.5.4C-27 and 15.6.5.4C-28.

15.6.5.4C.4 Post Accident Core Boron Concentration

An evaluation has been performed of the potential for the boron concentration to build up in the core following a cold leg LOCA. The evaluation methodology is discussed and demonstrated via simplified calculations and results in Subsection 2.3.4 and Appendix H of Reference 24. The detailed

calculations and results are described in Reference 27. This evaluation considers both short-term operations, before ADS is actuated, and long-term operations, after ADS is actuated. These evaluations and their results are discussed in the follow paragraphs.

Short-term – Prior to ADS actuation, it is not likely for boron to build up significantly in the core. Normally, water circulation mixes boron in the RCS and prevents buildup in the core. In order for boron to start to build up in the core region, water circulation through the steam generators and PRHR HX has to stop. In addition, significant injection of borated water is needed from the CMTs and the CVS. For this situation to happen, the hot legs need to void sufficiently to allow the steam generator tubes to drain. Once the steam generator tubes void, the cold legs will also void since they are located higher than the hot legs. When the top of the cold legs void, the CMTs will begin to drain. When the CMTs drain to the ADS stage 1 setpoint, ADS is actuated.

Short-term Results – As shown in Subsection 15.6.5.4B.3.4, a 2-inch LOCA requires less than 16 minutes from the time that the hot legs void significantly until ADS is actuated. For larger LOCAs, this time difference is shorter, as seen for the 10-inch cold leg LOCA (Subsection 15.6.5.4B.3.6). The core boron concentration will not build up significantly in this short time. If the break is smaller than 2 inches, voiding of the hot legs will occur at a later time. With maximum operation of CVS makeup, it takes more than 8 hours for the core boron concentration to build up significantly. In addition, the volume of the boric acid storage tank limits the maximum buildup of boron in the core.

Following a small LOCA where ADS is not actuated, the operators are guided to sample the RCS boron concentration and to initiate a post-LOCA cooldown and depressurization. The cooldown and depressurization of the RCS reduces the leak rate and facilitates recovery of the pressurizer level. Recovery of the pressurizer level allows for re-establishment of water flow through the RCS loops, which mixes the boron. The operators are guided to take an RCS boron sample within 8 hours of the accident and several more during the plant cooldown. The purpose of the boron samples is to assess that there is adequate shutdown margin and that the RCS boron concentration has not built up to excessive levels. The maximum calculated core boron concentration 8 hours after a LOCA without ADS actuation is less than 40,000 ppm. Operator action within 8 hours maintains the maximum core boron concentration well below the boron solubility limit for the core inlet temperatures during the cooldown.

Long-term – Once ADS is actuated, water carryover out the ADS Stage 4 lines limits the potential core boron concentration buildup following a cold leg LOCA. The design of the AP1000 facilitates water discharge from the hot legs as follows:

- PXS recirculation flow capability tends to fill the hot legs and bring the water level up to the ADS Stage 4 inlet.
- ADS Stage 4 lines discharge at an elevation 3 to 4 feet above the containment water level.

With water carried out ADS Stage 4, the core boron concentration increases until the boron added to the core in the safety injection flow equals the boron removed in the water leaving the RCS through the ADS Stage 4 flow. The lower the ADS Stage 4 vent quality, the lower the core boron concentration buildup.

Long-term Results – Analyses have been performed to bound the maximum core boron concentration buildup. These analyses demonstrate that highest ADS Stage 4 vent qualities result from the following:

- Highest decay heat levels

- Lowest PXS injection/ADS 4 vent flows, including high line resistances and low containment water levels

The long-term cooling analysis discussed in Subsection 15.6.5.4C.2 is consistent with these assumptions. The ADS Stage 4 vent quality resulting from this analysis is approximately 62 percent at the beginning of IRWST injection and the quality decreases to less than 40 percent at the initiation of recirculation at around 2 hours. The vent quality from ADS Stage 4 continues to decrease to approximately 10 percent at 14 days.

With the maximum ADS Stage 4 vent qualities, the maximum core boron concentration peaks at a value of about 12,000 ppm at approximately 0.5 hours after the break. After this time, the core boron concentration decreases as the ADS Stage 4 vent quality decreases, reaching 5400 ppm about 8 hours after the accident. The core boron solubility temperature reaches a maximum of 90°F (at 12,000 ppm) and quickly drops to 40°F (at 5400 ppm). With these low core boron solubility temperatures, there is no concern with cold PXS injection water causing boron precipitation in the core. With the IRWST located inside containment, its water temperature is normally expected to be above these solubility temperatures. The minimum core inlet temperature is greater than the solubility temperature considering heatup of the injection by steam condensation in the downcomer and pickup of sensible heat from the reactor vessel, core barrel, and lower support plate.

The boron concentration of water in the containment is about 2900 ppm at the start of recirculation. In the long term, the containment boron concentration increases as the reactor vessel boron concentration decreases, reaching a value of approximately 3100 ppm after the boric acid storage tank empties. The solubility temperature of the containment water at its maximum boron concentration is 32°F.

With high decay heat values, the ADS Stage 4 vent flows and velocities are high. These high vent velocities result in flow regimes that are annular for more than 30 days. The annular flow regime moves water up and out the ADS Stage 4 lines. This flow regime is based on the Taitel-Dukler vertical flow regime map. Lower decay heat levels can be postulated later in time or just after a refueling outage. Significantly lower decay heat levels result in lower ADS Stage 4 vent qualities. They also result in ADS Stage 4 vent flows/velocities that are lower. Even with low ADS Stage 4 vent flow velocities, the AP1000 plant will move water out the ADS Stage 4 operating as a manometer. Small amounts of steam generated in the core reduce the density of the steam/water mixture in the core, upper plenum, and ADS Stage 4 line as it bubbles up through the water. As a result, the injection head is sufficient to push the less dense, bubbly steam/water mix out the ADS Stage 4 line.

At the time recirculation begins, the containment level will be about 109.3 feet (for a non-DVI LOCA) and will be about 108.0 feet (for a DVI LOCA). Over a period of weeks after a LOCA, water may slowly leak from the flooded areas in containment to other areas inside containment that did not initially flood. As a result, the minimum containment water could decrease to 103.5 feet. During recirculation operation following a LOCA and ADS actuation, the operators are guided to maintain the containment water level above the 107-foot elevation by adding borated water to the containment. In addition, if the plant continues to operate in the recirculation mode, the operators are guided to increase the level to 109 feet within 30 days of the accident. These actions provide additional margin in water flow through the ADS Stage 4 line. The operators are also guided to sample the hot leg boron concentration prior to initiating recovery actions that might introduce low temperature water to the reactor.

15.6.5.4C.5 Conclusions

Calculations of AP1000 long-term cooling performance have been performed using the WCOBRA/TRAC model developed for AP1000 and described in Reference 24. The DEDVI case was chosen because it reaches sump recirculation at the earliest time (and highest decay heat). A window mode

case at the minimum containment water level postulated to occur around 2 weeks into long-term cooling was also performed.

The DEDVI small-break LOCA exhibits no core uncovery due to its adequate reactor coolant system mass inventory condition during the long-term cooling phase from initiation into containment recirculation. Adequate flow through the core is provided to maintain a low cladding temperature and to prevent any buildup of boric acid on the fuel rods. The wall-to-wall floodup case using the window mode technique demonstrates that effective core cooling is also provided at the minimum containment water level. The results of these cases demonstrate the capability of the AP1000 passive systems to provide long-term cooling for a limiting LOCA event.

15.6.6 References

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Table 15.6.1-1
Time Sequence of Events for Incidents That Cause a Decrease in Reactor Coolant Inventory

Accident	Event	Time (seconds)
Inadvertent opening of a pressurizer safety valve	Pressurizer safety valve opens fully	0.00
	Low-2 pressurizer pressure reactor trip setpoint reached	19.50
	Rods begin to drop	21.50
	Minimum DNBR occurs	22.30
Inadvertent opening of an ADS Stage 2 or 3 train	ADS valves begin to open	0.00
	Low-2 pressurizer pressure reactor trip setpoint reached	22.49
	Rods begin to drop	24.49
	Minimum DNBR occurs	25.40
	ADS valves fully open	30.00

Table 15.6.2-1
Parameters Used in Evaluating the Radiological Consequences of a Small Line Break Outside Containment

Reactor coolant iodine activity	Initial activity equal to the design basis reactor coolant activity of 1.0 μCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 500 (see Table 15A-2 in Appendix 15A)[(a)]
Reactor coolant noble gas activity	280 μCi/g dose equivalent Xe-133
Break flow rate (gpm)	130[(b)]
Fraction of reactor coolant flashing	0.47
Duration of accident (hr)	0.5
Atmospheric dispersion (χ/Q) factors	See Table 15A-5
Nuclide data	See Table 15A-4

Notes:
a. Use of accident-initiated iodine spike is consistent with the guidance in the Standard Review Plan.
b. At density of 62.4 lb/ft^3.

Table 15.6.3-1
Steam Generator Tube Rupture Sequence of Events

Events	Time (seconds)
Double-ended steam generator tube rupture	0
Loss of offsite power	0
Reactor trip	0
Reactor coolant pumps and main feedwater pumps assumed to trip and begin to coastdown	0
Two chemical and volume control pumps actuated and pressurizer heaters turned on	0
Low-2 pressurizer level signal generated	2,591
Ruptured steam generator power-operated relief valve fails open	2,591
Core makeup tank injection and PRHR operation begins (following maximum delay)	2,608
Ruptured steam generator power-operated relief valve block valve closes on Low-2 steam line pressure signal	3,177
Chemical and volume control system isolated on High steam generator narrow range level coincident with reactor trip (P-4) permissive	15,057
Break flow terminated	34,185

Table 15.6.3-2
Steam Generator Tube Rupture Mass Release Results

Total Mass Flow from Initiation of Event to Cooldown to RNS[1] Conditions

	Start of Event to Break Flow Termination (Pounds Mass)	Break Flow Termination to Cut-in of RNS (Pounds Mass)
Ruptured steam generator		
– Atmosphere	267,190	83,800
Intact steam generator		
– Atmosphere	197,000	1,019,000
Break flow	452,761	0

Note:
1. RNS = normal residual heat removal

Table 15.6.3-3
Parameters Used in Evaluating the Radiological Consequences of a Steam Generator Tube Rupture

Reactor coolant iodine activity	
– Accident initiated spike	Initial activity equal to the equilibrium operating limit for reactor coolant activity of 1.0 μCi/g dose equivalent I-131 with an assumed iodine spike that increases the rate of iodine release from fuel into the coolant by a factor of 335 (see Appendix 15A). Duration of spike is 8.0 hours.
– Pre-accident spike	An assumed iodine spike that results in an increase in the reactor coolant activity to 60 μCi/g of dose equivalent I-131 (see Appendix 15A)
Reactor coolant noble gas activity	280 μCi/g dose equivalent Xe-133
Reactor coolant alkali metal activity	Based on design basis activity (see Table 15A-9)
Secondary coolant initial iodine and alkali metal	1% of reactor coolant concentrations at maximum equilibrium conditions
Reactor coolant mass (lb)	3.7 E+05
Offsite power	Lost on reactor trip
Condenser	Lost on reactor trip
Time of reactor trip	Beginning of the accident
Duration of steam releases (hr)	16
Atmospheric dispersion factors	See Appendix 15A
Nuclide data	See Appendix 15A
Steam generator in ruptured loop	
– Initial secondary coolant mass (lb)	1.17 E+05
– Primary-to-secondary break flow	See Figure 15.6.3-5
– Integrated flashed break flow (lb)	See Figure 15.6.3-10
– Steam released (lb)	See Table 15.6.3-2
– Iodine partition coefficient	1.0 E-02[a]
– Alkali metals partition coefficient	3.5 E-03[a]
Steam generator in intact loop	
– Initial secondary coolant mass (lb)	2.30 E+04
– Primary-to-secondary leak rate (lb/hr)	52.16[b]
– Steam released (lb)	See Table 15.6.3-2
– Iodine partition coefficient	1.0 E-02[a]
– Alkali metals partition coefficient	3.5 E-03[a]

Notes:
a. Iodine partition coefficient does not apply to flashed break flow.
b. Equivalent to 150 gpd at psia cooled liquid at 62.4 lb/ft^3.

Table 15.6.5-1
Core Activity Releases to the Containment Atmosphere

Nuclide	Gap Release Released over 0.5 hr. (0.167 - 0.667 hr)[1]	Core Melt In-vessel Release (0.667 - 1.967 hr)[1]
Noble gases	0.05	0.95
Iodines	0.05	0.35
Alkali metals	0.05	0.25
Tellurium group	–	0.05
Strontium and barium	–	0.02
Noble metals group	–	0.0025
Cerium group	–	0.0005
Lanthanide group	–	0.0002

Notes:
1. Releases are stated as fractions of the original core fission product inventory.
2. Dash (–) indicates not applicable.

Table 15.6.5-2 (Sheet 1 of 3)
Assumptions and Parameters Used in Calculating Radiological Consequences of a Loss-of-Coolant Accident

Primary coolant source data	
– Noble gas concentration	280 μCi/g dose equivalent Xe-133
– Iodine concentration	1.0 μCi/g dose equivalent I-131
– Primary coolant mass (lb)	4.39 E+05
Containment purge release data	
– Containment purge flow rate (cfm)	16,000
– Time to isolate purge line (seconds)	30
– Time to blow down the primary coolant system (minutes)	10
– Fraction of primary coolant iodine that becomes airborne	1.0
Core source data	
– Core activity at shutdown	See Table 15A-3
– Release of core activity to containment atmosphere (timing and fractions)	See Table 15.6.5-1
– Iodine species distribution (%)	
• Elemental	4.85
• Organic	0.15
• Particulate	95
Containment leakage release data	
– Containment volume (ft^3)	2.06 E+06
– Containment leak rate, 0-24 hr (% per day)	0.10
– Containment leak rate, > 24 hr (% per day)	0.05
– Elemental iodine deposition removal coefficient (hr^{-1})	1.9
– Decontamination factor limit for elemental iodine removal	200
– Removal coefficient for particulates (hr^{-1})	See Appendix 15B
Main control room model	
– Main control room gross volume (ft^3)	3.89 E+04
– Control support area gross volume (ft^3)	7.56 E+04
– Normal HVAC operation (prior to switchover to an emergency mode)	
• Air intake flow (cfm)	1650
• Filter efficiency	Not applicable
– Atmospheric dispersion factors (sec/m^3)	See Table 15A-6

Table 15.6.5-2 (Sheet 2 of 3)
Assumptions and Parameters Used in Calculating
Radiological Consequences of a Loss-of-Coolant Accident

Main control room model (cont.)	
– Occupancy	
• 0 –24 hr	1.0
• 24–96 hr	0.6
• 96–720 hr	0.4
– Breathing rate (m^3/sec)	3.5 E-04
Control room with emergency habitability system credited (VES Credited)	
– Main control room activity level at which the emergency habitability system actuation is actuated (Ci/m^3 of dose equivalent I-131)	2.0 E-07
– Response time to actuate VES based on radiation monitor response time and VBS isolation (sec)	200
– Interval with operation of the emergency habitability system	
• Flow from compressed air bottles of the emergency habitability system (cfm)	60
• Unfiltered inleakage via ingress/egress (scfm)	5
• Unfiltered inleakage from other sources (scfm)	10
• Recirculation flow through filters (scfm)	600
• Filter efficiency (%)	
• Elemental iodine	90
• Organic iodine	90
• Particulates	99
– Time at which the compressed air supply of the emergency habitability system is depleted (hr)	72
– After depletion of emergency habitability system bottled air supply (>72 hr)	
• Air intake flow (cfm)	1900
• Intake flow filter efficiency (%)	Not applicable
• Recirculation flow (cfm)	Not applicable
– Time at which the compressed air supply is restored and emergency habitability system returns to operation (hr)	168

Table 15.6.5-2 (Sheet 3 of 3)
Assumptions and Parameters Used in Calculating
Radiological Consequences of a Loss-of-Coolant Accident

Control room/CSA with credit for continued operation of HVAC (VBS Supplemental Filtration Mode Credited)	
– Time delay to switch from normal operation to the supplemental air filtration mode (sec)	265
– Unfiltered inleakage via ingress/egress (cfm)	10
– Unfiltered inleakage from other sources (cfm)	50
– Filtered air intake flow (cfm)	800
– Filtered air recirculation flow (cfm)	3200
– Filter efficiency (%)	
• Elemental iodine	99
• Organic iodine	99
• Particulates	99
Miscellaneous assumptions and parameters	
– Offsite power	Not applicable
– Atmospheric dispersion factors (offsite)	See Table 15A-5
– Nuclide dose conversion factors	See Table 15A-4
– Nuclide decay constants	See Table 15A-4
– Offsite breathing rate (m^3/sec)	
0–8 hr	3.5 E-04
8–24 hr	1.8 E-04
24–720 hr	2.3 E-04

Table 15.6.5-3
Radiological Consequences of a Loss-of-Coolant Accident With Core Melt

	TEDE Dose (rem)
Exclusion zone boundary dose (1.3 - 3.3 hr)(1)	23.5
Low population zone boundary dose (0 - 30 days)	22.2
Main control room dose (emergency habitability system in operation)	
– Airborne activity entering the main control room	3.70
– Direct radiation from adjacent structures, including sky shine	0.30
– Filter shine	0.32
– Spent fuel pool boiling	0.01
– Total	4.33
Main control room dose (normal HVAC operating in the supplemental filtration mode)	
– Airborne activity entering the main control room	4.50
– Direct radiation from adjacent structures, including sky shine	0.30
– Filter shine	0.03
– Spent fuel pool boiling	0.01
– Total	4.84

Note:
1. This is the 2-hour period having the highest dose.

Table 15.6.5-4
Major Plant Parameter Assumptions
Used in the Best-Estimate Large-Break LOCA Analysis

Parameter	Value
Plant Physical Configuration	
Steam generator tube plugging level	≤ 10% (10% tube plugging bounds 0%)
Hot assembly location	Under support column (Bounds under open hole or guide tube)
Pressurizer location	In intact loop (Bounds location in broken loop)
Initial Operating Conditions	
Reactor power	Core power < 1.01*3400 MWt
Peak linear heat rate	See Table 15.6.5-7
Hot rod assembly power	See Table 15.6.5-7
Hot assembly power	$P_{HA} \leq 1.654$
Axial power distribution(1)	See Figure 15.6.5.4A-13
Peripheral assembly power	$0.2 \leq P_{LOW} \leq 0.8$
Fluid Conditions	
Reactor coolant system average temperature	$573.6 - 8.0°F \leq T_{AVG} \leq 573.6 + 8.0°F$
Pressurizer pressure	2250 ± 50 psia
Pressurizer level (water volume)	1000 ft^3 (nominal)
Accumulator temperature	$50°F \leq T_{ACC} \leq 120°F$
Accumulator pressure	$652 \text{ psia} \leq P_{ACC} \leq 784 \text{ psia}$
Accumulator water volume	$1666.8 \text{ ft}^3 \leq V_{ACC} \leq 1732.3 \text{ ft}^3$
Reactor Coolant System Boundary Conditions	
Single failure assumption	Failure of one CMT isolation valve to open
Offsite power availability	Available (Bounds loss of offsite power at time zero)
Reactor coolant pump automatic trip delay time after receiving S-signal	5.3 s
Containment pressure	Bounded (minimum)

Note:
1. Treatment of axial power distribution consistent with WCAP-16009-P-A (Reference 32) methodology.

Table 15.6.5-5
AP1000 LOCA Chronology

BLOWDOWN		BREAK OCCURS
		REACTOR TRIP (PRESSURIZER PRESSURE OR HIGH CONT. PRESSURE)
		S SIGNAL (HIGH CONT. PRESSURE)
		CMT INJECTION BEGINS
		ACCUMULATOR INJECTION BEGINS
		END OF BLOWDOWN
	REFILL	BOTTOM OF CORE RECOVERY
REFLOOD		CALCULATED PCT OCCURS
		ACCUMULATORS EMPTY: CMT INJECTION COMMENCES AGAIN
LONG TERM COOLING		ADS ACTIVATES ON LOW CMT LEVEL SIGNALS/IRWST ACTIVATES
		IRWST EMPTY: COOLING CONTINUES VIA CIRCULATION OF SUMP WATER

Table 15.6.5-6
Best-Estimate Large-Break Sequence of Events for the Limiting PCT Case

Event	Time (seconds)
Break initiation	0.0
Safeguards signal	2.2
CMT isolation valves begin to open	4.2
Reactor coolant pumps trip	9.5
Accumulator injection begins	~13
End of blowdown	27.5
Bottom of core recovery	39.5
Calculated PCT occurs	~58
Core quench occurs	~240
CMT injection resumes	~200
End of transient	265

Table 15.6.5-7
Summary of Peaking Factor Burndown Supported by AP1000 Plant Best Estimate Large Break LOCA CRR Updated Analysis Considering TCD

Hot Rod Burnup (GWd/MTU)	Fdh (includes uncertainties)(1)	FQ Transient (Max FQ, includes uncertainties)	FQ SS Baseload (without uncertainties)
0	1.72	2.60	2.10
30	1.72	2.60	2.10
49	1.55	2.30	1.85
55	1.55	2.30	1.85
62	1.40	1.90	1.45

Note:

1. Hot assembly power follows the same burndown, since it is a function of FdH.

Table 15.6.5-8
Best-Estimate Large-Break LOCA Results

10 CFR 50.46 Requirement	Value	Criteria
Calculated 95th percentile PCT (°F)	1936*	≤ 2200
Maximum local cladding oxidation (%)	4.2	≤ 17
Maximum core-wide cladding oxidation (%)	0.30	≤ 1
Coolable geometry	Core remains coolable	Core remains coolable
Long-term cooling	Core remains cool in long term	Core remains cool in long term

*Value contains 2°F bias for PCT sensitivity to PRHR isolation

Table 15.6.5-9
Initial Conditions for AP1000 Small-Break LOCA Analysis

Condition	Calculation	Nominal Steady-state
Pressurizer pressure (psia)	2300.1	2300
Vessel inlet temperature (°F)	534.03	534.59
Vessel outlet temperature (°F)	612.16	612.61
Vessel flow rate (lbm/sec)	31118	31118
Steam generator pressure (psia)	794.76	794.59

Table 15.6.5-10
ADS Parameters Used in Small-Break LOCA Analyses

ADS Valve Actuation Signal [percentage of core makeup tank volume]		Actuation Time (seconds)	Minimum Valve Flow Area (for each path, in^2)	Number of Paths	Valve Opening Time (seconds)
Stage 1 — Control CMT Level Low-3	67.5	32 after CMT Level Low-3	4.6(3)	2 out of 2	≤ 48
Stage 2 — Control		48 after Stage 1	16(3)	2 out of 2	≤ 120
Stage 3 — Control		120 after Stage 2	16(3)	2 out of 2	≤ 120
Stage 4A — CMT Level Low-6	20	128 after Stage 3(1)	66	1 out of 2	≤ 4(2)
Stage 4B		60 after Stage 4A	66	2 out of 2	≤ 4(2)

Notes:

1. The interlock requires coincidence of CMT Level Low-6 as well as 128 seconds after the Stage 3 actuation signal is generated.
2. This includes “arm-fire” processing delay and the assumed valve opening time.
3. The areas listed for the ADS Stage 1/2/3 valves are an effective flow area.

Table 15.6.5-11
Inadvertent ADS Depressurization Sequence of Events

Event	AP1000 Time (seconds)
Inadvertent opening of ADS valves	0.0
ADS Stage 2	48.0
Reactor trip signal	50.8
Steam turbine stop valves close	50.8
“S” signal	59.7
Main feed isolation valves close	66.7
Reactor coolant pumps start to coast down	66.7
ADS Stage 3	168.0
Accumulator injection starts	288
Accumulator tank empties (1 / 2)	753.1 / 751.8
ADS Stage 4	1664.5
Core makeup tank empties (1 / 2)	2020 / 2027
Core uncovery begins	2567
IRWST injection starts*	2854
Core uncovery ends	2905

Note:
*Continuous injection period

Table 15.6.5-12
2-Inch Cold Leg Break Sequence of Events

Event	Time (seconds)
Break opens	0.0
Reactor trip signal	53.7
Steam turbine stop valves close	53.7
“S” signal	65.3
Main feed isolation valves close	72.3
Reactor coolant pumps start to coast down	72.3
ADS Stage 1	1202.8
ADS Stage 2	1250.8
Accumulator injection starts	1315
ADS Stage 3	1370.8
Accumulator tank empties (1 / 2)	1799.8 / 1798.2
ADS Stage 4	2228.6
Core makeup tank empty (1 / 2)	2577 / 2594
Core uncovery begins	2910
IRWST injection starts*	3147
Core uncovery ends	3215

Note:
*Continuous injection period

Table 15.6.5-13
Double-Ended Direct Vessel Injection Line Break Sequence of Events – 20 psia Containment Backpressure

Event	Time (seconds)
Break opens	0.0
Reactor trip signal	13.4
Steam turbine stop valves close	13.4
“S” signal	19.8
Main feed isolation valves close	26.8
Reactor coolant pumps start to coast down	26.8
ADS Stage 1	181.4
ADS Stage 2	229.4
Accumulator injection starts	246.2
ADS Stage 3	349.4
ADS Stage 4	477.4
Accumulator empties (1 / 2)	453.9 / 590.6
Core makeup tank empties (1 / 2)	225.1 / 1861.2
Intact DVI line IRWST injection starts*	1868.3

Note:
* Continuous injection period

Table 15.6.5-13A
Not Used

Table 15.6.5-14
10-Inch Cold Leg Break Sequence of Events

Event	AP1000 Time (seconds)
Break opens	0.0
Reactor trip signal	5.5
Steam turbine stop valves close	5.5
“S” signal	6.7
Main feed isolation valves close	13.7
Reactor coolant pumps start to coast down	13.7
Accumulator injection starts	84
Accumulator tank empties (1 / 2)	477.4 / 488.6
ADS Stage 1	761.1
ADS Stage 2	809.9
ADS Stage 3	929.1
ADS Stage 4	1383.6
IRWST injection starts**	2746
Core makeup tank empties (1 / 2)	* / 2063

Note:

* The CMT does not empty.

** Continuous injection period.

Table 15.6.5-15
Double-Ended Direct Vessel Injection Line Break Sequence of Events (Entrainment Sensitivity)

Event	Time (seconds)
Break opens	0.0
Reactor trip signal	13.4
Steam turbine stop valves close	13.4
“S” signal	19.9
Main feed isolation valves close	26.8
Reactor coolant pumps start to coast down	26.8
ADS Stage 1	180.5
ADS Stage 2	228.5
Intact accumulator injection starts	245
ADS Stage 3	348.5
ADS Stage 4	476.5
Accumulator tank empties (1 / 2)	451.6 / 597.1
Intact loop IRWST injection starts*	2508
Core makeup tank empties (1 / 2)	223 / 1889

Note:
* Continuous injection period

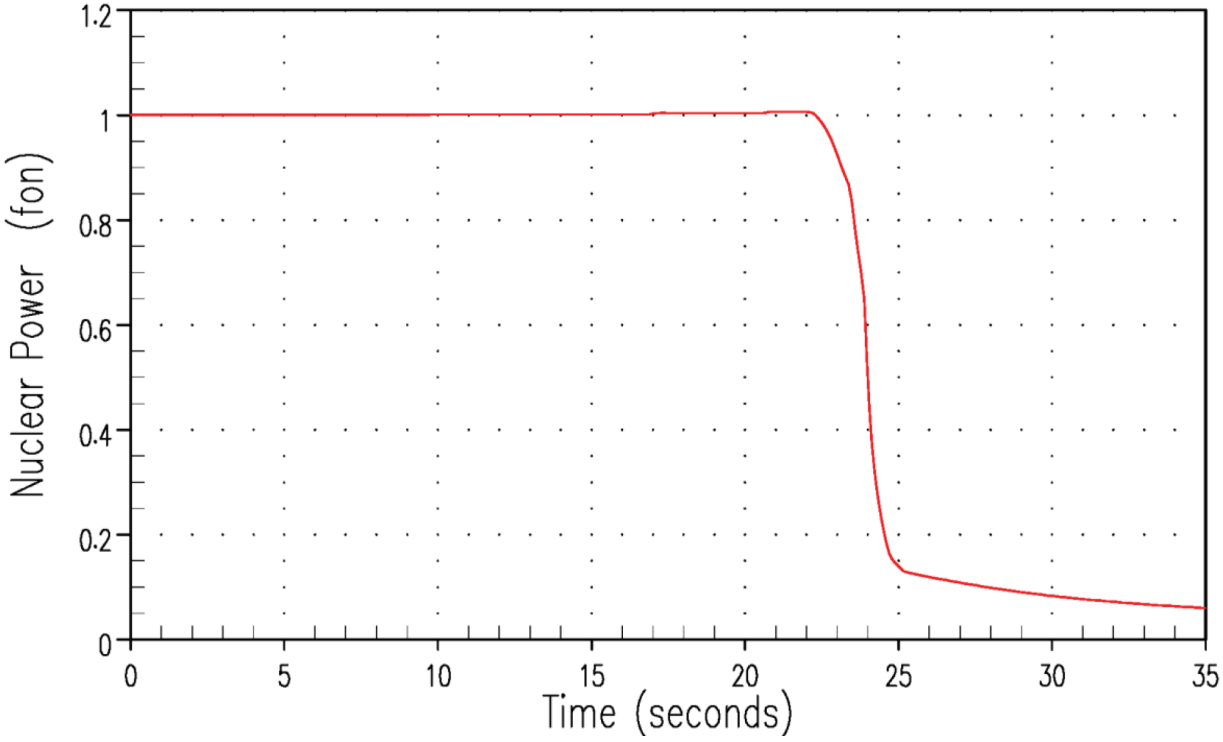


Figure 15.6.1-1
Nuclear Power Transient
Inadvertent Opening of a Pressurizer Safety Valve

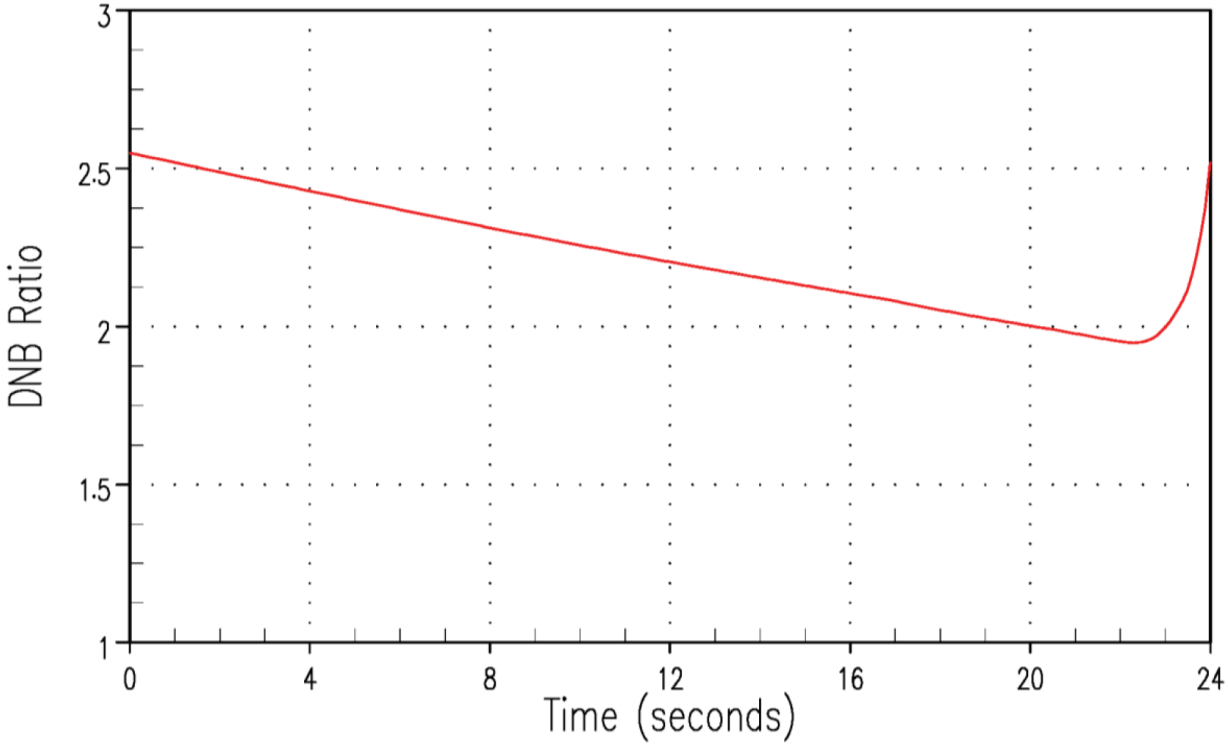


Figure 15.6.1-2
DNBR Transient
Inadvertent Opening of a Pressurizer Safety Valve

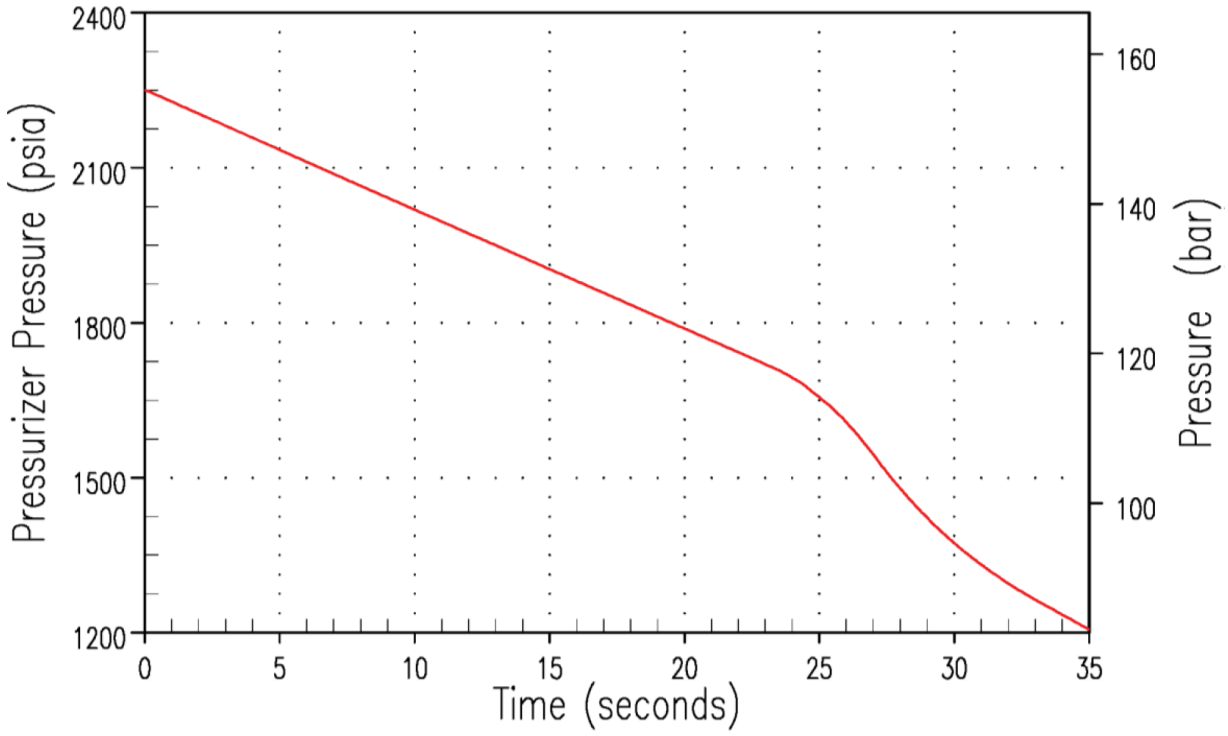


Figure 15.6.1-3
Pressurizer Pressure Transient
Inadvertent Opening of a Pressurizer Safety Valve

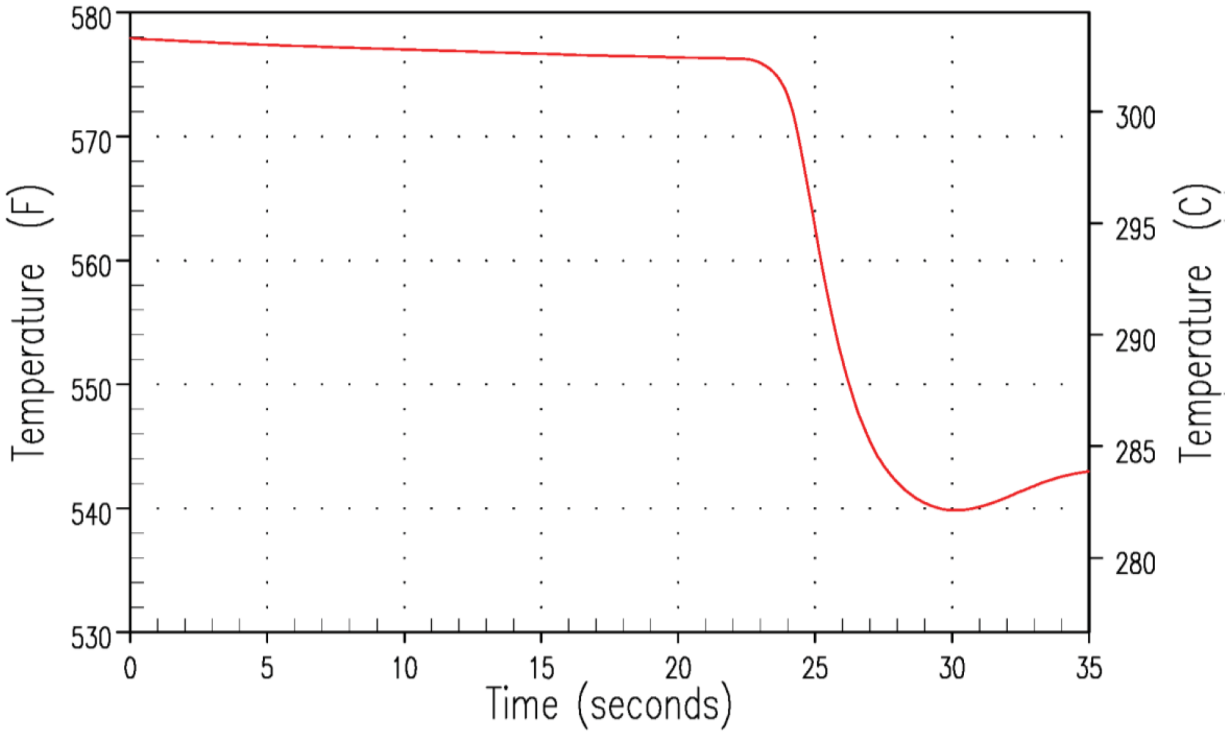


Figure 15.6.1-4
Core Average Temperature Transient
Inadvertent Opening of a Pressurizer Safety Valve

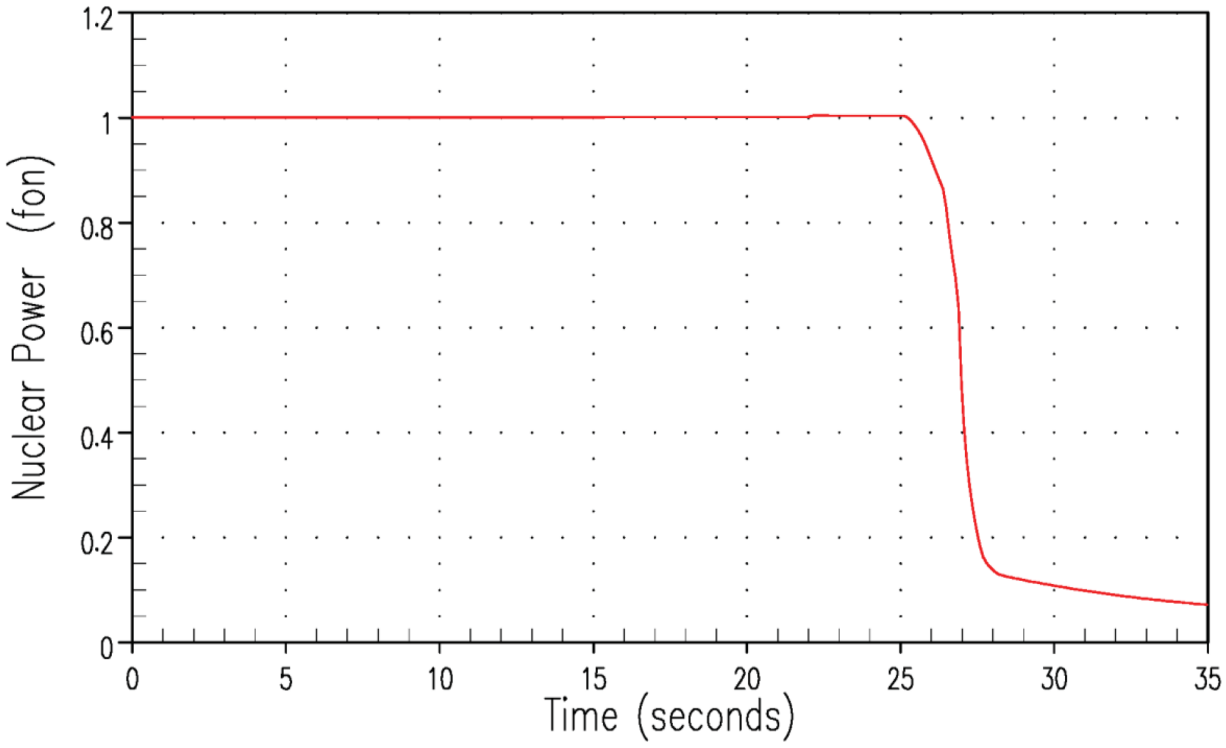


Figure 15.6.1-5
Nuclear Power Transient
Inadvertent Opening of an ADS Stage 2 or 3 Train

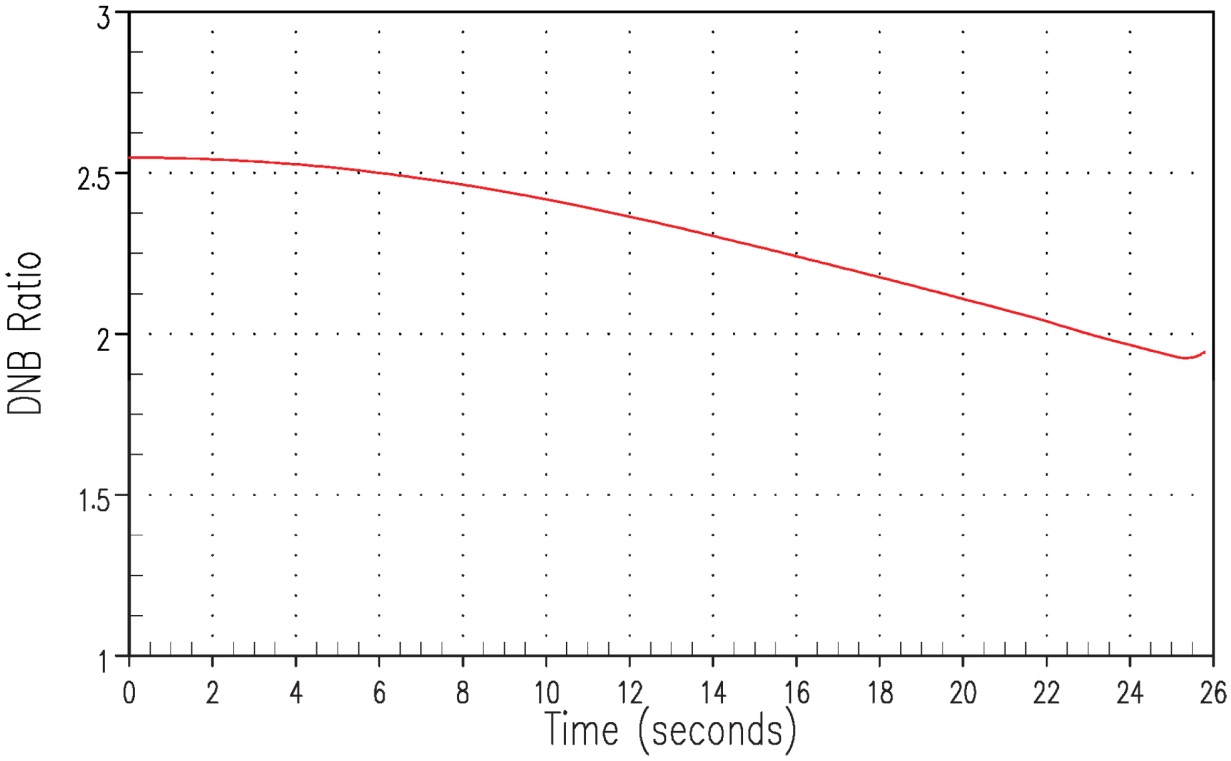


Figure 15.6.1-6
DNBR Transient
Inadvertent Opening of an ADS Stage 2 or 3 Train

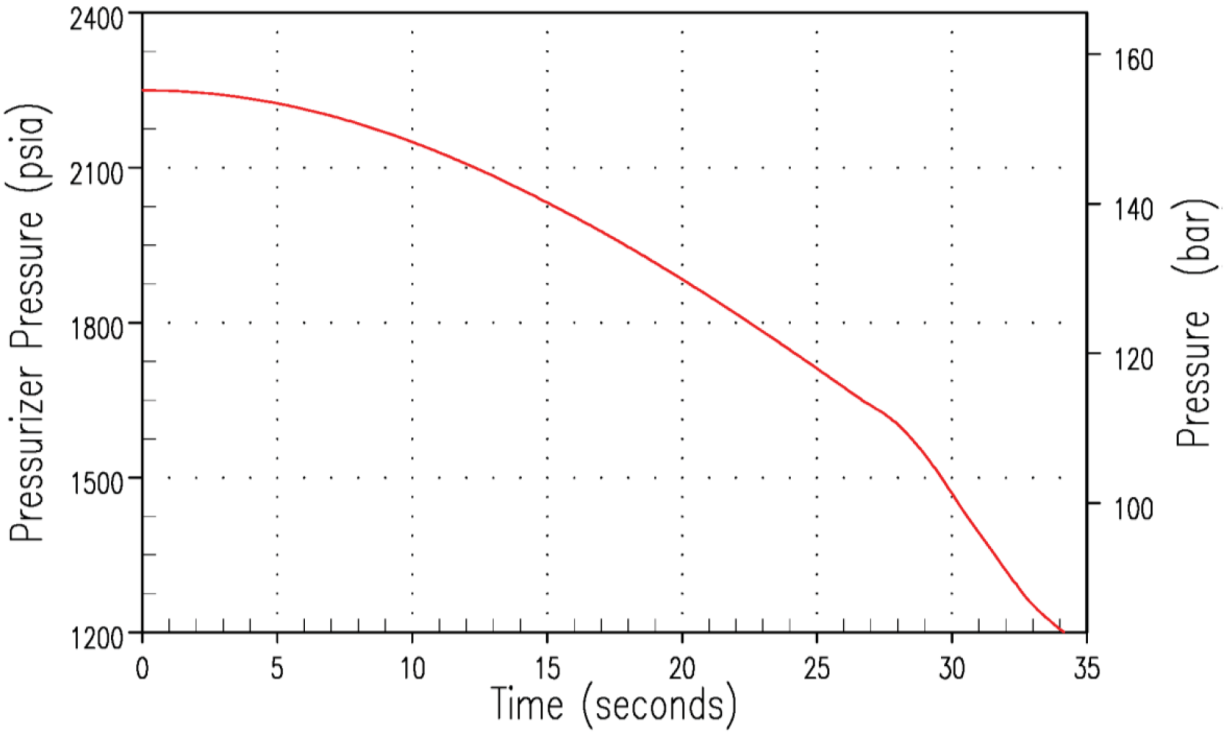


Figure 15.6.1-7
Pressurizer Pressure Transient
Inadvertent Opening of an ADS Stage 2 or 3 Train

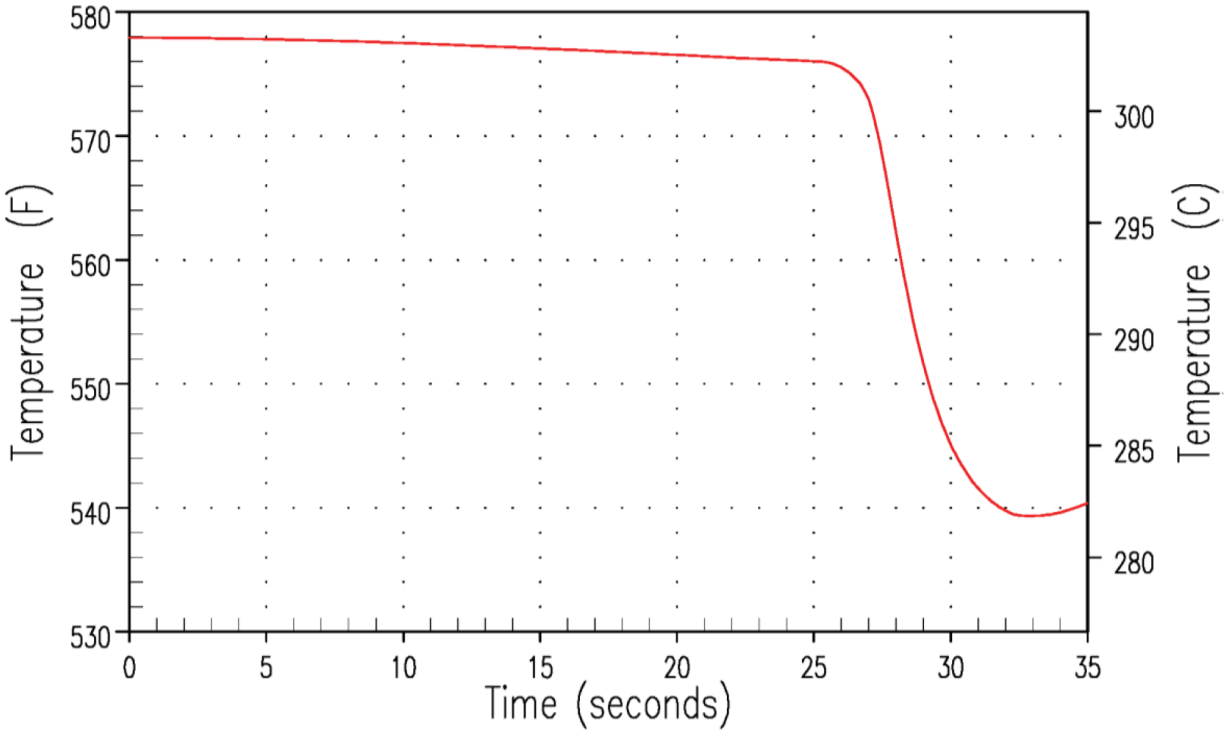


Figure 15.6.1-8
Core Average Temperature Transient
Inadvertent Opening of an ADS Stage 2 or 3 Train

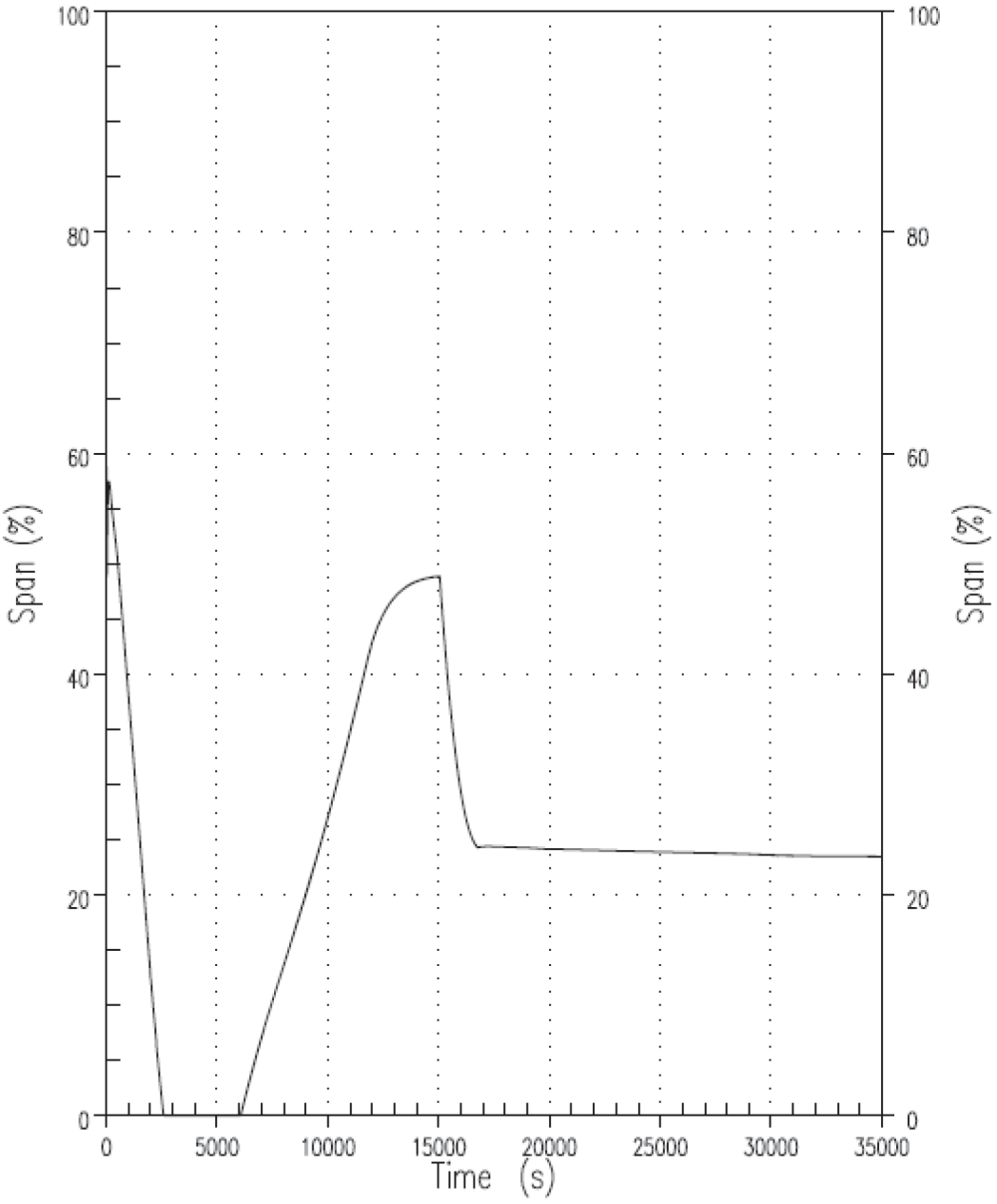


Figure 15.6.3-1
Pressurizer Level for SGTR

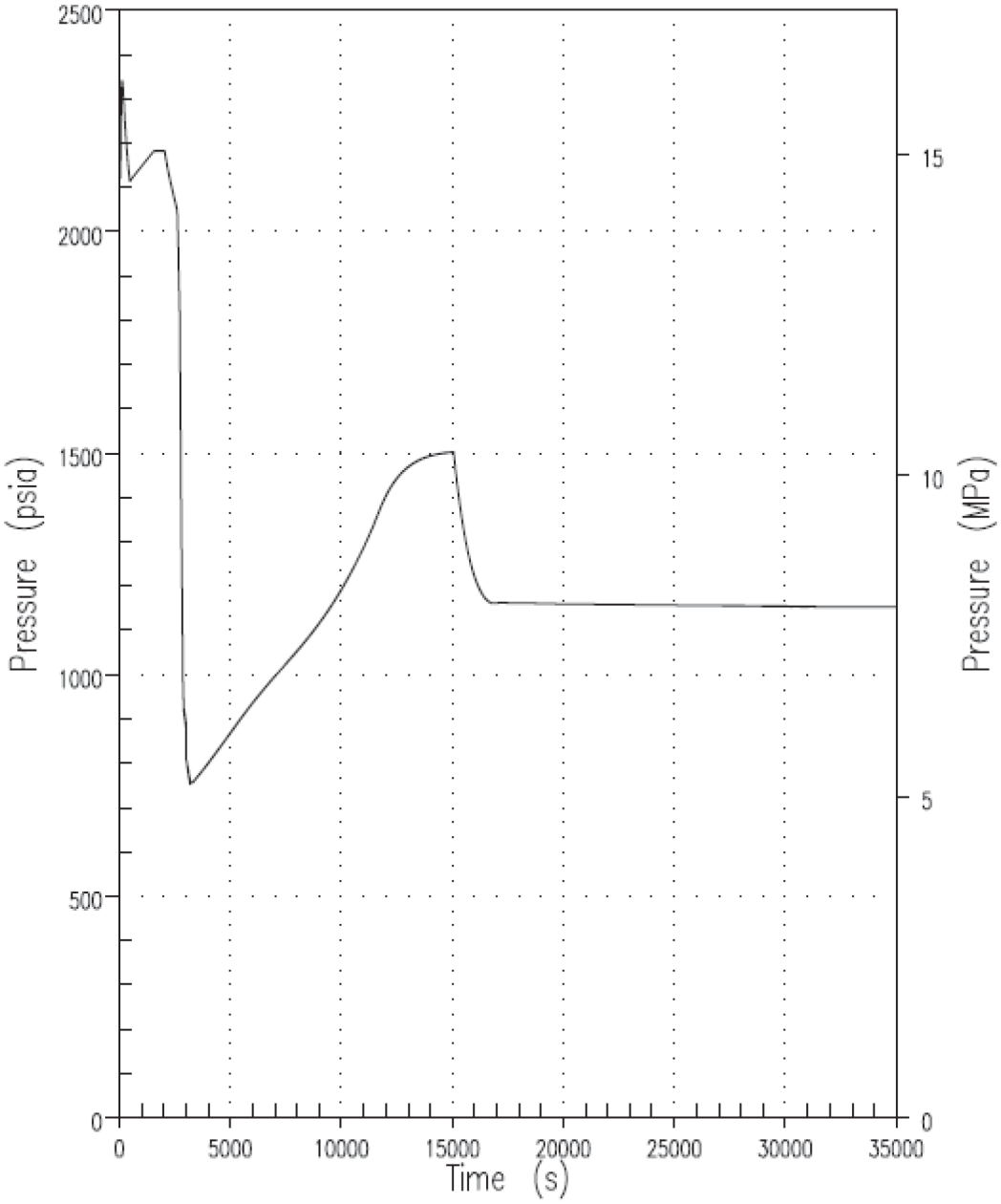


Figure 15.6.3-2
Reactor Coolant System Pressure for SGTR

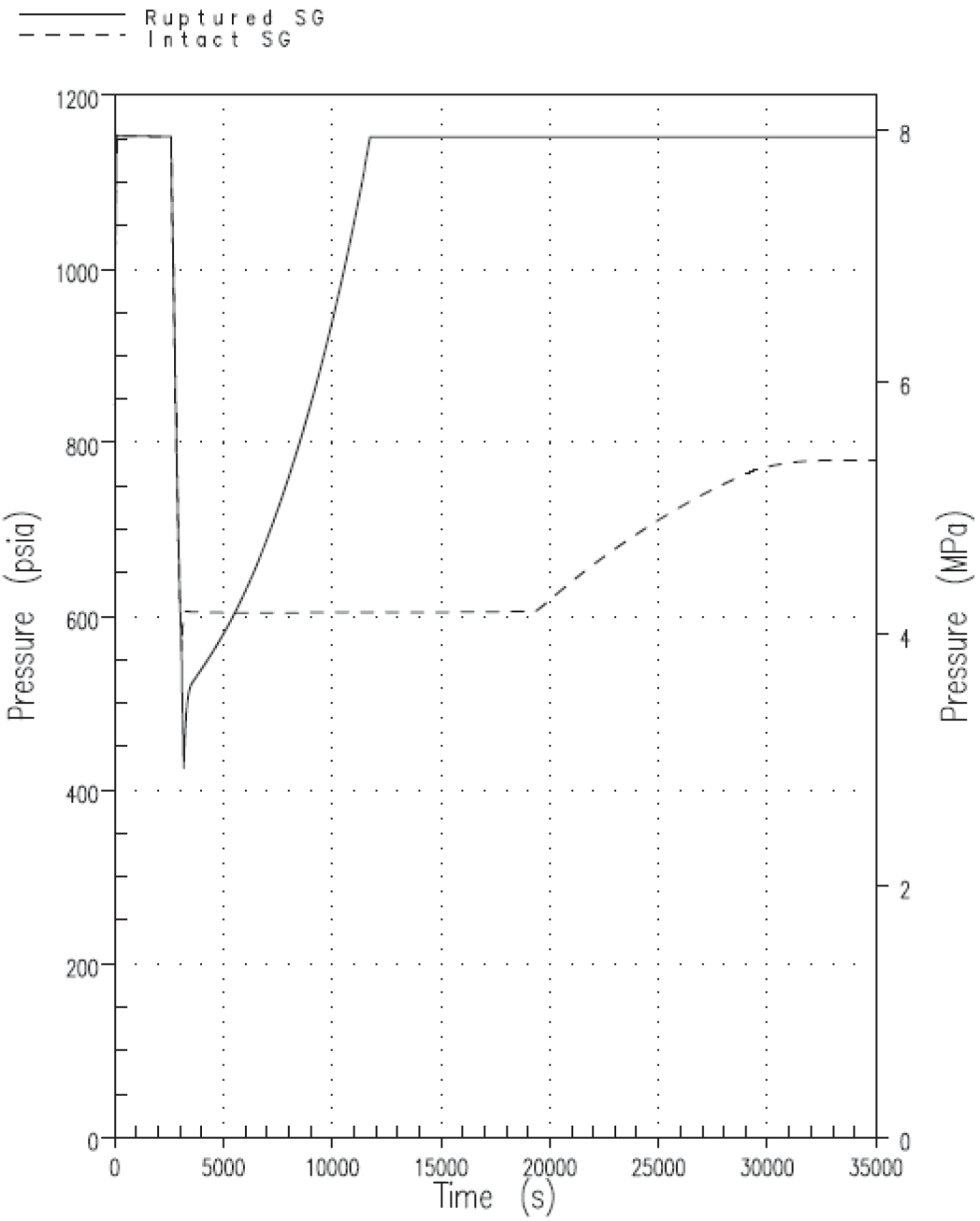


Figure 15.6.3-3
Secondary Pressure for SGTR

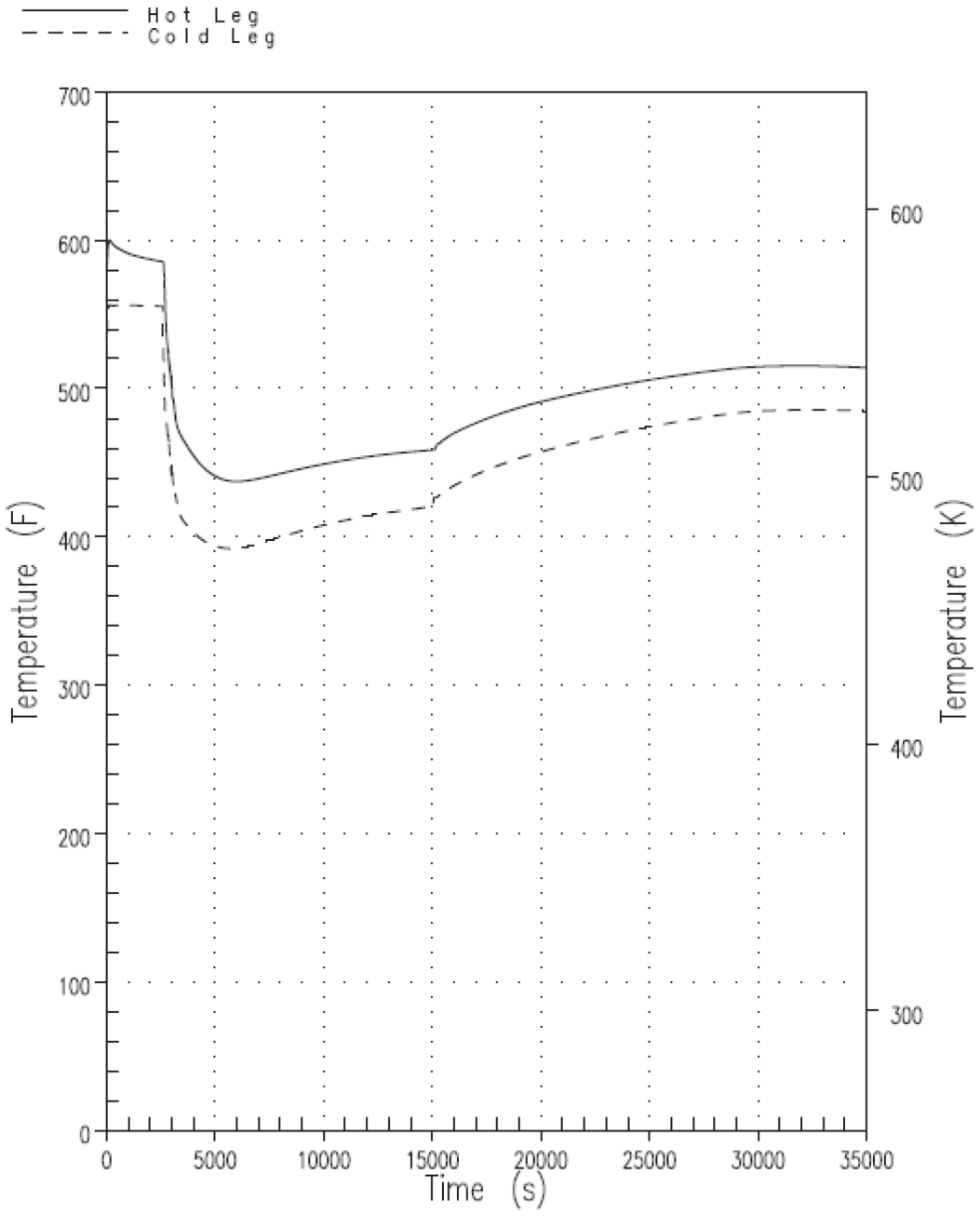


Figure 15.6.3-4
Intact Loop Hot and Cold Leg
Reactor Coolant System Temperature for SGTR

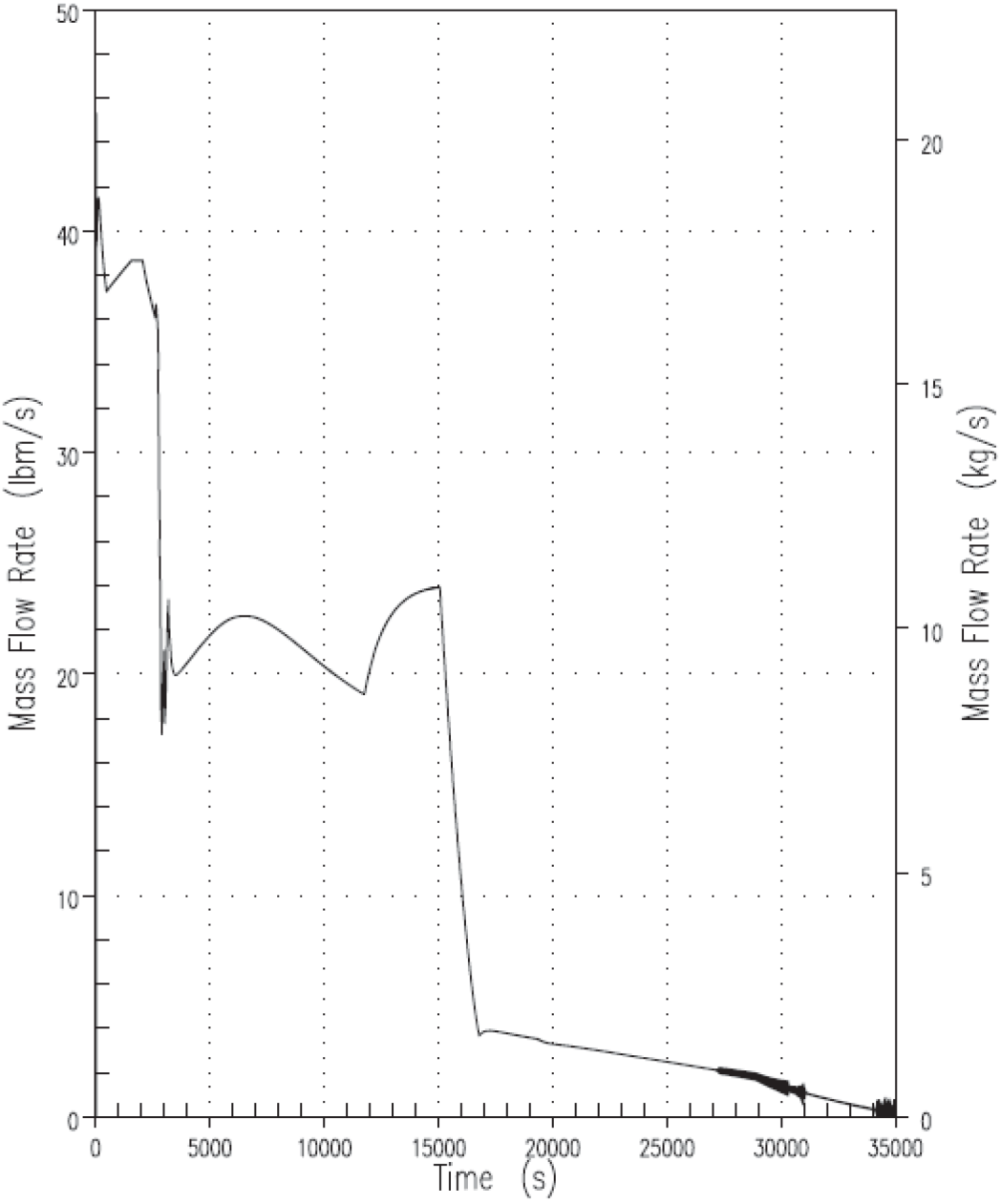


Figure 15.6.3-5
Primary-to-Secondary Break Flow Rate for SGTR

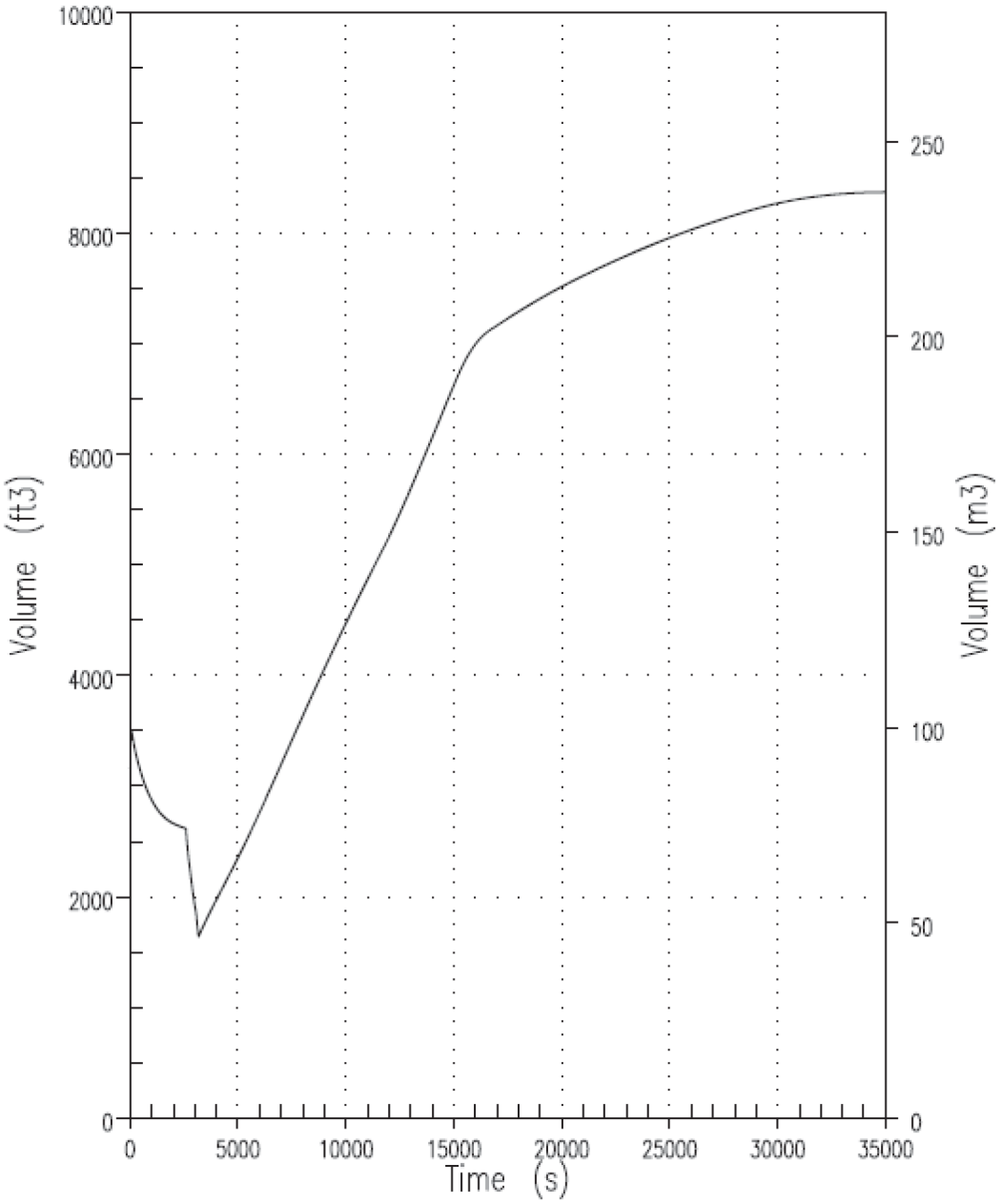


Figure 15.6.3-6
Ruptured Steam Generator Water Volume for SGTR

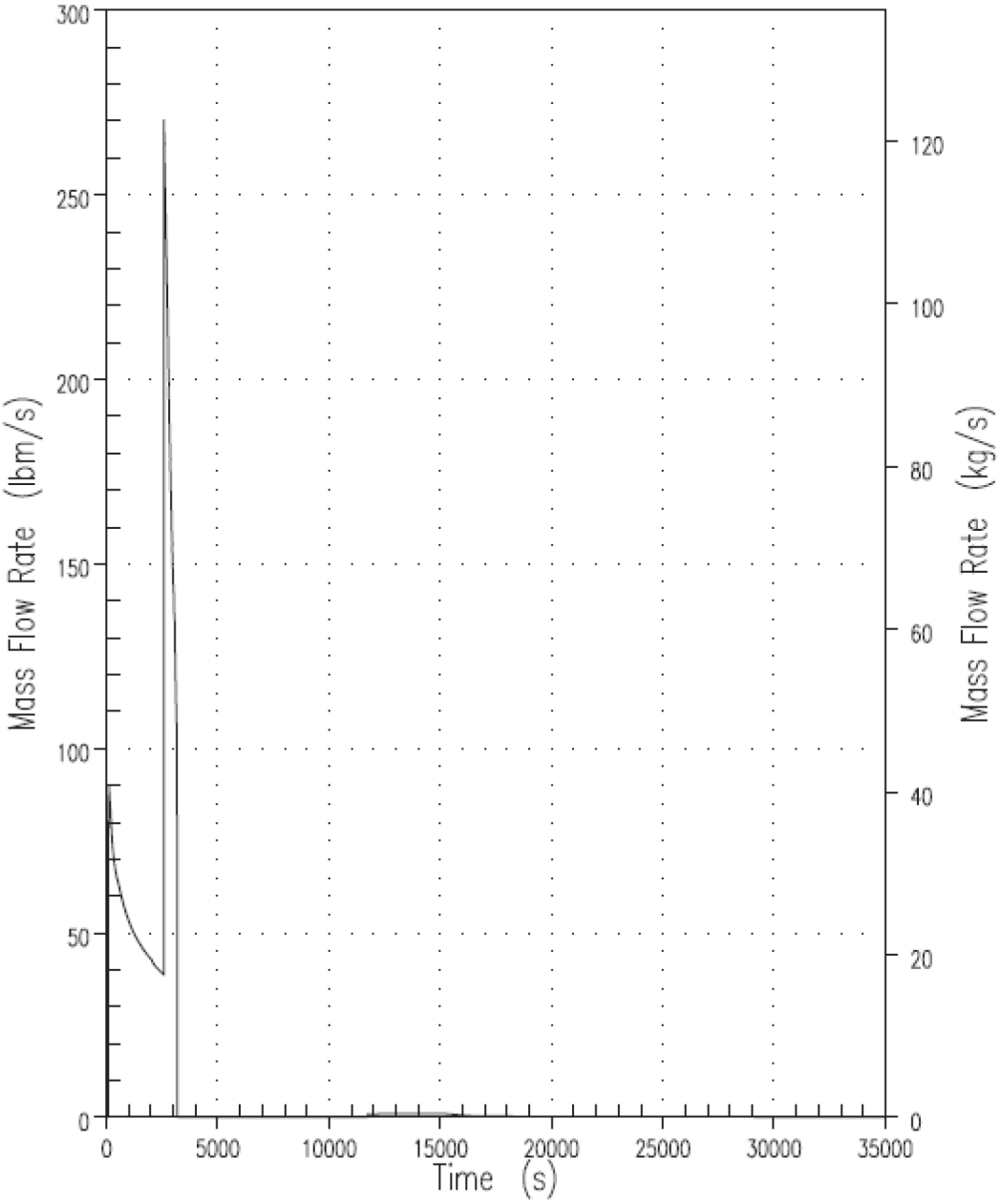


Figure 15.6.3-7
Ruptured Steam Generator Mass Release Rate to the Atmosphere for SGTR

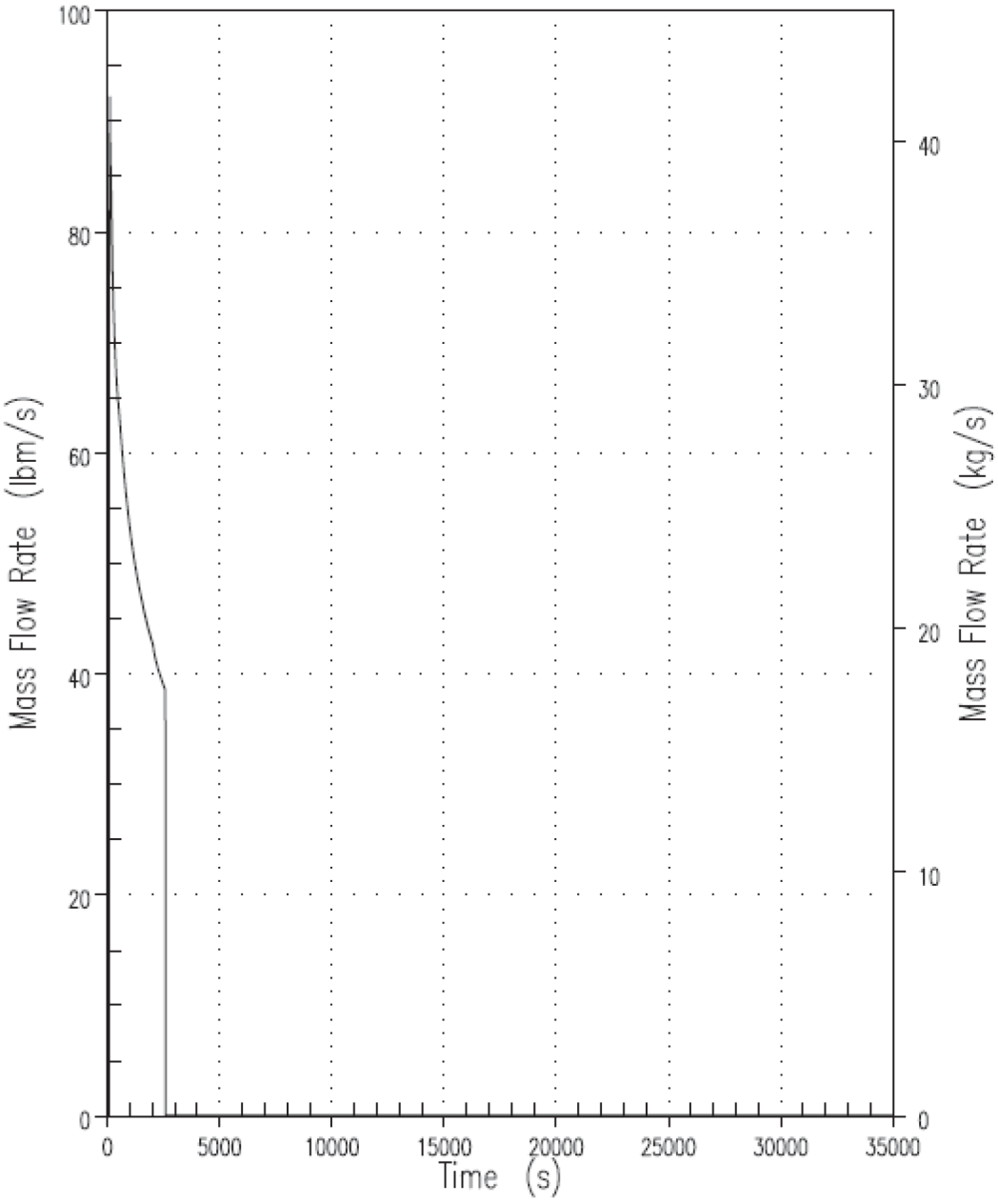


Figure 15.6.3-8
Intact Steam Generator Mass
Release Rate to the Atmosphere for SGTR

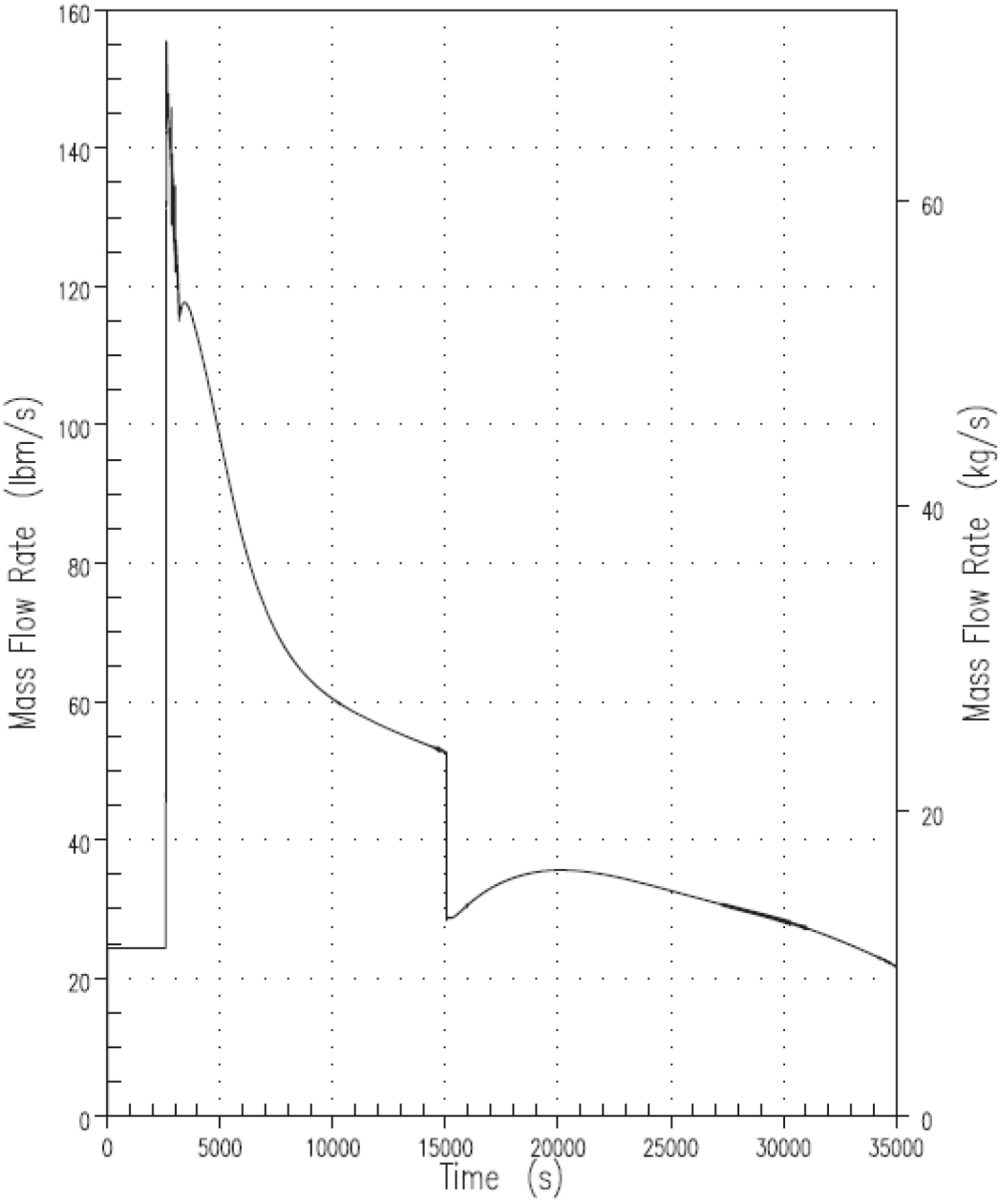


Figure 15.6.3-9
Plant Total Chemical and Volume Control System and Core Makeup Tank Injection Flow for SGTR

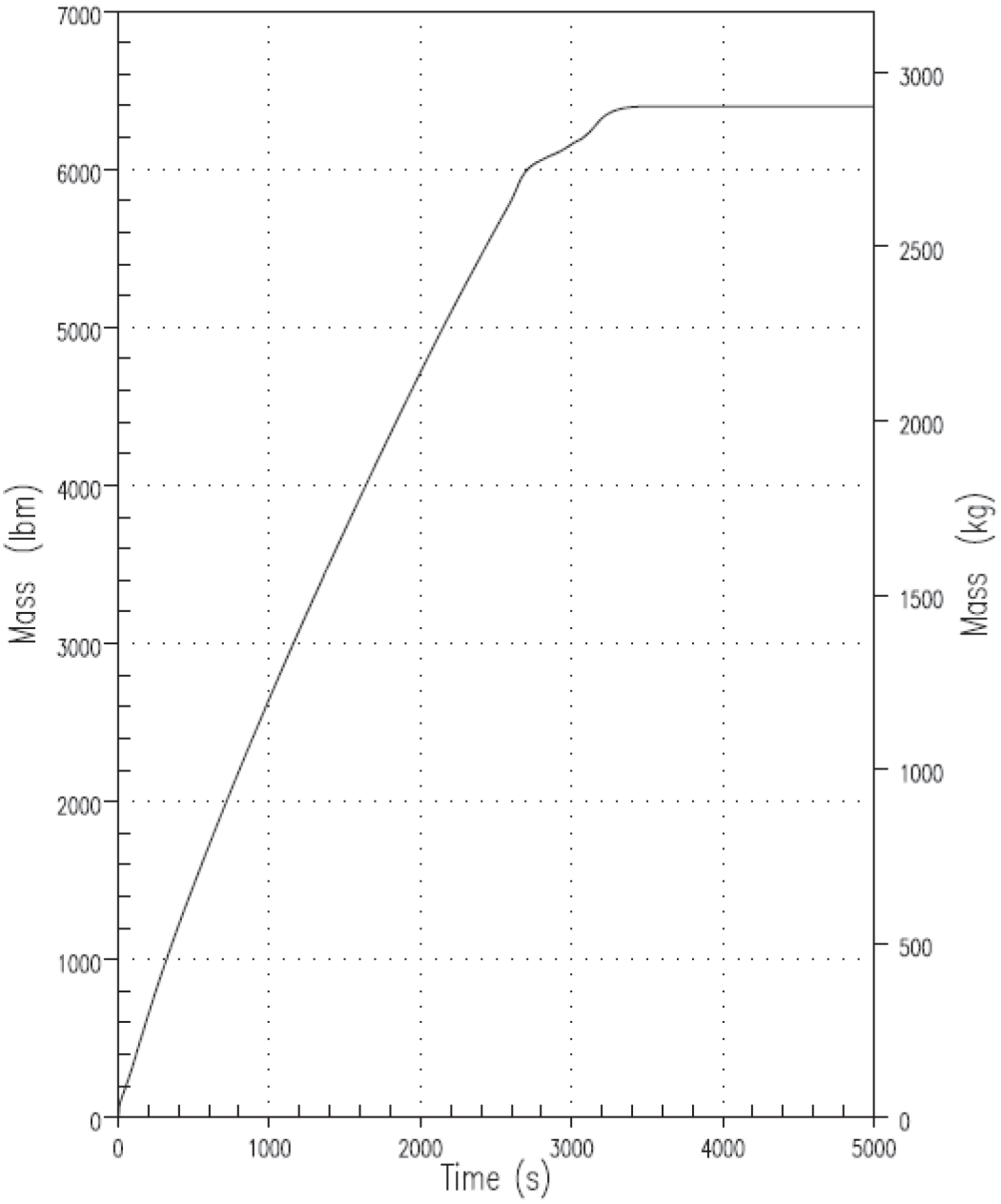


Figure 15.6.3-10
Integrated Flashed Break Flow for SGTR

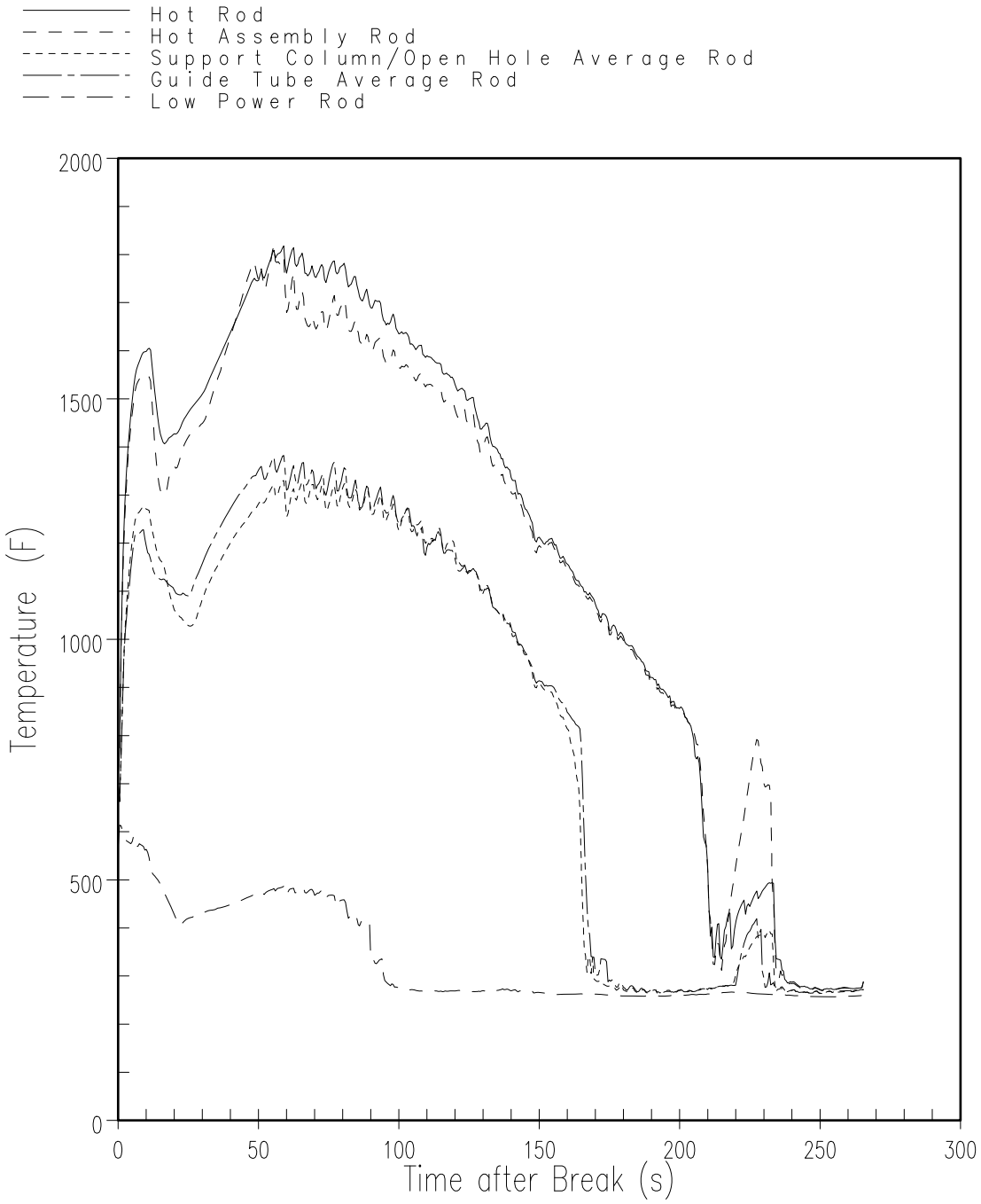


Figure 15.6.5.4A-1
WCOBRA/TRAC Peak Cladding Temperature for All Five Rod Groups for 95th Percentile Estimator PCT Case

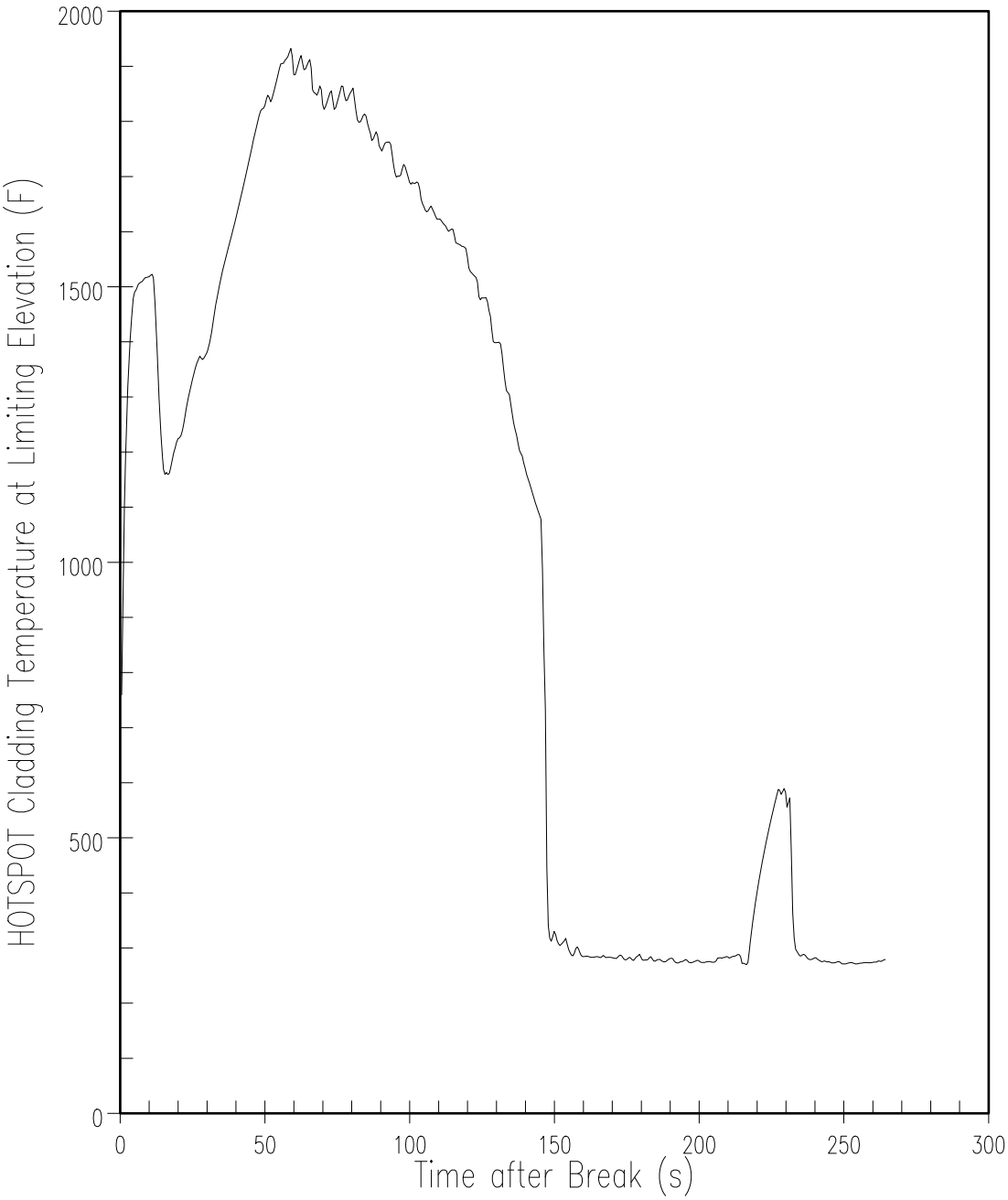


Figure 15.6.5.4A-2
HOTSPOT Cladding Temperature Transient at Limiting Elevation for 95th Percentile Estimator PCT Case

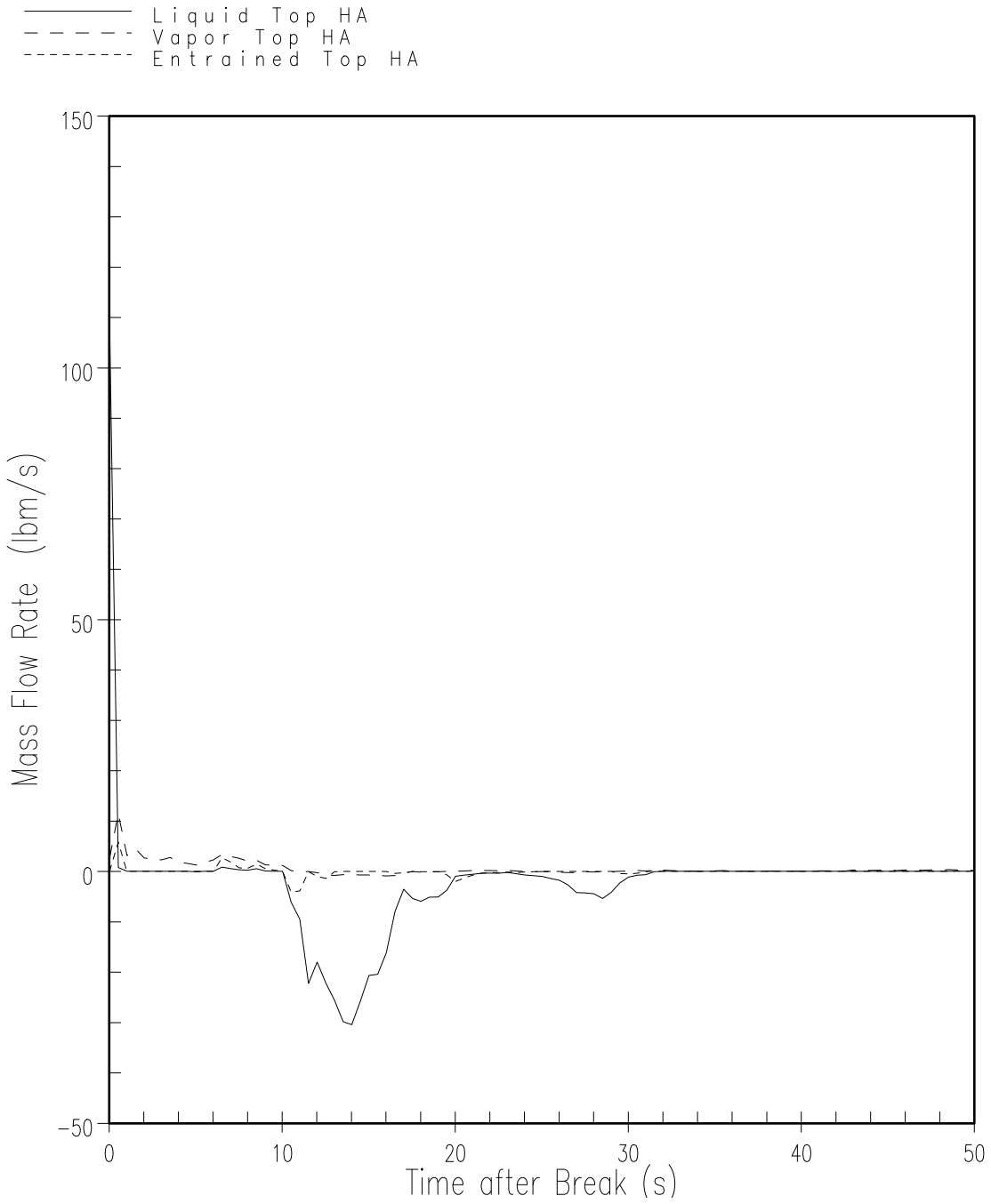


Figure 15.6.5.4A-3
Mass Flow at Top of Hot Assembly Channel
for 95th Percentile Estimator PCT Case

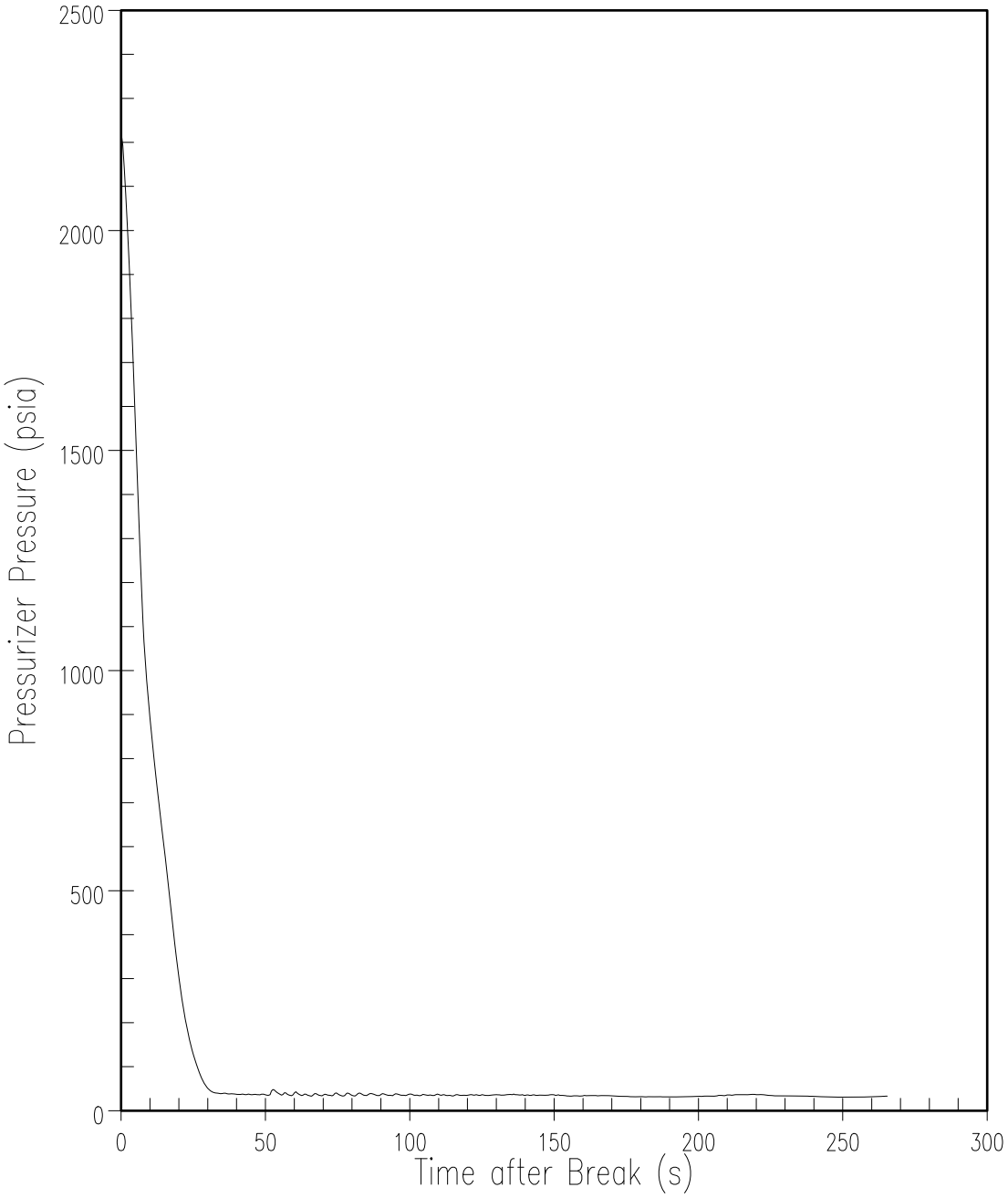


Figure 15.6.5.4A-4
Pressurizer Pressure for
95th Percentile Estimator PCT Case

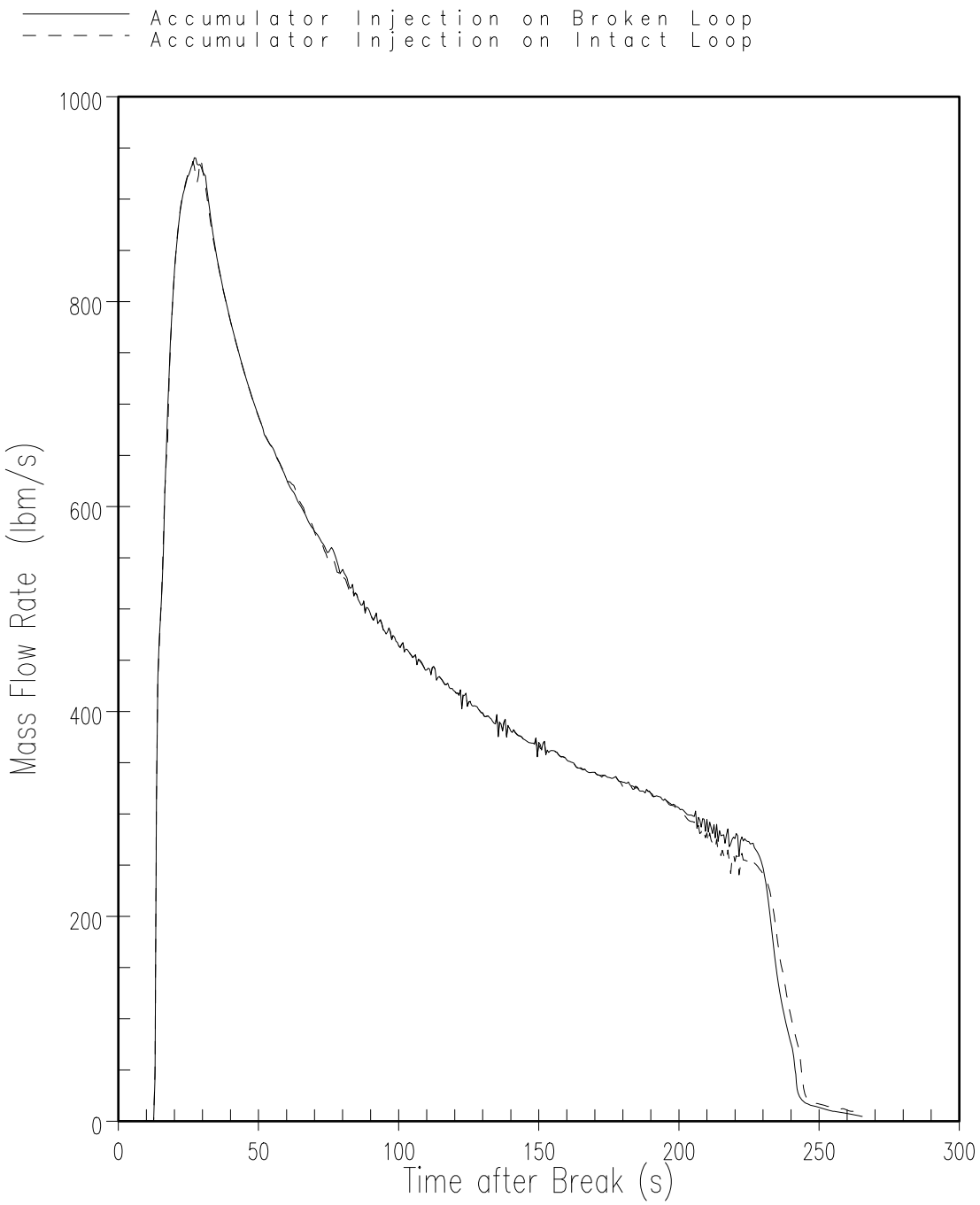


Figure 15.6.5.4A-5
Accumulator Injection Flow for
95th Percentile Estimator PCT Case

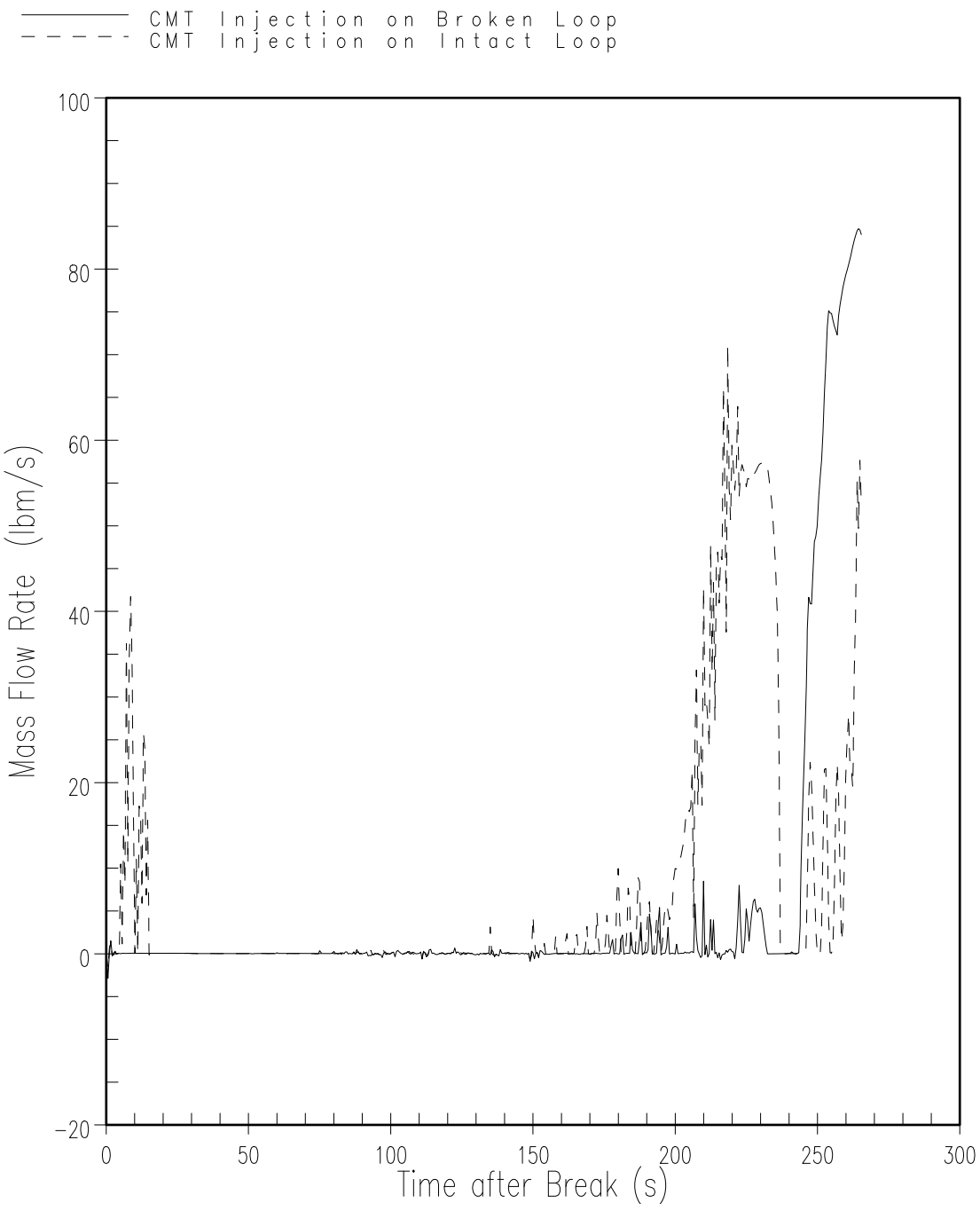


Figure 15.6.5.4A-6
Core Makeup Tank Injection Flow
for 95th Percentile Estimator PCT Case

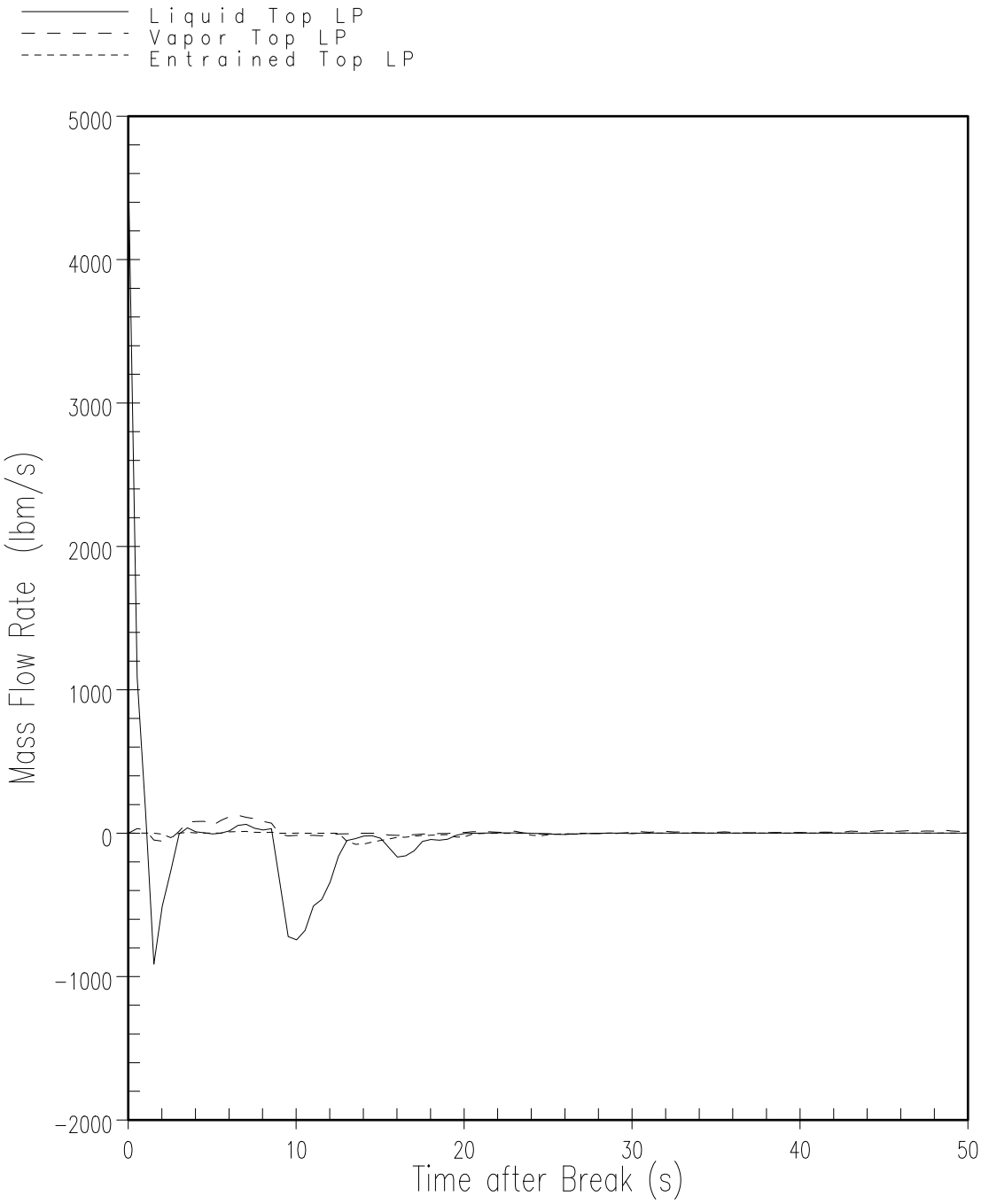


Figure 15.6.5.4A-7
Mass Flow at Top of Peripheral Assemblies Channel for 95th Percentile Estimator PCT Case

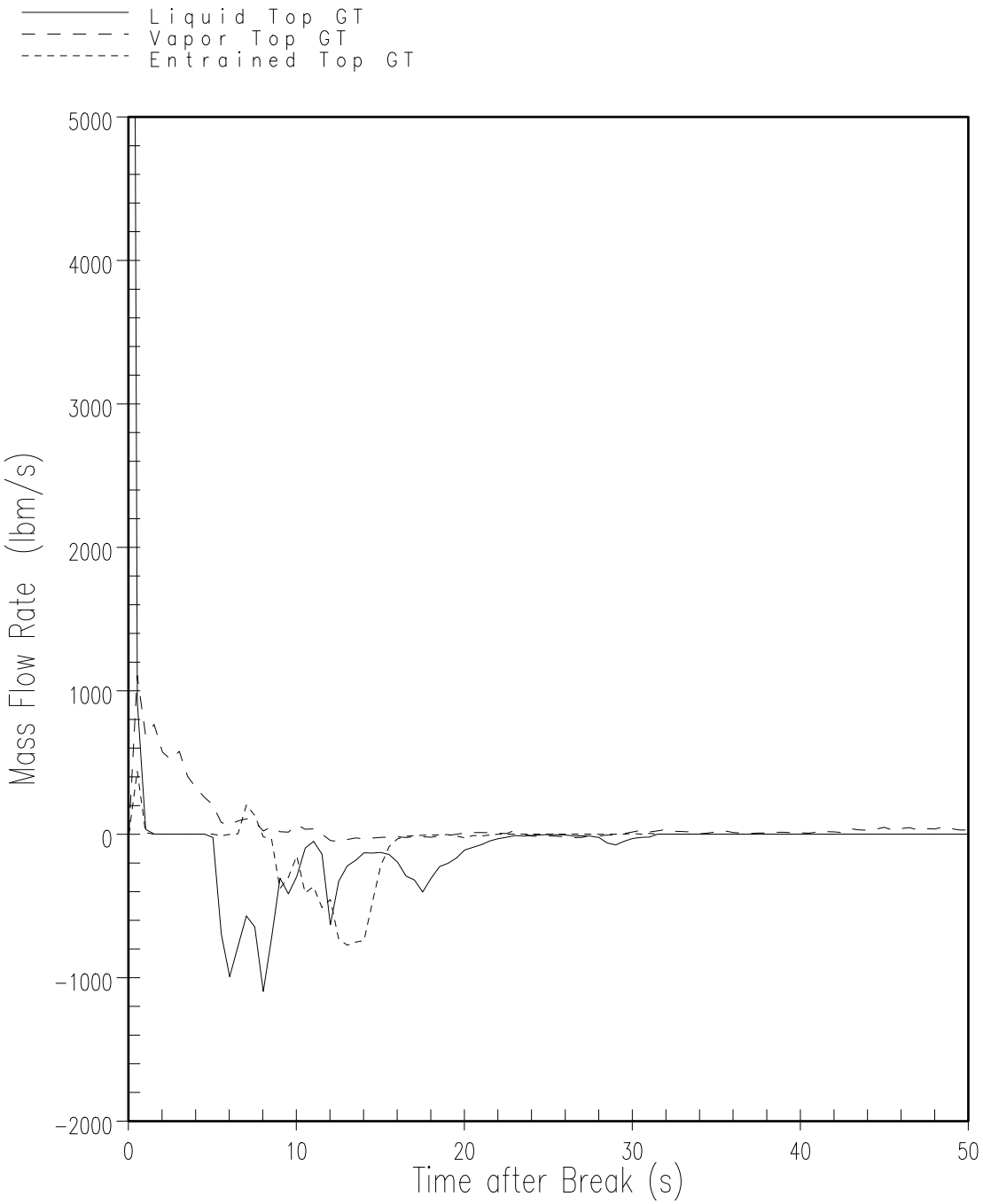


Figure 15.6.5.4A-8
Mass Flow at Top of Guide Tube Assemblies Channel for 95th Percentile Estimator PCT Case

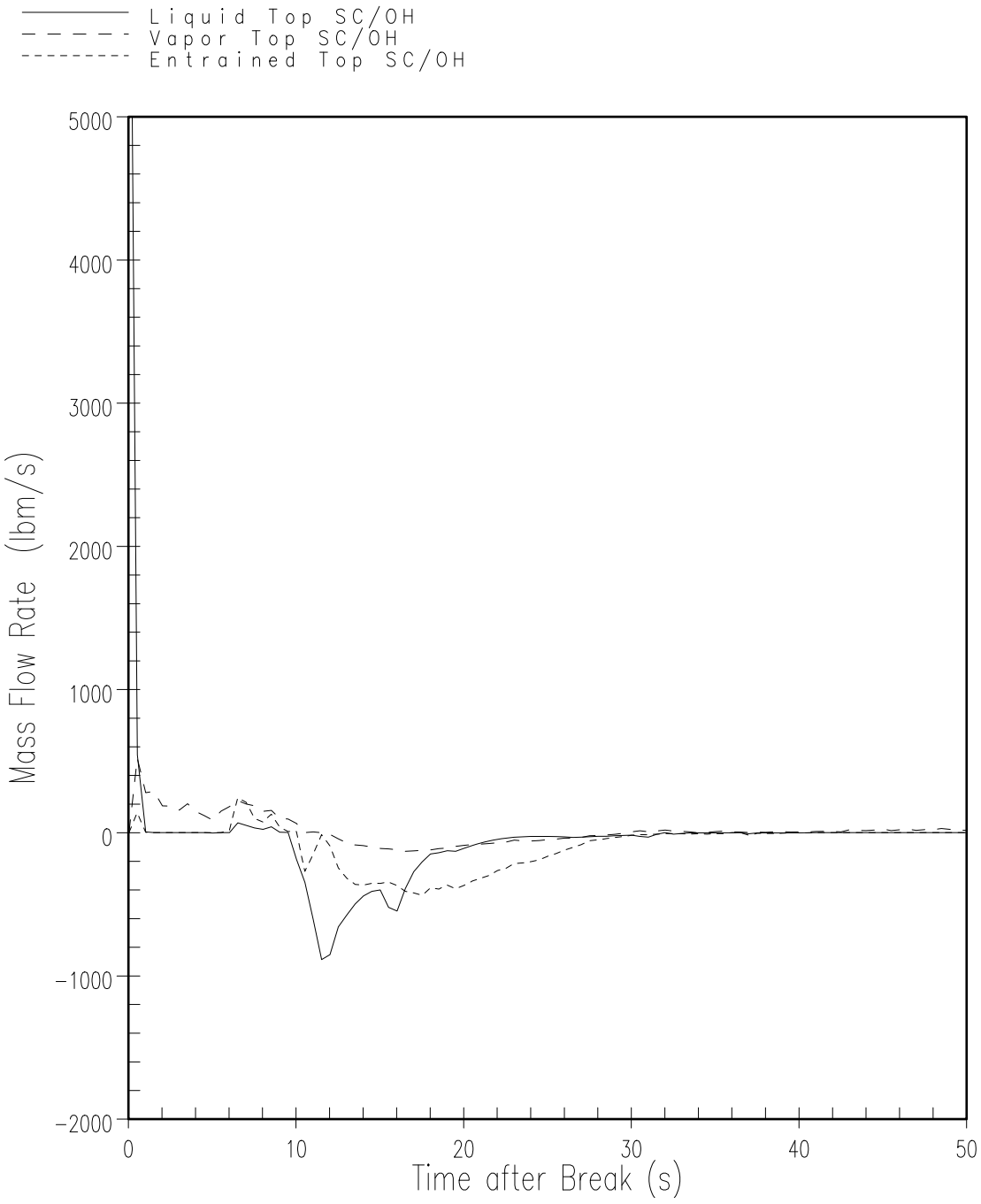


Figure 15.6.5.4A-9
Mass Flow at Top of Support Column/Open Hole Assemblies Channel for 95th Percentile Estimator PCT Case

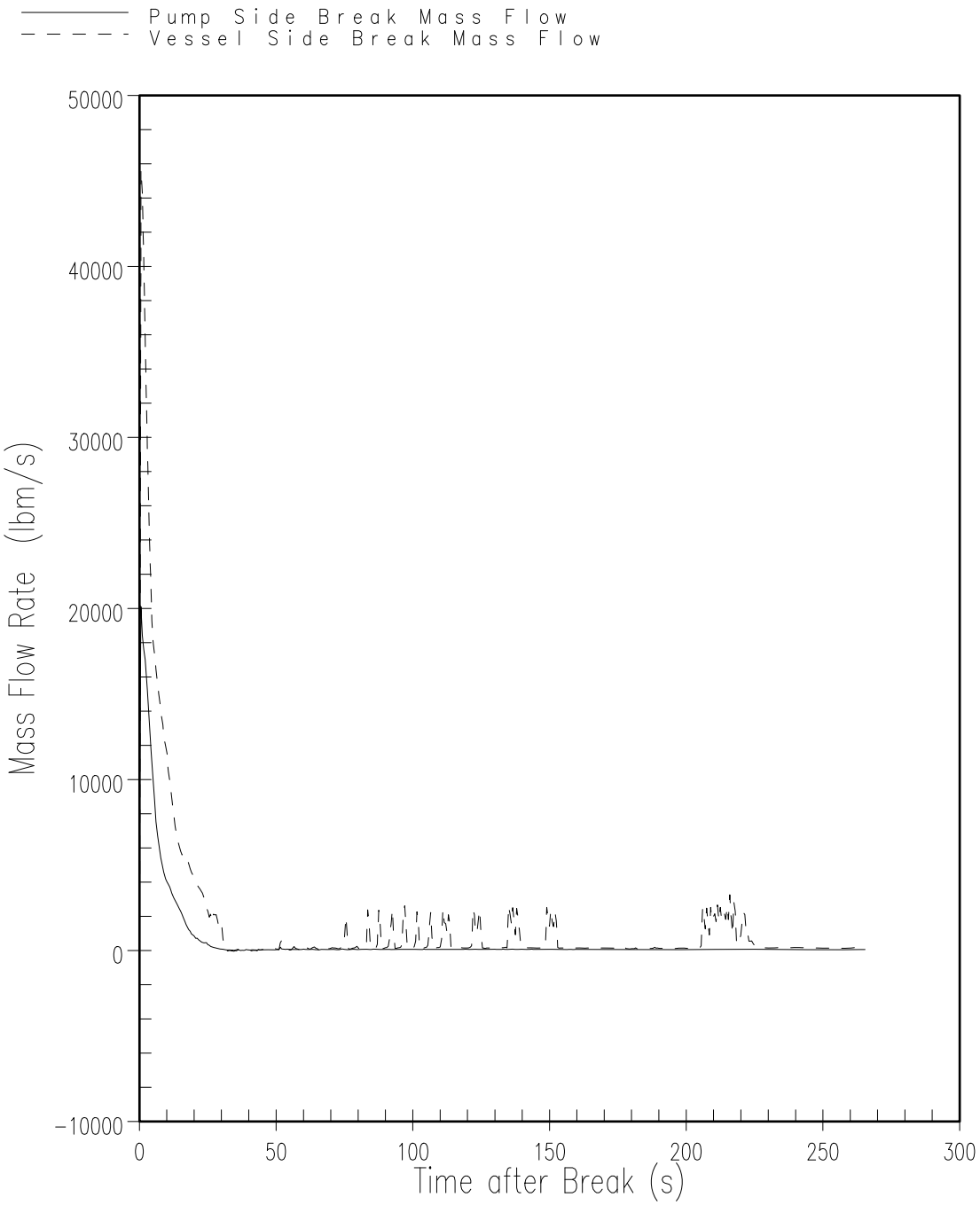


Figure 15.6.5.4A-10
Break Mass Flow for
95th Percentile Estimator PCT Case

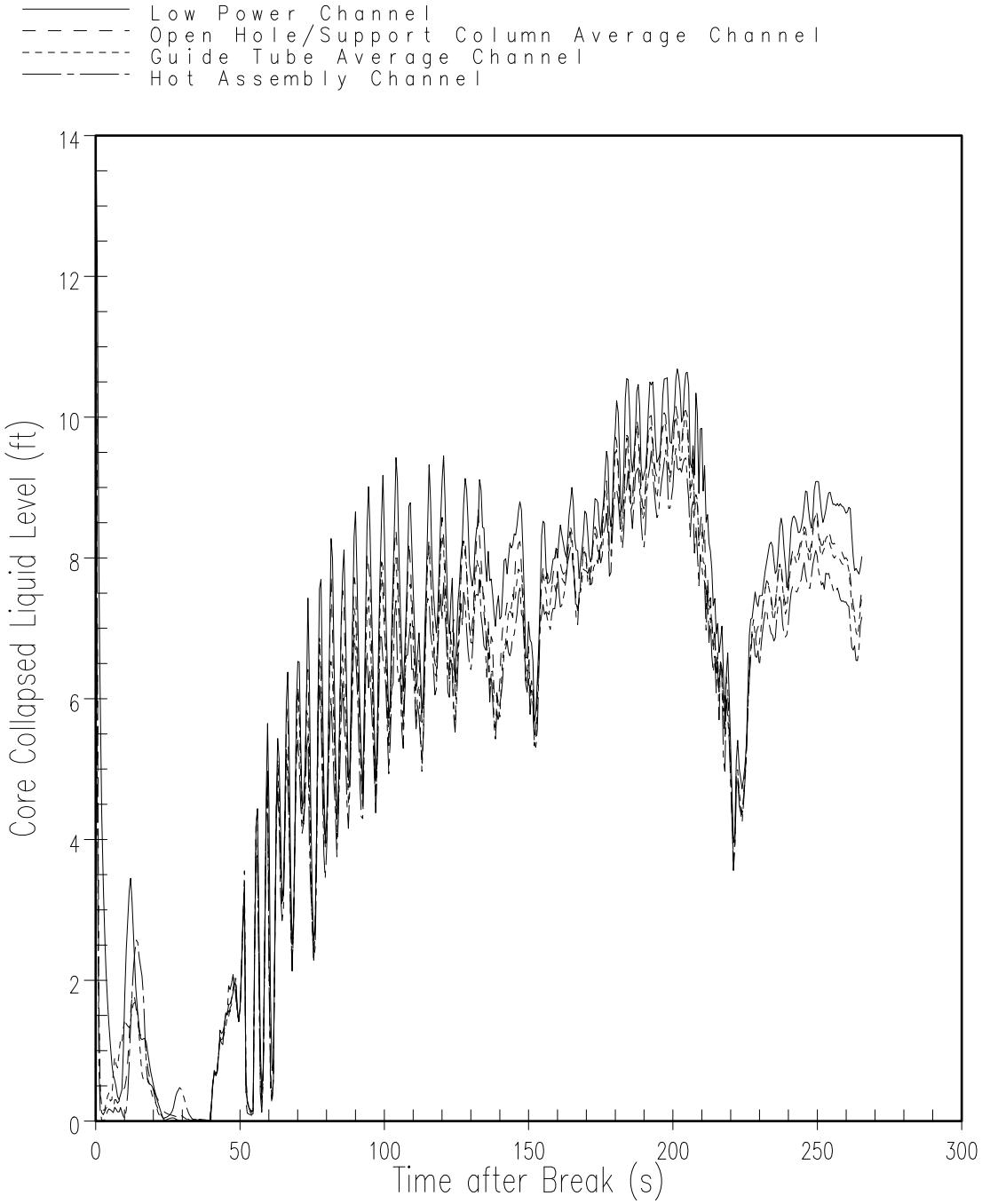


Figure 15.6.5.4A-11
Core Channel Collapsed Liquid Levels for 95th Percentile Estimator PCT Case (Reference Point: Bottom of Active Fuel)

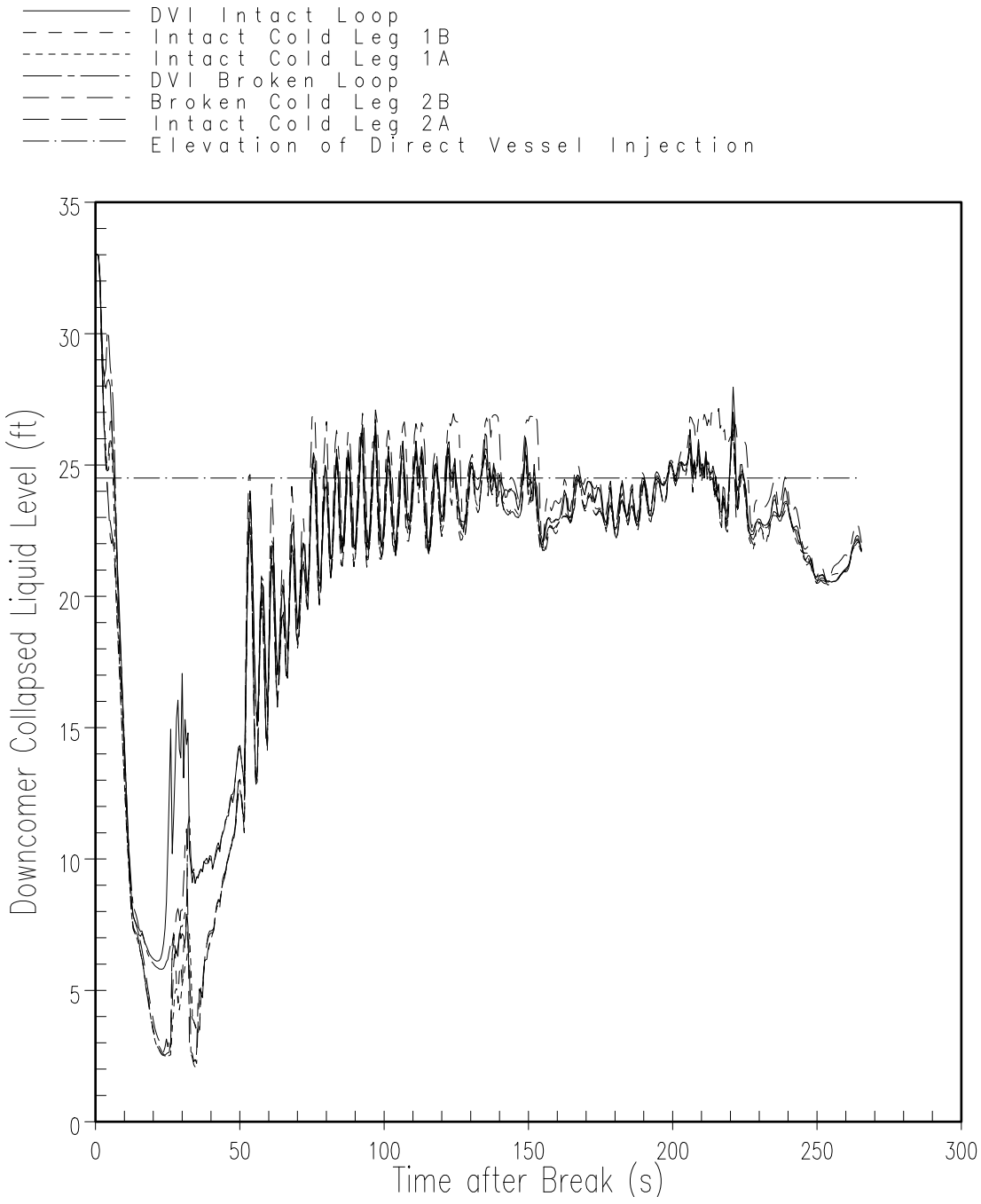


Figure 15.6.5.4A-12
Downcomer Channel Collapsed Liquid Levels for 95th Percentile Estimator PCT Case (Reference Point: Inside Bottom of Vessel)

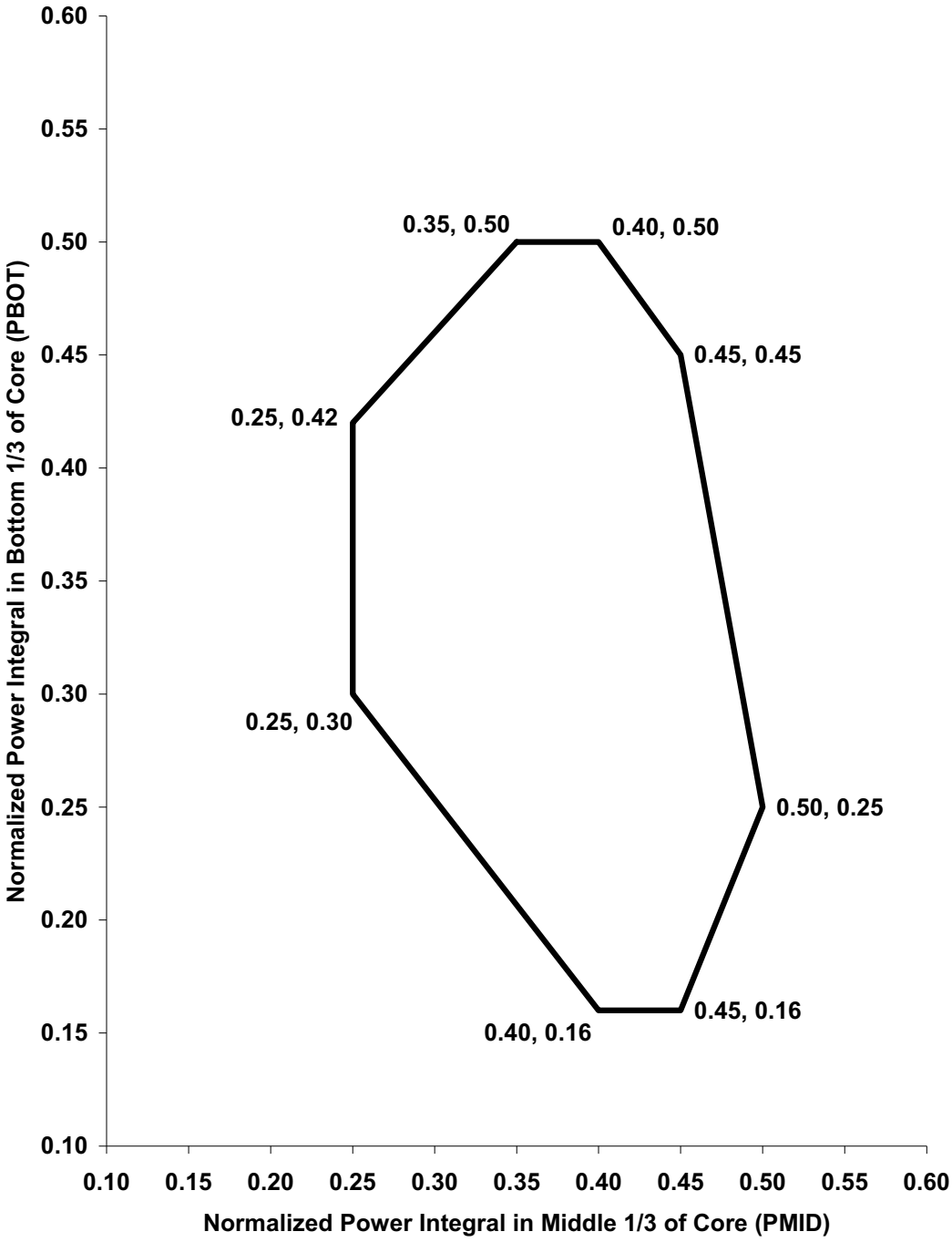


Figure 15.6.5.4A-13
PBOT/PMID Box Supported by AP1000 ASTRUM Analysis

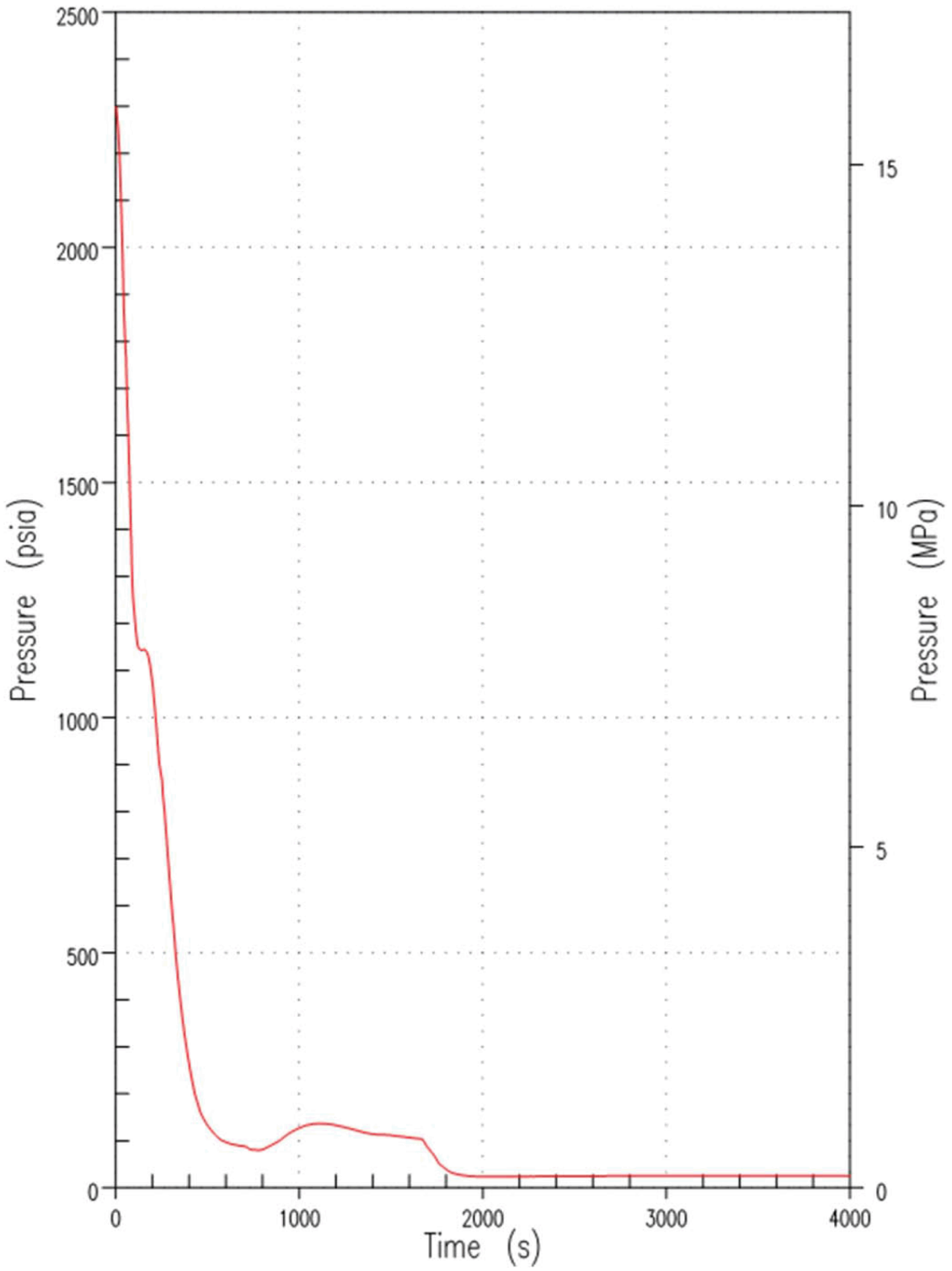


Figure 15.6.5.4B-1(a)
Inadvertent ADS – RCS Pressure

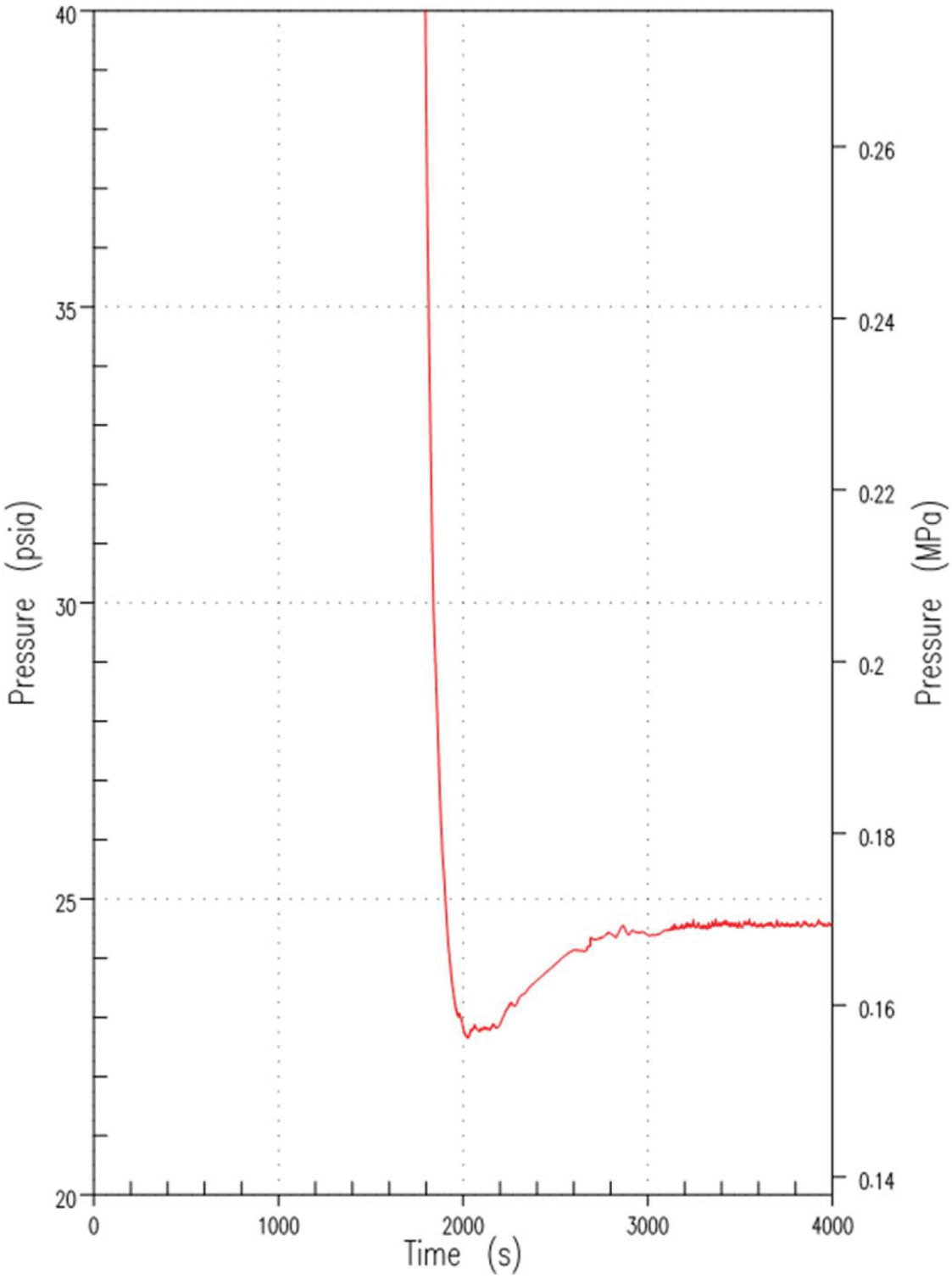


Figure 15.6.5.4B-1(b)
Inadvertent ADS – RCS Pressure (Zoomed)

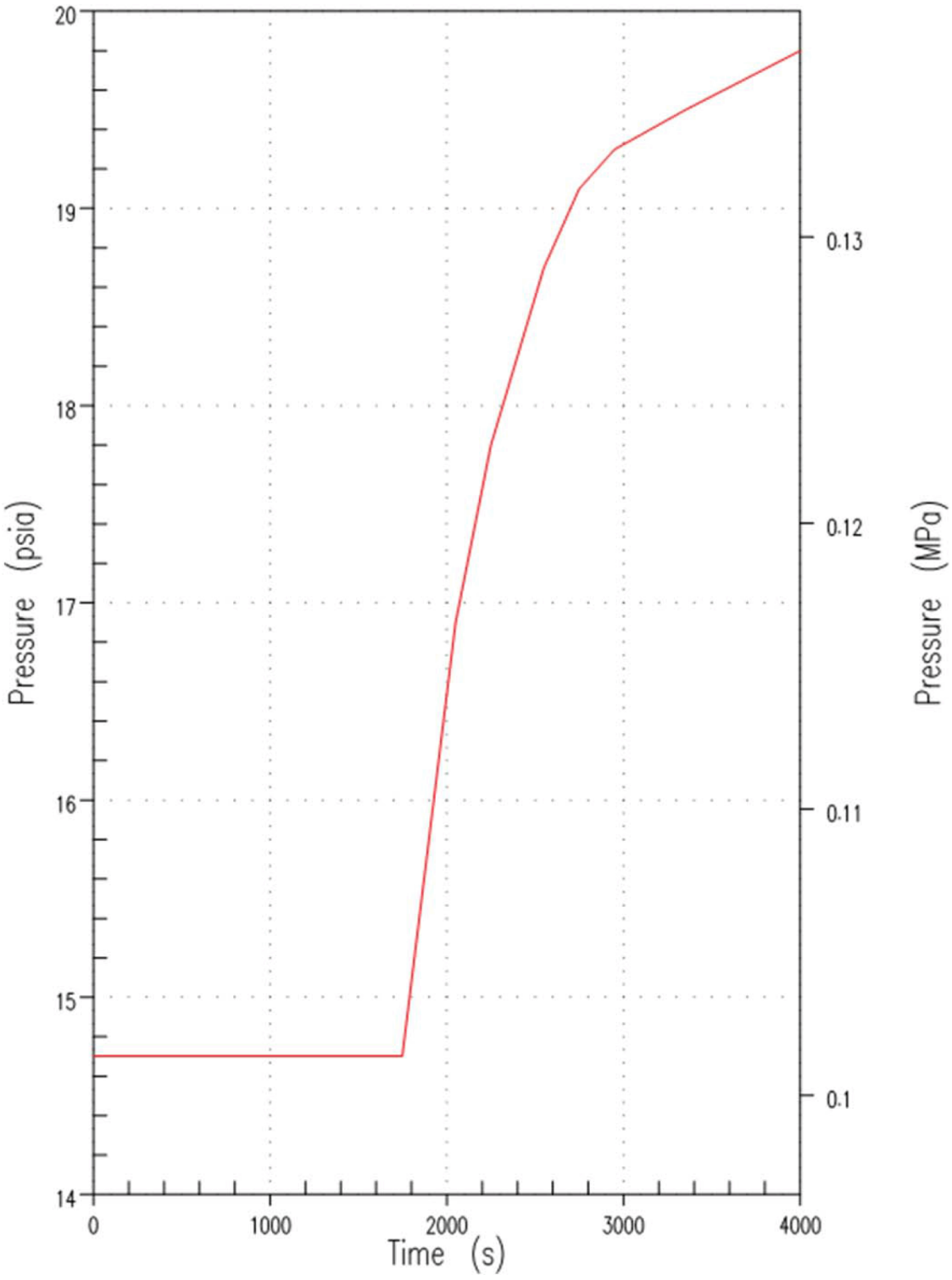


Figure 15.6.5.4B-1(c)
Inadvertent ADS – Containment Pressure

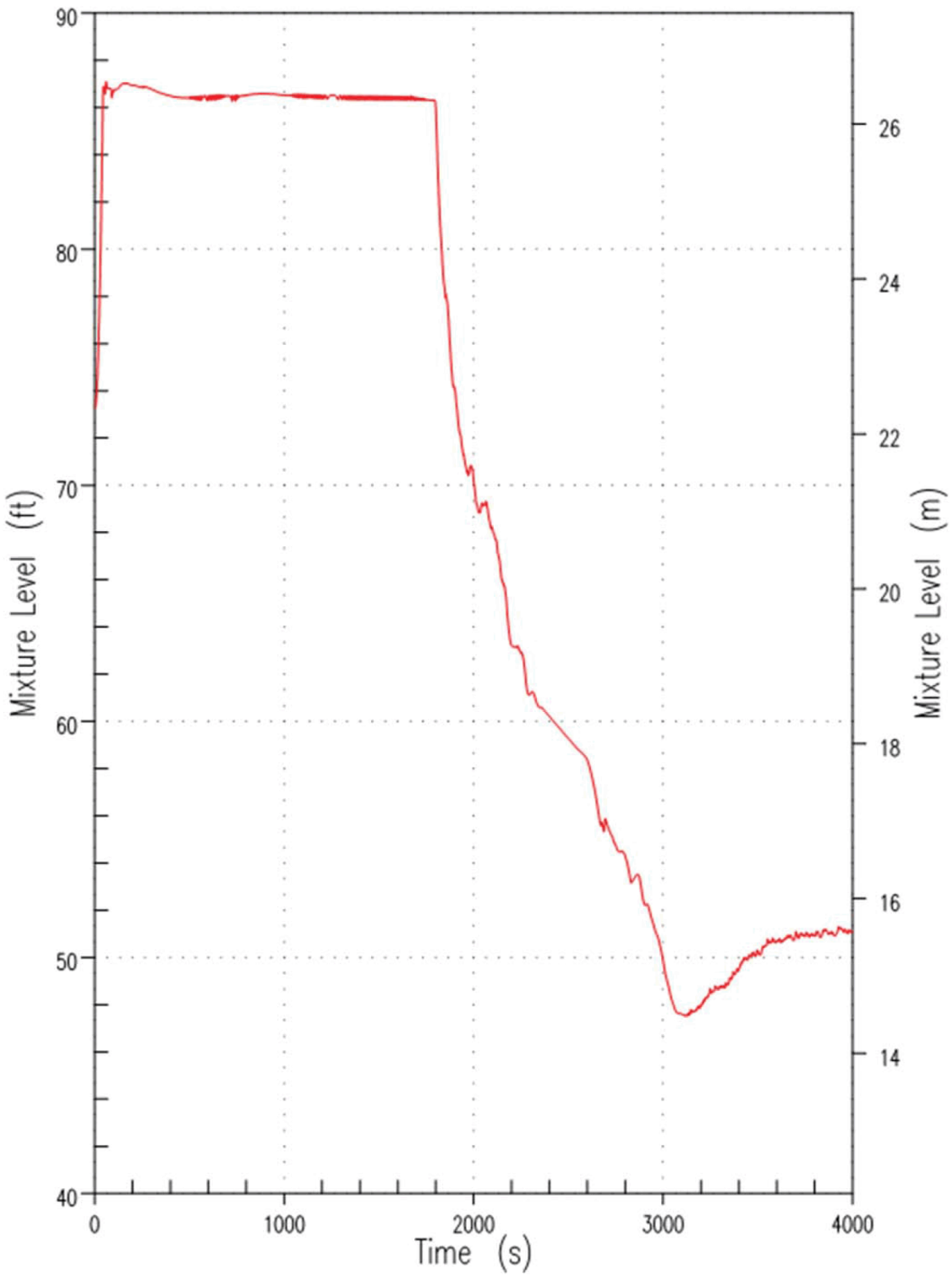


Figure 15.6.5.4B-2
Inadvertent ADS – Pressurizer Mixture Level

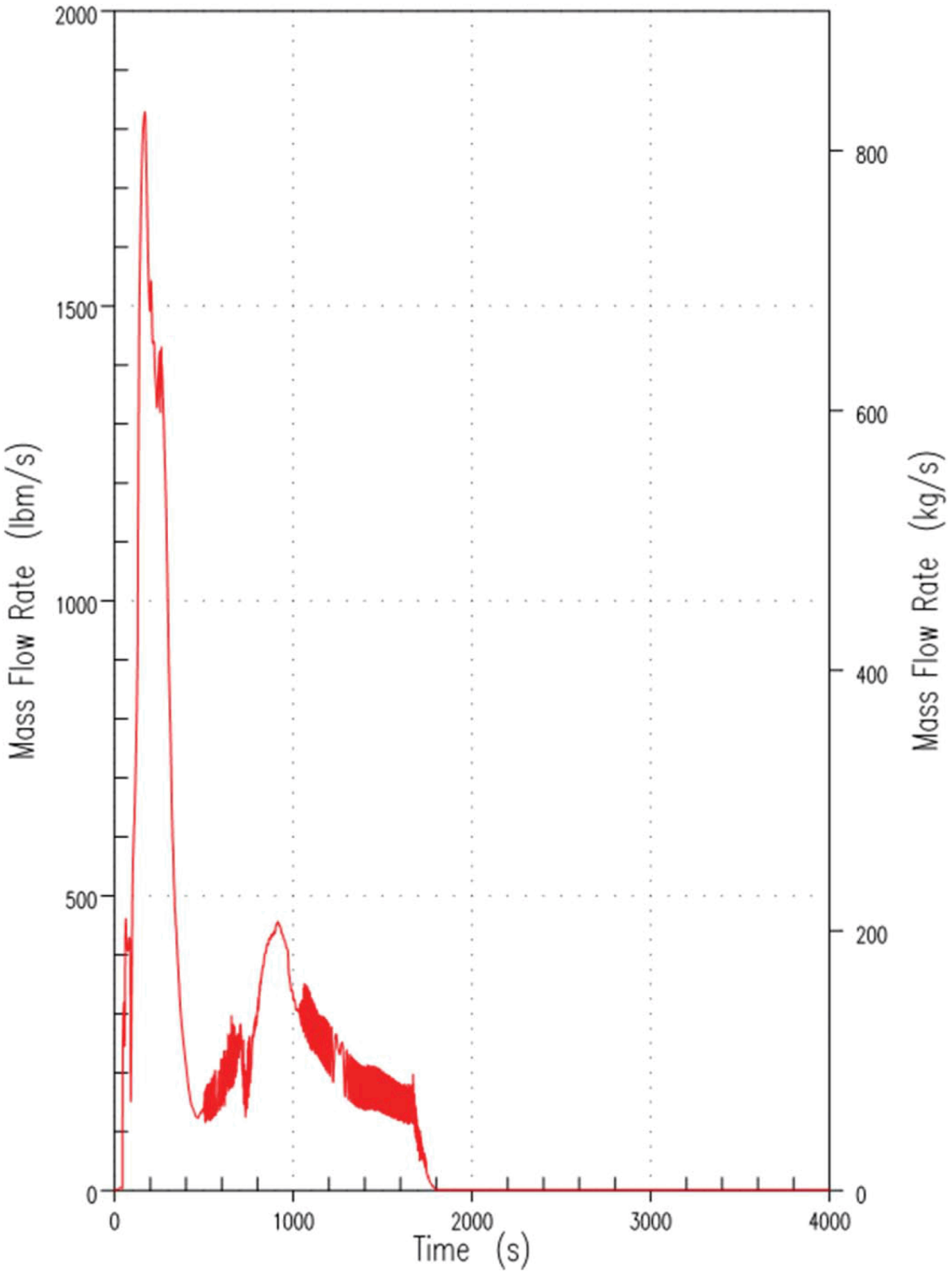


Figure 15.6.5.4B-3
Inadvertent ADS – ADS 1-3 Liquid Discharge

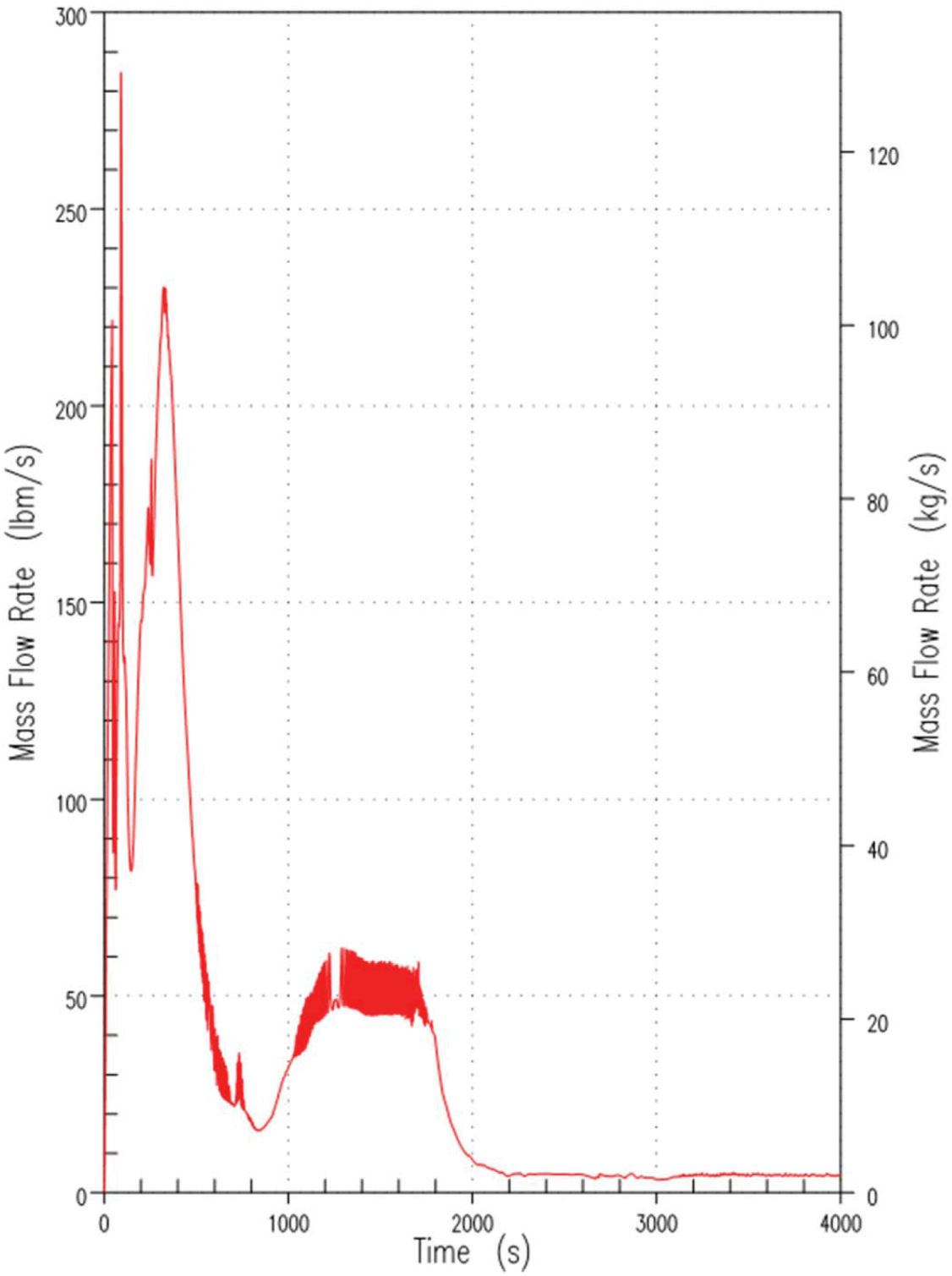


Figure 15.6.5.4B-4(a)
Inadvertent ADS – ADS 1-3 Vapor Discharge

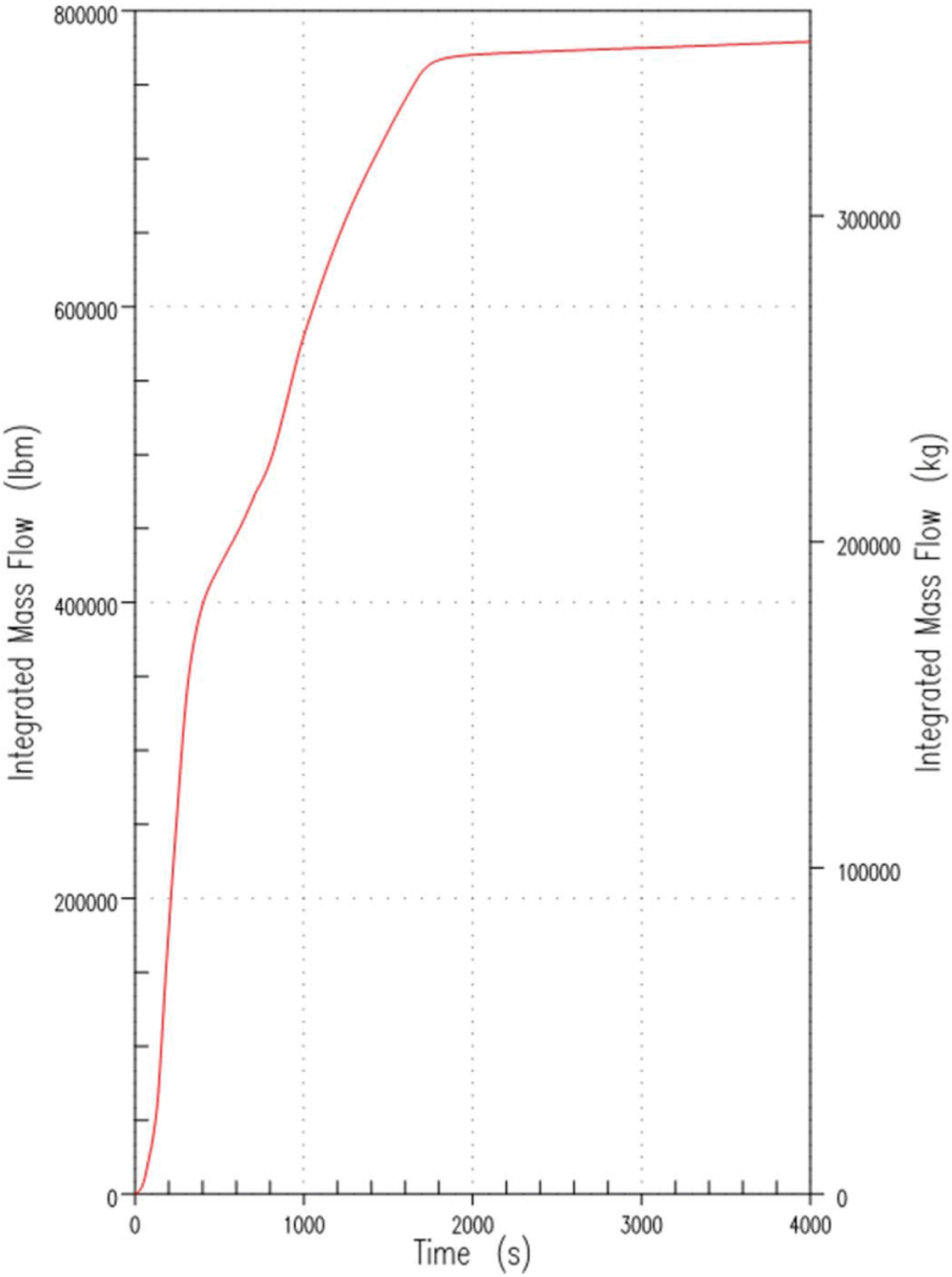


Figure 15.6.5.4B-4(b)
Inadvertent ADS – ADS 1-3 Integrated Discharge

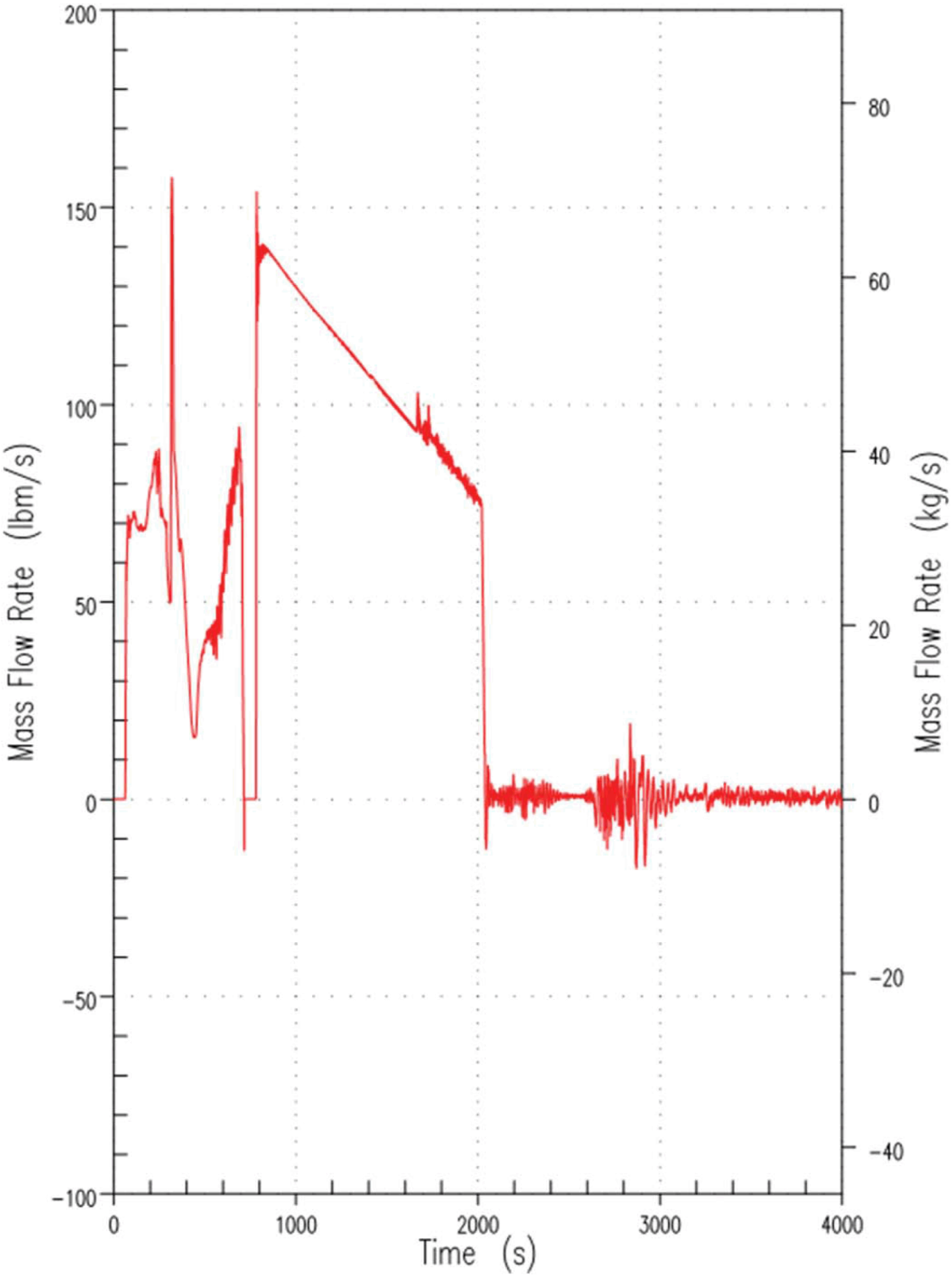


Figure 15.6.5.4B-5
Inadvertent ADS – CMT-1 Injection Rate

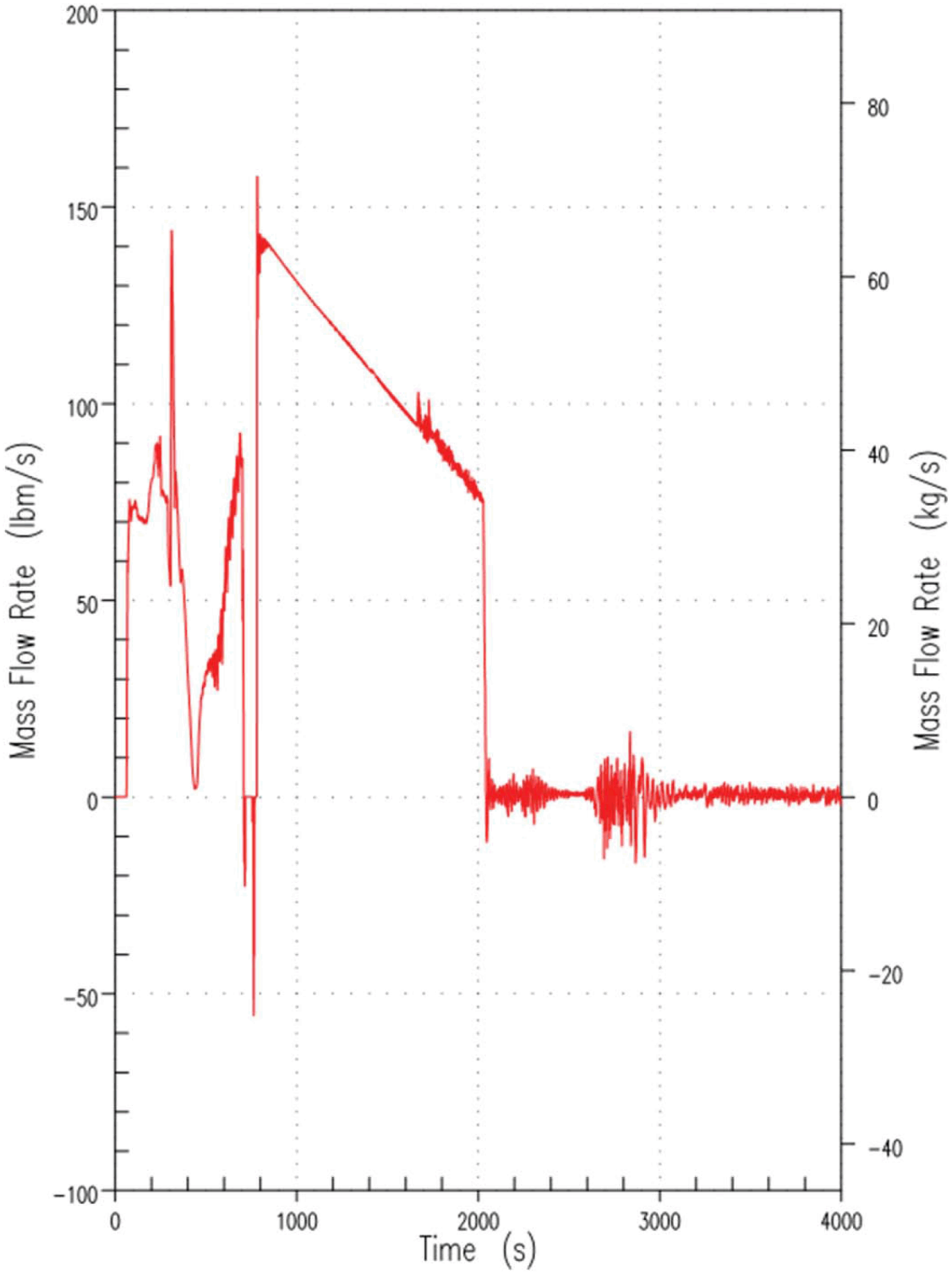


Figure 15.6.5.4B-6
Inadvertent ADS – CMT-2 Injection Rate

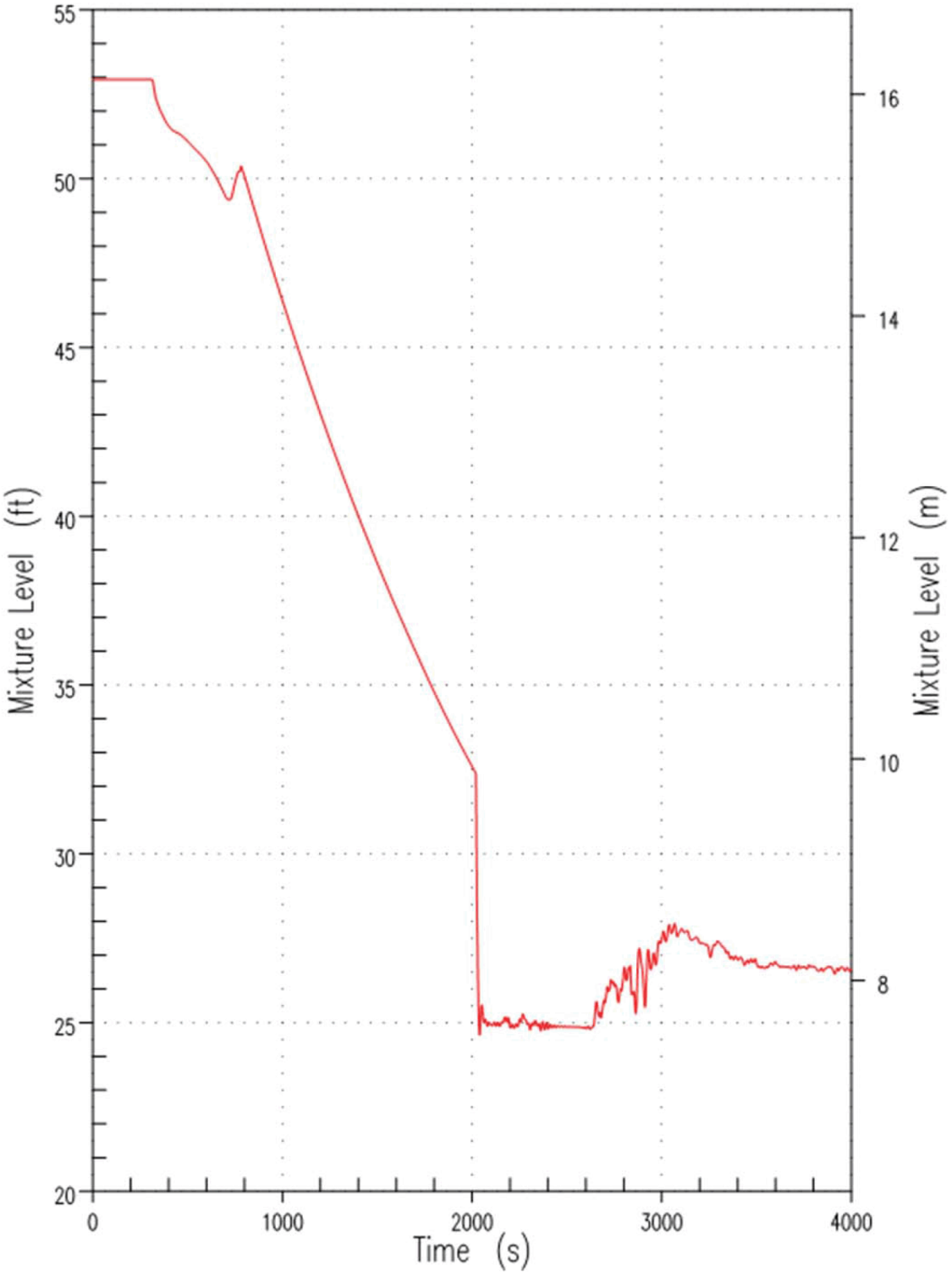


Figure 15.6.5.4B-7
Inadvertent ADS – CMT-1 Mixture Level

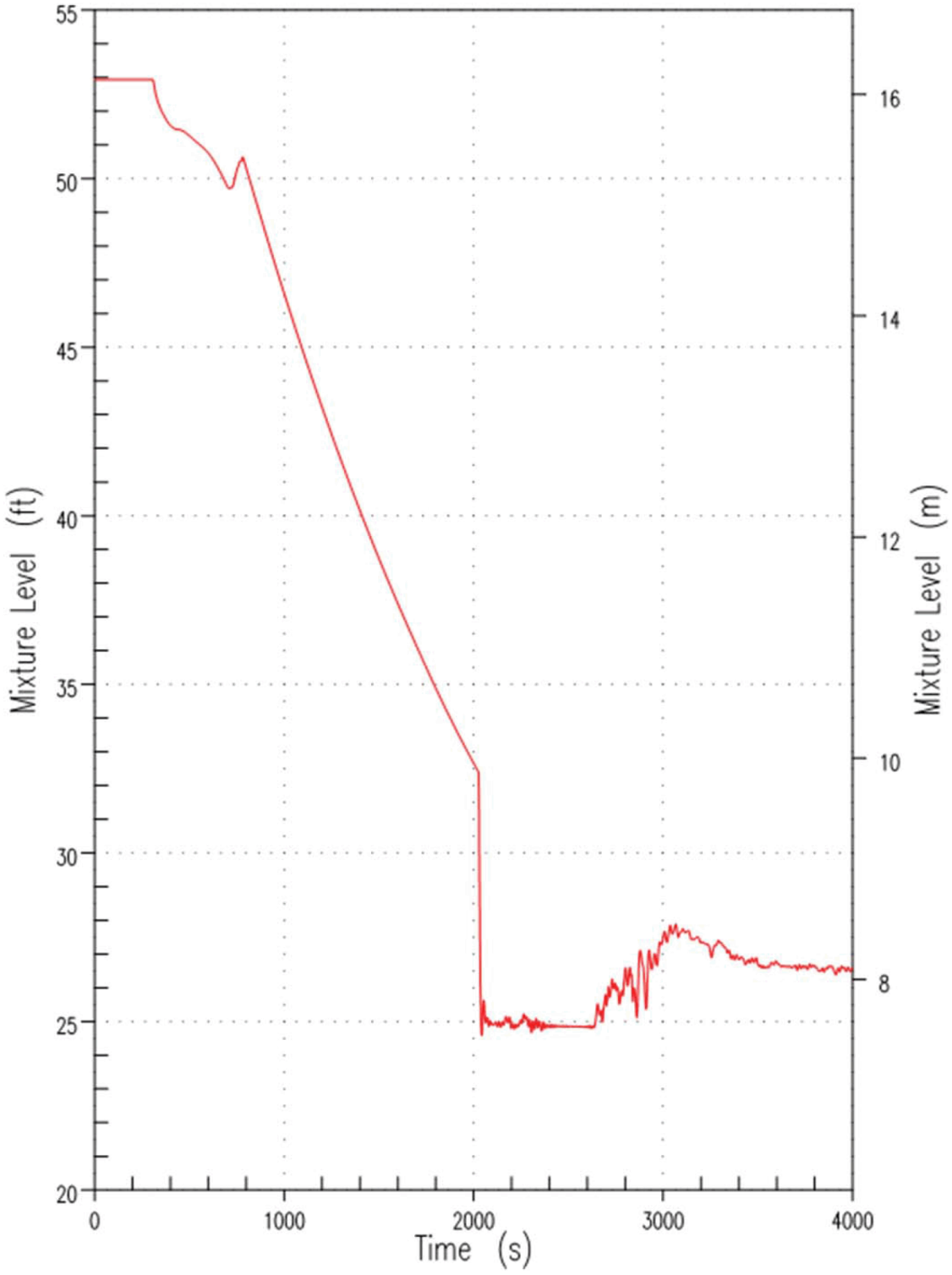


Figure 15.6.5.4B-8
Inadvertent ADS – CMT-2 Mixture Level

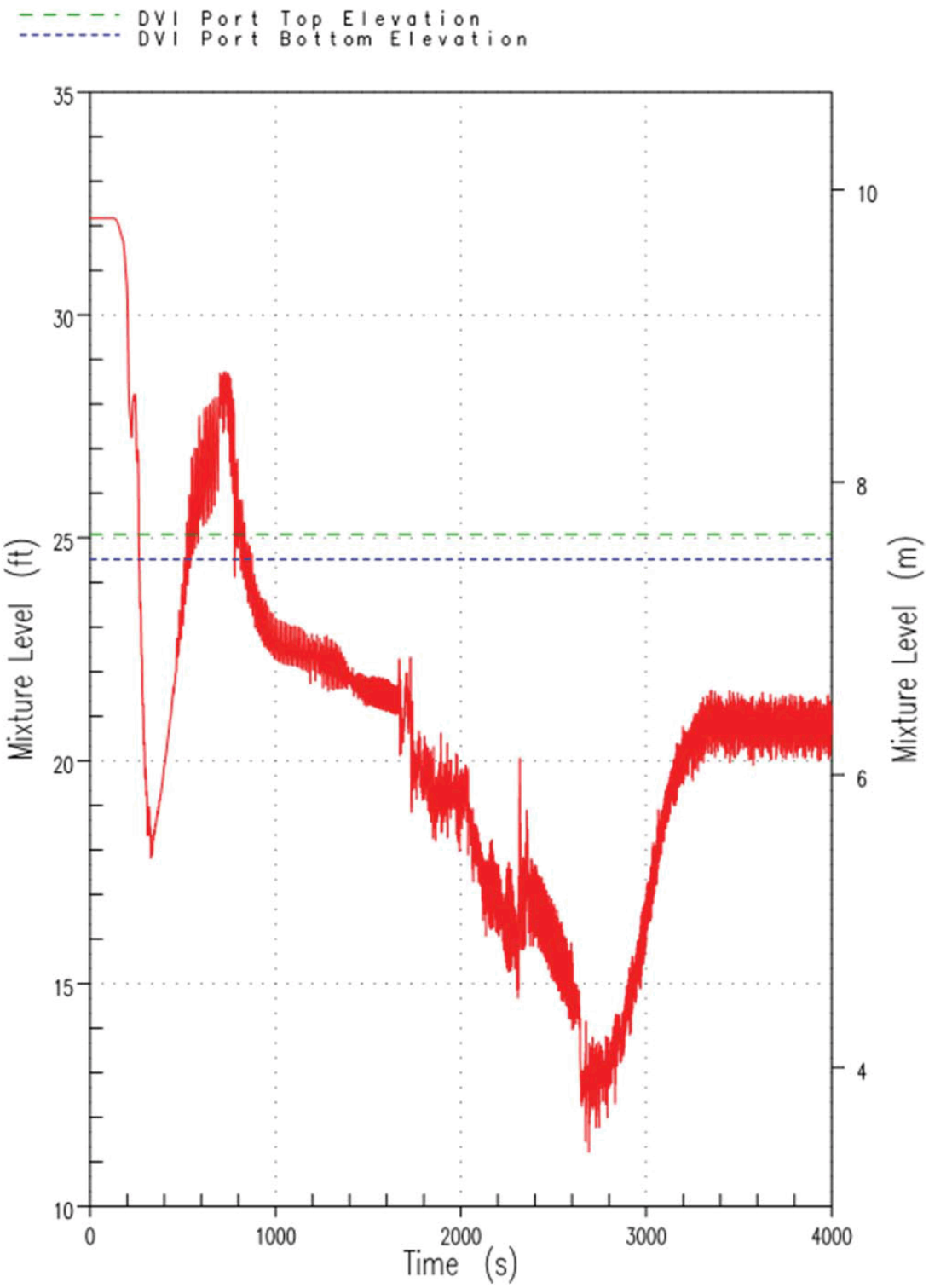


Figure 15.6.5.4B-9
Inadvertent ADS – Downcomer Mixture Level

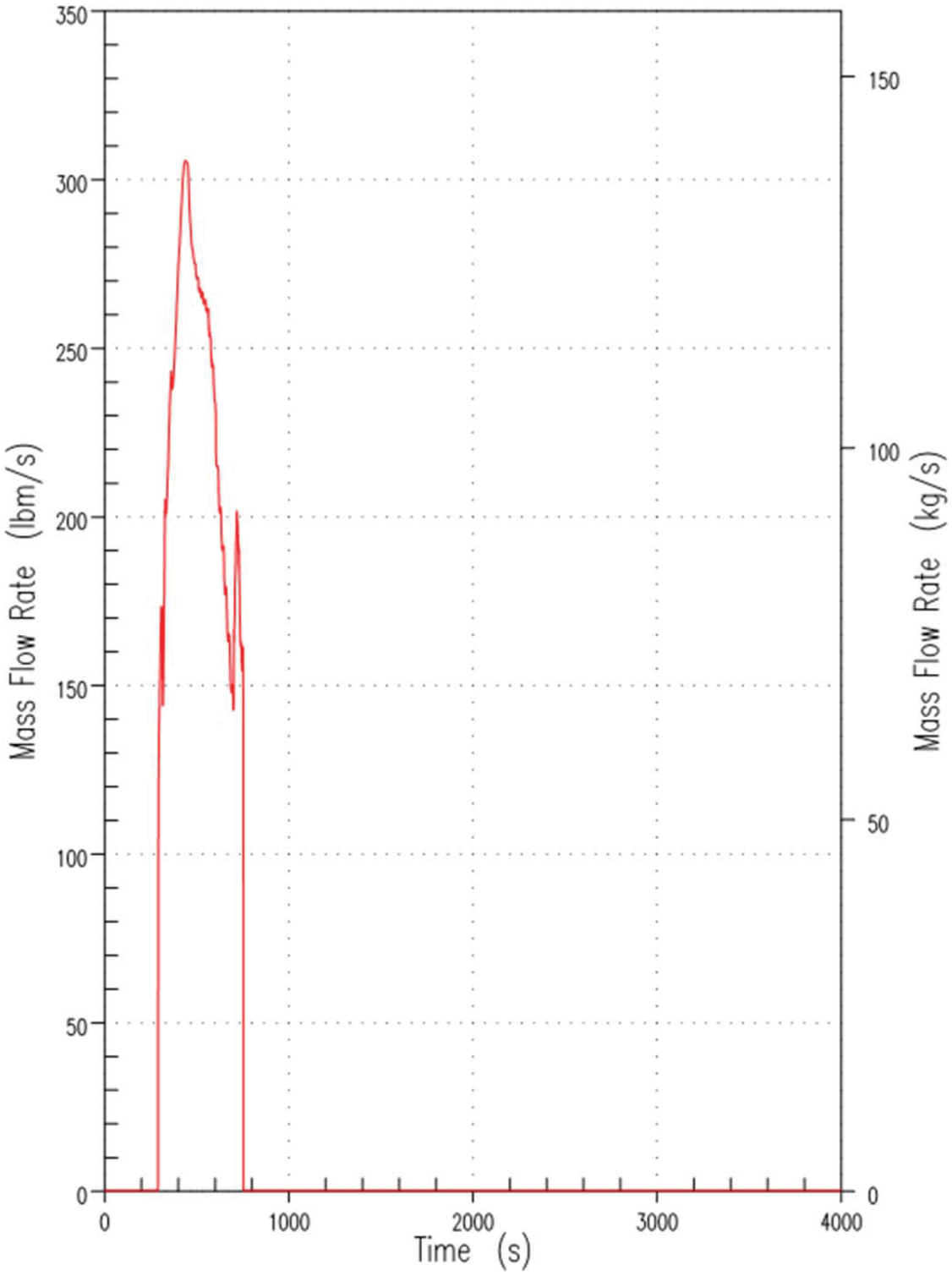


Figure 15.6.5.4B-10
Inadvertent ADS – Accumulator-1 Injection Rate

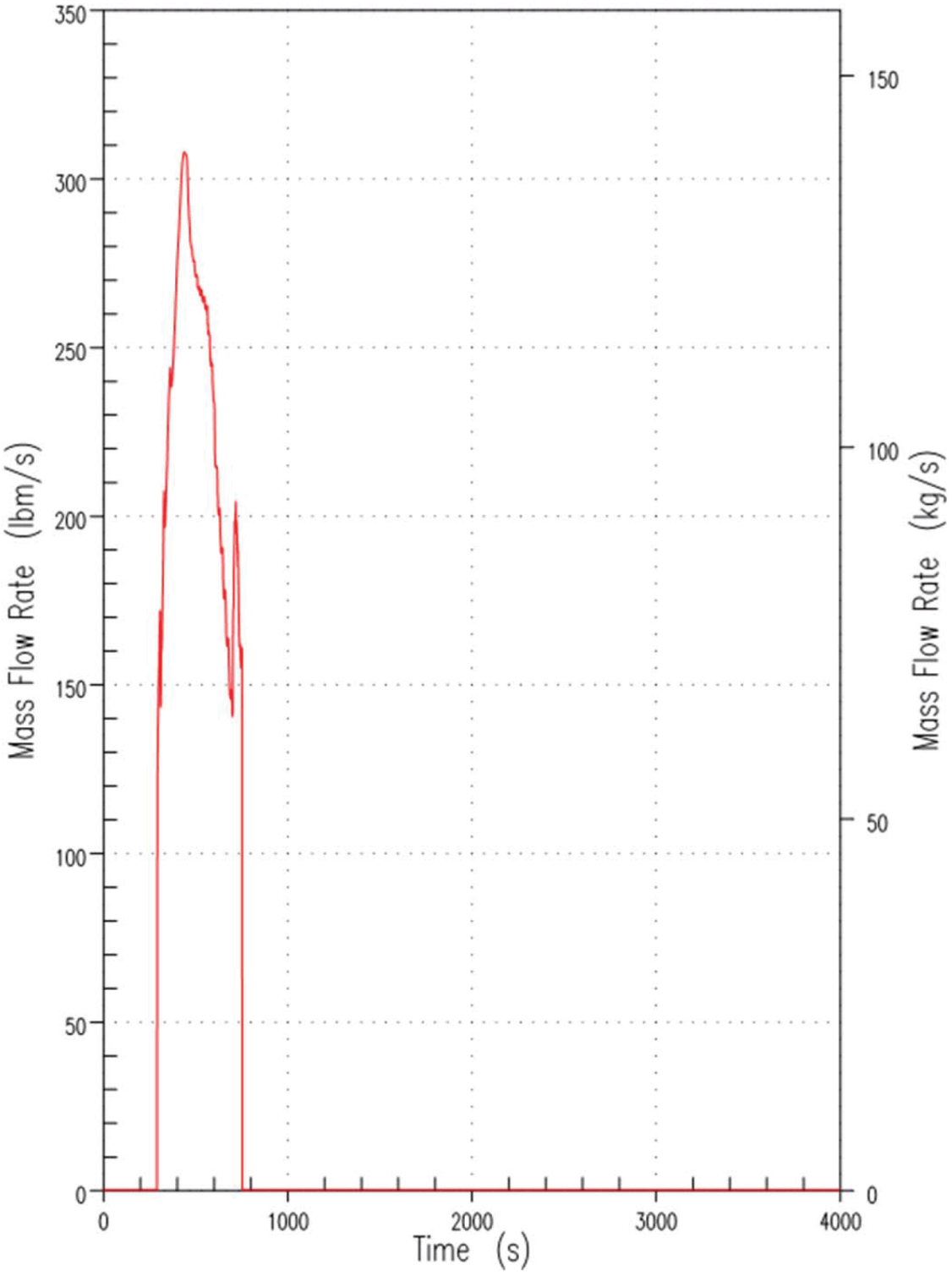


Figure 15.6.5.4B-11
Inadvertent ADS – Accumulator-2 Injection Rate

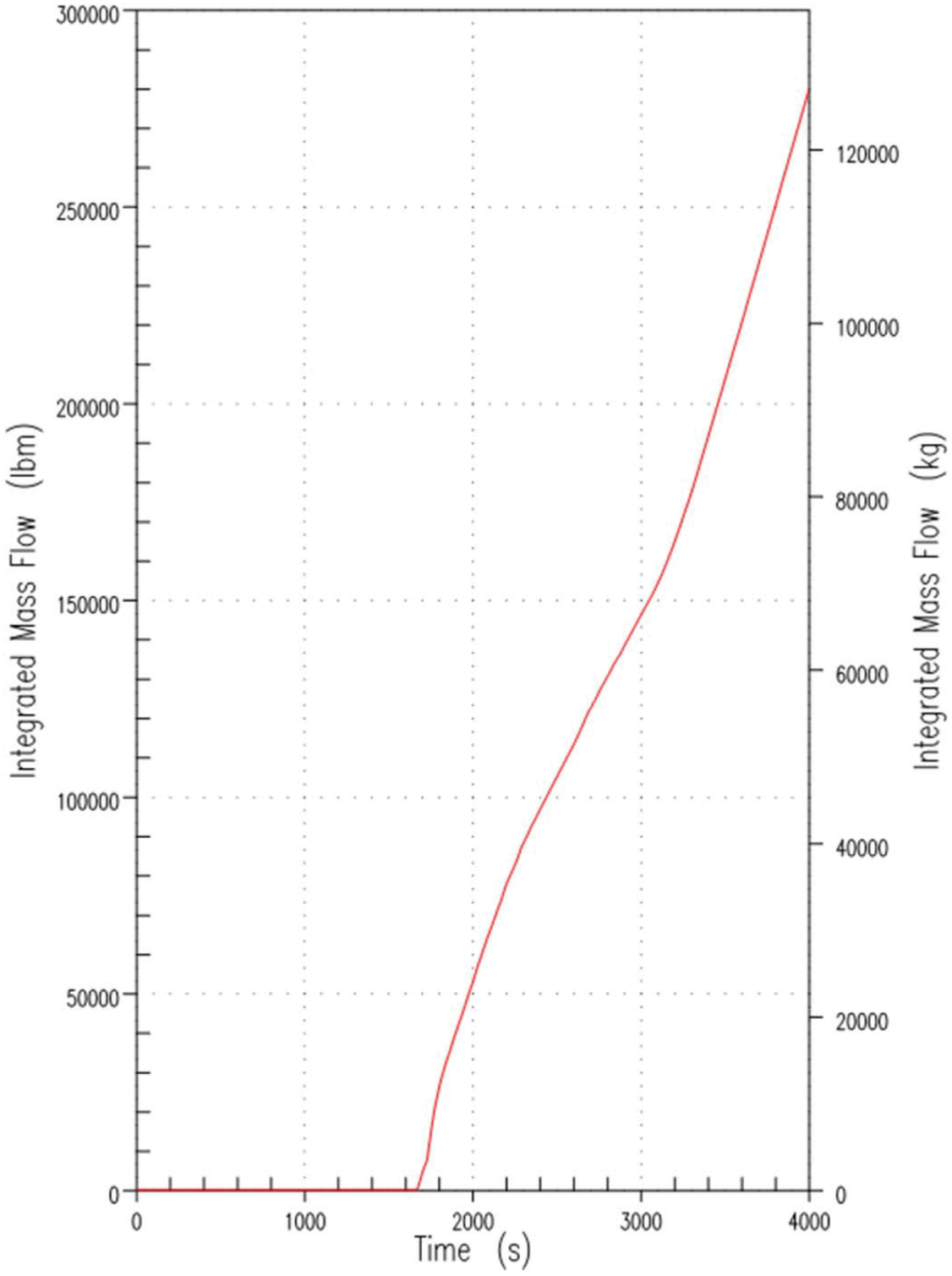


Figure 15.6.5.4B-12(a)
Inadvertent ADS – ADS-4 Integrated Discharge

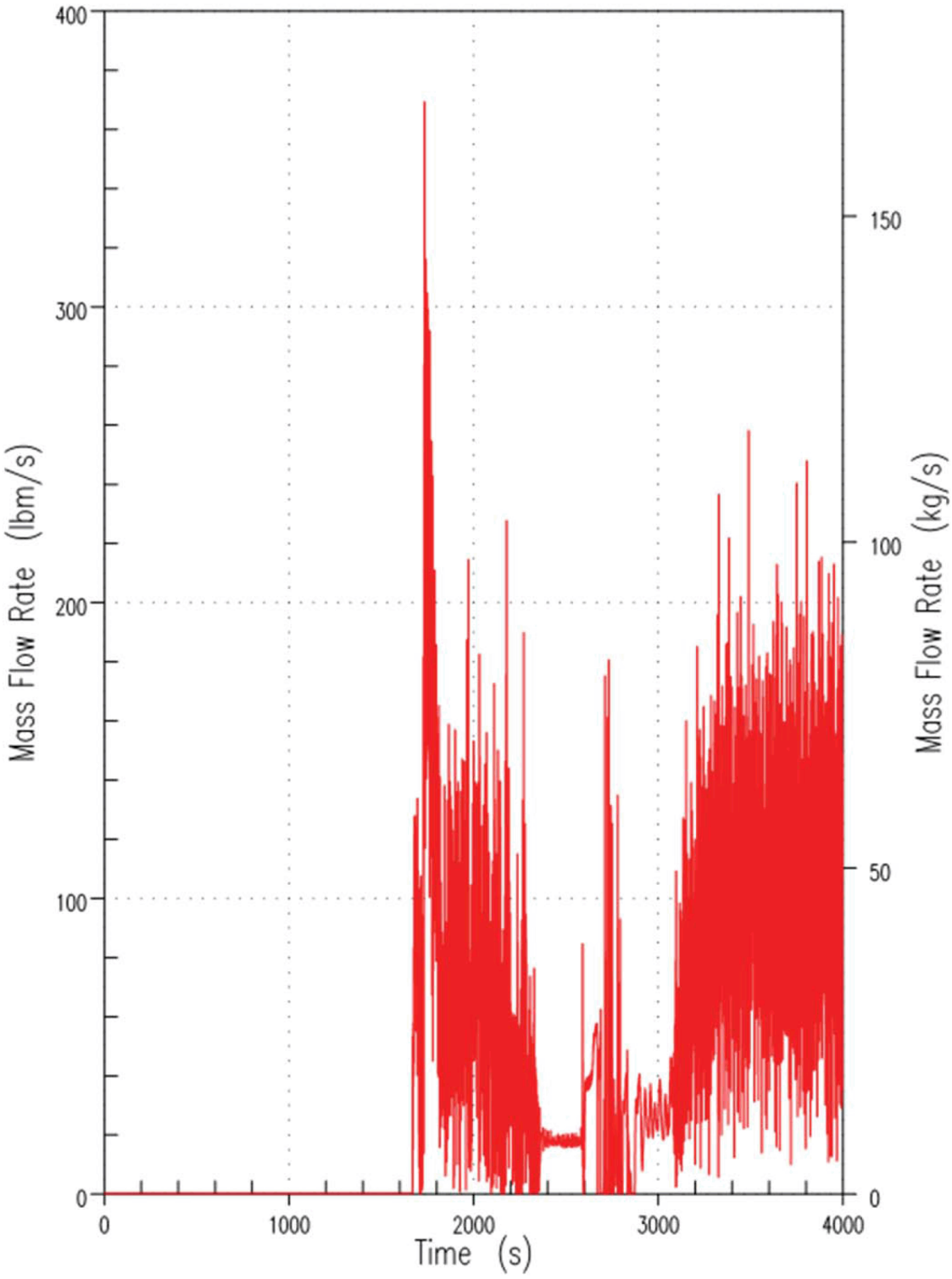


Figure 15.6.5.4B-12(b)
Inadvertent ADS – ADS-4 Liquid Discharge

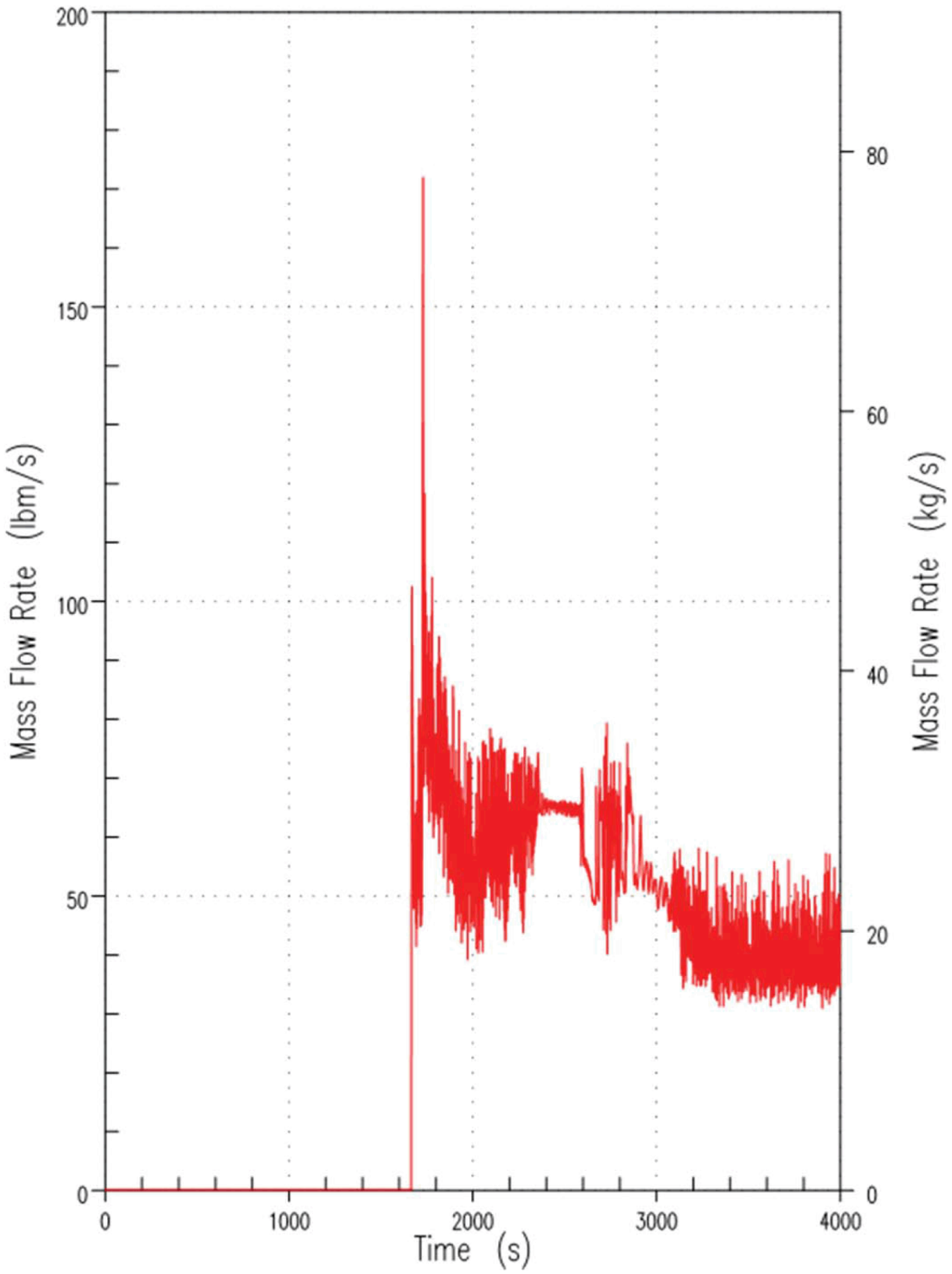


Figure 15.6.5.4B-12(c)
Inadvertent ADS – ADS-4 Vapor Discharge

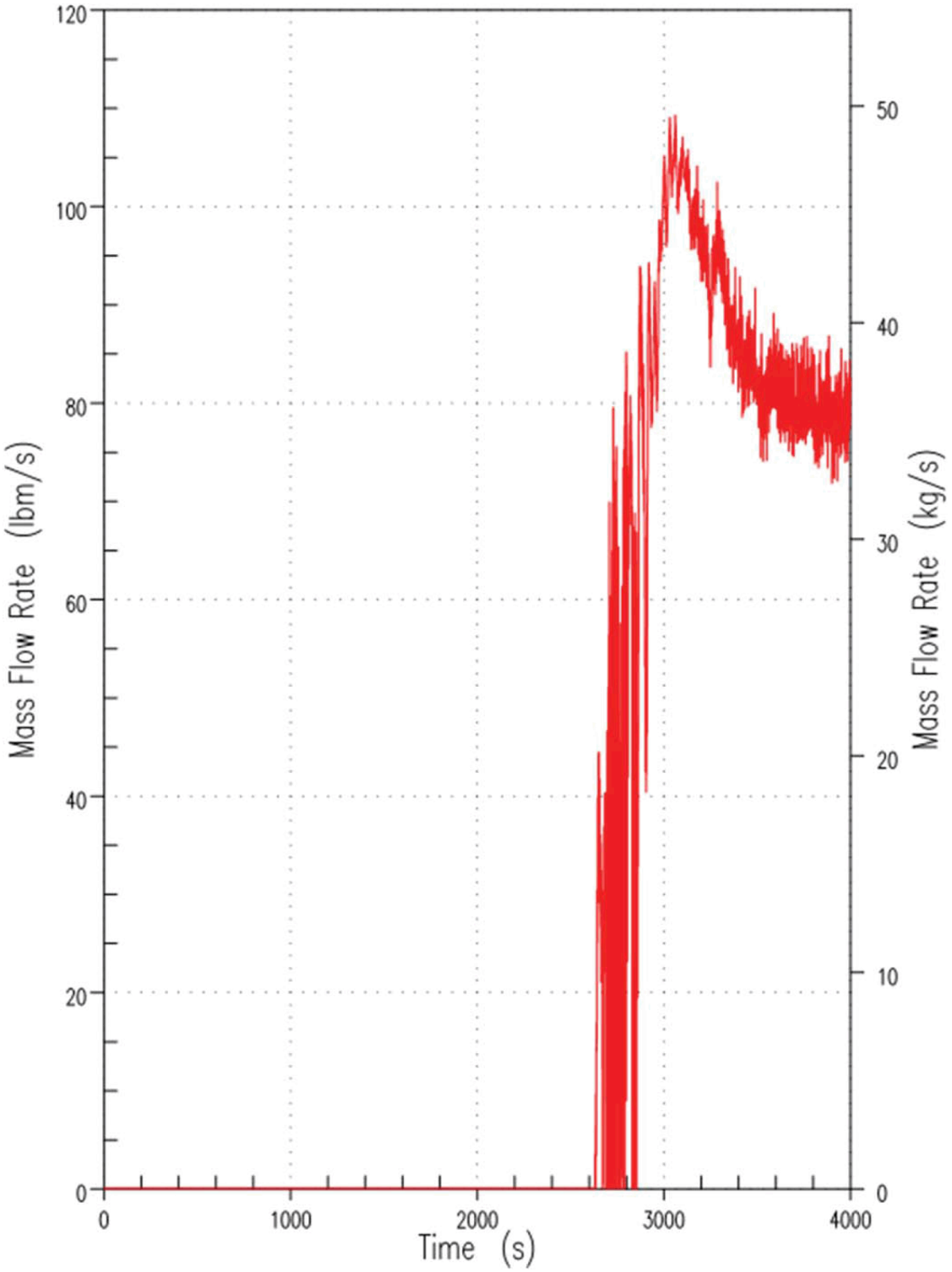


Figure 15.6.5.4B-13
Inadvertent ADS – IRWST-1 Injection Rate

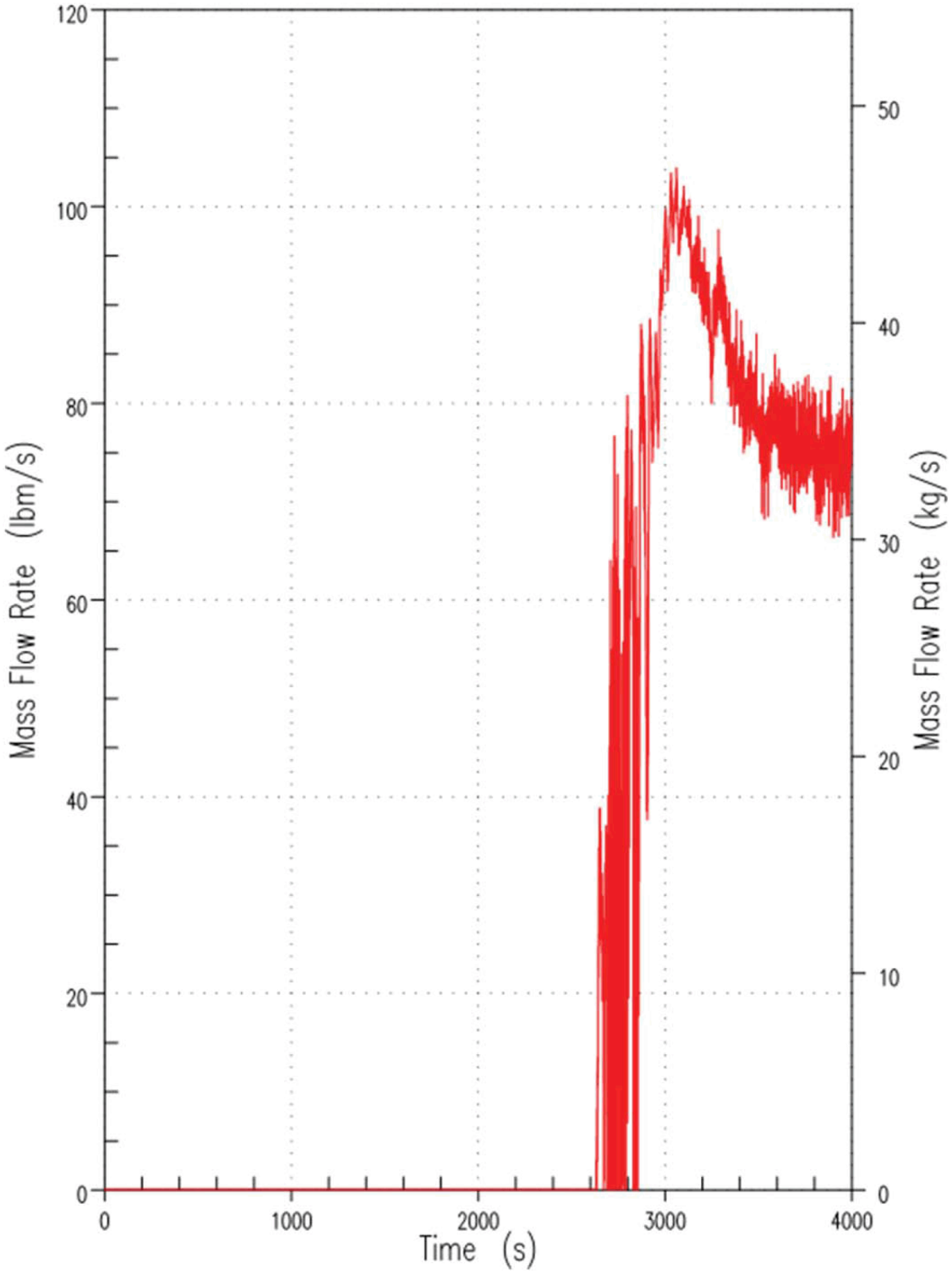


Figure 15.6.5.4B-14
Inadvertent ADS – IRWST-2 Injection Rate

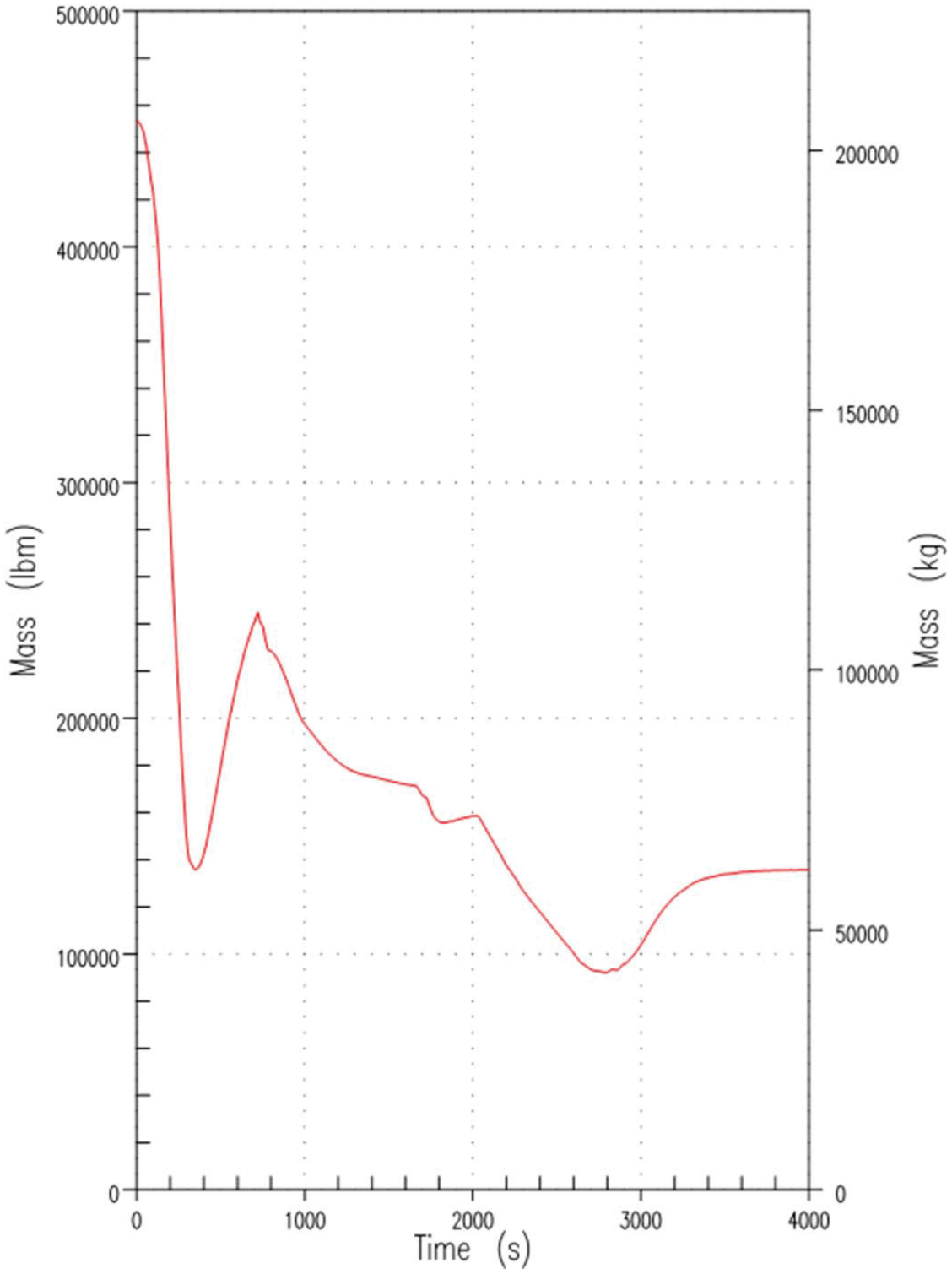


Figure 15.6.5.4B-15(a)
Inadvertent ADS – RCS System Inventory



Figure 15.6.5.4B-15(b)
Inadvertent ADS – Reactor Vessel Mixture Inventory

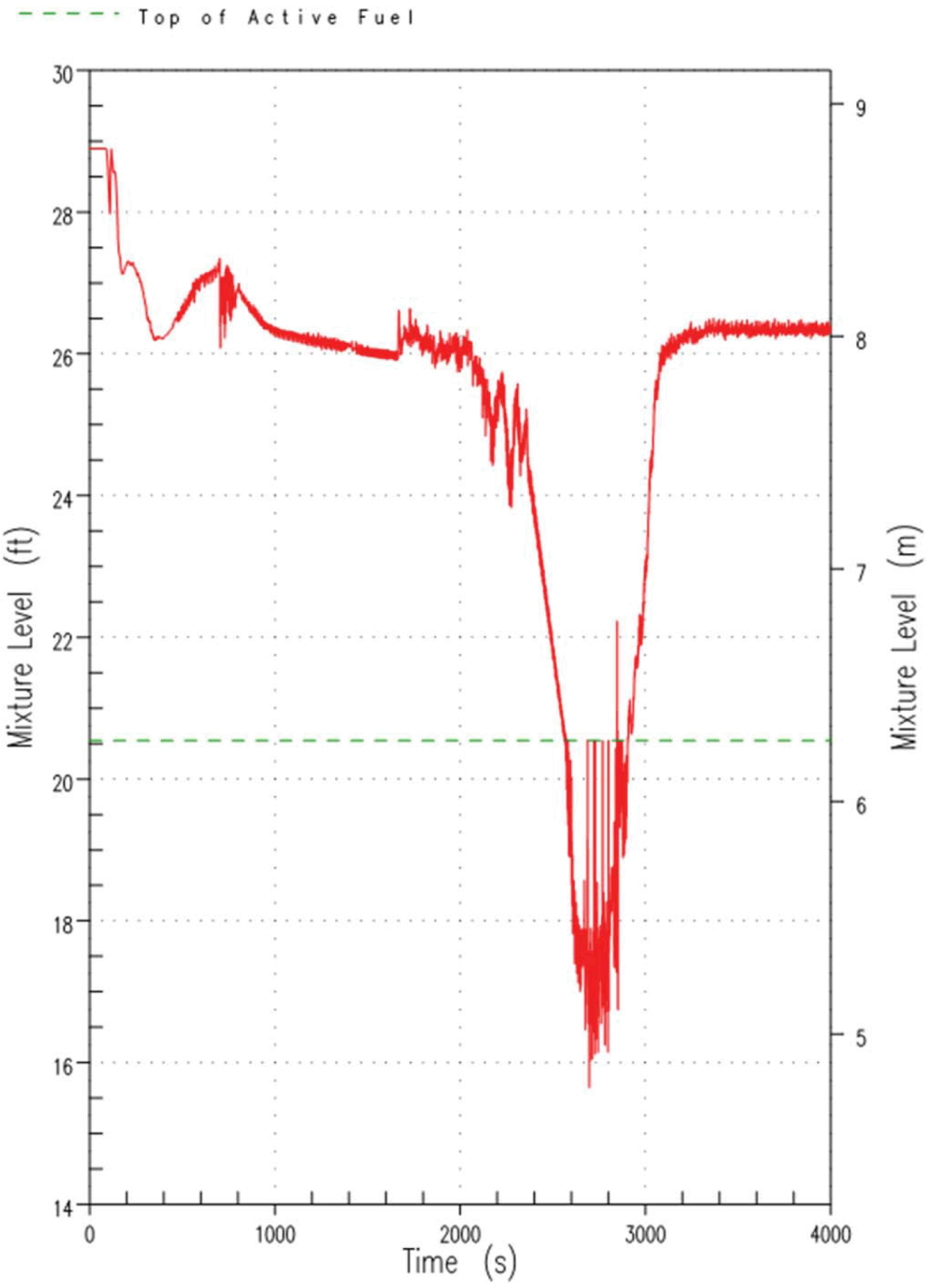


Figure 15.6.5.4B-16(a)
Inadvertent ADS – Core/Upper Plenum Mixture Level

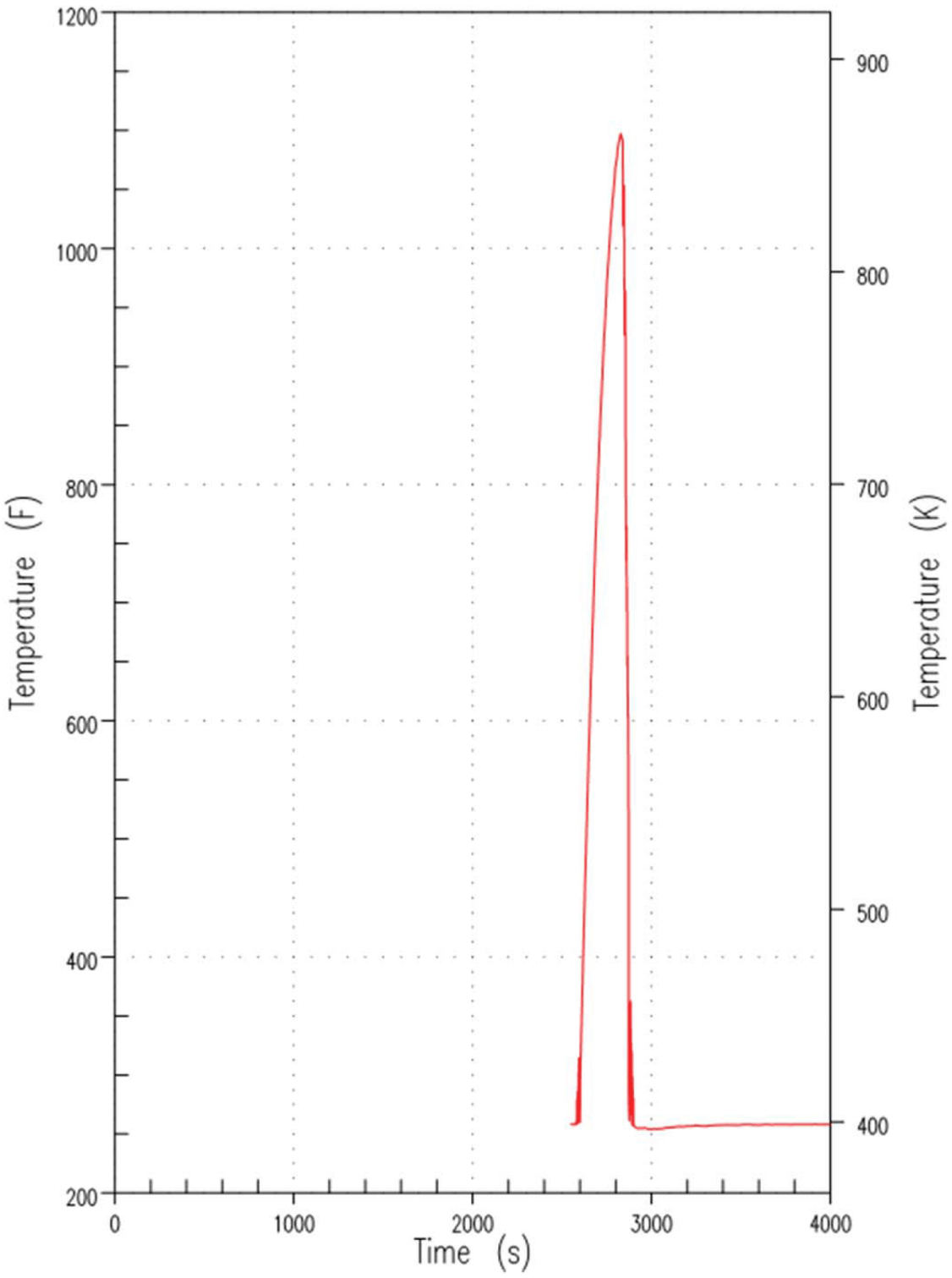


Figure 15.6.5.4B-16(b)
Inadvertent ADS – Peak Cladding Temperature

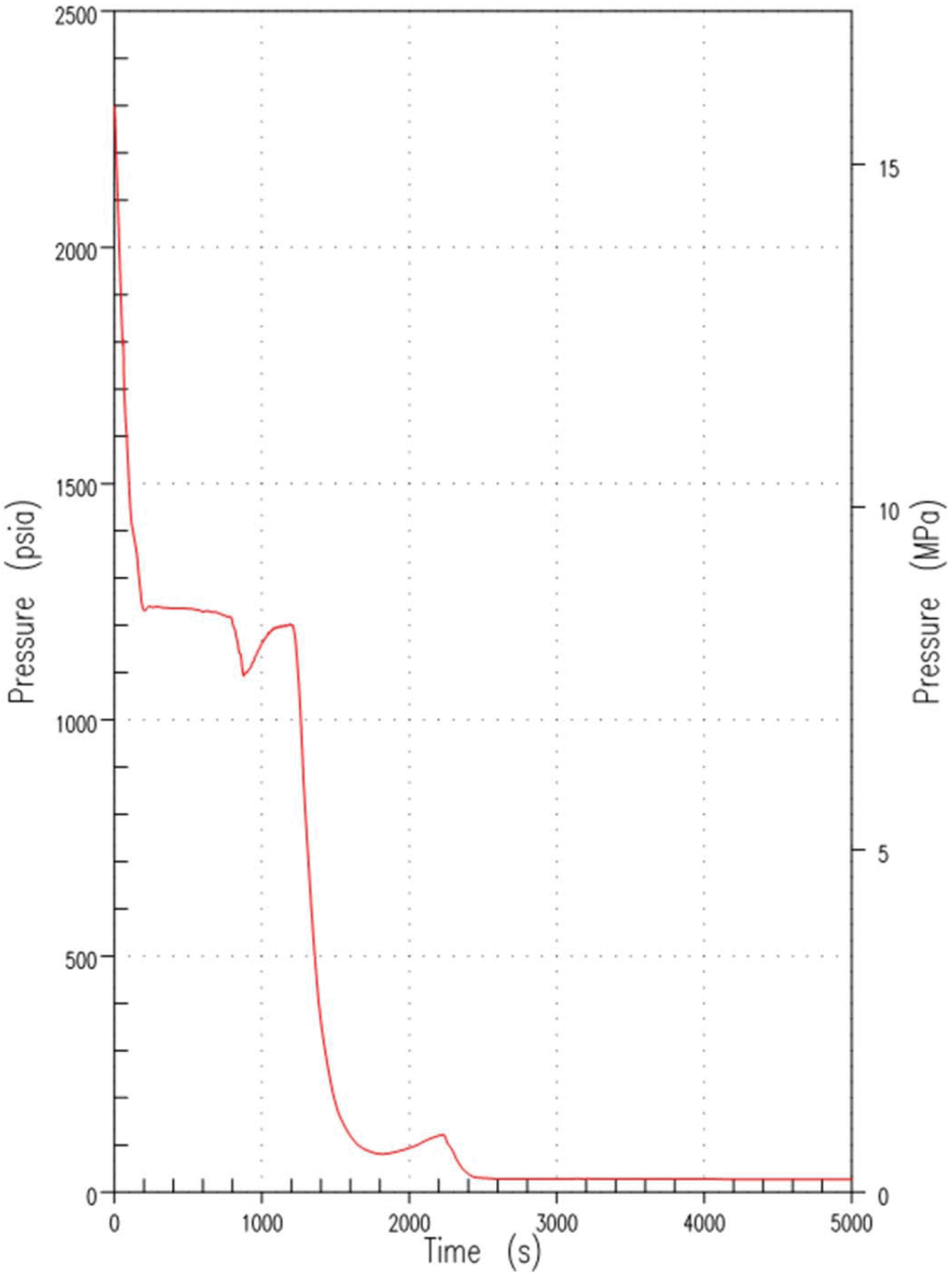


Figure 15.6.5.4B-17(a)
2-inch Cold Leg Break – RCS Pressure

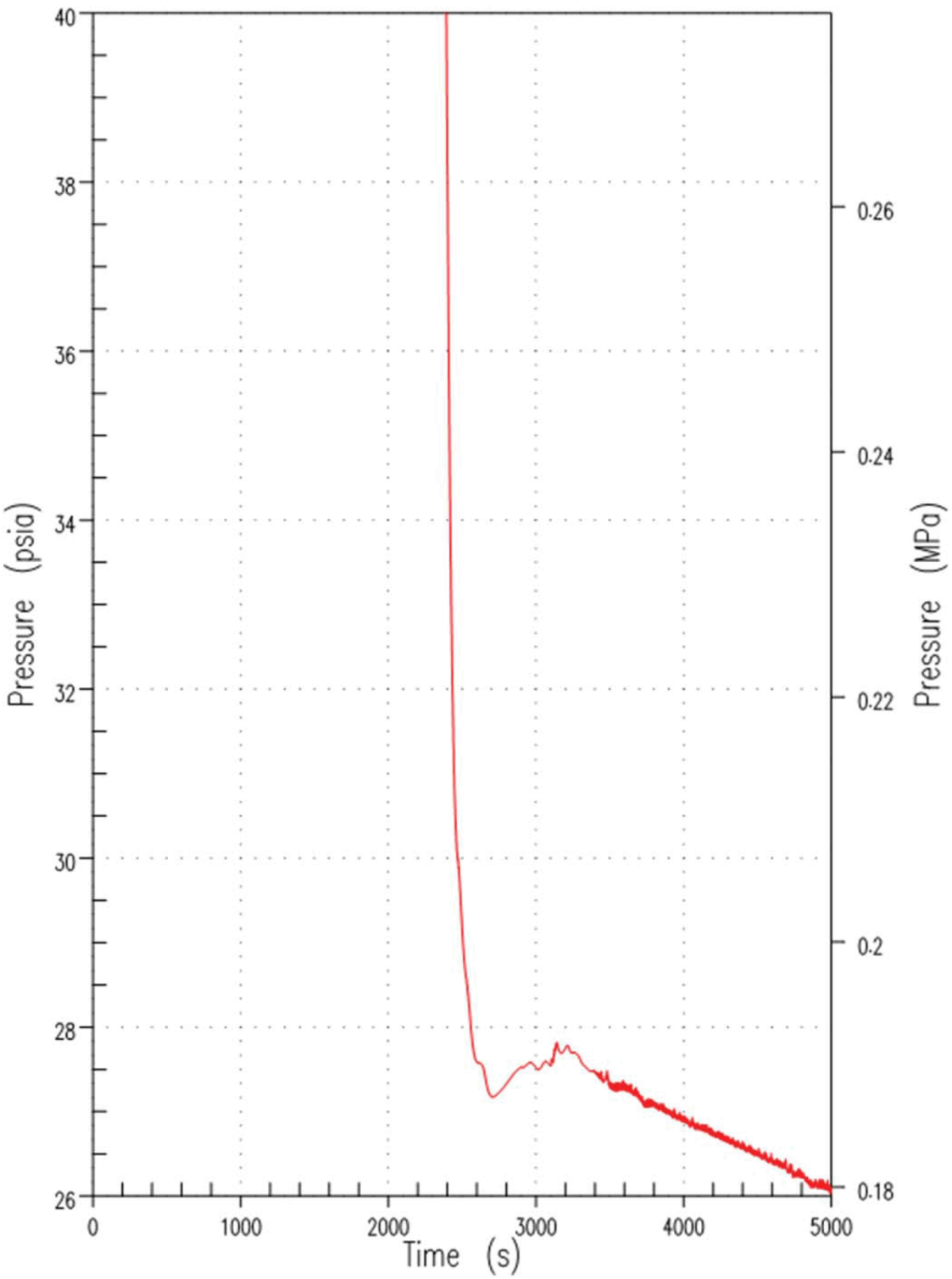


Figure 15.6.5.4B-17(b)
2-Inch Cold Leg Break – RCS Pressure (Zoomed)

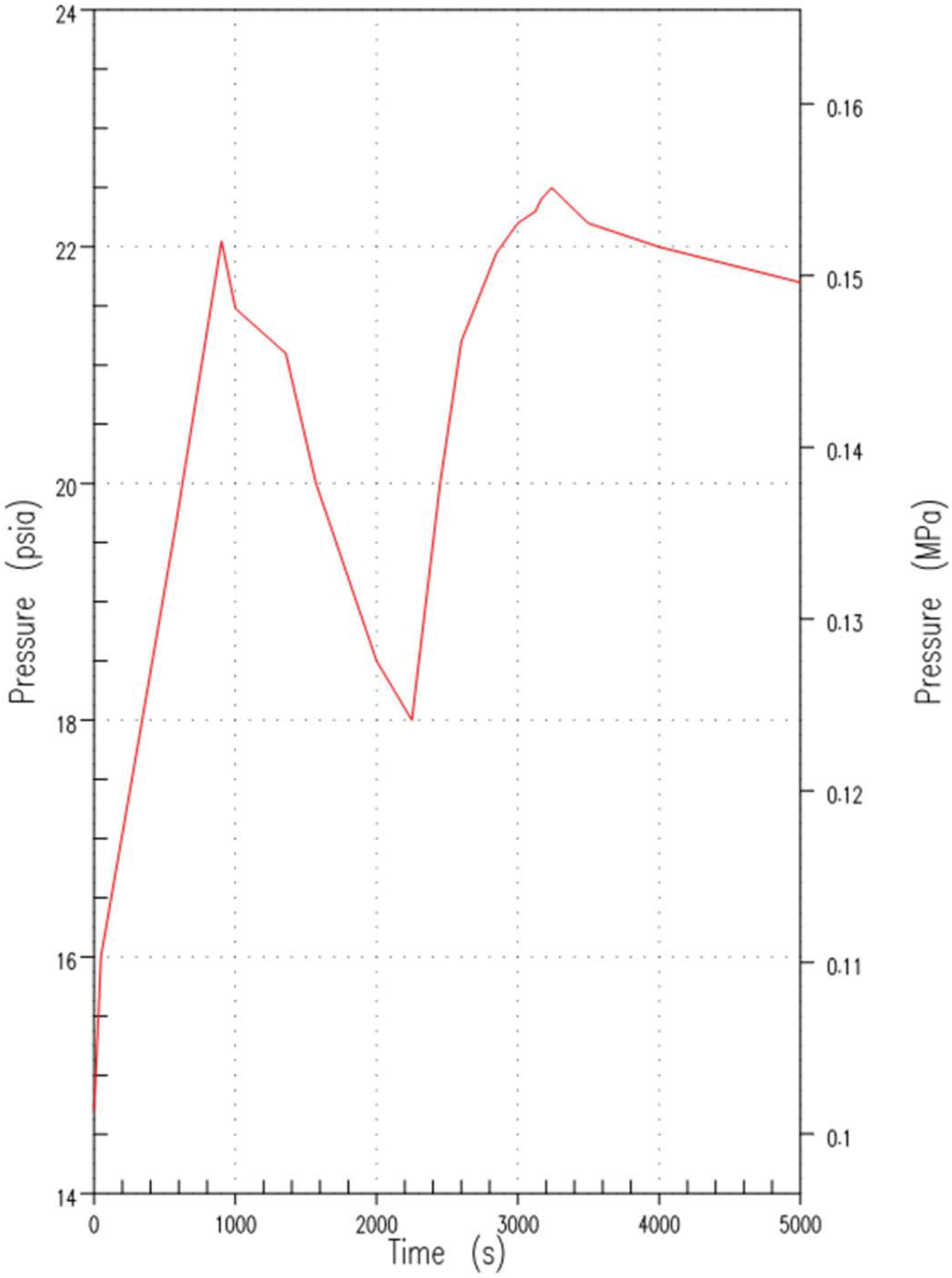


Figure 15.6.5.4B-17(c)
2-Inch Cold Leg Break – Containment Pressure

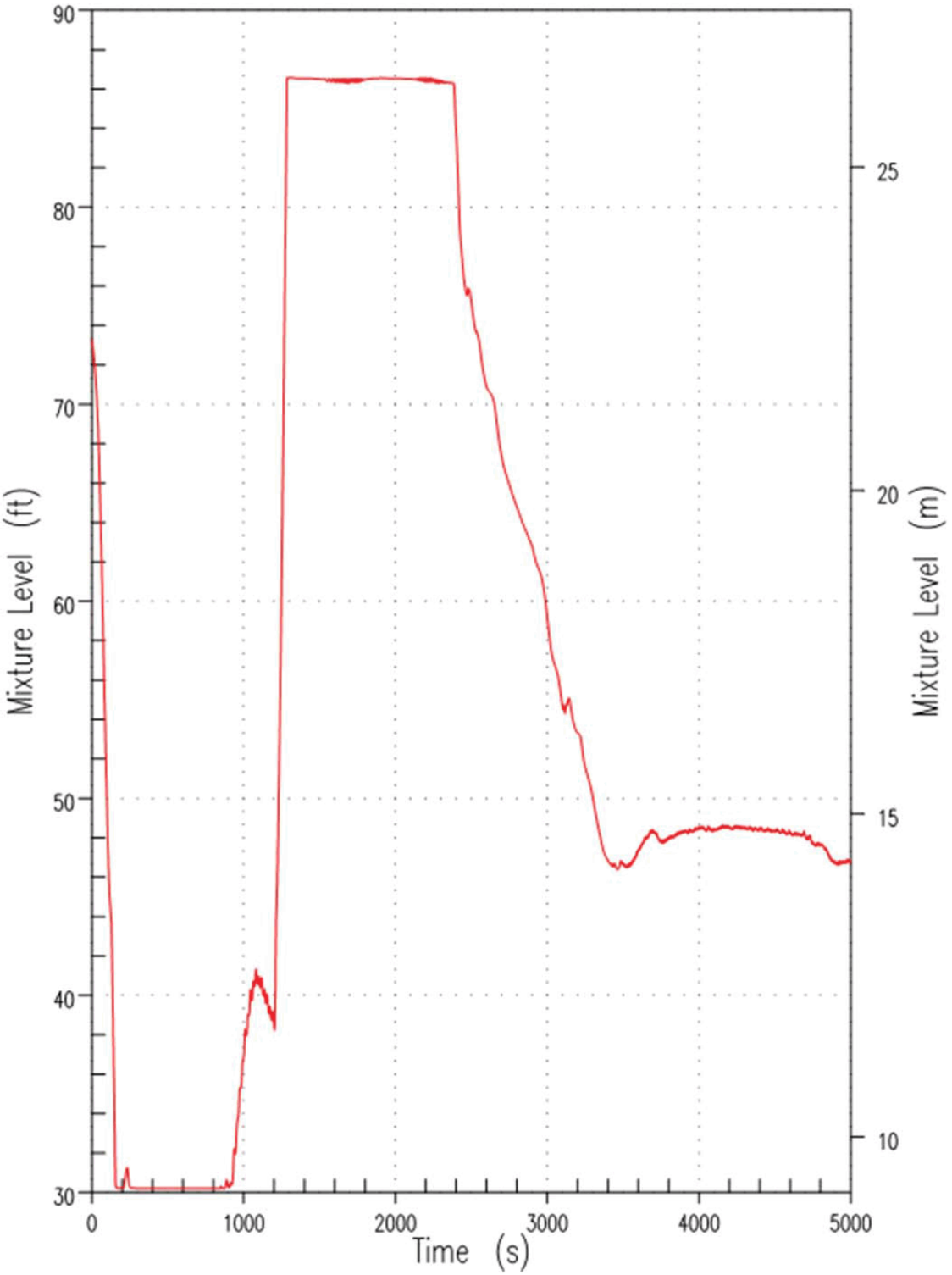


Figure 15.6.5.4B-18
2-inch Cold Leg Break – Pressurizer Mixture Level

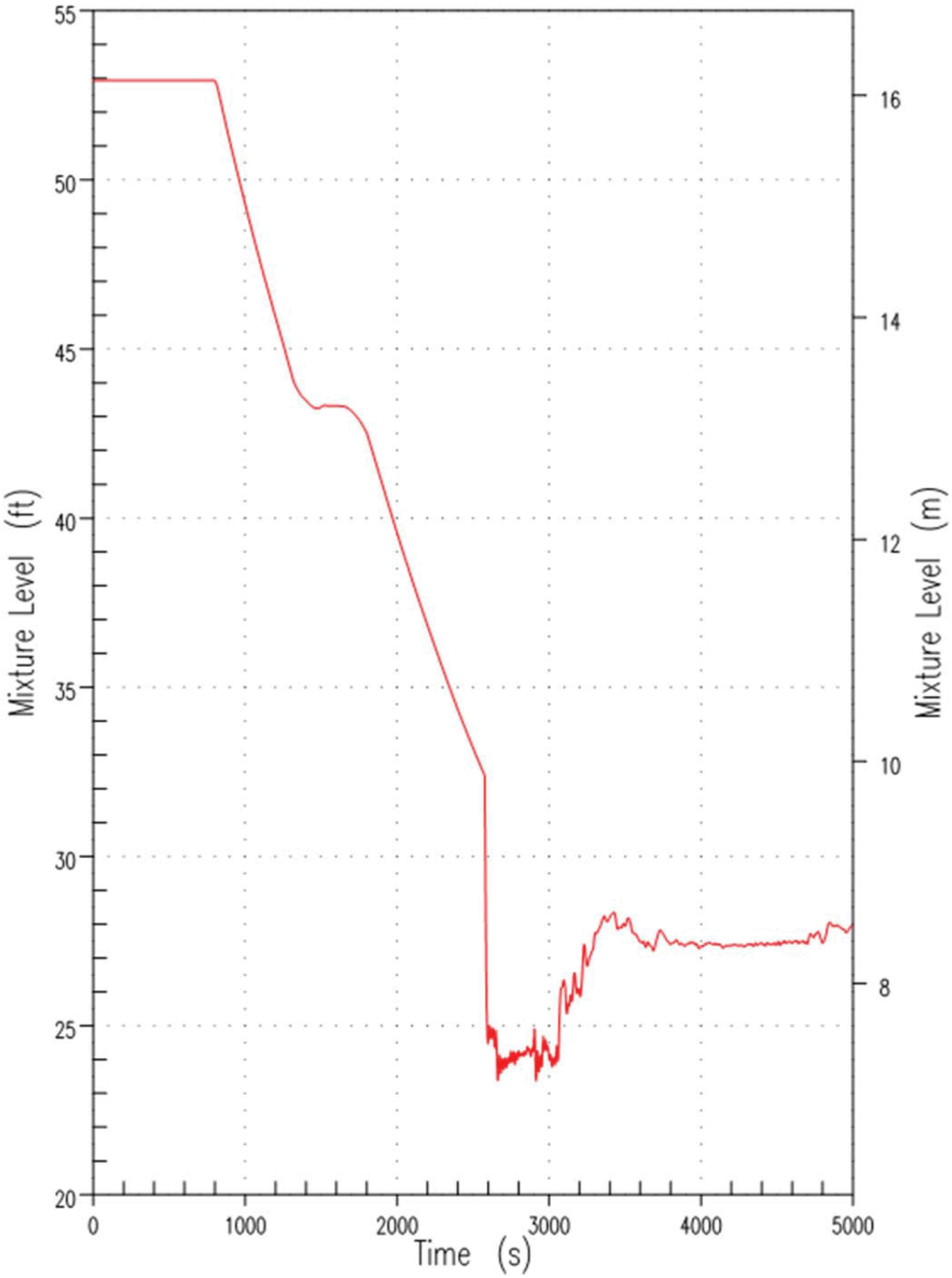


Figure 15.6.5.4B-19
2-inch Cold Leg Break – CMT-1 Mixture Level

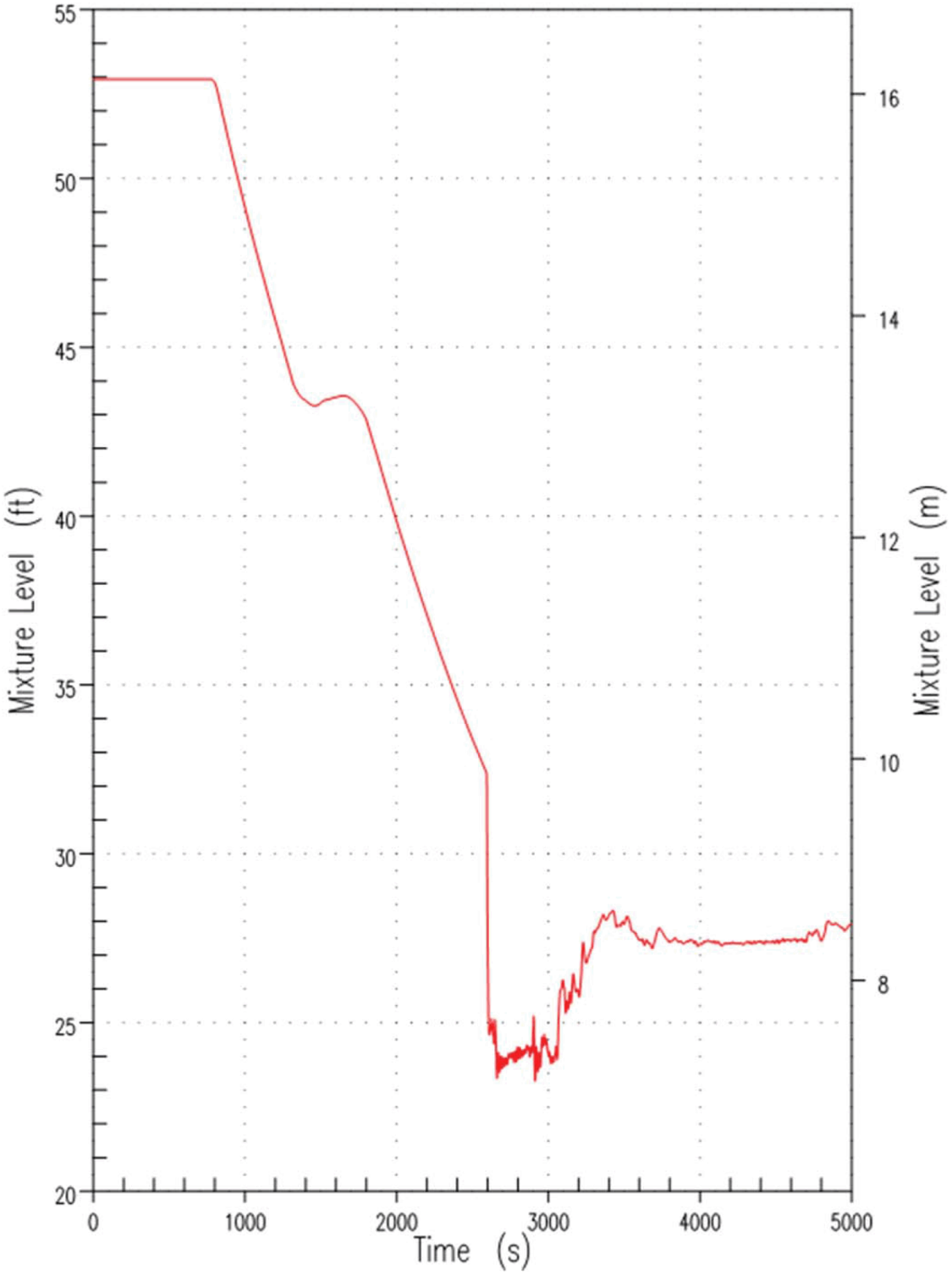


Figure 15.6.5.4B-20
2-inch Cold Leg Break – CMT-2 Mixture Level

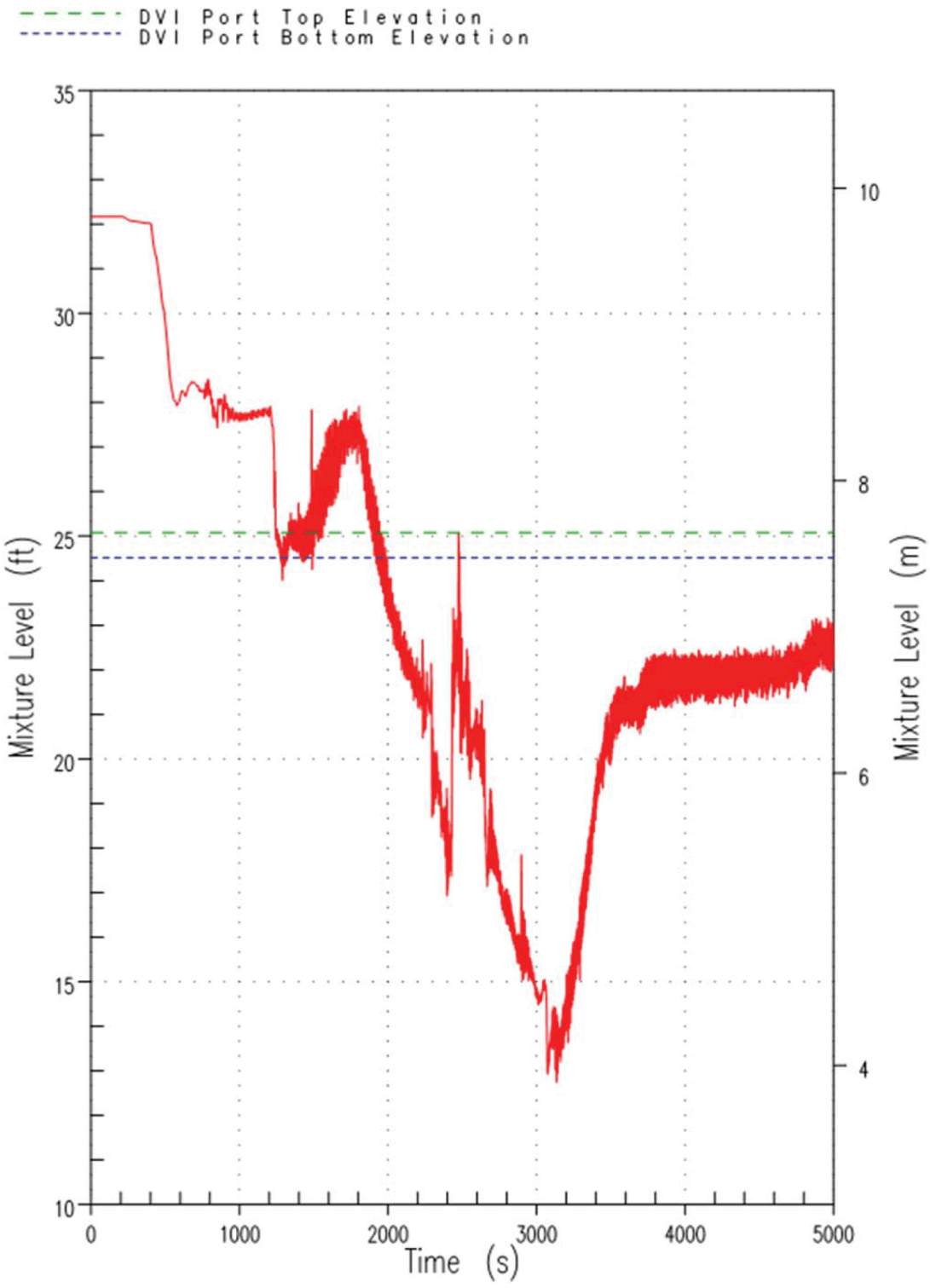


Figure 15.6.5.4B-21
2-inch Cold Leg Break – Downcomer Mixture Level

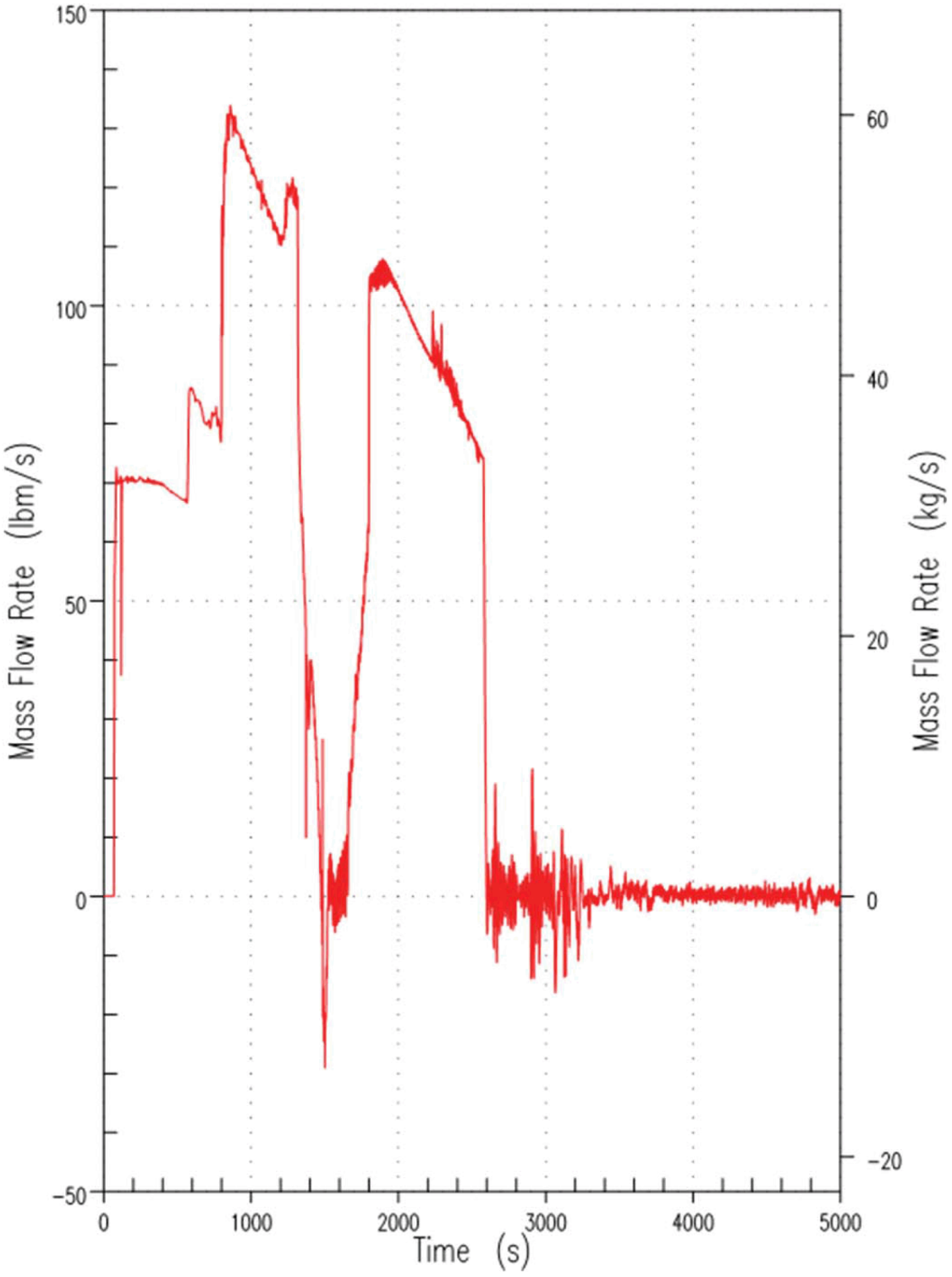


Figure 15.6.5.4B-22
2-inch Cold Leg Break – CMT-1 Injection Rate

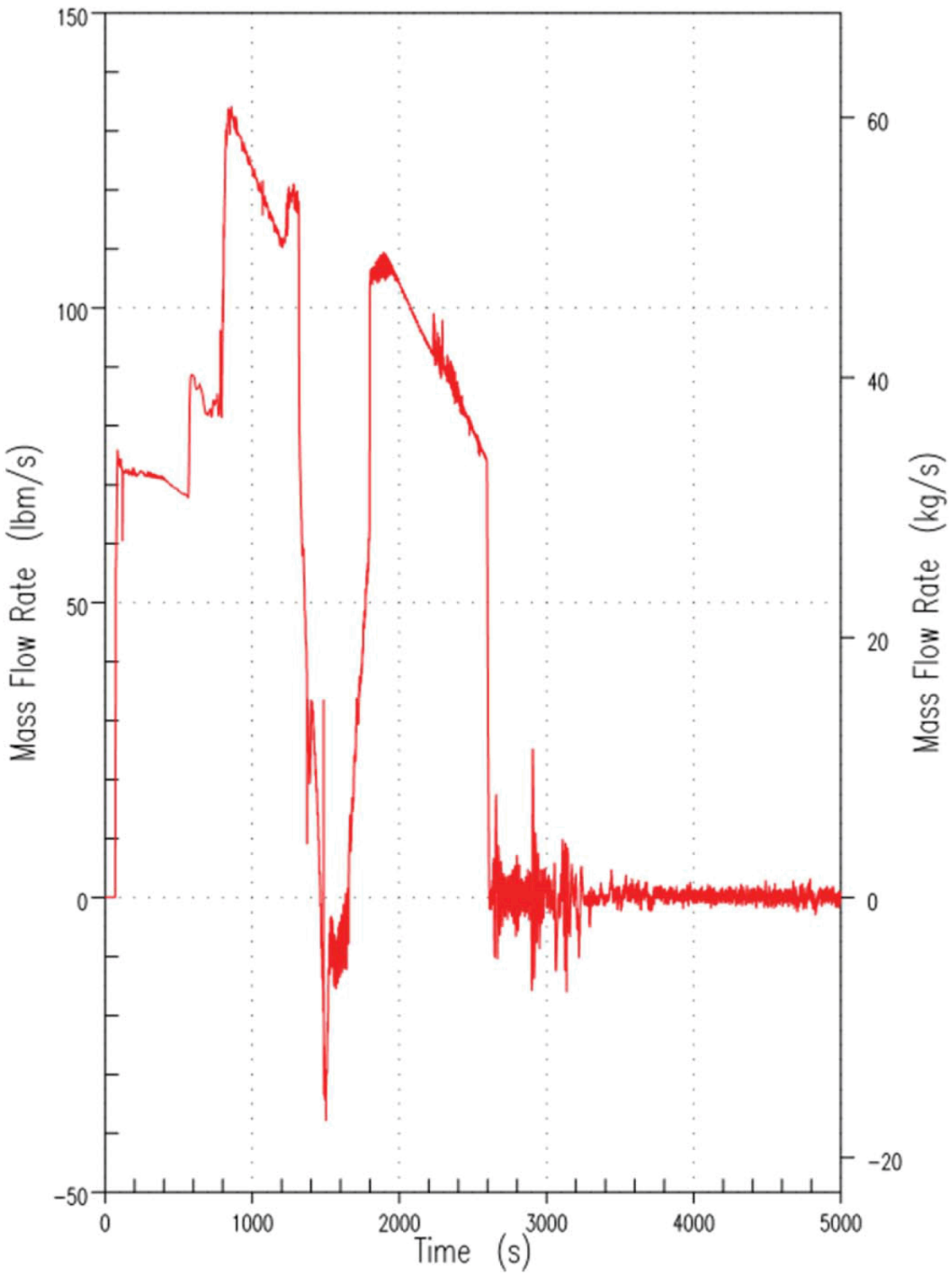


Figure 15.6.5.4B-23
2-inch Cold Leg Break – CMT-2 Injection Rate

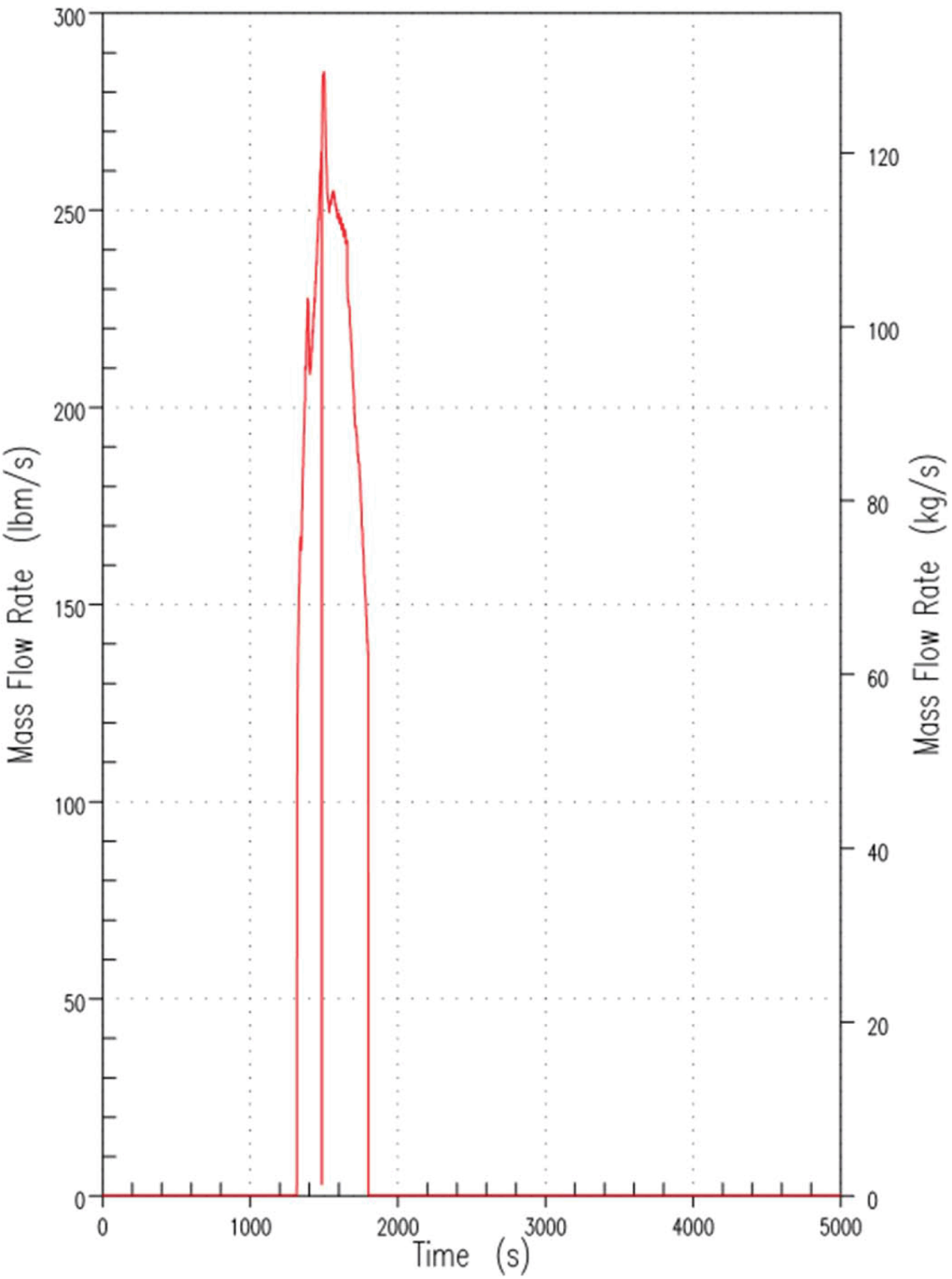


Figure 15.6.5.4B-24
2-inch Cold Leg Break – Accumulator-1 Injection Rate

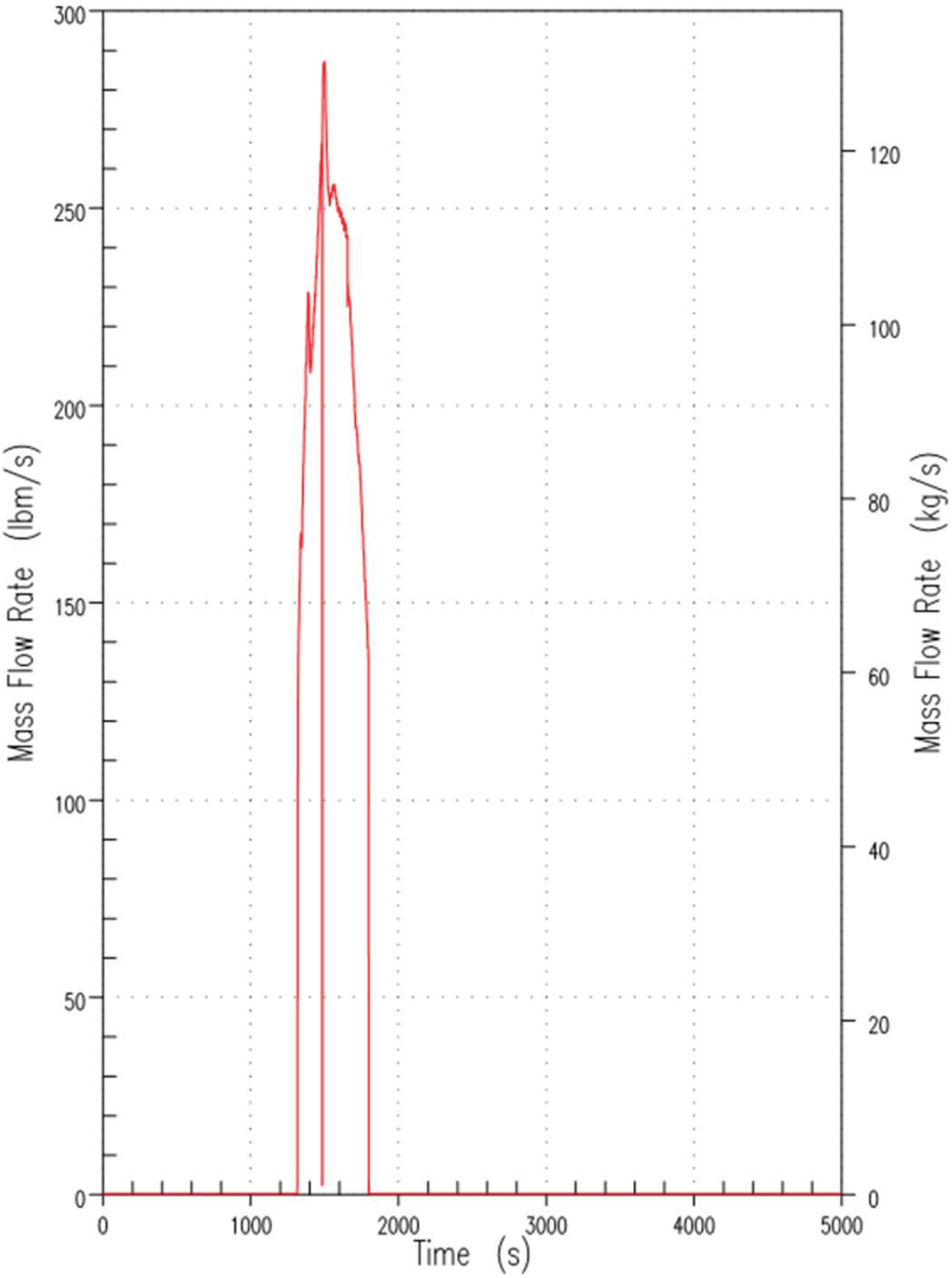


Figure 15.6.5.4B-25
2-inch Cold Leg Break – Accumulator-2 Injection Rate

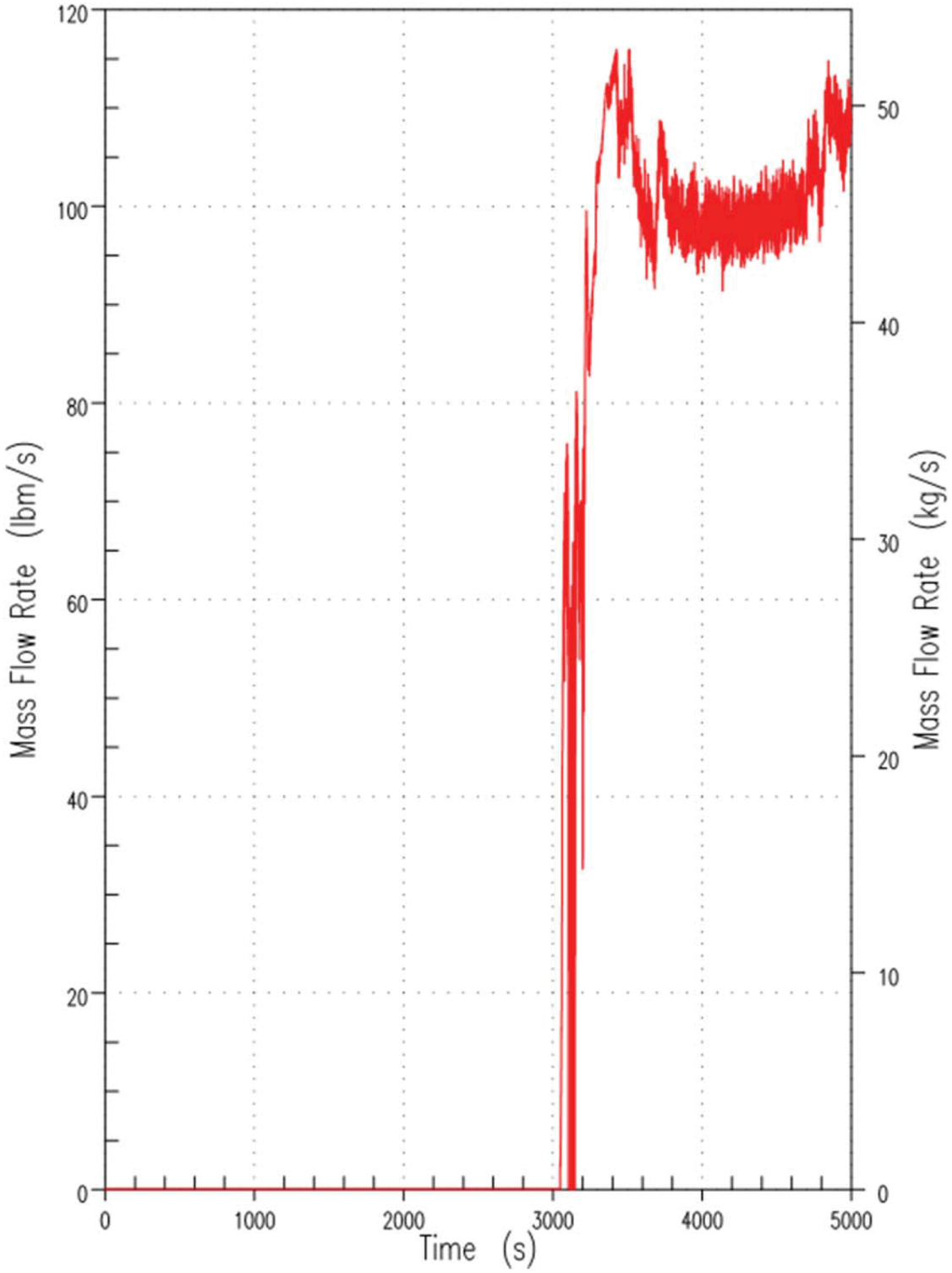


Figure 15.6.5.4B-26
2-inch Cold Leg Break – IRWST-1 Injection Rate

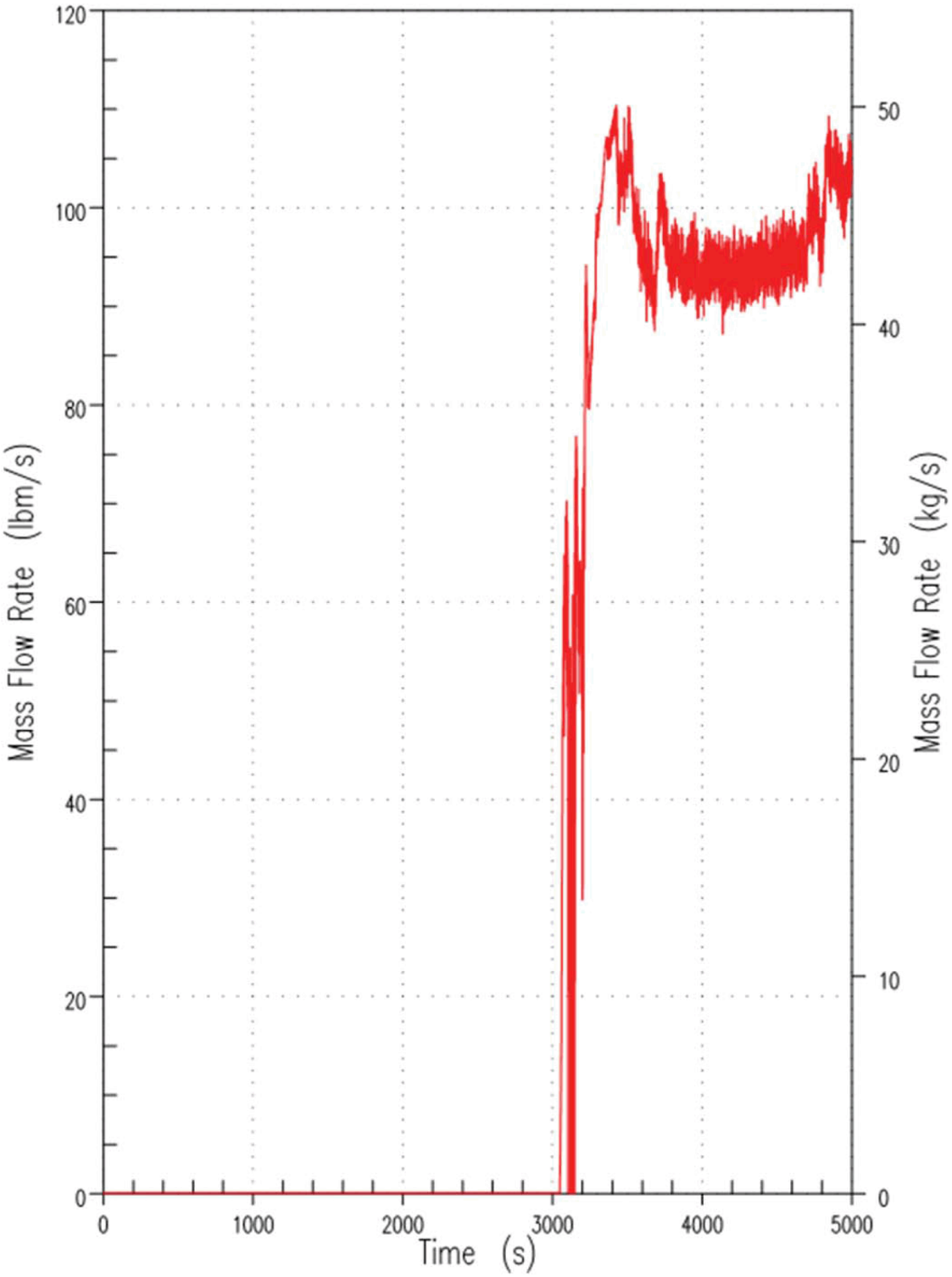


Figure 15.6.5.4B-27
2-inch Cold Leg Break – IRWST-2 Injection Rate

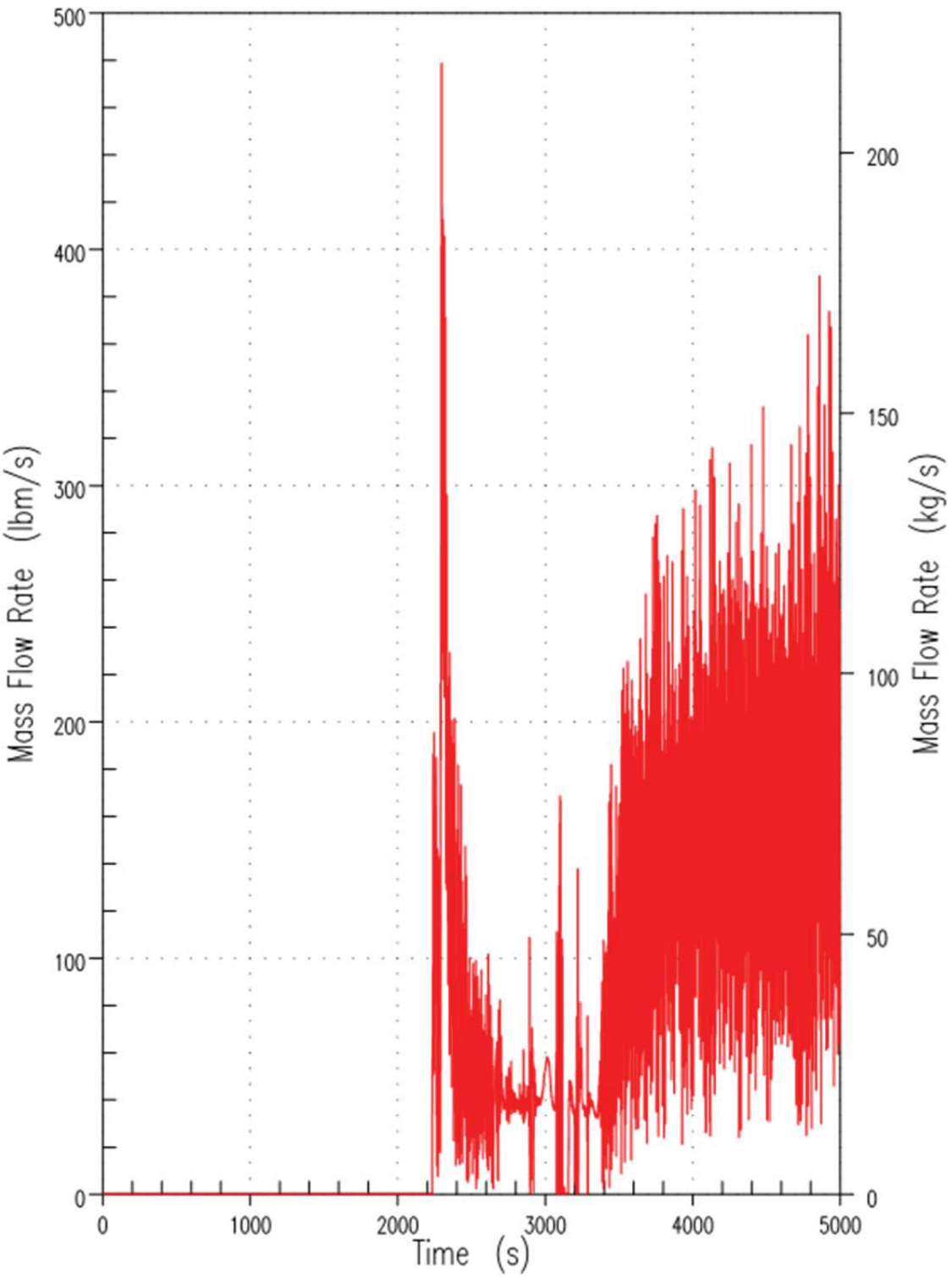


Figure 15.6.5.4B-28(a)
2-inch Cold Leg Break – ADS-4 Liquid Discharge

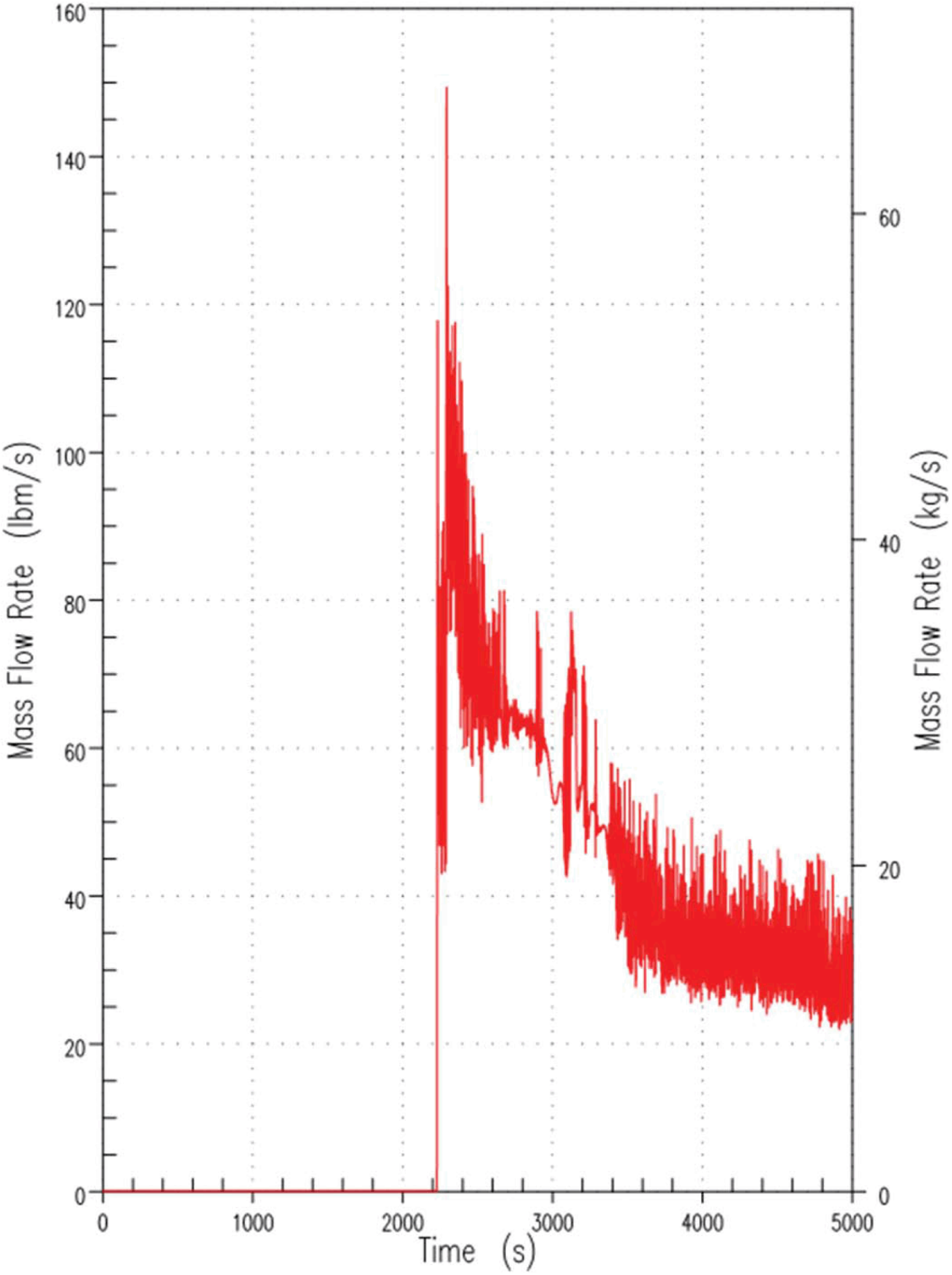


Figure 15.6.5.4B-28(b)
2-Inch Cold Leg Break – ADS-4 Vapor Discharge

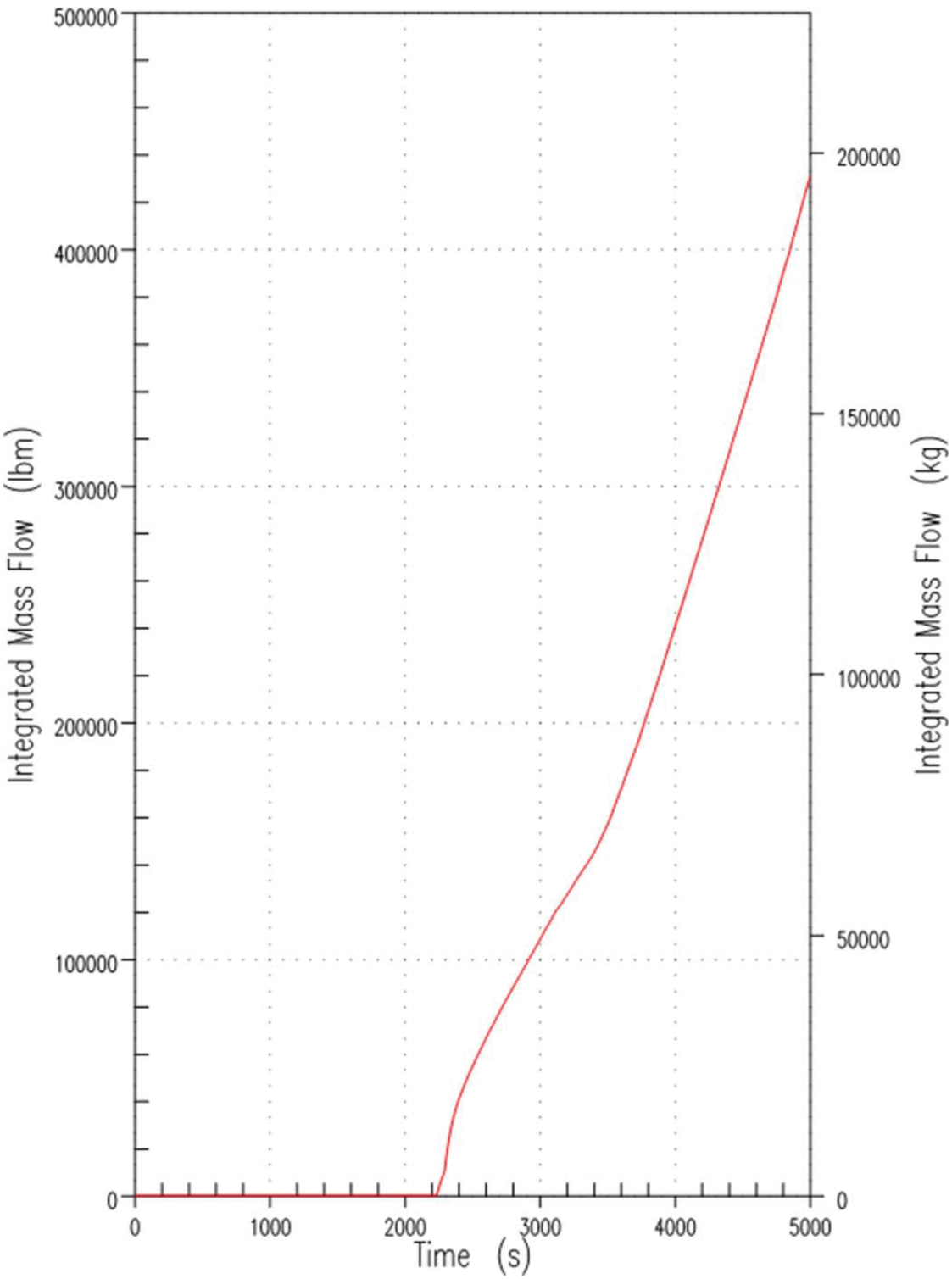


Figure 15.6.5.4B-28(c)
2-Inch Cold Leg Break – ADS-4 Integrated Discharge

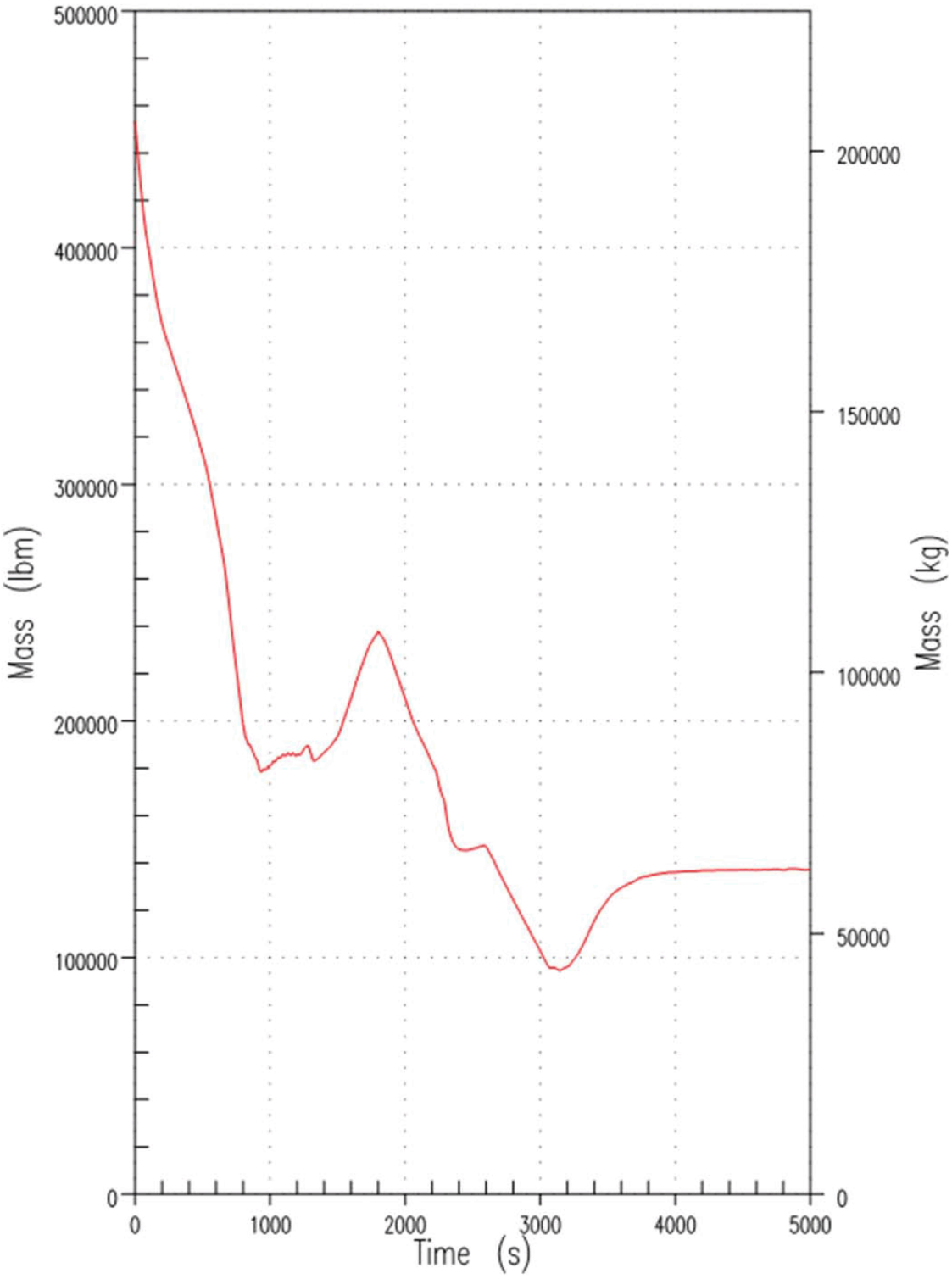


Figure 15.6.5.4B-29(a)
2-inch Cold Leg Break – RCS System Inventory

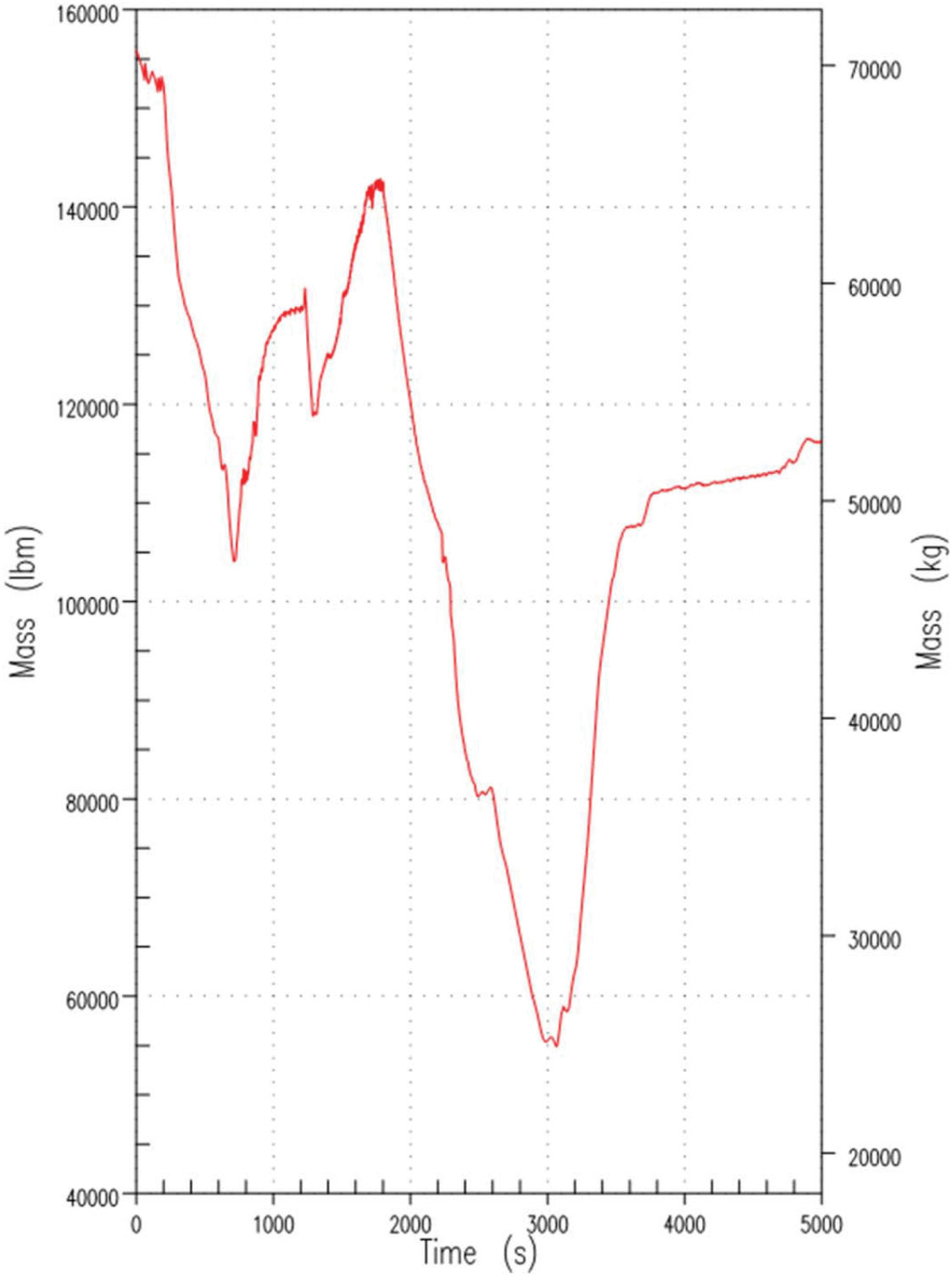


Figure 15.6.5.4B-29(b)
2-Inch Cold Leg Break – Reactor Vessel Mixture Inventory

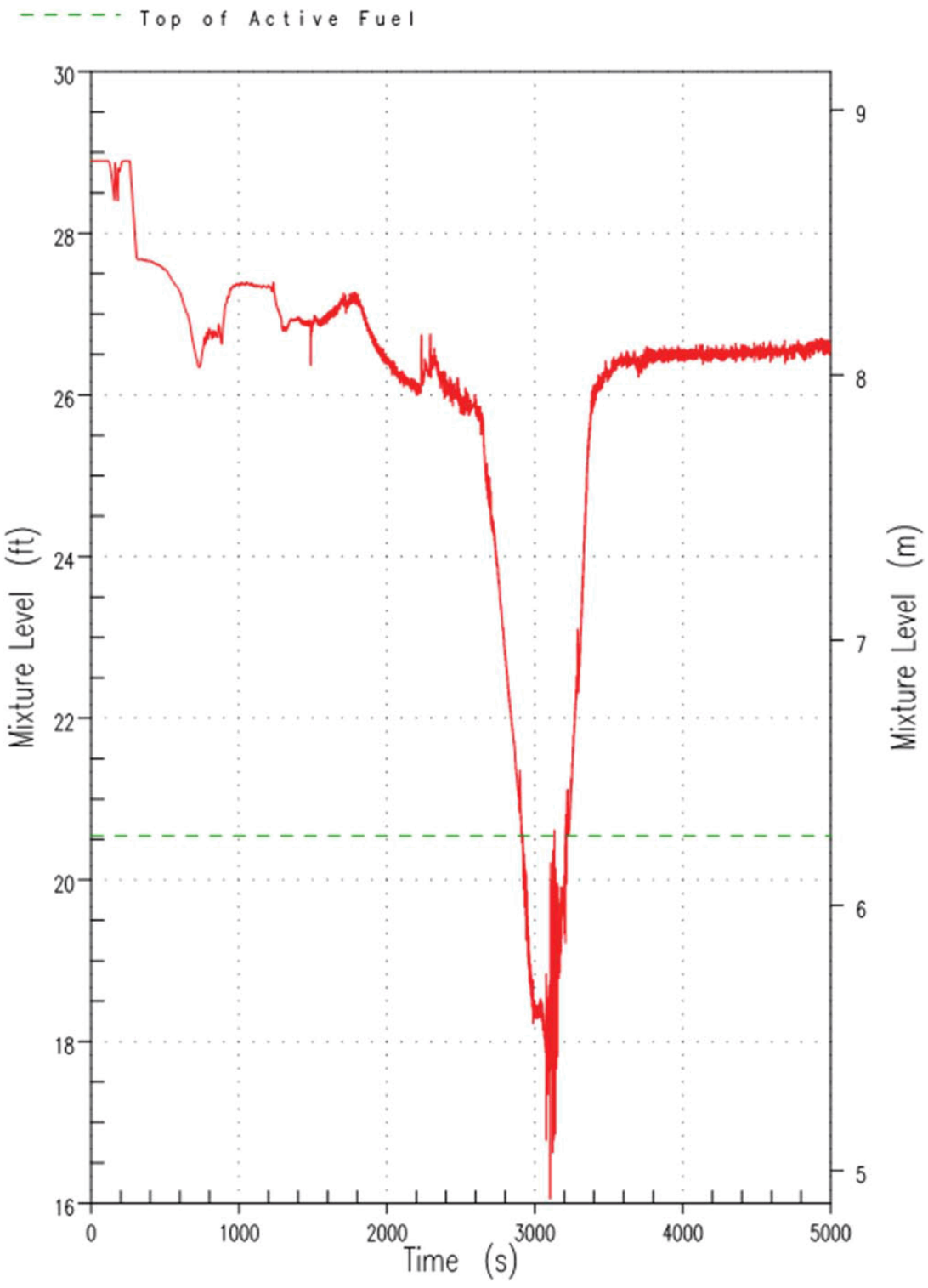


Figure 15.6.5.4B-30(a)
2-inch Cold Leg Break – Core/Upper Plenum Mixture Level

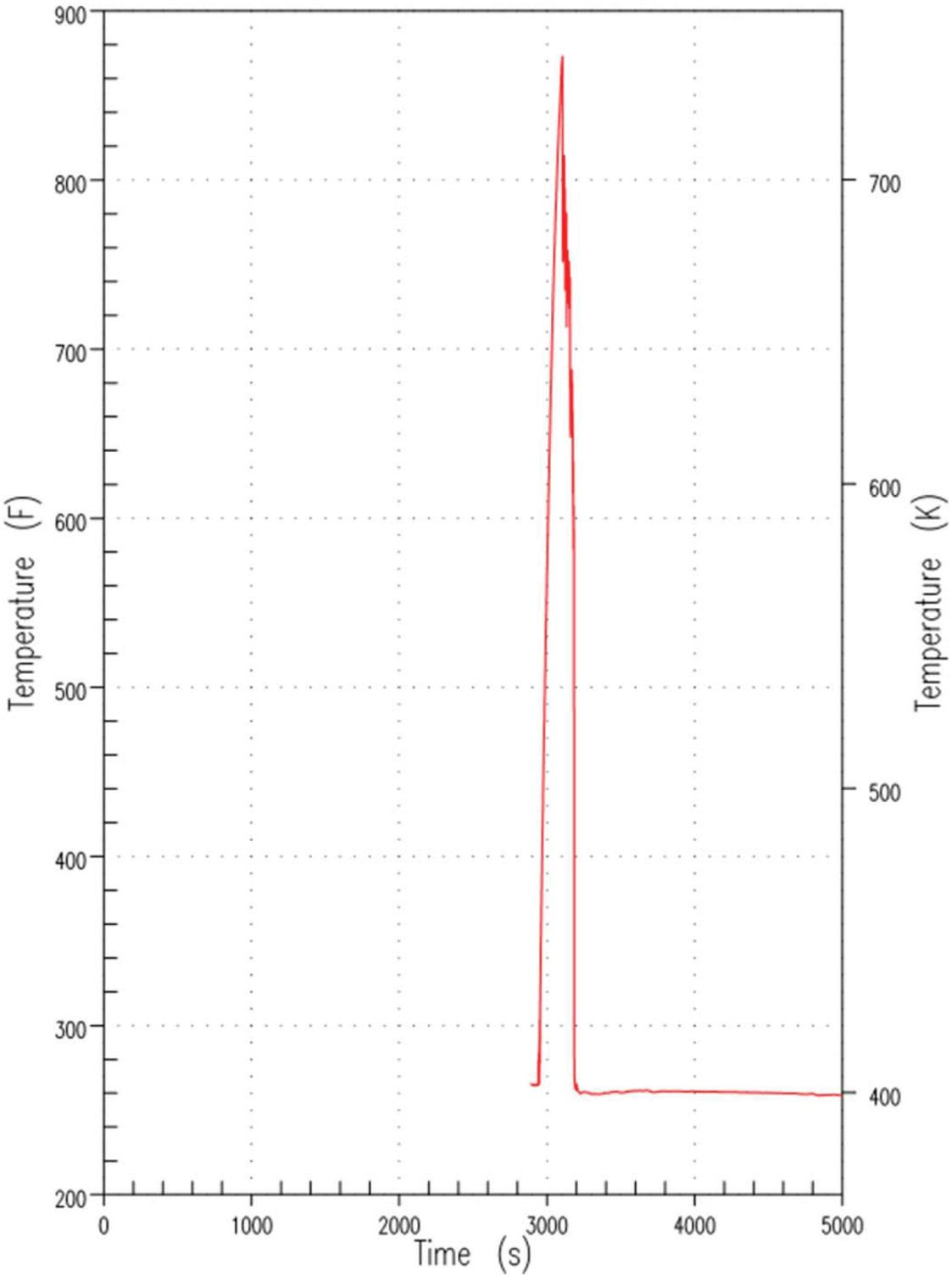


Figure 15.6.5.4B-30(b)
2-Inch Cold Leg Break – Peak Cladding Temperature

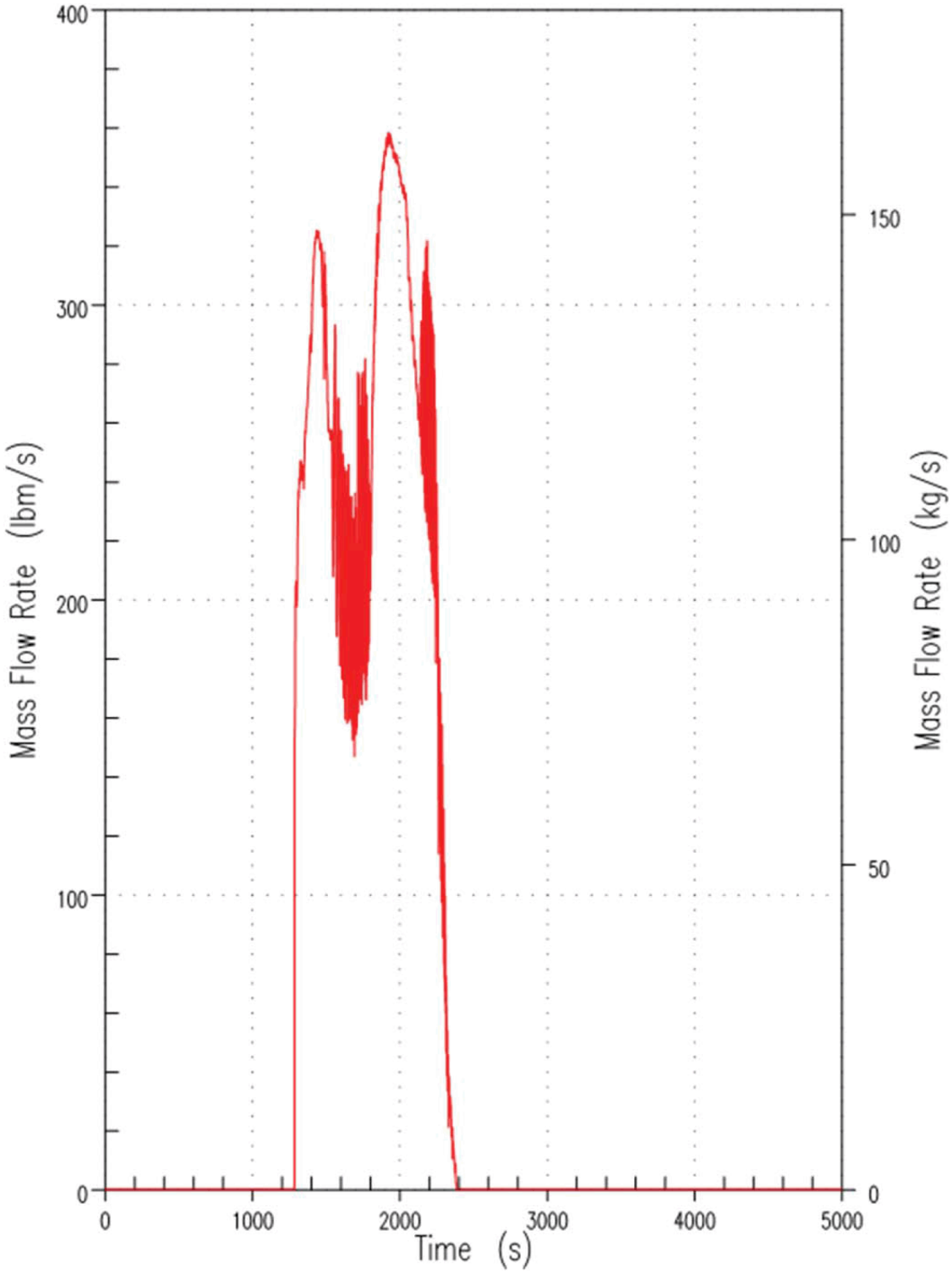


Figure 15.6.5.4B-31(a)
2-inch Cold Leg Break – ADS 1-3 Liquid Discharge

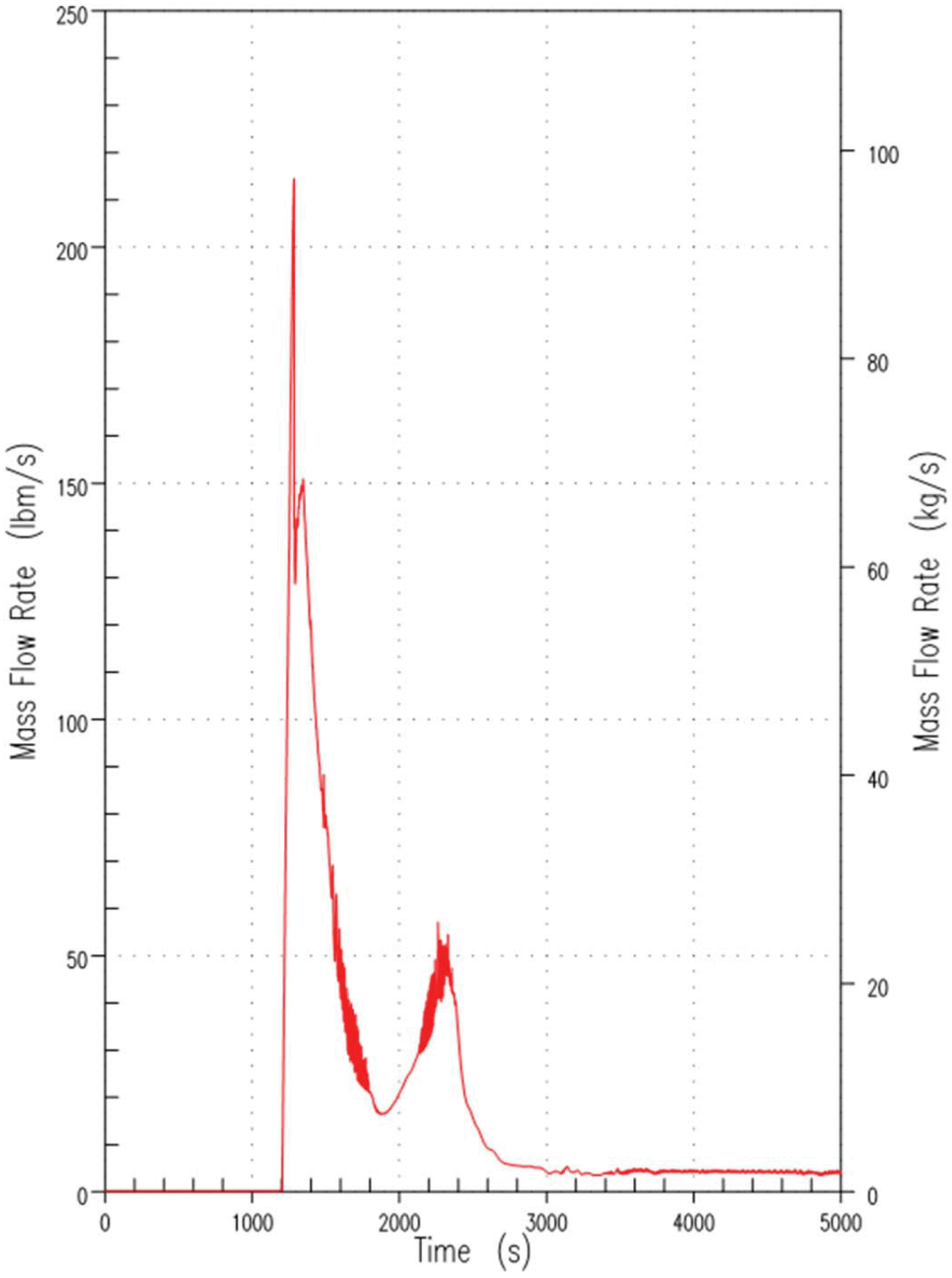


Figure 15.6.5.4B-31(b)
2-Inch Cold Leg Break – ADS 1-3 Vapor Discharge

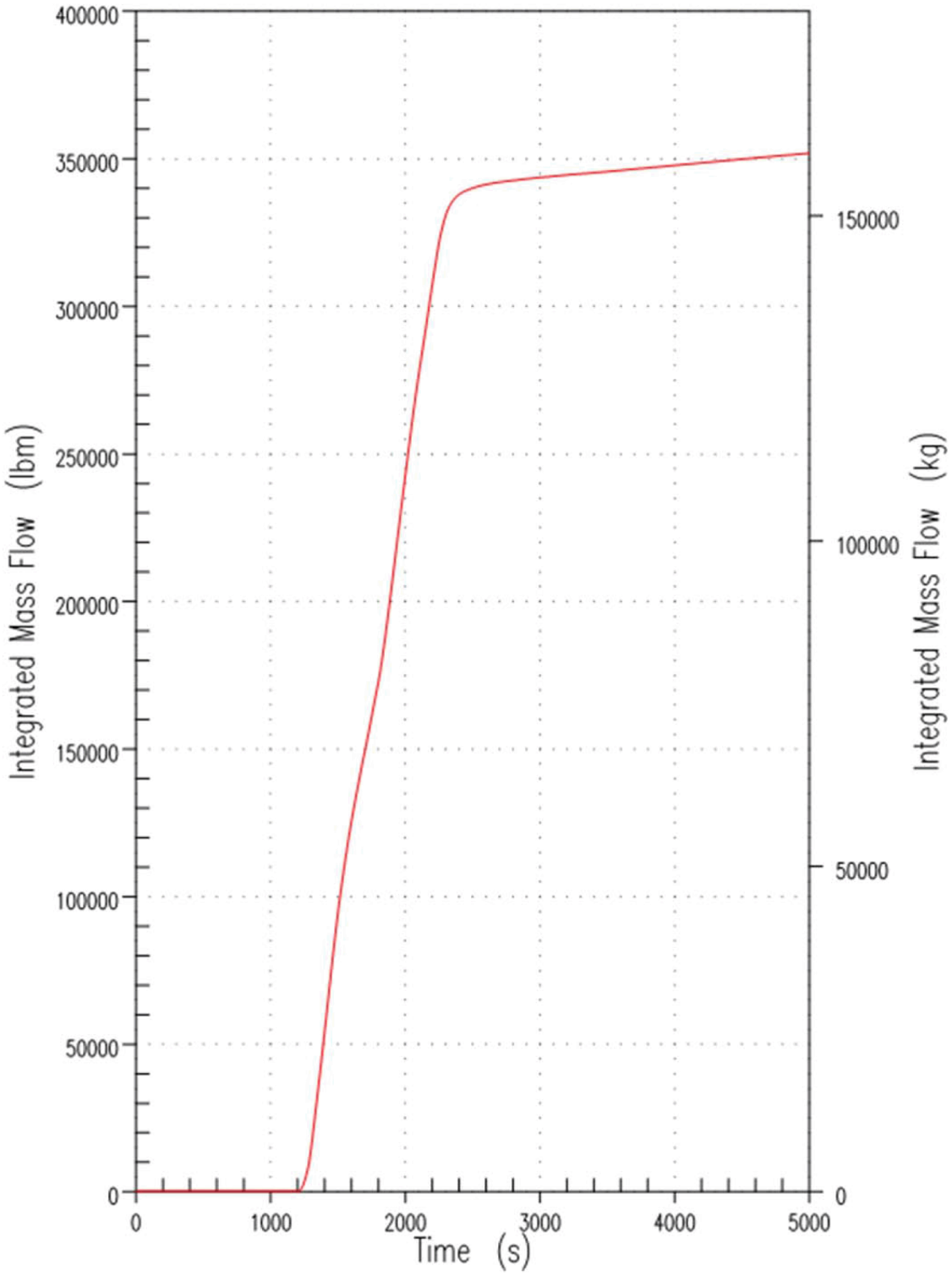


Figure 15.6.5.4B-31(c)
2-Inch Cold Leg Break – ADS 1-3 Integrated Discharge

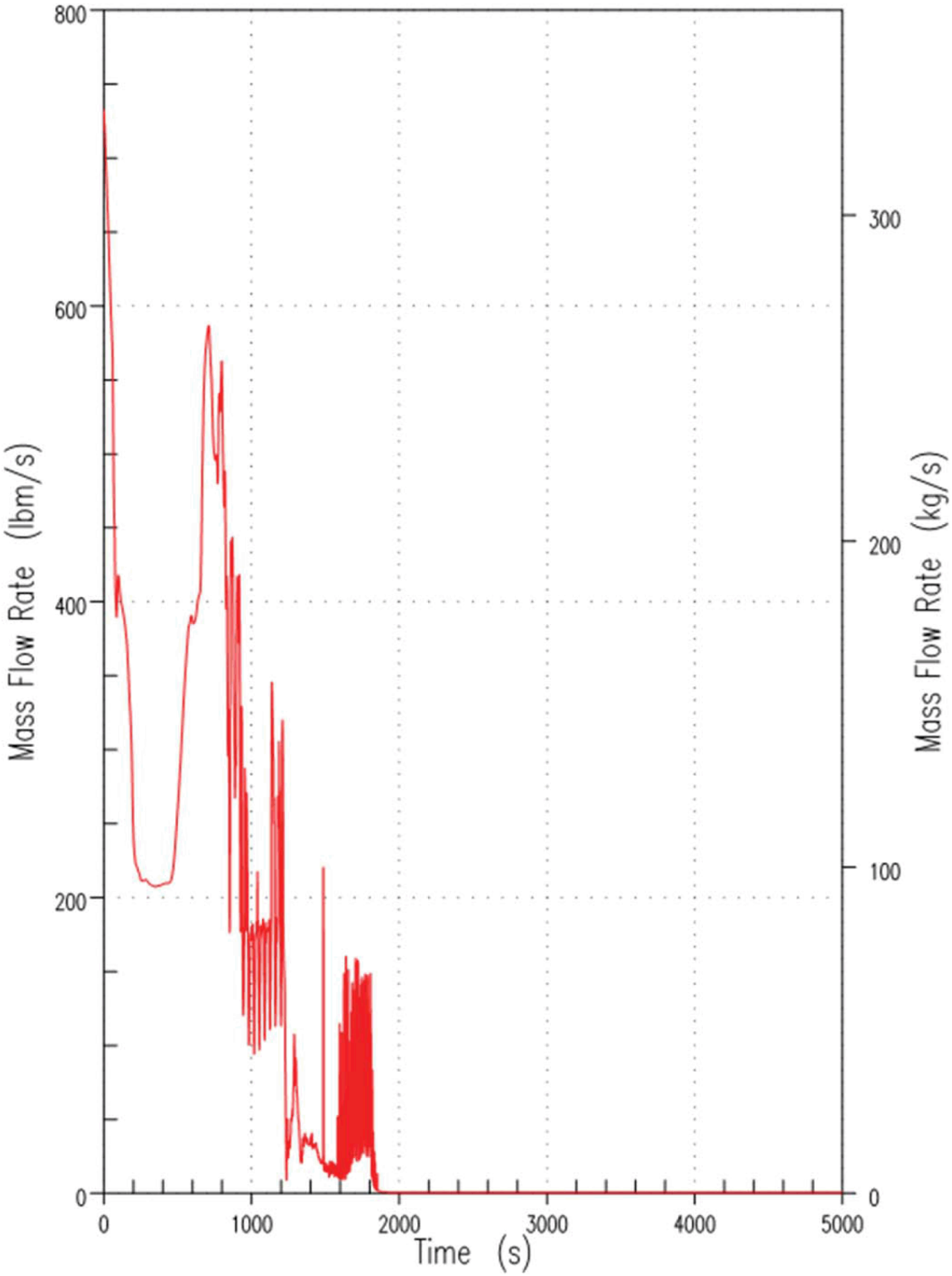


Figure 15.6.5.4B-32
2-inch Cold Leg Break – Liquid Break Discharge

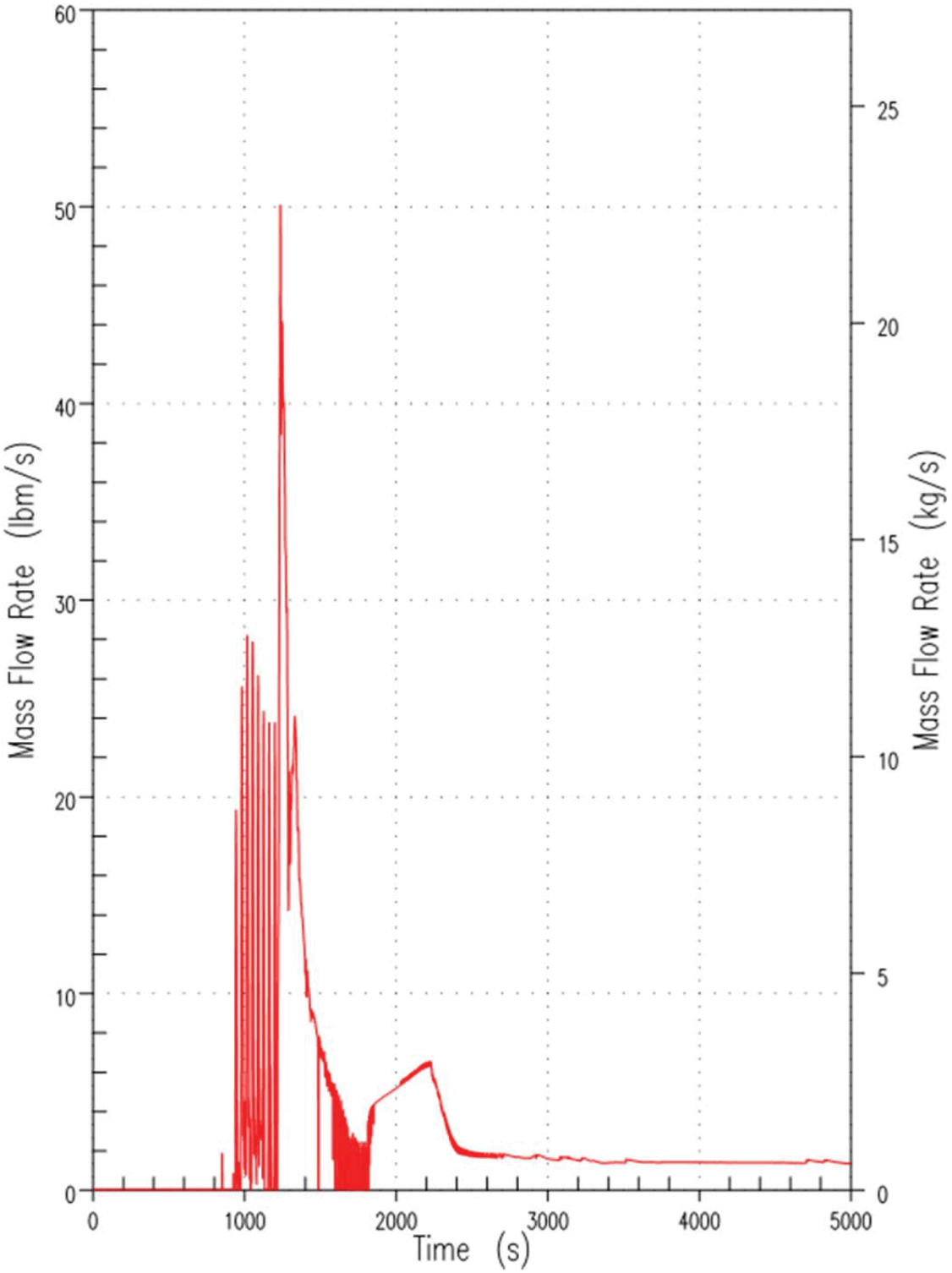


Figure 15.6.5.4B-33
2-inch Cold Leg Break – Vapor Break Discharge

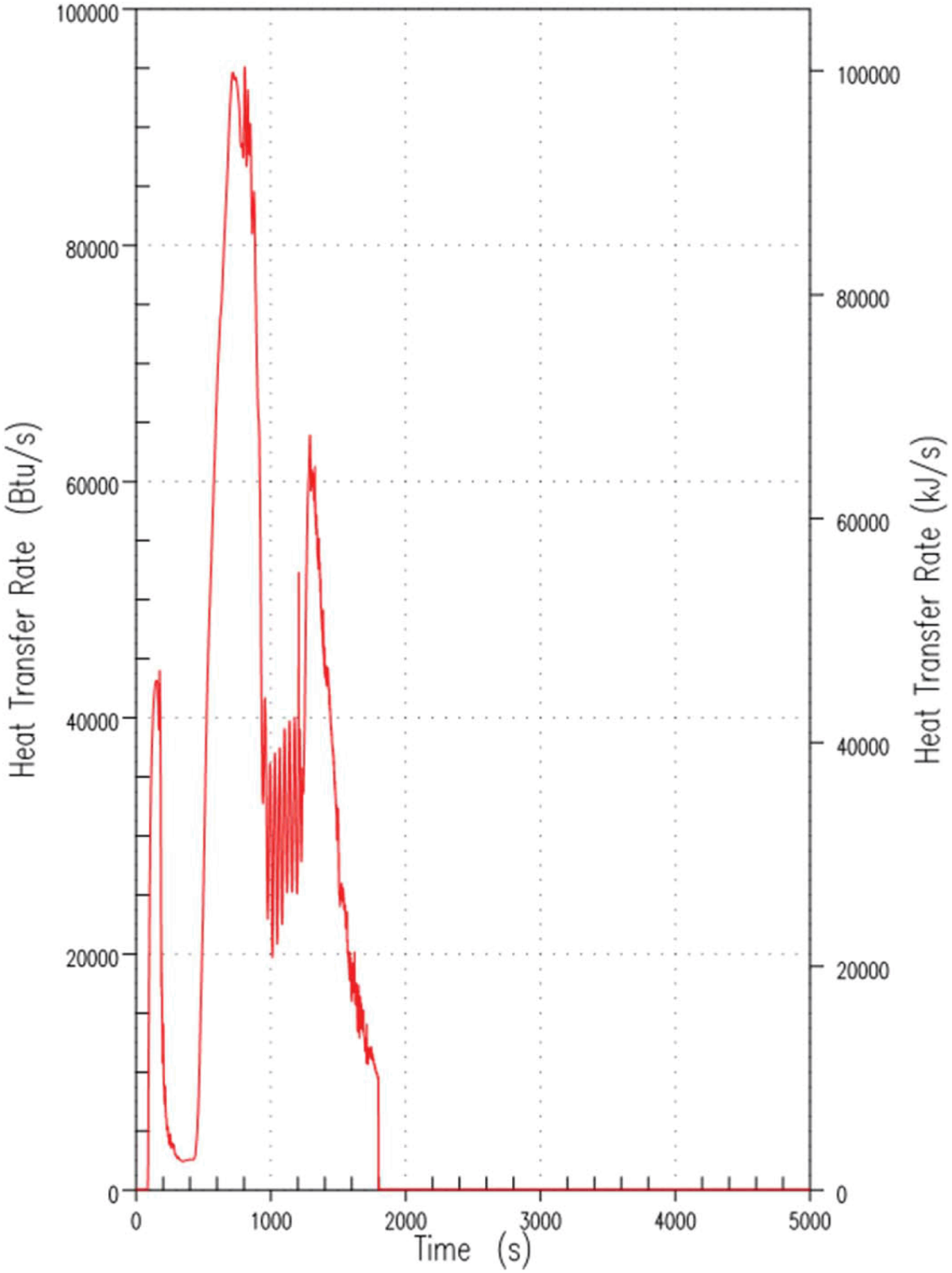


Figure 15.6.5.4B-34
2-inch Cold Leg Break – PRHR Heat Removal Rate

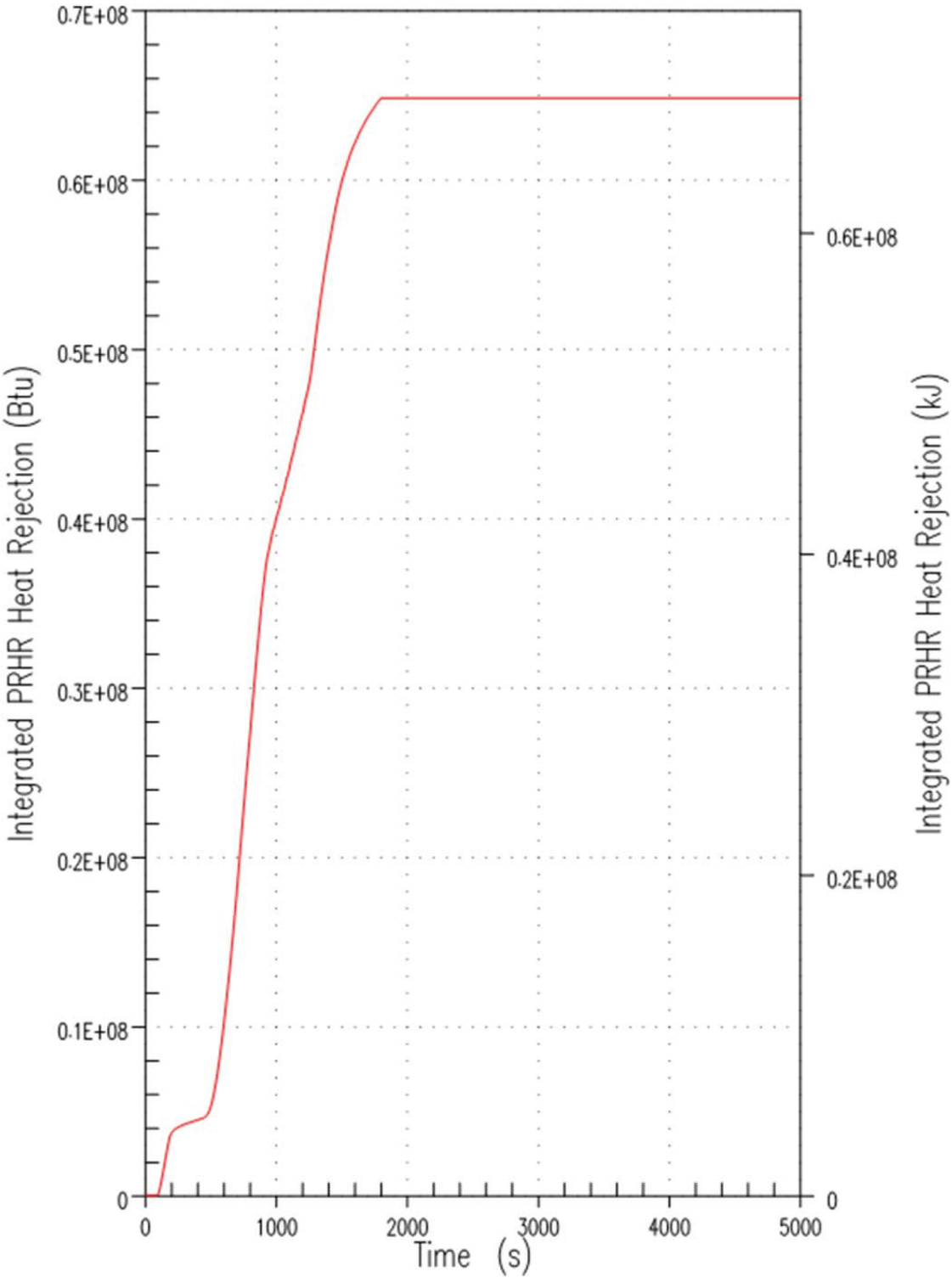


Figure 15.6.5.4B-35
2-inch Cold Leg Break – Integrated PRHR Heat Removal

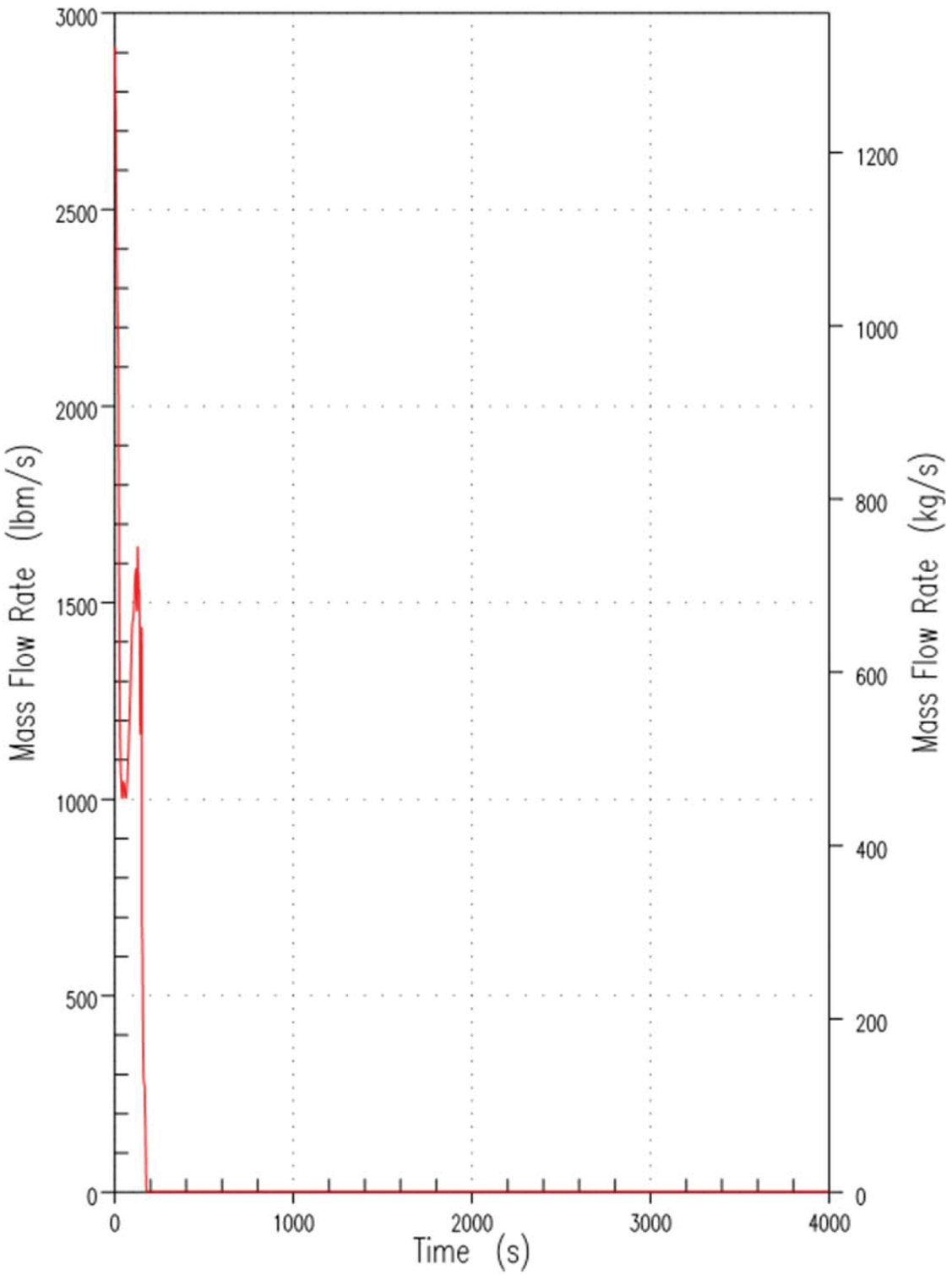


Figure 15.6.5.4B-36
20 psia DEDVI Line Break – Vessel Side Liquid Break Discharge

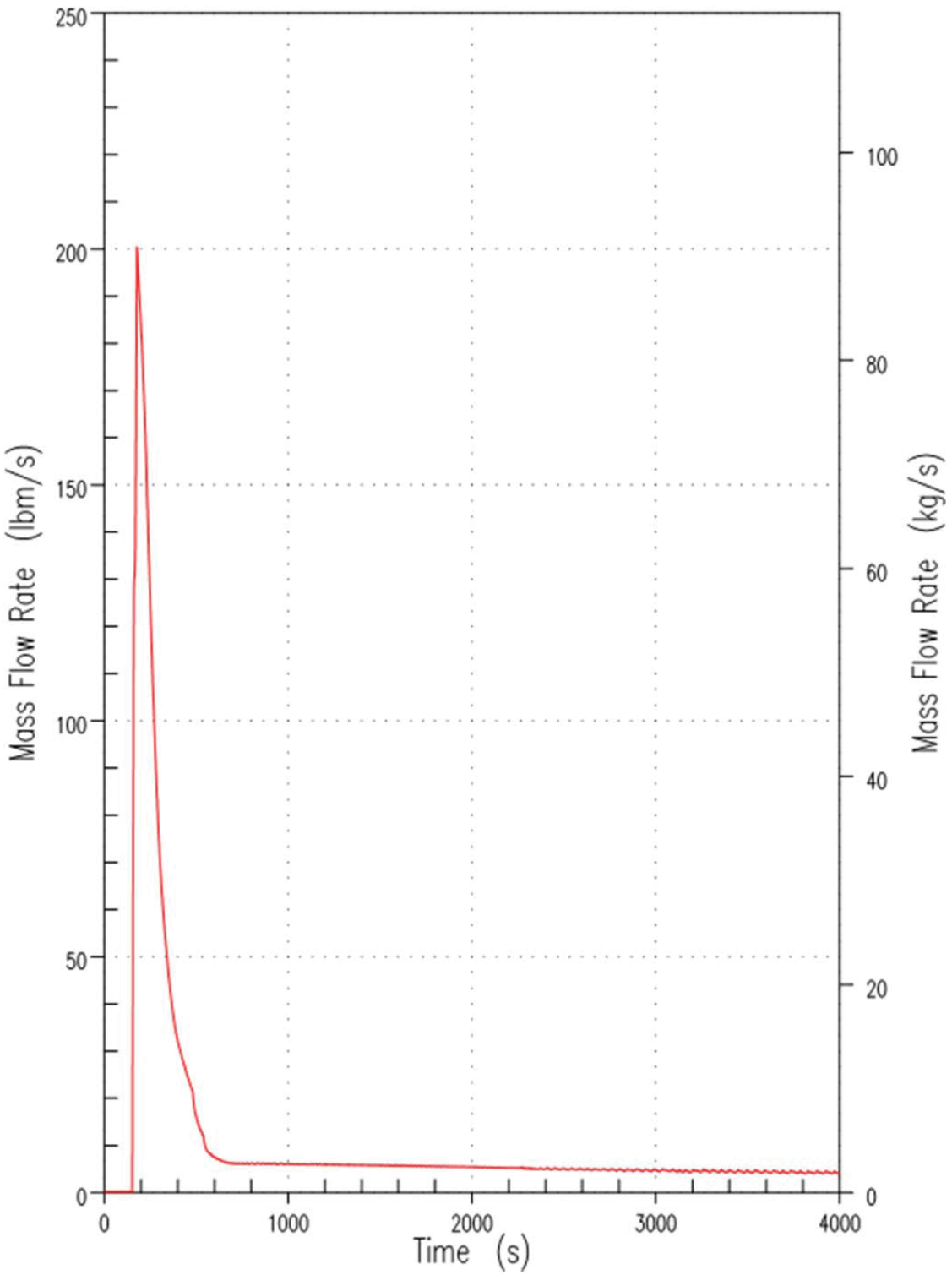


Figure 15.6.5.4B-37
20 psia DEDVI Line Break – Vessel Side Vapor Break Discharge

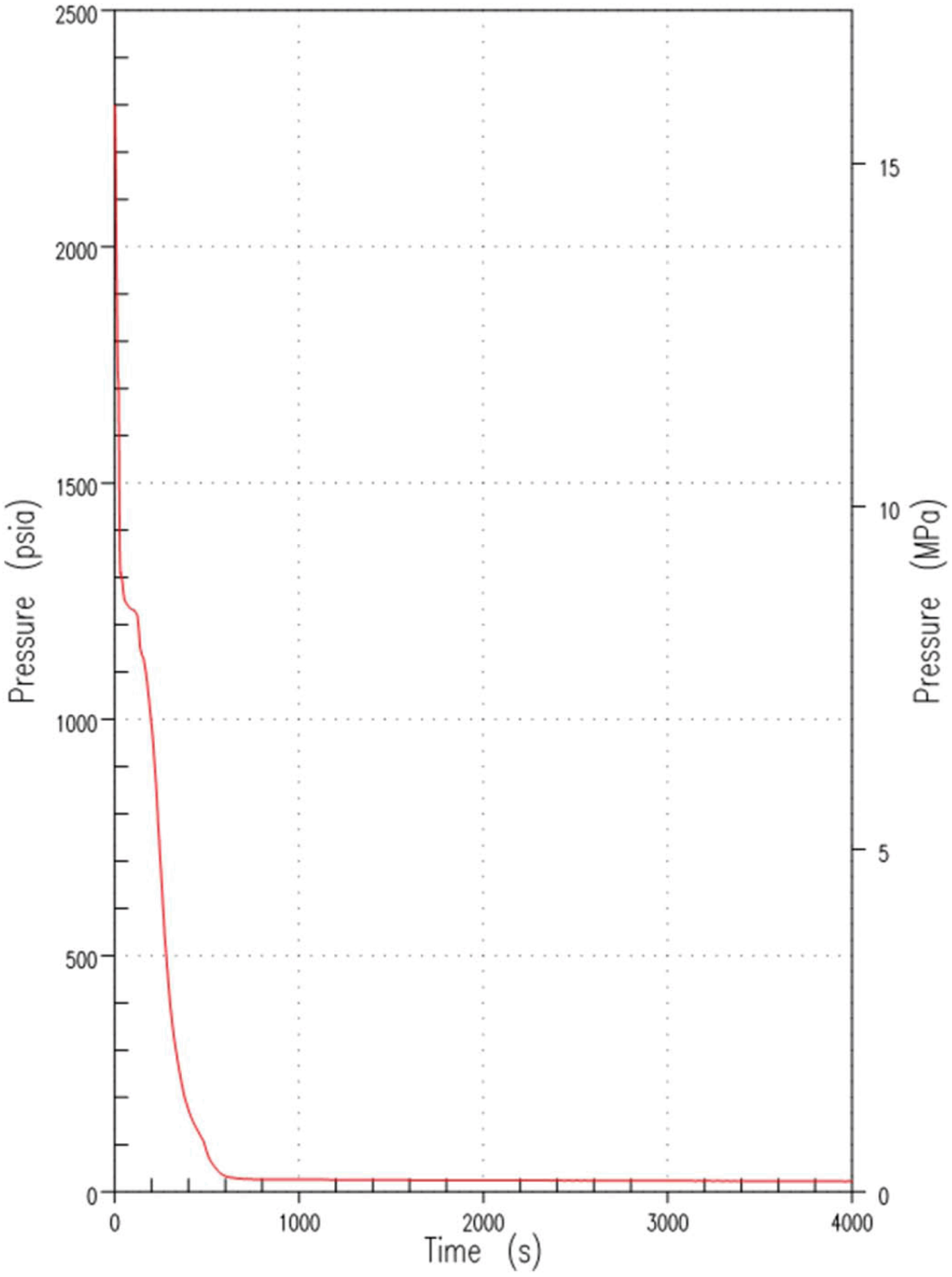


Figure 15.6.5.4B-38(a)
20 psia DEDVI Line Break – RCS Pressure

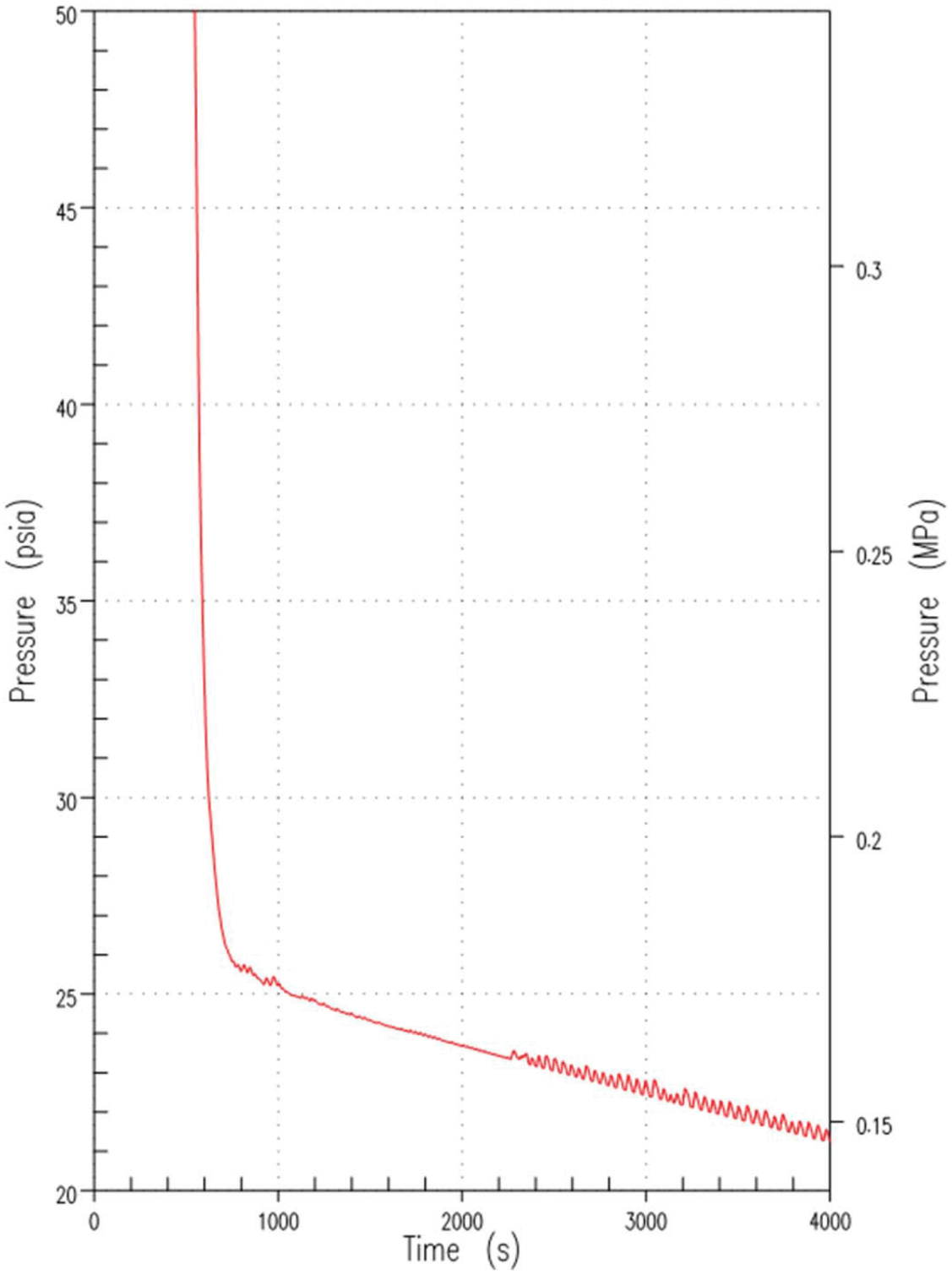


Figure 15.6.5.4B-38(b)
20 psia DEDVI Line Break – RCS Pressure (Zoomed)

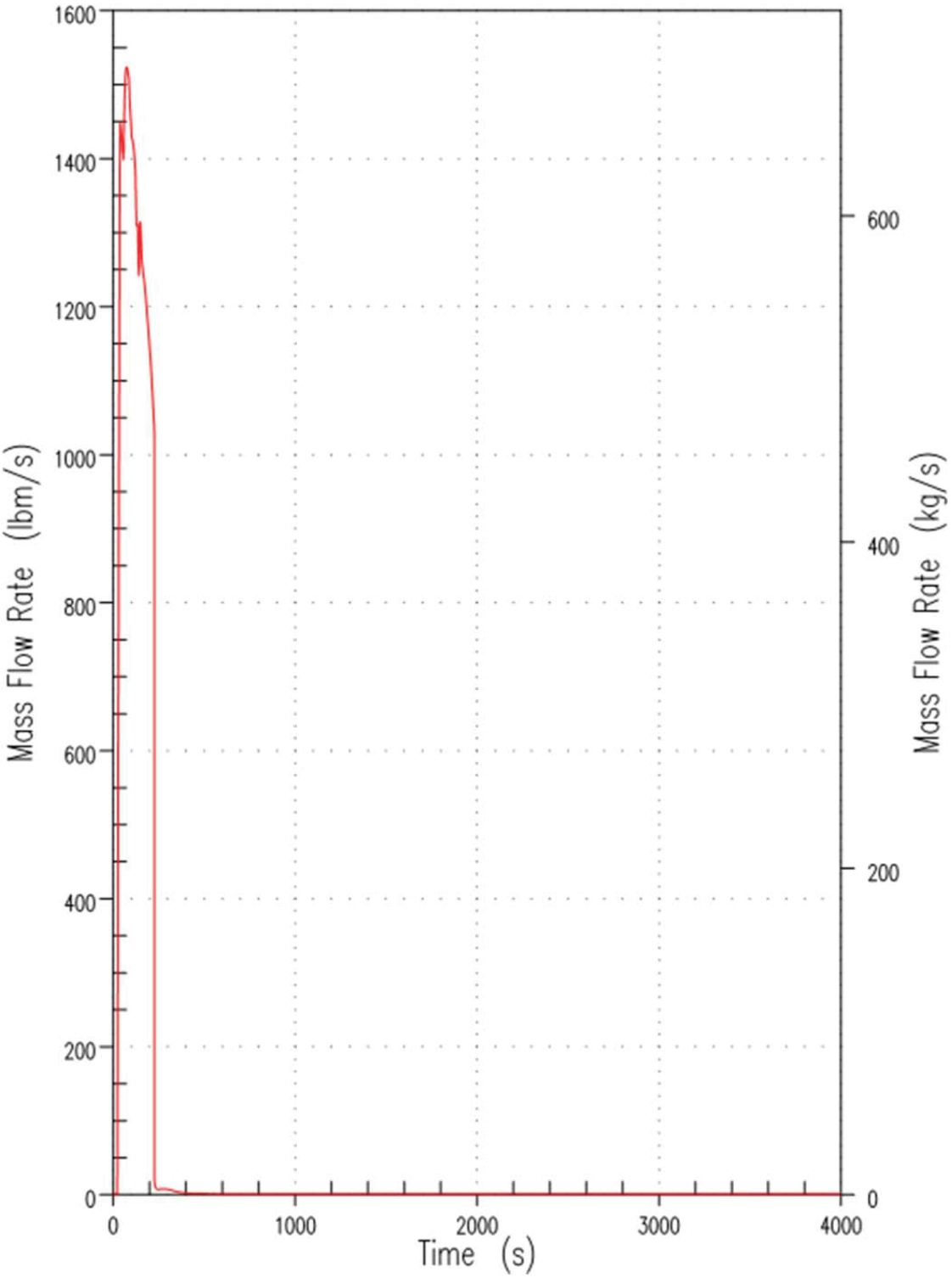


Figure 15.6.5.4B-39
20 psia DEDVI Line Break – Broken CMT Injection Rate

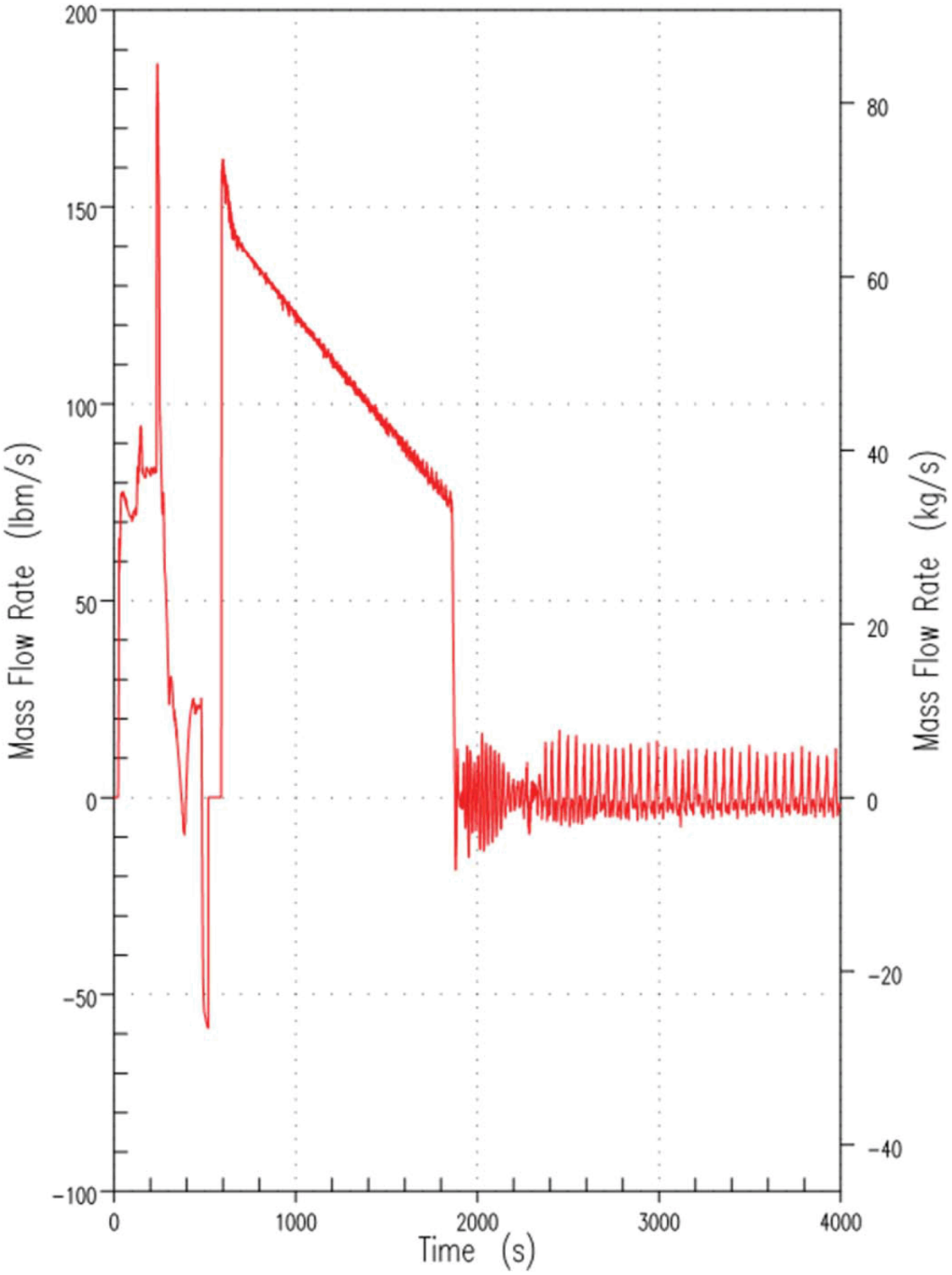


Figure 15.6.5.4B-40
20 psia DEDVI Line Break – Intact CMT Injection Rate

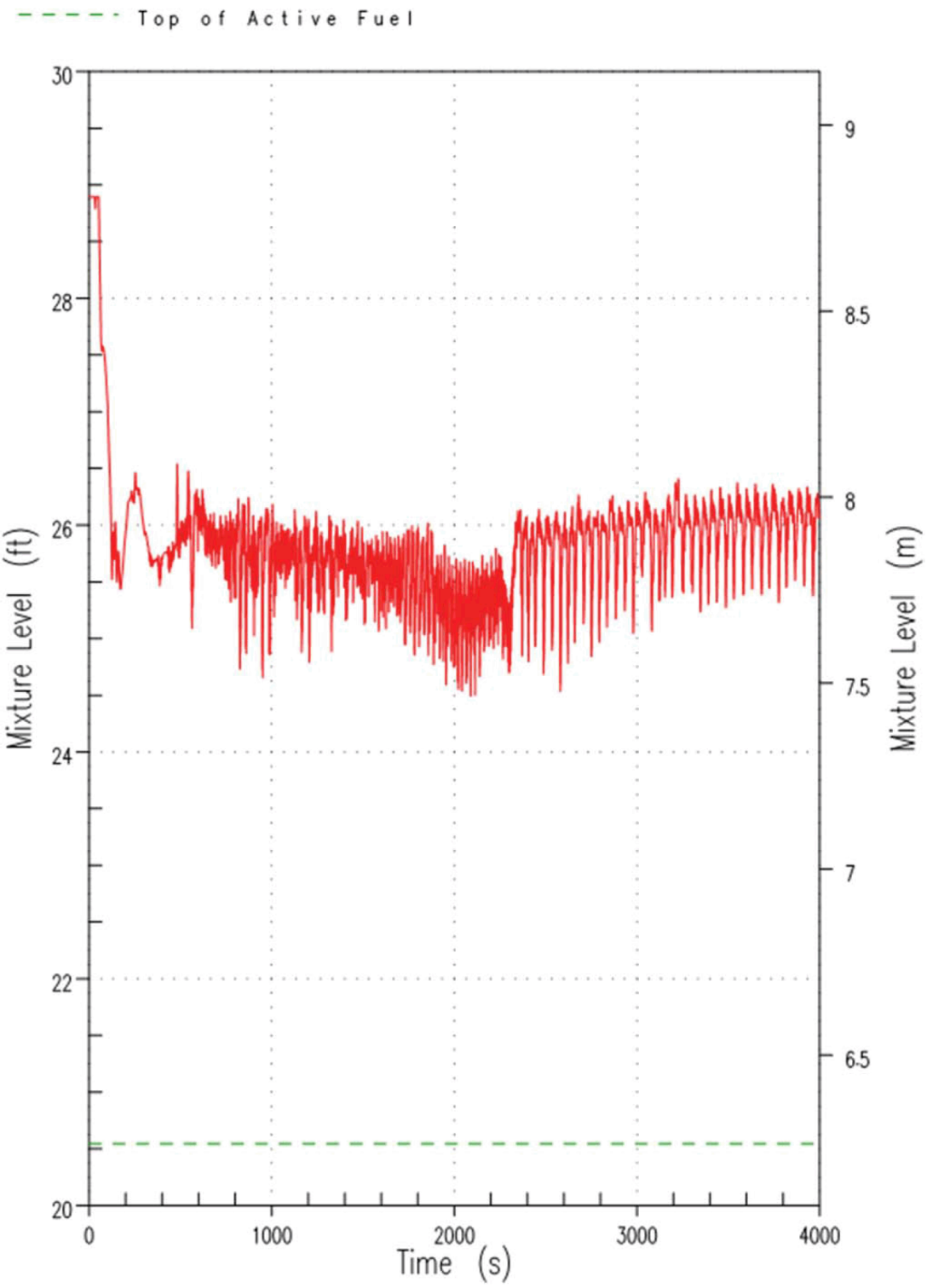


Figure 15.6.5.4B-41
20 psia DEDVI Line Break – Core/Upper Plenum Mixture Level

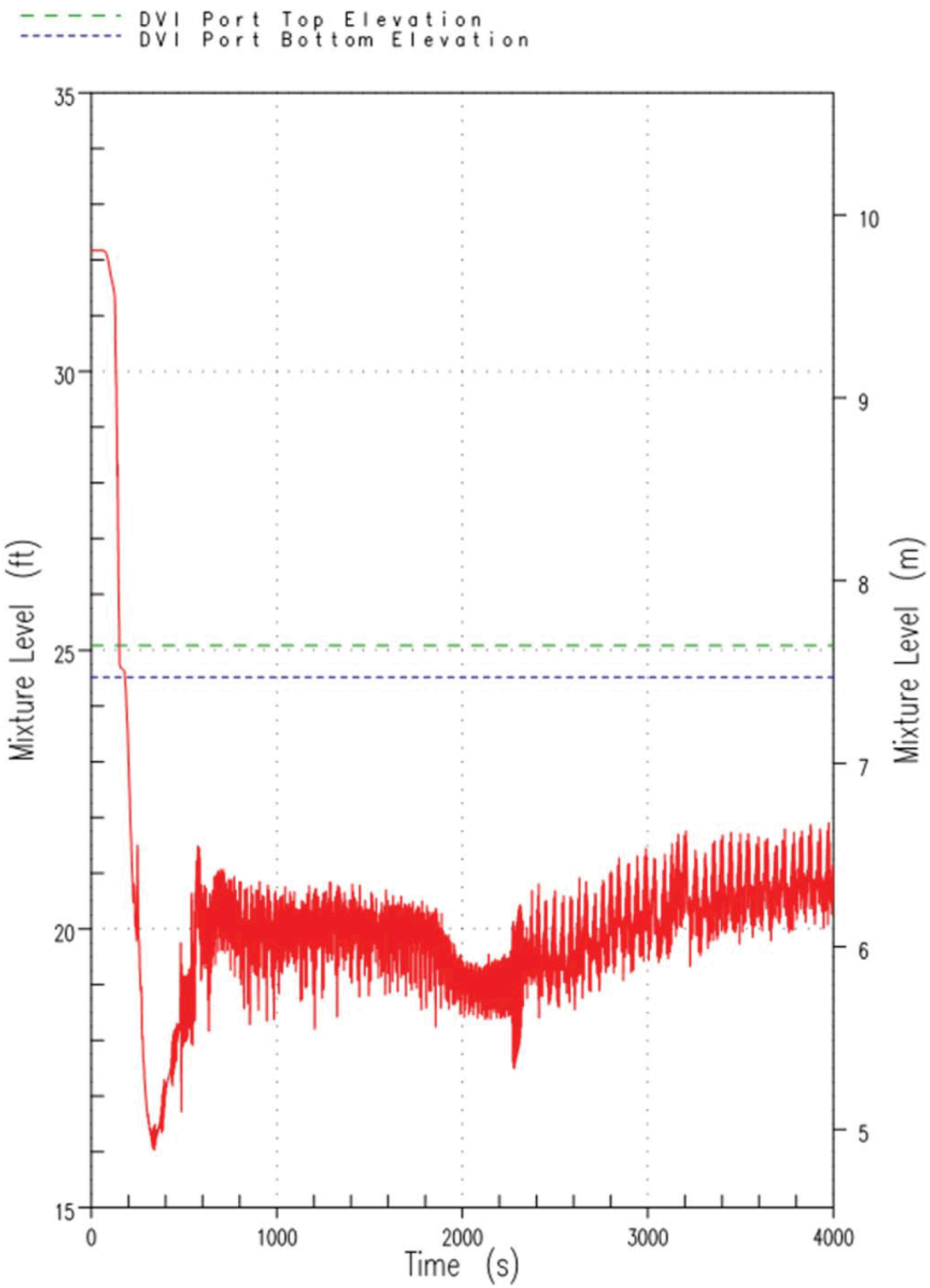


Figure 15.6.5.4B-42
20 psia DEDVI Line Break – Downcomer Mixture Level

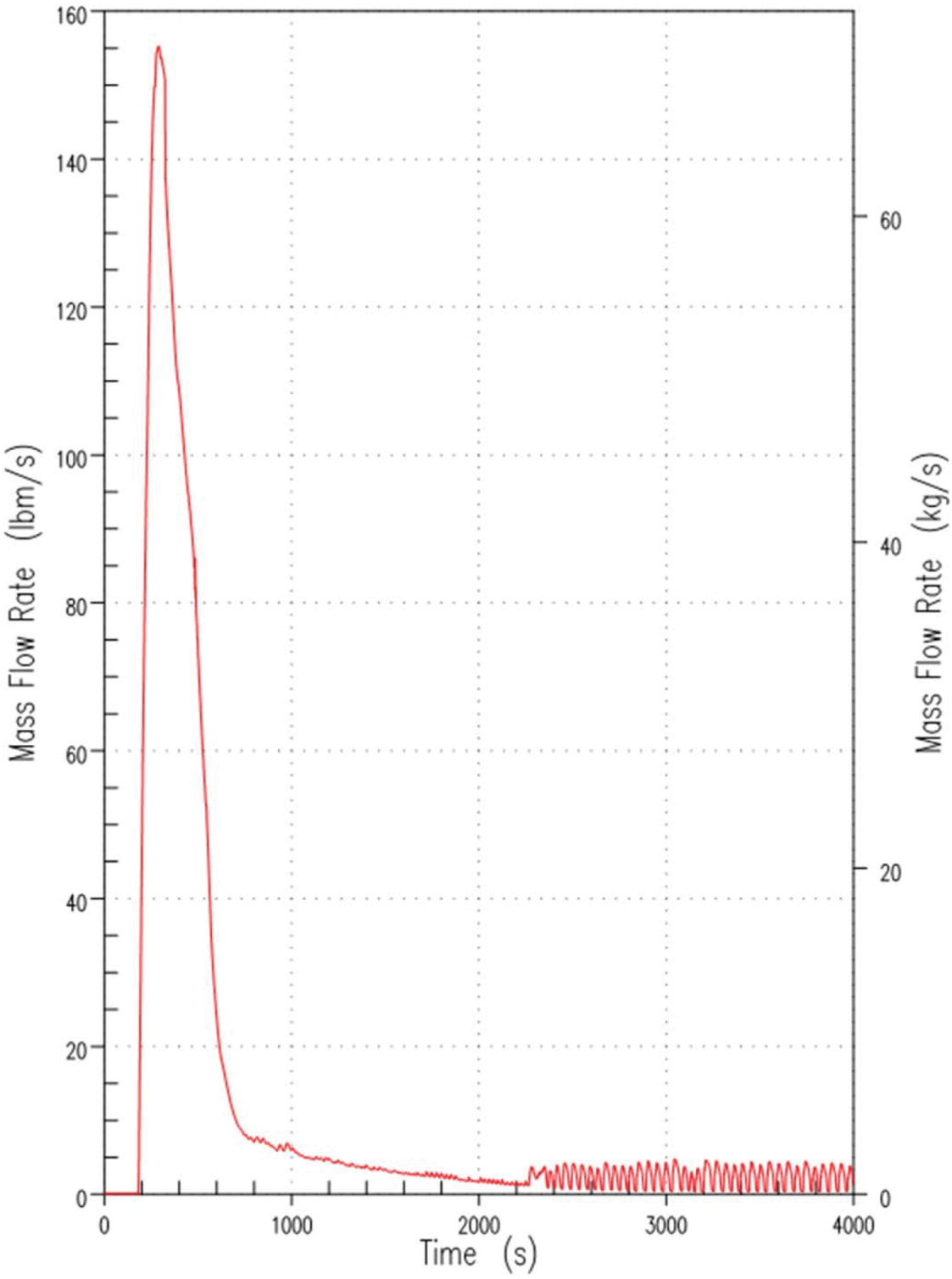


Figure 15.6.5.4B-43(a)
20 psia DEDVI Line Break – ADS 1-3 Vapor Discharge

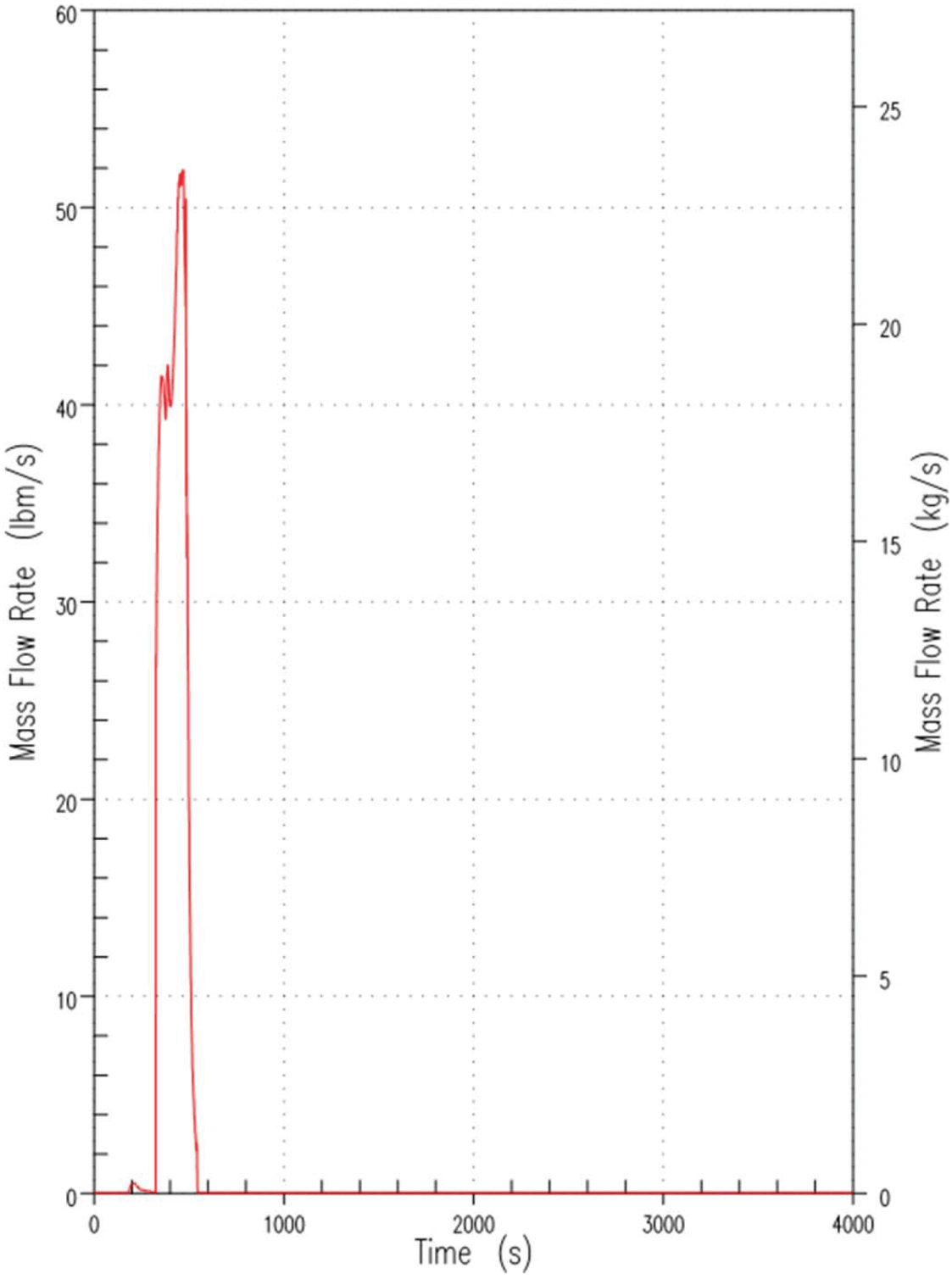


Figure 15.6.5.4B-43(b)
20 psia DEDVI Line Break – ADS 1-3 Liquid Discharge

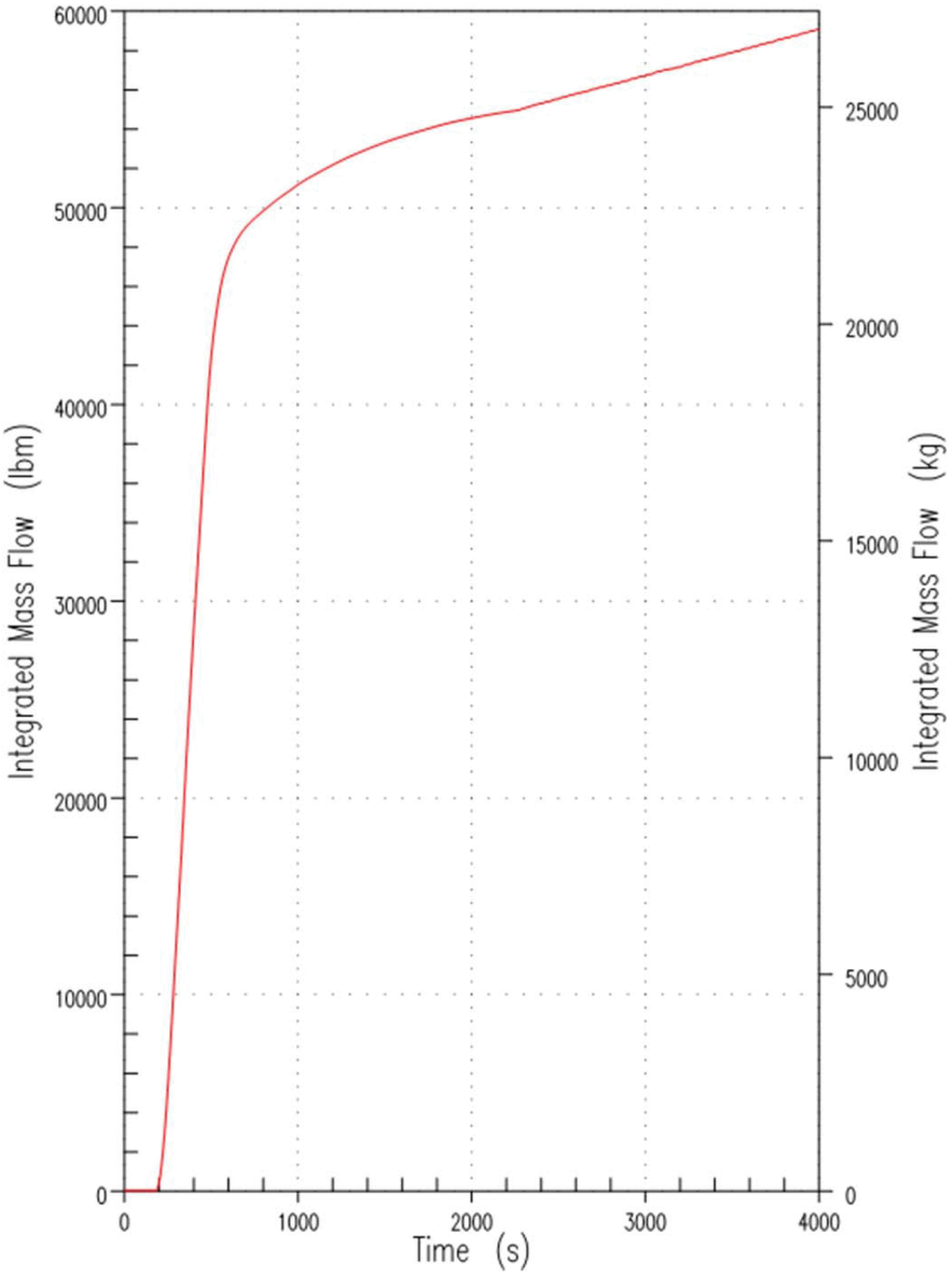


Figure 15.6.5.4B-43(c)
20 psia DEDVI Line Break – ADS 1-3 Integrated Discharge

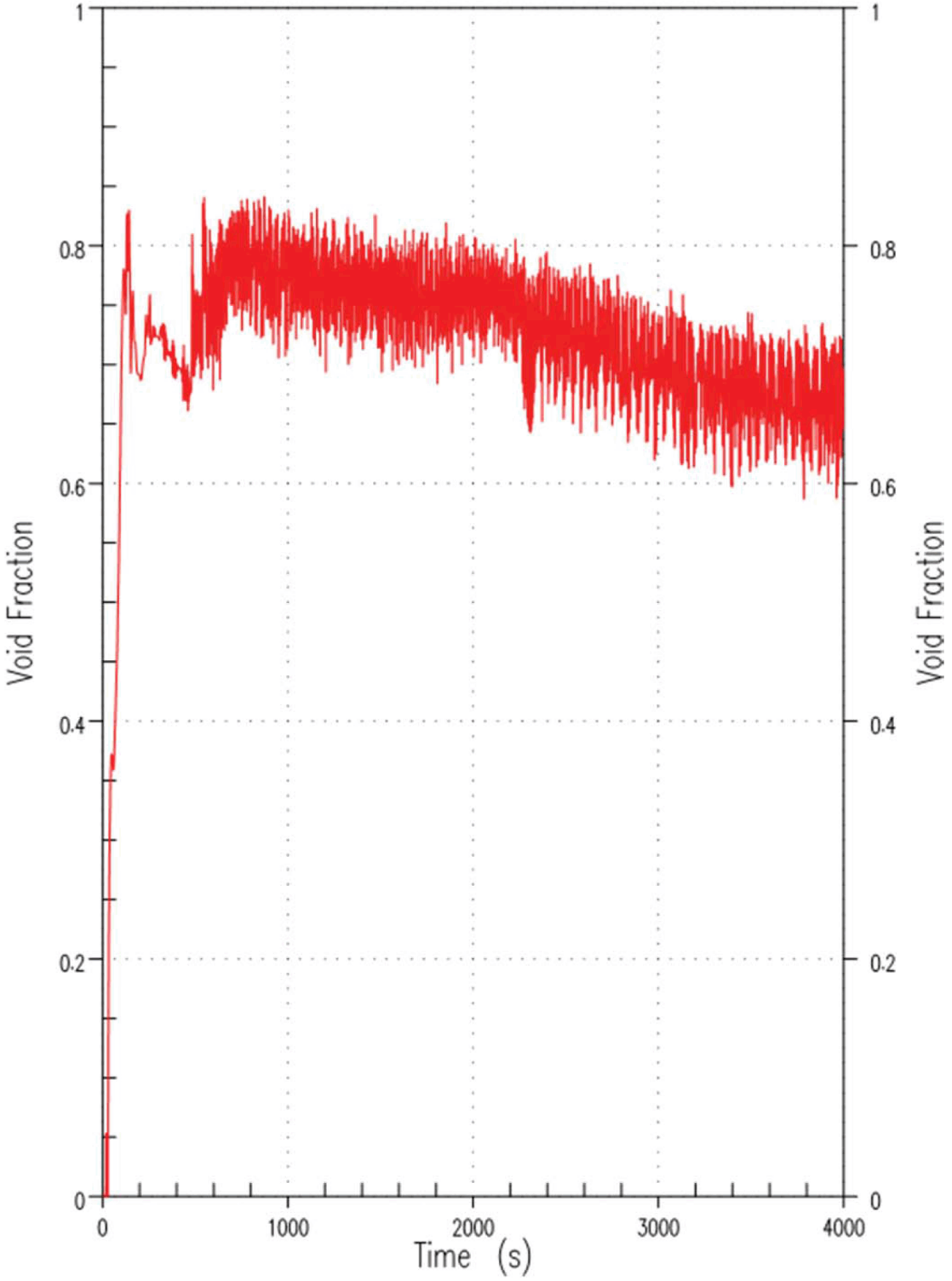


Figure 15.6.5.4B-44
20 psia DEDVI Line Break – Core Exit Void Fraction

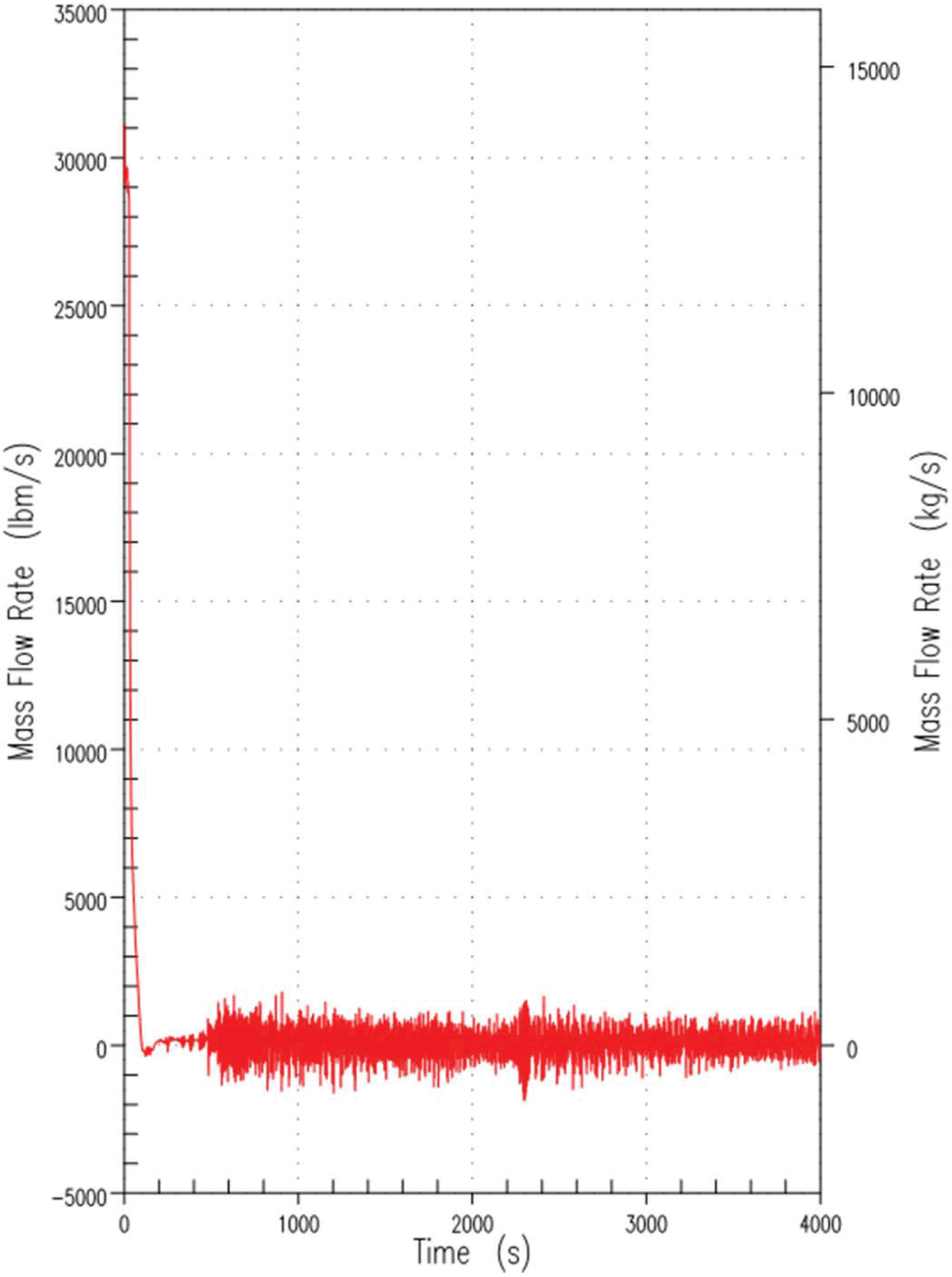


Figure 15.6.5.4B-45
20 psia DEDVI Line Break – Core Exit Liquid Flow Rate

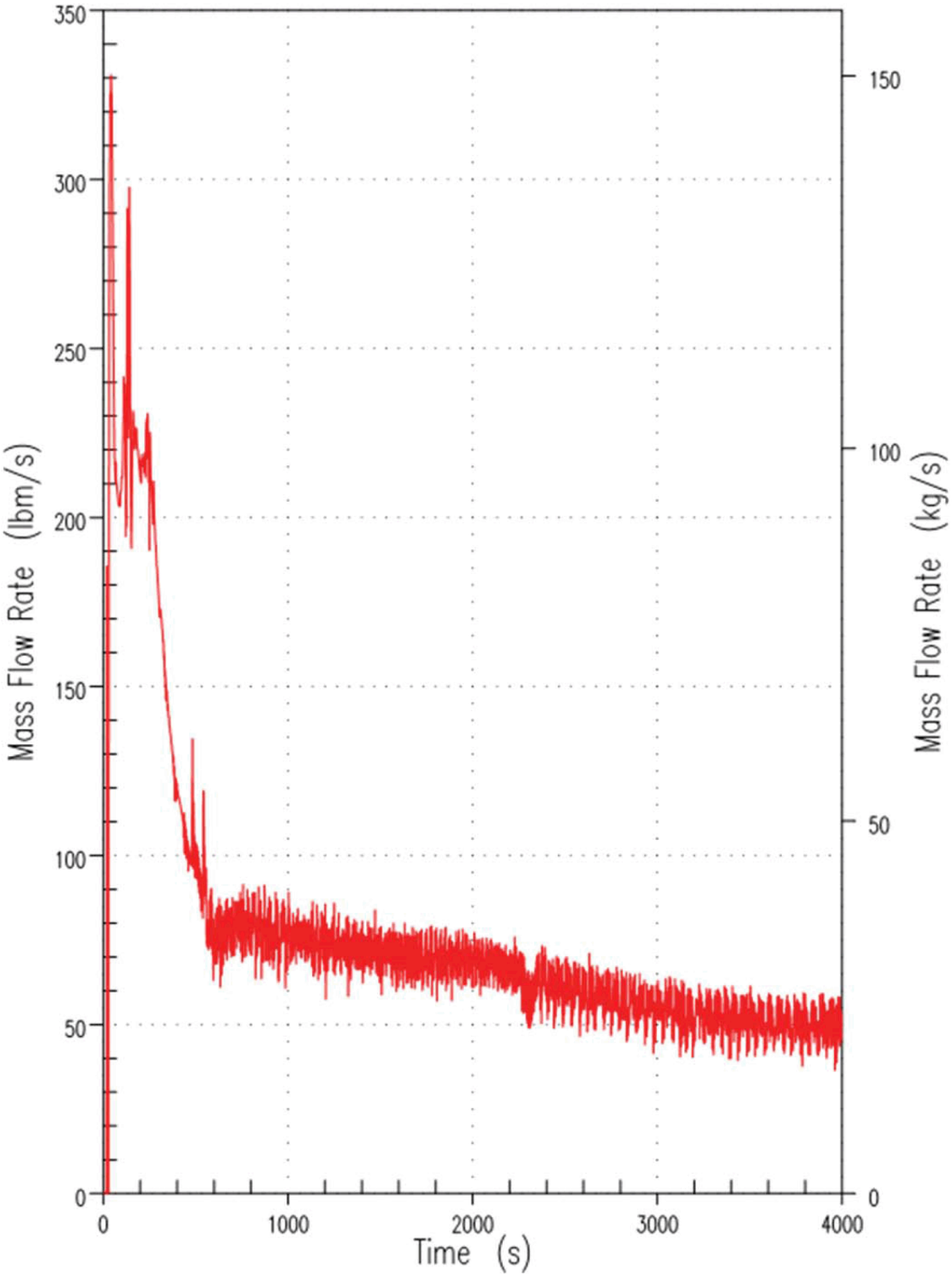


Figure 15.6.5.4B-46
20 psia DEDVI Line Break – Core Exit Vapor Flow Rate

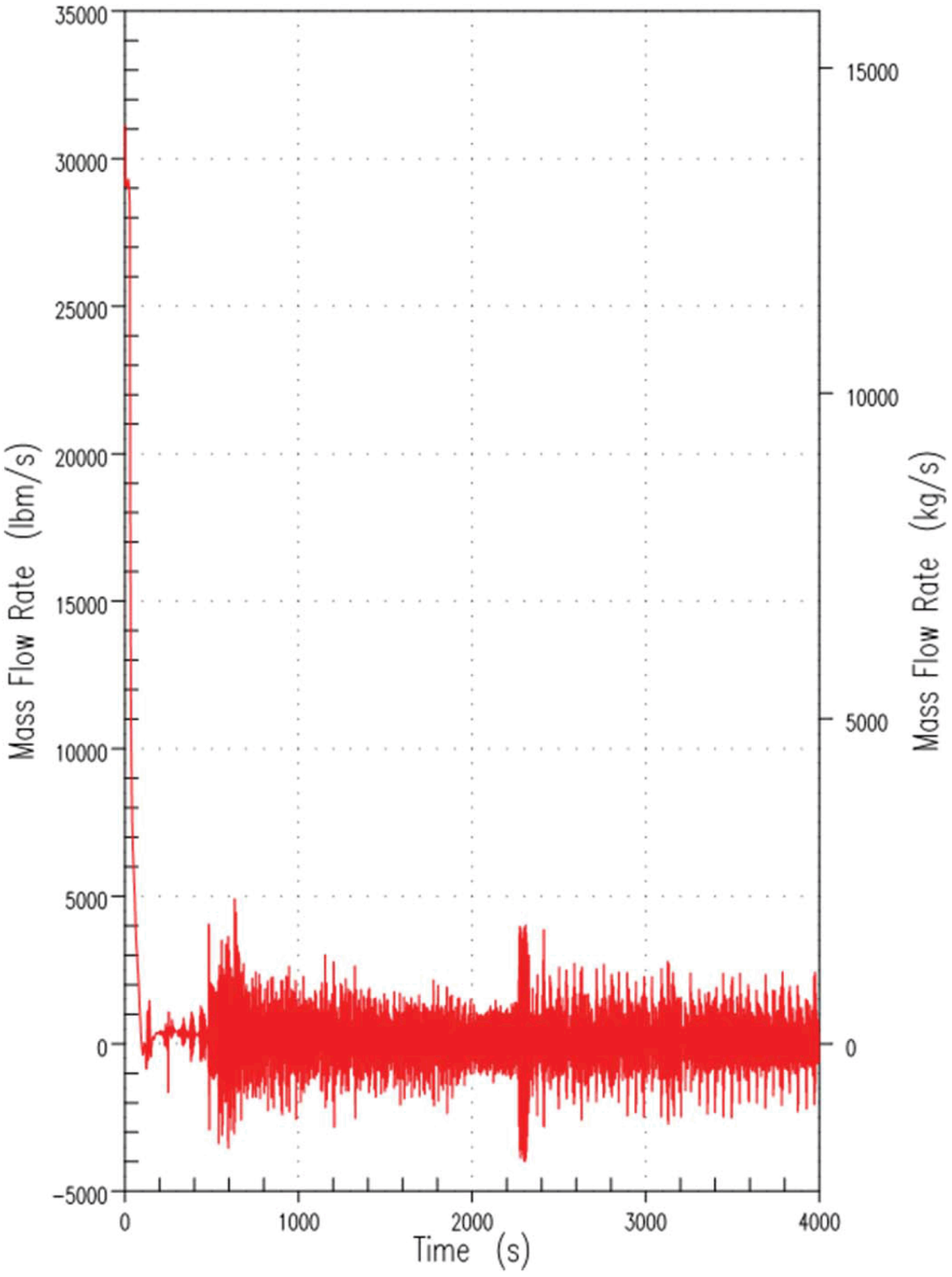


Figure 15.6.5.4B-47
20 psia DEDVI Line Break – Lower Plenum to Core Flow Rate

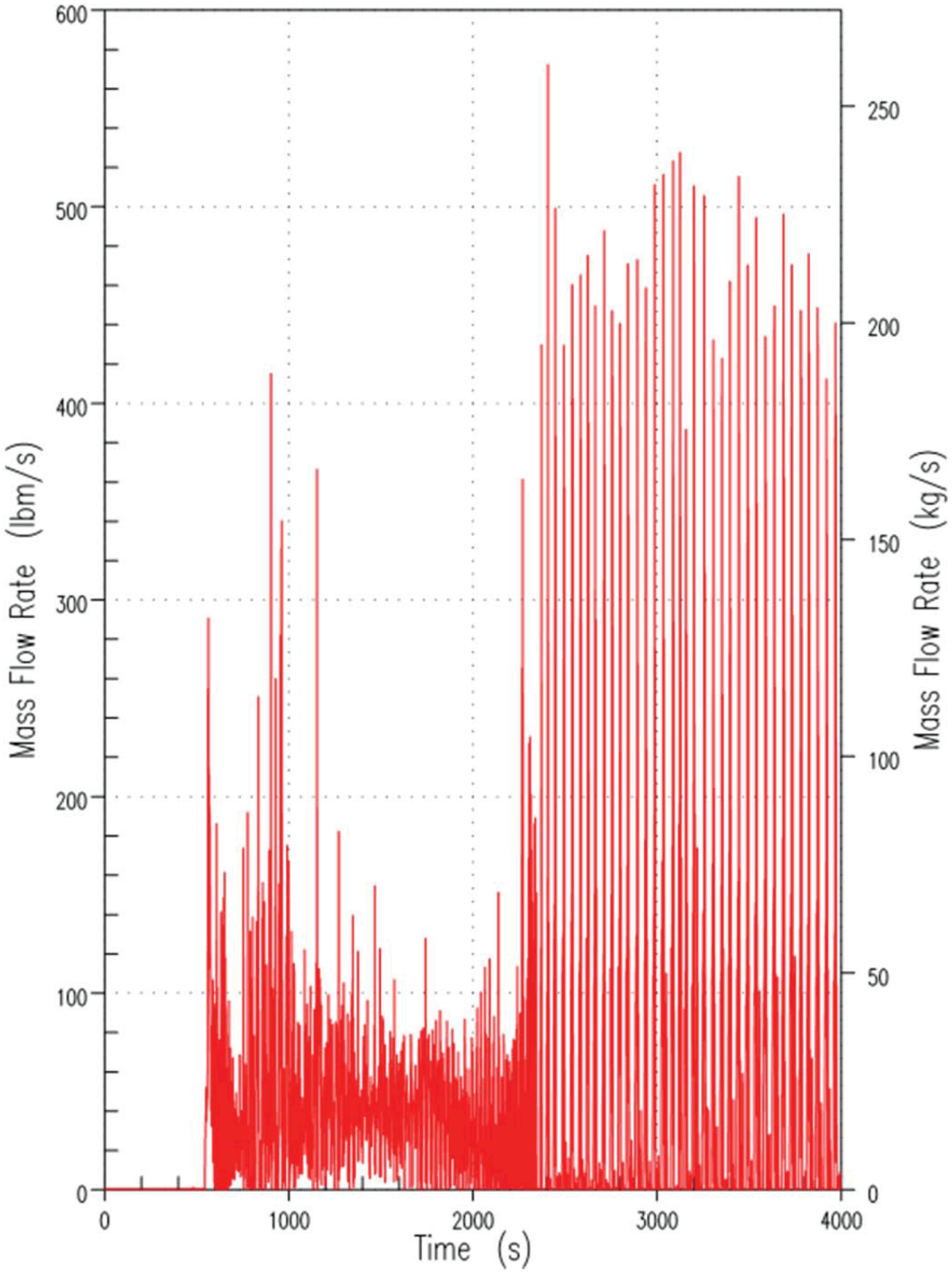


Figure 15.6.5.4B-48(a)
20 psia DEDVI Line Break – ADS-4 Liquid Discharge

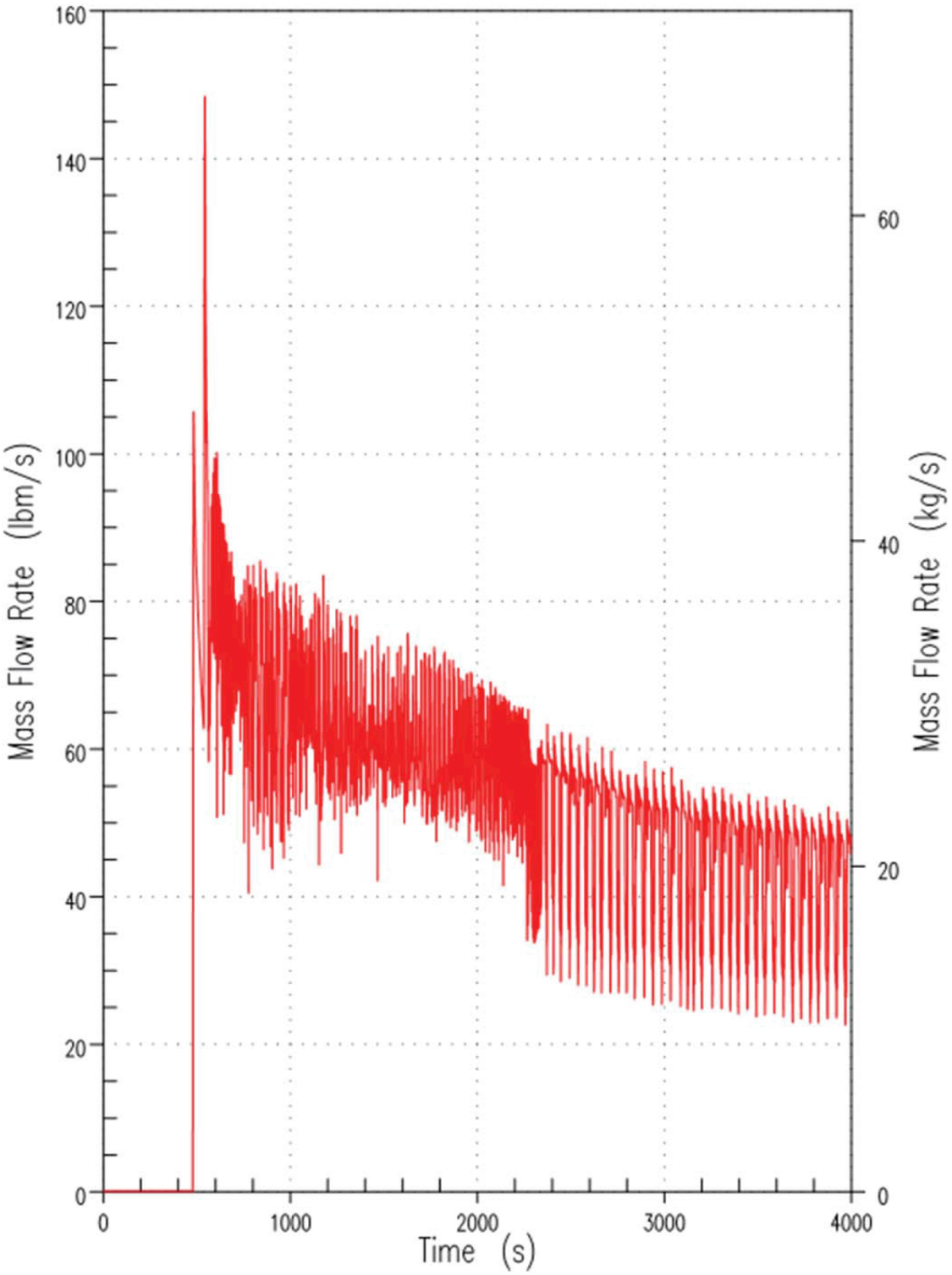


Figure 15.6.5.4B-48(b)
20 psia DEDVI Line Break – ADS-4 Vapor Discharge

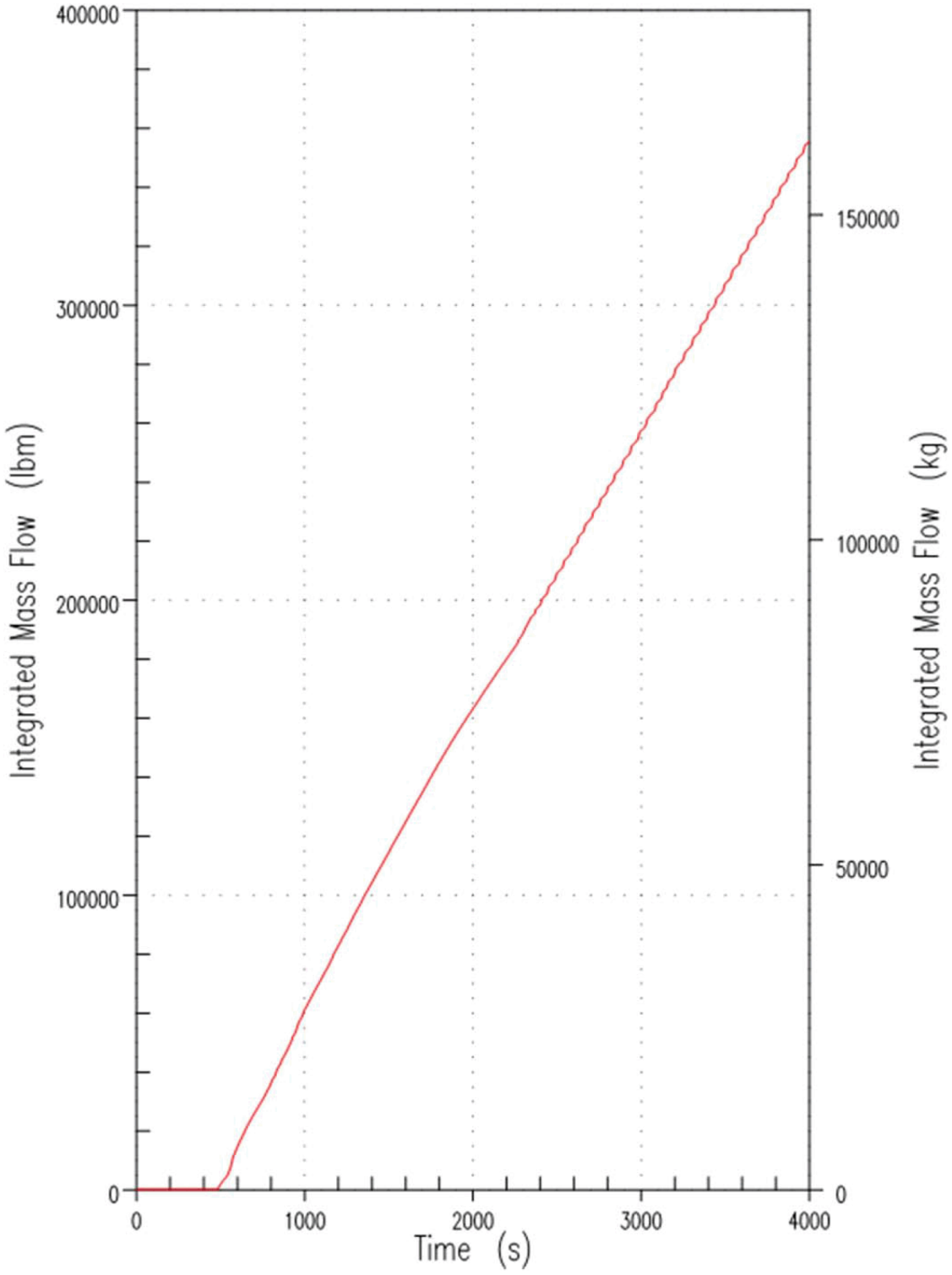


Figure 15.6.5.4B-49
20 psia DEDVI Line Break – ADS-4 Integrated Discharge

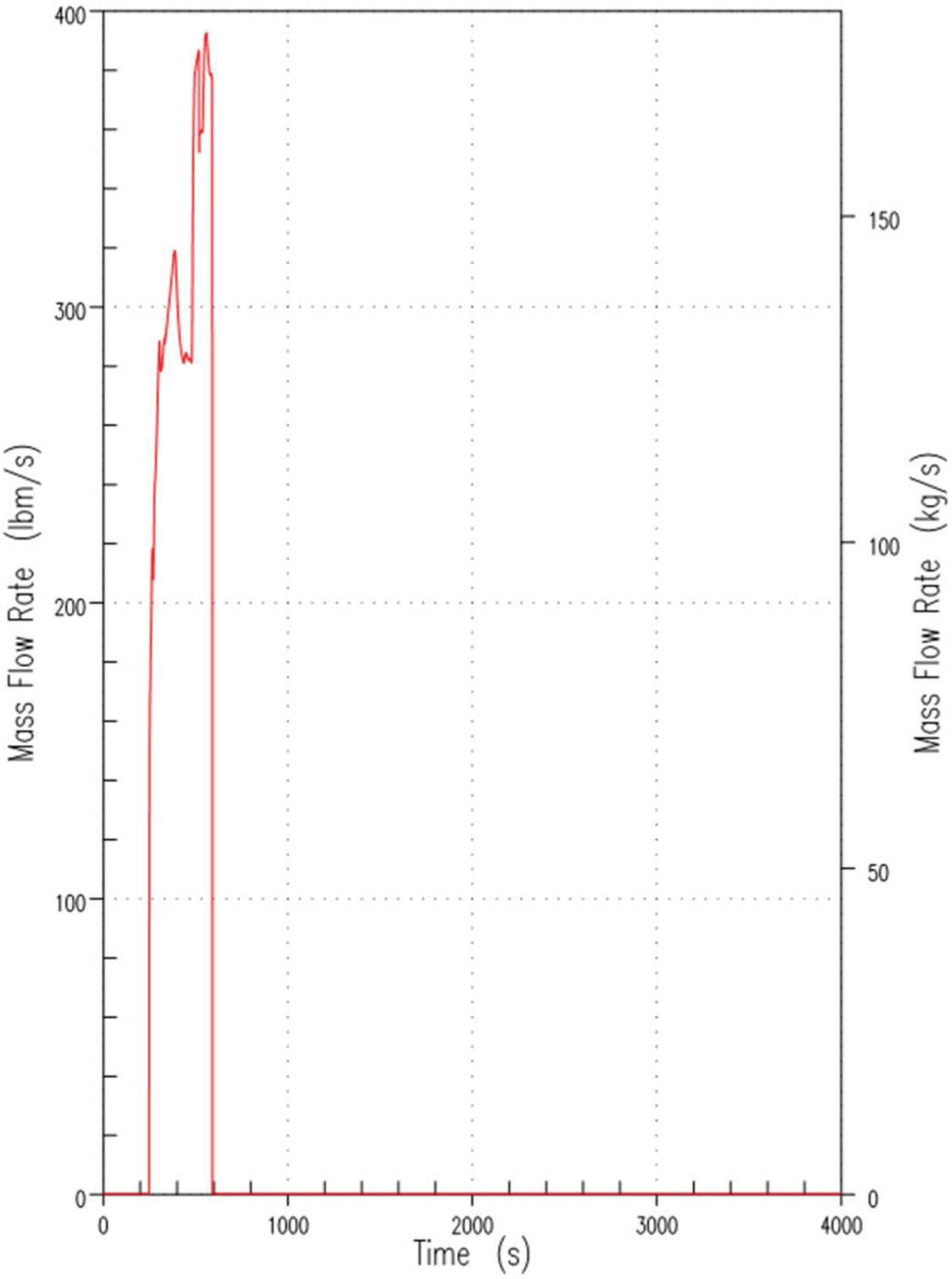


Figure 15.6.5.4B-50
20 psia DEDVI Line Break – Intact Accumulator Flow Rate

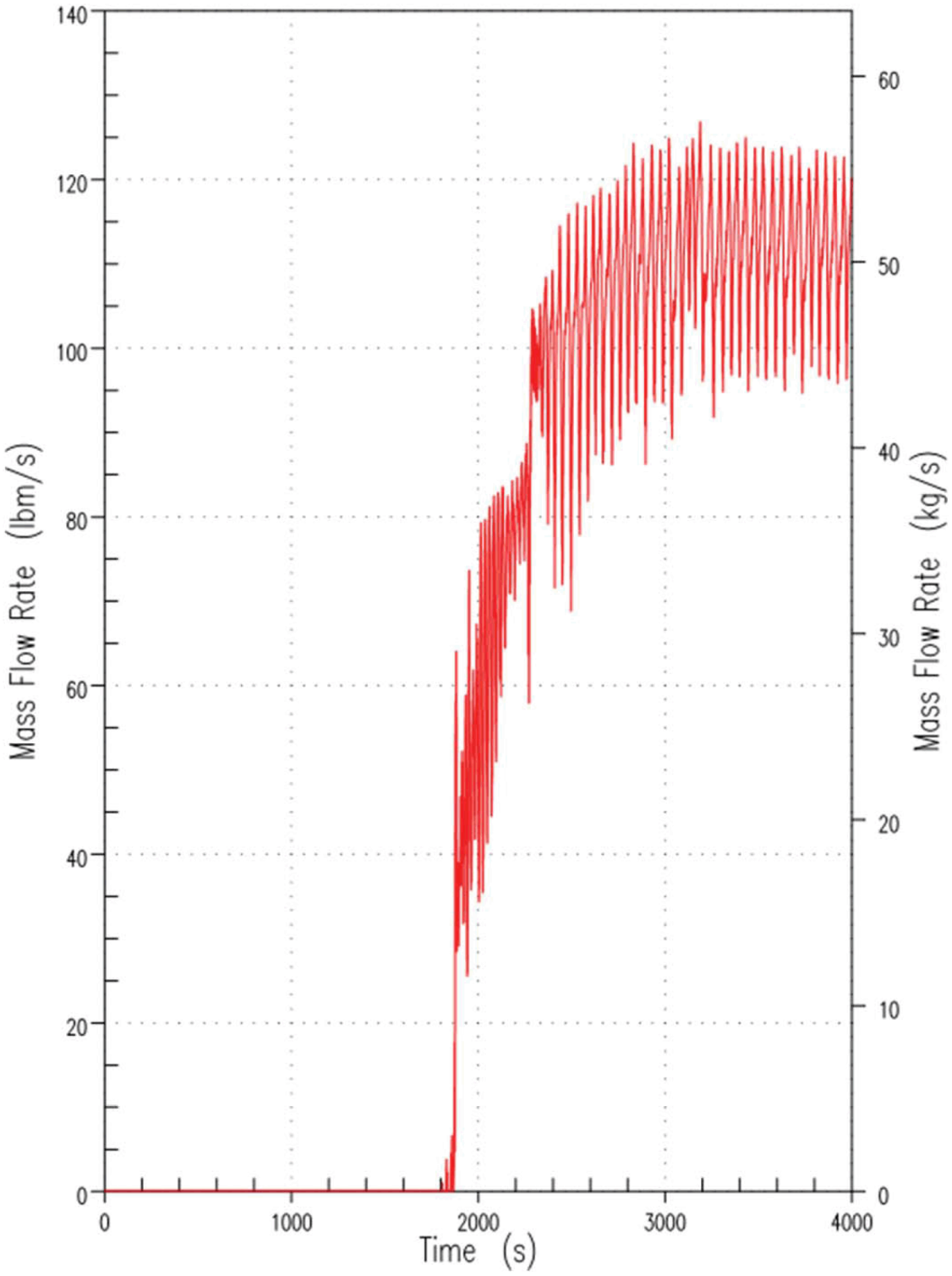


Figure 15.6.5.4B-51
20 psia DEDVI Line Break – Intact IRWST Injection Rate

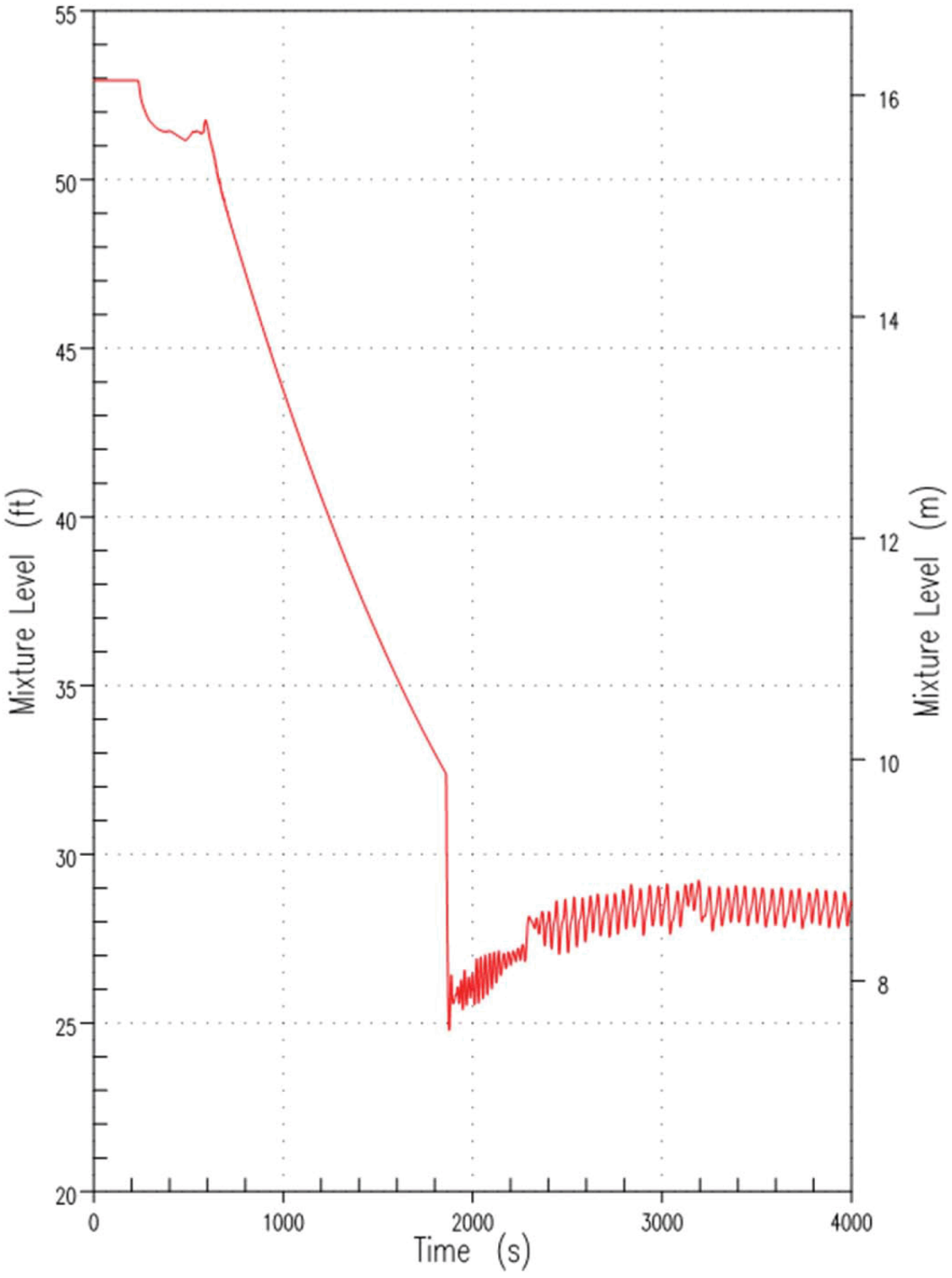


Figure 15.6.5.4B-52
20 psia DEDVI Line Break – Intact CMT Mixture Level

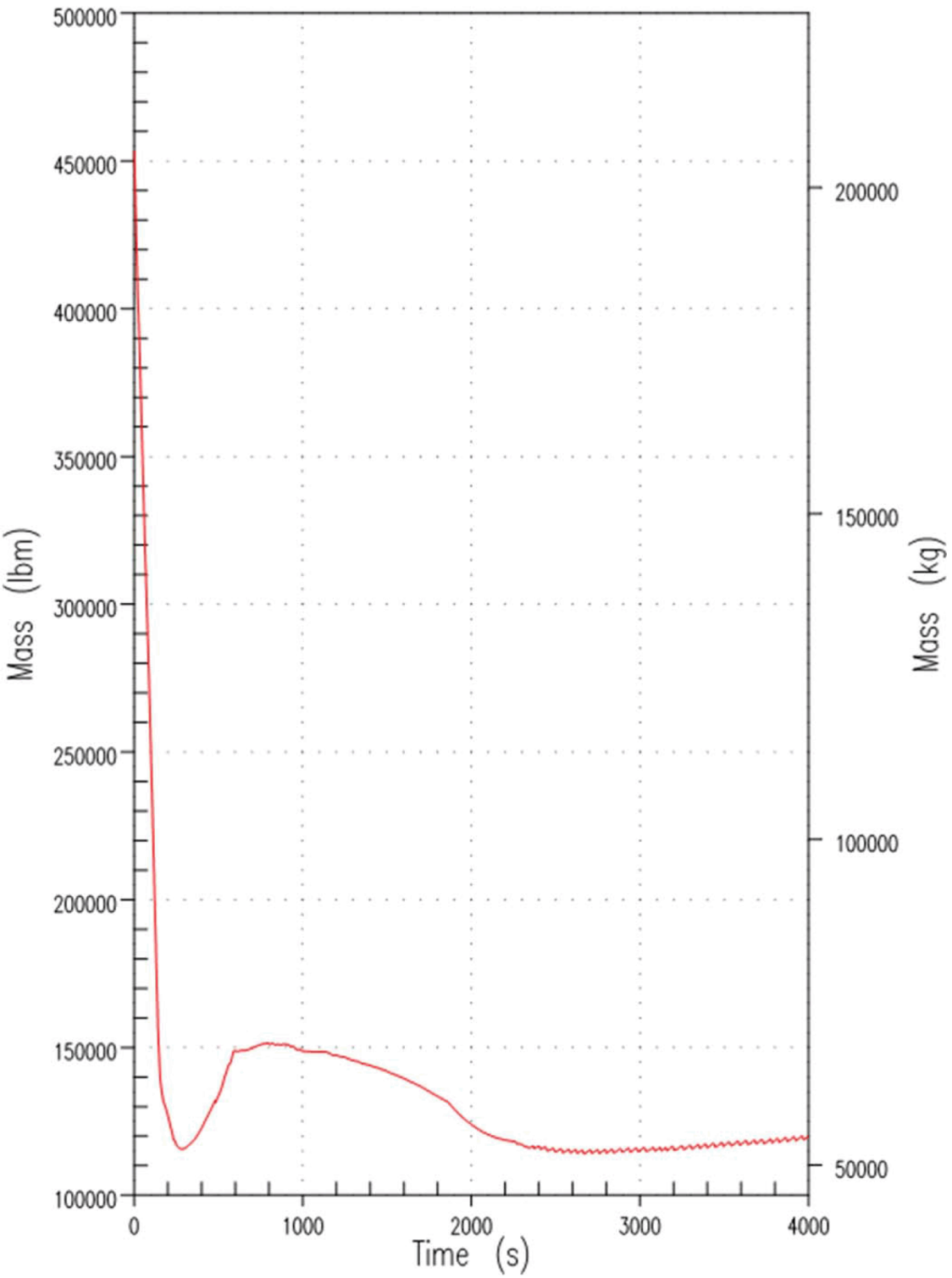


Figure 15.6.5.4B-53(a)
20 psia DEDVI Line Break – RCS System Inventory

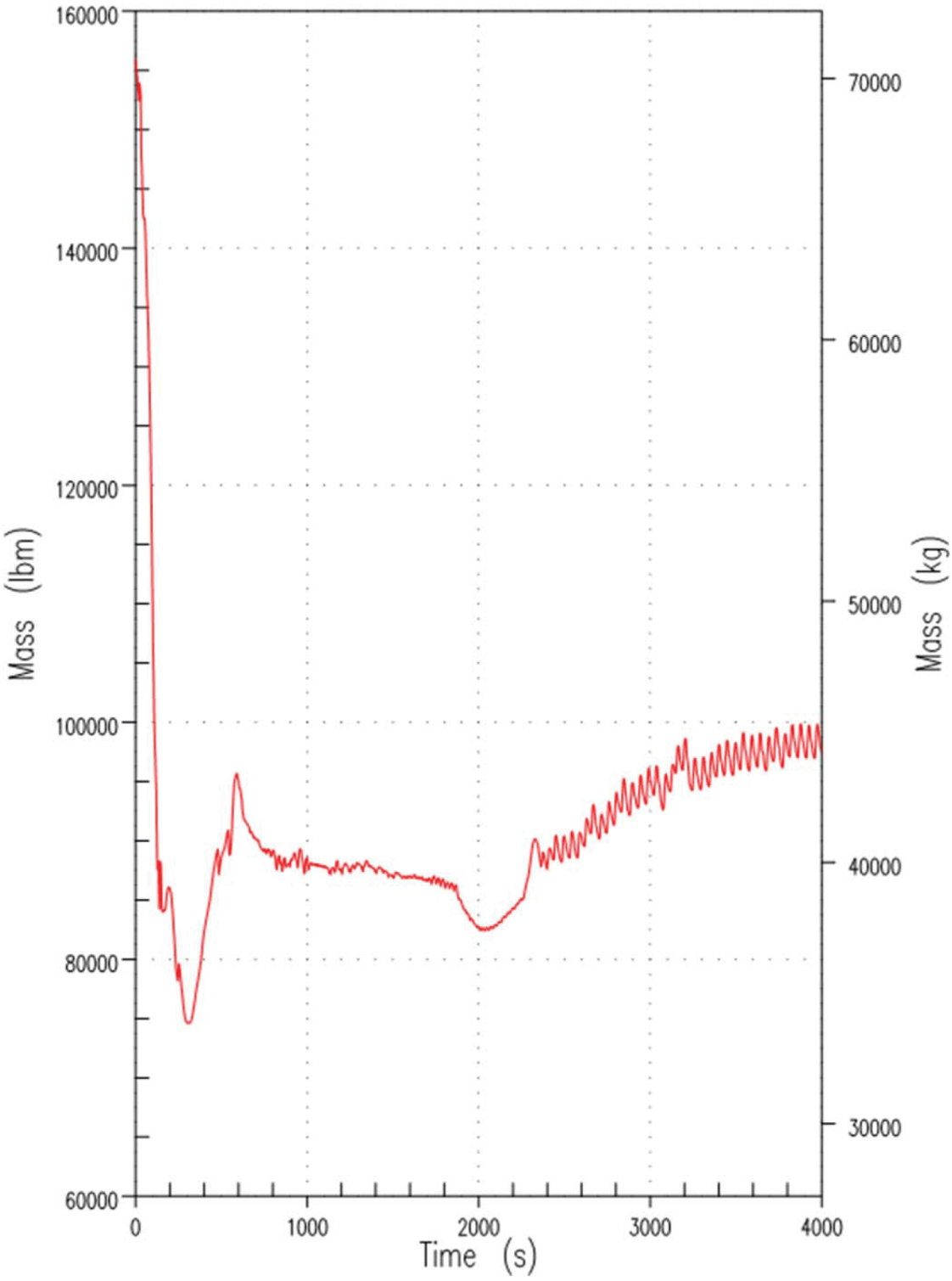


Figure 15.6.5.4B-53(b)
20 psia DEDVI Line Break – Reactor Vessel Mixture Inventory

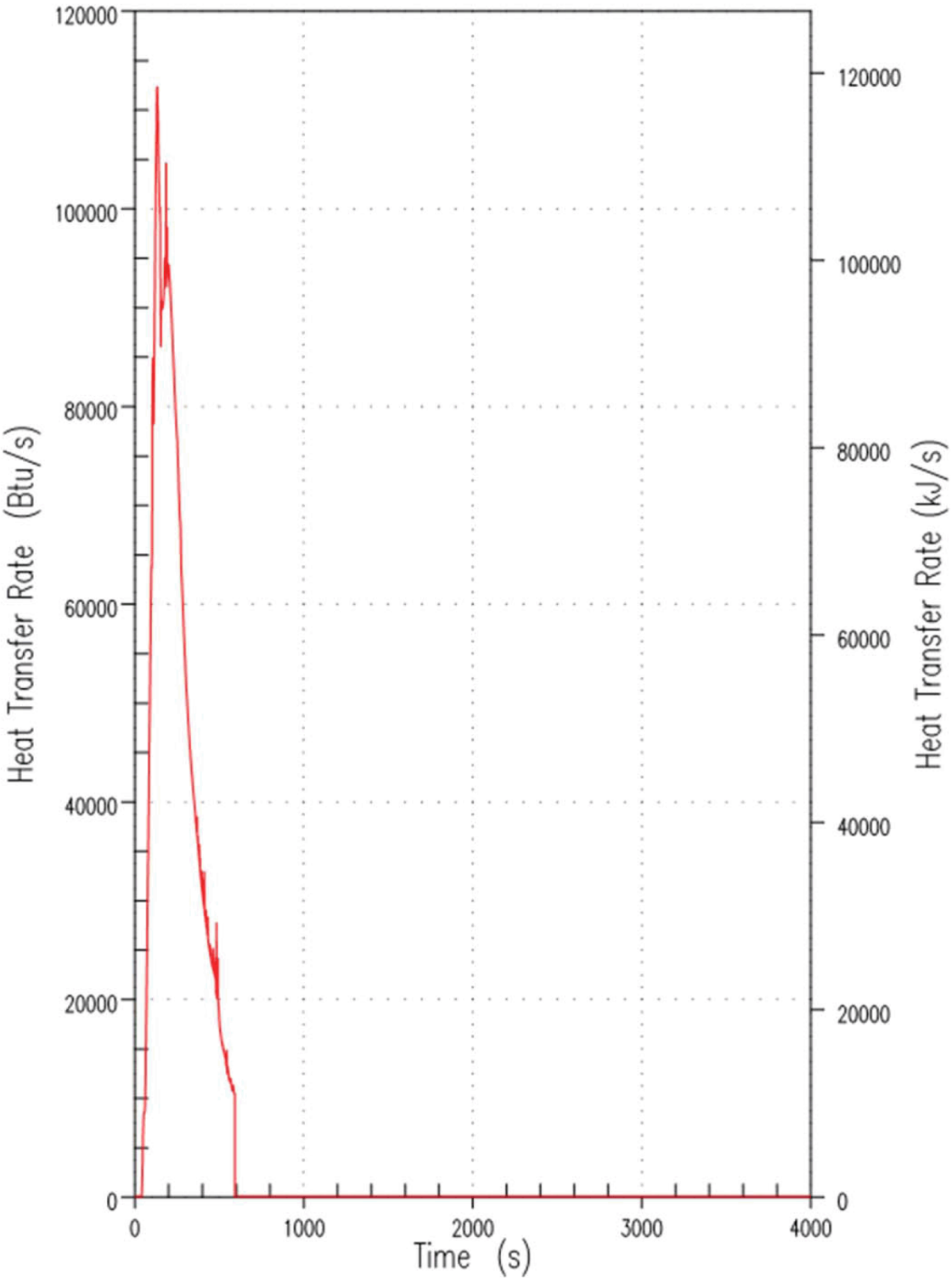


Figure 15.6.5.4B-54
20 psia DEDVI Line Break – PRHR Heat Removal Rate

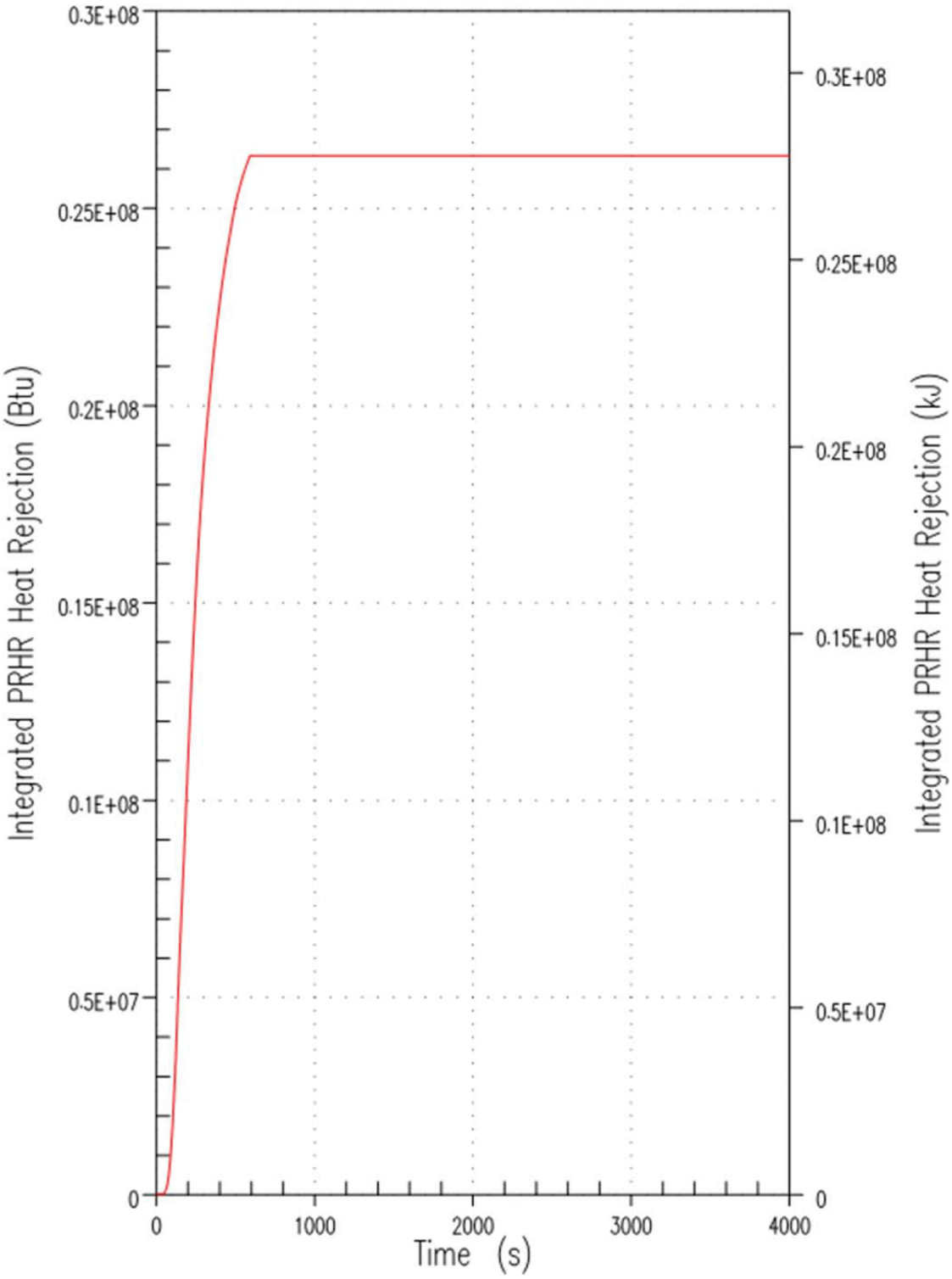


Figure 15.6.5.4B-55
20 psia DEDVI Line Break – Integrated PRHR Heat Removal

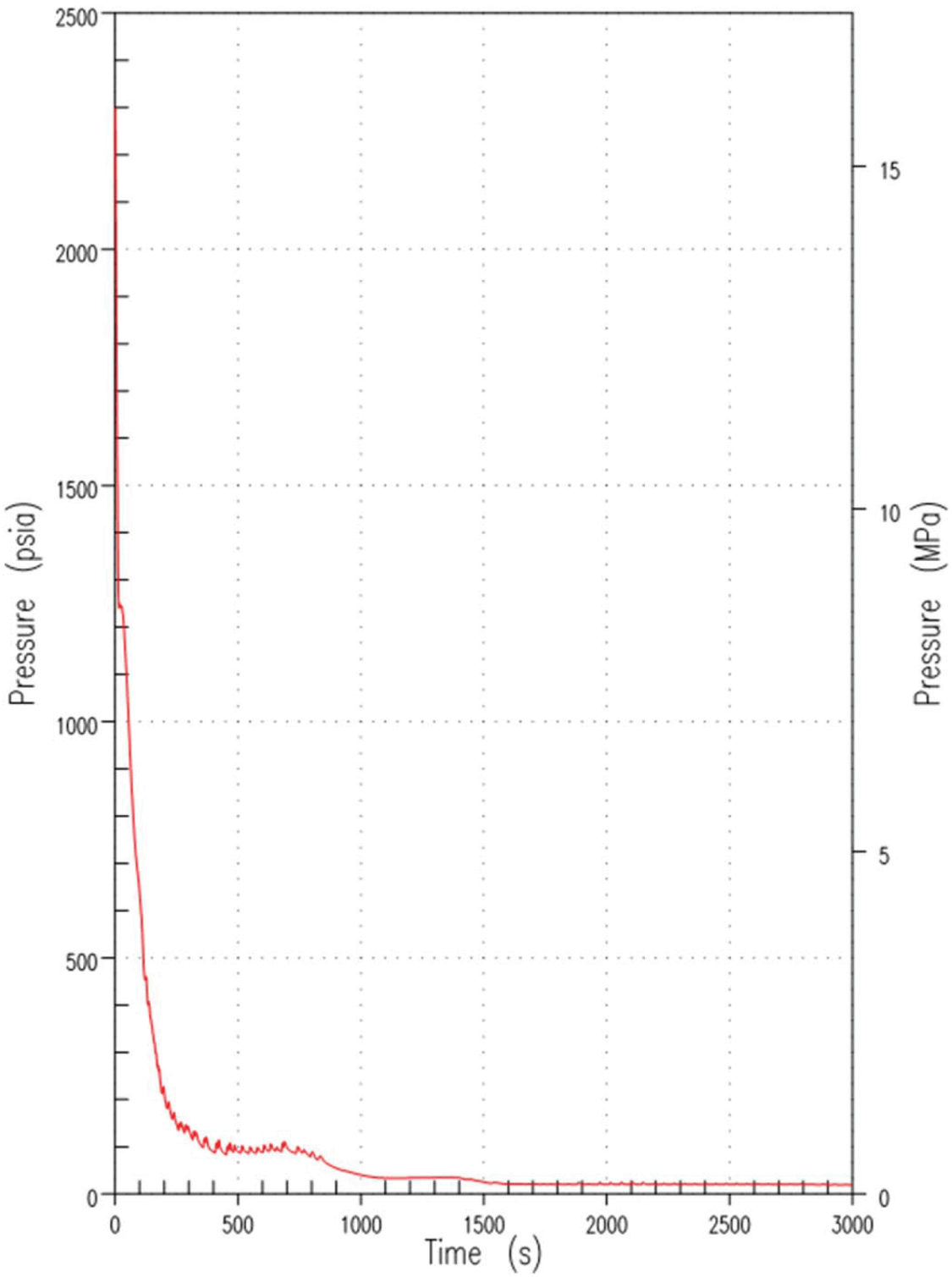


Figure 15.6.5.4B-56(a)
10-inch Cold Leg Break – RCS Pressure

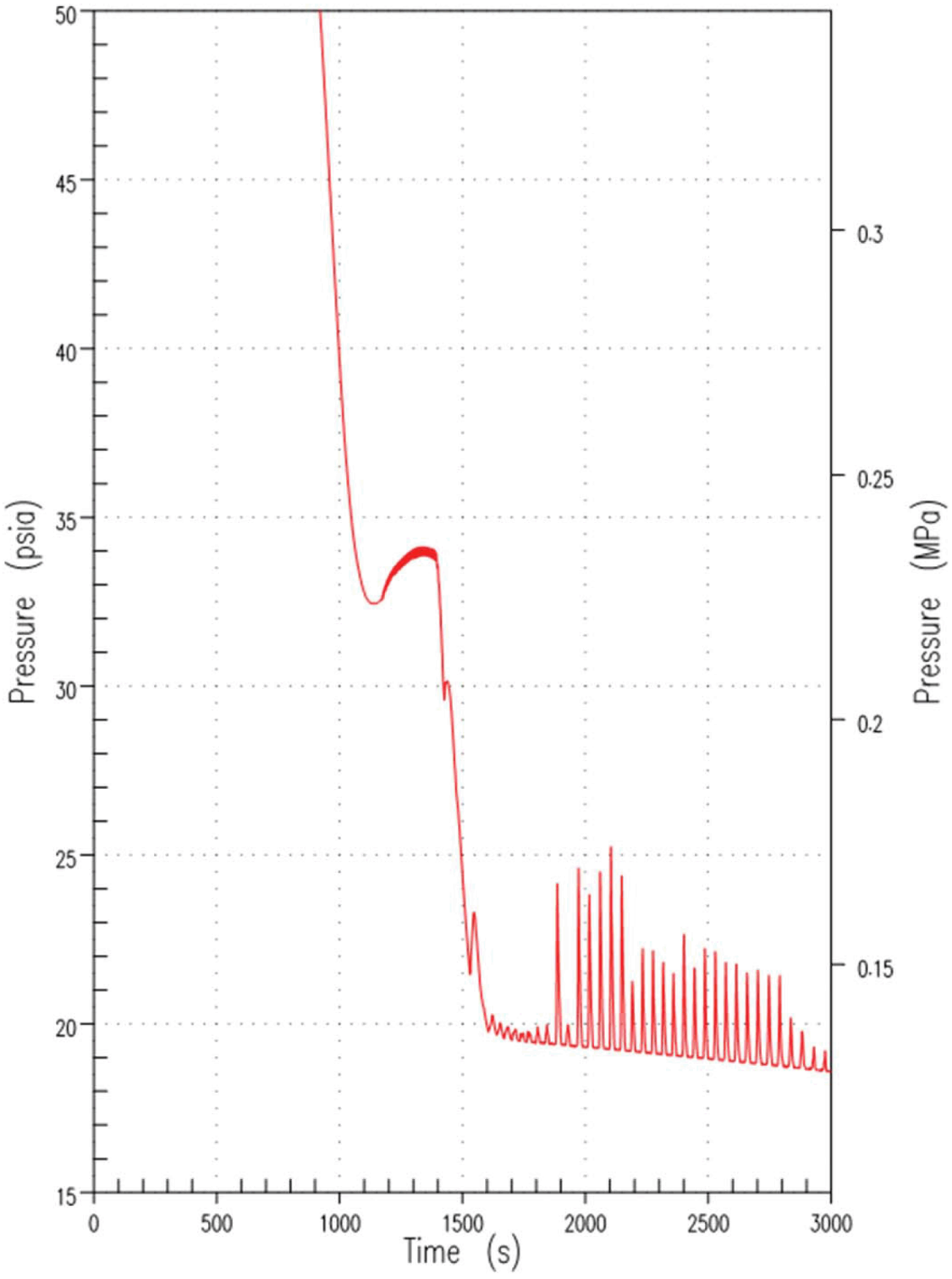


Figure 15.6.5.4B-56(b)
10-Inch Cold Leg Break – RCS Pressure (Zoomed)

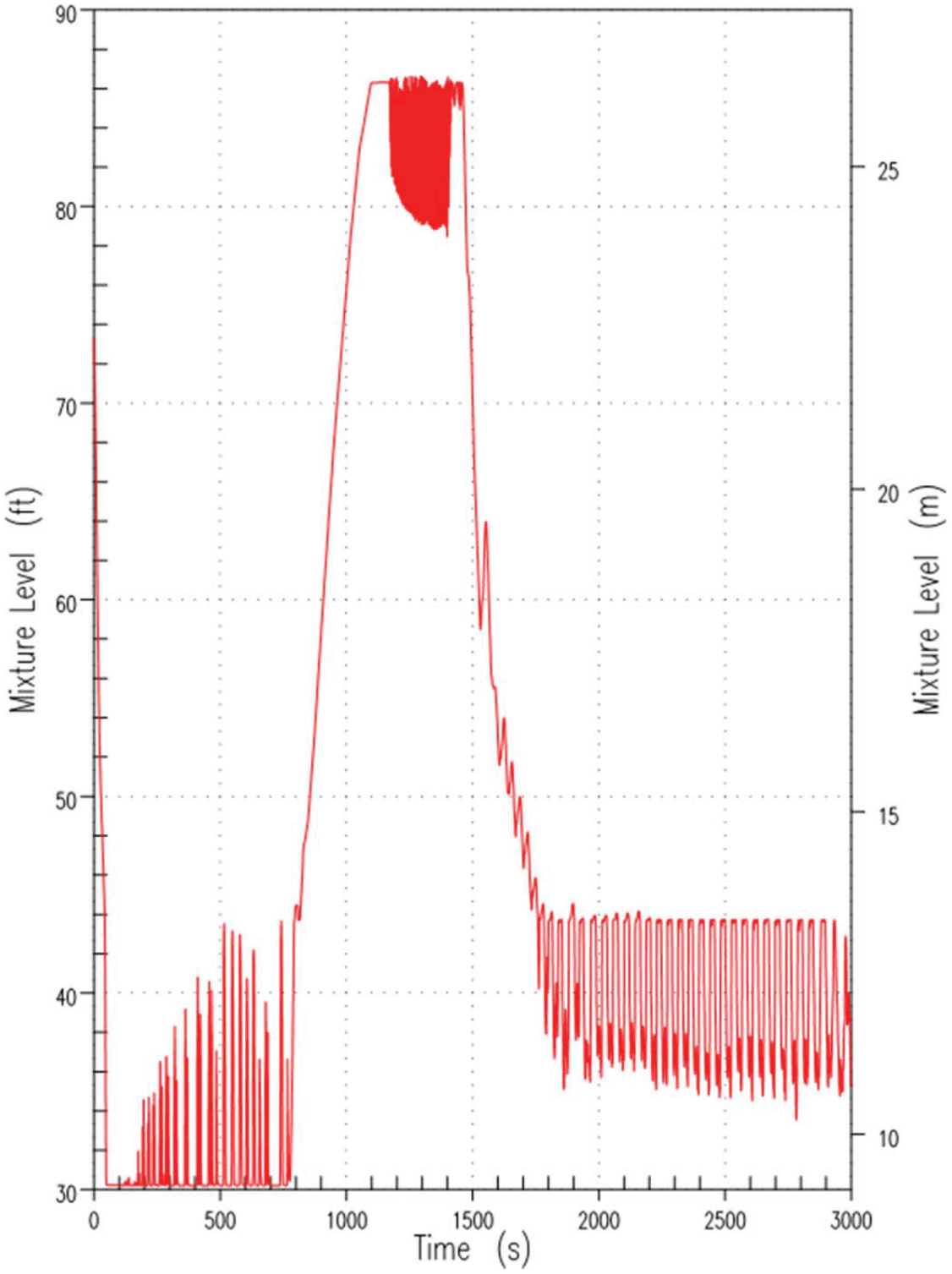


Figure 15.6.5.4B-57
10-inch Cold Leg Break – Pressurizer Mixture Level

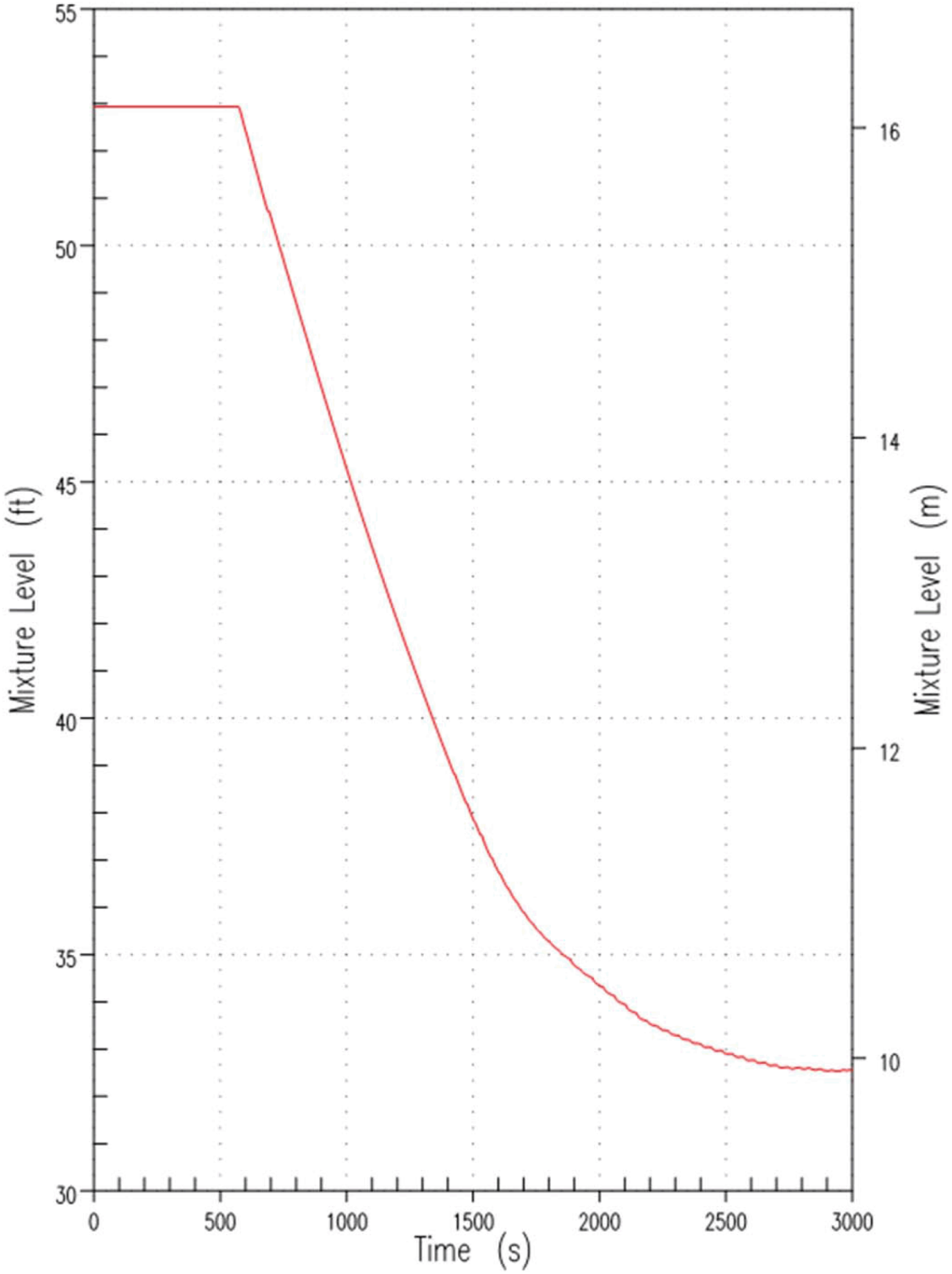


Figure 15.6.5.4B-58
10-inch Cold Leg Break – CMT-1 Mixture Level

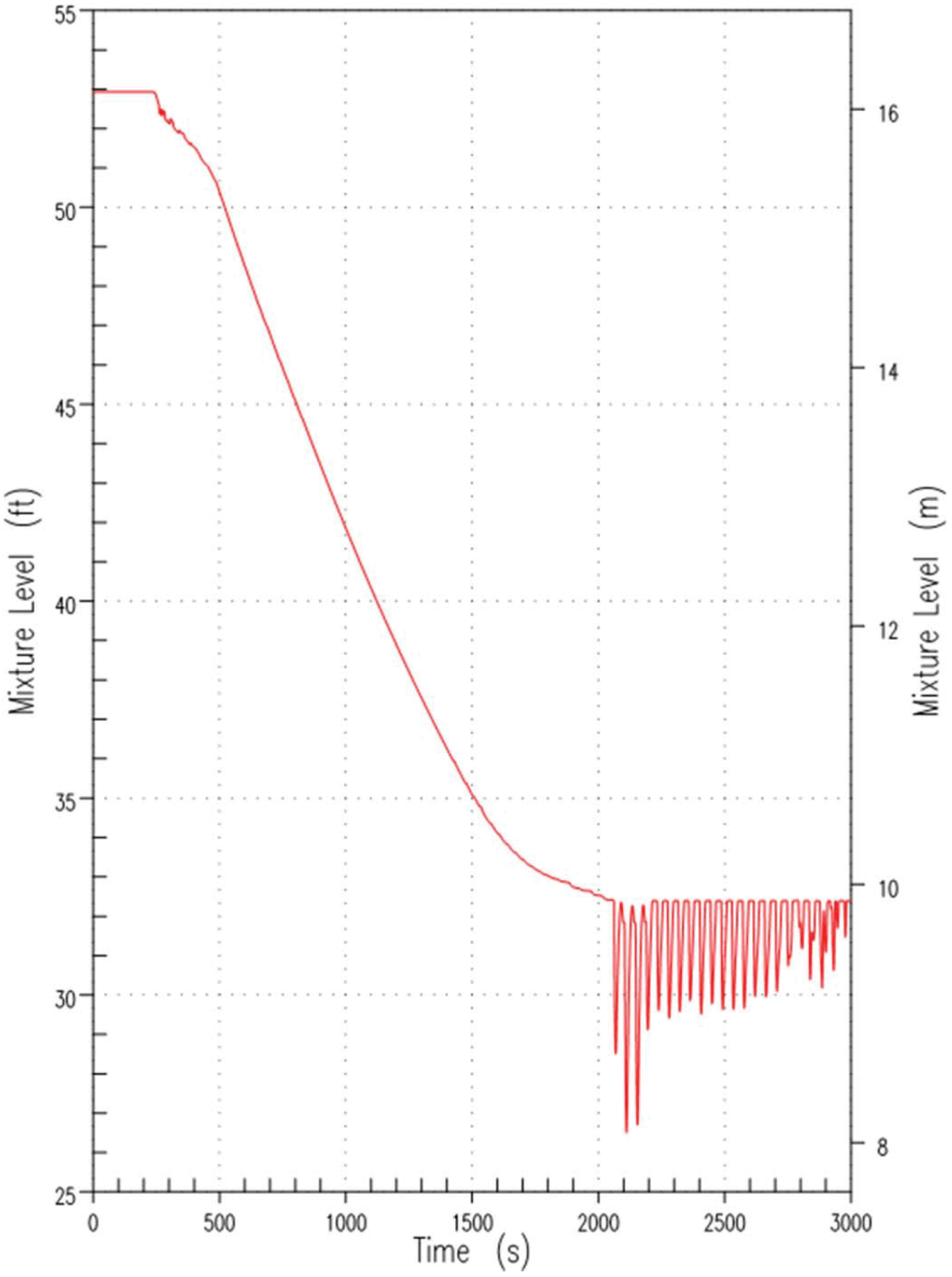


Figure 15.6.5.4B-59
10-inch Cold Leg Break – CMT-2 Mixture Level

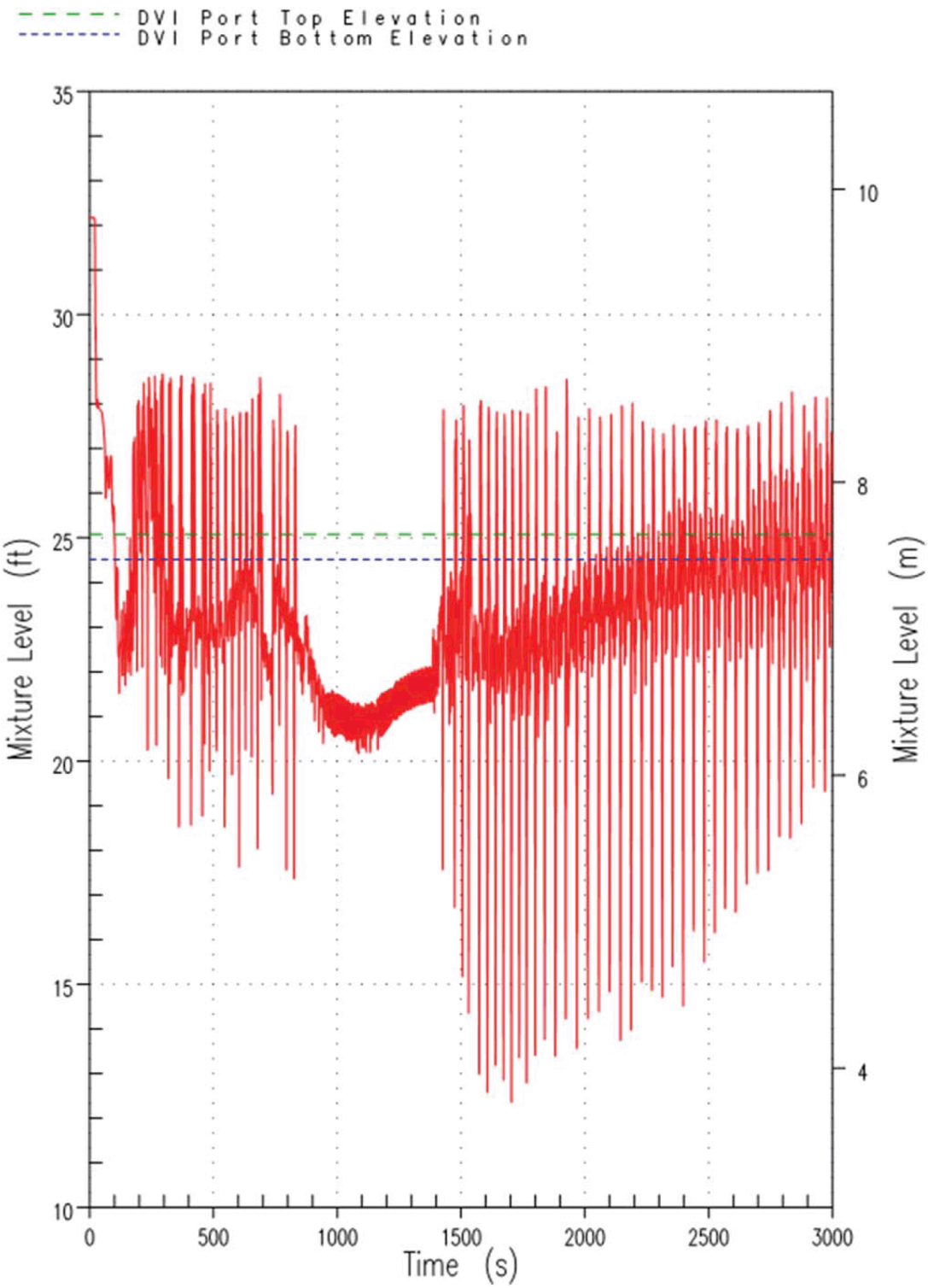


Figure 15.6.5.4B-60
10-inch Cold Leg Break – Downcomer Mixture Level

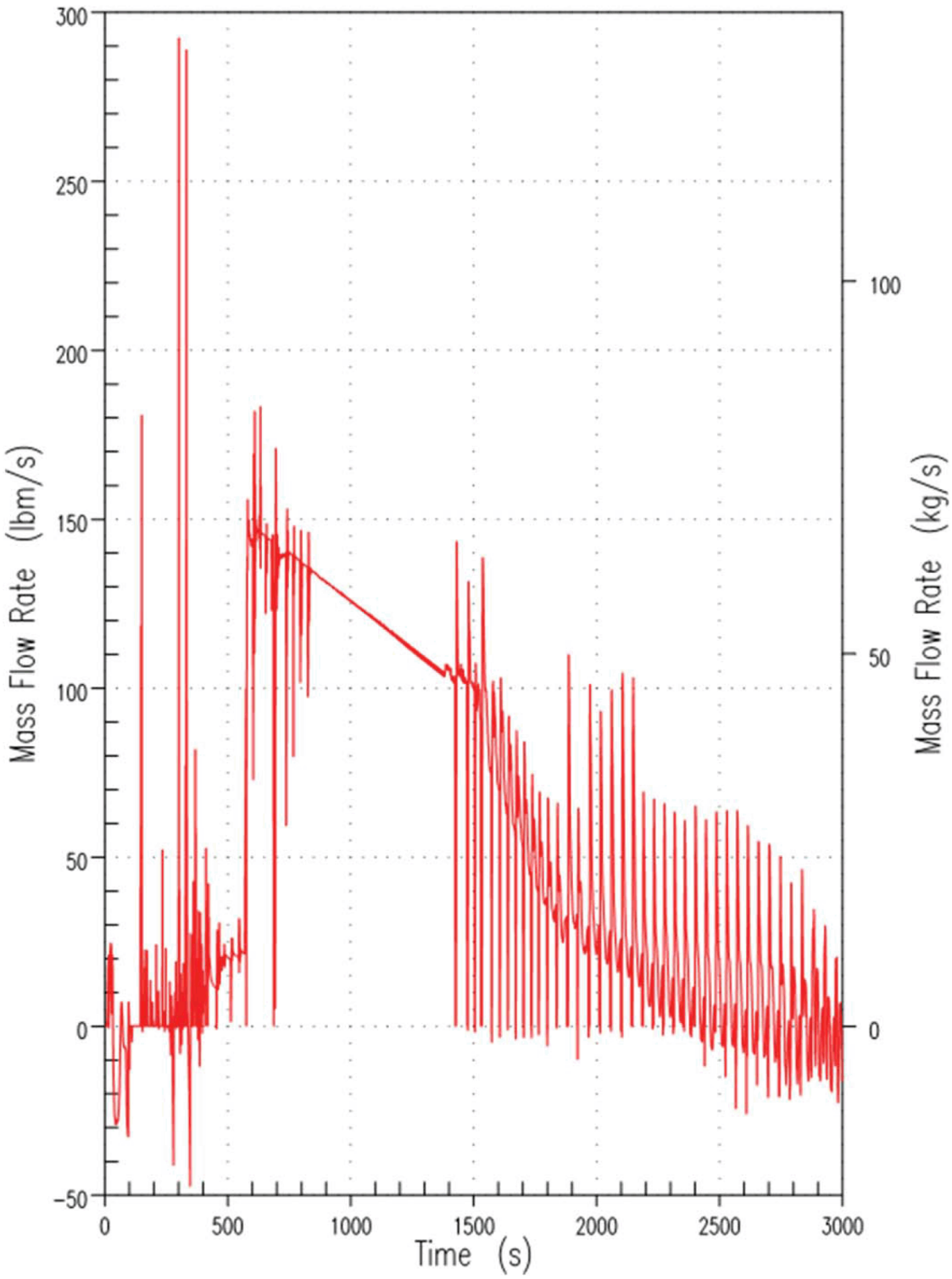


Figure 15.6.5.4B-61
10-inch Cold Leg Break – CMT-1 Injection Rate

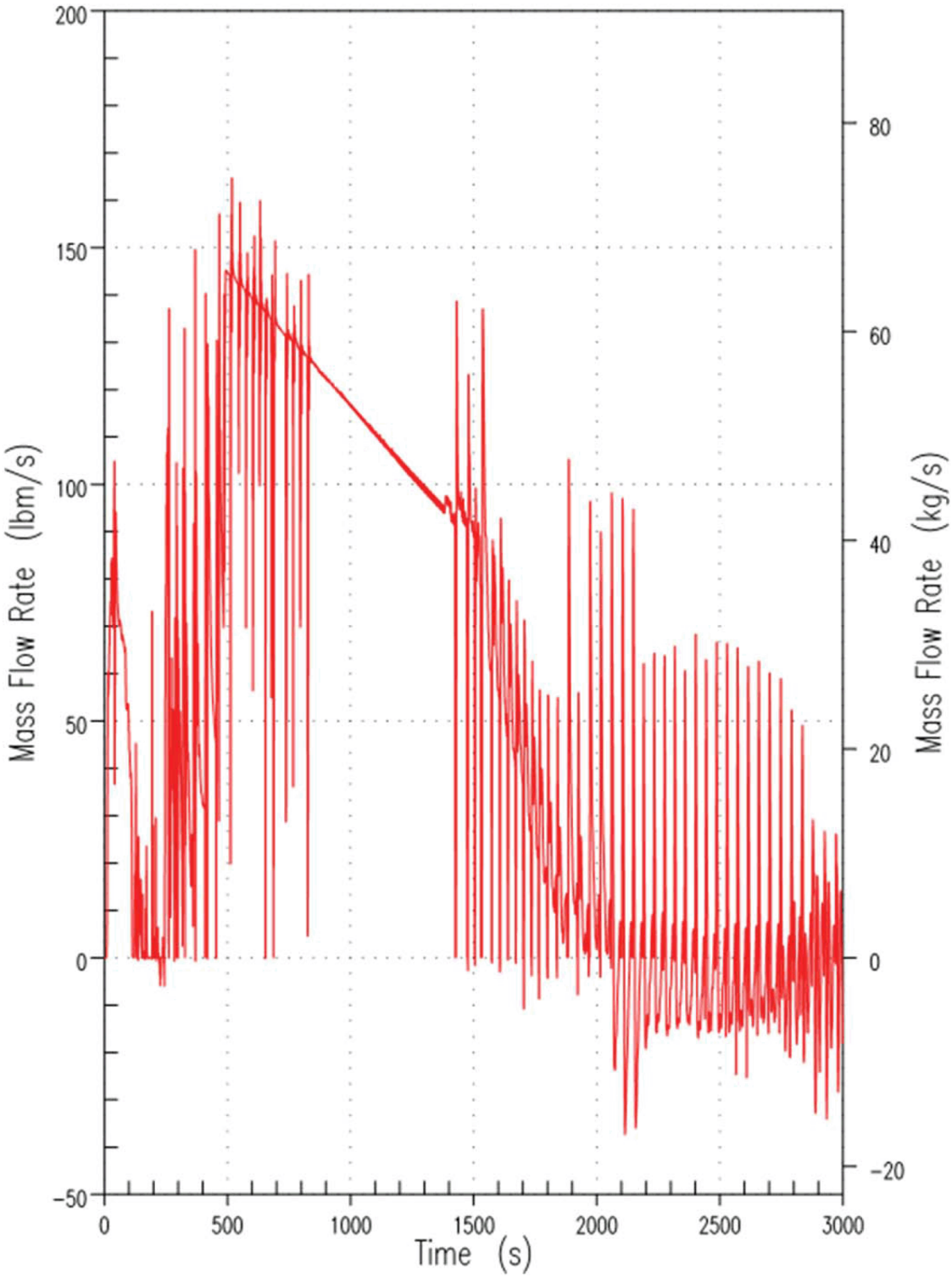


Figure 15.6.5.4B-62
10-inch Cold Leg Break – CMT-2 Injection Rate

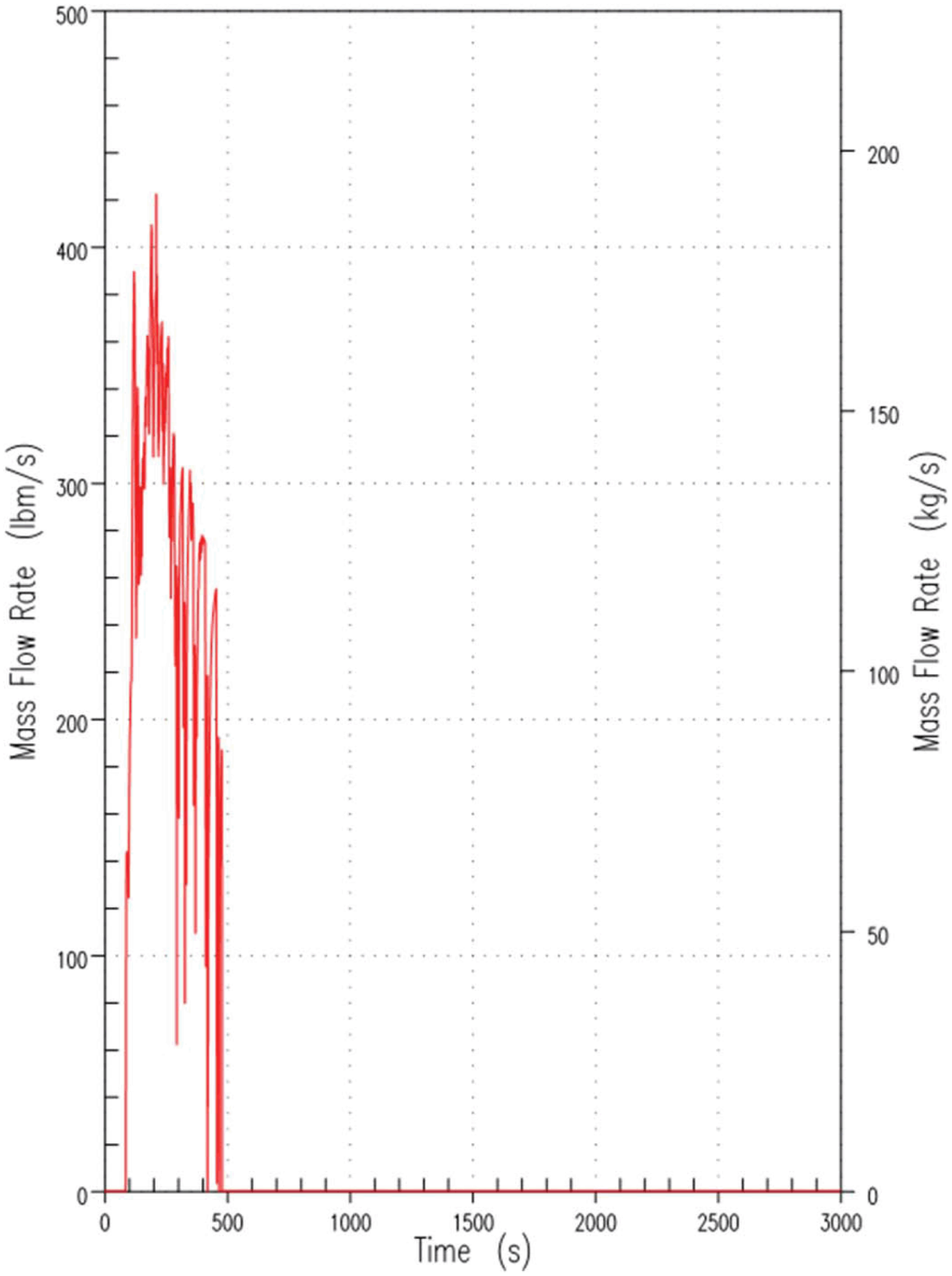


Figure 15.6.5.4B-63
10-inch Cold Leg Break – Accumulator-1 Injection Rate

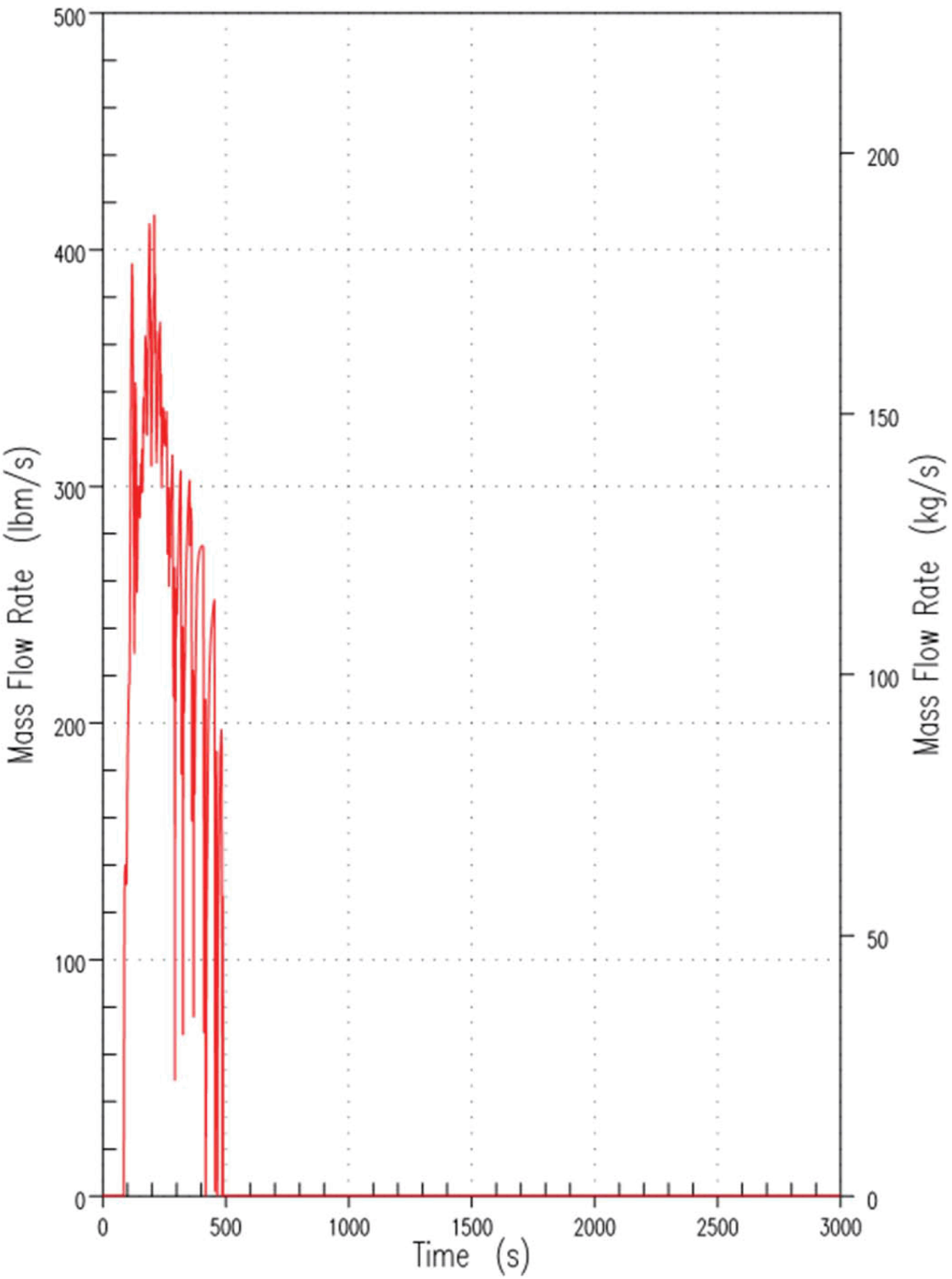


Figure 15.6.5.4B-64
10-inch Cold Leg Break – Accumulator-2 Injection Rate

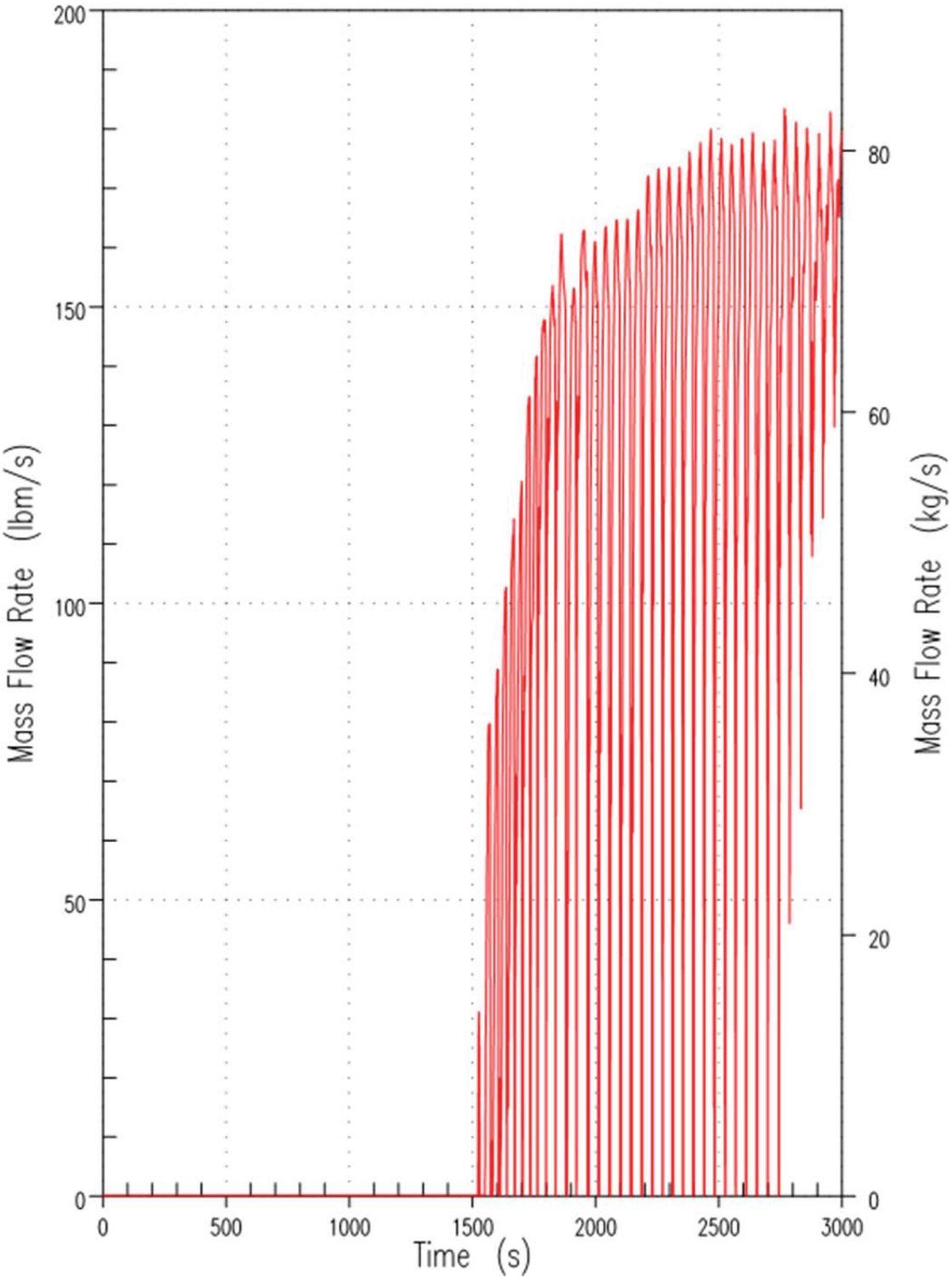


Figure 15.6.5.4B-65
10-inch Cold Leg Break – IRWST-1 Injection Rate

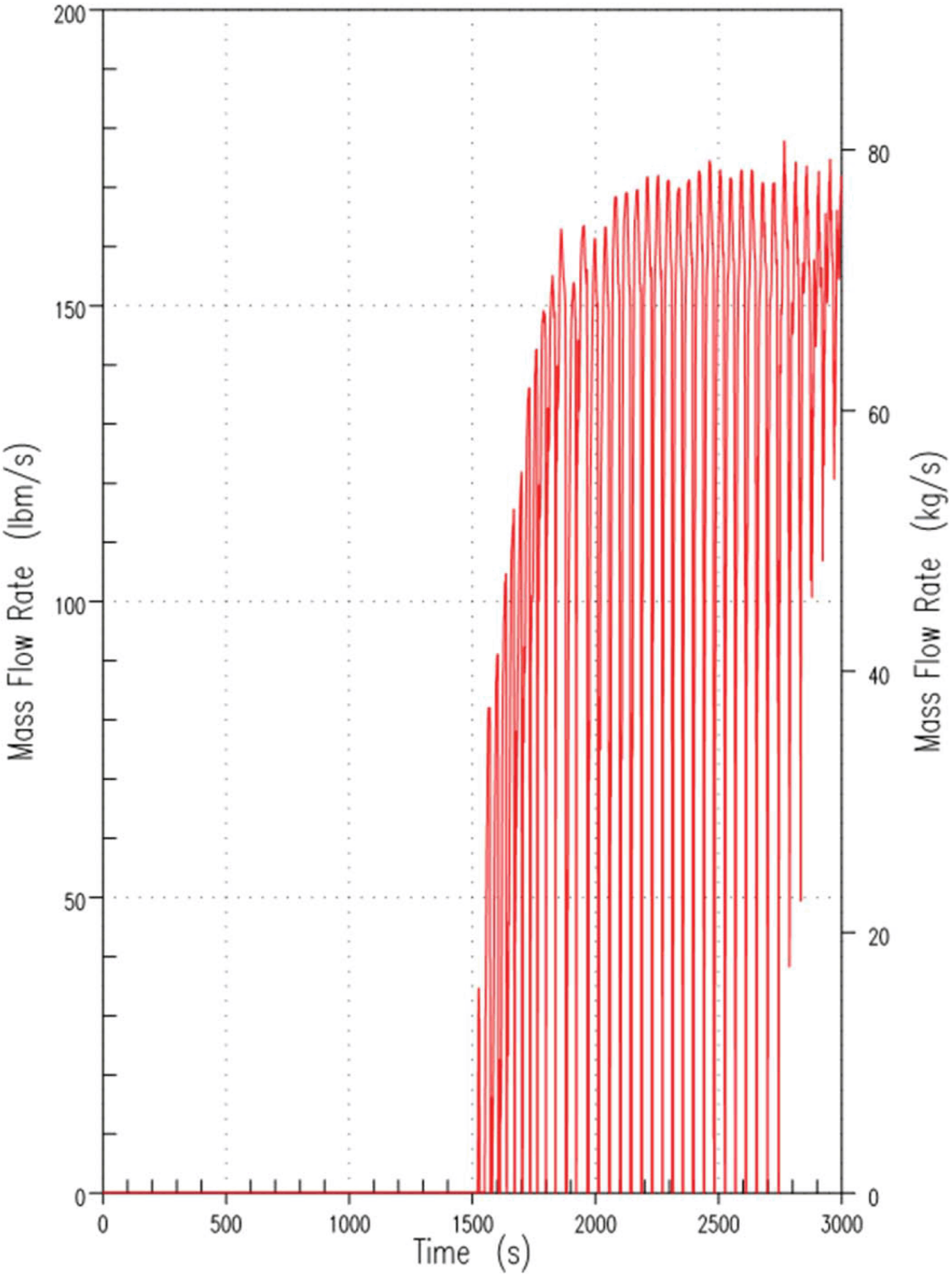


Figure 15.6.5.4B-66
10-inch Cold Leg Break – IRWST-2 Injection Rate

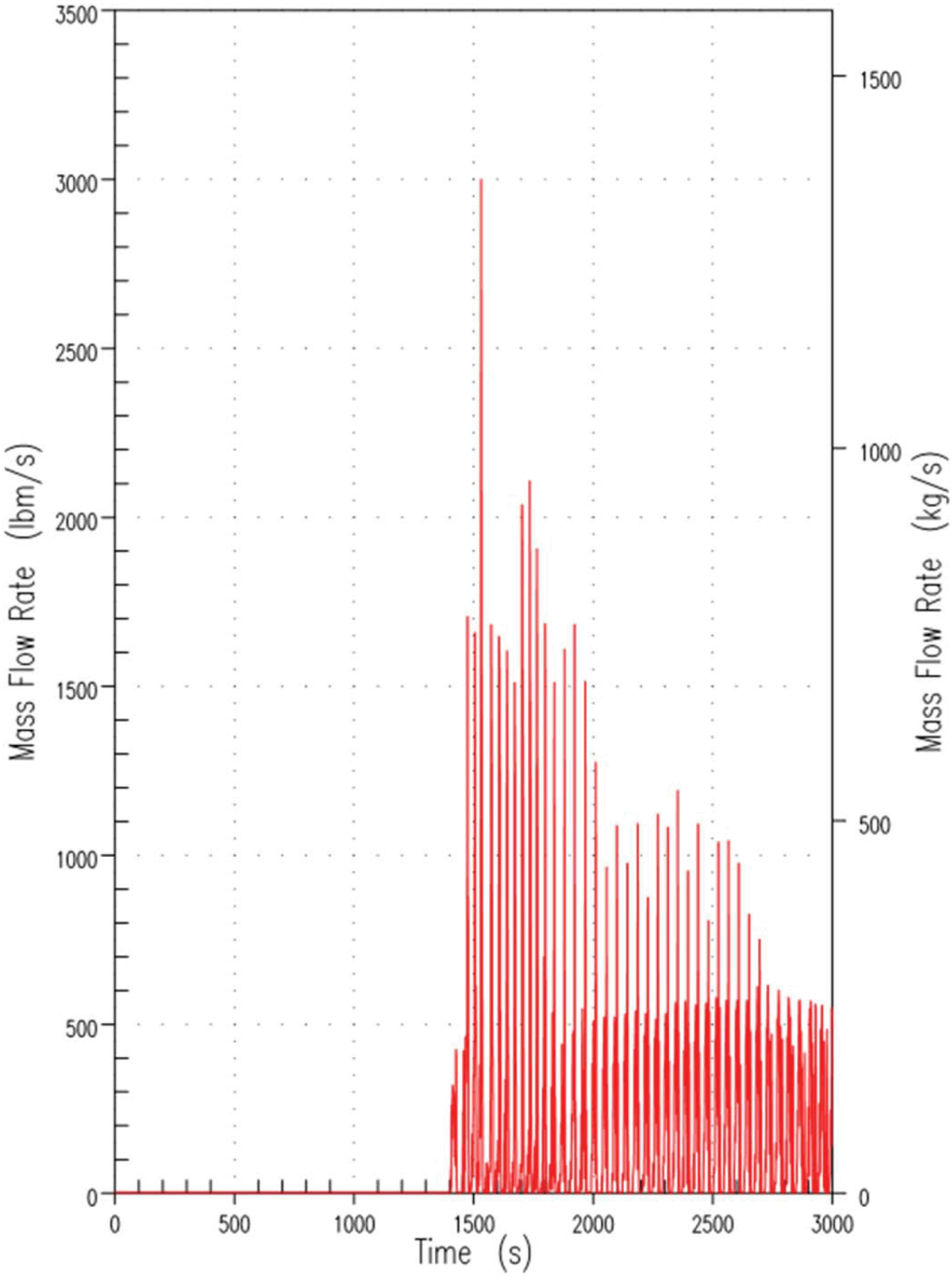


Figure 15.6.5.4B-67(a)
10-inch Cold Leg Break – ADS-4 Liquid Discharge

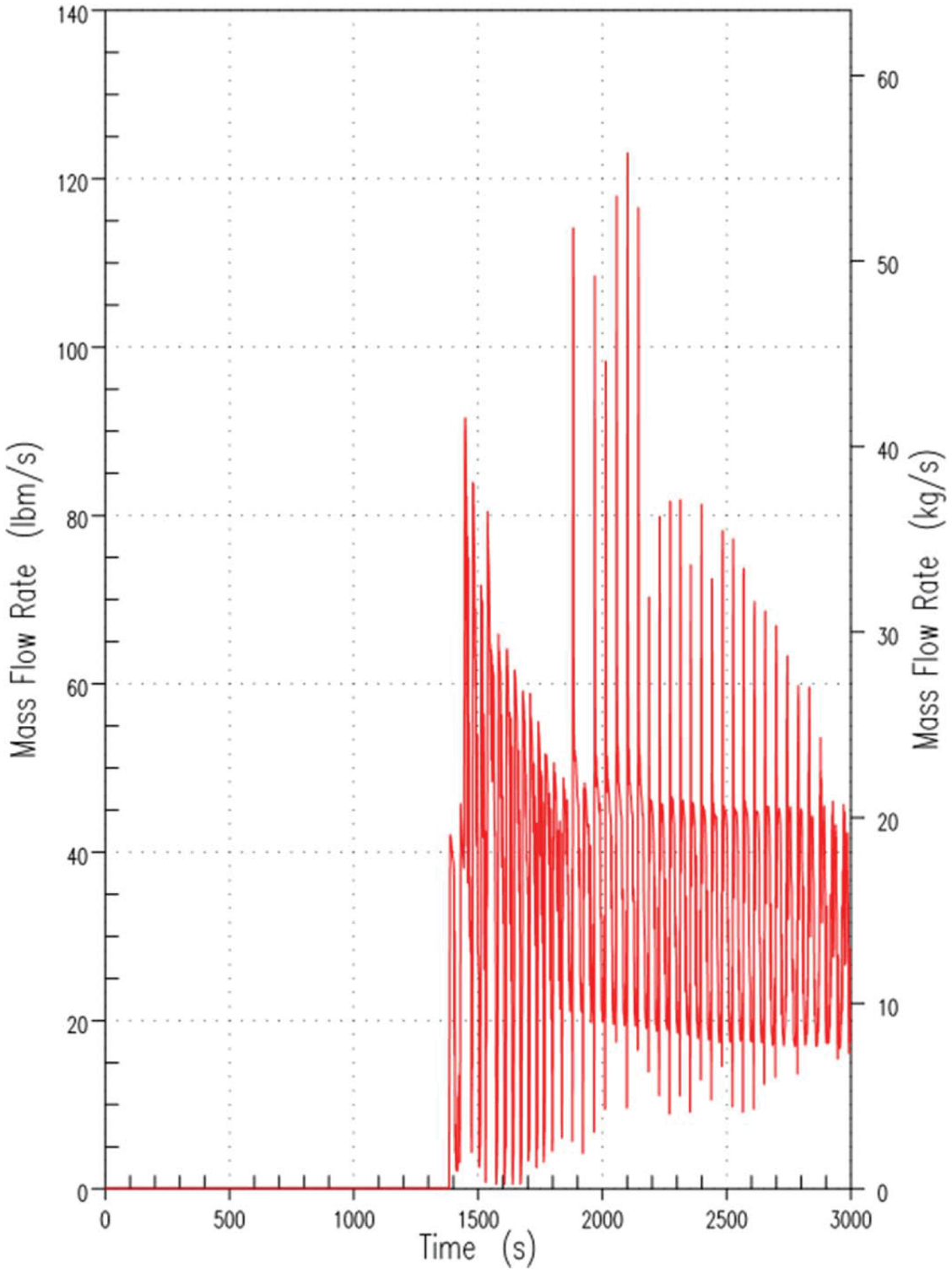


Figure 15.6.5.4B-67(b)
10-Inch Cold Leg Break – ADS-4 Vapor Discharge

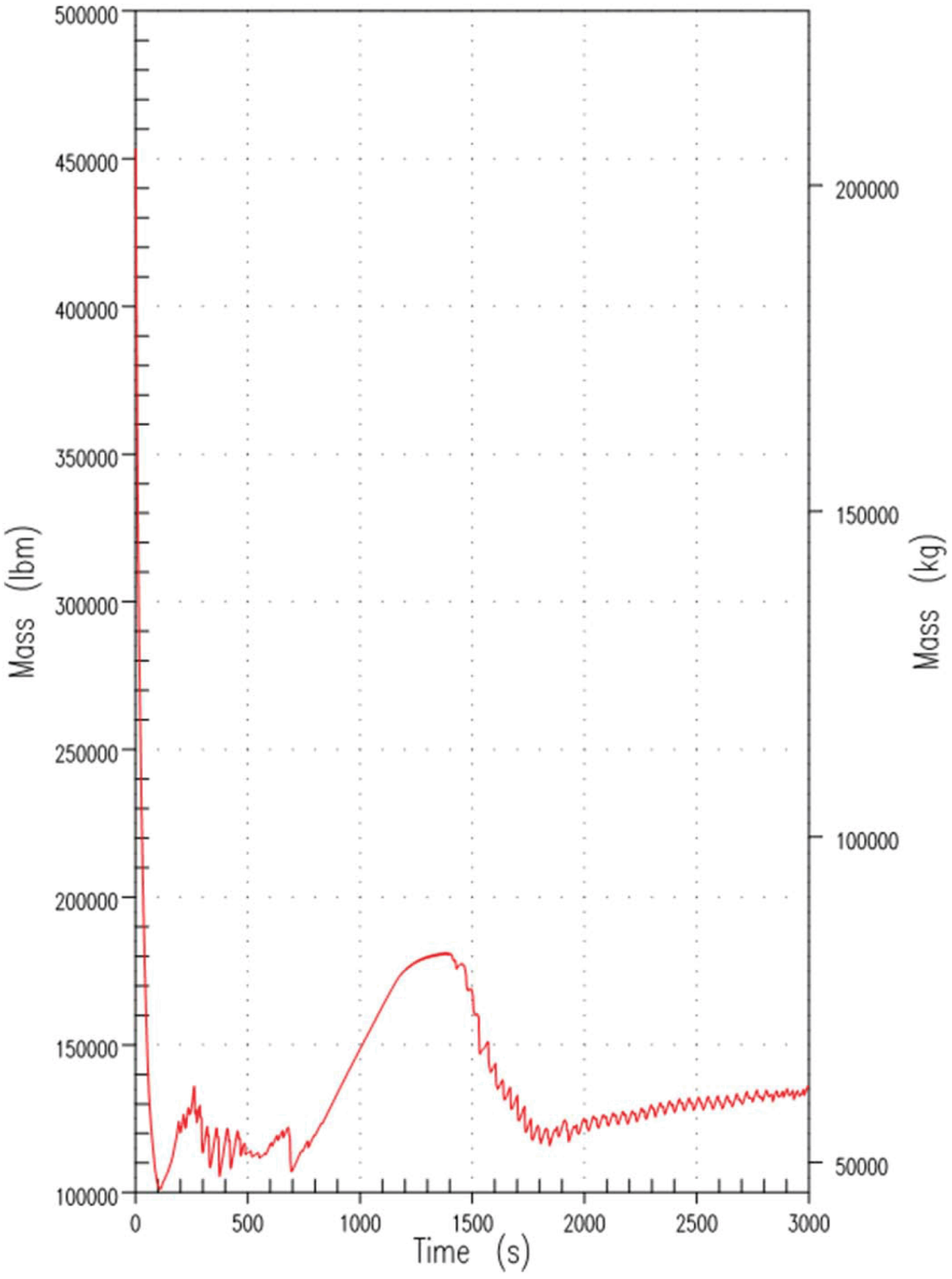


Figure 15.6.5.4B-68(a)
10-inch Cold Leg Break – RCS System Inventory

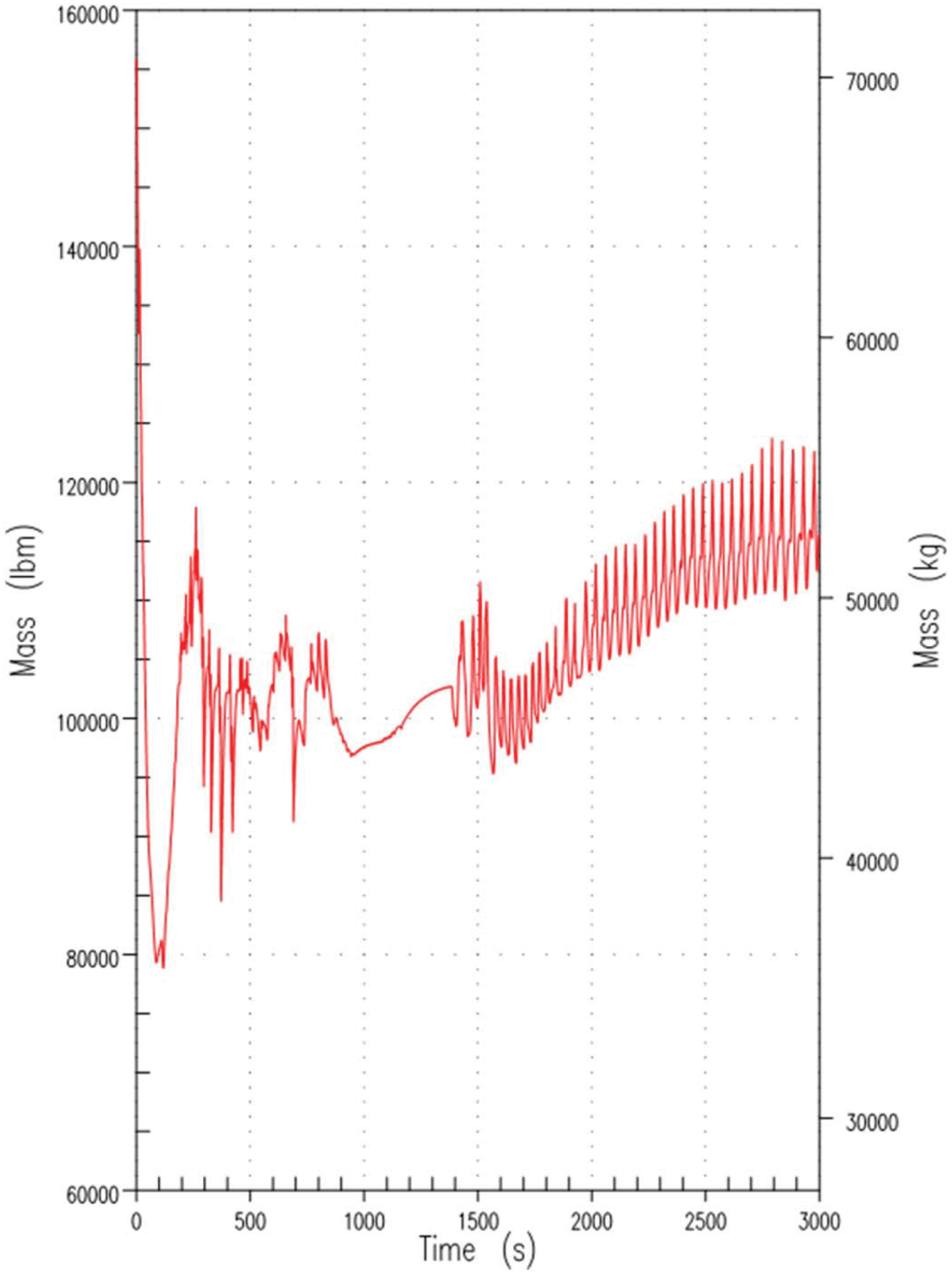


Figure 15.6.5.4B-68(b)
10-Inch Cold Leg Break – Reactor Vessel Mixture Inventory

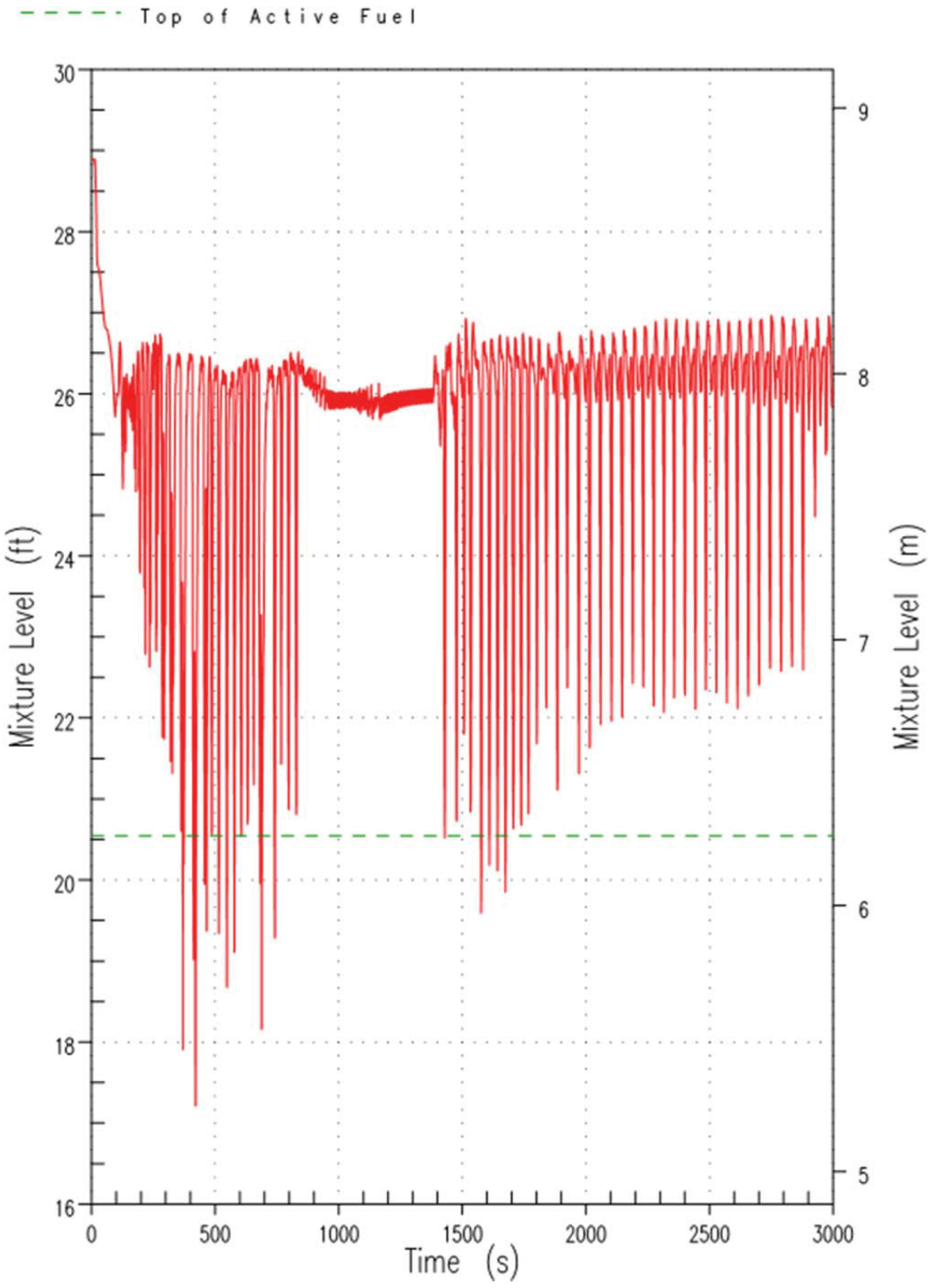


Figure 15.6.5.4B-69
10-inch Cold Leg Break – Core/Upper Plenum Mixture Level

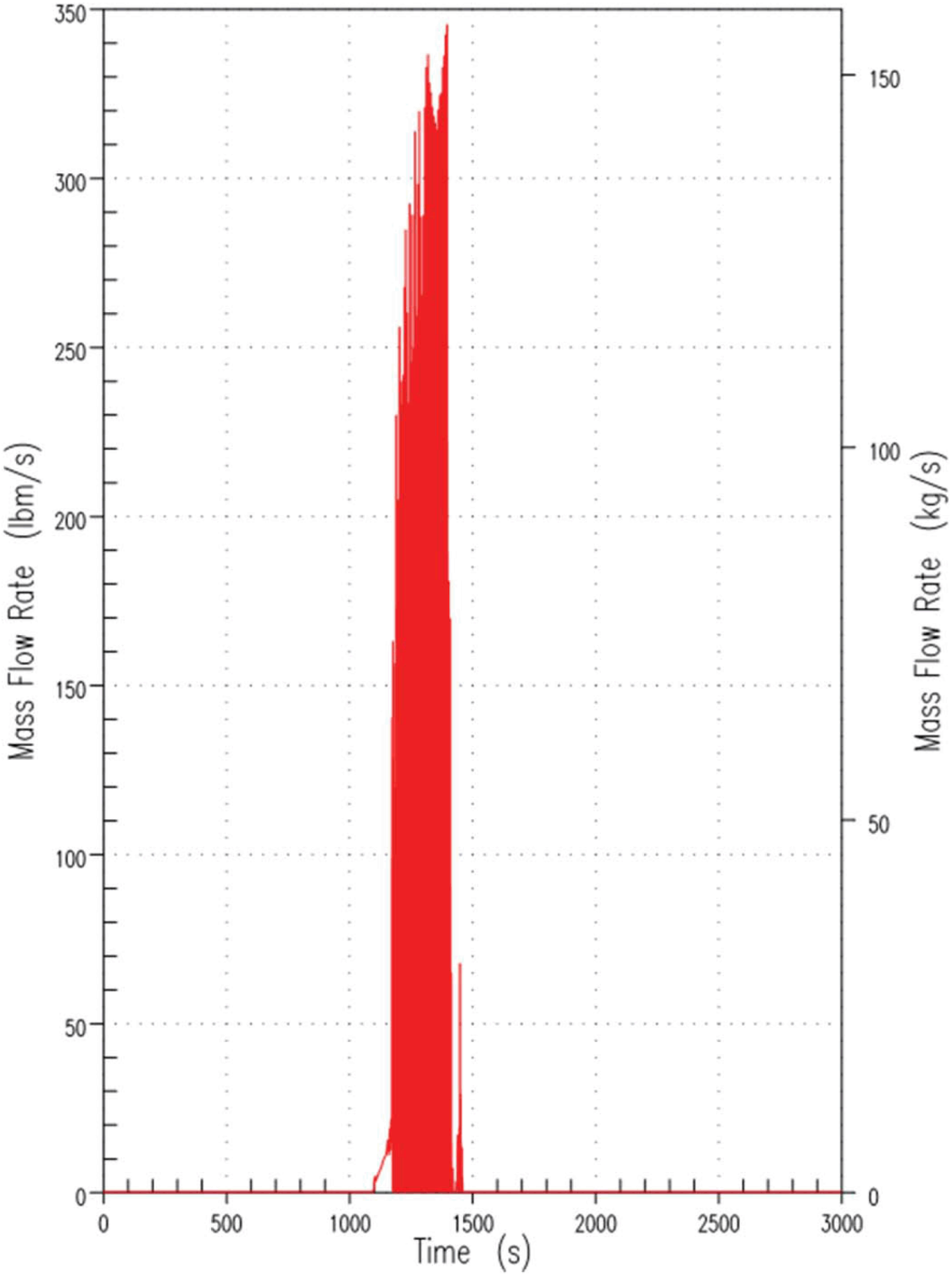


Figure 15.6.5.4B-70(a)
10-inch Cold Leg Break – ADS 1-3 Liquid Discharge

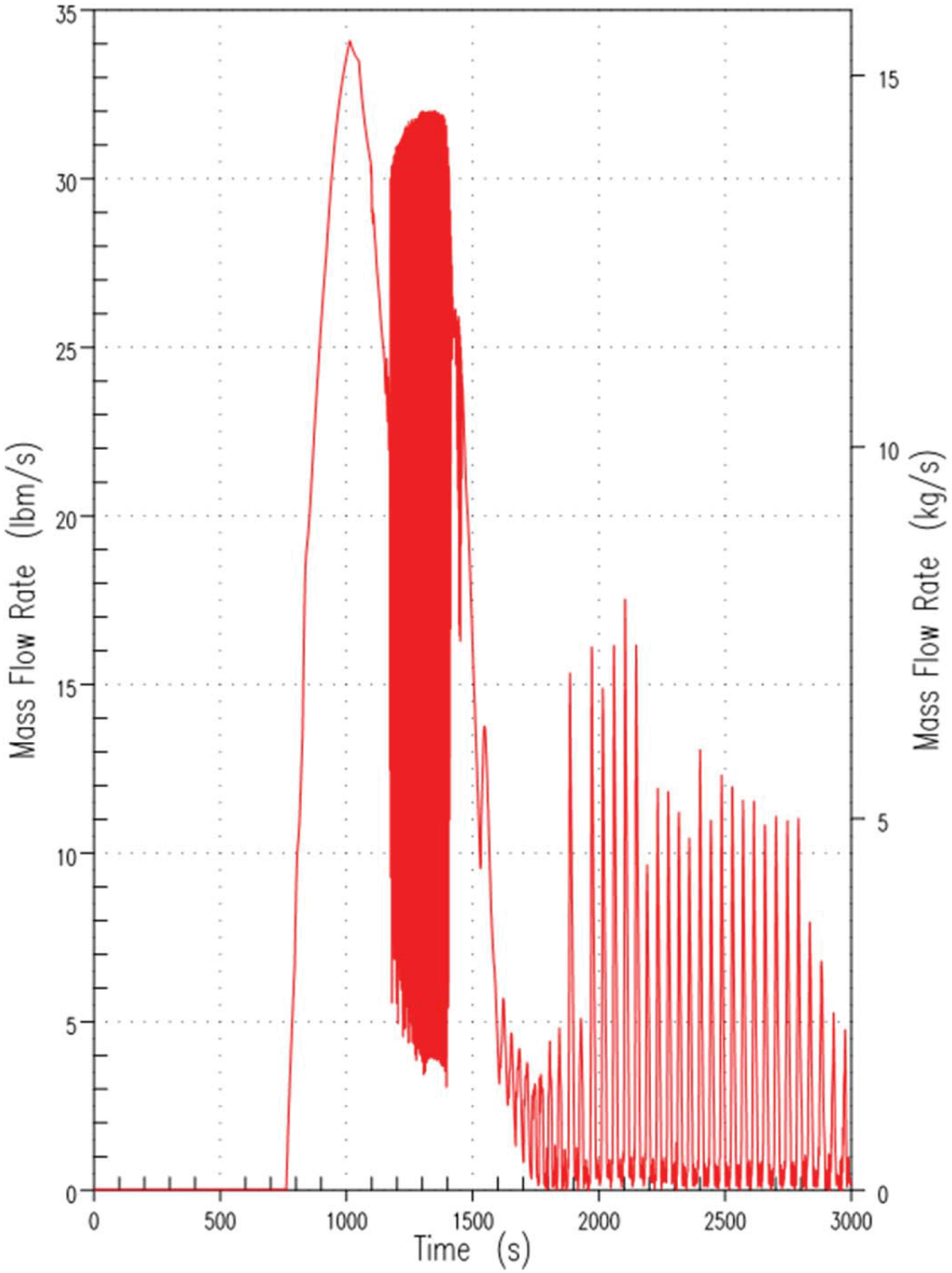


Figure 15.6.5.4B-70(b)
10-Inch Cold Leg Break – ADS 1-3 Vapor Discharge

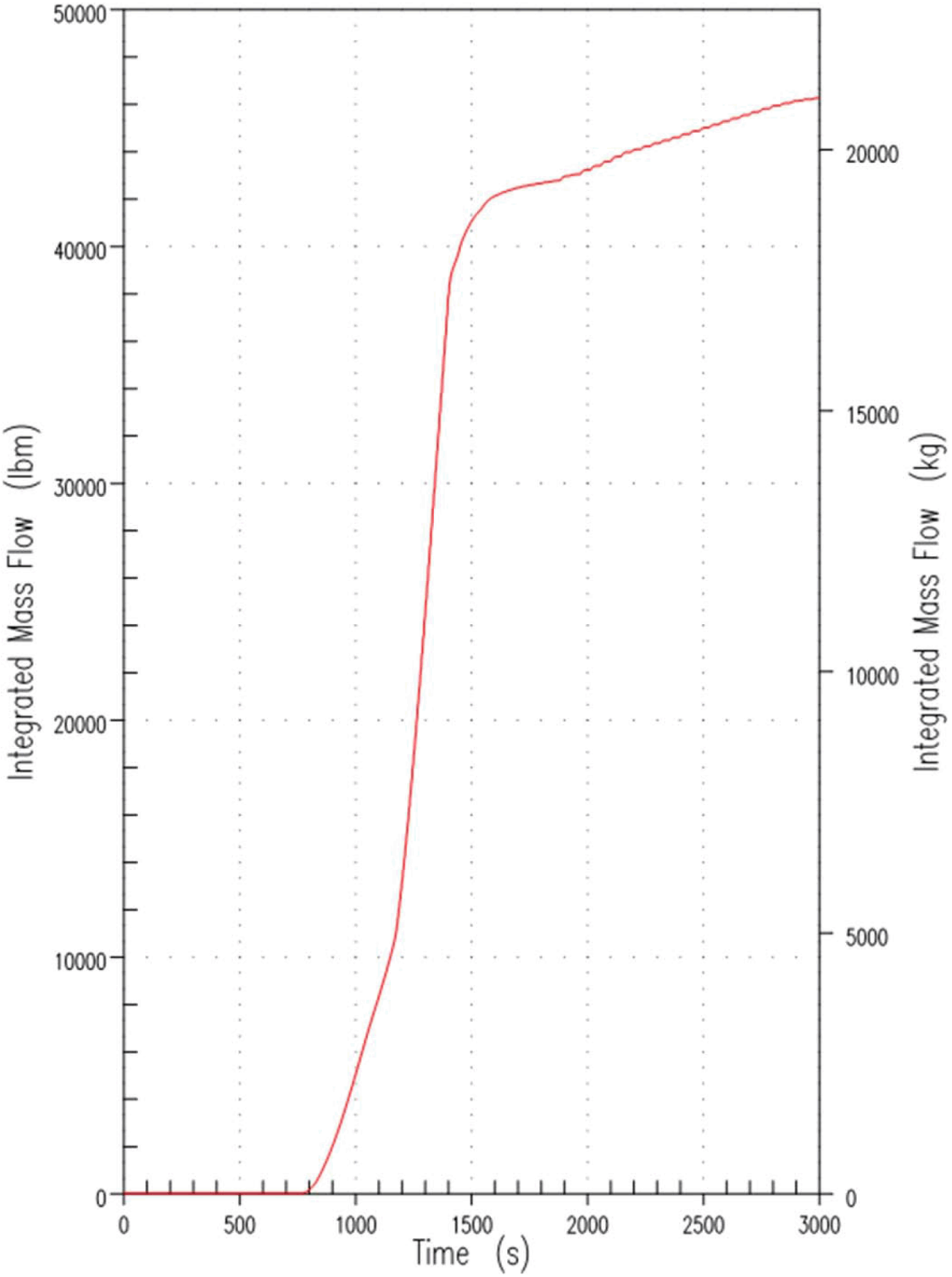


Figure 15.6.5.4B-70(c)
10-Inch Cold Leg Break – ADS 1-3 Integrated Discharge

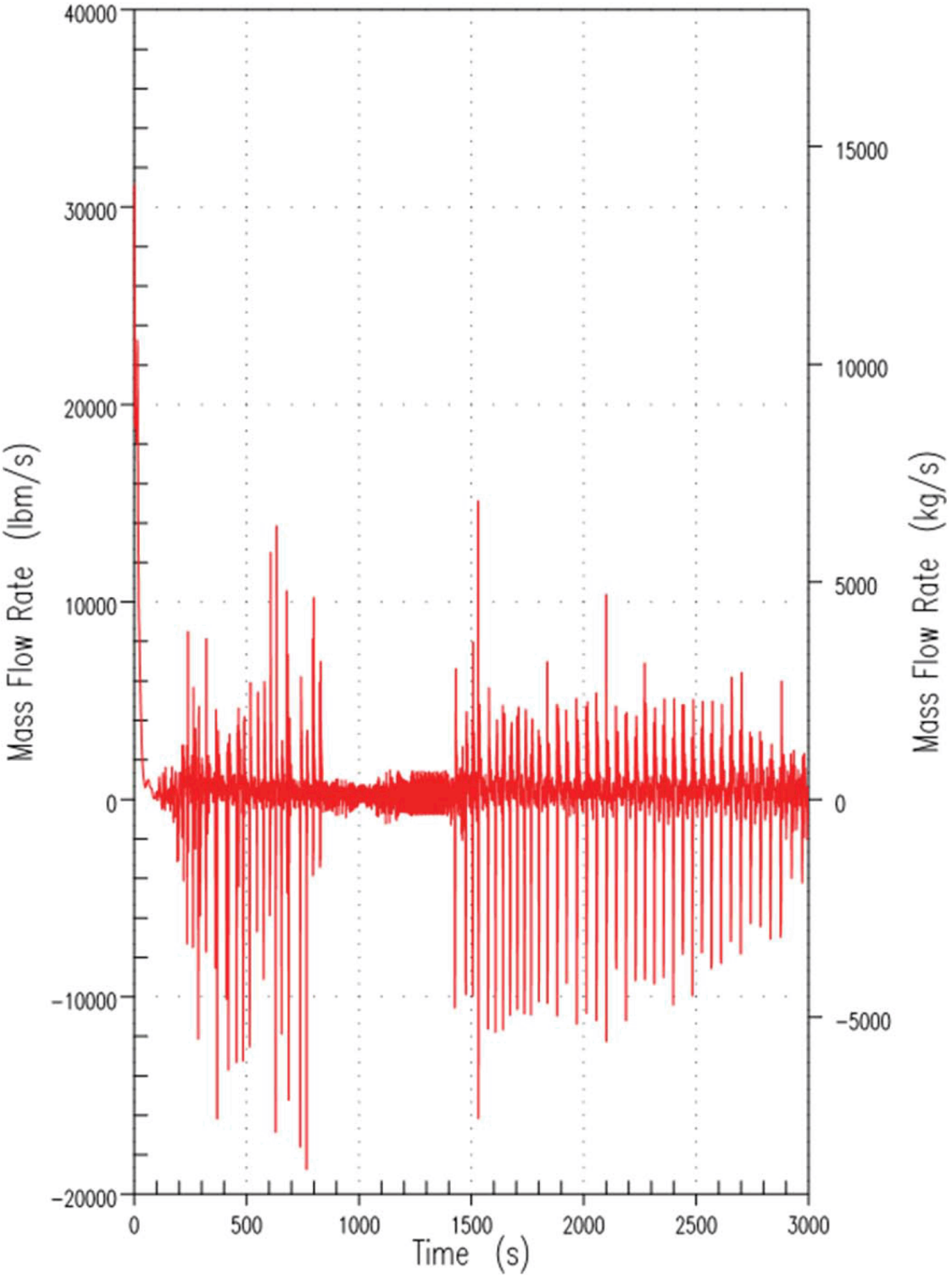


Figure 15.6.5.4B-71
10-inch Cold Leg Break – Core Exit Liquid Flow

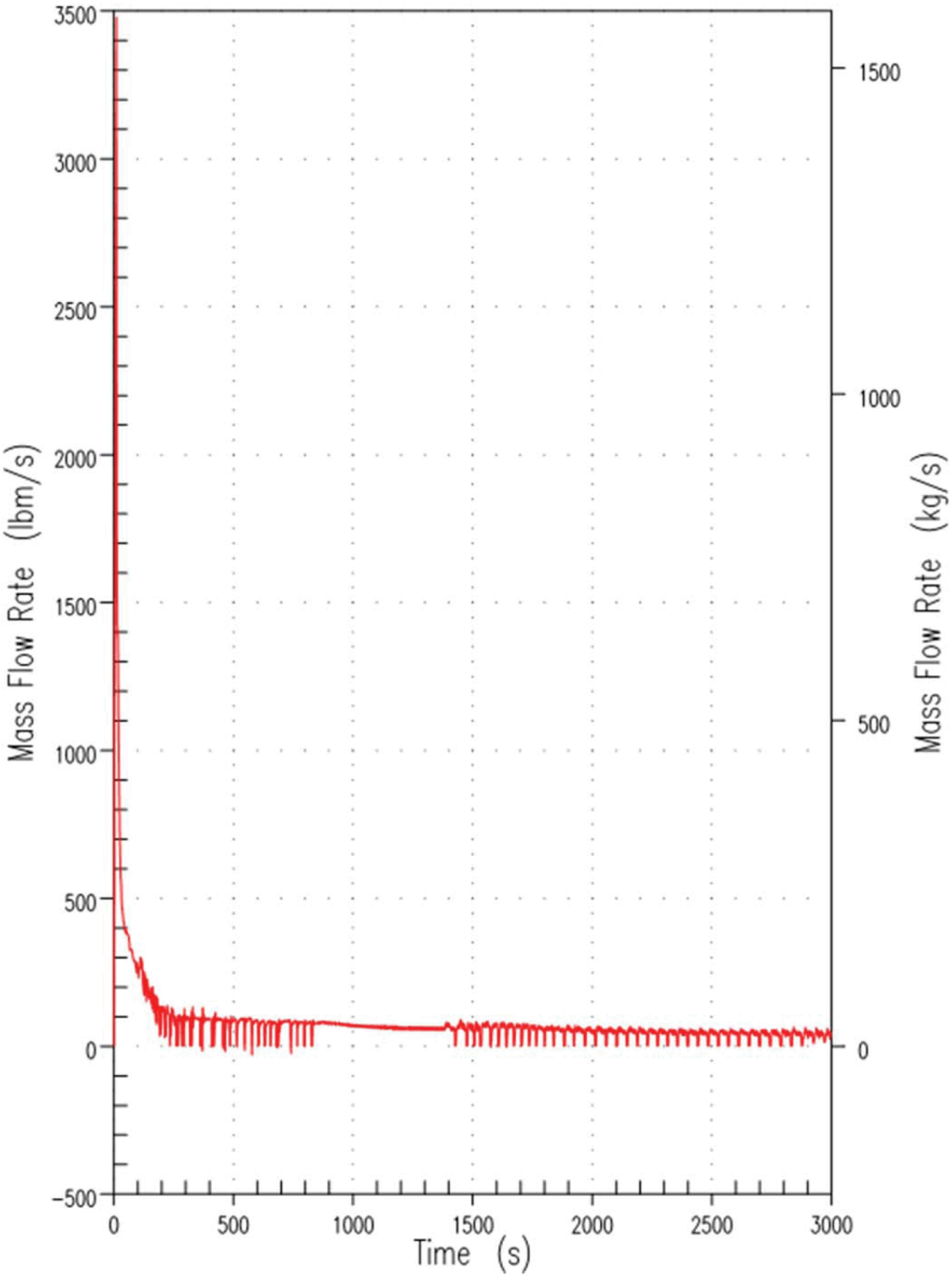


Figure 15.6.5.4B-72
10-inch Cold Leg Break – Core Exit Vapor Flow

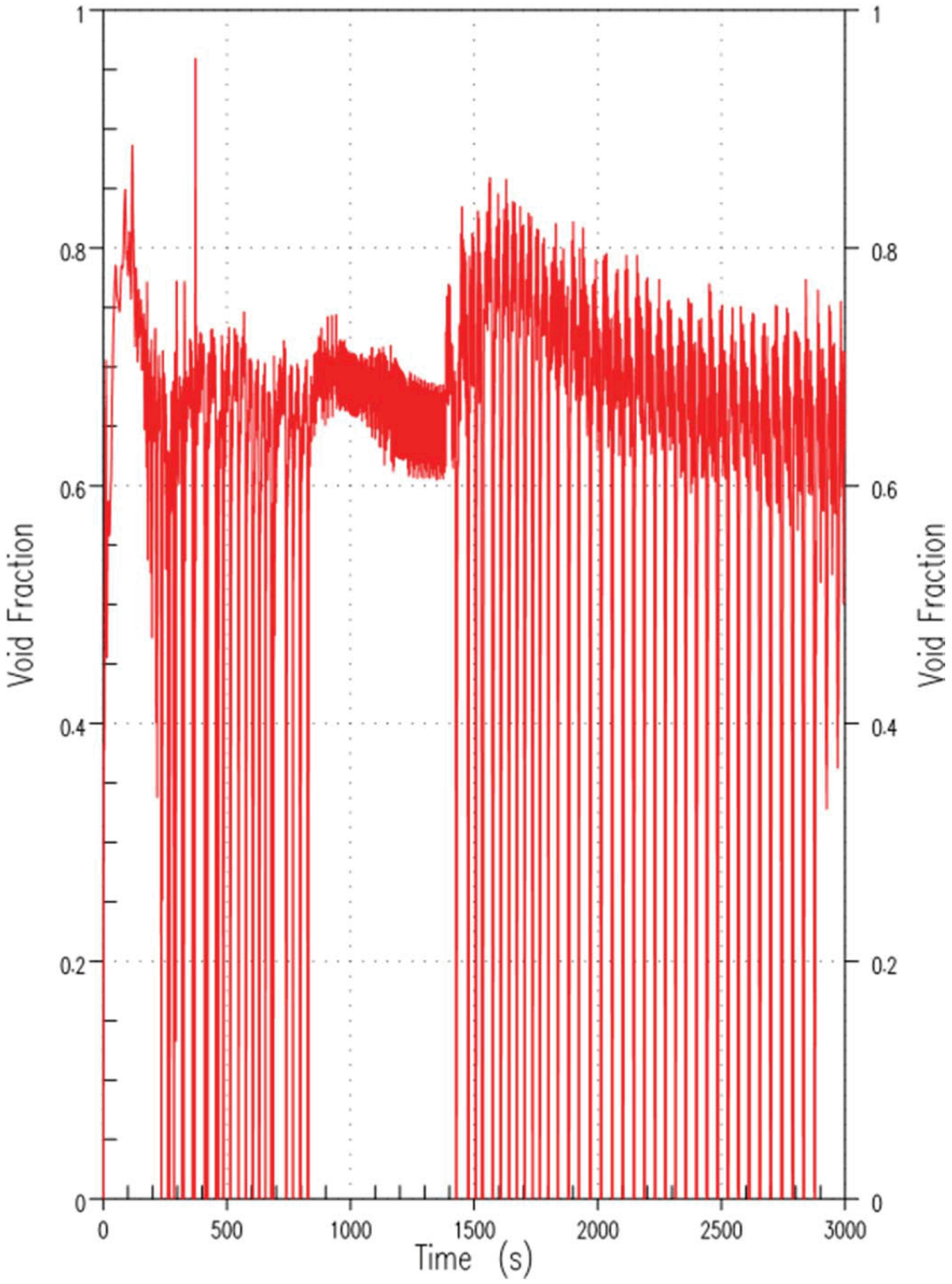


Figure 15.6.5.4B-73
10-inch Cold Leg Break – Core Exit Void Fraction

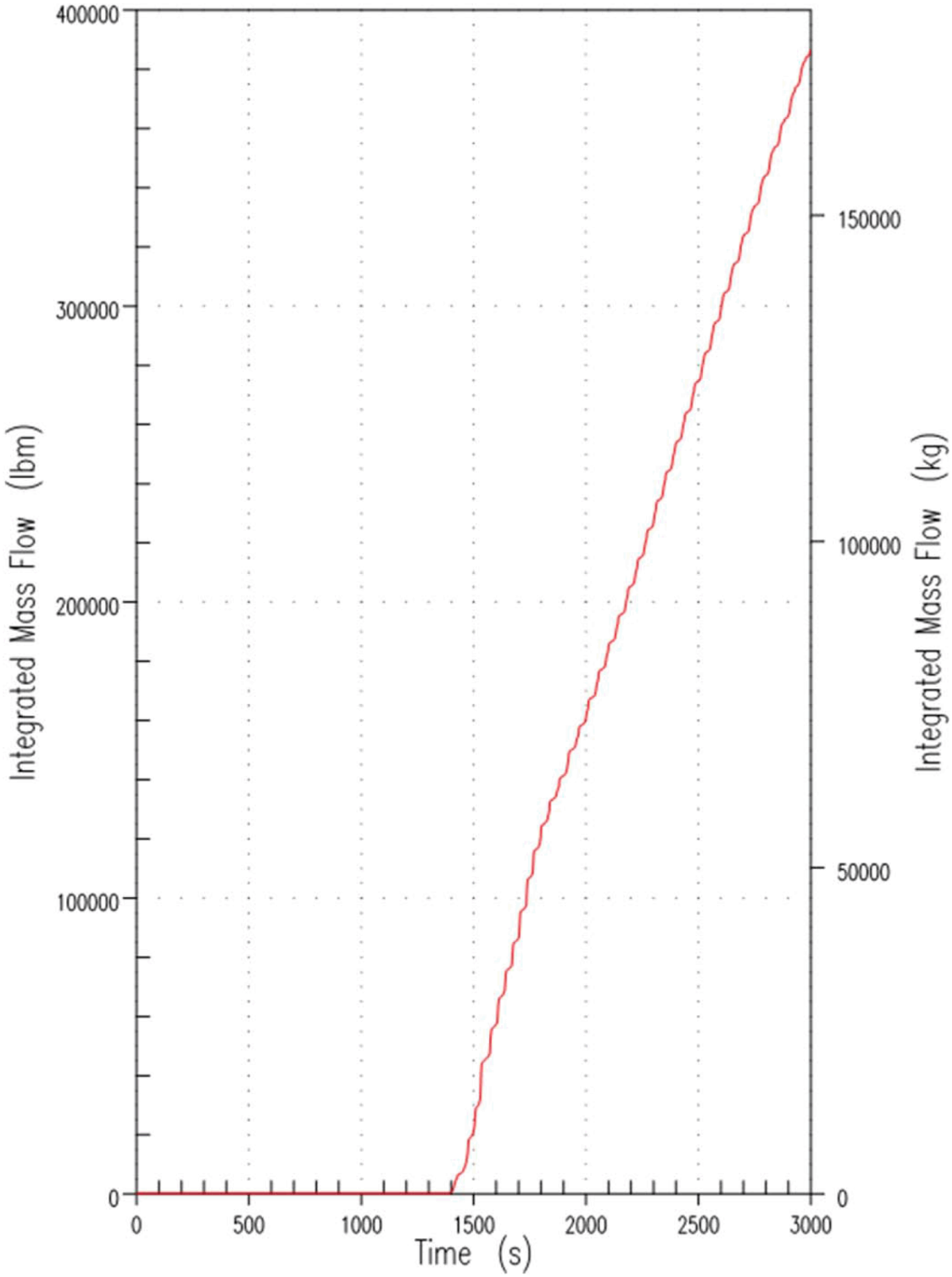


Figure 15.6.5.4B-74
10-inch Cold Leg Break – ADS-4 Integrated Discharge

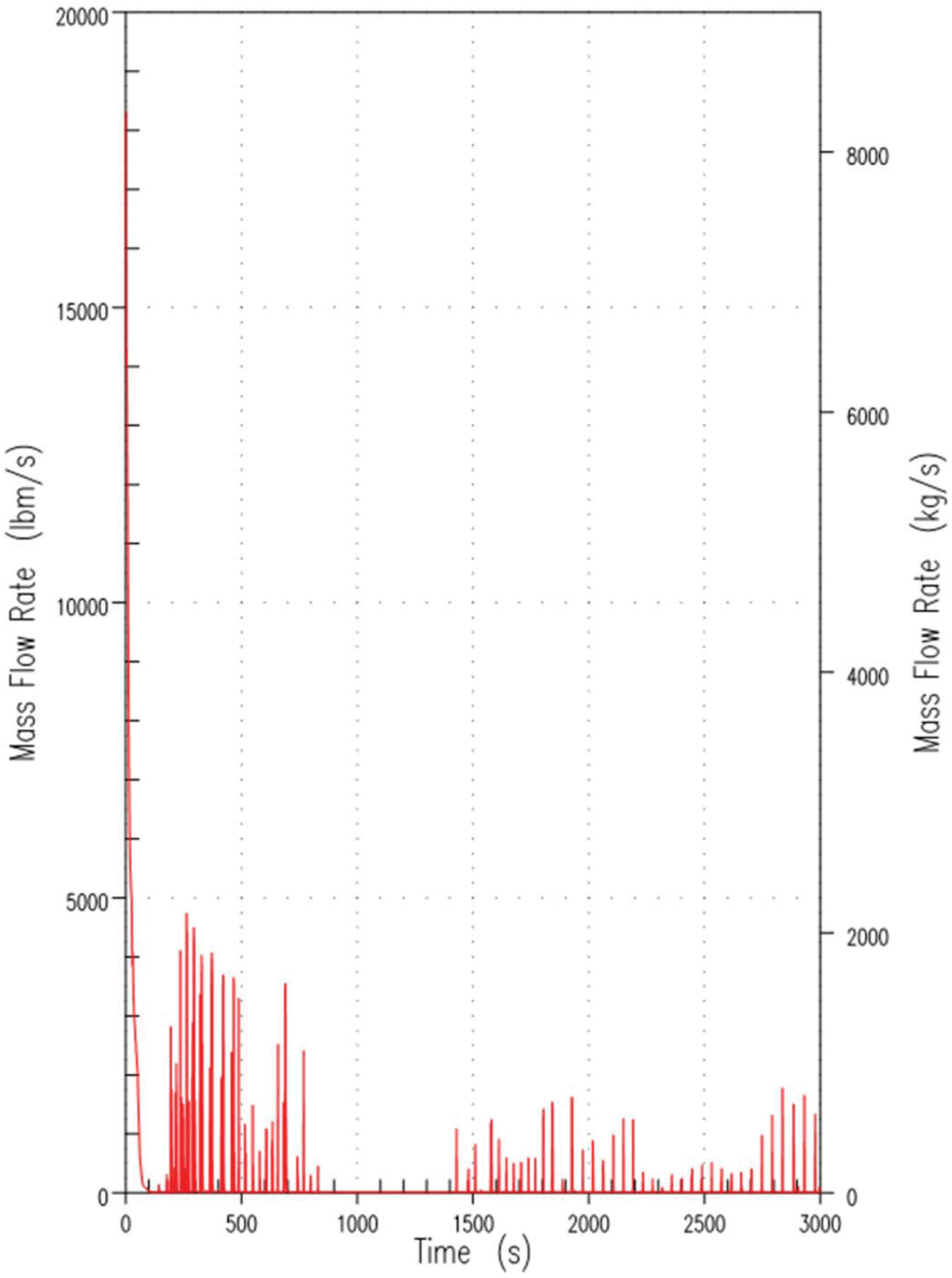


Figure 15.6.5.4B-75
10-inch Cold Leg Break – Liquid Break Discharge

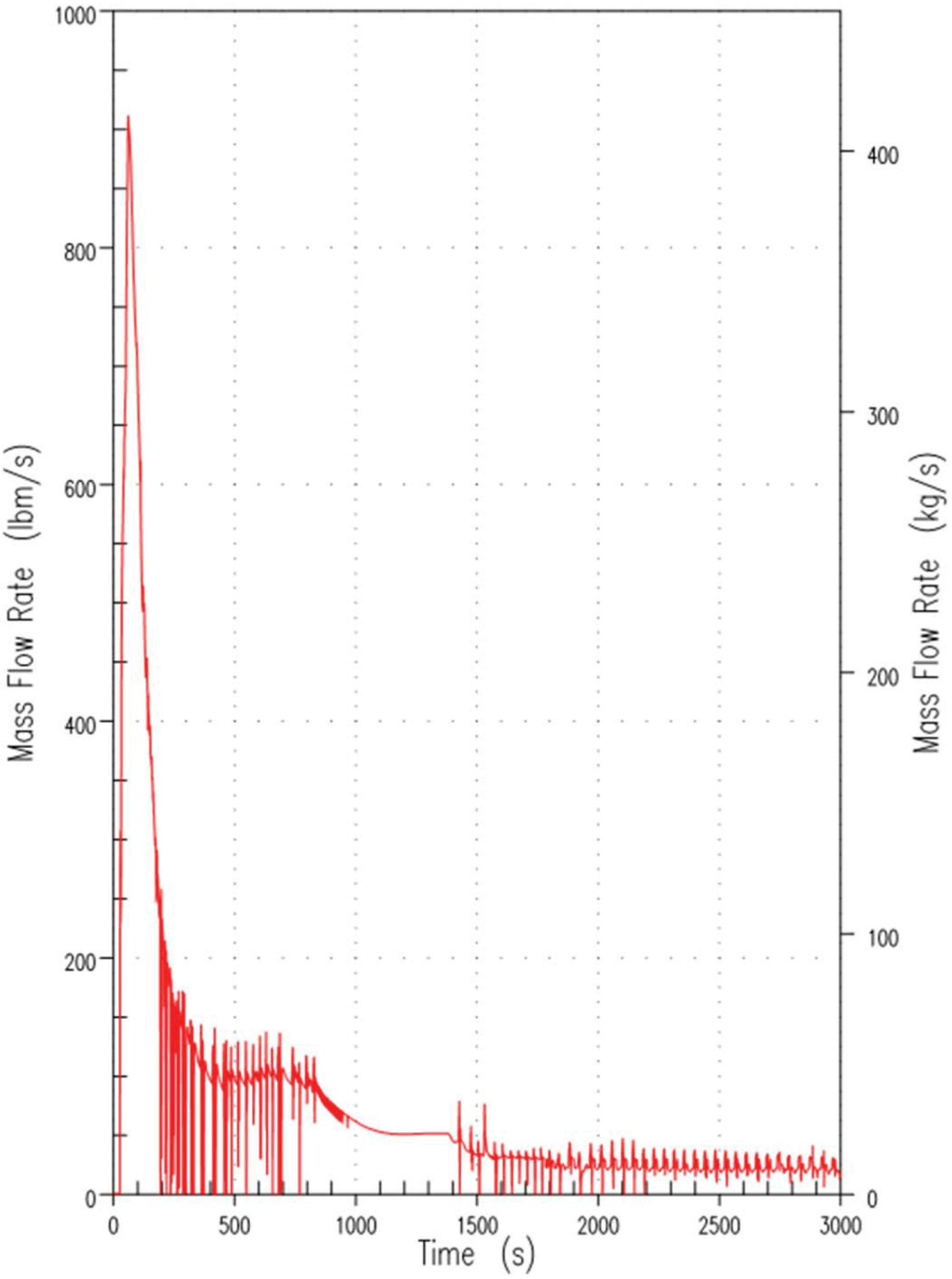


Figure 15.6.5.4B-76
10-inch Cold Leg Break – Vapor Break Discharge

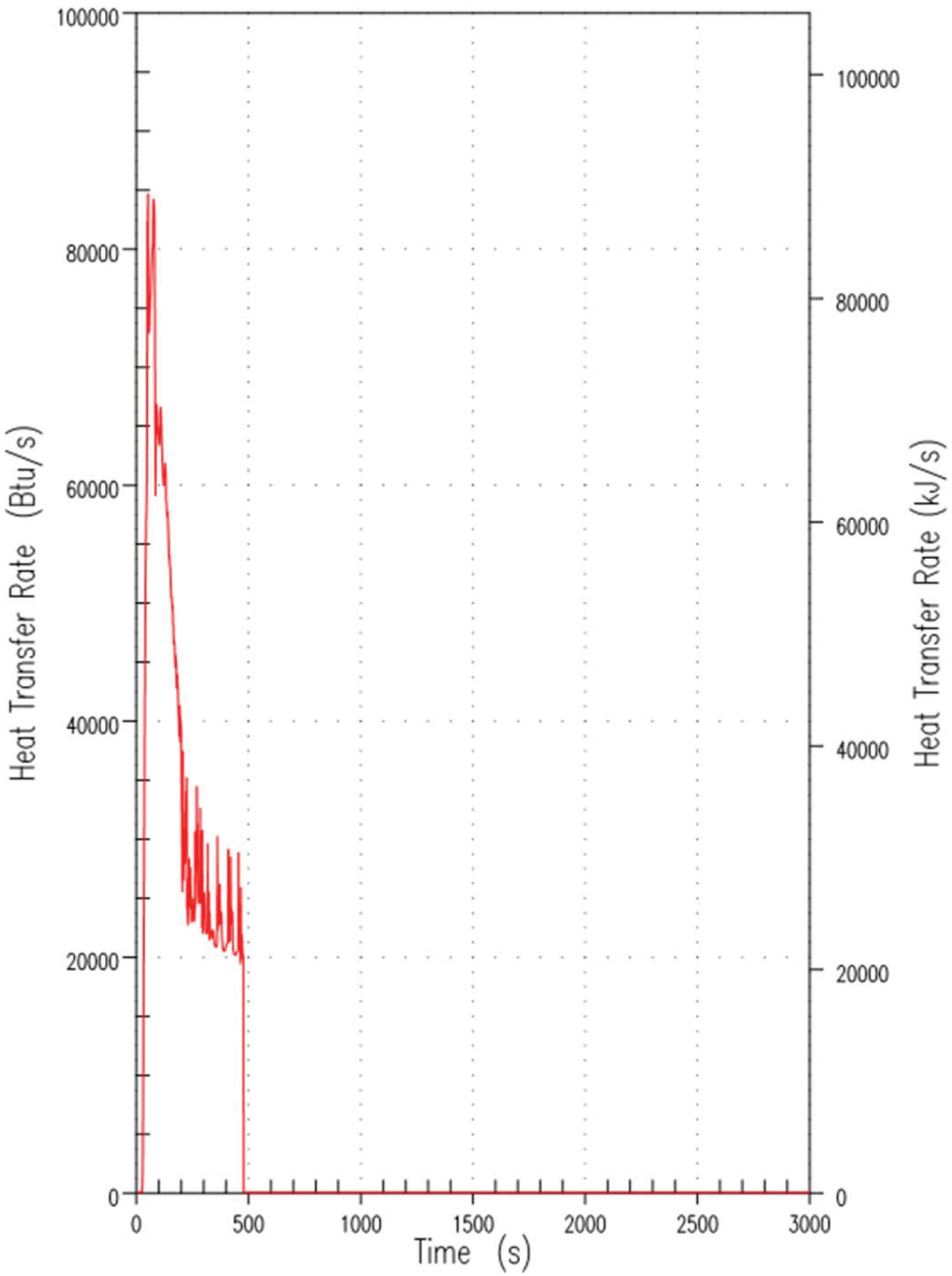


Figure 15.6.5.4B-77
10-inch Cold Leg Break – PRHR Heat Removal Rate

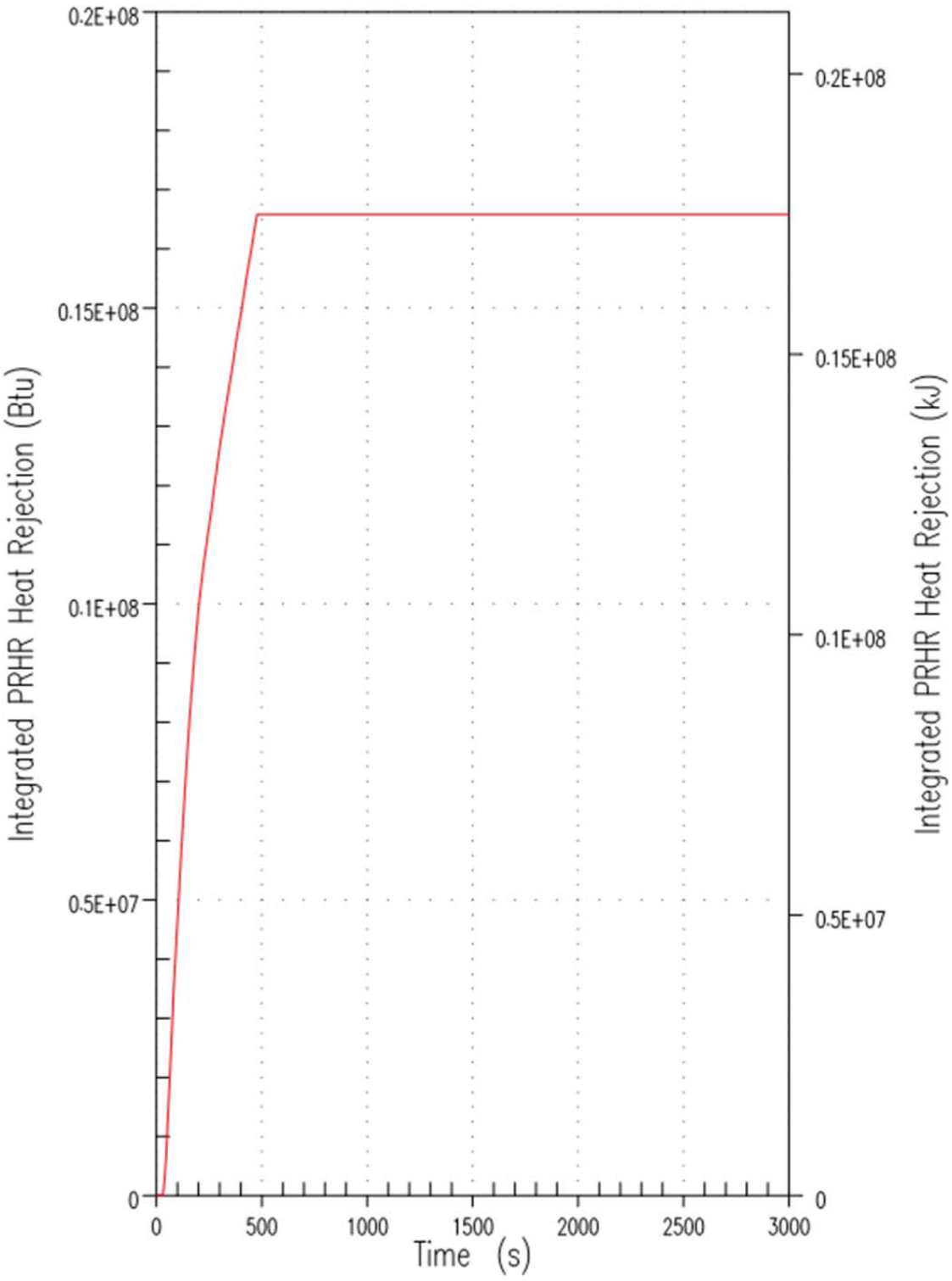


Figure 15.6.5.4B-78
10-inch Cold Leg Break – Integrated PRHR Heat Removal

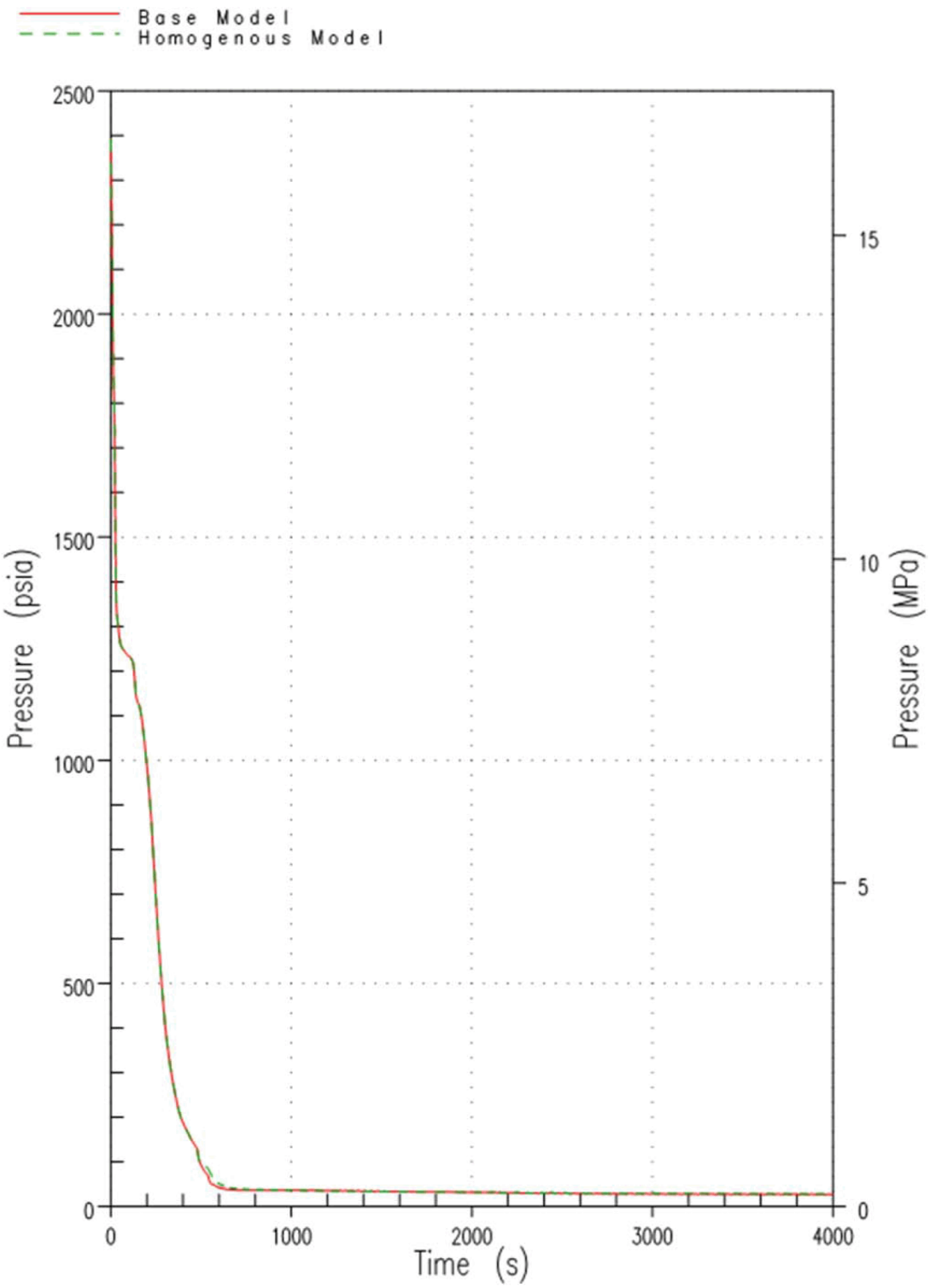


Figure 15.6.5.4B-79(a)
DEDVI Entrainment – Downcomer Pressure Comparison

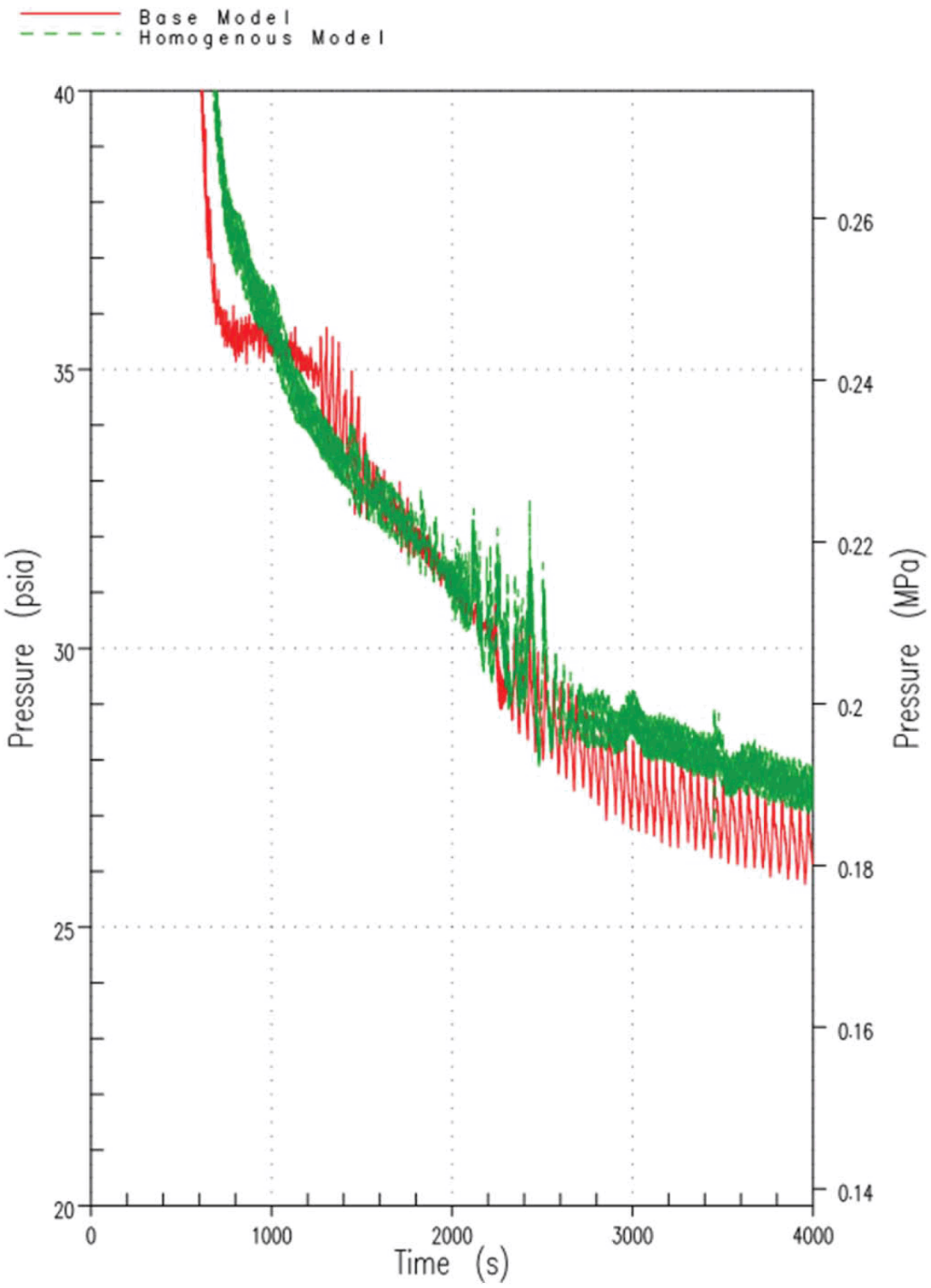


Figure 15.6.5.4B-79(b)
DEDVI Entrainment – Downcomer Pressure Comparison (Zoomed)

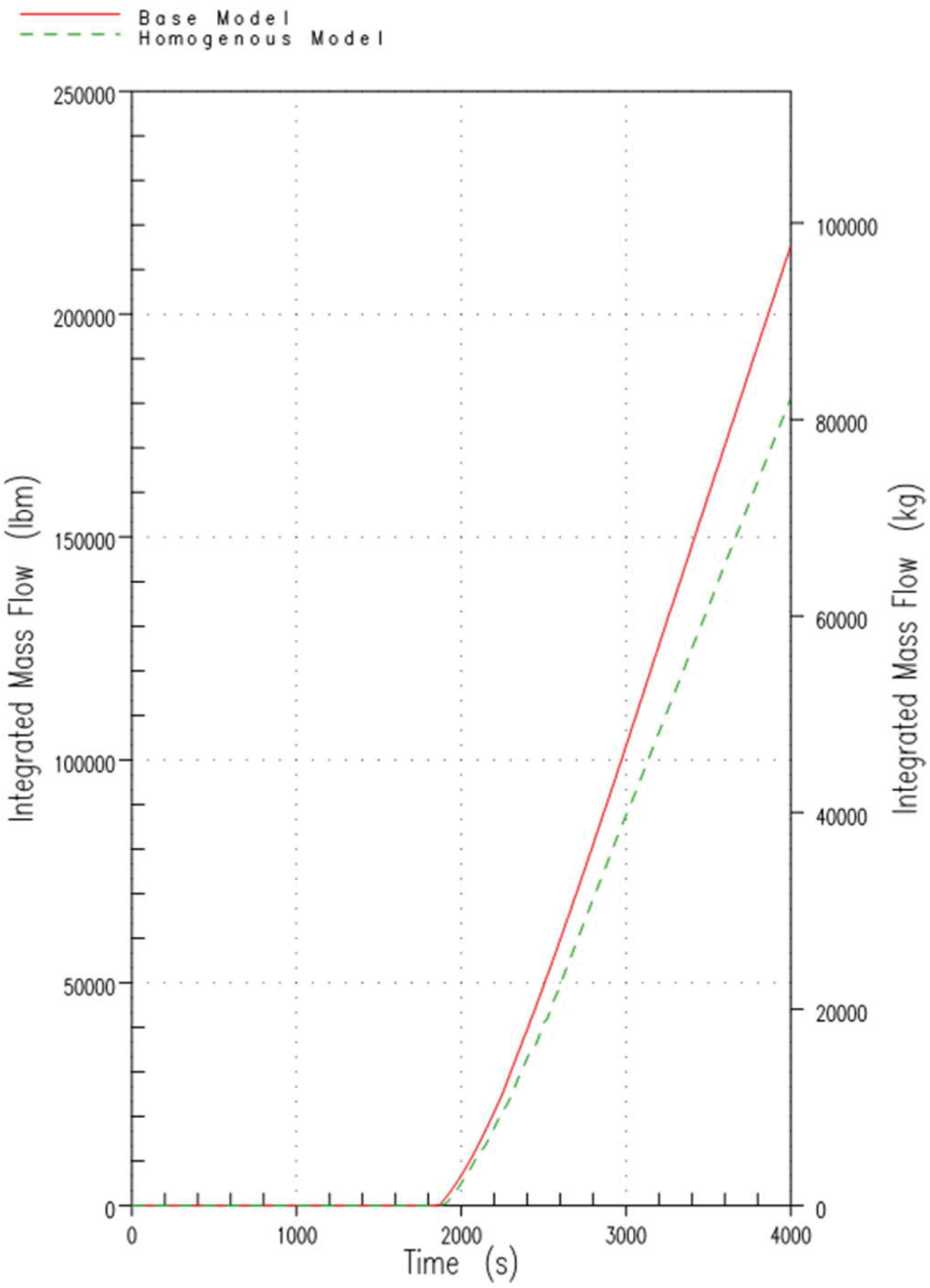


Figure 15.6.5.4B-80
DEDVI Entrainment – Intact IRWST Integrated Injection Flow

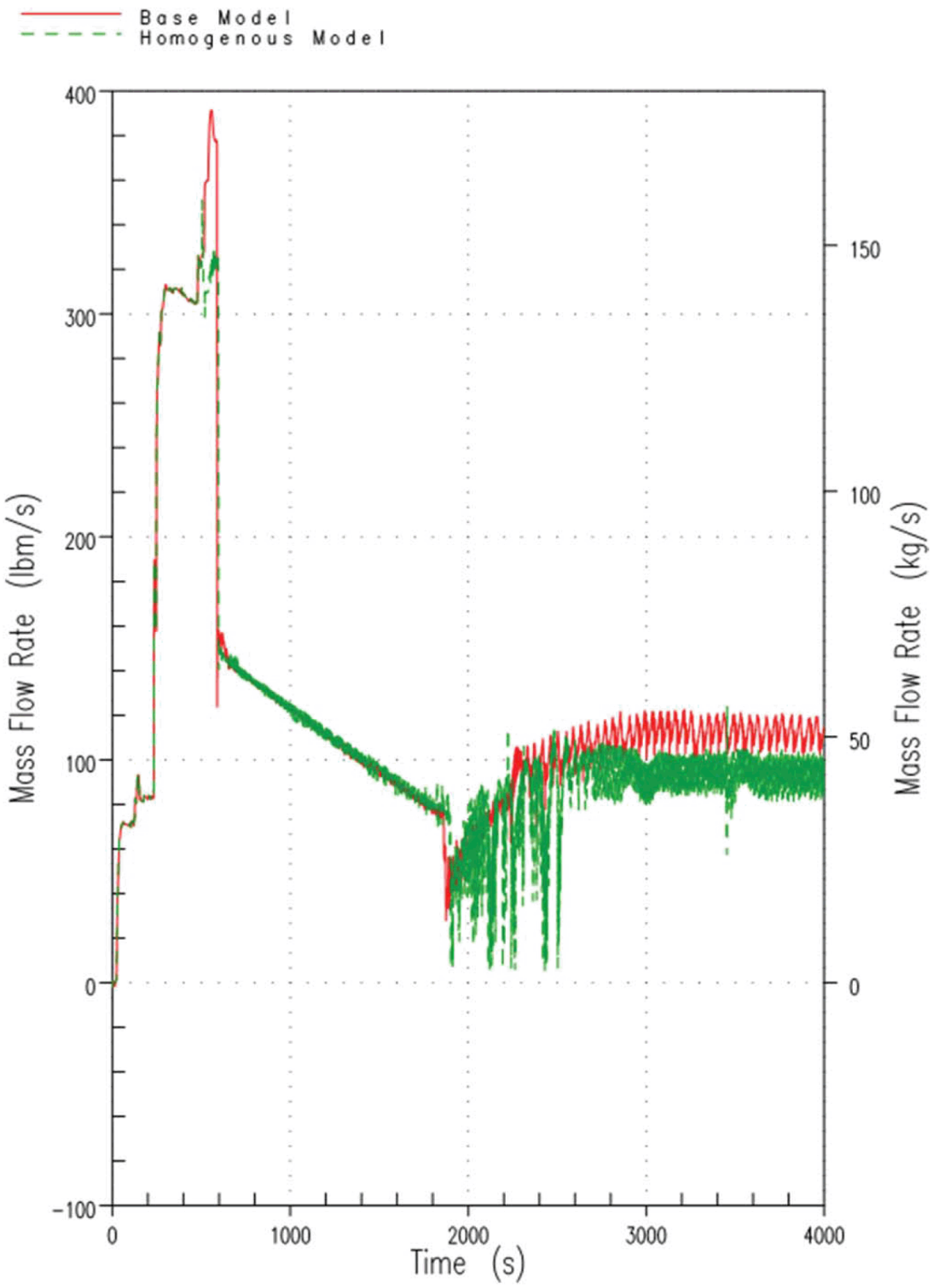


Figure 15.6.5.4B-81
DEDVI Entrainment – Intact DVI Line Injection Flow

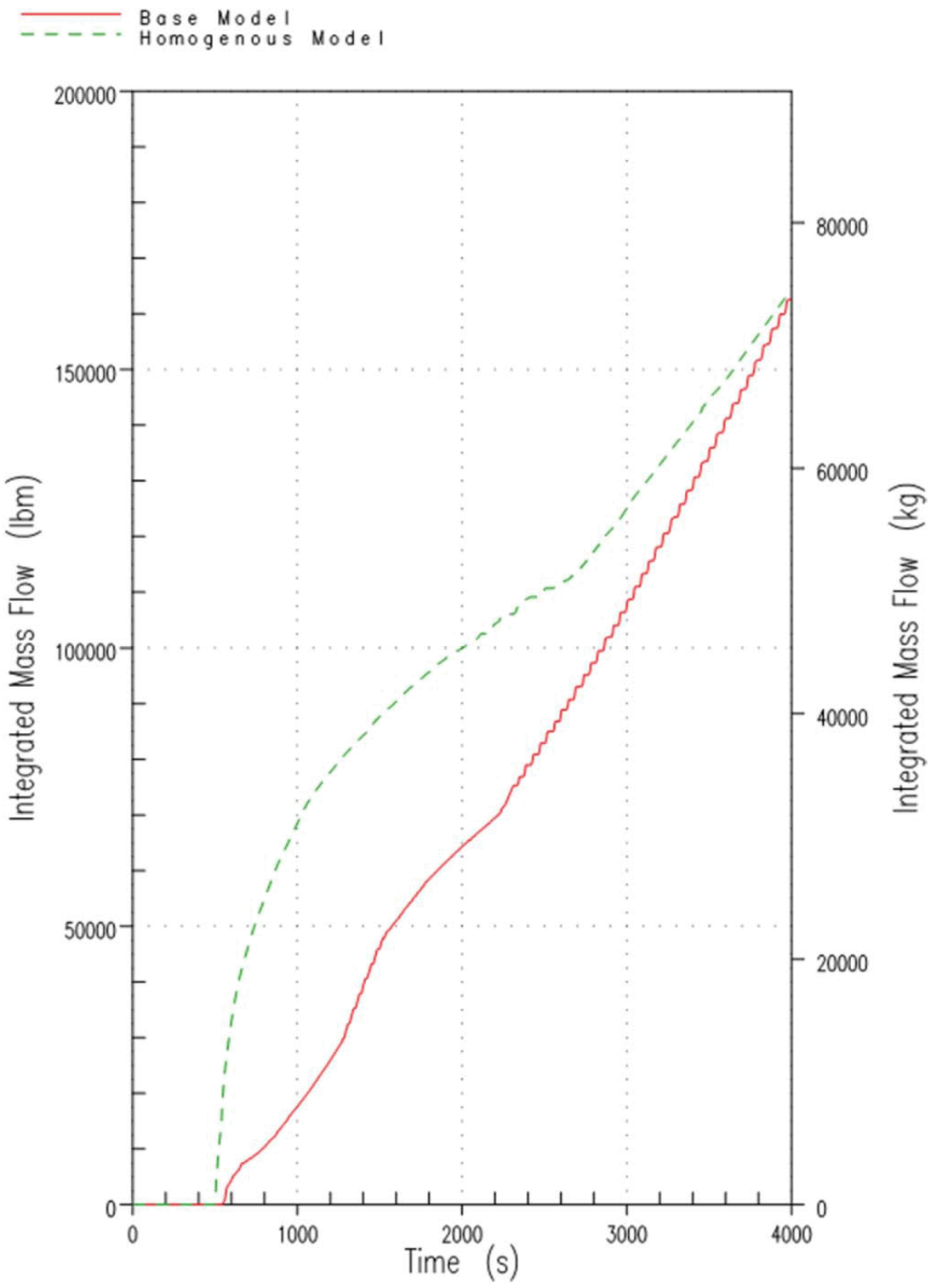


Figure 15.6.5.4B-82
DEDVI Entrainment – ADS-4 Integrated Liquid Discharge Comparison

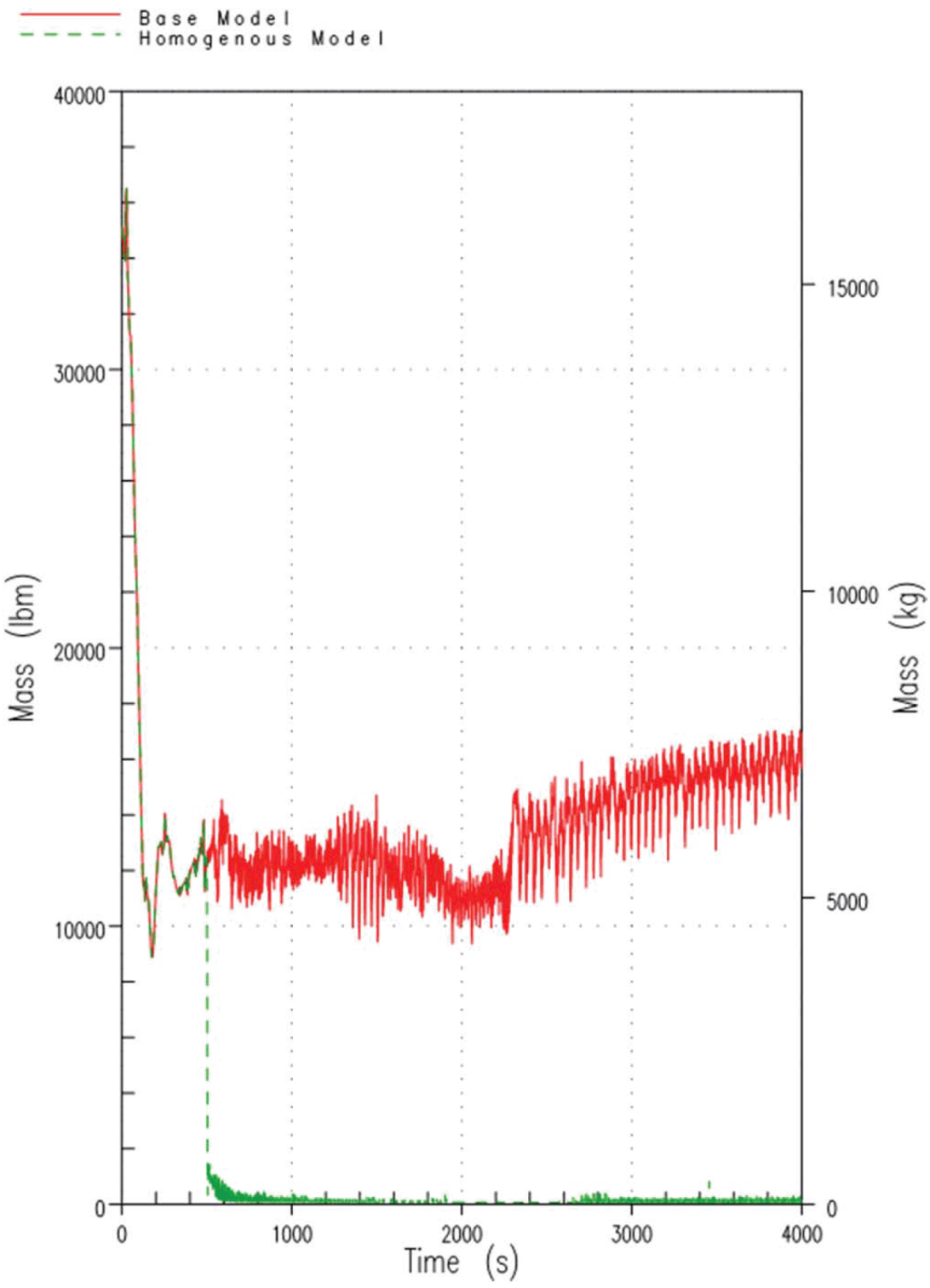


Figure 15.6.5.4B-83
DEDVI Entrainment – Upper Plenum Mixture Mass Comparison

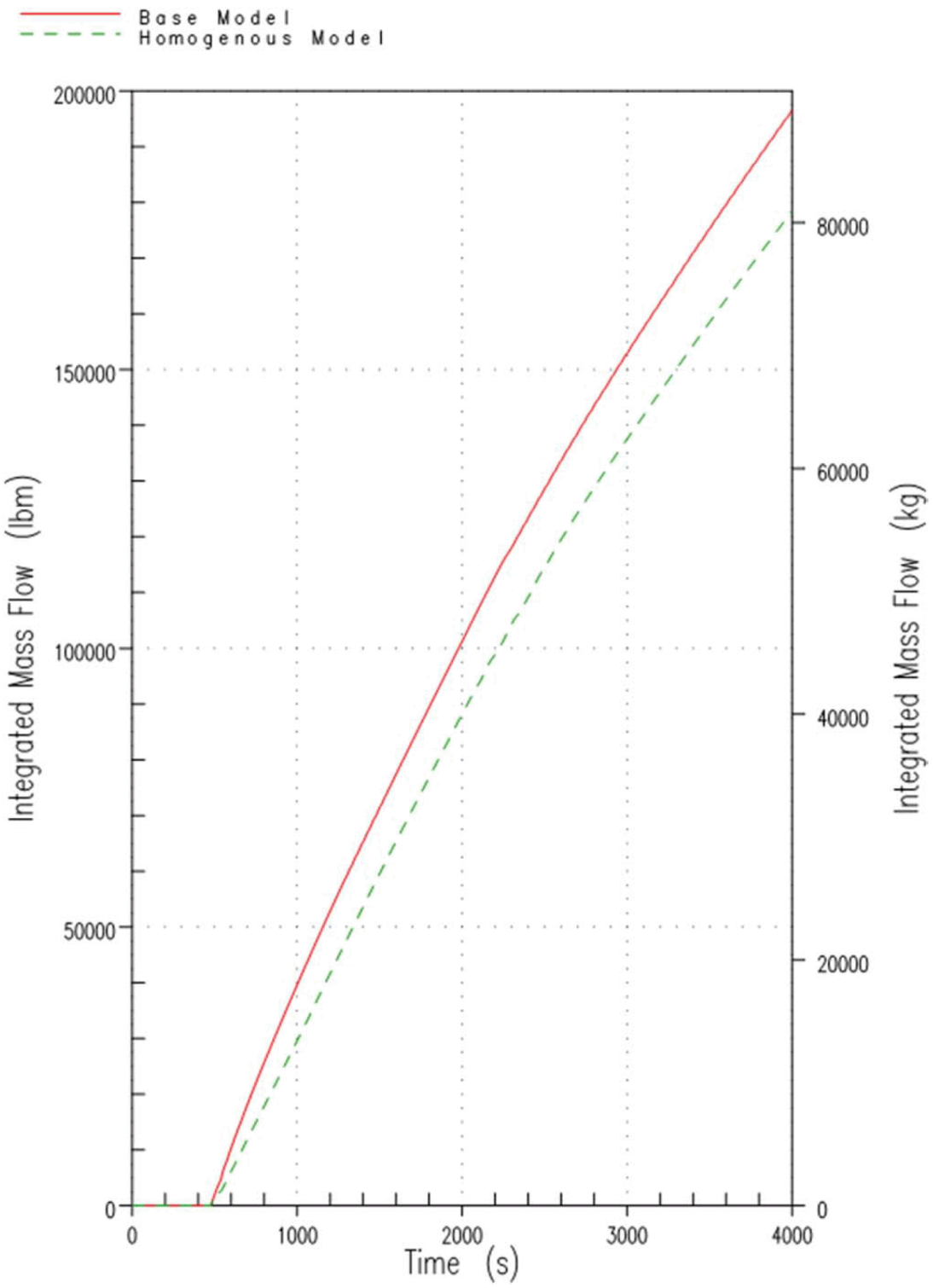


Figure 15.6.5.4B-84
DEDVI Entrainment – ADS-4 Integrated Vapor Discharge Comparison

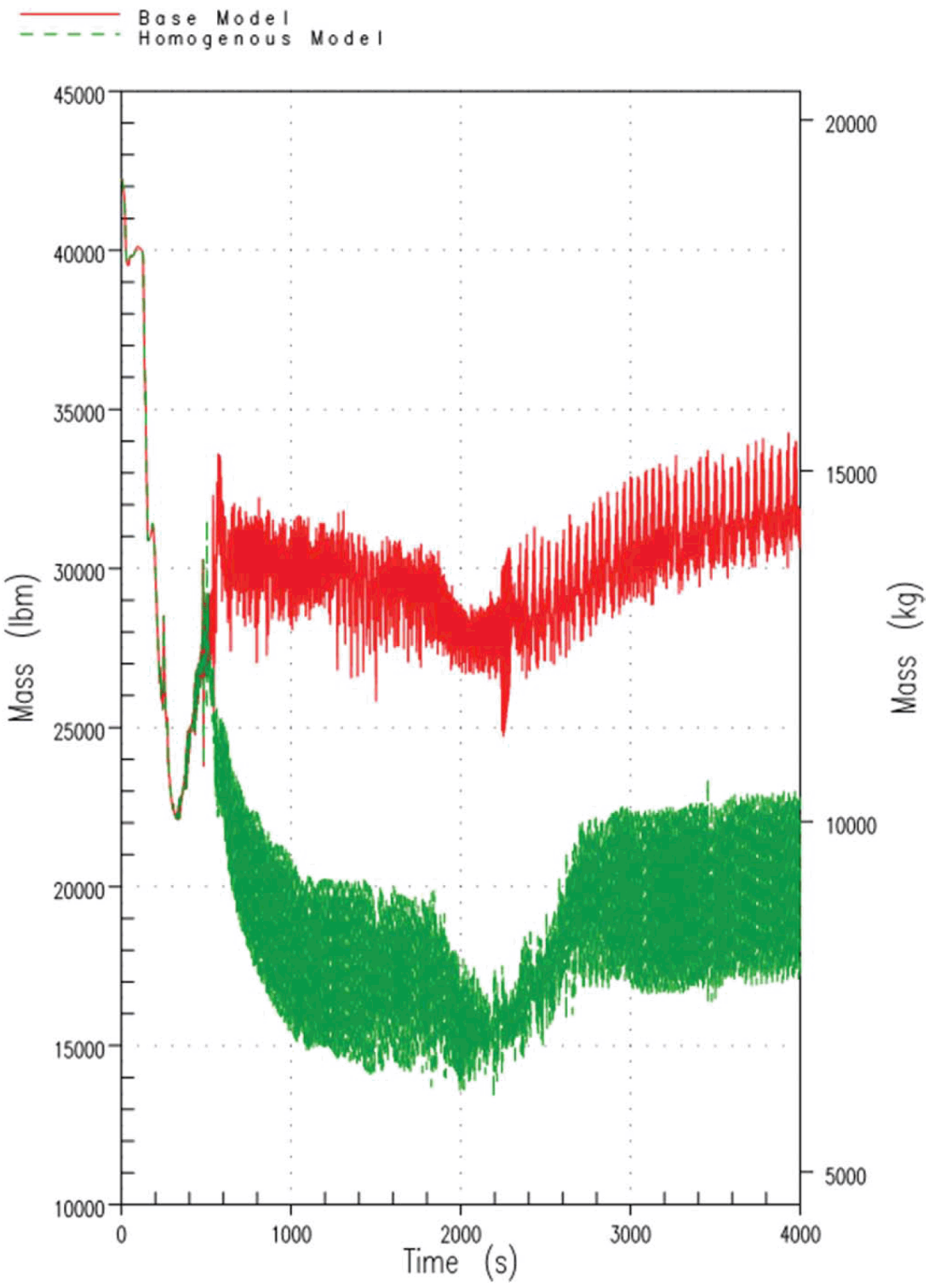


Figure 15.6.5.4B-85
DEDVI Entrainment – Downcomer Region Mass Comparison

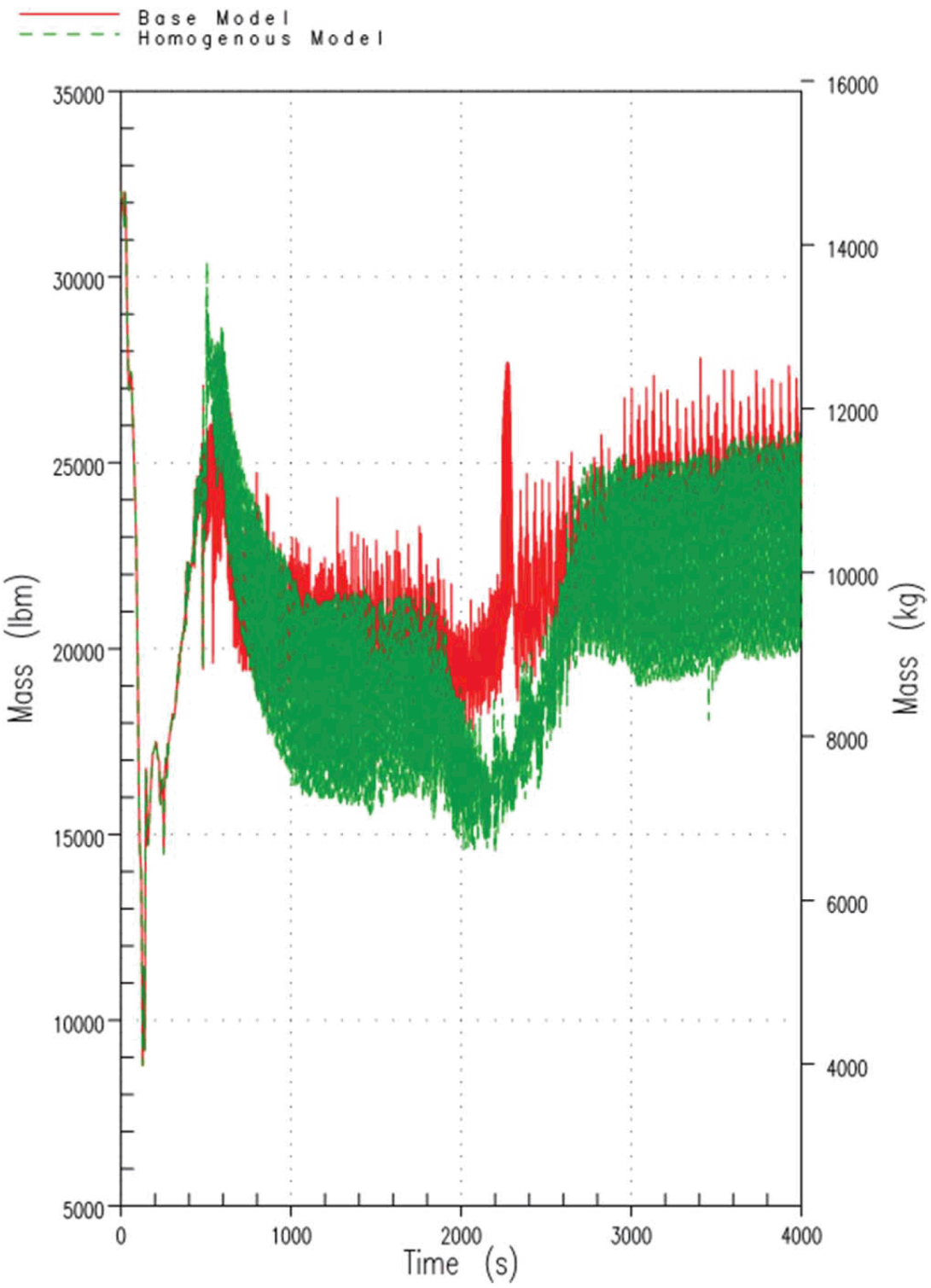


Figure 15.6.5.4B-86(a)
DEDVI Entrainment – Core Region Mass Comparison

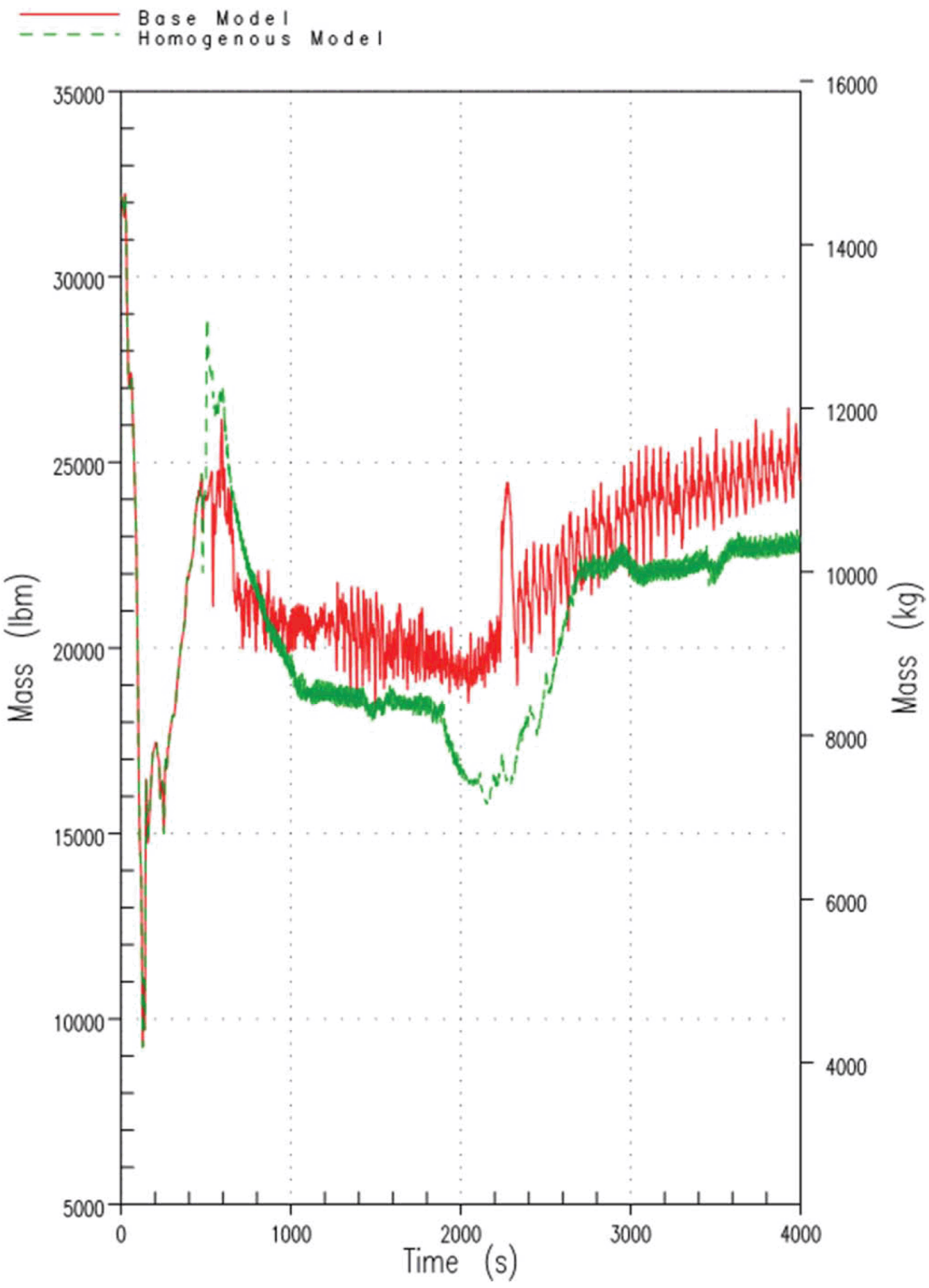


Figure 15.6.5.4B-86(b)
DEDVI Entrainment – Core Region Mass Comparison (Smoothed)

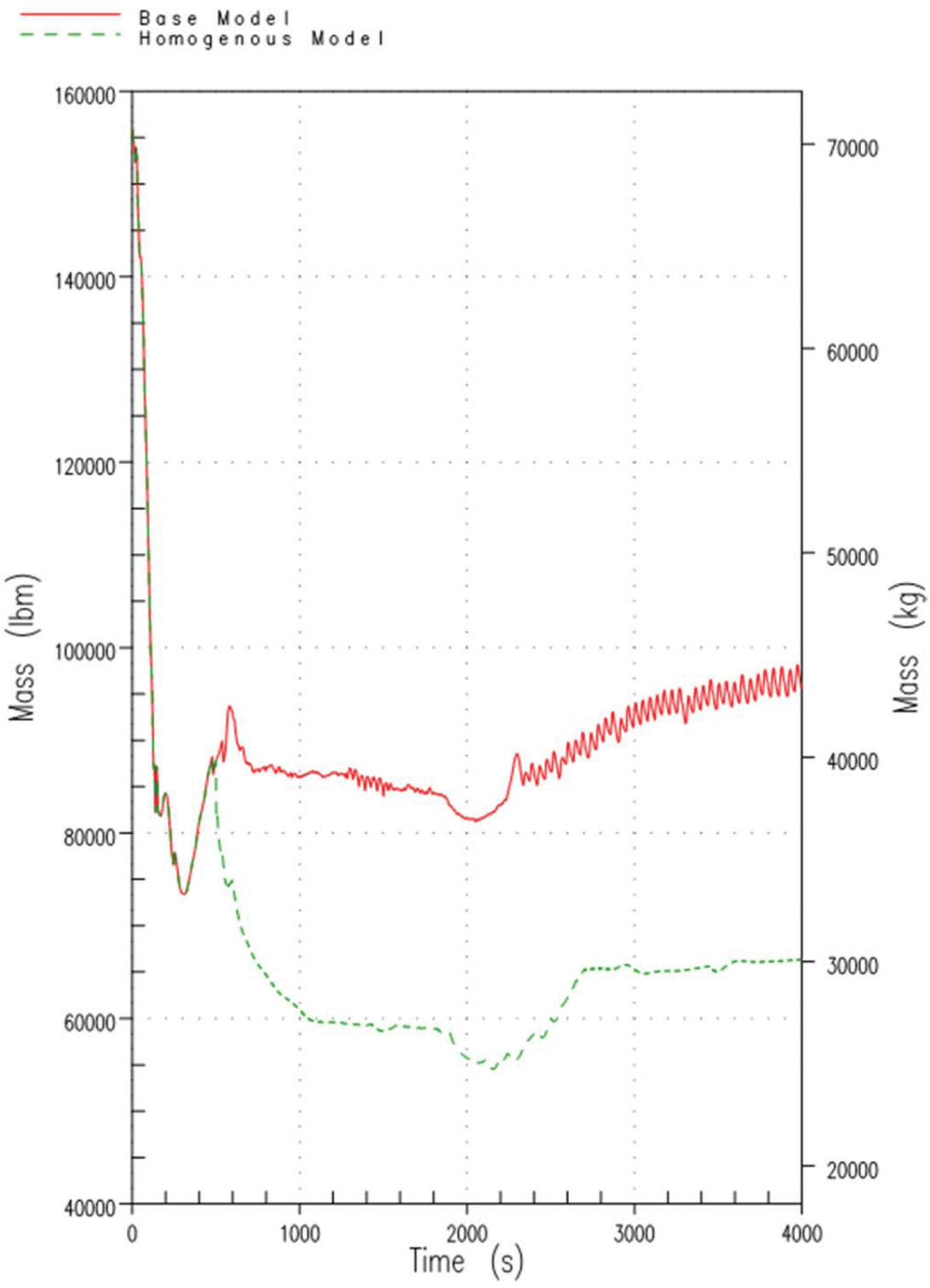


Figure 15.6.5.4B-87
DEDVI Entrainment – Vessel Mixture Mass Comparison

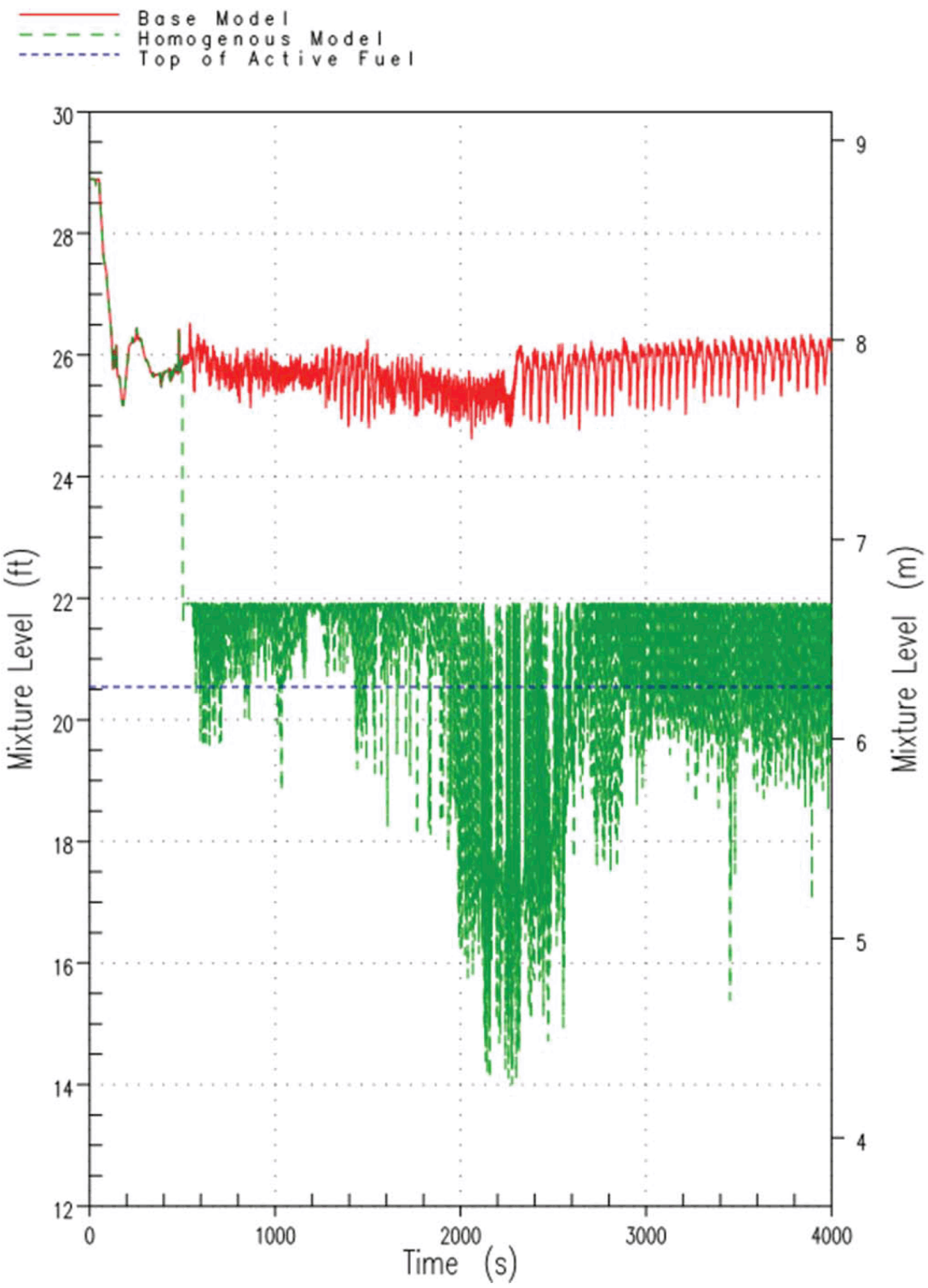


Figure 15.6.5.4B-88(a)
DEDVI Entrainment – Core/Upper Plenum Mixture Level Comparison

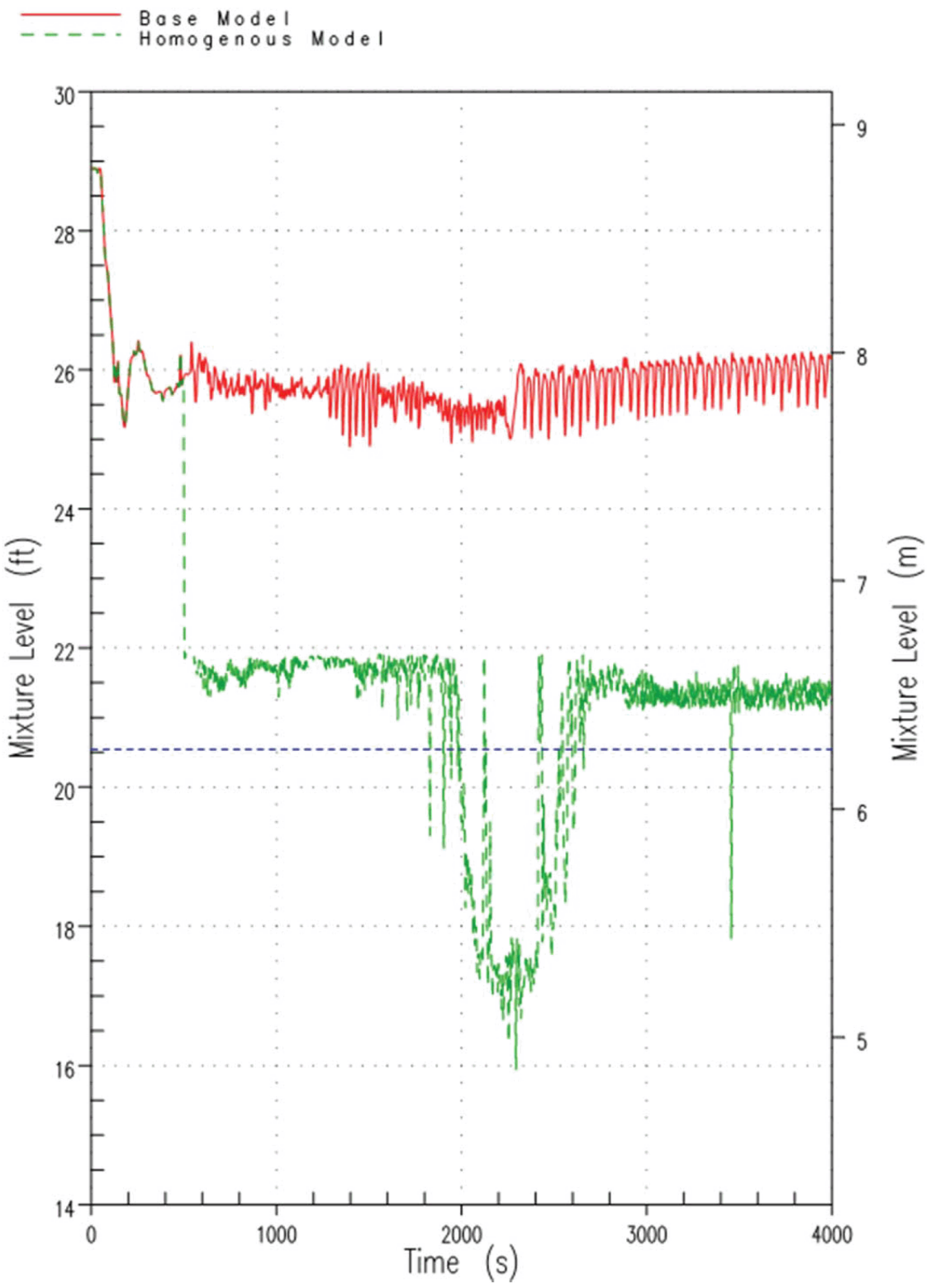


Figure 15.6.5.4B-88(b)
DEDVI Entrainment – Core/Upper Plenum Mixture Level Comparison (Smoothed)

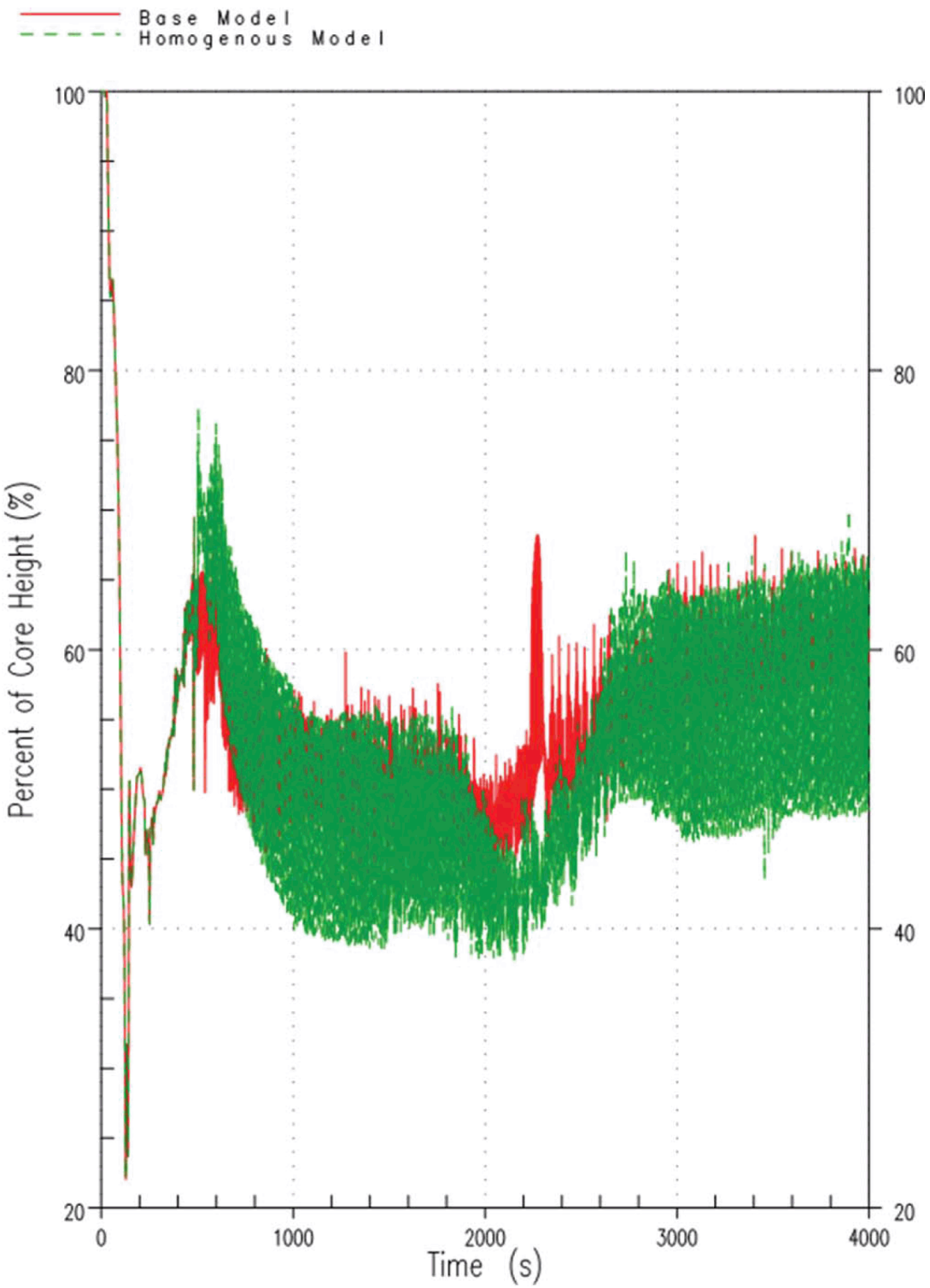


Figure 15.6.5.4B-89(a)
DEDVI Entrainment – Core Collapsed Liquid Level Comparison

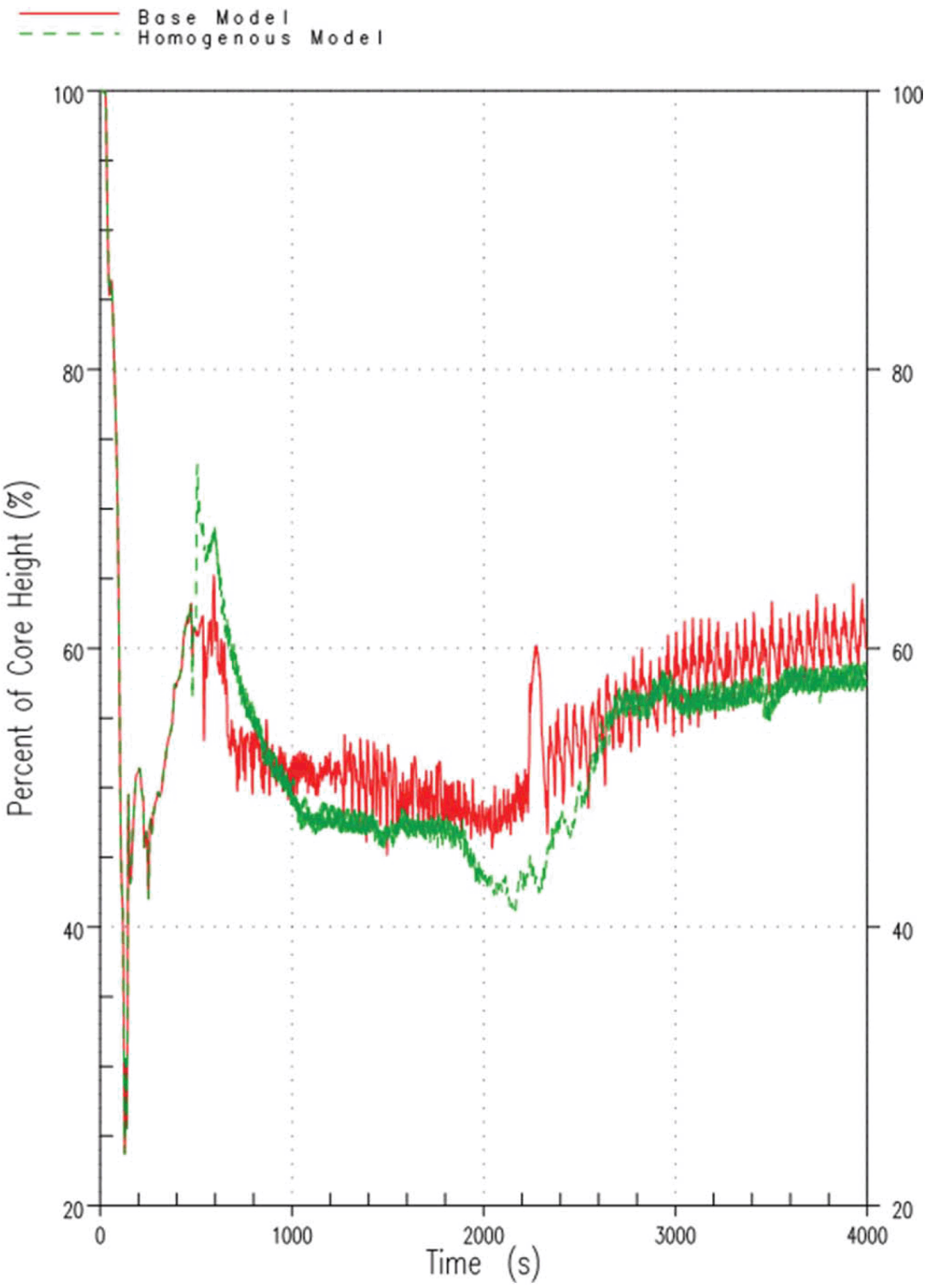


Figure 15.6.5.4B-89(b)
DEDVI Entrainment – Core Collapsed Liquid Level Comparison (Smoothed)

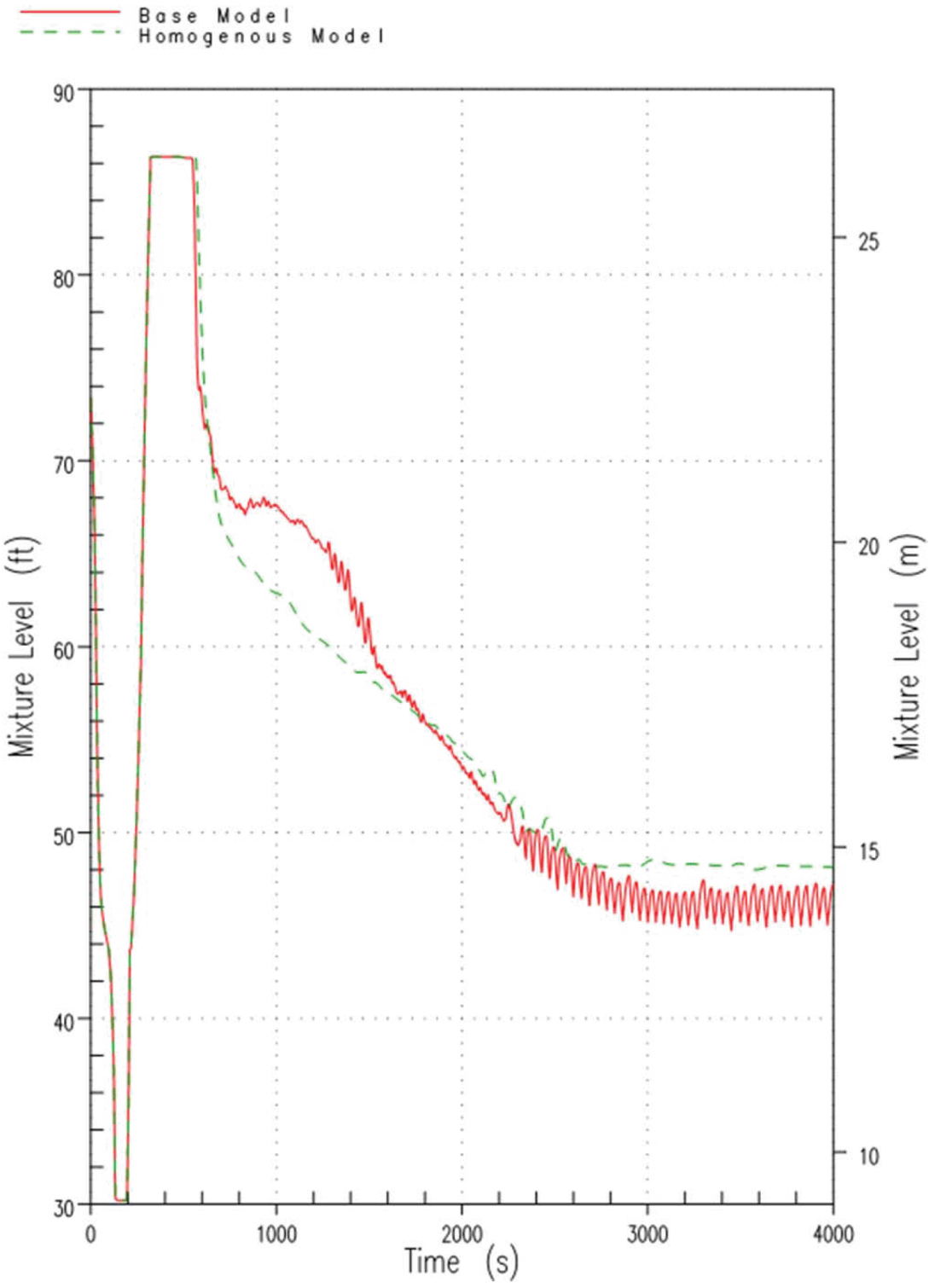


Figure 15.6.5.4B-90
DEDVI Entrainment – Pressurizer Mixture Level Comparison

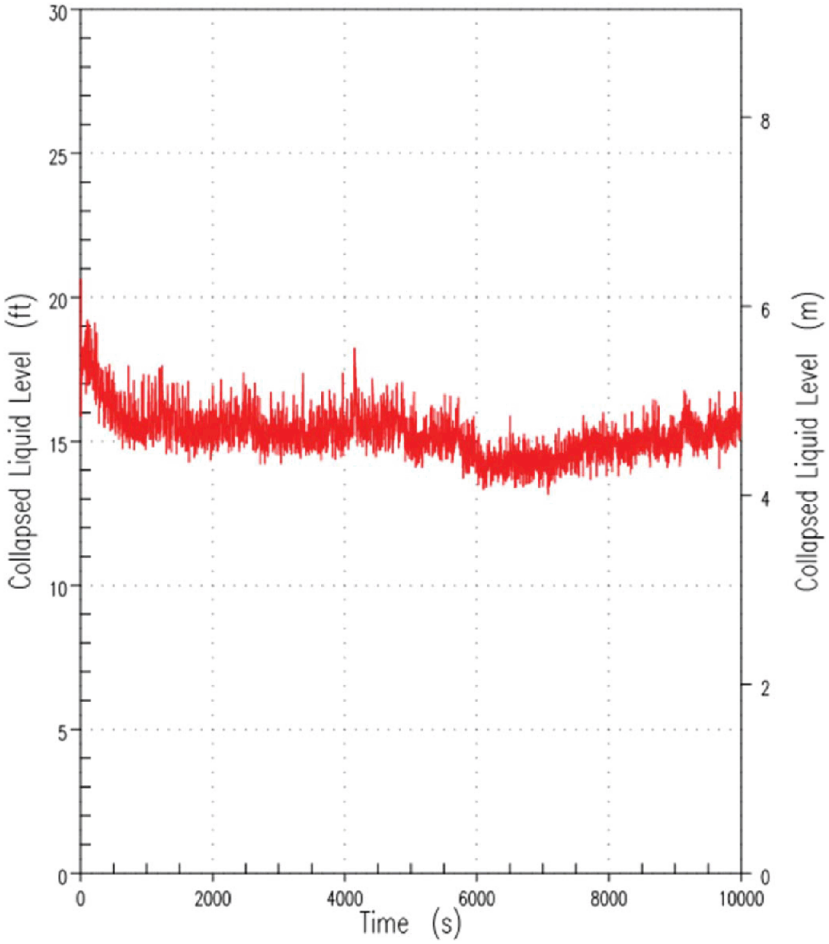


Figure 15.6.5.4C-1
Collapsed Level of Liquid in the Downcomer
(DEDVI Case)

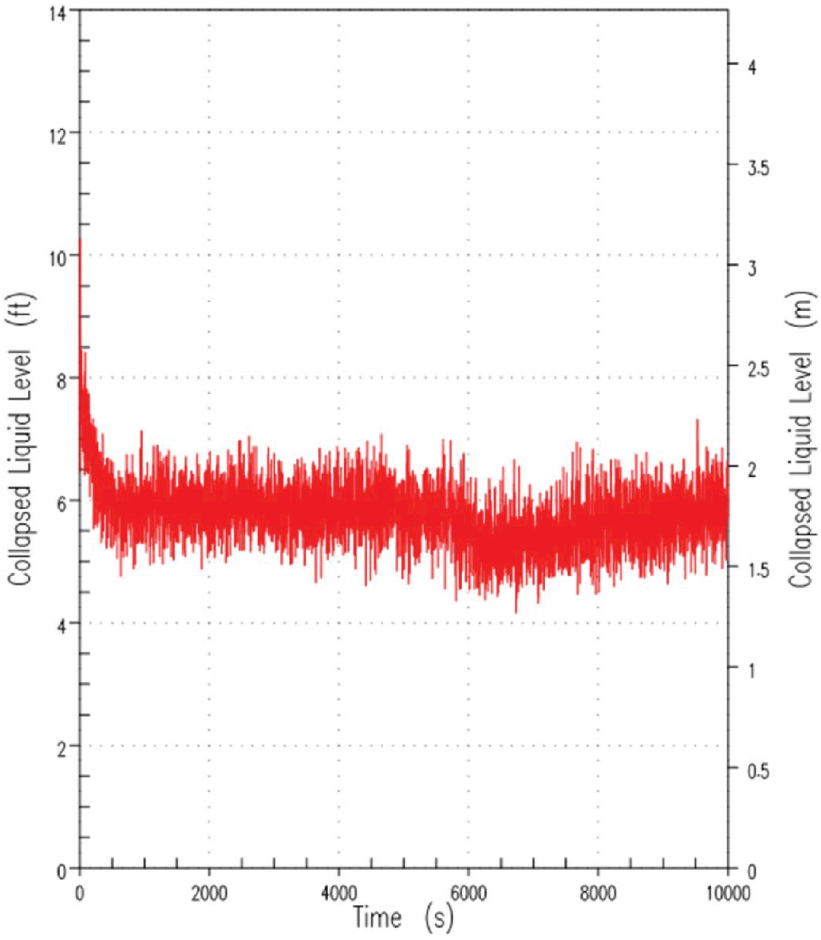


Figure 15.6.5.4C-2
Collapsed Level of Liquid over the Heated Length of the Fuel (DEDVI Case)

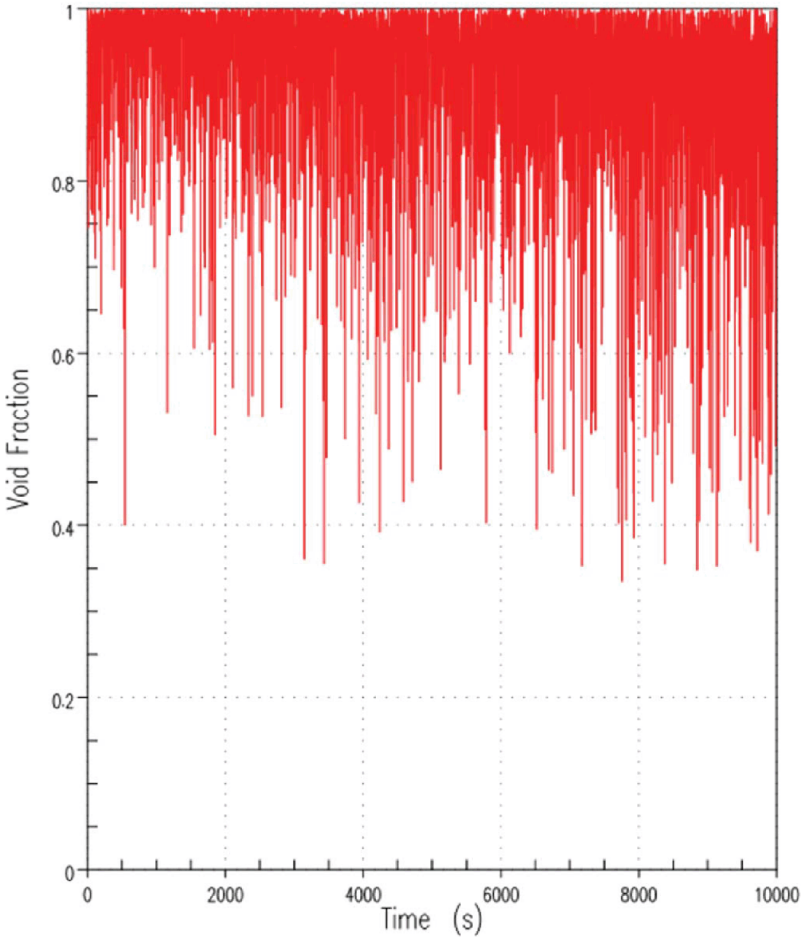


Figure 15.6.5.4C-3
Void Fraction in Core Hot Assembly Top Cell
(DEDVI Case)

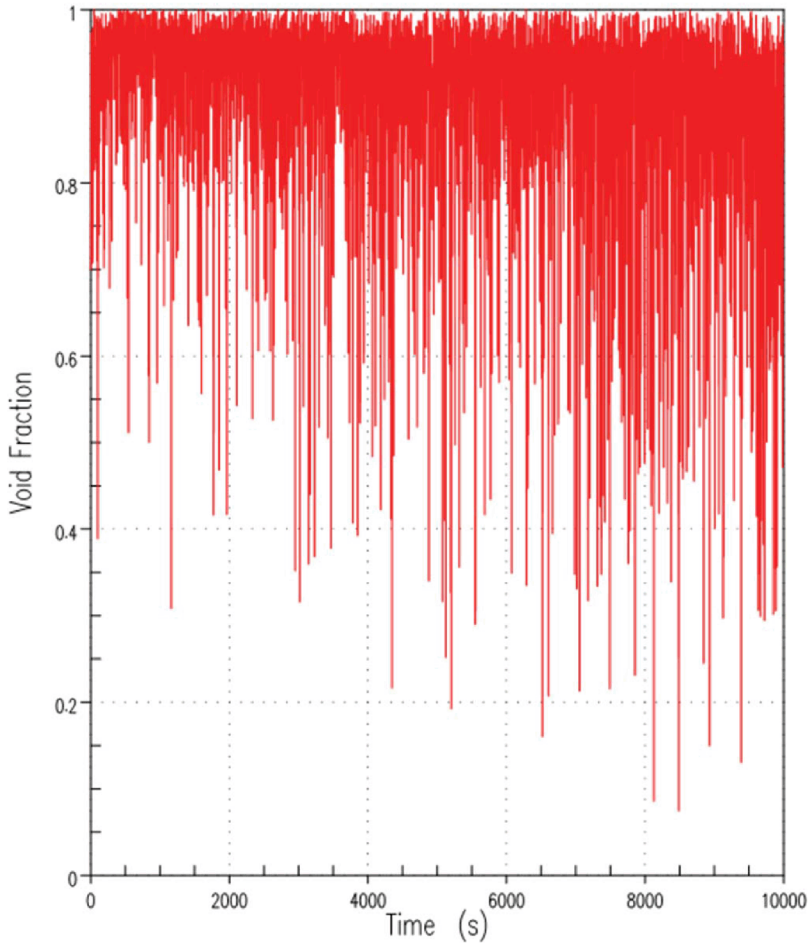


Figure 15.6.5.4C-4
Void Fraction in Core Hot Assembly Second from Top Cell
(DEDVI Case)

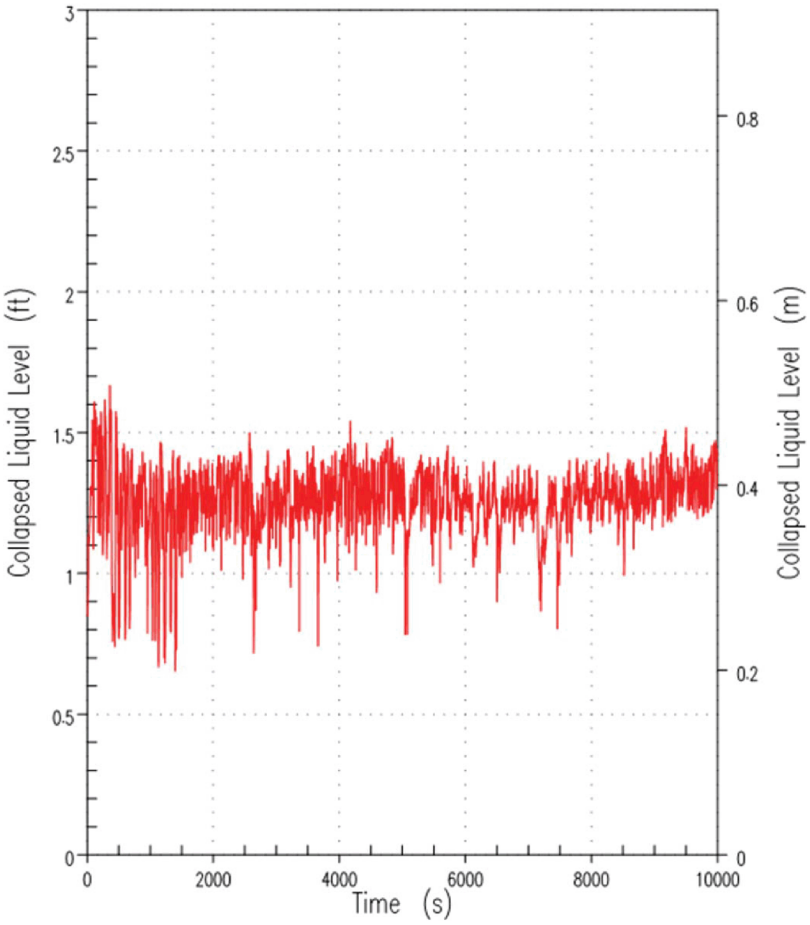


Figure 15.6.5.4C-5
Collapsed Liquid Level in the Hot Leg of Pressurizer Loop (DEDVI Case)

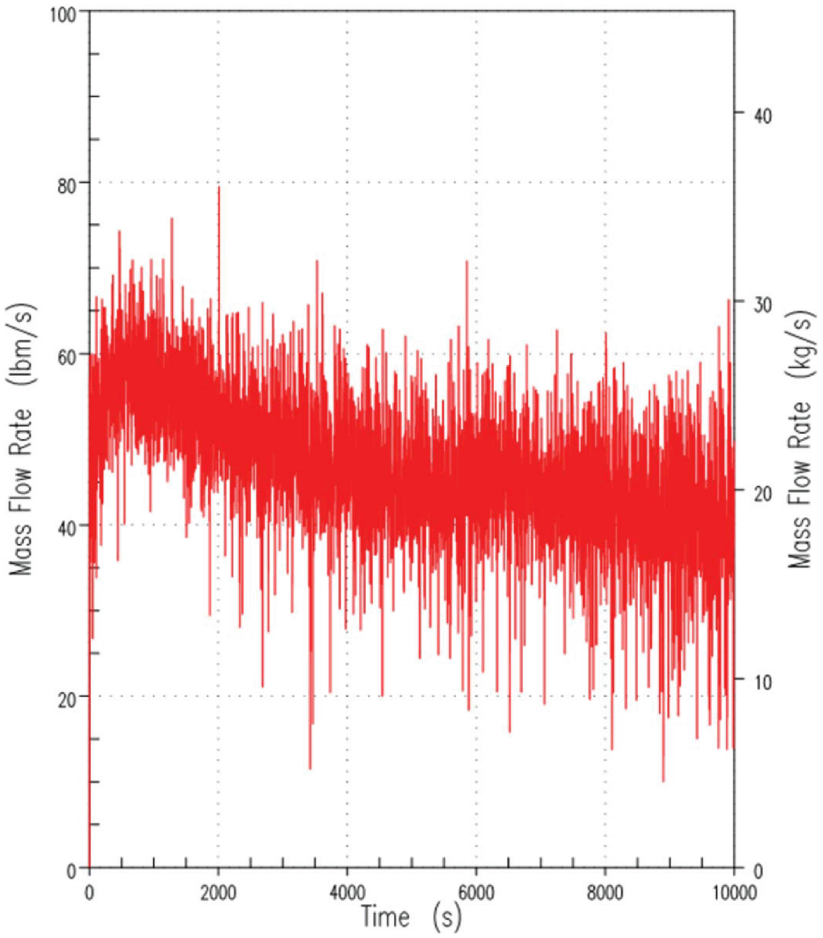


Figure 15.6.5.4C-6
Vapor Rate out of the Core
(DEDVI Case)

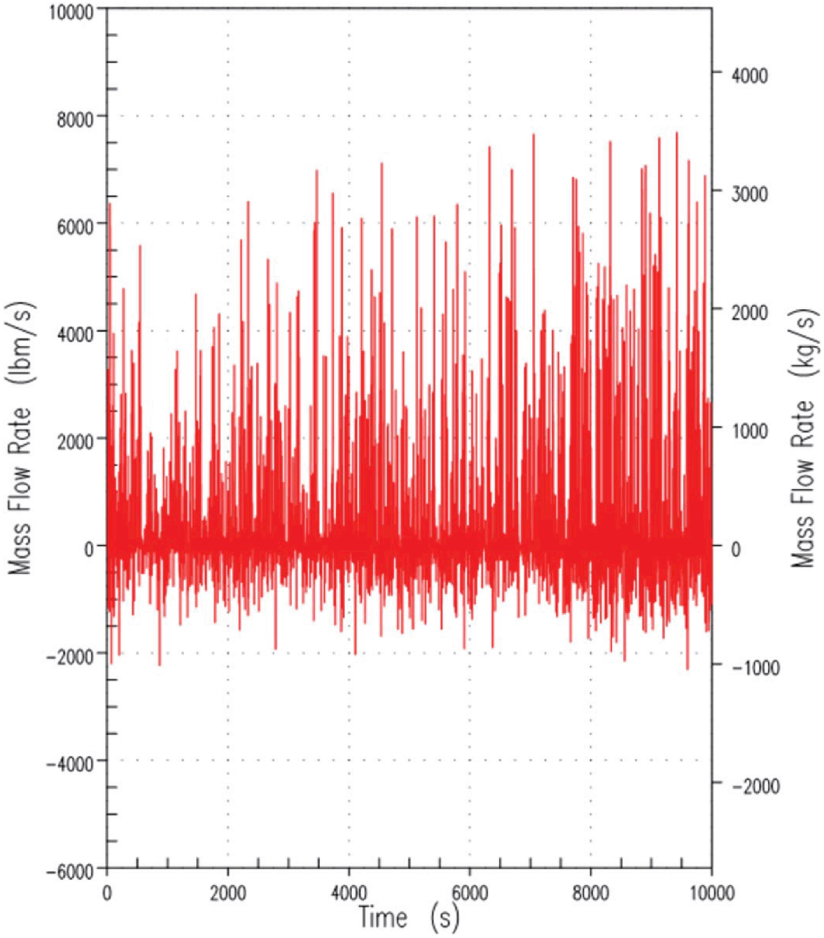


Figure 15.6.5.4C-7
Liquid Flow Rate out of the Core
(DEDVI Case)

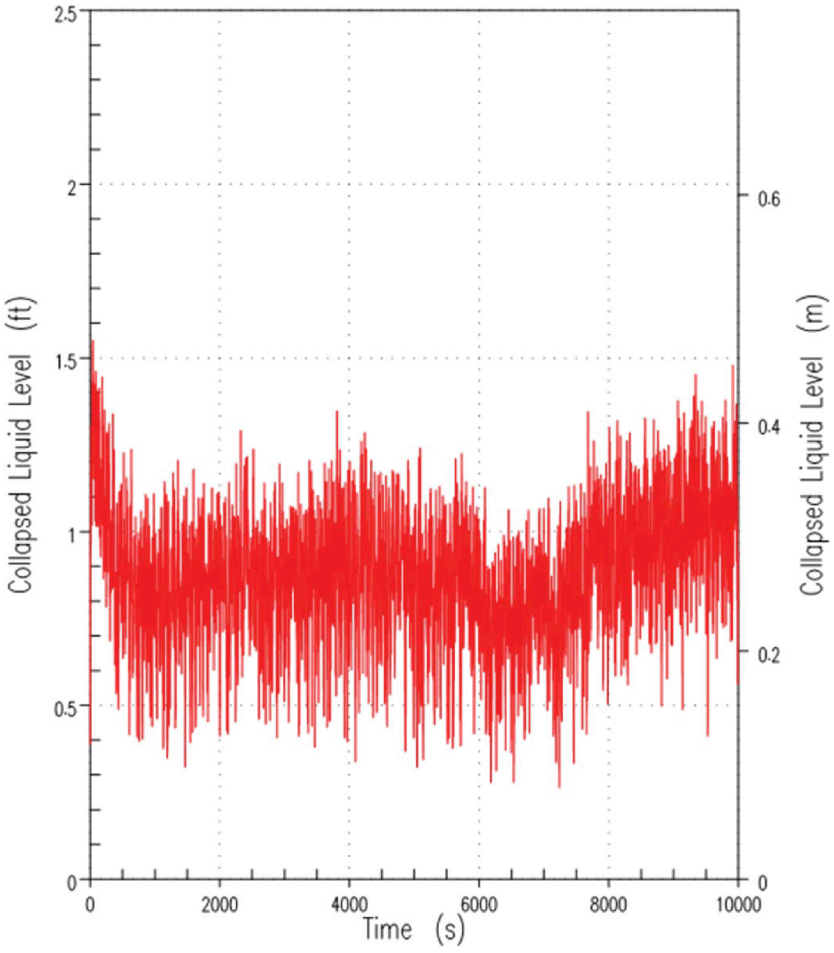


Figure 15.6.5.4C-8
Collapsed Liquid Level in the Upper Plenum
(DEDVI Case)

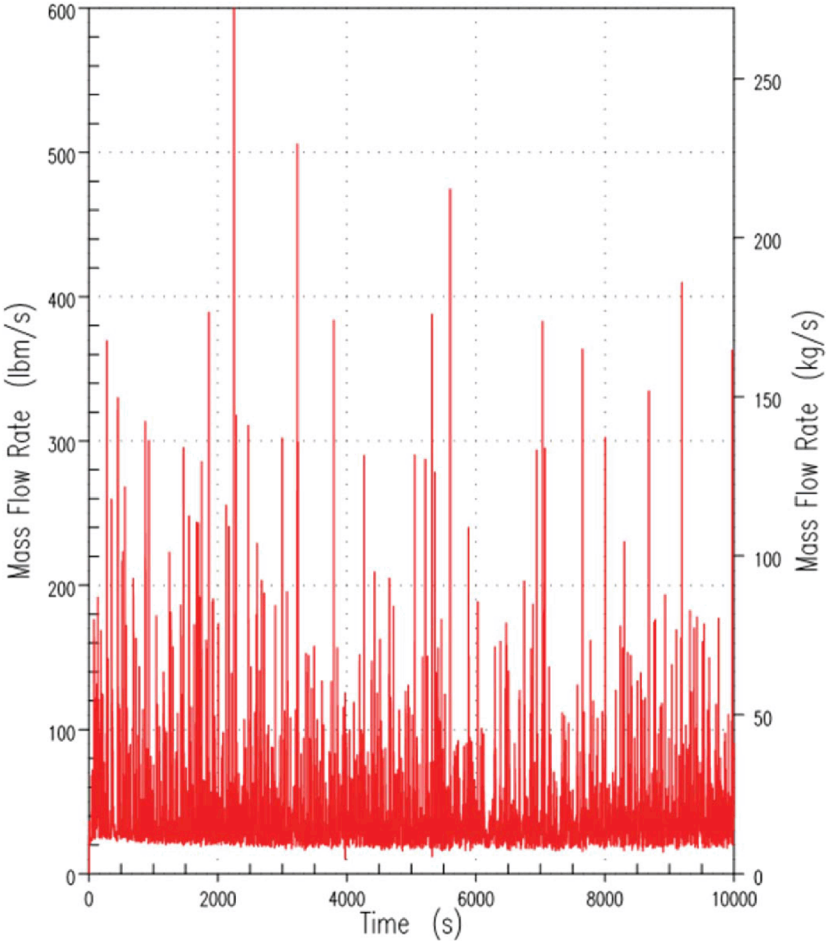


Figure 15.6.5.4C-9
Mixture Flow Rate Through ADS Stage 4A Valves
(DEDVI Case)

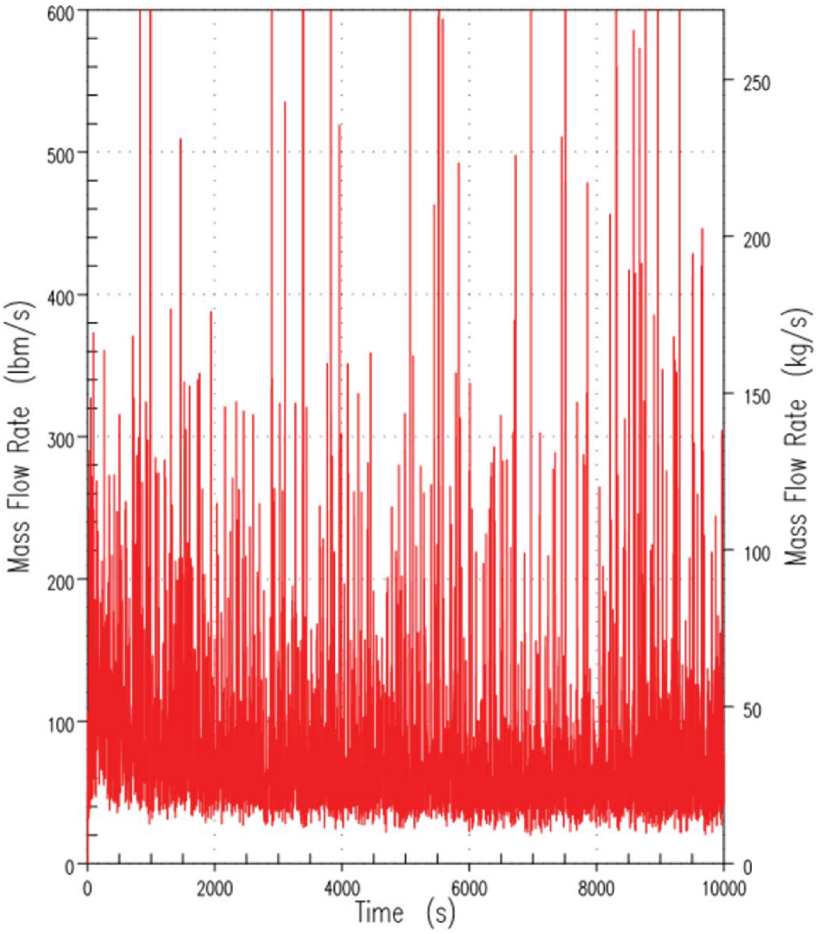


Figure 15.6.5.4C-10
Mixture Flow Rate Through ADS Stage 4B Valves
(DEDVI Case)

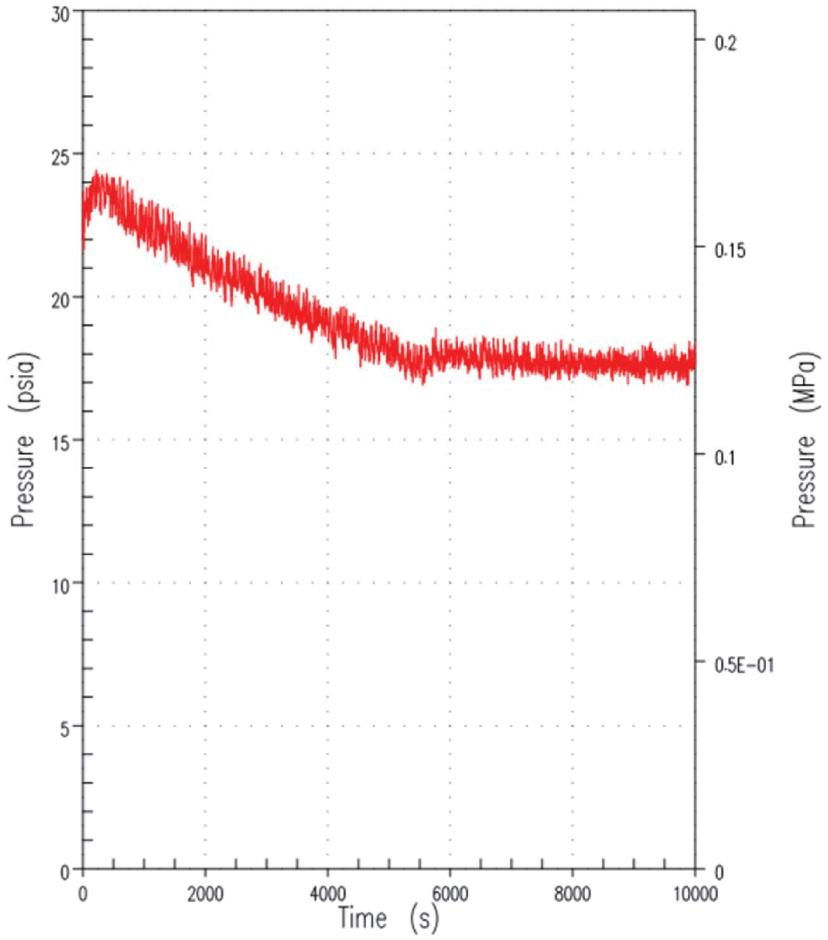


Figure 15.6.5.4C-11
Upper Plenum Pressure
(DEDVI Case)

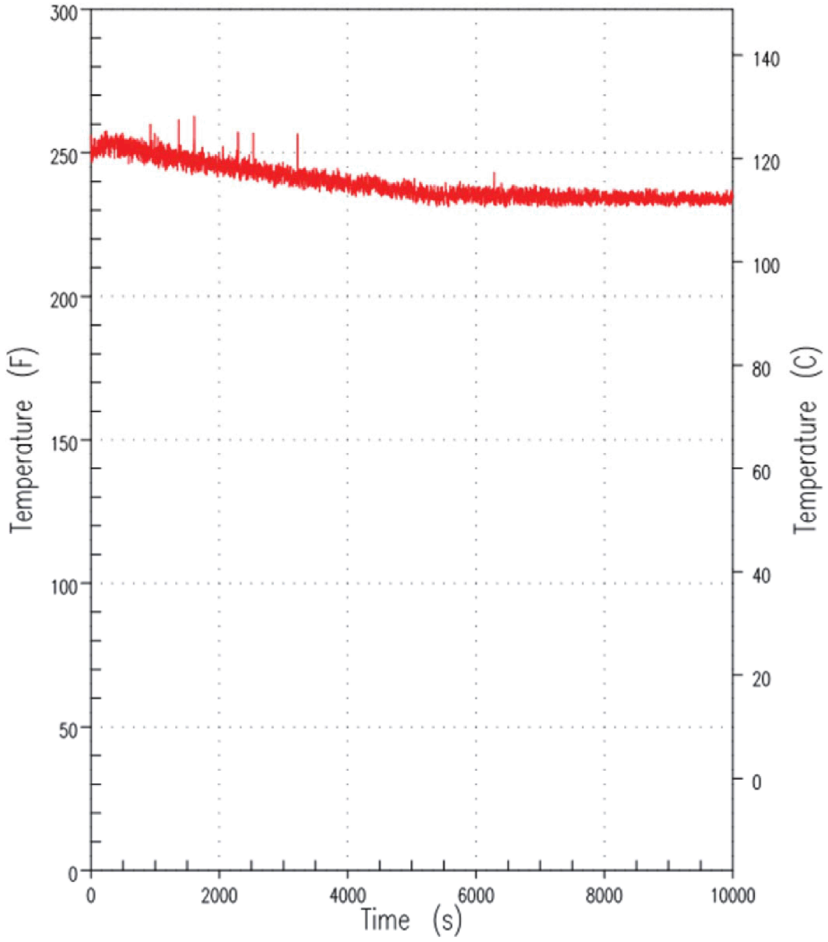


Figure 15.6.5.4C-12
Peak Cladding Temperature
(DEDVI Case)

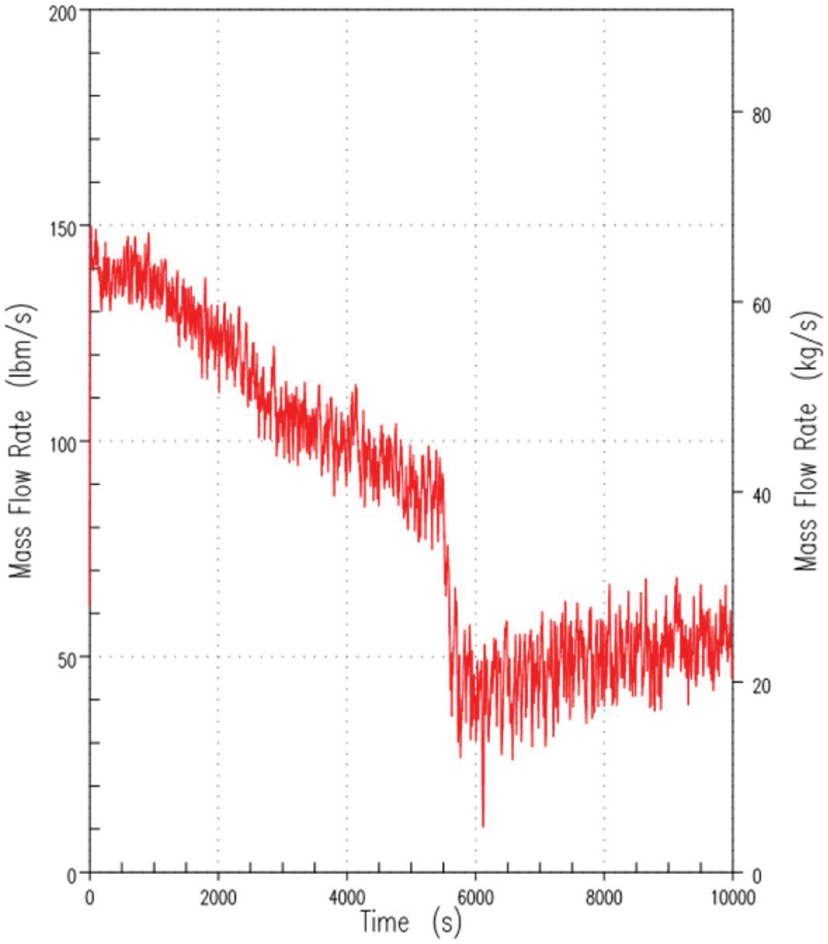


Figure 15.6.5.4C-13
DVI–A Mixture Flow Rate
(DEDVI Case)

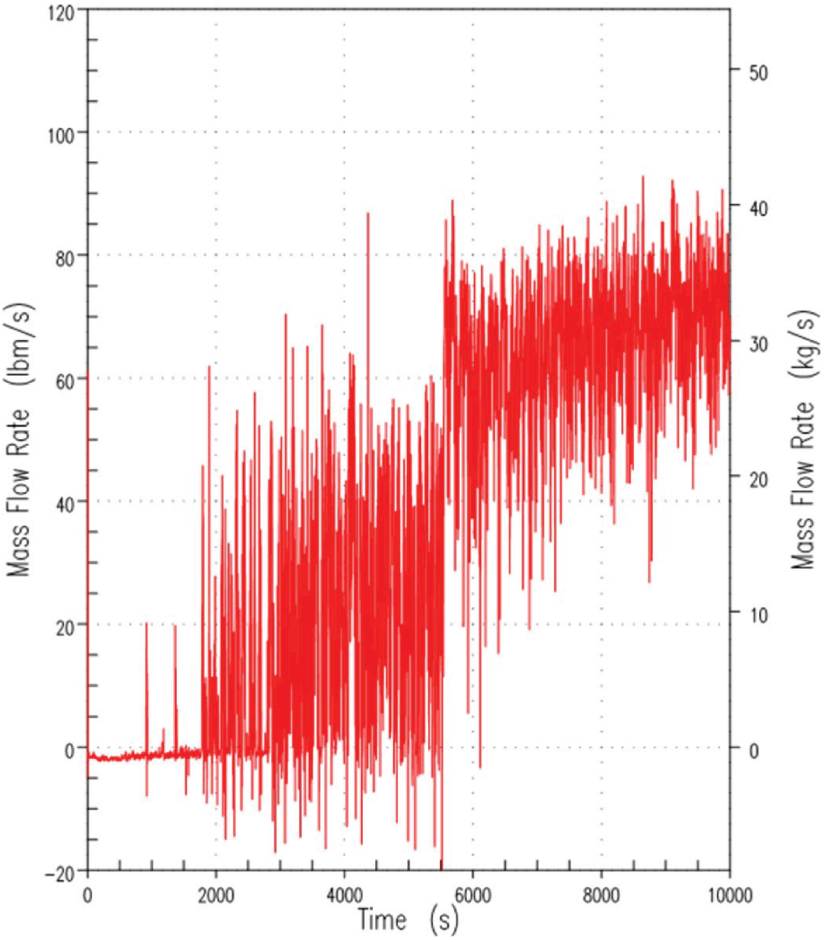


Figure 15.6.5.4C-14
DVI–B Mixture Flow Rate
(DEDVI Case)

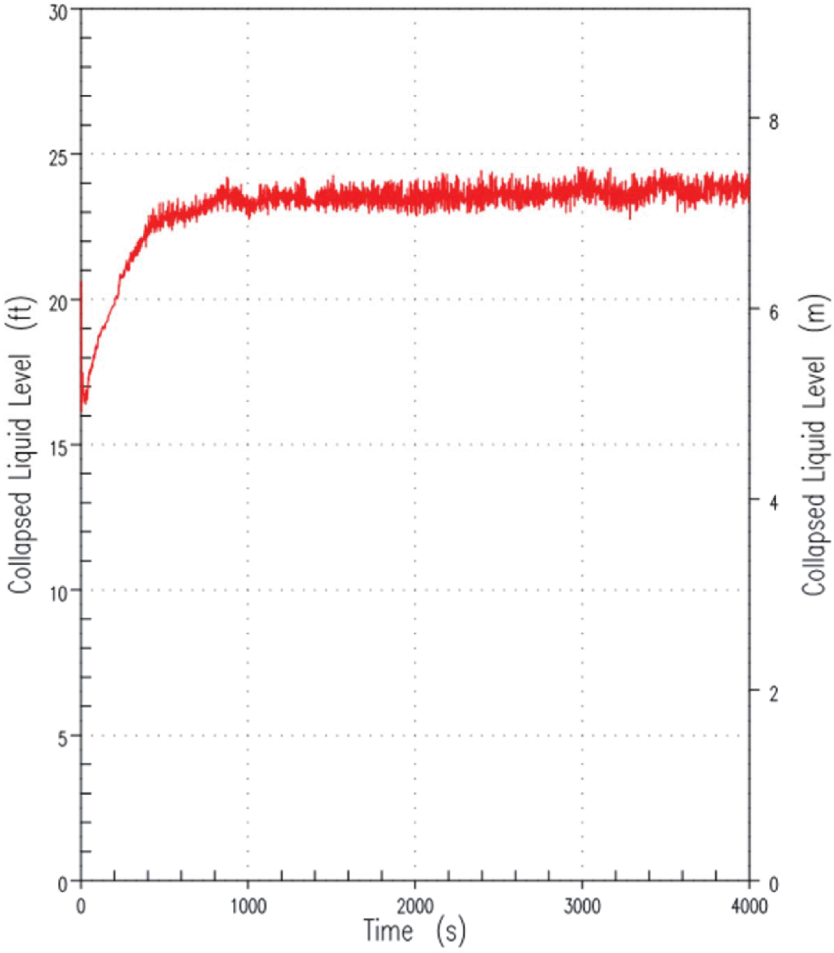


Figure 15.6.5.4C-15
Collapsed Level of Liquid in the Downcomer
(Wall-to-Wall Floodup Case) – 14.7 psia

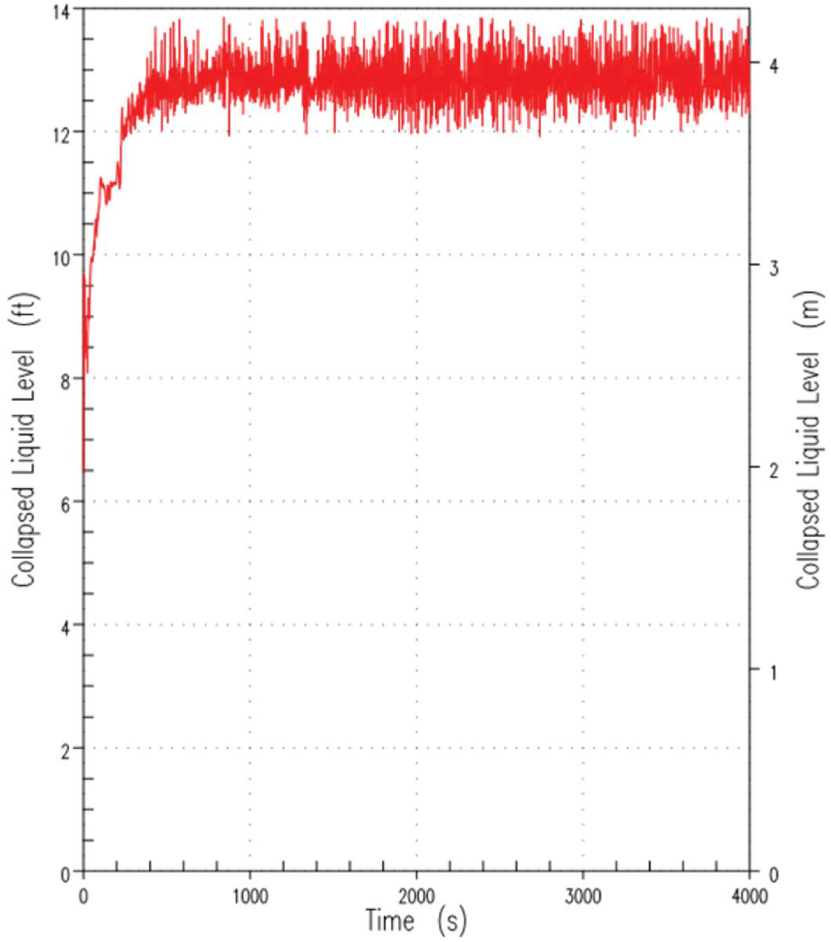


Figure 15.6.5.4C-16
Collapsed Level of Liquid Over the Heated Length of the Fuel (Wall-to-Wall Floodup Case) – 14.7 psia

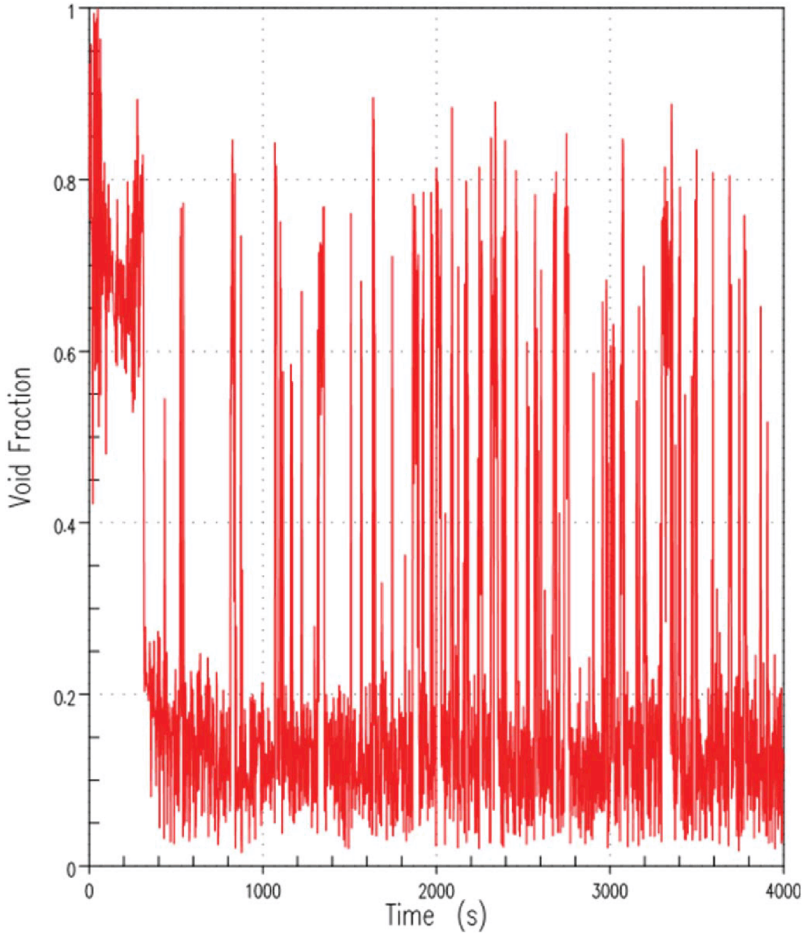


Figure 15.6.5.4C-17
Void Fraction in Core Hot Assembly Top Cell
(Wall-to-Wall Floodup Case) – 14.7 psia

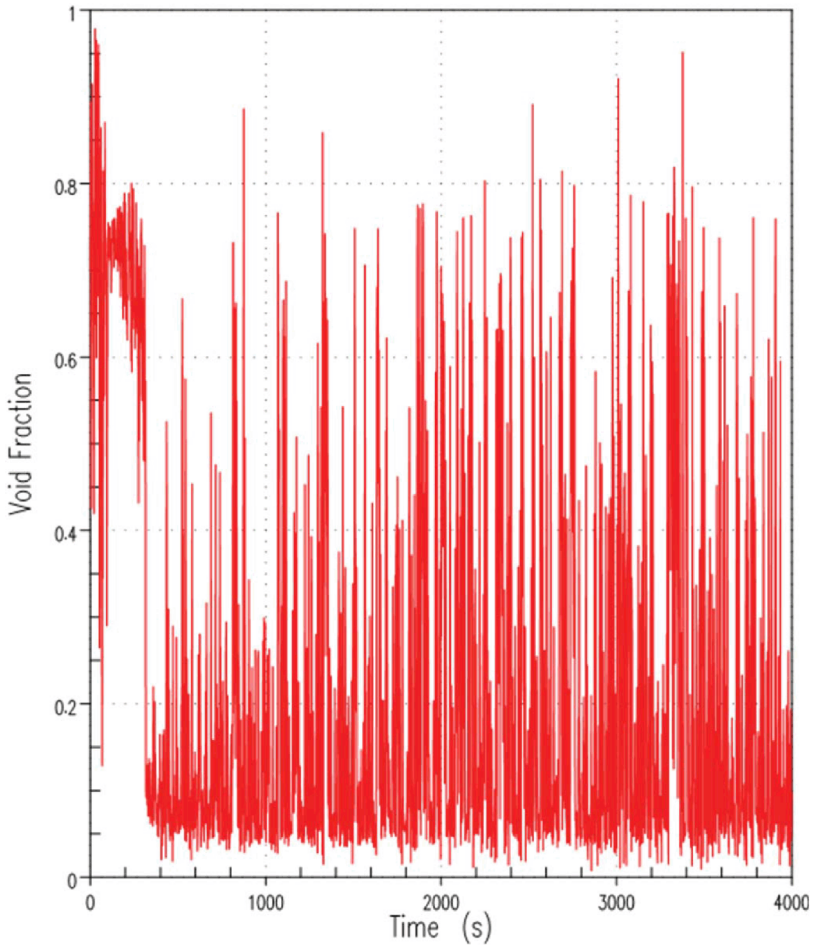


Figure 15.6.5.4C-18
Void Fraction in Core Hot Assembly Second from Top Cell
(Wall-to-Wall Floodup Case) – 14.7 psia

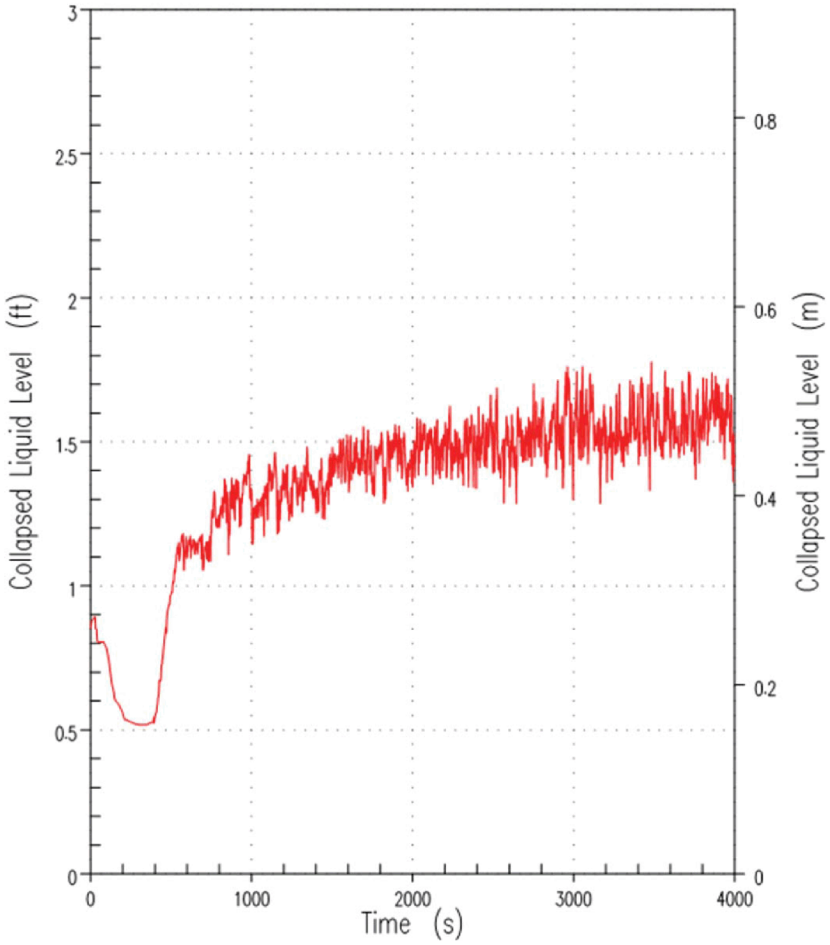


Figure 15.6.5.4C-19
Collapsed Liquid Level in the Hot Leg of Pressurizer Loop (Wall-to-Wall Floodup Case) – 14.7 psia

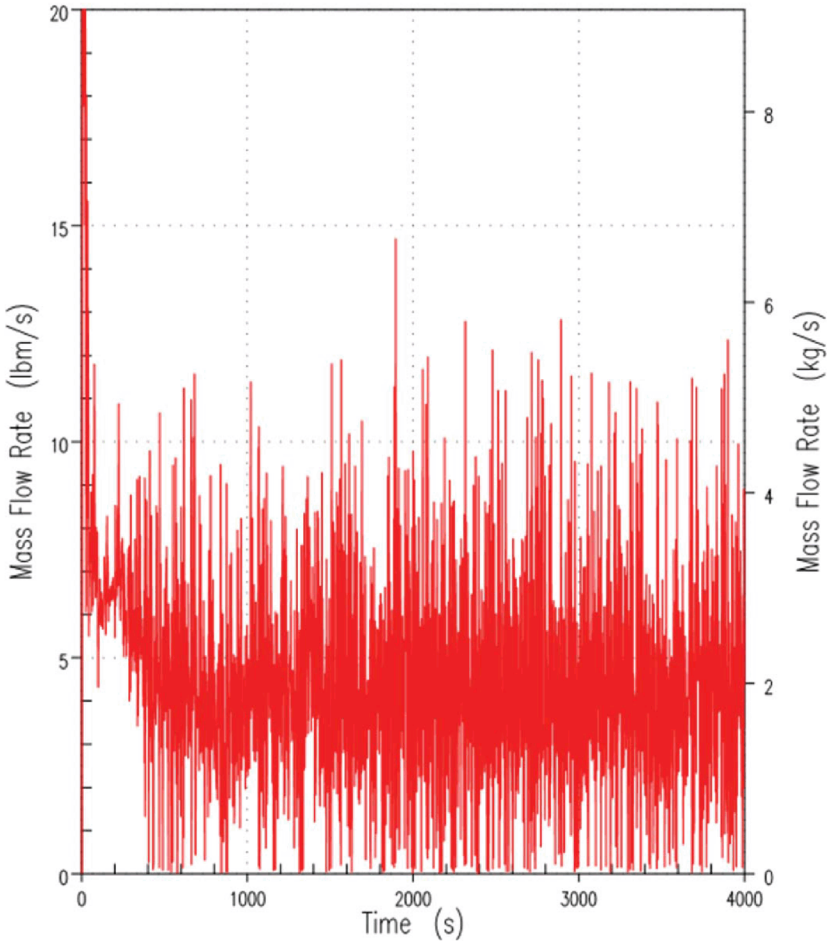


Figure 15.6.5.4C-20
Vapor Rate out of the Core
(Wall-to-Wall Floodup Case) – 14.7 psia

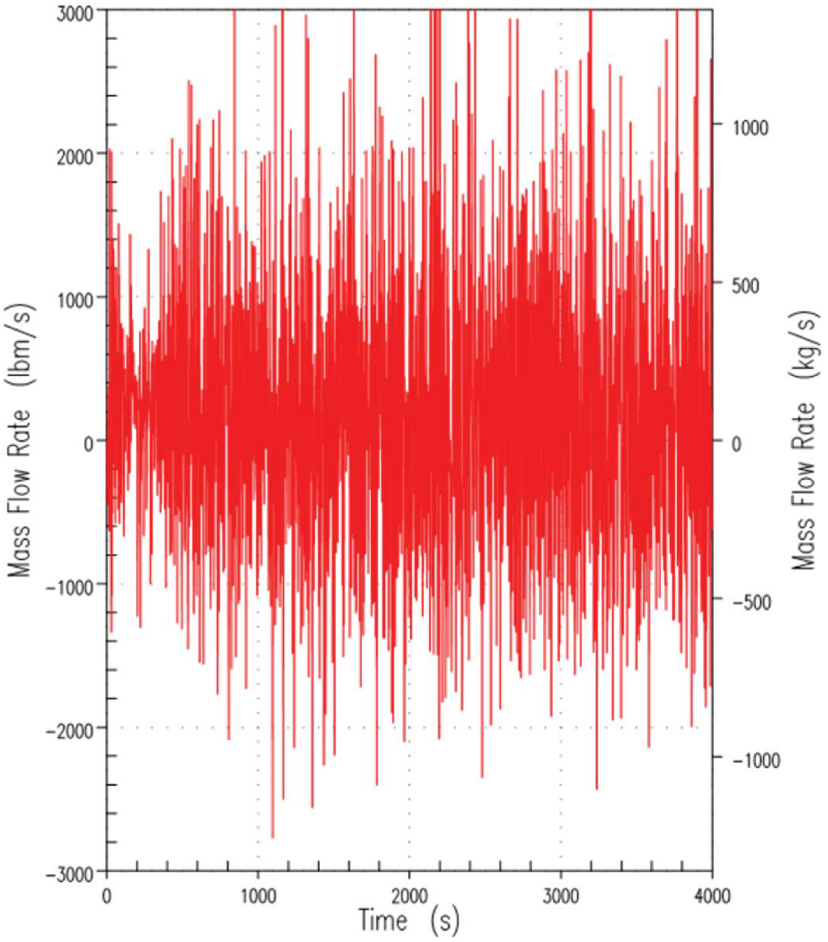


Figure 15.6.5.4C-21
Liquid Flow Rate out of the Core
(Wall-to-Wall Floodup Case) – 14.7 psia

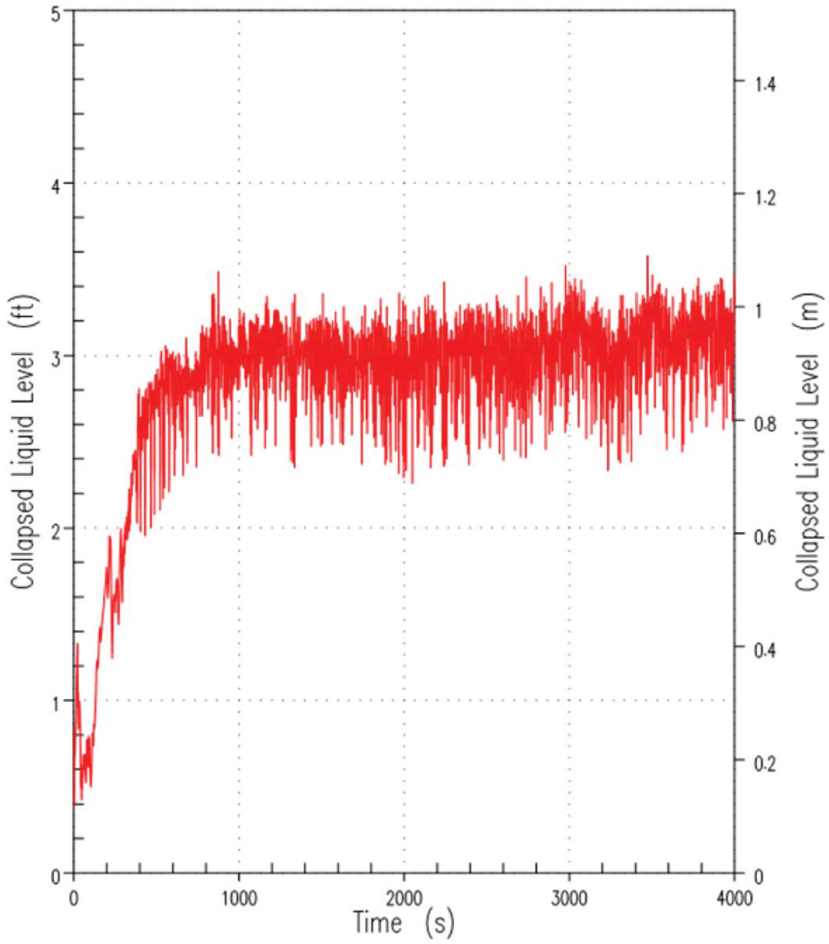


Figure 15.6.5.4C-22
Collapsed Liquid Level in the Upper Plenum
(Wall-to-Wall Floodup Case) – 14.7 psia

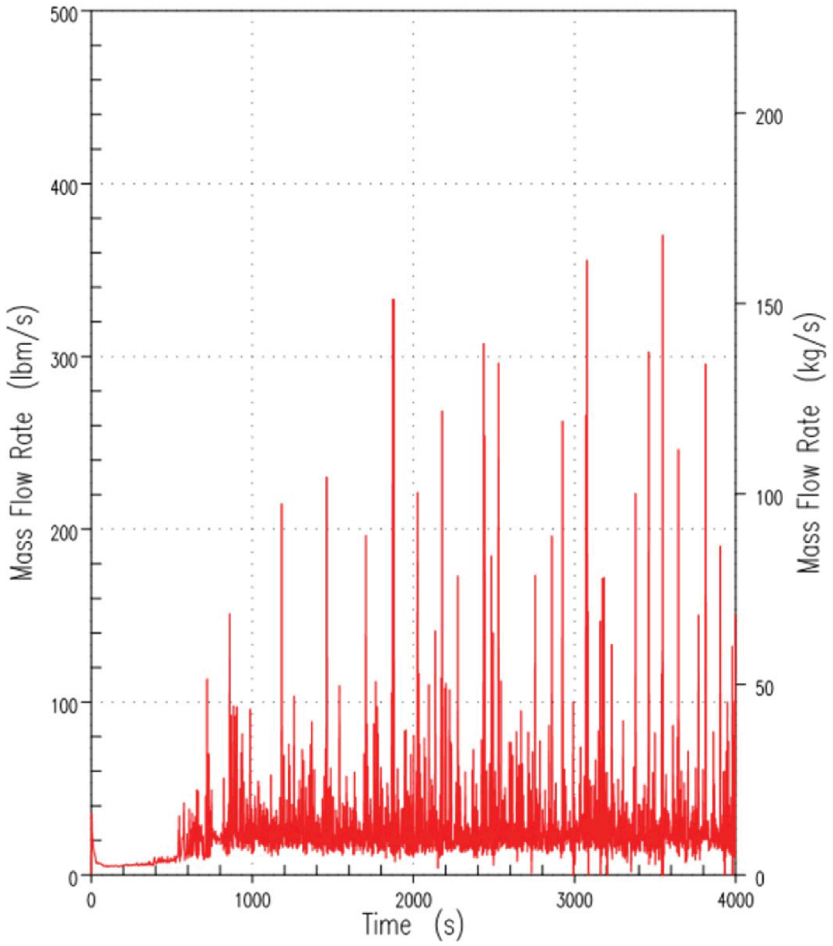


Figure 15.6.5.4C-23
Mixture Flow Rate Through ADS Stage 4A Valves
(Wall-to-Wall Floodup Case) – 14.7 psia

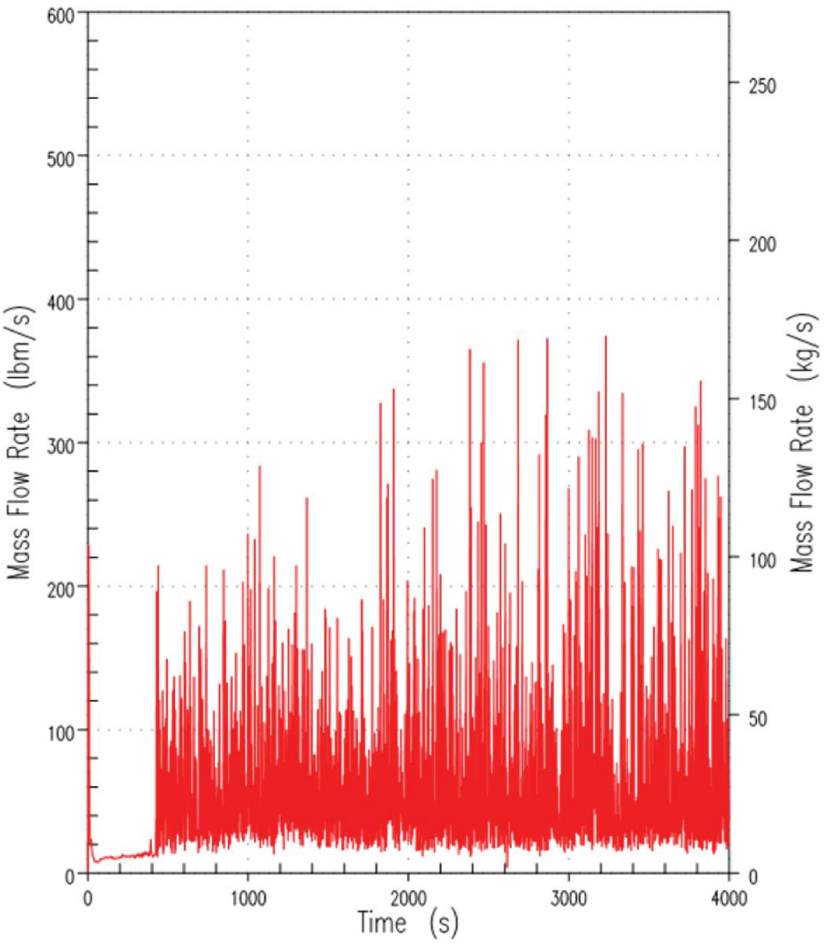


Figure 15.6.5.4C-24
Mixture Flow Rate Through ADS Stage 4B Valves
(Wall-to-Wall Floodup Case) – 14.7 psia

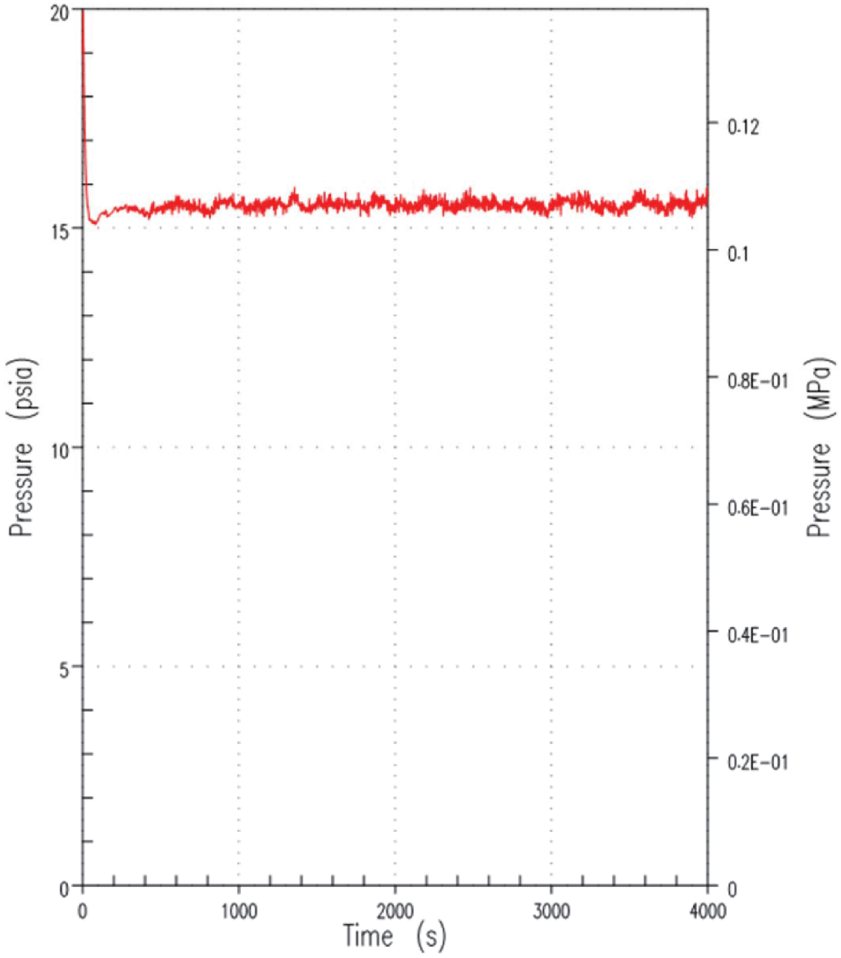


Figure 15.6.5.4C-25
Upper Plenum Pressure
(Wall-to-Wall Floodup Case) – 14.7 psia

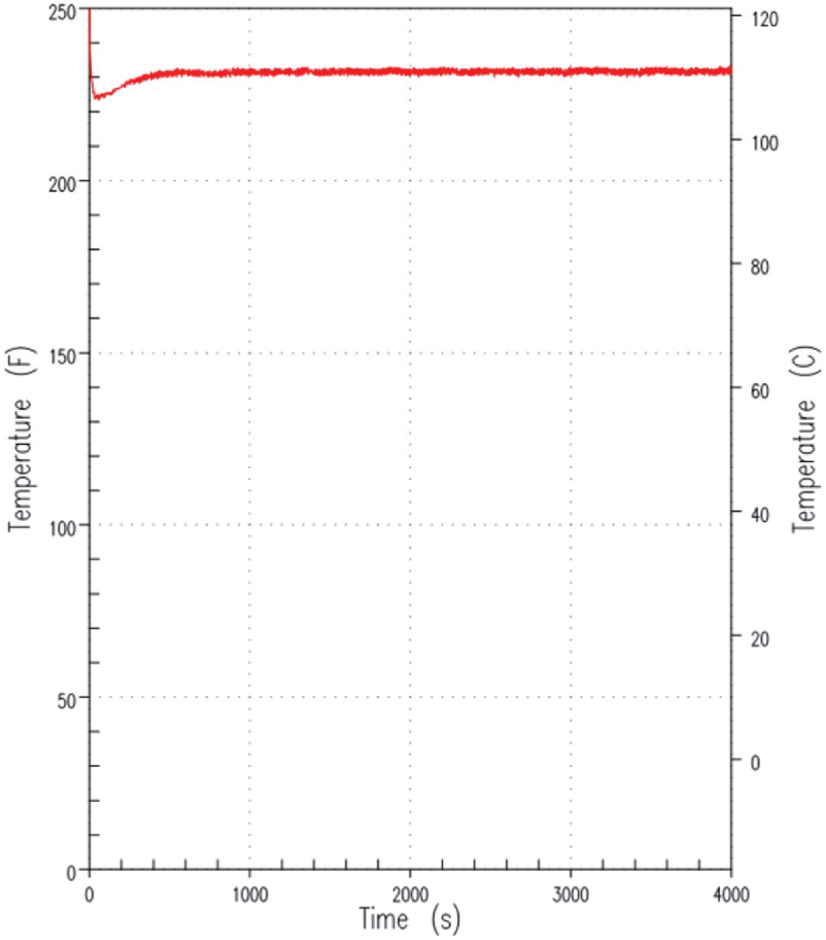


Figure 15.6.5.4C-26
Hot Rod Cladding Temperature Near Top of Core
(Wall-to-Wall Floodup Case) – 14.7 psia

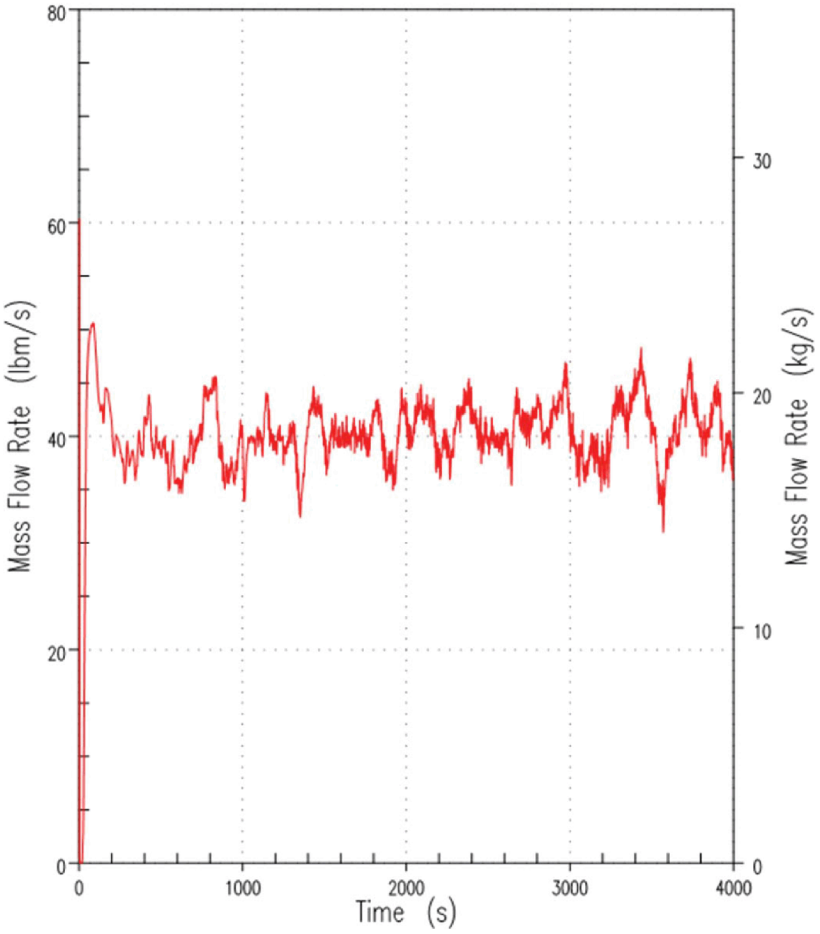


Figure 15.6.5.4C-27
DVI-A Mixture Flow Rate
(Wall-to-Wall Floodup Case) – 14.7 psia

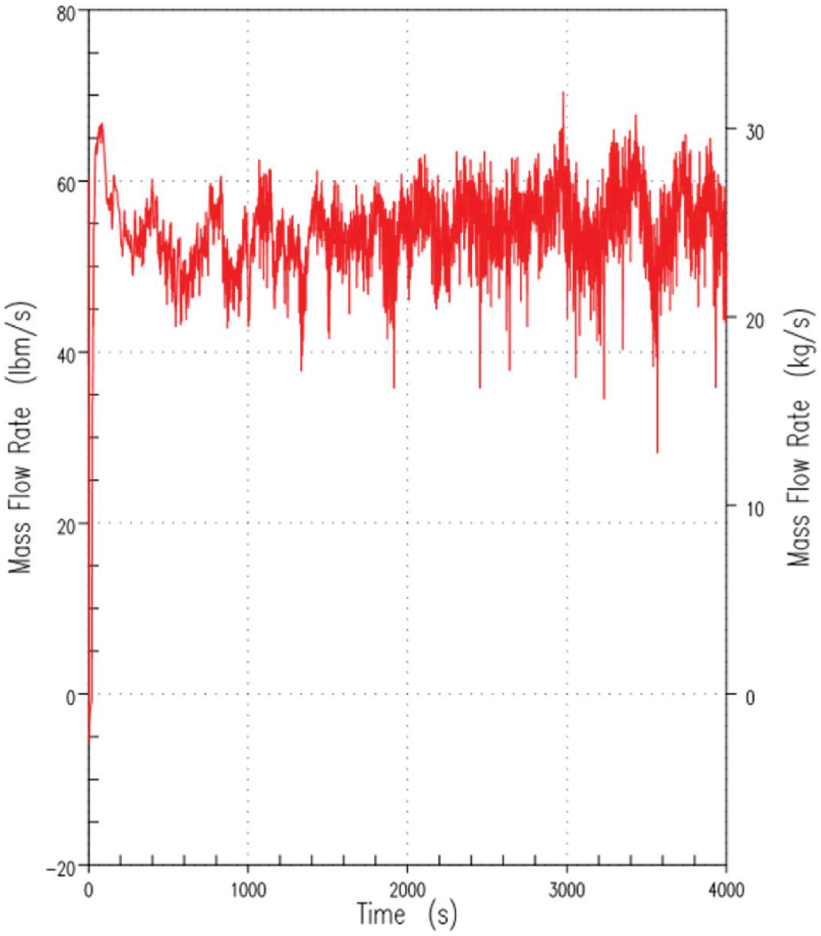


Figure 15.6.5.4C-28
DVI-B Mixture Flow Rate
(Wall-to-Wall Floodup Case) – 14.7 psia

15.7 Radioactive Release from a Subsystem or Component

This group of events includes the following:

- Gas waste management system leak or failure
- Liquid waste management system leak or failure (atmospheric release)
- Release of radioactivity to the environment via liquid pathways
- Fuel handling accident
- Spent fuel cask drop accident

15.7.1 Gas Waste Management System Leak or Failure

The AP1000 gaseous radwaste system is a low-pressure, low-flow charcoal delay process. Failure of the gaseous radwaste system results in a minor release of activity that is not significant. The Standard Review Plan no longer includes this event as part of the review. Therefore, no analysis is provided.

15.7.2 Liquid Waste Management System Leak or Failure (Atmospheric Release)

The AP1000 liquid radwaste system tanks do not contain significant levels of gaseous activity because liquids expected to contain gaseous radioactivity are processed by a gas stripper before being directed to storage. The tanks are open to the atmosphere so that any evolution of gaseous activity is continually released through the monitored plant vent. The Standard Review Plan no longer includes this event as part of the review. Therefore, no analysis is provided.

15.7.3 Release of Radioactivity to the Environment Due to a Liquid Tank Failure

Tanks containing radioactive fluids are located inside plant structures.

In the event of a tank failure, the liquid would be drained by the floor drains to the auxiliary building sump. From the sump, the water would be directed to the waste holdup tank. The basemat of the auxiliary building is 6-feet thick, the exterior walls are 3-feet thick, and the building is seismic Category I. The exterior walls are sealed to prevent leakage. Thus, it is assumed that there is no release of the spilled liquid waste to the environment. However, the Standard Review Plan states that credit cannot be taken for liquid retention by unlined building foundations. Analysis of the impact of this event is performed as discussed in Subsection 2.4.13. This analysis includes consideration of tank liquid level, processing and decay of tank contents, potential paths of spilled waste to the environment, as well as other pertinent factors.

15.7.4 Fuel Handling Accident

A fuel handling accident can be postulated to occur either inside the containment or in the fuel handling area inside the auxiliary building. The fuel handling accident is defined as the dropping of a spent fuel assembly such that every rod in the dropped assembly has its cladding breached so that the activity in the fuel/cladding gap is released.

The possibility of a fuel handling accident is remote because of the many administrative controls and the equipment operating limits that are incorporated in the fuel handling operations (see Subsection 9.1.4). Only one spent fuel assembly is lifted at a time, and the fuel is moved at low speeds, exercising caution that the fuel assembly not strike anything during movement. The containment, auxiliary building, refueling pool, and spent fuel pool are designed to seismic Category I requirements to thus provide their integrity in the event of a safe shutdown earthquake. The spent fuel storage racks are located to prevent a credible external missile from reaching the stored fuel assemblies. The fuel handling equipment is designed to prevent the handling equipment from falling

onto the fuel in the reactor vessel or that stored in the spent fuel pool. The facility is designed so that heavy objects, such as the spent fuel shipping cask, cannot be carried over or tipped into the spent fuel pool.

15.7.4.1 Source Term

The inventory of fission products available for release at the time of the accident is dependent on a number of factors, such as the power history of the fuel assembly, the time delay between reactor shutdown and the beginning of fuel handling operations, and the volatility of the nuclides.

The fuel handling accident source term is derived from the core source term detailed in Appendix 15A by taking into account the factors below. The assumptions used to define the fuel handling accident initial airborne release source term are provided in Table 15.7-1 along with the derived source term.

15.7.4.1.1 Fission Product Gap Fraction

During power operation, a portion of the fission products generated in the fuel pellet matrix diffuses into the fuel/cladding gap. The fraction of the assembly fission products found in the gap depends on the rate of diffusion for the nuclide in question as well as the rate of radioactive decay. In the event of a fuel handling accident, the gaseous and volatile radionuclides contained in the fuel/cladding gap are free to escape from the fuel assembly. The radionuclides of concern are the noble gases (kryptons and xenons) and iodines. Based on NUREG-1465 (Reference 1), the fission product gap fraction is 3-percent of fuel inventory. For this analysis, the gap fractions are increased to be consistent with the guidance of Regulatory Guide 1.183 (Reference 2). The gap fractions are listed in Table 15.7-1.

15.7.4.1.2 Iodine Chemical Form

Consistent with NUREG-1465 guidance, the iodine released from the damaged fuel rods is assumed to be 95-percent cesium iodide, 4.85-percent elemental iodine, and 0.15-percent organic iodine.

Cesium iodide is nonvolatile, and the iodine in this form dissolves in water but does not readily become airborne. However, consistent with the guidance in Regulatory Guide 1.183, it is assumed that the cesium iodide is instantaneously converted to the elemental form when released from the fuel into the low pH water pool.

15.7.4.1.3 Assembly Power Level

All fuel assemblies are assumed to be handled inside the containment during the core shuffle so a peak power assembly is considered for the accident. Any fuel assembly can be transferred to the spent fuel pool; during a core off-load, all fuel assemblies are discharged to the spent fuel pool. To obtain a bounding condition for the fuel handling accident analysis, it is assumed that the accident involves a fuel assembly that operated at the maximum rated fuel rod peaking factor. This is conservative because the entire fuel assembly does not operate at this level.

15.7.4.1.4 Radiological Decay

The fission product decay time experienced prior to the fuel handling accident is at least 48 hours.

15.7.4.2 Release Pathways

The spent fuel handling operations take place underwater. Thus, activity releases are first scrubbed by the column of water 23 feet in depth. This has no effect on the releases of noble gases or organic

iodine but there is a significant removal of elemental iodine. Consistent with the guidance in Regulatory Guide 1.183, the overall pool scrubbing decontamination factor for iodine is assumed to be 200.

In the case of a single bundle dropped and lying horizontally on top of the spent fuel racks, there may be less than 23 feet of water above the top of the fuel bundle and the surface of the water, indicated by the width of the bundle. The fuel handling accident analysis bounds the case of a single bundle lying horizontally on top of the spent fuel racks by demonstrating that the overall decontamination factor of 200 is valid for pool depths of 21.5 feet.

After the activity escapes from the water pool, it is assumed that it is released directly to the environment within a 2-hour period without credit for any additional iodine removal process.

If the fuel handling accident occurs in the containment, the release of activity can be terminated by closure of the containment purge lines on detection of high radioactivity. No credit is taken for this in the analysis. Additionally, no credit is taken for removal of airborne iodine by the filters in the containment purge lines.

For the fuel handling accident postulated to occur in the spent fuel pool, there is assumed to be no filtration in the release pathway. Activity released from the pool is assumed to pass directly to the environment with no credit for holdup or delay of release in the building.

15.7.4.3 Dose Calculation Models

The models used to calculate doses are provided in Appendix 15A.

Table 15.7-1 lists the assumptions used in the analysis. The guidance of Regulatory Guide 1.183 is reflected in the analysis assumptions.

15.7.4.4 Identification of Conservatisms

The fuel handling accident dose analysis assumptions contain a number of conservatisms. Some of these conservatisms are described in the following subsections.

15.7.4.4.1 Fuel Assembly Power Level

The source term is based on the assumption that all of the fuel rods in the damaged assembly have been operating at the maximum fuel rod radial peaking factor. In actuality, this is true for only a small fraction of the fuel rods in any assembly. The overall assembly power level is less than the maximum radial peaking factor.

15.7.4.4.2 Fission Product Gap Fraction

The assumption of Regulatory Guide 1.183 gap fractions for the short-lived nuclides is conservative by a factor of 2 or more, depending on the nuclide.

15.7.4.4.3 Amount of Fuel Damage

It is assumed that all fuel rods in a fuel assembly are damaged so as to release the fission product inventory in the fuel/cladding gap. In an actual fuel handling accident, it is expected that there would be few rods damaged to this extent.

15.7.4.4.4 Iodine Plateout on Fuel Cladding

Although it is expected that virtually all elemental iodine plates out on the fuel cladding and is unavailable for atmospheric release, no credit is taken for plateout.

15.7.4.4.5 Presence of Organic Iodine

Although 0.15% of the iodine is assumed to be in the organic form (and thus not subject to scrubbing removal in the water pool), there would be no organic iodine in the fuel rods. Any formation of organic iodine would occur gradually and would not contribute to early releases of activity.

15.7.4.4.6 Conversion of Cesium Iodide to Form Elemental Iodine

The analysis assumes that all of the cesium iodide converts immediately to the elemental iodine form after release to the water pool and is treated in the same manner as the iodine initially in the elemental form. While the low pH solution does support conversion to the elemental form, the conversion would not occur unless the cesium iodide was dissolved in the water. The elemental iodine that is formed would thus be in the water solution and not in the bubbles of gas released from the damaged fuel. Additionally, conversion of cesium iodide would occur slowly and the elemental iodine formed would not be immediately available for release.

15.7.4.4.7 Meteorology

It is unlikely that the conservatively selected meteorological conditions are present at the time of the accident.

15.7.4.4.8 Time Available for Radioactive Decay

The dose analysis assumes that the fuel handling accident involves one of the first fuel assemblies handled. If it were one of the later fuel handling operations, there is additional decay and a reduction in the source term.

The dose evaluation was performed assuming 48 hours decay.

15.7.4.5 Offsite Doses

Using the assumptions from Table 15.7-1, the calculated doses from the initial releases are determined to be 2.8 rem TEDE at the site boundary and 1.2 rem TEDE at the low population zone outer boundary. These doses are well within the dose guideline of 25 rem TEDE identified in 10 CFR Part 50.34. The phrase "well within" is taken as meaning 25 percent or less.

15.7.5 Spent Fuel Cask Drop Accident

The spent fuel cask handling crane is prevented from travelling over the spent fuel. No radiological consequences analysis is necessary for the dropped cask event.

15.7.6 Combined License Information

An analysis of the consequences of potential release of radioactivity to the environment due to a liquid tank failure is addressed in Subsection 2.4.13.

15.7.7 References

1. Sofer, L., et al., "Accident Source Terms for Light-Water Nuclear Power Plants," NUREG-1465, February 1995.

2. U. S. NRC Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors, " July 2000.

Table 15.7-1
Assumptions Used to Determine
Fuel Handling Accident Radiological Consequences

Source term assumptions	
– Core power (MWt)	3434(1)
– Decay time (hr)	48
Core source term after 48 hours decay (Ci)	
I-130	1.28 E+05
I-131	8.18 E+07
I-132	9.10 E+07
I-133	4.06 E+07
I-135	1.17 E+06
Kr-85m	1.52 E+04
Kr-85	1.07 E+06
Kr-88	5.45 E+02
Xe-131m	1.02 E+06
Xe-133m	4.47 E+06
Xe-133	1.70 E+08
Xe-135m	1.91 E+05
Xe-135	1.04 E+07
Number of fuel assemblies in core	157
Amount of fuel damage	One assembly
Maximum rod radial peaking factor	1.75
Percentage of fission products in gap	
I-131	8
Other iodines	5
Kr-85	10
Other noble gases	5
Pool decontamination factor for iodine	200
Activity release period (hr)	2
Atmospheric dispersion factors	See Table 15A-5 in Appendix 15A
Breathing rates (m^3/sec)	3.5 E-4
Nuclide data	See Appendix 15A

Note:

1. The main feedwater flow measurement supports a 1-percent power uncertainty.

15.8 Anticipated Transients Without Scram

15.8.1 General Background

An anticipated transient without scram (ATWS) is an anticipated operational occurrence during which an automatic reactor scram is required but fails to occur due to a common mode fault in the reactor protection system. Under certain circumstances, failure to execute a required scram during an anticipated operational occurrence could transform a relatively minor transient into a more severe accident. ATWS events are not considered to be in the design basis for Westinghouse plants.

15.8.2 Anticipated Transients Without Scram in the AP1000

For Westinghouse plants, the ATWS rule (10 CFR 50.62) requires the installation of equipment that is diverse from the reactor protection system to automatically trip the turbine and initiate decay heat removal. This equipment must be designed to perform its function in a reliable manner and be independent from sensor output to final actuation device from the existing reactor protection system.

The basis for the ATWS rule requirements, as outlined in SECY-83-293 (Reference 1), is to reduce the risk of core damage because of ATWS to less than 10^{-5} per reactor year.

The AP1000 includes a diverse actuation system, which provides the AMSAC protection features mandated for Westinghouse plants by 10 CFR 50.62, plus a diverse reactor scram (see Section 7.7). Thus, the ATWS rule is met.

15.8.3 Conclusion

The AP1000 is equipped with a diverse actuation system, which provides the functions required by the ATWS rule (10 CFR 50.62). The ATWS core damage frequency for the AP1000 is well below the SECY-83-293 goal of 10^{-5} per reactor year. The AP1000 ATWS core damage frequency is discussed in Chapter 33 of the Probabilistic Risk Assessment (PRA). The AP1000 design meets the ATWS rule (10 CFR 50.62) and its ATWS core damage frequency safety goal basis.

15.8.4 Combined License Information

This section contained no requirement for additional information.

15.8.5 References

1. Dircks, W. J., "Amendments to 10 CFR 50 Related to Anticipated Transients Without Scram (ATWS) Events," SECY-83-293, U.S. NRC, July 19, 1983.

Appendix 15A Evaluation Models and Parameters for Analysis of Radiological Consequences of Accidents

This appendix contains the parameters and models that form the basis of the radiological consequences analyses for the various postulated accidents.

15A.1 Offsite Dose Calculation Models

Radiological consequences analyses are performed to determine the total effective dose equivalent (TEDE) doses associated with the postulated accident. The determination of TEDE doses takes into account the committed effective dose equivalent (CEDE) dose resulting from the inhalation of airborne activity (that is, the long-term dose accumulation in the various organs) as well as the effective dose equivalent (EDE) dose resulting from immersion in the cloud of activity.

15A.1.1 Immersion Dose (Effective Dose Equivalent)

Assuming a semi-infinite cloud, the immersion doses are calculated using the equation:

$$D_{im} = \sum_i DCF_i \sum_j R_{ij} (\chi/Q)_j$$

where:

D_{im} = Immersion (EDE) dose (rem)

DCF_i = EDE dose conversion factor for isotope i (rem-m^3/Ci-s)

R_{ij} = Amount of isotope i released during time period j (Ci)

$(\chi/Q)_j$ = Atmospheric dispersion factor during time period j (s/m^3)

15A.1.2 Inhalation Dose (Committed Effective Dose Equivalent)

The CEDE doses are calculated using the equation:

$$D_{CEDE} = \sum_i DCF_i \sum_j R_{ij} (BR)_j (\chi/Q)_j$$

where:

D_{CEDE} = CEDE dose (rem)

DCF_i = CEDE dose conversion factor (rem per curie inhaled) for isotope i

R_{ij} = Amount of isotope i released during time period j (Ci)

$(BR)_j$ = Breathing rate during time period j (m^3/s)

$(\chi/Q)_j$ = Atmospheric dispersion factor during time period j (s/m^3)

15A.1.3 Total Dose (Total Effective Dose Equivalent)

The TEDE doses are the sum of the EDE and the CEDE doses.

15A.2 Main Control Room Dose Models

Radiological consequences analyses are performed to determine the TEDE doses associated with the postulated accident. The determination of TEDE doses takes into account the CEDE dose resulting from the inhalation of airborne activity (that is, the long-term dose accumulation in the various organs) as well as the EDE dose resulting from immersion in the cloud of activity.

15A.2.1 Immersion Dose Models

Due to the finite volume of air contained in the main control room, the immersion dose for an operator occupying the main control room is substantially less than it is for the case in which a semi-infinite cloud is assumed. The finite cloud doses are calculated using the geometry correction factor from Murphy and Campe (Reference 1).

The equation is:

$$D_{im} = \frac{1}{GF} \sum_{i} DCF_i \sum_{j} (IAR)_{ij} O_j$$

where:

D_{im} = Immersion (EDE) dose (rem)

GF = Main control room geometry factor =$1173/V^{0.338}$

V = Volume of the main control room (ft^3)

DCF_i = EDE dose conversion factor for isotope i (rem-m^3/Ci-s)

$(IAR)_{ij}$ = Integrated activity for isotope i in the main control room during time period j (Ci-s/m^3)

O_j = Fraction of time period j that the operator is assumed to be present

15A.2.2 Inhalation Dose

The CEDE doses are calculated using the equation:

$$D_{CEDE} = \sum_{i} DCF_i \sum_{j} (IAR)_{ij} (BR)_j O_j$$

where:

D_{CEDE} = CEDE dose (rem)

DCF_i = CEDE dose conversion factor (rem per curie inhaled) for isotope i

$(IAR)_{ij}$ = Integrated activity for isotope i in the main control room during time period j (Ci-s/m^3)

$(BR)_j$ = Breathing rate during time period j (m^3/s)

O_j = Fraction of time period j that the operator is assumed to be present

15A.2.3 Total Dose (Total Effective Dose Equivalent)

The TEDE doses are the sum of the EDE and the CEDE doses.

15A.3 General Analysis Parameters

15A.3.1 Source Terms

The sources of radioactivity for release are dependent on the specific accident. Activity may be released from the primary coolant, from the secondary coolant, and from the core if the accident involves fuel failures. The radiological consequences analyses use conservative design basis source terms.

15A.3.1.1 Primary Coolant Source Term

The design basis primary coolant source terms are listed in Table 11.1-2. Primary coolant alkali metal source terms are contained in Table 15A-8. These source terms are based on continuous plant operation with 0.25-percent fuel defects. The remaining assumptions used in determining the Table 11.1-2 primary coolant source terms are listed in Table 11.1-1. The concentrations in Table 15A-8 were calculated using the same methods as those used to develop the source term in Table 11.1-2, only with slightly different inputs (i.e. using a power of 3430 MWt, an initial boron concentration of 1490 ppm, and a shorter operating time).

The accident dose analyses take into account increases in the primary coolant source terms for iodines, alkali metals, and noble gases above those listed in Table 15A-8, consistent with the Tech Spec limits of 1.0 μCi/g dose equivalent I-131 for the iodines and 280 μCi/g dose equivalent Xe-133 for the noble gases. The accident dose analyses concentrations reflecting these increases are contained in Table 15A-9.

The radiological consequences analyses for certain accidents also take into account the phenomenon of iodine spiking, which causes the concentration of radioactive iodines in the primary coolant to increase significantly. Table 15A-1 lists the concentrations of iodine isotopes associated with a pre-existing iodine spike. This is an iodine spike that occurs prior to the accident and for which the peak primary coolant activity is reached at the time the accident is assumed to occur. These isotopic concentrations are also defined as 60 μCi/g dose equivalent I-131. The probability of this adverse timing of the iodine spike and accident is small.

Although it is unlikely for an accident to occur at the same time that an iodine spike is at its maximum reactor coolant concentration, for many accidents it is expected that an iodine spike would be initiated by the accident or by the reactor trip associated with the accident. Table 15A-2 lists the iodine appearance rates (rates at which the various iodine isotopes are transferred from the core to the primary coolant by way of the assumed cladding defects) for normal operation. The iodine spike appearance rates are assumed to be as much as 500 times the normal appearance rates.

15A.3.1.2 Secondary Coolant Source Term

The secondary coolant source term used in the radiological consequences analyses is conservatively assumed to be 1 percent of the primary coolant equilibrium source term. This is more conservative than using the design basis secondary coolant source terms listed in Table 11.1-5.

Because the iodine spiking phenomenon is short-lived and there is a high level of conservatism for the assumed secondary coolant iodine concentrations, the effect of iodine spiking on the secondary coolant iodine source terms is not modeled.

There is assumed to be no secondary coolant noble gas source term because the noble gases entering the secondary side due to primary-to-secondary leakage enter the steam phase and are discharged via the condenser air removal system.

15A.3.1.3 Core Source Term

Table 15A-3 lists the core source terms at shutdown for an assumed three-region equilibrium cycle at end of life after continuous operation at 1 percent above full core thermal power. The main feedwater flow measurement supports a 1-percent power uncertainty. In addition to iodines and noble gases, the source terms listed include nuclides that are identified as potentially significant dose contributors in the event of a degraded core accident. The design basis loss-of-coolant accident analysis is not expected to result in significant core damage, but the radiological consequences analysis assumes severe core degradation.

15A.3.2 Nuclide Parameters

The radiological consequence analyses consider radioactive decay of the subject nuclides prior to their release, but no additional decay is assumed after the activity is released to the environment. Table 15A-4 lists the decay constants for the nuclides of concern.

Table 15A-4 also lists the dose conversion factors for calculation of the CEDE doses due to inhalation of iodines and other nuclides and EDE dose conversion factors for calculation of the dose due to immersion in a cloud of activity. The CEDE dose conversion factors are from EPA Federal Guidance Report No. 11 (Reference 2) and the EDE dose conversion factors are from EPA Federal Guidance Report No. 12 (Reference 3).

15A.3.3 Atmospheric Dispersion Factors

Subsection 2.3.4 lists the off-site short-term atmospheric dispersion factors (χ/Q) for the reference site. Table 15A-5 (Sheet 1 of 2) reiterates these χ/Q values.

The atmospheric dispersion factors (χ/Q) to be applied to air entering the main control room following a design basis accident are specified at the HVAC intake and at the annex building entrance (which would be the air pathway to the main control room due to ingress/egress). A set of reference **AP1000** χ/Q values is identified for each potential activity release location that has been identified and the two control room receptor locations. These reference **AP1000** χ/Q values are listed in Table 15A-6 and are provided in Table 2.0-201.

Site-specific χ/Q values provided in Section 2.3 are bounded by the values given in Tables 15A-5 and 15A-6.

Table 15A-7 identifies the AP1000 source and receptor data to be used when determining the site-specific control room χ/Q values using the ARCON96 code (References 4 and 5).

The main control room reference **AP1000** χ/Q values do not incorporate occupancy factors.

The locations of the potential release points and their relationship to the main control room air intake and the annex building access door are shown in Figure 15A-1.

15A.4 References

1. Murphy, K. G., Campe, K. M., "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19," paper presented at the 13th AEC Air Cleaning Conference.

2. EPA Federal Guidance Report No. 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," EPA-520/1-88-020, September 1988.

3. EPA Federal Guidance Report No. 12, "External Exposure to Radionuclides in Air, Water, and Soil," EPA 402-R-93-081, September 1993.

4. NUREG/CR-6331, Ramsdell, J. V. and Simonen, C. A., "Atmospheric Relative Concentrations in Building Wakes," Revision 1, May 1997.

5. Regulatory Guide 1.194, Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants, June 2003.

Table 15A-1
Reactor Coolant Iodine Concentrations for
Maximum Iodine Spike of 60 µCi/g Dose Equivalent I-131

Nuclide	µCi/g
I-130	0.38
I-131	42.8
I-132	61.8
I-133	81.6
I-134	15.7
I-135	51.9

Table 15A-2
Iodine Appearance Rates in the Reactor Coolant

Nuclide	Equilibrium Appearance Rate (Ci/min)
I-130	4.05E-03
I-131	3.34E-01
I-132	1.50E+00
I-133	7.70E-01
I-134	8.07E-01
I-135	6.96E-01

Table 15A-3 (Sheet 1 of 2)
Reactor Core Source Term(1)

	Nuclide	Inventory (Ci)		Nuclide	Inventory (Ci)
Iodines	I-130	1.87E+06	Noble Gases	Kr-85m	2.52E+07
	I-131	9.48E+07		Kr-85	1.07E+06
	I-132	1.38E+08		Kr-87	4.96E+07
	I-133	1.95E+08		Kr-88	6.66E+07
	I-134	2.19E+08		Xe-131m	1.03E+06
	I-135	1.85E+08		Xe-133m	6.07E+06
Cs Group	Cs-134	1.65E+07		Xe-133	1.92E+08
	Cs-136	3.87E+06		Xe-135m	4.08E+07
	Cs-137	1.09E+07		Xe-135	3.87E+07
	Cs-138	1.82E+08		Xe-138	1.66E+08
	Rb-86	1.80E+05	Sr & Ba	Sr-89	9.48E+07
Te Group	Te-127m	1.37E+06		Sr-90	8.34E+06
	Te-127	8.44E+06		Sr-91	1.17E+08
	Te-129m	4.74E+06		Sr-92	1.25E+08
	Te-129	2.49E+07		Ba-139	1.73E+08
	Te-131m	1.88E+07		Ba-140	1.68E+08
	Te-132	1.35E+08	Ce Group	Ce-141	1.59E+08
	Sb-127	8.71E+06		Ce-143	1.48E+08
	Sb-129	2.67E+07		Ce-144	1.22E+08
Ru Group	Ru-103	1.44E+08		Pu-238	2.22E+05
	Ru-105	9.92E+07		Pu-239	2.53E+04
	Ru-106	4.54E+07		Pu-240	3.96E+04
	Rh-105	9.21E+07		Pu-241	1.01E+07
	Mo-99	1.77E+08		Np-239	1.99E+09
	Tc-99m	1.56E+08			

Note:

1. The following assumptions apply:
   - Core thermal power of 3434 MWt (1 percent above the design core power of 3400 MWt). The main feedwater flow measurement supports a 1-percent power uncertainty.
   - Three-region equilibrium cycle core at end of life

Table 15A-3 (Sheet 2 of 2)
Reactor Core Source Term(1)

	Nuclide	Inventory (Ci)
La Group	Y-90	8.73E+06
	Y-91	1.23E+08
	Y-92	1.26E+08
	Y-93	1.42E+08
	Nb-95	1.65E+08
	Zr-95	1.63E+08
	Zr-97	1.62E+08
	La-140	1.77E+08
	La-142	1.52E+08
	Pr-143	1.44E+08
	Nd-147	6.12E+07
	Am-241	1.04E+04
	Cm-242	2.81E+06
	Cm-244	2.42E+05

Note:

1. The following assumptions apply:
   - Core thermal power of 3434 MWt (1 percent above the design core power of 3400 MWt). The main feedwater flow measurement supports a 1-percent power uncertainty.
   - Three-region equilibrium cycle core at end of life

Table 15A-4 (Sheet 1 of 4)
Nuclide Parameters

A. HALOGENS			
Isotope	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	**CEDE Dose Conversion Factor (Sv/Bq)**
I-130	5.61×10^{-2}	1.04×10^{-13}	7.14×10^{-10}
I-131	3.59×10^{-3}	1.82×10^{-14}	8.89×10^{-9}
I-132	3.01×10^{-1}	1.12×10^{-13}	1.03×10^{-10}
I-133	3.33×10^{-2}	2.94×10^{-14}	1.58×10^{-9}
I-134	7.91×10^{-1}	1.30×10^{-13}	3.55×10^{-11}
I-135	1.05×10^{-1}	7.98×10^{-14}	3.32×10^{-10}
B. NOBLE GASES			
Isotope	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	
Kr-85m	1.55×10^{-1}	7.48×10^{-15}	
Kr-85	7.38×10^{-6}	1.19×10^{-16}	
Kr-87	5.45×10^{-1}	4.12×10^{-14}	
Kr-88	2.44×10^{-1}	1.02×10^{-13}	
Xe-131m	2.43×10^{-3}	3.89×10^{-16}	
Xe-133m	1.32×10^{-2}	1.37×10^{-15}	
Xe-133	5.51×10^{-3}	1.56×10^{-15}	
Xe-135m	2.72	2.04×10^{-14}	
Xe-135	7.63×10^{-2}	1.19×10^{-14}	
Xe-138	2.93	5.77×10^{-14}	

Table 15A-4 (Sheet 2 of 4)
Nuclide Parameters

C. ALKALI METALS			
Nuclide	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	**CEDE Dose Conversion Factor (Sv/Bq)**
Cs-134	$3.84x10^{-5}$	$7.57x10^{-14}$	$1.25x10^{-8}$
Cs-136	$2.2x10^{-3}$	$1.06x10^{-13}$	$1.98x10^{-9}$
Cs-137(1)	$2.64x10^{-6}$	$2.88x10^{-14}$	$8.63x10^{-9}$
Cs-138	1.29	$1.21x10^{-13}$	$2.74x10^{-11}$
Rb-86	$1.55x10^{-3}$	$4.81x10^{-15}$	$1.79x10^{-9}$
D. TELLURIUM GROUP			
Nuclide	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	**CEDE Dose Conversion Factor (Sv/Bq)**
Te-127m	$2.65x10^{-4}$	$1.47x10^{-16}$	$5.81x10^{-9}$
Te-127	$7.41x10^{-2}$	$2.42x10^{-16}$	$8.60x10^{-11}$
Te-129m	$8.6x10^{-4}$	$1.55x10^{-15}$	$6.47x10^{-9}$
Te-129	$5.98x10^{-1}$	$2.75x10^{-15}$	$2.42x10^{-11}$
Te-131m	$2.31x10^{-2}$	$7.01x10^{-14}$	$1.73x10^{-9}$
Te-132	$8.86x10^{-3}$	$1.03x10^{-14}$	$2.55x10^{-9}$
Sb-127	$7.5x10^{-3}$	$3.33x10^{-14}$	$1.63x10^{-9}$
Sb-129	$1.6x10^{-1}$	$7.14x10^{-14}$	$1.74x10^{-10}$
E. STRONTIUM AND BARIUM			
Nuclide	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	**CEDE Dose Conversion Factor (Sv/Bq)**
Sr-89	$5.72x10^{-4}$	$7.73x10^{-17}$	$1.12x10^{-8}$
Sr-90	$2.72x10^{-6}$	$7.53x10^{-18}$	$3.51x10^{-7}$
Sr-91	$7.3x10^{-2}$	$3.45x10^{-14}$	$4.49x10^{-10}$
Sr-92	$2.56x10^{-1}$	$6.79x10^{-14}$	$2.18x10^{-10}$
Ba-139	$5.02x10^{-1}$	$2.17x10^{-15}$	$4.64x10^{-11}$
Ba-140	$2.27x10^{-3}$	$8.58x10^{-15}$	$1.01x10^{-9}$

Note:

1. The listed average gamma disintegration energy for Cs-137 is due to the production and decay of Ba-137m.

Table 15A-4 (Sheet 3 of 4)
Nuclide Parameters

F. NOBLE METALS			
Nuclide	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	**CEDE Dose Conversion Factor (Sv/Bq)**
Ru-103	$7.35x10^{-4}$	$2.25x10^{-14}$	$2.42x10^{-9}$
Ru-105	$1.56x10^{-1}$	$3.81x10^{-14}$	$1.23x10^{-10}$
Ru-106	$7.84x10^{-5}$	0.0	$1.29x10^{-7}$
Rh-105	$1.96x10^{-2}$	$3.72x10^{-15}$	$2.58x10^{-10}$
Mo-99	$1.05x10^{-2}$	$7.28x10^{-15}$	$1.07x10^{-9}$
Tc-99m	$1.15x10^{-1}$	$5.89x10^{-15}$	$8.80x10^{-12}$
G. CERIUM GROUP			
Nuclide	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	**CEDE Dose Conversion Factor (Sv/Bq)**
Ce-141	$8.89x10^{-4}$	$3.43x10^{-15}$	$2.42x10^{-9}$
Ce-143	$2.1x10^{-2}$	$1.29x10^{-14}$	$9.16x10^{-10}$
Ce-144	$1.02x10^{-4}$	$8.53x10^{-16}$	$1.01x10^{-7}$
Pu-238	$9.02x10^{-7}$	$4.88x10^{-18}$	$1.06x10^{-4}$
Pu-239	$3.29x10^{-9}$	$4.24x10^{-18}$	$1.16x10^{-4}$
Pu-240	$1.21x10^{-8}$	$4.75x10^{-18}$	$1.16x10^{-4}$
Pu-241	$5.5x10^{-6}$	$7.25x10^{-20}$	$2.23x10^{-6}$
Np-239	$1.23x10^{-2}$	$7.69x10^{-15}$	$6.78x10^{-10}$

Table 15A-4 (Sheet 4 of 4)
Nuclide Parameters

H. LANTHANIDE GROUP			
Nuclide	**Decay Constant (hr^{-1})**	**EDE Dose Conversion Factor ($Sv\text{-}m^3/Bq\text{-}s$)**	**CEDE Dose Conversion Factor (Sv/Bq)**
Y-90	1.08×10^{-2}	1.90×10^{-16}	2.28×10^{-9}
Y-91	4.94×10^{-4}	2.60×10^{-16}	1.32×10^{-8}
Y-92	1.96×10^{-1}	1.30×10^{-14}	2.11×10^{-10}
Y-93	6.86×10^{-2}	4.80×10^{-15}	5.82×10^{-10}
Nb-95	8.22×10^{-4}	3.74×10^{-14}	1.57×10^{-9}
Zr-95	4.51×10^{-4}	3.60×10^{-14}	6.39×10^{-9}
Zr-97	4.1×10^{-2}	9.02×10^{-15}	1.17×10^{-9}
La-140	1.72×10^{-2}	1.17×10^{-13}	1.31×10^{-9}
La-141	1.76×10^{-1}	2.39×10^{-15}	1.57×10^{-10}
La-142	4.5×10^{-1}	1.44×10^{-13}	6.84×10^{-11}
Nd-147	2.63×10^{-3}	6.19×10^{-15}	1.85×10^{-9}
Pr-143	2.13×10^{-3}	2.10×10^{-17}	2.19×10^{-9}
Am-241	1.83×10^{-7}	8.18×10^{-16}	1.20×10^{-4}
Cm-242	1.77×10^{-4}	5.69×10^{-18}	4.67×10^{-6}
Cm-244	4.37×10^{-6}	4.91×10^{-18}	6.70×10^{-5}

Table 15A-5
Offsite Atmospheric Dispersion Factors (χ/Q) for Accident Dose Analysis

Site boundary χ/Q (s/m^3)	
0–2 hours(1)	5.1×10^{-4}
Low population zone χ/Q (s/m^3)	
0–8 hours	2.2×10^{-4}
8–24 hours	1.6×10^{-4}
24–96 hours	1.0×10^{-4}
96–720 hours	8.0×10^{-5}

Note:

1. Nominally defined as the 0- to 2-hour interval but is applied to the 2-hour interval having the highest activity releases in order to address 10 CFR Part 50.34 requirements

Table 15A-6
Control Room Atmospheric Dispersion Factors (χ/Q) for Accident Dose Analysis

χ/Q (s/m^3) at HVAC Intake for the Identified Release Points[1]						
	Plant Vent or PCS Air Diffuser[3]	**Ground Level Containment Release Points[4]**	**PORV and Safety Valve Releases[5]**	**Steam Line Break Releases**	**Fuel Handling Area[6]**	**Condenser Air Removal Stack[7]**
0 – 2 hours	2.53E-03	4.00E-03	1.92E-02	2.13E-02	6.0E-3	6.0E-3
2 – 8 hours	1.98E-03	2.28E-03	1.60E-02	1.76E-02	4.0E-3	4.0E-3
8 – 24 hours	7.96E-04	1.03E-03	6.90E-03	7.50E-03	2.0E-3	2.0E-3
1 – 4 days	6.40E-04	9.03E-04	4.96E-03	5.43E-03	1.5E-3	1.5E-3
4 – 30 days	4.78E-04	7.13E-04	4.16E-03	4.55E-03	1.0E-3	1.0E-3
χ/Q (s/m^3) at Annex Building Door for the Identified Release Points[2]						
	Plant Vent or PCS Air Diffuser[3]	**Ground Level Containment Release Points[4]**	**PORV and Safety Valve Releases[5]**	**Steam Line Break Releases**	**Fuel Handling Area[6]**	**Condenser Air Removal Stack[7]**
0 – 2 hours	1.0E-3	1.0E-3	4.0E-3	4.0E-3	6.0E-3	2.0E-2
2 – 8 hours	7.5E-4	7.5E-4	3.2E-3	3.2E-3	4.0E-3	1.8E-2
8 – 24 hours	3.5E-4	3.5E-4	1.2E-3	1.2E-3	2.0E-3	7.0E-3
1 – 4 days	2.8E-4	2.8E-4	1.0E-3	1.0E-3	1.5E-3	5.0E-3
4 – 30 days	2.5E-4	2.5E-4	8.0E-4	8.0E-4	1.0E-3	4.5E-3

Notes:

1. These dispersion factors are to be used 1) for the time period preceding the isolation of the main control room and actuation of the emergency habitability system, 2) for the time after 72 hours when the compressed air supply in the emergency habitability system would be exhausted and outside air would be drawn into the main control room, and 3) for the determination of control room doses when the non-safety ventilation system is assumed to remain operable such that the emergency habitability system is not actuated.
2. These dispersion factors are to be used when the emergency habitability system is in operation and the only path for outside air to enter the main control room is that due to ingress/egress.
3. These dispersion factors are used for analysis of the doses due to a postulated small line break outside of containment. The plant vent and PCS air diffuser are potential release paths for other postulated events (loss-of-coolant accident, rod ejection accident, and fuel handling accident inside the containment); however, the values are bounded by the dispersion factors for ground level releases.
4. The listed values represent modeling the containment shell as a diffuse area source, and are used for evaluating the doses in the main control room for a loss-of-coolant accident, for the containment leakage of activity following a rod ejection accident, and for a fuel handling accident occurring inside the containment.
5. The listed values bound the dispersion factors for releases from the steam line safety & power-operated relief valves. These dispersion factors would be used for evaluating the doses in the main control room for a steam generator tube rupture, a main steam line break, a locked reactor coolant pump rotor, and for the secondary side release from a rod ejection accident.
6. The listed values bound the dispersion factors for releases from the fuel storage and handling area. The listed values also bound the dispersion factors for releases from the fuel storage area in the event that spent fuel boiling occurs and the fuel building relief panel opens on high temperature. These dispersion factors are used for the fuel handling accident occurring outside containment and for evaluating the impact of releases associated with spent fuel pool boiling.
7. This release point is included for information only as a potential activity release point. None of the design basis accident radiological consequences analyses model release from this point.

Table 15A-7
Control Room Source/Receptor Data for Determination Of Atmospheric Dispersion Factors

Source Description	Release Elevation Note 1 (m)	Horizontal Straight-Line Distance To Receptor		
		Control Room HVAC Intake (Elevation 19.7 m) (Δ1)	Annex Building Access (Elevation 1.5 m) (Δ2)	Comment
Plant Vent (⬡1)	55.7	128 ft (39.0 m)	350 ft (106.6 m)	
PCS Air Diffuser (⬡2)	69.8	114 ft (34.7 m)	332 ft (101.1 m)	
Auxiliary Building Fuel Handling Area Blowout Panel (⬡3)	17.4	201 ft (61.2 m)	416 ft (126.8 m)	Note 3
Radwaste Building Truck Staging Area Door (⬡4)	1.5	204 ft (62.1 m)	411 ft (125.2 m)	Note 3
Steam Vent (⬡5)	17.1	55 ft (16.7 m)	250 ft (76.2 m)	
PORV/Safety Valves (⬡6)	19.2	58 ft (17.6 m)	235 ft (71.6 m)	
Condenser Air Removal Stack (⬡7)	49.5	307 ft (93.5 m)	112 ft (34.1 m)	Note 3
Containment Shell (Diffuse Area Source) (⬡8)	Same as Receptor Elevation (19.7 m or 1.5 m)	48 ft (14.6 m)	268 ft (81.6 m)	Note 2

Notes:

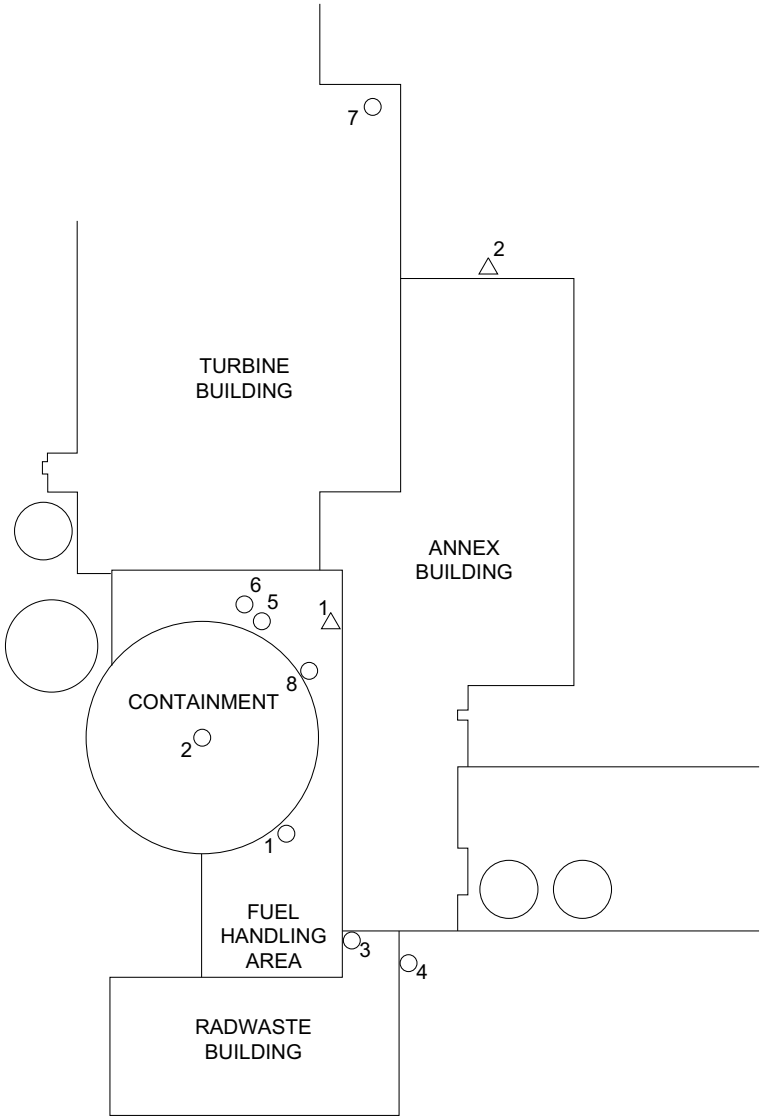
1. All elevations relative to grade at 0.0 m.
2. For calculating distance, the source is defined as the point on the containment shell closest to receptor.
3. Vertical distance traveled is conservatively neglected.
4. ⬡ – Refer to Symbols on Figure 15A-1.
5. Δ – Refer to Symbols on Figure 15A-1.

Table 15A-8
Reactor Coolant Concentrations at Design Fuel Defect Level of 0.25%

Nuclide	Activity (μCi/g)
Kr-85m	7.10E-01
Kr-85	2.50E+00
Kr-87	4.10E-01
Kr-88	1.24E+00
Xe-131m	1.06E+00
Xe-133m	1.23E+00
Xe-133	1.01E+02
Xe-135m	1.41E-01
Xe-135	2.53E+00
Xe-138	2.14E-01
I-130	4.57E-03
I-131	5.17E-01
I-132	7.46E-01
I-133	9.84E-01
I-134	1.90E-01
I-135	6.27E-01
Cs-134	4.53E-01
Cs-136	6.66E-01
Cs-137	3.70E-01
Cs-138	3.19E-01
Rb-86	5.25E-03

Table 15A-9
Reactor Coolant Concentrations for Radiological Consequence Analyses

Nuclide	Activity (μCi/g)
Kr-85m	3.40E+00
Kr-85	1.91E-01
Kr-87	1.08E+01
Kr-88	8.11E+01
Xe-131m	2.64E-01
Xe-133	1.01E+02
Xe-133m	1.08E+00
Xe-135m	1.84E+00
Xe-135	1.93E+01
Xe-138	7.92E+00
I-130	3.67E-04
I-131	5.17E-01
I-132	8.65E-03
I-133	1.75E-01
I-134	7.59E-04
I-135	2.34E-02
Cs-134	6.25E-01
Cs-136	9.19E-01
Cs-137	5.10E-01
Cs-138	4.40E-01
Rb-86	7.24E-03



○ SOURCES

1. PLANT VENT
2. PCS AIR DIFFUSER
3. AUXILIARY BUILDING FUEL HANDLING AREA BLOWOUT PANEL
4. RADWASTE BUILDING TRUCK STAGING AREA DOOR
5. STEAM VENT
6. PORV & SAFETY VALVES
7. CONDENSER AIR REMOVAL STACK
8. CONTAINMENT SHELL (AS DIFFUSE AREA SOURCE)

△ RECEPTORS

1. CONTROL ROOM HVAC INTAKE
2. ANNEX BUILDING ACCESS

Figure 15A-1
Site Plan with Release and Intake Locations

Appendix 15B Removal of Airborne Activity from the Containment Atmosphere Following a LOCA

The AP1000 design does not depend on active systems to remove airborne particulates or elemental iodine from the containment atmosphere following a postulated loss-of-coolant accident (LOCA) with core melt. Naturally occurring passive removal processes provide significant removal capability such that airborne elemental iodine is reduced to very low levels within a few hours and the airborne particulates are reduced to extremely low levels within 12 hours.

15B.1 Elemental Iodine Removal

Elemental iodine is removed by deposition onto the structural surfaces inside the containment. The removal of elemental iodine is modeled using the equation from the Standard Review Plan (Reference 1):

$$\lambda_d = \frac{K_w A}{V}$$

where:

λ_d = first order removal coefficient by surface deposition

K_w = mass transfer coefficient (specified in Reference 1 as 4.9 m/hr)

A = surface area available for deposition

V = containment building volume

The available deposition surface is 251,000 ft^2, and the containment building net free volume is 2.06 x 10^6 ft^3. From these inputs, the elemental iodine removal coefficient is 1.9 hr^{-1}.

Consistent with the guidance of Reference 1, credit for elemental iodine removal is assumed to continue until a decontamination factor (DF) of 200 is reached in the containment atmosphere. Because the source term for the LOCA (defined in Subsection 15.6.5.3) is modeled as a gradual release of activity into the containment, the determination of the time at which the DF of 200 is reached needs to be based on the amount of elemental iodine that enters the containment atmosphere over the duration of core activity release.

15B.2 Aerosol Removal

The deposition removal of aerosols from the containment atmosphere is accomplished by a number of processes including sedimentation, diffusiophoresis, and thermophoresis. All three of the deposition processes are significant contributors to the overall removal process in the AP1000. The large contributions from diffusiophoresis and thermophoresis to the total removal are a direct consequence of the high heat transfer rates from the containment atmosphere to the containment wall that characterize the passive containment cooling system.

Because of the AP1000 passive containment cooling system design, there are high sensible heat transfer rates (resulting in higher thermophoretic removal of aerosols) when condensational heat transfer is low (and the aerosol removal by diffusiophoresis is also low). The reverse is also true. Thus, there is an appreciable deposition removal throughout the accident from either diffusiophoresis or thermophoresis, in addition to the removal by sedimentation.

15B.2.1 Mathematical Models

The models used for the three aerosol removal processes are discussed as follows.

15B.2.1.1 Sedimentation

Gravitational sedimentation is a major mechanism of aerosol removal in a containment. A standard model (Stokes equation with the Cunningham slip correction factor) for this process is used. The Stokes equation (Reference 2) is:

$$\upsilon_s = \frac{2\rho_p g r^2 Cn}{9\mu}$$

where:

u_s = settling velocity of an aerosol particle

ρ_p = material density of the particle

g = gravitational acceleration

r = particle radius

μ = gas viscosity

Cn = Cunningham slip correction factor, a function of the Knudsen number (Kn) which is the gas molecular mean free path divided by the particle radius

However, the Stokes equation makes the simplifying assumption that the particles are spherical. The particles are expected to be nonspherical, and it is conventional to address this by introducing a "dynamic shape factor" (Reference 2) in the denominator of the Stokes equation, such that the settling velocity for the nonspherical particle is the same as for a spherical particle of equal volume. The value of the dynamic shape factor (ϕ) thus depends on the shape of the particle and, in general, must be experimentally determined.

The concept of dynamic shape factor can also be applied to a spherical particle consisting of two components, one of which has the density of the particle material, while the other component has a different density (Reference 9). In this manner, the impact of the void fraction in the particle can be modeled. Thus, the revised Stokes equation is:

$$\upsilon_s = \frac{2\rho_p g r^2 Cn}{9\mu\phi}$$

The derivation of ϕ follows.

The two-component particle is considered to have a density ρ_{av} and an effective radius of r_e. Assuming that the second component of the particle is the void volume and letting the void fraction be ε, then the average density of the particle is:

ρ_{av} = the average density of the particle = $\rho_p (1-\varepsilon) + \rho_v\varepsilon$

where:

ρ_v = density of the void material (0.0 for gas filled, 1.0 for water filled)

ε = void fraction

ρ_p = material density (solid particle with no voids)

The definition of ϕ is obtained from the Stokes equation and the equation for mass of a sphere:

$$\frac{2\rho_p g r^2 Cn}{9\mu\phi} = \frac{2\rho_{av} g r_e^2 Cn}{9\mu}$$

which reduces to:

$$\rho_p r^2 = \phi\rho_{av} r_e^2$$

and

$$\frac{4\rho_p \pi r_0^3}{3} = \frac{4\rho_{av} \pi r_e^3}{3}$$

which reduces to:

$$\rho_p r_0^3 = \rho_{av} r_e^3$$

Then:

$$\phi = \frac{\rho_p r^2}{\rho_{av} r_e^2}$$

and

$$r_e = r\left(\frac{\rho_{av}}{\rho_p}\right)^{-1/3}$$

From these two relationships, the dynamic shape factor is given by:

$$\phi = \left(\frac{\rho_{av}}{\rho_p} \right)^{-1/3}$$

15B.2.1.2 Diffusiophoresis

Diffusiophoresis is the process whereby particles are swept to a surface (for example, containment wall) by the flow set up by a condensing vapor (Stefan flow). The deposition rate is independent of the particle size and is proportional to the steam condensation rate on the surface. The standard equation for this phenomenon is due to Waldmann and Schmitt (Reference 3):

$$\upsilon_d = \frac{\sqrt{M_v}}{\sqrt{M_v} + \chi_{a/v}\sqrt{M_a}} \frac{W}{\rho_v}$$

where:

u_d = diffusiophoretic deposition velocity

$\chi_{a/v}$ = ratio of mole fraction of air to mole fraction of steam in the containment atmosphere

M_v = molecular weight of steam

M_a = molecular weight of air

W = steam condensation rate on the wall

ρ_v = mass density of steam in the containment atmosphere

Because of the design of the passive containment cooling system, steam condensation rates are high at certain times in the design basis LOCA; thus at these times, diffusiophoretic deposition rates are significant.

15B.2.1.3 Thermophoresis

Thermophoresis is the process whereby particles drift toward a surface (for example, the containment wall) under the influence of a temperature gradient in the containment atmosphere at the surface. The effect arises because the gas molecules on the hot side of the particles undergo more collisions with the particle than do those on the cold side. Therefore, there is a net momentum transfer to the particle in the hot-to-cold direction. There are several models in the literature for this effect; the one used is the Brock equation in a form due to Talbot et al. (Reference 4). As indicated below, this model is in agreement with experimental data. The thermophoretic deposition rate is somewhat dependent on particle size and is proportional to the temperature gradient at the wall, or equivalently, the sensible heat transfer rate to the wall. The Talbot equation is:

$$\upsilon_{th} = \frac{2\,C_s\,Cn\,(\mu_g/\rho_g)\,[\alpha + C_T\,Kn]\,dT}{[1+2(\alpha + C_T\,Kn)][1+3\,C_M\,Kn]}\left(\frac{1}{T}\right)\frac{dT}{dy}$$

where:

υ_{th} = thermophoretic deposition velocity

α = k_g/k_p which is the ratio of the thermal conductivities of the gas (evaluated at the gas temperature at each time step) and the aerosol particle (k_p is set equal to the thermal conductivity of water – the results are not sensitive to k_p or α.)

Kn = Knudsen number (equal to the gas molecular mean free path divided by the particle radius)

Cn = Cunningham slip correction factor, a function of the Knudsen number

μ_g = gas viscosity

ρ_g = gas density

C_S = slip accommodation coefficient (Reference 4 gives the best value as 1.17.)

C_T = thermal accommodation coefficient (Reference 4 gives the best value as 2.18.)

C_M = momentum accommodation coefficient (Reference 4 gives the best value as 1.14.)

The temperature gradient at the wall, dT/dy, can be evaluated as

$$\frac{dT}{dy} = \frac{\phi_s}{k_g}$$

where ϕ_s is the sensible heat flux to the wall, and k_g is the thermal conductivity of the gas. The sensible heat flux used in the analysis is the convective heat transfer calculated as discussed in Subsection 15B.2.4.7.

15B.2.2 Other Removal Mechanisms

In addition to the above mechanisms, there are others that were not considered, including turbulent diffusion and turbulent agglomeration. The neglect of these mechanisms adds further conservatism to the calculation.

15B.2.3 Validation of Removal Mechanisms

The aerosol processes are well established and have been confirmed in many separate effects experiments, which are discussed in standard references (References 2 through 4). The Stokes formula for sedimentation velocity has been well confirmed for particles whose diameters are less than about 50 μm. In the present calculations, these make up basically all of the aerosol.

There are some separate effects validations of the diffusiophoretic effect, but the best confirmation comes from integral experiments such as the LACE tests (Reference 5). Calculations of these and other integral tests accurately predict the integrated mass of plated aerosol material only if diffusiophoresis is taken into account. If it is neglected, the predicted plated mass is about two orders of magnitude too small, compared to the observed plated mass.

The Talbot equation for the thermophoretic effect has been experimentally confirmed to within about 20 to 50 percent over a wide range of particle sizes (Reference 4). The temperature gradient at the wall, which drives this phenomenon, can be approximated by the temperature difference between the bulk gas and the wall divided by an appropriate length scale obtained from heat transfer correlations. Alternatively, because sensible heat transfer rates to the wall are available, it is easier and more accurate to use these rates directly to infer the temperature gradient.

15B.2.4 Parameters and Assumptions for Calculating Aerosol Removal Coefficients

The parameters and assumptions were selected to conservatively model the environment that would be expected to exist as a result of a LOCA with concurrent core melt.

15B.2.4.1 Containment Geometry

The containment is assumed to be a cylinder with a volume of 55,481 m^3 (1.959 x 10^6 ft^3). This volume includes those portions of the containment volume that would be participating in the aerosol transport and mixing; this excludes dead-ended volumes and flooded compartments. The horizontal surface area available for aerosol deposition by sedimentation is 2900 m^2 (31,200 ft^2). This includes projecting areas such as decks in addition to the floor area and excludes areas in dead-ended volumes and areas that would be flooded post-LOCA. The surface area for Brownian diffusive plateout of aerosols is 8008 m^2 (86,166 ft^2).

15B.2.4.2 Source Size Distribution

The aerosol source size distribution is assumed to be lognormal, with a geometric mean radius of 0.22 μm and a geometric standard deviation equal to 1.81. These values are derived from an evaluation of a large number of aerosol distributions measured in a variety of degraded-fuel tests and experiments. The sensitivity of aerosol removal coefficient calculations to these values is small.

15B.2.4.3 Aerosol Void Fraction

Review of scanning electron microscope photographs of deposited aerosol particles from actual core melt and fission product vaporization and aerosolization experiments (the Argonne STEP-4 test [Reference 10] and the INEL Power Burst Facility SFD 1-4 test [Reference 6]) indicates that the deposited particles are relatively dense, supporting a void fraction of 0.2.

The above-mentioned test results indicate that a void fraction of 0.2 is appropriate for modeling the aerosols resulting from a core melt. As part of the sensitivity study that was performed for the AP600 project, a case was run with a void fraction of 0.9. That analysis showed that the high void fraction resulted in an integrated release of aerosols over a 24-hour period that was less than 14 percent greater than that calculated when using the void fraction of 0.2. Thus, it is clear that the removal of aerosols from the containment atmosphere is not highly sensitive to the value selected for the void fraction. This is largely due to the fact that, while the selected value for void fraction has a significant impact on the calculated sedimentation removal, the impact on thermophoresis and diffusiophoresis removal is slight or none. The impact for AP1000 of using the higher value for void fraction would be less than was determined for the AP600 since sedimentation removal comprises a smaller fraction of the total removal calculated for the AP1000.

For additional conservatism, the AP1000 aerosol removal analysis uses a void fraction of 0.4 and assumes the voids are filled with air.

15B.2.4.4 Fission Product Release Fractions

Core inventories of fission products are from ORIGEN calculations for the AP1000 at end of the fuel cycle. Fractional releases to the containment of the fission products are those specified in Subsection 15.6.5.3.

15B.2.4.5 Inert Aerosol Species

The inert species include SnO_2, UO_2, Cd, Ag, and Zr. These act as surrogates for all inert materials forming aerosols. The ratio of the total mass of inert species to fission product species was assumed to be 1.5:1. This value and the partitioning of the total inert mass among its constituents are consistent with results from degraded fuel experiments (Reference 6).

15B.2.4.6 Aerosol Release Timing and Rates

Aerosol release timing is in accordance with the source term defined in Subsection 15.6.5.3. Aerosol release takes place in two main phases: a gap release lasting for 0.5 hour, followed by an early in-vessel release of 1.3 hours duration. During each phase, the aerosols are assumed to be released at a constant rate. These rates were obtained for each species by combining its core inventory, release fraction, and times of release.

Only cesium and iodine are released during the gap release phase. During the in-vessel release phase, the other fission product and inert species are released as well.

15B.2.4.7 Containment Thermal-Hydraulic Data

The thermal-hydraulic parameters used in the aerosol removal calculation are the containment gas temperature, the containment pressure, the steam condensation rate on the wall, the steam mole fraction, and the convective heat transfer rate, all as functions of time. The AP1000-specific parameters were obtained using MAAP4 (Reference 7) for the 3BE-1 severe accident sequence (medium LOCA with failure to inject water from the refueling water storage tank into the reactor vessel). The thermal-hydraulic data are thus consistent with a core melt sequence.

15B.2.5 Aerosol Removal Coefficients

The aerosol removal coefficients are provided in Table 15B-1 starting at the onset of core damage through 24 hours. The removal coefficients for times beyond 24 hours are not of concern because there would be so little aerosol remaining airborne at that time. The values range between 0.29 hr^{-1} and 1.1 hr^{-1} during the time between the onset of core damage (0.167 hour) and 24 hours.

These removal coefficients conservatively neglect steam condensation on the airborne particles, turbulent diffusion, and turbulent agglomeration. Additionally, the assumed source aerosol size is conservatively small being at the low end of the mass mean aerosol size range of 1.5 to 5.5 μm used in NUREG/CR-5966 (Reference 8). Selection of smaller aerosol size would underestimate sedimentation.

Unlike the case for the elemental iodine removal, there is no limit assumed on the removal of aerosols from the containment atmosphere.

15B.3 References

1. NUREG-0800, Section 6.5.2, Revision 2, "Containment Spray as a Fission Product Cleanup System."

2. Fuchs, N. A., The Mechanics of Aerosols, Pergamon Press, Oxford, 1964.

3. Waldmann, L., and Schmitt, K. H., "Thermophoresis and Diffusiophoresis of Aerosols," Aerosol Science, C. N. Davies, ed., Academic Press, 1966.

4. Talbot, L., Chang, R. K., Schefer, R. W., and Willis, D. R., "Thermophoresis of Particles in a Heated Boundary Layer," J. Fluid Mech. 101, 737-758 (1980).

5. Rahn, F. J., "The LWR Aerosol Containment Experiments (LACE) Project," Summary Report, EPRI-NP-6094D, Electric Power Research Institute, Palo Alto, Nov. 1988.

6. Petti, D. A., Hobbins, R. R., and Hagrman, D. L., "The Composition of Aerosols Generated during a Severe Reactor Accident: Experimental Results from the Power Burst Facility Severe Fuel Damage Test 1-4," Nucl. Tech. 105, p.334 (1994).

7. MAAP4 - Modular Accident Analysis Program for LWR Power Plants, Computer Code Manual, May 1994.

8. Powers D. A., and Burson, S. B., "A Simplified Model of Aerosol Removal by Containment Sprays," NUREG/CR-5966, June 1993.

9. Powers, D. A., "Monte Carlo Uncertainty Analysis of Aerosol Behavior in the AP600 Reactor Containment under Conditions of a Specific Design-Basis Accident, Part 1," Technical Evaluation Report, Sandia National Laboratories, June 1995.

10. Baker, L. Jr., Fink, J.K., Simms, R., Schlenger, B.J., Herceg, J.E., “Source Term Experiments Project (STEP): A Summary: Final Report,” EPRI-NP-5753M, March 1988.

Table 15B-1 (Sheet 1 of 3)
Aerosol Removal Coefficients in the AP1000 Containment Following a Design Basis LOCA With Core Melt

Time Interval (hours)	Removal Coefficient (hr^{-1})
0.167 – 0.179	1.141
0.179 – 0.200	1.013
0.200 – 0.251	0.944
0.251 – 0.292	0.882
0.292 – 0.433	0.842
0.433 – 0.631	0.901
0.631 – 0.684	0.821
0.684 – 0.801	0.781
0.801 – 0.893	0.735
0.893 – 1.033	0.699
1.033 – 1.171	0.662
1.171 – 1.233	0.627
1.233 – 1.331	0.594
1.331 – 1.395	0.562
1.395 – 1.429	0.551
1.429 – 1.475	0.576
1.475 – 1.519	0.537
1.519 – 1.579	0.510
1.579 – 1.653	0.483
1.653 – 1.776	0.458
1.776 – 1.903	0.430
1.903 – 1.991	0.462
1.991 – 2.067	0.429
2.067 – 2.176	0.396
2.176 – 2.371	0.380
2.371 – 2.621	0.337

Table 15B-1 (Sheet 2 of 3)
Aerosol Removal Coefficients in the AP1000 Containment Following a Design Basis LOCA With Core Melt

Time Interval (hours)			Removal Coefficient (hr^{-1})
2.621	–	2.822	0.320
2.822	–	2.872	0.357
2.872	–	2.973	0.327
2.973	–	3.176	0.302
3.176	–	3.684	0.287
3.684	–	3.737	0.328
3.737	–	3.839	0.304
3.839	–	3.990	0.298
3.990	–	4.090	0.317
4.090	–	4.438	0.346
4.438	–	4.684	0.369
4.684	–	4.880	0.396
4.880	–	4.928	0.449
4.928	–	5.362	0.435
5.362	–	5.460	0.459
5.460	–	5.511	0.518
5.511	–	5.608	0.487
5.608	–	6.040	0.479
6.040	–	6.090	0.537
6.090	–	6.615	0.506
6.615	–	6.753	0.567
6.753	–	7.194	0.513
7.194	–	7.285	0.594
7.285	–	7.814	0.518
7.814	–	7.904	0.581

Table 15B-1 (Sheet 3 of 3)
Aerosol Removal Coefficients in the AP1000 Containment Following a Design Basis LOCA With Core Melt

Time Interval (hours)			Removal Coefficient (hr^{-1})
7.904	–	8.431	0.528
8.431	–	8.521	0.589
8.521	–	9.387	0.529
9.387	–	9.553	0.568
9.553	–	11.189	0.530
11.189	–	14.937	0.516
14.937	–	17.610	0.506
17.610	–	24	0.492

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UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
16.1	Technical Specifications	16.1-1
16.1.1	Introduction to Technical Specifications	16.1-1
16.1.2	References	16.1-2
16.2	Design Reliability Assurance Program	16.2-1
16.3	Investment Protection	16.3-1
16.3.1	Investment Protection Short-Term Availability Controls	16.3-1
16.3.2	Combined License Information	16.3-1

LIST OF TABLES

Table Number	Title	Page
16.3-1	List of Investment Protection Short-term Availability Controls	16.3-2

16.1 Technical Specifications

16.1.1 Introduction to Technical Specifications

LCO Selection Criteria

The screening criteria of 10CFR50.36, c(2)(ii) stated below has been used to identify the structures, systems, and parameters for which Limiting Conditions for Operation (LCOs) have been included in the AP1000 Technical Specifications.

1. Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

2. A process variable, design feature, or operating restriction that is an initial condition of a Design Basis Accident or Transient Analyses that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

3. A structure, system or component that is part of the primary success path and which functions or actuates to mitigate a Design Basis Accident or Transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

4. A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

Technical Specification Content

The content of the AP1000 Technical Specifications meets the 10CFR50.36 requirements and is consistent with the Technical Specification Improvement Program, NUREG 1431, Rev. 2, to the maximum extent possible. The content differs from NUREG 1431 only as necessary to reflect technical differences between the “typical” Westinghouse design and the AP1000 design.

Completion Times and Surveillance Frequencies

The Completion Times and Surveillance Frequencies specified in NUREG 1431 have been applied to similar Actions and Surveillances Requirements in AP1000. Refer to Westinghouse letter DCP/NRC0891 for a discussion regarding selection of Completion Times and Surveillance Frequencies for those AP1000 Tech Specs for which no comparable NUREG 1431 system/function exists and for those AP1000 system design differences which lead to deviations from NUREG 1431 Completion Times and Surveillance Frequencies.

Shutdown Completion Times/Mode Definitions

The AP1000 plant design is different from current Westinghouse designs in that the systems normally used for MODE reduction are non-safety systems; and therefore, are not covered by LCO requirements in Technical Specifications. The passive safety systems, which shut down the plant require a longer period of time to accomplish mode changes and can not reduce the RCS temperature to below 200°F.

Combined License Information

The set of generic technical specifications were used as a guide in the development of the plant-specific technical specifications. The preliminary information originally provided in brackets [ ] has been revised with the updated information, including information provided in APP-GW-GLR-064 (Reference 1) and APP-GW-GLN-075 (Reference 2). In accordance with 10 CFR Part 52, Appendix D, Section VIII.C.6, following the issuance of the license, the generic technical specifications have no further effect on the plant-specific technical specifications.

16.1.2 References

1. APP-GW-GLR-064, “AP1000 Generic Technical Specifications Completion,” Westinghouse Electric Company LLC.

2. APP-GW-GLN-075, “AP1000 Generic Technical Specifications for Design Changes,” Westinghouse Electric Company LLC.

3. APP-RXS-Z0R-001, Revision 3, “AP1000 Generic Pressure Temperature Limits Report,” April 2018.

16.2 Design Reliability Assurance Program

See Section 17.4 for information on the AP1000 Design Reliability Assurance Program (D-RAP).

16.3 Investment Protection

16.3.1 Investment Protection Short-Term Availability Controls

The importance of nonsafety-related systems, structures and components in the AP1000 has been evaluated. The evaluation uses PRA insights to identify systems, structures and components that are important in protecting the utilities investment and for preventing and mitigating severe accidents. To provide reasonable assurance that these systems, structures and components are functional during anticipated events short-term availability controls are provided. These investment protection systems, structures and components are also included in the D-RAP/OPRAAs (refer to Section 17.4), which provides confidence that availability and reliability are designed into the plant and that availability and reliability are maintained throughout plant life through the use of reliability assurance activities as listed in Subsection 17.4.4. Technical Specifications are not required for these systems, structures and components because they do not meet the selection criteria applied to the AP1000 (refer to Subsection 16.1.1).

Table 16.3-1 lists nonsafety-related systems, structures and components that have investment protection short-term availability controls which are contained in the Technical Requirements Manual (TRM). The portions of the TRM containing these short-term availability controls are incorporated by reference into this subsection as FSAR Tier 2 information. These are identified in the TRM Table of Contents with FSAR Scope as “DCD-Plant Specific (Tier 2).” These short-term availability controls define:

- Equipment that shall be FUNCTIONAL
- Operational MODES when the equipment shall be FUNCTIONAL
- Testing and inspections that are used to demonstrate the equipment’s FUNCTIONALITY
- Operational MODES that are used for planned maintenance operations
- Remedial actions that are taken if the equipment is not FUNCTIONAL

Station procedures govern and control the FUNCTIONALITY of investment protection systems, structures, and components, in accordance with the Tier 2 information within the TRM, and provide the operating staff with instruction for implementing required actions when FUNCTIONALITY requirements are not met. Procedure development is addressed in Section 13.5. TRM Use and Application Sections 1.2, 1.3, and 1.4, as well as TRM Applicability Sections TR 3.0.1, TR 3.0.2, TRS 3.0.1, TRS 3.0.2, and TRS 3.0.3 constitute a portion of these procedural controls, but are not considered Tier 2 information. These, and other procedural controls, are identified in the TRM Table of Contents with FSAR Scope as “Administrative” and are not considered incorporated by reference as UFSAR content.

TRM Section 1.1, Definitions, contains defined terms that appear in capitalized type. TRM Section 1.1, Definitions, is also incorporated by reference into this subsection as FSAR Tier 2 information.

TRM material that is incorporated by reference as UFSAR Standard Content, is noted in the TRM Table of Contents with FSAR Scope as “UFSAR Standard Content.” One example of this is previous COL Appendix A, Technical Specifications, material that has been relocated to the TRM under License Amendment.

16.3.2 Combined License Information

The procedure to control the functionality of investment protection systems, structures and components is addressed in Subsection 16.3.1.

Table 16.3-1 List of Investment Protection Short-term Availability Controls

TRM 3.3.1	Diverse Actuation System (DAS) Automatic Actuation
TRM 3.6.1	Passive Containment Cooling Water Storage Tank (PCCWST) and Spent Fuel Pool Makeup - Long Term Shutdown
TRM 3.6.2	Hydrogen Igniters
TRM 3.7.1	Normal Residual Heat Removal System (RNS) - Reactor Coolant System (RCS) Makeup
TRM 3.7.2	Normal Residual Heat Removal System (RNS) - Reactor Coolant System (RCS) Open
TRM 3.7.3	Component Cooling Water System (CCS) - Reactor Coolant System (RCS) Open
TRM 3.7.4	Service Water System (SWS) - Reactor Coolant System (RCS) Open
TRM 3.7.5	Main Control Room (MCR) Cooling - Long Term Shutdown
TRM 3.7.6	I&C Room Cooling - Long Term Shutdown
TRM 3.8.1	AC Power Supplies - Operating
TRM 3.8.2	AC Power Supplies - Reactor Coolant System (RCS) Open
TRM 3.8.3	AC Power Supplies - Long Term Shutdown
TRM 3.8.4	Non Class 1E DC and UPS System (EDS)

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 17	QUALITY ASSURANCE	17.1-1
17.1	Quality Assurance During the Design and Construction Phases	17.1-1
17.2	Quality Assurance During the Operations Phase	17.2-1
17.3	Quality Assurance During Design, Procurement, Fabrication, Inspection, and/or Testing of Nuclear Power Plant Items	17.3-1
17.4	Design Reliability Assurance Program	17.4-1
17.4.1	Introduction	17.4-1
17.4.2	Scope	17.4-1
17.4.3	Design Considerations	17.4-1
17.4.4	Relationship to Other Administrative Programs	17.4-1
17.4.5	The AP1000 Design Organization	17.4-2
17.4.6	Objective	17.4-2
17.4.7	D-RAP	17.4-3
17.4.7.1	SSCs Identification and Prioritization	17.4-3
17.4.7.2	Not Used	17.4-5
17.4.7.3	Not Used	17.4-5
17.4.7.4	D-RAP Implementation	17.4-5
17.4.8	Glossary of Terms	17.4-7
17.5	Quality Assurance Program Description	17.5-1
17.6	Maintenance Rule Program	17.6-1
17.6.1	Maintenance Rule Program Description	17.6-1
17.6.1.1	Maintenance Rule Scoping per 10 CFR 50.65(b)	17.6-1
17.6.1.2	Monitoring and Corrective Action per 10 CFR 50.65(a)(1)	17.6-2
17.6.1.3	Preventive Maintenance per 10 CFR 50.65(a)(2)	17.6-2
17.6.1.4	Periodic Evaluation of Monitoring and Preventive Maintenance per 10 CFR 50.65(a)(3)	17.6-3
17.6.1.5	Risk Assessment and Risk Management per 10 CFR 50.65(a)(4)	17.6-3
17.6.2	Maintenance Rule Training and Qualification	17.6-3
17.6.3	Maintenance Rule Program Relationship With Reliability Assurance Activities	17.6-3
17.6.4	Maintenance Rule Program Relationship With Industry Operating Experience Activities	17.6-4
17.6.5	Maintenance Rule Program Implementation	17.6-4
17.7	Combined License Information Items	17.7-1
17.8	References	17.8-1

LIST OF TABLES

Table Number	Title	Page
17-1	Quality Assurance Program Requirements for Systems, Structures, And Components Important to Investment Protection	17.3-3
17.4-1	Risk-Significant SSCs Within the Scope of D-RAP	17.4-8
17.4-2	Example of Risk-Significant Ranking of SSCs for the Automatic Depressurization System	17.4-16

LIST OF FIGURES

Figure Number	Title	Page
17.4-1	Design Reliability Assurance Program and Operational Phase Reliability Assurance Activities	17.4-17

Chapter 17 Quality Assurance

17.1 Quality Assurance During the Design and Construction Phases

SNC is responsible for the establishment and execution of quality assurance program requirements during the design, construction, and operations phases of VEGP Units 3 and 4. SNC may delegate the work of establishing and executing the quality assurance program, or any parts thereof, but retains responsibility for the quality assurance program.

Southern Nuclear has contracted with several vendors to develop the VEGP Units 3 and 4 COL application, including site characterization activities. The process of collection, review, and analysis of specific data was performed principally either under the Bechtel Corporation QA program or the MacTec QA program. SNC oversight is provided through its review and approval of these QA plans, by conducting QA audits and surveillances, and by direct participation in and oversight of the COL application development activities. The latter includes providing site specific applicant input and review of COL application content, signing the COL application as applicant at submittal, and working directly with these and other contractors to respond to NRC requests for additional information.

The “Quality Assurance Program Description” (QAPD) discussed in Section 17.5 establishes the QA program under which this COL application was developed and further established the requirements for the remaining portion of the design and construction phases.

17.2 Quality Assurance During the Operations Phase

See Section 17.5.

17.3 Quality Assurance During Design, Procurement, Fabrication, Inspection, and/or Testing of Nuclear Power Plant Items

This section outlines the quality assurance program applicable to the design, procurement, fabrication, inspection, and/or testing of items and services for the AP1000 Project. The design for AP1000 is based upon employing the design of AP600 to the maximum extent possible. As a result, a continuous quality program spanning AP600 design as well as AP1000 design has been used. Westinghouse has and will continue to maintain a quality assurance program meeting the requirements of 10 CFR 50 Appendix B for the AP1000 program that will be applicable to the design, procurement, fabrication, inspection, and/or testing activities.

Effective March 31, 1996, activities affecting the quality of items and services for the AP600 Project during design, procurement, fabrication, inspection, and/or testing were being performed in accordance with the quality plan described in "Westinghouse Electric Corporation – Energy Systems Business Unit, Quality Management System," (Reference 1). The Quality Management System (QMS) has been maintained as the Quality Plan for the AP1000 program and subsequent revisions have been submitted to and accepted by the NRC as meeting the requirements of 10 CFR 50 Appendix B.

Prior to introduction of the QMS as the quality plan applicable to the AP1000 project, activities on the AP600/AP1000 program were performed in accordance with topical report WCAP 8370 (References 2 and 3), Westinghouse Energy Systems Business Unit/Power Generation Business Unit Quality Assurance Plan. WCAP 8370 was subsequently superseded by the Westinghouse QMS to describe the quality assurance plan and Westinghouse commitments to meet the requirements of 10 CFR 50 Appendix B.

The current Westinghouse quality plan for work being performed on the AP1000 is the Westinghouse Electric Company Quality Management System (QMS) (Reference 9). The referenced revision of the QMS was accepted by the NRC as meeting the requirements of 10 CFR 50, Appendix B, on December 29, 2014.

A project-specific quality plan was issued to supplement the quality management system document and the topical reports for design activities affecting the quality of structures, systems, and components for the AP600 project (Reference 4). This plan referenced the NQA-1-1989 edition through NQA-1b-1991 addenda and was applicable to work performed for the AP1000 design prior to March 16, 2007.

Effective March 16, 2007, NQA-1 is applicable for work performed for the AP1000 project. As such, a project-specific quality plan is no longer required, and the Westinghouse Electric Company Quality Management System (QMS) (Reference 9) is the quality program for work performed for the AP1000 project. Work by Westinghouse for the AP1000 plant is performed in accordance with the Westinghouse QMS in effect at the time of the work.

Quality Assurance requirements for systems, structures, and components will be graded based on the safety classification as indicated in Section 3.2. Safety-related systems are classified as Equipment Classes A, B and C, and will meet the requirements of 10 CFR 50, Appendix B. For systems, structures, and components included in the regulatory treatment of nonsafety systems (RTNSS), the quality requirements are identified in Table 17-1. See Section 16.3 for systems that should be considered for designation of systems and components included in the regulatory treatment of nonsafety systems.

While Westinghouse retains the overall responsibility for the AP1000 design, portions of the design are developed by external organizations. Each organization maintains a quality assurance program that meets the NQA-1 criteria that apply to its work scope. In accordance with the QMS, Westinghouse performs an initial evaluation of these programs and monitors their continued effective implementation through audits, surveillance, and evaluation of the performance of external organizations.

Table 17-1 (Sheet 1 of 3)
Quality Assurance Program Requirements for Systems, Structures, And Components Important to Investment Protection

The following outlines the quality assurance program requirements for suppliers of systems, structures, or components to which the requirements for investment protection short-term availability controls apply.
1. Organization The normal line organization may verify compliance with the requirements of this table. A separate or dedicated quality assurance organization is not required.
2. Quality Assurance Program It is expected that the existing body of supplier's procedures or practices will describe the quality controls applied to the subject equipment. A new or separate QA program is not required.
3. Design Control Measures shall be established to ensure that contractually established design requirements are included in the design. Applicable design inputs shall be included or correctly translated into design documents, and deviations therefrom shall be controlled. Normal supervisory review of the designer's work is an adequate control measure.
4. Procurement Document Control Applicable design bases and other requirements necessary to assure component performance, including design requirements, shall be included or referenced in documents for procurement of items and services, and deviations therefrom shall be controlled.
5. Instructions, Procedures, and Drawings Activities affecting quality shall be performed in accordance with documented instructions, procedures, or drawings of a type appropriate to the circumstances. This may include such things as written instructions, plant procedures, cautionary notes on drawings, and special instructions on work orders. Any methodology which provides the appropriate degree of guidance to personnel performing activities important to the component functional performance will satisfy this requirement.
6. Document Control The issuance and change of documents that specify quality requirements or prescribe activities affecting quality shall be controlled to assure that correct documents are employed.
7. Control of Purchased Items and Services Measures are to be established to ensure that all purchased items and services conform to appropriate procurement documents.

Table 17-1 (Sheet 2 of 3)
Quality Assurance Program Requirements for Systems, Structures, And Components Important to Investment Protection

8. Identification and Control of Purchased Items Measures shall be established where necessary, to identify purchased items and preserve their investment protection important functional performance capability. Examples of circumstances requiring such control include the storage of environmentally sensitive equipment or material, and the storage of equipment or material that has a limited shelf-life.
9. Control of Special Processes Measures shall be established to control special processes, including welding, heat treating, and non-destructive testing. Applicable codes, standards, specifications, criteria, and other special requirements may serve as the basis of these controls.
10. Inspection Inspections shall be performed where necessary to verify conformance of an item or activity to specified requirements, or to verify that activities are being satisfactory accomplished. Inspections need not be performed by personnel who are independent of the line organization. However, inspections, where necessary, shall be performed by knowledgeable personnel.
11. Test Control Measures shall be established, as appropriate, to test equipment prior to installation to demonstrate conformance with design requirements. Tests shall be performed in accordance with test procedures. Test results shall be recorded and evaluated to ensure that test requirements have been met.
12. Control of Measuring and Test Equipment Measures shall be established to control, calibrate, and adjust measuring and test equipment at specific intervals.
13. Handling, Storage, and Shipping Handling, storage, cleaning, packaging, shipping, and preservation of items shall be controlled to prevent damage or loss and to minimize deterioration.
14. Inspection, Test, and Operating Status Measures shall be established to identify items that have satisfactory passed required tests and inspections, and to indicate status of inspection, test, and operability as appropriate.
15. Control of Nonconforming Items Items that do not conform to specified requirements shall be identified and controlled to prevent inadvertent installation or use.

Table 17-1 (Sheet 3 of 3)
Quality Assurance Program Requirements for Systems, Structures, And Components Important to Investment Protection

16. Corrective Action Measures shall be established to ensure that failures, malfunctions, deficiencies, deviations, defective components, and nonconformances are properly identified, reported, and corrected.
17. Records Records shall be prepared and maintained to furnish evidence that the above requirements for design, procurement, document control, inspection, and test activities have been met.
18. Audits Audits which are independent of line management are not required, if line management periodically reviews and documents the adequacy of the suppliers process and takes any necessary corrective action. Line management is responsible for determining whether reviews conducted by line management or audits conducted by and organization independent of line management are appropriate. If performed, audits shall be conducted and documents to verify compliance with design and procurement documents, instructions, procedures, drawings, and inspection and test activities.

17.4 Design Reliability Assurance Program

This subsection presents the AP1000 Design Reliability Assurance Program (D-RAP).

17.4.1 Introduction

The AP1000 D-RAP is implemented as an integral part of the AP1000 design process to provide confidence that reliability is designed into the plant and that the important reliability assumptions made as part of the AP1000 probabilistic risk assessment (PRA) (Reference 5) will remain valid throughout plant life. The PRA quantifies plant response to a spectrum of initiating events to demonstrate the low probability of core damage and resultant risk to the public. PRA input includes specific values for the reliability of the various structures, systems, and components (SSCs) in the plant that are used to respond to postulated initiating events.

The D-RAP, shown in Figure 17.4-1, is implemented during Design Certification. The D-RAP identifies risk-significant SSCs for inclusion into the site Operational Phase Reliability Assurance Activities (OPRAAs) using probabilistic, deterministic, and other methods.

The OPRAAs provides confidence that the operations and maintenance activities performed by the operating plant support should maintain the reliability assumptions made in the plant PRA.

17.4.2 Scope

The D-RAP includes a design evaluation of the AP1000 and identifies the aspects of plant operation, maintenance, and performance monitoring pertinent to risk-significant SSCs. In addition to the PRA, deterministic tools, industry sources, and expert opinion are used to identify and prioritize those risk-significant SSCs.

The quality assurance requirements for non-safety related SSCs within the scope of D-RAP is in accordance with the Quality Assurance Program Description (QAPD), Part III.

17.4.3 Design Considerations

As part of the design process, risk-significant components are evaluated to determine their dominant failure modes and the effects associated with those failure modes. For most components, a substantial operating history is available which defines the significant failure modes and their likely causes.

The identification and prioritization of the various possible failure modes for each component lead to suggestions for failure prevention or mitigation. This information is provided as input to the OPRAAs.

The design reflects the reliability values assumed in the design and PRA as part of procurement specifications. When an alternative design is proposed to improve performance in either area, the revised design is first reviewed to provide confidence that the current assumptions in the other areas are not violated. When a potential conflict exists between safety goals and other goals, safety goals take precedence.

17.4.4 Relationship to Other Administrative Programs

The D-RAP manifests itself in other administrative and operational programs. The technical specifications provide surveillance and testing frequencies for certain risk-significant SSCs, providing confidence that the reliability values assumed for them in the PRA will be maintained during plant operations. Risk-significant systems that provide defense-in-depth or result in significant improvement in the PRA evaluations are included in the scope of the D-RAP.

The OPRAAs are comprised of site administrative, maintenance, operational, and testing programs to enhance operational phase reliability throughout the designed plant life. As documented in Reference 10 and Reference 12, the following reliability assurance programs are credited as OPRAAs:

- Maintenance Rule Program (Reference 10)
- Quality Assurance Program (Section 17.2)
- Inservice Testing Program (Section 3.9)
- Inservice Inspection Program (Section 5.2 and Section 6.6)
- Technical Specifications Surveillance Test Program (COL Appendix A)
- AP1000 Investment Protection Short Term Availability Controls Program (Section 16.3)
- Site Maintenance Program

17.4.5 The AP1000 Design Organization

The AP1000 organization of Section 1.4 formulates and implements the AP1000 D-RAP.

The AP1000 management staff is responsible for the AP1000 design and licensing.

The AP1000 staff coordinates the program activities, including those performed within Westinghouse as well as work completed by the architect-engineers and other supporting organizations listed in Section 1.4.

The AP1000 staff is responsible for development of the D-RAP and the design, analyses, and risk and reliability engineering required to support development of the program. Westinghouse is responsible for the safety analyses, the reliability analyses, and the PRA.

The reliability analyses are performed using common databases from Westinghouse and from industry sources such as INPO and EPRI.

The Risk and Reliability organization is responsible for developing the D-RAP and has direct access to the AP1000 staff. Risk and Reliability is responsible for keeping the AP1000 staff cognizant of the D-RAP risk-significant items, program needs, and status. Risk and Reliability participates in the design change control process for the purpose of providing D-RAP-related inputs to the design process. Additionally, a cognizant representative of Risk and Reliability is present at design reviews. Through these interfaces, Risk and Reliability can identify interfaces between the performance of risk-significant SSCs and the reliability assumptions in the PRA. Meetings between Risk and Reliability and the designer are then held to manage interface issues.

17.4.6 Objective

The objective of the D-RAP is to design reliability into the plant and to maintain the AP1000 reliability consistent with the NRC-established PRA safety goals.

The following goals have been established for the D-RAP:

- Provide reasonable assurance that
  - The AP1000 is designed, procured, constructed, maintained and operated in a manner consistent with the assumptions and risk insights in the AP1000 PRA for these risk-significant SSCs
  - The risk-significant SSCs do not degrade to an unacceptable level during plant operations

  - The frequency of transients that challenge the AP1000 risk-significant SSCs are minimized

  - The risk-significant SSCs function reliably when they are challenged

- Provide a mechanism for establishing baseline reliability values for risk-significant SSCs identified by the risk determination methods used to implement the Maintenance Rule (10 CFR 50.65) and consistent with PRA reliability and availability design basis assumptions used for the AP1000 design

- Provide a mechanism for establishing baseline reliability values for SSCs consistent with the defense-in-depth functions to minimize challenges to the safety-related systems

- Generate design and operational information to be used for ongoing plant reliability assurance activities

Development of maintenance assessments and recommendations and the site-specific portion of the program is the responsibility of the Combined License applicant.

17.4.7 D-RAP

The definition portion of the D-RAP includes the initial identification of SSCs to be included in the program, implementation of the aspects applicable to design efforts, and definition of the scope, requirements, and implementation options to be included in the later phases.

17.4.7.1 SSCs Identification and Prioritization

The initial task of the D-RAP is identification of risk-significant SSCs to be included within the scope of the program. As shown in Figure 17.4-1, the AP1000 PRA is used to identify those SSCs, consistent with the criteria of Reference 7 for risk achievement worth (RAW), risk reduction worth (RRW), and Fussel-Vesely worth (FVW). Note that, although Reference 7 was developed for AP600, it is directly applicable to AP1000. The review of light water reactor industry experience and industry notices (such as licensee event reports) supports the process. An expert panel is also employed in the selection process.

PRA-based measurements provide information that contributes to the identification and prioritization of SSCs. A component's RAW is the factor by which the plant's core damage frequency increases if the component reliability is assigned the value 0.0. Components with risk achievement worth values of 2 or greater are considered for inclusion in the D-RAP.

RRW is used in the selection process. A component's risk reduction worth is the amount by which the plant's core damage frequency decreases if the component's reliability is assigned the value 1.0. A threshold measure of 1.005 or greater is used as the cutoff. Components with RRW of 1.005 or greater are considered for inclusion in the D-RAP.

FVW is also used in the screening process. This is a measure of an event's contribution to the overall plant core damage frequency. Components with Fussel-Vesely worth of 0.5 percent or greater are considered for inclusion in the D-RAP.

Deterministic considerations are also instrumental in identifying risk-significant SSCs. The deterministic identification of risk-significant SSCs encompasses the following guidelines and considerations:

- ATWS rule (10 CFR 50.62)

- Loss of all ac power (10 CFR 50.63)
- Post-72-hour actions
- Containment performance
- Adverse interactions with the AP1000 safety-related systems
- Seismic considerations

Nonsafety-related systems identified as risk-significant are considered in the scope of the D-RAP:

- Diverse actuation system
- Non-Class 1E dc and uninterruptible power supply system
- Offsite power, main ac power, and onsite standby power systems
- Normal residual heat removal system
- Component cooling water system
- Service water system

Finally, risk-significant SSCs are selected using industry experience, regulations, and engineering judgment.

17.4.7.1.1 Level 1 PRA and Shutdown Analysis

The Level 1 PRA evaluates accident sequences from initiating events and failures of safety functions to core damage events. The probability of core damage and the identification of dominant contributors to that state are also determined in this analysis.

A low-power and shutdown assessment is conducted to address concerns about risk of operations during shutdown conditions. It encompasses operation when the reactor is in a subcritical state or is in a transition between subcriticality and power operation up to 5 percent of rated power. It consists of a Level 1 PRA and an evaluation of release frequencies and magnitudes.

Included in the D-RAP are events that meet the threshold risk achievement worth, risk reduction worth, or Fussel-Vesely worth values defined in Subsection 17.4.7.1.

17.4.7.1.2 Level 2 Analysis

The Level 2 analysis predicts the plant response to severe accidents and offsite fission product releases. Specifically, the analysis includes the following sections:

- Evaluating severe accident phenomena and fission product source terms
- Modeling the containment event tree
- Analyzing hydrogen burn, mixing, and igniter placement
- Modeling the AP1000 utilizing the MAAP4 code

Equipment used in the prevention of severe accidents and severe post-accident boundary conditions is credited in the Level 1 and Level 2 PRA analyses. An example of this preventive equipment is the reactor coolant system automatic depressurization system (ADS). Successful depressurization leads to core cooling, and in the event that injection fails, results in a low pressure core damage sequence that has fewer uncertainties and can be more easily mitigated than high pressure core damage.

The containment event tree used in the AP1000 Level 2 PRA examines the operation of equipment which mitigates the threat to the containment from severe accident phenomena. The systems credited for the mitigation of large fission product releases are containment isolation, passive containment cooling water (PCS), and operator action to flood the cavity by opening the recirculation valves and energizing the hydrogen igniters.

17.4.7.1.3 External Event Analyses

These analyses consider the events whose cause is external to all the systems associated with normal and emergency operations situations. They include the following:

- Internal flood
- Seismic margins analysis
- External events evaluations (such as high winds and tornados, external floods, and transportation accidents)
- Fire

The internal flood analysis identifies, analyzes, and quantifies the core damage risk contribution as a result of internal flooding during at-power and shutdown conditions. The analysis models potential flood vulnerabilities in conjunction with random failures modeled as part of the internal events PRA.

The seismic margins analysis identifies potential vulnerabilities and demonstrates seismic margin beyond the safe shutdown earthquake. The capacity of those components required to bring the plant to a safe, stable shutdown is evaluated.

17.4.7.1.4 Expert Panel

Meetings were held among Systems Engineering, PRA, and Reliability Engineering to perform the final selection of SSCs that should be included in the D-RAP. As shown in Figure 17.4-1, industry-wide information sources and engineering judgment were employed in considering the addition of SSCs to the D-RAP.

17.4.7.1.5 SSCs to be Included in D-RAP

Table 17.4-1 lists the non-site-specific SSCs included in the D-RAP. In Figure 17.4-1, this list is denoted as "Risk-significant items (non-site-specific)." For each item listed in the "SSC" column, there is a corresponding "Rationale" given. Items whose values exceed the thresholds for RAW or RRW are included and noted as such. Other SSCs are included based upon their significance to Level 2 analysis, external event analyses, or seismic margin analysis. Additional items are included based upon an expert panel review. The "Insights and Assumptions" column provides additional insights into the selection process.

The use of Fussel-Vesely worth resulted in no SSC selections.

17.4.7.2 Not Used

17.4.7.2.1 Not Used

17.4.7.3 Not Used

17.4.7.4 D-RAP Implementation

The following is an example of a system that was reviewed and modified under the D-RAP. The design and analytical results presented here are intended as an example.

The automatic depressurization system, which is part of the reactor coolant system, acts in conjunction with the passive core cooling system to mitigate design basis accidents. The automatic depressurization system valves are discussed in Subsection 5.4.6.

An earlier AP600 automatic depressurization system design contained four depressurization stages, with motor-operated valves in all stages. Preliminary PRA analysis established that fourth stage failure, in certain combination with failures of other stages, was a major contributor to core damage frequency. Thus, it was concluded that the fourth stage valves should be diverse in design from the valves in other stages to reduce common cause failure.

As a result of joint meetings among the AP600 PRA, Design, and staff organizations to discuss core melt frequency improvements, the fourth stage automatic depressurization system was changed from a motor-operated valve to a squib (explosively actuated) valve. The new configuration of the system is shown in the reactor coolant system P&ID (Figure 5.1-5). An example of the analytical results that reflect this change is provided in Table 17.4-2. This design feature is included in the AP1000 design to maintain the core melt frequency improvements included in the AP600 design.

As part of the evaluation of the squib valves, a failure modes and effects analysis (FMEA) was prepared to identify subcomponent failures and critical items that could lead to hazardous or abnormal conditions of the automatic depressurization system and the plant. The identification of failure modes facilitated the development of recommended maintenance and in-service testing activities to maximize valve reliability.

The squib valve is a completely static electromechanical assembly. Prior to activation, there are no moving parts. No powered components are needed to hold a stem seat or globe in place by torque, solenoid coils, or friction. The explosive actuator is a simple, passive device that is triggered by an applied voltage.

Because the automatic depressurization system fourth stage valves perform safety-related functions, they will be subject to in-service testing to verify that they are ready to function in an accident.

Example FMEA results for the fourth stage squib valves and the second and third stage motor-operated valves are included in Table 6.3-3.

17.4.8 Glossary of Terms

D-RAP	Design Reliability Assurance Program – performed as part of the AP1000 design effort to assure that the reliability assumptions of the PRA remain valid throughout the plant operating lifetime.
FVW	Fussel-Vesely Worth
MR	Maintenance Rule
OPRAAs	Operational Phase Reliability Assurance Activities
PRA	Probabilistic Risk Assessment
RAW	Risk Achievement Worth
Risk-significant	Any SSC determined in the PRA or by risk-significance analysis (e.g., Level 2 PRA and shutdown risk analysis) to be a major contributor to overall plant risk
RRW	Risk Reduction Worth
RTNSS	Regulatory Treatment of Nonsafety Systems
SSC	Structures, Systems, and Components

Table 17.4-1 (Sheet 1 of 8)
Risk-Significant SSCs Within the Scope of D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
System: Component Cooling Water (CCS)		
Component Cooling Water Pumps (CCS-MP-01A/B)	EP	These pumps provide cooling of the normal residual heat removal system (RNS) and the spent fuel pool heat exchanger. Cooling the RNS heat exchanger is important to investment protection during shutdown reduced-inventory conditions. CCS valve realignment is not required for reduced-inventory conditions.
System: Containment System (CNS)		
Containment Vessel (CNS-MV-01)	EP, L2	The containment vessel provides a barrier to steam and radioactivity released to the atmosphere following accidents.
Hydrogen Igniters (VLS-EH-1 through -66)	RAW/CCF, L2, Regulations	The hydrogen igniters provide a means to control H_2 concentration in the containment atmosphere, consistent with the hydrogen control requirements of 10 CFR 50.34f.
System: Chemical and Volume Control System (CVS)		
Makeup Pumps (CVS-MP-01A/B)	EP	These pumps provide makeup to the RCS to accommodate leaks and to provide negative reactivity for shutdowns, steam line breaks, and ATWS.
Makeup Pump Suction and Discharge Check Valves (CVS-PL-V113, -V160A/B)	EP	These CVS check valves are normally closed and have to open to allow makeup pump operation.
Letdown Isolation Valves (CVS-PL-V045, -V047)	RAW	The CVS letdown isolation valves automatically close to prevent excessive reactor coolant letdown and provide containment isolation. These containment isolation valves are important in limiting offsite releases following core melt accidents.
System: Diverse Actuation System (DAS)		
DAS Processor Cabinets and Control Panel (used to provide automatic and manual actuation) (DAS-JD-001, -002, -003, OCS-JC-20)	RAW	The DAS is diverse from the PMS and provides automatic and manual actuation of selected plant features including control rod insertion, turbine trip, passive residual heat removal (PRHR) heat exchanger actuation, core makeup tank actuation, isolation of critical containment lines, and passive containment cooling system (PCS) actuation.
Auxiliary Building UPS Distribution Panels (EDS2-EA-12, EDS3-EA-14A)	RAW	These panels distribute power to the DAS equipment.

Table 17.4-1 (Sheet 2 of 8)
Risk-Significant SSCs Within the Scope of D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
Control Cabinets for the Rod Drive MG Sets (Generator Field Control Relays) (PLS-JD-RDM001, PLS-JD-RDM002)	RAW	These relays open on a DAS reactor trip signal demand to de-energize the control rod MG sets and allow the rods to drop.
System: Main ac Power System (ECS)		
Reactor Coolant Pump Switchgear (ECS-ES-31, -32, -41, -42, -51, -52, -61, -62)	RAW/CCF	These breakers open automatically to allow core makeup tank operation.
Ancillary Diesel Generators (ECS-MS-01, -02)	EP	For post-72 hour actions, these generators are available to provide power for Class 1E monitoring, MCR lighting and for refilling the PCS water storage tank and spent fuel pool.
6900 Vac Buses (ECS-ES-1, -2)	RAW	These are ac power buses fed by the onsite DGs and offsite power.
System: Main and Startup Feedwater System (FWS)		
Startup Feedwater Pumps (FWS-MP-03A/B)	EP	The startup feedwater system pumps provide feedwater to the steam generator. This capability provides an alternate core cooling mechanism to the PRHR heat exchangers for non-loss-of-coolant-accidents or steam generator tube ruptures.
System: General I&C[4]		
Low Pressure/DP Sensors – IRWST Wide Range Level (PXS-046, -047, -048) – IRWST Lower Narrow Range Level (PXS-066, -067, -068, -069)	RAW/CCF	These in-containment refueling water storage tank (IRWST) level sensors support PMS functions. They are used in automatic actuation of refueling cavity and SFS isolation, and IRWST recirculation actions, and they provide indications to the operator.
High Pressure/DP Sensors – RCS Hot Leg Level (RCS-160A/B) – Pressurizer Pressure (RCS-191A/B/C/D) – Pressurizer Level (RCS-195A/B/C/D) – SG Narrow-Range Level (SGS-001, -002, -003, -004, -005, -006, -007, -008) – SG Wide-Range Level (SGS-011, -012, -013, -014, -015, -016, -017, -018)	RAW/CCF/EP	The following sensors are included in this group. These sensors support PMS and PLS functions. They are used in reactor trip and ESF functions, and provide indications to the operator. Main feedwater and nonsafety-related startup feedwater flow sensors support startup feedwater actuation and other safety-related startup feedwater flow sensors support PRHR actuation. The hot leg level sensors automatically actuate the IRWST injection and automatic depressurization system (ADS) valves during shutdown conditions.

Table 17.4-1 (Sheet 3 of 8)
Risk-Significant SSCs Within the Scope of D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
– Main Steam Line Pressure (SGS-030, -031, -032, -033, -034, -035, -036, -037) – Main Feedwater Low-Range Flow (FWS-050A/C/E, -051A/C/E) – Startup Feedwater Flow (SGS-055A/B/C/D/E, -056A/B/C/D/E)		
CMT Level Sensors (PXS-011A/B/C/D, -012A/B/C/D, -013A/B/C/D, -014A/B/C/D)	RAW/CCF	These level sensors provide input for automatic actuation of the ADS. They also provide indications to the operator.
System: Class 1E DC Power and Uninterruptible Power System (IDS)		
250 Vdc 24-hour Buses, Batteries, Inverters, and Chargers (IDSA-DB-1A/B, IDSB-DB-1A/B, IDSC-DB-1A/B, IDSD-DB-1A/B, IDSA-DU-1, IDSB-DU-1, IDSC-DU-1, IDSD-DU-1, IDSA-DC-1, IDSB-DC-1, IDSC-DC-1, IDSD-DC-1, IDSA-DS-1, IDSB-DS-1, IDSC-DS-1, IDSD-DS-1)	RAW/CCF	The batteries provide power for the PMS and safety-related valves. The chargers are the preferred source of power for Class 1E dc loads and are the source of charging for the batteries. The inverters provide uninterruptible ac power to the I&C system. The buses distribute power to the Class 1E dc loads.
250 Vdc and 120 Vac Distribution Panels (IDSA-DD-1, -EA-1/2, IDSB-DD-1, -EA-1/2/3, IDSC-DD-1, -EA-1/2/3, IDSD-DD-1, -EA-1/2)	RAW	These panels distribute power to components in the plant that require 1E power support and for the PMS.
Fused Transfer Switch Boxes (IDSA-DF-1, IDSB-DF-1/-2, IDSC-DF-1/-2, IDSD-DF-1)	RAW	The fused disconnect switches connect the different levels of Class 1E distribution panels.

Table 17.4-1 (Sheet 4 of 8)
Risk-Significant SSCs Within the Scope of D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
250 Vdc Motor Control Centers (IDSA-DK-1, IDSB-DK-1, IDSC-DK-1, IDSD-DK-1)	EP	These buses provide power for the PMS and safety-related valve operation.
System: Passive Containment Cooling System (PCS)		
Recirculation Pumps (PCS-MP-01A/B)	EP	These pumps provide the motive force to refill the PCS water storage tank during post-72 hour support actions.
PCCWST Drain Isolation Valves (PCS-PL-V001A/B/C)	EP, L2	These valves (two AOVs and one MOV) open automatically to drain water from a water storage tank onto the outside surface of the containment shell. This water provides evaporative cooling of the containment shell following accidents.
System: Plant Control System (PLS)		
PLS Actuation Hardware (Control functions listed in Note 5)	RAW/CCF	This common cause failure event is assumed to disable all logic outputs from the PLS associated with CVS reactor makeup, RNS reactor injection, spent fuel cooling, component cooling of RNS SFS heat exchangers, service water cooling of CCS heat exchangers, standby diesel generators, and hydrogen igniters.
PLS Actuation Software (Control functions listed in Note 5)	RAW/CCF	This common cause failure event is assumed to disable the software in the PLS associated with CVS reactor makeup, RNS reactor injection, spent fuel cooling, component cooling of RNS SFS heat exchangers, service water cooling of CCS heat exchangers, standby diesel generators, and hydrogen igniters.
System: Protection and Safety Monitoring System (PMS)		
PMS Actuation Software	RAW/CCF	The PMS software provides the automatic reactor trip and ESF actuation functions listed in Tables 7.2-2 and 7.3-1.
PMS Actuation Hardware	RAW/CCF	The PMS hardware provides the automatic reactor trip and ESF actuation functions listed in Tables 7.2-2 and 7.3-1.
Main Control Room (MCR) 1E Displays and System Level Controls (OCS-JC-10, -11)	RAW/CCF	This includes the Class 1E PMS displays and controls. These displays and system level controls provide important plant indications to allow the operator to monitor and control the plant during accidents.
Reactor Trip Switchgear (PMS-JD-RTS A01/02, B01/02, C01/02, D01/02)	RAW/CCF	These breakers open automatically to allow insertion of the control rods.

Table 17.4-1 (Sheet 5 of 8)
Risk-Significant SSCs Within the Scope of D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
System: Passive Core Cooling System (PXS)		
IRWST Hood Vent Covers (PXS-MY-Y21, PXS-MY-Y22, PXS-MY-Y23, PXS-MY-Y24, PXS-MY-Y25, PXS-MY-Y26, PXS-MY-Y27, PXS-MY-Y28, PXS-MY-Y29, PXS-MY-Y30, PXS-MY-Y31, PXS-MY-Y32, PXS-MY-Y33, PXS-MY-Y41, PXS-MY-Y47, PXS-MY-Y48)	RAW/CCF	IRWST hood vent covers provide the functionality to vent steam into containment. The IRWST hood vent covers prevent debris from entering the IRWST and minimize evaporation. Safety functions support hydrogen venting strategy and prevent overpressurization of the IRWST.
IRWST SG Wall Vent Covers (PXS-MY-Y61, PXS-MY-Y62, PXS-MY-Y63, PXS-MY-Y64)	RAW/CCF	IRWST SG wall vent covers provide the functionality to vent steam into containment. The IRWST SG wall vent covers prevent debris from entering the IRWST and minimize evaporation. Safety functions support hydrogen venting strategy and prevent overpressurization of the IRWST.
IRWST Overflow Weir Covers (PXS-MY-Y71, PXS-MY-Y72, PXS-MY-Y73, PXS-MY-Y74, PXS-MY-Y75, PXS-MY-Y76)	RAW/CCF	IRWST overflow weir covers allow water overflow into the refueling cavity during ADS blowdown and PRHR Hx operation. The IRWST overflow weir covers prevent debris from entering the IRWST and minimize evaporation. Safety functions accommodate volume and mass increases and support hydrogen venting strategy.
IRWST Screens (PXS-MY-Y01A/B/C)	RAW/CCF	The IRWST injection lines provide long-term core cooling following a LOCA. These screens are located inside the IRWST and prevent large particles from being injected into the RCS. They are designed so that they will not become obstructed.
Containment Recirculation Screens (PXS-MY-Y02A/B)	RAW/CCF	The containment recirculation lines provide long-term core cooling following a LOCA. The screens are located in the containment and prevent large particles from being injected into the RCS. They are designed so that they will not become obstructed.
CMT Discharge Isolation Valves (PXS-PL-V014A/B, PXS-PL-V015A/B)	RAW/CCF	These air-operated valves automatically open to allow core makeup tank injection.
CMT Discharge Check Valves (PXS-PL-V016A/B, PXS-PL-V017A/B)	RAW/CCF	These check valves are normally open. They close during rapid accumulator injection.
Accumulator Discharge Check Valves (PXS-PL-V028A/B, -V029A/B)	RAW/CCF	These check valves open when the RCS pressure drops below the accumulator pressure to allow accumulator injection.
PRHR Heat Exchanger Control Valves (PXS-PL-V108A/B)	RAW/CCF	The PRHR heat exchangers provide core cooling following non-LOCAs, steam generator tube ruptures, and anticipated transients without scram. The air-operated valves automatically open to initiate PRHR heat exchanger operation.

Table 17.4-1 (Sheet 6 of 8)
Risk-Significant SSCs Within the Scope of D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
Containment Recirculation Squib Valves (PXS-PL-V118A/B, PXS-PL-V120A/B)	RAW/CCF	The containment recirculation lines provide long-term core cooling following a LOCA. These squib valves open automatically to allow containment recirculation when the IRWST level is reduced to about the same level as the containment level. These squib valves can also allow long-term core cooling to be provided by the RNS pumps. These squib valves can provide a rapid flooding of the containment to support in-vessel retention during a severe accident.
IRWST Injection Check Valves (PXS-PL-V122A/B, -V124A/B)	RAW/CCF	The containment recirculation lines provide long-term core cooling following a LOCA. These check valves open when the IRWST level is reduced to approximately the same level as the containment level.
IRWST Injection Squib Valves (PXS-PL-V123A/B, -V125A/B)	RAW/CCF	The IRWST injection lines provide long-term core cooling following a LOCA. These squib valves open automatically to allow injection when the RCS pressure is reduced to below the IRWST injection head.
IRWST Gutter Bypass Isolation Valves (PXS-PL-V130A/B)	RAW/CCF	These valves direct water collected in the IRWST gutter to the IRWST. This capability extends PRHR heat exchanger operation.
System: Reactor Coolant System (RCS)		
ADS Stage 1/2/3 Valves (MOV) (RCS-PL-V001A/B, -V002A/B, -V003A/B, -V011A/B, -V012A/B, -V013A/B)	RAW/CCF	The ADS provides a controlled depressurization of the RCS following LOCAs to allow core cooling from the accumulator, IRWST injection, and containment recirculation. The ADS provides "bleed" capability for feed/bleed cooling of the core. The ADS also provides depressurization of the RCS to prevent a high-pressure core melt sequence.
ADS Stage 4 Valves (Squib) (RCS-PL-V004A/B/C/D)	RAW/CCF	The ADS provides a controlled depressurization of the RCS following LOCAs to allow core cooling from the accumulator, IRWST injection, and containment recirculation. The ADS provides "bleed" capability for feed/bleed cooling of the core. The ADS also provides depressurization of the RCS to prevent a high-pressure core melt sequence.
Pressurizer Safety Valves (RCS-PL-V005A/B)	RRW	These valves provide overpressure protection of the RCS.

Table 17.4-1 (Sheet 7 of 8)
Risk-Significant SSCs Within the Scope of D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
Reactor Vessel Insulation Water Inlet and Steam Vent Devices (RXS-MN-01)	EP	These devices provide an engineered flow path to promote in-vessel retention of the core in a severe accident.
Reactor Cavity Doorway Damper	EP	This device provides a flow path to promote in-vessel retention of the core in a severe accident.
Fuel Assemblies (157 assemblies with tag numbers beginning with RXS-FA)	SMA	The nuclear fuel assembly includes the fuel pellets, fuel cladding, and associated support structures. This equipment, which provides a first barrier for release of radioactivity and allows for effective core cooling, had the least margin in the seismic margin analysis.
System: Normal Residual Heat Removal System (RNS)		
Residual Heat Removal Pumps (RNS-MP-01A/B)	RAW/CCF	These pumps provide shutdown cooling of the RCS. They also provide an alternate RCS lower pressure injection capability following actuation of the ADS. The operation of these pumps is important to investment protection during shutdown reduced-inventory conditions. RNS valve realignment is not required for reduced-inventory conditions.
RNS Motor-Operated Valves (RNS-PL-V011, -V022, -V023, -V055)	RRW	These MOVs align a flow path for nonsafety-related makeup to the RCS following ADS operation, initially from the cask loading pit and later from the containment.
RNS Stop Check Valves (RNS-PL-V015A/B), RNS Check Valves (RNS-PL-V017 A/B)	CCF/EP	These stop check valves and check valves are in the discharge of the RNS pumps. They prevent backflow from the RCS.
RNS Check Valves (RNS-PL-V007 A/B, -V013, -V056)	L2 RAW/EP	Check valves V007 A/B and V013 provide a flow path from the RNS pumps to the RCS. Failure of these valves to open will result in the loss of long-term cooling from the RNS. Check valve V056 provides a flow path from the cask loading pit to the RNS pump inlet.
System: Spent Fuel Cooling System (SFS)		
Spent Fuel Cooling Pumps (SFS-MP-01A/B)	EP	These pumps provide flow to the heat exchangers for removal of the design basis heat load.
System: Steam Generator System (SGS)		
Main Steam Safety Valves (SGS-PL-V030A/B, -V031A/B, -V032A/B, -V033A/B, -V034A/B, -V035A/B)	RRW	The steam generator main steam safety valves provide overpressure protection of the steam generator. They also provide core cooling by venting steam from the steam generator.

Table 17.4-1 (Sheet 8 of 8)
Risk-Significant SSCs Within the Scope of D-RAP

System, Structure, or Component (SSC)[1]	Rationale[2]	Insights and Assumptions
Main Steam and Feedwater Isolation Valves (SGS-PL-V040A/B, -V057A/B)	RAW/EP	The steam generator main steam and feedwater isolation valves provide isolation of the steam generator following secondary line breaks and steam generator tube rupture.
System: Service Water System (SWS)		
Service Water Pumps and Cooling Tower Fans (SWS-MP-01A/B, SWS-MA-01A/B)	EP	These pumps and fans provide cooling of the CCS heat exchanger which is important to investment protection during shutdown reduced-inventory conditions. Service water system valve realignment is not required for reduced-inventory conditions.
System: Nuclear Island Nonradioactive Ventilation System (VBS)		
VBS MCR and I&C Rooms B/C Ancillary Fans (VBS-MA-10A/B, -11, -12)	EP	For post-72 hour actions, these fans are available to provide cooling of the MCR and the two I&C rooms (B/C) that provide post-accident monitoring.
System: Containment Air Filtration System (VFS)		
VFS Containment Purge Isolation Valves (VFS-PL-V003, -V004, -V009, -V010)	RAW	The VFS containment purge isolation valves provide isolation of containment following an accident. These containment isolation valves are important in limiting offsite releases following core melt accidents.
System: Chilled Water System (VWS)		
Air Cooled Chillers and Pumps (VWS-MS-02, -03, VWS-MP-02, -03)	EP	This VWS subsystem provides chilled cooling water to the CVS makeup pump room. The pumps and chillers are important components of the VWS.
System: Liquid Radwaste System (WLS)		
Sump Containment Isolation Valves (WLS-PL-V055, -V057)	RAW	The sump containment isolation valves provide isolation of containment following an accident. These containment isolation valves are important in limiting offsite releases following core melt accidents.
System: Onsite Standby Power System (ZOS)		
Onsite Diesel Generators (ZOS-MS-05A/B)	RAW/CCF	These diesel generators provide ac power to support operation of nonsafety-related equipment such as the startup feedwater pumps, CVS pumps, RNS pumps, CCS pumps, SWS pumps, and the PLS. Providing ac power to the RNS and the equipment necessary to support its operation is important to investment protection during reduced inventory conditions.
Engine Room Exhaust Fans (VZS-MY-V01A/B, -V02A/B)	RAW/CCF	These fans provide ventilation of the rooms containing the onsite diesel generators.

Notes:

1. Only includes equipment at the **component** level. Other parts of the SSC or support systems are not included unless specifically listed.
2. Definition of Rationale Terms:
   CCF = Common Cause Failure (for the SSCs whose inclusion rationale is RAW/CCF, the RAW is based on common cause failure of two or more of the specified SSCs.
   EP = Expert Panel
   RAW = Risk Achievement Worth
   RRW = Risk Reduction Worth
   SMA = Seismic Margin Analysis
3. Maintenance/surveillance recommendations for equipment are documented in each appropriate section.
4. This category captures instrumentation and control equipment common cause failures across systems.
5. The PLS provides control of the following functions:
   CVS Reactor Makeup
   RNS Reactor Injection from Cask Loading Pit
   Startup Feedwater from CST
   Spent Fuel Cooling
   Component Cooling of RNS and SFS Heat Exchangers
   Service Water Cooling of the CCS Heat Exchangers
   Onsite Diesel Generators
   Hydrogen Igniters

Table 17.4-2
Example of Risk-Significant Ranking of SSCs for the Automatic Depressurization System

Rank[1]	Event Code	Description
1	ED3MOD07	EDS3 EA1 distribution panel failure or unavailable due to testing and maintenance
2	AD4MOD07, AD4MOD08, AD4MOD09, AD4MOD10	Hardware failure of 2 of 4 automatic depressurization system Stage 4 squib valves
3	EC1BS001TM, ECBS012TM, EC1BS121TM, EC2BS002TM, EC2BS022TM, EC2BS221TM	Unavailability of bus ECS ES due to unscheduled maintenance
4	AD2MOD01, AD2MOD02, AD2MOD03, AD2MOD04	Hardware failure of 2 of 4 automatic depressurization system Stages 2 and 3 of lines 1 and 2 (includes motor-operated valves)
5	EC0MOD01	Main generator breaker ES01 fails to open
6	ED3MOD01	Fixed component fails: circuit breaker, inverter or static transfer switch
7	Z01MOD01, Z02MOD01	Diesel generator fails to start and run or breaker 102 fails to close
8	Z02DG001TM, Z02DG001TM	Standby diesel generator unavailable due to testing and maintenance

Note:
1. The ranking is in the order of decreasing risk achievement component importance.

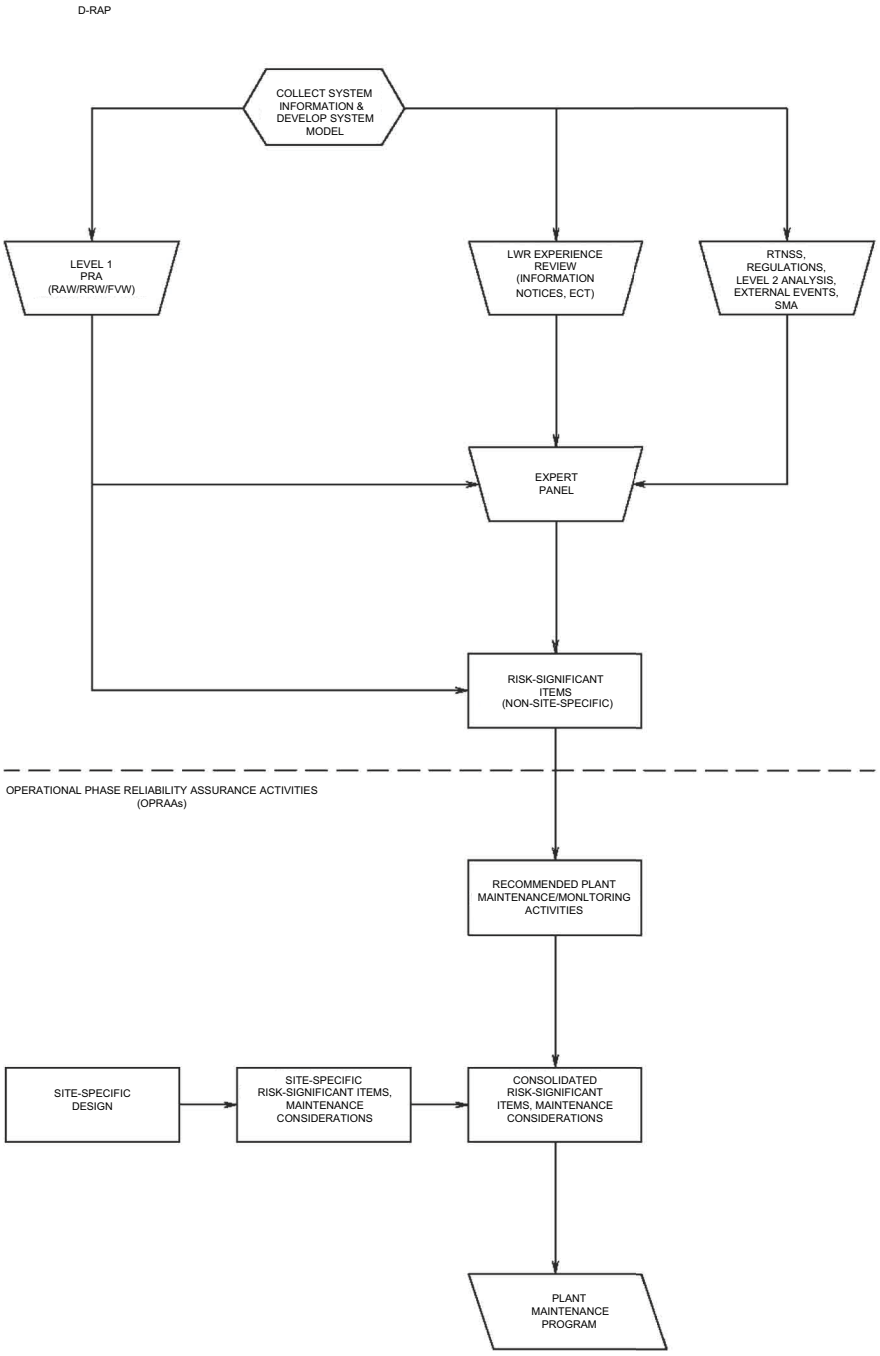

Figure 17.4-1
Design Reliability Assurance Program and Operational Phase Reliability Assurance Activities

17.5 Quality Assurance Program Description

The Quality Assurance Program in place during the design, construction, and operations phases is described in the QAPD, which is maintained as a separate document. This QAPD is incorporated by reference (see Table 1.6-201). This QAPD is based on NEI 06-14A, "Quality Assurance Program Description" (Reference 201).

Conformance statements for QA-related Regulatory Guides (including Regulatory Guides 1.28, 1.30, 1.33, 1.38, 1.39, 1.94, and 1.116) are provided in Appendix 1A. While many Regulatory Guide positions can be identified as applicable to the scope of work identified and addressed by the DCD and others can be identified as applicable to the scope of work identified and addressed by the COLA, some QA guidance related positions could be accomplished by either scope of work and thus be addressed in either the DCD or the COLA. These positions are primarily dependent on who performs the work. The DCD conformance statement indicates an exception to apply NQA-1. The COLA identifies an exception to apply NQA-1. Per Section 17.3, WEC work performed up to March 15, 2007 applied a 1991 version of the standard. A 1994 version of the standard is applied for work performed after that date by WEC. If the work is performed under the applicant's COL program, the 1994 version of NQA-1 identified in the COLA QAPD is applied. Thus, DCD scope (identified in Appendix 1A) and "remaining scope" differentiate the application of the guidance identified in these Regulatory Guides.

The QAPD is the SNC Nuclear Development Quality Assurance Manual.

Table 13.4-201 provides milestones for operational quality assurance program implementation.

17.6 Maintenance Rule Program

This section incorporates NEI 07-02A, “Generic FSAR Template Guidance for Maintenance Rule Program Description for Plants Licensed Under 10 CFR Part 52” Reference 202.

Table 13.4-201 provides milestones for maintenance rule program implementation.

The Maintenance Rule (MR) Program provides assurance that structures, systems, and components (SSCs) within the scope of the program remain reliable and capable of fulfilling their intended functions and provides processes for assessing and managing potential increases in risk that might result from proposed maintenance activities. The MR Program meets the requirements of 10 CFR 50.65 Reference 203.

17.6.1 Maintenance Rule Program Description

The MR program follows the guidance in NUMARC 93-01 Reference 204, as endorsed and modified by Regulatory Guide 1.160, Reference 205, without any exceptions that could materially and negatively affect the effectiveness of the program. The principal functions of the program are described in the following subsections.

The MR program includes appropriate control of procedures, documents, computer software and data, as applicable.

17.6.1.1 Maintenance Rule Scoping per 10 CFR 50.65(b)

17.6.1.1.a The SSCs within the scope of the MR program include safety-related SSCs and certain non-safety-related SSCs, as determined using a MR scoping procedure. The scoping procedure addresses:

- Safety-related SSCs.
- Non-safety-related SSCs that mitigate accidents or transients.
- Non-safety-related SSCs that are used in Emergency Operating Procedures, where ‘used’ means directly used to mitigate the accident or transient via explicit reference in the EOP or used in steps of procedures referenced by the EOP. Additionally, SSCs explicitly referenced in back-up or lower-tier methods in the EOPs and provide reasonable assurance of mitigation success, or whose use is implied in an EOP and essential to the completion of an EOP step, are considered within scope of the Maintenance Rule.
- Non-safety-related SSCs whose failure prevents safety-related SSCs from fulfilling their safety-related functions.
- Non-safety-related SSCs whose failure causes scrams or actuates safety systems.

The SSCs within the scope of the MR program are evaluated against performance criteria to determine which SSCs will have goals established and monitoring activities performed in accordance with 10 CFR 50.65(a)(1).

17.6.1.1.b Safety significance classifications and bases of in-scope SSCs, e.g., high safety significance (HSS) or low safety significance (LSS), are determined using processes consistent with Subsection 9.3.1 of NUMARC 93-01. They include determination of risk significance criteria and appropriate consideration of operating experience, generic failure data, component reliability information, probabilistic risk assessment (PRA) insights, and the recommendations of an expert panel. All SSCs identified as risk-significant via the Reliability Assurance Program for the design phase (DRAP – see Section 17.4) are included within the initial MR scope as HSS SSCs. This includes risk-significant SSCs identified as part of the design certification phase or follow-on COL applicant/holder phases of DRAP.

17.6.1.1.c The expert panel is established in accordance with NUMARC 93-01 prior to fuel load authorization and utilizes operating, maintenance and systems expertise, PRA insights, and other applicable information to update and maintain the MR scope and SSC classifications.

17.6.1.2 Monitoring and Corrective Action per 10 CFR 50.65(a)(1)

SSCs within the scope of the MR are initially classified as (a)(2) (ref. Section 17.6.1.3), except where it is determined that an SSC should be initially classified as (a)(1), e.g., an SSC that fails during start-up testing.

SSCs that do not meet performance criteria established for (a)(2) monitoring (ref. Section 17.6.1.3) are evaluated for (a)(1) classification in accordance with MR program procedures, with recommended corrective actions identified as appropriate. Necessary corrective actions are implemented in accordance with the site Corrective Action Program. The MR expert panel reviews whether SSCs are to be classified as (a)(1). Monitoring goals are established for SSCs classified as (a)(1), as appropriate, commensurate with the SSCs' safety significance, and considering applicable industry operating experience, with the objective of providing reasonable assurance that the SSC is proceeding to acceptable performance levels and that the corrective actions taken were effective.

For SSCs that do not meet established (a)(1) monitoring goals following corrective actions initially identified and implemented, appropriate additional corrective actions are taken.

17.6.1.3 Preventive Maintenance per 10 CFR 50.65(a)(2)

Monitoring as specified in 10 CFR 50.65(a)(1) is not required where it has been demonstrated that the performance or condition of an SSC is being effectively controlled through the performance of appropriate preventive maintenance (PM), such that the SSC remains capable of performing its intended function.

The MR program includes procedures for managing SSC performance in accordance with 10 CFR 50.65(a)(2) requirements during plant operation consistent with NUMARC 93-01. To monitor the effectiveness of the maintenance performed on the various SSCs, performance criteria are established at the plant, system, train, or component level commensurate with safety, risk significance and SSC function. SSC performance criteria (e.g., failure rate, unavailability or condition-based) are chosen that are reasonable, measurable, and technically appropriate for the purpose of timely identification of degraded SSC performance or condition. For risk-significant SSCs identified via DRAP, performance criteria are consistent with the reliability and availability assumptions used in the PRA.

When a performance criterion is not met, the SSC is evaluated for (a)(1) classification in accordance with MR program procedures, including review by the Expert Panel. Should the Expert Panel conclude that the SSC should not be classified as (a)(1), or that no (a)(1) monitoring goals need be

established, a technical justification establishing the appropriateness of continued management of SSC performance under (a)(2) is documented and maintained.

SSCs that provide little or no contribution to system safety function or can be allowed to run to failure due to an acceptable risk may be categorized in a “run-to-failure” status (i.e., perform corrective maintenance rather than preventive maintenance) consistent with NUMARC 93-01.

Preventive maintenance is subject to risk assessment and management per 10 CFR 50.65(a)(4) (ref. Section 17.6.1.5).

17.6.1.4 Periodic Evaluation of Monitoring and Preventive Maintenance per 10 CFR 50.65(a)(3)

The MR program includes procedures for the periodic evaluation of the performance and condition monitoring activities and associated goals and preventive maintenance activities in accordance with 50.65(a)(3). The following considerations are included:

- how procedures govern the scheduling and timely performance of (a)(3) evaluations.
- documenting, reviewing and approving evaluations, providing and implementing results.
- review of 50.65(a)(1) goals and 50.65(a)(2) performance criteria, condition monitoring criteria, SSC performance and condition history and effectiveness of corrective action
- making adjustments to achieve or restore balance between reliability and availability.
- industry operating experience.

17.6.1.5 Risk Assessment and Risk Management per 10 CFR 50.65(a)(4)

The MR program includes procedures for maintenance risk assessment and management in accordance with 10 CFR 50.65(a)(4), employing the methods described in NUMARC 93-01, Section 11. The risk from maintenance activities is both assessed (i.e., using a risk-informed process to evaluate the overall contribution to risk of the planned maintenance activities) and managed (i.e., providing plant personnel with proper awareness of the risk, and taking actions as appropriate to control the risk).

The MR program and procedures reflect, as appropriate, consideration of issues associated with grid/offsite power reliability as identified in NRC Generic Letter 2006-02, items 5 and 6.

17.6.2 Maintenance Rule Training and Qualification

The MR program is supported by appropriate training and qualification for designated personnel. Training is commensurate with MR responsibilities, including MR program administration, the expert panel process, operations, engineering, maintenance, licensing, and plant management, as appropriate. Maintenance Rule Program training and qualification materials are based on regulatory requirements and guidance, and training records are maintained in accordance with plant procedures.

17.6.3 Maintenance Rule Program Relationship With Reliability Assurance Activities

Reliability during the operations phase is assured through the implementation of operational programs, i.e., the MR program, the Quality Assurance Program, inservice inspection and testing programs, the Technical Specifications surveillance test program, and maintenance programs.

Descriptions of the programs are provided in the following chapters/sections:

The maintenance rule program (Section 17.6)

The quality assurance program (Section 17.5)

Inservice inspection program (Sections 5.2 and 6.6)

Inservice testing program (Section 3.9)

The technical specifications surveillance test program (COL Appendix A)

17.6.4 Maintenance Rule Program Relationship With Industry Operating Experience Activities

Industry Operating Experience (IOE) comprises information from a variety of sources that is applicable and available to the nuclear industry with the intent of minimizing, through shared experiences, adverse plant conditions or situations. Sources of IOE include information programs organized by the reactor vendor, safety-related equipment suppliers, the NRC, the Institute of Nuclear Power Operations (INPO) and the Electric Power Research Institute (EPRI).

IOE is reviewed for plant-specific applicability and, where appropriate, is applied in various elements of the MR program and procedures, including scoping, performance/condition criteria development, monitoring, goal-setting, corrective action, training, program assessment, and maintenance and procurement activities. The specific steps for employing IOE in the various MR program areas are contained in program procedures.

Condition monitoring of underground or inaccessible cables is incorporated into the maintenance rule program. The cable condition monitoring program incorporates lessons learned from industry operating experience, addresses regulatory guidance, and utilizes information from detailed design and procurement documents to determine the appropriate inspections, tests and monitoring criteria for underground and inaccessible cables within the scope of the maintenance rule (i.e., 10 CFR 50.65). The program takes into consideration Generic Letter 2007-01.

17.6.5 Maintenance Rule Program Implementation

MR Program documents will be developed and maintained, and the MR program will be implemented by the time that initial fuel loading has been authorized.

17.7 Combined License Information Items

17.7.1 The design phase Quality Assurance program is addressed in Sections 17.1 and 17.5.

17.7.2 The Quality Assurance program for procurement, fabrication, installation, construction and testing of structures, systems and components in the facility, including provisions for seismic Category II structures, systems, and components, is addressed in Section 17.5.

17.7.3 The PRA importance measures, the expert panel process, and other deterministic methods to determine the site-specific list of SSCs under the scope of RAP are addressed in APP-GW-GLR-117 (Reference 11).

17.7.4 The Quality Assurance program for operations is addressed in Section 17.5.

17.7.5 The activities represented in Figure 17.4-1 as "Plant Maintenance Program" include the tasks necessary to maintain the reliability of risk-significant SSCs as addressed in APP-GW-GLR-117 (Reference 11). Reference 8 contains examples of cost-effective maintenance enhancements, such as condition monitoring and shifting time-directed maintenance to condition-direction maintenance.

17.7.6 The Maintenance Rule (10 CFR 50.65) activities that prescribe SSC performance-related goals during plant operation are addressed in APP-GW-GLR-117 (Reference 11).

17.7.7 The D-RAP activities are addressed in APP-GW-GLR-117 (Reference 11), and include:

- Reliability data base — Historical data available on equipment performance. The compilation and reduction of this data provides the plant with source of component reliability information.
- Surveillance and testing — In addition to maintaining the performance of the components necessary for plant operation, surveillance and testing provides a high degree of reliability for the safety-related SSCs.
- Maintenance plan — This plan describes the nature and frequency of maintenance activities to be performed on plant equipment. The plan includes the selected SSCs identified in the D-RAP.

17.7.8 The integration of the objectives of the OPRAAs into the Quality Assurance Program developed to implement 10 CFR 50, Appendix B, including failures of non-safety-related, risk-significant SSCs that result from design and operational errors in accordance with SECY-95-132, Item E, is addressed in Section 17.5.

17.8 References

1. "Energy Systems Business Unit – Quality Management System," Revision 2.

2. WCAP-8370, Revision 12a, “Energy Systems Business Unit - Power Generation Business Unit Quality Assurance Plan,” April 1992.

3. WCAP-8370/7800, Revision 11A/7A, “Energy Systems Business Unit - Nuclear Fuel Business Unit Quality Assurance Plan,” December 1988.

4. WCAP-12600, Revision 4, "AP600 Advanced Light Water Reactor Design Quality Assurance Program Plan," January 1998.

5. APP-GW-GL-022, AP1000 Probabilistic Risk Assessment Rev. 8, August 2004 [ML042230497].

6. Not used.

7. NRC/DCP0669, "Criteria for Establishing Risk Significant Structures, Systems, and Components (SSCs) to be Considered for the AP600 Reliability Assurance Program," January 16, 1997.

8. Lofgren, E. V., Cooper, et al., "A Process for Risk-Focused Maintenance," NUREG/CR-5695, March 1991.

9. Westinghouse Electric Company Quality Management System (QMS), Revision 7, dated October 1, 2013.

10. NEI 07-02, “Generic FSAR Template Guidance for Maintenance Rule Program Description for Plants Licensed Under 10 CFR Part 52.”

11. APP-GW-GLR-117, “Incorporation of the Maintenance Rule,” Westinghouse Electric Company LLC.

12. SECY 95-132, “Policy and Technical Issue With the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs (SECY 94-084).”

201. Nuclear Energy Institute, Technical Report NEI 06-14A, “Quality Assurance Program Description,” Revision 7, July 2009.

202. Nuclear Energy Institute, “Generic FSAR Template Guidance for Maintenance Rule Program Description for Plants Licensed Under 10 CFR Part 52,” NEI 07-02A, Revision 0, March 2008.

203. 10 CFR 50.65, “Requirements for monitoring the effectiveness of maintenance at nuclear power plants.”

204. Nuclear Management and Resources Council, Inc., "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," NUMARC 93-01, Rev. 4F, April 2018 [ML18120A069].

205. Regulatory Guide 1.160, Rev. 4, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 18	HUMAN FACTORS ENGINEERING	18.1-1
18.1	Overview	18.1-1
18.1.1	References	18.1-3
18.2	Human Factors Engineering Program Management	18.2-1
18.2.1	Human Factors Engineering Program Goals, Scope, Assumptions, and Constraints	18.2-1
18.2.1.1	Human Factors Engineering Program Goals	18.2-1
18.2.1.2	Assumptions and Constraints	18.2-1
18.2.1.3	Applicable Facilities	18.2-3
18.2.1.4	Applicable Human System Interfaces	18.2-3
18.2.1.5	Applicable Plant Personnel	18.2-3
18.2.1.6	Technical Basis	18.2-3
18.2.2	Human System Interface Design Team and Organization	18.2-4
18.2.2.1	Responsibility	18.2-4
18.2.2.2	Organizational Placement and Authority	18.2-4
18.2.2.3	Composition	18.2-5
18.2.2.4	Team Staffing Qualifications	18.2-7
18.2.3	Human Factors Engineering Processes and Procedures	18.2-9
18.2.3.1	General Process and Procedures	18.2-9
18.2.3.2	Process Management Tools	18.2-12
18.2.3.3	Integration of Human Factors Engineering and Other Plant Design Activities	18.2-12
18.2.3.4	Human Factors Engineering Documentation	18.2-13
18.2.3.5	Human Factors Engineering in Subcontractor Efforts	18.2-13
18.2.4	Human Factors Engineering Issues Tracking	18.2-14
18.2.5	Human Factors Engineering Technical Program and Milestones	18.2-14
18.2.6	Combined License Information	18.2-15
18.2.6.1	Human Factors Engineering Program	18.2-15
18.2.6.2	Emergency Operations Facility	18.2-15
18.2.7	References	18.2-16
18.3	Operating Experience Review	18.3-1
18.3.1	Combined License Information	18.3-1
18.3.2	References	18.3-1
18.4	Functional Requirements Analysis and Allocation	18.4-1
18.4.1	Combined License Information	18.4-1
18.4.2	References	18.4-2
18.5	AP1000 Task Analysis Implementation Plan	18.5-1
18.5.1	Task Analysis Scope	18.5-1
18.5.2	Task Analysis Implementation Plan	18.5-2
18.5.2.1	Function-Based Task Analyses	18.5-2
18.5.2.2	OSA-1	18.5-2
18.5.2.3	OSA-2	18.5-3
18.5.2.4	Task Analysis of Maintenance, Test, Inspection and Surveillance Tasks	18.5-3
18.5.2.5	Technical Support Center and Emergency Operations Facility	18.5-4

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
18.5.3	Job Design Factors	18.5-4
18.5.4	Combined License Information Item	18.5-4
18.5.5	References	18.5-4
18.6	Staffing	18.6-1
18.6.1	Combined License Information Item	18.6-2
18.6.2	References	18.6-2
18.7	Integration of Human Reliability Analysis with Human Factors Engineering	18.7-1
18.7.1	Combined License Information	18.7-1
18.7.2	References	18.7-1
18.8	Human System Interface Design	18.8-1
18.8.1	Implementation Plan for the Human System Interface Design	18.8-2
18.8.1.1	Functional Design	18.8-3
18.8.1.2	Design Guidelines	18.8-4
18.8.1.3	Design Specifications	18.8-4
18.8.1.4	Man-in-the-Loop Testing	18.8-5
18.8.1.5	Mockup Activities	18.8-5
18.8.1.6	Human System Interface Design Documentation	18.8-6
18.8.1.7	Task-Related Human System Interface Requirements	18.8-6
18.8.1.8	General Human System Interface Design Feature Selection	18.8-6
18.8.1.9	Human System Interface Characteristics: Identification of High Workload Situations	18.8-7
18.8.1.10	Human System Interface Software Design and Implementation Process	18.8-8
18.8.2	Safety Parameter Display System (SPDS)	18.8-9
18.8.2.1	General Safety Parameter Display System Requirements	18.8-9
18.8.2.2	Display of Safety Parameters	18.8-10
18.8.2.3	Reliability	18.8-11
18.8.2.4	Isolation	18.8-11
18.8.2.5	Human Factors Engineering	18.8-11
18.8.2.6	Minimum Information	18.8-12
18.8.2.7	Procedures and Training	18.8-12
18.8.3	Operation and Control Centers System	18.8-12
18.8.3.1	Main Control Room Mission and Major Tasks	18.8-13
18.8.3.2	Main Control Area Mission and Major Tasks	18.8-13
18.8.3.3	Operations Work Area Mission and Major Tasks	18.8-14
18.8.3.4	Remote Shutdown Workstation Mission and Major Tasks	18.8-14
18.8.3.5	Technical Support Center Mission and Major Tasks	18.8-14
18.8.3.6	Operations Support Center Mission and Major Tasks	18.8-15
18.8.3.7	Radwaste Control Area Mission and Major Tasks	18.8-15
18.8.3.8	Local Control Stations Mission and Major Tasks	18.8-16
18.8.3.9	Emergency Operations Facility	18.8-16

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	18.8.4 Human Factors Design for the Non-Human-System Interface Portion of the Plant	18.8-16
	18.8.4.1 General Plant Layout and Design	18.8-16
	18.8.5 Combined License Information	18.8-18
	18.8.6 References	18.8-19
18.9	Procedure Development	18.9-1
	18.9.1 Combined License Information	18.9-1
	18.9.2 References	18.9-1
18.10	Training Program Development	18.10-1
	18.10.1 Combined License Information	18.10-1
	18.10.2 References	18.10-1
18.11	Human Factors Engineering Verification and Validation	18.11-1
	18.11.1 Combined License Information	18.11-1
	18.11.2 References	18.11-1
18.12	Inventory	18.12-1
	18.12.1 Inventory of Displays, Alarms, and Controls	18.12-1
	18.12.2 Minimum Inventory of Main Control Room Fixed Displays, Alarms, and Controls	18.12-1
	18.12.3 Remote Shutdown Workstation Displays, Alarms, and Controls	18.12-6
	18.12.4 Combined License Information	18.12-6
	18.12.5 References	18.12-6
18.13	Design Implementation	18.13-1
	18.13.1 References	18.13-1
18.14	Human Performance Monitoring	18.14-1
	18.14.1 References	18.14-2
APPENDIX 18A	NOT USED	18A-1

LIST OF TABLES

Table Number	Title	Page
18.8-1	Human Performance Issues to be Addressed by the HSI Design	18.8-22
18.12.2-1	Minimum Inventory of Fixed Position Controls, Displays, and Alerts	18.12-7

LIST OF FIGURES

Figure Number	Title	Page
18.1-1	Human Factors Engineering (HFE) Design and Implementation Process	18.1-4
18.2-1	Human System Interface (HSI) Design Team Process	18.2-17
18.2-2	Human System Interface (HSI) Design Team Organization and Relationship to AP1000 Organization	18.2-18
18.2-3	Overview of the AP1000 Human Factors Engineering Process	18.2-19
18.5-1	Top Four Levels of the Normal Power Operation for a Westinghouse PWR	18.5-6
18.5-2	Task Analysis Utilized as Design Input	18.5-7
18.8-1	Soft Control Interactions	18.8-24
18.8-2	Mapping of Human System Interface Resources to Operator Decision-Making Model	18.8-25
18.11-1	Not Used	18.11-3

Chapter 18 Human Factors Engineering

18.1 Overview

Human factors engineering deals with designing and implementing resources and environments that help people perform tasks more reliably. Traditionally, human factors engineering includes the consideration of:

- Anthropometric or physical fit of humans to either their task-assisting machines or to their surroundings (for example, height, reach, and visual limitations)

- Biomechanical fit of the physical capabilities and limitations of humans relative to the requirements of their tasks (for example, lifting limits and push-pull limits)

- Biophysical fit of the physiological capabilities and limitation of humans to their environment (for example, tolerance to heat or cold, harmful chemicals, and noise)

More recently, the human factors engineering discipline also models human error. Human errors include:

- Errors of execution or “slips”
- Errors of intention or “mistakes” (Reference 1)

Slips are errors in which a person’s intentions are correct, but an incorrect method for executing the action is chosen. Mistakes are errors in which the person forms an incorrect intention but then correctly executes it. Slips tend to be the result of poorly designed physical interfaces (for example, switches on a control board that look or feel alike) or of a poorly designed work environment (for example, temperatures that cause worker exhaustion). Mistakes are cognitive or mental errors. Human factors engineering includes cognitive systems engineering. This discipline focuses on the design of interfaces between humans and machines that support the operator decision-making activities that are required by the task. Cognitive systems engineering is particularly important when designing an interface for operators that control a real-time process, such as a nuclear power plant.

The rapid changes in digital computer and color graphics display technology offer the AP1000 design team an opportunity to improve the real-time decision support for the AP1000 operating staff. The AP1000 has a plant-wide network that provides pre-processed plant data to those members of the plant’s staff who have need of it. The real-time process control interface between the plant’s staff and the plant’s process equipment is the instrumentation and control (I&C) equipment driving graphical display devices in an integrated Human System Interface. Cognitive systems engineering is applied in the design of the human system interface.

The layout and environmental design of the main control room and the remote shutdown room, and the supplementary support areas, such as the technical support center, are sites of application of the traditional disciplines of human factors engineering.

Design input including decisions made in the design of the AP1000 that affect interfaces is provided. This includes input on the operating staff training program and on the development of the plant operating procedures.

Because of the rapid changes that are taking place in the digital computer and graphic display technology employed in a modern human system interface, design certification of the AP1000 focuses upon the process used to design and implement human system interfaces for the AP1000, rather than on the details of the implementation. As a result, this chapter describes the processes used to provide human factors engineering in the design of the AP1000.

This chapter describes the application of the human factors engineering disciplines to the design of the AP1000. [*The basis for the human factors engineering program is the human factors engineering process specified in Reference 2.*]* Figure 18.1-1 illustrates the elements of the human factors engineering program. These elements correspond to the elements specified in References 2, 10, and 11. The organization of this chapter parallels these elements. In addition to the elements of the program review model, this chapter includes a description of the minimum inventory of controls, displays, and alarms present in the main control room and at the remote shutdown workstation.

18.1.1 References

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2. *NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.*]*

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4. Not used.

5. Not used.

6. Not used.

7. Not used.

8. Not used.

9. Not used.

10. NUREG-0711, Revision 1, "Human Factors Engineering Program Review Model," May 2002.

11. NUREG-0711, Revision 2, "Human Factors Engineering Program Review Model," U.S. NRC, February 2004.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

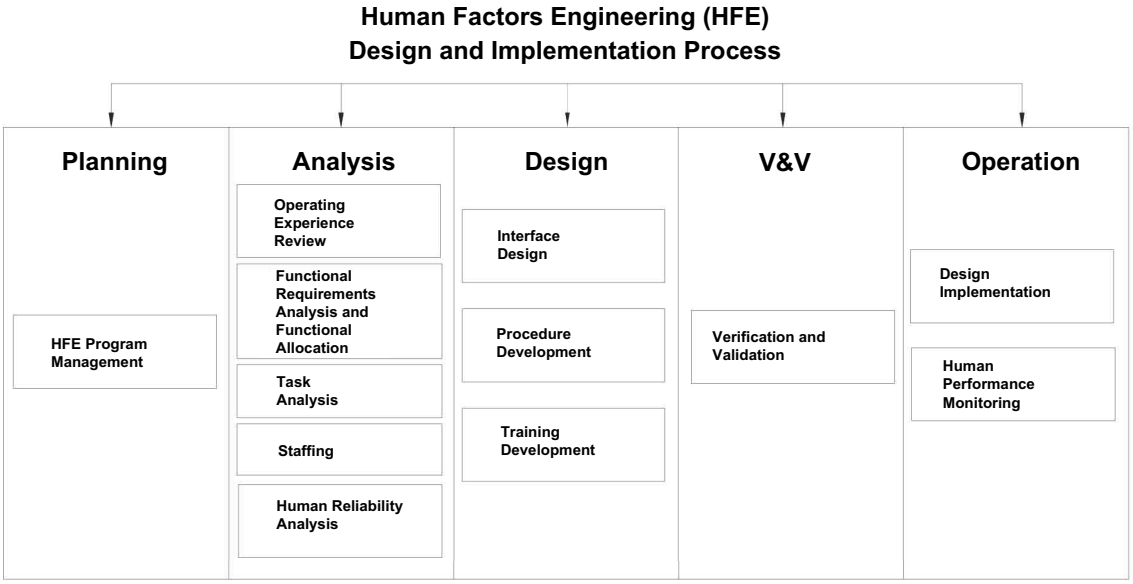

Figure 18.1-1
Human Factors Engineering (HFE)
Design and Implementation Process

18.2 Human Factors Engineering Program Management

The purpose of this section is to describe the goals of the AP1000 human factors engineering program, the technical program to accomplish these goals, the human system interface design team, and management and organizational structure that support the implementation of the technical program.

Human factors engineering is the system engineering of human system interfaces. The program management tools and procedures that govern the design of AP1000 systems apply to the human factors engineering activity. This approach integrates the design of human system interfaces with other plant systems.

18.2.1 Human Factors Engineering Program Goals, Scope, Assumptions, and Constraints

18.2.1.1 Human Factors Engineering Program Goals

The goal of the human factors engineering program is to provide the users of the plant operation and control centers effective means for acquiring and understanding plant data and executing actions to control the plant's processes and equipment.

The objective is to enable personnel tasks to be accomplished within time and performance criteria.

18.2.1.2 Assumptions and Constraints

There are a number of inputs to the human factors engineering design process that specify assumptions or constraints on the human factors engineering program and the human system interfaces design.

Major design inputs include regulatory guidelines, guidance from utilities and utility representative groups, utility requirements documents, and AP1000 plant systems design specifications. The requirements resulting from these design inputs are captured in human system interface specification documents and functional requirements documents.

While assumptions and constraints specified by design inputs are provisionally treated as design requirements, the appropriateness of these requirements is evaluated as part of the human factors engineering design process. Results of human factors engineering activities such as operating experience review, task analyses, mockup activities and verification and validation activities are used to provide feedback on the adequacy of initial human system interface design assumptions and constraints. If results of human factors engineering analyses or evaluations indicate that initial human system interface design assumptions or constraints are inadequate, then the human system interface design requirements are revised utilizing the standard AP1000 design configuration change control process.

Listed below are some of the major inputs to the AP1000 human system interface design and the assumptions and constraints they impose on the AP1000 human system interface design process and human system interfaces design.

Regulatory Requirements

One of the requirements for the AP1000 human factors engineering program is that it complies with applicable regulatory requirements. [*The human factors engineering process is designed to meet the human factors engineering design process requirements specified in NUREG-0711 (Reference 1).*]* This is also in accordance with References 7 and 10.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Utility Requirements

Another source of design input is utility customer requirements. Utility input can take the form of utility requirements documents, and/or input from utility representative groups serving in an advisory capacity.

Examples of utility requirements that impact the human system interface design are:

- **Operating staff assumptions.** A single reactor operator (RO) should be able to control major plant functions performed from the main control room during normal power operations.

- **Assumptions with respect to human system interface resources.** The human system interface design shall include an integrating overview display and mimic in the main control room.

The AP1000 design goals with respect to control room staffing are addressed in Section 18.6 and WCAP-14694 (Reference 3). As noted in WCAP-14694, a number of elements of the AP1000 human factors engineering design process are used to help achieve, verify and validate the control room staffing design goal. These include operating experience review, function analysis and allocation, task analysis, human reliability assessment, human system interface design, procedures, training, and human factors engineering verification and validation.

As described in Section 18.8, one of the human system interface resources is a wall panel information system. The wall panel information system is intended to meet the utility requirement for an integrating overview display and mimic in the main control room. A number of design activities establish the basis and functional requirements for the wall panel information system. Design activities include conducting operating experience reviews in nuclear power plants and related industries to examine the requirements for individual and group situation awareness and how these can best be supported.

Plant System Design Information

The design of the plant systems is an essential input to the human system interface design process. The physical implementation specifications as well as the systems designer's intent with regard to expected systems operation and performance are used as input to the design of the AP1000 human system interfaces. System design data are documented in the individual system specification documents. The input representing the plant's physical structure is represented by the piping and instrumentation drawings, general arrangement drawings, and equipment drawings.

System design specifications include specifications with respect to function allocation between automated systems and human operators. The system design specifications indicate which functions are to be automated, which are to be manual, and which require joint input of person and machine. In addition, the system design specifications indicate the set of instruments and controls that are implemented in the AP1000.

The AP600 function requirements analysis and function allocation document (Reference 4) provides information on the approach to initial function allocation and presents the results for AP600 safety functions. The results include a specification of level of automation and personnel responsibility for AP1000 safety functions, processes, and systems. The results also document the rationale for function allocation decisions for AP1000 safety functions.

The report also describes human factors activities that are conducted as part of the AP1000 human system interface design process to verify the adequacy of function allocation decisions, and establish the ability of operators to perform the role assigned to them. Function-based task analyses are used to verify that the sensors and controls that are provided are sufficient to enable operators to perform

the role assigned to them in system performance. Workload analyses are used to evaluate the adequacy of the integrated roles assigned to operators across systems. Integrated system validation is used to establish the adequacy of the function allocation using man-in-the-loop tests in dynamic simulated plant conditions.

Technology Limits

Recent advances in the technology of digital computing have made it possible and practical to change the performance and role of the human system interface in a process control application such as a nuclear power plant. For the AP1000, a position regarding the limits of the implementation technology to be assumed for the human system interfaces is derived from assessment of existing technology and anticipated advancements. An emphasis is placed on utilization of proven, reliable technology. The decision on the specific technology to be employed is made on a case-by-case basis after available technology alternatives are evaluated.

18.2.1.3 Applicable Facilities

[*Facilities included in the scope of the AP1000 human factors engineering program are the main control room (MCR), the technical support center (TSC), the remote shutdown room, the emergency operations facility (EOF), and local control stations.*]*

The EOF is designed as discussed in Subsection 18.2.6, including specification of a location, in accordance with the AP1000 human factors engineering program. Communication with the emergency operations facility is also as discussed in Subsection 18.2.6. Section 13.3 discusses the responsibility for emergency planning.

The EOF and TSC communications strategies, as well as the EOF and TSC Human Factors attributes, are described in the Emergency Plan. Subsection 9.5.2.2.5 provides additional information related to offsite interfaces.

18.2.1.4 Applicable Human System Interfaces

[*The scope of the human system interfaces encompasses the instrumentation and control systems which perform the monitoring, control, and protection functions associated with all modes of plant normal operation as well as off-normal, emergency, and accident conditions. Both the physical and the cognitive characteristics of those humans involved in the use, control, maintenance, test, inspection, and surveillance of plant systems are accommodated.*]*

18.2.1.5 Applicable Plant Personnel

[*The AP1000 human factors engineering program and the design of the human system interfaces includes the selection, synthesis, and distribution of process data to plant operations personnel as well as other plant personnel. These additional users include management, engineering, maintenance, health physics and chemistry personnel.*]*

18.2.1.6 Technical Basis

[*The human factors engineering program is performed in accordance with accepted industry standards, guidelines, and practices.*]* The references listed at the end of each Chapter 18 section and within any supporting documentation and reports are used to guide the human factors engineering program. [*The human factors engineering process specified in Reference 1 is used.*]* This is also in accordance with References 7 and 10.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

18.2.2 Human System Interface Design Team and Organization

The human system interface design team is part of the AP1000 systems engineering function and has similar responsibility, authority, and accountability as the rest of the design disciplines. Figure 18.2-1 depicts the process used by the human system interface design team members. Figure 18.2-2 shows the organization of the human system interface design team and its relationship to the AP1000 design organization.

18.2.2.1 Responsibility

[*The mission of the human system interface design team is to develop the main control room and ancillary control facilities (such as remote shutdown workstation) that support plant personnel in the safe operation and maintenance of the plant. The human system interface design team is responsible for coordinating the human factors aspects associated with designing the structures, systems, and components that make up the main control room and ancillary control facilities.*

The human system interface design team is responsible for:

- *Development of human system interface plans and guidelines*
- *Oversight and review of human system interface design, development, test, and evaluation activities*
- *Initiation, recommendation, and provision of solutions for problems identified in the implementation of the human system interface activities*
- *Assurance that human system interface activities comply with the human system interface plans and guidelines*]*

18.2.2.2 Organizational Placement and Authority

The organization of the human system interface design team and its relation to the AP1000 design organization is depicted in Figure 18.2-2. The structure of the organization may change, but the functional nature of the human system interface design team is retained through the change. The human system interface design team consists of an instrumentation and control system manager, advisors/reviewers team, core human system interface design team, and human system interface technical lead. The technical disciplines described in Subsections 18.2.2.3 and 18.2.2.4 are organized by function within the core human system interface design team. The core human system interface design team and the advisors/reviewers team report to the instrumentation and control system manager. The human system interface technical lead works within the human system interface design function and reports to the instrumentation and control system manager through the manager of the human system interface design function. The instrumentation and control system manager is responsible for the design of the AP1000 instrumentation and control systems which include the human system interfaces. The instrumentation and control system manager reports to the AP1000 project manager.

The manager of the human system interface design function, who performs the function of technical project management for the human factors engineering design process, is responsible for the overall human system interface design and for integration of the human system interface design with the overall plant design. The advisors/reviewers team is responsible for overseeing the general progress of the human system interface design, providing guidance within the core human system interface design team, reviewing and providing comments on documents, specifications, and drawings pertaining to the human system interface design, and providing supplemental expertise in particular areas of design. The responsibility of the core human system interface design team is to produce the

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detailed design of the human system interfaces. The human system interface design function is responsible for the functional design of the human system interfaces, main control room and workstation layout (ergonomics), controls, the plant information system displays, the wall panel information system, the PMS safety displays, the alarm system, and computerized procedures system design and specification. The responsibilities of the human system interface technical lead include coordinating the technical work of the functional engineering groups, providing the administrative and technical interface between the functional engineering groups and the advisors/ reviewers team, and tracking the identification and resolution of human factors engineering design issues through operating experience review.

18.2.2.3 Composition

[*The human system interface design team consists of a multi-disciplinary technical staff. The team is under the leadership of an individual experienced in the management of the design and operation of process control facilities for complex technologies. The technical disciplines of the design team include:*

- *Technical project management*
- *Systems engineering*
- *Nuclear engineering*
- *Instrumentation and control (I&C) engineering*
- *Architect engineering*
- *Human factors engineering*
- *Plant operations*
- *Computer system engineering*
- *Plant procedure development*
- *Personnel training*
- *Systems safety engineering*
- *Maintainability/inspectability engineering*
- *Reliability/availability engineering*]*

The responsibilities of the individual technical disciplines include:

- Technical Project Management
  - Provide central point of contact for management of the human factors engineering design and implementation process
  - Develop and maintain schedule for human factors engineering design process
- Systems Engineering
  - Provide knowledge of the purpose, technical specifications, and operating characteristics of plant systems
  - Provide input to human factors engineering task analyses
  - Participate in development of procedures and scenarios for task analyses, and integrated system validation
- Nuclear Engineering
  - Provide knowledge of the processes involved in reactivity control and power generation

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  - Provide input to human factors engineering task analyses
  - Participate in development of scenarios for task analyses, and integrated system validation

- Instrumentation and Control (I&C) Engineering
  - Provide knowledge of control and display hardware design, selection, functionality, and installation
  - Provide input to software quality assurance programs
  - Participate in the design, development, test, and evaluation of the human system interfaces

- Architect Engineering
  - Provide knowledge of plant component layout and the overall structure of the plant including design characteristics and performance requirements for the containment building, control room, remote shutdown room, and local control stations
  - Provide input to human factors engineering task analyses
  - Participate in development of scenarios for task analyses, and integrated system validation

- Human Factors Engineering
  - Provide knowledge of human performance capabilities and limitations, human factors design and evaluation practices, and human factors principles, guidelines, and standards
  - Develop and perform human factors analyses and participate in resolution of human factors problems

- Plant Operations
  - Provide knowledge of operational activities relevant to characterizing tasks and environment and development of human system interface components, procedures, and training programs
  - Participate in development of scenarios for task analyses, and integrated system validation

- Computer System Engineering
  - Provide knowledge of data processing required for human system interface displays and controls
  - Participate in design and selection of computer-based equipment
  - Participate in development of scenarios for task analyses, and integrated system validation, particularly those involving failures of the human system interface data processing systems

- Plant Procedure Development
  - Provide knowledge of operational tasks and procedure formats
  - Provide input for development of emergency operating procedures, computer-based procedures, and training systems
  - Participate in development of scenarios for task analyses, and integrated system validation
- Personnel Training
  - Develop content and format of personnel training programs
  - Participate in development of scenarios for task analyses, and integrated system validation
- Systems Safety Engineering
  - Identify safety concerns
  - Perform system safety hazard analysis such as thermal atmospheric analysis, toxicology analysis, and radiological analysis
- Maintainability/Inspectability Engineering
  - Provide knowledge of maintenance, inspection, and surveillance activities
  - Provide input in the areas of maintainability and inspectability
  - Support design, development, and evaluation of control room and other human system interface components
  - Participate in development of scenarios for task analyses, and integrated system validation
- Reliability/Availability Engineering
  - Provide knowledge of plant system and component reliability and availability and assessment methodologies
  - Provide input to design of human system interface equipment
  - Participate in development of scenarios for task analyses, and integrated system validation

18.2.2.4 Team Staffing Qualifications

In choosing the human system interface design team members, greater emphasis is placed on the individual's relevant experience to the specific discipline than on formal education. Alternative personal credentials may be selectively substituted for the education and experience requirements specified below. The professional experience of the human system interface design team as a collective whole satisfies the experience qualifications. The human system interface design team members have the following backgrounds:

- Technical Project Management
  - Bachelor’s degree
  - Five years experience in nuclear power plant design or operations and three years of management experience
- Systems Engineering
  - Bachelor of Science degree
  - Four years of cumulative experience of the following areas of systems engineering: design, development, integration, operation, and test and evaluation
- Nuclear Engineering
  - Bachelor of Science degree
  - Four years of experience in the following areas of nuclear engineering: design, development, test, or operations
- Instrumentation and Control (I&C) Engineering
  - Bachelor of Science degree
  - Four years of experience in hardware and software design aspects of process control systems; familiarity with software quality assurance and control
  - Experience in at least one of the following areas of instrumentation and control engineering: development, power plant operations, test evaluations
- Architect Engineering
  - Bachelor of Science degree
  - Four years experience in design of power plant structures and building services
- Human Factors Engineering
  - Bachelor’s degree in Human Factors Engineering, Engineering Psychology, or related science
  - Four years experience in the following areas of human factors engineering: human factors aspects of human system interfaces (design, development, and test and evaluation of human system interfaces for process control applications) and four years experience in human factors aspects of workplace design (design, development, and test and evaluation of workplaces)
- Plant Operations
  - Current or prior senior reactor operator (SRO) license/senior reactor operator instructor certification
  - Two years experience in PWR nuclear power plant operations

- Computer System Engineering
  - Bachelor's degree in Electrical Engineering or Computer Science or graduate degree in other engineering discipline
  - Four years experience in design of computer systems and real-time system applications; familiarity with software quality assurance and control
- Plant Procedure Development
  - Bachelor's degree
  - Four years experience in developing nuclear power plant operating procedures
- Personnel Training
  - Bachelor's degree
  - Four years experience in the development of personnel training programs for power plants and experience in the application of systematic training development methods
- Systems Safety Engineering
  - Bachelor of Science degree or Bachelor's degree in Science
  - Experience in system safety engineering, such as thermal atmospheric analysis, toxicology, radiological analysis and applicable OSHA limits
- Maintainability/Inspectability Engineering
  - Bachelor of Science degree or Bachelor's degree in Science
  - Four years of cumulative experience in at least two of the following areas of power plant maintainability and inspectability engineering activity: design, development, integration, test and evaluation, and analysis/resolution of maintenance problems.
- Reliability/Availability Engineering
  - Bachelor's degree
  - Four years of cumulative experience in at least two of the following areas of power plant reliability engineering activity: design, development, integration, and test and evaluation. Knowledge of computer-based, human system interfaces.

18.2.3 Human Factors Engineering Processes and Procedures

Activities performed relating to human factors engineering are performed in accordance with documented procedures under the quality assurance program for the AP1000. These procedures provide for control of processes as described below.

18.2.3.1 General Process and Procedures

The instrumentation and control system function is responsible for development of the AP1000 instrumentation and control (I&C), including human system interfaces, and coordinating and

integrating AP1000 instrumentation and control and human system interfaces with other AP1000 plant design activities. The overall operation of the project instrumentation and control systems function is defined. The function includes human system interface design of control rooms and control boards, instrumentation and control design, and control room/equipment design. The function includes definition of an engineering plan, review of inputs, production of system documentation, verification of work, procurement and manufacturing follow-up, and acceptance testing. An iterative feature is built into the process.

Documents produced as part of the instrumentation and control and human system interface design process include:

- Operating experience review documents
- Task analysis documents
- Functional requirements documents
- Human system interface design guidelines documents
- Design specification documents
- Instrumentation and control architecture diagrams
- Block diagrams
- Room layout diagrams
- Instrumentation lists
- System specification documents

The procedures governing instrumentation and control engineering work specify methods for verification of work. The types of verification include:

- Design verification by design reviews
- Design verification by independent review/alternative calculations
- Design verification by testing

System Specification Documents

System specification documents identify specific system design requirements and show how the design satisfies the requirements. They provide a vehicle for documenting the design and they address information interfaces among the various design groups.

System specification documents follow established format and content requirements. The content of a system specification document includes:

- Purpose of the system
- Functional requirements and design criteria for the system
- System design description including system arrangement and performance parameters
- Layout
- Instrumentation and control requirements
- Interfacing system requirements

The section on interfacing system requirements describes the support needed from and provided to other systems.

System specification documents document human factors and human system interaction requirements. This includes specification of task requirements, information requirements, and equipment requirements for operations, surveillance, test, and maintenance activities.

System specification documents provide specification of instrument and control requirements including:

- System input to the I&C channel list
- Reference to control logic diagrams
- Alarm requirements and characteristics
- Requirements and characteristics of plant status indications

A system specification document for the operation and control centers system provides a mechanism for documenting and tracking human system interface requirements and design specifications. The operation and control centers system specification document is the umbrella document for capturing generic human factors requirements. It provides a uniform operational philosophy and a design consistency among human system interface resources, including alarm system, plant information system, wall panel information system, and computerized procedures.

Functional requirements and design specifications for the AP1000 operation and control centers system, including the main control room, the technical support center, the remote shutdown room, and local control stations are provided in the operation and control centers system specification document. Functional requirements documents and design specification documents are generated for each of the individual human system interface resources (including alarm system, plant information system, wall panel information system, computerized procedures, controls). Functional requirements documents specify the applicable codes, standards, and design requirements and constraints to be met by the design. These documents are referenced by the operation and control centers system specification document.

Design specification documents provide the design specifications for individual human system interface resources and their integration. Included in these specifications are layout and arrangement drawings, algorithms, and display system descriptions, including display task descriptions, display layouts, and navigation mechanisms.

The operation and control centers system specification document, the functional requirement documents, and design specification documents provide input to the generation of I & C system specification documents such as the system specification document for the data display and processing system.

Design Configuration Change Control Process

Design changes are controlled to assure that proposed changes to design documents under configuration control are appropriately evaluated for impacts and that approved changes are communicated to the responsible design organizations.

The design configuration change control process is used to control and implement changes to the design. It is used when the design to be changed has been previously released in a document for project use and placed under configuration control. A design change proposal is the vehicle used to initiate and document review of proposed design changes. Design change proposals include identification of impacts of the proposed design change from affected functional groups. In some instances, human factors engineering issues are addressed by the initiation of design change proposals. In other instances, they are addressed as a consequence of human factor engineering review of design change proposals originating from other disciplines. Design change proposals are maintained in a database that is used to track the status of each design change proposal from initiation through implementation and closure.

Design Review of Human Factors Engineering Products

Design reviews by a multi-disciplined review team are established as a verification method. Requirements for the design review process, including selection of the review team, preparation of information for review, identification and follow of action items, and documentation of the proceedings, are defined.

Design reviews provide a method of design verification consisting of a systematic overall evaluation of a design that is conducted by an independent design review team. Design reviews are conducted at appropriate stages of design development to provide an objective, independent review of design adequacy, safety, performance, and cost. Design reviews are performed by persons not directly associated with the specific design development, but who, as a group, are knowledgeable in the appropriate technical disciplines.

Original designs, as well as major design changes, are subject to the design review process. For each design review, a design review data package is prepared. It includes checklists, including one specifically addressing human factor engineering questions, which are used by design review committee members to aid their review. For each design issue identified through the use of checklists or otherwise, an action item is initiated.

[*Action items are tracked through the design issues tracking system database as described in subsection 18.2.4. The responsibility of entering design review action items into the design issues tracking system database is assigned to the manager responsible for the system reviewed. The responsible design manager is responsible for tracking and addressing open action items.*]*

18.2.3.2 Process Management Tools

Tools are provided to facilitate communication across design disciplines and organizations to enhance consistency. An AP1000 design database enables parties involved in the engineering design of the plant to access up-to-date plant design data. Procedures define requirements and responsibilities for moving data into the database.

Tools are provided to guide the design review process. These include design review checklists that support evaluation of design adequacy, and a database for tracking action items generated as a result of the design review process. Further details on the process of tracking action items generated by design reviews are provided in Subsections 18.2.3.1 and 18.2.4.

A design configuration change control process is used to control and implement proposed design changes. Design change proposals are maintained in a database that is used to track the status of each design change proposal from initiation through implementation and closure.

A design issues tracking system database is used to document and track design issues that are identified during the plant design process. Further details on the design issues tracking system are provided in Subsection 18.2.4.

18.2.3.3 Integration of Human Factors Engineering and Other Plant Design Activities

The AP1000 design process provides for the integration of human factors engineering activities among the design groups.

The instrumentation and control systems design function is responsible for the development of the AP1000 instrumentation and control systems, including the human system interface. Coordination and integration of the instrumentation and control and human system interface design with other plant design activities is performed by the instrumentation and control systems design function. An iterative design process that includes review and feedback from other engineering and design groups at the design interface is specified. Subsection 18.2.3.1 describes the responsibilities and design process of the instrumentation and control system design function.

System specification documents provide the primary vehicle for transmitting system design data and interface requirements, including human factors engineering and human system interface requirements, to the affected AP1000 design and analysis groups. The system specification

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documents include a section on interfacing system requirements that describes the support needed from and provided to other systems in the plant. Interface control is performed at the design interfaces and design changes affecting the interfaces are coordinated. Subsection 18.2.3.1 provides details on system specification documents.

A design configuration change control process provides the process and actions to implement design changes. Subsection 18.2.3.1 provides further details on this process.

Engineering design databases serve as a repository of AP1000 design data for parties involved in engineering design activities of the plant. A technical document control system is used to track the status of AP1000 documents. By using the engineering design databases and the technical document control system, parties have access to up-to-date design data to perform their respective design activities.

Section 18.8 presents the implementation plan for the design of the human system interface. Figure 18.2-3 provides an overview of the AP1000 human factors engineering process, including the design stages of the human system interface. The relationship of other human factors engineering process elements to the human system interface design is shown.

18.2.3.4 Human Factors Engineering Documentation

Procedures address documentation for AP1000, including document preparation, review, retention, access, and configuration control. These procedures apply to all AP1000 activities, including human factors engineering.

Documents refer to any self contained portrayal of the AP1000 design or its basis. These include design criteria, descriptions, specifications, drawings, analysis reports, safety reports and calculations.

A procedure establishes requirements and responsibilities for the preparation, review, and approval of AP1000 design documents. The procedure specifies that documents are to be reviewed by appropriate reviewers, and comments are to be resolved prior to issuance of the document. Appropriate reviewers include responsible engineers or managers impacted by the information in the document.

Changes to released documents are reviewed and approved in accordance with the design configuration change control procedure for the AP1000 program.

Procedures establish content and format requirements for system specification documents. Other procedures addressing documentation requirements include those for design configuration change control, design reviews, design criteria, and control of subcontractor submittals.

Sections 18.3 through 18.12 provide information on the types of documents that are generated as part of the AP1000 human factors engineering program.

18.2.3.5 Human Factors Engineering in Subcontractor Efforts

Human factors engineering and human system interface requirements are passed on to subcontractors through engineering documents including design criteria and system specification documents.

Activities within subcontractor design organizations are performed in accordance with the written procedures of those organizations. [*Effective implementation of each organization's quality assurance program is monitored by their respective internal audit programs, and by supplier audits.*]*

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See Section 17.3 for quality assurance requirements associated with subcontractor human factors engineering design efforts.

18.2.4 Human Factors Engineering Issues Tracking

A tracking system is used to address human factors issues that are known to the industry and/or identified throughout the life cycle of the human factors engineering/human system interface design, development, and evaluation. The tracking system enables the documentation and tracking of issues that need to be addressed at some later date.

Tracking of human factors engineering issues is accomplished within the framework of the overall plant design process. In this manner, human factors engineering issues are addressed in the same way as those for other disciplines.

[*The design issues tracking system database is used to track AP1000 design issues to resolution, including human factors engineering issues. This database receives input from the following three sources:*

- *Operating experience review*
- *Design reviews*
- *Design issues associated with the design of the human system interface and the operation and control centers system*]*

For each design issue entered into the database, the actions taken to address the issue and the final resolution of the issue are documented.

The human factors issues in the operating experience review report (Reference 2) that are identified as requiring further consideration by the AP1000 design are entered into the design issues tracking system database.

[*The design review process also provides input to the design issues tracking system database. For each design issue identified through the design review process, an action item is initiated. Action items are entered into the design issues tracking system database. Human factors action items from design reviews are included in the database. For preliminary and intermediate design reviews, some action items may be deferred to a more appropriate, subsequent design review. The responsibility of entering design review action items into the design issues tracking system database is assigned to the manager responsible for the system reviewed.*]*

Human factors engineering design issues directly associated with the AP1000 human system interfaces and the operation and control centers system (such as the main control room, remote shutdown room, and technical support center) are entered into the design issues tracking system database. These are design issues that are identified by the human system interface and operation and control centers system designers as issues that need to be addressed by the human system interface design.

The AP1000 project manager, as shown on Figure 18.2-2, is responsible for the maintenance and documentation of the design issues tracking system. For each issue entered into the design issues tracking system database, a “responsible engineer” field is used to assign an engineer the responsibility for resolution of the issue.

18.2.5 Human Factors Engineering Technical Program and Milestones

[*The human factors engineering program is performed in accordance with the human factors engineering process specified in NUREG-0711 (Reference 1).*]* Figure 18.1-1 shows the elements of

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the AP1000 human factors engineering program. [*These elements conform to the elements of the Program Review Model specified in Reference 1, as augmented by Reference 7.*]* This is also in accordance with Reference 10.

Human factors engineering Program Management is addressed in Section 18.2. The remaining elements are addressed in Sections 18.3 through 18.11, 18.13, and 18.14.

These sections address the activities conducted as part of the corresponding human factors engineering element, including the accepted industry standards, guidelines, and practices used as technical guidance, the inputs to the element, and the products, including documents that are generated as output. The facilities, equipment, and tools employed are also addressed in the section corresponding to each element.

Figure 18.2-3 provides an overview of the Westinghouse human factors engineering process. The figure summarizes the major activities of the human factors engineering program, their relative order, and the inputs and outputs for the major activities. The boxes in the diagram indicate major human factors engineering activities. The activities are presented in approximate chronological order, with the outputs of each activity serving as inputs to subsequent activities. The items listed below the activity boxes are the document outputs from that human factors engineering activity. The human factors engineering process includes iterations considering the outcomes of subsequent analysis and design activities, design reviews, and testing. In this approach, design issues are addressed and resolved through the iterative stages of the human factors engineering process. Potential points of iteration are indicated in Figure 18.2-3. Further details on the activities, inputs, and output documents associated with the various elements of the human factors engineering program are provided in the sections corresponding to each human factors engineering element.

Figure 18.2-3 provides a program milestone schedule of human factors engineering tasks showing relationships between human factors engineering elements and activities, products, and reviews. Internal design reviews are performed at various points throughout the design process.

18.2.6 Combined License Information

18.2.6.1 Human Factors Engineering Program

The execution of the NRC approved human factors engineering program as presented by Section 18.2 is addressed in APP-OCS-GBH-001 (Reference 8), and the applicable changes are incorporated into the UFSAR.

The AP1000 Human Factors Engineering Program Plan (Reference 8) fully captures the information certified in Section 18.2. Reference 8 provides execution guidance for the NRC-approved HFE program.

18.2.6.2 Emergency Operations Facility

The design of the emergency operations facility in accordance with the AP1000 human factors engineering program is addressed in Reference 9 (APP-GW-GLR-136).

Reference 9 captures the method by which the AP1000 Human Factors Engineering Program Plan (Reference 8) will be applied to TSCs and EOFs that support an AP1000 plant.

EOF and TSC communications, and EOF and TSC human factors attributes are addressed in Subsection 18.2.1.3.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

18.2.7 References

[*1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.*]*

2. WCAP-14645, "Human Factors Engineering Operating Experience Review Report For The AP1000 Nuclear Power Plant," Revision 3, May 2006.

3. WCAP-14694, "Designers Input to Determination of the AP600 Main Control Room Staffing Level," Revision 0, July 1996.

4. WCAP-14644, "AP600/AP1000 Functional Requirements Analysis and Allocation," Revision 1, October 2008.

5. Reason, J. T., "Human Error," Cambridge, U.K., Cambridge University Press, 1990.

6. Not used.

[*7. NUREG-0711, Rev. 1, "Human Factors Engineering Program Review Model," U.S. NRC, May 2002.*]*

8. APP-OCS-GBH-001, "AP1000 Human Factors Engineering Program Plan," Westinghouse Electric Company LLC.

9. APP-GW-GLR-136, "AP1000 Human Factors Program Implementation for the Emergency Operations Facility and Technical Support Center," Westinghouse Electric Company LLC.

10. NUREG-0711, Revision 2, "Human Factors Engineering Program Review Model," U.S. NRC, February 2004.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

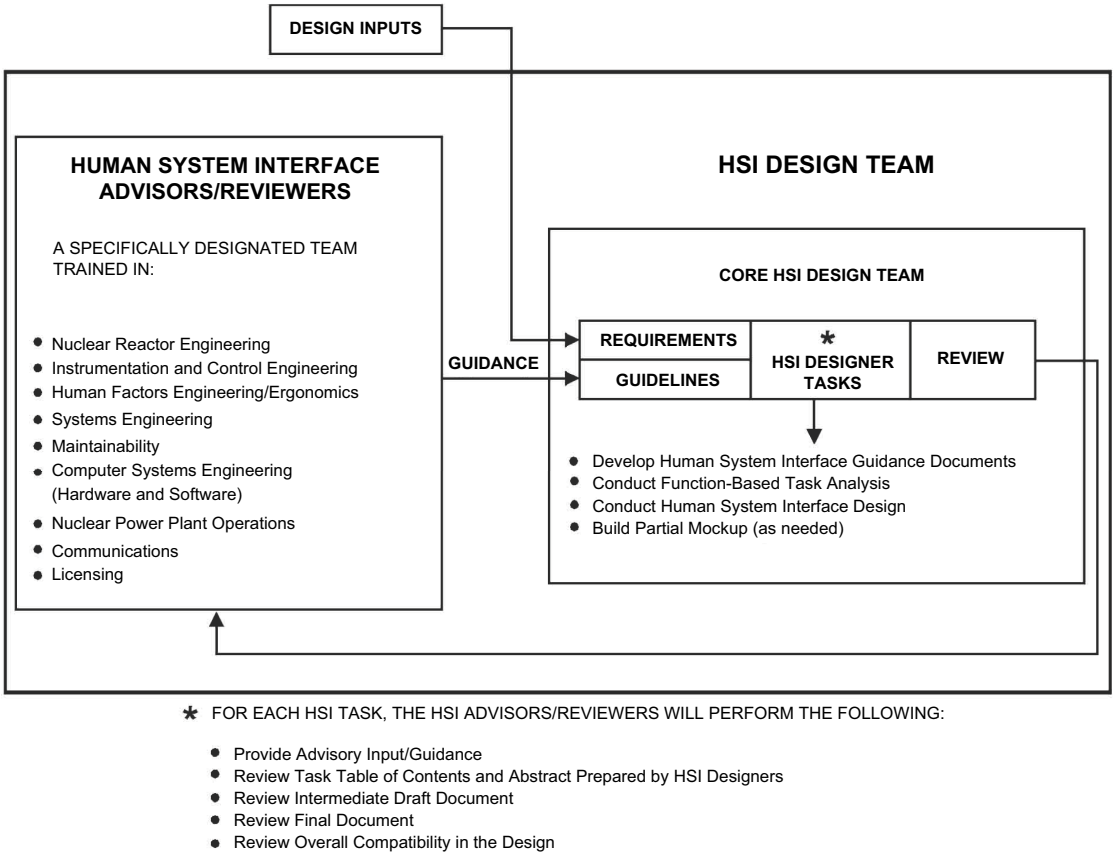

Figure 18.2-1
[*Human System Interface (HSI) Design Team Process*]*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

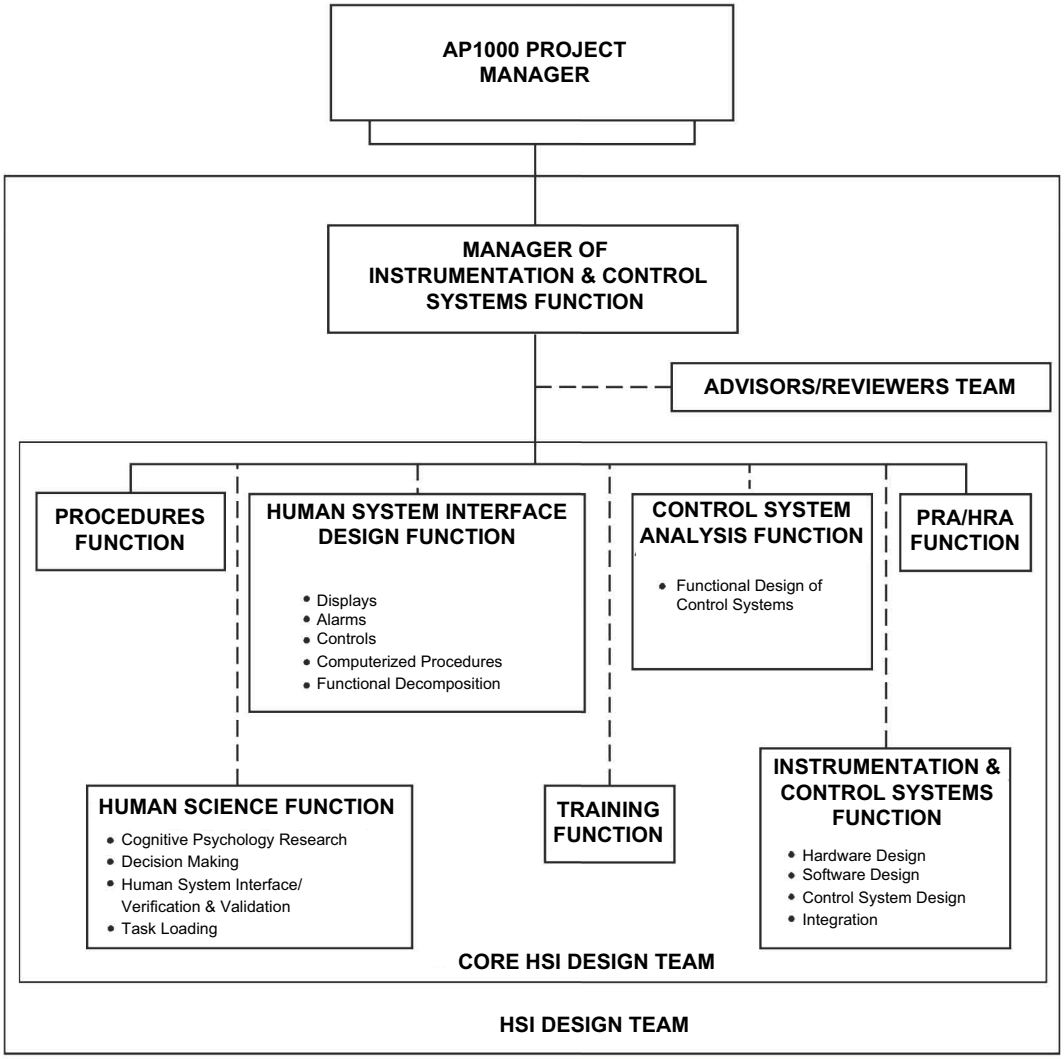

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Figure 18.2-2
Human System Interface (HSI) Design Team
Organization and Relationship to AP1000 Organization

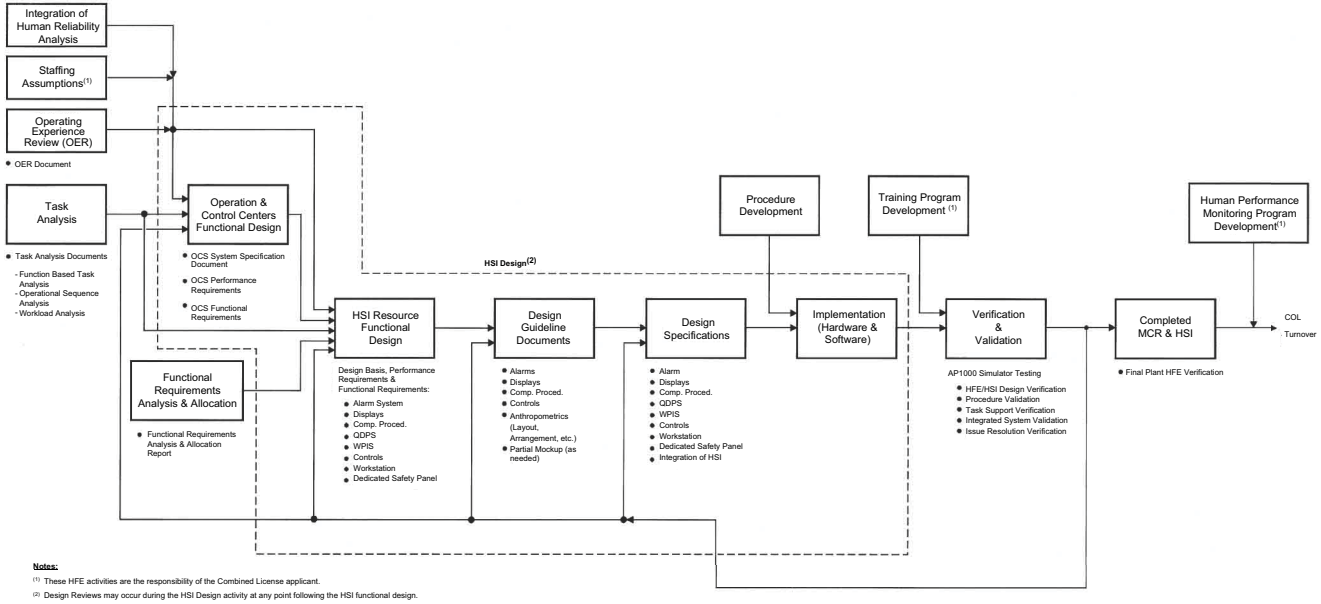

Figure 18.2-3
Overview of the AP1000 Human Factors Engineering Process

18.3 Operating Experience Review

The objective of the operating experience review is to identify and analyze human factors engineering-related problems and issues encountered in previous designs that are similar to the AP1000. Reference 1 documents the results of this review, including descriptions of how the AP1000 design addresses each identified issue.

18.3.1 Combined License Information

Combined License applicant responsibilities identified in Reference 1 are presented in Sections 10.4.12, 16.2, 18.2.6, 18.6.1, and 18.10.1.

18.3.2 References

1. WCAP-14645, “Human Factors Engineering Operating Experience Review Report for the AP1000 Nuclear Power Plant,” Revision 3, May 2006.

18.4 Functional Requirements Analysis and Allocation

Functional requirements and function allocation analyses are performed to establish and document design decisions with respect to level of plant automation.

Functional requirements analysis is defined as the "identification of those functions that must be performed to satisfy plant safety objectives, that is, to prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public" (Reference 1).

Function allocation is defined as the "analysis of the requirements for plant control and the assignment of control functions to (1) personnel (e.g., manual control), (2) system elements (e.g., automatic control and passive, self-controlling phenomena), and (3) combinations of personnel and system elements (e.g., shared control and automatic systems with manual backup)" (Reference 1).

Reference 2 documents the methods and results of the functional requirements analysis and function allocation conducted for AP600.

The report provides a description of the AP600 approach to functional requirements analysis and presents the results for AP600 safety functions. The results include a description of AP600 processes, systems, and components involved in maintaining AP600 safety functions. The report also includes a similar analysis for current Westinghouse pressurized water reactor designs to serve as a reference in identifying areas where the AP600 plant differs from previous designs for which operating experience exists. An explicit comparison of the AP600 design with the reference plant design is provided that identifies plant functions, processes, and systems that are new or modified relative to the reference plant design. This includes changes in level of automation.

The report also describes the AP600 approach to initial function allocation and presents the results for AP600 safety functions. A methodology adapted from Reference 3 is used to document the rationale for initial allocation decisions and verify the acceptability of the initial allocation from a human factors perspective. The results include a specification of level of automation and personnel responsibility for AP600 safety functions, processes, and systems. The rationale for the function allocation decisions for AP600 safety functions is documented.

Since AP1000 is like AP600 in its operation and approach to safety functions, Reference 2 is directly applicable to AP1000. It is used as is for functional requirements and function allocation analyses for AP1000.

The report includes a description of human factors activities that are conducted as part of the AP600 HSI design process to verify the adequacy of function allocation decisions and establish the capability of operators to perform the role assigned to them. This is applied to AP1000 and includes:

- How human factors input is provided early in the design process
- How the integrated role of the operator across the systems is confirmed for acceptability
- Mechanisms available for reconsidering, and if necessary, changing AP1000 function allocations in response to operating experience, and the outcomes of ongoing analyses and trade studies

18.4.1 Combined License Information

This section contained no requirement for additional information.

18.4.2 References

1. NUREG-0711, “Human Factors Engineering Program Review Model,” U.S. NRC, July 1994.

2. WCAP-14644, “AP600/AP1000 Functional Requirements Analysis and Function Allocation,” Revision 1, October 2008.

3. NUREG/CR-3331, “A Methodology for Allocation of Nuclear Power Plant Control Functions to Human and Automated Control,” 1983.

18.5 AP1000 Task Analysis Implementation Plan

[*Task analysis, according to the Human Factors Engineering Program Review Model (Reference 1), has the following objectives:*

- *Provide one of the bases for the human system interface design decisions*
- *Match human performance requirements with human capabilities*
- *Provide input to procedure development*
- *Provide input to staffing, training, and communications requirements of the plant*]*

This section describes the scope of the AP1000 task analysis activities and the task analysis implementation plan. In addition to References 1 and 16, References 2 through 13 are inputs to this plan.

18.5.1 Task Analysis Scope

[*The scope of the AP1000 task analysis is divided into two complementary activities: function-based task analysis (FBTA) and traditional task analysis, or operational sequence analysis (OSA). The scope of the function-based task analysis is the Level 4 functions*]* identified in Figure 18.5-1. This figure is the functional decomposition (goal-means analysis) for normal power operations in a standard pressurized water reactor. Examples of functions at Level 4 are "Control RCS Coolant Pressure" and "Control Containment Pressure." This set of functions defines the breadth of functions to be analyzed. The function-based task analysis will be expanded in scope to include any additional Level 4 functions identified.

[*The traditional task analysis, or operational sequence analysis, is developed for a representative set of operational and maintenance tasks. The following guidelines are applied to select tasks:*

- *Tasks are selected to represent the full range of operating modes, including startup, normal operations, abnormal and emergency operations, transient conditions, and low-power and shutdown conditions.*

- *Tasks are selected that involve operator actions that are identified as either critical human actions or risk-important tasks, based on the criteria in Reference 13.*

- *Tasks are selected to represent the full range of activities in the AP1000 emergency response guidelines.*

- *Tasks are selected that involve maintenance, test, inspection, and surveillance (MTIS) actions. A representative set of maintenance, test, inspection, and surveillance tasks are analyzed for a subset of the "risk-significant" systems/structures/components (SSCs).*

The set of tasks to be analyzed are not identified as a part of design certification. The OSAs listed below are included in the set of tasks to be analyzed: (Each of these satisfies one or more of the selection criteria described above.)

  - *Plant heatup and startup from post-refueling to 100% power*
  - *Reactor trip, turbine trip, and safety injection*
  - *Natural circulation cooldown (startup feedwater with steam generator)*
  - *Loss of reactor or secondary coolant*
  - *Post loss-of-coolant accident cooldown and depressurization*
  - *Loss of RCS inventory during shutdown*
  - *Loss of the normal residual heat removal system (RNS) during shutdown*
  - *Manual automatic depressurization system (ADS) actuation*

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– *Manual reactor trip via PMS, via diverse actuation system (DAS)*
– *ADS valve testing during Mode 5*

The human factors engineering program review model (Reference 1) indicates that task analysis should include tasks that are considered to be high-risk and tasks that require critical human actions. Reference 13 defines criteria for critical human actions and risk-important tasks and has identified a list of examples of AP600 tasks that meet these criteria. Reference 13 is applicable to AP1000.]*

Section 16.2 identifies the systems/structures/components included in the Reliability Assurance Program. A subset of these systems/structures/components and a representative set of associated maintenance, tests, inspection and surveillance tasks will be selected by an expert panel. This panel will be comprised of representatives with expertise from relevant groups in the design process, such as systems engineering, reliability engineering, probabilistic risk analysis, human factors engineering, and human system interface design. The set of maintenance, test, inspection and surveillance tasks identified through the expert panel process will be considered to be "risk important" tasks, and will be included in task analysis activities.

18.5.2 Task Analysis Implementation Plan

Figure 18.5-2 shows the proposed sequence of task analyses. Figure 18.5-2 provides information concerning the task analysis and human system interface design elements. [*Task analysis includes both a function-based task analysis and an operational sequence analysis.*]* In Figure 18.5-2, the operational sequence analysis in the task analysis box is designated as OSA-1 since two operational sequence analyses will be implemented.

18.5.2.1 Function-Based Task Analyses

Function-based task analysis is applied to each of the Level 4 functions. There are four components to a function-based task analysis. First, analysis is performed to identify the set of goals relevant to the function. Second, a functional decomposition is performed. This decomposition identifies the processes that, either individually or in combination, have a significant effect on the function. Third, a process analysis is performed by applying a set of questions derived from Rasmussen's model (References 6–9) analysis approach. [*The set of questions used and basis for the methodology is provided in Reference 12.*]* An example of a question from the process analysis is "Are the process data valid?" The results of the process analysis identify the indications, parameters, and controls that the operator uses to make decisions about the respective function. Finally, there is a verification that the indications and controls, identified in the process analysis are included in the AP1000 design.

From the function-based task analyses, the following types of information are obtained:

- A completeness check on the availability of needed indications, parameters, and controls. This includes indications and controls needed for supervisory control of automated systems and manual over-ride.

- Input to the specification and layout of functional displays.

18.5.2.2 OSA-1

The operational sequence analysis completed as part of the task analysis process focuses on specifying the operational requirements for the complete set of tasks selected. For each task, an analysis of the task is conducted that includes the following:

- Plant state data required at each step
- Source of the data (alarm, display, oral communication)

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- Action to be taken or decision to be made from the data
- Relevant criterion or reference values
- Information that provides feedback on the action's adequacy
- Other temporal constraints (ordering, tasks that need to be done in parallel)
- Task support requirements needed (required tools)
- Considerations of work environment

The task analyses are developed from the emergency response guidelines and the Probabilistic Risk Assessment event sequences associated with critical or risk-important actions. The following potential limitations on task performance are considered:

- Limits on human performance
- Limits on crew communications

This first operational sequence analysis provides the following types of information:

- Frequency and co-occurrence of plant state parameters and controls
- Display design and organization constraints
- Inventory of alarms, controls, and parameters needed to perform the sequences

As shown in Figure 18.5-2, the function-based task analysis and OSA-1 feed into the human system interface design by providing task performance guidance and constraints. The display and operator workstation design is based on this information.

18.5.2.3 OSA-2

The critical issues for the second operational sequence analysis are:

- Task requirements - This analysis identifies the requirements necessary for the operator to perform the task activities.

- Time to perform tasks - A set of performance time assumptions will be established and used to determine the time required for actions to be completed. These assumptions will provide estimates of task performance times that can be compared to performance time requirements.

- Operator workload analysis - An evaluation of the effect of the human system interface design and the task demands on operator workload will be conducted.

- Operational crew staffing - The workload analysis provides an indication of the adequacy of staffing assumptions. In cases where the operational sequence analysis indicates high operator workload values, or insufficient time available for performance, alternative staffing assumptions or changes to the human system interface design or task allocation to reduce operator workload is evaluated.

This second operational sequence analysis is performed for a representative subset of tasks that include the critical human actions and risk-important tasks and tasks that have human performance concerns (for example, potential for high workload or high error rates).

18.5.2.4 Task Analysis of Maintenance, Test, Inspection and Surveillance Tasks

The maintenance, test, inspection, and surveillance tasks that are identified to be "risk-important" are analyzed using operational sequence task analyses. OSA-1 analyses are conducted on the set of maintenance, test, inspection, and surveillance tasks identified to be "risk-important."

18.5.2.5 Technical Support Center and Emergency Operations Facility

OSA-1 analysis is conducted for the technical support center (TSC) and emergency operations facility (EOF) for the tasks where the data and displays available in the main control room may be utilized to support the TSC and/or EOF functions.

18.5.3 Job Design Factors

Section 18.6 addresses the control room staffing that applies to the AP1000. The staffing level of the main control room, job design considerations, and crew skills are discussed in Subsection 18.6.1.

18.5.4 Combined License Information Item

18.5.4.1 Task Analysis Implementation

The execution and documentation of the task analysis implementation plan presented in Section 18.5 are addressed in APP-GW-GLR-081 (Reference 14), and the applicable changes are incorporated into the UFSAR.

18.5.4.2 Main Control Room Position Scope and Responsibilities

The scope and responsibilities of each main control room position, considering the assumptions and results of the task analysis are addressed in APP-OCS-GJR-003 (Reference 15), and the applicable changes are incorporated into the UFSAR.

18.5.5 References

[*1. NUREG-0711, "Human Factors Engineering Program Review Model," U.S. NRC, July 1994.*]*

2. U.S. NRC Guidance, NUREG/CR-3371, "Task Analysis of Nuclear Power Plant Control Room Crews."

3. IEC-964, "Design for Control Rooms of Nuclear Power Plants."

4. Department of Defense Documents: DI-H-7055, "Critical Task Analysis Report," and MIL-STD-1478, "Task Performance Analysis."

5. NATO Document, "Applications of Human Performance Models to System Design," edited by McMillan, Beevis, Salas, Strub, Sutton, & van Breda, New York: Plenum Press, 1989.

6. Rasmussen, J., "Information Processing and Human-Machine Interaction, An Approach to Cognitive Engineering," New York: North-Holland, 1986.

7. Hollnagel, E. and Woods, D. D., "Cognitive Systems Engineering: New Wine in New Bottles," International Journal of Man-Machine Studies, Volume 18, 1983, pages 583-600.

8. Roth, E. and Mumaw, R., "Using Cognitive Task Analysis to Define Human Interface Requirements for First-of-a-Kind Systems," Proceedings of the Human Factors and Ergonomics Society 39th Annual Meeting, San Diego, Ca., 1995, pp. 520-524.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

9. Vicente, K. J., "Task Analysis, Cognitive Task Analysis, Cognitive Work Analysis: What=s the Difference?" Proceedings of the Human Factors and Ergonomics Society 39th Annual Meeting, San Diego, Ca., 1995, pp. 534-537.

10. Drury, C. G., Paramour, B., Van Cott, H. P., Grey, S. N., and Corlett, E. N., "Task Analysis," Handbook of Human Factors, Salvendy, G. (ed.), New York: John Wiley & Sons, 1987.

11. Woods, D. D., "Application of Safety Parameter Display Evaluation Project to Design of Westinghouse SPDS," Appendix E to "Emergency Response Facilities Design and V & V Process," WCAP-10170, submitted to the U.S. Nuclear Regulatory Commission in support of their review of the Westinghouse Generic Safety Parameter Display System (Non-Proprietary) (Pittsburgh, PA, Westinghouse Electric Corp.), April 1982.

[*12. WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Revision 0, July 1996.*]*

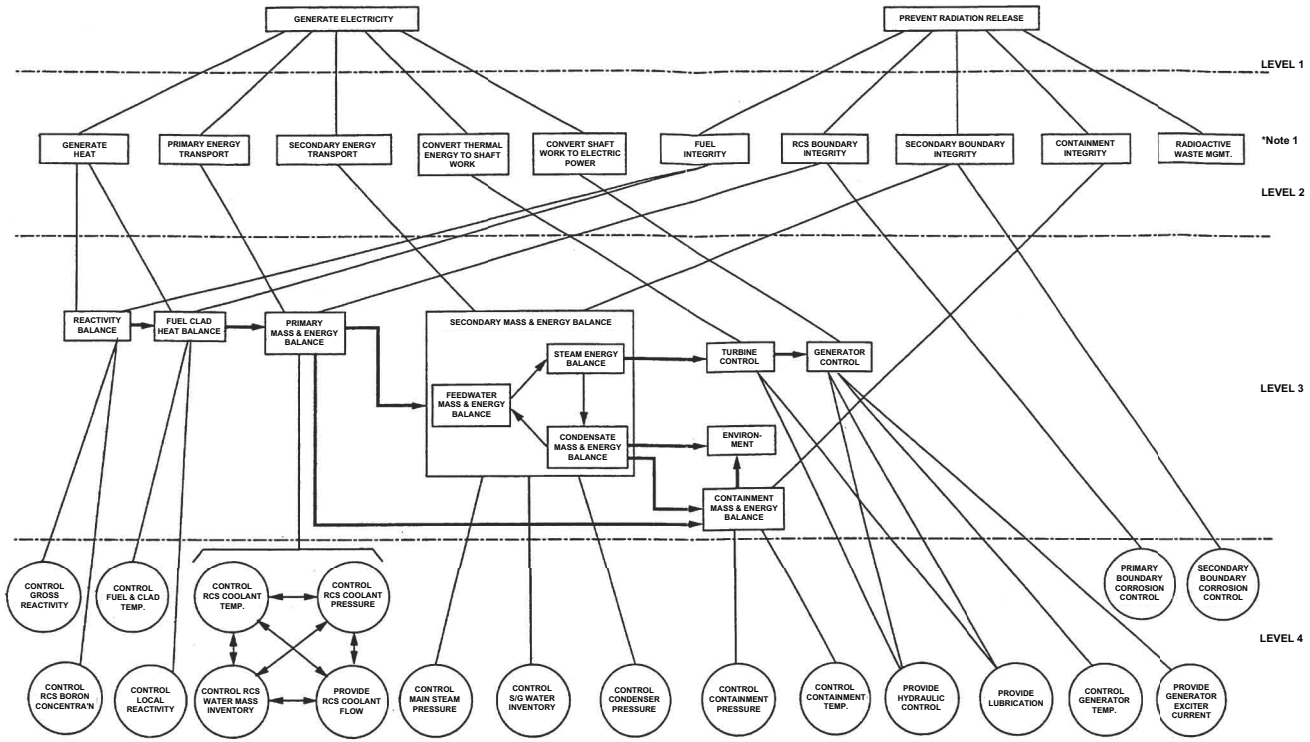
[*13. WCAP-14651, "Integration of Human Reliability Analysis and Human Factors Engineering Design Implementation Plan," Revision 2, May 1997.*]*

14. APP-GW-GLR-081, "Closure of COL Information Item 18.5-1, Task Analysis," Westinghouse Electric Company LLC.

15. APP-OCS-GJR-003, "AP1000 Main Control Room Staff Roles and Responsibilities," Westinghouse Electric Company LLC.

16. NUREG-0711, “Human Factors Engineering Program Review Model,” Revision 2, U.S. NRC, February 2004.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.



*Note 1: Decomposition and subsequent task analysis of this activity is performed as part of a similar process applied to the radioactive waste control center.

Figure 18.5-1
Top Four Levels of the Normal Power Operation for a Westinghouse PWR

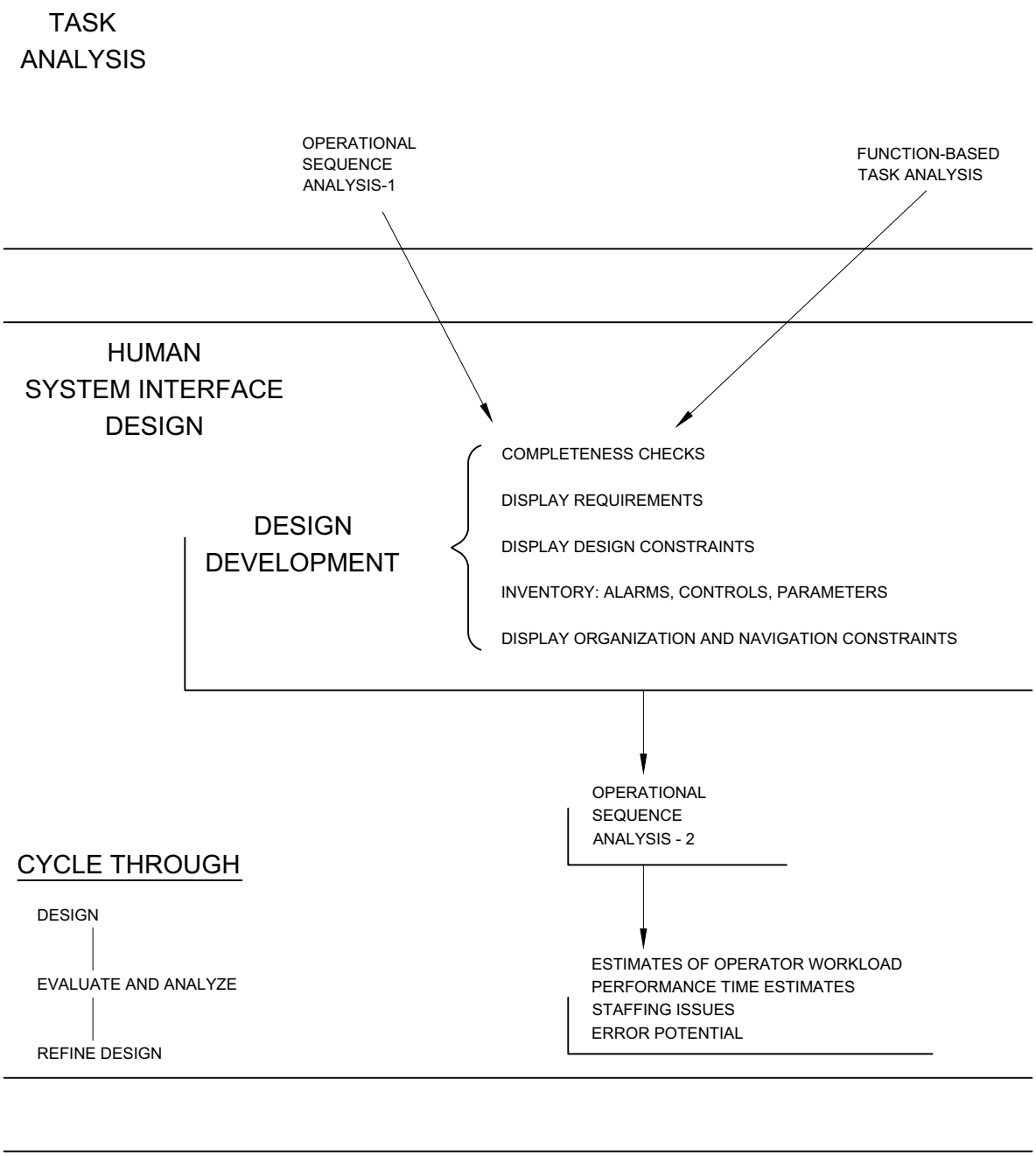


Figure 18.5-2
Task Analysis Utilized as Design Input

18.6 Staffing

Categories of personnel that are addressed by the Human Factors Engineering program per NUREG-0711, “Human Factors Engineering Program Review Model” (Reference 201), include:

- Licensed operators
- Shift Supervisors
- Non-licensed operators
- Shift technical advisors
- Instrumentation and control technicians
- Mechanical maintenance technicians
- Electrical maintenance technicians
- Radiation protection technicians
- Chemistry technicians
- Engineering support

The minimum level of staffing for control room personnel who directly monitor and control the plant is stated in Table 13.1-202 and meets the requirements of 10 CFR 50.54(m). Information about the staffing levels of security personnel is contained in the separately submitted physical security plan.

Qualification requirements of plant personnel listed above are discussed in Subsections 13.1.1.4, Qualifications of Technical Support Personnel, and 13.1.3, Qualification Requirements of Nuclear Plant Personnel, and, for security personnel, in the physical security plan.

The baseline level of staffing for the categories of personnel discussed above is derived from experience in current operating nuclear power plants. The number of personnel in operating plants has evolved over many years to a level that is safe and efficient and provides adequate personnel to operate the plant under all conditions, including abnormal and emergency, meets regulatory requirements, and supports individual training and personal needs.

Iterative adjustments are implemented to the level of staffing, as necessary, based on findings and input from periodic reviews and staffing analysis. Input to this analysis includes information derived from the other elements of the human factors engineering program, particularly operating experience review, functional requirements analysis and function allocation, task analysis, human reliability analysis, human-system interface design, procedure development, and training program development.

In addition to the regulatory requirements referenced, input to the analyses and the level of staffing is provided by WCAP-14694, “Designer’s Input to Determination of the AP600 Main Control Room Staffing Level” (Reference 1), AP1000 Combined License Technical Report APP-GW-GLR-010, “AP1000 Main Control Room Staff Roles and Responsibilities” (Reference 202), and EPRI Technical Report 1011717, “Program on Technology Innovation: Staff Optimization Scoping Study for New Nuclear Power Plants” (Reference 203).

18.6.1 Combined License Information Item

The staffing levels and qualifications of plant personnel including operations, maintenance, engineering, instrumentation and control technicians, radiological protection technicians, security, and chemists, and the number of operators needed to directly monitor and control the plant from the main control room, including the staffing requirements of 10CFR50.54(m), is addressed in Section 18.6.

18.6.2 References

1. WCAP-14694, "Designer's Input To Determination of the AP600 Main Control Room Staffing Level," Revision 0, July 1996.

201. United States Nuclear Regulatory Commission, “Human Factors Engineering Program Review Model,” NUREG-0711, Revision 2, February 2004.

202. Westinghouse, “AP1000 Main Control Room Staff Roles and Responsibilities,” APP-GW-GLR-010, Rev. 2, June 2007.

203. EPRI, “Program on Technology Innovation: Staff Optimization Scoping Study for New Nuclear Power Plants,” Technical Report 1011717, Final Report, August 2005.

18.7 Integration of Human Reliability Analysis with Human Factors Engineering

Human reliability analysis (HRA) evaluates the potential for human error that may affect plant safety. There are important interfaces between the human factors engineering program and human reliability analysis. Human reliability analysis makes use of outputs of human factors engineering/HSI design activities including analyses of operator functions and tasks and specifications of HSI characteristics. Human reliability analysis is a source of input to human factors engineering/HSI design in identifying plant scenarios, human actions, and HSI components that are important to plant safety and reliability.

[*The objective of integration of human reliability analysis with human factors engineering is to specify the interfaces between human reliability analysis and human factors engineering activities. Reference 1 documents the implementation plan for the integration of human reliability analysis with human factors engineering design.*]* Reference 2 documents the execution and documentation of this implementation plan.

[*The objective of the human reliability analysis/human factors engineering integration implementation plan is to enable:*

- *Human reliability analysis activity to integrate the results of the human factors engineering design activities*

- *Human factors engineering design activities to address critical human actions, risk important tasks, and human error mechanisms, in order to minimize the likelihood of personnel error and to provide for error detection and recovery capability*]*

Human reliability analysis methodology and results are described in Chapter 30 of the AP1000 PRA.

18.7.1 Combined License Information

The execution and documentation of the human reliability analysis/human factors engineering integration implementation plan that is presented in Section 18.7 is addressed in Reference 2 (APP-GW-GL-011, WCAP-16555).

18.7.2 References

[*1. WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Revision 2, May 1997.*]*

2. WCAP-16555, "AP1000 Identification of Critical Human Actions and Risk Important Tasks," Revision 0, March 2006.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

18.8 Human System Interface Design

This section provides an implementation plan for the design of the human system interface (HSI) and information on the human factors design for the non-HSI portion of the plant. The human system interface includes the design of the operation and control centers system (OCS) and each of the human system interface resources.

The operation and control centers system includes the main control room, the technical support center, the remote shutdown room, emergency operations facility, local control stations and associated workstations for each of these centers. The AP1000 human system interface resources include:

- Wall panel information system
- Alarm system (also identified as alarm presentation system)
- Plant information system
- Computerized procedure system
- Soft controls/dedicated controls
- PMS safety displays

The wall panel information system presents information about the plant for use by the operators. No control capabilities are included. The wall panel information system provides dynamic display of plant parameters and alarm information so that a high level understanding of current plant status can be readily ascertained. It is located at one end of the main control area at a height such that persons seated at the reactor operator and senior reactor operator workstations can view it while sitting at their respective workstations. It provides information important to maintaining the situation awareness of the crew and for supporting crew coordination. The wall panel information station provides a dynamic display of the plant. It also serves as the alarm system overview panel display. The display of plant disturbances (alarms) and plant process data is integrated on this wall panel information system display. The wall panel information system is a nonsafety-related system. It is designed to have a high level of reliability.

The mission of the AP1000 alarm system, together with the other human system interface resources, is to provide the operation and control centers operating staff with the means for acquiring and understanding the plant's behavior. The alarm system improves the performance of the operating crew members, when acting both as individuals and as a team, by improving the presentation of the plant's process alarms. [*The alarm system supports the control room crew members in the following steps or activities of Rasmussen's operator decision-making model (Reference 25):*]*

- The "alert" activity, which alerts the operator to off-normal conditions

- The "observe what is abnormal" activity, which aids the user in focusing on the important issue(s)

- The process "state identification" activity, which aids the user in understanding the abnormal conditions and provides corrective action guidance. It guides the operating crew into the information display system.

The plant information system is a subset of the data display and processing system (non-Class 1E system), presenting plant process information for use by the operators. The plant information system provides dynamic indications of plant parameters and visual alerts so that an understanding of current plant conditions and status is readily ascertained. The plant information system uses color-graphic visual display units located on the operation and control centers workstations to display plant process data. These displays provide information important to monitoring, planning, and controlling the operation of plant systems and obtaining feedback on control actions. The displays provided by

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the plant information system are nonsafety-related displays, but provide information on both safety-related and nonsafety-related systems.

The computerized procedure system has a mission to assist plant operators in monitoring and controlling the execution of plant procedures. The computerized procedures system is a software system. It runs on the hardware selected for the operation and control centers. The computerized procedure system is accessible from the workstations in the main control room. A procedure writer's guide is developed as part of the human system interface design implementation plan for the computerized procedure system. The writer's guide is the design guidelines document for the computerized procedure system. Information on the writer's guide and on the computerized procedure system is found in Reference 31. Application of the computerized procedure system for emergency operating procedures is licensed outside the United States and is being used in an operating nuclear power plant. Additionally, the application of the computerized procedure system for turbine-generator startup and shutdown is being used in another operating nuclear power plant located outside the United States. Human factors engineering review guidance for computer-based procedures is presented by Reference 9. The design of a backup to the computerized procedure system, to handle the unlikely event of a loss of the computerized procedure system, is developed as part of the human system interface design process. Design options include the use of a paper backup. [*The acceptability of the computerized procedure system and its backup will be confirmed as integral elements of the AP1000 design by the implementation of the AP1000 verification and validation program (Reference 24).*]* Procedure development is addressed in Sections 13.5 and 18.9.

The mission of the controls in the main control room is to allow the operator to operate the plant safely under normal conditions, and to maintain it in a safe condition under accident conditions. The main control room includes both safety-related and nonsafety-related controls. The types of controls in the main control room include both discrete (dedicated) control switches and soft controls. The discrete control switches are controls dedicated to a single function. Figure 18.8-1 shows a representative model of the soft controls used in AP1000. The soft control units are control devices whose resulting actions are selectable by the operator. The instrumentation and control architecture uses both discrete control switches and soft control units. The soft control units are used to provide a compact alternative to the traditional control board switches by substituting virtual switches in the place of the discrete switches.

The final configuration of these elements is dependent upon the results of the human system interface design process described in Subsection 18.8.1 below.

The mission of the PMS safety displays is to provide a Class 1E system to present to the main control room operators the plant parameters which demonstrate the safety of the plant. The qualified data processing system provides for the display of the variables as described in Section 7.5. The informational content of qualified data processing system is provided to the remote shutdown workstation through the plant information system.

18.8.1 Implementation Plan for the Human System Interface Design

Figure 18.2-3 provides an overview of the AP1000 human factors engineering process, including the design stages of the human system interface. The relationship of other human factors engineering process elements to the human system interface design is shown.

The functional design of the operation and control centers system and the human system interface is the activity where the functional requirements for the human system interface resources of the main control room and related operation and control centers system are developed. The output of the functional design is a set of documents that specify the mission, design bases, performance requirements, and functional requirements for each human system interface resource. These

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functional requirement documents and the human system interface design guidelines are used to develop the design specifications. The design specifications are provided as input to the hardware and software system designers for design implementation.

The following subsections describe the activities conducted as part of the human system interface design and the documents that are produced.

18.8.1.1 Functional Design

A system specification document for the operation and control centers system documents and tracks human system interface requirements and design specifications. The operation and control centers system specification document is the umbrella document for capturing human factors requirements and providing a uniform operational philosophy, and design consistency among the individual human system interface resources.

Included in the operation and control centers system specification document are functional requirements and specifications for the AP1000 operation and control centers system, including the main control room, the technical support center, the remote shutdown room, and local control stations. In addition, functional requirement documents are generated for each of the individual human system interface resources. These documents are referenced by the operation and control centers system specification document.

The operation and control centers system specification document and the individual human system interface functional requirement documents include mission statements and performance requirements. The mission statements establish the high level goals and main tasks to be supported by the control center or human system interface resource. Performance requirements represent high level design goals and help to clarify the functional designer's intent. They are high level requirements that may not be readily verifiable by testing or other quantitative means, but are important considerations for meeting the goals defined in the mission statements. The design bases establish the foundation for the design and the rationale behind engineering decisions made and criteria established for the design. Functional requirements include requirements needed to meet the criteria defined in the applicable codes, standards, and customer requirements.

The operations and control centers functional requirements document includes requirements to meet failure, diversity, electrical separation, and other applicable criteria. This document establishes requirements related to access control, redundancy, independence, identification and test capability, and defines requirements on system inputs and outputs. It specifies the system safety classification and defines applicable quality assurance, reliability goals, and environmental qualification requirements. The specification of the cognitive activities in the operator decision-making model that each human system interface resource is intended to support is provided in the operation and control centers functional requirements document.

Reference 25 describes the operator decision-making model and associated operator cognitive activities. As shown in Figure 18.8-2, the HSI interface resources are mapped to four major classes of operator cognitive activities in the model (detection and monitoring, interpretation, control, and feedback).

The contents of this map are then considered in terms of sources of operational complexity that add operator performance demands. The two general sources of complexity considered are 1) use of multiple as opposed to single HSI resources, and 2) increasing situational or scenario-based complexity. Considering the impact of complexity on the mapping leads to "issues"; that is, general cases where adequate human performance should be confirmed.

Table 18.8-1 presents the resulting set of human performance issues. Note that “feedback” issues have been addressed under “control,” rather than as a separate activity, because feedback activities follow directly from control activities. These human performance issues serve as input to the development of the performance requirements for the operation and control centers system specification document and to the individual human system interface functional requirement documents. The human performance issues and requirements will be addressed by the verification and validation activities described by Reference 24.

18.8.1.2 Design Guidelines

Guidelines for the human system interface design have been developed for the human system interface resources to facilitate the standard and consistent application of human factors engineering (HFE) principles to the design (see Reference 1). Reference 1 contains standards and conventions guidelines and tailors generic human factors engineering guidance to the AP1000 human system interface design and defines how those human factors engineering principles are applied.

These guidelines enable groups of people to simultaneously develop the human system interface in a consistent manner in accordance with the human factors engineering principles established for the design. [*The guidelines are used to perform the human factors engineering design verification activity of the human factors verification and validation plan (Reference 24).*]*

Human system interface design guideline documents include:

- Anthropometric guidelines
- Alarm guidelines
- Display guidelines
- Controls guidelines
- Computerized procedures guidelines

The AP1000 human system interface design guidelines document provides:

- Statements of their intended scope, references to source materials, and instructions for their proper use.

- Specification of accepted human factors engineering guidelines, standards, and principles to which the AP1000 human system interface conforms.

- Specification of design conventions (for example, coding conventions) to which the AP1000 human system interface conforms.

- Documentation of deviations from human factors engineering guidelines, standards and principles, and justification based on documented rationale such as trade study results, literature-based evaluations, demonstrated operational experience, and tests and experiments.

The accepted human factors engineering guidelines documents that were used in compiling the AP1000 human system interface design guidelines document are found in References 2 through 8.

18.8.1.3 Design Specifications

Design specifications are written for the operation and control centers system and the human system interface resources. The design specification documents are the result of applying the guidelines to the functional design. They provide the design for each human system interface resource, including the integration of the hardware and software modules, to satisfy the human system interface

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functional design requirements. Included in these specifications are layout and arrangement drawings, algorithms, display layouts, display task descriptions, navigation mechanisms and resource lists.

The functional requirement documents are used to define the bases for the system design specifications.

The operation and control centers system specification document and human system interface functional requirements and design specification documents provide input to the generation of instrumentation and control system specification documents, such as the system specification document for the data display and processing system. These specification documents are used as inputs to the hardware and software system designers to generate implementation documents such as hardware and software specifications.

18.8.1.4 Man-in-the-Loop Testing

An integral part of the human system interface design process is the conduct of man-in-the-loop engineering tests to obtain feedback from prototype design products early in the design process.

The use of engineering tests is a good engineering practice, which reflects an iterative design process. By providing feedback early, before the detailed design is complete, engineering tests can help to improve the design and to avoid problems in the final product. Engineering tests also may offer concrete insight on questions that cannot be resolved logically (for example, by guidance or analysis). Finally, results from engineering tests provide evidence of design adequacy. Engineering tests thus serve to increase confidence and reduce project risk in the design process.

Engineering tests are performed to obtain empirical results that can be applied directly to understanding and improving the design product. More specifically, engineering tests are designed to produce the following types of results for the prototype design:

- Design-specific operating experience
- Confirmation of necessary performance and integration
- Identification of specific problems
- Subjective feedback from expert users and observers

[*The man-in-the-loop test plan to obtain feedback from prototype design products early in the design process is defined and documented in Reference 46.*]* The results of the engineering testing are used to refine the design of the operation and control centers system and the human system interface.

18.8.1.5 Mockup Activities

A mockup of portions of the main control room working area is constructed as part of the human system interface design process. The partial mockup consists mainly of non-operational representations of the desks, displays, and panels. The mockups are constructed to the anthropometric profiles and arranged in the floor layout intended for the main control room.

The partial mockup is used to examine and verify, as needed, physical layout aspects such as availability of workspace, physical access, visibility, and related anthropometric and human factors engineering issues. It will also be used for walk-through exercises to examine issues such as staffing levels, task allocation, and procedure usage.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

18.8.1.6 Human System Interface Design Documentation

The human system interface design is documented through a system specification document for the operation and control centers system, functional requirement documents, design criteria documents, design review documents, and documentation of design configuration change control.

18.8.1.7 Task-Related Human System Interface Requirements

As shown in Figure 18.2-3, the results of other human factors engineering program elements are used as input and bases for developing the operation and control center system and human system interface resources functional design (mission statements, performance requirements, design bases, functional requirements), guideline documents and the design specification documents. Staffing assumptions, operating experience reviews, functional requirements analysis and allocations, task analysis, and integration of human reliability analysis provide the bases for identifying the human system interface requirements needed to support human functions and tasks. The resulting human system interface requirements are documented in the human system interface resource functional design documents (operation and control centers system specification document and the individual human system interface resource functional requirements document), guidelines document and design specification documents. Subsections 18.8.1.1 through 18.8.1.3 provide descriptions of these documents.

The AP1000 task analysis, described in Section 18.5, includes two complementary activities: function-based task analysis (FBTA) and traditional task analysis, or operational sequence analysis (OSA). The function-based task analysis identifies the indications, parameters, and controls that the operator needs to make decisions about the respective function. There is also a verification that the indications and controls identified in the process analysis are included in the design. The operational sequence analysis, completed as part of the task analysis process, focuses on specifying the operational requirements for the complete set of tasks selected. One of the guidelines used in selecting tasks for analysis are those tasks that represent the full range of activities in the AP1000 emergency response guidelines. One type of information provided by the operational sequence analysis is an inventory of alarms, controls, and parameters needed to perform the task sequences. The operational task analysis results include the identification of controls, alarms, and parameters needed by the operator to execute task sequences found within the emergency response guidelines. These results serve as a cross-check with the function-based task analysis results. Design reviews held during the human system interface design serve as another means of verifying completeness and identifying and correcting omissions. [*The task support verification activity of the human factors verification and validation (Reference 24) verifies that the human system interface design provides the necessary alarms, displays, and controls to support personnel tasks.*]*

The collective results of the task analysis activities identify the tasks and operational information needed by the operator to execute these tasks. For each display, a display task description is written. The display task description includes the identification of the informational needs to be supported by the display. The features, dynamic characteristics, calculated values, and supporting algorithms for the display are part of the display task description. The design specification of a display includes the range, precision, and measurement units of the parameters provided in the display. These parametric characteristics are chosen to support the task and the operator informational needs. The parametric characteristics, identified in the design specification, are provided using the guidelines presented in the design guidelines document for displays. The basis for the parametric characteristics chosen for the displays is found in the design guidelines document.

18.8.1.8 General Human System Interface Design Feature Selection

The AP1000 human system interface resources include the wall panel information system, alarm system, plant information system, computerized procedure system, controls, (soft and dedicated)

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and the PMS safety displays. These human system interface resources are used as a starting point to define how the human system interface supports operator performance. [*Reference 25 describes the operator decision-making model that is used by the task analysis activities to identify the operator's information and control requirements.*]* The human system interface resources are mapped to the major classes of operator activities identified from this model. Figure 18.8-2 illustrates this mapping. The human performance requirements that each human system interface resource supports are identified as part of the design process.

The human system interface resources are chosen based upon utility requirements and review of operating experience. The goal of the human system interface design is to provide the operators with effective means for acquiring and understanding plant data and executing actions to control the plant's processes and equipment. Through implementation of the human system interface design process, the identified AP1000 human system interface resources are developed.

Design alternatives for a feature within a human system interface resource (such as the use of a mouse, trackball, or touchscreen for soft controls) are evaluated. A decision is made based upon evaluation methods including human factors/trade-off studies, reviews of nuclear industry operating experience or reviews of other industry experience, experience gained from past projects, and utility input. The basis and rationale for the decisions are provided in the functional design documentation.

18.8.1.9 Human System Interface Characteristics: Identification of High Workload Situations

Identification of high operator workload situations and their consequent changes in operator response times or likelihood of operator error is a usability issue. Potential impact on operator workload is a criterion in selecting the human performance issues identified in Table 18.8-1.

Identification of high-workload situations through analytic techniques and part-task simulations is part of the human factors engineering program (Section 18.5 on Task Analysis).

Use of Workload Measurement Techniques

As part of task analysis activities (Section 18.5), analytic approaches are used to estimate workload. Analytic methods include the use of task analysis.

Usability Guidance

Usability guidance is included in the human system interface design guidelines, as discussed in Subsection 18.8.1.2.

Workstation Usage Scenarios

The physical layout of the AP1000 control room and related control centers follows established ergonomic guidelines including consideration of fatigue and alertness of operators sitting at workstations.

Environmental Conditions

Determination of environmental conditions (lighting, noise, ambient working temperatures, radiation, air quality, and humidity) in the control room, the remote shutdown room, and at local control stations employ well-accepted standards from the fields of industrial and human engineering such as References 14, 15 and 16. Relevant guidance from prior studies in the nuclear power area (References 17 through 20) is also used.

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The worst credible conditions that can be encountered by operators in the main control room are identified as outcomes of design basis scenarios. Effects on operator performance and the effects of extremes of habitability during degraded conditions are considered in the design specification.

Local Control Actions

Critical human actions and risk important tasks are identified by the probabilistic risk assessment/ human reliability analysis process. [*Reference 23 presents the process of identifying the critical human actions and risk important tasks and the implementation plan for integrating human reliability analysis into the human factors engineering program*.]* Critical human actions or risk important tasks are examined by task analysis, human system interface design, and procedure development, to identify changes to the operator task or the control and display environment to reduce or eliminate sources of error.

18.8.1.10 Human System Interface Software Design and Implementation Process

This subsection describes the software design, implementation, and verification process established to verify that human system interface functional requirements are implemented by the software. The software design, implementation, and verification process uses a top-down approach to incorporate the system design requirements and the functional requirements into software module design.

Software refers to the computer instructions and information provided to implement a subset of the human system interface functional requirements. The software design and implementation process is a subset of the overall human system interface design process. It consists of system software design specifications, software design, software implementation, and software verification.

The system software design specification activity takes as its input the system functional requirement and specification documents and produces software design requirements documents and the software verification test procedures. Software design requirements documents list the functions, performance, design constraints, and attributes of the system software.

The software design activity takes software design requirements and produces software design specification documents. Software design specification documents provide the details for the software design at the module level and assembly level. These documents define the software language, logical structure, variable names, information flow, logical processing steps, and data structure of the system software programs. They also describe the functions performed, support software, storage and execution limitations, interface constraints, error conditions, error detection, error response actions, and details of the software operation in the hardware environment.

The software implementation activity implements the software design specifications in the form of documented source programs and object code. The source program and associated documentation contain the comments, functional diagrams, external references, and internal module descriptions.

The object code is generated from the source program and installed in processor memory to perform the functions specified by the software design specifications.

In the software verification testing activity, the software is tested to verify that it complies to the system software design requirements. The software is tested according to the software verification test procedures.

Nonconformances of the software to the software verification test procedures are documented by trouble reports, and changes are made. In the case where the error is a result of an error in the system software design requirements or the software design specifications, these documents are revised. The software test results report presents a summary of the software verification testing results.

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18.8.2 Safety Parameter Display System (SPDS)

[*The Safety Parameter Display System is designed following the human system interface design implementation plan*]* described in Subsection 18.8.1. [*The Safety Parameter Display System is integrated into the design of the AP1000 human system interface resources.*]*

As noted in Section 4.1.a of Reference 27 "...the principle purpose and function of the Safety Parameter Display System is to aid the control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by operators to avoid a degraded core. This can be particularly important during anticipated transients and the initial phase of an accident." Since the main intended use is during relatively rare occurrences, human-factors engineering suggests that the operators will find that the use of data acquisition habits acquired and repeated during the normal operation of the plant will be the most successful. A system in the control room that only varies its output during abnormalities may require a shift in mental focus and in data acquisition habits and subsequent analysis. An effective means for conveying the safety state of the plant is to provide data and displays for normal operation that employs the Safety Parameter Display System required principles for data synthesis, concentration and display. This operator interface is operational over the range of plant conditions specified by the Safety Parameter Display System requirements, as well as during normal operations.

The operator-interface to the plant is improved by integrating Safety Parameter Display System requirements into the overall human system interface design to avoid the need for another system that is infrequently used.

The following subsections describe [*the approach to meeting the regulatory requirements for a Safety Parameter Display System by addressing the Safety Parameter Display System requirements of References 26 and 27.*]*

18.8.2.1 General Safety Parameter Display System Requirements

The AP1000 human system interface resources used to address the Safety Parameter Display System requirements are the alarm system, plant information system (workstation visual display unit displays), and the computerized procedure system. The AP1000 human system interface data display (alarms and visual display unit displays) is organized around the Safety Parameter Display System requirement of plant process functions. Expressing plant state in terms of process functions is incorporated in the AP1000 control room design. This is expected to improve the human interface by making the data presentation interface seamless as the plant moves from one operational state to another.

An alarm system which organizes the presentation of alarms by process function and adapts a "dark board" approach (for all plant modes) continually indicates the state of each of the functions. By remaining dark when the process is performing as expected, the process functions are interpreted as being satisfied. An alarm indication displayed in any function indicates that the function is in jeopardy. In this way, the set of alarms that is active is the minimum set. The alarm system is capable of displaying a full range of alarms based on important plant parameters and data trends. The alarms indicate when process limits are being approached and exceeded.

Section 18.7 and [*Reference 23 present an implementation plan for integrating the human reliability analysis with human factors engineering.*]* The critical human actions and the risk important tasks identified through the execution of this plan are used as an input to the task analysis activities and subsequently to the design of the human system interface. They are also used to evaluate the Safety Parameter Display System functions and parameters selected to monitor these functions. The human system interface, which includes the integration of Safety Parameter Display System

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requirements, is designed to reduce the likelihood of operator error and provide for error detection and recovery capability for the identified critical human actions and risk important tasks.

18.8.2.2 Display of Safety Parameters

The functionally organized plant information system displays, including the Safety Parameter Display System-related displays, are accessed on the workstation visual display units (VDU) using a cursor. The AP1000 operator workstations employ a windowing system which allows a single cursor to cover the visual display unit screens. The design allows the operator to recover a specific parameter within one or two actuations of the pointing device.

The design goal for the AP1000 human system interface is to update the displays every 1 to 2 seconds. The process data sampling rate is 1 second or less. Sequence of events (SOE) points can be sampled at a rate of once every milli-second and are available within the AP1000 human system interface. The Safety Parameter Display System responds to user commands in less than 10 seconds. The design goal for graphical display response time, from user command to developed graphical display, in the AP1000 human system interface is 2 seconds.

The AP1000 alarm system includes plant overview alarms that are organized around the concept of plant process functions. These process functions address the five SPDS functions. The alarm system overviews, including the functional organization, are integrated into the wall panel information system displays.

During the execution of emergency operating procedures, the computerized procedure system provides a continuous display of the status of each critical safety function.

The Safety Parameter Display System data and data display organization are available to the control room staff.

[*The AP1000 human system interface process display set (from the plant information system) is organized into two hierarchies that are linked together. One is focused upon providing the process data from a functional perspective and the other from a physical perspective. Both follow the concept of abstraction/aggregation suggested by Rasmussen as described in Reference 25. Top levels in the hierarchy are plant wide summaries, lower levels are component details. The hierarchy is structured so as to reflect the plant process functional decomposition performed during the function based task analysis described in Reference 25.*]*

Process display presentation for the control room users is organized by functions. The function based task analysis integrates the functional organization design principles dictated by the Safety Parameter Display System requirements into the AP1000 human system interface.

Plant process displays and plant controls necessary to operate the plant are located on the reactor operator console. There are a total of six redundant workstations on the reactor operator console.

Because the Safety Parameter Display System requirements are an integral part of the AP1000 human system interface design, the Safety Parameter Display System workstation is the AP1000 human system interface control room workstation, the Safety Parameter Display System displays are the workstation displays; and the display accessing “controls” used to access Safety Parameter Display System displays are the same as those used to access any workstation display.

Safety Parameter Display System-related information is physically displayed such that the information can be read from the Safety Parameter Display System user’s position. Each reactor operator’s workstation contains the human system interface operator process displays. The senior

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reactor operator has separate workstations that have the operator process displays. The wall panel information system is available to the main control room staff.

The AP1000 human system interface provides the status of the Safety Parameter Display System functions. The Safety Parameter Display System functions include:

- Reactivity control
- Reactor core cooling and heat removal from the primary system
- Reactor coolant system integrity
- Radioactivity control
- Containment conditions

The AP1000 alarm system provides overview alarms addressing the five Safety Parameter Display System functions. These overview alarms, integrated into the wall panel information system displays, are continuously displayed. Most of the safety parameters used to monitor the status of each Safety Parameter Display System function are continuously displayed on the wall panel information system displays. Those that are not continuously displayed on the wall panel are accessible at the operator's workstation. During the execution of emergency operating procedures, the AP1000 computerized procedure system provides a continuous display of the status of the critical safety functions.

Safety Parameter Display System-related information is physically displayed such that the information is readable from the reactor operator workstation. Each reactor operator's workstation contains the plant information system process displays. The control room supervisor (shift foreman) has an independent workstation that also has the process displays. The wall panel information system is available to the main control room staff.

18.8.2.3 Reliability

The AP1000 instrumentation and control (I&C) systems, including the human system interface, have reliability/availability design criteria. A description of the instrumentation and control system design features is found within Section 7.1.

The human system interface design includes the capability to build password or key-lock accessibility on the human system interface database. In addition, the system carries and displays data quality on the data in the system.

The alarm overviews integrated into the wall panel information system include indication of the operability of the alarm system itself.

18.8.2.4 Isolation

The Safety Parameter Display System as integrated into the overall human system interface is isolated from safety systems. Electrical isolation devices are discussed in Subsection 7.1.2.

18.8.2.5 Human Factors Engineering

Section 5 of Reference 28 presents the need for human-factors engineering in the design of the Safety Parameter Display System. The Safety Parameter Display System is designed using the implementation plan described in Subsection 18.8.1. [*This implementation plan includes the application of human factors engineering principles that address the criteria of the Human Factors Engineering Program Review Model (Reference 29).*]* This is also in accordance with Reference 48.

The AP1000 main control room and human system interface design reduces the number of individual computerized operator support systems by incorporating the requirements of the Safety Parameter

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Display System into the design requirements for the AP1000 human system interface. This is accomplished primarily by those human system interface resources that produce and display the process abnormality alarms and the process graphical visual display units.

Parameter units of measure, labels, and abbreviations displayed by the human system interface resources are consistent with the units of measure, labels, and abbreviations included in the emergency operating procedures.

The human system interface displays information is in a form that does not require transformation or calculation. High- and low-level setpoints are consistent with the reactor protection system setpoints. The high- and low-level setpoints are visible in both the messages created by the AP1000 alarm system and on the indications, trends and graphs that appear as part of the process displays of the AP1000 plant information system.

Consistency of calculated values, such as subcooling margin, is maintained. The AP1000 instrumentation and control and human system interface architecture shares process data through a database.

The technical basis for software specifications are verified with plant data (for example, heat-up and cool-down limits, steam generator setpoints and high- and low-level alarm setpoints). The AP1000 human system interface is designed so that the plant data is a separate data file independent of the software specifications.

18.8.2.6 Minimum Information

The AP1000 human system interface resources used to address the Safety Parameter Display System requirements are the alarm system, plant information system, and the computerized procedure system. The AP1000 human system interface displays sufficient information to determine plant safety status with respect to the Safety Parameter Display System safety functions. [*The safety functions and respective parameters presented in Table 2 of Reference 32 are used as a starting point for the AP1000.*]* The human system interface design implementation plan is described in Subsection 18.8.1 and includes the integration of Safety Parameter Display System requirements into the human system interface. [*The Safety Parameter Display System design issue of "minimum information" is tracked by the human factors engineering issues tracking system.*]*

18.8.2.7 Procedures and Training

Sections 13.2 and 13.5 describe the development of training programs and plant procedures respectively. Reference 30 describes how training insights are passed from the designer to operations personnel who participate as subjects in the HFE V&V activities. Reference 31 provides input to the development of plant operating procedures.

18.8.3 Operation and Control Centers System

The human system interface includes the design of the operation and control centers system. The design of each of these control centers is conducted using the human system interface implementation plan presented in Subsection 18.8.1. The mission for each of the operation and control centers in the AP1000 is provided in the following subsections. Coupled with each mission statement is a brief description of the major tasks and design features that are supported by that center.

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18.8.3.1 Main Control Room Mission and Major Tasks

The mission of the main control room is to provide a seismically qualified habitable and comfortable location for housing the resources for a limited number of humans to monitor and control the plant processes.

The major tasks performed in the main control room include monitoring, supervising, managing, and controlling those aspects of the plant processes related to the thermodynamic and energy conversion processes under normal, abnormal, and emergency conditions. Operating staff can monitor, supervise, manage, and control processes that have a real-time requirement for protecting the health and safety of operating personnel. The main control room supports the operator's decision-making process, and promotes the interaction with other plant personnel, while preventing distractions by non-operating personnel. The main control room provides the interfacing resources between the operation of the plant and the maintenance of the plant. Its areas include the main control area, the operations work area, the shift supervisor's office, and the operations break room (see Figure 1.2-8). Habitability systems are described in Sections 6.4 and 9.4.

18.8.3.2 Main Control Area Mission and Major Tasks

[*The mission of the main control area is to provide the support facilities necessary for the operators to monitor and control the AP1000 efficiently and reliably. Figure 6.4-1 provides a view of the main control area. The main control area includes the reactor operator workstations, the supervisor's workstation, the dedicated safety panel and the wall panel information system. The layout, size and ergonomics of the operator workstations and the wall panel information system depicted in this figure does not reflect the results of the human system interface design implementation plan*]* described in Subsection 18.8.1. The actual size, shape, ergonomics and layout of the operator workstations and the wall panel information system is an output of the implementation plan.

[*The major task of the main control area is to provide the human system interface resources that determine the plant state and implement the desired changes to the plant state during both normal and emergency plant operations. The main control area provides alarms to alert the operator to the need for further investigation. Plant process data displays permit the operator to observe abnormal conditions and identify the plant state. The controls enable the operator to execute actions. The process data displays and the alarms provide feedback to enable the operator to observe the effects of the control actions.*

Each reactor operator workstation contains the displays and controls to start up the plant, maneuver the plant, and shut down the plant.]* Reference 44 presents input for the determination of the staffing level of the operating crew in the main control room. [*Each workstation is designed to be manned by one operator. There is sufficient space and operator interface devices for two operators. The physical makeup of the reactor operator workstations is identical. The human system interface resources available at each workstation are:*

- *Plant information system displays*
- *Control displays (soft controls)*
- *Alarm system displays*
- *Computerized procedure displays*
- *Screen and component selector controls*

The supervisor workstation is identical to the reactor operator workstations, except that its controls are locked-out. The supervisor workstation contains both internal plant and external plant communications systems.

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Upon failure of a reactor operator workstation, the failed workstation is locked out, and the supervisor workstation controls are unlocked. This modified workstation configuration maintains independent, redundant workstations.

A dedicated safety panel is located in the main control area. The PMS safety displays and the dedicated safety system controls are provided in this panel. These visual display units are the only monitoring display devices in the main control room that are seismically qualified and provide the post-accident monitoring capabilities in accordance with Regulatory Guide 1.97. Dedicated system-level safety system control switches are located on the dedicated safety panel to provide the operators with safety system actuation capabilities.]* A minimum inventory of these dedicated displays and controls are presented in Section 18.12.

[*There is storage space for supplies, protective clothing and some spare parts. Cabinets are provided for necessary documents, and a drawing laydown area is provided for the operators' use. Restroom and kitchen facilities are provided for the main control room operations crew.*]*

18.8.3.3 Operations Work Area Mission and Major Tasks

The operations work area provides an area for personnel who support plant operations to work in close proximity to the main control area, but not in the main control area, in order to minimize distractions to the plant operators. Personnel in the operations work area can access plant data via one or more workstations to enable personnel to monitor the current state of systems, major components, and equipment. Additional support equipment may be provided as needed.

18.8.3.4 Remote Shutdown Workstation Mission and Major Tasks

[*The mission of the remote shutdown workstation is to provide the resources to bring the plant to a safe shutdown condition after an evacuation of the main control room. The remote shutdown workstation resources are based on an assumed evacuation of the main control room without an opportunity to accomplish tasks involved in the shutdown except reactor trip.*]* Subsection 7.4.3 discusses safe shutdown using the remote shutdown workstation, including design basis information.

18.8.3.5 Technical Support Center Mission and Major Tasks

The mission of the technical support center (TSC) is to provide an area and resources for use by personnel providing plant management and technical support to the plant operating staff during emergency evolutions. The TSC relieves the reactor operators of peripheral duties and communications not directly related to reactor system manipulations and prevents congestion in the control room. The Technical Support Center (TSC) location is described in the Emergency Plan.

Communications needs are established for the staff within the TSC, and between the TSC and the plant (including the main control room and operational support center), the emergency operations facility, the Combined License holder management, the outside authorities (including the NRC), and the public.

The design includes adequate shielding as discussed in Chapter 12. Adequate space, resources and access is provided for maintenance, emergency equipment and storage.

Consistent with NUREG 0737, the technical support center is nonsafety-related and is not required to be available after a safe shutdown earthquake.

The size of the TSC complies with the size requirements of Reference 28. [*The TSC complies with the habitability requirements of Reference 27 when electrical power is available.*]*

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Should habitability be challenged within the TSC due to lack of cooling or a high radiation level resulting from a beyond-design-basis accident, the plant management function of the TSC is transferred to the main control room.

The EOF design is discussed in Chapters 13 and 18, including the specification of its location (Subsection 18.2.6) and emergency planning, and associated communication interfaces among the main control room, the TSC, and the EOF (Section 13.3).

Subsection 18.2.1.2 provides a description of assumptions and constraints, including utility requirements, that are used as inputs to the human factors engineering program and the human system interface design. As stated earlier under Section 18.8, the human system interface design includes the design of the operation and control centers system (main control room, TSC, remote shutdown room, emergency operations facility, local control stations and associated workstations) and each of the human system interface resources. The main control room design (environment, layout, number and design of workstations) supports emergency operations with a maximum crew compliment consisting of eleven individuals. These eleven include two individuals with senior reactor operator licenses, three with reactor operator licenses, one observer from the NRC, one from the plant owner's management and one communicator.

[*The design of the TSC's interfaces is included with the design of the human system interface*.]* Subsection 18.8.1 provides an implementation plan for the design of the human system interface. As shown in Figure 18.2-3, the results of the human factors engineering program elements are used as input and bases for developing the operation and control center system and human system interface resources functional design. This includes task analysis. Section 18.5 provides the implementation plan for the task analysis activities.

An uninterruptible power supply system provides approximately two hours of backup power supply to the TSC displays should ac power become unavailable.

18.8.3.6 Operations Support Center Mission and Major Tasks

The operations support center (OSC) is not within the scope of the human factors engineering program, but it is an emergency response facility. The mission of the operations support center is to provide a habitable area for operations support personnel and the resources to coordinate the assignment of duties and tasks to personnel outside of the main control room and the technical support center in support of plant emergency operation. The operations support center and the TSC are in different locations. The Operations Support Center (OSC) location is described in the Emergency Plan.

The major task of the operations support center is to provide a centralized area and the necessary supporting resources for the assembly of predesignated operations support personnel during emergency conditions. The operations support center provides the resources for communicating with the main control room and the technical support center. This permits personnel reporting to the operations support center to be assigned to duties in support of emergency operations.

18.8.3.7 Radwaste Control Area Mission and Major Tasks

The mission of the radwaste control area is to provide a habitable area and the appropriate resources for the operation of the radwaste processing systems. These resources include alarms, displays, controls, and procedures. These resources are located in a control area outside of the main control room.

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18.8.3.8 Local Control Stations Mission and Major Tasks

The mission of local control stations is to provide the resources, outside of the main control room, the remote shutdown room, and the radwaste control area, for operations personnel to perform monitoring and control activities. The capability to access displays and controls (controls as assigned by the main control room operators) for local control and monitoring, from selected locations throughout the plant, is provided. Activities that are implemented through local control stations are reviewed to verify that their removal from the main control room is consistent with the operator staffing and performance considerations. Human system interface locations are provided for single task operations such as the operation of a manual valve.

18.8.3.9 Emergency Operations Facility

The design of the emergency operations facility, including specification of the location, in accordance with the AP1000 human factors engineering program, is discussed in Subsection 18.2.6.

18.8.4 Human Factors Design for the Non-Human-System Interface Portion of the Plant

18.8.4.1 General Plant Layout and Design

The AP1000 design process incorporates a human engineering approach to operations and maintenance. Maintainability design guidelines and human factors and as-low-as-reasonably-achievable (ALARA) checklists are used to meet the requirements of a human engineered environment. The design objectives include reducing worker exposure and eliminating unnecessary inspection and maintenance tasks.

18.8.4.1.1 Maintainability

Design features such as component selection, layout and standardization increase the probability that targeted repair times are achieved. These features coupled with a preventative maintenance program help the AP1000 meet its objectives for operation and maintenance. Design requirements from the utility industry and industry design practices establish criteria for layout, changeout, and replacement for parts and components; access for major pieces of equipment; and vehicle passage.

Critical path outage models are prepared for the AP1000. A typical refueling and maintenance outage schedule is used by design engineers. The model indicates maintenance windows for major outage events. Maintenance and testing of equipment and necessary plant operations (for example, refueling, heatup, and cooldown) are scheduled within the outage window.

18.8.4.1.2 Accessibility and Equipment Laydown Provisions

AP1000 maintainability design guidelines assist designers in identifying top-level layout requirements for equipment accessibility. Component engineers specify space requirements for routine maintenance, inservice inspection, testing and component replacement.

Frequency of inspection and maintenance dictates whether permanent platforms, ladders, and scaffolding are provided.

Overhead access is considered when equipment or tooling must be lifted into place or supported by a crane. Removable floor gratings and plugs are examples of features that provide overhead accessibility.

Permanent lifting devices are provided to enhance maintainability.

The use of robotics and automated devices are considered in the AP1000 design.

Robotic devices, such as refueling cavity decontamination units, are considered in the layout of the refueling cavity so that such interferences as light fixtures, tool hangers and personnel ladders are removable or do not affect the use of the robotic units.

Valve space enveloping drawings indicate the minimum space requirements. Equipment and module designers locate and arrange the valves to maintain the required space envelope.

The turbine-generator contains built-in features to increase accessibility for in-place inspection and maintenance. Access ports in the turbine housings allow routine inspections to be performed without dismantling the turbine casing. Laydown area is provided in the turbine building to access components and to allow for concurrent work.

18.8.4.1.3 Lighting

The AP1000 normal and emergency lighting system is designed to provide illumination levels required for the safe performance of plant operation under normal and emergency conditions.

18.8.4.1.4 Radiation Protection and Safety

The AP1000 design process incorporates radiation exposure reduction principles to keep worker dose ALARA. ALARA checklists are used in design evaluations. Exposure length, distance, shielding, and source reduction are the fundamental criteria incorporated into the design process.

Design features such as readily detachable insulation, as-built smooth surfaces for non-destructive examination, and “modular type” replacement components reduce worker time in radiation areas.

The large AP1000 containment vessel provides laydown space to transfer subcomponents to storage areas until needed. The reactor head is remotely located on the operating deck to reduce background radiation to refueling personnel.

Provisions for remotely operated tooling are considered during the design process. Space is provided to clean and inspect the reactor vessel O-ring grooves using a remotely operated device. Remotely controlled radiation and surveillance equipment is considered for high radiation areas.

Special provisions for radiation shielding are included in the AP1000 design. Permanent shielding built into the integrated head package reduces worker exposure resulting from the incore instrumentation operation.

Material selection and surface conditioning are important elements in radiation exposure reduction. Electropolishing of surfaces exposed to reactor coolant primary water is considered to reduce crud deposits and aid in decontamination.

The AP1000 radioactive waste processing facilities are designed to concentrate radioactive waste processing and drumming activities in remote areas to reduce contact with the majority of plant personnel.

18.8.4.1.5 Communication

The AP1000 communication system provides voice communication during normal operations, plant outages, and emergency operations. The system includes broadcast of alarm signals in plant-wide emergency situations. The wireless telephone system enables plant personnel to remain in direct communication via wireless, hand-carried telephones throughout the plant. Headset-style telephones

are available for individuals requiring hands-free operation. Some communication devices have built-in compatibility with protective clothing including respirators.

A paging system is used as a backup to the wireless telephone system. In the event of a failure of the wireless system, personnel communicate via a plant-wide broadcast and five party lines. Emergency broadcasts are announced through this system.

Communication during AP1000 refueling and maintenance outages is enhanced by a sound-powered communication system. Refueling, maintenance, and cold shutdown loops are provided. Jacks are placed in locations where plant personnel are located during these activities.

A private branch exchange system is capable of duplex voice communication between stations. These telephones are placed in acoustic booths in those areas having high ambient noise levels to improve user interface. See Subsection 9.5.2 for information on the communication system.

A site wide radio system provides primary wireless communications for Security and fire brigade activities. Radio system is also used by other departments as needed.

18.8.4.1.6 Temperature, Humidity, Ventilation

Radioactive and nonradioactive ventilation systems are provided in required areas. The ventilation systems are designed to control the environment within the plant and to protect the environment outside the plant. Requirements for temperature, humidity, and ventilation vary, depending on work location, frequency of use, and work description.

18.8.4.1.7 Emergency Equipment

Emergency equipment for treatment of injured personnel is placed in appropriate locations. Provisions for emergency equipment are considered during plant layout.

18.8.4.1.8 Storage

Storage facilities are identified in the AP1000. Radioactively clean and contaminated storage areas are designated.

18.8.4.1.9 Coding and Labeling

Equipment located in the AP1000 has a unique identifier and plant descriptive name. The configuration management system includes the identification of the equipment in the plant. Each component is assigned an identifier during the design process. The identifier is maintained through manufacturing, construction, and operation. The components are labeled according to the assigned identifier. These labels help avoid errors in operating or working on the wrong equipment and in reporting problems or conditions observed in the plant. The labels help reduce the training burden for operating and maintenance personnel.

Color, syntax, abbreviations and symbols are consistently applied. The labels are located in an easily visible location on the component and are not hidden by insulation, equipment covers, or surrounding equipment. Labels are fastened to the component to prevent easy detachment of the label.

18.8.5 Combined License Information

The execution and documentation of the human system interface design implementation plan that is presented by Section 18.8 is addressed in APP-GW-GLR-082 (Reference 47), and the applicable changes are incorporated into the UFSAR.

18.8.6 References

1. APP-OCS-J1-002, “AP1000 Human System Interface Design Guidelines,” (Westinghouse Proprietary).

2. CEI/IEC 964, “Design for Control Rooms of Nuclear Power Plants,” International Electrotechnical Commission, Geneva, Switzerland, 1989.

3. IEEE Std 1023-2004, “IEEE Recommended Practice for the Application of Human Factors Engineering to Systems, Equipment and Facilities of Nuclear Power Generating Stations and Other Nuclear Facilities.”

4. IEEE Std 1289-1998, “IEEE Guide for the Application of Human Factors Engineering in the Design of Computer-Based Monitoring and Control Displays for Nuclear Power Generating Stations.”

5. NUREG-0700, “Human-System Interface Design Review Guideline,” Rev. 2, U.S. Nuclear Regulatory Commission, Washington, D.C., May 2002.

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9. NUREG/CR-6634, “Computer-Based Procedure Systems: Technical Basis and Human Factors Review Guidance,” U.S. Nuclear Regulatory Commission, Washington, D.C., March 2000.

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13. Roth, E. M. and Hoecker, D. G., “Human Factors Issues Associated with Soft Controls: Design Goals and Available Guidance,” 1994.

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16. Van Cott and Kinkade, “Human Engineering Guide to Equipment Design,” Washington D.C.: U.S. Government Printing Office, 1972.

17. Electric Power Research Institute, “Human Factors Guide for NPP Control Room Development,” Final Report on Project 1637-1. EPRI NP-3659, 1984.

18. Electric Power Research Institute, “Advanced Light Water Reactor Utility Requirements Document, Vol. III. ALWR Passive Plant, Chapter 10: Man-Machine Interface Systems,” Revision 6, December 1993.

19. International Electrotechnical Commission, “Design for Control Rooms of Nuclear Power Plants,” IEC Standard 964, 1989.

20. International Electrotechnical Commission, “Operating Conditions for Industrial-Process Measurement and Control Equipment,” IEC Standard 654-1, 1979.

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22. 29CFR1910, “Occupational Safety and Health Standards,” 1975.

[*23. WCAP-14651, “Integration of Human Reliability Analysis With Human Factors Engineering Design Implementation Plan,” Revision 2, May 1997.*]*

[*24. WCAP-15860, “Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan,” Revision 2, October 2003.*]*

[*25. WCAP-14695, “Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology,” Revision 0, July 1996.*]*

[*26. 10 CFR 50.34 (f) (2) (iv).*]*

[*27. NUREG-0737, Supplement 1; “Requirements for Emergency Response Capability.”*]*

28. NUREG-0696, “Functional Criteria For Emergency Response Facilities.”

[*29. NUREG-0711, “Human Factors Engineering Program Review Model,” U.S. NRC, July 1994.*]*

30. WCAP-14655, “Designer’s Input for the Training of the Human Factors Engineering Verification and Validation Personnel,” Revision 1, August 1996.

31. WCAP-14690, “Designer’s Input to Procedure Development for the AP600,” Revision 1, June 1997.

[*32. NUREG-1342, “A Status Report Regarding Industry Implementation of Safety Parameter Display Systems.”*]*

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*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

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41. Not used.

42. Not used.

43. American National Standards Institute, 1988, “ANSI/HFS 100-1988, American National Standard for Human Factors Engineering of Visual Display Terminal Workstations,” (Santa Monica, CA, Human Factors Society, American National Standards Institute).

44. WCAP-14694, “Designer’s Input to Determination of the AP600 Main Control Room Staffing Level,” Revision 0, July 1996.

45. AP1000 Probabilistic Risk Assessment.

[*46. WCAP-14396, “Man-in-the-Loop Test Plan Description,” Revision 3, November 2002.*]*

47. APP-GW-GLR-082, “Execution and Documentation of the Human System Interface Design Implementation Plan,” Westinghouse Electric Company LLC.

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*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 18.8-1 (Sheet 1 of 2)
[*HUMAN PERFORMANCE ISSUES TO BE ADDRESSED BY THE HSI DESIGN*]*

Operator Activity: Detection and Monitoring
Issue 1: Do the wall panel information system and the workstation summary and overview displays support the operator in maintaining an awareness of plant status and system availability without needing to search actively through the workstation displays?
Issue 2: Does the wall panel information system support the operator in getting more detail about plant status and system availability by directed search of the workstation functional and physical displays?
Issue 3: Do the HSI features support efficient navigation to locate specific information?
Issue 4: Do the HSI features effectively support crew awareness of plant condition?
Operator Activity: Interpretation and Planning
Issue 5: Does the alarm system convey information in a way that enhances operator awareness and understanding of plant condition?
Issue 6: Does the physical and functional organization of plant information on the workstation displays enhance diagnosis of plant condition and the planning/selection of recovery paths?
Issue 7: Does the integration of alarms, wall panel information system, workstation, and procedures support the operator in responding to single-fault events?
Issue 8: Does the integration of alarms, wall panel information system, workstation and procedures support the operator in interpretation and planning during multiple-fault events?
Issue 9: Does the integration of alarms, wall panel information system, workstation and procedures support the crew in interpretation and planning during multiple-fault events?
Issue 10: Does the integration of alarms, wall panel information system, workstation, and procedures support the crew in interpretation and planning during severe accidents?

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 18.8-1 (Sheet 2 of 2)
[*HUMAN PERFORMANCE ISSUES TO BE ADDRESSED BY THE HSI DESIGN*]*

Operator Activity: Controlling Plant State
Issue 11: Do the HSI features support the operator in performing simple, operator-paced control tasks?
Issue 12: Do the HSI features support the operator in performing control tasks that require assessment of preconditions, side effects and post-conditions?
Issue 13: Do the HSI features support the operator in performing control tasks that require multiple procedures?
Issue 14: Do the HSI features support the operator in performing event paced control tasks?
Issue 15: Do the HSI members features support the operator in performing control tasks that require coordination among crew?

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

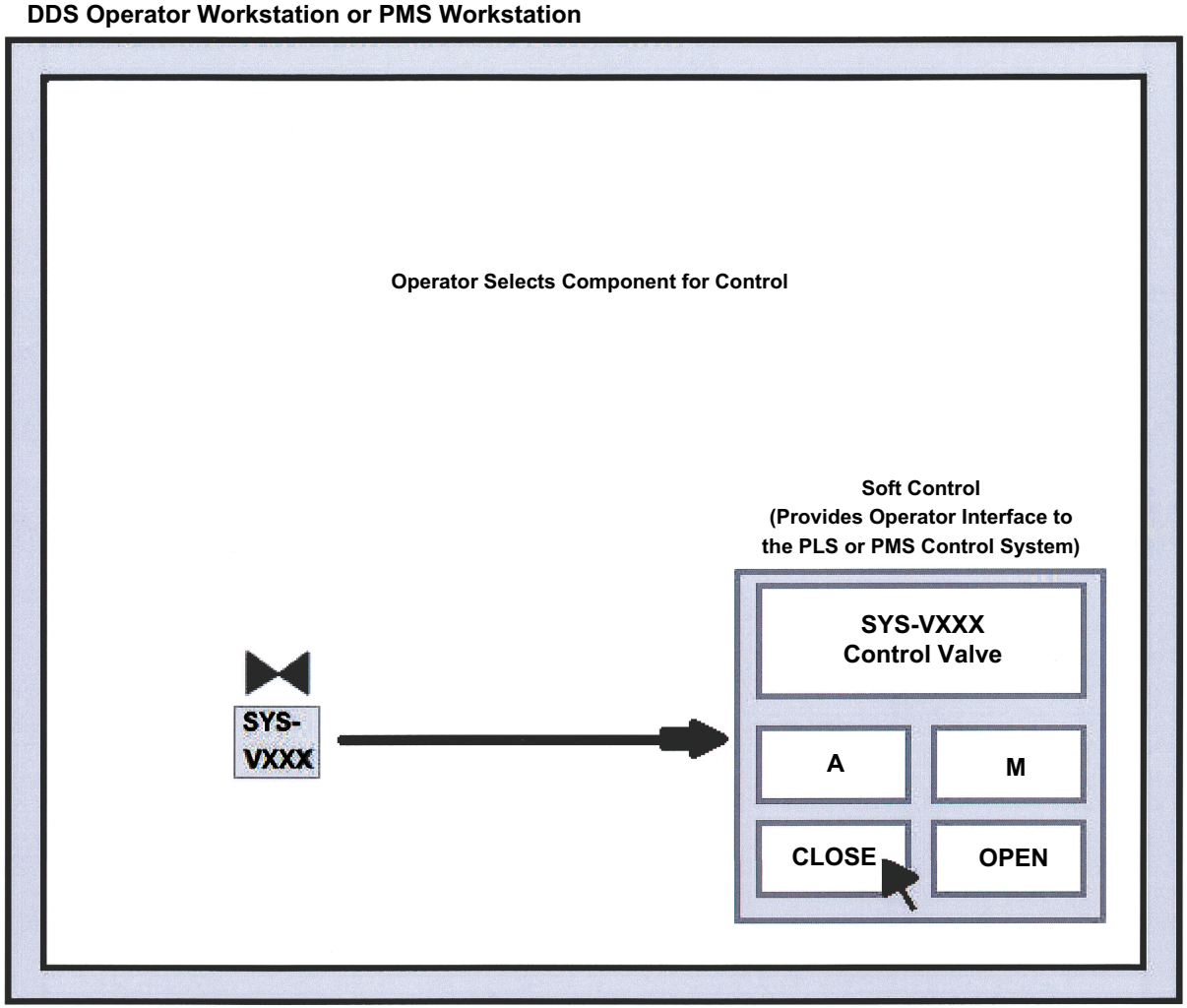

Figure 18.8-1
Soft Control Interactions

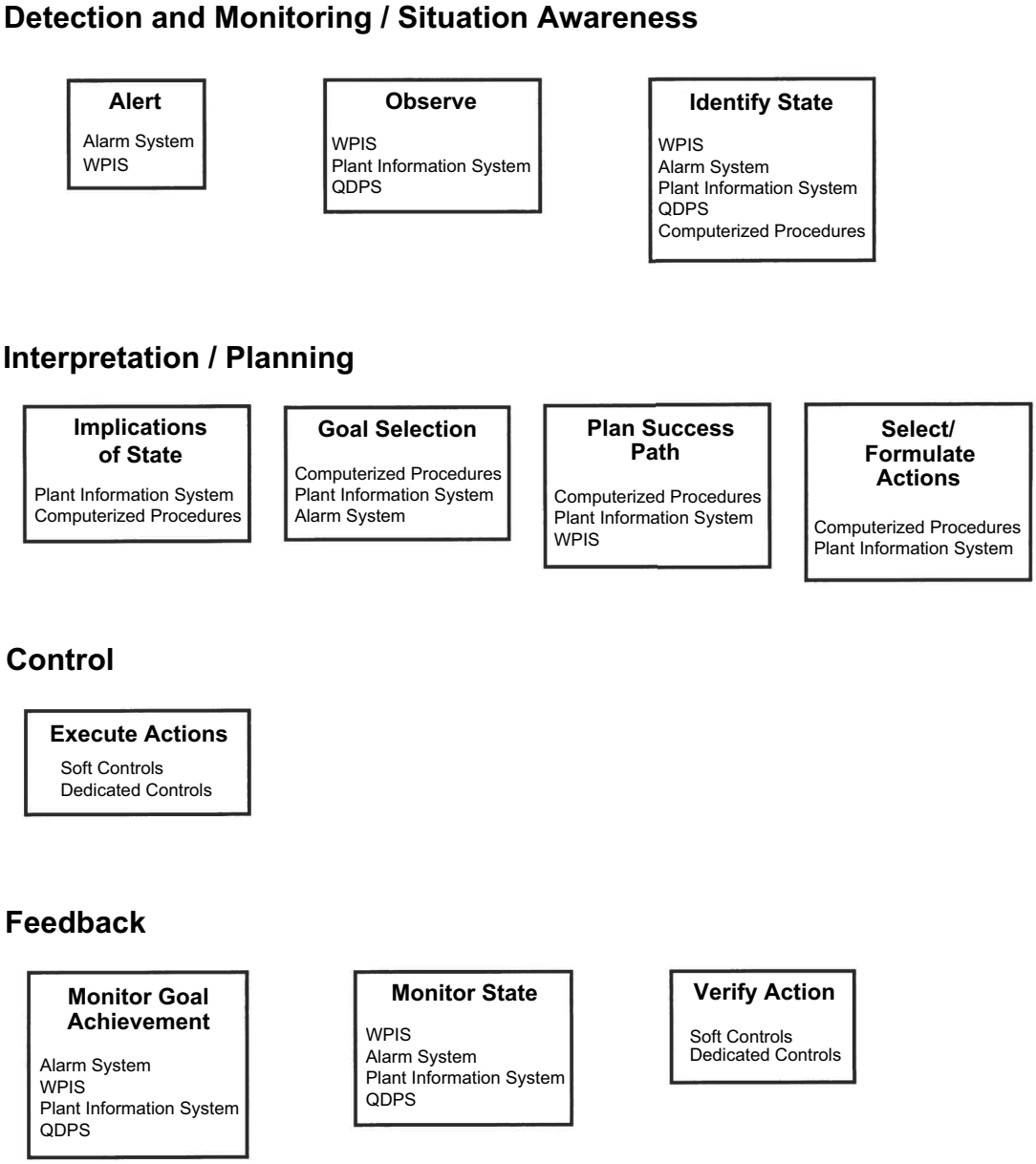

Figure 18.8-2
Mapping of Human System Interface Resources to Operator Decision-Making Model

18.9 Procedure Development

WCAP-14690, "Designer's Input to Procedure Development for the AP600" (Reference 1), provides input for the development of plant operating procedures, including information on the development and design of the AP600 emergency response guidelines and emergency operating procedures. It applies directly to AP1000 since AP1000 is operated in the same manner as AP600. The WCAP also includes information on the computerized procedure system, which is the human system interface through which operators execute the plant procedures.

18.9.1 Combined License Information

The responsibility for procedure development is addressed in APP-GW-GLR-040 (Reference 2), and the applicable changes are incorporated into the UFSAR.

18.9.2 References

1. WCAP-14690, "Designer's Input to Procedure Development for the AP600," Revision 1, June 1997.

2. APP-GW-GLR-040, "Plant Operations, Surveillance, and Maintenance Procedures," Westinghouse Electric Company LLC.

18.10 Training Program Development

WCAP-14655, "Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel" (Reference 1), describes the design and implementation of the training program for the training of the operations personnel who participate as subjects in the Human Factors Engineering (HFE) Verification and Validation. The WCAP also describes the process used to develop the specification of the role of the operator for AP1000 and how this role and training insights can be passed from the designer to the developer of the training program.

Information regarding training program development is located in Section 13.2, Training. The training organization and roles and responsibilities of training personnel are discussed in Section 13.1, Organizational Structure of Applicant.

18.10.1 Combined License Information

The responsibility for training program development is addressed in Sections 18.10, 13.1, and 13.2.

18.10.2 References

1. WCAP-14655, "Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel," Revision 1, August 1996.

18.11 Human Factors Engineering Verification and Validation

A programmatic level description of the AP1000 human factors engineering verification and validation program is provided by Reference 1. Using the programmatic level description, the development of an implementation plan for the AP1000 human factors engineering verification and validation is executed and documented as discussed in Reference 2. The implementation of the verification and validation activities is detailed in the five documents References 3 to 7.

The verification and validation activities are in accordance with Reference 1. There are a number of exceptions in respect to human factors engineering verification and validation. The details of these exceptions and the corresponding justifications are provided in References 3 to 5.

18.11.1 Combined License Information

The development, execution and documentation of an implementation plan for the verification and validation of the AP1000 human factors engineering program is addressed in Reference 2 (APP-GW-GLR-084).

18.11.2 References

[1. *WCAP-15860 , "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Revision 2, October 2003.*]*

2. APP-GW-GLR-084, "AP1000 Human Factors Engineering Verification and Validation," Westinghouse Electric Company LLC.

[3. *APP-OCS-GEH-120, "AP1000 Human Factors Engineering Design Verification Plan,"*]* Revision 3, December 2014, Westinghouse Electric Company LLC.(1)

[4. *APP-OCS-GEH-220, "AP1000 Human Factors Engineering Task Support Verification Plan,"*]* Revision 6, February 2018, Westinghouse Electric Company LLC.(2)

[5. *APP-OCS-GEH-320, "AP1000 Human Factors Engineering Integrated System Validation Plan,"*]* Revision 7, February 2018, Westinghouse Electric Company LLC(3) [*(as modified by changes provided in UFSAR Appendix 18A)*]*

[6. *APP-OCS-GEH-420, "AP1000 Human Factors Engineering Discrepancy Resolution Process,"*]* Revision 2, December 2014, Westinghouse Electric Company LLC.(4)

[7. *APP-OCS-GEH-520, "AP1000 Plant Startup Human Factors Engineering Design Verification Plan,"*]* Revision 4, December 2014, Westinghouse Electric Company LLC.(5)

Notes:

1. [*Section 1, Section 2, and Section 3 of APP-OCS-GEH-120 are Tier 2*. Changes to these portions of the document require prior NRC approval.*]* The remainder of the document, including its revision number, is Tier 2.

2. [*Section 1, Section 2, Section 3, Section 4, and Section 5 of APP-OCS-GEH-220 are Tier 2*. Changes to these portions of the document require prior NRC approval.*]* The remainder of the document, including its revision number, is Tier 2.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

3. [*Section 1, Section 2, Section 3, Section 4, Section 5, Section 6, and Section 7 of APP-OCS-GEH-320 are Tier 2*. Changes to these portions of the document require prior NRC approval.*]* The remainder of the document, including its revision number, is Tier 2.

4. [*Section 1 and Section 2 of APP-OCS-GEH-420 are Tier 2*. Changes to these portions of the document require prior NRC approval.*]* The remainder of the document, including its revision number, is Tier 2.

5. [*Section 1, Section 2, and Section 3 of APP-OCS-GEH-520 are Tier 2*. Changes to these portions of the document require prior NRC approval.*]* The remainder of the document, including its revision number, is Tier 2.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Figure 18.11-1 Not Used
(See Reference 5, Figure 1.1-1, "AP1000 Verification and Validation Activities.")

18.12 Inventory

18.12.1 Inventory of Displays, Alarms, and Controls

[*An inventory of instruments, alarms, and controls for the AP1000 systems is provided in the respective system piping and instrumentation diagrams and/or the respective system specification documents.*

The AP1000 system design engineers determine the specific sensors, instrumentation, controls, and alarms that are needed to operate the various plant systems. The instruments, alarms, and controls for each system are documented in the piping and instrumentation diagram and/or the respective system specification documents. An instrument, alarm, and control is specified by the system design engineer if it is needed to control, verify, or monitor the operation of the system and its components. System functions and their respective functional requirements are considered by the system designer when determining the need for a specific instrument, alarm, or control.

The role of the Human System Interface design team in the determination of the total inventory list is one of verification. As described in Section 18.5, human system interface design team has functionally decomposed the plant. The top four levels of this model for the AP1000 are shown in Figure 18.5-1. Each Level 4 function has a function-based task analysis (FBTA) performed as described in the Task Analysis Implementation Plan. Considering the plant operating modes and emergency operations, the function-based task analysis:

- *Identifies the functions goals*
- *Identifies the processes used to achieve each goal*
- *Documents the performance of a cognitive task analysis of each process*

The cognitive task analysis of each process answers the monitoring/feedback, planning, and controlling questions. The answers to these questions identify the data for each functional process (instrumentation, indications, alarms, and controls) needed by the operator to make decisions. The results of the cognitive task analysis phase of each function-based task analysis are used to verify the inventory list of instruments, controls, and alarms developed by the AP1000 system designers and documented in the respective design documents.]*

18.12.2 Minimum Inventory of Main Control Room Fixed Displays, Alarms, and Controls

Background

[The human system interface design includes the appropriate plant displays, alarms, and controls needed to support a broad range of expected power generation, shutdown, and accident mitigation operations. Soft control displays and plant information displays are generated by a computer and can be changed to perform different functions, allow control of different devices, or display different information. These displays appear on display devices such as cathode ray tubes, flat panel screens, or visual display units. Alarms are used to direct operator attention. Soft controls are provided through devices such as a keyboard, touch screen, mouse, or other equivalent input devices. The majority of the operations for both the AP1000 main control room and the remote shutdown workstation are expected to employ soft control displays and plant information displays.

The AP1000 human system interface design also includes a minimum inventory of dedicated or fixed-position displays and controls. The minimum inventory of AP1000 fixed-position instrumentation includes those displays, controls, and alarms that are used to monitor the status of critical safety functions and to manually actuate the safety-related systems that achieve these critical safety functions.

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Fixed-position alarms and displays are available at a fixed location and are continuously available, though not necessarily displayed, to the operator. Fixed-position displays can be accessed by the operator to monitor the plant status, based on indications from critical plant variables or parameters. Fixed-position alarms are designed to direct operator attention to the need to perform safety-related functions for which there is no automatic actuation function. Although not continuously displayed, the fixed-position displays and alarms are quickly and easily retrievable.

Fixed-position controls provide a means for manual reactor and turbine trip, and safety-related system/component actuation. Fixed-position controls are available to the operator to perform tasks in the operation of safety-related systems and components used to mitigate the consequences of an accident and to establish and maintain safe shutdown conditions following an accident. The fixed-position controls are a manual backup to the automatic protection signals provided by the protection and safety monitoring system.]*

Design Basis and Minimum Inventory

[*A systematic process was implemented to identify the minimum inventory of AP1000 fixed-position controls, displays, and alarms, using established selection criteria directly related to the specific AP1000 accident mitigation operator actions and the critical safety functions identified in the emergency response guidelines.*

The AP1000 design basis for accident mitigation protects the following three fission product barriers:

- *Fuel matrix/fuel rod cladding*
- *Reactor coolant system pressure boundary*
- *Containment*

Therefore, the minimum inventory of fixed instrumentation includes those displays, controls, and alarms used to monitor the status of these fission product barriers and manually actuate the safety-related systems that achieve the critical safety functions protecting these barriers.

Six critical safety functions are identified in the Emergency Response Guidelines (ERGs). These critical safety functions are physical processes, conditions, or actions designed to maintain the plant conditions within the acceptable design basis.

The AP1000 critical safety functions are:

- *Reactivity control*
- *Reactor core cooling*
- *Heat sink maintenance*
- *Reactor coolant system integrity*
- *Containment environment*
- *Reactor coolant system inventory control*

The minimum inventory of AP1000 fixed instrumentation includes those displays, controls, and alarms that are used to monitor the status of these critical safety functions and to manually actuate the safety-related systems that achieve these critical safety functions.]*

Minimum Inventory Selection Criteria

[*The following selection criteria are used to develop the minimum inventory of instrumentation controls, displays, and alarms:*

- *Regulatory Guide 1.97 Types A, B, and C, Category 1 instrumentation*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

- *Dedicated controls for manual safety-related system actuation (reactor trip, turbine trip, engineered safety feature actuation)*
- *Controls, displays, and alarms required to perform critical manual actions as identified from the PRA analysis*
- *Alarms provided for operator use in performing safety functions to respond to design basis events for which there is no automatically-actuated safety function*
- *Controls, displays, and alarms necessary to maintain the critical safety functions and safe shutdown conditions*

For the main control room, the minimum inventory of displays is provided by the PMS safety displays. For the remote shutdown workstation, the minimum inventory of displays is provided by the nonsafety-related displays of the plant information system.

An alarm is a device that provides warning by means of a signal or sound. The parameters and associated alarms, listed in DCD Table 18.12.2-1, identify challenges to the critical safety functions. This minimum inventory of alarms is embedded in displays as visual signals. For example, the visual signal may involve a change of color, brightness, flashing, or a combination of these. For clarity, these alarms are called visual alerts to distinguish them from other alarms which may include sound. For the main control, the visual alerts are embedded in the safety-related displays. For the remote shutdown workstation, the visual alerts are embedded in the nonsafety-related displays.

*The minimum inventory resulting from the implementation of these selection criteria is provided in Table 18.12.2-1.]**

Regulatory Guide 1.97

[*The guidelines in Regulatory Guide 1.97 provide an effective basis for selection criteria to identify the minimum inventory of fixed displays, controls, and alarms, since these guidelines are consistent with monitoring the status of the fission product barriers and the associated critical safety functions in the AP1000 Emergency Response Guidelines.*

Regulatory Guide 1.97 provides a method to identify the post-accident monitoring (PAMS) instrumentation to monitor plant variables and systems during and following an accident. Selected post-accident monitoring instrumentation is required to remain functional over the range of the accident conditions and must be able to survive the accident environment for the length of time its function is required. The instrumentation helps the operator to identify the accident, to implement proper corrective actions, and to observe plant response to these actions in order to determine the need for additional actions. Five types of accident monitoring instrumentation and associated performance criteria are provided in the regulatory guide.

Within each type of post-accident monitoring instrumentation, there are three categories (Categories 1, 2, and 3) that are related to the qualification (seismic and environmental conditions) and reliability (safety-related power supply and single failures) of the specific instrumentation.

The Category 1 variables are considered as primary variables and meet appropriate qualification, design, and interface requirements discussed in subsection 7.5.2.2.1 and listed in Tables 7.5-2 and 7.5-3. These variables provide the appropriate capabilities and reliability that are required for the parameters. Only the Category 1 (primary) variables are included in the minimum inventory selection criteria. Category 2 and Category 3 instrumentation are not included in the selection criteria for the minimum inventory.

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Type A, Type B, and Type C are considered in developing the selection criteria for identification of the minimum inventory, since these three types are related to monitoring the three fission product barriers. The details of instrumentation designed to meet the guidelines in Regulatory Guide 1.97 are presented in Section 7.5.

Type A variables are defined in subsection 7.5.2.1. As discussed in subsection 7.5.3.1, Type A variables provide primary information to permit the main control room operating staff to:

- *Perform the diagnosis in the AP1000 emergency operating procedures*
- *Take specified preplanned, manually-controlled actions, for which automatic controls are not provided, and that are required for safety-related systems to accomplish their safety-related function to recover from a design basis accident*

There are no specific, preplanned, manually-controlled actions for safety-related systems to recover from design basis accidents in the AP1000 design. Therefore, as reflected in Table 7.5-4, there are no Type A variables.

Type B variables are defined in subsection 7.5.2.1. As discussed in subsection 7.5.3.2, Type B variables provide information to the main control room operating staff to assess the process of accomplishing critical safety functions in the emergency response guidelines. The Type B variables are identified in Table 7.5-5.

Type C variables are defined in subsection 7.5.2.1. As discussed in subsection 7.5.3.3, Type C variables provide the control room operating staff with information to monitor the potential for breach or the actual gross breach of:

- *Incore fuel cladding*
- *Reactor coolant system boundary*
- *Containment boundary*

The Type C variables are identified in Table 7.5-6.]*

Dedicated Controls

[*The selection criteria of AP1000 minimum inventory include dedicated, fixed-position controls that provide the capability to manually initiate system-level actuation signals for the safety-related systems and components that are used to achieve the critical safety functions. These dedicated controls provide the capability to initiate manual reactor and turbine trip, safeguards actuation, individual actuation of various safety-related, passive components and containment isolation.*]*

Probabilistic Risk Assessment Critical Human Actions

[*As described in Section 18.7 and Reference 1, the human factors engineering design process includes integration of PRA and the associated human reliability analysis insights into the AP1000 design. The human reliability analysis integration includes the identification of critical human actions through the consideration of specific deterministic and PRA criteria. These selection criteria for minimum inventory identify dedicated, fixed-position displays, alarms, and controls required to support critical human actions identified from the integration of human reliability analysis into the human factors engineering design process.*]*

Dedicated Alarms

[*As specified by Criterion 1, the minimum inventory of instrumentation requires dedicated instrumentation displays of the Regulatory Guide 1.97 Type A variables so that the operator can identify the need to take preplanned manually-controlled actions to mitigate the consequences of a*

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

design basis accident, where a safety-related system needed to support a critical safety function is not automatically actuated.

The fourth criterion for minimum inventory is included to identify alarms needed to automatically alert the operator to the need to take these preplanned manually controlled actions.

One of the design goals of the AP1000 is to minimize the need for operator actions to mitigate the consequences of design basis events. As part of the implementation of this design goal, the safety-related systems required to mitigate the consequences of design basis accidents and most anticipated operational occurrences are automatically actuated. There are no specific preplanned, manually-controlled actions required for the safety-related systems to mitigate design basis accidents in the AP1000 design.

Another design goal for the AP1000 is to enhance defense in depth, which includes the use of automatically actuated safety-related systems as a backup to other automatically actuated safety-related systems. For example, if beyond-design-basis failures occurred such that the safety-related passive residual heat removal heat exchanger failed to actuate, other safety-related systems would automatically actuate to provide core cooling, without the need for operator action for either group of safety-related components. This design approach enhances overall plant safety.

The AP1000 minimum inventory includes a criterion for evaluating the need for dedicated alarms for preplanned operator actions. However, as a result of these two design approaches, the level of protection available to mitigate the consequences of an accident and to achieve the critical safety functions is provided without the need for preplanned operator actions for either the primary safety-related systems or the backup safety-related systems. Since there are no specific preplanned, manually-controlled actions for safety-related systems required to respond to design basis accidents in the AP1000 design, there are also no dedicated, fixed-position alarms identified in the minimum inventory list.]*

Critical Safety Functions and Safe Shutdown

[*The design basis for the AP1000 requires protecting the three fission product barriers in the plant (the fuel matrix and cladding, the reactor coolant system pressure boundary, and containment) following design basis events. The AP600 system/event matrix (Reference 2) identifies four safety-related, post-accident mitigation functions that are required as part of the design basis for the AP600 to protect the integrity of these fission product barriers. This document is directly applicable to AP1000. The design basis of the AP1000 requires safety-related systems that can perform these four safety-related functions for design basis events.*

The AP1000 Emergency Response Guidelines were developed by using the system/event matrix document as the plant response design basis and following the standardized process for Emergency Response Guideline development for Westinghouse PWRs. The design approach described in the system/event matrix document organizes the identified safety-related and nonsafety-related systems, structures and components into the appropriate groups that perform the four safety-related design basis functions. In developing the AP1000 Emergency Response Guidelines, the same groups of safety-related and nonsafety-related systems in the system/event matrix are used to perform their basic design functions, but they are organized somewhat differently from the system/event matrix to support development of symptom-based functional guidelines that can be more effectively used by the operators. These four design basis safety functions identified in (Reference 2) are expanded into the six critical safety functions in writing the symptom-based AP1000 Emergency Response Guidelines.

The six Emergency Response Guidelines critical safety functions (and the four design basis safety functions that the critical safety functions must satisfy) are physical processes, conditions, or actions taken using the safety-related and nonsafety-related systems to maintain the plant conditions within

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the acceptable design basis. These systems provide the physical equipment used to initiate and control the processes that achieve the critical safety functions.

By accomplishing the emergency response guideline critical safety functions following a design basis event, the plant is able to mitigate the consequences of the event and to establish and maintain safe shutdown conditions. The minimum inventory list identifies sufficient controls, displays, and alarms to monitor and control operation of the safety-related systems to achieve the six critical safety functions identified in the Emergency Response Guidelines and to establish and maintain safe shutdown conditions following an accident.

Tables 7.5-4, 7.5-5, and 7.5-6 identify the instrumentation and the associated Emergency Response Guidelines critical safety functions that each instrument supports for each of the Type A, B, and C post-accident instrumentation, respectively.]*

Minimum Inventory Selection Criteria Implementation Process

[*Section 7.5 provides a discussion of the development of the requirements of Regulatory Guide 1.97 and the implementation process for the AP1000 (Criteria 1, 2, and 4).*

Section 18.7 and Reference 1 provide a discussion of the implementation process for identification of critical PRA operator actions (Criteria 3). Chapter 30 of the AP1000 PRA describes the process for the human reliability analysis.]*

18.12.3 Remote Shutdown Workstation Displays, Alarms, and Controls

[*Subsection 7.4.3 discusses safe shutdown using the remote shutdown workstation following an evacuation of the main control room.*

The main control room provides the capability to perform accident mitigation and safe shutdown tasks for design basis events. The only types of events that would require evacuation of the main control room and control from the remote shutdown workstation are localized emergencies where the main control room environment is unsuitable for the operators or where the main control room workstations and equipment become damaged.

Evacuation of the main control room is not expected to occur coincident with any other design basis events. Subsection 9.5.1 of the Standard Review Plan (NUREG-0800) specifically excludes consideration of other design basis events coincident with a fire.

The design capability for the remote shutdown workstation is to provide the capability to establish and maintain safe shutdown conditions following a main control room evacuation, as described in subsection 7.4.3.1.1. The controls, displays, and alarms listed in Table 18.12.2-1 are retrievable from the remote shutdown workstation.]*

18.12.4 Combined License Information

This section contained no requirement for additional information.

18.12.5 References

[*1. WCAP-14651, "Integration of Human Reliability Analysis With Human Factors Engineering Design Implementation Plan," Revision 2, May 1997.*]*

2. WCAP-13793, "The AP600 System/Event Matrix," June 1994.

*In accordance with the departure evaluation process specified in License Condition 2.D.(13), NRC Staff approval may be required prior to implementing a change in this information.

Table 18.12.2-1 (Sheet 1 of 2)
Minimum Inventory of
Fixed Position Controls, Displays, and Alerts

Description	Control	Display	Alert[2]
Neutron flux		x	x
Neutron flux doubling[3]			x
Startup rate		x	x
RCS pressure		x	x
Wide range T_{hot}		x	
Wide range T_{cold}		x	x
RCS cooldown rate compared to the limit based on RCS pressure		x	x
Wide range T_{cold} compared to the limit based on RCS pressure		x	x
Change of RCS temperature by more than 5°F in the last 10 minutes			x
Containment water level		x	x
Containment pressure		x	x
Pressurizer water level		x	x
Pressurizer water level trend		x	
Pressurizer reference leg temperature		x	
Reactor vessel - Hot leg water level		x	x
Pressurizer pressure		x	
Core exit temperature		x	x
RCS subcooling		x	x
RCS cold overpressure limit		x	x
IRWST water level		x	x
PRHR flow		x	x
PRHR HX outlet temperature		x	x
PRHR HX inlet isolation and control valve status		x	x
PCS storage tank water level		x	
PCS cooling flow		x	
IRWST to RNS suction valve status[3]		x	x
Remotely operated containment isolation valve status[3]		x	
Containment area high range radiation level		x	x
Containment pressure (extended range)		x	
CMT level[1]		x	

Table 18.12.2-1 (Sheet 2 of 2)
Minimum Inventory of
Fixed Position Controls, Displays, and Alerts

Description	Control	Display	Alert[2]
Manual reactor trip (Also initiates turbine trip Figure 7.2-1, sheet 14.)	x		
Manual safeguards actuation	x		
Manual CMT actuation	x		
Manual main control room emergency habitability system actuation[4]	x		
Manual ADS actuation (1-3 and 4)	x		
Manual PRHR actuation	x		
Manual containment cooling actuation	x		
Manual IRWST injection actuation	x		
Manual containment recirculation actuation	x		
Manual containment isolation	x		
Manual main steam line isolation	x		
Manual feedwater isolation	x		
Manual containment hydrogen igniter (nonsafety-related)[5]	x		
Manual ADS and IRWST injection unblock[6]	x		
Manual containment vacuum relief	x		

Notes:

1. Although this parameter does not satisfy any of the selection criteria of Subsection 18.12.2, its importance to manual actuation of ADS justifies its placement on this list.
2. These parameters are used to generate visual alerts that identify challenges to the critical safety functions. For the main control room, the visual alerts are embedded in the safety-related displays as visual signals. For the remote shutdown workstation, the visual alerts are embedded in the nonsafety-related displays as visual signals.
3. These instruments are not required after 24 hours. (Subsection 7.5.4 includes more information on the class 1E valve position indication signals, specified as part of the post-accident monitoring instrumentation.)
4. This manual actuation capability is not needed at the remote shutdown workstation.
5. At the remote shutdown workstation, containment hydrogen igniter control is provided as a “soft” control.
6. These controls are not required at the remote shutdown workstation.

18.13 Design Implementation

This process element is added by Reference 2 to the Program Review Model specified in Reference 1. However, it mostly applies to plant modernization. The portions of the added element that apply to new plants were formerly addressed under the Verification and Validation element in Reference 1. Since these aspects of the Program Review Model are unchanged, AP1000 will continue to address them under Section 18.11 as “Issue Resolution Verification” and “Final Plant HFE Verification.”

18.13.1 References

1. NUREG-0711, “Human Factors Engineering Program Review Model,” U.S. NRC, July 1994.

2. NUREG-0711, Rev. 1, “Human Factors Engineering Program Review Model,” U.S. NRC, May 2002.

18.14 Human Performance Monitoring

Human performance monitoring applies after the plant is placed in operation. The human performance monitoring process implements the guidance and methods as described in Reference 1.

The human performance monitoring process provides reasonable assurance that:

- The design can be effectively used by personnel, including within the control room and between the control room and local control stations and support centers.
- Changes made to the human system interface(s), procedures, and training do not have adverse effects on personnel performance, (e.g., a change does not interfere with previously trained skills).
- Human actions can be accomplished within time and performance criteria.
- The acceptable level of performance established during the design integrated system validation is maintained.

The human performance monitoring process is structured such that:

- Human actions are monitored commensurate with their safety importance.
- Feedback of information and corrective actions are accomplished in a timely manner.
- Degradation in performance can be detected and corrected before plant safety is compromised (e.g., by use of the plant simulator during training exercises).

The human performance monitoring process for risk-informed changes is integrated into the corrective action program, training program and other programs as appropriate. Identified human performance conditions/issues are evaluated for human factors engineering applicability.

Human factors engineering conditions are assigned specific human factors cause determination codes, trended for indications of degraded performance or potential human performance failures and have specific corrective actions identified.

The cause investigation:

- Identifies the cause of the failure or degraded performance to the extent that corrective action can be taken consistent with the corrective action program requirements.
- Addresses failure significance which includes the circumstances surrounding the failure or degraded performance, the characteristics of the failure, and whether the failure is isolated or has generic or common cause implications.
- Identifies and establishes corrective actions necessary to preclude the recurrence of unacceptable failures or degraded performance in the case of a significant condition adverse to quality.

When appropriate, design changes are integrated into training exercises to monitor for degradation in performance and allow for early detection and corrective actions before plant safety is challenged (e.g., by use of the plant simulator during training exercises).

Plant or personnel performance under actual design conditions may not be readily measurable. When actual conditions cannot be simulated, monitored, or measured, the available information that most closely approximates performance data in actual conditions should be used.

Monitoring strategies for human performance trending after the implementation of design changes is capable of demonstrating that performance is consistent with that assumed in the various analyses conducted to justify the change.

Risk-informed changes are screened commensurate with their safety importance to determine if the change requires monitoring of actions. For changes which require monitoring, the appropriate monitoring requirements are determined and implemented in the training program or other program as appropriate.

18.14.1 References

1. NUREG-0711, Rev. 1, “Human Factors Engineering Program Review Model,” U.S. NRC, May 2002.

Appendix 18A Not Used

Southern Nuclear

UFSAR Table of Contents

Chapter 1 — Introduction and General Description of the Plant

Chapter 2 — Site Characteristics

Chapter 3 — Design of Structures, Components, Equipment and Systems

Chapter 4 — Reactor

Chapter 5 — Reactor Coolant System and Connected Systems

Chapter 6 — Engineered Safety Features

Chapter 7 — Instrumentation and Controls

Chapter 8 — Electric Power

Chapter 9 — Auxiliary Systems

Chapter 10 — Steam and Power Conversion

Chapter 11 — Radioactive Waste Management

Chapter 12 — Radiation Protection

Chapter 13 — Conduct of Operation

Chapter 14 — Initial Test Program

Chapter 15 — Accident Analyses

Chapter 16 — Technical Specifications

Chapter 17 — Quality Assurance

Chapter 18 — Human Factors Engineering

Chapter 19 — Probabilistic Risk Assessment

UFSAR Formatting Legend

Color	Description
	Original Westinghouse AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Departures from AP1000 DCD Revision 19 content (part of plant-specific DCD)
	Standard FSAR content
	Site-specific FSAR content
	Linked cross-references (chapters, appendices, sections, subsections, tables, figures, and references)

TABLE OF CONTENTS

Section	Title	Page
CHAPTER 19	PROBABILISTIC RISK ASSESSMENT	19.1-1
19.1	Introduction	19.1-1
19.1.1	Scope	19.1-2
19.2	Internal Events	19.2-1
19.2.1	Internal Events Results	19.2-3
19.3	Internal Flood	19.3-1
19.3.1	Internal Flood Results	19.3-1
19.4	Internal Fire	19.4-1
19.4.1	Internal Fire Results	19.4-1
19.5	Seismic PRA	19.5-1
19.5.1	Seismic Fragility	19.5-1
19.5.2	Seismic PRA Results	19.5-2
19.6	Other External Hazards	19.6-1
19.6.1	Other External Hazards PRA Results	19.6-3
19.7	Shutdown Defense-In-Depth	19.7-1
19.8	Maintenance and Upgrade Process	19.8-1
19.9	Conclusions	19.9-1
19.9.1	PRA Insights	19.9-1
19.9.2	Conclusions	19.9-2
19.10	References	19.10-1
19.11	Combined License Information	19.11-1
19.11.1	References	19.11-2
19.12	Severe Accident Phenomena Treatment	19.12-1
19.12.1	Introduction	19.12-1
19.12.2	Treatment of Physical Processes	19.12-1
19.12.2.1	In-Vessel Retention of Molten Core Debris	19.12-1
19.12.2.2	Fuel-Coolant Interaction (Steam Explosions)	19.12-2
19.12.2.3	Hydrogen Combustion and Detonation	19.12-3
19.12.2.4	High-Pressure Melt Ejection	19.12-4
19.12.2.5	Core Debris Coolability	19.12-4
19.12.2.6	Containment Pressurization from Decay Heat	19.12-5
19.12.2.7	Elevated Temperatures (Equipment Survivability)	19.12-5
19.12.2.8	Summary	19.12-5
19.12.3	Analysis Method	19.12-6
19.12.4	Severe Accident Analyses	19.12-6
19.12.5	Insights and Conclusions	19.12-6
19.12.6	References	19.12-6
19.13	Reactor Coolant System Depressurization	19.13-1
19.13.1	Introduction	19.13-1
19.13.2	Definition of High Pressure	19.13-1
19.13.3	References	19.13-1
19.14	Containment Isolation	19.14-1
19.15	Reactor Vessel Reflooding	19.15-1
19.16	In-Vessel Retention of Molten Core Debris	19.16-1
19.16.1	Introduction	19.16-1
19.16.2	Background on the Application of In-Vessel Retention to the Passive Plant	19.16-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
19.16.3	Application of In-Vessel Retention to the AP1000 Passive Plant	19.16-2
19.16.4	Reactor Vessel Failure Criteria	19.16-2
19.16.5	In-Vessel Melt Progression and Relocation	19.16-2
19.16.6	Application of Heat Transfer Correlations to the AP1000	19.16-3
19.16.6.1	Debris Pool to Vessel Wall Heat Transfer	19.16-3
19.16.6.2	Vessel Wall to External Cooling Water Heat Transfer	19.16-3
19.16.7	Quantification of Heat Load on the Reactor Vessel Wall	19.16-4
19.16.8	Reactor Coolant System Depressurization	19.16-4
19.16.9	Reactor Cavity Flooding	19.16-4
19.16.10	Reactor Vessel Insulation Design Concept	19.16-4
19.16.10.1	Description of Reactor Vessel Insulation and Venting	19.16-5
19.16.10.2	Design Analysis of the Insulation and Support Frame	19.16-5
19.16.10.3	Reactor Vessel External Surface Treatment	19.16-5
19.16.11	Reactor Vessel Failure	19.16-5
19.16.12	Summary	19.16-5
19.16.13	References	19.16-6
19.17	Passive Containment Cooling	19.17-1
19.18	Hydrogen Mixing and Combustion Analysis	19.18-1
19.18.1	Introduction	19.18-1
19.18.2	Controlling Phenomena	19.18-1
19.18.3	Major Assumptions and Phenomenological Uncertainties	19.18-2
19.18.3.1	Hydrogen Generation	19.18-2
19.18.3.2	Containment Pressure	19.18-2
19.18.3.3	Flammability Limits	19.18-3
19.18.3.4	Detonation Limits and Loads	19.18-3
19.18.3.5	Igniter System	19.18-3
19.18.3.6	Other Ignition Sources	19.18-4
19.18.3.7	Severe Accident Management Actions	19.18-4
19.18.4	Hydrogen Generation and Mixing	19.18-4
19.18.5	Hydrogen Burning at Igniters	19.18-4
19.18.6	Early Hydrogen Combustion	19.18-5
19.18.6.1	Hydrogen Generation Rates	19.18-5
19.18.6.2	Hydrogen Release Locations	19.18-5
19.18.6.3	Early Hydrogen Combustion Ignition Sources	19.18-7
19.18.7	Diffusion Flame Analysis	19.18-7
19.18.8	Early Hydrogen Detonation	19.18-8
19.18.9	Deflagration in Time Frame 3	19.18-8
19.18.10	Detonation in Intermediate Time Frame	19.18-8
19.18.11	Safety Margin Basis Containment Performance Requirement	19.18-8
19.18.12	Summary	19.18-8
19.18.13	References	19.18-9
19.19	Core Damage and Severe Release Frequency from Events at Shutdown	19.19-1

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
19.19.1	Summary of Shutdown Level 1 Results	19.19-1
19.19.2	Large Release Frequency for Shutdown and Low-Power Events	19.19-3
19.19.3	Shutdown Results Summary	19.19-3
19.20	{HISTORICAL}—Seismic Margin Analysis	19.20-1
19.20.1	Introduction	19.20-1
19.20.2	Calculation of HCLPF Values	19.20-1
19.20.2.1	Seismic Margin HCLPF Methodology	19.20-1
19.20.2.2	Calculation of HCLPF Values	19.20-1
19.20.3	Seismic Margin Model	19.20-6
19.20.3.1	Major SMA Model Assumptions	19.20-6
19.20.3.2	Seismic Initiating Events	19.20-7
19.20.3.3	Seismic Event Trees	19.20-8
19.20.3.4	Seismic Fault Trees	19.20-11
19.20.4	Calculation of Plant HCLPF	19.20-11
19.20.4.1	HCLPFs for Basic Events	19.20-11
19.20.4.2	Calculation of Initiating Event HCLPFs	19.20-11
19.20.4.3	Calculation of AP1000 Plant HCLPF	19.20-12
19.20.5	Sensitivity Analyses	19.20-12
19.20.6	Results and Insights	19.20-13
19.20.6.1	AP1000 SMA Results	19.20-13
19.20.6.2	AP1000 SMA Insights	19.20-13
19.20.6.3	Site Specific Seismic Margin Analysis	19.20-14
19.20.7	References	19.20-15
APPENDIX 19A	NOT USED	19A-1
APPENDIX 19B	EX-VESSEL SEVERE ACCIDENT PHENOMENA	19B-1
19B.1	Reactor Vessel Failure	19B-2
19B.2	Direct Containment Heating	19B-3
19B.3	Ex-Vessel Steam Explosions	19B-4
19B.4	Core Concrete Interactions	19B-4
19B.4.1	Containment Pressurization due to Core Concrete Interactions	19B-5
19B.5	Conclusions	19B-6
19B.6	References	19B-6
APPENDIX 19C	NOT USED	19C-1
APPENDIX 19D	EQUIPMENT SURVIVABILITY ASSESSMENT	19D-1
19D.1	Introduction	19D-1
19D.2	Applicable Regulations and Criteria	19D-1
19D.3	Definition of Controlled, Stable State	19D-2
19D.4	Definition of Equipment Survivability Time Frames	19D-2
19D.4.1	Time Frame 0 - Pre-Core Uncovery	19D-2
19D.4.2	Time Frame 1 - Core Heatup	19D-3
19D.4.3	Time Frame 2 - In-Vessel Severe Accident Phase	19D-3
19D.4.4	Time Frame 3 - Ex-Vessel Severe Accident Phase	19D-3
19D.5	Definition of Active Operation Time	19D-4
19D.6	Equipment and Instrumentation for Severe Accident Management	19D-4
19D.6.1	Time Frames 0 and 1 - Accident Initiation, Core Uncovery and Heatup	19D-4

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
19D.6.1.1	Injection into the RCS	19D-4
19D.6.1.2	Injection into Containment	19D-5
19D.6.1.3	Decay Heat Removal and Injection into the Steam Generators	19D-5
19D.6.1.4	Depressurize Reactor Coolant System	19D-6
19D.6.1.5	Depressurize Steam Generators	19D-7
19D.6.1.6	Containment Heat Removal	19D-7
19D.6.1.7	Containment Isolation	19D-7
19D.6.1.8	Hydrogen Control	19D-8
19D.6.1.9	Accident Monitoring	19D-8
19D.6.2	Time Frame 2 - In-Vessel Core Melting and Relocation	19D-8
19D.6.2.1	Injection into the RCS	19D-8
19D.6.2.2	Injection into Containment	19D-9
19D.6.2.3	Decay Heat Removal and Injection into the Steam Generators	19D-9
19D.6.2.4	Depressurize RCS	19D-10
19D.6.2.5	Depressurize Steam Generators	19D-10
19D.6.2.6	Containment Heat Removal	19D-10
19D.6.2.7	Containment Isolation	19D-11
19D.6.2.8	Hydrogen Control	19D-11
19D.6.2.9	Control Fission Product Releases	19D-11
19D.6.2.10	Accident Monitoring	19D-11
19D.6.3	Time Frame 3 - Ex-Vessel Core Relocation	19D-12
19D.6.3.1	Injection into the RCS	19D-12
19D.6.3.2	Injection into Containment	19D-12
19D.6.3.3	Decay Heat Removal and Injection into the Steam Generators	19D-12
19D.6.3.4	Depressurize RCS	19D-12
19D.6.3.5	Depressurize Steam Generators	19D-12
19D.6.3.6	Containment Heat Removal	19D-12
19D.6.3.7	Containment Isolation and Venting	19D-13
19D.6.3.8	Combustible Gas Control	19D-13
19D.6.3.9	Control Fission Product Releases	19D-13
19D.6.3.10	Accident Monitoring	19D-13
19D.6.4	Summary of Equipment and Instrumentation	19D-13
19D.7	Severe Accident Environments	19D-14
19D.8	Assessment of Equipment Survivability	19D-14
19D.8.1	Approach to Equipment Survivability	19D-14
19D.8.1.1	Equipment Type	19D-14
19D.8.1.2	Equipment Location	19D-14
19D.8.1.3	Time Duration Required	19D-14
19D.8.1.4	Severe Environment Experiments	19D-14
19D.8.2	Equipment Located in Containment	19D-15
19D.8.2.1	Differential Pressure and Pressure Transmitters	19D-15
19D.8.2.2	Thermocouples	19D-15
19D.8.2.3	Resistance Temperature Detectors (RTDs)	19D-15
19D.8.2.4	Hydrogen Monitors	19D-15

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
19D.8.2.5	Radiation Monitors	19D-16
19D.8.2.6	Solenoid-Operated Valves (SOVs) and Air-Operated Valves (AOVs)	19D-16
19D.8.2.7	Motor-Operated Valves	19D-16
19D.8.2.8	Squib Valves	19D-16
19D.8.2.9	Position Sensors	19D-17
19D.8.2.10	Hydrogen Igniters	19D-17
19D.8.2.11	Electrical Containment Penetration Assemblies	19D-17
19D.8.2.12	Cables	19D-17
19D.8.2.13	Float Level Sensors	19D-17
19D.8.2.14	Containment Hatches (Gasket Material Only)	19D-18
19D.8.2.15	Containment Shell	19D-18
19D.8.2.16	Assessment of Equipment for Sustained Burning	19D-18
19D.8.3	Equipment Located Outside Containment	19D-18
19D.9	Conclusions of Equipment Survivability Assessment	19D-19
19D.10	References	19D-19
APPENDIX 19E	SHUTDOWN EVALUATION	19E-1
19E.1	Introduction	19E-1
19E.1.1	Purpose	19E-1
19E.1.2	Scope	19E-1
19E.1.3	Background	19E-1
19E.2	Major Systems Designed to Operate During Shutdown	19E-1
19E.2.1	Reactor Coolant System	19E-2
19E.2.1.1	System Description	19E-2
19E.2.1.2	Design Features to Address Shutdown Safety	19E-2
19E.2.2	Steam Generator and Feedwater Systems	19E-6
19E.2.2.1	System Description	19E-6
19E.2.2.2	Design Features to Address Shutdown Safety	19E-6
19E.2.3	Passive Core Cooling System	19E-7
19E.2.3.1	System Description	19E-7
19E.2.3.2	Design Features to Address Shutdown Safety	19E-7
19E.2.3.3	Shutdown Operations	19E-10
19E.2.4	Normal Residual Heat Removal System	19E-11
19E.2.4.1	System Description	19E-11
19E.2.4.2	Design Features to Address Shutdown Safety	19E-11
19E.2.5	Component Cooling and Service Water Systems	19E-13
19E.2.6	Containment Systems	19E-14
19E.2.6.1	System Description	19E-14
19E.2.6.2	Design Features to Address Shutdown Safety	19E-14
19E.2.7	Chemical and Volume Control System	19E-15
19E.2.7.1	System Description	19E-15
19E.2.7.2	Design Features to Address Shutdown Safety	19E-15
19E.2.8	Spent Fuel Pool Cooling System	19E-16
19E.2.8.1	System Description	19E-16
19E.2.8.2	Design Features to Address Shutdown Safety	19E-16
19E.2.9	Control and Protection Systems	19E-16
19E.3	Shutdown Maintenance Guidelines and Procedures	19E-16

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
19E.3.1	Maintenance Guidelines and Insights Important to Reducing Shutdown Risk	19E-17
19E.3.1.1	Availability Requirements for Safety-Related Systems	19E-17
19E.3.1.2	Availability Guidelines for Systems Important for Investment Protection	19E-17
19E.3.1.3	Reactor Coolant System Precautions and Limitations at Shutdown	19E-17
19E.3.2	Shutdown Risk Management	19E-19
19E.3.3	Shutdown Emergency Response Guidelines Overview	19E-20
19E.4	Safety Analyses and Evaluations	19E-20
19E.4.1	Introduction	19E-20
19E.4.1.1	Matrix of Chapter 15 Events	19E-21
19E.4.2	Increase in Heat Removal from the Primary System	19E-21
19E.4.2.1	Feedwater System Malfunctions Which Increase Heat Removal from the Primary System	19E-21
19E.4.2.2	Excessive Increase in Secondary Steam Flow	19E-22
19E.4.2.3	Credible and Hypothetical Steam Line Breaks	19E-23
19E.4.2.4	Inadvertent PRHR HX Operation	19E-23
19E.4.3	Decrease in Heat Removal by the Secondary System	19E-25
19E.4.3.1	Loss of Load and Turbine Trip	19E-25
19E.4.3.2	Loss of ac Power	19E-25
19E.4.3.3	Loss of Normal Feedwater	19E-26
19E.4.3.4	Feedwater System Pipe Break	19E-26
19E.4.4	Decrease in Reactor Coolant Flow Rate	19E-26
19E.4.4.1	Partial and Complete Loss of Forced RCS Flow	19E-26
19E.4.4.2	Reactor Coolant Pump Shaft Seizure or Break	19E-27
19E.4.5	Reactivity and Power Distribution Anomalies	19E-27
19E.4.5.1	Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition	19E-27
19E.4.5.2	Uncontrolled RCCA Bank Withdrawal at Power	19E-28
19E.4.5.3	RCCA Misalignment	19E-28
19E.4.5.4	Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	19E-29
19E.4.5.5	Chemical and Volume Control System Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant	19E-29
19E.4.5.6	Inadvertent Loading of a Fuel Assembly in an Improper Position	19E-29
19E.4.5.7	RCCA Ejection	19E-29
19E.4.6	Increase in Reactor Coolant Inventory	19E-29
19E.4.7	Decrease in Reactor Coolant Inventory	19E-30
19E.4.7.1	Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the Automatic Depressurization System	19E-30
19E.4.7.2	Failure of Small Lines Carrying Primary Coolant Outside Containment	19E-31

TABLE OF CONTENTS (CONTINUED)

Section	Title	Page
	19E.4.7.3 Steam Generator Tube Rupture in Lower Modes	19E-31
	19E.4.8 Loss-of-Coolant Accident Events in Shutdown Modes	19E-32
	19E.4.8.1 Double-Ended Cold-Leg Guillotine	19E-32
	19E.4.8.2 Loss of Normal Residual Heat Removal System Cooling in Mode 4 and Mode 5 with Reactor Coolant System Intact	19E-33
	19E.4.8.3 Loss of Normal Residual Heat Removal System Cooling in Mode 5 with Reactor Coolant System Open	19E-35
	19E.4.9 Radiological Consequences	19E-37
	19E.4.10 Other Evaluations and Analyses	19E-37
	19E.4.10.1 Low Temperature Overpressure Protection	19E-37
	19E.4.10.2 Shutdown Temperature Evaluation	19E-38
19E.5	Technical Specifications	19E-39
	19E.5.1 Summary of Shutdown Technical Specifications	19E-39
19E.6	Shutdown Risk Evaluation	19E-39
19E.7	Compliance with NUREG-1449	19E-39
19E.8	Conclusion	19E-40
19E.9	References	19E-40
APPENDIX 19F	MALEVOLENT AIRCRAFT IMPACT	19F-1
19F.1	Introduction and Background	19F-1
19F.2	Scope	19F-1
19F.3	Assessment Methodology	19F-1
19F.4	Results/Conclusions	19F-1
	19F.4.1 Shield Building and Auxiliary Building	19F-2
	19F.4.2 Site Arrangement	19F-2
	19F.4.3 Core Cooling and Containment Integrity	19F-3
	19F.4.4 Reactor Trip	19F-4
	19F.4.5 Supporting Power, Instrumentation, and Control Equipment	19F-4
	19F.4.6 Fire Barriers	19F-4
19F.5	References	19F-5

LIST OF TABLES

Table Number	Title	Page
19.2-1	Summary of Systems in the PRA	19.2-2
19.2-2	VEGP 3&4 At-Power Internal Events PRA Results	19.2-3
19.3-1	VEGP Units 3&4 At-Power Internal Flooding PRA Results	19.3-1
19.4-1	VEGP Units 3&4 At-Power Internal Fire PRA Results	19.4-1
19.5-1	VEGP Units 3&4 At-Power Seismic PRA Results	19.5-2
19.6-1	Summary of External Hazards Screening	19.6-1
19.9-1	Summary of VEGP 3&4 At-Power PRA Results	19.9-3
19.19-1	Summary of AP1000 PRA during Shutdown Events Results	19.19-4
19.20-1	Seismic Margin Parameters and HCLPF Values—{HISTORICAL}	19.20-16
19.20-2	Basic Events HCLPF Values—{HISTORICAL}	19.20-18
19.20-3	EQ-IEV-STRUC (EQSTR-02) HCLPF—{HISTORICAL}	19.20-23
19.20-4	EQ-IEV-RVFA (EQRVF-02) HCLPF—{HISTORICAL}	19.20-24
19.20-5	EQ-IEV-LLOCA HCLPF—{HISTORICAL}	19.20-24
19.20-6	EQ-IEV-SLOCA HCLPF—{HISTORICAL}	19.20-25
19.20-7	EQ-IEV-ATWS HCLPF—{HISTORICAL}	19.20-25
19.20-8	Sequence and Plant HCLPF—{HISTORICAL}	19.20-26
19B-1	Not Used	19B-7
19D-1	Definition of Equipment Survivability Time Frames	19D-20
19D-2	AP1000 High Level Actions Relative to Accident Management Goals	19D-21
19D-3	Equipment and Instrumentation Operation Prior to End of Time Frame 1 - Core Uncovery and Heatup	19D-22
19D-4	Equipment and Instrumentation Operation During Time Frame 2 - In-Vessel Core Melting and Relocation	19D-25
19D-5	Equipment and Instrumentation Operation During Time Frame 3 - Ex-Vessel Core Relocation	19D-28
19D-6	Not Used	19D-30
19D-7	Sustained Hydrogen Combustion Survivability Assessment	19D-31
19D-8	Equipment Located Inside Containment (Time Frames T0 and T1)	19D-34
19D-9	Equipment Located Inside Containment (Time Frames T2 and T3)	19D-46
19E.2-1	Evaluation of a Loss of RNS at Mid-Loop With No IRWST Injection	19E-42
19E.4.1-1	AP1000 Accidents Requiring Shutdown Evaluation or Analysis	19E-43
19E.4.8-1	Double-Ended Cold-Leg Guillotine Break – Sequence of Events	19E-45
19E.4.8-2	Loss of Normal Residual Heat Removal System Cooling in Mode 4 and Mode 5 With Reactor Coolant System Intact – Sequence of Events	19E-45
19E.4.8-3	Loss of Normal Residual Heat Removal System Cooling in Mode 5 With Reactor Coolant System Open – Sequence of Events	19E-46
19E.4.8-4–19E.4.8-5	Not Used	19E-47
19E.4.10-1	Sequence of Events Following a Loss of ac Power Flow with Condensate from the Containment Shell Being Returned to the IRWST	19E-48

LIST OF FIGURES

Figure Number	Title	Page
19.16-1	Containment Floodable Region	19.16-7
19.16-2	Containment Floodable Region – Expanded View	19.16-8
19.20-1	Seismic Initiating Event Hierarchy Tree—{HISTORICAL}	19.20-27
19.20-2	Seismic Induced Gross Structural Collapse Event Tree—{HISTORICAL}	19.20-28
19.20-3	Seismic Induced Excessive LOCA Event Tree—{HISTORICAL}	19.20-29
19.20-4	Seismic Induced Large LOCA Event Tree—{HISTORICAL}	19.20-30
19.20-5	Seismic Induced Small LOCA Event Tree—{HISTORICAL}	19.20-31
19.20-6	Seismic Induced ATWS Event Tree—{HISTORICAL}	19.20-32
19.20-7	Seismic Induced LOSP Event Tree—{HISTORICAL}	19.20-33
19B-1	Illustration of Hinging Type of Failure Resulting in Rapid Melt Release	19B-8
19B-2	Illustration of Localized Type of Failure Resulting in Slow Melt Release	19B-9
19B-3–19B-8b	Not Used	19B-10
19E.2-1	Reactor Coolant System Level Instruments Used During Shutdown	19E-49
19E.2-2	IRWST Injection Flow Path	19E-50
19E.2-3	AP1000 Permanent Cavity Seal Ring	19E-51
19E.4.8-1	Mode 3 DECLG Break, Break Flow Rates, Vessel and RCP Sides	19E-52
19E.4.8-2	Mode 3 DECLG Break, Pressurizer Pressure	19E-53
19E.4.8-3	Mode 3 DECLG Break, Upper Plenum Collapsed Liquid Level	19E-54
19E.4.8-4	Mode 3 DECLG Break, Downcomer Collapsed Liquid Level	19E-55
19E.4.8-5	Mode 3 DECLG Break, Core Collapsed Liquid Level	19E-56
19E.4.8-6(a	Mode 3 DECLG Break, Peak Cladding Temperature	19E-57
19E.4.8-6(b	Mode 3 DECLG Break, CMT Liquid Volume	19E-58
19E.4.8-7	Core Outlet Temperature, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-59
19E.4.8-8	Pressurizer Pressure, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-60
19E.4.8-9	RNS Relief Valve Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-61
19E.4.8-10	Pressurizer Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-62
19E.4.8-11	Core Stack Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-63
19E.4.8-12	Downcomer Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-64
19E.4.8-13	CMT to DVI Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-65
19E.4.8-14	CMT Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-66
19E.4.8-15	ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-67
19E.4.8-16	ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-68

LIST OF FIGURES (CONTINUED)

Figure Number	Title	Page
19E.4.8-17	ADS Stage 4 Vapor Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-69
19E.4.8-18	ADS Stage 4 Liquid Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-70
19E.4.8-19	Loop 1 IRWST Injection Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-71
19E.4.8-20	Primary Mass Inventory, Loss of RNS in Mode 4 and Mode 5 with RCS Intact	19E-72
19E.4.8-21	Pressurizer Pressure, Loss of RNS in Mode 4 and Mode 5 with RCS Intact, Manual Safety System Actuation at 1800 Seconds	19E-73
19E.4.8-22	RNS Relief Valve Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact, Manual Safety System Actuation at 1800 Seconds	19E-74
19E.4.8-23	Core Stack Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact, Manual Safety System Actuation at 1800 Seconds	19E-75
19E.4.8-24	Core Outlet Fluid Temperature, Loss of RNS in Mode 5 with RCS Open	19E-76
19E.4.8-25	Pressurizer Pressure, Loss of RNS in Mode 5 with RCS Open	19E-77
19E.4.8-26	Pressurizer Mixture Level, Loss of RNS in Mode 5 with RCS Open	19E-78
19E.4.8-27	ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 5 with RCS Open	19E-79
19E.4.8-28	ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 5 with RCS Open	19E-80
19E.4.8-29	Core Stack Mixture Level, Loss of RNS in Mode 5 with RCS Open	19E-81
19E.4.8-30	Downcomer Mixture Level, Loss of RNS in Mode 5 with RCS Open	19E-82
19E.4.8-31	Loop 2 Hot-Leg Mixture Level, Loss of RNS in Mode 5 with RCS Open	19E-83
19E.4.8-32	ADS Stage 4 Vapor Flow, Loss of RNS in Mode 5 with RCS Open	19E-84
19E.4.8-33	ADS Stage 4 Liquid Flow, Loss of RNS in Mode 5 with RCS Open	19E-85
19E.4.8-34	IRWST Injection Flow, Loss of RNS in Mode 5 with RCS Open	19E-86
19E.4.8-35	Primary Mass Inventory, Loss of RNS in Mode 5 with RCS Open	19E-87
19E.4.10-1	Shutdown Temperature Evaluation, RCS Temperature	19E-88
19E.4.10-2	Shutdown Temperature Evaluation, PRHR Heat Transfer	19E-89
19E.4.10-3	Shutdown Temperature Evaluation, PRHR Flow Rate	19E-90
19E.4.10-4	Shutdown Temperature Evaluation, IRWST Heatup	19E-91

Chapter 19 Probabilistic Risk Assessment

19.1 Introduction

This section presents an overview of the Probabilistic Risk Assessment (PRA) performed for VEGP Units 3&4. The PRA models developed for VEGP Units 3&4 are built upon the generic AP1000® plant PRA model and have been upgraded to the ASME/ANS NRC-endorsed standard (Reference 1) including site-specific information and expanded to evaluate the site seismic hazard. VEGP Units 3&4 PRA models are peer reviewed in accordance with current industry practices, as endorsed by the NRC. Results of the PRA models summarized in this chapter show that VEGP peer reviewed PRA models and results meet the NRC PRA safety goals and the associated regulatory guidance, i.e., as addressed for Regulatory Guide 1.200 (Reference 2) in Appendix 1A. The site-specific detailed risk analyses present the associated core damage frequency (CDF) and large early release frequency (LERF).

The purpose of the AP1000 PRA was to provide inputs to the optimization of the AP1000 design and to verify that the US NRC PRA safety goals were satisfied as part of the design certification process. The purpose of the PRA performed for VEGP Units 3&4 is to assess site-specific risk.

The process of upgrading the generic AP1000 plant PRA to a site-specific PRA included reviewing and evaluating changes to the design, procedures and programs of VEGP Units 3&4 for impact to the PRA. This process captures the differences between the generic AP1000 plant and Vogtle Units 3 and 4.

The upgraded Chapter 19 Section 19.1 through Section 19.10 reflect the VEGP Units 3&4 site-specific PRA. The licensing basis cross-references throughout the Current Licensing Basis excluding these sections continue to refer to the generic AP1000 plant PRA and remain acceptable as the site-specific PRA does not invalidate or change the information contained in these sections. The site-specific PRA is consistent with the described information.

The purpose of this chapter is to focus on the scope and results for the VEGP Units 3&4 plant PRA models for:

- Internal Events (Section 19.2)
- Internal Flood (Section 19.3)
- Internal Fire (Section 19.4)
- Seismic PRA (Section 19.5)
- Other External Hazards (Screening) (Section 19.6)

Section 19.7 discusses the Shutdown Defense-In-Depth (DID) model that qualitatively assess risk in accordance with 10 CFR 50.65(a)(4). Section 19.8 discusses the PRA maintenance and upgrade process used to reasonably reflect the as-built and as-operated plant configurations in the PRA models consistent with regulatory requirements. Section 19.9 discusses the PRA insights, the revised results for internal events, internal flood, internal fire, seismic and other external hazards, and compares the revised results to the Commission's goals for CDF and LERF.

Section 19.10 lists overall references used as part of the standards and guidance used for the Vogtle 3 and 4 site-specific PRA. The standard review plan (Reference 17) was used as the overall justification for References 1 and Reference 2. Section 19.10 also lists a set of industry accepted guidance documents from the NRC, EPRI and ANS which provide the standard of practice for RG 1.200 (Reference 2) recommended peer reviews.

Section 19.11 contains combined license information that has been retained from the generic AP1000 plant PRA. Sections 19.12, 19.13, 19.14, 19.15, 19.16, 19.17, and 19.18 contain severe

accident information that has been retained from the generic AP1000 plant PRA. Section 19.19 contains shutdown evaluation information that has been retained from the generic AP1000 plant PRA. These sections are periodically updated pursuant to UFSAR maintenance regulations. Section 19.20 is retained in Chapter 19 as historical seismic margins analysis information and is not maintained.

19.1.1 Scope

The PRA analysis for VEGP Units 3&4 consists of full-scope Level 1 and Level 2 “at-power” PRA. Detailed PRA models were developed for internal events, internal floods, internal fire, and seismic hazards. Other external hazards were screened from detailed evaluation in accordance with the qualitative and quantitative screening requirements of Part 6 of Reference 1. An expanded discussion of the external hazard screening is presented in Section 19.6.

An exemption from 10 CFR 50.71(h)(1) granted by the NRC on October 26, 2018 (Reference 16) modifies the requirement for the initial PRA for VEGP Units 3&4 to cover those initiating events and modes for which RG 1.200, Rev. 2 (Reference 2), endorses standards. The exemption from 10 CFR 50.71(h)(1) applies to the development of the initial VEGP Units 3&4 Level 1 and Level 2 PRA.

The Level 1 analysis includes:

- Internal initiating events (IEs) evaluation
- Event tree and success criteria analyses
- Plant systems analysis using fault tree models
- Common cause failure and human reliability analyses
- Data analysis
- Quantification to calculate CDF

Level 1 analyses were applied to plant internal events and the following hazards:

- Internal fire
- Internal flooding
- Seismic hazard

Level 1 analyses have been performed in accordance with the ASME/ANS PRA Standard (Reference 1). Reference 1 provides the specific requirements for performing PRAs used to support risk-informed decisions for commercial light water reactor nuclear power plants.

The Level 2 analysis includes:

- An evaluation of severe accident phenomena and fission product source terms
- Modelling of the containment event tree and associated success criteria
- Analysis of hydrogen burning and mixing
- Quantification to calculate LERF

A containment event tree (CET) supported by plant system and phenomenological fault trees are used to calculate the plant large early release frequency and large release frequency.

Level 2 PRA analyses were performed in accordance with the ASME/ANS RA-S-1.2-2014 Trial Use Level 2 Standard (Reference 8). As with Reference 1, Reference 8 provides the specific guidance for performing Level 2 PRAs.

CDF and LERF analyses performed using the above standards have been peer reviewed consistent with the available guidance at the time. (References 3, 4, 5, and 6)

The design certification AP1000 PRA included specific supplemental analyses addressing select risk-related shutdown issues. Shutdown risk assessments were limited to developing and integrating risk insights into deterministic plant operational strategies and were evaluated based on standard engineering practice.

The design certification AP1000 Low-Power Shutdown Evaluation has not been upgraded as part of the development of the VEGP Units 3&4 Level 1 and Level 2 PRA. A defense-in-depth shutdown model was developed to qualitatively assess risk and is managed in accordance with 10 CFR 50.65(a)(4). That effort uses qualitative methods and is adequate to manage risk during shutdown conditions.

The design certification of the AP1000 included an offsite dose evaluation. This offsite dose quantification is bounding for the VEGP Units 3&4 site (Reference 18). Accident offsite doses at the site boundary that could exist in the first 24 hours after a severe accident are either less than 25 rem, or for those releases that are greater than 25 rem, have a frequency of much less than 1E-06.

19.2 Internal Events

The internal events plant model includes: 1) Level 1 quantification of CDF that also supports quantification of Level 2 release categories, 2) use of appropriate models and computer codes accounting for methodology limitations, 3) identification and evaluation of dependencies related to multiple human failure events in the same cutsets, 4) detailed review of the quantification results for reasonableness and identification of significant contributors to CDF and LERF, 5) uncertainty and sensitivity analysis, and 6) detailed documentation of the quantification process and results.

The plant model integrates the accident sequences, system models, data and human reliability analysis (HRA) for each IE group to support evaluation of CDF for each accident sequence. The total mean CDF and LERF was determined using methodology that accounts for plant response in addition to failures in the evaluation of accident sequences, accounts for the state-of-knowledge correlation, and provides detailed importance measures.

Table 19.2-1 provides a list of the front line and support systems addressed within the internal events PRA.

Table 19.2-1 Summary of Systems in the PRA

System in the PRA	Acronym (System - Function)
Passive Core Cooling System - Passive Residual Heat Removal	PXS- PRHR
Passive Core Cooling System - Core Makeup Tanks	PXS - CMT
Passive Core Cooling System - Accumulator	PXS - ACC
Passive Core Cooling System - Automatic Depressurization System	RCS - ADS
Passive Core Cooling System - In-containment Refueling Water Storage Tank	PXS - IRWST
Passive Containment Cooling	PCS
Main and Startup Feedwater System	FWS
Main Steam System	MSS
Condensate System	CDS
Condenser Air Removal System	CMS
Circulating Water System	CWS
Steam Generator System	SGS
Chemical and Volume Control System	CVS
Demineralized Water Treatment System	DTS
Demineralized Water Transfer and Storage System	DWS
Containment Hydrogen Control System	VLS
Normal Residual Heat Removal System	RHR
Component Cooling Water System	CCS
Service Water System	SWS
Central Chilled Water System	VWS
Air-Conditioning, Heating, Cooling, and Ventilation System	VAS, VBS, VES
Non-Class 1E AC Power System	ECS
Class 1E dc & UPS System	IDS
Non-Class 1E dc & UPS System	EDS
Standby Diesel Fuel Oil System	DOS
Containment Isolation	CNS
Compressed and Instrument Air System	CAS
Turbine Building Closed Cooling Water System	TCS
Protection and Safety Monitoring System	PMS
Diverse Actuation System	DAS
Plant Control System	PLS

19.2.1 Internal Events Results

A quantitative internal events PRA of the VEGP Units 3&4 design performed to evaluate plant CDF and LERF for at-power events provided the following results:

Table 19.2-2 VEGP 3&4 At-Power Internal Events PRA Results

	Plant CDF	Plant LERF
Internal Events At-Power	3.94E-07/reactor-year	3.83E-08/reactor-year

19.3 Internal Flood

An internal flooding PRA was performed based on VEGP Units 3&4 site-specific information.

Fluid systems that are potential flood sources were identified for the internal flooding PRA. For these systems, the information on pipe length, pipe diameter and associated flood area was collected. The piping information obtained was used in addition to industry pipe rupture frequency data to quantify the initiating event frequencies for a specific flood source system in a specific room.

Flood source capacity along with door and penetration information were used to identify propagation pathways for each flood scenario to determine impacted PRA-related structures, systems, and components (SSCs).

Flood scenarios were screened and identified for further evaluation. Each of the flood scenarios were characterized by the flood area, flood source, failure mechanism, potential failure modes of the flood source, potential impact on components in the flood area and areas along the propagation path and plant impact. Four distinct failure modes (spray, flood, major flood, high-energy line break (HELB)) were considered in characterizing flood scenarios.

19.3.1 Internal Flood Results

A quantitative internal flooding PRA of the VEGP Units 3&4 design performed to evaluate plant CDF and LERF for at-power events provided the following results:

Table 19.3-1 VEGP Units 3&4 At-Power Internal Flooding PRA Results

	Plant CDF	Plant LERF
Internal Flooding During At-Power Events	2.17E-07/reactor-year	8.40E-08/reactor-year

19.4 Internal Fire

The at-power internal fire PRA was developed following NUREG/CR-6850 and supplemental methodology as endorsed by the NRC. The internal fire PRA analysis was based on the Level 1 and Level 2 release categories from the internal events modified to account for fire specific failures and multiple spurious actuations. The plant fire PRA model includes: 1) Plant Boundary Definition and Partitioning, 2) Component Selection, 3) Cable selection, 4) Qualitative Screening, 5) Fire Risk Model, 6) Ignition Frequency Development, 7) Quantitative Screening, 8) Scoping Fire Modeling, 9) Detailed Circuit Failure Analysis, 10) Circuit Failure Likelihood Analysis, 11) Detailed Fire Modeling, 12) Fire Human Reliability Analysis, 13) Fire Risk Quantification, 14) Uncertainty and Sensitivity Analysis, and 15) detailed documentation of the quantification process and results.

19.4.1 Internal Fire Results

A quantitative internal fire PRA of the VEGP Units 3&4 design performed to evaluate plant CDF and LERF for at-power events provided the following results:

Table 19.4-1 VEGP Units 3&4 At-Power Internal Fire PRA Results

	Plant CDF	Plant LERF
Internal Fire During At-Power Events	8.54E-07/reactor-year	3.42E-07/reactor-year

19.5 Seismic PRA

The VEGP Units 3&4 Seismic PRA (SPRA) follows industry recognized guidance such as References 7, 9, 10, and 11 to estimate the frequencies of core damage and Level 2 release categories. The SPRA assembles the results of the seismic hazard analysis, fragility analysis, and the seismic accident sequence model into a large fault tree including seismic initiating events (ground motion intervals) with separate top events for CDF and Level 2 release categories. The quantification is a convolution of the seismic hazard fragility for each screened in SSCs including contributions of random hardware and human failures to contribute to the CDF and Level 2 results. The convolution is approximated by FRANX software (Reference 12) and the SPRA in general as follows:

- **Hazard Treatment**: Each of the 16 identified intervals is assigned a representative peak ground acceleration (PGA) (geometric mean between the interval lower and upper bounds) and a corresponding occurrence frequency (calculated as the interval lower bound exceedance frequency minus the upper bound exceedance frequency).

- **Fragility Treatment**: The fragility for each SSC is used to calculate the failure probability for each interval (i.e., failure probability at the representative PGA assigned to each interval).

- **Model Logic**: For each interval, the model logic ANDs the seismic initiating event (i.e., the hazard) with the fragility. Solution of the fault tree generates minimal cut sets each containing a seismic initiating event AND fragility event(s). The result is an approximate solution to the hazard convolved with the fragilities.

19.5.1 Seismic Fragility

The seismic fragility evaluation estimates the conditional probability of failure of each screened in SSC. Fragilities for SPRA are expressed in terms of PGA using a double lognormal model with three parameters: median acceleration capacity (A_m), logarithmic standard deviation of the aleatory (randomness) uncertainty (β_R), and logarithmic standard deviation of the epistemic (modeling and data) uncertainty (β_U). β_R and β_U can be combined into a composite variability (β_C) referred to as mean fragility. A high confidence, low probability of failure (HCLPF) capacity is the ground motion level at which there is 95% confidence of at most 5% probability of failure. The fragility parameters are used to develop a complete family of fragility curves for each screened in SSC.

This analysis has been developed in accordance with industry guidance provided in Electric Power Research Institute (EPRI) 3002012994 (Reference 7). The Conservative Deterministic Failure Margins (CDFM) methodology was used as a first step. For components that were risk significant, the fragilities were revised using a Separation of Variables (SOV) approach.

Most fragilities were developed based on the Hybrid approach which uses the CDFM method to generate HCLPF values. The HCLPF capacity is computed, and conservatively biased generic random variability β_R and uncertainty β_U logarithmic standard deviation values are used to estimate the median acceleration capacity, A_m, value. Significant top contributors and SSCs that require a more detailed/refined fragility evaluation are identified through several sets of quantifications and sensitivity studies. The SOV method, which estimates a realistic median acceleration capacity, is employed and corresponding logarithmic standard deviations β_R and β_U for each variable affecting the response and capacity is evaluated.

Fragility estimates for risk significant contributors are calculated realistically, while conservatism is acceptable for fragility estimates associated with components that are not important risk contributors.

The degree of realism (and associated effort) is commensurate with the importance of the fragility estimates in the risk profile. The PRA logic is used through several sets of quantifications and sensitivity studies to identify fragilities that should be further refined. After each quantification and completion of the sensitivity study, important risk contributors were identified, and the fragilities were refined to understand seismic risk insights and identify those components with the highest risk contribution.

19.5.2 Seismic PRA Results

A quantitative Seismic PRA of the VEGP Units 3&4 design performed to estimate plant CDF and LERF for at-power events provided the following results:

Table 19.5-1 VEGP Units 3&4 At-Power Seismic PRA Results

	Plant CDF	Plant LERF
Seismic Events At-Power	6.89E-08/reactor- year	2.83E-08/reactor- year

19.6 Other External Hazards

A qualitative External Hazards Analysis was performed based on the VEGP Units 3&4 site-specific information.

Potential external hazards were identified and evaluated for the Vogtle site to determine if any hazards should be further evaluated in a detailed PRA. The potential hazards evaluation concluded that solar flares and solar storms and electromagnetic interference should be added to the Vogtle site list of potential hazards. In addition to the list of external hazards requiring consideration in the PRA Standard (Reference 1), several other site-specific sources (including industry guidance documents and Vogtle site records) were consulted to ensure the list of hazards considered is complete. The requirements of the ASME/ANS RA-Sa Addendum to PRA Standard (Reference 1) were applied throughout this assessment.

Qualitative screening of external hazards was performed in two (2) parts based on the criteria outlined in SR EXT-B1 and SR EXT-C1 of the PRA Standard (Reference 1). SR EXT-B1 provides a preliminary screen that resulted in eliminating most hazards. Hazards that could not be eliminated based on the criteria of SR EXT-B1 were evaluated against the criteria of SR EXT-C1. SR EXT-C1 screening criteria requires an acceptable basis for bounding analysis or demonstrably conservative analysis for the hazard exists.

The screening results for each hazard considered in the External Hazards analysis are provided in Table 19.6-1.

Table 19.6-1 Summary of External Hazards Screening

ID	External Hazard	Screening Conclusion	
		SR EXT-B1(1) Criteria Applied	SR EXT-C1(1) Criteria Applied
1	Aircraft Impacts	N/A	C
2	Avalanche	3	N/A
3	Biological Events	1, 5	N/A
4	Coastal Erosion	1, 3	N/A
5	Drought	1, 5	N/A
6	External Flooding	1	A
7	Electromagnetic Interference	1	N/A
8	Extreme Winds and Tornadoes	N/A	B, C
9	Fog	1, 4	N/A
10	Forest Fire	1, 3	N/A
11	Frost	1, 4	N/A
12	Hail	1, 4	N/A

Table 19.6-1 Summary of External Hazards Screening (Continued)

ID	External Hazard	Screening Conclusion	
		SR EXT-B1[(1)] Criteria Applied	SR EXT-C1[(1)] Criteria Applied
13	High Summer Temperature	1, 5	N/A
14	High Tide	3	N/A
15	Hurricane	4	N/A
16	Ice Cover	1	N/A
17	Industrial or Military Facility Accident	1	A
18	Internal Flooding	Not Screenable - Full Scope at-power Internal Flooding PRA Performed to Part 3 of the ASME PRA Standard. See Section 19.3	
19	Landslide	3	N/A
20	Lightning	1, 4	N/A
21	Low Lake or River Water Level	1, 5	N/A
22	Low Winter Temperature	1, 5	N/A
23	Meteorite/Satellite Strikes	N/A	C
24	Pipeline Accident	3	N/A
25	Precipitation, Intense	4	N/A
26	Release of Chemicals from On-Site Storage	1	A
27	River Diversion	1	N/A
28	Sandstorm	3	N/A
29	Seiche	3	N/A
30	Seismic Activity	Not Screenable - Full Scope at-power Seismic PRA Performed to Part 5 of the ASME PRA Standard. See Section 19.4	
31	Snow	N/A	C
32	Soil Shrink-Swell	1	N/A
33	Solar Flares or Solar Storms	N/A	C
34	Storm Surge	4	N/A

Table 19.6-1 Summary of External Hazards Screening (Continued)

ID	External Hazard	Screening Conclusion	
		SR EXT-B1[(1)] Criteria Applied	SR EXT-C1[(1)] Criteria Applied
35	Toxic Gas	1	N/A
36	Transportation Accidents	3	A
37	Tsunami	3	N/A
38	Turbine-Generated Missiles	N/A	B, C
39	Volcanic Activity	3	N/A
40	Waves	4	N/A

Notes:
1. Screening criteria SR EXT-B1 and SR EXT-C1 are presented in ASME/ANS-RA-Sa 2009 (Reference 1)

19.6.1 Other External Hazards PRA Results

A quantitative other external hazards PRA of the VEGP Units 3&4 design was not performed to evaluate plant CDF and LERF for at-power events. Application of the screening criteria SR EXT-B1 and SR EXT-C1 demonstrate that the events are either not significant enough to impact the plant or have an acceptable basis for bounding analysis or demonstrably conservative analysis.

19.7 Shutdown Defense-In-Depth

The Shutdown Defense-In-Depth (DID) model was developed following NUMARC 91-06 (Reference 13), EPRI TR-1013501 (Reference 14) and EPRI TR-1016231 (Reference 15) methodology. This qualitative shutdown DID risk assessment is intended to support the requirements of Article (a)(4) of 10CFR50.65. This assessment evaluates the key safety functions applicable to shutdown operating states.

19.8 Maintenance and Upgrade Process

The PRA maintenance and upgrade process is a means to reasonably reflect the as-built and as-operated plant configurations in the PRA models consistent with the regulatory positions on PRA maintenance and upgrades.

PRA upgrades are performed in accordance with applicable requirements and would include incorporation into the PRA model of a new methodology or significant changes in scope or capability that impact the significant accident sequences or the significant accident progression sequences.

PRA maintenance is performed on a regularly scheduled basis. A screening process is used to determine whether a PRA update should be performed promptly based upon the nature of the changes in design or procedures. Changes that do not meet the threshold for prompt update are tracked for the next regulatory scheduled revision. If the screening process determines that the changes do warrant a prompt PRA update, the update is made as soon as practical consistent with the required change importance and the applications being used.

Various information sources are monitored to identify changes or new information that affects the model assumptions or quantification. Plant specific design, procedure, and operational changes are reviewed for risk impact. Information sources include applicable operating experience, plant modifications, engineering calculation revisions, procedure changes, industry studies, and NRC information.

The PRA maintenance and upgrade process incorporates the appropriate new information including any significant modeling errors that may be discovered during routine use of the PRA and modifies the applicable PRA logic models and associated documents. The impact on the risk insights is clearly indicated.

The PRA maintenance and upgrade process is governed by procedures and peer reviews to facilitate PRA quality. The performance of peer reviews conforms with industry peer review guidance.

19.9 Conclusions

19.9.1 PRA Insights

PRA insights refer to the results and findings of the PRA. A synopsis of the insights gained from the PRA about the VEGP Units 3&4 design includes:

- The VEGP Units 3&4 design benefits from the high level of redundancy and diversity of the passive safety-related systems. The passive systems have been shown to be reliable; their designs are simple so that a limited number of components are required to function.
- VEGP Units 3&4 are less dependent on non-safety-related systems than current plants licensed under 10 CFR Part 50 regulations or advanced light water reactor evolutionary plants.
- The nonsafety-related support systems (AC power, component cooling water, service water, and instrument air) have a limited role in the plant risk profile because the passive safety-related systems do not require cooling water or AC power.
- VEGP Units 3&4 are less dependent on human actions than current plants licensed under 10 CFR Part 50 regulations or advanced light water reactor evolutionary plants.
- Single system or component failures are not overly important due to the redundancy and diversity of safety-related systems in the design. For example, the following lines of defense are available for reactor coolant system (RCS) makeup:
  - CVS
  - CMTs with power locked-out from the open CMT balance line inlet isolation MOVs which prevents inadvertent closure of the inlet isolation valves and loss of CMT due to fire-induced hot-short
  - Partial automatic depressurization system in combination with normal residual heat removal
  - Full automatic depressurization system with accumulators and in-containment refuelling water storage tank
  - Full automatic depressurization system with core makeup tanks and in-containment refuelling water storage tank
- Typical current PRA dominant IEs are significantly less important for VEGP Units 3&4. For example, the RCP seal LOCA event has been eliminated as a core damage initiator since VEGP Units 3&4 use sealless reactor coolant pumps. Another example is the LOOP event. The station blackout and loss of offsite power event is a minor contributor compared to legacy plants since the VEGP Units 3&4 passive safety-related systems do not require the support of AC power for 72 hours following loss of offsite power.
- Passive safety-related systems are available in shutdown modes. Planned maintenance of passive features is only performed during shutdown modes when that feature is not risk important. In addition, planned maintenance of non-safety-related defense-in-depth features used during shutdown is performed at power when these systems are less risk important.
- The VEGP Units 3&4 design includes features to contribute to the low likelihood of interfacing system LOCAs between the RNS and the RCS.

- A relief valve located in the common RNS discharge line outside containment provides protections against excess pressure.

- Two remotely operated MOVs connecting the suction and discharge headers to the IRWST are interlocked with the isolation valves connecting the RNS pumps to the hot leg. This prevents inadvertent opening of the two MOVs when the RNS is aligned for shutdown cooling and potential diversion and draining of reactor coolant system.

- Power to the four isolations MOVs connecting the RNS pumps to the RCS hot leg is administratively blocked at their motor control centers during normal power operation.

- The potential for containment isolation and containment bypass is lessened by having fewer penetrations to allow fission product release. In addition, normally open and risk important penetrations are fail-closed, thus eliminating the dependence on instrumentation and controls and batteries for these penetrations.

- The VEGP Units 3&4 Design includes features to enhance the likelihood of retaining the core within the reactor vessel for severe accident sequences. These features include:

  - The depressurization of the reactor coolant system below 150 psi facilitates in-vessel retention of molten core debris

  - Passive containment can withstand severe accidents without PCS water cooling the containment shell. Air cooling alone is sufficient to maintain containment pressure below failure pressure with high probability.

  - Reflooding the reactor pressure vessel through the break can have a significant effect on a severe accident by quenching core debris, achieving a controlled stable state, and producing hydrogen

  - The reactor vessel lower head has no vessel penetrations, thus eliminating penetration failure as a potential vessel failure mode. Preventing the relocation of molten core debris to the containment eliminates the occurrence of several severe accident phenomena, such as ex-vessel fuel-coolant interactions and core-concrete interaction, which may threaten the containment integrity. Therefore, VEGP Units 3&4, through the prevention of core debris relocation to the containment, significantly reduces the likelihood of containment failure.

- The potential for the spreading of fires and floods to safety-related equipment is reduced by the VEGP Units 3&4 layout.

- The design philosophy of minimizing the number of potential flooding sources in safety related areas, along with the physical separation of redundant safety-related components and systems from each other and from nonsafety-related components, minimizes the consequences of internal flooding.

19.9.2 Conclusions

The VEGP Units 3&4 design has evolved over a period of years, including the work done for the AP600 design. PRA techniques have been used since the beginning in an iterative process to optimize the AP600/AP1000 Nuclear Power Plant (NPP) with respect to public safety. Each of these iterations has included:

- Development/refinement of the PRA model
- Use of the model to identify weaknesses

- Quantification of PRA benefits of alternate designs and operational strategies
- Adoption of selected design and operational improvements.

The scope and detail of the PRA model has increased from the early studies as the plant design has matured. This iterative design process has resulted in a number of design and operational improvements. This VEGP Units 3&4 UFSAR revision includes the revised results for the RG 1.200 models for internal events, internal flood, internal fire, seismic and other external hazards. The risk associated with the VEGP Units 3&4 design compares favorably against the Commission's goals of less than 10E-4 per year (/yr) for CDF and less than 10E-5/yr for LERF. The total CDF and LERF for VEGP Units 3&4 during at-power events provide the following results:

Table 19.9-1 Summary of VEGP 3&4 At-Power PRA Results

	Plant CDF	Plant LERF
Internal Events	3.94E-07/reactor-year	3.83E-08/reactor-year
Internal Flood	2.17E-07/reactor-year	8.40E-08/reactor-year
Internal Fire	8.54E-07/reactor-year	3.42E-07/reactor-year
Seismic Events	6.89E-08/reactor-year	2.83E-08/reactor- year
Total During At-Power Events	1.53E-06/reactor-year	4.93E-07/reactor-year

19.10 References

1. ASME/ANS-RA-Sa 2009, “Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications,” American Society of Mechanical Engineers, February 2009.

2. NRC Regulatory Guide 1.200, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities,” Revision 2, March 2009.

3. NEI 00-02, “Probabilistic Risk Assessment (PRA) Peer Review Process Guidance,” Revision A3, Nuclear Energy Institute, March 2000.

4. NEI 05-04, “Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard,” Revision 2, Nuclear Energy Institute, November 2008.

5. NEI 07-12, “Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines,” Revision 0, Nuclear Energy Institute, November 2008.

6. NEI 12-13, “External Hazards PRA Peer Review Process Guidelines,” Revision 0, Nuclear Energy Institute, August 2012.

7. EPRI 3002012994, “Seismic Fragility and Seismic Margin Guidance for Seismic Probabilistic Risk Assessment,” Electric Power Research Institute, Palo Alto, CA: September 2018.

8. ASME/ANS RA-S-1.2-2014, “Severe Accident Progression and Radiological Release (Level 2) PRA Standard for Nuclear Power Plant Applications for Light Water Reactors (LWR), Trial Use and Pilot Application”, American Society of Mechanical Engineers, 2014.

9. EPRI 3002000709, “Seismic Probabilistic Risk Assessment Implementation Guide,” Electric Power Research Institute, Palo Alto, CA: December 2013.

10. EPRI 3002008093, “An Approach to Human Reliability Analysis for External Events with a Focus on Seismic,” Electric Power Research Institute, Palo Alto, CA: December 2016.

11. EPRI 3002012980, “Methodology for Seismically Induced Internal Fire and Flood Probabilistic Risk Assessment,” Electric Power Research Institute, Palo Alto, CA: June 2018.

12. FRANX Software, EPRI, www.EPRI.com.

13. NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management,” December 1991.

14. EPRI TR-1013501, “Qualitative Risk Assessment Methods for Shutdown Risk Management,” Electric Power Research Institute, Palo Alto, CA: November 2006.

15. EPRI TR-1016231, “Development of a Shutdown Qualitative Risk Assessment Standard,” Electric Power Research Institute, Palo Alto, CA: January 2008.

16. Exemptions from the Requirements of 10 CFR 50.71(h)(1) RE: Request for Exemption from Timing of PRA Standards, dated October 26, 2018 (ADAMS Accession Number ML18278A046).

17. NRC Standard Review Plan 19.0 Probabilistic Risk Assessment and Severe Accident Evaluation for New Reactors, Revision 3, December 2015.

18. APP-GW-GL-022, AP1000 Probabilistic Risk Assessment, Westinghouse Electric, LLC, Rev. 8, August 2004 [ML042230497].

19.11 Combined License Information

A review of the differences between the as-built plant and the design used as the basis for the AP1000 seismic margins analysis will be completed prior to fuel load. A verification walkdown will be performed with the purpose of identifying differences between the as-built plant and the design. Any differences will be evaluated and the seismic margins analysis modified as necessary to account for the plant-specific design, and any design changes or departures from the certified design. A comparison of the as-built SSC high confidence, low probability of failures (HCLPFs) to those assumed in the AP1000 seismic margin evaluation will be performed prior to fuel load. Deviations from the HCLPF values or assumptions in the seismic margin evaluation due to the as-built configuration and final analysis will be evaluated to determine if vulnerabilities have been introduced. The requirements to which the equipment is to be purchased are included in the equipment specifications. Specifically, the equipment specifications include:

1. Specific minimum seismic requirements consistent with those used to define the Table 19.20-1 HCLPF values.

   This includes the known frequency range used to define the HCLPF by comparing the required response spectrum (RRS) and test response spectrum (TRS). The test response spectra are chosen so as to demonstrate that no more than one percent rate of failure is expected when the equipment is subjected to the applicable seismic margin ground motion for the equipment identified to be applicable in the seismic margin insights of the site-specific PRA.The range of frequency response that is required for the equipment with its structural support is defined.

2. Hardware enhancements that were determined in previous test programs and/or analysis programs will be implemented.

A review of the differences between the as-built plant and the design used as the basis for the AP1000 PRA and AP1000 DCD Table 19.59-18 will be completed prior to fuel load. The plant-specific PRA-based insight differences will be evaluated and the plant-specific PRA model modified as necessary to account for plant-specific design and any design changes or departures from the design certification PRA.

As discussed in AP1000 DCD Subsection 19.58.3, it has been confirmed that the Winds, Floods and Other External Events analysis documented in AP1000 DCD Section 19.58 is applicable to the site. The site-specific design has been evaluated and is consistent with the AP1000 PRA assumptions. Therefore, AP1000 DCD Section 19.58 is applicable to this design.

A review of the differences between the as-built plant and the design used as the basis for the AP1000 internal fire and internal flood analyses will be completed prior to fuel load. Plant specific internal fire and internal flood analyses will be evaluated and the analyses modified as necessary to account for the plant-specific design, and any design changes or departures from the certified design.

The AP1000 Severe Accident Management Guidance (SAMG) from APP-GW-GLR-070, Reference 19.11-1, is implemented on a site-specific basis. Key elements of the implementation include:

- SAMG based on APP-GW-GLR-070 is provided to Emergency Response Organization (ERO) personnel in assessing plant damage, planning and prioritizing response actions and implementing strategies that delineate actions inside and outside the control room.

- Severe accident management strategies and guidance are interfaced with the Emergency Operating Procedures (EOP's) and Emergency Plan.
- Responsibilities for authorizing and implementing accident management strategies are delineated as part of the Emergency Plan.
- SAMG training is provided for ERO personnel commensurate with their responsibilities defined in the Emergency Plan.

A thermal lag assessment of the equipment required to mitigate severe accidents (hydrogen igniters and containment penetrations) will be performed to provide additional assurance that this equipment can perform its severe accident functions during environmental conditions resulting from hydrogen burns associated with severe accidents. This assessment will be performed prior to fuel load and is required only for equipment used for severe accident mitigation that has not been tested at severe accident conditions. The ability of the equipment to perform during severe accident hydrogen burns will be assessed using the Environment Enveloping method or the Test Based Thermal Analysis method discussed in EPRI NP-4354 (Reference 19.11-2).

As discussed in Subsection 19.20.6.3, it has been confirmed that the Seismic Margin Analysis (SMA) documented in Section 19.20 is applicable to the site. The site-specific effects (i.e., soil-related failure modes, etc.) have been evaluated and it was concluded that the plant-specific plant-level HCLPF value is equal to or greater than 1.67 times the site-specific GMRS peak ground acceleration.

19.11.1 References

19.11-1. APP-GW-GLR-070, "Development of Severe Accident Management Guidance," Westinghouse Electric Company LLC.

19.11-2. "Large Scale Hydrogen Burn Equipment Experiments," EPRI-NP-4354, December 1985.

19.12 Severe Accident Phenomena Treatment

19.12.1 Introduction

This section describes how the AP1000 containment addresses challenges from severe accident phenomena, and how the challenges are evaluated in the AP1000 probabilistic risk assessment (PRA). In the PRA, the Modular Accident Analysis Program (MAAP) version 4.04 code (Reference 19.12-8) is used to evaluate severe accident scenarios. Severe accident phenomenological uncertainties are treated with Risk-Oriented Accident Analysis Methodology (ROAAM) (Reference 19.12-2) phenomenological evaluations, with AP1000-specific decomposition event tree phenomenological evaluations, or with assumptions that certain low-frequency severe accident phenomena fail the containment. The objective of these studies is to show, with a high degree of confidence, that the AP1000 containment will accommodate the effects of severe accidents in a range of scenarios for at least the first 24 hours after the onset of core damage. Such evaluations demonstrate the robustness of the containment design.

19.12.2 Treatment of Physical Processes

The following eight issues are identified in Reference 19.12-1 as being representative of the phenomenological issues pertaining to severe accident conditions:

1. Loss-of-coolant accident (LOCA)
2. Fuel-coolant interaction (steam explosion)
3. Hydrogen combustion and detonation
4. Melt attack on concrete structure or containment pressure boundary
5. High-pressure melt ejection
6. Core-concrete interaction (CCI)
7. Containment pressurization from decay heat
8. Elevated temperature (equipment survivability)

The challenge to the containment integrity from a LOCA blowdown is covered in the containment design basis and is not specifically addressed here. Treatment of physical processes affecting the remaining challenges is discussed in this chapter.

19.12.2.1 In-Vessel Retention of Molten Core Debris

In-vessel retention (IVR) of core debris by external reactor vessel cooling is a severe accident mitigation attribute of the AP1000 design; it is discussed in detail in Section 19.16. With the reactor vessel intact and debris retained in the lower head, phenomena such as molten core-concrete interaction and ex-vessel steam explosion, which occur as a result of core debris relocation to the reactor cavity, are prevented.

The AP1000 reactor vessel insulation and containment geometry promote in-vessel retention. Engineered design features of the AP1000 containment flood the containment reactor cavity region during accidents, and thereby, submerge the reactor vessel in water.

Chapter 39 of the AP1000 PRA presents an AP1000-specific evaluation to determine the likelihood that sufficient heat can be removed from the outside surface of the submerged reactor pressure vessel lower head to prevent reactor vessel failure and relocation of debris to containment. The methodology used to quantify the margin to vessel failure in Reference 19.12-2 for the AP600 was adapted to the AP1000. For the AP1000 the methodology assumes that:

- The RCS is depressurized.
- The reactor vessel is submerged above the 98-ft elevation in the containment.
- The reactor vessel insulation promotes the two-phase natural circulation in the reactor vessel cooling annulus.
- The reactor vessel external surface is bare metal.

The containment event tree includes a node to ascertain that the reactor coolant system (RCS) is depressurized and a node to determine if adequate water is available in the cavity to achieve two-phase natural circulation. Success at both of these nodes is required to demonstrate that the conditions and assumptions of the IVR analysis are met. The AP1000 design specifies that the reactor vessel insulation is designed appropriately and that the outer surface of the reactor vessel promotes wetability.

Accounting for the uncertainties in thermal-hydraulic parameters, the heat fluxes to the vessel wall and reactor vessel internals from the debris pool are calculated. The results show large margin to failure for the reactor vessel if it is externally cooled by water.

19.12.2.2 Fuel-Coolant Interaction (Steam Explosions)

A steam explosion may occur as a result of molten metal or oxide core debris mixing with water and interacting thermally. Steam explosions are postulated to occur inside the reactor vessel when debris relocates from the core region into the lower plenum and in the reactor cavity if the vessel fails and debris is ejected from it into water in the reactor cavity.

19.12.2.2.1 In-Vessel Fuel-Coolant Interaction

In-vessel steam explosions were studied extensively in the AP600 analyses. A ROAAM analysis of the AP600 reactor vessel lower head integrity under in-vessel steam explosion loading is presented in Reference 19.12-3. Typically, in-vessel steam explosion analyses focus on the α-mode containment failure, which is induced by the reactor vessel upper head failure. The ROAAM analysis focused on failure of the lower head since that steam explosion vessel failure mode would impair the in-vessel retention capability of the reactor vessel. The ROAAM analysis concludes that lower-head vessel failure from in-vessel steam explosion is physically unreasonable with very large margin to failure.

Based on the in-vessel core relocation scenario for the AP1000, the in-vessel steam explosion ROAAM analysis presented for the AP600 can be extended to the AP1000. The mass flow rate, superheat and composition of debris in the relocation from the upper core region to the lower head is expected to be essentially the same as the AP600. The geometry of the lower head of the AP1000 is the same as the AP600. Therefore, it is reasonable to extend the results of the AP600 in-vessel steam explosion ROAAM analysis to the AP1000.

The results of the in-vessel steam explosion ROAAM can also be extended to containment failure induced by in-vessel steam explosions (α-mode containment failure). The likelihood for vessel failure and subsequent containment failure due to in-vessel steam explosion is so small as to be negligible.

This conclusion is in agreement with the conclusions of the U.S. Nuclear Regulatory Commission (NRC)-sponsored Steam Explosion Review Group (Reference 19.12-4).

19.12.2.2.2 Ex-Vessel Fuel-Coolant Interaction

The first level of defense for ex-vessel steam explosion is the in-vessel retention of the molten core debris. If molten debris does not relocate from the vessel to the containment, there are no conditions for ex-vessel steam explosion. In the event that the reactor cavity is not flooded and the vessel fails, the PRA containment event tree assumes that the containment fails in the early time frame.

An analysis of the structural response of the reactor cavity was performed for the AP600 (Reference 19.12-5, Appendix B). As in the in-vessel steam explosion analysis, the results of this AP600 ex-vessel steam explosion analysis are extended to the AP1000. The vessel failure modes for AP600 and AP1000 are the same. The initial debris mass, superheat and composition are assumed to be the same as the AP600. The reactor cavity geometry and water depth prior to vessel failure are the same as AP600. Therefore, the results of the AP600 ex-vessel steam explosion analysis are considered to be appropriate for the AP1000.

19.12.2.3 Hydrogen Combustion and Detonation

A decomposition event tree analysis discussed in Section 19.18 evaluates the potential for hydrogen combustion threatening the containment integrity during a severe accident sequence in the AP1000. The analysis examines diffusion flame burning and local detonation occurring during in-vessel hydrogen generation prior to hydrogen mixing in the containment and global deflagration and detonation, which may occur later when the hydrogen is mixed throughout the containment. Only in-vessel hydrogen generation is considered, since vessel failure and ex-vessel debris relocation is assumed to fail containment.

The AP1000 provides defense-in-depth to address hydrogen diffusion flames that may challenge containment integrity. The first level of defense is the stage four automatic depressurization system (ADS Stage 4) lines from the RCS, which prevent significant hydrogen releases to the in-containment refueling water storage tank (IRWST) and Passive Core Cooling System (PXS) compartments. ADS Stage 4 vents from the RCS hot legs to the loop compartments, which are shielded from the containment shell and have a constant source of oxygen from the natural circulation in the containment. Hydrogen can burn as a diffusion flame in the loop compartments without threatening the containment integrity. If ADS Stage 4 fails, the AP1000 has provided design considerations in IRWST vents to mitigate diffusion flames near the containment walls. Vents from the passive injection system compartments and chemical and volume control system compartment are located away from the containment shell and penetrations in order to mitigate the threat from hydrogen diffusion flames.

Containment failure from a directly initiated detonation wave is not considered to be a credible event for the AP1000 containment. There are no ignition sources of sufficient energy to directly initiate a detonation in the AP1000 containment. Deflagration to detonation transition (DDT) is considered to be the only likely mechanism to produce a detonation in the AP1000 containment.

The likelihood of DDT in the AP1000 containment is evaluated locally in confined compartments during in-vessel hydrogen generation and globally after in-vessel generation is concluded and hydrogen is mixed in the containment. For a DDT to occur, the combination of the gas mixture sensitivity to detonation and the geometric configuration potential for flame acceleration must be conducive to DDT. Since the hydrogen concentration necessary to form a detonable mixture depends on the size of the enclosure, concentration requirements for DDT in different regions of the AP1000 containment are extrapolated from the FLAME facility data (Reference 19.12-6) using scaling arguments based on the detonation cell width. The geometric requirement is evaluated considering aspects such as the degree of confinement and the extent and type of obstacles present in the

postulated flame propagation path. In all cases, DDT is assumed to result in containment failure in the containment event tree analysis.

Global hydrogen deflagration and the potential for containment failure are modeled on the containment event tree. Adiabatic, isochoric, complete combustion (AICC) is assumed, and peak pressure probability distributions are developed for the accident scenarios. The probability of containment failure due to hydrogen deflagration is evaluated from the containment failure probability distribution combined with the peak pressure probability distribution.

19.12.2.4 High-Pressure Melt Ejection

The AP1000 incorporates design features that prevent high-pressure core melt. These features include the passive residual heat removal (PRHR) system and the ADS. These design features provide primary system heat removal and depressurization to prevent high pressure core damage conditions. The consequences from postulated high pressure melt ejection (HPME) are mitigated by the containment layout which provides a torturous pathway to the upper compartment, and no direct pathway for the impingement of debris on the containment shell.

In high-pressure core damage sequences the potential exists for creep-rupture-induced failures of the RCS piping at the hot-leg nozzles, the surge line, the steam generator tubes and, given debris relocation to the lower plenum, in the reactor vessel lower head. Failure of the hot-leg nozzle or surge line prior to failures of other components results in the rapid depressurization of the RCS. Failure of the steam generator tubes results in a containment bypass and a large release of fission products to the environment. Failure of the lower head of the reactor vessel results in the potential for HPME.

Hot-leg nozzle failure is expected prior to steam generator tube failure, but because of large uncertainties, hot-leg nozzle creep rupture failure is not credited with preventing steam generator tube failure. In the PRA, steam generator tube failure is assumed for high-pressure sequences in the containment event tree analysis unless operator action to depressurize the RCS with the ADS is successful.

19.12.2.5 Core Debris Coolability

In accident sequences where the reactor pressure vessel failure is not prevented, core debris may be discharged into the reactor cavity. The likely vessel failure modes produce a low pressure melt ejection (LPME) to the containment. The AP1000 cavity design provides area for the core debris to spread. Passive containment cooling system (PCS) heat removal ensures steam condensation on the inside containment shell. This condensate is recirculated back to the reactor cavity to provide a long-term supply of water to cool the core debris.

At vessel failure it is very likely that the cavity will be filled with water from the RCS, core makeup tanks (CMTs), and accumulators to at least the 83-ft elevation. There are significant uncertainties associated with debris spreading into a water-filled cavity. Debris-spreading is mainly a function of the highly uncertain vessel failure mode. A large-scale lower-head failure releasing debris at a high rate would enhance spreading, while a localized failure mode would release debris at a slow rate, which would most likely cause the debris to pile up under the reactor vessel and minimize spreading.

Given the uncertainties in the debris-spreading and in non-condensable gas generation and combustion, the containment event tree analysis does not credit containment integrity in the event of failure of the lower head of the vessel and relocation of the core.

A limited set of deterministic analyses of debris spreading and core-concrete interaction in the AP1000 cavity is presented in Appendix 19B. The analyses show that basemat melt-through is not predicted to occur within 24 hours of the accident initiation. Basemat melt through is predicted to

occur before pressurization of the containment by non-condensable gases challenges the containment integrity.

19.12.2.6 Containment Pressurization from Decay Heat

The AP1000 containment is cooled via the PCS (see Section 19.17). Evaporative water cooling of the containment shell provides long term containment cooling and limits the containment pressure to less than the design pressure for all severe accident events except hydrogen combustion (which is addressed separately). Containment water is provided to the top of the containment via redundant, diverse system of valves and lines, including a line that can be connected to an outside water source, such as a fire truck.

In the unlikely event that water cannot be supplied to the top of the containment shell for an extended period of time, air-only cooling by air flowing through the PCS annulus provides significant cooling to the containment. Under the right environmental conditions, the containment is expected to reach an equilibrium pressure that will not challenge containment integrity. However, under nominal-to-conservative environmental conditions, containment integrity by air-cooling alone cannot be assured. In this case, containment failure is predicted to occur more than 24 hours after accident initiation.

A significant amount of time is available for operator action to vent the containment under the severe accident management guidance (SAMG). Containment venting mitigates uncontrolled releases of fission products from a failed containment. The AP1000 can be vented on an ad-hoc basis under the SAMG from a number of containment penetrations. Containment venting also reduces the partial pressure of non-condensable gases in the containment, and thus creates a new containment underpressure failure mode that may occur if containment is cooled after venting.

19.12.2.7 Elevated Temperatures (Equipment Survivability)

Reference 19.12-7 states that equipment identified as being useful to mitigate the consequences of severe accidents must be designed to provide reasonable assurance that it will continue to operate in a severe accident environment for the length of time needed to accomplish its function. Also, 10 CFR 50.44 requires safety equipment to continue performing its function after being exposed to a containment environment created as a consequence of generating a quantity of hydrogen equivalent to that from 100-percent cladding oxidation. As the AP1000 design uses thermal igniters to burn hydrogen in a controlled manner, it is necessary to demonstrate that the safety equipment can continue to perform its function in the high-temperature environment created by the hydrogen burning.

The functions of the equipment in containment for which credit is taken in the AP1000 PRA were reviewed to determine if the equipment is required to operate in a severe accident environment and beyond design basis limits. The equipment and the basis for operation are the same as the AP600 except for the igniter equipment, which is similar to the AP600. Therefore, the results of the AP600 are extended to the AP1000 for equipment survivability (see Appendix 19D).

19.12.2.8 Summary

The potential for and the consequences of severe accident phenomena are evaluated. The preventive and mitigative features of the AP1000 addressing the severe accident phenomena are discussed. This information is applied to the containment event trees and used in the quantification of the large release frequency.

19.12.3 Analysis Method

The design certification of the AP1000 included consideration by the NRC of the topic referred to in this section.

19.12.4 Severe Accident Analyses

The design certification of the AP1000 included consideration by the NRC of the topic referred to in this section.

19.12.5 Insights and Conclusions

The analyses of the severe accident phenomena for the AP1000 PRA highlight the following insights and conclusions:

- The design of the AP1000 reactor vessel, vessel insulation, and reactor cavity; and the ability to flood the cavity after a severe accident reduce the potential challenges to the containment integrity by maintaining the vessel integrity.
- Should a failure of the reactor vessel occur, the design of the reactor cavity enhances the ability to cool any core debris that exits the vessel.
- Lower head vessel failure due to in-vessel steam explosions is physically unreasonable.
- The ADS and PRHR system are design features that can be used to prevent high-pressure core melt in a severe accident.
- A directly-initiated hydrogen detonation in the AP1000 containment is not a credible event.
- The equipment needed to mitigate the consequences of a severe accident is designed to provide reasonable assurance that it will continue to operate during an accident.

19.12.6 References

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19.12-2. Theofanous, T. G., et al., “In-Vessel Coolability and Retention of a Core Melt,” DOE/ID-10460, July 1995.

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19.12-5. GW-GL-022, AP600 Probabilistic Risk Assessment, August 1998.

19.12-6. Sherman, M. P., Tieszen, S. R., and Benedick, W. B., *FLAME Facility - The Effects of Obstacles and Transverse Venting on Flame Acceleration and Transition to Detonation for Hydrogen-Air Mixtures at Large Scale*, SAND85-1264, Sandia National Laboratories, NUREG/CR-5275, April 1989.

19.12-7. Attachment to letter from D. M. Crutchfield, Office of Nuclear Reactor Regulation, to E. E. Kintner, Advanced Light Water Reactor Steering Committee, “Major Technical and Policy Issues Concerning the Evolutionary and Passive Plant Designs,” dated February 27, 1992.

19.12-8. “EPRI MAAP 4.0 Users Manual.”

19.13 Reactor Coolant System Depressurization

19.13.1 Introduction

Depressurization of the reactor coolant system is required for the external water cooling of the reactor vessel that will prevent vessel failure and core debris relocation to the containment (Reference 19.13-1). If the reactor coolant system (RCS) is at high pressure during core damage, containment failure may be postulated by several severe accident phenomena including induced failure of the steam generator tubes, high-pressure melt ejection, and direct containment heating.

19.13.2 Definition of High Pressure

High pressure is defined to support the assumptions of the PRA model. Induced steam generator tube rupture, high-pressure melt ejection, and reactor vessel failure into the flooded cavity will not occur if there is successful reactor coolant system depressurization.

Vessel failure can occur at elevated pressures with melted core debris in the vessel. This could cause the ejection of core debris from the vessel, followed by entrainment of debris in the high-velocity steam and water blowdown that would follow. Direct containment heating (DCH) and shifting of the reactor vessel are postulated containment failure mechanisms related to high pressure ejection of molten core debris.

Vessel failure and ex-vessel severe accident phenomena are prevented in the AP1000 by external cooling of the reactor vessel when the cavity is flooded. Flooding of the cavity occurs when the in-containment refueling water storage tank (IRWST) water fills the cavity. This can happen because of depressurization and subsequent in-containment refueling water storage tank water injection or when the cavity flood lines on the in-containment refueling water storage tank are opened. This cooling confirms the core debris will remain in the vessel. Heat transfer from the molten debris in the vessel through the lower head will thin the vessel wall and reduce the capability of the vessel to withstand higher pressures. It is conservatively assumed in this analysis that molten core debris in the vessel could cause failure at pressures greater than 150 psig.

If there is no molten core debris in the vessel, the vessel and the rest of the reactor coolant system, including the stream generator tubes, are expected to remain intact at pressures up to 3200 psig. This is consistent with the design of the reactor coolant system primary side.

19.13.3 References

19.13-1. Theofanous, T. G., et al., "In-Vessel Coolability and Retention of a Core Melt," DOE/ID-10460, July 1995.

19.14 Containment Isolation

Containment isolation is required before significant fission-product release after core uncovery. If the containment is not isolated, then the core damage results in a fission-product release to the environment. Containment isolation following an accident is achieved automatically by the protection and safety monitoring system or by the operator as instructed by an Emergency Response Guideline.

19.15 Reactor Vessel Reflooding

Reflooding of the in-vessel core debris will occur following an accident if the reactor coolant system is sufficiently depressurized and if the in-containment refueling water storage tank water can enter the reactor vessel, either through one or both in-containment refueling water storage tank gravity injection lines or through a break in the reactor coolant system.

Successful reflooding of the reactor vessel following an accident that resulted in core damage provides additional cooling to core debris and the vessel wall. It may also have the undesirable effect of leading to the production of hydrogen if water reacts with unoxidized zirconium and molten core debris.

19.16 In-Vessel Retention of Molten Core Debris

19.16.1 Introduction

In-vessel retention of molten core debris through water cooling of the external surface of the reactor vessel is a severe accident management feature of the AP1000. During postulated severe accidents, the accident management strategy to flood the reactor cavity with in-containment refueling water storage tank water and submerge the reactor vessel is credited with preventing vessel failure in the AP1000 probabilistic risk assessment. The water cools the external surface of the vessel and prevents molten debris in the lower head from failing the vessel wall and relocating into containment. Retaining the debris in the reactor vessel protects containment integrity by eliminating the occurrence of ex-vessel severe accident phenomena, such as ex-vessel steam explosion and core-concrete interaction, which have large uncertainties with respect to containment integrity.

The AP1000 provides for in-vessel retention with features that promote external cooling of the reactor vessel:

- The reliable multi-stage reactor coolant system depressurization system results in low stresses on the vessel wall after the pressure is reduced.
- The vessel lower head has no vessel penetrations to provide a failure mode for the vessel other than creep failure of the wall itself.
- The floodable reactor cavity can submerge the vessel above the coolant loop elevation with water intentionally drained from the in-containment refueling water storage tank.
- The reactor vessel insulation provides an engineered pathway for water-cooling the vessel and for venting steam from the reactor cavity.

19.16.2 Background on the Application of In-Vessel Retention to the Passive Plant

The Risk-Oriented Accident Analysis Methodology (ROAAM) analysis of the in-vessel retention phenomena (References 19.16-1 and 19.16-2) provided the basis for the application of the in-vessel retention accident management strategy to the AP600 passive plant and quantification of vessel failure in the AP600 PRA (Reference 19.16-3). The ROAAM included an analysis of the in-vessel melt progression and evaluation of the structural and thermal challenges to the vessel during the relocation to the lower head, including in-vessel steam explosion. Testing and evaluation of the uncertainties associated with the thermal loads produced by the in-vessel circulating molten debris pool, and heat removal limitations due to boiling crisis on the exterior vessel surface were performed in the ACOPO (Reference 19.16-4) and ULPU programs (References 19.16-1 and 19.16-5). The ROAAM concluded that the limiting challenge to the vessel integrity is the thermal loading produced during the steady-state heat transfer to the lower head wall after complete debris relocation to the lower plenum. The in-vessel retention ROAAM analyses and testing showed that the water in the AP600 cavity will remove the heat produced by the molten debris bed in the lower head with significant margin while the structural integrity of the lower head was maintained.

Based on the ROAAM results, vessel failure in the AP600 was considered to be physically unreasonable, and a probability of zero was applied to vessel failure in the AP600 PRA (Reference 19.16-3) if the following conditions of the ROAAM analysis were met:

- The reactor coolant system was depressurized.
- The reactor vessel was submerged sufficiently to wet the heated surface.

- Reactor vessel insulation and containment water recirculation flow paths allowed sufficient ingress of water and venting of steam from the cavity.
- The treatment of the lower head outside surface (painting, coatings, etc.) did not interfere with water cooling of the vessel.

19.16.3 Application of In-Vessel Retention to the AP1000 Passive Plant

To establish a strong basis for crediting in-vessel retention in the AP1000, the following steps are taken:

- Establish design measures to increase the capability of the water to remove heat from the external surface of the reactor vessel (increase critical heat flux).
- Demonstrate that the thermal failure remains the limiting failure over the structural failure for the AP1000.
- Demonstrate that the AP1000 in-vessel melt progression does not change from the AP600 melt progression in such as way as to challenge the vessel integrity during relocation.
- Demonstrate that the heat load correlation, as applied from the ACOPO program (Reference 19.16-4), scales appropriately to the AP1000.
- Quantify the thermal loads using probability distributions developed specifically for the AP1000.

These items are discussed in the following sections.

19.16.4 Reactor Vessel Failure Criteria

The conclusions of the structural analyses performed for the AP600 in Reference 19.16-1 can be extrapolated to the AP1000. Thus, for the AP1000, success of in-vessel retention can be based solely on the thermal success criterion.

19.16.5 In-Vessel Melt Progression and Relocation

The AP1000 core and lower internals geometry has been changed from the AP600 geometry as a result of the higher power output. The core is made up of 157 fuel assemblies with a 14-foot active fuel length. To accommodate the larger reactor core, the thick stainless steel reflector has been replaced by a nominal 1″ thick core stainless steel shroud. The thick bottom plate of the shroud is mounted flush on the support plate. There are no former plates in the annulus between the shroud and the core barrel. The core barrel is 2″ thick and hangs from the upper head flange. Cooling holes through the core shroud provide cooling flow to the shroud from the core flow.

The phenomena associated with melting the core and the relocation of the molten debris to the lower plenum play an important role in the composition and configuration of the debris pool (Reference 19.16-2). In turn, the characteristics of the debris pool significantly impact the heat loading to the lower head wall and the challenge to lower head integrity (Reference 19.16-1). Therefore, understanding the melting and relocation scenarios plays an important role in the assessment of in-vessel retention of molten core debris in the lower plenum.

The important conclusions from the analysis of the lower plenum debris pool formation are:

- The lower plenum debris bed is cooled with water during the entire relocation process prior to contact with the support plate. Transient debris configurations are not predicted to threaten vessel integrity.

- The lower plenum oxide debris subsumes the lower core support plate before dry out in the lower plenum occurs. If the relocated debris is assumed to be instantaneously quenched in the lower plenum water, the oxide debris contacts the lower support plate before the debris can return to a superheated condition. Therefore, the lower core support plate, core shroud and a sizeable fraction of the core barrel are subsumed in the debris bed. The focusing effect is mitigated.

- The lower plenum debris bed is predicted to form a metal layer over oxide pool configuration.

- The potential for debris interaction creating a bottom metal pool of uranium dissolved in zirconium is expected to be small.

- The earliest time to achieve the fully molten, circulating debris bed in the lower plenum is 2.7 hours after event initiation.

19.16.6 Application of Heat Transfer Correlations to the AP1000

19.16.6.1 Debris Pool to Vessel Wall Heat Transfer

The heat transfer from the oxide pool containing the decay heat producing fission products to the lower head of the reactor vessel is described using correlations that were developed in the Department of Energy (DOE) program for the AP600 in-vessel retention assessment.

The correlations developed in the ACOPO experiments and used in the AP600 in-vessel retention ROAAM for heat transfer from the debris pool to the lower head wall are applicable for use in the AP1000 in-vessel retention analysis.

19.16.6.2 Vessel Wall to External Cooling Water Heat Transfer

The heat transfer from the vessel wall to the cooling water is limited by the transition to film boiling at the external surface of the vessel wall. The maximum heat flux that can be removed prior to the transition to film boiling is the critical heat flux. If the heat flux from the debris pool to the wall is less than the critical heat flux, the vessel maintains sufficient strength to carry the load on the vessel. At heat fluxes above the critical heat flux, the external wall temperature increases significantly, the strength of the wall is lost, and the vessel fails.

Testing has been performed with ULPU-2000 Configuration IV (Reference 19.16-4) which demonstrates the feasibility of increasing the critical heat flux for AP1000. The heat removal capability is enhanced by constructing a hemispherical baffle outside the lower head to channel the cooling water flow and by assuring the flooding level in the containment outside the reactor vessel is sufficient for two phase natural circulation (Reference 19.16-4).

The AP1000 employs a reactor vessel insulation design that provides water inlet, steam venting and a baffle around the lower head to enhance the heat removal and increase the critical heat flux on the reactor vessel external surface. The insulation is vented from the annulus between the insulation and vessel to the vessel nozzle gallery at the 98 ft elevation.

19.16.7 Quantification of Heat Load on the Reactor Vessel Wall

With the baffle installed in the AP1000 and the cavity adequately flooded, significant margin-to-failure for in-vessel retention via external reactor vessel cooling is achieved.

Based on the results of the ROAAM testing and analysis and the UPLU-2000 Configuration IV testing, vessel failure is concluded to be physically unreasonable in the AP1000 PRA provided the following conditions are met:

- The reactor coolant system is depressurized.
- The vessel is submerged adequately to promote natural circulation of water through the baffle surrounding the lower head.
- Reactor vessel insulation remains structurally sound under the pressure loads produced by the boiling external to the reactor vessel, allows water inlet at the bottom and venting of steam at the top, and provides the proper baffling to increase the critical heat flux on the external surface of the vessel lower head.
- The reactor vessel external surface conditions do not preclude the wetting phenomena identified as the cooling mechanism in the ULPU testing.

19.16.8 Reactor Coolant System Depressurization

Reactor coolant system depressurization is discussed in Section 19.13.

19.16.9 Reactor Cavity Flooding

Reactor cavity flooding is accomplished through either operator action or through the progression of the accident. The operator floods the cavity by opening a motor-operated valve and a squib valve in the recirculation lines between the in-containment refueling water storage tank and the containment recirculation sump, as shown in Figure 6.3-3. The operator action is prescribed by entering the AFR-C.1 Function Restoration Guideline (Reference 19.16-6) when the core-exit thermocouples reach 1200°F. The water floods the containment by flowing out of the recirculation screens, filling the containment floodable region of the containment, shown in Figure 19.16-1, to at least the 107′ 2″ elevation, shown in Figure 19.16-2.

To achieve the high critical heat flux for the AP1000 lower head, water level in containment must be sufficient for two phase natural circulation flow. The vents from the AP1000 reactor vessel insulation exit to the vessel nozzle gallery at the 98 ft elevation. It is conservatively assumed that the water level in the containment has to reach the 98 ft elevation within seventy minutes after the core exit temperature exceeds 1200°F, for successful vessel cooling.

The AP600 procedures instructed the operator to flood the reactor cavity at the end of AFR-C.1 Function Restoration Guideline before entering the severe accident management guidelines. The AP1000 requires the cavity to be flooded to a higher level and more quickly than the AP600. For the AP1000, the operator action to initiate cavity flooding has been moved to the entry of the AFR-C.1 Function Restoration Guideline to meet the time requirement for cavity flooding success.

19.16.10 Reactor Vessel Insulation Design Concept

With respect to in-vessel retention severe accident management, the goal of the reactor vessel insulation is to ensure that there will always be an adequate water layer next to the reactor vessel to promote heat transfer from the reactor vessel. The insulation will define an optimized flow path next

to the lower head to enhance the critical heat flux. The cooling of the vessel in a severe accident is accomplished by providing:

- A means of allowing water free access to the region between the reactor vessel and insulation.
- A frame that maintains the structural integrity of the insulation surrounding the lower head which provides the baffle for the water flow next to the vessel.
- A means to vent steam generated by the water cooling the vessel wall from the insulation surrounding the reactor vessel.
- A support frame to prevent the insulation panels above the vessel lower head from breaking free and blocking water from cooling the reactor vessel exterior surface.

19.16.10.1 Description of Reactor Vessel Insulation and Venting

Subsection 5.3.5 provides a description of the reactor vessel insulation and the functional requirements for the insulation.

19.16.10.2 Design Analysis of the Insulation and Support Frame

The insulation forms an engineered pathway to enhance the cooling of the external surface of the reactor vessel during in-vessel retention. Structural support to maintain this pathway is provided.

19.16.10.3 Reactor Vessel External Surface Treatment

Based on the reactor vessel system design specification, the surface is not coated and remains as bare metal.

19.16.11 Reactor Vessel Failure

Based on the analysis of in-vessel retention, an intact reactor vessel remains intact if the reactor coolant system is depressurized and the reactor vessel is adequately submerged.

19.16.12 Summary

In-vessel retention of molten core debris via external reactor vessel cooling can be accomplished in the AP1000.

- The reactor vessel insulation must provide a structurally sound baffle around the lower head and lower cylinder of the vessel to channel the flow between the vessel and insulation. An insulation design that provides the proper water inlet, steam venting and flow baffling is specified for the AP1000.
- The reactor cavity must be flooded to an elevation of at least 98 ft prior to the onset of the steady–state heat flux to the vessel wall from the debris to produce the driving head required to enhance the critical heat flux on the vessel surface. The operator action to flood the cavity has been moved to the first step of the emergency operating procedures to provide adequate flooding.

19.16.13 References

19.16-1. Theofanous, T.G., et al., “In-Vessel Coolability and Retention of a Core Melt,” DOE/ID-10460, July 1995.

19.16-2. Theofanous, T.G., et al., “Lower Head Integrity Under In-Vessel Steam Explosion Loads,” DOE/ID-10541, June 1996.

19.16-3. AP600 PRA Report, GW-GL-022, August 1998.

19.16-4. Theofanous, T.G., and S. Angeli, “Natural Convection for In-Vessel Retention at Prototypic Rayleigh Numbers,” Nuclear Engineering and Design, 200, 1-9 (2000).

19.16-5. Angelini, S., et al., “The Mechanism and Prediction of Critical Heat Flux in Inverted Geometries,” Nuclear Engineering and Design, 200, 83-94 (2000).

19.16-6. AP600 Emergency Response Guidelines.

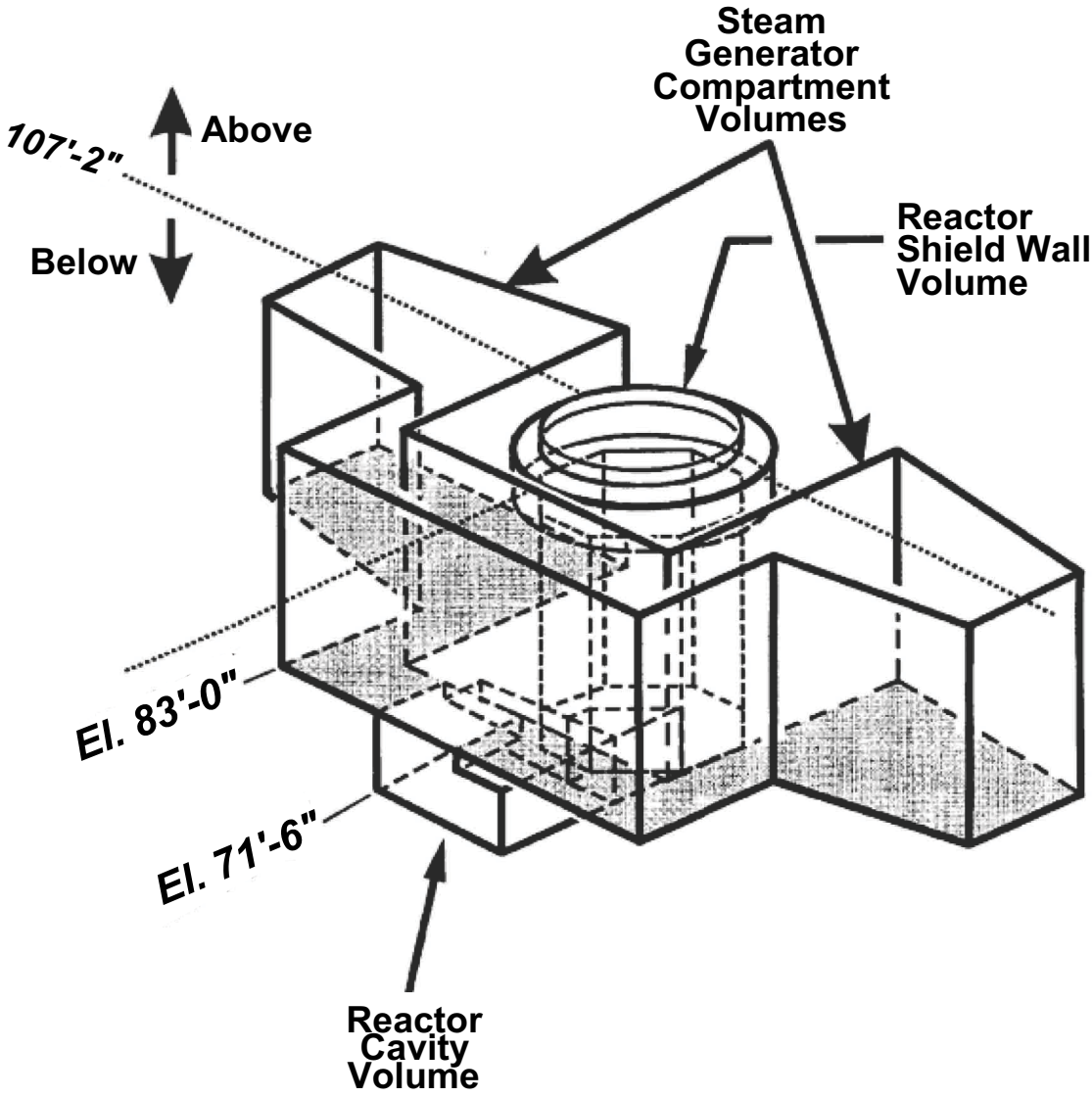

Figure 19.16-1
Containment Floodable Region

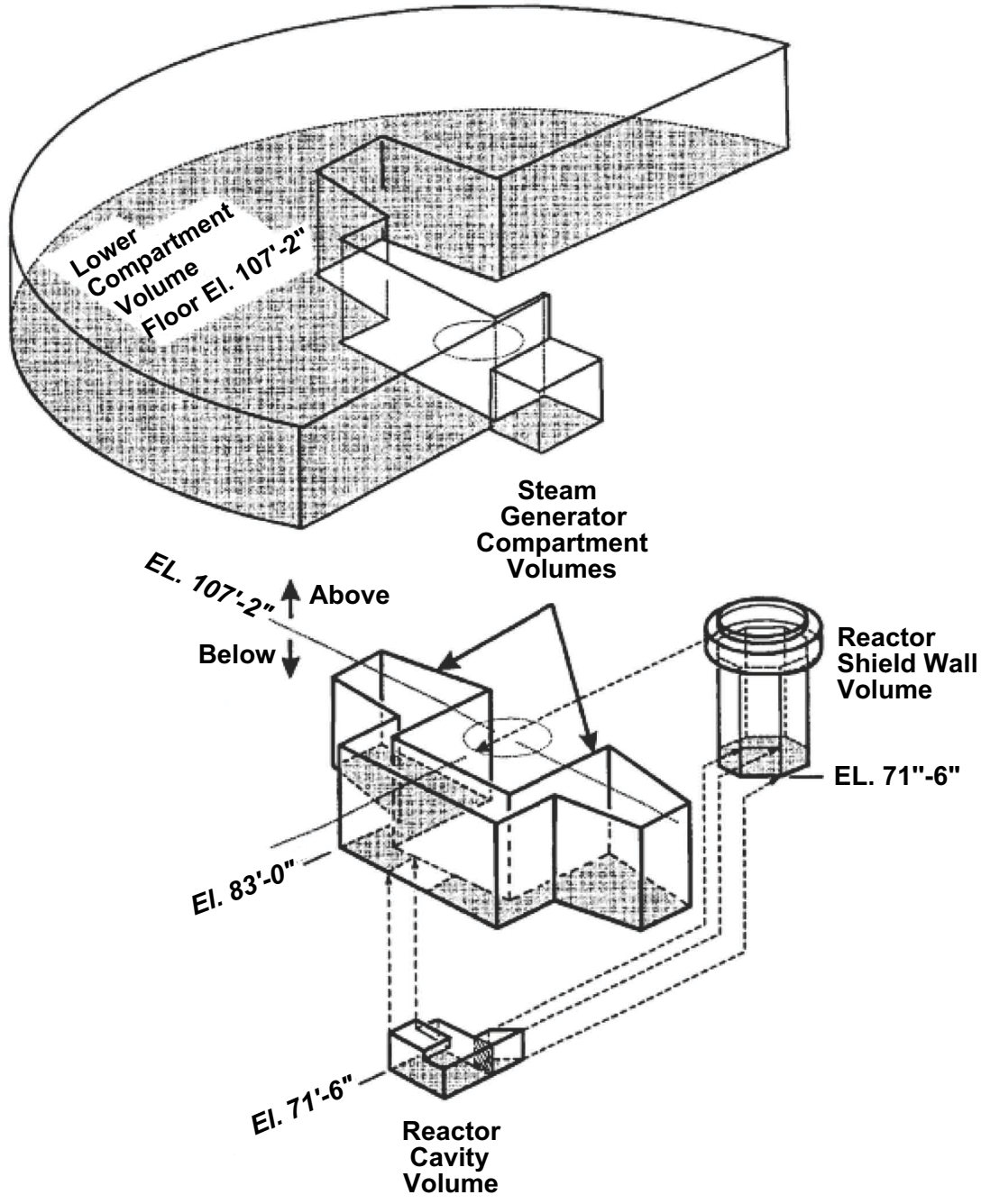

Figure 19.16-2
Containment Floodable Region – Expanded View

19.17 Passive Containment Cooling

The Nuclear Regulatory Commission (NRC) containment performance goal for advanced containment systems is to provide a leak-tight barrier to fission product release for 24 hours following an accident, and to remain as a barrier against uncontrolled releases following that time. The AP1000 containment is cooled via the passive containment cooling system (PCS). Barring hydrogen combustion and ex-vessel phenomena that are addressed elsewhere in the AP1000 containment event tree analysis, the AP1000 containment is not expected to exceed the design-basis pressure during a severe accident. No threat to the containment integrity from long-term overpressurization is predicted.

In the event that design-basis cooling fails, the containment pressure will exceed the design basis, although containment failure within 24 hours is predicted to be highly unlikely. After 24 hours, the operator may vent the containment to prevent uncontrolled failure of the containment per the severe accident management guidelines. Once vented, the steam concentration in the containment will increase and improve the heat removal capacity of the passive cooling such that no further venting would be required.

19.18 Hydrogen Mixing and Combustion Analysis

19.18.1 Introduction

In the course of a severe accident, a substantial amount of combustible gases can be generated in-vessel from the oxidation of the zirconium and other metals. The AP1000 containment is provided with nonsafety-related hydrogen igniters to control the concentration of combustible gases. If the igniters operate, combustion of hydrogen plumes may present a thermal load to the containment. Combustible gas can accumulate in the containment at flammable concentrations if the igniter system fails to function. The AP1000 hydrogen analysis quantifies the threat to containment integrity with and without hydrogen igniters.

If vessel failure does not occur, the amount of hydrogen in the containment is limited to the mass generated during the in-vessel core heatup and relocation. If vessel failure occurs with water in the cavity, an additional amount of hydrogen may be generated from ex-vessel fuel-coolant interactions. Furthermore, if the debris layer in the cavity is not coolable or if insufficient water is available in the containment to cool the debris, and subsequent thermal attack of concrete occurs, additional hydrogen and other combustible gas, such as carbon monoxide, will be generated. The AP1000 PRA assumes containment failure if vessel failure is predicted, so the evaluation of containment integrity from hydrogen combustion only considers in-vessel hydrogen generation.

Hydrogen combustion is evaluated during two time frames: early (during the in-vessel relocation and hydrogen generation) and intermediate (prior to 24 hours after the onset of core damage). In the early time frame, containment challenge is considered from hydrogen burning as an unmixed plume (diffusion flame) and from local detonation at high concentrations in confined compartments below the operating deck. In the intermediate time frame when the hydrogen is mixed, containment challenge from global deflagration and potential detonation due to stratification of gases is considered. The hydrogen is assumed to burn within 24 hours of core damage.

19.18.2 Controlling Phenomena

The conditions required for combustion in the containment are flammable gas mixtures and the presence of an ignition source. Typically, a spark is sufficient to cause ignition. If the mixture temperature is above ~1000 K, auto-ignition can occur without the presence of an ignition source. The flammability limits are determined by the concentrations and temperature of the combustible gas-air-diluent mixture. Hydrogen and the oxygen in the air are the reactants in the combustion reaction. Steam, carbon dioxide, and excess nitrogen in the mixture act as inertants that may inhibit the reaction.

Hydrogen-air-steam mixtures can burn in several modes: diffusion flames, slow and accelerated deflagrations, and detonations (Reference 19.18-1). Burning of an unmixed hydrogen plume near the source results in a diffusion flame. Diffusion flames are stationary and result primarily in thermal loads on nearby structures or equipment. Deflagrations or detonations are burning of premixed gases. In practical terms, a slow deflagration is a flame that travels at a speed much slower than the speed of sound such that the pressure inside the containment equilibrates during the combustion. No dynamic loads are generated. Accelerated deflagrations travel fast enough to generate shock waves and dynamic loads. Detonations travel at supersonic velocities and also generate dynamic loads. The static loads that result from deflagrations can be predicted and bounded. The maximum dynamic loads from accelerated flames and detonations are difficult to calculate.

Standing diffusion flames on the in-containment refueling water storage tank pool or at the in-containment refueling water storage tank vents can be postulated early into an accident following core uncovery for sequences in which the automatic depressurization system stages 1 through 3 provide a primary depressurization mechanism. A standing diffusion flame at the vent could present a

thermal load to the containment steel shell, which is close to some of the vents. If the primary system break is in one of the PXS valve/accumulator rooms which flood with water and submerge the break, diffusion flames can also be postulated at the room exit in the maintenance floor. This location has a direct line of sight with the personnel and equipment hatches, electrical penetrations, and the containment shell, and may present a thermal loading challenge.

The static loads associated with deflagrations are limited by thermodynamics. If all of the chemical energy available in the mixture is converted to temperature and pressure, then the maximum pressure is limited by the adiabatic, isochoric (constant volume), complete combustion (AICC) pressure. The actual pressure would drop over time from this peak because of heat losses to water, structures, and equipment in containment. Dynamic pressure loads are not limited by the adiabatic, isochoric, complete combustion value because the local pressure is due to very rapid, nonequilibrium combustion.

The mode of combustion depends on the mixture concentrations, initial conditions, and boundary conditions (Reference 19.18-1). Near the hydrogen source, hydrogen may not be mixed significantly with the air in the containment. If ignition occurs there, then a diffusion flame may be formed. Further downstream from the hydrogen source, mixing will have occurred and a deflagration or detonation may result, depending on the hydrogen concentration and geometric boundary factors. In some cases, accelerated flames may also develop to detonations, which are called deflagration-to-detonation transition (DDT). The occurrence of flame acceleration and deflagration-to-detonation transition is complex and not completely understood. It is dependent on a number of parameters. These include hydrogen and oxygen concentrations; nature and concentration of inertants; gas temperature and pressure before ignition; ignition source; the size and shape of the compartment in which the combustion occurs; and the number, size, and shape of any obstacles in the compartment.

In AP1000, direct initiation of detonation by sufficiently high-energy sources from equipment in containment is unlikely (Reference 19.18-2: Since AP1000 is very similar to AP600, the phenomenological evaluations are valid for AP1000.), but mechanisms to accelerate a flame to a detonation may occur. Deflagration-to-detonation transition is considered the most likely mechanism. Transition to detonation is considered in several sections of the containment for accident sequences that result in hydrogen concentrations greater than 10 volume percent, including the passage connecting the two steam generator compartments, the core makeup tank and equipment bay, in-containment refueling water storage tank gas space, steam generator compartments, and steam generator operating deck.

19.18.3 Major Assumptions and Phenomenological Uncertainties

Because of phenomenological uncertainties, a number of assumptions are necessary in the hydrogen analysis.

19.18.3.1 Hydrogen Generation

The degree to which the cladding is oxidized during the in-vessel phase of the accident sequence and the availability of water to the core determines the rate and the mass of hydrogen released to the containment during the early time phase. The rate and mass of hydrogen produced are important parameters in determining the hydrogen concentration and the flammability limits of the gas mixtures in the containment compartments.

19.18.3.2 Containment Pressure

The containment pressure is an important parameter in the determination of the pre-burn boundary conditions. A higher initial pressure can result in a higher peak pressure, but the increased steam

mass can inert the mixture and prevent combustion. If the passive containment cooling system water is not operational, containment pressures are elevated and combustion is steam inerted.

19.18.3.3 Flammability Limits

A flammable condition is determined by flammability limits. Flammability limits of a combustible gas mixture are defined as the limiting gas compositions at a given temperature and pressure in which a deflagration will propagate once ignited. There is information on flammability limits of hydrogen-air-steam mixtures at temperatures less than 149°C. For hydrogen, there are two lean propagation limits considered, upward and downward. At lean upward propagation limits, flames will propagate upward because of buoyancy. At lean downward propagation limits, flames will propagate upward and downward throughout the volume by their own reaction kinetics. Hence, the extent of flame propagation (or combustion completeness) for combustion at lean flammability limits is determined by the hydrogen concentration. This relation is a result from the Nevada Test Site (Reference 19.18-3). The addition of steam or other inert gas has a strong effect on the hydrogen concentration and flammability (Reference 19.18-4).

Combustion initiated by igniters occurs at lean upward flammability limits with a small pressure rise. However, with the failure of igniters, combustion at a hydrogen mixture at a concentration above the lean downward propagation limits may result in much larger pressure and temperature consequences. The global burn considered in the analysis is defined as combustion at or above the lean downward propagation limits. This definition includes the possibility that a global burn becomes a detonation, since the occurrence of a detonation requires a hydrogen concentration much above the lean downward propagation limits. Combustion regimes and associated adiabatic, isochoric, complete combustion pressure are approximately demonstrated for hydrogen-air mixtures in Reference 19.18-5.

19.18.3.4 Detonation Limits and Loads

A detonation is a supersonic combustion front that produces a dynamic load in excess of the adiabatic, isochoric, complete combustion value. The energy release from the combustion of the hydrogen-air-steam mixture sustains the shock structure that ignites and burns the mixture. The detonation limits cannot currently be predicted by any first-principles theory. Engineering correlations used to predict the limits have been developed based on a measurable quantity called the detonation cell width. For simplified discussion, the detonation cell width can be considered a characteristic length that describes the sensitivity of the mixture to detonation. The smaller the detonation width, the easier it is to get the mixture to detonate and sustain propagation. Deflagration-to-detonation transition is considered, and the method of NUREG/CR-4803 (Reference 19.18-6) is used to evaluate the potential for flame acceleration.

Since the lowest hydrogen concentration for which deflagration-to-detonation transition has been observed in the intermediate-scale FLAME facility at Sandia is 15 percent (Reference 19.18-7), and 10 CFR 50.44 limits hydrogen concentration to less than 10 percent, the likelihood of deflagration-to-detonation transition is assumed to be zero if the hydrogen concentration is less than 10 percent.

19.18.3.5 Igniter System

The AP1000 nonsafety-related hydrogen igniter system, if operational during a severe accident, will burn hydrogen as soon as the lean upward flammability limits are met. Thus, the concentration of hydrogen is maintained, on average, at the lean upward flammability limits. However, depending on the hydrogen release rate, location and oxygen availability, locally high concentrations may exist in the in-containment refueling water storage tank or in the subcompartment where the pipe break occurs.

The hydrogen igniters are actuated by manual action when core-exit temperature exceeds a predetermined temperature as directed by the emergency response guidelines (ERG). The indication and actuation are done with containment conditions within the equipment qualification limits of the systems used, within the design basis of the plant and systems, and before fission-product releases to the containment, so equipment survivability of the monitoring and actuation systems during the time frame that they are required to perform is supported (see Appendix 19D).

19.18.3.6 Other Ignition Sources

A flammable mixture will not burn without an ignition source unless the temperature of the mixture is sufficiently high (~1000 K) that auto-ignition becomes possible. Hot surfaces or random sparks from equipment or static electricity may be postulated ignition sources. High-temperature gas jets exiting from the reactor coolant system may become an ignition source. However, the gas stream may not have enough momentum to entrain the surrounding flammable mixture, especially in the depressurized cases.

19.18.3.7 Severe Accident Management Actions

Severe accident management guidance that is considered in the AP1000 PRA is the operator action to flood the reactor cavity in the event of core damage. This action often results in the late reflooding of a damaged core due to the time required for the operator to diagnose the problem and take the action. Some events will lead to core reflooding through the natural progression of the accident.

19.18.4 Hydrogen Generation and Mixing

The design certification of the AP1000 included consideration by the NRC of the topic referred to in this section.

19.18.5 Hydrogen Burning at Igniters

Analyses of AP600 demonstrated the effectiveness of the hydrogen igniter system as placed in the passive containment geometry. The cases in the burning analysis were chosen for variation in hydrogen generation rate, release locations into containment, in-containment refueling water storage tank water level, and PXS compartment flooding. The cases considered 100 percent cladding reaction. The behavior of the AP1000 is essentially the same as the AP600 with respect to hydrogen release rates and locations.

Generally, the reactor coolant system is depressurized prior to hydrogen generation. Hydrogen is released to the containment through ADS stage 4 as it is generated in the core. Natural circulation in the containment provides oxygen for burning the hydrogen at the igniters in the loop compartments, close to the source. The loop compartments are shielded from the containment shell and most equipment and instrumentation that would be used to mitigate and monitor the accident.

Igniters located in the IRWST, PXS and CVS compartments, CMT room and at various elevations in the upper compartment provide coverage for hydrogen that may be released through the IRWST, PXS/CVS or in the CMT room.

The igniter system maintains the global uniform hydrogen concentration in the containment at or below lower flammability limits. In the most likely severe accidents, the hydrogen is burned primarily in a favorable location that protects the integrity of the containment and mitigative and monitoring equipment.

19.18.6 Early Hydrogen Combustion

Early hydrogen combustion is defined as burning that occurs during the period the hydrogen is released from the primary system to the containment. During this time, the hydrogen may not be well mixed in the containment and, depending on release locations, may be concentrated in the in-containment refueling water storage tank, PXS valve/accumulator rooms or chemical and volume control system room, steam generator compartments or maintenance floor. If sufficient oxygen is available, the compartments may become locally detonable. If oxygen is not available in the compartment, the plume may travel to a location where oxygen is available and it can burn as a diffusion flame.

19.18.6.1 Hydrogen Generation Rates

Qualitative hydrogen generation characteristics can be inferred from the availability of steam and the availability of overheated, unreacted zirconium in the reactor vessel. Based on the insights from hydrogen generation and mixing analyses, the hydrogen generation can be classified into one of three categories: boiloff generation rate, early-reflood generation rate, and late-reflood generation rate. This section briefly defines each type of hydrogen release in the AP1000 hydrogen analysis and the conditions under which they occur.

19.18.6.1.1 Boiloff Hydrogen Generation

Boiloff hydrogen generation occurs as the water inventory in the reactor vessel is depleted by decay heat. The steam generation is limited to the decay heat boiloff in the covered fraction of the core and overheated, unreacted zirconium surface area is limited to the upper regions of the core, which have not relocated below the water line. Core relocation to the lower head may produce a rapid steam generation that produces a brief period of rapid oxidation, but by this time, the core geometry is lost and very little unoxidized zirconium surface area is available for sustained hydrogen production.

19.18.6.1.2 Early-Reflood Hydrogen Generation

Early-reflood hydrogen generation occurs in the event of the reflooding of an overheated, relatively intact core. Quenching of the core provides a large quantity of steam and a large, overheated, unreacted zirconium surface area for oxidation. Shattering of the cladding due to thermal stresses can enhance the oxidation rate. In the early-reflood case, the oxidation of the zirconium is limited only by the degree of core uncovery prior to the reflood. The rate and degree of zirconium oxidation is expected to be greater than the no-reflood case.

19.18.6.1.3 Late-Reflood Hydrogen Generation

Late-reflood hydrogen generation occurs in the event of a reflood after the core has degraded significantly and possibly after relocation to the lower head. Much of the core geometry is lost and little surface area is available for oxidation, even when steaming from quenching debris is available.

19.18.6.2 Hydrogen Release Locations

The hydrogen release locations in the containment determine the hydrogen mixing in the containment and regions of high hydrogen concentration in the event that the igniters fail. The flow paths from release points in confined compartments to the volumes where oxygen is available determine possible locations where diffusion flames may occur.

19.18.6.2.1 Automatic Depressurization System Stages 1, 2, and 3

Stages 1, 2 and 3 of the automatic depressurization system relieve the reactor coolant system pressure from the top of the pressurizer to the in-containment refueling water storage tank. The water level in the in-containment refueling water storage tank at the time of the release determines the steam concentration in the tank. If the spargers are covered, the steam is quenched out of the gas flow and the hydrogen is released to the gas space of the tank. If the spargers are not covered, the steam concentration is high and will drive the air out of the tank. If the igniters are available, diffusion flames may be postulated at the in-containment refueling water storage tank vent exits for large sustained hydrogen releases. If igniters are not available, the possibility of hydrogen detonation is evaluated.

19.18.6.2.2 Automatic Depressurization System Stage 4

Stage 4 of the automatic depressurization system relieves steam and hydrogen from the hot leg of the reactor coolant system to the steam generator compartments in the containment. The steam generator compartments, along with the maintenance floor and the upper compartment, form the major natural-circulation path in the containment. Oxygen starvation of any potential diffusion flames in the steam generator compartment is not expected for low-pressure hydrogen releases from automatic depressurization system stage 4. The containment shell is sheltered from flames in the steam generator compartments by the concrete walls, so diffusion flames at the igniters in the steam generator compartments are not considered to be a threat to the containment integrity. If igniters are not available, good mixing in the compartment mitigates the threat of detonation for the low-pressure releases.

19.18.6.2.3 Break Location

The reactor coolant system break provides a pathway from the reactor coolant system to one of several compartments in the containment. A failure of a component in the reactor coolant system loop (hot leg or cold leg) will relieve hydrogen to the loop compartment. Hydrogen released from the break to the loop compartment will behave similarly to the hydrogen released from stage 4 automatic depressurization system.

A failure of the direct vessel injection line or a break in the chemical and volume control system piping will relieve hydrogen to one of the small compartments under the maintenance floor, the chemical and volume control system room or one of the two PXS valve/accumulator rooms. These compartments are dead-ended and communicate with the maintenance floor through stairway or room vents. The initial blowdown through the break fills the compartment with steam and drives the air out of the compartment. After the blowdown and reactor coolant system depressurization, countercurrent flow between the compartment and the maintenance floor slowly replenishes the air.

Each of the dead-ended compartments has a one-way drain to the containment sump in the cavity. The break flow into a dead-ended compartment will not fill the compartment with water, as the draining and flashing of the break flow removes the water to the containment sump. However, a broken direct vessel injection line in a PXS valve/accumulator room may allow the in-containment refueling water storage tank to drain into the PXS valve/accumulator room if the injection valves open in the broken line. The draining of the in-containment refueling water storage tank water into the PXS valve/accumulator room will fill the PXS valve/accumulator room and spill water over the curb into the maintenance floor.

If the igniters are available, hydrogen released to the dead-ended compartments during the core degradation may burn initially, but may become oxygen starved. The plume then rises through the stairway to the maintenance floor, which is amply supplied with oxygen by the containment natural circulation. A diffusion flame can be postulated at the exit of the dead ended compartments in the

maintenance floor. The exterior wall of the maintenance floor is the steel containment shell below the passive containment cooling system annulus, the lower-level equipment hatch, and the personnel hatch. Many electrical penetrations pass through the maintenance floor wall to the auxiliary building.

19.18.6.3 Early Hydrogen Combustion Ignition Sources

For a burn to be initiated, an ignition source is required. Igniters mitigate the threat to the containment integrity from global deflagration and detonation. If a hydrogen plume can produce a diffusion flame, the igniters provide the ignition source.

19.18.7 Diffusion Flame Analysis

Diffusion flames can be postulated to occur at vents or exits from compartments with a hydrogen source that are dead-ended or not well-mixed. Incombustible gas mixtures that include a high concentration of hydrogen may develop in the compartment. When the plume of hydrogen exits the compartment into a room containing oxygen and an ignition source, burning of the plume as a standing flame at the vent may produce locally high temperatures. If the release of hydrogen is sustained, the heat load from the burning may threaten equipment, including the containment shell integrity.

The overall geometry of the AP1000 containment is relatively open. Ninety-seven percent of the containment free volume participates in containment natural circulation and is well-mixed. However, the IRWST, PXS and CVS compartments are small, confined rooms that may have a hydrogen source, and thus may be postulated to produce a diffusion flame at vents. This section discusses the conditions that may produce a standing diffusion flame in these locations, and presents the quantification of the containment failure probability given the presence of a sustained diffusion flame at a dead-ended compartment vent.

AP1000 Diffusion Flame Mitigation Strategy

Hydrogen is a byproduct of a severe accident, and hydrogen pathways to the IRWST, PXS and CVS subcompartments cannot be completely ruled out, particularly in the IRWST, to which the effluent of the first stages of the reactor coolant system automatic depressurization system are directed. The other compartments can only have hydrogen releases in the event that a break occurs there, but some of the highest frequency severe accident sequences have breaks in a DVI line, which traverses a PXS compartment. Therefore, the potential for diffusion flames from these subcompartment locations cannot be excluded from the probabilistic risk assessment.

The AP1000 addresses diffusion flames by adopting a defense-in-depth philosophy in the design. In the highest frequency severe accidents, sustained hydrogen release is prevented from occurring in the dead-ended compartments. In sequences where diffusion flames at IRWST or PXS/CVS compartment vents may be postulated, design strategies are initiated to mitigate the threat to the containment integrity by locating hydrogen plumes where they do not challenge containment integrity.

The first level of defense against the threat to containment integrity from diffusion flames is the prevention of sustained hydrogen releases to dead-ended compartments. The highest frequency severe accident sequences have full reactor coolant system depressurization prior to core damage. Hydrogen is released at low pressure to the containment as it is produced in the core. Stage four of the automatic depressurization system provides a pathway of substantially lower resistance (by approximately one order of magnitude) compared to the maximum break size in the DVI line that relieves to the PXS compartment and to the other three ADS stages that relieve to the IRWST. Additionally, the ADS spargers in the IRWST generally have a 10-ft static head of water above them, which further increases the resistance to flow of hydrogen to the IRWST.

Hydrogen released from ADS stage 4 is relieved to the loop compartments, which are supplied with oxygen by the containment natural circulation and shielded from the containment shell by high concrete walls. Hydrogen is able to burn in the loop compartments without threatening the containment integrity. Therefore, ADS stage 4 provides the first level of defense against diffusion flames.

In the event that ADS stage 4 fails to adequately direct hydrogen away from confined compartments, the compartment vents are designed to preferentially release the hydrogen at locations where it burns, but does not challenge containment integrity.

Vents from the PXS and CVS compartments to the CMT room are located well away from the containment shell and containment penetrations. Access hatches to the subcompartments that are near the containment shell are covered and secured closed such that they will not open as a result of a pipe break inside the compartment. Therefore, hydrogen releases to the CMT room from the subcompartments have been shown to not challenge the containment integrity.

19.18.8 Early Hydrogen Detonation

Hydrogen detonation can be initiated from a high-energy ignition source or by deflagration-to-detonation transition during flame acceleration. A review of potential ignition sources in containment concludes that the maximum source is too small to directly initiate a detonation (Reference 19.18-2: Since AP1000 is very similar to AP600, the phenomenological evaluations are valid for AP1000.). Therefore, the occurrence of detonation is related to the potential for deflagration-to-detonation transition in the AP1000 containment analysis.

The methodology of Sherman and Berman (Reference 19.18-6) is used to evaluate the likelihood of deflagration-to-detonation transition. The analysis considers the hydrogen release rates to the containment, core reflooding, the containment release locations, and in-containment refueling water storage tank and PXS valve/accumulator room water levels to determine the probabilities.

19.18.9 Deflagration in Time Frame 3

The design certification of the AP1000 included consideration by the NRC of the topic referred to in this section.

19.18.10 Detonation in Intermediate Time Frame

The design certification of the AP1000 included consideration by the NRC of the topic referred to in this section.

19.18.11 Safety Margin Basis Containment Performance Requirement

The AP1000 containment meets the criteria of the safety margin basis containment performance requirement.

19.18.12 Summary

The major insights of the hydrogen mixing and combustion analysis are as follows:

- No containment failure from hydrogen is predicted if the hydrogen igniters are operational.

- Operation of the stage 4 automatic depressurization system valves releases much of the hydrogen generated in the reactor coolant system to the steam generator rooms where it can be well mixed in the containment to mitigate the threat of diffusion flames from sustained hydrogen released through the in-containment refueling water storage tank.

- The threat of detonation is predominantly due to hydrogen releases to the PXS valve/accumulator rooms below the 107′ 2″ containment elevation (direct vessel injection line breaks). The compartment is a confined region with little ventilation. Equipment and grating are present to promote turbulence. A break in the compartment induces a high-temperature environment creating good conditions for potential deflagration-to-detonation transition.

- The probability of containment failure due to diffusion flame is very small.

- No containment failure is predicted from deflagration.

Analyses are performed to meet the requirements of 10 CFR 50.44. Igniter burning analyses with rapid hydrogen generation and 100-percent cladding reaction conclude that the igniter system maintains the global uniform hydrogen concentration in the containment at or below lower flammability limits. If the stage 4 automatic depressurization system is available, the hydrogen is well mixed in the containment and no excessive concentrations are predicted in the in-containment refueling water storage tank or PXS valve/accumulator rooms. If the stage 4 automatic depressurization system is failed, hydrogen in the in-containment refueling water storage tank and PXS valve/accumulator rooms can reach high concentrations. However, the mixtures are oxygen starved and are not flammable or detonable. The safety margin basis containment performance requirement is met as the loss-of-coolant accident plus 100-percent active cladding reaction hydrogen burn peak pressure provides margin to the ASME Service Level C stress limits.

19.18.13 References

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19.19 Core Damage and Severe Release Frequency from Events at Shutdown

19.19.1 Summary of Shutdown Level 1 Results

As shown by the dominant cutsets of the AP600 and AP1000 shutdown models, the risk profiles of these plants for events during shutdown conditions are almost identical. The results indicate that the three events dominating the CDF are loss of component cooling/service water during drained condition, loss of RNS during drained condition, and loss of offsite power during drained condition. The AP1000 and AP600 initiating event core damage contributions are similar for the two plants.

The dominant sequences are described in the subsections that follow. The dominant accident sequences comprise 95.3 percent of the level 1 shutdown PRA core damage frequency. These dominant sequences consist of:

- Loss of component cooling or service water system initiating event during drained condition with a contribution of 76.7 percent of the CDF
- Loss of RNS initiating event during drained condition with a contribution of 10.4 percent of the CDF
- Loss of offsite power initiating event during drained condition with a contribution of 8.2 percent of the CDF

Loss of Component Cooling or Service Water System Initiating Event During Drained Condition

These sequences are described as the loss of decay heat removal initiated by failure of the component cooling water or service water system during drained condition. The loss of decay heat removal occurs following loss of component cooling water system (CCS) or service water system (SWS) during mid-loop/vessel flange operation, which has an estimated duration of 120 hours per 18 months refueling cycle.

The major contributors to risk due to loss of CCS or SWS during drained condition are the following:

- Hardware failures of both service water pumps or common cause failure of digital input/output modules from the protection and monitoring system (PMS)
- Common cause failure of the ADS 4th stage squib valves
- Common cause failure of the recirculation line squib valves
- Common cause failure of the IRWST injection squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

Loss of RNS Initiating Event During Drained Condition

This sequence is described as the loss of decay heat removal initiated by failure of the RNS during drained condition. The loss of decay heat removal occurs following loss of RNS during mid-loop/vessel flange operation, which has an estimated duration of 120 hours per 18 months refueling cycle.

The major contributors to risk due to loss of RNS during drained condition are the following:

- Common cause failure of the RNS pumps to run
- Common cause failure of the recirculation line squib valves
- Common cause failure of the ADS 4th stage squib valves
- Common cause failure of the IRWST injection squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

Loss of Offsite Power Initiating Event During Drained Condition (with failure of grid recovery within 1 hour)

This sequence is initiated by loss of offsite power during mid-loop/vessel flange operation, which has an estimated duration of 120 hours per 18 months refueling cycle. Following this initiating event, the RNS does not restart automatically, and the grid is not recovered within 1 hour.

The major contributors to risk given loss of offsite power (without grid recovery) are the following:

- Failure of the RNS pump to run or restart
- Failure of the diesel generator to start or run
- Failure of the main breaker to open
- Failure to recover ac power within 1 hour
- Failure of Ovation digital output modules for RNS-V055
- Common cause failure of the ADS 4th stage squib valves
- Common cause failure of batteries IDSA-DB-1A/1B
- Common cause failure to start engine-driven fuel pumps
- Common cause failure of the IRWST injection squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

Loss of Offsite Power Initiating Event During Drained Condition (with success of grid recovery within 1 hour)

This sequence is initiated by loss of offsite power during mid-loop/vessel flange operation which has an estimated duration of 120 hours per 18 months refueling cycle. Following this initiating event, the RNS does not restart automatically, the grid is recovered within 1 hour but manual RNS restart after grid recovery fails.

The major contributors to risk, given loss of offsite power (with grid recovery), are the following:

- Failure of the RNS pump to run or restart
- Common cause failure of the ADS 4th stage squib valves
- Failure of Ovation digital output modules for RNS-V055
- Common cause failure of the recirculation line squib valves
- Common cause failure of the IRWST injection squib valves
- Common cause failure of the strainers in the IRWST tank
- Common cause failure of the recirculation sump strainers

Conclusions

The conclusions drawn from the shutdown Level 1 study are as follows:

- The overall shutdown core damage frequency is very small (1.03E-07/year).

- Initiating events during reactor coolant system drained conditions contribute approximately 95 percent of the total shutdown core damage frequency. Loss of decay heat removal capability (during drained condition) due to failure of the component cooling water system or service water system is the initiating event with the greatest contribution (approximately 77 percent of the shutdown core damage frequency).

- Common cause failures of in-containment refueling water storage tank components contribute approximately 56 percent of the total shutdown core damage frequency. Common cause failure of the in-containment refueling water storage tank valves contributes approximately 45 percent of the total shutdown core damage frequency.

- Common cause failures of the automatic depressurization system stage 4 squib valves contribute approximately 26 percent to the total shutdown core damage frequency. The function of the automatic depressurization system is important to preclude the effects of surge line flooding. This indicates that maintaining the reliability of the automatic depressurization system is important.

- Common cause failures of the containment sump recirculation squib valves contribute approximately 22 percent to the total shutdown core damage frequency. This function is important during drained conditions. This indicates that maintaining the reliability of the recirculation line squib valves is important.

- Human errors are not overly important to shutdown core damage frequency. There is no particular dominant contributor. Sensitivity results show that the shutdown core damage frequency would remain very low even with little credit for operator actions.

- One action, operator failure to recognize the need for reactor coolant system depressurization during safe/cold shutdown conditions, is identified as having a significant risk increase value. This indicates it is important that the procedures include this action and the operators understand and are appropriately trained for it.

- Individual component failures are not significant contributors to shutdown core damage frequency, and there is no particular dominant contributor. This confirms the at-power conclusion that single independent component failures do not have a large impact on core damage frequency for AP1000 and reflects the redundancy and diversity of protection at shutdown as well.

- The in-containment refueling water storage tank provides a significant benefit during shutdown because it serves as a passive backup to the normal residual heat removal system.

19.19.2 Large Release Frequency for Shutdown and Low-Power Events

The baseline PRA shutdown large release frequency (LRF) for AP600 was calculated to be 1.5E-08 per reactor-year, associated with a shutdown CDF of 9.0E-08 per year. The AP1000 LRF is estimated to be 1.72E-08 per year, with the same risk profile as that of AP600 (see Table 19.19-1). This LRF compares well with the AP1000 at-power LRF of 1.95E-08 per year.

19.19.3 Shutdown Results Summary

The results of the low-power and shutdown assessment show that the AP1000 design includes redundancy and diversity at shutdown not found in current plants. In particular, the in-containment refueling water storage tank provides a unique safety backup to the normal residual heat removal system. Maintenance at shutdown has less impact on the defense-in-depth features for AP1000 than for current plants. In accordance with plant technical specifications, safety-related system planned

maintenance is performed only during those shutdown modes when the protection provided by the safety-related system is not required. Further, maintenance of nonsafety systems, such as the normal residual heat removal system, component cooling water system, and service water system, is performed at power to avoid adversely affecting shutdown risk. These contribute to the extremely low shutdown core damage frequency and the low large release frequency.

A quantitative internal events, internal flood, and internal fire PRA of the AP1000 design performed to estimate plant CDF and LRF during shutdown events provided the following results:

Table 19.19-1 Summary of AP1000 PRA during Shutdown Events Results

Events	Core Damage Frequency (per year)	Large Release Frequency (per year)
Internal Events	1.03E-07	1.72E-08
Internal Flood	3.22E-09	5.37E-10
Internal Fire	8.5E-08(1)	1.43E-08
Sum =	1.91E-07	3.20E-08

Note:

1. Internal fire during shutdown is evaluated quantitatively as a response to an NRC question and isnot reported elsewhere in this document.

19.20 {HISTORICAL—Seismic Margin Analysis

19.20.1 Introduction

In accordance with Section II.N, Site-Specific Probabilistic Risk Assessments and Analysis of External Events, of SECY-93-087 (Reference 19.20-1), the U.S. Nuclear Regulatory Commission (NRC) approved the following staff recommendations:

> "PRA insights will be used to support a margins-type assessment of seismic events. A PRA-based seismic margin analysis will consider sequence-level High Confidence, Low Probability of Failures (HCLPFs) and fragilities for all sequences leading to core damage or containment failures up to approximately one and two-thirds the ground motion acceleration of the Design Basis SSE."

The PRA based seismic margin analysis (SMA) and the methodology described in this section is consistent with the recommendation of SECY-93-087.

Seismic margins methodology is employed to identify potential vulnerabilities and demonstrate seismic margin beyond the design-level safe shutdown earthquake (SSE). The capacity of those components required to bring the plant to a safe, stable condition is assessed. The structures, systems, and components identified as important to seismic risk are addressed. For this PRA-based seismic margin analysis, HCLPFs are calculated and reported at the sequence level. In addition, insights related to random and/or human failures are reported, as deemed appropriate, for each sequence.

19.20.2 Calculation of HCLPF Values

19.20.2.1 Seismic Margin HCLPF Methodology

The seismic margin analysis is based on established criteria, design specifications, existing qualification test reports, established basic design characteristics and configurations, and public domain generic data.

The seismic margin assessment is used to demonstrate margin over the SSE of 0.3g. Consistent with SECY-93-087 (Reference 19.20-1), the goal of the SMA is therefore to demonstrate that the plant HCLPF is at least 0.5g peak ground acceleration (pga). This is also called the review level earthquake (RLE). The AP1000 seismic response spectra are included in Tier 1, Chapter 5 (see Tier 1, Figures 5.0-1 through 5.0-4). It will be necessary for a COL (combined operating license) applicant to demonstrate that the seismic response for the applicant's plant is equal to or less than that used in the calculation of the HCLPF values, and to evaluate the potential for soil liquefaction using the applicant's site specific conditions. This will ensure a reserve margin that exceeds a 0.5g seismic level. See Subsection 19.20.6.3.

19.20.2.2 Calculation of HCLPF Values

A seismic margin analysis is made up of two major tasks:

1. A PRA-based model to determine the plant HCLPF
2. Determination of the plant structure and component HCLPFs

The second task, determination of HCLPF seismic acceleration values for plant structures and components, is discussed in this section; the PRA-based model is herein discussed as far as the seismic event trees and major assumptions associated with seismic fault trees development are concerned. The HCLPF values used in the analysis, which now include—HISTORICAL}

{HISTORICAL—HCLPF values for hard-rock, high-frequency sites and soil sites, are summarized in Table 19.20-1.

19.20.2.2.1 Review of Plant Information

The assessment uses the following plant information:

- Structural and seismic design criteria and procedures
- Structural design calculations
- Layout and design drawings
- Test reports
- Piping and instrumentation diagrams
- Equipment design specifications
- Generic fragility data
- AP1000 plant response spectra.

19.20.2.2.2 System Analysis

Section 7.4 provides a discussion of the systems required for safe shutdown. The structures and components associated with these systems are considered in the seismic margin assessment. It is noted that the same success criteria as in the AP1000 PRA sensitivity case where no credit is taken for non-safety related systems, is used as the starting point for the AP1000 PRA-based seismic margins analysis. This success criterion is not necessarily defined in terms of reaching specific plant modes, but rather on reaching a sustainable safe plant state. The bases for these success criteria are given in the AP1000 PRA report (Reference 19.20-5).

19.20.2.2.3 Analysis of Structure Response

The purpose of a seismic fragility analysis is to define the maximum limit, seismic capacity, of functional capability or operability with the associated uncertainty for plant components and structures that could have an effect on safe shutdown of the plant following a seismic event. Capacity in the seismic margin assessment, expressed in terms of the free field peak ground level acceleration, is the level of the seismic event that results in failure of a given component or structure to perform its safety-related function. Failures leading to loss of safety function could result from such things as: loss of a pressure boundary; significant inelastic deformation; partial collapse; loss of support functions; or a combination of failure modes. In the calculation of the HCLPF value for a system, structure, or component, the governing failure mode is established by examining the different potential failure modes possible. Each failure mode has different reserve margin. As an example, ductility may be very large for tension failure, whereas, for buckling, ductility generally does not contribute to reserve margin.

A fragility evaluation is made for the key structures and components. The HCLPF for the equipment and structures is established using one of the following:

- Probabilistic fragility analysis
- Conservative deterministic failure margin (CDFM) method
- Test results
- Deterministic approach
- Generic fragility data

These methods are briefly discussed below.

Probabilistic Fragility Analysis

This method is used to define HCLPF values for structures such as:—HISTORICAL}

- {HISTORICAL—Steam generator supports
- Reactor pressure vessel supports
- Pressurizer supports
- Containment vessel

There are many sources of conservatism and variability in the estimation of seismic peak ground acceleration capacity for seismic margin assessment. HCLPF values reflective of the seismic capacity are derived from median capacity using formulas based on the log-normal distribution. The HCLPF values reflect a 95-percent confidence (probability) of not exceeding a 5-percent probability of failure (Reference 19.20-2).

The HCLPF is defined by a lognormal probability distribution that is a function of median seismic capacity and composite standard deviation, βc:

$$\text{HCLPF} = \text{Median Capacity} \times e^{[-2.3 \times \beta c]}$$

The median seismic capacity is related to the mean seismic capacity by the expression:

$$\text{Median Capacity} = \text{Mean Capacity} \times e^{[-(\beta c \text{\^{}} 2)/2]}$$

The mean peak seismic ground capacity, A_m, is related to the stress and strength design margin factors by the following expression:

$$A_m = (\Pi_i [X_i])A_o$$

where:

A_m = Mean peak seismic ground capacity

X_i = i^{th} design mean margin factor

Π_i = Product notation

A_o = Nominal seismic peak ground capacity

It is noted that the composite standard deviation is equal to the root mean square of the composite standard deviation associated with each of the margin factors. That is:

$$\beta_c = \sqrt{[\Sigma_i (\beta_c)_i^2]}$$

The conservatisms and variability identified and considered in this assessment are associated with stress and strength margin factors. The basic grouping of margin factors are: deterministic strength factor; variable strength factors; material; damping; inelastic energy absorption, ductility; and analysis or modeling error.

Conservative Deterministic Failure Margin Method

The HCLPF values for the shield building and the exterior walls of the Auxiliary Building were calculated using the conservative deterministic failure margin approach. A finite element analysis was performed of the structures that considered cracking of the concrete and redistribution of the loads. Deterministic margin factors were defined for three items: strength; inelastic energy absorption; and damping. —HISTORICAL}

{HISTORICAL—The polar crane HCLPF is calculated using the Westinghouse's design specification of Polar Crane and the vendor structural qualification calculation. The CDFM approach is used allowing the stress to reach yield and using a ductility factor of 1.25.

In addition, the HCLPF values for the Reactor Coolant Pump external heat exchanger and for the Passive Containment Cooling System are calculated with the CDFM approach.

Test Results

For the electrical equipment where documented test results are available, the HCLPF value is defined from comparison of required response spectra (RRS) and test response spectra (TRS). The method employed follows a deterministic approach using existing test data for similar types of equipment.

The existing test data was reviewed to determine a lower bound seismic capacity.

When the natural frequency of the equipment is not known, it was assumed that the natural frequency coincided with the required response spectra peak acceleration so that the lowest HCLPF value was calculated. It is noted that where equipment frequencies are known, and are used for comparing the RRS and TRS, these frequencies will be included in the design specification for the equipment to assure that the dynamic characteristics are the same as those expected.

Relay Chatter

Solid-state switching devices and electro-mechanical relays will be used in the AP1000 protection and control systems. Solid-state switching devices are inherently immune to mechanical switching discontinuities such as contact chatter. Robust electro-mechanical relays are selected for AP1000 applications such that inherent mechanical contact chatter is within the required system performance criteria. Therefore, contact chatter has no effect on system operation and was, therefore, not included in the seismic margin analysis. The COL must confirm the use of seismically robust electro-mechanical relays in the engineered safety features actuation and control systems.

Moreover, the loss of offsite power event has a very low HCLPF value (0.09g). The control rod motor generator sets are powered by AC load centers that are de-energized on loss of offsite power sources. When the control rod motor generator sets are de-energized, current to the magnetic jack mechanisms stops and the gripper coils open, allowing the rods to drop into the core. Therefore, relay chatter is not an issue for reactor trip.

Finally, passive residual heat removal (PRHR) and core makeup tank (CMT) system valves automatically fail open upon loss of instrument air due to loss of seismically induced loss of offsite power. Thus, relay chatter is not an issue for PRHR and CMT system functions.

Deterministic Approach

A lower bound estimate of the HCLPF is obtained for selected structures or equipment based on margin to design limit for the appropriate load combination defined by the fault tree logic. Where applicable, the increased capacity due to inelastic energy absorption is defined using the recognized and recommended ductility factor of 1.25.

This approach was used for the primary components to verify that their supports would control the HCLPF value. It was also used for a few cases to define the HCLPF when it was apparent that its seismic capacity would not control the plant HCLPF value. This approach was used for: containment baffle plate supports; Interior Containment Structure and IRWST; PRHR heat exchanger; core makeup tank; and valves.—HISTORICAL}

{HISTORICAL—**Generic Fragility Data**

Generic fragility data was used when insufficient information was available to define the HCLPF value using one of the methods described above. Those cases where this approach was used were:

- Reactor internals and core assembly that includes fuel
- Control rod drive mechanism (CRDM)
- Reactor coolant pump
- Accumulator tank
- Piping
- Cable trays
- Valves
- Ceramic insulators

The Utility Requirements Document for Advanced Light Water Reactor, Reference 19.20-3, was used for all of the components listed above except ceramic insulators, which used recognized industry low seismic capacity data.

19.20.2.2.4 Evaluation of Seismic Capacities of Components and Plant

Table 19.20-1 provides the HCLPF values for the equipment, structures, and systems considered in the seismic margin evaluation. Also shown in this table is the approach used to define the HCLPF value, as described in Subsection 19.20.2.2.3. The evaluation considers the effect of uplift and sliding of the nuclear island basemat foundation. The nuclear island seismic response has been evaluated at 1.1 times the Review Level Earthquake (RLE) and was found to retain its stability against sliding and overturning.

In the design of the AP1000, careful consideration is given to those areas that are recognized as important to plant seismic risk. In addition to paying special attention to those critical components that have HCLPF values close to the review level earthquake, the design process considers potential interaction with both safety-related and nonsafety-related systems or structures, as well as adequate anchorage load transfer and structural ductility. The seismic margin evaluation provides a means of identifying specific equipment and/or structures that are vulnerable to beyond design basis seismic events.

Equipment qualification is the generation and maintenance of evidence to ensure that safety systems and equipment will operate on demand to meet system performance requirements during normal/abnormal and accident environmental conditions. The methodology for qualification of safety-related electrical and mechanical equipment is defined in Appendix 3D and further expanded for seismic high frequency considerations in Appendix 3I. The intent of the qualification process defined in these Appendixes is to ensure a high reliability for equipment and system safety. Qualification by test, analysis or a combination of test and analysis is performed to verify the safety-related electrical and mechanical equipment will operate as intended under normal/abnormal and accident environmental conditions over the installed life. Details on the qualification process are provided to the equipment vendors in specifications and qualification methodology documents during procurement under a 10CFR50 Appendix B quality assurance program.

19.20.2.2.5 Verification of Equipment Fragility Data

The AP1000 safety-related equipment is designed to meet the safe shutdown earthquake requirements defined in Chapter 3. This seismic margin evaluation has focused on demonstrating that the design of the nuclear island structures, safety-related equipment, and equipment supports can carry the loads induced by the review level earthquake discussed here. This evaluation incorporates as-specified equipment data. After the plant has been built, it will be necessary to perform a verification of the seismic margin assessment for the installed conditions. —HISTORICAL}

19.20.2.2.6 {HISTORICAL—Turbine Building Seismic Interaction

As part of the seismic margin assessment, the seismic interaction between the turbine building and the nuclear island was evaluated according to guidance provided in Reference 19.20-4. It was determined that:

- To protect the adjacent nuclear island auxiliary building the first bay of the turbine building has been classified as seismic category II.
- It is not likely that the size and energy of debris from the turbine building will be large enough to result in penetration through the auxiliary building roof structure.

Even though it is not likely that penetration of turbine building debris could be large enough or have sufficient energy for penetration through the auxiliary building roof structure, this event was evaluated. The consequences of damage to the safety-related equipment in the auxiliary building were investigated. It was determined from this investigation that should an event occur that causes the failure of equipment in the upper elevations of the auxiliary building, the results of the seismic margin assessment, the plant HCLPF value, and the insights derived from the seismic margin assessment are not affected. Moreover, the steam line break events, which would result from the damage of equipment in the upper elevations, are not dominant contributors to the core damage frequency. Further, the loss of equipment in the upper elevations will not affect the passive safety systems that would be used to put the plant in a safe shutdown condition should an event occur.

19.20.3 Seismic Margin Model

In this section, the AP1000 Risk-Based Seismic Margins Model is summarized and the plant HCLPF for AP1000 is determined.

HCLPFs are calculated for the seismic Category I safety-related systems that are called upon via the seismic event trees to mitigate an accident caused by the initiating seismic event.

19.20.3.1 Major SMA Model Assumptions

In this section, the general characteristics and major assumptions of the AP1000 SMA model are discussed.

1. The seismic event is assumed to occur while the plant is operating at full power.
2. A review level earthquake equal to 0.5g is used for the seismic margin analysis.
3. It is assumed that the seismic event would result in loss of offsite power since the AC power equipment is not seismic Category I. (The offsite insulators on the feed lines from the offsite power grid fail such that a loss of offsite power occurs.) No credit is taken for onsite emergency AC power (diesel generators).
4. No credit is taken for non-safety related systems. They are assumed to have failed or be non-functional due to the seismic event. This includes all equipment in the turbine building and the turbine building itself; as discussed in Subsection 19.20.3.3, structural failure of the turbine building is assumed not to impact the structural integrity of the adjacent auxiliary building.
5. The seismically induced SMA initiating event categories and their event trees are taken from the AP600 PRA model. For each initiating event, the PRA logical modeling (i.e., seismic event and fault trees) developed for AP600 structures, systems, and—HISTORICAL}

{HISTORICAL—components have been used as the starting point and their applicability to the AP1000 design has been assessed and confirmed. The applicability of the base AP600 to the AP1000 has been addressed in a supporting calculation. Cutsets associated with each sequence are generated and then the min-max method is used to calculate the plant HCLPF value.

19.20.3.2 Seismic Initiating Events

The first step in Seismic Margins Model is to evaluate which initiating events could occur as a result of a seismic event. For this purpose, a Seismic Initiating Event Hierarchy Tree is constructed. This event tree is given in Figure 19.20-1 and discussed below. Based on this hierarchy event tree, seismic initiating event categories are defined and their event tree models are constructed (as discussed in Subsection 19.20.3.3).

Given that a seismic event occurs, the hierarchy event tree is constructed such that the seismically-induced initiating event with the most challenge to the plant safety systems is considered first: gross structure collapse. This category is labeled as EQ-STRUC and is the first initiating event category to be modeled and quantified.

If gross structure collapse does not occur, next the reactor coolant system (RCS) loss-of-coolant-accident (LOCA) category in excess of emergency core cooling system (ECCS) capacity (also termed as “Vessel Failure”) is considered. This category is labeled as EQ-RVFA.

If vessel failure does not occur, then large RCS LOCAs are considered. This category is labeled as EQ-LLOCA.

If EQ-LLOCA does not occur, then small RCS LOCAs are considered. This category is labeled as EQ-SLOCA. Steam generator tube rupture (SGTR) and large secondary line break (SLB) events are folded into the small LOCA category, as discussed in Subsection 19.20.3.3.

Next considered is the seismically induced anticipated transient without scram (ATWS) event. This event is labeled as EQ-ATWS.

Finally, all other transients are considered in the category labeled EQ-LOSP. The seismically induced LOSP event occurs at low HCLPF values (e.g., lower than the SSE at 0.3g) and does not affect the plant HCLPF, as discussed in Subsection 19.20.4.2. The cutsets for this event are all “mixed cutsets,” containing seismically induced initiating event coupled with random failures leading to core damage. This event is included in the model for additional insights and completeness.

Thus, the hierarchy tree defines six initiating event categories. Each of these is discussed and an event tree for each is constructed in Subsection 19.20.3.3.

The PRA-based seismic margins analysis does not consider seismic hazard curves. Therefore, initiating event frequencies are not calculated for each seismically generated initiating event category. Although seismically generated initiating event frequencies are not calculated, it is important to evaluate the seismic vulnerability of the components and systems that contribute to the initiating event categories. This is done by estimating a HCLPF for each seismic initiating event category, as discussed in Subsection 19.20.3.3.—HISTORICAL}

19.20.3.3 {HISTORICAL—**Seismic Event Trees**

The six seismically induced initiating event categories defined by the hierarchy event tree model of Subsection 19.20.3.2 are further discussed to model seismically induced failures that will determine the HCLPF for each of these initiating events. The six categories considered are:

1.	EQ-STRUC	Gross structural collapse
2.	EQ-RVFA	LOCA in excess of emergency core cooling system capacity
3.	EQ-LLOCA	Large LOCA
4.	EQ-SLOCA	Small LOCA
5.	EQ-ATWS	ATWS
6.	EQ-LOSP	Loss of offsite power

The small LOCA category also covers SGTR and SLB events. As discussed later in the success paths, the SLOCA success path used for SMA is also applicable (conservatively) to the SGTR and unisolated SLB events given that only safety-related systems are credited and considered in the PRA-based SMA.

The last event, LOSP, is postulated at 0.09g. This event may also be viewed to represent a larger family of transients associated with loss of main feedwater, loss of compressed air, turbine trip, reactor trip, loss of service water/component cooling water, etc, following a seismic event and LOSP since no credit is taken for these non-safety systems in the SMA models. Moreover, a seismically induced transient containing LOSP, becomes a station blackout (SBO) event since no credit is taken for diesel generators that are not seismically qualified.

Each of the SMA events are further discussed below.

1. EQ-STRUC (Gross Structural Collapse)

   This event includes seismically induced failures of AP1000 structures that may result in core damage and large fission product release.

   The AP1000 structures are classified in 5 groups:

   1. Nuclear Island

      This consists of the containment, shield building, and auxiliary building.

      Nuclear island is structurally designed to meet seismic Category I.

   2. Turbine Building

      The first bay (the portion of the turbine building adjacent to the nuclear island outlined in Table 3.2-2 and including the portion of the basemat under this area) of the turbine building is classified as Seismic Category II, and the main area of the turbine building structure is designed to meet the International Building Code. For the SMA model, it is assumed to have failed. Thus no credit is taken for systems in this building.—HISTORICAL}

3. {HISTORICAL—Annex Building

   The high rise portion of the annex building is designed to meet seismic Category II. For the SMA model, it is assumed to have failed. Thus, no credit is taken for systems in this building.

4. Diesel Generator Building

   The diesel generator building is designed to meet the UBC. For the SMA model, it is assumed to have failed. Thus, no credit is taken for systems in this building.

5. Radwaste Building

   The radwaste building is designed to meet the UBC. For the SMA model, it is assumed to have failed. Thus, no credit is taken for systems in this building.

Thus, only the nuclear island is considered for the SMA model; the interaction between the other buildings and the nuclear island is assumed to have no detrimental effect on the nuclear island structures. This assumption needs to be verified by a plant walkdown when an AP1000 plant is built.

The failures of the nuclear island structures are modeled in terms of the driving structures of the steel containment vessel, the shield building, and the auxiliary building.

The EQ-STRUC event tree is shown in Figure 19.20-2; HCLPF value for EQ-STRUC is calculated in Subsection 19.20.4.

2. EQ-RVFA (LOCA in Excess of ECCS Capacity)

   This event represents the “vessel failures” where the event leads to excessive loss of RCS inventory that can not be made up by the ECCS capacity. In this case, core damage is postulated. A complete dependency between seismic induced failures of SSCs that share basic characteristics (i.e., component type, location/elevation, etc.), the “vessel failure” event comprises the following types of structural and component failures:

   1. Seismically induced failures of the reactor vessel
   2. Seismically induced failures of the steam generators
   3. Seismically induced failures of the other RCS components
   4. Seismically induced failures of two direct vessel injection (DVI) lines
   5. Seismically induced failures of fuel.

   The EQ-RVFA event tree is shown in Figure 19.20-3; HCLPF value for EQ-RVFA is calculated in Subsection 19.20.4.

3. EQ-LLOCA (Large LOCA)

   Seismically induced large LOCA initiating event category, EQ-LLOCA, contains RCS breaks with break sizes greater than 9 inches. Since the seismic event failures assume that if one pipe breaks by a seismic event, all redundant similar pipes will break at the same time, all major RCS pipe breaks are conservatively included in this category; thus, no medium LOCA is defined in the initiating event hierarchy tree. Also included in this category are the failures of the PRHR heat exchanger by a seismic event.

   The EQ-LLOCA event tree is shown in Figure 19.20-4; HCLPF value for EQ-LLOCA is calculated in Subsection 19.20.4.—HISTORICAL}

4. {HISTORICAL—EQ-SLOCA (Small LOCA)

Seismically induced small LOCA initiating event category, EQ-SLOCA, contains RCS breaks with break sizes less than 2 inches of equivalent diameter. Since the seismic event failures assume that if one pipe breaks by a seismic event, all redundant similar pipes will break at the same time, all major RCS pipe breaks are conservatively included in the large LOCA category. For the small LOCA category, RCS leaks from instrument lines are used as the representative event. The small LOCA category also includes and bounds events such as

- Steam Generator Tube Rupture (SGTR)
- Large Steam Line Breaks (SLB) (due to generation of S signal and RCS inventory shrinkage)

For SGTR events, breaks of one or more (up to 5) tubes have been considered for the AP1000 design. An event with 5 steam generator tubes rupturing has an equivalent LOCA break flow area of a 1.46 inch diameter hole. The rupture of more than 5 tubes by a seismic event is conservatively bounded by the structural failure of a steam generator, which is included in the EQ-RVFA initiating event.

Due to the modification of the Reactor Coolant Pump (RCP) Heat Exchanger (HX) from the AP600 design to the AP1000 design, an additional entry is added to the seismic induced Small LOCA. This reflects the possibility that in the event of a RCP HX pipe break, a small LOCA will be induced. Flow from the RCS inventory will be restricted by the labyrinth seal surrounding the RCP motor shaft; tolerances on the labyrinth seal allow for a maximum flow area of $1.389 in^2$. This corresponds to approximately a 1.3 inch pipe break. A postulated seismic induced break of all eight tubes does not change the equivalent break flow rate for each pump and when considering the break in all pumps, a total of approximately 2.7 inch pipe break equivalent LOCA needs to be considered. This is judged to be consistent with the definition of seismically induced small LOCA given above.

The EQ-SLOCA event tree is shown in Figure 19.20-5; HCLPF value for EQ-SLOCA is calculated in Subsection 19.20.4.

5. EQ-ATWS (Anticipated Transients without Scram)

The EQ-ATWS event addresses the seismically induced ATWS initiating event related to the failure of the core assembly or guide tubes or the control rod drive systems to remain functional so that the rods can not fall into the core. The fuel is still intact and can be cooled. The failure mode associated with seismically induced fuel failure has been already addressed in EQ-RVFA event.

Because offsite power is postulated to have been lost, the control rod motor generator sets would be de-energized even if the reactor trip function failed. If the core assembly or the control rod system failed, the rods are postulated to fail to insert into the core.

The EQ-ATWS event tree is shown in Figure 19.20-6; the HCLPF value for EQ-ATWS is calculated in Subsection 19.20.4.

6. EQ-LOSP (Loss of Offsite Power)

The EQ-LOSP event addresses the seismically induced loss of offsite power. This event occurs at relatively low intensity earthquakes. The driving failure for loss of offsite power is represented by failure of ceramic insulators in the switchyard. The HCLPF value for these—HISTORICAL}

{HISTORICAL—insulators is 0.09g, which is lower than the review level earthquake of 0.5g, and the plant SSE of 0.3g. Such an earthquake does not challenge any of the safety-related systems that are built to withstand the SSE and have margin for higher g levels. Thus, this event does not lead to purely seismically driven failure combinations for a core damage sequence. This event model contains only "mixed cutsets" for core damage; these are failure combinations of seismically induced initiating event coupled with random failures of safety-related systems.

The EQ-LOSP event tree is shown in Figure 19.20-7; this event does not contribute to plant HCLPF.

19.20.3.4 Seismic Fault Trees

System fault trees for mitigation functions have been modified to account for seismically-induced failures. The AP600 system seismic fault trees have been reviewed for applicability to the AP1000 and only limited and minor changes have been deemed necessary.

19.20.4 Calculation of Plant HCLPF

This section presents the SMA calculations based on the model developed in Subsection 19.20.3.

The initiating event HCLPFs are calculated in Subsection 19.20.4.2. The plant HCLPF is calculated in Subsection 19.20.4.3.

The analysis demonstrates that all structures and components required to maintain the plant in a safe stable state are expected to function following a seismic event of 0.5g acceleration.

19.20.4.1 HCLPFs for Basic Events

The HCLPF values for various AP1000 structures and components were determined in a supporting calculation and are given in Table 19.20-1. The basic events defined in the SMA model for seismic failures are assigned their own HCLPF values, as shown in Table 19.20-2. These HCLPF values are taken from Table 19.20-1. When not self-evident, the "Source" column in Table 19.20-2 explains how the information Table 19.20-1 has been used.

For reasons beyond the development of the PRA-based AP1000 SMA, Table 19.20-1 groups all the electrical equipment into two major categories: "Non-Sensitive to High Frequency Excitation" and "Sensitive to High Frequency Excitation". For the purposes of the PRA-based SMA, all electrical equipment has been assumed to be from the limiting categories among the two, which has an HCLPF value of 0.5; this assumption is for the purposes of this analysis only and is conservative for this purpose.

19.20.4.2 Calculation of Initiating Event HCLPFs

Initiating event HCLPFs are calculated by assigning the HCLPF values from Table 19.20-2 to the seismically induced failures modeled in Subsection 19.20.3.3 for initiating events. The HCLPF associated to the initiating events will be the minimum among those for each of the potential initiator; the results of these calculations are given in Tables 19.20-3 through 19.20-7; results are presented for the AP1000 before and after this modification for DCD Revision 17. EQ-IEV-LOSP is already assigned a HCLPF 0.09g, representing the failure of ceramic insulators but it does not contribute to plant HCLPF since it has only mixed cutsets (seismic and random failures combined in cutsets).—HISTORICAL}

{HISTORICAL—The initiating event HCLPFs are summarized below:

Initiating Event	HCLPF	Dominated by
EQ-IEV-STRUC	0.55g	Polar crane
EQ-IEV-RVFA	0.50g	Fuel and pressurizer failure
EQ-IEV-LLOCA	0.81g	RCS piping
EQ-IEV-SLOCA	0.54g	Steam generator tube failure
EQ-IEV-ATWS	0.50g	Core assembly failures
EQ-IEV-LOSP	0.09g	Ceramic insulator failure

When the min-max method is used, the HCLPF of seismic sequences resulting from an initiating event can not be less than the initiating event HCLPF since it appears in every cutset. If the initiating event is postulated to lead directly to core damage, the IE HCLPF is used in the determination of the plant HCLPF.

Since both EQ-STRUC and EQ-RVFA events are postulated to lead to core damage, and EQ-STRUC is postulated to go to large early release as well, plant HCLPF can be determined at this point to be at least 0.50g for core damage and at least 0.55g for large, early release consequences.

19.20.4.3 Calculation of AP1000 Plant HCLPF

The final AP1000 plant HCLPF calculation also considers the mitigation portion of the PRA logic. Even though this is not going to change the values identified in Subsection 19.20.4.2, the complete calculation provides further insights on the seismic margin of the AP1000 design.

All basic events in the AP1000 SMA model (listed in Table 19.20-2) are assigned a dummy probability value of 0.5; the model is then quantified and cutsets are generated. The min-max approach is then applied to the obtained cutsets at each failure sequence level to evaluate the sequence HCLPF value, the event tree HCLPF value and the overall plant HCLPF value.

The cutset generated from the SMA model are listed and analyzed through the min-max approach discussed above in a supporting calculation. Sequence level results are presented in Table 19.20-8 where also the plant level HCLPF value is presented.

19.20.5 Sensitivity Analyses

A 99% confidence associated with the test response spectra is expected for all the HCLPF extracted from tests (method [6] in Table 19.20-1). To address this expectation a sensitivity case was run to the AP1000 PRA-based SMA.

Since electrical equipment is tested and qualified to the SSE (i.e., 0.30g), the HCLPF values in Table 19.20-1 for all tested equipment are set to 0.3g. While the selected values are extremely conservative due to the engineering margins normally adopted for the qualification tests, such values would not change either the overall AP1000 plant HCLPF value or any sequence or event tree level HCLPF value.

The Polar Crane HCLPF value dominates the plant level HCLPF for the Gross Structural Collapse initiating event. Therefore, the fragility analysis of the polar crane was performed using both CDFM and PRA-based fragility analysis. It was demonstrated that the calculated HCLPF values from these two methods are above 0.5g and have a difference of less than 5%.—HISTORICAL}

19.20.6 {HISTORICAL—Results and Insights

19.20.6.1 AP1000 SMA Results

The AP1000 PRA-based SMA has demonstrated that for structures, systems, and components required for safe shutdown, the HCLPF magnitudes are equal to or greater than 0.50g. This HCLPF is determined by various structures, systems, and components with an HCLPF value of 0.5g.

Thus, the AP1000 plant can meet or exceed the requirement to withstand a review level earthquake of 0.5g. It is observed that electrical equipment qualification consistent with the Certified Seismic Design Response Spectra (CSDRS) at 0.3g (with a 99% confidence associated to the Test Response Spectra – TRS) supports the overall plant HCPLF value of 0.5g.

The success paths used for the SMA are taken conservatively in many cases, and credit for operator actions for events at 0.5g review level earthquake has been avoided. Thus, the results are valid without operator intervention, which indicates a strong point of the AP1000 design to mitigate seismically induced core damage and large release sequences.

All SMA sequences are evaluated with loss of offsite power and loss of onsite AC power leading to a station blackout event. The plant design is shown to be robust against seismic event sequences each of which contain station blackout coupled with other seismic or random failures.

19.20.6.2 AP1000 SMA Insights

The SMA results also point out the following insights:

1. Design Features

   The AP1000 design provides some aspects that make the plant more robust against the review level earthquakes. Namely:

   - Reactor trip is ensured without the actuation signal due to the loss of offsite power occurring and rods inserting by gravity.
   - PRHR system valves fail open without actuation signal following loss of power/loss of instrument air. Thus, PRHR cooling is immediately available.
   - CMT system valves fail open without actuation signal following loss of power/loss of instrument air. Thus, CMT injection is immediately available.

   Thus, three key mitigating systems, reactor trip, PRHR cooling, and CMT injection are available with high confidence and low probability of failure, without dependence on actuation signals immediately after a review level seismic event.

   Moreover, the passive containment cooling system air operated valves also fail open in a review level earthquake, due to loss of offsite power/instrument air. As a result, the passive containment cooling system is automatically actuated and has enough water inventory to last for 72 hours.

2. DC System Fragility

   Control rods, PRHR, CMT, and passive core cooling systems would be operational after potential loss of protection and safety monitoring system (PMS) or DC control power. Thus, the plant can successfully mitigate a transient event even with a failure of PMS or DC control power. However, the DC control power system HCLPF is the same as the plant HCLPF (0.50g).—HISTORICAL}

{HISTORICAL—This HCLPF has the potential to become a driving failure, if it were to be coupled with a LOCA event with low HCLPF. However, no such low HCLPF LOCA events are identified in the current model.

3. Importance of Valve Room Fragilities

   Fragility of certain valve rooms, where the passive core cooling system valves are concentrated, becomes an important factor; the SMA model depends on the successful functioning of these valves to mitigate LOCA accidents. These rooms are labeled as 11206/11207 and contain CMT, accumulator, IRWST injection, and cavity recirculation valves. Since the HCLPF of these rooms is relatively high, compared to the plant HCLPF value, the seismic failure of many passive core cooling system valves does not become a contributor to plant HCLPF.

4. Operator Actions

   Operator actions are not credited in the SMA model for the 0.50g review level events. Inclusion of operator actions in the models would provide additional success paths, such as manual actuation of the automatic depressurization system (ADS) after failure of CMTs to inject. However, this inclusion would not affect the plant HCLPF or the major conclusions of the SMA. Thus, the AP1000 design is already robust with respect to its response to seismic events, even without taking credit for operator actions.

5. IRWST Failure

   This failure is modeled to render PRHR, gravity injection, and recirculation systems inoperable. Thus, it becomes a single point failure that affects both the transient (e.g. LOSP events) and LOCA success paths. Failure of IRWST is modeled as a part of gross structural failure, as well as in PRHR and gravity injection system fault trees. The IRWST HCLPF is 0.71g and therefore significantly above the plant level HCLPF.

   Additionally, an argument can be made that when the IRWST fails, its inventory would end up in the containment cavity and can be used to recirculate cavity water back into the RCS, leading to successful core cooling. Although this scenario is plausible and credible, such success sequences (e.g. sequences where gravity injection is skipped, directly going into cavity recirculation) are not analyzed in the AP1000 PRA. For this purpose, no credit for such a success path is taken in the present model.

6. Large Fission Product Release

   The large fission product release is driven by the same seismic sequences that dominate the plant core damage. This is due to either the nature of the initiating event (such as gross structural failure initiating event, EQ-STRUC), or postulated containment failure following a reactor vessel failure (RVFA) (such as EQ-RVFA initiating event or some ATWS sequences leading the RVFA). Failure of containment isolation or containment cooling system due to their system components or system actuation failures does not dominate the plant large release HCLPF.

19.20.6.3 Site Specific Seismic Margin Analysis

The VEGP GMRS exceeds the AP1000 CSDRS over certain frequency ranges. Site-specific seismic soil-structure interaction analyses of the AP1000 Nuclear Island (NI) using the VEGP GMRS ground motion and VEGP soil profile demonstrated that the resulting VEGP in-structure response spectra (ISRS) at the six key locations are enveloped by the AP1000 CSDRS broadened ISRS by a significant margin except for minor exceedances at very low frequency ranges. These slight exceedances have been shown to have no impact on the NI structures, systems,—HISTORICAL}

{HISTORICAL—and components. Therefore, the Tier 1 criteria for SSE have been satisfied. This evaluation is presented in Section 3.7. In regards to seismic demand for the NI structures, systems, and components, it can be concluded that the Seismic Margin Assessment analysis documented in Section 19.20 is applicable to the VEGP site.

For seismic stability of the NI with regards to sliding and overturning, it was demonstrated that VEGP NI margins against sliding and overturning were greater than the limiting margins calculated for the standard AP1000 design cases. For seismic stability, it can be concluded that the Seismic Margin Assessment analysis documented in Section 19.20 is applicable to the VEGP site.

For site specific conditions relating to soil-related failure modes, the demonstration of adequate seismic margin of the AP1000 design at the VEGP site is performed for a review level earthquake of 1.67 x VEGP GMRS, where the VEGP site-specific review level earthquake seismic responses and seismic loads are defined as 1.67 x VEGP GMRS seismic responses and seismic loads.

Potential for soil liquefaction was evaluated at 1.67 x VEGP GMRS which produces a peak ground acceleration of 0.44g. The liquefaction potential factor of safety was found to be high such that liquefaction potential was screened out as a contributor to design-specific plant-level HCLPF capacity. Similarly, bearing pressure capacity to demand still demonstrated sufficient margin so this potential failure mode was screened out as a contributor to design specific plant-level HCLPF capacity.

19.20.7 References

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19.20-2. Budnitz, R. J., et al., "An Approach to the Quantification of Seismic Margins in Nuclear Power Plants," NUREG/CR-4334, UCID-20444, August 1985.

19.20-3. Advanced Light Water Reactor Utility Requirements Document, Volume III, ALWR Passive Plant, Chapter 1, Appendix A, PRA Key Assumptions and Groundrules, Revisions 5 & 6, Issued December 1993.

19.20-4. "A Methodology for Assessment of Nuclear Power Plant Seismic Margin," Electric Power Research Institute, EPRI NP-6041, October 1988.

19.20-5. APP-GW-GL-022, Revision 8, AP1000 Probabilistic Risk Assessment, Westinghouse Electric, LLC, August 2004 [ML042230487].—HISTORICAL}

Table 19.20-1 (Sheet 1 of 2)
Seismic Margin Parameters and HCLPF Values—{HISTORICAL}

Description	Median pga[1]	βc	HCLPF Value[1]	Basis
Buildings/Structures				
Shield Building – Tension Ring	-	-	0.73	[2]
Shield Building – Air Inlet	-	-	0.71	[2]
Shield Building – Conical Roof	-	-	0.71	[2]
Shield Building – PCS Tank	-	-	0.81	[2]
Shield Building – SC/RC Connection	-	-	>0.67	[2]
Shield Building – RC Cylindrical Wall	-	-	0.67	[2]
Steel Containment Vessel – Buckling	1.94	0.42	0.73	[3]
Steel Containment Vessel – Overturning	5.74	0.62	1.38	[3]
Containment Baffle – Support Failure	-	-	0.91	[4]
Interior Containment Structure & IRWST Tank	-	-	0.71	[4]
Exterior Walls of Auxiliary Building – Wall 1	-	-	0.97	[2]
Exterior Walls of Auxiliary Building – Wall 11	-	-	0.88	[2]
Primary Components				
Reactor Pressure Vessel	-	-	0.56	[4]
Reactor Pressure Vessel Supports	1.58	0.35	0.71	[3]
Reactor Internals and Core Assembly (includes fuel)	1.5	0.51	0.5	[5]
Control Rod Drive Mechanism (CRDM)	2.2	0.51	0.7	[5]
Steam Generator	-	-	0.54	[4]
Steam Generator Support Column Buckling	1.14	0.33	0.54	[3]
Steam Generator Lower Lateral Support	1.23	0.34	0.57	[3]
Steam Generator Intermediate Supports	1.17	0.30	0.59	[3]
Pressurizer	-	-	0.58	[4]
Pressurizer Upper Support Weld[10]	1.02	0.31	0.50	[3]
Pressurizer Upper Support Strut	1.11	0.29	0.56	[3]
Pressurizer Lower Support Strut	1.41	0.29	0.72	[3]
Reactor Coolant Pump[9]	2.2	0.51	0.68	[5]
Reactor Coolant Pump Heat Exchanger[9]	-	-	0.55	[2]
Mechanical Equipment				
Polar Crane	-	-	0.55	[2]

Table 19.20-1 (Sheet 2 of 2)
Seismic Margin Parameters and HCLPF Values—{HISTORICAL}

Description	Median pga[1]	βc	HCLPF Value[1]	Basis
Piping – Support Controlled	3.3	0.61	0.81	[5]
Cable trays – Support Controlled	2.2	0.61	0.54	[5]
Accumulator Tank	2.2	0.46	0.76	[5]
Core Make Up Tank	-	-	0.87	[4]
Heat Exchanger (PRHR)	-	-	1.11	[4]
Valves				
Higher than El. 100′	3.3	0.61	0.81	[5]
Equal to or Lower than El. 100′	-	-	1.02	[4]
Passive Containment Cooling System	-	-	0.67	[2]
Electrical Equipment				
Non-Sensitive to High Frequency Excitation	-	-	0.5	[6]
Sensitive to High Frequency Excitation	-	-	0.52	[6]
Ceramic Insulators[7]	0.2	0.35	0.09	[8]

Notes of Table 19.20-1:

[1] pga is the free field peak ground acceleration level for the seismic event.
[2] HCLPF based on conservative deterministic fragility margin approach.
[3] HCLPF based probabilistic fragility analysis.
[4] HCLPF based on deterministic approach.
[5] HCLPF based on URD recommended generic fragility data.
[6] HCLPF based on design margin, code requirements and test margins inherent to the seismic qualification testing. Qualification testing with 99% confidence on the TRS will be limited to 0.3g.
[7] The capacity of the ceramic insulators is less than the review level earthquake of 0.5g. The failure of the ceramic insulators is considered in the PRA analysis.
[8] HCLPF based on recognized generic fragility data
[9] Both the Reactor Coolant Pump Support and Reactor Coolant Pump External Heat Exchanger HCLPF values are controlled by Steam Generator Support.
[10] The HCLPF value of the Pressurizer Upper Support Weld is calculated as 0.6 g using conservative deterministic failure margin method. The value of 0.5 g in the table is used in the PRA/SMA and is more conservative.

Table 19.20-2 (Sheet 1 of 5)
Basic Events HCLPF Values—{HISTORICAL}

BE ID	BE Description	HCLPF (g)	Source
EQ-AB-EXTWALL	Failure of Auxiliary Building Exterior Wall	0.88	Exterior walls of auxiliary building, limiting values between *wall 1* and *wall 11*
EQ-AB-FLOOR	Failure of Auxiliary Building Floor	0.88	Same as auxiliary building exterior wall
EQ-AB-INTWALL	Failure of Auxiliary Building Interior Wall	0.88	Same as auxiliary building exterior wall
EQ-ACC-CV28	Accumulator Check Valves 28A and 28B Fail	1.02	In rooms 11206/11207, below elevation 100′
EQ-ACC-CV29	Accumulator Check Valves 29A and 29B Fail	1.02	In rooms 11206/11207, below elevation 100′
EQ-ACC-TANKS	Accumulator Tanks Fail	0.76	
EQ-ACDISPANEL	120 Volt AC Distribution Panels Fail	0.5	Limiting value among those provided for electrical equipment
EQ-ADS-S1MOVS	ADS Stage 1 MOVs RCS-PL-V001A/B and RCS-PL-V011A/B Fail	0.81	In rooms 11603/11703, above elevation 100′
EQ-ADS-S2MOVS	ADS Stage 2 MOVs RCS-PL-V002A/B and RCS-PL-V012A/B Fail	0.81	In rooms 11603/11703, above elevation 100′
EQ-ADS-S3MOVS	ADS Stage 3 MOVs RCS-PL-V003A/B and RCS-PL-V013A/B Fail	0.81	In rooms 11603/11703, above elevation 100′
EQ-ADS-S4VALVES	ADS Stage 4 Squib Valves 4A/B/C/D Fail	0.81	In rooms 11301/11302, above elevation 100′
EQ-BAF-SUPP	Failure of Containment Baffle Support	0.91	
EQ-BAT-RACK	Battery Racks Fail	0.5	Limiting value among those provided for electrical equipment.
EQ-BATTERY	250 Vdc Batteries Fail	0.5	Limiting value among those provided for electrical equipment.

Table 19.20-2 (Sheet 2 of 5)
Basic Events HCLPF Values—{HISTORICAL}

BE ID	BE Description	HCLPF (g)	Source
EQ-CABINETS	PMS Cabinet Fail	0.5	Limiting value among those provided for electrical equipment.
EQ-CABLETRAY	Cable Trays Fail	0.54	
EQ-CAS-AOV-1415	Containment CAS Isolation Valves AOV 14 and 15 Fail	0.81	In rooms 12405/11400, above elevation 100′
EQ-CER-INSULATOR	Seismically induced failure of ceramic insulators	0.09	
EQ-CMT-AOV	CMT AOV 14A/B and 15A/B Fail by Seismic Event	1.02	In rooms 11206/11207, below elevation 100′
EQ-CMT-CV	CMT CV 16A/B or 17A/B Fail by Seismic Event	1.02	In rooms 11206/11207, below elevation 100′
EQ-CMT-LEVELSWT	CMT Level Switch Fails	0.5	Limiting value among those provided for electrical equipment.
EQ-CMT-TANKS	CMT Tanks Fail by Seismic Event	0.87	
EQ-CONTPR-SENSOR	Containment Pressure Sensor or Transmitter Fails	0.5	Limiting value among those provided for electrical equipment.
EQ-CORE-ASSEMBLY	Failure of Core Assembly	0.5	
EQ-CRDM	Failure of Control Rod Drive Mechanism	0.7	
EQ-CV-BUCKLE	Containment Vessel Buckling	0.73	
EQ-CV-INTER	Failure of the Interior (concrete) Structure of Containment	0.71	
EQ-CV-OVERT	Containment Vessel Overturning	1.38	
EQ-DCDISPANEL	250 Vdc Distribution Panel Fails	0.5	Limiting value among those provided for electrical equipment.
EQ-DCMCC	DC Motor Control Centers Fail	0.5	Limiting value among those provided for electrical equipment.

Table 19.20-2 (Sheet 3 of 5)
Basic Events HCLPF Values—{HISTORICAL}

BE ID	BE Description	HCLPF (g)	Source
EQ-DC-SWBRD	250 Vdc Switchboard Fails	0.5	Limiting value among those provided for electrical equipment.
EQ-DVI-PIPES	Seismically Induced Failure of Both DVI Lines	0.81	
EQ-ELECTRONICS	PMS Electronic Fail	0.5	Limiting value among those provided for electrical equipment.
EQ-INSTR-PIPES	Failure of RCS Instruments Lines	0.81	
EQ-INVERTER	250 Vdc Inverters Fail	0.5	Limiting value among those provided for electrical equipment.
EQ-IRW-INJCV	IRWST Injection CV 122A/B and 124A/B Fail by Seismic Event	1.02	In rooms 11206/11207, below elevation 100′
EQ-IRW-INJSQ	IRWST Injection Squib Valves 123A/B and 125A/B Fail by Seismic Event	1.02	In rooms 11206/11207, below elevation 100′
EQ-IRW-RECCV	Sump Recirculation Check valves 119A/B Fail by Seismic Event	1.02	In rooms 11206/11207, below elevation 100′
EQ-IRW-RECMOV	Sump Recirculation MOVs 117A/B Fail by Seismic Event	1.02	In rooms 11206/11207, below elevation 100′
EQ-IRW-RECSQ	Failure of Recirculation Squib Valves 118A/B and 120A/B by Seismic Event	1.02	In rooms 11206/11207, below elevation 100′
EQ-IRWST-TANK	Failure of IRWST	0.71	
EQ-MSL-SENSOR	Main Steam Line Pressure Sensor or Transmitter Fails	0.5	Limiting value among those provided for electrical equipment.
EQ-PCC-TANK	Passive Containment Core Cooling Tank Fails	0.81	
EQ-POL-CRANE	Failure of the Polar Crane	0.55	
EQ-PRHR-AOV	Passive RHR AOVs PXS-PL-V108A and B Fail by Seismic Event	0.81	In room 11300, above elevation 100′
EQ-PRHR-HX	Failure of Passive RHR Heat Exchanger	1.11	

Table 19.20-2 (Sheet 4 of 5)
Basic Events HCLPF Values—{HISTORICAL}

BE ID	BE Description	HCLPF (g)	Source
EQ-PRZR-FAILS	Seismically Induced Failures of the Pressurizer	0.5	Pressurizer upper support weld (limiting HCLPF among pressurizer components)
EQ-PRZR-LVTRANS	Seismically Induced Failure of Pressurizer Level Transmitter	0.5	Limiting value among those provided for electrical equipment.
EQ-PRZR-SENSOR	Pressurizer Sensor Or Transmitter Fails	0.5	Limiting value among those provided for electrical equipment.
EQ-PRZR-SV	Pressurizer Safety Valves RCS-PL-V005A/B Fail Seismically	0.81	In rooms 11603/11703, above elevation 100′
EQ-RCP-FAILS	Reactor Coolant Pumps Fail	0.54	Same as SG due to connection between RCP & SG.
EQ-RCP-HX	Seismically Induced RCP HX Failure Inducing a LOCA	0.55	
EQ-RCS-PIPES	Failure of RCS Piping	0.81	
EQ-RV-FAILS	Reactor Pressure Vessel Fails	0.56	
EQ-RV-FUEL	Fuel in Reactor Vessel Fails	0.5	
EQ-RV-HDPK	Reactor Vessel Integrated Head Package Fails	0.7	Same as CRDM due to physical location
EQ-SG-FAILS	Seismically Induced Failures of the Steam Generators	0.54	
EQ-SGTR	Seismically Induced SGTR	0.54	Same as SG failure
EQ-SHBLD-ROOF	Shield Building Roof Fails	0.71	
EQ-SHBLD-WALL	Shield Building Wall Fails	0.71	Same as roof
EQ-SLB	Failure of Feed and Steam Pipes on Secondary Side	0.81	
EQ-TRSFSWITCH	Transfer Switches Fail	0.5	Limiting value among those provided for electrical equipment.

Table 19.20-2 (Sheet 5 of 5)
Basic Events HCLPF Values—{HISTORICAL}

BE ID	BE Description	HCLPF (g)	Source
EQ-VFS-AOV-0304	Containment Air Filtration System Containment Air Supply Isolation Valves AOV 03 and 04 Fail	0.81	In rooms 12452/11400, above elevation 100′
EQ-VFS-AOV-0910	Containment Air Filtration System Containment Air Exhaust Isolation Valves Fail (009, 010, 800A/B, and 803A/B)	0.81	In rooms 12452/11400, above elevation 100′
EQ-WLS-AOV-5557	WLS Cont. Sump Isolation Valves AOV 55 and 57 Fail	0.81	In rooms 11300/12244, above elevation 100′

Table 19.20-3
EQ-IEV-STRUC (EQSTR-02) HCLPF—{HISTORICAL}

		Original AP1000	Updated AP1000
1	EQ-AB-FLOOR	0.51g	0.88g
2	EQ-AB-EXTWALL	0.51g	0.88g
3	EQ-AB-INTWALL	0.51g	0.88g
4	EQ-BAF-SUPP	1.30g	0.91g
5	EQ-PCC-TANK	0.51g	0.81g
6	EQ-SHBLD-ROOF	0.51g	0.71g
7	EQ-SHBLD-WALL	0.51g	0.71g
8	EQ-CV-INTER	0.50g	0.71g
9	EQ-CV-BUCKLE	0.66g	0.73g
10	EQ-CV-OVERT	1.11g	1.38g
11	EQ-IRWST-TANK	0.50g	0.71g
12	EQ-POL-CRANE	0.77g	0.55g
	IE HCLPF=	0.50g	0.55g

Table 19.20-4
EQ-IEV-RVFA (EQRVF-02) HCLPF—{HISTORICAL}

		Original AP1000	Updated AP1000
1	EQ-DVI-PIPES	0.81g	0.81g
2	EQ-SG-FAILS	0.54g	0.54g
3	EQ-RCP-FAILS	0.68g	0.54g
4	EQ-PRZR-FAILS	0.55g	0.50g
5	EQ-RV-FUEL	0.50g	0.50g
6	EQ-RV-HDPK	0.70g	0.70g
7	EQ-RV-FAILS	0.64g	0.56g
	IE HCLPF =	0.50g	0.50g

Table 19.20-5
EQ-IEV-LLOCA HCLPF—{HISTORICAL}

		Original AP1000	Updated AP1000
1	EQ-PRHR-HX	0.76g	1.11g
2	EQ-RCS-PIPES	0.81g	0.81g
	IE HCLPF =	0.76g	0.81g

Table 19.20-6
EQ-IEV-SLOCA HCLPF—{HISTORICAL}

		Original AP1000	Updated AP1000
RCS Instrumentation Pipe Breaks	EQ-INSTR-PIPES	0.81g	0.81g
Secondary Line Breaks	EQ-SLB	0.81g	0.81g
SGTR	EQ-SGTR	0.54g	0.54g
RCP HX	EQ-RCP-HX	-	0.55g
	HCLPF =	0.54g	0.54g

Table 19.20-7
EQ-IEV-ATWS HCLPF—{HISTORICAL}

		Original AP1000	Updated AP1000
1	EQ-CORE-ASSEMBLY	0.50g	0.50g
2	EQ-CRDM	0.70g	0.70g
	HCLPF =	0.50g	0.50g

Table 19.20-8
Sequence and Plant HCLPF—{HISTORICAL}

ET	Original AP1000	Updated AP1000
EQ-STRUC	EQSTR-02	0.55
	EQ-STRUC HCLPF	*0.55*
EQ-RVFA	EQRVF-02	0.50
	EQ-RVFA HCLPF	*0.50*
EQ-LLOCA	EQLLO-02	0.81
	EQLLO-03	0.81
	EQLLO-05	0.81
	EQLLO-06	0.81
	EQLLO-08	0.81
	EQLLO-09	0.81
	EQLLO-10	0.81
	EQLLO-11	0.81
	EQ-LLOCA HCLPF	*0.81*
EQ-SLOCA	EQSLO-02	0.54
	EQSLO-03	0.54
	EQSLO-04	0.54
	EQSLO-05	0.87
	EQ-SLOCA HCLPF	*0.54*
EQ-ATWS	EQATW-02	0.50
	EQATW-03	0.50
	EQATW-04	0.50
	EQATW-05	0.87
	EQATW-06	0.81
	EQATW-07	0.71
	EQ-ATWS HCLPF	*0.50*
EQ-LOSP	*All mixed cut sets (IE HCLP =0.09)*	*N/A*
	Plant HCLPF	***0.50***

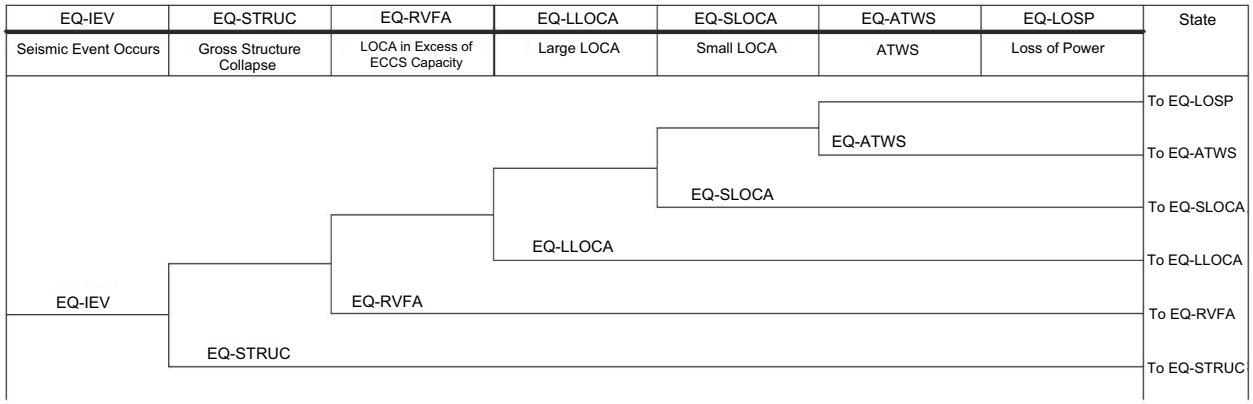

Figure 19.20-1
Seismic Initiating Event Hierarchy Tree—{HISTORICAL}

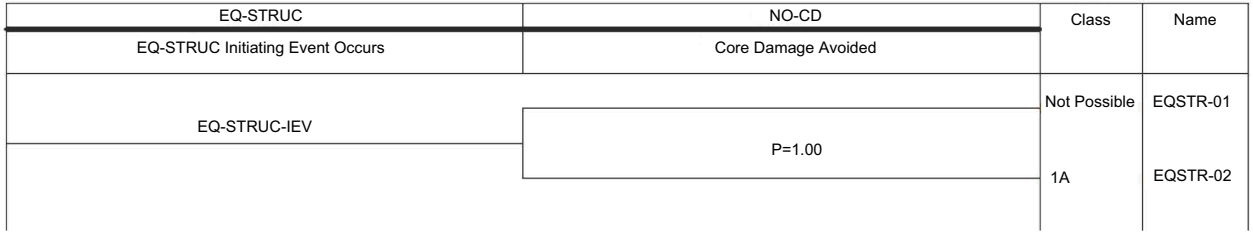

Figure 19.20-2
Seismic Induced Gross Structural Collapse Event Tree—{HISTORICAL}

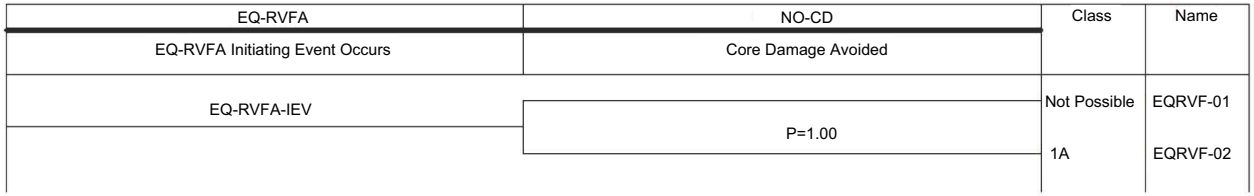

Figure 19.20-3
Seismic Induced Excessive LOCA Event Tree—{HISTORICAL}

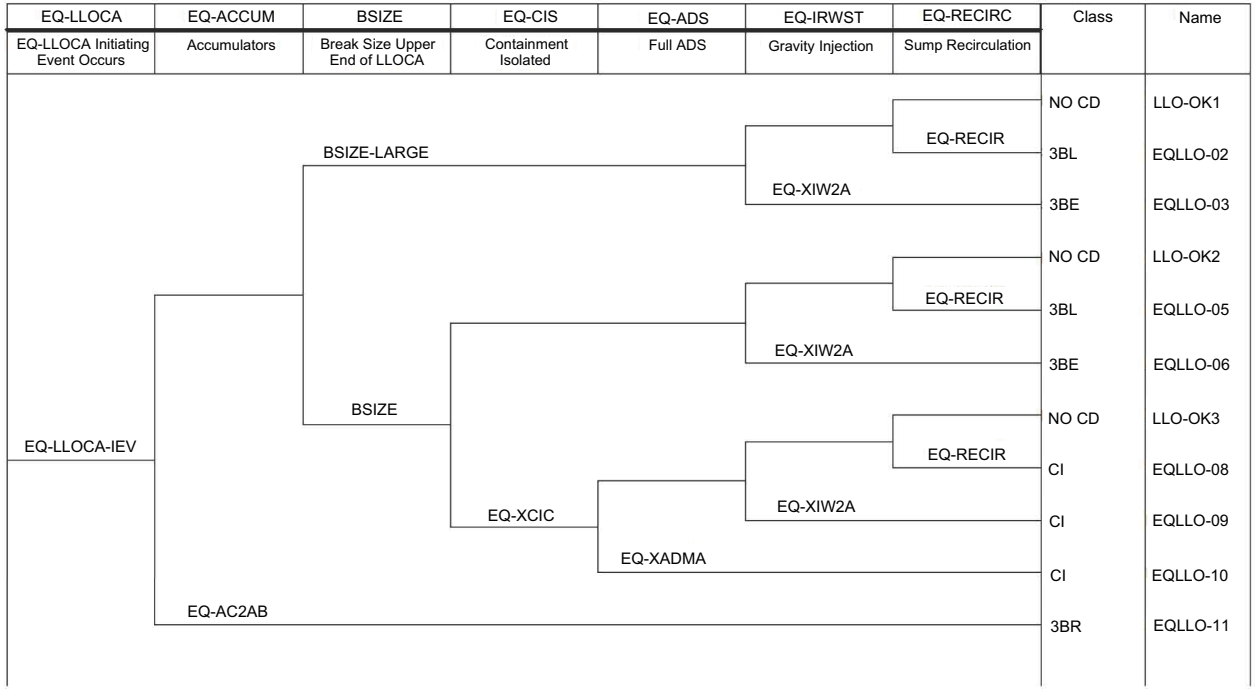

Figure 19.20-4
Seismic Induced Large LOCA Event Tree—{HISTORICAL}

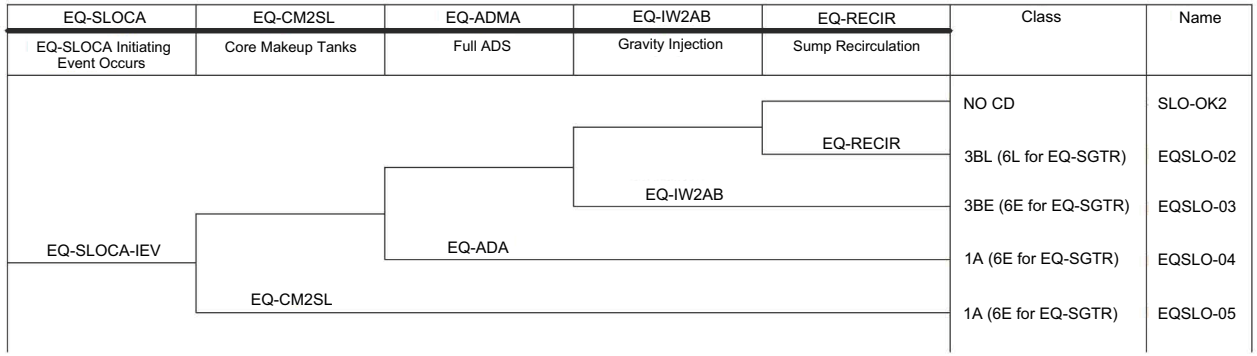

Figure 19.20-5
Seismic Induced Small LOCA Event Tree—{HISTORICAL}

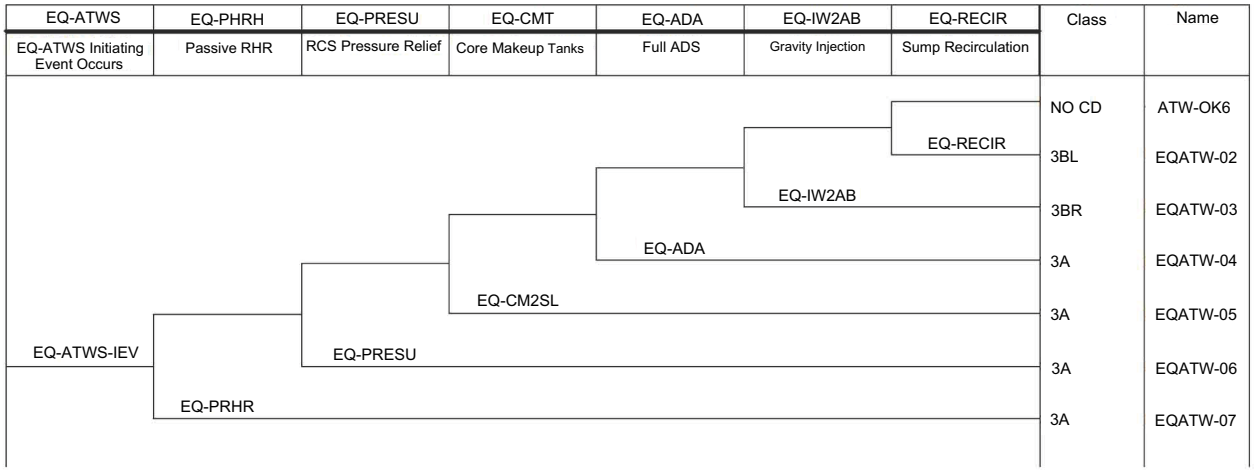

Figure 19.20-6
Seismic Induced ATWS Event Tree—{HISTORICAL}

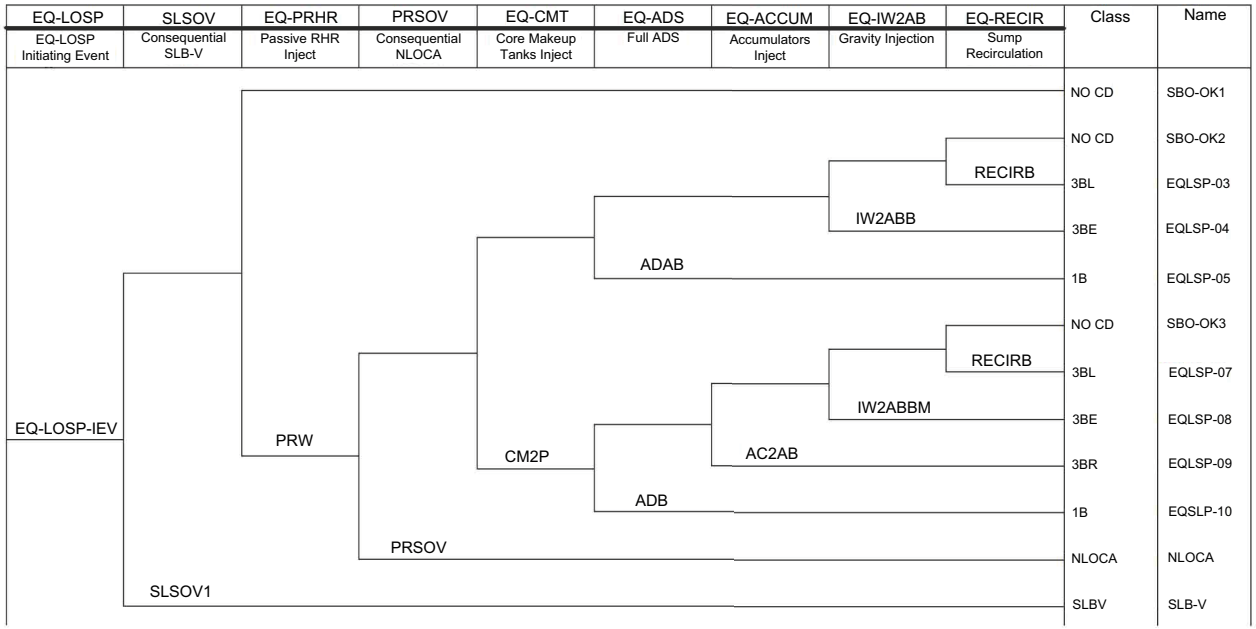

Figure 19.20-7
Seismic Induced LOSP Event Tree—{HISTORICAL}

Appendix 19A Not Used

Appendix 19B Ex-Vessel Severe Accident Phenomena

One of the key AP1000 severe accident design features is the capability to retain the core debris within the reactor vessel for a large number of severe accident sequences by flooding the reactor cavity and submerging the outer surface of the reactor vessel. The heat removal capability of the water on the external surface of the reactor vessel prevents the reactor vessel wall from reaching temperatures where failure of the reactor vessel could occur. This has been termed in-vessel retention (IVR) and is described in detail in Chapter 39 of the AP1000 Level 2 PRA. The primary benefit of in-vessel retention of the core is that ex-vessel severe accident phenomena associated with relocation of core debris to the containment, which can be a dominant containment failure mechanism, are physically prevented. Thus, retention of the core within the reactor vessel results in a significant reduction in the potential for large fission product releases to the environment for core damage accidents.

The probability of various levels of fission product releases (release categories) has been determined in the AP1000 Level 2 PRA, using a containment event tree which describes the various severe accident phenomena that can impact the fission product release quantities and probability of release. In the quantification of the AP1000 Level 2 PRA it was conservatively assumed that the containment would fail at the time of reactor vessel failure for all core damage sequences in which the core debris could not be retained within the reactor vessel. The two principle ways identified in the AP1000 Level 2 PRA of retaining the core within the reactor vessel are reflooding the core with water before the core begins to relocate within the reactor vessel and submerging the outer surface of the reactor vessel to the reactor coolant loop nozzles. Using this approach, the regulatory and industry severe accident performance targets for the AP1000 design criteria were met. Therefore, it was considered unnecessary to investigate the consequences of reactor vessel failure on a realistic basis, including quantification of uncertainties.

The AP1000 design includes features to enhance the likelihood of retaining the core within the reactor vessel for severe accident sequences. These features include:

- Depressurization of the reactor coolant system (RCS) in the event of an accident by either automatic or manual actuation of the highly reliable automatic depressurization system (ADS)
- A containment layout wherein the water relieved from the reactor coolant system (either from the ADS discharge or a break in the RCS) accumulates in the reactor cavity region
- The capability to manually initiate flooding of the reactor cavity by gravity draining the in-containment refueling water storage tank (IRWST) into the reactor cavity
- The absence of in-core penetrations in the reactor vessel bottom head eliminates a possible reactor vessel failure mode
- The reactor cavity layout provides for rapid flooding of the reactor vessel to the reactor coolant loop nozzle elevation
- The reactor vessel insulation design promotes the two-phase natural circulation in the vessel cooling annulus
- The external reactor vessel surface treatment is bare metal

Some of the AP1000 design features to reduce the probability of a core damage accident and to enhance the likelihood of in-vessel retention of core debris in the event of a core damage accident are counter to the design philosophy that would be used to mitigate the consequences of ex-vessel severe accident phenomena. In particular, two of the design features are mutually exclusive between

preventing ex-vessel phenomena and mitigating the consequences of ex-vessel phenomena. On balance, the AP1000 severe accident risk profile is substantially reduced by the features that prevent ex-vessel severe accident phenomena. Two of the more noteworthy features are:

- The large mass of the AP1000 core provides for a slower accident progression, which enhances the capability to prevent a core damage accident (i.e., a reduced core damage frequency). The larger mass of core materials may result in more severe consequences from some of the potential ex-vessel phenomena such as core debris coolability and core concrete interactions.

- The small reactor cavity floor area reduces the amount of water required to completely submerge the reactor vessel. The small cavity floor area also provides for a more rapid flooding of the cavity if manual initiation of IRWST draining to the reactor cavity is required to submerge the reactor vessel. The small reactor cavity floor area may result in more severe consequences from some of the severe accident ex-vessel phenomena such as core debris coolability and core concrete interactions.

The purpose of this section is to provide the results of a limited number of deterministic investigations of the consequences of ex-vessel severe accident phenomena for the AP1000 design. The results of these deterministic investigations show that the challenges to the integrity of the containment posed by ex-vessel severe accident phenomena are generally within the structural capability of the containment. From these investigations, the conclusion is the capability to prevent large fission product releases to the environment does not depend on the ability to retain the core within the reactor vessel for core damage accident sequences.

The limited deterministic investigations of ex-vessel severe accident phenomena described in this section includes: ex-vessel steam explosions, direct containment heating and core concrete interactions. These ex-vessel phenomena are strongly dependent on the assumptions made concerning the mode of reactor vessel failure for the AP1000 design. Therefore, the reactor vessel failure mode is described first, followed by a description of the ex-vessel phenomena investigations.

19B.1 Reactor Vessel Failure

The AP1000 reactor vessel has a main cylindrical section approximately 4 meters in diameter and a hemispherical bottom head. The bottom head is approximately 15 cm (6 inches) thick and is made of carbon steel with an inner cladding of stainless steel to prevent contact between reactor coolant and carbon steel during normal plant operations. The bottom head of the reactor vessel does not contain any discontinuities or penetrations that could impact the mode of reactor vessel failure as the molten core material relocates to the bottom head.

Based on the similar vessel configurations of AP600 and AP1000, the possible failure modes for the AP600 reactor vessel, as documented in Reference 19B-1, are extended to the AP1000. The most likely failure mode is creep failure of the vessel wall due to heating of the vessel wall by the core debris that has relocated to the reactor vessel bottom head. Since creep failure is a strongly temperature-dependent phenomenon, the location of the failure is predicted to be at the upper surface of the core debris pool that has relocated to the reactor vessel bottom head. For most severe accident sequences, this location is near the junction of the hemispherical bottom head and the cylindrical portion of the vessel.

As described in Reference 19B-2, the presence of water on the external surface of the reactor vessel, as in the case of a flooded reactor cavity, does not alter the conclusion that the highest heat fluxes to the reactor vessel walls will be at a point near the top of the in-vessel molten core pool. This would correspond to the region of the reactor vessel most susceptible to creep failure. However,

reactor vessel failure will not occur for the case in which the reactor coolant system is depressurized and the reactor cavity is filled with water to the reactor coolant loop elevation.

For the case in which the outside of the reactor vessel is initially submerged but a sufficient in-flow of water to the reactor cavity cannot be maintained, the reactor vessel wall location experiencing the highest heat fluxes would uncover and lose its external cooling before other locations on the reactor vessel lower head. Thus, creep failure of the vessel would be expected to occur at the same location as the case with no water in the reactor cavity.

Two reactor vessel failure cases, as described below, are carried through the deterministic analyses of ex-vessel steam explosions and core concrete interactions. For the consideration of ex-vessel steam explosions and core concrete interactions, it is assumed that the reactor vessel is initially submerged in water but that gravity draining of water from the IRWST does not occur. As the water in the reactor cavity boils down, the outside of the reactor vessel at the elevation at the top of the in-vessel core pool will dry out and begin to heat up. As the vessel wall heats up, it undergoes thinning due to dissolution and melting until failure occurs. The manner in which the reactor vessel fails is treated in two separate scenarios described below.

In the first scenario, the formation of a localized opening occurs due to asymmetric heating around the circumference followed by the vessel tearing around nearly all of its circumference. This would result in the bottom part of the reactor vessel and the bottom head hinging such that the lower head swings downward and comes to rest on the cavity floor. This behavior is illustrated in Figure 19B-1. A hinging type of failure would result in an immediate pouring of core debris onto the cavity floor with metal flowing ahead of oxide. The relationship between the height of the reactor vessel above the floor is such that all but a minor part of the oxide melt would be free to flow immediately out of the head.

In the second scenario, the head and bottom part of the vessel do not hinge downward. In this scenario, the formation of a localized opening permits molten core debris to drain into the cavity lowering the in-vessel core debris depth and thereby decreasing the thermal load on the vessel wall formerly adjacent to the melt. This type of failure is illustrated in Figure 19B-2. In this case, the continued boildown of water level is followed by the release of the core debris located above the water level after a delay interval during which heatup, thinning, and localized failure of the wall will occur. Over time, the elevation of the failure location moves downward over the vessel wall and lower head. This type of failure gives rise to a very slow release rate with the core debris first relocating downward through the water before collecting and spreading on the cavity floor.

19B.2 Direct Containment Heating

Direct containment heating (DCH) is defined as the rapid energy addition to the containment atmosphere as a result of several physical and chemical processes that can occur if the core debris is forcibly ejected from the reactor vessel. The prerequisites for direct containment heating are vessel failure occurs at a location where a substantial portion of the core debris that has relocated to the lower head is ejected into the reactor cavity before the RCS gases are discharged from the RCS and the RCS is at a high pressure (sometimes called high pressure melt ejection or HPME).

To preclude the potential for high-pressure core melt ejection leading to containment failure via DCH, SECY-93-087 (Reference 19B-4) directs passive light water reactor (LWR) designs to:

- Provide a reliable depressurization system
- Provide cavity design features to decrease the amount of ejected core debris that reaches the upper compartment

The AP1000 design incorporated design features that prevent high-pressure core melt. These features include the passive residual heat removal (PRHR) system and the ADS, both subsystems of the passive core cooling system (PXS). Depressurization of the AP1000 RCS in the event of an accident is provided by automatic or manual actuation of the ADS. Redundancy and diversity are included within the ADS design to ensure a highly reliable depressurization system. The ADS consists of four different valve stages that open sequentially to reduce reactor coolant system pressure in a controlled fashion. All four-valve stages are arranged into two identical groups. Different valve types/sizes are utilized within the ADS stages to provide diversity. Based on these ADS design features, a highly reliable depressurization system is provided which precludes the potential for high-pressure core melt ejection in the AP1000 design. The AP1000 PRHR and ADS subsystems are described in additional detail in Chapters 8 and 11 of the AP1000 PRA and in Section 6.3 of this document.

Even though high-pressure core melt ejection is not a likely scenario for the AP1000, SECY-93-087 directs passive LWR designs to include cavity design features to decrease the amount of ejected core debris from reaching the upper compartment. The AP1000 design includes design features to retain and quench the core debris within the reactor cavity in the unlikely event of core debris relocation outside the reactor vessel. These features include:

- A containment layout wherein the water accumulates in the reactor cavity region
- The capability to manually initiate flooding of the reactor cavity by gravity draining the IRWST into the reactor cavity
- The reactor cavity geometry is arranged to provide a torturous pathway from the reactor cavity to the loop compartment and no direct pathway for the impingement of debris on the containment shell

19B.3 Ex-Vessel Steam Explosions

The first level of defense for ex-vessel steam explosion is the in-vessel retention of the molten core debris. If molten debris does not relocate from the vessel to the containment, there are no conditions for ex-vessel steam explosion. In the event that the reactor cavity is not flooded and the vessel fails, the PRA containment event tree assumes that the containment fails in the early time frame.

An analysis of the structural response of the reactor cavity was performed for the AP600 (Reference 19B-3). As in the in-vessel steam explosion analysis, the results of this AP600 ex-vessel steam explosion analysis are extended to the AP1000. The vessel failure modes for AP600 and AP1000 are the same. The initial debris mass participating in the interaction, superheat and composition are assumed to be the same as for AP600. The mass assumption is conservative since the AP1000 reactor vessel lower head is closer to the cavity floor resulting in less debris mass participating in the interaction. The reactor cavity geometry and water depth prior to vessel failure are the same as AP600. Therefore, the results of the AP600 ex-vessel steam explosion analysis are considered to be appropriate for the AP1000.

19B.4 Core Concrete Interactions

If the reactor vessel fails when the RCS is at a low pressure, the molten core debris will pour from the reactor vessel onto the reactor cavity floor. If a steam explosion does not occur, the pour will spread over the cavity floor and begin to transfer heat to the concrete floor of the reactor cavity. Due to the predicted mode of reactor vessel failure and the shape of the AP600 reactor cavity, analyses of the possible spreading of the core debris over the cavity floor were conducted. The results were used as input to the MAAP4 code for analysis of core concrete interactions for AP1000.

An investigation of the spreading of core debris that pours into the reactor cavity was conducted for reactor vessel failure that occurs at low RCS pressure. The investigation considered the vessel failure mode and location, as well as the recognition that the oxide and metal components of the in-vessel core debris are predicted to be separated. Since the oxide and metal components of the core debris have very different physical characteristics (e.g., viscosity or heat capacity), the separated in-vessel layers influence the spreading of the core debris in the reactor cavity. The melt spreading analysis was conducted for two reactor vessel failure modes, hinged and localized failures.

For the hinged vessel failure case, the analysis results show that the core debris is spread relatively uniformly over the reactor cavity floor. However, the distribution of the metal and oxide components of the core debris is not uniformly distributed over the reactor cavity floor. In the region directly under the reactor vessel, the core debris consists primarily of the oxide component. At the opposite end of the reactor cavity, the core debris consists mainly of the metal component of the core debris released from the reactor vessel. The core debris is still almost totally molten at the end of the spreading analysis.

A different behavior is predicted for the localized reactor vessel failure case. The analysis predicts that the core debris will accumulate at the reactor vessel end of the reactor cavity. The distribution of the metal and oxide components of the core debris is not uniformly distributed over the reactor cavity floor. In the region directly under the reactor vessel, the core debris consists primarily of the oxide component. At the opposite end of the reactor cavity, the core debris consists mainly of the metal component of the core debris released from the reactor vessel. The core debris is almost totally frozen at the end of the spreading analysis.

The core concrete interactions for the AP1000 design were analyzed for two concrete types: basaltic concrete and common limestone-sand concrete. The common limestone-sand concrete has a significantly higher noncondensable gas generation rate, compared to basaltic concrete and should therefore present a more severe containment pressurization transient. On the other hand, the basaltic concrete suffers higher ablation rate, due to its physical properties (mainly, its lower decomposition energy), and should therefore present a more severe basemat penetration failure mode, compared to common limestone-sand concrete. In all cases, a 3.5 m deep water pool is initially present in the cavity while debris is being released into it.

Based on analyses, it can be concluded that: a) the goal of protecting the containment fission product boundary during the first 24 hours of a core melt accident is met, b) it is not necessary to specify a concrete type for the containment basemat since credible containment basemat failure that could lead to fission product releases to the atmosphere are likely to occur at times well beyond 24 hours, and c) the reactor cavity sump is adequately protected such that it is not a weakness in containment basemat integrity during postulated accidents that lead to core concrete interactions.

19B.4.1 Containment Pressurization due to Core Concrete Interactions

The containment pressurization due to steam and noncondensable gas generation during the episodes of core concrete interactions described above was assessed to determine the effect of core concrete interactions on the containment integrity.

The indicator of a challenge to containment integrity for the containment pressurization due to the noncondensable gases produced from core concrete interactions is the Service Level “C” pressure, which is 91 psig (0.73 MPa). This is well below the 50 percent containment failure probability value of 135 psig (1.03 MPa).

The results also show that, in all cases the containment does not pressurize to Service Level “C” containment challenge indicator value prior to the time that the core debris completely penetrates the containment basemat. Thus, for these cases there is no potential challenge to containment integrity

due to overpressurization since: a) there is no longer a source of mass and energy input to the containment after the core debris penetrates the entire basemat, and b) basemat penetration assures that the containment will be depressurized through the basemat failure.

Based on these analyses, it can be concluded that it is not necessary to specify a concrete type for the containment basemat since containment overpressure failure due to non-condensable gas generation from core concrete interactions is not likely for any credible severe accident scenarios.

19B.5 Conclusions

The results of the limited deterministic analyses of ex-vessel severe accident phenomena presented in this section show that early containment failure is not a certainty if the reactor vessel fails. Based on the deterministic analyses, direct containment heating that might ensue from a high pressure melt ejection would not challenge the integrity of the containment. Ex-vessel steam explosions, assessed on a very conservative basis would not produce impulse loads that would challenge the integrity of the containment due to localized failures of the reactor cavity floor and walls. In addition, these analyses indicate that the ex-vessel steam explosion loads are not strong enough to displace the reactor vessel from its location inside the biological shield. Thus, there is no challenge to any containment penetrations connected to the reactor vessel or to the reactor coolant loops. In the case of a vessel failure at a low RCS pressure, the core concrete interactions analyses indicate that the containment integrity would not be challenged in the first 24 hours of the event and thus no significant releases of fission products are predicted in that time frame.

Thus, it is concluded that prevention of large fission product releases to the environment is not dependent on the integrity of the reactor vessel. If reactor vessel failure occurs, there may be challenges to the containment integrity, but these challenges are highly uncertain and the most likely challenge (containment failure by core penetration of the cavity basemat) would not occur in the first 24 hours of the accident. Thus, the AP1000 assumption that reactor vessel failure always leads to containment failure is a conservatism in the AP1000 risk profile.

19B.6 References

19B-1. “AP600 Phenomenological Evaluation Summaries,” WCAP-13388 (Proprietary) Rev. 0, June 1992 and WCAP-13389 (Nonproprietary), Rev. 1, 1994.

19B-2. Theofanous, T. G., et al., “In-Vessel Coolability and Retention of a Core Melt,” DOE/ID-10460, July 1995.

19B-3. “AP600 Probabilistic Risk Assessment,” GW-GL-022, August 1998.

19B-4. “Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Design,” SECY-93-087, dated April 2, 1993.

Table 19B-1 Not Used

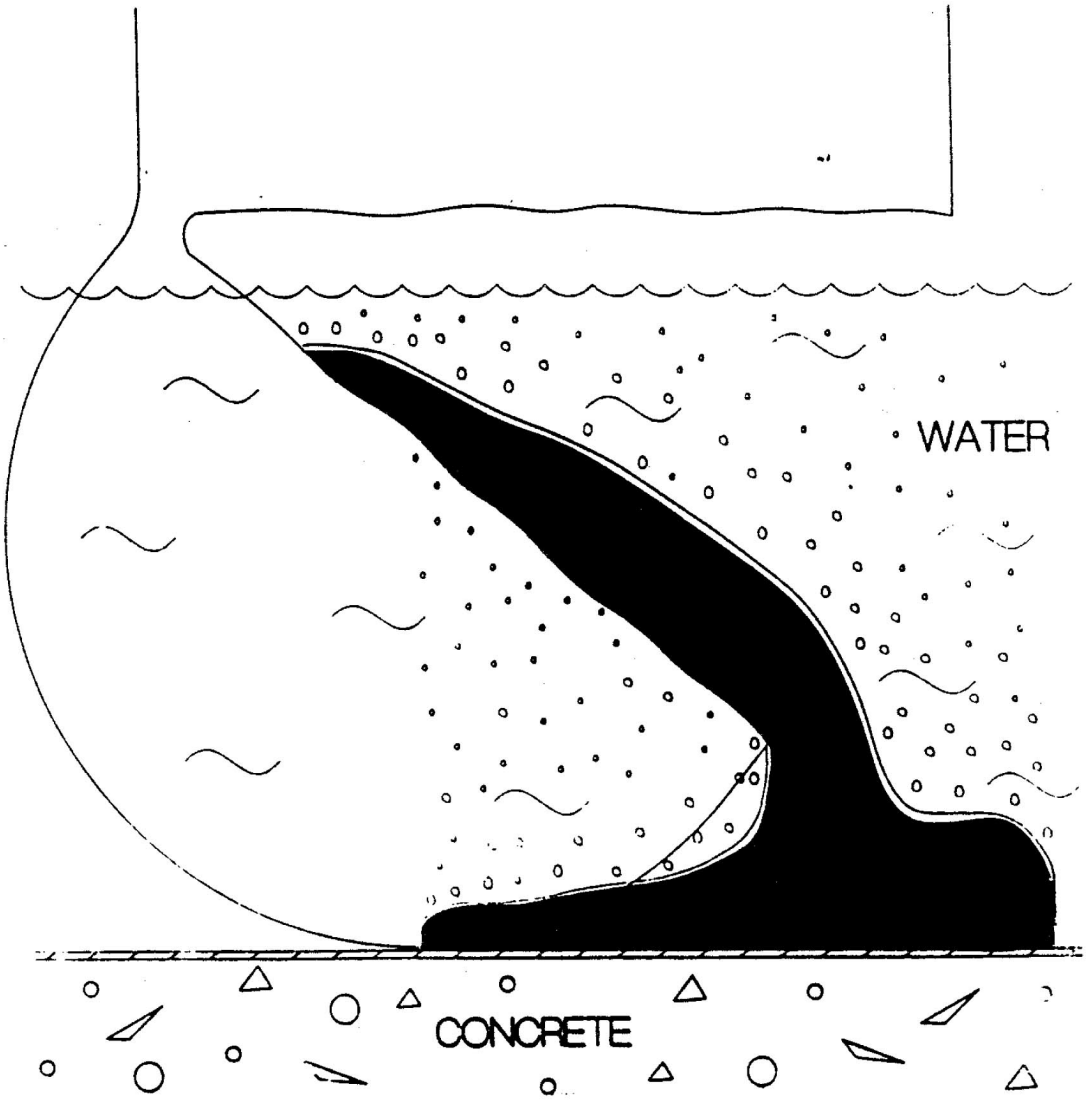

Figure 19B-1
Illustration of Hinging Type of Failure Resulting in Rapid Melt Release

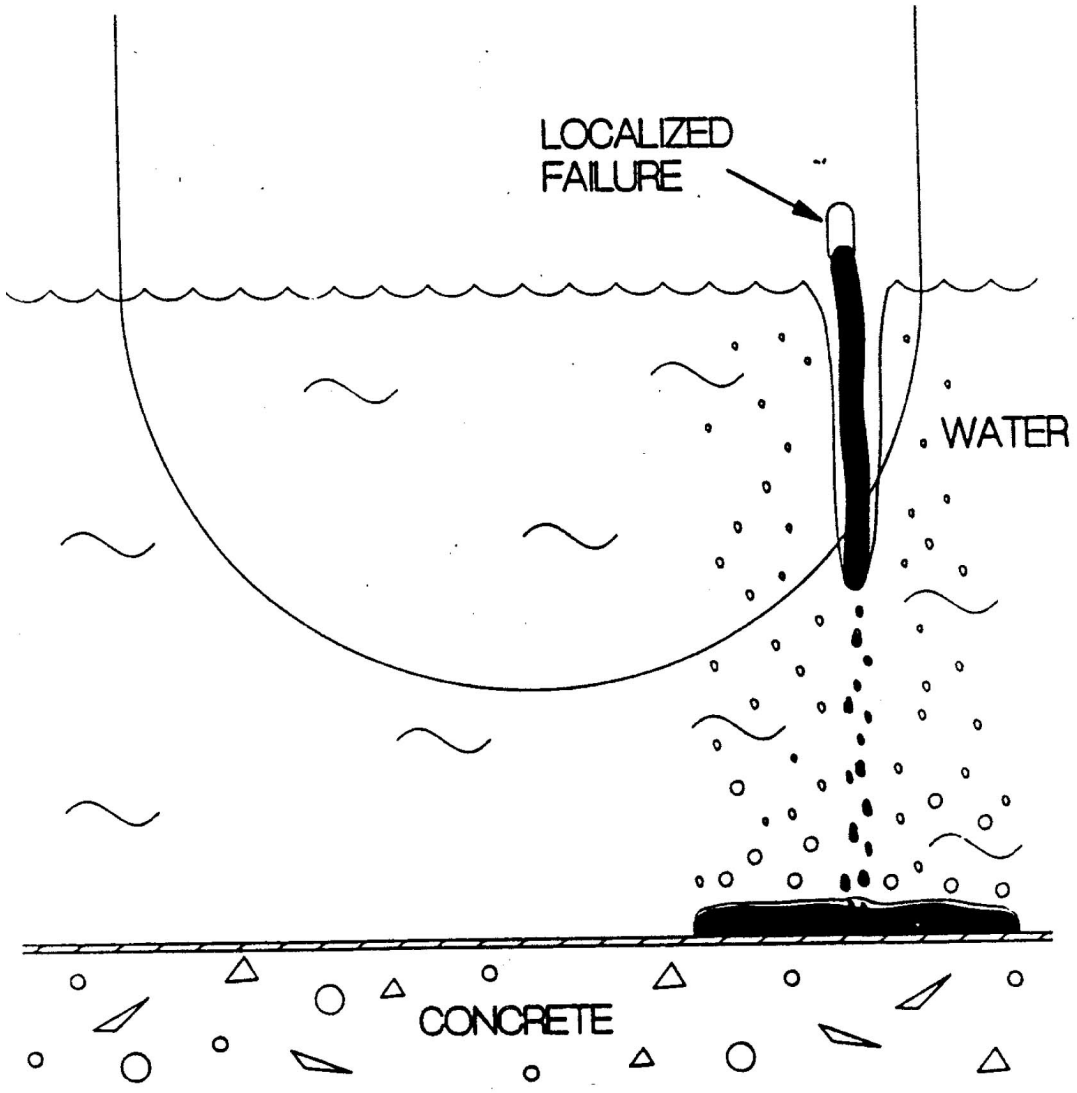

Figure 19B-2
Illustration of Localized Type of Failure Resulting in Slow Melt Release

Figures 19B-3–19B-8b Not Used

Appendix 19C Not Used

Appendix 19D Equipment Survivability Assessment

19D.1 Introduction

The purpose of the equipment survivability assessment is to evaluate the availability of equipment and instrumentation used during a severe accident to achieve a controlled, stable state after core damage under the unique containment environments. Severe accident phenomena may create harsh, high temperature and pressure containment environments with a significant concentration of combustible gases. Local or global burning of the gases may occur, presenting additional challenges to the equipment. Analyses demonstrate that there is reasonable assurance that equipment used to mitigate and monitor severe accident progression is available at the time it is called upon to perform.

The methodology used to demonstrate equipment survivability is:

- Identify the high level actions used to achieve a controlled, stable state
- Define the accident time frames for each high level action
- Determine the equipment and instruments used to diagnose, perform and verify high level actions in each time frame
- Determine the bounding environment within each time frame
- Demonstrate reasonable assurance that the equipment will survive to perform its function within the severe environment.

19D.2 Applicable Regulations and Criteria

Equipment that is classified as safety-related must perform its function within the environmental conditions associated with design-bases accidents. The level of assurance provided by equipment required for design-bases events is “equipment qualification.”

The environmental conditions resulting from beyond design basis events may be more limiting than conditions from design-bases events. The NRC has established criteria to provide a reasonable level of assurance that necessary equipment will function in the severe accident environment within the time span it is required. This criterion is referred to as “equipment survivability.”

The applicable criteria for equipment, both mechanical and electrical, required for recovery from in-vessel severe accidents are provided in 10 CFR 50.34(f):

- Part 50.34(f)(2)(ix)(c) states that equipment necessary for achieving and maintaining safe shutdown of the plant and maintaining containment integrity will perform its safety function during and after being exposed to the environmental conditions attendant with the release of hydrogen generated by the equivalent of a 100 percent fuel-clad metal-water reaction including the environmental conditions created by activation of the hydrogen control system.
- Part 50.34(f)(2)(xvii) requires instrumentation to measure containment pressure, containment water level, containment hydrogen concentration, containment radiation intensity, and noble gas effluent.
- Part 50.34(f)(2)(xix) requires instrumentation adequate for monitoring plant conditions following an accident that includes core damage.

- Part 50.44(c)(2) states that systems necessary to ensure containment integrity shall be demonstrated to perform their function under conditions associated with an accident that releases hydrogen generated from 100-percent fuel-clad metal-water reaction.

Part 50.44(c)(4) states that equipment must be provided for monitoring hydrogen in the containment that is functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere following a significant beyond design-basis accident for accident management, including emergency planning. The applicable criteria for equipment, both electrical and mechanical, required to mitigate the consequences of ex-vessel severe accidents are discussed in Section III.F, “Equipment Survivability” of SECY-90-016. The NRC recommends in SECY-93-087 that equipment provided only for severe accident protection need not be subject to 10 CFR 50.49 equipment qualification requirements, the 10 CFR 50 Appendix B quality assurance requirements, or 10 CFR 50 Appendix A redundancy/diversity requirements. However, mitigation features must be designed to provide reasonable assurance they will operate in the severe accident environment for which they are intended and over the time span for which they are needed.

19D.3 Definition of Controlled, Stable State

The goal of accident management is to achieve a controlled, stable state following a beyond design basis accident. Establishment of a controlled, stable state protects the integrity of the containment pressure boundary. The conditions for a controlled, stable state are defined by APP-GW-GL-027, the “Framework for AP1000 Severe Accident Management Guidance” (SAMG) (Reference 19D-1).

For a controlled, stable core state:

- A process must be in place for transferring the energy being generated in the core to a long-term heat sink.

- The bulk core temperature must be well below the point where chemical or physical changes might occur.

For a controlled, stable containment state:

- A process must be in place for transferring the energy that is released to the containment to a long-term heat sink.

- The containment boundary must be protected.

- The containment and reactor coolant system conditions must be well below the point where chemical or physical processes (severe accident phenomena) might result in a dynamic change in containment conditions or a failure of the containment boundary.

19D.4 Definition of Equipment Survivability Time Frames

The purpose of the equipment survivability time frames is to identify the time span in the severe accident in which specific equipment is required to perform its function. The phenomena and environment associated with that phase of the accident defines the environment which challenges the equipment survivability. The equipment survivability time frame definitions are summarized in Table 19D-1.

19D.4.1 Time Frame 0 - Pre-Core Uncovery

Time Frame 0 is defined as the period of time in the accident sequence after the accident initiation and prior to core uncovery. The fuel rods are cooled by the water/steam mixture in the reactor vessel.

The accident has not yet progressed beyond the design basis of the plant, and hydrogen generation and the release of fission products from the core is negligible. Emergency Operating Procedures (EOPs) are designed to maintain or recover the borated water inventory and heat removal in the reactor coolant system to prevent core uncovery and establish a safe, stable state. Recovery within Time Frame 0 prevents the accident from becoming a severe accident. Equipment survivability in Time Frame 0 is covered under the design basis equipment qualification program for the primary accident management strategies.

19D.4.2 Time Frame 1 - Core Heatup

Time Frame 1 is defined as the period of time after core uncovery and prior to the onset of significant core damage as evidenced by the rapid zirconium-water reactions in the core. This is the transition period from design basis to severe accident environment. The overall core geometry is intact and the uncovered portion of the core is overheating due to the lack of decay heat removal. Hydrogen releases are limited to relatively minor cladding oxidation and some noble gas and volatile fission products may be released from the fuel-clad gap due to rupture of fuel rod cladding at these higher temperatures. As the core-exit gas temperature increases above 1200 degrees F, the EOPs transition to a red path indicating inadequate core cooling (FR-C.1). Upon entry into FR-C.1, the control room staff initiates actions to mitigate a severe accident by turning on the hydrogen igniters for hydrogen control and flooding the reactor cavity to prevent reactor pressure vessel failure. The operators attempt to reduce the core temperature by depressurizing the RCS and re-establish the borated water inventory in the reactor coolant system. Recovery in Time Frame 1 prevents the accident from becoming a core melt. In general, the containment conditions are expected to be within the design basis conditions while the reactor vessel and RCS conditions will be slightly above the design basis. Equipment survivability in Time Frame 1 is evaluated to demonstrate it is within the equipment qualification envelope except for components inside the RCS pressure boundary.

19D.4.3 Time Frame 2 - In-Vessel Severe Accident Phase

Time Frame 2 is the period of time in the severe accident after the accident progresses beyond the onset of rapid zirconium-water reactions and prior to the establishment of a controlled, stable state (end of in-vessel core relocation), or prior to reactor vessel failure. The onset of rapid zirconium-water reactions of the fuel rod cladding and hydrogen generation defines the beginning of Time Frame 2. The heat of the exothermic reaction accelerates the degradation, melting and relocation of the core. Fission products are released from the fuel-clad gap as the cladding bursts and from the fuel matrix as the UO_2 pellets melt. Over the period of Time Frame 2, the initial, intact geometry of the core is lost as it melts and relocates downward. Severe accident management strategies exercised during Time Frame 2 are designed to recover reactor coolant system inventory and heat removal, to maintain reactor vessel integrity and to maintain containment integrity. Recovery actions in Time Frame 2 may create containment environmental challenges by increasing the rate of hydrogen and steam generation.

19D.4.4 Time Frame 3 - Ex-Vessel Severe Accident Phase

Time Frame 3 is defined as the period of time after the reactor vessel fails until the establishment of a controlled, stable state. The AP1000 design and the AP1000 EOPs provide the capability to flood the reactor vessel and depressurize the RCS to prevent vessel failure in a severe accident. This severe accident Time Frame 3 is predicted to be a very low probability event. However, it is included in the SAMG to provide guidance in the event that reactor vessel failure occurs. Molten core debris is relocated from the reactor vessel onto the containment cavity floor which creates the potential for rapid steam generation, core-concrete interaction and non-condensable gas generation. Severe accident management strategies implemented in Time Frame 3 are designed to monitor the accident progression, attempt to re-establish a coolable core configuration on the containment floor, maintain containment integrity and mitigate fission product releases to the environment.

19D.5 Definition of Active Operation Time

Equipment only needs to survive long enough to perform its function to protect the containment fission product boundary. In the case of some items, such as valves or motor-operators, once the equipment performs its function, and changes state (e.g., opens), the function is completed. An exception to this is solenoid-operated valves that must maintain a position other than their design basis failure position (e.g., a fail closed AOV that must remain open for a strategy to remain effective). For other items, such as pumps, the equipment must operate continuously to perform its function. The time of active operation is the time during which the equipment must perform its function.

19D.6 Equipment and Instrumentation for Severe Accident Management

The AP1000 EOPs (Reference 19D-2) and severe accident management guidance (SAMG) framework (Reference 19D-1) define actions that accomplish the goals for achieving a controlled, stable state and terminating fission product releases in an accident. The high level actions from the accident management framework are summarized in Table 19D-2 and provide the basis for identifying equipment. This section discusses the EOP and SAMG actions within each of the time frames of the accident to determine the equipment and instrumentation and the active operation time in which they are needed to provide reasonable assurance of achieving a controlled, stable state.

The AP1000 SAMG (Reference 19D-3) provides the primary input to the selection of the instrumentation used for monitoring the actions. The instrument used to diagnose the need for the action and monitor the response are listed. Instruments to evaluate potential negative impacts are covered under other high level actions in the framework and therefore are also considered for survivability.

The equipment and instrumentation used in each time frame are summarized in Tables 19D-3 through 19D-5. Although the SAMG considers all possible paths for each high level action, only the primary method is listed in Tables 19D-4 and 19D-5 for the equipment survivability assessment.

19D.6.1 Time Frames 0 and 1 - Accident Initiation, Core Uncovery and Heatup

Time Frame 0 represents the accident time prior to core uncovery. Time Frame 1 represents the time following core uncovery, but prior to the rapid oxidation of the core. Aside from potential ballooning of the cladding, the core has not lost its initial intact geometry and coolability is assured by recovering the core with borated water.

During Time Frames 0 and 1, most of the equipment that is automatically actuated will receive a signal to start. However, given that the accident has progressed to core uncovery and heatup, some critical equipment has not actuated. From accident initiation until the time of core uncovery (Time Frame 0) the conditions are bounded by the design basis and covered under equipment qualification. During Time Frame 1, the containment environment is still within the design basis of the plant and the control room is operating within the Emergency Operating Procedures, but the conditions have degraded. Accident management to achieve a controlled, stable state, via the EOPs, is geared toward recovering the core cooling before the coolable geometry is lost.

19D.6.1.1 Injection into the RCS

Failure of RCS injection is likely to be the reason the accident has proceeded to core uncovery. Successful injection into the RCS removes the sensible and decay heat from the core. Prior to the onset of rapid oxidation of the cladding, successful RCS injection recovers the accident before it progresses to substantial damage and establishes a controlled, stable state. Failure to inject into the RCS at a sufficient rate allows the accident to proceed into Time Frame 2 and the SAMG.

The equipment and systems used to inject into the RCS during Time Frame 0 and 1 are the core makeup tanks, accumulators and IRWST (which are part of the passive core cooling system (PXS)), the chemical and volume control system (CVS) makeup pumps, and the normal residual heat removal (RNS) pumps. For non-LOCA and small LOCA sequences, depressurization of the RCS using the automatic depressurization system (ADS) is required for successful injection.

The plant response is monitored using the system flow rates, IRWST water level indication, RCS pressure, core-exit temperature, and RCS temperature.

19D.6.1.2 Injection into Containment

The operator is instructed via the EOPs to inject water into the containment to submerge the reactor vessel and cool the external surface if core overheating begins to occur. This action is performed later in Time Frame 1, but prior to entry into the SAMG. Successful cavity flooding, in conjunction with RCS depressurization, prevents vessel failure in the event of molten core relocation to the vessel lower head. Failure of cavity flooding allows the accident to proceed to vessel failure and molten core relocation into the containment (Time Frame 3) if timely injection into the reactor vessel cannot be established to cool the core and prevent substantial core relocation to the lower head.

The PXS motor-operated and squib recirculation valves are opened manually to drain the IRWST water into the containment in Time Frame 1.

The plant response is monitored by core-exit temperature, containment water level indication, and IRWST water level indication.

19D.6.1.3 Decay Heat Removal and Injection into the Steam Generators

In the event of non-LOCA or small LOCA sequences, the RCS pressure is elevated above the secondary pressure. In Time Frame 0, the SGs and PRHR are used for decay heat removal. Note that PRHR is effective only in Time Frame 0. Failure of the PRHR may be the reason that the event proceeds to core overheating. Recovery of the PRHR will provide decay heat removal. Failure of feedwater to the steam generators with the PRHR failed may also be a cause for core overheating and recovery of injection to the steam generators may be required. If the steam generators remain dry without PRHR recovery and the core is uncovered, the tube integrity or hot leg nozzle integrity may be threatened by creep rupture failure at the onset of rapid oxidation (entry into Time Frame 2) if the RCS is at a high pressure. Injecting to the steam generators provides a heat sink to the RCS by boiling water on the secondary side, and protects the tubes by cooling them. Successful steam generator injection can establish a controlled, stable state if the losses from the RCS can be recovered and mitigated. Failure to inject to the steam generator requires depressurization of the RCS to prevent creep rupture failure of the tubes and loss of the containment integrity at the onset of rapid oxidation in Time Frame 2.

For accident sequences initiated by steam generator tube rupture, the procedures instruct the control room to isolate feedwater to the faulted steam generator, and to use feedwater to the intact steam generator in conjunction with steam generator depressurization and PRHR initiation to cooldown the reactor coolant system and isolate the break. In Time Frame 1, PRHR initiation or feed to the intact steam generators may be used to re-establish a primary heat sink to cooldown the RCS and a controlled, stable state if the losses from the RCS can be recovered and mitigated. Failure to recover the PRHR or to feed the intact steam generator may lead to a continued loss of coolant to the faulted steam generator and progression to Time Frame 2.

The main feedwater and startup feedwater pumps are used to inject into a pressurized secondary system. The AP1000 plant design does not allow for use of low pressure systems (e.g., condensate, fire water, or service water) to feed the steam generators.

The plant response is monitored with the steam generator water level indication, steam line pressure, core-exit temperature, RCS temperature, IRWST temperature, and IRWST water level indication.

19D.6.1.4 Depressurize Reactor Coolant System

19D.6.1.4.1 Non-LOCA and Small LOCA Sequences

In Time Frame 0, RCS depressurization is not used for most accidents because the steam generators and PRHR are used to establish a controlled stable state.

In the event of non-LOCA or a small LOCA sequences, the RCS pressure will remain above the secondary pressure. If the steam generators are dry and the core is uncovered, the hot leg nozzle or tube integrity is threatened by creep rupture failure at the onset of rapid cladding oxidation (beginning of Time Frame 2). Timely depressurization (prior to significant cladding oxidation) of the RCS mitigates the threat to the tubes, allows injection of the accumulators and IRWST water, and provides a long-term heat sink to establish a controlled, stable state. Failure to depressurize can result in the failure of the tubes and a loss of containment integrity when oxidation begins.

For steam generator tube rupture (SGTR) initiated sequences, depressurization of the RCS can be used to isolate the faulted steam generator, and re-establish core cooling via injection.

The automatic depressurization system (ADS) is required to depressurize the RCS to allow the PXS systems to inject. However, the recovery of passive residual heat removal (PRHR) or feedwater to the steam generators will provide a substantial heat sink to depressurize the RCS and mitigate the threat to the tubes. The auxiliary pressurizer sprays are not evaluated for survivability since the inclusion of several other safety-related systems which perform the same function provides reasonable assurance of RCS depressurization in the event of a non-LOCA or small LOCA severe accident.

The RCS pressure, steam generator pressure, IRWST water level, and IRWST temperature can be used to monitor the plant response to the RCS depressurization.

19D.6.1.4.2 LOCA Sequences

In Time Frame 0, steam generators and PRHR are not effective due to low RCS pressure.

LOCA sequences (other than small LOCA sequences) by definition are depressurized below the secondary system pressure by the initiating event and therefore, are not a threat to steam generator tube integrity upon the onset of rapid oxidation. Depressurization may be required for injection to establish a long-term heat sink. Medium LOCAs require additional depressurization to allow the injection of RNS or PXS. Large LOCAs are fully depressurized by the initiating event.

In LOCA sequences, the ADS is effective in providing depressurization capability to allow injection to the RCS. While RCS cooldown and depressurization using the steam generators could be effective, it is not evaluated here for survivability for LOCA sequences. RCS cooldown using pressurizer sprays was determined to not be effective for the larger LOCA sequences because of the loss of communication between the RCS and the pressurizer for these sequences.

The RCS pressure can be used to monitor the plant response to the RCS depressurization.

19D.6.1.4.3 Prevent Reactor Vessel Failure

Depressurization of the RCS, along with injecting into the containment is an accident management strategy to prevent vessel failure. The depressurization of the RCS reduces the stresses on the

damaged vessel wall facilitating the in-vessel retention of core debris. To prevent reactor vessel failure, the RCS must be depressurized to nearly containment conditions.

The ADS is used to depressurize the RCS to prevent reactor vessel failure. The use of the steam generators to depressurize the RCS to prevent vessel failure was determined to not be effective because it cannot bring the RCS pressure down far enough in the time frame of interest for accidents that progress to Time Frame 1 (i.e., no water on primary side of steam generators).

The RCS pressure can be used to monitor the plant response to the RCS depressurization.

19D.6.1.5 Depressurize Steam Generators

The steam generators may be depressurized to depressurize the RCS in non-LOCA and small LOCA sequences. Injection to the steam generator must be available to depressurize the secondary system to prevent creep rupture failure of the tubes.

The steam generator PORV and main steam bypass valves are used for depressurizing the steam generators. The MSIV must be opened in order to use the main steam bypass valves.

Depressurization of the steam generators is used in the EOPs as a means to cool down and depressurize the RCS. Depressurization of the steam generators is called for in the EOPs and is appropriate only in Time Frame 1 as the RCS is depressurized in order to minimize the pressure differential across the steam generator tubes.

The steam line pressure, steam generator water level, and RCS pressure can be used to monitor the plant response.

19D.6.1.6 Containment Heat Removal

Containment heat removal is not explicitly listed as a high level action in the AP1000 SAMG Framework, but it is implicit in the high level action “Depressurize Containment.” Containment heat removal is provided by the passive containment cooling system (PCS). Water cooling of the shell is needed to establish a controlled, stable state with the containment depressurized. The actuation of PCS water is typically automatic in Time Frame 0.

PCS water is supplied to the external surface of the containment shell from the PCS water storage tank or the post-72 hour passive containment cooling ancillary water storage tank. Alternative water sources can be provided via separate connections outside containment.

The containment heat removal can be monitored with the containment pressure and the PCS water flowrate or PCS water and passive containment cooling ancillary water storage tank levels.

19D.6.1.7 Containment Isolation

Containment isolation is not explicitly listed as a high level action in the AP1000 SAMG Framework, but it is implicit as a requirement to protect the fission product barrier.

Containment isolation is provided by an intact containment shell and the containment isolation system which closes the isolation valve in lines penetrating the containment shell that may be open to either the RCS or containment atmosphere following an accident.

The containment isolation can be monitored by the containment pressure and the containment isolation system valve positions.

19D.6.1.8 Hydrogen Control

Maintaining the containment hydrogen concentration below a globally flammable limit is a requirement for a controlled, stable state. The containment can withstand the pressurization from a global deflagration. While hydrogen is not generated in a significant quantity until Time Frame 2, provisions are provided in the EOPs within Time Frame 1 to turn on the hydrogen igniters before hydrogen generation begins so that hydrogen can be burned as it is produced.

Severe accident hydrogen control in the AP1000 is provided by hydrogen igniters. The containment has passive auto-catalytic recombiners (PARs) as well, which are credited for reducing long-term hydrogen releases in cases with igniter failure. The PARs are passive equipment that cannot be controlled by the operating staff from the control room.

The igniters are manually actuated from the control room in the EOPs on high core-exit temperature. The intention is to actuate the igniters prior to the onset of significant cladding oxidation (Time Frame 1). The containment hydrogen concentration is monitored prior to igniter actuation so that a globally flammable mixture is not unintentionally ignited by the hydrogen igniters.

The plant response to the igniter actuation can be monitored by containment hydrogen concentration using the hydrogen monitors or containment atmosphere sampling, which is part of the primary sampling system. The containment pressure response can also be used to indicate hydrogen burning, which creates a distinctive pressure global peak, but not continual hydrogen burning by the igniters because the energy release to containment is at a low rate and the containment pressure response cannot be distinguished from other heat generation processes.

19D.6.1.9 Accident Monitoring

Accident monitoring is a post-TMI requirement as outlined in 10 CFR 50.34(f). Aside from the accident management purposes outlined above, monitoring the progression of the accident and radioactive releases provides input to emergency response and emergency action levels.

Accident monitoring is provided by the in-containment monitors for pressure, hydrogen concentration, water levels, temperature and radiation, core-exit temperature, IRWST water level, RCS pressure, and steam generator radiation monitors.

19D.6.2 Time Frame 2 - In-Vessel Core Melting and Relocation

Time Frame 2 represents the period of core melting and relocation and the entry into the SAMG. The intact and coolable in-vessel core geometry is lost, and relocation of core debris into the lower head is likely. The in-vessel hydrogen generation and fission product releases from the fuel matrix occur during this time frame.

19D.6.2.1 Injection into the RCS

In Time Frame 2, the in-vessel core configuration loses its coolable geometry and it is likely that at least some of the core debris will migrate to the reactor vessel lower head. If the RCS is depressurized and the reactor vessel is submerged, the core debris will be retained in the reactor vessel. However, injection into the RCS to cover and cool the core debris is required to achieve a controlled, stable state. RCS injection is not required to protect the containment fission product boundary. Injection is successful if it is sufficient to quench the sensible heat from the core debris and refill the reactor vessel. Decay heat removal will then be accomplished by a combination of heat transfer to the water in the reactor vessel and heat transfer to the water on the exterior surface of the reactor vessel.

Severe accident studies for the AP1000 indicate that even with the reactor vessel refilled and the exterior surface of the reactor vessel submerged, the entire core debris may not return to low temperatures (e.g., less than 1200°F for a substantial period of time (e.g., months) if most of the core debris has relocated to the reactor vessel bottom head. This is due to the heat transfer rate through the outer shell of frozen core debris in relation to the heat generation in the central unfrozen core debris. However, this is an extreme case (i.e., no recovery of injection to the RCS until the entire core debris is in the reactor vessel bottom head).

Guidance for establishing RCS injection would be from the AP1000 SAMG (Reference 19D-3). Water can be injected into the RCS using the CVS or the RNS systems. The PXS (CMT, accumulator, IRWST) is not credited in Time Frame 2 in survivability assessments because automatic and manual activation of the system is attempted several times in Time Frame 0 and 1.

Post-core damage, the actions may be monitored with RCS pressure or temperature, containment pressure or CVS or RNS flow rates.

19D.6.2.2 Injection into Containment

The objective of injection to the containment prior to reactor vessel failure (Time Frame 3) is to cool the external surface of the reactor vessel to maintain the core debris in the vessel. Due to the lead time required to submerge the bottom head of the reactor vessel prior to core relocation of the bottom head, injecting to the containment for in-vessel retention is achieved by instructing the operator to drain the IRWST in the EOPs within Time Frame 1.

Since a long lead time is required to submerge the exterior surface of the RPV, the objective of injecting into containment in Time Frame 2 is to provide water in the containment if the accident progresses to RPV failure and Time Frame 3. Two methods are used to inject into containment during Time Frame 2; the containment spray and the addition of water to the IRWST to overflow into containment. There are three methods used to add makeup to the IRWST to overflow; RNS pumps, makeup pumps, and spent fuel system pumps. Draining the IRWST to containment is not credited in Time Frame 2 in survivability assessments because activation of the system is attempted several times in Time Frame 1, and diverse systems are credited to provide reasonable assurance of containment injection survivability in this time frame. If the vessel fails, the accident progresses to Time Frame 3.

Post-core damage, the actions may be monitored with containment water level indication or IRWST water level indication if IRWST overfill is used.

19D.6.2.3 Decay Heat Removal and Injection into the Steam Generators

In transients and small LOCAs, initiation of PRHR or injection into the steam generators is required to be recovered in Time Frame 1 to be successful. If the secondary side is dry and the RCS is not depressurized, the steam generator tubes can experience creep rupture due to circulation of hot gases when the cladding oxidation begins at the onset of Time Frame 2. Steam generator injection is not required for LOCAs which depressurize the RCS below the secondary system pressure.

Within Time Frame 2, steam generator injection can be utilized in unisolated SGTR sequences to maintain the water level on the secondary side for mitigation of fission product releases. Injecting into the steam generators, along with depressurization of the RCS, is an accident management action to isolate containment or scrub fission products. Failure to inject to the ruptured steam generator in Time Frame 2 can lead to continued breech of the containment fission product boundary and large offsite doses.

Steam generator feed for non-ruptured SGs is not credited in Time Frame 2 because it is attempted several times in Time Frame 0 and Time Frame 1. However, re-initiation of feedwater to the ruptured steam generator is not attempted until the SAMG, which is not used until Time Frame 2. Thus, re-initiation of feedwater is a Time Frame 2 activity.

The main feedwater and startup feedwater pumps are used to inject into a pressurized secondary system.

The plant response is monitored with the core-exit temperature, RCS temperature, steam generator water level and steam line pressure.

19D.6.2.4 Depressurize RCS

RCS depressurization is required within Time Frame 1 for facilitating in-vessel retention of core debris and for successfully preventing steam generator tube failure in high pressure severe accident sequences. The steam generator tubes or hot leg nozzles may fail due to creep rupture after the onset of rapid oxidation at the beginning of Time Frame 2. RCS depressurization facilitates in-vessel retention of core debris in conjunction with injection into the containment to give time to recover pumped injection sources to the RCS to establish a controlled, stable state. RCS depressurization is provided by instructing the operator to depressurize the system in the EOPs in Time Frame 1.

Three methods are used to depressurize the RCS during Time Frame 2: ADS, auxiliary pressurizer spray, and reactor vessel head vent. ADS and auxiliary pressurizer spray are not credited in Time Frame 2 in survivability assessments because activation of the system is attempted several times in Time Frame 1. Survivability of the reactor vessel head vent is assessed only in Time Frame 2.

19D.6.2.5 Depressurize Steam Generators

Active operation to depressurize a steam generator can be used to cooldown the RCS prior to Time Frame 2. After the onset of core melting and relocation, depressurizing steam generators could threaten steam generator tube integrity. Depressurizing the steam generator in Time Frame 2 does not facilitate the establishment of a controlled, stable state. Depressurization of the steam generators is called for in the EOPs and is appropriate only in Time Frame 1 if the RCS is depressurized in order to minimize the pressure differential across the steam generator tubes.

19D.6.2.6 Containment Heat Removal

Automatic actuation of PCS water occurs in Time Frame 0 or 1. In Time Frame 2, PCS flowrate and level are monitored to determine if additional water is needed to permit continuation of PCS flow. Alternate water sources can be provided by connections to the external passive containment cooling water storage tank (PCCWST) which is outside the containment pressure boundary and not subjected to the harsh environment.

In addition to PCS water, a nonsafety-related containment spray system can provide heat removal from containment. The design basis purpose of containment spray is scrubbing fission products and containment spray is actuated on high containment radiation levels. This would most likely occur in Time Frame 2 when the fuel rods are overheated and melting. Manually actuating the containment spray system involves opening an air-operated valve inside the containment and actuating valves and a pump outside the containment. Once open, the active operation of the valve inside the containment is completed.

Post-core damage, the actions may be monitored with PCS flow rate and PCCWST water level, containment water level, and containment pressure.

19D.6.2.7 Containment Isolation

Active operation of containment isolation valves is required in Time Frame 0 or 1 to establish the containment fission product barrier. Therefore, only the survivability of the containment pressure boundary, including penetrations, is required to maintain containment isolation after Time Frame 1.

19D.6.2.8 Hydrogen Control

The operator action to actuate the igniters occurs prior to the hydrogen generation at the onset of Time Frame 2. The igniters need to survive and receive power throughout the hydrogen release to maintain the hydrogen concentration below the lower flammability limit during the hydrogen generation in Time Frame 2.

If containment becomes steam inert in Time Frame 2, the igniters will become ineffective and hydrogen will accumulate in containment. The passive auto-catalytic recombiners (PARs) are also available to control hydrogen in containment and can be effective in a steam inert environment. The PARs are passive equipment that are not controlled by the operating staff from the control room.

The plant response to the igniter actuation can be monitored by containment hydrogen concentration using the hydrogen monitors or containment atmosphere sampling, which is part of the primary sampling system. The containment pressure response can also be used to indicate hydrogen burning which creates a distinctive pressure global peak, but not continual hydrogen burning by the igniters because the energy release to containment is at a low rate and the containment pressure response cannot be distinguished from other heat generation processes.

19D.6.2.9 Control Fission Product Releases

A nonsafety-related containment spray system is provided in AP1000 to wash aerosol fission products from the containment atmosphere. The spray system is manually actuated from the SAMG which is entered at the onset of Time Frame 2. Operating the spray involves opening an air-operated valve inside the containment and actuating valves and a pump outside the containment. Once open, the active operation of the valve inside the containment is completed.

Post-core damage, this action may be monitored with containment water level.

19D.6.2.10 Accident Monitoring

During the initial core melting and relocation, containment hydrogen and radiation monitors are used for core damage assessment and verification of the hydrogen igniter operation. Steam generator radiation monitoring is used to determine steam generator tube integrity. In the longer term, containment atmosphere and containment liquid sampling can be used to monitor hydrogen and radiation. Containment pressure, temperature, and water level indication and RCS pressure need to be monitored throughout Time Frame 2.

During a severe accident, the instrumentation may be subjected to conditions well beyond its design basis. The SAMG does not automatically eliminate instrumentation based on its design basis in comparison to severe accident conditions. Instead, the AP1000 SAMG relies on all available instrumentation indications and instructs the user to constantly compare instrumentation readings to diverse sources to validate the instrumentation reading. It is also noteworthy that while target values are established for various plant parameters to indicate a controlled stable state, the trends of the parameters being monitored are equally as important in managing the accident. The parameter trends indicate whether strategies are effective and determine if additional strategies need to be considered.

19D.6.3 Time Frame 3 - Ex-Vessel Core Relocation

Time Frame 3 represents the phase of the accident after vessel failure. The core debris is in the reactor cavity, and the IRWST water is not injected into the containment.

19D.6.3.1 Injection into the RCS

The RCS is failed. Injection to the RCS is no longer needed in Time Frame 3. Note that the AP1000 SAMG considers RCS injection as a means to inject water into the reactor cavity in Time Frame 3.

19D.6.3.2 Injection into Containment

Water coverage to the ex-vessel debris bed is passively provided by the containment design to drain water from the RCS via the IRWST. Water condensing on the PCS shell is returned to the reactor cavity after filling the IRWST to the overflow. The addition of water to the IRWST from other sources to overflow into containment is also a method of injecting water into containment. Containment spray can also be used to inject water into containment in Time Frame 3. Draining the IRWST to containment is not credited in Time Frame 3 in survivability assessments because activation of the system is attempted several times in Time Frame 1, and diverse systems are credited to provide reasonable assurance of containment injection survivability in this time frame. Containment spray and overflowing the IRWST are also not credited in Time Frame 3 survivability assessments because these methods are already credited in Time Frame 2.

19D.6.3.3 Decay Heat Removal and Injection into the Steam Generators

The RCS is failed. PRHR activation or injection into the steam generators is no longer needed in Time Frame 3. Injection to the steam generator for SGTR fission product scrubbing is not required to maintain the water level.

19D.6.3.4 Depressurize RCS

The RCS is depressurized by the vessel failure in Time Frame 3.

19D.6.3.5 Depressurize Steam Generators

The RCS is failed. Steam generator depressurization is not needed in Time Frame 3.

19D.6.3.6 Containment Heat Removal

Active initiation of PCS water is completed prior to Time Frame 3. PCS flowrate and level are monitored for post-72 hour activities. Alternate water sources can be provided by connections to the external PCCWST which is outside the containment pressure boundary and not subjected to the harsh environment.

In addition to PCS water, a nonsafety-related containment spray system can provide heat removal from containment. The design basis purpose of containment spray is scrubbing fission products and containment spray is actuated on high containment radiation levels. This would most likely occur in Time Frame 2 when the fuel rods are overheated and melting. Manually actuating the containment spray system involves opening an air-operated valve inside the containment and actuating valves and a pump outside the containment. Once open, the active operation of the valve inside the containment is completed.

Post-core damage, the actions may be monitored with PCS flowrate and PCCWST water level, containment water level and containment pressure.

19D.6.3.7 Containment Isolation and Venting

Continued operation of the containment shell as a pressure boundary is needed to maintain containment isolation in Time Frame 3. Containment temperature needs to be monitored because prolonged exposure of organic materials (e.g., equipment and personnel hatch seals) to high temperatures (> 400°F) can degrade the material.

In the event of containment pressurization above design pressure due to core concrete interaction non-condensable gas generation, the containment can be vented. Venting protects containment isolation by preventing an uncontrolled containment failure airborne release pathway. The vent can be opened and closed as required to maintain pressure in the containment below its failure pressure. Containment venting does not prevent or mitigate containment basemat failure due to core concrete interaction. Containment venting to the spent fuel pool is available through RNS hot leg suction line MOVs.

19D.6.3.8 Combustible Gas Control

The hydrogen igniters are used to control combustible gases. Active operation of igniters continues to control the release of combustible gases (e.g., hydrogen and carbon monoxide) from the degradation of concrete in the reactor cavity.

If containment becomes steam inert in Time Frame 3, the igniters will become ineffective and hydrogen will accumulate in containment. The passive auto-catalytic recombiners (PARs) are also available to control hydrogen in containment and can be effective in a steam inert environment. The PARs are passive equipment that are not controlled by the operating staff from the control room.

The plant response to the igniter actuation can be monitored by containment hydrogen concentration using the containment atmosphere sampling, which is part of the primary sampling system. The containment pressure response can also be used to indicate hydrogen burning which creates a distinctive pressure global peak, but not continual hydrogen burning by the igniters because the energy release to containment is at a low rate and the containment pressure response cannot be distinguished from other heat generation processes.

19D.6.3.9 Control Fission Product Releases

The nonsafety-related sprays are actuated in Time Frame 2. The operation of the nonsafety-related containment spray continues, possibly into Time Frame 3, until the water from the source tank is depleted.

Post-core damage, this action may be monitored with containment water level.

19D.6.3.10 Accident Monitoring

Containment pressure, temperature, water level and radiation, steam generator radiation and the containment hydrogen concentration are sufficient to monitor the accident in the long-term. Hydrogen concentration and radiation can be monitored with containment atmosphere and liquid sampling functions. In both Time Frame 2 and Time Frame 3, auxiliary building radiation monitors, if properly correlated, could be used for containment radiation monitoring.

19D.6.4 Summary of Equipment and Instrumentation

The equipment and instrumentation used in achieving a controlled, stable state following a severe accident, and the time it operates are summarized in Tables 19D-3 through 19D-5.

19D.7 Severe Accident Environments

The design certification of the AP1000 included consideration by the NRC of the topic referred to in this section.

19D.8 Assessment of Equipment Survivability

Since severe accidents are very low probability events, the NRC recommends in SECY-93-087, that equipment desired to be available following a severe accident need not be subject to the qualification requirements of 10CFR50.49, the quality assurance requirements of 10CFR50 Appendix B, or the redundancy/diversity requirements of 10CFR50 Appendix A. It is satisfactory to provide reasonable assurance that the designated equipment will operate following a severe accident by comparing the AP1000 severe accident environments to design basis event/severe accident testing or by design practices.

19D.8.1 Approach to Equipment Survivability

The approach to survivability is by equipment type, equipment location, survival time required, and the use of design basis event qualification requirements and severe environment experimental data.

19D.8.1.1 Equipment Type

The various types of equipment needed to perform the activities discussed above are transmitters, thermocouples, resistance temperature detectors (RTDs), hydrogen and radiation monitors, valves, pumps, valve limit switches, containment penetration assemblies, igniters, and cables.

19D.8.1.2 Equipment Location

Some of the in-containment equipment, such as transmitters, has been deliberately located to avoid the most severe calculated environments. Other equipment is located outside containment. The performance of the equipment was judged based on the most severe postulated event for that location.

19D.8.1.3 Time Duration Required

Requirements are defined for each time frame, so the equipment evaluation only discusses performance during these periods. A limited amount of equipment has been designated for the long term (Time Frame 3) and these parameters can be monitored outside containment.

19D.8.1.4 Severe Environment Experiments

The primary source for performance expectations of similar equipment in severe accident environments is EPRI NP-4354, “Large Scale Hydrogen Burn Equipment Experiments.” This information is supplemented by NUREG/CR-5334, “Severe Accident Testing of Electrical Penetration Assemblies.” These programs tested equipment types that had previously been qualified for design basis event environmental conditions. The temperature in the chamber for the first program was in the 700°F - 800°F range for ten to twenty minutes during the continuous hydrogen injection tests. Although the conditions at the equipment would be somewhat less severe, the chamber conditions envelop all of the longer duration profiles indicated for the AP1000 events. The equipment in this program was also exposed to significant hydrogen burn spikes that are also postulated for the AP1000 plant. The same equipment was exposed to and survived several events, both pre-mixed and continuous hydrogen injection which provides confidence in its ability to survive a postulated severe accident. The second program tested containment penetrations to high temperatures for long durations. A penetration was tested under severe accident conditions simulated with steam up to

400°F and 75 psia for ten days. The results indicated that the electrical performance of the penetration would not lead to degraded equipment performance for the first four days. The mechanical performance did not degrade (no leaks) during the entire test.

19D.8.2 Equipment Located in Containment

The exposure to elevated temperatures as a direct result of the postulated severe accident or as a result of hydrogen burning is the primary parameter of interest. Pressure environments do not exceed the design basis event conditions for which the equipment has been qualified if PCS is operating as designed. Radiation environments also do not exceed the design basis event conditions throughout Time Frames 1 and 2.

19D.8.2.1 Differential Pressure and Pressure Transmitters

The functions defined for accident management that utilize in-containment transmitters are IRWST water level, reactor coolant system pressure, steam generator wide range water level, and containment pressure. Most of these transmitters that provide this information are located in rooms where the environment is limited to short duration temperature transients. These transients exceed ambient design basis temperature conditions but should not impact the transmitter performance since the internal transmitter temperature do not increase significantly above that experienced during design basis testing. EPRI NP-4354 documents transmitter performance during several temperature transients with acceptable results. The IRWST water level transmitters are located in the maintenance floor and are only required during Time Frames 1 and 2. The environment during Time Frames 1 and 2 does not exceed the design basis qualification parameters of the transmitters if PCS is operating as designed. Reactor system pressure and steam generator wide range water level are required through the second time frame. The only long term application is the containment pressure transmitter which may eventually be impacted by the severe accident radiation dose.

19D.8.2.2 Thermocouples

The function defined for severe accident management that uses thermocouples is core-exit temperature. The core-exit temperature is only required during Time Frame 1. The temperatures to which the thermocouples are exposed during the defined time frames do not exceed the thermocouple design.

19D.8.2.3 Resistance Temperature Detectors (RTDs)

Both hot and cold leg temperatures are defined as parameters for severe accident management in Time Frame 1. RTDs are utilized for these measurements and will perform until their temperature range is exceeded. The hot leg RTDs could fail as the temperature increases well above the design conditions of the RTDs but the cold leg RTDs should perform throughout Time Frame 1. RTDs are also utilized through Time Frame 3 for the containment temperature measurement and are exposed to temperature transients that exceed design basis qualification conditions. EPRI NP-4354 documents RTD performance during several temperature transients with acceptable results.

19D.8.2.4 Hydrogen Monitors

Containment hydrogen is defined as a parameter to be monitored throughout the severe accident scenarios. Early in the accident, the hydrogen may be monitored by a galvanic device with an electrochemical sensor. The hydrogen monitors are located in the main containment area. The design limits of this device may be exceeded after the first few hours of some of the postulated accidents and performance may be uncertain. If the device fails, post-accident sampling of containment atmosphere using analysis of grab samples may be used to determine containment hydrogen concentrations.

19D.8.2.5 Radiation Monitors

Containment radiation is defined as a parameter to be monitored throughout the severe accident scenarios. The containment radiation monitors are located in the main containment area. Early in the accident, the design basis event qualified containment radiation monitor provides the necessary information until the environment exceeds the design limits of the monitor. If the device fails, containment radiation is determined through the containment atmosphere sampling function or by portable monitors located against the outside of the containment shell.

19D.8.2.6 Solenoid-Operated Valves (SOVs) and Air-Operated Valves (AOVs)

Qualified solenoid valves are used to vent air-operated valves (AOVs) to perform the function required. In Time Frame 1, the core makeup tank AOVs located in the accumulator room provide a path for RCS injection, the PRHR AOVs located in the maintenance floor provide a path for RCS heat removal and the containment is isolated by AOVs located in the maintenance floor and the PXS valve/accumulator room. The environment to which these solenoid valves may be exposed in Time Frame 1 is not significantly different than the design basis events to which the devices are qualified. In Time Frame 2, the RCS boundary AOV located in the maintenance floor is used for CVS injection into the RCS and the containment spray AOV located in the maintenance floor is used for control of fission product release. Also in Time Frame 2, the reactor vessel head vent solenoid valves provide a path for RCS depressurization. In addition, throughout Time Frame 3, access to the containment environment from the containment atmosphere sampling function is through solenoid valves located in the maintenance floor. During Time Frame 2 and Time Frame 3, these valves may be exposed to transient conditions due to hydrogen burns that exceed design basis event qualification. Solenoid valves in an energized condition were included in the hydrogen burn experiments (EPRI NP-4354) and survived many transients. Shielding provided by the location of the valves limits the severe accident radiation dose to the typical design basis qualification dose for these valves.

19D.8.2.7 Motor-Operated Valves

Motor-operated valves (MOVs) are utilized in several applications during the severe accident scenarios. MOVs in the accumulator and core makeup tank path are normally open and remain open. In Time Frame 1, the PXS recirculation MOVs located in the PXS valve/accumulator room are required for injection of water into the containment, MOVs for the first three stages of ADS located in a compartment above the pressurizer are required for RCS depressurization and the containment is isolated by MOVs located in the maintenance floor and the PXS valve/accumulator room. The environment to which these MOVs may be exposed in Time Frame 1 is not significantly different than the design basis events to which they are qualified. In Time Frame 2, the charging and injection MOV located in the maintenance floor provides a path from the CVS for RCS injection and an RNS MOV located in the PXS valve/accumulator room provides a path from the IRWST for RCS injection. In addition, throughout Time Frame 3, containment venting to the spent fuel pool is available through RNS hot leg suction line MOVs located in the RNS valve room. During Time Frames 2 and 3, these valves may be exposed to transient conditions due to hydrogen burns that exceed design basis event qualification. MOVs were included in the hydrogen burn experiments (EPRI NP-4354) and survived many transients. Shielding provided by the location of the valve limits the severe accident radiation dose to the typical design basis qualification dose for these valves.

19D.8.2.8 Squib Valves

Squib valves are only required in Time Frame 1 when the severe accident environment is not significantly different than the design basis environment for which these valves are qualified. IRWST and PXS recirculation squib valves located in the accumulator room are used for injection into the RCS and containment, respectively. For RCS depressurization, the fourth stage ADS squib valves are located in steam generator compartments 1 and 2.

19D.8.2.9 Position Sensors

Position sensors are required to monitor the position of containment isolation valves that could lead directly to an atmospheric release. These isolation valves actuate early in the transient, so verification is only required during Time Frame 1. The position sensors are located in the maintenance floor and the environment in this time frame does not exceed the design basis event qualification environment of the position sensors.

19D.8.2.10 Hydrogen Igniters

The hydrogen igniters are distributed throughout the containment and are designed to perform in environments postulated for severe accidents. The successful results of igniter testing through several hydrogen burns is documented in EPRI NP-4354 and provides confidence in the performance of these devices.

19D.8.2.11 Electrical Containment Penetration Assemblies

The electrical containment penetrations are located in the lower compartment and are required to perform both electrically and mechanically throughout the severe accident. The hydrogen burn equipment experiments documented by EPRI NP-4354 included penetrations qualified for nuclear plants. Electrical testing on the penetration cables after all the pre-mixed and continuous injection tests concluded that most of the cables passed the electrical tests while submerged in water. These tests consisted of ac (at rated voltage) and dc (at three times rated voltage) withstand tests and insulation resistance tests at 500 volts. The penetrations were also tested under simulated severe accident conditions at 400°F and 75 psia for about 10 days (NUREG/CR-5334). The results indicated that some degradation in instrumentation connected to the penetration may occur in four days under these severe conditions. The maintenance floor may experience short temperature transients above 400°F but stable temperatures are significantly less, so it is expected that the electrical performance would be maintained throughout the event. The only long term measurement utilizing these penetrations is containment pressure and this can be measured outside containment if necessary. There was no degradation of mechanical performance of the electrical penetrations (maintaining the seal) in either test program.

19D.8.2.12 Cables

The hydrogen burn equipment experiments documented by EPRI NP-4354 included twenty-four different cable types qualified for nuclear plants. Electrical testing on these cables after all the pre-mixed and continuous injection tests concluded that all (fifty two samples) of the cables passed the electrical tests while submerged. These tests consisted of ac (at rated voltage) and dc (at three times rated voltage) withstand tests and insulation resistance tests at 500 volts. Due to the exposure to many events, some cable samples had extensive damage in the form of charring, cracking and bulging of the outer jackets and still performed satisfactorily. The cables tested are representative of cables specified for the AP1000 and are only exposed to short single temperature transients in their respective locations. Proper performance can be expected. The only long term measurement utilizing cables is containment pressure, which can be measured outside containment if necessary.

19D.8.2.13 Float Level Sensors

The function defined for severe accident management that uses float level sensors is containment water level. Containment water level is required through Time Frame 2. The temperature to which the float level sensors are exposed during the time frame does not exceed the float level sensor design.

19D.8.2.14 Containment Hatches (Gasket Material Only)

The equipment hatch and a personnel hatch are located at the operating deck elevation. The maintenance hatch and a second personnel hatch are located at the maintenance floor elevation. The gasket material of the hatches is required to perform throughout the severe accident to maintain the containment pressure boundary. In the severe accident environment, during hydrogen combustion, the equipment experiences ambient temperature conditions beyond their design basis. However, the hatches are enclosed in the thick metal of the hatch barrels. The internal temperature does not rise beyond that experienced during design basis equipment qualification testing. Therefore, there is reasonable assurance of survivability of this equipment.

19D.8.2.15 Containment Shell

The containment shell is used to maintain containment integrity. The shell is exposed to the severe accident environment in the upper compartment and Room 11300. The upper compartment shell is externally cooled by the PCS. In the analysis, the lower shell is modeled as a heat sink that is adiabatic on the external side and therefore provides the bounding temperature transient for the whole of the containment steel. The active operation time of the containment extends through Time Frame 3 (ex-vessel severe accident environment). The containment shell remains within the code limits during the severe accident. Therefore, the containment shell is expected to survive the severe accident pressure and temperatures predicted for the AP1000 plant.

19D.8.2.16 Assessment of Equipment for Sustained Burning

The equipment necessary for equipment survivability in sustained burning environments is defined in Tables 19D-3 through 19D-5. The equipment in Table 19D-3 includes equipment and instrumentation operation during Time Frame 1 - core uncovery and heatup, and is prior to the release of significant quantities of hydrogen. Therefore, it does not have to be qualified for sustained hydrogen burning. Table 19D-7 specifies the equipment and instrumentation used in Time Frames 2 and 3 to provide reasonable assurance of achieving a controlled stable state. The specific equipment located inside containment which must survive a severe accident for Time Frames 0 and 1 is listed in Table 19D-8 and in Table 19D-9 for severe accident Time Frames 2 and 3.

19D.8.3 Equipment Located Outside Containment

Other functions defined for severe accident management are performed outside containment and the equipment is not subjected to the harsh environment of the event. This equipment includes, but is not limited to:

- Steam line radiation monitor,
- Transmitters for monitoring steam line pressure,
- Passive containment cooling system flow and tank level,
- Containment atmosphere sampling function,
- Makeup pumps and flow measurement,
- RNS pumps and flow measurement,
- SFS pumps and flow measurement,
- RNS MOVs
- MFW pumps and valves,
- SFW pumps and valves,
- Steam generator PORVs and main steam bypass valves for depressurization,
- Recirculation pumps, PCS valves and fire water pumps and valves for containment heat removal,
- Containment isolation valves (outside containment),
- Auxiliary building radiation monitor,

- MOV and manual valve from RNS hot leg suction lines to the spent fuel pool and
- Fire water, fire pumps, valves and flow measurement used to provide containment spray and backup containment cooling.

19D.9 Conclusions of Equipment Survivability Assessment

The equipment defined for severe accident management was reviewed for performance during the environments postulated for these events. Survivability of the equipment was evaluated based on design basis event qualification testing, severe accident testing, and the survival time required following the initiation of the severe accident. The equipment that is qualified for design basis events has a high probability of surviving postulated severe accident events and performing satisfactorily for the time required.

This assessment provides reasonable assurance that equipment, both electrical and mechanical, used to mitigate the consequences of severe accidents and achieve a controlled, stable state can perform over the time span for which they are needed.

19D.10 References

19D-1. APP-GW-GL-027, “Framework for AP1000 Severe Accident Management Guidance,” Westinghouse Electric Company LLC.

19D-2. AP1000 Emergency Operating Procedures.

19D-3. APP-GW-GJR-400, “AP1000 Severe Accident Management Guidelines,” Westinghouse Electric Company LLC.

Table 19D-1
Definition of Equipment Survivability Time Frames

Time Frame	Beginning Time	Ending Time	Comments
0	Accident initiation	safe, stable state or core uncovery	• Bounded by design basis equipment qualification environment
1	Core uncovery	controlled, stable state or rapid cladding oxidation	• Core uncovery and heatup • Bounded by design basis equipment qualification environment
2	Rapid cladding oxidation	controlled, stable state or vessel failure	• In-vessel core melting and relocation • Entry into SAMG
3	Vessel failure	controlled, stable state or containment failure	• Ex-vessel core relocation

Table 19D-2
AP1000 High Level Actions Relative to Accident Management Goals

Goal	Element	High Level Action*
Controlled, stable core	water inventory in RCS	• inject into RCS • depressurize RCS
	water inventory in containment	• inject into containment
	heat transfer to IRWST	• initiate PRHR
	heat transfer to SGs	• inject into RCS • inject into SGs
	heat transfer to containment	• inject into RCS • inject into containment • depressurize RCS • initiate PRHR
Controlled, stable containment	heat transfer from containment	• depressurize containment • vent containment • water on outside containment
	isolation of containment	• inject into SGs • depressurize RCS
	hydrogen prevention/control	• burn hydrogen • pressurize containment • depressurize RCS • inject into containment • vent containment • water on outside containment
	core concrete interaction prevention	• inject into containment
	high pressure melt ejection prevention	• inject into containment • depressurize RCS
	creep rupture prevention	• depressurize RCS • inject into SGs
	containment vacuum prevention	• pressurize containment
Terminate fission product release	isolation of containment	• inject into SGs • depressurize RCS
	reduce fission product inventory	• inject into containment • depressurize RCS
	reduce fission product driving force	• depressurize containment • water on outside containment

Note:
* See Tables 19D-3, 19D-4 and 19D-5

Table 19D-3 (Sheet 1 of 3)
Equipment and Instrumentation Operation Prior to End of Time Frame 1 - Core Uncovery and Heatup

Action	Equipment	Instrumentation	Purpose	Comment
Inject into RCS	• CMT • accumulator • IRWST • CVS • RNS	• core-exit t/c's • RCS pressure • RCS RTDs • CVS flow • RNS flow • IRWST water level	• restore core cooling	• injection must often be recovered to be successful in severe accident
Inject to SGs	• MFW • SFW	• SG WR water level • steam line pressure	• decay heat removal • make SGs available to depressurize RCS • prevent SG tube creep rupture	• injection source must often be recovered to be successful in severe accident
Decay Heat Removal	• PRHR Hx • via SGs	• IRWST water level • IRWST temperature • core-exit t/c's • RCS RTDs	• decay heat removal	• only works if RCS is reflooded and IRWST water level covers PRHR Hx
Depressurize RCS	• ADS • aux pressurizer spray • via SGs • PRHR Hx	• RCS pressure • IRWST water level • IRWST temperature • steam line pressure	• facilitate injection to RCS • long term heat transfer path	• ADS often automatic
			• prevent SG tube creep rupture • containment integrity	• RCS depressurization required prior to significant cladding oxidation to prevent creep rupture
			• isolate break in SGTR	• uses intact SG or PRHR
			• prevent vessel failure	• requires injection to containment to be successful

Table 19D-3 (Sheet 2 of 3)
Equipment and Instrumentation Operation Prior to End of Time Frame 1 - Core Uncovery and Heatup

Action	Equipment	Instrumentation	Purpose	Comment
Depressurize SGs	• SG PORV • main steam bypass	• steam line pressure • RCS pressure • SG WR water level	• depressurize RCS • minimize pressure differential across SG tubes	• requires injection into SGs to prevent creep rupture
Inject Into Containment	• IRWST drains	• core-exit t/c's • containment water level • IRWST water level	• prevent vessel failure	• manual cavity flooding action in EOP
Containment Isolation	• containment isolation system • containment shell • penetrations • containment hatches (gasket material only)	• containment isolation system valve position • containment pressure	• containment integrity	• containment isolation system often automatic • manual action in EOP
Control Hydrogen	• igniter • PARs	• containment hydrogen monitors • containment atmosphere sampling functions • containment pressure	• containment integrity	• manual igniter action in EOP
Containment Heat Removal	• PCS water • external water	• containment pressure • PCS flowrate • PCS tank level	• containment integrity • alleviate environmental challenge to equipment • long term heat transfer path	• PCS water automatic

Table 19D-3 (Sheet 3 of 3)
Equipment and Instrumentation Operation Prior to End of Time Frame 1 - Core Uncovery and Heatup

Action	Equipment	Instrumentation	Purpose	Comment
Accident Monitoring		• SG radiation • containment pressure • containment temperature • containment hydrogen monitors • containment water level • containment radiation • containment atmosphere sampling functions • containment liquid sampling function • auxiliary building radiation • core-exit t/c's • RCS pressure • IRWST water level	• accident management • emergency response(1) • emergency action levels(1)	• required by 10 CFR 50.34(f)

Note:
1. Note that the instrumentation required for emergency response and emergency action levels is an open item because the EALs are not yet developed.

Table 19D-4 (Sheet 1 of 3)
Equipment and Instrumentation Operation During Time Frame 2 -
In-Vessel Core Melting and Relocation

Action	Equipment	Instrumentation	Purpose	Comment
Inject into RCS	• CMT • accumulator • IRWST • CVS • RNS	• RCS pressure • containment pressure • CVS flow • RNS flow • RCS temperature	• cool core debris in-vessel	• RCS injection needed to cool in-vessel debris for reasonable assurance of controlled, stable state
Decay Heat Removal	• via SGs	• SG WR water level • steam line pressure • core-exit t/c's • RCS RTDs	• decay heat removal	
Inject Into Containment	• containment spray • overflow IRWST • RNS • IRWST drains	• containment water level	• prevent vessel failure	• containment spray only actuated on high containment radiation in SAMG which occurs in Time Frame 2
Inject to SGs	• MFW • SFW	• SG WR water level • steam line pressure	• isolate containment in SGTR • scrub fission products	• also requires RCS depressurization for containment isolation
Depressurize RCS	• ADS • aux pressurizer spray • reactor vessel head vent	• RCS Pressure	• prevent vessel failure • containment integrity	• needed for in-vessel retention of core debris • needed for prevention of TI-SGTR • try to recover in Time Frame 2, if not successful in Time Frame 1

Table 19D-4 (Sheet 2 of 3)
Equipment and Instrumentation Operation During Time Frame 2 -
In-Vessel Core Melting and Relocation

Action	Equipment	Instrumentation	Purpose	Comment
Depressurize SGs				• not needed in Time Frame 2
Containment Heat Removal	• PCS water • external water • containment spray	• PCS flowrate • PCS tank level • containment water level • containment pressure	• containment integrity	• active operation completed in Time Frame 1; needs to be continued in Time Frame 2
Containment Isolation	• containment shell • penetrations • containment hatches (gasket material only)	• containment pressure	• containment integrity	• containment isolation system active operation completed in Time Frame 1
Control Hydrogen	• igniters • PARs	• containment hydrogen monitors • containment atmosphere sampling function • containment pressure	• containment integrity	• active operation continues in Time Frame 2 • monitors only required initially to verify hydrogen igniter operation
Control Fission Product Releases	• containment spray	• containment water level	• scrub fission products	• containment spray only actuated on high containment radiation in SAMG which occurs in Time Frame 2

Table 19D-4 (Sheet 3 of 3)
Equipment and Instrumentation Operation During Time Frame 2 -
In-Vessel Core Melting and Relocation

Action	Equipment	Instrumentation	Purpose	Comment
Accident Monitoring		• SG radiation • containment pressure • containment temperature • containment hydrogen monitors • containment water level • containment radiation • containment atmosphere sampling functions • containment liquid sampling function • auxiliary building radiation • RCS pressure	• accident management • emergency response(1) • emergency action levels(1)	• active operation continues in Time Frame 2

Note:
1. Note that the instrumentation required for emergency response and emergency action levels is an open item because the EALs are not yet developed.

Table 19D-5 (Sheet 1 of 2)
Equipment and Instrumentation Operation During Time Frame 3 - Ex-Vessel Core Relocation

Action	Equipment	Instrumentation	Purpose	Comment
Inject into RCS				• not needed in Time Frame 3
Decay heat removal				• not needed in Time Frame 3
Inject into SGs				• not needed in Time Frame 3
Depressurize RCS				• not needed in Time Frame 3
Depressurize SGs				• not needed in Time Frame 3
Inject Into Containment	• Containment spray • Overflow IRWST - CVS - RNS - SFS • IRWST drains	• containment water level	• cool ex-vessel core debris to prevent or mitigate consequences of CCI • scrub fission products released from ex-vessel core debris	• only get to Time Frame 3 if there is no water in containment or if RCS depressurization fails
Containment Heat Removal	• PCS water • external water • containment spray	• PCS flowrate • PCS tank level • containment water level • containment pressure	• containment integrity	• active operation completed in Time Frame 1; needs to be continued in Time Frame 3
Containment Isolation	• containment shell • penetrations • containment hatches (gasket material only)	• containment pressure • containment temperature	• containment integrity	• active operation of containment isolation system completed in Time Frame 1
	• RNS hot leg suction MOVs	• containment pressures • SFP water level	• containment vent	• manual action within SAMG
Control Hydrogen	• igniters	• containment atmosphere sampling function • containment pressure	• containment integrity	• active operation continues in Time Frame 3 • PARS may be effective in Time Frame 3 if igniters are not effective

Table 19D-5 (Sheet 2 of 2)
Equipment and Instrumentation Operation During Time Frame 3 - Ex-Vessel Core Relocation

Action	Equipment	Instrumentation	Purpose	Comment
Control Fission Product Release	• containment spray	• containment water level	• scrub fission products	• containment spay only actuated on high containment radiation in SAMG which occurs in Time Frame 3
Accident Monitoring		• SG radiation • containment pressure • containment temperature • containment hydrogen monitors • containment water level • containment radiation • containment atmosphere sampling function • containment liquid sampling function • auxiliary building radiation monitors	• accident management • emergency response(1) • emergency action levels(1)	• active operation continues in Time Frame 3

Note:
1. The instrumentation required for emergency response and emergency action levels is an open item because the EALs are not yet developed.

Table 19D-6 Not Used

Table 19D-7 (Sheet 1 of 3)
Sustained Hydrogen Combustion Survivability Assessment

EQUIPMENT AND INSTRUMENTATION	SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT
Equipment	
PXS equipment (injection)	The PXS equipment utilized for introduction of cooling water includes component redundancy and is separated into two delivery flow paths. The two flow paths are physically separated into two trains such that if one train is disabled due to a sustained burn from DVI or other line break within that subsystem, the other subsystem will function.
CVS equipment (injection)	The equipment providing for CVS injection is located within the CVS compartment with the exception of the CVS makeup isolation valve. In accordance with the above, a sustained burn will not occur within the CVS compartment and, therefore, the equipment within this compartment utilized for CVS makeup will be operable. The CVS makeup isolation valve is normally in the correct position for severe accident scenario and is considered operable.
RNS equipment (injection)	Injection via the RNS is dependent only upon check valves within containment and, therefore, is not susceptible to sustained burning effects.
Main Feedwater	The operability of main feedwater system to inject feedwater to steam generators is not dependent upon equipment located within containment and, therefore, is not susceptible to sustained burning effects.
Startup Feedwater	The operability of startup feedwater system to inject feedwater to steam generators is not dependent upon equipment located within containment and, therefore, is not susceptible to sustained burning effects.
Fire Water, containment spray, and external containment vessel cooling	The operability of the fire water system to provide makeup for containment spray and for external containment vessel cooling is not dependent upon equipment located within containment and, therefore, is not susceptible to sustained burning effects.

Table 19D-7 (Sheet 2 of 3)
Sustained Hydrogen Combustion Survivability Assessment

EQUIPMENT AND INSTRUMENTATION	SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT
Equipment	
Containment Shell	As discussed in Subsection 19.18.7 of this document, hydrogen plumes are located away from the containment shell to mitigate the threat to the containment integrity.
Containment Lower Equipment Hatch and Seals	The lower equipment hatch and seals on the containment vessel may be exposed to heat transfer from a sustained flame at the vents from the PXS valve/accumulator room to the maintenance floor. The equipment hatch and seals have been shown by analysis to be unlikely to fail or leak.
Igniters	Igniters are specified and designed to withstand the effects of sustained burning and, therefore, are considered operable for these events.
Instrumentation	
RCS Pressure	There are four RCS pressurizer pressure transmitters. Two transmitters are located at a distance greater than 75 feet from the vent from the PXS valve/accumulator room and are therefore beyond the distance that potentially causes operability concerns from a sustained flame. The other two transmitters are located in a different room from the fourth stage ADS valves. This precludes radiative heating, which could potentially cause operability concerns.
Containment Pressure	There are three extended range containment pressure transmitters. The three transmitters are located such that they cannot all be exposed to a sustained flame from either of the vents from the PXS valve/accumulator room into the maintenance floor at the base of the CMTs. Therefore, continued operability of the containment pressure function is provided.
SG 1 Wide Range Level	There are four steam generator wide range levels for SG 1. Two of the transmitters are located at a distance of greater than 20 feet from a CMT and are, therefore, beyond the distance that could potentially cause operability concerns from a sustained flame from the vent from the PXS valve/accumulator room into the maintenance floor at the base of the CMT. The other two transmitters are located over 20 feet below the fourth stage ADS valves. This precludes radiative heating, which could potentially cause operability concerns.
SG 2 Wide Range Level	Based on the layout of the four steam generator wide range levels for SG 2, at least two of the transmitters will not be exposed to a sustained flame from either of the vents from the PXS valve/accumulator room into the maintenance floor at the base of the CMTs. Therefore, continued operability of the SG 2 wide range level indication function is provided.

Table 19D-7 (Sheet 3 of 3)
Sustained Hydrogen Combustion Survivability Assessment

EQUIPMENT AND INSTRUMENTATION	SUSTAINED HYDROGEN COMBUSTION SURVIVABILITY ASSESSMENT
Instrumentation	
Containment Hydrogen Monitors	There are 3 containment hydrogen monitors located in the containment dome. There are no sustained burns that could potentially affect the sensors.
Containment Atmosphere Sampling Function	The capabilities to perform containment atmosphere sampling are discussed in Subsection 9.3.3.1.2.2 – Post-Accident Sampling. Successful containment atmosphere sampling is dependent on the availability of the containment atmosphere sampling isolation valves. The sample return function is provided by the containment air sample return containment isolation valves. The containment atmosphere sampling function provides a backup to the VLS hydrogen monitoring. The containment isolation valves are located less than 20 feet from the PXS-A compartment vent. The survivability of the valves has been considered in their placement in the containment. The sampling valve is located in Room 11300 which does not normally have a direct hydrogen source term. In the event of a specific primary pipe break (DVI line break), the potential hydrogen releases from the break would be mitigated by the ADS-4 valves and the hydrogen would be released to the loop compartment instead of Room 11300. The combination of failures that may be postulated to produce hydrogen releases and sustained burning in the vicinity has a low probability. There is reasonable assurance for the survivability of the valves by demonstrating that the valves survive the more likely hydrogen release scenarios.
Containment Liquid Sampling Function	The capabilities to perform containment liquid sampling are discussed in Subsection 9.3.3.1.2.2 – Post-Accident Sampling. Successful sampling is dependent on the availability of either of the hot leg sample source isolation valves and the containment isolation valves in series with the isolation valve. The sample isolation valve from reactor coolant hot leg number 1 is located in a different room from the fourth stage ADS valves. This precludes radiative heating, which could potentially cause operability concerns. The sample isolation valve from reactor coolant hot leg number 2 is located in a different room from the fourth stage ADS valves. This precludes radiative heating, which could potentially cause operability concerns. The containment isolation valves are located less than 20 feet from the PXS-A compartment vent. The survivability of the valves has been considered in their placement in the containment. The sampling valve is located in Room 11300 which does not normally have a direct hydrogen source term. In the event of a specific primary pipe break (DVI line break), potential hydrogen releases from the break would be mitigated by the ADS-4 valves and the hydrogen would be released to the loop compartment instead of Room 11300. The combination of failures that may be postulated to produce hydrogen releases from the break (DVI line break and common cause failures of multiple ADS-4 valves) and sustained burning in the vicinity of these valves has a low probability. Defense-in-depth precluding sustained combustion in this room provides reasonable assurance for the survivability of the valves, which are demonstrated to survive the more likely hydrogen release scenarios.

Table 19D-8 (Sheet 1 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
19D.8.2.1	**Differential Pressure and Pressure Transmitters**				
	PXS – IRWST Water Level	**T0,T1-A1,A2,A3,A4,A10**		**2**	**Sense level**
PXS-JE-LT046	IRWST Level Transmitter		11300		
PXS-JE-LT047	IRWST Level Transmitter		11300		
PXS-JE-LT048	IRWST Level Transmitter		11300		
	RCS Pressure	**T0,T1-A1,A4,A5,A10**		**2**	**Sense pressure**
RCS-JE-PT140A	RCS Wide Range Pressure Trans. A		11300		
RCS-JE-PT140C	RCS Wide Range Pressure Trans. C		11300		
RCS-JE-PT140B	RCS Wide Range Pressure Trans. B		11306		
RCS-JE-PT140D	RCS Wide Range Pressure Trans. D		11306		
	SG Wide Range Water Level	**T0,T1-A3,A5**		**2 per SG**	**Sense level**
SGS-JE-LT012	SG 1 Wide Range Level Transmitter		11201		
SGS-JE-LT016	SG 1 Wide Range Level Transmitter		11201		
SGS-JE-LT011	SG 1 Wide Range Level Transmitter		11300		
SGS-JE-LT015	SG 1 Wide Range Level Transmitter		11300		
SGS-JE-LT013	SG 2 Wide Range Level Transmitter		11300		
SGS-JE-LT014	SG 2 Wide Range Level Transmitter		11300		
SGS-JE-LT017	SG 2 Wide Range Level Transmitter		11300		
SGS-JE-LT018	SG 2 Wide Range Level Transmitter		11300		
	Containment Pressure	**T0,T1-A6,A7,A8,A10**		**2**	**Sense pressure**
PCS-JE-PT012	Extended Range Cont. Pressure 1		11400		
PCS-JE-PT013	Extended Range Cont. Pressure 2		11400		
PCS-JE-PT014	Extended Range Cont. Pressure 3		11400		
19D.8.2.2	**Thermocouples**				
	Core-exit Temperature	**T0,T1-A1,A2,A3,A10**		**2 (Note 2)**	**Sense temperature**
IIS-JE-TE002	Core-exit Thermocouple, B09		11105		
IIS-JE-TE003	Core-exit Thermocouple, C04		11105		
IIS-JE-TE005	Core-exit Thermocouple, C08		11105		
IIS-JE-TE008	Core-exit Thermocouple, E02		11105		
IIS-JE-TE010	Core-exit Thermocouple, E06		11105		
IIS-JE-TE012	Core-exit Thermocouple, E10		11105		

Table 19D-8 (Sheet 2 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
IIS-JE-TE015	Core-exit Thermocouple, G02		11105		
IIS-JE-TE016	Core-exit Thermocouple, G04		11105		
IIS-JE-TE017	Core-exit Thermocouple, G06		11105		
IIS-JE-TE020	Core-exit Thermocouple, G12		11105		
IIS-JE-TE021	Core-exit Thermocouple, G14		11105		
IIS-JE-TE025	Core-exit Thermocouple, J08		11105		
IIS-JE-TE026	Core-exit Thermocouple, J10		11105		
IIS-JE-TE030	Core-exit Thermocouple, L04		11105		
IIS-JE-TE033	Core-exit Thermocouple, L10		11105		
IIS-JE-TE035	Core-exit Thermocouple, L14		11105		
IIS-JE-TE038	Core-exit Thermocouple, N08		11105		
IIS-JE-TE039	Core-exit Thermocouple, N10		11105		
IIS-JE-TE040	Core-exit Thermocouple, N12		11105		
IIS-JE-TE041	Core-exit Thermocouple, P07		11105		
IIS-JE-TE001	Core-exit Thermocouple, B07		11105		
IIS-JE-TE004	Core-exit Thermocouple, C06		11105		
IIS-JE-TE006	Core-exit Thermocouple, C10		11105		
IIS-JE-TE009	Core-exit Thermocouple, E04		11105		
IIS-JE-TE013	Core-exit Thermocouple, E12		11105		
IIS-JE-TE014	Core-exit Thermocouple, E14		11105		
IIS-JE-TE018	Core-exit Thermocouple, G08		11105		
IIS-JE-TE019	Core-exit Thermocouple, G10		11105		
IIS-JE-TE022	Core-exit Thermocouple, J02		11105		
IIS-JE-TE023	Core-exit Thermocouple, J04		11105		
IIS-JE-TE024	Core-exit Thermocouple, J06		11105		
IIS-JE-TE027	Core-exit Thermocouple, J12		11105		
IIS-JE-TE029	Core-exit Thermocouple, L02		11105		
IIS-JE-TE031	Core-exit Thermocouple, L06		11105		
IIS-JE-TE034	Core-exit Thermocouple, L12		11105		

Table 19D-8 (Sheet 3 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
IIS-JE-TE036	Core-exit Thermocouple, N04		11105		
IIS-JE-TE037	Core-exit Thermocouple, N06		11105		
IIS-JE-TE007	Core-exit Thermocouple, C12		11105		
IIS-JE-TE011	Core-exit Thermocouple, E08		11105		
IIS-JE-TE028	Core-exit Thermocouple, K14		11105		
IIS-JE-TE032	Core-exit Thermocouple, L08		11105		
IIS-JE-TE042	Core-exit Thermocouple, P09		11105		
19D.8.2.3	**Resistance Temperature Detectors (RTDs)**				
	Hot Leg RTDs	**T0,T1-A1,A3**		**2**	**Sense temperature**
RCS-JE-TE135A	RCS Hot Leg 1 Wide Range RTD		11201		
RCS-JE-TE135B	RCS Hot Leg 2 Wide Range RTD		11202		
	Cold Leg RTDs	**T0,T1-A1,A3**		**2**	**Sense temperature**
RCS-JE-TE125A	RCS Cold Leg 1A Wide Range RTD		11201		
RCS-JE-TE125C	RCS Cold Leg 1B Wide Range RTD		11201		
RCS-JE-TE125B	RCS Cold Leg 2A Wide Range RTD		11202		
RCS-JE-TE125D	RCS Cold Leg 2B Wide Range RTD		11202		
	Containment Temperature	**T0,T1-A10**		**2**	**Sense temperature**
VCS-JE-TE053A	Operating Floor Area Temperature A		11500		
VCS-JE-TE053B	Operating Floor Area Temperature B		11500		
	IRWST Water Temperature	**T0,T1-A3,A4**		**2**	**Sense temperature**
PXS-JE-TE041	IRWST Water Temperature		11300, 11305		
PXS-JE-TE042	IRWST Water Temperature		11300, 11305		
PXS-JE-TE043	IRWST Water Temperature		11300, 11305		
PXS-JE-TE044	IRWST Water Temperature		11300, 11305		
19D.8.2.4	**Hydrogen Monitors**				
	Hydrogen Monitors	**T0,T1-A8,A10**		**2**	**Sense concentration**
VLS-JE-AE001	Hydrogen Monitor		11500		
VLS-JE-AE002	Hydrogen Monitor		11500		
VLS-JE-AE003	Hydrogen Monitor		11500		

Table 19D-8 (Sheet 4 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
19D.8.2.5	**Radiation Monitors**				
	PXS Radiation Monitors	**T0,T1-A10**		**2**	**Sense radiation**
PXS-JE-RE160	Containment Radiation Detector A		11500		
PXS-JE-RE161	Containment Radiation Detector B		11500		
PXS-JE-RE162	Containment Radiation Detector C		11500		
PXS-JE-RE163	Containment Radiation Detector D		11500		
19D.8.2.6	**Solenoid-Operated Valves (SOVs) and Air-Operated Valves (AOVs)**				
	PXS Core Makeup Tank AOVs	**T0,T1-A1**		**1 per CMT**	**Transfer open**
PXS-PL-V014A	CMT A Discharge Isolation		11206		
PXS-PL-V015A	CMT A Discharge Isolation		11206		
PXS-PL-V014B	CMT B Discharge Isolation		11207		
PXS-PL-V015B	CMT B Discharge Isolation		11207		
	PXS PRHR AOVs	**T0,T1-A3,A4**		**1**	**Transfer open**
PXS-PL-V108A	PRHR HX Control A		11300		
PXS-PL-V108B	PRHR HX Control B		11300		
	Containment Isolation AOVs and SOVs	**T1-A7**		**All**	**Varies, see below**
CVS-PL-V045	Letdown Containment Isolation		11300		Transfer close
PSS-PL-V008	Cont. Air Sample Cont. Isolation		11400		Transfer open and close
PSS-PL-V010A	Liquid Sample Line Cont. Isolation A		11400		Transfer open and close
PSS-PL-V010B	Liquid Sample Line Cont. Isolation B		11400		Transfer open and close
PSS-PL-V024	Containment Atmosphere Sample Return Isolation		11400		Transfer open and close
RNS-PL-V061	RNS Return from CVS Cont. Isolation		11208		Transfer close
VFS-PL-V004	Cont. Purge Inlet Cont. Isolation		11400		Transfer open and close
VFS-PL-V009	Cont. Purge Discharge Cont. Isolation		11400		Transfer open and close
VWS-PL-V082	Fan Coolers Return Cont. Isolation		11500		Transfer close
WLS-PL-V055	Sump Discharge Cont. Isolation		11300		Transfer close
WLS-PL-V067	RCDT Gas Outlet Cont. Isolation		11300		Transfer close

Table 19D-8 (Sheet 5 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
	CVS RCS Boundary AOVs	**T0,T1-A1**		**All**	**Transfer open and close**
CVS-PL-V081	RCS Purification Return Line Stop Valve		11304		
CVS-PL-V084	Auxiliary Pressurizer Spray Line Isolation		11304		
	Containment Sampling Function	**T0,T1-A8,A10**		**All**	**Transfer open and close**
PSS-PL-V001A/B	Hot Leg Sample Isol Valves	A10	11300		
PSS-PL-V010A/B	Liquid Sample Cont. Isol Valves	A10	11400		
PSS-PL-V008	Containment Air Sample Cont. Isolation	A8, A10	11400		
PSS-PL-V024	Containment Atmosphere Sample Return Isolation	A8, A10	11400		
PSS-PL-V002	Containment Sump Sample Isolation Valve	A10	11400		
	Reactor Vessel Head Vent SOVs	**T1-A4**		**2 valves in the same flowpath**	**Transfer open and close**
RCS-PL-V150A	Reactor Vessel Head Vent		11601		
RCS-PL-V150B	Reactor Vessel Head Vent		11601		
RCS-PL-V150C	Reactor Vessel Head Vent		11601		
RCS-PL-V150D	Reactor Vessel Head Vent		11601		
19D.8.2.7	**Motor-Operated Valves (MOVs)**				
	PXS Accumulator MOVs	**T1-A1**		**1 per Accum**	**Transfer open**
PXS-PL-V027A	Accumulator A Discharge Isolation		11206		
PXS-PL-V027B	Accumulator B Discharge Isolation		11207		
	PXS Core Makeup Tank MOVs	**T0,T1-A1**		**1 per CMT**	**Transfer open**
PXS-PL-V002A	CMT A Inlet Isolation		11400		
PXS-PL-V002B	CMT B Inlet Isolation		11400		
	PXS Recirculation MOVs	**T1-A2**		**1**	**Transfer open**
PXS-PL-V117A	Cont. Recirculation. A Isolation		11206		
PXS-PL-V117B	Cont. Recirculation. B Isolation		11207		
	ADS Stages 1, 2, 3, & 4 MOVs	**T1-A4**		**1 flowpath per stage**	**Transfer open**
RCS-PL-V001A	First Stage ADS A		11703		
RCS-PL-V011A	First Stage ADS Isolation A		11703		
RCS-PL-V002A	Second Stage ADS A		11703		
RCS-PL-V012A	Second Stage ADS Isolation A		11703		

Table 19D-8 (Sheet 6 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
RCS-PL-V003A	Third Stage ADS A		11703		
RCS-PL-V013A	Third Stage ADS Isolation A		11703		
RCS-PL-V001B	First Stage ADS B		11603		
RCS-PL-V011B	First Stage ADS Isolation B		11603		
RCS-PL-V002B	Second Stage ADS B		11603		
RCS-PL-V012B	Second Stage ADS Isolation B		11603		
RCS-PL-V003B	Third Stage ADS B		11603		
RCS-PL-V013B	Third Stage ADS Isolation B		11603		
RCS-PL-V014A	Fourth Stage ADS MOV		11301		
RCS-PL-V014B	Fourth Stage ADS MOV		11302		
RCS-PL-V014C	Fourth Stage ADS MOV		11301		
RCS-PL-V014D	Fourth Stage ADS MOV		11302		
	Containment Isolation MOVs	**T1-A7**		**All**	**Varies, see below**
CCS-PL-V207	CCS Containment Isolation Valve		11400		Transfer close
CVS-PL-V091	Makeup Line Cont. Isolation		11300		Transfer open and close
RNS-PL-V002A	RNS HL Suction & Cont. Isolation – A		11208		Transfer open and close
RNS-PL-V002B	RNS HL Suction & Cont. Isolation – B		11208		Transfer open and close
RNS-PL-V023	RNS Suction from IRWST – Cont. Isolation		11208		Transfer open and close
SFS-PL-V034	SFS Suction Line Cont. Isolation		11206		Transfer close
	CVS Charging and Injection MOVs	**T0, T1-A1**		**1**	**Transfer open and close**
CVS-PL-V091	Makeup Line Cont. Isolation		11300		
	RNS MOVs	**T1-A1**		**2**	**Transfer open and close**
RNS-PL-V001A/B	RNS Suction Isol from Hot Leg		11208		
RNS-PL-V002A/B	RNS Suction Isol from Hot Leg		11208		
RNS-PL-V023	RNS Suction from IRWST – Cont. Isolation		11208		
RNS-PL-V024	IRWST Discharge Isolation Valve		11206		

Table 19D-8 (Sheet 7 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
	PXS PRHR MOV	**T0, T1-A3, A4**		**1**	**Transfer open**
PXS-PL-V101	PRHR HX Inlet Isolation		11500		
19D.8.2.8	**Squib Valves**				
	IRWST Injection	**T1-A2**		**2**	**Transfer open**
PXS-PL-V123A	IRWST Injection Line A Squib Valve		11206		
PXS-PL-V125A	IRWST Injection Line A Squib Valve		11206		
PXS-PL-V123B	IRWST Injection Line B Squib Valve		11207		
PXS-PL-V125B	IRWST Injection Line B Squib Valve		11207		
	PXS Containment Recirculation	**T1-A2**		**2**	**Transfer open**
PXS-PL-V118A	Cont. Recirculation A Squib Valve		11206		
PXS-PL-V120A	Cont. Recirculation A Squib Valve		11206		
PXS-PL-V118B	Cont. Recirculation B Squib Valve		11207		
PXS-PL-V120B	Cont. Recirculation B Squib Valve		11207		
	Fourth Stage ADS	**T1-A4**		**3**	**Transfer open**
RCS-PL-V004A	Fourth Stage ADS A		11301		
RCS-PL-V004C	Fourth Stage ADS C		11301		
RCS-PL-V004B	Fourth Stage ADS B		11302		
RCS-PL-V004D	Fourth Stage ADS D		11302		
19D.8.2.9	**Position Sensors**				
	Valve Position Sensors	**T1-A7**		**All**	**Sense valve position**
CCS-PL-V207-L	CCS Containment Isolation Valve		11400		
CVS-PL-V045-L	Letdown Containment Isolation		11300		
CVS-PL-V091-L	Makeup Line Cont. Isolation		11300		
PSS-PL-V008-L	Containment Air Sample Cont. Isolation		11400		
PSS-PL-V010A-L	Liquid Sample Cont. Isolation Valve A		11400		
PSS-PL-V010B-L	Liquid Sample Cont. Isolation Valve B		11400		
PSS-PL-V024-L	Containment Atmosphere Sample Return Isolation		11400		
RNS-PL-V002A-L	RNS HL Suction & Cont. Isolation – A		11208		
RNS-PL-V002B-L	RNS HL Suction & Cont. Isolation – B		11208		
RNS-PL-V023-L	RNS Suction from IRWST – Cont. Isolation		11208		
RNS-PL-V061-L	RNS Return from CVS – Cont. Isolation		11208		

Table 19D-8 (Sheet 8 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
SFS-PL-V034-L	SFS Suction Line Cont. Isolation.		11206		
VFS-PL-V004-L	Containment Purge Inlet Cont. Isolation		11400		
VFS-PL-V009-L	Containment Discharge Cont. Isolation		11400		
VWS-PL-V082-L	Fan Coolers Return Cont. Isolation Valve		11500		
WLS-PL-V055-L	Sump Discharge Cont. Isolation		11300		
WLS-PL-V067-L	RCDT Gas Outlet Cont. Isolation		11300		
19D.8.2.10	**Hydrogen Igniters**				
	Hydrogen Igniters	**T1-A8**		**Note 3**	**Ignite hydrogen**
VLS-EH-01	Hydrogen Igniter 01, 1		11204		
VLS-EH-02	Hydrogen Igniter 02, 2		11204		
VLS-EH-03	Hydrogen Igniter 03, 1		11204		
VLS-EH-04	Hydrogen Igniter 04, 2		11204		
VLS-EH-05	Hydrogen Igniter 05, 1		11402		
VLS-EH-06	Hydrogen Igniter 06, 2		11502		
VLS-EH-07	Hydrogen Igniter 07, 2		11402		
VLS-EH-08	Hydrogen Igniter 08, 1		11502		
VLS-EH-09	Hydrogen Igniter 09, 1		11305		
VLS-EH-10	Hydrogen Igniter 10, 2		11305		
VLS-EH-11	Hydrogen Igniter 11, 2		11401		
VLS-EH-12	Hydrogen Igniter 12, 1		11501		
VLS-EH-13	Hydrogen Igniter 13, 1		11401		
VLS-EH-14	Hydrogen Igniter 14, 2		11501		
VLS-EH-15	Hydrogen Igniter 15, 2		11305		
VLS-EH-16	Hydrogen Igniter 16, 1		11305		
VLS-EH-17	Hydrogen Igniter 17, 2		11207		
VLS-EH-18	Hydrogen Igniter 18, 1		11207		
VLS-EH-19	Hydrogen Igniter 19, 2		11208		
VLS-EH-20	Hydrogen Igniter 20, 2		11206		
VLS-EH-21	Hydrogen Igniter 21, 1		11206		
VLS-EH-22	Hydrogen Igniter 22, 1		11400		
VLS-EH-23	Hydrogen Igniter 23, 2		11400		
VLS-EH-24	Hydrogen Igniter 24, 2		11400		

Table 19D-8 (Sheet 9 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
VLS-EH-25	Hydrogen Igniter 25, 2		11400		
VLS-EH-26	Hydrogen Igniter 26, 2		11400		
VLS-EH-27	Hydrogen Igniter 27, 1		11300		
VLS-EH-28	Hydrogen Igniter 28, 1		11400		
VLS-EH-29	Hydrogen Igniter 29, 1		11400		
VLS-EH-30	Hydrogen Igniter 30, 2		11403		
VLS-EH-31	Hydrogen Igniter 31, 1		11400		
VLS-EH-32	Hydrogen Igniter 32, 1		11400		
VLS-EH-33	Hydrogen Igniter 33, 2		11209		
VLS-EH-34	Hydrogen Igniter 34, 1		11209		
VLS-EH-35	Hydrogen Igniter 35, 1		11500		
VLS-EH-36	Hydrogen Igniter 36, 2		11500		
VLS-EH-37	Hydrogen Igniter 37, 1		11500		
VLS-EH-38	Hydrogen Igniter 38, 2		11500		
VLS-EH-39	Hydrogen Igniter 39, 1		11500		
VLS-EH-40	Hydrogen Igniter 40, 2		11500		
VLS-EH-41	Hydrogen Igniter 41, 2		11500		
VLS-EH-42	Hydrogen Igniter 42, 1		11500		
VLS-EH-43	Hydrogen Igniter 43, 1		11500		
VLS-EH-44	Hydrogen Igniter 44, 1		11500		
VLS-EH-45	Hydrogen Igniter 45, 2		11500		
VLS-EH-46	Hydrogen Igniter 46, 2		11500		
VLS-EH-47	Hydrogen Igniter 47, 1		11500		
VLS-EH-48	Hydrogen Igniter 48, 2		11500		
VLS-EH-49	Hydrogen Igniter 49, 1		11503		
VLS-EH-50	Hydrogen Igniter 50, 2		11503		
VLS-EH-51	Hydrogen Igniter 51, 1		11500		
VLS-EH-52	Hydrogen Igniter 52, 2		11500		
VLS-EH-53	Hydrogen Igniter 53, 2		11500		
VLS-EH-54	Hydrogen Igniter 54, 1		11500		
VLS-EH-55	Hydrogen Igniter 55, 1		11504		
VLS-EH-56	Hydrogen Igniter 56, 2		11504		

Table 19D-8 (Sheet 10 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
VLS-EH-57	Hydrogen Igniter 57, 2		11504		
VLS-EH-58	Hydrogen Igniter 58, 1		11504		
VLS-EH-59	Hydrogen Igniter 59, 2		11503		
VLS-EH-60	Hydrogen Igniter 60, 1		11503		
VLS-EH-61	Hydrogen Igniter 61, 1		11500		
VLS-EH-62	Hydrogen Igniter 62, 2		11500		
VLS-EH-63	Hydrogen Igniter 63, 1		11500		
VLS-EH-64	Hydrogen Igniter 64, 2		11500		
VLS-EH-65	Hydrogen Igniter 65, 1		11500		
VLS-EH-66	Hydrogen Igniter 66, 2		11500		
19D.8.2.11	**Electrical Containment Penetration Assemblies**				
	Electrical Containment Penetration Assemblies	**T1-A7**		**All**	**Maintain containment boundary; Conduct electricity for sensors and igniters**
ECS-EY-P01X	Electrical Penetration P01		11400		
ECS-EY-P02X	Electrical Penetration P02		11400		
DAS-EY-P03Z	Electrical Penetration P03		11400		
ECS-EY-P06Y	Electrical Penetration P06		11400		
ECS-EY-P07X	Electrical Penetration P07		11400		
ECS-EY-P09W	Electrical Penetration P09		11400		
ECS-EY-P10W	Electrical Penetration P10		11400		
IDSA-EY-P11Z	1E Electrical Penetration P11		11400		
IDSA-EY-P12Y	1E Electrical Penetration P12		11400		
IDSA-EY-P13Y	1E Electrical Penetration P13		11400		
IDSD-EY-P14Z	1E Electrical Penetration P14		11306		
IDSD-EY-P15Y	1E Electrical Penetration P15		11306		
IDSD-EY-P16Y	1E Electrical Penetration P16		11306		
ECS-EY-P17X	Electrical Penetration P17		11300		
ECS-EY-P18X	Electrical Penetration P18		11300		

Table 19D-8 (Sheet 11 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
ECS-EY-P19Z	Electrical Penetration P19		11300		
ECS-EY-P20Z	Electrical Penetration P20		11300		
EDS-EY-P21Z	Electrical Penetration P21		11300		
ECS-EY-P22X	Electrical Penetration P22		11300		
ECS-EY-P23X	Electrical Penetration P23		11300		
ECS-EY-P24	Spare Electrical Penetration		11300		
ECS-EY-P25W	Electrical Penetration P25		11300		
ECS-EY-P26W	Electrical Penetration P26		11300		
IDSC-EY-P27Z	1E Electrical Penetration P27		11300		
IDSC-EY-P28Y	1E Electrical Penetration P28		11300		
IDSC-EY-P29Y	1E Electrical Penetration P29		11300		
IDSB-EY-P30Z	1E Electrical Penetration P30		11306		
IDSB-EY-P31Y	1E Electrical Penetration P31		11306		
IDSB-EY-P32Y	1E Electrical Penetration P32		11306		
19D.8.2.12	**Cables**				
	Cables	**T0,T1-A10**	**Note 1**	**All**	**Conduct electricity for valves, sensors and igniters**
19D.8.2.13	**Float Level Sensors**				
	PXS Containment Water Level	**T0,T1-A2,A10**		**2**	**Sense level**
PXS-JE-LE050	Containment Floodup Level		11104		
PXS-JE-LE052	Containment Floodup Level		11104		
PXS-JE-LE051	Containment Floodup Level		11104		
19D.8.2.14	**Containment Hatches (Gasket Material Only)**				
	Containment Hatches (Gasket Material Only)	**T0,T1-A7**		**All**	**Maintain containment boundary**
CNS-MY-Y01	Equipment Hatch		11500		
CNS-MY-Y02	Maintenance Hatch		11300		
CNS-MY-Y03	Personnel Hatch – Upper		11500		
CNS-MY-Y04	Personnel Hatch – Lower		11300		

Table 19D-8 (Sheet 12 of 12)
Equipment Located Inside Containment (Time Frames T0 and T1)

Section and Equip Tag No.	Description	Time Frames T0,T1 and Actions (Notes 4, 5)	Room Number	Required Channels/ Divisions	Function
19D.8.2.15	**Containment Vessel**				
	Containment Vessel	**T0,T1-A7**			**Maintain containment boundary**
CNS-MV-01	Containment Shell				

Notes:
1. Cables are located in most rooms inside containment.
2. A channel consists of two thermocouples within a single division. Each quadrant contains two divisions. The minimum requirement is two OPERABLE thermocouples in each of the two divisions for each quadrant. All Core Exit Thermocouples are located inside the Reactor Pressure Vessel which is in Room 11105 (reactor cavity).
3. There are two groups of igniters. Each containment compartment and hydrogen pathway is covered by at least one igniter in each group. The minimum requirement is one igniter is OPERABLE in each compartment and hydrogen pathway.
4. See Appendix 19D, Section 19D.4 for definitions of Equipment Survivability Time Frames T0 and T1.
5. See Appendix 19D, Section 19D.6 for Actions associated with Time Frames T0 and T1.
   - A1 = Subsection 19D.6.1.1
   - A2 = Subsection 19D.6.1.2
   - A3 = Subsection 19D.6.1.3
   - A4 = Subsection 19D.6.1.4
   - A5 = Subsection 19D.6.1.5
   - A6 = Subsection 19D.6.1.6
   - A7 = Subsection 19D.6.1.7
   - A8 = Subsection 19D.6.1.8
   - A10 = Subsection 19D.6.1.9

Table 19D-9 (Sheet 1 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
19D.8.2.1	**Differential Pressure and Pressure Transmitters**				
	RCS Pressure	**T2-A1, A4, A10**		**2**	**Sense pressure**
RCS-JE-PT140A	RCS Wide Range Pressure Trans. A		11300		
RCS-JE-PT140C	RCS Wide Range Pressure Trans. C		11300		
RCS-JE-PT140B	RCS Wide Range Pressure Trans. B		11306		
RCS-JE-PT140D	RCS Wide Range Pressure Trans. D		11306		
	SG Wide Range Water Level	**T2-A3**		**2 per SG**	**Sense level**
SGS-JE-LT012	SG 1 Wide Range Level Transmitter		11201		
SGS-JE-LT016	SG 1 Wide Range Level Transmitter		11201		
SGS-JE-LT011	SG 1 Wide Range Level Transmitter		11300		
SGS-JE-LT015	SG 1 Wide Range Level Transmitter		11300		
SGS-JE-LT013	SG 2 Wide Range Level Transmitter		11300		
SGS-JE-LT014	SG 2 Wide Range Level Transmitter		11300		
SGS-JE-LT017	SG 2 Wide Range Level Transmitter		11300		
SGS-JE-LT018	SG 2 Wide Range Level Transmitter		11300		
	Containment Pressure	**T2-A1, T2, T3-A6, A7, A8, A10**		**2**	**Sense pressure**
PCS-JE-PT012	Extended Range Cont. Pressure 1		11400		
PCS-JE-PT013	Extended Range Cont. Pressure 2		11400		
PCS-JE-PT014	Extended Range Cont. Pressure 3		11400		
19D.8.2.2	**Thermocouples**				
	Core-exit Temperature	**T2-A3, A10**		**2 (Note 2)**	**Sense temperature**
IIS-JE-TE002	Core-exit Thermocouple, B09		11105		
IIS-JE-TE003	Core-exit Thermocouple, C04		11105		
IIS-JE-TE005	Core-exit Thermocouple, C08		11105		
IIS-JE-TE008	Core-exit Thermocouple, E02		11105		
IIS-JE-TE010	Core-exit Thermocouple, E06		11105		
IIS-JE-TE012	Core-exit Thermocouple, E10		11105		
IIS-JE-TE015	Core-exit Thermocouple, G02		11105		
IIS-JE-TE016	Core-exit Thermocouple, G04		11105		

Table 19D-9 (Sheet 2 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
IIS-JE-TE017	Core-exit Thermocouple, G06		11105		
IIS-JE-TE020	Core-exit Thermocouple, G12		11105		
IIS-JE-TE021	Core-exit Thermocouple, G14		11105		
IIS-JE-TE025	Core-exit Thermocouple, J08		11105		
IIS-JE-TE026	Core-exit Thermocouple, J10		11105		
IIS-JE-TE030	Core-exit Thermocouple, L04		11105		
IIS-JE-TE033	Core-exit Thermocouple, L10		11105		
IIS-JE-TE035	Core-exit Thermocouple, L14		11105		
IIS-JE-TE038	Core-exit Thermocouple, N08		11105		
IIS-JE-TE039	Core-exit Thermocouple, N10		11105		
IIS-JE-TE040	Core-exit Thermocouple, N12		11105		
IIS-JE-TE041	Core-exit Thermocouple, P07		11105		
IIS-JE-TE001	Core-exit Thermocouple, B07		11105		
IIS-JE-TE004	Core-exit Thermocouple, C06		11105		
IIS-JE-TE006	Core-exit Thermocouple, C10		11105		
IIS-JE-TE009	Core-exit Thermocouple, E04		11105		
IIS-JE-TE013	Core-exit Thermocouple, E12		11105		
IIS-JE-TE014	Core-exit Thermocouple, E14		11105		
IIS-JE-TE018	Core-exit Thermocouple, G08		11105		
IIS-JE-TE019	Core-exit Thermocouple, G10		11105		
IIS-JE-TE022	Core-exit Thermocouple, J02		11105		
IIS-JE-TE023	Core-exit Thermocouple, J04		11105		
IIS-JE-TE024	Core-exit Thermocouple, J06		11105		
IIS-JE-TE027	Core-exit Thermocouple, J12		11105		
IIS-JE-TE029	Core-exit Thermocouple, L02		11105		
IIS-JE-TE031	Core-exit Thermocouple, L06		11105		
IIS-JE-TE034	Core-exit Thermocouple, L12		11105		

Table 19D-9 (Sheet 3 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
IIS-JE-TE036	Core-exit Thermocouple, N04		11105		
IIS-JE-TE037	Core-exit Thermocouple, N06		11105		
IIS-JE-TE007	Core-exit Thermocouple, C12		11105		
IIS-JE-TE011	Core-exit Thermocouple, E08		11105		
IIS-JE-TE028	Core-exit Thermocouple, K14		11105		
IIS-JE-TE032	Core-exit Thermocouple, L08		11105		
IIS-JE-TE042	Core-exit Thermocouple, P09		11105		
19D.8.2.3	**Resistance Temperature Detectors (RTDs)**				
	Hot Leg RTDs	**T2-A1,A3**		**2**	**Sense temperature**
RCS-JE-TE135A	RCS Hot Leg 1 Wide Range RTD		11201		
RCS-JE-TE135B	RCS Hot Leg 2 Wide Range RTD		11202		
	Cold Leg RTDs	**T2-A1,A3**		**2**	**Sense temperature**
RCS-JE-TE125A	RCS Cold Leg 1A Wide Range RTD		11201		
RCS-JE-TE125C	RCS Cold Leg 1B Wide Range RTD		11201		
RCS-JE-TE125B	RCS Cold Leg 2A Wide Range RTD		11202		
RCS-JE-TE125D	RCS Cold Leg 2B Wide Range RTD		11202		
	Containment Temperature	**T3-A7,T2,T3-A10**		**2**	**Sense temperature**
VCS-JE-TE053A	Operating Floor Area Temperature A		11500		
VCS-JE-TE053B	Operating Floor Area Temperature B		11500		
19D.8.2.4	**Hydrogen Monitors**				
	Hydrogen Monitors	**T2-A8,T2,T3-A10**		**2**	**Sense concentration**
VLS-JE-AE001	Hydrogen Monitor		11500		
VLS-JE-AE002	Hydrogen Monitor		11500		
VLS-JE-AE003	Hydrogen Monitor		11500		
19D.8.2.5	**Radiation Monitors**				
	PXS Radiation Monitors	**T2,T3-A10**		**2**	**Sense radiation**
PXS-JE-RE160	Containment Radiation Detector A		11500		
PXS-JE-RE161	Containment Radiation Detector B		11500		
PXS-JE-RE162	Containment Radiation Detector C		11500		
PXS-JE-RE163	Containment Radiation Detector D		11500		

Table 19D-9 (Sheet 4 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
19D.8.2.6	**Solenoid-Operated Valves (SOVs) and Air-Operated Valves (AOVs)**				
	CVS RCS Boundary AOVs	**T2-A1,A4**		**All**	**Transfer open and close**
CVS-PL-V081	RCS Purification Return Line Stop Valve		11304		
CVS-PL-V084	Auxiliary Pressurizer Spray Line Isolation		11304		
	Containment Spray AOVs	**T2,T3-A2,A6,A9**	**Note 4**	**All**	**Transfer open**
FPS-PL-V701	Containment Spray Header AOV		11500		
	Containment Sampling Function	**T2,T3-A8,A10**		**All**	**Transfer open and close**
PSS-PL-V001A/B	Hot Leg Sample Isol Valves	**A10**	11300		
PSS-PL-V010A/B	Liquid Sample Cont. Isol Valves	**A10**	11400		
PSS-PL-V008	Containment Air Sample Cont. Isolation	**A8, A10**	11400		
PSS-PL-V024	Containment Atmosphere Sample Return Isolation	**A8, A10**	11400		
PSS-PL-V002	Containment Sump Sample Isolation Valve	**A10**	11400		
	Reactor Vessel Head Vent SOVs	**T2-A4**		**2 valves in the same flowpath**	**Transfer open and close**
RCS-PL-V150A	Reactor Vessel Head Vent		11601		
RCS-PL-V150B	Reactor Vessel Head Vent		11601		
RCS-PL-V150C	Reactor Vessel Head Vent		11601		
RCS-PL-V150D	Reactor Vessel Head Vent		11601		
	PXS AOV	**T2, T3-A2**		**1 valve**	**Transfer open**
CVS-PL-V089	PXS Makeup AOV		11300		
PXS-PL-V234	IRWST makeup AOV		11400		
19D.8.2.7	**Motor-Operated Valves (MOVs)**				
	CVS Charging and Injection MOVs	**T2-A1**		**All**	**Transfer open**
CVS-PL-V091	Makeup Line Cont. Isolation		11300		
	RNS MOVs	**T2,T3-A2, A7**		**All**	**Transfer open and close**
RNS-PL-V024	IRWST Discharge Isolation Valve	A2	11206		
RNS-PL-V001A	RNS HL Suction Isolation – Inner A	A2, A7	11208	**2 valves in the same flowpath**	
RNS-PL-V001B	RNS HL Suction Isolation – Inner B	A2, A7	11208		
RNS-PL-V002A	RNS HL Suction & Cont. Isolation – A	A2, A7	11208		
RNS-PL-V002B	RNS HL Suction & Cont. Isolation – B	A2, A7	11208		

Table 19D-9 (Sheet 5 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
19D.8.2.10	**Hydrogen Igniters**				
	Hydrogen Igniters	**T2,T3-A8**		**Note 3**	**Ignite hydrogen**
VLS-EH-01	Hydrogen Igniter 01, 1		11204		
VLS-EH-02	Hydrogen Igniter 02, 2		11204		
VLS-EH-03	Hydrogen Igniter 03, 1		11204		
VLS-EH-04	Hydrogen Igniter 04, 2		11204		
VLS-EH-05	Hydrogen Igniter 05, 1		11402		
VLS-EH-06	Hydrogen Igniter 06, 2		11502		
VLS-EH-07	Hydrogen Igniter 07, 2		11402		
VLS-EH-08	Hydrogen Igniter 08, 1		11502		
VLS-EH-09	Hydrogen Igniter 09, 1		11305		
VLS-EH-10	Hydrogen Igniter 10, 2		11305		
VLS-EH-11	Hydrogen Igniter 11, 2		11401		
VLS-EH-12	Hydrogen Igniter 12, 1		11501		
VLS-EH-13	Hydrogen Igniter 13, 1		11401		
VLS-EH-14	Hydrogen Igniter 14, 2		11501		
VLS-EH-15	Hydrogen Igniter 15, 2		11305		
VLS-EH-16	Hydrogen Igniter 16, 1		11305		
VLS-EH-17	Hydrogen Igniter 17, 2		11207		
VLS-EH-18	Hydrogen Igniter 18, 1		11207		
VLS-EH-19	Hydrogen Igniter 19, 2		11208		
VLS-EH-20	Hydrogen Igniter 20, 2		11206		
VLS-EH-21	Hydrogen Igniter 21, 1		11206		
VLS-EH-22	Hydrogen Igniter 22, 1		11400		
VLS-EH-23	Hydrogen Igniter 23, 2		11400		
VLS-EH-24	Hydrogen Igniter 24, 2		11400		
VLS-EH-25	Hydrogen Igniter 25, 2		11400		
VLS-EH-26	Hydrogen Igniter 26, 2		11400		

Table 19D-9 (Sheet 6 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
VLS-EH-27	Hydrogen Igniter 27, 1		11300		
VLS-EH-28	Hydrogen Igniter 28, 1		11400		
VLS-EH-29	Hydrogen Igniter 29, 1		11400		
VLS-EH-30	Hydrogen Igniter 30, 2		11403		
VLS-EH-31	Hydrogen Igniter 31, 1		11400		
VLS-EH-32	Hydrogen Igniter 32, 1		11400		
VLS-EH-33	Hydrogen Igniter 33, 2		11209		
VLS-EH-34	Hydrogen Igniter 34, 1		11209		
VLS-EH-35	Hydrogen Igniter 35, 1		11500		
VLS-EH-36	Hydrogen Igniter 36, 2		11500		
VLS-EH-37	Hydrogen Igniter 37, 1		11500		
VLS-EH-38	Hydrogen Igniter 38, 2		11500		
VLS-EH-39	Hydrogen Igniter 39, 1		11500		
VLS-EH-40	Hydrogen Igniter 40, 2		11500		
VLS-EH-41	Hydrogen Igniter 41, 2		11500		
VLS-EH-42	Hydrogen Igniter 42, 1		11500		
VLS-EH-43	Hydrogen Igniter 43, 1		11500		
VLS-EH-44	Hydrogen Igniter 44, 1		11500		
VLS-EH-45	Hydrogen Igniter 45, 2		11500		
VLS-EH-46	Hydrogen Igniter 46, 2		11500		
VLS-EH-47	Hydrogen Igniter 47, 1		11500		
VLS-EH-48	Hydrogen Igniter 48, 2		11500		
VLS-EH-49	Hydrogen Igniter 49, 1		11503		
VLS-EH-50	Hydrogen Igniter 50, 2		11503		
VLS-EH-51	Hydrogen Igniter 51, 1		11500		
VLS-EH-52	Hydrogen Igniter 52, 2		11500		
VLS-EH-53	Hydrogen Igniter 53, 2		11500		
VLS-EH-54	Hydrogen Igniter 54, 1		11500		

Table 19D-9 (Sheet 7 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
VLS-EH-55	Hydrogen Igniter 55, 1		11504		
VLS-EH-56	Hydrogen Igniter 56, 2		11504		
VLS-EH-57	Hydrogen Igniter 57, 2		11504		
VLS-EH-58	Hydrogen Igniter 58, 1		11504		
VLS-EH-59	Hydrogen Igniter 59, 2		11503		
VLS-EH-60	Hydrogen Igniter 60, 1		11503		
VLS-EH-61	Hydrogen Igniter 61, 1		11500		
VLS-EH-62	Hydrogen Igniter 62, 2		11500		
VLS-EH-63	Hydrogen Igniter 63, 1		11500		
VLS-EH-64	Hydrogen Igniter 64, 2		11500		
VLS-EH-65	Hydrogen Igniter 65, 1		11500		
VLS-EH-66	Hydrogen Igniter 66, 2		11500		
19D.8.2.11	**Electrical Containment Penetration Assemblies**				
	Electrical Containment Penetration Assemblies	**T2,T3-A7**		**All**	**Maintain containment boundary; Conduct electricity for sensors and igniters**
ECS-EY-P01X	Electrical Penetration P01		11400		
ECS-EY-P02X	Electrical Penetration P02		11400		
DAS-EY-P03Z	Electrical Penetration P03		11400		
ECS-EY-P06Y	Electrical Penetration P06		11400		
ECS-EY-P07X	Electrical Penetration P07		11400		
ECS-EY-P09W	Electrical Penetration P09		11400		
ECS-EY-P10W	Electrical Penetration P10		11400		
IDSA-EY-P11Z	1E Electrical Penetration P11		11400		
IDSA-EY-P12Y	1E Electrical Penetration P12		11400		
IDSA-EY-P13Y	1E Electrical Penetration P13		11400		
IDSD-EY-P14Z	1E Electrical Penetration P14		11306		
IDSD-EY-P15Y	1E Electrical Penetration P15		11306		

Table 19D-9 (Sheet 8 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
IDSD-EY-P16Y	1E Electrical Penetration P16		11306		
ECS-EY-P17X	Electrical Penetration P17		11300		
ECS-EY-P18X	Electrical Penetration P18		11300		
ECS-EY-P19Z	Electrical Penetration P19		11300		
ECS-EY-P20Z	Electrical Penetration P20		11300		
EDS-EY-P21Z	Electrical Penetration P21		11300		
ECS-EY-P22X	Electrical Penetration P22		11300		
ECS-EY-P23X	Electrical Penetration P23		11300		
ECS-EY-P24	Spare Electrical Penetration		11300		
ECS-EY-P25W	Electrical Penetration P25		11300		
ECS-EY-P26W	Electrical Penetration P26		11300		
IDSC-EY-P27Z	1E Electrical Penetration P27		11300		
IDSC-EY-P28Y	1E Electrical Penetration P28		11300		
IDSC-EY-P29Y	1E Electrical Penetration P29		11300		
IDSB-EY-P30Z	1E Electrical Penetration P30		11306		
IDSB-EY-P31Y	1E Electrical Penetration P31		11306		
IDSB-EY-P32Y	1E Electrical Penetration P32		11306		
19D.8.2.12	**Cables**				
	Cables	**T2,T3-A10**	**Note 1**	**All**	**Conduct electricity for valves, sensors and igniters**
19D.8.2.13	**Float Level Sensors**				
	PXS Containment Water Level	**T2,T3-A2,A6,A9,A10**		**2**	**Sense level**
PXS-JE-LE050	Containment Floodup Level		11104		
PXS-JE-LE052	Containment Floodup Level		11104		
PXS-JE-LE051	Containment Floodup Level		11104		
19D.8.2.14	**Containment Hatches (Gasket Material Only)**				
	Containment Hatches (Gasket Material Only)	**T2,T3-A7**		**All**	**Maintain containment boundary**
CNS-MY-Y01	Equipment Hatch		11500		
CNS-MY-Y02	Maintenance Hatch		11300		
CNS-MY-Y03	Personnel Hatch – Upper		11500		
CNS-MY-Y04	Personnel Hatch – Lower		11300		

Table 19D-9 (Sheet 9 of 9)
Equipment Located Inside Containment (Time Frames T2 and T3)

Section and Equip Tag No.	Description	Time Frames T2,T3 and Actions (Notes 6, 7)	Room Number	Desired Channels/ Divisions (Note 5)	Function
19D.8.2.15	**Containment Vessel**				
	Containment Vessel	**T2,T3-A7**		**All**	**Maintain containment boundary**
CNS-MV-01	Containment Shell				

Notes:
1. Cables are located in most rooms inside containment.
2. A channel consists of two thermocouples within a single division. Each quadrant contains two divisions. The minimum requirement is two OPERABLE thermocouples in each of the two divisions for each quadrant. All Core Exit Thermocouples (CETs) are located inside the Reactor Pressure Vessel which is in Room 11105 (reactor cavity).
3. There are two groups of igniters. Each containment compartment and hydrogen pathway is covered by at least one igniter in each group. The minimum requirement is one igniter is OPERABLE in each compartment and hydrogen pathway.
4. Equipment is part of the fire protection system, on vertical pipe inside containment, feeding water to top rings, Room 11500.
5. Time Frames T2 and T3 are beyond design basis, and therefore, only one channel of each instrumentation parameter is required to be OPERABLE. However, it is preferred to have more than one channel of each parameter available to resolve information ambiguity.
6. See Appendix 19D, Section 19D.4 for definitions of Equipment Survivability Time Frames T2 and T3.
7. See Appendix 19D, Section 19D.6 for Actions associated with Time Frames T2 and T3.

Time Frame T2

- A1 = Subsection 19D.6.2.1
- A2 = Subsection 19D.6.2.2
- A3 = Subsection 19D.6.2.3
- A4 = Subsection 19D.6.2.4
- A5 = Subsection 19D.6.2.5
- A6 = Subsection 19D.6.2.6
- A7 = Subsection 19D.6.2.7
- A8 = Subsection 19D.6.2.8
- A9 = Subsection 19D.6.2.9
- A10 = Subsection 19D.6.2.10

Time Frame T3

- A1 = Subsection 19D.6.3.1
- A2 = Subsection 19D.6.3.2
- A3 = Subsection 19D.6.3.3
- A4 = Subsection 19D.6.3.4
- A5 = Subsection 19D.6.3.5
- A6 = Subsection 19D.6.3.6
- A7 = Subsection 19D.6.3.7
- A8 = Subsection 19D.6.3.8
- A9 = Subsection 19D.6.3.9
- A10 = Subsection 19D.6.3.10

Appendix 19E Shutdown Evaluation

19E.1 Introduction

Westinghouse has considered shutdown operations in the design of the A1000 nuclear power plant. The AP1000 defense-in-depth design philosophy to provide normally operating active systems and passive safety-related systems gives the AP1000 a greater degree of safety during shutdown operations as well as normal power operation when compared to currently operating plants. This appendix presents and evaluates the AP1000 design features in the context of the specific shutdown issues identified by the Nuclear Regulatory Commission.

19E.1.1 Purpose

This appendix presents AP1000 design features that address the issues of shutdown risk and shutdown safety. This appendix further evaluates these design features with respect to their ability to reduce and or mitigate the consequences of events that can occur during shutdown.

19E.1.2 Scope

The scope of this appendix includes discussions of the following:

- Systems designed to operate during shutdown
- Shutdown operations – including maintenance insights, risk management, and Emergency Response Guidelines (ERGs) (Reference 1)
- Safety analyses and evaluations for shutdown operations
- Technical Specifications
- Shutdown risk evaluations – including shutdown PRA results and insights and fire/flood risk
- Compliance with the guidance in NUREG-1449 (Reference 2)

19E.1.3 Background

The Diablo Canyon event of April 10, 1987, and the loss of ac power at the Vogtle plant on March 20, 1990, led the NRC staff to issue NUREG-1449, which provides an evaluation of the shutdown risk issue. During the AP600 Design Certification review, the NRC requested that Westinghouse perform a systematic assessment of the shutdown risk issue to address areas identified in NUREG-1449 as applicable to the AP600 design. The AP1000 design is based extensively on the AP600, and the systems, structures and components that are important in maintaining a low shutdown risk for AP600 are generally the same design and/or have the same design basis with respect to their role in reducing shutdown risk. Therefore, the conclusions from the assessment of the shutdown risk for the AP600 are applicable to the AP1000. This appendix summarizes the assessment of the shutdown risk issue for AP1000.

19E.2 Major Systems Designed to Operate During Shutdown

Westinghouse has considered shutdown modes, shutdown alignments, and industry issues related to shutdown in the design of the AP1000 safety-related and nonsafety-related systems designed to operate or be available during shutdown. This section provides descriptions of the important systems designed to operate during shutdown and includes specific design features that have been

incorporated for shutdown operations with a discussion of their operating modes or alignment during shutdown.

In this appendix, references are made to the various AP1000 operating modes. The AP1000 operating modes have been defined in Technical Specifications, Table 1.1-1. The mode definitions for the AP1000 are similar to that of current Westinghouse pressurized water reactors (PWRs), with the difference being the definition of Mode 4, safe shutdown.

In the AP1000, Mode 4 has been redefined as safe shutdown and corresponds to the range of RCS temperature between 420°F and 200°F. The upper temperature limit corresponds to the RCS temperature that can be achieved by the passive safety-related systems 36 hours after shutdown. The ability of the passive safety-related systems to achieve Mode 4 within 36 hours is shown in Subsection 4.10.2 of this appendix.

19E.2.1 Reactor Coolant System

19E.2.1.1 System Description

The reactor coolant system (RCS) is described in Chapter 5.

19E.2.1.2 Design Features to Address Shutdown Safety

The AP1000 has incorporated design features that address issues related to shutdown operations. This subsection provides a discussion of the RCS design features that are incorporated to address shutdown operations or that are important to minimizing the risk to plant safety during shutdown.

19E.2.1.2.1 Loop Piping Offset

The RCS hot legs and cold legs are vertically offset. This permits draining of the steam generators for nozzle dam insertion with the hot leg level much higher than traditional designs. The RCS must be drained to a level sufficient to provide a vent path from the pressurizer to the steam generators. This loop piping offset also allows an RCP to be replaced without removing the full core.

19E.2.1.2.2 RCS Instrumentation

Instrumentation is provided to monitor the RCS process parameters as required by the PLS and PMS as discussed in Chapter 7. This subsection describes RCS instrumentation designed to accommodate shutdown operations.

RCS Hot Leg Level

There are two safety-related RCS hot leg level channels, one located in each hot leg. These level indicators are provided primarily to monitor the RCS water level during mid-loop operation following shutdown operations. These are totally independent of each other. One level tap is at the bottom of the hot leg, and the other tap is on the top of the hot leg close to the steam generator. The steam generator tap is located at the high point of the tubing run. The level tap for the instrument in the hot leg with the normal residual heat removal system (RNS) step-nozzle suction line connection is between the reactor vessel and the step-nozzle. Figure 19E.2-1 shows a simplified sketch of the RCS level instruments.

These channels provide signals for the following protection functions:

- Isolation of letdown on Low-4 level on a one-out-of-two basis.

- Actuation of fourth-stage ADS valves on Low-4 (empty) hot leg level on a two-out-of-two basis. Actuation of fourth-stage ADS causes actuation of IRWST injection.

These functions protect the plant during shutdown operations. Letdown isolation assists the operators when draining the RCS to a mid-loop level. If the operators fail to isolate letdown, these channels send a signal to close the letdown valves and stop the draining process.

In the event of a loss of the RNS during shutdown, coolant inventory could be boiled away. When the hot leg water level indicates that the loops are empty, IRWST injection and fourth-stage ADS are actuated 25 minutes after receipt of the empty hot leg level signal.

These channels are also used to generate the alarms on low hot leg water level. The alarm setpoints are selected to give the operator sufficient time to take the manual actions necessary to prevent the automatic actuation described previously. Indication of these channels is retrievable in the main control room. This variable is used by the operator to monitor the status of RCS inventory following an accident and is, therefore, classified as a post-accident monitoring system (PAMS) variable as discussed in Section 7.5.

The accuracy and response time of the hot leg level instruments are consistent with the standard engineered safety features (ESF) actuation discussed in Section 7.3. Concerns related to potential problems of noncondensible gases in the hot leg level instrument lines that have been raised in NRC Information Notice 92-54, Level Instrumentation Inaccuracies Caused by Rapid Depressurization (Reference 3), have been addressed in the layout of the instrument lines. In addition, as the hot leg level instruments are provided primarily for shutdown operations, off-gassing due to sudden depressurization of the RCS in shutdown modes is not a concern.

In the AP1000, draining of the RCS to mid-loop conditions is achieved in a controlled manner as discussed in Subsection 19E.2.1.2.4. Due to the low RCS drain rate, and the RCS step-nozzle as discussed in Subsection 19E.2.1.2.3, the amount of air-entrainment, and therefore RCS level perturbation during mid-loop, is negligible. Draining of the RCS is conducted in a quasi-steady-state, and the reliability of an accurate level reading is high.

Pressurizer Level

A fifth nonsafety-related independent pressurizer level transmitter, calibrated for low temperature conditions, provides water level indication during startup, shutdown, and refueling operations in the main control room and in the remote shutdown workstation. The upper level tap is connected to an ADS valve inlet header above the top of the pressurizer. The lower level tap is connected to the bottom of the hot leg. This provides level indication for the entire pressurizer and a continuous reading as the level in the pressurizer decreases to mid-loop levels during shutdown operations.

RCS Hot Leg Wide-Range Temperatures

The RCS contains two safety-related thermowell-mounted hot leg wide-range temperature detectors, one in each hot leg. The orientation of the resistance temperature detectors enables measurement of the reactor coolant fluid in the hot leg when in normal inventory conditions. Their range is selected to accommodate the low RCS temperatures that can be attained during shutdown. Two nonsafety-related RNS temperature instruments upstream of the RNS heat exchangers indicate RCS hot leg temperature when in reduced inventory conditions. In addition, at least two incore thermocouple channels are available to measure the core exit temperature during mid-loop RNS operation. These two thermocouple channels are associated with separate electrical divisions.

Pressurizer Surge Line Temperatures

There are three nonsafety-related temperature detectors located on the RCS pressurizer surge line. These instruments monitor the pressurizer surge line fluid temperature during plant normal

operations to detect thermal stratification in the surge line. Two of the temperature detectors are on a moderately sloped run approximately midway between the RCS hot leg and the pressurizer. One detector is on the bottom of the pipe and the other detector on the top. The third detector is located on the pressurizer surge line close to the pressurizer nozzle. This detector is used to monitor cold water insurges to the pressurizer during transient operations.

The temperature is monitored at the three locations using strap-on resistance temperature detectors. Temperature indication is provided in the main control room. One low-temperature alarm is provided to alert the operator of thermal stratification in the surge line. This alarm is associated with the detector on the bottom of the pipe.

During shutdown operations, this temperature instrumentation will be monitored to detect possible surge line stratification. If stratification is detected, the operators can increase spray flow to increase the outsurge from the pressurizer and reduce stratification in the surge line.

19E.2.1.2.3 Step-nozzle Connection

The AP1000 RNS uses a step-nozzle connection to the RCS hot leg. The step-nozzle connection has two effects on mid-loop operation. One effect is to lower the RCS hot leg level at which a vortex occurs in the residual heat removal pump suction line due to the lower fluid velocity in the hot leg nozzle. This increases the margin from the nominal mid-loop level to the level where air entrainment into the pump suction begins.

Another effect of the step-nozzle is that, if a vortex should occur, the maximum air entrainment into the pump suction as shown experimentally will be no greater than 5 percent (Reference 4). The RNS pumps can operate with 5% air-entrainment. As discussed in NUREG-0897 (Reference 5), low levels of air ingestion can be tolerated, and a pump inlet void fraction of 5% has been shown experimentally to reduce the pump head less than 15%. At this level of degradation, the RNS pumps would maintain decay heat removal. The step-nozzle thereby precludes air binding of the pump and will allow for RNS pump operation with low water levels in the hot leg.

19E.2.1.2.4 Improved RCS Draindown Method

During the cooldown operations, the RCS water level is drained to a mid-loop level to permit steam generator draining and maintenance activities. The AP1000 has improved the reliability of draindown operations by incorporating a dedicated drain path to be used to reduce the water level in the RCS controlled in the main control room. In current plants, various drain paths can be used either locally or remotely from the control room. These drain paths include the safety-related residual heat removal system, loop drain valves, and letdown. The result is that draining of the RCS can be difficult to control, and perturbations in water level can occur due to inadvertent system manipulations of which the operators are not always aware.

The AP1000 RCS drain path is via the CVS letdown line from the RNS cross-connect provided to maintain full RCS purification flow during shutdown. The letdown line flow control valve controls the letdown rate, which controls the RCS draindown rate. At the appropriate time during the cooldown, the operator initiates the draindown by manually positioning the CVS letdown control valve. At this time, the makeup pumps are turned off and the letdown flow control valve controls the drain rate to the liquid radwaste system at the initial maximum rate of approximately 100 gpm. The rate is reduced as the level in the RCS approaches the top of the hot leg. The letdown rate is manually controlled based upon the difference in flow instruments readings in the CVS letdown line and injection line. The letdown flow control valve as well as the letdown line containment isolation valve receives a signal to automatically close once the appropriate level is attained. Alarms actuate in the control room if the RCS level falls below the automatic letdown valve closure setpoint so that the operator is alerted to manually isolate the letdown line. Furthermore, an automatic isolation of the letdown line is actuated

on Low-2 hot leg level. This draindown method provides a reliable means of attaining mid-loop conditions.

19E.2.1.2.5 ADS Valves

The ADS first-, second-, and third-stage valves, connected to the top of the pressurizer, are open whenever the core makeup tanks (CMTs) are blocked during shutdown conditions while the reactor vessel upper internals are in place. This provides a vent path that, when combined with the required ADS stage 4 actuation, provides adequate steam venting area to reduce RCS pressure during shutdown conditions if decay heat removal is lost. Actuation of ADS stage 4, either automatically or manually (as described in Subsection 19E.4.8.3) allows the in-containment water storage tank to provide injection flow following a loss of decay heat removal. In addition, ADS fourth-stage valves are required to be available during reduced inventory operations to preclude surge line flooding following a loss of the RNS. Because of the potential for counter-current flow limitation in the surge line, it is essential to establish and maintain venting capability with ADS Stage 4 for gravity injection and containment recirculation following an extended loss of RNS when the RCS is open during shutdown operations.

19E.2.1.2.6 Steam Generator Channel Head

The AP1000 steam generator is a vertical-shell U-tube evaporator with integral moisture separating equipment. The generator is discussed in Subsection 5.4.2.

On the primary side, the reactor coolant flow enters the primary chamber via the hot leg nozzle. The lower portion of the primary chamber is hemispherical and merges into a cylindrical portion, which mates to the tubesheet. This arrangement provides enhanced access to all tubes, including those at the periphery of the bundle, with robotics equipment. This feature enhances the ability to inspect, replace, and repair portions of the AP1000 unit compared to the more hemispherical primary chamber of earlier designs. The channel head is divided into inlet and outlet chambers by a vertical divider plate extending from the apex of the head to the tubesheet.

The reactor coolant enters the inverted U-tubes, transferring heat to the secondary side during its traverse, and returns to the cold leg side of the primary chamber. The flow exits the steam generator via two cold leg nozzles to which the reactor coolant pumps are directly attached.

The AP1000 steam generator channel head has provisions to drain the head. For minimizing deposits of radioactive corrosion products on the channel head surfaces and for enhancing the decontamination of these surfaces, the channel head cladding is machined or electropolished for a smooth surface.

The steam generator is equipped with permanently mounted nozzle dam brackets, which are designed to support nozzle dams during refueling operations. The design pressure of the nozzle dam bracket and nozzle dam is selected to withstand the RCS pressures that can occur during a loss of shutdown cooling. The nozzle dam design pressure is at least 50 psia.

The AP1000 nozzle dams can be installed with the hot leg water level at the nominal water level for mid-loop operations. The nozzle dams can be inserted via the steam generator manway. The ADS valves connected to the pressurizer are open during all reduced inventory operations including nozzle dam installation, and when combined with the required ADS stage 4 actuation, provide adequate steam venting area to reduce RCS pressure following a loss of decay heat removal when the nozzle dams are installed.

19E.2.2 Steam Generator and Feedwater Systems

19E.2.2.1 System Description

This section discusses the AP1000 steam generator system (SGS) and the main and startup feedwater system (FWS) designs as they relate to shutdown operations. These systems are discussed in Chapter 10.

19E.2.2.2 Design Features to Address Shutdown Safety

19E.2.2.2.1 Feedwater Control

The AP1000 provides improvements in feedwater control that minimizes the probability of loss of feedwater transients during low power and shutdown modes. The main feedwater pumps are capable of providing feedwater during all modes of operation, including plant startup and standby conditions. In addition, the startup feedwater pumps are automatically started in the event that the main feedwater pumps are unable to continue to operate. The startup feedwater pumps are also automatically loaded on the diesels for operation following a loss of normal ac power and offsite power, during operating modes when the steam generators can be used for decay heat removal.

19E.2.2.2.2 Safety-Related Actuation in Shutdown Modes

The AP1000 has safety-related actuations associated with the SGS that are operable during shutdown modes. These include the PRHR HX actuation on Low-2 steam generator wide range water level during shutdown modes, and this is discussed in Subsection 19E.2.3 of this appendix. Also included is the isolation of the main steam line on a high (large) negative rate of change in steam pressure. This safety-related signal is provided to address a steam line break that could occur in Mode 3. If actuated, this signal causes the MSIVs to close to terminate the blowdown of the SGS following a steam line break. This signal is placed into service below the setpoint that disables the Low-2 steam line pressure signal (P11) that actuates steam line isolation as discussed in Section 7.3. When the operator manually blocks the Low-2 steam line pressure signal, the steam line high pressure-negative rate signal is automatically enabled.

This signal is operable during Mode 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). In Modes 4, 5, and 6, this function is not needed for accident detection and mitigation. Subsection 19E.4.2.3 discusses steam line break events that could occur in shutdown modes. Operability of this actuation logic is discussed in the AP1000 Technical Specifications.

19E.2.2.2.3 Steam Generator Cooling in Shutdown Modes

The secondary side of the steam generators can be recirculated during shutdown by circulating their contents through the blowdown system to promote heat transfer from the steam generators to the primary system. This feature reduces the challenges to low-temperature overpressure events. During RCS water-solid operation, heat input from the steam generators is capable of challenging the low-temperature relief valves. The Technical Specifications prevent the operators from starting an RCP with the steam generator secondary side temperature more than 50°F higher than the primary side, with the pressurizer water-solid. With the RCS water-solid, the heat input that could occur would cause the system to be pressurized to the setpoints of the low-temperature overpressure relief valves in the RNS.

When the RCPs are operating, the secondary side of the steam generator is cooled by steaming to the MSS. Once the RNS is aligned, and steaming to the MSS is decreased, the secondary side of the steam generators is cooled by operation of the RNS. However, once the RCPs are tripped, water

does not circulate through the primary side of the tubes and the secondary side of the steam generators remains at elevated temperature. With the ability to circulate the secondary side via the blowdown system, the AP1000 reduces the probability that an RCP would be started with the secondary side of the generator at elevated temperature.

The AP1000 has also incorporated steam generator fluid thermocouples to monitor the temperature of the fluid in the secondary side of the steam generator. This improves the ability of the operators to monitor this temperature to prevent them from inadvertently starting an RCP with the secondary side at elevated temperatures.

19E.2.3 Passive Core Cooling System

19E.2.3.1 System Description

The passive core cooling system (PXS) is described in Section 6.3.

19E.2.3.2 Design Features to Address Shutdown Safety

A significant improvement in shutdown safety for the AP1000 is the availability of a dedicated safety-related system that can be automatically or manually actuated in response to an accident that can occur during shutdown. In current plants, the safety-related systems that mitigate the consequences of an accident are also the operating systems that are used for decay heat removal. In the AP1000, nonsafety-related active systems provide the first level of defense, while the passive safety-related systems are available during shutdown modes to mitigate the consequences of an accident. This design approach results in a significant improvement in the AP1000 shutdown risk.

19E.2.3.2.1 Core Makeup Tanks

The CMTs provide RCS makeup. During shutdown, the CMTs are available in Modes 3, 4, and 5, until the RCS pressure boundary is open and the pressurizer water level is reduced. During power operation, the CMTs are automatically actuated on various signals including a safeguards actuation signal (low RCS pressure, low RCS temperature, Low-2 steam line pressure, and High-2 containment pressure) and on Low-2 pressurizer water level. See Chapter 7 for a description of the AP1000 PMS actuation logic. In shutdown modes, portions of the safeguards actuation signal are disabled to allow the RCS to be cooled and depressurized for shutdown. For instance, the low RCS pressure and temperature, and Low-2 steam line pressure signals are blocked in Mode 3 prior to cooling and depressurizing the RCS. Therefore, during shutdown Modes 3, 4, and 5, the primary signal that actuates the CMTs due to a loss of inventory is the pressurizer level signal. In Mode 5, with the RCS open (in preparation for reduced inventory operations), the Low-2 pressurizer level signal is blocked prior to draining the pressurizer. Therefore, in Mode 5 with the RCS open, the CMTs are not required to be available and the RCS makeup function is provided by the IRWST.

The CMTs also provide an emergency boration function for accidents such as steam line breaks. However, the signals that provide the primary protection for this function (Low-2 steam line pressure, low RCS pressure, and low RCS temperature) are blocked in Mode 3 as discussed above. Prior to blocking these signals in Mode 3, the Technical Specifications require that the RCS be sufficiently borated. For these events, the pressurizer level signal provides automatic actuation of the CMTs for a steam line break that might occur due to the RCS shrinkage that would occur.

19E.2.3.2.2 Accumulators

The PXS accumulators provide safety injection following a LOCA. In Mode 3, the accumulators must be isolated to prevent their operation when the RCS pressure is reduced to below their set pressure.

The accumulator isolation valves are closed when the RCS pressure is reduced to 1000 psig to block their injection when the RCS pressure is reduced to below the normal accumulator pressure.

19E.2.3.2.3 In-containment Refueling Water Storage Tank

The IRWST provides long-term RCS makeup. During shutdown, the IRWST is available until Mode 6, when the reactor vessel upper internals are removed and the refueling cavity flooded. At that time, the IRWST is not required, due to the large heat capacity of the water in the refueling cavity.

The IRWST injection paths are actuated on a Low-6 CMT water level. This signal is available in shutdown Modes 3, 4, and 5, with the RCS intact. When the RCS is open to transition to reduced inventory operations, the CMT actuation logic on Low-2 pressurizer level is removed, and the CMTs can be taken out of service. For these modes, automatic actuation of the IRWST can be initiated (on a two-out-of-two basis) on Low-4 hot leg level.

19E.2.3.2.4 Passive Residual Heat Removal Heat Exchanger

The PRHR HX provides decay heat removal during power operation and is required to be available in shutdown Modes 3 and 4, and in Mode 5 until the RCS is open except during vacuum fill. In these modes, the PRHR HX provides a passive decay heat removal path. It is automatically actuated on a CMT actuation signal, which would eventually be generated on a loss of shutdown decay heat removal, as shown in the analysis provided in Section 19E.4 of this appendix. In modes with the RCS open (portions of Mode 5 and Mode 6), decay heat removal is provided by “feeding” water from the IRWST and “bleeding” steam from the ADS.

19E.2.3.2.5 Reduced Challenges to Low-Temperature Overpressure Events

Another design feature of the PXS that reduces challenges to shutdown safety is the elimination of high-head safety injection pumps in causing low temperature overpressure events. In current plants, during water solid operations that may be necessary to perform shutdown maintenance, the high-head safety injection pumps are a major source of cold overpressure events. To address this, plants are required to lock out safety injection pumps to prevent them from inadvertently causing a cold overpressure event. This eliminates a potential source of safety injection for a loss of inventory event that could occur at shutdown. With the AP1000 PXS, the CMTs are not pressurized above RCS pressure and are, therefore, not capable of causing a cold overpressure event. Therefore, they are not isolated until the pressurizer is drained for mid-loop. Low-temperature overpressure events are discussed in Subsection 19E.4.10.1.

19E.2.3.2.6 Discussion of Safe Shutdown for AP1000

The functional requirements for the PXS specify that the plant be brought to a safe, stable condition using the PRHR HX for events not involving a loss of coolant. As stated in Subsection 6.3.1.1.1, the PRHR HX, in conjunction with the passive containment cooling system (PCS), provides sufficient heat removal to satisfy the post-accident safety evaluation criteria for at least 72 hours. Additionally, the PXS, in conjunction with the PCS, and the ADS, has the capability to establish long-term safe shutdown conditions in the RCS as identified in Subsection 7.4.1.1.

The CMTs automatically provide injection to the RCS after they are actuated on low reactor coolant temperature or low pressurizer pressure or level. The PXS can maintain stable plant conditions for a long time in this mode of operation, depending on the reactor coolant leakage and the availability of ac power sources. For example, with a technical specification leak rate of 10 gpm, stable plant conditions can be maintained for at least 10 hours. With a smaller leak, a longer time is available.

In scenarios when ac power sources are unavailable for approximately 22 hours, the ADS automatically actuates. However, after the initial plant cooldown following a non-LOCA event, operators assess plant conditions and have the option to perform recovery actions to further cool and depressurize the RCS in a closed-loop mode of operation, i.e., without actuation of the ADS. After verifying the RCS is in an acceptable, stable condition, such that automatic depressurization is not needed, the operators may take action to extend PRHR HX operation by de-energizing the loads on the Class 1E dc batteries powering the protection and safety monitoring system actuation cabinets. After operators have taken action to extend its operation, the PRHR HX, in conjunction with the PCS, has the capability to maintain safe, stable conditions. The ADS remains available to maintain safe shutdown conditions at a later time.

In most sequences, the operators would return the plant to normal system operations and terminate passive system operation within several hours in accordance with the plant emergency operating procedures. For LOCAs and other postulated events, when the core makeup tank level reaches the automatic depressurization actuation setpoint, and other postulated events where the PRHR HX operation is not extended or exhausted, the ADS may be initiated. This results in injection from the accumulators and subsequently from the in-containment refueling water storage tank, once the RCS is nearly depressurized. For these conditions, the RCS depressurizes to saturated conditions at about 250°F within 24 hours. The PXS can maintain this safe shutdown condition as identified in Subsection 7.4.1.1.

The primary function of the PXS during a safe shutdown using only safety-related equipment is to provide a means for boration, injection, and core cooling. Analysis is provided in Subsection 19E.4.10.2 of this appendix that verifies the ability of the AP1000 passive safety systems to meet the safe shutdown requirements.

19E.2.3.2.7 Containment Recirculation Screens

The PXS containment recirculation screens may have to function in the longer-term during a shutdown accident that results in ADS operation. Effective screen design, plant layout, and other factors prevent clogging of these screens by debris during such accident operations.

- Two very large interconnected screens are provided.
- A significant delay is provided between the accident/ADS stage opening and the initiation of recirculation (at least 2 hours).
- Deep flood up levels are provided post ADS operation (31 ft of water above the lowest level in containment and 25.5 ft above floors around screens).
- Bottom of screens are located well above the lowest containment level (13.5 feet) as well as the floors around them (2 feet).
- Top of screens are located well below the containment floodup level (~10 ft from top screens to minimum flood level).
- Screens have a protective plate located no more than 1 foot, 3 inches above the top of the face of the screens, which extends at least 8 feet, 3 inches perpendicular to the front and at least 7 feet to the side of the face of the screens.

- Screens have conservative flow areas to account for plugging. Operation of the nonsafety-related normal residual heat removal pumps with suction from the IRWST and the containment recirculation lines is considered in sizing screens. Note that adequate PXS performance can be supported by one screen with more than 90 percent of its surface area completely blocked.

- During recirculation operation, the velocity approaching the screens is very low, which limits the transport of debris.

- Each screen has a fine screen.

- Technical Specifications require the screens to be inspected during each refueling outage.

- As discussed in Subsection 6.3.8.1, a cleanliness program to limit the amount of foreign materials that might be left in the containment following refueling and maintenance outages and become debris during an accident.

19E.2.3.3 Shutdown Operations

Operation of the PXS during operating modes and during accident events including shutdown events is discussed in Subsection 6.3.3. The following is a discussion of a loss of shutdown cooling during reduced inventory operations which can be a limiting shutdown event.

19E.2.3.3.1 Operation During Loss of Normal Residual Heat Removal Cooling During Mid-loop Events

During RCS maintenance, the most limiting shutdown condition anticipated is with the reactor coolant level reduced to the hot leg (mid-loop) level and the RCS pressure boundary opened. It is normal practice to open the steam generator channel head manway covers to install the hot leg and cold leg nozzle dams during a refueling outage. In this situation, the RNS is used to cool the RCS. The AP1000 incorporates features to reduce the probability of losing RNS. However, because the RNS is nonsafety-related, its failure has been considered.

In this situation, core cooling is provided by the safety-related PXS, using gravity injection from the IRWST, while venting through the ADS valves (and possibly through other openings in the RCS). Note that with the RCS depressurized and the pressure boundary opened, the PRHR HX is unable to remove the decay heat because the RCS cannot heat sufficiently above the IRWST temperature.

During plant shutdown, at 1000 psig, the accumulators are isolated to prevent inadvertent injection. Prior to draining the RCS inventory below the no-load pressurizer level, the CMTs are isolated by closing the inlet MOVs to preclude inadvertent draining into the RCS while preparing for mid-loop operation. Although these tanks are isolated from the RCS, the valves can be remotely opened by the operators to provide additional makeup water injection.

Prior to initiating the draindown of RCS to mid-loop level, the automatic depressurization first-, second-, and third-stage valves are opened. This alignment, when combined with the required ADS stage 4 actuation, provides adequate steam venting area to reduce RCS pressure in the event of a loss of nonsafety-related decay heat removal during mid-loop operation. The ADS first- to third-stage valves are required to be opened before blocking the CMTs. They are required to remain open until either the RCS level is increased and the RCS is closed, or until the upper core internals are removed and the refueling cavity flooded. Note that the upper internals can restrict the vent flow path and prevent water in the refueling cavity from draining into the RCS unless ADS valves are open.

The IRWST injection squib valves and fourth stage ADS valves are automatically opened if the RCS hot leg level indication decreases below a Low-4 setpoint or manually as described in Subsection 19E.4.8.3. A time delay is provided to provide time for the operators to restore nonsafety-related decay heat removal prior to actuating the PXS. The time delay with an alarm in the containment serves to protect maintenance personnel. Once the IRWST injection valves and fourth stage ADS valves open, the IRWST provides gravity-driven injection to cool the core. Containment recirculation flow would be automatically initiated when the IRWST level dropped to the Low-3 level to provide long-term core cooling.

Subsection 19E.4.8.3 provides the assessment of the loss of the RNS during mid-loop operations. Table 19E.2-1 provides the results of calculations performed to demonstrate the amount of time between a loss of RNS that could occur at mid-loop until core uncovery. This calculation is performed with the RCS water level at the nominal mid-loop water level and is performed with conservative, design basis assumptions for decay heat. As described previously and shown in Table 19E.2-1, the operators have a significant amount of time to actuate gravity injection before core uncovery. In addition, the PMS, on a two-out-of-two basis, provides a signal to actuate the IRWST when the hot legs empty.

This arrangement provides automatic core cooling protection, in mid-loop operation, while also providing protection (an evacuation alarm and sufficient time to evacuate) for maintenance personnel in containment during mid-loop operation.

Containment closure capability is required to be maintained during mid-loop operation, as discussed in Subsection 19E.2.6.2 of this appendix. With the containment closed, containment recirculation can continue indefinitely with decay heat generating steam condensed on the containment vessel and drained back into the IRWST and/or the containment recirculation.

19E.2.4 Normal Residual Heat Removal System

19E.2.4.1 System Description

The normal residual heat removal system (RNS) is discussed in Subsection 5.4.7. Operability of the RNS is tested, via connections to the IRWST, before its alignment to the RCS hot leg for shutdown cooling.

19E.2.4.2 Design Features to Address Shutdown Safety

The AP1000 has incorporated various design features to improve shutdown safety. The RNS features that have been incorporated to address shutdown safety are described in this subsection.

19E.2.4.2.1 RNS Pump Elevation and NPSH Characteristics

The AP1000 RNS pumps are located at the lowest elevation in the auxiliary building. This location provides the RNS pumps with a large available NPSH during all modes of operation including RCS mid-loop and reduced inventory operations. The large NPSH provides the pumps with the capability to operate during most mid-loop conditions without throttling the RNS flow. If the RCS is at mid-loop level and saturated conditions, some throttling of a flow control valve is necessary to maintain adequate net positive suction head for the RNS pumps. The RNS pumps can be restarted and operated with RCS conditions that might occur following a temporary loss of RNS cooling.

The plant piping configuration, piping elevations and routing, and the pump characteristics allow the RNS pumps to be started and operated at their full design flow rates in most conditions without the need to reduce RNS pump flow to meet pump NPSH requirements. This reduces the potential failure

mechanism that exists in current PWRs, where failure of an air-operated control valve can result in pump runout and cavitation during mid-loop operations.

19E.2.4.2.2 Self-Venting Suction Line

Most of the RNS pump suction line is sloped upward from the RNS pump to the reactor coolant system hot leg. In the level portions of piping, there are no local high points. This eliminates potential problems with refilling the pump suction line if an RNS pump is stopped due to pump cavitation and/or excessive air entrainment. With the self-venting suction line, the line will refill and the pumps can be immediately (no additional operator action required) restarted once an adequate level in the hot leg is re-established.

19E.2.4.2.3 IRWST Injection via the RNS Suction Line

During shutdown modes, initiating events such as the loss of the nonsafety-related RNS are postulated. Such events would require IRWST injection as discussed in Subsection 19E.2.3 of this appendix, and as shown in the accident analyses provided in Section 19E.4. For initiating IRWST injection, the operation of PXS squib valves in the IRWST injection line is required. However, the operators can use the RNS pump suction line that connects to the IRWST to provide controlled IRWST injection. This flow path, shown in Figure 19E.2-2, connects the IRWST directly to the RCS via the RNS hot leg suction isolation valves and provides a diverse method for IRWST injection. In addition, it would be the preferred method of providing IRWST injection because the flow would be controllable by the operation of the IRWST suction line isolation valve. The RNS isolation valve is equipped with a throttle capability to provide the operators with the capability to control the injection flow via this path. The operator would monitor the RCS hot leg level while controlling flow through this valve. This path provides IRWST injection regardless of whether the RNS pumps are operating.

19E.2.4.2.4 Codes and Standards/Seismic Protection

The portions of the RNS located outside containment (that serve no active safety functions) are classified as AP1000 equipment Class C so that the design, manufacture, installation, and inspection of this pressure boundary is in accordance with the following industry codes and standards and regulatory requirements: 10 CFR 50, Appendix B (Reference 6); Regulatory Guide 1.26, quality group C (Reference 7); and ASME Boiler and Pressure Vessel Code, Section III, Class 3 (Reference 8), with restriction as described in Subsection 5.2.1.1. The pressure boundary is classified as seismic Category I.

19E.2.4.2.5 Increased Design Pressure

The portions of the RNS from the RCS to the containment isolation valves outside containment are designed to the operating pressure of the RCS. The portions of the system downstream of the suction line containment isolation valve and upstream of the discharge line containment isolation valve are designed so that its ultimate rupture strength is not less than the operating pressure of the RCS. The design pressure of the RNS is 900 psig, which is 40 percent of operating RCS pressure.

19E.2.4.2.6 Reactor Coolant System Isolation Valve

The RNS contains an isolation valve in the pump suction line from the RCS. This motor-operated containment isolation valve is designed to the RCS pressure. It provides an additional barrier between the RCS and lower pressure portions of the RNS.

19E.2.4.2.7 Normal Residual Heat Removal System Relief Valve

The inside containment RNS relief valves are connected to the residual heat removal pump suction line. These valves are designed to provide low-temperature, overpressure protection of the RCS as described in Subsection 5.2.2. The valves, connected to the high-pressure portion of the pump suction line, reduce the risk of overpressurizing the low-pressure portions of the system.

19E.2.4.2.8 Features Preventing Inadvertent Opening of Isolation Valves

The RCS isolation valves are interlocked to prevent their opening at RCS pressures above 450 psig. Section 7.6 discusses this interlock. The power to these valves is administratively blocked during normal power operation.

In addition, these valves are interlocked with the RNS/IRWST isolation valves to prevent their opening with the RNS open to the IRWST. This precludes the blowdown of the RCS to the IRWST through the RNS upon system initiation.

19E.2.4.2.9 RCS Pressure Indication and High Alarm

The AP1000 RNS contains an instrumentation channel that indicates pressure in each normal residual heat removal pump suction line. A high-pressure alarm is provided in the main control room to alert the operator to a condition of rising RCS pressure that could eventually exceed the design pressure of the RNS.

19E.2.4.2.10 RNS Break Outside Containment

For a postulated RNS break outside the containment while in Modes 4, 5, and 6, the RCS loses inventory through the postulated break. Manual operator actions are taken to isolate RNS and isolate containment within ten minutes of the break. If the RCS inventory level continues to decrease, a backup automatic isolation signal is provided on an ADS Stage 4 actuation to isolate RNS isolation and containment isolation valves to prevent further loss of inventory.

19E.2.5 Component Cooling and Service Water Systems

Two different means are provided to protect the lower-pressure CCS from overpressure if RNS heat exchanger tube leakage occurs during plant cooldown or shutdown operations.

A relief valve is located on the CCS cooling water line, inside the upstream and downstream manual isolation valves for each RNS heat exchanger. The valve satisfies requirements in Section VIII of the ASME code for overpressure protection of heat transfer equipment. This relief valve provides both thermal overpressure and tube leakage protection in the event that the section of piping containing the RNS heat exchanger is isolated from the remainder of the CCS. The valve discharges to the auxiliary building sump through the WRS.

If RNS heat exchanger tube leakage occurs with the affected heat exchanger not isolated from the CCS, the excess volume added to the CCS by the leak will begin to fill the CCS surge tank. If the CCS surge tank fills before the leak is isolated, fluid is discharged through the tank vent into the turbine building sump to prevent over-pressurization of any portion of the CCS. Leakage into the system will produce a CCS liquid radiation monitor alarm, and an increase in CCS surge tank level that results in a tank high level alarm.

Doses from the RNS heat exchanger tube rupture event would be below those produced by the primary sample line break outside containment with the plant at power.

19E.2.6 Containment Systems

19E.2.6.1 System Description

The containment systems are described in Section 6.2.

19E.2.6.2 Design Features to Address Shutdown Safety

The AP1000 has addressed the issue of containment closure at shutdown and incorporated the following requirements in the Technical Specifications. In shutdown Modes 3 and 4, containment status is the same as at-power. Specifically, containment integrity is required, the major equipment hatches are closed and sealed, and containment air locks and isolation valves are operable.

In Modes 5 and 6, containment closure capability is required during shutdown operations when there is fuel inside containment. Containment closure is required to maintain, within containment, the cooling water inventory. Due to the large volume of the IRWST and the reduced sensible heat during shutdown, the loss of some of the water inventory can be accepted. Further, accident analyses provided in Section 19E.4 of this appendix show that containment closure capability is not required to meet offsite dose requirements. Therefore, containment does not need to be leak-tight as required for Modes 1 through 4.

In Modes 5 and 6, there is no potential for steam release into the containment immediately following an accident. Pressurization of the containment could occur only after heatup of the IRWST due to PRHR HX operation (Mode 5 with RCS intact), after heatup of the RCS with direct venting to the containment (Mode 5 with reduced RCS inventory or Mode 6 with the refueling cavity not fully flooded), or after heatup of the RCS and refueling cavity (Mode 6 with refueling cavity fully flooded). To limit the magnitude of cooling water inventory losses and because local manual action may be required to achieve containment closure, the containment hatches, air locks, and penetrations must be closed prior to steaming into containment.

The containment equipment hatches, which are part of the containment pressure boundary, provide a means for moving large equipment and components into and out of containment. If closed, the equipment hatch is held in place by at least four bolts. If open, each equipment hatch can be closed using a dedicated set of hardware, tools, and equipment. A self-contained power source is provided to drive each hoist while lowering the hatch into position. Large equipment and components may be moved through the hatches as long as they can be removed and the hatch closed prior to steaming into the containment.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during Modes 1, 2, 3, and 4 unit operation. Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment operability is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Temporary equipment connections (for example, power or communications cables) are permitted as long as they can be removed to allow containment closure prior to steaming into the containment.

Containment spare penetrations, which also provide a part of the containment boundary, provide for temporary support services (electrical, I&C, air, and water supplies) during Modes 5 and 6. Each penetration is flanged and normally closed. During periods of plant shutdown, temporary support systems may be routed through the penetrations; temporary equipment connections (for example, power or communications cables) are permitted as long as they can be removed to allow containment closure prior to steaming into the containment.

The spare penetrations must be closed or, if open, capable of closure prior to reaching boiling conditions within reactor coolant inventory. Temporary containment penetrations that may be employed during shutdown modes must have a design pressure equal to the containment design pressure of 59 psig.

Containment penetrations, including purge system flow paths, that provide direct access from containment atmosphere to outside atmosphere must be isolated or isolatable on at least one side. Isolation may be achieved by an operable automatic isolation valve or by a manual isolation valve, blind flange, or equivalent.

The fuel transfer canal may be opened to provide for the transfer of new and spent fuel into and out of containment during Modes 5 and 6. At times when the canal is opened, it must be isolatable on at least one side by closure of the flange within containment or the gate valve outside containment.

19E.2.7 Chemical and Volume Control System

19E.2.7.1 System Description

The chemical and volume control system (CVS) is described in Subsection 9.3.6.

19E.2.7.2 Design Features to Address Shutdown Safety

The AP1000 CVS is a nonsafety-related system. However, portions of the system are safety-related and perform safety-related functions, such as containment isolation, termination of inadvertent RCS boron dilution, RCS pressure boundary preservation, and isolation of excessive makeup.

Boron dilution events during low power modes can occur for a number of reasons, including malfunctions of the reactor makeup control system. Regardless of the cause, the protection is the same. The CVS is designed to avoid and/or terminate boron dilution events by automatically closing either one of two series, safety-related valves in the demineralized water supply line to the makeup pump suction to isolate the dilution source. Additionally, the suction line for the CVS makeup pump is automatically realigned to draw borated water from the boric acid tank. The automatic boron dilution protection signal is safety-related and is generated upon any reactor trip signal, source-range flux multiplication signal, or low input voltage to the Class 1E dc and uninterruptible power supply system battery chargers.

The safety analysis of boron dilution accidents is provided in Chapter 15 and is discussed in Subsection 19E.4.5 of this appendix. For dilution events that occur during shutdown, the source-range flux-doubling signal closes the safety-related remotely operated CVS makeup line isolation valves to terminate the event. In addition, the signal is used to isolate the line from the demineralized water system to the makeup pump suction by closing the two safety-related remotely operated valves. The three-way pump suction control valve aligns the makeup pumps to take suction from the boric acid tank and, therefore, stops the dilution.

For refueling operations, administrative controls are used to prevent boron dilutions by verifying that the valves in the line from the demineralized water system are closed and locked. These valves block the flow paths that can allow unborated makeup water to reach the RCS. Makeup required during refueling uses borated water supplied from the boric acid tank by the CVS makeup pumps.

During refueling operations (Mode 6), two source-range neutron flux monitors are operable to monitor core reactivity. This is required by the plant Technical Specifications. The two operable source-range neutron flux monitors provide a signal to alert the operator to unexpected changes in core reactivity. The potential for an uncontrolled boron dilution accident is precluded by isolating the unborated water sources. This is also required by the plant Technical Specifications.

The source range flux doubling function can be manually blocked during shutdown conditions when below the P-8 setpoint after the operator isolates unborated water source flow paths. When blocked during shutdown conditions, an automatic close signal is also sent to the CVS demineralized water system isolation valves to prevent inadvertent boron dilution.

19E.2.8 Spent Fuel Pool Cooling System

19E.2.8.1 System Description

The spent fuel pool cooling system (SFS) is discussed in Subsection 9.1.3.

19E.2.8.2 Design Features to Address Shutdown Safety

The AP1000 has incorporated various design features to improve shutdown safety. The SFS features that have been incorporated to address shutdown safety are described in this subsection.

19E.2.8.2.1 Seismic Design

The spent fuel pool, fuel transfer canal (FTC), cask loading pit (CLP), cask washdown pit (CWP), and gates from the spent fuel pool-CLP and FTC-spent fuel pool are all integral with the auxiliary building structure. The auxiliary building is seismic Category I design and is designed to retain its integrity when exposed to a safe shutdown earthquake (SSE). The suction and discharge connections between the spent fuel pool and RNS are safety Class C, which is also seismic Category I. The emergency makeup water line from the PCS water storage tank to the spent fuel pool actually connects with the RNS pump suction line. This emergency makeup line is also safety Class C and seismic Category I. The spent fuel pool level instruments connections to the spent fuel pool are safety Class C, seismic Category I, and have 3/8-inch flow restricting orifices at the pool wall to limit the amount of a leak from the pool if the instrument or its piping develops a leak.

The refueling cavity is integral with the containment internal structure, and as such, is seismic Category I, and is designed to retain its integrity when exposed to an SSE. In addition, the AP1000 has incorporated a permanently welded seal ring to provide the seal between the vessel flange and the refueling cavity floor. This permanent cavity seal ring is part of the refueling cavity and is seismic Category I. Figure 19E.2-3 is a simplified drawing of the AP1000 permanent cavity seal ring. The permanent cavity seal ring is designed to accommodate the thermal transients associated with the reactor vessel flange.

19E.2.9 Control and Protection Systems

The AP1000 control and protection systems support the operations necessary for the AP1000 to achieve shutdown. These systems consist of a nonsafety-related plant control system (PLS), a safety-related protection and safety monitoring system (PMS), and a nonsafety-related diverse actuation system (DAS). These systems are discussed in Chapter 7.

19E.3 Shutdown Maintenance Guidelines and Procedures

This section presents an overview discussion of AP1000 shutdown maintenance guidelines and procedures captured as part of the AP1000 design and design certification program. Shutdown maintenance requirements and guidelines have been identified in various licensing submittals, such as the AP1000 Technical Specifications and the design reliability assurance program, (Section 17.4).

Shutdown procedures were addressed in the AP600 design certification program by the submittal of the AP600 Emergency Response Guidelines (ERGs) (Reference 1), which include shutdown emergency procedures. These shutdown emergency procedures are applicable to the AP1000.

This section summarizes the major shutdown maintenance guidelines and procedures that have been identified.

19E.3.1 Maintenance Guidelines and Insights Important to Reducing Shutdown Risk

This section presents an overview of AP1000 shutdown maintenance guidelines and insights, which are either required for plant safety or are effective at reducing shutdown risk.

19E.3.1.1 Availability Requirements for Safety-Related Systems

Availability controls of the AP1000 safety-related systems are provided by the Technical Specifications. These availability requirements cover all modes of operation including shutdown.

19E.3.1.2 Availability Guidelines for Systems Important for Investment Protection

Availability guidelines for systems important for investment protection are discussed in the AP1000 Design Reliability Assurance Program, Section 17.4.

19E.3.1.3 Reactor Coolant System Precautions and Limitations at Shutdown

Precautions and limitations for RCS operation at shutdown are considered to minimize the risk to plant safety at shutdown. The most important of these are captured in the AP1000 Technical Specifications. However, other precautions and limitations associated with maintenance and operation at shutdown have been identified during the design of the AP1000. These are based on both the past operating experience of PWRs, as well as the designer's knowledge of the unique AP1000 design features. A summary of these precautions and limitations that apply to shutdown maintenance and operation is provided in this section.

19E.3.1.3.1 General Shutdown

Precautions and limitations for general shutdown are as follows:

- To provide mixing, at least one reactor coolant pump (RCP) or a normal residual heat removal pump should be in service while chemicals are being added to the system or the boron concentration is being changed.

- Reactor coolant samples must be taken at the regular intervals to check coolant chemistry, activity level, and boron concentration as specified in the appropriate Technical Specifications including 3.1.1, 3.4.11, and 3.1-1. In addition, during shutdown modes, more frequent checks on RCS boron concentration should be made when changes in RCS boron concentration are being made.

- When the RNS is in operation, the reactor coolant temperature should not exceed 350°F. The reactor coolant pressure should be limited to avoid approaching the RNS relief valve setpoints.

- The maximum allowable heatup and cooldown rates for the RCS are provided in the Technical Specifications.

- During cooldown, the RCPs located in the loop containing the pressurizer spray line should be operated to provide adequate pressurizer spray.

- The accumulators must be isolated prior to reducing the RCS pressure to the accumulator pressure (637 to 769 psig).

19E.3.1.3.2 Water-Solid Operation

Precautions and limitations for water-solid operation are as follows:

- The RNS inlet line should not be isolated from the reactor coolant loop unless there is a steam bubble in the pressurizer or the makeup pumps are stopped. This precaution provides relief valve protection of the RCS when it is at low pressure and water-solid.

- Whenever the plant is water-solid and the reactor coolant pressure is being maintained by the letdown containment isolation outside-containment valve, the RNS should remain open to the reactor coolant loops to maintain sufficient letdown flow through the bypass line from the RNS to the letdown heat exchanger, until a steam bubble is formed in the pressurizer. During this mode of operation, the isolation valve in the bypass line from the RNS to the letdown heat exchanger should be in the full-open position and the letdown orifice bypass valve should also be open.

- If all RCPs are stopped and the reactor coolant temperature is greater than 200°F, the first pump should not be restarted until a steam bubble has formed in the pressurizer. This precaution will minimize the pressure transient when the first pump is started. The steam bubble will accommodate the resultant expansion.

- When the reactor coolant pressure is being maintained by the letdown containment isolation outside containment valve, changes to the flow rate through the RNS loop by throttling of valves or starting and stopping the RNS pumps will result in changes to the reactor coolant pressure.

- Whenever the reactor coolant temperature is above 160°F, at least one RCP should be in operation.

19E.3.1.3.3 Steam Generators

Precautions and limitations for steam generators are as follows:

- During cooldown, all steam generators should be connected to the steam header to provide uniform cooldown of the reactor coolant loops.

- During steam plant warmup and at hot standby, draw steam slowly and regulate feedwater additions carefully to avoid rapid cooling of the reactor coolant.

- During cooldown, once RNS is in operation, and after the RCPs have been tripped, actions should be taken to cool the contents of the steam generator secondary side, either by recirculation of this water to promote reverse heat transfer to the primary side or by draining the contents via the blowdown lines.

19E.3.1.3.4 Surge Line

During heatup and cooldowns, the temperature difference between the pressurizer and the hot legs should be less than 320°F. This prevents unacceptable stress levels in the surge line.

19E.3.1.3.5 Reduced-Inventory Operations

Precautions and limitations for reduced-inventory operations are as follows:

- The timing of the initiation of draindown is highly dependent of the scenario that requires the drained condition. However, in order to drain down to mid-loop conditions, the reactor coolant pumps must be tripped, and the RCS temperature must be less than saturation. Typically, the reactor coolant pumps operate until the RCS temperature is reduced to less than 160°F. For a refueling outage, the transition to reduced inventory conditions should typically begin about 3-4 days after shutdown. For a forced outage condition, reduced inventory operations should not begin until the RCS temperature is less than 160°F.

  The time after shutdown directly affects the time that the RCS would boil and the rate at which inventory would be depleted following a loss of cooling event. Table 19E.2-1 presents the time to reach saturation, and the time to core uncovery for a loss of heat sink event initiated from mid-loop conditions at 28 hours after shutdown. For loss of heat sink events initiated earlier, the time to reach saturation and the time to uncover the core would be slightly decreased. The performance of the IRWST injection, in conjunction with ADS, is sufficient to mitigate the consequences of the event.

  The time after shutdown impacts the requirements for containment closure during shutdown as discussed in Subsection 19E.2.6.2 of this appendix (and captured in the Technical Specifications). For reduced inventory conditions, if the time to steaming (inside containment) following a loss of heat sink event is less than the time required to close the containment equipment hatches, then these hatches should be closed. If the time after shutdown is sufficiently long, such that steaming to containment would not occur prior to the containment hatches being able to be closed, then the equipment hatches could be open, with the ability to close them.

- As the RCS is drained, the rate of change in water level will vary non-linearly for a given drain rate due to the geometry of the RCS and the offset hot leg and cold leg piping. It is important to drain the RCS at a low rate to minimize the possibility of overdraining the system. Evaluations have been performed that indicate that a drain rate of 20 gpm is sufficient once the water level has been reduced to the top of the hot leg.

- After maintenance operations that result in draining the RCS, the system should be refilled with borated makeup water at the prevailing RCS boron concentration via the chemical and volume control system (CVS) makeup pumps. If the RCPs are drained, the pumps should be refilled with borated water via the pump drain line so that the pump is completely filled with borated water.

- After maintenance operations on the CVS purification loop (demineralizer, filters, and heat exchangers), the system should be purged, draining potential unborated water to the liquid radwaste system, and refilling it with borated water from the RCS. These operations should not be conducted at mid-loop or reduced inventory operations to avoid an inadvertent drop in RCS water level during mid-loop.

- The RCS hot leg level instruments should be operable and available prior to reduced inventory operations. Their automatic actuation functions are required to be operable in shutdown modes as described in Technical Specification 3.3.10.

19E.3.2 Shutdown Risk Management

This appendix contains insights of which Westinghouse is currently aware and which are related to AP1000 design certification.

19E.3.3 Shutdown Emergency Response Guidelines Overview

The AP600 ERGs (Reference 1) provide functional guidance for responding to accidents and transients that affect plant safety during shutdown modes of operation (operational Modes 5 and 6). The shutdown ERGs consist of a shutdown safety status tree for monitoring the critical safety functions and six shutdown guidelines for responding to the respective challenges to plant safety. The AP600 ERGs are applicable to AP1000 for the purpose of developing Emergency Operating Procedures.

The shutdown safety status tree provides a systematic method of determining the safety status of the plant. This status tree represents the critical safety functions that are of concern during plant shutdown conditions. Prior to this shutdown condition, the plant can be in any state ranging from heatup and pressurization (from 200°F to no-load temperature) to full power operation. Under these conditions (plant Modes 4 through 1), plant monitoring and response to a reactor trip or requirement for safety injection are covered by the optimal recovery guidelines, status trees, and function restoration guidelines of the at-power ERGs.

By using the shutdown status tree, plant conditions are monitored during plant shutdown after entering Mode 5 while normal operating procedures are in use for plant shutdown operations. The shutdown safety status tree is arranged so that the functions are checked in order of importance. Core cooling during shutdown conditions is addressed first. During plant shutdown conditions, the RNS provides core cooling, which requires adequate RCS inventory to operate properly. RCS inventory checks are made first to show core cooling will not be interrupted because of inadequate RCS inventory and as an early symptom to a loss of shutdown core cooling. After adequate RCS inventory is checked, RNS operation is checked to verify shutdown core cooling is being provided by the RNS. After RNS operation is verified, containment radiation is checked so that an unexpected uncontrolled release will not occur because containment integrity may be breached during plant shutdown maintenance activities. Core reactivity is then checked by monitoring source range flux doubling as an early symptom of an unintended RCS boron dilution, which should occur at a slow enough rate to allow appropriate action to be taken to reestablish shutdown margin. RCS cold overpressure symptoms of RCS pressure and temperature are monitored for maintaining the RCS pressure boundary integrity safety function.

Lastly, RCS temperature change, aside from any normal expected RCS temperature change, is used as an early symptom for potential degradation of the core cooling safety function and the RCS pressure boundary integrity safety function. The shutdown safety status tree is considered to be satisfied when all status tree blocks have been satisfied. If a challenge is identified during the monitoring of the tree, the tree directs plant operators to one of the appropriate six shutdown guidelines for mitigating actions.

The format and arrangement of the shutdown ERG documentation is similar to the at-power ERGs consisting of guidelines and background documents. Implementation of the shutdown ERGs into plant procedures will also be similar to the at-power ERGs with the task allocation between the man and the computer for doing this to be decided when designing features of the man-machine interface system.

19E.4 Safety Analyses and Evaluations

19E.4.1 Introduction

This section reviews each of the design basis accidents (DBAs) and transients presented in Chapter 15, with respect to lower power and shutdown modes. In Subsections 19E.4.2 through 19E.4.9, evaluations or analyses are performed for each case of the transient and LOCA analyses for events occurring at low power and shutdown operations, including the reduced reactor coolant system

(RCS) inventory and refueling operations. The evaluations discuss the effects of key plant parameters (for example, plant control parameters, neutronic and thermal hydraulic parameters, and engineering safety features [ESFs]) on plant transient response (such as departure from nucleate boiling ratio [DNBR], peak pressure, and peak cladding temperature). The limiting case for each event category is identified. For those limiting cases bounded by the cases analyzed at power conditions, supporting rationales are provided.

For those events where analyses are presented in the shutdown modes, a discussion of the adequacy of the codes used is presented in Subsection 19E.4.1.2.

In Subsection 19E.4.10, additional analyses and evaluations demonstrate that the passive systems can bring the plant to a stable, safe condition and maintain this condition.

19E.4.1.1 Matrix of Chapter 15 Events

Table 19E.4.1-1 provides a list of Chapter 15 events. This table categorizes the events as “E” (requiring evaluation), “A” (requiring analysis), or “n/a” (not applicable). The “n/a” events are bounded by at-power analyses or current analyses.

The events denoted by an “n/a” in Table 19E.4.1-1 are as follows:

- Boron dilution design basis transient explained in Subsection 15.4.6 because it explicitly considers all modes such that no analysis or evaluation is required for this appendix

- Rod cluster control assembly (RCCA) withdrawal at-power explained in Subsection 15.4.2 because this event occurs only at-power

19E.4.2 Increase in Heat Removal from the Primary System

19E.4.2.1 Feedwater System Malfunctions Which Increase Heat Removal from the Primary System

Faults that decrease feedwater temperature or increase feedwater flow can be postulated in the feedwater system. These faults could increase heat removal from the primary system, which reduces RCS temperature. The reduction in RCS temperature could lead to an increase in core power generation (due to a negative moderator temperature coefficient) and result in a reduction in margin-to-core design limits. Unchecked, excessive feedwater flow could also result in overfilling the steam generators.

Discussions and analyses, initiated from Modes 1 and 2, of RCS cooldowns caused by feedwater system malfunctions are presented in Subsections 15.1.1 and 15.1.2. Subsection 15.1.1 covers reductions in feedwater temperature, and Subsection 15.1.2 covers increases in feedwater flow. Modes 1 and 2 are the limiting initial conditions for feedwater system induced RCS cooldown transients.

Protection against feedwater system induced cooldown transients is provided by the protection and safety monitoring system (PMS) through automatic functions that trip the reactor and isolate the feedwater system. The protection functions are available in all modes during which the feedwater system is in operation. Reactor trip includes overpower Δt, high power-range nuclear flux, high intermediate-range nuclear flux, or high source-range nuclear flux. The PMS closes the main feedwater control valves on low-1 RCS average temperature signal. The PMS also closes the main feedwater isolation valves and trips the booster/main feedwater pumps when RCS average temperature decreases below the low-2 RCS T_{avg} setpoint. These protection functions are arranged to detect symmetrical plant transients with a channel out of service and a single channel failure.

Additional PMS functions are provided to detect and protect against asymmetrical feedwater system malfunctions. Automatic reactor trip, closure of the main feedwater control and isolation valves, closure of the startup feedwater control and isolation valves, tripping of the booster/main feedwater pumps, and tripping of the startup feedwater pumps occur if the level in a single steam generator is above the High-3 water level setpoint. Similar actions occur if cold leg temperature in a single RCS loop decreases below the Low-2 T_{cold} setpoint. The High-3 steam generator level setpoint is active in Modes 1 through 4 unless the various feedwater valves are closed. This ensures that the steam generators cannot inadvertently be overfilled. The Low-2 T_{cold} signal is available in Modes 1 through 3. In Mode 3 prior to blocking the Low-2 T_{cold} signal, the RCS must be borated to cold shutdown conditions. With the RCS borated, no feedwater malfunction can be postulated to cool the RCS such that a core power excursion would occur.

The feedwater malfunction associated with a drop in feedwater temperature is less severe as power level is decreased. Normal operating feedwater temperature decreases as plant power level decreases. Therefore, if a fault suddenly reduces the feedwater temperature, the maximum change in feedwater temperature will occur if the plant is operating at full power.

As discussed in Subsection 19E.2.2 of this appendix, in Modes 2 and below, feedwater entering the steam generators is routed through the startup feedwater control valves. The maximum achievable flow rate through the startup feedwater path is much less than when flow is being controlled by the main feedwater control valves. Therefore, failure of a main feedwater control valve in Mode 2 and below is not likely. The assumption of a failed open startup feedwater control valve, in Mode 2 and below, will result in a relatively slow transient due to low feedwater flow rate.

The most severe RCS cooldowns caused by feed system malfunctions will occur in Modes 1 or 2. In Modes 3 or 4, RCS cooldowns due to feedwater malfunctions would be precluded, inconsequential, or less severe than in Modes 1 or 2. The analyses presented in Chapter 15 bound the consequences of this class of events initiated in the shutdown modes.

19E.4.2.2 Excessive Increase in Secondary Steam Flow

An excessive increase in secondary steam flow (excessive load increase) is caused by a rapid increase in steam flow that results in a power mismatch between the reactor core power and the steam generator load demand. The plant control system (PLS) is designed to accommodate a 10-percent step load increase in steam flow in the range of 25 to 100 percent of full power. Analyses results for a 10-percent step increase in steam flow are presented in Subsection 15.1.3. The analyses are performed for Mode 1 from full-power initial conditions. Depending upon the plant and PMS characteristics (setpoint uncertainties), a reactor trip signal may or may not be generated for an excessive load increase from full power.

An excessive load increase in Mode 1 is considered limiting because an excessive load increase at full power will put the plant at the highest achievable power level. Load increases at less than full power, or during startup (Mode 2), will not reach as high a power level. The excessive load increase, in Mode 2, will not be as severe as the Mode 1 excessive load increase.

In Mode 3, the excessive load increase may be considered to be a simple steam release because there can be no load, per se, when the turbine is off-line and the core is subcritical. The Mode 3 load increase will be less limiting than the Mode 1 or Mode 2 case because the core is already subcritical. Automatic safeguards actuation signals may not be available if blocked by the operator (blocking is necessary to depressurize and cool down the RCS). However, the RCS must be borated to meet shutdown margin requirements at cold shutdown (200°F) prior to blocking automatic safeguards actuation signals to prevent a return to criticality in the event of a cooldown.

The Mode 4 situation is bounded by Mode 3 because pressure and temperature conditions in the primary and secondary systems are reduced. At some point in Mode 4, the RNS will be placed in service. In Modes 5 and 6, the RNS should be in operation. Any steam release will have little or no effect upon the core.

19E.4.2.3 Credible and Hypothetical Steam Line Breaks

The spurious opening of a steam generator safety or relief valve is a Condition II event and referred to as a credible steam line break. This event affects the core like a load increase but the analysis assumptions that are applied are different. The credible steam line break is usually assumed to be an unisolatable, uncontrolled steam release, which causes a non-uniform core cooldown (typical of an open safety valve) during the period immediately following a reactor trip which inserts all but the most reactive rod cluster control assembly (RCCA). The resulting reactivity excursion may be large enough to overcome the shutdown margin and return the core to critical, especially when there is little or no decay heat (with power peaking in the region of the stuck RCCA). The credible steam line break is analyzed in Mode 2, and the results are presented in Subsection 15.1.4. The assumptions used in the analysis lead to a more severe, post-trip transient than will result from a load increase initiated in Mode 1.

In Mode 1, prior to reactor trip, the transient characteristics of an inadvertent opening of a steam generator safety or relief valve are similar to the excessive load increase. A reactor trip signal, if needed, may result from overpower ΔT logic. After the reactor trip, the concern becomes a possible return to criticality with the most reactive RCCA stuck in the fully withdrawn position, leading to high local power levels. However, a post-trip return to criticality is less likely when this event occurs in Mode 1 than in Mode 2 because there will be more decay heat present, which tends to retard the cooldown.

In Mode 3, results are expected to be better than the Mode 2 case because pressure, temperature, and flow conditions will be less limiting. An occurrence in Mode 4 will be less severe than in Modes 2 or 3 due to the lower initial RCS temperature, and an effective decoupling of the secondary system from the primary system as the reactor coolant pumps (RCPs) are removed from service and the RNS is started. Automatic safeguards actuation signals are available through Mode 3, until the RCS is borated and the automatic safeguards signals are blocked (see excessive load increase discussion). Both CMTs continue to be available for automatic actuation on low-2 pressurizer level or manual actuation through Mode 4 with the RCS not being cooled by the RNS (see Technical Specification LCO 3.5.2). In Mode 4 with the RNS in operation and in Mode 5 with the RCS pressure boundary intact, one CMT is available for activation if needed.

Any cooldown in Modes 5 and 6 caused by depressurization of the secondary system is meaningless because the RCS is already cold, and the RNS system effectively decouples the steam generators from the core.

The steam line rupture is a Condition IV event, producing a greater uncontrolled steam release than the spurious opening of a steam generator safety valve (described above), but the relative effects in the various modes and requirements for protection equipment are the same. This is the most severe cooldown event.

19E.4.2.4 Inadvertent PRHR HX Operation

Inadvertent actuation of the PRHR HX causes an injection of relatively cold water into the RCS. This produces a reactivity insertion in the presence of a negative moderator temperature coefficient. Because the PRHR HX is connected to only one RCS loop, the cooldown resulting from its actuation is asymmetric with respect to the core. Inadvertent actuation of the PRHR HX could lead to an asymmetric power increase and a reduction in margin-to-core design limits.

A limiting analysis of an inadvertent actuation of the PRHR HX heat exchanger is presented in Subsection 15.1.6. The analysis is initiated in Mode 1 from hot full-power conditions. This is the most limiting case.

The PRHR HX heat transfer rate is a function of the inlet temperature to the heat exchanger and the flow rate through the heat exchanger. PRHR HX heat transfer rate is higher with high flow rates and high inlet temperatures. Therefore, the maximum heat removal rate will occur when the plant is at full-power condition with forced RCS flow and a high hot leg temperature. At plant full-power conditions, the PRHR HX heat removal rate is approximately 10 percent of full power. At hot zero power (HZP) conditions with natural circulation, heat removal by the PRHR HX is approximately 1.5 percent to 2 percent of full power.

The heat sink for the PRHR HX is the in-containment refueling water storage tank (IRWST), in which the heat exchanger is submerged. Prior to actuation of the PRHR HX, the fluid within the heat exchanger is in thermal equilibrium with the fluid in the IRWST. Thus, the PRHR HX is initially filled with relatively cold fluid which is at containment ambient temperature. When the PRHR HX is actuated, the initial fluid outsurge is fluid at containment ambient temperature. Once the original fluid in the PRHR HX is purged, the out-flow temperature trend of the heat exchanger is set by the temperature entering the heat exchanger from the RCS hot leg minus the temperature drop through the heat exchanger. Thus, the outlet fluid temperature is limited by the cooling capacity of the PRHR HX.

If the reactor is at power (Mode 1 or 2) when the PRHR HX is inadvertently actuated, a cooldown induced increase in core power will occur. The transient response will have two parts. As the cold fluid from the PRHR HX, which is initially at the ambient IRWST temperature, enters the RCS, a large core power increase will occur. The magnitude of the power increase is proportional to the volume of the cold fluid in the PRHR HX. Once the original fluid is purged from the PRHR HX, the fluid temperature exiting the PRHR HX increases to a value limited by the cooling capacity of the PRHR HX. Core power will then decrease to a value higher than the initial core power, but in equilibrium with the heat removal capability of the steam generators plus the PRHR HX.

With the assumptions of a protection system channel out of service as allowed by the Technical Specifications, a failure of an additional protection system channel, and maximum instrument uncertainties, the asymmetric core power transient may not result in actuating any overpower reactor trips, such as high nuclear flux or overpower Δt. In this case, the core power transient is controlled only by the initial volume of cold water in the PRHR HX and the heat removal capability of the heat exchanger.

Higher initial core power will result in the largest achievable core power and in more severe consequences. Therefore, if the reactor is at-power, the full-power case produces the worst results.

In Mode 3, because the reactor is subcritical, inadvertent actuation of the PRHR HX produces a less severe power excursion than if the reactor is at power or at HZP with the reactor just critical. If in Mode 3 below no-load temperature, the cooldown caused by the actuation of the PRHR HX results in the cold leg temperature dropping below the Low-2 T_{cold} safeguards signal setpoint. This function actuates a reactor trip, initiates boration by the CMTs, and most importantly, trips all the RCPs. When the RCPs trip, natural circulation flow begins in the RCS and the PRHR HX loop. When natural circulation flow is initiated, the heat removal capability of the PRHR HX decreases to approximately 1.5 percent of full power and the severity of the transient is minimized. With the RCS in natural circulation, the cooldown rate of the RCS is also slowed. If criticality is obtained, boration by the CMTs will bring the core subcritical again.

The Low-2 T_{cold} safeguards signal may be blocked by the operator in Mode 3 to allow plant depressurization and cooldown to lower modes. However, prior to blocking the Low-2 T_{cold}

safeguards signal, the RCS is borated to the shutdown margin requirements at cold shutdown (200°F). Therefore, in Mode 3 with safeguards signals blocked or in Mode 4, cooldown of the RCS by inadvertent actuation of the PRHR HX will not result in a reactivity excursion, which produces a power increase.

In Modes 5 and 6, the RCS will be borated such that a cooldown-induced power excursion could not be postulated. The RCS will be at 200°F or less, and with initial RCS temperatures this low, no significant cooling of the RCS by inadvertent actuation of the PRHR HX could be postulated.

19E.4.3 Decrease in Heat Removal by the Secondary System

19E.4.3.1 Loss of Load and Turbine Trip

Discussions and analyses of the consequences of loss of load, turbine trip, inadvertent closure of main steam isolation valves (MSIVs), or loss of condenser vacuum are presented in Subsections 15.2.2 through 15.2.5. These events are characterized by a rapid reduction in steam flow from the steam generators. This results in an increase in steam pressure and a heatup of the primary side if the reactor power is not reduced. The effects of the primary to secondary power mismatch during these events are mitigated by tripping the reactor and opening secondary and primary side safety valves. The severity of these events is increased if the primary to secondary power mismatch is increased. Therefore, the most severe results occur if the plant is initially operating in Mode 1 at maximum-rated plant power conditions rather than lower power conditions. The turbine is off-line below Mode 1 and transients related to turbine-related faults cannot occur.

In Modes 2, 3, or 4, the plant may be removing decay heat by dumping steam to the condenser. In Mode 4 when the RCS is below 350°F, decay heat is removed using the RNS. In Modes 2, 3, or 4, the transient response to a loss of condenser vacuum or inadvertent MSIV closure is bounded by the turbine trip analysis from full power because the power mismatch is low. Decay heat removal can still be accomplished by the steam generators through atmospheric steam relief through power-operated relief valves (PORVs) if available or through steam generator safety valves, which are available through Mode 4 (see Technical Specification LCO 3.7.1). Additionally, decay heat can be removed with the PRHR HX, which is available through Mode 5 with the RCS intact (see Technical Specifications LCO 3.5.4 and 3.5.5).

19E.4.3.2 Loss of ac Power

A discussion and an analysis of a loss of ac power event are provided in Subsection 15.2.6. The loss of ac power results in the loss of forced primary coolant flow and the loss of main feedwater flow. This results in a heatup and pressurization of the RCS. If the reactor is at power, the event is mitigated by tripping the reactor. The reactor may be automatically tripped on Low-2 RCP speed, Low-2 RCS flow, Low-2 steam generator narrow range water level, or several other primary side heatup signals. Also reactor trip may occur due to the loss of power to the control rod drive mechanisms.

Following reactor trip, the PRHR HX is activated for decay heat removal. Automatic PRHR HX actuation on Low-2 steam generator wide range water level is available in Modes 1 through 3 and in Mode 4 when the RCS is not being cooled by the RNS. The most limiting case for loss of ac power would be if the plant were at full rated power. This will result in the highest decay heat levels and stored energy in the RCS and the heat removal capability of the PRHR HX will be maximized. In Modes 4 or 5 with the RNS in operation, the plant response to a loss of ac power is the same at the loss of RNS cooling as discussed in Subsection 19E.4.8 of this appendix.

19E.4.3.3 Loss of Normal Feedwater

The main feedwater system is in operation during Modes 1 and 2. The startup feedwater system is used in Mode 2 below approximately 2 percent power, in Mode 3, and in Mode 4 before the RNS is aligned. In Mode 4 with the RNS aligned and in Modes 5 and 6, the feedwater system is not used, and therefore, loss of feedwater events is irrelevant.

A discussion and an analysis of a loss of normal feedwater event from rated full-power conditions are provided in Subsection 15.2.7. The loss of normal feedwater flow results in a heatup and pressurization of the RCS. If the reactor is at-power, the event is mitigated by tripping the reactor on Low-2 steam generator narrow range water level.

Following reactor trip, the PRHR HX is activated for decay heat removal. Automatic PRHR HX actuation on Low-2 steam generator wide range water level is available in Modes 1 through 3 and in Mode 4 when the RCS is not being cooled by the RNS. The most limiting case for a loss of normal feedwater is with the plant initially at full rated power. This case will have the highest decay heat levels and stored energy in the RCS and the heat removal capability of the PRHR HX will be maximized. The analysis initiated from full power bounds cases initiated from the shutdown modes.

19E.4.3.4 Feedwater System Pipe Break

Depending upon the size of the break and plant operating conditions, the break could cause either an RCS heatup or an RCS cooldown. The cooldown aspects are less severe than a steam line break, which is discussed in Subsection 19E.4.2.3 of this appendix and is not considered in the following discussion.

The main feedwater system is in operation during Modes 1 and 2. The startup feedwater system is used in Mode 2 below approximately 2 percent power, in Mode 3, and in Mode 4 before the RNS is aligned. In Mode 4 with the RNS aligned and in Modes 5 and 6, the feedwater system is not used, and therefore, a loss of feedwater caused by a feedwater system pipe break will not cause a heatup of the RCS.

A discussion and an analysis of feedwater system pipe break from rated full-power conditions are provided in Subsection 15.2.8. A rupture of a feedwater system pipe results in a loss of feedwater flow causing a heatup and pressurization of the RCS. If the reactor is at-power, the event is mitigated by tripping the reactor on Low-2 steam generator narrow range water level.

Following reactor trip, the PRHR HX is activated for decay heat removal. Automatic PRHR HX actuation on Low-2 steam generator wide range water level is available in Modes 1 through 3 and in Mode 4 when the RCS is not being cooled by the RNS. The most limiting case for a feedline break occurs with the plant at full rated power. This case will have the highest decay heat levels and the highest stored energy in the RCS and the heat removal capability of the PRHR HX will be maximized.

19E.4.4 Decrease in Reactor Coolant Flow Rate

19E.4.4.1 Partial and Complete Loss of Forced RCS Flow

A partial loss of forced RCS flow may be caused by a mechanical or an electrical failure in an RCP or from a fault in the power supply to the pumps. An RCP failure will result in only the loss of a single RCP. A fault in the power supplies for the RCPs could result only in the loss of one, two, or all four RCPs.

The loss of one or more RCPs reduces the heat removal rate from the primary to the secondary coolant system and thereby causes a heatup in the RCS. The heatup of the RCS results in an

increase in RCS pressure and a decrease in margin-to-core design limits (that is, departure from nucleate boiling [DNB]). An occurrence at full power will produce a greater and more rapid heatup than at part-power conditions or low-power conditions in Mode 2. Therefore, for evaluating the maximum RCS pressure or the minimum DNB ratio, analyses are performed at full-power conditions. Analyses for partial loss of forced RCS flow transients are presented in Subsection 15.3.1. Analyses for a complete loss of flow are presented in Subsection 15.3.2. These analyses bound loss of flow events initiated in other modes.

Protection for loss of forced RCS flow events is provided by tripping the reactor. This reduces reactor power and preserves margin-to-DNB limits. The AP1000 PMS includes a reactor trip on Low-2 RCS flow in any cold leg and a reactor trip on Low-2 RCP speed in any two of four RCPs. These two reactor trips are used to detect all possible partial and complete loss of RCS flow transients. Opening of the pressurizer safety valves in conjunction with the reactor trip prevents overpressurization of the RCS.

Below Mode 2, when the core is subcritical, forced RCS flow is not needed because margin-to-DNB is not an issue. It is common to have one or more RCPs out of service below Mode 2 because full RCS flow is no longer needed. In Modes 3 through 5, LCO 3.4.4 of the Technical Specifications requires that all four RCPs need to be operating if the Plant Control System is capable of rod withdrawal or one or more rods is not fully inserted, to ensure that DNB limits are not exceeded, in the event RCCAs are inadvertently withdrawn. If the Plant Control System is incapable of rod withdrawal, all rods are fully inserted, and unborated water sources are isolated from the RCS, no RCPs are required to be operating in Modes 3 through 5.

Following reactor trip in loss of forced RCS flow events, decay heat removal is required. The PRHR HX or the steam generators can be used for decay heat removal. In the event of a complete loss of forced RCS flow, RCS natural circulation is adequate to remove core decay heat. This is demonstrated by the loss of ac power analysis presented in Subsection 15.2.6.

19E.4.4.2 Reactor Coolant Pump Shaft Seizure or Break

An RCP shaft seizure or break results in a partial loss of forced RCS flow. The results are similar to partial loss of flow events discussed in Subsection 19E.4.4.1 of this appendix except that the rate of flow reduction is much more rapid if an RCP shaft breaks or seizes. Like the partial loss of flow, a locked or broken RCP shaft reduces the heat removal rate from the primary to secondary coolant system and thereby causes a heatup of the RCS. An occurrence at full power produces the most severe heatup transient. The discussion for the partial loss of flow with respect to limiting modes and protection is applicable to the RCP shaft seizures or breaks.

Analyses and evaluation of RCP shaft seizures and breaks for Mode 1, from full-power conditions, are provided in Subsections 15.3.3 and 15.3.4. The analyses bound events initiated from the shutdown modes.

19E.4.5 Reactivity and Power Distribution Anomalies

19E.4.5.1 Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition

An uncontrolled RCCA bank withdrawal from a subcritical condition could cause a reactivity excursion, which if not terminated by a reactor trip, could result in DNB. Subsection 15.4.2 presents an analysis for the uncontrolled RCCA bank withdrawal from a subcritical condition in Mode 2. Assumptions are used that make the analysis bound an occurrence in Modes 2, 3, 4, or 5. Specific conservative assumptions are made for the number of RCPs operating, the reactor trip functions credited, initial RCS temperature, and the magnitude of the reactivity excursion.

A single failure in the rod control system could cause the withdrawal of only one bank, and its withdrawal rate would be expected to be slower than the maximum rod speed possible when in automatic rod control. The analysis assumes the simultaneous withdrawal of the combination of two sequential RCCA banks having the greatest combined worth at the maximum possible speed.

LCO 3.3.1–3.3.7 of the AP1000 Technical Specifications gives the operational requirements for reactor trips. The source-range high neutron flux trip must be in operation in Modes 3, 4, and 5 if the reactor trip breakers are closed. If the reactor trip breakers are open, then an RCCA withdrawal is precluded from occurring. The source-range high neutron flux trip is available in Mode 2 if power is below the P-6 interlock. In these instances, the source-range high neutron flux trip would be available to terminate the event, by tripping any withdrawn and withdrawing rods, before any significant power level could be attained. Therefore, DNB would be precluded. The intermediate-range high neutron flux reactor trip is also available in Mode 2. The analysis assumes that reactor trip does not occur until the power-range (low setting) high neutron flux setpoint is reached. No credit is assumed in the analysis for the source-range high neutron flux reactor trip or the intermediate-range high neutron flux reactor trip.

LCOs 3.4.4 and 3.4.5 of the AP1000 Technical Specifications give the operation requirements for RCPs. LCO 3.4.4 specifies that all four RCPs must be operating whenever the Plant Control System is capable of rod withdrawal or one or more rods is not fully inserted in Modes 1 through 5.

The RCS temperature is assumed to be at the HZP value in the analysis. This is more limiting than that of a lower initial system temperature for DNB and core kinetics feedback calculations.

These conservative assumptions result in the core returning to critical and generating power before reactor trip occurs. The analysis presented in Chapter 15 bounds the inadvertent RCCA bank withdrawal from a subcritical condition transient in Modes 2 through 5.

19E.4.5.2 Uncontrolled RCCA Bank Withdrawal at Power

This transient is defined only in Mode 1.

19E.4.5.3 RCCA Misalignment

RCCA misalignment events are analyzed in Subsection 15.4.3. RCCA misalignment events include the following:

- One or more dropped RCCAs
- Statically misaligned RCCA
- Withdrawal of a single RCCA

This group of events may result in core radial power distribution perturbations, which may cause allowable design power peaking factors and DNB design limits to be exceeded. Therefore, these events are a concern only in the at-power modes, and the severity will be increased at high power. If the reactor is subcritical, DNB will not be a concern.

Following the dropping of one or more RCCAs while at-power, core power will immediately be reduced. The reduced core power and the continued steam demand to the turbine causes a reactor coolant temperature decrease. If the reactor is in manual control, the core power rises due to moderator feedback to the initial power level at a reduced core inlet temperature. If the reactor is in automatic control, the control system detects the drop in power and initiates withdrawal of a control bank. Power overshoot above the initial power level may occur as the control system withdraws a bank. Following dropping of one or more RCCAs, the most severe results occur when the control system overshoots the initial power level in conjunction with a perturbation in the radial power

distribution. This is the most limiting case for this event, and the results are presented in Chapter 15. If the reactor is in any of the subcritical modes, dropping RCCAs will not result in any power transient.

As in the case of dropped RCCAs, statically misaligned RCCAs have no effect in the absence of a critical neutron flux and are not a concern below Mode 2. The most limiting case, and analysis, is for Mode 1 which also bounds Mode 2 operation.

The most limiting case for the withdrawal of a single RCCA is an occurrence while in Mode 1. An occurrence in any of the subcritical modes will have no effect. The shutdown margin requirements are specified in LCO 3.1.1 of the AP1000 Technical Specifications. The shutdown margin requirements are determined assuming the most reactive RCCA is fully withdrawn from the core. Therefore, no single RCCA withdrawal initiated from the subcritical modes will insert enough reactivity to attain criticality.

19E.4.5.4 Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature

This event is precluded from occurring during at-power modes by Technical Specifications. Startup of an inactive RCP while in any of the subcritical modes will have relatively little effect upon core temperature because there will be little or no temperature difference between the loops. Subsection 15.4.4 discusses the consequences of this event for the AP1000.

19E.4.5.5 Chemical and Volume Control System Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant

Boron dilution analyses and evaluations for Modes 1 through 5 are provided in Subsection 15.4.6. In Mode 6, administrative controls isolate the RCS from potential sources of unborated water by locking closed specified valves in the chemical and volume control system (CVS), and Demineralized Water Transfer and Storage System, and thereby preclude an uncontrolled boron dilution transient. Makeup needed during refueling is supplied from the boric acid tank which contains borated water.

19E.4.5.6 Inadvertent Loading of a Fuel Assembly in an Improper Position

Fuel loading errors – such as inadvertent loading of one or more fuel assemblies into improper positions, having a fuel rod with one or more pellets of the wrong enrichment, or having a fuel assembly with pellets of the wrong enrichment – may result in power shapes in excess of design values. Subsection 15.4.7 presents Mode 1 results for this event which bound the results for operation in Mode 2. This event is meaningful only if the reactor is at-power and, therefore, not applicable in the subcritical Modes of 3 through 6.

19E.4.5.7 RCCA Ejection

Analyses for RCCA ejections in Mode 1 and Mode 2 are presented in Tier 2 Information Subsection 15.4.8. The cases analyzed in Chapter 15 are the most limiting cases. The shutdown margin requirements are specified in LCO 3.1.1 of the AP1000 Technical Specifications. The shutdown margin requirements are determined assuming the most reactive RCCA is fully withdrawn from the core. Therefore, the ejection of a single RCCA initiated from the subcritical modes would not insert enough reactivity to attain criticality.

19E.4.6 Increase in Reactor Coolant Inventory

An increase in RCS inventory could be caused by inadvertent actuation of the CMTs or by malfunctions in the CVS system. Analyses of events that increase the RCS inventory are provided in Section 15.5. Subsection 15.5.1 presents the analysis results for inadvertent actuation of the CMT. Subsection 15.5.2 contains results from the analysis of a CVS malfunction which increases RCS

inventory. These events do not present a challenge to core design limits. If unchecked, these events could lead to an overfill of the pressurizer and possible loss of reactor coolant from the system. The increase in pressurizer water volume is slow during these events and is controlled by the injection rate, core decay heat produced, and heat removal rate from the RCS. While the pressurizer safety valves may open, the steam relief from the pressurizer safety valves is low and no serious challenge to the RCS pressure boundary occurs (if the pressurizer does not fill).

The Chapter 15 analyses for these events are performed with the plant initially in Mode 1 at full-power conditions. This results in the maximum amount of stored energy in the plant and in the maximum core decay heat. If the plant was assumed to be at part power, or in the subcritical modes, the amount of stored energy and decay heat will be significantly reduced.

If a spurious “S” signal occurs causing the CMTs to be actuated, the reactor is also tripped and the PRHR HX is also actuated. The CMTs will begin injecting cold, borated fluid into the RCS. The injected fluid expands as it is heated in the RCS by decay heat. The expansion is counteracted by decay heat removal through the PRHR HX. The severity of the expansion is increased with higher decay heat levels.

Malfunctions in the CVS, which add excess inventory to the RCS, are protected against by the inclusion of automatic CVS isolation functions in the PMS. If a safeguards signal has occurred (which also would activate the CMTs), the CVS is automatically isolated if the pressurizer level exceeds the high-1 pressurizer level setpoint. Above the high-1 pressurizer level setpoint, there is a high-2 pressurizer level setpoint, which also isolates the CVS. The high-2 pressurizer level function is not interlocked with the safeguards signal. The high-2 function protects in situations where the reactor is at-power or a safeguards signal has not occurred. The high-2 pressurizer level function is available in Modes 1 through Mode 3 and in Mode 4 when the RNS is not operating. These functions effectively prevent overfilling of the pressurizer when the CVS acts alone or where CVS interacts to also cause the CMTs to be actuated.

Isolation of CVS on high-2 pressurizer level is available in Modes 1 through 4 until the plant is operating on RNS. There are applications where the RCS may be filled water-solid when the RNS is in operation. In Modes 4, 5, and 6 when the RNS is in operation, low-temperature overpressure protection (LTOP) of the RCS pressure boundary is provided by the RNS relief valves. A discussion of this is provided in Subsection 19E.4.10.1 of this appendix.

19E.4.7 Decrease in Reactor Coolant Inventory

19E.4.7.1 Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the Automatic Depressurization System

Subsection 15.6.1 includes analyses and evaluations of the inadvertent opening of a pressurizer safety valve or the inadvertent operation of the automatic depressurization system (ADS).

When analyzed as depressurization events, inadvertent opening of primary side relief valves, if the reactor is at-power, could result in exceeding core design limits, specifically DNB criteria. Violation of DNB criteria is not a realistic concern if the reactor is in any of the subcritical modes. Therefore, these events are analyzed in Mode 1 at the maximum rated power and the analysis performed bounds cases initiated from Mode 2. These events bound events that can occur at shutdown.

The inadvertent ADS is analyzed as a loss-of-coolant accident in Mode 1 to demonstrate acceptance to the limits specified in 10 CFR 50.46. As described in Subsection 15.6.5, this analysis is a “no-break” small-break LOCA calculation. The inadvertent opening of the 4-inch nominal size ADS Stage 1 valves is a situation that minimizes the venting capability of the RCS. Only the ADS valve vent area is available; no additional vent area exists due to a break. This case examines whether sufficient vent

area is available to completely depressurize the RCS and achieve injection from the IRWST without core uncovery. The case analyzed at-power bounds the inadvertent ADS during shutdown because the lower decay heat levels at shutdown reduce the challenge to the ADS vent capacity. More limiting loss-of-coolant accidents at shutdown are analyzed as described in Subsection 19E.4.8.

19E.4.7.2 Failure of Small Lines Carrying Primary Coolant Outside Containment

This event is reported in Subsection 15.6.2 as the rupture of a primary coolant sample line; the radiological consequences of this event are analyzed during Mode 1 because the coolant temperature and iodine concentrations bound those that would exist in the other modes. Concerning shutdown risk, the consequences of a sample line break during Modes 2, 3, 4, or 5 are no more severe than if the accident occurs during Mode 1 operation.

19E.4.7.3 Steam Generator Tube Rupture in Lower Modes

The steam generator tube rupture (SGTR) analysis presented in Chapter 15 is the limiting case with respect to offsite doses. The analysis was performed at full power because this results in the maximum offsite dose. The key inputs from the thermal-hydraulic SGTR analysis performed with the LOFTTR2 computer code to the offsite dose analysis are the amount of flashed primary to secondary break flow and the steam released from the faulted steam generator. Both of these will be significantly reduced at lower power levels and in lower modes of operation.

Margin to overfill analyses are not presented in Chapter 15, however an analysis is performed to demonstrate margin to steam generator overfill with no operator actions modeled. This is necessary because the dose analysis does not include consideration of water relief from the ruptured steam generator PORV/MSSV. This margin to steam generator overfill analysis was supported by the assertion that an analysis with operator actions modeled will also demonstrate margin to overfill. The overfill analysis with no operator actions discussed in Chapter 15 was initiated at full power. WCAP-10698-P-A (Reference 9) indicates that margin to overfill is reduced when the SGTR is initiated at zero power because of the higher initial steam generator secondary liquid inventory. WCAP-10698-P-A concludes that zero power and lower mode SGTR overfill analyses are not limiting, based primarily on more rapid operator responses expected in those conditions. This is discussed further in the Appendices to WCAP-10698-P-A. When operator actions are credited for AP1000 SGTR mitigation, the plant behaves in a manner comparable to a standard Westinghouse PWR and the conclusions of WCAP-10698-P-A apply.

When operator actions are not relied upon and only the AP1000 automatic RCS cooling and depressurization are credited, margin to overfill would still be maintained for SGTR events initiated at lower power levels and lower modes despite the increased initial steam generator secondary side inventory corresponding to the lower initial power assumption. This is because the automatic protection system actions that prevent overfill are independent of the operator actions. For operating plants, there is a set period of time from the start of the event until the operator can reverse the trend toward filling the steam generator. Therefore, the initial margin to overfill directly impacts the final margin. For the AP1000, the primary cooldown and depressurization occur automatically when the PRHR HX is actuated on a Low-3 pressurizer pressure “S” signal or Low-2 pressurizer level CMT actuation signal. The primary pressure may still be held up by the CVS, until it is isolated on a high steam generator level signal. For the AP1000, a higher initial steam generator water level results in the CVS flow being terminated earlier.

In Mode 4, the PRHR HX actuation is provided by the Low-2 pressurizer level signal. Although this results in delayed cooling and depressurization, margin to steam generator overfill is still maintained. The increase in mass in the secondary side of the ruptured steam generator is directly related to the reduction in pressurizer water level, because (once the CVS is isolated on high steam generator water level) there is no source of makeup to the RCS. The steam generator secondary side can

accommodate the amount of fluid initially contained in the pressurizer and still retain a significant amount of margin to steam generator overfill. The PRHR HX will, therefore, be actuated on Low-2 pressurizer water level in sufficient time for the PRHR HX to cool and depressurize the primary and terminate break flow before steam generator overfill will occur.

In Mode 4 with an RCS temperature less than 350° F and in Modes 5 and 6, the RCS pressure and temperature are reduced; thus, an SGTR event is not considered credible.

19E.4.8 Loss-of-Coolant Accident Events in Shutdown Modes

The AP1000 DCD presents a spectrum of break sizes of the postulated LOCAs at the full-power operating condition. Other things being equal, the reduction in power to decay heat levels associated with shutdown mode operations will make all LOCA events less limiting than those analyzed at full power and reported in Subsection 15.6.5. However, as the plant proceeds through shutdown modes of operation, various PXS equipment are removed from service at identified points in time. One particularly significant action in the course of taking the AP1000 to cold shutdown, in the elimination of PXS equipment, is the isolation of the accumulators at 1000 psig. This procedural action reduces the capability of the PXS to mitigate LOCAs. For assessing the adequacy of the remaining PXS components to mitigate postulated LOCA events, the limiting double-ended cold-leg guillotine (DECLG) break, analyzed in Chapter 15, is analyzed assuming it occurs immediately after the isolation of the accumulators. The analysis is performed using the AP1000 Large-Break LOCA WCOBRA-TRAC model used for the at-power Design Basis Accident analysis. Only safety-related systems are modeled in the analysis of this event.

Depressurization of the AP1000 primary system during shutdown operations will be performed with the same care taken to avoid the flashing of liquid in the core and upper head that is taken by current operating plants. Prudent plant operation dictates that subcooling margin be retained as pressure is reduced. Therefore, since the AP1000 shutdown operations will be conducted in a prudent, controlled manner, it is anticipated that the RCS temperature will be near the 420°F lower limit of Mode 3 when the accumulators are isolated.

For these analyses, the plant was assumed to be shut down in Mode 3 at steady-state conditions of 1000 psig and 425°F with the accumulators isolated. An initial pressure of 1000 psig is assumed because this is the highest pressure with the accumulators isolated and a hot-leg temperature of 425°F is the highest expected temperature when the pressure is 1000 psig. The decay heat level accounts for a ~2-hour power descension from full power to reactor trip plus a ~1-hour post-trip period until the accumulators are isolated. When accounting for the power descension, this leads to a conservative analyzed shutdown time equivalent to 1.71 hours. The Low-3 pressurizer pressure safeguards signal is also assumed to be disabled because the initial pressure is below the setpoint.

19E.4.8.1 Double-Ended Cold-Leg Guillotine

The DECLG break is analyzed using the WCOBRA/TRAC computer code and the AP1000-specific noding, which is based on the AP600 noding, presented in WCAP-14171, Revision 1 (Reference 10). Table 19E.4.8-1 summarizes the results.

This case models the double-ended rupture of one of the two cold legs in the RCS loop without the PRHR HX at a pressure of 1000 psig just after the accumulators are isolated. Only the core makeup tanks (CMTs) and IRWST are available to deliver PXS flow. This break evaluates the ability of the plant to withstand a large LOCA during shutdown with its conditions and equipment availability. The nominal discharge coefficient (1.0) is modeled. The analysis is performed with ANSI-5.1-1979+2σ decay heat, and Technical Specification/Core Operating Limits Report maximum peaking factors.

The break is assumed to open instantaneously at 0.0 seconds. The subcooled discharge from the broken cold leg (Figure 19E.4.8-1) causes a rapid RCS depressurization (Figure 19E.4.8-2). In Figure 19E.4.8-1, the positive flow direction is the normal operation direction. The reversal of flow entering the vessel to flow out of the break is shown. Due to High-2 containment pressure, an “S” signal is generated at 2.2 seconds. Following a 2.0-second delay, the isolation valves on the CMT and PRHR HX outlet lines begin to open. The reactor coolant pumps trip at 9.5 seconds. The nominal discharge coefficient of 1.0, identified in full-power LOCA analyses, is assumed.

Within a few seconds, the collapsed liquid level drops within the upper plenum due to voiding (Figure 19E.4.8-3). The downcomer collapsed liquid level (Figure 19E.4.8-4) quickly falls below the elevation of the cold legs; the elevation of the top of the core is 20.47 feet.

CMT injection from both tanks replenishes the RCS mass inventory. Injection from the CMTs as the RCS pressure declines terminates the peak cladding temperature (PCT) transient because the stable injection of water from the CMTs exceeds the break flow. The core collapsed level refills as shown in Figure 19E.4.8-5. The draining of the CMTs is delayed by condensation occurring at the top of the tank (Figure 19E.4.8-6(b)). After brief periods of draining early in the transient, sustained CMT injection is established at ~150 seconds for the intact cold leg and ~200 seconds for the broken cold leg. The maximum PCT value is approximately 1840°F for this bounding break size as shown in Figure 19E.4.8-6(a), and all the 10 CFR 50.46 (Reference 15) acceptance criteria are met.

19E.4.8.2 Loss of Normal Residual Heat Removal System Cooling in Mode 4 and Mode 5 with Reactor Coolant System Intact

This analysis is applicable when the RCS pressure boundary is intact less than 28 hours after shutdown. For this analysis, it is assumed that the RNS has just been placed in operation at 2.5 hours after reactor shutdown with the RCS at 350°F and 400 psig (414.7 psia). It is assumed that a loss of offsite power occurs, resulting in a loss of flow through the RNS, and thus, in a loss of RNS cooling. The MSS is assumed to be unavailable for heat removal during the event, except for the main steam safety valves. The steam generator secondary side is assumed to be at saturated conditions for 350°F with the normal water level. Because the Mode 4 plant conditions assumed for the analysis are more limiting than Mode 5 conditions, this analysis is also applicable for a loss of RNS cooling in Mode 5 when the RCS is intact.

The Technical Specifications indicate one CMT is operable during Mode 4 with RCS cooling provided by RNS and Mode 5 with RNS not vented, and all of the fourth-stage ADS flow paths are operable when the RCS is intact less than 28 hours after shutdown. The Technical Specifications permit one of six first-, second-, and third-stage ADS flow paths to be unavailable, and this analysis assumes the second-stage ADS flow path is not operable. One of the four available fourth-stage ADS valves is assumed to fail to open on demand as the single failure, consistent with the single failure assumption used for the full power small-break LOCA analyses.

Two cases were analyzed. The first allowed for automatic safety system actuation on a Low-2 pressurizer level signal late in the event. During this time, the only mechanism for removing decay heat is boiling off the RCS inventory and venting through the RNS relief valve. The second calculation assumes operator action 1800 seconds (30 minutes) after the loss of RNS cooling.

For the scenario with the RCS pressure boundary intact for at least 28 hours after shutdown, the Technical Specifications permit one fourth-stage ADS flow path to be unavailable and indicate only three ADS Stage 1, 2, and 3 flow paths are operable, including a minimum of two paths in the second- and third-stage. This scenario shows increased margin to core uncovery relative to the cases for Mode 4 and Mode 5 RCS intact less than 28 hours after reactor shutdown. Therefore, the cases described herein are bounding with respect to core uncovery margin, and the Mode 5 scenario with RCS boundary intact for at least 28 hours after reactor shutdown is not discussed any further.

Automatic Safety System Actuation

The accident analyzed is a loss of RNS cooling, which is assumed to result in a complete loss of heat removal for the RCS. The sequence of events for this analysis is presented in Table 19E.4.8-2.

Following the loss of RNS cooling, there is no active mechanism for heat removal from the RCS. The core decay heat generation causes the reactor coolant temperature and pressure to increase. Although the MSS is assumed to be unavailable for heat removal (with the exception of the main steam safety valves), the steam generators represent a heat sink that slows the rate of heatup of the reactor coolant. The fluid temperature at the core outlet for the transient is shown in Figure 19E.4.8-7. The reactor coolant heatup causes the system pressure to increase, as shown in Figure 19E.4.8-8, until the pressure reaches the RNS relief valve setpoint of 500 psig (514.7 psia) at approximately 742 seconds (0.21 hours). The normal relieving capacity of the RNS relief valve is conservatively approximated at 991 gpm at 550 psig (564.7 psia), and the pressure is maintained by the capacities of the relief valves based on the NOTRUMP Henry-Fauske Homogeneous Equilibrium Model of the choke flow area and back pressures at different water pressures and temperatures as conditions change in the RCS. The analysis model considers the negative impact of increases in RCS temperature on relief capacity. After the additional installation of relief valve RNS-V020, in parallel with RNS-V021, the total relieving capacity is within 0.3% (988 gpm) of the flow used in Subsection 19E.4.8, but considering that the 0.3% reduction is based on a higher inlet water temperature for the relief valves (400°F), the actual relieving capacity compared to the analysis of record rated RNS relief flowing temperature of 350°F would show a small benefit to the fluid conditions in the reactor vessel. Flow out the relief valve is shown in Figure 19E.4.8-9. The expansion of the water due to the coolant temperature increase also causes the pressurizer level to increase slightly as shown in Figure 19E.4.8-10.

The loss of reactor coolant through the relief valve is not sufficient to remove the core decay heat, and the reactor coolant temperature continues to increase until the core outlet temperature reaches saturation near the relief valve setpoint at approximately 2785 seconds (0.77 hours). The generation of steam in the core causes the system pressure to increase above the RNS relief valve setpoint and the pressurizer level to continue to increase. A mixture level begins to form in the upper plenum at approximately 2850 seconds (0.79 hours) and drops to the top of the hot-leg elevation as shown in Figure 19E.4.8-11. At about 3319 seconds (0.92 hours), enough mass has been discharged such that a mixture level also forms in the downcomer (Figure 19E.4.8-12) and the downcomer two-phase level begins to decrease. As the boiling front moves lower and lower into the core, more steam generation occurs and the pressure continues to increase. When the entire core length is boiling, the upper plenum mixture level is within the hot-leg perimeter. There is a brief period of two-phase discharge out the RNS relief valve when the upper plenum mixture level drops near the bottom of the hot leg at approximately 7225 seconds (2.00 hours). Following this period there is sufficient steam generation due to the loss of heat sink, that vapor is able to flow into the pressurizer and promote pressurizer draining.

As the pressurizer level decreases, a safety systems actuation signal is generated automatically on Low-2 pressurizer level. Following a 2.0-second delay, the isolation valves on the available CMT tank delivery lines begin to open and CMT injection flow is initiated at approximately 8620 seconds (2.39 hours) as shown in Figure 19E.4.8-13. The opening of the PRHR HX isolation valve on a safety systems actuation signal starts the flow through the heat exchanger. The CMT injection and PRHR actuation causes the reactor coolant pressure to decrease below the RNS relief valve setpoint, and the loss of reactor coolant via the RNS relief valve is terminated at approximately 9145 seconds (2.54 hours). As the CMT level decreases (Figure 19E.4.8-14), the first-stage ADS setpoint at 67.5 percent volume is reached and flow initiates at 9078 seconds (2.52 hours). The second-stage and third-stage ADS valves also open following the timer delays for the actuation of the second-stage and third-stage ADS valves. The vapor and liquid flow through the ADS valves (Figures 19E.4.8-15 and 19E.4.8-16) results in a rapid depressurization of the reactor coolant system. The CMT reaches the fourth-stage ADS setpoint of 20 percent volume, and the first of the fourth-stage paths begins to

open at 9688 seconds (2.69 hours). As noted previously, one of the four available fourth-stage paths is assumed to fail as the single active failure. The vapor and liquid flow through the fourth-stage ADS paths (Figures 19E.4.8-17 and 19E.4.8-18) further reduces the pressure to the point where IRWST injection begins at approximately 10,018 seconds (2.78 hours) (Figure 19E.4.8-19).

The CMT and IRWST injection reverses the decrease in the core stack and downcomer mixture levels as shown in Figures 19E.4.8-11 and 19E.4.8-12, respectively. As shown in Figure 19E.4.8-11, the core stack mixture level is maintained above the elevation of the top of the core active fuel (20.54 feet) throughout the transient. At the end of the transient, the core stack mixture level has been restored to within the hot-leg perimeter. The fluid temperature at the core outlet has also been reduced and is being maintained at less than 250ºF. As shown in Figure 19E.4.8-20, the reactor coolant mass inventory reaches a minimum of approximately 111,000 lbm; IRWST injection causes the subsequent increase in the inventory. The reactor coolant mass inventory has stabilized near 130,500 lbm at the end of the transient. Thus, it is concluded that the consequences of a loss of RNS in Modes 4 and 5 with the RCS intact are acceptable.

Manual Safety System Actuation

If operator action occurs 1800 seconds (0.50 hours) after the loss of RNS event, the CMT and PRHR isolation valves would open earlier when compared to the automatic case, allowing for heat removal via CMT and PRHR circulation. However, the decay heat is greater than the PRHR capacity and therefore the RCS pressure increases to the RNS relief valve setpoint, causing RCS inventory to be vented (Figure 19E.4.8-21 and Figure 19E.4.8-22). With heat removal being achieved through CMT and PRHR circulation, and via RCS mass discharge out of the RNS relief valve, CMT draining and ADS actuation occurs approximately 1.3 hours later compared to the automatic actuation case. Even with a conservative modeling approach allowing for bulk saturation of the IRWST, the core continues to be cooled by a two phase mixture (Figure 19E.4.8-23). The sequence of events for this case is also shown in Table 19E.4.8-2.

19E.4.8.3 Loss of Normal Residual Heat Removal System Cooling in Mode 5 with Reactor Coolant System Open

This analysis is applicable when the RCS pressure boundary is open at any time after shutdown in Mode 5. For this analysis, it is assumed that the RNS is in operation in Mode 5 at 24 hours after reactor shutdown with one tier of ADS Stage 1, 2, and 3 valves open and the RCS vented to the IRWST. The reactor coolant temperature is assumed to be at 160°F, and the pressurizer pressure is near equilibrium with the IRWST. The steam generator secondary side is assumed to be drained, and thus, there is no secondary heat sink for this case. It is assumed that the CMTs and the PRHR are not available because the Technical Specifications permit them to be taken out of service when the RCS is open in Mode 5. It is also assumed that three of the fourth-stage ADS valves are available for potential use by the operators. In addition, one of the three available fourth-stage ADS valves is assumed to fail to open on demand as the single failure. The Technical Specifications also permit one of the two IRWST injection paths to be out of service in Mode 5 with the RCS open, and thus, only one of the IRWST injection paths is assumed to be available.

It is assumed that a loss of offsite power occurs, resulting in a loss of RNS flow, and thus a loss of RNS cooling. The sequence of events for this analysis is presented in Table 19E.4.8-3.

Following the loss of RNS cooling, there is no mechanism for heat removal from the RCS and the core decay heat generation results in an increase in the reactor coolant temperature. The fluid temperature at the core outlet for the transient is shown in Figure 19E.4.8-24. The core outlet fluid temperature increases steadily until approximately 2160 seconds (0.60 hours) when saturation temperature is reached and voiding is initiated in the core. Because the RCS is vented to the IRWST via ADS Stages 1, 2, and 3, the pressure initially remains relatively constant until approximately 2400 seconds (0.67 hours) as shown in Figure 19E.4.8-25. As the void generation in the system

continues, the vapor flow through ADS Stages 1, 2, and 3 is not sufficient to maintain the pressure, and it begins to increase. The pressure increases to approximately 93.0 psia, and then begins to decrease. As shown in Figure 19E.4.8-26, the pressurizer level also increases as the reactor coolant temperature increases. The level subsequently reaches the top of the pressurizer as a result of the steam generation in the system. As shown in Figures 19E.4.8-27 and 19E.4.8-28, a mixture of steam and water is discharged via ADS Stages 1, 2, and 3 after the pressurizer fills.

The continued loss of reactor coolant through ADS Stages 1, 2, and 3 causes the pressure to begin to decrease after approximately 4100 seconds (1.14 hours). The core outlet temperature is at saturation and also begins to decrease as the pressure decreases. A mixture level begins to form in the upper plenum at approximately 2380 seconds (0.66 hours), and the level begins to decrease, as shown in Figure 19E.4.8-29, as the voiding continues in the system. At about 3080 seconds (0.86 hours), enough mass has been discharged that a mixture level forms in the downcomer (Figure 19E.4.8-30) and the downcomer level also begins to decrease. The pressurizer level does not decrease significantly due an increasing void fraction in the pressurizer.

As the voiding in the core continues, the core stack mixture level continues to decrease as shown in Figure 19E.4.8-29. The void fraction in the hot legs also increases, and the mixture level in the hot leg begins to decrease after 2375 seconds (0.66 hours). The hot leg is empty at approximately 4554 seconds (1.27 hours) as shown in Figure 19E.4.8-31. This is the normal signal for opening the fourth-stage ADS valves and to initiate IRWST injection when the systems are aligned for automatic actuation. Thus, it is assumed that the operator will initiate manual action at 4554 seconds (1.27 hours) to open the fourth-stage ADS valves and to open the IRWST flow path to permit IRWST injection when the downcomer pressure is sufficiently low. Discharge through one of the fourth-stage ADS valves is initiated at 4674 seconds (1.30 hours) as shown in Figures 19E.4.8-32 and 19E.4.8-33. As noted previously, one of the three available fourth-stage ADS paths is assumed to fail to open as the single active failure. The flow through the fourth-stage ADS path results in a further reduction in the pressurizer pressure and a rapid decrease in the pressurizer level. The downcomer pressure is also reduced to the point where IRWST injection is initiated at approximately 5029 seconds (1.40 hours) (Figure 19E.4.8-34).

The IRWST injection reverses the decrease in the core stack and downcomer mixture levels as shown in Figures 19E.4.8-29 and 19E.4.8-30, respectively. As shown in Figure 19E.4.8-29, the core stack mixture level is maintained well above the elevation of the top of the core active fuel (20.54 feet) throughout the transient. At the end of the transient, the core stack mixture level has been restored to approximately the middle of the hot-leg elevation. The fluid temperature at the core outlet has also been reduced to approximately 230°F. As shown in Figure 19E.4.8-35, the reactor coolant mass inventory reaches a minimum of approximately 122,500 pounds and then begins to increase as a result of the IRWST injection. Thus, it is concluded that when the appropriate operator action is performed, two ADS Stage 4 valves are effective in reducing system pressure so that the consequences of a loss of RNS in Mode 5 with the RCS vented are acceptable.

The analysis presented here is a conservative analysis of a loss of RNS cooling during reduced inventory conditions. During Mode 5, prior to draining to mid-loop conditions from a water solid initial condition, the operator manually opens the ADS Stages 1 through 3 paths to the IRWST. With the RCS open, the operator could proceed to slowly drain the RCS to mid-loop conditions for performing steam generator maintenance or other maintenance that requires a reduced RCS water level. Before the operator starts draining to mid-loop conditions, it is postulated that a loss of decay heat removal via the nonsafety-related RNS occurs. A loss of RNS cooling at this time is selected because it is the earliest time the RCS could be placed into a reduced inventory (that is, RCS open) condition. In addition, the backpressure on the reactor vessel, due to the presence of water in the pressurizer, is higher at this time. This presents the most challenging condition for the ADS to depressurize the RCS to IRWST cut-in pressure. This transient represents the most limiting “surge line flooding” scenario, a term commonly used for operating plants to refer to the phenomenon associated with water in the

pressurizer and surge line causing a high backpressure in the RCS. This potentially challenges the ability of the low head safety injection systems to inject properly. In addition, this scenario can potentially challenge the design pressure of temporary nozzle dams placed in the steam generators to facilitate maintenance of the RCS during refueling.

Mid-Loop Operations

For a loss of the RNS during mid-loop operations, calculations have been performed to determine the time until core uncovery would occur. The results of these calculations are presented in Table 19E.2-1. The progression of events following a loss of RNS cooling during mid-loop results in a heatup of the core to saturation, followed by a boiling off of the coolant to the IRWST via the ADS Stages 1, 2, and 3 valves. Eventually, the operator actuates the IRWST based upon indications of a loss of RCS subcooling and/or a loss of RCS inventory. The conditions in the RCS following IRWST and fourth-stage ADS actuation are similar to the other cases in this evaluation. As shown in Table 19E.2-1, the operator has at least 42 minutes from the loss of RNS cooling until the onset of core uncovery to manually actuate the IRWST and ADS Stage 4. In general, when considering appropriate operator action to mitigate the event, the results of a loss of RNS during mid-loop conditions are similar, but slightly less severe than the other cases presented in this evaluation due to the lower levels of decay heat and to the absence of the initial water inventory in the pressurizer. This serves to reduce the surge line flooding phenomenon that degrades the depressurization capability of the ADS Stages 1 through 3 vent paths.

19E.4.9 Radiological Consequences

This section presents evaluations that confirm that the radioactive material releases from the AP1000 events postulated to be initiated in a shutdown mode have acceptable consequences.

- The Standard Review Plan (Reference 12) no longer includes the atmospheric releases from radioactive gas waste system failure and radioactive liquid waste system leak or failure events as part of the review. As discussed in Subsections 15.7.1 and 15.7.2, no analysis for these events is provided.

- Release of radioactivity to the environment due to a liquid tank failure is addressed in Subsection 15.7.3 and is not mode dependent.

- The fuel handling accident described in Subsection 15.7.4, while not mode dependent, is analyzed in the applicable and bounding mode and accounts for spent fuel pool boiling. This accident analysis bounds radioactivity releases from other Chapter 15 events during low power and shutdown operations. The LOCA analysis results show PCT remains below 2200°F, and there are no fuel cladding failures.

- The spent fuel cask drop accident described in Subsection 15.7.5 is not mode dependent.

- Appendix 15A contains the evaluation models and parameters that form the basis of the radiological consequences analyses for the various postulated accidents. This methodology applies in all modes of operation.

In summary, there are no shutdown risks associated with the radiological consequences methodology or parameters, or the postulated or applicable events, which need to be considered outside the scope of what is already analyzed for Section 15.7.

19E.4.10 Other Evaluations and Analyses

19E.4.10.1 Low Temperature Overpressure Protection

For the AP1000, the normal residual heat removal system (RNS) suction relief valves are located immediately downstream of the RCS suction isolation valves. These relief valves protect the RNS from overpressurization and provide low temperature overpressure protection (LTOP) for the RCS components when the RNS is aligned to the RCS to provide decay heat removal during plant shutdown and startup operations. The RNS relief valves are sized to provide LTOP by limiting the RCS and RNS pressure to less than the 10 CFR 50 Appendix G (Reference 13) steady-state pressure limit. Subsection 5.2.2 provides a discussion of the AP1000 low temperature overpressure protection design bases.

19E.4.10.2 Shutdown Temperature Evaluation

As discussed in Subsection 6.3.1.1.4, the PRHR HX is required to be able to cool the RCS to a safe, stable condition after shutdown following a non-LOCA event. The following summarizes a non-bounding, conservative analysis, which demonstrates the PRHR HX can meet this criterion and cool the RCS to the specified, safe shutdown condition of 420°F within 36 hours. This analysis demonstrates that the passive systems can bring the plant to a safe, stable condition and maintain this condition so that no transients will result in the specified acceptable fuel design limit and pressure boundary design limit being violated and that no high-energy piping failure being initiated from this condition results in 10 CFR 50.46 (Reference 15) criteria.

As discussed in Subsections 6.3.3 and 7.4.1.1, the PRHR HX operates to reduce the RCS core average temperature to the safe shutdown condition following a non-LOCA event. An analysis of the loss of main feedwater with a loss of ac power event demonstrates that the passive systems can bring the plant to a safe, stable condition following postulated transients. A non-bounding, conservative analysis is represented in Figures 19E.4.10-1 through 19E.4.10-4 The progression of this event is outlined in Table 19E.4.10-1. Though some of the assumptions of this evaluation are based on nominal conditions, many of the analysis assumptions are bounding.

The performance of the PRHR HX is affected by the containment pressure. Containment pressure determines the PRHR HX heat sink (the IRWST water) temperature. The WGOTHIC containment response model described in Subsection 6.2.1.1.3 was used to determine the containment pressure response to this transient, which was used as an input to the plant cooldown analysis performed with LOFTRAN. Some changes were made to the WGOTHIC model to provide conservative results for the long-term safe shutdown analysis.

The PRHR HX performance is also affected by the IRWST water level when the level drops below the top of the PRHR HX tubes. The IRWST water level is affected by the heat input from the PRHR HX and by the amount of steam that leaves the IRWST and does not return to the IRWST through the IRWST gutter arrangement. The principal steam condensate losses include steam that stays in the containment atmosphere, steam that condenses on heat sinks inside containment other than the containment vessel, and dripping or splashing losses due to obstructions on the inner containment vessel wall. The WGOTHIC containment response model also provided the mass balance with respect to the steam lost to the containment atmosphere and to condensation on passive heat sinks other than the containment vessel. The WGOTHIC analysis inputs (including the mass of the heat sinks and heat transfer rates) were biased to increase steam condensate losses. The WGOTHIC model provides the time-dependent condensate return rate, which was incorporated into the LOFTRAN computer code described in Subsection 15.0.11.2 to demonstrate that the RCS core average temperature could be cooled to 420°F within 36 hours.

Summarizing this transient, the loss of normal feedwater occurs, followed by the reactor trip and loss of ac power. The PRHR HX is actuated on the Low-2 steam generator wide range water level signal. Eventually a safeguards actuation signal is actuated on Low-2 cold leg temperature and the CMTs are actuated.

Once actuated, at about 3,000 seconds, the CMTs operate in recirculation mode, injecting cold borated water into the RCS. In the first part of their operation, due to the injection of cold water, the CMTs operate in conjunction with the PRHR HX to reduce RCS temperature. Due to the primary system cooldown, the PRHR heat transfer capability drops below the decay heat and the RCS cooldown is essentially driven by the CMT cold injection flow. However, at about 6,000 seconds, the CMT cooling effect decreases and the RCS starts heating up again (Figure 19E.4.10-1). The RCS temperature increases until the PRHR HX can match decay heat. At about 49,000 seconds, the PRHR heat transfer matches decay heat and it continues to operate to reduce the RCS temperature to below 420°F within 36 hours. As seen from Figure 19E.4.10-1 the cold leg temperature in the loop with the PRHR is reduced to 420°F at about 56,530 seconds, while the core average temperature reaches 420°F at about 128,260 seconds (approximately 35.6 hours).

As discussed in Subsection 7.4.1.1, a timer is used to automatically actuate the ADS if offsite and onsite power are lost for about 24 hours. This timer automates putting the open loop cooling features into service prior to draining the Class 1E dc 24-hour batteries that operate the ADS valves. Before 22 hours, if the plant conditions indicate that the ADS would not be needed until well after 24 hours, the operators are directed to de-energize all loads on the 24-hour batteries. This action will block actuation of the ADS and preserves the ability to align open loop cooling at a later time. Operation of the ADS in conjunction with the CMTs, accumulators, and IRWST reduces the RCS pressure and temperature to below 420°F. The ability to actuate ADS and IRWST injection provides a safety-related, backup mode of decay heat removal that is diverse to extended PRHR HX operation.

As discussed in Subsection 6.3.3.2.1.1, the PRHR HX can operate in this mode for at least 72 hours to maintain RCS conditions within the applicable Chapter 15 safety evaluation criteria. In addition, the analysis supporting this section shows the PRHR HX is expected to maintain safe shutdown conditions for greater than 14 days. One important consideration with regard to the duration closed-loop cooling can be maintained is the RCS leak rate. This duration of closed-loop cooling can be achieved with expected RCS leak rates. For abnormal leak rates, it may become necessary to initiate open-loop cooling earlier than 14 days.

19E.5 Technical Specifications

While the Technical Specification guidance provided in NUREG-1449 (Reference 2) relates to existing plant shutdown operation concerns, the underlying concerns relating to causes of events and recovery from those events during shutdown operations are applicable to the AP1000. Subsection 19E.5.1 summarizes the shutdown Technical Specifications. Subsection 19E.5.2 summarizes the AP1000's compliance with SECY-93-190 (Reference 16).

19E.5.1 Summary of Shutdown Technical Specifications

The content of the AP1000 Technical Specifications meets the requirements of 10 CFR 50.36 (Reference 17) and is consistent with the guidance provided in NUREG-1431 (Reference 18). For the AP1000, passive systems are used to safely shut down the plant. Because this design feature is different from existing plants, and because NUREG-1449 provides a reasonable basis for creating shutdown Technical Specifications, the AP1000 Technical Specifications are improved to include specifications for these systems in the shutdown modes.

19E.6 Shutdown Risk Evaluation

The “AP1000 Probabilistic Risk Assessment (PRA)” (Reference 19) provides an assessment of the plant risk associated with events at shutdown.

19E.7 Compliance with NUREG-1449

The Diablo Canyon event of April 10, 1987, and the loss of ac power event at the Vogtle plant on March 20, 1990, led the Nuclear Regulatory Commission (NRC) staff to issue NUREG-1449, “Shutdown and Low Power Operation at Commercial Nuclear Power Plants in the United States” (Reference 2), to provide an evaluation of the shutdown risk issue. The scope of NUREG-1449 includes subjects such as operating experiences as documented in generic letters, operator training, technical specifications, residual heat removal capacity, temporary reactor coolant boundaries, rapid boron dilution, containment capacity, fire protection, outage planning and control, and instrumentation.

The NRC requested Westinghouse to assess the compliance of AP600 with NUREG-1449. It was recognized that some of the issues discussed in NUREG-1449 are the responsibility of the plant owners because they relate to operation, maintenance, and refueling plans, procedures, and risk management. However, the NRC believed that the level of defense-in-depth against shutdown events would be improved if clear guidance is provided to the areas discussed above by the plant designer. The NRC requested that Westinghouse perform a systematic assessment of the shutdown risk issue to address areas identified in NUREG-1449 as they are applicable to the AP1000 design and document the results.

This Appendix provides the systematic assessment of the shutdown risk issue to address areas identified in NUREG-1449. This assessment includes design basis evaluations of events that can occur during shutdown and a probabilistic assessment of plant risk at shutdown. The design of the AP1000 builds on the lessons-learned from the industry with regard to shutdown safety, including the guidance provided in NUREG-1449.

19E.8 Conclusion

This AP1000 Shutdown Evaluation provides a systematic evaluation of the AP1000 during shutdown operations. As demonstrated in this appendix, the AP1000 is designed to mitigate events that can occur during shutdown modes. In addition, the risk of core damage as a result of an accident that may occur during shutdown has been demonstrated to be acceptably low.

19E.9 References

1. Letter, Westinghouse to NRC, DCP/NRC1385, AP600 Emergency Response Guidelines.

2. NUREG-1449, “Shutdown and Low Power Operations at Commercial Nuclear Power Plants in the United States,” September 1993.

3. NRC Information Notice 92-54, “Level Instrumentation Inaccuracies Caused by Rapid Depressurization,” July 24, 1992.

4. Letter, Westinghouse to NRC, DCP/NRC0124, APWR-0452, “AP600 Vortex Mitigator Development Test for RCS Mid-loop Operation,” July 6, 1994.

5. NUREG-0897, Rev. 1, “Containment Emergency Sump Performance,” October 1985.

6. Title 10, Code of Federal Regulations, Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Processing Plants.”

7. NRC Regulatory Guide 1.26, “Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants,” Revision 3, February 1976.

8. American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section III, 1998 with 2000 Addenda.

9. Lewis, R. N., Huang, P., Behnke, D. H., Fittante, R. L., and Gelman, A., WCAP-10698-P-A (Proprietary) and WCAP-10750-A (Non-Proprietary), “SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill,” August 1987.

10. WCAP-14171, Revision 2 (Proprietary) and WCAP-14172, Revision 2 (Non-Proprietary), “WCOBRA/TRAC Applicability to AP600 Large-Break Loss-of-Coolant Accident,” March 1998.

11. Not used.

12. NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,” Revision 1, July 1981.

13. Title 10, Code of Federal Regulations, Part 50, Appendix G, “Fracture Toughness Requirements.”

14. Not used.

15. Title 10, Code of Federal Regulations, Part 50, (10 CFR 50.46).

16. NRC letter, SECY-93-190, “Regulatory Approach to Shutdown and Low-Power Operations,” July 12, 1993.

17. Title 10, Code of Federal Regulations, Part 50.36, “Technical Specifications.”

18. NUREG-1431, “Standard Technical Specifications – Westinghouse Plants,” April 1995.

19. APP-GW-GL-022, “AP1000 Probabilistic Risk Assessment,” Westinghouse Electric, LLC, Rev. 8, August 2004 [ML042230497].

Table 19E.2-1
Evaluation of a Loss of RNS at Mid-Loop With No IRWST Injection

Time After Shutdown	Time After Loss of RNS to Boiling	Time After Loss of RNS to Empty Hot Leg	Time After Loss of RNS to Core Uncovery
28 hours	3 minutes	20 minutes	42 minutes

Table 19E.4.1-1 (Sheet 1 of 2)
AP1000 Accidents Requiring Shutdown Evaluation or Analysis

Tier 2 Section	Titles	Evaluation or Analysis Required
15.1	Increase in Heat Removal from the Primary System	
15.1.1	Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature	E
15.1.2	Feedwater System Malfunctions that Result in an Increase in Feedwater Flow	E
15.1.3	Excessive Increase in Secondary Steam Flow	E
15.1.4	Inadvertent Opening of a Steam Generator Relief or Safety Valve	E
15.1.5	Steam System Piping Failure	E
15.1.6	Inadvertent Operation of the Passive Residual Heat Removal Heat Exchanger	E
15.2	Decrease in Heat Removal by the Secondary System	
15.2.1	Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	E
15.2.2	Loss of External Electrical Load	E
15.2.3	Turbine Trip	E
15.2.4	Inadvertent Closure of Main Steam Isolation Valves	E
15.2.5	Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip	E
15.2.6	Loss of ac Power to the Plant Auxiliaries	E
15.2.7	Loss of Normal Feedwater Flow	E
15.2.8	Feedwater System Pipe Break	E
15.3	Decrease in Reactor Coolant System Flow Rate	
15.3.1	Partial Loss of Forced Reactor Coolant Flow	E
15.3.2	Complete Loss of Forced Reactor Coolant Flow	E
15.3.3	Reactor Coolant Pump Shaft Seizure (Locked Rotor)	E
15.3.4	Reactor Coolant Pump Shaft Break	E
15.4	Reactivity and Power Distribution Anomalies	
15.4.1	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low-Power Startup Condition	E
15.4.2	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power	n/a
15.4.3	Rod Cluster Control Assembly Misalignment (System Malfunction or Operator Error)	E
15.4.4	Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	E

Table 19E.4.1-1 (Sheet 2 of 2)
AP1000 Accidents Requiring Shutdown Evaluation or Analysis

Tier 2 Section	Titles	Evaluation or Analysis Required
15.4.6	Chemical and Volume Control System Malfunction That Results in a Decrease in the Boron Concentration in the Reactor Coolant	n/a
15.4.7	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position	E
15.4.8	Spectrum of Rod Cluster Control Assembly Ejection Accidents	
15.5	Increase in Reactor Coolant Inventory	
15.5.1	Inadvertent Operation of the Core Makeup Tanks (CMT) During Power Operation	E
15.5.2	Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory	E
15.6	Decrease in Reactor Coolant Inventory	
15.6.1	Inadvertent Opening of a Pressurizer Safety Valve or Inadvertent Operation of the ADS	E
15.6.2	Failure of Small Lines Carrying Primary Coolant Outside Containment	E
15.6.3	Steam Generator Tube Rupture	E
15.6.5	Loss of Coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary	E/A
15.7	Radioactive Release From a Subsystem or Component	E

Table 19E.4.8-1
Double-Ended Cold-Leg Guillotine Break – Sequence of Events

Event	Time (seconds)
Break open	0.0
"S" signal receipt (including delay)	4.2
RCPs start to coast down	9.5
Sustained CMT draindown begins (CMT connected to intact cold leg)	~150
Sustained CMT draindown begins (CMT connected to broken cold leg)	~200
Lower plenum refilled	~250

Table 19E.4.8-2
Loss of Normal Residual Heat Removal System Cooling in Mode 4 and Mode 5 With Reactor Coolant System Intact – Sequence of Events

Event	Automatic Actuation Time After Loss of RNS		Manual Actuation Time After Loss of RNS	
	(seconds)	(hours)	(seconds)	(hours)
Loss of RNS cooling	0	0	0	0
RNS relief valve flow starts	742	0.21	742	0.21
CMT and PRHR actuated	8619	2.39	1800	0.50
RNS relief valve flow terminated	9141	2.54	14,024	3.90
ADS Stage 1 flow starts	9078	2.52	13,830	3.84
ADS Stage 2 flow starts	9126	2.54	13,878	3.86
ADS Stage 3 flow starts	9246	2.57	13,998	3.89
ADS Stage 4 flow starts	9688	2.69	14,353	3.99
IRWST injection starts	10,018	2.78	14,666	4.07

Table 19E.4.8-3
Loss of Normal Residual Heat Removal System Cooling in Mode 5 With Reactor Coolant System Open – Sequence of Events

Event	Time After Loss of RNS	
	(seconds)	(hours)
Loss of RNS cooling	0	0
Hot leg empty	4554	1.27
ADS Stage 4 flow initiated	4674	1.30
IRWST injection starts	5029	1.40

Tables 19E.4.8-4–19E.4.8-5 Not Used

Table 19E.4.10-1
Sequence of Events Following a Loss of ac Power Flow with Condensate from the Containment Shell Being Returned to the IRWST

Event	Time (seconds)
Feedwater is Lost	10.0
Low-2 Steam Generator Narrow Range Water Level Reactor Trip Setpoint Reached	61.3
Rods Begin to Drop	63.3
Turbine Trip	68.3
Loss of Offsite ac Power, Reactor Coolant Pumps Begin to Coast Down	71.3
Low-2 Steam Generator Wide Range Water Level Reached	206.6
PRHR HX Actuation on Low-2 Steam Generator Wide Range Water Level	218.6
Low-2 T_{cold} Setpoint Reached	2,952
Steam Line Isolation on Low-2 T_{cold} Signal	2,964
CMTs Actuated on Low-2 T_{cold} Signal	2,964
IRWST Reaches Saturation Temperature	15,520
Heat Extracted by PRHR HX Matches Core Decay Heat	49,000
Cold Leg Temperature Reaches 420°F (loop with PRHR)	56,530
Core Average Temperature Reaches 420°F (loop with PRHR)	128,260

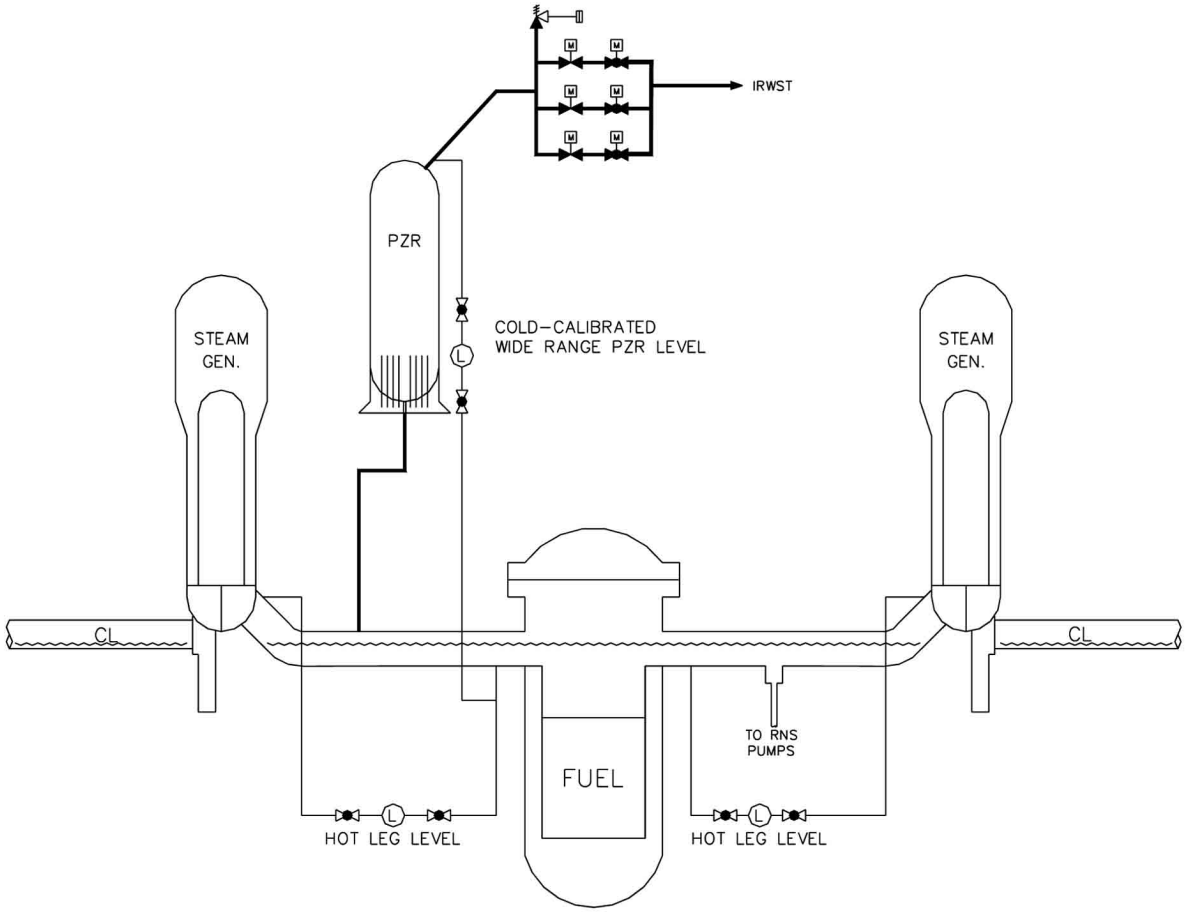

Figure 19E.2-1
Reactor Coolant System Level Instruments Used During Shutdown

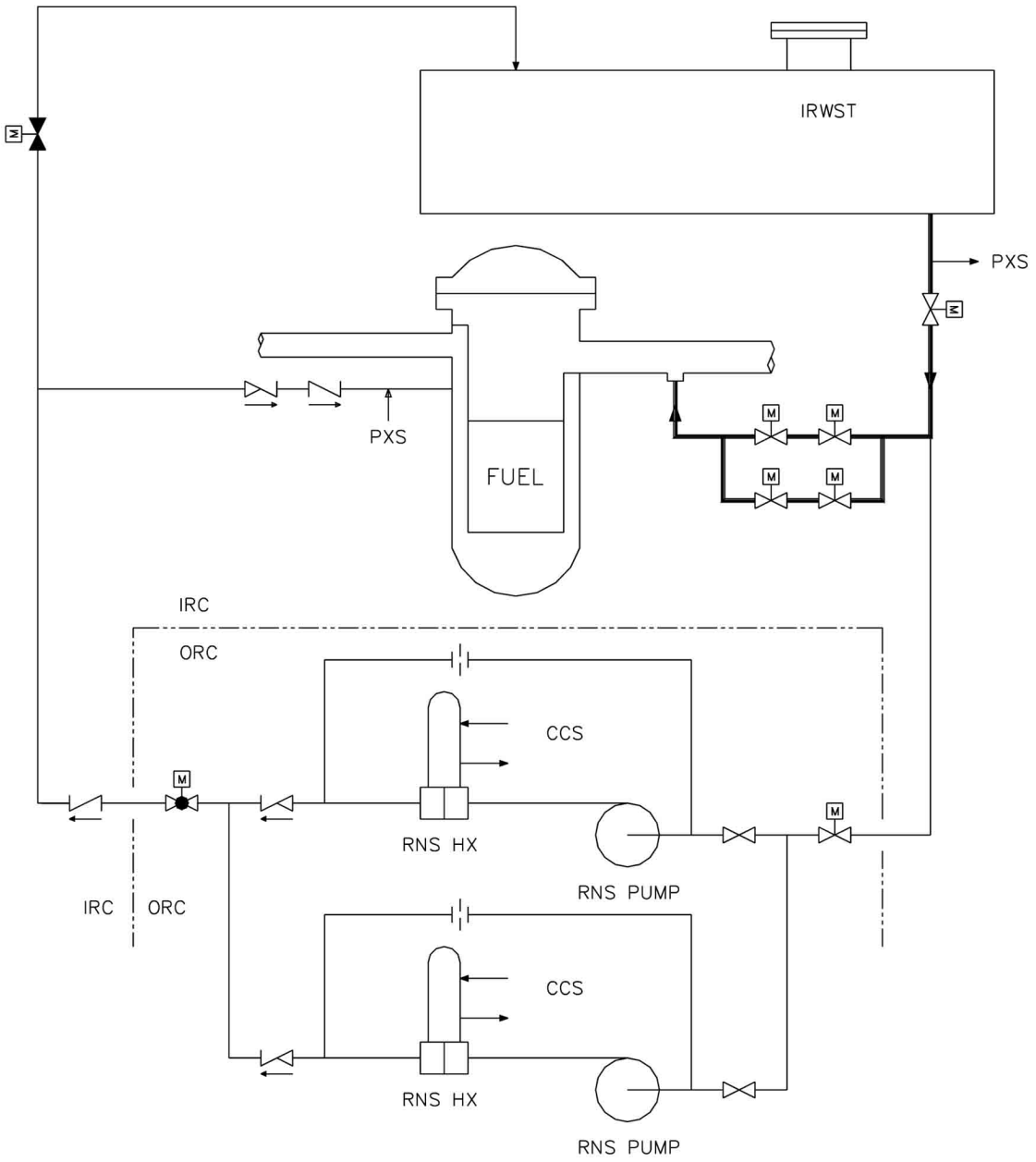

Figure 19E.2-2
IRWST Injection Flow Path

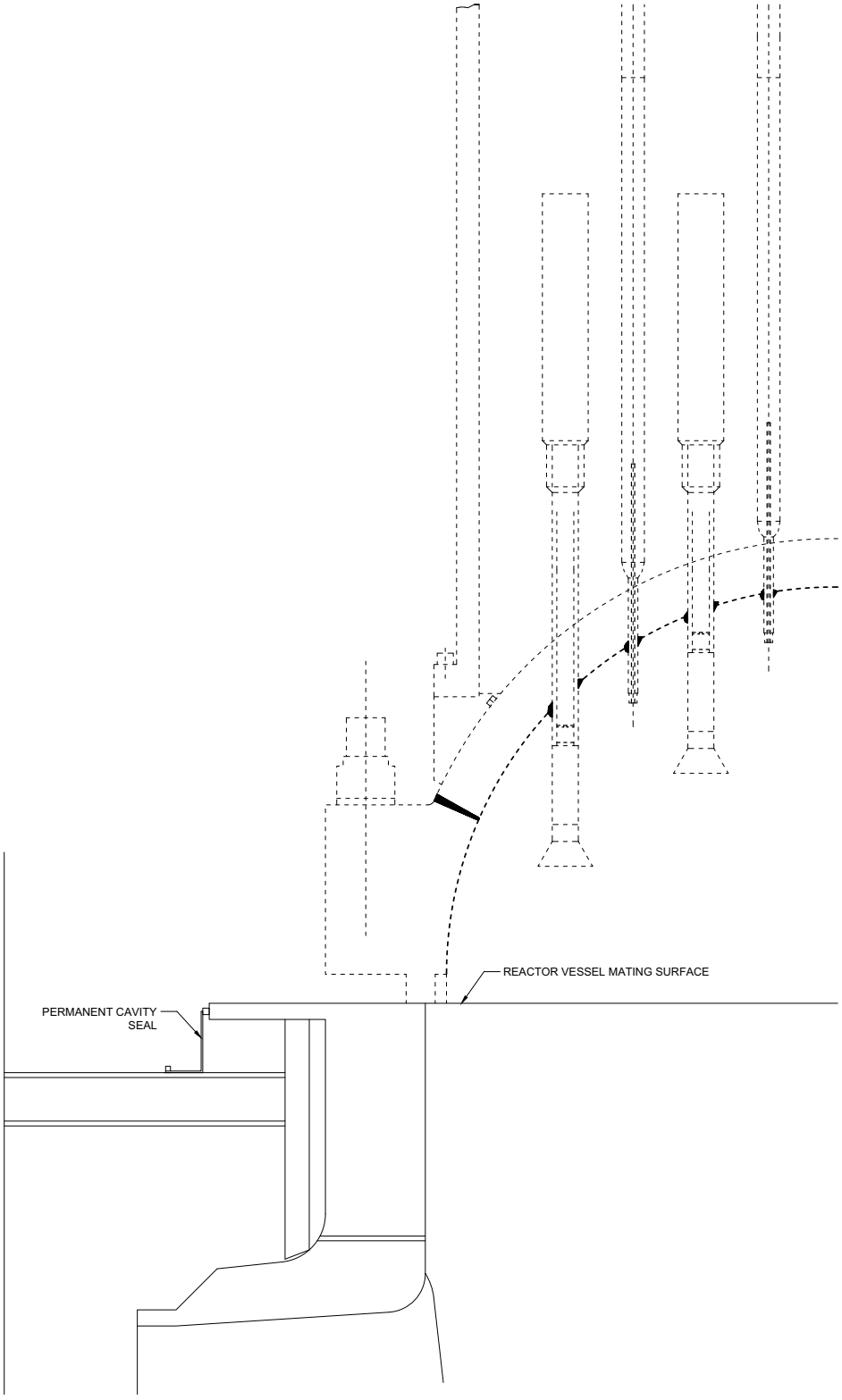

Figure 19E.2-3
AP1000 Permanent Cavity Seal Ring

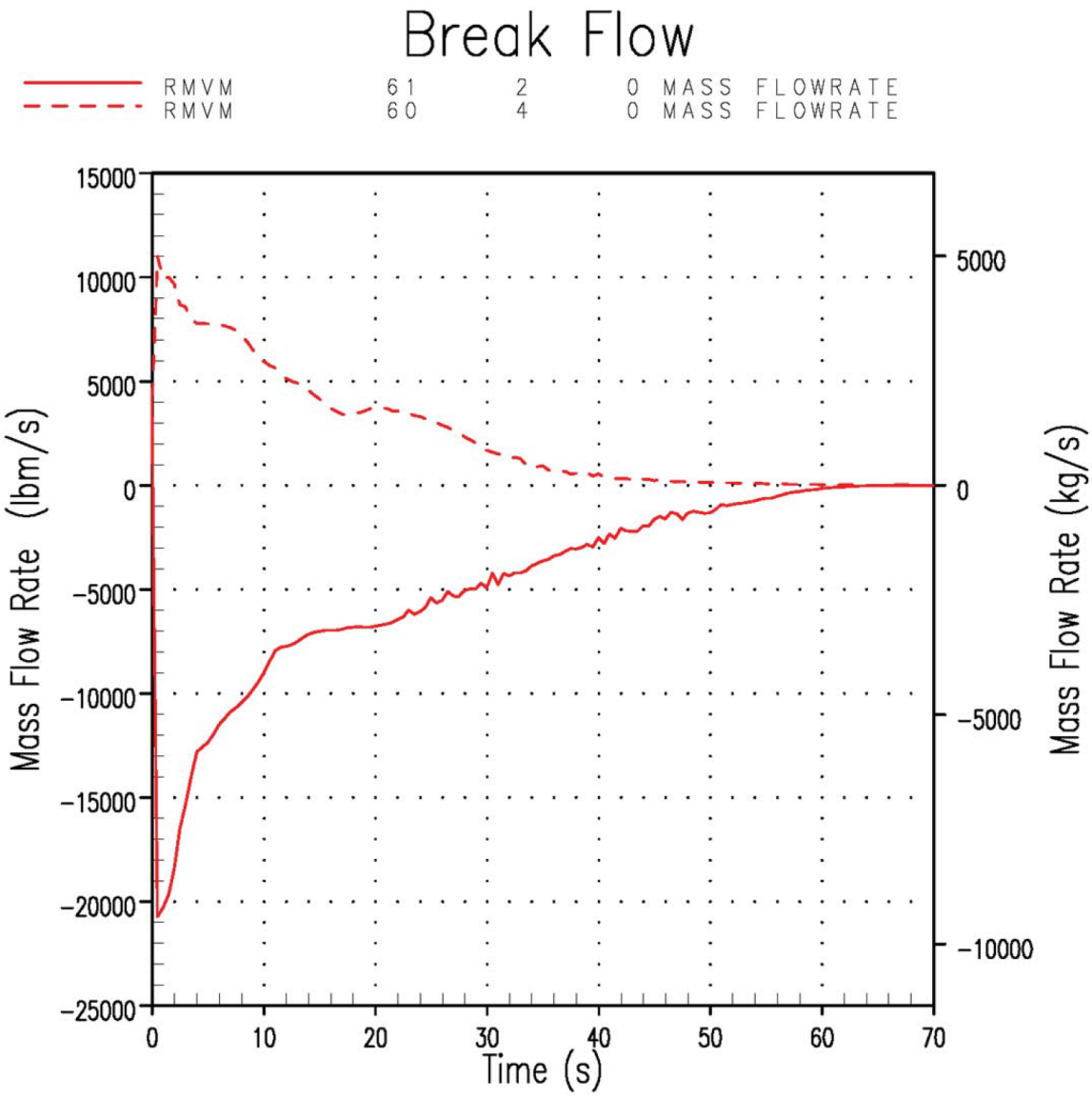

Figure 19E.4.8-1
Mode 3 DECLG Break, Break Flow Rates, Vessel and RCP Sides

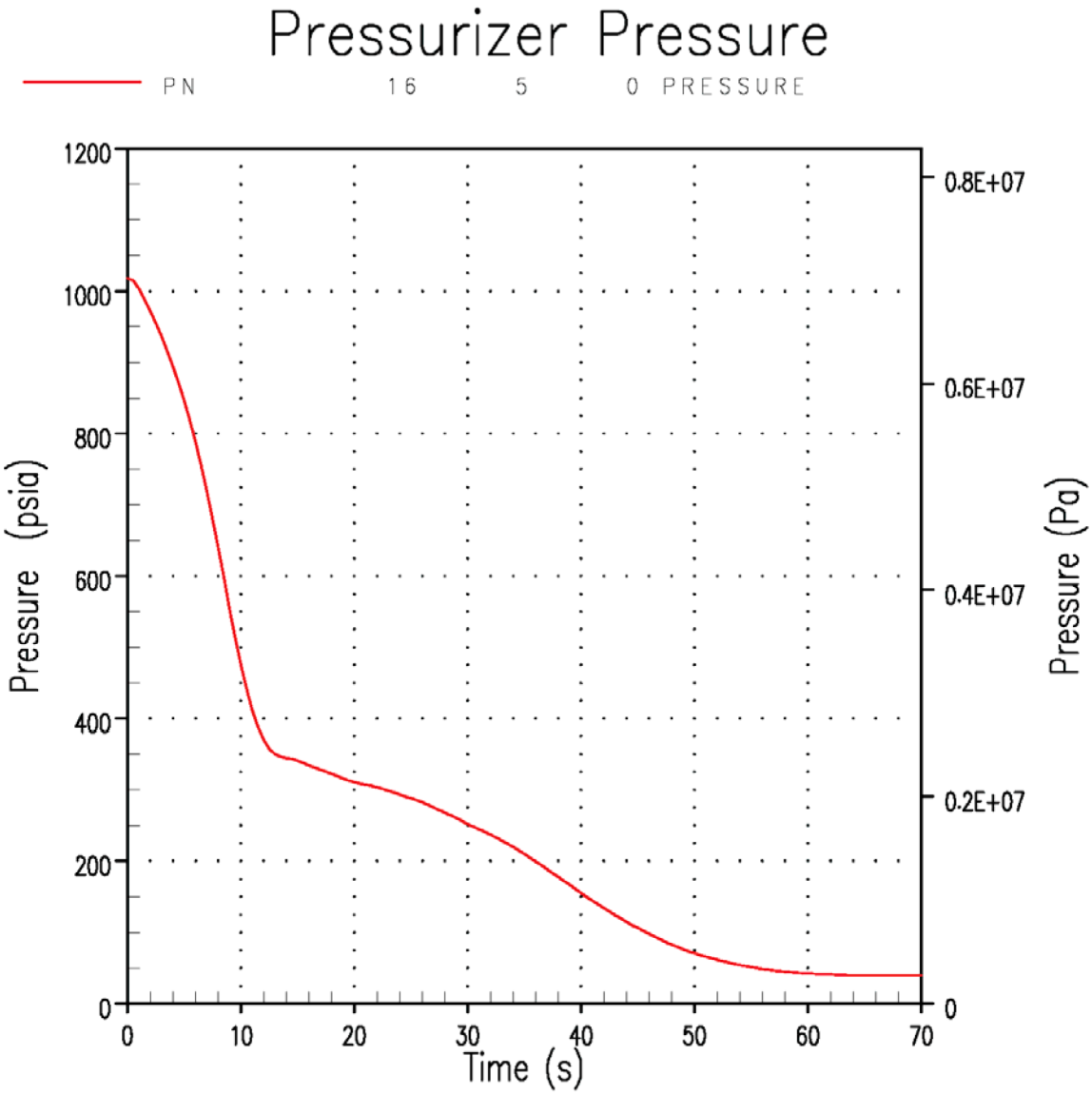

Figure 19E.4.8-2
Mode 3 DECLG Break, Pressurizer Pressure

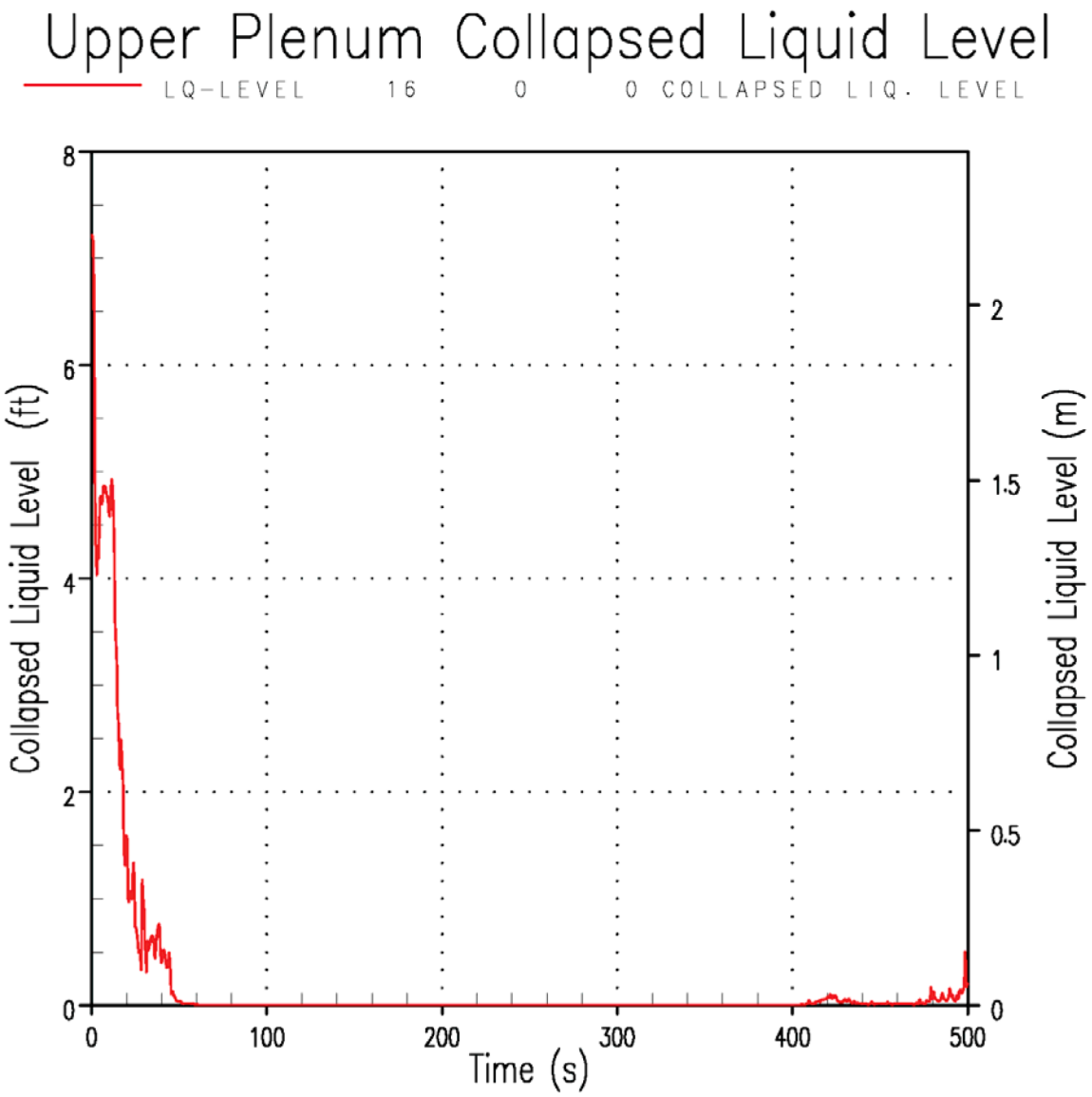

Figure 19E.4.8-3
Mode 3 DECLG Break, Upper Plenum Collapsed Liquid Level

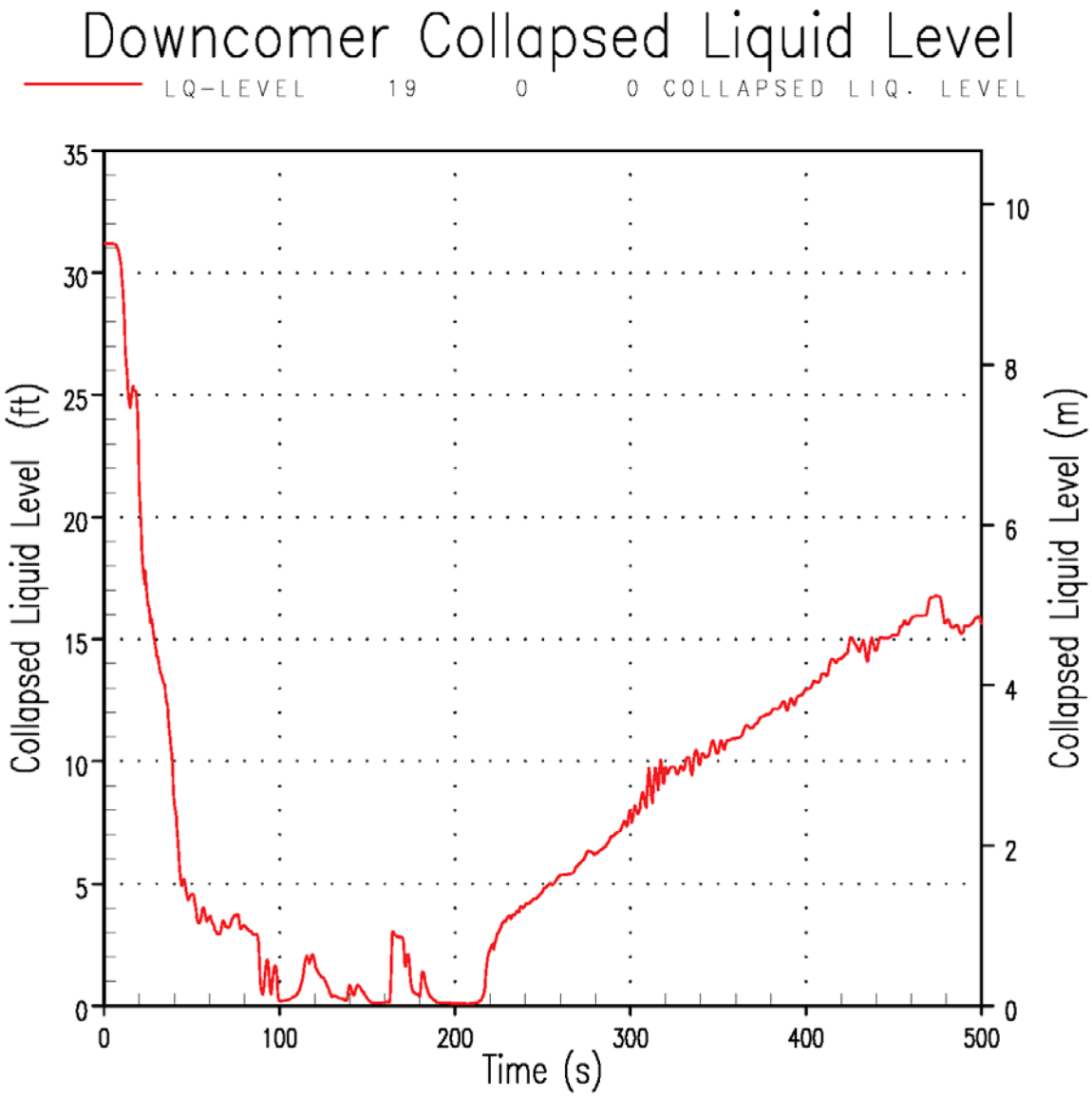

Figure 19E.4.8-4
Mode 3 DECLG Break, Downcomer Collapsed Liquid Level

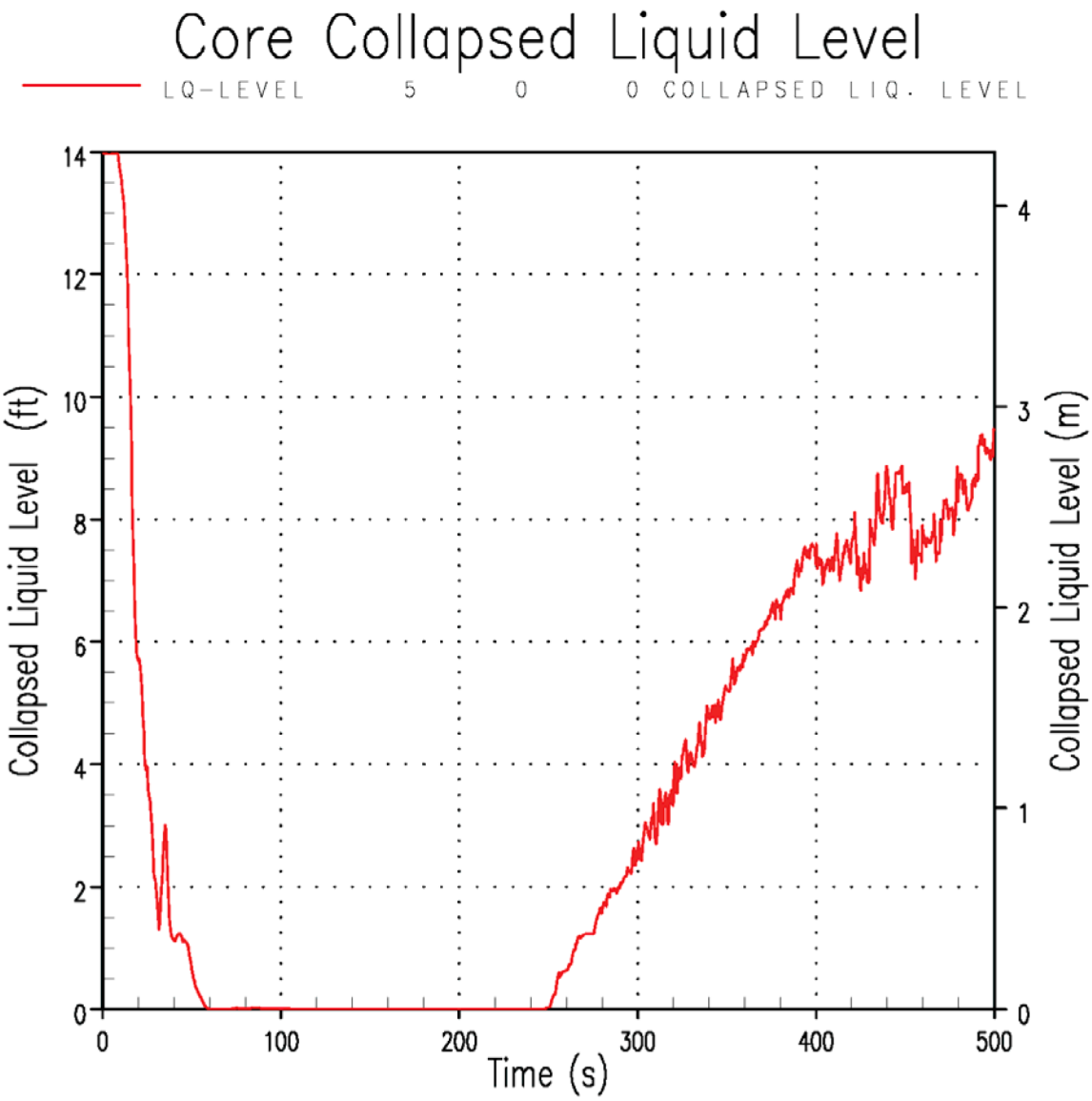

Figure 19E.4.8-5
Mode 3 DECLG Break, Core Collapsed Liquid Level

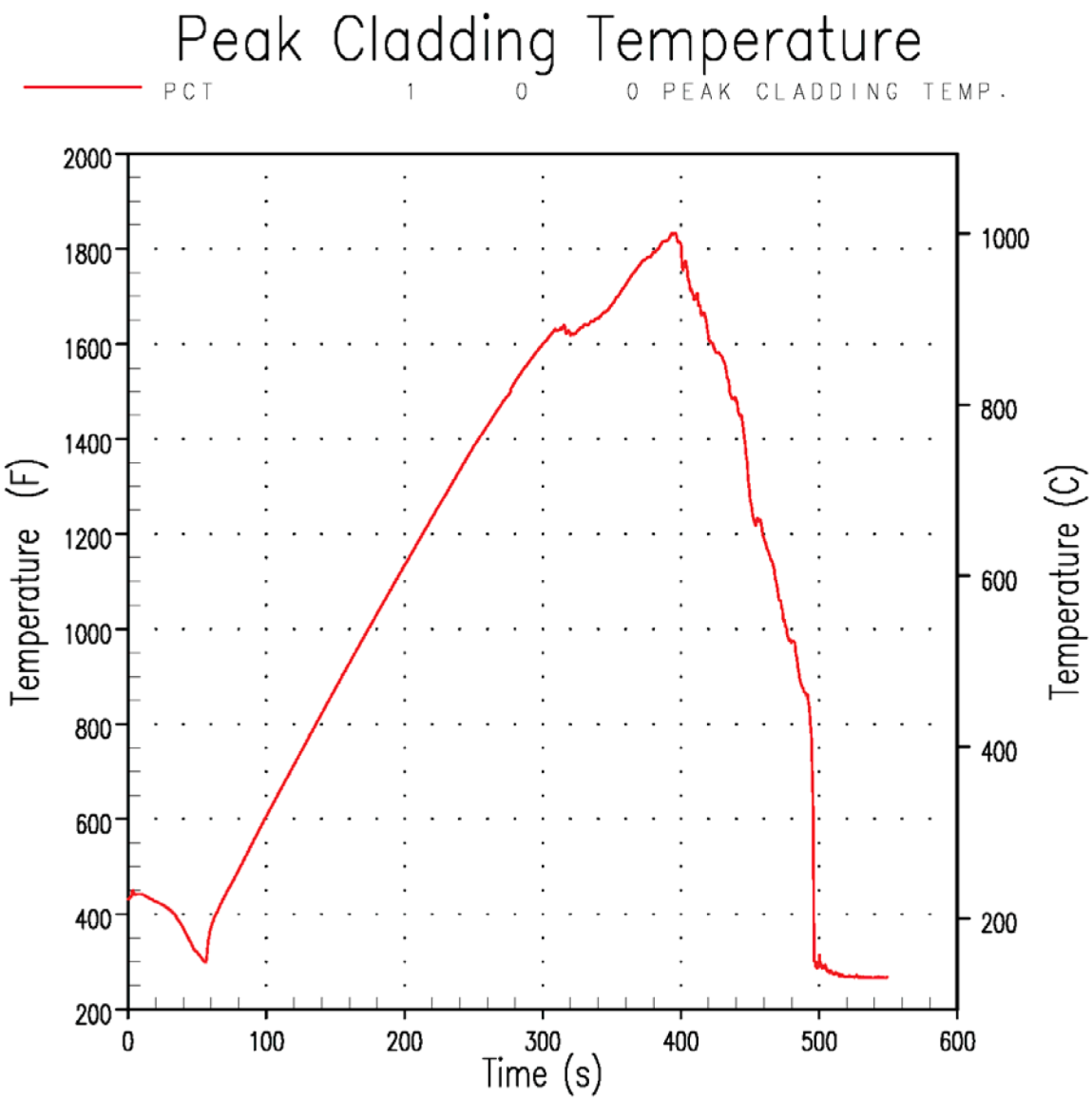

Figure 19E.4.8-6(a)
Mode 3 DECLG Break, Peak Cladding Temperature

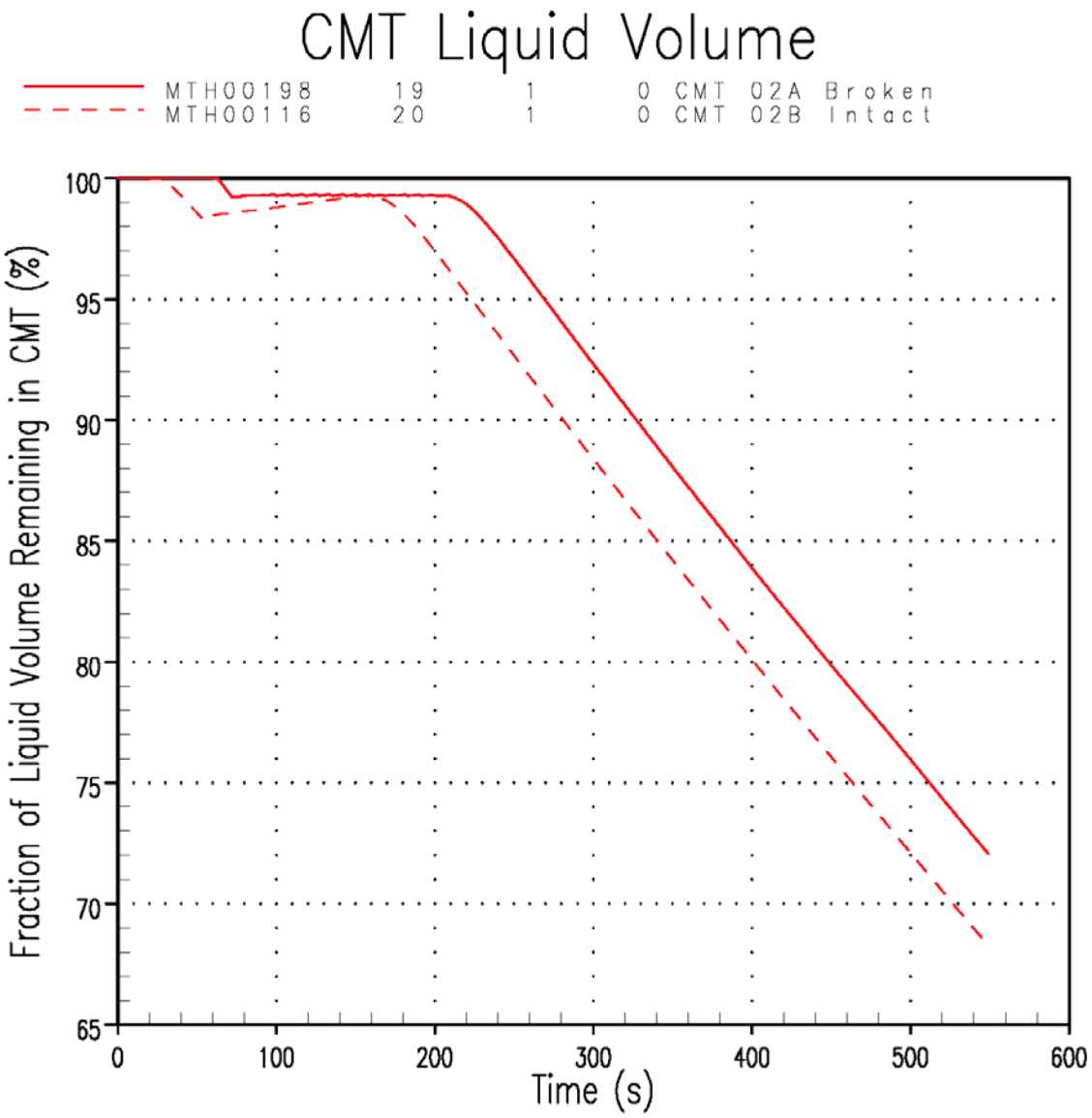

Figure 19E.4.8-6(b)
Mode 3 DECLG Break, CMT Liquid Volume

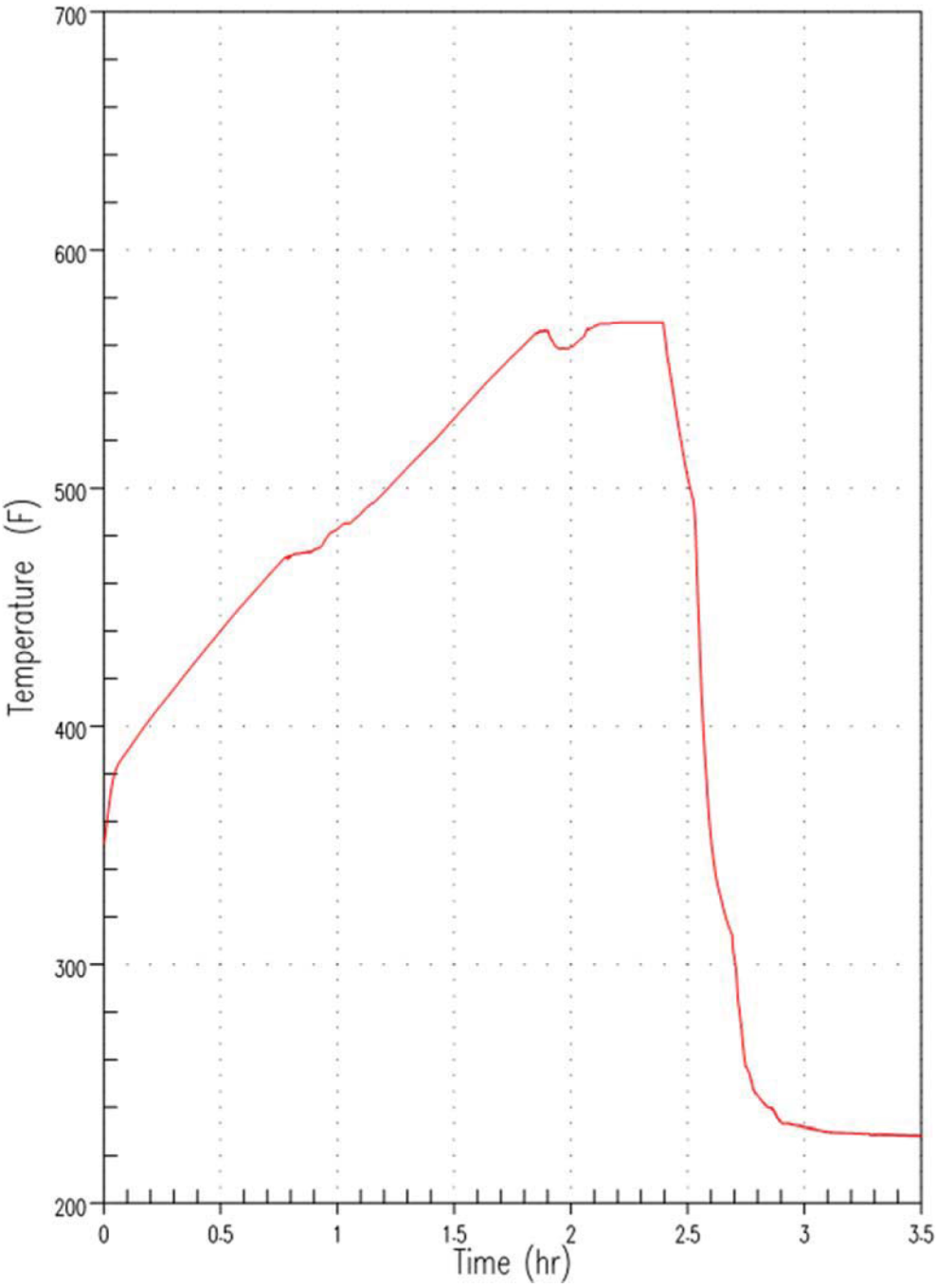

Figure 19E.4.8-7
Core Outlet Temperature, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

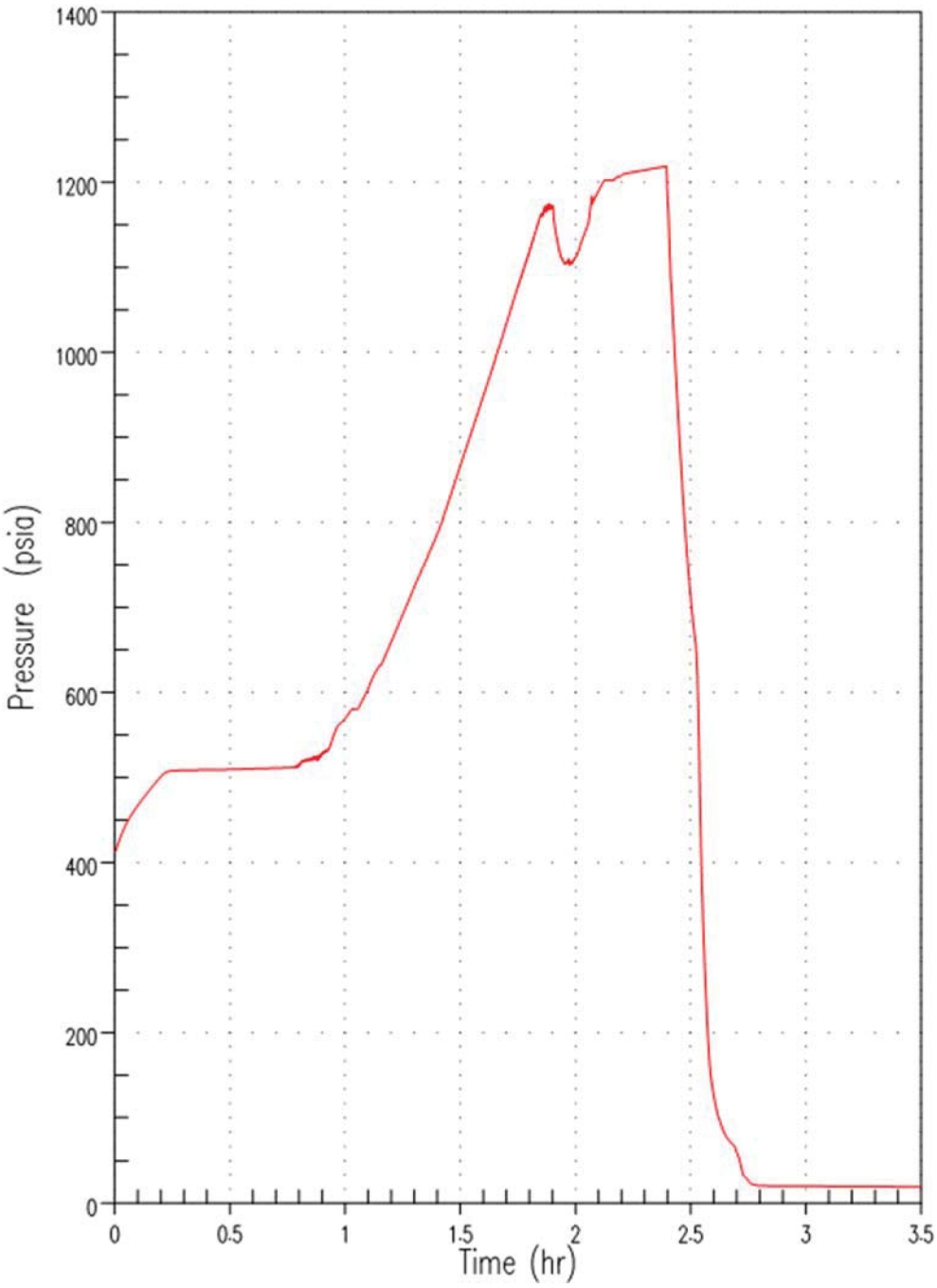

Figure 19E.4.8-8
Pressurizer Pressure, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

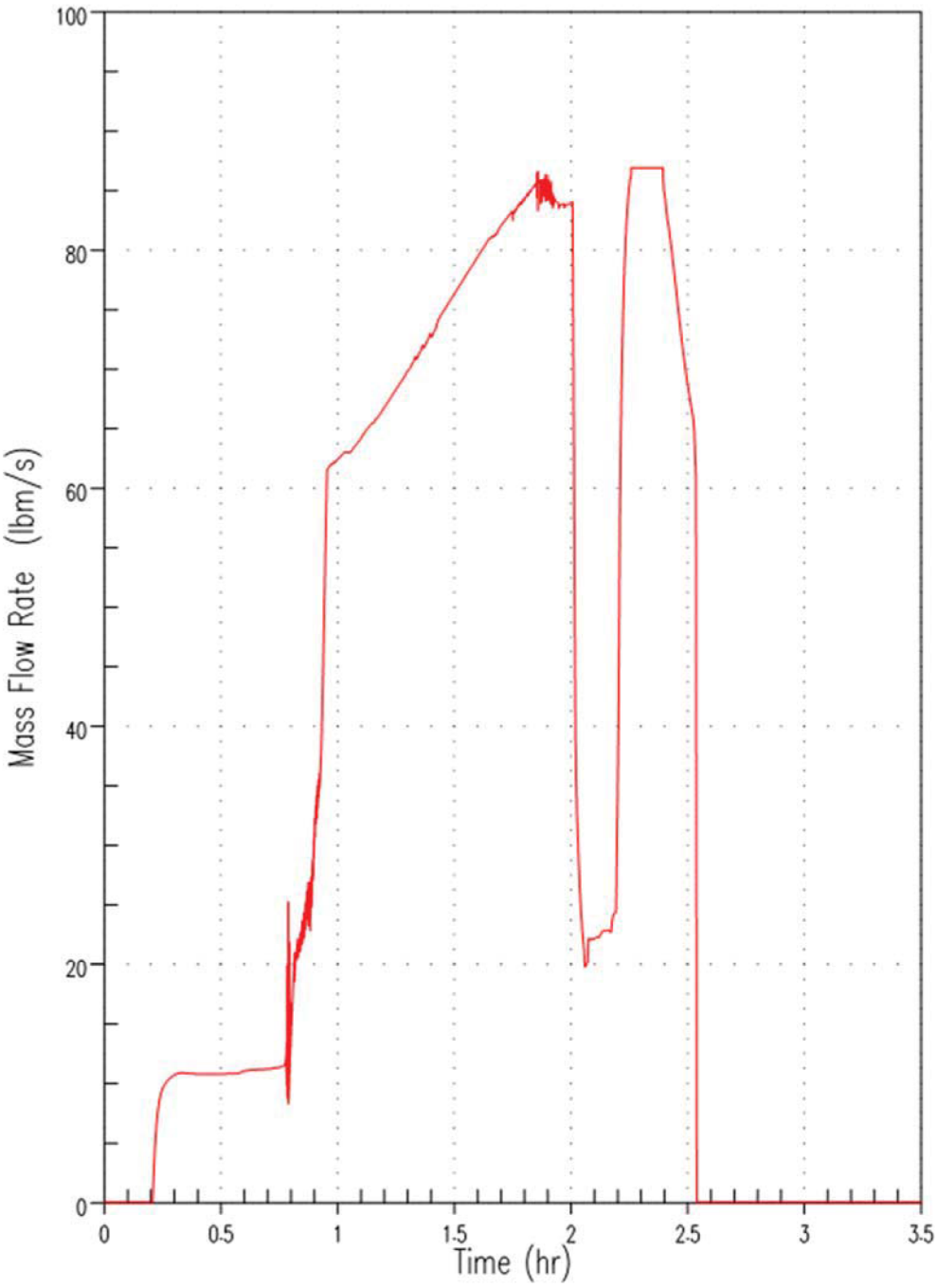

Figure 19E.4.8-9
RNS Relief Valve Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

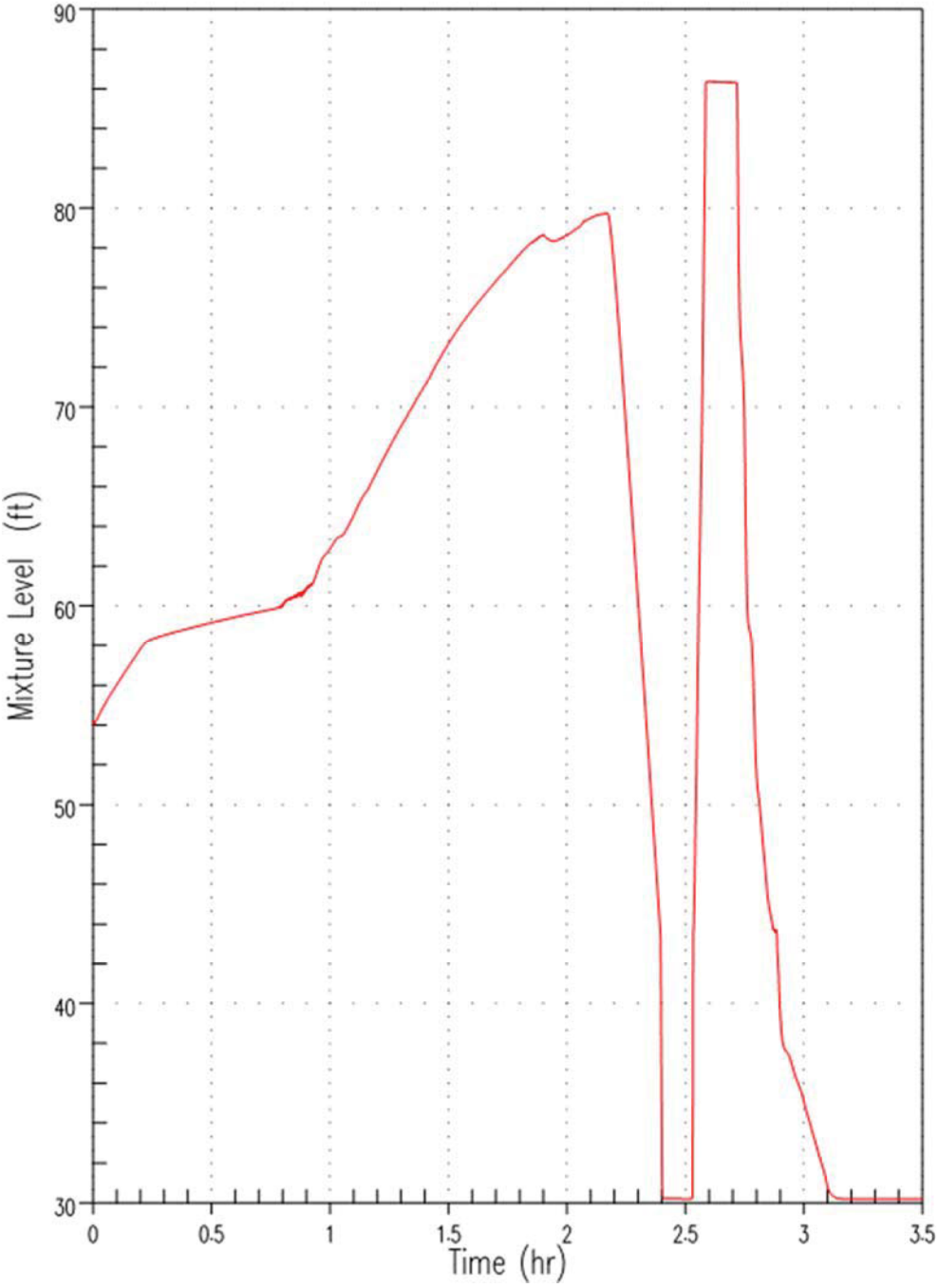

Figure 19E.4.8-10
Pressurizer Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

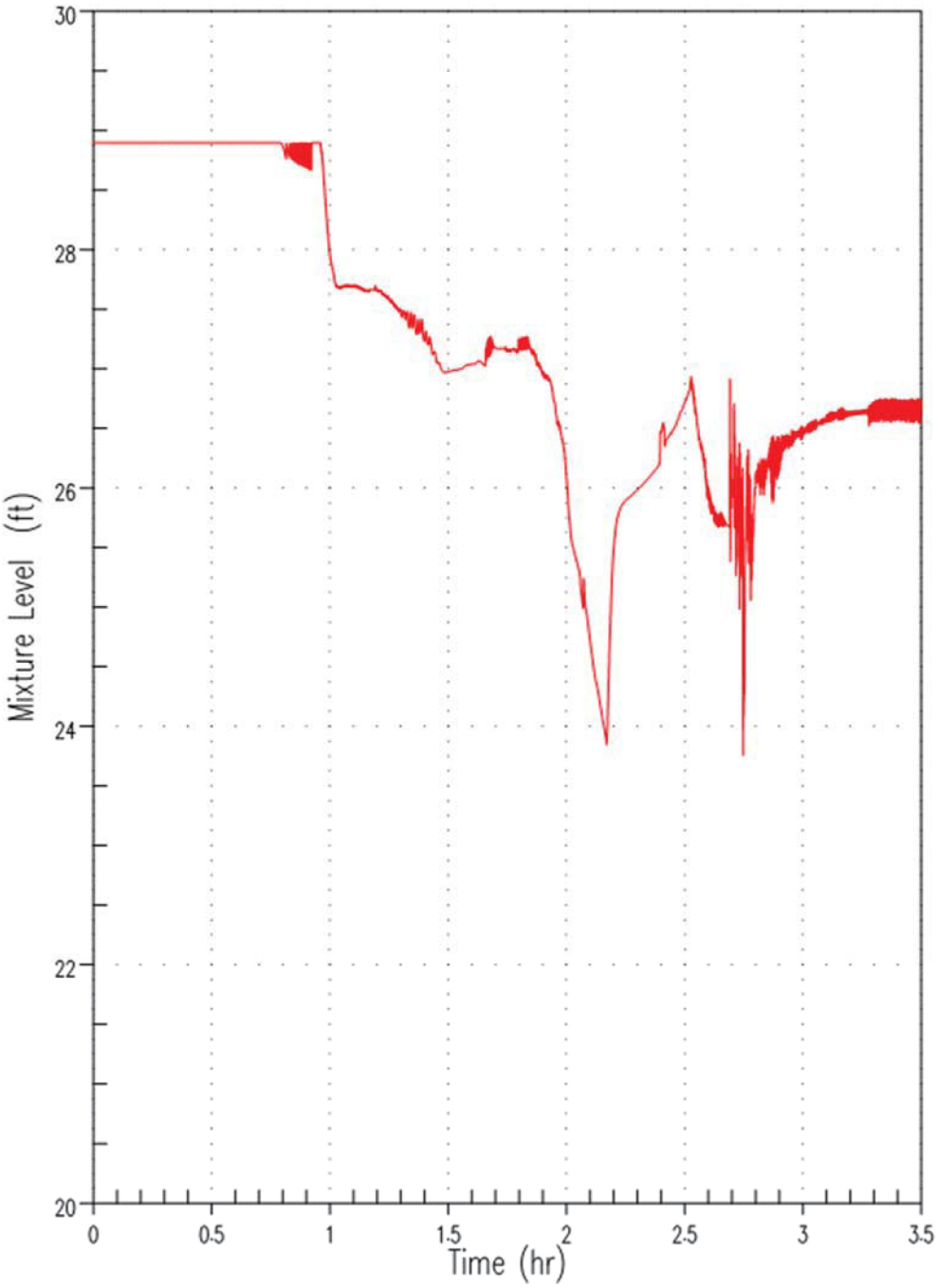

Figure 19E.4.8-11
Core Stack Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

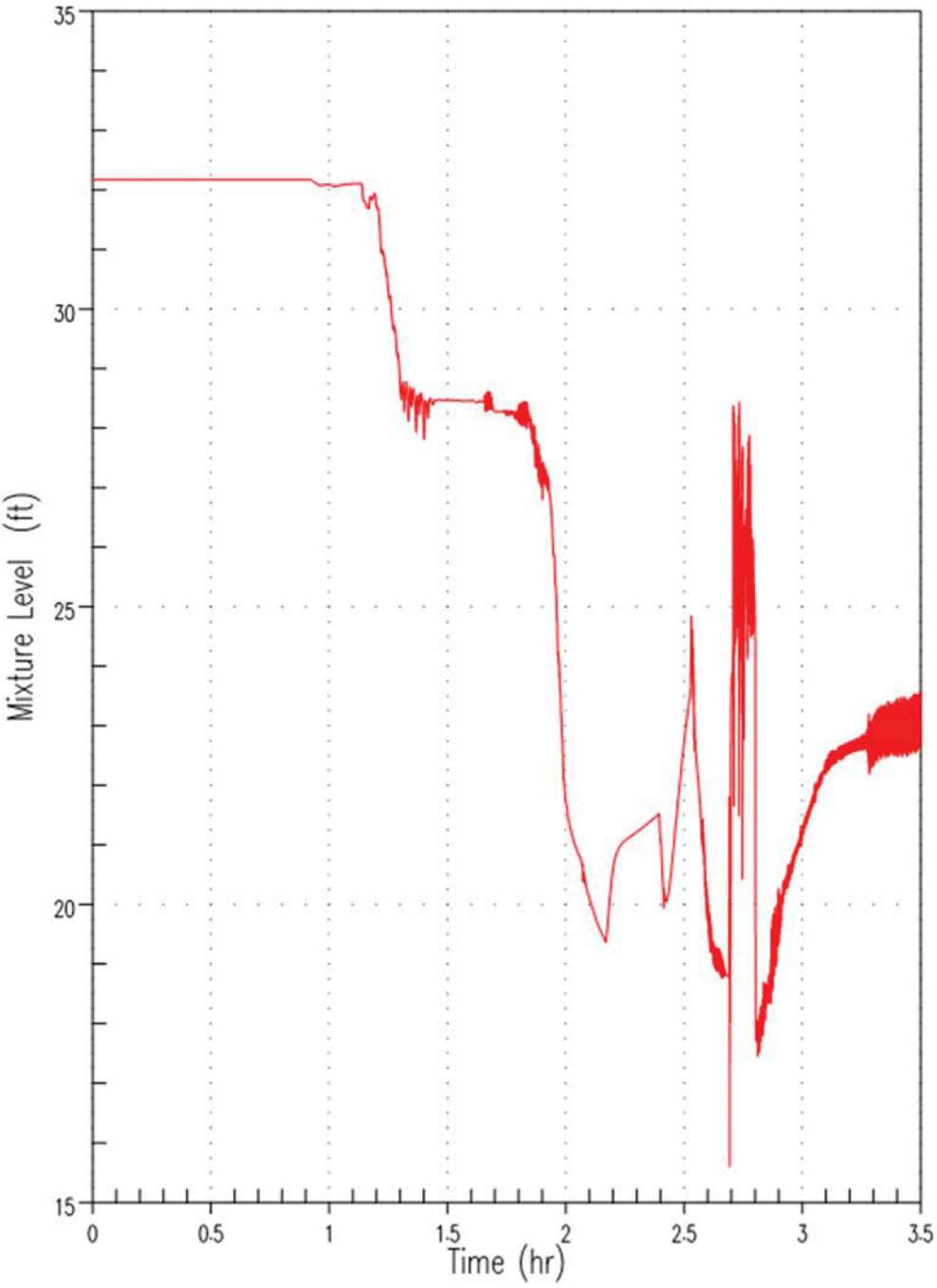

Figure 19E.4.8-12
Downcomer Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

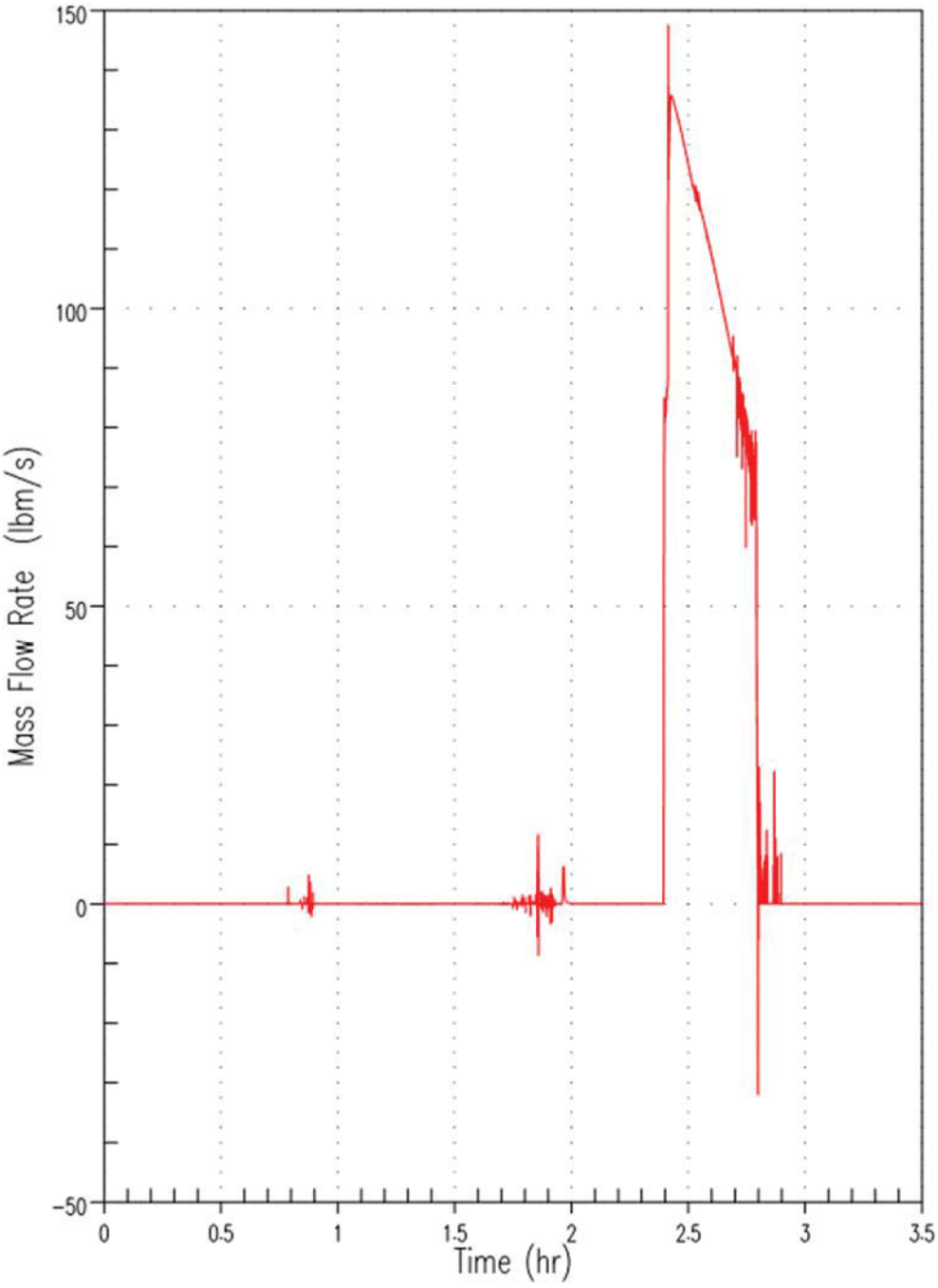

Figure 19E.4.8-13
CMT to DVI Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

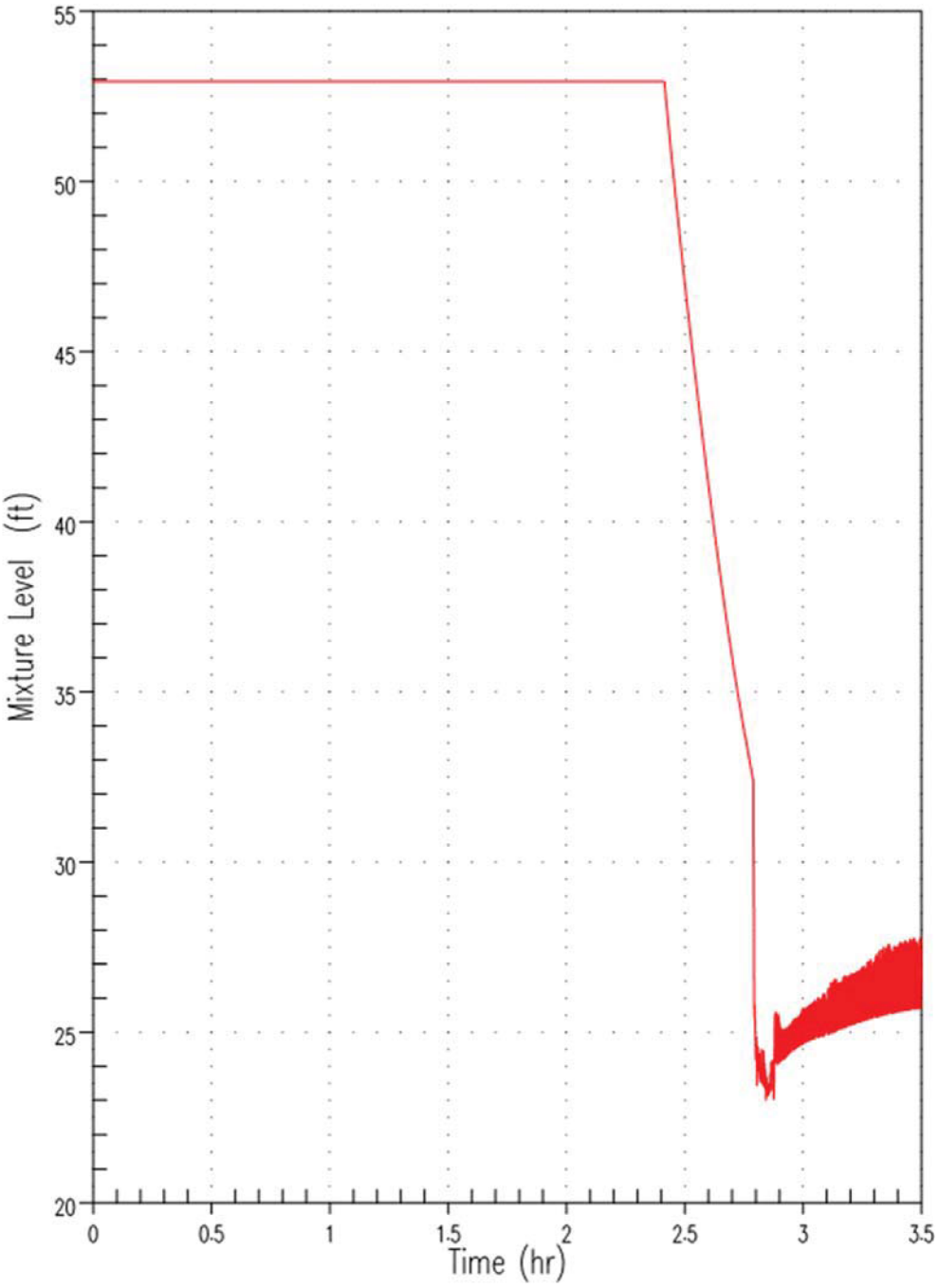

Figure 19E.4.8-14
CMT Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

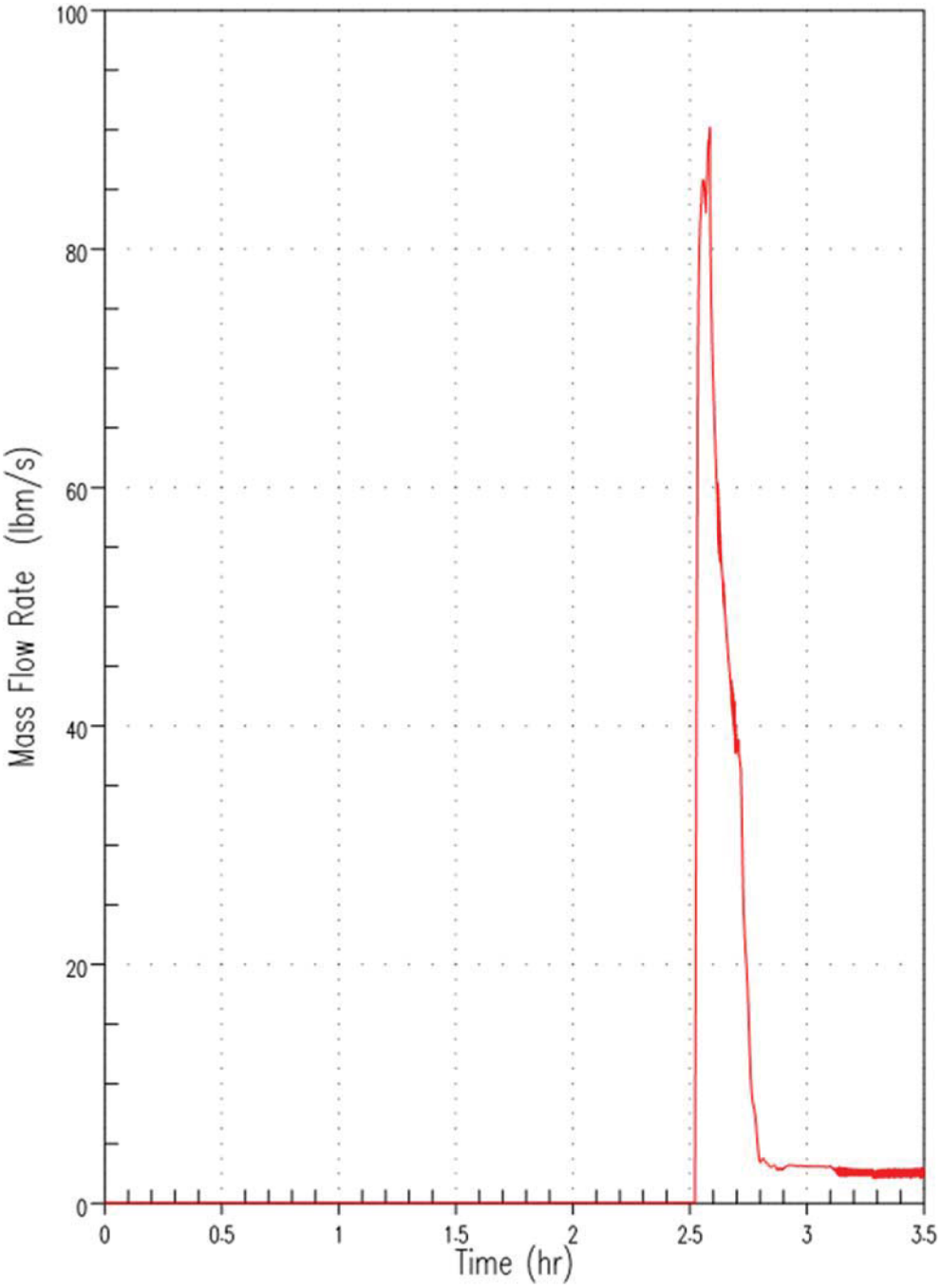

Figure 19E.4.8-15
ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

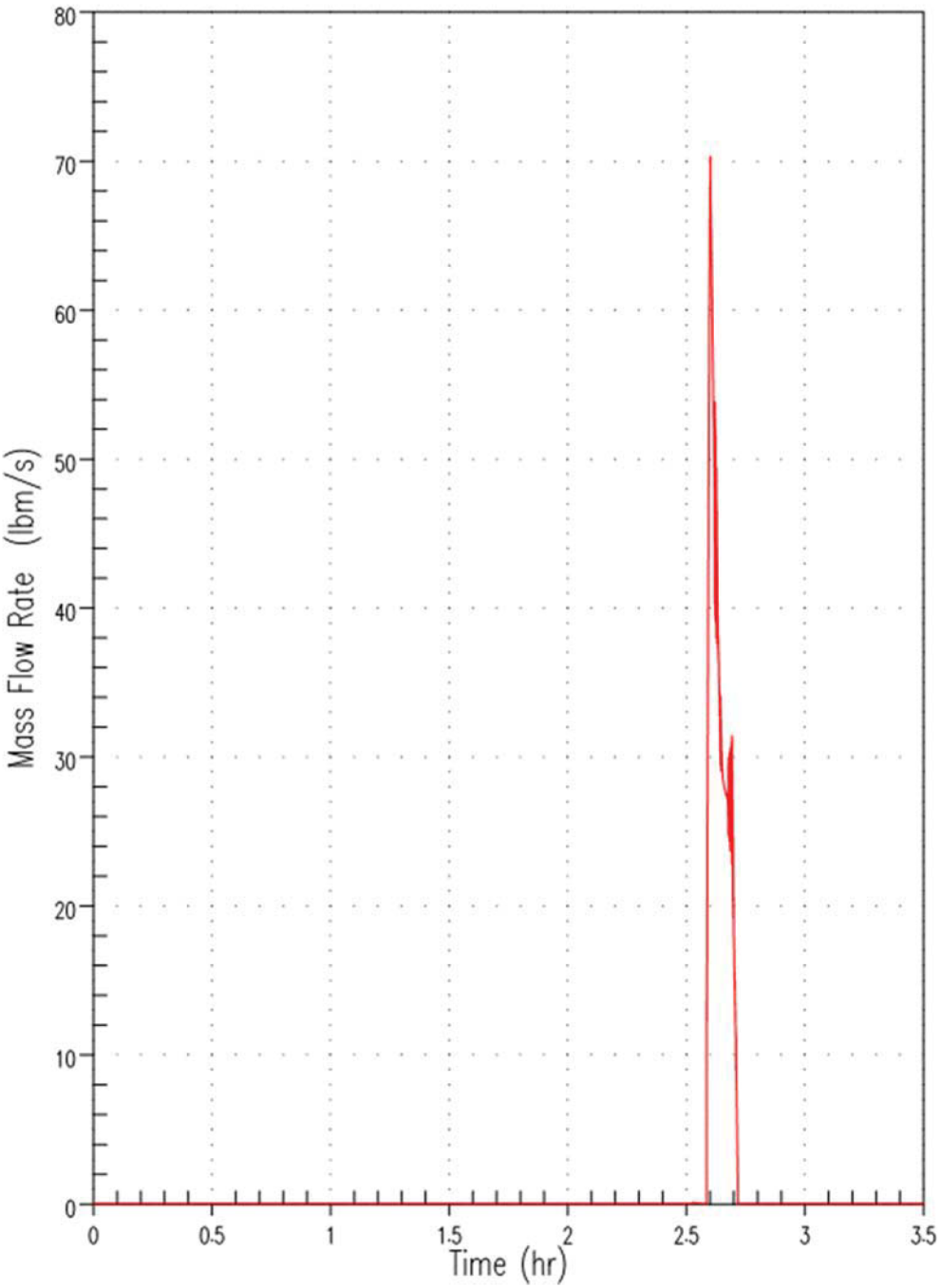

Figure 19E.4.8-16
ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

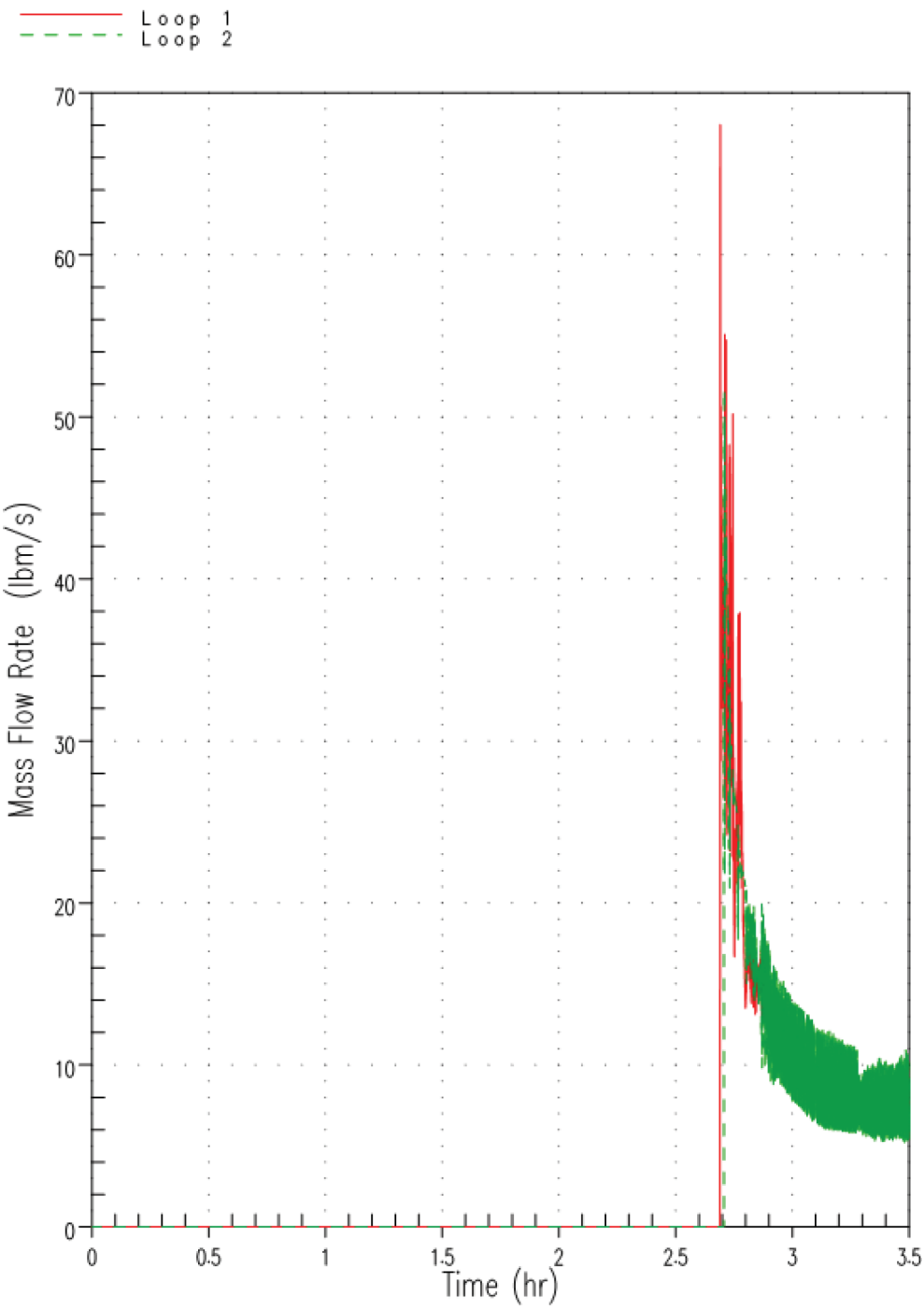

Figure 19E.4.8-17
ADS Stage 4 Vapor Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

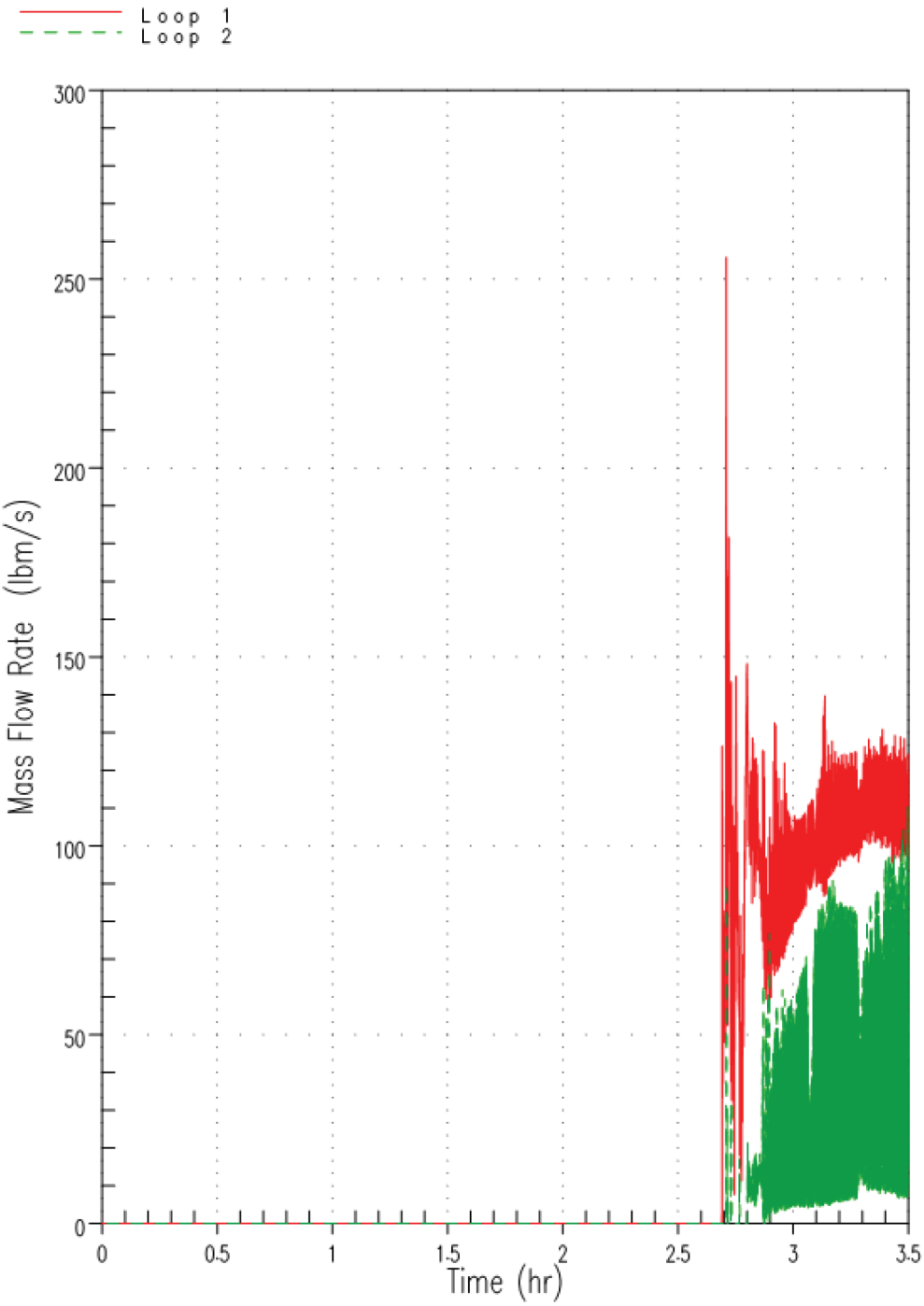

Figure 19E.4.8-18
ADS Stage 4 Liquid Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

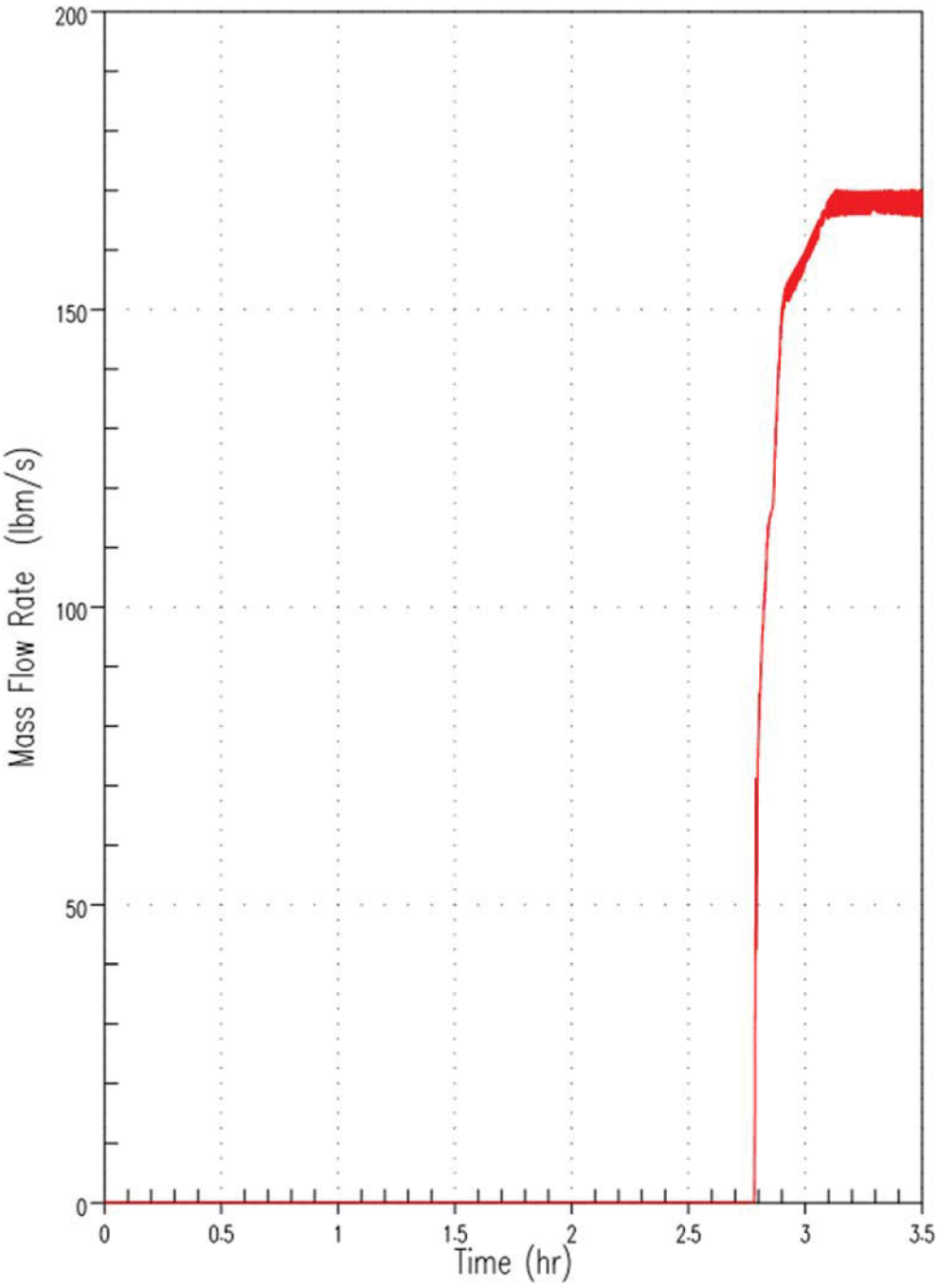

Figure 19E.4.8-19
Loop 1 IRWST Injection Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

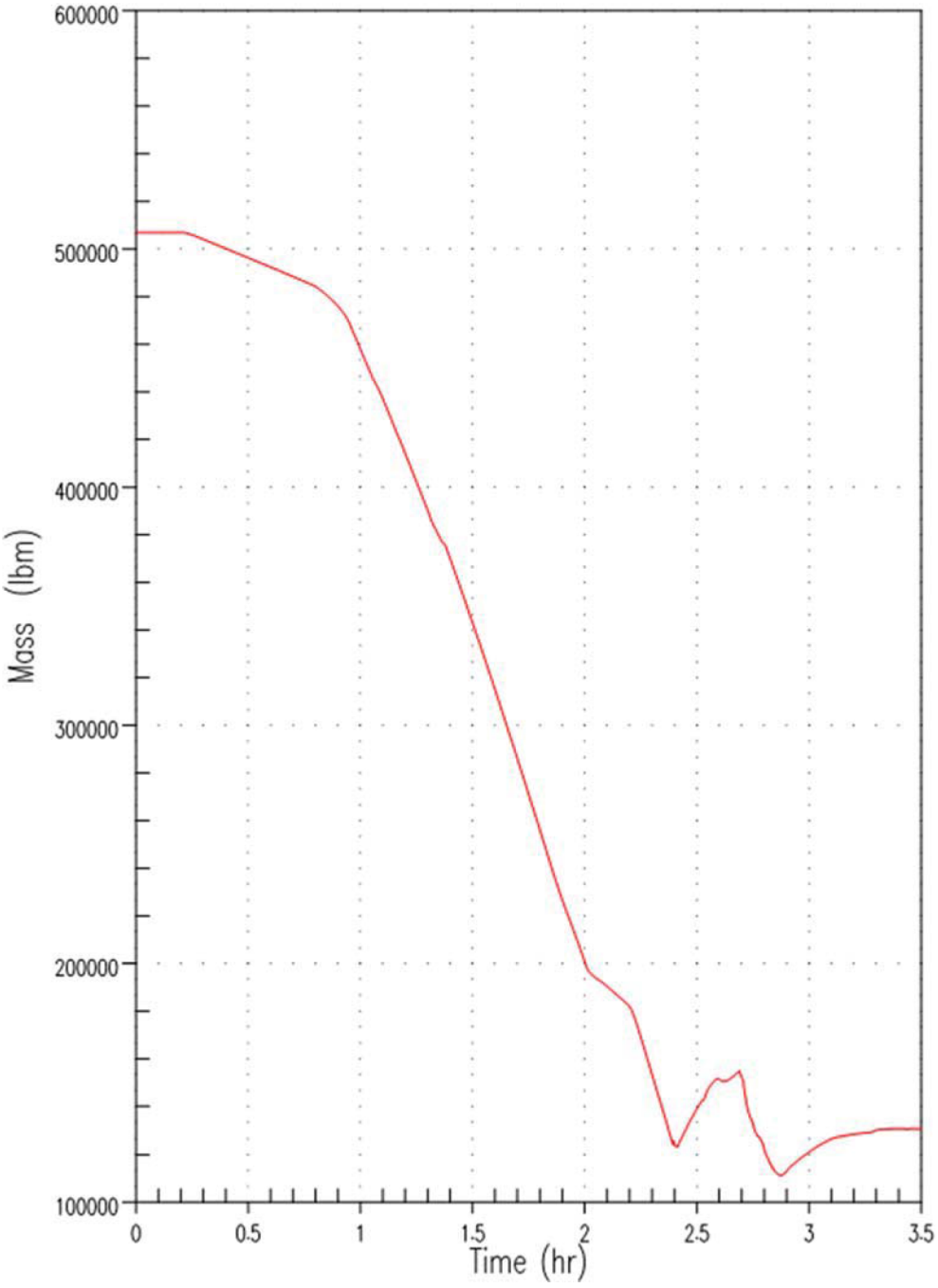

Figure 19E.4.8-20
Primary Mass Inventory, Loss of RNS in Mode 4 and Mode 5 with RCS Intact

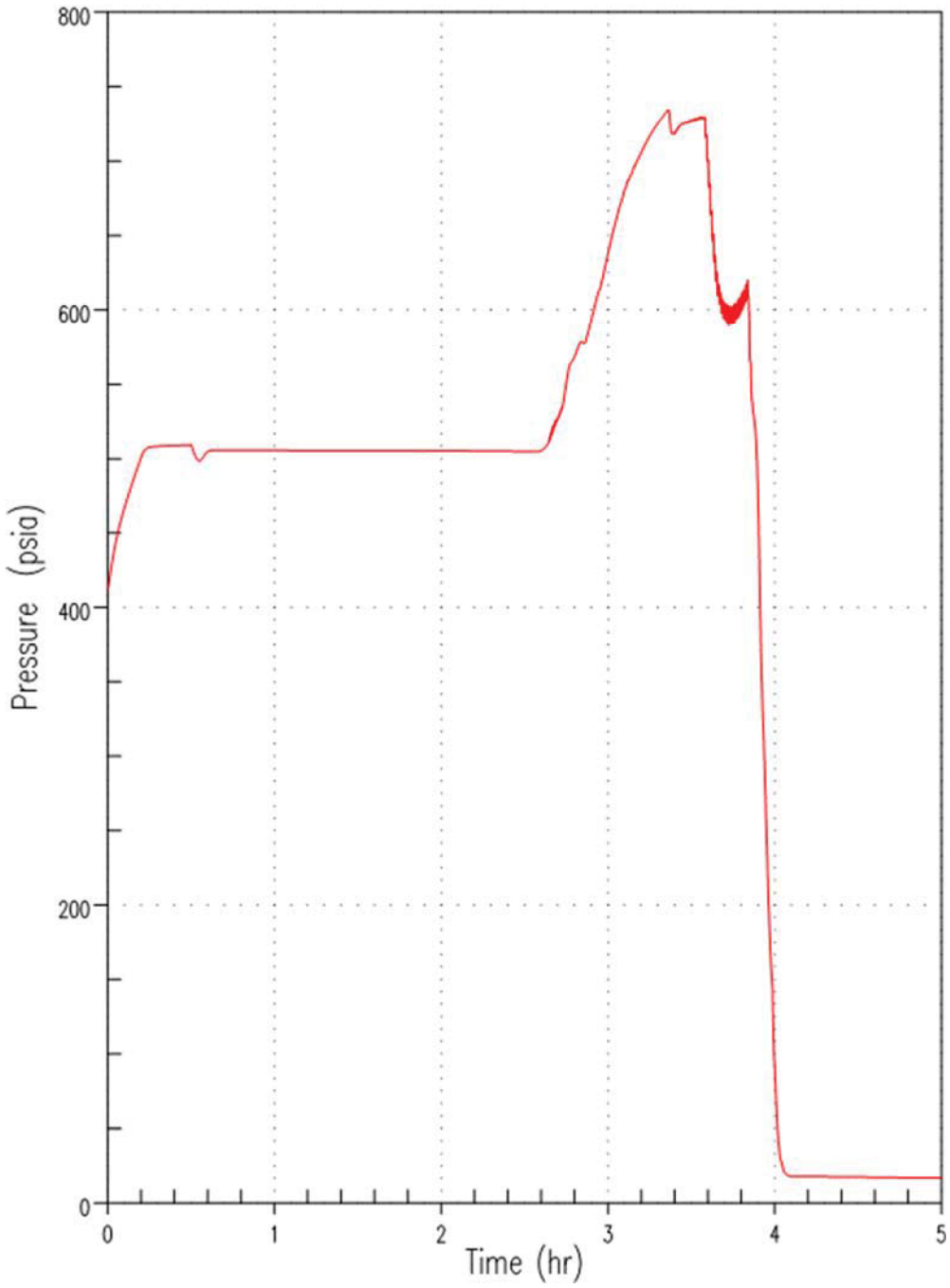

Figure 19E.4.8-21
Pressurizer Pressure, Loss of RNS in Mode 4 and Mode 5 with RCS Intact, Manual Safety System Actuation at 1800 Seconds

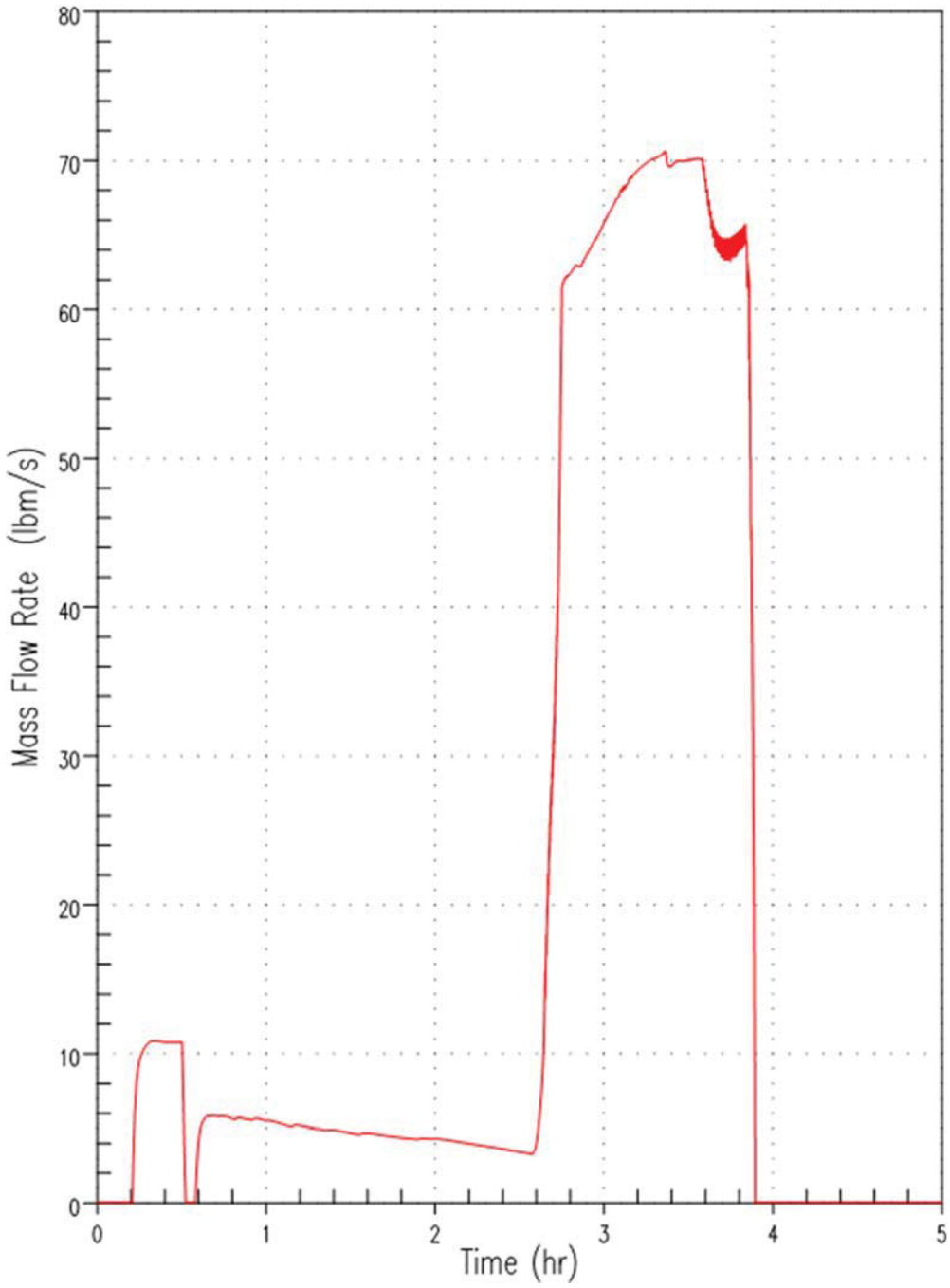

Figure 19E.4.8-22
RNS Relief Valve Flow, Loss of RNS in Mode 4 and Mode 5 with RCS Intact, Manual Safety System Actuation at 1800 Seconds

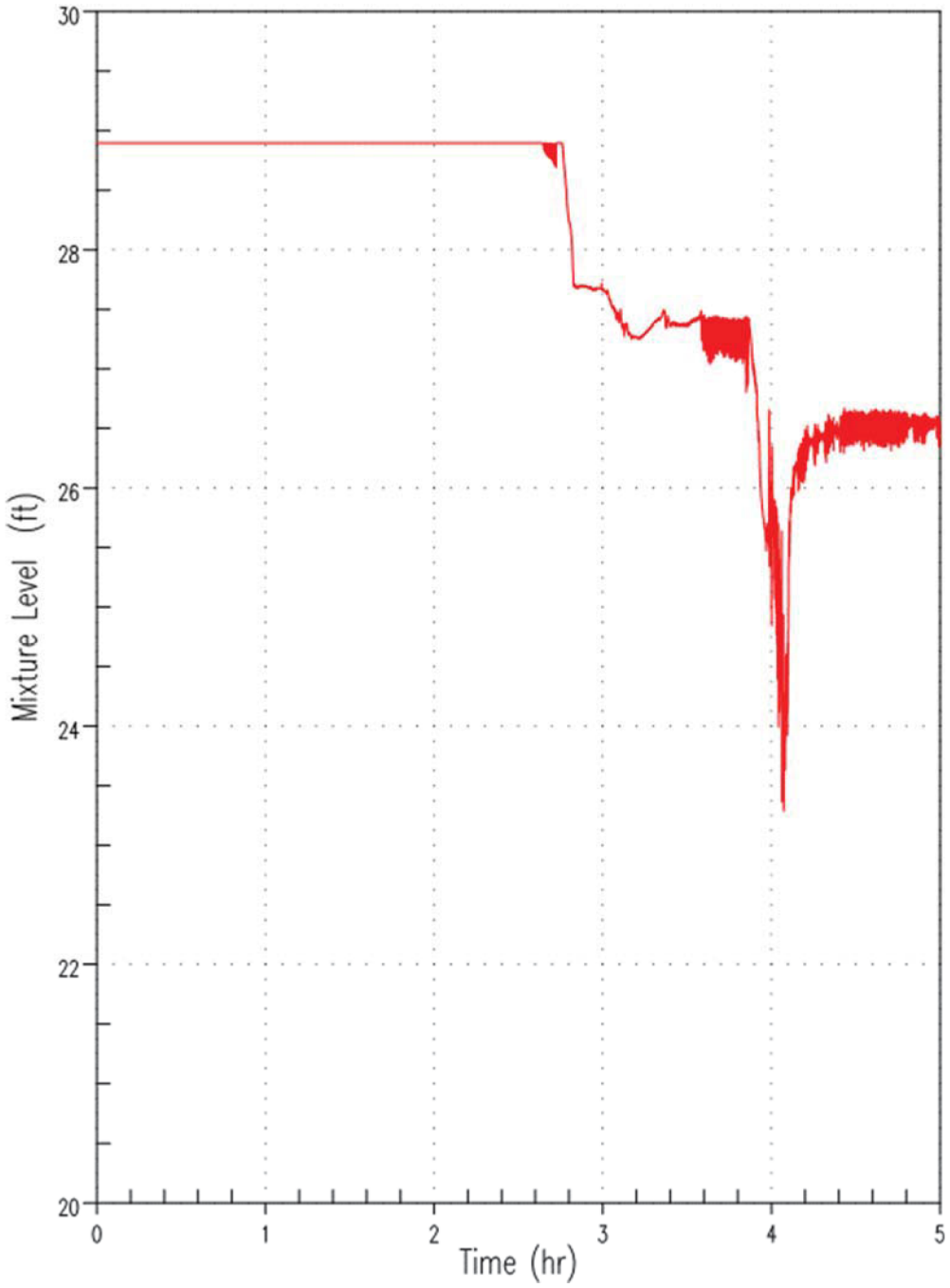

Figure 19E.4.8-23
Core Stack Mixture Level, Loss of RNS in Mode 4 and Mode 5 with RCS Intact, Manual Safety System Actuation at 1800 Seconds

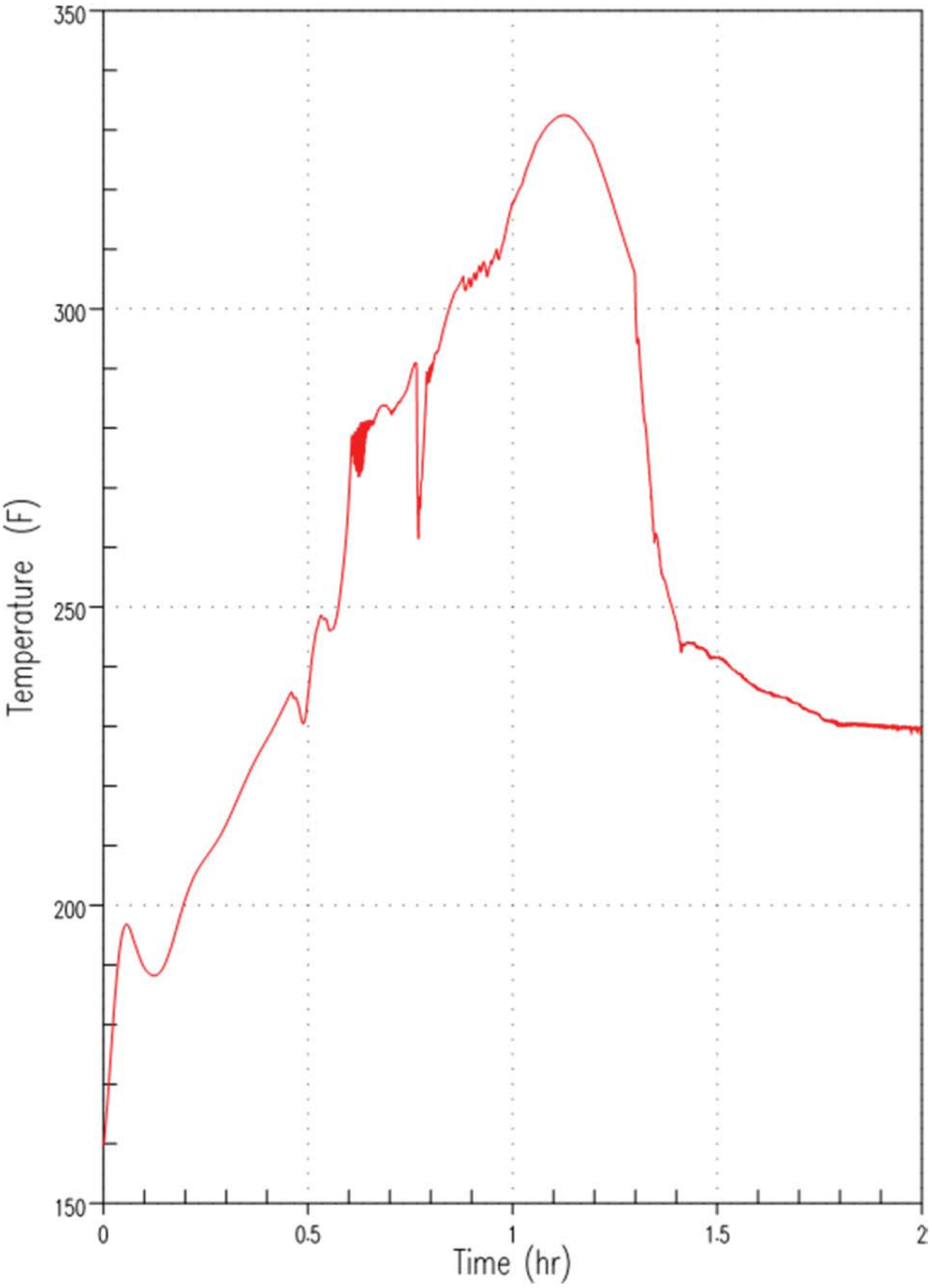

Figure 19E.4.8-24
Core Outlet Fluid Temperature, Loss of RNS in Mode 5 with RCS Open

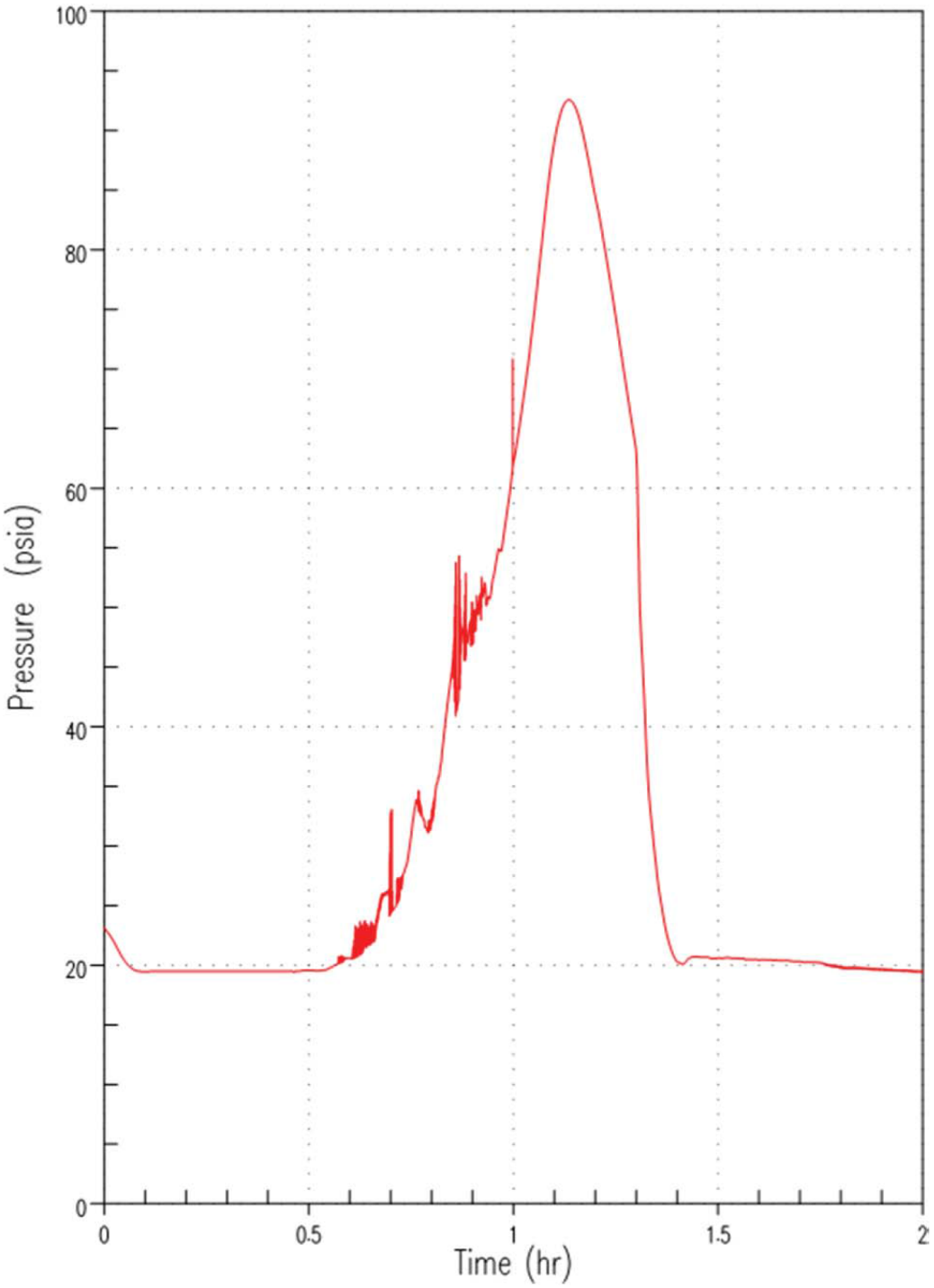

Figure 19E.4.8-25
Pressurizer Pressure, Loss of RNS in Mode 5 with RCS Open

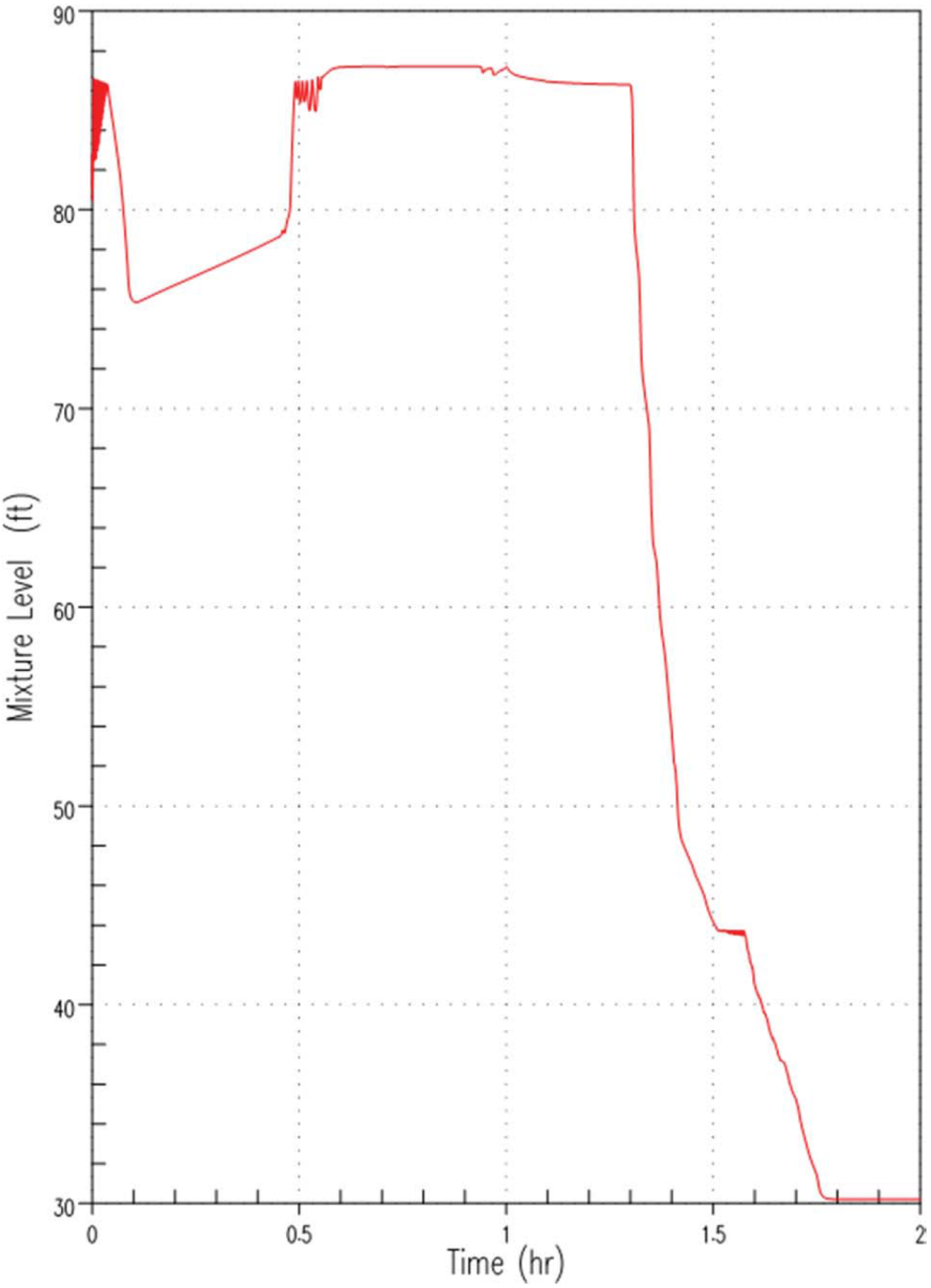

Figure 19E.4.8-26
Pressurizer Mixture Level, Loss of RNS in Mode 5 with RCS Open

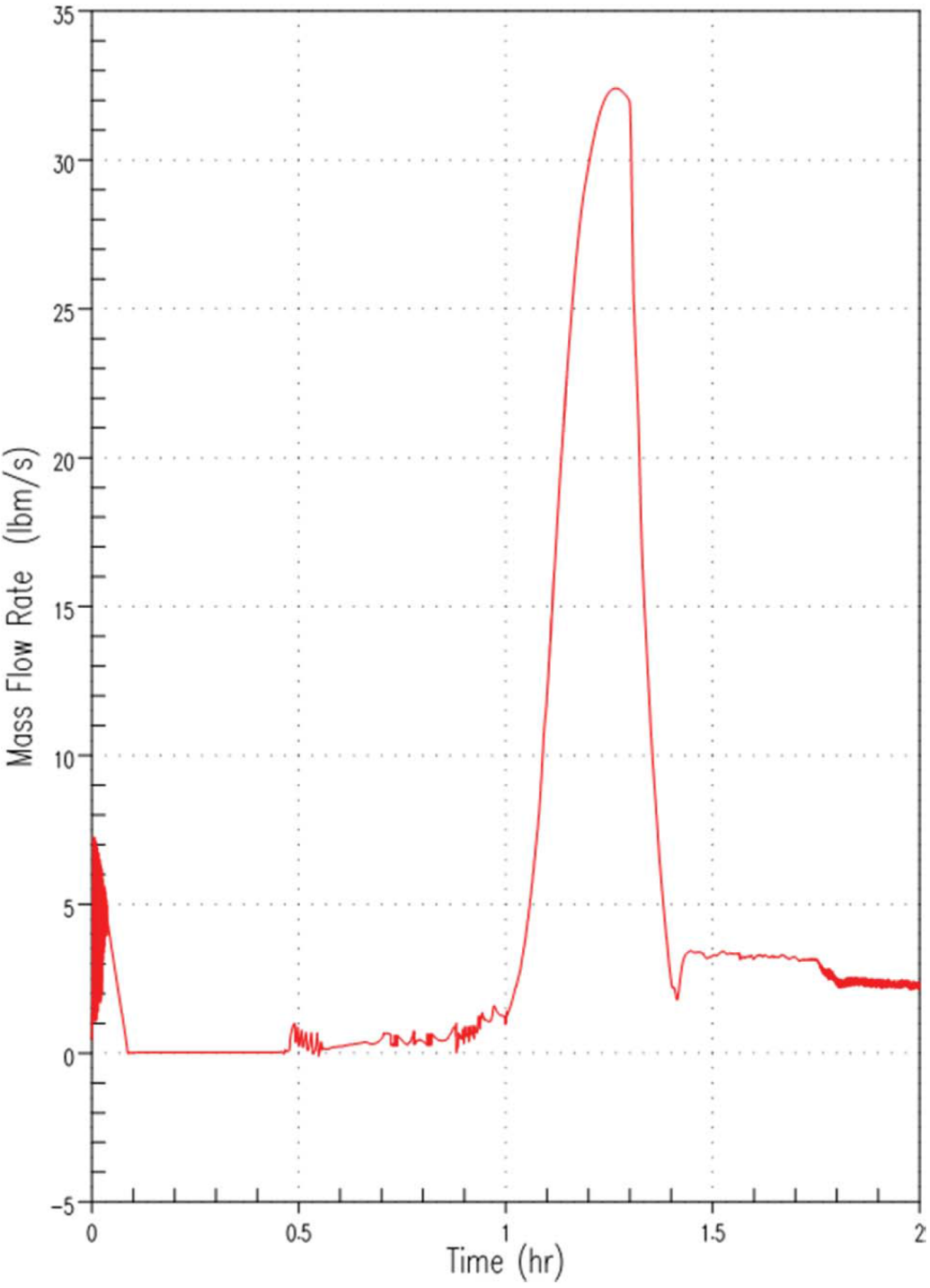

Figure 19E.4.8-27
ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 5 with RCS Open

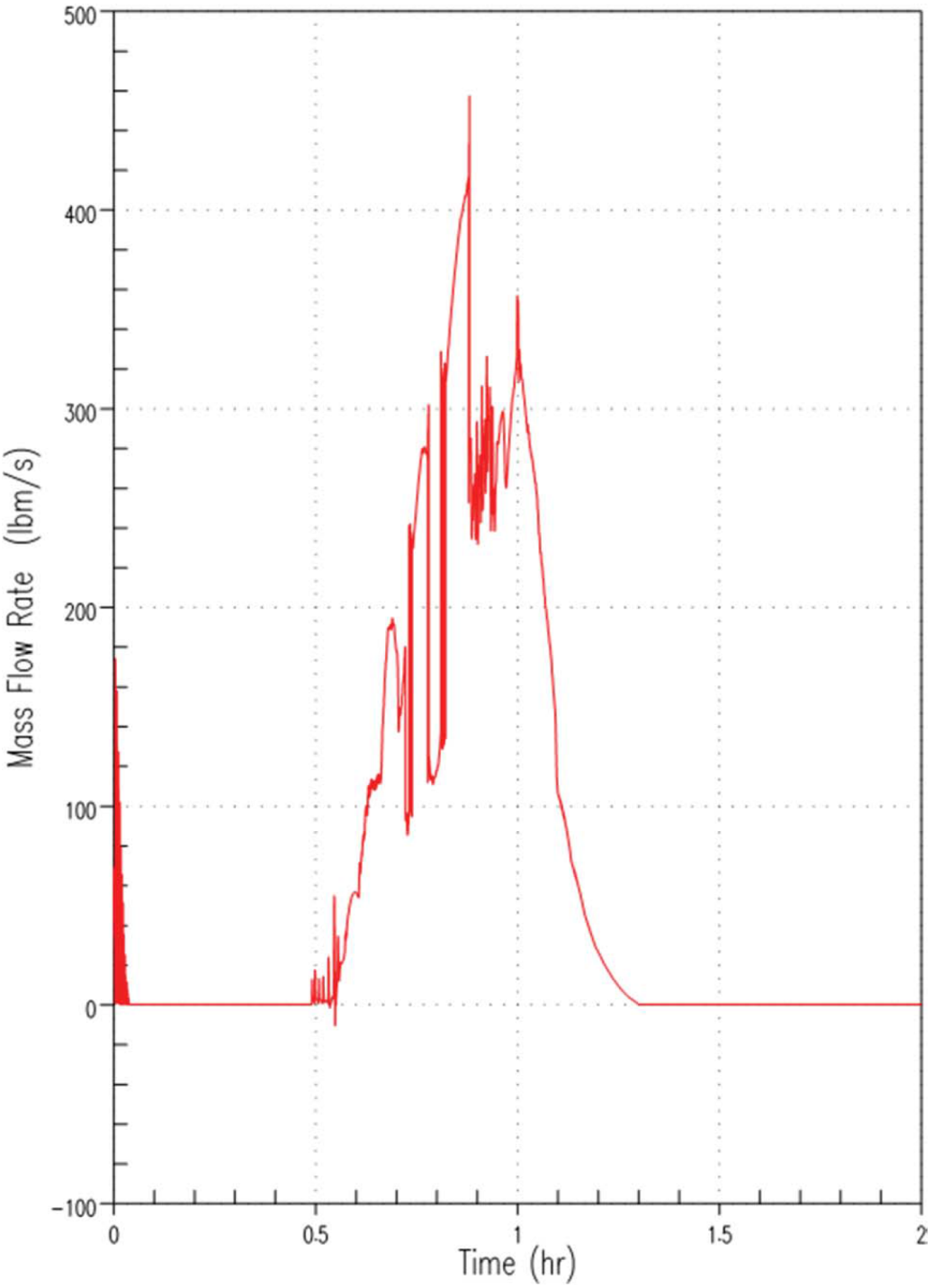

Figure 19E.4.8-28
ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 5 with RCS Open

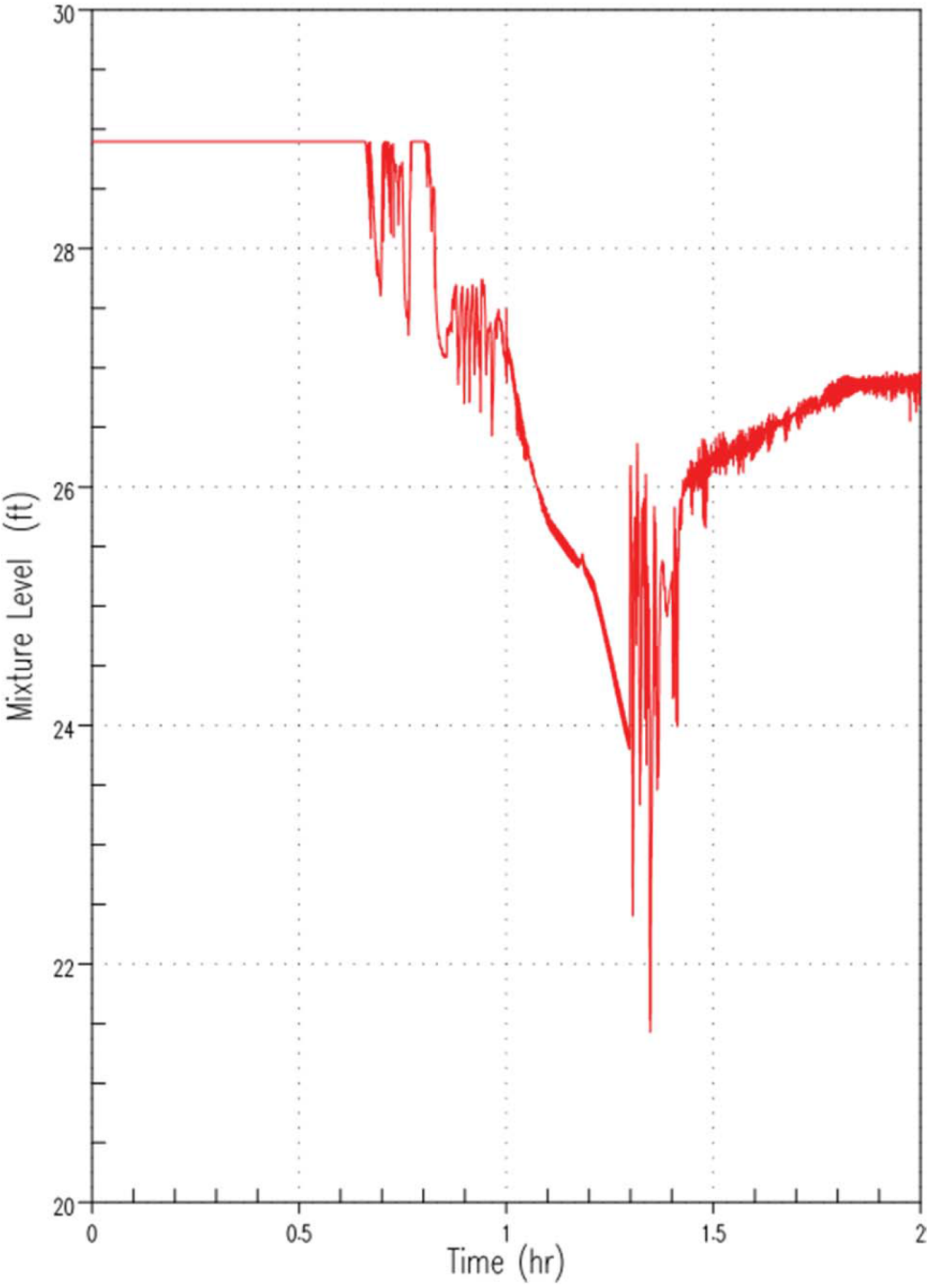

Figure 19E.4.8-29
Core Stack Mixture Level, Loss of RNS in Mode 5 with RCS Open

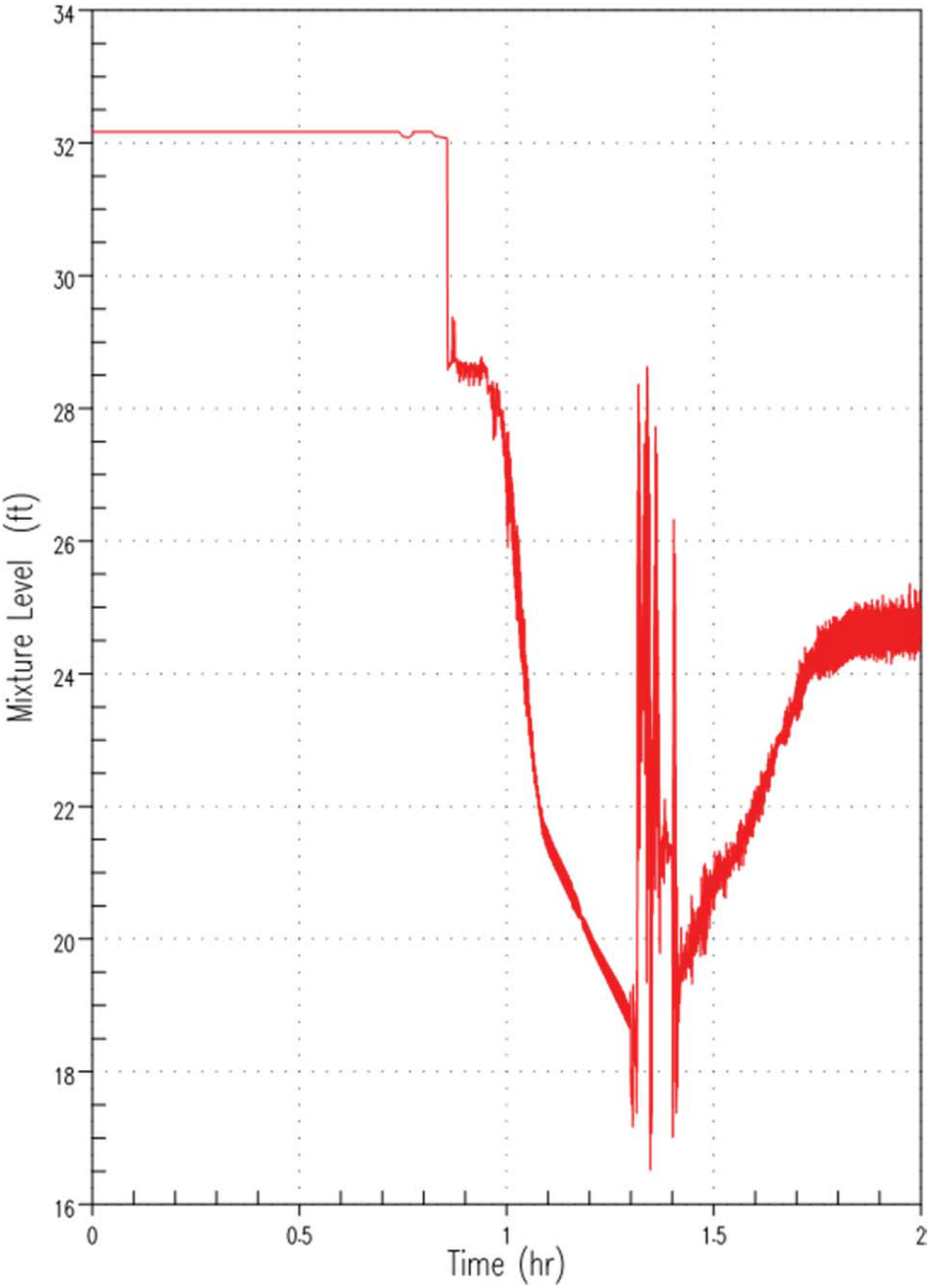

Figure 19E.4.8-30
Downcomer Mixture Level, Loss of RNS in Mode 5 with RCS Open

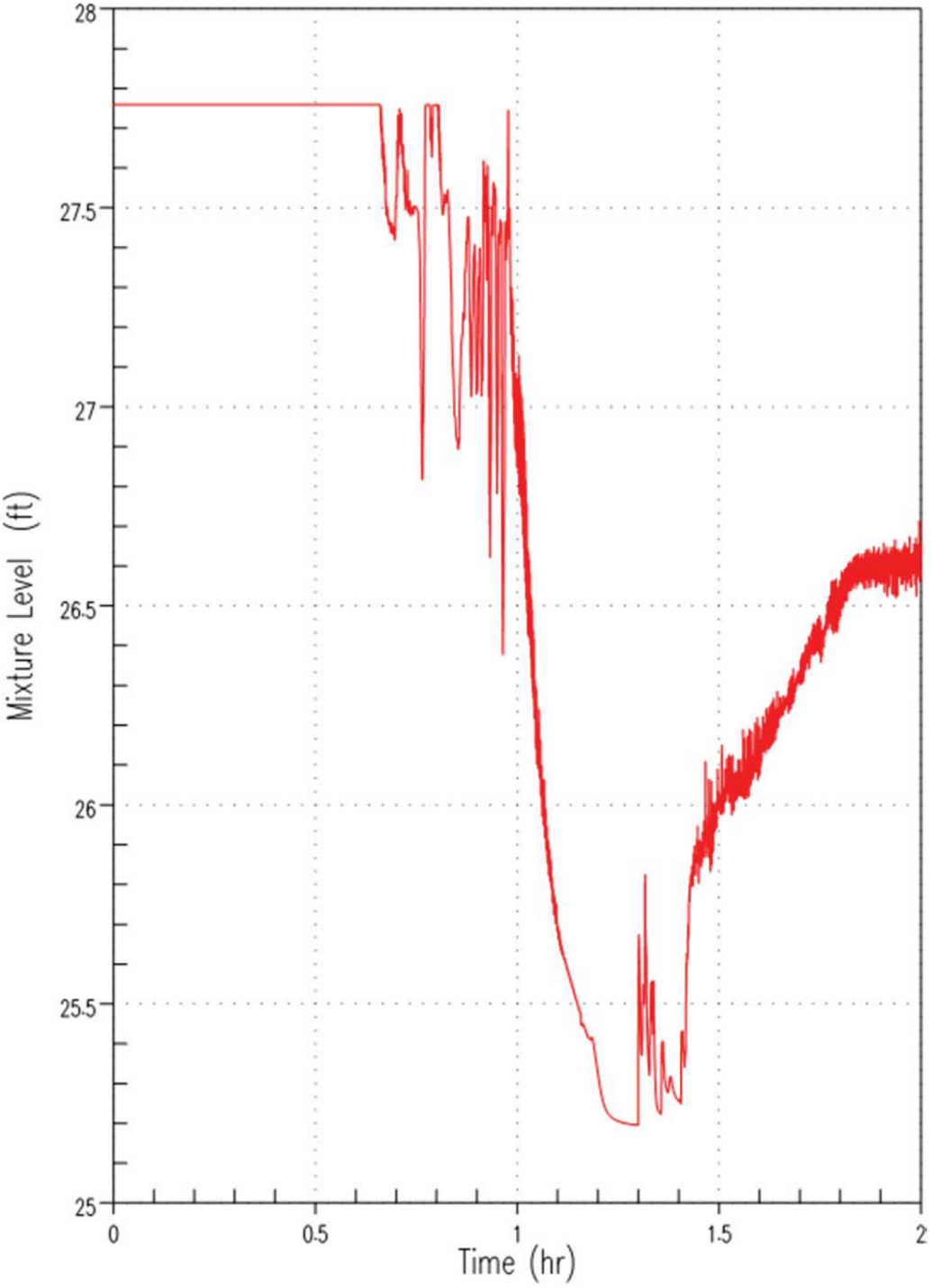

Figure 19E.4.8-31
Loop 2 Hot-Leg Mixture Level, Loss of RNS in Mode 5 with RCS Open

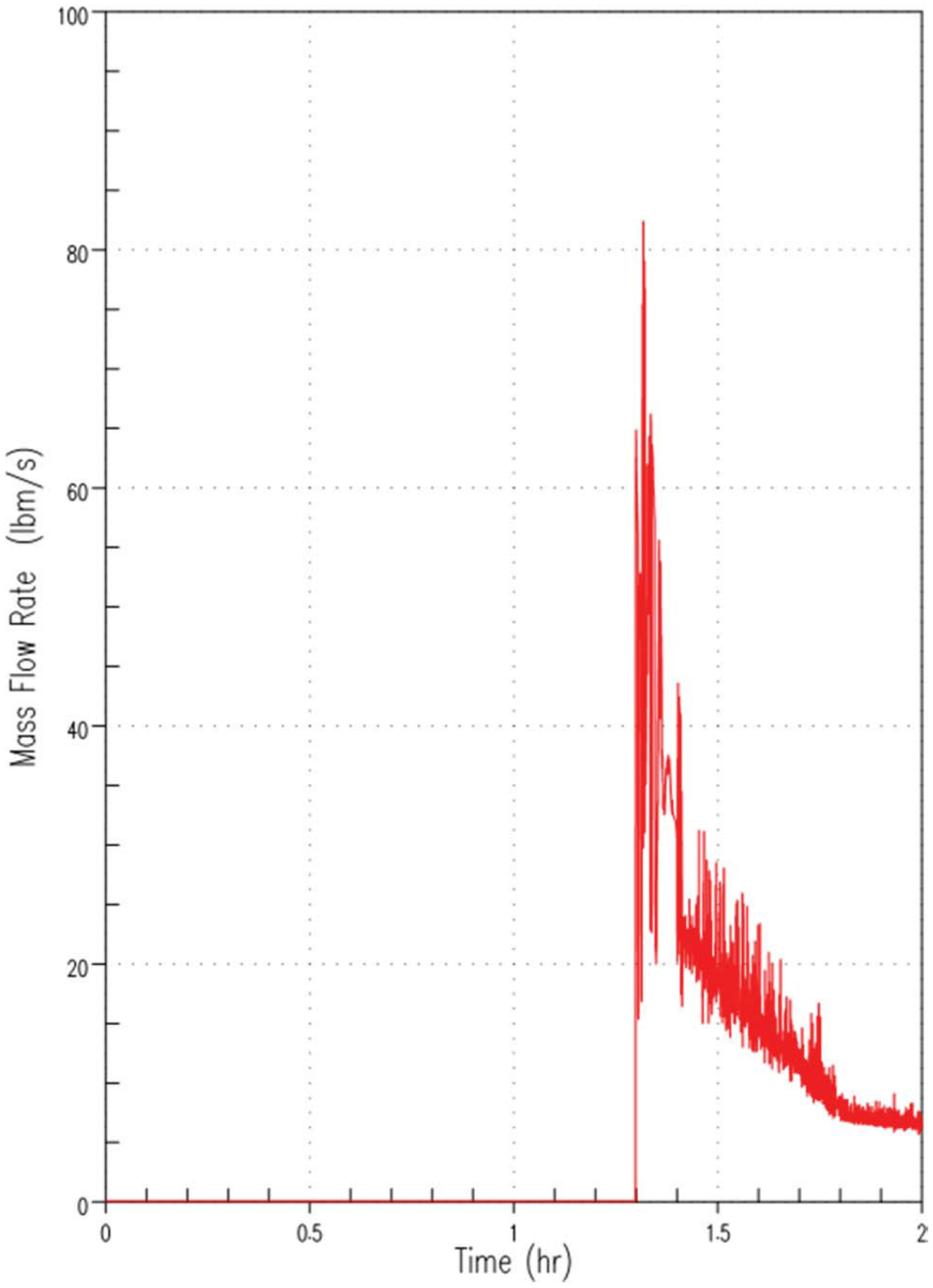

Figure 19E.4.8-32
ADS Stage 4 Vapor Flow, Loss of RNS in Mode 5 with RCS Open

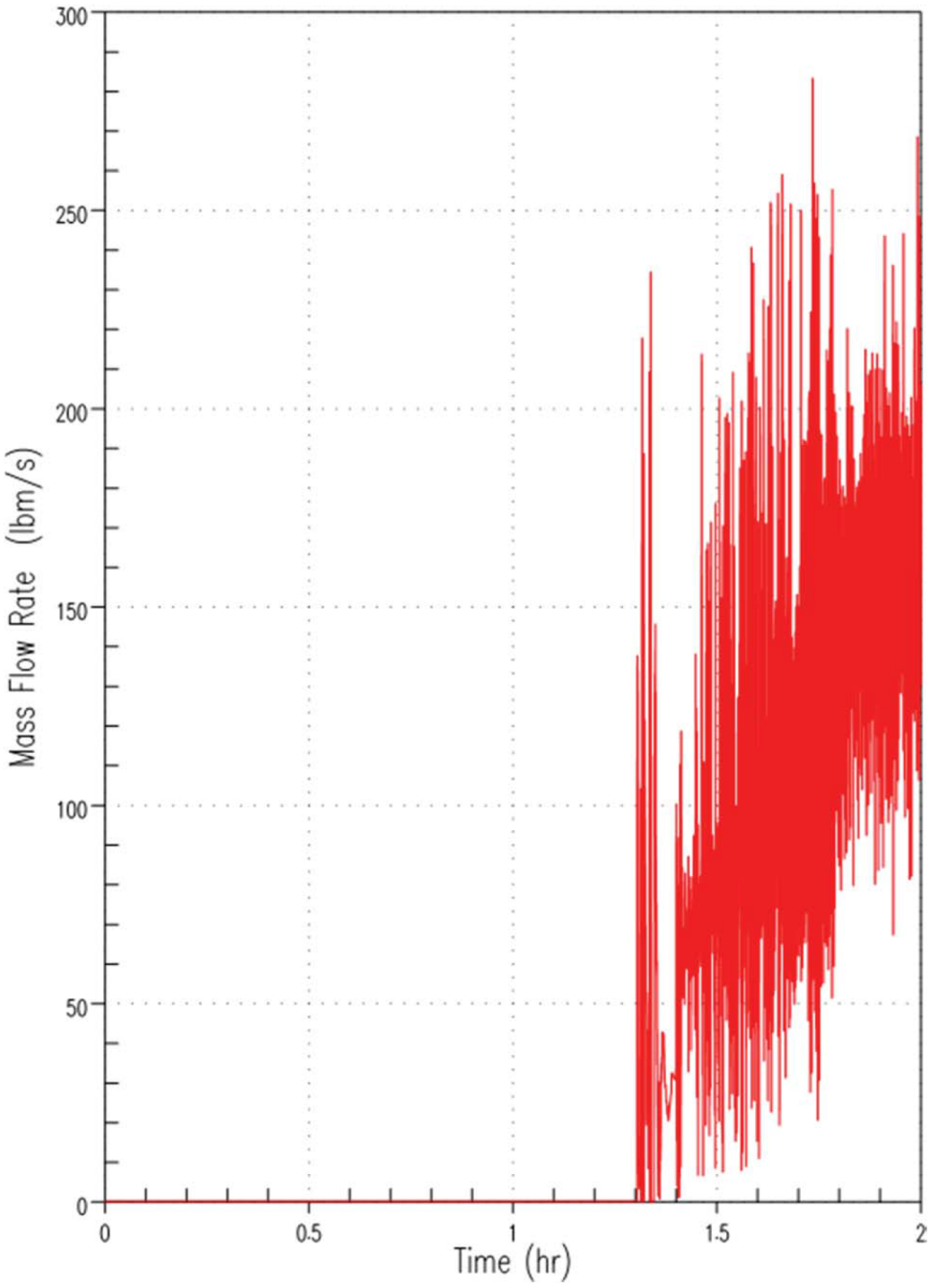

Figure 19E.4.8-33
ADS Stage 4 Liquid Flow, Loss of RNS in Mode 5 with RCS Open

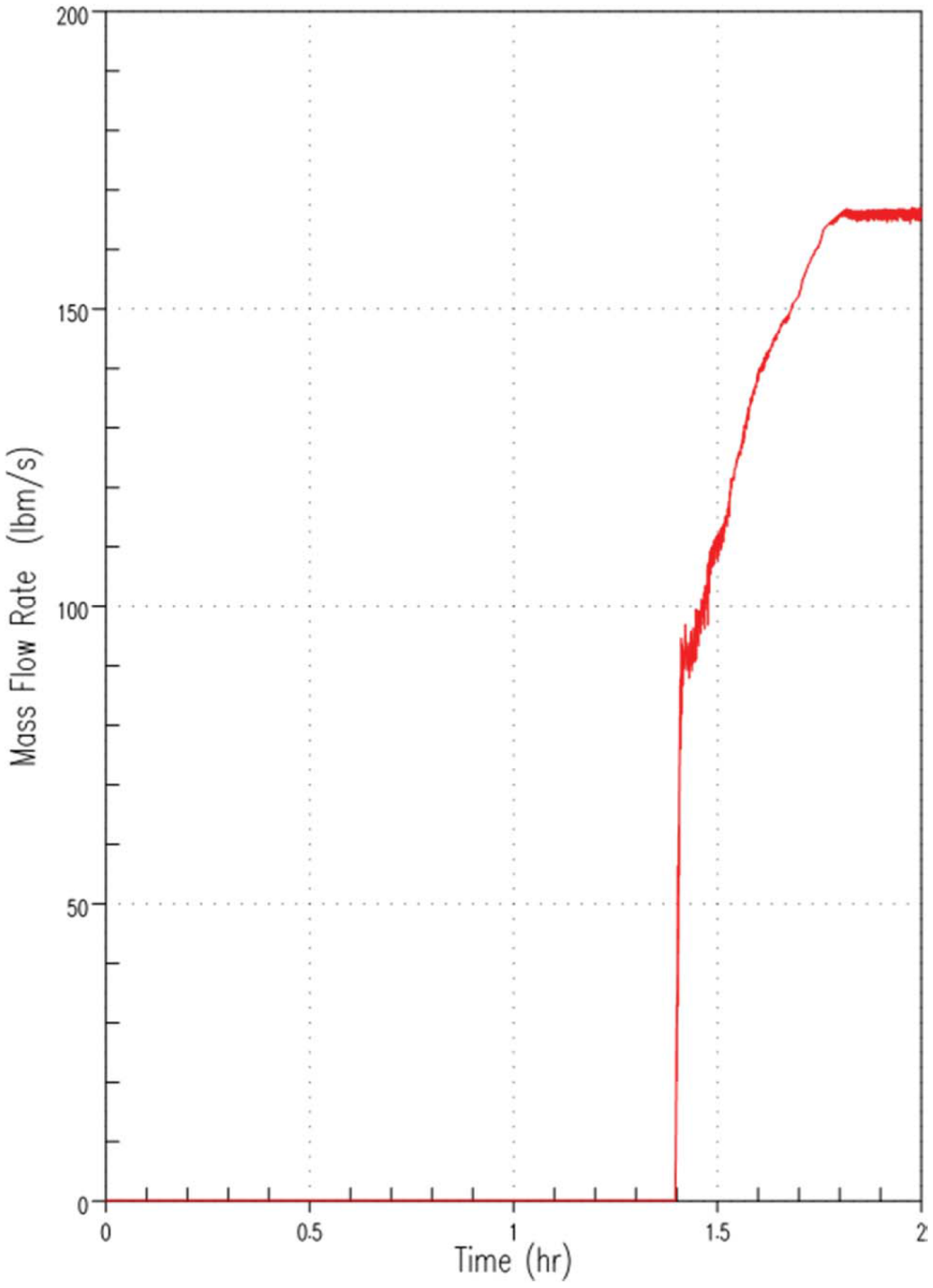

Figure 19E.4.8-34
IRWST Injection Flow, Loss of RNS in Mode 5 with RCS Open

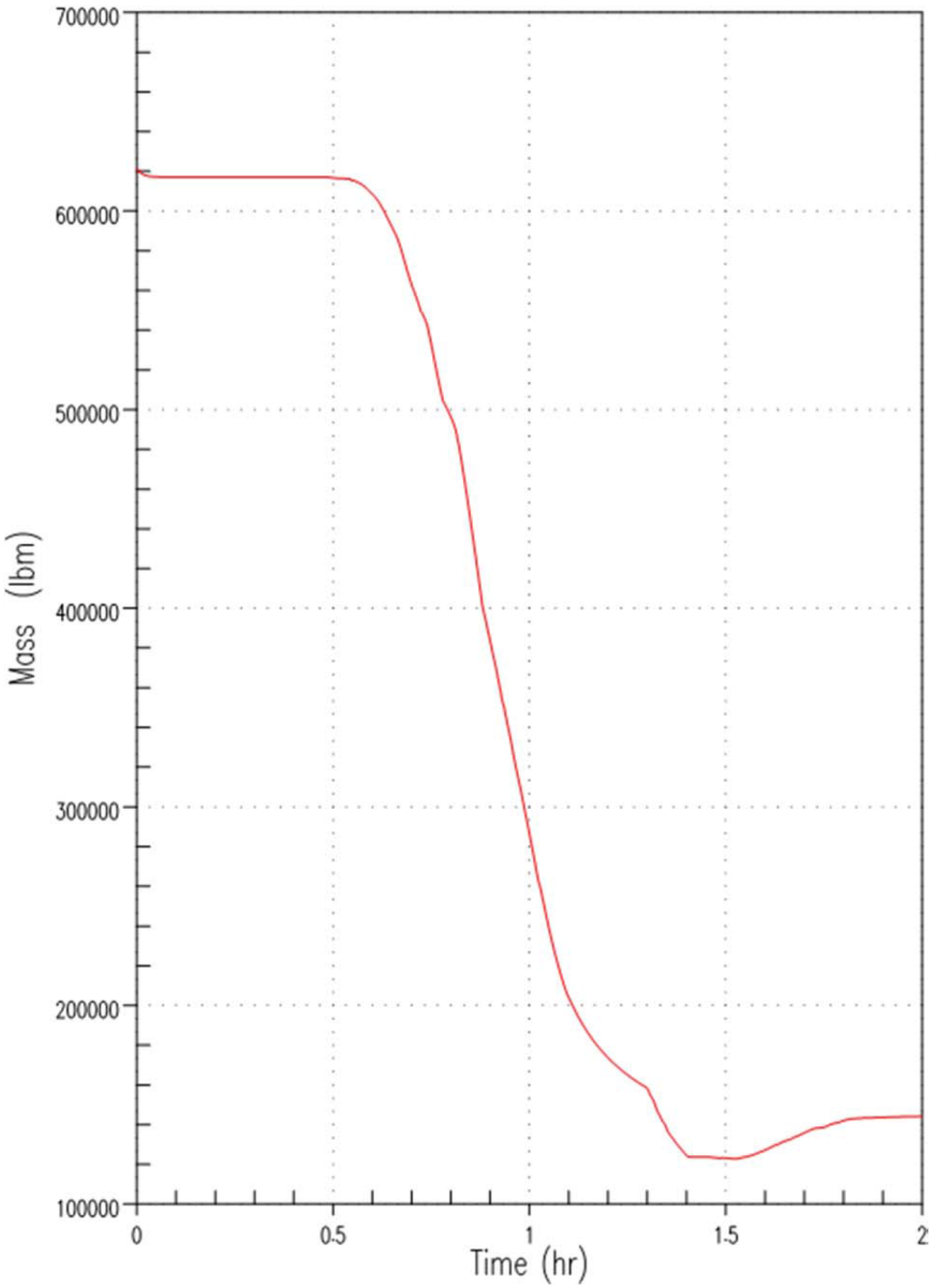

Figure 19E.4.8-35
Primary Mass Inventory, Loss of RNS in Mode 5 with RCS Open

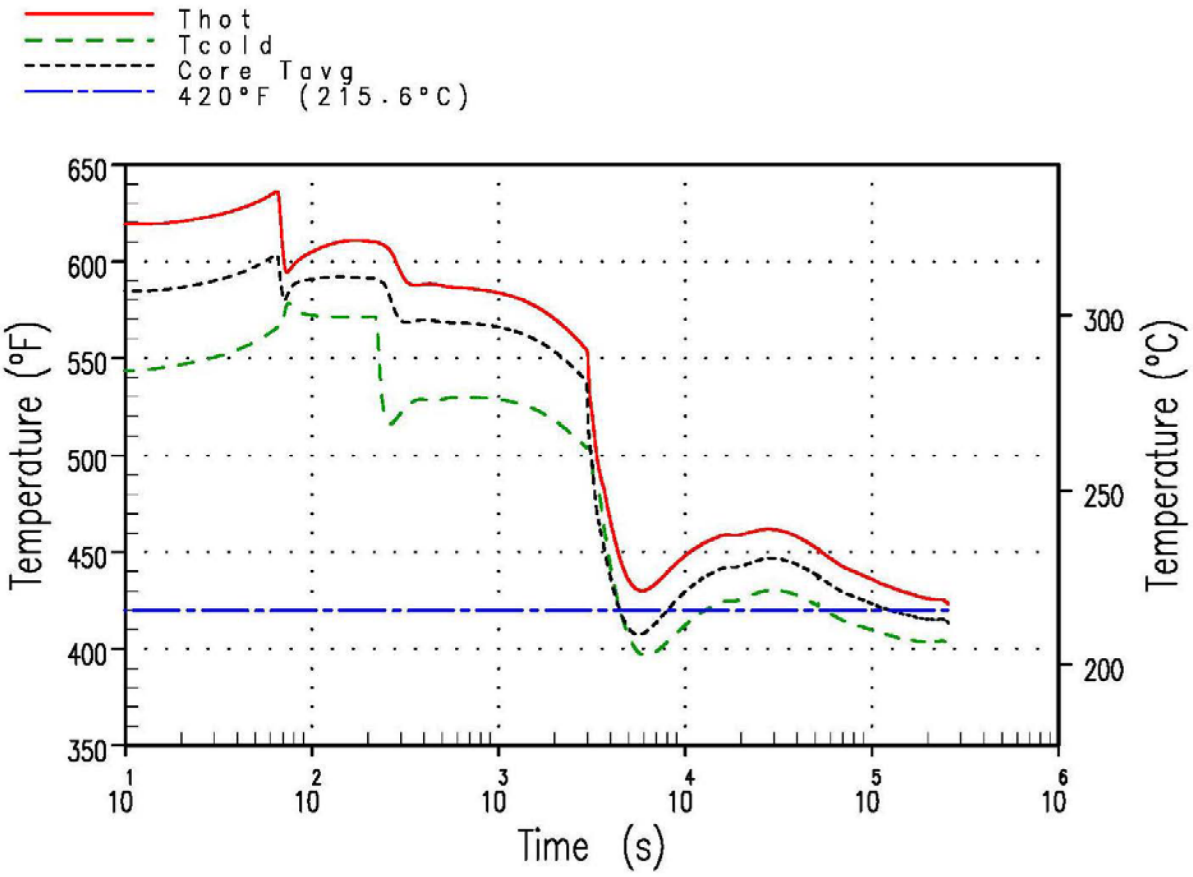

Figure 19E.4.10-1
Shutdown Temperature Evaluation, RCS Temperature

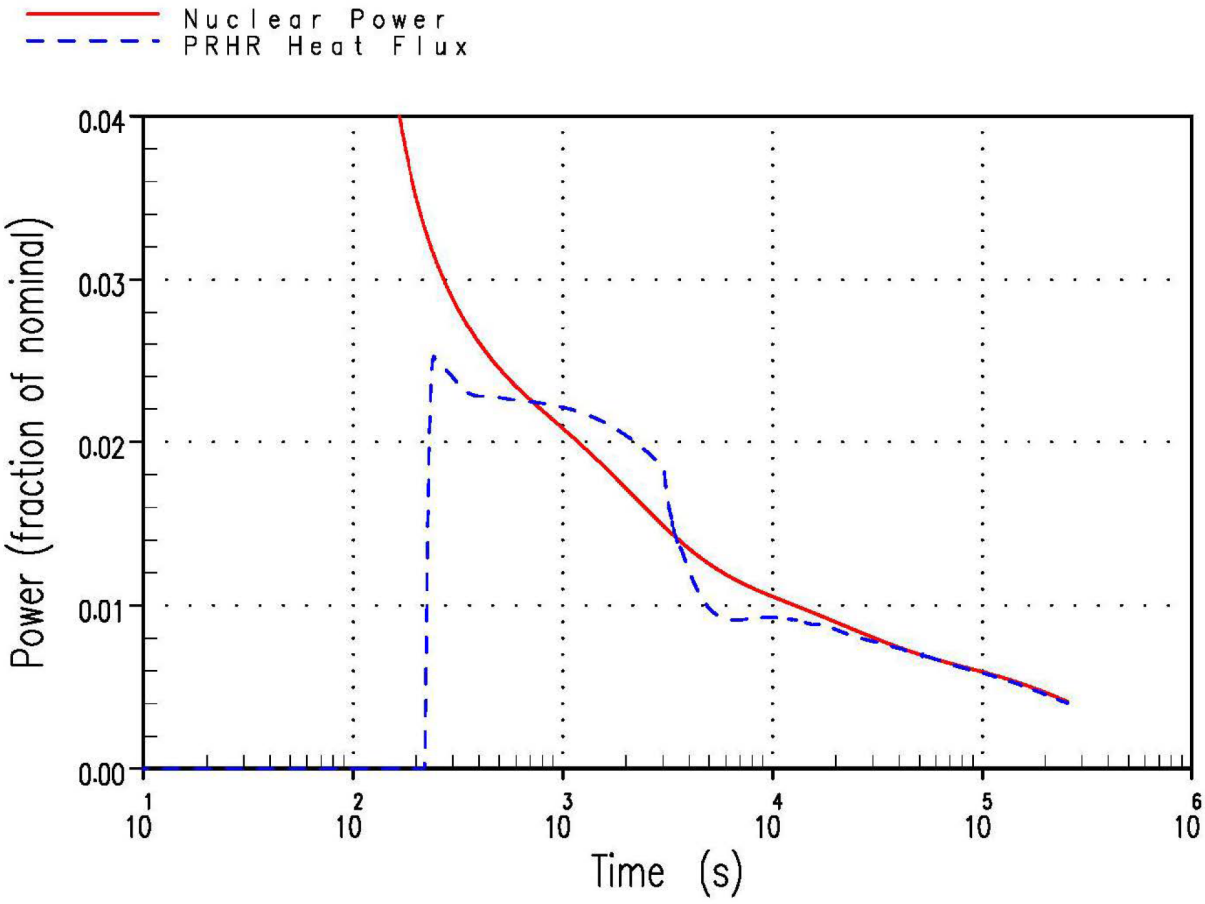

Figure 19E.4.10-2
Shutdown Temperature Evaluation, PRHR Heat Transfer

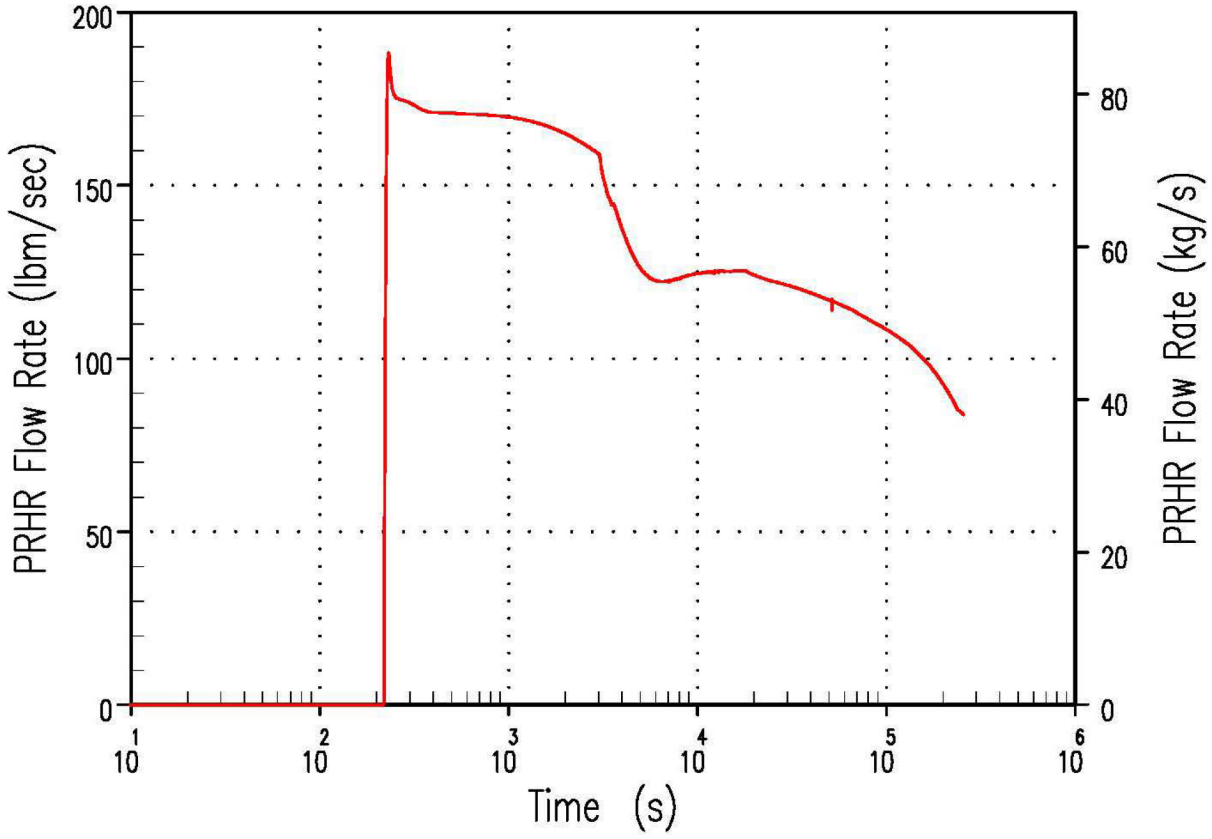

Figure 19E.4.10-3
Shutdown Temperature Evaluation, PRHR Flow Rate

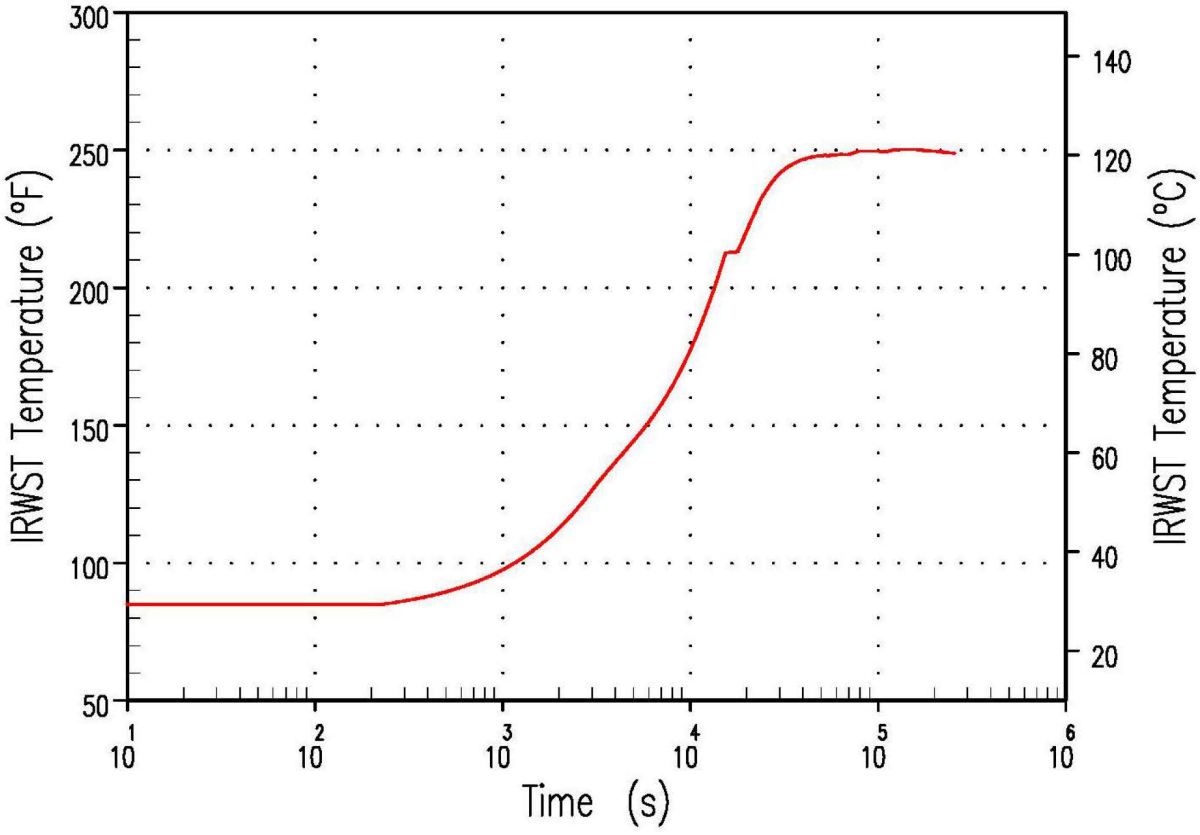

Figure 19E.4.10-4
Shutdown Temperature Evaluation, IRWST Heatup

Appendix 19F Malevolent Aircraft Impact

19F.1 Introduction and Background

A design-specific assessment of the effects on the AP1000 of the beyond design basis impact of a large commercial aircraft has been performed in accordance with 10 CFR 50.150(a) to identify design features and functional capabilities that demonstrate with reduced use of operator actions: (i) the reactor core remains cooled, the containment remains intact, and (ii) spent fuel pool integrity is maintained. The specific assumptions regarding the aircraft impact were based on guidance provided by the NRC and the Nuclear Energy Institute, including the loading function derived from the aircraft impact characteristics for use in assessments of aircraft impact effects.

This appendix describes those design features and functional capabilities identified in the assessment, and discusses how the identified design features and functional capabilities show that with reduced use of operator actions, the reactor core remains cooled and the containment remains intact, and spent fuel pool integrity is maintained. In the following discussion, the identified design features are designated as “key design features.”

19F.2 Scope

The evaluation of plant damage caused by the impact of a commercial aircraft is a complex analysis problem involving phenomena associated with structural impact, shock-induced vibration, and fire effects. The assessment of the aircraft impact also considers structural damage, such as that caused by the impact/penetration of hardened components (e.g., engine rotors, landing gear).

An assessment of the effects of aircraft fuselage and wing structure is also performed.

An assessment of the effects of shock-induced vibration on systems, structures, and components is performed.

An assessment of the impact/penetration of hardened aircraft components, such as engine rotors and landing gear is performed.

Perforation of analyzed structural components, including the containment vessel and the spent fuel pool liner, is not predicted; therefore, realistic assessments of the damage to internal systems, structures, and components caused by 1) burning aviation fuel and 2) secondary impacts are not required.

19F.3 Assessment Methodology

Methods described in NEI 07-13, Revision 7 (Reference 1) were followed to assess the effects on the structural integrity of the primary containment and spent fuel pool, and to assess the physical, fire, and vibration effects of the aircraft impact on the core cooling capability of the existing and enhanced design. In accordance with the recommendation set forth in subsection 2.4.1(3) of NEI 07-13, Revision 7, an analytical evaluation and experimental verification has been performed for the first of a kind steel-concrete modular design feature subjected to the aircraft impact loading.

19F.4 Results/Conclusions

A detailed aircraft impact assessment was performed for AP1000 in accordance with the guidance in NEI 07-13 (Reference 1). The assessment concludes that an aircraft impact would not inhibit AP1000’s core cooling capability, would not impact containment integrity, and would not impact spent fuel pool integrity based on best-estimate calculations.

The assessment resulted in the identification of the following design features and functional capabilities; changes to which are evaluated and reported in accordance with 10 CFR 50.150(d).

19F.4.1 Shield Building and Auxiliary Building

The shield building, as described in Chapter 3, is a key design feature for the protection of the safety systems located inside containment from the impact of a large commercial aircraft. The design of access openings is also a key design feature included as part of the shield building design. The assessment concludes that a strike upon the shield building would not result in perforation of the shield building so damage to the containment vessel would not occur. Therefore, the systems and equipment within the containment vessel are not damaged from the impact or from exposure to jet fuel.

The assessment finds that safety-related components inside containment, including the reactor pressure vessel and passive core cooling system, remain intact and maintain their intended capabilities following the shock-induced vibrations resulting from the impact of a large commercial aircraft based on applying the methodology in Reference 1.

This assessment also concludes that because of the structural integrity of the auxiliary building, a strike upon the auxiliary building would not result in loss of spent fuel pool liner integrity nor would it prevent the ability to manually actuate the system and equipment potentially required for core cooling. Both the structural design of the shield building and the auxiliary building, as described in Chapter 3, are considered key design features.

19F.4.2 Site Arrangement

The assessment credits the design and arrangement of certain building features, depicted in Figures 3.7.2-12 and 3.7.2-19, to limit the effects of a potential aircraft impact on the auxiliary building. These key features are as follows:

- The design of the wall along the south end of the turbine building at column line 11.2, as described in Subsection 3.7.2.8.3, is a key design feature for the protection of the auxiliary building from the impact of a large commercial aircraft.

- The design of the wall along the east side of the annex building at column line E, as depicted in Figure 3.7.2-19, is a key design feature for the protection of the auxiliary building from the impact of a large commercial aircraft.

- The design and location of the spent fuel pool in the southern portion of the auxiliary building, as depicted in Figure 3.7.2-12 and described in Subsection 9.1.2.2, is a key design feature for the protection of the spent fuel from the effects of an impact of a large commercial aircraft. The spent fuel pool is located in area 6 of the auxiliary building. The spent fuel pool liner is protected from the east, south, and west by a minimum of 7 feet, 3 inches of concrete and from the north by the location of the shield building. Therefore, the liner is not impacted and the spent fuel pool integrity is maintained.

- The locations of the main control room (MCR), remote shutdown station, and secondary diverse actuation system (DAS) panels are a key design feature for the protection against the physical and fire damage resulting from the impact of a large commercial aircraft. The detailed aircraft impact assessment shows that an aircraft impact cannot destroy all three of these locations due to the number of barriers associated with these locations. The main control room is located in room 12401, the remote shutdown station is located in room 12303, and the secondary DAS panels are located in room 12554. The assessment determined that any impact scenario would not destroy all three of these locations, and from any one of these locations, passive safety injection and recirculation for long-term core cooling can be initiated.

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- The design of the five oversized doors located on the east wall of room [ ]SRI, the east wall of room [ ]SRI, the shield building wall on the west side of room [ ]SRI, east wall of room [ ]SRI and the shield building wall on the west side of room [ ]SRI are key design features for the protection against the physical and fire damage resulting from the impact of a large commercial aircraft. These doors and their connections to the walls are considered key design features because they are designed with a thickness that provides impact resistance equivalent to that of the wall. The doors at the east wall of room [ ]SRI, the shield building wall on the west side of room [ ]SRI, east wall of room [ ]SRI, and the shield building wall on the west side of room [ ]SRI are normally thicker than what is required for impact resistance due to radiation shielding. The door on the east wall of room [ ]SRI is calculated to have a thickness of at least 5" steel to meet the impact resistance requirement. The walls are considered key design features for protecting containment integrity and core cooling.

19F.4.3 Core Cooling and Containment Integrity

If necessary, core cooling can be maintained by actuating the passive safety injection portion of the Passive Core Cooling System (PXS) and Reactor Coolant System (RCS) as described in Section 6.3. The portions of the PXS and RCS required for safety injection are located inside containment and are key design features. Their location protects them from damage due to an aircraft impact because the containment vessel remains intact and has no structural damage. The following valves are key design features and need to actuate for passive safety injection and recirculation for long-term core cooling:

- ADS Stage 4 squib valves, RCS-V004A/B/C/D (3 of 4)
- In-containment refueling water storage tank (IRWST) injection line squib valves, PXS-V123A/B and PXS-V125A/B (1 of 4)
- Recirculation line squib valves, PXS-V118A/B and PXS-V120A/B (1 of 4)

The steel containment vessel is protected by the shield building and is a key design feature. Based on beyond design basis calculations, the steel containment vessel is not impacted as a result of an aircraft impact on the shield building. If necessary, containment integrity is maintained by portions of the Passive Containment Cooling System (PCS). Containment integrity is maintained via air-only cooling by the passive containment cooling system. As discussed in Section 19.17, with air-only cooling (without design basis cooling), containment failure within 24 hours is predicted to be highly unlikely.

For design basis accidents, containment cooling is provided by water cooling of containment. Water cooling is distributed onto the containment vessel by the PCS water distribution bucket located above the containment vessel. Although the water distribution bucket is predicted to be unnecessary following an aircraft impact, an assessment has been performed on the water distribution bucket and predicts the support structure to be intact.

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19F.4.4 Reactor Trip

The reactor trip equipment is a key design feature. This equipment includes the sensors and manual inputs, protection and safety monitoring system cabinets, and reactor trip switchgear as described in Subsection 7.2.1. In the event of an aircraft impact, it is likely that ac power will be lost. On a loss of ac power, the control rods are de-energized and fall by gravity into the reactor core. If ac power is not lost, plant shutdown will be controlled by the intact protection and safety monitoring system or initiated manually from the main control room, remote shutdown room, or reactor trip switchgear. Additionally, if PMS is not intact as a result of the impact, the reactor trip breakers will open due to undervoltage. This results in the control rods being de-energized and falling into the reactor core. If the reactor trip switchgear or rod drive motor-generator sets are not intact, the rods also are de-energized and fall by gravity into the reactor core.

19F.4.5 Supporting Power, Instrumentation, and Control Equipment

The supporting equipment for the main control room, remote shutdown station, and secondary DAS panels are key design features. These include the class 1E batteries, the supporting PMS control and instrumentation cabinets and cabling for the equipment identified in Subsection 19F.4.3, the transfer switch to isolate the MCR and transfer controls to the remote shutdown room, and the DAS cabling for the DAS Processor Cabinet 1, Processor Cabinet 2, and Squib Valve Control Cabinet, which are referred to as the DAS secondary panels. These key design features enable the actuation of safety injection through operation of the squib valves. The functional capabilities of the secondary DAS panels are described in Subsection 7.7.1.11. These key design features are protected by their spatial separation as described in Subsection 19F.4.2.

19F.4.6 Fire Barriers

The design and location of 3-hour fire barriers within the auxiliary building are key design features for the protection of equipment needed to manually actuate the systems and equipment potentially required for core cooling following the impact of a large commercial aircraft. The assessment credited the design and location of fire barriers (including doors), as described in Appendix 9A, to limit the effects of fire damage created by the impact of a large commercial aircraft. Penetrations through

specific barriers in the auxiliary building are rated to withstand a differential pressure of 5 psid based on the methodology in Reference 1. These barriers are identified in Subsection 9.5.1.2.1.1.

19F.5 References

1. NEI 07-13, Revision 7, “Methodology for Performing Aircraft Impact Assessments for New Plant Designs.”